- A nonrated penetration of structural steel to Zone 22-C-2 with sheet metal covers. (Ref. 6.9)

Floor/Ceiling:

- 3-hour barrier.
- Duct penetrations without a fire damper communicate from Fire Zone 24-E (above) to Fire Area 22-C below. (Ref. 6.8)

2.0 COMBUSTIBLES

2.1 Floor Area: 150 ft^2

2.2 In situ Combustible Materials

- Bulk Cable
- Polyethylene
- Plastic
- Rubber

2.3 Transient Combustible Materials

Transient combustible materials are strictly controlled in accordance with procedure OM8.ID4 and Engineering Calculation M-824. Below is a listing of reasonably expected transient combustible materials:

- Clothing/Rags
- Lubricants
- Miscellaneous Class A & B combustibles
- Solvents
- Wood
- Plastic
- Paper

2.4 Fire Severity

- Low

3.0 FIRE PROTECTION

3.1 Detection

- Smoke detection is provided.

3.2 Suppression

- CO_2 hose stations and portable fire extinguishers are available in the vicinity.

4.0 SAFE SHUTDOWN FUNCTIONS

4.1 Diesel Fuel Oil System

Diesel fuel oil pump 0-1 may be lost due to a fire in this area. Redundant diesel fuel oil pump 0-2 remains available.

4.2 Emergency Power

A fire in this area may disable diesel generator 2-2. Offsite power is not affected in this area and will remain available for safe shutdown. In addition, diesel generators 2-1 and 2-3 will remain available for safe shutdown.

4.3 HVAC

A fire in this area may affect one train of required HVAC equipment (S-67). S-67 is not necessary for a fire in this area.

5.0 CONCLUSION

The following fire protection features will mitigate the consequences of a design basis fire and assure the capability to achieve safe shutdown:

- Deviations to requirements for 3-hour boundaries have been documented in the referenced Appendix R exemptions and engineering evaluations. These references verify that the subject boundaries are capable of maintaining adequate separation between redundant components to assure safe shutdown.

- CO_2 hose station and portable fire extinguishers are available in the vicinity.

- Redundant safe shutdown functions are located outside this fire zone.

- Low Fire Severity.

- Manual fire fighting equipment is available in adjacent area/zones.

The existing fire protection for the area provides an acceptable level of safety equivalent to that provided by 10 CFR 50, Appendix R, Section III.G.

6.0 REFERENCES

6.1 Drawing Number 5l5574
6.2 Drawing Number 50l399
6.3 Drawing Number 06l882
6.4 DCPP Unit 2 Review of l0 CFR 50, Appendix R (Rev. 2)
6.5 Calculation M-824, Combustible Loading
6.6 Drawing 065127, Fire Protection Information Report, Unit 2
6.7 Deleted in Revision 13
6.8 NECS File: 131.95, FHARE: 33, Undampered Ventilation Duct Penetrations
6.9 NECS File: 131.95, FHARE: 30, Unrated Gaps in Appendix R Barriers in the Turbine Building
6.10 NECS File: 131.95, FHARE: 122, Staircase S-7 Fire Area Boundary
6.11 Calculation 134-DC, Electrical Appendix R Analysis
6.12 Calculation M-928, 10 CFR 50, Appendix R, Safe Shutdown Analysis
6.13 NECS File: 131.95, FHARE: 118, Appendix R Fire Area Plaster Barriers
6.14 NECS File: 131.95, FHARE: 109, Acceptance Criteria for Penetration Seals in Selected Barriers

FIRE AREA TB-13

1.0 PHYSICAL CHARACTERISTICS

1.1 Location

This fire zone is located at the south end of the Turbine Building at El. 107 ft and El. 119 ft (4-kV switchgear ventilation fan room).

1.2 Description

This fire zone is an irregularly shaped area that incorporates two levels of the southwest end of the Turbine Building. On the l07-ft level the zone is the area above the ceiling of Fire Zones 22-A-1, 22-C-1, and 22-C-2. On the 119-ft level the zone is the 4kV switchgear ventilation fan room between Area 24-D and Zone 25 (TB-13). The air supply for these fans is from the El. 119 ft open ventilation hatch located in the northwest corner of the floor.

1.3 Boundaries

NOTE: NC designates a fire rated assembly that is not credited for compliance to 10 CFR 50 Appendix R or to Appendix A to BTP APCSB 9.5-1.

North:

El. 107 ft

- A 3-hour rated barrier to Zone 19-A (TB-7)
- A 3-hour rated door to Zone 19-A

El. 119 ft

- 3-hour barrier to Fire Zone 19-A (TB-7)
- 3-hour rated double door to Fire Zone 19-A

South:

El. 107 ft

- 3-hour rated barrier to Fire Zone 22-C-2 with nonrated features. (Ref. 6.14)
- A 3-hour rated single door to Fire Zone 22-C-2

El. 119 ft

- Nonrated barrier to Fire Zone 25 [NC]. Structural steel modifications for the block walls were deemed acceptable with no fireproofing. (Ref. 6.11)
- A 3-hour rated door to Fire Zone 25. [NC]

East:

El. 107 ft

- A 2-hour rated barrier communicates to Fire Zones 23A (TB-10). (Refs. 6.12 and 6.17)
- 1-1/2-hour rated door to Fire Zone 23-A (TB-13) (Ref. 6.21)
- Lesser rate penetration seal to Fire Zone 23-A. (Ref. 6.18)

El. 119 ft

- 2-hour rated barrier to Fire Area 24-D, and Zone 23-E (TB-7). (Refs. 6.12 and 6.17)
- A non-rated barrier to Fire Zone S-7 (TB-13) (Ref. 6.13)
- A duct penetration without fire damper to Zone 23-E. (Refs. 6.8 and 6.21)
- Lesser rate penetration seals to Fire Zones 24-D and 24-E. (Ref. 6.18)
- Three duct penetrations without fire dampers to Area 24-D. The ducts are provided with a 1-hour rated fire resistive covering in Area 24-D. (Refs. 6.5, 6.8 and 6.21)
- 2-hour rated barrier to fire zone S-7 on mezzanine (El. 127 ft). (Ref. 6.13)

West:

El. 107 ft

- 3-Hour rated barrier to Fire Zone 22-C-2.

El. 119 ft

- A nonrated barrier to Zone 25. [NC]
- A 1-1/2-hour rated door to Zone 25 [NC] at El. 127 ft above the mezzanine. (Ref. 6.21)
- The space between the mezzanine (Zone 25) and the exterior wall is wide open to provide air intake. (Ref. 6.21)
- The light fixtures in the hallway of Zone 25 are recessed in the ceiling without any fire barriers to Area 24-E.
- 2-hour rated barrier to Zone S-6. (Ref. 6.7)

Floor:

- 3-hour rated barrier except for: An open ventilation opening that connects El. 104 ft and 119 ft of Zone 24-E. Nonrated barrier between 24-E and 25 NC (El. 127 ft). (Ref. 6.6)
  - A duct without a fire damper to Zone 23-C-1. (Refs. 6.8 and 6.21)
  - 2 dampered ducts to 4kV cable spreading rooms Fire Zones 23-A and 23-B.

Ceiling:

- 3-hour rated barrier to Zones 25 and 26 (El. 107 ft).
- 3-hour rated barrier to Zones 19-D (El. 119 ft).

2.0 COMBUSTIBLES

2.1 Floor Area: 1,211 ft^2 (Ref. 6.12)

2.2 In situ Combustible Materials

- Clothing/Rags
- Rubber
- Cable
- Paper

2.3 Transient Combustible Materials

Transient combustible materials are strictly controlled in accordance with procedure OM8.ID4 and Engineering Calculation M-824. Below is a listing of reasonably expected transient combustible materials:

- Clothing/Rags
- Lubricants
- Miscellaneous Class A & B combustibles
- Solvents
- Wood
- Plastic
- Paper

2.4 Fire Severity

- Low

3.0 FIRE PROTECTION

3.1 Detection

- Smoke detection is provided throughout the 119-ft elevation.

3.2 Suppression

- A wet pipe automatic sprinkler (El. 119 ft) with remote annunciation.
- Portable fire extinguishers
- CO_2 hose station
- Fire hose station

4.0 SAFE SHUTDOWN FUNCTIONS

4.1 Emergency Power System

A fire in this area may disable circuits associated with diesel generator 2-3. Offsite power is not affected in this area and will remain available for safe shutdown. In addition, diesel generators 2-1 and 2-2 will remain available for safe shutdown.

4.2 HVAC

A fire in this area may affect fans S-67, S-68 and S-69. The 4160 volt switchgear will not be affected by a loss of HVAC, therefore safe shutdown will not be affected. (Ref. 6.9)

5.0 CONCLUSION

The following fire protection features mitigate the consequences of the design basis fire and assure the capability to achieve safe shutdown:

- Deviations to requirements for 3-hour boundaries have been documented in the referenced Appendix R engineering evaluations. These references verify that the subject boundaries are capable of maintaining adequate separation between redundant components to assure safe shutdown.

- Low Fire Severity.

- Smoke detection is available at El. 119 ft.

- Automatic wet pipe sprinkler system at El. 119 ft.

- CO_2 and fire hose stations.

- Portable fire extinguishers.

The existing fire protection provides an acceptable level of fire safety equivalent to that provided by Section III.G.2, because these fans are not required for safe shutdown.

6.0 REFERENCES

6.1 Drawing Numbers 515574, 515575
6.2 DCPP Unit 2 Review of 10 CFR 50, Appendix R (Rev. 2)
6.3 Calculation M-824, Combustible Loading
6.4 Drawing 065127, Fire Protection Information Report, Unit 2
6.5 NECS File: 131.95, FHARE: 15, HVAC Ducts Wrapped in Pyrocrete 102
6.6 NECS File: 131.95, FHARE: 44, Traveling Crew Quarters Wall
6.7 NECS File: 131.95, FHARE: 119, Plaster Barriers Credited for Appendix A to BTP (APCSB) 9.5-1
6.8 NECS File: 131.95, FHARE: 33, Undampered Ventilation Duct Penetrations
6.9 Calculations M-911 and M-912
6.10 Deleted in Revision 13
6.11 NECS File: 131.95, FHARE: 106, Block Walls Modified in the 4kV Switchgear Area
6.12 DCP H-50177, Diesel Generator Air Flow Improvement Modification, Units 1 and 2.
6.13 NECS File: 131.95: FHARE: 122, Staircase S-7 Fire Area Boundary
6.14 NECS File: 131.95, FHARE: 30, Unrated Gaps in Appendix R Barriers in the Turbine Building
6.15 Calculation 134-DC, Electrical Appendix R Analysis
6.16 Calculation M-928, 10 CFR 50, Appendix R, Safe Shutdown Analysis
6.17 NECS File: 131.95, FHARE: 118, Appendix R Fire Area Boundary Plaster Barriers
6.18 NECS File: 131.95, FHARE: 109, Acceptance Criteria for Penetration Seals in Selected Barriers
6.19 Deleted
6.20 Deleted
6.21 NECS File: 131.95, FHARE 157, Unprotected Fire Rated Assemblies and Lack of Area-Wide Detection/Suppression

FIRE AREA TB-13

1.0 PHYSICAL CHARACTERISTICS

1.1 Location

Fire Zone S-7 is a stairway, in the southern end of Unit 2 Turbine Building that goes from the 85-ft elevation up to the 140-ft main turbine deck.

1.2 Description

This stairway is centered between the east and west sides of the Turbine Building. It runs from El. 85 ft to the turbine deck with access through fire rated doors at all elevations, except where it opens onto the turbine deck.

1.3 Boundaries

El. 85 ft

North:

- 2-hour rated barrier to Fire Area 20. (Ref. 6.8)

South:

- 3-hour rated concrete barrier to the exterior

East:

- 2-hour rated barrier to Fire Area 20 (Ref. 6.8)

West:

- 3-hour rated barrier to Fire Area 22-C
- A 1-1/2-hour rated door to Fire Area 22-C (Ref. 6.12)
- A nonrated seismic gap to Fire Area 22-C. (Ref. 6.8)

El. 104 ft

North:

- 2-hour rated barrier to Fire Zone 23-C (TB-12) (Ref. 6.8)

South:

- 2-hour rated barrier to the exterior shaft wall

East:

- 2-hour rated barrier to Fire Zone 23-C (TB-12). (Ref. 6.8)
- A 1-1/2-hour rated door to Fire Zone 23-C.
- Duct penetration with a fire damper communicates to Fire Zone 23-C.
- Lesser rated penetration seals to Fire Zone 23-C. (Ref. 6.11)

West:

- 2-hour rated barrier to Fire Zone 23-C-1 (TB-13) (Ref. 6.8)
- A 1-1/2-hour rated door to Fire Zone 23-C-1.
- A duct penetration without a fire damper communicates to Fire Zone 23-C-1. (Ref. 6.7)
- Lesser rated penetration seals to 23-C-1. (Ref. 6.11)

<u>El. 119 ft</u>

North:

- 2-hour rated barrier to Fire Area 24-D. (Ref. 6.8)

South:

- 2-hour rated barrier to the exterior.

East:

- 2-hour rated barrier to Fire Area 24-D. (Ref. 6.8)
- A 1-1/2-hour rated door to Fire Area 24-D.
- Duct penetration without a damper communicates to Fire Area 24-D. However, the ducting in Area 24-D is enclosed in a 1-hour rated enclosure. (Ref. 6.7)
- Lesser rated penetration seals to Fire Area 24-D. (Ref. 6.11)

West:

- 2-hour rated barrier to Fire Zone 25
- Nonrated barrier to Fire Zone 24-E (TB-13). (Ref. 6.8)
- A 1-1/2-hour rated door to Fire Zone 25.

- Duct penetration without a damper communicates to Fire Zone 24-E. (Ref. 6.7)

El. 140 ft

The stairway is open to Fire Zone 19-D.

(Note: Electrical and mechanical penetrations are sealed at the barriers commensurate with the hazards to which they are exposed. The structural steel within the fire zone is unprotected.)

2.0 COMBUSTIBLES

2.1 Floor Area: 128 ft^2

2.2 In situ Combustible Materials

- Cable Insulation
- Rubber
- Plastic

2.3 Transient Combustible Materials

Transient combustible materials are strictly controlled in accordance with procedure OM8.ID4 and Engineering Calculation M-824. Below is a listing of reasonably expected transient combustible materials:

- Clothing/Rags
- Lubricants
- Miscellaneous Class A & B combustibles
- Solvents
- Wood
- Plastic
- Paper

2.4 Fire Severity

- Low

3.0 FIRE PROTECTION

3.1 Detection

None

3.2 Suppression

- Manual suppression capability is available from other areas.

4.0 SAFE SHUTDOWN FUNCTIONS

4.1 Diesel Fuel Oil System

Diesel fuel oil pump 0-1 may be lost due to a fire in this area. The redundant diesel fuel oil pump 0-2 will remain available.

4.2 Emergency Power

A fire in this area may disable diesel generator 2-2. Offsite power is not affected in this area and will remain available for safe shutdown. In addition, diesel generators 2-1 and 2-3 will remain available for safe shutdown.

4.3 HVAC

A fire in this area may result in the loss of one train of required HVAC equipment (S-67). S-67 is not necessary for a fire in this area.

5.0 CONCLUSION

The following features will mitigate the consequences of the design basis fire and assure the capability to achieve safe shutdown:

- Deviations to requirements for 3-hour boundaries have been documented in the referenced Appendix R exemptions and engineering evaluations. These references verify that the subject boundaries are capable of maintaining adequate separation between redundant components to assure safe shutdown.

- Manual suppression capability is provided in the adjacent zones.

- Substantial barriers, also electrical and mechanical penetrations sealed commensurate with barrier rating.

- Low fire severity.

The existing fire protection for the area provides an acceptable level of fire safety equivalent to that provided by 10 CFR 50, Appendix R, Section III.G.

6.0 REFERENCES

6.1 Drawing Nos. 515573, 515574, 515575, 515576
6.2 Drawing No. 501399
6.3 Drawing Number 061882
6.4 DCPP Unit 2 Review of 10 CFR 50, Appendix R (Rev. 2)
6.5 Calculation M-824, Combustible Loading
6.6 Drawing 065127, Fire Protection Information Report, Unit 2
6.7 NECS File: 131.95, FHARE: 33, Undampered Ventilation Duct Penetrations
6.8 NECS File: 131.95, FHARE: 122, Staircase S-7 and S-6, Fire Area Boundary
6.9 Calculation 134-DC, Electrical Appendix R Analysis
6.10 Calculation M-928, 10 CFR 50, Appendix R, Safe Shutdown Analysis
6.11 NECS File: 131.95, FHARE: 109, Acceptance Criteria for Penetration Seals in Selected Barriers
6.12 SSER - 31

FIRE AREA V-3

1.0 PHYSICAL CHARACTERISTICS

1.1 Location

Fuel Handling Building El. 85 ft, 93 ft, 100 ft and 115 ft; Auxiliary Building main exhaust fan room No. 2, El. 115 ft; Auxiliary Building exhaust filter room, El. 100 ft; Auxiliary Building normal concrete exhaust duct, El. 93 ft; ad plenum, El. 85 ft.

1.2 Description

This fire zone is located in the south end of the Unit 2 fuel handling building at El. 100 and 115 ft and includes a concrete exhaust air duct at El. 93 ft running from the Auxiliary Building to this zone.

1.3 Boundaries

NOTE: NC designates a fire rated assembly that is not credited for compliance to 10 CFR 50 Appendix R or to Appendix A to BTP APCSB 9.5-1.

North:

Three-hour rated barriers with the following exceptions:

El. 85 ft:

- A 1-hour rated barrier with an undampered vent opening to Fire Zone 3-C. NC (Ref. 6.8)
- A 1-1/2-hour equivalent rated door communicating with Zone 3-L. NC
- A duct penetration without a damper to Fire Zone 3-A. NC (Ref. 6.9)

El. 100 ft:

- Three nonrated doors communicating with Zone 3-V-2. NC
- A duct penetration without a fire damper penetrates zone 32. NC (Ref. 6.5)

El. 115 ft:

- Five nonrated doors communicating with Zone 3-V-9. NC
- Two duct penetrations without fire dampers penetrate to Zone 3-V-9. NC

South:

- 3-hour rated barriers. [NC]

East:

- 3-hour rated barriers with the following exceptions. [NC]

El. 100 ft

A Duct penetration without a fire damper penetrates to Zone 32. [NC] (Ref. 6.5)

- Nonrated barrier to the exterior area at El. 115 ft. [NC]

West:

- 3-hour rated barriers. [NC]
- Floor/Ceiling.
- Duct penetrations without fire dampers penetrate at 85-ft and 115-ft elevations.

2.0 COMBUSTIBLES

2.1 Floor Area: 1,150 ft^2

2.2 In situ Combustible Materials

- Bulk Cable
- Foam Rubber
- Rubber
- Lube Oil
- Plastic

2.3 Transient Combustible Materials

Transient combustible materials are strictly controlled in accordance with procedure OM8.ID4 and Engineering Calculation M-824. Below is a listing of reasonably expected transient combustible materials:

- Clothing/Rags
- Lubricants
- Miscellaneous Class A & B combustibles
- Solvents
- Wood

- Plastic
- Paper

2.4 Fire Severity

- Low

3.0 FIRE PROTECTION

3.1 Detection

- Smoke detection at El. 115 ft

3.2 Suppression

- Portable fire extinguishers
- Hose stations

4.0 SAFE SHUTDOWN FUNCTIONS

4.1 Fire Zone 3-V-3

4.1.1 Auxiliary Feedwater

AFW pumps 2-2 and 2-3 may be lost due to a fire in this area. Redundant AFW pump 2-1 will remain available.

5.0 CONCLUSION

The following fire protection features mitigate the consequences of the design basis fire and assure the capability to achieve safe shutdown:

- AFW pump 2-1 and associated components are independent of this fire zone and remain available for safe shutdown. (Ref. Section 4)

- Manual fire fighting equipment is available.

- Smoke detection provided in areas of combustible loading only (El. 115 ft).

- Deviations to requirements for 3 hour boundaries have been documented in the referenced Appendix R exemptions and engineering evaluations. These references verify that the subject boundaries are capable of maintaining adequate separation between redundant components to assure safe shutdown.

The existing fire protection features in this area provide an acceptable level of fire safety equivalent to that provided by 10 CFR 50, Appendix R, Section III.G.

6.0 REFERENCES

6.1 Drawing Numbers 515577, 515578
6.2 DCPP Unit 2 Review of 10 CFR 50, Appendix R, Rev. 2
6.3 Calculation M-824, Combustible Loading
6.4 Drawing 065127, Fire Protection Information Report, Unit 2
6.5 NECS File: 131.95, FHARE: 40, Undampered Penetration Ducts
6.6 Calculation 134-DC, Electrical Appendix R Analysis
6.7 Calculation M-928, 10 CFR 50, Appendix R, Safe Shutdown Analysis
6.8 NECS File: 131.95, FHARE: 38, Undampered Ventilation Duct in a 1-Hour Barrier
6.9 NECS File: 131.95, FHARE: 60, Undampered Ventilation Ducts

APPENDIX 9.5B

REGULATORY COMPLIANCE SUMMARY

APPENDIX 9.5B

DCPP REGULATORY COMPLIANCE SUMMARY

A review of PG&E's compliance with Appendix A of NRC's Branch Technical Position (BTP) APCSB 9.5-1 was completed for the Diablo Canyon Power Plant (DCPP). PG&E's documents and correspondence on fire protection were reviewed to identify all commitments made regarding the applicable guidelines. Each commitment was evaluated to determine PG&E's compliance. The detailed results of this evaluation are documented in DCPP Commitment Closeout sheets for each guideline and commitment. Table B-1 summarizes the results of the evaluation.

TABLE B-1

COMPARISON OF DCPP TO APPENDIX A OF BTP APCSB 9.5-1

A. OVERALL REQUIREMENTS OF NUCLEAR PLANT FIRE PROTECTION PROGRAM

Guideline Statement	DCPP Compliance to Commitment
1. Personnel	
Responsibility for the overall fire protection program should be assigned to 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 experienced 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	Responsibility for the overall fire protection program has been assigned to the President of PG&E. All fire protection staff and engineers satisfy the applicable qualification requirements. The responsibilities of the fire protection staff are described in administrative and fire fighting procedures. Appendix 9.5H details the organization, training, equipment, and implementing procedures related to the fire protection personnel.

TABLE B-1

COMPARISON OF DCPP TO APPENDIX A OF BTP APCSB 9.5-1
A. OVERALL REQUIREMENTS OF NUCLEAR PLANT FIRE PROTECTION PROGRAM

	Guideline Statement	DCPP Compliance to Commitment
2.	Design Bases	
	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 relative to maintaining ability to perform safety shutdown functions and minimize radioactive releases to the environment.	The overall fire protection program is based on the evaluation of potential fire hazards throughout the plant. The Appendix R Reports for DCPP Units 1 and 2 analyze the effect of a postulated design basis fire relative to safe shutdown functions and minimize radioactive releases to the environment.
3.	Backup	
	Total reliance should not be placed on a single automatic fire suppression system. Appropriate backup fire suppression capability should be provided.	In areas of the plant where automatic fire suppression systems are employed, appropriate backup fire suppression capability is provided by installation of manual hose stations, portable fire extinguishers and portable fire pumps. Each backup method is surveilled as per procedure to ensure equipment availability so total reliance is not dependent upon a single automatic fire suppression system.
4.	Single Failure Criterion	
	A single failure in the fire suppression system should not impair both the primary and backup fire suppression capability. For example, redundant fire water pumps with the 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 single failure in the fire suppression system will not impair both the primary and backup suppression capability due to the nature of the primary and backup water supplies, the independence of power supplies for the associated pumps and valves, and the provision for portable backup fire pumps. Portions of the fire water system have been analyzed in regard to the design basis earthquake and are seismically qualified so that all hose-reels in safety-related areas of the plant will be available following a safe shutdown earthquake. The seismically qualified portion of the fire system can be readily isolated from the rest of the fire system. Other than those areas required to be available after the design basis earthquake, postulated fires or fire protection system failures are not considered concurrent with other plant accidents or the most severe natural phenomena. Lightning rods are installed at the high points of the containment, and lightning arrestors are installed on each of the phases of the main and

TABLE B-1

COMPARISON OF DCPP TO APPENDIX A OF BTP APCSB 9.5-1
A. OVERALL REQUIREMENTS OF NUCLEAR PLANT FIRE PROTECTION PROGRAM

	Guideline Statement	DCPP Compliance to Commitment
		auxiliary transformers. The effects of lightning strikes are included in the overall plant fire protection program
5.	Fire Suppression Systems	
	Failure or inadvertent operation of the fire suppression systems should not incapacitate safety-related systems or components. Fire suppression systems that are pressurized during normal plant operation should meet the guidelines specified in BTP APSCB 3-1, "Protection Against Postulated Piping Failure in Fluid Systems Outside Containment."	Failure or inadvertent operation of the fire suppression system has been evaluated in response to this guidance and NRC Information Notice 83-41. Failure due to seismic acceleration is not a concern, as determined in SSER No. 9 by the NRC. Fire suppression systems that are pressurized during normal plant operation meet the guidelines of APSCB 3-1.
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.	Amendment 51, in conjunction with the implementation of fire protection procedures, ensures that the fire protection program is fully operational in fire zones storing new reactor fuel and in adjacent fire zones.
	Schedule for implementation of modifications, if any, will be established on a case-by-case basis.	
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. Schedule for implementation of modifications, if any, will be established on a case-by-case basis.	The fire protection program for Units 1 and 2 is fully operational and documented. The program was established prior to initial fuel loading. Schedule for implementation of modifications was established by 10 CFR 50.48(c).
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 hazards. The superintendent of the operating plant should have the lead responsibility for site fire protection.	The fire protection program provided adequate protection for the operating unit from construction fire hazards, as assessed by audits and design change verifications. The Plant Manager had ultimate responsibility for site fire protection during construction

TABLE B-1

COMPARISON OF DCPP TO APPENDIX A OF BTP APCSB 9.5-1
A. OVERALL REQUIREMENTS OF NUCLEAR PLANT FIRE PROTECTION PROGRAM

	Guideline Statement	DCPP Compliance to Commitment
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.	For fire areas unique to only one unit, the Fire Hazards Analyses postulates a fire to occur in only one unit at a time. For fire areas in common facilities, the Fire Hazards Analyses present evaluations to ensure safe shutdown of both units.

TABLE B-1

COMPARISON OF DCPP TO APPENDIX A OF BTP APCSB 9.5-1
B. ADMINISTRATIVE PROCEDURES, CONTROLS AND FIRE BRIGADE

	Guideline Statement	DCPP Compliance to Commitment
1.	General Administrative Procedures	
	Administrative procedures consistent with the need for maintaining the performance of the fire protection system and personnel in nuclear power plants should be provided.	PG&E maintains performance of the DCPP Fire Protection Program and its personnel through effective administrative procedures guided by NFPA codes.
	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 Fire Protection Program presents detailed information on the administrative procedures required to implement the fire protection program.
2.	Bulk Storage of Combustibles	
	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 (RG) 1.39, "Housekeeping Requirements for Water-Cooled Nuclear Power Plants," provides guidance on housekeeping, including the disposal of combustible materials.	Administrative measures prohibiting bulk storage of combustible materials inside or adjacent to safety-related buildings or systems in operation have been established. DCPP follows the guidance presented in RG 1.39. Certain areas containing safe shutdown equipment disposal of combustible materials have been designated as posted "No Storage" areas to eliminate the possibility of an exposure fire from bulk storage of combustibles.

TABLE B-1

COMPARISON OF DCPP TO APPENDIX A OF BTP APCSB 9.5-1
B. ADMINISTRATIVE PROCEDURES, CONTROLS AND FIRE BRIGADE

Guideline Statement	DCPP Compliance to Commitment
3. Normal and Abnormal Conditions	
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 and appropriate special actions and procedures such as fire watches or temporary fire barriers implemented to assure adequate fire protection and reactor safety. In particular:	Adequate fire protection and reactor safety at DCPP are maintained during normal and abnormal conditions or anticipated operations such as modifications and refueling activities by appropriate review by the DCPP Plant Staff Review Committee and the plant fire protection organization. Appropriate special actions are taken when needed as determined by these reviews.
(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.	Work involving ignition sources at DCPP is controlled by Procedure IDAP OM8.ID1, Fire Loss Prevention and Administrative Procedure. (See Appendix 9.5H.) Persons trained and experienced in fire protection both review and implement these procedures. Qualified firewatches are provided when requirements of the ignition source control program cannot be met.
(b) Leak testing, and similar procedures such as air flow determination, should use one of the commercially available aerosol techniques. Open flame or combustion generated smoke should not be permitted.	PG&E ensures that neither open flame nor combustion generated smoke is used for leak testing through the above referenced administrative procedures. Testing is by commercial aerosol techniques, soap bubble test, or measurement of pressure change.
(c) Use of combustible material, e.g., HEPA and charcoal filters, dry ion exchange resins or other combustible supplies, in safety-related systems or equipment should be permitted only when suitable fire retardant treated wood (scaffolding, lay noncombustible substitutes are not available. If wood must be used, only 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.	The use of combustible materials at DCPP is strictly controlled through Administrative Procedure. (See Appendix 9.5H.) Combustible materials are used in safety-related systems only when suitable noncombustible substitutes are not available. The fire hazard analysis considers all in-situ combustibles to determine the adequacy of the installed fire protection systems.

TABLE B-1

COMPARISON OF DCPP TO APPENDIX A OF BTP APCSB 9.5-1
B. ADMINISTRATIVE PROCEDURES, CONTROLS AND FIRE BRIGADE

Guideline Statement	DCPP Compliance to Commitment
4. Self-sufficient Fire Fighting Capability	
Nuclear power plants are frequently located in remote areas, at some distances 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.	DCPP is self-sufficient with respect to fire fighting activities as described in the Administrative Procedure. (See Appendix 9.5H.) The San Luis Obispo County Fire Department provides a backup to primary fire brigade response to the power plant structures.
5. Fire Brigade Organization, Training, and Equipment	
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 for Nuclear Power Plants," should be followed as applicable.	Organization, training, and equipment maintenance of the DCPP fire brigade is assured through an active Fire Protection Program and its supporting administrative and inspection procedures. The emergency plan established was developed to comply with the provisions of Appendix E to 10 CFR 50 and used the guidance contained in the "Guide to the Preparation of Emergency Plans for Production and Utilization Facilities."
(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 routing 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 for testing and maintaining fire protection emergency lighting and communications systems are in effect. Administrative procedures describe the responsibilities for and disposition of the test and maintenance records resulting from the test procedures. Fire brigade members are trained in the use, testing, and maintenance of equipment. Abnormal operating conditions (such as may occur during maintenance periods) are reviewed and appropriate fire protection control measures are initiated.
(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 fire fighting 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	DCPP Fire Brigade training occurs in accordance with the Fire Protection Program. A formal training program exists for fire brigade members. Formal training sessions are held at least quarterly, and individual training records are maintained in the plant files. Training sessions are supplemented by preplanned fire drills, conducted on a quarterly basis.

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COMPARISON OF DCPP TO APPENDIX A OF BTP APCSB 9.5-1
B. ADMINISTRATIVE PROCEDURES, CONTROLS AND FIRE BRIGADE

Guideline Statement	DCPP Compliance to Commitment
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 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.	DCPP ensures proper fire protection coverage of the plant site through a 24-hour fire brigade supplied by shift personnel. Each brigade member satisfies the training requirements outlined in the Fire Protection Program which discusses plant and offsite fire department involvement. Local fire department members are trained in the special hazards and precautions associated with fires on nuclear power plant sites.
(d) NFPA 17, "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, Standard 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 pages 27-11 of Volume 8, 19/1-/2 are also applicable for good training references. In addition, courses in fire prevention and fire suppression which are recognized and/or sponsored by the fire protection industry should be utilized.	Fire brigade organization, training, and fire drills are described in Appendix 9.5H. NFPA standards were used when organizing the fire brigade and developing the fire protection program implementing procedures. They will continue to be used when developing new or revising existing procedures.

TABLE B-1

COMPARISON OF DCPP TO APPENDIX A OF BTP APCSB 9.5-1
C. QUALITY ASSURANCE PROGRAM

Guideline Statement	DCPP Compliance to Commitment
Quality Assurance (QA) programs of applicants and contractors should be developed and implemented to assure that the requirements for design, procurement installation, and testing and administrative control for the fire protection program for safety-related areas as defined in this branch position are satisfied. The program should be under the management control of the QA organization. The QA program criteria that apply to the fire protection program should include the following:	The QA Program, as described in Chapter 17 of the FSAR Update, assures that requirements for design, procurement, construction, testing, and related administrative activities for the Fire Protection (FP) Program for safety-related areas are satisfied.
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.	Procedures ensure that all design-related guidelines of the branch technical position are included in the design and procurement documents and that deviations are controlled.
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.	Procedures govern inspections, tests, administrative controls, fire drills, and training relating to the FP Program.
3. Control of Purchase Material, Equipment, and Services	
Measures should be established to assure that purchased material, equipment, and services conform to the procurement documents.	Procedures address procurement and establish guidelines to assure that purchased material, equipment, and services conform to the procurement documents.
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.	DCMs S-18 and T-13, and Appendix 9.5H provide a list of procedures that govern inspections, tests, administrative controls, fire drills, and training related to the FP Program. Following modifications, installation tests are initiated by procedures that govern the design change process.

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COMPARISON OF DCPP TO APPENDIX A OF BTP APCSB 9.5-1
C. QUALITY ASSURANCE PROGRAM

Guideline Statement	DCPP Compliance to Commitment
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.	Test programs are laid out in detail in surveillance test procedures and are controlled by administrative procedures. The design change process mandates inspections following modifications. Procedures governing periodic inspections are laid out in the surveillance test procedures. Test results are documented evaluated, and their acceptability determined in accordance with these procedures.
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.	Procedures establish measures to provide for the identification of items that have satisfactorily passed required tests and inspections.
7. Nonconforming Items	
Measures should be established to control items that do not conform to specified requirements to prevent inadvertent use or installation.	The control of nonconforming items is governed by administrative procedures that mandate identification and reporting requirements to prevent inadvertent use or installation.
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 nonconformance are promptly identified, reported, and corrected.	Policies governing corrective measures relative to fire protection failures, malfunctions, deficiencies, deviations, defective components, uncontrolled combustible material, and nonconformances are addressed in administrative procedures.
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.	Procedures provide for collection and retention of the records that are generated to verify the quality of the fire protection program.
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.	Audits are conducted and documented to verify FP Program compliance. Procedures governing audits are presented in the administrative procedures manual.

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COMPARISON OF DCPP TO APPENDIX A OF BTP APCSB 9.5-1
D. GENERAL GUIDELINES FOR PLANT PROTECTION

Guideline Statement	DCPP Compliance to Commitment
1. Building Design	
(a) Plant layouts should be arranged to: (1) Isolate safety-related systems from unacceptable fire hazards. (2) Separate redundant safety-related systems from each other so that both are not subject to damage from a single fire hazard. Alternatives: (A) 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. (B) A separate system to perform the safety function should be provided.	Plant layouts isolate safety-related systems from unacceptable fire hazards by (1) physical distance between potential hazards and safety-related equipment; (2) fire barriers; (3) administrative control over storage combustibles; and (4) detection and suppression systems. Redundant safety-related systems are separated according to the criteria of 10 CFR 50, Appendix R, Section III.G. Various exemptions to these requirements have been requested per 10 CFR 50.48 and are detailed in Appendix R Reports for Units 1 and 2.
(b) In order to accomplish (a)(1) above, safety-related systems and fire hazards 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.	A detailed fire hazard analysis identifies safety-related systems and fire hazards throughout the plant. This analysis is complete and updated as necessary.
(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 hours. Cabling for redundant safety divisions should be separated by walls having three-hour fire barriers.	Units 1 and 2 use separate cable spreading rooms that are isolated from other areas of the plant by three-hour fire barriers except for the exemptions noted in the fire hazards analysis for these rooms (see Appendix 9.5A). Cabling for redundant safety divisions is not separated by three-hour fire walls. However, alternate safe shutdown capability independent of the cable spreading room has been provided. Therefore, a cable spreading room fire affecting redundant safety divisions would not adversely affect the ability to attain a safe shutdown.
(d) Interior wall and structural components, thermal insulation materials and radiation shielding materials, and soundproofing should be noncombustible. Interior finishes should be noncombustible 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 or less in its use configuration (ASTM E84 test, "Surface Burning Characteristics of Building Materials").	All interior wall and structural components, thermal insulation, radiation shielding materials, and soundproofing are noncombustible or have been evaluated to ensure that safe shutdown capability is not adversely impacted. The Fire Hazards Analysis (Appendix 9.5A) ensures that fire barriers can adequately contain postulated fire of the calculated severity.

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D. GENERAL GUIDELINES FOR PLANT PROTECTION

Guideline Statement	DCPP Compliance to Commitment
(e) Metal deck roof construction should be noncombustible (see the building materials directory of the Underwriters' Laboratory, Inc.) or listed as Class 1 by Factory Mutual System Approval Guide.	Built-up metal roof construction is not utilized at DCPP.
(f) Suspended ceilings and their supports should be of noncombustible construction. Concealed spaces should be devoid of combustibles.	Suspended ceilings and supports are constructed of noncombustible materials, diffusers, and insulated pipe wraps in the control room. The fire hazards analysis (Appendix 9.5A) for the control room indicates that presence of this material does not present an unacceptable fire hazard. Concealed spaces above suspended ceilings are kept free of combustibles except for-fire area 4-A, counting and chemical laboratory, where redundant conduits containing cables essential to safe shutdown are located above the suspended ceiling. The laboratory ceiling has been replaced with a membrane fire-rated ceiling. The fire hazards analysis for fire area 4-A ensures that these combustibles do not adversely impact safe shutdown.
(g) High voltage-high amperage transformers installed inside buildings containing safety-related systems should be of the dry type or insulated and cooled with noncombustible liquid.	All high-amperage transformers installed inside buildings are of the dry type, as documented on drawings.
(h) Buildings containing safety-related systems, having openings in exterior walls closer than 50 feet to flammable oil-filled transformers should be protected from the effects of a fire by:	Buildings containing safety-related systems, having openings in exterior walls closer than 50 feet to flammable oil-filled transformers, are protected from the effect of a fire by two-hour rated barriers.
(1) Closing of the opening to have fire resistance equal to three hours.	The acceptability of this construction is evaluated in Appendix 9.5A.
(2) Constructing a three-hour fire barrier between the transformers and the wall openings.	
(3) Closing the opening and providing the capability to maintain a water curtain in case of a fire.	
(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 provided as required to contain water and direct it to floor drains. (See NFPA 92M,	Floor drains (or other drainage means) of adequate capacity for anticipated fire water runoff are located in areas of the plant where sprinklers are located and in most areas where fire water hose reels would be used. Floor drains are not provided in some electrical areas. However, since automatic sprinklers are not located in these areas, any fire fighting involving use of water in these areas would be done with

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D. GENERAL GUIDELINES FOR PLANT PROTECTION

Guideline Statement	DCPP Compliance to Commitment
"Waterproofing and Draining of Floors"). Drains in area 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.	hose reels by the fire brigade. If water was accumulating in a compartment, the fire brigade would open doors to allow runoff to stairwells or other areas. Furthermore, the quantity of water that might be expected to be used in an electrical area is not enough to cause flooding, even in a closed compartment. Flooding would not occur to such a level that safe shutdown equipment would be endangered. Equipment is mounted on pedestals, minimizing any adverse effects of water suppression systems. Building sumps and sump pumps have adequate capacity to handle anticipated fire water flows. Drain lines in areas containing significant amounts of combustible liquids are sized and sloped to minimize backflow into other areas and to prevent the spread of fire through the drain system. All drainage from areas that may contain radioactivity is processed through the liquid radwaste systems and automatically monitored prior to discharge.
(j) Floors, walls, and ceilings enclosing separate fire areas should have minimum fire rating of three-hours. Penetration 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 systems 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: (1) Water curtain in case of fire. (2) Flame retardant coatings. (3) Additional fire barriers.	Floors walls, and ceilings enclosing separate fire areas are fire rated as appropriate for the local fire hazard. The adequacy of fire barriers in accordance with Appendix R is evaluated as part of the fire barrier penetration program.

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D. GENERAL GUIDELINES FOR PLANT PROTECTION

Guideline Statement	DCPP Compliance to Commitment
2. Control of Combustibles	
(a) Safety-related systems should be isolated from combustible materials. When this is not possible because of the nature of the safety system or the combustible material, special protection 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:	Safety-related systems are isolated and separated from combustible materials wherever possible. When this is not possible, special protection has been provided to prevent a fire from defeating the safety system functions. "Fire Hazard Analysis" in Appendix 9.5A and the "Report on 10 CFR 50, Appendix R Review" have shown that a single fire will not impair redundant safe shutdown system functions because (a) one train of redundant safe shutdown related equipment/components has been protected by rated fire-retardant materials; or (b) the affected components have been protected by automatic fire suppression; or both.
(1) Emergency diesel generator fuel oil day	Each emergency diesel generator room is enclosed by three-hour fire barriers, and automatic CO_2 low-pressure flooding is furnished. Fire hazards analyses for the diesel generator rooms are presented in Appendix 9.5A.
(2) Turbine-generator oil and hydraulic control fluid systems.	The turbine building is separated from the rest of the plant by three-hour fire barriers. CO_2 flooding is provided to the lube oil reservoir rooms, and sprinkler/spray systems provide fire suppression capabilities to various areas in the turbine building (see Appendix 9.5A).
(3) Reactor coolant pump lube oil system.	The reactor coolant pumps are provided with wet- pipe sprinkler systems. Reactor coolant pump oil collection system has also been provided to prevent a fire from defeating the safety system functions. Fire Hazards Analyses are presented in Appendix 9.5A and Appendix 9.5C.
(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.")	Bulk gas storage is not permitted inside structures housing safety-related equipment. A separate chemical and gaseous storage vault is provided for storage of hydrogen and nitrogen. The bulk CO_2 storage tank is separated from any safety-related equipment in the turbine building. Bulk hydrogen and nitrogen storage tanks are located outside the turbine building, on the east side.
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	Hydrogen and nitrogen bottles stored in the chemical and gaseous storage area in the laboratory or machine shop are oriented

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D. GENERAL GUIDELINES FOR PLANT PROTECTION

Guideline Statement	DCPP Compliance to Commitment
wall penetration in the event of the container failure. Use of compressed gases (especially flammable and fuel gases) inside buildings should be controlled. (Refer to NFPA 6, "Industrial Fire Loss Prevention.")	perpendicular to the fuel handling building. An analysis was performed to determine the consequences to safety-related equipment in the unlikely event of container failure. The analysis showed that no unacceptable damage would result from the missile hazard of a failed gas container. Therefore, the intent of this guideline is met.
(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 noncombustible 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.	The use of plastics has been minimized. Within equipment, boards, panels, and devices, insulation is either fluorinated ethylene-propylene, cross-linked polyethylene, polyvinyl chloride (PVC) with an asbestos jacket (NEC Type TA), or PVC alone. The use of PVC has been kept to a minimum, and is used only where a manufacturer has standardized his production with this material.
(d) Storage of flammable liquids should, as a minimum, comply with the requirements of NFPA 30, "Flammable and Combustible Liquids Code."	Storage of flammable liquids meets the intent of NFPA 30, "Flammable and Combustible Liquids Code."
3. Electric Cable Construction, Cable Trays, and Cable Penetrations	
(a) Only noncombustible materials should be used for cable spreading rooms.	Fire protection guidelines are incorporated into the design of the cable spreading rooms. Safety-related cables are routed in steel conduits.
(b) See Section F.3 for fire protection guidelines for cable spreading rooms.	Fire protection guidelines are incorporated into the design of the cable spreading rooms. Safety-related cables are routed in steel conduits.
(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.	Cable trays outside the cable spreading room are provided with automatic sprinkler systems or fire-resistive enclosures, or a separation analysis per 10 CFR 50 Appendix R has been performed and accepted by the NRC. The adequacy of cable tray protection is evaluated in Appendix 9.5A, Fire Hazards Analysis. Cables are designed to be wetted down without electrical faulting. Manual hose stations and hand extinguishers are provided as backup fire suppression. Operation or malfunction of sprinkler systems will not adversely impact safety-related equipment.
When safety-related cables do not satisfy the provisions of RG 1.75, all exposed cables should be covered with an approved fire retardant coating	Redundant field-run safety-related cables are routed in separate conduit

TABLE B-1

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D. GENERAL GUIDELINES FOR PLANT PROTECTION

Guideline Statement	DCPP Compliance to Commitment
and automatic fire suppression system should be provided.	and insulation and jacket material is fire retardant. Automatic fire suppression systems have been installed at DCPP.
(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.	Cable tray penetrations are sealed to an equivalent fire resistance rating of the fire barrier itself. Fireproofing materials have met the requirements of ASTM E-119 tests.
(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 grouted 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.)	Cable tray fire stops made of Dow Corning Q3-6548 silicone foam are installed at intervals of 4 feet on vertical trays and 10 feet on horizontal cable trays, and with 5 feet of cable tray crossings, either above or below the crossing. (Ref: Dwg 050029 DCP A-47854, DCP M-049476, FHAREs 101, 143) PG&E's Engineering Research staff conducted fire tests in 1975, which proved the cable tray fire stops prevented the spread of fire to the other side of the fire stop for both the horizontal and vertical trays.
(f) Electric cable construction 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 383 flame test requirements, all cables must be covered with an approved flame retardant coating and properly derated.	Electrical cables at DCPP meet the intent of IEEE 383-1974 flame test requirements as stated in the referenced report. The following categories of cables installed in the power block after June 1, 1991 are exempt from the IEEE 383-1974 flame test requirements (Reference: ABB Impell Corporation Document No. 0170-219-001, Revision 2, PG&E Electrical Cable Acceptability Analysis): (1) Cables tested to the flame test requirements in UL 910, UL 1666 or UL 1581 (Vertical Tray Flame Test). The flame tests in these UL Standards meet or exceed the requirements of IEEE 383-1974 flame test using the ribbion gas burner. (2) Cables installed in non combustible totally closed enclosures such as conduits, terminal boxes, panels, cabinets etc.
(g) To the extent practical, cable construction that does not give off corrosive gases while burning should be used. (Applicable to new cable installations.)	Some PVC insulated cables are used in the plant. However, the small amount of PVC present does not produce significant hazards. To the extent practical, all new cable installations will utilize cables that do not give off corrosive gases when burned.

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D. GENERAL GUIDELINES FOR PLANT PROTECTION

Guideline Statement	DCPP Compliance to Commitment
(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.	Cable trays, raceways, and conduit are used exclusively for cables. Administrative controls exist to prevent storage in cable trays and raceways.
Installed equipment in cable tunnel or culverts need not be removed if they present no hazard to the cable runs as determined by the fire hazard analysis.	
(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.	Smoke venting capability is provided and is discussed in the referenced emergency procedures.
(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 not be installed in floor trenches or culverts in the control room.	All power and control cables entering the control room terminate there, and are considered necessary for control room operation. The cabling terminates at terminal blocks inside the control panels. No floor trenches or culverts exist in the control room.
Existing cabling installed in concealed floor and ceiling spaces should be protected by an automatic total flooding Halon system.	
4. Ventilation	
(a) The products of combustion that need to be removed from a specific fire area should be evaluated to determine how they can 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 (TS).	The DCPP ventilation systems either supply fresh outside air to rooms or exhaust air from rooms into a closed duct system (or both for some rooms).
The products of combustion which need to be removed from a specific fire area should be evaluated to determine how they will be controlled.	The ventilation exhaust systems have been evaluated to determine the capability for removing smoke and products of combustion in the event of a fire. Ventilation exhaust capabilities, either manual or automatic, exist in all plant areas. Ventilation for manual fire fighting in areas with normal ventilation flow cutoff can be accomplished with portable blower-exhaust fans and by opening doors. These fans exhaust to the outside or to nearby operating ventilation exhaust ducts. If the normal ventilation system is used for heat and smoke venting, the heat and smoke would be discharged outside, not to other rooms.
	The ventilation system has been conservatively designed to provide adequate cooling for all equipment under all operating modes.

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D. GENERAL GUIDELINES FOR PLANT PROTECTION

Guideline Statement	DCPP Compliance to Commitment
	Ventilation system discharges from areas containing radioactive materials are continuously monitored to determine whether releases are within the TS limits.
(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.	Ventilation systems either supply fresh outside air to rooms or discharge air from rooms into a closed duct system (or both for some rooms). Single failures will not violate controlled areas or affect personnel habitability. Safety-related ventilation exhaust systems employ redundant components and subsystems where necessary to ensure reliable system operation. Inadvertent operation will not violate the controlled areas of the plant design.
(c) The power supply and controls for mechanical ventilation systems should be run outside the fire area served by the system.	Power supplies and controls for mechanical ventilation systems are run outside the fire area or zone served, to the extent practical. However, there are certain fire areas or zones in which redundant ventilation system components or circuitry could be affected by an unmitigated fire.
(d) Fire suppression systems should be installed to protect charcoal filters in accordance with RG 1.52, "Design Testing and Maintenance Criteria for Atmospheric Cleanup Air Filtration."	Charcoal filters are generally installed to meet the intent of RG 1.52. However, water spray systems have not been provided, since the maximum postulated radioactivity on the charcoal filters is below that required for auto-ignition of the filter. The degree of compliance with RG 1.52 is summarized in Table 9.4-2 of this FSAR Update.
(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.	Fresh air intakes to areas containing safety-related equipment are located remote from exhaust air outlets to the extent practicable. The possibility of contaminating the intake air with products of combustion is extremely unlikely. The approximate distances between air supply intakes and the nearest exhaust air outlets for buildings and areas housing safety-related equipment are listed below:

Building or Area	Intake-Exhaust Approximate Distance
Control room	50 feet
Containment	150 feet
Auxiliary building (including fuel handling area)	200 feet

TABLE B-1

COMPARISON OF DCPP TO APPENDIX A OF BTP APCSB 9.5-1
D. GENERAL GUIDELINES FOR PLANT PROTECTION

Guideline Statement	DCPP Compliance to Commitment
	<table><tr><th>Building or Area</th><th>Intake-Exhaust Approximate Distance</th></tr><tr><td>Diesel generator area</td><td>40 feet</td></tr><tr><td>4.16kV switchgear room</td><td>80 feet</td></tr><tr><td>Turbine building (general)</td><td>150 feet</td></tr><tr><td>Battery room area</td><td>25 feet</td></tr></table>
(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-hours and automatic fire doors at least equal to the enclosure construction, each opening into the building. Elevators should not be used during fire emergencies.	Stairwells are designed to minimize smoke infiltration. They are located to provide escape and access routes for fire fighting and are enclosed by two-hour fire walls with either "A" or B" labeled, normally closed fire doors. All exits are clearly marked. The ratings of various stairwells elevators, and chutes were analyzed and upgraded where necessary to meet the requirements of 10 CFR 50 Appendix R and as accepted by the NRC. Stairwell S-1 contains a nonrated access hatch to the ventilation shaft.
Where stairwells or elevators cannot be enclosed in three-hour fire rated barrier with equivalent fire doors, escape and access routes should be established by pre-fire plan and practiced in drills by operating and fire brigade personnel.	Pre-fire plans are established and in place.
(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 square foot of venting area per 200 square feet of floor area should be provided. If forced-convection ventilation is used, 300 CFI should be provided for every 200 square feet of floor area. See NFPA 204 for additional guidance on smoke control.	The diesel fuel oil storage tanks are buried and do not require ventilation. PG&E uses forced ventilation to serve the cable spreading and switchgear rooms; however, fire dampers are used to assist fire extinguishment and reduce smoke propagation. Smoke removal plans subsequent to a fire are discussed in fire brigade training and fire fighting procedures.
(h) Self-contained breathing apparatus, using full face positive pressure masks, approved by NIOSH (National Institute for Occupational Safety and Health - approval formerly given by the U.S. 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 system piped from a storage reservoir if practical. Service or operating life should be a minimum of one-half hour for the self-contained units.	Self-contained breathing apparatus (SCBAs) are provided for fire brigade and control room personnel use at DCPP. Administrative controls exist to ensure their availability. At least two extra bottles are located onsite for those SCBAs that would be utilized by the Shift Fire Brigade and minimum control room compliment of operators. An onsite recharging system exists to permit quick and complete replenishment of exhausted supply air bottles.

TABLE B-1

COMPARISON OF DCPP TO APPENDIX A OF BTP APCSB 9.5-1
D. GENERAL GUIDELINES FOR PLANT PROTECTION

Guideline Statement	DCPP Compliance to Commitment
At least two extra air bottles should be located onsite for each self-contained breathing unit. In addition, an onsite six-hour supply of reserve air should be provided and arranged to permit quick and complete replenishment of exhaust supply air bottles as they are returned. If compressors are used as a source of breathing air, only units provided for breathing air should be used. Special care must be taken to locate the compressor in areas free of dust and contaminants.	
(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 1303 Systems.")	DCPP uses ventilation dampers to maintain the necessary gas concentration once the system has been actuated in a room protected by CO_2 or Halon.
5. Lighting and Communication	
Lighting and two-way voice communication are vital to safe shutdown and emergency response in the event of fire. Suitable fixed and portable emergency lighting and communication devices should be provided to satisfy the following requirements:	
(a) Fixed emergency lighting should consist of sealed beam units with individual eight-hour minimum battery power supplies.	PG&E installed emergency lighting system provides an acceptable margin of safety equivalent to that provided by the more conservative technical requirements of 10 CFR 50, Appendix R, Section III.J. (See Appendix 9.5D.)
(b) Suitable sealed beam battery powered portable hand lights should be provided for emergency use.	The need for portable hand lights to satisfy emergency use requirements in the event of a fire has been superseded by the more stringent regulations of 10 CFR 50, Appendix R, Section III.J.
(c) Fixed emergency communication should use voice powered sets at preselected stations.	Voice-powered communications systems are not used at DCPP. The primary communications system is a direct-dial company telephone network. A secondary communications system is the plant radio system, which includes various base stations, distributed portable units, and mobile units. The radio system is controlled and periodically tested through administrative means.

TABLE B-1

COMPARISON OF DCPP TO APPENDIX A OF BTP APCSB 9.5-1
D. GENERAL GUIDELINES FOR PLANT PROTECTION

Guideline Statement	DCPP Compliance to Commitment
(d) Fixed repeaters installed to permit use of portable radio communication units should be protected from exposure fire damage.	The control room base station radio control consoles are powered from vital power and are afforded the protection of the control room. The remote shutdown panel for each unit is equipped with a base station radio control point and a plant telephone. Portable radios are available for communications with either the control room or the remote shutdown panel. Effective communications can be maintained while shutdown is occurring, either from the control room or the remote shutdown panel.

TABLE B-1

COMPARISON OF DCPP TO APPENDIX A OF BTP APCSB 9.5-1
E. FIRE DETECTION AND SUPPRESSION

Guideline Statement	DCPP Compliance to Commitment
1. Fire Detection System	
(a) Fire detection systems should as a minimum comply with NFPA 72D, "Standard for the Installation, Maintenance and Use of Proprietary Protection Signaling Systems". Deviations from the requirements of NFPA 72D should be identified and justified.	An evaluation of the fire detection systems' compliance with NFPA 72D was performed. For all areas of noncompliance, engineering evaluations were provided to show that the intent of NFPA 72D was met, or modifications were made. A central supervising station is provided in the Control Room from which the control room operators can monitor the fire alarms for the DCPP site. The central supervising station provides an automatic and permanent visual recording of alarms and fire protection equipment initiation. FHARE 116, Testing and Maintenance of Ionization Smoke Detectors evaluates the frequency of performing sensitivity testing.
(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.	The fire detection system gives audible and visual alarms in the control room.
(c) Fire alarms should be distinctive and unique. They should not be capable of being confused with any other plant system alarms.	The fire alarms outside the control room at DCPP are distinctive and unique. Site fire alarm characteristics are described in the Emergency Plan. The site fire alarm uses a combination of siren and horn signals. These measures ensure that alarms outside the control room are not confused with other plant system alarms. The site fire alarm is manually activated.
(d) Fire detection and actuation systems should be connected to the plant emergency power supply.	Fire detection and actuation systems are connected to the plant emergency power supply.
2. Fire Protection Water Supply Systems	
(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 organization 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 a unlined pipe over a period of years can significantly reduce water flow through the	A 12 inch underground yard fire main loop is installed to furnish anticipated firewater requirements. The water supply system is installed commensurate with the guidance of NFPA 24. Yard main piping was constructed using epoxy-lined asbestos cement. Repair and maintenance activities are performed in accordance with applicable NFPA guidelines. Means are available and procedures exist for treating and flushing portions of the fire main. The plant yard loop is sectionalized, and each plant feed line can be isolated without interrupting fire water

Guideline Statement	DCPP Compliance to Commitment
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. 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.	supply to the remainder of the plant. The fire main system piping is separate from service and sanitary water system piping.
(b) A common yard fire main loop may serve multiunit nuclear power plant sites, if crossconnected between units. Sectional control valves should permit maintaining independence of the individual loop around each unit. For such installation, 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 separate plants (approaching 1 mile or more), separate yard fire main loops should be used. Sectionalized systems are acceptable.	A common yard fire main loop serves both Units 1 and 2, since the two units are in close proximity. The system uses sectional valves, which permit a common water supply to serve both units. A south site loop supplies water to the nonnuclear south site facilities. It may be cross-tied by opening valves FP-1214 and FU-4 to supplement the yard fire main loop.
(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 three-hour fire wall.	The primary water supply for this system is a 5.0 million gallon reservoir, divided in two isolable compartments. This reservoir supplies and pressurizes the fire water system, and meets system pressure and flow requirements. As backup to the reservoir, two 1500 gpm fire pumps provide water from a 300,000 gallon fire water storage tank. These pumps would not normally be required to supply the fire main system. The pumps are powered from redundant 480 volt vital circuits and start automatically (in sequence) on low fire system pressure.
Alarms indicating pump running, driver availability, or failure to start should be provided in the control room.	Alarms indicating pump running and failure to start are 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".	Fire pump installation meets the intent of NFPA 20.

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COMPARISON OF DCPP TO APPENDIX A OF BTP APCSB 9.5-1
E. FIRE DETECTION AND SUPPRESSION

Guideline Statement	DCPP Compliance to Commitment
(d) Two separate reliable water supplies should be provided. If tanks are used, two 100 % (minimum of 300,000 gallons each) systems 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 eight hours.	The fire protection water is supplied by two sources: (a) 5.0 million gallon gravity-feed raw water storage reservoir (b) 300,000 gallon water storage tank The power block outside yard loop is fed by the raw water reservoir.
Common tanks are permitted to 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.	The 300,000-gallon seismically qualified fire water tank is located inside the transfer storage tank as a separate container. A flow path is available from the transfer tank, but a check valve prevents reverse flow. Refer to Section 9.5.1.2.1 for additional description.
(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 hours, but not less than 300,000 gallons. This flow rate should be based (conservatively) on 1,000 gpm for manual hose streams plus the greater of:	A fire water supply system flow test is performed once every three years to verify the ability of system piping to deliver the design flow rate of the largest required water suppression system identified in the PG&E Equipment Control Guidelines (see Chapter 16 of this FSAR Update) plus 500 gpm for hose.
(1) All sprinkler heads opened and flowing in the largest designed fire area.	
(2) The largest open head deluge system(s) operating.	
(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 conditions should also be satisfied:	DCPP uses a common water supply of 5.0 million gallons for fire protection and plant make-up water. A separate 300,000 gallon tank may be used to service the fire protection system if necessary. The ultimate heat sink for DCPP is the ocean.
(1) The additional fire protection water requirements are designed into the total storage capacity.	
(2) Failure of the fire protection system should not degrade the function of the ultimate heat sink.	
(g) Outside manual hose installation should be sufficient to reach any location with an effective hose stream. To accomplish this, hydrants should be	A fire hose system is provided that allows all outside areas to be reached by at least two hose streams. Each hose cabinet is equipped with

TABLE B-1

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E. FIRE DETECTION AND SUPPRESSION

Guideline Statement	DCPP Compliance to Commitment
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 1,000 feet.	100 feet of 1-1/2 inch hose, a combination nozzle and spanner wrench. Threads are compatible with those used by local fire departments. The system meets the intent of NFPA 24.
Threads compatible with those used by local fire departments should be provided on all hydrants, hose couplings, and standpipe risers.	
3. Water Sprinklers and Hose Standpipe Systems	
(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 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.	The automatic sprinkler system and manual hose stations are supplied by a sectionalized underground fire main loop arranged such that no single failure could impair the entire fire protection system. See Section 9.5.1.2 for further details. Each sprinkler system and manual hose station standpipe is provided with an independent connection to the yard main. The turbine building contains an internal loop that acts as an extension of the yard main system.
Each sprinkler and standpipe system should be equipped with OS&Y (outside screw and yoke) gate valve, or other approved shutoff valve, and water flow alarm. Safety-related equipment that does not itself require sprinkler water fire protection, but is subject to unacceptable damage if wetted by sprinkler water discharge should be protected by water shields or baffles.	Each sprinkler system is equipped with an OS&Y gate valve or an approved shutoff valve, in addition to a flow alarm to alert the control room in the event of system actuation. Each standpipe system is not provided with a separate OS&Y; however, the sectionalizing valves ensure that single failure will not adversely impact the rest of the fire protection system. The Moderate Energy Line Break Program ensures that safety-related equipment susceptible to water damage is protected by water shields or baffles.
(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 of Valves.") When electrical supervision of fire protection valves is not practical, an adequate management supervision program should be	The sectionalizing fire loop main valves are electrically supervised at DCPP. An administrative program of locking, sealing, and inspecting valves is in place for those fire water supply valves that are impractical to supervise electrically.

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E. FIRE DETECTION AND SUPPRESSION

Guideline Statement	DCPP Compliance to Commitment
provided. Such a program should include locating valves open with strict key control; tamper proof seals; and periodic, visual check of all valves.	
(c) Automatic sprinkler systems should as a minimum conform to requirements of appropriate standards such a NFPA 13, "Standard for the Installation of Sprinkler Systems," and NFPA 15, "Standard for Water Spray Fixed Systems."	DCPP automatic sprinkler systems are used in various areas of the plant and are installed commensurate with the requirements of NFPA 13.
(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 feet of 1-1/2 inch 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 foot intervals. Individual standpipes should be at least 4 inch diameter for multiple hose connections and 2-1/2 inch diameter for single hose connections. These systems should follow the requirements of NFPA No. 14 for sizing, spacing, and pipe support requirements (NELPIA).	Hose stations are provided throughout DCPP at approximately 100 foot intervals and provided with 75 or 100 foot maximum hose length so that all locations within the plant can be reached with at least one effective hose stream. Fire hose standpipes are minimum 4 inch diameter for multiple hose connections and 2 inch for single hose connections. The standpipe systems were installed commensurate with the guidelines of NFPA 14. Access and occupancy requirements were considered in specifying hose reel locations.
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 shutoff valves and pressure reducing devices (if applicable) outside the area.	
(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.	Combination spray/straight stream nozzles are installed inside the buildings. Fire fighting procedures specify what equipment should be used to fight the various types of fires depending upon their location. Surveillance procedures assure on a periodic basis that this equipment is available for use. Fire brigade members are trained to use the appropriate equipment for the fire.
(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).	PG&E's fire protection staff evaluated the appropriate suppression systems to be used for the fire hazard. No foam suppression systems exist at DCPP. Total flooding CO_2 systems or water spray systems are used where flammable liquid is considered a fire hazard.

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COMPARISON OF DCPP TO APPENDIX A OF BTP APCSB 9.5-1
E. FIRE DETECTION AND SUPPRESSION

Guideline Statement	DCPP Compliance to Commitment
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 or FM approved agents should be used.	Halon suppression systems are not utilized at Diablo Canyon.
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.	
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."	Carbon dioxide extinguishing systems at DCPP were installed commensurate with the guidelines of NFPA 12. The systems are periodically tested by surveillance procedures.
Particular consideration should also be given to:	Consideration has been given to the following design requirements:
(a) Minimum required CO_2 concentration and soak time.	(a) The design concentrations of the low-pressure total flooding systems are:
(b) Toxicity of CO_2.	- Diesel generator = 35% - Lube oil reservoir room = 34% - Cable spreading room = 50%
(c) Possibility of secondary thermal shock (cooling) damage.	
(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	The high-pressure total flooding system provided for the circulation water pump has an extended discharge capability of 20 minutes at reduced flow rate.

TABLE B-1

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E. FIRE DETECTION AND SUPPRESSION

Guideline Statement	DCPP Compliance to Commitment
(f) Possibility and probability of CO_2 systems being out-of-service because of personnel safety considerations. 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.	(b) Thirty-second time delay, before system actuation, is provided for evacuation of personnel. (c) Discharge nozzles are located away from equipment to minimize thermal shock damage. (d) Offsetting requirements for venting during CO_2 injection are provided to prevent overpressurization. (e) Pressure plugs are provided in the CO_2 piping to delay closure of discharge dampers and thus prevent overpressurization. (f) Each CO_2 total flooding system is equipped with a total mechanical system disable. The disable is supplied for personnel safety during maintenance in the area.
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.	Fire extinguishers are provided throughout DCPP commensurate with the requirements of NFPA 10 and 10A, and are inspected monthly. Maintenance on the fire extinguishers is performed on an annual basis.

TABLE B-1

COMPARISON OF DCPP TO APPENDIX A OF BTP APCSB 9.5-1
F. GUIDELINES FOR SPECIFIC PLANT AREAS

Guideline Statement	DCPP Compliance to Commitment
1. Primary and Secondary Containment	
(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: (1) Lubricating oil or hydraulic fluid systems for the primary coolant pumps	Fire detection and suppression systems in containment are provided on the basis of specific identified hazards. Appendix 9.5C provides a description of fire protection features for the RCPs and evaluates its compliance with the requirements of 10 CFR 50, Appendix R, Section III.O. (See Appendix 9.5C.) An automatic wet pipe waterspray system is provided for each reactor coolant pump. Operation of the water spray system does not compromise integrity of the containment or other safety-related systems.
(2) Cable tray arrangements and cable penetrations	Hose reel stations are provided in the containment cable penetration zone, and portable extinguishers are distributed outside the containment. Cable tray arrangements and cable penetrations are protected. Ionization smoke detectors are provided in the penetration areas. DCPP meets 10 CFR 50, Appendix R, Section III.G. separation criteria as demonstrated in the Fire Hazards Analysis (Appendix 9.5A).
(3) Charcoal filters	Fire protection provided for the charcoal filters is discussed in Section D.4(d) of this table.
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.	
Fire detection systems should alarm and annunciate in the control room. The type of detection used and the location of the detectors should be most suitable to the particular type of fire that could be expected from the identified hazard. A primary containment general area fire detection capability should be provided as backup for the above described hazard detection. To accomplish this, suitable smoke detection (e.g., visual observation, light scattering, and particle counting) should be installed in the air recirculating system ahead of any filters.	Fire detection capability is provided for the containment. Smoke detectors are provided for the reactor coolant pumps, and detectors are provided in the containment electrical penetration area. Additional detection capability is provided by flame detectors above the operating deck. The flame detectors are designed to detect a fire resulting from transient combustibles that could be introduced during refueling and maintenance outages. A flow alarm on the containment fire water line gives control room indication of RCP sprinkler system actuation. Fire detection systems annunciate in the control room.
Automatic fire suppression capability need not be provided in the primary containment atmospheres that are inerted during normal operation. However,	When maintenance or repair on the single fire protection line to the containment is being done, backup fire hoses can be brought into containment. In addition, portable fire extinguishing equipment is

TABLE B-1

COMPARISON OF DCPP TO APPENDIX A OF BTP APCSB 9.5-1
F. GUIDELINES FOR SPECIFIC PLANT AREAS

Guideline Statement	DCPP Compliance to Commitment
special fire protection requirements during refueling and maintenance operations should be satisfied as provided below.	available.
Operation of the fire protection systems should not compromise integrity of the containment or the other safety-related systems. Fire protection activities in the containment areas should function in conjunction with total containment requirements such as control of contaminated liquid and gaseous release and ventilation.	
(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.	The use of combustible materials inside the containment during refueling and maintenance operations is discussed in Sections B.2 and B.3 of this table. In addition to administrative controls, portable fire extinguishers are installed at strategic locations throughout the containment. Standpipes with hose stations are provided as discussed in Appendix 9.5A.
Management procedures and controls necessary to assure adequate fire protection are discussed in Section F.3(a) of this table. 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.	Self-contained breathing apparatus are provided near the control room and are available for use by fire fighting and damage control personnel as described in Section D.4(h) of this table. These units are intended for use in emergency situations. The control room is located in proximity to the containment access area.
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 be independent of any breathing apparatus or air supply systems provided for general plant activities.	

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F. GUIDELINES FOR SPECIFIC PLANT AREAS

Guideline Statement	DCPP Compliance to Commitment
2. Control Room	
The control room is essential to the 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 three hours.	The control room is constructed of noncombustible or fire-resistive materials with the exeption of the control consoles and room desk, which are constructed of fire retardant wood, and the floor, which is carpeted. The control room complex is separated from the rest of the plant by minimum three-hour fire barriers (with the exception of certain ventilation penetrations through the walls and special bulletproof, pressure- tight doors that are not labeled as fire rated). (See Appendix 9.5A)
Control room cabinets and consoles are subject to damage from two distinct fire hazards: (a) Fire originating within a cabinet or console. (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 shutoff 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.	Extinguishers are located within the control room, and hose stations are located in adjacent rooms. Fog nozzles are used, designed to satisfy electrical safety requirements and minimize damage from hose stream impingement.
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.	
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.	Smoke detectors are provided in the control room cabinets and consoles containing redundant safe shutdown cabling. FHARE 93 evaluates acceptability of not installing smoke detectors in safety-related HVAC cabinets, POV1 and POV2 and nonsafety-related digital feedwater cabinets RODFW1 and RODFW2 for Units 1 and 2. Additionally, the control room is continuously occupied, and operators would normally detect fires, visually or by smell, before extensive damage occurred.
Breathing apparatus for control room operators should be readily available.	Breathing apparatus for operators is readily available in the control room complex.
Control room floors, ceiling, supporting structures, and walls, including penetrations and doors, should be designed to a minimum fire rating of three hours. All penetration seals should be airtight.	
The control room ventilation intake should be provided with smoke detection capability to automatically alarm locally and isolate the control room ventilation	The control room ventilation intake and exhaust are provided with smoke detectors that alarm in the control room. The control room ventilation system is not automatically isolated. However, the operator can isolate the system manually. He also has the option of operating the system on a once-through (no recirculation) basis, using all outside air. This mode would remove any smoke from the control room.
	Power and control cables entering the control room terminate there and are considered essential for control room operation. Cabling is not located in concealed floor and ceiling spaces. Drains are not provided, but safety-related equipment is mounted high enough above floor level that flooding is not feasible.

TABLE B-1

COMPARISON OF DCPP TO APPENDIX A OF BTP APCSB 9.5-1
F. GUIDELINES FOR SPECIFIC PLANT AREAS

Guideline Statement	DCPP Compliance to Commitment
system to protect operators by preventing smoke from entering the control room. 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.	
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.	
If such concealed spaces are used, however, they should have fixed automatic total flooding Halon protection.	
3. Cable Spreading Room	
(a) The preferred acceptable (fire suppression) methods are:	
(1) 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 or spray nozzles should consider cable tray sizing and arrangements to assure 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 Aqueous Film Forming Foam (AFFF).	The cable spreading function is fulfilled by three rooms: (1) The 4.16kV cable spreading rooms are located in the turbine building (see Appendix 9.5A). They supply power for safety-related functions. This power is distributed in three isolated trains, separated from each other by two-hour fire barriers. Each compartment is constructed with two entrances at opposite ends. The 4.16kV switchgear and cable spreading areas are separated from the remainder of the turbine building by minimum two-hour rated fire barriers and from the outdoor transformers by two-hour fire barriers. The floor and ceiling slabs are two feet thick, and all electrical penetrations are sealed for a fire rating commensurate with the barrier rating. Fire-stopped cable trays are used in each compartment but are not stacked. All cables leaving this area are routed in steel conduit, and the redundant electrical divisions are separated by minimum two-hour barriers in the area adjacent to the 4.16kV cable spreading rooms. Fire suppression in this area is provided by manual CO_2 hose stations, manual water hose stations, and portable extinguishers.
(2) Manual hoses and portable extinguishers should be provided as backup.	
(3) 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 three-hour rated fire wall. (Refer to NFPA 251 to ASTM E-119 for fire test resistance rating.)	

TABLE B-1

COMPARISON OF DCPP TO APPENDIX A OF BTP APCSB 9.5-1
F. GUIDELINES FOR SPECIFIC PLANT AREAS

Guideline Statement	DCPP Compliance to Commitment
(4) At least two remote and separate entrances are provided to the room for access by fire brigade personnel.	Detection is provided by ionization smoke detectors that alarm locally and in the control room.
(5) Aisle separation provided between tray stacks should be at least three feet wide and eight feet high.	(2) The nonvital cable spreading room is located below the 12kV switchgear room (see Appendix 9.5A). It supplies power for nonsafety-related functions. Fire-stopped cable trays are used throughout. Fire suppression in this area is provided by manual CO_2 hose stations, manual water hose stations, and portable extinguishers. Detection is provided by ionization smoke detectors that alarm locally and in the control room. (3) The auxiliary building cable spreading room (see Appendix 9.5A) is located just under the control room. It contains control cables (both safety-related and nonsafety-related) and the reactor protection racks. This room is enclosed on all sides, floor, and ceiling by three-hour rated fire barriers. Two entrances on opposite sides of the room are provided. All safety-related circuits are routed in steel conduits or are in trays located beneath the checker plate floor. All nonsafety-related circuits are routed in fire stopped cable trays. Nowhere do tray stacks exceed three high or two wide. Redundant protection sets are separated to the extent practical. The function of this area is backed up by a remote hot shutdown panel adjacent to the 480 volt switchgear room (see Appendix 9.5A). This panel is wired independent of the cable spreading room. Alternate shutdown capability, completely independent of the control room and cable spreading room, has been provided at DCPP. Fire suppression in this area is provided by a total flooding automatic CO_2 system actuated by heat detection. This system may also be actuated manually. Manual water hose reels and portable extinguishers serve as a backup. Ionization smoke detectors are also provided that alarm locally and in the control room.

TABLE B-1

COMPARISON OF DCPP TO APPENDIX A OF BTP APCSB 9.5-1
F. GUIDELINES FOR SPECIFIC PLANT AREAS

Guideline Statement	DCPP Compliance to Commitment
(b) For cable spreading rooms that do not provide divisional cable separation of (a)(3) in addition to meeting (a)(1), (a)(2), (a)(4), and (a)(5) above, an auxiliary shutdown system with all cabling independent of the cable spreading room should be provided:	
(1) Divisional cable separation should meet the guidelines of Regulatory Guide 1.75, "Physical Independence of Electrical Systems."	
(2) All cabling should be covered with a suitable fire retardant coating.	
(3) 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.	
(4) Plants that cannot meet the guidelines of RG 1.75, in addition to meeting (1), (2), (4), and (5) above, an auxiliary shutdown system with all cabling independent of the cable spreading room should be provided.	
4. Plant Computer Room	
Safety-related computer 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 computers used at DCPP do not serve safety-related functions. However, since they are housed adjacent to safety-related areas, detailed fire hazards analysis has been performed for the plant computer rooms (see Appendix 9.5A). Results of the fire hazards analysis show that the computer rooms do not constitute a significant fire hazard. Hose stations and portable extinguishers provide suppression capability in these areas, and smoke detectors are provided in the computer rooms and the exhaust air ducts from the computer rooms.
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.	The switchgear rooms are separated from the remainder of the plant by two-hour or three-hour fire barriers. Each vital (safety-related) switchgear bus is located in its own room and separated from the other by two-hour fire barriers. An evaluation of the adequacy of these barriers is presented in Appendix 9.5A.

TABLE B-1

COMPARISON OF DCPP TO APPENDIX A OF BTP APCSB 9.5-1
F. GUIDELINES FOR SPECIFIC PLANT AREAS

Guideline Statement	DCPP Compliance to Commitment
Acceptable protection for cables that pass through the switchgear room is automatic water or gas suppression. Such automatic suppression must consider preventing unacceptable damage to electrical equipment and possible necessary containment of agent following discharge.	All switchgear rooms are provided with ionization smoke detectors, which annunciate in the control room and locally. The switchgear areas are protected by manual CO_2 hose stations. Hose reel stations and portable extinguishers are readily available.
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.	The area housing the remote safe shutdown panel is provided with ionization smoke detection that alarms in the control room. Minimizing combustible materials has been a primary design consideration at DCPP. Design and administrative control of combustibles are described in Section D.1 and Section B.2. All remote safety-related panels are within reach of hose stations and portable extinguishers. Smoke detectors are provided in the hot shutdown panels. Refer to Appendix 9.5A for the fire hazards of the hot shutdown remote control panel area (fire areas 5-A-4 and 5-B-4).
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 three hours inclusive of all penetrations and openings. (See NFPA 69, "Standard on Explosion Prevention System.") Ventilation systems in the battery rooms should be capable of maintaining the hydrogen concentration well below 2 vol. % hydrogen concentration. Stand pipe and hose and portable extinguishers should be provided.	The vital battery rooms are provided with three- hour rated fire barriers separating them from other areas of the plant. The adequacy of the nonvital battery room barriers is evaluated in Appendix 9.5A. Natural ventilation will maintain the hydrogen concentration below 2% volume. (Reference FHARE 132)
Alternatives: (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 1-1/2 hours. (c) Provide a remote manual actuated sprinkler system in each room and provide the 1-1/2-hour fire barriers separation.	Manual CO_2 hose stations, fire water hose stations, and portable extinguishers are readily available to this area.

TABLE B-1

COMPARISON OF DCPP TO APPENDIX A OF BTP APCSB 9.5-1
F. GUIDELINES FOR SPECIFIC PLANT AREAS

Guideline Statement	DCPP Compliance to Commitment
8. Turbine Lubrication and Control Oil Storage and Use Areas	
A blank fire wall having a minimum resistance rating of three hours 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 building contains the turbine lubrication and control oil system. The turbine building is separated from all other areas by three-hour fire barriers. The clean and dirty lube oil storage areas are contained in their own three-hour barriers. The lube oil reservoir area is protected by an automatic CO_2 flooding system. The clean and dirty lube oil storage room is equipped with automatic wet-pipe sprinklers. The entire area is supplied with fire hose reels and portable extinguishers. Further discussion on these areas is found in Appendix 9.5A.
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 hours. Automatic fire suppression such as AFFF foam, or sprinkler 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 1,000 gallons 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 hours, 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. When day tanks cannot be separated from the diesel generator, one of the	DCPP is designed with three diesel generators per unit. (see Appendix 9.5A). Each diesel is manufactured with a nominal 550 gallon capacity day tank as an integral part of the frame. Three-hour rated fire barriers are provided between the diesel generator compartments and the rest of the plant. Drainage is provided, sized to remove fire fighting water, and smoke venting can be achieved manually. Fire suppression is provided by an automatic total flooding CO_2 system in each compartment This system alarms locally and annunciates in the control room. It can also be initiated locally or from the control room. Fire hose reels and portable extinguishers are readily available to each compartment.

Guideline Statement	DCPP Compliance to Commitment
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.	
10. Diesel Fuel Oil Storage Areas	
Diesel fuel oil tanks with a capacity greater than 1,100 gallons should not be located inside the building containing safety-related equipment. They should be located at least 50 feet from any building containing safety-related equipment, or if located within 50 feet, they should be housed in a separate building with construction having a minimum fire resistance rating of three hours. Buried tanks are considered as meeting the three-hour resistance requirements. See NFPA 30, "Flammable and Combustible Liquids Code," for additional guidance.	The diesel fuel oil storage areas are located outside the turbine building, buried several feet below grade. A detailed description of the storage areas is provided in Appendix 9.5A.
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.	
In operating plants where tanks are located directly above or below the diesel generators and cannot reasonable be moved, separating floors and main structural members should, as a minimum, have fire resistance rating of three hours. 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).	

TABLE B-1

COMPARISON OF DCPP TO APPENDIX A OF BTP APCSB 9.5-1
F. GUIDELINES FOR SPECIFIC PLANT AREAS

Guideline Statement	DCPP Compliance to Commitment
(b) Automatic closed head sprinklers.	
(c) Automatic AFFF that is delivered by a sprinkler system or spray system.	
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.	Automatic sprinkler protection has been provided for the auxiliary feedwater pumps, the charging pumps, the component cooling water pumps, and the boric acid transfer pumps. Appendix 9.5A demonstrates that all other safe shutdown pumps will not endanger other safe shutdown equipment in the event of a fire. Areas containing pumps required for safe shutdown are provided with ionization smoke detection capabilities. Fire water hose reels and portable extinguishers are provided throughout the plant to serve as backup fire suppression.
12. New Fuel Area	
Hand and 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. 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.	The new fuel storage area is located in a concrete vault and is not to be used for storage of combustible materials other than a plastic wrapper on new fuel. Portable extinguishers and fire hose reels are readily available to this vault. Two drains are provided and sized to prevent flooding in this area as a result of fire fighting. Ionization smoke detection is provided for this area. The fuel storage configuration is such that the water density ranges of fire fighting equipment will not allow criticality. (Reference: NRC Staff Response to the Testimony of Bridenbaugh, Hubbard, and Minor; February 18, 1976).
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.	The spent fuel pool area is provided with hose stations, portable extinguishers, and optical detection which alarms in the control room.

TABLE B-1

COMPARISON OF DCPP TO APPENDIX A OF BTP APCSB 9.5-1
F. GUIDELINES FOR SPECIFIC PLANT AREAS

Guideline Statement	DCPP Compliance to Commitment
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 and 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 handheld and large wheeled units.	The radwaste buildings are independent structures located approximately 100 feet east of the auxiliary building. Automatic wet pipe sprinkler systems are installed in the north and south buildings, where combustible materials are normally stored. The sprinkler systems alarm upon actuation. Annunciation of the alarm is in the building's main control room and at a local annunciator mounted outside the north storage building on the west wall. This fire protection arrangement was chosen in lieu of a fire detection system. Building drains for the north storage building are directed to the liquid radwaste system. The south storage building's dry active waste storage room has a 2-inch dike sloped to a sump that can contain the sprinkler water in the event of a fire. HVAC design and engineering are commensurate with the guidelines of NFPA 90A.
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.	Storage of flammable liquids at DCPP is controlled through administrative procedures. Flammable liquids are not stored in decontamination areas. The decontamination areas are located inside the fuel handling building, which is provided with hose stations and fire extinguishers. Detection is provided in the 140 ft elevation of fire zone 3-R, which opens to the decontamination areas below via a large equipment hatch.
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 feet of separation should be provided between outdoor tanks and combustible materials where feasible.	The refueling water storage tank and condensate storage tank are safety-related and required for safe plant shutdown. No combustible materials are stored in proximity to these tanks. Hose stations and fire hydrants from the yard main provide fire suppression capability. Portable extinguishers are located nearby. No fire hazards exist that could adversely affect the availability of these tanks. Additionally, these tanks have been encased in gunite as a part of seismic upgrading. A fire in the

TABLE B-1

COMPARISON OF DCPP TO APPENDIX A OF BTP APCSB 9.5-1
F. GUIDELINES FOR SPECIFIC PLANT AREAS

Guideline Statement	DCPP Compliance to Commitment
	vicinity of these tanks would not affect the tanks due to the insulating properties of the gunite.
	Approximately 12 feet separates these tanks from the common outside walls of the fuel building.
17. Cooling Towers	
Cooling towers should be of noncombustible construction or so located that a fire will not adversely affect any safety-related systems or equipment. Cooling towers should be of noncombustible construction when the basin are used for the ultimate heat sink or for the fire protection water supply.	Not applicable. Cooling towers are not used at DCPP.
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.	A fire hazards analysis exists that documents the fire hazards that may threaten safe shutdown equipment. This analysis and the Appendix R Reports submitted to the NRC demonstrate that miscellaneous areas do not have an adverse impact on the ability of either unit to shut down in the event of a fire.
	A fuel oil tank for the auxiliary boilers is buried in the hillside, to the east and north of the fuel handling area. This tank is empty and has been abandoned in place.

TABLE B-1

COMPARISON OF DCPP TO APPENDIX A OF BTP APCSB 9.5-1
F. GUIDELINES FOR SPECIFIC PLANT AREAS

Guideline Statement	DCPP Compliance to Commitment
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.	A complete welding and open flame permit system exists and is governed by the referenced administrative procedure. Oxygen and acetylene are stored in the hot shop and warehouse areas. Fuel gases are also used routinely in the machine shop area and hot shop. Fire hazards analyses of these areas considered the contribution of fuel gases to the overall combustible loading. Safety-related equipment is not present in any of these areas. The warehouse area and machine shop are protected by automatic sprinkler systems, with fire hoses and portable extinguishers providing backup. The hot shop is protected by hose reels and backed up by portable fire extinguishers. Permits are required whenever welding or cutting is done outside established shop areas (see Section B.3(a) of this table).
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.")	Dry ion exchange resins are stored in a sprinklered area of the main warehouse, which is located remote from the power block. Portable extinguishers are provided.
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.	Storage and protection arrangements are designed to meet the intent of NFPA-49. Storage facilities are located remote from the power block and are protected from flooding by a berm.

TABLE B-1

COMPARISON OF DCPP TO APPENDIX A OF BTP APCSB 9.5-1
F. GUIDELINES FOR SPECIFIC PLANT AREAS

Guideline Statement	DCPP Compliance to Commitment
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 or combustibles. These materials should be protected from exposure to fires in adjacent areas as well. Consideration should be given to requirements for removal of isotropic decay heat from entrained radioactivity materials.	Spent ion exchange resins are sluiced to the spent resin storage tanks in the auxiliary building. The resin is retained in a water solution in the tank. Storage in this manner eliminates the potential for combustion. Combustible loadings in this and adjacent areas are small, and no ignition sources are present. All filter housings are constructed of noncombustible materials (steel and concrete) and are located in areas that are relatively free from ignition sources and combustibles. Maximum postulated filter fission product loading is below that necessary to cause autoignition of charcoal filters. Fire hazards analysis of individual plant areas indicates that materials containing radioactivity are adequately protected from exposure to fire.

APPENDIX 9.5C

REACTOR COOLANT PUMP OIL COLLECTION SYSTEM EVALUATION TO 10 CFR 50, APPENDIX R, SECTION III.O

APPENDIX 9.5C

REACTOR COOLANT PUMP OIL COLLECTION SYSTEM EVALUATION TO 10 CFR 50, APPENDIX R, SECTION III.O

A. BACKGROUND

In 1975, Pacific Gas and Electric Company (PG&E) provided a system to collect and contain a potential oil leak from the Westinghouse reactor coolant pump (RCP) motors. The four RCPs were considered as two sets, two RCPs per set. A separate oil collection system was provided for each set. Each collection system was designed to collect and contain a potential oil spill of up to 50 gallons. Automatic smoke detection and wet pipe automatic sprinkler systems were installed to provide active fire protection for each RCP. NRC review and acceptance of the fire protection provision for the RCPs is contained within Supplemental Safety Evaluation Report (SSER) No. 8.

In March 1981, PG&E committed to provide a lube oil collection system consistent with the requirements of Appendix R, Section III.O. A review was made of the existing collection system and several modifications were made. The major modification involved replacing the two oil collection systems with one, and increasing the capacity of the collection tank to accommodate the entire lube oil inventory of one RCP motor. On July 15, 1983, a deviation from the requirements of Appendix R, Section III.O was requested for the RCP oil collection system on Unit 1. SSER 23 evaluated this request and approved the deviation. A similar deviation was requested for the Unit 2 RCP oil collection system on December 6, 1984, and approved in SSER 31 (which referenced SSER 23). The following discussion addresses the Unit 2 system (Fire Area 9, Fire Zones 9A, 9B, and 9C). The Unit 1 system is similar and will have the corresponding Unit 1 fire areas and zones (Fire Area 1 and Fire Zones 1A, 1B, and 1C).

B. RCP AREA DESCRIPTION

The RCPs are located in two areas within Fire Zone 9-B (fire area 9). Fire Zone 9- is separated from Fire Zone 9-A (containment penetration area) by a reinforced concrete shield wall which also serves as a support structure for the polar crane.

Fire Zone 9-B is separated from Fire Zone 9-C (control rod drive area) by the elevation 140-foot floor slab and the reinforced concrete biological shield wall from elevation 140 feet to approximately 110 feet. The biological shield wall separates Zone 9-B into two areas (north and south) above elevation 110 feet. Each RCP is above this elevation, therefore, the biological shield serves as a

barrier between the north area, in which RCPs 2-1 and 2-2 are located, and the south area, in which RCPs 2-3 and 2-4 are located. The north and south areas communicate through open areas from approximately elevation 110 feet to the containment floor slab at elevation 91 feet and through open ventilation gratings above each RCP at elevation 140 feet. Each RCP is separated from the others by a minimum of approximately 45 feet.

C. RCP OIL COLLECTION SYSTEM

Each RCP is equipped with an oil collection system to collect and contain any reasonable oil leak. The oil collection system consists of a series of collection pans surrounding each pump draining to a lube oil collection tank.

The collection pans surrounding each pump consist of 18-gauge sheet metal fastened to the platform grating at elevation 110 feet. Each pan has a minimum 1-7/8-inch rim and approximate collection area of 10 to 30 square feet. Each pan is connected to the adjacent pan by an overlapping joint and a mechanical fastener. All openings through and between the collection pans for conduit, pipes, etc., are surrounded by drip shields draining to the collection pans. A skirt is installed around the pump motor coupling to direct leaks on the outside of the motor casing (upper lube oil cooler, level instrumentation, etc.) to the collection pans below. The oil lift pump and piping is enclosed by a sheet metal shield. Spray from a potential oil lift pump leak would be confined to within the shield and the oil directed to the collection pans. Leaks internal to the motor casing are diverted to the collection pans below by a gutter inside the coupling area or collected above the main pump flange. The main pump flange is surrounded by a 2-inch rim with an overflow drain to the collection pans. All joints are caulked to prevent leakage.

Each collection pan is equipped with a 1-1/2-inch drain pipe connected to a 2-inch drain line. The drain lines for each pump connect to a 2-inch common header and enter the containment annulus through penetrations in the shield wall. The common header drain line is routed to an oil collection tank located under the fuel transfer canal in the containment annulus at elevation 91 feet.

The RCP oil collection tank has a 285-gallon capacity and is equipped with a valved drain, a 2-inch overflow, and a 2-inch vent. The vent is equipped with a flame arrester.

The tank is designed to contain the oil inventory of one RCP motor with margin.

Additionally, a closeout procedure for containment requires that the tank be verified empty after extended maintenance outage periods.

D. ACTIVE FIRE PROTECTION CAPABILITY

D.1 Detection

A smoke detector is provided between each RCP and the corresponding steam generator. The ventilation flowpath around the RCP was considered when the detectors were situated. Additional detectors are provided in the containment annulus in the exhaust air flowpath for Zone 9-B. These detectors annunciate in the continually manned control room.

D.2 Suppression

A wet-pipe automatic sprinkler system is provided for each RCP. The water flow alarm annunciates in the continually manned control room. The sprinkler system piping is designed such that a seismic event would not impact safety-related equipment due to system failure.

Manual fire suppression capability, in the form of portable fire extinguishers and fire hose stations, is available for use in the RCP areas. Portable fire extinguishers are brought to the containment since they are not stored there during Modes 1 through 4.

E. COMBUSTIBLES

The combustible loading for the RCP areas is included in the discussion of Fire Area 9.

F. DESCRIPTION OF DEVIATION

F.1 Statement of Problem

The above described RCP oil collection system is in compliance with Appendix R, Section III.O, and Item 2 of the NRC Staff Position Paper,[a] except for drainage of an overflow "to a safe location where the lube oil will not present an exposure fire hazard to or otherwise endanger safety related equipment." In the unlikely event of an overflow from a multiple RCP lube oil spill, RCP oil would be discharged from the RCP oil collection tank into the containment annulus floor trench at elevation 91 feet.

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[a] Presented in R. H. Vollmer's April 1, 1983, memorandum to D. G. Eisenhut concerning the oil collection system reactor coolant pumps, Florida Power and Light Company, St. Lucie 2, Docket No. 50-389, from J. Olshinski to D. G. Eisenhut.

F.2 Basis for Deviation Request (Unit 1)

a. The RCP lube oil collection tank overflow pipe discharges downward to a recessed trench in the elevation 91 feet floor, along the outside of the shield wall. This trench is sloped so that an RCP lube oil overflow would flow to the containment drain sump.

b. The overflow pipe of the oil collection tank has pickup from 3 inches above the tank bottom. Thus, in the remote likelihood of a multiple RCP motor lube oil spill and fire propagation to the oil collection tank, such a fire would not be extended to the oil discharges to the floor trench.

c. The Westinghouse RCP CS VSS motor currently utilizes a high flash point lubricating oil (425°F). The fire point of this oil is 520°F. Therefore, a high-energy ignition source would be necessary to sustain combustion in the unlikely event that a multiple RCP lube oil spill occurs and oil is discharged through the overflow pipe. An additional evaluation on the impact of the flash point temperature is included in FHARE 115.

d. Because an oil-to-water heat exchanger serves each bearing assembly, and the heat exchanger discharge water and bearing temperatures are monitored and alarm in the continuously manned control room, it is not deemed credible for the RCP lube oil to reach temperatures within 50 percent of its flash point.

e. There are various components and circuits necessary for safe shutdown in the vicinity of this floor trench. Power cable is routed in conduit. Other circuits are not considered to present a high-energy ignition source.

F.3 Basis for Deviation Request (Unit 2)

a. The RCP oil collection system, including the oil collection tank and overflow piping, has been designed to withstand the safe shutdown earthquake.

b. The RCP lube oil collection tank overflow pipe discharges downward to a recessed trench in the floor at elevation 91 feet, along the outside of the shield wall. This trench is sloped so that any RCP lube oil overflow would flow to the containment drain sump.

c. The inlet of the overflow pipe of the oil collection tank, located 3 inches above the tank bottom, will drain water off the bottom of the tank while containing the entire oil inventory of one RCP. The discharge is piped to the containment annulus trench such that splashing of the tank overflow in the trench is precluded.

d. The Westinghouse RCP motor currently utilizes a high flash point lubricating oil (425°F). The fire point of this oil is 520°F. Therefore, a high-energy ignition source would be necessary to initiate combustion in the unlikely event that a multiple RCP lube oil spill (greater than 285 gallons) occurs and oil is discharged through the overflow pipe. An additional evaluation on the impact of the flash point temperature is included in FHARE 115.

e. The lube oil flash point is sufficiently higher than any ignition sources in the vicinity of the tank overflow pipe or the anticipated flowpath of the overflowing oil.

f. Because an oil-to-water heat exchanger serves each bearing assembly that maintains the oil temperature below 200°F, and since the heat exchanger discharge water and bearing temperature are monitored and alarm in the continuously manned control room, it is not deemed credible for the RCP lube oil to reach temperatures near its flash point.

g. There are three safe shutdown functions located between 10 and 20 feet from the RCP oil collection tank: valves 8000C and PCV-456 for pressurizer pressure relief and LT-406 for pressurizer level measurement. A fire of 40 feet in diameter from the RCP oil spill collection tank would not jeopardize the safe shutdown of the plant.

G. SAFETY EVALUATION

The safety evaluation of the Units 1 and 2 RCP lube oil collection system, and the basis for acceptability of the deviation from Section III.O requirements, are documented in SSER 23. The concern with an unmitigated fire due to an overflow of lube oil from the collection system that could damage safety-related equipment in the vicinity was resolved based on the design of the collection system and the physical properties of the oil. The following are the technical bases for the safety evaluation:

- The overflow line for the lube oil collection tank discharges into a trench that is sloped to channel any potential oil spill to the containment drain sump.

- The oil has a high flash point temperature which would represent a significant hazard only if atomized or if the oil came in contact with a high-energy ignition source.

- The oil collection system is designed to withstand a safe shutdown earthquake.

- There are no ignition sources in the anticipated flow path of the overflowing oil.

- Smoke detectors, if activated by a fire, would annunciate in the control room and the fire brigade would be summoned.

- Fire damage to safety-related circuits in the area would not affect the ability to achieve and maintain safe shutdown.

APPENDIX 9.5D

EMERGENCY LIGHTING CAPABILITY
EVALUATION TO 10 CFR 50, APPENDIX R, SECTION III.J

APPENDIX 9.5D

EMERGENCY LIGHTING CAPABILITY EVALUATION TO 10 CFR 50, APPENDIX R, SECTION III.J

A. EMERGENCY LIGHTING SYSTEM DESCRIPTION

The emergency lighting system at the Diablo Canyon Power Plant (DCPP) consists of three independent systems:

1. Emergency AC Lighting System, 120 Vac

   The emergency ac lighting system is continuously energized. On loss of normal power supply to the vital G and H buses, the emergency diesel generators will start and pick up load in 10 seconds. The emergency ac lighting system will then be powered continuously by the emergency diesel generators. In the control room, the emergency ac lights are backed-up instantaneously by an independent uninterruptible power supply (UPS) with a four-hour rated battery. The UPS and battery are to bridge the power interruption during diesel starting and loading. The UPS and battery are not required for Appendix R and are rated QA Class N, Non Class IE, Design Class II, Non-Seismic. Tables 9.5D-1 and 9.5D-2 for Fire Area 8C are relying on the diesel-backed emergency ac lighting and BOLs to satisfy Appendix R requirements in the control room.

   In the pipe rack area, the emergency ac lights are powered from an UPS with an eight hour rated battery power supply. The UPS is fed from a non-Class 1E source. This UPS is located to ensure lighting is available in this area during all fire scenarios which require operator manual actions on the pipe rack.

2. Emergency DC Lighting System, 125 Vdc

   The 125 Vdc emergency lighting system is energized instantly upon loss of the emergency ac lighting system and is deenergized, after a 5-second time delay, on return of power supply to the emergency ac lighting system. These lights are powered from the nonvital station batteries and will provide sufficient emergency lighting for at least one hour.

3. Emergency Self-Contained Lighting, Battery Operated Lights (BOLs) with 8-Hour Battery Supply

   The emergency BOLs are located in various strategic areas of the plant which require lighting during safe shutdown. This lighting is either supplemental or additional to the emergency lighting system, so that

adequate light would still be available should damage occur to either the emergency lighting circuits or the normal lighting circuits serving a particular area. The emergency self-contained lights are energized upon failure of the associated ac lighting system (either normal or emergency lighting) and subsequently deenergized when the associated ac lighting system is returned to service.

B. METHOD OF EVALUATION

The review for compliance with 10 CFR 50, Section III.J, dealt with those fire zones or areas that may require the control room operator to take manual action at a remote location. This location may be either in an area where a fire is postulated or in an area unaffected by the single fire. In either case, emergency lighting is needed for access and egress routes to that remote location from the control room. Generally, it was assumed that if a fire were to occur, the emergency lighting circuit, including feeder circuit, that exists in the fire zone or area would be lost. Loss of lighting circuits that may affect lighting in other zones or areas was also taken into consideration. This approach ensures that lighting along the entire access and egress route is accounted for when needed. If no manual action is required of the plant operators for a fire in a particular zone or area, then the potential loss of emergency ac lights was not evaluated.
(Safe shutdown can be achieved by the operators from, the main control room, where emergency lights exist.)

An analysis of the effects of a fire was performed to demonstrate that adequate lighting for access and egress routes to safe shutdown components is provided. The results of this analysis are summarized in Section D.

C. LEVEL OF ILLUMINATION FOR EMERGENCY LIGHTING

A program was instituted to verify that plant emergency lighting provides sufficient levels of illumination to allow any needed operations of safe shutdown equipment, and to ensure that access and egress routes to such equipment will have adequate illumination for the traversal of these routes.

D. SUMMARY

The emergency lighting table matrix, in Table 9.5D-1 for Unit 1 and Table 9.5D-2 for Unit 2, identifies the type of emergency lighting credited in each fire area. The availability of each type of light is contingent upon lighting circuit routing and the specific fire scenario which requires access/egress through or operator action within the fire area specified. Specific details on 10 CFR 50 Appendix R emergency lighting including lighting units necessary for Appendix R, operator access/egress routes, operator manual actions which require emergency lighting, and availability of emergency lighting based upon power supply circuit routing are provided in design calculation 335-DC. The emergency lighting analysis and

supporting documentation were reviewed by the NRC and determined to be adequate for compliance with Section III.J of Appendix R to 10 CFR 50 (Ref. NRC letter to PG&E dated April 4, 1997, Chron. No. 232672).

E. DESCRIPTION OF DEVIATION

E.1 Statement of Problem

Section III.J of Appendix R requires that "emergency lighting units with at least an 8-hour battery power supply be provided in all areas needed for operation of safe shutdown equipment and in access and egress routes thereto."

J-9.5D(1) Because eight hour battery backed lighting units are not provided at all operator manual action locations and access/egress routes, the emergency lighting system at DCPP is not in strict compliance with Section III.J.

This request for exemption from 10 CFR 50 Appendix R Section III.J was originally submitted in NRC docket 50-275 (Unit 1) and 50-323 (Unit 2) "Pacific Gas and Electric Company Review of 10 CFR 50 Appendix R Section III.G, III.J and III.O." Based on the NRC review of the above documents and clarifying description provided subsequently, the NRC staff approved the deviation to 10 CFR 50) Appendix R Section III.J in SSER 23 (Unit 1) and SSER 31 (Unit 2).

E.2 Basis for Exemption (Unit 1)

a. Three independent emergency lighting systems have been provided: ac lighting from the G and H buses of the emergency diesels, dc lighting for at least 1 hour from the nonvital station batteries, and BOLs with 8-hour battery packs in selected key locations throughout DCPP.

b. Where manual operation of certain safe shutdown equipment is taken credit for, as discussed in Appendix◦9.5G, the emergency lighting systems that provide for light along the access and egress routes to this equipment have been evaluated to ensure a reliable source of light is available.

E.3 Basis for Exemption (Unit 2)

a. Three independent emergency lighting systems have been provided: ac lighting from the G and H buses of the emergency diesels, dc lighting for at least 1 hour from the nonvital station batteries, and BOLs with 8-hour battery packs in selected key locations throughout DCPP.

b. Where manual operation of certain safe shutdown equipment is taken credit for, the emergency lighting systems that provide for light along the

access and egress routes to this equipment have been evaluated to ensure that a reliable source of light is available.

c. Fixed emergency lighting is provided at all operator manual locations, which require emergency lighting and in access/egress routes thereto.

TABLE 9.5D-1

Emergency Lighting Table Matrix (Unit 1)

Fire Area	Emergency Lighting Credited		
	AC	DC	BOL
3AA			X
3B3	X		
3BB-85	X		X
3BB-100	X		X
3BB-115	X		X
3C	X		
3H1	X		
3L	X		X
3Q1	X		X
3R	X		
3X	X		X
5A1			X
5A2	X		X
5A3	X		X
5A4	X		X
6A1	X	X	X
6A2	X		X
6A3	X		X
6A5	X		X
8C	X		X
10			X
11A1			X
11B1			X
11C1			X
11D			X
12E			X
13A	X		X
13B	X		X
13C	X		X
13D			X
13E	X		X
14A	X	X	X
14D	X	X	
14E	X		X
28	UPS		
34			X
S1	X		X
S2	X		X
S3	X		X

<u>Legend</u>

AC: Emergency AC Lighting, 120 Vac
DC: Emergency DC Lighting, 125 Vdc
BOL: Battery Operated Lights, 8-hour Battery Supply
UPS: AC lighting with 8-hour battery backup power supply

TABLE 9.5D-2

Emergency Lighting Table Matrix (Unit 2)

Fire Area	Emergency Lighting Credited		
	AC	DC	BOL
3AA	X	X	X
3C	X		
3CC-85	X		X
3CC-100	X		X
3CC-115			X
3D3	X		
3I1	X		
3L	X		X
3T1			X
3X	X		X
4B	X		X
5B1	X		X
5B2	X		X
5B3	X		X
5B4	X		X
6B1	X	X	X
6B2	X		X
6B3	X		X
6B5			X
8C	X		X
19A	X	X	X
19D	X	X	
19E			X
22A1			X
22B1			X
22B2			X
22C1			X
22C			X
23E	X	X	X
24A	X		X
24B	X		X
24C	X		X
24D			X
29	UPS		
34			X
S1	X		X
S2	X		X
S4	X		X
S5			X
S7	X	X	X

Legend

AC: Emergency AC Lighting, 120 Vac
DC: Emergency DC Lighting, 125 Vdc
BOL: Battery Operated Lights, 8-hour Battery Supply
UPS: AC lighting with 8-hour battery backup power supply

APPENDIX 9.5E

10 CFR 50, APPENDIX R, SECTION III.L
ALTERNATIVE AND DEDICATED SHUTDOWN CAPABILITY

APPENDIX 9.5E

10 CFR 50, APPENDIX R, SECTION III.L
ALTERNATIVE AND DEDICATED SHUTDOWN CAPABILITY

As required by Section III.G.3 of 10 CFR 50, Appendix R, alternative shutdown capability and its associated circuits, independent of cables, systems or components in the area, room or zone under consideration, is provided:

> where the protection of systems whose function is required for hot shutdown does not satisfy the requirements of Section III.G.2.

In addition, fire detection and a fixed fire suppression system must be installed in the area, room or zone under consideration.

Section III.L delineates the requirements for the alternative shutdown capability credited to meet Section III.G.3. The alternative shutdown capability is required to accommodate postfire conditions where offsite power is available and where offsite power is not available for 72 hours. The alternative shutdown capability provided for a specific fire area must be able to:

(a) achieve and maintain subcritical reactivity conditions in the reactor;

(b) maintain reactor coolant inventory;

(c) achieve and maintain hot standby conditions;

(d) achieve cold shutdown conditions within 72 hours; and

(e) maintain cold shutdown conditions, thereafter.

The performance goals for the shutdown function must be:

(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 within the level indication in the pressurizer.

(c) The reactor heat removal function shall be capable of 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.

Alternative shutdown capability is credited for a fire in the control room (fire area 8-C) or the cable spreading rooms (fire area 7-A or 7-B). A deviation from Appendix R, Section III.G.3 for fire area 8-C was granted by the NRC for lack of area-wide fixed fire suppression system (Reference SSER No. 23). Postfire safe shutdown is carried out from outside the control room using control and monitoring functions provided at the remote hot shutdown panel (HSP), the dedicated shutdown panel (DSP), local indications, 4 kV and 480 V switchgears, local control panels, or locally at the valve.

Operating Procedures OP AP-8A and OP AP-8B implement the postfire safety shutdown capability. The repair actions credited involve manually aligning valves necessary to operate auxiliary spray for RCS depressurization. The repair actions are included in OP AP-8A and OP AP-8B.

The components and actions credited for the alternative shutdown capability are identified in the safe shutdown analysis section (Section 4.0 of Appendix 9.5A) for Fire Area 7-A for Unit 1 and Fire Area 7-B for Unit 2. The performance goals for the safe shutdown functions were achieved, and the requirements of Sections III.G.3 and III.L were achieved.

APPENDIX 9.5F

FIRE BARRIER FIGURES

APPENDIX 9.5F

FIRE BARRIER FIGURES

List of Figures:

[a] This figure corresponds to a controlled engineering drawing that is incorporated by reference into the FSAR Update. See Table 1.6-1 for the correlation between the FSAR Update Figure number and the corresponding controlled engineering drawing number.

REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

FIGURE 9.5F-20A TO BE WITHHELD FROM
PUBLIC PER 10 CFR 2.390 AND
SECY-04-0191.

FIGURE 9.5F-20B TO BE WITHHELD FROM
PUBLIC PER 10 CFR 2.390 AND
SECY-04-0191.

FIGURE 9.5F-20C TO BE WITHHELD FROM PUBLIC PER 10 CFR 2.390 AND SECY-04-0191.

FIGURE 9.5F-20D TO BE WITHHELD FROM
PUBLIC PER 10 CFR 2.390 AND
SECY-04-0191.

FIGURE 9.5F-21 TO BE WITHHELD FROM
PUBLIC PER 10 CFR 2.390 AND
SECY-04-0191.

FIGURE 9.5F-22 TO BE WITHHELD FROM
PUBLIC PER 10 CFR 2.390 AND
SECY-04-0191.

FIGURE 9.5F-23 TO BE WITHHELD FROM
PUBLIC PER 10 CFR 2.390 AND
SECY-04-0191.

FIGURE 9.5F-24 TO BE WITHHELD FROM
PUBLIC PER 10 CFR 2.390 AND
SECY-04-0191.

FIGURE 9.5F-25 TO BE WITHHELD FROM
PUBLIC PER 10 CFR 2.390 AND
SECY-04-0191.

FIGURE 9.5F-26 TO BE WITHHELD FROM
PUBLIC PER 10 CFR 2.390 AND
SECY-04-0191.

FIGURE 9.5F-27 TO BE WITHHELD FROM
PUBLIC PER 10 CFR 2.390 AND
SECY-04-0191.

FIGURE 9.5F-28 TO BE WITHHELD FROM
PUBLIC PER 10 CFR 2.390 AND
SECY-04-0191.

FIGURE 9.5F-29 TO BE WITHHELD FROM
PUBLIC PER 10 CFR 2.390 AND
SECY-04-0191.

FIGURE 9.5F-30 TO BE WITHHELD FROM
PUBLIC PER 10 CFR 2.390 AND
SECY-04-0191.

FIGURE 9.5F-31 TO BE WITHHELD FROM
PUBLIC PER 10 CFR 2.390 AND
SECY-04-0191.

FIGURE 9.5F-32 TO BE WITHHELD FROM
PUBLIC PER 10 CFR 2.390 AND
SECY-04-0191.

FIGURE 9.5F-33 TO BE WITHHELD FROM PUBLIC PER 10 CFR 2.390 AND SECY-04-0191.

APPENDIX 9.5G

EQUIPMENT REQUIRED FOR SAFE SHUTDOWN

APPENDIX 9.5G

EQUIPMENT REQUIRED FOR SAFE SHUTDOWN

Tables 9.5G-1 and 9.5G-2 for DCPP Units 1 and 2, respectively, list the minimum equipment required to bring the plant to a cold shutdown condition as defined by 10 CFR 50, Appendix R, Section III.G.

The "Redundancy/Comments" column is simplified and does not actually represent the component interrelationships needed to ensure safe shutdown. PG&E Engineering Calculation M-680 contains detailed component lists and logic diagrams which give component functions and interrelationships. For example, 1 of 2 ASW pumps and 1 of 2 ASW pump room exhaust fans are required for safe shutdown. The ASW pump that is credited following a postulated fire must also have its associated exhaust fan free from fire damage. These interrelationships are shown on the logic diagrams.

The ability to safely shutdown the plant following a fire in any fire area is evaluated using the safe shutdown logic diagrams, documented in PG&E Engineering Calculation M-928, and summarized in Section 4.0 of Appendix 9.5A of this FSAR Update.

TABLE 9.5G-1 (UNIT 1)

SYSTEM AND ACTIVE COMPONENTS	REDUNDANCY/COMMENTS
1. Emergency Power Supply	
a. Diesel generators 1-1, 1-2, 1-3 and associated equipment	2 of 3 diesel generators required; Offsite power (nonalternate shutdown areas only)
b. Diesel fuel oil transfer pumps	1 of 2 pumps required
c. Day tank level control valves required	1 of 2 LCVs per day tank
LCV-85, LCV-88 LCV-86, LCV-89 LCV-87, LCV-90	
d. Vital batteries	2 of 3 required
e. Vital Battery chargers	2 of 5 required
f. Vital ups	2 of 4 channels required
g. 4kV Vital switchgear	2 of 3 required
h. Vital DC distribution panels	2 of 3 required
i. 480 V Vital switchgear	2 of 3 required
j. Vital instrument ac distribution panels	2 of 4 panels required
k. Fuel oil storage tanks TK 0-1 and TK 0-2	1 of 2 required
l. Startup transformers	2 of 2 required
m. 12kV Startup Bus	1 required
2. Auxiliary Feedwater System	
a. Auxiliary feedwater (AFW) pumps: turbine-driven AFW pump 1-1 and motor-driven AFW pumps 1-2 and 1-3	1 of 3 pumps required
b. AFW pump turbine steam isolation valve:	Applicable only to pump 1-1
FCV-95, FCV-152, FCV-15	Required for AFW pump 1-1

SYSTEM AND ACTIVE COMPONENTS	REDUNDANCY/COMMENTS
FCV-37, FCV-38	Spurious operation only; 1 of 2 valves required for AFW pump 1-1
c. SG Aux Feedwater supply:	
Pump 1-1: LCV-106, LCV-107, LCV-108, and LCV-109	1 of 4 valves required for pump 1-1
Pump 1-2: LCV-110, LCV-111	1 of 2 valves required for Pump 1-2
Pump 1-3: LCV-113, LCV-115	1 of 2 valves required for Pump 1-3
d. Water supply and associated valves:	
1) Condensate storage tank, or	No valves required
2) Raw Water Storage Reservoir (RWSR) FCV-436, FCV-437	1 of 2 valves required for RWSR; manually operated for AFW supply, if required
3) RWSR system manual valves 0-1557, 0-280, 1-121, 1-159, 1-180	Manually align valves when transferring to RWSR
3. Residual Heat Removal System[a]	
a. Residual heat removal (RHR) pumps 1-1 and 1-2	1 of 2 pumps required
b. RHR heat exchangers (HX) 1-1 and 1-2	1 of 2 HX required
c. RHR valves:	
HCV-670, RHR HX Bypass	Valve required
HCV-637, HCV-638, RHR to cold leg loop	1 of 2 valves required
8726A, 8726B, RHR HX Bypass	1 of 2 valves required
d. RHR heat sink:	
Component cooling water (CCW) system	See Item 5
Auxiliary saltwater (ASW) system	See Item 6

[a] Components of RHR system are required for COLD SHUTDOWN (credit is taken for manual alignment of the RHR System to ensure postfire safe shutdown capability).

SYSTEM AND ACTIVE COMPONENTS		REDUNDANCY/COMMENTS
e.	RHR valves 8701 and 8702, Loop 4 Recirculation to RHR	1 of 2 required to maintain reactor coolant pressure boundary during HOT STANDBY (HSB) Both valves can be manually opened for COLD SHUTDOWN (CSD); valves' power breakers are normally open at the motor control center
f.	8707 RHR pumps suction relief valve	Required for overpressure protection when RHR System is in service
g.	8808A, 8808B, 8808C, 8808D Accumulator outlet valve to cold leg	Valves required closed in transition from HSB to CSD Can be manually closed
h.	System components considered for spurious operation:	
	FCV-641A, FCV-641B, RHR pump recirc	Spurious Operation Only
	Valve 8703, Loops 1 & 2 RHR injection	Spurious operation only; valve power breaker is normally open at the motor control center
	8700A, 8700B, RHR Pump Suction	Spurious Operation Only
	8716A, 8716B, RHR HX return to loops	Spurious Operation Only
	8804B, RHR HX 1-2 to SI Pump Suction	Spurious Operation Only
	8809A, 8809B, Cold leg RHR injection	Spurious Operation Only
4.	Charging and Boration	
a.	Centrifugal charging pumps 1-1 , 1-2, and 1-3	1 of 3 pumps required
b.	Charging pump (CCP1 and 2) cooling:	
	CCW system	See Item 5

SYSTEM AND ACTIVE COMPONENTS	REDUNDANCY/COMMENTS
ASW system	See Item 6
c. Centrifugal charging pump 1-1 and charging 1-2 auxiliary lube oil pumps.	Only utilized to start pumps; can be bypassed
d. Borated Water Source - Flowpath to Charging Pumps	Either the RWST or BAST flowpath will provide adequate boration capability
1) Using boric acid storage tanks:	
Boric acid storage tanks	2 of 2 tanks (and manual crosstie valve 8476) required
Boric acid transfer pumps	1 of 2 pumps required.
Valve 8104	Manual valve 8471 and FCV-110A can be used as redundant flowpaths
8460A, 8460B, BA transfer pump discharge	1 of 2 required
2) Using refueling water storage tank:	The VCT may initially be used for RCS makeup prior to alignment of RWST
Valves 8805A, 8805B	1 of 2 valves required open
LCV-112B, LCV-112C, VCT isolation	1 of 2 valves required closed
e. Flowpath to RCS:	1 flowpath required
FCV-128	Required for CCPs if using RCP seals or regenerative heat exchanger flowpath
1) Through the Regenerative Heat Exchanger:	
HCV-142, 8107, and 8108	Valves required for flowpath

SYSTEM AND ACTIVE COMPONENTS	REDUNDANCY/COMMENTS
8146, 8147	1 of 2 valves required open for charging; both valves required closed for auxiliary spray
8145, 8148	1 of 2 valves required for auxiliary spray (for RCS pressure reduction in the transition from HSB to CSD); spurious auxiliary spray is also considered
2) RCP Seal injection flowpath:	
8121, RCP Seal Water Relief Valve	Provides relief path if seal return is isolated
8384A, 8384B, 8396A (RCP seal injection filter isolation valves)	Manually close valves to isolate seal injection and seal return
3) Charging injection flowpath:	
8801A, 8801B	1 of 2 valves required
8803A, 8803B	1 of 2 valves required
f. System components considered for spurious operation:	
8166, 8167, HCV-123, excess letdown HX inlet isolation	Spurious Operation Only
8149A, 8149B, 8149C, LCV-459, LCV-460 letdown isolation	Spurious Operation Only
8105, 8106, Centrifugal charging pump recirculation line isolation	Spurious Operation Only
FCV-110B, FCV-111B, boric acid Blender outlet valves	Spurious Operation Only
HCV-104, HCV-105, boric acid transfer pump recirculation	Spurious Operation Only

SYSTEM AND ACTIVE COMPONENTS	REDUNDANCY/COMMENTS
g. Components considered for spurious operation	
8804A, Charging pump suction header	Spurious operation only
Containment Spray Pumps 1-1 and 1-2 and associated discharge valves 9001A and 9001B	Spurious operation only
SI Pumps 1-1 and 1-2	Spurious operation only
9003A, 9003B, RHR Pumps to Containment Spray Ring Header Isolation	Spurious operation only
8982A, 8982B, Containment Recirc Sump Isolation	Spurious operation only; valves are normally closed/power removed
FT-128, Charging header flow PT-142, Charging header pressure FT-134, Letdown Hx flow LT-112, VCT level LT-920, RWST level	Diagnostic instruments to assist with spurious operation response
5. <u>Component Cooling Water System</u>	
a. CCW pumps 1-1, 1-2, and 1-3	1 of 3 pumps required
b. CCW heat exchangers 1-1, 1-2 and surge tank 1-1	1 of 2 HX required; surge tank required
c. CCW valves:	
FCV-430, FCV-431, CCW supply headers	1 of 2 valves required
FCV-364, FCV-365, RHR HX CCW Outlet	1 of 2 valves required for RHR system cooling; valves required for COLD SHUTDOWN; manual operation assumed in event of failure of remote control
d. CCW pumps 1-1, 1-2, 1-3, auxiliary lube oil pumps	Only required to start CCW pump; can be bypassed

SYSTEM AND ACTIVE COMPONENTS	REDUNDANCY/COMMENTS
e. CCW heat sink:	
ASW system	See Item 6
f. System components considered for spurious operation:	
FCV-355, FCV-356, FCV-357, FCV-750, CCW Header "C" and RCP thermal barrier HX valves	Spurious Operation Only
FT-65, FT-68, FT-79, CCW header flow PT-5, PT-6, CCW Hx Diff. Pressure	Diagnostic instruments to assist with spurious operation response
6. Auxiliary Saltwater System	
a. Auxiliary saltwater (ASW) pumps 1-1, 1-2	1 of 2 pumps required
b. ASW valves:	
FCV-602, FCV-603, ASW to CCW HX inlet loop	1 of 2 valves required
c. ASW cross connect valves FCV-495, FCV-496	Evaluated for ASW boundary isolation
d. System components considered for spurious operation: FCV-601, ASW gates 1-8 and 1-9	Spurious Operation Only; power removed to ASW gates during normal operation
7. Main Steam System	
a. 10 percent atmospheric dump valves: PCV-19, PCV-20, PCV-21, PCV-22	1 of 4 valves required for cooldown; backup to 10 percent steam relief valves provided by main steam code safety valves
b. Steam generator blowdown inboard isolation valves: FCV-760, FCV-761, FCV-762, FCV-763	Required to close to maintain water inventory for safe shutdown

SYSTEM AND ACTIVE COMPONENTS		REDUNDANCY/COMMENTS
	FCV-244 and FCV-160, FCV-246 and FCV-157, FCV-248 and FCV-154, FCV-250 and FCV-151	Required to close only if above steam generator blowdown FCVs fail to close
c.	FCV-41, FCV-42, FCV-43, FCV-44	All four MSIVs required to close to maintain steam generator water inventory
d.	System process line boundary valves considered for spurious operation: FCV-22, FCV-23, FCV-24, FCV-25	Spurious Operation Only
8.	Instrumentation	
a.	Steam generator level: SG 1-1: LT-516[a] , LT-517, LT-518, LT-519 SG 1-2: LT-526[a], LT-527, LT-528, LT-529 SG 1-3: LT-536[a], LT-537, LT-538, LT-539 SG 1-4: LT-546[a], LT-547, LT-548, LT-549	1 steam generator required for cooldown; 1 of 4 level transmitters required per steam generator
b.	Steam generator pressure: Loop 1: PT-514, PT-515, PT-516, PI-518 Loop 2: PT-524, PT-525, PT-526, PI-528 Loop 3: PT-534, PT-535, PT-536, PI-538 Loop 4: PT-544, PT-545, PT-546, PI-548	1 steam generator required for cooldown; 1 of 4 instruments required for that loop

[a] Cold calibrated

SYSTEM AND ACTIVE COMPONENTS	REDUNDANCY/COMMENTS
c. Reactor coolant system temperature: Loop 1: TE-410C, TE-413B Loop 2: TE-423A, TE-423B Loop 3: TE-433A, TE-433B Loop 4: TE-443A, TE-443B	1 loop required for cooldown; hot leg and cold leg temperature indication required for that loop
d. Reactor coolant system pressure: PT-403, PT-405, PT-406	1 of 3 wide-range PTs required
e. Pressurizer level: LT-459, LT-460, LT-461, LT-406[a]	1 of 4 required
f. Source range flux monitors: NE-31, NE-32, NE-51, NE-52	1 of 4 required
g. Boric Acid Storage Tank Level: LT-102, LT-106	1 of 2 required; tank level can be monitored locally if required
h. Condensate Storage Tank Level: LT-40	AFW pump suction can be aligned to RWSR if CST inventory is depleted
9. Ventilation for Safe Shutdown Equipment	
a. 480 V switchgear room and inverter room supply and exhaust fans S-43, FCV-5045, S-44, FCV-5046, E-43, and E-44	[b]
b. 4.16kV switchgear room supply fans S-67, S-68, S-69	Safe shutdown will not be adversely affected by loss of these fans
c. ASW pump room exhaust fans E-101, E-103	1 of 2 required

[a] Cold calibrated. Apply temperature correction to indicated level when using this transmitter in the hot condition.

[b] Portable fans, powered by diesel driven electric generators, can be used in the event that permanent ventilation fans are unavailable due to fire. These fans are to be used in accordance with post-fire safe shutdown procedure CP M-10. These fans can also be used in the unlikely event of a loss of control room ventilation.

SYSTEM AND ACTIVE COMPONENTS	REDUNDANCY/COMMENTS
10. Reactor Coolant System	
a. Pressurizer power-operated relief valves PCV-455C, 474, 456 and block valves 8000A, B, and C	Required to prevent LOCA due to stuck-open valve. PORV's PCV-455C and PCV-456 can also be used for RCS pressure reduction in the transition from HSB to CSD; backup for RCS overpressure protection is provided by pressurizer code safety valves
b. System components considered for spurious actuation:	
PCV-455A, PCV-455B	Spurious Operation Only
8078A, 8078B, 8078C, 8078D	Spurious Operation Only
c. Reactor Coolant Pumps	Ability to trip RCPs is evaluated to prevent unacceptable RCP seal damage or spurious normal spray
d. Pressurizer Heaters 1-1, 1-2, 1-3, and 1-4	All heater groups are evaluated for spurious operation; vital groups 1-2 and 1-3 are evaluated as an "operational convenience" to support safe shutdown

TABLE 9.5G-2 (UNIT 2)

SYSTEM AND ACTIVE COMPONENTS	REDUNDANCY/COMMENTS
1. Emergency Power Supply	
a. Diesel generators 2-1, 2-2, 2-3 and associated equipment	2 of 3 diesel generators required; Offsite power (nonalternate shutdown areas only)
b. Diesel fuel oil transfer pumps 0-1, 0-2	1 of 2 pumps required
c. Day tank level control valves: LCV-85, LCV-88 LCV-86, LCV-89 LCV-87, LCV-90	1 of 2 LCVs per day tank required
d. Vital batteries	2 of 3 required
e. Vital Battery chargers	2 of 5 required
f. Vital ups	2 of 4 channels required
g. 4kV Vital switchgear	2 of 3 required
h. Vital DC distribution panels	2 of 3 required
i. 480 V Vital switchgear	2 of 3 required
j. Vital instrument ac distribution panels	2 of 4 panels required
k. Fuel oil storage tanks TK 0-1 and TK 0-2	1 of 2 required
l. Startup transformers	2 of 2 required
m. 12kV Startup Bus	1 required
2. Auxiliary Feedwater System	
a. Auxiliary feedwater (AFW) pumps: turbine-driven AFW pump 2-1 and motor-driven AFW pumps 2-2 and 2-3	1 of 3 pumps required.
b. AFW pump turbine steam isolation valve: FCV-95, FCV-152, FCV-15	Applicable only to AFW pump 2-1 Required for AFW pump 2-1

SYSTEM AND ACTIVE COMPONENTS	REDUNDANCY/COMMENTS
FCV-37, FCV-38	Spurious operation only; 1 of 2 valves required for AFW pump 2-1
c. SG AUX Feedwater supply:	
Pump 2-1: LCV-106, LCV-107, LCV-108, and LCV-109	1 of 4 valves required for pump 2-1
Pump 2-2: LCV-110, LCV-111	1 of 2 valves required for pump 2-2
Pump 2-3: LCV-113, LCV-115	1 of 2 valves required for pump 2-3
d. Water supply and associated valves:	
1) Condensate storage tank, or	No valves required
2) Raw Water Storage Reservoir (RWSR) FCV-436, FCV-437	1 of 2 valves required to be manually operated for RWSR
3) RWSR system manual valves 0-1557, 0-280, 1-121, 1-159, 1-180	Manually align valves when transferring to RWSR
3. Residual Heat Removal System[a]	
a. Residual heat removal (RHR) pumps 2-1 and 2-2	1 of 2 pumps required
b. RHR heat exchangers 2-1 and 2-2	1 of 2 HX required
c. RHR valves:	
HCV-637, HCV-638, RHR to cold leg loop	1 of 2 valves required
HCV-670, RHR HX Bypass 8726A, 8726B, RHR HX Bypass	Valve required 1 of 2 valves required
d. RHR heat sink:	
Component cooling water (CCW) system	See Item 5
Auxiliary saltwater (ASW) system	See Item 6

[a] Components of RHR system are required for COLD SHUTDOWN only (Credit is taken for manual alignment of the RHR system to ensure postfire safe shutdown capability).

SYSTEM AND ACTIVE COMPONENTS	REDUNDANCY/COMMENTS
e. RHR valves 8701 and 8702, hot leg RHR suction	1 of 2 required to maintain reactor coolant pressure boundary during HSB; both valves can be manually opened for CSD; valve power breakers are normally open at the motor control center
f. 8707, RHR pump suction relief valve	Required for overpressure protection when RHR system is in service
g. 8808A, 8808B, 8808C, 8808D Accumulator outlet valve to cold leg	Valves required closed in transition from HSB to CSD; can be manually closed
h. System components considered for spurious operation:	
FCV-641A, FCV-641B, RHR pump recirc	Spurious Operation Only
Valve 8703, loops 1 and 2 RHR injection	Spurious Operation Only; valve power circuit is normally racked out at the motor control center
8700A, 8700B, RHR Pump Suction	Spurious Operation Only
8716A, 8716B, RHR HX return to loops	Spurious Operation Only
8804B, RHR HX 2-2 to SI Pump Suction	Spurious Operation Only
8809A, 8809B, cold leg RHR injection	Spurious Operation Only
4. Charging and Boration	
a. Centrifugal charging pumps 2-1, 2-2, and 2-3	1 of 3 pumps required
b. Charging pump cooling:	
CCW system	See Item 5
ASW system	See Item 6

SYSTEM AND ACTIVE COMPONENTS	REDUNDANCY/COMMENTS
c. Centrifugal charging pumps 2-1 and 2-2, auxiliary lube oil pumps	Only utilized to start charging pumps; can be bypassed
d. Borated water source to charging pumps	Either the RWST or BAST flowpath will provide adequate boration capability
1) Using boric acid storage tanks:	
Boric acid storage tanks	2 of 2 tanks and manual cross-tie valve 8476 required
Boric acid transfer pumps	1 of 2 pumps required
Valve 8104	Manual valve 8471 and FCV-110A can be used as redundant flowpath
8460A, 8460B, BA transfer pump discharge	1 of 2 required
OR	
2) Using refueling water storage tank:	The VCT may initially be used for RCS makeup prior to alignment of RWST
Valves 8805A and 8805B	1 of 2 valves required open
Valves LCV-112B and LCV-112C, VCT Isolation	1 of 2 valves required closed
e. Flowpath to RCS:	1 flowpath required
FCV-128	Required for CCPs if using RCP seals or regenerative heat exchanger flowpath
1) Regenerative heat exchanger flowpath:	
HCV-142, 8107, and 8108	Valves required for flowpath

SYSTEM AND ACTIVE COMPONENTS	REDUNDANCY/COMMENTS
8146, 8147	1 of 2 valves required open for charging; both valves required closed for auxiliary spray
8145, 8148	1 of 2 valves required for auxiliary spray (for RCS pressure reduction in transition from HSB to CSD); spurious auxiliary spray is also considered
2) RCP seal injection flowpath:	
8121, RCP Seal Water Relief Valve	Provides relief path if seal return is isolated
8384A, 8384B, 8396A (RCP seal injection filter isolation valves)	Manually close valves to isolate seal injection and seal return
3) Charging injection flowpath:	
8801A, 8801B	1 of 2 valves required
8803A, 8803B	1 of 2 valves required
f. System components considered for spurious operation:	
8166, 8167, HCV-123, excess letdown HX inlet isolation	Spurious Operation Only
8149A, 8149B, 8149C, LCV-459, LCV-460 letdown isolation	Spurious Operation Only
8105, 8106, Centrifugal charging pump recirculation line isolation	Spurious Operation Only
FCV-110B, FCV-111B, boric acid blender outlet valves	Spurious Operation Only
HCV-104, HCV-105, boric acid transfer pump recirculation	Spurious Operation Only
8804A, Charging pump suction header	Spurious Operation Only

SYSTEM AND ACTIVE COMPONENTS		REDUNDANCY/COMMENTS
	Containment Spray Pumps 2-1 and 2-2 and associated discharge valves 9001A and 9001B	Spurious Operation Only
	SI Pumps 2-1 and 2-2	Spurious Operation Only
	9003A, 9003B, RHR Pumps to Containment Spray Ring Header Isolation	Spurious Operation Only
	8982A, 8982B, Containment Recirc Sump Isolation	Spurious Operation Only; valves are normally closed with power removed
	FT-128, Charging header flow PT-142, Charging header pressure FT-134, Letdown Hx flow LT-112, VCT level LT-920, RWST level	Diagnostic instruments to assist with spurious operation response
5.	Component Cooling Water System	
a.	CCW pumps 2-1, 2-2, and 2-3	1 of 3 pumps required
b.	CCW heat exchangers 2-1, 2-2, and surge tank 2-1	1 of 2 HX required Surge tank required
c.	CCW valves:	
	FCV-430, FCV-431, CCW supply headers	1 of 2 valves required
	FCV-364, FCV-365, RHR HX CCW outlet	1 of 2 valves required for RHR system cooling; valves required for COLD SHUTDOWN; manual operation assumed in event of failure of remote control
d.	CCW pumps 2-1, 2-2, 2-3, auxiliary lube oil pumps	Only required to start CCW pump; can be bypassed

SYSTEM AND ACTIVE COMPONENTS	REDUNDANCY/COMMENTS
e. CCW heat sink:	
ASW system	See Item 6
f. System components considered for spurious operation:	
FCV-355, FCV-356, FCV-357, FCV-750, CCW Header C and RCP thermal barrier HX valves.	Spurious Operation Only
FT-65, FT-68, FT-79, CCW header flow PT-5, PT-6, CCW Hx Diff. Pressure	Diagnostic instruments to assist with spurious operation response
6. Auxiliary Saltwater System	
a. Auxiliary saltwater (ASW) pumps 2-1, 2-2	1 of 2 pumps required
b. ASW valves:	
FCV-602, FCV-603, ASW to CCW HX inlet loop	1 of 2 valves required
c. ASW cross connect valves FCV-495, FCV-496	Evaluated for ASW boundary isolation
d. System components considered for spurious operation:	
ASW Gates 2-8 and 2-9, FCV-601	Spurious Operation Only; power removed to ASW gates during normal operation
7. Main Steam System	
a. 10 percent atmospheric dump valves PCV-19, PCV-20, PCV-21, PCV-22	1 of 4 valves required for cooldown; backup to 10 percent steam relief valves provided by main steam code safety valves

SYSTEM AND ACTIVE COMPONENTS	REDUNDANCY/COMMENTS
b. Steam generator blowdown inboard isolation valves: FCV-760, FCV-761 FCV-762, and FCV-763	Required to close to maintain water inventory for safe shutdown
FCV-244 and FCV-160, FCV-246 and FCV-157, FCV-248 and FCV-154, FCV-250 and FCV-151	Required to close only if above steam generator blowdown FCVs fail to close
c. FCV-41, FCV-42, FCV-43, FCV-44	All four MSIVs required closed to maintain SG water inventory
d. System component considered for spurious operation:	
FCV-22, FCV-23, FCV-24, FCV-25	Spurious Operation Only
8. Instrumentation	
a. Steam generator level SG 2-1: LT-516[a], LT-517, LT-518, LT-519 SG 2-2: LT-526[a], LT-527, LT-528, LT-529 SG 2-3: LT-536[a], LT-537, LT-538, LT-539 SG 2-4: LT-546[a], LT-547, LT-548, LT-549	1 steam generator required for; cooldown 1 of 4 level transmitters required per steam generator
b. Steam generator pressure: Loop 1: PT-514, PT-515, PT-516, PI-518 Loop 2: PT-524, PT-525, PT-526, PI-528 Loop 3: PT-534, PT-535, PT-536, PI-538 Loop 4: PT-544, PT-545, PT-546, PI-548	1 steam generator required for cooldown; 1 of4 instruments required for that loop

[a] Cold calibrated. Apply temperature correction to indicated level when using these transmitters in the hot condition.

SYSTEM AND ACTIVE COMPONENTS	REDUNDANCY/COMMENTS
c. Reactor coolant system temperature: Loop 1: TE-413A, TE-413B Loop 2: TE-423A, TE-423B Loop 3: TE-433A, TE-433B Loop 4: TE-443A, TE-443B	1 loop required for cooldown; hot leg and cold leg temperature indication required for that loop
d. Reactor coolant system pressure: PT-403, PT-405, PT-406	1 of 3 wide-range PTs required
e. Pressurizer level: LT-459, LT-460, LT-461, LT-406[a]	1 of 4 required
f. Source range flux monitors: NE-31, NE-32, NE-51, NE-52	1 of 4 required
g. Boric acid storage tank level: LT-102, LT-106	1 of 2 required tank level can be monitored locally if required
h. Condensate storage tank level: LT-40	AFW pump suction can be aligned to RWSR if CST inventory is depleted
9. Ventilation for Safe Shutdown Equipment	
a. 480V switchgear room and inverter room supply and exhaust fans S-45, FCV-5045, S-46, FCV-5046, E-45, and E-46	[b]
b. 4.16kV switchgear room supply fans S-67, S-68, S-69	Safe shutdown will not be adversely affected by loss of these fans
c. ASW pump room exhaust fans E-102 and E-104	1 of 2 required

[a] Cold Calibrated. Apply temperature correction to indicated level when using this transmitter in the hot condition.

[b] Portable fans, powered by diesel driven electric generators, can be used in the event that permanent ventilation fans are unavailable due to fire. These fans are to be used in accordance with post-fire safe shutdown procedure CP M-10. These fans can also be used in the unlikely event of a loss of control room ventilation.

SYSTEM AND ACTIVE COMPONENTS	REDUNDANCY/COMMENTS
10. Reactor Coolant System	
a. Pressurizer power operated relief valves PCV-455C, 474, 456 and block valves 8000A, B, and C.	Required to prevent LOCA due to stuck-open valve; PORVs PCV-455C and PCV-456 can be used for RCS pressure reduction in the transition from HSB to CSD; backup for RCS overpressure protection is provided by pressurize code safety valves
b. System components considered spurious actuation:	
PCV-455A, PCV-455B	Spurious Operation Only
8078A, 8078B, 8078C, 8078D	Spurious Operation Only
c. Reactor Coolant Pumps	Ability to trip RCPs is evaluated to prevent unacceptable RCP seal damage or spurious normal spray
d. Pressurizer Heaters 2-1, 2-2, 2-3 and 2-4	All heater groups for spurious operation; vital groups 2-2 and 2-3 evaluated as an "operational convenience" to support safe shutdown

APPENDIX 9.5H

INSPECTION AND TESTING REQUIREMENTS AND PROGRAM ADMINISTRATION

APPENDIX 9.5H

INSPECTION AND TESTING REQUIREMENTS AND PROGRAM ADMINISTRATION

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APPENDIX 9.5H

INSPECTION AND TESTING REQUIREMENTS AND PROGRAM ADMINISTRATION

SCOPE

The purpose of the "Fire Protection Program" is to provide assurance through a defense-in-depth approach that a fire at the plant will not seriously endanger the safety of personnel, will not cause an unacceptable loss of property, will not prevent the performance of necessary safe shutdown functions and will not significantly increase the risk of radioactive releases to the environment. The "Fire Protection Program" consists of the utilization of fire resistive materials where feasible, fire detection and extinguishing systems and equipment, administrative controls and procedures and trained emergency response personnel."

ORGANIZATION

A. Administrative Responsibilities

1. The President of PG&E has overall responsibility for the fire protection program. Direct authority for implementing the program is delegated through the company line organization to the director in direct charge of the company facility.

2. The Senior Vice President, Chief Nuclear Officer, is responsible for implementing and maintaining in effect all provisions of the approved fire protection program for DCPP as required by the facility operating licenses.

3. The Site Vice President is responsible for overall safe operation of the plant and has control over onsite activities necessary for safe operation and maintenance of the plant including fire protection.

4. The Vice President, Nuclear Services is responsible for fire protection.

5. The Director, Engineering Services is responsible for:

   - establishment of all technical and quality classification requirements for engineering and design of fire protection structures, systems, and components, including changes and modifications.

   - maintenance of Chapter 9, Section 5.1 of the FSAR.

   - assignment of qualified Fire Protection Engineers for review and acceptance of fire protection related design changes.

- maintenance of the technical bases for Fire Hazards Appendix R Evaluations (FHAREs)

- Initiating follow-up actions as necessary to correct identified deficiencies.

- Fire Protection matters with insurance company inspectors.

6. The Director - Quality Verification, is responsible for ensuring audits of the Fire Protection Program are conducted in accordance with license requirements.

7. The Director, Security and Emergency Services has the ultimate responsibility for the Diablo Canyon Fire Protection Program. The Director, Security and Emergency Services is responsible for:

   - Implementation of the Fire Loss Prevention Program.

   - The day-to-day coordination of the Fire Protection Program.

8. The Director, Security and Emergency Services is responsible for the implementation of the Plant Fire Brigade Program, including the training and administration of the Plant Fire Brigade as conducted by the Supervisor - Fire Protection.

9. The Supervisor - Fire Protection is responsible for:

   - Ensuring the shift fire brigade complement is available for emergency response.

   - The day to day coordination, management, and implementation of the Fire Brigade Program, including fire brigade training.

   - Life Safety Program.

   - Pre-fire planning.

   - Site emergency responses for fires, hazardous materials, medical, and rescues.

   - Plant interface with state and county fire codes, company departments for life/safety code compliance, regulators, and the California Department of Forestry and Fire.

   - Monitoring fire prevention programs, including the control of ignition sources and adherence to Plant Administrative procedures.

9. Plant department heads and supervisors are required to ensure that the surveillance, testing and administrative fire protection procedures for which they are responsible are implemented and that their department personnel attend required fire protection and fire safety training.

10. The Shift Supervisor and Shift Foreman are responsible to monitor the operability of the plant fire protection system and to ensure that all appropriate compensatory measures have been implemented in accordance with the ECG for the systems or portions of systems which have been declared inoperable. The Shift Foreman is also responsible for the approval, extension or revocation of Weld Permits in the absence of a member of Fire Protection.

11. The Fire Brigade Leader is responsible to direct the fire fighting efforts at the scene of the fire and has the authority to order plant personnel to assist in fighting a fire.

12. Plant fire brigade members are required to participate in all aspects of the Fire Brigade Training Program and ensure all training requirements are kept current. They shall respond in a safe and timely fashion to all fire alarms and cooperate with offsite fire fighting agencies to extinguish site fires.

13. It is the responsibility of all plant employees to immediately report all fires, assist Fire brigade personnel as directed in a fire fighting effort, report all fire hazards to their supervisor, work safely and in such a manner as not to create a fire hazard and to be acquainted with the use and location of emergency equipment.

B. Fire Brigade Organization and Responsibilities

1. There is one Fire Brigade on each shift providing continuous response capability. The Fire Brigade personnel may have no other fire emergency responsibilities that would prevent them from performing Fire Brigade duties.

1 Leader	Fire Brigade Leader Qualified
4 Crew Members	Fire Brigade Member Qualified

Note: The Fire Brigade Leader is a member of the Fire Brigade and has been specifically trained as a Fire Brigade Leader and designated as such by the Supervisor - Fire Protection. A qualified Nuclear Operator or Licensed Operator will accompany the Fire Brigade Leader in all emergency responses, unless the Nuclear Operator or Licensed Operator is the Fire Brigade Leader.

2. Site Emergency Coordinator's (SEC) responsibilities include:

   a. Dispatching the Fire Brigade to the scene of a fire emergency.

b. Dispatching additional personnel to the scene of the fire as requested by the Fire Brigade Leader.

c. Shutdown of fire affected or sensitive equipment.

d. Modifying ventilation as required by the fire emergency.

e. De-energizing affected equipment.

f. Requesting assistance from the San Luis Obispo County Fire Department/California Department of Forestry (CDF) if required.

g. Notifying site Security in the event that outside assistance is required.

h. Notifying the System Dispatcher if unit load is affected.

i. Notifying persons required by plant emergency procedures.

3. The Fire Brigade Leader's responsibilities are:

a. Command at the scene of the fire emergency.

b. Safely coordinate the fire attack by the Fire Brigade and account for personnel.

c. Establish a communication link between the scene of the fire emergency and the SEC.

d. Advise the SEC of the need for assistance.

e. During occasions when offsite professional fire fighting assistance is required the Brigade Leader is encouraged to rely heavily on the recommendations and expertise of these professionals. The ultimate responsibility and authority at the scene, however, remains that of the Brigade Leader.

4. All Fire Brigade member's responsibilities are:

a. To participate in the training and drill exercises scheduled for the brigade.

b. To respond in a safe and timely manner to all fire alarms.

c. To assist offsite fire fighting personnel with extinguishment of onsite fires.

d. To be particularly alert of fire hazards and take immediate action to get them corrected.

5. Fire Detection by plant personnel

   a. Reporting of fires takes precedence over fighting a fire. Only personnel who are trained in the use of fire fighting equipment may attempt to suppress a fire.

   b. Fires can be reported automatically by the fire alarm signal system or manually by plant personnel by calling the control room or using a radio to contact the control room.

SPECIAL CONSIDERATIONS

A. License Requirements

Operating License Condition 2.C(4) and 2.C(5) for Units 1 and 2, respectively, require PG&E to maintain the approved Fire Protection Program. Changes can be made to the approved program without NRC approval provided the changes do not affect the ability to achieve and maintain safe shutdown requirements.

Certain portions of the fire protection system are required by the license to be operable. Prior to removing any portion(s) of the various fire protection systems from operation or upon discovering that a portion is inoperable, the Shift Supervisor or Shift Foreman shall be notified and a clearance request or other appropriate document submitted in accordance with the plant fire system impairment reporting system. Operability of fire protection systems are controlled by Equipment Control Guidelines (ECGs).

Amendments 75 and 74 of the Unit 1 and Unit 2 Operating License, respectively, relocated the fire protection details of the DCPP Technical Specifications (TS) into this Appendix and into the administratively controlled ECGs (see Chapter 16 of this FSAR Update). As a result, this Appendix provides the basis for the administratively controlled fire protection plan ECGs. The list of ECGs is located in the section entitled "Fire Protection Operability And Surveillance Requirements" of this Appendix. Administrative Procedures provide guidance in the handling and documenting of impairments.

B. Notification of Insurance Carrier

The insurance carrier shall be informed of impairments to the fire system in accordance with the plant fire system impairment reporting system. The Insurance Department shall also be informed of fire incidents at the plant.

C. Fire Rated Assemblies

1. Fire rated assemblies are defined as steel doors and their associated hardware, electrical and mechanical penetration seals, fire rated enclosures around safe shutdown circuits, credited cable tray fire stops, and ventilation dampers which provide the equivalent fire rating as the penetrated barrier (walls, floors, ceilings).

2. Fire Rated Assemblies governed by 10 CFR 50, Appendix R are controlled by ECG 18.7.1. Fire Rated Assemblies governed by BTP 9.5-1, Appendix A are controlled by 18.7.2. In accordance with ECG 18.7.1 and ECG 18.7.2, a fire watch is to be provided during the period the fire barrier is open or not functional, as required by the plant license and fire system impairment reporting system.

3. Temporary fire barrier penetration sealing material may be used until the permanent barriers have been installed and visually inspected to assure they are functional. However, this does not replace fire watch requirements.

D. Welding, Cutting, Grinding, and Brazing

Welding, cutting, grinding or brazing will be performed in accordance with the provisions of plant administrative procedures.

E. Combustible Materials in Safety-Related Areas

1. Use of combustibles in safety-related areas is to be strictly controlled and is the responsibility of the area or work supervisor. Specific controls are delineated in plant procedures.

2. During refueling and maintenance operations, fire retardant and noncombustible materials should be used where practicable.

3. Smoking is strictly prohibited in the building and structures within the protected areas and in areas where "No Smoking" signs are posted.

F. Solvent Cleaning

1. "No Smoking" signs shall be posted in the immediate area where solvent cleaning is performed and where other work involves open exposure of flammable liquid or gas.

2. Solvent cleaning with flammable liquids, when possible, should be done out of doors with maximum ventilation available and a portable fire extinguisher in the immediate area.

3. Safety solvents should be used in lieu of more flammable solvents where practicable.

TRAINING

A. All Plant Employees

Plant utility employees shall receive initial site specific fire protection training through General Employee Training or similar instruction delivery methods. This training shall include a discussion of the "Fire Protection Program," reporting of fires, fire prevention techniques and use of extinguishing agents. Special training programs for fire watch and other emergency response personnel shall be conducted as required prior to assignment to those positions.

B. Fire Brigade Training

The Supervisor - Fire Protection is responsible for the content of the Fire Brigade Training Program. All members are trained to a level of competency commensurate with the duties expected to be performed.

1. General

   Federal and State Regulations require periodic training of Fire Brigade members. The training program utilizes classroom instruction, practice in fighting typical fires, and fire drills. Training is conducted on a continuing basis. Training sessions are designed such that all areas are completed every two years for Fire Brigade members.

2. Classroom Instructions

   The classroom instruction program includes:

   a. Identification of major fire hazards, locations of these hazards, and the type of fire with which each hazard is associated.

   b. Fire extinguishing agents best suited for controlling the fires, identification of the location of fire fighting equipment and familiarization with the plant layout including access and egress routes.

   c. The proper use of fire fighting equipment and the correct method of fighting the various types of fires which are likely to occur.

   d. Instruction in the Fire Protection Program including the direction and coordination of the fire fighting activities and individual responsibilities.

   e. The types of toxic characteristics of expected products of combustion from typical fires which can occur.

f. The proper method for fighting fires in various plant locations including confined spaces.

g. Fire fighting procedures and strategies including recent changes.

h. Plant modifications that have a significant impact on fire protection.

i. Personnel rescue operations.

j. The proper use of communication, lighting, ventilation and emergency breathing apparatus.

k. The direction and the coordination of fire fighting activities (Fire Brigade Leaders only).

3. Fire Brigade Drills

a. Fire Brigade drills are conducted quarterly for each Fire Brigade.

b. The drills are conducted on the plant site in areas containing significant fire hazards where similar fires of that type, size and arrangement could reasonably occur.

c. Drills are conducted so that each Fire Brigade member can participate. Each Brigade member should participate in at least one drill per year.

d. At least one drill per year for each Fire brigade is performed on a back-shift.

e. At least one drill per year for each Fire Brigade is unannounced.

f. Drills will be observed by supervisory personnel to:

(1) Assess the effectiveness of the notification systems and times for the response of the Fire Brigade and their selection and use of equipment.

(2) Assess the individual Fire Brigade member's knowledge of his responsibilities, conformance with established procedures and the use of fire fighting and other emergency equipment to the extent practicable.

(3) Assess the Fire Brigade Leader's effectiveness in direction of the fire fighting effort.

(4) Assess the overall effectiveness of the drill to determine if the training objectives are being met.

g. Two drills per year shall involve a coordinated response involving the plant Fire Brigade and offsite fire protection agencies.

4. Practice

Live fire training shall be conducted annually to provide experience in the skills and techniques of bringing fires under control and the use of fire fighting equipment and self-contained breathing apparatus under strenuous fire fighting conditions.

5. Minimum Physical Requirements

A medical screening evaluation shall be performed annually for each fire Brigade member to identify potential cardiopulmonary deficiencies which may be aggravated by strenuous fire fighting activities. All members of the plant fire Brigade shall meet the medical screening acceptance criteria for respirator users.

6. Records and Evaluations

Records of the training conducted, classroom instruction attendance and drill participation shall be entered in the DCPP Training Records Program. Attendance and participation records shall be retained as a minimum for the duration of the individual's employment at DCPP.

FIRE EQUIPMENT INSPECTION AND MAINTENANCE

To meet the plant license, CAL-OSHA, and insurance carrier requirements, fire equipment for the plant is inspected and maintained on a routine basis.

IMPLEMENTING FIRE PROGRAM PROCEDURES

The nature of the Fire Protection Program is such that it may affect all plant personnel. As a result, implementing fire program procedures are included in several locations in the Plant Manual.

An informational listing of procedures related to the Fire Protection Program can be found in Design Criteria Memorandum S-18, “Fire Protection System,” and T-13, “Appendix R Fire Protection.” Some portions of the Plant Manual in which they are found are listed below.

Administrative Procedures

Fire Loss Prevention
Fire Brigade Training
Welding, Cutting and Open Flame
Storage and Handling of Combustible Materials
Fire System Impairment
Control of Flammable Materials
Fire Watch and Welding Personnel
Fire Protection Program Administration

Operating Procedures

Fire Water System
Fire Supplement Water System Valve Checklist

Emergency Procedures

Control Room Inaccessibility (Establishing Hot Standby and Cold Shutdown)
Radiological Fire
Non-radiological Fire
Fire Protection of Safe Shutdown Equipment

Maintenance Procedures

Fire Pump Disassembly, Repair & Reassembly
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RHR Pump Control Transfer Switch
Centrifugal Charging Pump CCP3 Operability
Manual Auxiliary Spray Valves

FIRE PROTECTION OPERABILITY AND SURVEILLANCE REQUIREMENTS

This section identifies the DCPP fire protection operability and surveillance requirements. These requirements were relocated from the TS by LAR 90-11 into ECGs. ECGs are also provided for equipment credited for Appendix R safe shutdown that are not covered by existing Technical Specifications. As such, this section provides the basis for the administratively controlled fire protection plan ECGs as stated in the License Requirements section of this Appendix. The ECGs associated with the Fire Protection Program and the bases are provided below:

ECG 18.1, “Fire Suppression Systems/Fire Suppression Water Systems”

ECG 18.2, “Fire Hose Stations”

ECG 18.4, “Spray and/or Sprinkler System”

ECG 18.5, “CO_2 System”

BASIS:

The operability (as defined in DCPP Technical Specifications) of the Fire Suppression Systems ensure that adequate fire suppression capability is available to confine and suppress fires occurring in any portion of the facility where safety-related equipment is located. The Fire Suppression System consists of the water system, spray and/or sprinklers, CO_2, and firewater hose stations. The collective capability of the Fire Suppression System is adequate to minimize potential damage to safety-related equipment and is a major element in the facility Fire Protection Program.

In the event that portions of the Fire Suppression Systems are inoperable, alternate fire fighting equipment is required to be made available in the affected areas until the inoperable equipment is restored to service. When the inoperable fire fighting equipment is intended for use as a backup means of fire suppression, a longer period of time is allowed to provide an alternate means of fire fighting than if the inoperable equipment is the primary means of fire suppression.

The surveillance requirements provide assurance that the minimum operability requirements of the Fire Suppression Systems are met.

In the event the Fire Suppression Water System becomes inoperable, prompt corrective measures must be taken since this system provides the major fire suppression capability of the plant.

ECG 18.3, "Fire Detection Instrumentation"

BASIS:

The operability of the detection instrumentation ensures that adequate warning capability is available for prompt detection of fires. This capability is required in order to detect and locate fires in their early stages. Prompt detection of fires will reduce the potential for damage of safety-related equipment and is an integral element in the overall facility Fire Protection Program.

In the event that a portion of the fire detection instrumentation is inoperable, the establishment of frequent fire patrols in the affected areas is required to provide detection capability until the inoperable instrumentation is restored to operability.

Since the fire detectors installed in the plant are nonseismic, an inspection will be performed following a seismic event to detect any fires.

ECG 18.7, "Fire Rated Assemblies"

GENERAL BASIS:

The functional integrity of the fire rated assemblies and associated penetration seals ensures that fires will be confined or adequately retarded from spreading to adjacent fire areas/zones or from affecting redundant safe shutdown circuits (10 CFR 50, Appendix R), and that safety-related equipment is protected from high fire hazards (BTP 9.5-1, Appendix A). This design feature minimizes the possibility of a single fire rapidly involving several fire areas/zones of the facility prior to detection and extinguishment. The fire rated assemblies and penetration seals are a passive element in the facility Fire Protection Program and are subject to periodic inspections.

ECG 18.7.1, "10 CFR 50 APPENDIX R Fire Rated Assemblies"

BASIS:

Fire Rated Assemblies governed by 10 CFR 50, Appendix R are controlled by ECG 18.7.1. Appendix R fire rated assemblies are used to protect Safe Shutdown equipment from fire hazards.

The fire rated assemblies, including fire rated enclosures, penetration seals, fire doors and fire dampers, are considered functional when the visually observed condition is the same as the as-designed configuration. For those fire rated assemblies that are not in the as-designed configuration, either the appropriate ECG action shall be performed until the fire rated assembly is returned to the as-designed configuration, or an evaluation is performed to show that the as-built configuration has not degraded the capability of the fire rated assembly to prevent the spread of fire from adversely affecting the ability to achieve and maintain safe shutdown conditions (i.e., FHARE).

During periods of time when a fire rated assembly is not functional, either (1) a continuous fire watch is required to be maintained in the immediate vicinity of the affected barrier, or (2) the fire detectors or detection capability of the automatic fire suppression system on at least one side of the affected barrier must be verified operable and an hourly fire watch patrol established until the barrier is restored to functional status.

Both the fire detectors and automatic fire suppression system provide detection and alarm capability in the control room for early warning of a fire, so that the operators can muster the Fire Brigade.

A fire watch is considered continuous if the patrol can monitor the immediate area of the nonfunctional fire rated assembly at least once per 15 minutes or less. Because of existing administrative controls on storage of in-situ and transient combustible materials, hot work permits (ignition sources), and the existence of low combustible loading throughout DCPP and the widely dispersed locations of the combustible materials, it is not expected that a large uncontrolled fire will occur within 15 minutes. A fire watch monitoring the affected area at least once per 15 minutes will accomplish the intent of a continuous fire watch.

For penetration seals, an alternate to either the continuous or roving fire watches, a temporary repair may be implemented. A size limitation of 16 square inches of the impaired sealant surface area for any individual gap or void is established based on available testing. An analysis of DCPP fire testing for the use of ceramic blanket and fiber to maintain a fire rated seal has been performed. This compensatory measure is only acceptable as a temporary repair due to the inability to maintain and control this configuration. Penetration seals repaired in accordance with this method shall be tracked and permanently repaired to the as-designed configuration.

For openings in non-combustible enclosures that form part of a fire barrier, an alternate administrative control may be implemented. Non-combustible enclosures are metal conduits, junction boxes, condulets, panels, etc., used for electric cable routing. These enclosures are considered part of fire rated assemblies when they are used in lieu of internal conduits seals (ICS). For open enclosures, the presence of personnel performing work or inspections may be used in lieu of a fire watch. While these individuals may or may not have the fire watch qualification (FIRE1), their presence will ensure that if a fire were to occur, it would be detected in its incipient stage. This administrative control is an alternative to either the continuous or roving fire watch specified in ECG-18.7.1 or ECG 18.7.2.

For fire rated assemblies that do not have fire detection on at least one side of the assembly, use of the portable detection system as an alternate fire detection system is acceptable. Usage of the portable detection system in conjunction with an hourly firewatch does not reduce the effectiveness of existing fire protection capability.

ECG 18.7.2, "NRC BRANCH TECHNICAL POSITION (BTP) 9.5-1 APPENDIX A Fire Rated Assemblies"

BASIS:

Fire Rated Assemblies governed by BTP 9.5-1, Appendix A are controlled by ECG 18.7.2.

Appendix A fire rated assemblies include all walls, floor/ceilings, fire rated enclosures, fire doors, fire dampers, hatches, penetration seals (outside containment), and credited cable tray firestops which are used to protect safety related equipment from fire hazards.

Appendix A fire rated assemblies are those fire rated assemblies that are not credited to separate redundant safe shutdown equipment and are not required to ensure safe shutdown capability is maintained, but are instead credited to protect safety related equipment from fire hazards. In the event that a fire rated assembly that is necessary for defense-in-depth or to protect safety related equipment from fire hazards becomes INOPERABLE, appropriate compensatory measures per ECG 18.7.2 must be taken while the assembly is being restored to operability or until an evaluation can be made demonstrating that other compensatory measures are not required.

The functional integrity of the fire rated assemblies, including penetration seals, ensures that a fire will be confined to its area of origin. This will ensure flames and hot gasses are prevented from spreading to adjacent fire areas/zones, and that safety related equipment is protected from fire hazards (NRC Branch Technical Position (BTP) 9.5-1, Appendix A, "Overall Requirements of Nuclear Plant Fire Protection Program"). These design features minimize the possibility of a single

fire rapidly involving several fire areas/zones of the facility prior to detection and extinguishment.

Appendix A to BTP 9.5-1 provides the following guidance on “Building Design”: Floors, walls, and ceilings enclosing separate fire areas should have minimum fire rating of three-hours. 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. Penetrations for ventilation systems should be protected by a standard “fire door damper” where required.

Appendix A fire rated assemblies are used to protect safety related equipment from fire hazards, whereas, Appendix R fire rated assemblies are used to protect Safe Shutdown equipment from fire hazards. As a result, fire propagation across Appendix A fire barriers will not affect the ability to reach safe shutdown conditions. The ECG 18.7.2 ensures that the fire rating of these Appendix A barriers will be maintained.

The fire rated assemblies, including walls, floors/ceilings, fire rated enclosures, penetration seals, fire doors, fire dampers, credited cable tray firestops, and hatches are considered functional when the observed condition is the same as the as-designed configuration. For those fire rated assemblies that are not in the as-designed configuration, either the appropriate ECG action shall be performed, until the fire rated assembly is returned to the as-designed configuration, or a documented evaluation of an impaired Appendix A fire rated assembly may be conducted. Because fire rated assemblies applicable to ECG 18.7.2 in and of themselves do not impact the ability to provide adequate separation of redundant trains of safe shutdown systems, impairment of ECG 18.7.2 barriers has limited impact on the ability to achieve and maintain safe shutdown in the event of a fire. However, an evaluation of an ECG 18.7.2 impairment may be completed to assess if an adequate level of defense-in-depth will continue to be provided within the affected fire area, and determine if other compensatory action is not required. The impairment shall still be corrected in a timely fashion. Accordingly, an ECG 18.7.2 Fire Rated Assembly Impairment Evaluation may be performed, considering: escape and access routes; location, quantity, and type of combustible material in the fire area; the presence of ignition sources and their likelihood of occurrence; the automatic fire suppression and fire detection capability in the fire area; the manual fire suppression capability in the fire area; cumulative effects with existing impairments; and the human error probability where applicable.

The controls provided by ECG 18.7.2 are based upon maintaining the passive design features as evaluated and accepted by the NRC. The action statements are based upon temporary compensatory measures for degraded barrier features.

Removal of a barrier or excessive degradations of a barrier must be evaluated for additional compensatory measures.

ECG 4.2, “Steam Generator Level and Pressure Instruments (Appendix R)”

BASIS:

The local steam generator (SG) level and pressure instruments are electrically independent of the control room/cable spreading room. Therefore, the instruments are protected from the effects of a fire in these rooms that would require shutdown from outside the control room. LT-516, LT-526, LT-536, and LT-546 and their associated level indicators at the dedicated shutdown panel provide level indication outside of the control room for the SGs. PI-518, PI-528, PI-538, and PI-548 provide pressure indication outside of the control room for the SGs.

ECG 7.1, “RCS Instrumentation (Appendix R)”

BASIS:

LT-406 (LI-406) and PT-406 (PI-406) provide indication of pressurizer level and RCS pressure at the Dedicated Shutdown Panel (DSP). Technical Specifications require indication of these parameters at the Hot Shutdown Panel (HSP); however, these instruments are also required at the DSP following a control room or cable spreading room fire and control room evacuation.

ECG 7.2, “PORV Emergency Close Switch at the HSP (Appendix R)”

BASIS:

The 10 CFR 50 Appendix R safe shutdown analysis takes credit for the operability of PCV-455C or PCV-456 (or pressurizer auxiliary spray valves 8145 or 8148) to achieve cold shutdown in the event of a fire in the plant. In addition, spurious opening of any of the three PORVs due to fire in several fire areas must be either prevented or mitigated by an operator taking manual action to close a PORV using the emergency close switch at the HSP.

ECG 8.1, “Centrifugal Charging Pump CCP3”

BASIS:

This ECG ensures the Units 1 and 2 Centrifugal Charging Pump CCP3 are available to pump at least 55 gpm at 5800 feet (2550 psid) of pump head to the RCS during plant conditions if the centrifugal charging pumps CCP1 and CCP2 were to become inoperable due to fire in the CCP area.

In the event of a fire in the CCP rooms, a loss of power to the CCP1 and CCP2 pumps and a loss of control room start to the CCP3 could occur. However, the starting circuit of CCP3 can be bypassed at the switchgear, which is located in another fire area. Hence, CCP3 is not affected by a CCP area fire. The Fire Hazards Analysis concluded that safe shutdown will not be adversely affected by the loss of equipment in the CCP fire area due to the availability of redundant equipment and/or manual actions. The Fire Hazard Analysis also took credit for the following:

A. Smoke detection over the charging pumps

B. Automatic wet-pipe sprinkler over the pumps

C. Manual fire fighting equipment

NRC Safety Evaluation Report Supplement 23 found the above an acceptable method of meeting 10 CFR 50, Appendix R requirements.

ECG 8.2, “Chemical and Volume Control System Valves (Appendix R)”

BASIS:

CVCS valves 8145, 8146, 8147 and 8148 are required for auxiliary spray. Auxiliary spray is a credited means of reducing RCS pressure in the transition from Hot Standby to Cold Shutdown for an Appendix R post-fire safe shutdown. The normal (8146) and alternate (8147) charging paths are credited paths for RCS makeup and boration for an Appendix R post-fire safe shutdown.

ECG 10.1, “Residual Heat Removal Pump Transfer Switch at 4kV Switchgear (Appendix R)”

BASIS:

In the event of a fire in the control room/cable spreading room, the capability to start an RHR pump from the 4kV switchgear is required to shutdown the plant. The transfer switch is used to transfer the switchgear to local control and isolate the control room circuitry.

ECG 37.1, “Hot Shutdown Panel (HSP) Neutron Flux Indicators (Appendix R)”

BASIS:

Source range flux indication at the HSP is provided by these instruments in the event of control room/cable spreading room fire and control room evacuation. NE-51 and NE-52 are also credited for post-fire availability for postulated fires outside of the control room or cable spreading room.

For the ECGs related to Appendix R safe shutdown equipment, the Allowed Outage Time of 30 days and separate Condition entry are consistent with License Amendment Request 93-01, which requested changes to the Remote Shutdown TS in accordance with the Westinghouse Standard Technical Specifications (NUREG-1431). The Instrumentation section of the TS governs other Remote Shutdown instrumentation of the same importance as this instrumentation.

Alternate Compensatory Measures

In certain situations an alternate compensatory measure to a compensatory measure specified in a fire protection ECG may be more appropriate (NRC Regulatory Issue Summary 2005-07, "Compensatory Measures to Satisfy the Fire Protection Program Requirements"). For example, the compensatory measure required for a degraded fire barrier is typically an hourly fire watch, or, in the case of an inoperable spray or sprinkler system, is a continuous fire watch with backup fire suppression equipment. Fire watches may not be the most effective compensatory measure for degraded or inoperable fire protection features or post-fire safe-shutdown capability (see Information Notice 97-48, “Inadequate or Inappropriate Interim Fire Protection Compensatory Measures,” dated July 9, 1997).

A different compensatory measure or combination of measures (e.g., additional administrative controls, operator briefings, temporary procedures, interim shutdown strategies, operator manual actions, temporary fire barriers, temporary detection or suppression systems) may be implemented. A documented evaluation of the impact of the proposed alternate compensatory measure and its adequacy compared to the compensatory measure required by the ECG must be completed. The evaluation must demonstrate that the alternate compensatory measure would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire. Any alternate compensatory measure must maintain compliance with the General Design Criteria and 10 CFR 50.48(a), and must be retained as a record pursuant to 10 CFR 50.48(a). The evaluation of the alternate compensatory measure should incorporate risk insights regarding the location, quantity, and type of combustible material in the fire area; the presence of ignition sources and their likelihood of occurrence; the automatic fire suppression and fire detection capability in the fire area; the manual fire suppression capability in the fire area; and the human error probability where applicable.

The following table provides a list of alternate compensatory measures that have been implemented and their corresponding LBIE evaluations:

LBIE	Description
2006-006	ECG 18.7 alternate compensatory measure implemented to address specific non-compliance concern in Fire Area 3-CC. The non-compliance involved inadequate separation of safe shutdown cables. The alternate compensatory measure consisted of additional combustible and hot work controls, a daily walkdown of the area, and fire brigade guidance.

LBIE	Description
LBIE Screen Dated 09/05/06 AR A0676852	ECG 18.7 alternate compensatory measures implemented to address missing fire barriers required to comply with Appendix R Section III.G.2. The alternate compensatory measures are post-fire operator manual actions that have been demonstrated to be feasible and reliable in accordance with NRC Triennial Fire Protection Inspection Procedure, Attachment 71111.05TTP, issued 05/09/06. Note that this only applies to manual actions already identified and implemented by the approved Fire Protection Program. Implementation of manual actions not already identified by the approved Fire Protection Program would require a LBIE Section II evaluation.
LBIE 2007-005 AR A0655791	ECG 18.7 alternate compensatory measures implemented to address missing fire barriers to protect cables associated with FCV-355, which are required to comply with Appendix R Section III.G.2 in Fire Areas 4B (U1 & U2), 5A3, 5A4, 6A3, 6A5, 8G, 5B3, 5B4, 6B3, 6B5 and 8H. The alternate compensatory measure credited operator action to locally open FCV-355 after tripping its power breaker. In addition, administrative controls were implemented to restrict the storage of transient combustible materials and use of hot work in the affected fire areas.
LBIE Screen for OTSC to CP M-10 dated 1/10/08 AR A0715723	ECG 18.7 alternate compensatory measures implemented to address missing fire barriers to protect the auto transfer capability of the emergency diesel generators, which are required to comply with Appendix R Section III.G.2 in Fire Areas 10, TB-5/12B and 20. The alternate compensatory measure credited operator action to locally trip startup or auxiliary transformer breakers, and then to manually load the diesel generator to the respective bus either from the control room or locally at the 4kV switchgear. In addition, administrative controls were implemented to restrict the storage of transient combustible materials and use of hot work in the affected fire areas.

LBIE	Description
LBIE 2008-05 LBIE-2008-06 AR A0717058 50043787-04	ECG 18.7 alternate compensatory measures implemented to address missing fire barriers to protect cables associated with FCV-128, which are required to comply with Appendix R Section III.G.2 in Fire Areas 5A4and 5B4. The alternate compensatory measure credited operator action to secure CCW valve FCV-355 and/or FCV-356 to provide CCW to the RCP TBHX. In addition, administrative controls were implemented to restrict the storage of transient combustible materials and use of hot work in the affected fire areas.
LBIE 2008-05 LBIE 2008-06 AR A0724491 50038548 50521553 50521554 50521555 LBIE 2013-009	ECG 18.7 alternate compensatory measures implemented to address missing fire barriers to protect cables associated with safe shutdown equipment. The concerns were identified during the NFPA 805 transition project and involve fire damage to cables affecting multiple spurious operation of equipment in the following fire areas: CR-1, 34, 3BB (100-ft and 115-ft), 5A2, 5A3, 5A4, 6A1, 6A2, 6A3, 7A, 8G, TB-7/14A, TB-7/12E, 28, 3CC (100-ft and 115-ft), 5B2, 5B3, 5B4, 6B1, 6B2, 6B3, 7B, 8H, TB-7/23E, and 29. The alternate compensatory measure credited either an operator action or existing non-rated fire barriers. In addition, administrative controls were implemented to restrict the storage of transient combustible materials and use of hot work in the affected fire areas, in conjunction with a shift order.

LBIE	Description
LBIE 2012-023	ECG 18.7 alternate compensatory measures implemented to address fire barriers that were not installed to an approved configuration. Specifically: The fire barrier between the Unit 1 isophase room, just South of the 4kV switchgear and cable spreading rooms, fire area TB-7/12-E and the Unit 1 transformer area, fire area 28. The fire barrier between the Unit 2 isophase room, just North of the 4kV switchgear and cable spreading rooms, fire area TB-7/23-E and the Unit 2 transformer area, fire area 29. The fire barriers between the Unit 1 and Unit 2 penetration area ceilings, fire areas 3-BB and 3-CC at elevation 115' and the exterior area above, fire area 34. The fire barrier between the floor of the control room ventilation equipment room, fire areas CR-1/8-B-3 and CR-1/8-B-4, and the adjacent areas below.

Chapter 10

STEAM AND POWER CONVERSION SYSTEM

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TABLES

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FIGURES

NOTE:

[a] This figure corresponds to a controlled engineering drawing that is incorporated by reference into the FSAR Update. See Table 1.6-1 for the correlation between the FSAR Update figure number and the corresponding controlled engineering drawing number.

Chapter 10

STEAM AND POWER CONVERSION SYSTEM

This chapter provides information concerning the plant steam power conversion (heat utilization) system. The steam and power conversion system (SPCS) includes the turbine-generator, steam supply system, feedwater system, main condenser, and related subsystems. The auxiliary feedwater system is discussed in Chapter 6.

Descriptive information is provided to allow understanding of the system, with emphasis on those aspects of design and operation that affect the reactor and its safety features, or contribute to the control of radioactivity. The radiological aspects of normal system operation are summarized in this chapter and are presented in detail in Chapter 11. Design and quality code classifications applied to the steam and power conversion system are discussed in Chapter 3.

10.1 SUMMARY DESCRIPTION

The SPCS is designed to convert the heat produced in the reactor to electrical energy. In each unit, reactor heat absorbed by the reactor coolant system (RCS) produces sufficient steam in four steam generators to supply the turbine-generator.

The SPCS is designed to operate on a closed, condensing cycle, with full flow condensate demineralization, and six stages of regenerative feedwater heating. Turbine exhaust steam is condensed in a single shell, surface-type condenser and returned to the steam generators through three stages of feedwater pumping. All three low-pressure turbine elements exhaust into a common condenser steam space. The arrangement of the equipment associated with the SPCS is shown in Figures 3.2-2, 3.2-3, 3.2-4, and 10.3-6.

The SPCS is designed to receive the heat absorbed by the RCS during normal power operation, as well as following an emergency shutdown of the turbine-generator from full load. Heat rejection under the latter condition is accomplished by steam bypass to the condenser and pressure relief to the atmosphere. Either the turbine bypass or the pressure relief system (without operation of safety valves) can dissipate the heat from the RCS following a turbine trip and a reactor trip. Trips, automatic control actions, and alarms are initiated by deviations of system variables from preset values. In every instance, automatic control functions are programmed so that appropriate corrective action is taken to protect the RCS (see Chapter 7).

The SPCS does not normally contain radioactivity. The vents and drains associated with the secondary cycle are arranged in a manner similar to those in a conventional fossil fuel generating station. However, the condenser air removal equipment will handle radioactive noncondensable gases during a steam generator primary-to-secondary tube leak. Means are provided to monitor (see Section 11.6) the

discharge of radioactive material to the environment, to ensure that it is within the limits of 10 CFR 20 under normal operating conditions, or in the event of anticipated system malfunctions or accident conditions. Detection of these gases is described in Sections 10.4.2 and 11.4.

All SPCS equipment required for nuclear safety is classified as Design Class I, and the appropriate systems are sufficiently redundant to ensure maintenance of their safety functions. Specifically, the auxiliary feedwater system and portions of the main steam and main feedwater systems are required to perform various safety functions involving removal of decay heat and are classified as Design Class I. Safety functions relative to the auxiliary feedwater system are presented in Chapter 6.

Turbine heat balances at maximum calculated and full load conditions are shown, respectively, in Figures 10.1-1 and 10.1-2 for Unit 2, and Figures 10.1-5 and 10.1-6 for Unit 1. Typical operating parameters for the secondary system are listed in Table 10.1-2.

Tables 10.1-1 and 10.1-2 summarize important design and performance characteristics of equipment upon which the safety of the SPCS operation depends. The design performance characteristics and safety-related design features are described in the remainder of Chapter 10. The principal safety-related design features involve the main steam, main and auxiliary feedwater, turbine bypass, and steam generator blowdown systems. Safety-related design features of the auxiliary feedwater system are discussed in Chapter 6.

10.1.1 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

10.2 TURBINE-GENERATOR

The basic function of the turbine-generator is to convert thermal energy initially to mechanical energy and finally to electrical energy. The turbine-generator receives saturated steam from the four steam generators through the main steam system. Steam is exhausted from the turbine-generator to the main condenser.

10.2.1 DESIGN BASES

10.2.1.1 Turbine-Generator System Safety Functional Requirements

1) Protection from Missiles

The turbine-generator is designed to ensure that failure of the turbine-generator is minimized and will not result in the generation of missiles that could affect safe shutdown of either unit.

10.2.1.2 10 CFR 50.62 – Requirements for Reduction of Risk from Anticipated Transients Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants

The turbine-generator meets the requirement of 10 CFR 50.62 by responding to an AMSAC signal to trip the turbine under ATWS conditions.

10.2.1.3 Generic Letter 89-08, May 1989 – Erosion/Corrosion-Induced Pipe Wall Thinning

DCPP has implemented formalized procedures and administrative controls in accordance with Generic Letter 89-08 to assure long-term implementation of its erosion/corrosion monitoring program for the turbine-generator.

10.2.2 SYSTEM DESCRIPTION

The Siemens-Westinghouse BB96 high pressure (HP) turbine is coupled to three Alstom ND56R low pressure (LP) turbines in a four-casing, tandem-compound, six-flow exhaust, 1800 rpm unit, with 57-inch last-stage blades. The ac generator is connected to the turbine shaft, and a brushless exciter is coupled to the generator.

10.2.2.1 Turbine

The turbine consists of one double-flow, high-pressure element in tandem with three double-flow, low-pressure elements. Moisture separation and reheating of the steam are provided between the high-pressure and low pressure turbines by six horizontal axis, two-stage reheat cylindrical shell combined moisture separator-reheater (MSR) assemblies. Three of these assemblies are located on each side of the low-pressure turbine elements.

Steam from the exhaust of the high-pressure turbine element enters one end of each MSR assembly, where internal manifolds in the lower section distribute the wet steam. The steam then flows through a moisture separator where the moisture is removed and the condensate drained to a drain tank from which it is pumped to the suction of the main feedwater pumps. The steam leaving the separator flows over two tube bundles where it is reheated in two stages. The reheated steam leaves through nozzles in the top of the assemblies and flows to the low pressure turbines through a stop valve and an intercept valve in each reheat steam line. Two MSR assemblies furnish steam to each of the three low-pressure turbine elements. The first stage tube bundle in the reheater is supplied with extraction steam from the high-pressure turbine, and the second-stage tube bundle is supplied from the main steam lines ahead of the high-pressure turbine. The supply steam condenses in the tubes; the condensate from the high-pressure tube bundle flows to the shell of the high-pressure feedwater heaters, while the condensate from the low-pressure tube bundle flows to the heater 2 drain tank.

A turbine shaft sealing system, using steam to seal the annular openings where the shaft penetrates the casings, prevents steam outleakage or air inleakage along the shaft. Turbine steam extraction connections are provided for six stages of feedwater heating.

10.2.2.2 Performance Requirements

The main turbine-generators and their auxiliary systems are designed for steam flow corresponding to 3,500 MWt and 3,580 MWt, which in turn correspond to the maximum calculated thermal performance data of the Units 1 and 2 nuclear steam supply systems (NSSS), respectively, at the original design ultimate expected thermal power. The Unit 2 turbine-generator has a higher power rating because of subsequent uprating of the Unit 2 NSSS. The intended mode of operation of both Unit 1 and Unit 2 is base loaded at levels limited to the lower licensed reactor level of 3,411 MWt (refer to Table 15.1-1).

10.2.2.3 Operating Characteristics

The steam generator characteristic pressure curves (Figure 10.2-1) are the bases for design of the turbine. The steam generator pressure curve shown in Figure 10.2-1 corresponds to the SG outlet pressure. The calculated curve is based on thermal

design conditions with vessel T_{avg} of 577.6ºF and 10 percent steam generator tube plugging (Reference 1). The pressure at the turbine main steam valves does not exceed the pressure shown on the steam characteristic pressure curve for the corresponding turbine load. With a pressurized water reactor, it is recognized that the pressure at the turbine steam valves rises as the load on the turbine is reduced below rated load. During abnormal conditions at any given load, the pressure may exceed the pressure on the steam generator characteristic pressure curve by 30 percent on a momentary basis, but the total aggregate duration of such momentary swings above characteristic pressure over the whole turbine load range does not exceed a total of 12 hours per 12-month operating period.

The turbine inlet pressure is not directly controlled. A load index from the turbine first-stage pressure is compared to the reactor coolant loop T_{avg}; the control rods are then positioned accordingly (refer to Section 7.7.2.8).

10.2.2.4 Functional Limitations

The plant is designed to sustain sudden large load decreases, as described in Section 5.1.6.2. This capability is provided by the use of controlled steam dump (turbine bypass) from the secondary system. This dump serves as a short-term artificial load, allowing the reactor to automatically cut back power without tripping. The reactor control system itself is not rapid enough to follow a sudden loss of load without allowing certain reactor plant variables (e.g., pressure and temperature) to exceed allowable operating limits. Therefore, a sufficiently large controlled steam dump, capable of simulating an external load on the reactor, is used to prevent the reactor from tripping.

The rates at which electrical load may be increased or decreased without tripping the reactor, including operation of the steam dump (bypass system), are as follows:

(1) Without steam bypass - If electrical load decrease does not exceed a step change of 10 percent, or a sustained ramp load decrease of 5 percent per minute, then the steam bypass will not operate. Steam bypass is not used to control load increases.

(2) With steam bypass - If electrical load decrease does exceed a step change of 10 percent or a sustained ramp load decrease of 5 percent per minute, then a combination of steam dump groups 1, 2, and 3 of the turbine bypass system (refer to Section 10.4.4.2) will operate. If the decrease is less than 50 percent, then a step change with control rods will account for a 10 percent load decrease, and the turbine bypass system will operate and control up to 40 percent of the remaining load decrease.

(3) Electrical load increases are limited by the reactor control system to 5 percent full power per minute, or step changes of 10 percent of full power within the power range of 15 to 100 percent of full power.

For further explanation of the steam bypass and relief system, refer to Section 10.4.4. Steam bypass and relief valves are listed in Table 10.1-1. For electrical loading, refer to Chapter 8, Electric Power.

The functional limitations imposed by the design or operational characteristics of the turbine-generator are:

(1) Retrofitted with Alstom LP turbines, the units are suitable for continuous full load underfrequency operation down to 56.4 Hz. Operation below 56.4 Hz is limited to 10 seconds per event. There is no specific accumulated time limit for operation below 56.4 Hz. A trip within 0.5 seconds is required below 54.9 Hz.

(2) Under frequency set points and time delays are coordinated with PG&E's Under Frequency Load Shedding (UFLS) Program, per Utility Operations Standard UO S1426, which conservatively bounds turbine vendor requirements.

(3) Load changes cause thermal stress in the turbine rotor, which persists as long as there are differences between the surface and interior temperatures of the rotor body. Operational procedures for changing load, that tend to ensure a maximum time period before the appearance of fatigue cracking, are required. Load changing recommendations are based on 10,000 cycles of general turbine operation. For example, the following load changes can be made instantaneously, without exceeding the 10,000-cycle recommendations: 0-10 percent, 10-30 percent, 20-53 percent, 30-78 percent, 40-85 percent, and 50-100 percent.

(4) Operation at less than 5 percent rated load should be avoided; however, when necessary, auxiliary load may be carried indefinitely on the main generator following rejection of the main load, provided;

  (a) Low-pressure turbine exhaust hood spray is placed in service when hood temperature exceeds 175°F; and if hood temperature increases to 250°F for more than 15 minutes, the turbine is tripped

  (b) All supervisory instrument readings are within allowable alarm limits

10.2.2.5 Lubrication

Turbine-generator bearings are lubricated by a conventional oil system. The volute type, centrifugal main oil pump is mounted on the turbine rotor and supplies all of the oil requirements for the lubrication system during normal operation. An ac motor-driven centrifugal pump supplies bearing oil for operating the turbine-generator on turning gear during coastdown after a trip, and during startup. A backup dc motor-driven bearing oil pump operates, in case of loss of ac power or if the ac pump fails to start, to lubricate

the turbine-generator bearings during coastdown of the unit after tripout. Air-side and hydrogen-side ac motor-driven seal oil pumps are provided to supply oil to the generator hydrogen seal oil systems. An air side dc motor-driven seal oil backup pump operates in case of loss of ac power, to prevent leakage of the generator hydrogen. A lift pump is provided for bearings 3, 4, 5, 6, and 7 to lift the turbine rotor shaft off the journal bearing to reduce the starting load on the turning gear motor. Bearing 8 was retrofitted with an integral bearing lift system.

10.2.2.6 Cooling

The cooling water requirements of the turbine-generator are met partially by the service cooling water system (refer to Section 9.2.1), and partially by the main condensate and feedwater system (refer to Section 10.4.7).

The following main turbine-generator heat exchangers are cooled by the service cooling water system:

(1) Turbine lubricating oil coolers

(2) Generator hydrogen seal oil coolers

(3) Exciter air-to-water heat exchangers

(4) Electrohydraulic control fluid cooler

(5) Main generator isophase bus duct cooler

The following main turbine-generator heat exchangers are cooled by the main condensate and feedwater system:

(1) Generator hydrogen coolers

(2) Generator stator water coolers

(3) Gland steam condenser

10.2.2.7 Turbine Electrohydraulic Control System

The turbine is equipped with a digital electrohydraulic (DEH) control system that uses programmable triple modular redundant (TMR) digital controllers, dual redundant digital servo position controllers, input/output modules, and a high-pressure, fire-resistant, fluid supply system to operate the turbine control valves. By regulating the flow of steam through the turbine, the control system regulates turbine speed prior to the time that the generator is synchronized, and controls unit power output when the generator is connected to the PG&E transmission system. The control system also provides

overspeed protection. Retrofitted with Alstom LP turbines, the control system also provides low condenser vacuum and low bearing oil protection.

Unit electrical loading is completely under the control of the reactor operator except when automatic runbacks are in progress. No automatic offsite load dispatching is utilized.

10.2.2.8 Turbine Steam Flow Control

The flow control of the main inlet steam is accomplished by four main stop valves in series with four governor control valves.

Each main stop valve operates in either a fully opened or fully closed position. The valve is opened when high-pressure fluid enters the hydraulic actuator cylinder and forces the piston to overcome spring closing pressure. It is closed immediately upon the dumping of main stop valve emergency trip fluid to provide quick closing independent of the electrical system. The valve may also be closed upon activation of the solenoid valve for periodic test of valve stem freedom. The purpose of the main stop valve, which is installed in the main steam line ahead of the governor control valve, is to provide an additional safety device to limit turbine overspeed.

Each governor control valve is of the single-seat, plug type design. The valve is opened when high pressure electrohydraulic (EH) fluid enters the actuator and overcomes the spring force of the valve as transmitted by the operating levers. During normal operation, control of the governor control valve is by a servo valve that regulates oil pressure in the actuator, based on information supplied from the DEH system controller. A linear variable differential transformer (LVDT) develops an analog signal proportional to the valve position, which is fed back to the controller to complete the control loop. The controller signal positions the control valves over a wide range of turbine speeds during startup and for load control after the unit is synchronized. The governor control valve is closed by reducing pressure on the dump valve. The dump valve can be activated by means of the emergency trip system, or by the auxiliary governor trip, to provide quick closing independent of the electrical system.

The flow control of steam to the low-pressure sections of the turbine is accomplished by six reheat stop valves in series with six interceptor valves.

Each reheat stop valve operates in either the fully opened or fully closed position. The valve is opened when high-pressure fluid enters the actuator hydraulic cylinder and forces the piston to overcome spring closing pressure. It is closed immediately upon dumping of main stop valve emergency trip fluid, on actuation of the emergency trip device. It may also be closed upon activation of the solenoid valve for periodic testing of valve stem freedom. The major function of the reheat stop valves is to shut off the flow of steam to the low-pressure turbines, when required.

Each interceptor valve normally operates in a fully opened position. The valve is opened when high-pressure fluid is admitted through an orifice to the hydraulic cylinder operating piston. As the fluid pressure increases beneath the piston, it overcomes the force of the closing springs and opens the steam valve. It is quickly closed when the emergency trip fluid is released to drain. The purpose of this valve is to limit the flow of steam from the MSRs to the low-pressure turbines after a sudden load reduction.

10.2.2.9 Partial Loss of Load

A feature called close-intercept valve (CIV) was built into the original turbine control system to close the intercept valves. This CIV feature was designed to sense a load mismatch between high pressure exhaust pressure and generated power. CIV actuation would close the intercept valves for a preset time period. This feature was disabled on the original Westinghouse-supplied turbine control system and is not present in the new system.

10.2.2.10 Complete Loss of Load

When a mismatch of LP turbine inlet pressure and generator output megawatts occurs, and the breaker opens, this condition is detected as a complete load loss. When the generator breaker opens, the load drop anticipation (LDA) is set, requesting overspeed protection control (OPC) action. Refer to Section 10.2.3.1 for a description of the OPC system.

All governor and interceptor valves are then rapidly closed. The LDA load loss circuit is inoperable below 22 percent of load, as measured by LP turbine inlet pressure.

10.2.2.11 Overspeed Action

OPC action also occurs when turbine speed is equal to, or greater than, 103 percent of rated speed. Governor and interceptor valves are closed until the speed drops below 103 percent.

The OPC system may be tested by using the OPC test function. If the breaker is open and the OPC test function is activated, a signal is generated; this signal indicates that the speed of the turbine is over 103 percent. The OPC system then closes the valves as though an actual overspeed condition had occurred.

10.2.2.12 Speed Channel System

Three separate electromagnetic pickups input speed information to the turbine control system. These inputs are validated against a high and low reference to determine when a transducer fails high or low. The control system uses a median signal select logic to determine the controlling speed signal for turbine speed control, OPC, and redundant overspeed protection.

10.2.2.13 Automatic Runbacks and Programmed Ramps

The turbine control system implements protective runbacks and programmed ramps (load reductions). The OTΔT and OPΔT protective runbacks are described in Section 7.7.2.4.2. The loss of main generator stator cooling protective runback is discussed in Section 10.2.2.15. Main turbine programmed ramps anticipating loss of steam flow are main feedwater pump trip and heater drip pump trip. A turbine runback anticipating a loss of heat sink is a trip of a circulating water pump.

10.2.2.14 Trip System Operability

The operability of the main turbine inlet valves and turbine trip system is verified by periodic functional tests. Operability of the trip system in the event of postulated accidents has also been reviewed. The trip system is protected from falling debris and will remain operational during and following postulated accidents (refer to Section 3.5.2.2.1.2).

Administrative operating requirements ensure that the turbine building crane is parked away from the steam inlet valves during turbine operation, to preclude damage to the valves from a postulated crane fall.

10.2.2.15 Protective Features

Post Alstom LP turbine retrofit, the low vacuum mechanical trip feature has been removed and low vacuum trip is now provided through the DEH. The following other protective devices are independent of the electronic controller and, when initiated, will cause tripping of all turbine valves:

(1) Mechanical overspeed trip (refer to description in 10.2.3.1)

(2) Low bearing oil pressure trip (this is provided by both the mechanical trip, independent of the electronic controller, as well as through the DEH).

(3) Thrust bearing trip

(4) Electrical solenoid trip, actuated by:

  (a) Safety injection system or steam generator high-high level

  (b) Generator loss of field

  (c) Reactor trip

  (d) Unit trip

  (e) Manual trip switches in control room

(f) Turbine speed 111.5 percent or dc bus trip (DEH)

(g) ATWS mitigation system actuation circuitry

(5) Manual lever located at the turbine

Each of the above tripping devices releases autostop oil. The oil release results in a decrease of autostop oil pressure that opens a diaphragm-operated trip valve in the EH high-pressure fluid system to release the pressure and close all steam valve actuators.

The generator is protected by a load runback feature on loss of cooling water to the generator stator. The runback is accomplished at a rate of approximately 40 percent load drop per minute by the turbine control system. If the generator runback fails to start in 45 seconds, the generator is additionally protected by a time delay trip, which results in a unit trip. Reverse power and antimotoring protection is also provided for the generator.

In addition to the devices described above, the turbine and steam system are protected by the following indicators and design features:

(1) Dropped reactor control rod signal light on the main control board

(2) Isolation valve in each steam generator steam line

(3) Check valve in each steam generator steam line

(4) Safety valves in each steam generator steam line

(5) Safety valves in the MSR inlet (cold reheat) piping

(6) Extraction line nonreturn valves

(7) Exhaust casing rupture diaphragms

(8) Turbine steam and casing drains which open automatically at loads less than 20 percent

The turbine-generator and associated steam handling equipment have received extensive mechanical, electrical, and radiological safety evaluations. Protective features regarding personnel and equipment safety are presented in this section. Safety features for reactor protection, in the event of a turbine-generator trip or sudden load reduction, are presented in Section 10.4.4.

10.2.2.16 Design Codes

The turbine-generator and associated components are classified as PG&E Design Class II. Section 3.2 presents a discussion of design classifications and code requirements.

10.2.3 SAFETY EVALUATION

10.2.3.1 Turbine-Generator System Safety Functional Requirements

(1) Protection from Missiles

Tests and analyses regarding the potential generation and effects of missiles, caused by the turbine-generator are discussed in Section 3.5.2.2.1. Criteria for determining the turbine inspection scope and frequency required to prevent missile generation are also discussed in Section 3.5.2.2.1.

The overspeed protection control (OPC) system controls turbine overspeed in the event of a partial or complete loss of load, or if the turbine reaches or exceeds 103 percent of rated speed. In the event that turbine shaft speed exceeds 103 percent of rated speed, overspeed protection is afforded through information (in rpm) supplied by three speed transducers to the OPC system. The signals from the transducers are validated against a high and low reference to determine when a transducer fails high or low. The turbine control system uses a median signal select logic to determine the controlling speed signal.

A mechanical overspeed trip device is also provided that will automatically trip the unit at 111 percent of rated speed. The mechanism consists of a spring-loaded plunger located in the turbine shaft, which extends radially outward when 111 percent of rated speed is reached. When extended, the plunger contacts a lever, which in turn dumps control hydraulic fluid (autostop oil), causing all turbine steam inlet control and stop valves to close.

An electronic trip signal is generated by the DEH control system, at 111.5 percent of rated speed, as redundant overspeed protection. With the retrofitted Alstom LP turbines, this trip signal is used to energize two solenoid valves, either of which dumps autostop oil. This trip signal is set approximately 10 rpm higher than the mechanical overspeed device previously described.

Overspeed protection is necessary to preclude turbine rotor failure and associated turbine generated missiles (refer to Section 3.5.2.2.1).

10.2.3.2 10 CFR 50.62 – Requirements for Reduction of Risk from Anticipated Transients Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants

The turbine-generator meets the requirement of 10 CFR 50.62 by responding to an AMSAC signal to trip the turbine under ATWS conditions. The main turbine must have equipment from sensor output to final actuation device, that is diverse from the reactor trip system, to automatically initiate the auxiliary (or emergency) feedwater system and initiate a turbine trip under conditions indicative of an ATWS (refer to Section 7.6.3.5).

10.2.3.3 Generic Letter 89-08, May 1989 – Erosion/Corrosion-Induced Pipe Wall Thinning

DCPP has implemented formalized procedures and administrative controls in accordance with Generic Letter 89-08 to assure long-term implementation of its erosion/corrosion monitoring program for the turbine-generator.

10.2.4 TESTS AND INSPECTIONS

Turbine-generator tests and inspections are described in Sections 3.5.2.2.1, 10.2.2.11, 10.2.2.14 and 10.2.3.1.

10.2.5 INSTRUMENTATION APPLICATIONS

Instrumentation is provided to continuously monitor and alarm the following turbine-generator parameters:

(1) Shaft vibration at main bearings

(2) Shaft eccentricity

(3) Shell expansion

(4) Differential expansion between turbine shell and rotor

(5) Turbine speed

(6) Turbine metal temperatures

(7) Bearing temperatures

(8) Hydrogen gas and stator cooling water temperatures

(9) Exhaust hood temperatures

(10) Condenser vacuum

(11) Thrust bearing wear

10.2.6 REFERENCES

1. Delta 54 Replacement Steam Generator Thermal and Hydraulic Design Analysis Report for Diablo Canyon, WCAP-16573-P, August 2007.

10.3 MAIN STEAM SYSTEM

The main steam system conveys the generated steam from the nuclear steam supply system to the turbine generator, turbine driven feedwater pumps, steam dump, reheaters, and via the auxiliary steam system, to the gland steam system and air ejectors. Main steam is also provided to the turbine driven auxiliary feedwater pump.

Refer to Section 10.4.4 for details on the 10 percent atmospheric dump valves.

The main steam system SSCs from the steam generators up to and including the main steam isolation valves (MSIVs) outside of the containment are PG&E Design Class I. The main steam system SSCs downstream of the MSIVs are PG&E Design Class II.

10.3.1 DESIGN BASES

10.3.1.1 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class I portion of the main steam system is designed to withstand the effects of, or is protected against, natural phenomena such as earthquakes, winds, floods and tsunamis, and other local site effects. The effects of a tornado on the main steam system are addressed to ensure plant safe shutdown can be achieved.

10.3.1.2 General Design Criterion 3, 1971 – Fire Protection

The PG&E Design Class I portion of the main steam system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

10.3.1.3 General Design Criterion 4, 1967 – Sharing of Systems

The PG&E Design Class I portion of the main steam system and its components are not shared by the DCPP Units unless safety is shown not to be impaired by the sharing.

10.3.1.4 General Design Criterion 11, 1967 – Control Room

The PG&E Design Class I portion of the main steam system is designed to support actions to maintain and control the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

10.3.1.5 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain the PG&E Design Class I portion of the main steam system variables within prescribed operating ranges.

10.3.1.6 General Design Criterion 15, 1967 – Engineered Safety Features Protection Systems

The PG&E Design Class I portion of the main steam system provides for sensing accident situations.

10.3.1.7 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

Means are provided for monitoring the facility effluent discharge path for radioactivity that could be released from the main steam system. The effluent discharge path includes both the PG&E Design Class I and PG&E Design Class II portions of the system.

10.3.1.8 General Design Criterion 21, 1967 – Single Failure Definition

The PG&E Design Class I portion of the main steam system is designed to remain operable after sustaining a single failure. Multiple failures resulting from a single event are treated as a single failure.

10.3.1.9 General Design Criterion 49, 1967 – Containment Design Basis

The main steam system is designed so that the containment structure can accommodate, without exceeding the design leakage rate, the pressures and temperatures resulting from the largest credible energy release following a LOCA, including a considerable margin for effects from metal-water or other chemical reactions that could occur as a consequence of failure of emergency core cooling systems.

10.3.1.10 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The PG&E Design Class I portion of the main steam system provides capability for testing the functional operability of valves essential to the containment isolation function.

10.3.1.11 General Design Criterion 57, 1971 – Closed System Isolation Valves

The PG&E Design Class I portion of the main steam system is designed to provide isolation valves outside the containment capable of automatic and manual closure.

10.3.1.12 Main Steam System Safety Function Requirements

(1) Protection from Missiles and Dynamic Effects

The PG&E Design Class I portion of the main steam system is designed to be protected against the effects of missiles and dynamic effects which may result from plant equipment failures.

(2) Decay Heat Removal

The PG&E Design Class I portion of the main steam system is designed to remove decay heat from the reactor coolant system through the steam generator safety valves and by providing steam to power the auxiliary feedwater (AFW) pump turbine.

(3) Main Steam Isolation

The MSIVs are designed to isolate automatically in the event of a main steam line break (MSLB) either upstream or downstream of the MSIVs to prevent uncontrolled steam release and limit the steam release to the contents of a single steam generator.

(4) Secondary Side Pressure Control

The main steam system is designed with safety valves to protect the system from overpressurization.

(5) Steam Flow Restriction

The main steam system is designed with flow restrictors that limit the steam flow in the event of a MSLB at any location on the steam line.

10.3.1.13 10 CFR 50.49 – Environmental Qualification

The PG&E Design Class I main steam system components that require environmental qualification (EQ) are qualified to the requirements of 10 CFR 50.49.

10.3.1.14 10 CFR 50.55a(f) – Inservice Testing Requirements

American Society of Mechanical Engineers (ASME) code components within the PG&E Design Class I portion of the main steam system are tested to the requirements of 10 CFR 50.55a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical.

10.3.1.15 10 CFR 50.55a(g) – Inservice Inspection Requirements

ASME code components within the PG&E Design Class I portion of the main steam system are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

10.3.1.16 10 CFR 50.63 – Loss of All Alternating Current Power

The PG&E Design Class I portion of the main steam system provides a means for removing decay heat from the reactor coolant system by discharging steam from the steam generators to the atmosphere, and also provides steam to power the AFW pump turbine in the event of a station blackout (SBO) event.

10.3.1.17 10 CFR Part 50 Appendix R (Sections III.G, J, and L) – Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979

Section III.G - Fire Protection of Safe Shutdown Capability: Fire protection of the PG&E Design Class I portion of the main steam system is provided by a combination of physical separation, fire-rated barriers, and/or automatic suppression and detection.

Section III.J - Emergency Lighting: Emergency lighting or BOLs are provided in areas where operation of the PG&E Design Class I portions of the main steam system may be required to safely shut down the unit following a fire.

Section III.L - Alternative and Dedicated Shutdown Capability: Safe shutdown capabilities are provided in the control room and at an alternate location via the hot shutdown panel (HSP) as required for the safe shutdown of the plant following a fire event.

10.3.1.18 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The main steam system provides instrumentation to monitor main steam flow and radiation release from the steam generator safety valves during and following an accident.

10.3.1.19 NUREG-0737 (Item II.F.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.F.1 – Additional Accident Monitoring Instrumentation:

Position (1) – The PG&E Design Class I display instrumentation is designed to include the noble gas effluent radiological monitor. The radiation monitoring system provides instrumentation to monitor venting from the steam generator safety valves during and following an accident.

10.3.1.20 Generic Letter 89-08, May 1989 – Erosion/Corrosion-Induced Pipe Wall Thinning

DCPP has implemented formalized procedures and administrative controls to assure long-term implementation of its erosion/corrosion monitoring program for the main steam system.

10.3.2 SYSTEM DESCRIPTION

The arrangement of the equipment associated with the main steam system is shown in Figures 3.2-4 and 10.3-6. Steam from the four steam generators is supplied to the turbine-generator(refer to Section 10.2).

Saturated steam from the four steam generators passes through the containment wall in carbon steel pipes arranged to satisfy flexibility and PG&E Design Class I requirements. Each main steam line is anchored to the containment wall at the penetration.

The measured steam flow has a functional PG&E Design Class II application. The flow signal is used by the PG&E Design Class II three-element feedwater controller and as a PG&E Design Class II load index signal for the main feedwater pumps (refer to Section 7.7.2.7).

Steam flow restrictors are installed in each steam line inside the containment. The pressure drop at rated load between the steam generators and the turbine throttle is approximately 40 psi. Steam flow is measured by monitoring dynamic head in nozzles inside the steam pipes. The nozzles, which are of smaller diameter than the main steam pipe, are located inside the containment near the steam generators.

Connections are provided in the four main steam lines, between the containment and the isolation valves, for spring-loaded safety valves and power-operated relief valves, and (in two of the four) steam lines to the auxiliary feed pump drive turbine, as shown in Figures 3.2-4 and 10.3-6.

The steam supply to the auxiliary feedwater pump turbine is PG&E Design Class I because of the ESF requirements of the auxiliary feedwater system (refer to Section 6.5). The steam supply lines from two of the four steam generators are interconnected upstream of the steam line stop valve to provide both redundancy and balanced steam flow. Both isolation and check valves in series in each of these lines provide the required valve redundancy that acts to prevent reverse flow.

The function of the MSIV is provided by a quick-acting isolation valve and a check valve installed in each main steam line. These valves are located outside of the containment structure and downstream of the safety valves. This design ensures that steam line isolation occurs for breaks either upstream or downstream of the valves. These check valves prevent reverse flow from an unfaulted steam generator in the event of a pipe break upstream of the check valves. Additional data on these valves are provided in

Appendix 5.5A, including a discussion of the capability of the main steam isolation and check valves to withstand closure loads following a postulated MSLB.

The main steam system is designed so that a failure of a main steam line at any point along its length, or a malfunction of a valve installed therein, or any consequential damage, will not:

(1) Reduce the flow capacity of the AFW system

(2) Render inoperable any engineered safety feature (i.e., controls, power or instrumentation cables, emergency core cooling, or containment heat removal piping)

(3) Cause gross failure of any other steam or feedwater line valve

(4) Initiate a loss-of-coolant accident (LOCA)

Discussion of containment integrity for an MSLB is presented in Chapters 6 and 15. Furthermore, an MSLB between the exterior of the containment and the quick-acting isolation valve will not compromise the effectiveness of any containment barrier other than the broken steam line itself. Since the MSIVs are a secondary barrier that serve to back up the steam generator tubes, containment leaktight integrity will not be degraded as a result of a steam line break in this case.

The steam lines and the shell-sides of the steam generators are considered an extension of the containment boundary and, as such, are not to be damaged as a consequence of damage to the reactor coolant system. The steam generator shells and steam lines are, therefore, designed to be protected against reactor coolant system missiles (refer to Section 3.6.1.1).

Applicable design and quality code classifications are discussed in Chapter 3. The classification and applicable codes for the main steam system are identified in the DCPP Q-List (refer to Reference 8 of Section 3.2). Faults involving the main steam system are discussed in Sections 15.3.2 and 15.4.2.

The MSIVs can be operated manually from the control room as described in Section 10.3.3.4. There are also manual bypass valves around those air-operated MSIV bypass valves on main steam leads 2 and 3. These local manual bypass valves can be used to drain condensate accumulated in piping upstream of the MSIVs upon a loss of instrument air supply prior to the startup of the auxiliary feedwater pump turbine.

10.3.3 SAFETY EVALUATION

10.3.3.1 General Design Criterion 2, 1967 – Performance Standards

The main steam lines, together with their supports and structures between each steam generator and its associated isolation valves (including the check valves), are PG&E Design Class I.

The main steam lines are designed to perform their safety functions under the effects of earthquakes (refer to Section 3.7.2.1.7.3). The main steam system downstream of the MSIVs is PG&E Design Class II, however the main steam piping downstream of the MSIVs up to the column line G pipe anchor is considered PG&E QA Class S, and seismic analyses of piping up to the column line G pipe anchor have determined that a seismic event will not prevent the MSIVs from performing their PG&E Design Class I isolation function.

The main steam lines are designed to perform their safety functions under the effects of floods and tsunamis (refer to Section 2.4.3.5).

The containment structure, pipeway structure, and auxiliary building, which contain the main steam system's PG&E Design Class I SSCs, are PG&E Design Class I (refer to Section 3.8). These buildings, or applicable portions thereof, are designed to withstand the effects of winds (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), and earthquakes (refer to Section 3.7). These designs protect the main steam system, ensuring its safety functions will be performed.

Portions of main steam lines, including the MSIVs, are located outside and on the roof of the auxiliary building and are partially resistant to tornadoes, however, the capability of the system to support plant safe shutdown is maintained (refer to Section 3.3.2.3.2.7).

10.3.3.2 General Design Criterion 3, 1971 – Fire Protection

The main steam system has been evaluated, in accordance with the guidelines of Branch Technical Position APCSB 9.5-1, for safe shutdown following a fire (refer to Appendix 9.5A).

As described in Appendix 9.5B, Table B-1, plant layouts isolate PG&E Design Class I systems from unacceptable fire hazards. Therefore, a fire will not affect the main steam system's ability to safely shutdown the plant.

Each MSIV is opened by air and closes when either of the solenoid valves (powered from separate Class 1E 125-Vdc power supplies) in its vent line is energized, releasing the air. In the event of a fire at the nearby main transformer bank, solenoid valve wiring could conceivably be burned, shorted, or opened, thus preventing solenoid energization

and MSIV closure. To ensure MSIV closure in this event, a valve with a thermal fuse (automatic sprinkler type) has been installed in the vent lines of MSIV 41 and MSIV 42 on Unit 1 and Unit 2.

10.3.3.3 General Design Criterion 4, 1967 – Sharing of Systems

Each DCPP unit can supply portions of the other unit's auxiliary steam from its PG&E Design Class II portion of the main steam system downstream of the MSIVs. Check valves in the supply lines prevent cross-flow of the main steam if this feature is utilized. Failure of this check valve would not affect either Unit because both units operate within the same design parameters.

The PG&E Design Class I portion of the main steam system is not affected by this feature.

10.3.3.4 General Design Criterion 11, 1967 – Control Room

The MSIVs can be operated manually from the control room. The MSIVs have remote-manual, air-operated bypass valves for the pressure equalization that is necessary to open the valves. The bypass valves are operated from the control room and automatically close on the same signals that automatically close the MSIVs.

Position indication is provided on the main control board for all MSIVs and bypass valves. Additionally, the main control board provides indications of main steam flow and steam generator pressure.

If access to the control room is lost, necessary main steam system valves can be operated locally with steam generator pressure indicated on the hot shutdown panel.

10.3.3.5 General Design Criterion 12, 1967 – Instrumentation and Control Systems

The MSIVs automatically close on high negative steam line pressure rate, low steam line pressure, or on a high-high containment pressure signal. Instrumentation and controls for the main steam system are discussed in Sections 6.2.4, 7.3, and 9.3.1.3.

Refer to Section 10.3.3.7 for radiation monitoring instrumentation.

10.3.3.6 General Design Criterion 15, 1967 – Engineered Safety Features Protection Systems

The main steam system monitors steam pressure and provides the signal to ESFAS (refer to Section 7.3).

10.3.3.7 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

The radiation monitoring system continuously monitors the main steam system (refer to Section 11.4.2.2.1).

Steam generated in the steam generators is not normally radioactive. However, in the event of primary-to-secondary system leakage due to a steam generator tube leak, it is possible for the main steam to become radioactively contaminated. A full discussion of the radiological aspects of primary-to-secondary leakage, including anticipated operating concentration of radioactive contaminants, means of detection of radioactive contamination, anticipated releases to the environment, and limiting conditions for operation, is included in Sections 7.5.2.3, 11.1.6, 11.4.2.2, and 15.5.

10.3.3.8 General Design Criterion 21, 1967 – Single Failure Definition

The instrumentation and control circuits for steam line isolation (refer to Section 7.3) are redundant in the sense that a single failure cannot prevent isolation. Each MSIV is opened by air and closes when either of the solenoid valves (powered from separate Class 1E 125-Vdc sources) in its vent line is energized, releasing the air.

The instrumentation and control circuits for the main steam system pressure provided to ESFAS are redundant in that a single failure cannot prevent the safety injection signal actuation. Each steam header employs two-out-of-three logic for its signal.

The main steam supply to the turbine-driven AFW pump is provided from both the number 2 and number 3 steam headers.

10.3.3.9 General Design Criterion 49, 1967 – Containment Design Basis

The main steam line containment penetrations are designed and analyzed to withstand the pressures and temperatures that could result from a LOCA without exceeding design leakage rates. Refer to Section 3.8.1.1.3 for additional details.

10.3.3.10 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The main steam system isolation valves required for containment closure are periodically tested for operability. Testing of the components required for the CIS is discussed in Section 6.2.4.1.4.

10.3.3.11 General Design Criterion 57, 1971 – Closed System Isolation Valves

The main steam system containment penetrations and isolation valves are part of the containment isolation system (CIS). Refer to Section 6.2.4 and Table 6.2.-39 for penetration details.

10.3.3.12 Main Steam System Safety Function Requirements

(1) Protection from Missiles and Dynamic Effects

The PG&E Design Class I portion of the main steam system is protected from the effects of missiles and dynamic effects as described in Sections 3.5.1 and 3.6.1.1, respectively.

(2) Decay Heat Removal

The main steam system provides means for removing decay heat from the reactor coolant system by discharging steam from the steam generators to the atmosphere through the steam generator safety valves and also by providing steam to power the AFW pump turbine (refer to Sections 6.5.2 and 7.4.2).

(3) Main Steam Isolation

The MSIVs and check valves (MSIV/CV) are located outside of the containment structure and downstream of the safety valves. The fast-acting isolation valves are provided in each main steam line and will fully close within 10 seconds of a large steam line break. This design ensures that steam line isolation occurs for breaks either upstream or downstream of the valves. The MSIV/CV are credited to prevent reverse flow from the steamline header and intact steam generators. For breaks downstream of the isolation valves, closure of all valves would completely terminate the blowdown. For any break, in any location, no more than one steam generator would blow down even if one of the isolation valves fails to close. Cases that postulate the failure of the MSIV/CV are discussed in Section 6.2D.3.3. The MSIVs automatically close on high negative steam line pressure rate, low steam line pressure, or on a high-high containment pressure signal and can also be operated from the control room (refer to Sections 10.3.3.4 and 10.3.3.5).

Uncontrolled steam release as a result of a main steam line failure is therefore limited to the contents of one steam generator, thus keeping the related effect upon the reactor core within the prescribed bounds. (The main steam line rupture event is discussed in detail in Appendix 6.2D, Section 15.3.2, and Section 15.4.2.) This results in the need for both isolation valves and check valves, as well as special design considerations for the main steam lines themselves. These considerations are necessary to ensure that damage to a portion of one steam line does not result in damage to the corresponding portion of the other steam lines or the other steam generators. They are covered in detail in the MSLB discussion (refer to Section 15.4.2).

(4) Secondary Side Pressure Control

Five spring loaded safety valves are installed on each main steam line, upstream of the MSIVs, to protect the main steam system from overpressurization. The pressure

setpoints for these valves are progressively set from 1065 psig to 1115 psig as shown in Table 10.1-1. Refer to Section 3.9.2.2.5 for additional discussion regarding the safety valves.

(5) Steam Flow Restriction

Each steam generator has an integral flow restrictor located in the steam outlet nozzle to limit the steam blowdown from the steam generators in the event of a main steam line rupture. The flow restrictor consists of seven 6.03-inch ID venturi nozzles. Each main steam line also includes an in-line 16-inch diameter flow restrictor that acts to limit the maximum flow and the resulting thrust forces created by a steam line break. The flow restrictors are discussed in more detail in Sections 5.5.4 and 15.4.2.
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10.3.3.13 10 CFR 50.49 – Environmental Qualification

Main steam system components required to function in harsh environments under accident conditions are qualified to the applicable environmental conditions to ensure that they will continue to perform their safety functions. The affected equipment is listed on the EQ Master List. Main steam EQ components include solenoid valves and position switches for the MSIVs and MSIV bypass valves, and steam flow and pressure transmitters. Section 3.11 describes the DCPP EQ Program and the requirements for the environmental design of electrical and related mechanical equipment.

10.3.3.14 10 CFR 50.55a(f) – Inservice Testing Requirements

Main steam system components that are within the IST program are the MSIVs, MSIV bypass valves, the isolation valves for the 10% steam dumps (the steam dump valves themselves are discussed in Section 10.4.4), and the safety valves.

The inservice testing (IST) requirements for these components are contained in the IST Program Plan and comply with the ASME code for Operation and Maintenance of Nuclear Power Plants.

10.3.3.15 10 CFR 50.55a(g) – Inservice Inspection Requirements

The main steam system piping has a periodic inservice inspection (ISI) program in accordance with the ASME BPVC, Section XI.

10.3.3.16 10 CFR 50.63 – Loss of All Alternating Current Power

Decay heat is removed from the core by natural circulation of the reactor coolant. This heat is then transferred to the secondary side of the steam generators and discharged to the atmosphere through the atmospheric steam dumps. Main steam provides steam to power the turbine-driven AFW pump.

10.3.3.17 10 CFR Part 50 Appendix R (Sections III.G, J, and L) – Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979

10 CFR Part 50 Appendix R requires the evaluation of the safe shutdown capability for DCPP in the event of a fire and the loss of offsite power. The main steam system satisfies the applicable requirements of 10 CFR Part 50 Appendix R, Sections III.G, J, and L.

Section III.G - Fire Protection of Safe Shutdown Capability: Tables 9.5G-1 and 9.5G-2 for DCPP Unit 1 and Unit 2, respectively, list the minimum equipment required to bring the plant to a cold shutdown condition as defined by 10 CFR Part 50, Appendix R, Section III.G. Specifically, all four MSIVs (required to close to maintain steam generator water inventory) and the MSIV bypass valves (considered for spurious operation only) are the minimum required equipment to bring the plant to a cold shutdown condition. These components are provided fire protection features appropriate to the requirements of Section III.G. The actions necessary for safe shutdown for fires in certain fire areas involve manually aligning valves.

Section III.J - Emergency Lighting: Emergency lighting or battery operated lights (BOL) are provided in areas where operation of main steam system valves may be required for safe shutdown following a fire as defined by 10 CFR Part 50, Appendix R, Section III.J (refer to Appendix 9.5D).

Section III.L - Alternative and Dedicated Shutdown Capability: Safe shutdown capabilities are provided in the control room and at alternate locations via the hot shutdown panel and/or local operation of valves in accordance with 10 CFR Part 50 Appendix R, Section III.L (refer to Section 7.4). The ability to safely shut down the plant following a fire in any fire area is summarized in Section 4.0 of Appendix 9.5A.

10.3.3.18 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Category 2 main steam flow indication and radiation monitoring for the vents from the steam generator safety valves are provided in the control room for Regulatory Guide 1.97, Revision 3 monitoring (refer to Table 7.5-6).

10.3.3.19 NUREG-0737 (Item II.F.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.F.1 – Additional Accident Monitoring Instrumentation:

Position (1) – The PG&E Design Class I display instrumentation for main steam line activity monitoring when venting from the steam generator safety valves during and

following an accident is provided and is described in Section 7.5.2.3 and Section 11.4.2.2.1.

10.3.3.20 Generic Letter 89-08, May 1989 – Erosion/Corrosion-Induced Pipe Wall Thinning

DCPP procedures identify the interdepartmental responsibilities and interfaces for the Flow-Accelerated Corrosion (FAC) Monitoring Program for all plant systems, including the main steam system.

10.3.4 TESTS AND INSPECTIONS

The piping from the steam generator, up to and including the main steam line isolation valves, is equipped with removable insulation for inservice inspection of welds. The tests and inspections that apply to the main steam line isolation valves are in accordance with the DCPP Technical Specifications (Reference 1). Main steam line isolation valves are tested periodically to verify their ability to close within the required time (refer to Section 7.3 for a discussion of the response times for the steam line isolation signal).

Preoperational and startup testing requirements applicable to the main steam system are discussed in Chapter 14.

Since the major components of the steam and power conversion system are accessible during normal power operation, leakage from the valves located upstream of the MSIVs is monitored by routine visual inspection by the operators.

The MSIVs, and the valves upstream of them and outside the containment, are designed and packed to have the capability of limiting gland leakage along the stem to no more than one cubic centimeter of water per hour per inch of stem diameter, when subjected to a hydrostatic test pressure of 1100 psig, or 0.03 scf of air per hour per inch of stem diameter with a differential pressure of 80 psi. They are designed to have the capability to limit the valve seat leakage rate to 0.1 scf per hour per inch of seat diameter, when subjected to a pneumatic pressure of 80 psig. Table 10.3-1 summarizes the potential leakages for valves located upstream of the steam line isolation valves, and lists the leak rates measured through these leak paths during initial plant startup testing.

However, since the secondary system is a closed system inside containment whose integrity is not damaged by a LOCA, the offsite dose consequences via the leak paths identified in Table 10.3-1 are small when compared to the consequences from the containment atmosphere leakage assumed in the offsite dose analysis. Hence, pursuant to Table 6.2-39, there are no local leak rate limits established for these leakage paths, since in accordance with 10 CFR Part 50, Appendix J, this leakage is not required to be measured.

10.3.5 WATER CHEMISTRY

The secondary water chemistry control program is discussed in Section 5.5.2.3.5. Steam generator blowdown for chemistry control is discussed in Section 10.4.8. The main steam sampling system is discussed in Section 9.3. Chemical treatment of the secondary system water for corrosion control is discussed in Section 10.4.9.

10.3.6 INSTRUMENTATION APPLICATIONS

Instrumentation for the main steam system is discussed in Sections 10.3.3.4 and 10.3.3.5.

10.3.7 REFERENCES

1. Technical Specifications, Diablo Canyon Power Plant Units 1 and 2, Appendix A to License Nos. DPR-80 and DPR-82, as amended.

10.3.8 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

10.4 OTHER FEATURES OF STEAM AND POWER CONVERSION SYSTEM

10.4.1 MAIN CONDENSER

The main condenser provides a heat sink and collection volume for steam and condensate discharged from the main turbine, feedwater pump turbines, turbine bypass system, feedwater heater drains, and other miscellaneous flows, drains, and vents.

10.4.1.1 Design Bases

The main condenser is classified as PG&E Design Class II. There are no regulatory requirements associated with the main condenser. Radioactive leak detection is discussed in Section 10.4.2.

10.4.1.2 System Description

The main condenser is designed to condense full load steam and maintain a nominal absolute pressure of 1.71 inches of mercury at 85 percent cleanliness. Sufficient surface (618,150 square feet) is provided to condense turbine bypass system steam (up to 40 percent of maximum calculated capability flow), following a load reduction, or under controlled startup conditions, or from residual and decay heat at shutdown.

The condenser hotwells are sized to provide adequate storage of water (138,000 gallons) to allow for the water lost to the atmosphere and "shrinkage" on a 50 percent load reduction. The condensate leaving the hotwells is deaerated to 0.005 cc/liter dissolved oxygen level. The main condenser is provided with a means of detecting saltwater leakage.

During operation, air is removed from the condenser by steam jet air ejectors and discharged to the plant vent. The discharged air is continuously monitored for radioactivity. No control functions are associated with this radiation monitor. For drawing initial vacuum, the condenser is evacuated by a wet-type rotary vacuum pump which discharges air to the atmosphere. The condenser vacuum pump may also be placed into service in the event of degraded condenser vacuum. Refer to Section 10.4.2 for a discussion of the main condenser evacuation system.

The main condensing surface is mounted beneath the low-pressure turbine elements in two shells with interconnected steam spaces. The tubes are arranged parallel to the turbine shaft. The performance data for both the Unit 1 and Unit 2 condensers are summarized in Table 10.4-1.

The following materials are used in the condenser:

(1) Shell and tube supports - carbon steel, ASTM A285, Grade C

(2) Tubesheets - 90-10 copper nickel, ASTM B171 (with corrosion-resistant coating on the saltwater side)

(3) Water boxes - carbon steel, ASTM A285, Grade C, lined with corrosion resistant coating on the saltwater side

(4) Tubes - titanium

The condenser will condense up to 40 percent of the full load main steam flow during a load reduction, startup, or shutdown. As discussed in Chapter 15, the steam generator safety valves protect the NSSS from overpressure if the condenser is not available or if the steam flow exceeds the capacity of the condenser. The secondary system is normally not radioactive. However, in the event of primary-to-secondary leakage through leaking steam generator tubes, it is possible for the main steam to become radioactively contaminated. A discussion of the assumed leakage rates, treatment methods, and calculated activity levels is included in Section 11.1.6, and an inventory of radionuclides in the condenser for an assumed leak rate is shown in Table 11.1-27.

10.4.1.3 Safety Evaluation

The main condenser is classified as PG&E Design Class II. There are no regulatory requirements associated with the main condenser. Radioactive leak detection is discussed in Section 10.4.2.

10.4.1.4 Tests and Inspections

Tests and inspections of the main condenser are done in accordance with plant procedures.

10.4.1.5 Instrumentation Applications

Instrumentation is provided to monitor and control main condenser operation.

10.4.2 MAIN CONDENSER EVACUATION SYSTEM

The main condenser evacuation system (MCES) removes noncondensable gases from the main condenser during plant startup, cooldown, and normal operation. The system is classified as PG&E Design Class II.

10.4.2.1 Design Bases

10.4.2.1.1 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

The MCES is provided with means for monitoring the release of radioactivity in facility effluent discharge paths.

10.4.2.1.2 NUREG-0737 (Item II.F.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.F.1 – Additional Accident-Monitoring Instrumentation:

Position (1) – The MCES is designed with noble gas effluent monitors that are installed with an extended range designed to function during accident conditions.

Position (2) – The MCES is designed with provisions for sampling of plant effluents for post-accident releases of radioactive iodines and particulates and onsite laboratory capabilities.

10.4.2.2 System Description

The MCES consists of a wet-type rotary vacuum pump and steam jet air ejectors. The vacuum pump is common to both units and is used to draw an initial vacuum in the condenser of either unit and may be used during degraded vacuum conditions. The steam jet air ejectors are used after the initial pumpdown and are designed to remove air that may degrade the ability of the condenser to maintain a nominal absolute pressure of 1.71 inches of mercury, as described in Section 10.4.1.2.

The wet-type rotary vacuum pump has a capacity of approximately 7000 cubic feet per minute.

The steam jet air ejector system consists of two stages of steam jets mounted on a combined inter-after surface condenser. The air ejector system is designed to remove 360 pounds per hour of air saturated with water vapor at 71.5°F, and a suction pressure of 1 inch of mercury absolute pressure when supplied with steam at 85 psig. The first stage consists of eight 25 percent capacity jets and the second stage consists of twin 100 percent capacity jets.

Refer to Section 5.5.2 for information on PG&E's implementation of Electric Power Research Institute primary-to-secondary leak guidelines.

10.4.2.3 Safety Evaluation

10.4.2.3.1 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

Air is discharged from the vacuum pump through a local vent. During vacuum pump operation, grab samples are taken at the local vent in support of the Radioactive Effluent Controls Program. In addition, evaluations have been performed that demonstrate potential radioactive discharges remain within 10 CFR 100 limits. Noncondensables vented from the steam jet air ejectors while the plant is at power operation are discharged through the plant vent that is continuously monitored for radioactivity. Further discussion of releases due to steam generator leakage and the radiation monitoring of the plant vent is given in Sections 7.5.2.3, 9.4.2, 11.1.6 and 11.4.

10.4.2.3.2 NUREG-0737 (Item II.F.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.F.1 – Additional Accident-Monitoring Instrumentation:

Position (1) – Extended range noble gas effluent monitoring is installed in the plant vent, which includes exhaust from the steam jet air ejectors, and is designed to function during accident conditions. Refer to Section 9.4.2 for information on the plant vent and Figures 3.2-2 and 3.2-23 for a depiction of steam jet air ejector after-condenser exhaust routing to the plant vent. Refer to Section 11.4 for discussion of radiation monitors.

Position (2) – Installed capability is provided in the plant to obtain samples of the particulate and iodine radioactivity concentrations that may be present in the gaseous effluent being discharged to the environment from the plant vent, which includes the steam jet air ejector exhaust, under accident and post-accident conditions. The technical support center laboratory is available for onsite testing of the air samples. Refer to Section 9.4.2 for information on the plant vent and Figures 3.2-2 and 3.2-23 for a depiction of steam jet air ejector after-condenser exhaust routing to the plant vent. Refer to Section 11.4 for discussion of radiation monitors.

10.4.2.4 Tests and Inspections

Tests and inspections of the MCES are done in accordance with plant procedures.

10.4.2.5 Instrumentation Applications

Instrumentation is provided to monitor and control MCES operation.

10.4.3 TURBINE GLAND SEALING SYSTEM

The turbine gland sealing system provides shaft sealing for the main turbine and feedwater pump turbine.

10.4.3.1 Design Bases

The turbine gland sealing system is designed to prevent the leakage of air into, or steam out of, the turbines along the turbine shaft. The system has no PG&E Design Class I functions and is classified as PG&E Design Class II.

10.4.3.1.1 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

Means shall be provided for monitoring the containment atmosphere, the facility effluent discharge paths, and the facility environs for radioactivity that could be released from normal operations, from anticipated transients, and from accident conditions.

10.4.3.1.2 NUREG-0737 (Item II.F.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.F.1 - Additional Accident-Monitoring Instrumentation:

Position (1) - Item II.F.1, Position (1) requires monitoring of post-accident effluent noble gas releases from the turbine gland sealing system.

Position (2) - Item II.F.1, Position (2) requires monitoring of post-accident effluent radioactive iodine and particulate releases from the turbine gland sealing system.

10.4.3.2 System Description

The turbine glands are of the labyrinth type. When the unit is being started, and partially during normal operation, steam is supplied to the gland header from the main steam line to seal the high-pressure and low-pressure turbine glands. The auxiliary boiler also can be used to supply sealing steam during startup. When the turbine is operating under load, the steam pressure inside the high-pressure turbine increases and steam leaks outward toward the rotor ends. The leakage from the high-pressure glands partially supplies the steam requirements for the low-pressure glands, while the remainder is furnished by the main steam gland regulator. Adequate steam pressure is maintained in the gland area at all times to prevent the leakage of air into, or steam out of, the turbine along the turbine shaft.

At normal operating conditions, the exhaust from the gland seals is approximately 3000 pounds per hour of air saturated with water vapor at 150°F. The gland steam condenser maintains a pressure slightly below atmosphere in the gland leak-off system to prevent the escape of steam from the glands. The air and noncondensable gases from the turbine gland seal condenser are exhausted to the plant vent, which is continuously monitored (refer to Section 11.4.2).

10.4.3.3 Safety Evaluation

10.4.3.3.1 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

The turbine gland sealing system has no PG&E Design Class I function. In the event of steam generator leakage and continued plant operation, the gland sealing system prevents the release of radioactive steam to the turbine building. If gland seals are lost due to a malfunction of the system, a small amount of steam could be released depending on the type of equipment malfunction. Upon the loss of gland sealing steam, the turbine would be tripped to prevent seal or rotor damage. A turbine trip would prevent additional radioactive steam from entering the turbine.

The air and noncondensable gases from the gland seal condenser are routed to the plant vent (refer to Sections 9.4.2 and 11.4.2). In the event that the gland steam becomes contaminated, it will be detected by radiation detectors located in the plant vent (normal range [NR] and redundant normal range [RNR] radiation monitors). The turbine building is not monitored for leakage from the glands. Details of the radiological evaluation of the system are included in Section 11.3.6.

10.4.3.3.2 NUREG-0737 (Item II.F.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.F.1 - Additional Accident-Monitoring Instrumentation:

Position (1) - Radiation detection instruments are provided in the plant vent to monitor post-accident effluent noble gas releases from the turbine gland sealing system. Refer to Section 9.4.2 for information on the plant vent and Figure 3.2-23 for a depiction of turbine gland steam condenser exhaust routing to the plant vent. Refer to Section 11.4 for discussion of radiation monitors.

Position (2) - Radiation detection instruments are provided in the plant vent to monitor post-accident effluent radioactive iodine and particulate releases from the turbine gland sealing system. Refer to Section 9.4.2 for information on the plant vent and Figure 3.2-23 for a depiction of turbine gland steam condenser exhaust routing to the plant vent. Refer to Section 11.4 for discussion of radiation monitors.

10.4.4 TURBINE BYPASS SYSTEM

The turbine bypass system (TBS) bypasses main steam directly to the main condenser and atmosphere, depending on the required capacity, during the emergency condition caused by a sudden load reduction by the turbine-generator or turbine trip, and during plant startup and shutdown.

10.4.4.1 Design Bases

Of the 25 turbine bypass valves (refer to Section 10.4.4.2), only the four 10 percent atmospheric dump valves have a safety function (refer to Section 10.4.4.3.7). Therefore, the design bases in this section apply only to these valves and their associated upstream piping systems.

10.4.4.1.1 General Design Criterion 2, 1967 – Performance Standards

The 10 percent atmospheric dump valves are designed to withstand the effects of, or shall be protected against, natural phenomena, such as earthquakes, flooding, tornadoes, winds, and other local site effects.

10.4.4.1.2 General Design Criterion 3, 1971 – Fire Protection

The 10 percent atmospheric dump valves are designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

10.4.4.1.3 General Design Criterion 11, 1967 – Control Room

The 10 percent atmospheric dump valves are designed to support actions to maintain and control the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

10.4.4.1.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain the 10 percent atmospheric dump valves' variables within prescribed operating ranges.

10.4.4.1.5 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The piping system associated with the 10 percent atmospheric dump valves is provided with leakage detection, isolation, and containment capabilities having redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating this system. The piping system associated with the 10 percent atmospheric dump valves shall be provided with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

10.4.4.1.6 General Design Criterion 57, 1971 – Closed System Isolation Valves

The main steam system headers associated with the 10 percent atmospheric dump valves contain piping connected to containment penetrations that are neither part of the reactor coolant pressure boundary nor connected directly to the containment atmosphere. These penetrations are provided with one local or remote-manual valve outside the containment.

10.4.4.1.7 Turbine Bypass System Safety Function Requirements

(1) Protection from Missiles and Dynamic Effects

The 10 percent atmospheric dump valves are designed to be protected against the effects of missiles and dynamic effects, which may result from equipment failures.

(2) Reactor Coolant System Cooldown

The 10 percent atmospheric dump valves are designed to provide a method for reactor coolant system (RCS) cooldown.

10.4.4.1.8 10 CFR 50.55a(f) – Inservice Testing Requirements

The 10 percent atmospheric dump valves are tested to the requirements of 10 CFR 50.55a(f)(4) and a(f)(5) to the extent practical.

10.4.4.1.9 10 CFR 50.55a(g) – Inservice Inspection Requirements

The 10 percent atmospheric dump valves are inspected to the requirements of 10 CFR 50.55a(g)(4) and a(g)(5) to the extent practical.

10.4.4.1.10 10 CFR 50.63 – Loss of All Alternating Current Power

The 10 percent atmospheric dump valves are required to perform their safety function of supporting reactor coolant system cooldown in the event of a station blackout (SBO).

10.4.4.1.11 10 CFR Part 50 Appendix R (Sections III.G, III.J, and III.L) – Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979

Section III.G – Fire Protection of Safe Shutdown Capability: Fire protection of the 10 percent atmospheric dump valves is provided by a combination of physical separation, fire-rated barriers, and/or automatic suppression and detection.

Section III.J – Emergency Lighting: Emergency lighting or battery operated lights (BOLs) is provided in areas where operation of the 10 percent atmospheric dump valves may be required to safely shut down the Unit following a fire.

Section III.L – Alternative and Dedicated Shutdown Capability: Safe shutdown capabilities are provided in the control room and at an alternate location via the hot shutdown panel (HSP) or locally at the 10 percent atmospheric dump valves as required for the safe shutdown of the plant following a fire event.

10.4.4.2 System Description

The TBS consists of 25 power relief valves. Four of these valves (10 percent dump valves) take steam from each main steam line and discharge to the atmosphere. The remaining 21 valves take steam from the dump headers (connected to all main steam lines)and discharge either into spray distribution headers in the condenser (40 percent dump valves) or to the atmosphere (35 percent dump valves). The system thus provides an artificial load on the reactor coolant system during the emergency condition of a sudden load reduction by the turbine-generator or a turbine trip (four of the 40 percent dump valves are used during cooldown).

The valve groups are opened in the following sequence:

(1) Cooldown valves (four of twelve 40 percent dump valves)

(2) Bypass valves (remaining eight of twelve 40 percent dump valves)

NOTE: Plant capability is provided to use all 12 valves for cooldown during Mode 3 after boration to cold shutdown conditions.

(3) Atmospheric relief valves (nine 35 percent atmospheric dump valves downstream of the main steam isolation valves (MSIVs))

(4) Atmospheric relief valves (four 10 percent atmospheric dump valves upstream of the MSIVs)

NOTE: Group 4 of the atmospheric dump valves (ADVs) are set at a lower pressure than the spring-loaded safety valves.

The TBS is thus designed with a capacity to bypass a range of approximately 66 to 79 percent of the full load steam flow over the range of full load operating conditions to the main condenser and the atmosphere combined. The exact capacities of these relief valves depend on the full load operating conditions. Valve groups 1, 2, and 3 are credited in determining this capacity. The steam dump capacity to the main condenser alone (groups 1 and 2) has a range of approximately 35 to 41 percent of the full load steam flow over the range of full load operating conditions.

The capacity of the TBS, combined with the 10 percent step-load-change characteristics of the reactor, provides the capability of accepting a sudden load reduction of up to 50 percent, without reactor trip or operation of the spring-loaded safety valves or 10 percent atmospheric dump valves.

The total amount of steam released to the atmosphere during a loss of generator external load assuming that the condenser is not available for steam dump is discussed in Section 15.5.10.2.

With the exception of group 4 of the atmospheric dump valves, the TBS is not essential to the safe operation of the plant; it is required to give the plant flexibility of operation and a controlled cooldown. The steam generator safety valves provide relieving capacity during a period when all valves are out of service (refer to Section 10.3.2).

Failure of the 40 percent dump valves, the 35 percent atmospheric relief valves downstream of the main steam isolation valves, or any pipe downstream of the MSIVs could result in a rapid cooldown and depressurization of the steam generators until the MSIVs close on high negative steam line pressure rate or low steam line pressure signals. The transients and radiological consequences associated with such a failure would not be as severe as the double-ended severance of a main steam line, as discussed in Section 15.5.18. Failure of any of these components (or pipe associated with them) downstream of the MSIVs could not cause overpressurization of a steam generator because of the location of the spring-loaded safety valves upstream of the MSIVs.
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The TBS has been analyzed for potential effects of piping rupture on nearby safety-related equipment. Details of this analysis are presented in Section 3.6.4.

10.4.4.2.1 Design Codes and Standards

The piping and valves associated with the 40 percent and 35 percent dump valves are classified as PG&E Design Class II because they are not required for RCS cooldown, as discussed in Section 10.4.4.3.

The 10 percent atmospheric dump valves and associated upstream piping are classified as PG&E Design Class I because they are required for RCS cooldown, as discussed in Section 10.4.4.3.7.

Applicable codes and standards for piping, valves, and fittings are discussed in Section 3.2.

10.4.4.3 Safety Evaluation

10.4.4.3.1 General Design Criterion 2, 1967 – Performance Standards

The 10 percent atmospheric dump valves are PG&E Design Class I components and are located either on the roof of the PG&E Design Class I auxiliary building at elevation 143 feet (steam leads 3 and 4) or on a support structure external to the containment at

elevation 112 feet-6 inches (steam leads 1 and 2). These elevations are above the level affected by floods and tsunamis.

PG&E Design Class I SSCs in locations exposed to the weather are evaluated against tornado-related effects including impact by tornado-induced missiles. Refer to Section 3.3.2.3 for the results of the evaluation.

The 10 percent atmospheric dump valves are required to function following a DE, DDE, and HE (refer to Sections 3.7.1.1 and 3.7.6.1).

10.4.4.3.2 General Design Criterion 3, 1971 – Fire Protection

The 10 percent atmospheric dump valves have been evaluated for safe shutdown following a fire (refer to Appendix 9.5G). Only one of the four valves is required for safe shutdown and the valves' steam relief functions are backed up by the main steam code safety valves. Therefore, a fire will not affect the valves' abilities to safely shutdown the plant.

10.4.4.3.3 General Design Criterion 11, 1967 – Control Room

The 10 percent atmospheric dump valves can be controlled manually from within the control room in order to maintain safe operational status of the plant. In the event that control room access is lost due to fire or other causes, the valves can be controlled manually from the hot shutdown panel (refer to Section 7.4.2.1.2.3).

10.4.4.3.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation for manually operating the 10 percent atmospheric dump valves is provided in the main control room, at the hot shutdown panel, and locally at the valve (refer to Section 7.4.2.1.2.3). Valve position indication is provided on the Emergency Response Facility Data System (ERFDS) (refer to Section 7.5.2.9).

10.4.4.3.5 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The 10 percent atmospheric dump valves, required for containment closure, are periodically tested for operability. Testing of the components required for the containment isolation system (CIS) is discussed in Section 6.2.4.

10.4.4.3.6 General Design Criterion 57, 1971 – Closed System Isolation Valves

The containment penetrations associated with the 10 percent atmospheric dump valves comply with the requirements of GDC 57, 1971, as described in Section 6.2.4 and Table 6.2-39.

10.4.4.3.7 Turbine Bypass System Safety Function Requirements

(1) Protection from Missiles and Dynamic Effects

The 10 percent atmospheric dump valves are protected against postulated missile sources as described in Section 3.5.1.2.

The 10 percent atmospheric dump valves are PG&E Design Class I equipment and therefore are designed to be protected against dynamic effects which may result from equipment failures as described in Section 3.6.

(2) Reactor Coolant System Cooldown

The 10 percent atmospheric dump valves provide a means for plant cooldown by discharging steam to the atmosphere when the condenser, the condenser circulating water pumps, or steam dump to the condenser is not available. Under such circumstances, the 10 percent atmospheric dump valves, in conjunction with the auxiliary feedwater system, permit the plant to be cooled down from the pressure setpoint of the lowest-set MSSVs to the point where the residual heat removal system can be placed in service. In the event of a steam generator tube rupture (SGTR) event in conjunction with loss of offsite power, the 10 percent atmospheric dump valves are used to cool down the RCS to a temperature that permits equalization of the primary and secondary pressures at a pressure below the lowest-set MSSV.

With the loss of both the normal air supply and the backup nitrogen supply to the 10 percent atmospheric dump valves, the normal supplies are blocked and the PG&E Design Class I backup air bottle system is activated (refer to Section 9.3.1.6). With the backup air bottle system activated, control of the valves is remote manual via the PG&E Design Class I control circuit from the control room ensuring the valves can cooldown the RCS.

10.4.4.3.8 10 CFR 50.55a(f) – Inservice Testing Requirements

The TBS components that are within the IST program are the four 10 percent atmospheric dump valves.

The inservice testing (IST) requirements for these components are contained in the IST Program Plan and comply with the ASME code for Operation and Maintenance of Nuclear Power Plants.

10.4.4.3.9 10 CFR 50.55a(g) – Inservice Inspection Requirements

The 10 percent atmospheric dump valves have a periodic inservice inspection (ISI) program in accordance with the ASME B&PV Code, Section XI (refer to Section 5.2.8).

10.4.4.3.10 10 CFR 50.63 – Loss of All Alternating Current Power

During an SBO, decay heat is removed from the core by natural circulation of the reactor coolant. This heat is then transferred to the secondary side of the steam generators and discharged to the atmosphere through the 10 percent atmospheric dump valves.

The 120-Vac system provides power to the analog control portion and the enabling logic of the steam dump control system. It also provides 120-Vac power to the controls for the 10 percent atmospheric dump valve backup air controls ensuring they can perform their safety function of supporting RCS cooldown in the event of an SBO.

10.4.4.3.11 10 CFR Part 50 Appendix R (Sections III.G, J, and L) – Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979

10 CFR Part 50 Appendix R requires the evaluation of the safe shutdown capability for DCPP in the event of a fire and the loss of offsite power. The 10 percent atmospheric dump valves satisfy the applicable requirements of 10 CFR Part 50 Appendix R, Sections III.G, J, and L.

Section III.G – Fire Protection of Safe Shutdown Capability: For the TBS, one out of four 10 percent atmospheric dump valves is the minimum required equipment to bring the plant to a cold shutdown condition. The 10 percent atmospheric dump valves are provided with fire protection features appropriate to the requirements of Section III.G.

Section III.J – Emergency Lighting: Emergency lighting or battery operated lights (BOL) are provided in areas where operation of the 10 percent atmospheric dump valves may be required for safe shutdown following a fire as defined by 10 CFR Part 50, Appendix R, Section III.J (refer to Appendix 9.5D).

Section III.L – Alternative and Dedicated Shutdown Capability: Safe shutdown capabilities are provided in the control room and at alternate locations in accordance with 10 CFR Part 50 Appendix R, Section III.L (refer to Section 7.4 and Appendix 9.5E). The ability to safely shut down the plant following a fire in any fire area is summarized in Section 4.0 of Appendix 9.5A.

10.4.4.4 Tests and Inspections

Local test facilities for the bypass flow control valves are not provided. The 40 percent dump valves and the 35 percent dump valves are PG&E Design Class II and are tested at reactor low power levels.

Each 10 percent atmospheric dump valve , associated block valve, and associated remote manual controls, including the backup air bottles, is demonstrated operable on a frequency interval required by the Technical Specifications.

Additionally, each 10 percent atmospheric dump block valve is verified open at least once per 31 days

Should evidence indicate that radioactivity is being released as a result of leakage through these valves during the post-accident recovery period, action such as tightening packing will be taken to eliminate the source.

10.4.4.5 Instrumentation Applications

During normal operating transients for which the plant is designed, the TBS is automatically regulated by the reactor coolant temperature control system to maintain the programmed coolant temperature.

When a transient results in a plant trip, the operator transfers bypass control to the pressure control mode and regulates the system to maintain no-load steam pressure. Lower pressures can be maintained automatically by adjustment of the pressure setpoint. During a plant cooldown, the bypass system is manually controlled to achieve the required cooling rate. This is accomplished by manual adjustment of the pressure setpoint in the control room and requires a minimum operation of four bypass valves to the condenser.

Refer to Section 10.4.4.3.4 for additional information on instrumentation and controls.

10.4.5 CIRCULATING WATER SYSTEM

The circulating water system provides the heat sink required for removal of waste heat in the power plant's thermal cycle. The system has the principal function of removing heat by absorbing this energy in the main condenser.

10.4.5.1 Design Bases

10.4.5.1.1 Circulating Water System Safety Function Requirements

(1) Internal Flooding Protection

The circulating water system is designed to prevent flooding of PG&E Design Class I equipment.

10.4.5.2 System Description

The circulating water system is designed to provide cooling water necessary to condense the steam entering the main condenser. The system also serves the intake coolers, condensate cooler, and service cooling water heat exchangers. The design temperature rise in the circulating water system at full load operation is 18°F. The design flow per unit is nominally 862,000 gpm.

The circulating water system is classified as PG&E Design Class II.
Condenser circulating water is seawater from the Pacific Ocean. The ocean water level normally varies between zero and +6 feet mean lower low water (MLLW) datum. Mean sea level (MSL) zero is equivalent to +2.6 feet MLLW.

A curtain wall at the front of the intake structure limits the amount of floating debris entering the intake structure. Bar racks near the front of the intake structure intercept large submerged debris. The bar racks have 3/8-inch thick bars at 3-3/8 inch centers. Traveling screens intercept all material larger than the screen mesh opening (3/8 inch clear square openings).

The total flow in each unit's circulating water system is nominally 862,000 gpm, which is pumped by two circulating water pumps per unit through two circulating water conduits per unit to the condenser inlet water boxes. Each pump has a discharge valve and bypass line around the valve. Approximately 4000 gpm of the circulating water flow is used per unit to cool the service cooling water heat exchangers and 1000 gpm to cool the pump motor cooling water.

At the intake structure, each circulating water system consists of two circulating water pumps with 12-kV motors cooled by an air-to-water heat exchanger. The cooling water is provided from a closed-loop cooling system.

The chlorination system provides chemical treatment of the circulating water to control macro and micro fouling in the intake tunnels, piping, and the condenser tubes. The system is used as needed.

The chlorination system, which is shown as part of Figure 3.2-17, provides an oxidizing biocide to the suction of the circulating water pumps for control of macro and micro fouling. Liquid sodium hypochlorite and a supplemental chemical are stored in tanks at the intake structure (common to both units). Adequate valving is provided for isolating any of the tanks from the system. Each tank is within a containment tank sized to contain the entire contents of the storage tank. When chlorination is required (based on a time schedule), the chemicals are injected via metering pumps and injected into the intake structure. In addition, dechlorinating injections are made between the outlet of the main condenser and the discharge structure as required to ensure National Pollutant Discharge Elimination System (NPDES) permit requirements are met. Concentrations of chlorine in the circulation water system outfall are discussed in detail in Reference 1 and the NPDES permit.

The circulating water pumps are not required for safety of the units. Dependable pump operation is necessary, however, for reliable operation of electric generating plants and provisions to ensure their operation are incorporated in the design.

10.4.5.3 Safety Evaluation

10.4.5.3.1 Circulating Water System Safety Function Requirements

(1) Internal Flooding Protection

Due to the low operating pressure of the circulating water system, the probability of a line, expansion joint, or waterbox failure is very low. The differential head across the circulating water pumps at shutoff is a nominal 160 feet. At high tide, the pump discharge head at shutoff would be 163.4 feet (refer to Section 10.4.5.2), measured at elevation zero, MSL datum. However, provisions exist in the design of the circulating water system that prevent the circulating water pumps from operating at shutoff head.

The design of the inlet and outlet of the circulating water to the condenser consists of several components. The circulating water flows through the embedded supply conduit, the inlet transition spool piece, the inlet expansion joint, and inlet condenser water box prior to entering the condenser tubes. Similarly, upon exiting the tubes, the circulating water passes through the outlet waterbox, expansion joint, transition spool piece, and embedded discharge conduit prior to being discharged to the ocean. The transition spool pieces, expansion joints, and condenser (including waterboxes) are located in the turbine building. The discharge gates are located in the embedded discharge conduit in the yard.

The design pressure of the rubber expansion joints on the inlet and outlet of the condenser (located at an elevation of 85 feet) is 81 feet.

Thus, if a circulating water pump were to pump against closed discharge gates, the pressure on the expansion joint (the pump discharge head minus the static elevation head) would be less than the design pressure. The design pressure of the transition inlet and outlet spool pieces (located at an elevation of 81 feet) is 58 feet. Similarly, the design pressure of the condenser water boxes (located at an elevation of 85 feet) is 58 feet. To prevent operating the circulating water pump and system in a configuration that could result in overpressurizing the transition spool pieces and waterboxes, mechanical stops on the condenser discharge gate operators and structural stops on the gate guide tracks inhibit the complete closing of the discharge gates. Dynamic water hammer pressures will not occur due to inadvertent closing of the water gates because the motor operators close the gates at a rate of only 15 inches per minute. These measures make circulating water system overpressurization a highly improbable event.

Inlet spool pieces and water boxes are constructed of ductile carbon steel with a corrosion-resistant internal coating, and their catastrophic failure, such that significant seawater could flood the turbine building, is not a credible assumption. The cast iron outlet spool piece was hydrotested to 1.5 times the maximum attainable circulating water system pressure.

A flooding analysis was performed based on the failure of an operator to properly secure a condenser waterbox manway cover. In order to obtain a conservative flooding rate for this scenario, waterbox manhole cover failure was assumed to be coincident with an operating error in which both circulating water pumps were running and both discharge gates were closed to the stops. In this event, approximately 43,000 gpm or 5,700 cfm of water could be expected to flow from a lower inlet waterbox manhole (the manholes with the greatest incident head of water). This flow would fill the sump and equipment pit storage areas below elevation 85 feet in 15 minutes, if the building drains are assumed to be functioning, and in 10 minutes, if the drains are not functioning. During this time, alarms would be given for turbine building sump high level and for water in the condenser pit. It may be assumed that the condensate pumps, being flooded, would have tripped, giving dramatic indication of an irregular condition.

In order to provide additional time for operators to react to this flooding casualty, a fire door was installed between the main condensers and the corridor to the emergency diesel generator rooms in order to minimize the amount of water that could enter the compartments. The door is locked closed and monitored through the security system. This door will allow at least 12 more minutes (assuming no flow of water from the building) for the postulated manhole failure flow after sumps and pits are flooded.

Subsequent to the fire door installation, a float switch system was mounted on the walls of the condenser pit. This instrumentation system eliminated the need for operator action in order to protect PG&E Design Class I equipment from any type of circulating water system leakage. The system will automatically trip the circulating water pumps if water fills the condenser pit thereby assuring that the turbine building cannot be flooded by a circulating water system leak. The system employs two-out-of-three logic for a high degree of reliability and it provides a high condenser pit level alarm indication in the control room.

10.4.5.4 Tests and Inspections

Tests and inspections of the circulating water system are done in accordance with plant procedures.

10.4.5.5 Instrumentation Applications

Instrumentation is provided to monitor and control circulating water system operation. As described in Section 10.4.5.3.1(1), high water level in the turbine building condenser pit will trip the circulating water pumps and provide an alarm in the control room.

10.4.6 CONDENSATE POLISHING SYSTEM

The PG&E Design Class II condensate polishing system removes both dissolved and suspended corrosion products and impurities from the condensate. The system is important to maintaining secondary water chemistry and minimizes the buildup of sludge in the steam generators.

10.4.6.1 Design Bases

10.4.6.1.1 General Design Criterion 3, 1971 – Fire Protection

The condensate polishing system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

10.4.6.1.2 General Design Criterion 9, 1967 – Reactor Coolant Pressure Boundary

The materials of construction of the pressure-retaining boundary of the steam generator tubes are protected by control of secondary chemistry from corrosion that might otherwise reduce the system structural integrity during its service lifetime. The condensate polishing system functions to contribute to the secondary chemistry control.

10.4.6.1.3 Condensate Polishing System Function Requirement

(1) Internal Flooding

The condensate polishing system shall be designed to be protected against the effects of internal flooding which may result from equipment failures.

10.4.6.1.4 Regulatory Guide 1.78, June 1974, Assumptions for Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release

The DCPP control room should be appropriately protected from hazardous chemicals that may be discharged as a result of equipment failures, operator errors, or events and conditions outside the control of the plant.

10.4.6.2 System Description

The condensate polishing system is comprised of seven mixed bed demineralizers. Either six or seven demineralizers are in service processing the full condensate flow (approximately 21,000 gpm) depending on whether any one of the demineralizers is in the regeneration mode or not. The demineralizer in the regeneration mode is taken out of service and is regenerated externally in order to minimize the possibility of introducing regenerant chemicals in the condensate and feedwater system. The external regeneration process for one demineralizer normally takes about 12 to 16 hours.

Components of the condensate polishing system, including demineralizers, regenerators, and associated equipment, are located in the turbine building buttresses. The system is capable of either automatic or manual operation, and can be bypassed if necessary.

The vessels are designed to Section VIII of the ASME code. The system piping is designed to ANSI B31.1 (refer to Section 3.2).

The condensate polishing system is classified as PG&E Design Class II. Although located within the PG&E Design Class I turbine building buttresses, the system and component supports, including enclosures, do not compromise the PG&E Design Class I seismic requirement of the turbine building buttress structure.

Personnel safety provisions include smoke detectors and portable fire extinguishers in compartments where potential for fire exists. Eyewashes and a safety shower are also provided in the chemical storage and chemical feed pump areas.

10.4.6.3 Safety Evaluation

10.4.6.3.1 General Design Criterion 3, 1971 – Fire Protection

The chemicals of the condensate polishing system (sodium hydroxide and sulfuric scid) are stored in accordance with the requirements of Branch Technical Position 9.5-1 (refer to Appendix 9.5B, Table B-1).

10.4.6.3.2 General Design Criterion 9, 1967 – Reactor Coolant Pressure Boundary

The condensate polishing system is designed to polish the full condensate flow during startup and normal plant operation. During startup, the system allows recirculation of condensate at approximately 5500 gpm through the condensate polishing demineralizers and feedwater heaters, returning it to the main condenser. This design provision allows a more complete cleanup of secondary water prior to system startup.

The condensate polishing system monitors the secondary chemistry to protect the steam generator tubes which are a part of the reactor coolant pressure boundary from degradation during the course of its lifetime. This is in compliance with the steam generator tube integrity requirements of Generic Letter 85-02.

10.4.6.3.3 Condensate Polishing System Safety Function Requirement

(1) Internal Flooding

The condensate polishing system is designed so that its failure will not impact the PG&E Design Class I SSCs in the turbine buttress building.

10.4.6.3.4 Regulatory Guide 1.78, June 1974, Assumptions for Evaluating the Habitability of a Nuclear Power Plant Control Room during a Postulated Hazardous Chemical Release

The DCPP control room is adequately protected from hazardous chemicals that may be discharged from the condensate polishing system, including sodium hydroxide and sulfuric acid. These chemicals have been analyzed to show that they do not adversely impact the control room.

Details of the control room habitability evaluations are discussed in Sections 6.4.1 and 9.4.1.

10.4.6.4 Tests and Inspections

Tests and inspections of the condensate polishing system are done in accordance with plant procedures.

10.4.6.5 Instrumentation Applications

Instrumentation is provided to monitor and control the condensate polishing system operation.

10.4.7 CONDENSATE AND FEEDWATER SYSTEM

The condensate and feedwater system, shown in Figures 3.2-2 and 3.2-3, receives condensate from the condenser hotwells and delivers it to the steam generator at the required pressure and temperature. In the steam generator, the condensate removes heat from the reactor coolant and is converted into steam.

10.4.7.1 Design Bases

The condensate and feedwater system is primarily a Design Class II system except for a part of the feedwater system that supplies heated water to the steam generators. The steam generator feedwater pumps are designed for maximum calculated load operating conditions (see Figures 10.1-5 and 10.1-1, for DCPP Units 1 and 2, respectively), and are capable of supplying the required feedwater flow to the steam generators under transient load reduction conditions. The condensate pumps and condensate booster pumps provide adequate suction pressure to the feedwater pumps under load transient conditions. During a main turbine control system load drop anticipate transient or a loss of feedwater pump load reduction, the standby condensate pump / condensate booster pump set will start, the stator coil and cooling water flow for valve FCV-31 will open, and hotwell rejection valve LCV-12 will close to provide adequate suction to the feedwater pumps.

The criteria for feedwater line isolation valve closure are discussed in Section 6.2. The pressure-retaining components, or compartments of components, conform to the following codes as minimum design criteria:

(1) System pressure vessels and feedwater heaters - ASME Boiler and Pressure Vessel Code, Section VIII

(2) System valves, fittings, and piping - ANSI Code for Pressure Piping B31.1 and B31.7 where applicable. The feed lines from the isolation valves to the steam generators are covered by the ASME Boiler and Pressure Vessel Code, Section I

10.4.7.2 System Description

The main condensate and feedwater system is of the closed type, with deaeration accomplished in the condenser. Condensate is pumped through the generator hydrogen coolers and stator coolers, the gland steam condenser, and the air ejector condensers to the suction of the condensate booster pumps, which pump the condensate though the condensate polishing system and five stages of low-pressure feedwater heaters to the feedwater pumps. The water discharged from the feedwater pumps flows through the single stage of high pressure heaters into the steam generators. All feedwater heaters are horizontal, one-third-size units (three in parallel), except heater 6 drain cooler, which is a single full-size straight tubed heat exchanger.

Three half capacity, three-stage, vertical, can-type, centrifugal, motor driven condensate pumps are provided with separate hotwell suction lines and a common discharge manifold. Three condensate booster pumps are provided. These are half capacity, horizontal, split case, centrifugal, motor driven pumps with common suction and discharge manifolds. Two half capacity, high speed turbine driven feedwater pumps are provided, with common suction and discharge manifolds. All pumps are equipped with minimum flow protective devices.

Feedwater flows to the steam generators through four lines penetrating the containment, one line for each steam generator. Flow regulating valves, isolation valves, bypass regulating valves, and a check valve are installed in each line outside the containment.

A feedwater pump control system controls the speed of the turbine-driven feedwater pumps to achieve a programmed pressure differential between the feedwater header leaving the number 1 feedwater heaters and the main steam common header. The programmed pressure differential varies as a function of unit load. Feedwater header-steam-header differential pressure indication is also provided in the control room.

Each feedwater flow regulator is positioned by its own three-element control system (see Chapter 7). All main feedwater piping downstream from the final feedwater check

valve and motor-operated isolation valve (inclusive) is designed to meet Design Class I requirements. Warmup lines are provided on the discharge of the feedwater pumps to circulate heated feedwater back through an idle feedwater pump to keep it warm and ready for service.

Drains from feedwater heaters 1 and 2 flow to the heater 2 drain tank with the flashed steam from the drain tank vented to heater 2. The heater 2 drain pump takes suction from the heater 2 drain tank and discharges to the feedwater pump suction manifold. Drains from the four lower pressure heaters cascade to the heater 6 drain cooler and then to the main condenser.

10.4.7.3 Safety Evaluation

The main condensate and feedwater system does not have to operate to ensure safe shutdown of the NSSS. The auxiliary feedwater system, described in Section 6.5, provides adequate feedwater to the steam generators from the condensate storage tank in the event of a loss of main feedwater. The reactor transient and radiological consequences of a main feedwater line break are discussed in Section 15.4.2. The rupture of a main feedwater line is one of the principal breaks considered in the analysis of dynamic effects of pipe breaks outside the containment. Additional barriers and restraints have been added, as required, to protect safety systems from a feedwater line rupture, or protect the feedwater line from another line rupture. In the event leakage develops from one of the feedwater heaters, that heater can be isolated and repaired while the generating unit remains on line. Since the secondary side is normally not radioactive, most leakage through valve seals will not present any radiological problems. The consequences of having the secondary side of the plant radioactive due to steam generator leakage are discussed in Chapters 11 and 15.

The Design Class I portion of the feedwater system is physically located well above ground elevation and is not susceptible to failure by flooding from other ruptured systems. The active components in the main feedwater system required to operate in the event of a design basis accident are the check valves upstream of the auxiliary feedwater nozzles on the main feedwater lines, the main feedwater motor-operated isolation valves, and the main feedwater control and bypass control valves.

Feedwater is introduced into the steam generators through a feedwater nozzle located in the upper shell. The nozzle does not require a flow-limiting device because the feedring itself provides this function. The nozzle contains a welded thermal liner that minimizes the impact of rapid feedwater temperature transients on the nozzle. The feedwater distribution ring is welded to the feedwater nozzle to minimize the potential for draining the ring. The feedring is located above the elevation of the feed nozzle to minimize the time required to fill the feed nozzle during a cold water addition transient. The feedwater is discharged through spray nozzles installed on the top of the ring. These features reduce the thermal fatigue loading on the feedwater nozzle, eliminate steady-state thermal stratification in the feedwater nozzle and feedwater piping elbow at the feedwater nozzle entrance, and minimize the potential for bubble- collapse water

hammer in the feedwater distribution ring. The feedwater piping elbow at the feedwater nozzle entrance also contains an elbow thermal liner that minimizes the effects of thermal stratification on the elbow-to-nozzle weld and the weld of the feedwater inlet thermal sleeve to feedwater nozzle.

The steam generator feedring is fabricated from alloy steel with a significant chromium content to provide enhanced erosion/corrosion resistance characteristics. The feedring has spray nozzles that are spaced around the feedring circumference to distribute the feedwater into the upper shell recirculating water pool. The spray nozzle perforations also act to prevent loose parts ingress from the feedwater system.

Also, following a review of the experience with water hammer at other plants in that portion of the feedwater piping inside the containment (the Design Class I portion at Diablo Canyon), this piping has been modified as shown in Figures 10.4-2 and 10.4-3 to minimize the possibility of a damaging water hammer.

10.4.7.4 Flooding

A postulated failure of the condensate or feedwater Design Class II piping in the turbine building would result in approximately 19,800 cubic feet of the water being released to the turbine building floor, if the entire contents of the hotwell and heater drain tank were discharged. Maloperation of the condensate or feedwater system due to a broken pipe would be detected by feedwater heater temperature transients or pump trips due to runout overcurrent. In addition, level switches, which alarm in the control room, are installed in the turbine building sump and in the condenser pit closest to the diesel generators of each unit to alert the operator to the flooding condition. Spillage from most broken pipes could be detected and isolated before significant flooding occurred.

Adverse environmental conditions created by flashing water from broken pipes are not expected, due to the large building volume. Environmental effects due to high energy pipe ruptures outside the containment are more fully evaluated and discussed in Section 3.6.4.

In the event that the entire contents of the hotwell and heater drain tanks are discharged to the turbine building, the operability of Design Class I equipment (diesel generator and component cooling water heat exchangers) in the building is not endangered. The volume of water that would be discharged is within the capacity of the turbine building drain system. This system includes one 18-inch drain line from the turbine building sump of each unit to the circulating water system discharge canal (see Figure 3.2-27). If this drain were clogged, the water flow would begin to fill the turbine building sumps and equipment pits below 85 feet (see Figures 1.2-16 and 1.2-20). However, the capacity (58,000 cubic feet) below this elevation is more than three times the potential flooding volume. Water would not accumulate to a level that would endanger the operability of the diesel generators since the area of the passageway through which water may enter the room is one-half the drain area on the west side of the rooms.

Because of their elevation above the turbine building floor, the component cooling water heat exchangers are not susceptible to flooding damage.

These provisions also protect safety-related equipment from flooding damage caused by the failure of other Design Class II piping or components located in the turbine building.

The Design Class I equipment in the auxiliary building is not endangered by turbine building flooding. The area of the auxiliary building housing Design Class I equipment is separated from the turbine building by 70 feet of doors and passageways. If water does enter the auxiliary building, it will drain to the building pipe tunnel, which has a capacity of approximately 345,000 gallons. The auxiliary building drain system is completely separate from the turbine building system so back flow through the drain system is not possible.

10.4.8 STEAM GENERATOR BLOWDOWN SYSTEM

The steam generator blowdown system is used in conjunction with the condensate and feedwater chemical injection system and the condensate polishing system to maintain steam generator water chemistry within the plant-specific limits.

The steam generator blowdown system functions are primarily PG&E Design Class II. The only PG&E Design Class I function performed by the system is containment isolation. The portions of the system from the steam generator nozzles to the isolation valves outside containment that perform this function are PG&E Design Class I.

10.4.8.1 Design Bases

10.4.8.1.1 General Design Criterion 2, 1967 - Performance Standards

The PG&E Design Class I portion of the steam generator blowdown system is designed to withstand the effects of, or is protected against, natural phenomena such as earthquakes, floods, tornadoes, winds, and other local site effects.

10.4.8.1.2 General Design Criterion 3, 1971 - Fire Protection

The PG&E Design Class I portion of the steam generator blowdown system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

10.4.8.1.3 General Design Criterion 9, 1967 - Reactor Coolant Pressure Boundary

The materials of construction of the pressure-retaining boundary of the steam generator tubes are protected by control of secondary chemistry from corrosion that might otherwise

reduce the system structural integrity during its service lifetime. The steam generator blowdown system functions to contribute to the secondary chemistry control.

10.4.8.1.4 General Design Criterion 11, 1967 - Control Room

The PG&E Design Class I portion of the steam generator blowdown system is designed to support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

10.4.8.1.5 General Design Criterion 12, 1967 - Instrumentation and Control

Instrumentation and controls are provided as required to monitor and maintain the PG&E Design Class I portion of the steam generator blowdown system variables within prescribed operating ranges.

10.4.8.1.6 General Design Criterion 16, 1967 - Monitoring Reactor Coolant Pressure Boundary

The steam generator blowdown system provides means for monitoring the reactor coolant pressure boundary to detect leakage.

10.4.8.1.7 General Design Criterion 17, 1967 - Monitoring Radioactivity Releases

Means are provided for monitoring the facility effluent discharge path for radioactivity that could be released from the steam generator blowdown system.

10.4.8.1.8 General Design Criterion 21, 1967 - Single Failure Definition

The PG&E Design Class I portion of the steam generator blowdown system is designed to tolerate a single failure during the period of recovery following an accident without loss of its protective function, including multiple failures resulting from a single event, which is treated as a single failure.

10.4.8.1.9 General Design Criterion 54, 1971 - Piping Systems Penetrating Containment

The steam generator blowdown system is provided with leakage detection, isolation, and containment capabilities having redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating this system. The steam generator blowdown system is provided with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

10.4.8.1.10 General Design Criterion 57, 1971 - Closed System Isolation Valves

The steam generator blowdown system contains piping connected to containment penetrations that are neither part of the reactor coolant pressure boundary nor connected directly to the containment atmosphere. These penetrations are provided with one local or remote-manual valve outside the containment.

10.4.8.1.11 Steam Generator Blowdown System Safety Function Requirements

(1) Protection from Missiles and Dynamic Effects

The PG&E Design Class I portion of the steam generator blowdown system is designed to be protected against the effects of missiles and dynamic effects, which may result from equipment failures.

(2) Decay Heat Removal

The steam generator blowdown system is designed to facilitate the removal of decay heat from the reactor coolant system.

10.4.8.1.12 10 CFR 50.49 - Environmental Qualification

Steam generator blowdown system components that require environmental qualification (EQ) are qualified to the requirements of 10 CFR 50.49.

10.4.8.1.13 10 CFR 50.55a(f) - Inservice Testing Requirements

Steam generator blowdown system ASME Code components are tested to the requirements of 10 CFR 50.55a(f)(4) and a(f)(5) to the extent practical.

10.4.8.1.14 10 CFR 50.55a(g) - Inservice Inspection Requirements

Steam generator blowdown system ASME Code components are inspected to the requirements of 10 CFR 50.55a(g)(4) and a(g)(5) to the extent practical.

10.4.8.1.15 10 CFR 50.62 - Anticipated Transient Without Scram

The PG&E Design Class I portion of the steam generator blowdown system is isolated upon receipt of a signal from the Anticipated Transient Without Scram (ATWS) Mitigation System Actuation Circuitry (AMSAC).

10.4.8.1.16 10 CFR Part 50 Appendix R (Section III.G, J, and L) - Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979

The PG&E Design Class I portion of the steam generator blowdown system is designed to isolate to maintain steam generator inventory to facilitate decay heat removal to achieve and maintain a safe shutdown condition for fire events.

Section III.G - Fire Protection of Safe Shutdown Capability: Fire protection of the steam generator blowdown system is provided by a combination of physical separation, fire-rated barriers, and/or automatic suppression and detection.

Section III.J - Emergency Lighting: Emergency lighting or battery operated lights (BOL) are provided in areas where operation of the steam generator blowdown system may be required to safely shutdown the Unit following a fire.

Section III.L - Alternative and Dedicated Shutdown Capability: Safe shutdown capabilities are provided in the control room and locally at the steam generator blowdown system containment isolation valves for the safe shutdown of the plant following a fire event.

10.4.8.1.17 Regulatory Guide 1.97, Revision 3, May 1983 - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The steam generator blowdown system containment isolation valve position status is required for post-accident instrumentation.

10.4.8.1.18 Generic Letter 89-08, May 1989 - Erosion/Corrosion-Induced Pipe Wall Thinning

DCPP has implemented formalized procedures and administrative controls to assure long-term implementation of its erosion/corrosion monitoring program for the steam generator blowdown system.

10.4.8.2 System Description

A piping and instrumentation schematic for the steam generator blowdown system is shown in Figure 3.2-4.

The steam generator blowdown system for each unit is composed of two processing paths. One path discharges blowdown flow via the steam generator blowdown tank to the circulating water discharge tunnel. The other path recycles blowdown flow to the main condenser via the blowdown treatment system and/or the blowdown treatment bypass line. The recycle path can discharge a portion of blowdown flow to the discharge tunnel. Blowdown flow for each unit can be directed to either blowdown path

alone, or to both paths simultaneously. The blowdown piping is also used as the interface between the steam generators and the Rapid Fill and Drain System that was added to facilitate operation of the steam generators during Unit outages.

Blowdown flow in the discharge path is processed via the steam generator blowdown tank; approximately 35 percent of the blowdown flow flashes to steam inside the tank and is vented to the atmosphere. The remaining liquid, approximately 65 percent of the blowdown flow, is discharged by gravity to the condenser circulating water discharge.

Blowdown flow in the recycle path may be processed by the blowdown treatment system or the blowdown treatment bypass line. This treatment system reduces the temperature and pressure of the water. The treatment system may also demineralize and recycle the blowdown water to the condensate system. In the treatment system, blowdown enters a flash tank where it is reduced in pressure. Flashed water vapor is vented from the tank through a pressure control valve to either a feedwater heater to improve cycle thermal efficiency or to the main condenser. The blowdown liquid then passes through a heat exchanger where the temperature is further reduced to approximately 110°F. The liquid may then enter a prefilter and demineralizer before being recycled to the main condenser. If required, a portion of the flash tank liquid flowing out of the heat exchangers can be routed to the plant outfall via the blowdown overboard drain line to improve the secondary water chemistry.

Blowdown water first passes through a prefilter and is then directed through one of two 60 cubic foot mixed bed demineralizers. The demineralizer removes both radioactive and nonradioactive ionic impurities. The liquid is then recycled to the main condenser. The blowdown treatment bypass line routes the depressurized, undemineralized blowdown directly to the condenser.

The blowdown tank process path and the blowdown treatment portion of the recycle process path are designed to accommodate 150 gpm of blowdown water total from four steam generators on a continuous basis. The blowdown tank process path also allows a total flow of 320 gpm temporarily during certain plant conditions.

The blowdown treatment bypass portion of the recycle path, including the flash tank, is designed for 1 percent of the main steaming rate at 100 percent plant load from four steam generators on a continuous basis (approximately 400 gpm total).

The steam generator blowdown system is classified as PG&E Design Class I from the steam generator nozzles up to and including the isolation valves outside of the containment and PG&E Design Class II downstream of the containment isolation valves. The classification and applicable codes for the steam generator blowdown system are identified in the DCPP Q-List (refer to Reference 8 of Section 3.2).

The blowdown system's effect on plant safety is minimal, since neither the blowdown function nor the treatment function is required continuously. Either function may be interrupted temporarily to replace failed components. Neither function is required to operate following a LOCA.

Ruptured components or failed-open valves could cause unplanned blowdown of secondary steam. Since blowdown piping in this system is 6 inches or smaller, such pipe break accidents fall within the category of minor secondary system pipe breaks. Consequences of this type of accident are detailed in Sections 15.2.14 and 15.3.2. The probability of radiation leakage is small since the system is normally nonradioactive. If, however, a failure of a blowdown pipe occurs while steam generator leakage is also taking place, the consequences are within the limits described in Section 15.3.2 for minor secondary system pipe breaks.

All filter and demineralizer components are located in the auxiliary building, from which leakage is processed through the liquid radwaste system. An automatically controlled isolation valve provides shutoff of the blowdown discharge path to the plant outfall if significant activity is detected. In any case, the results of failure are bounded by those of the pipe break referred to above (refer to Section 10.4.8.3.7).

The evaluation of radiological and environmental effects is treated in Section 11.2.

10.4.8.3 Safety Evaluation

10.4.8.3.1 General Design Criterion 2, 1967 - Performance Standards

The containment structure and auxiliary building, which contain the steam generator blowdown system’s PG&E Design Class I components, are PG&E Design Class I (refer to Section 3.8). These buildings or applicable portions thereof are designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), earthquakes (refer to Section 3.7), and other natural phenomena (refer to Sections 3.8.1.3 and 3.8.2.3 for the containment and auxiliary buildings, respectively), and to protect the system SSCs to ensure their safety functions and designs are maintained.

The PG&E Design Class I portions of the steam generator blowdown system are designed to perform their safety functions under the effects of earthquakes.

10.4.8.3.2 General Design Criterion 3, 1971 - Fire Protection

The steam generator blowdown system is designed to the fire protection guidelines of BTP APCSB 9.5-1 (refer to Appendix 9.5B, Table B-1).

10.4.8.3.3 General Design Criterion 9, 1967 - Reactor Coolant Pressure Boundary

Suspended and dissolved solids that are brought in by the feedwater concentrate in the steam generator shell-side water during plant operation. Water must be blown down using the steam generator blowdown system to maintain water chemistry as specified in plant procedures. Sampling and monitoring of nonradioactive solids is accomplished by continuous conductivity measurements and grab sample analysis.

The steam generator blowdown system protects the steam generator tubes, which are a part of the reactor coolant pressure boundary, from degradation during their lifetime. This is in compliance with the steam generator tube integrity requirements of Generic Letter 85-02.

10.4.8.3.4 General Design Criterion 11, 1967 - Control Room

Controls, and position indication, for the steam generator blowdown system containment isolation valves are provided in the control room such that the system may be manually operated to perform its safety function.

The system isolation valves can be operated manually from the main control room. These valves can also be closed by locally venting air from the valve operator solenoids if access to the control room is lost.

10.4.8.3.5 General Design Criterion 12, 1967 - Instrumentation and Control

The outboard containment isolation valves close on the containment isolation signal, Phase A. The inboard containment isolation valves close on the steam line isolation signal. Refer to Table 6.2-39.

The outboard containment isolation valves also close automatically on an AFW pump start (refer to Section 6.5.2.1.2), AMSAC actuation (refer to Section 7.6.2.3), and high radioactivity in the blowdown system (refer to Sections 10.4.8.3.7 and 11.4.2.2).

10.4.8.3.6 General Design Criterion 16, 1967 - Monitoring Reactor Coolant Pressure Boundary

Steam generator blowdown radiation detectors are available to detect steam generator tube leakage as described in Section 5.2.7 and Table 5.2-16. The radiation monitoring system is described in Section 11.4.

10.4.8.3.7 General Design Criterion 17, 1967 - Monitoring Radioactivity Releases

The steam generator blowdown system is continuously monitored for radioactivity. The sampling system parallels the blowdown flow from each steam generator. Continuous sampling and monitoring for radioactivity is accomplished with a single composite sample taken from the four steam generator sample lines and passed through a radiation monitor.

The criterion used for isolation of the blowdown system is based on the concentration of activity in the blowdown. When the sampling system radiation monitor detects a preset activity level, the steam generator blowdown isolation valves and the blowdown tank effluent valve close. The isolation system has been designed so that the blowdown tank effluent valve closes before any significant radioactive liquid reaches the effluent isolation valve. Upon detection of activity, plant personnel may process the blowdown via the blowdown treatment system as directed by Chemistry.

The radiation monitoring system is described in Section 11.4.

10.4.8.3.8 General Design Criterion 21, 1967 - Single Failure Definition

The instrumentation and control circuits for the steam generator blowdown system containment isolation function are redundant in the sense that a single failure cannot prevent containment isolation (refer to Section 6.2.4.4.5). The valve control circuits are supplied with separate Class 1E 125-Vdc power. The isolation valves will fail closed on a loss of air or power.

10.4.8.3.9 General Design Criterion 54, 1971 - Piping Systems Penetrating Containment

The steam generator blowdown system isolation valves required for containment closure are periodically tested for operability. Testing of the components required for the containment isolation system (CIS) is discussed in Section 6.2.4.

10.4.8.3.10 General Design Criterion 57, 1971 - Closed System Isolation Valves

The steam generator blowdown system containment penetrations comply with the requirements of GDC 57, 1971, as described in Section 6.2.4 and Table 6.2-39.

10.4.8.3.11 Steam Generator Blowdown System Safety Function Requirements

(1) <u>Protection from Missiles and Dynamic Effects</u>

The PG&E Design Class I portion of the steam generator blowdown system is protected from the effects of missiles and dynamic effects as described in Sections 3.5.1 and 3.6.1.1, respectively.

(2) Decay Heat Removal

The steam generator blowdown system facilitates the removal of decay heat from the reactor coolant system by isolating on an AFW pump start or an AMSAC actuation (refer to Sections 6.5 and 7.6.2.3, respectively) and maintaining steam generator inventory.

10.4.8.3.12 10 CFR 50.49 - Environmental Qualification

The steam generator blowdown system containment isolation valves are required to function in harsh environments under accident conditions and are qualified to the applicable environmental conditions to ensure that they will continue to perform their safety functions. Section 3.11 describes the DCPP EQ Program and the requirements for the environmental design of electrical and related mechanical equipment. The valves are listed on the EQ Master List.

10.4.8.3.13 10 CFR 50.55a(f) - Inservice Testing Requirements

Steam generator blowdown system components that are within the IST program are the four inboard containment blowdown isolation valves, the four outboard containment blowdown isolation valves, and the four outboard containment sample isolation valves.

The inservice testing (IST) requirements for these components are contained in the IST Program Plan and comply with the ASME code for Operation and Maintenance of Nuclear Power Plants.

10.4.8.3.14 10 CFR 50.55a(g) - Inservice Inspection Requirements

The steam generator blowdown system piping has a periodic inservice inspection (ISI) program in accordance with the ASME B&PV Code, Section XI.

10.4.8.3.15 10 CFR 50.62 - Anticipated Transient Without Scram

The blowdown flow from the steam generators is automatically isolated as a result of an AMSAC actuation (refer to Section 7.6.2.3).

10.4.8.3.16 10 CFR Part 50 Appendix R (Section III.G, J, and L) - Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979

10 CFR Part 50 Appendix R requires the evaluation of the safe shutdown capability for DCPP in the event of a fire and the loss of offsite power. The steam generator blowdown system satisfies the applicable requirements of 10 CFR Part 50 Appendix R, Sections III.G, J, and L.

Section III.G - Fire Protection of Safe Shutdown Capability: The inboard blowdown isolation valves and the outboard isolation valves (if the inboard valves fail to close) are the minimum required equipment to bring the plant to a cold shutdown condition. These components are provided with fire protection features appropriate to the requirements of Section III.G.

Section III.J - Emergency Lighting: Emergency lighting or battery operated lights (BOL) are provided in areas where operation of the steam generator blowdown system containment isolation valves may be required for safe shutdown following a fire as defined by 10 CFR Part 50, Appendix R, Section IIIJ (refer to Appendix 9.5D).

Section III.L - Alternative and Dedicated Shutdown Capability: Safe shutdown capabilities are provided in the control room and at alternate locations in accordance with 10 CFR Part 50 Appendix R, Section III.L (refer to Section 7.4 and Appendix 9.5E). The ability to safely shut down the plant following a fire in any fire area is summarized in Section 4.0 of Appendix 9.5A.

10.4.8.3.17 Regulatory Guide 1.97, Revision 3, May 1983 - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The steam generator blowdown system's outboard containment isolation valves' indications are credited for compliance with Regulatory Guide 1.97, Revision 3. The steam generator blowdown tank vent does not require monitoring. Refer to Table 7.5-6, Notes 56 and 59.

10.4.8.3.18 Generic Letter 89-08, May 1989 - Erosion/Corrosion-Induced Pipe Wall Thinning

DCPP procedures identify the interdepartmental responsibilities and interfaces for the Flow-Accelerated Corrosion (FAC) Monitoring Program for the steam generator blowdown system.

10.4.8.4 Tests and Inspections

The steam generator blowdown system is operated continuously during plant operation, thereby demonstrating system operability without the special inspections or testing required for standby systems. Equipment evaluations and inspections are performed periodically on the blowdown systems.

10.4.8.5 Instrumentation Applications

Instrumentation for the steam generator blowdown system is discussed in Sections 10.4.8.3.4 and 10.4.8.3.5.

10.4.9 CONDENSATE AND FEEDWATER CHEMICAL INJECTION SYSTEM

Chemical feed equipment is provided for chemical additions to the discharge of the condensate polishing system, to the main feedwater pumps' suction header, and to the discharge of the auxiliary feedwater pumps (refer to Figure 3.2-3 for the location of the injection points). The chemicals are injected into the condensate and feedwater system to prevent corrosion in the feedwater system and the steam generators. The condensate and feedwater chemical injection system has no safety function and is classified as PG&E Design Class II.

10.4.9.1 Design Bases

10.4.9.1.1 General Design Criterion 3, 1971 – Fire Protection

The condensate and feedwater chemical injection system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

10.4.9.1.2 General Design Criterion 9, 1967 – Reactor Coolant Pressure Boundary

The materials of construction of the pressure-retaining boundary of the steam generator tubes are protected by control of secondary chemistry from corrosion that might otherwise reduce the system structural integrity during its service lifetime. The condensate and feedwater chemical injection system functions to contribute to the secondary chemistry control.

10.4.9.1.3 Condensate and Feedwater Chemical Injection System Safety Function Requirement

(1) Internal Flooding

The condensate and feedwater chemical injection system is designed to be protected against the effects of internal flooding which may result from equipment failures.

10.4.9.1.4 Regulatory Guide 1.78, June 1974, Assumptions for Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release

The DCPP control room is appropriately protected from hazardous chemicals that may be discharged as a result of equipment failures, operator errors, or events and conditions outside the control of the plant.

10.4.9.2 System Description

The steam generator blowdown system protects the steam generator tubes, which are a part of the reactor coolant pressure boundary, from degradation during their lifetime. This is in compliance with the steam generator tube integrity requirements of Generic Letter 85-02.

Three sets of chemical feed pumps are available in each unit for the main feedwater system. The first set consists of 3 chemical feed pumps used to inject chemicals. Individual pumps are dedicated to ethanolamine and hydrazine/carbohydrazine injection, with the third pump on standby for either service. The pumps are not used under normal operating conditions.

During normal operation, a second chemical injection feed system in each unit is used to inject concentrated ethanolamine and hydrazine solutions.

The condensate hydrazine and ethanolamine feed system for each unit consists of a 250-gallon stainless steel hydrazine day tank with two chemical feed pumps, one in operation and one standby, and a 250-gallon stainless steel ethanolamine day tank with two chemical feed pumps, one in operation and one standby. Bulk 35 percent (by weight) hydrazine is stored in liquibins and is pumped by a transfer pump to the hydrazine day tank. A 6,000 gallon closed vertical pressure vessel, with a fume scrubber and two transfer pumps, stores and supplies the ethanolamine hydroxide chemical (85 percent aqueous solution of ethanolamine) for both units. The concentrated solution is pumped as needed to the ethanolamine day tank. The four chemical feed pumps output is manually controlled. The desired ethanolamine and hydrazine concentration in the condensate can be controlled manually. The water is monitored for conductivity and dissolved oxygen at the condensate pump discharge. Conductivity and dissolved oxygen, plus pH and hydrazine concentration, are also monitored at the final feedwater header before branching to the four steam generators.

A third chemical feed system is available, but not normally used. It is similar to the 2nd chemical system described above, except the hydrazine day tank is 200 gallons, the ethanolamine day tank is 300 gallons, and has 4 chemical feed pumps. Condensate from the condensate pump discharge header can be used to dilute the hydrazine and ethanolamine in the respective chemical day tank.

The auxiliary feedwater pump chemical feed system for each unit consists of a 500 gallon stainless steel tank, a 300 gallon stainless steel tank, and five chemical feed pumps that are piped so that the fifth pump is used as a shared spare. The chemical feed rate will be manually controlled. The chemical feed pumps pump into the discharge side of the auxiliary feedwater pumps. An injection line runs to the discharge of each of the three auxiliary feedwater pumps.

The secondary boric acid system consists of two boric acid mix/feed tanks (each tank having a capacity of 1325 gallons), three 50 percent feed pumps (each pump having a

capacity of 60 gallons per hour), and a screw feeder for loading the boric acid to the mix/feed tanks. Also provided are two tank mixers (mechanical agitators) for ensuring a complete and thorough mixing of the boric acid solution in the tanks. The pumping injection flow rate will be manually controlled, primarily based on the boric acid concentration in the steam generator blowdown.

10.4.9.3 Safety Evaluation

10.4.9.3.1 General Design Criterion 3, 1971 – Fire Protection

The chemicals of the condensate and feedwater chemical injection system (Hydrazine/Carbohydrazine, Ethanolamine and Boric Acid) are stored in accordance with the requirements of Branch Technical Position 9.5-1 (refer to Appendix 9.5B, Table B-1).

10.4.9.3.2 General Design Criterion 9, 1967 – Reactor Coolant Pressure Boundary

The condensate and feedwater chemical injection system is designed to provide the following chemical additions to the condensate and feedwater systems to reduce steam generator tube corrosion:

(1) Ethanolamine to the discharge line of each demineralizer in the condensate polishing system or to the condensate pumps' discharge header when the condensate polisher system is out of service, as required, to control the pH of the feedwater and steam generator water.

(2) Hydrazine, or a mixture of hydrazine and carbohydrazide, to the main feedwater pump suction piping to scavenge oxygen from the feedwater to a level within procedural guidelines with a residual of hydrazine at the inlet to the steam generators. Because of the similarity with hydrazine and carbohydrazide being bounded, from a safety and environmental perspective, by hydrazine, the mixture will be handled as if it were hydrazine.

(3) Ethanolamine and hydrazine, or other chemicals as specified by chemistry procedures, to the auxiliary feedwater pumps discharge to control the chemistry in the steam generators when the auxiliary feedwater pumps are used to supply water to steam generators.

(4) Boric acid solution to the main feedwater pump suction piping to reduce denting of tubes in the steam generator.

(5) Other chemicals as specified by chemistry procedures.

The system provides the capability to condition the water in the steam generator during wet lay-up, hydrotesting, and other times when the main feedwater system is not in operation.

The condensate and feedwater chemical injection systems are designed to provide adequate amounts of conditioning chemicals to the secondary system, as required, for the prevention of corrosion in the condensate and feedwater systems and the steam generator tubes.

The condensate and feedwater chemical injection system protects the steam generator tubes, which are a part of the reactor coolant pressure boundary, from degradation during their lifetime. This is in compliance with the steam generator tube integrity requirements of Generic Letter 85-02.

10.4.9.3.3 Condensate and Feedwater Chemical Injection System Safety Function Requirement

(1) Internal Flooding

The ethanolamine/hydrazine injection pumps and supply tanks for the condensate system are located in the turbine building west buttress and the turbine building. The concentrations in the ethanolamine and hydrazine supply tanks can be up to 85 percent and 35 percent, respectively. The tanks are vented to the outside of the building. There are no engineered safety features in the vicinity that would be damaged or rendered inaccessible by a ruptured supply tank.

The bulk ethanolamine storage tank, its fume scrubber, and its two transfer pumps are located in the turbine building west buttress, which houses the condensate polishers. Toppling of this vertical tank is not expected to damage the nearby PG&E Design Class I diesel fuel oil lines which are inside an adequately covered recessed pipe trench. Any accidental chemical spill, which is harmless to the steel pipes, would be confined within the trench and be prevented from reaching the diesel generator room by firestops.

The auxiliary feedwater pump chemical injection system supply tanks are located in the auxiliary building over a ventilation opening at the 115 foot elevation floor. The auxiliary feedwater pumps served are located below on the 100-foot elevation floor. A ruptured supply tank could cause 300 or 500 gallons of solution to fall partially on motor-driven auxiliary feedwater pump 1-3 or 2-3. The motor has a drip-proof enclosure and the centerline of the pump motor unit is 2 feet-6 inches above the 100-foot floor elevation. The area is drained by two 4 inch floor drains. The floor area in the vicinity of the auxiliary feedwater pumps is in excess of 1000 square feet so that 500 gallons would cause less than 1 inch of depth on the floor. Motor-driven auxiliary feedwater pump 1-3 or 2-3 could be impacted, due to water in the motor, by this accident; however, the second motor-driven pump and the turbine-driven pump would still be available.

The boric acid mix/feed tanks are located in the turbine building at the 85-foot elevation (ground level). The boric acid feed pumps are also located at this elevation. The floor area at this elevation (ground level) is large enough so that a ruptured feed tank would cause only a negligible depth of water on the floor, even though up to 1100 gallons of solution could be released. The only PG&E Design Class I component that could be affected by water is the diesel generator fire protection controls for Unit 1 only. These controls are wall mounted in a splash-proof box. In addition, the feed tanks are constrained to prevent any lateral movement or overturning and resist a seismic event. There are no other engineered safety features in the vicinity that would be damaged or rendered inaccessible by a ruptured feed tank. The feed tanks are purged with nitrogen and vented to the building.

10.4.9.3.4 Regulatory Guide 1.78, June 1974, Assumptions for Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release

The DCPP control room is adequately protected from hazardous chemicals that may be discharged from the condensate and feedwater chemical injection system. These chemicals have been analyzed to show that they do not adversely impact the control room.

Details of the control room habitability evaluations are discussed in Sections 6.4.1 and 9.4.1.

The condensate hydrazine and ethanolamine feed system for each unit consists of a 250-gallon stainless steel hydrazine day tank with two chemical feed pumps, one in operation and one standby, and a 250-gallon stainless steel ethanolamine day tank with two chemical feed pumps, one in operation and one standby. Bulk 35 percent (by weight) hydrazine is stored in liquibins provided by the chemical supplier. A 6,000 gallon closed vertical pressure vessel stores and supplies the ethanolamine hydroxide chemical (85 percent aqueous solution of ethanolamine) for both units.

A third chemical feed system is available, but not normally used. It is similar to the 2nd chemical system described above, except the hydrazine day tank is 200 gallons, the ethanolamine day tank is 300 gallons.

The auxiliary feedwater pump chemical feed system for each unit consists of a 500 gallon stainless steel tank and a 300 gallon stainless steel tank.

The secondary boric acid system consists of two boric acid mix/feed tanks each tank having a capacity of 1325 gallons.

10.4.9.4 Tests and Inspections

Tests and inspections of the condensate and feedwater chemical injection system are done in accordance with plant procedures.

10.4.9.5 Instrumentation Applications

The rate of feed of the chemical injection pumps into the main condensate and feedwater systems is proportioned to feedwater flow with manual adjustment of rate of chemical injection to rate of feedwater flow. The main condensate and feedwater supply tanks are equipped with level gauge glasses. The auxiliary feedwater supply tanks are equipped with low level alarm switches in addition to level gauge glasses. The chemical feed pump motors will alarm on overcurrent.

The pumping injection flow rate for the boric acid injection system will be manually controlled based on the boric acid concentration in the steam generator blowdown. The feed tanks are equipped with level indicators and the feed pumps include thermal overload protection.

10.4.10 REFERENCES

1. Final Environmental Statement for Diablo Canyon Power Plant, U.S. Nuclear Regulatory Commission, Washington, D.C., May 1973.

10.4.11 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

TABLE 10.1-1

STEAM BYPASS AND RELIEF VALVES

Design Class[(a)]	Relieves to	Pressure Mode	Pressure[(b)]	Capacity ± 10%
Main Steam Power-operated Valves (10% Atmospheric Dump Valves):				
I	Atmosphere	Operating	790 psia	327,255 lb/hr
		Maximum	1,179 psia	495,949 lb/hr
Turbine Bypass Valves (40% Cooldown and Bypass Valves):				
II	Condenser	Operating	790 psia	527,099 lb/hr
		Maximum	1,165 psia	789,875 lb/hr
Power-operated Steam Relief Valves (35% Atmospheric Relief Valves):				
II	Atmosphere	Operating	790 psia	612,014 lb/hr
		Maximum	1,165 psia	917,123 lb/hr

Main Steam Spring-loaded Safety Valves:

Design Class	Relieves to	Set Pressure	At 3% Accumulation	Valve Full Open	Orifice Size (inches)
I	Atmosphere	1,065 psig	803,790 lb/hr	867,431 lb/hr	4.515
I	Atmosphere	1,078 psig	813,471 lb/hr	877,875 lb/hr	4.515
I	Atmosphere	1,090 psig	822,408 lb/hr	887,516 lb/hr	4.515
I	Atmosphere	1,103 psig	832,090 lb/hr	897,960 lb/hr	4.515
I	Atmosphere	1,115 psig	841,027 lb/hr	907,601 lb/hr	4.515

(a) PG&E Design Class; refer to Table 3.2-1

(b) Ref.: DCMs M-46 (U-1) and M-71 (U-2)
10% pressure values from envelopes of lines 227 and 228, which have the highest accident pressure
35% pressure values from envelope of line 590, which supplies the PORVs
40% pressure values from envelope of line 587 supplying the valves

TABLE 10.1-2

SECONDARY SYSTEM OPERATING PARAMETERS
AT 100 PERCENT RATED POWER

Mass of water in one steam generator, lb	102,600
Mass of steam in one steam generator, lb	6,900
Secondary side operating temperature, °F	522
Steam generator blowdown tank capacity, ft^3	641
Air ejector flowrate - rated, scfm	25
- expected average, scfm	2.5
Total mass of water in secondary system, lb	2,800,000
Total mass of steam in secondary system, lb	60,000

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

TABLE 10.3-1

MAIN STEAM LINE VALVE PLANT STARTUP LEAKAGE TEST RESULTS

Valve Type and Leakage Path	*Quantity*	*Leakage per Valve*
Leakage to atmosphere through seat of 6-inch safety valves[(a)]	*20*	*10 bubbles/min*
Leakage to atmosphere through seat of 8-inch power-operated relief valves	*4*	*24 cc/hr*
Leakage to auxiliary feed pump turbine through seat of 4-inch isolation valves	*2*	*6 cc/hr*
Leakage to atmosphere through stems of gate valves in series with power-operated relief valves[(b)]	*4*	*12 cc/hr*
Leakage to atmosphere through stems of main steam isolation valves[(c)]	*4*	*4 cc/hr*
Leakage to atmosphere through stems of globe valves bypassing the main steam isolation valves	*4*	*negligible*

(a) Tested in accordance with API Standard 527. Test made after popping with nitrogen and then pressure reduced to 92 percent of nitrogen popping pressure.

(b) Tested seat at 1500 psig for 3 minutes. Result shown is maximum of all valves tested - hydro test.

(c) Requirement: leakage per valve shall not exceed 2 cc of water per hour when subjected to hydrostatic pressure of 1100 psig, or 0.06 scfh of air with a differential pressure of 80 psi. There are two valves per valve assembly. These are purchase specifications, not operational test requirements.

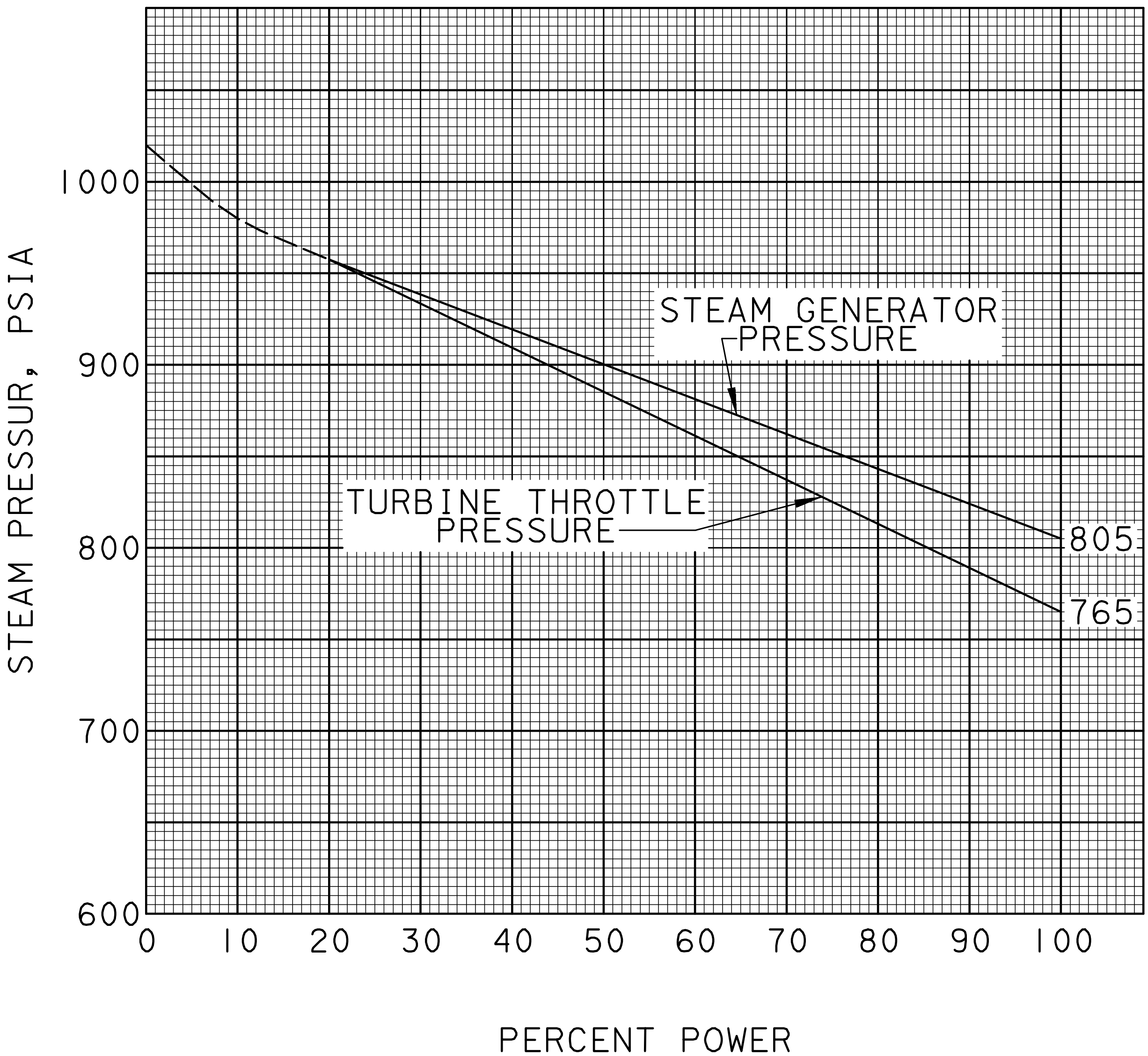
TABLE 10.4-1

MAIN CONDENSER PERFORMANCE DATA

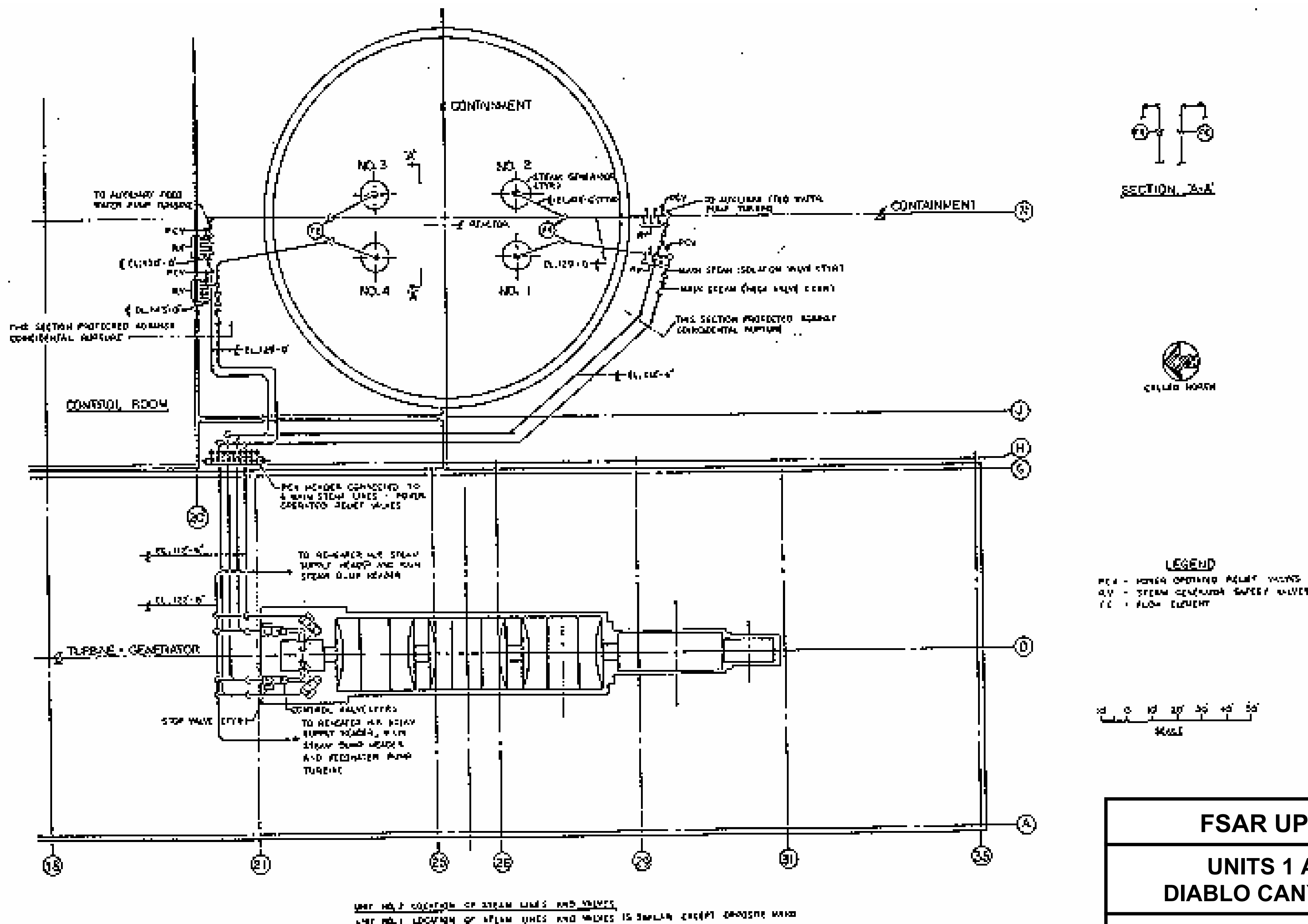
The condenser for each unit has two shells. The data given below are based on the full load heat balance.

Characteristics	Unit 1 Shell	Unit 2 Shell
Total heat load, Btu/hr[c]	8.19×10^9	8.19×10^9
Absolute pressure in condensing zone, in. Hg (with 56.5°F circulating water temperature at inlet to condenser)	1.71	1.71
Circulating water flow, gpm[d]	862,000	862,000
Average velocity in tube, ft/sec	6.8	6.8
Effective surface area, ft^2 [e]	618,150	618,150
Cleanliness factor, % [a]	85	85
Tube outside diameter, in.	1	1
Tube BWG	22	22
Tube overall length, ft	40 ft 9 in.	40 ft 9 in.
Tube effective length, ft	40.56	40.56
Number of tubes	58,216	58,216
Total condensate stored at maximum operating level (82 ft-6 in.), cu ft	18,880[b]	18,880[b]

(a) This is the percent of clean tube heat transfer coefficient used in the design of the condenser.
(b) There is a single hotwell for each unit.
(c) The Unit 1 and Unit 2 condensers were originally rated for a nominal heat load of 7.6×10^9 Btu/hr. The post Alstom LP Turbine Retrofit heat loads based upon the Alstom supplied “Full Load” heat balance diagrams for Unit 1 and Unit 2 are bounded by the Westinghouse approximated value shown in the table. Refer to Figures 10.1-6 and 10.1-2 for the full load heat balances, Unit 1 and Unit 2, respectively.
(d) This is a nominal value based on pump design documents and impacts on flow due to varying tidal conditions.
(e) Vendor supplied value. It is considered a nominal value.



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 10.2-1 STEAM GENERATOR CHARACTERISTIC PRESSURE CURVES



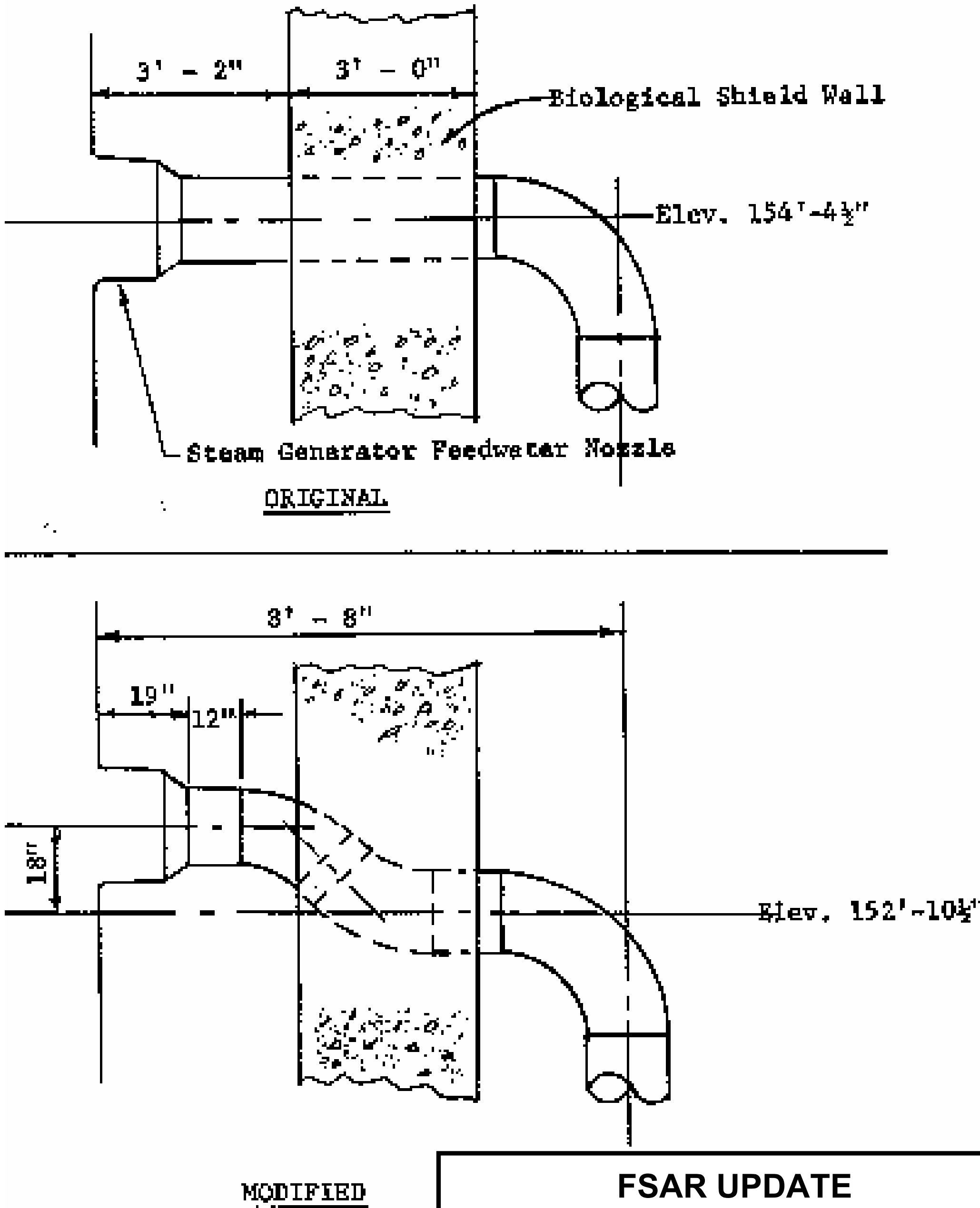
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

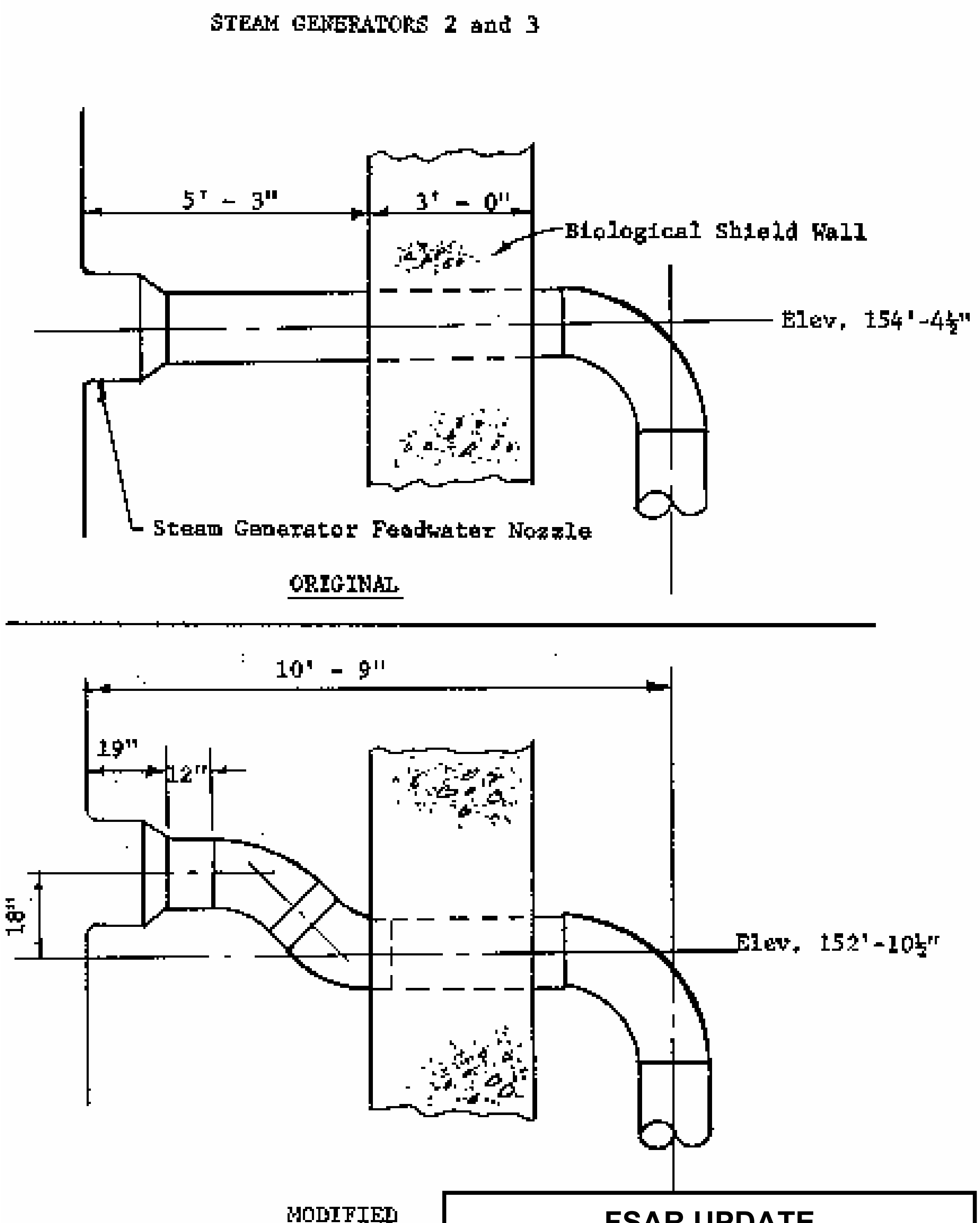
FIGURE 10.3-6
LOCATION OF STEAM LINES AND VALVES

Revision 11 November 1996

STEAM GENERATORS 1 and 4



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 10.4-2 REVISION OF STEAM GENERATOR FEEDWATER PIPING STEAM GENERATORS 1 AND 4



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 10.4-3
REVISION OF STEAM GENERATOR FEEDWATER PIPING
STEAM GENERATORS 2 AND 3

Chapter 11

RADIOACTIVE WASTE MANAGEMENT

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TABLES (Continued)

Chapter 11

FIGURES

FIGURES (Continued)

NOTE:

[a] This figure corresponds to a controlled engineering drawing that is incorporated by reference into the FSAR Update. See Table 1.6-1 for the correlation between the FSAR Update figure number and the corresponding controlled engineering drawing number.

Chapter 11

RADIOACTIVE WASTE MANAGEMENT

The purpose of this chapter is to provide a complete description and state the design objectives of the radioactive waste systems to demonstrate compliance with the general provisions of 10 CFR 20 and 10 CFR 50. Performance evaluation of the radioactive waste treatment systems is described.

This chapter is divided into the following sections:

In the sections on liquid and gaseous waste systems, all significant release pathways of radioactive liquids and gases are identified and discussed, including those not directly associated with waste treatment systems; for example, blowdown system releases and steam leakage.

A pre-operation evaluation of the liquid and gaseous radwaste systems was performed to demonstrate the system's ability to maintain releases within regulations. To carry out an activity analysis of the plant that covers different combinations of basic operating parameters, two cases were selected: a Design Basis Case and a case identified as "Normal Operation," which includes anticipated operational occurrences, and is hereinafter referred to as the Normal Operation Case. These cases do not represent the typical results of actual plant operation, and the operational basis and resulting values are not license limits.

For the Design Basis Case, the plant was assumed to have been operated for a full year at full thermal power of 3568 Mwt with a capacity factor of 80 percent and a fuel defect level of 1 percent. The radwaste systems were assumed to be in operation as designed, and primary system leakage was assumed to be negligible. The complete set of other assumptions associated with this case are listed in Table 11.1-2 and discussed in detail in the following sections.

For the Normal Operation Case the plant was assumed to have been operated for a full year at full power with a capacity factor of 80 percent and a fuel defect level of 0.12 percent. Coincident with this condition, it was assumed that there existed primary system leakage of 100 pounds per day to the secondary system, 1 percent of primary coolant noble gas inventory and 0.001 percent of primary coolant iodine inventory to the containment, and 160 pounds per day to the auxiliary building. These assumptions are

in agreement with those provided in the NRC Report NUREG-0017 for normal operation of a pressurized water reactor (PWR) (see Reference 9 of Section 11.1). The complete set of assumptions for this case is also discussed in the following sections. As a result of the analyses of these cases, the following conclusions can be drawn.

Diablo Canyon Power Plant (DCPP) Units 1 and 2 can be operated under normal conditions, including the consideration of anticipated operational occurrences in conformance with:

(1) The general provisions of 10 CFR 20 and 10 CFR 50

(2) The dose limits established in 10 CFR 20 for the release of radioactive materials

(3) The radiation dose limits specified in Appendix I to 10 CFR 50

The radioactive waste release values provided in this chapter are nominal values. Actual release values are reported to the NRC in the DCPP Annual Radioactive Effluent Release Report.

11.1 SOURCE TERMS

This section describes the routine (or operational) source term and the pre- operational evaluation of source term for the Design Basis Case and the Normal Operation Case.

Routine source term:

The operational source term in the reactor coolant system and supporting systems are monitored on a routine basis in accordance with plant Technical Specifications and plant approved procedures. The information is readily available to site personnel for evaluating source term and trends.

The Station policy is to operate the plant with zero fuel defects to achieve a low source term in the primary coolant.

The plant operating philosophy is to maintain leakage from the primary system well below Technical Specification limits.

This operating philosophy is fundamental to minimizing the input of radioactive material into the liquid radwaste (LRW) and gaseous radwaste (GRW) systems, and therefore minimize activity that may be released from the station.

There have been periods when a fuel leak develops and the RCS Dose Equivalent Iodine (DEI) has been near the Technical Specification value of 1.0 μCi/cc for periods of time. The station has demonstrated that the LRW and GRW systems operating per station procedures has maintained plant releases at a fraction of Technical Specification and 10 CFR 20 limits.

Routine operating reactor coolant system DEI is normally only a fraction of the Technical Specification value of 1.0 μCi/cc.

The routine operating source term is much lower than the cases described below.

Tritium is produced as part of the fission process of the reactor and its production is a direct function of power produced and capacity factor. Tritium being an isotope of water is not removed in the treatment systems. Given that tritium has a 12.5 year half life, essentially all the tritium produced is released from the plant via the LRW system or through evaporation via the plant vent.

Pre Operation source term evaluations:

The preoperational evaluation of radioactive materials produced and stored in the reactor system is reported and discussed in this section. These sources have been computed for two basic sets of plant operating conditions: the Design Basis Case and the Normal Operation Case.

The complete isotopic source terms are presented in tabular form along with the basic assumptions used in the computations. The activities and concentrations were calculated with the EMERALD NORMAL (Reference 8) digital computer program. A detailed discussion of the physical data and assumptions used is contained in the following paragraphs:

11.1.1 BASIC PHYSICAL DATA AND CONSTANTS

The values of isotopic physical data used in the radiological effects analyses are listed in Table 11.1-1. The values of half-lives and fission yields were taken from the Meek and Rider report (Reference 1) and from Tobias (Reference 10) and are in general agreement with those in TID-14844 (Reference 2) and ORNL-2127 (Reference 3). The values for average beta energies are those provided in Perkins and King (Reference 4) and the average gamma energies are taken from Tobias. The values of decay constants were calculated from the half-lives with the standard formula. The fission yields were modified to account for plutonium buildup by using the values for uranium and plutonium fissioned during an equilibrium core cycle as follows:

$$\text{Yield (U + Pu)} = \frac{[\text{Fissions (U) x Yield (U)}] + [\text{Fissions (Pu) x Yield (Pu)}]}{\text{Fissions (U + Pu)}}$$

The number of fissions per megawatt-second is taken to be 3.15×10^{16}, which agrees well with the value of 3.2×10^{16} used in Reference 2.

11.1.2 DETERMINATION OF ACTIVITY INVENTORIES IN REACTOR CORE

The EMERALD NORMAL program was run for 11 months with zero initial activities, and the result was decayed one month. The resulting core activities (assuming one-third of the core was replaced at refueling) were then set equal to the initial activities and the process repeated. Taking one-third of the activities after the first cycle, plus one-third of the activities after the second cycle, gives an approximation to the initial activities for an equilibrium core cycle. The core inventories for the year's operating cycle were then computed using an 80 percent capacity factor to ensure a realistic inventory of Kr-85. The power level and other basic assumptions are provided in Tables 11.1-2, and 11.1-3. The resulting core inventories are listed in Tables 11.1-4 and 11.1-5. These calculated core inventories are in general agreement with those tabulated in TID-14844, with those listed in the USNRC Reactor Safety Study (WASH-1400) (Reference 12), and with those listed in the Diablo Canyon Preliminary Safety Analysis Report (Reference 5).

Actual operating configuration is 21 months of operation, with a mixture of fuel with enrichments up to 5 percent, with maximum analyzed burnup of 50,000 MWD/MTU. The EMERALD NORMAL 12-month cycle core inventory results in higher calculated doses. Therefore, it bounds the actual operating configuration.

11.1.3 DETERMINATION OF INVENTORIES IN FUEL ROD GAPS

The computed gap activities are based on buildup in the fuel from the fission process and diffusion to the fuel rod gap at rates dependent on the operating temperature. For this analysis, the fuel pellets were divided into five concentric rings, each with a release rate dependent on the mean fuel temperature within that ring. The diffusing isotope is assumed present in the gas gap when it has diffused to the boundary of the outer ring. The core temperature distribution used in this analysis, based on hot channel factors of F_H = 1.70 and F_q = 2.82, is presented in Table 11.1-6.

The diffusion coefficient, D', for Xe and Kr in UO_2, varies with temperature in accordance with the following expression:

$$D'_T = D'_{(1673)} \exp^{-\frac{E}{R}\left(\frac{1}{T} - \frac{1}{1673}\right)} \qquad (11.1\text{-}1)$$

where:

E	= activation energy
$D'_{(1673)}$	= diffusion coefficient at 1673°K = 1 x 10^{-11} sec^{-1}
T	= temperature in °K
R	= gas constant

This expression is valid for temperatures above 1100°C. Below this temperature, fission gas release occurs mainly by two temperature independent phenomena, recoil and knock-out, and is predicted by using D' at 100°C. The value used for D' (1673°K), based on data at burnups greater than 10^{19} fission/cc, is used to account for possible fission gas release by other mechanisms and pellet cracking during irradiation.

The diffusion coefficients for iodine isotopes are assumed to be the same as those for Xe and Kr (References 6 and 7).

The resulting fractions of core activity present in the fuel rod gaps are listed in Table 11.1-7, along with the total inventories of activity in the gaps.

11.1.4 DETERMINATION OF PRIMARY COOLANT ACTIVITIES

The basic data and assumptions used in calculating the coolant concentrations for the Design Basis Case and the Normal Operation Case are provided in Tables 11.1-2, 11.1-3, 11.1-8, 11.1-9, and 11.1-10. The coolant concentrations and activities, listed in Tables 11.1-11, 11.1-12, and 11.1-13, are provided for the operating temperature. The activities of corrosion products deposited in the steam generator are provided in Table 11.1-14. The total amounts of activity produced and removed from the coolant during the operating period are provided in Tables 11.1-16 and 11.1-17. All models and equations, including parent-daughter production, purification terms, boron feed-bleed terms, and coolant leakage terms are provided in detail in Reference 8, and are

generally consistent with those provided in NUREG-0017 (Reference 9). The demineralizer decontamination factors assumed are listed in Table 11.1-15. The basic assumptions and data used in calculating the activities on the pressurizer are listed in Table 11.1-18, and the calculated activities for the two cases are provided in Tables 11.1-19 and 11.1-20.

11.1.5 DETERMINATION OF TRITIUM ACTIVITIES IN PRIMARY COOLANT

Tritium atoms are generated in the fuel at a rate of approximately 8×10^{-5} atoms per fission, or 1.05×10^{-2} curies/MWt/day. Any boron bearing control rods in the core are a potential source of tritium.

A direct source of tritium is the reaction of neutrons with dissolved boron in the reactor coolant. Boron is used in the reactor coolant for reactivity control. Neutron reactions with lithium are also a direct source of tritium. Lithium hydroxide is used for pH control.

Figure 11.1-1 shows calculated versus measured tritium production in the reactor coolant for the R. E. Ginna plant. A 10 percent release from the fuel rods was assumed for the calculation.

11.1.5.1 Ternary Fissions - Cladding Diffusion

With zirconium alloy cladding, approximately 10 percent of the tritium produced in the fuel will diffuse through the cladding into the coolant (Reference 11).

11.1.5.2 Tritium Produced from Boron Reactions

The neutron reactions with boron that result in the production of tritium are:

B^{10} (n, 2 α) T
B^{10} (n, α) Li^7 (n, n α) T
B^{11} (n, T) Be^9
B^{10} (n, d) Be^{9*} (n, α) Li^6 (n, α)T

Of the above reactions, only the first two contribute significantly to the tritium production. The B^{11} (n, T) Be^9 reaction has a threshold of 14 MeV and a cross section of 5 mb. Since the neutrons produced at this energy result in a flux of less than 10^9 n/cm^2-sec, the tritium produced from this reaction is negligible. The B^{10} (n,d) reaction may be neglected since Be^{9*} has been found to be unstable.

11.1.5.3 Tritium Produced from Lithium Reactions

The neutron reactions with lithium resulting in the production of tritium are:

Li^7 (n, n α) T
Li^6 (n, α) T

Lithium hydroxide is used for pH adjustment of the reactor coolant. Lithium concentrations may reach a value of 6.0 ppm at the beginning-of-cycle. During normal plant operations the lithium is maintained within an operational band per plant procedure. At the end-of-cycle, the lithium concentrations may decrease to 0.0 ppm. This is accomplished by the addition of Li^7 OH and by a cation demineralizer included in the chemical and volume control system. This demineralizer will remove any excess of lithium such as could be produced in the B^{10} (n, α) Li^7 reaction.

The Li^6 (n,α) T reaction is controlled by limiting the Li^6 impurity in the Li^7 OH used in the reactor coolant and by lithiating the demineralizers with 99.9 atom percent Li^7.

11.1.5.4 Control Rod Sources

In a fixed burnable poison rod, there are two primary sources of tritium generation: the B^{10} (n, 2 α) T and the B^{10} (n, α) Li^7 (n, n α) T reactions. Unlike the coolant, where the Li^7 level is controlled, there is a buildup of Li^7 in the burnable poison rods. The burnable poison rods are required during the first year of operation only. During this time, the tritium production is 72 curies/pound B^{10}.

The control rod materials used at DCPP are Ag-In-Cd; there are no tritium sources in these materials.

11.1.5.5 Tritium Production from Deuterium Reactions

Since the fraction of naturally occurring deuterium in water is less than 0.0015, the tritium produced from this reaction is negligible (less than 1 curie per year).

11.1.5.6 Total Tritium Sources in Coolant

A summary of the sources of tritium in the reactor coolant system are listed in Table 11.1-22, and all basic data and assumptions used are provided in Table 11.1-21. The calculated total tritium produced in the reactor plant, 1640 curies/year, agrees fairly well with the NUREG-0017 value of 0.4 Ci/MWt/year, which gives 1427 curies/year, the difference being conservative.

11.1.6 DETERMINATION OF SECONDARY SYSTEM ACTIVITIES

In order to estimate the potential plant releases as a result of secondary system leakage or discharges, during periods when significant activity exists in the steam system, the steam system activity levels have been determined. As discussed earlier, the range of possible combinations of plant operating conditions has been represented by making an activity analysis on the basis of 0.12 percent fuel defects, coincident with a leakage of 100 pounds per day to the secondary system. The projected plant releases for this condition are based on the assumption that these conditions persist throughout the full year. The steam system operating conditions assumed for the activity analysis are listed in Tables 11.1-23, 11.1-24, and 11.1-25, and the results of the analysis are

provided in Tables 11.1-26 through 11.1-31. The equations and models for the activity balances and transport calculations are detailed in Reference 8, and they are generally consistent with those provided in NUREG-0017.

11.1.7 REFERENCES

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8. S.G. Gillespie and W.K. Brunot, EMERALD NORMAL - A Program for the Calculation of Activity Releases and Doses from Normal Operation of a Pressurized Water Plant, Program Description and User's Manual, Pacific Gas and Electric Company, Revision 1, December 1974.

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10. A. Tobias, Data from the Calculation of Gamma Radiation Spectra and Beta Heating from Fission Products, (Revision 2), RD/B/M2453, Central Electricity Generating Board, England, October 1972.

11. WCAP 8253, Source Term Data for Westinghouse Pressurized Water Reactors, May 1974.

12. Reactor Safety Study (WASH-1400), An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants, Appendix VI, U.S. Nuclear Regulatory Commission, October 1975.

11.2 LIQUID WASTE SYSTEM

The liquid radwaste system (LRS) collects and processes the radioactive liquid wastes generated from the primary side of the plant during operation. The LRS reduces the activity of these liquid wastes to levels acceptable for discharge to the environment. The system is designed to minimize dose to plant personnel and the general public in accordance with NRC regulations. Presented in this section are design objectives, equipment and operational descriptions, process flow diagrams, and radiological evaluation of the liquid waste system.

Three other major liquid waste streams that may potentially be radiologically contaminated are included in this chapter, although they are not technically part of the LRS.

11.2.1 DESIGN OBJECTIVES

The design objectives of the liquid waste system are to:

(1) Collect radioactive liquid wastes generated by the primary side of the plant

(2) Provide sufficient liquid wastes surge and processing capacity so that operation and availability of the plant is not limited

(3) Reduce the volume of radioactive waste that must be shipped off site for disposal

(4) Process liquid wastes for discharge to the environment to meet the limits specified in 10 CFR 20 and the guidelines in Appendix I to 10 CFR 50 (as low as is reasonably achievable (ALARA))

(5) Maintain safe operating conditions and system integrity throughout all anticipated operating conditions

(6) Ensure that dose to the public is maintained below the dose limits specified in 10 CFR 20, Appendix I to 10 CFR 50 and 40 CFR 190

(7) Provide adequate drainage during normal operation and postulated flooding conditions following equipment failure as described in Section 9.3.3

11.2.2 SYSTEM DESCRIPTION

11.2.2.1 General

Units 1 and 2 share a common LRS, except for equipment located inside containment. A detailed piping and instrumentation schematic of the LRS is shown in Figure 3.2-19. The common waste system consists of the following five collection subsystems:

(1) Equipment drain subsystem

(2) Floor drain subsystem

(3) Chemical drain subsystem

(4) Laundry and hot shower and laundry/distillate subsystem

(5) Demineralizer regenerant subsystem

These five collection subsystems are described in the following sections.

The floor drain, chemical drain, laundry/distillate, laundry and hot shower, and demineralizer regenerant subsystems generally collect low activity level liquid wastes. The equipment drain subsystem collects liquids with variable activity levels. The demineralizer regenerant subsystem is used as backup for the floor drain and equipment drain subsystem.

Following treatment, effluents from the LRS are released to the environment at either of the units' circulating water system discharge structures via the auxiliary saltwater system (see Figure 11.2-9). The waste liquid releases are diluted in the auxiliary saltwater system and main circulating water system flows. Releases require positive operator action, are continuously monitored, and are automatically isolated in the event of a high radiation alarm or a power failure.

11.2.2.1.1 Chemical and Volume Control System

A major source of radioactive waste liquids is the reactor coolant system (RCS). The bulk of these wastes are processed and retained within the chemical and volume control system (CVCS), with a portion being routed to the LRS. A piping and instrumentation schematic of the CVCS is shown in Figure 3.2-8. A complete description of the CVCS is included in Section 9.3.

11.2.2.2 Equipment Drain or Closed Drain Subsystem

The closed drain system is so called because drains from equipment are connected directly to the drainage system. Closed drain wastes are not exposed to the

atmosphere until they reach their destination. Inside containment closed drain wastes flow to the reactor coolant drain tank. Sources include the following:

(1) Reactor coolant loop drains

(2) Pressurizer relief tank

(3) Reactor coolant pumps secondary seals

(4) Excess letdown line (during startup)

(5) Accumulators

(6) Refueling canal

(7) Reactor coolant pumps seal water inlet line drain

(8) Reactor flange leakoff

(9) Excess letdown heat exchanger

(10) Regenerative heat exchanger outlet line drain

When the reactor coolant drain tank reaches a preset liquid level, the wastes are automatically pumped to the liquid holdup tanks for processing in the CVCS. The pumps may also be manually started prior to reaching the preset level. The wastes may also be pumped to the equipment drain receiver tanks or the refueling water storage tanks when required. An integrating flow meter on the reactor coolant drain pump discharge reads out on the auxiliary building control board, and reactor coolant drain tank high and low level alarms to the main annunciator are provided.

Closed drainage from equipment in the auxiliary building is collected in the miscellaneous equipment drain tank. Sources include the following:

(1) Chemical and volume control system

  (a) Deborating demineralizer drain

  (b) Mixed bed demineralizer drain

  (c) Evaporator condensate demineralizer drain (abandoned in place)

  (d) Cation bed demineralizer drain

  (e) Evaporator feed ion exchanger drains

(f) Reactor coolant filter

(g) Seal water heat exchanger (tube side) and filter

(h) Volume control tank drain and sample line drain

(i) Charging pumps, header, bypass, and seal injection filter

(j) Letdown heat exchanger (tube side)

(k) Gas stripper feed pumps drain

(l) Liquid holdup tanks recirculation pumps, line, and relief valve discharge

(m) Boric acid preheater drain (abandoned in place)

(n) Boric acid evaporator (abandoned in place)

(o) Boric acid evaporator condensate filters (abandoned in place)

(p) Concentrates holding tanks and pump 0-2 (abandoned in place)

(q) Boric acid evaporator condenser relief valve

(2) Safety injection system (SIS)

(a) Containment recirculation water chamber

(b) Safety injection pumps seal and drip pocket drain

(c) Various valve steam leakoffs

(3) Residual heat removal (RHR) system

(a) RHR heat exchanger tube side drains

(b) RHR pump and line drain

(c) Various valve steam leakoffs

(4) NSSS sampling system

(a) NSSS sampling sink drain

(b) NSSS sample line drain

(c) Volume control tank sample line drain

(5) Containment spray system

(a) Containment spray line drain

(b) Containment spray pumps

(6) Spent fuel pool cooling system

(a) Spent fuel pool resin trap filter

(b) Spent fuel pool filter

(c) Spent fuel pool pumps

(d) Refueling water purification filter

(e) Spent fuel pool skimmer filter, pump, strainer, and drain

(f) Spent fuel pool heat exchanger

(g) Spent fuel pool demineralizer drain

(7) Component cooling water system (CCWS)

(a) Waste gas compressor seal water coolers

(8) Liquid radwaste system

(a) Equipment drain receivers overflow and pumps

(b) Processed waste receivers (formally the waste concentrator condensate tank (WCCT)) overflow and pumps

(c) Spent resin motive water pumps

(d) Spent resin storage tanks

(9) Gaseous radwaste system

(a) Gas decay tanks drain

(b) Waste gas compressor moisture separator

(c) Gaseous radwaste vent header drain

(10) Turbine steam supply system

(a) Steam generator blowdown tank

(11) Gland steam sealing system

Note: Normally the following drains go to the miscellaneous condensate return tank and turbine building sump. They can be routed to the MEDT if elevated levels of radioactivity are present.

(a) Gland steam condenser drains

(b) Steam jet air ejector

When the miscellaneous equipment drain tank reaches a preset liquid level, the wastes are automatically pumped to the equipment drain receiver tanks. A high level alarm function is provided.

Closed drain wastes being transferred to the equipment drain receiver tanks are routed to one of the two tanks. When that tank reaches its high level setpoint, incoming flow is automatically diverted to the second equipment drain receiver tank. The filled tanks are normally recirculated, sampled, and analyzed before further batch processing. A high and low level alarm function is provided for each tank.

11.2.2.3 Floor Drains and Open Drain Subsystem

The open drain system drains potentially contaminated areas in the containment buildings and the auxiliary building with equipment that does not normally handle reactor coolant. The piping systems and trenches used in this system permit exposure of the contents to the atmosphere.

Inside containment floor drain wastes are collected in the containment sumps and the reactor cavity sump. Sources include the following:

(1) Reactor coolant pump seal No. 3 leakoff

(2) Excess letdown heat exchanger shell relief and drain

(3) Reactor coolant pump thermal barrier relief

(4) Reactor coolant pump upper bearing cooling relief

(5) Containment fan cooler drip pans and coils

(6) Reactor vessel support cooler relief

(7) Reactor coolant pump lube oil spill collection tanks

Integrating flow meters in the discharge lines from the reactor cavity sumps and containment sumps are provided to detect leakage from in-containment sources.

Potentially contaminated auxiliary building floor drain wastes are collected in the auxiliary building sump. The uncontaminated floor drains from the auxiliary building drain to other discharge pathways such as the sanitary drainage system, outside, etc.

Sources for the auxiliary building sump include the following:

(1) Chemical and volume control system

   (a) Charging pump base drains

   (b) Boric acid tanks, filters, and transfer pump drains

   (c) Boric acid evaporator Unit 1 concentrates pumps (abandoned in place)

   (d) Boric acid distillate pump drains (abandoned in place)

   (e) Boric acid concentrates filters (abandoned in place)

   (f) Boric acid reserve tanks and transfer pumps' drain

   (g) Chemical mixing tank

   (h) Batching tank

   (i) Concentrate holding tank pump 0-1 (abandoned in place)

(2) NSSS sampling system

   (a) Sample sinks (1-2 and 2-2)

(3) Containment spray system

   (a) Spray additive tank

(4) Spent fuel pool cooling system

   (a) Spent fuel pool sump

(5) Component cooling water system

(a) Component cooling water surge tank relief

(b) RHR heat exchanger shell side drains

(6) Liquid radwaste system

(a) Floor drain receivers and pumps

(b) Chemical drain tank overflow

(c) Laundry and hot shower tanks overflow

(d) Spent resin loadout area

(e) Spent resin transfer filters

(f) Laundry/distillate tanks and pumps drain and tank overflow

(7) Ventilation system

(a) Plant vent drains

(8) Auxiliary steam system

(a) Auxiliary steam hydrazine feed unit

(b) Package boiler blowdown tempering tank

(c) Auxiliary steam drain receiver and pumps

(9) Elevation 140 ft. roof drains discharge to LRS only if contamination is detected

The RHR compartments spills collect in the RHR sumps that are normally discharged to the floor drain receivers.

When a sump has filled to a preset level, the wastes are automatically pumped to one of two floor drain receiver tanks. When a tank has reached its high level setpoint, sump flow will automatically be diverted to the second floor drain receiver tank. The filled tank is normally recirculated, sampled, and analyzed before further batch processing. A high level alarm function is provided for each sump. A high level and low level alarm function is provided for each floor drain receiver tank.

11.2.2.4 Chemical Drain Subsystem

Chemical wastes are generated due to routine chemical and radiochemical sampling and analyses. Chemical wastes from both units drain by gravity to a divided chemical drain tank. The filled section is recirculated, sampled, and analyzed before discharge.

11.2.2.5 Laundry and Hot Shower, and Laundry/Distillate Subsystem

Laundry, hot shower and treated CVCS liquids are generally very low in activity. The laundry and hot shower wastes are generated by laundering contaminated protective clothing and by personnel decontamination. CVCS liquid holdup tank (LHUT) water is routed to the liquid radwaste system when reuse in the reactor cavity or spent fuel pool is not possible.

The hot shower wastes flow by gravity to one of the laundry and hot shower tanks. When one of the laundry and hot shower tanks is filled, the flow is manually diverted to the second tank. The filled tank is recirculated, sampled, and analyzed before further batch processing or discharge.

The laundry waste will normally drain to one of the laundry/distillate tanks for discharge. Treated LHUT water may be drained to one of the laundry/distillate tanks or to one of the demineralizer regenerant receiver tanks for further treatment by the liquid radwaste system. When one of the laundry/distillate tanks is filled, the flow is manually diverted to the second tank. The filled tank is recirculated, sampled, and analyzed before further batch processing or discharge.

11.2.2.6 Demineralizer Regenerant Subsystem

The demineralizer regenerant subsystem consists of two 15,000 gallon demineralizer regenerant receivers (arranged in parallel) located adjacent to the equipment drain receivers in the auxiliary building. Originally, it was intended that regeneration wastes from the steam generator blowdown treatment system, deborating demineralizers, or evaporator distillate demineralizers were to be routed to these tanks, and neutralized by concentrated sulfuric acid or sodium hydroxide. The steam generator blowdown regeneration system never operated and changes in California EPA regulations halted neutralization of other regenerants in the demineralizer regenerant receivers.

The demineralizer regenerant receivers collect equipment or floor drain liquid and function as surge capacity for these systems. In addition, treated LHUT liquid can be drained to the demineralizer regenerant receivers for additional processing.

11.2.3 LIQUID RADWASTE SYSTEM OPERATION

The LRS is operated on a batch basis. When a floor drain receiver, equipment drain receiver, chemical drain, laundry/distillate tank, laundry and hot shower tank, or demineralizer regenerant receiver is filled, it is isolated to prevent accumulation of additional contaminated waste. Control interlocks prevent tanks from being simultaneously filled and discharged. The tanks are normally recirculated, sampled, and analyzed to determine if additional treatment is required. Batches of equipment and floor drains are normally processed to reduce radioactivity concentrations prior to discharge.

11.2.3.1 Liquid Radwaste Processing Sub System

Batches requiring further treatment are processed through the radwaste media filters, ion exchangers, filters and/or mobile liquid process system. The radwaste media filters and ion exchangers are normally operated in series. Both in-door and out-door locations are provided for mobile liquid process systems. Mobile liquid process systems may be used to augment LRS in-plant components. Treated liquid is collected in the Processed Waste Receivers. In addition, treated LHUT liquid can be routed to the Processed Waste Receivers. These batches are then sampled and analyzed prior to discharge.

11.2.3.2 Liquid Radwaste Discharge Sub System

Batches that contain sufficiently low quantities of radioactivity to meet discharge limits are treated by filtration and discharged to the outfall of the circulating water via the auxiliary saltwater discharge. Circulating water flow is verified prior to initiating a release.

Written operating procedures govern the mechanics of discharging liquid radwaste to the unrestricted area (Reference 8).

As part of the procedures, records of plant water inventories, circulating water flow rates, and radwaste batch analysis data sheets are kept to ensure that the discharges are maintained below the applicable regulations.

11.2.4 SYSTEM DESIGN

The systems that handle radioactive or potentially radioactive liquid wastes, as designed, comply with the intent of GDC 60 and 64 of Appendix A to 10 CFR 50.

The components of the LRS are listed in Table 11.2-10. A similar listing for the CVCS is provided in Table 9.3-6. Included are equipment size or capacity, applicable flowrate, material of construction, and design temperature and pressure.

Applicable codes and standards for process equipment used in the liquid waste system are presented in the DCPP Q-List (see Reference 8 of Section 3.2). Equivalent data for the CVCS are shown in Table 9.3-5.

The seismic and quality group classifications for these components and associated piping are also provided in the DCPP Q-List 9 (see Reference 8 of Section 3.2). Radiological monitoring is discussed in detail in Section 11.4.

The routing of all piping is strictly controlled by the design engineers and is specified on the piping drawings. Consequently, there are field-fabricated lines, but no field-routed lines. Lines that are field-fabricated have the following characteristics: (a) the lines are routed to minimize operator dose, all deviations from the specified routing require prior approval of the piping engineer, and as-built drawings are made showing final dimensions, (b) the sizes, schedules, materials, and code classes are specified on the piping drawings, (c) the field-fabricated piping is similar to shop-fabricated piping in design, quality assurance procedures, and inspection, (d) pipe hanger placement is not specified on piping drawings, but a maximum spacing between hangers is specified as a design standard, and (e) a design review is conducted in accordance with the quality assurance procedures described in Chapter 17 in the same manner as for shop-fabricated piping.

11.2.5 PERFORMANCE DATA

LRW process equipment is evaluated for it's effectiveness in removing radioactivity on a batch basis. Approved Plant procedures govern concentrations of activity that must be processed and limits the activity in any individual batch prior to release. When the process equipment removal efficiency no longer produces water to meet these requirements, the filters, media or ion exchange resin is replaced.

11.2.6 PLANT RELEASES

11.2.6.1 Current Operational Releases

The actual releases from the plant site are summarized in the Annual Radiological Effluents report to the NRC. The report summarizes the liquid, gaseous and solid radwaste that is released from the site for the past year and provides the calculated dose to the public, which is calculated using the site dose calculating manual. Releases from DCPP have routinely demonstrated compliance within the general provisions of, and dose limits established in, 10 CFR 20 and 10 CFR 50.

11.2.6.2 Pre-Operational Estimated Release Evaluation

The following information provides historical perspective demonstrating that DCPP's anticipated operation would result in releases within applicable regulations. This information does not necessarily reflect current operating conditions or practices.

The estimated releases based on the original design were calculated with the EMERALD-NORMAL computer program, supplemented by hand calculations. Two process flow diagrams of the LRS are presented to depict the modes of operation for the two cases used for radiation release analysis: the Design Basis Case, and the Normal Operation Case. The flow diagram for the Design Base Case, Figure 11.2-2, shows the waste stream sources and processing route of liquid waste for the assumptions of this case. The numbered waste input streams have their annual flow and isotopic spectra listed in Table 11.2-5. The numbered process streams are listed in Table 11.2-8, along with flows and isotopic concentrations. The flow diagram for the Normal Operation Case is shown in Figure 11.2-3. Flows and isotopic parameters for this case are listed in Tables 11.2-5 and 11.2-9.

The detailed assumptions used in calculation of estimated activity release from the LRS are listed in Table 11.2-1. Tables 11.2-3 and 11.2-4 list the activity concentration spectrum for the input sources. A tabulation of the estimated annual release by isotope is provided in Tables 11.2-14 and 11.2-15 for the two cases.

For the Normal Operation Case with anticipated operational occurrences, as defined in RG 1.112 (Reference 7), an additional release of 0.15 Ci/yr per reactor with the same isotopic makeup as in Table 11.2-15 is assumed. This annual release is provided in Table 11.2-18 for one unit. Since an average of 2 days holdup time is available upstream of both the boric acid and waste treatment systems, no additional release, assuming the systems are out of service, is postulated.

The detailed assumptions used in the calculation of estimated activity release from the CVCS to the LRS are listed in Table 11.2-2. A tabulation of the isotopic flows through the system components is provided in Tables 11.2-6 and 11.2-7, and the estimated annual releases to the LRS are provided in Tables 11.2-8 and 11.2-9 for the Design Basis and Normal Operation Cases.

For purposes of estimating annual average plant radionuclide releases, approximately two-thirds of the boric acid evaporator distillate produced is assumed to be recycled to the primary water storage tank, and the rest routed to the liquid waste system. This release (350,000 gallons/year for each unit) is primarily for tritium control purposes.

A list of assumed decay times for system tanks is provided in Table 11.2-13. Demineralizer decontamination factors are listed in Table 11.1-15.

During conditions corresponding to the Design Basis Case, which assumes a 1 percent fuel defect level with negligible primary system leakage, the floor drain wastes will have an approximate activity level of 0.0015 mCi/cc. These wastes are normally filtered and released to the main condenser circulating water discharge canal.

During conditions corresponding to the Normal Operation Case, which assumes a 0.12 percent fuel defect level with primary system leakage, the activity level of the floor

drain wastes is approximately 0.1 mCi/cc. Under this operating condition, the wastes will be processed through the filters and/or ion exchangers.

The chemical drain wastes will have an approximate activity level of 9×10^{-4} μCi/cc during conditions corresponding to the Design Basis Case. During conditions corresponding to the Normal Operation Case, the wastes will be approximately 1×10^{-4} μCi/cc.

During conditions corresponding to the assumptions of Design Basis Case, the approximate activity level in the processed effluent from the equipment drain receiver tanks is 0.007 μCi/cc. The activity level of the processed effluent is 0.002 μCi/cc during conditions corresponding to the Normal Operation Case.

The steam generator blowdown system is depicted on two process flow diagrams that show the two paths of operation of the system and the assumptions used in the radiation release analyses. Figure 11.2-4 shows the discharge path with blowdown directed to the blowdown tank and the circulating water discharge structure. Figure 11.2-5 shows the recycle path with blowdown directed to the blowdown treatment system. For the Design Basis Case, it is assumed that the blowdown is processed via the discharge path because this case assumes no primary-to-secondary leakage and no activity is present in the secondary system. For the Normal Operation Case, it is assumed that the blowdown is processed only via the recycle path and the discharge path is isolated since the assumptions for this case result in significant levels of activity in the secondary system. Table 11.2-16 shows the total annual volumetric flows for one unit and the activity concentrations corresponding to the alphabetically labeled process streams in these two figures for the Normal Operation Case.

The estimated annual activity releases from the turbine building sump for one unit are listed in Tables 11.2-14 and 11.2-15 for the Design Basis Case and the Normal Operations Case, respectively. Table 11.2-17 lists the total annual estimated volumes released from the liquid waste system for two units for both cases and includes the turbine building sump discharge.

The tritium concentration in the RCS is controlled by bleeding coolant from the RCS to the LRS via the CVCS (see Section 9.3.4). Other losses from the RCS are through radioactive decay and mixing of the primary coolant with refueling cavity water during refueling. The calculation of the tritium concentration in the various plant water sources is based on the following assumptions:

(1) Tritium activity in the RCS is provided in Table 11.1-22 for the anticipated operational occurrences case.

(2) The total volume of water released from the RCS for the analysis of the Design Basis Case and the anticipated operational occurrences case is 350,000 gallons per year per unit.

(3) The temperature of the spent fuel pool is constant at 100°F throughout the life of the plant except during refueling when the temperature rises to 125°F. The air above the spent fuel pool is 80°F at 70 percent relative humidity.

(4) The water temperature of the refueling canal, when filled with borated water from the refueling water storage tank, is 125°F. The air above the refueling canal is 80°F at 70 percent relative humidity. Mixing with 15 percent of the water from the spent fuel pool occurs during each refueling period.

(5) During refueling, the containment purge fans are in continuous operation.

(6) No water is lost from the spent fuel pool or refueling water storage tank, except through evaporation.

(7) Evaporation from the spent fuel pool is calculated by the equation (Reference 3):

$$\frac{V}{A} = \frac{95.0 + 0.425\,V_a}{W}\,(p_w - p_a) \qquad (11.2\text{-}1)$$

where:

V = loss rate from the water volume, lbm/hr
A = exposed area of the water volume, ft^2
W = latent heat of vaporization of the water, Btu/lbm
V_a = velocity of the air across the surface of the water, ft/min
p_w = vapor pressure of the water, in. of Hg
p_a = vapor pressure of the water in air, in. of Hg

The important parameters for evaluating tritium losses and distribution in the plant are provided in Table 11.2-11.

The resulting tritium concentrations in various plant areas are shown in Figures 11.2-6 through 11.2-8. It should be noted that the tritium concentrations plotted in these figures are yearly averages or, in the case of airborne concentrations during refueling, are averages during the refueling periods, based on a 1 year fuel cycle with 11 months operation and 1 month refueling. The tritium management procedures are designed to ensure that tritium airborne concentrations in all normally occupied plant areas are significantly below levels required to ensure compliance with 10 CFR 20, Subparts C and D. The restriction of primary coolant tritium concentration by releasing demineralized water from the RCS is intended to reduce in-plant personnel radiation dose.

The above analysis was performed to demonstrate that DCPP “normal operation” radiological effluents meet the criteria of 10 CFR 50, Appendix I. This analysis is conservative and bounds DCPP current operation. The analysis was performed prior to plant operation and will be modified only if a design change or operational change rendered it nonconservative.

11.2.7 RELEASE POINTS

The four major release pathways are as follows:

(a) from the LRS to the discharge structure via either the Unit 1 or Unit 2 auxiliary saltwater discharge lines (Figures 11.2-2, 11.2-3, and 11.2-9);

(b) from the Unit 1 or Unit 2 steam generator blowdown:

  (1) via the steam generator blowdown tanks to the discharge structure via the respective unit's discharge conduit (Figures 11.2-4 and 11.2-9);

  (2) via diversion from the steam generator blowdown recycle line to the main condenser.

(c) from the turbine building sump to the discharge structure via either the Unit 1 or Unit 2 turbine-generator building sump discharge line (Figure 11.2-5).

(d) from the condensate demineralizer regenerant system via either the high conductivity tank or the low conductivity tank.

Other minor discharge pathways may exist. Those identified pathways, monitored radiologically, are included in the offsite dose calculation manual and/or implementing procedures.

The LRS is described in Section 11.2.2. The other three main discharge pathways are described in Sections 11.2.7.1 through 11.2.7.3 below.

11.2.7.1 Turbine Building Drain System

The concentration of radioactivity in the turbine building drains is expected to be low, even in the event of significant primary-to-secondary steam generator leakage. The radiation level and flow of liquid from the turbine building drains are monitored at the oily water separator to verify that there are no unaccounted for or unexpected releases from the turbine building drains. If significant radioactivity is detected coming from the turbine building drains, the discharge can be routed to the LRS for treatment. The monitoring system is in conformance with Regulatory Guide 1.21 (Reference 9) and General Design Criterion (GDC) 4 of Appendix A to 10 CFR 50.

Turbine building sump wastes are normally released to the environment via each unit's circulating water discharge structure (see Figure 11.2-9). A detailed piping and instrumentation schematic of the turbine building sump systems is shown in Figure 3.2-27.

11.2.7.2 Steam Generator Blowdown System

The steam generator blowdown system for each unit provides two processing paths. One path discharges blowdown flow to the environment via the steam generator blowdown tank and the circulating water discharge tunnel. The other path recycles blowdown flow to the main condenser via the blowdown treatment system and/or the blowdown treatment bypass line. The recycle path can discharge a portion of blowdown flow to the discharge tunnel. Blowdown flow for each unit can be directed to either blowdown path alone, or to both paths simultaneously.

During plant operation, steam generator water collects suspended and dissolved solids that are brought in by the feedwater. Water must be blown down from the steam generators to maintain low solids concentration for efficient operation (Reference 1).

The blowdown flow maybe directed to either or both the discharge and recycle paths for a total blowdown flow of approximately 400 gpm per unit to maintain water chemistry and low solids concentration. If activity is detected at preset levels in the blowdown system, the blowdown will be automatically isolated from the discharge path and blowdown flow will be limited to the recycle path at up to 150 gpm per unit.

A record of the activity level of the blowdown discharged to the circulating water canal and steam generator blowdown tank vent will be maintained. Appropriate flow measurement instruments on the steam generator blowdown tank inlets and liquid discharge will indicate and record all releases. The quantity of activity released to the atmosphere and circulating water canal can thus be directly determined.

The steam generator blowdown system in the recycle path may normally be used for water recovery by processing blowdown, upon exiting the flash tank, directly to the condenser via the blowdown bypass line and/or by processing blowdown through a flash tank, heat exchanger, prefilter, and demineralizer. In the treatment system processing path, blowdown is reduced in pressure and temperature within the flash tank and heat exchanger. A mixed bed demineralizer with prefilter is used to reduce any solids concentration and any activity in the blowdown. Two demineralizers can be operated in parallel or series service with a system flow capability of 20 to 150 gpm. The mixed bed resin is in the hydrogen and hydroxide form. The effluent from the demineralizer is high quality water equivalent to condensate makeup. The treated blowdown enters a resin trap filter before being recycled to the main condenser.

Upon ion exchange exhaustion (indicated by increased effluent conductivity), the mixed bed demineralizer resin is replaced with new resin.

A description of the design bases, on-line monitoring, isolation criteria, design codes, system description, safety evaluation, inspection, and testing of the steam generator blowdown system is provided in Section 10.4.8.

11.2.7.3 Condensate Demineralizer Regenerant Solution

The condensate demineralizer regenerant solution is the waste created from regenerating anion and cation resin used to clean water in the condenser. The resin is regenerated with sulfuric acid and sodium hydroxide. The high conductivity tank (HCT) normally receives the initial rinse water that may contain most of the acid, caustic and contaminants removed from the resin. The low conductivity tank (LCT) normally receives cleaner water used as a final rinse of the resin. The concentration of radioactivity in the condensate demineralizer regenerant solution is expected to be low.

The HCT is discharged as a discreet batch. The tank pH is adjusted within an acceptable range consistent with NPDES and other state requirements. The tank is then recirculated, sampled and analyzed prior to issuing a discharge permit.

The LCT is normally discharged as a discreet batch. The tank is recirculated, sampled and analyzed prior to issuing a discharge permit. In some cases, the LCT is allowed to discharge as a continuous discharge for a period of time. In this configuration, more than one sample is taken during the discharge period to ensure that the discharge remains within limits.

11.2.7.4 Typical Volumes Released

These are not limiting volumes but are an approximation of routine plant discharge volumes. Volumes can change as defined in the site procedures as long as 10 CFR 20, and 10 CFR 50, Appendix I criteria are maintained.

Typical LRS Annual Release Volumes:

Source	UFSAR Section	Nominal Quantity (gallons)
Equipment Drains	11.2.2.2	400,000 to 500,000
Floor Drains	11.2.2.3	200,000 to 400,000
Treated CVCS	11.2.2.1.1; Table 11.2-1 #27	470,000 to 750,000
Laundry & Hot Shower Drains	11.2.2.5	50,000 to 250,000
Chemical Drains	11.2.2.4	13,000 to 30,000
Sub Total		1.1 M to 1.9 M

Typical Plant Annual Release Volumes:

Pathways	Nominal Quantity (gallons)
LRS	1.1 M to 1.9 M
U-1 SGBD	30M
U-2 SGBD	30M
Turbine Bldg Sump	15M
U-1 Condensate Demineralizer Regenerant Tanks	5M
U-2 Condensate Demineralizer Regenerant Tanks	5M

Only trace amounts of activity are in the pathways that are not LRS.

11.2.8 DILUTION FACTORS

11.2.8.1 Current Operational Doses

The condenser cooling water and the auxiliary saltwater system of Units 1 and 2 are used for dilution of released liquid wastes. The dilution flow available per unit is 876,000 gallons per minute. (See Chapter 10 for a description of the circulating water system and Chapter 9 for the auxiliary saltwater system.)

11.2.8.2 Pre-Operational Dose Factors

The pre-operational estimated activity concentrations listed in Tables 11.2-21 through 11.2-23 are for one unit's turbine building wastes and liquid waste system diluted with one unit's annual circulating water flow. It should be noted that this method of calculation yields a maximum annual average concentration within the circulating water discharge structure.

For the calculation of all internal and external doses from liquid effluent releases, a dilution factor of 5 was used from the point of release to the organism or dose point. This value was taken from Table A-1 of RG 1.109 (Reference 5) as a conservative estimate of the dilution at the edge of the initial mixing zone for a high-velocity surface discharge. This factor is considered very conservative; experimental dye studies (Reference 2) have determined that the average dilution factor for fish, invertebrate, and sediment exposure to liquid effluents is 100. The dilution factor of 5 was confirmed by the NRC staff in the Final Environmental Statement for Diablo Canyon Units 1 and 2 (Reference 4).

11.2.9 CACULATED DOSES

11.2.9.1 Current Operation Doses

Current operation doses are calculated in accordance with the offsite dose calculation manual contained in site approved procedures in accordance with 10 CFR 20 and appropriate NRC Regulatory Guides.

All liquid wastes are discharged to saline waters, which are not used as a source of drinking water or irrigation water. Thus, the only significant pathways to man from this source are through food chains involving marine organisms. Liquid releases have been examined for the possible effects on man and on aquatic organisms. For man, the pathways considered are the intake of aquatic foods that were grown within the radiological influence of the plant.

11.2.9.2 Pre-Operation Estimated Doses

Pre-operational radiation dose calculations are presented in Tables 11.2-24 through 11.2-26 for the Design Basis Case, the Normal Operation Case, and the Normal Operation Case with anticipated operational occurrences. These tables list the doses from one unit. The dose via water pathways was calculated with the EMERALD NORMAL program, which uses liquid dose models and assumptions based on RG 1.109.

Pre-operational calculations included direct exposures through contact with water by swimming or by exposures in shoreline areas where minute quantities of radioactivity may be deposited.

The usage factor for fish and invertebrate consumption and sediment exposure time were taken from RG 1.109, as were the bioaccumulation factors for fish, invertebrates, and plants. The complete set of bioaccumulation factors used is listed in Table 11.2-20. A list of effluent concentrations after dilution is provided in Tables 11.2-21 through 11.2-23.

The individual doses from fish consumption were based on rockfish caught and eaten by a sport fisherman, with a 1-day delay between the time of catch and consumption. The individual doses from invertebrate consumption were based on abalone, caught noncommercially and eaten with a 1-day delay between the time of catch and consumption. The possible doses from swimming or boating were based on the exposure periods listed in RG 1.109. A summary of the dose assumptions for liquid pathways exposures is provided in Table 11.2-19.

On the basis of the calculated estimates of radiation dose presented in Tables 11.2-24 through 11.2-26, it was concluded that under normal conditions, including the consideration of anticipated operational occurrences, the potential dose from liquid

effluents from DCPP Units 1 and 2 would be well within the dose limits specified in 10 CFR 50, Appendix I.

11.2.10 REFERENCES

1. A.B. Sisson, et al., Evaluation for Removal of Radionuclides from PWR Steam Generator Blowdowns, International Water Conference, November 2, 1971.

2. Preliminary Safety Analysis Report, Nuclear Unit Number 2, Diablo Canyon Site, Pacific Gas and Electric Company, Docket Number 50-323.

3. Handbook of Fan Engineering, 6th Ed., Buffalo Forge Company.

4. Diablo Canyon Final Environmental Statement, U.S. Atomic Energy Commission, May 1973, Docket Numbers 50-275 and 50-323.

5. Regulatory Guide 1.109, Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I, USNRC, March 1976.

6. EMERALD-NORMAL, a Program for the Calculation of Activity Releases and Potential Doses from the Normal Operation of a Pressurized Water Reactor Plant, Revision 2, Pacific Gas and Electric Company, July 1976.

7. Regulatory Guide 1.112, Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Light-Water Cooled Power Reactors, USNRC, April 1976.

8. DCPP Plant Procedures.

9. Regulatory Guide 1.21, Measuring, Evaluating, and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials in Liquid and Gaseous Effluents from Light-water-cooled Nuclear Power Plants, USNRC, December 1971.

11.3 GASEOUS WASTE SYSTEM

The gaseous radwaste system (GRS) provides controlled handling and disposal of gaseous wastes generated during plant operation. The system is designed to minimize dose to plant personnel and the general public in accordance with NRC regulations. In this section, the GRS is described. The following sections include the design objectives, equipment design, operational descriptions, process flow diagrams.

11.3.1 DESIGN OBJECTIVES

The GRS system is designed to collect, store, monitor, and release plant waste gas streams that may contain radioactive noble gases, iodine, and radioactive particulate material. The GRS collects gaseous wastes with potentially high levels of radioactive isotopes and hydrogen, but low levels of oxygen, and is designed to meet the following objectives:

(1) Provide the capacity to collect and store the radioactive gaseous wastes

(2) Provide sufficient capacity and storage to process and store in a shielded area, the volume of gaseous effluents directly from the RCS

(3) Provide cover gas for the liquid holdup tanks

(4) Provide a means of sampling gaseous effluents

(5) Ensure that releases of radioactive gaseous wastes are kept as low as is reasonably achievable (ALARA)

(6) Maintain the release of radioactive gases below limits specified by 10 CFR 20

(7) Ensure that dose to the public is maintained below the dose limits specified in Appendix I to 10 CFR 50

In addition to the release planned from the GRS, other releases of radioactive gases from the plant are possible under some operating conditions; for example, in periods during which primary coolant system leakage occurs. These additional pathways that can, under some plant operating conditions, release radioactive gases are:

(1) Containment purge

(2) Auxiliary building ventilation

(3) Fuel handling building ventilation

(4) Main condenser air ejector

(5) Gland steam condenser

(6) Steam generator blowdown system

(7) Power relief valves

(8) Main steam and reheat relief valves

(9) Solid radwaste storage building ventilation

(10) Laundry facility ventilation

(11) Condenser vacuum pump

These release pathways are described in Chapters 9, 10, and 11.

Most waste gas releases are routed to the plant vent, with the exception of any power relief valves, main steam relief valves, reheat valves, solid radwaste storage facility, radwaste storage building/laundry facility exhaust, chemical laboratories exhaust, turbine building exhaust, condenser vacuum pump exhaust, and any miscellaneous steam leakage. Locations of the release points in the plant are shown in Figure 11.3-4. The design exit velocity at the plant vent is 17 m/sec during normal plant operation.

Tritium is also released via the plant vent system mainly due to evaporation from the spent fuel pool.

11.3.2 SYSTEM DESCRIPTION

The GRS is designed to process radioactive gases consisting primarily of nitrogen and hydrogen with low levels of oxygen. The gases are collected by the vent header system from various primary and auxiliary systems. Radioactive or potentially radioactive gaseous wastes result from collection of excess cover gas in the liquid holdup tanks, degasification in the volume control tank, and cover gas displaced in the pressurizer relief tank and reactor coolant drain tank. A piping schematic for the GRS is shown in Figure 3.2-24.

Each unit has a vent header network and surge tank. Gases collected by the vent header system are routed to a surge tank equipped with a safety relief valve to prevent overpressurization.

Each unit's surge tank feeds that unit's waste gas compressor and/or a shared spare compressor through a pressure control valve set to maintain constant compressor suction pressure. The system is designed such that the shared spare compressor will automatically start if the pressure in the surge tank rises above 3 psig. An oxygen monitor on the moisture separator discharge limits the concentration of oxygen that can

be fed to the gas decay tanks. The monitor actuates an alarm at 2 percent 0_2 concentration and trips the compressors at 4 percent.

The compressor discharge is routed into a network of valves feeding the gas decay tanks. Based on downstream conditions and operator selection, the system controls the positioning of these valves. One tank will be filling, with one tank on standby, and one tank being used for cover gas. The system will automatically switch to the standby tank when the fill tank reaches 100 psig. Should this fail to happen, the system will alarm when the tank reaches 105 psig. Each decay tank is located in an individual shielded vault and is equipped with a safety relief valve that discharges to the plant vent.

The gas decay tanks are provided for the holdup of radioactive gases prior to release to the environment. The design provides the capability to hold gases for a minimum of 45 days. This is not a requirement to holdup gases for that period of time. The holdup time required is that which would result in releases that are in compliance with release rate and dose limits. Each gas decay tank may be operated as a cover gas supply for the liquid holdup tanks. Normal coolant letdown then displaces the gases back into the GRS. This process effectively increases the volume of storage available for gaseous holdup.

Each gas decay tank is equipped with a flow control valve connected to the plant vent. The discharge of each valve is routed into a common flow control valve that provides redundant means of isolation and requires manual operation by the control system to ensure no inadvertent venting may take place. Downstream of the common flow control valve is a radiation monitor that controls a downstream control valve. If the activity in the discharging waste gas exceeds its upper limit, the control valve closes, terminating the release. The final processing of waste gas prior to release to the atmosphere is by a high-efficiency particulate air (HEPA) filter located just downstream of the radiation control valve and just upstream of the plant vent.

The sampling system associated with the GRS is used to monitor the hydrogen and oxygen content of the gases in the system and to collect grab samples for oxygen concentration analysis. Thirteen sample points exist in this system including all influent sources and each of the gas decay tanks. These sample points may be monitored continuously, or intermittently as required, or grab samples may be taken from manual sample taps. The gas analyzer is equipped with a sample tap for taking bottled samples to undergo radiological testing.

11.3.3 GASEOUS RADWASTE SYSTEM OPERATION

The GRS will handle gaseous discharge from the various sources. The volume of gases will originate from displaced cover gas in the liquid holdup tanks. The gaseous flow is discharged to the vent header and routed to the surge tank. The suction pressure to the normally operating compressor is maintained at approximately 0.5 psig via a pressure regulator on the surge tank outlet. During normal operation, the waste gas compressor starts and stops based on surge tank pressure. to maintain 1.1 psig to

2.0 psig in the surge tank. If a control malfunction occurs causing the compressor to continuously operate, a recycle valve would open returning gases from the moisture separator at 0.9 psig pressure in the surge tank. This supplies gases back to the compressor suction preventing evacuation of the compressor suction piping. In addition, if the liquid holdup tank header pressure is at or below the setpoints drops below 0.75 psig, a recycle valve from the gas decay tanks would open to maintain the cover gases in the liquid holdup tanks. A shared Unit 1 and 2 spare compressor will start on a high surge tank pressure of 3 psig. The waste gas compressor discharges into a gas decay tank through a series of automatic valves. When the decay tank is filled to 100 psig, the inlet valve to the filled tank closes and the inlet valve to a standby tank opens. Should this fail to happen, a high pressure alarm sounds at 105 psig. The remaining tank is now positioned as the standby tank with the filled tank isolated for decay and release.

The gases in the decay tanks are periodically checked for buildup of hydrogen and oxygen. The gas analyzer checks for oxygen in the range 0-2 percent (±0.1 percent) and for hydrogen over three ranges: 0-5 percent (±0.1 percent), 0-50 percent (±1 percent), and 0-100 percent (±2 percent). The analyzer is set to provide an alarm if the oxygen concentration reaches 2 percent and the hydrogen reaches 3.5 percent. Additionally, the gases directed into the decay tanks being filled during waste gas compressor operation are continuously monitored for oxygen content via oxygen analyzer CEL 75 and 76, which alarms at 2 percent oxygen concentration. However, hydrogen concentration in the system is not monitored as its concentration is assumed at all times to be 4 percent (the flammability limit for hydrogen is 6 percent oxygen concentration) or more by volume for all plant operating modes. In this manner, the potential for explosive hydrogen/oxygen mixtures will be mitigated. The capability exists for diluting the gas with nitrogen (Figure 3.2-24) using pneumatically operated valves controlled from the auxiliary building control panel. A grab sample will be taken for isotopic analyses from the gas decay tanks and waste gas sources as required by the plant Technical Specifications (Reference 6).

11.3.4 SYSTEM DESIGN

The systems that handle radioactive or potentially radioactive gaseous waste are designed to comply with the intent of GDC 60 and 64 of Appendix A to 10 CFR 50.

The GRS, including the gas analyzer package, is designed and fabricated as Design Class II. The equipment and piping code classification are listed in the DCPP Q-List (see Reference 8 of Section 3.2). The design and operating parameters for the GRS equipment are shown in Table 11.3-1.

11.3.5 PERFORMANCE TESTS

All GRS radiation and chemical monitors used in system evaluation are functionally tested and calibrated periodically to ensure the accuracy of measurements. The types of radiation monitors and locations are contained in Section 11.4.

Measurements are made on a continuous basis and records maintained of the quantity of radioactive gases released. Comparison of results provides a check on the continuing performance of the waste gas systems. This approach proves effective in documenting deficiencies and their corrections. The routine radiation-monitoring program also detects leakage from the GRS by detecting minute changes in the activity of air in the areas occupied by the system. Appropriate means are used to locate and correct any increase in leakage.

11.3.6 PLANT RELEASES

11.3.6.1 Current Operational Releases

The actual gaseous releases are performed in accordance with approved plant procedures. The plant vent pathway is continuously monitored for noble gases, particulates and iodines.

The containment atmosphere is sampled and evaluated prior to release via the plant vent pathway during power operations. During periods of maintenance and refueling outages most releases continue via the plant vent pathway. However the containment equipment hatch may be open at times during maintenance resulting in direct communication between the containment and the outside air. If flow out of the containment equipment hatch is detected, containment air is evaluated per plant approved procedures to ensure a significant release via the equipment hatch is accounted for.

11.3.6.2 Pre-Operational Estimated Release Evaluation

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

The following information provides historical perspective demonstrating that DCPP's anticipated operation would result in releases within applicable regulations. This information does not necessarily reflect current operating conditions or practices.

The potential release pathways for radioactive gases have been described in previous paragraphs. Table 11.3-2 lists the estimated annual releases for the Design Basis Case, and Table 11.3-3 lists the estimated annual releases for the Normal Operation Case. The assessments of total curies released via each of the various pathways are discussed below. All release calculations were performed using the EMERALD-NORMAL (Reference 1) computer code.

Table 11.3-4 lists the estimated annual gaseous radwaste flows. Tables 11.3-5 through 11.3-8 list the estimated activities in the gas decay tanks and the volume control tank for the Design Basis and Normal Operation Cases.

For the release from venting of the gas decay tanks, it was assumed that the full volume of primary coolant is degassed twice a year, and the quantities of radioactive gases released are listed in Table 11.3-2 for the Design Basis Case and in Table 11.3-3 for the Normal Operation Case.

Containment venting releases are based on an assumed leakage of 1 percent of the primary coolant noble gas inventory and 0.001 percent of the primary coolant iodine inventory per day to the containment. It was assumed that the containment air is purged 24 times a year, and that the containment air is first circulated through the charcoal filters (described in Section 9.4.5) if the plant has been operating with significant primary coolant leakage to the containment. This recirculation is assumed to reduce the airborne iodine content by 98 percent, based on a filter decontamination factor (DF) of 10 for iodine, a circulation flowrate of 24,000 cfm for 16 hours, a containment free volume of 2.6 x 10^6 cubic feet, and a mixing efficiency of 70 percent. The resulting releases of iodine and noble gases for the Normal Operation Case are provided in Table 11.3-3.

In the event of leakage of primary coolant to the auxiliary building, the auxiliary building ventilation system can become a release pathway. In the calculation of release via this pathway, in the Normal Operation Case, it has been assumed that primary coolant leakage is 160 pounds per day, with a partition factor of 1 for noble gases and 0.0075 for iodine, with no iodine filtration in the ventilation system. The calculated releases via this pathway are provided in Table 11.3-3.

Because of the cleanup of the spent fuel pool water, the very large iodine removal capability of the water, the long decay times for noble gases and iodines in fuel rods handled in the pool, low fuel temperatures, and opportunity for prior release of gases in the containment, the amounts of iodine and noble gases released from the spent fuel pool to the environment under normal conditions are small. In the calculation of the release via this pathway, it was assumed that one-third of a core of spent fuel with 100 hours decay is placed in the spent fuel pool at the beginning of an operating cycle. Radionuclides diffuse through defects in fuel elements when cold at a rate 10^5 less than at normal core operating temperature. A partition factor of 0.001 is assumed for iodine and 1 for noble gases in the pool. The fuel handling building ventilation charcoal filter system is assumed to be 90 percent efficient for iodine removal. The calculated releases via this pathway are provided in Table 11.3-3.

Releases from the waste concentrator condenser vent will be negligible, and small amounts of gas that are released via this mechanism are included in the analysis by conservatively assuming that they are vented to the atmosphere before entering the GRS.

During periods when primary-to-secondary leakage exists, some release of noble gases and iodine will occur via the main condenser air ejector. To calculate these releases, it was assumed that all noble gases are transferred directly to the condenser vapor space, where they are released through the ejector after some decay. The parameters

used in the calculation are provided in Tables 11.1-23, 11.1-24, and 11.1-25. These assumptions are consistent with those provided in NUREG-0017. Five percent of the iodine leakage from the primary to the secondary system is assumed to be in volatile form and to behave in a manner similar to a noble gas at steam generator operating temperatures. A partition factor of 0.15 is assumed for volatile iodine in the condenser, and zero for nonvolatile iodine, so the iodine release from this pathway is entirely in volatile form. The activity releases via this pathway are provided in Table 11.3-3.

A small potential source of activity release exists from the gland steam condenser. Because of the small steam flowrate used, however, both the noble gas and the iodine release rates via this mechanism will be negligible compared with the air ejector releases, and this mechanism has not been calculated separately.

The steam generator blowdown tank vent was not considered to be a significant source of iodine release for the purposes of the offsite dose calculations since the blowdown tank was not expected to be used during periods when significant activity is present in the blowdown.

Significant release via the power relief valves and main steam and reheat relief valves is not expected under normal operating conditions.

A small potential source of gaseous activity release exists from the laundry/radwaste storage building and solid radwaste storage facility ventilation systems. However, because of the degassed nature of contaminated materials that enter these facilities, noble gas release rate via these pathways will be negligible compared with other listed pathways, and therefore have not been included. Similarly, since iodine will not be gaseous, iodine releases via these pathways have not been included.

As a result of normal secondary system steam and water leakage, some iodines and noble gases will escape to the environment if significant activity exists in the secondary system. For the Normal Operation Case, a water leakage of 5 gpm was assumed, along with a steam leakage of 1700 lb/hr. The releases via this pathway are also listed in Table 11.3-3.

During plant startup after a cold shutdown, small quantities of radioactive gases may be released from the vacuum pumps (when the condenser is pumped down) and from the cover gas of the liquid holdup tanks. Gases from the liquid holdup tanks are processed by the GRS, but the discharge from the condenser is vented directly to the atmosphere. Calculations were performed to evaluate the contribution to the total annual air dose at the site boundary in the NW sector of gases released from the condenser during startup. The results of these calculations are listed in Table 11.3-9. Additional assumptions used in the calculations are:

(1) Initial secondary system activity equal to equilibrium levels with 0.12 percent fuel defects and 100 pounds per day primary-to-secondary leakage (Normal Operation Case).

(2) *An "equivalent downtime" is used that is equal to a step change from full power to cold shutdown, a 24-hour down-time, and a step change back to full power.*

(3) *During shutdown, all noble gases are assumed to accumulate in the condenser vapor space; an effective partition factor of 0.15 is assumed for iodine between the secondary system water and the condenser vapor space for volatile iodine species, and zero for nonvolatile iodine.*

(4) *All airborne condenser activity is immediately released to the environment on startup. All iodine released is assumed to be volatile, and therefore not to be absorbed into food pathways. The critical dose point is considered to be the site boundary in the NW sector.*

This analysis was performed to demonstrate that DCPP “normal operation” radiological effluents meet the criteria of 10 CFR 50, Appendix I. This analysis is conservative and bounds DCPP current operation. This analysis was performed prior to plant operation and would be modified only if a design change or operational change rendered it nonconservative.

11.3.7 DILUTION FACTORS

11.3.7.1 Current Operational Dilution Factors

The meteorological program is discussed in detail in Section 2.3. All current plant releases are calculated with average χ/Q values using 5-year historical meteorological conditions.

11.3.7.2 Pre-Operational Dilution Factors

The pre-operational evaluation values of dilution factor (χ/Q) used in the calculation of annual average offsite radiation dose are provided in Table 11.3-11 for the locations specified in Table 11.3-10. The values of deposition rate (D/Q) used in the calculation of annual average offsite radiation dose are provided in Table 11.3-12 for the locations specified in Table 11.3-10. The D/Q values were derived from Figure 7 of RG 1.111 (Reference 3) for a ground level release.

The resulting pre-operational evaluation maximum offsite annual average atmospheric activity concentrations in each onshore sector are provided in Table 11.3-13 for the Design Basis Case and in Table 11.3-14 for the Normal Operation Case.

11.3.8 DOSES

11.3.8.1 Current Operational Doses

Doses for current operation are calculated in accordance with the site dose calculation manual contained in site approved procedures in accordance with 10 CFR 20 and appropriate NRC Regulatory Guides.

11.3.8.2 Pre-Operational Doses

Pre-operational dose calculations were performed at the critical distances for each age group and existing dose pathways in each onshore sector within 5 miles of Unit 1. The critical distances assumed in each sector are provided in Table 11.3-10. The milk cow and milk goat food pathways were not identified within 5 miles of the plant and were therefore not considered.

The models used to calculate the offsite radiation doses are those discussed in RG 1.109 (Reference 4) for a ground level release. The standard usage factors provided in RG 1.109 were used, as well as the standard decay times, transfer factors, and dose conversion factors. Since a ground level release was assumed, the gamma total body and air doses were calculated using the semi-infinite cloud model described in RG 1.109, which gives generally conservative results.

The results of the offsite dose calculations are presented in Tables 11.3-15 through 11.3-29 for the Design Base Case, and in Tables 11.3-30 through 11.3-44 for the Normal Operation Case. Actual results obtained from the environmental radiological monitoring program are discussed in Section 11.6. On the basis of the calculated estimates of radiation dose presented in Tables 11.3-15 through 11.3-44 and the results of the radiological monitoring program, it can be concluded that, under normal conditions, including consideration of anticipated operational occurrences, the potential dose from gaseous effluents from DCPP Units 1 and 2 will be well within the dose limits provided in Appendix I to 10 CFR 50.

11.3.9 REFERENCES

1. S.G. Gillespie and W.K. Brunot, EMERALD-NORMAL - A Program for the Calculation of Activity Releases and Doses from Normal Operation of a Pressurized Water Plant, Revision 1, Pacific Gas and Electric Company, December 1974.

2. NUREG-0017, Calculation of Releases of Radioactive Materials in Liquid and Gaseous Effluents from Pressurized Water Reactors (PWR-GALE code), USNRC, May 1976.

3. Regulatory Guide 1.111, Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light Water-Cooled Reactors, USNRC, March 1976.

4. Regulatory Guide 1.109, Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I, USNRC, March 1976.

5. DCPP Plant Procedures.

6. Technical Specifications, Diablo Canyon Power Plant Units 1 and 2, Appendix to License Nos. DPR-80 and DPR-82, as amended.

11.4 PROCESS AND EFFLUENT RADIOLOGICAL MONITORING SYSTEM

11.4.1 DESIGN OBJECTIVES

The radiological monitoring system is designed to provide radioactivity measurements, records alarms, and/or automatic line isolation in order to control and/or process, the release of radioactive fluids in compliance with applicable regulations. It monitors process and effluent streams wherever a potential release of radioactivity exists during all modes of plant operation.

The design objectives for the radiation monitoring system are to:

(1) Warn of any radiation health hazard to operating personnel

(2) Warn of leakage from process systems containing radioactive fluids

(3) Monitor amount of activity released in effluents

(4) Isolate or divert lines containing liquid and gaseous activity when activity levels reach a preset limit

(5) Record the radioactivity present at various plant locations

In the event of an accident, the process and effluent radiological monitoring system, in conjunction with the area radiation monitoring system, will provide information on the concentration and dispersion of radioactivity throughout the plant, thereby enabling operating personnel to evaluate the severity and mitigate the consequences of an accident.

11.4.2 CONTINUOUS MONITORING

11.4.2.1 General Description

The components[a] of the radiation monitoring system are designed for operation in the following ranges of conditions:

(1) Temperature - An ambient temperature range of 40° to 120°F.

(2) Humidity - 0 to 95 percent relative humidity.

[a] The only components of this system that are exposed to a wider range of conditions are located in the containment. This includes detectors and associated local alarm and indication equipment for the area-type monitoring channels there. Some of these, namely the low level-normal ops monitors are not expected to operate following a major loss-of-coolant accident. Postaccident high-range gamma monitors are used for postaccident situations.

(3) Pressure - Components in the auxiliary building and control room are designed for normal atmospheric pressure. Area monitoring system components inside the containment are designed to withstand containment test pressure.

(4) Radiation - Process and area radiation monitors are of a nonsaturating design so that they will register full-scale if exposed to radiation levels up to 100 times full-scale indication.

(5) Radiation monitoring equipment is designed and located such that radiation damage to electrical insulation and other materials will not affect their usefulness over the life of the plant.

(6) The radiation monitoring system is designed such that it can be checked, tested, and recalibrated as required.

Most of the control room radiation monitoring system equipment used for normal operation and anticipated operational occurrences are centralized in cabinets. A data logger is provided in the radiation monitoring system cabinets in the control room. Each monitoring channel is sequentially recorded. Equipment used solely for postaccident monitoring is located in additional cabinets in the control room. The digital radiation monitoring system equipment is located in a six-bay cabinet while the control room air supply and pressurization system is in the room control monitor rack (RCRM). Sliding channel drawers are normally used for rapid replacement of units, assemblies, and entire channels. It is possible to completely remove the various chassis from the cabinet after disconnecting the cable connectors from the rear of these units.

Detector output is usually measured in either counts per minute (cpm), milliroentgens per hour (mR/hr), or roentgens per hour (R/hr) and microcuries per cubic centimeter (μCi/cc). Each channel has a minimum range of three decades. Radiation monitors are listed in Tables 5.2-16 and 11.4-1. The iodine monitors are isotopic I-131 monitors and read in cpm, microcuries (μCi), or microcuries per second (μCi/sec).

The radiation monitoring system is divided into the following subsystems:

(1) The process radiation monitoring system that monitors radiation levels in various plant and component effluent streams

(2) The area monitoring system that monitors radioactivity in various areas within the plant

The locations of all detectors with respect to plant equipment for Unit 1 are listed in Table 11.4-1. Unit 2 detectors are in corresponding locations. Piping sequence and locations of process detectors are found in appropriate piping schematics, shown as figures in Section 3.2.

11.4.2.2. Process Radiation Monitoring System

11.4.2.2.1 Description

This system, as illustrated in Figure 11.4-1, consists of multiple channels that monitor radiation levels in various plant operating systems. The output from each channel detector except the digital radiation monitor is transmitted to the radiation monitoring system cabinets where the radiation level is indicated on a meter and recorded by a multipoint recorder. Except for air particulate/iodine/noble gas monitors in the Technical Support Center (TSC) and the adjacent laboratory, the gas decay tank cubicles, and the steam generator blowdown overboard monitor, the radiation monitoring system cabinets for most process radiation monitors are located in the control room. The radiation monitoring system cabinets for the TSC and the adjacent laboratory are located in the computation center. High-radiation level alarms are indicated on the radiation monitoring system cabinets with annunciation at one of two main annunciators. Except for the monitors in the TSC, the adjacent laboratory and some supplementary monitors, the main annunciator for process monitors is at the control board in the control room.

The control board annunciator provides several windows that alarm for input channels (process or area) detecting high radiation. The main annunciator for the TSC and the adjacent laboratory is in the TSC panel HVAC annunciator in the computation center. Four windows are provided for this annunciator, one each for high-radiation alarms from:

(1) TSC area monitors

(2) Laboratory area monitor

(3) TSC air particulate/iodine/noble gas monitors

(4) Laboratory air particulate/iodine/noble gas monitors

Verification of which channel has alarmed is done at the radiation monitoring system cabinets serving that annunciator (see Figure 11.4-1).

A tabulation of the process radiation monitoring channels is found in Table 11.4-1. The minimum sensitivity is based on a Co-60 background level of 2 mR/hr.

A typical channel contains a completely integrated modular assembly that includes the following:

(1) Log Level Amplifier

Accepts detector pulses, performs a log integration (converts total pulse rate to a logarithmic analog signal), and amplifies the resulting output for suitable indicating and recording.

(2) Power Supplies

Furnishes electrical power for the circuits, relays, alarm lights, and detectors.

(3) Test-Calibration Circuitry

Provides a precalibrated pulse signal to test channel electronics and a solenoid-operated radiation check source to verify channel operation. A common annunciator on the main control board indicates when a channel is in the test mode.

(4) Radiation Level Meter

Provides a dual scale calibrated logarithmically from 10^1 to 10^4, and 10^1 to 10^6 counts per minute. The wide-range level signal is also recorded by the recorder.

(5) Indicating Lights

Indicate high-radiation alarms, tests, and circuit failures. A number of annunciator windows on the main control board is actuated either on high radiation signal from the channels or from any channel failure, and another window is lit when channels are placed in the test mode. However, the digital radiation monitoring system and a few other monitors do not have this “test” alarm feature.

(6) Bistable Circuits

Two bistable circuits are provided: one to alarm on high radiation (actuation point may be set at any level within the range of the instruments), and one to alarm on loss of signal (circuit failure).

(7) Check Source

A remotely operated long half-life radiation check source or electronic check source is furnished for each channel. The check source simulates the radiation being monitored. The check source deflection is sufficient to cause an upscale indication. The main steam line radiation monitors and the control room pressurization system radiation monitors have a fixed “keep alive” source mounted directly on the detector. It is used only to keep the channel out of a low fail condition.

The process radiation monitoring system consists of the radiation monitoring channels described in Items 1 through 28 below. (The prefix numbers, where used with channel

identification, indicate monitors associated with Unit 1 or Unit 2; 0 indicates a shared monitor or no unit designation.)

The sample lines for the air particulate and gaseous radiation monitors (containment, RHR heat exchanger compartment exhaust, control room, TSC, laboratories, and plant vent) are designed and installed in accordance with the recommendations of Reference 2.

The flow in each of the sample lines (1-inch diameter, typically) is turbulent. Particle deposition due to gravity and Brownian diffusion are assumed to be small since the horizontal runs of the sample lines are short and the sample velocity is high. Long-radius bends are used for all sample lines, including the inlet lines to the monitors, to preclude deposition due to extreme turns. Isokinetic probes are used wherever the sample is taken from a moving airstream. Deposition in the basically vertical sample line runs are assumed to be largely due to turbulent deposition and is analyzed in the description for each of the air particulate monitors.

(1) *Containment - Air Particulate Monitor (1-R-11 and 2-R-11)*

This monitor is provided to measure air particulate gamma radioactivity in the containment.

The sampler for this channel takes a continuous air sample from the containment atmosphere. The inlet line from inside the containment is routed through the containment penetration to the monitor, which is located adjacent to the penetration.

The sample is monitored by a scintillation counter-filter paper detector assembly.

The particulate matter is collected on the filter paper's constantly moving surface and is viewed by a photomultiplier-scintillation crystal combination. The sample is returned to the containment after it passes through the series-connected gas monitor.

The pulse signal is transmitted to the radiation monitoring system cabinets in the control room.

Lead shielding is provided to reduce the background level to where it does not interfere with the detector's sensitivity.

(2) *Containment - Radioactive Gas Monitor (1-R-12 and 2-R-12)*

This monitor is provided to measure gaseous beta-gamma radioactivity in the containment. The detector consists of a gamma sensitive Geiger-Mueller (GM) tube mounted in the monitor container.

This channel takes a continuous air sample from the containment atmosphere that passes through the air particulate monitor (1-R-11, 2-R-11), and then through the gas monitor assembly. The sample is circulated in a fixed volume where it is monitored by a radiation detector. The sample is then returned to the containment. Its output is transmitted to the radiation monitoring system cabinets in the control room.

(3) *Residual Heat Removal Heat Exchanger Compartment Exhaust Duct Air Particulate Detector Monitor (1-R-13 and 2-R-13)*

This monitor is provided to measure air particulate gamma radioactivity in the RHR heat exchanger compartments' exhaust ducts to detect a leaking recirculation loop component in the event of a loss-of-coolant accident (LOCA). It operates in the same manner as the containment air particulate monitor.

The sampler for this channel takes a continuous common air sample from the exhaust ducts of both RHR compartments.

An isokinetic probe is installed in each RHR compartment exhaust duct. The monitor is located in proximity to the sample points.

The sample is monitored by a scintillation counter-filter paper detector assembly. The sample is then returned to the exhaust ducts. Ducts may be sampled individually by use of a selector switch at the console. High radiation is annunciated at the main control board.

(4) *Plant Noble Gas Vent Monitor (1-R-14, 2-R-14) (1-R-14R, 2-R-14R)*

Each channel consists of a pressurized three liter volume monitored by a beta scintillation detector. RM-14 is part of the normal range (NR) skid. RM-14R is part of the redundant normal range (RNR) skid. Local indication for these channels is provided by the Local Radiation Processors (LRPs) mounted on their respective skids. Remote indication for these channels is provided by the Radiation Display Units (RDUs) for their respective skids. The RDUs are mounted in the radiation monitoring system panels in the control room. The ranges of these monitors are as follows:

(1) Plant vent noble gas effluent (RE-14, RE-14R): 2.2×10^{-8} to 2.2×10^{-1} μCi/cc

(5) *Condenser Air Ejector Gas Monitor (1-R-15, 1-R-15R, 2-R-15, 2-R-15R)*

These channels monitor the discharge from the air ejector exhaust header of the condensers. Gaseous radiation is indicative of a primary-to-secondary system leak. The gas discharge is routed to the plant vent. High radiation is annunciated at the main control board.

(6) *Component Cooling Liquid Monitors (1-R-17A, 2-R-17A, 1-R-17B, 2-R-17B)*

These channels continuously monitor the component cooling water (CCW) system for radiation indicative of a leak of reactor coolant from the reactor coolant system (RCS) and/or the RHR loop to the CCW. Each channel employs an off-line detector using a bypass line from CCW pump discharge to suction. Due to the discharge piping configuration, however, only one monitor is sampling flow representative of the bulk system when only one CCW heat exchanger is in service. A high-radiation-level signal initiates closure of the valve located in the component cooling surge tank vent line to prevent gaseous radiation release. Adequate lead shielding is provided to reduce the effect of background radiation so that it does not interfere with the detector's sensitivity.

(7) *Liquid Radwaste Effluent Monitor (O-R-18)*

This channel continuously monitors discharges from the liquid radwaste system (LRS). Automatic valve closure is initiated to prevent further release after a high radiation level is indicated and alarmed, and flow is diverted to the equipment drain receiver tanks. Scintillation counters located in in-line samplers monitor these effluent discharges. An alarm function is provided on the main control board and the auxiliary building control board. Adequate lead shielding is provided to reduce the effect of background radiation so that it does not interfere with the detector's sensitivity. In addition, samples from the LRS batches are analyzed in the laboratory.

(8) *Steam Generator Blowdown Sample Monitor (1-R-19, 2-R-19)*

This channel monitors the liquid phase of the secondary side of the steam generator for radioactivity (which would indicate a primary-to-secondary system leak) providing backup information to that of the condenser air removal gas monitor. Blowdown samples from each of the four steam generators are combined in a common header and the common sample is continuously monitored by a scintillation counter in an in-line sampler assembly.

Adequate lead shielding is provided to reduce the effect of background radiation so that it does not interfere with the detector's sensitivity. High activity alarm indications are displayed locally and at the radiation monitoring system cabinets, with annunciation at the control board in the control room.

If a high activity alarm occurs, isolation valves in the blowdown and sample lines acting with the valve in the line from the blowdown tank to the discharge structure will close and the blowdown tank liquid effluent will be diverted to the equipment drain receiver tank. Subsequent identification of the leaking steam generator would then be made by manual override of sample line isolation and drawing separate samples from each steam generator for analysis.

(9) *Gas Decay Tank Discharge Gas Monitor (1-R-22, 2-R-22)*

This channel monitors the gaseous discharge from the gas decay tanks. The detector consists of a Geiger-Mueller tube inserted into an in-line fixed volume container that includes adequate shielding to reduce the background radiation low enough not to interfere with the detector's sensitivity. This channel will alarm on the main control board and auxiliary building control board and close the gas decay tanks discharge valve on a high radiation level signal.

(10) *Plant Vent Particulate Monitors (1-R-28, 2-R-28)(1-R-28R, 2-R-28R)*

Each channel consists of a fixed particulate filter monitored by a beta scintillation detector. RM-28 is part of the NR skid. RM-28R is part of the RNR skid. The sample for each skid is isokinetically drawn from the plant vent stack. Local indication for these channels is provided by the LRPs mounted on their respective skids. Remote indication for these channels is provided by the RDUs for their respective skids. The RDUs are mounted in the radiation monitoring system panels in the control room. The ranges of these monitors are as follows:

(1) Plant vent air particulate effluent (RE-28, RE-28R): 1×10^{-12} to 2.27×10^{-4} μCi/cc

(11) *Plant Vent Iodine Monitors (1-R-24, 2-R-24)(1-R-24R, 2-R-24R)*

Each channel consists of a charcoal cartridge filter monitored by a gamma scintillation detector. Iodine is discriminated using a single channel analyzer. RM-24 is part of the NR skid. RM-24R is part of the RNR skid. The sample for each skid is isokinetically drawn from the plant vent stack. Local indication for these channels is provided by the LRPs mounted on their respective skids. Remote indication for these channels is provided

by the RDUs for their respective skids. The RDUs are mounted in the radiation monitoring system panels in the control room.

(12) *Steam Generator Blowdown Tank Liquid Effluent Monitor (1-R-23, 2-R-23)*

This channel is provided to continuously measure liquid effluent from the blowdown tank. The channel employs a scintillation counter located in an off-line sample chamber. Adequate shielding is employed to reduce effects of background radiation.

The count rate is handled in the same manner as for the basic radiation monitoring system. Output is recorded in conjunction with, and parallel to, the recorded outputs of the flow elements related to the blowdown tank inputs and effluents at a local panel specifically provided for that function. Output is also recorded at the data logger in the radiation monitoring system cabinets in the control room.

Alarms are provided on the main control board for high and low radiation (instrument failure). A high-radiation signal isolates the blowdown discharge, and diverts blowdown tank liquid effluent to the equipment drain receiver tank.

(13) *High-Range Plant Vent Gas Monitor (1-R-29, 2-R-29) Postaccident Monitor*

This monitor measures high-range gross gamma radioactivity in the plant vent. The detector consists of a shielded ion chamber contiguous to the plant vent and mounted on an adjacent support structure. A control room readout, with an associated recording device, is provided on the postaccident monitoring (PAM) panel. Also provided on this panel are the high and low (instrument failure) radiation alarms. The high and fail radiation alarms are also provided on the main control board. The high alarm also alarms in the State of California Office of Emergency Services in Sacramento.

(14) *Containment Purge Exhaust Monitors (1-R-44A, 2-R-44A)(1-R-44B, 2-R-44B)*

Each channel consists of a beta scintillation detector mounted to the side of the Containment Purge Exhaust (CPE) duct. The detectors are mounted diametrically opposed on the 48-in CPE duct. Their location is on the downstream of the CPE fan, E-3. Local indication for each channel is provided by the wall mounted LRPs associated with each detector. Remote indication for each channels is provided by the RDUs. The RDUs are mounted in the radiation monitoring system panels in the control room. These monitors provide an engineered safety feature actuation signal to

close the CVI valves in the case of high radioactivity exhausting the containment.

(15) *Extended Range Noble Gas Monitor (1-R-87, 2-R-87)*

The extended range (ER) channel, RM-87, uses a beta scintillation detector operated in the current mode. The ER noble gas detector is less sensitive and the volume of the detection chamber is smaller than those of the NR noble gas channel. The ER chamber is not pressurized. The sample is isokinetically drawn off the plant vent stack at approximately 1/20th the rate of the sample for the NR and RNR skids. The chamber is downstream of two identical trains of particulate and iodine roughing filters/grab samplers. Alternating between the trains allows removing a grab sample while continuing to monitor the stack. The grab samplers are to be used for assessing post accident releases of particulates and Iodine using laboratory instruments. All of this equipment is mounted on the ER skid. Local indication for RM-87 is provided on the LRP for the NR Skid. Remote indication for RM-87 is provided on the RDU for the NR skid. The RDU is mounted in the radiation monitoring system panels in the control room. Indication for RM-87 is on the same indicating channel used for RM-14.

(16) *TSC Air Supply Radioactive Particulate Monitor (O-R-66)*

This monitor is provided to measure air particulate gamma radioactivity in the ventilation air supply to the TSC. The isokinetic flow sampler for this channel takes a continuous air sample from the TSC ventilation air supply duct.

(17) *TSC Air Supply Noble Gas Monitor (O-R-67)*

This monitor is provided to measure the noble gas activity in the ventilation air supply to the TSC. The same isokinetic flow as described in item (16) above is used for the analysis.

(18) *TSC Air Supply Iodine Radiation Monitor (O-R-82)*

This monitor is provided to measure the iodine activity in the ventilation air supply to the TSC. The same isokinetic flow as described in item (16) above is used for the analysis.

(19) *Laboratory Adjacent to the TSC Radioactive Particulate Monitor (O-R-68)*

This monitor is provided to measure air particulate gamma radioactivity in the laboratory. The sample is drawn directly from the room.

(20) *Laboratory Adjacent to the TSC Noble Gas Monitor (O-R-69)*

This monitor is provided to measure the noble gas activity in the laboratory. The sample is drawn directly from the room.

(21) *Laboratory Adjacent to the TSC Iodine Radiation Monitor (O-R-83)*

This monitor is provided to measure the iodine activity in the laboratory. The sample is drawn directly from the room.

(22) *Radwaste Storage Building Ventilation Exhaust Air Particulate Samplers (0-RX-55, 0-RX-56)*

These samplers consist of in-line particulate filter assemblies, which provide the capability to sample and subsequently assess (via laboratory analysis), the concentrations of radioactive material present in the exhaust from the radwaste storage building. RX-55 samples the exhaust from the solid radwaste (old) storage building, and RX-56 samples the exhaust from the laundry/respirator cleaning facility and radwaste (new) storage building prior to the discharge of these effluent points to the environment.

(23) *Oily Water Separator Effluent Monitor (O-R-3)*

This channel continuously monitors the turbine building sump retention tank discharge into the oily water separator.

(24) *Condensate Demineralizer Waste Regenerant Discharge Monitoring*

The contents of the condensate demineralizer regenerant waste tanks will be processed and periodically sampled prior to release, in accordance with plant procedure.

(25) *Main Steam Line Activity Monitors (1-R-71 through 1-R-74 and 2-R-71 through 2-R-74)*

These monitors consist of gamma-sensitive Geiger-Mueller tubes and are provided to continuously monitor the main steam lines. The detectors are located next to each main steam line and measure the steam activity from the line's shine.

(26) *Gas Decay Tank Cubicle Radiation Monitors (1-R-41, 1-R-42, 1-R-43, 2-R-41, 2-R-42, 2-R-43)*

These monitors are for detecting noble gas activity in the gas decay tanks. The detectors are located in compartments adjacent to the decay tanks and provide indication on the auxiliary building control board.

(27) *Solid Radwaste Inspection Station Radiation Monitors (0-R-84, 0-R-85)*

These radiation monitors are provided to permit the assessment of the contact (R-84) and one-meter (R-85) radiation dose rates being given off from material containers being prepared for storage and shipment as solid radioactive waste. The detectors are located at the decontamination/inspection station in the solid radwaste storage area.

11.4.2.2.2 Design Evaluation

An evaluation of instrumentation function relative to monitoring and controlling releases of radioactivity from various plant systems is discussed below.

(1) *Fuel Handling Inside Containment*

For activity releases inside containment, the air particulate and gas monitors RE-11 and RE-12 will alarm in the control room. The air exhausted from the containment through the containment purge and exhaust lines is monitored by RM-44A and RM-44B. In the event that the pre-determined high alarm setpoint levels are exceeded, these radiation monitoring channels will initiate a signal that would cause the closure of the CVI valves and mitigate the consequences of the accident. The ranges of the containment monitors are as follows:

(1) Containment air particulate (RE-11): 5×10^{-11} to 5×10^{-6} μCi/cc

(2) Containment noble gas (RE-12): 5×10^{-6} to 5×10^{-1} μCi/cc

(2) *Liquid and Gas Wastes*

For ruptures or leaks in the waste processing system, plant area monitors and the vent stack monitor will alarm on an increase in radiation over a preset level. For cases where leaks are involved, the operator may control activity release by system isolation. For more severe postulated accident cases, such as rupture of waste tanks, activity release is not controlled. The radiological consequences of the postulated accidents are not based on instrument action. For inadvertent releases relative to violation of administrative procedures, monitors provide alarms and the means for limiting radioactive releases. The gas decay tank discharge monitor will close the flow control valve in the waste decay tanks discharge line when the radiation level in the line exceeds a preset level. Where liquid waste releases are involved, the liquid radwaste discharge monitor trips shut a valve in the discharge line when the radioactivity in the discharge line exceeds a preset level and redirects the flow to the equipment drain receiver tanks.

For steam generator blowdown releases, the blowdown effluent monitor and the blowdown sample monitor isolate the blowdown discharge and will divert the blowdown tank liquid effluent to the equipment drain receiver tanks.

11.4.2.3 Area Radiation Monitoring System

11.4.2.3.1 Description

This system consists of multiple channels that monitor radiation levels in various areas of the plant. The system has low-range monitors for normal operation and high-range monitors for postaccident conditions. These monitors and their locations are listed in Table 11.4-1.
The selection and location of the monitoring areas are based on multiple considerations, including occupancy status of various plant zones, potential for increase in background activity levels due to operations carried out in a particular location, and desirability of surveillance of infrequently visited areas.

A typical channel of the area radiation monitoring system consists of a fixed-position, gamma-sensitive Geiger-Mueller tube detector. The detector count rate is amplified, and its log count rate is displayed by the readout in the radiation monitoring system cabinets. The radiation level is indicated locally at the detector and at the radiation monitoring system cabinets and it is also recorded. Except for the area monitors in the TSC and the adjacent laboratory, the radiation monitoring system cabinets are located in the control room. The radiation monitoring system cabinet for the area monitors in the TSC and laboratory is located in the TSC computation center. High-radiation alarms are displayed on one of two main annunciators, on the radiation monitoring system cabinets, and at the detector location. The control room annunciator provides several

windows that alarm for process or area channels detecting high radiation, except for the monitors in the TSC and laboratory. The main annunciator for high radiation detected by the TSC and laboratory area monitors is the TSC HVAC annunciator located in the computation center. A separate window is provided on this annunciator for the TSC area monitors and for the laboratory area monitor. Verification of which channel has alarmed is done at the radiation monitoring system cabinets. Each channel contains a completely integrated modular assembly (see the description of the process radiation monitoring system in Section 11.4.2.2.).

The log level amplifier module amplifies the radiation level signal for indication and recording. The module also provides controls for actuation of the channel check source.

A meter is mounted on the front of each readout module and is scaled to read logarithmically from 1.0×10^{-1} to 1.0×10^{4} mR/hr. The exceptions are the control room ventilation intake monitor, which has a range of 1.0×10^{-2} to 1.0×10^{3} mR/hr, the pressurization intake monitor, which has a range of 1.0×10^{-2} mR/hr to 1.0×10^{4} mR/hr, and the area monitor for the PV monitoring skid and the HRSS postaccident sampling room, which has a range of 1.0×10^{-1} to 1.0×10^{7} mR/hr. A local meter, scaled logarithmically from 1.0×10^{-2} to 1.0×10^{4} mR/hr, is mounted at the detector assembly.

Two mutually redundant high-range containment monitors RE-30 and RE-31 are provided for each unit, each consisting of a detector mounted inside the containment liner to mitigate the effects of local hot spots and to obtain the best "view" of the containment free volume. The units are powered from separate instrument power channels.

Each detector is a hermetically sealed, stacked, parallel plate, three-terminal guarded ionization chamber, operated in the saturated mode. The detector and its special cable are environmentally qualified to IEEE 323-1974.

Each readout has a range of 1 to 10^{7} R/hr and has high alarm, failure alarm, logarithmic scale recorder, and electronic system and detector checks.

11.4.2.3.2 Design Evaluation

Radiation detection instruments are located in areas of the plant that house equipment containing or processing radioactive materials. These instruments continually detect, compute, and record operating radiation levels. If the radiation level should rise above the setpoint listed for each channel (see Table 11.4-1), an alarm is initiated in a control room.

Local annunciation is provided at the detector to indicate high radiation levels to personnel in the area. The monitoring system is operated in conjunction with regular and special radiation surveys and with chemical and radiochemical analyses performed by the plant staff. Adequate information and warning is thereby provided for the continued safe operation of the plant and assurance that personnel dose does not exceed 10 CFR 20 limits.

11.4.3 SAMPLING

11.4.3.1 Basis for Selection of Sample Locations

Locations for periodic sampling are based on the following:

(1) Sampling of process fluids that contain radioactivity

(2) Sampling of process fluids not normally radioactive that may become radioactively contaminated due to some component failure

11.4.3.2 Expected Composition and Concentration

Because of the diversity of sources of sampled fluids, the activity levels are expected to range from negligible to the reactor coolant concentrations provided in Section 11.1. Concentrated liquid samples may have higher than normal RCS specific activities.

11.4.3.3 Quantity to Be Measured

Samples expected to contain radioactivity are analyzed periodically as specified in the radiological monitoring and controls procedures and the chemical analysis procedures of the Plant Manual.

11.4.3.4 Sampling Frequency and Procedures

Sampling frequency varies according to the sample being analyzed and previous activity level of the sample. The sampling frequency for effluents is specified in the radiological and monitoring procedures of the Plant Manual. The sampling frequency for non-effluent samples is specified in the chemical analysis procedures of the Plant Manual.

11.4.3.5 Analytical Procedures and Sensitivity

Analytical procedures are in accordance with the Plant Chemistry Manual. The required sensitivities are specified in the radiological and monitoring procedures of the Plant Manual.

Equipment used for radiation analysis is located near the primary chemical laboratory and the laboratory near the TSC.

11.4.3.6 Influence of Results on Plant Operations

The Technical Specifications lists the appropriate radioactive contamination limits on the pertinent systems, as well as the required actions if the limits are exceeded.

11.4.4 CALIBRATION AND MAINTENANCE

11.4.4.1 Alarm Setpoints

The alarm/trip setpoints for radioactive liquid and gaseous effluent radiation monitors (as defined in Technical Specifications) are determined in accordance with the methodology and parameters in the offsite dose calculation procedure. The alarm/trip setpoints for all other process and area radiation monitors are established by administrative procedures and controlled in Vol. 9B, Table T-IIC-2, "I&C RMS Data Book for Radiation Monitoring and Allied System Data," and are based on protection of public health and safety, plant personnel health and safety, and maintaining efficient plant operation.

Table 11.4-3 lists those monitors that affect valve control operations, together with their effect.

11.4.4.2 Definitions

Radiation Monitor Channel Functional Test - Injection of a simulated signal into the channel as close to the sensor as practicable to verify operability including alarm and/or trip functions.

Radiation Monitor Channel Source Check - The qualitative assessment of channel response when the channel sensor is exposed to a radiological source.

Other definitions are listed in Section 1 of Reference 1.

11.4.4.3 Calibration Procedure

Area and process monitors were initially calibrated by their original manufacturer. Response curves for each detector were provided with the instrument. These curves essentially relate detector performance to the energy spectrum that the detector would see in operation.

11.4.4.3.1 Area Monitors

Based upon the requirements of the plant Technical Specifications, traceable radioactive sources are used to calibrate the area monitors. The monitors are also functionally checked periodically in accordance with the plant Technical Specifications.

11.4.4.3.2 Process Monitors

For the process monitors the, detectors are calibrated with traceable radioactive sources on the frequency defined in the plant Technical Specifications or Equipment Control Guidelines (ECGs) (see Chapter 16). Further, the detector response is correlated to the results of analysis of the process stream with calibrated counting room equipment.

11.4.4.4. Test Frequencies

Calibration and functional checks of the process and area monitors are performed at frequencies that are in accordance with the plant Technical Specifications and Equipment Control Guidelines.

11.4.4.5 System Summary

It is concluded that the administrative controls imposed on the operator, combined with the radiation monitoring system design, provide a high degree of assurance against accidental release of radioactivity to the environment.

11.4.5 REFERENCES

1. Technical Specifications, Diablo Canyon Power Plant Units 1 and 2, Appendix A to License Nos. DPR-80 and DPR-82, as amended.

2. ANSI N13.1-1969, American National Standard Guide to Sampling Airborne Radioactive Materials in Nuclear Facilities.

11.5 SOLID WASTE SYSTEM

11.5.1 FUNCTION

The solid radwaste system (SRS) is designed to process, package, and store the radioactive wastes generated by plant operations until they are shipped offsite for permanent disposal at a licensed burial facility. Figure 11.5-1 is a flow diagram of the SRS.

11.5.2 DESIGN OBJECTIVES

The design objectives of the SRS are:

(1) To provide a means for collecting and processing the plant's radioactive waste streams in accordance with both regulatory and burial site criteria without limiting the functionality of the plant

(2) To maintain any potential radiation dose to plant personnel and the environment, as a result of the operation of the SRS, as low as is reasonably achievable (ALARA), within the dose limits of 10 CFR 20

(3) To package the plant's solid radioactive wastes in conformance with the requirements of 10 CFR 71

11.5.3 SYSTEM INPUTS

The SRS collects the following inputs for processing, packaging, and disposal:

(1) Spent filter/ion exchange media

(2) Spent ion exchange resin

(3) Spent filter cartridges

(4) Miscellaneous dry active wastes (i.e., contaminated paper, rags, clothing, tools, etc.)

The SRS input from each of the plant radioactive waste streams is presented in Table 11.5-1. Tables 11.5-2 and 11.5-4 list the activities of the spent ion exchange resins, the spent filter media, and the spent cartridge filters for both the normal and design basis cases.

11.5.4 COMPONENTS

The SRS has five major subsystems: the spent filter/ion exchange media processing system, the spent resin processing system, the spent filter cartridge processing system,

the mobile radwaste processing system (MRPS), and the dry active waste processing system. The function of each of these subsystems is described in the following paragraphs.

11.5.4.1 Spent Resins Processing System

The system for transferring spent resins from any of the ion exchangers to the spent resin storage tanks (SRSTs) consists of four separate headers connected to four eductors and discharge systems that permit the transfer of resin from any of the 30 ion exchanger units to either of two SRSTs. Pressurized air is used to transfer resin from either SRST to the loadout station (LS) to which the MRPS container is connected. Pressurized air can also be used to transfer resin from one SRST to the other. Two SRST eductors are provided to transfer resin from one SRST to the other. Figure 11.5-3 is a flow diagram of the spent resin processing system.

The general layout of the system is shown in Figure 11.5-11. The SRSTs are located in shielded cells. All of the valves, instruments, and the discharge eductor are located in a separately shielded area (valve gallery) adjacent to the SRST cells. The spent resin LS is located on the east outside wall of the auxiliary building.

A spent resin sampling system allows for the collection of grab samples as resins enter the SRSTs or while the spent resins are being transferred out of the SRSTs to the MRPS.

All of the equipment associated with this system is considered potentially highly radioactive. None of the equipment, which is located behind shielding, will be approached either for operation or maintenance except under the direction of plant radiation protection personnel under the special work permit rules of the plant.

11.5.4.2 Spent Filter/Ion Exchange Media Processing System

Pressurized air is used to transfer exhausted media from either of the two radwaste media filters to the LS to which the MRPS container is connected.

11.5.4.3 Spent Filter Cartridge Processing System

This system is designed to remove and handle spent filter cartridges generated in the filters of the chemical and volume control system (CVCS), spent fuel storage system, and liquid radwaste system. The radioactively contaminated spent filter cartridges can be removed from the filter housing or vessels with the operator remaining behind shielding. The spent cartridges are transferred to storage or to the MRPS in shielded transfer casks.

It is assumed that the whole change-out procedure takes 1 hour. This includes loading clean filter cartridges. Half an hour can be spent with the operator protected from

radioactive spent cartridges by the transfer cask. For the remaining time, the operator is protected from the filter cartridges by concrete, steel, and/or lead shields.

Figures 11.5-6 through 11.5-8 show the location of filters in the system.

Figures 11.5-9 and 11.5-10 display the system for capturing the filters using the grappling hook, cask, pulley, and mirrors.

11.5.4.4 Mobile Radwaste Processing System

The MRPS is a skid-mounted mobile radwaste dewatering/solidification system. The MRPS for media and resin is located on a concrete pad as shown in Figure 11.5-12 and in Bay 2 of the Solid Radwaste facility for filters. This space will accommodate the spillage of resins via concrete sloped to a drain within the area.

The MRPS is operated on a batch basis to solidify concentrates, to dewater or solidify spent ion exchange or filtration media, and to encapsulate spent cartridge filters. Slurries from the media filter vessels are sluiced out to the MRPS and dewatered or solidified. Spent resin slurries are sluiced to the MRPS (see Section 11.5.5) from the spent resin storage tank and dewatered or solidified. Filter cartridges are transferred to the MRPS container in a shielded spent filter transfer cask, if required. Waste concentrates, ion exchange media, filtration media, and cartridge filters will be dewatered or solidified in accordance with the process control program detailed in the Plant Procedures Manual.

Normally, containers are dewatered or solidified in processing shields. The containers are stored in the shields until shipment. The containers are transferred by mobile cranes into the shipping casks. Containers may be dewatered and/or solidified while in casks on the trailers by which they will be shipped. When processing is finished in shipping casks, the containers are shipped immediately so that no in-plant handling is required.

Complete waste solidification or absence of free liquid prior to shipment are ensured by the implementation of a process control program consistent with the recommendations of NUREG-0472 (Reference 1). For medium and high activity waste, level sensors monitor the levels in the waste containers and provide alarm signals to alert the MRPS operator to take action to prevent filling beyond preset levels. Low activity waste level may be monitored by sight by the MRPS operator. Potential waste container overflows are contained by the curbed processing pad, then flow into a sump that will return the spill to the radwaste system.

11.5.4.5 Dry Active Waste Processing System

Potentially radioactive dry wastes are collected at appropriate locations throughout the plant, as dictated by the volume of the wastes generated during operation or maintenance. The wastes are then segregated, processed, and packaged.

Compressible dry active wastes may be processed by compaction in either a drum or box compactor. During compaction, the airflow in the vicinity of the compactor is directed by the compactor exhaust fan through a high-efficiency particulate filter before it is discharged.

Large or highly radioactive components and equipment that have been contaminated during reactor operation and that are not amenable to compaction are handled either by qualified plant personnel or by outside contractors specializing in radioactive materials handling, and the components and equipment are packaged in shipping containers of an appropriate size and design.

11.5.4.6 Mixed Waste

Mixed waste is liquid or solid waste that is both hazardous and radioactive. Mixed waste is segregated and accumulated in drums in Bay 6 of the Solid Radwaste Storage Facility (SRSF). Filled drums of mixed waste are placed in storage in Bay 5 of the SRSF.

11.5.4.7 Component Failures and System Malfunctions

Analyses have been performed to evaluate potential dose to operating personnel should the solid radwaste systems malfunction or components fail. The components and systems considered most likely to fail are discussed below.

During the transfer of spent resin to the SRSTs, a failure of the motive water pump could result in lines becoming clogged with resin. The lines may be cleaned out by starting up the second motive water pump and using the normal operating procedure. The CVCS resin transfer piping system includes cleanout flanges, which can be used if the lines cannot be cleaned by using the normal procedure. The cleanout flanges are located in areas that are shielded from the main resin transfer lines, and minimize the dose to operating personnel during a cleanout operation.

During the transfer of spent resin from a demineralizer to an SRST, failure of a pneumatically operated valve on the outlet of the demineralizer would require special operator action. The valves have reach-rods extending through the shield wall, permitting manual operation of the valve. After flushing the demineralizer completely and allowing sufficient time for decay of any residual activity, the operating personnel would perform the required repair on the valve. A maximum dose of 800 mR is estimated to occur in the repair of a valve on a CVCS mixed bed demineralizer.

As a backup in the event the pneumatically operated tank outlet valve fails during transfer of spent resin from one of the SRSTs, the valve can be controlled by manual operators extending through a second shield wall to the operating area.

11.5.5 PACKAGING

Disposable mild steel liners are used for packaging dewatered, solidified or encapsulated wastes. The typical liner sizes may range from 80 to 300 cubic feet. High Integrity Containers (HIC) are also used for packaging dewatered or encapsulated wastes. The typical HIC sizes may range from 75 to 200 cubic feet. Wet solid waste may be packaged for further off-site treatment, on-site storage or off-site disposal.

Dry active wastes may be packaged for further off-site treatment, on-site storage or off-site disposal. For on-site storage and direct disposal, 55-gallon steel drums or 4 x 4 x 6 foot steel boxes will typically be used. Drums and boxes classified as IP1 and IP2 containers will be utilized as applicable.

11.5.6 STORAGE FACILITIES

Onsite storage for packaged wastes will be provided by the solid radwaste storage facility (SRSF) or by the radwaste storage building (RSB). These buildings are located east of the auxiliary building, as shown in Figure 11.5-4.

The SRSF provides a storage area for metal boxes, drums, and shielded filters. The SRSF can hold 580 drums or 65 boxes and 60 drums. The arrangement of the rooms in the SRSF is shown in Figure 11.5-5. A forklift is used for moving the containers into and within the storage area. Concrete walls provide shielding between the various vaults in the SRSF. Encapsulation or dewatering of filters may occur in the SRSF. Segregation and compaction of dry active waste is also performed in the SRSF.

The RSB provides storage areas for 180 liners or HICs and compacted dry active waste in 4 x 4 x 6 foot boxes or 55-gallon drums. The liner storage vaults are sized to accommodate 80 ft^3 containers stacked 3 wide by 2 high.

An overhead crane assembly is used for moving liners or HICs to their respective storage areas in the RSB. A shielded cask rail car is used to transport liners or HICs from the load-out area to the storage vaults. Encapsulation of filters and dewatering of resin may occur in the shielded cask rail car in the RSB truck bay. A liner-inspection/decontamination station is also provided for preparing containers for storage or shipping.

The compacted dry active waste storage area (DAW vault) is sized to accommodate 522 boxes at 93 ft^3 each, totaling 48,456 ft^3 of storage. Drums can also be stored in this facility. A fork lift is used for moving the containers into and within the DAW vault.

The old steam generators (OSGs) and old reactor vessel head assemblies (ORVHAs) were removed from DCPP Units 1 and 2 during the steam generator and reactor vessel head replacement projects. These ten large components are temporarily stored in the OSG Storage Facility (OSGSF) specifically constructed for this purpose. The OSGSF meets the radwaste storage requirements for temporary storage of the OSGs and

ORVHAs until site decommissioning. The OSGSF is designed to be used as a non-occupied mausoleum for the temporary storage of the OSGs and ORVHAs. No other radwaste storage is permitted within this facility.

11.5.7 SHIPMENT

The shipment of prepacked solid waste from the plant site to burial locations is contracted to firms licensed to transport radioactive material in accordance with applicable Department of Transportation regulations. All shipping containers and transportation casks are in conformance with 49 CFR 171 to 49 CFR 178 and 10 CFR 71, as applicable. Table 11.5-5 summarizes the expected quantities to be shipped.

11.5.8 REFERENCES

1. NUREG-0472, Radiological Effluent Technical Specifications for PWRs, Rev. 3, USNRC, March 1979.

11.5.9 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

11.6 OFFSITE RADIOLOGICAL MONITORING PROGRAM

The environmental radiation monitoring program was developed to comply with the requirements of the State of California Department of Health Services, Radiological Health Section, and the NRC.

The monitoring program required by the DCPP Technical Specifications (Reference 6) includes monitoring, sampling, analysis, and reporting, including performance of a Land Use Census and participation in an Interlaboratory Comparison Program.

11.6.1 EXPECTED BACKGROUND

The 1984 results of the preoperational monitoring program are shown in Table 11.6-4 and Reference 1. Table 11.6-4 summarizes measurements of external dose with thermoluminescent dosimeters (TLDs), gross beta, gamma isotopic, and I-131 activities in air samples and gamma isotopic and I-131 and/or tritium activities (as appropriate for particular samples) in marine and terrestrial samples. There are no known local man-made sources of radioactivity in the vicinity of DCPP; therefore, the variations shown in these tables are considered to be either natural variations or fallout from weapons testing. Gamma isotopic analyses were made of all marine and terrestrial samples. Only a few showed measurable activities above background. The results of all samples with detected activity during the preoperational period January 1, 1981, through March 31, 1984, are included in the Preoperational Environmental Report (Reference 8).

The data, presented on an annual basis, show local differences in activity as well as seasonal variations. Terrestrial variations may be attributable to such factors as variation in the spatial distribution of radionuclides in the soil, the amount of rainfall, TLD locations in valleys as contrasted to hillsides, and secondary sources of airborne dust from such activities as construction or farming.

These data and those for previous years serve as a baseline during plant operation.

11.6.2 CRITICAL PATHWAYS

Based on the expected radiological releases from Units 1 and 2 (Section 11.2 and 11.3), and the tabulated estimates of dose, none of the releases is expected to significantly increase the total dose to man relative to natural background. Calculations show which principal pathways for atmospheric releases will give the maximum doses. All doses through aquatic releases are expected to be negligible.

The levels of radiation in environmental samples are expected to be very low and, for many isotopes, below the minimum detectable level, using the best techniques available today. For this reason, dose analyses are performed based principally on plant effluent data, with secondary analyses based on environmental data.

For airborne releases, the Offsite Dose Calculations Procedure (ODCP) is used with measured local meteorological data, measured release data of the gases and particulates, plus local demographic data, to estimate individual dose.

From the gamma dosimeter stations for the direct radiation measurements, in general, the offsite stations are used to serve as reference points for natural background and manmade environmental radiation that is not associated with plant operations. Onsite and fenceline stations are used to measure dose from the plant. Therefore, direct radiation dose above background is obtained and compared to calculated doses.

For radiological releases to the ocean, the ODCP is used in conjunction with effluent data to estimate dose from the consumption of aquatic foods grown within the radiological influence of the plant.

Radiological reconcentration data for species in the vicinity of Diablo Cove are obtained from RG 1.109 (Reference 7).

Aquatic food intake is based on the parameters provided in Reference 7 via the ODCP.

Consideration is also given to any group that has unusually high per capita consumption.

11.6.3 SAMPLING MEDIA, LOCATION AND FREQUENCY

11.6.3.1 Marine Samples

The types of marine samples, the frequency of collection, and the sampling location are shown in Table 11.6-1. These samples were selected to represent various food products.

11.6.3.2 Terrestrial Samples

Possible dose to man could result from atmospheric immersion and inhalation, and consumption of radionuclides deposited as particulates from the gaseous effluent of DCPP. To monitor the above pathways, various types of terrestrial samples are collected and analyzed. Air samples using particulate filters and iodine cartridges are taken continuously at a minimum of four sample locations. The sites were selected to provide data at downwind locations, major population centers, and areas that are not influenced by plant operations. It should be noted that 8 of 16 sectors surrounding DCPP are located over water, therefore the 5 air sampling stations recommended by the Branch Technical Position for Radiological Environmental Monitoring Program (Revision 1, 1979) were reduced to 4 air sampling stations.

Gamma dosimetry measurements are made at environmental monitoring stations using TLDs. The TLDs were selected because of their sensitivity and the ease of readout.

Drinking water samples are collected from the Raw Water Reservoirs. Surface water samples are collected from the plant outfall.

Samples of various foodstuffs produced in the area are also collected when available.

The terrestrial sampling frequency reflects the areas that are most sensitive to changes in radioactive levels and in dose measurements. Thus, the airborne sampling is weekly, the TLD measurements are quarterly, and the terrestrial foods measurements are monthly or in season.

11.6.4 ANALYTICAL SENSITIVITY

11.6.4.1 Types of Analyses

The types of radiological analyses performed on each sample are presented in Table 11.6-1. The offsite radiological program emphasizes analyses for those radionuclides expected to be present in the DCPP effluent and those that will be the major contributors to dose to the public.

The effluent from DCPP is expected to contain radionuclides whose identity and activity can be determined by gamma spectrometry. Thus, all samples are placed in a fixed geometry and analyzed by gamma spectrometry. Other analysis techniques can be utilized as deemed necessary.

11.6.4.2 Measuring Equipment

The equipment presently in use for the radiological monitoring program typically includes, but is not limited to:

(1) Gas-flow proportional counter for gross beta analyses

(2) High purity intrinsic germanium detectors (or equivalent)

(3) Thermoluminescent dosimeters for external dose measurements

(4) Beta-gamma coincidence spectrometer

(5) Liquid scintillation spectrometer

11.6.4.3 Sample Detection Sensitivity

The ability to accurately determine the radioactivity in a sample is a function of many variables including the following: (a) sample size, (b) self-absorption in the sample, (c) detector counting efficiency, (d) counting time background count rate, (e) half-life of the isotope, (f) loss of radionuclides in sample preparation, and (g) ability to distinguish between isotopes with similar gamma emission energies. Consistent results are

obtained by standardizing procedures that maintain as many of the above variables constant as practicable.

11.6.5 DATA ANALYSIS AND PRESENTATION

The data acquired from the environmental monitoring program falls into the categories of:

(1) Information on the distribution of radioactivity in lower trophic levels in the physical environs of DCPP

(2) Information on external radiation in the vicinity of DCPP

(3) Information on radionuclides in foodstuffs that may result in a dose to man

In examining the distribution of radionuclides in the environment and lower trophic levels, comparisons are made to the preoperational data to determine if there are any biological or physical compartments in nature that are accumulating radioactivity. Similarly, external radioactivity measurements during plant operation are compared with the average and range of data obtained in the preoperational program.

If radionuclides due to plant effluents are found in foodstuffs, estimates of radiation dose are made that utilize the best estimates of food consumption. These dose calculations are compared with those based on plant emission data with the appropriate meteorological and aquatic dispersion models as discussed in Section 11.6.2.

The data from the offsite monitoring program are reported annually. The reports include the basic data on sampling locations, organism collected, counting data, gross activity levels, identification of gamma emitting isotopes, and the associated counting errors. Tables 11.6-13 and 11.6-14 tabulate estimated concentrations and depositions based on the monitoring program.

11.6.6 PROGRAM STATISTICAL SENSITIVITY

The activity in environmental samples is expected to be low after dilution and dispersion of radionuclides released by the power plant. For many isotopes, the radioactivity will be below the lower limits of detection (LLD) that are listed in Table 11.6-11. Doses calculated from environmental measurements at the LLD will demonstrate doses below 5 millirem per year. With dose estimated from effluent data as shown in Sections 11.2 and 11.3, much lower dose levels can be estimated even though large errors may be introduced in the dispersion modeling. Thus, doses estimated using effluent data will provide a more detailed definition of the dose increments due to the operation of DCPP than will dose estimates calculated from the environmental measurements.

Counting errors for effluent data and errors associated with the calculational models will be used to determine the overall sensitivity of estimated dose. Where dose calculations

are based on environmental data, errors in the environmental sample analysis will be included in the overall program sensitivity analysis.

11.6.7 REFERENCES

1. 1984 Annual Environmental Radiological Report, Diablo Canyon Power Plant, Pacific Gas and Electric Company, San Ramon, CA, Report 411-85.123, 1985.

2. Deleted in Revision 1.

3. Deleted in Revision 1.

4. Deleted in Revision 1.

5. Deleted in Revision 1.

6. Technical Specifications, Diablo Canyon Power Plant Units 1 and 2, Appendix A to License Nos. DPR-80 and DPR-82, as amended.

7. Regulatory Guide 1.109, Revision 1, Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I, USNRC, October 1977.

8. Preoperational Radiological Environmental Report, Diablo Canyon Power Plant, Pacific Gas and Electric Company, San Ramon, CA, Report 411-84.530, 1985.

TABLE 11.1-1

LIBRARY OF PHYSICAL DATA FOR ISOTOPES

Number	Nuclide	Half-life, hours	Yield Fract	Beta Energy, MeV/Dis	Gamma Energy, MeV/Dis	Decay Const., hr^{-1}
1	H-3	0.108E 06	0.800E-04	0.00620	0.0	0.642E-05
2	Cr-51	0.667E 03	0.0	0.00055	0.02900	0.104E-02
3	Mn-54	0.727E 04	0.0	0.00590	0.83500	0.953E-04
4	Fe-55	0.648E 02	0.0	0.0	0.00600	0.107E-01
5	Co-58	0.171E 04	0.0	0.03100	0.98100	0.405E-03
6	Fe-59	0.108E 04	0.0	0.12900	1.17000	0.642E-03
7	Co-60	0.461E 05	0.0	0.10400	2.49000	0.150E-04
8	Kr-83M	0.186E 01	0.470E-02	0.03900	0.00050	0.373E 00
9	Kr-85M	0.440E 01	0.103E-01	0.25200	0.16000	0.157E 00
10	Kr-85	0.941E 05	0.0	0.22100	0.00200	0.736E-05
11	Kr-87	0.127E 01	0.194E-01	1.34000	0.76400	0.546E 00
12	Kr-88	0.277E 01	0.279E-01	0.37200	2.03000	0.250E 00
13	Sr-89	0.123E 04	0.369E-01	0.55600	0.0	0.563E-03
14	Sr-90	0.245E 06	0.455E-01	0.16900	0.0	0.283E-05
15	Y-90	0.639E 02	0.0	0.91200	0.0	0.208E-01
16	Sr-91	0.972E 01	0.461E-01	0.62400	0.84000	0.713E-01
17	Y-91	0.147E 04	0.120E-02	0.59300	0.00400	0.471E-03
18	Sr-92	0.270E 01	0.453E-01	0.21400	1.29000	0.257E 00
19	Y-92	0.360E 01	0.390E-02	1.39000	0.48500	0.192E 00
20	Zr-95	0.157E 04	0.585E-01	0.11100	0.73900	0.441E-03
21	Nb-95	0.841E 03	0.136E-02	0.04500	0.76000	0.824E-03
22	Mo-99	0.680E 02	0.607E-01	0.40500	0.12600	0.102E-01
23	I-131	0.193E 03	0.319E-01	0.18300	0.39200	0.359E-02
24	Te-132	0.779E 02	0.464E-01	0.06100	0.23100	0.890E-02
25	I-132	0.240E 01	0.530E-03	0.48500	2.28000	0.289E 00
26	I-133	0.210E 02	0.620E-01	0.49300	0.62400	0.330E-01
27	Xe-133M	0.552E 02	0.0	0.20700	0.02100	0.126E-01
28	Xe-133	0.127E 03	0.0	0.15500	0.04500	0.546E-02
29	Cs-134	0.180E 05	0.410E-04	0.16800	1.57000	0.385E-04
30	I-134	0.866E 00	0.764E-01	0.94100	2.58000	0.800E 00
31	I-135	0.670E 01	0.600E-01	0.31600	1.56000	0.103E 00
32	Xe-135M	0.260E 00	0.0	0.10400	0.42100	0.267E 01
33	Xe-135	0.920E 01	0.313E-02	0.30400	0.26200	0.753E-01
34	Cs-136	0.312E 03	0.377E-03	0.11900	2.21000	0.222E-02
35	Cs-137	0.236E 06	0.633E-01	0.17300	0.56200	0.294E-05
36	Xe-138	0.233E 00	0.558E-01	0.5900	1.28000	0.297E 01
37	Ba-140	0.307E 03	0.596E-01	0.27400	0.21200	0.226E-02
38	La-140	0.401E 02	0.103E-02	0.43900	2.31000	0.173E-01
39	Ce-144	0.685E 04	0.485E-01	0.09300	0.01600	0.101E-03
40	Pr-144	0.292E 00	0.0	1.20000	0.06400	0.237E 01

TABLE 11.1-2

BASIC ASSUMPTIONS FOR CORE
AND COOLANT INVENTORIES FOR DESIGN BASIS CASE

Reactor core thermal power, mw	3568.0
Duration of cycle, hr	8760.0
Capacity factor during period	0.800
Number of fissions per megawatt-second	0.315E17
Total mass of uranium in core, lb	1.97E5
Total mass of plutonium in core, lb	6.05E2
Reload uranium enrichment, percent	3.18
Reload mass of fissile plutonium, lb	0.0
Primary-to-secondary leakrate, gpm	0.0
Primary coolant leakage to containment, gpm	0.0
Primary coolant leakage to auxiliary building, gpm	0.0
Fraction of fuel with defective cladding	0.01
Weight of water in primary system, lb	5.66E5
Volume of water in primary system, gal.	9.40E4
Letdown flowrate, gpm	75.0
Capacity factor of primary cation demineralizer	0.1
Average shim bleed flowrate, gpm	1.0
Fraction of shim bleed flow discharged to environment	0.667

TABLE 11.1-3

BASIC ASSUMPTIONS FOR CORE AND COOLANT INVENTORIES FOR NORMAL OPERATION CASE

Reactor core thermal power, mw	3568.0
Duration of cycle, hr	8760.0
Capacity factor during period	0.800
Number of fissions per megawatt-second	0.315E17
Total mass of uranium in core, lb	1.97E5
Total mass of plutonium in core, lb	6.05E2
Reload uranium enrichment, percent	3.18
Reload mass of fissile plutonium, lb	0.0
Primary-to-secondary leakrate, gpm	0.0115
Primary coolant leakage to containment, gpm	0.0385
Primary coolant leakage to auxiliary building, gpm	0.0184
Fraction of fuel with defective cladding	0.0012
Weight of water in primary system, lb	5.66E5
Volume of water in primary system, gal.	9.40E4
Letdown flowrate, gpm	75.0
Capacity factor of primary cation demineralizer	0.1
Average shim bleed flowrate, gpm	1.0
Fraction of shim bleed flow discharged to environment	0.667

TABLE 11.1-4

CORE ACTIVITY INVENTORIES FOR DESIGN BASIS CASE (CURIES)

Nuclide	Initial Act.	Produced	Decayed	Lkge to Coolt.	Inventory	Equil Inven.	Curies/Megawatt
Cr-51	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mn-54	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fe-55	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Co-58	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fe-59	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Co-60	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kr-83M	0.0	0.4660E 11	0.4658E 11	0.2340E 06	0.1428E 08	0.1428E 08	0.4001E 04
Kr-85M	0.0	0.4317E 11	0.4314E 11	0.5127E 06	0.3129E 08	0.3129E 08	0.8769E 04
Kr-85	0.4007E 06	0.4639E 06	0.3932E 05	0.1249E 05	0.8128E 06	0.5461E 07	0.2278E 03
Kr-87	0.0	0.2817E 12	0.2816E 12	0.9662E 06	0.5893E 08	0.5893E 08	0.1652E 05
Kr-88	0.0	0.1857E 12	0.1856E 12	0.1389E 07	0.8475E 08	0.8475E 08	0.2375E 05
Sr-89	0.4946E 06	0.5532E 09	0.4910E 09	0.2510E 03	0.1116E 09	0.1121E 09	0.3129E 05
Sr-90	0.3073E 07	0.3425E 07	0.1173E 06	0.1194E 02	0.6380E 07	0.1382E 09	0.1786E 04
Y-90	0.3073E 07	0.4497E 09	0.4464E 09	0.1897E 01	0.6346E 07	0.1382E 09	0.1779E 04
Sr-91	0.4745E-14	0.8746E 11	0.8732E 11	0.3527E 03	0.1400E 09	0.1400E 09	0.3925E 05
Y-91	0.6767E 08	0.5924E 09	0.5177E 09	0.5060E 02	0.1424E 09	0.1437E 09	0.3992E 05
Sr-92	0.0	0.3094E 12	0.3093E 12	0.3470E 03	0.1376E 09	0.1376E 09	0.3857E 05
Y-92	0.0	0.2519E 12	0.2518E 12	0.6027E 02	0.1495E 09	0.1495E 09	0.4189E 05
Zr-95	0.8460E 08	0.6871E 09	0.5960E 09	0.6221E 02	0.1758E 09	0.1777E 09	0.4926E 05
Nb-95	0.1083E 09	0.1142E 10	0.1073E 10	0.6000E 02	0.1777E 09	0.1818E 09	0.4981E 05
Mo-99	0.8000E 05	0.1646E 11	0.1628E 11	0.9199E 05	0.1844E 09	0.1844E 09	0.5168E 05
I-131	0.4937E 07	0.3048E 10	0.2956E 10	0.3082E 06	0.9689E 08	0.9689E 08	0.2715E 05
Te-132	0.1553E 06	0.1098E 11	0.1084E 11	0.3510E 05	0.1409E 09	0.1409E 09	0.3950E 05
I-132	0.1602E 06	0.3560E 12	0.3559E 12	0.4614E 06	0.1426E 09	0.1426E 09	0.3995E 05
I-133	0.6024E-02	0.5444E 11	0.5425E 11	0.6155E 06	0.1883E 09	0.1883E 09	0.5278E 05
Xe-133M	0.1593E 04	0.4954E 09	0.4908E 09	0.7318E 05	0.4519E 07	0.4519E 07	0.1267E 04
Xe-133	0.3309E 07	0.8969E 10	0.8780E 10	0.3012E 07	0.1882E 09	0.1882E 09	0.5276E 05
Cs-134	0.1460E 01	0.3605E 07	0.1284E 07	0.1248E 05	0.3116E 07	0.3116E 07	0.8734E 03
I-134	0.0	0.1627E 13	0.1627E 13	0.7610E 06	0.2321E 09	0.2321E 09	0.6504E 05
I-135	0.0	0.1651E 12	0.1650E 12	0.5971E 06	0.1823E 09	0.1823E 09	0.5108E 05
Xe-135M	0.0	0.6164E 12	0.6163E 12	0.4329E 06	0.2643E 08	0.2643E 08	0.7407E 04
Xe-135	0.9747E-15	0.1264E 12	0.1838E 11	0.4567E 06	0.2789E 08	0.2789E 08	0.7816E 04
Cs-136	0.1542E 06	0.7228E 08	0.2129E 08	0.3588E 04	0.1145E 07	0.1145E 07	0.3209E 03
Cs-137	0.4430E 07	0.4946E 07	0.1753E 06	0.2235E 05	0.9173E 07	0.1658E 09	0.2571E 04
Xe-138	0.0	0.4416E 13	0.4416E 13	0.2779E 07	0.1695E 09	0.1695E 09	0.4751E 05
Ba-140	0.2375E 08	0.3580E 10	0.3423E 10	0.4367E 03	0.1810E 09	0.1610E 09	0.5074E 05
La-140	0.2732E 08	0.2668E 11	0.2652E 11	0.7071E 02	0.1642E 09	0.1842E 09	0.5162E 05
Ce-144	0.6129E 08	0.1306E 09	0.7999E 08	0.3644E 02	0.1119E 09	0.1473E 09	0.3135E 05
Pr-144	0.6127E 08	0.1877E 13	0.1876E 13	0.3643E 02	0.1119E 09	0.1473E 09	0.3135E 05

TABLE 11.1-5

CORE ACTIVITY INVENTORIES FOR NORMAL OPERATION CASE (CURIES)

Nuclide	Initial Act.	Produced	Decayed	Lkge to Coolt.	Inventory	Equil Inven.	Curies/Megawatt
Cr-51	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mn-54	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fe-55	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Co-58	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fe-59	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Co-60	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kr-83M	0.0	0.4660E 11	0.4658E 11	0.2809E 05	0.1428E 08	0.1428E 08	0.4001E 04
Kr-85M	0.0	0.4317E 11	0.4314E 11	0.6152E 05	0.3129E 08	0.3129E 08	0.8769E 04
Kr-85	0.4007E 06	0.4639E 06	0.3963E 05	0.1511E 04	0.8235E 06	0.6932E 07	0.2308E 03
Kr-87	0.0	0.2817E 12	0.2816E 12	0.1159E 06	0.5893E 08	0.5893E 08	0.1652E 05
Kr-88	0.0	0.1857E 12	0.1857E 12	0.1667E 06	0.8475E 08	0.8475E 08	0.2375E 05
Sr-89	0.4946E 08	0.5532E 09	0.4910E 09	0.3012E 02	0.1116E 09	0.1121E 09	0.3129E 05
Sr-90	0.3073E 07	0.3425E 07	0.1173E 06	0.1433E 01	0.6380E 07	0.1382E 09	0.1788E 04
Y-90	0.3073E 07	0.4497E 09	0.4465E 09	0.2276E 00	0.6346E 07	0.1382E 09	0.1779E 04
Sr-91	0.4745E-14	0.8746E 11	0.8732E 11	0.4233E 02	0.1400E 09	0.1400E 09	0.3925E 05
Y-91	0.6767E08	0.5924E 09	0.5177E 09	0.6072E 01	0.1424E 09	0.1437E 09	0.3992E 05
Sr-92	0.0	0.3094E 12	0.3093E 12	0.4164E 02	0.1376E 09	0.1376E 09	0.3857E 05
Y-92	0.0	0.2519E 12	0.2518E 12	0.7232E 01	0.1495E 09	0.1495E 09	0.4189E 05
Zr-95	0.8460E 08	0.6871E 09	0.5960E 09	0.7466E 01	0.1758E 09	0.1777E 09	0.4926E 05
Nb-95	0.1083E 09	0.1142E 10	0.1073E 10	0.7200E 01	0.1777E 09	0.1818E 09	0.4981E 05
Mo-99	0.8000E 05	0.1646E 11	0.1628E 11	0.1104E 05	0.1844E 09	0.1844E 09	0.5168E 05
I-131	0.4937E 07	0.3048E 10	0.2956E 10	0.3699E 05	0.9690E 08	0.9690E 08	0.2716E 05
Te-132	0.1553E 06	0.1098E 11	0.1084E 11	0.4212E 04	0.1409E 09	0.1409E 09	0.3950E 05
I-132	0.1602E 06	0.3560E 12	0.3559E 12	0.5537E 05	0.1426E 09	0.1426E 09	0.3995E 05
I-133	0.6024E 02	0.5444E 11	0.5425E 11	0.7387E 05	0.1883E 09	0.1883E 09	0.5278E 05
Xe-133M	0.1593E 04	0.4954E 09	0.4908E 09	0.8783E 04	0.4520E 07	0.4520E 07	0.1267E 04
Xe-133	0.3309E 07	0.8969E 10	0.8784E 10	0.3616E 06	0.1883E 09	0.1883E 09	0.5278E 05
Cs-134	0.1460E 01	0.3605E 07	0.1298E 07	0.1514E 04	0.3121E 07	0.3121E 07	0.8749E 03
I-134	0.0	0.1627E 13	0.1627E 13	0.9132E 05	0.2321E 09	0.2321E 09	0.6504E 05
I-135	0.0	0.1651E 12	0.1650E 12	0.7165E 05	0.1823E 09	0.1823E 09	0.5108E 05
Xe-135M	0.0	0.6164E 12	0.6163E 12	0.5195E 05	0.2643E 08	0.2643E 08	0.7407E 04
Xe-135	0.9747E-15	0.1264E 12	0.1838E 11	0.5481E 05	0.2789E 08	0.2789E 08	0.7816E 04
Cs-136	0.1542E 06	0.2228E 08	0.2129E 08	0.4307E 03	0.1145E 07	0.1145E 07	0.3210E 03
Cs-137	0.4430E 07	0.4946E 07	0.1755E 06	0.2686E 04	0.9197E 07	0.1887E 09	0.2578E 04
Xe-138	0.0	0.4416E 13	0.4416E 13	0.3335E 06	0.1695E 09	0.1695E 09	0.4751E 05
Ba-140	0.2375E 08	0.3580E 10	0.3423E 10	0.5240E 02	0.1810E 09	0.1810E 09	0.5074E 05
La-140	0.2732E 08	0.2668E 11	0.2652E 11	0.8486E 01	0.1842E 09	0.1842E 09	0.5162E 05
Ce-144	0.6129E 08	0.1306E 09	0.7999E 08	0.4372E 01	0.1119E 09	0.1473E 09	0.3135E 05
Pr-144	0.6127E 08	0.1877E 13	0.1876E 13	0.4372E 01	0.1119E 09	0.1473E 09	0.3135E 05

TABLE 11.1-6

BASIC ASSUMPTIONS FOR FUEL ROD GAP INVENTORIES

Percent of Core Fuel Within Given Temperature Range[a]	Power, MWt	Fuel Temperature Range, °F
0.0	0.1961	>3400
0.1	3.1373	3400 - 3200
0.3	10.3922	3200 - 3000
0.7	25.1	3000 - 2800
1.6	58.333	2800 - 2600
2.9	104.61	2600 - 2400
4.3	152.55	2400 - 2200
5.9	211.275	2200 - 2000
84.1	2999.02	<2000

(a) Based on hot channel factors of F_H = 1.70 and F_q = 2.82.

TABLE 11.1-7

ACTIVITY IN FUEL ROD GAPS

Nuclide	Pellet Release Fraction	Gap Inventory, Ci
Kr-83M	0.000824	0.118E 05
Kr-85M	0.001240	0.388E 05
Kr-85	0.167000	0.138E 06
Kr-87	0.000668	0.394E 05
Kr-88	0.000998	0.846E 05
I-131	0.008220	0.797E 06
I-132	0.000901	0.128E 06
I-133	0.002710	0.510E 06
Xe-133M	0.004370	0.198E 05
Xe-133	0.006670	0.126E 07
I-134	0.000557	0.129E 06
I-135	0.001540	0.281E 06
Xe-135M	0.000303	0.801E 04
Xe-135	0.001800	0.502E 05
Xe-138	0.000316	0.536E 05

TABLE 11.1-8

INPUT CONSTANTS FOR COOLANT ACTIVITIES FOR DESIGN BASIS CASE

Nuclide	Fuel to Coolant, Ci/hr	Fuel Escape Rate, sec^{-1}	Pur. Rate, hr^{-1}	P-S Leak Rate, hr^{-1}	Prim-Cont Lk Rate, hr^{-1}	Prim-Aux Lk Rate hr^{-1}
H-3	0.0	0.0	0.5897E-03	0.0	0.0	0.0
Cr-51	0.3010E-01	0.0	0.6034E-01	0.0	0.0	0.0
Mn-54	0.4820E-02	0.0	0.6034E-01	0.0	0.0	0.0
Fe-55	0.2890E-01	0.0	0.6034E-01	0.0	0.0	0.0
Co-58	0.2500E 00	0.0	0.6034E-01	0.0	0.0	0.0
Fe-59	0.1570E-01	0.0	0.6034E-01	0.0	0.0	0.0
Co-60	0.3090E-01	0.0	0.6034E-01	0.0	0.0	0.0
Kr-83M	0.3340E 02	0.6500E-07	0.8840E-03	0.0	0.0	0.0
Kr-85M	0.7316E 02	0.6500E-07	0.8840E-03	0.0	0.0	0.0
Kr-85	0.1426E 01	0.6500E-07	0.8840E-03	0.0	0.0	0.0
Kr-87	0.1379E 03	0.6500E-07	0.8840E-03	0.0	0.0	0.0
Kr-88	0.1982E 03	0.6500E-07	0.8840E-03	0.0	0.0	0.0
Sr-89	0.3582E-01	0.1000E-10	0.6034E-01	0.0	0.0	0.0
Sr-90	0.1704E-02	0.1000E-10	0.6034E-01	0.0	0.0	0.0
Y-90	0.2707E-03	0.1600E-11	0.8840E-03	0.0	0.0	0.0
Sr-91	0.5033E-01	0.1000E-10	0.6034E-01	0.0	0.0	0.0
Y-91	0.7220E-02	0.1600E-11	0.8840E-03	0.0	0.0	0.0
Sr-92	0.4952E-01	0.1000E-10	0.6034E-01	0.0	0.0	0.0
Y-92	0.8600E-02	0.1600E-11	0.8840E-03	0.0	0.0	0.0
Zr-95	0.8878E-02	0.1600E-11	0.6034E-01	0.0	0.0	0.0
Nb-95	0.8562E-02	0.1600E-11	0.6034E-01	0.0	0.0	0.0
Mo-99	0.1313E 02	0.2000E-08	0.8840E-03	0.0	0.0	0.0
I-131	0.4398E 02	0.1300E-07	0.5976E-01	0.0	0.0	0.0
Te-132	0.5009E 01	0.1000E-08	0.5976E-01	0.0	0.0	0.0
I-132	0.6584E 02	0.1300E-07	0.5976E-01	0.0	0.0	0.0
I-133	0.8783E 02	0.1300E-07	0.5576E-01	0.0	0.0	0.0
Xe-133M	0.1044E 02	0.6500E-07	0.8840E-03	0.0	0.0	0.0
Xe-133	0.4298E 03	0.6500E-07	0.8840E-03	0.0	0.0	0.0
Cs-134	0.1781E 01	0.1300E-07	0.3637E-01	0.0	0.0	0.0
I-134	0.1086E 03	0.1300E-07	0.5976E-01	0.0	0.0	0.0
I-135	0.8520E 02	0.1300E-07	0.5976E-01	0.0	0.0	0.0
Xe-135M	0.6177E 02	0.6500E-07	0.8840E-03	0.0	0.0	0.0
Xe-135	0.6517E 02	0.6500E-07	0.8840E-03	0.0	0.0	0.0
Cs-136	0.5120E 00	0.1300E-07	0.3637E-01	0.0	0.0	0.0
Cs-137	0.3189E 01	0.1300E-07	0.3637E-01	0.0	0.0	0.0
Xe-138	0.3988E 03	0.6500E-07	0.8840E-01	0.0	0.0	0.0
Ba-140	0.8231E-01	0.1000E-10	0.6034E-01	0.0	0.0	0.0
La-140	0.1009E-01	0.1000E-11	0.6034E-01	0.0	0.0	0.0
Ce-144	0.5199E-02	0.1600E-11	0.6034E-01	0.0	0.0	0.0
Pr-144	0.5199E-02	0.1600E-11	0.6034E-01	0.0	0.0	0.0

TABLE 11.1-9

INPUT CONSTANTS FOR COOLANT ACTIVITIES FOR NORMAL OPERATION CASE

Nuclide	Fuel to Coolant, Ci/hr	Fuel Escape Rate, sec^{-1}	Pur. Rate, hr^{-1}	P-S Leak Rate, hr^{-1}	Prim-Cont Lk Rate, hr^{-1}	Prim-Aux Lk Rate hr^{-1}
H-3	0.0	0.0	0.5897E-03	0.7340E-05	0.2457E-04	0.1174E-04
Cr-51	0.3010E-01	0.0	0.6034E-01	0.7340E-05	0.2457E-04	0.1174E-04
Mn-54	0.4820E-02	0.0	0.6034E-01	0.7340E-05	0.2457E-04	0.1174E-04
Fe-55	0.2890E-01	0.0	0.6034E-01	0.7340E-05	0.2457E-04	0.1174E-04
Co-58	0.2500E 00	0.0	0.6034E-01	0.7340E-05	0.2457E-04	0.1174E-04
Fe-59	0.1570E-01	0.0	0.6034E-01	0.7340E-05	0.2457E-04	0.1174E-04
Co-60	0.3090E-01	0.0	0.6034E-01	0.7340E-05	0.2457E-04	0.1174E-04
Kr-83M	0.4008E 01	0.6500E-07	0.8840E-03	0.7340E-05	0.4167E-03	0.1174E-04
Kr-85M	0.8779E 01	0.6500E-07	0.8840E-03	0.7340E-05	0.4167E-03	0.1174E-04
Kr-85	0.1725E 00	0.6500E-07	0.8840E-03	0.73403-05	0.4167E-03	0.1174E-04
Kr-87	0.1854E 02	0.6500E-07	0.8840E-03	0.7340E-05	0.4167E-03	0.1174E-04
Kr-88	0.2379E 02	0.6500E-07	0.8840E-03	0.7340E-05	0.4167E-03	0.1174E-04
Sr-89	0.4298E-02	0.1000E-10	0.6034E-01	0.7340E-05	0.2457E-04	0.1174E-04
Sr-90	0.2045E-03	0.1000E-10	0.6034E-01	0.7340E-05	0.2457E-04	0.1174E-04
Y-90	0.3248E-04	0.1600E-11	0.8840E-03	0.7340E-05	0.2457E-04	0.1174E-04
Sr-91	0.6040E-02	0.1000E-10	0.6034E-01	0.7340E-05	0.2457E-04	0.1174E-04
Y-91	0.8664E-03	0.1600E-11	0.8840E-03	0.7340E-05	0.2457E-04	0.1174E-04
Sr-92	0.5942E-02	0.1000E-10	0.6034E-01	0.7340E-05	0.2457E-04	0.1174E-04
Y-92	0.1032E-02	0.1600E-11	0.8840E-03	0.7340E-05	0.2457E-04	0.1174E-04
Zr-95	0.1065E-02	0.1600E-11	0.6034E-01	0.7340E-05	0.2457E-04	0.1174E-04
Mb-95	0.1027E-02	0.1600E-11	0.6034E-01	0.7340E-05	0.2457E-04	0.1174E-04
Mb-99	0.1575E 01	0.2000E-08	0.8840E-03	0.7340E-05	0.2457E-04	0.1174E-04
I-131	0.5278E 01	0.1300E-07	0.5976E-01	0.7340E-05	0.2457E-04	0.1174E-04
Te-132	0.6011E 00	0.1000E-08	0.5976E-01	0.7340E-05	0.2457E-04	0.1174E-04
I-132	0.7901E 01	0.1300E-07	0.5976E-01	0.7340E-05	0.2457E-04	0.1174E-04
I-133	0.1054E 02	0.1300E-07	0.5976E-01	0.7340E-05	0.2457E-04	0.1174E-04
Me-133M	0.1253E 01	0.6500E-07	0.8840E-03	0.7340E-05	0.4167E-03	0.1174E-04
Mn-133	0.5160E 02	0.6500E-07	0.8840E-03	0.7340E-05	0.4167E-03	0.1174E-04
Cs-134	0.2161E 00	0.1300E-07	0.3637E-01	0.7340E-05	0.2457E-04	0.1174E-04
I-134	0.1303E 02	0.1300E-07	0.5976E-01	0.7340E-05	0.2457E-04	0.1174E-04
I-135	0.1022E 02	0.1300E-07	0.5976E-01	0.7340E-05	0.2457E-04	0.1174E-04
Xe-135M	0.7412E 01	0.6500E-07	0.8840E-03	0.7340E-05	0.4167E-03	0.1174E-04
Xe-135	0.7821E 01	0.6500E-07	0.8840E-03	0.7340E-05	0.4167E-03	0.1174E-04
Cs-136	0.6145E-01	0.1300E-07	0.3637E-01	0.7340E-05	0.2457E-04	0.1174E-04
Cs-137	0.3832E 00	0.1300E-07	0.3637E-01	0.7340E-05	0.2457E-04	0.1174E-04
Xe-138	0.4759E 02	0.6500E-07	0.8840E-03	0.7340E-05	0.4167E-03	0.1174E-04
Ba-140	0.7477E-02	0.1000E-10	0.6034E-01	0.7340E-05	0.2457E-04	0.1174E-04
La-140	0.1211E-02	0.1600E-11	0.6034E 01	0.73403-05	0.2457E-04	0.1174E-04
Ce-144	0.6239E-03	0.1600E-11	0.6034E-01	0.7340E-05	0.2457E-04	0.1174E-04
Pr-144	0.6239E-03	0.1600E-11	0.6034E-01	0.7340E-05	0.2457E-04	0.1174E-04

TABLE 11.1-10

BASIC DATA FOR CORROSION PRODUCT ACTIVITIES

Core Wetted Areas, Effective, in^2	
Zirconium	9.42×10^6
Stainless steel	6.09×10^5
Inconel	1.01×10^6
Out-of-core Wetted Area, Inconel, in^2	2.74×10^7
Coolant velocity, ft/sec	
Core	15.0
Steam generator	18.6
Nominal Base Metal Release Rates, mg/dm^2-mo	
Zirconium	0.0
Stainless steel	0.5
Inconel	1.0
Coolant Crud Level, ppm	0.1
Permanent Crud Film, Nominal, mg/dm^2	
Incore	50
Out-of-core	50
Transient Crud Layer, Nominal, mg/dm^2	
Incore	50
Out-of-core	50
Total mass of metal in contact with primary coolant, lb	2.2×10^6

TABLE 11.1-11

PRIMARY COOLANT ACTIVITIES FOR DESIGN BASIS CASE

Nuclide	Concentration, μCi/cc	Activity, Ci
H-3	0.7934E 00	0.2823E 03
Cr-51	0.1378E-02	0.4904E 00
Mn-54	0.2241E-03	0.7976E-01
Fe-55	0.1143E-02	0.4069E 00
Co-58	0.2600E-01	0.9250E-01
Fe-59	0.7236E-03	0.2575E 00
Co-60	0.1439E-02	0.5120E 00
Kr-83M	0.2513E 00	0.8943E 02
Kr-85M	0.1298E 01	0.4619E 03
Kr-85	0.4166E 01	0.1482E 04
Kr-87	0.7089E 00	0.2522E 03
Kr-88	0.2219E 01	0.7895E 03
Sr-89	0.1653E-02	0.5881E 00
Sr-90	0.7937E-04	0.2824E-01
Y-90	0.1382E-03	0.4919E-01
Sr-91	0.1075E-02	0.3824E 00
Y-91	0.1534E-01	0.5460E 01
Sr-92	0.4390E-03	0.1562E 00
Y-92	0.5619E-03	0.2000E 00
Zr-95	0.4105E-03	0.1461E 00
Nb-95	0.3989E-03	0.1420E 00
Mo-99	0.3331E 01	0.1185E 04
I-131	0.1951E 01	0.6941E 03
Te-132	0.2050E 00	0.7296E 02
I-132	0.7008E 00	0.2494E 03
I-133	0.2661E 01	0.9469E 03
Xe-133M	0.2243E 01	0.7983E 03
Xe-133	0.1947E 03	0.6927E 05
Cs-134	0.1375E 00	0.4893E 02
I-134	0.3549E 00	0.1263E 03
I-135	0.1467E 01	0.5221E 03
Xe-135M	0.2778E 00	0.9884E 02
Xe-135	0.3918E 01	0.1394E 04
Cs-136	0.3729E-01	0.1327E 02
Cs-137	0.2464E 00	0.8767E 02
Xe-138	0.3746E 00	0.1333E 03
Ba-140	0.2798E-02	0.9955E 00
La-140	0.9882E-03	0.3516E 00
Ce-144	0.2418E-03	0.8602E-01
Pr-144	0.2418E-03	0.8603E-01
Zn-65	0.8000E-02	0.2846E-01

TABLE 11.1-12

PRIMARY COOLANT ACTIVITIES FOR NORMAL OPERATION CASE

Nuclide	Concentration, µCi/cc	Activity, Ci
H-3	0.7377E 00	0.2625E 03
Cr-51	0.1377E-02	0.4901E 00
Mn-54	0.2240E-03	0.7970E-01
Fe-55	0.1143E-02	0.4066E 00
Co-58	0.1156E-01	0.4113E 01
Fe-59	0.7230E-03	0.2573E 00
Co-60	0.1438E-02	0.5116E 00
Kr-83M	0.3012E-01	0.1072E 02
Kr-85M	0.1553E 00	0.5528E 02
Kr-85	0.3579E 00	0.1273E 03
Kr-87	0.8500E-01	0.3025E 02
Kr-88	0.2658E 00	0.9458E 02
Sr-89	0.1982E-03	0.7052E-01
Sr-90	0.9517E-05	0.3387E-02
Y-90	0.1652E-04	0.5879E-02
Sr-91	0.1289E-03	0.4587E-01
Y-91	0.1784E-02	0.6347E 00
Sr-92	0.5267E-04	0.1874E-01
Y-92	0.6741E-04	0.2399E-01
Zr-95	0.4922E-04	0.1752E-01
Nb-95	0.4784E-04	0.1702E-01
Mo-99	0.3981E 00	0.1417E 03
I-131	0.2340E 00	0.8325E 02
Te-132	0.2459E-01	0.8749E 01
I-132	0.8408E-01	0.2992E 02
I-133	0.3192E 00	0.1136E 03
Xe-133M	0.2608E 00	0.9280E 02
Xe-133	0.2186E 02	0.7778E 04
Cs-134	0.1666E-01	0.5929E 01
I-134	0.4258E-01	0.1515E 02
I-135	0.1760E 00	0.6263E 02
Xe-135M	0.3332E-01	0.1186E 02
Xe-135	0.4674E 00	0.1663E 03
Cs-136	0.4470E-02	0.1591E 01
Cs-137	0.2958E-01	0.1052E 02
Xe-138	0.4495E-01	0.1599E 02
Ba-140	0.3355E-03	0.1194E 00
La-140	0.1185E-03	0.4215E-01
Ce-144	0.2899E-04	0.1032E-01
Pr-144	0.2899E-04	0.1032E-01

TABLE 11.1-13

REACTOR COOLANT NITROGEN-16 ACTIVITY

Location	Activity, µCi/cc
Core outlet	87
Reactor outlet nozzle	71
Steam generator inlet	67
Steam generator outlet	45
Reactor coolant pump inlet	43
Reactor coolant pump outlet	42
Reactor inlet nozzle	40
Core inlet	33

TABLE 11.1-14

DEPOSITED CORROSION PRODUCT ACTIVITY
IN STEAM GENERATOR

	Concentration, μCi/cm^2				
	Operating Time, months				
Isotope	0	6	12	24	36
Mn-54	1.0×10^{-5}	0.15	0.60	1.5	2.0
Mn-56	1.0×10^{-5}	3.3	3.3	3.3	3.3
Co-58	1.0×10^{-2}	4.5	10.2	11.0	11.0
Fe-59	1.0×10^{-4}	1.4	3.0	3.0	3.0
Co-60	1.0×10^{-3}	0.20	0.80	2.0	3.5

TABLE 11.1-15

DEMINERALIZER AND EVAPORATOR DECONTAMINATION FACTORS

Nuclide	Primary Mxd Bed	Primary Cation	Letdown Mxd Bed	Letdown Cation	Letdown Anion	BA Evap Feed Ion Exchangers[b]	Waste Mxd. Beds[a]
H-3	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 00
Cr-51	1.000E 01	1.000E 02	1.000E 02	1.000E 02	1.000E 00	1.000E 03	1.000E 03
Mn-54	1.000E 01	1.000E 02	1.000E 02	1.000E 02	1.000E 00	1.000E 03	1.000E 03
Fe-55	1.000E 01	1.000E 02	1.000E 02	1.000E 02	1.000E 00	1.000E 03	1.000E 03
Co-58	1.000E 01	1.000E 02	1.000E 02	1.000E 02	1.000E 00	1.000E 03	1.000E 03
Fe-59	1.000E 01	1.000E 02	1.000E 02	1.000E 02	1.000E 00	1.000E 03	1.000E 03
Co-60	1.000E 01	1.000E 02	1.000E 02	1.000E 02	1.000E 00	1.000E 03	1.000E 03
Kr-83M	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 00
Kr-85M	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 00
Kr-85	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 00
Kr-87	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 00
Kr-88	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 00
Sr-89	1.000E 01	1.000E 02	1.000E 02	1.000E 02	1.000E 00	1.000E 03	1.000E 03
Sr-90	1.000E 01	1.000E 02	1.000E 02	1.000E 02	1.000E 00	1.000E 03	1.000E 03
Y-90	1.000E 00	1.000E 00	1.000E 01	1.000E 00	1.000E 00	1.000E 03	1.000E 03
Sr-91	1.000E 01	1.000E 02	1.000E 02	1.000E 02	1.000E 00	1.000E 03	1.000E 03
Y-91	1.000E 00	1.000E 00	1.000E 01	1.000E 00	1.000E 00	1.000E 03	1.000E 03
Sr-92	1.000E 01	1.000E 02	1.000E 02	1.000E 02	1.000E 00	1.000E 03	1.000E 03
Y-92	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 03	1.000E 03
Zr-95	1.000E 01	1.000E 02	1.000E 02	1.000E 02	1.000E 00	1.000E 03	1.000E 03
Nb-95	1.000E 01	1.000E 02	1.000E 02	1.000E 02	1.000E 00	1.000E 03	1.000E 03
Mo-99	1.000E 00	1.000E 00	1.000E 02	1.000E 00	1.000E 00	1.000E 03	1.000E 03
I-131	1.000E 01	1.000E 00	1.000E 02	1.000E 00	1.000E 02	1.000E 02	1.000E 03
Te-132	1.000E 01	1.000E 00	1.000E 02	1.000E 00	1.000E 02	1.000E 03	1.000E 03
I-132	1.000E 01	1.000E 00	1.000E 02	1.000E 00	1.000E 02	1.000E 02	1.000E 03
I-133	1.000E 01	1.000E 00	1.000E 02	1.000E 00	1.000E 02	1.000E 02	1.000E 03
Xe-133M	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 00
Xe-133	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 00
Cs-134	2.000E 00	1.000E 01	2.000E 00	1.000E 01	1.000E 00	1.000E 03	2.000E 01
I-134	1.000E 01	1.000E 00	1.000E 02	1.000E 00	1.000E 02	1.000E 02	1.000E 03
I-135	1.000E 01	1.000E 00	1.000E 02	1.000E 00	1.000E 02	1.000E 02	1.000E 03
Xe-135M	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 00
Xe-135	1.000E 00	1.000E00	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 00
Cs-136	2.000E 00	1.000E 01	2.000E 00	1.000E 01	1.000E 00	1.000E 03	2.000E 01
Cs-137	2.000E 00	1.000E 01	2.000E 00	1.000E 01	1.000E 00	1.000E 03	2.000E 01
Xe-138	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 00	1.000E 00
Ba-140	1.000E 01	1.000E 02	1.000E 02	1.000E 02	1.000E 00	1.000E 03	1.000E 03
La-140	1.000E 01	1.000E 02	1.000E 02	1.000E 02	1.000E 00	1.000E 03	1.000E 03
Ce-144	1.000E 01	1.000E 02	1.000E 02	1.000E 02	1.000E 00	1.000E 03	1.000E 03
Pr-144	1.000E 01	1.000E 02	1.000E 02	1.000E 02	1.000E 00	1.000E 03	1.000E 03

(a) Two waste mixed beds in series.
(b) Boric Acid Evaporator has been abandoned in place.

TABLE 11.1-16

PRODUCTION AND REMOVALS IN PRIMARY COOLANT FOR DESIGN BASIS CASE

Nuclide	Produced, Ci	Decayed, Ci	Cleaned Up, Ci	Lked to Sec, Ci	Lked to Cont, Ci	Lked to Aux, Ci
H-3	0.1642E 04	0.1463E 02	0.1345E 04	0.0	0.0	0.0
Cr-51	0.2637E 03	0.4455E 01	0.2070E 03	0.0	0.0	0.0
Mn-54	0.4222E 02	0.6647E-01	0.3366E 02	0.0	0.0	0.0
Fe-55	0.2532E 03	0.3805E 02	0.1718E 03	0.0	0.0	0.0
Co-58	0.2190E 04	0.1458E 02	0.1737E 04	0.0	0.0	0.0
Fe-59	0.1375E 03	0.1445E 01	0.1087E 03	0.0	0.0	0.0
Co-60	0.2707E 03	0.6729E-01	0.2161E 03	0.0	0.0	0.0
Kr-83M	0.2926E 06	0.2916E 06	0.5535E 03	0.0	0.0	0.0
Kr-85M	0.6409E 06	0.6359E 06	0.2855E 04	0.0	0.0	0.0
Kr-85	0.1250E 05	0.6654E 02	0.7987E 04	0.0	0.0	0.0
Kr-87	0.1208E 07	0.1205E 07	0.1562E 04	0.0	0.0	0.0
Kr-88	0.1736E 07	0.1728E 07	0.4885E 04	0.0	0.0	0.0
Sr-89	0.3138E 03	0.2897E 01	0.2482E 03	0.0	0.0	0.0
Sr-90	0.1493E 02	0.6984E-03	0.1192E 02	0.0	0.0	0.0
Y-90	0.5049E 01	0.4623E 01	0.3015E 00	0.0	0.0	0.0
Sr-91	0.4409E 03	0.2386E 03	0.1615E 03	0.0	0.0	0.0
Y-91	0.6483E 02	0.2065E 02	0.3098E 02	0.0	0.0	0.0
Sr-92	0.4338E 03	0.3511E 03	0.6602E 02	0.0	0.0	0.0
Y-92	0.3386E 03	0.3369E 03	0.1238E 01	0.0	0.0	0.0
Zr-95	0.7777E 02	0.5637E 00	0.6165E 02	0.0	0.0	0.0
Nb-95	0.7605E 02	0.1023E 01	0.5991E 02	0.0	0.0	0.0
Mo-99	0.1150E 06	0.1047E 06	0.7267E 04	0.0	0.0	0.0
I-131	0.3852E 06	0.2179E 05	0.2902E 06	0.0	0.0	0.0
Te-132	0.4388E 05	0.5676E 04	0.3050E 05	0.0	0.0	0.0
I-132	0.7610E 06	0.6303E 06	0.1044E 06	0.0	0.0	0.0
I-133	0.7694E 06	0.2734E 06	0.3961E 06	0.0	0.0	0.0
Xe-133M	0.9896E 05	0.8554E 05	0.4819E 04	0.0	0.0	0.0
Xe-133	0.3935E 07	0.3131E 07	0.4059E 06	0.0	0.0	0.0
Cs-134	0.1560E 05	0.1645E 02	0.1243E 05	0.0	0.0	0.0
I-134	0.9513E 06	0.8851E 06	0.5288E 05	0.0	0.0	0.0
I-135	0.7464E 06	0.4727E 06	0.2185E 06	0.0	0.0	0.0
Xe-135M	0.5840E 07	0.2304E 07	0.6113E 03	0.0	0.0	0.0
Xe-135	0.1519E 07	0.9150E 06	0.8591E 04	0.0	0.0	0.0
Cs-136	0.4485E 04	0.2574E 03	0.3372E 04	0.0	0.0	0.0
Cs-137	0.2793E 05	0.2248E 01	0.2227E 05	0.0	0.0	0.0
Xe-138	0.3474E 07	0.3473E 07	0.8258E 03	0.0	0.0	0.0
Ba-140	0.5458E 03	0.1965E 02	0.4202E 03	0.0	0.0	0.0
La-140	0.2388E 03	0.5309E 02	0.1483E 03	0.0	0.0	0.0
Ce-144	0.4554E 02	0.7609E-01	0.3631E 02	0.0	0.0	0.0
Pr-144	0.1831E 04	0.1785E 04	0.3631E 02	0.0	0.0	0.0

TABLE 11.1-17

PRODUCTION AND REMOVALS IN PRIMARY COOLANT FOR NORMAL OPERATION CASE

Nuclide	Produced, Ci	Decayed, Ci	Cleaned Up, Ci	Lked to Sec, Ci	Lked to Cont, Ci	Lked to Aux, Ci
H-3	0.1642E 04	0.1384E 02	0.1271E 04	0.1583E 02	0.5299E 02	0.2532E 02
Cr-51	0.2637E 03	0.4452E 01	0.2068E 03	0.2516E-01	0.8424E-01	0.4026E-01
Mn-54	0.4222E 02	0.6643E-01	0.3364E 02	0.4092E-02	0.1370E-01	0.6547E-02
Fe-55	0.2532E 03	0.3803E 02	0.1717E 03	0.2088E-01	0.6991E-01	0.3341E-01
Co-58	0.2190E 04	0.1457E 02	0.1736E 04	0.2112E 00	0.7070E 00	0.3379E 00
Fe-59	0.1375E 03	0.1443E 01	0.1086E 03	0.1321E-01	0.4423E-01	0.2114E-01
Co-60	0.2707E 03	0.6725E-01	0.2159E 03	0.2627E-01	0.8794E-01	0.4203E-01
Kr-83M	0.3511E 05	0.3495E 05	0.6634E 02	0.5509E 00	0.3127E 02	0.8814E 00
Kr-85M	0.7691E 05	0.7610E 05	0.3417E 03	0.2837E 01	0.1611E 03	0.4540E 01
Kr-85	0.1512E 04	0.6269E 01	0.7526E 03	0.6249E 01	0.3547E 03	0.9998E 01
Kr-87	0.1449E 06	0.1445E 06	0.1873E 03	0.1555E 01	0.8826E 02	0.2488E 01
Kr-88	0.2084E 06	0.2070E 06	0.5852E 03	0.4859E 01	0.2758E 03	0.7774E 01
Sr-89	0.3765E 02	0.3474E 00	0.2976E 02	0.3621E-02	0.1212E-01	0.5794E-02
Sr-90	0.1791E 01	0.8376E-04	0.1429E 01	0.1739E-03	0.5821E-03	0.2782E-03
Y-90	0.6057E 00	0.5525E 00	0.3603E-01	0.2992E-03	0.1002E-02	0.4787E-03
Sr-91	0.5291E 02	0.2862E 02	0.1938E 02	0.2357E-02	0.7892E-02	0.3772E-02
Y-91	0.7779E 01	0.2407E 01	0.3611E 01	0.2999E-01	0.1004E 00	0.4798E-01
Sr-92	0.5205E 02	0.4212E 02	0.7922E 01	0.9637E-03	0.3226E-02	0.1542E-02
Y-92	0.4063E 02	0.4041E 02	0.1485E 00	0.1233E-02	0.4127E-02	0.1973E-02
Zr-95	0.9332E 01	0.6760E-01	0.7392E 01	0.8993E-03	0.3011E-02	0.1439E-02
Nb-95	0.9126E 01	0.1226E 00	0.7184E 01	0.8740E-03	0.2926E-02	0.1398E-02
Mo-99	0.1380E 05	0.1252E 05	0.8687E 03	0.7213E 01	0.2415E 02	0.1154E 02
I-131	0.4623E 05	0.2614E 04	0.3480E 05	0.4275E 01	0.1431E 02	0.6840E 01
Te-132	0.5285E 04	0.6807E 03	0.3658E 04	0.4493E 00	0.1504E 01	0.7189E 00
I-132	0.9131E 05	0.7562E 05	0.1252E 05	0.1538E 01	0.5148E 01	0.2461E 01
I-133	0.9233E 05	0.3279E 05	0.4751E 05	0.5835E 01	0.1954E 02	0.9336E 01
Xe-133M	0.1188E 05	0.9952E 04	0.5607E 03	0.4655E 01	0.2643E 03	0.7448E 01
Xe-133	0.4722E 06	0.3629E 06	0.4574E 05	0.3798E 03	0.2156E 05	0.6077E 03
Cs-134	0.1093E 04	0.1993E 01	0.1506E 04	0.3040E 00	0.1018E 01	0.4865E 00
I-134	0.1142E 06	0.1062E 06	0.6345E 04	0.7793E 00	0.2609E 01	0.1247E 01
I-135	0.8958E 05	0.5671E 05	0.2621E 05	0.3220E 01	0.1078E 02	0.5152E 01
Xe-135M	0.7006E 06	0.2764E 06	0.7333E 02	0.6089E 00	0.3456E 02	0.9742E 00
Xe-135	0.1823E 06	0.1092E 06	0.1025E 04	0.8511E 01	0.4831E 03	0.1362E 02
Cs-136	0.5383E 03	0.3086E 02	0.4042E 03	0.8158E-01	0.2731E 00	0.1305E 00
Cs-137	0.3357E 04	0.2699E 00	0.2674E 04	0.5397E 00	0.1807E 01	0.8635E 00
Xe-138	0.4168E 06	0.4167E 06	0.9908E 02	0.8227E 00	0.4670E 02	0.1316E 01
Ba-140	0.6550E 02	0.2356E 01	0.5038E 02	0.6130E-02	0.2052E-01	0.9807E-02
La-140	0.2865E 02	0.6365E 01	0.1778E 02	0.2163E-02	0.7241E-02	0.3461E-02
Ce-144	0.5465E 01	0.9124E-02	0.4354E 01	0.5296E-03	0.1773E-02	0.8474E-03
Pr-144	0.2195E 03	0.2141E 03	0.4354E 01	0.5297E-03	0.1773E-02	0.8474E-03

TABLE 11.1-18

BASIC ASSUMPTIONS FOR PRESSURIZER ACTIVITIES

Pressurizer liquid volume, gal.	8080
Pressurizer vapor volume, gal.	5400
Flowrate, gpm	1
Stripping fraction for noble gases	1
Stripping fraction for other isotopes	0.0

TABLE 11.1-19

ACTIVITY IN PRESSURIZER FOR DESIGN BASIS CASE

Liquid Phase

Nuclide	Activity, Ci	Concent, µCi/cc
H-3	0.224E 02	0.731E 00
Cr-51	0.369E-01	0.121E-02
Mn-54	0.676E-02	0.221E-03
Fe-55	0.143E-01	0.468E-03
Co-58	0.335E 00	0.109E-01
Fe-59	0.203E-01	0.665E-03
Co-60	0.438E-01	0.143E-02
Kr-83M	0.0	0.0
Kr-85M	0.0	0.0
Kr-85	0.0	0.0
Kr-87	0.0	0.0
Kr-88	0.0	0.0
Sr-89	0.469E-01	0.153E-02
Sr-90	0.242E-02	0.792E-04
Y-90	0.314E-02	0.103E-03
Sr-91	0.310E-02	0.101E-03
Y-91	0.404E 00	0.132E-01
Sr-92	0.377E-03	0.123E-04
Y-92	0.100E-02	0.327E-04
Zr-95	0.118E-01	0.387E-03
Nb-95	0.121E-01	0.397E-03
Mo-99	0.425E 02	0.139E 01
I-131	0.401E 02	0.131E 01
Te-132	0.285E 01	0.931E-01
I-132	0.331E 01	0.108E 00
I-133	0.149E 02	0.488E 00
Xe-133M	0.0	0.0
Xe-133	0.0	0.0
Cs-134	0.417E 01	0.136E 00
I-134	0.998E-01	0.326E-02
I-135	0.300E 01	0.982E-01
Xe-135M	0.0	0.0
Xe-135	0.0	0.0
Cs-136	0.875E 00	0.286E-01
Cs-137	0.751E 01	0.246E 00
Xe-138	0.0	0.0
Ba-140	0.655E-01	0.214E-02
La-140	0.549E-01	0.179E-02
Ce-144	0.728E-02	0.238E-03
Pr-144	0.728E-02	0.238E-03

Steam Phase

Nuclide	Activity, Ci	Concent µCi/cc
Kr- 83M	0.510E-01	0.250E-02
Kr- 85M	0.623E 00	0.305E-01
Kr- 85	0.186E 04	0.913E 02
Kr- 87	0.983E-01	0.482E-02
Kr- 88	0.671E 00	0.329E-01
Xe-133M	0.135E 02	0.664E 00
Xe-133	0.258E 04	0.127E 03
Xe-135M	0.443E 00	0.217E-01
Xe-135	0.693E 01	0.340E 00
Xe-138	0.954E 02	0.468E-03

Pressurizer Deposited Activity

Nuclide	Activity, $\mu Ci/c^2$
Cr-51	9.80E-02
Mn-54	1.50E-01
Mn-56	2.20E-02
Co-58	3.80E 00
Co-60	1.60E-01
Fe-59	1.40E-01

TABLE 11.1-20

ACTIVITY IN PRESSURIZER FOR NORMAL OPERATION CASE

Liquid Phase

Nuclide	Activity, Ci	Concent, µCi/cc
H-3	0.211E 02	0.691E 00
Cr-51	0.349E-01	0.121E-02
Mn-54	0.675E-02	0.221E-03
Fe-55	0.143E-01	0.468E-03
Co-58	0.335E 00	0.109E-01
Fe-59	0.203E-01	0.664E-03
Co-60	0.438E-01	0.143E-02
Kr-83M	0.0	0.0
Kr-85M	0.0	0.0
Kr-85	0.0	0.0
Kr-87	0.0	0.0
Kr-88	0.0	0.0
Sr-89	0.562E-02	0.184E-03
Sr-90	0.290E-03	0.950E-05
Y-90	0.376E-03	0.123E-04
Sr-91	0.272E-03	0.121E-04
Y-91	0.471E-01	0.154E-02
Sr-92	0.453E-04	0.148E-05
Y-92	0.120E-03	0.393E-05
Zr-95	0.142E-02	0.464E-04
Nb-95	0.146E-02	0.476E-04
Mo-99	0.508E 01	0.166E 00
I-131	0.481E 01	0.157E 00
Te-132	0.342E 00	0.112E-01
I-132	0.397E 00	0.130E-01
I-133	0.179E 01	0.586E-01
Xe-133M	0.0	0.0
Xe-133	0.0	0.0
Cs-134	0.505E 00	0.165E-01
I-134	0.120E-01	0.391E-03
I-135	0.360E 00	0.118E-01
Xe-135M	0.0	0.0
Xe-135	0.0	0.0
Cs-136	0.105E 00	0.343E-02
Cs-137	0.901E 00	0.295E-01
Xe-138	0.0	0.0
Ba-140	0.785E-02	0.257E-03
La-140	0.658E-02	0.215E-03
Ce-144	0.873E-03	0.285E-04
Pr-144	0.873E-03	0.285E-04

Steam Phase

Nuclide	Activity, Ci	Concent µCi/cc
Kr- 83M	0.612E-02	0.300E-03
Kr- 85M	0.745E-01	0.365E-02
Kr- 85	0.175E 03	0.860E 01
Kr- 87	0.118E-01	0.578E-03
Kr- 88	0.803E-01	0.394E-02
Xe-133M	0.158E-01	0.773E-01
Xe-133	0.291E 03	0.143E 02
Xe-135M	0.532E-01	0.261E-02
Xe-135	0.829E 00	0.406E-01
Xe-138	0.114E-02	0.561E-04

Pressurizer Deposited Activity

Nuclide	Activity mCi/c^2
Cr-51	9.80E-02
Mn-54	1.50E-01
Mn-56	2.20E-02
Co-58	3.80E 00
Co-60	1.60E-01
Fe-59	1.40E-01

TABLE 11.1-21

BASIC ASSUMPTIONS FOR TRITIUM ACTIVITY
IN PRIMARY COOLANT

1.	Core Thermal Power	3568 MWt
2.	Plant Load Factor	0.8
3.	Core Volume	1153 ft^3
4.	Core Volume Fractions	
	a. UO_2	0.3052
	b. Zr + SS	0.1000
	c. H_2O	0.5948
5.	Initial Reactor Coolant Boron Level	
	a. Initial cycle	840 ppm
	b. Equilibrium cycle	1200 ppm
6.	Reactor Coolant Volume	12,560 ft^3
7.	Reactor Coolant Transport Times	
	a. Incore	0.77 sec
	b. Out-of-core	10.87 sec
8.	Reactor Coolant Peak Lithium Level (99% pure Li^7)	2.2 ppm
9.	Core Average Neutron Fluxes, n/cm^2-sec	
	a. E > 6 MeV	2.91×10^{12}
	b. E > 5 MeV	7.90×10^{12}
	c. 3 MeV ≤ E ≤ 6 MeV	2.26×10^{13}
	d. 1 MeV ≤ E ≤ 5 MeV	5.31×10^{13}
	e. E < 0.625 eV	2.26×10^{13}
10.	Neutron Reaction Cross Sections	
	a. B^{10} (n, 2α) T: σ(1 MeV ≤ E ≤ 5 MeV) =	31.6 mb (spectrum weighted)
	σ(E > 5 MeV) =	75 mb
	b. Li^7 (n, n α V) T: σ(3 MeV ≤ E ≤ 6 MeV) =	39.1 mb (spectrum weighted)
	σ(E > 6 MeV) =	400 mb
11.	Fraction of Ternary Tritium Diffusing Through Zirconium Cladding	
	a. Design value	0.30
	b. Expected value	0.01

TABLE 11.1-22

TRITIUM ACTIVITY IN PRIMARY COOLANT

Tritium Source	Core Activity, Ci	Coolant Activity, Ci	Total Produced in Coolant, Ci
Cycle = 8760 Hours			
Ternary fissions	0.196E05	0.121E03	1092.76
Burnable poison rods	0.0	0.0	0.0
Control rods	0.0	0.0	0.0
Boron shim control	0.0	0.270E02	442.40
Lithium-7 reaction	0.0	0.100E01	9.05
Lithium-6 reaction	0.0	0.105E02	94.97
Deuterium reaction	0.0	0.294E00	2.66
Total	0.196E05	0.160E03	1641.84

TABLE 11.1-23

STEAM SYSTEM OPERATING CONDITIONS ASSUMED FOR ACTIVITY ANALYSIS FOR NORMAL OPERATION CASE

Parameter	Value			
	Steam Gen. 1	Steam Gen. 2	Steam Gen. 3	Steam Gen. 4
Steam flowrate to condenser from unit (lb/hr)	3804300.0	3804300.0	3804300.0	3804300.0
Feedwater flowrate to unit (lb/hr)	3804725.0	3804725.0	3804725.0	3804725.0
Blowdown flowrate from unit (lb/hr)	17647.5	17647.5	17647.5	17647.5
Steam venting flowrate from unit (lb/hr)	0.0	0.0	0.0	0.0
Total weight of steam vented from unit during period-lb	0.0	0.0	0.0	0.0
Weight of water in unit (lb)	81500.0	81500.0	81500.0	81500.0
Volume of water in unit (ft^3)	1680.4	1680.4	1680.4	1680.4
Density of water in unit (lb/ft^3)	48.5	48.5	48.5	48.5
Fraction of primary to secondary leakage to this unit	0.25	0.25	0.25	0.25
Leakage flowrate to this unit (computed) (gal./min)	0.0029	0.0029	0.0029	0.0029
Total gallons of prim. cool. leaked into unit in period	1208.8	1208.8	1208.8	1208.8
Total steam flowrate of condenser (lb/hr)	15217200.0			
Total condensate flowrate from condenser (lb/hr)	15221402.0			
Weight of water in condenser (lb)	1700000.0			
Volume of water in condenser (ft^3)	27243.58			
Density of water in condenser (lb/ft^3)	62.39			
Total primary to secondary leak rate (gal./min)	0.0115			
Water leakage rate from secondary system (gal./min)	5.0			
Steam leakage rate from secondary system (lb/hr)	1700.0			
Flowrate of water to blowdown cleanup system (lb/hr)	51763.78			
Capacity factor of blowdown cleanup system	1.0			

TABLE 11.1-24

ADDITIONAL SECONDARY SYSTEM OPERATING PARAMETERS

Mass of water in one steam generator, lb	81,500
Mass of steam in one steam generator, lb	7,200
Secondary side operating temperature, °F	519
Steam generator blowdown tank capacity, ft^3	641
Air ejector flowrate - rated, scfm	25
- expected average, scfm	2.5
Total mass of water in secondary system, lb (minus condenser)	1,000,000
Total mass of steam in secondary system, lb	61,200

TABLE 11.1-25

STEAM GENERATOR PARTITION FACTORS[(a)]

Nuclide	St.Gen.1	St.Gen.2	St.Gen.3	St.Gen.4
H-3	1.0000	1.0000	1.0000	1.0000
Cr-51	0.0007	0.0007	0.0007	0.0007
Mn-54	0.0007	0.0007	0.0007	0.0007
Fe-55	0.0007	0.0007	0.0007	0.0007
Co-58	0.0007	0.0007	0.0007	0.0007
Fe-59	0.0007	0.0007	0.0007	0.0007
Co-60	0.0007	0.0007	0.0007	0.0007
Kr-83M	1.0000	1.0000	1.0000	1.0000
Kr-85M	1.0000	1.0000	1.0000	1.0000
Kr-85	1.0000	1.0000	1.0000	1.0000
Kr-87	1.0000	1.0000	1.0000	1.0000
Kr-88	1.0000	1.0000	1.0000	1.0000
Sr-89	0.0007	0.0007	0.0007	0.0007
Sr-90	0.0007	0.0007	0.0007	0.0007
Y-90	0.0007	0.0007	0.0007	0.0007
Sr-91	0.0007	0.0007	0.0007	0.0007
Y-91	0.0007	0.0007	0.0007	0.0007
Sr-92	0.0007	0.0007	0.0007	0.0007
Y-92	0.0007	0.0007	0.0007	0.0007
Zr-95	0.0007	0.0007	0.0007	0.0007
Nb-95	0.0007	0.0007	0.0007	0.0007
Mo-99	0.0007	0.0007	0.0007	0.0007
I-131	0.0065	0.0065	0.0065	0.0065
Te-132	0.0007	0.0007	0.0007	0.0007
I-132	0.0065	0.0065	0.0065	0.0065
I-133	0.0065	0.0065	0.0065	0.0065
Xe-133M	1.0000	1.0000	1.0000	1.0000
Xe-133	1.0000	1.0000	1.0000	1.0000
Cs-134	0.0007	0.0007	0.0007	0.0007
I-134	0.0065	0.0065	0.0065	0.0065
I-135	0.0065	0.0065	0.0065	0.0065
Xe-135M	1.0000	1.0000	1.0000	1.0000
Xe-135	1.0000	1.0000	1.0000	1.0000
Cs-136	0.0007	0.0007	0.0007	0.0007
Cs-137	0.0007	0.0007	0.0007	0.0007
Xe-138	1.0000	1.0000	1.0000	1.0000
Ba-140	0.0007	0.0007	0.0007	0.0007
La-140	0.0007	0.0007	0.0007	0.0007
Ce-144	0.0007	0.0007	0.0007	0.0007
Pr-144	0.0007	0.0007	0.0007	0.0007

(a) Iodine partition factors are for nonvolatile species only and include partitioning in moisture separators.

TABLE 11.1-26

TOTAL ADDITIONS AND REMOVALS OF ACTIVITY IN EACH STEAM GENERATOR FOR NORMAL OPERATION CASE (CURIES)

Nuclide	Leakage in	From Feedwater	To Main Stm	To Blowdown	Vented	Decayed	Leaked
H-3	0.3007E 01	0.6511E 04	0.6513E 04	0.0	0.0	0.8954E-03	0.7276E 00
Cr-51	0.5976E-02	0.5983E-03	0.8659E-03	0.5681E-02	0.0	0.2753E-04	0.9674E-07
Mn-54	0.9719E-03	0.9793E-04	0.1414E-03	0.9280E-03	0.0	0.4126E-06	0.1580E-07
Fe-55	0.4960E-02	0.4651E-03	0.6877E-03	0.4512E-02	0.0	0.2251E-03	0.7683E-07
Co-58	0.5015E-01	0.5043E-02	0.7288E-02	0.4782E-01	0.0	0.9040E-04	0.8142E-04
Fe-59	0.3137E-02	0.3150E-03	0.4554E-03	0.2988E-02	0.0	0.8944E-05	0.5088E-07
Co-60	0.6239E-02	0.6290E-03	0.9083E-03	0.5959E-02	0.0	0.4179E-06	0.1015E-06
Sr-89	0.8600E-03	0.8638E-04	0.1249E-03	0.8193E-03	0.0	0.2153E-05	0.1395E-07
Sr-90	0.4130E-04	0.4164E-05	0.6013E-05	0.3945E-04	0.0	0.5205E-09	0.6717E-09
Y-90	0.7106E-04	0.1159E-04	0.1160E-04	0.6919E-04	0.0	0.3850E-05	0.1296E-08
Sr-91	0.5599E-03	0.3580E-04	0.6114E-04	0.4011E-03	0.0	0.1334E-03	0.6831E-08
Y-91	0.7122E-02	0.1191E-02	0.1191E-02	0.7105E-02	0.0	0.1719E-04	0.1331E-06
Sr-92	0.2289E-03	0.4779E-05	0.1516E-04	0.9944E-04	0.0	0.1191E-03	0.1693E-08
Y-92	0.2928E-03	0.3159E-04	0.3218E-04	0.1919E-03	0.0	0.1896E-03	0.3595E-08
Zr-95	0.2136E-03	0.2147E-04	0.3103E-04	0.2036E-03	0.0	0.4192E-06	0.3467E-08
Nb-95	0.2076E-03	0.3162E-04	0.3163E-04	0.2075E-03	0.0	0.7978E-06	0.3534E-08
Mo-99	0.1713E 01	0.1612E 00	0.2381E 00	0.1562E 01	0.0	0.7425E-01	0.2660E-04
I-131	0.1015E 01	0.1372E 01	0.1418E 01	0.9519E 00	0.0	0.1678E-01	0.1584E-03
Te-132	0.1067E 00	0.1013E-01	0.1492E-01	0.9786E-01	0.0	0.4061E-02	0.1666E-05
I-132	0.3652E 00	0.2914E 00	0.3006E 00	0.2018E 00	0.0	0.2861E 00	0.3358E-04
I-133	0.1386E 01	0.1620E 01	0.1689E 01	0.1133E 01	0.0	0.1837E 00	0.1887E-03
Cs-134	0.7721E-01	0.2177E-01	0.2178E-01	0.7217E-01	0.0	0.2567E-04	0.2433E-05
I-134	0.1851E 00	0.4043E-01	0.5234E-01	0.3513E-01	0.0	0.1380E 00	0.5847E-05
I-135	0.7647E 00	0.6716E 00	0.7138E 00	0.4791E 00	0.0	0.2433E 00	0.7974E-04
Cs-136	0.1938E-01	0.4603E-02	0.5473E-02	0.1813E-01	0.0	0.3720E-03	0.6114E-06
Cs-137	0.1282E 00	0.3120E-01	0.3695E-01	0.1224E 00	0.0	0.3320E-05	0.4128E-05
Ba-140	0.1456E-02	0.1445E-03	0.2097E-03	0.1976E-02	0.0	0.1449E-04	0.2343E-07
La-140	0.5137E-03	0.8819E-04	0.8811E-04	0.5781E-03	0.0	0.4660E-04	0.9843E-08
Ce-144	0.1258E-03	0.1267E-04	0.1831E-04	0.1201E-03	0.0	0.5668E-07	0.2045E-08
Pr-144	0.1258E-03	0.1717E-04	0.1836E 04	0.1205E-03	0.0	0.1334E-02	0.2051E-08

TABLE 11.1-27

EQUILIBRIUM ACTIVITIES AND CONCENTRATIONS IN EACH STEAM GENERATOR FOR NORMAL OPERATION CASE

Nuclide	Activity, Ci	Concentration, μCi/cc
H-3	0.1991E-01	0.4184E-03
Cr-51	0.3782E-05	0.7947E-07
Mn-54	0.6177E-06	0.1298E-07
Fe-55	0.3003E-05	0.6312E-07
Co-58	0.3183E-04	0.6689E-06
Fe-59	0.1989E-05	0.4180E-07
Co-60	0.3967E-05	0.8336E-07
Sr-89	0.5454E-06	0.1146E-07
Sr-90	0.2626E-07	0.5518E-09
Y-90	0.4584E-07	0.9633E-09
Sr-91	0.2670E-06	0.5611E-08
Y-91	0.4683E-05	0.9842E-07
Sr-92	0.6619E-07	0.1391E-08
Y-92	0.1331E-06	0.2797E-08
Zr-95	0.1355E-06	0.2848E-08
Nb-95	0.1381E-06	0.2903E-08
Mo-99	0.1030E-02	0.2164E-04
I-131	0.6670E-03	0.1402E-04
Te-132	0.6514E-04	0.1369E-05
I-132	0.1414E-03	0.2971E-05
I-133	0.7942E-03	0.1669E-04
Cs-134	0.9512E-04	0.1999E-05
I-134	0.2462E-04	0.5173E-06
I-135	0.3357E-03	0.7055E-05
Cs-136	0.2390E-04	0.5023E-06
Cs-137	0.1614E-03	0.3391E-05
Ba-140	0.9160E-06	0.1925E-07
La-140	0.3848E-06	0.8087E-08
Ce-144	0.7994E-07	0.1680E-08
Pr-144	0.8019E-07	0.1685E-08

TABLE 11.1-28

TOTAL ADDITIONS AND REMOVALS OF ACTIVITY IN THE CONDENSER
FOR NORMAL OPERATION CASE (CURIES)

Nuclide	From Mainsteam	To Feedwater	Decayed	Water Leakage
H-3	0.2605E-05	0.2605E 05	0.1867E-01	0.4283E 01
Cr-51	0.3464E-02	0.2394E-02	0.2777E-06	0.3935E-06
Mn-54	0.5658E-03	0.3918E-03	0.4171E-08	0.6442E-07
Fe-55	0.2751E-02	0.1861E-02	0.2223E-05	0.3060E-06
Co-58	0.2915E-01	0.2017E-01	0.9131E-06	0.3317E-05
Fe-59	0.1822E-02	0.1260E-02	0.9030E-07	0.2072E-06
Co-60	0.3633E-02	0.2516E-02	0.4225E-08	0.4137E-06
Sr-89	0.4995E-03	0.3456E-03	0.2174E-07	0.5682E-07
Sr-90	0.2405E-04	0.1666E-04	0.5262E-11	0.2739E-08
Y-90	0.4640E-04	0.4636E-04	0.5615E-07	0.7622E-08
Sr-91	0.2446E-03	0.1432E-03	0.1140E-05	0.2355E-07
Y-91	0.4765E-02	0.4764E-02	0.2508E-06	0.7833E-04
Sr-92	0.6063E-04	0.1912E-04	0.5481E-06	0.3144E-08
Y-92	0.1287E-03	0.1264E-03	0.2717E-05	0.2078E-07
Zr-95	0.1241E-03	0.8590E-04	0.4235E-08	0.1412E-07
Nb-95	0.1265E-03	0.1265E-03	0.1164E-07	0.2080E-07
Mo-99	0.9523E 00	0.6449E 00	0.7340E-03	0.1060E-03
I-131	0.5673E 01	0.5488E 01	0.2201E-02	0.9023E-03
Te-132	0.5967E-01	0.4052E-01	0.4026E-04	0.6663E-05
I-132	0.1202E 01	0.1166E 01	0.3760E-01	0.1917E-03
I-133	0.6755E 01	0.6482E 01	0.2389E-01	0.1066E-02
Cs-134	0.8715E-01	0.8711E-01	0.3746E-06	0.1432E-04
I-134	0.2094E 00	0.1618E 00	0.1446E-01	0.2660E-04
I-135	0.2855E 01	0.2687E 01	0.3104E-01	0.4418E-03
Cs-136	0.2189E-01	0.1842E-01	0.4569E-05	0.3028E-05
Cs-137	0.1478E 00	0.1248E 00	0.4094E-07	0.2052E-04
Ba-140	0.8390E-03	0.5782E-03	0.1458E-06	0.9507E-07
La-140	0.3524E-03	0.3528E-03	0.4610E-06	0.5801E-07
Ce-144	0.7322E-04	0.5070E-04	0.5729E-09	0.8337E-08
Pr-144	0.7345E-04	0.6860E-04	0.1020E-04	0.1129E-07

TABLE 11.1-29

EQUILIBRIUM ACTIVITIES AND CONCENTRATIONS IN THE CONDENSER FOR NORMAL OPERATION CASE

Nuclide	Activity, Ci	Concentration, μCi/cc
H-3	0.4151E 00	0.5381E-03
Cr-51	0.3815E-07	0.4945E-10
Mn-54	0.6244E-08	0.8093E-11
Fe-55	0.2966E-07	0.3844E-10
Co-58	0.3215E-06	0.4168E-09
Fe-59	0.2008E-07	0.2603E-10
Co-60	0.4010E-07	0.5198E-10
Sr-89	0.5507E-08	0.7139E-11
Sr-90	0.2655E-09	0.3441E-12
Y-90	0.6685E-09	0.8665E-12
Sr-91	0.2282E-08	0.2959E-11
Y-91	0.6835E-07	0.8859E-10
Sr-92	0.3047E-09	0.3950E-12
Y-92	0.1908E-08	0.2473E-11
Zr-95	0.1369E-08	0.1774E-11
Nb-95	0.2016E-08	0.2613E-11
Mo-99	0.1013E-04	0.1314E-07
I-131	0.8746E-04	0.1134E-06
Te-132	0.6458E-06	0.8372E-09
I-132	0.1858E-04	0.2409E-07
I-133	0.1033E-03	0.1339E-06
Cs-134	0.1388E-05	0.1800E-08
I-134	0.2578E-05	0.3342E-08
I-135	0.4282E-04	0.5550E-07
Cs-136	0.2935E-06	0.3805E-09
Cs-137	0.1989E-05	0.2579E-08
Ba-140	0.9215E-08	0.1195E-10
La-140	0.5623E-08	0.7289E-11
Ce-144	0.8081E-09	0.1047E-11
Pr-144	0.1094E-08	0.1419E-11

TABLE 11.1-30

TOTAL ADDITIONS AND REMOVALS OF ACTIVITY IN THE CONDENSER VAPOR SPACE FOR NORMAL OPERATION CASE

Nuclide	Inleak Rate, Ci/hr	Tot. Inleakage, Ci	Vent Rate, hr^{-1}	Vent Rate, Ci/hr	Tot. Vented, Ci	Decayed, Ci
Kr-83	0.7861E-04	0.5509E 00	0.1650E 00	0.2413E-04	0.1690E 00	0.3817E 00
Kr-85M	0.4049E-03	0.2837E 01	0.1650E 00	0.2071E-03	0.1451E 01	0.1385E 01
Kr-85	0.7133E-03	0.6249E 01	0.1650E 00	0.7133E-03	0.6244E 01	0.2787E-03
Kr-87	0.2219E-03	0.1555E 01	0.1650E 00	0.5151E-04	0.3610E 00	0.1194E 01
Kr-88	0.6933E-03	0.4859E 01	0.1650E 00	0.2755E-03	0.1930E 01	0.2927E 01
I-131	0.4575E-05	0.3206E-01	0.1650E 00	0.4477E-05	0.3136E-01	0.6824E-03
I-132	0.1646E-05	0.1153E-01	0.1650E 00	0.5985E-06	0.4193E-02	0.7338E-02
I-133	0.6245E-05	0.4376E-01	0.1650E 00	0.5204E-05	0.3645E-01	0.7290E-02
Xe-133M	0.6653E-03	0.4662E 01	0.1650E 00	0.6182E-03	0.4330E 01	0.3294E 00
Xe-133	0.5421E-01	0.3799E 03	0.1650E 00	0.5248E-01	0.3675E 03	0.1215E 02
I-134	0.8341E-06	0.5845E-02	0.1650E 00	0.1426E-06	0.9991E-03	0.4845E-02
I-135	0.3446E-05	0.2415E-01	0.1650E 00	0.2118E-05	0.1484E-01	0.9301E-02
Xe-135M	0.6224E-03	0.4362E 01	0.1650E 00	0.3628E-04	0.2543E 00	0.4107E 01
Xe-135	0.1304E-02	0.9136E 01	0.1650E 00	0.8951E-03	0.6270E 01	0.2862E 01
Xe-138	0.1174E-03	0.8227E 00	0.1650E 00	0.6170E-05	0.4324E-01	0.7794E 00

TABLE 11.1-31

EQUILIBRIUM ACTIVITIES AND CONCENTRATIONS IN THE CONDENSER VAPOR SPACE FOR NORMAL OPERATION CASE

Nuclide	Activity, Ci	Concentration, mCi/cc
Kr-83M	0.1462E-03	0.5164E-07
Kr-85M	0.1255E-02	0.4434E-06
Kr-85	0.4323E-02	0.1527E-05
Kr-87	0.3122E-03	0.1103E-06
Kr-88	0.1670E-02	0.5897E-06
I-131	0.2697E-04	0.9524E-08
I-132	0.3618E-05	0.1278E-08
I-133	0.3141E-04	0.1109E-07
Xe-133M	0.3746E-02	0.1323E-05
Xe-133	0.3180E 00	0.1123E-03
I-134	0.8637E-06	0.3050E-09
I-135	0.1281E-04	0.4522E-08
Xe-135M	0.2194E-03	0.7747E-07
Xe-135	0.5419E-02	0.1914E-05
Xe-138	0.3740E-04	0.1321E-07

TABLE 11.2-1

ASSUMPTIONS USED FOR INPUT WASTE STREAMS AND ACTIVITY CALCULATIONS
BASED ON ORIGINAL SYSTEM DESIGN

1. Each stream of liquid waste input is categorized by one of the following isotopic concentration spectra, which are shown for the two analyses cases in Tables 11.2-3 and 11.2-4:

   Spectrum I - Degassed primary coolant
   Spectrum II - Degassed primary coolant with 48 hours of decay
   Spectrum III - 1.0% of degassed primary coolant with 48 hours of decay
   Spectrum IV - 0.01% of degassed primary coolant with 48 hours of decay
   Spectrum V - 0.001% of primary coolant with 48 hours of decay; principally component cooling water.

2. Heat exchangers are periodically drained producing 25 gallons/inch inlet piping/year for the Design Basis Case and 1.5 times the above for the Normal Operation Case.

3. Pumps are periodically drained producing 10 gallons/inch suction/year for the Design Basis Case and 1.5 times the above for the Normal Operation Case.

4. Pump baseplate leakage of 0.10 gallons/day for the Design Basis Case and 1.5 times the above for the Normal Operation Case

5. Tanks are periodically drained producing 100 gallons/5 feet diameter/year for the Design Basis Case and 1.5 times the above for the Normal Operation Case.

6. Filter cartridge replacement three times per year, producing 15 gallons/replacement for the Design Basis Case and 1.5 times the above volume for the Normal Operation Case.

7. Sampling produces 4 gallons/sample (2 gallons/sample to laboratory drain and 2 gallons/sample due to line purging, 7 samples/day/unit).

8. Valve stem leakage of 10 cc/day for the Design Basis Case and 1.5 times the above for the Normal Operation Case.

9. No waste from relief valve discharges for the Design Basis Case and 50 gallons/year for the Normal Operation Case.

10. Laundry waste of 3 washloads per week producing 210 gallons/washload for the CDesign Basis Case and 1.5 times the above volume for the Normal Operation Case.

11. Personnel decontamination showers of 4 showers/day producing 5 gallons/shower for the Design Basis Case and 1.5 times the above volume for the Normal Operation Case.

12. Personnel handwashes of 25 per day producing 0.5 gallons/wash for the Design Basis Case and 1.5 times the above volume for the Normal Operation Case.

13. Periodic system piping drains of 200 gallons/year/system/unit for the Design Basis Case and 1.5 times the above volume for the Normal Operation Case.

14. Containment fan cooler drains of 1,000 gallons/year/unit for the Design Basis Case and 1.5 times the above volume for the Normal Operation Case.

15. Each reactor coolant pump 3 seal leaks 100 cc/hour for the Design Basis Case and the Normal Operation Case.

16. Spent resin loadout area washdown of 200 gallons/year for the Design Basis Case and 1.5 times the above for the Normal Operation Case.

17. Demineralizer overflow produces 500 gallons/backwash and resin replacement of one demineralizer per set annually for the Design Basis Case and the Normal Operation Case.

18. Reactor coolant drain tank wastes are processed through the CVCS for the Design Basis Case and 500 gallons/year/unit to the liquid waste system for the Normal Operation Case.

19. Miscellaneous floor drain leakage of 5,000 gallons/year for the Design Basis Case and 1.5 times the above volume for the Normal Operation Case.

20. Miscellaneous leakage of 160 pounds/day/unit of Spectrum I wastes to the auxiliary building for the Normal Operation Case.

21. Miscellaneous leakage of 40 gallons/day/unit of Spectrum I wastes to the containment building for the Normal Operation Case.

22. RHR pump leakage of 0.25 gallons/pump for the Normal Operation Case.

23. Waste will be allowed 48 hours of decay before processing from the chemical drain, laundry and hot shower, miscellaneous equipment drain, and reactor coolant drain tanks. (This includes fill time and discharge time.)

24. Waste will be allowed 336 hours of decay in the floor drain receiver and equipment drain receiver tanks before processing. (This includes one-half of the fill time plus one-half of the discharge time.)

25. Waste will be allowed 24 hours of decay in the waste condensate tank before processing.

26. No decay credit is taken for sumps.

27. For tritium control, 350,000 gallons/unit will be discharged annually.

28. Primary-to-secondary steam generator leakage of 100 lb/day of primary coolant for the Normal Operation Case.

TABLE 11.2-2

ASSUMPTIONS FOR CALCULATIONS OF ACTIVITY RELEASED FROM CVCS
BASED ON ORIGINAL SYSTEM DESIGN

Average Shim Bleed Flowrate, gpm		1.0
Capacity of Liquid Holdup Tank, gal.		83000
DFs for CVC Demineralizers		(Given in Table 11.1-15)
DF for Boric Acid Evaporator [a]	- iodine	102
	- other nuclides	103
Capacity of Monitor Tank, gal.		25000
Fraction of Boric Acid Evaporator Distillate Recycled [a]		0.333

(a) Boric Acid Evaporator has been abandoned in place

TABLE 11.2-3

ACTIVITY CONCENTRATION SPECTRUM I THROUGH V FOR
INPUT WASTE SOURCES, DESIGN BASIS CASE
(μCi/cc)[a]

Nuclide	Spectrum I	Spectrum II	Spectrum III	Spectrum IV	Spectrum V
H-3	0.11E+01	0.11E+01	0.11E-01	0.11E-03	0.11E-04
Cr-51	0.19E-02	0.19E-02	0.19E-04	0.19E-06	0.19E-07
Mn-54	0.31E-03	0.30E-03	0.30E-05	0.30E-07	0.30E-08
Fe-55	0.15E-02	0.92E-03	0.92E-05	0.92E-07	0.92E-08
Co-58	0.17E-01	0.16E-01	0.16E-03	0.16E-05	0.16E-06
Fe-59	0.10E-02	0.97E-03	0.97E-05	0.97E-07	0.97E-08
Co-60	0.19E-02	0.19E-02	0.19E-04	0.19E-06	0.19E-07
Kr-83M	0.35E+00	0.0	0.0	0.0	0.0
Kr-85M	0.18E+01	0.0	0.0	0.0	0.0
Kr-85	0.58E+01	0.0	0.0	0.0	0.0
Kr-87	0.99E+00	0.0	0.0	0.0	0.0
Kr-88	0.31E+01	0.0	0.0	0.0	0.0
Sr-89	0.24E-02	0.23E-02	0.23E-04	0.23E-06	0.23E-07
Sr-90	0.11E-03	0.11E-03	0.11E-05	0.11E-07	0.11E-08
Y-90	0.19E-04	0.16E-04	0.16E-06	0.16E-08	0.16E-09
Sr-91	0.15E-02	0.50E-04	0.50E-06	0.50E-08	0.50E-09
Y-91	0.21E-02	0.20E-02	0.20E-04	0.20E-06	0.20E-07
Sr-92	0.61E-03	0.27E-08	0.27E-10	0.27E-12	0.27E-13
Y-92	0.78E-04	0.25E-07	0.25E-09	0.25E-11	0.25E-12
Zr-95	0.57E-03	0.56E-03	0.56E-05	0.56E-07	0.56E-08
Nb-95	0.56E-03	0.56E-03	0.56E-05	0.56E-07	0.56E-08
Mo-99	0.46E-01	0.28E-01	0.28E-03	0.28E-05	0.28E-06
I-131	0.28E+01	0.23E+01	0.23E-01	0.23E-03	0.23E-04

TABLE 11.2-3

Nuclide	Spectrum I	Spectrum II	Spectrum III	Spectrum IV	Spectrum V
Te-132	0.29E+00	0.19E+00	0.19E-02	0.19E-04	0.19E-05
I-132	0.97E+00	0.20E+00	0.20E-02	0.20E-04	0.20E-05
I-133	0.38E+01	0.77E+00	0.77E-02	0.77E-04	0.77E-05
Xe-133M	0.31E+01	0.0	0.0	0.0	0.0
Xe-133	0.20E+03	0.0	0.0	0.0	0.0
Cs-134	0.19E+00	0.19E+00	0.19E-02	0.19E-04	0.19E-05
I-134	0.49E+00	0.10E-16	0.10E-18	0.10E-20	0.10E-21
I-135	0.21E+01	0.15E-01	0.15E-03	0.15E-05	0.15E-06
Xe-135M	0.39E+00	0.0	0.0	0.0	0.0
Xe-135	0.54E+01	0.0	0.0	0.0	0.0
Cs-136	0.51E-01	0.46E-01	0.46E-03	0.46E-05	0.46E-06
Cs-137	0.35E+00	0.35E+00	0.35E-02	0.35E-04	0.35E-05
Xe-138	0.51E+00	0.0	0.0	0.0	0.0
Ba-140	0.39E-02	0.35E-02	0.35E-04	0.35E-06	0.35E-07
La-140	0.14E-02	0.27E-02	0.27E-04	0.27E-06	0.27E-07
Ce-144	0.33E-03	0.33E-03	0.33E-05	0.33E-07	0.33E-08
Pr-144	0.33E-03	0.33E-03	0.33E-05	0.33E-07	0.33E-08

(a) A plateout decontamination factor of 10 for yttrium and 100 for molybdenum is assumed for all waste streams.

TABLE 11.2-4

ACTIVITY CONCENTRATION SPECTRUM I THROUGH V FOR
INPUT WASTE SOURCES, DESIGN BASIS CASE
(μCi/cc)[a]

Nuclide	Spectrum I	Spectrum II	Spectrum III	Spectrum IV	Spectrum V
H-3	0.11E+01	0.10E+01	0.10E-01	0.10E-03	0.10E-04
Cr-51	0.19E-02	0.19E-02	0.19E-04	0.19E-06	0.19E-07
Mn-54	0.31E-03	0.30E-03	0.30E-05	0.30E-07	0.30E-08
Fe-55	0.15E-02	0.92E-03	0.92E-05	0.92E-07	0.92E-08
Co-58	0.17E-01	0.16E-01	0.16E-03	0.16E-05	0.16E-06
Fe-59	0.10E-02	0.97E-03	0.97E-05	0.97E-07	0.97E-08
Co-60	0.19E-02	0.19E-02	0.19E-04	0.19E-06	0.19E-07
Kr-83M	0.42E-01	0.0	0.0	0.0	0.0
Kr-85M	0.22E+00	0.0	0.0	0.0	0.0
Kr-85	0.67E+00	0.0	0.0	0.0	0.0
Kr-87	0.12E+00	0.0	0.0	0.0	0.0
Kr-88	0.38E+00	0.0	0.0	0.0	0.0
Sr-89	0.28E-03	0.27E-03	0.27E-05	0.27E-07	0.23E-08
Sr-90	0.13E-04	0.13E-04	0.13E-06	0.13E-08	0.13E-09
Y-90	0.24E-05	0.19E-05	0.19E-07	0.19E-09	0.19E-10
Sr-91	0.18E-03	0.59E-07	0.59E-07	0.59E-09	0.59E-10
Y-91	0.25E-03	0.24E-03	0.24E-05	0.24E-07	0.24E-08
Sr-92	0.74E-04	0.33E-09	0.33E-11	0.33E-13	0.33E-14
Y-92	0.93E-05	0.30E-08	0.30E-10	0.30E-12	0.30E-13
Zr-95	0.68E-04	0.67E-04	0.67E-06	0.67E-08	0.67E-09
Nb-95	0.67E-04	0.67E-04	0.67E-06	0.67E-08	0.67E-09
Mo-99	0.56E-02	0.34E-02	0.34E-04	0.34E-06	0.34E-07
I-131	0.32E+00	0.27E+00	0.27E-02	0.27E-04	0.27E-05

TABLE 11.2-4

Nuclide	Spectrum I	Spectrum II	Spectrum III	Spectrum IV	Spectrum V
Te-132	0.35E-01	0.23E+01	0.23E-03	0.23E-05	0.23E-06
I-132	0.12E+00	0.23E+01	0.23E-03	0.23E-05	0.23E-06
I-133	0.44E+00	0.91E+01	0.91E-03	0.91E-05	0.91E-06
Xe-133M	0.38E+00	0.0	0.0	0.0	0.0
Xe-133	0.32E+02	0.0	0.0	0.0	0.0
Cs-134	0.24E+01	0.24E+01	0.24E-03	0.24E-05	0.24E-06
I-134	0.60E+01	0.12E-17	0.12E-19	0.12E-21	0.12E-22
I-135	0.25E+00	0.17E-02	0.17E-04	0.17E-06	0.17E-07
Xe-135M	0.46E+01	0.0	0.0	0.0	0.0
Xe-135	0.65E+00	0.0	0.0	0.0	0.0
Cs-136	0.63E-02	0.56E-02	0.56E-04	0.56E-06	0.56E-07
Cs-137	0.42E+01	0.42E+01	0.42E-03	0.42E-05	0.42E-06
Xe-138	0.63E+01	0.0	0.0	0.0	0.0
Ba-140	0.47E-03	0.42E-03	0.42E-05	0.42E-07	0.42E-08
La-140	0.17E-03	0.32E-03	0.32E-05	0.32E-07	0.32E-08
Ce-144	0.40E-04	0.40E-04	0.40E-06	0.40E-08	0.40E-09
Pr-144	0.40E-04	0.40E-04	0.40E-06	0.40E-08	0.40E-09

(a) A plateout decontamination factor of 10 for yttrium and 100 for molybdenum is assumed for all waste streams.

TABLE 11.2-5

ANNUAL FLOW AND ISOTOPIC SPECTRA FOR LIQUID WASTE INPUTS
THIS TABLE APPLIES TO THE ESTIMATED RELEASES AND RADIOLOGICAL CONSEQUENCES CALCULATED, BASED ON ORIGINAL DESIGN
(SEE FIGURES 11.2-2 and 11.2-3)

Stream Number[a]	Stream Identification	Design Basis Case Flow[b]	Normal Operation Case Flow[b]	Concentration Spectrum
1A	Safety injection tank drain	80	120	IV
1B	Safety injection tank drain	80	120	IV
2A	Safety injection system piping drains	200	300	IV
2B	Safety injection system piping drains	200	300	IV
3A	Spray additive tank relief and drain	140	260	III
3B	Spray additive tank relief and drain	140	260	II
4A	Containment spray pump drains	200	300	II
4B	Containment spray pump drains	200	300	III
5A	Component cooling water (CCW) surge tank relief valve	0	50	V
5B	CCW surge tank relief valve	0	50	V
6A	RHR heat exchanger (CCW) drain	600	900	V
6B	RHR heat exchanger (CCW) drain	600	900	V
7A	Waste gas compressor seal cooler relief valve (CCW)	0	100	V
7B	Waste gas compressor seal cooler relief valve (CCW)	0	50	V
8A	Sample sink drains	2,920	4,380	IV
8B	Sample sink drains	2,920	4,380	IV
[c]	Chemical drain tank drain and overflow	-	-	-
[c]	Laundry and hot shower tank drain and overflow	-	-	-
[c]	Radwaste filter drains	-	-	-
[c]	Floor drain receiver tank drain and overflow	-	-	-
9	Spent resin loadout area drain	200	300	IV
10A	Charging pump (CCP1) baseplate drain	135	165	III
10B	Charging pump (CCP2) baseplate drain	135	165	III
11A	Chemical mixing tank drain	20	30	IV
11B	Chemical mixing tank drain	20	30	IV
12A [f]	Boric acid and concentrates filter drain	90	135	IV
12B [f]	Boric acid and concentrates filter drain	90	135	IV
13 [f]	Concentrates holding tank drain and overflow	120	180	IV
14 [f]	Concentrates holding tank pump drains	20	30	IV
15A	Boric acid tank drain and overflow	400	600	IV
15B	Boric acid tank drain and overflow	400	600	IV
16	Batching tank drain and overflow	100	150	IV

TABLE 11.2-5

Stream Number[a]	Stream Identification	Design Basis Case Flow[b]	Normal Operation Case Flow[b]	Concentration Spectrum
17A [f]	Boric acid evaporator heat exchanger drains	300	450	IV
17B [f]	Boric acid evaporator heat exchanger drains	300	450	IV
18A [f]	Boric acid evaporator pump drains	80	120	IV
18B [f]	Boric acid evaporator pump drains	80	120	IV
19A	Monitor tank drain and overflow	800	1,200	IV
19B	Monitor tank drain and overflow	800	1,200	IV
20	Miscellaneous leakage (Units 1 and 2)		14,600	I
21	Miscellaneous floor drains (Units 1 and 2)	5,000	7,500	IV
22A	Containment fan cooler drain	1,000	1,500	IV
22B	Containment fan cooler drain	1,000	1,500	IV
23A	Reactor coolant pump labyrinth seal relief valve (CCW)	0	50	V
23B	Reactor coolant pump labyrinth seal relief valve (CCW)	0	50	V
24A	Reactor coolant pump thermal barrier relief (CCW)	-	50	V
24B	Reactor coolant pump thermal barrier relief (CCW)	-	50	V
25A	Biological shield plate relief (CCW)	-	50	V
25B	Biological shield plate relief (CCW)		50	V
26A	Reactor coolant pump upper and lower bearing relief (CCW)	-	50	V
06B	Reactor coolant pump upper and lower bearing relief (CCW)	-	50	V
27A	Reactor vessel support coolers relief (CCW)	-	50	V
27B	Reactor vessel support coolers relief (CCW)	-	50	V
28A	Reactor coolant pump No. 3 seal	925	1,400	III
28B	Reactor coolant pump No. 3 seal	925	1,400	III
29A	Excess letdown heat exchanger relief (CCW)	-	50	V
29B	Excess letdown heat exchanger relief (CCW)	-	50	V
30A	Miscellaneous equipment leakages	-	11,700	I
30B	Miscellaneous equipment leakages	-	11,700	I
31A	Reactor coolant drain tank relief valve	-	50	II
31B	Reactor coolant drain tank relief valve	-	50	II
33A	Miscellaneous pump leakage	70	10	III
33B	Miscellaneous pump leakage	70	110	III
34	Laboratory drains	10,220	15,330	IV
35	Laundry drains	32,760	49,140	V
36	Personnel decontamination	11,860	16,340	V

Stream Number[a]	Stream Identification	Design Basis Case Flow[b]	Normal Operation Case Flow[b]	Concentration Spectrum
37A	CVCS valve leakoffs	6	9	II
37B	CVCS valve leakoffs	6	9	II
38A	Letdown heat exchanger tube side drain	75	110	II
38B	Letdown heat exchanger tube side drain	75	110	II
39A	Volume control tank drain	150	225	II
39B	Volume control tank drain	150	225	II
40A	Charging pump (CCP1) drains	140	210	II
40B	Charging pump (CCP2) drains	140	210	II
41A	Reactor coolant filter	45	60	II
41B	Reactor coolant filter	45	60	II
42A	Seal water injection filter	90	135	II
42B	Seal water injection filter	90	135	II
43A	Seal water filter	45	60	II
43B	Seal water filter	45	60	II
44A	Ion exchange filter	45	60	IV
44B	Ion exchange filter	45	60	IV
45A	Liquid holdup tank drain	1,050	1,575	II
45B	Liquid holdup tank drain	700	1,050	II
46A	CVCS miscellaneous piping drains	200	300	II
46B	CVCS miscellaneous piping drains	200	300	II
47A	RHR heat exchanger drain	700	1,050	II
47B	RHR heat exchanger drain	700	1,050	II
48A	RHR pump drain	280	420	II
48B	RHR pump drain	280	420	II
49A	RHR piping drains	200	300	II
49B	RHR piping drains	200	300	II
50A	Spent fuel pit cooling system piping drains	200	300	III
50B	Spent fuel pit cooling system piping drains	200	300	III
51A	Spent fuel pit cooling system filter drains	225	340	III
51B	Spent fuel pit cooling system filter drains	225	340	III
52A	Containment sump pump discharge piping drain	200	300	III
52B	Containment sump pump discharge piping drain	200	300	III
[c]	Equipment drain receiver tank drain and overflow	-	-	-
[c]	Equipment drain receiver tank pump drain	-	-	-
[c]	Waste Concentrator Condensate tank drain and overflow	-	-	-
[c]	Waste Concentrator Condensate tank pump drain	-	-	-

TABLE 11.2-5

Stream Number[(a)]	Stream Identification	Design Basis Case Flow[(b)]	Normal Operation Case Flow[(b)]	Concentration Spectrum
(c)	Radwaste concentrator heat exchanger drains	-	-	-
(c)	Radwaste concentrator pump drains	-	-	-
(c)	Waste concentrates tank drain and overflow	-	-	-
53	Spent resin motive water pump drains	60	90	III
54A	Waste gas moisture separator drain	40	60	III
54B	Waste gas moisture separator drain	20	30	III
55A	Waste gas decay tank drain	420	630	III
55B	Waste gas decay tank drain	420	630	III
56A	Waste gas compressor inlet piping drain	200	300	III
56B	Waste gas compressor inlet piping drain	200	300	III
57A	Sample sink drains	2,190	3,290	III
57B	Sample sink drains	2,190	3,290	III
58A	CVCS demineralizer overflow	5,500	5,500	III
58B	CVCS demineralizer overflow	5,500	5,500	III
59A	Steam generator blowdown tank drain	(d)	(d)	(d)
59B	Steam generator blowdown tank drain	(d)	(d)	(d)
(c)	Spent resin tank overflow	-	-	-
60A	Waste regenerant tank discharge	-	121,700	(e)
60B	Waste regenerant tank discharge	-	121,700	(e)

(a) The letters "A" and "B" on the stream numbers refer to Units 1 and 2 inputs, respectively.

(b) Annual estimated flow in gallons per year.

(c) These streams are intra-system leakages and are not counted as input.

(d) The steam generator blowdown tank will have significant activity only when significant primary to secondary leakage occurs.

(e) Calculated from secondary system activity concentrations and blowdown flowrate.

(f) Equipment is abandoned in place and no longer in use.

TABLE 11.2-6

ISOTOPIC FLOWS THROUGH CVC SYSTEM, DESIGN BASIS CASE

	Liquid Holdup Tank		BA Evap Feed Ion Exchangers		Monitor Tank	
Nuclide	Inflow, Ci/hr	Outflow, Ci/hr	Inflow, Ci/hr	Liq Outflow, Ci/hr	Inflow, Ci/hr	To Wst Cond Tank, Ci/hr
H-3	0.230E-00	0.229E-00	0.229E-00	0.223E-00	0.223E-00	0.149E-00
Cr-51	0.318E-05	0.188E-05	0.188E-09	0.188E-12	0.188E-12	0.124E-12
Mn-54	0.517E-06	0.492E-06	0.492E-10	0.492E-13	0.492E-13	0.328E-13
Fe-55	0.264E-05	0.120E-07	0.120E-11	0.120E-14	0.120E-14	0.705E-15
Co-58	0.267E-04	0.217E-04	0.217E-08	0.217E-11	0.217E-11	0.144E-11
Fe-59	0.167E-05	0.121E-05	0.121E-09	0.121E-12	0.121E-12	0.799E-13
Co-60	0.332E-05	0.329E-05	0.329E-09	0.329E-12	0.329E-12	0.219E-12
Kr-83	0.211E-01	0.0	0.0	0.0	0.0	0.0
Kr-85M	0.109E-00	0.365E-35	0.365E-35	0.0	0.0	0.0
Kr-85	0.243E-00	0.242E-00	0.242E-00	0.0	0.0	0.0
Kr-87	0.594E-01	0.0	0.0	0.0	0.0	0.0
Kr-88	0.186E-00	0.323E-55	0.323E-55	0.0	0.0	0.0
Sr-89	0.381E-05	0.287E-05	0.287E-09	0.287E-12	0.287E-12	0.190E-12
Sr-90	0.183E-06	0.183E-06	0.183E-10	0.183E-13	0.183E-13	0.122E-13
Y-90	0.344E-04	0.327E-06	0.327E-06	0.327E-09	0.327E-09	0.192E-10
Sr-91	0.248E-05	0.615E-21	0.615E-25	0.615E-28	0.615E-28	0.174E-28
Y-91	0.354E-02	0.279E-02	0.279E-02	0.279E-05	0.279E-05	0.185E-06
Sr-92	0.101E-05	0.669E-62	0.669E-66	0.669E-69	0.669E-69	0.205E-70
Y-92	0.141E-03	0.106E-45	0.106E-45	0.106E-48	0.106E-48	0.700E-51
Zr-95	0.946E-06	0.757E-06	0.757E-10	0.757E-13	0.757E-13	0.502E-13
Nb-95	0.919E-06	0.893E-06	0.893E-10	0.893E-13	0.893E-13	0.595E-13
Mo-99	0.830E-00	0.488E-02	0.488E-02	0.488E-05	0.488E-05	0.288E-07
I-131	0.490E-01	0.802E-02	0.802E-04	0.802E-06	0.802E-08	0.513E-08
Te-132	0.515E-02	0.582E-04	0.582E-06	0.582E-09	0.582E-11	0.349E-11

TABLE 11.2-6

	Liquid Holdup Tank		BA Evap Feed Ion Exchangers		Monitor Tank	
Nuclide	Inflow, Ci/hr	Outflow, Ci/hr	Inflow, Ci/hr	Liq Outflow, Ci/hr	Inflow, Ci/hr	To Wst Cond Tank, Ci/hr
I-132	0.176E-01	0.600E-04	0.600E-06	0.600E-08	0.600E-10	0.472E-11
I-133	0.669E-01	0.400E-08	0.400E-10	0.400E-12	0.400E-14	0.180E-14
Xe-133M	0.183E-00	0.329E-03	0.329E-03	0.0	0.0	0.0
Xe-133	0.154E-02	0.997E-00	0.997E-00	0.0	0.0	0.0
Cs-134	0.908E-02	0.890E-02	0.445E-03	0.445E-06	0.445E-06	0.297E-06
I-134	0.893E-02	0.0	0.0	0.0	0.0	0.0
I-135	0.369E-01	0.846E-24	0.846E-26	0.846E-28	0.846E-30	0.163E-30
Xe-135M	0.233E-01	0.128E-24	0.128E-24	0.0	0.0	0.0
Xe-135	0.327E-00	0.139E-16	0.139E-16	0.0	0.0	0.0
Cs-136	0.246E-02	0.804E-03	0.402E-04	0.402E-07	0.402E-07	0.261E-07
Cs-137	0.163E-01	0.162E-01	0.812E-03	0.812E-06	0.812E-06	0.542E-06
Xe-138	0.314E-01	0.0	0.0	0.0	0.0	0.0
Ba-140	0.645E-05	0.207E-05	0.207E-09	0.207E-12	0.207E-12	0.134E-12
La-140	0.228E-05	0.238E-05	0.238E-09	0.238E-12	0.238E-12	0.154E-12
Ce-144	0.557E-06	0.529E-06	0.529E-10	0.529E-13	0.529E-13	0.353E-13
Pr-144	0.557E-06	0.529E-06	0.529E-10	0.529E-13	0.529E-13	0.353E-13

TABLE 11.2-7

ISOTOPIC FLOWS THROUGH CVC SYSTEM, NORMAL OPERATION CASE

	Liquid Holdup Tank		BA Evap Feed Ion Exchangers		Monitor Tank	
Nuclide	Inflow, Ci/hr	Outflow, Ci/hr	Inflow, Ci/hr	Liq Outflow, Ci/hr	Inflow, Ci/hr	To Wst Cond Tank, Ci/hr
H-3	0.218E 00	0.217E 00	0.217E 00	0.211E 00	0.211E 00	0.140E 00
Cr-51	0.317E-05	0.188E-05	0.188E-09	0.188E-12	0.188E-12	0.124E-12
Mn-54	0.516E-06	0.492E-06	0.492E-10	0.492E-13	0.492E-13	0.328E-13
Fe-55	0.263E-05	0.120E-07	0.120E-11	0.120E-14	0.120E-14	0.705E-15
Co-58	0.266E-04	0.217E-04	0.217E-08	0.217E-11	0.217E-11	0.144E-11
Fe-59	0.167E-05	0.121E-05	0.121E-09	0.121E-12	0.121E-12	0.790E-13
Co-60	0.331E-05	0.329E-05	0.329E-09	0.329E-12	0.329E-12	0.219E-12
Kr-83M	0.252E-02	0.0	0.0	0.0	0.0	0.0
Kr-85M	0.130E-01	0.436E-36	0.436E-36	0.0	0.0	0.0
Kr-85	0.229E-01	0.228E-01	0.228E-01	0.0	0.0	0.0
Kr-87	0.713E-02	0.0	0.0	0.0	0.0	0.0
Kr-88	0.223E-01	0.386E-56	0.386E-56	0.0	0.0	0.0
Sr-89	0.457E-06	0.344E-06	0.344E-10	0.344E-13	0.344E-13	0.228E-13
Sr-90	0.219E-07	0.219E-07	0.219E-11	0.219E-14	0.219E-14	0.146E-14
Y-90	0.411E-05	0.392E-07	0.392E-07	0.392E-10	0.392E-10	0.230E-11
Sr-91	0.297E-06	0.737E-22	0.737E-26	0.737E-29	0.737E-29	0.209E-29
Y-91	0.412E-03	0.325E-03	0.325E-03	0.325E-06	0.325E-06	0.216E-07
Sr-92	0.122E-06	0.803E-63	0.803E-67	0.803E-70	0.803E-70	0.246E-71
Y-92	0.169E-04	0.127E-46	0.127E-46	0.127E-49	0.127E-49	0.840E-52
Zr-95	0.113E-06	0.908E-07	0.908E-11	0.908E-14	0.908E-14	0.602E-14
Nb-95	0.110E-06	0.107E-06	0.107E-10	0.107E-13	0.107E-13	0.713E-14
M0-99	0.992E-01	0.583E-03	0.583E-03	0.583E-06	0.583E-06	0.344E-08
I-131	0.588E-02	0.962E-03	0.962E-05	0.962E-07	0.962E-09	0.615E-09

TABLE 11.2-7

	Liquid Holdup Tank		BA Evap Feed Ion Exchangers		Monitor Tank	
Nuclide	Inflow, Ci/hr	Outflow, Ci/hr	Inflow, Ci/hr	Liq Outflow, Ci/hr	Inflow, Ci/hr	To Wst Cond Tank, Ci/hr
Te-132	0.618E-03	0.698E-05	0.698E-07	0.698E-10	0.698E-12	0.418E-12
I-132	0.211E-02	0.720E-05	0.720E-07	0.720E-09	0.720E-11	0.567E-12
I-133	0.802E-02	0.480E-09	0.480E-11	0.480E-13	0.480E-15	0.215E-15
Xe-133M	0.213E-01	0.383E-04	0.383E-04	0.0	0.0	0.0
Xe-133	0.174E 01	0.112E 00	0.112E 00	0.0	0.0	0.0
Cs-134	0.110E-02	0.108E-02	0.539E-04	0.539E-07	0.539E-07	0.360E-07
I-134	0.107E-02	0.0	0.0	0.0	0.0	0.0
I-135	0.443E-02	0.101E-24	0.101E-26	0.101E-28	0.101E-30	0.196E-31
Xe-135M	0.279E-02	0.153E-25	0.153E-25	0.0	0.0	0.0
Xe-135	0.390E-01	0.166E-17	0.166E-17	0.0	0.0	0.0
Cs-136	0.295E-03	0.964E-04	0.482E-05	0.482E-08	0.482E-08	0.313E-08
Cs-137	0.195E-02	0.195E-02	0.975E-04	0.975E-07	0.975E-07	0.650E-07
Xe-138	0.377E-02	0.0	0.0	0.0	0.0	0.0
Ba-140	0.773E-06	0.248E-06	0.248E-10	0.248E-13	0.248E-13	0.161E-13
La-140	0.273E-06	0.285E-06	0.285E-10	0.285E-13	0.285E-13	0.185E-13
Ce-144	0.668E-07	0.635E-07	0.835E-11	0.635E-14	0.635E-14	0.423E-14
Pr-144	0.668E-07	0.635E-07	0.635E-11	0.635E-14	0.635E-14	0.423E-14

TABLE 11.2-8

ANNUAL FLOW AND ACTIVITY CONCENTRATION OF PROCESS STREAMS FOR DESIGN BASIS CASE

Stream Number[(a)]	1	2	3	4	5
Annual Flow, gal./yr	3850	17370	0.0	140	44620
Nuclide	Concentration, µCi/cc				
H-3	0.533E-02	0.697E-03	0.0	0.110E-01	0.110E-04
Cr-51	0.899E-05	0.118E-05	0.0	0.185E-04	0.176E-07
Mn-54	0.148E-05	0.193E-06	0.0	0.304E-05	0.303E-08
Fe-55	0.444E-04	0.581E-06	0.0	0.915E-05	0.548E-08
Co-58	0.795E-04	0.104E-04	0.0	0.164E-03	0.160E-06
Fe-59	0.471E-05	0.616E-06	0.0	0.970E-05	0.941E-08
Co-60	0.945E-05	0.124E-05	0.0	0.194E-04	0.194E-07
Sr-89	0.112E-04	0.146E-05	0.0	0.230E-04	0.224E-07
Sr-90	0.533E-06	0.697E-07	0.0	0.110E-05	0.110E-08
Y-90	0.778E-07	0.102E-07	0.0	0.160E-06	0.541E-09
Sr-91	0.242E-06	0.317E-07	0.0	0.499E-06	0.163E-10
Y-91	0.991E-05	0.130E-05	0.0	0.204E-04	0.199E-07
Sr-92	0.133E-10	0.173E-11	0.0	0.273E-10	0.122E-18
Y-92	0.119E-09	0.156E-10	0.0	0.245E-09	0.314E-16
Zr-95	0.271E-05	0.354E-06	0.0	0.558E-05	0.546E-08
Nb-95	0.270E-05	0.353E-06	0.0	0.556E-05	0.556E-08
M0-99	0.137E-03	0.179E-04	0.0	0.281E-03	0.172E-06
I-131	0.114E-01	0.149E-02	0.0	0.234E-01	0.197E-04
Te-132	0.925E-03	0.121E-03	0.0	0.190E-02	0.124E-05
I-132	0.954E-03	0.125E-03	0.0	0.197E-02	0.128E-05
I-133	0.374E-02	0.489E-03	0.0	0.770E-02	0.158E-05
Cs-134	0.943E-03	0.123E-03	0.0	0.194E-02	0.194E-05
I-134	0.492E-19	0.643E-20	0.0	0.101E-18	0.211E-38
I-135	0.707E-04	0.924E-05	0.0	0.146E-03	0.102E-08
Cs-136	0.225E-03	0.294E-04	0.0	0.462E-03	0.416E-06
Cs-137	0.169E-02	0.221E-03	0.0	0.347E-02	0.347E-05
Ba-140	0.170E-04	0.222E-05	0.0	0.349E-04	0.313E-07
La-140	0.129E-04	0.169E-05	0.0	0.266E-04	0.301E-07
Ce-144	0.161E-05	0.211E-06	0.0	0.332E-05	0.330E-08
Pr-144	0.161E-05	0.211E-06	0.0	0.332E-05	0.330E-08

TABLE 11.2-8

Stream Number[(a)]	6	7	8	9	10
Annual Flow, gal./yr	10220	21360	76200	0.0	12690
Nuclide	Concentration, µCi/cc				
H-3	0.110E-03	0.160E-02	0.469E-03	0.0	0.491E+00
Cr-51	0.176E-06	0.190E-05	0.567E-06	0.0	0.029E-03
Mn-54	0.303E-07	0.430E-06	0.126E-06	0.0	0.136E-03
Fe-55	0.548E-07	0.367E-07	0.208E-07	0.0	0.414E-03
Co-58	0.160E-05	0.208E-04	0.614E-05	0.0	0.733E-02
Fe-59	0.941E-07	0.114E-05	0.338E-06	0.0	0.435E-03
Co-60	0.194E-06	0.282E-05	0.828E-06	0.0	0.871E-03
Sr-89	0.224E-06	0.277E-05	0.821E-06	0.0	0.103E-02
Sr-90	0.110E-07	0.160E-06	0.469E-07	0.0	0.492E-04
Y-90	0.541E-08	0.156E-06	0.449E-07	0.0	0.720E-05
Sr-91	0.163E-09	0.287E-17	0.314E-10	0.0	0.328E-04
Y-91	0.199E-06	0.254E-05	0.750E-06	0.0	0.913E-03
Sr-92	0.122E-17	0.0	0.235E-16	0.0	0.434E-05
Y-92	0.314E-15	0.0	0.605E-16	0.0	0.563E-06
Zr-95	0.546E-07	0.701E-06	0.207E-06	0.0	0.250E-03
Nb-95	0.556E-07	0.797E-06	0.234E-06	0.0	0.249E-03
Mo-99	0.172E-05	0.134E-05	0.707E-06	0.0	0.127E-01
I-131	0.197E-03	0.102E-02	0.324E-03	0.0	0.105E+01
Te-132	0.124E-04	0.140E-04	0.631E-05	0.0	0.860E-01
I-132	0.128E-04	0.144E-04	0.651E-05	0.0	0.935E-01
I-133	0.158E-04	0.172E-07	0.305E-05	0.0	0.366E+00
Cs-134	0.194E-04	0.279E-03	0.821E-04	0.0	0.870E-01
I-134	0.211E-37	0.0	0.406E-38	0.0	0.345E-02
I-135	0.102E-07	0.171E-19	0.196E-08	0.0	0.212E-01
Cs-136	0.416E-05	0.319E-04	0.976E-05	0.0	0.207E-01
Cs-137	0.347E-04	0.506E-03	0.149E-03	0.0	0.156E+00
Ba-140	0.313E-06	0.238E-05	0.729E-06	0.0	0.157E-02
La-140	0.301E-06	0.274E-05	0.825E-06	0.0	0.118E-02
Ce-144	0.330E-07	0.468E-06	0.137E-06	0.0	0.149E-03
Pr-144	0.330E-07	0.468E-06	0.137E-06	0.0	0.149E-03

TABLE 11.2-8

Stream Number[(a)]	58A&B	59A&B	60A&B	11	12
Annual Flow, gal./yr	11000	0.0	0.0	23990	0.0
Nuclide	Concentration, µCi/cc				
H-3	0.110E-01	0.0	0.0	0.264E+00	0.0
Cr-51	0.185E-04	0.0	0.0	0.315E-03	0.0
Mn-54	0.304E-05	0.0	0.0	0.712E-04	0.0
Fe-55	0.915E-05	0.0	0.0	0.614E-05	0.0
Co-58	0.164E-03	0.0	0.0	0.345E-02	0.0
Fe-59	0.970E-05	0.0	0.0	0.189E-03	0.0
Co-60	0.194E-04	0.0	0.0	0.467E-03	0.0
Sr-89	0.230E-04	0.0	0.0	0.460E-03	0.0
Sr-90	0.110E-05	0.0	0.0	0.265E-04	0.0
Y-90	0.160E-06	0.0	0.0	0.259E-04	0.0
Sr-91	0.499E-06	0.0	0.0	0.694E-15	0.0
Y-91	0.204E-04	0.0	0.0	0.420E-03	0.0
Sr-92	0.273E-10	0.0	0.0	0.0	0.0
Y-92	0.245E-09	0.0	0.0	0.0	0.0
Zr-95	0.558E-05	0.0	0.0	0.116E-03	0.0
Nb-95	0.556E-05	0.0	0.0	0.132E-03	0.0
Mo-99	0.281E-03	0.0	0.0	0.223E-03	0.0
I-131	0.234E-01	0.0	0.0	0.170E+00	0.0
Te-132	0.190E-02	0.0	0.0	0.233E-02	0.0
I-132	0.197E-02	0.0	0.0	0.241E-02	0.0
I-133	0.770E-02	0.0	0.0	0.301E-05	0.0
Cs-134	0.194E-02	0.0	0.0	0.463E-01	0.0
I-134	0.101E-18	0.0	0.0	0.0	0.0
I-135	0.146E-03	0.0	0.0	0.910E-17	0.0
Cs-136	0.462E-03	0.0	0.0	0.530E-02	0.0
Cs-137	0.347E-02	0.0	0.0	0.838E-01	0.0
Ba-140	0.349E-04	0.0	0.0	0.396E-03	0.0
La-140	0.266E-04	0.0	0.0	0.454E-03	0.0
Ce-144	0.332E-05	0.0	0.0	0.775E-04	0.0
Pr-144	0.332E-05	0.0	0.0	0.775E-04	0.0

TABLE 11.2-8

Stream Number[a]	13	14	15	16	17
Annual Flow, gal./yr	0.0	23990	700,000	723,990	800,190
Nuclide	Concentration, µCi/cc				
H-3	0.0	0.264E+00	0.101E+01	0.985E-00	0.891E+00
Cr-51	0.0	0.315E-06	0.806E-12	0.104E-07	0.634E-07
Mn-54	0.0	0.712E-07	0.217E-12	0.236E-08	0.141E-07
Fe-55	0.0	0.614E-08	0.468E-14	0.203E-09	0.216E-08
Co-58	0.0	0.345E-05	0.957E-11	0.114E-06	0.688E-06
Fe-59	0.0	0.189E-06	0.503E-12	0.626E-08	0.379E-07
Co-60	0.0	0.467E-06	0.146E-11	0.155E-07	0.929E-07
Sr-89	0.0	0.460E-06	0.126E-11	0.152E-07	0.919E-07
Sr-90	0.0	0.265E-07	0.806E-13	0.878E-09	0.526E-08
Y-90	0.0	0.259E-07	0.126E-09	0.980E-09	0.516E-08
Sr-91	0.0	0.694E-18	0.116E-27	0.0	0.299E-11
Y-91	0.0	0.420E-06	0.121E-05	0.118E-05	0.114E-05
Sr-92	0.0	0.0	0.136E-69	0.0	0.224E-17
Y-92	0.0	0.0	0.463E-50	0.0	0.576E-17
Zr-95	0.0	0.116E-06	0.332E-12	0.384E-08	0.232E-07
Nb-95	0.0	0.132E-06	0.393E-12	0.437E-08	0.262E-07
Mo-99	0.0	0.223E-06	0.191E-06	0.192E-06	0.241E-06
I-131	0.0	0.170E-03	0.337E-07	0.567E-05	0.360E-04
Te-132	0.0	0.233E-05	0.232E-10	0.772E-07	0.673E-06
I-132	0.0	0.241E-05	0.312E-10	0.799E-07	0.690E-06
I-133	0.0	0.301E-08	0.121E-13	0.997E-10	0.291E-06
Cs-134	0.0	0.232E-02	0.196E-05	0.788E-04	0.791E-04
I-134	0.0	0.0	0.0	0.0	0.0
I-135	0.0	0.910E-20	0.187E-09	0.0	0.187E-09
Cs-136	0.0	0.265E-03	0.171E-05	0.898E-05	0.903E-05
Cs-137	0.0	0.419E-02	0.357E-05	0.142E-03	0.143E-03
Ba-140	0.0	0.396E-06	0.906E-12	0.131E-07	0.183E-07
La-140	0.0	0.454E-06	0.101E-11	0.150E-07	0.921E-07
Ce-144	0.0	0.775E-07	0.232E-12	0.257E-08	0.154E-07
Pr-144	0.0	0.776E-07	0.232E-12	0.257E-08	0.154E-07

TABLE 11.2-8

Stream Number[a]	18	19
Annual Flow, gal./yr	800,190	(See Section 11.2.7.)
Nuclide	Concentration, μCi/cc	
H-3	0.891E+00	0.774E-06
Cr-51	0.634E-07	0.551E-13
Mn-54	0.141E-07	0.123E-13
Fe-55	0.216E-08	0.188E-14
Co-58	0.688E-06	0.598E-12
Fe-59	0.379E-07	0.329E-13
Co-60	0.929E-07	0.807E-13
Sr-89	0.919E-07	0.799E-13
Sr-90	0.526E-08	0.457E-14
Y-90	0.516E-08	0.448E-14
Sr-91	0.299E-11	0.260E-17
Y-91	0.114E-05	0.991E-12
Sr-92	0.224E-19	0.195E-23
Y-92	0.576E-17	0.501E-23
Zr-95	0.232E-07	0.202E-13
Nb-95	0.262E-07	0.228E-13
Mo-99	0.241E-06	0.209E-12
I-131	0.360E-04	0.313E-10
Te-132	0.673E-06	0.585E-12
I-132	0.690E-06	0.600E-12
I-133	0.291E-06	0.253E-12
Cs-134	0.791E-04	0.687E-10
I-134	0.0	0.0
I-135	0.187E-09	0.164E-15
Cs-136	0.903E-05	0.785E-11
Cs-137	0.143E-03	0.124E-09
Ba-140	0.813E-07	0.706E-13
La-140	0.921E-07	0.800E-13
Ce-144	0.154E-07	0.134E-13
Pr-144	0.154E-07	0.134E-13

(a) See Figure 11.2-2 for waste stream number identification.

TABLE 11.2-9

ANNUAL FLOW AND ACTIVITY CONCENTRATION OF PROCESS STREAMS FOR NORMAL OPERATION CASE

Stream Number[(a)]	1	2	3	4	5
Annual Flow, gal./yr	29800	37530	100	220	65480
Nuclide	Concentration, µCi/cc				
H-3	0.009E+00	0.307E+00	0.103E+01	0.103E-01	0.103E-04
Cr-51	0.153E-02	0.582E-03	0.185E-02	0.185E-04	0.176E-07
Mn-54	0.240E-03	0.914E-04	0.304E-03	0.304E-05	0.303E-08
Fe-55	0.120E-02	0.457E-03	0.915E-03	0.915E-05	0.548E-08
Co-58	0.131E-01	0.499E-02	0.164E-01	0.164E-03	0.160E-06
Fe-59	0.787E-03	0.299E-03	0.970E-03	0.970E-05	0.941E-08
Co-60	0.153E-02	0.582E-03	0.194E-02	0.194E-04	0.194E-07
Sr-89	0.219E-03	0.831E-04	0.271E-03	0.271E-05	0.263E-08
Sr-90	0.104E-04	0.395E-05	0.132E-04	0.132E-06	0.132E-09
Y-90	0.186E-05	0.706E-06	0.194E-05	0.194E-07	0.651E-10
Sr-91	0.142E-03	0.539E-04	0.590E-05	0.590E-07	0.193E-11
Y-91	0.197E-03	0.748E-04	0.245E-03	0.245E-05	0.239E-08
Sr-92	0.578E-04	0.220E-04	0.329E-09	0.329E-11	0.147E-19
Y-92	0.731E-05	0.278E-05	0.295E-08	0.295E-10	0.378E-17
Zr-95	0.535E-04	0.204E-04	0.667E-04	0.667E-06	0.653E-09
Nb-95	0.525E-04	0.199E-04	0.667E-04	0.667E-06	0.667E-09
Mo-99	0.437E-02	0.166E-02	0.341E-02	0.341E-04	0.209E-07
I-131	0.251E+00	0.955E-01	0.269E+00	0.269E-02	0.226E-05
Te-132	0.273E-01	0.104E-01	0.227E-01	0.227E-03	0.148E-06
I-132	0.917E-01	0.349E-01	0.234E-01	0.234E-03	0.153E-06
I-133	0.349E+00	0.133E+00	0.913E-01	0.913E-01	0.187E-06
Cs-134	0.186E-01	0.706E-02	0.236E-01	0.236E-03	0.235E-06
I-134	0.469E-01	0.178E-01	0.124E-17	0.124E-19	0.259E-39
I-135	0.196E+00	0.747E-01	0.175E-02	0.175E-04	0.122E-09
Cs-136	0.492E-02	0.187E-02	0.562E-02	0.562E-04	0.505E-07
Cs-137	0.328E-01	0.125E-01	0.417E-01	0.417E-03	0.417E-06
Ba-140	0.372E-03	0.141E-03	0.424E-03	0.424E-05	0.381E-08
La-140	0.131E-03	0.499E-04	0.323E-03	0.323E-05	0.366E-08
Ce-144	0.317E-04	0.120E-04	0.401E-04	0.401E-06	0.399E-09
Pr-144	0.317E-04	0.120E-04	0.401E-04	0.401E-04	0.399E-09

TABLE 11.2-9

Stream Number[a]	6	7	8	9	10
Annual Flow, gal./yr	15330	67650	80100	1000	19000
Nuclide	Concentration, µCi/cc				
H-3	0.103E-03	0.527E+00	0.278E-04	0.103E-01	0.459E+00
Cr-51	0.176E-06	0.705E-03	0.477E-07	0.195E-02	0.828E-03
Mn-54	0.303E-07	0.152E-03	0.820E-08	0.306E-03	0.136E-03
Fe-55	0.548E-07	0.216E-04	0.148E-07	0.153E-02	0.413E-03
Co-58	0.160E-05	0.748E-02	0.434E-06	0.167E-01	0.731E-02
Fe-59	0.941E-07	0.414E-03	0.255E-07	0.100E-02	0.434E-03
Co-60	0.194E-06	0.994E-03	0.526E-07	0.195E-02	0.869E-03
Sr-89	0.263E-07	0.118E-03	0.713E-08	0.278E-03	0.121E-03
Sr-90	0.132E-08	0.678E-05	0.357E-09	0.132E-04	0.590E-05
Y-90	0.651E-09	0.663E-05	0.176E-09	0.236E-05	0.869E-06
Sr-91	0.193E-10	0.365E-14	0.521E-11	0.181E-03	0.374E-05
Y-91	0.239E-07	0.110E-03	0.648E-08	0.250E-03	0.109E-03
Sr-92	0.147E-18	0.0	0.397E-19	0.737E-04	0.465E-06
Y-92	0.378E-16	0.0	0.102E-16	0.931E-05	0.601E-07
Zr-95	0.653E-08	0.302E-04	0.177E-08	0.681E-04	0.298E-04
Nb-95	0.667E-08	0.338E-04	0.181E-08	0.667E-04	0.298E-04
Mo-99	0.209E-06	0.929E-04	0.566E-07	0.556E-02	0.154E-02
I-131	0.226E-04	0.491E-01	0.613E-05	0.320E+00	0.121E+00
Te-132	0.148E-05	0.897E-03	0.400E-06	0.347E-01	0.102E-01
I-132	0.153E-05	0.926E-03	0.413E-06	0.117E+00	0.110E-01
I-133	0.187E-05	0.348E-05	0.507E-06	0.445E+00	0.430E-01
Cs-134	0.235E-05	0.120E-01	0.637E-06	0.236E-01	0.105E-01
I-134	0.259E-38	0.0	0.701E-39	0.598E-01	0.377E-03
I-135	0.122E-08	0.103E-15	0.330E-09	0.250E+00	0.235E-02
Cs-136	0.505E-06	0.152E-02	0.137E-06	0.625E-02	0.252E-02
Cs-137	0.417E-05	0.214E-01	0.113E-05	0.417E-01	0.186E-01
Ba-140	0.381E-07	0.114E-03	0.103E-07	0.473E-03	0.190E-03
La-140	0.366E-07	0.130E-03	0.991E-08	0.167E-03	0.143E-03
Ce-144	0.399E-08	0.200E-04	0.108E-08	0.403E-04	0.179E-04
Pr-144	0.399E-08	0.200E-04	0.108E-08	0.403E-04	0.179E-04

TABLE 11.2-9

Stream Number[a]	58A&B	59A&B	60A&B	11	12
Annual Flow, gal./yr	11000	300	0	98650	0
Nuclide	Concentration, µCi/cc				
H-3	0.1832-01	0.0	0.0	0.461E+00	0.0
Cr-51	0.185E-04	0.0	0.0	0.469E-03	0.0
Mn-54	0.304E-05	0.0	0.0	0.130E-03	0.0
Fe-55	0.915E-05	0.0	0.0	0.305E-05	0.0
Co-58	0.164E-05	0.0	0.0	0.587E-02	0.0
Fe-59	0.970E-05	0.0	0.0	0.305E-03	0.0
Co-60	0.194E-04	0.0	0.0	0.867E-03	0.0
Sr-89	0.271E-05	0.0	0.0	0.889E-04	0.0
Sr-90	0.132E-06	0.0	0.0	0.593E-05	0.0
Y-90	0.194E-07	0.0	0.0	0.590E-05	0.0
Sr-91	0.590E-07	0.0	0.0	0.101E-15	0.1
Y-91	0.245E-05	0.0	0.0	0.849E-04	0.0
Sr-92	0.329E-11	0.0	0.0	0.0	0.0
Y-92	0.295E-10	0.0	0.0	0.0	0.0
Zr-95	0.667E-06	0.0	0.0	0.234E-04	0.0
Nb-95	0.667E-06	0.0	0.0	0.286E-04	0.0
Mo-99	0.341E-04	0.0	0.0	0.137E-04	0.0
I-131	0.269E-02	0.0	0.0	0.181E-01	0.0
Te-132	0.227E-03	0.0	0.0	0.149E-03	0.0
I-132	0.234E-03	0.0	0.0	0.154E-03	0.0
I-133	0.913E-03	0.0	0.0	0.197E-06	0.0
Cs-134	0.236E-03	0.0	0.0	0.104E-01	0.0
I-134	0.124E-19	0.0	0.0	0.0	0.0
I-135	0.175E-04	0.0	0.0	0.241E-17	0.0
Cs-136	0.562E-04	0.0	0.0	0.758E-03	0.0
Cs-137	0.417E-03	0.0	0.0	0.187E-01	0.0
Ba-140	0.424E-05	0.0	0.0	0.561E-04	0.0
La-140	0.323E-05	0.0	0.0	0.645E-04	0.0
Ce-144	0.401E-06	0.0	0.0	0.170E-04	0.0
Pr-144	0.401E-06	0.0	0.0	0.170E-04	0.0

TABLE 11.2-9

Stream Number[a]	13	14	15	16	17
Annual Flow, gal./yr	0	98650	7000000	798650	878950
Nuclide	Concentration, µCi/cc				
H-3	0.0	0.461E+00	0.906E+00	0.851E+00	0.773E+00
Cr-51	0.0	0.469E-06	0.806-12	0.579E-07	0.570E-07
Mn-54	0.0	0.130E-06	0.217E-12	0.161E-07	0.154E-07
Fe-55	0.0	0.305E-08	0.468E-14	0.377E-09	0.169E-08
Co-58	0.0	0.587E-05	0.957E-11	0.725E-06	0.698E-06
Fe-59	0.0	0.305E-06	0.503E-12	0.377E-07	0.366E-07
Co-60	0.0	0.867E-06	0.146E-11	0.107E-06	0.102E-06
Sr-89	0.0	0.889E-07	0.151E-12	0.110E-07	0.106E-07
Sr-90	0.0	0.593E-08	0.957E-14	0.732E-09	0.698E-09
Y-90	0.0	0.590E-08	0.151E-10	0.742E-09	0.690E-09
Sr-91	0.0	0.101E-18	0.136E-28	0.125E-19	0.475E-12
Y-91	0.0	0.849E-07	0.141E-06	0.134E-06	0.122E-06
Sr-92	0.0	0.0	0.161E-70	0.0	0.0
Y-92	0.0	0.0	0.554E-51	0.0	0.0
Zr-95	0.0	0.234E-07	0.398E-13	0.289E-08	0.279E-08
Nb-95	0.0	0.286E-07	0.473E-13	0.353E-09	0.337E-09
Mo-99	0.0	0.137E-07	0.227E-07	0.216E-07	0.248E-07
I-131	0.0	0.181E-04	0.408E-08	0.224E-05	0.259E-05
Te-132	0.0	0.149E-06	0.277E-11	0.184E-07	0.532E-07
I-132	0.0	0.154E-06	0.373E-11	0.190E-07	0.549E-07
I-133	0.0	0.197E-09	0.141E-14	0.235E-10	0.462E-07
Cs-134	0.0	0.520E-03	0.237E-06	0.644E-04	0.586E-04
I-134	0.0	0.0	0.0	0.0	0.0
I-135	0.0	0.241E-20	0.131E-30	0.0	0.301E-10
Cs-136	0.0	0.379E-04	0.206E-07	0.470E-05	0.428E-05
Cs-137	0.0	0.935E-03	0.428E-06	0.116E-03	0.106E-03
Ba-140	0.0	0.561E-07	0.106E-12	0.693E-08	0.724E-08
La-140	0.0	0.654E-07	0.121E-12	0.797E-08	0.815E-08
Ce-144	0.0	0.170E-07	0.282E-13	0.210E-08	0.201E-08
Pr-144	0.0	0.170E-07	0.282E-13	0.210E-08	0.201E-08

TABLE 11.2-9

Stream Number[a]	18	19
Annual Flow, gal./yr	878750	(See Section 11.2.7.)
Nuclide	Concentration, µCi/cc	
H-3	0.773E+00	0.738E-06
Cr-51	0.570E-07	0.543E-13
Mn-54	0.154E-07	0.147E-13
Fe-55	0.169E-08	0.161E-14
Co-58	0.698E-06	0.666E-12
Fe-59	0.366E-07	0.349E-13
Co-60	0.102E-06	0.973E-13
Sr-89	0.106E-07	0.101E-13
Sr-90	0.698E-09	0.635E-15
Y-90	0.690E-09	0.658E-15
Sr-91	0.475E-12	0.453E-18
Y-91	0.122E-06	0.116E-12
Sr-92	0.0	0.0
Y-92	0.0	0.0
Zr-95	0.279E-08	0.266E-14
Nb-95	0.337E-09	0.306E-15
Mo-99	0.248E-07	0.237E-13
I-131	0.259E-05	0.247E-12
Te-132	0.532E-07	0.508E-13
I-132	0.549E-07	0.524E-13
I-133	0.462E-07	0.441E-13
Cs-134	0.586E-04	0.559E-10
I-134	0.0	0.0
I-135	0.301E-10	0.287E-16
Cs-136	0.428E-05	0.408E-11
Cs-137	0.106E-03	0.101E-09
Ba-140	0.724E-08	0.691E-14
La-140	0.815E-08	0.778E-14
Ce-144	0.201E-08	0.192E-14
Pr-144	0.201E-08	0.192E-14

(a) See Figure 11.2-3 for waste stream number identification.

TABLE 11.2-10

EQUIPMENT DESIGN SUMMARY DATA
LIQUID RADWASTE SYSTEM

Tank	Quantity	Type	Volume gal	Pressure, psig	Temperature, °F	Material
Reactor coolant drain	1[f]	Horiz	400	25	267	SS
Laundry and hot shower	2[a]	Vert	1,000	5	300	CS
Chemical drain	1[a]	Horiz	1,000	0	150	SS
Aux. Building sump	1[a]	-	7,300	0	120	SS
Misc. equip. drain	1[a]	-	5,500	0	180	SS
Processed waste receiver	2[a]	Vert	15,000	0	180	SS
Floor drain receiver	2[a]	Vert	15,000	0	180	SS
Equipment drain receiver	2[a]	Vert	15,000	0	180	SS
Demineralizer regenerant receiver	2[a]	Vert	15,000	0	180	[b]
Laundry/distillate	2[a]	Vert	25,000	0	150	SS
Containment structure sump	1[f]	NA	700	0	140	[g]
Reactor cavity sump	1[f]	NA	300	0	140	[g]
RHR pump room sump	1[f]	NA	500	0	180	[g]

Pump	Qty.	Type	Flow, gpm	Head, ft	Pressure, psig	Temp, °F	Mtl.[d]
Reactor coolant drain tank	2[f]	Vert Cent.	150	170	150	300	SS
Chemical drain	1[a]	Horiz Cent.[c]	20	122	150	180	SS
Laundry and hot shower drain	2[a]	Vert Cent.[c]	20	122	150	180	CS
Misc. equip. drain tank	2[a]	Horiz Cent.[c]	50	45	150	180	CS[h]
Floor drain receiver	2[a]	Vert. Cent.[c]	50	300	150	180	SS
Equipment drain receiver	2[a]	Vert Cent.[c]	50	300	150	180	SS
Processed waste receiver	2[a]	Vert Cent.[c]	50	122	150	180	SS
Containment structure sump	4[f]	Vert Cent.[c]	50	45	150	140	CI[h]
Demineralizer regenerant receiver	2[a]	Vert Cent.[c]	50	300	150	180	SS
Reactor cavity sump	2[f]	Horiz Cent.[e]	30	75	150	140	SS
RHR pump room sumps	4[f]	Vert Cent .	50	40	150	180	CI[h]
Aux. Building sump	2[a]	Horiz Cent.[e]	50	45	150	180	CI[h]
Laundry/distillate	2[a]	Horiz Cent.	150	200	150	115	SS

TABLE 11.2-10

Miscellaneous	Quantity	Capacity	Type
Radwaste filters	5[(a)]	50 gpm	Cartridge
Media filters	2[(a)]	50 gpm	Media bed
Ion exchangers	2[(a)]	50 gpm	Bead resin
Spent Resin Transfer Filters	2[(a)]	120 gpm	Cartridge

(a) Equipment common to Units 1 and 2
(b) Carbon steel with a neoprene lining
(c) Mechanical seal provided
(d) Wetted surfaces only
(e) Deep well jet pump
(f) Per unit
(g) Concrete
(h) Cast iron Ni Resist Type D2

TABLE 11.2-11

PARAMETERS USED IN TRITIUM ANALYSIS
FOR PLANT WATER SOURCES

Parameter	Value
Primary system volume, gal.	94,000
Volume of water in primary water storage tank, gal.	200,000
Volume of water in refueling water storage tank, gal.	450,000
Volume of water in spent fuel pool, gal.	442,000
Percent of mixing of spent fuel pool water with refueling canal during refueling	15
Evaporative loss from spent fuel pool during operation, gal./day	500
Evaporative loss from spent fuel pool during refueling, gal./day	1,360
Evaporative loss from refueling canal during refueling, gal./day	485

TABLE 11.2-13

CALCULATED AND ASSUMED HOLDUP TIMES
FOR LIQUID WASTE SYSTEM TANKS

Tank	Qty.	Capacity, gal.	Fill Time, Days	Release Time, Days	Assumed Decay Time, Days	Assumed Decay Time, Hours
Liquid holdup	5[a]	83,000	46.1	3.07	21.0	504.0
Monitor	2	25,000	0.93	0.093	0.5	12.0
Waste Condensate	1	15,000	2.23	0.56	1.0	24.0
Reactor coolant drain	1	400	116.8	7.4E-4	2.0	48.0
Laundry and hot shower	2[a]	1,000	3.6	0.03	2.0	48.0
Chemical drain	1[a]	1,000	7.6	0.014	2.0	48.0
Miscellaneous equipment drain	1[a]	20,000	123.0	0.3	2.0	48.0
Equipment drain receiver	1	15,000	42.5	0.56	14.0	336.0
Floor drain receiver	1	15,000	33.7	0.08	14.0	336.0
Waste regenerant	1	15,000	-	-	18.0	432.0

(a) Equipment common to both units.

TABLE 11.2-14

ESTIMATED ANNUAL ACTIVITY RELEASE FOR
DESIGN BASIS CASE (ONE UNIT)

Nuclide	Radwaste System, Ci/yr	Turbine Bldg Sump, Ci/yr	Condensate Polishing System, Ci/yr	One Unit Total, Ci/yr
H-3	0.135E+04	0.0	0.0	0.135E+04
Cr-51	0.960E-04	0.0	0.0	0.960E-04
Mn-54	0.213E-04	0.0	0.0	0.213E-04
Fe-55	0.327E-05	0.0	0.0	0.327E-05
Co-58	0.104E-02	0.0	0.0	0.104E-02
Fe-59	0.574E-04	0.0	0.0	0.574E-04
Co-60	0.141E-03	0.0	0.0	0.141E-03
Sr-89	0.139E-03	0.0	0.0	0.139E-03
Sr-90	0.797E-03	0.0	0.0	0.797E-03
Y-90	0.781E-05	0.0	0.0	0.781E-05
Sr-91	0.453E-08	0.0	0.0	0.453E-08
Y-91	0.173E-02	0.0	0.0	0.173E-02
Sr-92	0.339E-14	0.0	0.0	0.339E-14
Y-92	0.872E-14	0.0	0.0	0.872E-14
Zr-95	0.351E-04	0.0	0.0	0.351E-04
Mb-95	0.397E-04	0.0	0.0	0.397E-04
Mo-99	0.365E-03	0.0	0.0	0.365E-03
I-131	0.545E-01	0.0	0.0	0.545E-01
Te-132	0.102E-02	0.0	0.0	0.102E-02
I-132	0.104E-02	0.0	0.0	0.104E-02
I-133	0.441E-03	0.0	0.0	0.441E-03
Cs-134	0.120E-02	0.0	0.0	0.120E-02
I-134	0.0	0.0	0.0	0.0
I-135	0.284E-06	0.0	0.0	0.284E-06
Cs-136	0.137E-01	0.0	0.0	0.137E-01
Cs-137	0.216E+00	0.0	0.0	0.216E+00
Ba-140	0.123E-03	0.0	0.0	0.123E-03
La-140	0.139E-03	0.0	0.0	0.139E-03
Ce-144	0.233E-04	0.0	0.0	0.233E-04
Pr-144	0.233E-04	0.0	0.0	0.233E-04
Total (excluding H-3)				0.411E+00

TABLE 11.2-15

ESTIMATED ANNUAL ACTIVITY RELEASE FOR
NORMAL OPERATION CASE (ONE UNIT)

Nuclide	Radwaste System, Curies/yr	Turbine Bldg Sump, Curies/yr	Condensate Polishing System[(a)], Curies/yr	One Unit Total, Curies/yr
H-3	0.129E+04	0.430E+01	0.0	0.129E+04
Cr-51	0.948E-04	0.390E-06	0.106E-02	0.126E-02
Mn-54	0.256E-04	0.645E-07	0.246E-03	0.297E-03
Fe-55	0.281E-05	0.302E-06	0.120E-03	0.788E-03
Co-58	0.116E-02	0.334E-05	0.113E-01	0.136E-01
Fe-59	0.609E-04	0.207E-06	0.644E-03	0.771E-03
Co-60	0.170E-03	0.414E-06	0.163E-02	0.197E-02
Sr-89	0.176E-04	0.565E-07	0.183E-03	0.220E-03
Sr-90	0.111E-05	0.271E-08	0.108E-04	0.130E-04
Y-90	0.115E-05	0.764E-08	0.751E-05	0.948E-05
Sr-91	0.790E-09	0.239E-07	0.607E-07	0.934E-07
Y-91	0.203E-03	0.780E-06	0.232E-02	0.276E-02
Sr-92	0.0	0.310E-08	0.0	0.339E-08
Y-92	0.0	0.207E-07	0.0	0.226E-07
Zr-95	0.464E-05	0.143E-07	0.473E-04	0.568E-04
Nb-95	0.530E-06	0.207E-07	0.720E-04	0.794E-04
Mo-99	0.412E-04	0.103E-03	0.356E-01	0.391E-01
I-131	0.431E-02	0.895E-03	0.114E+01	0.125E+01
Te-132	0.885E-04	0.668E-05	0.288E-02	0.325E-02
I-132	0.913E-04	0.191E-03	0.0	0.309E-03
I-133	0.768E-04	0.103E-02	0.371E-01	0.418E-01
Cs-134	0.975E-03	0.143E-04	0.310E-01	0.141E+00
I-134	0.0	0.263E-04	0.0	0.288E-04
I-135	0.501E-07	0.446E-03	0.162E-03	0.488E-03
Cs-136	0.712E-02	0.302E-05	0.312E-02	0.112E-01
Cs-137	0.176E-00	0.207E-04	0.452E-01	0.242E+00
Ba-140	0.120E-04	0.955E-07	0.174E-04	0.323E-04
La-140	0.136E-04	0.501E-07	0.403E-04	0.114E-03
Ce-144	0.334E-05	0.796E-08	0.317E-04	0.383E-04
Pr-144	0.334E-05	0.111E-07	0.317E-04	0.383E-04
Total (excluding H-3)				0.160E+01

(a) Resin regenerant discharge.

TABLE 11.2-16

ANNUAL FLOW AND ACTIVITY CONCENTRATION OF PROCESS STREAMS
FOR STEAM GENERATOR BLOWDOWN SYSTEM FOR NORMAL OPERATION CASE
BASED ON ORIGINAL SYSTEM DESIGN

Stream Number	A	B	C	D	E
Annual Flow, gal./yr	76,300,000	0.0	42,865,000	42,865,000	0.0
Nuclide	Concentration, µCi/cc				
H-3	0.420E-03	0.0	0.303E-03	0.303E-03	0.0
Cr-51	0.790E-07	0.0	0.102E-06	0.102E-08	0.0
Mn-54	0.130E-07	0.0	0.168E-07	0.168E-09	0.0
Fe-55	0.630E-07	0.0	0.013E-07	0.813E-09	0.0
Co-58	0.670E-06	0.0	0.864E-06	0.864E-08	0.0
Fe-59	0.420E-07	0.0	0.542E-07	0.542E-07	0.0
Co-60	0.830E-07	0.0	0.107E-06	0.107E-08	0.0
Sr-89	0.110E-07	0.0	0.142E-07	0.142E-09	0.0
Sr-90	0.550E-09	0.0	0.709E-09	0.709E-11	0.0
Y-90	0.960E-09	0.0	0.124E-08	0.124E-08	0.0
Sr-91	0.560E-08	0.0	0.722E-08	0.722E-10	0.0
Y-91	0.980E-07	0.0	0.126E-06	0.126E-06	0.0
Sr-92	0.140E-08	0.0	0.181E-08	0.181E-10	0.0
Y-92	0.280E-08	0.0	0.361E-08	0.361E-08	0.0
Zr-95	0.280E-08	0.0	0.361E-08	0.361E-10	0.0
Nb-95	0.290E-08	0.0	0.374E-08	0.374E-10	0.0
Mo-99	0.220E-04	0.0	0.284E-04	0.284E-04	0.0
I-131	0.140E-04	0.0	0.172E-04	0.172E-06	0.0
Te-132	0.140E-05	0.0	0.181E-05	0.181E-07	0.0
I-132	0.300E-05	0.0	0.368E-05	0.368E-07	0.0
I-133	0.170E-04	0.0	0.208E-04	0.208E-06	0.0
Cs-134	0.200E-05	0.0	0.258E-05	0.129E-05	0.0
I-134	0.520E-06	0.0	0.637E-06	0.637E-08	0.0
I-135	0.710E-05	0.0	0.870E-05	0.870E-07	0.0
Cs-136	0.500E-06	0.0	0.645E-06	0.322E-06	0.0
Cs-137	0.340E-05	0.0	0.439E-05	0.219E-05	0.0
Ba-140	0.190E-07	0.0	0.245E-07	0.245E-09	0.0
La-140	0.810E-08	0.0	0.104E-07	0.104E-09	0.0
Ce-144	0.170E-08	0.0	0.219E-08	0.219E-10	0.0
Pr-144	0.170E-08	0.0	0.219E-08	0.219E-10	0.0

TABLE 11.2-16

Stream Number	F	G	H	I
Annual Flow, gal./yr	0.0	42,865,000	0.0	2,600,00
Nuclide	Concentration, µCi/cc			
H-3	0.0	0.303E-03	0.0	0.540E-03
Cr-51	0.0	0.102E-08	0.0	0.490E-10
Mn-54	0.0	0.168E-09	0.0	0.810E-11
Fe-55	0.0	0.813E-09	0.0	0.380E-10
Co-58	0.0	0.864E-08	0.0	0.420E-09
Fe-59	0.0	0.542E-09	0.0	0.260E-10
Co-60	0.0	0.107E-08	0.0	0.520E-10
Sr-89	0.0	0.142E-09	0.0	0.710E-11
Sr-90	0.0	0.709E-11	0.0	0.340E-12
Y-90	0.0	0.124E-08	0.0	0.870E-12
Sr-91	0.0	0.722E-10	0.0	0.300E-11
Y-91	0.0	0.126E-06	0.0	0.890E-10
Sr-92	0.0	0.181E-10	0.0	0.390E-12
Y-92	0.0	0.361E-08	0.0	0.250E-11
Zr-95	0.0	0.361E-10	0.0	0.180E-11
Nb-95	0.0	0.374E-10	0.0	0.260E-11
Mo-99	0.0	0.284E-04	0.0	0.130E-07
I-131	0.0	0.172E-06	0.0	0.110E-06
Te-132	0.0	0.101E-07	0.0	0.840E-09
I-132	0.0	0.368E-07	0.0	0.240E-07
I-133	0.0	0.208E-06	0.0	0.130E-06
Cs-134	0.0	0.129E-05	0.0	0.180E-08
I-134	0.0	0.637E-08	0.0	0.330E-08
I-135	0.0	0.870E-07	0.0	0.560E-07
Cs-136	0.0	0.322E-06	0.0	0.380E-09
Cs-137	0.0	0.219E-05	0.0	0.260E-08
Ba-140	0.0	0.245E-09	0.0	0.120E-10
La-140	0.0	0.104E-09	0.0	0.730E-11
Ce-144	0.0	0.219E-10	0.0	0.100E-11
Pr-144	0.0	0.219E-10	0.0	0.140E-11

(a) See Figures 11.2-4 and 11.2-5 for stream number identification.

TABLE 11.2-17

SUMMARY OF ESTIMATED LIQUID WASTE SYSTEM
ANNUAL WASTE VOLUMES FOR UNITS 1 AND 2

	Stream Number[a]	Total Annual Volume, Gallons (Design Basis Case)	Total Annual Volume, Gallons (Normal Operation Case)
Laundry, showers, handwashers	5	44,620	65,480
Chemical laboratory drains	6	10,220	15,330
Floor drain subsystem	7	21,360	-[b]
Equipment drain subsystem	11	23,990	98,650
Steam generator blowdown treatment system	F & H	-	-[c]
CPS regenerant wastes	-	-	2,360,000
Turbine-generator building sump	1	-	5,200,000
CVCS (tritium control)	15	700,000	700,000
Total plant discharge for two units		800,190	8,439,460

(a) See Figures 11.2-2, 11.2-3, and 11.2-5.

(b) Floor drain volume included in equipment drain volume (stream 11) for treatment in normal operation case.

(c) Analysis assumed no resin regeneration for steam generator blowdown treatment system.

TABLE 11.2-18

ESTIMATED ANNUAL LIQUID EFFLUENT RELEASE FOR
NORMAL OPERATION CASE WITH
ANTICIPATED OPERATIONAL OCCURRENCES
(ONE UNIT)

Nuclide	Release, curies
H-3	1.29 E+03
Cr-51	1.26 E-03
Mn-54	2.97 E-04
Fe-55	7.88 E-04
Co-58	1.36 E-02
Fe-59	7.71 E-04
Co-60	1.97 E-03
Sr-89	2.20 E-04
Sr-90	1.30 E-05
Y-90	9.48 E-06
Sr-91	9.34 E-08
Y-91	2.76 E-03
Sr-92	3.39 E-09
Y-92	2.26 E-08
Zr-95	5.68 E-05
Nb-95	7.94 E-05
Mo-99	3.91 E-02
I-131	1.25 E00
Te-132	3.25 E-03
I-132	3.09 E-04
I-133	4.18 E-02
Cs-134	1.44 E-01
I-134	2.88 E-05
I-135	4.88 E-04
Cs-136	1.12 E-02
Cs-137	2.42 E-01
Ba-140	3.23 E-05
La-140	1.14 E-04
Ce-144	3.83 E-05
Pr-144	3.83 E-05
Total (excluding H-3)	1.75 E00

TABLE 11.2-19

BASIC ASSUMPTIONS FOR LIQUID PATHWAYS EXPOSURES

Plant dilution flow	876000 gpm
Length of plant cycle	8760.00 hr

Biological and Environmental Parameters

Receiving body of water	Pacific Ocean
Receiving water type	Ocean

Dilution factor from discharge to swimming water	5.0E 00
Dilution factor from discharge to drinking water	5.0E 00
Dilution factor from discharge to fish	5.0E 00
Dilution factor from discharge to invertebrates	5.0E 00
Dilution factor from discharge to aquatic plants	5.0E 00

Decay time from environment to water = 5.0E-01 Fish = 1.0E 00 Invertebrates = 1.0E 00 Aquatic Plants = 1.0E 00
Consumption by Man, days

Decay time from discharge to sediment, days = 1.00E 00
Accumulation time for sediment activity, days = 1.10E 04

	Food Consumption Rates, kg/yr				Exposure Time Hours/Year	
Age Group	Water	Fish	Invertebrates	Aquatic Plants	Swimming	Shore
Adult	0.0	2.10E 01	5.00E 00	0.0	5.20E 01	1.20E 01
Teenager	0.0	1.60E 01	3.80E 00	0.0	5.20E 01	6.70E 01
Child	0.0	6.90E 00	1.70E 00	0.0	2.90E 01	1.40E 01
Infant	0.0	0.0	0.0	0.0	0.0	0.0

TABLE 11.2-20

BIOACCUMULATION FACTORS

Nuclide	Fish	Inverteb.	Aq. Plants
H-3	9.00E-01	9.30E-01	9.30E-01
Cr-51	4.00E 02	2.00E 03	2.00E 03
Mn-54	5.50E 02	4.00E 02	5.50E 03
Fe-55	3.00E 03	2.00E 04	7.30E 02
Co-58	1.00E 02	1.00E 03	1.00E 03
Fe-59	3.00E 03	2.00E 04	7.30E 02
Co-60	1.00E 02	1.00E 03	1.00E 03
Sr-89	2.00E 00	2.00E 01	1.00E 01
Sr-90	2.00E 00	2.00E 01	1.00E 01
Y-90	2.50E 01	1.00E 03	5.00E 03
Sr-91	2.00E 00	2.00E 01	1.00E 01
Y-91	2.50E 01	1.00E 03	5.00E 03
Sr-92	2.00E 00	2.00E 01	1.00E 01
Y-92	2.50E 01	1.00E 03	5.00E 03
Zr-95	2.00E 02	8.00E 01	1.00E 03
Nb-95	3.00E 04	1.00E 02	5.00E 02
Mo-99	1.00E 01	1.00E 01	1.00E 01
I-131	1.00E 01	5.00E 01	1.00E 03
Te-132	1.00E 01	1.00E 02	1.00E 03
I-132	1.00E 01	5.00E 01	1.00E 03
I-133	1.00E 01	5.00E 01	1.00E 03
Cs-134	4.00E 01	2.50E 01	5.00E 01
I-134	1.00E 01	5.00E 01	1.00E 03
I-135	1.00E 01	5.00E 01	1.00E 03
Cs-136	4.00E 01	2.50E 01	5.00E 01
Cs-137	4.00E 01	2.50E 01	5.00E 01
Ba-140	1.00E 01	1.00E 02	5.00E 02
La-140	2.50E 01	1.00E 03	5.00E 03
Ce-144	1.00E 01	6.00E 02	6.00E 02
Pr-144	2.50E 01	1.00E 03	5.00E 03

TABLE 11.2-21

EFFLUENT CONCENTRATIONS AFTER INITIAL DILUTION: DESIGN BASIS CASE

Nuclide	Release Rate[a], Ci/yr	Average Yearly Concentration in Discharge, µCi/cc
H-3	1.35E+03	7.75E-07
Cr-51	9.60E-05	5.51E-14
Mn-54	2.13E-05	1.22E-14
Fe-55	3.27E-06	1.88E-15
Co-58	1.04E-03	5.97E-13
Fe-59	5.74E-05	3.29E-14
Co-60	1.41E-04	8.09E-14
Sr-89	1.39E-04	7.98E-14
Sr-90	7.97E-06	4.57E-15
Y-90	7.81E-06	4.48E-15
Sr-91	4.53E-09	2.60E-18
Y-91	1.73E-03	9.93E-13
Sr-92	3.39E-15	1.95E-24
Y-92	8.72E-15	5.00E-24
Zr-95	3.51E-05	2.01E-14
Nb-95	3.97E-05	2.28E-14
Mo-99	3.65E-04	2.09E-13
I-131	5.45E-02	3.13E-1
Te-132	1.02E-03	5.85E-13
I-132	1.09E-03	5.97E-13
I-133	4.41E-04	2.53E-13

TABLE 11.2-21

Nuclide	Release Rate[a], Ci/yr	Average Yearly Concentration in Discharge, µCi/cc
Cs-134	1.20E-01	6.89E-11
I-134	0.0	0.0
I-135	2.84E-07	1.63E-16
Cs-136	1.37E-02	7.86E-12
Cs-137	2.16E-01	1.24E-10
Ba-140	1.23E-04	7.06E-14
La-140	1.39E-04	7.98E-14
Ce-144	2.33E-05	1.34E-14
Pr-144	2.33E-05	1.34E-14
Totals	1.35E+03	7.75E-07
Totals excluding H-3	4.11E-01	2.36E-10

(a) One unit

TABLE 11.2-22

EFFLUENT CONCENTRATIONS AFTER INITIAL DILUTION: NORMAL OPERATION CASE

Nuclide	Release Rate[a], Ci/yr	Average Yearly Concentration in Discharge, μCi/cc
H-3	1.29E+03	7.42E-07
Cr-51	1.16E-03	6.66E-13
Mn-54	2.72E-04	1.56E-13
Fe-55	1.23E-04	7.06E-14
Co-58	1.25E-02	7.17E-12
Fe-59	7.05E-04	4.05E-13
Co-60	1.80E-03	1.13E-12
Sr-89	2.01E-04	1.15E-13
Sr-90	1.19E-05	6.83E-15
Y-90	8.67E-06	4.97E-15
Sr-91	8.54E-08	4.90E-17
Y-91	2.52E-03	1.45E-12
Sr-92	0.31E-08	1.78E-18
Y-92	0.21E-07	1.20E-17
Zr-95	5.20E-05	2.98E-14
Nb-95	7.26E-05	4.17E-14
Mo-99	3.57E-02	2.05E-11
I-131	1.15E-00	6.60E-10
I-132	2.82E-04	1.62E-13
I-133	3.82E-02	2.19E-11
Cs-134	1.29E-01	7.40E-11
I-134	0.26E-04	1.49E-14
I-135	6.08E-04	3.49E-13
Cs-136	1.02E-02	5.85E-12
Cs-137	2.21E-01	1.27E-10
Ba-140	2.95E-05	1.69E-14
La-140	1.04E-04	5.97E-14
Ce-144	3.51E-05	2.01E-14
Pr-144	3.51E-05	2.01E-14
Totals	1.29E+03	7.42E-07
Totals excluding H-3	1.60E+00	9.24E-10

(a) One unit

TABLE 11.2-23

EFFLUENT CONCENTRATIONS AFTER INITIAL DILUTION: NORMAL OPERATION WITH ANTICIPATED OPERATIONAL OCCURRENCES

Nuclide	Release Rate[(a)], Ci/yr	Average Yearly Concentration in Discharge, µCi/cc
H-3	1.29E+03	7.42E-07
Cr-51	1.26E-03	7.23E-13
Mn-54	2.99E-04	1.70E-13
Fe-55	7.88E-04	4.52E-13
Co-58	1.36E-02	7.80E-12
Fe-59	7.71E-04	4.42E-13
Co-60	1.97E-03	1.13E-12
Sr-89	2.20E-04	1.26E-13
Sr-90	1.30E-05	7.46E-15
Y-90	9.48E-06	5.44E-15
Sr-91	9.34E-08	5.36E-17
Y-91	2.76E-03	1.58E-12
Sr-92	3.39E-09	1.95E-18
Y-92	2.26E-08	1.30E-17
Zr-95	5.68E-05	3.26E-14
Nb-95	7.94E-05	4.56E-14
Mo-99	3.91E-02	2.24E-11
I-131	1.25E+00	7.17E-10
Te-132	3.25E-03	1.86E-12
I-132	3.09E-04	1.77E-13
I-133	4.18E-02	2.40E-10
Cs-134	1.41E-01	8.09E-11
I-134	2.88E-05	1.65E-14
I-135	4.88E-04	2.80E-13
Cs-136	1.12E-02	6.43E-12
Cs-137	2.42E-01	1.39E-10
Ba-140	3.23E-05	1.85E-14
La-140	1.14E-04	6.54E-14
Ce-144	3.83E-05	2.20E-14
Pr-144	3.83E-05	2.20E-14
Totals	1.29E+03	7.43E-07
Totals excluding H-3	1.75E+00	2.64E-03

(a) One unit

TABLE 11.2-24

DOSES RESULTING FROM RADIOACTIVE RELEASES IN LIQUID WASTES: DESIGN BASIS CASE (mrem/yr)

Age Group = Adult

Exposure Pathway	Whole Body	Skin	Bone	GI Tract	Thyroid	Lung	Kidney	Liver
Drinking water	0.0	--	0.0	0.0	0.0	0.0	0.0	0.0
Consumption of fish	7.22E-3	0.0	2.39E-3	4.30E-4	2.56E-3	7.51E-4	1.66E-3	4.33E-3
Consumption of invertebrates	5.17E-4	0.0	3.65E-4	2.09E-4	2.76E-3	1.43E-4	2.90E-4	6.89E-4
Consumption of aquatic plants	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Exposure to contaminated sediment	4.18E-4	4.87E-4	0.0	0.0	0.0	0.0	0.0	0.0
Swimming in water	4.67E-6	5.39E-5	0.0	0.0	0.0	0.0	0.0	0.0
Total	4.16E-4	5.41E-4	2.76E-3	6.39E-4	5.31E-3	8.94E-4	1.95E-3	5.02E-3

Age Group = Teenager

Exposure Pathway	Whole Body	Skin	Bone	GI Tract	Thyroid	Lung	Kidney	Liver
Drinking water	0.0	--	0.0	0.0	0.0	0.0	0.0	0.0
Consumption of fish	1.89E-3	0.0	2.53E-3	3.27E-4	2.34E-3	7.63E-4	1.62E-3	4.38E-3
Consumption of invertebrates	3.12E-4	0.0	3.85E-4	1.61E-4	2.56E-3	1.38E-4	2.77E-4	6.87E-4
Consumption of aquatic plants	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Exposure to contaminated sediment	2.33E-3	2.72E-3	0.0	0.0	0.0	0.0	0.0	0.0
Swimming in water	4.67E-6	5.39E-5	0.0	0.0	0.0	0.0	0.0	0.0
Total	4.54E-3	2.77E-3	2.91E-3	4.88E-4	4.89E-3	9.01E-4	1.90E-3	5.06E-3

Age Group = Child

Exposure Pathway	Whole Body	Skin	Bone	GI Tract	Thyroid	Lung	Kidney	Liver
Drinking water	0.0	--	0.0	0.0	0.0	0.0	0.0	0.0
Consumption of fish	8.42E-4	0.0	3.14E-3	2.30E-4	2.37E-3	6.11E-4	1.37E-3	3.83E-3
Consumption of invertebrates	1.58E-4	0.0	4.96E-4	9.23E-5	2.72E-3	1.15E-4	2.43E-4	6.22E-4
Consumption of aquatic plants	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Exposure to contaminated sediment	4.87E-4	5.68E-4	0.0	0.0	0.0	0.0	0.0	0.0
Swimming in water	2.60E-6	3.01E-5	0.0	0.0	0.0	0.0	0.0	0.0
Total	1.49E-3	5.98E-4	3.64E-3	3.22E-4	5.09E-3	7.27E-4	1.61E-3	4.45E-3

Age Group = Infant

Exposure Pathway	Whole Body	Skin	Bone	GI Tract	Thyroid	Lung	Kidney	Liver
Drinking water	0.0	--	0.0	0.0	0.0	0.0	0.0	0.0
Consumption of fish	0.0	--	0.0	0.0	0.0	0.0	0.0	0.0
Consumption of invertebrates	0.0	--	0.0	0.0	0.0	0.0	0.0	0.0
Consumption to aquatic plants	0.0	--	0.0	0.0	0.0	0.0	0.0	0.0
Exposure to contaminated sediment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Swimming in water	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

TABLE 11.2-25

DOSES RESULTING FROM RADIOACTIVE RELEASES IN LIQUID WASTES: NORMAL OPERATION CASE (mrem/yr)

Age Group = Adult

Exposure Pathway	Whole Body	Skin	Bone	GI Tract	Thyroid	Lung	Kidney	Liver
Drinking water	0.0	--	0.0	0.0	0.0	0.0	0.0	0.0
Consumption of fish	3.49E-3	0.0	2.61E-3	8.36E-4	4.77E-2	7.74E-4	1.94E-3	4.77E-3
Consumption of invertebrates	6.74E-4	0.0	5.48E-4	7.66E-4	5.65E-2	1.72E-4	5.79E-4	1.11E-3
Consumption of aquatic plants	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Exposure to contaminated sediment	4.36E-4	5.09E-4	0.0	0.0	0.0	0.0	0.0	0.0
Swimming in water	1.03E-5	5.88E-5	0.0	0.0	0.0	0.0	0.0	0.0
Total	4.56E-3	5.68E-4	3.16E-3	1.60E-3	1.04E-1	9.46E-4	2.52E-3	5.88E-3

Age Group = Teenager

Exposure Pathway	Whole Body	Skin	Bone	GI Tract	Thyroid	Lung	Kidney	Liver
Drinking water	0.0	--	0.0	0.0	0.0	0.0	0.0	0.0
Consumption of fish	2.06E-3	0.0	2.76E-3	5.83E-4	4.45E-2	7.96E-4	1.92E-3	4.75E-3
Consumption of invertebrates	4.61E-4	0.0	5.78E-4	5.05E-4	5.26E-2	1.73E-4	5.81E-4	9.82E-4
Consumption of aquatic plants	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Exposure to contaminated sediment	2.44E-3	2.84E-3	0.0	0.0	0.0	0.0	0.0	0.0
Swimming in water	1.03E-5	5.88E-5	0.0	0.0	0.0	0.0	0.0	0.0
Total	4.97E-3	2.90E-3	3.34E-3	1.09E-3	9.71E-2	9.69E-4	2.50E-3	5.73E-3

Age Group = Child

Exposure Pathway	Whole Body	Skin	Bone	GI Tract	Thyroid	Lung	Kidney	Liver
Drinking water	0.0	--	0.0	0.0	0.0	0.0	0.0	0.0
Consumption of fish	9.64E-4	0.0	3.43E-3	3.19E-4	4.59E-2	6.37E-4	1.636-3	4.16E-3
Consumption of invertebrates	3.07E-4	0.0	7.49E-4	2.23E-4	5.63E-2	1.45E-4	5.17E-4	8.95E-4
Consumption of aquatic plants	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Exposure to contaminated sediment	5.09E-4	5.94E-4	0.0	0.0	0.0	0.0	0.0	0.0
Swimming in water	5.74E-6	3.28E-5	0.0	0.0	0.0	0.0	0.0	0.0
Total	1.79E-3	6.27E-4	4.18E-3	5.42E-4	1.02E-1	7.82E-4	2.15E-3	5.05E-3

TABLE 11.2-25

Age Group = Infant

Exposure Pathway	Whole Body	Skin	Bone	GI Tract	Thyroid	Lung	Kidney	Liver
Drinking water	0.0	--	0.0	0.0	0.0	0.0	0.0	0.0
Consumption of fish	0.0	--	0.0	0.0	0.0	0.0	0.0	0.0
Consumption of invertebrates	0.0	--	0.0	0.0	0.0	0.0	0.0	0.0
Consumption of aquatic plants	0.0	--	0.0	0.0	0.0	0.0	0.0	0.0
Exposure to contaminated sediment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Swimming in water	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

TABLE 11.2-26

DOSES RESULTING FROM RADIOACTIVE RELEASES IN LIQUID WASTES:
NORMAL OPERATIONAL WITH ANTICIPATED OPERATIONAL OCCURRENCES (mrem/yr)

Age Group = Adult

Exposure Pathway	Whole Body	Skin	Bone	GI Tract	Thyroid	Lung	Kidney	Liver
Drinking water	0.0	--	0.0	0.0	0.0	0.0	0.0	0.0
Consumption of fish	3.74E-3	0.0	2.86E-3	8.86E-4	5.20E-2	8.20E-4	2.10E-3	5.20E-3
Consumption of invertebrates	7.32E-4	0.0	6.00E-4	8.30E-4	6.16E-2	1.82E-4	6.26E-4	1.21E-3
Consumption of aquatic plants	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Exposure to contaminated sediment	4.78E-4	5.58E-4	0.0	0.0	0.0	0.0	0.0	0.0
Swimming in water	1.13E-5	5.99E-5	0.0	0.0	0.0	0.0	0.0	0.0
Total	4.96E-3	6.18E-4	3.46E-3	1.72E-3	1.14E-1	1.00E-1	2.73E-3	6.41E-3

Age Group = Teenager

Exposure Pathway	Whole Body	Skin	Bone	GI Tract	Thyroid	Lung	Kidney	Liver
Drinking water	0.0	--	0.0	0.0	0.0	0.0	0.0	0.0
Consumption of fish	2.23E-3	0.0	3.02E-3	6.17E-4	4.85E-2	8.51E-4	2.08E-3	5.18E-3
Consumption of invertebrates	4.99E-4	0.0	6.32E-4	5.47E-4	5.74E-2	1.85E-4	6.31E-4	1.07E-3
Consumption of aquatic plants	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Exposure to contaminated sediment	2.67E-3	3.11E-3	0.0	0.0	0.0	0.0	0.0	0.0
Swimming in water	1.13E-5	5.99E-5	0.0	0.0	0.0	0.0	0.0	0.0
Total	5.41E-3	3.17E-3	3.66E-3	1.16E-3	1.06E-1	1.04E-3	2.71E-3	6.25E-3

Age Group = Child

Exposure Pathway	Whole Body	Skin	Bone	GI Tract	Thyroid	Lung	Kidney	Liver
Drinking water	0.0	--	0.0	0.0	0.0	0.0	0.0	0.0
Consumption of fish	1.04E-3	0.0	3.76E-3	3.32E-4	5.01E-2	6.80E-4	1.77E-3	4.54E-3
Consumption of invertebrates	3.31E-4	0.0	8.19E-4	2.40E-4	6.15E-2	1.54E-4	5.61E-4	9.75E-4
Consumption of aquatic plants	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Exposure to containment sediment	5.58E-4	6.51E-4	0.0	0.0	0.0	0.0	0.0	0.0
Swimming in water	6.28E-6	3.34E-5	0.0	0.0	0.0	0.0	0.0	0.0
Total	1.95E-3	6.84E-4	4.58E-3	5.71E-4	1.12E-1	8.34E-4	2.33E-4	5.51E-3

TABLE 11.2-26

Age Group = Infant

Exposure Pathway	Whole Body	Skin	Bone	GI Tract	Thyroid	Lung	Kidney	Liver
Drinking water	0.0	--	0.0	0.0	0.0	0.0	0.0	0.0
Consumption of fish	0.0	--	0.0	0.0	0.0	0.0	0.0	0.0
Consumption of invertebrates	0.0	--	0.0	0.0	0.0	0.0	0.0	0.0
Consumption of aquatic plants	0.0	--	0.0	0.0	0.0	0.0	0.0	0.0
Exposure to contaminated sediment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Swimming in water	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

TABLE 11.3-1

EQUIPMENT DESIGN AND OPERATING PARAMETERS
FOR GASEOUS RADWASTE SYSTEM, UNITS 1 AND 2

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1. Waste Gas Compressor
   Number used: 3; 1 each unit, 1 shared
   Type: horizontal, centrifugal compressor
   Temperature: 70°F - 130°F
   Inlet pressure: 0.5 psig - 2.0 psig
   Capacity: 40 cfm at inlet pressure 2.0 psig and discharge pressure 110 psig
   Cooling water rate: 42.5 gpm
   Driver: 25 hp

2. Surge Tank
   Number used: 2; 1 each unit
   Type: horizontal
   Size: 18' x 1'
   Volume: 14 ft^3
   Design pressure: 405 psig/Design temperature: 650°F
   Operating maximum pressure: 10 psig
   Material: ASTM A106 Carbon Steel (PG&E pipe specification K2)

3. Gas Decay Tank
   Number used: 6; 3 each unit
   Type: vertical
   Size: 13' x 8'
   Volume: 760 ft^3
   Design temperature: 150°F

3. Gas Decay Tank (continued)
   Design pressure: 150 psig
   Operating maximum pressure: 105 psig
   Material: SA285C, carbon steel
   Design as per ASME Boiler and Pressure Vessel Code, Section III, Class C

4. Waste Gas Analyzer
   Number used: 2; 1 each unit
   Oxygen analyzer:
   - Range: 0-5% (±2% of full range)
   - Alarm: 2% oxygen

   Hydrogen analyzer:
   - Range: 0-5% (±2% of full range)
     0-50% (±2% of full range)
     0-100% (±2% of full range)
   - Alarm: 3.5% hydrogen

   Sample channel: 16

5. Discharge filter
   Number used: 2; 1 each unit
   Type: HEPA filter
   Size: 8" x 8" x 5-7/8"
   Efficiency: 99.97% on 0.3 micron particles
   Capacity: 55 cfm at 1" water gauge differential

TABLE 11.3-2
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

GASEOUS WASTE SYSTEM RELEASE: DESIGN BASIS CASE
(CURIES)

Nuclide	*Gas Decay Tank Venting*	*Steam Containment Venting*	*Condenser System Leakage*	*Auxiliary Offgas Venting*	*Spent Building Venting*	*Secondary Fuel Pool Release*	*System Water Leakage*	*Total Release*
Kr- 83M	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.197E-19*	*---*	*0.197E-19*
Kr- 85M	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.224E-09*	*---*	*0.224E-09*
Kr- 85	*0.505E 04*	*0.0*	*0.0*	*0.0*	*0.0*	*0.538E-01*	*---*	*0.505E 04*
Kr- 87	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.169E-26*	*---*	*0.169E-26*
Kr- 88	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.360E-13*	*---*	*0.360E-13*
Xe-133M	*0.210E-02*	*0.0*	*0.0*	*0.0*	*0.0*	*0.127E-02*	*---*	*0.337E-02*
Xe-133	*0.411E 03*	*0.0*	*0.0*	*0.0*	*0.0*	*0.189E 00*	*---*	*0.411E 03*
Xe-135M	*0.482E-46*	*0.0*	*0.0*	*0.0*	*0.0*	*0.668E-07*	*---*	*0.668E-07*
Xe-135	*0.262E-31*	*0.0*	*0.0*	*0.0*	*0.0*	*0.276E-06*	*---*	*0.276E-04*
Xe-138	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*---*	*0.0*
I -131	*---*	*0.0*	*0.0*	*0.0*	*0.0*	*0.112E-04*	*0.0*	*0.112E-04*
I -132	*---*	*0.0*	*0.0*	*0.0*	*0.0*	*0.167E-05*	*0.0*	*0.167E-05*
I -133	*---*	*0.0*	*0.0*	*0.0*	*0.0*	*0.194E-06*	*0.0*	*0.194E-06*
I -134	*---*	*0.0*	*0.0*	*0.0*	*0.0*	*0.310E-08*	*0.0*	*0.310E-08*
I -135	*---*	*0.0*	*0.0*	*0.0*	*0.0*	*0.177E-07*	*0.0*	*0.177E-07*

TABLE 11.3-3

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

GASEOUS WASTE SYSTEM RELEASE: NORMAL OPERATION CASE
(CURIES)

Nuclide	*Gas Decay Tank Venting*	*Containment Venting*	*Condenser Offgas Venting*	*Auxiliary Building Venting*	*Spent Fuel Pool Release*	*Steam System Leakage*	*Secondary System Water Leakage*	*Total Release*
Kr - 83	*0.0*	*0.287E 00*	*0.169E 00*	*0.110E-01*	*0.236E-20*	*0.615E-04*	*---*	*0.156E 01*
Kr - 85M	*0.0*	*0.350E 01*	*0.145E-01*	*0.567E 01*	*0.269E-10*	*0.317E-03*	*---*	*0.106E 02*
Kr - 85	*0.439E 03*	*0.443E 03*	*0.624E 01*	*0.100E 02*	*0.654E-02*	*0.558E-03*	*---*	*0.898E 03*
Kr - 87	*0.0*	*0.554E 00*	*0.361E 00*	*0.311E 01*	*0.203E-27*	*0.174E-03*	*---*	*0/402E 01*
Kr - 88	*0.0*	*0.378E 01*	*0.193E 01*	*0.972E 01*	*0.432E-14*	*0.543E-03*	*---*	*0.154E 02*
Xe - 133M	*0.244E-03*	*0.721E 02*	*0.433E 01*	*0.931E 01*	*0.152E-03*	*0.521E-03*	*---*	*0.858E 02*
Xe - 133	*0.434E 02*	*0.118E 05*	*0.367E 03*	*0.760E 03*	*0.227E-01*	*0.424E-01*	*---*	*0.129E 05*
Xe - 135M	*0.577E-47*	*0.920E 00*	*0.254E 00*	*0.122E 01*	*0.001E-08*	*0.486E-03*	*---*	*0.239E 01*
Xe - 135	*0.313E-32*	*0.280E 02*	*0.626E-01*	*0.170E 02*	*0.331E-05*	*0.102E-02*	*---*	*0.513E 02*
Xe - 138	*0.0*	*0.530E-01*	*0.432E-01*	*0.165E 01*	*0.0*	*0.919E-04*	*---*	*0.174E 01*
I - 131	*---*	*0.336E-01*	*0.312E-01*	*0.637E-01*	*0.859E-05*	*0.630E-03*	*0.897E-06*	*0.129E 00*
I - 132	*---*	*0.188E 00*	*0.418E-02*	*0.230E-01*	*0.752E-06*	*0.134E-03*	*0.191E-06*	*0.215E 00*
I - 133	*---*	*0.685E-02*	*0.363E-01*	*0.872E-01*	*0.165E-06*	*0.751E-03*	*0.106E-05*	*0.131E 00*
I - 134	*---*	*0.378E-04*	*0.999E-03*	*0.117E-01*	*0.310E-08*	*0.234E-04*	*0.266E-07*	*0.127E-01*
I - 135	*---*	*0.121E-02*	*0.148E-01*	*0.482E-01*	*0.177E-07*	*0.318E-03*	*0.441E-06*	*0.645E-01*

TABLE 11.3-3

Nuclide	*Total Release*
H - 3	*0.33E 03*
Cr - 51	*0.0*
Mn - 54	*0.44E-01*
Fe - 55	*0.0*
Co - 58	*0.15E-00*
Fe - 59	*0.15E-01*
Co - 60	*0.68E-01*
Sr - 89	*0.33E-02*
Sr - 90	*0.56E-03*
Y - 90	*0.0*
Sr - 91	*0.0*
Y - 91	*0.0*
Sr - 92	*0.0*
Y - 92	*0.0*
Zr - 95	*0.0*
Nb - 95	*0.0*
Mo - 99	*0.0*
Te - 132	*0.0*
Cs - 134	*0.44E-01*
Cs - 136	*0.0*
Cs - 137	*0.75E-01*
Ba - 140	*0.0*
La - 140	*0.0*
Ce - 144	*0.0*
Pr - 144	*0.0*
C - 14	*0.80E 01*

TABLE 11.3-4

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

ANNUAL GASEOUS RADWASTE FLOWS
(Standard Cubic Feet Per Year)

Source			*Flow*
Liquid holdup tanks:	*Displaced*	*60,300*	
	Recycled	*15,300*	
			45,000
Volume control tank			*19,000*
Boric acid gas stripper[b]			*7,400*
Reactor coolant drain tank			*250*
Pressurizer relief tank			*350*
Nitrogen added to gas decay tanks			*28,000*
Total annual discharge			*100,000*[a]

(a) Assumes:
1. Two cold shutdowns per year
2. Base loaded plant operation
3. Hydrogen controlled to less than 4%

(b) Equipment is abandoned in place and no longer in use.

TABLE 11.3-5

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

MAXIMUM ACTIVITY IN GAS DECAY TANK: DESIGN BASIS CASE

Nuclide	*Activity, Ci*	*Concentration, μCi/cc*
Kr-83M	*0.894E 02*	*0.421E 01*
Kr-85M	*0.462E 03*	*0.217E 02*
Kr-85	*0.160E 04*	*0.754E 02*
Kr-87	*0.252E 03*	*0.119E 02*
Kr-88	*0.790E 03*	*0.372E 02*
Xe-133M	*0.798E 03*	*0.376E 02*
Xe-133	*0.693E 05*	*0.326E 04*
Xe-135M	*0.988E 02*	*0.465E 01*
Xe-135	*0.139E 04*	*0.656E 02*
Xe-138	*0.133E 03*	*0.628E 01*

TABLE 11.3-6

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

MAXIMUM ACTIVITY IN GAS DECAY TANK:
NORMAL OPERATION CASE

Nuclide	*Activity, Ci*	*Concentration, μCi/cc*
Kr-83M	*0.107E 02*	*0.505E 00*
Kr-85M	*0.553E 02*	*0.260E 01*
Kr-85	*0.130E 03*	*0.612E 01*
Kr-87	*0.302E 02*	*0.142E 01*
Kr-88	*0.946E 02*	*0.445E 01*
Xe-133M	*0.928E 02*	*0.437E 01*
Xe-133	*0.778E 04*	*0.366E 03*
Xe-135M	*0.119E 02*	*0.558E 00*
Xe-135	*0.166E 03*	*0.783E 01*
Xe-138	*0.160E 02*	*0.753E 00*

TABLE 11.3-7

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

ACTIVITY IN VOLUME CONTROL TANK: DESIGN BASIS CASE

	Liquid Phase		*Vapor Phase*		
Nuclide	*Activity, Ci*	*Concentration, µCi/cc*	*Activity, Ci*	*Concentration, µCi/cc*	*Total Act, Ci*
H - 3	*0.497E 01*	*0.732E 00*	*0.0*	*0.0*	*0.497E 01*
Cr- 51	*0.935E-02*	*0.138E-02*	*0.0*	*0.0*	*0.935E-02*
Mn- 54	*0.152E-02*	*0.224E-03*	*0.0*	*0.0*	*0.152E-02*
Fe- 55	*0.773E-02*	*0.114E-02*	*0.0*	*0.0*	*0.773E-02*
Co- 58	*0.785E-01*	*0.115E-01*	*0.0*	*0.0*	*0.785E-01*
Fe- 59	*0.491E-02*	*0.722E-03*	*0.0*	*0.0*	*0.491E-02*
Co- 60	*0.976E-02*	*0.144E-02*	*0.0*	*0.0*	*0.976E-02*
Kr- 83M	*0.0*	*0.0*	*0.495E 00*	*0.109E 00*	*0.495E 00*
Kr- 85M	*0.0*	*0.0*	*0.276E 01*	*0.609E 00*	*0.276E 01*
Kr- 85	*0.0*	*0.0*	*0.657E 01*	*0.145E 01*	*0.657E 01*
Kr- 87	*0.0*	*0.0*	*0.132E 01*	*0.291E 00*	*0.132E 01*
Kr- 88	*0.0*	*0.0*	*0.456E 01*	*0.101E 01*	*0.456E 01*
Sr- 89	*0.112E-01*	*0.165E-02*	*0.0*	*0.0*	*0.112E-01*
Sr- 90	*0.538E-03*	*0.792E-04*	*0.0*	*0.0*	*0.538E-03*
Y - 90	*0.928E-03*	*0.137E-03*	*0.0*	*0.0*	*0.928E-03*
Sr- 91	*0.710E-02*	*0.104E-02*	*0.0*	*0.0*	*0.710E-02*
Y - 91	*0.955E-01*	*0.140E-01*	*0.0*	*0.0*	*0.955E-01*
Sr- 92	*0.271E-02*	*0.398E-03*	*0.0*	*0.0*	*0.271E-02*
Y - 92	*0.374E-02*	*0.550E-03*	*0.0*	*0.0*	*0.374E-02*
Zr- 95	*0.278E-02*	*0.410E-03*	*0.0*	*0.0*	*0.278E-02*
Nb- 95	*0.271E-02*	*0.398E-03*	*0.0*	*0.0*	*0.271E-02*
Mo- 99	*0.223E 02*	*0.328E 01*	*0.0*	*0.0*	*0.223E 02*
I -131	*0.132E 02*	*0.194E 01*	*0.0*	*0.0*	*0.132E 02*
Te-132	*0.139E 01*	*0.204E 00*	*0.0*	*0.0*	*0.139E 01*
I -132	*0.441E 01*	*0.649E 00*	*0.0*	*0.0*	*0.441E 01*
I -133	*0.178E 02*	*0.262E 01*	*0.0*	*0.0*	*0.178E 02*
Xe-133M	*0.213E-02*	*0.314E-03*	*0.493E 01*	*0.109E 01*	*0.493E 01*
Xe-133	*0.378E-01*	*0.556E-02*	*0.416E 03*	*0.919E 02*	*0.416E 03*
Cs-134	*0.932E 00*	*0.137E 00*	*0.0*	*0.0*	*0.932E 00*
I -134	*0.183E 01*	*0.269E 00*	*0.0*	*0.0*	*0.183E 01*
I -135	*0.957E 01*	*0.141E 01*	*0.0*	*0.0*	*0.957E 01*
Xe-135M	*0.715E 00*	*0.105E 00*	*0.304E 00*	*0.672E-01*	*0.102E 01*
Xe-135	*0.260E 00*	*0.382E-01*	*0.858E 01*	*0.189E 01*	*0.884E 01*
Cs-136	*0.252E 00*	*0.371E 01*	*0.0*	*0.0*	*0.252E 00*
Cs-137	*0.167E 01*	*0.246E 00*	*0.0*	*0.0*	*0.167E 01*
Xe-138	*0.0*	*0.0*	*0.388E 00*	*0.857E-01*	*0.388E 00*
Ba-140	*0.190E-01*	*0.279E-02*	*0.0*	*0.0*	*0.190E-01*
La-140	*0.678E-02*	*0.998E-03*	*0.0*	*0.0*	*0.678E-02*
Ce-144	*0.164E-02*	*0.241E-03*	*0.0*	*0.0*	*0.164E-02*
Pr-144	*0.164E-02*	*0.241E-03*	*0.0*	*0.0*	*0.164E-02*

TABLE 11.3-8

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

ACTIVITY IN VOLUME CONTROL TANK: NORMAL OPERATION CASE

	Liquid Phase		Vapor Phase		
Nuclide	*Activity, Ci*	*Concentration, µCi/cc*	*Activity, Ci*	*Concentration, µCi/cc*	*Total Act, Ci*
H - 3	*0.470E 01*	*0.692E 00*	*0.0*	*0.0*	*0.470E 01*
CR- 51	*0.934E-02*	*0.137E-02*	*0.0*	*0.0*	*0.934E-02*
Mn- 54	*0.152E-02*	*0.224E-03*	*0.0*	*0.0*	*0.152E-02*
Fe- 55	*0.772E-02*	*0.114E-02*	*0.0*	*0.0*	*0.772E-02*
Co- 58	*0.784E-01*	*0.115E-01*	*0.0*	*0.0*	*0.784E-01*
Fe- 59	*0.490E-02*	*0.772E-03*	*0.0*	*0.0*	*0.490E-02*
Co- 60	*0.975E-02*	*0.144E-02*	*0.0*	*0.0*	*0.975E-02*
Kr- 83M	*0.0*	*0.0*	*0.594E-01*	*0.131E-01*	*0.594E-01*
Kr- 85M	*0.0*	*0.0*	*0.330E 00*	*0.729E-01*	*0.330E 00*
Kr- 85	*0.0*	*0.0*	*0.619E 00*	*0.137E 00*	*0.619E 00*
Kr- 87	*0.0*	*0.0*	*0.158E 00*	*0.349E-01*	*0.158E 00*
Kr- 88	*0.0*	*0.0*	*0.547E 00*	*0.121E 00*	*0.547E 00*
Sr- 89	*0.134E-02*	*0.198E-03*	*0.0*	*0.0*	*0.134E-02*
Sr- 90	*0.646E-04*	*0.950E-05*	*0.0*	*0.0*	*0.646E-04*
Y - 90	*0.111E-03*	*0.163E-04*	*0.0*	*0.0*	*0.111E-03*
Sr- 91	*0.851E-03*	*0.125E-03*	*0.0*	*0.0*	*0.851E-03*
Y - 91	*0.111E-01*	*0.164E-02*	*0.0*	*0.0*	*0.111E-01*
Sr- 92	*0.325E-03*	*0.478E-04*	*0.0*	*0.0*	*0.325E-03*
Y - 92	*0.448E-03*	*0.660E-04*	*0.0*	*0.0*	*0.448E-03*
Zr- 95	*0.334E-03*	*0.491E-04*	*0.0*	*0.0*	*0.334E-03*
Nb- 95	*0.325E-03*	*0.477E-04*	*0.0*	*0.0*	*0.325E-03*
Mo- 99	*0.267E 01*	*0.392E 00*	*0.0*	*0.0*	*0.267E 01*
I -131	*0.158E 01*	*0.233E 00*	*0.0*	*0.0*	*0.158E 01*
Te-132	*0.166E 00*	*0.245E-01*	*0.0*	*0.0*	*0.166E 00*
I -132	*0.529E 00*	*0.779E-01*	*0.0*	*0.0*	*0.529E 00*
I -133	*0.214E 01*	*0.315E 00*	*0.0*	*0.0*	*0.214E 01*
Xe-133M	*0.256E-03*	*0.376E-04*	*0.573E 00*	*0.127E 00*	*0.574E 00*
Xe-133	*0.453E-02*	*0.667E-03*	*0.469E 02*	*0.104E 02*	*0.469E 02*
Cs-134	*0.113E 00*	*0.166E-01*	*0.0*	*0.0*	*0.113E 00*
I -134	*0.219E 00*	*0.323E-01*	*0.0*	*0.0*	*0.219E 00*
I -135	*0.115E 01*	*0.169E 00*	*0.0*	*0.0*	*0.115E 01*
Xe-135M	*0.858E-01*	*0.126E-01*	*0.365E-01*	*0.806E-02*	*0.122E 00*
Xe-135	*0.311E-01*	*0.458E-02*	*0.102E 01*	*0.226E 00*	*0.105E 01*
Cs-136	*0.303E-01*	*0.445E-02*	*0.0*	*0.0*	*0.303E-01*
Cs-137	*0.200E 00*	*0.295E-01*	*0.0*	*0.0*	*0.200E 00*
Xe-138	*0.00*	*0.0*	*0.466E-01*	*0.103E-01*	*0.446E-01*
Ba-140	*0.227E-02*	*0.335E-03*	*0.0*	*0.0*	*0.227E-02*
La-140	*0.813E-03*	*0.120E-03*	*0.0*	*0.0*	*0.813E-03*
Ce-144	*0.197E-03*	*0.289E-04*	*0.0*	*0.0*	*0.197E-03*
Pr-144	*0.197E-03*	*0.289E-04*	*0.0*	*0.0*	*0.197E-03*

TABLE 11.3-9
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

GASEOUS RELEASES DUE TO COLD SHUTDOWN AND STARTUPS
(Released from Condenser)

Nuclide	*Released, Ci*	*Fraction of Total Annual Release*
Kr-83m	*1.89E-8*	*1.21E-8*
Kr-85m	*2.91E-5*	*2.75E-6*
Kr-85	*4.32E-3*	*4.75E-6*
Kr-87	*6.36E-10*	*1.58E-10*
Kr-88	*4.14E-6*	*2.69E-7*
I-131[a]	*4.32E-5*	*3.32E-4*
I-132[a]	*7.69E-9*	*2.79E-7*
I-133[a]	*2.51E-5*	*1.90E-4*
Xe-133m	*2.80E-3*	*3.29E-5*
Xe-133	*2.80E-1*	*2.17E-5*
I-134[a]	*7.34E-15*	*5.73E-13*
I-135[a]	*1.98E-6*	*3.06E-5*
Xe-135m	*1.89E-5*	*1.20E-5*
Xe-135	*1.20E-3*	*2.63E-5*
Xe-138	*0.0*	*0.0*
Totals	*2.89E-1*	*6.54E-4*

(a) Volatile form only.

Notes:
Beta air dose at 0.5 miles NW of plant = 1.55E-5 mrem/yr
Gamma air dose at 0.5 miles NW of plant = 5.12E-6 mrem/yr

TABLE 11.3-10

DISTANCES IN MILES FROM DCPP UNIT 1 REACTOR CENTERLINE TO THE NEAREST
MILK COW, MEAT ANIMAL, MILK GOAT, RESIDENCE, VEGETABLE GARDEN, AND SITE BOUNDARY

	22-1/2° Radial Sectors[a]								
Nearest	NW	NNW	N	NNE	NE	ENE	E	ESE	SE
Milk cow	None[b]	None	None	None	None	None	None	None	None
Meat animal	0.5	0.5	0.5	0.5	0.5	0.7	1.0	1.0	1.1
Milk goat	None	None	None	None	None	None	None	None	None
Residence	None	1.5	None	None	None	4.5	None	None	None
Vegetable garden	3.6	3.6	None	None	None	None	None	3.7	3.7
Site boundary	0.5	0.5	0.5	0.5	0.5	0.7	1.0	1.0	1.1

(a) Sectors not shown contain no land beyond the site boundary, other than islets not used for the purposes indicated in this table.

(b) None within 5 miles, typical of other places where "None" is used.

TABLE 11.3-11

ESTIMATES OF RELATIVE CONCENTRATION (χ/Q)[a] AT LOCATIONS SPECIFIED IN TABLE 11.3-10

	22-1/2° Radial Sectors								
Nearest	NW	NNW	N	NNE	NE	ENE	E	ESE	SE
Milk cow	None	None	None	None	None	None	None	None	None
Meat animal	$1.58X10^{-6}$	$8.67X10^{-7}$	$4.93X10^{-7}$	$2.44X10^{-7}$	$1.62X10^{-7}$	$9.18X10^{-8}$	$1.07X10^{-7}$	$5.20X10^{-7}$	$1.32X10^{-6}$
Milk goat	None	None	None	None	None	None	None	None	None
Residence	None	$3.30X10^{-7}$	None	None	None	$1.40X10^{-8}$	None	None	None
Vegetable garden	$1.50X10^{-7}$	$1.50X10^{-7}$	None	None	None	None	None	$1.00X10^{-7}$	$1.00X10^{-7}$
Site boundary	$1.58X10^{-6}$	$8.67X10^{-7}$	$4.93X10^{-7}$	$2.44X10^{-7}$	$1.62X10^{-7}$	$9.18X10^{-8}$	$1.07X10^{-7}$	$5.20X10^{-7}$	$1.32X10^{-6}$

(a) In units of seconds per cubic meter.

TABLE 11.3-12

ESTIMATES OF DEPOSITION (χ/Q)[a] AT LOCATIONS SPECIFIED IN TABLE 11.3-10

	22-1/2° Radial Sectors								
Nearest	NW	NNW	N	NNE	NE	ENE	E	ESE	SE
Milk cow	None	None	None	None	None	None	None	None	None
Meat animal	$2.54X10^{-8}$	$1.33X10^{-8}$	$5.50X10^{-9}$	$3.27X10^{-9}$	$4.13X10^{-9}$	$1.77X10^{-9}$	$1.65X10^{-9}$	$8.47X10^{-9}$	$2.90X10^{-8}$
Milk goat	None	None	None	None	None	None	None	None	None
Residence	None	$2.08X10^{-9}$	None	None	None	$6.49X10^{-11}$	None	None	None
Vegetable garden	$8.13X10^{-10}$	$4.27X10^{-10}$	None	None	None	None	None	$7.91X10^{-10}$	$3.20X10^{-9}$
Site boundary	$2.54X10^{-8}$	$1.33X10^{-8}$	$5.50X10^{-9}$	$3.27X10^{-9}$	$4.13X10^{-9}$	$1.77X10^{-9}$	$1.65X10^{-9}$	$8.47X10^{-9}$	$2.90X10^{-8}$

(a) In units of meters^{-2}, includes sector width and frequency of winds in each sector.

TABLE 11.3-13

ANNUAL AVERAGE ATMOSPHERIC ACTIVITY CONCENTRATIONS
AT SITE BOUNDARY FOR DESIGN BASIS CASE (μCi/cc)

	Sector								
Nuclide	NW	NNW	N	NNE	NE	ENE	E	ESE	SE
I-135	7.633E-22	4.189E-22	2.382E-22	1.179E-22	7.826E-23	4.277E-23	4.806E-23	2.336E-22	5.864E-22
H-3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cr-51	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mn-54	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fe-55	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Co-58	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fe-59	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Co-60	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kr-83M	9.868E-34	5.415E-34	3.079E-34	1.524E-34	1.012E-34	5.734E-35	6.683E-35	3.248E-34	8.245E-34
Kr-85M	1.121E-23	6.153E-24	3.499E-24	1.732E-24	1.150E-24	6.515E-25	7.594E-25	3.691E-24	9.369E-24
Kr-85	2.528E-10	1.387E-10	7.887E-11	3.903E-11	2.592E-11	1.469E-11	1.712E-11	8.318E-11	2.112E-10
Kr-87	8.455E-41	4.639E-41	2.638E-41	1.306E-41	8.669E-42	4.912E-42	5.726E-42	2.783E-41	7.063E-41
Kr-88	1.805E-27	9.905E-28	5.632E-28	2.788E-28	1.851E-28	1.049E-28	1.222E-28	5.941E-28	1.508E-27
Sr-89	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sr-90	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Y-90	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sr-91	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Y-91	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sr-92	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Y-92	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Zr-95	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nb-95	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mo-99	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I-131	4.819E-19	2.644E-19	1.504E-19	7.442E-20	4.941E-20	2.700E-20	3.034E-20	1.474E-19	3.702E-19
Te-132	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I-132	7.214E-20	3.959E-20	2.251E-20	1.114E-20	7.397E-21	4.042E-21	4.542E-21	2.207E-20	5.542E-20
I-133	8.355E-21	4.585E-21	2.607E-21	1.290E-21	8.567E-22	4.681E-22	5.260E-22	2.556E-21	6.419E-21
Xe-133M	1.688E-16	9.265E-17	5.268E-17	2.607E-17	1.731E-17	9.810E-10	1.143E-17	5.557E-17	1.411E-16
Xe-133	2.058E-11	1.129E-11	6.420E-12	3.178E-12	2.110E-12	1.196E-12	1.393E-12	6.772E-12	1.719E-11
Cs-134	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I-134	1.336E-22	7.332E-23	4.169E-23	2.064E-23	1.370E-23	7.486E-24	8.413E-24	4.088E-23	1.027E-22

TABLE 11.3-13

	Sector								
Nuclide	NW	NNW	N	NNE	NE	ENE	E	ESE	SE
Xe-135M	3.345E-21	1.835E-21	1.044E-21	5.165E-22	3.429E-22	1.943E-22	2.265E-22	1.101E-21	2.794E-21
Xe-135	1.382E-18	7.582E-19	4.311E-19	2.134E-19	1.417E-19	8.028E-20	9.357E-20	4.547E-19	1.154E-18
Cs-136	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cs-137	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Xe-138	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ba-140	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
La-140	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ce-144	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pr-144	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
C-14	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

TABLE 11.3-14

ANNUAL AVERAGE ATMOSPHERIC ACTIVITY CONCENTRATIONS
AT SITE BOUNDARY FOR NORMAL OPERATION CASE (μCi/cc)

	Sector								
Nuclide	NW	NNW	N	NNE	NE	ENE	E	ESE	SE
H-3	1.401E-11	7.687E-12	4.371E-12	2.163E-12	1.436E-12	7.848E-13	8.820E-13	4.286E-12	1.076E-11
Cr-51	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mn-54	1.918-15	1.053E-15	5.985E-14	2.967E-16	1.967E-16	1.075E-16	1.208E-16	5.869E-16	1.474E-15
Fe-55	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Co-58	4.466E-15	3.548E-15	2.017E-15	9.985E-16	6.629E-16	3.622E-16	4.071E-16	1.978E-15	4.967E-15
Fe-59	6.466E-16	3.548E-16	2.017E-16	9.985E-17	6.629E-17	3.622E-17	4.071E-17	1.978E-16	4.967E-16
Co-60	2.931E-15	1.608E-5	9.146E-16	4.526E-16	3.005E-16	1.642E-16	1.845E-16	8.968E-16	2.252E-15
Kr-83M	7.805E-14	4.283E-14	2.435E-14	1.205E-14	8.002E-15	4.535E-15	5.286E-15	2.569E-14	6.521E-14
Kr-85M	5.323E-13	2.921E-13	1.661E-13	8.221E-14	5.458E-14	3.093E-14	3.605E-14	1.752E-13	4.447E-13
Kr-85	4.558E-11	2.501E-11	1.422E-11	7.039E-12	4.674E-12	2.648E-12	3.087E-12	1.500E-11	3.808E-11
Kr-87	2.016E-13	1.104E-13	6.290E-14	3.113E-14	2.067E-14	1.171E-14	1.365E-14	6.635E-14	1.684E-13
Kr-88	7.725E-13	4.239E-13	2.410E-13	1.193E-13	7.921E-14	4.488E-14	5.232E-14	2.542E-13	6.454E-13
Sr-89	1.422E-16	7.805E-17	4.438E-17	2.197E-17	1.458E-17	7.969E-18	8.955E-10	4.352E-17	1.093E-16
Sr-90	2.414E-17	1.325E-17	7.532E-18	3.720E-18	2.475E-18	1.352E-18	1.520E-18	7.386E-18	1.854E-17
Y-90	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sr-91	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Y-91	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sr-92	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Y-92	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Zr-95	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nb-95	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mo-99	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I-131	5.601E-15	3.073E-15	1.748E-15	8.649E-16	5.742E-16	3.138E-16	3.526E-16	1.714E-15	4.303E-15
Te-132	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I-132	1.190E-15	6.529E-16	3.712E-16	1.837E-16	1.220E-16	6.666E-17	7.491E-17	3.640E-14	9.141E-16
I-133	5.673E-15	3.113E-15	1.770E-15	8.761E-16	5.816E-16	3.178E-16	3.572E-17	1.736E-15	4.358E-15
Xe-133M	4.259E-12	2.337E-12	1.329E-12	6.577E-13	4.367E-13	2.475E-13	2.884E-13	1.402E-12	3.558E-12
Xe-133	6.468E-10	3.549E-10	2.018E-10	9.989E-11	6.632E-11	3.758E-11	4.381E-11	2.129E-10	5.404E-10
Cs-134	1.918E-15	1.053E-15	5.985E-16	2.962E-16	1.967E-16	1.075E-16	1.208E-16	5.869E-16	1.474E-15
I-134	5.496E-16	3.016E-16	1.715E-16	8.487E-17	5.635E-17	3.079E-17	3.460E-17	1.682E-16	4.222E-16
I-135	2.787E-15	1.529E-15	8.697E-16	4.304E-16	2.858E-16	1.562E-16	1.755E-16	8.528E-16	2.141E-15

	Sector								
Nuclide	NW	NNW	N	NNE	NE	ENE	E	ESE	SE
Xe-135M	7.857E-14	4.311E-14	2.452E-14	1.213E-14	8.056E-15	4.565E-15	5.321E-15	2.586E-14	6.564E-14
Xe-135	2.287E-12	1.255E-12	7.135E-13	3.532E-13	2.345E-13	1.329E-13	1.549E-13	7.526E-13	1.911E-12
Cs-136	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cs-137	3.254E-15	1.786E-15	1.015E-15	5.026E-16	3.337E-16	1.823E-16	2.049E-16	9.957E-16	2.500E-15
Xe-138	8.728E-14	4.789E-14	2.723E-14	1.348E-14	8.948E-15	5.071E-15	5.910E-15	2.872E-14	7.291E-14
Ba-140	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
La-140	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ce-144	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pr-144	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
C-14	3.448E-13	1.892E-13	1.076E-13	5.325E-14	3.536E-14	1.932E-14	2.171E-14	1.055E-13	2.649E-13

TABLE 11.3-15

OFFSITE DOSES FOR NW SECTOR AT DISTANCE 0.5 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
DESIGN BASIS CASE

Dose	Adult	Teen	Child	Infant
Ingestion bone	4.406E-08	3.486E-08	6.434E-08	0.0
Ingestion liver	6.312E-08	4.925E-08	6.592E-08	0.0
Ingestion whole body	3.611E-08	2.935E-08	4.974E-08	0.0
Ingestion thyroid	2.065E-05	1.421E-05	2.143E-05	0.0
Ingestion kidney	1.080E-07	6.383E-08	4.026E-08	0.0
Ingestion lung	0.0	0.0	0.0	0.0
Ingestion GI	1.663E-08	9.324E-09	5.645E-09	0.0
Total bone	4.406E-08	3.486E-08	6.434E-08	0.0
Total liver	6.312E-08	4.925E-08	6.592E-08	0.0
Total whole body	3.611E-08	2.935E-08	4.974E-08	0.0
Total thyroid	2.065E-05	1.421E-05	2.143E-05	0.0
Total kidney	1.080E-07	6.383E-08	4.026E-08	0.0
Total lung	0.0	0.0	0.0	0.0
Total GI	1.663E-08	9.324E-09	5.645E-09	0.0
Gamma air	5.145E-01	5.145E-01	5.145E-01	5.145E-01
Beta air	1.161E-02	1.161E-02	1.161E-02	1.161E-02

TABLE 11.3-16

OFFSITE DOSES FOR NW SECTOR AT DISTANCE 3.6 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
DESIGN BASIS CASE

Dose	Adult	Teen	Child	Infant
Ingestion bone	5.578E-10	9.049E-10	2.186E-09	0.0
Ingestion liver	7.992E-10	1.279E-09	2.289E-09	0.0
Ingestion whole body	4.573E-10	7.619E-10	1.690E-09	0.0
Ingestion thyroid	2.615E-07	3.688E-07	7.281E-07	0.0
Ingestion kidney	1.368E-09	1.657E-09	1.368E-09	0.0
Ingestion lung	0.0	0.0	0.0	0.0
Ingestion GI	2.105E-10	2.421E-10	1.918E-10	0.0
Total bone	5.578E-10	9.049E-10	2.186E-09	0.0
Total liver	7.992E-10	1.279E-09	2.239E-09	0.0
Total whole body	4.573E-10	7.619E-10	1.690E-09	0.0
Total thyroid	2.615E-07	3.688E-07	7.281E-07	0.0
Total kidney	1.368E-09	1.657E-09	1.368E-09	0.0
Total lung	0.0	0.0	0.0	0.0
Total GI	2.105E-10	2.421E-10	1.918E-10	0.0

TABLE 11.3-17

OFFSITE DOSES FOR NNW SECTOR AT DISTANCE 0.5 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
DESIGN BASIS CASE

Dose	Adult	Teen	Child	Infant
Ingestion bone	2.312E-08	1.829E-08	3.377E-08	0.0
Ingestion liver	3.313E-08	2.585E-08	3.460E-08	0.0
Ingestion whole body	1.895E-08	1.540E-08	2.610E-08	0.0
Ingestion thyroid	1.084E-05	7.455E-06	1.125E-05	0.0
Ingestion kidney	5.669E-08	3.350E-08	2.113E-08	0.0
Ingestion lung	0.0	0.0	0.0	0.0
Ingestion GI	8.726E-09	4.894E-09	2.962E-09	0.0
Total bone	2.312E-08	1.829E-08	3.377E-08	0.0
Total liver	3.313E-08	2.585E-08	3.460E-08	0.0
Total whole body	1.895E-08	1.540E-08	2.610E-08	0.0
Total thyroid	1.084E-05	7.455E-06	1.125E-05	0.0
Total kidney	5.669E-08	3.350E-08	2.113E-08	0.0
Total lung	0.0	0.0	0.0	0.0
Total GI	8.726E-09	4.894E-09	2.962E-09	0.0
Gamma air	2.823E-01	2.823E-01	2.823E-01	2.823E-01
Beta air	6.371E-03	6.371E-03	6.371E-03	6.371E-03

TABLE 11.3-18

OFFSITE DOSES FOR NNW SECTOR AT DISTANCE 1.5 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
DESIGN BASIS CASE

Dose	Adult	Teen	Child	Infant
Inhalation bone	2.077E-09	1.937E-09	2.985E-09	4.420E-09
Inhalation liver	2.971E-09	2.732E-09	3.047E-09	5.218E-09
Inhalation whole body	1.687E-09	1.617E-09	2.294E-09	3.049E-09
Inhalation thyroid	9.794E-07	7.988E-07	1.009E-06	1.722E-06
Inhalation kidney	5.094E-09	3.559E-09	1.884E-09	1.326E-09
Inhalation lung	0.0	0.0	0.0	0.0
Inhalation GI	5.289E-10	3.526E-10	1.810E-10	1.360E-10
External whole body	1.692E-03	1.692E-03	1.692E-03	1.692E-03
External skin	7.394E-02	7.394E-02	7.394E-02	7.394E-02
Total bone	1.692E-03	1.692E-03	1.692E-03	1.692E-03
Total liver	1.692E-03	1.692E-03	1.692E-03	1.692E-03
Total whole body	1.692E-03	1.692E-03	1.692E-03	1.692E-03
Total thyroid	1.693E-03	1.693E-03	1.693E-03	1.694E-03
Total kidney	1.692E-03	1.692E-03	1.692E-03	1.692E-03
Total lung	1.692E-03	1.692E-03	1.692E-03	1.692E-03
Total GI	1.692E-03	1.692E-03	1.692E-03	1.692E-03

TABLE 11.3-19

OFFSITE DOSES FOR NNW SECTOR AT DISTANCE 3.6 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
DESIGN BASIS CASE

Dose	Adult	Teen	Child	Infant
Ingestion bone	2.926E-10	4.746E-10	1.146E-09	0.0
Ingestion liver	4.192E-10	6.706E-10	1.175E-09	0.0
Ingestion whole body	2.398E-10	3.996E-10	8.862E-10	0.0
Ingestion thyroid	1.371E-07	1.934E-07	3.819E-07	0.0
Ingestion kidney	7.174E-10	8.692E-10	7.174E-10	0.0
Ingestion lung	0.0	0.0	0.0	0.0
Ingestion GI	1.104E-10	1.270E-10	1.006E-10	0.0
Total bone	2.926E-10	4.746E-10	1.146E-09	0.0
Total liver	4.192E-10	6.706E-10	1.175E-09	0.0
Total whole body	2.398E-10	3.996E-10	8.862E-10	0.0
Total thyroid	1.371E-07	1.934E-07	3.819E-07	0.0
Total kidney	7.174E-10	8.692E-10	7.174E-10	0.0
Total lung	0.0	0.0	0.0	0.0
Total GI	1.104E-10	1.270E-10	1.006E-10	0.0

TABLE 11.3-20

OFFSITE DOSES FOR N SECTOR AT DISTANCE 0.5 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
DESIGN BASIS CASE

Dose	Adult	Teen	Child	Infant
Ingestion bone	9.551E-09	7.557E-09	1.395E-08	0.0
Ingestion liver	1.368E-08	1.068E-08	1.429E-08	0.0
Ingestion whole body	7.829E-09	6.363E-09	1.078E-08	0.0
Ingestion thyroid	4.477E-06	3.080E-06	4.647E-06	0.0
Ingestion kidney	2.342E-08	1.384E-08	8.729E-09	0.0
Ingestion lung	0.0	0.0	0.0	0.0
Ingestion GI	3.605E-09	2.022E-09	1.224E-09	0.0
Total bone	9.551E-09	7.557E-09	1.395E-08	0.0
Total liver	1.368E-08	1.068E-08	1.429E-08	0.0
Total whole body	7.829E-09	6.363E-09	1.078E-08	0.0
Total thyroid	4.477E-06	3.080E-06	4.647E-06	0.0
Total kidney	2.342E-08	1.384E-08	8.729E-09	0.0
Total lung	0.0	0.0	0.0	0.0
Total GI	3.605E-09	2.022E-09	1.224E-09	0.0
Gamma air	1.605E-01	1.605E-01	1.605E-01	1.605E-01
Beta air	3.623E-03	3.623E-03	3.623E-03	3.623E-03

TABLE 11.3-21

OFFSITE DOSES FOR NNE SECTOR AT DISTANCE 0.5 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
DESIGN BASIS CASE

Dose	Adult	Teen	Child	Infant
Ingestion bone	5.688E-09	4.500E-09	8.306E-09	0.0
Ingestion liver	8.148E-09	6.358E-09	8.510E-09	0.0
Ingestion whole body	4.662E-09	3.789E-09	6.421E-09	0.0
Ingestion thyroid	2.666E-06	1.834E-06	2.767E-06	0.0
Ingestion kidney	1.395E-08	8.240E-09	5.198E-09	0.0
Ingestion lung	0.0	0.0	0.0	0.0
Ingestion GI	2.146E-09	1.204E-09	7.287E-10	0.0
Total bone	5.688E-09	4.500E-09	8.306E-09	0.0
Total liver	8.148E-09	6.358E-09	8.510E-09	0.0
Total whole body	4.662E-09	3.789E-09	6.421E-09	0.0
Total thyroid	2.666E-06	1.834E-06	2.767E-06	0.0
Total kidney	1.395E-08	8.240E-09	5.198E-09	0.0
Total lung	0.0	0.0	0.0	0.0
Total GI	2.146E-09	1.204E-09	7.287E-10	0.0
Gamma air	7.945E-02	7.945E-02	7.945E-02	7.945E-02
Beta air	1.793E-03	1.793E-03	1.793E-03	1.793E-03

TABLE 11.3-22

OFFSITE DOSES FOR NE SECTOR AT DISTANCE 0.5 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
DESIGN BASIS CASE

Dose	Adult	Teen	Child	Infant
Ingestion bone	7.178E-09	5.679E-09	1.048E-08	0.0
Ingestion liver	1.028E-08	8.024E-09	1.074E-08	0.0
Ingestion whole body	5.884E-09	4.782E-09	8.104E-09	0.0
Ingestion thyroid	3.365E-06	2.315E-06	3.492E-06	0.0
Ingestion kidney	1.760E-08	1.040E-08	6.560E-09	0.0
Ingestion lung	0.0	0.0	0.0	0.0
Ingestion GI	2.709E-09	1.519E-09	9.197E-10	0.0
Total bone	7.178E-09	5.679E-09	1.048E-08	0.0
Total liver	1.028E-08	8.024E-09	1.074E-08	0.0
Total whole body	5.884E-09	4.782E-09	8.104E-09	0.0
Total thyroid	3.365E-06	2.315E-06	3.492E-06	0.0
Total kidney	1.760E-08	1.040E-08	6.560E-09	0.0
Total lung	0.0	0.0	0.0	0.0
Total GI	2.709E-09	1.519E-09	9.197E-10	0.0
Gamma air	5.275E-02	5.275E-02	5.275E-02	5.275E-02
Beta air	1.190E-03	1.190E-03	1.190E-03	1.190E-03

TABLE 11.3-23

OFFSITE DOSES FOR ENE SECTOR AT DISTANCE 0.7 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
DESIGN BASIS CASE

Dose	Adult	Teen	Child	Infant
Ingestion bone	3.068E-09	2.427E-09	4.481E-09	0.0
Ingestion liver	4.395E-09	3.430E-09	4.591E-09	0.0
Ingestion whole body	2.515E-09	2.044E-09	3.464E-09	0.0
Ingestion thyroid	1.438E-06	9.892E-07	1.493E-06	0.0
Ingestion kidney	7.522E-09	4.445E-09	2.804E-09	0.0
Ingestion lung	0.0	0.0	0.0	0.0
Ingestion GI	1.158E-09	6.493E-10	3.931E-10	0.0
Total bone	3.068E-09	2.427E-09	4.481E-09	0.0
Total liver	4.395E-09	3.430E-09	4.591E-09	0.0
Total whole body	2.515E-09	2.044E-09	3.464E-09	0.0
Total thyroid	1.438E-06	9.892E-07	1.493E-06	0.0
Total kidney	7.522E-09	4.445E-09	2.804E-09	0.0
Total lung	0.0	0.0	0.0	0.0
Total GI	1.158E-09	6.493E-10	3.931E-10	0.0
Gamma air	2.989E-02	2.989E-02	2.989E-02	2.989E-02
Beta air	6.746E-04	6.746E-04	6.746E-04	6.746E-04

TABLE 11.3-24

OFFSITE DOSES FOR ENE SECTOR AT DISTANCE 4.5 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
DESIGN BASIS CASE

Dose	Adult	Teen	Child	Infant
Inhalation bone	7.466E-11	6.962E-11	1.073E-10	1.589E-10
Inhalation liver	1.068E-10	9.819E-11	1.095E-10	1.876E-10
Inhalation whole body	6.065E-11	5.813E-11	8.247E-11	1.096E-10
Inhalation thyroid	3.521E-08	2.872E-08	3.628E-08	6.191E-08
Inhalation kidney	1.831E-10	1.279E-10	6.772E-11	4.766E-11
Inhalation lung	0.0	0.0	0.0	0.0
Inhalation GI	1.901E-11	1.267E-11	6.505E-12	4.890E-12
External whole body	7.179E-05	7.179E-05	7.179E-05	7.179E-05
External skin	3.137E-03	3.137E-03	3.137E-03	3.137E-03
Total bone	7.179E-05	7.179E-05	7.179E-05	7.179E-05
Total liver	7.179E-05	7.179E-05	7.179E-05	7.179E-05
Total whole body	7.179E-05	7.179E-05	7.179E-05	7.179E-05
Total thyroid	7.183E-05	7.182E-05	7.183E-05	7.185E-05
Total kidney	7.179E-05	7.179E-05	7.179E-05	7.179E-05
Total lung	7.179E-05	7.179E-05	7.179E-05	7.179E-05
Total GI	7.179E-05	7.179E-05	7.179E-05	7.179E-05

TABLE 11.3-25

OFFSITE DOSES FOR E SECTOR AT DISTANCE 1.0 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
DESIGN BASIS CASE

Dose	Adult	Teen	Child	Infant
Ingestion bone	2.867E-09	2.268E-09	4.186E-09	0.0
Ingestion liver	4.107E-09	3.204E-09	4.289E-09	0.0
Ingestion whole body	2.350E-09	1.910E-09	3.236E-09	0.0
Ingestion thyroid	1.344E-06	9.243E-07	1.395E-06	0.0
Ingestion kidney	7.028E-09	4.153E-09	2.620E-09	0.0
Ingestion lung	0.0	0.0	0.0	0.0
Ingestion GI	1.082E-09	6.067E-10	3.673E-10	0.0
Total bone	2.867E-09	2.268E-09	4.186E-09	0.0
Total liver	4.107E-09	3.204E-09	4.289E-09	0.0
Total whole body	2.350E-09	1.910E-09	3.236E-09	0.0
Total thyroid	1.344E-06	9.243E-07	1.395E-06	0.0
Total kidney	7.028E-09	4.153E-09	2.620E-09	0.0
Total lung	0.0	0.0	0.0	0.0
Total GI	1.082E-09	6.067E-10	3.673E-10	0.0
Gamma air	3.484E-02	3.484E-02	3.484E-02	3.484E-02
Beta air	7.863E-04	7.863E-04	7.863E-04	7.863E-04

TABLE 11.3-26

OFFSITE DOSES FOR ESE SECTOR AT DISTANCE 1.0 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
DESIGN BASIS CASE

Dose	Adult	Teen	Child	Infant
Ingestion bone	1.472E-08	1.165E-08	2.150E-08	0.0
Ingestion liver	2.109E-08	1.646E-08	2.203E-08	0.0
Ingestion whole body	1.207E-08	9.807E-09	1.662E-08	0.0
Ingestion thyroid	6.900E-06	4.746E-06	7.162E-06	0.0
Ingestion kidney	3.609E-08	2.133E-08	1.345E-08	0.0
Ingestion lung	0.0	0.0	0.0	0.0
Ingestion GI	5.555E-09	3.116E-09	1.886E-09	0.0
Total bone	1.472E-08	1.165E-08	2.150E-08	0.0
Total liver	2.109E-08	1.646E-08	2.203E-08	0.0
Total whole body	1.207E-08	9.807E-09	1.662E-08	0.0
Total thyroid	6.900E-06	4.746E-06	7.162E-06	0.0
Total kidney	3.609E-08	2.133E-08	1.345E-08	0.0
Total lung	0.0	0.0	0.0	0.0
Total GI	5.555E-09	3.116E-09	1.886E-09	0.0
Gamma air	1.693E-01	1.693E-01	1.693E-01	1.693E-01
Beta air	3.821E-03	3.821E-03	3.821E-03	3.821E-03

TABLE 11.3-27

OFFSITE DOSES FOR ESE SECTOR AT DISTANCE 3.7 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
DESIGN BASIS CASE

Dose	Adult	Teen	Child	Infant
Ingestion bone	5.431E-10	8.810E-10	2.128E-09	0.0
Ingestion liver	7.781E-10	1.245E-09	2.180E-09	0.0
Ingestion whole body	4.452E-10	7.418E-10	1.645E-09	0.0
Ingestion thyroid	2.546E-07	3.590E-07	7.089E-07	0.0
Ingestion kidney	1.332E-09	1.613E-09	1.332E-09	0.0
Ingestion lung	0.0	0.0	0.0	0.0
Ingestion GI	2.050E-10	2.357E-10	1.867E-10	0.0
Total bone	5.431E-10	8.810E-10	2.128E-09	0.0
Total liver	7.781E-10	1.245E-09	2.180E-09	0.0
Total whole body	4.452E-10	7.418E-10	1.645E-09	0.0
Total thyroid	2.546E-07	3.590E-07	7.089E-07	0.0
Total kidney	1.332E-09	1.613E-09	1.332E-09	0.0
Total lung	0.0	0.0	0.0	0.0
Total GI	2.050E-10	2.357E-10	1.867E-10	0.0

TABLE 11.3-28

OFFSITE DOSES FOR SE SECTOR AT DISTANCE 1.1 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
DESIGN BASIS CASE

Dose	Adult	Teen	Child	Infant
Ingestion bone	5.046E-08	3.992E-08	7.369E-08	0.0
Ingestion liver	7.229E-08	5.641E-08	7.550E-08	0.0
Ingestion whole body	4.136E-08	3.361E-08	5.696E-08	0.0
Ingestion thyroid	2.365E-05	1.627E-05	2.455E-05	0.0
Ingestion kidney	1.237E-07	7.311E-08	4.611E-08	0.0
Ingestion lung	0.0	0.0	0.0	0.0
Ingestion GI	1.904E-08	1.068E-08	6.465E-09	0.0
Total bone	5.046E-08	3.992E-08	7.369E-08	0.0
Total liver	7.229E-08	5.641E-08	7.550E-08	0.0
Total whole body	4.136E-08	3.361E-08	5.696E-08	0.0
Total thyroid	2.365E-05	1.627E-05	2.455E-05	0.0
Total kidney	1.237E-07	7.311E-08	4.611E-08	0.0
Total lung	0.0	0.0	0.0	0.0
Total GI	1.904E-08	1.068E-08	6.465E-09	0.0
Gamma air	4.298E-01	4.298E-01	4.298E-01	4.298E-01
Beta air	9.700E-03	9.700E-03	9.700E-03	9.700E-03

TABLE 11.3-29

OFFSITE DOSES FOR SE SECTOR AT DISTANCE 3.7 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
DESIGN BASIS CASE

Dose	Adult	Teen	Child	Infant
Ingestion bone	2.200E-09	3.569E-09	8.620E-09	0.0
Ingestion liver	3.152E-09	5.043E-09	8.832E-09	0.0
Ingestion whole body	1.803E-09	3.005E-09	6.664E-09	0.0
Ingestion thyroid	1.031E-06	1.454E-06	2.872E-06	0.0
Ingestion kidney	5.394E-09	6.535E-09	5.394E-09	0.0
Ingestion lung	0.0	0.0	0.0	0.0
Ingestion GI	8.303E-10	9.547E-10	7.563E-10	0.0
Total bone	2.200E-09	3.569E-09	8.620E-09	0.0
Total liver	3.152E-09	5.043E-09	8.832E-09	0.0
Total whole body	1.803E-09	3.005E-09	6.664E-09	0.0
Total thyroid	1.031E-06	1.454E-06	2.872E-06	0.0
Total kidney	5.394E-09	6.535E-09	5.394E-09	0.0
Total lung	0.0	0.0	0.0	0.0
Total GI	8.303E-10	9.547E-10	7.563E-10	0.0

TABLE 11.3-30

OFFSITE DOSES FOR NW SECTOR AT DISTANCE 0.5 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
NORMAL OPERATION CASE

Dose	Adult	Teen	Child	Infant
Ingestion bone	6.470E-02	5.040E-02	8.703E-02	0.0
Ingestion liver	1.065E-01	8.164E-02	1.019E-01	0.0
Ingestion whole body	8.301E-02	4.040E-02	3.180E-02	0.0
Ingestion thyroid	2.400E-01	1.651E-01	2.491E-01	0.0
Ingestion kidney	3.293E-02	1.946E-02	1.227E-02	0.0
Ingestion lung	1.215E-02	1.041E-02	1.146E-02	0.0
Ingestion GI	1.136E-01	5.889E-02	3.272E-02	0.0
Total bone	6.470E-02	5.040E-02	8.703E-02	0.0
Total liver	1.065E-01	8.164E-02	1.019E-01	0.0
Total whole body	8.301E-02	4.040E-02	3.180E-02	0.0
Total thyroid	2.400E-01	1.651E-01	2.491E-01	0.0
Total kidney	3.293E-02	1.946E-02	1.227E-02	0.0
Total lung	1.215E-02	1.041E-02	1.146E-02	0.0
Total GI	1.136E-01	5.889E-02	3.272E-02	0.0
Gamma air	7.859E-01	7.859E-01	7.859E-01	7.859E-01
Beta air	2.496E-01	2.496E-01	2.496E-01	2.496E-01

TABLE 11.3-31

OFFSITE DOSES FOR NW SECTOR AT DISTANCE 3.6 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
NORMAL OPERATION CASE

Dose	Adult	Teen	Child	Infant
Ingestion bone	3.185E-02	5.189E-02	1.052E-01	0.0
Ingestion liver	3.432E-02	5.455E-02	9.099E-02	0.0
Ingestion whole body	2.788E-02	2.742E-02	2.522E-02	0.0
Ingestion thyroid	3.039E-03	4.286E-03	8.463E-03	0.0
Ingestion kidney	1.127E-02	1.365E-02	1.127E-02	0.0
Ingestion lung	3.721E-02	1.365E-02	1.127E-02	0.0
Ingestion GI	1.088E-02	1.168E-02	8.568E-03	0.0
Total bone	3.185E-02	5.189E-02	1.052E-01	0.0
Total liver	3.432E-02	5.455E-02	9.099E-02	0.0
Total whole body	2.788E-02	2.742E-02	2.522E-02	0.0
Total thyroid	3.039E-03	4.286E-03	8.463E-03	0.0
Total kidney	1.127E-02	1.365E-02	1.127E-02	0.0
Total lung	3.721E-03	6.847E-03	1.030E-02	0.0
Total GI	1.088E-02	1.168E-02	8.568E-03	0.0

TABLE 11.3-32

OFFSITE DOSES FOR NNW SECTOR AT DISTANCE 0.5 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
NORMAL OPERATION CASE

Dose	Adult	Teen	Child	Infant
Ingestion bone	3.396E-02	2.645E-02	4.568E-02	0.0
Ingestion liver	5.590E-02	4.285E-02	5.346E-02	0.0
Ingestion whole body	4.357E-02	2.120E-02	1.669E-02	0.0
Ingestion thyroid	1.260E-01	8.665E-02	1.307E-01	0.0
Ingestion kidney	1.728E-02	1.021E-02	6.442E-03	0.0
Ingestion lung	6.378E-03	5.463E-03	6.017E-03	0.0
Ingestion GI	5.964E-02	3.091E-02	1.717E-02	0.0
Total bone	3.396E-02	2.645E-02	4.568E-02	0.0
Total liver	5.590E-02	4.285E-02	5.346E-02	0.0
Total whole body	4.357E-02	2.120E-02	1.669E-02	0.0
Total thyroid	1.260E-01	8.665E-02	1.307E-01	0.0
Total kidney	1.728E-02	1.021E-02	6.442E-03	0.0
Total lung	6.378E-03	5.463E-03	6.017E-03	0.0
Total GI	5.964E-02	3.091E-02	1.717E-02	0.0
Gamma air	4.312E-01	4.312E-01	4.312E-01	4.312E-01
Beta air	1.370E-01	1.370E-01	1.370E-01	1.370E-01

TABLE 11.3-33

OFFSITE DOSES FOR NNW SECTOR AT DISTANCE 1.5 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
NORMAL OPERATION CASE

Dose	Adult	Teen	Child	Infant
Inhalation bone	1.892E-03	1.164E-03	1.037E-03	1.221E-03
Inhalation liver	6.453E-03	4.281E-03	3.282E-03	3.440E-03
Inhalation whole body	3.269E-03	1.809E-03	1.646E-03	1.686E-03
Inhalation thyroid	1.736E-02	1.368E-02	1.719E-02	2.823E-02
Inhalation kidney	3.043E-03	2.126E-03	1.125E-03	7.919E-04
Inhalation lung	7.415E-03	6.104E-03	5.589E-03	7.540E-03
Inhalation GI	3.073E-03	1.751E-03	1.594E-03	1.630E-03
External whole body	2.043E-01	2.043E-01	2.043E-01	2.043E-01
External skin	2.950E-01	2.950E-01	2.950E-01	2.950E-01
Total bone	2.062E-01	2.054E-01	2.053E-01	2.055E-01
Total liver	2.107E-01	2.085E-01	2.075E-01	2.077E-01
Total whole body	2.075E-01	2.061E-01	2.059E-01	2.059E-01
Total thyroid	2.216E-01	2.179E-01	2.214E-01	2.325E-01
Total kidney	2.073E-01	2.064E-01	2.054E-01	2.050E-01
Total lung	2.117E-01	2.104E-01	2.098E-01	2.118E-01
Total GI	2.073E-01	2.060E-01	2.059E-01	2.059E-01

TABLE 11.3-34

OFFSITE DOSES FOR NNW SECTOR AT DISTANCE 3.6 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
NORMAL OPERATION CASE

Dose	Adult	Teen	Child	Infant
Ingestion bone	1.672E-02	2.723E-02	5.521E-02	0.0
Ingestion liver	1.801E-02	2.863E-02	4.776E-02	0.0
Ingestion whole body	1.463E-02	1.439E-02	1.324E-02	0.0
Ingestion thyroid	1.594E-03	2.248E-03	4.439E-03	0.0
Ingestion kidney	5.915E-03	7.166E-03	5.915E-03	0.0
Ingestion lung	1.953E-03	3.594E-03	5.404E-03	0.0
Ingestion GI	5.711E-03	6.131E-03	4.497E-03	0.0
Total bone	1.672E-02	2.723E-02	5.521E-02	0.0
Total liver	1.801E-02	2.863E-02	4.776E-02	0.0
Total whole body	1.463E-02	1.439E-02	1.324E-02	0.0
Total thyroid	1.594E-03	2.248E-03	4.439E-03	0.0
Total kidney	5.915E-03	7.166E-03	5.915E-03	0.0
Total lung	1.953E-03	3.594E-03	5.404E-03	0.0
Total GI	5.711E-03	6.131E-03	4.497E-03	0.0

TABLE 11.3-35

OFFSITE DOSES FOR N SECTOR AT DISTANCE 0.5 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
NORMAL OPERATION CASE

Dose	Adult	Teen	Child	Infant
Ingestion bone	1.403E-02	1.093E-02	1.887E-02	0.0
Ingestion liver	2.309E-02	1.770E-02	2.209E-02	0.0
Ingestion whole body	1.800E-02	8.761E-03	6.895E-03	0.0
Ingestion thyroid	5.204E-02	3.580E-02	5.401E-02	0.0
Ingestion kidney	7.140E-03	4.219E-03	2.661E-03	0.0
Ingestion lung	2.635E-03	2.257E-03	2.486E-03	0.0
Ingestion GI	2.464E-02	1.277E-02	7.096E-03	0.0
Total bone	1.403E-02	1.093E-02	1.887E-02	0.0
Total liver	2.309E-02	1.770E-02	2.209E-02	0.0
Total whole body	1.800E-02	8.761E-03	6.895E-03	0.0
Total thyroid	5.204E-02	3.580E-02	5.401E-02	0.0
Total kidney	7.140E-03	4.219E-03	2.661E-03	0.0
Total lung	2.635E-03	2.257E-03	2.486E-03	0.0
Total GI	2.464E-02	1.277E-02	7.096E-03	0.0
Gamma air	2.452E-01	2.452E-01	2.452E-01	2.452E-01
Beta air	7.789E-02	7.789E-02	7.789E-02	7.789E-02

TABLE 11.3-36

OFFSITE DOSES FOR NNE SECTOR AT DISTANCE 0.5 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
NORMAL OPERATION CASE

Dose	Adult	Teen	Child	Infant
Ingestion bone	8.356E-03	6.509E-03	1.124E-02	0.0
Ingestion liver	1.375E-02	1.054E-02	1.315E-02	0.0
Ingestion whole body	1.072E-02	5.217E-03	4.106E-03	0.0
Ingestion thyroid	3.099E-02	2.131E-02	3.216E-02	0.0
Ingestion kidney	4.252E-03	2.513E-03	1.585E-03	0.0
Ingestion lung	1.569E-03	1.344E-03	1.481E-03	0.0
Ingestion GI	1.468E-02	7.605E-03	4.226E-03	0.0
Total bone	8.356E-03	6.509E-03	1.124E-02	0.0
Total liver	1.375E-02	1.054E-02	1.315E-02	0.0
Total whole body	1.072E-02	5.217E-03	4.106E-03	0.0
Total thyroid	3.099E-02	2.131E-02	3.216E-02	0.0
Total kidney	4.252E-03	2.513E-03	1.585E-03	0.0
Total lung	1.569E-03	1.344E-03	1.481E-03	0.0
Total GI	1.468E-02	7.605E-03	4.226E-03	0.0
Gamma air	1.214E-01	1.214E-01	1.214E-01	1.214E-01
Beta air	3.855E-02	3.855E-02	3.855E-02	3.855E-02

TABLE 11.3-37

OFFSITE DOSES FOR NE SECTOR AT DISTANCE 0.5 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
NORMAL OPERATION CASE

Dose	Adult	Teen	Child	Infant
Ingestion bone	1.055E-02	8.215E-03	1.418E-02	0.0
Ingestion liver	1.736E-02	1.331E-02	1.660E-02	0.0
Ingestion whole body	1.353E-02	6.585E-03	5.182E-03	0.0
Ingestion thyroid	3.911E-02	2.690E-02	4.059E-02	0.0
Ingestion kidney	5.367E-03	3.171E-03	2.000E-03	0.0
Ingestion lung	1.980E-03	1.696E-03	1.868E-03	0.0
Ingestion GI	1.852E-02	9.598E-03	5.333E-03	0.0
Total bone	1.055E-02	8.215E-03	1.418E-02	0.0
Total liver	1.736E-02	1.331E-02	1.660E-02	0.0
Total whole body	1.353E-02	6.585E-03	5.182E-03	0.0
Total thyroid	3.911E-02	2.690E-02	4.059E-02	0.0
Total kidney	5.367E-03	3.171E-03	2.000E-03	0.0
Total lung	1.980E-03	1.696E-03	1.868E-03	0.0
Total GI	1.852E-02	9.598E-03	5.333E-03	0.0
Gamma air	8.058E-02	8.058E-02	8.058E-02	8.058E-02
Beta air	2.559E-02	2.559E-02	2.559E-02	2.559E-02

TABLE 11.3-38

OFFSITE DOSES FOR ENE SECTOR AT DISTANCE 0.7 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
NORMAL OPERATION CASE

Dose	Adult	Teen	Child	Infant
Ingestion bone	4.508E-03	3.512E-03	6.064E-03	0.0
Ingestion liver	7.420E-03	5.688E-03	7.097E-03	0.0
Ingestion whole body	5.784E-03	2.815E-03	2.215E-03	0.0
Ingestion thyroid	1.671E-02	1.150E-02	1.735E-02	0.0
Ingestion kidney	2.294E-03	1.356E-03	8.551E-04	0.0
Ingestion lung	8.467E-04	7.252E-04	7.988E-04	0.0
Ingestion GI	7.918E-03	4.103E-03	2.280E-03	0.0
Total bone	4.508E-03	3.512E-03	6.064E-03	0.0
Total liver	7.420E-03	5.688E-03	7.097E-03	0.0
Total whole body	5.784E-03	2.815E-03	2.215E-03	0.0
Total thyroid	1.671E-02	1.150E-02	1.735E-02	0.0
Total kidney	2.294E-03	1.356E-03	8.551E-04	0.0
Total lung	8.467E-04	7.252E-04	7.988E-04	0.0
Total GI	7.918E-03	4.103E-03	2.280E-03	0.0
Gamma air	4.566E-02	4.566E-02	4.566E-02	4.566E-02
Beta air	1.450E-02	1.450E-02	1.450E-02	1.450E-02

TABLE 11.3-39

OFFSITE DOSES FOR ENE SECTOR AT DISTANCE 4.5 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
NORMAL OPERATION CASE

Dose	Adult	Teen	Child	Infant
Inhalation bone	6.802E-05	4.186E-05	3.728E-05	4.388E-05
Inhalation liver	2.320E-04	1.539E-04	1.180E-04	1.236E-04
Inhalation whole body	1.175E-04	6.502E-05	5.915E-05	6.060E-05
Inhalation thyroid	6.241E-04	4.919E-04	6.180E-04	1.015E-03
Inhalation kidney	1.094E-04	7.641E-05	4.045E-05	2.847E-05
Inhalation lung	2.665E-04	2.194E-04	2.009E-04	2.710E-04
Inhalation GI	1.105E-04	6.296E-05	5.729E-05	5.859E-05
External whole body	6.780E-03	6.780E-03	6.780E-03	6.780E-03
External skin	1.031E-02	1.031E-02	1.031E-02	1.031E-02
Total bone	6.848E-03	6.822E-03	6.817E-03	6.824E-03
Total liver	7.012E-03	6.934E-03	6.898E-03	6.903E-03
Total whole body	6.897E-03	6.845E-03	6.839E-03	6.840E-03
Total thyroid	7.404E-03	7.272E-03	7.398E-03	7.795E-03
Total kidney	6.889E-03	6.856E-03	6.820E-03	6.808E-03
Total lung	7.046E-03	6.999E-03	6.981E-03	7.051E-03
Total GI	6.890E-03	6.843E-03	6.837E-03	6.838E-03

TABLE 11.3-40

OFFSITE DOSES FOR E SECTOR AT DISTANCE 1 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
NORMAL OPERATION CASE

Dose	Adult	Teen	Child	Infant
Ingestion bone	4.214E-03	3.283E-03	5.668E-03	0.0
Ingestion liver	6.936E-03	5.317E-03	6.634E-03	0.0
Ingestion whole body	5.406E-03	2.631E-03	2.071E-03	0.0
Ingestion thyroid	1.562E-02	1.074E-02	1.621E-02	0.0
Ingestion kidney	2.144E-03	1.267E-03	7.993E-04	0.0
Ingestion lung	7.914E-04	6.779E-04	7.467E-04	0.0
Ingestion GI	7.401E-03	3.835E-03	2.131E-03	0.0
Total bone	4.214E-03	3.283E-03	5.668E-03	0.0
Total liver	6.936E-03	5.317E-03	6.634E-03	0.0
Total whole body	5.406E-03	2.631E-03	2.071E-03	0.0
Total thyroid	1.562E-02	1.074E-02	1.621E-02	0.0
Total kidney	2.144E-03	1.267E-03	7.993E-04	0.0
Total lung	7.914E-04	6.779E-04	7.467E-04	0.0
Total GI	7.401E-03	3.835E-03	2.131E-03	0.0
Gamma air	5.322E-02	5.322E-02	5.322E-02	5.322E-02
Beta air	1.690E-02	1.690E-02	1.690E-02	1.690E-02

TABLE 11.3-41

OFFSITE DOSES FOR ESE SECTOR AT DISTANCE 1 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
NORMAL OPERATION CASE

Dose	Adult	Teen	Child	Infant
Ingestion bone	2.163E-02	1.685E-02	2.909E-02	0.0
Ingestion liver	3.560E-02	2.729E-02	3.404E-02	0.0
Ingestion whole body	2.775E-02	1.350E-02	1.063E-02	0.0
Ingestion thyroid	8.020E-02	5.517E-02	8.324E-02	0.0
Ingestion kidney	1.101E-02	6.503E-03	4.102E-03	0.0
Ingestion lung	4.061E-03	3.479E-03	3.832E-03	0.0
Ingestion GI	3.798E-02	1.968E-02	1.094E-02	0.0
Total bone	2.163E-02	1.685E-02	2.909E-02	0.0
Total liver	3.560E-02	2.729E-02	3.404E-02	0.0
Total whole body	2.775E-02	1.350E-02	1.063E-02	0.0
Total thyroid	8.020E-02	5.517E-02	8.324E-02	0.0
Total kidney	1.101E-02	6.503E-03	4.102E-03	0.0
Total lung	4.061E-03	3.479E-03	3.832E-03	0.0
Total GI	3.798E-02	1.968E-02	1.094E-02	0.0
Gamma air	2.586E-01	2.586E-01	2.586E-01	2.586E-01
Beta air	8.215E-02	8.215E-02	8.215E-02	8.215E-02

TABLE 11.3-42

OFFSITE DOSES FOR ESE SECTOR AT DISTANCE 3.7 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
NORMAL OPERATION CASE

Dose	Adult	Teen	Child	Infant
Ingestion bone	3.101E-02	5.052E-02	1.024E-01	0.0
Ingestion liver	3.341E-02	5.311E-02	8.859E-02	0.0
Ingestion whole body	2.714E-02	2.669E-02	2.456E-02	0.0
Ingestion thyroid	2.959E-03	4.173E-03	8.239E-03	0.0
Ingestion kidney	1.097E-02	1.329E-02	1.097E-02	0.0
Ingestion lung	3.623E-03	6.667E-03	1.003E-02	0.0
Ingestion GI	1.059E-02	1.137E-02	8.341E-03	0.0
Total bone	3.101E-02	5.052E-02	1.024E-01	0.0
Total liver	3.341E-02	5.311E-02	8.859E-02	0.0
Total whole body	2.714E-02	2.669E-02	2.456E-02	0.0
Total thyroid	2.959E-03	4.173E-03	8.239E-03	0.0
Total kidney	1.097E-02	1.329E-02	1.097E-02	0.0
Total lung	3.623E-03	6.667E-03	1.003E-02	0.0
Total GI	1.059E-02	1.137E-02	8.341E-03	0.0

TABLE 11.3-43

OFFSITE DOSES FOR SE SECTOR AT DISTANCE 1.1 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
NORMAL OPERATION CASE

Dose	Adult	Teen	Child	Infant
Ingestion bone	7.411E-02	5.773E-02	9.968E-02	0.0
Ingestion liver	1.220E-01	9.351E-02	1.167E-01	0.0
Ingestion whole body	9.508E-02	4.627E-02	3.642E-02	0.0
Ingestion thyroid	2.749E-01	1.891E-01	2.853E-01	0.0
Ingestion kidney	3.771E-02	2.229E-02	1.406E-02	0.0
Ingestion lung	1.392E-02	1.192E-02	1.313E-02	0.0
Ingestion GI	1.302E-01	6.745E-02	3.748E-02	0.0
Total bone	7.411E-02	5.773E-02	9.968E-02	0.0
Total liver	1.220E-01	9.351E-02	1.167E-01	0.0
Total whole body	9.508E-02	4.627E-02	3.642E-02	0.0
Total thyroid	2.749E-01	1.891E-01	2.853E-01	0.0
Total kidney	3.771E-02	2.229E-02	1.406E-02	0.0
Total lung	1.392E-02	1.192E-02	1.313E-02	0.0
Total GI	1.302E-01	6.745E-02	3.748E-02	0.0
Gamma air	6.566E-01	6.566E-01	6.566E-01	6.566E-01
Beta air	2.085E-01	2.085E-01	2.085E-01	2.085E-01

TABLE 11.3-44

OFFSITE DOSES FOR SE SECTOR AT DISTANCE 3.7 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
NORMAL OPERATION CASE

Dose	Adult	Teen	Child	Infant
Ingestion bone	1.255E-01	2.044E-01	4.144E-01	0.0
Ingestion liver	1.352E-01	2.149E-01	3.584E-01	0.0
Ingestion whole body	1.098E-01	1.080E-01	9.935E-02	0.0
Ingestion thyroid	1.199E-02	1.690E-02	3.338E-02	0.0
Ingestion kidney	4.439E-02	5.378E-02	4.439E-02	0.0
Ingestion lung	1.466E-02	2.697E-02	4.056E-02	0.0
Ingestion GI	4.286E-02	4.602E-02	3.375E-02	0.0
Total bone	1.255E-01	2.044E-01	4.144E-01	0.0
Total liver	1.352E-01	2.149E-01	3.584E-01	0.0
Total whole body	1.098E-01	1.080E-01	9.935E-02	0.0
Total thyroid	1.199E-02	1.690E-02	3.338E-02	0.0
Total kidney	4.439E-02	5.378E-02	4.439E-02	0.0
Total lung	1.466E-02	2.697E-02	4.056E-02	0.0
Total GI	4.286E-02	4.602E-02	3.375E-02	0.0

Table 11.4-1

RADIATION MONITORS AND READOUTS

RMS Channel	RMS Description	Elevation	Range	Detector Type	Location	Unit(e) No.	Indication	Readout(s) Location	Recorder	Location
R -1	Control room area monitor	140 ft	0.1 to E4 mR/hr	GM	NE area rad rack behind main control panel	0 0	RI-1 RM-1	Local RNRMA	RR-1	RNRMA
R -2	Containment area monitor	140 ft	0.1 to E4 mR/hr	GM	West containment wall at personnel hatch	1 1 2 2	RI-2 RM-2 RI-2 RM-2	Local RNRMA Local RNRMC	RR-2 RR-2	RNRMA RNRMC
R -3	Oily water separator effluent monitor	85 ft	10 to E6 cpm	Gamma Scint.	Oily water separator room	0	RM-3	RNRMA	RR-3	RNRMA
R -4	Centrifugal charging pump CCP3 (room #2) monitor	73 ft	0.1 to E4 mR/hr	GM	SE corner at charging pump 1-3, pump outside of SE corner (N-wall at charging pump 2-3)	1 1 2 2	RI-4 RM-4 RI-4 RM-4	Local RNRMA Local RNRMC	RR-4 RR-4	RNRMA RNRMC
R -6	NSSS sampling room area monitor	100 ft	0.1 to E4 mR/hr	GM	SW corner on U-1 (NW corner on U-2)	1 1 2 2	RI-6 RM-6 RI-6 RM-6	Local RNRMA Local RNRMC	RR-6 RR-6	RNRMA RNRMC
R -7	Incore seal table monitor - area monitor	115 ft	0.1 to E4 mR/hr	GM	South hatch at upper internals laydown area on U-1 (North on U-2)	1 1 2 2	RI-7 RM-7 RI-7 RM-7	Local RNRMA Local RNRMC	RR-7 RR-7	RNRMA RNRMC
R -10	Auxiliary bldg control board area monitor	85 ft	0.1 to E4 mR/hr	GM	South wall	0 0	RI-10 RM-10	Local RNRMA	RR-10	RNRMA
R -11	Containment air particulate monitor	100 ft	10 to E6 cpm	Gamma Scint.	Area GE	1 2	RM -11 RM -11	RNRMB RNRMD	RR-11 RR-11	RNRMA RNRMC
R -12	Containment air radioactive gas monitor	100 ft	10 to E6 cpm	GM	Area GE	1 2	RM -12 RM -12	RNRMB RNRMD	RR-12 RR-12	RNRMA RNRMC
R -13	RHR exhaust duct air particulate monitor	100 ft	10 to E6 cpm	Gamma Scint	Wall in north corridor at RHR ht exchg.area - area K for U-1 (South for U-2)	1 2	RM -13 RM -13	RNRMB RNRMD	RR-13 RR-13	RNRMA RNRMC

Table 11.4-1

RMS Channel	RMS Description	Elevation	Range	Detector Type	Location	Unit(e) No.	Indication	Readout(s) Location	Recorder	Location
R -14 and R-14R	Plant vent radioactive gas monitors	85ft	10 to 5E6 cpm	Beta Scint	Plant vent at NE wall/ penetration room - area L for U-1 (SE for U-2)	1 1 2 2	RM-14 RM-14R RM-14 RM-14R	RNRMS3 RNRMS4 RNRMS3 RNRMS4	EARS EARS EARS EARS	TSC TSC TSC TSC
R -15 and R-15R	Steam jet air ejector radioactive gas dischg. monitors	104ft	10 to 5E6 cpm	Beta Scint.	Turb. Bldg., Area C on wall at Col. line 10 between Col. lines C&D for U-1 (line 26 for U-2)	1 1 2 2	RM-15 RM-15R RM-15 RM-15R	RNRMS4 RNRMS4 RNRMS4 RNRMS4	EARS EARS EARS EARS	TSC TSC TSC TSC
R -17A and R -17B	CCW discharge header effluent monitors	73 ft	10 to E6 cpm	Gamma Scint.	Outside east door on wall at component cooling pump room	1 1 2 2	RM -17A RM -17B RM -17A RM -17B	RNRMB RNRMB RNRMD RNRMD	RR-17A RR-17B RR-17A RR-17B	RNRME RNRME RNRMC RNRMC
R -18	Liquid radwaste discharge line effluent monitor	55 ft	10 to E6 cpm	Gamma Scint.	Pipe tunnel from radwaste (north corridor)	0	RM -18	RNRME	RR-18	RNRME
R -19	Steam generator blowdown sample effluent monitor	100 ft	10 to E6 cpm	Gamma Scint.	SE side of containment structure/penetration room - area GE for U-1 (NE for U-2)	1 1 2 2	RI-19 RM -19A RI-19 RM -19A	SGSP RNRMB SGSP RNRMD	RR-19 RR-19 	RNRME RNRMC
R -22	Gas decay tank radioactive gas discharge monitor	55 ft	10 to E6 cpm	GM	Pipe tunnel	1 2	RM-22 RM-22	RNRME RNRMC	RR-22 RR-22	RNRME RNRMC
R -23	Steam generator blowdown tank effluent to out-fall monitor	100 ft	1 to E6 cpm	Gamma Scint.	Area GE	1 1 2 2	RI-23 Scint. 	PM205 PM205 	RR-23 RR-23A RR-23 RR-23A	PM205 RNRME PM205 RNRMC
R -24 and R-24R	Plant vent iodine monitor	85ft	10 to 5E6 cpm	Gamma Scint.	Plant vent at area L	1 1 2 2	RM-24 RM-24R RM-24 RM-24R	RNRMS3 RNRMS4 RNRMS3 RNRMS4	EARS EARS EARS EARS	TSC TSC TSC TSC
R -25	Main control room air intake monitor	160 ft	0.01 to E3 mR/hr	Gamma Scint.	Auxiliary bldg. control room air intake	1 2	RI-25 RI-25	RCRM RCRM	-	-
R -26	Main control room air intake monitor	160 ft	0.01 to E3 mR/hr	Gamma Scint.	Auxiliary bldg. control room air intake	1 2	RI-26 RI-26	RCRM RCRM	-	-

RMS Channel	RMS Description	Elevation	Range	Detector Type	Location	Unit(e) No.	Indication	Readout(s) Location	Recorder	Location
R -28 and R-28R	Plant vent air particulate monitors	85ft	10 to 5E6 cpm	Beta Scint.	Plant vent at NE wall to containment structure/penetration room - area L, for U-1 (SE for U-2)	1 1 2 2	RM-28 RM-28R RI-28 RI-28R	RNRMS3 RNRMS4 RNRMS3 RNRMS4	EARS EARS EARS EARS	TSC TSC TSC TSC
R -29	Plant vent high radiation gross gamma monitor	155 ft	0.1 to E7 mR/hr	ION	Plant vent on platform on NW side of duct for U-1 (SW for U-2)	1 2	RI-29 RI-29A RI-29	PAM-2 Local PAM-2	RR-29 RR-29	PAM-2 PAM-2
R -30	Containment high range area radiation monitor - 1	140 ft	1 to E7 R/hr	ION	East stairway	1 2	RI-30 RI-30	PAM-2 PAM-2	RR-30 RR-30	PAM-1 PAM-1
R -31	Containment high range area radiation monitor - 2	140 ft	1 to E7 R/hr	ION	West stairway	1 2	RI-31 RI-31	PAM-2 PAM-2	RR-31 RR-31	PAM-1 PAM-1
R -34	Area Monitor for Plant Vent Monitoring Skid	85ft	0.1 to E7 mR/hr	ION	Plant vent at NE wall penetration room - Area L for U-1 (SE for U-2)	1 1 2 2	RC-22 RI-34 RC-22 RI-34	Local Local Local Local	RR-34 RR-34	PAM-2 PAM-2
R-41	Gas decay tank cubicle radiation monitor (1-1, 2-1) -	64 ft	1 to E4 mR/hr	ION	Gas decay tank 1	1 2 2	RI-41 RI-41	ABCP ABCP	-	-
R-42	Gas decay tank cubicle radiation monitor (1-2, 2-2)	64 ft	1to E4 mR/hr	ION	Gas decay tank 2	1 2	RI-42 RI-42	ABCP ABCP	-	-
R-43	Gas decay tank cubicle radiation monitor (1-3, 2-3)	64 ft	1 to E4 mR/hr	ION	Gas decay tank 3	1 2	RI-43 RI-43	ABCP ABCP	-	-
R-44A and R-44B	Containment Purge Exhaust	100 ft	10 to 5E6 cpm	Beta Scint.	Area L	1 1 2 2	RM-44A RM-44B RM-44A RM-44B	RNRMS1 RNRMS2 RNRMS1 RNRMS2	EARS EARS EARS EARS	TSC TSC TSC TSC
R -48	HRSS (Sentry) post-accident sampling room	85 ft	0.1 to E7 mR/hr	ION	HRSS	1 2	RI-48 RI-48	POPLSI POPLSI	-	-

Table 11.4-1

RMS Channel	RMS Description	Elevation	Range	Detector Type	Location	Unit(e) No.	Indication	Readout(s) Location	Recorder	Location
R -51	Control room pressurization system ventilation intake air monitor	140ft	0.01 to E4 mR/hr	GM	NW corner of turbine building	1	RI-51	RCRM	-	-
R -52	Control room pressurization system ventilation intake air monitor	140 ft	0.01 to E4 mR/hr	GM	NW corner of turbine building	1	RI-52	RCRM	-	-
R -53	Control room pressurization system ventilation intake air monitor	140ft	0.01 to E4 mR/hr	GM	SW corner of turbine building	2	RI-53	RCRM	-	-
R -54	Control room pressurization system ventilation intake air monitor	140 ft	0.01 to E4 mR/hr	GM	SW corner of turbine building	2	RI-54	RCRM	-	-
R -58	Spent Fuel Pool Area Monitor	140 ft	0.1 to E4 mR/hr	GM	West wall column line 11[1] and 25[1]	1 1 2 2	RI-58 RI-58A RI-58 RI-58A	Local PAM-2 Local PAM-2	RR-58 RR-58	RNRMA RNRMC
R -59	New Fuel Storage Area Monitor	140 ft	0.1 to E4 mR/hr	GM	West wall column line 15[3] and 20[3]	1 1 2 2	RI-59 RI-59A RI-59 RI-59A	Local PAM-2 Local PAM-2	RR-59 RR-59	RNRMA RNRMC
R -60	TSC-Office Area Radiation Monitor	104 ft	0.1 to E4 mR/hr	GM	East wall at exit door	0	RI-60	Local	RR-60	Local
R -61	TSC-Operations/RMS Area Monitor	104 ft	0.1 to E4 mR/hr	GM	South wall at doorway	0	RI-61	Local	RR-61	Local
R -62	TSC-Computations Center Area Monitor	104 ft	0.1 to E4 mR/hr	GM	South wall at doorway	0	RI-62	Local	RR-62	Local
R -63	TSC-NRC Office Area Monitor	104 ft	0.1 to E4 mR/hr	GM	North wall at doorway	0	RI-63	Local	RR-63	Local
R -64	TSC-HVAC Equipment room area monitor	104 ft	0.1 to E4 mR/hr	GM	East wall at midpoint	0	RI-64	Local	RR-64	Local
R -65	TSC-laboratory area monitor	104 ft	0.1 to E4 mR/hr	GM	North wall at midpoint	0	RI-65	Local	RR-65	Local

RMS Channel	RMS Description	Elevation	Range	Detector Type	Location	Unit(e) No.	Indication	Readout(s) Location	Recorder	Location
R -66	TSC-air particulate monitor	104 ft	10 to E6 cpm	Beta Scint.	TSC-HVAC equipment room	0	RI-66	Local	RR-66	Local
R -67	TSC-noble gas monitor	104 ft	10 to E6 cpm	Beta Scint.	TSC-HVAC equipment room	0	RI-67	Local	RR-67	Local
R -68	TSC-laboratory air particulate monitor	104 ft	10 to E6 cpm	Beta Scint.	TSC-HVAC equipment room	0	RI-68	Local	RR-68	Local
R -69	TSC-laboratory noble gas monitor	104 ft	10 to E6 cpm	Beta Scint.	TSC-HVAC equipment room	0	RI-69	Local	RR-69	Local
R -71	Main steam line noble gas radiation monitor (lead 1)	130 ft	10 to E6 cpm	GM	Outside NW side of containment - area FW for U-1 (SW for U-2)	1 2	RI-71 RI-71	RNGFFD RNGFFD	RR-71 RR-71	RNRME RNRMC
R-72	Main steam line noble gas radiation monitor (lead 2)	130 ft	10 to E6 cpm	GM	Outside NW side of containment - area FW for U-1 (SW for U-2)	1 2	RI-72 RI-72	RNGFFD RNGFFD	RR-72 RR-72	RNRME RNRMC
R-73	Main steam line noble gas radiation monitor (lead 3)	130 ft	10 to E6 cpm	GM	Outside containment area GW	1 2	RI-73 RI-73	RNGFFD RNGFFD	RR-73 RR-73	RNRME RNRMC
R-74	Main steam line noble gas radiation monitor (lead 4)	130 ft	10 to E6 cpm	GM	Outside containment area GW	1 2	RI-74 RI-74	RNGFFD RNGFFD	RR-74 RR-74	RNRME RNRMC
R-82	TSC-iodine monitor	104 ft	10 to E6 cpm	Gamma Scint.	TSC-HVAC equipment room	0	RI-82	Local	RR-82	RMPTSC
R-83	TSC-laboratory iodine monitor	104 ft	10 to E6 cpm	Gamma Scint.	TSC-HVAC equipment room	0	RI-83	Local	RR-83	RMPTSC
R-84	Contact inspection station radiation monitor	115 ft	0.1 to E3 R/hr	ION Chamber	Solid radwaste storage area	0	RM-84	Local	-	-
R-85	One-meter inspection station radiation monitor	115 ft	0.1 to E3 R/hr	ION Chamber	Solid radwaste storage area	0	RM-85	Local	-	-
R-87	Plant vent extended range radioactive gas monitors	85 ft	1E-12 to 1E-4 amps	Beta Scint.	Plant vent at NE walls/penetration room - area L for U-1 (SE for U-2)	1 2	RM-14 RM-14	RNRMS3 RNRMS3	EARS EARS	TSC TSC

Table 11.4-1

RMS Channel	RMS Description	Elevation	Range	Detector Type	Location	Unit(e) No.	Indication	Readout(s) Location	Recorder	Location
R-90	R/W Storage	115 ft	0.1 to E4 mR/hr	GM	R/W Storage Truck Bay	0	RI-90A RI-90B	Local Mechanical RM Control RM	-	-
R-92	Laundry facility	132 ft	10 to E5 cpm	GM	Laundry RM	0	-	-	RR-92	Local
RF-87A and RF-87B	Particulate and iodine grab sampling assembly (Post Accident)	85 ft			Plant vent at NE wall/penetration room - area L for U-1 (SE for U-2)	1 2	- -	- -	- -	- -
RX-55	Laundry and Radwaste Facility Exhaust Sampler	115 ft			Ventilation room Old Radwaste Building	0				
RX-56	Radwaste Storage and Laundry Facility Exhaust Sampler	142 ft			Mezzanine Area New Radwaste Building	0				

(a) Deleted in Revision 4
(b) Deleted in Revision 9
(c) Deleted in Revision 11
(d) Post-LOCA sampling control panel
(e) Units designation: 0 = 1 monitor common to both Units
1 = Unit 1 monitor
2 = Unit 2 monitor

Symbol	Location	Symbol	Location
1 ABCP	Auxiliary building control panel, elevation 85 ft	11 RNRMA	Radiation monitor rack A, control room
2 ABRV	Auxiliary building roof vent access area	12 RNRMB	Radiation monitor rack B, control room
3 RNGFFD	Main steam line radiation monitor rack, control room	13 RNRMC	Radiation Monitor rack C, control room
4 HRSS	Sentry high radiation sampling room	14 RNRMD	Radiation Monitor rack D, control room
5 PAM-1	Post accident monitor panel 1, control room	15 RNRME	Radiation monitor rack E, control room
6 PAM-2	Post accident monitor panel 2, control room	16 SGSP	Steam generation sample panel
7 POPLSI	Post-LOCA sampling control panel	17 RMPTSC	Radiation monitor panel, TSC
8 PM197	Panel 197, access area of auxiliary building		
9 PM205	Mechanical panel 205, auxiliary building		
10 RCRM	Rack control room monitor - Unit 2 side control room[P-11.4(1)]		

TABLE 11.4-3

RADIATION MONITOR - VALVE CONTROL OPERATIONS

Radiation Element	Affected Valves	Effect
RE-17A and RE-17B	SV225, RCV16	Close CCW surge tank vent.
RE-18	SV233, RCV18, FCV477	Liquid radwaste control valves: Close liquid radwaste over-board and open liquid radwaste equipment drain receiver dump.
RE-23	SV237, FCV160, SV238, FCV157, SV239, FCV154, SV240, FCV151, SV242, FCV498, SV241, FCV499	(a) High radiation (1) close steam generators 1 to 4 blowdown tank inlet and sample, (2) close steam generator blowdown tank outlet, (3) close blowdown tank outlet to discharge tunnel and open blowdown tank outlet to equipment drain receiver; (b) Power loss to RE-23 - (1) close steam generators 1 to 4 blowdown tank inlet and sample, (2) close steam generator blowdown tank outlet, (3) close blowdown tank outlet to discharge tunnel and open blowdown tank outlet to equipment drain receiver.
RE-19	SV237, FCV160, SV238, FCV157, SV239, FCV154, SV240, FCV151, SV242, FCV498, SV241, FCV499	High radiation (1) close steam generators 1 to 4 blowdown tank inlet and sample, (2) close steam generator blowdown tank outlet, (3) close blowdown tank outlet to discharge tunnel and open blowdown tank outlet to equipment drain receiver.
RE-51, RE-52, RE-53, and RE-54	-	Initiate control room pressurization system.
RE-44A and RE-44B	Trains A and B containment vent isolation valves	Closure.
RE-22	SV218, RCV17	Gaseous radwaste vent closure.

TABLE 11.5-1

SOLID RADWASTE SYSTEM INPUT VOLUMES

Source	Design Basis Volume	Normal Operation Volume	Bases
Boric acid waste concentrates	11,700 gal/yr	23,190 gal/yr	EPRI NP-3370
Spent ion exchange resin	1,600 ft^3/yr	1,600 ft^3/yr	EPRI NP-3370
Expended filtration/ion exchange media	400 ft^3/yr	400 ft^3/yr	12 beds/yr
Spent filter cartridges (requiring encapsulation)	240/yr	240/yr	EPRI NP-3370
Dry active waste	210 boxes	180 boxes	EPRI NP-3370, EPRI NP-2900

TABLE 11.5-2

ACTIVITY IN RADWASTE SYSTEM DEMINERALIZERS NORMAL OPERATION CASE
(CURIES/YEAR)

Nuclide	Primary Mxd Bed Demin	Primary Cation Demin	Letdown Mxd Bed Demin	Letdown Cation Demin	Letdown Anion Demin	Spent Fuel Pool Demin
H-3	0.0	0.0	0.0	0.0	0.0	0.0
Cr-51	0.281E 02	0.309E-00	0.179E-02	0.179E-04	0.0	0.119E-04
Mn-54	0.282E 02	0.310E-00	0.289E-02	0.289E-04	0.0	0.693E-04
Fe-55	0.227E 01	0.249E-01	0.111E-05	0.111E-07	0.0	0.856E-13
Co-58	0.587E 03	0.646E 01	0.515E-01	0.515E-03	0.0	0.863E-03
Fe-59	0.238E 02	0.262E 00	0.185E-02	0.185E-04	0.0	0.225E-04
Co-60	0.250E 03	0.275E 01	0.267E-01	0.267E-03	0.0	0.983E-04
Sr-89	0.740E 01	0.814E-01	0.600E-03	0.600E-05	0.0	0.190E-04
Sr-90	0.175E 01	0.192E-01	0.188E-03	0.188E-05	0.0	0.113E-04
Y-90	0.173E 01	0.190E-01	0.186E-03	0.186E-05	0.0	0.112E-04
Sr-91	0.384E-01	0.422E-03	0.102E-20	0.102E-22	0.0	0.976E-10
Y-91	0.377E-01	0.415E-03	0.101E-20	0.101E-22	0.0	0.960E-10
Sr-92	0.436E-02	0.479E-04	0.310E-62	0.310E-64	0.0	0.934E-12
Y-92	0.436E-02	0.479E-04	0.310E-62	0.310E-64	0.0	0.934E-12
Zr-95	0.231E 01	0.255E-01	0.199E-03	0.199E-05	0.0	0.248E-04
Nb-95	0.349E 01	0.384E-01	0.323E-03	0.323E-05	0.0	0.391E-04
Mo-99	0.0	0.0	0.0	0.0	0.0	0.0
I-131	0.138E 04	0.0	0.265E 00	0.0	0.265E-04	0.216E-02
Te-132	0.586E 02	0.0	0.776E-03	0.0	0.776E-08	0.472E-04
I-132	0.648E 02	0.0	0.801E-03	0.0	0.102E-07	0.487E-04
I-133	0.205E-03	0.0	0.144E-07	0.0	0.144E-11	0.165E-05
Cs-134	0.146E 04	0.131E 03	0.401E 01	0.361E 01	0.0	0.817E-02
I-134	0.113E 01	0.0	0.0	0.0	0.0	0.730E-10
I-135	0.361E 02	0.0	0.971E-24	0.0	0.971E-28	0.225E-07
Cs-136	0.237E 02	0.213E 01	0.217E-01	0.195E-01	0.0	0.119E-04
Cs-137	0.301E 04	0.271E 03	0.843E 01	0.759E 01	0.0	0.255E-01
Ba-140	0.315E 01	0.346E-01	0.109E-03	0.109E-05	0.0	0.422E-05
La-140	0.330E 01	0.362E-01	0.125E-03	0.125E-05	0.0	0.476E-05
Ce-144	0.357E 01	0.393E-01	0.365E-03	0.365E-05	0.0	0.159E-04
Pr-144	0.357E-01	0.393E-01	0.365E-03	0.365E-05	0.0	0.159E-04

TABLE 11.5-2

	Primary	Primary	Letdown	Letdown	Letdown	Spent Fuel
Nuclide	Mxd Bed Demin	Cation Demin	Mxd Bed Demin	Cation Demin	Anion Demin	Pool Demin
H-3	0.0	0.0	0.0	0.0	0.0	0.0
Cr-51	0.281E 02	0.309E-00	0.179E-02	0.179E-04	0.0	0.119E-04
Mn-54	0.282E 02	0.310E-00	0.289E-02	0.289E-04	0.0	0.693E-04
Fe-55	0.227E 01	0.249E-01	0.111E-05	0.111E-07	0.0	0.856E-13
Co-58	0.588E 03	0.646E 01	0.516E-01	0.516E-03	0.0	0.863E-03
Fe-59	0.238E 02	0.262E 00	0.185E-02	0.185E-04	0.0	0.225E-04
Co-60	0.250E 03	0.275E 01	0.267E-01	0.267E-03	0.0	0.983E-04
Sr-89	0.617E 02	6.679E 00	0.500E-02	0.500E-04	0.0	0.566E-04
Sr-90	0.146E 02	0.160E 00	0.156E-02	0.156E-04	0.0	0.684E-04
Y-90	0.144E 02	0.158E 00	0.155E-02	0.155E-04	0.0	0.677E-04
Sr-91	0.320E 00	0.352E-02	0.853E-20	0.853E-22	0.0	0.980E-10
Y-91	0.315E 00	0.346E-02	0.840E-20	0.840E-22	0.0	0.964E-10
Sr-92	0.363E-01	0.399E-03	0.258E-61	0.258E-63	0.0	0.934E-12
Y-92	0.363E-01	0.399E-03	0.258E-61	0.258E-63	0.0	0.934E-12
Zr-95	0.193E 02	0.212E 00	0.166E-02	0.166E-04	0.0	0.401E-04
Nb-95	0.291E 02	0.320E 00	0.270E-02	0.270E-04	0.0	0.672E-04
Mo-99	0.0	0.0	0.0	0.0	0.0	0.0
I-131	0.115E 05	0.0	0.221E 01	0.0	0.221E-03	0.280E-02
Te-132	0.489E 03	0.0	0.647E-02	0.0	0.647E-07	0.525E-04
I-132	0.540E 03	0.0	0.668E-02	0.0	0.853E-07	0.543E-04
I-133	0.171E 04	0.0	0.120E-06	0.0	0.120E-10	0.194E-05
Cs-134	0.120E 05	0.108E 04	0.331E 02	0.298E 02	0.0	0.345E-01
I-134	0.941E 01	0.0	0.0	0.0	0.0	0.730E-10
I-135	0.301E 03	0.0	0.809E-23	0.0	0.809E-27	0.225E-07
Cs-136	0.197E 03	0.178E 02	0.181E 00	0.163E 00	0.0	0.336E-04
Cs-137	0.251E 05	0.226E 04	0.702E 02	0.632E 02	0.0	0.131E 00
Ba-140	0.263E 02	0.289E 00	0.906E-03	0.906E-05	0.0	0.713E-05
La-140	0.275E 02	0.302E 00	0.104E-02	0.104E-04	0.0	0.792E-05
Ce-144	0.298E 02	0.327E 00	0.305E-02	0.305E-04	0.0	0.868E-04
Pr-144	0.289E 02	0.327E 00	0.305E-02	0.305E-04	0.0	0.869E-04

TABLE 11.5-4

ACTIVITY COLLECTED IN RADWASTE FILTER CARTRIDGES AT TIME OF REPLACEMENT[a]
(CURIES)

DESIGN BASIS CASE

	RCC Letdown[b]				Radwaste[c]		
Nuclide	Primary Loop	Ion Exchge	Concentrates	Condensate	0-1	0-2	0-3
H-3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cr-51	0.148E 00	0.429E-07	0.214E-07	0.214E-10	0.418E-05	0.731E-03	0.212E-05
Mn-54	0.669E-01	0.312E-07	0.156E-07	0.156E-10	0.268E-05	0.475E-03	0.136E-05
Fe-55	0.125E-01	0.280E-10	0.140E-10	0.140E-13	0.165E-07	0.153E-05	0.833E-08
Co-58	0.232E 01	0.925E-06	0.462E-06	0.462E-09	0.827E-04	0.146E-01	0.421E-04
Fe-59	0.112E 00	0.396E-07	0.198E-07	0.198E-10	0.365E-05	0.643E-03	0.186E-05
Co-60	0.481E 00	0.234E-06	0.117E-06	0.117E-09	0.198E-04	0.352E-02	0.101E-04

NORMAL OPERATION CASE

	RCC Letdown[b]				Radwaste[c]		
Nuclide	Primary Loop	Ion Exchge	Concentrates	Condensate	0-1	0-2	0-3
H-3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cr-51	0.148E 00	0.428E-07	0.214E-07	0.214E-10	0.372E-06	0.446E-02	0.441E-06
Mn-54	0.669E-01	0.312E-07	0.156E-07	0.156E-10	0.184E-06	0.356E-02	0.301E-06
Fe-55	0.125E-01	0.280E-10	0.140E-10	0.140E-13	0.125E-07	0.313E-05	0.637E-08
Co-58	0.232E 01	0.924E-06	0.462E-06	0.462E-09	0.620E-05	0.102E 00	0.904E-05
Fe-59	0.112E 00	0.396E-07	0.198E-07	0.198E-10	0.292E-06	0.427E-02	0.393E-06
Co-60	0.481E 00	0.234E-06	0.117E-06	0.117E-09	0.134E-05	0.269E-01	0.225E-05

(a) Three cartridge replacements per cycle.
(b) As Designated on Figure 11.5-6.
(c) As Designated on Figure 11.5-8.

TABLE 11.5-5

SUMMARY OF RADWASTE MATERIALS SHIPMENT

Material	Quantity per Year	Quantity Possible per Shipment	Shipments per Year	Shipment Method
Packaged wastes				
Solidified liquid concentrates	0 ft^3	100 ft^3	0	truck
Class B/C Resins	160 ft^3	80 ft^3	2	truck
Class A Resin	400 ft^3	200 ft^3	2	truck
Spent filter cartridges	240	100	2	truck
Filtration/ion exchange media	60 ft^3	200 ft^3	1/2	truck
Dry active wastes	50 boxes	10 boxes	5	truck

TABLE 11.6-1

RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

Exposure Pathway and/or Sample	Number of Samplesand Sample Locations	Sampling and Collection Frequency	Type of Analysis
1. Airborne			
Radioiodine and particulates	≥ 4 stations	Continuous sampler operation with sample collection weekly, or more frequently if required by dust loading	Radioiodine canister. I-131 analysis weekly. Particulate sampler. Analyze for gross beta radioactivity ≥ 24 hours following filter change. Perform gamma isotopic analysis on each sample when gross beta activity is > 10 times the yearly mean of control samples. Perform gamma isotopic analysis on composite (by location) quarterly.
2. Direct radiation	≥ 30 stations, ≥ 2 phosphors at each location	Quarterly	Gamma dose. Quarterly.
3. Waterborne			
a. Drinking	1 station	Monthly grab sample	I-131 analysis, gamma isotopic analysis monthly, and tritium analysis quarterly.
b. Surface	1 station	Monthly grab sample	Gamma isotopic analysis monthly. Tritium analysis quarterly.

TABLE 11.6-1

Exposure Pathway and/or Sample	Number of Samples and Sample Locations	Sampling and Collection Frequency	Type of Analysis
4. Ingestion			
a. Milk	Samples from milking animals in three locations within 5 km distance having the highest dose potential. If there are none, then one sample from milking animals in each of three areas from 5 to 8 km distant where doses are calculated to be greater than 1 mrem per yr. One sample from milking animals at a control location 15 to 30 km distant and in the least prevalent wind direction.	Semimonthly when animals are on pasture; monthly at other times	Gamma isotopic and I-131 analysis.
b. Fish and Invertebrates	$\geq$2 stations	Sample in season, or semi-annually if they are not seasonal	Gamma isotopic analysis on edible portions.
c. Food products	$\geq$ 2 stations (if available)	Monthly during growing season portion (if available)	Gamma isotopic analysis on edible.

TABLE 11.6-4

ENVIRONMENTAL RADIOLOGICAL MONITORING PROGRAM SUMMARY (PREOPERATIONAL RESULTS)

Medium or Pathway Sampled (Unit of Measurement)	Type and Total Number of Analyses Performed	Lower Limit of Detection[a] (LLD)	Location: Name, Distance[d] and Direction	Location: Mean(1)[b] Range[b]	All Control Locations Mean(1)[b] Range[b]	Number of Reportable Occurrences
Seawater, (pCi. L^{-1})	Tritium (12)	-	-	None detected	-	0
	Gamma Isotopic (36)	-	-	None detected	-	0
	54Mn			None detected		
	59Fe	3.79×10^{2} (c)		None detected		
	58Co			None detected		
	60Co			None detected		
	65Zn			None detected		
	95Zr			None detected		
	95Nb			None detected		
	131I			None detected		
	134Cs			None detected		
	137Cs			None detected		
	140Ba	2.14×10^{3} (c)		None detected		
	140La	6.09×10^{2} (c)		None detected		
Surface water (pCi. L^{-1})	Tritium (12)	-	-	None detected	-	0
	Gross Beta (12)	-	Sta. 5S2, 0.6 mi, 65°	2.94(12/12) 2.24-3.58	-	0
	Gamma Isotopic	-				0
	54Mn			None detected		
	59Fe			None detected		
	58Co			None detected		
	60Co			None detected		
	65Zn			None detected		

Medium or Pathway Sampled (Unit of Measurement)	Type and Total Number of Analyses Performed	Lower Limit of Detection[a] (LLD)	Location: Name, Distance[d] and Direction	Location: Mean(1)[b] Range[b]	All Control Locations Mean(1)[b] Range[b]	Number of Reportable Occurrences
	95Zr			None detected		
	95Nb			None detected		
	131I			None detected		
	134Cs			None detected		
	137Cs			None detected		
	140Ba	$1.35x10^{2(c)}$		None detected		
	140La	$3.48x10^{1(c)}$		None detected		
Drinking water ($pCi. L^{-1}$)	Tritium (12)		-	None detected	-	0
	Gross Beta (12)		Sta. D W1, 0.0 mi, in plant	2.4 (8/12) 2.24-4.09	-	0
	131-Iodine (12)			None detected	-	0
	Gamma Isotopic (12)				-	0
	54Mn			None detected		
	59Fe			None detected		
	58Co			None detected		
	60Co			None detected		
	65Zn			None detected		
	95Zr			None detected		
	95Nb			None detected		
	131I			None detected		
	134Cs			None detected		
	137Cs			None detected		
	140Ba			None detected		
	140La			None detected		

TABLE 11.6-4

Medium or Pathway Sampled (Unit of Measurement)	Type and Total Number of Analyses Performed	Lower Limit of Detection[a] (LLD)	Location: Name, Distance[d] and Direction	Location: Mean(1)[b] Range[b]	All Control Locations Mean(1)[b] Range[b]	Number of Reportable Occurrences
Outfall ($pCi. L^{-1}$)	Tritium (18)		-	None detected	-	0
	Gamma Isotopic (18)			None detected		
	54Mn			None detected		
	59Fe			None detected		
	58Co			None detected		
	60Co			None detected		
	65Zn			None detected		
	95Zr			None detected		
	95Nb			None detected		
	131I			None detected		
	134Cs			None detected		
	137Cs			None detected		
	140Ba	$2.74x10^{3}$[c]		None detected		
	140La	$8.35x10^{2}$[c]		None detected		
Airborne ($pCi. m^{-3}$)	131I (507)		-	None detected	0.108 (3/211) 0.0137-0.159	0
	Gross Beta (507)		-	0.012(296/296) 0.004-0.033	0.010(211/211) 0.005-0.033	
	Gamma Isotopic (507)		-		-	0
	134Cs			None detected	None detected	
	137Cs			None detected	None detected	
Fish and seafood ($pCi. kg^{-1}$)	Gamma Isotopic (79)		-		-	0
	54Mn	$1.46x10^{2}$		None detected	None detected	

Medium or Pathway Sampled (Unit of Measurement)	Type and Total Number of Analyses Performed	Lower Limit of Detection[(a)] (LLD)	Location: Name, Distance[(d)] and Direction	Location: Mean(1)[(b)] Range[(b)]	All Control Locations Mean(1)[(b)] Range[(b)]	Number of Reportable Occurrences
	59Fe	$5.19x10^2$		None detected	None detected	
	58Co	$1.74x10^2$		None detected	None detected	
	60Co	$2.02x10^2$		None detected	None detected	
	65Zn	-		None detected	None detected	
	134Cs	$1.50x10^2$		None detected	None detected	
	137Cs	$1.46x10^2$		None detected	16.4 (5/57)	
Milk ($pCi. L^{-1}$)	131I (30)		-	None detected	None detected	0
	Gamma Isotopic (30)		-			0
	134Cs			None detected	None detected	
	137Cs			None detected	None detected	
	140Ba			None detected	None detected	
	140La			None detected	None detected	
Food products ($pCi. kg^{-1}$)	Gamma Isotopic (36)		-		-	0
	131I	$6.65x10^1$			None detected	None detected
	134Cs				None detected	None detected
	137Cs				None detected	None detected

TABLE 11.6-4

Medium or Pathway Sampled (Unit of Measurement)	Type and Total Number of Analyses Performed	Lower Limit of Detection[a] (LLD)	Location: Name, Distance[d] and Direction	Location: Mean(1)[b] Range[b]	All Control Locations Mean(1)[b] Range[b]	Number of Reportable Occurrences
Direct radiation (mR)	TLD Packets (335)	1 mR/mo[e]	Sta. 3S1[f] 0.4 mi, 23°	77.2(313/313) 49.6-106.9 mR/yr	Sta. 2F2 and 4D1 62.0(22/22) 67.8-66.2 mR/yr	0
				8.9 (11/11[f] 7.9-10.1 mR/mo (106.9 mR/yr)		

(a) Unless specified, all required LLDs were met.
(b) Mean and range based upon detectable measurements only. Fraction of detectable measurements at specified locations is indicated in parentheses (1); e.g., (10/12) means 10 samples out of 12 collected showed activity.
(c) A priori LLD not met due to elapse time between collection and count dates, short half-life of nuclide involved, and equipment failure. Value listed is worst case.
(d) Only one station location for this sample type; therefore, no control or indicator stations are listed.
(e) Sensitivity of TLD system.
(f) Indicator location with Highest Annual Mean.

TABLE 11.6-11

MAXIMUM VALUES FOR THE LOWER LIMITS OF DETECTION (LLD)

Analysis	Water (pCi/l)	Airborne Particulate or Gases (pCi/m^3)	Fish (pCi/kg, wet)	Milk (pCi/l)	Food Products (pCi/kg, wet)	Sediment (pCi/kg, dry)
Gross beta	4	0.01				
H-3	2000*					
Mn-54	15		130			
Fe-59	30		260			
Co-58, 60	15		130			
Zn-65	30		260			
Zr- Nb -95	15					
I-131	1**	0.07		1	60	
Cs-134	15	0.05	130	15	60	150
Cs-137	18	0.06	150	18	80	180
Ba- La -140	15			15		

* For surface water samples, a value of 3000 pCi/l may be used.
** If no drinking water pathway exists, a value of 15 pCi/l may be used.

Table Notation

The LLD is defined, for purposes of these specifications, as the smallest concentration of radioactive material in a sample that will yield a net count, above system background, that will be detected with 95 percent probability with only 5 percent probability of falsely concluding that a blank observation represents a "real" signal.

For a particular measurement system (which may include radiochemical separation):

$$LLD = \frac{4.66 S_b}{E \times V \times 2.22 \times Y \exp(-\lambda t)}$$

where:

LLD is "a priori" the lower limit of detection as defined above (as pCi per unit mass or volume)

S_b is the standard deviation of the background counting rate or of the counting rate of a blank sample as appropriate (as counts per minute)

E is the counting efficiency (as counts per transformation)

V is the sample size (in units of mass or volume)

2.22 is the number of transformations per minute per picocurie

Y is the fractional radiochemical yield (when applicable)

λ is the radioactive decay constant for the particular radionuclide

t is the elapsed time between sample collection (or end of the sample collection period) and time of counting

The value of S_b used in the calculation of the LLD for a detection system will be based on the actual observed variance of the background counting rate or of the counting rate of the blank samples (as appropriate) rather than on an unverified theoretically predicted variance. In calculating the LLD for a radionuclide determined by gamma ray spectrometry, the background will include the typical contributions of other radionuclides normally present in the samples (e.g., potassium-40 in milk samples).

Analyses will be performed in such a manner that the stated LLDs will be achieved under routine conditions. Occasionally, background fluctuations, unavoidably small sample sizes, the presence of interfering nuclides, or other uncontrollable circumstances may render these LLDs unachievable. In such cases, the contributing factors will be identified and described in the Annual Environmental Radiological Operating Report.

TABLE 11.6-13

ESTIMATED RELATIVE CONCENTRATIONS $(\overline{\chi / Q})$ [(a)]

	22-1/2° Radial Sectors								
Nearest	NW	NNW	N	NNE	NE	ENE	E	ESE	SE
Milk cow	None	None	None	None	None	None	None	None	None
Meat animal	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Milk goat	None	None	None	None	None	None	None	None	None
Residence	$1.53X10^{-7}$	$4.16X10^{-7}$	None	$3.89X10^{-8}$	$2.00X10^{-8}$	$3.64X10^{-8}$	$5.89X10^{-8}$	$7.07X10^{-7}$[(b)]	None
Vegetable garden	None	None	None	None	None	None	None	None	None
Site boundary	$3.44X10^{-6}$	$2.70X10^{-6}$	$1.51X10^{-6}$	$8.25X10^{-7}$	$1.62X10^{-7}$	$9.18X10^{-8}$	$1.07X10^{-7}$	$5.20X10^{-7}$	$1.32X10^{-6}$

(a) In units of seconds per cubic meter.
(b) Vegetable farm has workers with residence occupancy factor of 1/2 for inhalation and group plane pathway.

TABLE 11.6-14

ESTIMATED DEPOSITIONS (χ/Q)[a]

	22-1/2° Radial Sectors								
Nearest	NW	NNW	N	NNE	NE	ENE	E	ESE	SE
Milk cow	None	1.21×10^{-10}	6.52×10^{-11}	4.09×10^{-11}	4.48×10^{-11}	6.13×10^{-11}	1.13×10^{-10}	3.79×10^{-10}	
Meat animal	1.50×10^{-8}	6.71×10^{-9}	3.47×10^{-9}	2.18×10^{-9}	1.43×10^{-9}	1.64×10^{-9}	1.67×10^{-9}	5.53×10^{-9}	3.55×10^{-8}
Milk goat	None	None	None	None	None	None	None	None	None
Residence	3.83×10^{-10}	8.15×10^{-10}	None	8.75×10^{-11}	4.00×10^{-11}	7.85×10^{-11}	1.41×10^{-10}	4.77×10^{-9}	None
Vegetable garden	None	None	None	None	None	None	1.41×10^{-10}	4.77×10^{-9}	None
Site boundary	1.50×10^{-8}	6.81×10^{-9}	3.47×10^{-9}	2.18×10^{-9}	1.43×10^{-9}	1.64×10^{-9}	1.67×10^{-9}	5.53×10^{-9}	3.55×10^{-8}

(a) In units of meters^{-2}, includes sector width and frequency of winds in each sector.

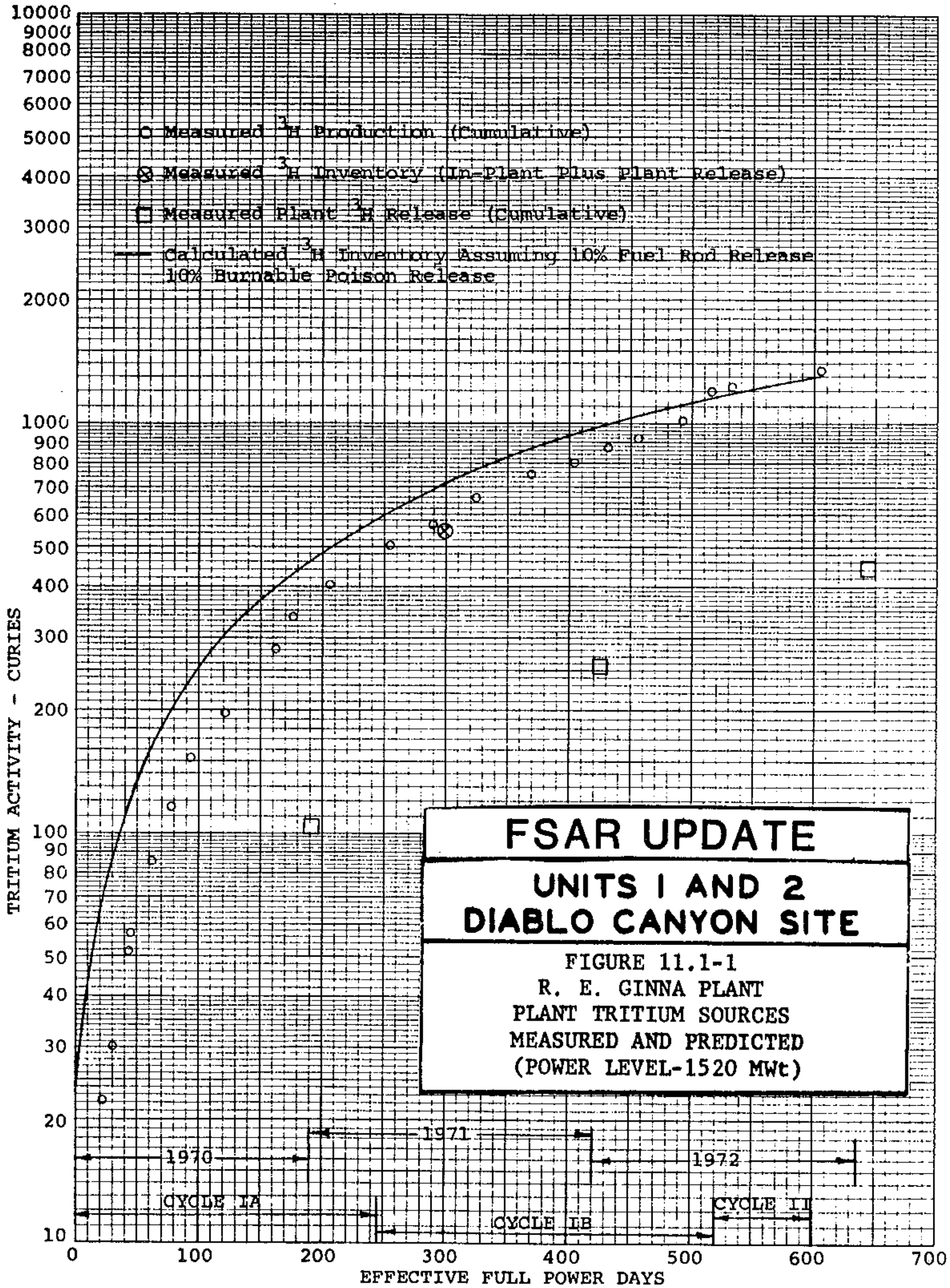
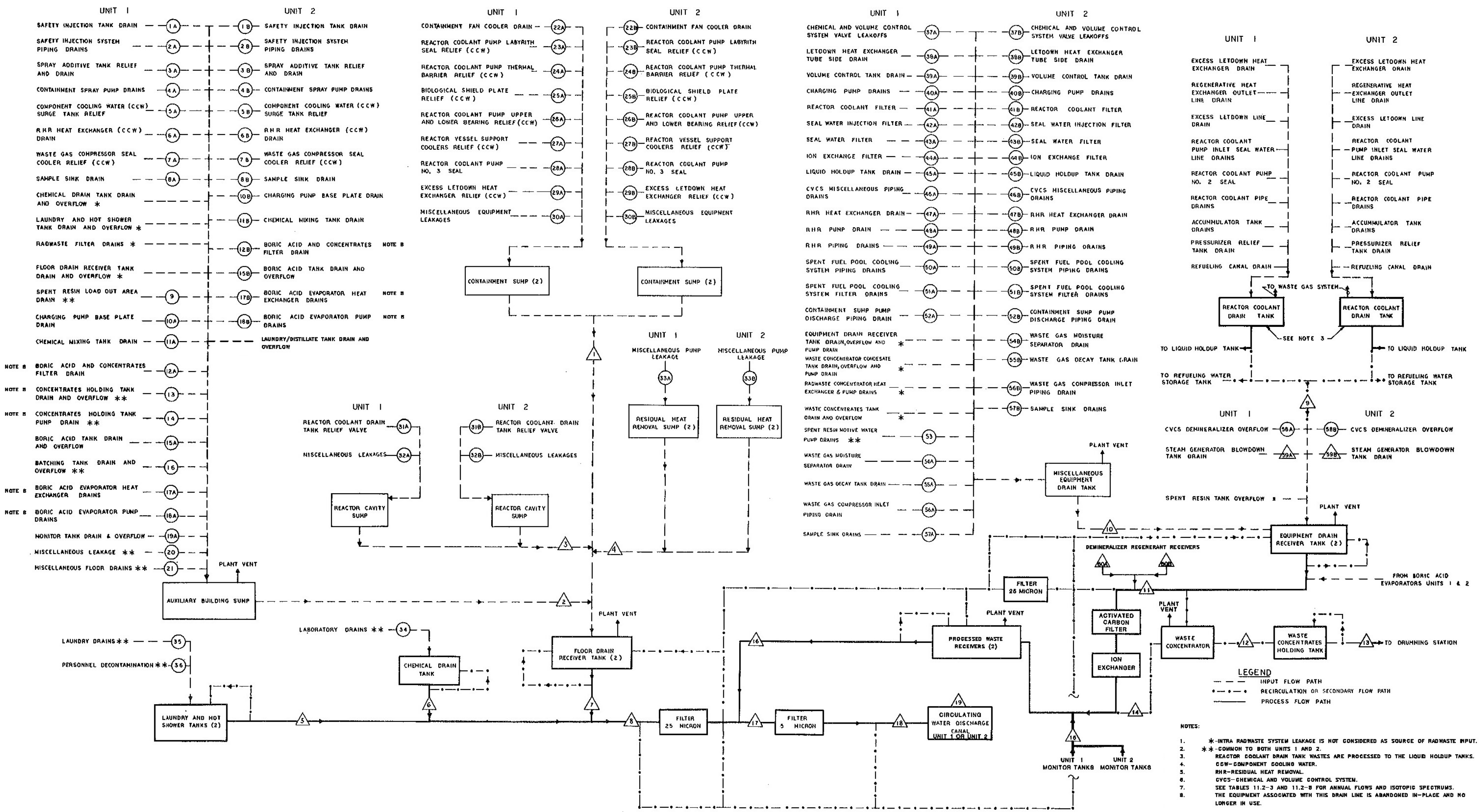


FIGURE 11.1-1
R. E. GINNA PLANT
PLANT TRITIUM SOURCES
MEASURED AND PREDICTED
(POWER LEVEL-1520 MWt)

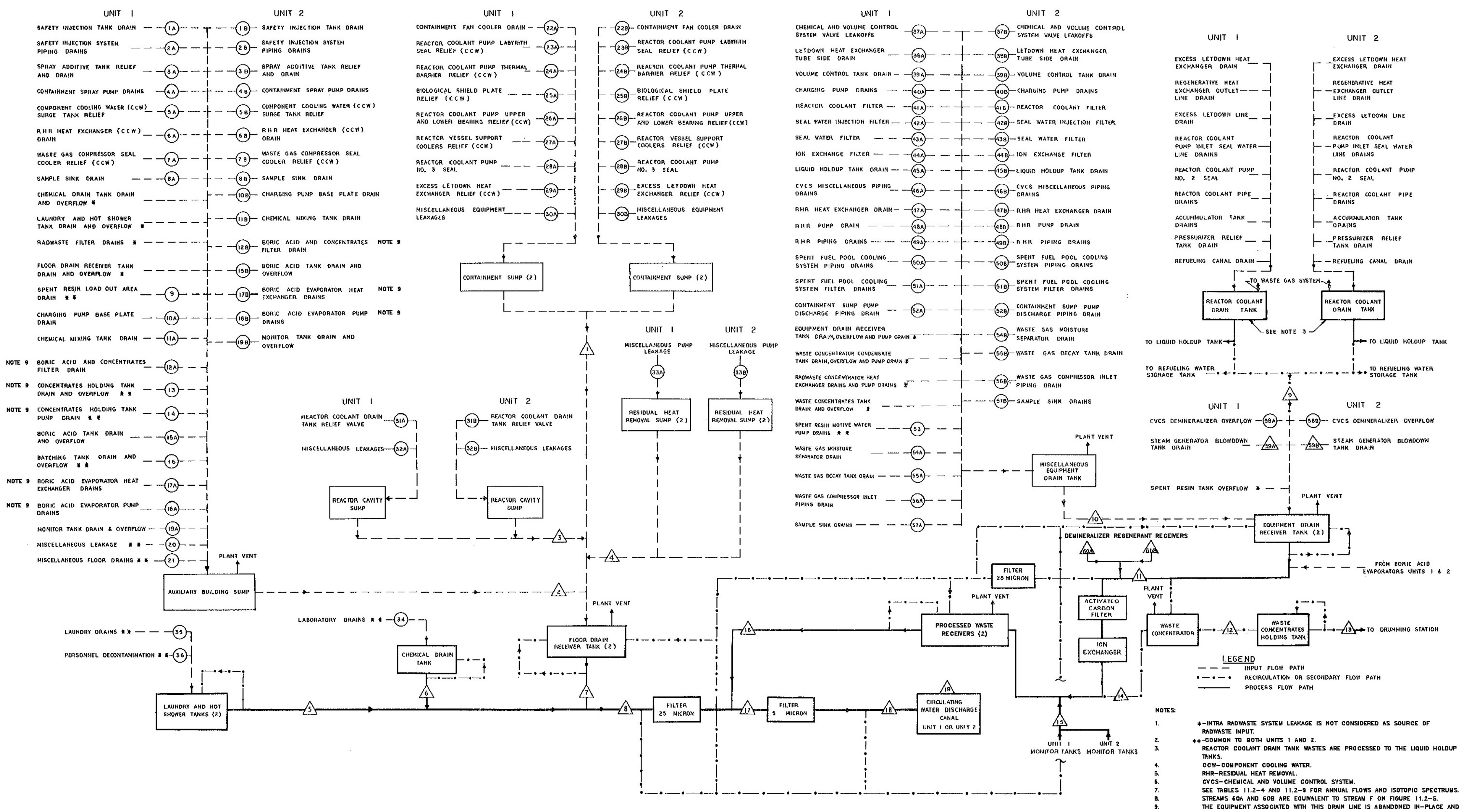


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 11.2-2

LIQUID WASTE PROCESS FLOW DIAGRAM
DESIGN BASIS CASE



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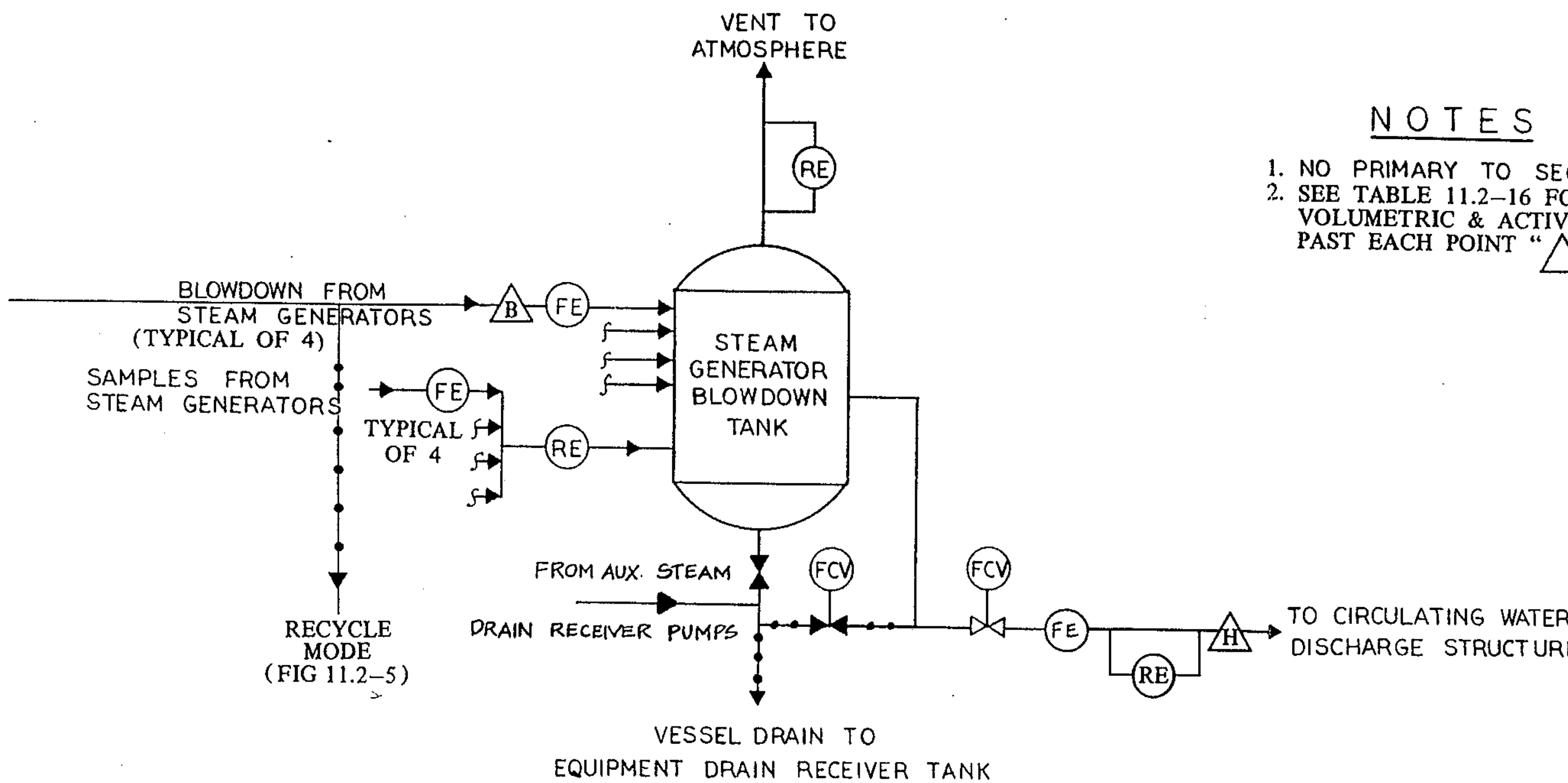
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 11.2-3

LIQUID WASTE PROCESS FLOW DIAGRAM
NORMAL OPERATIONS CASE



LEGEND

PROCESS FLOW PATH

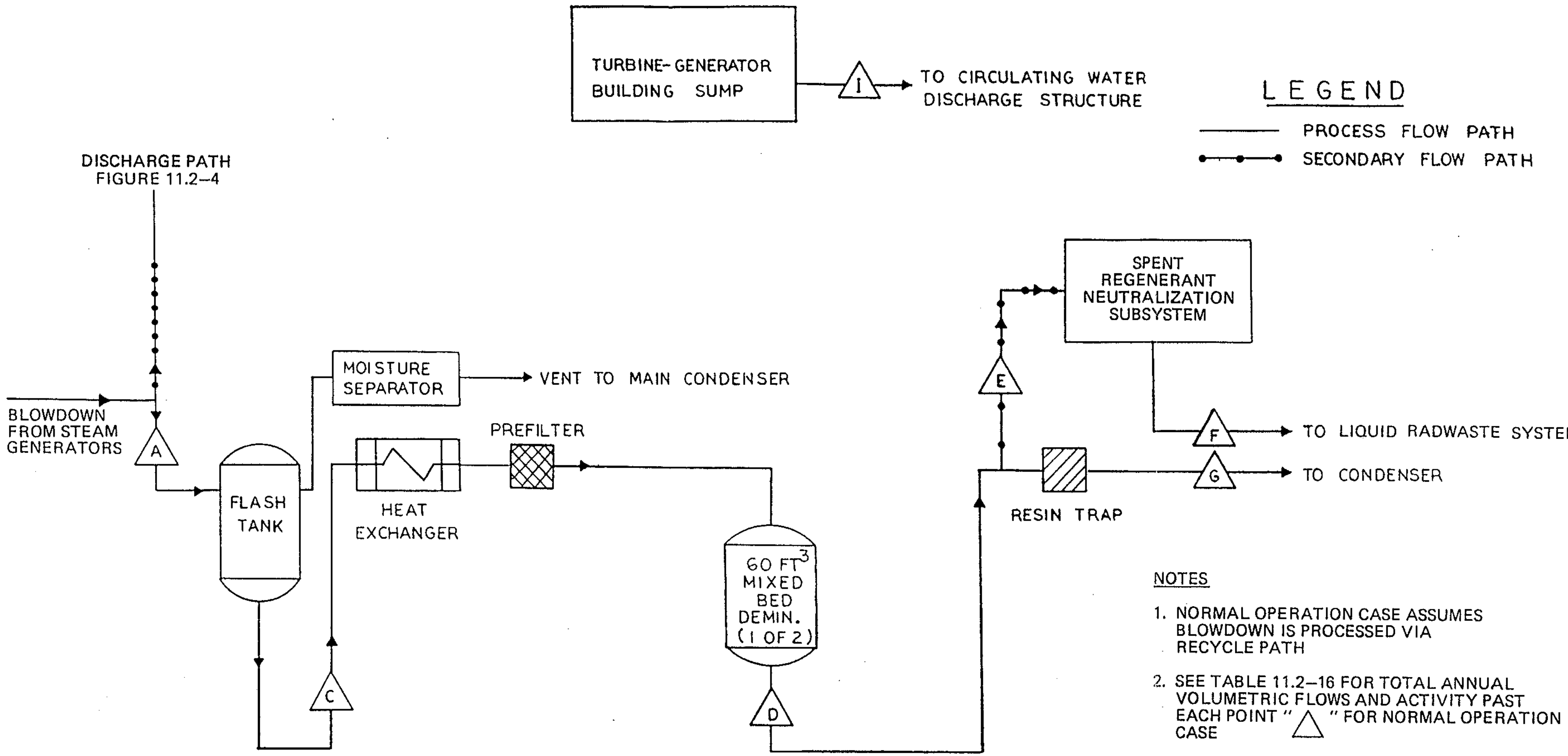
SECONDARY FLOW PATH

NOTES

1. NO PRIMARY TO SECONDARY LEAKAGE
2. SEE TABLE 11.2-16 FOR TOTAL ANNUAL VOLUMETRIC & ACTIVITY FLOW PAST EACH POINT "△"

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 11.2-4 BLOWDOWN SYSTEM FLOW DIAGRAM DISCHARGE MODE

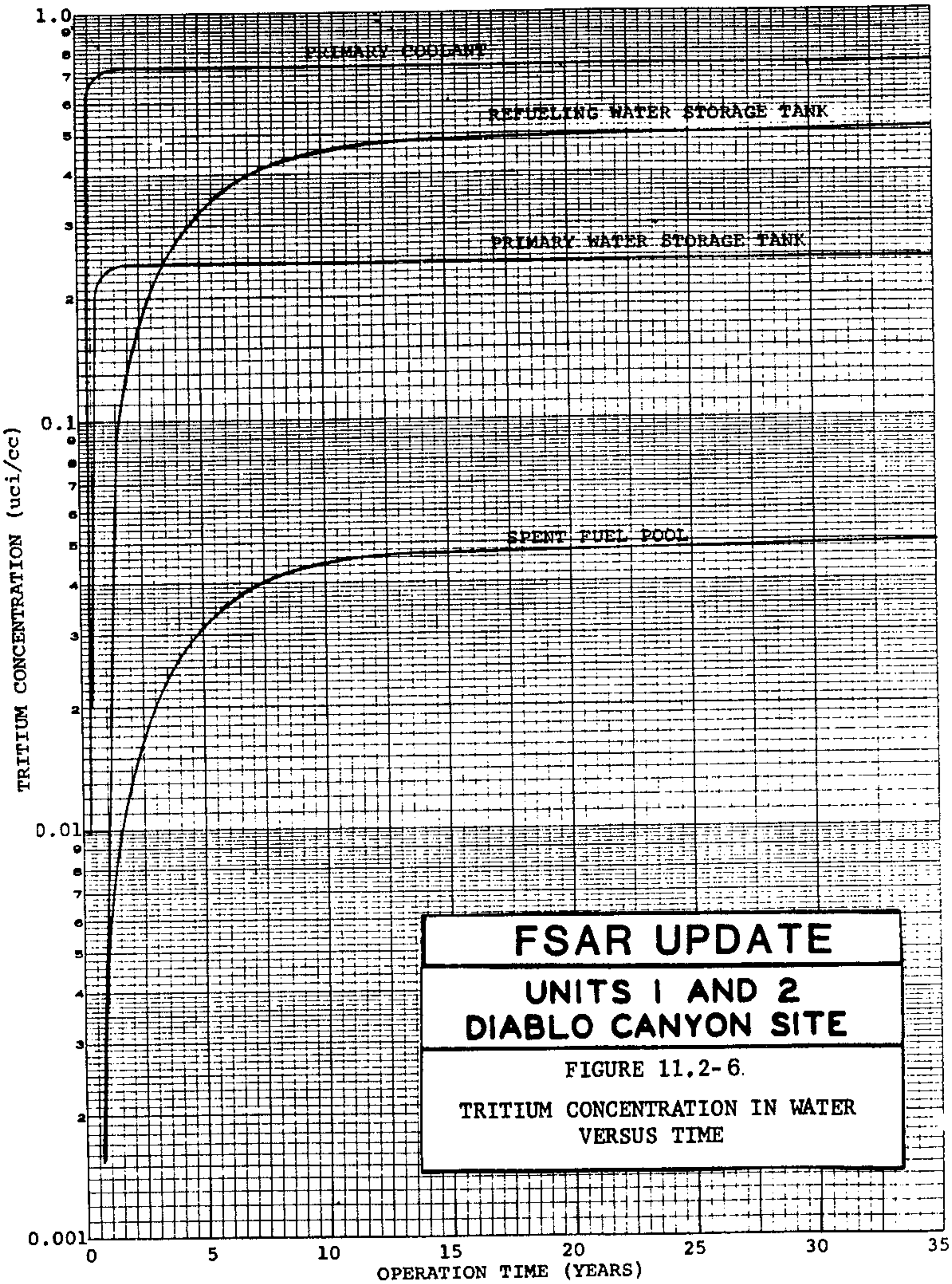
Revision 11 November 1996



NOTES

1. NORMAL OPERATION CASE ASSUMES BLOWDOWN IS PROCESSED VIA RECYCLE PATH
2. SEE TABLE 11.2–16 FOR TOTAL ANNUAL VOLUMETRIC FLOWS AND ACTIVITY PAST EACH POINT "△" FOR NORMAL OPERATION CASE
3. STREAM F IS EQUIVALENT TO STREAM 60 A AND 60 B ON FIGURE 11.2–3.

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 11.2–5 BLOWDOWN SYSTEM FLOW DIAGRAM RECYCLE PATH



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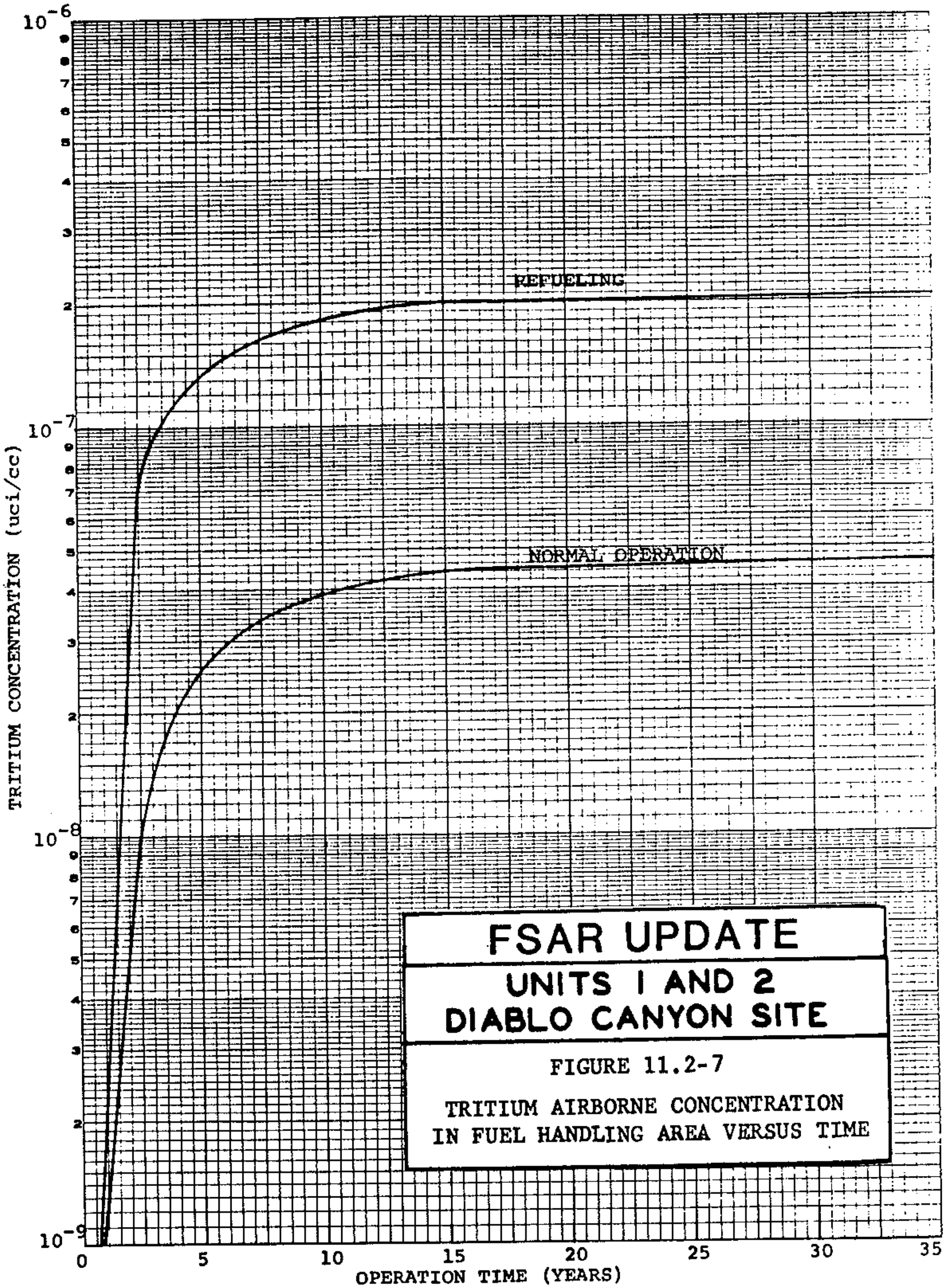
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 11.2-6

TRITIUM CONCENTRATION IN WATER VERSUS TIME

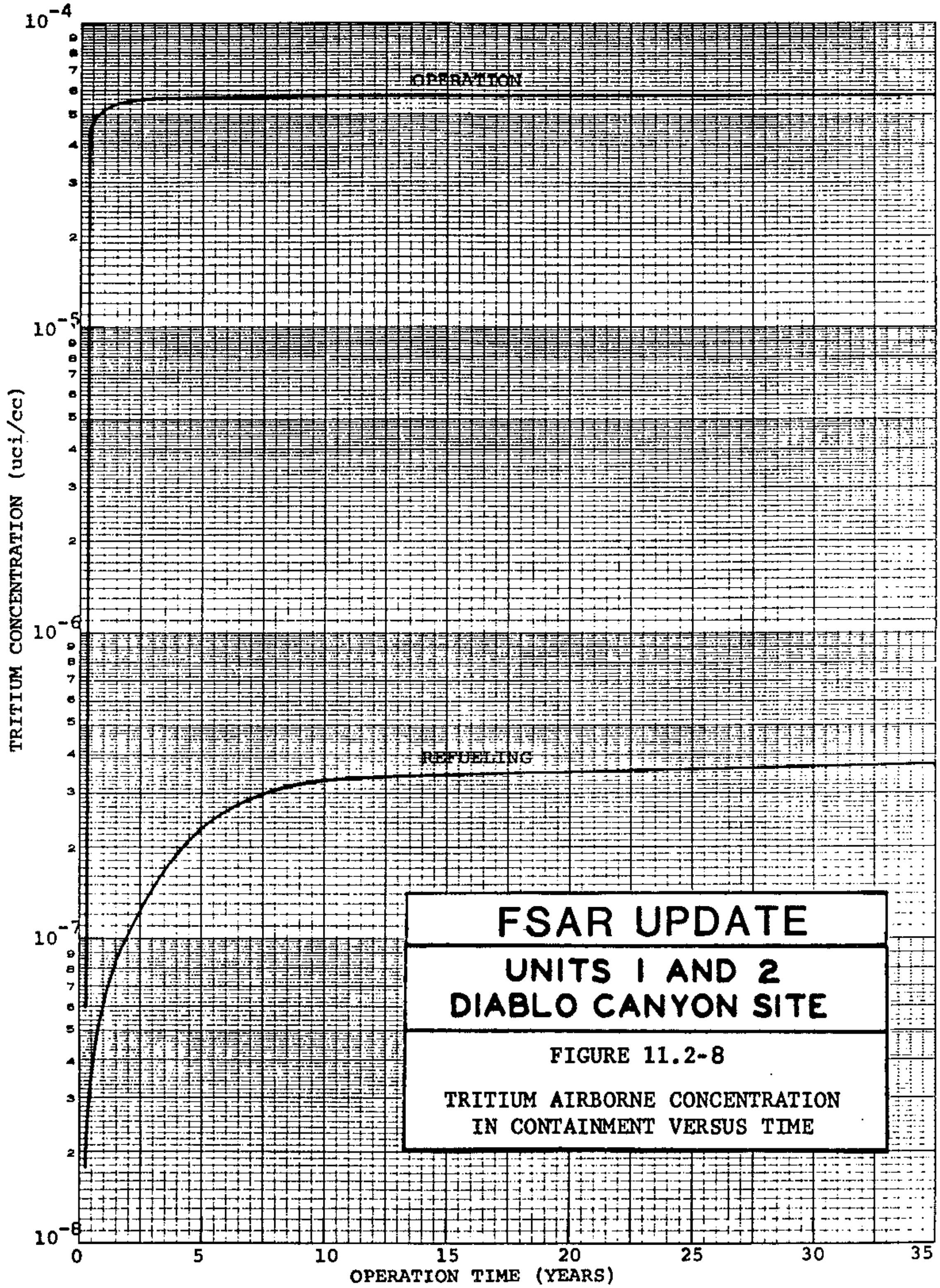


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 11.2-7

TRITIUM AIRBORNE CONCENTRATION IN FUEL HANDLING AREA VERSUS TIME

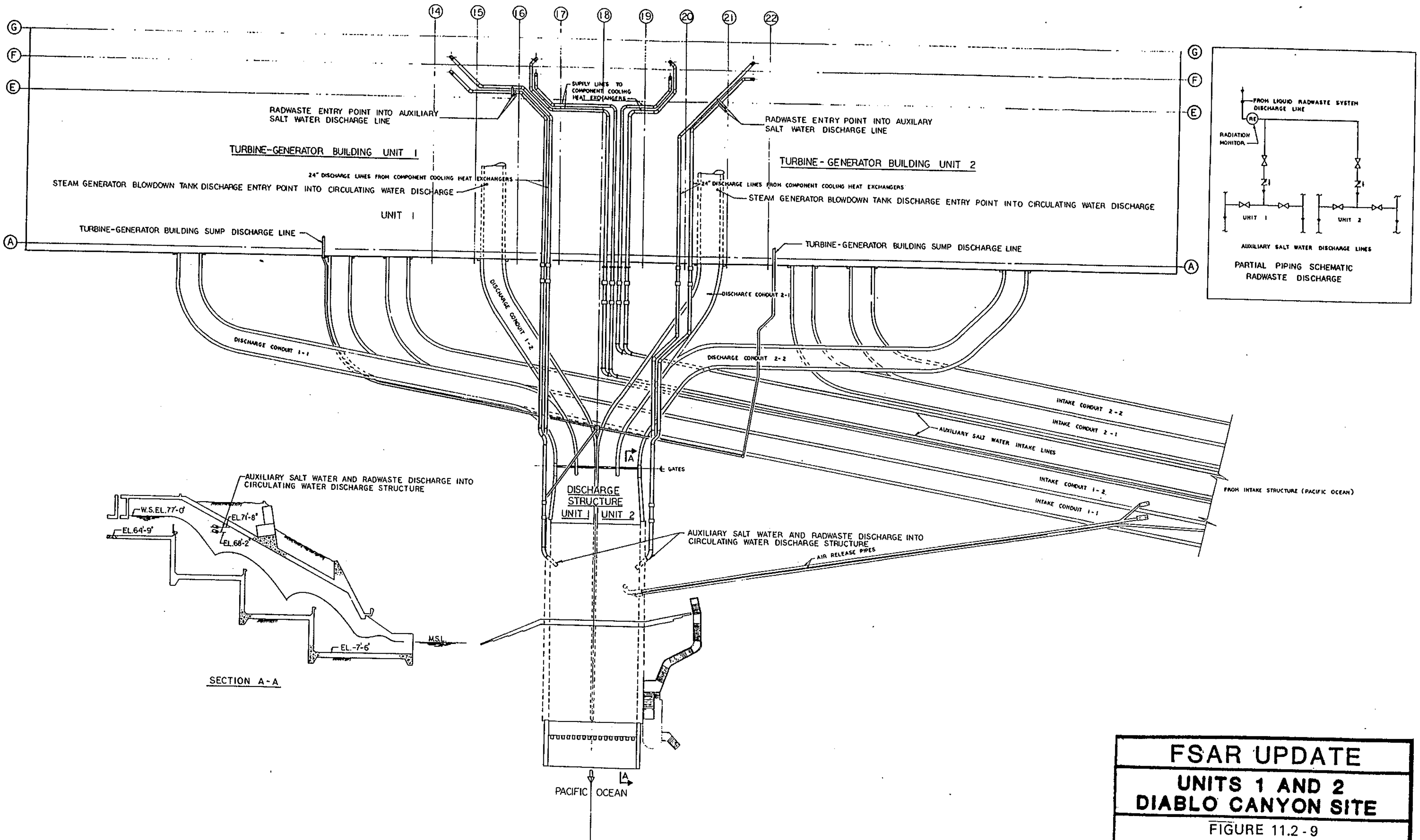


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 11.2-8

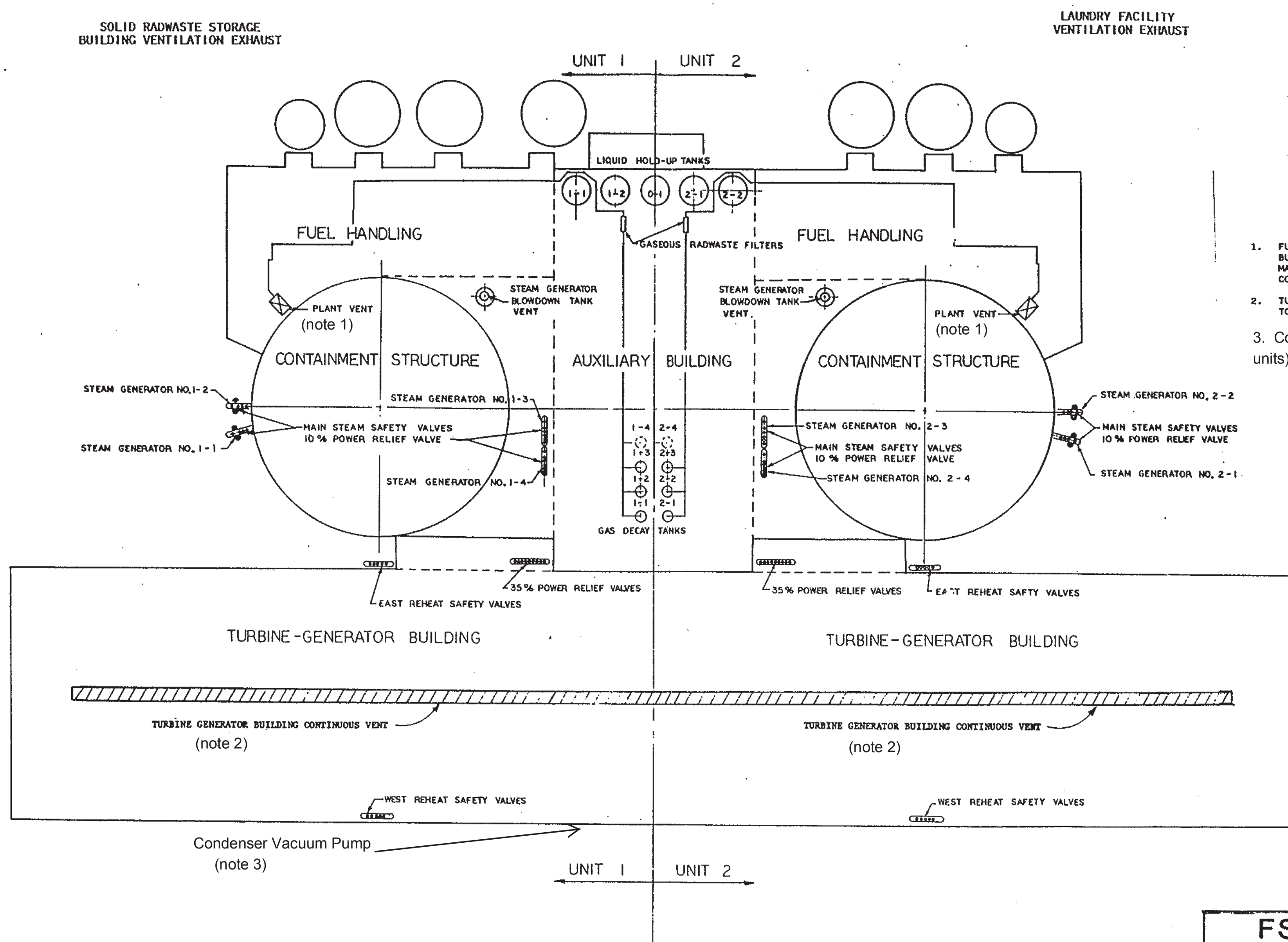
TRITIUM AIRBORNE CONCENTRATION IN CONTAINMENT VERSUS TIME



FSAR UPDATE

UNITS 1 AND 2 DIABLO CANYON SITE

FIGURE 11.2-9
SITE PLOT PLAN
RADWASTE DISCHARGE



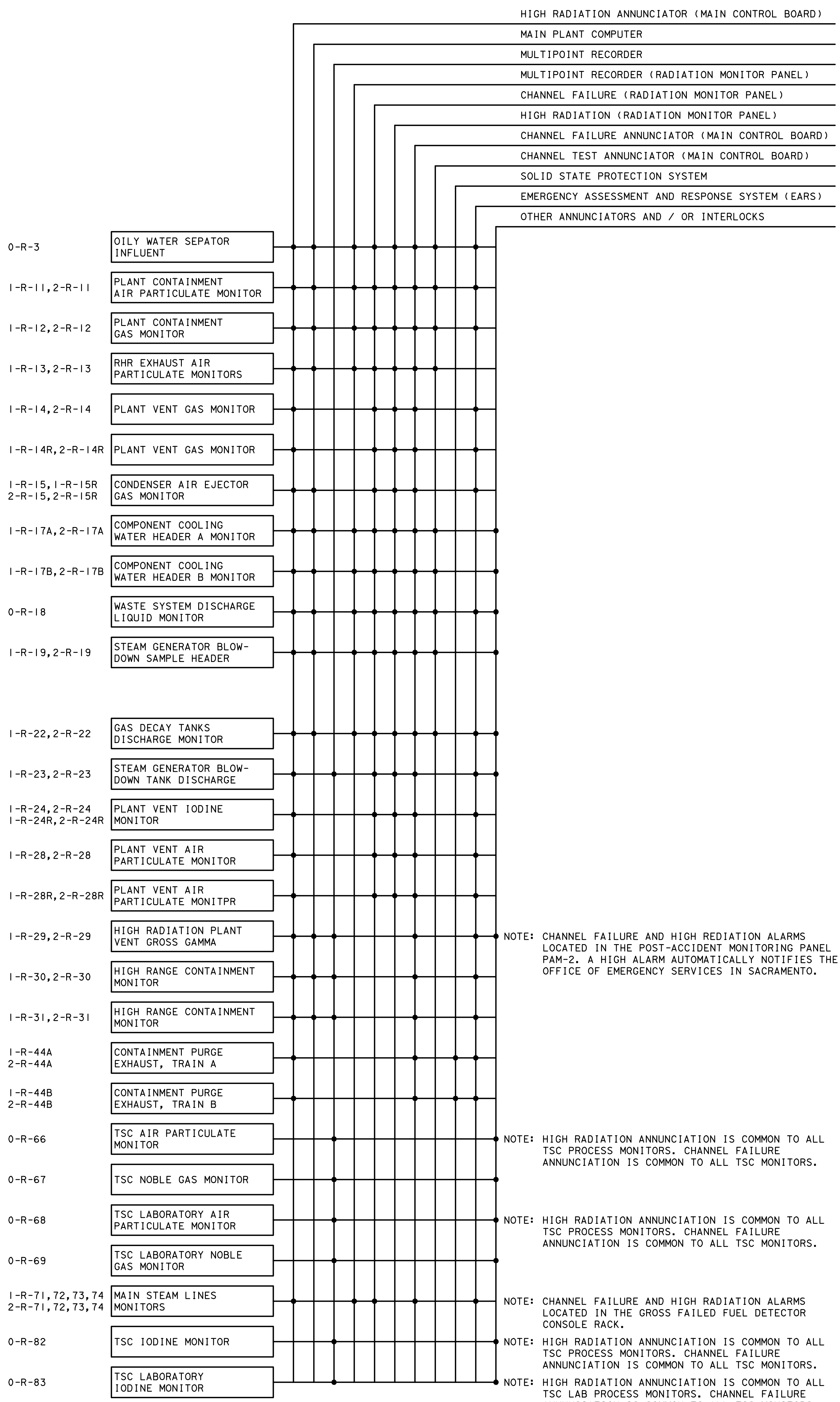
NOTES

1. FUEL HANDLING BUILDING VENTILATION, AUXILIARY BUILDING VENTILATION, CONTAINMENT VENTILATION, MAIN CONDENSER AIR EJECTOR, AND GLAND STEAM CONDENSER DISCHARGE TO PLANT VENT.
2. TURBINE-GENERATOR BUILDING VENTILATION DISCHARGE TO THE ATMOSPHERE.
3. Condenser vacuum pump (shared between units) exhausts to the atmosphere.

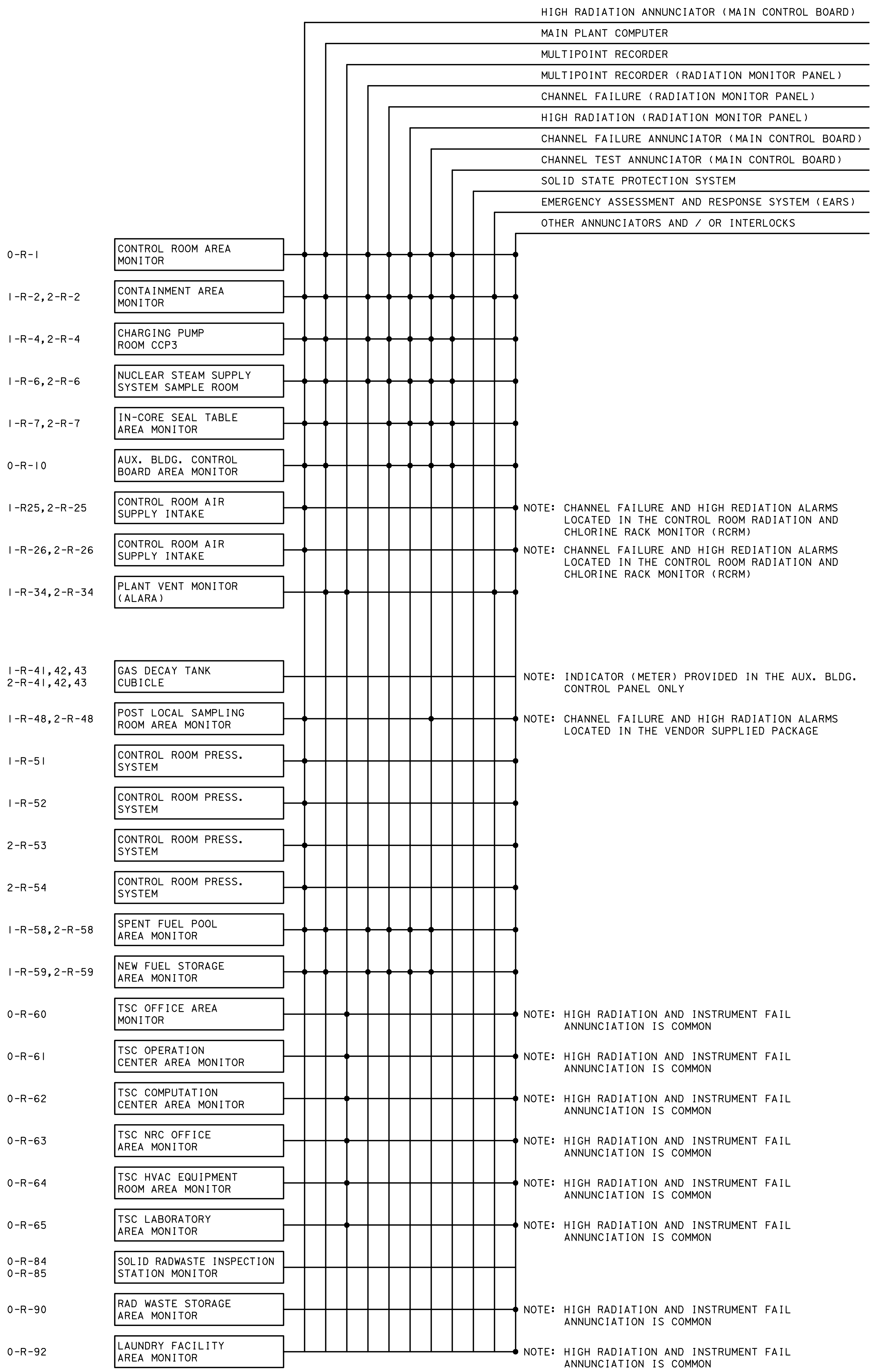
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 11.3-4
GASEOUS WASTE SYSTEMS' RELEASE POINTS



FSAR UPDATE
UNITS 1 AND 2
DIABLO CANYON SITE
FIGURE 11.4-1 Sheet 1 of 2
RADIATION MONITORING SYSTEM
Revision 18 October 2008



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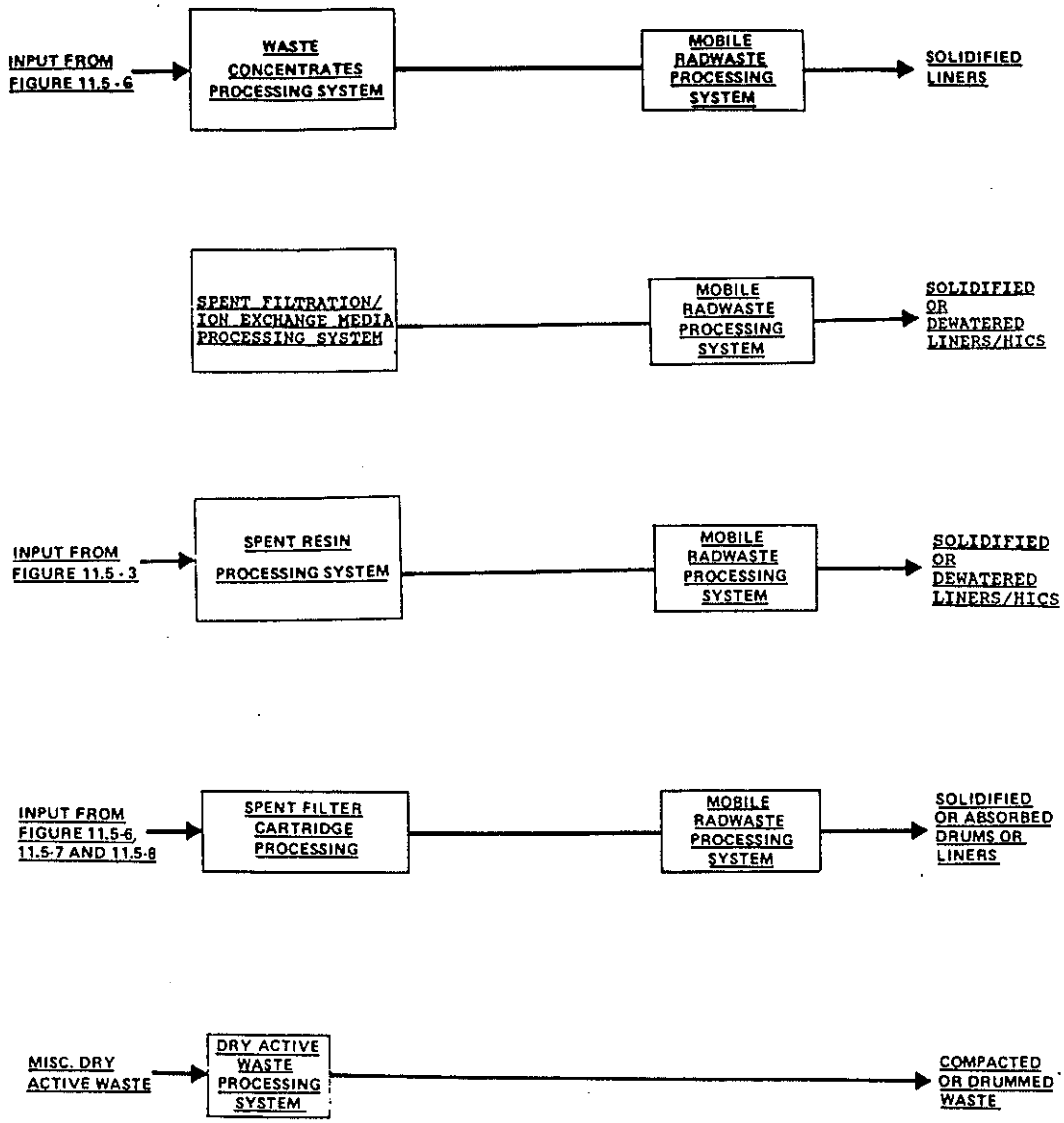
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 11.4-1 Sheet 2 of 2
RADIATION MONITORING SYSTEM

Revision 18 October 2008

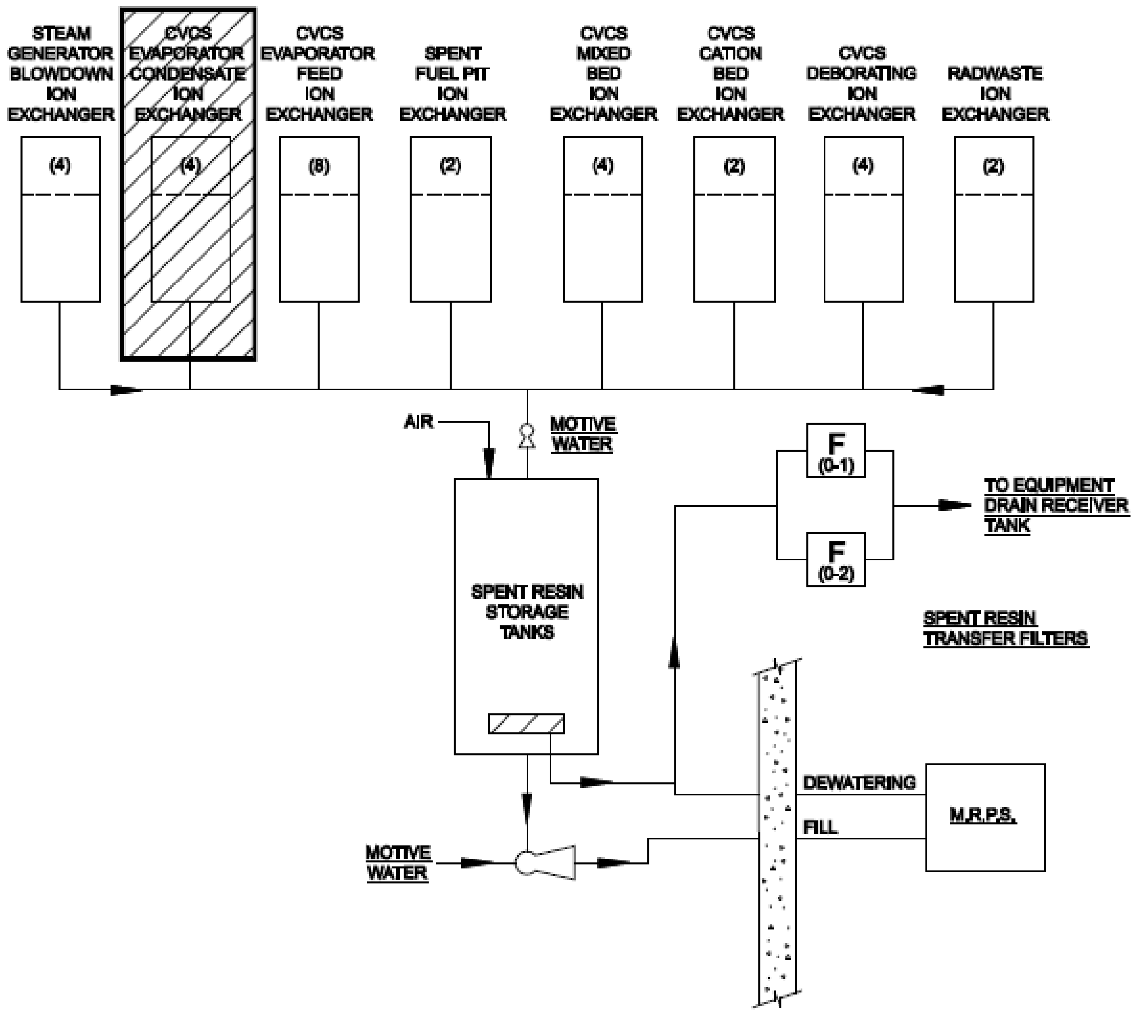


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 11.5-1

SOLID RADWASTE SYSTEM



NOTES:

1. SHADED AREA DENOTES ABANDONED EQUIPMENT.

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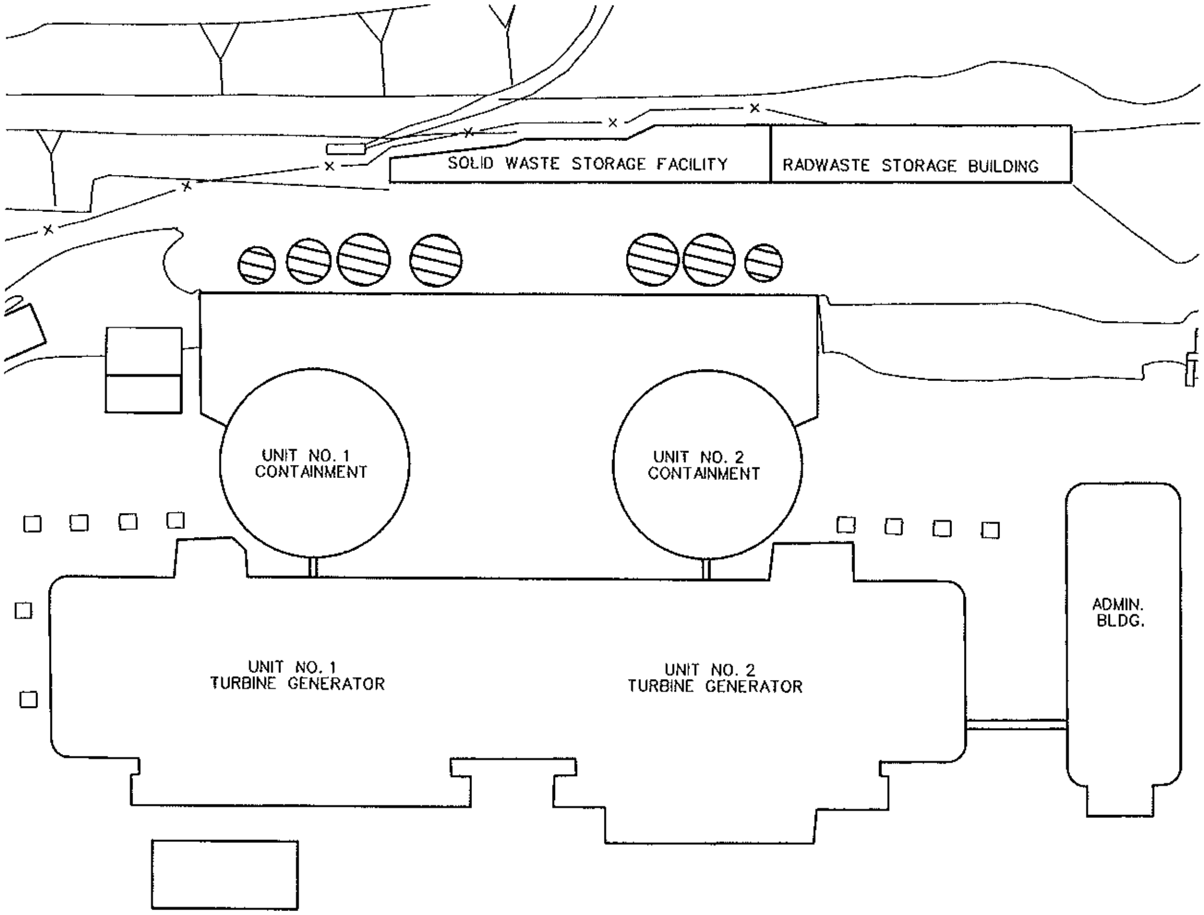
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 11.5-3

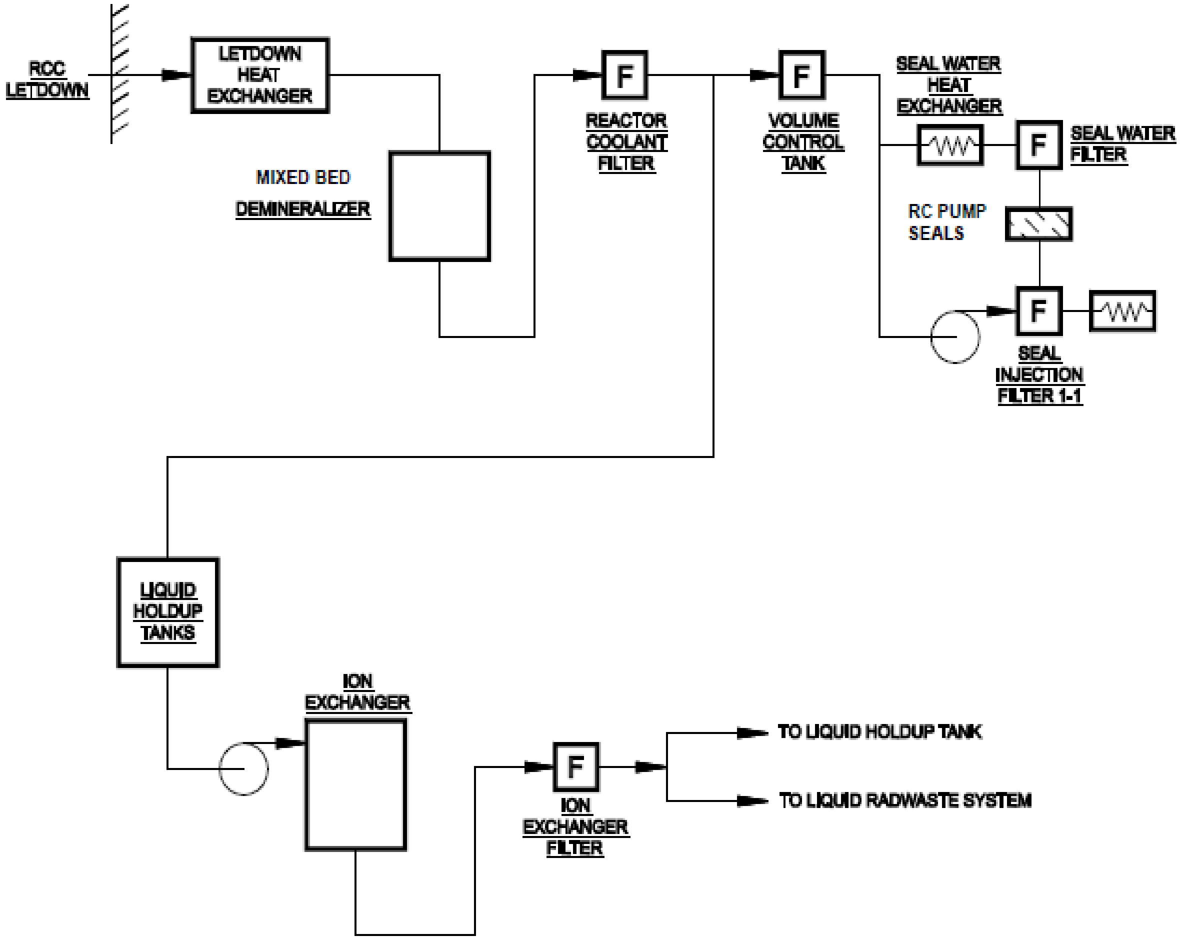
SPENT RESIN FLOW DIAGRAM

Revision 20 November 2011

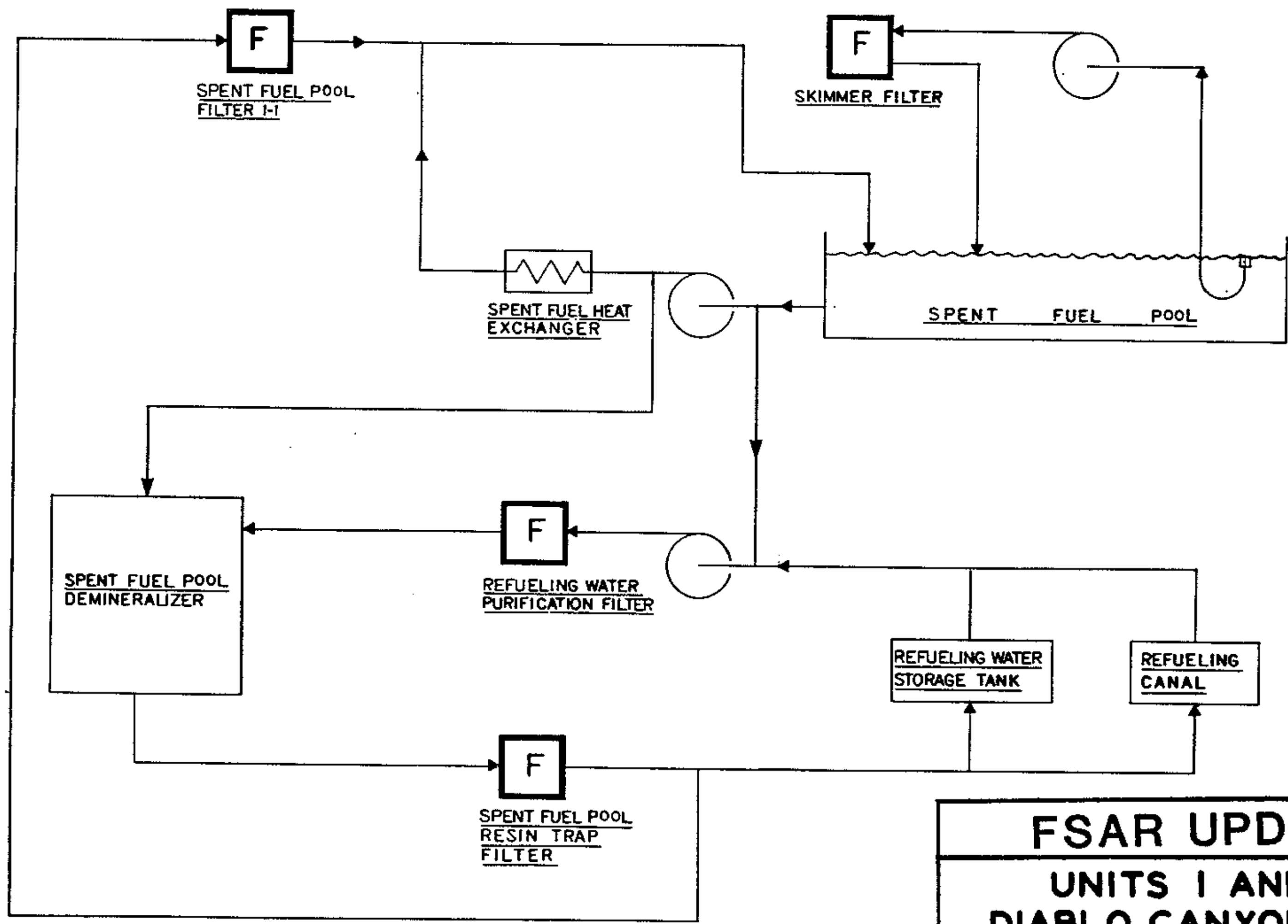


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 11.5-4 LOCATION OF ONSITE STORAGE FACILITY

Revision 16 June 2005



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 11.5-6 CHEMICAL AND VOLUME CONTROL SYSTEM DISPLAYING FILTERS



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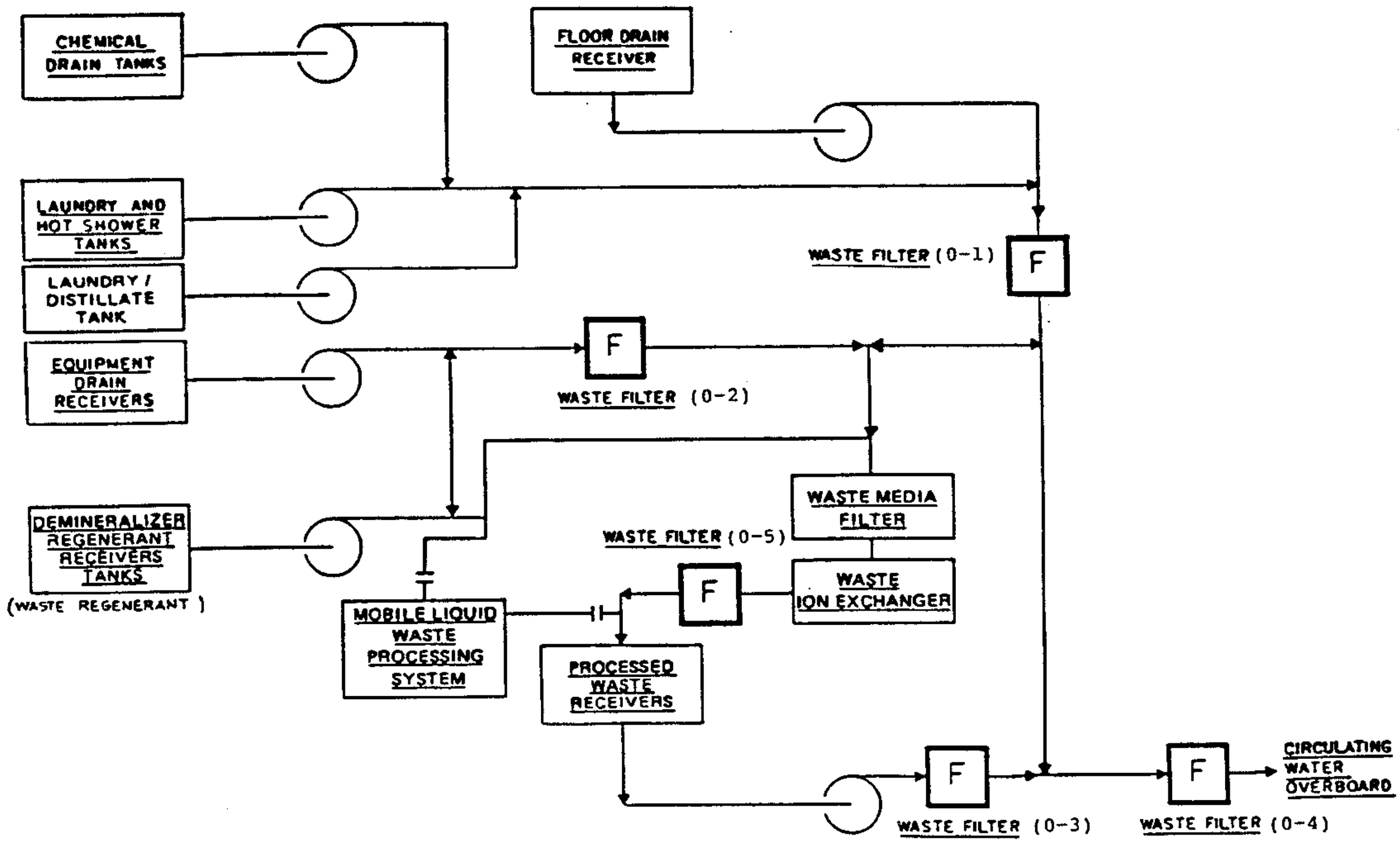
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 11.5-7
SPENT FUEL POOL DISPLAYING FILTERS

Revision 11 November 1996



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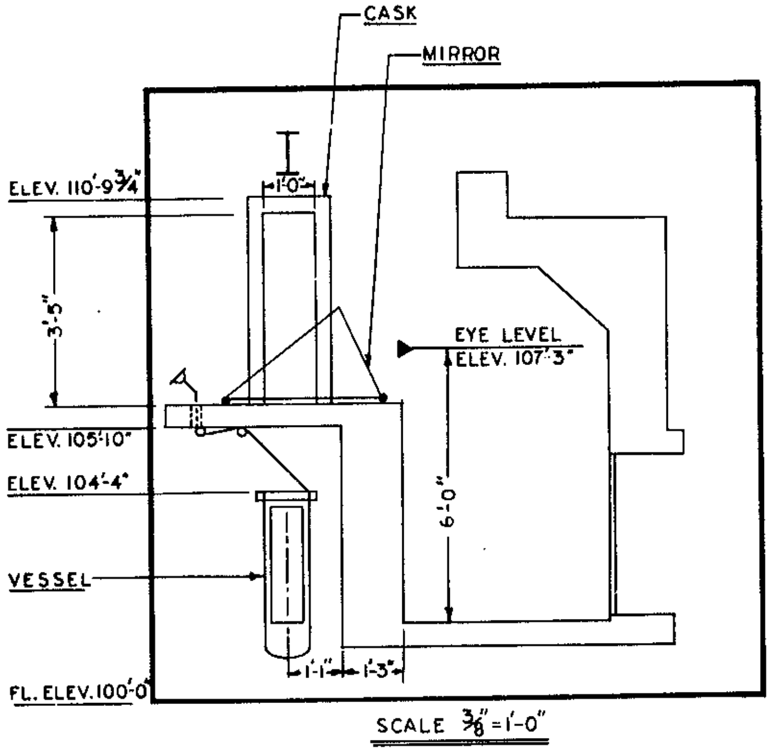
UNITS 1 AND 2
DIABLO CANYON SITE

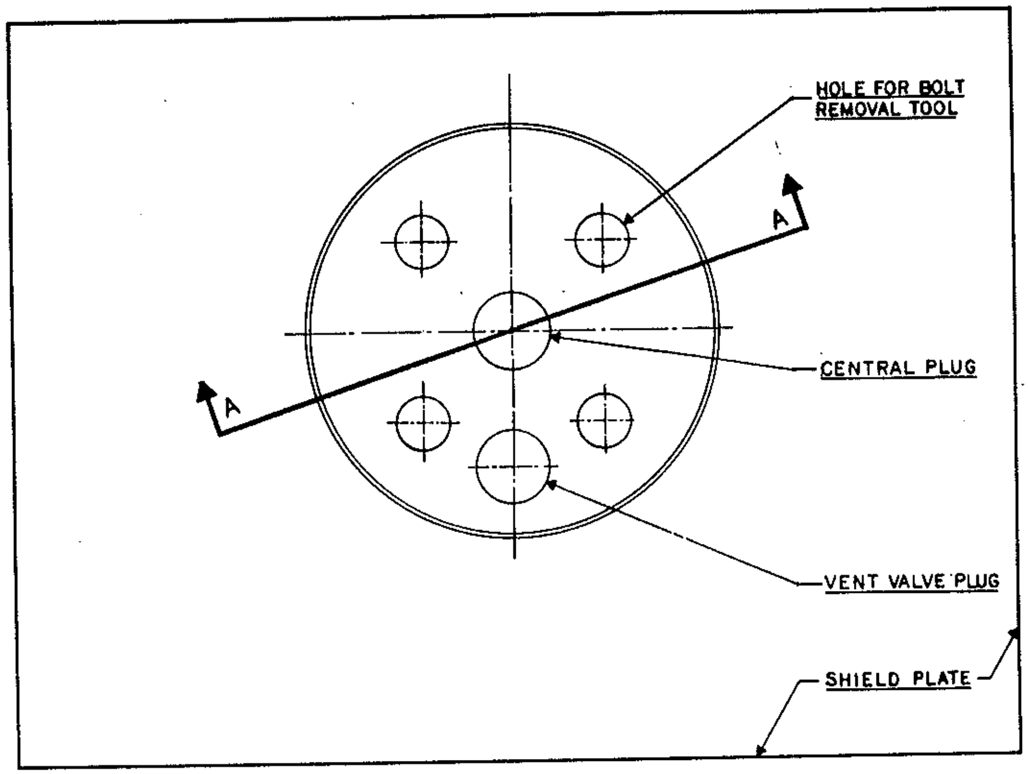
FIGURE 11.5-8
LIQUID RADWASTE SYSTEM
DISPLAYING FILTERS

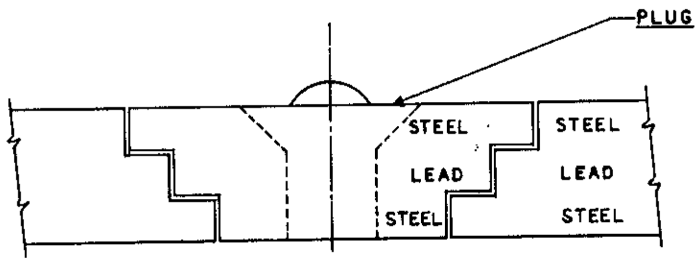


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 11.5-9
SYSTEM FOR CAPTURING
EXPENDED FILTER CARTRIDGES



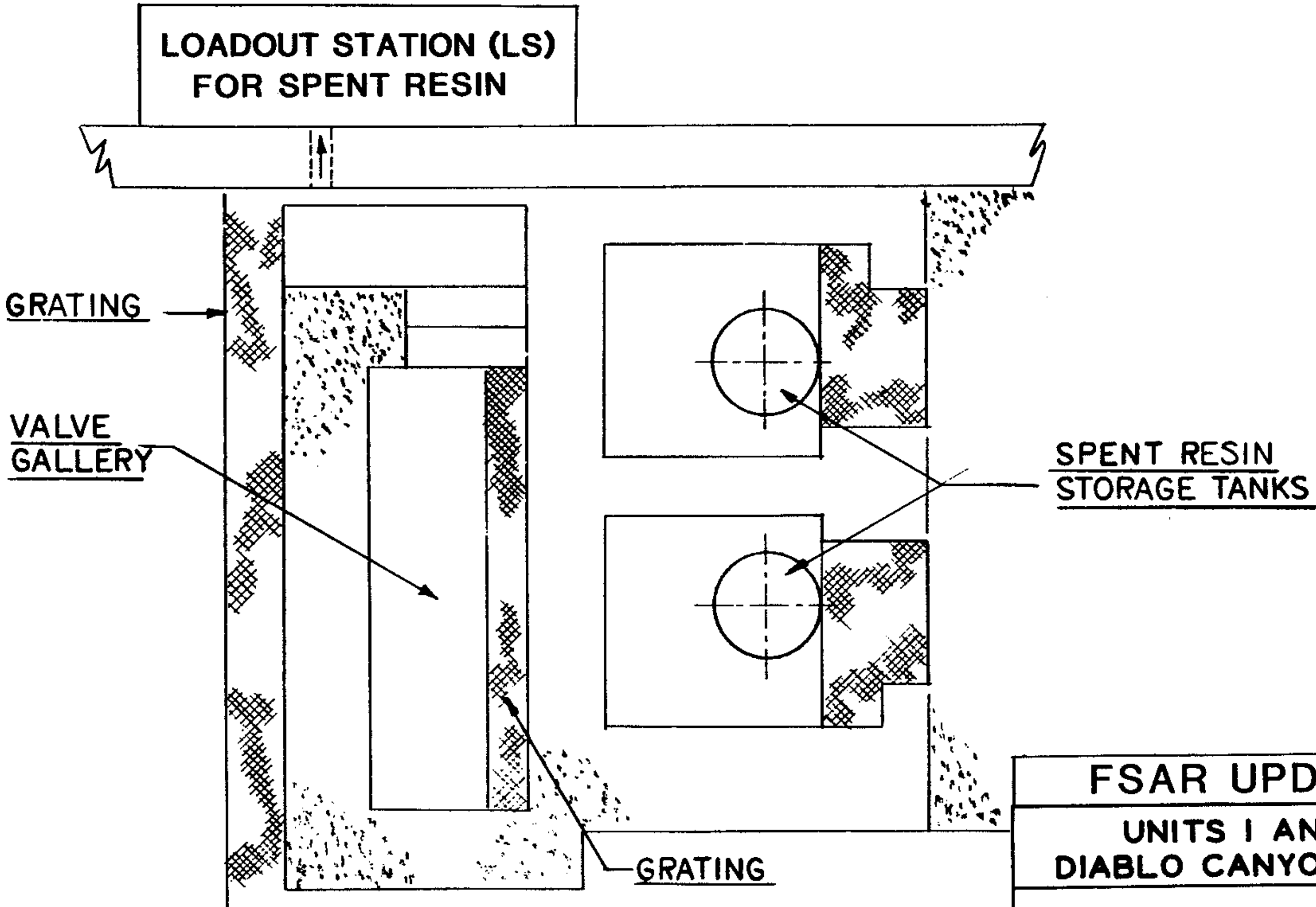


SECTION A-A

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

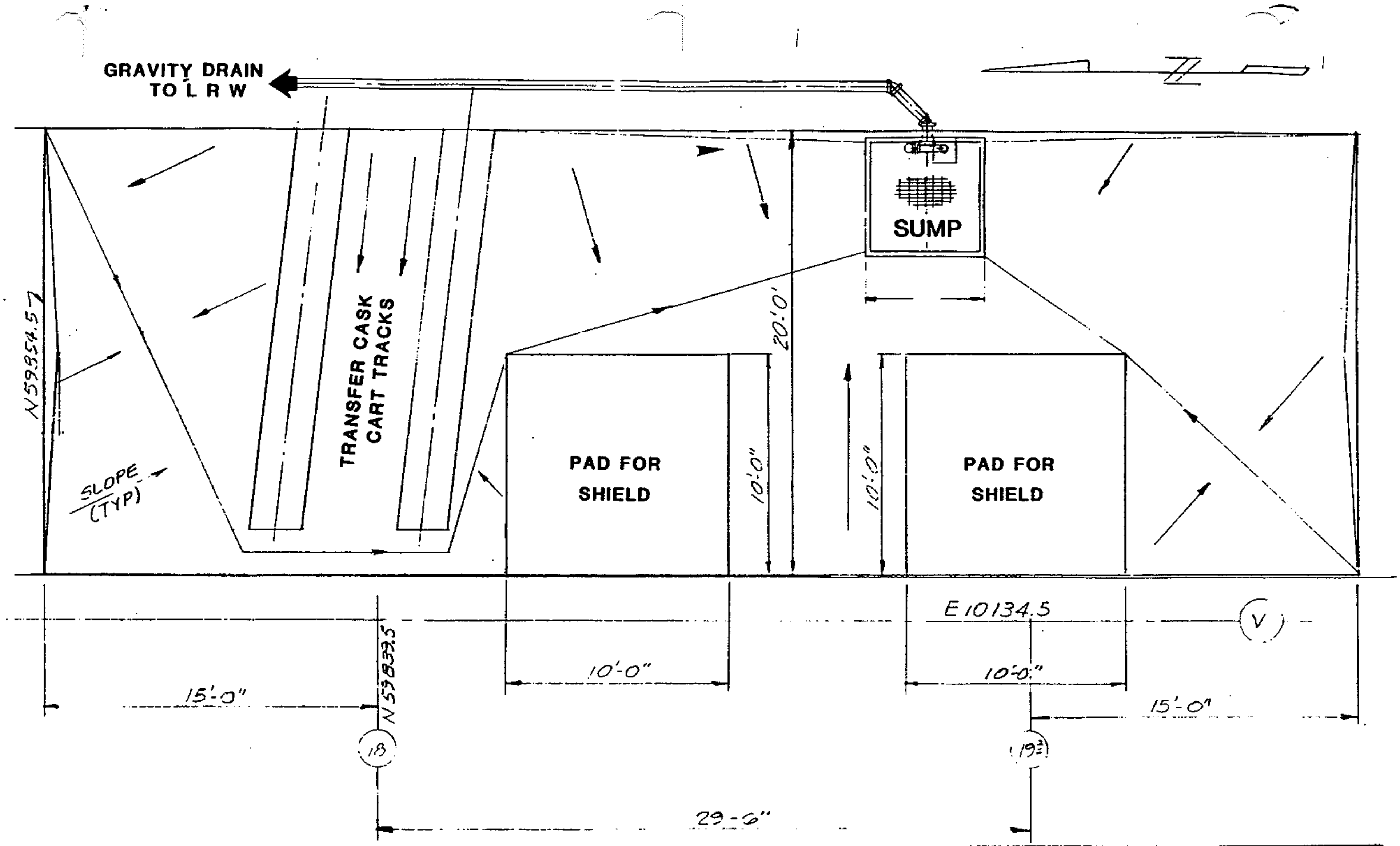
FIGURE 11.5 - 10
COVER OF FILTER VESSEL



FSAR UPDATE

UNITS I AND 2
DIABLO CANYON SITE

FIGURE 11.5–11
SPENT RESIN STORAGE AREA



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 11.5-12
LOAD OUT STATION

Chapter 12

RADIATION PROTECTION

CONTENTS

CONTENTS (Continued)

Chapter 12

TABLES

TABLES (Continued)

Chapter 12

FIGURES

Chapter 12

RADIATION PROTECTION

The purpose of this chapter is to demonstrate that both external and internal radiation dose resulting from operation of the Diablo Canyon Power Plant (DCPP) will be kept as low as is reasonably achievable (ALARA) and within applicable limits.

12.1 SHIELDING

This section describes the radiation shielding objectives and design configuration, identifies and characterizes source terms, summarizes important features of the area radiation monitoring system, describes those operating procedures that ensure external dose is kept ALARA, and gives estimates of dose to operating personnel and persons proximate to the DCPP site boundary.

12.1.1 DESIGN OBJECTIVES

The overall design objectives for shielding during normal operation, maintenance, and refueling, including anticipated operational occurrences, are:

(1) To protect all onsite personnel from external radiation dose to the extent that doses are maintained within the limits specified in 10 CFR 20 and are ALARA

(2) To ensure that the maximum continuous occupancy external dose delivered to any point on the site boundary is consistent with the guidelines provided in Appendix I to 10 CFR 50 regarding the dose from plant effluents, and 40 CFR 190 for total dose to individuals in the general public

(3) To provide sufficient access and occupancy time to various locations within the plant to allow personnel to conduct routine operation, refueling, and maintenance activities without exceeding the dose limits specified in 10 CFR 20

(4) To reduce potential neutron activation of equipment and mitigate the possibility of radiation-induced material damage

In addition, the shielding is designed to provide adequate protection under all postulated accident conditions, including a loss of primary coolant, to achieve the following objectives:

(1) To permit plant personnel to effect an orderly recovery from an accident condition

(2) To ensure that the direct radiation from plant structures is sufficiently low so that the total dose at the site boundary from both direct radiation and effluents is within the limits specified in 10 CFR 100 for all postulated accident conditions

(3) To permit continued operation of the other unit on the site in the unlikely event that a design basis accident occurs at one unit

A postaccident radiation shielding design review for DCPP, as required by NUREG 0737 (Reference 7), was performed and is reported in Reference 1.

12.1.2 DESIGN DESCRIPTION

This section discusses the specific design criteria for individual shielding systems required to achieve the overall objectives and describes the actual shielding design.

12.1.2.1 Shielding Locations and Basic Configurations

Figure 1.2-1 shows a plot plan of the site and indicates the location of roads, major plant buildings, and switchyards. It should be noted that the plant site is not served by railroad facilities. Figure 1.2-2 presents a detail of the plant layout and shows the location of outside tanks that could house potentially radioactive materials.

Figures 1.2-4 through 1.2-9 provide scaled plan views of Unit 1 buildings that contain process equipment for treatment of radioactive fluids, and indicate locations and basic configurations of the shielding provided. Figures 1.2-10 through 1.2-12 show similar views of Unit 2 structures. Corresponding sectional views of Unit 1 structures including shielding are shown in Figures 1.2-21 through 1.2-26. Comparable sectional views of Unit 2 structures are shown in Figures 1.2-28 through 1.2-30. Units 1 and 2 are similar with respect to shielding design.

12.1.2.2 General Shielding Design Criteria and Features

One of the principal design objectives for plant shielding is to reduce the expected radiation levels within plant structures to values that will allow plant personnel to gain access to normal work areas and remain there for sufficient time to perform required routine work without exceeding normal occupational dose limits. To implement this objective, plant areas capable of personnel occupancy are classified into one of five zones on the basis of expected frequency and duration of occupancy during routine operation, refueling, and maintenance[1]. A maximum design dose rate criterion is defined for each zone; it is consistent with the previously stated overall shielding design objectives. Plant shielding is designed to ensure that radiation dose rates in all plant areas are below the classified zone limits.

[1] Radiation zone maps show general zones. Background details may not be accurate.

The radiation zone criteria are summarized in Table 12.1-1. The specific zoning for all plant areas during normal operation in Unit 1 is shown in Figures 12.1-1 through 12.1-12. Radiation zones for Unit 2 are similar to those for Unit 1.

Typical Zone 0 areas are the turbine building and turbine plant service areas, the control room, and the TSC. Typical Zone I areas are the auxiliary building work stations and corridors and the outer surfaces of the containment and auxiliary building. Zone II areas include the surface of the refueling water during refueling (except during movement of a fuel assembly) and the operating deck of the containment during reactor shutdown. Areas designated Zone III include the sampling room and reactor containment penetration areas, including ventilation, steam line, and electrical penetrations. Typical Zone IV areas are within the regions adjacent to the reactor coolant system (RCS) at power operation and the demineralizer and volume control tank spaces. The postaccident radiation levels within the plant structures are discussed in Reference 1.

The radiologically controlled areas (RCAs) within plant structures (Zones I, II, III, and IV) are separated by barriers from the uncontrolled areas (Zone 0) to avoid inadvertent entry of unauthorized personnel. Entrance into the radiologically controlled areas is normally made from a single access control station at the +85 foot elevation of the auxiliary building and is under procedural control. An auxiliary access control, located on the 140 ft elevation, may be utilized to provide more efficient access into the RCA, including containment buildings. Other access control stations may be temporarily established to support plant operations on an ad hoc basis. Within the radiologically control areas, all areas are appropriately marked and/or barricaded in accordance with 10 CFR 20 and other applicable regulations. Areas designated Zone IV, such as the room containing the equipment and floor drain receiver tanks and the waste concentrator tanks, are accessible to plant personnel only at infrequent intervals, for limited periods of time, and then under strict radiological control. The dry active waste and resin liner storage areas in the radwaste storage building are also designated as Zone IV.

Care has been taken to ensure that radiologically controlled area zones that are normally relatively low dose rate areas (i.e., Zones I and II) are not likely to be subjected to unexpected increases in dose rate due to the rapid introduction of radioactive materials into nearby process piping or other means. The routing of all plant piping is strictly controlled. Pipes that carry radioactive materials are routed in radiologically controlled access areas properly zoned for that level of activity.

Shielding is arranged to protect personnel from direct gamma radiation that could otherwise stream through piping penetrations. Reach rods are provided where necessary to permit the operator to remain behind shielding while operating valves. For the radwaste storage building, exposure of site workers is minimized through the use of concrete shielding around the stored material, remote handling of high activity liners, and controlled access to the storage building.

12.1.2.3 Containment Shielding Design

Containment shielding is divided into four categories according to functions: primary shield, secondary shield, fuel handling shield, and accident shield. Each of these is discussed below.

12.1.2.3.1 Primary Shield

The primary shield consists of the core baffle, water annuli, barrel-thermal shield (all of which are within the reactor vessel), the reactor vessel wall, and a concrete structure surrounding the reactor vessel.

The primary shield (or parts thereof) performs the following functions:

(1) Reduces the energy-dependent neutron flux incident on the reactor vessel to prevent material property changes that might unduly restrict operation of the plant

(2) Attenuates reactor core neutron flux to prevent excessive activation of plant components and structures outside the primary shield

(3) Limits the gamma flux in both the reactor vessel and primary shield concrete to avoid large temperature gradients and/or dehydration of the concrete

(4) Reduces the radiation levels from reactor sources so that limited access is possible to certain areas within the reactor containment building during full power operation

(5) Reduces the residual radiation from the core to levels that will permit access to the region between the primary and secondary shields at a reasonable time after shutdown

The concrete structure immediately surrounding the reactor vessel extends up from the base of the containment and is an integral part of the main structural concrete support for the reactor vessel. It extends upward to join the concrete cavity over the reactor. The reactor cavity, which is approximately rectangular in shape, extends upward to the operating floor. A steel shield plate is provided where each of the eight reactor coolant pipes penetrates the primary shield.

The primary concrete shield is air-cooled to prevent overheating and dehydration from the heat generated by radiation absorption in the concrete. Eight "windows" are provided in the primary shield for insertion of the out-of-core nuclear instrumentation. Cooling for this instrumentation is also provided by air.

12.1.2.3.2 Secondary Shield

The secondary shield surrounds the primary shield and the reactor coolant loops and consists of the annular polar crane support wall, the concrete operating floor over the primary coolant loops, and the shell of the containment structure. The shell of the containment structure also serves as the accident shield.

The main function of the secondary shielding is to attenuate the radiation originating in the reactor and reactor coolant. Although the interior of the containment is a Zone IV area during full power operation, the secondary shielding is designed to reduce radiation levels to a point where limited access to certain areas within the containment is possible. The areas where limited accessibility is intended include the operating floor at elevation +140 feet and the annular areas between the crane wall and the containment shell on elevations +91 and +115 feet. The radiation levels in these areas are generally less than 15 mR/hr. The secondary shield will also limit the full power dose rate outside the containment building to less than 1 mrem/hr.

12.1.2.3.3 Fuel Handling Shield

The reactor cavity, flooded during refueling operations, provides a temporary water shield above the components being withdrawn from the reactor vessel. The water height during movement of fuel assemblies is at least 23 feet above the reactor vessel flange. This height ensures that a minimum of 8 feet of water will be above the top of a withdrawn fuel assembly (about 9 feet of water above the active fuel). With upper internals in place, the water height during the unlatching of control rods is 23 feet above the fuel assemblies (12 feet above the reactor vessel flange).

The fuel handling shield is designed to facilitate the removal and transfer of spent fuel assemblies and control rod clusters from the reactor vessel to the spent fuel pool. It is designed to attenuate direct radiation from spent fuel and control rod clusters to less than 2.5 mR/hr at the refueling cavity water surface except during movement of a fuel assembly and as noted below.

The fuel handling shield also provides attenuation of radiation from the reactor vessel internals. During removal of the upper internals package, the control rod drive lead screws and top hat assemblies must be raised above the water surface producing temporary radiation levels in excess of 1 R/hr. In the stored position, the very top of the lead screws extend from the surface producing localized dose rates to operators in the immediate area of less than 100 mrem/hr. The general area dose rate at the side of the pool is less than 5 mrem/hr near the upper internals.

The refueling canal is a passageway connected to the reactor cavity and extending to the inside surface of the reactor containment. The canal is formed by two concrete walls that extend upward to the same height as the reactor cavity. During refueling, the canal is flooded with borated water to the same height as the reactor cavity.

The spent fuel assemblies and control rod clusters are remotely removed from the reactor containment through the horizontal spent fuel transfer tube and placed in the spent fuel pool. Concrete shielding and barriers protect personnel from radiation during the time a spent fuel assembly is being transferred from the containment to the spent fuel pool.

12.1.2.3.4 Accident Shield

The accident shield consists of the reinforced concrete cylindrical containment shell that is capped by a hemispherical reinforced concrete dome. This shielding includes supplemental shielding in front of the containment penetrations.

The equipment access hatch is shielded by a solid concrete block shadow shield. The main function of the accident shield is to reduce radiation levels outside the containment building to an acceptable level following a design basis accident (DBA).

12.1.2.4 Fuel Handling Area Shielding Design

Spent fuel is stored in the spent fuel pool located in the fuel handling area. This area is located in the auxiliary building adjacent to the containment. The basic shield configuration for the Unit 1 spent fuel pool is shown in plan views in Figure 1.2-5 and in sectional views in Figures 1.2-23 and 1.2-24.

Water is used to provide shielding over the spent fuel assemblies so visual observation of fuel handling operations can be realized. The depth of the pool provides a submergence for the top of a fuel assembly of at least 8 feet during normal fuel handling operations and 23 feet submergence while fuel is stored in the fuel racks. Pool water level is indicated, and any water removed from the pool must be pumped out since there are no gravity drains.

The shielding for the fuel handling area restricts the dose rate to less than or equal to 5 mrem/hr in normally occupied areas.

Dose rates at the surface of the spent fuel pool will normally be less than or equal to 10 mrem/hr. During transfer of a spent fuel assembly, the minimum water level above the active fuel will be about 9 feet. With a peak fuel assembly (1.55 times full power level) being transferred, the maximum calculated dose rate at the surface of the pool is 50 mrem/hr. However, dose rates to the operator on the refueling platform will be less than 20 mrem/hr. The calculated doses exclude any contribution to dose rate from radioactivity contained in the spent fuel pool water. For additional information on the spent fuel pool water, see Section 9.1.3.2.

12.1.2.5 Auxiliary Building Shielding Design

The purpose of the shielding in the auxiliary building is to protect personnel working near various system components in the chemical and volume control system (CVCS), the residual heat removal system, the waste disposal system, the sampling system, and the auxiliary coolant systems. The general layout of the shielding in the auxiliary building is shown on plan views of Figures 1.2-4 through 1.2-9. Sectional views are included in Figures 1.2-21 through 1.2-23, 1.2-25, and 1.2-26.

The shielding provided for the auxiliary building is designed to limit the dose rate during normal operation to less than 1 mR/hr in normally occupied areas, and at or below 2.5 mR/hr in areas requiring periodic occupancy. In addition, the auxiliary building shielding is designed to provide limited access to areas within the building during the long-term recirculation phase following a loss-of-coolant accident (LOCA).

The auxiliary building shielding consists of concrete walls around equipment and piping that contain significant quantities of activity. Each equipment compartment is individually shielded so that compartments may be entered without having to shut down and/or decontaminate the adjacent system. In some cases, such as the tube withdrawal spaces for the abandoned boric acid and waste evaporators (shown in Figure 1.2-7), removable concrete block walls are provided to allow personnel access to equipment during maintenance periods. The shield material provided throughout the auxiliary building is regular concrete except for some of the shielding around the reactor coolant filter, which is high-density concrete. The principal auxiliary building shielding provided is tabulated in Table 12.1-2.

12.1.2.6 Control Room Shielding Design

The control room shield consists of the concrete walls and roof of the control room. A plan view of the control room is shown in Figure 1.2-4, and sectional views are shown in Figures 1.2-25 and 1.2-26.

Normal radiation levels in the control room are less than 0.5 mR/hr. The limiting case for shielding design is post-DBA conditions. The control room shielding is designed to limit the integrated doses under postaccident conditions to less than or equal to 2.5 rem to the whole body, which is well below the value of 5 rem specified in 10 CFR 50, General Design Criterion (GDC) 19.

12.1.2.7 Technical Support Center Shielding Design

The Technical Support Center is designed to be habitable throughout the course of a DBA. Concrete shielding in the walls, roof, and floor is designed to limit the integrated doses under postaccident conditions to less than or equal to 2.5 rem to the whole body, consistent with the criterion for the control room.

12.1.2.8 Postaccident Sampling Compartment

The sampling compartment is shielded from external sources by concrete walls and concrete support columns. Personnel should be able to perform necessary postaccident sampling operations without experiencing a radiation dose exceeding the limits specified in NUREG-0737.

12.1.2.9 Old Steam Generator Storage Facility

The old steam generators (OSGs) and old reactor vessel head assemblies (ORVHAs) were removed from DCPP Units 1 and 2 during the steam generator and reactor vessel head replacement projects. These ten large components are temporarily stored in the OSG Storage Facility (OSGSF) specifically constructed for this purpose. The OSGSF meets the radwaste storage requirements for temporary storage of the OSGs and ORVHAs until site decommissioning. The radiological design of the OSGSF meets the radiation shielding requirements of 40 CFR 190, 10 CFR 20, and the DCPP License. The building is designed to have a maximum contact dose rate of 0.2 mR/hr on the exterior wall surface. This value is less than and is bounded by the 0.5 mR/hr radiation dose rate limitation requirement stated in Table 12.1-1 for the Plant Occupancy Zone in which the OSGSF is located (Zone 0 – Unlimited Access). The building design also provides locking access control entrance doors and concrete labyrinths designed to provide shielding.

12.1.3 SOURCE TERMS

The normal full power sources utilized for shielding and dose calculations are based on operation for 1 year at a core thermal power of 3568 MWt with an 85 percent capacity factor. The source terms were calculated using the EMERALD-NORMAL (Reference 2) computer code, which is described in detail in Section 15.5.8, and the source terms are assumed to be the maximum that would occur under either the design basis case or the normal operation case (including anticipated operational occurrences); both of these conditions are defined in Chapter 11. The isotopic source terms applicable to dose calculations are listed in the tables in Section 11.1 and Tables 12.1-3 through 12.1-13.

Actual operating configuration is 21 months of operation, with a mixture of fuel with enrichments up to 5 percent, with maximum analyzed burnup of 50,000 MWD/MTU. The EMERALD NORMAL 12-month cycle core inventory results in higher calculated doses. Therefore, it bounds the actual operating configuration.

To review the adequacy of shielding thickness for the shielded compartments, the computer code ISOSHLD (Reference 3) was used. ISOSHLD performs gamma ray shielding calculations for isotopic sources in a wide variety of source and shield configurations. Attenuation calculations are performed by point kernel integration, with attenuation and buildup factors provided for shields with an effective atomic number of from 4 to 82. Section 15.5.9 provides a more detailed description of the code. For these shielding calculations, source and shield configurations were approximated by

cylindrical or slab geometry, and the radiation exposure rates were calculated, using ISOSHLD, at all locations outside the shielded compartments where exposure to plant personnel is possible.

In addition, radiation dose rates were calculated for the storage tanks outside the auxiliary building, i.e., the primary water storage tank and the refueling water storage tank. Exposure rates were calculated, using ISOSHLD, immediately outside the tanks and at the site boundary (800 meters).

The results of these calculations are shown in Table 12.1-14. The calculations are for direct gamma exposure only; at distances such as 800 meters, the contribution from air-scattered gamma rays can increase the total dose rate by as much as a factor of 2 (Reference 4). The calculated exposure rates at the site boundary are small enough that any contribution from air-scattered gamma rays will still produce a negligible result.

12.1.4 AREA MONITORING

The plant's area radiation monitoring system is described in detail in Section 11.4. A brief summary of the important features of this system follows.

The area radiation monitoring system consists of fixed detectors mounted at the locations listed in Table 11.4-1.

The area radiation monitoring system is not required for safe shutdown of the plant. The principal purpose of the system is to alert personnel of increasing radiation levels in the monitored areas. Upon receipt of an alarm, the normal procedure is for operations personnel to investigate the cause and then take any action that is warranted. In general, the area radiation monitors have no automatic functions other than their alarm function. The exceptions to this are the instruments in the spent fuel and new fuel storage areas that automatically transfer the fuel handling building ventilation system to the charcoal filter mode (see Section 9.4.4) and sound an alarm in the hot shop area.

12.1.5 OPERATING PROCEDURES

The operating procedures that ensure external exposures will be kept ALARA can be grouped into three broad categories:

(1) Routine surveillance of the dose rate at various plant locations

(2) Preplanning and procedural control of radiation work

(3) Analysis of dose actually received

Each of these is discussed below:

(1) During the initial startup test program, a series of neutron and gamma dose rate measurements were performed to verify that there are no defects or inadequacies in the shielding that might hinder normal operation and/or maintenance activities. In addition, a comprehensive program of routine gamma dose rate measurements is an integral part of the plant radiation protection program. This information is used to identify areas where special measures may be required to avoid unnecessary radiation exposure, to assist in the preplanning of work, and to help identify equipment malfunctions that lead to increased dose rates. Radiation areas are appropriately posted and/or barricaded in accordance with the requirements of 10 CFR 20 or the plant Technical Specifications (Reference 6).

(2) Under the provisions of the plant Radiation Protection Program, all radiation work is carried out under a radiation work permit. These work permits are instruction sheets intended to ensure that appropriate precautions will be taken during the performance of all radiation work. As such, they specify protective clothing requirements, monitoring requirements, dosimetry requirements, expected radiation conditions, and any special measures required to control the dose received by personnel. Such special measures might include limiting the stay time in an area, erection of temporary shielding, use of remote handling tools, or other techniques appropriate to the specific situations. Personnel are instructed in radiation protection in accordance with specific procedures established in Volume I of the Plant Manual.

(3) Self-reading dosimeters, coupled with the results of the thermoluminescent dosimeters (TLDs) or film badges, are routinely checked by radiation protection personnel to verify that each individual's exposure, as shown on the individual's permanent record, is within expected values. If a person's exposure appears to be higher than estimated, radiation protection personnel investigate and initiate corrective action. Radiation workers are responsible for remaining cognizant of their current exposure status.

12.1.6 ESTIMATES OF EXPOSURE

An assessment of the expected radiation dose to individuals as a result of DCPP operations results in the following general conclusions:

(1) The annual man-rem external exposure in offsite locations resulting from direct shine from plant structures containing radioactive materials is extremely small. For example, the annual continuous occupancy dose at a distance of 800 meters contributed by direct shine from the containment has been calculated to be approximately 1.5 mR using the conservative

assumption that the dose rate on its exterior surface is the maximum design value of 1 mr/hr.

(2) The man-rem exposure to the general public is, for all practical purposes, the result of airborne and liquid releases from the radioactive waste disposal system. Although this exposure is expected to be very low, numerical estimates have been made and are presented in Sections 11.2.9 and 11.3.9 for liquid and gaseous releases, respectively.

(3) Estimates of personnel exposures have been obtained from surveys of exposure at other operating plants and from calculations based on anticipated occupancy times for various job classifications in various areas within the plant. The calculated exposures compare reasonably well with those experienced at other plants.

12.1.6.1 Calculated Exposure Estimates

The annual exposure to plant personnel for normal operation of the two units is calculated to be about 50 man-rem. (This information is historical documentation and does not reflect current operating exposures.) This value is derived from anticipated occupancy times for various job classifications in various areas within the plant. The dose rates assigned to the various areas are based on normal plant operation assuming approximately 0.2 percent fuel defects. Table 12.1-15 presents a summary of the calculated values of man-rem exposure on the basis of occupancy factors listed in Table 12.2-17 and dose rates in various areas.

Experience at other pressurized water reactors has shown that normal operational activities generally account for only part of a plant's total exposure. Hence, the total estimated annual dose with both units operating, and including special maintenance and refueling activities, is about 400 man-rem. (This information is historical documentation and does not reflect current operating exposures.)

12.1.6.2 Exposure Estimates Based on Operating Plant Experience

Reference 5 reports that for 1981 the annual average collective dose from a pressurized water reactor was 652 man-rems.

12.1.6.3 Exposure Estimates for Diablo Canyon

Based on the above described exposure estimates from both analytical predictions and records of exposures at actual operating plants, it is believed that 200 man-rem per year per unit represents a reasonable estimate of the maximum total exposure to be expected for performance of all normal operations, testing, and maintenance at DCPP. The exposure for two-unit operation should be somewhat less than double the value for operation of one unit, since certain facilities, such as the radwaste treatment system,

are common to both units. (This information is historical documentation and does not reflect current operating exposures.)

The regulations of 10 CFR 20 limit the Total Effect Dose Equivalent (TEDE) to 5 rem per year. Pacific Gas and Electric Company limits TEDE to 5 rem per year with guidelines for maintaining doses at levels below this value.

If operating experience reveals areas where exposure problems exist, appropriate changes will be made in plant shielding, source strengths, locations, or operating practices as required to maintain personnel doses ALARA.

12.1.7 REFERENCES

1. Diablo Canyon Units 1 and 2 Radiation Shielding Review, Rev. 3, June 1984.

2. S. G. Gillespie and W. K. Brunot, EMERALD NORMAL - A program for the Calculation of Activity Releases and Doses from Normal Operation of a Pressurized Water Plant, Program Description and User's Manual, Pacific Gas and Electric Company, March 1973.

3. R. L. Engel, et al, ISOSHLD - A Computer Code for the General Purpose Isotope Shielding Analysis, BNWL-236, UC-34, Physics, Pacific Northwest Laboratory, Richland, Washington, June 1966.

4. Reactor Handbook, Second Edition, Volume III, Part B, Oak Ridge National Laboratory, 1962.

5. Occupational Radiation Exposure at Commercial Nuclear Power Reactors 1981, NUREG-0713, Vol. 3, Nov. 1982.

6. Technical Specifications, Diablo Canyon Power Plant Units 1 and 2, Appendix A to License Nos. DPR-80 and DPR-82, as amended.

7. NUREG 0737, Clarification of TMI Plan Requirements, USNRC, November 1980.

12.2 VENTILATION

The ventilation systems at DCPP are designed to provide a suitable environment for personnel and equipment during normal plant operation, including anticipated operational occurrences. Parts of the ventilation system also perform safety-related functions such as cooling of engineered safety feature (ESF) motors, postaccident containment heat removal, and ensure postaccident control room and Technical Support Center habitability. These are described in detail in Section 9.4. The portions of the ventilation systems designed to remove radioactive materials from the ventilation flows prior to release to the atmosphere are described below, together with the assumptions made to calculate airborne activity concentrations.

12.2.1 DESIGN OBJECTIVES

The overall design objectives of the ventilation systems from the standpoint of control of airborne radioactive materials are to:

(1) Maintain airborne radioactive material concentrations in normal work areas in the auxiliary building and fuel handling area within the values provided in 10 CFR 20.1-20.601 and maintain airborne radioactive material concentrations in normal work areas in the turbine building within the maximum permissible concentration (MPC) values given in Appendix B, Table I, of 10 CFR 20.1-20.601

(2) Operate in conjunction with other gaseous waste disposal equipment to ensure that the dose from concentrations of airborne radioactive materials in unrestricted areas beyond the site boundary are within the limits specified in Appendix I to 10 CFR 50

(3) Provide the ability to maintain and/or reduce the airborne radioactive material concentrations in normally unoccupied areas within the plant structure to levels that will allow periodic access as required for nonroutine work

(4) Ensure that the dose restrictions of 10 CFR 100 are satisfied following a DBA

(5) Ensure that the control room and Technical Support Center remain habitable following a DBA in accordance with the requirements of 10 CFR 50 and GDC 19.

12.2.2 DESIGN DESCRIPTION

The following paragraphs present brief descriptions of the ventilation systems for each of the major plant structures. The descriptions include building volumes, flowrates, and filter characteristics used when estimating airborne activity concentrations in the various

plant areas. As noted, more complete design descriptions of the ventilation systems can be found in Section 9.4.

12.2.2.1 Containment Ventilation Systems

The systems provided for ventilation of the atmosphere inside the containment, including design criteria, are discussed in detail in Sections 6.2.3 and 9.4 and include:

(1) Containment purge supply and exhaust system

(2) Containment fan coolers

(3) Iodine removal units

The containment purge system includes a single supply fan and a single exhaust fan. Supply air is drawn from the atmosphere through a roughing filter. The purge exhaust fan draws air from the main ventilation header in the containment and exhausts it to the plant vent, from which it is released to atmosphere at the top of the containment. The purge exhaust air is not filtered. This system is not in continuous operation during power operation, but is provided for use on a periodic basis as required prior to personnel entry.

Five fan cooler units are provided in the containment. The principal purpose of these units is to recirculate and cool the containment atmosphere during normal operation and following a DBA.

Each containment building is provided with two iodine removal units consisting of a recirculation fan complete with roughing filter, HEPA filter, and charcoal filter on the fan suction. These units are operated as required during normal operation to control airborne iodine and particulate concentrations in the containment atmosphere.

Parameters used for the containment airborne activity concentration analysis are presented in Table 12.2-12.

12.2.2.2 Control Room Ventilation System

A detailed description of the control room ventilation system, including design criteria, is provided in Section 9.4.1. Briefly, it consists of the equipment necessary to provide the following modes of operation:

(1) Mode 1 - 73 percent of the control room air is recirculated, 27 percent of the air is outside makeup, and 100 percent of the air is passed through roughing filters.

(2) Mode 2 - 100 percent of the air is outside makeup, passed through roughing filters, and is used to purge smoke from the control room in the event of a fire.

(3) Mode 3 - control room is isolated from outside air. 100 percent of air is recirculated with 27 percent passing through HEPA and charcoal filters. Mode 3 operation is manually initiated on human detection, i.e., odor/smell by control room operators.

(4) Mode 4 - used in the event of airborne radioactivity and the requirement of long-term occupancy of the control room. This mode isolates and pressurizes the control room and mechanical equipment room through the HEPA and charcoal filters with outside air to reduce local infiltration. The Mode 3 recirculation train operates concurrently.

The design of the control room ventilation system ensures that the control room will remain habitable during postaccident operation in accordance with the requirements of 10 CFR 50, Appendix A, Criterion 19.

Parameters used for the analysis are presented in Table 12.2-2.

12.2.2.3 Auxiliary Building Ventilation System

The auxiliary building ventilation system is described in detail in Section 9.4.2. Briefly, the system for each unit contains two full-capacity supply fans that draw air from the atmosphere just above the auxiliary building and then discharge it to the occupied areas of the building and to the ESF pump compartments whenever they are in operation. Two full-capacity exhaust fans draw air from various locations throughout the building and discharge it to the plant vent, where it is released at the top of the containment.

Under normal circumstances, the exhaust air is passed through a roughing filter and HEPA filter prior to entering the vent. Under accident conditions (as indicated by a safety injection signal), the air exhausted from the ESF pump compartments is passed through a charcoal filter in addition to the roughing and HEPA filters. Exhaust air from other portions of the building will continue to be passed through roughing and HEPA filters only. If only one supply/exhaust fan set is available under accident conditions, exhaust air from areas other than the safety feature pump compartments will be isolated.

In all modes of operation, the ventilation flow patterns are designed so that the air flows from areas of lower potential contamination to areas of higher potential contamination. The system is balanced so that the building is normally under a slight negative pressure.

Parameters used for the analysis are presented in Table 12.2-3.

12.2.2.4 Fuel Handling Building Ventilation System

The fuel handling building ventilation system, including design criteria, is described in detail in Section 9.4.4. Two full-capacity supply fans discharge into duct work in the corridors and equipment compartments below the spent fuel pool floor. Three full-capacity exhaust fans are provided. They collect air from along one side of the pool, just above the surface. In this manner, the air provides a sweeping action over the surface of the pool. During normal operation, one nonvital exhaust fan is in operation and the air is passed through a roughing and HEPA filter before being discharged to the plant vent. Under accident conditions, as sensed by high radiation on the area radiation monitors in the vicinity, one of two vital exhaust fans are placed in operation and the exhaust flow is passed through a charcoal filter in addition to the roughing and HEPA filters.

Parameters used for the airborne activity concentration analysis are given in Table 12.2-4.

12.2.2.5 Turbine Building Ventilation

Ventilation in the turbine building is provided by a number of cabinet fans mounted on the exterior wall of the building. These fans draw air from the surrounding atmosphere into the building through roughing filters. The air is discharged from the roof of the building without treatment. This system, described in Section 9.4.3, is intended only to provide personnel comfort since the potential for introduction of airborne radioactivity into the turbine building, as a result of water or steam leakage from the steam system, is very low. It should be noted in this regard that the condenser air ejector discharge, which could be a point of release of radioactive materials in the event of steam generator tube leakage, is piped to the plant vent.

The volume of the turbine building served by the cabinet fans is 5.125×10^6 cubic feet (one unit). The ventilation flowrate is 420,000 cfm.

12.2.2.6 Technical Support Center Ventilation

The TSC is provided with its own ventilation system in which air supplied from the control room pressurization system is passed through HEPA and charcoal filters. The redundant Class I control room pressurization fans supply air to the TSC which can be maintained at a positive pressure of about 1/8-inch H_20. Self-contained air conditioning units are also provided for the offices, the operations center, and the laboratory areas. A detailed description of the system is provided in Section 9.4.11.

12.2.2.7 Postaccident Sampling Compartment Ventilation

One of two 100-percent capacity, redundant, pressurization fans will deliver 1000 cfm of charcoal-filtered outside air to the complex. One of two 100-percent capacity, redundant exhaust fans will discharge 700 cfm of charcoal-filtered air to the

atmosphere. The differential of 1000 cfm delivered air and 700 cfm discharged air maintains a positive pressure in the complex.

12.2.3 SOURCE TERMS

The following sections describe the source terms used to estimate the airborne radioactivity levels for normal operation in areas within plant structures, including each building in the reactor facility.

12.2.3.1 Auxiliary Building Source Terms

The auxiliary building ventilation system has been designed to prevent the transport of airborne radioactive materials into normal work areas. For example, equipment representing potential sources is located in compartments off the main corridors, with the ventilation flow directed from the corridors to the compartments and then to the plant vent. As a result, the occurrence of a situation wherein an equipment leak would introduce radioactive materials into the air of a normally occupied area is minimized. However, for purposes of estimating the maximum air activity concentrations that could occur in normally occupied operating spaces of the auxiliary building, the following source terms were assumed:

(1) Two-unit leakage of 20 gpd per unit of primary coolant at 0.2 percent fuel defects uniformly distributed in the auxiliary building main corridors (volume = 370,000 cubic feet) with a ventilation exhaust flow of 75,000 cfm

(2) Partition factors of 0.005 for iodines, 1 for noble gases, and 0.26 for tritium as tritiated water (HTO).

No credit is taken for condensation of HTO or plateout of iodines.

The results of this analysis are presented in Table 12.2-5.

Certain individual rooms within the auxiliary building contain reactor auxiliary equipment that can potentially generate the maximum airborne activity concentrations expected at any time during normal operating conditions. These areas are the CVCS letdown heat exchanger room, the volume control tank room, the charging pump rooms, and the gas decay tank rooms. Occasional entry may be required into these areas during the course of normal operations for maintenance or repair purposes. Access to these areas will be under strict procedural control at all times. Thorough radiation surveys will be conducted prior to access to these spaces so that necessary controls can be prescribed to limit personnel exposure. It should be emphasized that the airborne activity concentrations calculated for these rooms are the maximum that could occur in spaces where access is strictly controlled, and do not reflect the anticipated concentrations in areas of normal occupancy.

The source term for the CVCS letdown heat exchanger room is based on the following assumptions:

(1) CVCS leakage of 1 gpd of hot primary coolant at 0.2 percent fuel defects occurs upstream of the letdown heat exchanger

(2) The volume of the compartment is taken to be 6500 cubic feet with a ventilation flowrate of 1200 cfm

(3) Partition factors of 0.10 for iodines, 1 for noble gases, and 0.35 for tritium as HTO are assumed

The source term for the volume control tank room is based on the following assumptions:

(1) CVCS leakage of 10 gpd of cold primary coolant at 0.2 percent fuel defects occurs upstream of the tank

(2) The room volume is taken to be 2140 cubic feet with a ventilation flowrate of 600 cfm

(3) Partition factors are assumed to be 0.001 for iodines, 1 for noble gases, and 0.01 for tritium as HTO

The source term for the charging pump compartment is based on the following assumptions:

(1) CVCS leakage of 10 gpd of cold primary coolant at 0.2 percent fuel defects occurs upstream of the pump

(2) The compartment volume is taken to be 3900 cubic feet with a ventilation flowrate of 400 cfm

(3) Partition factors of 0.001 for iodines, 1 for noble gases, and 0.01 for tritium as HTO are assumed

The source term for the gas decay tank compartment is based on the following assumptions:

(1) Gas decay tank leakage of 0.01 scfm is assumed with tank activity inventory as shown in Table 11.3-5

(2) The compartment volume is taken to be 3490 cubic feet with a ventilation flowrate of 40 cfm

(3) A partition factor of 1 is assumed for noble gases at the leakage point

The resulting maximum airborne activity concentrations in these spaces during normal operation are summarized in Tables 12.2-6 through 12.2-9. (Note that the actual ventilation flowrates for the above rooms are higher than the assumed values used for the source term analysis. The higher flowrates would result in lower airborne activity concentrations in these spaces and would be enveloped by the values shown in Tables 12.2-6 through 12.2-9.)

12.2.3.2 Fuel Handling Area Source Term

Airborne activity in the fuel handling area is produced primarily from tritium evaporation and iodine and noble gas partitioning from the spent fuel pool. The evaporation of tritium is discussed in Section 11.2.2, and the calculated airborne tritium concentrations above the spent fuel pool as a function of plant operating time are shown in Figure 11.2-7. The iodine and noble gas releases from the spent fuel pool are based on the following assumptions:

(1) Fuel handling area volume of 4700 cubic feet with a ventilation flowrate of 35,750 cfm

(2) Partition factors of 0.001 for iodines and 1 for noble gases

(3) Spent fuel pool activity concentrations and production rates are listed in Table 12.2-10

The resulting airborne activity concentrations during normal operation in the fuel handling areas are summarized in Table 12.2-11.

12.2.3.3 Containment Source Term

The source term for containment airborne activity during normal operation is based on the following assumptions:

(1) Leakage of 240 lb/day of primary coolant at 0.2 percent fuel defects

(2) Partition factors of 0.10 for iodines, 1 for noble gases, and 0.35 for tritium as HTO at the leakage point

(3) Ninety days of activity accumulation. No credit taken for plateout, containment leakage, cleanup recirculation unit operation, or other activity removal except natural decay

The resulting airborne activity concentrations are listed in Table 12.2-12.

12.2.3.4 Turbine Building Source Term

The source term for the turbine building is based on the following assumptions:

(1) Two-unit main steam leakage of 1700 lb/hr per unit and condenser water leakage of 5 gpm per unit into the turbine building based on 20 gpd per unit of primary-to-secondary system leakage of primary coolant with 0.2 percent fuel defects

(2) Partition factors of 1 for noble gases, iodines, and tritium for steam leakage at the point of leakage

(3) Partition factors of 0.001 for iodines and 0.01 for tritium as HTO for condenser water leakage

(4) Turbine building volume of 10.25 x 10^6 cubic feet with a ventilation flowrate of 840,000 cfm (two units)

The resulting airborne activity concentrations during normal operation are listed in Table 12.2-13.

12.2.3.5 Control Room Source Term

The source term for the control room is assumed to result from the total plant gaseous waste releases as indicated in Table 11.3-3. The airborne activity concentration at the control room intake is calculated using an assumed annual average χ/Q of 1.78 x 10^{-4} sec/m^3, and the total gaseous release from both units.

The source term for the control room itself is calculated using the following assumptions:

(1) Intake airborne activity concentrations as provided in Table 12.2-14

(2) Control room Mode 1 operation with intake and exhaust flowrates assumed to be 4200 cfm. The control room volume is taken as 125,000 cubic feet

(3) No credit is taken for filtration or other removal of activity from the incoming air

The resulting control room airborne activity concentrations for normal operation are presented in Table 12.2-15.

12.2.3.6 Technical Support Center Source Term

The TSC airborne activity concentrations for normal operation are expected to be similar to those in the control room.

12.2.4 AIRBORNE RADIOACTIVITY MONITORING

The instruments and methods used for airborne radioactivity monitoring include certain channels in the process monitoring system, the plant area monitoring system, continuous air monitors (CAMs), and portable low volume air samplers.

12.2.4.1 Process and Area Monitoring Systems

The process and area monitoring systems (including particulate collection) as well as instruments designed to continue functioning during off-normal events and emergencies are described in detail in Section 11.4. The monitors, with their readout locations, are also listed in Table 11.4-1.

Based on operational data, permanently installed air particulate and gas monitors (APGMs) may be correlated against air samples collected in close proximity to the sample collection point. After more than two decades of plant operations, experience has shown that the vast majority of such samples are statistically indistinguishable from background, making such correlations at these levels of little value. When taken, however, these grab samples are gross counted and analyzed for isotopic and quantification as appropriate. The response of the APGMs during the period of grab sampling may be correlated to the total μCi/cc measured in the grab sample and this correlation may be used to develop the instrument response in counts per minute (CPM) versus concentration in μCi/cc. The effect of ambient background is taken into account.

Correlation frequencies may be established that are appropriate for the specific instrument involved based on considerations such as likely variation in isotopic mixture, history of the instrument in terms of calibration shift, use of the instrument for quantitative work, and the potential for a statistically significant measured value above background resulting from licensed material.

12.2.4.2 Grab Sampling Program

The grab sampling program consists of collection of air moisture for tritium analysis and air for noble gas particulate and halogen analysis. The location and frequency of the samples are determined based on the potential for a statistically significant measured value above background resulting from licensed material. Some samples may be scheduled on a periodic basis. Samples for particulate and halogen activities are collected on fixed filters backed up by a triethylenediamine (TEDA)-impregnated charcoal or a silver zeolite cartridge. Air is passed through these sample collectors using a constant flowrate pump. The filters and charcoal cartridges are changed out for laboratory analysis.

12.2.4.2.1 Tritium and Noble Gas Analyses

Collection of air moisture for tritium analysis and air for noble gas analysis may be performed during certain activities such as flood up of the reactor cavity and subsequent fuel movement. DCPP radiation control procedures define the scope, procedure, and frequency of these analyses.

12.2.4.3 Continuous Air Monitors

Portable CAMs may be used at selected locations as part of the airborne radioactivity surveillance program. Use of the CAMs is based on the potential for airborne as a result of plant conditions or work activities.

12.2.5 OPERATING PROCEDURES

The grab air sampling program and the use of portable CAMS are described in DCPP procedures.

12.2.6 ESTIMATES OF INHALATION DOSES

The calculations of in-plant inhalation and immersion doses to plant operating and maintenance personnel are based on the estimated airborne concentrations for plant areas presented in Tables 12.2-5 through 12.2-15 and on the estimated occupancy factors for these areas presented in Table 12.2-17. The dose to plant personnel also depends on engineering controls to minimize airborne concentrations, on the type of respiratory protection equipment, if any, being worn, and on other administrative procedures such as purging of contaminated areas, limiting occupancy, etc. Note: These calculations are historical in nature and were completed prior to the 1994 new 10 CFR 20. At that time the concept of maximum permissible concentration (MPC) based on a presumed chronic uptake and resultant body burdens over the years was dropped and replaced by the concept of the derived concentration (DAC) based on annual dose limits and the assumption of acute rather than chronic exposures. Although prior to 1994 compliance was demonstrated by the number of MPC hours accumulated in a week, the tables in the FSAR reflect doses that are very conservatively calculated and far higher than what has historically been encountered during more than 2 decades of operation. These doses are still bounding and the MPC values will not be replaced with DACs.

The newer values and definitions are currently contained in 10 CFR 20 and included in plant procedures as appropriate.

Respiratory protective equipment may be used to limit dose from iodine, and particulates in accordance with 10 CFR 20 requirements. Tritium dose may be limited by either respiratory protection and protective suits to reduce the effective concentration

below the 10 CFR 20 level, or by limiting personnel occupancy in areas of high concentration.

The estimated inhalation and immersion doses to plant personnel for normal full power operation are presented in Table 12.2-18 in units of person-rem/year.

It should be noted that the calculated doses to plant personnel in Table 12.2-18 are conservative estimates and, in view of the strict administrative controls over personnel dose due to the conservative assumptions used in the calculation of the source terms listed in Section 12.2.3, are much higher than would be expected under normal operating conditions. In particular, the assumptions for primary coolant leakage to the auxiliary building are extremely conservative, since continuous leakage of 20 gpd into the corridors and into three compartments simultaneously is assumed, giving a total leakage rate twice that of the anticipated operational occurrences case.

It is expected that personnel inhalation dose will be low and essentially negligible in comparison to external dose. The inhalation doses at offsite locations are the result of releases of gaseous waste. These doses are referred to in Section 11.3.

12.3 HEALTH PHYSICS PROGRAM

This section describes the objectives, facilities and equipment, and dosimetry methods and procedures related to radiation protection of personnel at the Diablo Canyon Power Plant (DCPP).

12.3.1 PROGRAM OBJECTIVES

The plant operating organization is described in Section 13.1.2 and illustrated in Figure 13.1-2. The Radiation Protection Manager is responsible for administering, coordinating, planning, and scheduling all radiation protection activities at the plant. The Chemistry and Environmental Operations Manager is responsible for administrating, coordinating, planning and scheduling all chemistry, radiochemistry, and environmental activities at the plant.

The principal objectives of the Radiation Protection Program are to:

(1) Establish programs to help minimize the radiation dose to personnel consistent with the objective of operation of the plant in a safe, reliable, and efficient manner

(2) Ensure compliance with all applicable regulations and PG&E policies pertaining to radiation protection and release of radioactive materials

The Radiation Protection Program for the plant is carried out in accordance with PG&E's program directives. The program directives are statements of the policy covering each aspect of the Radiation Protection Program and are based on appropriate NRC regulations. The program directives are implemented by various interdepartmental and department level administrative procedures and working level procedures contained in the Plant Manual. All personnel whose work involves the potential for exposure to radiation or radioactive materials receive training, commensurate with their risk, in radiation safety based on these documents.

12.3.2. FACILITIES AND EQUIPMENT

The principal radiation protection facilities for the plant are discussed below.

(1) Access Control

Entrance and exit from the main radiologically controlled areas of the plant are normally made through a central access control point on the 85-foot elevation. This area is used for administratively processing personnel in and out of the radiologically controlled area, as well as providing a final contamination control point between the radiologically controlled area and the rest of the plant. An auxiliary access control, located on the 140 ft elevation, may be utilized to provide more efficient

access into the RCA, including containment buildings. Other access control stations may be temporarily established to support plant operations on an ad hoc basis.

The access controls on the 85 ft and 140 ft elevations include provisions for logging personnel in and out of the radiologically controlled areas on radiation work permits. There is a portal monitor located at the exit of these access controls to serve as a final contamination monitor for personnel exiting the radiologically controlled area. The 85 ft access control area has a decontamination facility that drains into the liquid radwaste system.

(2) Radiochemical Laboratory and Counting Room

These facilities are used for plant chemistry and radiochemistry programs as well as for processing samples for radiation protection analyses. These facilities include detectors tied into a gamma spectroscopy system. Other counters and detectors are available and are used for gross alpha and beta counting and for tritium analyses.

(3) Calibration Facility

A calibration facility is provided for onsite calibration of most of the portable radiation monitoring instrumentation and some of the process monitors. The calibration facility is equipped with an irradiator for routine calibration of gamma-sensitive dose rate instruments. The irradiator is designed so that instruments can be accurately positioned for reproducible dose rates. The irradiator is traceable to the National Institute for Standards and Technology (NIST). Another irradiator is used for calibration of the TLDs and the self-reading dosimeters. The irradiator is traceable to the NIST. Other irradiators, traceable to the NIST may also be used for calibration activities at DCPP. Calibration of instruments is performed using controlled vendor manuals or approved procedures.

In addition to the sources located in the calibration facility, additional sources mounted in standardized geometry fixtures are used for the calibration of process radiation monitoring instruments. These sources are stored in the calibration facility or shielded safes near the chemistry laboratory.

Instruments that cannot be properly calibrated using the available facilities at DCPP are returned to the manufacturer or other appropriate contractors for calibration.

(4) First Aid Room

A medical facility with extensive emergency treatment capability is located in Building 102. The facility is staffed with trained emergency medical personnel. The facility serves as a general first aid area for minor injuries and an interim treatment area for seriously injured personnel until they can be transported to an offsite hospital or care facility. The medical facility has the capability of responding to injured persons who are also radiologically contaminated.

(5) Laboratory

A laboratory adjacent to the TSC may be used for counting in-plant samples if the normal counting room facilities become unusable following a postulated accident. The laboratory is equipped with a gamma spectroscopy system.

(6) Laundry Facility

An onsite laundry facility is provided for on-site cleaning and monitoring of protective clothing and respirators. An offsite laundry service is also used and may be used exclusively. The introduction of single-use protective clothing may significantly reduce or eliminate the need for onsite or offsite laundry services. The laundry facility is located above the solid radwaste storage facility.

The major categories of radiation protection equipment are described below.

(1) Portable radiation survey instruments for alpha, beta, and gamma radiation detection and dose rate instruments for measuring beta, gamma, and neutron dose rates are listed in Table 12.3-1. Some of the dose rate instruments are extended-range instruments to provide emergency monitoring capability.

(2) Air sampling equipment and continuous air monitors are listed in Table 12.3-2. This equipment is described further in Section 12.2.4.

(3) Respiratory protection equipment available for routine and emergency use is listed in Table 12.3-3.

(4) Protective clothing is available for the plant in sufficient quantities to accommodate normal operation, refueling outages, and the initial stages of recovery from a major emergency (1 to 2 weeks).

(5) Several types of emergency, evacuation, and decontamination kits are available at the plant site and at key offsite locations. The contents of the

kits vary according to their intended use and include some or all of the following:

(a) Portable radiation monitoring instruments

(b) Air sampling equipment - some with batteries

(c) Environmental sampling and labeling equipment

(d) Protective clothing and respiratory protection equipment

(e) Portable radio communication equipment

(f) Decontamination supplies

(g) Procedures, maps, area drawings, etc.

12.3.3 PERSONNEL DOSIMETRY

The official and permanent record of accumulated external radiation dose received by individuals is obtained from interpretation of the TLDs. All individuals who are required to be monitored by 10 CFR 20 are issued beta-gamma TLDs and are required to wear them in a radiologically controlled area. TLDs are typically supplied and processed by a contractor. Dosimetry badges are changed on a routine basis, although the TLD of any individual may be processed at any time to determine the individual’s dose status. Extremity or neutron dosimetry, as well as additional TLDs or film badges, are available and are issued as required.

Personnel working in the radiologically controlled areas are provided with a means of estimating their accumulated external dose. Ordinarily, this is accomplished with the use of self-reading dosimeters. Dose estimates are updated daily, or more frequently when conditions warrant. These estimates are replaced by official dose records when the TLDs are analyzed. Information regarding an individual's dose is available so that personnel may keep themselves informed of their current dose status. Reports giving official personnel dose information are available to supervisors. These reports serve as a tool for the supervisor in making future job assignments. Individuals are closely monitored and may be restricted from further radiation work if their dose estimate reaches the administrative guideline, which is set below the dose limits established by 10 CFR 20.

The control of internal exposure to radioactive material will be supplemented by a routine bioassay program consisting of whole body counting and passive monitoring using personnel contamination and portal monitors. Whole body counting is normally performed onsite. Urinalysis performed by an outside contractor may be used on a non-routine confirmatory basis as required. The frequency of sampling depends on the person's potential dose to airborne hazards.

Although engineering controls are normally used to control airborne radioactivity, use of respiratory protection equipment, control of access, limitation of exposure times, or other controls may be required to help maintain personnel exposure as low as is reasonably achievable.

TABLE 12.1-1

PLANT ZONE CLASSIFICATIONS

Zone	Condition of Occupancy	Design Maximum Dose Rate, mrem/hr[a]
O	Unlimited access - areas that do not require controlled access for radiological reasons and can be occupied by plant personnel or visitors on an unlimited time basis	≤ 0.5
I	Normal access - areas to which access is controlled for radiological reasons, but which require, or would permit, continuous occupancy by radiation workers during normal working hours	≤ 1.0
II	Controlled access requiring periodic occupancy	≤ 2.5
III	Controlled access requiring short-term occupancy	≤ 15
IV	Controlled access requiring infrequent occupancy	> 15

(a) Basis: Full power operation of both Units with 1 percent failed fuel.

TABLE 12.1-2

PRINCIPAL AUXILIARY BUILDING SHIELDING

Component	Shielding Thickness, ft-in.					
	Walls					
	N[(a)]	S[(a)]	E[(a)]	W(a)	Floor	Ceiling
Demineralizers	4-0[(b)]	1-0	4-0	3-0	3-0	2-6
Charging pump	2-0	2-0[(b)]	2-6[(b)]	2-6	2-0	2-0
Liquid holdup tanks	2-6[(b)]	2-6	Ground	2-6[(b)]	Ground	2-0
Spent resin tanks	3-4	3-4	3-10	3-10[(b)]	3-0	4-0
Volume control tank	3-0[(b)]	2-6[(b)]	3-0[(b)]	3-0	2-6	2-0
Reactor coolant filter	2-6	2-6	2-0	2-0	2-0	2-0
Gas stripper (on boric acid evaporator) [(c)]	2-0	3-0[(b)]	3-0[(b)]	3-0[(b)]	2-0	3-0
Gas decay tanks	4-0[(b)]	4-0	4-0	3-0	Ground	5-0
Gas compressors	2-0[(b)]	2-0	3-0	2-0[(b)]	Ground	5-0
Waste concentrators	3-0[(b)]	3-0[(b)]	2-0[(b)]	2-0[(b)]	2-0	2-0

(a) Refer to orientation of Unit 1 equipment for directions.

(b) Dimensions identified with (b) are the thicknesses separating the component from potentially occupied areas, and are the limiting thickness from the standpoint of dose rate to personnel.

(c) Equipment is abandoned in place and no longer in service.

TABLE 12.1-3

MAXIMUM ACTIVITY IN LIQUID HOLDUP TANK

Nuclide	Activity, Curies	Concentration, μCi/cc
Cr-51	0.202E 00	0.713E-03
Mn-54	0.167E 00	0.589E-03
Mn-56	0.213E 01	0.752E-02
Co-58	0.537E 01	0.190E-01
Fe-59	0.223E 00	0.787E-03
Co-60	0.169E 00	0.597E-03
Sr-89	0.543E 00	0.192E-02
Sr-90	0.259E-01	0.916E-04
Sr-91	0.274E 00	0.969E-03
Sr-92	0.510E-01	0.180E-03
Y-90	0.315E-01	0.111E-03
Y-91	0.106E 01	0.375E-02
Y-92	0.159E 00	0.563E-03
Zr-95	0.693E 00	0.245E-02
Nb-95	0.687E 00	0.242E-02
Mo-99	0.144E 03	0.509E 00
Te-132	0.518E 02	0.183E 00
Cs-134	0.402E 02	0.142E 00
Cs-136	0.153E 01	0.539E-02
Cs-137	0.623E 02	0.220E-00
Ba-140	0.750E 00	0.265E-02
La-140	0.289E 00	0.102E-02
Ce-144	0.688E-01	0.243E-03
Pr-144	0.688E-01	0.243E-03
I-131	0.492E 03	0.174E 01
I-132	0.944E 02	0.333E 00
I-133	0.707E 03	0.250E 01
I-134	0.418E 01	0.147E-01
I-135	0.281E 03	0.994E 00
Kr-83M	0.163E 02	0.574E-01
Kr-85	0.175E 04	0.617E 01
Kr-85M	0.223E 03	0.789E 00
Kr-87	0.273E 02	0.965E-01
Kr-88	0.260E 03	0.920E 00
Xe-133	0.510E 05	0.180E 03
Xe-133M	0.575E 03	0.203E 01
Xe-135	0.188E 04	0.664E 01
Xe-135M	0.877E-03	0.310E-05
Xe-138	0.747E-03	0.264E-05

TABLE 12.1-4

MAXIMUM ACTIVITY IN RCS CHARGING PUMP

Nuclide	Concentrations, μCi/cc
Cr-51	0.7160E-03
Mn-54	0.5890E-03
Mn-56	0.2210E-01
Co-58	0.1900E-01
Fe-59	0.7890E-03
Co-60	0.5970E-03
Sr-89	0.1922E-02
Sr-90	0.9162E-04
Sr-91	0.1289E-02
Sr-92	0.5030E-03
Y-90	0.1121E-03
Y-91	0.3755E-02
Y-92	0.6316E-03
Zr-95	0.2450E-02
Nb-95	0.2424E-02
Mo-99	0.5301E 00
Te-132	0.1895E 00
Cs-134	0.1420E 00
Cs-136	0.5440E-02
Cs-137	0.2201E-00
Ba-140	0.2673E-02
La-140	0.9010E-03
Ce-144	0.2430E-03
Pr-144	0.2430E-03
I-131	0.1761E 01
I-132	0.6456E 00
I-133	0.2851E 01
I-134	0.3620E 01
I-135	0.1503E 00
Kr-83M	0.2547E 00
Kr-85	0.6158E 01
Kr-85M	0.1481E 01
Kr-87	0.8558E 00
Kr-88	0.2502E 01
Xe-133	0.1839E 03
Xe-133M	0.2135E 01
Xe-135	0.8441E 01
Xe-135M	0.1322E 00
Xe-138	0.3875E 00

TABLE 12.1-5

MAXIMUM ACTIVITY IN WASTE EVAPORATOR

Nuclide	Activity, Curies	Concentration, μCi/cc
Cr-51	0.360E-08	0.211E-08
Mn-54	0.123E-04	0.723E-05
Mn-56	0.0	0.0
Co-58	0.256E-04	0.150E-04
Fe-59	0.132E-06	0.777E-07
Co-60	0.254E-04	0.149E-04
Sr-89	0.129E-05	0.756E-06
Sr-90	0.871E-05	0.511E-05
Sr-91	0.0	0.0
Sr-92	0.0	0.0
Y-90	0.871E-05	0.511E-05
Y-91	0.572E-05	0.336E-05
Y-92	0.0	0.0
Zr-95	0.482E-05	0.283E-05
Nb-95	0.102E-04	0.599E-05
Mo-99	0.0	0.0
Te-132	0.0	0.0
Cs-134	0.980E-02	0.575E-02
Cs-136	0.160E-11	0.940E-12
Cs-137	0.208E-01	0.122E-01
Ba-140	0.569E-12	0.334E-12
La-140	0.655E-12	0.384E-12
Ce-144	0.966E-05	0.567E-05
Pr-144	0.966E-05	0.567E-05
I-131	0.290E-14	0.170E-14
I-132	0.144E-35	0.848E-36
I-133	0.0	0.0
I-134	0.0	0.0
I-135	0.0	0.0

TABLE 12.1-6

MAXIMUM ACTIVITY IN BORIC ACID EVAPORATOR [(b)]

Gaseous Activity (In Gas Stripper Condenser)

Isotope	Activity in Feedwater, µCi/cc	Activity in Condenser, µCi/cc
Kr-83m	5.7E-02	1.2E+00
Kr-85	6.2E+00	1.3E+02
Kr-85m	7.9E-01	1.7E+01
Kr-87	9.6E-02	2.0E+00
Kr-88	9.2E-01	1.9E+01
Xe-133	1.8E+02	3.8E+03
Xe-133m	2.0E+00	4.3E+01
Xe-135	6.6E+00	1.4E+02
Xe-135m	3.1E-06	6.5E-05
Xe-138	2.6E-06	5.5E-05

Liquid Activity (In Concentrates Holding Tank) [(b)]

Isotope	Activity in[(a)] Feedwater, µCi/cc	Activity in Condenser, µCi/cc
I-131	1.7E-02	2.8E-02
I-132	3.3E-03	2.8E-03
I-133	2.5E-02	3.1E-02
I-134	1.5E-04	0.0
I-135	9.9E-03	6.0E-02
Mo-99	5.1E-03	7.8E-02
Cs-134	7.1E-03	1.2E-01
Cs-137	1.1E-02	1.2E-01

(a) Isotopes with small activity are not listed.

(b) Equipment is abandoned in place and no longer in service.

TABLE 12.1-7

MAXIMUM ACTIVITY IN SPENT FUEL POOL[a]

Nuclide	Activity, Curies	Concentration, μCi/cc
Cr-51	9.59E-04	6.98E-08
Mn-54	8.46E-04	6.15E-08
Mn-56	1.18E-10	8.58E-15
Co-58	2.66E-02	1.94E-06
Fe-59	1.09E-03	7.92E-08
Co-60	8.59E-04	6.25E-08
Kr-83M	0.0	0.0
Kr-85M	0.0	0.0
Kr-85	0.0	0.0
Kr-87	0.0	0.0
Kr-88	0.0	0.0
Sr-89	2.96E-03	2.15E-07
Sr-90	1.47E-04	1.07E-08
Y-90	2.36E-04	1.72E-08
Sr-91	1.58E-05	1.15E-09
Y-91	9.03E-03	6.57E-07
Sr-92	1.74E-06	1.26E-10
Y-92	6.85E-07	4.99E-11
Zr-95	3.81E-03	2.77E-07
Nb-95	3.89E-03	2.83E-07
Mo-99	6.33E-01	4.61E-05
I-131	3.37E 00	2.46E-04
Te-132	2.48E-01	1.80E-05
I-132	2.57E-01	1.87E-05
I-133	6.62E-01	4.82E-05
X-133M	0.0	0.0
X-133	0.0	0.0
Cs-134	2.23E-01	1.62E-05
I-134	1.28E-03	9.29E-08
I-135	7.25E-03	5.28E-07
Xe-135M	0.0	0.0
Xe-135	0.0	0.0
Cs-136	9.55E-03	6.95E-07
Cs-137	4.60E-01	3.35E-05
Xe-138	0.0	0.0
Ba-140	3.63E-03	2.64E-07
La-140	3.19E-03	2.32E-07
Ce-144	3.87E-04	2.82E-08
Pr-144	3.87E-04	2.82E-08

(a) Basis: Primary coolant with 1 percent fuel defects, three days decay, and purification by the CVCS demineralizers, at a flowrate of 120 gpm, is dispersed in the refueling water. A 15 percent mixing of the spent fuel pool with the refueling water is assumed.

TABLE 12.1-8

MAXIMUM ACTIVITY IN MONITOR TANK AND WASTE CONDENSATE TANK

	Monitor Tank		Waste Condensate Tank	
Nuclide	Activity, Curies	Concentration, μCi/cc	Activity, Curies	Concentration, μCi/cc
H-3	0.200E 02	0.211E 00	0.120E 02	0.211E 00
Cr-51	0.665E-07	0.703E-09	0.399E-07	0.703E-09
Mn-54	0.556E-07	0.588E-09	0.334E-07	0.588E-09
Mn-56	0.192E-07	0.203E-09	0.115E-07	0.203E-09
Co-58	0.179E-05	0.189E-07	0.107E-05	0.189E-07
Fe-59	0.738E-07	0.780E-09	0.443E-07	0.780E-09
Co-60	0.565E-07	0.597E-09	0.339E-07	0.597E-09
Sr-89	0.200E-06	0.211E-08	0.120E-06	0.211E-08
Sr-90	0.963E-08	0.102E-09	0.578E-08	0.102E-09
Sr-91	0.371E-07	0.392E-09	0.222E-07	0.392E-09
Sr-92	0.559E-09	0.590E-11	0.335E-09	0.590E-11
Y-90	0.962E-05	0.102E-06	0.577E-05	0.102E-06
Y-91	0.353E-03	0.373E-05	0.212E-03	0.373E-05
Y-92	0.329E-05	0.348E-07	0.198E-05	0.348E-07
Zr-95	0.255E-06	0.270E-08	0.153E-06	0.270E-08
Nb-95	0.255E-06	0.269E-08	0.153E-06	0.269E-08
Mo-99	0.420E-04	0.444E-06	0.252E-04	0.444E-06
Te-132	0.154E-04	0.162E-06	0.922E-05	0.162E-06
Cs-134	0.552E-02	0.584E-04	0.331E-02	0.584E-04
Cs-136	0.269E-03	0.284E-05	0.161E-03	0.284E-05
Cs-137	0.114E-01	0.120E-03	0.682E-02	0.120E-03
Ba-140	0.269E-06	0.284E-08	0.161E-06	0.284E-08
La-140	0.144E-06	0.152E-08	0.865E-07	0.152E-06
Ce-144	0.255E-07	0.269E-09	0.153E-07	0.269E-09
Pr-144	0.255E-07	0.269E-09	0.153E-07	0.269E-09
I-131	0.157E-02	0.165E-04	0.939E-03	0.165E-04
I-132	0.220E-04	0.233E-06	0.132E-04	0.233E-06
I-133	0.152E-02	0.161E-04	0.912E-03	0.161E-04
I-134	0.307E-09	0.325E-11	0.184E-09	0.325E-11
I-135	0.235E-03	0.248E-05	0.141E-03	0.248E-05

TABLE 12.1-9

MAXIMUM ACTIVITY IN SPENT RESIN TANK

Nuclide	Activity, Curies
Cr-51	5.95E-01
Mn-54	1.40E 00
Mn-56	3.28E-01
Co-58	2.36E 01
Fe-59	7.92E-01
Co-60	1.72E 00
Sr-89	2.06E 00
Sr-90	2.75E-01
Y-90	2.81E-01
Sr-91	2.48E-01
Y-91	3.03E 00
Sr-92	3.83E-02
Y-92	4.49E-02
Zr-95	2.94E 00
Nb-95	3.73E 00
Mo-99	1.61E 02
I-131	6.29E 02
Te-132	5.89E 01
I-132	8.82E 01
I-133	6.52E 02
Cs-134	8.94E 00
I-134	2.76E 03
I-135	1.95E 02
Cs-136	3.52E 00
Cs-137	6.41E 02
Ba-140	1.77E 00
La-140	1.22E 00
Ce-144	5.38E-01
Pr-144	5.38E-01

TABLE 12.1-10

MAXIMUM ACTIVITY IN WASTE CONCENTRATES TANK

Nuclide	Activity, Curies	Concentration, μCi/cc
H-3	0.216E 00	0.570E-01
Cr-51	0.719E-03	0.190E-03
Mn-54	0.627E-03	0.166E-03
Mn-56	0.222E-06	0.586E-07
Co-58	0.198E-01	0.524E-02
Fe-59	0.812E-03	0.214E-03
Co-60	0.638E-03	0.169E-03
Kr-83M	0.0	0.0
Kr-85M	0.0	0.0
Kr-85	0.0	0.0
Kr-87	0.0	0.0
Kr-88	0.0	0.0
Sr-89	0.551E-03	0.145E-03
Sr-90	0.272E-04	0.718E-05
Y-90	0.171E-04	0.453E-05
Sr-91	0.668E-05	0.176E-05
Y-91	0.121E-03	0.320E-04
Sr-92	0.194E-08	0.513E-09
Y-92	0.178E-05	0.470E-06
Zr-95	0.708E-03	0.187E-03
Nb-95	0.720E-03	0.190E-03
Mo-99	0.711E-01	0.188E-01
I-131	0.378E 00	0.999E-01
Te-132	0.295E-01	0.780E-02
I-132	0.313E-01	0.828E-02
I-133	0.109E 00	0.289E-01
Xe-133M	0.0	0.0
Xe-133	0.0	0.0
Cs-134	0.303E-01	0.802E-02
I-134	0.636E-13	0.168E-13
I-135	0.157E-02	0.414E-03
Xe-135M	0.0	0.0
Xe-135	0.0	0.0
Cs-136	0.138E-02	0.364E-03
Cs-137	0.643E-01	0.170E-01
Xe-138	0.0	0.0
Ba-140	0.689E-03	0.182E-02
La-140	0.582E-03	0.154E-03
Ce-144	0.717E-04	0.189E-04
Pr-144	0.717E-04	0.189E-04

TABLE 12.1-11

MAXIMUM ACTIVITY IN RADWASTE SYSTEM DRAIN TANKS

Nuclide	Equipment Drain Receiver Tank Concentration, μCi/cc	Floor Drain Receiver Tank Concentration, μCi/cc
H-3	0.74E 01	0.23E-02
Cr-51	0.26E-03	0.79E-05
Mn-54	0.22E-03	0.66E-05
Mn-56	0.81E-02	0.10E-04
Co-58	0.70E-02	0.21E-03
Fe-59	0.29E-03	0.88E-03
Co-60	0.22E-03	0.68E-03
Sr-89	0.20E-03	0.59E-05
Sr-90	0.94E-05	0.29E-06
Y-90	0.27E-05	0.14E-06
Sr-91	0.12E-03	0.64E-06
Y-91	0.41E-04	0.13E-05
Sr-92	0.47E-04	0.59E-07
Y-92	0.47E-04	0.14E-05
Zr-95	0.25E-03	0.76E-05
Nb-95	0.25E-03	0.76E-05
Mo-99	0.45E-01	0.10E-02
I-131	0.16E 00	0.45E-02
Te-132	0.17E-01	0.41E-03
I-132	0.59E-01	0.59E-03
I-133	0.26E 00	0.32E-02
Cs-134	0.10E-01	0.32E-03
I-134	0.33E-01	0.40E-04
I-135	0.14E 00	0.41E-03
Cs-136	0.54E-03	0.16E-04
Cs-137	0.22E-01	0.68E-03
Ba-140	0.27E-03	0.78E-05
La-140	0.97E-03	0.51E-05
Ce-144	0.25E-04	0.76E-06
Pr-144	0.25E-04	0.76E-06

Nuclide	Chemical Drain Tank Concentration, µCi/cc	Laundry and Hot Shower Tank Concentration, µCi/cc
H-3	0.22E-04	0.22E-05
Cr-51	0.68E-07	0.68E-08
Mn-54	0.59E-07	0.59E-08
Mn-56	0.53E-11	0.53E-12
Co-58	0.19E-05	0.19E-06
Fe-59	0.77E-07	0.77E-08
Co-60	0.60E-07	0.60E-08
Sr-89	0.21E-06	0.21E-07
Sr-90	0.10E-07	0.10E-08
Sr-91	0.44E-08	0.44E-09
Sr-92	0.23E-12	0.23E-13
Y-90	0.11E-07	0.11E-08
Y-91	0.37E-06	0.37E-07
Y-92	0.51E-07	0.51E-08
Zr-95	0.27E-06	0.27E-07
Nb-95	0.27E-06	0.27E-07
Mo-99	0.33E-04	0.33E-05
Te-132	0.12E-04	0.12E-05
Cs-134	0.12E-04	0.12E-05
Cs-136	0.53E-06	0.53E-07
Cs-137	0.24E-04	0.24E-05
Ba-140	0.27E-06	0.27E-07
La-140	0.21E-06	0.21E-07
Ce-144	0.27E-07	0.27E-08
Pr-144	0.27E-07	0.27E-08
I-131	0.15E-03	0.15E-04
I-132	0.19E-04	0.19E-05
I-133	0.58E-04	0.58E-05
I-134	0.75E-21	0.75E-22
I-135	0.10E-05	0.10E-06

TABLE 12.1-12

MAXIMUM ACTIVITY IN PRIMARY WATER STORAGE TANK

Nuclide	Activity, Curies	Concentration, μCi/cc
Cr-51	2.27E-10	3.00E-13
Mn-54	9.21E-10	1.22E-13
Mn-56	0.0	0.0
Co-58	1.47E-07	1.95E-10
Fe-59	4.16E-10	5.49E-13
Co-60	1.18E-09	1.56E-12
Sr-89	1.27E-09	1.67E-12
Sr-90	2.09E-10	2.76E-13
Y-90	1.70E-08	2.25E-11
Sr-91	8.05E-23	1.06E-25
Y-91	2.56E-04	3.39E-07
Sr-92	0.0	0.0
Y-92	3.26E-37	4.30E-40
Zr-95	1.97E-09	2.60E-12
Nb-95	2.96E-09	3.91E-12
Mo-99	6.50E-08	8.58E-11
I-131	7.49E-05	9.89E-08
Te-132	5.01E-08	6.62E-11
I-132	5.18E-08	6.84E-11
I-133	3.55E-10	4.69E-13
Cs-134	5.35E-03	7.07E-06
I-134	0.0	0.0
I-135	5.83E-22	7.71E-25
Cs-136	3.11E-10	2.12E-08
Cs-137	3.58E-10	1.63E-05
Ba-140	4.14E-10	4.11E-13
La-140	4.14E-10	4.72E-13
Ce-144	1.60E-05	5.47E-13
Pr-144	1.23E-02	5.47E-13

TABLE 12.1-13

MAXIMUM ACTIVITY IN REFUELING WATER STORAGE TANK

Nuclide	Activity, Curies	Concentration, μCi/cc
Cr-51	4.19E-07	2.03E-10
Mn-54	6.80E-07	3.30E-10
Mn-56	0.0	0.0
Co-58	1.75E-05	8.51E-09
Fe-59	6.14E-07	2.98E-10
Co-60	7.28E-07	3.53E-10
Sr-89	4.63E-06	2.25E-09
Sr-90	1.01E-06	4.92E-10
Y-90	6.39E-07	3.11E-10
Sr-91	3.31E-12	1.61E-15
Y-91	6.38E-06	3.10E-09
Sr-92	2.29E-21	1.11E-24
Y-92	3.15E-18	1.53E-21
Zr-95	7.22E-06	3.51E-09
Nb-95	1.06E-05	5.17E-09
Mo-99	9.36E-06	4.55E-09
I-131	4.93E-04	2.39E-07
Te-132	4.87E-06	2.36E-09
I-132	8.47E-06	4.12E-09
I-133	9.20E-07	4.47E-10
Cs-134	8.51E-03	4.13E-06
I-134	0.0	0.0
I-135	9.10E-11	4.42E-14
Cs-136	6.52E-05	3.17E-08
Cs-137	1.54E-02	7.45E-06
Ba-140	1.42E-06	6.91E-10
La-140	1.32E-06	6.41E-10
Ce-144	1.74E-06	8.43E-10
Pr-144	1.74E-06	8.43E-10

TABLE 12.1-14

RADIATION EXPOSURE RATES FROM EXTERNAL STORAGE TANKS

Tank	Maximum Dose Rate at Tank Surface, mR/hr	Maximum Dose Rate at 800 meters, mR/hr[(a)]
Primary water storage tank	5.52 E-03	6.47 E-10
Refueling water storage tank	3.18 E-03	7.25 E-10

(a) Direct gamma radiation only (see Section 12.1).

TABLE 12.1-15

CALCULATED ANNUAL MAN-REM EXPOSURE OF PLANT PERSONNEL[a]
3Due to Normal Operation
(This information is historical documentation and does not reflect current operating exposures)

Area	Zone	Expected Dose Rate r/hr	Operators[b]		Chemical and Radiation Protection Technicians[c]		Control Technicians[d]		Electrical and Mechanical Maint. Personnel[e]	
			man-hr/wk	man-rem/wk	man-hr/wk	man-rem/wk	man-hr/wk	man-rem/wk	man-hr/wk	man-rem/wk
1. Control Room	0	1.0×10^{-4}	2000	0.20	10	0.001	300	0.03	0.3	0.0
2. Turbine Building	0	1.0×10^{-4}	700	0.07	10	0.001	1000	0.10	3000	0.30
3. Outside	0	2.0×10^{-5}	150	0.003	50	0.001	100	0.002	2	0.0
4. Aux Bldg Corridors	I	1.0×10^{-4}	700	0.07	2200	0.22	500	0.05	2600	0.26
5. Fuel Handling Area	II	2.5×10^{-4}	2	0.0005	8	0.002	120	0.03	320	0.08
6. Primary Sample Room	III	1.5×10^{-2}	2	0.03	3	0.05	1.00	0.02	6	0.09
7. Containment	IV	1.5×10^{-1}	0.5	0.08	2	0.25	2	0.3	0.3	0.05
8. Volume Control Tank Compartment	IV	5	0.03	0.15	0.2	1.00	0	0	0.2	1.0
9. Charging Pumps	IV	2×10^{-1}	0.60	0.12	0.5	0.10	3	0.6	7.0	1.35
10. Letdown HX	IV	1.5	0.03	0.05	0.20	0.30	0	0.00	0.30	0.50
11. Gas Decay Tanks	IV	0.5	0.04	0.02	0.30	0.15	0	0.00	0.30	0.15

TABLE 12.1-15

Area	Zone	Expected Dose Rate r/hr	Operators[b] man-hr/wk	Operators[b] man-rem/wk	Chemical and Radiation Protection Technicians[c] man-hr/wk	Chemical and Radiation Protection Technicians[c] man-rem/wk	Control Technicians[d] man-hr/wk	Control Technicians[d] man-rem/wk	Electrical and Mechanical Maint. Personnel[e] man-hr/wk	Electrical and Mechanical Maint. Personnel[e] man-rem/wk
Total Man-rem/wk				0.81		2.08		1.132		3.78
Total Man-rem/yr 52 wk/yr				42.00		108.00		59.00		197.00

PLANT ANNUAL TOTAL DUE TO NORMAL OPERATION (including 32 man-rems for supervisors): 406 man-rems[f]

(a) Average work week for all personnel-40 hours.
(b) Two-unit shift crew of 22 people, continuous coverage, 3696 man-hours/week.
(c) 60 chemical and radiation protection technicians, 2400 man-hours/week.
(d) 60 control technicians, 2400 man-hours/week.
(e) 149 man crew, 5960 man-hours/week.
(f) Special maintenance and refueling activities are expected to add another 400 man-rems for a total of 800 man-rems per year.

TABLE 12.2-1

DESIGN VALUES FOR CONTAINMENT VENTILATION SYSTEM

Containment Free Air Volume, ft^3	2.6×10^6
Purge Supply Fan Flow Rate, cfm	50,000
Purge Exhaust Fan Flow Rate, cfm	55,000
Fan Cooler Flow Rate, cfm/Fan Cooler Unit	
Normal operation	110,000
Postaccident	47,000
Iodine Removal Fan Flow Rate, cfm/fan	12,000
HEPA Filter Efficiency for 0.3 m DOP Particles, %	≥ 99.97
Charcoal Filter Efficiency, %[a]	
Elemental iodine	≥ 99
Methyl iodide	≥ 85

(a) Radioactive elemental iodine and radioactive iodide as methyl iodide, respectively. (Efficiency rates are for filters as originally specified. Replacement filters shall comply with the requirements of Regulatory Guide 1.52 and ANSI N509.)

TABLE 12.2-2

DESIGN VALUES FOR CONTROL ROOM VENTILATION SYSTEM

Total Room Volume[(a)], Unit 1 plus Unit 2, ft^3	170,000
Supply Fan Rating, cfm/fan	7,800
Minimum number of operable fans	1/Unit
Recirculation Flowrate Under Accident Conditions, cfm	2,100
HEPA Filter Efficiency for 0.3 m Particles DOP, %	≥ 99.97
Charcoal Filter Efficiency, %[(b)]	
Elemental iodine	≥ 99
Methyl iodide	≥ 85

(a) Includes all areas served by control room ventilation, including control room, computer room, record storage room, control room kitchen, foreman's office, safeguards and HVAC equipment room.

(b) Radioactive elemental iodine and radioactive iodide as methyl iodide, respectively. (Efficiency rates are for filters as originally specified. Replacement filters shall comply with the requirements of Regulatory Guide 1.52 and ANSI N509.)

TABLE 12.2-3

DESIGN VALUES FOR AUXILIARY BUILDING VENTILATION SYSTEM

Auxiliary Building Volume, Unit 1 plus Unit 2, ft^3	1,312,000
Supply Fan Rating, cfm/fan	67,500
Exhaust Fan Rating, cfm/fan	73,500
HEPA Filter Efficiency for 0.3 m Particles DOP, %	≥ 99.97
Charcoal Filter Efficiency, %[(a)]	
Elemental iodine	≥ 99
Methyl iodide	≥ 85

(a) Radioactive elemental iodine and radioactive iodide as methyl iodide, respectively. (Efficiency rates are for filters as originally specified. Replacement filters shall comply with the requirements of Regulatory Guide 1.52 and ANSI N509.)

TABLE 12.2-4

DESIGN VALUES FOR FUEL HANDLING BUILDING VENTILATION SYSTEM

Fuel Handling Building Volume, Each Unit, ft^3	525,000
Supply Fan Rating, cfm/fan	23,300
Exhaust Fan Rating, cfm/fan	35,750
HEPA Filter Efficiency for 0.3 m Particles DOP, %	≥ 99.97
Charcoal Filter Efficiency, %[(a)]	
Elemental iodine	≥ 99
Methyl iodide	≥ 85

(a) Radioactive elemental iodine and radioactive iodide as methyl iodide, respectively. (Efficiency rates are for filters as originally specified. Replacement filters shall comply with the requirements of Regulatory Guide 1.52 and ANSI N509.)

TABLE 12.2-5

ESTIMATED AIRBORNE ACTIVITY CONCENTRATIONS IN
AUXILIARY BUILDING WORK AREAS FOR NORMAL OPERATION

Nuclide	Concentration μCi/cc	MPC Air-10 CFR 20 μCi/cc
H-3	4.22E-09	5.00E-06
Cr-51	0.0	2.00E-06
Mn-54	0.0	4.00E-08
Mn-56	0.0	5.00E-07
Co-58	0.0	5.00E-08
Fe-59	0.0	5.00E-08
Co-60	0.0	9.00E-09
Kr-83M	4.02E-09	1.00E-06
Kr-85M	2.37E-08	6.00E-06
Kr-85	5.81E-08	1.00E-05
Kr-87	1.33E-08	1.00E-06
Kr-88	3.98E-08	1.00E-06
Sr-89	0.0	1.00E-08
Sr-90	0.0	1.00E-09
Y-90	0.0	1.00E-07
Sr-91	0.0	1.00E-07
Y-91	0.0	3.00E-08
Sr-92	0.0	3.00E-07
Y-92	0.0	3.00E-07
Zr-95	0.0	3.00E-08
Nb-95	0.0	1.00E-07
Mo-99	0.0	2.00E-07
I-131	1.43E-10	9.00E-09
Te-132	0.0	2.00E-07
I-132	5.13E-11	2.00E-07
I-133	2.31E-10	3.00E-08
Xe-133M	3.53E-08	1.00E-05
Xe-133	2.83E-06	1.00E-05
Cs-134	0.0	1.00E-08
I-134	2.76E-11	5.00E-07
I-135	1.21E-10	1.00E-07
Xe-135M	7.09E-09	1.00E-06
Xe-135	5.34E-08	4.00E-06
Cs-136	0.0	2.00E-07
Cs-137	0.0	1.00E-08
Xe-138	5.07E-09	1.00E-06
Ba-140	0.0	4.00E-08
La-140	0.7	4.00E-08
Ce-144	0.0	6.00E-09
Pr-144	0.0	1.00E-06

TABLE 12.2-6

ESTIMATED AIRBORNE ACTIVITY CONCENTRATIONS IN LETDOWN HEAT EXCHANGER COMPARTMENT FOR NORMAL OPERATION

Nuclide	Concentration μCi/cc	MPC Air-10 CFR 20 μCi/cc
H-3	8.96E-09	5.00E-06
Cr-51	0.0	2.00E-06
Mn-54	0.0	4.00E-08
Mn-56	0.0	5.00E-07
Co-58	0.0	5.00E-08
Fe-59	0.0	5.00E-08
Co-60	0.0	9.00E-09
Kr-83M	6.30E-09	1.00E-06
Kr-85M	3.72E-08	6.00E-06
Kr-85	9.16E-08	1.00E-05
Kr-87	2.08E-08	1.00E-06
Kr-88	6.27E-08	1.00E-06
Sr-89	0.0	3.00E-08
Sr-90	0.0	1.00E-09
Y-90	0.0	1.00E-07
Sr-91	0.0	3.00E-07
Y-91	0.0	3.00E-08
Sr-92	0.0	3.00E-07
Y-92	0.0	3.00E-07
Zr-95	0.0	3.00E-08
Nb-95	0.0	1.00E-07
Mo-99	0.0	2.00E-07
I-131	4.49E-09	9.00E-09
Te-132	0.0	2.00E-07
I-132	1.61E-09	2.00E-07
I-133	7.27E-09	3.00E-08
Xe-133M	5.58E-08	1.00E-05
Xe-133	4.45E-06	1.00E-05
Cs-134	0.0	1.00E-08
I-134	8.63E-10	5.00E-07
I-135	3.80E-09	1.00E-07
Xe-135M	1.17E-08	1.00E-06
Xe-135	8.42E-08	4.00E-06
Cs-136	0.0	2.00E-07
Cs-137	0.0	1.00E-08
Xe-138	7.84E-09	1.00E-06
Ba-140	0.0	4.00E-08
La-140	0.0	1.00E-07
Ce-144	0.0	6.00E-09
Pr-144	0.0	1.00E-06

TABLE 12.2-7

ESTIMATED AIRBORNE ACTIVITY CONCENTRATIONS IN
VOLUME CONTROL TANK COMPARTMENT FOR NORMAL OPERATION

Nuclide	Concentration μCi/cc	MPC Air-10 CFR 20 μCi/cc
H-3	5.11E-09	5.00E-06
Cr-51	0.0	2.00E-06
Mn-54	0.0	4.00E-08
Mn-56	0.0	5.00E-07
Co-58	0.0	5.00E-08
Fe-59	0.0	5.00E-08
Co-60	0.0	9.00E-09
Kr-83M	1.28E-07	1.00E-06
Kr-85M	7.50E-07	6.00E-06
Kr-85	1.84E-06	1.00E-05
Kr-87	4.24E-07	1.00E-06
Kr-88	1.27E-06	1.00E-06
Sr-89	0.0	3.00E-08
Sr-90	0.0	1.00E-09
Y-90	0.0	1.00E-07
Sr-91	0.0	3.00E-07
Y-91	0.0	3.00E-08
Sr-92	0.0	3.00E-07
Y-92	0.0	3.00E-07
Zr-95	0.0	3.00E-08
Nb-95	0.0	1.00E-07
Mo-99	0.0	2.00E-07
I-131	9.02E-10	9.00E-09
Te-132	0.0	2.00E-07
I-132	3.26E-10	2.00E-07
I-133	1.46E-09	3.00E-08
Xe-133M	1.12E-06	1.00E-05
Xe-133	8.94E-05	1.00E-05
Cs-134	0.0	1.00E-08
I-134	1.77E-10	5.00E-07
I-135	7.66E-10	1.00E-07
Xe-135M	2.35E-07	1.00E-06
Xe-135	1.69E-06	4.00E-06
Cs-136	0.0	2.00E-07
Cs-137	0.0	1.00E-08
Xe-138	1.69E-07	1.00E-06
Ba-140	0.0	4.00E-08
La-140	0.0	1.00E-07
Ce-144	0.0	6.00E-09
Pr-144	0.0	1.00E-06

TABLE 12.2-8

ESTIMATED AIRBORNE ACTIVITY CONCENTRATIONS IN
CHARGING PUMP COMPARTMENT FOR NORMAL OPERATION

Nuclide	Concentration μCi/cc	MPC Air-10 CFR 20 μCi/cc
H-3	7.64E-09	5.00E-06
Cr-51	0.0	2.00E-06
Mn-54	0.0	4.00E-08
Mn-56	0.0	5.00E-07
Co-58	0.0	5.00E-08
Fe-59	0.0	5.00E-08
Co-60	0.0	9.00E-09
Kr-83M	1.84E-07	1.00E-06
Kr-85M	1.10E-06	6.00E-06
Kr-85	2.75E-06	1.00E-05
Kr-87	6.00E-07	1.00E-06
Kr-88	1.85E-06	1.00E-06
Sr-89	0.0	3.00E-08
Sr-90	0.0	1.00E-09
Y-90	0.0	1.00E-07
Sr-91	0.0	3.00E-07
Y-91	0.0	3.00E-08
Sr-92	0.0	3.00E-07
Y-92	0.0	3.00E-07
Zr-95	0.0	3.00E-08
Nb-95	0.0	1.00E-07
Mo-99	0.0	2.00E-07
I-131	1.35E-09	9.00E-09
Te-132	0.0	2.00E-07
I-132	4.73E-10	2.00E-07
I-133	2.18E-09	3.00E-08
Xe-133M	1.67E-06	1.00E-05
Xe-133	1.34E-04	1.00E-05
Cs-134	0.0	1.00E-08
I-134	2.46E-10	5.00E-07
I-135	1.13E-09	1.00E-07
Xe-135M	2.84E-07	1.00E-06
Xe-135	2.51E-06	4.00E-06
Cs-136	0.0	2.00E-07
Cs-137	0.0	1.00E-08
Xe-138	2.01E-07	1.00E-06
Ba-140	0.0	4.00E-08
La-140	0.0	1.00E-07
Ce-144	0.0	6.00E-09
Pr-144	0.0	1.00E-06

TABLE 12.2-9

ESTIMATED AIRBORNE ACTIVITY CONCENTRATIONS IN
GAS DECAY TANK COMPARTMENT FOR NORMAL OPERATION

Nuclide	Concentration μCi/cc	MPC Air-10 CFR 20 μCi/cc
H-3	0.0	5.00E-06
Cr-51	0.0	2.00E-06
Mn-54	0.0	4.00E-08
Mn-56	0.0	5.00E-07
Co-58	0.0	5.00E-08
Fe-59	0.0	5.00E-08
Co-60	0.0	9.00E-09
Kr-83M	3.29E-08	1.00E-06
Kr-85M	4.67E-07	6.00E-06
Kr-85	3.19E-04	1.00E-05
Kr-87	7.36E-08	1.00E-06
Kr-88	4.91E-07	1.00E-06
Sr-89	0.0	3.00E-08
Sr-90	0.0	1.00E-09
Y-90	0.0	1.00E-07
Sr-91	0.0	3.00E-07
Y-91	0.0	3.00E-08
Sr-92	0.0	3.00E-07
Y-92	0.0	3.00E-07
Zr-95	0.0	3.00E-08
Nb-95	0.0	1.00E-07
Mo-99	0.0	2.00E-07
I-131	0.0	9.00E-09
Te-132	0.0	2.00E-07
I-132	0.0	2.00E-07
I-133	0.0	3.00E-08
Xe-133M	8.90E-06	1.00E-05
Xe-133	1.68E-03	1.00E-05
Cs-134	0.0	1.00E-08
I-134	0.0	5.00E-07
I-135	0.0	1.00E-07
Xe-135M	7.30E-09	1.00E-06
Xe-135	2.15E-06	4.00E-06
Cs-136	0.0	2.00E-07
Cs-137	0.0	1.00E-08
Xe-138	4.64E-09	1.00E-06
Ba-140	0.0	4.00E-08
La-140	0.0	1.00E-07
Ce-144	0.0	6.00E-09
Pr-144	0.0	1.00E-06

TABLE 12.2-10

ESTIMATED ACTIVITY CONCENTRATIONS IN SPENT FUEL POOL
FOR ANTICIPATED OPERATIONAL OCCURRENCES CASE

Nuclide	Rate mCi/cc	Activity Curies	MPC Air-10 CFR 20 mCi/cc
Cr-51	0.0	0.0	0.0
Mn-54	0.0	0.0	0.0
Mn-56	0.0	0.0	0.0
Co-58	0.0	0.0	0.0
Fe-59	0.0	0.0	0.0
Co-60	0.0	0.0	0.0
Kr-83M	0.622E-24	0.0	0.0
Kr-85M	0.806E-14	0.0	0.0
Kr-85	0.169E-05	0.0	0.0
Kr-87	0.621E-31	0.0	0.0
Kr-88	0.129E-17	0.0	0.0
Sr-89	0.821E-08	0.587E-06	0.351E-09
Sr-90	0.242E-08	0.180E-06	0.108E-09
Y-90	0.388E-09	0.216E-06	0.129E-09
Sr-91	0.679E-13	0.801E-12	0.479E-15
Y-91	0.196E-08	0.762E-05	0.456E-08
Sr-92	0.153E-21	0.567E-21	0.339E-24
Y-92	0.822E-19	0.427E-18	0.255E-21
Zr-95	0.135E-07	0.975E-06	0.583E-09
Nb-95	0.211E-07	0.154E-05	0.918E-09
Mo-99	0.454E-07	0.445E-05	0.266E-08
I-131	0.765E-06	0.449E-04	0.268E-07
Te-132	0.208E-07	0.931E-06	0.557E-09
I-132	0.279E-06	0.181E-05	0.108E-08
I-133	0.101E-07	0.218E-06	0.130E-09
Xe-133M	0.404E-07	0.0	0.0
Xe-133	0.574E-05	0.0	0.0
Cs-134	0.323E-05	0.473E-03	0.282E-06
I-134	0.0	0.0	0.0
I-135	0.260E-11	0.222E-10	0.133E-13
Xe-135M	0.365E-11	0.0	0.0
Ye-135	0.803E-09	0.0	0.0
Cs-136	0.293E-08	0.325E-06	0.194E-09
Cs-137	0.347E-05	0.511E-03	0.305E-06
Xe-138	0.0	0.0	0.0
Ba-140	0.232E-08	0.148E-06	0.882E-10
La-140	0.425E-09	0.969E-07	0.579E-10
Ce-144	0.393E-08	0.290E-06	0.174E-09
Pr-144	0.393E-08	0.290E-06	0.174E-09

TABLE 12.2-11

ESTIMATED AIRBORNE ACTIVITY CONCENTRATIONS IN
FUEL HANDLING AREAS FOR NORMAL OPERATION

Nuclide	Concentration μCi/cc	MPC Air-10 CFR 20 μCi/cc
H-3	1.18E-08	5.00E-06
Cr-51	0.0	2.00E-06
Mn-54	0.0	4.00E-08
Mn-56	0.0	5.00E-07
Co-58	0.0	5.00E-08
Fe-59	0.0	5.00E-08
Co-60	0.0	9.00E-09
Kr-83M	3.96E-29	1.00E-06
Kr-85M	5.23E-20	6.00E-06
Kr-85	1.15E-11	1.00E-05
Kr-87	3.88E-36	1.00E-06
Kr-88	8.28E-24	1.00E-06
Sr-89	0.0	3.00E-08
Sr-90	0.0	1.00E-09
Y-90	0.0	1.00E-07
Sr-91	0.0	3.00E-07
Y-91	0.0	3.00E-08
Sr-92	0.0	3.00E-07
Y-92	0.0	3.00E-07
Zr-95	0.0	3.00E-08
Nb-95	0.0	1.00E-07
Mo-99	0.0	2.00E-07
I-131	2.01E-16	9.00E-09
Te-132	0.0	2.00E-07
I-132	7.16E-17	2.00E-07
I-133	2.66E-18	3.00E-08
Xe-133M	2.66E-13	1.00E-05
Xe-133	3.79E-11	1.00E-05
Cs-134	0.0	1.00E-08
I-134	0.0	5.00E-07
I-135	6.79E-22	1.00E-07
Xe-135M	2.54E-17	1.00E-06
Xe-135	5.24E-15	4.00E-06
Cs-136	0.0	2.00E-07
Cs-137	0.0	1.00E-08
Xe-138	0.0	1.00E-06
Ba-140	0.0	4.00E-08
La-140	0.0	1.00E-07
Ce-144	0.0	6.00E-09
Pr-144	0.0	1.00E-06

TABLE 12.2-12

ESTIMATED AIRBORNE ACTIVITY CONCENTRATIONS IN CONTAINMENT FOR NORMAL OPERATION

Nuclide	Concentration μCi/cc	MPC Air-10 CFR 20 μCi/cc
H-3	1.63E-05	5.00E-06
Cr-51	0.0	2.00E-06
Mn-54	0.0	4.00E-08
Mn-56	0.0	5.00E-07
Co-58	0.0	5.00E-08
Fe-59	0.0	5.00E-08
Co-60	0.0	9.00E-09
Kr-83M	1.46E-08	1.00E-06
Kr-85M	2.00E-07	6.00E-06
Kr-85	1.66E-04	1.00E-05
Yr-87	3.33E-08	1.00E-06
Kr-88	2.13E-07	1.00E-06
Sr-89	0.0	3.00E-08
Sr-90	0.0	1.00E-09
Y-90	0.0	1.00E-07
Sr-91	0.0	3.00E-07
Y-91	0.0	3.00E-08
Sr-92	0.0	3.00E-07
Y-92	0.0	3.00E-07
Zr-95	0.0	3.00E-08
Nb-95	0.0	1.00E-07
Mo-99	0.0	2.00E-07
I-131	1.04E-06	9.00E-09
Te-132	0.0	2.00E-07
I-132	4.79E-09	2.00E-07
I-133	1.84E-07	3.00E-08
Xe-133M	3.87E-06	1.00E-05
Xe-133	6.87E-04	1.00E-05
Cs-134	0.0	1.00E-08
I-134	9.67E-10	5.00E-07
I-135	3.10E-08	1.00E-07
Xe-135M	3.53E-08	1.00E-06
Xe-135	1.00E-06	4.00E-06
Cs-136	0.0	2.00E-07
Cs-137	0.0	1.00E-08
Xe-138	2.79E-09	1.00E-06
Ba-140	0.0	4.00E-08
La-140	0.0	1.00E-07
Ce-144	0.0	6.00E-09
Pr-144	0.0	1.00E-06

TABLE 12.2-13

ESTIMATED AIRBORNE ACTIVITY CONCENTRATIONS IN
TURBINE BUILDING FOR NORMAL OPERATION

Nuclide	Concentration µCi/cc	MPC Air-10 CFR 20 µCi/cc
H-3	1.79E-10	5.00E-06
Cr-51	0.0	2.00E-06
Mn-54	0.0	4.00E-08
Mn-56	0.0	5.00E-07
Co-58	0.0	5.00E-08
Fe-59	0.0	5.00E-08
Co-60	0.0	9.00E-09
Kr-83M	2.81E-14	1.00E-06
Kr-85M	1.66E-13	6.00E-06
Kr-85	4.08E-13	1.00E-05
Kr-87	9.23E-14	1.00E-06
Kr-88	2.79E-13	1.00E-06
Sr-89	0.0	3.00E-08
Sr-90	0.0	1.00E-09
Y-90	0.0	1.00E-07
Sr-91	0.0	3.00E-07
Y-91	0.0	3.00E-08
Sr-92	0.0	3.00E-07
Y-92	0.0	3.00E-07
Zr-95	0.0	3.00E-08
Nb-95	0.0	1.00E-07
Co-99	0.0	2.00E-07
I-131	5.14E-13	9.00E-09
Te-132	0.0	2.00E-07
I-132	2.33E-14	2.00E-07
I-133	8.84E-14	3.00E-08
Xe-133M	2.49E-13	1.00E-05
Xe-133	2.00E-11	1.00E-05
Cs-134	0.0	1.00E-08
I-134	4.50E-16	5.00E-07
I-135	1.49E-14	1.00E-07
Xe-135M	3.91E-13	1.00E-06
Xe-135	4.19E-13	4.00E-06
Cs-136	0.0	2.00E-07
Cs-137	0.0	1.00E-08
Xe-138	3.43E-14	1.00E-06
Ba-140	0.0	4.00E-08
La-140	0.0	1.00E-07
Ce-144	0.0	6.00E-09
Pr-144	0.0	1.00E-06

TABLE 12.2-14

ESTIMATED AIRBORNE ACTIVITY CONCENTRATIONS AT
CONTROL ROOM INTAKE FOR NORMAL OPERATION

Nuclide	Concentration μCi/cc	MPC Air-10 CFR 20 μCi/cc
H-3	1.42 E-10	5.00 E-06
Kr-83M	3.19 E-11	1.00 E-06
Kr-85M	2.07 E-10	6.00 E-06
Kr-85	1.95 E-08	1.00 E-05
Kr-87	1.02 E-10	1.00 E-06
Kr-88	3.30 E-10	1.00 E-06
I-131	6.60 E-13	9.00 E-09
I-132	1.42 E-13	2.00 E-07
I-133	8.92 E-13	3.00 E-08
Xe-133M	3.82 E-10	1.00 E-05
Xe-133	3.68 E-08	1.00 E-05
I-134	3.84 E-14	5.00 E-07
I-135	3.68 E-13	1.00 E-07
Xe-135M	7.37 E-11	1.00 E-06
Xe-135	5.29 E-10	4.00 E-06
Xe-138	4.15 E-11	1.00 E-06

TABLE 12.2-15

ESTIMATED AIRBORNE ACTIVITY CONCENTRATIONS IN CONTROL ROOM FOR NORMAL OPERATION

Nuclide	Concentration μCi/cc	MPC Air-10 CFR 20 μCi/cc
H-3	3.41E-10	5.00E-06
Cr-51	0.0	2.00E-06
Mn-54	0.0	4.00E-08
Mn-56	0.0	5.00E-07
Co-58	0.0	5.00E-08
Fe-59	0.0	5.00E-08
Co-60	0.0	9.00E-09
Kr-83M	2.77E-11	1.00E-06
Kr-85M	1.93E-10	6.00E-06
Kr-85	1.96E-08	1.00E-05
Kr-87	8.35E-11	1.00E-06
Kr-88	2.98E-10	1.00E-06
Sr-89	0.0	3.00E-08
Sr-90	0.0	1.00E-09
Y-90	0.0	1.00E-07
Sr-91	0.0	3.00E-07
Y-91	0.0	3.00E-08
Sr-92	0.0	3.00E-07
Y-92	0.0	3.00E-07
Zr-95	0.0	3.00E-08
Nb-95	0.0	1.00E-07
Mo-99	0.0	2.00E-07
I-131	6.58E-13	9.00E-09
Te-132	0.0	2.00E-07
I-132	1.28E-13	2.00E-07
I-133	8.79E-13	3.00E-08
Xe-133M	3.78E-10	1.00E-05
Xe-133	3.67E-08	1.00E-05
Cs-134	0.0	1.00E-08
I-134	2.89E-14	5.00E-07
I-135	3.53E-13	1.00E-07
Xe-135M	3.54E-11	1.00E-06
Xe-135	5.13E-10	4.00E-06
Cs-136	0.0	2.00E-07
Cs-137	0.0	1.00E-08
Xe-138	1.87E-11	1.00E-06
Ba-140	0.0	4.00E-08
La-140	0.0	1.00E-07
Ce-144	0.0	6.00E-09
Pr-144	0.0	1.00E-06

TABLE 12.2-17

ESTIMATED OCCUPANCY FACTORS FOR PLANT AREAS
(Hours per 7-day Week)

Area	Operators[a]	Chemical and Radiation Protection Technicians[b]	Control Technicians[c]	Elect. and Mechanical Maintenance Personnel[d]
Control room	2000	10	300	0.3
Turbine building	700	10	1000	3000
Outside	150	50	100	2
Auxiliary building corridors	700	2200	500	2600
Fuel handling area	2	8	120	320
Primary sampling room	2	3	1	6
Containment	0.5	2	2	0.3
Volume control tank compartment	0.03	0.2	-	0.2
Charging pump compartment	0.6	0.5	3	7
Letdown heat exchanger compartment	0.03	0.2	-	0.3
Gas decay tank compartment	0.04	0.3	-	0.3
Offices	141	116	374	24
Total	3,696	2,400	2,400	5,960

(a) Operators - 22 men for 2 units x 168 hr/week = 3,696 man-hr/week.
(b) Chemical and radiation protection technicians - 60 men for 2 units x 40 hr/week = 2,400 man-hr/week.
(c) Control technicians - 60 men for 2 units x 40 hr/week – 2,400 man-hr/week.
(d) Maintenance personnel - electrical and mechanical - 149 men for 2 units x 40 hr/week = 5,960 man-hr/week.

TABLE 12.2-18

ESTIMATED INHALATION AND IMMERSION DOSES FOR PLANT AREAS
Plant Personnel Exposures (Man-rem/yr)[a]

Area	Dose	Operators	Chemical and Radiation Protection Technicians	Control Technicians	Electrical and Mechanical Maintenance Personnel	Total
1. Control room	Inhalation thyroid	1.69 E-01	6.02 E-04	1.76 E-02	2.58 E-05	1.88 E-01
	Inhalation whole body[b]	2.56 E-01	9.03 E-04	2.68 E-02	3.86 E-05	2.83 E-01
	Immersion (beta and gamma)	1.03 E+00	3.68 E-03	1.08 E-01	1.58 E-04	1.14 E+00
2. Turbine building	Inhalation thyroid	3.64 E-02	2.50 E-04	4.85 E-02	1.48 E-01	2.33 E-01
	Inhalation whole body[b]	4.95 E-02	3.40 E-04	6.61 E-02	2.01 E-01	3.17 E-01
	Immersion (beta and gamma)	2.11 E-04	1.45 E-06	2.82 E-04	8.63 E-04	1.36 E-03
3. Auxiliary building corridors (includes primary sampling room)	Inhalation thyroid	1.46 E+01	4.52 E+01	1.08 E+01	5.27 E+01	7.59 E+01
	Inhalation whole body[b]	1.16 E+01	3.62 E+00	8.69 E-01	4.19 E+00	9.84 E+00
	Immersion (beta and gamma)	2.22 E+01	6.88 E+01	1.65 E+01	7.99 E+01	1.88 E+02
4. Fuel handling area	Inhalation thyroid	3.30 E-08	1.89 E-07	2.55 E-06	6.55 E-06	9.32 E-06
	Inhalation whole body[b]	7.85 E-03	4.50 E-02	6.05 E-01	1.56 E+00	2.22 E+00
	Immersion (beta and gamma)	6.01 E-06	3.43 E-05	4.62 E-04	1.19 E-03	1.69 E-03

Area	Dose	Operators	Chemical and Radiation Protection Technicians	Control Technicians	Electrical and Mechanical Maintenance Personnel	Total
5. Containment	Inhalation thyroid	5.86 E-03[e]	1.69 E-02[e]	2.53 E-02[e]	3.06 E-03[e]	5.11 E-02[e]
	Inhalation whole body[b]	3.60 E-02[f]	1.04 E-01[f]	1.55 E-01[f]	1.86 E-02[f]	3.13 E-01[f]
	Immersion (beta and gamma)	4.03 E+00	1.16 E+01	1.73 E+01	2.08 E+00	3.50 E+01
6. Volume control tank compartment	Inhalation thyroid	4.24 E-04	2.52 E-03	0.0	2.11 E-03	5.05 E-03
	Inhalation whole body[b]	6.48 E-05	3.84 E-04	0.0	3.22 E-04	7.71 E-04
	Immersion (beta and gamma)	3.22 E-02	1.91 E-01	0.0	1.60 E-01	3.84 E-01
7. Charging pump compartment	Inhalation thyroid	1.14 E-02[d]	.5 E-03[d]	6.27 E-03[d]	1.26 E-01[d]	1.53 E-01[d]
	Inhalation whole body[b]	1.74 E-03	1.45 E-03	9.57 E-03	1.93 E-02	2.35 E-02
	Immersion (beta and gamma)	8.65 E-01	7.2 E-01	4.75 E-01	9.5 E+00	5.28 E+02
8. Letdown heat exchanger compartment	Inhalation thyroid	2.09 E-04[c]	1.14 E-03[c]	0.0	1.91 E-03[c]	3.26 E-03[c]
	Inhalation whole body[b]	1.02 E-04	5.96 E-04	0.0	9.93 E-04	1.69 E-03
	Immersion (beta and gamma)	1.62 E-04	8.84 E-03	0.0	1.47 E-02	2.37 E-02

Area	Dose	Operators	Chemical and Radiation Protection Technicians	Control Technicians	Electrical and Mechanical Maintenance Personnel	Total
9. Gas decay tank compartment	Inhalation thyroid	0.0	0.0	0.0	0.0	0.0
	Inhalation whole body[b]	0.0	0.0	0.0	0.0	0.0
	Immersion (beta and gamma)	5.12 E-01	4.8 E+00	0.0	4.8 E+00	1.01 E+01
Total for All Areas	Inhalation thyroid	1.49 E+01	4.52 E+01	1.1 E+01	5.3 E+01	1.24 E+02
	Inhalation whole body[b]	1.53 E+00	3.77 E+00	1.72 E+00	5.99 E+00	1.30 E+01
	Immersion (beta and gamma)	2.47 E+02	8.62 E+01	3.44 E+01	9.65 E+01	4.64 E+02

(a) Basis: 50 weeks/year.
(b) From tritium inhalation and absorption through skin.
(c) Includes use of a respirator with a protection factor of 100.
(d) Includes use of a respirator with a protection factor of 10.
(e) Includes use of a respirator with a protection factor of 10,000.
(f) Includes use of a protective suit, hood, and respirator with a total protection from tritium factor of 100.

TABLE 12.3-1

HEALTH PHYSICS PORTABLE INSTRUMENTATION

Item No.	Instrument Identification	Nominal Quantity	Detector Type	Radiation Measured	Range
Dose Rate Meters					
1.	High Range	2	GM	g	1 R/hr - 10 Kr/hr
2.	Low Range	5	GM	g	Dose Rate: Bkg to 3000 mR/hr
3.	Dose Rate Meter	30	Ion chamber	b, g	0-5,000 mR/hr
4.	Condenser R-meter	1	Ion chamber	G	0-0.25, 0-2.5, 0-25 R
Self-Reading Pocket Ion Chambers					
1.	Direct Reading Pocket Dosimeters	250	Ion chamber	G	0-200 mR
2.	Direct Reading Pocket Dosimeters	50	Ion chamber	g	0-1R and 0-2R
3.	Direct Reading Pocket Dosimeters	60	Ion chamber	g	0-5 R
4.	Direct Reading Pocket Dosimeters	5	Ion chamber	g	0-50R
5.	Direct Reading Pocket Dosimeters	5	Ion chamber	g	0-100 R

TABLE 12.3-1

Item No.	Instrument Identification	Nominal Quantity	Detector Type	Radiation Measured	Range
Count Rate Meters					
1.	Count Rate Meter	5	GM	-	0-500,000 cpm
2.	Count Rate Meter	10	-	-	0-70,000 cpm
3.	Pulse Rate Meter	3	-	-	0-500,000 cpm
4.	Count Rate Meter	40	-	-	0-50,000 cpm
Count Rate Meter Probes And Detectors					
1.	Hand Probe	30	GM	b, g	-
2.	Shielded Hand Probe	10	GM	b, g	-
3.	Alpha Scintillation Probe	1	ZnS(Ag)	Alpha	-
4.	Gamma Scintillation Probe	2	NaI(TI)	g	-
Scintillation Monitors					
1.	Rad Portal Monitor	4	Scintil.	b, g	0-9999 cpm
2.	Portable Gamma Monitor	2	Scintil.	g	0.1 to 1000 mR/hr

TABLE 12.3-1

Item No.	Instrument Identification	Nominal Quantity	Detector Type	Radiation Measured	Range
Neutron Proportional Counters					
1.	Portable Rem Counter	1	BF_3	n, thermal to fast	0-5000 mrem/hr
Solid-State Dosimeters					
1.	Personal Electronic Dosimeters	500	Si	b, g	0-9999 mR
Miscellaneous					
1.	Self-reading Dosimeter Charger	4	-	-	-
2.	Scaler with Ratemeter	1	-	-	Scaler, 10^6- 1 counts: Ratemeter, 0-500, 0-5K, 0-50K, 0-500K cpm
3.	Extendable Probe Dose Rate Meter	10	GM	b, g	0-1000 R/hr

A variety of portable instrumentation is available for radiological monitoring. The general equipment types are summarized in this table. It should be noted that this list is intended only to be illustrative of what may be in use. Quantities and types of specific equipment may vary from time to time as conditions change, new products appear on the market, etc.

TABLE 12.3-2

HEALTH PHYSICS AIR SAMPLING INSTRUMENTATION

Item No.	Instrument Identification	Nominal Quantity	Detector Type	Radiation Measured	Range
1.	Personnel Air Sampler	6	-	-	0-4 liters/min
2.	Portable Air Samplers	10	-	-	1-2 cfm
3.	Continuous Air Monitor Single Channel Particulate / Iodine or Particulate Noble Gas	6	Sealed Gas - Proportional	Beta	~ 0.3-4 cfm

NOTE: A variety of air sampling equipment is available for radiological monitoring. The general equipment types are summarized in this table. It should be noted that this list is intended only to be illustrative of what may be in use. Quantities and types of specific equipment may vary from time to time as conditions change, new products appear on the market, etc.

TABLE 12.3-3

RESPIRATORS APPROVED FOR USE AT DIABLO CANYON POWER PLANT FOR PROTECTION AGAINST RADIOACTIVE MATERIALS

Type of Respirator	Nominal Quantity
Air purifying, full facepiece, various sizes	100
Powered air purifying respirator (PAPR)	5
Airline respirator, constant flow	20
Self-contained breathing	108

NOTE: A variety of respirators are available for use. The general types are summarized in this table. It should be noted that this list is intended only to be illustrative of what may be in use. Quantities and types of specific equipment may vary from time to time as conditions change, new products appear on the market, etc.

FIGURE 12.1-1 TO BE WITHHELD FROM
PUBLIC PER 10 CFR 2.390 AND
SECY-04-0191.

FIGURE 12.1-2 TO BE WITHHELD FROM PUBLIC PER 10 CFR 2.390 AND SECY-04-0191.

FIGURE 12.1-3 TO BE WITHHELD FROM
PUBLIC PER 10 CFR 2.390 AND
SECY-04-0191.

FIGURE 12.1-4 TO BE WITHHELD FROM
PUBLIC PER 10 CFR 2.390 AND
SECY-04-0191.

FIGURE 12.1-5 TO BE WITHHELD FROM
PUBLIC PER 10 CFR 2.390 AND
SECY-04-0191.

FIGURE 12.1-6 TO BE WITHHELD FROM
PUBLIC PER 10 CFR 2.390 AND
SECY-04-0191.

FIGURE 12.1-7 TO BE WITHHELD FROM
PUBLIC PER 10 CFR 2.390 AND
SECY-04-0191.

FIGURE 12.1-8 TO BE WITHHELD FROM
PUBLIC PER 10 CFR 2.390 AND
SECY-04-0191.

FIGURE 12.1-9 TO BE WITHHELD FROM
PUBLIC PER 10 CFR 2.390 AND
SECY-04-0191.

FIGURE 12.1-10 TO BE WITHHELD FROM
PUBLIC PER 10 CFR 2.390 AND
SECY-04-0191.

FIGURE 12.1-11 TO BE WITHHELD FROM
PUBLIC PER 10 CFR 2.390 AND
SECY-04-0191.

FIGURE 12.1-12 TO BE WITHHELD FROM
PUBLIC PER 10 CFR 2.390 AND
SECY-04-0191.

Chapter 13

CONDUCT OF OPERATIONS

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Chapter 13

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Chapter 13

CONDUCT OF OPERATIONS

Pacific Gas and Electric Company (PG&E) became involved in the operation of nuclear power plants in 1957 after many years of successfully operating its fossil-fueled power plants. In the operation of Humboldt Bay Power Plant (HBPP), Unit 3, and Diablo Canyon Power Plant (DCPP), Units 1 and 2, PG&E has demonstrated its dedication as a competent and safety-oriented operating organization. PG&E is also committed to continually developing and enhancing the organization responsible for operation of its power plants to meet expanded technical and regulatory requirements. In keeping with this commitment, PG&E has made significant changes since commencement of operations in its nuclear organization and operating policies to strengthen PG&E's capability to operate its nuclear power plants safely and reliably for all operating conditions.

13.1 ORGANIZATIONAL STRUCTURE

13.1.1 CORPORATE ORGANIZATION

PG&E's organizational structure is shown in Figure 17.1-1. The manner in which the various PG&E departments function in performing the design, operation, and quality assurance of DCPP is described in succeeding sections. Chapter 17 provides further discussion of the utility organization.

13.1.1.1 Corporate Functions, Responsibilities, and Authorities

The Board of Directors of PG&E Corporation oversees the governance of PG&E.

The Chairman, CEO, and President, PG&E Corporation, is accountable to the Board of Directors and establishes the corporate policies, goals, and objectives related to all of PG&E's activities and operations. Reporting to the Chairman, CEO, and President, PG&E Corporation, is the President, PG&E.

The President, PG&E, is a member of the Board of Directors and is responsible for and directs the planning, distribution, and development of all the Company’s energy resources and nuclear power generation. These functions include such activities as planning and development, engineering, construction, and fossil and nuclear power plant operations. Reporting to the President and Chief Executive Officer, PG&E, is the Senior Vice President, Chief Nuclear Officer, Senior Vice President, Safety and Shared Services, and the Executive Vice President – Electric Operations.

The Executive Vice President – Electric Operations, through the Director – Applied Technology Services, is responsible for providing, upon request: (1) technical investigations, tests, analyses, examinations, and calibration services in support of Diablo Canyon and Humboldt Bay Power Plants; (2) developing, evaluating, qualifying,

testing, and improving welding, brazing, and heat-treating procedures required by the company; and (3) providing evaluation support of these procedures.

The Senior Vice President, Safety and Shared Services, through the Support Services Supervisor – Engineering Records Unit, is responsible for providing document services support for Diablo Canyon and Humboldt Bay Power Plants. These services include indexing, preparing, and duplicating microfiche for the drawing control system; storing the master microfiche and drawings that cannot be microfilmed; and scanning and indexing drawings when requested by Nuclear Generation. They also provide remote storage of master microfilm reels for the records management system (RMS) and storage of vendor manuals. The Senior Vice President, Safety and Shared Services, through the Manager – Nuclear Supply Chain, is responsible for the administration, coordination, planning, and operation of warehousing and material procurement in support of DCPP construction and operations, as well as for contract services.

The Senior Vice President, Chief Nuclear Officer, is responsible for the safe and efficient operation of PG&E's nuclear power plants. The Senior Vice President, Chief Nuclear Officer, is the corporate officer specified by the DCPP Technical Specifications, Section 5, who shall have corporate responsibility for overall plant nuclear safety and shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining, and providing technical support to the plant to ensure nuclear safety. Reporting to the Senior Vice President, Chief Nuclear Officer, is the Site Vice President; Director, Quality Verification; Director, Humboldt Bay Nuclear; Vice President, Nuclear Services; DCPP Employee Concerns Program supervisor and the Director Compliance, Alliance, and Risk.

The Site Vice President is responsible for overall safe operation of the plant and has control over onsite activities necessary for safe operation and maintenance of the plant. Reporting to the Site Vice President is the Director, Site Services; Director, Learning Services; Station Director, and the Director, Industry Relations.

Reporting to the Vice President, Nuclear Services is the Director, Engineering Services; Director, Technical Services; Director, Strategic Projects; Director, Equipment Reliability; Manager, Integrated Service Supplier; and Director, Security and Emergency Services.

13.1.1.2 Corporate Staffing and Organizational Relationships

Current operations of PG&E are organized under and responsible to the Chairman of the Board. Reporting directly to the Chairman of the Board is the Chairman, Chief Executive Officer, and President, PG&E Corporation.

Reporting directly to the Chairman, CEO, and President, PG&E Corporation is the President, PG&E.

Reporting to the President, PG&E, is the Senior Vice President, Chief Nuclear Officer; the Senior Vice President, Safety and Shared Services; and the Executive Vice President – Electrical Operations.

Reporting to the Senior Vice President, Chief Nuclear Officer, is the Site Vice President; the Director, Quality Verification; the Director, Humboldt Bay Nuclear; the DCPP Employee Concerns Program Supervisor; Vice President, Nuclear Services, and the Director Compliance, Alliance, and Risk.

Reporting to the Site Vice President is the Director, Site Services; Director, Learning Services; Station Director, and the Director, Industry Relations.

Reporting to the Vice President, Nuclear Services is the Director, Engineering Services; Director, Technical Services; Director, Strategic Projects; Director, Equipment Reliability; Manager, Integrated Service Supplier; and Director, Security and Emergency Services.

13.1.1.3 Interrelationship With Contractors And Suppliers

The working interrelationships and organizational interfaces between PG&E, Westinghouse (the nuclear steam supply system (NSSS) manufacturer) and other suppliers and contractors are described in Chapter 1.

13.1.1.4 Technical Staff

Nuclear Generation may call upon a variety of other PG&E departments, as well as outside consultants, to assist in the technical support of nuclear power plant operations as shown in Figure 17.1-1.

PG&E's overall technical capability is such that most technical support functions for nuclear power plants are handled within the PG&E organization. Outside consultants are available to provide technical support in all technical areas for plant operations and are used to assist on special problems as required. Consultant personnel interface with PG&E specialists in a variety of technical, engineering, and design areas.

13.1.2 OPERATING ORGANIZATION

13.1.2.1 Plant Organization

Overall responsibility for the operation of Diablo Canyon is assigned to the Senior Vice President, Chief Nuclear Officer. The division of responsibilities is as follows:

(1) Senior Vice President, Chief Nuclear Officer

    (a) Site Vice President

(b) Vice President, Nuclear Services

(c) Employee Concerns Program Supervisor

(d) Director, Quality Verification

(e) Director, Compliance, Alliance, and Risk

(f) Director, Humboldt Bay Nuclear

(2) Site Vice President

(a) Station Director
Director, Operations
Operations
Radiation Protection
Chemistry and Environmental
Operations Performance
Operations Planning
Director, Nuclear Work Management
Daily Work Control
Outage Management
Outage Services
Planning
Director, Maintenance Services
Electrical
Instrumentation and Controls
Maintenance Team
Mechanical

(b) Director, Site Services
Performance Improvement
Procedure and Document Services
Special Applications Group
Regulatory Services

(c) Director, Learning Services

(d) Director, Industry Relations

(3) Vice President, Nuclear Services

(a) Director, Engineering Services
Mechanical Systems Engineering
Technical Support Engineering

Instrumentation, Controls, and Electrical Systems Engineering
Design Engineering
Project Engineering

(b) Director, Technical Services
Senior Manager, Nuclear Fuels
Senior Manager, Geosciences
Director, License Renewal

(c) Director, Strategic Projects
Project Services
Project managers for various special projects
Construction

(d) Director, Equipment Reliability

(e) Manager Integrated Services Supplier

(f) Director, Security and Emergency Services
Security Services
Emergency Planning
Cyber Secrity
Nuclear Projects Fukushima
Industrial Fire Group

(4) Director, Compliance, Alliance and Risk
Manager Nuclear Supply Chain

The organizational charts for positions described in this section are provided in Figures 13.1-1A and C.

13.1.2.2 Personnel Functions, Responsibilities, and Authorities

13.1.2.2.1 Senior Vice President, Chief Nuclear Officer

The Senior Vice President, Chief Nuclear Officer, is responsible for the safe and efficient operation of PG&E's nuclear power plants, quality verification, and the employee concerns program.

The site organizational chart for positions described in this section are provided in Figure 13.1-1A.

13.1.2.2.1.1 Site Vice President

The Site Vice President is responsible for overall safe operation of the plant and has control over onsite activities necessary for safe operation and maintenance of the plant.

13.1.2.2.1.1.1 Station Director

The Station Director is responsible within those limits established by the plant operating licenses and the policy of the Senior Vice President, Chief Nuclear Officer, for the development and implementation of those programs, procedures, and instructions required for the operation of DCPP. The Station Director has been delegated the necessary authority to approve and direct development and implementation of these programs, procedures, and instructions. The Station Director is the Plant Manager specified in the DCPP Technical Specifications, Section 5.

13.1.2.2.1.1.2 Director, Site Services

The Director, Site Services provides direct supervision over Performance Improvement, Special Applications Group, Regulatory Services, and Procedure and Document Services. Reporting to the Director, Site Services is the Manager, Procedure and Document Services; the Manager, Performance Improvement; Manager, Special Applications; and the Manager, Regulatory Services. The Manager, Specialized Application Group – Generation is matrixed to the Director, Site Services and reports to Information Systems Technology Services.

13.1.2.2.1.1.2.1 Manager, Procedure and Document Services

The Manager, Procedure and Document Services is responsible for the control and distribution of all controlled drawings and implementation of the record management program and DCPP's procedure program. This position is also responsible for the overall coordination of DCPP's procedure program and for providing various procedure related services.

13.1.2.2.1.1.2.2 Manager, Specialized Applications Group – Generation

The Manager, Specialized Applications Group – Generation is responsible for overall Coordination of software lifecycle management activities conducted within Nuclear Generation-Information Systems, including administration of the software program inventory.

13.1.2.2.1.1.2.3 Manager, Performance Improvement

The Manager, Performance Improvement is responsible for the overall management of the Performance Improvement Program; for providing oversight to ensure trends adverse to quality are identified, and for identifying key performance indicators to be used in assessing the overall health of the Performance Improvement process.

13.1.2.2.1.1.2.4 Manager, Regulatory Services

The Manager, Regulatory Services is responsible for NRC regulatory submittals; the License Amendment process; the Reportability process; the Technical Specification Bases and Final Safety Analysis Report Update processes; the commitment management process; and coordinating interactions with the NRC inspectors.

13.1.2.2.1.1.3 Director, Learning Services

The Director, Learning Services is responsible for the overall implementation, maintenance, monitoring, and evaluation of nuclear generation activities associated with personnel training and qualifications and for obtaining and maintaining accreditation for training programs specifically identified by INPO.

13.1.2.2.1.1.4 Director, Industry Relations

The Director, Industry Relations serves as the lead administrative point of contact for the Institute of Nuclear Power Operations and serves on the STARS Alliance Management Council.

13.1.2.2.1.2 Vice President, Nuclear Services

The Vice President, Nuclear Services is responsible for configuration control; design bases defense and management; providing engineering support for plant operations; managing technical programs related to system and component health and long-term planning; replacement parts design; design drafting; engineering support of emergent work; predictive monitoring of equipment performance; nuclear fuel configuration management; preventive maintenance management; plant transient analysis design bases defense and management; complying with regulatory requirements pertaining to SSCs; geotechnical services; Equipment Reliability; Security and Emergency Services; and Strategic Projects. In addition, this position is specifically charged with development, evaluation, qualification, testing, and improvement of nondestructive examination procedures required by PG&E and for evaluation of these types of procedures that are used at DCPP by other organizations.

Reporting to the Vice President, Nuclear Services is the Director, Engineering Services; the Director, Technical Services; the Director, Strategic Projects; Director, Equipment Reliability; Manager, Integrated Services Supplier; and the Director, Security and Emergency Services.

13.1.2.2.1.2.1 Director, Engineering Services

The Director, Engineering Services is responsible for providing day-to-day engineering support for plant operations and for performance of modifications to the plant. Reporting to the Director, Engineering Services are the Manager, Mechanical Engineering; Manager, Technical Support Engineering; Manager, Design Engineering;

Manager, Projects Engineering and the Manager, Instrumentation, Controls, and Electrical Engineering.

13.1.2.2.1.2.2 Director, Technical Services

The Director, Technical Services is responsible for Nuclear Fuels Purchasing, Geosciences, and the License Renewal project.

13.1.2.2.1.2.2.1 Senior Manager, Nuclear Fuels Purchasing

The Senior Manager, Nuclear Fuels Purchasing, is responsible for developing, directing, and administering the company-wide nuclear fuel procurement strategy, inventory policy, and fuel contract management program in support of plant operations.

13.1.2.2.1.2.2.2 Senior Manager, Geosciences

The Senior Manager, Geosciences is responsible for providing seismic, geologic, and geotechnical services for the safe and reliable operation of company facilities. Of particular importance to DCPP and Humboldt Bay Power Plant are the department capabilities and expertise in the following areas: site characterization, earthquake activity interpretations, seismic hazard analyses, ground motion studies, post-earthquake inspections, seismic risk evaluations, seismic instrumentation, geotechnical explorations, and soil and rock testing.

13.1.2.2.1.2.2.3 Director, License Renewal

The Director, License Renewal is responsible for the License Renewal Project.

13.1.2.2.1.2.3 Director, Strategic Projects

The Director, Strategic Projects is responsible for project management services for Diablo Canyon, including management of all strategic projects.

Reporting to the Director, Strategic Projects is the Manager, Project Services and project managers for various special projects identified by DCPP management, and the Manager, Construction Management.

13.1.2.2.1.2.3.1 Manager, Project Services

The Manager, Project Services is responsible for implementation of capital and expense projects at Diablo Canyon. These projects would be considered as “typical” utility commitments for equipment reliability and component improvements.

13.1.2.2.1.2.3.2 Manager, Construction Management

The Manager, Construction Management is responsible for administering, coordinating, planning, and scheduling all construction maintenance activities at the plant. This position provides direction, assistance, and guidance to onsite contractor and facilities maintenance.

13.1.2.2.1.2.4 Director, Security and Emergency Services

The Director, Security and Emergency Services is responsible for implementation of the Emergency Plan and the Security Program, which includes the Security Plan and the industrial Fire Group. Reporting to the Director, Security and Emergency Services is Manager, Security Services, Manager Emergency Planning, and the Supervisor, Cyber Security.

13.1.2.2.1.2.4.1 Managers, Security Services

The Managers, Security Services are responsible for developing, planning, and coordinating all activities associated with eh plant security program.

13.1.2.2.1.2.4.2 Supervisor, Cyber Security

The Supervisor, Cyber Security is the single point of contact for DCPP Cyber Security Program.

13.1.2.2.1.2.4.3 Manager, Emergency Planning

The Manager, Emergency Planning is responsible for the development, coordination, and implementation of all emergency planning activities, including providing the plant interface with the corporate emergency planning activities; and for the development, coordination, and implementation of emergency planning at the site.

13.1.2.2.1.2.4.4 Manager, Nuclear Projects Fukushima

The Manager, Nuclear Projects Fukushima is responsible for the Fukushima Project at the station.

13.1.2.2.1.2.4.5 Industrial Fire Group

Refer to UFSAR Appendix 9.5H for responsibilities.

13.1.2.2.1.2.5 Director, Equipment Reliability

The Director, Equipment Reliability is responsible for equipment reliability at the station.

13.1.2.2.1.2.6 Manager, Integrated Service Supplier

The Manager, Integrated Service Supplier is responsible for the coordination with the Integrated Service Supplier.

13.1.2.2.1.3 Director, Quality Verification

The Director, Quality Verification, is responsible for management of the Quality Assurance (QA) Program and for assuring that the QA Program is implemented and complied with by all involved organizations, both internal and external to PG&E. Refer to Section 17.1 for additional responsibilities. The Director, QV, is responsible for independent review and oversight of operations, corrective action, plant support, engineering, procurement, and maintenance activities performed by or for DCPP. These responsibilities are described in Chapter 17.

13.1.2.2.1.4 Director, Compliance, Alliance, and Risk

The Director, Compliance, Alliance, and Risk, is responsible for integrated business planning, the continuous improvement process, Corporate Risk and Compliance programs, Business Finance, STARS, and CNO support. The Manager, Nuclear Supply Chain, is matrixed to the Director, Compliance, Alliance, and Risk and reports directly to generation supply chain, Director, Sourcing.

13.1.2.2.1.4.1 Manager, Nuclear Supply Chain

The Manager, Nuclear Supply Chain, is responsible for administering, coordinating, planning, and operation of warehousing and procurement of materials in support of plant operations and construction, as well as for contract services. This position is responsible for the functions within the materials procurement group including: the procurement specialist group, warehousing operations, and materials coordination.

13.1.2.2.1.5 Employee Concerns Program Supervisor

The Supervisor, Employee Concerns Program is responsible for management of a program, independent of line management, for company and contractor employees to raise concerns dealing with harassment, intimidation, retaliation or discrimination without fear of retaliation.

13.1.2.2.2 Operating Organization Responsibilities

The plant operating organization authorized for two-unit operation is shown in Figure 13.1-1C.

13.1.2.2.2.1 Functions, Responsibilities, and Authorities

The functions, responsibilities, and authorities of key supervisor positions in the DCPP operating organization are summarized briefly in the following paragraphs. Each organization that supports DCPP documents and maintains current a written description of its internal organization. This documentation describes the business unit or department's structure, levels of authority, lines of communication, and assignments of responsibility. Such documentation takes the form of organization charts supported by written job descriptions or other narrative material in sufficient detail that the duties and authority of each individual whose work affects quality is clear. Interfaces between organizations are described in administrative procedures or other documents controlled in accordance with the appropriate requirements of Section 17.6.

13.1.2.2.2.2 Station Director

The Station Director is responsible for operations, maintenance, and nuclear work management. The Station Director is the plant manager specified in the DCPP Technical Specifications, Section 5.

13.1.2.2.2.2.1 Director, Operations Services

The Director, Operations Services, exercises direct supervision over operations activities. The Director, Operations Services, reports to the Station Director. Reporting to the Director, Operations Services, is the Manager, Operations; the Manager, Operations Planning; the Manager, Operations Performance; and the Manager, Chemistry and Environmental Operations.

13.1.2.2.2.2.1.1 Manager, Operations

The Manager, Operations, is the operations manager specified in the DCPP Technical Specifications, Section 5. He is the responsible Manager for ensuring that appropriate operating procedures are available and that operating personnel are familiar with the procedures. In carrying out these responsibilities, he provides direct supervision to the Operations Superintendent (if the Manager, Operations, does not hold a Senior Reactor Operator (SRO) license for Diablo Canyon), the Operations Dayshift Supervisor, the technical assistants, and the operations engineers.
During high workload periods (such as outages), the Director, Operations Services, may choose to appoint an additional operations manager in order to better fulfill the responsibilities listed above. In such cases, the division of responsibilities will be clearly identified, and establishment of that position will be communicated to all appropriate organizations.

13.1.2.2.2.2.1.1.1 Operations Superintendent

If the operations manager does not hold an SRO license for Diablo Canyon, the Operations Superintendent shall hold an SRO license for Diablo Canyon. The

Operations Superintendent shall be responsible for providing operating instructions to the Shift Foremen and Shift Managers as indicated in Figure 13.1-5. The Operations Superintendent satisfies the operations middle manager position specified in the Technical Specifications and shall meet the requirements of ANSI 3.1-1993, Sections 4.2.2 and 4.3. This position is not intended to be filled using rotational personnel.

If the operations manager holds an SRO license for Diablo Canyon, the Operations Superintendent position is not required to be staffed as indicated in Figure 13.1-6.

13.1.2.2.2.2.1.1.2 Shift Manager

The Shift Manager is responsible for overall supervision of the operation of the facility. He provides direct supervision to the Shift Foremen, and, in the absence of higher supervision, is in full charge of the plant. In the event of an operating emergency, the Shift Manager is authorized to take any actions he deems necessary.

13.1.2.2.2.2.1.1.3 Shift Foreman

The Shift Foreman is responsible for providing direct supervision of the plant operators, the work they perform, and for providing administrative support in this area. The Shift Foreman has command and control responsibility for the control room for his assigned unit.

The Shift Foreman may also be assisted by a work control shift foreman. The work control shift foreman is an optionally manned position, whose function is described in the appropriate administrative procedure.

13.1.2.2.2.2.1.1.4 Shift Technical Advisor

The shift technical advisor (STA) function will normally be assigned to one of the SRO licensed operators on crew. The STA function may be assigned to an STA-qualified individual supplementing the crew.

The STA provides technical and analytical support to the operating shift crew to ensure safe operation of the plant.
During transient and emergency events, the STA qualified individual is responsible for applying their background to the analysis and response to the event and advising the rest of the crew, as applicable, on actions to terminate or mitigate the consequences of such events.

13.1.2.2.2.2.1.2 Manager, Operations Planning

The Operations Planning Manager is responsible for outage and daily work control planning and clearance preparation.

13.1.2.2.2.2.1.3 Manager, Operations Performance

The Operations Performance Manager is responsible for the oversight of Operations Training programs, and the Operations administrative support.

13.1.2.2.2.2.1.4 Manager, Chemistry and Environmental Operations

The Manager, Chemistry and Environmental Operations, is responsible for administering, coordinating, planning, and scheduling all chemistry activities at the plant. He is also responsible for coordinating DCPP environmental activities and for developing and managing programs to achieve and maintain compliance with all environmental regulations and requirements.

13.1.2.2.2.2.1.5 Manager, Radiation Protection

The Manager, Radiation Protection, is responsible for administering, coordinating, planning, and scheduling all radiation protection activities at the plant. The Manager, Radiation Protection, is the radiation protection manager specified in the DCPP Technical Specifications, Section 5. While the manager reports directly to the Operations Director, he has direct access to the Site Vice President, and the Senior Vice President, Chief Nuclear Officer on matters concerning radiation protection and support.

13.1.2.2.2.2.2 Director, Nuclear Work Management

The Director, Nuclear Work Management, is responsible for the management of DCPP unit outages including planning, organizing, staffing, directing, and controlling the preparation of outages. The Director, Nuclear Work Management, is also responsible for the daily work control process and organization.

13.1.2.2.2.2.2.1 Manager, Daily Work Control

The Manager, Work Control, is responsible for outage and maintenance-critical scheduling, and is responsible to ensure that all maintenance, refueling, and modification activities are coordinated between the various maintenance organizations and that proper interfaces and detailed plans exist for the timely and safe performance of all plant activities.

13.1.2.2.2.2.2.2 Manager, Outage Management

The Manager, Outage is responsible for outage and scheduling (including refueling, maintenance, and unplanned outages), and is responsible to ensure that all outage maintenance and modification activities are coordinated between the various maintenance organizations and that proper interfaces and detailed plans exist for the timely and safe performance of all plant activities.

13.1.2.2.2.2.2.3 Manager, Outage Services

The Manager, Outage Services is responsible outage strategies and outage-related business planning, as well as refueling outage safety plan development and outage work window planning.

13.1.2.2.2.2.2.4 Manager, Planning

The Manager, Planning, is responsible for planning work instructions for all maintenance activities at the plant. This position provides direction, assistance, and guidance to maintenance planning personnel in preventive and corrective maintenance techniques and programs.

13.1.2.2.2.2.3 Director, Maintenance Services

The Director, Maintenance Services, exercises direct supervision over maintenance. Reporting to the director is the Manager, Electrical Maintenance; the Manager, Instrumentation and Controls Maintenance; the Manager, Mechanical Maintenance; and the Manager, Maintenance Support.

13.1.2.2.2.2.3.1 Manager, Electrical Maintenance

The Manager, Electrical Maintenance, is responsible for administering, coordinating, planning, and scheduling all electrical maintenance activities at the plant. This position provides direction, assistance, and guidance to electrical maintenance personnel in preventive and corrective maintenance techniques and programs.

13.1.2.2.2.2.3.2 Manager, Instrumentation and Controls Maintenance

The Manager, Instrumentation and Controls (I&C) Maintenance, is responsible for administering, coordinating, planning, and scheduling all I&C maintenance activities at the plant. This position provides direction, assistance, and guidance to I&C maintenance personnel in preventive and corrective maintenance techniques and programs.

13.1.2.2.2.2.3.3 Manager, Maintenance Support

The Manager, Maintenance Support, is responsible for administering, coordinating, planning, and scheduling all multi-disciplined team activities at the plant. This position provides direction, assistance, and guidance to operations support team personnel in preventive and corrective maintenance techniques and programs.

13.1.2.2.2.2.3.4 Manager, Mechanical Maintenance

The Manager, Mechanical Maintenance, is responsible for administering, coordinating, planning, and scheduling all mechanical maintenance activities at the plant. This position provides direction, assistance, and guidance to mechanical maintenance personnel in preventive and corrective maintenance techniques and programs.

13.1.2.3 Shift Crew Composition

With either or both units fueled and above 200°F in primary system temperature, a minimum shift organization is composed of:

- one Shift Manager and one Shift Foreman, each with a Senior Operator License.
- three Licensed Operators, at least one will be assigned to each unit.
- three Auxiliary Operators, at least one will be assigned to each unit.
- one Shift Technical Advisor, an individual who provides technical support to the unit operations shift crew in the areas of thermal hydraulics, reactor engineering, and plant analysis with regard to safe operation of the unit. This position will be manned unless there is a crew member with an SRO license who meets the qualifications specified by the Commission Policy Statement on Engineering Expertise on Shift.
- one Chemical and Radiation Protection Technician. This organization is shown in Figure 13.1-3.

With both units defueled or both units at or below 200°F in primary system temperature, the minimum shift crew complement is reduced to:

- one Shift Foreman.
- no Senior Licensed Operator. However, at least one licensed Senior Operator or licensed Senior Operator limited to fuel handling will be present during core alterations on either unit who has no other concurrent responsibilities.
- two licensed operators, at least one will be assigned to each unit.
- three auxiliary operators, at least one will be assigned to each unit.
- one chemical and radiation protection technician.

This organization is shown in Figure 13.1-4.

The shift crew composition may be one less than the above minimum requirements, 10 CFR 50.54(m)(2)(i), and the Technical Specifications for a period of time not to exceed two hours in order to accommodate unexpected absence of on duty shift crew members provided immediate action is taken to restore the shift crew composition to within the above minimum requirements. This provision does not permit any shift crew position to be unmanned upon shift change due to an oncoming shift crewman being late or absent.

The establishment of the shift organization is based on consideration of PG&E's power plant staffing philosophy, the evaluation of the operating practices of U.S. pressurized water reactor plants, PG&E's experience with HBPP and large (up to 750 MWe) fossil-fuel units, and the expanded technical and operational regulatory requirements of nuclear power operation.

This shift organization provides effective manpower to cover the operating contingencies that can reasonably be expected to occur during normal operation of the plant. An organization of this size is also effective to monitor operation of engineered safety systems in the event of any plant accidents. The shift organization includes sufficient personnel to perform those operations required to implement the required portions of the Emergency Plan.

The shift chemical and radiation protection technician performs the chemistry sampling and analysis radiation monitoring, and other chemistry and radiation protection functions normally encountered during both normal and nonroutine operations. In addition, all licensed operators are trained in chemistry and radiation protection as part of their operator license training.

13.1.3 QUALIFICATION REQUIREMENTS FOR NUCLEAR PLANT PERSONNEL

13.1.3.1 Minimum Qualification Requirements

PG&E is using Regulatory Guide 1.8 (ANSI/ANS 3.1-1978) as the basis for establishing minimum qualification requirements for comparable management, supervisory, and technical positions in the plant organization. One exception is that the Manager, Radiation Protection, shall meet or exceed the qualification requirements of Regulatory Guide 1.8, Revision 2, April 1987 for the Radiation Protection Manager. A second exception is that the operations manager shall meet or exceed the minimum qualifications as specified in Technical Specification 5.2.2.e. A third exception is that the licensed Reactor Operators and SROs shall meet or exceed the minimum qualifications of ANSI/ANS 3.1-1993 (Reference 6) as endorsed by Regulatory Guide 1.8, Revision 3, May 2000 (Reference 7) with the exceptions clarified in the current revision to NUREG-1021 (Reference 8), Section ES-202. Other exceptions are summarized in Table 17.1-1.

The minimum qualification processes for physical force personnel (operators,

instrument technicians, maintenance personnel, and chemical and radiation protection technicians) are defined by the Institute of Nuclear Power Operation (INPO) accreditation criteria (Reference 5). PG&E has received, and will maintain, INPO accreditation of the training and qualification programs for physical force personnel.

13.1.3.2 Qualifications of Plant Personnel

PG&E has addressed NUREG-0660 (Reference 1), NUREG-0731 (Reference 2), and Regulatory Guide 1.8 (Reference 3) (ANSI/ANS-3.1-1978, Standard for Qualification and Training of Personnel of Nuclear Power Plants) as the basis for establishing minimum educational background and experience requirements for all management, supervisory, and professional personnel.

The key management, supervisory, and technical positions in the plant organization are filled by individuals who have been actively engaged in the nuclear power field. Qualification forms for personnel holding the key positions in the plant operating organization are maintained on file at the plant.

13.1.4 REFERENCES

1. NUREG-0660, NRC Action Plan Developed as a Result of the TMI-2 Accident, Task I.B.1

2. NUREG-0731, Guidelines for Utility Management Structure and Technical Resources

3. Regulatory Guide 1.8, Personnel Selection and Training, USNRC February 1979

4. Regulatory Guide 1.33, Quality Assurance Program Requirements (Operation), USNRC February 1978

5. ACAD 00-001, Revision 0, The Process for Accreditation of Training in the Nuclear Power Industry, January 2000

6. ANSI/ANS 3.1, American National Standard for Selection, Qualification, and Training of Personnel for Nuclear Power Plants, April 1993

7. Regulatory Guide 1.8, Qualification and Training of Personnel for Nuclear Power Plants, Revision 3, May 2000

8. NUREG-1021, Operator Licensing Examination Standards for Power Reactors

13.2 TRAINING PROGRAM

13.2.1 INITIAL PROGRAM DESCRIPTION

The experience obtained by PG&E since 1956 in training personnel for operation and maintenance of nuclear power plants has enabled it to clearly define the training requirements for each position in the plant organization and to evaluate the various means of obtaining this training. Based on this experience, PG&E chose to utilize a combination of formal classroom training and on-the-job experience with operating nuclear plants to achieve its training goals. A brief summary of each of the initial training activities is given in Table 13.2-1. The extent to which each individual participated in these activities was determined based on the person's position in the plant organization and his previous experience. A training summary for the initial operating organization is presented in Table 13.2-2.

Tables 13.2-1 and 13.2-2 summarize the initial plant training program and are historical in nature.

13.2.1.1 Program Content

The training programs described in Sections 13.2.1.1.1, 13.2.1.1.2, 13.2.1.2, 13.2.1.3, 13.2.1.4, 13.2.1.5, and 13.2.1.6 were for the initial plant personnel and are retained herein for historical value. Starting with Section 13.2.1.7, the present and ongoing plant training programs are described.

13.2.1.1.1 Training for Initial Plant Supervisorial Personnel

The training programs for the initial appointees to supervisory positions in the Diablo Canyon operating organization are summarized in Table 13.2-2.

The first formal involvement by a member of the plant staff in the Diablo Canyon project occurred in early 1968, when the Power Plant Engineer was assigned to PG&E's General Office for approximately 2 months to assist in the preparation of the preliminary safety analysis report (PSAR) for Unit 1. In the spring of 1969, both the Power Plant Engineer and the Supervisor of Operations were engaged in similar work on the Unit 2 PSAR for approximately 6 months, and they also assisted in the conceptual design of several plant systems. These two individuals were then assigned to the R. E. Ginna plant in the latter part of 1969 to participate in the startup testing program. Since that time, other key plant supervisory personnel have been sent to various pressurized water reactor (PWR) plants that were in operation or in the startup testing program. The majority of these assignments took place in the period from 1970 to 1972.

In July 1970, the second major step in the early supervisory training activities occurred with the organization of the Diablo Canyon Task Force at Humboldt Bay. This was the first time that the majority of the supervisory staff was assembled as a group. Initially, the Task Force consisted of 14 individuals on a full- or part-time basis. During the

period that the group was at Humboldt Bay, work was begun on the various Task Force assignments, including preparation of training material, operating manuals, licensing material and technical specifications, and performing an operational review of the plant design.

In August 1971, the Task Force was transferred to the site, along with several supervisors who had not previously been on the Task Force, in order to obtain maximum participation of plant staff personnel in onsite activities, including observation of equipment installation and review and comment on the system and equipment preoperational and startup test procedures prepared by the General Construction Department.

The second basic phase of the training program began with the arrival onsite of selected plant operators about 5 years before the initial anticipated core loading. At that time, the formal nuclear training courses required to prepare individuals for the operator license examinations began. These courses were conducted by members of the plant supervisory staff. Depending on a particular individual's experience and qualifications, supervisors were either instructors or participants as appropriate during different portions of this program. In most cases, the supervisors participating in these courses had completed similar training at the Humboldt Bay Power Plant.

In addition to participation in the formal training programs, the supervisors were actively engaged in preoperational testing and checkout of systems and equipment, hot functional testing, initial loading and low level testing, and in the power escalation program leading to commercial operation, as those activities took place.

13.2.1.1.2 Training for Plant Physical Force Personnel

All physical force personnel were trained in radiation protection, quality assurance, and security procedures and practices to an extent commensurate with their duties. In addition, the chemical and radiation protection technicians and control technicians participated in the nuclear technology and plant design seminars. The chemical and radiation protection technicians were also trained in chemical and radiochemical techniques.

The first physical force personnel assigned to the site were the control technicians, three of whom arrived in late 1971. They were placed on loan to the General Construction instrument staff and participated in the installation and checkout of plant equipment. An apprentice control technician was transferred to the site in December 1972 and was also placed on loan to General Construction.

13.2.1.2 Coordination with Preoperational Tests and Fuel Loading

The schedule of formal nuclear training designed to prepare candidates for NRC Operator and Senior Operator License examinations is shown in Figure 13.2-1 in relation to the schedule for preoperational testing and initial fuel loading.

13.2.1.3 Practical Reactor Operation

The senior control operators and control operators for Unit 1 were assigned to the site about five years before the initial anticipated core loading and began formal training at that time. The remaining operators were assigned as the preoperational testing work load dictated. All operators received extensive on-the-job training in the operation of plant controls during the preoperational and startup testing programs.

Other physical force personnel were assigned to the site as dictated by the work load and in time to complete any training required prior to work assignment.

13.2.1.4 Reactor Simulator Training

The simulator training program for the "Cold" license candidates is described in Table 13.2-1, Section 16, Simulator Training.

13.2.1.5 Previous Nuclear Training

The majority of the initial supervisory personnel had several years of nuclear power plant experience at Humboldt Bay Power Plant or at other nuclear facilities. Thus, the initial training for this group was largely concentrated in two major areas: (a) becoming familiar with the differences between the PWR and boiling water reactor (BWR) concepts, and (b) study of the design and operation of the Diablo Canyon plant itself.

13.2.1.6 Other Scheduled Training

Plant personnel were required to participate in a program of lectures, demonstrations, written assignments, and drills designed to familiarize them with fire protection procedures, security procedures, medical and first aid techniques, radiation protection principles, their actions in the event of a plant emergency, and other topics. The extent of the training that a particular individual received was dependent on the responsibilities of his or her position on the plant staff.

13.2.1.7 Training Programs for Nonlicensed Personnel

Each individual on the plant staff receives training to some degree depending on the scope of their job duties and responsibilities. This training falls into three general categories: (a) standard PG&E training programs, (b) general employee training programs related to working at Diablo Canyon, and (c) training programs specific to job-related departmental duties.

All personnel receive general employee training as discussed in Section 13.2.1.8.

Each onsite NPG department has defined a training program directed toward the technical skills needed for job-related duties. These training programs are described in the Plant Manual.

13.2.1.8 General Employee Training Program

Training programs involving industrial safety, first aid, fire protection, security, emergency planning, radiation protection, quality control, and other general topics are conducted for onsite personnel to supplement specific job-related technical training programs.

General training for all onsite personnel is given in the following areas:

(1) General description of plant and facilities
(2) General site rules
(3) Radiological health and safety program
(4) Site emergency plans
(5) Industrial safety program (including medical emergency response notification, and general fire protection)
(6) Security program
(7) Quality assurance/orientation
(8) Fitness for Duty
(9) Hazardous Materials

The extent of training in the above topics varies from one person to another commensurate with factors such as the duties and responsibilities of the person's job, areas of the plant to be accessed, whether the access is to be escorted or unescorted, duration of the access, and prior experience.

13.2.1.9 Responsible Individual

The Senior Vice President, Chief Nuclear Officer has overall responsibility for the entire training effort for plant personnel. He is responsible for ensuring that necessary training programs are established, implemented, documented, and audited.

The Director, Learning Services, reports to the Director, Station Support, and is responsible within the Nuclear Generation organization for conducting the majority of plant training. The director is also responsible for training coordination so that resources are used effectively and the training program content reflects the actual needs of the various departments and workers and satisfies current NRC and industry standards.

Within Learning Services, there are functional groups reporting to the Director, Learning Services, that conduct operator, technical, maintenance, engineering, and general employee training. There is also an ongoing training development and administration effort.

13.2.2 LICENSED OPERATOR CONTINUING (REQUALIFICATION) TRAINING PROGRAM

The Diablo Canyon Licensed Operator Continuing Training Program was accredited by INPO in March 1986. This program is maintained in accordance with the standards specified in the accreditation criteria and is evaluated for accreditation renewal every four years.

On May 26, 1987, the NRC revised 10 CFR 55 regarding training and qualifications of licensed operators. As a result of this issuance, DCPP revised its Continuing Training Program to meet the requirements of 10 CFR 55 utilizing a Systems Approach to Training methodology.

In accordance with Generic Letter 87-07, PG&E submitted a response on April 28, 1988, to inform the NRC that the DCPP Continuing Training Program would be following a Systems Approach to Training methodology.

PG&E will comply with the functional requirements identified in the American National Standard Institute/American Nuclear Society (ANSI/ANS) 3.5-2009, “Nuclear Power Plant Simulators for Use in Operator Training and Examination.” Personnel qualifications will be in accordance with the requirements specified in Chapter 17, Table 17.1-1.

13.2.3 REPLACEMENT TRAINING

13.2.3.1 Licensed Operator and Senior Operator Training Program

The Diablo Canyon Licensed Operator and Senior Licensed Operator Training Program was accredited by INPO in March 1986. These programs are maintained in accordance with the standards specified in the accreditation criteria and are evaluated for accreditation renewal every four years.

On May 26, 1987, the NRC revised 10 CFR 55 regarding training and qualifications of licensed operators. As a result of this issuance, DCPP revised the Licensed Operator and Senior Licensed Operator Training Programs to meet the requirements of 10 CFR 55 utilizing a Systems Approach to Training methodology.

In accordance with Generic Letter 87-07, PG&E submitted a response on April 28, 1988, to inform the NRC that the DCPP Licensed Operator and Senior Licensed Operator Training Program would be following a Systems Approach to Training methodology.

13.2.3.2 Shift Technical Advisor Training Program

The Diablo Canyon Shift Technical Advisor (STA) Training Program was accredited by INPO in March 1986. This program is maintained in accordance with the standards

specified in the accreditation criteria and is evaluated for accreditation renewal every four years.

13.2.3.3 Non-Licensed Operator Training Program

The Diablo Canyon Non-Licensed Operator Training Program was accredited by INPO in March 1986. This program is maintained in accordance with the standards specified in the accreditation criteria and is evaluated for accreditation renewal every four years.

13.2.4 RECORDS

Training record files are maintained for all personnel. The files are maintained in accordance with Plant Manual procedures that state that the files shall contain records of qualifications, experience, training, and retraining for each member of the plant organization. Audits of the various plant training programs and records are conducted by the quality verification organization.

13.3 EMERGENCY PLANNING

A comprehensive Emergency Plan has been developed for Diablo Canyon as required by Section 50.47(b) and Appendix E to 10 CFR 50. It serves several purposes including:

(1) Establishing the emergency duties and responsibilities of the various members of the plant staff at or near the site

(2) Informing all affected agencies (including members of the plant staff) of the interfaces that have been established between the plant staff and participating PG&E and non-PG&E support groups

(3) Providing a convenient means for gathering together, by way of appendices to the Emergency Plan, the plans of the various participating offsite agencies such that plant staff personnel are made aware of the basic responsibilities and capabilities of these agencies

(4) Providing an overview of the facilities, equipment, and procedures utilized by the plant staff in the emergency in order to inform and assist those offsite agencies who must coordinate their activities with those of the plant staff

(5) Providing training and exercising of emergency plans for both licensee employees and other support groups' personnel

(6) Fulfilling licensing requirements of the NRC

The DCPP Emergency Plan has been developed in accordance with the guidance of NUREG-0654/FEMA-REP-1[(1)] and has been placed on the docket of each unit.

13.3.1 REFERENCES

1. NUREG-0654/FEMA-REP-1, Revision 1, Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants, November 1980.

13.4 REVIEW AND AUDIT

13.4.1 REVIEW AND AUDIT - CONSTRUCTION PHASE

The independent review and audit of construction activities was incorporated into the Quality Assurance Program during design, construction, and preoperational testing as prescribed by the Quality Assurance program as described in Chapter 17 of the FSAR Update.

13.4.2 REVIEW AND AUDIT - OPERATION PHASE

Review and audit during the operation phase is accomplished by senior members of the plant staff, independent review and audit groups, and management oversight groups as discussed below. In addition, the quality verification (QV) organization independently audits operation phase activities in accordance with FSAR Update, Chapter 17.

13.4.2.1 Plant Staff Review Committee

A PSRC has been established at the plant site to advise the Station Director on all matters related to nuclear safety. The PSRC's functions and responsibilities are detailed in Section 17.2 of this FSAR Update.

13.4.2.2 Independent Review and Audit Program

A program of independent review and audit of nuclear plant operations has been in effect since the initial operation of HBPP, Unit 3 in 1963. This program, which was applied to the preoperational testing, startup testing, and operation of DCPP, has been reviewed and appropriately modified so that it conforms to the requirements and recommendations of ANSI N18.7-1976, Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants.

This program satisfies the requirements of Sections 4.3 and 4.5 of ANSI 18.7-1976. The independent review and audit program functions and responsibilities are detailed in Section 17.2 of this FSAR Update.

13.4.2.3 Management Oversight Groups

As a means for corporate management to be involved in nuclear plant safety considerations and to ensure that these considerations are effectively applied to plant operation, management oversight groups have been established.

13.5 PLANT PROCEDURES AND PROGRAMS

13.5.1 PROCEDURES

Safety-related activities involving the design, operation, maintenance, and testing of plant systems and equipment are carried out in accordance with written policies and detailed written procedures. These policies and procedures, as well as others involving plant activities not related to safety, are incorporated into a Diablo Canyon Plant Manual. Because of its physical size and diversity of topics, this manual has been divided into multiple volumes.

Except as noted in FSAR Update Table 17.1-1, these policies and procedures implement the requirements of the NRC Regulatory Guide 1.33, Revision 2, Quality Assurance Program Requirements (Operations) (Reference 1) and the requirements and recommendations of ANSI N18.7-1976, Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants. Emergency operating procedures meet the requirements of Supplement 1 to NUREG-0737, Requirements for Emergency Response Capability (Reference 2).

The review, change, and approval process for these procedures is described in Section 17.5.

13.5.2 PROGRAMS

13.5.2.1 Process Control Program

The Process Control Program (PCP) contains the current formulas, sampling, analyses, tests, and determinations to be made to ensure that processing and packaging of solid radioactive wastes based on demonstrated processing of actual or simulated wet solid wastes will be accomplished in such a way as to ensure compliance with 10 CFR Parts 20, 61, and 71 and Federal and State regulations, burial ground requirements, and other requirements governing the disposal of solid radioactive waste.

Changes to the PCP are documented and records of review for changes made to the PCP are retained. The documentation contains:

- sufficient information to support the change together with the appropriate analyses or evaluations justifying the change(s), and

- a determination that the change will maintain the overall conformance of the solidified waste product to existing requirements of Federal, State, or other applicable regulations.

PCP changes become effective after review and approval by the Station Director.

13.5.2.2 Radiation Protection Program

Procedures for personnel radiation protection are prepared consistent with the requirements of 10 CFR 20 and are approved, maintained, and adhered to for all operations involving personnel radiation exposure.

13.5.2.3 In-Plant Radiation Monitoring

A program, which will ensure the capability to accurately determine the airborne iodine concentration in vital areas under accident conditions is established, implemented, and maintained. The program includes:

- Personnel training
- Procedures for monitoring
- Provisions for maintenance of sampling and analysis equipment

13.5.2.4 Backup Method for Determining Subcooling Margin

A program, which will ensure the capability to accurately monitor the Reactor Coolant System subcooling margin is established, implemented, and maintained. The program includes the following:

- Personnel training
- Procedures for monitoring

13.5.2.5 Containment Polar and Turbine Building Cranes

A program is established, implemented, and maintained to ensure that: (1) the parked location of the containment polar cranes precludes jet impingement from a postulated pipe rupture, and (2) the operation of the turbine building cranes is consistent with the restrictions associated with the current Hosgri seismic analysis of the turbine building. This program includes the following:

- Personnel training
- Procedures for the containment polar and turbine building cranes operation

The procedures will control the operation of the containment polar cranes in jet impingement zones.

13.5.2.6 Motor-Operated Valve Testing and Surveillance Program

A program is established to comply with Generic Letter 89-10, “Safety-Related Motor-Operated Valve Testing and Surveillance” and its supplements and Generic Letter 96-05, “Periodic Verification of Motor-Operated Valves.”

13.5.3 REFERENCES

1. Regulatory Guide 1.33, Rev. 2, Quality Assurance Program Requirements (Operational), USNRC, February 1978.

2. NUREG-0737, Supplement 1, Requirements for Emergency Response Capability, December 1982.

3. NRC Letter to PG&E, dated May 28, 1999, granting License Amendment 135, Units 1 and 2.

4. PG&E letter DCL-94-262, dated November 28, 1994, “Closure Response to NRC Generic Letter 89-10” and all supporting PG&E letters.

5. PG&E Letter DCL 99-031, dated March 25, 1999, “Response to Request for Additional Information Regarding NRC Generic Letter 96-05, Periodic Verification for Motor Operated Valves” and all supporting PG&E letters.

13.6 PLANT RECORDS

Plant records are maintained in accordance with established PG&E practices. The records management program is discussed in Chapter 17.

13.7 PHYSICAL SECURITY

The Security Plans for DCPP have been developed as required by 10 CFR 73 and DPR-80 and DPR-82 License Condition E.

The Security Plans include the following:

(1) The Physical Security Plan (PSP), including the following appendices:

   (a) Appendix A: Glossary of Security Plan terms

   (b) Appendix B: Training and Qualification Plan (per 10 CFR 73, Appendix B)

   (c) Appendix C: Safeguards Contingency Plan (per 10 CFR 73, Appendix C)

   (d) Appendix D: Independent Spent Fuel Installation Security Program (per 10 CFR 73.51)

(2) The Cyber Security Plan (CSP).

The PSP establishes and maintains a physical protection system and security organization on site for the purpose of protecting against radiological sabotage and preventing the theft of special nuclear material. Portions of the information contained in the PSP are considered to be "Safeguards Information" as defined in 10 CFR 73.2 and must therefore be protected against public disclosure and disseminated on a "need-to-know" basis as required by 10 CFR 73.21.

The CSP is the program implemented to prevent damage to, unauthorized access to, and allow restoration of computers, electronic communications systems, electronic communication services, wire communication, and electronic communication, including information contained therein, to ensure its availability, integrity, authentication, confidentiality, and non-repudiation. In control systems, this would include unauthorized access that could affect operation of plant structures, systems, or components. The CSP contains information that has been designated "Security-Related Information - Withhold under 10 CFR 2.390."

The PSP has been approved by the NRC and is implemented at the DCPP site.

The implementation of the CSP, including the key intermediate milestone dates and the full implementation date, will be in accordance with the implementation schedule submitted to the NRC in PG&E Letter DCL-11-040, dated April 4, 2011, and approved by the NRC Staff with License Amendments (LA) 210 (DPR-80) and LA 212 (DPR-82).

All changes to the Security Plans require evaluation per 10 CFR 50.54(p) to determine if prior NRC review and approval via 10 CFR 50.90, the License Amendment process, is required.

TABLE 13.2-1

SUMMARY OF ACTIVITIES EMPLOYED IN TRAINING PROGRAMS
FOR PERSONS IN THE INITIAL DIABLO CANYON OPERATING ORGANIZATION
(HISTORICAL AS SUBMITTED IN NOVEMBER 1978)

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1. Humboldt Bay Experience

   Many of the key individuals in the initial plant organization were members of the Humboldt Bay staff before they transferred to Diablo Canyon Power Plant and have extensive nuclear experience in their areas of responsibility. Certain other individuals, who were not members of the Humboldt Bay staff, have been assigned there for appropriate periods to participate in operations involving their areas of responsibility.

2. PWR Experience

   Key individuals were assigned to an operating PWR (or one in the process of preoperational and/or startup testing) to observe and/or participate in operations involving their areas of responsibility. The plants involved included R. E. Ginna, H. B. Robinson, Connecticut Yankee, Point Beach, and San Onofre. Assignments ranged from 3 weeks to 7 months, with most lasting approximately 1 month.

3. Participation in the Diablo Canyon Task Force

   This group consists of selected technical and operating supervisory personnel and is responsible for the preparation of training material, operating manuals, licensing material and Technical Specifications, test procedures, and for performing an operational review of the plant design.

4. Design Lecture Series

   This 4-week course was conducted in March 1971 at the Westinghouse Atomic Power Division in Pittsburgh, Pennsylvania. Fifteen supervisors on the plant staff and one member of the Department of Steam Generation attended this course. The trainees were given a series of lectures covering the function, design description, control and instrumentation, normal and abnormal operation, and maintenance of all principal components of the Diablo Canyon Units 1 and 2 nuclear steam supply systems. These lectures were given by Westinghouse design engineers who were closely associated with the design of the plant. The lectures were supplemented by study of written information on pressurized water reactor technology provided by Westinghouse and trips to Westinghouse manufacturing facilities where trainees were afforded an opportunity to witness actual fabrication of components.

5. <u>Nuclear Technology Course</u>

This course is taught by members of the plant staff and utilizes PG&E's Introduction To Nuclear Power training manual as a text. The purpose of this course is to provide a general background in the field of nuclear power plant technology. The major topics that are included in the course are:

a. Basic mathematics
b. Basic atomic and nuclear physics
c. Introduction to nuclear reactors and nuclear power plant cycles
d. Light water reactor physics
e. Heat transfer considerations in light water reactors
f. Operating characteristics of light water reactors
g. Nuclear instrumentation
h Chemical, radiochemical, and waste disposal considerations in light water reactor operation
i. Reactor safeguards.

These topics are treated in sufficient depth to prepare an individual for applicable portions of the Senior Operator License examination. The complete course, which is intended for license candidates, takes about 4 weeks and covers each of these topics in detail. Abbreviated versions of the course covering subjects directly related to their duties and responsibilities are given to other personnel as appropriate.

6. <u>Radiation Protection Training Course</u>

This course is taught by members of the plant staff and utilizes PG&E's Radiation Protection Training Manual, Radiation Control Standards And Procedures, and other appropriate material as texts. The standards are a compilation of technical statements of policy covering each aspect of a nuclear power plant's radiation protection program and are based on the requirements of 10 CFR 20 and other applicable regulations. The procedures provide practical information regarding the implementation of the standards and are based on adaptations to nuclear power plant requirements of procedures and practices widely used throughout the atomic energy industry.

The Training Manual is a general work that covers theory and other background material. The major topics covered in this course include:

a. Basic radiation physics and biology
b. Sources of radioactivity in nuclear power plants
c. Radiation protection instrumentation
d. Fundamentals of shielding
e. Personnel exposure limits

f. Protective clothing and equipment
g. Control and transfer of radioactive materials
h. Decontamination practices
i. Radiation monitoring techniques
j. Control of access
k. Records and reporting requirements.

The complete course for radiation and process monitors requires about 4 weeks. A similar course designed for NRC license examination candidates required about 1 week. Personnel in other classifications receive shorter courses covering those subjects directly related to their duties and responsibilities.

7. Plant Design and Operation Seminars

This seminar course is conducted by supervisory personnel on the plant staff and covers the design, description, and operation of each plant system plus related topics such as the Technical Specifications and the Site Emergency Plan. The course is primarily designed for operators and is expected to last about 8 weeks. As appropriate, personnel in other classifications will receive shorter courses covering systems and equipment related to their areas of responsibility.

8. NRC Operator and Senior Operator License Examination Seminars

These seminars are conducted by supervisory personnel on the plant staff for the benefit of license examination candidates. They consist of a review of appropriate items in activities 5, 6, and 7 above plus discussions of additional topics required to cover the items listed in 10 CFR 55.21-23. The length of this program will be determined following an evaluation of the needs of the individuals involved, but based on Humboldt Bay experience, it is expected to last about 4 weeks.

9. P-250 and P-2000 Computer Maintenance Courses

These courses, lasting a total of 16 weeks, were conducted in the fall of 1970 by Westinghouse Computer and Instrument Division personnel and were designed to provide comprehensive coverage of the construction, operation, repair, and maintenance of the P-250 and P-2000 computers. The course attended by Diablo Canyon personnel was held at PG&E's Pittsburg Power Plant where a P-250 computer was available for use by the students.

10. Instrument and Control Course

This is a 12-week course intended for instrument maintenance supervisors and technicians and is conducted by instructors from the Nuclear Instrumentation and Control

Department of Westinghouse at the department headquarters in Baltimore, Maryland. The general subjects covered include the design, maintenance, and testing of the solid-state rod control system, flux mapping system, nuclear instrumentation system, radiation monitoring system, and solid-state protection system. The course combines both formal classroom lectures on systems and modules and practical bench work with the equipment. Diablo Canyon personnel attended this course beginning in January 1972.

11. Process Controls Course

This 2-week course was conducted at the Portland General Electric Trojan site in June 1972 by Westinghouse Computer and Instrument Division personnel. The course material included lectures on both systems and modules for the various process control systems (feedwater control, steam dump, pressurizer level and pressure). In addition, the various modules were available for bench work by the students.

12. Refresher Course in Radiological Engineering

This 3-week course was conducted in 1972 by personnel from the health physics staff of the General Electric Company Vallecitos Nuclear Center. It was designed to provide graduate-level refresher training in radiological engineering topics such as internal and external radiation dosimetry, radiation biology, atmospheric diffusion modules, instrumentation, and environmental pathways. It consisted primarily of formal classroom lectures.

13. Chemistry and Radiochemistry Seminars

These seminars are conducted by supervisory personnel on the plant staff for training of radiation and process monitors, and will take about 4 months. The subject matter for these seminars will include such topics as basic chemistry, laboratory techniques, radiochemical methods, and theory and use of counting room equipment. A variety of texts will be employed, including PG&E procedures manuals, vendors' instruction manuals, and standard chemistry and radiochemistry texts. In addition, the classroom work will be supplemented by actual laboratory training as appropriate.

14. Nondestructive Testing School

This 3-week course is presented at the site by instructors from General Dynamics/Convair. The class consists of both formal lectures and practical demonstrations, and persons completing it and successfully passing the examinations are qualified as ASNT Level II inspectors for radiography, ultrasonic testing, magnetic particle testing, and liquid penetrant testing.

15. Operational Core Analysis Training

This 3-week course is presented in Pittsburgh, Pennsylvania, by Westinghouse and is intended for nuclear engineers. It discusses the theory and operation of the operational core analysis computer codes that will be used to monitor core thermal-hydraulic performance and fuel depletion.

16. Simulator Training

Candidates for "Cold" NRC licenses will attend a 14-day training program at the Westinghouse reactor simulator at Zion, Illinois.

The course has been established so that the typical day is divided approximately equally into classroom work and "hands-on" simulator time. Emphasis during the first week will be on taking the trainee through a simulated operational cycle from a cold shutdown through plant heatup/reactor startup/turbine-generator startup/power operation/plant shutdown/and plant cooldown. This first cycle will stress familiarization with control board and plant operation under normal operating conditions.

The second week's training will be a repeat of the training received the first week, but at an accelerated pace and will incorporate the maximum number of minor and major malfunction situations in the time allotted. The trainee will learn to identify specific malfunctions, analyze the hazards involved, and effect proper corrective actions. The second week will also incorporate simulation and evaluation of normal and abnormal plant transients and the required operator action to effect recovery from transient and accident situations.

A refresher simulator training course of seven days duration will be provided shortly before initial loading.

17. In-place Filter Testing Workshop

This 5-day workshop is conducted by the Harvard School of Public Health in Boston, Massachusetts. The subject matter deals with subjects of theory, design, and testing of HEPA and activated charcoal air filtration systems. About half of the time is devoted to classroom lectures and the other half consists of laboratory work using DOP generators and detection equipment and other filter testing devices. The Power Plant Engineer attended this course in September 1971.

TABLE 13.2-2

TRAINING SUMMARY FOR INDIVIDUALS IN THE INITIAL DIABLO CANYON OPERATING ORGANIZATION (HISTORICAL)

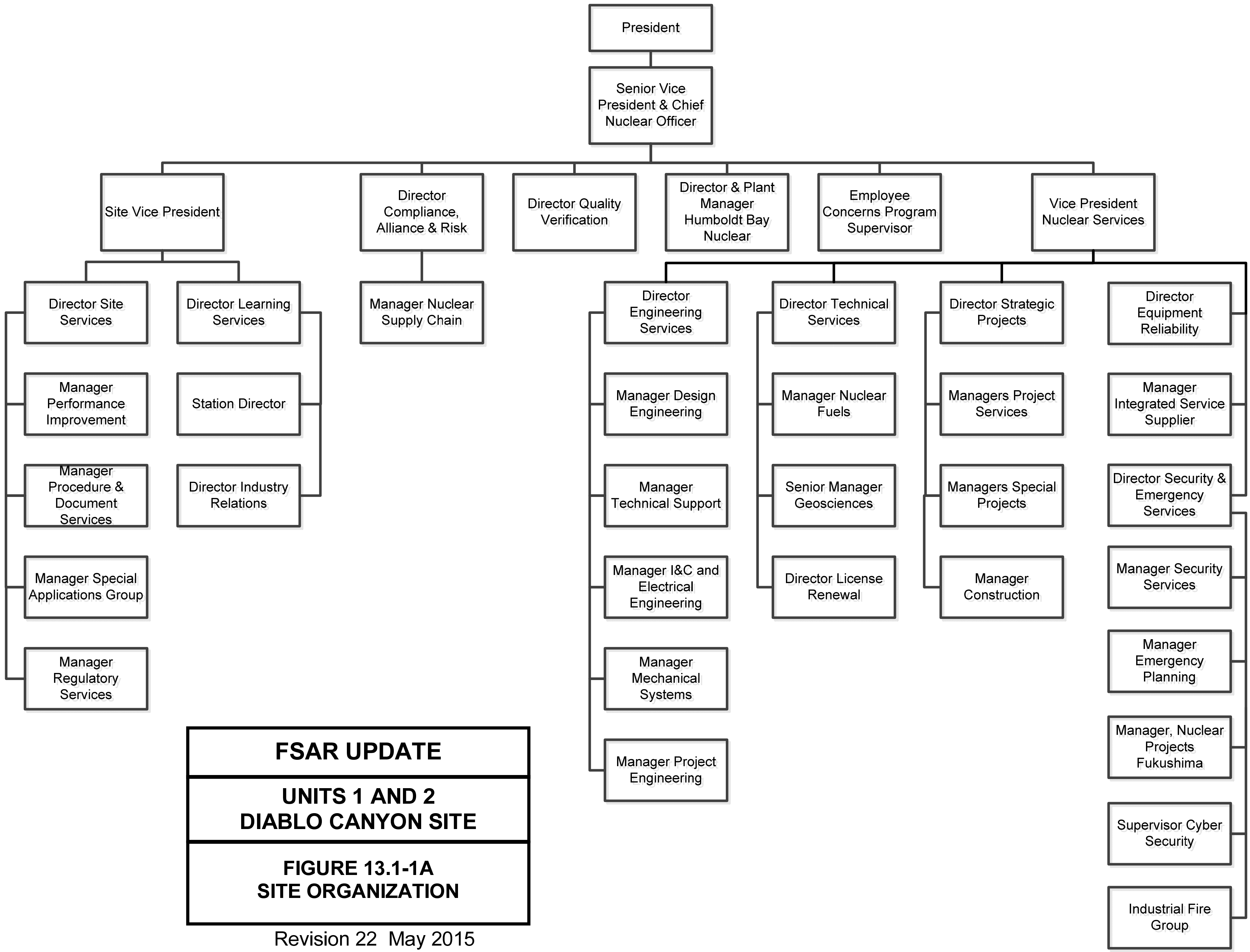
Position - Name	AEC License	Humblt. Bay Exper.	PWR Exper.	Task Force[(a)]	Dsgn. Lect. Series	Nuclr. Tech.	Rad. Prot. Course	Plant Dsgn. Semr.	Oper. Lic. Revw.	Comp. Maint.	I & C Course	Proc. Ctrls. Course	Rad. Engr. Refr.	Chem. Semrs.	NDT Sch.	Core Code	Anal. Trng.	Simul. Trng.
Plant Superint.	Cold SOL,OP	3 y	2 m	July 1970	P	OP	OP	OP	OP	-	-	-	-	-	-	-	-	P
Supv. of Operations	Cold SOL	3 y	6 m	July 1970	P	I	I	I	I	-	-	-	-	-	-	-	-	P
Power Plant Engr.	Cold SOL,OP	8 y	7 m	July 1970	P	I	I	I	I	-	-	-	P	-	-	-	-	P
Supv. of Maint.	-	9 y	1 m	Aug. 1971	P	OP	OP	OP	-	-	-	-	-	-	P	-	-	-
Relief Shift Supv.	Cold SOL	8 y	1 m	July 1970	P	OP	OP	I	I	-	-	-	-	-	-	-	-	P
Shift Foreman	Cold SOL	6 y	1 m	Oct. 1970	P	P	P	I,P	I,P	-	-	-	-	-	-	-	-	P
	Cold SOL	9 y	1 m	July 1970	P	P	P	I,P	I,P	-	-	-	-	-	-	-	-	P
	Cold SOL	9 y	1 m	Feb. 1972	-	P	P	I,P	I,P	-	-	-	-	-	-	-	-	P
	Cold SOL	10 m	1 m	May 1972	-	P	P	I,P	I,P	-	-	-	-	-	-	-	-	P
	Cold SOL	11 y	1 m	-	P	P	P	I,P	I,P	-	-	-	-	-	-	-	-	P
	Cold SOL	1 y	1 m	Aug. 1971	P	P	P	I,P	I,P	-	-	-	-	-	-	-	-	P
	Hot SOL	-	-	-	-	P	P	P	P	-	-	-	-	-	-	-	-	-
Nuclear Engineers	Cold SOL,OP	2 y	3 m[(b)]	Aug. 1970	P	I,OP	I,OP	I,OP	OP	-	-	-	-	-	P	-	-	-
	Cold SOL,OP	1 m	1 m[(b)]	Jan. 1971	-	I,OP	I,OP	I,OP	OP	-	-	-	-	-	-	-	-	P
	Hot SOL,OP	1 y	1 m	Dec. 1970	P	I,OP	I,OP	I,OP	OP	-	-	-	-	-	-	[(c)]	-	-
	Hot SOL,OP	-	-	-		OP	P	OP	OP	-	-	-	-	-	-	-	-	-
	Hot SOL,OP	-	-	-		OP	P	OP	OP	-	-	-	-	-	-	-	-	-
	Hot SOL,OP	-	-	-		OP	P	OP	OP	-	-	-	-	-	-	-	-	-
Chem. & Rad. Prot. Engr.	-	5 y	1 m	July 1970	-	OP	I	I,OP	I	-	-	-	P	I	-	-	-	-
		3 y	3 w	Nov. 1972	P	OP	I	I,OP	I	-	-	-	P	I	-	-	-	-
Instrument Engr.	-	8 y	2 m	July 1970	P	OP	OP	I,OP	-	-	P	-	-	-	-	-	-	-
Inst. & Contrls. Supv.	-	1 m	-	July 1970	-	OP	OP	I	-	P	P	P	-	-	-	-	-	-

TABLE 13.2-2

Position - Name	AEC License	Humblt. Bay Exper.	PWR Exper.	Task Force[(a)]	Dsgn. Lect. Series	Nuclr. Tech.	Rad. Prot. Course	Plant Dsgn. Semr.	Oper. Lic. Revw.	Comp. Maint.	I & C Course	Proc. Ctrls. Course	Rad. Engr. Refr.	Chem. Semrs.	NDT Sch.	Core Code	Anal. Trng.	Simul. Trng.
Q/A Coordinator	-	7 y	-	Aug. 1970	P	OP	I	I,P	I	-	-	-	-	-	-	-	-	-
Maintenance Engr.	-	-	-	-	-	OP	P	OP	-	-	-	-	-	-	-	-	-	-
Mechanical Foreman	-	-	-	-	-	OP	P	OP	-	-	-	-	-	-	-	-	-	-
Electrical Foreman	-	-	-	-	-	OP	P	OP	-	-	-	-	-	-	-	-	-	-
Operators	Hot L[(h)]	[(d)]	-	-	-	P	P	P	P	-	-	-	-	-	-	-	-	[(i)]
Control Technicians	-	[(e)]	-	-	-	OP	P	OP	-	[(f)]	[(g)]	-	-	-	-	-	-	-
Rad. & Proc. Monitrs.	-	OP	-	-	-	P	P	OP	-	-	-	-	-	P	-	-	-	-
Maint. Phys. Forces	-	-	-	-	-	-	P	-	-	-	-	-	-	-	-	-	-	-
Clerical	-	-	-	-	-	-	P	-	-	-	-	-	-	-	-	-	-	-

Key: y = years, m = months, w = weeks, P = participant, I = Instructor, OP = Optional Participation depends on work load and individual needs, SOL = Senior Operator License, L = Operator License

(a) Date given is date at which participation in Task Force project began. Task Force work largely complete by March 1973.
(b) Not including experience gained while not a PG&E employee.
(c) A second individual from the Steam Generation Department will also attend.
(d) It is expected that approximately 1/3 of the successful bidders will have had prior experience at Humboldt Bay. There are no plans to send others to Humboldt Bay.
(e) Two of the successful bidders have had several years of experience at Humboldt Bay. The other two have had approximately one month.
(f) Two only. A third individual has had computer experience in his previous assignment at a conventional plant. The fourth is receiving training as part of apprenticeship program.
(g) Three only. Fourth is in training as apprentice and will receive on-the-job experience prior to startup.
(h) For Assistant Control Operator and above.
(i) Three Senior Control Operators with prior Operator Licenses at Humboldt Bay.



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 13.1-1A
SITE ORGANIZATION

Revision 22 May 2015

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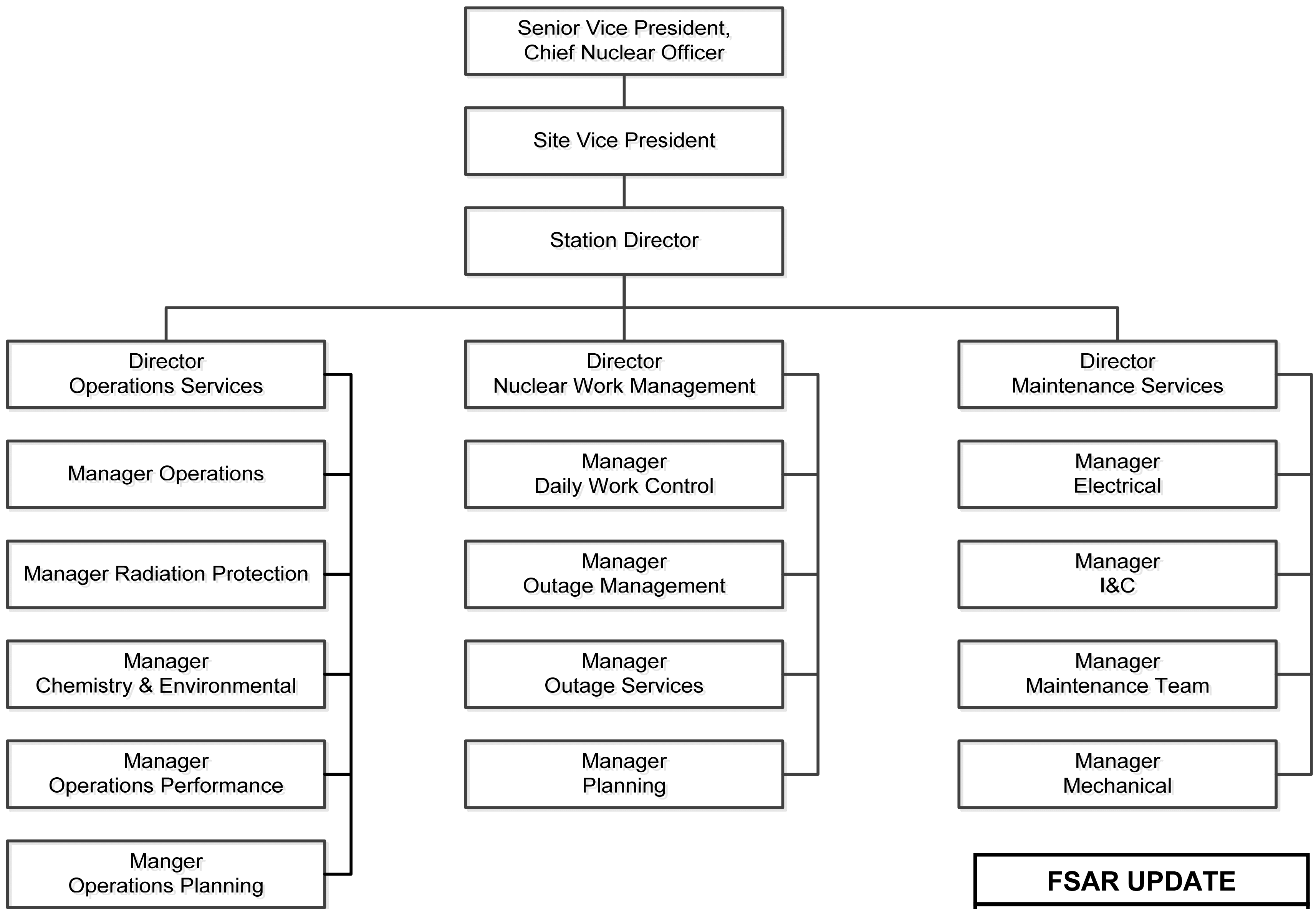
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 13.1-1B SERVICES ORGANIZATION

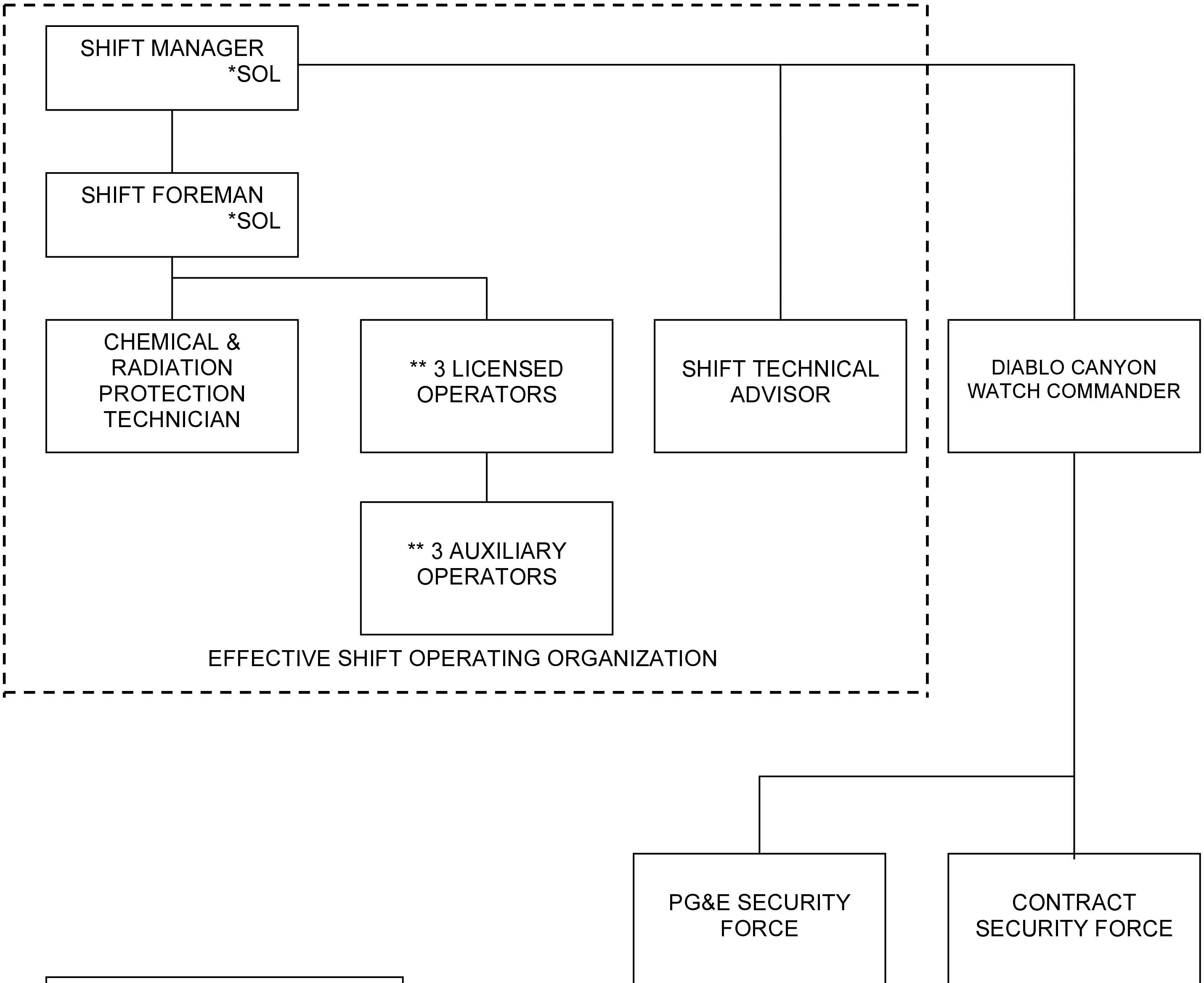


FSAR UPDATE

UNITS 1 AND 2 DIABLO CANYON SITE

FIGURE 13.1-1C OPERATING ORGANIZATION

Revision 22 May 2015



LEGEND:

SOL NRC SENIOR OPERATOR LICENSE REQUIRED

* SOL requirement may be fulfilled by any SOL individual. Not all Senior Control Operators have SOLs.

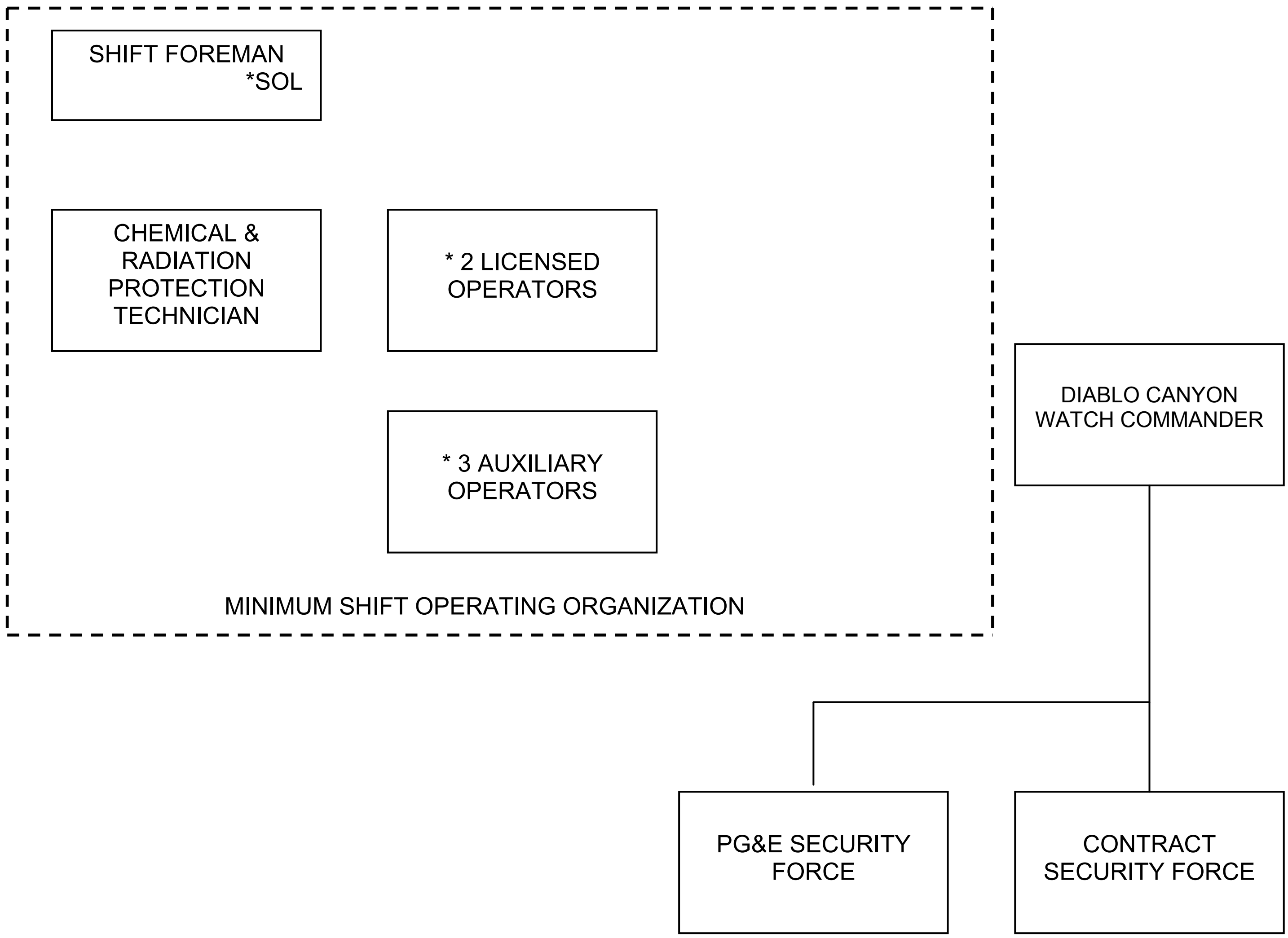
** Refer to FSAR Update, Section 13.1.2.3

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 13.1-3
EFFECTIVE SHIFT ORGANIZATION
EITHER OR BOTH UNITS FUELED AND ABOVE 200°F PRIMARY SYSTEM TEMPERATURE

Revision 22 May 2015



LEGEND:

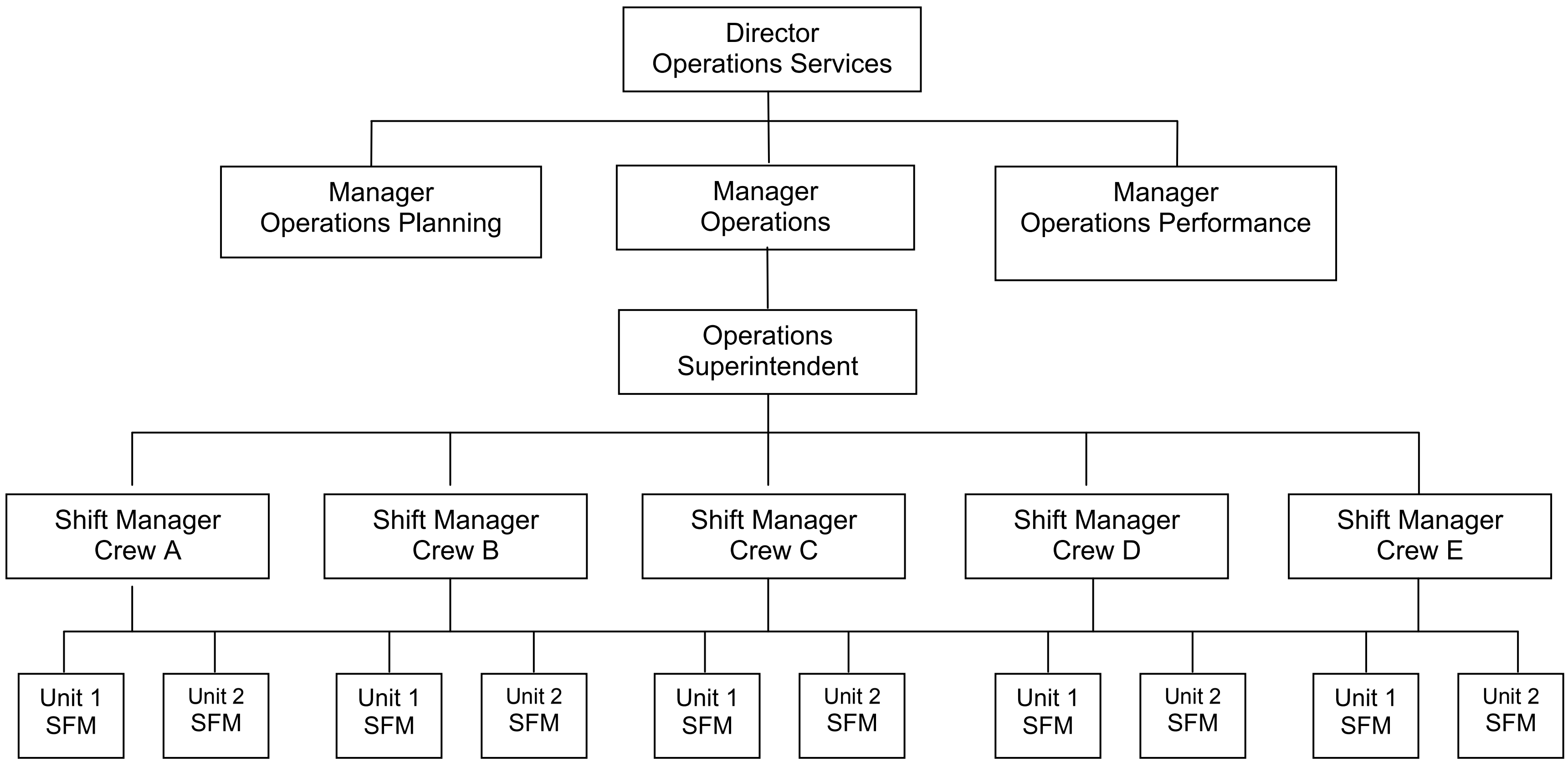
SOL NRC SENIOR OPERATOR LICENSE REQUIRED

* Refer to FSAR Update, Section 13.1.2.3

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 13.1-4
MINIMUM SHIFT ORGANIZATION
BOTH UNITS DEFUELED OR PRIMARY SYSTEM TEMPERATURE AT OR BELOW 200°F



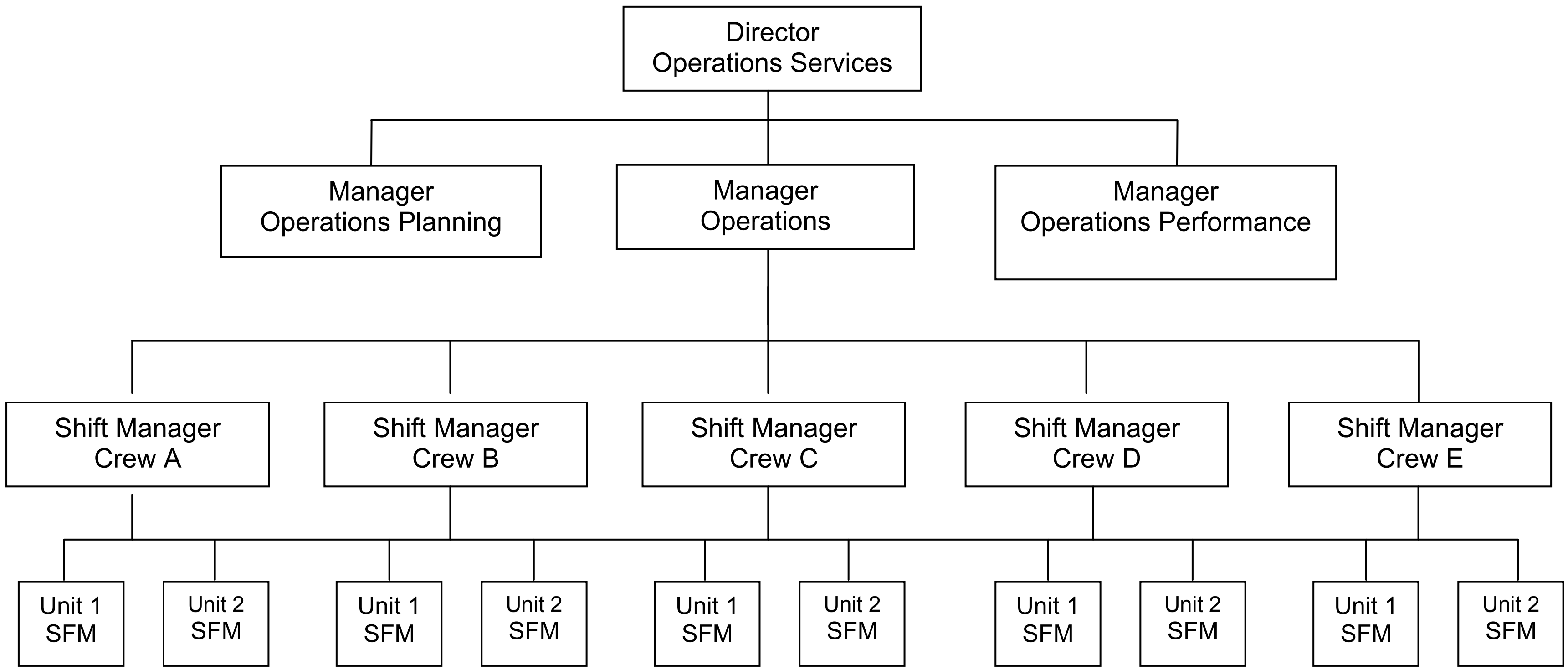
SFM – Shift Foreman

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 13.1-5
OPERATIONS ORGANIZATION IF MANAGER DOES NOT HOLD SRO LICENSE

Revision 19 May 2010



SFM – Shift Foreman

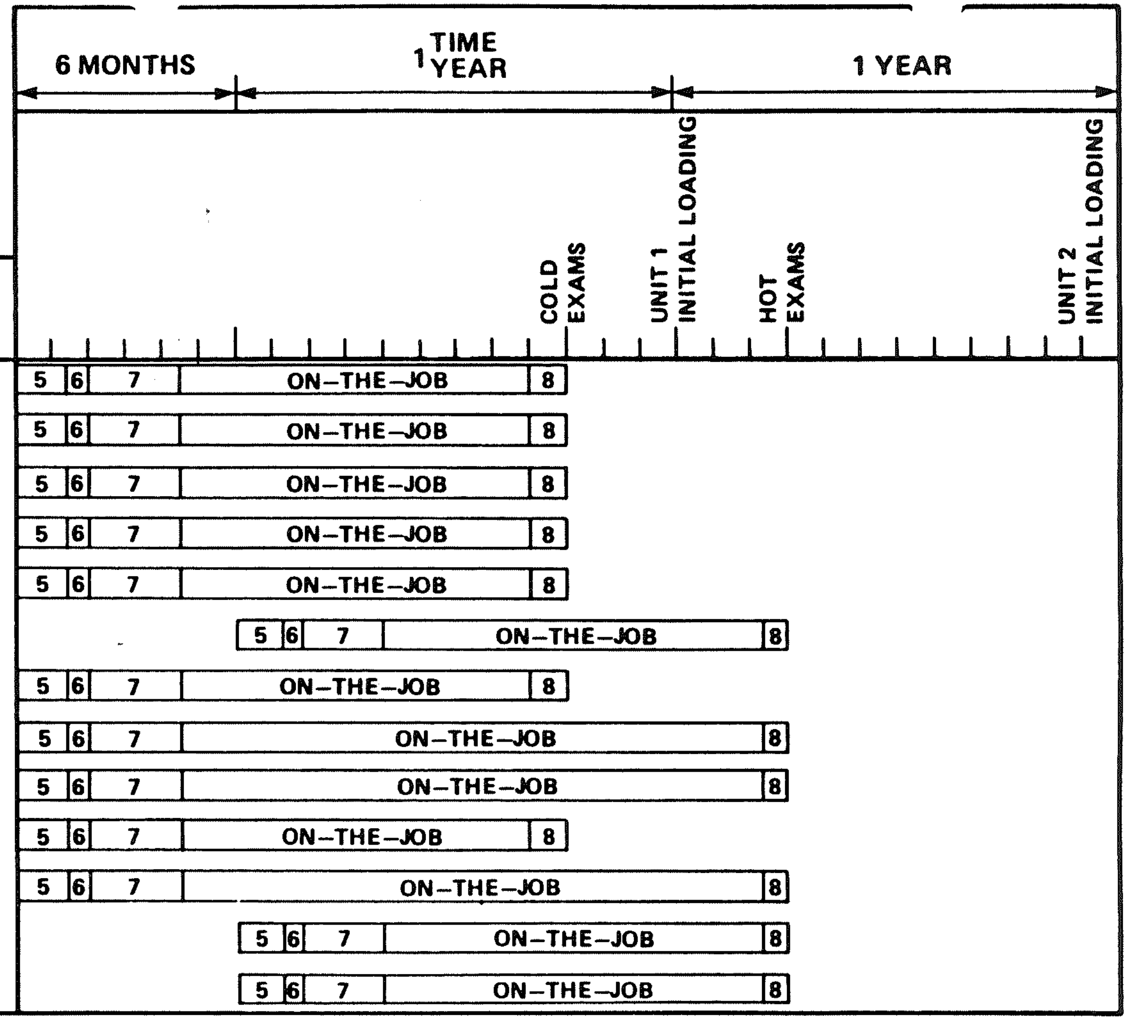
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 13.1-6
OPERATIONS ORGANIZATION IF MANAGER HOLDS SRO LICENSE

Revision 19 May 2010

POSITION	LICENSE
PLANT SUPERINTENDENT	COLD SOL*
SUPV. OF OPERATIONS	COLD SOL
POWER PLANT ENGINEER	COLD SOL*
RELIEF SHIFT SUPERVISOR	COLD SOL
SHIFT FOREMAN (6)	COLD SOL
SHIFT FOREMAN (1)	HOT SOL
NUCLEAR ENGINEERS (2)	COLD SOL*
NUCLEAR ENGINEERS (2)	HOT SOL*
SR. CONTROL OPERATORS	HOT SOL
SR. CONTROL OPERATORS (1)	COLD SOL
CONTROL OPERATORS	HOT L
ASSISTANT CONTROL OPERATORS	HOT L
AUXILIARY OPERATORS	



NOTE: 5 – NUCLEAR TECHNOLOGY COURSE
6 – RADIATION PROTECTION COURSE
7 – PLANT DESIGN SEMINAR
8 – LICENSE REVIEW SEMINAR
* – OPTIONAL

FSAR UPDATE

UNITS 1 AND 2 DIABLO CANYON SITE

FIGURE 13.2–1

INITIAL SCHEDULE OF PLANNED NUCLEAR TRAINING (HISTORICAL)

Chapter 14

INITIAL TESTS AND OPERATION

CONTENTS

Chapter 14

CONTENTS (continued)

Chapter 14

TABLES

Chapter 14

FIGURES

Chapter 14

INITIAL TESTS AND OPERATION

Sections 14.1 and 14.2 are historical in nature; they reflect the preoperational and initial startup test program through the start of commercial operation. Section 14.3 addresses the postcommercial operational test program.

14.1 TEST PROGRAM

The preoperational and initial startup program for the Pacific Gas and Electric Company's (PG&E's) Diablo Canyon Power Plant (DCPP) will demonstrate that:

(1) The plant is ready to operate in a manner that, with reasonable assurance, will not endanger the safety of the public.

(2) The procedures for operating the plant safely have been tested and demonstrated.

(3) The operating organization is knowledgeable about the plant and the procedures and is fully prepared to operate the plant safely.

The program is designed to demonstrate that structures, components, and systems meet the appropriate design criteria and otherwise operate satisfactorily. The program includes construction tests, preoperational or functional tests, initial fuel loading, and startup tests. The program will culminate in the operation of the plant at maximum guaranteed load.

The discussion of tests in this chapter generally excludes construction tests and otherwise includes only testing associated with safety-related requirements. Testing excluded from this discussion is administered in a manner consistent with the program described in this chapter.

Construction tests include hydrostatic testing, system cleaning, valve leakage tests, control valve operations, electrical continuity checks, electrical performance tests, and control instrument alignment. Construction tests are usually conducted as the components and systems are completed to ensure readiness for preoperational testing.

Preoperational tests demonstrate, insofar as possible prior to loading nuclear fuel, that those plant structures, components, and systems related to safety have been properly installed and operate according to design requirements. Preoperational tests that cannot be completed prior to fuel loading because the necessary test conditions do not exist will be completed when conditions are suitable for testing.

Preoperational testing of a system begins whenever construction is sufficiently advanced to indicate the test may be completed. This phase of testing began in 1973 and has been integrated with other construction activities.

Startup tests demonstrate that the plant will perform satisfactorily in normal operation and that, with reasonable assurance, the plant is capable of withstanding the transients analyzed in this Final Safety Analysis Report (FSAR).

14.1.1 ADMINISTRATIVE PROCEDURES -- TESTING

14.1.1.1 Organizational Responsibilities

The overall responsibility for the preoperational testing and startup program is assigned to the Lead Startup Engineer.

The Lead Startup Engineer directs other Station Construction Department personnel in preparing and conducting the testing program with technical assistance from the Engineering Department, Nuclear Plant Operations (NPO), the nuclear steam supply system (NSSS) vendor, and other equipment suppliers as appropriate. The plant operating organization performs all operations during the testing program. The Assistant Plant Manager/Plant Superintendent will designate a Startup Coordinator who will be responsible for startup operational activities. In some cases there will be procedures, administratively controlled by the NPO Department, which will be included in the Preoperational and Startup Test Program. Their inclusion will occur when they satisfy the requirements and objectives of a test that would normally be prepared at the direction of the Lead Startup Engineer.

14.1.1.2 Preparation of Procedures

Test procedures are prepared under the direction of the Lead Startup Engineer for all preoperational and startup tests. Each procedure consists of the test purpose and description, references, prerequisites, initial conditions, instructions (including acceptance criteria), and data and calculation sheets as required. The status of all preoperational and startup tests is maintained in a Startup Status Report.

The sources of information for writing the test procedures include approved drawings, specifications, technical literature, system functional descriptions, similar completed tests from other pressurized water reactor nuclear power plants, manufacturers' testing recommendations, plant operating procedures, general operating orders and instructions, and any other design or technical information available.

Test instructions are established using design and technical information and include acceptance criteria established from the functional requirements specified in the appropriate sections of this FSAR or from documents approved by the Engineering Department. Space for documenting test results is also included.

14.1.1.3 Reviewing and Approving Procedures

The Lead Startup Engineer is responsible for the preparation of each test procedure and will request review of tests by the Assistant Plant Manager/Plant Superintendent and others as considered appropriate. The Assistant Plant Manager/Plant Superintendent is responsible for obtaining comments from NPO. The Lead Startup Engineer and the Assistant Plant Manager/Plant Superintendent will indicate their review is complete by signing off the test cover sheet.

The Plant Staff Review Committee (PSRC) will review approved procedures, prior to their conduct, for units with an operating license.

14.1.1.4 Conducting Tests

The Lead Startup Engineer is responsible for conducting all preoperational and startup tests and assigns the responsibility for conducting individual tests to a Startup Engineer who, in turn, verifies that all the necessary conditions are established. The Lead Startup Engineer requests the plant Startup Coordinator to perform the operations step-by-step, following the sequence specified in the test procedure. During and subsequent to preoperational testing, power plant operating personnel will operate all switches, breakers, and valves for controlling energized equipment under the direct supervision of the Shift Foreman in accordance with the startup program, and/or at the request of the Startup Engineer.

14.1.1.5 Evaluating and Approving Results

The Startup Engineer and the Assistant Plant Manager/Plant Superintendent's representatives make an evaluation of the test results. If the results satisfy the acceptance criteria, they sign off the test as completed. The completed test procedure is reviewed by both the Lead Startup Engineer and the Assistant Plant Manager/Plant Superintendent and is signed to indicate approval of the completed test.

The results of preoperational tests of safety-related systems will undergo plant staff review prior to receipt of an operating license. Subsequent to the receipt of an operating license, the results of all completed preoperational and startup tests will be reviewed by the PSRC.

14.1.1.6 Documentation

Completed procedures and related data and test sheets will be properly identified, indexed, and retained for the plant's permanent files. The Lead Startup Engineer is responsible for the distribution of all completed test procedures. Distribution will be made as individual preoperational and startup test procedures are completed.

14.1.1.7 Personnel Qualifications

Since 1958, Station Construction Department management has selected personnel to direct the startup of eleven fossil-fueled, eight geothermal, and one nuclear-fueled steam-electric generating units. Only in the latter case was the responsibility shared and authority subordinated to direction from the NSSS supplier. The timely startup and exceptionally trouble-free performance of these units in operation demonstrates management's ability to select qualified personnel and the success of the system.

Personnel assigned to DCPP startup have been selected to meet the anticipated needs of startup service and transfer of operations to the Nuclear Power Generation Department of the units that will provide additional trouble-free generating capacity for PG&E. Their selection is based on personal backgrounds requiring minimum supplementary technical education or field experience. The Lead Startup Engineer is responsible for requesting, and the Manager of Station Construction is responsible for providing, any additional training to ensure that members of the startup organization have the abilities to satisfy management objectives and the following:

14.1.1.7.1 Lead Startup Engineer

The Lead Startup Engineer shall have a minimum of 10 years of power plant experience. Graduation in an engineering discipline shall count for 2 of these years, and a minimum of 3 years of power plant startup experience is required. Of the remaining 5 years, a maximum of 2 may be fulfilled by academic or field training in nuclear subjects. The Lead Startup Engineer shall be familiar with the design and performance of all the DCPP systems.

14.1.1.7.2 Startup Engineer

Startup Engineers shall have a minimum of 6 years of power plant experience. Graduation in an engineering discipline shall count for 2 of these years, and a minimum of 1 year of power plant startup experience is required. Of the remaining 3 years, a maximum of 1 year may be fulfilled by academic or field training in nuclear subjects. Startup Engineers shall be familiar with the design and performance objectives of the DCPP systems.

14.1.1.7.3 Assistant Startup Engineer

Assistant Startup Engineers shall have a minimum of 4 years of power plant experience. Graduation in an engineering discipline shall count for 2 of these years, and a minimum of 1 year of power plant startup experience is required. Assistant Startup Engineers shall be familiar with the design and performance objectives of assigned DCPP systems.

14.1.1.7.4 Startup Engineer Trainee

Startup Engineer Trainees shall, as a minimum, have either a degree in an engineering discipline or 2 years of power plant experience. Experience needed to fulfill the requirements for other positions within the Startup Department shall be gained by on-the-job training that includes preparation of preoperational and startup procedures and personal participation in the execution of preoperational tests of DCPP systems under the supervision of a Startup Engineer. Startup Engineer Trainees shall be familiar with the design and performance objectives of assigned DCPP systems.

14.1.1.8 Additional Qualifications

In addition, appointees to any of the above assignments may have additional qualifications that will allow them to fill the following positions:

14.1.1.8.1 Nuclear Advisor

Nuclear advisors shall have a minimum of a bachelor's degree in engineering or in physical science and 2 of years experience in such areas as reactor physics, core measurements, core heat transfer, and core physics testing programs. One year of experience may be fulfilled by academic training beyond the bachelor's degree program on a one-for-one time basis.

14.1.1.8.2 Chemistry Advisor

Chemistry advisors shall have a minimum of a bachelor's degree in engineering or in physical science, and 1 year of experience in water or wastewater treatment.

14.1.2 ADMINISTRATIVE PROCEDURES -- MODIFICATIONS

Test procedure inadequacies discovered at any time are corrected using written changes. All test procedure changes are reviewed and approved according to the administrative procedure for the original test procedure before final acceptance of the test by the Plant Superintendent. If the test results do not satisfy the acceptance criteria, or are otherwise contrary to the expected results, the Lead Startup Engineer is responsible for documenting the problem and acts as coordinator between General Construction and the Engineering Departments in resolving such problems, including any necessary system modifications. Resulting test changes shall be handled as described above. Any required retesting shall be handled according to the administrative procedure for conducting the original test. All test procedure changes for units with an operating license require PSRC review within the time frame established by the Technical Specifications[(1)].

Temporary system modifications required for testing are documented in the procedures and, following completion of testing, restoration to normal conditions is made and documented.

14.1.3 TEST OBJECTIVES AND PROCEDURES

14.1.3.1 Preoperational Testing

The testing program performed prior to fuel loading ensures that performance of equipment and systems is in accordance with design criteria. The program includes tests, adjustments, calibrations, and system operations necessary to ensure that initial fuel loading, initial criticality, and subsequent power operation can be safely undertaken. As installation of individual components and systems is completed, each is tested according to approved written procedures. The tests are designed to verify, as nearly as possible, the performance of the components and/or systems under conditions expected to be experienced during plant operation. The prerequisites for these tests include written confirmation that construction activities are complete.

During system tests for which normal plant conditions do not exist and cannot be simulated, the systems are operationally tested to the maximum extent possible. The remainder of the tests are performed when conditions are suitable for testing. Abnormal plant conditions are simulated during testing, when required, and when such conditions do not endanger personnel or equipment.

Evaluations of test results are made to verify that components and systems are performing satisfactorily and, if not, to provide a basis for recommending corrective action.

Where required, simulated signals or inputs are used to verify the full operating range of a system and to calibrate and align the system and instruments at these conditions. Later, systems that are used during normal operation are verified and calibrated under actual operating conditions. Systems that are not used during normal plant operation, but must be in a state of readiness to perform safety-related functions, are checked under all modes and test conditions prior to plant startup. Examples of these systems are the reactor trip system and engineered safety features system logic. Correct operation and setpoints are verified during this testing.

Testing performed during preoperational testing will be completed before fuel loading. In some cases, it will be necessary to defer certain preoperational tests until after fuel loading. These include tests to be performed on the complete rod control system, rod position indication, and complete incore movable detector system. These tests have been identified in Table 14.1-2, Fuel Loading and Initial Startup Testing Summary. Prior to the performance of hot testing following core loading, prerequisite cold testing will have been performed. An example of these tests is the cold rod drop time measurement test. In any event, the surveillance requirements of the Technical Specifications will be met as required for each mode transition.

14.1.3.2 Startup Testing

After satisfactory completion of final precritical tests, nuclear operation of the reactor begins. This final phase of startup and testing includes initial criticality, low power testing, and power level escalation. The purpose of these tests is to establish the operational characteristics of the plant and the core, to acquire data for the determination of setpoints, to establish administrative controls during reactor operations, and to ensure that operation is within license requirements. A brief description of the test program is presented in the following sections. Table 14.1-2 summarizes the tests that will be performed from fuel load through plant operation at rated power, and Figure 14.1-1 shows the sequence in which these tests are performed.

14.1.4 FUEL LOADING AND INITIAL OPERATIONS

14.1.4.1 Fuel Loading

The overall responsibility and direction for initial fuel loading is exercised by PG&E personnel. Fuel loading begins when all prerequisite system tests and operations have been satisfactorily completed, an operating license has been obtained from the U. S. Nuclear Regulatory Commission, and a review by the plant staff has determined that the requirements in the Technical Specifications have been met.

Access to the containment will be controlled by written procedure during fuel loading. Fuel handling tools and equipment shall have been checked out and dry runs conducted in the use and operation of equipment. The reactor vessel and associated components will be in a state of readiness to receive fuel. Water level will be maintained above the bottom of the nozzles and recirculation maintained to ensure a uniform boron concentration. Boron concentration can be increased via the recirculation system.

The as-loaded core configuration is specified as part of the core design studies conducted well in advance of fuel loading. The core is assembled in the reactor vessel that is already filled with water containing enough dissolved boric acid to maintain an effective multiplication factor of 0.95, or less, or a boron concentration greater than 2000 ppm. For initial core loading, the 2000 ppm minimum is limiting and results in an effective multiplication factor of less than 0.90. The refueling cavity is partially filled with borated water during initial fuel loading to provide lubrication for the fuel handling equipment. Coolant chemistry conditions are prescribed in the fuel loading procedure and verified periodically by chemical analysis of moderator samples prior to and during fuel loading operations.

Fuel loading instrumentation shall consist of at least two source range monitors. Normally, two permanently installed excore source range neutron channels and three temporary incore source range neutron channels will be available. The permanent channels, when responding, are monitored in the control room by licensed operators. The temporary channels installed inside the containment structure are monitored by knowledgeable test personnel who, in turn, communicate with the senior licensed

operator in charge of fuel loading. At least one channel is equipped with an audible count rate indicator audible in the control room and loading area. Both permanent channels have the capability of displaying the neutron count rate on strip chart recorders. The temporary channels indicate on count rate meters with a minimum of one channel recorded on a strip chart recorder. Minimum count rates attributable to neutrons generated in the core are required on at least two of the five (i.e., three temporary and two permanent) available neutron source range channels at all times following installation of the primary sources and the first ten fuel assemblies to continue fuel loading.

Two neutron sources are inserted into the core at locations and sequence specified in the fuel loading program to ensure a neutron population that produces a minimum of 1/2-count/sec for adequate monitoring of the core.

Fuel assemblies, together with inserted components (rod cluster control assemblies (RCCAs), burnable poison rods, source spider, or thimble plugging devices), are placed in the reactor vessel one at a time according to an approved sequence to provide reliable core monitoring that minimizes the possibility of core mechanical damage. The fuel loading procedure includes a tabular check sheet that prescribes the movements of each fuel assembly and its specified inserted components from its initial position in the fuel racks to its final position in the core. Checks are made of component serial numbers and types to guard against possible inadvertent exchanges or substitutions of components, and two reactor core fuel assembly tag boards are maintained throughout the core loading operation.

An initial increment of ten fuel assemblies, the first of which contains an active neutron source, is the minimum source-fuel increment that permits subsequent meaningful inverse count rate monitoring. This initial increment is determined by calculation and previous experience to be markedly subcritical $k_{eff} \leq 0.90$) under the required conditions of loading.

Each subsequent fuel loading increment is accompanied by detailed neutron count rate monitoring to determine that the just-loaded increment does not excessively increase the count rate and that the extrapolated inverse count rate ratio is not decreasing for unexplained reasons. The results of each loading step are evaluated according to written procedures before the next prescribed step is started.

Criteria for safe loading require that loading operations stop immediately if:

(1) An unanticipated increase in the neutron count rate by a factor of two occurs on all operating nuclear channels during any single loading step (excludes anticipated changes due to source/detector geometry)

(2) The neutron count rate on any individual nuclear channel unexpectedly increases by a factor of three during any single loading step (excludes anticipated changes due to source/detector geometry)

A "high count rate" alarm in the containment and the control room is coupled to the source range channels with a setpoint equal to or less than five times the current count rate. This alarm automatically alerts the fuel loading crew to an indication of high count rate and requires an immediate stop of all operations until the situation is evaluated. If it is immediately determined that no hazards to personnel exist, preselected personnel may remain in the containment to evaluate the cause and determine future action.

Fuel loading procedures specify alignment of fluid systems to prevent inadvertent dilution of the boron concentration in the reactor coolant, restrict the movement of fuel to preclude the possibility of mechanical damage, prescribe the conditions under which loading can proceed, identify chains of responsibility and authority, provide for continuous and complete fuel and core component accountability, and establish procedures to be observed in case of emergency.

14.1.4.2 Postloading Tests

Upon completion of fuel loading, the reactor upper internals and the pressure vessel head are installed and additional testing is performed prior to initial criticality. The final pressure tests are conducted after filling and venting of the reactor coolant system (RCS) is completed. The purpose of this phase of the program is to prepare the system for nuclear operation and to establish that design requirements necessary for operation are achieved.

Mechanical and electrical tests are performed on the RCCA drive mechanisms. A complete operational check of the RCCA drive mechanisms and the RCCA position indicator systems is performed. Tests are performed on the reactor trip circuits to verify manual trip operation and actual RCCA drop times are measured for each assembly. Whenever the RCCA drive mechanisms are being tested, the boron concentration in the RCS is such that criticality cannot be achieved with all RCCAs fully withdrawn. A complete functional electrical and mechanical check is made of the incore nuclear flux mapping system at operating temperature and pressure.

14.1.4.3 Initial Criticality

Initial criticality is established by sequentially withdrawing the shutdown and control groups of control rod assemblies from the core, leaving the last withdrawn control group inserted far enough in the core to provide effective control when criticality is achieved. Then the heavily borated reactor coolant is diluted until criticality is achieved. Successive stages of control rod assembly group withdrawal and of boron concentration reduction are monitored by observing changes in neutron count rate. Periodically, samples of the primary coolant boron concentration are obtained and analyzed.

The inverse count rate ratio is used as an indication of the nearness and rate of approach to criticality of the core during RCCA group withdrawal and during reactor coolant boron dilution. The rate of approach is reduced as the reactor approaches extrapolated criticality to ensure that effective control is maintained at all times. Written

procedures specify alignment of fluid systems, control the rate at which the approach to criticality may proceed, and predict initial values of core conditions under which criticality is expected.

14.1.4.4 Low Power Testing

A prescribed program of reactor physics measurements is undertaken to verify that the basic static and kinetic characteristics of the core are as expected and that the values of the kinetic coefficients assumed in the safety analysis are conservative.

The measurements are made at low power and at or near operating temperature and pressure. The measurements include verification of calculated control rod assembly group reactivity worths, isothermal temperature coefficient under various core conditions, differential boron concentration reactivity worth, and critical boron concentrations all as functions of control rod assembly group configuration. In addition, measurements of the power distribution are made. Concurrent tests are conducted on the instrumentation including the source and intermediate-range nuclear channels.

Written procedures specify the sequence of testing and the conditions under which each test is to be performed. This ensures both safety of operation and the relevancy and consistency of the results obtained. If significant deviations from design predictions exist, unacceptable behavior is revealed, or apparent anomalies develop, the testing is suspended while the situation is reviewed by PG&E to determine whether a question of safety is involved; the deviation is resolved prior to resumption of testing.

14.1.4.5 Power Level Escalation

When the operating characteristics of the plant have been verified by low power testing, a program of power level escalation in successive stages brings the unit to its full licensed power level. Reactor and unit operational characteristics are closely examined at each power level plateau and the relevance of the safety analysis is verified before escalation to the next programmed level.

Measurements are made to determine the relative power distribution in the core as functions of power level.

Secondary system heat balances ensure that the various indications of power level are consistent and provide a base for calibration of power range neutron channels. The ability of the reactor control system to respond effectively to signals from reactor plant and steam plant instrumentation under a variety of conditions encountered in normal operations is verified.

At prescribed power levels, the dynamic response characteristics of the reactor plant and steam plant are evaluated. The responses of system components are measured for design step and ramp changes in load, 50 percent reduction of load at design rate and normal recovery, net load rejection, and turbine trip.

Adequacy of radiation shielding is verified by gamma and neutron radiation surveys inside the containment and throughout the plant site at specified power levels. Periodic sampling of reactor coolant is performed to verify the chemical and radiochemical analysis of the reactor plant systems.

The functional performance requirements in some instances are described by specific quantitative acceptance criteria that are addressed in other sections of the FSAR. In other cases, acceptance standards may specify that a system or component perform a given action sequence. In either case, the detailed procedures or the referenced documents used in performing the test include specific acceptance criteria against which actual performance is measured. Plant conditions for each of the tests are listed in the test procedure.

When completed, this program provides assurance that plant performance is in accordance with the safety requirements established in the FSAR. The listing of the tests in Tables 14.1-1 and 14.1-2 includes specific identification of the objectives of each particular test that is required. Figure 14.1-1 gives a graphic presentation of the chronological sequence of startup testing.

14.1.5 ADMINISTRATIVE PROCEDURES -- SYSTEM OPERATION

14.1.5.1 Operating Procedures

Normal and emergency operation of all plant systems and/or major pieces of equipment are carried out in accordance with written procedures prepared by plant personnel and approved by the Plant Manager or his representative. These procedures are incorporated into the test program by the Lead Startup Engineer as appropriate. Where the prerequisite conditions for an operating procedure cannot be met during the test program, the procedure is demonstrated, under conditions simulating, as nearly as possible, the prerequisite conditions. The Assistant Plant Manager/Plant Superintendent reviews each startup test procedure to ensure that the operations specified in the test procedure are consistent with the normal and emergency operating procedures.

14.1.5.2 Safety Precautions

The measurements and operations during low power escalation testing are similar to normal unit operations at power and normal safety precautions are observed. Those tests that require special operating conditions are accomplished using test procedures that prescribe necessary limitations and precautions.

14.1.6 REFERENCES

1. <u>Technical Specifications</u>, Diablo Canyon Power Plant Units 1 and 2, Appendix A to License Nos. DPR-80 and DPR-82, as amended.

14.2 AUGMENTATION OF APPLICANT'S STAFF FOR INITIAL TESTS AND OPERATION

The startup group, under the direction of the Lead Startup Engineer, is responsible for conducting the preoperational and startup testing programs. As such, the startup group may be considered the augmenting organization for the normal plant operating staff during the testing period. The NSSS supplier will furnish technical advice to the startup group during the initial testing period. In addition, the plant technical staff will augment the startup group during the initial test program. This augmentation will include shift supervision and shift staff engineer support.

14.2.1 ORGANIZATIONAL FUNCTIONS, RESPONSIBILITIES, AND AUTHORITIES

PG&E's organizational structure is shown in Figure 17.1-1. The Vice President-General Construction is responsible for construction of DCPP Units 1 and 2. This responsibility extends until the plant is running and released for operation, and includes the startup and acceptance of equipment.

The Nuclear Power Generation organizational structure is described in Chapter 13.

The plant operating organization, also described in Chapter 13, is responsible for the safety of operating personnel and the general public, for providing the necessary operating personnel for the power plant, for the training of those personnel, and for the direction and supervision of their work during the startup of new facilities. All activities that could affect the operation of the plant are done under the cognizance of licensed personnel as required by the Technical Specifications[(1)].

Technical advice furnished by Westinghouse Electric Corporation (Westinghouse), the NSSS designer and manufacturer, is advisory in nature since only PG&E's Operating Department plant staff will be licensed to direct or control plant operation.

14.2.2 INTERRELATIONSHIPS AND INTERFACES

The Lead Startup Engineer functions as the principal contact between the construction and operating organizations for startup activities.

The Startup Coordinator functions as the Assistant Plant Manager/Plant Superintendent's representative for startup operational activities.

The working interrelationship between the Lead Startup Engineer and the Startup Coordinator is described in Section 14.2.3.

Westinghouse will provide technical advice on site to PG&E during installation, startup, testing, and initial operation of the NSSS. This will provide additional assurance that the NSSS is installed, started, tested, and operated in conformance with the design intent. Westinghouse personnel assigned to the site will provide technical advice and will

provide technical liaison with the Westinghouse home office to promptly resolve problems within the Westinghouse scope of responsibility.

14.2.3 KEY PERSONNEL FUNCTIONS, RESPONSIBILITIES, AND AUTHORITIES

14.2.3.1 Station Construction Department

The Station Construction Department designates a Lead Startup Engineer who reports to the DCPP Senior Site Representative.

The Lead Startup Engineer is responsible for:

(1) Preparing the preoperational and startup testing programs and schedules; approval of these programs will be by the Lead Startup Engineer's signature

(2) Obtaining and preparing system test and acceptance criteria

(3) Providing necessary written test procedures

(4) Incorporating operating orders, procedures, and instructions prepared by the Assistant Plant Manager/Plant Superintendent into the test program

(5) Obtaining comments on test procedures from the Assistant Plant Manager/Plant Superintendent

(6) Arranging for startup personnel necessary to conduct the program and ensuring the adequacy of their preparation

(7) Ensuring that all prerequisites for performing tests are satisfactorily completed

(8) Directing individual preoperational and startup tests

(9) Verifying that each preoperational or startup test is satisfactorily completed

(10) Releasing accepted systems to the Assistant Plant Manager/Plant Superintendent

(11) Participating as a member in plant staff review committee meetings during preoperational and startup testing

(12) Obtaining technical advice from Westinghouse as necessary

(13) Obtaining technical advice from PG&E's Engineering Department as necessary

14.2.3.2 Operating Department

The Plant Manager is responsible for serving as chairman of the Plant Staff Review Committee meetings as discussed in Chapter 13.

The Assistant Plant Manager/Plant Superintendent is responsible for:

(1) Reviewing the schedules and test procedures developed by the Lead Startup Engineer and approving the overall startup schedule

(2) Preparing equipment operating orders, procedures, and instructions in accordance with standard PG&E operating practices for inclusion in the testing program

(3) Verifying that operating personnel are qualified to perform the operations required by the test program. Qualification of operating personnel is discussed in Chapter 13

(4) Supervising operation of controls of all components and systems during the test programs as requested by the Lead Startup Engineer and in accordance with the startup program

(5) Witnessing tests on apparatus and equipment and making recommendations on test results

(6) Determining that plant components and systems meet operating requirements as to safety, reliability, and economy of operation

(7) Accepting independent auxiliary equipment and systems for operation as needed after satisfactory performance has been demonstrated

The Assistant Plant Manager/Plant Superintendent designates an individual as Startup Coordinator, and that individual is responsible for startup operational activities under the Assistant Plant Manager/Plant Superintendent. For DCPP Units 1 and 2, the Operations Manager has been designated as Startup Coordinator.

14.2.3.3 Westinghouse

Early in construction, Westinghouse provided a site manager to represent Westinghouse at the site.

The site technical advice that will be provided for startup testing will be dependent upon the test being performed, the level of testing activity at any specific time, and requests

by PG&E. Consequently, the personnel levels, categories, and schedules will be established by the site manager based on anticipated activities during each phase of the startup schedule. Westinghouse representatives will work in conjunction with the DCPP startup organization. A Westinghouse systems engineer will be assigned to the site for hot functional testing and other major systems testing activities. Supporting this engineer will be several field service engineers normally assigned on site during plant construction. These engineers will be augmented by specialists from the Westinghouse home office as required for adequate observation of the specific test being performed. The specialists will provide specific technical advice for specific tests.

A typical schedule for Westinghouse specialists follows:

(1) Reactor Coolant System Hydrotest - three specialists

(a) Reactor Coolant Pump Specialist

Scheduled to be on site 2 days prior to the hydrotest and for an approximate duration of 1 week or until satisfactory completion of the activity

(b) Chemist

Scheduled to be on site 2 days prior to the hydrotest and for an approximate duration of 1 week or until satisfactory completion of the activity

(c) Quality Assurance of Internals Inspector

Scheduled to be on site 2 weeks prior to the hydrotest and for an approximate duration of 2 weeks or until satisfactory completion of the activity

(2) Hot Functional Test - three specialists

(a) Reactor Coolant Pump Specialist

Scheduled to be on site 2 weeks prior to the hot functional test and for an approximate duration of 2 weeks or until satisfactory completion of the activity

(b) Chemist

Scheduled to be on site 2 days prior to the hot functional test and for an approximate duration of 1 week or until satisfactory completion of the activity

(c) Quality Assurance of Internals Inspector

Scheduled to be on site during the post-hot functional period and for an approximate duration of 1 week or until satisfactory completion of the activity

(3) <u>Core Loading - three specialists</u>

(a) Physicist

Scheduled to be on site 2 days prior to core loading and for an approximate duration of 1 week or until satisfactory completion of the activity

(b) Chemist

Scheduled to be on site 2 days prior to core loading and for an approximate duration of 1 week or until satisfactory completion of the activity

(c) Fuel Handling Specialist

Scheduled to be on site 1 week prior to core loading and for an approximate duration of 2 weeks or until satisfactory completion of the activity

(4) <u>Plant Startup - four specialists</u>

(a) Nuclear Test Engineer

Scheduled to be on site 1 week prior to startup and for an approximate duration of 8 weeks or until satisfactory completion of the activity

(b) Chemist

Scheduled to be on site 2 days prior to startup and for an approximate duration of 1 week or until satisfactory completion of the activity

(c) Transient Analyst

Scheduled to be on site prior to completion of each activity

(d) Reactivity Computer Instrumentation Specialist

Scheduled to be on site 1 day prior to startup and for an approximate duration of 2 weeks or until satisfactory completion of the activity

14.2.4 PERSONNEL QUALIFICATIONS

A resume for the Startup Coordinator (Operations Manager) is in the appendix to Chapter 13.

Qualifications of Westinghouse personnel providing technical advice include sufficient personal maturity, work experience, education, and specialized training to satisfy Westinghouse of their competence to adequately perform tasks assigned by the Westinghouse site manager. Due to the fluid nature of plant startup schedules, the individuals who will perform these assignments cannot be identified until specific milestones (i.e., hot functional, etc.) have actually occurred. Timing will be the principal factor in determining individual availability. Trainees and personnel with limited work experience are not used in positions of significant responsibility. Experience in the startup of nuclear power plants has indicated that the qualification of Westinghouse personnel assigned has been fully acceptable.

14.2.5 REFERENCES

1. Technical Specifications, Diablo Canyon Power Plant Units 1 and 2, Appendix A to License Nos. DPR-80 and DPR-82, as amended.

14.3 POSTCOMMERCIAL OPERATIONAL TEST PROGRAM

This section describes the program for testing modifications to DCPP systems per approved design changes. The program ensures design changes are reviewed for postmodification operational testing requirements and that all operational tests are developed and performed prior to returning affected equipment to service.

The engineering director has overall responsibility for postmodification testing.

The scope of a modification is evaluated against plant safety features, industry codes, regulatory requirements, etc. From this evaluation, the scope of required testing is determined. Temporary test procedures are prepared when existing plant procedures will not adequately test the modification. Procedures used for performance of operational testing of design changes are reviewed and approved by appropriate DCPP management. Operational testing ensures a modification will function in accordance with the design basis by simulating normal and transient conditions when practical.

DCPP defines testing based on work category. Post modification testing (PMT) consists of maintenance verification testing (MVT), operability verification testing (OVT), and design verification testing (DVT). These tests may consist of functional tests, dry-run tests, dynamic tests, and inspections. Qualified personnel review and evaluate the test results for acceptability prior to releasing the equipment for service.

PREOPERATIONAL TESTING SUMMARY

System Tests	Test Objectives
1. Electrical Systems	
1.1 Vital bus (4.16 kV, 480 V, 120 Vac)	1. To demonstrate full plant load capability and interchangeability of all alternate power sources.
	2. To verify automatic transfer of buses with and without offsite power available.
	3. To verify the 4.16 kV and 480 Vac vital bus load start logic.
1.2 Vital 125 Vdc system	1. To verify proper operation in normal and emergency conditions of batteries, battery chargers, 125 Vdc switchgear, and distribution panels.
	2. To verify battery capacities.
1.3 Communications systems	1. To verify that the site evacuation signal can be heard from any location at the site.
	2. To verify that the fire alarm signal can be heard from any location in the plant.
	3. To verify that communications stations for fuel loading are functional.
1.4 Emergency lighting	1. To verify adequacy for operator transit from point to point.
2. Diesel Engine Generator Units	1. To verify the start signal setpoints and logic.
	2. To verify the capability of the diesel engine generator units to supply power to vital equipment for plant cooldown during emergency conditions, such as loss of offsite power coincident with loss of turbine generator.
	3. To verify that redundant features of the system function according to the design intent.

System Tests	Test Objectives
2. (Continued)	4. To verify that the diesel fuel oil transfer pump will supply fuel oil from the diesel fuel oil storage tank to the diesel engine fuel oil day tank.
3. Fire Protection Systems	1. To verify that the fire pumps will supply water from the fire water tank to selected stations within the DCPP and that the automatic start features operate as designed.
	2. To verify that the low-pressure CO_2 system functions properly and that CO_2 is delivered to appropriate fire protection stations.
	3. To verify that the Halon system functions properly and that Halon is dispersed in the solid-state protection system room in acceptable concentrations.
4. Ventilation Systems	1. To verify the operation of the containment fan coolers and dampers according to design and to measure heat removal capability during hot functional testing.
	2. To verify that the auxiliary and fuel handling building exhaust and supply fans and the control room air conditioning units and their associated dampers, valves, and filters operate according to design.
	3. To verify the logic for postaccident condition initiation of containment pressure reduction.
	4. To verify the closure of containment purge supply and exhaust ducts and the pressure relief duct from a high radioactivity in containment signal.
5. Instrumentation and Control Systems	
5.1 Process instrumentation	1. Applicable alarm and control set- points are checked for conformance with design values.
5.2 Nuclear instrumentation	1. Prior to core loading, nuclear instruments will have been aligned and source range detector response to neutron source checked.

System Tests	Test Objectives
5.2 (Continued)	2. All required channels will be checked to verify operability within the required Technical Specifications interval.
5.3 Automatic reactor power control systems tests	1. The system alignment is verified at preoperational conditions to demonstrate the response of the system to simulated inputs. These tests are performed to verify that the systems will operate satisfactorily at power.
	2. At power, the alignment of the system is verified by programmed step changes and under actual test transient conditions.
5.4 Engineered safety features (ESF)	1. To verify ESF, setpoints, logic, and response times.
	2. To verify response of ESF equipment to a safety injection signal with and without offsite power available.
5.5 Reactor protection system	1. To test redundancy, coincidence, independence, and safe failure on loss of power to process instrumentation and reactor protection equipment.
	2. To verify reactor protection time response meets design requirements.
	3. To test automatic and manual reactor trip setpoints, logic, and reactor trip breakers.
5.6 Radiation monitoring systems	1. To calibrate against known standards and verify the operability and alarm setpoints of all process monitors (air particulate monitors, gas monitors, and liquid monitors) located in the plant.
6. System Functional Tests	
6.1 Reactor coolant system (RCS)	1. To verify the integrity and leaktightness of the RCS and auxiliary primary systems at the specified test pressure and temperature.
	2. To verify the capability of the pressurizer relief tank to function according to design.

System Tests	Test Objectives
6.1 (Continued)	3. To verify proper operation of the nuclear steam supply system and auxiliary systems local and remote indicators, alarms, recorders, and controllers for pressure, temperature, flow, and level.
	4. To verify resistance temperature detector (RTD) bypass loop flow and correct functional operation of control and indicating equipment and the detectors.
	5. To establish baseline data for inservice inspections and verify integrity of the system.
6.2 Chemical and volume control system (CVCS)	1. To verify that the design charging, letdown, and excess letdown flowrates are attainable.
	2. To verify that the reactor coolant purification equipment operates according to design parameters.
	3. To verify charging pump (CCP1 and 2) performance and response to a safety injection signal when the RCS is depressurized.
	4. To verify ability to control RCS water volume.
	5. To verify the ability to control chemical shim concentration.
	6. To verify the design seal water flowrates to each reactor coolant pump.
	7. To verify that pumps, filters, tanks, and heat tracing used for batching, storage, and transfer of 12% boric acid function satisfactorily as a system.
	8. To verify gas stripper and boric acid evaporator operation meets design requirements.
	9. To verify chemical addition and sampling features function according to design.
	10. To verify operating capability of process instrumentation and controls under normal conditions.

	System Tests	Test Objectives
6.3	Safety injection system	1. To verify the safety injection pump and accumulator performance and response to a safety injection signal when the RCS is depressurized.
		2. Test the systems to ensure capability of meeting design objectives.
6.4	Containment spray system	1. To verify the containment spray pump performance and response to a containment spray signal.
		2. Verify that the system can be tested to verify functional performance.
6.5	Residual heat removal system (RHRS)	1. To verify the RHR pump performance and response to a safety injection signal when the RCS is depressurized.
		2. To verify the system is capable of supplying emergency core cooling in the recirculation mode.
		3. To verify system capability for supplying cooling water during core loading.
		4. To verify the capability for plant cooldown assuming failure of a single active component.
6.6	Component cooling water system (CCWS)	1. To verify normal system operation according to the system description and design requirements.
		2. To verify the capability for plant cooldown assuming failure of a single active component.
6.7	Makeup water system	1. To verify the makeup water transfer pumps will transfer water from the condensate storage tank to the fire system, and to the CCW system surge tank.
		2. To verify the primary water makeup pumps will supply water from the primary water storage tank to the CCW system surge tank, to the boric acid blender, and to the chemical mixing tank in the CVCS system.

System Tests	Test Objectives
6.8 Auxiliary saltwater system (ASWS)	1. To verify normal system operation according to system description and design requirements. 2. To verify the capability for plant cooldown assuming failure of a single active component.
6.9 Liquid radwaste system	1. To verify that liquids can be collected in the reactor coolant drain tank and transferred to other tanks per design. 2. To verify waste processing according to the system description (includes waste concentrator, waste concentrator pumps, and liquid radwaste filter and tanks). 3. To verify that liquid radwaste releases can be controlled and excessive releases can be prevented. 4. To verify proper operation of primary system leak detection features and to verify proper operation of miscellaneous equipment drain tank pumps, equipment drain receivers, and pumps.
6.10 Gaseous radwaste system	1. To verify the collection and processing of gaseous radwaste is according to the system description.
6.11 Auxiliary feedwater system	1. To verify the turbine- and motor-driven auxiliary feedwater pumps deliver feedwater from the condensate storage tank to the steam generators at design flowrate and pressure and otherwise perform according to design in response to ESF signals.
6.12 Condensate, feedwater, and main steam	1. To check proper operation and indication of feedwater control and main steam line isolation valves for the appropriate actuation signals.
6.13 Hydrogen and nitrogen systems	1. To verify valve operability, regulating and reducing station performance, and the ability to supply the appropriate gas to interconnecting systems as required.

System Tests	Test Objectives
7. Hot Functional Tests	The intent of planned testing shall include but not be limited to the following: 1. To check RCS heatup and cooldown procedures. 2. To demonstrate satisfactory performance of components and systems that are exposed to RCS temperature. 3. To verify to the extent possible proper operation of instrumentation, controllers, and alarms. 4. To provide design operating conditions for testing the following auxiliary systems: a. CVCS b. Sampling system c. CCWS d. RHRS e. ASWS 5. To verify that water can be charged by the CVCS at rated flow against normal reactor coolant pressure. 6. To check letdown design flowrate for each operating mode. 7. To check operation of the excess letdown and seal water flowpaths. 8. To check steam generator instrumentation and control systems. 9. To verify the ability to cool down the plant using the steam generators. 10. To check thermal expansion and restraint of RCS components and piping. 11. To perform isothermal calibration of RTDs and incore thermocouples. 12. To operationally test the RHRS. 13. To check pressurizer level and pressure instrumentation and control systems.

System Tests	Test Objectives
7. (Continued)	14. To check RCS instrumentation and control systems.
	15. To verify the ability of the auxiliary feedwater system to feed the steam generators.
	16. To verify that steam generator blowdown operates according to design.
	17. To verify the capability of emergency process control from a location remote to the control room.
	18. To verify correct plant response to a safety injection signal under hot operating conditions. Verify system alignments, automatic transfer of electrical systems, and automatic sequential start of ESF equipment.
	19. Following hot functional testing, the reactor internals are removed and inspected for signs of excessive vibration.
8. Relief and Safety Valve Tests	1. To verify setpoints of the relief and safety valves.
9. Containment Building	1. To conduct structural integrity and integrated leakrate tests.
	2. To verify proper operation and leaktightness of air locks.
	3. To verify closure of all containment isolation valves for the appropriate signals.

TABLE 14.1-2

FUEL LOADING AND INITIAL STARTUP TESTING SUMMARY

Tests	Objectives
1. Startup Program Master Document	1. To define the sequence of tests and activities from preparation for fuel load through fuel loading, low power testing, and power ascension.
	2. To establish hold points for administrative control over proceeding into significant areas of testing or power plateaus.
2. Fuel Loading Program	
2.1 Fuel loading prerequisites and periodic checkoffs	1. To establish and maintain the prerequisite conditions for fuel loading.
2.2 Initial fuel loading	1. To specify the sequence of operation for fuel loading.
3. Precritical Test Program	
3.1 Incore movable detectors	1. To verify correct functional operation of control and indicating equipment.
3.2 Rod drive mechanism timing	1. To verify the proper timing for rod drive mechanism control equipment.
	2. To operationally check each control rod drive mechanism with a control rod attached.
3.3 Incore thermocouple-loop RTD cross calibration	1. To check and compare incore thermocouple readings with RCS RTD readings and calibrate the system if required.
3.4 Pressurizer spray and heater capacity and continuous spray flow setting	1. To establish the continuous spray flowrate.
	2. To verify the pressure control capability using spray flow and heaters.
3.5 RTD bypass loop flow measurement	1. To establish and verify acceptable flowrates.

Tests	Objectives
3.6 Rod drop time measurement	1. To determine the drop time of each control rod for selected conditions.
3.7 Rod position indication	1. To demonstrate satisfactory system performance of indication and alarm functions.
	2. To demonstrate that control rods operate over their entire length of travel.
3.8 Rod control system operational test	1. To demonstrate that the rod control system performs its required control and indication functions to verify availability for use just prior to criticality.
3.9 RCS flow measurement	1. To verify adequacy of RCS flow.
3.10 RCS flow coastdown	1. To verify the rate of change of reactor coolant flow subsequent to selective reactor coolant pump trips.
4. Initial Criticality and Low Power Physics Program	
4.1 Initial criticality	1. To bring the reactor critical for the first time.
	2. To compare the measured critical boron concentration with the expected critical boron concentration.
	3. To establish upper limit of flux level for zero power physics measurements.
4.2 Nuclear design checks	1. To verify the boron endpoint concentration, the isothermal temperature coefficient of reactivity, and zero power flux distribution for various rod configurations.
4.3 Rod and boron reactivity worth measurements	1. To verify design values of bank differential and integral worths during boron addition and dilution.
4.4 Rod cluster control assembly (RCCA) pseudo-ejection	1. To verify that the RCCA reactivity worth assumed in the accident analysis is conservative.
4.5 Minimum shutdown verification	1. To verify the reactivity worth of the shutdown banks.

Tests	Objectives
4.5 (Continued)	2. To measure the critical boron concentration with all shutdown and control banks inserted, less the most reactive rod assembly.
4.6 Conduct special test program (Unit 1 only) consisting of the following tests:	
a) Natural circulation	1. Provide supplementary technical information and operator training. (Tests a through g.)
b) Natural circulation with loss of pressurizer heaters	2. Determine capability of CVCS charging and letdown to cooldown the RCS. (Test f.)
c) Natural circulation at reduced pressure	3. Demonstrate ability to control RCS and steam generator parameters. (Test g.)
(d) Natural circulation with simulated loss of offsite ac power	
(e) Effect of steam generator isolation on natural circulation	
(f) Cooldown capability of the charging and letdown system	
(g) Simulated loss of all onsite and offsite ac power	
5 Power Ascension Program	
5.1 Thermal power measurements	1. To ascertain level of thermal power for establishment of plateaus for testing activities.
	2. To provide thermal power information for use in other tests.
5.2 Radiation surveys and shielding effectiveness	1. To obtain background information to establish access restrictions .
	2. To verify shielding adequacy.

	Tests	Objectives
5.3	Operational alignment of nuclear instrumentation systems (NIS)	1. To make necessary adjustments to the NIS as a function of reactor thermal power
5.4	Operational alignment of RCS temperature instrumentation at power	1. To make necessary adjustments to the T_{avg} and ΔT channels as a function of reactor thermal power
5.5	Calibration of steam and feedwater flow instrumentation at power	1. To calibrate steam and feedwater flow instrumentation as a function values determined from test instrumentation.
5.6	Turbine overspeed trip test	1. To test the main turbine electrical and mechanical overspeed trip mechanisms.
5.7	Incore power distribution	1. To verify that nuclear design predicted power distributions are valid for normal rod patterns and configurations.
5.8	Effluents and effluents monitoring	1. To verify level of radwaste releases.
5.9	Chemical and radiochemical analysis	1. To demonstrate ability to control RCS water chemistry.
5.10	Control systems checkout	1. To demonstrate proper operation of the: a. RCS b. Steam generator level control system c. Steam dump control system d. Turbine control system.
5.11	Control rod pseudo-ejection and above bank position measurements	1. To verify response of the excore detectors to a rod in above bank position.
		2. To verify the effects of a rod out of position and a pseudo-ejected rod upon neutron flux and hot channel factors.
5.12	Static rod drop and RCCA below bank position measurements (Unit 1 only)	1. To verify the response of excore detectors to a rod in below bank position.
		2. To verify that a single control rod assembly inserted fully or part way below the control bank results in acceptable hot channel factors.

Tests	Objectives
5.13 Rod group drop and plant trip	1. To verify functioning of negative rate trip circuitry in the excore detector system.
	2. To verify control systems performance as evidenced by plant parameter variations within acceptable limits.
5.14 Plant shutdown from outside the control room	1. To verify shutdown capability from backup control stations
5.15 Load swing tests	1. To verify control systems performance as evidenced by plant parameter variations within acceptable limits.
	2. To verify plant response to load changes.
5.16 Doppler power reactivity coefficient measurement	1. To verify nuclear design prediction of the Doppler-only power coefficient.
5.17 Incore-excore detector calibration	1. To form a relationship between incore and excore neutron detector signals for generated axial offsets
5.18 Large load reduction tests	1. To verify ability of plant to sustain large load reductions as evidenced by parameters remaining within acceptable limits.
5.19 Steam generator moisture carryover	1. To verify that actual steam generator moisture carryover is equal to or less than design value.
5.20 Nuclear steam supply system acceptance test	1. To operate the plant at or near 100% power for 100 hours to verify plant capability at sustained load.
5.21 Net load trip tests	1. To verify plant response to loss of plant load at the 50% and 100% power plateaus for Unit 1 and the 50% power plateau for Unit 2.
	2. To verify control systems performance as evidenced by plant parameter variations within acceptable limits.
5.22 Plant trip tests	1. To verify plant response to turbine generator trips at 50% and 100% power plateaus.

Tests	Objectives
5.22 (Continued)	2. To verify control systems performance as evidenced by plant parameter variations within acceptable limits.
	3. To verify automatic transfer to offsite standby power.
5.23 Natural circulation boron mixing cooldown test (Unit 1 only)	1. To verify ability to add and mix 12% boric acid, cooldown to RHR via natural circulation and continue cooldown to cold shutdown conditions

.

PROCEDURE TITLE OR TEST DESCRIPTION	PRE-FUEL LOAD	LOW POWER MODES 6 - 2					POWER OPERATION MODE 1					
		REF	CSD	HSD	HSB	STUP	≤15	30	50	75	90	100
<u>REFER TO TABLE 14.1-2</u>												
1.0 STARTUP PROGRAM												
1.1 Startup Program Master Document	O											O
2.0 FUEL LOADING PROGRAM												
2.1 Fuel Loading Prerequisites and Periodic Checkoffs	O	O										
2.2 Operational Alignment of Nuclear Instrumentation	O											
2.3 Effluents and Effluents Monitoring	O											
2.4 Chemical and Radiochemical Analysis	O											
2.5 Initial Fuel Loading		O										

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UNITS 1 AND 2
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FIGURE 14.1-1
CHRONOLOGICAL SEQUENCE
OF STARTUP TESTING
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PROCEDURE TITLE OR TEST DESCRIPTION	PRE-FUEL LOAD	LOW POWER MODES 6-2					POWER OPERATION MODE 1					
		REF	CSD	HSD	HSB	STUP	≤15	30	50	75	90	100
3.0 PRECRITICAL TEST PROGRAM												
3.1 Incore Movable Detectors		O	O	O	O							
3.2 Rod Drive Mechanism Timing			O		O							
3.3 Incore Thermocouple - Loop RTD Cross Calibration				O	O							
3.4 Pressurizer Spray and Heater Capacity and Continuous Spray Flow Setting					O							
3.5 RTD Bypass Loop Flow Measurement					O							
3.6 Rod Drop Time Measurement			O		O							
3.7 Rod Position Indication System					O							
3.8 Rod Control System Operational Test					O							
3.9 Reactor Coolant System Flow Measurement					O							
3.10 Reactor Coolant System Flow Coastdown					O							
3.11 Effluents and Effluent Monitoring	O	O			O							
3.12 Chemical and Radiochemical Analysis	O	O			O							
3.13 Operational Alignment of Nuclear Instrumentation	O				O							
3.14 Operational Alignment of Reactor Coolant System Temperature Instrumentation at Power					O							
3.15 Calibration of Steam and Feedwater Flow Instrumentation at Power					O							

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FIGURE 14.1-1
CHRONOLOGICAL SEQUENCE OF STARTUP TESTING
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PROCEDURE TITLE OR TEST DESCRIPTION	PRE-FUEL LOAD	LOW POWER MODES 6-2					POWER OPERATION MODE 1					
		REF	CSD	HSD	HSB	STUP	15	30	50	75	90	100
4.0 INITIAL CRITICALITY AND LOW POWER PHYSICS PROGRAM												
4.1 Initial Criticality						O						
4.2 Nuclear Design Checks						O						
4.3 Rod and Boron Reactivity Worth Measurements						O						
4.4 Rod Control Cluster Assembly Pseudo-ejection						O						
4.5 Minimum Shutdown Verification						O						
4.6 Operational Alignment of Nuclear Instrumentation	O				O	O						
4.7 Incore Power Distribution						O						
4.8 Effluents and Effluents Monitoring	O	- -	- -	- -	- -	O						
4.9 Chemical and Radiochemical Analysis	O	- -	- -	- -	- -	O						
4.10 Special Test Program (Unit 1 only)					O	O						

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FIGURE 14.1-1
CHRONOLOGICAL SEQUENCE OF STARTUP TESTING
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PROCEDURE TITLE OR TEST DESCRIPTION	PRE-FUEL LOAD	LOW POWER MODES 6 - 2					POWER OPERATION MODE 1					
		REF	CSD	HSD	HSB	STUP	≤15	30	50	75	90	100
5.0 POWER ASCENSION PROGRAM												
5.1 Thermal Power Measurements							O	O	O	O	O	O
5.2 Radiation Surveys and Shielding Effectiveness (Unit 1)							O	O	O	O		O
(Unit 2)							O		O			O
5.3 Operational Alignment of Nuclear Instrumentation	O				O	O	O	O	O	O	O	O
5.4 Operational Alignment of Reactor Coolant System Temperature Instrumentation at Power					O					O		O
5.5 Calibration of Steam and Feedwater Flow Instrumentation at Power					O			O	O	O	O	O
5.6 Turbine Overspeed Trip Test							O					
5.7 Incore Power Distribution						O	O	O	O	O	O	O
5.8 Effluents and Effluents Monitoring	O	- - -	- - -	- - -	- - -	- - -	O	—	—	—	—	O
5.9 Chemical and Radiochemical Analysis	O	- - -	- - -	- - -	- - -	- - -	O	—	—	—	—	O
5.10 Automatic Control Systems Checkout							O	O	O	O		O
5.11 Control Rod Pseudo-ejection and Above Bank Position Measurement								O				
5.12 Static Rod Drop and RCCA Below Bank Position Measurements (Unit 1 Only)									O			
5.13 Rod Group Drop and Plant Trip									O			
5.14 Plant Shutdown from Outside the Control Room									O			
5.15 Load Swing Tests								O	O	O		O
5.16 Doppler Power Reactivity Coefficient Measurement								O	O	O	O	

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FIGURE 14.1-1
CHRONOLOGICAL SEQUENCE OF STARTUP TESTING
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PROCEDURE TITLE OR TEST DESCRIPTION	PRE-FUEL LOAD	LOW POWER MODES 6 - 2					POWER OPERATION MODE 1					
		REF	CSD	HSD	HSB	STUP	≤15	30	50	75	90	100
5.0 POWER ASCENSION PROGRAM (Continued)												
5.17 Incore-Excore Detector Calibration (Test shown at 50% plateau to be performed slightly below 50% power)									O	O		
5.18 Large Load Reduction Tests										O		O
5.19 Steam Generator Moisture Carryover (Tests performed between 90% and 100% power)											O	O
5.20 Nuclear Steam Supply System Acceptance Test												O
5.21 Net Load Trip Tests (Unit 1)									O			O
(Unit 2)									O			
5.22 Plant Trip from 100% Power												O
5.23 Natural Circulation Boron Mixing Cooldown Test (Unit 1 only)			O	O	O							

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UNITS 1 AND 2
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FIGURE 14.1-1
CHRONOLOGICAL SEQUENCE
OF STARTUP TESTING
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CHAPTER 15

ACCIDENT ANALYSES

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FIGURES (Continued)

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FIGURES (Continued)

FIGURES (Continued)

Chapter 15

ACCIDENT ANALYSES

Since 1970, the ANS classification of plant conditions has been used to divide plant conditions into four categories in accordance with anticipated frequency of occurrence and potential radiological consequences to the public. The four categories are as follows:

(1) Condition I: Normal Operation and Operational Transients (Initial Conditions)

(2) Condition II: Faults of Moderate Frequency

(3) Condition III: Infrequent Faults

(4) Condition IV: Limiting Faults

The basic principle applied in relating design requirements to each of the conditions is that the most frequent occurrences must yield little or no radiological risk to the public, and those extreme situations having the potential for the greatest risk to the public shall be those least likely to occur. Where applicable, reactor trip system and engineered safety features functioning is assumed, to the extent allowed by considerations such as the single failure criterion, in fulfilling this principle.

In the evaluation of the radiological consequences associated with initiation of a spectrum of accident conditions, numerous assumptions must be postulated. In many instances these assumptions are a product of extremely conservative judgments. This is due to the fact that many physical phenomena, in particular fission product transport under accident conditions, are not understood to the extent that accurate predictions can be made. Therefore, the set of assumptions postulated would predominantly determine the accident classification.

The specific accident sequences analyzed in this chapter include those required by Revision 1 of Regulatory Guide 1.70, Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants, and others considered significant for the Diablo Canyon Power Plant (DCPP). Refer to UFSAR Table 15.0-1 for a comparison between Regulatory Guide 1.70, Revision 1, October 1972, Table 15-1 and the corresponding section(s) where the conditions are discussed. Because the DCPP design differs from other plants, some of the representative types of events identified in Table 15-1 of Regulatory Guide 1.70, Revision 1, October 1972 are not applicable to this plant. In addition, some events are analyzed or discussed in separate UFSAR chapters. The location of the analysis for each event or reason the event is not applicable to DCPP is provided in UFSAR Table 15.0-1.

This section of the FSAR describes the acceptance criteria, input assumptions, analysis techniques, equipment performance, and analysis results of the required accident analysis but does not include details on the set points, capacity or capabilities of mitigating equipment or operational limitations that determine the initial conditions for each analysis. For details of required reactor operational limitations and of the performance capabilities of the emergency equipment not covered in Chapter 15, refer to the following chapters of the UFSAR:

- Reactor coefficients, power distribution, reactivity controls, Refer to Chapter 4
- Reactor coolant flow, Refer to Chapter 5
- ECCS, Auxiliary feed water, Containment systems, Refer to Chapter 6
- Reactor trips and permissives, ESF actuation, Refer to Chapter 7
- Boration capabilities, Refer to Chapter 9

Additionally the availability, testing and performance criteria of the operational limits and mitigating systems are administratively controlled by the plant Technical Specifications described in Chapter 16 and Appendix A of the Diablo Canyon Power Plant Unit 1 and Unit 2 Operating Licenses.

15.1 CONDITION I - NORMAL OPERATION AND OPERATIONAL TRANSIENTS (INITIAL CONDITIONS)

15.1.1 INTRODUCTION

Condition I occurrences are those that are expected frequently or regularly in the course of power operation, refueling, maintenance, or maneuvering of the plant. As such, Condition I occurrences are accommodated with margin between any plant parameter and the value of that parameter which would require either automatic or manual protective action. Since Condition I occurrences occur frequently or regularly, they must be considered from the point of view of affecting the consequences of fault conditions (Conditions II, III, and IV). In this regard, analysis of each fault condition is generally based on a conservative set of initial conditions corresponding to the most adverse set of conditions that can occur during Condition I operation.

Typical Condition I events are shown below:

(1) Steady state and shutdown operations

Mode 1 - Power operation (greater than 5 percent of rated thermal power)

Mode 2 - Startup ($k_{eff} \geq 0.99$, less than or equal to 5 percent of rated thermal power)

Mode 3 - Hot standby (k_{eff} less than 0.99, T_{avg} greater than or equal to 350°F)

Mode 4 - Hot shutdown (subcritical, residual heat removal system in operation, k_{eff} less than 0.99, 200°F less than T_{avg} less than 350°F)

Mode 5 - Cold shutdown (subcritical, residual heat removal system in operation, k_{eff} less than 0.99, T_{avg} less than or equal to 200°F)

Mode 6 - Refueling (k_{eff} less than or equal to 0.95, T_{avg} less than or equal to 140°F)

(2) Operation with permissible deviations

Various deviations that may occur during continued operation as permitted by the plant Technical Specifications (Reference 1) must be considered in conjunction with other operational modes. These include:

(a) Operation with components or systems out of service

(b) Leakage from fuel with cladding defects

(c) Activity in the reactor coolant

1. Fission products

2. Corrosion products

3. Tritium

(d) Operation with steam generator leaks up to the maximum allowed by the Technical Specifications

(3) Normal Operational transients

Normal design transients which do not result in a reactor trip are listed below. Refer to Section 5.2.1.5.1 for additional details on these transients.

(a) Plant heatup and cooldown

(b) Step load changes (up to plus or minus 10 percent between 15 percent load and full load)

(c) Ramp load changes (up to 5 percent per minute between 15 percent load and full load)

(d) Turbine load reduction up to and including a 50 percent load rejection from full power

(e) Steady state fluctuations of the reactor coolant average temperature, for purposes of design, is assumed to increase or decrease at a maximum rate of 6°F in 1 minute.

15.1.2 COMPUTER CODES UTILIZED

Summaries of some of the principal computer codes used in transient analyses are given below. Other codes, in particular, very specialized codes in which the modeling has been developed to simulate one given accident, such as the NOTRUMP code used in the analysis of the RCS small pipe rupture (Section 15.3.1), and which consequently have a direct bearing on the analysis of the accident itself, are summarized in their respective accident analyses sections. The codes used in the analyses of each transient event are listed in Table 15.1-4.

15.1.2.1 FACTRAN

FACTRAN calculates the transient temperature distribution in a cross section of a metalclad UO_2 fuel rod (refer to Figure 15.1-8) and the transient heat flux at the surface of the cladding using as input the nuclear power and the time-dependent coolant parameters (pressure, flow, temperature, and density).

The code uses a fuel model that exhibits the following features simultaneously:

(1) A sufficiently large number of finite difference radial space increments to handle fast transients such as rod ejection accidents

(2) Material properties that are functions of temperature and a sophisticated fuel-to-cladding gap heat transfer calculation

(3) The necessary calculations to handle post-DNB transients: film boiling heat transfer correlations, zirconium-water reaction, and partial melting of the materials

The gap heat transfer coefficient is calculated according to an elastic pellet model. The thermal expansion of the pellet is calculated as the sum of the radial (one-dimensional) expansions of the rings. Each ring is assumed to expand freely. The cladding diameter is calculated based on thermal expansion and internal and external pressures.

If the outside radius of the expanded pellet is smaller than the inside radius of the expanded cladding, there is no fuel-cladding contact and the gap conductance is calculated on the basis of the thermal conductivity of the gas contained in the gap. If the pellet outside radius so calculated is larger than the cladding inside radius (negative gap), the pellet and the cladding are pictured as exerting upon each other a pressure sufficient to reduce the gap to zero by elastic deformation of both. This contact pressure determines the heat transfer coefficient.

FACTRAN is further discussed in the licensing topical report, Section 1.6.1, Item 44.

15.1.2.2 LOFTRAN

The LOFTRAN program is used for studies of transient response of a PWR system to specified perturbations in process parameters. LOFTRAN simulates a multiloop system by modeling the reactor core and vessel, hot and cold leg piping, steam generator (tube and shell-sides), pressurizer, and reactor coolant pumps, with up to four reactor coolant loops. The pressurizer heaters, spray, relief and safety valves are also considered in the program. Point model neutron kinetics, and reactivity effects of the moderator, fuel, boron, and rods are included. The secondary side of the steam generator utilizes a homogeneous, saturated mixture for the thermal transients and a water level correlation for indication and control. The reactor protection system is simulated to include reactor trips on neutron flux, overpower and overtemperature reactor coolant ΔT, high and low

pressure, low flow, and high pressurizer level. Control systems are also simulated including rod control, steam dump, feedwater control, and pressurizer pressure control. The safety injection system (SIS), including the accumulators, is also modeled.

LOFTRAN is a versatile program that is suited to both accident evaluation and control studies as well as parameter sizing. LOFTRAN also has the capability of calculating the transient value of DNB based on the input from the core limits illustrated in Figure 15.1-1. The core limits represent the minimum value of DNBR as calculated for a typical or thimble cell. LOFTRAN is further discussed in the licensing topical report, Section 1.6.1, Item 47.

15.1.2.3 PHOENIX- P

The PHOENIX-P computer code is a two-dimensional, multi-group, transport based lattice code and is capable of providing all necessary data for PWR analysis. Being a dimensional lattice code, PHOENIX-P does not rely on pre-determined spatial/spectral interaction assumptions for a heterogeneous fuel lattice. The PHOENIX-P computer code is approved by the NRC as the lattice code for generating macroscopic and microscopic few group cross sections for PWR analysis.

The PHOENIX-P computer code is described in more detail in Section 4.3.3 and is further discussed in the licensing topical report, Section 1.6.1, Item 60.

15.1.2.4 ANC

With the advent of VANTAGE 5 fuel and axial features such as axial blankets and part length burnable absorbers, the three dimensional nodal codes ANC (Advanced Nodal Code) has replaced the previous two group X-Y TURTLE code. The three dimensional nature of the nodal codes provides both the radial and axial power distributions, and also determines the critical boron concentrations and power distributions. The moderator coefficient is evaluated by varying the inlet temperature in the same calculations used for power distribution and reactivity predictions.

Axial calculations are used to determine differential control rod worth curves (reactivity versus rod insertion) and axial power shapes during steady state and transient xenon conditions. Group constants are obtained from three-dimensional nodal calculations homogenized by flux volume weighting.

The ANC computer code is described in more detail in Section 4.3.3 and is further discussed in the licensing topical reports, Section 1.6.1, Items 60 and 61.

15.1.2.5 TWINKLE

The TWINKLE program is a multidimensional spatial neutron kinetics code, which was patterned after steady state codes presently used for reactor core design. The code uses an implicit finite-difference method to solve the two-group transient neutron

diffusion equations in one-, two-, and three-dimensions. The code uses six delayed neutron groups and contains a detailed multiregion fuel-cladding-coolant heat transfer model for calculating pointwise Doppler and moderator feedback effects. The code handles up to 2000 spatial points and performs its own steady state initialization. Aside from basic cross section data and thermal-hydraulic parameters, the code accepts as input basic driving functions such as inlet temperature, pressure, flow, boron concentration, control rod motion, and others. Various edits provide channelwise power, axial offset, enthalpy, volumetric surge, pointwise power, fuel temperatures, and so on.

The TWINKLE code is used to predict the kinetic behavior of a reactor for transients that cause a major perturbation in the spatial neutron flux distribution.

TWINKLE is further described in the licensing topical report, Section 1.6.1, Item 50.

15.1.2.6 THINC

The Steady state and transient analysis using the THINC code (THINC-I, THINC-III and THINC-IV) is described in Section 4.4.3. THINC is further described in the licensing topical reports, Section 1.6.1, Item 28.

15.1.2.7 RETRAN-02

The Electric Power Research Institute (EPRI) RETRAN-02 program is used to perform the best-estimate thermal-hydraulic analysis of operational and accident transients for light water reactor systems. The program is constructed with a highly flexible modeling technique that provides the RETRAN-02 program the capability to model the actual performance of the plant systems and equipment.

The main features of the RETRAN-02 program are:

(1) A one-dimensional, homogeneous equilibrium mixture thermal-hydraulic model for the reactor cooling system

(2) A point neutron kinetics model for the reactor core

(3) Special auxiliary or component models (such as non-equilibrium pressurizer temperature transport delay)

(4) Control system models

(5) A consistent steady state initialization technique

The RETRAN-02 program is further discussed in Reference 21.

15.1.2.8 RETRAN-02W

The RETRAN-02W program is the Westinghouse version of the RETRAN-02 program. RETRAN-02W is used to determine plant transient response to selected accidents, as described in Sections 15.2 and 15.4. RETRAN-02W is further described in the licensing topical report, Section 1.6.1, Item 58.

15.1.2.9 NOTRUMP

The NOTRUMP computer code is a state-of-the-art, one-dimensional general network code consisting of a number of advanced features. Among these features is the calculation of thermal nonequilibrium in all fluid volumes, flow regime-dependent drift flux calculations with counter current flow limitations, mixture level tracking logic in multiple-stacked fluid nodes, and regime-dependent heat transfer correlations. Additional features of the code are condensation heat transfer model applied in the steam generator region, loop seal model, core reflux model, flow regime mapping, etc. NOTRUMP is used to model the thermal-hydraulic behavior of the system and thereby obtain time-dependent values of various core region parameters, such as system pressure, temperature, fluid levels and flow rates, etc.

Small-Break LOCA (SBLOCA) analysis performed using the NOTRUMP code is further described in Section 15.3 and in the licensing topical reports, Section 1.6.1, Items 63 and 64.

15.1.2.10 SBLOCTA (LOCTA-IV)

The NOTRUMP topical report WCAP-10054-P-A makes reference to the LOCTA-IV code (WCAP-8301) and provides modifications to the LOCTA-IV code for use in small break LOCA analyses (i.e., Small Break LOCTA). Further modifications for an annular fuel pellet model were submitted and approved by the NRC in WCAP-14710-P-A, which states, “the revised model has been installed in the SBLOCTA code, which is one of a series of codes descended from the original LOCTA-IV code, and is specific to analyzing small-break LOCA transients.” So, SBLOCTA is the actual computer code name, with base references of WCAP-8301 and WCAP-10054-P-A.
Small-Break LOCA analysis performed using the LOCTA-IV code is further described in Section 15.3 and listed as Reference 4 in that section.

15.1.2.11 <u>W</u>COBRA/TRAC

The thermal-hydraulic computer code (<u>W</u>COBRA/TRAC, Version Mod 7A, Revision 1) that was reviewed and approved for the calculation of fluid and thermal conditions in the PWR during a large break LOCA in WCAP-12945-P-A, Volumes I through V is described in Section 15.4.1.3 and in the licensing topical report, Section 1.6.1, Item 62.

15.1.2.12 HOTSPOT

The use of HOTSPOT along with WCOBRA/TRAC to examine Unit 2 uncertainty using the ASTRUM methodology is discussed in Section 15.4.1.7B.

15.1.2.13 MONTECF

Unit 2 uncertainty evaluation calculations using the ASTRUM methodology was performed by applying a direct, random Monte Carlo sampling to generate the input for the WCOBRA/TRAC and HOTSPOT computer codes as discussed in Section 15.4.1.7B.

15.1.2.14 COCO

Containment pressure is calculated using the COCO code (WCAP-8327 and WCAP-8326) as discussed in Section 15.4.1.3 and listed as Reference 61 in that section.

15.1.3 OPTIMIZATION OF CONTROL SYSTEMS

Prior to initial startup, a setpoint study (Reference 2) was performed in order to simulate performance of the reactor control and protection systems. Emphasis was placed on the development of a control system that will automatically maintain prescribed conditions in the plant even under the most conservative set of reactivity parameters with respect to both system stability and transient performance.

For each mode of plant operation, a group of optimum controller setpoints was determined. In areas where the resultant setpoints were different, compromises based on the optimum overall performance were made and verified. A consistent set of control system parameters was derived satisfying plant operational requirements throughout the core life and for power levels between 15 and 100 percent. The study contained an analysis of the following control systems: rod cluster assembly control, steam dump, steam generator level, pressurizer pressure, and pressurizer level.

Since initial startup, setpoints and control system components have been maintained to optimize performance. Plant operability margin-to-trip analyses are performed on the NSSS control systems for DCPP Units 1 and 2. The purpose of these analyses is to demonstrate that the margin to relevant reactor trip and Engineered Safety Features Actuation System (ESFAS) setpoints is adequate. The NSSS control systems setpoints and time constants are analyzed to provide stable plant response during and following the operational (Condition I) transients:
:

- 50 percent load rejection from 100 percent power
- 10 percent step-load decrease from 100 percent power
- 10 percent step-load increase from 90 percent power
- Turbine trip without reactor trip from permissive P-9 setpoint

When changes are made, the accident analyses are reviewed and revised as necessary. The impact of maintaining pressurizer level greater than or equal to 22 percent and less than or equal to 90 percent in Modes 3, 4, and 5 has been evaluated as acceptable because there is no adverse impact on any accident analyses (References 28 and 29).

15.1.4 INITIAL POWER CONDITIONS ASSUMED IN ACCIDENT ANALYSES

Reactor power-related initial conditions assumed in the accident analyses presented in this chapter are described in this section.

15.1.4.1 Power Rating

Table 15.1-1 lists the principal power rating values that are assumed in analyses performed in this section. Two ratings are given:

(1) The rated thermal power (RTP) output. The RTP is the total reactor core heat transfer rate to the reactor coolant of 3411 MWt for each unit.

(2) The nuclear steam supply system (NSSS) thermal power output. This power output includes the RTP plus the thermal power generated by the reactor coolant pumps.

(3) The engineered safety features (ESF) design rating. The Westinghouse-supplied ESFs are designed for a thermal power higher than the NSSS value in order not to preclude realization of future potential power capability. This higher thermal power value is designated as the ESF design rating.

Where initial power operating conditions are assumed in accident analyses, the NSSS or core rated thermal power output (plus allowance for errors in steady state power determination for some accidents) is assumed. Where demonstration of the adequacy of the ESF is concerned, the ESF design rating plus allowance for error is assumed. The thermal power values for each transient analyzed are given in Table 15.1-4.

15.1.4.2 Initial Conditions

For most accidents, which are DNB limited, nominal values of initial conditions are assumed. The allowances on power, temperature, and pressure are determined on a statistical basis and are included in the limit DNBR, as described in Reference 3. This procedure is known as the "Improved Thermal Design Procedure" (ITDP) and these accidents utilize the WRB-1 and WRB-2 DNB correlations (References 4 and 5). ITDP allowances may be more restrictive than non-ITDP allowances. The initial conditions for other key parameters are selected in such a manner to maximize the impact on DNBR. Minimum measured flow is used in all ITDP transients. The allowances on power, temperature, pressure, and flow that were evaluated for their effect on the ITDP

analyses for a 24-month fuel cycle are reported in Reference 22. These allowances are conservatively applicable for shorter fuel cycle lengths.

For accident evaluations that are not DNB limited, or for which the Improved Thermal Design Procedure is not employed, the initial conditions are obtained by adding maximum steady state errors to rated values. The following steady state errors are considered:

(1)	Core power	Plus or minus 2 percent allowance calorimetric error
(2)	Average RCS	Plus or minus 4.7°F allowance for deadband and measurement error temperature
(3)	Pressurizer pressure	Plus or minus 38 psi or plus or minus 60 psi allowance for steady state fluctuations and measurement error (see Note)

Note: Pressurizer pressure uncertainty is plus or minus 38 psi in analyses performed prior to 1993; however, NSAL 92-005 (Reference 17) indicates plus or minus 60 psi is a conservative value for future analyses. Reference 18 evaluates the acceptability of existing analyses, which use plus or minus 38 psi.

For some accident evaluations, an additional allowance has been conservatively added to the measurement error for the average RCS temperatures to account for steam generator fouling.

DCPP Units 1 and 2 are expected to operate at a Reactor Coolant System vessel average temperature (Tavg) over a range from 565 ºF to 577.3/577.6 ºF (Unit 1/Unit 2).

15.1.4.3 Power Distribution

The transient response of the reactor system is dependent on the initial power distribution. The nuclear design of the reactor core minimizes adverse power distribution through the placement of fuel assemblies, control rods, and by operation instructions. The power distribution may be characterized by the radial peaking factor $F_{\Delta H}$ and the total peaking factor F_q. The peaking factor limits are given in the Technical Specifications.

For transients that may be DNB-limited, the radial peaking factor is of importance. The radial peaking factor increases with decreasing power level due to rod insertion. This increase in $F_{\Delta H}$ is included in the core limits illustrated in Figure 15.1-1. All transients that may be DNB limited are assumed to begin with a $F_{\Delta H}$ consistent with the initial power level defined in the Technical Specifications.

The axial power shape used in the DNB calculation is discussed in Section 4.4.3.

For transients that may be overpower-limited, the total peaking factor F_q is of importance. The value of F_q may increase with decreasing power level so that the full power hot spot heat flux is not exceeded, i.e., F_q x Power = design hot spot heat flux. All transients that may be overpower-limited are assumed to begin with a value of F_q consistent with the initial power level as defined in the Technical Specifications.

The value of peak kW/ft can be directly related to fuel temperature as illustrated in Figures 4.4-1 and 4.4-2. For transients that are slow with respect to the fuel rod thermal time constant (approximately 5 seconds), the fuel temperatures are illustrated in Figures 4.4-1 and 4.4-2. For transients that are fast with respect to the fuel rod thermal time constant, (for example, rod ejection), a detailed heat transfer calculation is made.

15.1.5 TRIP POINTS AND TIME DELAYS TO TRIP ASSUMED IN ACCIDENT ANALYSES

A reactor trip signal acts to open two trip breakers connected in series feeding power to the control rod drive mechanisms. The loss of power to the mechanism coils causes the mechanism to release the rod cluster control assemblies (RCCAs), which then fall by gravity into the core. There are various instrumentation delays associated with each trip function, including delays in signal actuation, in opening the trip breakers, and in the release of the rods by the mechanisms. The total delay to trip is defined as the time delay from the time that trip conditions are reached to the time the rods are free and begin to fall. Limiting trip setpoints assumed in accident analyses and the time delay assumed for each trip function are given in Table 15.1-2. Reference is made in that table to the overtemperature and overpower ΔT trip shown in Figure 15.1-1. This figure presents the allowable reactor coolant loop average temperature and ΔT for the design flow and the NSSS Design Thermal Power distribution as a function of primary coolant pressure. The boundaries of operation defined by the Overpower ΔT trip and the Overtemperature ΔT trip are represented as "protection lines" on this diagram. The protection lines are drawn to include all adverse instrumentation and setpoint errors so that under nominal conditions a trip would occur well within the area bounded by these lines. The utility of this diagram is in the fact that the limit imposed by any given DNBR can be represented as a line. The DNB lines represent the locus of conditions for which the DNBR equals the safety analysis limit values (1.68 and 1.71 for V-5 thimble cell and typical cells, respectively) for analyses using the ITDP. All points below and to the left of a DNB line for a given pressure have a DNBR greater than the limit values. The diagram shows that DNB is prevented for all cases if the area enclosed with the maximum protection lines is not traversed by the applicable DNBR line at any point.

The current fuel cycles for the DCPP Unit 1 and Unit 2 only use the Vantage 5 (V-5) fuel assembly type. However, the safety analyses performed in support of the transition to Vantage-5 fuel also considered the presence of the Standard type fuel assemblies. The DNBR values and transient results presented in the UFSAR continue to reflect the Standard limits, since they are limiting with respect to DNB margin in comparison to the

Vantage-5 limits. Analyses performed subsequent to the transition to a full Vantage-5 core reflect only the Vantage-5 limits as described in Sections 15.2, 15.3, and 15.5. The area of permissible operation (power, pressure and temperature) is bounded by the combination of reactor trips: high pressurizer pressure (fixed setpoint); low pressurizer pressure (fixed setpoint); overpower and overtemperature ΔT (variable setpoints); and by a line defining conditions at which the steam generator safety valves open.

The limit values, which were used as the DNBR limits for all accidents analyzed with the ITDP are conservative compared to the actual design DNBR values required to meet the DNB design basis.

The difference between the limiting trip point assumed for the analysis and the normal trip point represents an allowance for instrumentation channel error and setpoint error. During startup tests, it is demonstrated that actual instrument errors and time delays are equal to or less than the assumed values.

Accident analyses that assume the steam generator low-low water level to initiate protection functions may be affected by the trip time delay (TTD) (Reference 19) that was developed to reduce the incidence of unnecessary feedwater related reactor trips.

Refer to Section 7.2.2.1.5 for a discussion about the low-low steam generator water level trip, including the TTD.

15.1.6 CALORIMETRIC ERRORS - POWER RANGE NEUTRON FLUX

The calorimetric error is the error assumed in the determination of core thermal power as obtained from secondary plant measurements. The total ion chamber current (sum of the top and bottom sections) is calibrated (set equal) to this measured power on a periodic basis. The secondary power is obtained from measurement of feedwater flow, feedwater inlet temperature to the steam generators, and steam pressure. High-accuracy instrumentation is provided for these measurements with accuracy tolerances much tighter than those that would be required to control feedwater flow.

15.1.7 ROD CLUSTER CONTROL ASSEMBLY INSERTION CHARACTERISTICS

The negative reactivity insertion following a reactor trip is a function of the acceleration of the RCCA and the variation in rod worth as a function of rod position.

With respect to accident analyses, the critical parameter is the time of insertion up to the dashpot entry or approximately 85 percent of the rod cluster travel. For accident analyses, the insertion time to dashpot entry is conservatively taken as 2.7 seconds. The RCCA position versus time assumed in accident analyses is shown in Figure 15.1-2.

Figure 15.1-3 shows the fraction of total negative reactivity insertion for a core where the axial distribution is skewed to the lower region of the core. This curve is used as input to all point kinetics core models used in transient analyses.

There is inherent conservatism in the use of this curve in that it is based on a skewed axial power distribution that would exist relatively infrequently. For cases other than those associated with xenon oscillations, significant negative reactivity would have been inserted due to the more favorable axial power distribution existing prior to trip.

The normalized RCCA negative reactivity insertion versus time is shown in Figure 15.1-4. The curve shown in this figure was obtained from Figures 15.1-2 and 15.1-3. A total negative reactivity insertion following a trip of 4 percent Δk is assumed in the transient analyses except where specifically noted otherwise. This assumption is conservative with respect to the calculated trip reactivity worth available as shown in Tables 4.3-2 and 4.3-3.

The normalized RCCA negative reactivity insertion versus time after trip curve for an axial power distribution skewed to the bottom (Figure 15.1-4) is used in transient analyses.

Where special analyses require the use of three-dimensional or axial one-dimensional core models, the negative reactivity insertion resulting from reactor trip is calculated directly by the reactor kinetic code and is not separable from other reactivity feedback effects. In this case, the RCCA position versus time of Figure 15.1-2 is used as code input.

15.1.8 REACTIVITY COEFFICIENTS

The transient response of the reactor coolant system is dependent on reactivity feedback effects, in particular the moderator temperature coefficient and the Doppler power coefficient. These reactivity coefficients and their values are discussed in detail in Chapter 4.

In the analysis of certain events, conservatism requires the use of large reactivity coefficient values, whereas in the analysis of other events, conservatism requires the use of small reactivity coefficient values. Some analyses, such as loss of reactor coolant from cracks or ruptures in the RCS, do not depend on reactivity feedback effects. The values used are given in Table 15.1-4; reference is made in that table to Figure 15.1-5 that shows the upper and lower Doppler power coefficients, as a function of power, used in the transient analysis. The justification for use of conservatively large versus small reactivity coefficient values is discussed on an event-by-event basis.

15.1.9 FISSION PRODUCT INVENTORIES

The fission product inventories existing in the core and fuel rod gaps are described in Section 15.5.3. The description of the models used for calculating fuel gap activities is included in Section 15.5.3.

15.1.10 RESIDUAL DECAY HEAT

Residual heat in a subcritical core consists of:

(1) Fission product decay energy

(2) Decay of neutron capture products

(3) Residual fissions due to the effect of delayed neutrons

These constituents are discussed separately in the following paragraphs.

15.1.10.1 Fission Product Decay

The heat generation rates from radioactive decay of fission products that have been assumed in the small break LOCA (SBLOCA) accident analyses are equal to 1.2 times the values for infinite operating time in the 1971 Draft ANS-5 Standard. (Reference 30)

The decay heat curve used for the Best Estimate large break LOCA (LBLOCA) analysis is based on the 1979 ANS decay heat curve as described in Section 8 of Reference 23. This curve with the 20 percent factor included is shown in Figure 15.1-6.The 1979 ANS decay heat curve (Reference 11) is used for the non-LOCA analyses. Figure 15.1-7 presents this curve as a function of time after shutdown.

15.1.10.2 Decay of U-238 Capture Products

Betas and gammas from the decay of U-239 (23.5-minute half-life) and Np-239 (2.35-day half-life) contribute significantly to the heat generation after shutdown. The cross sections for production of these isotopes and their decay schemes are relatively well known. For long irradiation times their contribution can be written as:

$$P_1 / P_0 = \frac{(E_{\gamma 1} + E_{\beta 1})\, c\, (1+\alpha)}{200\ \text{MeV}}\, e^{-\lambda_1 t} \text{ watts/watt} \qquad (15.1\text{-}1)$$

$$P_2 / P_0 = \frac{(E_{\gamma 2} + E_{\beta 2})\, c\, (1+\alpha)}{200\ \text{MeV}} \left[\frac{\lambda_2}{\lambda_1 - \lambda_2} (e^{-\lambda_2 t} - e^{-\lambda_1 t}) + e^{-\lambda_2 t} \right] \text{ watts/watt} \qquad (15.1\text{-}2)$$

where:

P_1/P_0 is the energy from U-239 decay
P_2/P_0 is the energy from Np-239 decay
t is the time after shutdown (seconds)
$c(1+\alpha)$ is the ratio of U-238 captures to total fissions = 0.6 (1 + 0.2)
λ_1 = the decay constant of U-239 = 4.91×10^{-4} per second
λ_2 = the decay constant of Np-239 decay = 3.41×10^{-6} per second
$E_{\gamma 1}$ = total γ-ray energy from U-239 decay = 0.06 MeV
$E_{\gamma 2}$ = total γ-ray energy from Np-239 decay = 0.30 MeV
$E_{\beta 1}$ = total β-ray energy from U-239 decay = 1/3[(a)] x 1.18 MeV
$E_{\beta 2}$ = total β-ray energy from Np-239 decay = 1/3[(a)] x 0.43 MeV

[(a)] Two-thirds of the potential β-energy is assumed to escape by the accompanying neutrinos.

For the SBLOCA, based on conservative modeling of the ratio of U-238 captures to total fissions, heavy element decay heat is calculated without applying further uncertainty correction (Reference 24). For the Best Estimate LOCA analysis, the heat from the radioactive decay of U-239 and Np-239 is calculated as described in Section 8 of Reference 23. The decay of other isotopes, produced by neutron reactions other than fission, is neglected. For the non-LOCA analysis, the decay of U-238 capture products is included as an integral part of the 1979 decay heat curve presented as Figure 15.1-7.

15.1.10.3 Residual Fissions

The time dependence of residual fission power after shutdown depends on core properties throughout a transient under consideration. Core average conditions are more conservative for the calculation of reactivity and power level than actual local conditions as they would exist in hot areas of the core. Thus, unless otherwise stated in the text, static power shapes have been assumed in the analysis and these are factored by the time behavior of core average fission power calculated by a point kinetics model calculation with six delayed neutron groups.

For the purpose of illustration, only one delayed neutron group calculation, with a constant shutdown reactivity of -4 percent Δk is shown in Figure 15.1-6.

15.1.10.4 Distribution of Decay Heat Following Loss-of-Coolant Accident

During an SBLOCA the core is rapidly shut down by void formation or RCCA insertion, or both, and long-term shutdown is assured by the borated ECCS water. A large fraction of the heat generation to be considered comes from fission product decay gamma rays. This heat is not distributed in the same manner as steady state fission power. Local peaking effects that are important for the neutron dependent part of the heat generation do not apply to the gamma ray source contribution. The steady state

factor of 97.4 percent that represents the fraction of heat generated within the cladding and pellet drops to 95 percent for the hot rod in a LOCA.
For example, 1/2 second after the rupture about 30 percent of the heat generated in the fuel rods is from gamma ray absorption. The gamma power shape is less peaked than the steady state fission power shape, reducing the energy deposited in the hot rod at the expense of adjacent colder rods. A conservative estimate of this effect is a reduction of 10 percent of the gamma ray contribution or 3 percent of the total. Since the water density is considerably reduced at this time, an average of 98 percent of the available heat is deposited in the fuel rods, the remaining 2 percent being absorbed by water, thimbles, sleeves, and grids. The net effect is a factor of 0.95, rather than 0.974, to be applied to the heat production in the hot rod.

For the Best Estimate LOCA analysis, the energy deposition modeling is performed as described in Section 8 of Reference 23.

15.1.11 REFERENCES

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15.2 CONDITION II - FAULTS OF MODERATE FREQUENCY

These faults result at worst in the reactor shutdown with the plant capable of returning to operation. By definition, these faults (or events) do not propagate to cause a more serious fault, i.e., a Condition III or IV fault. In addition, Condition II events are not expected to result in fuel rod failures, reactor coolant system (RCS) overpressurization, or main steam system (MSS) overpressurization. For the purposes of this report the following faults have been grouped into these categories:

(1) Uncontrolled rod cluster control assembly bank withdrawal from a subcritical condition

(2) Uncontrolled rod cluster control assembly bank withdrawal at power

(3) Rod cluster control assembly misoperation

(4) Uncontrolled boron dilution

(5) Partial loss of forced reactor coolant flow

(6) *Startup of an inactive reactor coolant loop* (Historical)

(7) Loss of external electrical load and/or turbine trip

(8) Loss of normal feedwater

(9) Loss of offsite power to the station auxiliaries

(10) Excessive heat removal due to feedwater system malfunctions

(11) Sudden feedwater temperature reduction

(12) Excessive load increase incident

(13) Accidental depressurization of the reactor coolant system

(14) Accidental depressurization of the main steam system

(15) Spurious operation of the safety injection system at power

Each of these faults of moderate frequency are analyzed in this section. In general, each analysis includes acceptance criteria, an identification of causes and description of the accident, an analysis of effects and consequences, a presentation of results, and relevant conclusions.

An evaluation of the reliability of the reactor protection system actuation following initiation of Condition II events has been completed and is presented in Reference 1 for the relay protection logic. Standard reliability engineering techniques were used to assess the likelihood of the trip failure due to random component failures. Common-mode failures were also qualitatively investigated. It was concluded from the evaluation that the likelihood of no trip following the initiation of Condition II events is extremely small (2×10^{-7} derived for random component failures). The solid-state protection system design has been evaluated by the same methods as used for the relay system and the same order of magnitude of reliability is provided.

Hence, because of the high reliability of the protection system, no special provision is included in the design to cope with the consequences of Condition II events without trip.

The time sequence of events corresponding to the respective Condition II fault is shown in Table 15.2-1.

15.2.1 UNCONTROLLED ROD CLUSTER CONTROL ASSEMBLY BANK WITHDRAWAL FROM A SUBCRITICAL CONDITION

15.2.1.1 Acceptance Criteria

The following is the relevant specific acceptance criterion.

(1) Minimum DNBR is not less than the appropriate limit value at any time during the transient.

15.2.1.2 Identification of Causes and Accident Description

A rod cluster control assembly (RCCA) withdrawal accident is defined as an uncontrolled increase in reactivity in the reactor core caused by withdrawal of RCCAs resulting in a power excursion. Such a transient could be caused by a malfunction of the reactor control or control rod drive systems. The Section 15.2.1 event occurs with the reactor at hot zero power (i.e., subcritical). The at-power case is discussed in Section 15.2.2.

Although the reactor can be brought to power from a subcritical condition by means of RCCA withdrawal, startup procedures following refueling also permit boron dilution. The maximum rate of reactivity increase in the case of boron dilution is less than that assumed in this analysis (Refer to Section 15.2.4).

The RCCA drive mechanisms are wired into preselected bank configurations that are not altered during core reactor life. These circuits prevent the assemblies from being withdrawn in other than their respective banks. Power supplied to the banks is controlled so that no more than two banks can be withdrawn at the same time. The RCCA drive mechanisms are of the magnetic latch type and coil actuation is sequenced to provide variable speed travel. The maximum reactivity insertion rate analyzed in the

detailed plant analysis is that occurring with the simultaneous withdrawal of the two control banks having the maximum combined worth at maximum speed.

The neutron flux response to a continuous reactivity insertion is characterized by a very fast rise terminated by the reactivity feedback effect of the negative Doppler coefficient. This self-limitation of the power burst is of primary importance since it limits the power to a tolerable level during the delay time for protective action. Should a continuous RCCA withdrawal accident occur, the transient will be terminated by the following automatic features of the reactor protection system.

15.2.1.2.1 Source Range High Neutron Flux Reactor Trip

The source range high neutron flux reactor trip is actuated when either of two independent source range channels indicates a neutron flux level above a preselected manually adjustable setpoint. This trip function may be manually bypassed when either intermediate range flux channel indicates a flux level above a specified level. It is automatically reinstated when both intermediate range channels indicate a flux level below a specified level.

15.2.1.2.2 Intermediate Range High Neutron Flux Reactor Trip

The intermediate range high neutron flux reactor trip is actuated when either of two independent intermediate range channels indicates a flux level above a preselected manually adjustable setpoint. This trip function may be manually bypassed when two of the four power range channels give readings above approximately 10 percent of full power and is automatically reinstated when three of the four channels indicate a power below this value.

15.2.1.2.3 Power Range High Neutron Flux Reactor Trip (Low Setting)

The power range high neutron flux trip (low setting) is actuated when two-out-of-four power range channels indicate a power level above approximately 25 percent of full power. This trip function may be manually bypassed when two of the four power range channels indicate a power level above approximately 10 percent of full power and is automatically reinstated when three of the four channels indicate a power level below 10 percent.

15.2.1.2.4 Power Range High Neutron Flux Reactor Trip (High Setting)

The power range high neutron flux reactor trip (high setting) is actuated when two-out-of-four power range channels indicate a power level above a preset setpoint. This trip function is always active.

15.2.1.2.5 Power Range High Positive Neutron Flux Rate Trip

The power range high positive neutron flux rate trip is actuated when the rate of change in power on two-out-of-four power range channels exceeds the preset setpoint. This trip function is always active.

15.2.1.3 Analysis of Effects and Consequences

This transient is analyzed by three digital computer codes. The TWINKLE (Reference 2) code is used to calculate the reactivity transient and hence the nuclear power transient. The FACTRAN (Reference 3) code is then used to calculate the thermal heat flux transient based on the nuclear power transient calculated by the TWINKLE code. FACTRAN also calculates the fuel, cladding, and coolant temperatures. A detailed thermal and hydraulic computer code, THINC (refer to Section 1.6.1, Item 28 and Section 4.4.3) (Reference 9) is used to calculate the DNB.

The event is not analyzed with the Improved Thermal Design Procedure since it is analyzed with reduced flow.

In order to give conservative results for a startup accident, the following assumptions are made concerning the initial reactor conditions:

(1) Since the magnitude of the power peak reached during the initial part of the transient for any given rate of reactivity insertion is strongly dependent on the Doppler coefficient, conservative values (low absolute magnitude) as a function of power are used. Refer to Section 15.1.6 and Table 15.1-4.

(2) Contribution of the moderator reactivity coefficient is negligible during the initial part of the transient because the heat transfer time between the fuel and the moderator is much longer than the neutron flux response time. However, after the initial neutron flux peak, the succeeding rate of power increase is affected by the moderator reactivity coefficient. The conservative value, given in Table 15.1-4, is used in the analysis to yield the maximum peak heat flux.

(3) The reactor is assumed to be at hot zero power. This assumption is more conservative than that of a lower initial system temperature. The higher initial system temperature yields a larger fuel-water heat transfer coefficient, larger specific heats, and a less negative (smaller absolute magnitude) Doppler coefficient, all of which tend to reduce the Doppler feedback effect thereby increasing the neutron flux peak. The initial effective multiplication factor is assumed to be 1 since this results in maximum neutron flux peaking.

(4) Reactor trip is assumed to be initiated by power range high neutron flux (low setting). The most adverse combination of instrument and setpoint errors, as well as delays for trip signal actuation and RCCA release, is taken into account. A 10 percent increase is assumed for the power range flux trip setpoint, raising it from the nominal value of 25 to 35 percent. Previous results, however, show that the rise in neutron flux is so rapid that the effect of error on this trip setpoint on the actual time at which the rods are released is negligible. In addition, the reactor trip insertion characteristic is based on the assumption that the highest worth RCCA is stuck in its fully withdrawn position. Refer to Section 15.1.5 for RCCA insertion characteristics.

(5) The maximum positive reactivity insertion rate assumed is greater than that for the simultaneous withdrawal of the combination of the two control banks having the greatest combined worth at maximum speed (45 inches/minute). Control rod drive mechanism design is discussed in Section 4.2.3.

(6) The initial power level is assumed to be below the power level expected for any shutdown condition. The combination of highest reactivity insertion rate and lowest initial power produces the highest peak heat flux.

15.2.1.4 Results

Figures 15.2.1-1 through 15.2.1-3 show the transient behavior for the indicated reactivity insertion rate with the accident terminated by reactor trip at 35 percent nominal power. This insertion rate is greater than that for the two highest worth control banks, both assumed to be in their highest incremental worth region.

Figure 15.2.1-1 shows the neutron flux transient. The neutron flux overshoots the full power nominal value but this occurs for only a very short time period. Hence, the energy release and the fuel temperature increase are relatively small. The thermal flux response, of interest for departure from nucleate boiling (DNB) considerations, is shown in Figure 15.2.1-2. The beneficial effect on the inherent thermal lag in the fuel is evidenced by a peak heat flux less than the full power nominal value. The DNBR remains above the applicable safety analysis limit value at all times.

Figure 15.2.1-3 shows the response of the average fuel, cladding, and coolant temperatures at the hot spot.

15.2.1.5 Conclusions

The analysis demonstrates that the acceptance criterion is met as follows:

(1) Minimum DNBR remains above the appropriate limit value at any time during the transient.

In the event of an RCCA withdrawal accident from the subcritical condition, the core and the RCS are not adversely affected since the combination of thermal power and the coolant temperature result in a DNBR above the limiting value.

15.2.2 UNCONTROLLED ROD CLUSTER CONTROL ASSEMBLY BANK WITHDRAWAL AT POWER

15.2.2.1 Acceptance Criteria

The following are the relevant specific acceptance criteria.

(1) The minimum DNBR must not go below the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell) (refer to Section 4.4.1.1.2) at any time during the transient.

(2) The peak core average power (heat flux) does not exceed a value that would cause fuel centerline melt at any time during the transient (refer to Section 4.4.2.2.7).

(3) The RCS pressure does not exceed 110% of design pressure (2,750 psia) at any time during the transient.

(4) The pressurizer does not go water solid at any time during the transient.

15.2.2.2 Identification of Causes and Accident Description

Uncontrolled RCCA bank withdrawal at power results in an increase in the core heat flux. Since the heat extraction from the steam generator (SG) lags behind the core power generation until the steam generator pressure reaches the relief or safety valve setpoint, there is a net increase in the reactor coolant temperature. Unless terminated by manual or automatic action, the power mismatch and resultant coolant temperature rise would eventually result in DNB, an RCS overpressure condition, or the pressurizer filled with liquid. Therefore, the reactor protection system is designed to terminate any such transient before the DNBR falls below the safety analysis limit values, the RCS pressure exceeds 110 percent of the design value, or the pressurizer becomes filled with liquid.

The automatic features of the reactor protection system that ensure these limits are not exceeded following the postulated accident include the following:

(1) The power range neutron flux instrumentation actuates a reactor trip if two-out-of-four channels exceed a high flux or a positive flux rate high setpoint.

(2) The reactor trip is actuated if any two-out-of-four ΔT channels exceed an overtemperature ΔT setpoint.

(3) The reactor trip is actuated if any two-out-of-four ΔT channels exceed an overpower ΔT setpoint.

(4) A high pressurizer pressure reactor trip actuated from any two-out-of-four pressure channels that are set at a fixed point.

(5) A high pressurizer water level reactor trip actuated from any two-out-of-three level channels that are set at a fixed point.

Reference 18 documents that the generic and conservatively bounding evaluations have been performed to ensure that the RCS overpressure and the pressurizer overfill conditions are not a concern for this event. One evaluation demonstrates that the positive flux rate trip provides adequate protection to ensure that the most limiting RCCA withdrawal event with respect to RCS pressure does not result in the peak RCS pressure exceeding 110 percent of the design limit. The positive flux rate trip setpoint and response time that are credited for this evaluation are listed in Table 15.1-2. Another evaluation demonstrates that the pressurizer water level high trip prevents a pressurizer overfill condition for those RCCA withdrawal events that are very slow and do not generate any other automatic protection signal. The pressurizer water level high trip response time is listed as N/A with the note indicating that the evaluation results are extremely insensitive to the assumed response time.

The generic evaluations of Reference 18 establish that the RCS overpressure and pressurizer overfill criteria are much less limiting, and only the minimum DNBR analysis is described in detail within this section.

The manner in which the combination of overpower and overtemperature ΔT trips provide fuel cladding protection over the full range of RCS conditions is described in Chapter 7 and Section 15.1.3.

15.2.2.3 Analysis of Effects and Consequences

This transient is analyzed by the LOFTRAN (Reference 4) code. This code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level. The core limits as illustrated in Figure 15.1-1 are used as input to LOFTRAN to determine the minimum DNBR during the transient.

This accident is analyzed with the Improved Thermal Design Procedure and the initial condition uncertainties are included in the limit DNBR as described in Reference 5. Therefore, initial conditions of nominal core power, nominal reactor coolant average

temperatures (including 2.5°F for steam generator fouling) and nominal reactor coolant pressure are assumed.

In order to obtain conservative results, the following assumptions are made:

(1) Reactivity Coefficients - two cases are analyzed:

(a) Minimum reactivity feedback. A positive moderator coefficient of reactivity of +5 pcm/°F is assumed. A variable Doppler power coefficient with core power is used in the analysis. A conservatively small (in absolute magnitude) value is assumed.

(b) Maximum reactivity feedback. A conservatively large positive moderator density coefficient of 0.43 Δk/gm/cc is assumed. A large (in absolute magnitude) negative Doppler power coefficient is assumed.

(2) The reactor trip on high neutron flux is assumed to be actuated at a conservative value of 118 percent of nominal full power. The ΔT trips include all adverse instrumentation and setpoint errors, while the delays for the trip signal actuation are assumed at their maximum values.

(3) The RCCA trip insertion characteristic is based on the assumption that the highest worth assembly is stuck in its fully withdrawn position.

(4) The maximum positive reactivity insertion rate is greater than that which would be obtained from the simultaneous withdrawal of the two control rod banks having the maximum combined worth at maximum speed.

The effect of RCCA movement on the axial core power distribution is accounted for by causing a decrease in overtemperature ΔT trip setpoint proportional to a decrease in margin to DNB.

15.2.2.4 Results

Figures 15.2.2-1 and 15.2.2-2 show the response of neutron flux, pressure, average coolant temperature, and DNBR (thimble cell) due to a rapid RCCA withdrawal starting from full power. Reactor trip on high neutron flux occurs shortly after the start of the accident. Since this is rapid with respect to the thermal time constants of the plant, small changes in T_{avg} and pressure result and a large margin to DNB is maintained.

The response of neutron flux, pressure, average coolant temperature, and DNBR (thimble cell) for a slow control rod assembly withdrawal from full power is shown in Figures 15.2.2-3 and 15.2.2-4. Reactor trip on overtemperature ΔT occurs after a longer period and the rise in temperature and pressure is consequently larger than for

rapid RCCA withdrawal. Again, the minimum DNBR is never less than the safety analysis limit values.

Figure 15.2.2-5 shows the minimum DNBR (thimble cell) as a function of reactivity insertion rate from initial full power operation for the minimum and for the maximum reactivity feedbacks. It can be seen that two reactor trip channels provide protection over the whole range of reactivity insertion rates. These are the high neutron flux and overtemperature ΔT trip channels. The minimum DNBR is never less than the safety analysis limit values.

Figures 15.2.2-6 and 15.2.2-7 show the minimum DNBR (thimble cell) as a function of reactivity insertion rate for RCCA withdrawal incidents starting at 60 and 10 percent power, respectively. The results are similar to the 100 percent power case, except that as the initial power is decreased, the range over which the overtemperature ΔT trip is effective is increased. In neither case does the DNBR fall below the safety analysis limit values.

The shape of the curves of minimum DNB ratio versus reactivity insertion rate in the reference figures is due both to reactor core and coolant system transient response and to protection system action in initiating a reactor trip. Referring to Figure 15.2.2-7, for example, it is noted that:

(1) For reactivity insertion rates above ~30 pcm/sec reactor trip is initiated by the high neutron flux trip for the minimum reactivity feedback cases. The neutron flux level in the core rises rapidly for these insertion rates while core heat flux and coolant system temperature lag behind due to the thermal capacity of the fuel and coolant system fluid. Thus, the reactor is tripped prior to significant increase in heat flux or water temperature with resultant high minimum DNB ratios during the transient. As reactivity insertion rate decreases, core heat flux and coolant temperatures can remain more nearly in equilibrium with the neutron flux. Minimum DNBR during the transient thus decreases with decreasing insertion rate.

(2) The Overtemperature ΔT reactor trip circuit initiates a reactor trip when measured coolant loop ΔT exceeds a setpoint based on measured RCS average temperature and pressure. It is important to note that the average temperature contribution to the circuit is lead-lag compensated in order to decrease the effect of the thermal capacity of the RCS in response to power increase.

(3) For reactivity insertion rate below ~30 pcm/sec the Overtemperature ΔT trip terminates the transient.

For reactivity insertion rates between ~30 pcm/sec and ~7 pcm/sec the effectiveness of the Overtemperature ΔT trip increases (in terms of increased minimum DNBR) due to the fact that with lower insertion rates

the power increase rate is slower, the rate of rise of average coolant temperature is slower and the system lags and delays become less significant.

(4) For reactivity insertion rates less than ~7 pcm/sec, the rise in the reactor coolant temperature is sufficiently high so that the steam generator safety valve setpoint is reached prior to trip. Opening of these valves, which act as an additional heat load on the RCS, sharply decreases the rate of increase of RCS average temperature. This decrease in rate of increase of the average RCS temperature during the transient is accentuated by the lead-lag compensation causing the Overtemperature ΔT trip setpoint to be reached later with a resulting lower minimum DNBR.

Figures 15.2.2-5, 15.2.2-6, and 15.2.2-7 illustrate minimum DNBRs calculated for minimum and maximum reactivity feedback.

Since the RCCA withdrawal at power incident is an overpower transient, the fuel temperatures rise during the transient until after reactor trip occurs. For high reactivity insertion rates, the overpower transient is fast with respect to the fuel rod thermal time constant, and the core heat flux lags behind the neutron flux response. Due to this lag, the peak core heat flux does not exceed 118 percent of its nominal value (i.e., the high neutron flux trip setpoint assumed in the analysis). Taking into account the effect of the RCCA withdrawal on the axial core power distribution, the peak fuel centerline temperature will still remain below the fuel melting temperature.

For slow reactivity insertion rates, the core heat flux remains more nearly in equilibrium with the neutron flux. The overpower transient is terminated by the Overtemperature ΔT reactor trip before a DNB condition is reached. The peak heat flux again is maintained below 118 percent of its nominal value. Taking into account the effect of the RCCA withdrawal on the axial core power distribution, the peak fuel centerline temperature will remain below the fuel melting temperature.

Since DNB is not predicted to occur at any time during the RCCA withdrawal at power transient, the ability of the primary coolant to remove heat from the fuel rod is not reduced. Thus, the fuel cladding temperature does not rise significantly above its initial value during the transient.

The calculated sequence of events for this accident is shown in Table 15.2-1. With the reactor tripped, the plant eventually returns to a stable condition. The plant may subsequently be cooled down further by following normal plant shutdown procedures.

15.2.2.5 Conclusions

The analysis demonstrates that the acceptance criteria are met as follows:

(1) There is margin to the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell). The accompanying DNBR figures for this event (Figure 15.2.2-2, and Figures 15.2.2-4 through 15.2.2-7) reflect the results for the more limiting Standard fuel (limit 1.48/1.44) previously in the core.

(2) The core heat flux is maintained below 118 percent of its nominal value. Thus the peak fuel centerline temperature will remain below the fuel melting temperature (refer to Section 4.4.2.2.7).

(3) The RCS pressure does not exceed 110 percent of design pressure (2,750 psia) at any time during the transient.

(4) The pressurizer does not become water solid during the event.

The high neutron flux and overtemperature ΔT trip channels provide adequate protection over the entire range of possible reactivity insertion rates; i.e., the minimum value of DNBR is always larger than the safety analysis limit values.

15.2.3 ROD CLUSTER CONTROL ASSEMBLY MISOPERATION

This section discusses RCCA misoperation that can result either from system malfunction or operator error.

15.2.3.1 Acceptance Criteria

The following is the relevant specific acceptance criterion.

(1) The minimum DNBR must not go below the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell) (refer to Section 4.4.1.1.2) at any time during the transient.

15.2.3.2 Identification of Causes and Accident Description

RCCA misoperation accidents include:

(1) One or more dropped RCCAs within the same group

(2) A dropped RCCA bank

(3) Statically misaligned RCCA

Each RCCA has a position indicator channel that displays the position of the assembly. The displays of assembly positions are grouped for the operator's convenience. Fully inserted assemblies are further indicated by a rod at bottom signal, which actuates a local alarm and a control room annunciator. Group demand position is also indicated.

RCCAs are always moved in preselected banks, and the banks are always moved in the same preselected sequence. Each bank of RCCAs is divided into two groups. The rods comprising a group operate in parallel through multiplexing thyristors. The two groups in a bank move sequentially such that the first group is always within one step of the second group in the bank. A definite schedule of actuation (or deactuation of the stationary gripper, movable gripper, and lift coils of a mechanism) is required to withdraw the RCCA attached to the mechanism. Since the stationary gripper, movable gripper, and lift coils associated with the four RCCAs of a rod group are driven in parallel, any single failure that would cause rod withdrawal would affect a minimum of one group. Mechanical failures are in the direction of insertion, or immobility.

A dropped RCCA, or RCCA bank, is detected by:

(1) A sudden drop in the core power level as seen by the nuclear instrumentation system

(2) Asymmetric power distribution as seen on out-of-core neutron detectors or core-exit thermocouples

(3) Rod at bottom signal

(4) Rod deviation alarm

(5) Rod position indication

Misaligned RCCAs are detected by:

(1) Asymmetric power distribution as seen on out-of-core neutron detectors or core-exit thermocouples

(2) Rod deviation alarm

(3) Rod position indicators

The deviation alarm alerts the operator whenever an individual rod position signal deviates from the other rods in the bank by a preset limit.

During time intervals when the Rod Position Deviation Monitor is inoperable:

(1) Each rod position indicator is determined to be operable by verifying that the Demand Position Indication System and the Digital Rod Position Indication System agree within 12 steps at least once per four hours.

During time intervals when the rod insertion limit monitor is inoperable, the individual rod positions are verified to be within insertion limits at least once per four hours.

If one or more rod position indicator channels should be out of service, detailed operating instructions are followed to ensure the alignment of the nonindicated RCCAs. The operator is also required to take action as required by the Technical Specifications (TS).

15.2.3.3 Analysis of Effects and Consequences

The accident is analyzed with the Improved Thermal Design Procedure and the initial condition uncertainties are included in the limit DNBR as described in Reference 5. Therefore, initial conditions of nominal core power, nominal reactor coolant average temperature and nominal reactor coolant pressure are assumed.

Method of Analysis

(1) One or More Dropped RCCAs from the Same Group

For evaluation of the dropped RCCA event, the transient system response is calculated using the LOFTRAN code. The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

Statepoints are calculated and nuclear models are used to obtain a hot channel factor consistent with the primary system conditions and reactor power. By incorporating the primary conditions from the transient and the hot channel factor from the nuclear analysis, the DNB design basis is shown to be met using the THINC code (refer to Section 1.6.1, Item 28 and Section 4.4.3). The transient response, nuclear peaking factor analysis, and DNB design basis confirmation are performed in accordance with the methodology described in Reference 10.

(2) Dropped RCCA Bank

A dropped RCCA bank results in a symmetric power change in the core. As discussed in Reference 10, assumptions made for the dropped

RCCA(s) analysis provide a bounding analysis for the dropped RCCA bank.

(3) Statically Misaligned RCCA

Steady state power distributions are analyzed using the computer codes as described in Table 4.1-2. The peaking factors are then used as input to the THINC code (refer to Section 1.6.1, Item 28 and Section 4.4.3) to calculate the DNBR. The analysis examines the case of the worst rod withdrawn from control bank D inserted at the insertion limit with the reactor initially at full power. The analysis assumes this incident to occur at beginning of life or the time in core life which this results in the minimum value of moderator temperature coefficient. This assumption maximizes the power rise and minimizes the tendency of increased moderator temperature to flatten the power distribution.

15.2.3.4 Results

(1) One or More Dropped RCCAs

Single or multiple dropped RCCAs within the same group result in a negative reactivity insertion. The core is not adversely affected during this period since power is decreasing rapidly.

Power may be reestablished either by reactivity feedback or control bank withdrawal. Following a dropped rod event in manual rod control, the plant will establish a new equilibrium condition. The equilibrium process without control system interaction is monotonic, thus removing power overshoot as a concern and establishing the automatic rod control mode of operation as the limiting case.

For a dropped RCCA event in the automatic rod control mode, the rod control system detects the drop in power and initiates control bank withdrawal. Power overshoot may occur due to this action by the automatic rod controller after which the control system will insert the control bank to restore nominal power. Figures 15.2.3-1 and 15.2.3-2 show a typical transient response to a dropped RCCA(s) in automatic control. Uncertainties in the initial conditions are included in the DNB evaluation as described in Reference 10. In all cases, the minimum DNBR remains above the safety analysis limit value.

Following plant stabilization, the operator may manually retrieve the RCCA(s) by following approved operating procedures.

(2) Dropped RCCA Bank

A dropped RCCA bank typically results in a reactivity insertion of greater than 500 pcm. The core is not adversely affected during the insertion period since power is decreasing rapidly. The dropped RCCA bank transient will proceed as described in the previous section for one or more dropped RCCA(s), except the return to power will be less due to the greater worth of the entire bank. The power transient for a dropped RCCA bank is symmetric. Following plant stabilization, normal procedures are followed.

(3) Statically Misaligned RCCA

The most severe misalignment situations with respect to DNBR at significant power levels arise from cases in which one RCCA is fully inserted, or where Bank D is fully inserted with one RCCA fully withdrawn. Multiple independent alarms, including a bank insertion limit alarm, alert the operator well before the postulated conditions are approached. The bank can be inserted to its insertion limit with any one assembly fully withdrawn without the DNBR falling below the limit value.

The insertion limits in the Technical Specifications may vary from time to time depending on a number of limiting criteria. The full power insertion limits on control bank D must be chosen to be above that position which meets the minimum DNBR and peaking factor limits. The full power insertion limits is usually dictated by other criteria. Detailed results will vary from cycle to cycle depending on fuel arrangements.

For this RCCA misalignment, with Bank D inserted to its full power insertion limit and one RCCA fully withdrawn, DNBR does not fall below the safety analysis limit value. This case is analyzed assuming the initial reactor power, pressure, and RCS temperatures are at their nominal values but with the increased radial peaking factor associated with the misaligned RCCA.

For RCCA misalignments with one RCCA fully inserted, the DNBR does not fall below the safety analysis limit value. This case is analyzed assuming the initial reactor power, pressure, and RCS temperatures are at their nominal values, but with the increased radial peaking factor associated with the misaligned RCCA.

DNB does not occur for the RCCA misalignment incident and thus the ability of the primary coolant to remove heat from the fuel rod is not reduced. The peak fuel temperature corresponds to a linear heat generation rate based on the radial peaking factor penalty associated with the misaligned RCCA and the design axial power distribution. The

resulting linear heat generation is well below that which would cause fuel melting.

Following the identification of an RCCA group misalignment condition by the operator, the operator is required to take action as required by the plant Technical Specifications and operating instructions.

15.2.3.5 Conclusions

The analysis demonstrates that the acceptance criterion is met as follows:

(1) For all cases of RCCA misoperation, the DNBR remains greater than the Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell); therefore, the DNB design criterion is met.

15.2.4 UNCONTROLLED BORON DILUTION

15.2.4.1 Acceptance Criteria

(1) There is ample/adequate time for the operator to mitigate a boron dilution event.

15.2.4.2 Identification of Causes and Accident Description

Reactivity can be added to the core by feeding unborated water into the RCS via the reactor makeup portion of the chemical and volume control system (CVCS). Boron dilution is a manual operation under strict administrative controls with procedures calling for a limit on the rate and duration of dilution. A boric acid blend system is provided to permit the operator to match the boron concentration of reactor coolant makeup water to that in the RCS during normal makeup injection. The CVCS is designed to limit, even under various postulated failure modes, the potential rate of dilution to a value, which after indication through alarms and instrumentation, provides the operator with sufficient time to correct the situation in a safe and orderly manner.

The opening of the primary water makeup control valves provides makeup to the RCS that can dilute the reactor coolant. Inadvertent dilution from this source can be readily terminated by closing the control valve. In order for makeup water to be added to the RCS at pressure, at least one charging pump must be running in addition to a primary makeup water pump.

The rate of addition of unborated makeup water to the RCS when it is not at pressure is limited by the capacity of the primary water supply pumps. The maximum addition rate in this case is 300 gpm, which is based on the capacity of both primary water supply pumps.

The boric acid from the boric acid tank is blended with primary grade water in the blender and the composition is determined by the preset flowrates of boric acid and primary grade water on the control board. In order to dilute, two separate operations are required:

(1) The operator must select from the automatic makeup mode to the dilute mode

(2) The operator must select start to initiate system start

Omitting either step would prevent dilution.

Information on the status of the reactor coolant makeup is continuously available to the operator. Lights are provided on the control board to indicate the operating condition of the pumps in the CVCS. Alarms are actuated to warn the operator if boric acid or demineralized water flowrates deviate from preset values as a result of system malfunction.

15.2.4.3 Analysis of Effects and Consequences

15.2.4.3.1 Method of Analysis

To cover all phases of the plant operation, boron dilution during refueling, startup, and power operation is considered in this analysis. Table 15.2-1 contains the time sequence of events for this accident.

15.2.4.3.2 Dilution During Refueling

During refueling the following conditions exist:

(1) One residual heat removal (RHR) pump is operating to ensure continuous mixing in the reactor vessel.

(2) The seal injection water supply to the reactor coolant pumps (RCPs) is typically isolated for the purpose of performing RCP maintenance.

(3) Boric acid supply to the suction of the charging pumps is available for the addition of boric acid to the RCS. Alternatively, boric acid supply may be lined up to the suction of the safety injection pumps when all the reactor vessel head bolts are fully detensioned.

(4) The boron concentration in the refueling water is greater than or equal to 2000 ppm, corresponding to a shutdown margin of at least 5 percent Δk with all RCCAs in; periodic sampling ensures that this concentration is maintained.

(5) Neutron sources are installed in the core and the source range detectors outside the reactor vessel are active and provide an audible count rate. *During initial core loading, BF_3 detectors are installed inside the reactor vessel and are connected to instrumentation giving audible count rates to provide direct monitoring of the core.* (Historical)

A minimum water volume in the RCS of 5717 cubic feet is considered. This corresponds to the volume necessary to fill the reactor vessel above the nozzles to ensure mixing via the RHR loop. A maximum dilution flow of 300 gpm and uniform mixing are assumed.

The operator has prompt and definite indication of any boron dilution from the audible count rate instrumentation and the high flux at shutdown alarm in the control room. Count rate will increase with the subcritical multiplication factor during boron dilution.

If a safety injection pump is used for boration, it is aligned to take suction from the refueling water storage tank (RWST) and discharge to the cold legs of the RCS, and the boundary valves from the CVCS to the safety injection system (SIS) are closed. These requirements ensure no new dilution flowpaths are introduced when using the SIS boration flowpath.

15.2.4.3.3 Dilution During Startup

The RCS is filled with borated water from the refueling water storage tank (RWST) prior to startup. This is modeled as 2000 ppm boron, which is conservative. DCPP TS limit the RWST to a minimum of 2300 ppm boron.

Core monitoring is by external BF_3 detectors. Mixing of the reactor coolant is accomplished by operation of the reactor coolant pumps. High source range flux level and all reactor trip alarms are effective. In the analysis, a maximum dilution flow of 300 gpm limited by the capacity of the two primary water makeup pumps is considered. The volume of the reactor coolant is approximately 9153 cubic feet, which is the active volume of the RCS excluding the pressurizer.

15.2.4.3.4 Dilution at Power

With the unit at power and the RCS at pressure, the dilution rate is limited by the capacity of the charging pumps. The effective reactivity addition rate for the reactor at full power and for a boron dilution flow of 262 gpm is shown as a function of RCS boron concentration in Figure 15.2.4-1. This figure includes the effect of increasing boron worth with dilution. The reactivity rate used in the analysis is 1.752×10^{-5} Δk/sec based on a conservatively high value for the expected boron concentration (1600 ppm) at power.

15.2.4.4 Conclusions

The analysis demonstrates that the acceptance criteria are met as follows:

For dilution during refueling and startup, the analysis assumes the following.

At the beginning of the core life, equilibrium cycle core, the boron concentration must be reduced from 2000 ppm to approximately 1600 ppm before the reactor will go critical. During refueling, this takes 32 minutes. This is ample time for the operator to recognize a high count rate signal and isolate the reactor makeup water source by closing valves and stopping the primary water supply pumps.

During startup, the minimum time required to reduce the reactor coolant boron concentration to 1600 ppm, where the reactor would go critical with all RCCAs in, is 38 minutes. Once again, this should be more than adequate time for the operator to recognize the high count rate signal and terminate the dilution flow.

For dilution during full power operation:

(1) With the reactor in automatic control at full power, the power and temperature increase from boron dilution results in the insertion of the RCCAs and a decrease in shutdown margin. Continuation of dilution and RCCA insertion would cause the assemblies to reach the minimum limit of the rod insertion monitor in approximately 4.7 minutes, assuming the RCCAs to be initially at a position providing the maximum operational maneuvering band consistent with maintaining a minimum control band incremental rod worth. Before reaching this point, however, two alarms would be actuated to warn the operator of the accident condition. The first of these, the low insertion limit alarm, alerts the operator to initiate normal boration.

    The other, the low-low insertion limit alarm, alerts the operator to follow emergency boration procedures. The low alarm is set sufficiently above the low-low alarm to allow normal boration without the need for emergency procedures. If dilution continues after reaching the low-low alarm, it takes approximately 15.0 minutes after the low-low alarm before the total shutdown margin (assuming 1.6 percent, consistent with the Technical Specifications) is lost due to dilution. Therefore, adequate time is available following the alarms for the operator to determine the cause, isolate the primary grade water source, and initiate boration.

(2) With the reactor in manual control and if no operator action is taken, the power and temperature rise will cause the reactor to reach the high neutron flux or overtemperature ΔT trip setpoint. The boron dilution accident in this case is essentially identical to a RCCA withdrawal accident at power. The maximum reactivity insertion rate for boron dilution is

shown in Figure 15.2.4-1 and is seen to be within the range of insertion rates analyzed for a RCCA withdrawal accident. Reactor trip will occur approximately 40 seconds after event initiation. If dilution were to continue after the reactor trip, there would still be approximately 14.5 minutes left after a reactor trip for the operator to determine the cause of dilution, isolate the primary grade water sources, and initiate reboration before the reactor can return to criticality assuming a 1.6 percent shutdown margin at the beginning of dilution. Therefore, there is ample time available (approximately 40 seconds to reactor trip plus 14.5 minutes after a reactor trip).

15.2.5 PARTIAL LOSS OF FORCED REACTOR COOLANT FLOW

15.2.5.1 Acceptance Criteria

The following is the relevant specific acceptance criterion.

(1) The minimum DNBR must not go below the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell) (refer to Section 4.4.1.1.2) at any time during the transient.

15.2.5.2 Identification of Causes and Accident Description

A partial loss of coolant flow accident can result from a mechanical or electrical failure in a reactor coolant pump, or from a fault in the power supply to the pump. If the reactor is at power at the time of the accident, the immediate effect of loss of coolant flow is a rapid increase in the coolant temperature. This increase could result in DNB with subsequent fuel damage if the reactor is not tripped promptly.

The necessary protection against a partial loss of coolant flow accident is provided by the low primary coolant flow reactor trip that is actuated by two-out-of-three low flow signals in any reactor coolant loop. Above approximately 35 percent power (Permissive 8), low flow in any loop will actuate a reactor trip. Between approximately 10 and 35 percent power (Permissive 7 and Permissive 8), low flow in any two loops will actuate a reactor trip. Reactor trip on low flow is blocked below Permissive 7.

A reactor trip on reactor coolant pump breakers open is provided as a backup to the low flow signals. Above Permissive 7, a breaker open signal from any two pumps will actuate a reactor trip. Reactor trip on reactor coolant pump breakers open is blocked below Permissive 7.

Normal power for the reactor coolant pumps is supplied through buses connected through transformers to the generator. Two reactor coolant pumps are on each bus. When a generator trip occurs, the buses are automatically transferred to a power source supplied from external power lines, and the pumps will continue to supply coolant flow to the core. Following any turbine trip where there are no electrical or mechanical faults

that require immediate tripping of the generator from the network, the generator remains connected to the network for approximately 30 seconds. The reactor coolant pumps remain connected to the generator thus ensuring full flow for approximately 30 seconds after the reactor trip before any transfer is made.

15.2.5.3 Analysis of Effects and Consequences

15.2.5.3.1 Method of Analysis

The following case has been analyzed:

(1) All loops operating, two loops coasting down.

This transient is analyzed by three digital computer codes. First the LOFTRAN code is used to calculate the loop and core flow during the transient. The LOFTRAN code is also used to calculate the time of reactor trip, based on the calculated flows and the nuclear power transient following reactor trip. The FACTRAN code is then used to calculate the heat flux transient based on the nuclear power and flow from LOFTRAN. Finally, the THINC code (refer to Section 1.6.1, Item 28 and Section 4.4.3) is used to calculate the minimum DNBR during the transient based on the heat flux from FACTRAN and the flow from LOFTRAN. The DNBR transient presented represents the minimum of the typical and thimble cells for Standard fuel, which bound VANTAGE 5 fuel.

15.2.5.3.2 Initial Conditions

The accident is analyzed using the Improved Thermal Design Procedure and the initial condition uncertainties are included in the limit DNBR as described in Reference 5. Therefore, initial conditions of nominal core power, nominal reactor coolant average temperature (including 2.5 °F for steam generator fouling) and nominal reactor coolant pressure are assumed.

15.2.5.3.3 Reactivity Coefficients

A conservatively large absolute value of the Doppler-only power coefficient is used (refer to Table 15.1-4). The total integrated Doppler reactivity from 0 to 100 percent power is assumed to be -0.016 Δk.

The most positive moderator temperature coefficient (+5 pcm/°F) is assumed since this results in the maximum hot spot heat flux during the initial part of the transient when the minimum DNBR is reached.

15.2.5.3.4 Flow Coastdown

The flow coastdown analysis is based on a momentum balance around each reactor coolant loop and across the reactor core. This momentum balance is combined with the continuity equation, a pump momentum balance, and the pump characteristics and is based on high estimates of system pressure losses.

15.2.5.4 Results

The calculated sequence of events is shown in Table 15.2-1. Figures 15.2.5-1 through 15.2.5-4 show the core flow coastdown, the loop flow coastdown, the heat flux coastdown, and the nuclear power coastdown. The minimum DNBR is not less than the safety analysis limit value. A plot of DNBR vs. time is given in Figure 15.2.5-5 for the most limiting thimble cell for Standard fuel, which bounds VANTAGE 5 fuel.

15.2.5.5 Conclusions

The analysis demonstrates that the acceptance criterion is met as follows:

(1) There is margin to the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell). The accompanying DNBR figure for this event (Figure 15.2.5-5) reflects the results for the more limiting Standard fuel (limit 1.48/1.44) previously in the core.

The analysis shows that the DNBR will not decrease below the safety analysis limiting values at any time during the transient. Thus no core safety limit is violated.

15.2.6 STARTUP OF AN INACTIVE REACTOR COOLANT LOOP

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

In accordance with the TS, DCPP operation during startup and power operation with less than four loops is not permitted. This analysis is presented for completeness.

15.2.6.1 Identification of Causes and Accident Description

If a plant is operating with one pump out of service, there is reverse flow through the loop due to the pressure difference across the reactor vessel. The cold leg temperature in an inactive loop is identical to the cold leg temperature of the active loops (the reactor core inlet temperature). If the reactor is operated at power, and assuming the secondary side of the steam generator in the inactive loop is not isolated, there is a temperature drop across the steam generator in the inactive loop and, with the reverse flow, the hot leg temperature of the inactive loop is lower than the reactor core inlet temperature.

Starting of an idle reactor coolant pump without bringing the inactive loop hot leg temperature close to the core inlet temperature would result in the injection of cold water into the core, which causes a rapid reactivity insertion and subsequent power increase.

This event is classified as an ANS Condition II incident (an incident of moderate frequency) as defined at the beginning of this chapter.

Should the startup of an inactive reactor coolant pump at an incorrect temperature occur, the transient will be terminated automatically by a reactor trip on low coolant loop flow when the power range neutron flux (two-out-of-four channels) exceeds the P-8 setpoint, which has been previously reset for three-loop operation.

15.2.6.2 Analysis of Effects and Consequences

This transient is analyzed by three digital computer codes. The LOFTRAN Code (Reference 4) is used to calculate the loop and core flow, nuclear power and core pressure and temperature transients following the startup of an idle pump. FACTRAN (Reference 3) is used to calculate the core heat flux transient based on core flow and nuclear power from LOFTRAN. The THINC Code (Reference 9) is then used to calculate the DNBR during the transient based on system conditions (pressure, temperature, and flow) calculated by LOFTRAN and heat flux as calculated by FACTRAN.

In order to obtain conservative results for the startup of an inactive pump accident, the following assumptions are made:

(1) *Initial conditions of maximum core power and reactor coolant average temperatures and minimum reactor coolant pressure resulting in minimum initial margin to DNB. A 25 percent maximum steady state power level including appropriate allowances for calibration and instrument errors is assumed, however DCPP is not allowed to be at power with an inactive loop. The high initial power gives the greatest temperature difference between the core inlet temperature and the inactive loop hot leg temperature.*

(2) *Following the start of the idle pump, the inactive loop flow reverses and accelerates to its nominal full flow value.*

(3) *A conservatively large (absolute value) negative moderator coefficient associated with the end of life.*

(4) *A conservatively low (absolute value) negative Doppler power coefficient is used.*

(5) The initial reactor coolant loop flows are at the appropriate values for one pump out of service.

(6) The reactor trip is assumed to occur on low coolant flow when the power range neutron flux exceeds the P-8 setpoint, which has been reset for N-1 loop operation. The P-8 setpoint is conservatively assumed to be 84 percent of rated power, which corresponds to the nominal N-1 loop operation setpoint plus 9 percent for nuclear instrumentation errors.

15.2.6.3 Results

The results following the startup of an idle pump with the above listed assumptions are shown in Figures 15.2.6-1 through 15.2.6-5. As shown in these curves, during the first part of the transient, the increase in core flow with cooler water results in an increase in nuclear power and a decrease in core average temperature. The minimum DNBR during the transient is considerably greater than the safety analysis limit values.

Reactivity addition for the inactive loop startup accident is due to the decrease in core water temperature. During the transient, this decrease is due both to a) the increase in reactor coolant flow, and b) as the inactive loop flow reverses, to the colder water entering the core from the hot leg side (colder temperature side prior to the start of the transient) of the steam generator in the inactive loop. Thus, the reactivity insertion rate for this transient changes with time. The resultant core nuclear power transient, computed with consideration of both moderator and Doppler reactivity feedback effects, is shown in Figure 15.2.6-1.

The calculated sequence of events for this accident is shown in Table 15.2-1. The transient results illustrated in Figures 15.2.6-1 through 15.2.6-5 indicate that a stabilized plant condition, with the reactor tripped, is approached rapidly. Plant cooldown may subsequently be achieved by following normal shutdown procedures.

15.2.6.4 Conclusions

The transient results show that the core is not adversely affected. There is considerable margin to the safety analysis DNBR limit values; thus, no fuel or cladding damage is predicted.

15.2.7 LOSS OF EXTERNAL ELECTRICAL LOAD AND/OR TURBINE TRIP

15.2.7.1 Acceptance Criteria

The following are the relevant specific acceptance criteria.

(1) The minimum DNBR must not go below the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell) (refer to Section 4.4.1.1.2) at any time during the transient.

(2) The RCS pressure does not exceed 110 percent of design pressure (2,750 psia) at any time during the transient.

(3) The Main Steam System (MSS) pressure does not exceed 110 percent of design pressure (1,210 psia) at any time during the transient.

15.2.7.2 Identification of Causes and Accident Description

A major load loss on the plant can result from either a loss of external electrical load or from a turbine trip. For either case, offsite power is available for the continued operation of plant components such as the reactor coolant pumps. The case of loss of offsite power is analyzed in Section 15.2.9.

For a turbine trip, the reactor would be tripped directly (unless it is below the P-9 setpoint) from a signal derived from the turbine autostop oil pressure and turbine stop valves. The automatic steam dump system accommodates the excess steam generation. Reactor coolant temperatures and pressure do not significantly increase if the steam dump system and pressurizer pressure control system are functioning properly. If the turbine condenser were not available, the excess steam generation would be dumped to the atmosphere. Additionally, main feedwater flow would be lost if the turbine condenser were not available. For this situation, steam generator level would be maintained by the auxiliary feedwater (AFW) system.

For a loss of external electrical load without subsequent turbine trip, no direct reactor trip signal would be generated. A continued steam load of approximately 5 percent would exist after total loss of external electrical load because of the electrical demand of plant auxiliaries.

In the event the steam dump valves fail to open following a large loss of load, the steam generator safety valves may lift and the reactor may be tripped by the high pressurizer pressure signal, the high pressurizer water level signal, or the overtemperature ΔT signal. The steam generator shell-side pressure and reactor coolant temperatures will increase rapidly. The pressurizer safety valves (PSVS) and steam generator safety valves are, however, sized to protect the RCS and steam generator against overpressure for all load losses without assuming the operation of the steam dump system, pressurizer spray, pressurizer power-operated relief valves, automatic RCCA control, or direct reactor trip on turbine trip.

The steam generator safety valve capacity is sized to remove the steam flow at the engineered safeguards design rating (105 percent of steam flow at rated power) from the steam generator without exceeding 110 percent of the steam system design pressure. The pressurizer safety valve capacity is sized based on a complete loss of heat sink with the plant initially operating at the maximum calculated turbine load along with operation of the steam generator safety valves. The pressurizer safety valves are

then able to maintain the RCS pressure within 110 percent of the RCS design pressure without direct or immediate reactor trip action.

A more complete discussion of overpressure protection can be found in Reference 8.

15.2.7.3 Analysis of Effects and Consequences

In this analysis, the behavior of the unit is evaluated for a complete loss of steam load from full power without a direct reactor trip. This is done to show the adequacy of the pressure-relieving devices and to demonstrate core protection margins. The reactor is not tripped until conditions in the RCS result in a trip. The turbine is assumed to trip without actuating all the turbine stop valve limit switches. This assumption delays reactor trip until conditions in the RCS result in a trip due to other signals. Thus, the analysis assumes a worst case transient. In addition, no credit is taken for steam dump actuation. Main feedwater flow is terminated at the time of turbine trip, with no credit taken for auxiliary feedwater (except for long-term recovery) to mitigate the consequences of the transient.

Total loss-of-load transients are analyzed for DNB and overpressure concerns. The LOFTRAN computer program (refer to Section 15.1) is used to analyze the total loss of load transients for the DNB concern. The RETRAN-02 computer program (refer to Section 15.1) is used to analyze the transients for the overpressure concern. Both programs simulate the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The programs compute pertinent variables, including temperatures, pressures, and power level.

The following assumptions are used in the LOFTRAN analysis for the DNB concern.

(1) Initial Operating Conditions

The accident is analyzed using the Improved Thermal Design Procedure and the initial condition uncertainties are included in the limit DNBR as described in Reference 5. Therefore, initial conditions of nominal core power, nominal reactor coolant average temperature (including 2.5°F for steam generator tube fouling) and nominal reactor coolant pressure are assumed.

(2) Moderator and Doppler Coefficients of Reactivity

The turbine trip is analyzed with both maximum and minimum reactivity feedback. The maximum feedback for end of life (EOL) cases assume a large negative moderator temperature coefficient and the most negative Doppler power coefficient. The minimum feedback for beginning of life (BOL) cases assume a minimum moderator temperature coefficient and the least negative Doppler coefficient.

(3) Reactor Control

From the standpoint of the maximum pressures attained, it is conservative to assume that the reactor is in manual control. If the reactor were in automatic control, the control rod banks would move prior to trip and reduce the severity of the transient.

(4) Steam Release

No credit is taken for the operation of the steam dump system or steam generator power-operated relief valves. The steam generator pressure rises to the safety valve setpoint where steam release through safety valves limits secondary steam pressure at the setpoint value.

(5) Pressurizer Spray and Power-Operated Relief Valves

Two cases for both BOL and EOL are analyzed using the LOFTRAN computer program.

(a) Full credit is taken for the effect of pressurizer spray and power-operated relief valves in reducing or limiting the coolant pressure. Safety valves are also operable.

(b) No credit is taken for the effect of pressurizer spray and power-operated relief valves in reducing or limiting the coolant pressure. Safety valves are operable.

(6) Feedwater Flow

Main feedwater flow to the steam generators is assumed to be lost at the time of turbine trip. No credit is taken for auxiliary feedwater flow since a stabilized plant condition will be reached before auxiliary feedwater initiation is normally assumed to occur; however, the auxiliary feedwater pumps would be expected to start on a trip of the main feedwater pumps. The auxiliary feedwater flow would remove core decay heat following plant stabilization.

The following assumptions are used in the RETRAN-02 analysis for the overpressure concern only.

(1) Initial Operating Conditions

The accident analysis assumes: maximum core power; maximum Tavg, and minimum operating RCS pressure 2189.7 psia is used in the analysis, which includes 60 psi uncertainty.

(2) Moderator and Doppler Coefficients of Reactivity

BOL minimum reactivity feedback is modeled assuming the most positive moderator temperature coefficient and the least negative Doppler temperature coefficient.

(3) Steam Release

No credit is taken for secondary heat removal from the steam dump system. Only the pressurizer safety valves and the main steam safety valves are credited for overpressure protection.

(4) Pressurizer Pressure Control

Since the total loss of load overpressure transients result in higher peak RCS and steam generator pressures at BOL, two cases are analyzed using the RETRAN-02 computer program for BOL only.

(a) For the peak secondary side pressure case assumes pressurizer pressure control. This delays the reactor trip and maximizes the heat transfer to the steam generators. Safety valves are also operable.

(b) For the peak RCS pressure case, no credit is taken for pressurizer pressure control, which maximizes the peak RCS pressure for the event. Safety valves are operable.

(5) Feedwater Flow

The turbine stop valves and feedwater control valves are assumed to close instantaneously at the initiation of the event to maximize the duration of the primary to secondary heat imbalance. The auxiliary feedwater system is conservatively not credited and assumed unavailable for decay heat removal during the event.

(6) Main Steam Safety Valves

The MSSV setpoints are assumed to be at their maximum 3 percent drift values. The RETRAN MSSVs are modeled to provide zero to full flow as a linear function from the lift setpoint to the full open 3 percent accumulation value.

(7) Pressurizer Safety Valve Water Loop Seal

All pressurizer safety valves have been converted to a steam-seat design and condensate in the loop is now continuously drained back to the pressurizer, thereby eliminating the water loop seal. Even though the water loop seal has been eliminated, the resulting benefit is not credited in the analysis. The presence of a water loop seal delays the opening of the pressurizer safety valve. The loop seal water starts to leak out from the safety valve when the safety valve setpoint is reached. However, no pressure is relieved from the pressurizer until the loop seal water is completely purged, after which the safety valve pops full open in less than 0.1 second. The loop seal water purge time of 1.272 seconds was used in the analysis.

(8) Maximize Reactor Power

It is conservative to maximize the reactor power. Therefore, the reactor trip due to high neutron flux is not credited in the analysis.

In all cases for DNB and overpressure concerns reactor trip is actuated by the first reactor protection system trip setpoint reached with no credit taken for the direct reactor trip on the turbine trip.

15.2.7.4 Results

The transient responses for a total loss of load from full power operation are shown for four cases the DNB concern is evaluated at BOL and EOL with pressure control since this condition bounds the cases without pressure control and overpressure concern is evaluated at BOL with and without pressure control. Refer to Figures 15.2.7-1 through 15.2.7-4 and Figures 15.2.7-9 through 15.2.7-12.

Figures 15.2.7-1 and 15.2.7-2 show the transient responses for the total loss of steam load at BOL, for the DNB concern, assuming full credit for the pressurizer spray and pressurizer power-operated relief valves. No credit is taken for the steam dump. The reactor is tripped by the high pressurizer pressure trip channel. The minimum DNBR is (thimble cell) well above the limit value.

Figures 15.2.7-3 and 15.2.7-4 show the responses for the total loss of load at EOL, for the DNB concern, assuming a large (absolute value) negative moderator temperature coefficient. All other plant parameters are the same as in the above case. As a result of the maximum reactivity feedback at EOL, no reactor protection system trip setpoint is reached. Because main feedwater is assumed to be lost, the reactor is tripped by the low-low steam generator water level trip channel. The DNBR (thimble cell) increases throughout the transient and never drops below its initial value. The pressurizer safety valves are not actuated in these transients.

Figures 15.2.7-9 and 15.2.7-10 show the typical transient responses for the total loss of load at BOL for the RCS overpressure concern. No credit is taken for the pressurizer spray, pressurizer power-operated relief valves, or steam dump. The pressurizer and main steam safety valves are modeled as described in assumptions 6 and 7. The initial pressurizer pressure includes the pressurizer pressure uncertainty to maximize the peak pressure. The reactor is tripped on the high pressurizer pressure signal. This case results in the highest RCS peak pressure among all cases. The peak RCS pressure is below 110 percent of the design value.

Figures 15.2.7-11 and 15.2.7-12 show the typical transient responses for the total loss of load at BOL for the secondary side overpressure concern, assuming full credit for the pressurizer spray and the pressurizer power-operated relief valves. No credit is taken for the steam dump. The models for the pressurizer and main steam safety valves and the initial pressurizer pressure are the same as those used in the above case. The reactor trip due to high neutron flux is not credited in order to maximize the peak steam generator pressure. The reactor is tripped on the high pressurizer pressure signal. This case results in the highest steam generator peak pressure among all cases. The peak steam generator pressure is below 110 percent of the design value.

Reference 8 presents additional results for a complete loss of heat sink including loss of main feedwater. This report shows the overpressure protection that is afforded by the pressurizer and steam generator safety valves.

Technical Specification 3.7.1 establishes reduced plant operating power limits for off normal conditions when one or more MSSVs are inoperable to ensure a loss of load event does not result in overpressurization of the steam generators. When two or more MSSVs are inoperable per steam generator loop, the reduced power limits are established using a conservative energy balance algorithm established in the Westinghouse Nuclear Safety Advisory Letter NSAL-94-001 as documented in Reference 21. To evaluate off normal plant operation with a single inoperable MSSV on one or more steam generator loops, an additional spectrum of loss of load analyses are performed as documented in Reference 22. These analyses use the RETRAN-02W code to analyze the BOL loss of load overpressure case as discussed in this section and which represents the limiting case for challenging the steam generator peak pressure limit. These analysis results, as summarized in the Technical Specification Bases 3.7.1, credit the overtemperature ΔT reactor trip to demonstrate that the specified reduced operating power limit ensures that the available relief capacity with one inoperable MSSV per loop maintains the peak steam generator pressure below 110 percent of the design value.

15.2.7.5 Conclusions

The analysis demonstrates that the acceptance criteria are met as follows:

(1) There is margin to the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell). The accompanying DNBR figures for this event

(Figures 15.2.7-1 and 15.2.7-3) reflect the results for the more limiting Standard fuel (limit 1.48/1.44) previously in the core.

(2) The calculated RCS pressure (2723 psia) does not exceed 110 percent of design pressure (2,750 psia) at any time during the transient.

(3) The calculated MSS peak pressure (1203 psia) does not exceed 110 percent of design pressure (1,210 psia) at any time during the transient.

Results of the analyses, including those in Reference 8, show that the plant design is such that a total loss of external electrical load without a direct or immediate reactor trip presents no hazard to the integrity of the RCS or the main steam system. Pressure-relieving devices incorporated in the two systems are adequate to limit the maximum pressures to within the design limits.

The integrity of the core is maintained by operation of the reactor protection system; i.e., the DNBR will be maintained above the safety analysis limit values. Thus, no core safety limit will be violated.

15.2.8 LOSS OF NORMAL FEEDWATER

15.2.8.1 Acceptance Criteria

The following is the relevant specific acceptance criterion.

(1) The pressurizer does not go water solid at any time during the transient.

15.2.8.2 Identification of Causes and Accident Description

A loss of normal feedwater (resulting from pump failures, valve malfunctions, or loss of offsite ac power) results in a reduction in the ability of the secondary system to remove the heat generated in the reactor core. If the reactor were not tripped during this accident, core damage would possibly occur from a sudden loss of heat sink. If an alternative supply of feedwater were not supplied to the SGs, residual heat following reactor trip would heat the primary system water to the point where water relief from the pressurizer would occur. A significant loss of water from the RCS could conceivably lead to core damage. Since the plant is tripped well before the steam generator heat transfer capability is reduced, the primary system conditions never approach a DNB condition.

The following provide the necessary protection against a loss of normal feedwater:

(1) Reactor trip on low-low water SG level in any steam generator

(2) Two motor-driven AFW pumps that are started on:

(a) Low-low SG water level in any steam generator

(b) Trip of both main feedwater pumps

(c) Any safety injection signal

(d) Loss of offsite power (automatic transfer to diesel generators)

(e) Manual actuation

(3) One turbine-driven auxiliary feedwater pump that is started on:

(a) Low-low SG water level in any two steam generators

(b) Undervoltage on both reactor coolant pump buses

(c) Manual actuation

The motor-driven AFW pumps are connected to vital buses and are supplied by the diesels if a loss of offsite power occurs. The turbine-driven pump utilizes steam from the secondary system and exhausts it to the atmosphere. The controls are designed to start both types of pumps within 1 minute even if a loss of all AC power occurs simultaneously with loss of normal feedwater. The AFW pumps take suction from the condensate storage tank for delivery to the steam generators.

The analysis shows that following a loss of normal feedwater, the AFW system is capable of removing the stored energy and residual decay heat, and RCP heat thus preventing either overpressurization of the RCS or liquid relief through the pressurizer power operated relief valves (PORVs) or safety valves.

15.2.8.3 Analysis of Effects and Consequences

A detailed analysis using the RETRAN-02W code (Reference 19) is performed in order to determine the plant transient following a loss of normal feedwater. The code describes the plant neutron kinetics, RCS including factors that influence the natural circulation, pressurizer, steam generators, and feedwater system, and compute pertinent variables, including the pressurizer pressure, pressurizer water level, and reactor coolant average temperature.

Major assumptions are:

(1) Reactor trip occurs on steam generator low-low level at 8 percent of narrow range span.

(2) The plant is initially operating at 102 percent of the nuclear steam supply system (NSSS) rating, including a conservatively large RCP heat of 20 MWt.

(3) Conservative core residual heat generation based on long-term operation at the initial power level preceding the trip is assumed. The ANSI/ANS-5.1-1979 + 2σ was used for calculation of residual decay heat levels.

(4) The auxiliary feedwater system is actuated by the low-low steam generator water level signal.

(5) The limiting single failure in the auxiliary feedwater system occurs (turbine-driven pump failure). The auxiliary feedwater system is assumed to supply a total of 600 gpm to all four SGs from the motor-driven pumps.

(6) The pressurizer sprays and heaters are assumed operable. This maximizes the peak transient pressurizer water volume. Sensitivity analyses determined that it is conservative to assume that the PORVs are inoperable (Reference 20).

(7) Secondary system steam relief is achieved through the self-actuated safety valves. The main steam safety valves are assumed to begin to lift 3 percent above the set pressure with a 5 psi accumulation to full open. Note that steam relief will, in fact, be through the power-operated relief valves or condenser dump valves for most cases of loss of normal feedwater. However, for the sake of analysis these have been assumed unavailable.

(8) The initial reactor coolant average temperature is 5.5°F lower than the nominal value. The initial pressurizer pressure is 60 psi above the nominal value.

(9) The minimum steam generator tube plugging (SGTP) of 0 percent was assumed.

(10) The initial feedwater temperature is assumed to be 435°F.

15.2.8.4 Results

Figures 15.2.8-1 through 15.2.8-3 show plant parameters following a loss of normal feedwater at the conditions associated with Unit 2, which were determined to be limiting when compared to Unit 1. Figure 15.2.8-2 shows the pressurizer pressure as a function of time.

Following the reactor and turbine trip from full load, the water level in the steam generators will fall due to the reduction of steam generator void fraction and because steam flow through the safety valves continues to dissipate the stored and generated

heat. One minute following the initiation of the low-low SG level trip, the motor-driven AFW pumps are automatically started, reducing the rate of water level decrease.

The capacity of the motor-driven AFW pumps combined with the available secondary inventory is capable of dissipating the core residual heat without liquid water relief from the RCS PORVs or safety valves.

From Figure 15.2.8-2 it can be seen that at no time is there liquid relief from the pressurizer. If the AFW delivered is greater than that of two motor-driven pumps, the initial reactor power is less than 102 percent of the NSSS rating, or the steam generator water level in one or more steam generators is above the low-low level trip point at the time of trip, then the results for this transient will be less limiting.

The calculated sequence of events for this accident is listed in Table 15.2-1. As shown in Figures 15.2.8-1 through 15.2.8-3, the plant approaches a stabilized condition following reactor trip and AFW initiation. Plant procedures may be followed to further cool down the plant.

15.2.8.5 Conclusions

The analysis demonstrates that the acceptance criterion is met as follows:

(1) The pressurizer does not become water solid during the event as shown in Figure 15.2.8-2.

Results of the analysis show that a loss of normal feedwater does not adversely affect the core, the RCS, or the steam system, since the AFW capacity is such that the pressurizer does not become water solid, which ultimately precludes reactor coolant liquid relief from the pressurizer relief or safety valves. This ensures a Condition III or IV event will not be generated.

15.2.9 LOSS OF OFFSITE POWER TO THE STATION AUXILIARIES

15.2.9.1 Acceptance Criteria

The following is the relevant specific acceptance criterion.

(1) The pressurizer does not go water solid at any time during the transient.

15.2.9.2 Identification of Causes and Accident Description

During a complete loss of offsite power and a turbine trip there will be loss of power to the plant auxiliaries, i.e., the reactor coolant pumps, condensate pumps, etc.

The events following a loss of AC power with turbine and reactor trip are described in the sequence listed below:

(1) Plant vital instruments are supplied by emergency power sources.

(2) As the steam system pressure rises following the trip, the steam system power-operated relief valves are automatically opened to the atmosphere. Steam dump to the condenser is assumed not to be available. If the power-operated relief valves are not available, the steam generator self-actuated safety valves may lift to dissipate the sensible heat of the fuel and coolant plus the residual heat produced in the reactor.

(3) As the no-load temperature is approached, the steam system power-operated relief valves (or the self-actuated safety valves, if the power-operated relief valves are not available) are used to dissipate the residual heat and to maintain the plant at the hot standby condition.

(4) The emergency diesel generators started on loss of voltage on the plant emergency buses begin to supply plant vital loads.

The AFW system is started automatically as discussed in the loss of normal feedwater analysis. The steam-driven auxiliary feedwater pump utilizes steam from the secondary system and exhausts to the atmosphere. The motor-driven AFW pumps are supplied by power from the diesel generators. The pumps take suction directly from the condensate storage tank for delivery to the steam generators.

Upon the loss of power to the reactor coolant pumps, coolant flow necessary for core cooling and the removal of residual heat is maintained by natural circulation in the reactor coolant loops.

15.2.9.3 Analysis of Effects and Consequences

A detailed analysis using the RETRAN-02W code (Reference 19) is performed in order to determine the plant transient following loss of offsite power. The code describes the plant neutron kinetics, RCS including factors that influence the natural circulation, pressurizer, steam generators, and feedwater system, and computes pertinent variables, including the pressurizer pressure, pressurizer water level, and reactor coolant average temperature.

Major assumptions differing from those in a loss of normal feedwater are:

(1) No credit is taken for immediate response of control rod drive mechanisms caused by a loss of offsite power.

(2) RCP coastdown to natural circulation conditions is assumed after reactor trip (i.e., rod motion), which is more limiting for long-term heat removal capability.

(3) The initial feedwater temperature is assumed to be 425°F.

(4) A nominal reactor coolant pump heat input of 14 MWt.

15.2.9.4 Results

The time sequence of events for the accident at the conditions associated with Unit 2, which were determined to be limiting, is given in Table 15.2-1. This event is bounded by the complete-loss-of-flow analysis (Section 15.3.4), in terms of minimum DNBR (Reference 23). Therefore, this event is not analyzed for DNB concerns, but rather, for the long-term heat removal capability. After the reactor trip, stored and residual heat must be removed to prevent damage to either the RCS or the core. The RETRAN-02W code results show that the natural circulation flow available is sufficient to provide adequate core decay heat removal following reactor trip and RCP coastdown.

Figures 15.2.9-1 through 15.2.9-3 show plant parameters following a loss of offsite power at the conditions associated with Unit 2, which were determined to be limiting. Figure 15.2.9-2 shows the pressurizer water volume as a function of time.

15.2.9.5 Conclusions

The analysis demonstrates that the acceptance criterion is met as follows:

(1) The pressurizer does not become water solid during the event as shown in Figure 15.2.9-2.

Results of the analysis show that, for the loss of offsite power to the station auxiliaries event, all safety criteria are met. Since the DNBR remains above the safety analysis limit, the core is not adversely affected. AFW capacity is sufficient to prevent the pressurizer from becoming water solid, which ultimately precludes reactor coolant liquid relief from the pressurizer relief and safety valves; this assures that the RCS is not overpressurized. This ensures that a Condition III or IV event will not be generated.

Analysis of the natural circulation capability of the RCS demonstrates that sufficient long-term heat removal capability exists following reactor coolant pump coastdown to prevent fuel or cladding damage.

15.2.10 EXCESSIVE HEAT REMOVAL DUE TO FEEDWATER SYSTEM MALFUNCTIONS

15.2.10.1 Acceptance Criteria

The following are the relevant specific acceptance criteria:

(1) The minimum DNBR must not go below the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell) (refer to Section 4.4.1.1.2) at any time during the transient.

(2) The peak linear heat generation rate does not exceed a value which would cause fuel centerline melt at any time during the transient (refer to Section 4.4.2.2.7).

15.2.10.2 Identification of Causes and Accident Description

Reductions in feedwater temperature or excessive feedwater additions are means of increasing core power above full power. Such transients are attenuated by the thermal capacity of the secondary plant and of the RCS. The overpower-overtemperature protection (neutron high flux, overtemperature ΔT, and overpower ΔT trips) prevent any power increase that could lead to a DNBR that is less than the DNBR limit.

One example of excessive feedwater flow would be a full opening of a feedwater control valve due to a feedwater control system malfunction or an operator error. At power, this excess flow causes a greater load demand on the RCS due to increased subcooling in the steam generator. With the plant at no-load conditions the addition of cold feedwater may cause a decrease in RCS temperature and thus a reactivity insertion due to the effects of the negative moderator temperature coefficient. Continuous excessive feedwater addition is prevented by the steam generator high-high level feedwater isolation and turbine trip.

15.2.10.3 Analysis of Effects and Consequences

The excessive heat removal due to a feedwater system malfunction transient is analyzed with the RETRAN-02W code. This code simulates a multiloop system, neutron kinetics, the pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

The system is analyzed to evaluate plant behavior in the event of a feedwater system malfunction. The accident is analyzed with the Improved Thermal Design Procedure and initial condition uncertainties are included in the limit DNBR as described in Reference 5. Therefore, initial conditions of nominal core power, nominal reactor coolant average temperatures and nominal reactor coolant pressure are assumed.

Excessive feedwater addition due to a control system malfunction or operator error that allows a feedwater control valve to open fully is considered. Two conditions are evaluated as follows:

(1) Accidental opening of one feedwater control valve with the reactor just critical at zero load conditions. The feedwater flow increase event at hot zero power conditions is not limiting with respect to departure from nucleate boiling concerns and is bounded by the full power event; therefore, the event has not been explicitly analyzed.

(2) Accidental opening of one feedwater control valve at full power (with automatic and manual rod control).

The reactivity insertion rate following a feedwater system malfunction is calculated with the following assumptions:

(1) For the feedwater control valve accident at full power, one feedwater control valve is assumed to malfunction resulting in a step increase to 250 percent of nominal feedwater flow to one steam generator.

(2) Coincident with the feedwater flow increase in the faulted loop, the feedwater temperature in all loops decreases approximately 23°F from the nominal full power value. This accounts for the effect of the feedwater passing through the heaters at a higher velocity.

(3) The initial water level in all the steam generators is at a conservatively low level.

(4) No credit is taken for the heat capacity of the RCS and steam generator thick metal in attenuating the resulting plant cooldown.

(5) The feedwater flow resulting from a fully open control valve is terminated by the steam generator high-high level signal that closes all feedwater control valves, closes all feedwater bypass valves, trips the main feedwater pumps, and shuts the motor-operated feedwater isolation valves.

15.2.10.4 Results

The full power case (EOL, with manual rod control) gives the largest reactivity feedback and results in the greatest power increase. A turbine trip and reactor trip is actuated when the steam generator level reaches the high-high level setpoint. Although turbine trip and subsequent reactor trip are assumed, the results show that the DNBR remains relatively constant prior to the time of reactor trip. This demonstrates that a reactor trip on turbine trip is not needed to protect against DNB, but is assumed as a means to terminate the transient.

Transient results (refer to Figures 15.2.10-1 through 15.2.10-3) show the core heat flux, pressurizer pressure, core T_{avg}, and DNBR (thimble cell), as well as the increase in nuclear power and loop ΔT associated with the increased thermal load on the reactor. Steam generator level rises until the feedwater is terminated as a result of the high-high steam generator level trip. The DNBR does not drop below the limit safety analysis DNBR.

15.2.10.5 Conclusions

The analysis demonstrates that the acceptance criteria are met as follows:

(1) There is margin to the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell) as shown on Figure 15.2.10-3.

(2) Figure 15.2.10-1 shows the total power is maintained below 118 percent of its nominal value. Thus the peak fuel centerline temperature will remain below the fuel melting temperature (refer to Section 4.4.2.2.7).

An excessive feedwater addition at no-load conditions is bounded by the analysis at full power. The DNBRs encountered for excessive feedwater addition at power are well above the safety analysis limit DNBR values.

15.2.11 SUDDEN FEEDWATER TEMPERATURE REDUCTION

15.2.11.1 Acceptance Criteria

The following are the relevant specific acceptance criteria.

(1) The minimum DNBR must not go below the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell) (refer to Section 4.4.1.1.2) at any time during the transient.

(2) The peak linear heat generation rate does not exceed a value that would cause fuel centerline melt at any time during the transient (refer to Section 4.4.2.2.7).

15.2.11.2 Identification of Causes and Accident Description

A concern was raised during the Unit 1 power ascension test program that an inadvertent actuation of the load transient bypass relay (LTBR) might initiate a transient that exceeds analyzed reactor operating limits. An evaluation performed showed that since the expected feedwater temperature decrease due to inadvertent actuation of the LTBR was significantly less than that of the net load trip, the consequences and events of inadvertent actuation of the LTBR were bounded by the feedwater temperature decrease event.

The automatic load transient bypass (LTB) feature has been eliminated for Units 1 and 2. Control of the feedwater heater bypass valve has been changed to manual only.

A reduction in feedwater temperature may be caused by an inadvertent manual opening of the feedwater heater bypass valve. This would divert flow around the low pressure feedwater heaters. A consequent maximum 70°F reduction in feedwater temperature to the steam generators would occur.

Feedwater temperature may also be reduced during a load rejection trip. The feedwater transient data taken from a 100 percent net load trip test with LTB active showed that a maximum feedwater temperature decrease of 230°F occurred over a 400-second time period. The temperature decrease without LTB is significantly less.

Reductions in temperature of feedwater entering the steam generators, if not accompanied by a corresponding reduction in steam flow, would result in an increase in core power and create a greater load demand on the RCS. The net effect on the RCS of a reduction in reactor coolant temperature is similar to the effect of increasing secondary steam flow. Such transients are attenuated by the thermal capacity of the secondary plant and of the RCS. The high neutron flux trip, overtemperature ΔT trip, and overpower ΔT trip act to prevent any power increase that could lead to a DNBR less than the limit value. The reactor may reach a new equilibrium condition at a power level corresponding to the new steam generator ΔT. A small temperature reduction results in only a small increase in reactor power and does not result in a reactor trip. A larger temperature reduction produces a larger increase in reactor power and may cause a power/temperature mismatch and a reactor trip.

15.2.11.3 Analysis of Effects and Consequences

The accident is analyzed with the Improved Thermal Design Procedure and initial condition uncertainties are included in the limit DNBR as described in Reference 5. Therefore, initial conditions of nominal core power, nominal reactor coolant average temperatures and nominal reactor coolant pressure are assumed.

15.2.11.3.1 Temperature Drops Less than 73°F

The protection available to mitigate the consequences of a decrease in feedwater temperature is the same as that for an excessive increase in steam flow event, as discussed in Section 15.2.12. A step load increase of 10 percent from full load was analyzed, and the minimum DNBR for this event was found to be above the safety analysis limit values.

The increase in heat load resulting from a 10 percent increase in load is equivalent to a 73°F drop in feedwater temperature at the steam generator inlet. Thus a feedwater temperature transient that results in a feedwater temperature drop of 73°F or less at the steam generator inlets is less severe than the excessive load increase incident presented in Section 15.2.12 and as such does not exceed any safety limits.

15.2.11.3.2 Temperature Drops Greater than 73°F

To address feedwater temperature reductions that exceed 73°F, analyses were performed assuming instantaneous temperature drops of 175°F and 250°F at the steam generator, with corresponding steam load reductions of 50 percent and 100 percent, respectively. The maximum temperature drop of 250°F was chosen to bound the temperature decrease of 230°F experienced during the net load trip test when the LTBR was actuated in response to a load reduction. In this test, feedwater temperature dropped approximately 230°F over a time period of 400 seconds, which is significantly less severe than the instantaneous drop of 250°F assumed in the analysis. Since LTB has been eliminated, the feedwater temperature drop will be significantly less and is bounded by the instantaneous drop of 250°F assumed in the analysis.

15.2.11.4 Results

Both a 175°F feedwater temperature reduction concurrent with a 50 percent load reduction and a 250°F feedwater temperature reduction concurrent with a full (100 percent) load reduction were analyzed. The analysis shows that the cooldown effects of the large feedwater reduction are more than counteracted by the reduced heat removal resulting from the turbine load reduction, such that the transient causes a heatup of the RCS. As a result, the core power decreases and the DNBR increases during the transient. These cases do not challenge core thermal limits.

15.2.11.5 Conclusions

The analysis demonstrates that the acceptance criteria are met as follows:

(1) There is margin to the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell).

(2) The total power is maintained below 118 percent of its nominal value. Thus the peak fuel centerline temperature will remain below the fuel melting temperature. (refer to Section 4.4.2.2.7).

All safety criteria are met for credible scenarios of sudden feedwater temperature reduction. Instantaneous feedwater temperature reductions up to 73°F result in an RCS cooldown that is bounded by the analysis of an excessive load increase incident presented in Section 15.2.12. This bounds the maximum feedwater temperature decrease of 70°F that could result from the inadvertent opening of a feedwater heater bypass valve. For feedwater temperature reductions during a load reduction transient, analyses conclude that these cases result in a net RCS heatup and core power decrease, with no significant challenge to the core thermal limits.

15.2.12 EXCESSIVE LOAD INCREASE INCIDENT

15.2.12.1 Acceptance Criteria

The following is the relevant specific acceptance criterion.

(1) The minimum DNBR must not go below the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell) (refer to Section 4.4.1.1.2) at any time during the transient.

15.2.12.2 Identification of Causes and Accident Description

An excessive load increase incident is defined as a rapid increase in the steam flow that causes a power mismatch between the reactor core power and the steam generator load demand. The reactor control system is designed to accommodate a 10 percent step-load increase or a 5 percent per minute ramp load increase in the range of 15 to 100 percent of full power. Any loading rate in excess of these values may cause a reactor trip actuated by the reactor protection system.

This accident could result from either an administrative violation such as excessive loading by the operator or an equipment malfunction in the steam dump control or turbine speed control.

Protection against an excessive load increase accident is provided by the following reactor protection system signals:

(1) Overpower ΔT

(2) Overtemperature ΔT

(3) Power range high neutron flux

15.2.12.3 Analysis of Effects and Consequences

This accident is analyzed using the LOFTRAN code. The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

Four cases are analyzed to demonstrate the plant behavior following a 10 percent step load increase from rated load. These cases are as follows:

(1) Reactor control in manual with BOL minimum moderator reactivity feedback

(2) Reactor control in manual with EOL maximum moderator reactivity feedback

(3) Reactor control in automatic with BOL minimum moderator reactivity feedback

(4) Reactor control in automatic with EOL maximum moderator reactivity feedback

For the BOL minimum moderator feedback cases, the core has the least negative moderator temperature coefficient of reactivity and the least negative Doppler only power coefficient curve; therefore the least inherent transient response capability. For the EOL maximum moderator feedback cases, the moderator temperature coefficient of reactivity has its highest absolute value and the most negative Doppler only power coefficient curve. This results in the largest amount of reactivity feedback due to changes in coolant temperature.

A conservative limit on the turbine valve opening is assumed, and all cases are studied without credit being taken for pressurizer heaters.

The accident is analyzed using the Improved Thermal Design Procedure and the initial condition uncertainties are included in the limit DNBR as described in Reference 5. Therefore, initial conditions of nominal core power, reactor coolant average temperature (plus 2.5°F for steam generator fouling) and nominal reactor coolant pressure are assumed.

Plant characteristics and initial conditions are further discussed in Section 15.1.

Normal reactor control systems and engineered safety systems are not required to function. The reactor protection system is assumed to be operable; however, reactor trip is not encountered for most cases due to the error allowances assumed in the setpoints. No single active failure will prevent the reactor protection system from performing its intended function.

The cases, which assume automatic rod control, are analyzed to ensure that the worst case is presented. The automatic function is not required.

15.2.12.4 Results

The calculated sequence of events for the excessive load increase incident is shown in Table 15.2-1.

Figures 15.2.12-1 through 15.2.12-4 illustrate the transient with the reactor in the manual control mode. As expected, for the BOL minimum moderator feedback case, there is a slight power increase, and the average core temperature shows a large decrease. This results in a DNBR, which increases above its initial value. For the EOL maximum moderator feedback manually controlled case, there is a much larger increase in reactor power due to the moderator feedback. A reduction in DNBR is experienced but DNBR remains above the limit value.

Figures 15.2.12-5 through 15.2.12-8 illustrate the transient assuming the reactor is in the automatic control mode. Both the BOL minimum and EOL maximum moderator feedback cases show that core power increases, thereby reducing the rate of decrease in coolant average temperature and pressurizer pressure. For both of these cases, the minimum DNBR remains above the limit value.

For all cases, the plant rapidly reaches a stabilized condition at the higher power level. Normal plant operating procedures would then be followed to reduce power.

The excessive load increase incident is an overpower transient for which the fuel temperatures will rise. Reactor trip does not occur for any of the cases analyzed, and the plant reaches a new equilibrium condition at a higher power level corresponding to the increase in steam flow.

Since DNB is not predicted to occur at any time during the excessive load increase transients, the ability of the primary coolant to remove heat from the fuel rod is not reduced. Thus, the fuel cladding temperature does not rise significantly above its initial value during the transient.

15.2.12.5 Conclusions

The analysis demonstrates that the acceptance criterion is met as follows:

(1) There is margin to the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell). The accompanying DNBR figures for this event (Figures 15.2.12-2, 15.2.12-4, 15.2.12-6 and 15.2.12-8) reflect the results for the more limiting Standard fuel (limit 1.48/1.44) previously in the core. The figures represent the thimble cell results.

The analysis presented above shows that for a 10 percent step load increase, the DNBR remains above the safety analysis limit values, thereby precluding fuel or cladding damage. The plant reaches a stabilized condition rapidly, following the load increase.

15.2.13 ACCIDENTAL DEPRESSURIZATION OF THE REACTOR COOLANT SYSTEM

15.2.13.1 Acceptance Criteria

The following is the relevant specific acceptance criterion.

(1) The minimum DNBR must not go below the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell) (refer to Section 4.4.1.1.2) at any time during the transient.

15.2.13.2 Identification of Causes and Accident Description

An accidental depressurization of the RCS could occur as a result of an inadvertent opening of a pressurizer relief or safety valve. Since a safety valve is sized to relieve approximately twice the steam flowrate of a relief valve, and will therefore allow a much more rapid depressurization upon opening, the most severe core conditions resulting from an accidental depressurization of the RCS are associated with an inadvertent opening of a pressurizer safety valve. Initially, the event results in a rapidly decreasing RCS pressure, which could reach the hot leg saturation pressure if a reactor trip does not occur. The pressure continues to decrease throughout the transient. The effect of the pressure decrease is to decrease the neutron flux via the moderator density feedback, but the reactor control system (if in the automatic mode) functions to maintain the power and average coolant temperature essentially constant until the reactor trip occurs. Pressurizer level increases initially due to expansion caused by depressurization and then decreases following reactor trip.

The reactor will be tripped by the following reactor protection system signals:

(1) Pressurizer low pressure

(2) Overtemperature ΔT

15.2.13.3 Analysis of Effects and Consequences

The accidental depressurization transient is analyzed with the LOFTRAN code. The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

This accident is analyzed with the Improved Thermal Design Procedure and the initial condition uncertainties are included in the limit DNBR as described in Reference 5. Therefore, initial conditions of nominal core power, nominal reactor coolant average temperature (plus 2.5 °F for steam generator fouling) and nominal reactor coolant pressure are assumed.

In order to obtain conservative results, the following assumptions are made:

(1) A positive moderator temperature coefficient of reactivity for (+ 7 pcm/°F) BOL operation is assumed in order to provide a conservatively high amount of positive reactivity feedback due to changes in moderator temperature. The spatial effect of voids due to local or subcooled boiling is not considered in the analysis with respect to reactivity feedback or core power shape. These voids would tend to flatten the core power distribution.

(2) A low (absolute value) Doppler-only power coefficient of reactivity such that the resultant amount of negative feedback is conservatively low in order to maximize any power increase due to moderator reactivity feedback.

15.2.13.4 Results

Figure 15.2.13-1 illustrates the nuclear power transient following the RCS depressurization accident. The nuclear power increases until the time reactor trip occurs on overtemperature ΔT, thus resulting in a rapid decrease in the nuclear power. The time of reactor trip is shown in Table 15.2-1. The pressure decay transient following the accident is given in Figure 15.2.13-2. The resulting DNBR (thimble cell) never goes below the safety analysis limit value as shown in Figure 15.2.13-1.

15.2.13.5 Conclusions

The analysis demonstrates that the acceptance criterion is met as follows:

(1) There is margin to the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell) shown on Figure 15.2.13-1.

The pressurizer low pressure and the overtemperature ΔT reactor protection system signals provide adequate protection against this accident, and the minimum DNBR remains in excess of the safety analysis limit value.

15.2.14 ACCIDENTAL DEPRESSURIZATION OF THE MAIN STEAM SYSTEM

15.2.14.1 Acceptance Criteria

The following is the relevant specific acceptance criterion.

(1) Minimum DNBR is not less than the applicable Safety Analysis Limit of 1.45 (W-3 DNB correlation, for coolant pressure less than 1,000 psia) at any time during the transient.

15.2.14.2 Identification of Causes and Accident Description

The most severe core conditions resulting from an accidental depressurization of the main steam system are associated with an inadvertent opening of a single steam dump, relief, or safety valve. The analyses, assuming a rupture of a main steam pipe, are discussed in Section 15.4.

The steam released as a consequence of this accident results in an initial increase in steam flow that decreases during the accident as the steam pressure falls. The energy removal from the RCS causes a reduction of coolant temperature and pressure. In the presence of a negative moderator temperature coefficient, the cooldown results in a reduction of core shutdown margin.

The analysis is performed to demonstrate that the following criterion is satisfied: Assuming a stuck RCCA and a single failure in the engineered safety features (ESF) the limit DNBR value will be met after reactor trip for a steam release equivalent to the spurious opening, with failure to close, of the largest of any single steam dump, relief, or safety valve.

The following systems provide the necessary mitigation of an accidental depressurization of the main steam system.

(1) SIS actuation from any of the following:

(a) Two-out-of-four low pressurizer pressure signals

(b) Two-out-of-three low steam line pressure signals on any one loop

(2) The overpower reactor trips (neutron flux and ΔT), the overtemperature ΔT reactor trip, and the reactor trip occurring in conjunction with receipt of the safety injection signal.

(3) Redundant isolation of the main feedwater lines: Sustained high feedwater flow would cause additional cooldown. Therefore, a safety injection signal will rapidly close all feedwater control valves, trip the main feedwater pumps, and close the feedwater isolation valves.

15.2.14.3 Analysis of Effects and Consequences

Due to the size of the break and the assumed initial conditions, an Accidental Depressurization of the Main Steam System event is bounded by the Main Steam Line Rupture accident analyzed in Section 15.4.2.1. As such, no explicit analysis is performed for the Accidental Depressurization of the Main Steam System. All applicable acceptance criteria are shown to be met via the results and conclusions in Section 15.4.2.1.

15.2.14.4 Conclusions

The applicable acceptance criterion is shown to be met via the results and conclusions in Section 15.4.2.1. The Rupture of a Main Steam Line at Hot Zero Power is a Condition IV event that meets the minimum DNBR criterion of the Condition II Accidental Depressurization of the Main Steam System. The Condition IV event models a large double-ended rupture, with more limiting results than the inadvertent opening of a SG PORV or dump valve, regardless of any differences in safety system actuations. Therefore, demonstrating that the Condition IV event meets the same Condition II criterion for minimum DNBR, as the calculated value is never below the limit value of 1.45 at any time during the transient, satisfies the acceptance criterion for the Condition II event discussed in Section 15.2.14.

15.2.15 SPURIOUS OPERATION OF THE SAFETY INJECTION SYSTEM AT POWER

15.2.15.1 Acceptance Criteria

The following are the relevant specific acceptance criteria.

(1) The minimum DNBR must not go below the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell) (refer to Section 4.4.1.1.2) at any time during the transient. This criterion is discussed in Section 15.2.15.2.

(2) The SSI event is terminated prior to exceeding the assumed maximum pressurizer PORV cycles supported by the backup nitrogen accumulators and prior to challenging the PSV liquid relief capability. This criterion is discussed in Section 15.2.15.3.

The RCS overpressure concern is bounded by the Section 15.2.7 event.

15.2.15.2 Spurious Safety Injection (SSI) DNBR Analysis

15.2.15.2.1 Identification of Causes and Accident Description

Spurious SIS operation at power could be caused by operator error or a false electrical actuating signal. A spurious signal may originate from any of the safety injection actuation channels. Refer to Section 7.2 for a description of the actuation system.

Following the actuation signal, the suction of the coolant charging pumps is diverted from the volume control tank to the RWST. The charging injection valves between the charging pumps and the injection header open automatically. The charging pumps then pump RWST water through the header and injection line and into the cold legs of each loop. The safety injection pumps also start automatically but provide no flow when the RCS is at normal pressure. The passive injection system and the RHR system also provide no flow at normal RCS pressure.

The analyses of the potential for DNB, loss of fuel integrity, and excessive cooldown are presented in the discussions herein.

An SIS signal normally results in a reactor trip followed by a turbine trip. However, it cannot be assumed that any single fault that actuates the SIS will also produce a reactor trip. Therefore, two different courses of events are considered.

Case A: Trip occurs at the same time spurious injection starts.

Case B: The reactor protection system produces a trip later in the transient.

For Case A, the operator should determine if the spurious signal was transient or steady state in nature, i.e., an occasional occurrence or a definite fault. The operator will determine this by following approved procedures. In the transient case, the operator would stop the safety injection. If the SIS must be disabled for repair, boration should continue and the plant brought to cold shutdown.

For Case B, the reactor protection system does not produce an immediate trip and the reactor experiences a negative reactivity excursion causing a decrease in the reactor power. The power unbalance causes a drop in T_{avg} and consequent coolant shrinkage, and pressurizer pressure and level drop. Load will decrease due to the effect of reduced steam pressure on load if the electrohydraulic governor fully opens the turbine throttle valve. If automatic rod control is used, these effects will be lessened until the rods have moved out of the core. The transient is eventually terminated by the reactor protection system low-pressure trip or by manual trip.

The time to trip is affected by initial operating conditions including core burnup history that affects initial boron concentration, rate of change of boron concentration, and Doppler and moderator coefficients.

Recovery from this incident for Case B is in the same manner as for Case A. The only difference is the lower T_{avg} and pressure associated with the power imbalance during this transient. The time at which reactor trip occurs is of no concern for this accident. At lighter loads coolant contraction will be slower resulting in a longer time to trip.

15.2.15.2.2 Analysis of Effects and Consequences

The spurious operation of the SIS is analyzed for DNBR with the LOFTRAN program. The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, steam generator safety valves, and the effect of the SIS. The program computes pertinent plant variables including temperatures, pressures, and power level.

Because of the power and temperature reduction during the transient, operating conditions do not approach the core limits. Analyses of several cases show that the results are relatively independent of time to trip.

A typical transient is considered representing conditions at BOL. Results at EOL are similar except that moderator feedback effects result in a slower transient.

The accident is analyzed using the Improved Thermal Design Procedure and the initial condition uncertainties are included in the limit DNBR as described in Reference 5. Therefore, initial conditions of nominal core power, nominal reactor coolant average temperature (plus 2.5°F for steam generator fouling) and nominal reactor coolant pressure are assumed.

The assumptions used in the analysis are:

(1) Moderator and Doppler Coefficients of Reactivity

A positive BOL moderator temperature coefficient was used. A low absolute value Doppler power coefficient was assumed.

(2) Reactor Control

The reactor was assumed to be in manual control.

(3) Pressurizer Heaters

Pressurizer heaters were assumed to be inoperative in order to increase the rate of pressure drop.

(4) Boron Injection

At time zero, two charging pumps (CCP1 and CCP2) begin injection and pump borated water through the SIS and into the cold leg of each loop.

(5) Turbine Load

Turbine load was assumed constant until the electrohydraulic governor drives the throttle valve wide open. Once the throttle valve is wide open, turbine load drops as the steam pressure decreases.

(6) Reactor Trip

Reactor trip was initiated by low pressure. The trip was conservatively assumed to be delayed until the pressure reached 1860 psia.

15.2.15.2.3 Results

The transient response for the minimum feedback case is shown in Figures 15.2.15-1 through 15.2.15-2. Nuclear power starts decreasing immediately due to boron injection, but steam flow does not decrease until 25 seconds into the transient when the turbine throttle valve goes wide open. The mismatch between load and nuclear power causes Tavg, pressurizer water level, and pressurizer pressure to drop. The low-pressure trip setpoint is reached at 23 seconds and rods start moving into the core at 25 seconds.

15.2.15.2.4 Conclusions

The analysis demonstrates that the acceptance criteria are met as follows:

(1) There is margin to the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell).

Results of the DNBR analysis show that spurious safety injection with or without immediate reactor trip presents no hazard to the integrity of the RCS.

DNBR is never less than the initial value. Thus, there will be no cladding damage and no release of fission products to the RCS.

If the reactor does not trip immediately, the low-pressure reactor trip will be actuated. This trips the turbine and prevents excess cooldown thereby expediting recovery from the incident.

15.2.15.3 Spurious Safety Injection (SSI) Pressurizer Overfill Analysis

15.2.15.3.1 Identification of Causes and Accident Description

The causes and accident description are essentially identical for the SSI DNBR analysis discussed in Section 15.2.15.2 and the SSI pressurizer overfill evaluation in this section. The pressurizer overfill cases model the long term plant response and the operator actions taken to terminate the event before the liquid relief capability of the PSV is challenged. The operator recovery actions for SSI mitigation at power are provided in the plant emergency operating procedures (EOPs). These operator actions, including making a pressurizer PORV available, stopping all but one centrifugal charging pump (CCP1 or CCP2), throttling the charging flow, and establishing RCS letdown flow, are discussed below.

(a) Make Pressurizer PORV Available

One of the first recovery actions that the EOPs describe is to verify a pressurizer PORV is available for pressure relief. The operator is directed to open an associated isolation valve as necessary to make a PORV available. The pressurizer overfill evaluation assumes that the operator makes a PORV available within 11 minutes of the initiation of the event.

(b) Stop All But One CCP (CCP1 or CCP2)

The EOPs provide direction, that in the event of a reactor trip or safety injection, the nonsafety-related centrifugal charging pump CCP3 is not needed and is secured. The pressurizer overfill evaluation conservatively assumes that CCP3 is operating when the SSI event occurs, since this

maximizes the pressurizer fill rate. The operators stop the CCP3 within 9 minutes of the event initiation.

Once the operators have identified that the SI is unnecessary, the EOPs direct the operators to stop all but one CCP (CCP1 or CCP2), and throttle the CCP (CCP1 or CCP2) flow as necessary to minimize the potential for pressurizer overfill while maintaining adequate RCP seal injection flow. The operators are assumed to stop all but one CCP (CCP1 or CCP2) within 14 minutes, and require one additional minute to throttle the charging flow.

(c) Restore Instrument Air and Establish RCS Letdown

The SI signal causes a Phase A containment isolation and a loss of instrument air to containment. In order to establish RCS letdown and terminate the SSI event, the EOPs direct the operators to restore instrument air to containment. The operators are assumed to restore instrument air to containment within 21 minutes of the event. The EOPs then direct the operators through a series of steps, which allow them to establish RCS letdown and stabilize the pressurizer level. The operators are able to establish RCS letdown and terminate the SSI event within 26 minutes.

There are three different cases analyzed to bound the potential impact of the plant control systems operation on the SSI event and the potential for pressurizer overfill.

Case 1

Case 1 assumes that the pressurizer pressure control system malfunctions such that the sprays, backup heaters, and proportional heaters all remain on during the event. Both Class 1 PORVs are unavailable. Case 1 establishes the maximum time available for the operators to open a pressurizer PORV block valve and make a PORV available, before the liquid relief capability of the PSV is challenged. The PSV capability is defined as a maximum of 3 openings under liquid relief conditions with the liquid temperature remaining greater than 613°F as established in Reference 16.

Case 2

Case 2 assumes that the pressurizer pressure control system malfunctions such that the sprays, backup heaters, and proportional heaters all remain on during the event. This case causes the earliest filling of the pressurizer and the earliest initiation of liquid relief through the pressurizer PORV. This case evaluates that the minimum capacity of the backup nitrogen accumulators is adequate to allow termination of the SSI event without challenging the liquid relief capability of the PSV.

Case 3

Case 3 assumes there is a loss of instrument air such that the pressurizer sprays are not operable. The pressurizer heaters remain on during the event. This case causes the earliest pressure increase to the PORV lift setpoint. The analyses of Cases 2 and 3 establish the bounding conditions for evaluating the potential impact of the pressurizer control systems on the time at which the pressurizer fills and the relative number of steam relief and liquid relief PORV cycles which occur during an SSI event.

15.2.15.3.2 Analysis of Effects and Consequences

The SSI event is analyzed for pressurizer overfill conditions with the RETRAN-02 program as documented in Reference 16. The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, steam generator safety valves, and the effect of the SSI. The program computes pertinent plant variables including temperatures, pressures, and power level.

The assumptions are:

(1) Initial Operating Conditions

The initial pressurizer pressure is assumed to be at 2,190 psia, which is 60 psi lower than the nominal value. The pressurizer pressure control system is also assumed to control to a reduced setpoint of 2,190 psia when it is operable. This lower RCS pressure results in increased emergency core cooling system (ECCS) injection flow during the transient and maximizes the challenges to the PSVs and PORVs.
The initial RCS Tavg is assumed to be at the minimum pressurizer program level corresponding to 560°F, which includes a bounding maximum RCS temperature uncertainty of 5°F. This conservatively maximizes the initial RCS mass, and minimizes the RCS volumetric shrinkage after the reactor trip. For this initial Tavg, the corresponding programmed initial pressurizer level is 51.2 percent, which bounds the pressurizer level uncertainty of 6.1 percent.

(2) Pressurizer Heaters

Both the backup and proportional pressurizer heaters are assumed to remain on even after the normal control setpoint is reached to conservatively maximize the pressurizer liquid volume and decrease the time to fill the pressurizer with liquid.

(3) Reactor Trip / Turbine Load

The reactor trip occurs coincident with the SI actuation, which results in an immediate turbine trip. There is no credit for heat removal from the steam

dump system to the condenser or atmosphere. Only the main steam safety valves are assumed to be operable, with a 3 percent setpoint drift and 3 percent accumulation. Main feedwater is lost coincident with the reactor/turbine trip. The analysis conservatively assumes that one motor-driven auxiliary feedwater (MDAFW) pump delivers the minimum flow of 390 gpm to four steam generators although a MDAFW is aligned to only two steam generators. The AFW fluid temperature is a maximum value of 100°F. The minimum heat transfer from the primary coolant loop to the secondary system leads to a conservatively early pressurizer fill condition and challenge to the pressurizer overfill condition.

(4) Moderator and Doppler Coefficients of Reactivity

Similar to the DNBR analysis, the pressurizer overfill analysis assumes a positive BOL moderator temperature coefficient and low absolute value Doppler power coefficient. Since the reactor trip occurs immediately for the pressurizer overfill case, these reactivity coefficients have a negligible impact on the results.

(5) Reactor Decay Heat

Conservative core residual heat generation is assumed based on long-term operation at the initial power level preceding the trip. The 1973 decay heat ANSI x 1.2 was used for calculation of residual decay heat levels.

(6) Pressurizer PORVs

The pressurizer PORV lift setpoint is assumed to be a minimum of 2,298 psia. The pressurizer PORV delay and stroke time are minimized. The PORV opens with a delay time of 0.589 second and a stroke time of 0.416 second, and closes with a delay time of 0.825 second and a stroke time of 0.819 second. The PORV valve area is assumed to increase/decrease linearly as the valve strokes open and closed. These assumptions conservatively maximize the number of PORV open cycles during the SSI event. The backup nitrogen accumulators can provide for more than 100 PORV cycles in the event of a loss of instrument air (refer to Section 9.3.1.6).

(7) ECCS Injection Flow

Two trains of ECCS pumps are assumed to provide the maximum injection flow versus RCS pressure. The RWST fluid temperature is assumed to be 35°F to maximize the ECCS fluid density.

15.2.15.3.3 Results

The sequence of events for the 3 pressurizer overfill cases is listed in Table 15.2.-1. Typical transient responses are shown in Figures 15.2.15-3 through 15.2.15-5.

Case 1

The spurious safety injection signal occurs at one second. This generates a concurrent reactor trip signal from full power conditions followed by a turbine trip signal one second later. The pressurizer pressure and pressurizer level initially decrease as the RCS power and temperature reduce from full power conditions to hot no load conditions. The initiation of the ECCS injection flow halts the post trip pressure decrease and then rapidly increases the pressure until the pressurizer spray valves open enough to maintain the pressurizer pressure relatively constant. The pressurizer level continues to increase due to ECCS injection flow until the pressurizer fills. The water solid RCS then experiences a rapid pressure increase to the pressurizer safety valve lift setpoint. The Case 1 analysis evaluation is considered complete when the fourth liquid relief of the PSV begins at a minimum of 720 seconds. This establishes the minimum time available for the operators to unblock a pressurizer PORV to prevent challenging the liquid relief capability of the PSV.

Case 2

The first part of each SSI case is essentially identical as the plant experiences the spurious safety injection, reactor trip, and turbine trip from full power conditions. The plant response for Case 2 is identical to Case 1 including up to the time that the pressurizer becomes water solid. For Case 2, the RCS pressure increases only to the pressurizer PORV lift setpoint where it is maintained relatively constant as the PORV continues to cycle and relieve liquid. By the time the SSI event is terminated at 26 minutes, the PORV has cycled a maximum of 50 times.

Case 3

In Case 3, the pressurizer sprays are not available such that after the reactor trip the RCS pressure continues increasing to the pressurizer PORV lift setpoint. The pressurizer PORV continues to cycle and relieve steam as the pressurizer level increases due to the ECCS injection flow. Without the pressurizer sprays, the RCS pressure is maintained near the PORV setpoint such that the pressurizer fills later than Case 1. Once the pressurizer becomes water solid, the PORV begins relieving liquid. By the time the SSI event is terminated at 26 minutes, the PORV has cycled a maximum of 93 times.

15.2.15.3.4 Conclusions

The analysis demonstrates that the acceptance criteria are met as follows:

(1) The operators have adequate time to terminate the event prior to exceeding the assumed maximum pressurizer PORV cycles supported by the backup nitrogen accumulators. The mitigation function of the Class I PORVs ensures that the SSI event can be terminated prior to challenging the PSV liquid relief capability.

Case 1 establishes that for the limiting SSI event, the operators have a minimum time of about 720 seconds or 12 minutes to make a pressurizer PORV available to prevent challenging the PSV liquid relief capability. These results conservatively bound the 11 minutes assumed for the operators to manually unblock a pressurizer PORV. Cases 2 and 3 establish that with the worst-case control system operation, the operators have adequate time to terminate an SSI event prior to exceeding the capacity of pressurizer PORV cycles provided by the backup nitrogen accumulators. The mitigation function of the Class I PORVs ensures that the SSI event can be terminated prior to challenging the PSV liquid relief capability.

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15.3 CONDITION III - INFREQUENT FAULTS

By definition, Condition III occurrences are faults that may occur very infrequently during the life of the plant. They will be accompanied with the failure of only a small fraction of the fuel rods although sufficient fuel damage might occur to preclude resumption of operation for a considerable outage time. The release of radioactivity will not be sufficient to interrupt or restrict public use of those areas beyond the exclusion radius. A Condition III fault will not, by itself, generate a Condition IV fault or result in a consequential loss of function of the reactor coolant system (RCS) or containment barriers. For the purposes of this report the following faults have been grouped into this category:

(1) Loss of reactor coolant, from small ruptured pipes or from cracks in large pipes, that actuates the emergency core cooling system (ECCS).

(2) Minor secondary system pipe breaks.

(3) Inadvertent loading of a fuel assembly into an improper position.

(4) Complete loss of forced reactor coolant flow.

(5) Single rod cluster control assembly (RCCA) withdrawal at full power.

Each of these infrequent faults is analyzed in this section. In general, each analysis includes acceptance criteria, an identification of causes and description of the accident, an analysis of effects and consequences, a presentation of results, and relevant conclusions.

The time sequences of events during four Condition III faults of type (1) above, small-break loss-of-coolant accident (SBLOCA), are shown in Table 15.3-1.

15.3.1 LOSS OF REACTOR COOLANT FROM SMALL RUPTURED PIPES OR FROM CRACKS IN LARGE PIPES THAT ACTUATES EMERGENCY CORE COOLING SYSTEM

15.3.1.1 Acceptance Criteria

15.3.1.1.1 10 CFR Part 50, Section 50.46, Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Reactors

(1) *Peak cladding temperature.* The calculated maximum fuel element cladding temperature shall not exceed 2200°F.

(2) *Maximum cladding oxidation*. The calculated total oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation.

(3) *Maximum hydrogen generation*. The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react. This reduces the potential for explosive hydrogen/oxygen mixtures inside containment.

(4) *Coolable geometry*. Calculated changes in core geometry shall be such that the core remains amenable to cooling.

(5) *Long-term cooling*. After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core.

15.3.1.1.2 Radiological Criteria

The radiological consequences of a SBLOCA are within the applicable guidelines and limits specified in 10 CFR Part 100 detailed in Section 15.5.11.

15.3.1.2 Identification of Causes and Accident Description

A LOCA is defined as a rupture of the RCS piping or of any line connected to the system. This includes small pipe breaks, typically a 3/8-inch diameter opening (0.11 square inch), up to and including a break size of 1.0 square foot that results in flow that is greater than the makeup flow rate from either CCP1 or CCP2 (refer to Section 6.3.3.6.2.2). Refer to Section 3.6 for a more detailed description of the LOCA boundary limits. The coolant that would be released to the containment contains fission products.

The maximum break size for which the normal makeup system can maintain the pressurizer level is obtained by comparing the calculated flow from the RCS through the postulated break against the charging system flow capability when aligned for maximum charging at normal RCS pressure.

Should a larger break occur, depressurization of the RCS causes fluid to flow to the RCS from the pressurizer resulting in a pressure and level decrease in the pressurizer. Reactor trip occurs when the pressurizer low-pressure trip setpoint is reached. The safety injection system (SIS) is actuated when the appropriate pressurizer low-pressure setpoint is reached. Reactor trip and SIS actuation are also initiated by a high containment pressure signal. The consequences of the accident are limited in two ways:

(1) Reactor trip and borated water injection complement void formation in causing rapid reduction of nuclear power to a residual level corresponding to the delayed fission and fission product decay

(2) Injection of borated water ensures sufficient flooding of the core to prevent excessive cladding temperatures

Before the break occurs, the plant is in an equilibrium condition; i.e., the heat generated in the core is being removed via the secondary system. During blowdown, heat from decay, hot internals, and the vessel continues to be transferred to the RCS. The heat transfer between the RCS and the secondary system may be in either direction depending on the relative temperatures. In the case of continued heat addition to the secondary system, system pressure increases and steam dump may occur. Makeup to the secondary side is automatically provided by the auxiliary feedwater (AFW) pumps. The safety injection signal stops normal feedwater flow by closing the main feedwater line isolation valves and initiates emergency feedwater flow by starting AFW pumps. The secondary flow aids in the reduction of RCS pressure. When the RCS depressurizes to below approximately 600 psia, the accumulators begin to inject water into the reactor coolant loops. The reactor coolant pumps are assumed to be tripped at the beginning of the accident and the effects of pump coastdown are included in the blowdown analyses.

15.3.1.3 Analysis of Effects and Consequences

For loss-of-coolant accidents due to small breaks less than 1 square foot, the NOTRUMP (Reference 12) computer code is used to calculate the transient depressurization of the RCS as well as to describe the mass and enthalpy of flow through the break. The NOTRUMP computer code is a one-dimensional general network code with a number of features. Among these features are the calculation of thermal nonequilibrium in all fluid volumes, flow regime-dependent drift flux calculations with counter-current flooding limitations, mixture level tracking logic in multiple-stacked fluid nodes, and regime-dependent heat transfer correlations. The NOTRUMP SBLOCA emergency core cooling system (ECCS) evaluation model was developed to determine the RCS response to design basis SBLOCAs and to address the NRC concerns expressed in NUREG-0611, "Generic Evaluation of Feedwater Transients and Small Break Loss-of-Coolant Accidents in Westinghouse-Designed Operating Plants."

In NOTRUMP, the RCS is nodalized into volumes interconnected by flowpaths. The broken loop is modeled explicitly, with the intact loops lumped into a second loop. The transient behavior of the system is determined from the governing conservation equations of mass, energy, and momentum applied throughout the system. A detailed description of the NOTRUMP code is provided in References 12 and 13.

The use of NOTRUMP in the analysis involves, among other things, the representation of the reactor core as heated control volumes with the associated bubble rise model to permit a transient mixture height calculation. The multinode capability of the program enables an explicit and detailed spatial representation of various system components. In particular, it enables a proper calculation of the behavior of the loop seal during a loss-of-coolant transient.

Safety injection flowrate to the RCS as a function of the system pressure is used as part of the input. The SIS was assumed to be delivering water to the RCS 27 seconds after the generation of a safety injection signal.

For the analysis, the SIS delivery considers pumped injection flow that is depicted in Figure 15.3-1 as a function of RCS pressure. This figure represents injection flow from the SIS pumps based on performance curves degraded 5 percent from the design head. The 27-second delay includes time required for diesel startup and loading of the safety injection pumps onto the emergency buses. The effect of residual heat removal (RHR) pump flow is not considered here since their shutoff head is lower than RCS pressure during the time portion of the transient considered here. Also, minimum safeguards ECCS capability and operability have been assumed in these analyses.

Peak cladding temperature analyses are performed with the LOCTA IV (Reference 4) code that determines the RCS pressure, fuel rod power history, steam flow past the uncovered part to the core, and mixture height history.

15.3.1.4 Results

15.3.1.4.1 Reactor Coolant System Pipe Breaks

This section presents the results of a spectrum of small break sizes analyzed. The small break analysis was performed at 102 percent of the Rated Core Power (3411 MWt), a Total Peaking Factor (FQT) of 2.70, a Thermal Design Flow of 87,700 / 88,500 gpm/loop (Unit 1 / Unit 2) and a steam generator tube plugging level of 10 percent. For Unit 1, the small-break analysis was performed for the Replacement Steam Generator (RSG). For Unit 2, the small break analysis was performed for the upflow core barrel/baffle configuration, upper head temperature reduction and RSG.

The limiting small break size was shown to be a 3-inch diameter break in the cold leg. In the analysis of this limiting break, an RCS T_{avg} window of 577.3 / 577.6°F, +5°F, -4°F (Unit 1 / Unit 2) was considered. The high T_{avg} cases were shown to be more limiting than the Low T_{avg} cases and therefore are the subject of the remaining discussion. The time sequence of events and the fuel cladding results for the breaks analyzed are shown in Tables 15.3-1 and 15.3-2.

During the earlier part of the small break transient, the effect of the break flow is not strong enough to overcome the flow maintained by the reactor coolant pumps through the core as they are coasting down following reactor trip. Therefore, upward flow through the core is maintained. The resultant heat transfer cools the fuel rods and cladding to very near the coolant temperature as long as the core remains covered by a two-phase mixture. This effect is evident in the accompanying figures.

The depressurization transients for the limiting 3-inch breaks are shown in Figure 15.3-9. The extent to which the core is uncovered for these breaks is presented in Figure 15.3-11. The maximum hot spot cladding temperature reached during the

transient, including the effects of fuel densification as described in Reference 3, is 1391 / 1288°F (Unit 1 / Unit 2). The peak cladding temperature transients for the 3-inch breaks are shown in Figure 15.3-13. The top core node vapor temperatures for the 3-inch breaks are shown in Figure 15.3-33. When the mixture level drops below the top of the core, the top core node vapor temperature increases as the steam superheats along the exposed portion of the fuel. The rod film coefficients for this phase of the transients are given in Figure 15.3-34. The hot spot fluid temperatures are shown in Figure 15.3-35 and the break mass flows are shown in Figure 15.3-36.

The core power (dimensionless) transient following the accident (relative to reactor scram time) is shown in Figure 15.3-8. The reactor shutdown time (4.7 sec) is equal to the reactor trip signal processing time (2.0 seconds) plus 2.7 seconds for complete rod insertion. During this rod insertion period, the reactor is conservatively assumed to operate at 102 percent rated power. The small break analyses considered 17x17 Vantage 5 fuel with IFMs, ZIRLO cladding, and an axial blanket. Fully enriched annular pellets, as part of an axial blanket core design, were modeled explicitly in this analysis. The results when modeling the enriched annular pellets were not significantly different than the results from solid pellet modeling.

Several figures are also presented for the additional break sizes analyzed. Figures 15.3-37, 15.3-2, and 15.3-40 present the RCS pressure transient for the 2-, 4-, and 6-inch breaks, respectively. Figures 15.3-38, 15.3-3, and 15.3-41 present the core mixture height plots for 2-, 4-, and 6-inch breaks, respectively. The peak cladding temperature transients for the 2-inch breaks are shown in Figure 15.3-39. The peak cladding temperature transients for the 4-inch breaks are shown in Figure 15.3-4. These results are not available for the 6-inch break because the core did not uncover for this transient.

The small break analysis was performed with the Westinghouse ECCS Small Break Evaluation Model (References 12 and 4) approved for this use by the Nuclear Regulatory Commission in May 1985. An approved cold leg SI condensation model, COSI (Reference 26), was utilized as part of the Evaluation Model.

15.3.1.5 Conclusions

The analysis demonstrates that the acceptance criteria are met as follows:

15.3.1.5.1 10 CFR Part 50, Section 50.46, Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Reactors

(1) *Peak cladding temperature*. The calculated maximum fuel element cladding temperature does not exceed 2200°F, as shown in Table 15.3-2.

(2) *Maximum cladding oxidation*. The calculated total oxidation of the cladding nowhere exceeds 0.17 times the total cladding thickness before oxidation, as shown in Table 15.3-2.

(3) *Maximum hydrogen generation*. Table 15.3-2 shows that the average cladding oxidation is less than 0.01 times the cladding thickness. Thus the calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam does not exceed 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react.

(4) & (5) *Coolable Geometry and Long Term Cooling*. The results associated with the SBLOCA analysis performed with the NOTRUMP Evaluation Model explicitly demonstrate compliance with Criteria 1 through 3. Because of the fuel rod burst and blockage models used in the LOCTA code, and modeling of the cold leg recirculation phase in NOTRUMP, SBLOCA analysis results also support the coolable geometry and long term cooling criteria. Since Criteria 1 through 3 are explicitly met, Criteria 4 and 5 are met as well. The SBLOCA phenomena and results are therefore in compliance with 10 CFR 50.46 acceptance criteria.

15.3.1.5.2 Radiological

The radiological consequences of a SBLOCA are within the applicable guidelines and limits specified in 10 CFR Part 100 detailed in Section 15.5.11.

15.3.2 MINOR SECONDARY SYSTEM PIPE BREAKS

15.3.2.1 Acceptance Criteria

(1) The minimum departure from nucleate boiling ratio (DNBR) does not go below the safety analysis limit (see Section 15.4.2.1.1 and 15.4.2.3.1) at any time during the transient to ensure that the core remains geometrically intact with no loss of core cooling capability.

(2) Any activity release must be such that the calculated doses at the site boundary are a small fraction of the applicable guidelines and limits specified in 10 CFR Part 100 as detailed in Section 15.5.12.

15.3.2.2 Identification of Causes and Accident Description

Included in this grouping are ruptures of secondary system lines which would result in steam release rates equivalent to a 6-inch diameter break or smaller.

15.3.2.3 Analysis of Effects and Consequences

Minor secondary system pipe breaks must not result in more than the failure of only a small fraction of the fuel elements in the reactor. Since the results of analysis presented in Section 15.4.2 for a major secondary system pipe rupture also meet these criteria, separate analyses for minor secondary system pipe breaks is not required.

The analyses of the more probable accidental opening of a secondary system steam dump, relief, or safety valve is presented in Section 15.2.14. These analyses are illustrative of a pipe break equivalent in size to a single valve opening.

15.3.2.4 Conclusions

The analysis demonstrates that the acceptance criteria are met as follows:

(1) The analysis presented in Section 15.4.2 demonstrates that the consequences of a minor secondary system pipe break are acceptable because a DNBR of less than the design basis values does not occur even for a more critical major secondary system pipe break.

(2) Section 15.5.12 demonstrates the potential radiological exposures to the public following a minor secondary system pipe rupture per the applicable guidelines and limits specified in 10 CFR Part 100 are met.

15.3.3 INADVERTENT LOADING OF A FUEL ASSEMBLY INTO AN IMPROPER POSITION

15.3.3.1 Acceptance Criteria

(1) In the event of a fuel loading error not identified until normal operation, the offsite dose consequences should be a small fraction of the applicable guidelines and limits specified in 10 CFR Part 100 as detailed in Section 15.5.1.

15.3.3.2 Identification of Causes and Accident Description

Fuel and core loading errors such as inadvertently loading one or more fuel assemblies into improper positions, loading a fuel rod during manufacture with one or more pellets of the wrong enrichment, or loading a full fuel assembly during manufacture with pellets of the wrong enrichment will lead to increased heat fluxes if the error results in placing fuel in core positions calling for fuel of lesser enrichment. The inadvertent loading of one or more fuel assemblies requiring burnable poison rods into a new core without burnable poison rods is also included among possible core loading errors.

Any error in enrichment, beyond the normal manufacturing tolerances, can cause power shapes that are more peaked than those calculated with the correct enrichments. The incore system of movable neutron flux detectors that is used to verify power shapes at the start of life is capable of revealing any assembly enrichment error or loading error that causes power shapes to be peaked in excess of the design value.

To reduce the probability of core loading errors, each fuel assembly is marked with an identification number and loaded in accordance with a core loading diagram. For each core loading, the identification number is checked to ensure proper core configuration.

The power distortion due to any combination of misplaced fuel assemblies would significantly raise peaking factors and would be readily observable with movable incore neutron flux detectors. In addition to the flux detectors, thermocouples are located at the outlet of about one-third of the fuel assemblies in the core. There is a high probability that these thermocouples would also indicate any abnormally high coolant enthalpy rise. Incore flux measurements are taken during the startup subsequent to every refueling operation. A more detailed discussion of the flux detection capabilities may be found in Section 4.3.2.2.

15.3.3.3 Analysis of Effects and Consequences

Steady state power distributions in the x-y plane of the core are calculated with the TURTLE code (see Section 1.6.1, Item 49, and Section 4.3.2.8.5), based on macroscopic cross sections calculated by the LEOPARD code (see Section 1.6.1, Item 48, and Section 4.3.3.2). A discrete representation is used wherein each individual fuel rod is described by a mesh interval. The power distributions in the x-y plane for a correctly loaded core assembly are given in Chapter 4 based on enrichments given in that section.

For each core loading error case analyzed, the percent deviations from detector readings for a normally loaded core are shown at all incore detector locations (see Figures 15.3-15 through 15.3-19).

15.3.3.4 Results

The following core loading error cases have been analyzed:

(1) Case A

The case in which a Region 1 assembly is interchanged with a Region 3 assembly. The particular case considered was the interchange of two adjacent assemblies near the periphery of the core (see Figure 15.3-15).

(2) Case B

The case in which a Region 1 assembly is interchanged with a neighboring Region 2 fuel assembly. Two analyses have been performed for this case (see Figures 15.3-16 and 15.3-17).

In Case B-1, the interchange is assumed to take place with the burnable poison rods transferred with the Region 2 assembly mistakenly loaded into Region 1.

In Case B-2, the interchange is assumed to take place closer to core center and with burnable poison rods located in the correct Region 2 position but in a Region 1 assembly mistakenly loaded into the Region 2 position.

(3) Case C

Enrichment error: the case in which a Region 2 fuel assembly is loaded in the core central position (see Figure 15.3-18).

(4) Case D

The case in which a Region 2 fuel assembly instead of a Region 1 assembly is loaded near the core periphery (see Figure 15.3-19).

15.3.3.5 Conclusions

In the event that a single rod or pellet has a higher enrichment than the nominal value, the consequences in terms of reduced DNBR and increased fuel and cladding temperatures will be limited to the incorrectly loaded rod or rods.

Fuel assembly loading errors are prevented by administrative procedures implemented during core loading. In the unlikely event that a loading error occurs, analyses in this section confirm that resulting power distribution effects will either be readily detected by the incore movable detector system or will cause a sufficiently small perturbation to be acceptable within the uncertainties allowed between nominal and design power shapes.

The analysis demonstrates the acceptance criterion is met as follows:

(1) No events leading to environmental radiological consequences are expected as a result of loading errors (see Section 15.5.13).

15.3.4 COMPLETE LOSS OF FORCED REACTOR COOLANT FLOW

15.3.4.1 Acceptance Criteria

(1) Maintain the minimum DNBR greater than the safety analysis limit for fuel (see Section 4.4.2.1).

15.3.4.2 Identification of Causes and Accident Description

A complete loss of forced reactor coolant flow may result from a simultaneous loss of electrical supplies to all reactor coolant pumps. If the reactor is at power at the time of the accident, the immediate effect of loss of coolant flow is a rapid increase in the coolant temperature. This increase could result in departure from nucleate boiling (DNB) with subsequent fuel damage if the reactor were not tripped promptly. The following reactor trips provide necessary protection against a loss of coolant flow accident:

(1) Undervoltage or underfrequency on reactor coolant pump power supply buses (primary protection)

(2) Low reactor coolant loop flow (backup to undervoltage and underfrequency trips)

(3) Pump circuit breaker opening (backup to low flow)

The reactor trip on reactor coolant pump bus undervoltage is provided to protect against conditions that can cause a loss of voltage to all reactor coolant pumps, i.e., loss of offsite power. This function is blocked below approximately 10 percent power (Permissive 7).

The reactor trip on reactor coolant pump underfrequency is provided to trip the reactor for an underfrequency condition, resulting from frequency disturbances on the major power grid. Underfrequency also opens the reactor coolant pump breakers that disengage the reactor coolant pumps from the power grid so that the pumps flywheel kinetic energy is available for full coastdown.

The reactor trip on low primary coolant loop flow is provided to protect against loss-of-flow conditions that affect only one reactor coolant loop. It also serves as a backup to the undervoltage and underfrequency trips. This function is generated by two-out-of-three low-flow signals per reactor coolant loop. Above approximately 35 percent power (Permissive 8), low flow in any loop will actuate a reactor trip. Between approximately 10 and 35 percent power (Permissive 7 and Permissive 8), low-flow in any two loops will actuate a reactor trip. A reactor trip from opened pump breakers is provided as a backup to the low-flow signals. Above Permissive 7 a breaker open signal from any 2 of 4 pumps will actuate a reactor trip. Reactor trip on reactor coolant pump breakers open is blocked below Permissive 7.

Normal power for the reactor coolant pumps is supplied through buses from a transformer connected to the generator. Two pumps are on each bus. When a generator trip occurs, the buses are automatically transferred to a transformer supplied from external power lines, and the pumps will continue to supply coolant flow to the core. Following any turbine trip, where there are no electrical or mechanical faults which require immediate tripping of the generator from the network, the generator remains connected to the network for approximately 30 seconds. The reactor coolant pumps remain connected to the generator thus ensuring full flow for 30 seconds after the reactor trip before any transfer is made.

15.3.4.3 Analysis of Effects and Consequences

This transient is analyzed by three digital computer codes. First the LOFTRAN (Reference 8) code is used to calculate the loop and core flow during the transient. The LOFTRAN code is also used to calculate the nuclear power transient. The FACTRAN (Reference 9) code is then used to calculate the heat flux transient based on the nuclear power and flow from LOFTRAN. Finally, the THINC (see Section 1.6.1, Item 28, and Section 4.4.3) code is used to calculate the minimum DNBR during the

transient based on the heat flux from FACTRAN and flow from LOFTRAN. The transients presented represent the minimum of the typical and thimble cells.

The following cases have been analyzed:

(1) Four of four loops coasting down (undervoltage).

(2) Reactor coolant pumps power supply frequency decay at a maximum constant 3 Hz/sec rate (underfrequency).

The method of analysis and the assumptions made regarding initial operating conditions and reactivity coefficients are identical to those discussed in Section 15.2, except that following the loss of supply to all pumps at power, a reactor trip is actuated by either bus undervoltage or bus underfrequency.

15.3.4.4 Results

The calculated sequence of events is shown in Table 15.3-3. Figures 15.3.4-1 through 15.3.4-3 show the flow coastdown, the heat flux coastdown, the nuclear power coastdown for the limiting complete loss of flow event, and the four-loop coastdown. The reactor is assumed to trip on the bus undervoltage signal, as this trip actuation is more DNBR limiting for the DCPP analysis than the transient initiated from underfrequency reactor trip. A plot of DNBR versus time is given in Figure 15.3.4-4. This plot represents the limiting cell for the four-loop coastdown.

15.3.4.5 Conclusions

The safety analysis results described in Section 15.3.4.4 have demonstrated that for the complete loss of forced reactor coolant flow, the minimum DNBR is above the safety analysis limit values of 1.71/1.68 (typical cell/thimble cell) during the transient; therefore, no core safety limit is violated.

15.3.5 SINGLE ROD CLUSTER CONTROL ASSEMBLY WITHDRAWAL AT FULL POWER

15.3.5.1 Acceptance Criteria

(1) No more than 5 percent of the fuel rods experience a DNBR less than the limit value.

15.3.5.2 Identification of Causes and Accident Description

By design, no single electrical or mechanical failure in the rod control system could cause the accidental withdrawal of a single RCCA from the inserted bank at full power operation. The operator could deliberately withdraw a single RCCA in the control bank; this feature is necessary in order to retrieve an assembly should one be accidentally

dropped. In the extremely unlikely event of simultaneous electrical failures that could result in single RCCA withdrawal, rod deviation and control rod urgent failure may be displayed on the plant annunciator, and the rod position indicators would indicate the relative positions of the assemblies in the bank. The urgent failure alarm also inhibits automatic rod motion in the group in which it occurs. Withdrawal of a single RCCA by operator action, whether deliberate or by a combination of errors, would result in activation of the same alarm and the same visual indications.

Each bank of RCCAs in the system is divided into two groups of four mechanisms each (except Group 2 of Bank D which consists of five mechanisms). The rods comprising a group operate in parallel through multiplexing thyristors. The two groups in a bank move sequentially such that the first group is always within one step of the second group in the bank. A definite schedule of actuation and deactuation of the stationary gripper, movable gripper, and lift coils of a mechanism is required to withdraw the RCCA attached to the mechanism. Since the four stationary grippers, movable grippers, and lift coils associated with the four RCCAs of a rod group are driven in parallel, any single failure that would cause rod withdrawal would affect a minimum of one group, or four RCCAs. Mechanical failures are either in the direction of insertion or immobility.

In the unlikely event of multiple failures that result in continuous withdrawal of a single RCCA, it is not possible, in all cases, to provide assurance of automatic reactor trip so that core safety limits are not violated. Withdrawal of a single RCCA results in both positive reactivity insertion tending to increase core power, and an increase in local power density in the core area covered by the RCCA.

15.3.5.3 Analysis of Effects and Consequences

Power distributions within the core are calculated by the ANC code based on macroscopic cross sections generated by PHOENIX-P (see Section 4.3.3). The peaking factors calculated by ANC (see Section 4.3.3) are then used by THINC (see Section 1.6.1, Item 28, and Section 4.4.3) to calculate the minimum DNBR for the event. The plant was analyzed for the case of the worst rod withdrawn from Control Bank D inserted at the insertion limit, with the reactor initially at full power.

15.3.5.4 Results

Two cases have been considered as follows:

(1) If the reactor is in the automatic control mode, withdrawal of a single RCCA will result in the immobility of the other RCCAs in the controlling bank. The transient will then proceed in the same manner as Case 2 described below. For such cases as above, a trip will ultimately ensue, although not sufficiently fast in all cases to prevent a minimum DNBR in the core of less than the safety limit.

(2) If the reactor is in the manual control mode, continuous withdrawal of a single RCCA results in both an increase in core power and coolant temperature, and an increase in the local hot channel factor in the area of the failed RCCA. In terms of the overall system response, this case is similar to those presented in Section 15.2; however, the increased local power peaking in the area of the withdrawn RCCA results in lower minimum DNBR than for the withdrawn bank cases. Depending on initial bank insertion and location of the withdrawn RCCA, automatic reactor trip may not occur sufficiently fast to prevent the minimum core DNBR from falling below the safety limit value. Evaluation of this case to determine the most limiting DNBR condition, which would occur at the power and coolant condition at which the overtemperature ΔT trip would be expected to trip the plant shows that an upper limit for the number of rods with a DNBR less than the safety limit value is 5 percent.

15.3.5.5 Conclusions

The analysis demonstrates the acceptance criterion is met as follows:

(1) For both cases of one RCCA fully withdrawn, with the reactor in either the automatic or manual control mode and initially operating at full power with Bank D at the insertion limit, 5 percent or less of the total fuel rods in the core will go below the minimum DNBR safety analysis limit.

For both cases discussed, the indicators and alarms mentioned would function to alert the operator to the malfunction before any DNB could occur. For Case 2 discussed above, the insertion limit alarms (low and low-low alarms) would also serve in this regard. However, operator action is not required to meet the acceptance criteria.

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15.4 CONDITION IV - LIMITING FAULTS

Condition IV occurrences are faults that are not expected to take place, but are postulated because their consequences would include the potential for the release of significant amounts of radioactive material. These are the most drastic occurrences that must be designed against and represent limiting design cases. Condition IV faults shall not cause a fission product release to the environment resulting in an undue risk to public health and safety in excess of guideline values of 10 CFR Part 100. A single Condition IV fault shall not cause a consequential loss of required functions of systems needed to cope with the fault including those of the emergency core cooling system (ECCS) and the containment. For the purposes of this report the following faults have been classified in this category:

(1) Major rupture of pipes containing reactor coolant up to and including double-ended rupture of the largest pipe in the reactor coolant system (RCS), i.e., loss-of-coolant-accident (LOCA)

(2) Major secondary system pipe ruptures

(3) Steam generator tube rupture

(4) Single reactor coolant pump (RCP) locked rotor

(5) Fuel handling accident

(6) Rupture of a control rod mechanism housing (rod cluster control assembly (RCCA) ejection)

(7) Rupture of a gas decay tank

(8) Rupture of a liquid holdup tank

(9) Rupture of a volume control tank

Each of these nine limiting faults is analyzed in this section. In general, each analysis includes acceptance criteria, an identification of causes and description of the accident, an analysis of effects and consequences, a presentation of results, and relevant conclusions.

The analyses of thyroid and whole body doses, resulting from events leading to fission product release, are presented in Section 15.5. The fission product inventories that form a basis for these calculations are presented in Chapter 11 and Section 15.5. Also included is a discussion of system interdependency contributing to limiting fission product leakages from the containment following a Condition IV occurrence.

The large break LOCA analysis contained in Section 15.4.1 has been revised to incorporate separate Best Estimate LOCA analyses for Units 1 and 2. The general discussion of the Best Estimate LOCA transient in Sections 15.4.1.2, 15.4.1.3, and 15.4.1.4 are applicable to Units 1 and 2. However, the statistical treatment methodologies are slightly different for Units 1 and 2. Statistical treatment methodologies for Units 1 and 2 are discussed in Sections 15.4.1.4A and 15.4.1.4B respectively.

15.4.1 MAJOR REACTOR COOLANT SYSTEM PIPE RUPTURES (LOCA)

15.4.1.1 Acceptance Criteria

15.4.1.1.1 10 CFR Part 50, Section 50.46, Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Reactors

It must be demonstrated that there is a high level of probability that the limits set forth in 10 CFR 50.46 are met. The acceptance criteria are listed below:

(1) *Peak cladding temperature*. The calculated maximum fuel element cladding temperature shall not exceed 2200 °F.

(2) *Maximum cladding oxidation*. The calculated total oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation.

(3) *Maximum hydrogen generation.* The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react.

(4) *Coolable geometry*. Calculated changes in core geometry shall be such that the core remains amenable to cooling.

(5) *Long-term cooling*. After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core.

15.4.1.1.2 Radiological Criteria

(1) The resulting potential exposures to individual members of the public and to the general population shall be lower than the applicable guidelines and limits specified in 10 CFR Part 100.

15.4.1.2 Background of Best Estimate Large Break LOCA

The analysis performed to comply with the requirements of 10 CFR 50.46 (Reference 1), and Revisions to the Acceptance Criteria (Reference 54) is presented in this section.

In 1988, the NRC Staff amended the requirements of 10 CFR 50.46 and Appendix K, "ECCS Evaluation Models," to permit the use of a realistic evaluation model to analyze the performance of the ECCS during a hypothetical LOCA. This decision was based on an improved understanding of LOCA thermal-hydraulic phenomena gained by extensive research programs. Under the amended rules, best estimate thermal-hydraulic models may be used in place of models with Appendix K features. The rule change also requires, as part of the LOCA analysis, an assessment of the uncertainty of the best estimate calculations. It further requires that this analysis uncertainty be included when comparing the results of the calculations to the prescribed acceptance criteria of 10 CFR 50.46. Further guidance for the use of best estimate codes is provided in Regulatory Guide 1.157 (Reference 55).

A LOCA evaluation methodology for three- and four-loop PWR plants based on the revised 10 CFR 50.46 rules was developed by Westinghouse with the support of EPRI and Consolidated Edison and has been approved by the NRC. The methodology is documented in WCAP-12945, "Code Qualification Document (CQD) for Best Estimate LOCA Analysis" (Reference 56).

The time sequence of events during a nominal large double-ended cold leg guillotine (DECLG) break LOCA is shown in Tables 15.41-1A and 15.4.1-1B. The results of the large break LOCA analysis are shown in Tables 15.4.1-2A and 15.4.1-2B and show compliance with the acceptance criteria. The analytical techniques used for the large break LOCA analysis are in compliance with 10 CFR 50.46 (Reference 1) as amended in Reference 54, and are described in Reference 56. Due to the significant differences between the Unit 1 and Unit 2 reactor vessel internals, plant-specific vessel models were developed and evaluated. The significant differences between the units are summarized below:

Unit 1	Unit 2
"Top Hat"-Upper Support Plate	Flat Upper Support Plate
Domed Lower Support Plate	Flat Lower Support Plate
Thermal Shield	Neutron Pads
Diffuser Plate	No Diffuser Plate

An analysis of each unit was performed and a comparison determined that the Unit 1 vessel model resulted in more limiting PCT values. As a result, the Best Estimate base Large Break LOCA analysis (Reference 60) results were based on Unit 1 and were considered bounding for both Unit 1 and Unit 2. Recently, the Unit 1 Best Estimate LOCA was reanalyzed for Unit 1 using the approved reanalysis methodology established in Reference 56. In the process of performing the Unit 1 reanalysis

(Reference 67), it was determined that the Unit 1 vessel model no longer consistently resulted in the limiting PCTs, and could not be considered bounding for Unit 2. Therefore, the reanalysis methodology (Reference 56) was only applied to Unit 1, and a new and separate Best Estimate Large Break LOCA analysis was performed for Unit 2 using an updated and slightly different methodology as described in Reference 69. Both Unit 1 and Unit 2 use the base Best Estimate Large Break LOCA analysis methodology and computer code as described in Reference 60 and described in Section 15.4.1.2, which is applicable to Units 1 and 2. Separate subsequent subsections describe the Unit 1 reanalysis methodology (Reference 67) and the Unit 2 analysis methodology, and the respective results.

15.4.1.3 WCOBRA/TRAC Thermal-hydraulic Computer Code

The thermal-hydraulic computer code that was reviewed and approved for the calculation of fluid and thermal conditions in the PWR during a large break LOCA is WCOBRA/TRAC, Version Mod 7A, Revision 1 (Reference 56). A detailed assessment of the computer code WCOBRA/TRAC was made through comparisons to experimental data. These assessments were used to develop quantitative estimates of the code's ability to predict key physical phenomena in the PWR large break LOCA. Slightly different revisions to this computer code were used for the Unit 1 reanalysis and the separate Unit 2 analysis as described in later sections.

WCOBRA/TRAC combines two-fluid, three-field, multi-dimensional fluid equations used in the vessel with one-dimensional drift-flux equations used in the loops to allow a complete and detailed simulation of a PWR. This best estimate computer code contains the following features:

(1) Ability to model transient three-dimensional flows in different geometries inside the vessel

(2) Ability to model thermal and mechanical non-equilibrium between phases

(3) Ability to mechanistically represent interfacial heat, mass, and momentum transfer in different flow regimes

(4) Ability to represent important reactor components such as fuel rods, steam generators, reactor coolant pumps, etc.

The two-fluid formulation uses a separate set of conservation equations and constitutive relations for each phase. The effects of one phase on another are accounted for by interfacial friction and heat and mass transfer interaction terms in the equations. The conservation equations have the same form for each phase; only the constitutive relations and physical properties differ. Dividing the liquid phase into two fields is a convenient and physically accurate way of handling flows where the liquid can appear in both film and droplet form. The droplet field permits more accurate modeling of

thermal-hydraulic phenomena, such as entrainment, de-entrainment, fallback, liquid pooling, and flooding.

WCOBRA/TRAC also features a two-phase, one-dimensional hydrodynamics formulation. In this model, the effect of phase slip is modeled indirectly via a constitutive relationship that provides the phase relative velocity as a function of fluid conditions. Separate mass and energy conservation equations exist for the two-phase mixture and for the vapor.

The reactor vessel is modeled with the three-dimensional, three field model, while the loop, major loop components, and safety injection points are modeled with the one-dimensional model.

All geometries modeled using the three-dimensional model are represented as a matrix of cells. The number of mesh cells used depends on the degree of detail required to resolve the flow field, the phenomena being modeled, and practical restrictions such as computing costs and core storage limitations.

The equations for the flow field in the three-dimensional model are solved using a staggered difference scheme on the Eulerian mesh. The velocities are obtained at mesh cell faces, and the state variables (e.g., pressure, density, enthalpy, and phasic volume fractions) are obtained at the cell center. This cell is the control volume for the scalar continuity and energy equations. The momentum equations are solved on a staggered mesh with the momentum cell centered on the scalar cell face.

The basic building block for the mesh is the channel, a vertical stack of single mesh cells. Several channels can be connected together by gaps to model a region of the reactor vessel. Regions that occupy the same level form a section of the vessel. Vessel sections are connected axially to complete the vessel mesh by specifying channel connections between sections. Heat transfer surfaces and solid structures that interact significantly with the fluid can be modeled with rods and unheated conductors. One-dimensional components are connected to the vessel. The basic scheme used also employs the staggered mesh cell. Special purpose components exist to model specific components such as the steam generator and pump.

A typical calculation using WCOBRA/TRAC begins with the establishment of a steady-state, initial condition with all loops intact. The input parameters and initial conditions for this steady-state calculation are discussed in the next section.

Following the establishment of an acceptable steady-state condition, the transient calculation is initiated by introducing a break into one of the loops. The evolution of the transient through blowdown, refill, and reflood proceeds continuously, using the same computer code (WCOBRA/TRAC) and the same modeling assumptions. Containment pressure is modeled with the BREAK component using a time dependent pressure table. Containment pressure is calculated using the COCO code (Reference 61) and mass and energy releases from the WCOBRA/TRAC calculation.

15.4.1.4 Thermal Analysis

15.4.1.4.1 Westinghouse Performance Criteria for ECCS

The reactor is designed to withstand thermal effects caused by a LOCA including the double-ended severance of the largest RCS pipe. The reactor core and internals together with the ECCS are designed so that the reactor can be safely shut down and the essential heat transfer geometry of the core preserved following the accident.

The ECCS, even when operating during the injection mode with the most severe single active failure, is designed to meet the acceptance criteria of 10 CFR 50.46.

15.4.1.4.2 Sequence of Events and Systems Operations

The sequence of events following a nominal large DECLG break LOCA is presented in Tables 15.4.1-1A and 15.4.1-1B for Units 1 and 2, respectively. Should a major break occur, depressurization of the RCS results in a pressure decrease in the pressurizer. The reactor trip signal subsequently occurs when the pressurizer low pressure trip setpoint is reached. A safety injection signal is generated when the appropriate setpoint is reached. These countermeasures will limit the consequences of the accident in two ways:

(1) Reactor trip and borated water injection complement void formation in causing rapid reduction of power to a residual level corresponding to fission product decay heat. No credit is taken during the LOCA transient for negative reactivity due to the boron concentration of the injection water. However, an average RCS/sump mixed boron concentration is calculated to ensure that the post-LOCA core remains subcritical. In addition, the insertion of control rods to shut down the reactor is not assumed in the large break analysis.

(2) Injection of borated water provides the fluid medium for heat transfer from the core and prevents excessive cladding temperatures.

For the present Westinghouse PWR design, the limiting single failure assumed for a large break LOCA is the loss of one train of ECCS pumps (one charging pump (CCP1 or CCP2), one high-head safety injection (SI) pump, and one residual heat removal pump). One ECCS train delivers flow through the injection lines to each loop, with the least resistant branch injection line spilling to containment backpressure (Figures 15.4.1-14A and 15.4.1-14B and Tables 15.4.1-7A and 15.4.1-7B). All emergency diesel generators (EDGs) are assumed to start in the modeling of the containment fan coolers and spray pumps. Modeling full operation of the containment heat removal system is required by Branch Technical Position CSB 6-1, and is a conservative assumption for the large break LOCA analysis.

15.4.1.4.3 Description of a Large Break LOCA Transient

Before the break occurs, the RCS is assumed to be operating normally at full power in an equilibrium condition, i.e., the heat generated in the core is being removed via the secondary system. A large DECLG break is assumed to open almost instantaneously in one of the main RCS pipes. Calculations have demonstrated that the most severe transient results occur for a DECLG break between the pump and the reactor vessel.

The large break LOCA transient can be divided into convenient time periods in which specific phenomena occur, such as various hot assembly heatup and cooldown transients. For a typical large break, the blowdown period can be divided into the critical heat flux (CHF) phase, the upward core flow phase, and the downward core flow phase. These are followed by the refill, reflood, and long-term cooling periods. Specific important transient phenomena and heat transfer regimes are discussed below, with the transient results shown in Figures 15.4.1-1A to 15.4.1-12A for Unit 1 and Figures 15.4.1-1B to 15.4.1-12B for Unit 2.

(1) Critical Heat Flux (CHF) Phase

Immediately following the cold leg rupture, the break discharge rate is subcooled and high. The regions of the RCS with the highest initial temperatures (core, upper plenum, upper head, and hot legs) begin to flash to steam, the core flow reverses, and the fuel rods begin to go through departure from nucleate boiling (DNB). The fuel cladding rapidly heats up while the core power shuts down due to voiding in the core. This phase is terminated when the water in the lower plenum and downcomer begins to flash. The mixture swells and intact loop pumps, still rotating in single-phase liquid, push this two-phase mixture into the core.

(2) Upward Core Flow Phase

Heat transfer is improved as the two-phase mixture is pushed into the core. This phase may be enhanced if the pumps are not degraded, or if the break discharge rate is low due to saturated fluid conditions at the break. If pump degradation is high or the break flow is large, the cooling effect due to upward flow may not be significant. Figures 15.4.1-4A and 15.4.1-4B show the void fraction for one intact loop pump and the broken loop pump for Units 1 and 2, respectively. The figures show that the intact loop remains in single-phase liquid flow for several seconds, resulting in enhanced upward core flow cooling. This phase ends as the lower plenum mass is depleted, the loop flow becomes two-phase, and the pump head degrades.

(3) Downward Core Flow Phase

The loop flow is pushed into the vessel by the intact loop pumps and decreases as the pump flow becomes two-phase. The break flow begins to dominate and pulls flow down through the core, up the downcomer to the broken loop cold leg, and out the break. While liquid and entrained liquid flow provide core cooling, the top of core vapor flow, as shown in Figures 15.4.1-5A and 15.4.1-5B for Units 1 and 2, respectively, best illustrate this phase of core cooling. Once the system has depressurized to the accumulator pressure, the accumulators begin to inject cold borated water into the intact cold legs. During this period, due to steam upflow in the downcomer, a portion of the injected ECCS water is calculated to be bypassed around the downcomer and out the break. As the system pressure continues to fall, the break flow, and consequently the downward core flow, are reduced. The core begins to heat up as the system pressure approaches the containment pressure and the vessel begins to fill with ECCS water.

(4) Refill Period

As the refill period begins, the core begins a period of heatup and the vessel begins to fill with ECCS water. This period is characterized by a rapid increase in cladding temperatures at all elevations due to the lack of liquid and steam flow in the core region. This period continues until the lower plenum is filled and the bottom of the core begins to reflood and entrainment begins.

(5) Reflood Period

During the early reflood phase, the accumulators begin to empty and nitrogen enters the system. This forces water into the core, which then boils, causing system repressurization, and the lower core region begins to quench. During this time, core cooling may increase due to vapor generation and liquid entrainment. During the reflood period, the core flow is oscillatory as cold water periodically rewets and quenches the hot fuel cladding, which generates steam and causes system repressurization. The steam and entrained water must pass through the vessel upper plenum, the hot legs, the steam generators, and the reactor coolant pumps before it is vented out the break. This flow path resistance is overcome by the downcomer water elevation head, which provides the gravity driven reflood force. From the later stage of blowdown to the beginning of reflood, the accumulators rapidly discharge borated cooling water into the RCS, filling the lower plenum and contributing to the filling of the downcomer. The pumped ECCS water aids in the filling of the downcomer and subsequently supplies water to maintain a full downcomer and complete the reflood period. As the quench front progresses up the

core, the PCT location moves higher into the top core region. As the vessel continues to fill, the PCT location is cooled and the early reflood period is terminated.

A second cladding heatup transient may occur due to boiling in the downcomer. The mixing of ECCS water with hot water and steam from the core, in addition to the continued heat transfer from the hot vessel and vessel metal, reduces the subcooling of ECCS water in the lower plenum and downcomer. The saturation temperature is dictated by the containment pressure. If the liquid temperature in the downcomer reaches saturation, subsequent heat transfer from the vessel and other structures will cause boiling and level swell in the downcomer. The downcomer liquid will spill out of the broken cold leg and reduce the driving head, which can reduce the reflood rate, causing a late reflood heatup at the upper core elevations. Figures 15.4.1-12A and 15.4.1-12B show only a slight reduction in downcomer level which indicates that a late reflood heatup does not occur for either Unit. However, the Unit 1 reanalysis methodology (Reference 67) still requires that both the early and late reflood PCT periods be considered, while the Unit 2 updated analysis methodology (Reference 69) has eliminated the need to evaluate the late reflood period for PCT. For the Unit 1 reanalysis, the first reflood peak is considered to be the maximum PCT, which occurs after the beginning of reflood, and before the beginning of gravity driven reflood. In Unit 1 Figure 15.4.1-1A, this corresponds to the maximum PCT between about 35 and 50 seconds after the break. The second reflood peak is then considered to be the maximum PCT, which occurs after the beginning of gravity driven reflood. This terminology for first and second reflood PCTs is only used in the further discussions of the Unit 1 Best Estimate LBLOCA reanalysis.

Continued operation of the ECCS pumps supplies water during the long-term cooling period. Core temperatures have been reduced to long-term steady state levels associated with dissipation of residual heat generation. When low level is reached in the refueling water storage tank (RWST), switchover to the recirculation phase is initiated. The residual heat removal (RHR) pumps are tripped, and the operator manually aligns the charging (CCP1 or CCP2) and safety injection (SI) pumps to the RHR pump discharge. Once the alignment is completed, all ECCS pumps recirculate containment recirculation sump water. The containment spray pumps continue to draw suction from the RWST until the low-low level is reached, at which time the containment spray pumps are tripped. If two RHR pumps are running, the containment spray valves can be aligned so that an RHR pump can be utilized to deliver recirculation water to the containment spray ring headers and spray nozzles for continued containment spray system post-accident operation.

Approximately 7.0 hours after initiation of the LOCA, the ECCS is realigned to supply water to the RCS hot legs in order to control the boric acid concentration in the reactor

vessel. Long-term cooling also includes long-term criticality control. To achieve long-term criticality control, a mixed-mean sump boron concentration is determined and verified against core design margins to ensure core subcriticality, without credit for RCCA insertion. A mixed-mean sump boron concentration is calculated based on minimum volumes for boron sources and maximum volumes for dilution sources. The calculated mixed-mean sump boron concentration is verified against available core design margins on a cycle-specific basis.

15.4.1.4A Unit 1 Best Estimate Large Break LOCA Evaluation Model

The thermal-hydraulic computer code that was reviewed and approved for the calculation of fluid and thermal conditions in the PWR during a large break LOCA is WCOBRA/TRAC, Version MOD7A Rev. 1 (Reference 56). Modeling of the PWR introduces additional uncertainties that are identified and quantified for the plant-specific Unit 1 analysis (Reference 60). The final step of the best estimate analysis methodology is to combine all the uncertainties related to the code and plant parameters, and estimate the PCT at 95 percent probability. The steps taken to derive the PCT uncertainty estimate are summarized below

(1) Plant Model Development

In this step, a WCOBRA/TRAC model of the plant is developed. A high level of noding detail is used in order to provide an accurate simulation of the transient. However, specific guidelines are followed to ensure that the model is consistent with models used in the code validation. This results in a high level of consistency among plant models, except for specific areas dictated by hardware differences, such as in the upper plenum of the reactor vessel or the ECCS injection configuration.

(2) Determination of Plant Operating Conditions

In this step, the expected or desired operating range of the plant to which the analysis applies is established. The parameters considered are based on a “key LOCA parameters” list that was developed as part of the methodology. A set of these parameters, at mostly nominal values, is chosen for input as initial conditions to the plant model. A transient is run utilizing these parameters and is known as the “initial transient.” Next, several confirmatory runs are made, which vary a subset of the key LOCA parameters over their expected operating range in one-at-a-time sensitivities. The most limiting input conditions, based on these confirmatory runs, are then combined into a single transient, which is then called the “reference transient.”

(3) PWR Sensitivity Calculations

A series of PWR transients is performed in which the initial fluid conditions and boundary conditions are ranged around the nominal condition used in the reference transient. The results of these calculations for DCPP form the basis for the determination of the initial condition bias and uncertainty discussed in Section 6 of Reference 60.

Next, a series of transients is performed that vary the power distribution, taking into account all possible power distributions during normal plant operation. The results of these calculations for DCPP form the basis for the determination of the power distribution bias and uncertainty discussed in Section 7 of Reference 60.

Finally, a series of transients is performed that vary parameters that affect the overall system response (“global” parameters) and local fuel rod response (“local” parameters). The results of these calculations for DCPP form the basis for the determination of the model bias and uncertainty discussed in Section 8 of Reference 60.

(4) Response Surface Calculations

Regression analyses are performed to derive PCT response surfaces from the results of the power distribution run matrix and the global model run matrix. The results of the initial conditions run matrix are used to generate a PCT uncertainty distribution.

(5) Uncertainty Evaluation

The total PCT uncertainty from the initial conditions, power distribution, and model calculations is derived using the approved methodology (Reference 56). The uncertainty calculations assume certain plant operating ranges that may be varied depending on the results obtained. These uncertainties are then combined to determine the initial estimate of the total PCT uncertainty distribution for the DECLG and split breaks. The results of these initial estimates of the total PCT uncertainty are compared to determine the limiting break type. If the split break is limiting, an additional set of split transients is performed that vary overall system response (“global” parameters) and local fuel rod response (“local” parameters). Finally, an additional series of runs is made to quantify the bias and uncertainty due to assuming that the above three uncertainty categories are independent. The final PCT uncertainty distribution is then calculated for the limiting break type, and the 95th percentile PCT is determined.

(6) Plant Operating Range

The plant operating range over which the uncertainty evaluation applies is defined. Depending on the results obtained in the above uncertainty evaluation, this range may be the desired range established in step 2, or may be narrower for some parameters to gain additional margin.

There are three major uncertainty categories or elements:

(1) Initial condition bias and uncertainty

(2) Power distribution bias and uncertainty

(3) Model bias and uncertainty

Conceptually, these elements may be assumed to affect the reference transient PCT as shown below.

$$PCT_i = PCT_{REFi} + \Delta PCT_{ICi} + \Delta PCT_{PDi} + \Delta PCT_{MODi} \qquad (15.4.1\text{-}1)$$

where,

PCT_{REFi} = Reference transient PCT: The reference transient PCT is calculated using WCOBRA/TRAC at the nominal conditions identified in Table 15.4.1-3A, for blowdown (i=1), first reflood (i=2), and second reflood (i=3).

ΔPCT_{ICi} = Initial condition bias and uncertainty: This bias is the difference between the reference transient PCT, which assumes several nominal or average initial conditions, and the average PCT taking into account all possible values of the initial conditions. This bias takes into account plant variations that have a relatively small effect on PCT. The elements that make up this bias and its uncertainty are plant specific.

ΔPCT_{PDi} = Power distribution bias and uncertainty: This bias is the difference between the reference transient PCT, which assumes a nominal power distribution, and the average PCT taking into account all possible power distributions during normal plant operation. Elements that contribute to the uncertainty of this bias are calculational uncertainties, and variations due to transient operation of the reactor.

ΔPCT_{MODi} = Model bias and uncertainty: This component accounts for uncertainties in the ability of the WCOBRA/TRAC code to accurately predict important phenomena that affect the overall system

response (“global” parameters) and the local fuel rod response (“local” parameters). The code and model bias is the difference between the reference transient PCT, which assumes nominal values for the global and local parameters, and the average PCT taking into account all possible values of global and local parameters.

The separability of the uncertainty components in the manner described above is an approximation since the parameters in each element may be affected by parameters in other elements. The bias and uncertainty associated with this assumption are quantified as part of the overall uncertainty methodology and included in the final estimates of the 95-percentile PCT ($PCT^{95\%}$).

The application of the reanalysis methodology to Unit 1 first determines a new reference transient PCT. The bias and uncertainty associated with the initial conditions, power distributions, and models are assumed to remain unchanged. This assumption is assessed to determine that the fundamental LOCA transient characteristics remain unchanged from the new reference transient to that of the original analysis. If applicable, the uncertainty in applying the reanalysis methodology is determined when the superposition assumption is requantified (i.e., the assumption that the major uncertainty elements are independent), and the new bias and new uncertainty is calculated.

15.4.1.5A Unit 1 Containment Backpressure

A conservatively bounding minimum containment back pressure (Figure 15.4.1-14A) is calculated using the methods and assumptions described in Reference 2, Appendix A. Containment back pressure is calculated using the COCO code (Reference 61) and mass and energy releases from the WCOBRA/TRAC calculation. Input parameters used for the Unit 1 containment backpressure calculation are presented in Table 15.4.1-5A. This minimum containment back pressure is modeled using a time dependent pressure table as a boundary condition for the Best Estimate Large Break LOCA analysis.

15.4.1.6A Unit 1 Reference Transient Description

A series of WCOBRA/TRAC calculations is performed to determine the PCT effect of variations in key LOCA parameters. An initial transient calculation is performed in which several parameters are set at their assumed bounding (most limiting) values in order to calculate a conservative PCT response to a large break LOCA. The results of these confirmatory runs, as well as the limiting plant determination runs, are incorporated into a final calculation that is referred to as the reference transient. The Unit 1 reference transient models a DECLG break that assumed the conditions listed in Table 15.4.1-3A and includes the Loss of Offsite Power (LOOP) assumption that was shown to produce more limiting PCT results than the offsite power available assumption. The reference transient calculation was performed with several parameters set at their bounding

values in order to calculate a relatively high PCT. Single parameter variation studies based on the reference transient were performed to assess which parameters have a significant effect on the PCT results. The results of these studies are presented in Section 15.4.1.7A. The reference transient is the basis for the uncertainty calculations necessary to establish the Unit 1 $PCT^{95\%}$.

15.4.1.7A Unit 1 Sensitivity Studies

A large number of single parameter sensitivity calculations of key LOCA parameters was performed to determine the PCT effect on the LBLOCA transient. These calculations are required as part of the approved Best Estimate LOCA methodology (Reference 56) to develop data for use in the uncertainty evaluation. For each sensitivity study, a comparison between the reference transient results and the sensitivity transient results was made. These single parameter sensitivity calculations were determined to remain applicable for the Unit 1 reanalysis methodology, as applied (Reference 67).

The results of a small sample of these sensitivity studies performed for the original analysis (Reference 60) are summarized in Table 15.4.1-4A. The results of the entire array of sensitivity studies are included in Reference 60. The Unit 1 reanalysis is documented in Reference 67. The conclusions of the confirmatory cases were determined to remain the same (i.e., limiting direction of conservatism).

15.4.1.7A.1 Unit 1 Initial Condition Sensitivity Studies

Several calculations were performed to evaluate the PCT effect of changes in the initial conditions on the LBLOCA transient. These calculations modeled single parameter variations in key initial plant conditions over the expected ranges of operation, including T_{AVG}, RCS pressure, and ECCS temperatures, pressures, and volumes. The results of these studies are presented in Section 6 of Reference 60.

The results of these sensitivity studies were used to develop uncertainty distributions for the blowdown, first, and second reflood peaks. The uncertainty distributions resulting from the initial conditions, ΔPCT_{ICi}, are used in the overall PCT uncertainty evaluation to determine the final estimate of $PCT^{95\%}$.

15.4.1.7A.2 Unit 1 Power Distribution Sensitivity Studies

Several calculations were performed to evaluate the PCT effect of changes in power distributions on the LBLOCA transient. The approved methodology was used to develop a run matrix of peak linear heat rate relative to the core average, maximum relative rod power, relative power in the bottom third of the core, and relative power in the middle third of the core, as the power distribution parameters to be considered. These calculations modeled single parameter variations as well as multiple parameter variations. The results of these studies indicate that power distributions with peak

powers skewed to the top of the core produced the most limiting PCTs. These results are presented in Section 7 of Reference 60.

The results of these sensitivity studies were used to develop response surfaces, which are used to predict the ΔPCT due to changes in power distributions for the blowdown, first, and second reflood peaks. The uncertainty distributions resulting from the power distributions, ΔPCT_{PDi}, are used in the overall PCT uncertainty evaluation to determine the final estimate of $PCT^{95\%}$.

15.4.1.7A.3 Unit 1 Global Model Sensitivity Studies

Several calculations were performed to evaluate the PCT effect of changes in global models on the LBLOCA transient. Reference 56 provides a run matrix of break discharge coefficient, broken cold leg resistance, and condensation rate as the global models to be considered for the double-ended guillotine break. These calculations modeled single parameter variations as well as multiple parameter variations. The limiting split break size was also identified using the approved methodology (Reference 56). These results are presented in Section 8 of Reference 60.

The results of these sensitivity studies were used to develop response surfaces, which are used to predict the ΔPCT due to changes in global models for the DECLG blowdown, first, and second reflood peaks. The uncertainty distribution resulting from the global models, ΔPCT_{MODi}, is used in the overall PCT uncertainty evaluation to determine the final estimate of $PCT^{95\%}$.

These single parameter sensitivity calculations were determined to remain applicable for the Unit 1 reanalysis methodology, as applied (Reference 67).

15.4.1.7A.4 Unit 1 Overall PCT Uncertainty Evaluation and Results

The equation used to initially estimate the 95 percentile PCT (PCT_i of Equation 15.4.1-1) was presented in Section 15.4.1.4A. Each of the uncertainty elements (ΔPCT_{ICi}, ΔPCT_{PDi}, ΔPCT_{MODi}) is considered to be independent of each other. Each element includes a correction or bias, which is added to PCT_{REFi} to move it closer to the expected, or average, PCT. The bias from each element has an uncertainty associated with the methods used to derive the bias.

Each bias component of the uncertainty elements is considered a random variable, whose uncertainty distribution is obtained directly, or is obtained from the uncertainty of the parameters of which the bias is a function. Since PCTi is the sum of these biases, it also becomes a random variable. Separate initial PCT frequency distributions are constructed as follows for the DECLG break and the limiting split break:

(1) Generate a random value of each uncertainty element (ΔPCT_{IC}, ΔPCT_{PD}, ΔPCT_{MOD})

(2) Calculate the resulting PCT using Equation 15.4.1-1

(3) Repeat the process many times to generate a histogram of PCTs

The results of this assessment showed the DECLG break to be the limiting break type.

A final verification step is performed to quantify the bias and uncertainty resulting from the superposition assumption (i.e., the assumption that the major uncertainty elements are independent). Several additional WCOBRA/TRAC calculations are performed in which variations in parameters from each of the three uncertainty elements are modeled for the DECLG break. These predictions are compared to the predictions based on Equation 15.4.1-1, and additional biases and uncertainties are applied where appropriate.

The superposition assumption verification step was performed for the Unit 1 reanalysis (Reference 67). These calculations resulted in an adjustment of the bias and uncertainty that is required for the reanalysis methodology.

The estimate of the PCT at 95 percent probability is determined by finding that PCT below which 95 percent of the calculated PCTs reside. This estimate is the licensing basis PCT, under the revised ECCS rule (10 CFR 50.46). The results of the Best Estimate LBLOCA analysis are presented in Table 15.4.1-2A. The difference between the 95 percentile PCT and the average PCT increases with each subsequent PCT period, due to propagation of uncertainties.

15.4.1.8A Unit 1 Additional Evaluations

Zircaloy Clad Fuel: An evaluation of Zircaloy clad fuel has shown that the Zircaloy clad fuel is bounded by the results of ZIRLO clad fuel analysis.

IFBA Fuel: An evaluation of IFBA fuel has shown that the IFBA fuel is bounded by the results of the non-IFBA fuel analysis.

T_{AVG} Coastdown: An end-of-cycle, full power T_{AVG} coastdown at 565°F evaluation was performed and concluded that there would be no adverse effect on the Best Estimate LBLOCA analysis as a T_{AVG} window between 565°F and 577.3°F was explicitly modeled in the Best Estimate LBLOCA analysis.

These evaluations have been shown to continue to apply for the Unit 1 reanalysis (Reference 67).

15.4.1.9A Unit 1 10 CFR 50.46 Results

It must be demonstrated that there is a high level of probability that the limits set forth in 10 CFR 50.46 are met. The demonstration that these limits are met is as follows:

(1) There is a high level of probability that the PCT shall not exceed 2200°F. The 95th percentile PCT results presented in Table 15.4.1-2A indicate that this regulatory limit has been met.

(2) The local maximum oxidation (LMO) calculated in the original BELOCA analysis results (Reference 60) is based on a limiting PCT transient that is in excess of the Unit 1 reanalysis 95 percentile PCT and remains bounding for Unit 1. Based on this original conservative PCT transient, a LMO of 11 percent was calculated, which meets the 10 CFR 50.46 acceptance criterion (b)(2), i.e., “Local Maximum Oxidation of the cladding less than 17 percent,” remains bounding for Unit 1, and is presented as an upper bound in Table 15.4.1-2A.

(3) The maximum core wide oxidation (CWO) determined in the original BELOCA analysis results (Reference 60) was based on limiting fuel temperatures that exceed those in the Unit 1 reanalysis and remain bounding for Unit 1. Based on these original conservative fuel temperatures, the total amount of hydrogen generated (i.e., CWO) , is 0.0089 times (0.89 percent) the maximum theoretical amount, which meets the 10 CFR 50.46 acceptance criterion (b)(3), i.e., “Core-Wide Oxidation less than 1 percent,” remains bounding for Unit 1, and is presented as an upper bound in Table 15.4.1-2A.

(4) Criterion (b)(4) has historically been satisfied by adherence to criteria (b)(1) and (b)(2), and by assuring that fuel deformation due to combined LOCA and seismic loads is specifically addressed. The approved methodology (Reference 56) specifies that effects of LOCA and seismic loads on core geometry do not need to be considered unless grid crushing extends beyond the assemblies in the low-power channel as defined in the DCPP WCOBRA/TRAC model. This situation has not been calculated to occur for DCPP Unit 1. Therefore, acceptance criterion (b)(4) is satisfied.

(5) The approved Westinghouse position on criterion (b)(5) is that this requirement is satisfied if a coolable geometry is maintained, and the core remains subcritical following the LOCA (Reference 56). This position is independent from and unaffected by the use of best-estimate LOCA methodology.

15.4.1.10A Unit 1 Plant Operating Range

The expected PCT and associated uncertainty presented above for Unit 1 are valid for a range of plant operating conditions. Many parameters in the reference transient calculation are at nominal values. The range of variation of the operating parameters has been accounted for in the estimated PCT uncertainty. Table 15.4.1-7A summarizes the operating ranges for Unit 1. Note that Figure 15.4.1-15A illustrates the axial power distribution limits that were analyzed and are verified on a cycle-specific basis. Table 15.4.1-5A summarizes the LBLOCA containment data used for calculating containment back pressure. If plant operation is maintained within the plant operating ranges presented in Table 15.4.1-7A, the LOCA analyses presented in this section are considered to be valid.

15.4.1.4B Unit 2 Best Estimate Large Break LOCA Evaluation Model

The thermal-hydraulic computer code, which was reviewed and approved for the calculation of fluid and thermal conditions in a PWR during a large break LOCA, is WCOBRA/TRAC Version MOD7A, Rev. 1 (Reference 56). Westinghouse has since developed an alternative uncertainty methodology called ASTRUM, which stands for Automated Statistical Treatment of Uncertainty Method (Reference 69). This method is still based on the "Code Qualification Document" (CQD) methodology (Reference 56). The ASTRUM methodology replaces the response surface technique with a statistical sampling method where the uncertainty parameters are simultaneously sampled for each case. The ASTRUM methodology has received NRC approval for referencing in licensing calculations (SER appended to Reference 69). The WCOBRA/TRAC MOD7A, Revision 6, is an evolution of Revision 1 that includes logic to facilitate the automation aspects of ASTRUM, user conveniences, and error corrections. WCOBRA/TRAC MOD7A, Revision 6, is documented in Reference 69.

A detailed assessment of the computer code WCOBRA/TRAC was made through comparisons with experimental data. These assessments were used to develop quantitative estimates of the code's ability to predict key physical phenomena in a PWR large break LOCA. Modeling of a PWR introduces additional uncertainties that are identified and quantified in the plant-specific analysis.

The final step in application of the best-estimate methodology for Unit 2, in which all uncertainties of the LOCA parameters are accounted for to estimate a PCT, local maximum oxidation (LMO), and core-wide oxidation (CWO) at 95-percent probability, is described below.

(1) Plant Model Development

In this step, a WCOBRA/TRAC model of the plant is developed. A high level of noding detail is used in order to provide an accurate simulation of the transient. However, specific guidelines are followed to ensure that the model is consistent with models used in the code validation. This results

in a high level of consistency among plant models, except for specific areas dictated by hardware differences, such as in the upper plenum of the reactor vessel or the ECCS injection configuration.

(2) Determination of Plant Operating Conditions

In this step, the expected or desired operating range of the plant to which the analysis applies is established. The parameters considered are based on a "key LOCA parameters" list that was developed as part of the methodology. A set of these parameters, at mostly nominal values, is chosen for input as initial conditions to the plant model. A transient is run utilizing these parameters and is known as the "initial transient." Next, several confirmatory runs are made, which vary a subset of the key LOCA parameters over their expected operating range in one-at-a-time sensitivities. Because certain parameters are not included in the uncertainty analysis, these parameters are set at their bounding condition. This analysis is commonly referred to as the confirmatory analysis. The most limiting input conditions, based on these confirmatory runs, are then combined into the model that will represent the limiting state for the plant, which is the starting point for the assessment of uncertainties.

(3) Assessment of Uncertainty

The ASTRUM methodology is based on order statistics. The technical basis of the order statistics is described in Section 11 of Reference 69. The determination of the PCT uncertainty, LMO uncertainty, and CWO uncertainty relies on a statistical sampling technique. According to the statistical theory, 124 WCOBRA/TRAC calculations are necessary to assess against the three 10 CFR 50.46 criteria (PCT, LMO, CWO). The uncertainty contributors are sampled randomly from their respective distributions for each of the WCOBRA/TRAC calculations. The list of uncertainty parameters, which are randomly sampled for each time in the cycle, break type (split or double-ended guillotine), and break size for the split break are also sampled as uncertainty contributors within the ASTRUM methodology.

Results from the 124 calculations are tallied by ranking the PCT from highest to lowest. A similar procedure is repeated for LMO and CWO. The highest rank of PCT, LMO, and CWO will bound 95 percent of their respective populations with 95-percent confidence level.

(4) Plant Operating Range

The plant operating range over which the uncertainty evaluation applies is defined. Depending on the results obtained in the above uncertainty evaluation, this range may be the desired range or may be narrower for some parameters to gain additional margin.

15.4.1.5B Unit 2 Containment Backpressure

A conservatively bounding minimum containment back pressure (Figure 15.4.1-14B) is calculated using the methods and assumptions described in Reference 2, Appendix A. Containment back pressure is calculated using the COCO code (Reference 61), the input parameters presented in Table 15.4.1-5B, mass and energy releases from the WCOBRA/TRAC calculation, and the structural heat sinks presented in Table 15.4.1-5A. Input parameters used for the Unit 2 containment backpressure calculation are presented in Table 15.4.1-5B. This minimum containment back pressure is modeled using a time dependent pressure table as a boundary condition for the Best Estimate Large Break LOCA analysis.

15.4.1.6B Unit 2 Confirmatory Studies

A few confirmatory studies were performed to establish the limiting conditions for the uncertainty evaluation. In the confirmatory studies performed, key LOCA parameters are varied over a range and the impact on the peak cladding temperature is assessed.

The results for the confirmatory studies are summarized in Table 15.4.1-4B. In summary, the limiting conditions for the plant at the time the design basis accident is postulated to occur are reflected in the final reference transient. These limiting conditions are:

(1) Loss of offsite power

(2) High RCS average temperature

(3) High steam generator tube plugging of 15 percent

(4) High average power fraction in the assemblies on the core periphery (fraction of power in outer assemblies = 0.8)

15.4.1.7B Unit 2 Uncertainty Evaluation

The ASTRUM methodology (Reference 69) differs from the previously approved Westinghouse Best-Estimate methodology (Reference 56) primarily in the statistical technique used to make a singular probabilistic statement with regard to the conformance of the system under analysis to the regulatory requirement of 10 CFR 50.46.

The ASTRUM methodology applies a non-parametric statistical technique to generate output e.g., PCT, LMO, and CWO from a combination of WCOBRA/TRAC and HOTSPOT (Reference 68) calculations. These calculations are performed by applying a direct, random Monte Carlo sampling to generate the input for the WCOBRA/TRAC and HOTSPOT computer codes.

This approach allows the formulation of a simple singular statement of uncertainty in the form of a tolerance interval for the numerical acceptance criteria of 10 CFR 50.46. Based on the non-parametric statistical approach, the number of Monte Carlo runs is only a function of the tolerance interval and associated confidence level required to meet the desired level of safety.

15.4.1.8B Unit 2 Limiting PCT Transient Description

The DCPP Unit 2 PCT-limiting transient is a DECLG break which analyzes conditions that fall within those listed in Table 15.4.1-7B. The sequence of events following is presented in Table 15.4.1-1B. The PCT-limiting case was chosen to show a conservative representation of the response to a large break LOCA.

15.4.1.9B Unit 2 10 CFR 50.46 Results

It must be demonstrated that there is a high level of probability that the limits set forth in 10 CFR 50.46 are met. The demonstration that these limits are met is as follows:

(1) Because the resulting PCT for the limiting case is 1872 °F, which represents a bounding estimate of the 95th percentile PCT at the 95-percent confidence level, the analysis confirms that 10 CFR 50.46 acceptance criterion (b)(1), i.e., “Peak Cladding Temperature less than 2200 °F”, is met. The results are shown in Table 15.4.1-2B.

(2) Because the resulting local maximum oxidation (LMO) for the limiting case is 1.64 percent, which represents a bounding estimate of the 95th percentile LMO at the 95-percent confidence level, the analysis confirms that 10 CFR 50.46 acceptance criterion (b)(2), i.e., “Local Maximum Oxidation of the cladding less than 17 percent,” is met. The results are shown in Table 15.4.1-2B.

(3) The limiting hot fuel assembly rod has a calculated maximum oxidation of 0.17 percent. Because this is the hottest fuel rod within the core, the calculated maximum oxidation for any other fuel rod would be less than this value. For the low power peripheral fuel assemblies, the calculated oxidation would be significantly less than this maximum value. The core wide oxidation (CWO) is essentially the sum of all calculated maximum oxidation values for all of the fuel rods within the core. Therefore, a detailed CWO calculation is not needed because the calculated sum will

always be less than 0.17 percent. Because the resulting CWO is conservatively assumed to be 0.17 percent, which represents a bounding estimate of the 95th percentile CWO at the 95-percent confidence level, the analysis confirms that 10 CFR 50.46 acceptance criterion (b)(3), i.e., “Core-Wide Oxidation less than 1 percent,” is met. The results are shown in Table 15.4.1-2B.

(4) Criterion (b)(4) has historically been satisfied by adherence to criteria (b)(1) and (b)(2), and by assuring that fuel deformation due to combined LOCA and seismic loads is specifically addressed. The approved methodology (Reference 56) specifies that effects of LOCA and seismic loads on core geometry do not need to be considered unless grid crushing extends beyond the assemblies in the low-power channel as defined in the DCPP WCOBRA/TRAC model. This situation has not been calculated to occur for DCPP Unit 2. Therefore, acceptance criterion (b)(4) is satisfied.

(5) The approved Westinghouse position on Criterion (b)(5) is that this requirement is satisfied if a coolable geometry is maintained, and the core remains subcritical following the LOCA (Reference 56). This position is independent from and unaffected by the use of best-estimate LOCA methodology.

15.4.1.10B Unit 2 Plant Operating Range

The accepted PCT and its uncertainty developed previously are valid for a range of Unit 2 plant operating conditions. The range of variation of the operating parameters has been accounted for in the uncertainty evaluation. Table 15.4.1-7B summarizes the operating ranges for DCPP Unit 2 as defined for the proposed operating conditions, which are supported by the Best-Estimate LBLOCA analysis. Table 15.4.1-5B summarizes the LBLOCA containment data used for calculating containment back pressure. It should be noted that other non-LBLOCA analyses may not support these ranges. If operation is maintained within these ranges, the LBLOCA results developed in this report using WCOBRA/TRAC are considered to be valid. Note that some of these parameters vary over their range during normal operation (accumulator temperature) and other ranges are fixed for a given operational condition (T_{avg}).

15.4.1.11 Conclusions (Common)

15.4.1.11.1 10 CFR 50.46 Acceptance Criteria

It must be demonstrated that there is a high level of probability that the limits set forth in 10 CFR 50.46 are met. The demonstration that these limits are met is as follows:

(1) The limiting PCT corresponds to a bounding estimate of the 95th percentile PCT at the 95-percent confidence level such that the

analysis confirms that 10 CFR 50.46 acceptance criterion (b)(1), i.e., “Peak Cladding Temperature less than 2200 ºF”, is demonstrated.

(2) 10 CFR 50.46 acceptance criterion (b)(2), requires that the maximum calculated reduction in fuel cladding thickness at any location in the core due to the zirconium and water (Zr-H_2O) reaction shall be less than 17 percent of the original cladding thickness. Because the Zr-H_2O reaction essentially oxidizes the fuel cladding and generates hydrogen as a by-product, the reduction in cladding thickness is evaluated based on the amount of H_2 generated (i.e., oxidation) at a given core location. The BELOCA methodology calculates the local maximum oxidation (LMO), which corresponds to a bounding estimate of the 95th percentile LMO at the 95-percent confidence level such that the analysis confirms that the 10 CFR 50.46 acceptance criterion (b)(2), i.e., “Local Maximum Oxidation of the Cladding Less than 17 percent,” is demonstrated.

(3) 10 CFR 50.46 acceptance criterion (b)(3) requires that the total quantity of fuel cladding oxidized due to the Zr-H_2O reaction shall be less than 1 percent, which is verified by ensuring the total calculated amount of H_2 generated is less than 1 percent of the theoretical maximum possible if all of the fuel cladding in the core was oxidized. The BELOCA methodology calculates the limiting core wide oxidation (CWO) which corresponds to a bounding estimate of the 95th percentile CWO at the 95-percent confidence level such that the analysis confirms that 10 CFR 50.46 acceptance criterion (b)(3), i.e., “Core-Wide Oxidation Less than 1 percent,” is demonstrated.

(4) 10 CFR 50.46 acceptance criterion (b)(4) requires that the calculated changes in core geometry are such that the core remains amenable to cooling. This criterion has historically been satisfied by adherence to criteria (b)(1) and (b)(2), and by assuring that fuel deformation due to combined LOCA and seismic loads is specifically addressed. The approved methodology (Reference 56) specifies that effects of LOCA and seismic loads on core geometry do not need to be considered unless fuel grid crushing extends beyond the assemblies representing the low-power channel.

(5) 10 CFR 50.46 acceptance criterion (b)(5) requires that long-term core cooling be provided following the successful initial operation of the ECCS. The approved Westinghouse position on this criterion is that this requirement is satisfied if a coolable geometry is maintained, and the core remains subcritical following the LOCA (Reference 56). This position is independent from and unaffected by the use of best-estimate LOCA methodology.

15.4.1.11.2 Radiological

Section 15.5.17.11 concludes that the resulting potential exposures have been found to be lower than the applicable guidelines and limits specified in 10 CFR Part 100.

15.4.2 MAJOR SECONDARY SYSTEM PIPE RUPTURE

Three major secondary system pipe ruptures are analyzed in this section: rupture of a main steam line at hot zero power, rupture of a main feedwater pipe, and rupture of a main steam line at power. The time sequence of events for each of these events is provided in Table 15.4-8.

15.4.2.1 Rupture of a Main Steam Line at Hot Zero Power

15.4.2.1.1 Acceptance Criteria

The following limiting criteria are applicable for a main steam line rupture at hot zero power:

15.4.2.1.1.1 Fuel Damage Criteria

Any fuel damage calculated to occur must be of sufficiently limited extent that the core will remain in place and intact with no loss of core cooling capability. This is conservatively demonstrated by meeting the following criteria:

(1) DNB will not occur on the lead rod with at least a 95 percent probability at a 95 percent confidence level. The minimum DNBR must not go below the applicable limit value of 1.45 at any time during the transient.

15.4.2.1.1.2 Radiological Criteria

(1) The resulting potential exposures to individual members of the public and to the general population shall be lower than the applicable guidelines and limits specified in 10 CFR Part 100.

15.4.2.1.2 Identification of Causes and Accident Description

The steam release from a rupture of a main steam pipe would result in an initial increase in steam flow that decreases during the accident as the steam pressure falls. The energy removal from the RCS causes a reduction of coolant temperature and pressure. In the presence of a negative moderator temperature coefficient, the cooldown results in a positive reactivity insertion and subsequent reduction of core shutdown margin. If the most reactive RCCA is assumed stuck in its fully withdrawn position after reactor trip, there is an increased possibility that the core will become critical and return to power. A return to power following a steam pipe rupture is a potential problem mainly because of the high power peaking factors that exist assuming the most reactive RCCA to be stuck in its fully withdrawn position. The core is ultimately shut down by the boric acid injection delivered by the SIS and accumulators.

In order to allow for routine plant heatups and cooldowns, plant procedures allow the SIS to be blocked per permissive P-11, provided that the RCS boron concentration is maintained at a value greater than or equal to the cold shutdown margin requirement. As discussed in Reference 63, this additional shutdown margin ensures that there would be no return to power for a steam pipe rupture such that the analysis of a rupture of a steam line at hot zero power remains bounding.

The analysis of a main steam pipe rupture is performed to demonstrate that the following criteria are satisfied:

(1) Assuming a stuck RCCA, with or without offsite power, and assuming a single failure in the engineered safety features (ESF) there is no consequential damage to the primary system and the core remains in place and intact.

(2) Energy release to containment from the worst steam pipe break does not cause failure of the containment structure (see Appendix 6.2D).

Although DNB and possible cladding perforation following a steam pipe rupture are not necessarily unacceptable, the following analysis, in fact, shows that the DNB design basis is met for any rupture assuming the most reactive assembly stuck in its fully withdrawn position.

The following functions provide protection for a steam line rupture:

(1) SIS actuation from any of the following:

  (a) Two-out-of-four low pressurizer pressure signals

  (b) Two-out-of-three low steam line pressure signals in any one loop

  (c) Two-out-of-three high containment pressure signals

(2) The overpower reactor trips (neutron flux and ΔT), the overtemperature ΔT reactor trip, and the reactor trip occurring in conjunction with receipt of the safety injection signal.

(3) Redundant isolation of the main feedwater lines: sustained high feedwater flow would cause additional cooldown. Therefore, a safety injection signal will rapidly close all feedwater control valves, trip the main feedwater pumps, and close the feedwater isolation valves that backup the control valves.

(4) Closure of the fast acting main steam line isolation valves on: (See Figure 7.2-1 and the Technical Specifications (Reference 30))

(a) Two-out-of-three low steam line pressure signals in any one loop

(b) Two-out-of-four high-high containment pressure

(c) Two-out-of-three high negative steam line pressure rate signals in any one loop (used only during cooldown and heatup operations)

The fast-acting isolation valves are provided in each main steam line and will fully close within 10 seconds of a large steam line break. For breaks downstream of the isolation valves, closure of all valves would completely terminate the blowdown. For any break, in any location, no more than one steam generator would blow down even if one of the isolation valves fails to close. A description of steam line isolation is included in Chapter 10.

The effective throat area of the integral flow restrictors in the steam generators is 1.388 ft^2, which is considerably smaller than the area of the main steam pipe. These restrictors serve to limit the maximum steam flow for any break at any location.

15.4.2.1.3 Analysis of Effects and Consequences

The analysis of the steam pipe rupture has been performed to determine:

(1) The plant transient conditions, including core heat flux and RCS temperature and pressure resulting from the cooldown following the steam line break. The RETRAN-02W code (Reference 70) has been used.

(2) The thermal and hydraulic behavior of the core following a steam line break. A detailed thermal and hydraulic digital-computer code, THINC (See Section 1.6.1, Item 28, and Section 4.4.3), has been used to determine if DNB occurs for the core conditions computed in (1) above.

The following conditions were assumed to exist at the time of a main steam line break accident.

(1) End of life (EOL) shutdown margin at no-load, equilibrium xenon conditions, and the most reactive assembly stuck in its fully withdrawn position: Operation of the control rod banks during core burnup is restricted in such a way that addition of positive reactivity in a steam line break accident will not lead to a more adverse condition than the case analyzed.

(2) The negative moderator coefficient corresponds to the EOL rodded core with the most reactive rod in the fully withdrawn position. The variation of the coefficient with temperature and pressure has been included. The k_{eff} versus temperature at 1050 psia corresponding to the negative moderator temperature coefficient, plus the Doppler temperature effect used is shown in Figure 15.4.2-2. The effect of power generation in the core on overall reactivity is shown in Figure 15.4.2-1.

The core properties associated with the sector nearest the affected steam generator and those associated with the remaining sector were conservatively combined to obtain average core properties for reactivity feedback calculations. To verify the conservatism of this method, the reactivity as well as the power distribution was checked with the advanced nodal code core model (see Section 4.3.3.3). These core analyses considered the Doppler reactivity from the high fuel temperature near the stuck RCCA, moderator feedback from the high water enthalpy near the stuck RCCA, power redistribution and non-uniform core inlet temperature effects. For cases in which steam generation occurs in the high flux regions of the core, the effect of void formation was also included. It was confirmed that the reactivity feedback model employed in the RETRAN-02W kinetics analysis was consistent with the core analysis and the overall analysis is conservative.

(3) The modeling of the SIS in RETRAN-02W is described in Reference 70. The minimum boric acid solution concentration of 2300 ppm in the RWST is assumed. The SIS piping downstream of the RWST isolation valves is assumed to contain no boron (0 ppm), which delays the delivery of boron to the reactor coolant loops from the RWST water. With this conservative assumption, the SIS and accumulators combine to limit the return to power. Cases were examined for both minimum and maximum SIS flow rates.

For the minimum SIS flow rate cases the most restrictive single failure in the SIS is considered. The SIS flow assumed conservatively corresponds to that delivered by only one high-head charging pump delivering full flow to the cold leg header. The charging pump (CCP1 or CCP2) is assumed

to begin providing flow to the RCS at 25 seconds after receipt of the SI signal for the case in which offsite power is assumed available, and at 35 seconds for the case where offsite power is not available; the additional 10-second delay is assumed to start the diesels and load the necessary safety injection equipment onto them.

For the maximum SIS flow rate cases, a flow profile was assumed that bounds the maximum flow from two high-head charging pumps (CCP1 and CCP2) plus two intermediate-head SI pumps plus the nonsafety-related CVCS charging pump (CCP3). A 2-second signal delay was assumed.

For this analysis, it was determined that the maximum SIS flow rate assumption is conservative for the more limiting case with offsite power available, due to the effect of higher SIS flow on the timing of cold leg accumulator actuation. The cold leg accumulators provide an additional source of borated water to the core when the RCS pressure decreases below the actuation setpoint. The minimum accumulator boron concentration of 2200 ppm is assumed, along with a conservatively low actuation setpoint of 577.2 psia. Actuation of the accumulators causes a significant influx of boron, which rapidly shuts down the reactor. Assuming the maximum SIS flow rate slows down the rate of the RCS pressure decrease and thus delays the accumulator actuation. If the most reactive RCCA is assumed stuck in its fully withdrawn position after a reactor trip, there is an increased possibility that the core will become critical and return to power. A return to power following a steam pipe rupture is a potential problem mainly because of the high power peaking factors that would exist assuming the most-reactive RCCA to be stuck in its fully withdrawn position. Therefore, the limiting case presented herein conservatively assumes a maximum SIS flow rate.

(4) Because the steam generators are equipped with integral flow restrictors with a 1.388 ft^2 throat area, any rupture with a break greater than this size, regardless of the location, would have the same effect on the reactor as a 1.388 ft^2 break. The following two cases have been considered in determining the core power and RCS transients:

(a) Complete severance of a pipe with the plant initially at no-load conditions and with offsite power available. Full reactor coolant flow is maintained.

(b) Complete severance of a pipe with the plant initially at no-load conditions and with offsite power unavailable. Loss of offsite power results in reactor coolant pump coastdown.

(5) Power peaking factors corresponding to one stuck RCCA and non-uniform core inlet coolant temperatures are determined at EOL. The coldest core inlet temperatures are assumed to occur in the sector with the stuck rod. The power peaking factors account for the effect of the local void in the region of the stuck control assembly during the return to power phase following the steam line break. This void in conjunction with the large negative moderator coefficient partially offsets the effect of the stuck assembly. The power peaking factors depend on the core power, operating history, temperature, pressure, and flow.

All the cases above assume initial hot shutdown conditions at time zero, because this represents the most limiting initial condition. Should the reactor be just critical or operating at power at the time of a steam line break, the reactor will be tripped by the normal overpower protection system when power level reaches a trip point. Following a trip at power the RCS contains more stored energy than at no-load, the average coolant temperature is higher than at no-load, and there is appreciable energy stored in the fuel. Thus, the additional stored energy is removed via the cooldown caused by the steam line break before the no-load conditions of RCS temperature and shutdown margin assumed in the analyses are reached. After the additional stored energy has been removed, the cooldown and reactivity insertions proceed in the same manner as in the analysis, which assumes no-load condition at time zero.

However, because the initial steam generator water inventory is greatest at no-load, the magnitude and duration of the RCS cooldown are less for steam line breaks occurring at power.

(6) In computing the steam flow during a steam line break, the Moody Curve (Reference 16) for fl/D = 0 is used.

(7) Perfect moisture separation in the steam generator is assumed. This assumption leads to conservative results because, in fact, considerable water would be discharged. Water carryover would reduce the magnitude of the temperature decrease in the core.

(8) To maximize the primary-to-secondary heat transfer rate, 0 percent steam generator tube plugging is assumed.

(9) All main and auxiliary feedwater pumps are assumed to be operating at full capacity when the rupture occurs. This assumption maximizes the cooldown. A conservatively high auxiliary feedwater flow rate of 1700 gpm at a minimum temperature of 60ºF is assumed to be delivered to the affected steam generator. Main feedwater is isolated 64 seconds following the SI signal by closure of the main feedwater isolation valves.

No credit is taken for the faster-closing main feedwater control valves. Auxiliary feedwater continues for the duration of the transient.

(10) The effect of heat transferred from thick metal in the reactor coolant system and the steam generators is not included in the cases analyzed. The heat transferred from these sources would be a net benefit because it would slow the cooldown of the RCS.

15.4.2.1.4 Results

The double-ended rupture of a main steam line at zero power was analyzed for both Units 1 and 2; however, only the results from the slightly more limiting Unit 1 cases are presented. Unit 2 results are similar. The time sequence of events, both with and without offsite power available for Unit 1, are presented in Table 15.4-8.

Figures 15.4.2-4 through 15.4.2-6 show the plant response following a main steam pipe rupture. Offsite power is assumed to be available such that full reactor coolant flow exists. The transient shown assumes an uncontrolled steam release from only one steam generator.

Figures 15.4.2-7 through 15.4.2-9 show the plant response for the case with a loss of offsite power. This assumption results in a coastdown of the reactor coolant pumps. In this case, the core power increases at a slower rate and reaches a lower peak value than in the case with offsite power available. The ability of the emptying steam generator to extract heat from the RCS is reduced by the decreased flow in the RCS. It should be noted that following a steam line break only one steam generator blows down completely. Thus, the remaining steam generators are still available for dissipation of decay heat after the initial transient is over. In the case with loss of offsite power, this heat would be removed to the atmosphere via the main steam safety valves.

15.4.2.1.5 Conclusions

The analysis demonstrates the acceptance criteria are met as follows:

15.4.2.1.5.1 Fuel Limits

Based on the results of the analysis, the core will remain in place and intact with no loss of core cooling capability.

A DNB analysis was performed for the limiting steam line break case with offsite power available as described above. The analysis demonstrated that the minimum DNBR remains well above the limit value of 1.45. Therefore, the DNB design basis is met for the steam line break event initiated from zero power.

15.4.2.1.5.2 Radiological

Section 15.5.18 concludes that potential exposures from major steam line ruptures will be well below the guideline levels specified in 10 CFR Part 100.

15.4.2.2 Major Rupture of a Main Feedwater Pipe

15.4.2.2.1 Acceptance Criteria

The following limiting criteria are applicable for a main feedwater pipe rupture:

15.4.2.2.1.1 Fuel Damage Criteria

Any fuel damage calculated to occur must be of sufficiently limited extent that the core will remain in place and intact with no loss of core cooling capability. This is conservatively demonstrated by meeting the following criteria:

(1) With respect to fuel damage due to “dryout” where the water level in the vessel drops below the top of the core, criterion that no bulk boiling occurs in the primary coolant system prior to event “turnaround” is applied. Turnaround is defined as the point when the heat removal capability of the steam generators, being fed by auxiliary feedwater (AFW), exceeds NSSS heat generation.

15.4.2.2.1.2 Maximum RCS and Main Steam System Pressure Requirements:

The maximum pressure in the RCS and main steam system should be maintained below 110 percent of the design value, 2748.5 psia and 1208.5 psia, respectively.

15.4.2.2.1.3 Radiological Criteria

The resulting potential exposures to individual members of the public and to the general population shall be lower than the applicable guidelines and limits specified in 10 CFR Part 100.

15.4.2.2.2 Identification of Causes and Accident Description

A major feedwater line rupture is defined as a break in a feedwater pipe large enough to prevent the addition of sufficient feedwater to the steam generators to maintain shell-side fluid inventory in the steam generators. If the break is postulated in a feedline between the check valve and the steam generator, fluid from the steam generator may also be discharged through the break. Further, a break in this location could preclude the subsequent addition of AFW to the affected steam generator. (A break upstream of the feedline check valve would affect the nuclear steam supply system (NSSS) only as a loss of feedwater. This case is covered by the evaluation in Section 15.2.8).

Depending on the size of the break and the plant operating conditions at the time of the break, the break could cause either an RCS cooldown (by excessive energy discharge through the break), or an RCS heatup. Potential RCS cooldown resulting from a secondary pipe rupture is evaluated in Section 15.4.2.1. Therefore, only the RCS heatup effects are evaluated for a feedline rupture.

A feedline rupture reduces the ability to remove heat generated by the core from the RCS for the following reasons:

(1) Feedwater to the steam generators is reduced. Since feedwater is subcooled, its loss may cause reactor coolant temperatures to increase prior to reactor trip

(2) Liquid in the steam generator may be discharged through the break, and would then not be available for decay heat removal after trip

(3) The break may be large enough to prevent the addition of any main feedwater after trip

The following provide the necessary protection against a main feedwater line rupture:

(1) A reactor trip on any of the following conditions:

 (a) High pressurizer pressure

 (b) Overtemperature ΔT

 (c) Low-low steam generator water level in any steam generator

 (d) Safety injection signals from any of the following:

 - Low steam line pressure
 - High containment pressure

 (Refer to Chapter 7 for a description of the actuation system.)

(2) An AFW system to provide an assured source of feedwater to the steam generators for decay heat removal (Refer to Chapter 6 for a description of the AFW system.)

15.4.2.2.3 Analysis of Effects and Consequences

The feedline break transient is analyzed using the RETRAN-02W computer code described in Reference 70. The RETRAN-02W model simulates the reactor coolant system, neutron kinetics, pressurizer, pressurizer relief and safety valves, pressurizer heaters, pressurizer spray, steam generators, feedwater system, and main steam safety

valves. The code computes pertinent plant variables including steam generator mass, pressurizer water volume, reactor coolant average temperature, reactor coolant system pressure, and steam generator pressure.

The feedline rupture analysis methodology is not intended to minimize the predicted time to pressurizer overfill, as this scenario is evaluated in Section 15.2.15. Pressurizer overfill concerns during feedline rupture were generically dispositioned by Westinghouse (Reference 64) and determined not to require evaluation since operator action is credited to preclude water relief by the PSVs.

Major assumptions are:

(1) The plant is initially operating at 102 percent of the NSSS rating, including a conservatively large RCP heat of 20 MWt for the case with offsite power available and a nominal (minimum guaranteed) RCP heat of 14 MWt for the case without offsite power available. These assumptions maximize the primary side heat that must be removed for each case.

(2) Initial reactor coolant average temperature is 5.0°F above the nominal value, and the initial pressurizer pressure is 60 psi above its nominal value.

(3) The initial pressurizer level is set to the nominal full power programmed level plus an uncertainty of +5.7 percent span for Diablo Canyon Units 1 and 2, resulting in an initial pressurizer level of 66.4 percent span and 66.8 percent span, respectively. Initial steam generator water level is at 75 percent narrow range span (NRS) in the faulted steam generator, and at 55 percent NRS in the intact steam generators.

(4) No credit is taken for the pressurizer power-operated relief valves or pressurizer spray.

(5) No credit is taken for the high pressurizer pressure reactor trip.

(6) Main feed to all steam generators is assumed to stop at the time the break occurs (all main feedwater spills out through the break).

(7) The break discharge quality is calculated by RETRAN-02W as a function of pressure and temperature.

(8) Reactor trip is assumed to be initiated when the low-low level trip setpoint in the ruptured steam generator is reached. A low-low level setpoint of 0 percent NRS is assumed.

(9) A double-ended break area of 0.5184 ft^2 is assumed. A break area of 0.5184 ft^2 corresponds to the flow area of the reducer leading to the

feedring, and is the largest effective area of flow out of the steam generators for the feedline break event. This minimizes the steam generator fluid inventory available for removal of long-term decay heat and stored energy following reactor trip, and thereby maximizes the resultant heatup of the reactor coolant.

(10) No credit is taken for heat energy deposited in RCS metal during the RCS heatup.

(11) No credit is taken for charging or letdown.

(12) The steam generator heat transfer correlation for the steam generator tubes is automatically adjusted by RETRAN-02W as the shell-side inventory decreases.

(13) Conservative core residual heat generation based on the 1979 ANS 5.1 (Reference 32) decay heat standard plus uncertainty was used for calculation of residual decay heat levels.

(14) The AFW is assumed to be initiated 10 minutes after the trip with a feed rate of 390 gpm

15.4.2.2.4 Results

Analyses were performed for both Units 1 and 2 separately; the most limiting case with offsite power and the corresponding case without offsite power are presented.

Results for two feedline break cases are presented. Results for a case in which offsite power is assumed to be available are presented in Section 15.4.2.2.4.1. Results for a case in which offsite power is assumed to be lost following reactor trip are presented in Section 15.4.2.2.4.2. The calculated sequence of events for both cases is listed in Table 15.4-8.

15.4.2.2.4.1 Feedline Rupture with Offsite Power Available

The system response following a feedwater line rupture, assuming offsite power is available, is presented in Figures 15.4.2-10 through 15.4.2-13. Results presented in Figures 15.4.2-11 and 15.4.2-13 show that pressures in the RCS and main steam system remain below 110 percent of the design pressures, 2748.5 psia and 1208.5 psia, respectively. Pressurizer pressure decreases after reactor trip on low-low steam generator water level due to the reduction of heat input. Following this initial decrease, pressurizer pressure increases to the pressurizer safety valve setpoint. This increase in pressure is the result of coolant expansion caused by the reduction in heat transfer capability in the steam generators. Figure 15.4.2-11 indicates a pressurizer water volume equivalent to a water-solid condition; however, this is not an acceptance criteria for the analysis. Pressurizer overfill does not require specific evaluation for

feedline rupture. At approximately 5900 seconds, decay heat generation decreases to a level such that the total RCS heat generation (decay heat plus pump heat) is less than auxiliary feedwater heat removal capability, and RCS pressure and temperature begin to decrease.

The results show that the core remains covered at all times and that no boiling occurs in the reactor coolant loops.

15.4.2.2.4.2 Feedline Rupture with Offsite Power Unavailable

The system response following a feedwater line rupture without offsite power available is similar to the case with offsite power available. However, as a result of the loss of offsite power (assumed to occur at reactor trip), the reactor coolant pumps coast down. This results in a reduction in total RCS heat generation by the amount produced by pump operation.

The reduction in total RCS heat generation produces a milder transient than in the case where offsite power is available. Results presented in Figures 15.4.2-14 through 15.4.2-17 show that pressure in the RCS and main steam system remain below 110 percent of the design pressures, 2748.5 psia and 1208.5 psia, respectively. Pressurizer pressure decreases after reactor trip on low-low steam generator water level due to the reduction of heat input. Following this initial decrease, pressurizer pressure increases to a peak pressure of 2426 psia at 106 seconds. This increase in pressure is the result of coolant expansion caused by the reduction in heat transfer capability in the steam generators. Figure 15.4.2-15 shows that the water volume in the pressurizer increases in response to the heatup, but does not fill the pressurizer. At approximately 2200 seconds, decay heat generation decreases to a level less than the auxiliary feedwater heat removal capability, and RCS temperature begins to decrease. The results show that the core remains covered at all times and that no boiling occurs in the reactor coolant loops.

15.4.2.2.5 Conclusions

Results of the analysis show that for the postulated feedline rupture, the assumed AFW system capacity is adequate to remove decay heat, to prevent overpressurizing the RCS, and to prevent uncovering the reactor core. The analysis documents that the acceptance criteria for a postulated feedline rupture are met as follows:

15.4.2.2.5.1 Fuel Damage

Any fuel damage calculated to occur is of sufficiently limited extent that the core will remain in place and intact with no loss of core cooling capability. This is conservatively demonstrated by Figures 15.4.2-12 and 15.4.2-16 that show no bulk boiling occurs in the primary coolant system prior to event “turnaround”.

15.4.2.2.5.2 Maximum RCS and Main Steam System Pressure

As shown in Figures 15.4.2-11 and 15.4.2-13, the maximum pressure in the RCS and main steam system is maintained below 110 percent of the design value, 2748.5 psia and 1208.5 psia, respectively.

15.4.2.2.5.3 Radiological

Section 15.5.19 concludes that potential exposures from major feedwater line ruptures will be well below the guideline levels specified in 10 CFR Part 100, and that the occurrence of such ruptures would not result in undue risk to the public.

15.4.2.3 Rupture of a Main Steam Line at Full Power

15.4.2.3.1 Acceptance Criteria

The following limiting criteria are applicable for a main steam line rupture at full power:

15.4.2.3.1.1 Fuel Damage Criteria

Any fuel damage calculated to occur must be of sufficiently limited extent that the core will remain in place and intact with no loss of core cooling capability. This is conservatively demonstrated by meeting the following criteria:

(1) DNB will not occur on the lead rod with at least a 95 percent probability at a 95 percent confidence level. The minimum DNBR must not go below the DNBR Safety Analysis Limit of 1.68/1.71 (see Section 4.4.1.1.2) at any time during the transient.

(2) The peak linear heat generation rate will not exceed a 22 kW/ft (Section 4.4.1.2 and Figure 4.4-2) which would cause fuel centerline melt.

15.4.2.3.1.2 Radiological Criteria

The resulting potential exposures to individual members of the public and to the general population shall be lower than the applicable guidelines and limits specified in 10 CFR Part 100.

15.4.2.3.2 Identification of Causes and Accident Description

A rupture in the main steam system piping from an at-power condition creates an increased steam load, which extracts an increased amount of heat from the reactor coolant system via the steam generators. This results in a reduction in reactor coolant system temperature and pressure. In the presence of a strong negative moderator temperature coefficient, typical of end-of-cycle conditions, the colder core inlet coolant temperature causes the core power to increase from its initial level due to the positive reactivity insertion. The power approaches a level equal to the total steam flow.

Depending on the break size, a reactor trip may occur due to overpower conditions or as a result of a steam line break protection function actuation.

The steam system piping failure accident analysis, described in Section 15.4.2.1, is performed assuming a hot zero power initial condition with the control rods inserted in the core, except for the most reactive rod, which remains fully withdrawn out of the core. This condition could occur while the reactor is at hot shutdown at the minimum required shutdown margin, or after the plant has been tripped manually, or by the reactor protection system following a steam line break from an at-power condition. For an at-power break, the FSAR Update Section 15.4.2.1 analysis represents the limiting condition with respect to core protection for the time period following reactor trip. The analysis of a main steam pipe rupture at power is performed to demonstrate that the following criteria are satisfied:

(1) Assuming a stuck RCCA and a single failure in the engineered safety features, there is no damage to the primary system and the core remains in place and intact.

(2) Core protection is maintained prior to, and immediately following, a reactor trip, if one is required, such that the DNBR remains above the applicable limit value for any rupture assuming the most reactive assembly stuck in its fully withdrawn position.

Depending on the size of the break, this event is classified as either an ANS Condition III (infrequent fault) or Condition IV (limiting fault) event. The main steam pipe rupture at power is protected by the same reactor protection and ESF functions as the main steam pipe rupture at hot zero power. Although DNB and possible clad perforation following a steam pipe rupture are not necessarily unacceptable, the analysis shows that the calculated DNBR remains above the applicable DNBR limit value.

15.4.2.3.3 Analysis of Effects and Consequences

The analysis of the steam line rupture is performed in the following stages:

(1) The RETRAN-02W code (Reference 70) is used to calculate the nuclear power, core heat flux, and RCS temperature and pressure transients resulting from the cooldown following the steam line break.

(2) The core radial and axial peaking factors are determined using the thermal-hydraulic conditions from the transient analysis as input to the nuclear core models. The THINC-IV code (see Section 4.4.3) is then used to calculate the DNBR for the limiting time during the transient.

This accident is analyzed with the Improved Thermal Design Procedure as described in Reference 62.

To give conservative results in calculating the DNBR during the transient, the following assumptions are made:

(1) Initial Conditions - The initial core power, reactor coolant temperature, and RCS pressure are assumed to be at their nominal full-power values. The full power condition is more limiting than part-power with respect to DNBR. Uncertainties in initial conditions are included in the DNBR limit value, as described in Reference 62.

(2) Break size - A spectrum of break sizes is analyzed. Small breaks do not result in a reactor trip; in this case core power stabilizes at an increased level corresponding to the increased steam flow. Intermediate-size breaks may result in a reactor trip on overpower ΔT as a result of the increasing core power. Larger break sizes result in a reactor trip soon after the break from the safety injection signal actuated by low steam line pressure, which includes lead/lag dynamic compensation.

(3) Break flow - The steam flow out the pipe break is calculated using the Moody curve for an fL/D value of 0 (Reference 16).

(4) Reactivity Coefficients - The analysis assumes maximum EOL moderator reactivity feedback and minimum Doppler-only power reactivity feedback in order to maximize the power increase following the break.

(5) Protection System - The analysis only models those reactor protection system features that would be credited for at power conditions and up to the time a reactor trip is initiated. Section 15.4.2.1, presents the analysis of the bounding transient following reactor trip, where engineered safety features are actuated to mitigate the effects of a steam line break.

(6) Control Systems - The results of a main steam pipe rupture at power would be made less severe as a result of control system actuation. Therefore, the mitigation effects of control systems have been ignored in the analysis.

15.4.2.3.4 Results

A spectrum of steam line break sizes was analyzed for each unit. The results show that for break sizes up to 0.49 ft^2 (Unit 1) and 0.50 ft^2 (Unit 2) a reactor trip is not generated. In this case, the event is similar to an excessive load increase event as described in Section 15.2.12. The core reaches a new equilibrium condition at a higher power equivalent to the increased steam flow. For break sizes larger than those noted above, a reactor trip is generated within a few seconds of the break on the safety injection signal from low steam line pressure.

The limiting case for demonstrating DNB protection is the 0.49 ft^2 (Unit 1) break, the largest break size that does not result in an early trip on low steam pressure SI actuation. The peak linear heat rate (kW/ft) remains below a value corresponding to fuel centerline melting. The time sequence of events for this case is shown in Table 15.4-8. Figures 15.4.2-18 through 15.4.2-21 show the transient response.

15.4.2.3.5 Conclusions

The analysis demonstrates the acceptance criteria are met as follows:

15.4.2.3.5.1 Fuel Damage

Any fuel damage calculated to occur is of sufficiently limited extent that the core will remain in place and intact with no loss of core cooling capability. This is conservatively demonstrated by the following:

(1) The analysis demonstrates that there is a large margin to the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell).

(2) The analysis calculates that the maximum linear power meets the fuel centerline melt limit of 22.0 kW/ft.

The analysis concludes that the DNB and fuel centerline design bases are met for the limiting case. Although DNB and possible clad perforation following a steam pipe rupture are not necessarily unacceptable and not precluded by the criteria, the above analysis shows that the minimum DNBR remains above the safety analysis limit.

15.4.2.3.5.2 Radiological

Section 15.5.18 concludes that potential exposures from main steam line ruptures at full power will be well below the guideline levels specified in 10 CFR Part 100, and that the occurrence of such ruptures would not result in undue risk to the public.

15.4.3 STEAM GENERATOR TUBE RUPTURE (SGTR)

15.4.3.1 Acceptance Criteria

The following limiting criteria are applicable for a SGTR:

(1) The resulting potential exposures to individual members of the public and to the general population shall be lower than the applicable guidelines and limits specified in Section 15.5.20.

(2) There are no regulatory acceptance criteria associated with a SGTR margin-to-overfill transient analysis. However, it will be demonstrated that there is sufficient margin to prevent overfill of the SG during an SGTR event. Overfill of the SG may result in significantly increased offsite dose

consequences, along with damage to secondary components such as the turbine and the main steam line.

15.4.3.2 Identification of Causes and Accident Description

The accident examined is the complete severance of a single steam generator tube. The accident is assumed to take place at power with the reactor coolant contaminated with fission products corresponding to continuous operation with a limited amount of defective fuel rods. The accident leads to an increase in contamination of the secondary system due to leakage of radioactive coolant from the reactor coolant system (RCS). In the event of a coincident loss of offsite power, or failure of the condenser steam dump system, discharge of activity to the atmosphere takes place via the steam generator power-operated relief valves (and safety valves if their setpoint is reached).

Although the steam generator tube material is thermally treated Inconel 690, a highly ductile material, it is assumed that complete severance could occur. The more probable mode of tube failure would be one or more minor leaks of undetermined origin. Activity in the steam and power conversion system is subject to continual surveillance and an accumulation of minor leaks that exceeds the limits established in the Technical Specifications (Reference 30) is not permitted during the unit operation.

The operator is expected to determine that a steam generator tube rupture has occurred, to identify and isolate the ruptured steam generator, and to complete the required recovery actions to stabilize the plant and terminate the primary to secondary break flow. These actions should be performed on a restricted time scale in order to minimize contamination of the secondary system and ensure termination of radioactive release to the atmosphere from the ruptured unit. Consideration of the indications provided at the control board, together with the magnitude of the break flow, leads to the conclusion that the recovery procedure can be carried out on a time scale that ensures that break flow to the secondary system is terminated before water level in the affected steam generator rises into the main steam pipe. Sufficient indications and controls are provided to enable the operator to carry out these functions satisfactorily.

Assuming normal operation of the various plant control systems, the following sequence of events is initiated by a tube rupture:

(1) Pressurizer low pressure and low-level alarms are actuated and charging pump flow increases in an attempt to maintain pressurizer level. On the secondary side there is a steam flow/feedwater flow mismatch before trip as feedwater flow to the affected steam generator is reduced due to the break flow that is now being supplied to that unit.

(2) The main steam line radiation monitors, the air ejector radiation monitor and/or the steam generator blowdown radiation monitor will alarm, indicating a sharp increase in radioactivity in the secondary system, and steam generator blowdown will be automatically terminated.

(3) Continued loss of reactor coolant inventory leads to a reactor trip signal generated by low pressurizer pressure or overtemperature ΔT. An SI signal, initiated by low pressurizer pressure, follows soon after the reactor trip. The SI signal automatically terminates normal feedwater supply and initiates AFW addition.

(4) The reactor trip automatically trips the turbine and, if offsite power is available, the steam dump valves open permitting steam dump to the condenser. In the event of a coincident loss of offsite power, the steam dump valves would automatically close to protect the condenser. The steam generator pressure would rapidly increase resulting in steam discharge to the atmosphere through the steam generator power-operated relief valves (PORVs) and safety valves if their setpoint is reached.

(5) Following reactor trip and SI actuation, the continued action of AFW supply and borated SI flow (supplied from the refueling water storage tank) provides a heat sink that absorbs some of the decay heat. This reduces the amount of steam bypass to the condenser, or in the case of loss of offsite power, steam relief to the atmosphere.

(6) SI flow results in stabilization of the RCS pressure and pressurizer water level, and the RCS pressure trends toward the equilibrium value where the SI flow rate equals the break flow rate.

In the event of an SGTR, the plant operators must diagnose the SGTR and perform the required recovery actions to stabilize the plant and terminate the primary to secondary leakage. The operator actions for SGTR recovery are provided in the Emergency Operating Procedures (Reference 42). The major operator actions include identification and isolation of the ruptured steam generator, cooldown and depressurization of the RCS to restore inventory, and termination of SI to stop primary to secondary leakage. These operator actions are described below:

(1) *Identify the ruptured steam generator*.

High secondary side activity, as indicated by the main steam line radiation monitors, the air ejector radiation monitor, or steam generator blowdown radiation monitor typically will provide the first indication of an SGTR event. The ruptured steam generator can be identified by an unexpected increase in steam generator level, or a high radiation indication on the corresponding main steam line monitor, or from a radiation survey of the main steam lines. For an SGTR that results in a reactor trip at high power, the steam generator water level may decrease off-scale on the narrow range for all of the steam generators. The AFW flow will begin to refill the steam generators, distributing approximately equal flow to each of the steam generators. Since primary to secondary leakage adds additional

liquid inventory to the ruptured steam generator, the water level will return to the narrow range earlier in that steam generator and will continue to increase more rapidly. This response, as indicated by the steam generator water level instrumentation, provides confirmation of an SGTR event and also identifies the ruptured steam generator.

(2) *Isolate the ruptured steam generator from the intact steam generators and isolate feedwater to the ruptured steam generator*.

Once a tube rupture has been identified, recovery actions begin by isolating steam flow from and stopping feedwater flow to the ruptured steam generator. In addition to minimizing radiological releases, this also reduces the possibility of overfilling the ruptured steam generator with water by (a) minimizing the accumulation of feedwater flow and (b) enabling the operator to establish a pressure differential between the ruptured and intact steam generators as a necessary step toward terminating primary to secondary leakage.

(3) *Cool down the RCS using the intact steam generators*.

After isolation of the ruptured steam generator, the RCS is cooled as rapidly as possible to less than the saturation temperature corresponding to the ruptured steam generator pressure by dumping steam from only the intact steam generators. This ensures adequate subcooling in the RCS after depressurization to the ruptured steam generator pressure in subsequent actions. If offsite power is available, the normal steam dump system to the condenser can be used to perform this cooldown. However, if offsite power is lost, the RCS is cooled using the PORVs on the intact steam generators.

(4) *Depressurize the RCS to restore reactor coolant inventory*.

When the cooldown is completed, SI flow will increase RCS pressure until break flow matches SI flow. Consequently, SI flow must be terminated to stop primary to secondary leakage. However, adequate reactor coolant inventory must first be assured. This includes both sufficient reactor coolant subcooling and pressurizer inventory to maintain a reliable pressurizer level indication after SI flow is stopped. Since leakage from the primary side will continue after SI flow is stopped until the RCS and ruptured steam generator pressures equalize, an "excess" amount of inventory is needed to ensure pressurizer level remains on span. The "excess" amount required depends on RCS pressure and reduces to zero when RCS pressure equals the pressure in the ruptured steam generator.

The RCS depressurization is performed using normal pressurizer spray if the reactor coolant pumps (RCPs) are running. However, if offsite power

is lost or the RCPs are not running for some other reason, normal pressurizer spray is not available. In this event, RCS depressurization can be performed using a pressurizer PORV or auxiliary pressurizer spray.

(5) *Terminate SI to stop primary to secondary leakage*.

The previous actions will have established adequate RCS subcooling, a secondary side heat sink, and sufficient reactor coolant inventory to ensure that SI flow is no longer needed. When these actions have been completed, SI flow must be stopped to terminate primary to secondary leakage. Primary to secondary leakage will continue after SI flow is stopped until the RCS and ruptured steam generator pressures equalize. Charging flow, letdown, and pressurizer heaters will then be controlled to prevent repressurization of the RCS and reinitiation of leakage into the ruptured steam generator.

Following SI termination, the plant conditions will be stabilized, the primary to secondary break flow will be terminated and all immediate safety concerns will have been addressed. At this time a series of operator actions are performed to prepare the plant for cooldown to cold shutdown conditions. Subsequently, actions are performed to cooldown and depressurize the RCS to cold shutdown conditions and to depressurize the ruptured steam generator.

15.4.3.3 Analysis of Effects and Consequences

15.4.3.3.1 SGTR Margin to Overfill (MTO) Analysis

An SGTR results in the leakage of contaminated reactor coolant into the secondary system and subsequent release of a portion of the activity to the atmosphere. Therefore, an analysis must be performed to assure that the radiological consequences resulting from an SGTR are within allowable guidelines. Another concern for SGTR consequences is the possibility of steam generator overfill because this could potentially result in a significant increase in the radiological consequences. Overfill could result in water entering the main steam line. If water continues to leak into the main steam lines, the release of liquid through the steam generator safety valves could result in an increase in radiological doses. Therefore, an analysis was performed to demonstrate margin to steam generator overfill, assuming the limiting single failure relative to overfill. The results of this analysis demonstrate that there is margin to steam generator overfill for DCPP.

The overfill analysis is presented in Reference 72 and the major assumptions include:

(1) Complete severance of a single tube located at the top of the tube sheet on the outlet side of the steam generator, resulting in double ended flow

(2) Initiation of the event from full power

(3) A loss of offsite power coincident with reactor trip

(4) Failure of an AFW control valve to close (limiting single failure)

(5) The PORVs on all three intact steam generators are fully opened during the RCS cooldown

(6) Operator actions are consistent with the times shown in Table 15.4-12

The SGTR MTO analysis acceptance criterion is to maintain a positive margin to overfill when the event is terminated. The limiting margin to overfill analysis presented in Reference 72 demonstrates that the steam generator liquid volume is 30 cubic feet less than the total steam generator volume of 5800 cubic feet when the SGTR event is terminated. The SGTR MTO analysis sequence of events is listed in Table 15.4-13A and the transient responses are presented in Figures 15.4.3-1A to 15.4.3-4A and Figures 15.4.3-6A to 15.4.3-8A.

An analysis was also performed to determine the transient thermal hydraulic data for input into the radiological consequences analysis, assuming the limiting single failure relative to doses without steam generator overfill (as opposed to one that is relative to overfill). Because steam generator overfill does not occur, the radiation consequences (see Section 15.5.20) calculated using the results of this analysis represent the limiting consequences for an SGTR for DCPP. The thermal hydraulic results used by the radiological consequences (Dose) analysis are discussed below.

15.4.3.3.2 SGTR Dose Input Analysis

A thermal and hydraulic analysis was performed to determine the plant response for a design basis SGTR, and to determine the integrated primary to secondary break flow and the mass releases from the ruptured and intact steam generators to the condenser and to the atmosphere. This information was then used to calculate the quantity of radioactivity released to the environment and the resulting radiological consequences. The thermal and hydraulic analysis discussed in this section is presented in Reference 41 and the results of the radiological consequences analysis are discussed in Section 15.5.20.

The plant response following an SGTR was analyzed with the RETRAN-02W program until the primary to secondary break flow is terminated. The reactor protection system and the automatic actuation of the engineered safeguards systems were modeled in the analysis. The major operator actions which are required to terminate the break flow for an SGTR were also simulated in the analysis.

Analysis Assumptions

The accident modeled is a double-ended break of one steam generator tube located at the top of the tube sheet on the outlet (cold leg) side of the steam generator. However, as indicated subsequently, the break flow flashing fraction was conservatively calculated assuming that all of the break flow comes from the hot leg side of the steam generator. The combination of these conservative assumptions regarding the break flow location results in a very conservative calculation of the radiation doses. It was assumed that the reactor is operating at full power at the time of the accident and the secondary mass was assumed to correspond to operation at the steam generator nominal level with an allowance for uncertainties. It was also assumed that a loss of offsite power occurs at the time of reactor trip and the highest worth control assembly was assumed to be stuck in its fully withdrawn position at reactor trip.

The limiting single failure was assumed to be the failure of the PORV on the ruptured steam generator. Failure of this PORV in the open position will cause an uncontrolled depressurization of the ruptured steam generator which will increase primary to secondary leakage and the mass release to the atmosphere. It was assumed that the ruptured steam generator PORV fails open when the ruptured steam generator is isolated, and that the PORV was isolated by locally closing the associated block valve.

The major operator actions required for the recovery from an SGTR are discussed in Section 15.4.3.2 and these operator actions were simulated in the analysis. The operator action times which were used for the analysis are presented in Table 15.4-12. It is noted that the PORV on the ruptured steam generator was assumed to fail open at the time the ruptured steam generator was isolated. It was assumed that the operators isolate the failed open PORV by locally closing the associated block valve to complete the isolation of the ruptured steam generator before proceeding with the subsequent recovery operations. It was assumed that the ruptured steam generator PORV was isolated at 30 minutes after the valve was assumed to fail open. After the ruptured steam generator PORV was isolated, an additional delay time of 5 minutes (Table 15.4-12) was assumed for the operator action time to initiate the RCS cooldown.

Transient Description

The RETRAN-02W (Reference 70) analysis results are described below. The sequence of events for this transient is presented in Table 15.4-13B.

Following the tube rupture, reactor coolant flows from the primary into the secondary side of the ruptured steam generator since the primary pressure is greater than the steam generator pressure. In response to this loss of reactor coolant, pressurizer level decreases as shown in Figure 15.4.3-1B. The pressurizer pressure also decreases as shown in Figure 15.4.3-2B as the steam bubble in the pressurizer expands. As the RCS pressure decreases due to the continued primary to secondary leakage, automatic reactor trip occurs on an overtemperature ΔT trip signal.

After reactor trip, core power rapidly decreases to decay heat levels. The turbine stop valves close and steam flow to the turbine is terminated. The steam dump system is designed to actuate following reactor trip to limit the increase in secondary pressure, but the steam dump valves remain closed due to the loss of condenser vacuum resulting from the assumed loss of offsite power at the time of reactor trip. Thus, the energy transfer from the primary system causes the secondary side pressure to increase rapidly after reactor trip until the steam generator PORVs (and safety valves if their setpoints are reached) lift to dissipate the energy, as shown in Figure 15.4.3-3B. The main feedwater flow will be terminated and AFW flow will be automatically initiated following reactor trip and the loss of offsite power.

The RCS pressure decreases more rapidly after reactor trip as energy transfer to the secondary shrinks the reactor coolant and the tube rupture break flow continues to deplete primary inventory. Pressurizer level also decreases more rapidly following reactor trip. The decrease in RCS inventory results in a low pressurizer pressure SI signal. After SI actuation, the SI flow rate maintains the reactor coolant inventory and the pressurizer level begins to stabilize. The RCS pressure also trends toward the equilibrium value where the SI flow rate equals the break flow rate.

Because offsite power was assumed lost at reactor trip, the RCPs trip and a gradual transition to natural circulation flow occurs. Immediately following reactor trip the temperature differential across the core decreases as core power decays (see Figures 15.4.3-4B and 15.4.3-5B), however, the temperature differential subsequently increases as natural circulation flow develops. The cold leg temperatures trend toward the steam generator temperature as the fluid residence time in the tube region increases. The intact steam generator loop temperatures slowly decrease due to the continued AFW flow until operator actions are taken to control the AFW flow to maintain the specified level in the intact steam generators. The ruptured steam generator loop temperatures also continue to slowly decrease until the ruptured steam generator is isolated, at which time the PORV is assumed to fail open.

Major Operator Actions

(1) *Identify and Isolate the Ruptured Steam Generator*

As indicated in Table 15.4-12, it was assumed that the ruptured steam generator is identified and isolated at 10 minutes after the initiation of the SGTR or when the narrow range level reaches 38 percent, whichever time is longer. Since the time to reach 38 percent narrow range level was 953 seconds, it was assumed that the actions to isolate the ruptured steam generator are performed at this time.

The ruptured steam generator PORV was also assumed to fail open at this time, and the failure was simulated at 953 seconds. The failure causes the ruptured steam generator to rapidly depressurize, which results in an increase in primary to secondary leakage. The

depressurization of the ruptured steam generator increases the break flow and energy transfer from primary to secondary which results in a decrease in the ruptured loop temperatures as shown in Figure 15.4.3-5B. As noted previously, the intact steam generator loop temperatures also decrease, as shown in Figure 15.4.3-4B, until the AFW flow to the intact steam generators is throttled. These effects result in a decrease in the RCS pressure and pressurizer level, until the failed open PORV is isolated.

It was assumed that the time required for the operator to identify that the ruptured steam generator PORV is open and to locally close the associated block valve is 30 minutes. Thus, the isolation of the ruptured steam generator was completed at 2753 seconds, and the depressurization of the ruptured steam generator was terminated. At this time, the ruptured steam generator pressure increases rapidly and the primary to secondary break flow begins to decrease.

(2) *Cool Down the RCS to establish Subcooling Margin*

After the ruptured steam generator PORV block valve was closed, a 5 minute operator action time was imposed prior to initiation of cooldown. The depressurization of the ruptured steam generator affects the RCS cooldown target temperature because the temperature is dependent upon the pressure in the ruptured steam generator. Since offsite power was lost, the RCS was cooled by dumping steam to the atmosphere using the intact steam generator PORVs. The cooldown was continued until RCS was subcooled 36°F including an allowance for instrument uncertainty. Because the pressure in the ruptured steam generator continued to decrease during the cooldown, the associated temperature the RCS was less than the initial target temperature, which had the net effect of extending the time for cooldown. The cooldown was initiated at 3053 seconds and was completed at 4424 seconds.

The reduction in the intact steam generator pressures required to accomplish the cooldown is shown in Figure 15.4.3-3B, and the effect of the cooldown on the RCS temperature is shown in Figure 15.4.3-4B. The pressurizer level and pressurizer pressure also decrease during this cooldown process due to shrinkage of the reactor coolant, as shown in Figures 15.4.3-1B and 15.4.3-2B, respectively.

(3) *Depressurize to Restore Inventory*

After the RCS cooldown, a 4 minute operator action time was included prior to depressurization. The RCS depressurization was initiated at 4664 seconds to assure adequate coolant inventory prior to terminating SI flow. With the RCPs stopped, normal pressurizer spray is not available and thus the RCS was depressurized by opening a pressurizer PORV.

The depressurization was continued until any of the following conditions are satisfied: RCS pressure is less than the ruptured steam generator pressure and pressurizer level is greater than the allowance of 12 percent for pressurizer level uncertainty, or pressurizer level is greater than 74 percent, or RCS subcooling is less than the 20°F allowance for subcooling uncertainty. The RCS depressurization reduces the break flow as shown in Figure 15.4.3-6B, and increases SI flow to refill the pressurizer as shown in Figure 15.4.3-1B.

(4) Terminate SI to Stop Primary to Secondary Leakage

The previous actions have established adequate RCS subcooling, verified a secondary side heat sink, and restored the reactor coolant inventory to ensure that SI flow is no longer needed. When these actions have been completed, the SI flow must be stopped to prevent repressurization of the RCS and to terminate primary to secondary leakage. The SI flow is terminated after a delay to allow for operator response if RCS subcooling is greater than the 20°F allowance for uncertainty, minimum AFW flow is available or at least one intact steam generator level is in the narrow range, the RCS pressure is stable or increasing, and the pressurizer level is greater than the 12 percent allowance for uncertainty.

After depressurization was completed, an operator action time of 2 minutes was assumed prior to SI termination. Since the above requirements are satisfied, SI termination was performed at this time. After SI termination, the pressurizer pressure decreases as shown in Figure 15.4.3-2B. Figure 15.4.3-6B shows that the primary to secondary leakage continues after the SI flow was stopped until the RCS and ruptured steam generator pressures equalize.

The ruptured steam generator water volume for the radiological consequences analysis is shown in Figure 15.4.3-7B. The mass of water in the ruptured steam generator is also shown as a function of time in Figure 15.4.3-8B.

Mass Releases

The mass releases were determined for use in evaluating the exclusion area boundary and low population zone radiation exposure. The steam releases from the ruptured and intact steam generators, the feedwater flows to the ruptured and intact steam generators, and primary to secondary break flow into the ruptured steam generator were determined for the period from accident initiation until 2 hours after the accident and from 2 to 8 hours after the accident. The releases for 0-2 hours were used to calculate the radiation doses at the exclusion area boundary for a 2 hour exposure, and the releases for 0-8 hours were used to calculate the radiation doses at the low population zone for the duration of the accident.

The operator actions for the SGTR recovery up to the termination of primary to secondary leakage were simulated in the RETRAN-02W analysis. Thus, the steam releases from the ruptured and intact steam generators, the feedwater flows to the ruptured and intact steam generators, and the primary to secondary leakage into the ruptured steam generator were determined from the RETRAN-02W results for the period from the initiation of the accident until the leakage was terminated.

Following the termination of leakage, it was assumed that the actions are taken to cool down the plant to cold shutdown conditions. The PORVs for the intact steam generators were assumed to be used to cool down the RCS to the RHR system operating temperature of 350°F, at the maximum allowable cooldown rate of 100°F/hr. The steam releases and the feedwater flows for the intact steam generator for the period from leakage termination until 2 hours were determined from a mass and energy balance using the calculated RCS and intact steam generator conditions at the time of leakage termination and at 2 hours. The RCS cooldown was assumed to be continued after 2 hours until the RHR system in-service temperature of 350°F is reached. Depressurization of the ruptured steam generator was then assumed to be performed to the RHR in-service pressure of 405 psia via steam release from the ruptured steam generator PORV. The RCS pressure was also assumed to be reduced concurrently as the ruptured steam generator is depressurized. It was assumed that the continuation of the RCS cooldown and depressurization to RHR operating conditions are completed within 8 hours after the accident since there is ample time to complete the operations during this time period. The steam releases and feedwater flows from 2 to 8 hours were determined for the intact steam generators from a mass and energy balance using conditions at 2 hours and at the RHR system in-service conditions. The steam released from the ruptured steam generator from 2 to 8 hours was determined based on a mass and energy balance for the ruptured steam generator using the conditions at the time of leakage termination and saturated conditions at the RHR in-service pressure.

After 8 hours, it was assumed that further plant cooldown to cold shut down as well as long-term cooling is provided by the RHR system. Therefore, the steam releases to the atmosphere are terminated after RHR in-service conditions are assumed to be reached at 8 hours.

During the time period from initiation of the accident until leakage termination, the releases were determined from the RETRAN-02W results for the time prior to reactor trip and following reactor trip. Since the condenser is in service until reactor trip, any radioactivity released to the atmosphere prior to reactor trip would be through the condenser air ejector and/or the condenser vacuum pump exhaust (if in operation). After reactor trip, the releases to the atmosphere were assumed to be via the steam generator PORVs. The mass release rates to the atmosphere from the RETRAN-02W analysis are presented in Figures 15.4.3-9 and 15.4.3-10 for the ruptured and intact steam generators, respectively, for the time period until leakage termination. The total flashed break flow from the RETRAN-02W analysis is presented in Figure 15.4.3-11. The mass releases calculated from the time of leakage termination until 2 hours and from 2-8 hours were also assumed to be released to the atmosphere via the steam

generator PORVs. The mass releases for the SGTR event for the 0-2 hour and 2-8 hour time intervals are presented in Table 15.4-14.

15.4.3.4 Conclusions

The analysis demonstrates the acceptance criteria are met as follows:

15.4.3.4.1 Overfill Analysis

The SGTR MTO analysis acceptance criteria are to maintain a positive margin to overfill when the event is terminated. Therefore, the limiting margin to overfill analysis demonstrates that the steam generator liquid volume is less than the total steam generator volume of 5800 cubic feet when the SGTR event is terminated.

15.4.3.4.2 Radiological

Section 15.5.20 demonstrates that the acceptance criteria for Dose Consequences of a SGTR are met. Table 15.5-71 provides offsite radiation doses from SGTR accident. Table 15.5-74 provides control room radiation doses from airborne activity in SGTR accident.

15.4.4 SINGLE REACTOR COOLANT PUMP LOCKED ROTOR

15.4.4.1 Identification of Causes and Accident Description

The accident postulated is an instantaneous seizure of an RCP rotor.

Following initiation of the reactor trip, heat stored in the fuel rods continues to be transferred to the coolant causing the coolant to expand. At the same time, heat transfer to the shell-side of the steam generators is reduced, first because the reduced flow results in a decreased tube-side film coefficient and then because the reactor coolant in the tubes cools down while the shell-side temperature increases (turbine steam flow is reduced to zero upon plant trip). The rapid expansion of the coolant in the reactor core, combined with reduced heat transfer in the steam generators causes an insurge into the pressurizer and a pressure increase throughout the RCS. The insurge into the pressurizer compresses the steam volume, actuates the automatic spray system, opens the power-operated relief valves, and opens the pressurizer safety valves in that sequence. The three power-operated relief valves are designed for reliable operation and would be expected to function properly during the accident. However, for conservatism, their pressure-reducing effect as well as the pressure-reducing effect of the spray is not included in the analysis.

15.4.4.2 Analysis of Effects and Consequences

Three digital computer codes are used to analyze this transient. The LOFTRAN (Reference 26) code is used to calculate the resulting loop and core coolant flow following the pump seizure. The LOFTRAN code is also used to calculate the time of reactor trip based on the calculated flow, the nuclear power following reactor trip, and to determine the peak pressure. The thermal behavior of the fuel located at the core hot spot is investigated using the FACTRAN (Reference 17) code, using the core flow and the nuclear power calculated by LOFTRAN. The FACTRAN code includes the use of a film boiling heat transfer coefficient. The THINC (Reference 31) code is used to calculate the DNBR during the transient based on flow calculated by LOFTRAN and heat flux calculated by FACTRAN.

The following case is analyzed:

(1) All loops operating, one locked rotor

At the beginning of the postulated locked rotor accident, i.e., at the time the shaft in one of the RCPs is assumed to seize, the plant is assumed to be operating under steady state operating conditions with respect to the margin to DNB, i.e., normal steady state power level, nominal steady state pressure, and nominal steady state coolant average temperature (+ 2.5°F for SG fouling). When the peak pressure is evaluated, the initial pressure is conservatively estimated as 38 psi above nominal pressure (2250 psia) to allow for errors in the pressurizer pressure measurement and control channels. This is done to obtain the highest possible rise in the coolant pressure during the transient. To obtain the maximum pressure in the primary side, conservatively high loop pressure drops are added to the calculated pressurizer pressure. The pressure response is shown in Figure 15.4.4-1.

15.4.4.2.1 Evaluation of the Pressure Transient

After pump seizure and reactor trip, the neutron flux is rapidly reduced by the effect of control rod insertion. Rod motion is assumed to begin 1 second after the flow in the affected loop reaches 87 percent of nominal flow (see Note d on Table 15.1-2). No credit is taken for the pressure-reducing effect of the pressurizer relief valves, pressurizer spray, steam dump, or controlled feedwater flow after plant trip. Although these operations are expected to occur and would result in a lower peak pressure, an additional degree of conservatism is provided by ignoring their effect. The pressurizer safety valves are assumed to initially open at 2500 psia and achieve rated flow at 2575 psia (3 percent accumulation).

15.4.4.2.2 Evaluation of the Effects of DNB in the Core During the Accident

For this accident, DNB is assumed to occur in the core and, therefore, an evaluation of the consequences with respect to fuel rod thermal transients is performed. Results obtained from analysis of this hot spot condition represent the upper limit with respect to cladding temperature and zirconium-water reaction.

In the evaluation, the rod power at the hot spot is conservatively assumed to be greater than or equal to two and a half times the average rod power (i.e., F_Q greater than or equal to 2.5) at the initial core power level.

15.4.4.2.3 Film Boiling Coefficient

The film boiling coefficient is calculated in the FACTRAN code using the Bishop-Sandberg-Tong film boiling correlation. The fluid properties are evaluated at film temperature (average between wall and bulk temperatures). The program calculates the film coefficient at every time step based on the actual heat transfer conditions at the time. The neutron flux, system pressure, bulk density, and mass flowrate as a function of time are used as program input.

For this analysis, the initial values of the pressure and the bulk density are used throughout the transient since they are the most conservative with respect to cladding temperature response. For conservatism, DNB was assumed to start at the beginning of the accident.

15.4.4.2.4 Fuel Cladding Gap Coefficient

The magnitude and time dependence of the heat transfer coefficient between fuel and cladding (gap coefficient) has a pronounced influence on the thermal results. The larger the value of the gap coefficient, the more heat is transferred between pellet and cladding. Based on investigations on the effect of the gap coefficient upon the maximum cladding temperature during the transient, the gap coefficient was assumed to increase from a steady state value consistent with the initial fuel temperature to 10,000 Btu/hr-ft^2-°F in 0.5 seconds after the initiation of the transient. This assumption causes energy stored in the fuel to be released to the cladding at the initiation of the transient and maximizes the cladding temperature during the transient.

15.4.4.2.5 Zirconium-steam Reaction

The zirconium-steam reaction can become significant above 1800°F (cladding temperature). The Baker-Just parabolic rate equation shown below is used to define the rate of the zirconium-steam reaction.

$$\frac{d(w^2)}{dt} = 33.3 \times 10^6 \exp\left[\frac{-45{,}500}{1.986T}\right] \tag{15.4-1}$$

where:

w = amount reacted, mg/cm^2
t = time, sec
T = temperature, °K
and the reaction heat is 1510 cal/gm.

15.4.4.3 Results

Transient values of pressurizer pressure, flow coastdown, hot channel heat flux, and neutron flux are shown in Figure 15.4.4-1 and Figures 15.4.4-3 through 15.4.4-5. Maximum RCS pressure, maximum cladding temperature, and amount of zirconium-water reaction are contained in Table 15.4-10. Figure 15.4.4-2 shows the cladding temperature transient for the worst case.

15.4.4.4 Conclusions

(1) Because the peak RCS pressure reached during any of the transients is less than that which would cause stresses to exceed the faulted condition stress limits, the integrity of the primary coolant system is not endangered.

(2) Because the peak cladding surface temperature calculated for the hot spot during the worst transient remains considerably less than 2700°F and the amount of zirconium-water reaction is small, the core will remain in place and intact with no consequential loss of core cooling capability.

(3) The results of the transient analysis show that for four-loop operation, less than 10 percent of the fuel rods will have DNBRs below the safety analysis limit values.

15.4.5 FUEL HANDLING ACCIDENT

15.4.5.1 Acceptance Criteria

The following limiting criterion is applicable for a fuel handling accident:

(1) The resulting potential exposures to individual members of the public and to the general population shall be lower than the applicable guidelines and limits specified in 10 CFR Part 100.

15.4.5.2 Identification of Causes and Accident Description

15.4.5.2.1 Fuel Handling Procedures

One major task that must be performed routinely as part of the operation of a nuclear power plant is the handling of the reactor fuel. The bulk of this fuel handling occurs during refueling outages, which occur every one to two years, and all of these

operations are carried out with the fuel under water. A typical refueling outage would include the following major operations:

(1) Shutdown of the reactor and cooldown to ambient conditions

(2) Removal and storage of pressure vessel head

(3) Filling of refueling cavity above the pressure vessel with water to provide shielding from radioactive fuel

(4) Transfer of the reactor fuel assemblies from the reactor itself to underwater storage racks in the spent fuel pool

(5) Performance of outage tasks appropriate to the "core off-load" window

(6) Return of the appropriate number of partially burned and new fuel assemblies to the reactor

Fuel handling operations within the containment building and the fuel handling area are accomplished with overhead cranes, specially designed fuel grapples, and miscellaneous other equipment. To facilitate the transfer of the fuel between the two buildings, an underwater penetration called the transfer tube is provided through the walls where the buildings adjoin. A conveyer cart is used to transport the fuel from one building to the other through this penetration. A more detailed description of the equipment used in fuel handling operations can be found in Chapter 9.
Spent fuel remains in storage in the spent fuel pool until placed in a cask for transport to the Diablo Canyon Independent Spent Fuel Storage Installation (ISFSI) or for shipment from the site.

15.4.5.2.2 Probability of Activity Release

In the above operations, there exists the remote possibility that one or more fuel assemblies will sustain some mechanical damage. There exists an even more remote possibility that this damage will be severe enough to breach the cladding and release some of the radioactive fission products contained therein.

Both the fuel handling procedure and the fuel handling equipment design adhere to the following safety criteria:

(1) Fuel handling operations must not commence before short-lived core activity has decayed, leaving only relatively long-lived activity. Equipment Control Guidelines for refueling operations specify the minimum waiting time.

(2) Fuel handling operations must preclude any critical configuration of the core, spent fuel, or new fuel.

(3) The fuel handling system design must ensure an adequate water depth for radiation shielding of operating personnel.

(4) Active components of the fuel handling systems must be designed such that loss-of-function failures will terminate in stable modes.

(5) The design of fuel handling equipment must minimize the possibility of accidental impact of a moving fuel assembly with any structure.

(6) The design of fuel handling equipment and procedures must minimize the possibility of any massive object damaging a stationary fuel assembly.

(7) Fuel assembly design must minimize the possibility of damage in the event that portable or hand tools come into contact with a fuel assembly.

(8) The design of structures around the fuel handling system must minimize the possibility of the structures themselves failing in the event of a double design earthquake (DDE), which is the safe shutdown earthquake, and Hosgri. Furthermore, the structures must minimize the possibility of any external missile from reaching fuel assemblies.

(9) Fuel handling equipment must be capable of supporting maximum loads under seismic conditions. Furthermore, fuel handling equipment must not generate missiles during seismic conditions. The earthquake loading of the fuel handling equipment is evaluated in accordance with the seismic considerations addressed in Sections 9.1.4.3.1 and 9.1.4.3.9.

Implementation of the above safety criteria into the fuel handling system design is discussed in greater detail in Chapter 9.

Because of the above design, the probability of breaching the fuel cladding and releasing radioactive fission products is very small.

15.4.5.2.3 Accident Description

In order to assess the probable extent of fuel cladding damage from a fuel handling accident, it is necessary to look more closely at specific fuel handling accidents that might realistically occur.

Multiple assemblies are loaded into the multi-purpose canister (MPC)/transfer cask assembly for movement to the ISFSI, as described in Section 9.1.4.2.6. The MPC is subsequently drained, evacuated, backfilled with helium, and sealed. However, extensive design and analysis along with application of the ISFSI Technical Specifications ensure temperatures remain within the design basis and no fuel cladding damage occurs.

The possibility of damaging fuel cladding by overheating during fuel handling operations was considered. Because irradiated fuel is always handled under water, overheating would require draining either the refueling cavity or the spent fuel pool while irradiated fuel was located within them. Consideration has been given in design of the cavity and pool to prevent either of these possibilities. The probability of losing coolant while an assembly is in the transfer tube is also extremely small in view of the fact that the tube is open on one end to the reactor cavity and on the other end to the pool. There is no realistic occurrence that would simultaneously block off both ends of the tube. Therefore, it is expected that there will be no radiological consequences over the lifetime of the plant that results from overheating during fuel handling operations.

The possibility of dropping a foreign object of sufficient size to produce cladding rupture onto irradiated fuel located either in the reactor or the pool is extremely remote because the design of the plant is such that only rarely are objects of this size transported over locations containing irradiated fuel. The three large objects that are routinely handled in the vicinity of irradiated fuel are the reactor head, upper internals package, which must be removed and reinstalled from the pressure vessel at each refueling outage, and the spent fuel shipment cask, which must be placed in the pool for loading. As discussed in Section 9.1.4.2.5, load drop analyses were performed for the reactor head and upper internals and are summarized in the PG&E NUREG-0612 submittal. It is not necessary to lift the cask over the fuel racks in moving it to or from the pool. Protection of nuclear fuel assemblies from overhead load handling is a key element of the Control of Heavy Loads Program described in Section 9.1.4.3.10.

The possibility has also been considered of one of the bridge cranes falling into the reactor or the pool as a result of an earthquake. However, both of these cranes are seismically qualified to Hosgri response spectra. Therefore, it is expected that there will be no radiological consequences over the lifetime of the plant that result from dropping objects onto radiated fuel.

If a fuel assembly were to strike an object, it is possible that the object might damage the fuel rods with which it comes into contact. If a fuel assembly were to strike against a flat, plane-like object or a linear, edge-like object, impact loads would be distributed across several fuel rods, and no cladding damage would be expected. If a fuel assembly were to strike against a sharp, corner-like object, impact loads would be concentrated, and cladding damage might occur. Thus, there is a very remote possibility that impact loads would be severe enough to rupture fuel cladding.

Analyses have been made by Westinghouse of the effects that would result from dropping a fuel assembly from an initial vertical orientation onto a flat surface, the core, or a loaded fuel rack. Westinghouse has also analyzed the case where an assembly in the holder on the conveyor car falls from the vertical to the horizontal position. The results of these analyses indicate there is only a very remote possibility of fuel cladding rupture.

The above discussion indicates that the unlikely event of a fuel cladding integrity failure would most likely result from a fuel assembly striking a sharp object or dropping a fuel assembly.

15.4.5.3 Results

15.4.5.3.1 Containment Building Accident

During fuel handling operations, the containment ventilation penetrations to the outside atmosphere are maintained in a closed or automatically isolable condition. Isolation is automatically actuated if either of the Containment Purge Exhaust (CPE) monitors, RM-44A or RM-44B, alarms due to a concentration of radioactivity in the containment purge exhaust duct that exceeds the alarm setpoint. However, these penetrations are also allowed to be open under administrative controls, which provide the capability of closure within approximately 30 minutes.

Other containment penetrations, such as the personnel airlock and equipment hatch are allowed to be open during fuel handling operations. These penetrations are capable of manual closure and will be closed in accordance with plant procedures should a fuel handling accident occur.

In addition to the functions of the above mentioned monitors, fixed area radiation monitors are located in the containment. Should a fuel assembly be dropped and release activity above a prescribed level, the area monitors would sound an audible alarm. Personnel would exit the containment and containment closure would be initiated immediately per administrative procedures.

Because of containment isolation and closure capabilities, activity released from damaged fuel rods will be managed such that both the onsite and offsite exposures are minimized. The containment iodine removal system (see Section 9.4.5) can be used to remove any radioactive iodine from the containment atmosphere, but is not credited for iodine removal in the radiological analysis (see Section 15.5.22), and controlled containment venting can be initiated with offshore winds. Thus, there is a reasonable probability that only limited onshore exposures will result from a containment fuel handling accident.

15.4.5.3.2 Fuel Handling Area Accident

A fuel assembly could be damaged in the transfer canal or the spent fuel pit in the fuel handling area. Supply air for the spent fuel pit area is swept across the fuel pit and transfer canal and exhausted through the vent. An area radiation monitor is located on the bridge over the spent fuel pit. Doors in the fuel handling area are closed to maintain controlled leakage characteristics in the spent fuel pit region during refueling operations involving irradiated fuel. Should a fuel assembly be damaged in the canal or in the pit and release radioactivity above a prescribed level, the radiation monitors sound an alarm and the spent fuel pit ventilation exhaust through charcoal filters will remove most

of the halogens prior to discharging it to the atmosphere. If the discharge is greater than the prescribed levels, an alarm sounds and the supply and exhaust ventilation systems servicing the spent fuel pit area can be manually shut down from the control room, limiting the leakage to the atmosphere.

The analysis of the radiological effects of this accident is contained in Section 15.5.22.1.

15.4.5.4 Conclusions

The analysis demonstrates the acceptance criteria are met as follows:

(1) Section 15.5.22 concludes that all potential exposures from a fuel handling accident will be well below the guideline levels specified in 10 CFR Part 100, and that the occurrence of such accidents would not result in undue risk to the public. Table 15.5-47 provides a summary of doses from a fuel handling accident in the fuel handling area. Table 15.5-50 provides a summary of offsite doses from a fuel handling accident inside containment.

15.4.6 RUPTURE OF A CONTROL ROD DRIVE MECHANISM HOUSING (ROD CLUSTER CONTROL ASSEMBLY EJECTION)

15.4.6.1 Acceptance Criteria

Conservative criteria are applied to ensure that there is little or no possibility of fuel dispersal in the coolant, gross lattice distortion, or severe shock waves. These criteria are:

15.4.6.1.1 Fuel Damage Criteria

(1) Average fuel pellet enthalpy at the hot spot below 225 cal/gm for unirradiated fuel and 200 cal/gm for irradiated fuel

(2) Average cladding temperature at the hot spot below the temperature at which cladding embrittlement may be expected (2700°F)

(3) Fuel melting will be limited to less than 10 percent of the fuel volume at the hot spot even if the average fuel pellet enthalpy is below the limits of Criterion (1) above

15.4.6.1.2 Maximum RCS Pressure Criteria

(1) Peak reactor coolant pressure less than that which would cause stresses to exceed the faulted condition stress limits

15.4.6.1.3 Radiological Criteria

(1) The resulting potential exposures to individual members of the public and to the general population shall be lower than the applicable guidelines and limits specified in 10 CFR Part 100.

15.4.6.2 Identification of Causes and Accident Description

This accident is defined as the mechanical failure of a control rod mechanism pressure housing resulting in the ejection of an RCCA and drive shaft. The consequence of this mechanical failure is a rapid positive reactivity insertion and system depressurization together with an adverse core power distribution, possibly leading to localized fuel rod damage.

15.4.6.2.1 Design Precautions and Protection

Certain features of the DCPP are intended to preclude the possibility of a rod ejection accident, or to limit the consequences if the accident were to occur. These include a sound, conservative mechanical design of the rod housings, together with a thorough quality control (testing) program during assembly, and a nuclear design that lessens the potential ejection worth of RCCAs and minimizes the number of assemblies inserted at high power levels.

15.4.6.2.2 Mechanical Design

The mechanical design is discussed in Section 4.2. Mechanical design and quality control procedures intended to preclude the possibility of an RCCA drive mechanism housing failure are listed below:

(1) Each full length control rod drive mechanism housing is completely assembled and shop tested at 3107 psig.

(2) Pressure housings were individually hydrotested. The lower latch housing to nozzle connection is hydrotested during hydrotest of the completed replacement RVCH.

(3) Stress levels in the mechanism are not affected by anticipated system transients at power, or by the thermal movement of the coolant loops. Moments induced by the design-basis earthquake can be accepted within the allowable primary working stress range specified by the ASME Code, Section III, for Class I components.

(4) The latch mechanism housing and rod travel housing are each a single length of forged Type-304 stainless steel. This material exhibits excellent notch toughness at all temperatures that will be encountered.

(5) The CRDM housing plug is an integral part of the rod travel housing.

A significant margin of strength in the elastic range together with the large energy absorption capability in the plastic range gives additional assurance that gross failure of the housing will not occur. The joints between the latch mechanism housing and rod travel housing are threaded joints reinforced by canopy-type rod welds. Administrative regulations require periodic inspections of these (and other) welds.

15.4.6.2.3 Nuclear Design

Even if a rupture of an RCCA drive mechanism housing is postulated, the operation of a plant utilizing chemical shim is such that the severity of an ejected RCCA is inherently limited. In general, the reactor is operated with the RCCAs inserted only far enough to permit load follow. Reactivity changes caused by core depletion and xenon transients are compensated by boron changes. Further, the location and grouping of control rod banks are selected during the nuclear design to lessen the severity of an RCCA ejection accident. Therefore, should an RCCA be ejected from its normal position during full-power operation, only a minor reactivity excursion, at worst, could be expected to occur.

However, it may be occasionally desirable to operate with larger than normal insertions. For this reason, a rod insertion limit is defined as a function of power level. Operation with the RCCAs above this limit guarantees adequate shutdown capability and acceptable power distribution. The position of all RCCAs is continuously indicated in the control room. An alarm will occur if a bank of RCCAs approaches its insertion limit or if one RCCA deviates from its bank. There are low and low-low level insertion monitors with visual and audio signals. Operating instructions require boration at low-level alarm and emergency boration at the low-low alarm.

15.4.6.2.4 Reactor Protection

The reactor protection in the event of a rod ejection accident has been described in Reference 18. The protection for this accident is provided by the power range high neutron flux trip (high and low setting) and high rate of neutron flux increase trip. These protection functions are described in detail in Section 7.2.

15.4.6.2.5 Effects on Adjacent Housings

Disregarding the remote possibility of the occurrence of an RCCA mechanism housing failure, investigations have shown that failure of a housing due to either longitudinal or circumferential cracking is not expected to cause damage to adjacent housings leading to increased severity of the initial accident.

15.4.6.2.6 Limiting Criteria

Due to the extremely low probability of an RCCA ejection accident, limited fuel damage is considered an acceptable consequence.

Comprehensive studies of the threshold of fuel failure and of the threshold of significant conversion of the fuel thermal energy to mechanical energy have been carried out as part of the SPERT project by the Idaho Nuclear Corporation (Reference 19). Extensive tests of zirconium-clad UO_2 fuel rods representative of those in PWR-type cores have demonstrated failure thresholds in the range of 240 to 257 cal/gm. However, other rods of a slightly different design have exhibited failures as low as 225 cal/gm. These results differ significantly from the TREAT (Reference 20) results, which indicated a failure threshold of 280 cal/gm. Limited results have indicated that this threshold decreases by about 10 percent with fuel burnup. The cladding failure mechanism appears to be melting for zero burnup rods and brittle fracture for irradiated rods. Also important is the conversion ratio of thermal to mechanical energy. This ratio becomes marginally detectable above 300 cal/gm for unirradiated rods and 200 cal/gm for irradiated rods; catastrophic failure, (large fuel dispersal, large pressure rise) even for irradiated rods, did not occur below 300 cal/gm.

15.4.6.3 Analysis of Effects and Consequences

The analysis of the RCCA ejection accident is performed in two stages: (a) an average core nuclear power transient calculation and (b) a hot spot heat transfer calculation.

The average core calculation is performed using spatial neutron kinetics methods to determine the average power generation with time including the various total core feedback effects, i.e., Doppler reactivity and moderator reactivity. Enthalpy and temperature transients in the hot spot are then determined by multiplying the average core energy generation by the hot channel factor and performing a fuel rod transient heat transfer calculation. The power distribution calculated without feedback is pessimistically assumed to persist throughout the transient.

A detailed discussion of the method of analysis can be found in Reference 21.

15.4.6.3.1 Average Core Analysis

The spatial kinetics computer code, TWINKLE (see Section 1.6.1 item 50 and Section 15.1.9.5) is used for the average core transient analysis. This code solves the two group neutron diffusion theory kinetic equations in one, two, or three spatial dimensions (rectangular coordinates) for six delayed neutron groups and up to 2000 spatial points. The computer code includes a detailed multi-region, transient fuel-clad-coolant heat transfer model for calculating pointwise Doppler, and moderator feedback effects.

In this analysis, the code is used as a one-dimensional axial kinetics code since it allows a more realistic representation of the spatial effects of axial moderator feedback and RCCA movement and the elimination of axial feedback weighting factors. However, since the radial dimension is missing, it is still necessary to employ very conservative methods (described below) of calculating the ejected rod worth and hot channel factor. A further description of TWINKLE appears in Section 15.1.9.5.

15.4.6.3.2 Hot Spot Analysis

The average core energy addition, calculated as described above, is multiplied by the appropriate hot channel factors, and the hot spot analysis is performed using the detailed fuel and cladding transient heat transfer computer code, FACTRAN. This computer code calculates the transient temperature distribution in a cross section of a metalclad UO_2 fuel rod, and the heat flux at the surface of the rod, using as input the nuclear power versus time and the local coolant conditions. The zirconium and water (Zr-H_2O) reaction is explicitly represented, and all material properties are represented as functions of temperature. A parabolic radial power generation is used within the fuel rod.

FACTRAN uses the Dittus-Boelter (Reference 28) or Jens-Lottes (Reference 29) correlation to determine the film heat transfer before DNB, and the Bishop-Sandberg-Tong correlation (Reference 23) to determine the film boiling coefficient after DNB. The DNB heat flux is not calculated; instead the code is forced into DNB by specifying a conservative DNB heat flux. The gap heat transfer coefficient can be calculated by the code; however, it is adjusted in order to force the full power steady state temperature distribution to agree with that predicted by design fuel heat transfer codes.

For full power cases, the design initial hot channel factor (F_Q) is input to the code. The hot channel factor during the transient is assumed to increase from the steady state design value to the maximum transient value in 0.1 seconds, and remain at the maximum for the duration of the transient. This is conservative, since detailed spatial kinetics models show that the hot channel factor decreases shortly after the nuclear power peak due to power flattening caused by preferential feedback in the hot channel. Further description of FACTRAN appears in Section 15.1.8.

15.4.6.3.3 System Overpressure Analysis

Because safety limits for fuel damage specified earlier are not exceeded, there is little likelihood of fuel dispersal into the coolant. The pressure surge may therefore be calculated on the basis of conventional heat transfer from the fuel and prompt heat generation in the coolant.

The pressure surge is calculated by first performing the fuel heat transfer calculation to determine the average and hot spot heat flux versus time. Using this heat flux data, a THINC calculation is conducted to determine the volume surge. Finally, the volume surge is simulated in a plant transient computer code. This code calculates the

pressure transient taking into account fluid transport in the system, heat transfer to the steam generators, and the action of the pressurizer spray and pressure relief valves. No credit is taken for the possible pressure reduction caused by the assumed failure of the control rod pressure housing (Reference 21).

15.4.6.3.4 Calculation of Basic Parameters

Input parameters for the analysis are conservatively selected on the basis of calculated values for this type of core. The more important parameters are discussed below. Table 15.4-11 presents the parameters used in this analysis. A summary of the values used in the reload analysis process is also provided in Table 15.4-11.

15.4.6.3.5 Ejected Rod Worths and Hot Channel Factors

The values for ejected rod worths and hot channel factors are calculated using three-dimensional calculations. Standard nuclear design codes are used in the analysis. No credit is taken for the flux-flattening effects of reactivity feedback. The calculation is performed for the maximum allowed bank insertion at a given power level as determined by the rod insertion limits. Adverse xenon distributions are considered in the calculations.

The total transient hot channel factor F_Q is then obtained by combining the axial and radial factors.

15.4.6.3.6 Reactivity Feedback Weighting Factors

The largest temperature rises, and hence the largest reactivity feedbacks, occur in channels where the power is higher than average. Since the weight of regions is dependent on flux, these regions have high weights. This means that the reactivity feedback is larger than that indicated by a simple single channel analysis. Physics calculations were carried out for temperature changes with a flat temperature distribution, and with a large number of axial and radial temperature distributions. Reactivity changes were compared and effective weighting factors determined. These weighting factors take the form of multipliers that, when applied to single channel feedbacks, correct them to effective whole core feedbacks for the appropriate flux shape. In this analysis, since a one-dimensional (axial) spatial kinetics method is employed, axial weighting is not used. In addition, no weighting is applied to the moderator feedback. A conservative radial weighting factor is applied to the transient fuel temperature to obtain an effective fuel temperature as a function of time accounting for the missing spatial dimension. These weighting factors were shown to be conservative compared to three-dimensional analysis.

15.4.6.3.7 Moderator and Doppler Coefficient

The critical boron concentrations at the beginning of life (BOL) and end-of-life (EOL) are adjusted in the nuclear code in order to obtain moderator density coefficient curves which are conservative compared to actual design conditions for the plant. As discussed above, no weighting factor is applied to these results.

The Doppler reactivity defect is determined as a function of power level using the one-dimensional steady state computer code with a Doppler weighting factor of 1. The resulting curve is conservative compared to design predictions for this plant. The Doppler weighting factor should be larger than 1 (approximately 1.3), just to make the present calculation agree with design predictions before ejection. This weighting factor will increase under accident conditions, as discussed above.

15.4.6.3.8 Delayed Neutron Fraction

Calculations of the effective delayed neutron fraction (β_{eff}) typically yield values of 0.70 percent at BOL and 0.50 percent at EOL for the first cycle. The accident is sensitive to β_{eff} if the ejected rod worth is nearly equal to or greater than β_{eff} as in zero power transients. In order to allow for future fuel cycles, pessimistic estimates of 0.55 percent at beginning of cycle and 0.44 percent at end of cycle were used in the analysis.

15.4.6.3.9 Trip Reactivity Insertion

The trip reactivity insertion assumed is given in Table 15.4-11 and includes the effect of one stuck rod. These values are reduced by the ejected rod reactivity. The shutdown reactivity was simulated by dropping a rod of the required worth into the core. The start of rod motion occurred 0.5 seconds after the high neutron flux trip point was reached. This delay is assumed to consist of 0.2 seconds for the instrument channel to produce a signal, 0.15 seconds for the trip breaker to open, and 0.15 seconds for the coil to release the rods. The analyses presented are applicable for a rod insertion time of 2.7 seconds from coil release to entrance to the dashpot, although measurements indicate that this value should be closer to 1.8 seconds.

The choice of such a conservative insertion rate means that there is over 1 second after the trip point is reached before significant shutdown reactivity is inserted into the core. This is particularly important conservatism for hot full power accidents.

The rod insertion versus time is described in Section 15.1.4.

15.4.6.4 Results

Typical reload values of the parameters used in the VANTAGE 5 analysis, as well as the results of the analysis, are presented in Table 15.4-11 and discussed below. Actual values vary slightly from reload to reload.

15.4.6.4.1 Beginning of Cycle, Full Power

Control Bank D was assumed to be inserted to its insertion limit. The worst ejected rod worth and hot channel factor were conservatively assumed to be 0.20 percent Δk and 6.70, respectively. The peak hot spot cladding average temperature was 2434°F. The peak hot spot fuel center temperature exceeded the BOL melting temperature of 4900°F; however, melting was restricted to less than 10 percent of the pellet.

15.4.6.4.2 Beginning of Cycle, Zero Power

For this condition, control Bank D was assumed to be fully inserted and C was at its insertion limit. The worst ejected rod is located in control Bank D and was conservatively assumed to have a worth of 0.785 percent Δk and a hot channel factor of 13. The peak hot spot cladding average temperature reached only 2660°F.

15.4.6.4.3 End of Cycle, Full Power

Control Bank D was assumed to be inserted to its insertion limit. The ejected rod worth and hot channel factors were conservatively assumed to be 0.21 percent Δk and 6.50, respectively. This resulted in an average PCT of 2218°F. The peak hot spot fuel center temperature exceeded the EOL melting temperature of 4800°F. However, melting was restricted to less than 10 percent of the pellet.

15.4.6.4.4 End of Cycle, Zero Power

The ejected rod worth and hot channel factor for this case were obtained assuming control Bank D to be fully inserted and Bank C at its insertion limit. The results were 0.85 percent Δk and 21.5, respectively. The peak cladding average and fuel center temperatures were 2632°F and 3849°F, respectively.

A summary of the cases presented above is given in Table 15.4-11. The nuclear power and hot spot fuel cladding temperature transients for these representative BOL full power and EOL zero power cases are presented in Figures 15.4.6-1 through 15.4.6-4.

15.4.6.4.5 Fission Product Release

It is assumed that fission products are released from the gaps of all rods entering DNB. In all cases considered, less than 10 percent of the rods entered DNB based on a detailed three-dimensional THINC analysis. Although limited fuel melting at the hot spot was predicted for the full power cases, in practice melting is not expected since the analysis conservatively assumed that the hot spots before and after ejection were coincident.

15.4.6.4.6 Lattice Deformations

A large temperature gradient will exist in the region of the hot spot. Since the fuel rods are free to move in the vertical direction, differential expansion between separate rods cannot produce distortion. However, the temperature gradients across individual rods may produce a force tending to bow the midpoint of the rods toward the hot spot. Physics calculations indicate that the net result of this would be a negative reactivity insertion. In practice, no significant bowing is anticipated, since the structural rigidity of the core is more than sufficient to withstand the forces produced. Boiling in the hot spot region would produce a net flow away from that region. However, the heat from fuel is released to the water relatively slowly, and it is considered inconceivable that cross flow will be sufficient to produce significant lattice forces. Even if massive and rapid boiling, sufficient to distort the lattice, is hypothetically postulated, the large void fraction in the hot spot region would produce a reduction in the total core moderator to fuel ratio, and a large reduction in this ratio at the hot spot. The net effect would therefore be a negative feedback. It can be concluded that no conceivable mechanism exists for a net positive feedback resulting from lattice deformation. In fact, a small negative feedback may result. The effect is conservatively ignored in the analyses.

15.4.6.5 Conclusions

Even on a pessimistic basis, the analyses indicate that the described fuel and cladding limits are not exceeded. It is concluded that there is no danger of sudden fuel dispersal into the coolant. Since the peak pressure does not exceed that which would cause stresses to exceed the faulted condition stress limits, it is concluded that there is no danger of further consequential damage to the reactor coolant system. The analyses show that less than 10 percent of the fuel rods enter DNB. Even in the portion of the core which does reach DNB, there will be no excessive release of fission product activity if the limiting hot channel factors are not exceeded (Reference 21).

The analysis shows the acceptance criteria for a RCCA Ejection Accident has been met as follows:

15.4.6.5.1 Fuel Damage

(1) Table 15.4-11 shows the average fuel pellet enthalpy at the hot spot (Maximum fuel stored energy) below 225 cal/gm for non-irradiated fuel and 200 cal/gm (360 Btu/lb) for irradiated fuel.

(2) Table 15.4-11 shows the average clad temperature at the hot spot (Maximum cladding average temperature) below 2700°F, the temperature above which clad embrittlement may be expected.

(3) Table 15.4-11 shows the fuel melting limited to less than the innermost 10 percent of the fuel pellet at the hot spot.

15.4.6.5.2 Maximum RCS Pressure

(1) A detailed calculation of the pressure surge for an ejection worth of one dollar reactivity insertion at BOL, hot full power, indicates that the peak pressure does not exceed that which would cause stress to exceed the faulted condition stress limits. Because the severity of the present analysis does not exceed this worst case analysis, the accident for this plant will not result in an excessive pressure rise or further damage to the RCS.

15.4.6.5.3 Radiological

(1) Section 15.5.23 concludes that offsite exposures from a RCCA ejection accident will be well below the guideline levels specified in 10 CFR Part 100, and that the occurrence of such accidents would not result in undue risk to the public. Table 15.5-52 provides a summary of offsite doses from a rod ejection accident.

15.4.7 RUPTURE OF A WASTE GAS DECAY TANK

Refer to Section 15.5.24 for the description of this event.

15.4.8 RUPTURE OF A LIQUID HOLDUP TANK

Refer to Section 15.5.25 for the description of this event.

15.4.9 RUPTURE OF VOLUME CONTROL TANK

Refer to Section 15.5.26 for the description of this event.

15.4.10 REFERENCES

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15.5 RADIOLOGICAL CONSEQUENCES OF PLANT ACCIDENTS

The purposes of this section are: (a) to identify accidental events that could cause radiological consequences, (b) to provide an assessment of the consequences of these accidents, and (c) to demonstrate that the potential consequences of these occurrences are within the limits, guidelines, and regulations established by the NRC.

An accident is an unexpected chain of events; that is, a process, rather than a single event. In the analyses reported in this section, the basic events involved in various possible plant accidents are identified and studied with regard to the performance of the engineered safety features (ESF). The full spectrum of plant conditions has been divided into four categories in accordance with their anticipated frequency of occurrence and risk to the public. The four categories as defined above are as follows:

Condition I: Normal Operation and Operational Transients

Condition II: Faults of Moderate Frequency

Condition III: Infrequent Faults

Condition IV: Limiting Faults

The basic principle applied in relating design requirements to each of these conditions is that the most frequent occurrences must yield little or no radiological risk to the public; and those extreme situations having the potential for the greatest risk to the public shall be those least likely to occur.

These categories and principles were developed by the American Nuclear Society (Reference 1). Similar, though not identical, categories have been defined in the guide to the Preparation of Environmental Reports (Reference 3). While some differences exist in the manner of sorting the different accidents into categories in these documents, the basic principles are the same.

It should also be noted that the range of plant operating parameters included in the Condition I category, and some of those in the Condition II category, fall in the range of normal operation. For this reason, the radioactive releases and radiological exposures associated with these conditions are analyzed in Chapter 11 and are not discussed separately in this chapter. The analyses of the variations in system parameters associated with Condition I occurrences or operating modes are discussed in Chapter 7 since these states are not accident conditions. In addition, some of the events identified as potential accidents in Regulatory Guide 1.70, Revision 1 (Reference 2), have no significant radiological consequences, or result in minor releases within the range of normal releases, and are thus not analyzed separately in this chapter.

15.5.1 DESIGN BASES

The following regulatory requirements, including Code of Federal Regulations (CFR) 10 CFR Part 100, General Design Criteria (GDC), Safety Guides, and Regulatory Guides are applicable to the DCPP radiological consequence analyses presented in this Chapter. They form the bases of the acceptance criteria and methodologies as described in the following Sections:

(1) 10 CFR Part 100, “Reactor Site Criteria”

(2) 10 CFR 50.67, “Accident Source Term”

(3) General Design Criterion 19, 1971 “Control Room”

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(5) Safety Guide 7, March 1971, “Control of Combustible Gas Concentrations in Containment”

(6) Safety Guide 24, March 1972, “Assumptions Used for Evaluating the Potential Radiological Consequences of a Pressurized Water Reactor Radioactive Gas Storage Tank Failure”

(7) Safety Guide 25, March 1972, “Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident in the Fuel Handling and Storage Facility for Boiling and Pressurized Water Reactors”

(8) Regulatory Guide 1.183, July 2000, “Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors”

(9) Regulatory Guide 1.195, May 2003, “Methods and Assumptions for Evaluating Radiological Consequences of Design Basis Accidents at Light-Water Nuclear Power Reactors”

The following table summarizes the accident events that have been evaluated for radiological consequences. The table identifies the applicable UFSAR Section describing the analysis and results for each event, the offsite/onsite locations and applicable dose limits, and the radiological analysis and isotopic core inventory codes used.

Accident Event	FSAR Section	Boundary	Dose Limit	Radiological Analysis Code(s)	Isotopic Core Inventory Code(s)
CONDITION II					
Loss of Electrical Load	15.5.10	EAB and LPZ Thyroid Whole Body	 300 rem 25 rem	EMERALD	EMERALD
CONDITION III					
Small Break LOCA	15.5.11	EAB and LPZ Thyroid Whole Body	 300 rem 25 rem	EMERALD	EMERALD
Minor Secondary System Pipe Breaks	15.5.12	EAB and LPZ Thyroid Whole Body	 300 rem 25 rem	N/A Refer to Section 15.5.12	N/A Refer to Section 15.5.12
Inadvertent Loading of a Fuel Assembly	15.5.13	EAB and LPZ Thyroid Whole Body	 300 rem 25 rem	N/A Refer to Section 15.5.13	N/A Refer to Section 15.5.13
Complete Loss of Forced Reactor Coolant Flow	15.5.14	EAB and LPZ Thyroid Whole Body	 300 rem 25 rem	N/A Refer to Section 15.5.14	N/A Refer to Section 15.5.14
Under-Frequency	15.5.15	EAB and LPZ Thyroid Whole Body	 300 rem 25 rem	EMERALD	EMERALD
Single Rod Cluster Control Assembly Withdrawal	15.5.16	EAB and LPZ Thyroid Whole Body	 300 rem 25 rem	EMERALD	EMERALD
CONDITION IV					
Large Break LOCA	15.5.17	EAB and LPZ Thyroid Whole Body Control Room Thyroid Whole Body	 300 rem 25 rem 30 rem 5 rem	EMERALD LOCADOSE	EMERALD ORIGEN-2

Accident Event	FSAR Section	Boundary	Dose Limit	Radiological Analysis Code(s)	Isotopic Core Inventory Code(s)
Main Steam Line Break	15.5.18	EAB and LPZ Pre-Accident Iodine Spike Thyroid Whole Body Accident-initiated Iodine Spike Thyroid Whole Body Control Room Thyroid Whole Body	 300 rem 25 rem 30 rem 2.5 rem 30 rem 5 rem	LOCADOSE	ORIGEN-2
Main Feedwater Line Break	15.5.19	EAB and LPZ Thyroid Whole Body	 300 rem 25 rem	N/A Refer to Section 15.5.19	N/A Refer to Section 15.5.19
Steam Generator Tube Rupture	15.5.20	EAB and LPZ Pre-Accident Iodine Spike Thyroid Whole Body Accident-initiated Iodine Spike Thyroid Whole Body Control Room Thyroid Whole Body	 300 rem 25 rem 30 rem 2.5 rem 30 rem 5 rem	RADTRAD	EMERALD-NORMAL
Locked Rotor	15.5.21	EAB and LPZ Thyroid Whole Body Control Room Thyroid Whole Body	 300 rem 25 rem 30 rem 5 rem	EMERALD	EMERALD
Fuel Handling-Fuel Handling Area	15.5.22.1	EAB and LPZ Control Room	0.063 Sv TEDE (6.3 rem) 0.05 Sv TEDE (5 rem)	LOCADOSE	ORIGEN-2

Accident Event	FSAR Section	Boundary	Dose Limit	Radiological Analysis Code(s)	Isotopic Core Inventory Code(s)
Fuel Handling-Inside Containment	15.5.22.2	EAB and LPZ Thyroid Whole Body Control Room Thyroid Whole Body	 75 rem 6 rem 30 rem 5 rem	LOCADOSE	ORIGEN-2
Control Rod Ejection	15.5.23	EAB and LPZ Thyroid Whole Body Control Room Thyroid Whole Body	 300 rem 25 rem 30 rem 5 rem	EMERALD	EMERALD
Waste Gas Decay Tank Rupture	15.5.24	EAB and LPZ Thyroid Whole Body	 300 rem 25 rem	EMERALD	EMERALD
Liquid Holdup Tank Rupture	15.5.25	EAB and LPZ Thyroid Whole Body	 300 rem 25 rem	LOCADOSE	ORIGEN-2
Volume Control Tank Rupture	15.5.26	EAB and LPZ Thyroid Whole Body	 300 rem 25 rem	EMERALD	EMERALD

15.5.2 APPROACH TO ANALYSES OF RADIOLOGICAL EFFECTS OF ACCIDENTS

The potential radiological effects of plant accidents are analyzed by the evaluation of all physical factors involved in each chain of events which might result in radiation exposures to humans. These factors include the meteorological conditions existing at the time of the accident, the radionuclide uptake rates, exposure times and distances, as well as the many factors which depend on the plant design and mode of operation. In these analyses, the factors affecting the consequences of each accident are identified and evaluated, and uncertainties in their values are discussed. Because some degree of uncertainty always exists in the prediction of these factors, it has become general practice to assume conservative values in making calculated estimates of radiation doses. For example, it is customarily assumed that the accident occurs at a time when very unfavorable weather conditions exist, and that the performance of the plant engineered safety systems is degraded by unexpected failures. The use of these unfavorable values for the various factors involved in the analysis provides assurance that each safety system has been designed adequately; that is, with sufficient capacity to cover the full range of effects to which each system could be subjected. For this reason, these conservative values for each factor have been called design basis values.

In a similar way, the specific chain of events in which all unfavorable factors are coincidentally assumed to occur has been called a design basis accident (DBA). In the process of safety review and licensing, the radiation exposure levels calculated for the DBA are compared to the guideline values established in 10 CFR 100.11 and 10 CFR 50.67, and if these calculated exposures fall below the guideline levels, the plant safety systems are judged to be adequate.

The calculated exposures resulting from a DBA are generally far in excess of what would be expected and do not provide a realistic means of assessing the expected radiological effects of real plant accidents.

For this reason, the original licensing basis included two evaluations, or cases, for each accident. The first case, called the expected case, used values, for each factor involved in the accident, which are estimates of the actual values expected to occur if the accident took place. The resulting doses were close to the doses expected to result from an accident of this type. The second case, the DBA, used the customary conservative assumptions. The calculated doses for the DBA, while not a realistic estimate of expected doses, can provide a basis for determination of the design adequacy of the plant safety systems.

The specific values of all important parameters, data, and assumptions used in the radiological exposure calculations are listed in the following sections. The details of the implementation of the equations, models, and parameters for accidents evaluated using the original licensing basis computer code EMERALD are described in the description of the EMERALD computer program (Reference 4) and the EMERALD-NORMAL computer program (Reference 5), which are described briefly in Section 15.5.8.1.

As discussed earlier, some of the radiological source terms for accidents and some of the releases resulting from Condition I and Condition II events have been included in Chapter 11.

15.5.3 ACTIVITY INVENTORIES IN THE PLANT PRIOR TO ACCIDENTS

The fission product inventories in the reactor core, the fuel rod gaps, and the primary coolant prior to an accident have been calculated using the same assumptions, models, and physical data described in Section 11.1, but for different core and plant operating conditions. The pre-accident inventories were calculated using the EMERALD computer code and are similar to those calculated for Tables 11.1-1 through 11.1-12 by the EMERALD-NORMAL code, except for slight differences in some nuclides due to different initial core inventories and irradiation times in the accident calculation.

The steam system operating conditions assumed for the calculation of pre-accident secondary system inventories are listed in Table 11.1-23. It should be noted that these steam system flowrates and masses are approximate lumped values, used for activity balances only, and assume gross lumping of feedwater system component flows and masses. While these values are adequate for activity balances, they should not be

used in the context of actual plant flow and energy balances. The activity inventories and concentrations existing in the secondary system are listed in Table 11.1-26.

Activity inventories in various radwaste system tanks are also listed in sections of Chapters 11 and 12 and will be cross-referenced in the sections of this chapter dealing with accidental releases from these tanks.

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Refueling shutdown studies at operating Westinghouse PWRs indicate that, during cooldown and depressurization of the RCS, a release of activated corrosion products and fission products from defective fuel has been found to increase the coolant activity level above that experienced during steady state operation. An increased core activity release of this sort, commonly referred to as "spiking," could be expected to occur during the depressurization of the RCS as the result of an accident, and should therefore be taken into account in the calculation of post-accident releases of primary coolant to the environment.

Table 15.5-1 illustrates the anticipated coolant activity increases of several isotopes for DCPP during shutdown. This table lists the expected activities during steady state operation and anticipated peak activities during plant cooldown operations. These data are based on measurements from an operating PWR that is similar in design to the DCPP and has operated with significant fuel defects. The measured activity levels for the operating plant are also included in Table 15.5-1.

The dominant nongaseous fission product released to the coolant during system depressurization is I-131. The activity level in the coolant was observed to be higher than the normal operating level for nearly a week following initial plant shutdown with the system purification rate varying between approximately 1×10^{-5} and 3×10^{-5} per second. Although lesser in magnitude, the other fission product particulates (cesium isotopes) exhibited a similar pattern of release and removal by purification. It is reasonable to project these data to the DCPP since the purification constants are similar, and it is standard operating procedure to purify the coolant through the demineralizers during plant cooldown.

Fission gas data from operating plants indicate a maximum increase of approximately 1.5 over the normal coolant gas activity concentration. However, system degassification procedures are implemented prior to and during shutdowns, and have proven to be an effective means for reducing the gaseous activity concentration and controlling the activity to levels lower than the steady state value during the entire cooldown and depressurization procedure. Although a steady state Xe-133 concentration of 127 μCi/gm was observed prior to degassification procedures (see Table 15.5-1), the maximum coolant concentration during the reactor depressurization was 65 μCi/gm. Further, the coolant activity was then reduced to approximately 1 μCi/gm in less than two days of degassification.

The corrosion product activity releases have been determined to be predominantly dissolved Co-58. From Table 15.5-1, it is noted that this contribution is less than 1 percent of the total expected coolant activity and is, therefore, considered to be a minor contribution.

For the calculation of the effect of spiking on accidental plant releases, the original licensing basis assumed the dominant isotopes were iodines, and all others were neglected. Using the measured I-131 concentrations given in Table 15.5-1 and a primary purification rate of 1 x 10^{-5} per second, effective I-131 fuel escape rate to the reactor coolant during a spike of 30 times the normal equilibrium value was calculated. This value was then applied to all iodine isotopes. Subsequent analyses assumed an accident-initiated spike of 500 times (for MSLB, refer to Section 15.5.18) and 335 times (for SGTR, refer to Section 15.5.20) the normal equilibrium value, as described in the appropriate subsections that follow, to be consistent with Technical Specification 3.4.16.

The duration of the spike was assumed to be 8 hours. This assumption can be justified by examining graphs of I-131 coolant concentration versus time during shutdowns for operating BWR plants (Reference 14). The assumption that the fuel escape rate continues at the elevated rates discussed above for the full 8 hours of the spike is conservative. The effect of iodine spiking was included in all accidents that involved leakage of primary coolant directly or indirectly to the environment.

15.5.4 EFFECTS OF PLUTONIUM INVENTORY ON POTENTIAL ACCIDENT DOSES

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Because of the somewhat higher fission yields of some isotopes associated with thermal fissions in Pu-239, a sensitivity study was conducted to determine the possible influence of this effect on potential accident doses.

This study demonstrates that accident doses are only slightly affected by the incorporation of Pu-239 fission yields into total core fission yields, even using the EOL plutonium inventories. The resulting differences, listed in Table 15.5-2, indicate that thyroid doses generally increase from 4 to 6 percent, and whole body doses generally decreased, from 2 to 5 percent, assuming the accident occurred at EOL.

In this study, total core fission yields were calculated by a mass weighting of U-235 fission yields and Pu-239 fission yields. Because the core mass of U-235 is considerably greater than the core mass of Pu-239, total core fission yields are close to U-235 fission yields. The masses of U-238 and Pu-241 that fission are extremely small, and thus U-238 and Pu-241 have essentially no effect on the total core fission yields.

15.5.5 POST-ACCIDENT METEOROLOGICAL CONDITIONS

For the analyses of offsite doses from the DBAs, the rare and unfavorable set of atmospheric dilution factors assumed in the NRC Regulatory Guide 1.4, Revision 1 (Reference 6) was used. On the basis of meteorological data collected at the DCPP site, these unfavorable dilution factors, assumed for the design bases cases, are not expected to exist for onshore wind directions more than 5 percent of the time. The particular values used for this site are given in Table 15.5-3.

For the analyses of offsite doses from the expected case accidents, the assumed atmospheric dilution factors are listed in Table 15.5-4. For these cases, 10 percent of the design basis case numbers were used. On the basis of study of the site data at DCPP, this assumption will result in calculated exposures higher than would be expected.

Because of the low probability of occurrence associated with these assumed dilution factors, significant downwind decay, variable shifts in population distribution due to possible emergency evacuation, and large variations in concentrations due to downwind topographical characteristics, appropriate assumptions for population exposure (man-rem) estimates following a significant accidental release are difficult to select. It is clear that using the same factors of conservatism established for individual exposures at locations near the site (the regulatory guide dilution factors) would yield calculated population exposures much higher than could physically occur. For these reasons, the population exposures (man-rem) for the expected cases have been calculated using the long-term dilution factors given in Table 15.5-5, and ten times these values have been assumed for the DBA cases.

Effects of release duration on downwind ground level concentration have been measured directly and determined theoretically from knowledge of the horizontal and vertical spectrum of turbulence. Both the observations and theory generally agree that only the horizontal components of turbulence near ground level contain any significant amount of energy in periods longer than a few seconds. As a result, only the lateral dimension of the cloud need be modified for concentration estimates for noncontinuous releases. Slade (Reference 7) using the approach recommended by Cramer, gives a time-dependent adjustment of the lateral component of turbulence to be:

$$\sigma_\theta (T) = \sigma_\theta (T_o) (T/T_o)^{0.2} \qquad (15.5\text{-}1)$$

where:

$\sigma_\theta (T)$ = lateral intensity of turbulence of a time period T, where T is a value less than 10 minutes

$\sigma_\theta (T_o)$ = lateral intensity of turbulence measured over a time period T_o, where T_o is on the order of 10 minutes

Near a source there is a direct linear relationship between σ_θ and the plume crosswind dimension σ_y so that the σ_y versus distance curves presented by Slade can be directly scaled by the factor $(T/T_o)^{0.2}$ to provide estimates of a reference σ_y at about 100 meters downwind from the source. Beyond this distance, the lateral expansion rates for continuous and noncontinuous point source releases are approximately the same, and thus the ratio of short-term release concentration to continuous release concentration for point sources is independent of stability class, downwind distance, or windspeed. For distances less than a few thousand meters the ratio approaches unity as the volume of the source increases.

Using the above scaling concept, the dilution equation in Regulatory Guide 1.4, Revision 1, and the cloud dimension curves given by Slade, the ratio of short-term release concentration to continuous release concentration was calculated for several different release durations (Figure 15.5-1). For a10-second duration, the short-term dilution factor is only 2.3 higher than the continuous release dilution factor, and thus the appropriate short-term release correction is within the uncertainty limits of the continuous release dilution factor.

The various plant accidents considered in Sections 15.2, 15.3, and 15.4 may result in activity release through various pathways: containment leakage, secondary steam dumping, ventilation discharge, and radioactive waste system discharge.

Post-accident containment leakage is a slow continuous process, and thus continuous release dilution factors apply for these cases.

Because of secondary loop isolation capabilities and because significant activity release is accompanied by large steam release, secondary steam dumping accidents release significant quantities of activity only through relief valves. Relief valve flow limitations combined with large steam release result in activity releases of long duration. Thus continuous release dilution factors apply for these cases.

The approximate duration of a ventilation discharge activity release can be estimated by dividing the volume of contaminated air by the discharge flowrate. Because estimates of release duration for liquid holdup tank rupture, gas decay tank rupture, volume control tank rupture, and fuel handling area accident are all over in 10 minutes, continuous release dilution factors apply for these cases.

Continuous release dilution factors have been applied to all Conditions II, III, and IV accidents discussed in Chapter 15 for the following reasons:

(1) Almost all Conditions II, III, and IV releases are definitely long-term releases

(2) Releases that might be considered short-term releases result in exposures well within 10 CFR Part 100 limits

(3) Short-term release dilution factors are only about twice as high as continuous release dilution factors

(4) The appropriate short-term release corrections are within the range of the uncertainties in the continuous release dilution factors

Furthermore, the above reasons indicate that a more sophisticated or complex short-term release dilution model is not justified.

The atmospheric dispersion factors for pressurization and infiltration air flows to the control room are analyzed using the modified Halitsky χ/Q methodology, which is discussed below.

As a result of the TMI accident, the NRC, in NUREG-0737 Section III.D.3.4, asked all nuclear power plants to review their post-LOCA control room habitability designs using the guidance of Standard Review Plan (SRP) 6.4 and the 1974 Murphy-Campe (M-C) paper (Reference 17). These reviews concluded that the atmospheric dispersion factor (χ/Q) methodology recommended in the M-C paper was overly conservative and inappropriate for most of the plant designs. The M-C equations are based primarily on the Halitsky data for round-topped EBR-II (PWR type) containments and are valid only for intake locations at least a half containment diameter from the containment wall. In most cases, however, the intake locations are closer to the building causing the wake. Thus, review of recent literature on building wake χ/Qs, models, wind tunnel tests, and field measurements resulted in the modified Halitsky χ/Q model.

Historically, the preliminary work on building wake χ/Qs was based on a series of wind tunnel tests by James Halitsky et al. Halitsky summarized these results in Meteorology and Atomic Energy 1968, D. H. Slade, Editor (Reference 7). In 1974 K. Murphy and K. Campe of the NRC published their paper based on a survey of existing data. This χ/Q methodology, which presented equations without derivation or justification, was adopted as the interim methodology in SRP 6.4 in 1975. Since that time, a series of actual building wake χ/Q measurements have been conducted at Rancho Seco (Reference 25), and several other papers have been published documenting the results of additional wind tunnel tests (see References 26 through 31).

The Diablo Canyon plant complex is composed of square-edged buildings and two cylindrical containment buildings. Infiltration air into the control room would come from the auxiliary building, which has air intakes slightly above the control room. This intake of air will be subject to building wake caused by the portion of the containment building above the highest roof elevation of the auxiliary building. Pressurization air for the control room is provided from intakes on the turbine building. The intake will be subject to building wake caused by a portion of the containment building above the turbine building roof and a portion of the turbine building wall facing west and the wall facing north.

J. Halitsky's efforts, summarized in Reference 7, present the basic equation as follows:

$$\chi / Q = K / A\bar{u} \qquad (15.5\text{-}2)$$

where

A = cross sectional area, m^2 orthogonal to $\bar{u}$

$\bar{u}$ = wind speed, m/s

K = isopleth (concentration coefficient - dimensionless)

It is found in many cases that the above Halitsky equation still provides a reasonable estimate of χ/Q. The following correction factors can be applied to this equation to account for situation and plant-specific features:

- Stream line flows are used in most wind tunnel tests
- Release points are generally much higher than 10 meters above ground
- Null wind velocity is observed at certain periods of time
- Isothermal temperatures are used in wind tunnel tests
- Buoyancy and jet momentum effects are ignored

Typical 1 hr field tests account for plume meander effects, while 3 to 5 minute wind tunnel tests do not.

A modified Halitsky χ/Q methodology, formulated by R. Bhatia, et al (Reference 32), is presented below.

$$\chi/Q = \frac{K}{A\bar{u}} \times f_1 \times f_2 \times f_3 \times f_4 \times f_5 \times f_6 \ \ (\mathrm{sec/m^3}) \qquad (15.5\text{-}3)$$

This modified Halitsky methodology is inherently conservative because the wind is assumed to be blowing towards the control room during the first or worst part of the accident, and because 5 percent wind speeds are used rather than 50 percent. In addition, the adjustment factors are always biased towards the minimum reduction that the data justifies.

As a test of the modified Halitsky method, calculated values of χ/Q, without using factors f_4 and f_5 due to their uncertainty, were compared to the 1-hour field test χ/Q data from Rancho Seco. Only one χ/Q was found to be higher than the calculated value. This was due to an external wake influence caused by wind channeling between the

nearby cooling towers. The wind channeling prevented the normal wake turbulence and variation effects over time, which normally spread the plume over a wide area. In most cases the modified Halitsky χ/Q was found to be a conservative estimate of the measured χ/Q; in some cases it was significantly higher.

The choice of K factors and the suggested modifying factors, f_1, f_2, etc., are discussed below.

K factors:

The choice of an appropriate K factor from the wind tunnel test data is critical for the χ/Q estimate to be valid. Halitsky in Reference 7 has several sets of K isopleths for round-topped containments (for PWRs) and block buildings (for BWRs). Multiple building complexes must be simulated by single equivalent structures. The effluent velocity to wind speed ratio of approximately 1 is valid for most power coolant systems. Various angles of wind incidence are shown to account for vortexing that could result in worse conditions than a wind normal to the building face. K factors should be estimated for various combinations of wind incidence angle and the appropriate effective building cross-sectional area causing the wake (not just the containment area) to determine the peak value, as was done by Walker (Reference 26).

The K factors were determined from Figure 5.29c in Reference 7, based on a conservative analysis of the locations for infiltration and pressurization intake airflows and the appropriate dimensions relative to the containment. A single pressurization intake nearest the containment was assumed. The selected K factors and appropriate building cross-sectional areas used for the base χ/Q values are given below. The 5 percent wind speed was derived from an analysis of Diablo Canyon meteorological data over a period of 10 years.

Case	K	$\bar{u}$ (meter/second)	A(m^2)	Base χ/Q (sec/m^3)
Pressurization	4	1	3690	1.084×10^{-3}
Infiltration	5	1	1661	3.01×10^{-3}

$\bar{u}$*, wind speed:*

Halitsky's K values are based on wind speeds measured at the top of the containment or building. Therefore, the M-C 5 percent wind speed at a 10 meter height should be adjusted to the actual speed at the top of containment or release point. The 5 percent wind speed is adjusted using the formulation presented by Wilson (Reference 30) as follows.

$$\bar{u}_T = \bar{u}\left(\frac{Z}{Z_{Ref}}\right).23 \qquad (15.5\text{-}4)$$

where:

$\bar{u}_T$ = wind speed at height Z
Z_{Ref} = 10 meters (5 percent wind speed reference height)

f_1, wind speed change factor/ f_2, wind direction change factor:

The factors shown below were used. They are based on Diablo Canyon meteorological data for a 10 year period of record.

Time Periods	f_1	f_2
0 - 8 hrs	1.0	1.0
8 - 24 hrs	0.83	0.92
24 - 96 hrs	0.66	0.84
96 - 720 hrs	0.48	0.67

f_3, wind turbulence effect:

Wilson in Reference 30 and field tests confirm Halitsky's statement that his K isopleths are a factor of 5 to 10 too conservative due to not accounting for random fluctuations of the wind approaching the building. Therefore, a factor of 0.2 was used for f_3.

f_4, elevated release effect:

Bouwmeester et al. (Reference 31) indicate that there are up to 10 null wind speed conditions during an hour of data collection. During these periods the effects of jet momentum, plume rise and buoyancy would result in the radioactive effluent being discharged above the effective wake boundary and thus not entering the wake cavity. A reduction factor of 1 was used.

F_5, time averaging effects:

Wind speed variations and wind direction meandering effects are not modeled in wind tunnel tests to account for this effect. Reference 31 indicates the use of the following equation:

$$C_p = C_m\left(\frac{t_p}{t_m}\right)^{-1/2} \qquad (15.5\text{-}5)$$

where:

C_p = prototype concentration

C_m = model concentration

t_p = prototype sampling time

t_m = model equivalent sampling time

Normal wind tunnel data is taken for 3 to 10 minute samples. Thus, for a 1-hour field test, C_p = 0.22 to 0.41 C_m, and for an 8 hour field test, C_p = 0.08 to 0.14. C_m A value of 0.5 was conservatively assumed for f_5.

f_6, adjustments to top of containment:

To account for wind speed at the top of containment, instead of the M-C 5 percent wind speed at 10 meter height, the factor $f_6 = \bar{u}/\bar{u}_T$ was included. The f_6 value equals 0.65.

Table 15.5-6 presents the resultant atmospheric dispersion factors (χ/Q) calculated using the modified Halitsky χ/Q methodology. These dispersion factors do not take credit for dual pressurization inlets and do not include the control room occupancy factors.

15.5.6 RATES OF ISOTOPE INHALATION

The breathing rates used in the calculations of inhalation doses are listed in Table 15.5-7. These values are based on the average daily breathing rates assumed in ICRP Publication 2 (Reference 8) which are also used in Regulatory Guide 1.4, Revision 1. The active breathing rates are used for all onsite dose calculations, which are based on expected exposure times.

15.5.7 POPULATION DISTRIBUTION

The distribution of population surrounding the plant site, which was used for the population exposure calculations, is discussed in Section 2.1, and the population distribution used is listed in Table 15.5-8. The actual post-accident population distribution could be significantly lower if any evacuation plan were implemented.

15.5.8 RADIOLOGICAL ANALYSIS PROGRAMS

15.5.8.1 Description of the EMERALD (Revision I) and EMERALD-NORMAL Program

The EMERALD program (Reference 4) is designed for the calculation of radiation releases and exposures resulting from abnormal operation of a large PWR. The

approach used in EMERALD is similar to an analog simulation of a real system. Each component or volume in the plant that contains a radioactive material is represented by a subroutine, which keeps track of the production, transfer, decay, and absorption of radioactivity in that volume. During the course of the analysis of an accident, activity is transferred from subroutine to subroutine in the program as it would be transferred from place to place in the plant. For example, in the calculation of the doses resulting from a LOCA, the program first calculates the activity built up in the fuel before the accident, then releases some of this activity to the containment volume. Some of this activity is then released to the atmosphere. The rates of transfer, leakage, production, cleanup, decay, and release are read in as input to the program.

Subroutines are also included that calculate the onsite and offsite radiation exposures at various distances for individual isotopes and sums of isotopes. The program contains a library of physical data for 25 isotopes of most interest in licensing calculations, and other isotopes can be added or substituted. Because of the flexible nature of the simulation approach, the EMERALD program can be used for most calculations involving the production and release of radioactive materials, including design, operational and licensing studies. The complete description of the program, including models and equations, is contained in Reference 4.

The EMERALD-NORMAL program (Reference 5) is a program incorporating the features of EMERALD, but designed specifically for releases from normal and near-normal operating conditions. It contains an expanded library of isotopes, including all those of interest in gaseous and liquid environmental exposures. Models for a radwaste system are included, using the specific configuration of radwaste system components in the DCPP. The program contains a subroutine for doses via liquid release pathways developed by the Bechtel Corporation and a tritium subroutine. The code calculates activity inventories in various radwaste tanks and plant components which are used for the initial conditions for accidents involving these tasks. In addition, it is used in some near-normal plant conditions classified in this document as Condition I and Condition II and discussed in Chapter 11.

15.5.8.2 Description of the LOCADOSE Program

The LOCADOSE program (Reference 47) is designed to calculate radionuclide activities, integrated activities, and releases from a number of arbitrarily specified regions. One region is specified as the environment. Doses and dose rates for five organs (thyroid, lung, bone, beta skin, and whole body) can be calculated for each region, and for a number of offsite locations with specified atmospheric dispersion factors. The control room can be specified as a special region for convenience in modeling airborne doses to the control room operators.

15.5.8.3 Description of the ORIGEN-2 Program

The core inventory and gamma ray energy spectra of post-accident fission products for selected accidents (See Section 15.5.1) were computed using the ORIGEN-2 computer program.

ORIGEN-2 (Reference 50) is a versatile point depletion and decay computer code for use in simulating nuclear fuel cycles and calculating the nuclide compositions of materials contained therein. This code represents a revision and update of the original ORIGEN computer code which has been distributed world-wide beginning in the early 1970s. Included in it are provisions for incorporating data generated by more sophisticated reactor physics codes, free-format input, the ability to simulate a wide variety of fuel cycle flowsheets, and more flexible and controllable output features.

15.5.8.4 Description of the ISOSHLD Program

ISOSHLD (Reference 9) is a computer code used to perform gamma ray shielding calculations for isotope sources in a wide variety of source and shield configurations. Attenuation calculations are performed by point kernel integration; for most geometries this is done by Simpson's rule numerical integration. Source strength in uniform or exponential distribution (where applicable) may be calculated by the linked fission product inventory code RIBD or by other options as desired. Buildup factors are calculated by the code based on the number of mean free paths of material between the source and detector points, the effective atomic number of a particular shield region (the last unless otherwise chosen), and the point isotropic Nuclear Development Associates (NDA) buildup data available as Taylor coefficients in the effective atomic number range of 4 to 82. Other data needed to solve most isotope shielding problems of practical interest are linked to ISOSHLD in various libraries.

15.5.8.5 Description of the ISOSHLD II Program

ISOSHLD II (Reference 11) is a shielding code that is principally intended for use in calculating the radiation dose, at a field point, from bremsstrahlung and/or decay gamma rays emitted by radioisotope sources. This program, with the newly-added bremsstrahlung mode, is an extension of the earlier version (ISOSHLD). Five shield regions can be handled with up to twenty materials per shield; the source is considered to be the first shield region, i.e., bremsstrahlung and decay gamma rays are produced only in the source. Point kernel integration (over the source region) is used to calculate the radiation dose at a field point.

15.5.8.6 Description of the RADTRAD Program

RADTRAD (Reference 52) uses a combination of tables and numerical models of source term reduction phenomena to determine the time-dependent dose at user-specified locations for a given accident scenario. It also provides the inventory, decay chain, and dose conversion factor tables needed for the dose calculation. The

RADTRAD code can be used to assess occupational radiation exposure, typically in the control room, as well as site boundary doses, and to estimate the dose attenuation due to modification of a facility or accident sequence.

15.5.9 (DELETED)

The information previously in this section has been moved to Section 15.5.8.4.

15.5.10 RADIOLOGICAL CONSEQUENCES OF CONDITION II FAULTS

15.5.10.1 Acceptance Criteria

The radiological consequences of accidents analyzed in Section 15.2 (or from other events involving insignificant core damage, but requiring atmospheric steam releases) shall not exceed the dose limits of 10 CFR 100.11 as outlined below:

(1) An individual located at any point on the boundary of the exclusion area for the two hours immediately following the onset of the postulated fission product release shall not receive a total radiation dose to the whole body in excess of 25 rem or a total radiation dose in excess of 300 rem to the thyroid from iodine exposure.

(2) An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose to the whole body in excess of 25 rem, or a total radiation dose in excess of 300 rem to the thyroid from iodine exposure.

15.5.10.2 Identification of Causes and Accident Description

As reported in Section 15.2, Condition II faults are not expected to cause breach of any of the fission product barriers, thus preventing fission product release from the core or plant. Under some conditions, however, small amounts of radioactive isotopes could be released to the atmosphere following Condition II events as a result of atmospheric steam dumps required for plant cooldown. The particular Condition II events that are expected to result in some atmospheric steam release are:

(1) Loss of electrical load and/or turbine trip

(2) Loss of normal feedwater

(3) Loss of offsite power to the station auxiliaries

(4) Accidental depressurization of the main steam system

The amount of steam released following these events depends on the time relief valves remain open and the availability of condenser bypass cooling capacity.

The amount of radioactive iodine released depends on the amount of steam released and the iodine concentration in the steam generator water prior to the accident. An analysis of potential thyroid doses has been made over the full range of possible values of these two key parameters; the results are presented in Figures 15.5-2 through 15.5-5. As shown on the figures, the potential thyroid doses are higher with increasing steam releases and iodine concentrations. Figures 15.5-2 and 15.5-3 are results that assume Regulatory Guide 1.4, Revision 1, assumptions for post-accident meteorology and breathing rates (Design Basis Case Assumptions). As shown in Figure 15.5-2, approximately 1.6 x 10^6 lbm of steam is the maximum steam release expected for a full cooldown without any condenser availability, and a steam release of approximately 1 x 10^5 lbm would result from releasing only the contents of one steam generator due to a safety valve release or steam line break with condenser cooling available.

Figures 15.5-2 through 15.5-5 illustrate the range of possible thyroid doses from Condition II events. The highest anticipated doses would result from an event such as loss of electrical load, and the potential thyroid and whole body doses from this particular event have been analyzed using the EMERALD program. For both the design basis case and the expected case, it was assumed that 656,000 lbm of steam would be released to the atmosphere during the first 2 hours, and an additional 1,035,000 lbm would be released during the following 6 hours for a limiting total release of about 1.7E+06 lbm (see Table 6.4.2-1 of Reference 49 for a summary of OSG and RSG Condition II event steam releases). The assumptions used for meteorology, breathing rates, population density, and other common factors were described in earlier paragraphs. Note that the preceding steam release quantities are associated with the original steam generator (OSG) loss of load (LOL) analysis which provides the basis for the dose analysis of record. These values are greater than the replacement steam generator (RSG) LOL with Tavg and Tfeed Range analysis releases (651,000 lbm and 1,023,000 lbm, respectively) and are therefore bounding since total dose is proportional to total steam release.

For the design basis case, it was assumed that the plant had been operating continuously with 1 percent fuel cladding defects and 1 gpm primary-to-secondary leakage. For the expected case calculation, operation at 0.2 percent defects and 20 gallons per day to the secondary was assumed. In both cases, leakage of water from primary to secondary was assumed to continue during cooldown at 75 percent of the pre-accident rate during the first 2 hours and at 50 percent of the pre-accident rate during the next 6 hours. These values were derived from primary-to-secondary pressure differentials during cooldown.

It was also conservatively assumed for both cases that the iodine partition factor in the steam generators releasing steam was 0.01, on a mass basis. In addition, to account for the effect of iodine spiking, fuel escape rate coefficients for iodines of 30 times the normal operation values given in Table 11.1-8 were used for a period of 8 hours

following the start of the accident. Other detailed and less significant modeling assumptions are presented in Reference 4.

The resulting potential exposures from this type of accident are summarized in Table 15.5-9 and are consistent with the parametric analyses presented in Figures 15.5-2 through 15.5-5.

15.5.10.3 Conclusions

It can be concluded from the results discussed that the occurrence of any of the events analyzed in Section 15.2 (or from other events involving insignificant core damage, but requiring atmospheric steam releases) will result in insignificant radiation exposures.

Additionally, the analysis demonstrates that the acceptance criteria are met as follows:

(1) The radiation dose to the whole body and to the thyroid of an individual located at any point on the boundary of the exclusion area for the two hours immediately following the onset of the postulated fission product release are insignificant as shown in Table 15.5-9.

(2) The radiation dose to the whole body and to the thyroid of an individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), are insignificant as shown in Table 15.5-9.

15.5.11 RADIOLOGICAL CONSEQUENCES OF A SMALL-BREAK LOCA

15.5.11.1 Acceptance Criteria

(1) The radiological consequences of a small-break loss-of-coolant-accident (SBLOCA) shall not exceed the dose limits of 10 CFR 100.11 as outlined below:

   i. An individual located at any point on the boundary of the exclusion area for the two hours immediately following the onset of the postulated fission product release shall not receive a total radiation dose to the whole body in excess of 25 rem or a total radiation dose in excess of 300 rem to the thyroid from iodine exposure.

   ii. An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose to the whole body in excess of 25 rem, or a total radiation dose in excess of 300 rem to the thyroid from iodine exposure.

(2) In accordance with the requirements of GDC 19, 1971, the dose to the control room operator under accident conditions shall not be in excess of 5 rem whole body or its equivalent to any part of the body (i.e., 30 rem thyroid and beta skin, Reference 51) for the duration of the accident.

15.5.11.2 Identification of Causes and Accident Description

As discussed in Section 15.3.1, a SBLOCA is not expected to cause fuel cladding failure. For this reason, the only activity release to the containment will be the dissolved noble gases and iodine in the reactor coolant water expelled from the pipe rupture. Some of this activity could be released to the containment atmosphere as the water flashes, and some of this amount could leak from the containment as a result of a rise in containment pressure.

The detailed description of the models used in calculating the potential exposures from a small LOCA is contained in Reference 4, and a general description is contained in Section 15.5.17 of this report. The specific assumptions used in the analysis are as follows:

(1) The fission product inventories, meteorological data, breathing rates, and population data are described in Sections 15.5.3, 15.5.5, 15.5.6, and 15.5.7, respectively. Other common assumptions are described in the previous sections of 15.5.

(2) It has been assumed that all of the water contained in the RCS is released to the containment. For the design basis case, the reactor coolant activities associated with 1 percent defective cladding were used; and for the expected case, the reactor coolant activities associated with 0.2 percent defective cladding were used. These activities and concentrations are listed in Tables 11.1-11 and 11.1-12, and all models and assumptions used in determining these values are described in Section 11.1.

(3) Of the amounts of noble gases contained in the primary coolant, 100 percent is assumed to be released to the containment atmosphere at the time of the accident. For the iodines, it is assumed that only 10 percent of the dissolved iodine in the coolant is released to the containment atmosphere, due to the solubility of the iodine. It is assumed that the amounts of iodine in chemical forms that are not affected by the spray system are negligible. These release fractions are used for both the design basis case and the expected case.

(4) In addition, to account for the effect of iodine spiking, all of the activity released from the fuel up to 8 hours after the accident is assumed to be released to the containment. Of the amounts of noble gases released to the containment, 100 percent is assumed to be released to the containment atmosphere. For the iodines, it is assumed that only

10 percent of the iodines released to the containment are released to the containment atmosphere.

(5) The spray removal rates for the SBLOCA are assumed to be the same as those applicable for the large break LOCA as described in Section 15.5.17.

(6) The containment leakage rates in this analysis are also assumed to be the same as for the large break LOCA and are discussed in Section 15.5.17.

The resulting potential exposures are listed in Table 15.5-10 and demonstrate that all calculated doses are well below the guideline values specified in 10 CFR 100.11. Since the activity releases from this type of event will be significantly lower than those from a large break LOCA, any control room exposure which might occur would be well within the established criteria discussed in Section 15.5.17. In addition, because of significantly lower fission product releases to the sump and the absence of any zirconium-water reaction, the amounts of free hydrogen produced by sump radiolysis following a small LOCA would not be of concern.

15.5.11.3 Conclusions

The analysis demonstrates that the acceptance criteria are met as follows:

(1) The radiation dose to the whole body and to the thyroid of an individual located at any point on the boundary of the exclusion area for the two hours immediately following the onset of the postulated fission product release are well within the dose limits of 10 CFR 100.11 as shown in Table 15.5-10.

(2) The radiation dose to the whole body and to the thyroid of an individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), are well within the dose limits of 10 CFR 100.11 as shown in Table 15.5-10.

(3) Since the activity releases from the SBLOCA are less than those from a large-break LOCA (LBLOCA), any control room dose which might occur would be well within the established criteria discussed in Section 15.5.17.

15.5.12 RADIOLOGICAL CONSEQUENCES OF MINOR SECONDARY SYSTEM PIPE BREAKS

15.5.12.1 Acceptance Criteria

The radiological consequences of accidents analyzed in Section 15.3 such as minor secondary system pipe breaks shall not exceed the dose limits of 10 CFR 100.11 as outlined below:

(1) An individual located at any point on the boundary of the exclusion area for the two hours immediately following the onset of the postulated fission product release shall not receive a total radiation dose to the whole body in excess of 25 rem or a total radiation dose in excess of 300 rem to the thyroid from iodine exposure.

(2) An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose to the whole body in excess of 25 rem, or a total radiation dose in excess of 300 rem to the thyroid from iodine exposure.

15.5.12.2 Identification of Causes and Accident Description

The effects on the core of sudden depressurization of the secondary system caused by an accidental opening of a steam dump, relief or safety valve were described in Section 15.2 and apply also to the case of minor secondary system pipe breaks. As shown in that analysis, no core damage or fuel rod failure is expected to occur. In Section 15.5.18, analyses are presented that show the effects on the core of a major steam line break, and, in this case also, no fuel rod failures are expected to occur.

The analyses presented in Section 15.2 demonstrate that a departure from nucleate boiling ratio (DNBR) of less than the safety analysis limit will not occur anywhere in the core in the event of a minor secondary system pipe rupture. The possible radiological consequences of this event, due to the release of some steam that might contain radioactive iodines, are discussed in Section 15.5.10. The resulting thyroid doses are presented parametrically in Figures 15.5-2 through 15.5-5 as a function of quantity of steam released and secondary system activity. In the event that a complete plant cooldown without condenser cooling capacity is necessary following the break, the potential exposures would be the same as those reported in Table 15.5-9 for loss of electrical load.

15.5.12.3 Conclusions

On the basis of the discussed results, it can be concluded that the potential exposures following a minor secondary system pipe rupture would be insignificant. Additionally, the analysis demonstrates that the acceptance criteria are met as follows:

- The radiation dose to the whole body and to the thyroid of an individual located at any point on the boundary of the exclusion area for the two hours immediately following the onset of the postulated fission product release are insignificant as shown in Table 15.5-9.

- The radiation dose to the whole body and to the thyroid of an individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), are insignificant as shown in Table 15.5-9.

15.5.13 RADIOLOGICAL CONSEQUENCES OF INADVERTENT LOADING OF A FUEL ASSEMBLY INTO AN IMPROPER POSITION

15.5.13.1 Acceptance Criteria

Fuel assembly loading errors shall be prevented by administrative procedures implemented during core loading. In the unlikely event that a loading error occurs, analyses supporting Section 15.3.3 shall confirm that no events leading to radiological consequences shall occur as a result of loading errors.

15.5.13.2 Identification of Causes and Accident Description

Fuel and core loading errors such as inadvertently loading one or more fuel assemblies into improper positions, loading a fuel rod during manufacture with one or more pellets of the wrong enrichment, or loading a full fuel assembly during manufacture with pellets of the wrong enrichment will lead to increased heat fluxes if the error results in placing fuel in core positions calling for fuel of lesser enrichment. The inadvertent loading of one or more fuel assemblies requiring burnable poison rods into a new core without burnable poison rods is also included among possible core loading errors. Because of margins present, as discussed in detail in Section 15.3.3, no events leading to radiological consequences are expected as a result of loading errors.

15.5.13.3 Conclusions

Because of margins present, as discussed in detail in Section 15.3.3, no events leading to radiological consequences are expected as a result of loading errors.

15.5.14 RADIOLOGICAL CONSEQUENCES OF COMPLETE LOSS OF FORCED REACTOR COOLANT FLOW

15.5.14.1 Acceptance Criteria

The radiological consequences of small amounts of radioactive isotopes that could be released to the atmosphere as a result of atmospheric steam dumping required for plant cooldown following a complete loss of forced reactor coolant flow shall not exceed the dose limits of 10 CFR 100.11 as outlined below:

(1) An individual located at any point on the boundary of the exclusion area for the two hours immediately following the onset of the postulated fission product release shall not receive a total radiation dose to the whole body in excess of 25 rem or a total radiation dose in excess of 300 rem to the thyroid from iodine exposure.

(2) An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose to the whole body in excess of 25 rem, or a total radiation dose in excess of 300 rem to the thyroid from iodine exposure.

15.5.14.2 Identification of Causes and Accident Description

As discussed in Section 15.3.4, a complete loss of forced reactor coolant flow may result from a simultaneous loss of electrical supplies to all reactor coolant pumps (RCPs). If the reactor is at power at the time of the accident, the immediate effect of loss of coolant flow is a rapid increase in the coolant temperature.

The analysis performed and reported in Section 15.3.4 has demonstrated that for the complete loss of forced reactor coolant flow, the DNBR does not decrease below the safety analysis limit during the transient, and thus there is no cladding damage or release of fission products to the RCS. For this reason, this accident has no significant radiological effects.

15.5.14.3 Conclusions

The analysis described in Section 15.3.4 demonstrates that there are no significant environmental effects of the Complete Loss of Forced Reactor Coolant Flow event. Therefore, the acceptance criteria are met as follows:

(1) The radiation dose to the whole body and to the thyroid of an individual located at any point on the boundary of the exclusion area for the two hours immediately following the onset of the postulated fission product release are insignificant.

(2) The radiation dose to the whole body and to the thyroid of an individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), are insignificant.

15.5.15 RADIOLOGICAL CONSEQUENCES OF AN UNDERFREQUENCY ACCIDENT

15.5.15.1 Acceptance Criteria

The radiological consequences of small amounts of radioactive isotopes that could be released to the atmosphere as a result of atmospheric steam dumping required for plant cooldown following an underfrequency accident shall not exceed the dose limits of 10 CFR 100.11 as outlined below:

(1) An individual located at any point on the boundary of the exclusion area for the two hours immediately following the onset of the postulated fission product release shall not receive a total radiation dose to the whole body in excess of 25 rem or a total radiation dose in excess of 300 rem to the thyroid from iodine exposure.

(2) An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose to the whole body in excess of 25 rem, or a total radiation dose in excess of 300 rem to the thyroid from iodine exposure.

15.5.15.2 Identification of Causes and Accident Description

A transient analysis for this unlikely event has been carried out. The analysis demonstrates that for an underfrequency accident, the DNBR does not decrease below the safety analysis limit during the transient, and thus there is no cladding damage or release of fission products to the RCS. However, small amounts of radioactive isotopes could be released to the atmosphere as a result of atmospheric steam dumping required for plant cooldown.

A detailed discussion of the potential radiological consequences of accidents involving atmospheric steam dumping is presented in Section 15.5.10. From the parametric analyses presented in that section, the potential exposures from an underfrequency accident are given in Table 15.5-11. On the basis of these potential exposures, it can be concluded that, although very unlikely, the occurrence of this accident would not cause undue risk to the health and safety of the public.

15.5.15.3 Conclusions

On the basis of the potential exposures discussed, it can be concluded that, although very unlikely, the occurrence of this accident would not cause undue risk to the health and safety of the public.

Additionally, the analysis demonstrates that the acceptance criteria are met as follows:

(1) The radiation dose to the whole body and to the thyroid of an individual located at any point on the boundary of the exclusion area for the two hours immediately following the onset of the postulated fission product release are insignificant as shown in Table 15.5-11.

(2) The radiation dose to the whole body and to the thyroid of an individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), are insignificant as shown in Table 15.5-11.

15.5.16 RADIOLOGICAL CONSEQUENCES OF A SINGLE ROD CLUSTER CONTROL ASSEMBLY WITHDRAWAL AT FULL POWER

15.5.16.1 Acceptance Criteria

The radiological consequences of a single rod cluster control assembly withdrawal shall not exceed the dose limits of 10 CFR 100.11 as outlined below:

(1) An individual located at any point on the boundary of the exclusion area for the two hours immediately following the onset of the postulated fission product release shall not receive a total radiation dose to the whole body in excess of 25 rem or a total radiation dose in excess of 300 rem to the thyroid from iodine exposure.

(2) An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose to the whole body in excess of 25 rem, or a total radiation dose in excess of 300 rem to the thyroid from iodine exposure.

15.5.16.2 Identification of Causes and Accident Description

A complete transient analysis of this accident is presented in Section 15.3.5. For the condition of one rod cluster control assembly (RCCA) fully withdrawn with the rest of the bank fully inserted, at full power, an upper bound of the number of fuel rods

experiencing DNBR less than the safety analysis limit is 5 percent of the total fuel rods in the core.

A detailed discussion of the potential radiological consequences of accidents involving small amounts of fuel rod failure is included in Section 15.5.21. From the parametric analyses presented in that section, the potential exposures from an RCCA withdrawal at full power resulting in 5 percent fuel failure are given in Table 15.5-12.

15.5.16.3 Conclusions

On the basis of the potential exposures discussed, it can be concluded that the occurrence of this accident would not cause undue risk to the health and safety of the public.

Additionally, the analysis demonstrates that the acceptance criteria are met as follows:

(1) The radiation dose to the whole body and to the thyroid of an individual located at any point on the boundary of the exclusion area for the two hours immediately following the onset of the postulated fission product release are insignificant as shown in Table 15.5-12.

(2) The radiation dose to the whole body and to the thyroid of an individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), are insignificant as shown in Table 15.5-12.

15.5.17 RADIOLOGICAL CONSEQUENCES OF MAJOR RUPTURE OF PRIMARY COOLANT PIPES

Various aspects of the radiological consequences of a large-break loss-of-coolant-accident (LBLOCA) are presented in this section.

15.5.17.1 Acceptance Criteria

(1) The radiological consequences of a major rupture of primary coolant pipes shall take into consideration fission product releases due to leakage from the containment, post-LOCA recirculation Loop leakage in the Auxiliary Building (inclusive of a residual heat removal (RHR) pump seal failure resulting in a 50 gpm leak for 30 minutes starting at T=24 hrs post-LOCA), and containment shine.

(2) The radiological consequences of a major rupture of primary coolant pipes shall not exceed the dose limits of 10 CFR 100.11 as outlined below:

i. An individual located at any point on the boundary of the exclusion area for the two hours immediately following the onset of the postulated fission product release shall not receive a total radiation dose to the whole body in excess of 25 rem or a total radiation dose in excess of 300 rem to the thyroid from iodine exposure.

ii. An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose to the whole body in excess of 25 rem, or a total radiation dose in excess of 300 rem to the thyroid from iodine exposure.

(3) In accordance with the requirements of GDC 19, 1971, the dose to the control room operator under accident conditions shall not be in excess of 5 rem whole body or its equivalent to any part of the body (i.e., 30 rem thyroid and beta skin, Reference 51) for the duration of the accident.

(4) In the event controlled venting of the containment is implemented post-LOCA using the containment hydrogen purge system (serves as a back-up capability for hydrogen control to the hydrogen recombiners), an individual located at any point on the boundary of the exclusion area, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose to the whole body in excess of 0.5 rem/year in accordance with 10 CFR Part 20.

15.5.17.2 Identification of Causes and Accident Description

15.5.17.2.1 Basic Events and Release Fractions

The accidental rupture of a main coolant pipe is the event assumed to initiate a LBLOCA. Analyses of the response of the reactor system, including the emergency core cooling system (ECCS), to ruptures of various sizes have been presented in Sections 15.3.1 and 15.4.1. As demonstrated in these analyses, the ECCS, using emergency power, is designed to keep cladding temperatures well below melting and to limit zirconium-water reactions to an insignificant level. As a result of the increase in cladding temperature and the rapid depressurization of the core, however, some cladding failure may occur in the hottest regions of the core. Following the cladding failure, some activity would be released to the primary coolant and subsequently to the inside of the containment building. Because of the pressurization of the containment building by the primary coolant water escaping from the pipe break, some of the volatile radioactive iodines and noble gases could leak from the containment building to the atmosphere.

It is not expected that a significant amount of organic iodine would be liberated from the fuel as a result of a LBLOCA. This conclusion is based on the results of fuel meltdown experiments conducted by the Oak Ridge National Laboratory. The fraction of the total iodine that is released in organic forms is expected to be on the order of 0.2 percent, or less, since the rate of thermal radiolytic decomposition would exceed the rate of production.

Organic compounds of iodine can be formed by reaction of absorbed elemental iodine on surfaces of the containment vessel. Experiments have shown that the rate of formation is dependent on specific conditions such as the concentration of iodine, concentration of impurities, radiation level, pressure, temperature, and relative humidity. The rate of conversion of airborne iodine is proportional to the surface-to-volume ratio of the enclosure, whether the process is limited to diffusion to the surface or by the reaction rate of the absorbed iodine. The observed yields of organic iodine as a function of aging time in various test enclosures, with various volume-to-surface area ratios, were extrapolated to determine the values for the DCPP containment vessel. The iodine conversion rates predicted in this manner did not exceed 0.0005 percent of the atmospheric iodine per hour.

The potential exposures following the postulated sequence of events in LBLOCAs have been analyzed for two cases. In the expected case, it has been assumed that the entire inventory of volatile fission products contained in the pellet-cladding gap spaces is released to the coolant during the time the core is being flooded by the ECCS. Of this gap inventory, 25 percent of the iodines and 100 percent of the noble gases are considered to be released to the containment atmosphere immediately following the pipe rupture. In this respect, the expected case does contain some degree of conservatism since the ECCS is designed to prevent gross cladding damage. In accordance with the experimental data reported in the previous paragraph, the fraction of iodine that is released in organic form is assumed to be 0.2 percent, and the production rate of organic forms is considered negligible. The iodine plateout rates are negligible (Reference 10) compared to the spray washout rates and are assumed to be zero. The particulate fraction of iodine is also assumed to be zero for the expected case since this fraction is small and the spray removal rates for particulates is large as shown in Reference 10.

For the design basis LOCA, it has been assumed that 25 percent of the equilibrium radioactive iodine inventory in the core is immediately available for leakage from the reactor containment. Ninety-one percent of this 25 percent is assumed to be in the form of elemental iodine, 4 percent of this 25 percent is in the form of organic iodides, and 5 percent of this 25 percent is in the form of particulate iodine. In addition, 100 percent of the noble gas inventory in the core is assumed to be immediately released to the containment building. As discussed in earlier paragraphs, releases of these magnitudes are not expected to occur, even if the ECCS does not perform as expected. An analysis using these assumptions is presented because these values are considered acceptable for a design basis analysis in Regulatory Guide 1.4, Revision 1.

15.5.17.2.2 Spray System Iodine Removal Rates

The containment spray system (CSS) is described in detail, along with a performance analysis, in Sections 6.2.2 and 6.2.3. The performance analysis includes the representation of the spatial distribution of droplets and iodine in the containment, as well as drop coalescence and other effects.

For the expected case analyses, the CSS is assumed to function with both spray pumps operating, giving an effective elemental iodine removal coefficient of 92 per hour. On the basis of experiments at Battelle, as described in Reference 10, the spray removal rate for organic iodides was assumed to be 0.058 per hour.

For the design basis case, it is assumed that one of the two spray pumps fails to operate, and the elemental iodine removal coefficient is reduced to 31 per hour. This assumption is consistent with the value of 32 per hour used in the PSAR analysis. It has also been assumed, for the design basis case, that the CSS has no effect on the organic and particulate iodines.

Although a subsequent safety evaluation showed that the Design Case coefficient of 31 per hour (for 2600 gpm spray header flow) should be reduced to approximately 29 per hour (for 2466 gpm spray header flow), the potential offsite dose increase due to this change is extremely small and can be considered insignificant (Reference 39).

15.5.17.2.3 Offsite Exposures from Containment Leakage

As a result of the pressurization of the containment following a LOCA, there is a possibility of containment leakage during the time that the containment pressure is above atmospheric. For the design basis case, the leakage rate has been assumed to be 0.1 percent per day for the first 24 hours following the accident, and 0.05 percent per day after the first day. These assumed rates are consistent with the Technical Specifications (Reference 22) limit, the assumed rates considered acceptable in Regulatory Guide 1.4, Revision 1, and the values assumed in the PSAR analyses.

For the expected case, the containment leakage rates used are 0.05 percent per day for the first day and 0.025 percent per day for the periods after 1 day. These rates were determined from averages of the actual predicted containment pressures presented in previous sections, with the assumption that some of the heat removal systems do not function at full capacity.

In this regard, the leakage rates assumed for the expected case analysis retain some degree of conservatism since the containment heat removal systems are designed to reduce the containment pressure to atmospheric following the initial pressure rise, thus terminating the leakage.

15.5.17.2.4 Containment Leakage Exposure Sensitivity Study

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

Sensitivity studies were performed to illustrate the dependence of the thyroid exposures on the spray system removal constant and the fraction of nonremovable iodines present in the containment. The results of these studies are shown in Figures 15.5-6, 15.5-7, and 15.5-8. The thyroid exposures, normalized to the exposure for zero spray removal constant, are shown as a function of spray constant in Figure 15.5-6, for a fixed fraction of nonremovable iodine forms of 15 percent. In Figures 15.5-7 and 15.5-8 thyroid exposures are plotted as a function of two parameters: the spray removal constant and the percent of nonremovable iodines. To determine an absolute exposure (rem) from Figure 15.5-7, the normalized exposure should be multiplied by 940.9 rem, which is the reference 2 hour-800 meter exposure for the design basis case with a zero spray constant and a zero nonremovable fraction. To determine an absolute exposure (rem) from Figure 15.5-8, the normalized exposure should be multiplied by 197.4 rem, which is the reference 30-day-10,000 meter exposure for the design basis case with a zero spray constant and a zero nonremovable fraction. As shown in these figures, combinations of these parameters that result in normalized exposures below the criterion line would result in a calculated absolute exposure less than the 300 rem guideline level specified in 10 CFR Part 100.

15.5.17.2.5 Radiological Consequences with DF of 100

The design basis LOCA was reviewed to evaluate potential differences in the offsite radiological dose consequences using a containment decontamination factor of 100 and a containment mixing flowrate of 94,000 cfm.

A containment mixing rate of 94,000 cfm corresponds with our current minimum design basis operation of two containment fan cooler units (CFCU). Calculations were based on reload fuel. A containment spray delay of 80 seconds was used. The radionuclide inventory source terms for the various fuel conditions were calculated using the ORIGEN-2 computer code with a power level of 3580 MWt. The radionuclide atmospheric releases and offsite doses were calculated with the LOCADOSE computer code.

Calculations were made relative to 10 CFR 100.11 requirements for offsite doses, at the 800 meter exclusion area boundary (EAB) at 2 hours and the 10,000 meter low population zone (LPZ) at 30 days, from post-LOCA containment leakage.

Table 15.5-75 presents the calculated offsite dose consequences from post-LOCA from various pathways. The limiting dose is the thyroid at the EAB. For the containment leakage pathway, the maximum thyroid dose of 107.06 rem exceeds the original design basis LOCA thyroid dose of 95.9 rem in Table 15.5-23. For the pre-existing small leakage, the EAB thyroid dose is 8.22 rem. These doses are comparable with the corresponding original design basis LOCA large leakage and small leakage cases doses.

All doses are within the 10 CFR 100.11 guidelines.

15.5.17.2.6 Offsite Exposures from Containment Shine

The site boundary 30-day DBA exposure from direct containment gamma radiation (containment shine) is estimated to be 0.0048 rem. Containment shine is a function of the activity present in the containment atmosphere. The EMERALD computer code was used to calculate the post-accident containment activity time-history, and the ISOSHLD II computer code was then used to calculate the containment shine exposure. The shine exposure model assumes a cylindrical radiation source having the same radius and height as the containment structure with a 3.5-foot-thick concrete shield surrounding it. The site boundary receptor point is assumed to be 800 meters from the containment structure.

15.5.17.2.7 Offsite Population Exposures from Containment Leakage

The calculated population exposures for the design basis case assumptions, and for the expected case, are summarized in Table 15.5-23. These whole body population exposures do not include the effects of any population redistribution due to evacuation. These exposures were calculated using the EMERALD computer code. The atmospheric dilution factors and population distribution utilized in the population exposure calculations are discussed in Section 15.5.5.

15.5.17.2.8 Offsite Exposures from Post-LOCA Recirculation Loop Leakage in the Auxiliary Building

Reactor coolant water that collects in the containment recirculation sump after a LOCA would contain radioactive fission products. Because containment recirculation sump water is circulated outside the containment, problems of potential exposure due to post-LOCA operation of external circulation loops with leakage have been evaluated.

Reactor coolant water, ECCS injection water, and containment spray water accumulate in the containment recirculation sump following a LOCA. Containment recirculation sump water is circulated by the RHR pumps, cooled via the RHR heat exchangers, returned to the containment via the RHR system piping and the CSS piping (if recirculation spray is used), passed through the RCS and the containment spray nozzles (if recirculation spray is used), and finally returned to the containment recirculation sump. In the event of circulation loop leakage in the auxiliary building, post-LOCA activity has a pathway to the atmosphere.

An illustration of this pathway for a small leak is given in Figure 15.5-9. For the small leakage situation, fission products in the leakage water are exposed to auxiliary building ventilation air flow for a long period of time. Thus, for the small leakage situation, all activity released to the auxiliary building would be released to the auxiliary building air, i.e., no credit for liquid-gas partitioning.

An illustration of post-LOCA activity pathway for a large leak is given in Figure 15.5-10. For the large leakage situation, fission products in the leakage water are exposed to auxiliary building ventilation air flow for a short period of time. Thus, most of the activity released to the auxiliary building would be transferred to the floor drain receiver tank, i.e., credit for liquid-gas partitioning.

The complete RHR system and CSS descriptions; including estimates of leakage, detection of leakage, equipment isolation, and corrective maintenance, are contained in Sections 5.5.6 and 6.2.2, respectively.

Post-LOCA auxiliary building loop leakage exposures were calculated for four different leakage cases:

(1) Expected small leakage case

(2) Expected large leakage case

(3) DBA small leakage case

(4) DBA large leakage case

Assumptions and numerical values used to calculate loop leakage exposures are listed in Table 15.5-24. Table 15.5-63 shows the results of the calculations based on these assumptions. Because an insignificant amount of noble gases would be in the containment recirculation sump water, the whole body exposures are negligible.

One possible approach to the evaluation of offsite exposures from post-LOCA recirculation loop leakage would include the following assumptions:

(1) A LOCA as an initiating event

(2) Failure of two ECCS trains resulting in gross fuel damage: Release of 50 percent of core iodine inventory and 100 percent of core noble gas inventory to the containment

(3) Failure of an RHR pump seal, resulting in the release of a significant amount of the above containment activity to the auxiliary building

(4) Failure of the passive auxiliary building charcoal filters resulting in the unfiltered release of iodine fission products to the environment

The assumption of this sequence of failures for analysis of offsite exposures, however, would be requiring plant design features in excess of the current guides and regulations, and in particular the requirements of ANS Standard N18.2, Nuclear Safety Criteria for the Design of Stationary Pressurized Water Power Plants. (See proposed addendum to ANS Standard N18.2, Single Failure Criteria for Fluid Systems (Reference 16)).

Applying the proposed standard to post-LOCA recirculation loop leakage the LBLOCA was assumed as the initiating event:

> "The unit shall be designed to tolerate an initiating event which may be a single active or passive failure in any system intended for use during normal operation."

The ECCS was assumed to function properly, as required by the ECCS acceptance criteria, preventing gross fuel damage. Although meeting these criteria is expected to preclude gross cladding damage, it was assumed for this analysis that 100 percent of the gap iodine and noble gas inventories were released to the containment recirculation sump.

For the large leakage cases, failure of an RHR pump seal was assumed as the single failure and can be tolerated without loss of the required functioning of the RHR system, as required by the following clauses in the proposed addendum to the ANS Standard N18.2:

> "Fluid systems provided to mitigate the consequences of Condition III and Condition IV events shall be designed to tolerate a single failure in addition to the incident which requires their function, without loss of the function to the unit.
>
> "A single failure is an occurrence which results in the loss of capability of a component to perform its intended safety functions when called upon. Multiple failures resulting from a single occurrence are considered to be a single failure. Fluid and electrical systems are considered to be designed against a single failure if neither (a) a single failure of any active component (assuming passive components function properly); nor (b) a single failure of a passive component (assuming active components function properly) results in a loss of the safety function to the nuclear steam electric generating unit.
>
> "An active failure is a malfunction, excluding passive failures, of a component which relies on mechanical movement to complete its intended function upon demand.
>
> "Examples of active failures include the failure of a valve or a check valve to move to its correct position, or the failure of a pump, fan or diesel generator to start.
>
> "Spurious action of a powered component originating within its actuation system shall be regarded as an active failure unless specific design features or operating restrictions preclude such spurious action.
>
> "A passive failure is a breach of the fluid pressure boundary or blockage of a process flowpath."

For the expected and DBA large leakage cases, the failure of auxiliary building charcoal filters, a second failure, was not assumed, in accordance with the standard.

For the expected and DBA small leakage cases, failure of auxiliary building charcoal filters was assumed as the single failure and can be tolerated without loss of the required function of the auxiliary building ventilation system, which provides cooling for ECCS components.

For the long-term small leakage cases, the charcoal filters are not needed to reduce exposures below the guideline values given in 10 CFR Part 100. In any case, the fans in the ventilation system are redundant, and only the passive charcoal beds themselves are not redundant.

For the expected small and large leakage cases, it was assumed that two ECCS trains, five fan coolers, and two containment spray trains functioned. For the DBA small and large leakage cases, it is assumed that two ECCS trains, two fan coolers, and one containment spray train functioned. The DBA assumptions result in high containment recirculation sump water temperatures and minimum containment recirculation sump water pHs.

For all four circulation loop leakage cases it was assumed that 100 percent of the gap iodine inventory was deposited in containment recirculation sump water.

For the expected small and large leakage cases, the assumed gap iodine inventories are listed in Table 11.1-7. The expected case gap iodine was assumed to be only elemental iodine. For the DBA small and large leakage cases, the assumed gap iodine inventories are based on release fractions given in Safety Guide 25, March 1972 (Reference 23). The DBA case gap iodine was assumed to be 99.75 percent elemental iodine and 0.25 percent organic iodine per Safety Guide 25, March 1972.

Radiological decay of activity in the containment recirculation sump was assumed for all leakage cases for both the time periods before and during loop leakage. No credit was taken for cleanup of activity in the containment recirculation sump.

Reactor coolant water, accumulator water, and refueling water storage tank (RWST) water make up the total volume of water in which activity is deposited. Consideration of emergency core cooling injection flowrates and containment spray injection flowrates yields the volume of RWST water (Chapter 6). Table 15.5-24 lists the assumed volume of water in which activity is deposited for the four leakage cases. For the large leakage cases, the volume of diluting water was taken as the volume when the leakage began. No credit was taken for the extra diluting water added from the RWST during the 30-minute leakage period.

Sodium hydroxide spray additive will provide for an increased pH in the containment recirculation sump water. Consideration of emergency core cooling injection flowrates and containment spray injection flowrates yields the pH of the containment recirculation sump water (Chapter 6). Table 15.5-24 lists the assumed pH of recirculation loop leakage water for the four leakage cases. For the large leakage cases, the pH was

taken as the pH when the leakage began. No credit was taken for the extra sodium hydroxide in the spray water added during the 30-minute leakage period.

The design evaluation conducted for the containment functional design yields the temperature of containment recirculation sump water as a function of time (Chapter 6). Table 15.5-24 lists the assumed temperature of recirculation loop leakage water for the four leakage cases. For the large leakage cases, the water temperature was taken as the temperature when the leakage began. No credit was taken for the decrease of water temperature during the 30-minute leakage period.

A review of the equipment in the RHR system loop and the CSS loop indicates that the largest leakage would result from the failure of an RHR pump seal. Evaluation of RHR pump seal leakage rate, assuming only the presence of a seal retention ring around the pump shaft, shows that flows less than 50 gpm would result (Chapter 6). Circulation loop piping leaks, valve packing leaks, and flange gasket leaks are much smaller and less severe than an RHR pump seal failure leak. Leakage from these components during normal post-LOCA operation of the RHR system loop and the CSS loop is estimated to be 1910 cc/hr (Chapter 6). On this basis, a 50 gpm leakrate was assumed for both the expected large leakage case and the DBA large leakage case, and a 1910 cc/hr leakrate was assumed for both the expected small leakage case and the DBA small leakage case.

For the DBA large leakage case, recirculation loop leakage was assumed to commence 24 hours after the start of the LBLOCA. This assumption is consistent with the discussion in Sections 3.1.1.1 and 6.3.3.5.3, and with the guidance in Standard Review Plan 15.6.5, Appendix B. In this context, the limiting recirculation loop long term passive failure is 50 gpm leakage at 24 hours after the start of the LBLOCA.

Evaluation of an RHR pump seal failure shows that the failure could be detected and the pump isolated well within 30 minutes (Chapter 6). A leakage duration of 30 minutes is conservatively assumed for both the expected and DBA large leakage cases. A leakage duration of 30 days is assumed for both the expected and DBA small leakage cases. As discussed earlier, the auxiliary building DF is a function of the Partition Factor (PF) for a particular isotope (Equation 15.5-7).

For both the expected and DBA large leakage cases, it was assumed that leakage water was pumped away to the floor drain receiver tank. Iodine in the leakage water was assumed to be exposed to auxiliary building ventilation air flow for a short period of time (0.05-0.10 hours), and thus, liquid-gas partitioning was assumed for elemental iodine isotopes.

The large leakage case elemental iodine PFs were calculated using the previously presented PF expression. Because the circulation water will be above 212°F (Chapter 6), a flashing process must be considered. For heat energy conservation on the basis of 1 lb:

$$h_{f0} = h_f(1-x) + h_g x \qquad (15.5\text{-}11)$$

Rearranging yields

$$x = \frac{h_{f0} - h_f}{h_g - h_f} \qquad (15.5\text{-}12)$$

where:

h_{f0}	=	initial enthalpy of liquid, Btu/lbm
h_f	=	final enthalpy of liquid, Btu/lbm
h_g	=	final enthalpy of vapor, Btu/lbm
x	=	fraction of initial mass that became vapor

The end point of the flashing process is 212°F, and thus the final enthalpies are based on this temperature. The mass fraction, x, is the ratio of the final mass of vapor to the total initial mass of water, so the mass ratio at the end of the flashing process becomes:

$$\frac{M_{vapor}}{M_{liquid}} = \frac{x}{1-x} \qquad (15.5\text{-}13)$$

Figures 15.5-11 and 15.5-12 present the expected and DBA large leakage case elemental iodine PFs as a function of both temperature and pH. For small PFs, the DF (see Equation 15.5-7) is approximately equal to the reciprocal of the PF. Figures 15.5-11 and 15.5-12 illustrate that auxiliary building iodine PFs and resulting DFs are relatively insensitive to water temperature, but much more sensitive to pH. Table 15.5-24 lists the assumed temperatures and pHs along with the resulting elemental iodine PFs and auxiliary building decontamination factors for both the expected and DBA large leakage cases.

For both the expected and DBA small leakage cases, it was assumed that leakage water was not pumped away. Elemental iodine in the leakage water was assumed to be exposed to auxiliary building ventilation air flow for a long period of time (100-150 hours), and thus, liquid-gas partitioning for elemental iodine isotopes was not assumed. For the small leakage case all elemental iodine activity released to the auxiliary building was assumed to be released to the auxiliary building atmosphere, i.e., a DF of 1.

Liquid-gas partitioning for organic iodine isotopes was not assumed for any of the four leakage cases. All organic iodine activity released to the auxiliary building was assumed to be released to the auxiliary building atmosphere, i.e., a decontamination factor of 1.

For all four loop leakage cases, no credit was taken for auxiliary building radiological decay or fission product plateout.

For the expected and DBA large cases, credit for auxiliary building charcoal filters was taken, and for the expected and DBA small leakage cases, no credit for auxiliary building charcoal filters was taken (as previously discussed with reference to ANS Standard N18.2 single failure criteria). Table 15.5-24 lists the assumed iodine filter efficiencies for each loop leakage case.

From the calculated DBA case offsite exposures from post-LOCA recirculation loop leakage in the auxiliary building listed in Table 15.5-63, it can be concluded that any exposures that occur via this combination of unlikely events would be well below the guideline levels in 10 CFR Part 100. In addition, even if no consideration is given to the effectiveness of the auxiliary building charcoal filters for the DBA leakage cases, the calculated exposures would still be below guideline levels specified in 10 CFR Part 100.

15.5.17.2.8.1 Maximum Allowable Leakage From Post-LOCA Recirculation Loop

Calculations have been performed to determine the maximum allowable leakage from recirculation loop components that could occur during post-LOCA recirculation operations before offsite and control room operator design basis radiation doses would exceed regulatory limits. A computer code (LOCADOSE) was used to determine design basis EAB and low population zone outer boundary (LPZ) offsite radiation doses and control room operator airborne radiation dose from post-LOCA containment leakage, RHR pump seal leakage, and pre-existing leakage from recirculation loop components outside containment. The calculations determined the amount of pre-existing recirculation leakage which could exist before offsite exposures would exceed 10 CFR 100.11 limits or control room operator exposures would exceed GDC 19, 1971 limits, if a LOCA were to simultaneously occur.

Table 15.5-63 shows the results of the calculations based on the above assumptions which determined that the maximum allowable leakage (in addition to the RHR pump seal leakage) from the recirculation loop at post-LOCA conditions of pressure and temperature was 1.85 gpm where the airborne activity is filtered by charcoal filters or 0.186 gpm where the airborne activity is unfiltered. The limitation is the GDC 19, 1971 allowable dose for the control room.

15.5.17.2.9 Offsite Exposures from Controlled Post-accident Containment Venting

Because of the potential release of significant amounts of hydrogen to the containment atmosphere following a LBLOCA, it is necessary to provide means of monitoring and controlling the post-accident concentration of hydrogen in the containment atmosphere. Redundant thermal hydrogen recombiners are the primary means of post-accident hydrogen control. As a backup, controlled containment venting (via the containment hydrogen purge system) with offshore flow, wind directions from northwest through east-southeast measured clockwise, provides hydrogen control with a high probability of

no inland exposures. As shown in Table 15.5-26, offshore wind directions occur over 50 percent of the time regardless of the season and, as shown in Table 15.5-27, have a high degree of persistence. The large time period (312 hours for DBA case) between the proposed hydrogen venting level (3.5 v/o) and the hydrogen flammability level (4.0 v/o) is much greater than the longest recorded period (37 consecutive hours) of onshore winds in any 22.5° sector. These data ensure a very high probability that venting can be carried out during the occurrence of offshore winds.

Even though there is a high probability that containment venting can be carried out when the wind is blowing offshore, if necessary at all, an evaluation is presented in the following paragraphs to determine potential exposures if venting were carried out during onshore winds.

Section 6.2.5 contains the analysis of post-accident hydrogen production and accumulation in the containment atmosphere and its control. Containment venting is also described in Section 6.2.5. The purge stream is withdrawn from the containment through one of two penetration lines. The stream is routed through a flow-measuring device, charcoal filters, exhaust fans, the radiation monitors, and finally to the plant vent.

Post-accident containment venting activity releases are calculated with the following equation:

$$ACT(I) = \frac{[1.0 - 0.01FILEFF(I)]60}{VOLUME} \int_{T(1)}^{T(2)} VENRATxAC(I)e^{-\lambda(I)t}dt \quad (15.5.14)$$

where:

ACT(I)	=	activity of isotope I released to the atmosphere, Ci
AC(I)	=	activity of isotope I released to the containment atmosphere, Ci
VOLUME	=	volume of containment atmosphere, cu ft
VENRAT	=	venting rate, cfm
$\lambda(I)$	=	removal constant for isotope I, hr^{-1}
FILEFF(I)	=	filter efficiency for isotope I, %
T(1)	=	time after LOCA that containment venting begins, hr
T(2)	=	time after LOCA that containment venting ends, hr
t	=	time, hr
60	=	minutes per hr

The above equation considers radiological decay during the time period prior to containment venting and the time period during containment venting. It also assumes that the LBLOCA activity released to the containment atmosphere is homogeneously dispersed throughout the containment atmospheric volume. Exposures from activity released to the atmosphere were calculated using the EMERALD computer code. EMERALD assumes there is no radiological decay during the atmospheric dispersion.

Containment venting exposures were calculated for both the expected case and the DBA case. Assumptions and numerical values used to calculate venting exposures are itemized in Table 15.5-28. Onshore controlled containment venting thyroid and whole body exposures are listed in Table 15.5-29.

Post-accident containment venting schedules are evaluated in Section 6.2.5. Assuming the venting system will operate an average 2 hours per day, the system flowrates during short venting periods are 120 cfm (expected) and 300 cfm (DBA). Equivalent continuous venting rates, 10 cfm and 25 cfm, were used to calculate venting activity releases.

In the event containment venting should be required during periods with onshore flow, the venting would be limited to those periods when Pasquill Stability Category D exists. Therefore, ground-level centerline atmospheric dispersion factors for Pasquill Stability Category D and an elevated release height of 70 meters were evaluated using a conventional Gaussian plume model and are listed in Table 15.5-30. The meteorological input parameters utilized were determined from onsite measurements, given in References 18, 19, and 20. Because an individual is assumed to be located on the plume centerline for the entire venting duration, exposures are centerline exposures and represent worst case conditions. The probability of an individual being located on the plume centerline for a 2-hour period is very small, and thus centerline exposures listed in Table 15.5-29 are very conservative.

During the time period prior to venting, activity released to the containment atmosphere is significantly reduced by both radiological decay and functioning of the safety features systems. The main contributors of radioactivity several hundred hours after the accident are the noble gases: Kr-85, Xe-133, and, to some extent, Xe-131m. Because Kr-85 has a half-life of 10.6 years, the exposures resulting from containment venting would not be significantly reduced if the venting could be further delayed for many months.

It can be concluded from the results presented in Table 15.5-29, along with the consideration of the very high probability of opportunities for offshore venting and the other favorable factors associated with the DCPP design and site, that, as a backup to the internal hydrogen recombiner system, controlled venting using the containment hydrogen purge system is an acceptable contingency method of post-accident hydrogen control for this plant. In addition, it can be concluded that the expected exposures due to venting, even using the assumptions in Safety Guide 7, will not exceed the annual dose limits of 10 CFR Part 20.

15.5.17.2.10 Post-accident Control Room Exposures

The design basis for control room ventilation, shielding, and administration is to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent to any

part of the body, for the duration of the most severe design basis accident. This basis is consistent with GDC 19, 1971.

The control room shielding, described in Section 12.1 is designed to attenuate gamma radiation from post-accident sources to levels consistent with the requirements of GDC 19, 1971.

The control room ventilation system is described in Section 9.4.1. It is designed to limit the concentration of post-accident activity in the control room air to levels consistent with requirements of GDC 19, 1971.

The control room post-accident administration is described in the DCPP Manual. It is to limit post-accident control room personnel exposures to levels consistent with requirements of GDC 19, 1971.

Exposures to control room personnel have been estimated for a design basis LOCA to evaluate the adequacy of the control room shielding, the adequacy of the control room ventilation system, and the adequacy of the control room administration in limiting exposures to the specified limits. Exposures have also been calculated for the expected case LBLOCA to obtain a more realistic estimate of exposure to control room personnel.

Radiation exposures to personnel in the control room could result from the following sources:

(1) Airborne activity, which infiltrates into the control room

(2) Direct gamma radiation to the control room from activity in the containment structure

(3) Direct gamma radiation to the control room from activity in the containment leakage plume.

The control room ventilation system is designed to minimize infiltration of post-accident airborne activity into the control room complex. Mode 4 operation of the ventilation system provides zone isolation with filtered positive pressurization and filtered recirculation. Mode 4 operation of the ventilation system is initiated automatically and the least contaminated positive pressurization inlet is selected manually as described in Chapter 9.4.1. Both the pressurization and partial recirculation air flow pass through high-efficiency particulate air (HEPA) and charcoal filters.

In addition to positive pressurization, there are vestibules on control room doors that will minimize infiltration. Table 15.5-31 identifies infiltration pathways and flowrates that have been used in the calculation of post-accident control room radiological exposures.

Airborne radiation doses inside the control room were evaluated for a DBA LOCA. Regulatory Guide 1.4, Revision 1 was used to determine activity levels in the containment. Activity releases are based on a containment leakage of 0.1 percent/day for the first day and 0.05 percent/day thereafter.

The containment leakage was assumed to be released unfiltered from the containment building to the atmosphere. Recirculation loop leakages, assumed to be from an RHR pump seal, will pass through charcoal filters and be released to the atmosphere through the main vent at the top of the containment.

Radioactivity from the atmosphere would enter the control room through two pathways:

(1) via the pressurization air intakes through charcoal filters

(2) via infiltration of air inleakage

The flow rate of pressurization air into the control room is 2100 cfm. The flow rate of recirculated control room air through the charcoal filters is 2100 cfm. Previous analyses had not taken credit for recirculation of control room air. This was an unnecessary conservatism in that a passive failure had already been assumed to occur (RHR pump seal leak) and a second failure is not required.

A 10 CFM inleakage rate per Standard Review Plan, Section 6.4, was conservatively assumed in the analysis due to the possible pathway through the single doors from the equipment condensing unit areas to the HVAC equipment room. Additionally, an assumed 10-second delay in closure of the CRVS outside air isolation dampers results in 2110 cfm of control room infiltration for the first 10 seconds following the design basis LOCA.

Table 15.5-32 presents a summary of the parameters used in the analysis.

The control room shielding is designed to minimize direct gamma radiation (containment shine). Control room exposures resulting from containment shine were estimated using ISOSHLD II. The control room receptor point is 27 feet from the containment structure and protected by an additional 2.5-foot-thick concrete shield. A further contribution to control room direct gamma radiation results from the atmospheric activity cloud external to the control room. Control room exposures resulting from plume shine were estimated using ISOSHLD II. The shine exposure model assumes a parallelepiped radiation source located directly above the control room. The control room receptor point is protected by a 1.5-foot-thick concrete shield.

Radiation exposures to personnel during egress and ingress could result from the following sources:

(1) Airborne activity in the containment leakage plume

(2) Direct gamma radiation from fission products in the containment structure

Post-accident egress-ingress exposures are based on 27 outbound excursions, from the control room to the site boundary, and 26 inbound excursions, from the site boundary to the control room. It was estimated that each excursion would take 5 minutes, and no credit was taken for breathing apparatus or special whole body shielding.

Egress-ingress thyroid and whole body exposures from airborne activity are functions of containment activity, containment leakage, atmospheric dispersion, and excursion time. The EMERALD computer code was used to calculate the airborne activity concentrations, and then conventional exposure equations were used to calculate gamma, beta, and thyroid exposures (Reference 6). The exposure from betas is calculated on the basis of an infinite uniform cloud, and exposure from gammas is calculated on the basis of a semi-infinite cloud.

Because of the containment shielding and short excursion time, egress-ingress containment shine exposures are small. Egress-ingress containment shine exposures were calculated using ISOSHLD-II. The shine model assumes a cylindrical radiation source having the same radius and height as the containment structure with a 3.5-foot-thick concrete shield surrounding it. The receptor point is assumed to be a distance of 10 meters.

Estimates of post-accident control room exposures and egress-ingress exposures are listed in Table 15.5-33. The sum of the DBA case exposures are within the specified criteria, and the expected case exposures demonstrate the conservatism of the DBA case exposures.

15.5.17.2.11 Summary

In the preceding sections, the potential exposures from a major primary system pipe rupture have been calculated for various possible mechanisms:

(1) Containment leakage

(2) RHR recirculation loop leakage

(3) Controlled post-accident containment venting

(4) Containment shine

The analyses have been carried out using the models and assumptions specified in regulations 10 CFR Part 100, 10 CFR Part 50, and the safety and regulatory guides. In all analyses, the resulting potential exposures to plant personnel, to individual members of the public, and to the general population have been found to be lower than the

applicable guidelines and limits specified in 10 CFR Part 100, 10 CFR Part 50, and 10 CFR Part 20.

15.5.17.3 Conclusions

Based on the results discussed, the occurrence of a major pipe rupture in the primary system of a DCPP unit would not constitute an undue risk to the health and safety of the public. In addition, the ESF provided for the mitigation of the consequences of a LBLOCA are adequately designed.

Finally, the analysis demonstrates that the acceptance criteria are met as follows:

(1) The radiological consequences of a major rupture of primary coolant pipes shall take into consideration fission product releases due to leakage from the containment, post-LOCA recirculation loop leakage in the Auxiliary Building (inclusive of a RHR pump seal failure resulting in a 50 gpm leak for 30 minutes starting at T=24 hrs post-LOCA), and containment shine as shown in Section 15.5.17.2.11.

(2) The radiological consequences of a major rupture of primary coolant pipes shall not exceed the dose limits of 10 CFR 100.11 as outlined below:

   i. An individual located at any point on the boundary of the exclusion area for the two hours immediately following the onset of the postulated fission product release shall not receive a total radiation dose to the whole body in excess of 25 rem or a total radiation dose in excess of 300 rem to the thyroid from iodine exposure as shown by the EAB whole body dose reported for containment shine in Section 15.5.17.2.6, and the remaining doses presented in Table 15.5-75.

   ii. An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose to the whole body in excess of 25 rem, or a total radiation dose in excess of 300 rem to the thyroid from iodine exposure as shown by the EAB whole body dose reported for containment shine in Section 15.5.17.2.6 (conservative when applied to the LPZ), and the remaining doses presented in Table 15.5-75.

(3) In accordance with the requirements of GDC 19, 1971, the dose to the control room operator under accident conditions shall not be in excess of 5 rem whole body or its equivalent to any part of the body (i.e., 30 rem thyroid and beta skin, Reference 51) for the duration of the accident as shown in Table 15.5-33.

(4) In the event controlled venting of the containment is implemented post-LOCA using the containment hydrogen purge system (serves as a back-up capability for hydrogen control to the hydrogen recombiners), an individual located at any point on the boundary of the exclusion area, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose to the whole body in excess of the annual dose limit of 10 CFR Part 20 as shown in Table 15.5-29.

15.5.18 RADIOLOGICAL CONSEQUENCES OF A MAJOR STEAM PIPE RUPTURE

15.5.18.1 Acceptance Criteria

(1) The radiological consequences of a major steam pipe rupture shall not exceed the dose limits of 10 CFR 100.11 as outlined below:

  i. An individual located at any point on the boundary of the exclusion area for the two hours immediately following the onset of the postulated fission product release shall not receive a total radiation dose in excess of the 10 CFR 100.11 dose limits for the whole body and the thyroid for the pre-existing iodine spike case and 10 percent of the 10 CFR 100.11 dose limits for the whole body and the thyroid for the accident-initiated iodine spike case.

  ii. An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose in excess of the 10 CFR 100.11 dose limits for the whole body and the thyroid for the pre-existing iodine spike case and 10 percent of the 10 CFR 100.11 dose limits for the whole body and the thyroid for the accident-initiated iodine spike case.

(2) In accordance with the requirements of GDC 19, 1971, the dose to the control room operator under accident conditions shall not be in excess of 5 rem whole body or its equivalent to any part of the body (i.e., 30 rem thyroid and beta skin, Reference 51) for the duration of the accident for both the pre-accident and the accident- initiated iodine spike cases.

15.5.18.2 Identification of Causes and Accident Description

As reported in Section 15.4.2, a major steam line rupture is not expected to cause cladding damage, and thus no release of fission products to the coolant is expected following this accident. If significant radioactivity exists in the secondary system prior to the accident, however, some of this activity will be released to the environment with the steam escaping from the pipe rupture. In addition, if an atmospheric steam dump from the unaffected steam generators is necessitated by unavailability of condenser capacity,

additional activity will be released. Section 15.5.18.2.1 discusses the main steam line break (MSLB) dose analysis of record which is based on the OSGs. The OSG MSLB dose analysis is bounding for the RSGs as discussed in the following section. (See Table 6.4.2-1 of Reference 49 for a summary of OSG and RSG MSLB steam releases.)

15.5.18.2.1 Radiological Assessment for Accident-Induced Leakage

Because tubes in the faulted steam generator encounter a higher differential pressure during steam line rupture conditions than normal operating conditions, there is a potential for primary-to-secondary leakage in degraded tubing to increase to a rate that is higher than that during normal operation. This leakage is referred to as accident-induced leakage. This section provides the updated licensing basis description and radiological consequence analysis for a major steam line rupture analysis using an accident-induced leak rate of 10.5 gpm (at room temperature conditions), which is higher than the operational leakage limit in the Technical Specifications. The NRC approved this analysis in a letter to PG&E dated February 20, 2003, "Issuance of Amendment: RE: Revision to Technical Specification 1.1, 'Definitions, Dose Equivalent I-131,' and Revised Steam Generator Tube Rupture and Main Steam Line Break Analyses." Application of this accident-induced leak rate is governed by SG Program accident-induced leakage performance criteria documented in the Technical Specifications.

The methodology selected for performing the radiological assessment follows NRC SRP 15.1.5, "Steam System Piping Failures Inside and Outside of Containment (PWR)," Revision 2, 1981. Using an accident-induced leak rate of 10.5 gpm (at room temperature conditions) in the faulted SG, calculations using the LOCADOSE computer program demonstrate that the offsite doses are within 10 percent of 10 CFR 100.11 limits and control room doses are within GDC 19, 1971, limits.

The resultant doses from the MSLB event using an accident-induced leak rate of 10.5 gpm are listed below. The limiting case is the accident initiated iodine spike as the thyroid dose at the EAB is at the 30 rem limit.

	Dose (rem)		
Location	Thyroid CDE	Beta Skin SDE	Whole Body DDE
Case 1: Accident-Initiated Spike			
EAB (0-2 hr)	30.0	1.50E-1	9.40E-2
LPZ (30 days)	6.49	1.92E-2	1.18E-2
• Dose Limit (10% of 10 CFR 100.11)	30.0	2.5	2.5
Control Room (30 days)	6.68E-1	7.10E-3	1.50E-4
• Dose Limit (GDC 19)	30	5	5
Case 2: Pre-Existing Spike			
EAB (0-2 hr)	46.4	1.37E-1	8.26E-2
LPZ (30 days)	3.69	9.70E-3	5.72E-3
• Dose Limit (10 CFR 100.11)	300	25	25
Control Room (30 days)	4.61E-1	5.56E-3	1.10E-4
• Dose Limit (GDC 19)	30	5	5

The input parameters for the dose analysis are summarized below.

(1) The operational (pre-MSLB) primary-to-secondary leak rate was assumed to be 1 gpm to yield a conservatively high isotopic concentration in the secondary system. Use of 1 gpm is more conservative than the Technical Specifications operational leak rate limit of 150 gpd per SG.

(2) During the accident, the primary-to-secondary leak rate in the faulted steam generator is assumed at the maximum rate of 10.5 gpm. The primary-to-secondary leak rate in each intact SG was assumed to be at the Technical Specifications operational leak rate limit of 150 gpd; therefore, the total leakage is 450 gpd.

(3) The MSLB occurred in the section of piping between the containment building and the main steam line isolation valves (MSIVs). Prior to control room isolation and pressurization, the control HVAC intake χ/Q is the unfiltered χ/Q utilized for the LOCA dose consequences analysis for control room inleakage.

(4) Loss of offsite power is assumed to occur coincident with MSLB accident.

(5) Conservatively, based on the Technical Specifications requirements for the safety injection signal and containment Phase A isolation, the control room will be isolated well within 35 seconds. To add more conservatism in this calculation, the control room is assumed to be isolated in 2 minutes.

(6) All releases were assumed to end after 8 hours, when the plant is placed on the RHR system.

(7) For a pre-existing iodine spike, the activity in the reactor coolant is based upon an iodine spike that has raised the reactor coolant concentration to 60 μCi/g of I-131 DEC, based on the Technical Specifications. The secondary coolant activity is 0.1 μCi/g of I-131 DEC, based on the Technical Specifications. Noble gas activity is based on 651 μCi/g of Xe-133 DEC associated with 1 percent failed fuel, which bounds the value in the Technical Specifications. The calculation of Xe-133 DEC ignores the contribution from Kr-83m, Kr-85, Kr-89, Xe-131m, and Xe-137 due to low concentration, short half life, or small dose conversion factor.

(8) For an accident-initiated (concurrent) iodine spike, the accident initiates an iodine spike in the reactor coolant system (RCS) that increases the iodine release rate from the fuel to a value 500 times greater than the release rate corresponding to an RCS concentration of 1 μCi/g of I-131 DEC. The 1 μCi/g I-131 DEC is based on the Technical Specifications. The iodine activity released to the RCS for the duration of the accident is conservatively assumed to mix instantaneously and uniformly in the RCS. Noble gas activity is based on 651 μCi/g of Xe-133 DEC associated with 1 percent failed fuel, which bounds the value in the Technical Specifications. To maximize the accident-initiated iodine spiking, a RCS letdown rate of 143 gpm with 100 percent iodine removal through the filters in the demineralizers is assumed.

(9) The thyroid dose conversion factors are based on ICRP Publication 30 (Reference 21) as documented in Federal Guidance Report (FGR) 11 and FGR 12 (References 41 and 42). The noble gas whole body dose conversion factors are based on those documented in FGR 12, Table III.1. The following table summarizes these conversion factors.

Isotope	Dose Conversion Factor
I-131	1.08E+06 (Rem/Ci)
I-132	6.44E+03 (Rem/Ci}
I-133	1.80E+05 (Rem/Ci}
I-134	1.07E+03 (Rem/Ci}
I-135	3.13E+04 (Rem/Ci}
Kr-85m	7.48E-15 (sv m^3/bq s)
Kr-87	4.12E-14 (sv m^3/bq s)
Kr-88	1.02E-13 (sv m^3/bq s)
Xe-133m	1.37E-15 (sv m^3/bq s)
Xe-133	1.56E-15 (sv m^3/bq s)
Xe-135m	2.04E-14 (sv m^3/bq s)
Xe-135	1.19E-14 (sv m^3/bq s)
Xe-138	5.77E-14 (sv m^3/bq s)

(10) Following the pipe rupture, auxiliary feedwater to the faulted loop is isolated and the SG is allowed to steam dry. The iodine partition factor for the faulted SG is assumed to be 1.0. Also, the iodine partition factor for the intact SG is conservatively assumed to be 1.0; i.e., no credit is taken for iodine partition.

(11) All activity in the SGs is released to the atmosphere in accordance with the release rates in Table 15.5-34, with added releases from primary-to-secondary leaks in the faulted loop and intact loops.

Atmospheric steam releases (not including primary-to-secondary leaks):

Ruptured loop	162,784 lb at 45.0 lb/ft^3 (0-2 hr)
	0 lb (2-8 hr)
Intact loops	393,464 lb at 45.0 lb/ft^3 (0-2hr) 915,000 lb at 50.0 lb/ft^3 (2-8 hr)

The above steam releases are for the OSG MSLB. The RSG MSLB steam releases are shown in Table 15.5-34.

As noted above, the limiting dose for MSLB is the EAB thyroid dose for the accident initiated iodine spike case and is based on steam releases in the first two hours of the accident. The OSG MSLB dose calculation assumes an accident-induced SG tube leak rate of 10.5 gpm using the Alternate Repair Criteria (ARC) methodology. The RSGs can not credit ARC and are required to maintain a much lower assumed SG tube leakage subsequent to a MSLB. Note that although the zero to two hour RSG ruptured loop release of 171,100 Ib is slightly greater than the equivalent OSG release of 162,784 Ib, the OSG MSLB dose analysis bounds the RSG MSLB releases since the assumed ARC tube leakage impact on dose is the dominant factor in the assessment of post-accident radiological consequences.

(12) The source term is based on a composite source term of 3.5 percent and 4.5 percent fuel enrichment. An evaluation has been performed and concluded that the current source term bounds the 5 percent enrichment fuel up to 50,000 MWD/MTU for a 21-month operating cycle.

(13) Atmospheric Dispersion Factors (sec/m3)

(Reference Tables 15.5-3 and 15.5-6)

Time	EAB	LPZ	Control Room	
			Pressurized	Infiltration
0-2 hr	5.29E-4	2.20E-5	7.05E-5	1.96E-4
2-8 hr		2.20E-5	7.05E-5	1.96E-4
8-24 hr		4.75E-6	5.38E-5	1.49E-4
24-96 hr		1.54E-6	3.91E-5	1.08E-4
96-720 hr		3.40E-7	2.27E-5	6.29E-5

(14) Control Room HVAC Flow Rates and Filtration Efficiencies:

Filtered Intake Flow	2100 cfm
Unfiltered Intake Flow	10 cfm (2110 cfm for t=0 to 10 sec.)
Exhaust Flow	2110 cfm
Filtered Recirculation Flow	2100 cfm

Charcoal Filter Iodine Removal Efficiency

Elemental	95 percent
Organic	95 percent
Particulate	95 percent

(15) RCS and Secondary Water Volume and Water Mass

RCS water volume	94,000 gallons
RCS water mass	566,000 pounds
Water in SGs	6735.54 ft^3 at 45.0 lb/ft^3 (0-2 hr) and 50.0 lb/ft^3 (2-8 hr) Loop 1 1683.88 ft^3 Loops 2, 3, 4 5051.65 ft^3
Water in Condensers	27243.59 ft^3 at 62.4 lb/ft^3
Water in SGs and Condensers	33979.13 ft^3

15.5.18.3 Conclusions

The analysis demonstrates that the acceptance criteria are met as follows:

(1) An individual located at any point on the boundary of the exclusion area for the two hours immediately following the onset of the postulated fission product release shall not receive a total radiation dose in excess of the 10 CFR 100.11 dose limits for the whole body and the thyroid for the pre-existing iodine spike case and 10 percent of the 10 CFR 100.11 dose limits for the whole body and the thyroid for the accident-initiated iodine spike case as shown in Section 15.5.18.2.1.

(2) An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not

receive a total radiation dose in excess of the 10 CFR 100.11 dose limits for the whole body and the thyroid for the pre-existing iodine spike case and 10 percent of the 10 CFR 100.11 dose limits for the whole body and the thyroid for the accident-initiated iodine spike case as shown in Section 15.5.18.2.1.

(3) In accordance with the requirements of GDC 19, 1971, the dose to the control room operator under accident conditions shall not be in excess of 5 rem whole body or its equivalent to any part of the body (i.e., 30 rem thyroid and beta skin, Reference 51) for the duration of the accident for both the pre-existing and the accident-initiated iodine spike cases as shown in Section 15.5.18.2.1.

As noted in Section 15.5.18.2.1, the above dose estimates reflect the OSGs and an accident induced leak rate of 10.5 gpm. The limiting case is a thyroid dose at the EAB which corresponds to the dose limit of 30 rem for an accident-initiated iodine spike. These dose estimates bound the doses with the RSGs which cannot credit Alternate Repair Criteria (ARC) for the steam generator tubes as the OSGs do.

15.5.19 RADIOLOGICAL CONSEQUENCES OF A MAJOR RUPTURE OF A MAIN FEEDWATER PIPE

15.5.19.1 Acceptance Criteria

The radiological consequences of a major rupture of a main feedwater pipe shall not exceed the dose limits of 10 CFR 100.11 as outlined below:

(1) An individual located at any point on the boundary of the exclusion area for the two hours immediately following the onset of the postulated fission product release shall not receive a total radiation dose to the whole body in excess of 25 rem or a total radiation dose in excess of 300 rem to the thyroid from iodine exposure.

(2) An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose to the whole body in excess of 25 rem, or a total radiation dose in excess of 300 rem to the thyroid from iodine exposure

15.5.19.2 Identification of Causes and Accident Description

As reported in Section 15.4.2, a major feedwater line rupture is not expected to cause cladding damage, and thus no release of fission products to the coolant is expected following this accident. If significant radioactivity exists in the secondary system prior to the accident, however, some of this activity will be released to the environment with the feedwater escaping from the pipe rupture. In addition, if an atmospheric steam dump

from the unaffected steam generators is necessitated by unavailability of condenser capacity, additional activity will be released. As discussed in Section 15.5.18, about 1.47E+06 lbm of secondary coolant is the limiting Condition IV event release expected for a full cooldown without any condenser availability.

The radiological consequences of about 1.47E+06 lbm of secondary coolant release have been discussed in Section 15.5.18.

15.5.19.3 Conclusions

Based on the results discussed, it can be concluded that potential exposures from major feedwater line ruptures will be well below the guideline levels specified in 10 CFR 100.11, and that the occurrence of such ruptures would not result in undue risk to the public.

Additionally, the analysis demonstrates that the acceptance criteria are met as follows:

(1) The radiation dose to the whole body and to the thyroid of an individual located at any point on the boundary of the exclusion area for the two hours immediately following the onset of the postulated fission product release are insignificant as shown in Table 15.5-9.

(2) The radiation dose to the whole body and to the thyroid of an individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), are insignificant as shown in Table 15.5-9.

15.5.20 RADIOLOGICAL CONSEQUENCES OF A STEAM GENERATOR TUBE RUPTURE (SGTR)

15.5.20.1 Acceptance Criteria

(1) The radiological consequences of a steam generator tube rupture shall not exceed the dose guidelines of SRP, Section 15.6.3, Revision 2, as outlined below

i. An individual located at any point on the boundary of the exclusion area for the two hours immediately following the onset of the postulated fission product release shall not receive a total radiation dose in excess of the 10 CFR 100.11 dose limits for the whole body and the thyroid for the pre-existing iodine spike case, and 10 percent of the 10 CFR 100.11 dose limits for the whole body and the thyroid for the accident-initiated iodine spike case.

ii. An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose in excess of the 10 CFR 100.11 dose limits for the whole body and the thyroid for the pre-existing iodine spike case, and 10 percent of the 10 CFR 100.11 dose limits for the whole body and the thyroid for the accident-initiated iodine spike case.

(2) In accordance with the requirements of GDC 19, 1971, the dose to the control room operator under accident conditions shall not be in excess of 5 rem whole body or its equivalent to any part of the body (i.e., 30 rem thyroid and beta skin, Reference 51) for the duration of the accident for both the pre-accident and the accident- initiated iodine spike cases.

15.5.20.2 Identification of Causes and Accident Description

The SGTR accident is reanalyzed for RSGs and is discussed in Section 15.4.3, and the thermal and hydraulic analysis presented in Section 15.4.3.3 provides the basis for the evaluation of radiological consequences discussed in this section.

15.5.20.2.1 Offsite Exposures

The evaluation of the radiological consequences of a steam generator tube rupture event assumes that the reactor has been operating at the maximum allowable Technical Specification (Reference 22) limits for primary coolant activity and 1 gpm primary to secondary leakage for sufficient time to establish equilibrium concentrations of radionuclides in the reactor coolant and in the secondary coolant. Radionuclides from the primary coolant enter the steam generator via the ruptured tube and primary to secondary leakage, and are released to the atmosphere through the steam generator PORVs (and safety valves) and via the condenser air ejector exhaust and/or the vacuum pump exhaust (if in operation).

The quantity of radioactivity released to the environment, due to an SGTR, depends upon primary and secondary coolant activity, iodine spiking effects, primary to secondary break flow flashing fractions, attenuation of iodine carried by the flashed portion of the break flow, partitioning of iodine between the liquid and steam phases, the mass of fluid released from the generator, and liquid-vapor partitioning in the turbine condenser hot well.

(1) *Design Basis Analytical Assumptions*

The major assumptions and parameters used in the analysis are itemized in Table 15.5-64.

(2) *Source Term Calculations*

The radionuclide concentrations in the primary and secondary system, prior to and following the SGTR are determined as follows:

(a) The iodine concentrations in the reactor coolant will be based upon pre-accident and accident initiated iodine spikes.

(i) Accident Initiated Spike - The initial primary coolant iodine concentration is 1 μCi/gm of Dose Equivalent (DE) I-131. Following the primary system depressurization associated with the SGTR, an iodine spike is initiated in the primary system which increases the iodine release rate from the fuel to the coolant to a value 335 times greater than the release rate corresponding to the initial primary system iodine concentration. The initial appearance rate can be written as follows:

$$P_i = A_i \lambda_i \qquad (15.5\text{-}15)$$

where:

P_i = Equilibrium appearance rate for iodine nuclide i
A_i = equilibrium RCS inventory of iodine nuclide i corresponding to 1 μCi/gm of DE I-131
λ_i = removal coefficient for iodine nuclide i

(j) Pre-accident Spike - A reactor transient has occurred prior to the SGTR and has raised the primary coolant iodine concentration from 1 to 60 μCi/gram of DE I-131.

(b) The initial secondary coolant iodine concentration is 0.1 μCi/gram of DE I-131.

(c) The chemical form of iodine in the primary and secondary coolant is assumed to be elemental.

(d) The initial noble gas concentrations in the reactor coolant are based upon 651 μCi/g of Xe-133 DEC for the noble gasses Kr-85m, Kr-87, Kr-88, Xe-133, Xe-133m, Xe-135m, Xe-135, and Xe-138, using noble gas whole body dose conversion factors documented in FGR 12 (Reference 42) Table III.1, associated with 1 percent fuel defects. The calculation of Xe-133 DEC ignores the contribution from Kr-85 and Xe-131m due to low concentration and small dose conversion factor.

(3) *Radioactivity Transport Analysis*

The iodine transport analysis considers break flow flashing, steaming, and partitioning. The analysis assumes that a fraction of the iodine carried by the break flow becomes airborne immediately due to flashing and atomization. The analysis conservatively took no credit for scrubbing of iodine contained in the atomized coolant droplets. The fraction of primary coolant iodine which is not assumed to become airborne immediately mixes with the secondary water and is assumed to become airborne at a rate proportional to the steaming rate and the iodine partition coefficient. This analysis conservatively assumes an iodine partition coefficient of 100 between the steam generator liquid and steam phases. Droplet removal by the dryers is conservatively assumed to be negligible.

The following assumptions and parameters were used to calculate the activity released to the atmosphere and the offsite doses following a SGTR.

(a) The mass of reactor coolant discharged into the secondary system through the rupture and the mass of steam released from the ruptured and intact steam generators to the atmosphere are presented in Table 15.4-14.

(b) The mass of break flow that flashes to steam and is immediately released to the environment is contained in Table 15.4-14 and is presented in Figure 15.4.3-11. The break flow flashing fraction was conservatively calculated assuming that 100 percent of the break flow is from the hot leg side of the steam generator, whereas the break flow actually consists of flow from both the hot leg and cold leg sides of the steam generator.

(c) No iodine scrubbing is credited for the break flow that flashes in the analysis and the iodine scrubbing efficiency is assumed to be 0 percent. Thus the location of the tube rupture is not significant for the radiological consequences. However, as discussed in Section 15.4.3.3, in the thermal and hydraulic analysis the tube rupture break flow is calculated conservatively assuming that the break is at the top of the tube sheet.

(d) The rupture (or leakage) site is assumed to be always covered with secondary water based on Reference 33, which concluded the effect of tube uncovery is essentially negligible for the radiological consequences for the limiting SGTR transient.

(e) The total primary to secondary leak rate for the 3 intact steam generators is assumed to be 1.0 gpm. The leakage to the intact

steam generators is assumed to persist for the duration of the accident.

(f) The iodine partition coefficient between the liquid and steam of the ruptured steam generator is assumed to be 100 for non-flashed flow and 1 for flashed flow. The iodine partition coefficient between the liquid and steam of the intact steam generator is assumed to be 100.

(g) No credit was taken for radioactive decay during release and transport, or for cloud depletion by ground deposition during transport to the site boundary or outer boundary of the low population zone.

(h) Short-term atmospheric dispersion factors (χ/Qs) for accident analysis and breathing rates are provided in Table 15.5-68. The breathing rates were obtained from NRC Regulatory Guide 1.4, Revision 2 (Reference 35). (Note: Although revision 2 was referenced in the analysis, the breathing rates are the same as those in Revision 1, which is the DCPP licensing basis).

(i) The noble gases in the break flow and primary to secondary leakage are assumed to be transferred instantly out of the steam generator to the atmosphere. The whole body gamma doses are calculated combining the dose from the released noble gases with the dose from the iodine releases.

(j) For the accident initiated iodine spike case, an iodine spiking factor of 335, obtained from Regulatory Guide 1.195, May 2003 (Reference 44) is assumed.

(4) *Offsite Dose Calculation*

In equations 15.5-17 and 15.5-18, no credit is taken for a cloud depletion by ground deposition or by radioactive decay during transport to the exclusion area boundary or to the outer boundary of the low population zone. Offsite thyroid doses are calculated using the equation:

$$D_{Th} = \sum_i \left[(DCF)_i \sum_j \left((IAR)_{ij} (BR)_j (\chi / Q)_j \right) \right] \qquad (15.5\text{-}17)$$

where:

$(IAR)_{ij}$ = integrated activity of iodine nuclide i released during the time interval j in Ci

$(BR)_j$ = breathing rate during time interval j in meter^3/ second (Table 15.5-68)

$(\chi/Q)_j$ = atmospheric dispersion factor during time interval j in seconds/meter^3 (Table 15.5-68)

$(DCF)_i$ = thyroid dose conversion factor via inhalation for iodine nuclide i in rem/Ci (Table 15.5-69)

D_{Th} = thyroid dose via inhalation in rem

Offsite whole-body gamma doses are calculated using the equation:

$$D_\gamma = 0.25 \sum_i \left[\bar{E}_{\gamma i} \sum_j \left((IAR)_{ij} (\chi/Q)_j \right) \right] \quad (15.5\text{-}18)$$

where:

$(IAR)_{ij}$ = integrated activity of noble gas nuclide i released during time interval j in Ci

$(\chi/Q)_j$ = atmospheric dispersion factor during time interval j in seconds/m^3

$\bar{E}_{\gamma i}$ = average gamma energy for noble gas nuclide i in MeV/dis (Table 15.5-70)

D_γ = whole body gamma dose due to immersion in rem

(5) *Offsite Dose Results*

Thyroid and whole-body gamma doses at the Exclusion Area Boundary and the outer boundary of the Low Population Zone are presented in Table 15.5-71. All of these RSG doses are within the allowable guidelines as specified by the SRP, Revision 2 (Section 15.6.3).

The SGTR dose analysis of record is based on the RSGs and all doses are within 10 CFR 100.11 limits. The limiting dose for the SGTR analysis accepted by the NRC based on the OSGs is the EAB zero to two hour thyroid dose of 30.5 rem for the accident initiated iodine spike analysis case. This dose exceeds the SRP 15.6.3 allowable guideline value of 30 rem by 0.5 rem. However, the NRC found the 30.5 rem value acceptable in a letter to PG&E, dated February 20,2003, "Issuance of Amendment: RE: Revision to Technical Specification 1.1, 'Definitions, Dose Equivalent 1-131,' and Revised Steam Generator Tube Rupture and Main Steam Line Break Analyses."

15.5.20.2.2 Control Room Exposures

Additional analyses were performed to determine the airborne doses to the control room operators from an SGTR. These calculations used the atmospheric releases of radioactivity determined in the analysis discussed in Section 15.5.20.2.1 and Reference 46. The control room is modeled as a discrete volume. The atmospheric dispersion factors calculated for the transfer of activity to the control room intake contained in Table 15.5-68 are used to determine the activity available at the control room intake. The inflow (filtered and unfiltered) to the control room and the control room filtered recirculation flow are used to calculate the concentration of activity in the control room. Control room parameters used in the analysis are presented in Table 15.5-72. The control room occupancy factors assumed were taken from Table 15.5-32.

Thyroid, whole body gamma, and beta skin doses are calculated for 30 days in the control room. Although all releases are terminated when the RHR system is put in service, the calculation is continued to account for additional doses due to continued occupancy.

The total primary to secondary leak rate is assumed to be 1.0 gpm. The leakage to the intact steam generators is assumed to persist for the duration of the accident.

The calculations determine the thyroid doses based on a pre-accident iodine spike and based on an accident initiated iodine spike with a spiking factor of 335. Both spike assumptions consider 0.1 μCi/gm D.E. I-131 secondary activity. The whole body doses are calculated combining the dose from the released noble gases with the dose from the iodine releases.

Control room thyroid doses are calculated using the following equation:

$$D_{Th} = \sum_i \left[DCF_i \left(\sum_j Conc_{ij} * (BR)_j \right) \right] \qquad (15.5\text{-}19)$$

where:

D_{Th} = thyroid dose via inhalation (Rem)
DCF_i = thyroid dose conversion factor via inhalation for isotope i (Rem/Ci) (Table 15.5-69)
$Conc_{ij}$ = concentration in the control room of isotope i, during time interval j, calculated dependent upon inleakage, filtered recirculation and filtered inflow (Ci-sec/m^3)
$(BR)_j$ = breathing rate during time interval j (m^3/sec) (Table 15.5-68)

Control room whole body doses are calculated using the following equation:

$$D_{WB} = 0.25 * \left(\frac{1}{GF} \right) * \sum_i E_{\gamma i} \left(\sum_j Conc_{ij} \right) \qquad (15.5\text{-}20)$$

where:

D_{WB} = whole body dose via cloud immersion (Rem)
GF = geometry factor, calculated based on Reference 17, using the equation $GF = \frac{1173}{V^{0.338}}$ where V is the control room volume in ft^3
$E_{\gamma i}$ = average gamma disintegration energy for isotope i (MeV/dis) (Table 15.5-70)
$Conc_{ij}$ = concentration in the control room of isotope i, during time interval j, calculated dependent upon inleakage, filtered recirculation and filtered inflow (Ci-sec/m^3)

Control room skin doses are calculated using the following equation:

$$D_{\beta} = 0.23 * \sum_i E_{\beta i} \left(\sum_j Conc_{ij} \right) \qquad (15.5\text{-}21)$$

where

D_{β} = whole body dose via cloud immersion (Rem)
$E_{\beta i}$ = average beta disintegration energy for isotope i (MeV/dis) (Table 15.5-70)

$Conc_{ij}$ = concentration in the control room of isotope i, during time interval j, calculated dependent upon inleakage, filtered recirculation and filtered inflow (Ci-sec/m^3)

Table 15.5-74 presents the resulting airborne doses to the control room operators. The resultant doses are well below the guidelines of GDC 19, 1971, and are below the corresponding post-LOCA control room exposures presented in Table 15.5-33.

15.5.20.3 Conclusions

The analysis demonstrates that the acceptance criteria are met as follows:

(1) An individual located at any point on the boundary of the exclusion area for the two hours immediately following the onset of the postulated fission product release shall not receive a total radiation dose in excess of dose guidelines of SRP, Section 15.6.3, Revision 2 (i.e., the 10 CFR 100.11 dose limits for the whole body and the thyroid for the pre-existing iodine spike case and 10 percent of the 10 CFR 100.11 dose limits for the whole body and the thyroid for the accident-initiated iodine spike case) as shown in Table 15.5-71.

(2) An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose in excess of the dose guidelines of SRP, Section 15.6.3, Revision 2 (i.e., 10 CFR 100.11 dose limits for the whole body and the thyroid for the pre-existing iodine spike case and 10 percent of the 10 CFR 100.11 dose limits for the whole body and the thyroid for the accident-initiated iodine spike case) as shown in Table 15.5-71.

(3) In accordance with the requirements of GDC 19, 1971, the dose to the control room operator under accident conditions shall not be in excess of 5 rem whole body or its equivalent to any part of the body (i.e., 30 rem thyroid and beta skin, Reference 51) for the duration of the accident for both the pre-existing and the accident-initiated iodine spike cases as shown in Table 15.5-74.

As noted in Section 15.5.20.2, the above dose estimates reflect the RSGs and are within 10 CFR 100.11 limits. The SGTR analysis accepted by the NRC based on OSGs is the EAB zero to two hour thyroid dose of 30.5 rem for the accident-initiated iodine spike analysis case. This dose exceeds the SRP 15.6.3 allowable guideline value of 30 rem by 0.5 rem. However, the NRC found the 30.5 rem value acceptable in a letter to PG&E, dated February 20,2003, "Issuance of Amendment: RE: Revision to Technical Specification 1.1, 'Definitions, Dose Equivalent 1-131,' and Revised Steam Generator Tube Rupture and Main Steam Line Break Analyses."

15.5.21 RADIOLOGICAL CONSEQUENCES OF A LOCKED ROTOR ACCIDENT

15.5.21.1 Acceptance Criteria

(1) The radiological consequences of a locked rotor accident shall not exceed the dose limits of 10 CFR 100.11 as outlined below:

i. An individual located at any point on the boundary of the exclusion area for the two hours immediately following the onset of the postulated fission product release shall not receive a total radiation dose to the whole body in excess of 25 rem or a total radiation dose in excess of 300 rem to the thyroid from iodine exposure.

ii. An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose to the whole body in excess of 25 rem, or a total radiation dose in excess of 300 rem to the thyroid from iodine exposure.

(2) In accordance with the requirements of GDC 19, 1971, the dose to the control room operator under accident conditions shall not be in excess of 5 rem whole body or its equivalent to any part of the body (i.e., 30 rem thyroid and beta skin, Reference 51) for the duration of the accident.

15.5.21.2 Identification of Causes and Accident Description

Under adverse circumstances, a locked rotor accident could cause small amounts of fuel cladding failure in the core. If this occurs, some fission products will enter the coolant and will mostly remain in the coolant until cleaned up by the primary coolant demineralizers, or in the case of noble gases, until stripped from the coolant. Following such an incident, there are several possible modes of release of some of this activity to the environment.

In the short-term, if the accident occurs at a time when significant primary-to-secondary leakage exists, some of the additional activity entering the coolant will leak into the secondary system. The noble gases will be discharged to the atmosphere via the air ejectors or by way of atmospheric steam dump. The iodines will remain mostly in the liquid form and be picked up by the blowdown treatment system. Some fraction of the iodines, however, will be released via the air ejectors or by way of atmospheric steam dump. In addition, if an atmospheric steam dump is necessary, some of the activity contained in the secondary system prior to the accident will be released.

The amounts of steam released depend on the time relief valves remain open and the availability of condenser bypass cooling capacity. The amounts of radioactive iodine released depend on the amounts of steam released, the amount of activity contained in the secondary system prior to the accident, and the amount contained in the primary

coolant which leaks into the secondary system. As discussed in Section 15.5.10, the amount of steam released following the locked rotor accident, if no condenser cooling is available, would not exceed approximately 1.7E+06 lbm. In the analysis of both the design basis case and the expected case, this amount of steam was assumed to be released.

For the design basis case, it was assumed that the plant had been operating continuously with 1 percent fuel cladding defects and 1 gpm primary-to-secondary leakage. For the expected case calculation, operation at 0.2 percent defects and 20 gallons per day to the secondary was assumed. In both cases, leakage of water from primary to secondary was assumed to continue during cooldown at 75 percent of the pre-accident rate during the first 2 hours and at 50 percent of the pre-accident rate during the next 6 hours. These values were derived from primary-to-secondary pressure differentials during cooldown. It was also conservatively assumed for both cases that the iodine Partition Factor in the steam generators releasing steam was 0.01 on a mass basis (Reference 15). In addition, to account for the effect of iodine spiking, fuel escape rate coefficients for iodines of 30 times the normal operation values given in Table 11.1-9 were used for a period of 8 hours following the start of the accident. Other detailed and less significant modeling assumptions are presented in Reference 4.

The assumptions used for meteorology, breathing rates, population density and other common factors were also described earlier. Both the primary and secondary coolant activities prior to the accident are discussed in Section 15.5.2.

In order to determine the primary coolant activities immediately after the accident, it was assumed that less than 10 percent of the total activity contained in the fuel rod gaps would be immediately released to the coolant and mixed uniformly in the coolant system volume. The gap inventories used are listed in Table 11.1-7.

All of the data and assumptions listed above were used with the EMERALD computer program to calculate the activity releases and potential doses following the accident. The calculated activity releases are listed in Table 15.5-41. The potential doses are given in Table 15.5-42. The exposures are also shown in Figures 15.5-14 and 15.5-15 as a function of the amount of fuel failure that occurs. On the left boundary of these graphs, in the region of negligible fuel failures, the exposures are just the component resulting from the activity already present in the secondary system, or which leaks through the steam generators at pre-accident primary coolant levels. These exposures correspond to those shown in Figures 15.5-2 through 15.5-5.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

Another mode of release following a locked rotor accident, or any accident involving significant fuel failure, is the long-term release by way of cleanup and leakage from the primary coolant system. The activity going through these pathways, principally Kr-85, would result in some incremental long-term dose beyond the normal yearly releases. This pathway of release has been evaluated, and the results are presented in

Figure 15.5-16. Since the activity released in this way would reach the environment over a long term, the annual average atmospheric dilution factors (Table 15.5-5) and breathing rates have been used. The amounts of activity released were determined by multiplying the activities released from the gaps following the accident by the release fractions listed in Table 15.5-40.

These long-term release fractions were determined from the normal radioactivity transport analysis carried out for Chapter 11, for the anticipated operational occurrences case. In essence, these fractions are the fractions of a curie reaching the environment per curie released to the coolant, for each isotope. The pathways included are primary cleanup, leakage to the containment, and leakage to the auxiliary building. As shown in Table 15.5-40, essentially all of the Kr-85 released to the coolant is eventually released to the environment, as would be physically expected, and lower fractions of the other isotopes are released, depending on their respective overall cleanup, leakage, and decay factors in the plant. It can be concluded by comparing these exposures to the short-term exposures in Figure 15.5-12 that the incremental long-term exposures are negligible additions to the radiological consequences of accidents of this kind.

In addition, it can be concluded that accidents of this kind would not result in significant additions to the annual doses expected from normal plant operation.

From these short-term and long-term analyses, it can also be concluded that all potential exposures from a locked rotor accident will be well below the guideline levels specified in 10 CFR 100.11, and that the occurrence of such accidents would not result in undue risk to the public. A detailed evaluation of potential exposures to control room personnel was made in Section 15.5.17, for conditions following a LBLOCA. The containment shine contribution to control room dose would not be applicable following a locked rotor accident.

15.5.21.3 Conclusions

By comparing the activity releases following a locked rotor accident, given in Table 15.5-41, with the activity releases calculated for a LBLOCA, given in Tables 15.5-13 and 15.5-14, it can be concluded that any control room exposures following a locked rotor accident will be well below the GDC 19, 1971, criterion level.

Additionally, the analysis demonstrates that the acceptance criteria are met as follows:

(1) The radiation dose to the whole body and to the thyroid of an individual located at any point on the boundary of the exclusion area for the two hours immediately following the onset of the postulated fission product release are well below the dose limits of 10 CFR 100.11 as shown in Table 15.5-42.

(2) The radiation dose to the whole body and to the thyroid of an individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release

(during the entire period of its passage), are well below the dose limits of 10 CFR 100.11 as shown in Table 15.5-42.

(3) Since the activity releases from the locked rotor accident given in Table 15.5-41 are less than those from a LBLOCA (see Table 15.5-13 and 15.5-14), any control room dose which might occur would be well within the established criteria of GDC 19, 1971 and discussed in Section 15.5.17.

15.5.22 RADIOLOGICAL CONSEQUENCES OF A FUEL HANDLING ACCIDENT

The procedures used in handling fuel in the containment and fuel handling area are described in detail in Section 15.4.5. In addition, design and procedural measures provided to prevent fuel handling accidents are also described in that section, along with a discussion of past experience in fuel handling operations. The basic events that could be involved in a fuel handling accident are discussed in that section, and the following discussion evaluates the potential radiological consequences of such an accident.

15.5.22.1 Fuel Handling Accident In The Fuel Handling Area

15.5.22.1.1 Acceptance Criteria

The radiological consequences of a fuel handling accident in the fuel handling area shall not exceed the dose limits of 10 CFR 50.67 as outlined below:

(1) An individual located at any point on the boundary of the exclusion area for any two hour period following the onset of the postulated fission product release shall not receive a total radiation dose in excess of 0.063 Sv (6.3 rem) total effective dose equivalent (TEDE).

(2) An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose in excess of 0.063 Sv (6.3 rem) total effective dose equivalent (TEDE).

(3) The dose to the control room operator under accident conditions shall not be in excess of 0.05 Sv (5 rem) total effective dose equivalent (TEDE) for the duration of the accident.

15.5.22.1.2 Identification of Causes and Accident Description

The radiological consequences of a fuel handling accident in the fuel handling area were analyzed using the LOCADOSE computer code.

The values assumed for individual fission product inventories are calculated for a source term assuming approximately 105 percent full power operation (3580 MW

thermal) immediately preceding shutdown. The accident is assumed to occur 100 hours after shutdown. This latter interval represents approximately the minimum time required to prepare (cooldown, head and internals removal, cavity flooding, etc.) the core for refueling and is therefore somewhat conservative in that it would require that the accident occur during handling of the first few fuel assemblies.

The source term is conservatively assumed to be a composite of the highest fission product activity totals for various combinations of burnup and enrichment. The ORIGEN-2 computer code was used to calculate these worst-case fission product inventories. The DBA gap activity inventory is based on NRC Safety Guide 25, March 1972, assumptions: radial peaking factor of 1.65, gap fraction of 10 percent for noble gases other than Kr-85, gap fraction of 30 percent for Kr-85, and gap fraction of 10 percent for iodines.

The assumption is made for both cases that 100 percent of the activity (consisting principally of fission product isotopes of the elements xenon, krypton, and iodine) present in the gap between the fuel pellets and the cladding in the damaged rods is immediately released to the pool or cavity water. This assumption is conservative for elemental iodine because the low cladding and gap temperatures would result in a large fraction of it being condensed and temporarily retained within the cladding.

The analysis assumes that the fission product release occurs at a water depth of 23 feet, which is the minimum water depth above the top of the fuel as required by Technical Specifications. The spent fuel pool, where handling operations are most likely to result in fuel damage, has a water depth of about 38 feet. Using a depth of 23 feet accounts for cases in which the release occurs from the top of an assembly that is resting vertically on the floor, and for releases that occur near the top of the storage racks. Finally, consistent with Safety Guide 25, March 1972 the analysis assumes that all activity that escapes from the pool to the fuel handling area air spaces is released from the area within a 2-hour time period.

Of the activity reaching the water, 100 percent of the noble gases, xenon and krypton, are assumed to be immediately released to the fuel handling area air spaces. However, the ability of the pool water to scrub iodine from the gas bubbles as they rise to the surface has been considered. The pool DFs for the inorganic and organic species are 500 and 1, respectively, giving an overall effective DF of 200 (i.e., 99.5 percent of the total released from the damaged rods is retained by the pool water). This difference in DFs for inorganic and organic iodine species results in the iodine above the fuel pool being composed of 75 percent inorganic and 25 percent organic species. These assumptions are consistent with those suggested in NRC Regulatory Guide 1.183, July 2000. Table 15.5-44 itemizes the gap activity available for release from the FHB atmosphere to the environment.

Table 15.5-45 itemizes the assumptions and numerical values used to calculate the fuel handling accident radiological exposures. The potential releases of activity to the atmosphere are listed in Table 15.5-44. The exposures resulting from the postulated

fuel handling accident inside the fuel handling area are presented in Table 15.5-47. These exposures are well below the Regulatory Guide 1.183, July 2000 limits and demonstrate the adequacy of the fuel handling safety systems.

In the very unlikely event of a serious fuel handling accident and in combination with the conservative assumptions discussed above, containment building or fuel handling area activity concentrations may be quite high. High activity concentrations necessitate the evacuation of fuel handling areas in order to limit exposures to fuel handling personnel. Upon indication of a serious fuel handling accident, the fuel handling area will be evacuated until the extent of the fuel damage and activity levels in the area can be determined. Any serious fuel handling accident would be both visually and audibly detectable via radiation monitors in the fuel handling areas that locally alarm in the event of high activity levels and would alert personnel to evacuate.

Although conservatively neglected for this analysis, the fuel handling area has the additional safety feature of ventilation air flow that sweeps the surface of the spent fuel pool carrying any activity away from fuel handling personnel. This sweeping of the spent fuel pool is expected to considerably lower activity levels in the fuel handling area in the event of a serious fuel handling accident.

After charcoal filter cleanup (another design feature conservatively neglected in this analysis), fuel handling area post-accident ventilation air exhausts through the plant vent at a height of 70 meters. Site meteorology is such that it is very unlikely that any airborne activity will enter the control room ventilation system.

Spent fuel cask accidents in the fuel handling area causing fuel damage are precluded due to crane travel limits and design and operating features as described in Sections 9.1.4.3.9 and 9.1.4.2.6. Spent fuel handling accidents in the fuel handling area would not jeopardize the health and safety of the public.

15.5.22.1.3 Conclusions

The analysis demonstrates that the acceptance criteria are met as follows:

(1) An individual located at any point on the boundary of the exclusion area for any two hour period following the onset of the postulated fission product release shall not receive a total radiation dose in excess of 0.063 Sv (6.3 rem) total effective dose equivalent (TEDE) as shown in Table 15.5-47.

(2) An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose in excess of 0.063 Sv (6.3 rem) total effective dose equivalent (TEDE) as shown in Table 15.5-47.

(3) The dose to the control room operator under accident conditions shall not be in excess of 0.05 Sv (5 rem) total effective dose equivalent (TEDE) for the duration of the accident as shown in Table 15.5-47.

15.5.22.2 Fuel Handling Accident Inside Containment

15.5.22.2.1 Acceptance Criteria

(1) The radiological consequences of a fuel handling accident inside containment shall not exceed the dose limits of 10 CFR 100.11 as outlined below:

   i. An individual located at any point on the boundary of the exclusion area for the two hours immediately following the onset of the postulated fission product release shall not receive a total radiation dose to the whole body in excess of 6 rem or a total radiation dose in excess of 75 rem to the thyroid from iodine exposure.

   ii. An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose to the whole body in excess of 6 rem, or a total radiation dose in excess of 75 rem to the thyroid from iodine exposure.

(2) In accordance with the requirements of GDC 19, 1971, the dose to the control room operator under accident conditions shall not be in excess of 5 rem whole body or its equivalent to any part of the body (i.e., 30 rem thyroid and beta skin, Reference 51) for the duration of the accident.

15.5.22.2.2 Identification of Causes and Accident Description

The offsite radiological consequences of a postulated fuel handling accident inside the containment are mitigated by containment closure. The following evaluation shows that in all cases the calculated exposures would be well below limits specified in 10 CFR 100.11.

During fuel handling operations, containment closure is not required. Generally, the containment ventilation purge system is operational and exhausts air from the containment through two 48-inch containment isolation valves. These two valves are connected in series. This flow of air from the containment is discharged to the environment via the plant vent.

This exhaust stream is monitored for activity by monitors in the plant vent. In the event of a postulated fuel handling accident, the plant vent monitors will alarm and result in the automatic closure of containment ventilation isolation valves. This activity release may result in offsite radiological exposures.

Containment penetrations are allowed to be open during fuel handling operations. The most prominent of these penetrations are the equipment hatch and the personnel airlock. Closure of these penetrations is achieved by manual means as discussed in Section 15.4.5. The closure of these penetrations is not credited in the design-basis fuel handling accident inside containment.

The FHA analysis assumes that the control room ventilation system of each unit remains in the normal mode of operation following the FHA. Thus, the design basis FHA does not credit charcoal filtration of the control room atmosphere intake flow or recirculation flow.

The evaluation of potential offsite exposures was performed for a design basis case, assuming plant parameters as limited by Technical Specifications. The assumptions of Safety Guide 25, March 1972, were used as guidance with the exceptions detailed below.

15.5.22.2.2.1 Activity Released to Containment Atmosphere

The assumptions made in determining the quantity of activity available for release from the containment refueling pool following the postulated accident are identical to those discussed in Section 15.5.22.1. For the DBA case, these assumptions are consistent with those in Safety Guides 25, March 1972, and 1.183, July 2000.

Consistent with the guidance of Safety Guide 25, March 1972, it was assumed that all the gap activity in the damaged rods is released and consists of 10 percent of the total noble gases other than Kr-85, 30 percent of the Kr-85, and 10 percent of the total radioactive iodine in the rods at the time of the accident.

An effective DF of 200 for the iodines was assumed for the water in the refueling cavity. This DF is consistent with the current guidance provided in Regulatory Guide 1.183, July 2000.

The dose conversion factors used are from ICRP Publication 30 (Reference 45). The use of these dose conversion factors is consistent with the current guidance provided in Regulatory Guide 1.183, July 2000.

15.5.22.2.2.2 Containment Closure

Following the postulated accident, airborne activity evolves from the surface of the pool where it mixes with air above the pool. Airborne activity is then assumed to be discharged to the environment via the open penetrations. The duration of the release was assumed to be within two seconds.

In addition to radiation monitor indications, a fuel handling accident would immediately be known to refueling personnel at the scene of the accident. These personnel would

initiate containment closure actions and are required by an Equipment Control Guideline to be in constant communication with control room personnel. The plant intercom system is described in Section 9.5.2.

15.5.22.2.2.3 Activity Released to Environment

The containment refueling pool is approximately rectangular in shape with approximate dimensions of 25 by 70 feet. The pool has a surface area of about 1750 square feet.

It was assumed that activity evolved from the pool was instantaneously mixed and retained within the approximately 33,600 cubic foot rectangular parallelepiped formed by the 25- by 70-foot pool and the 40-foot-high steam generators. Where the steam generators do not surround the pool, the radioactivity would actually be dispersed into a larger volume of air which would have the effect of reducing the dose. However, for conservatism, it was assumed that all the radioactivity remained within this 33,600-cubic-foot volume and was then transported to the environment within a two second time period through the open equipment hatch.

15.5.22.2.2.4 Offsite Exposures

The integrated release of activity to the environment and the resulting offsite radiological exposures were calculated for the postulated fuel handling accident inside containment using the LOCADOSE computer program.

Table 15.5-48 itemizes the DBA assumptions and numerical values used to calculate fuel handling accident radiological exposures. The calculated releases of activity to the atmosphere are listed in Table 15.5-49. The DBA exposures resulting from the postulated fuel handling accident inside containment are presented in Table 15.5-50. These exposures are well within the 10 CFR 100.11 limits.

15.5.22.2.2.5 Action Following Containment Isolation

Following manual containment closure after the fuel handling accident, activity can be removed from the containment atmosphere by the redundant PG&E Design Class II Iodine Removal System (two trains at 12,000 cfm per train), which consists of HEPA/charcoal filters. This system is described in Section 9.4.5. There are no Technical Specification requirements for this filtration system.

The containment can also be purged to the atmosphere at a controlled rate of up to 300 cfm per train through the HEPA/charcoal filters of the hydrogen purge system. This system is described in Section 6.2.5.

15.5.22.2.3 Conclusions

The analysis demonstrates that the acceptance criteria are met as follows:

(1) The radiation dose to the whole body and to the thyroid of an individual located at any point on the boundary of the exclusion area for the two hours immediately following the onset of the postulated fission product release are well below the dose limits of 10 CFR 100.11 as shown in Table 15.5-50.

(2) The radiation dose to the whole body and to the thyroid of an individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), are well below the dose limits of 10 CFR 100.11 as shown in Table 15.5-50.

(3) In accordance with the requirements of GDC 19, 1971, the dose to the control room operator under accident conditions shall not be in excess of 5 rem whole body or its equivalent to any part of the body (i.e., 30 rem thyroid and beta skin, Reference 51) for the duration of the accident as shown in Table 15.5-50.

15.5.22.3 Conclusion, Fuel Handling Accidents

In the preceding sections the potential offsite exposures from major fuel handling accidents have been calculated. The analyses have been carried out using the models and assumptions specified in pertinent regulatory guides. In all analyses the resulting potential exposures to individual members of the public and the general population have been found to be lower than the applicable guidelines and limits specified in 10 CFR 100.11. (FHA in Containment) and 10 CFR 50.67 (FHA in FHB).

On this basis, it can be concluded that the occurrence of a major fuel handling accident in a DCPP unit would not constitute an undue risk to the health and safety of the public.

Additionally, it can be concluded that the ESF provided for the mitigation of the consequences of a major fuel handling accident are adequate.

15.5.23 RADIOLOGICAL CONSEQUENCES OF A ROD EJECTION ACCIDENT

15.5.23.1 Acceptance Criteria

(1) The radiological consequences of a rod ejection accident shall not exceed the dose limits of 10 CFR 100.11 as outlined below:

i. An individual located at any point on the boundary of the exclusion area for the two hours immediately following the onset of the postulated fission product release shall not receive a total radiation dose to the whole body

in excess of 25 rem or a total radiation dose in excess of 300 rem to the thyroid from iodine exposure.

ii. An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose to the whole body in excess of 25 rem, or a total radiation dose in excess of 300 rem to the thyroid from iodine exposure.

(2) In accordance with the requirements of GDC 19, 1971, the dose to the control room operator under accident conditions shall not be in excess of 5 rem whole body or its equivalent to any part of the body (i.e., 30 rem) for the duration of the accident.

15.5.23.2 Identification of Causes and Accident Description

As discussed in Section 15.4.6, under adverse combinations of circumstances, some fuel cladding failures could occur following a rod ejection accident. In this case, some of the activity in the fuel rod gaps would be released to the coolant and in turn to the inside of the containment building. As a result of pressurization of the containment, some of this activity could leak to the environment.

For the design basis case, it was assumed that the plant had been operating continuously with 1 percent fuel cladding defects and 1 gpm primary-to-secondary leakage. For the expected case calculation, operation at 0.2 percent defects and 20 gallons per day to the secondary was assumed.

Following a postulated rod ejection accident, activity released from the fuel pellet-cladding gap due to failure of 10 percent of the fuel rods is assumed to be instantaneously released to the primary coolant. Releases to the primary coolant are assumed to be immediately and uniformly mixed throughout the coolant.

The activity released to the containment from the primary coolant through the ruptured control rod mechanism pressure housing is assumed to be mixed instantaneously throughout the containment and is available for leakage to the atmosphere.

It has been assumed for both the design basis and expected cases that 10 percent of the elemental iodine leaked to the coolant is released to the containment atmosphere as a result of flashing of some of the primary coolant water. Of the amounts of noble gases released to the primary coolant, 100 percent is assumed to be released to the containment atmosphere at the time of the accident. It is assumed that the amount of iodine in chemical forms that are not affected by the spray system are negligible. These release fractions are used for both the design basis case and the expected case.

Following the release to the containment, the fission products are assumed to leak from the containment at the same rates assumed for the LBLOCA, discussed in

Section 15.5.17. In addition, the spray system is assumed to be in operation and acts to remove the iodines from the containment atmosphere at the same rates assumed for the LBLOCA.

The assumptions used for meteorology, breathing rates, population density, and other common factors were also described in earlier sections. Both the primary and secondary coolant activities prior to the accident are given in Section 15.5.3. The gap activities are listed in Table 11.1-7.

All of the data and assumptions listed above were used with the EMERALD computer program to calculate the activity releases and potential doses following the accident. The calculated activity releases are listed in Table 15.5-51, and the potential doses are given in Table 15.5-52. Thyroid doses that would result from secondary steam releases can be determined from Figures 15.5-2 and 15.5-3 for the DBA conditions and Figures 15.5-4 and 15.5-5 for the expected conditions.

If atmospheric steam releases occur following this accident, there will be some additional exposures via this pathway. The detailed assumptions used in estimating mode of exposure are described in Section 15.5-21. The results are given parametrically in Figures 15.5-14 and 15.5-15. It should be noted that these figures are based on the assumptions of a full plant cooldown with no condenser capacity available, a condition that would not be expected to occur following a rod ejection accident.

From these analyses, it can be concluded that offsite exposures from this accident will be well below the guideline levels specified in 10 CFR 100.11, and that the occurrence of such accidents would not result in undue risk to the public. A detailed evaluation of potential exposures to control room personnel is made in Section 15.5.17 for conditions following a LOCA.

15.5.23.3 Conclusions

By comparing the activity releases following a rod ejection accident, given in Table 15.5-51, with the activity releases calculated for a LOCA, given in Tables 15.5-13 and 15.5-14, it can be concluded that any control room exposures following a rod ejection accident will be well below the GDC 19, 1971, criterion level.

Additionally, the analysis demonstrates that the acceptance criteria are met as follows:

(1) The radiation dose to the whole body and to the thyroid of an individual located at any point on the boundary of the exclusion area for the two hours immediately following the onset of the postulated fission product release are well below the dose limits of 10 CFR 100.11 as shown in Table 15.5-52.

(2) The radiation dose to the whole body and to the thyroid of an individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release

(during the entire period of its passage), are well below the dose limits of 10 CFR 100.11 as shown in Table 15.5-52.

(3) Since the activity releases from the rod ejection accident given in Table 15.5-51 are less than those from a LBLOCA (see Table 15.5-13 and 15.5-14), any control room dose which might occur would be well below the established criteria of GDC 19, 1971, and discussed in Section 15.5.17.

15.5.24 RADIOLOGICAL CONSEQUENCES OF A RUPTURE OF A WASTE GAS DECAY TANK

15.5.24.1 Acceptance Criteria

The radiological consequences of a rupture of a waste gas decay tank shall not exceed the dose limits of 10 CFR 100.11 as outlined below:

(1) An individual located at any point on the boundary of the exclusion area for the two hours immediately following the onset of the postulated fission product release shall not receive a total radiation dose to the whole body in excess of 25 rem or a total radiation dose in excess of 300 rem to the thyroid from iodine exposure.

(2) An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose to the whole body in excess of 25 rem, or a total radiation dose in excess of 300 rem to the thyroid from iodine exposure.

15.5.24.2 Identification of Causes and Accident Description

Radioactive waste gas decay tanks are used to permit decay of radioactive gases as a means of reducing or preventing the release of radioactive materials to the atmosphere. This system is discussed in detail in Section 11.3.

Three gas decay tanks are provided for each unit to afford operating flexibility and allow one or more tanks to be isolated from the rest of the system for an extended period of time. Most of the gas stored in the decay tanks is nitrogen cover gas displaced from the liquid waste holdup tanks. The radioactive components are principally the noble gases krypton and xenon, the particulate daughters of some of the krypton and xenon isotopes, and trace quantities of halogens.

A number of combinations of inadvertent operator errors and equipment malfunctions or failures could be identified that might result in a release of some or all of the activity stored in these tanks. In general, the amounts of activity that could be released by any such combination of events are limited in the following ways:

Plant Feature	Function
Limits on primary coolant activity	Restricts total curies present in volume control tank and gas decay tanks
Radiation monitor	Allows early detection of release, allowing operator action to terminate release
Limits on tank size	Restricts total curies present in any one tank
Isolation valves	Allows operator to terminate release
Operating procedures	Reduces probability of releases

In the evaluation of the waste gas decay tank failure accident, the fission product accumulation and release assumptions for the DBA case are consistent with those of NRC Safety Guide 24, March 1972 (Reference 24). These assumptions are:

(1) The reactor has been operating at full power with 1 percent defective fuel and a shutdown to cold condition has been conducted at the end of an equilibrium core cycle.

(2) All noble gases have been removed from the primary cooling system and transferred to the gas decay tank that is assumed to fail. No radioactive decay is assumed during transfer.

(3) The failure occurs immediately on completion of the waste gas transfer, releasing the entire maximum contents of the tank to the auxiliary building. The assumption of the release of the noble gas inventory from only a single tank is based on a design that allows all gas decay tanks to be isolated from each other when they are in use.

(4) All of the gases are exhausted from the auxiliary building at ground level over a 2-hour time period. There is no decay in the auxiliary building.

The evaluation of the radiation doses resulting from the design basis case accident is based on the maximum gas decay tank inventories given in Table 11.3-5.

The fission product accumulation and release assumptions used for the expected case are identical with those used for the DBA basis case, except that the tank inventories are based on operation with 0.2 percent defective fuel. The radiation doses resulting from the expected case accident are calculated from the maximum gas decay inventories given in Table 11.3-6.

The whole body doses resulting from the rupture of a gas decay tank were calculated for the time period 0-2 hours using the semi-infinite cloud submersion model. Atmospheric dispersion factors used in the analysis are given in Tables 15.5-3 and 15.5-4, and the breathing rates used are given in Table 15.5-7. Due to the presence of only trace amounts of iodine in the waste gas tanks, inhalation thyroid doses are negligible.

15.5.24.3 Conclusions

The resulting approximate radiation exposures from the rupture of a gas decay tank are presented in Table 15.5-53. As shown in the table, the individual doses are all well below the guideline doses of 10 CFR 100.11.

The analysis demonstrates that the acceptance criteria are met as follows:

(1) The radiation dose to the whole body and to the thyroid of an individual located at any point on the boundary of the exclusion area for the two hours immediately following the onset of the postulated fission product release are well below the dose limits of 10 CFR 100.11 as shown in Table 15.5-53.

(2) The radiation dose to the whole body and to the thyroid of an individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), are well below the dose limits of 10 CFR 100.11 as shown in Table 15.5-53.

15.5.25 RADIOLOGICAL CONSEQUENCES OF A RUPTURE OF A LIQUID HOLDUP TANK

15.5.25.1 Acceptance Criteria

The radiological consequences of a rupture of a liquid hold tank shall not exceed the dose limits of 10 CFR 100.11 as outlined below:

(1) An individual located at any point on the boundary of the exclusion area for the two hours immediately following the onset of the postulated fission product release shall not receive a total radiation dose to the whole body in excess of 25 rem or a total radiation dose in excess of 300 rem to the thyroid from iodine exposure.

(2) An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose to the whole body in excess of 25 rem, or a total radiation dose in excess of 300 rem to the thyroid from iodine exposure.

15.5.25.2 Identification of Causes and Accident Description

Radioactive liquid waste holdup tanks are used as part of the chemical and volume control system (CVCS) to collect and permit decay of radioactive liquids drawn from the reactor primary coolant for reactivity control. The CVCS is described in detail in Section 9.3.4.

Five liquid holdup tanks are provided for the two units to afford operating flexibility and allow one or more tanks to be isolated from the rest of the system for extended periods of time. The liquid processed through the holdup tanks contains dissolved fission and activation products, as well as radioactive noble gases mixed with nitrogen cover gas used in the tanks.

The liquid holdup tanks are located in vaults which are Design Class I structures, so that in the event of a rupture or spill all liquids are retained in the vaults. The volume of holdup tank vaults is sufficient to contain the full contents of the holdup tank without spillage from the vaults. Any gases released from the liquid holdup tanks are collected by the auxiliary building ventilation system and discharged via the auxiliary building vent.

In the evaluation of the liquid waste holdup tank rupture accident, the following fission product accumulation and release assumptions are used for the design basis case:

(1) The reactor has been operating at full power with 1 percent defective fuel for an equilibrium core cycle.

(2) A liquid holdup tank has been filled with primary coolant at a rate of 120 gpm, with credit for decay as the tank is filling.

(3) The failure occurs immediately upon completion of the liquid transfer, releasing the entire contents of the tank to the auxiliary building vault. The assumption of the release of the contents of only a single tank is based on a design that allows all liquid holdup tanks to be isolated from each other when they are in use.

(4) All of the noble gases and varying amounts of the iodines are released from the auxiliary building vault to the auxiliary building atmosphere. These effluents are exhausted from the auxiliary building at ground level. There is no decay in the auxiliary building. No liquids escape from the vaults during the accident.

The whole body radiation doses resulting from the rupture of a liquid holdup tank were calculated for the time period 0-2 hours using the semi-infinite cloud submersion model, and the inhalation thyroid doses were calculated using the models discussed earlier. Atmospheric dispersion factors used in the analysis are given in Tables 15.5-3 and 15.5-4, and the breathing rates used are given in Table 15.5-7.

15.5.25.3 Conclusions

The resulting radiation exposures from the rupture of a liquid holdup tank are listed in Table 15.5-56. As shown in the table, the individual doses are well below the guideline doses of 10 CFR 100.11.

Additionally, the analysis demonstrates that the acceptance criteria are met as follows:

(1) The radiation dose to the whole body and to the thyroid of an individual located at any point on the boundary of the exclusion area for the two hours immediately following the onset of the postulated fission product release are well below the dose limits of 10 CFR 100.11 as shown in Table 15.5-56.

(2) The radiation dose to the whole body and to the thyroid of an individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), are well below the dose limits of 10 CFR 100.11 as shown in Table 15.5-56.

15.5.26 RADIOLOGICAL CONSEQUENCES OF A RUPTURE OF A VOLUME CONTROL TANK

15.5.26.1 Acceptance Criteria

The radiological consequences of a rupture of a volume control tank shall not exceed the dose limits of 10 CFR 100.11 as outlined below:

(1) An individual located at any point on the boundary of the exclusion area for the two hours immediately following the onset of the postulated fission product release shall not receive a total radiation dose to the whole body in excess of 25 rem or a total radiation dose in excess of 300 rem to the thyroid from iodine exposure.

(2) An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose to the whole body in excess of 25 rem, or a total radiation dose in excess of 300 rem to the thyroid from iodine exposure.

15.5.26.2 Identification of Causes and Accident Description

The volume control tank is used as part of the CVCS to collect the excess water released from the RCS during modes 1 through 6, which is not accommodated by the pressurizer. For a complete description of the CVCS and the volume control tank in all modes of operation refer to Section 9.3.4.

The liquid processed through the volume control tank contains dissolved fission and activation products, as well as undissolved radioactive noble gases. A spray nozzle located inside the tank on the inlet line strips part of the noble gases from the incoming liquid, and these gases are retained in the volume control tank vapor space. In addition, an overpressure of hydrogen cover gas is provided for the tank to control the hydrogen concentration in the reactor coolant.

The volume control tank is located in a vault which is a PG&E Design Class I structure, so that in the event of a rupture or spill all liquids are retained in the vault. The volume of the tank vault is sufficient to contain the full contents of the tank without spillage from the vault. Any gases released from the volume control tank are collected by the auxiliary building ventilation system and discharged via the auxiliary building vent.

In the evaluation of the volume control tank rupture accident, the following fission product accumulation and release assumptions are used for the design basis case:

(1) The reactor has been operating at full power with 1 percent defective fuel for an equilibrium core cycle.

(2) The volume control tank contains its maximum equilibrium inventory of radioactivity at the time of the accident. The failure of the tank releases the entire tank contents to the containment vault.

(3) All of the noble gases and 10E-4 of the iodines are released from the containment vault to the auxiliary building atmosphere. These effluents are exhausted from the auxiliary building at ground level over a 2-hour time period through the auxiliary building filters, which have efficiencies of 90 percent for iodines and 0 percent for noble gases. A discussion of the assumed effectiveness of the auxiliary building charcoal filters is given in Section 15.5.17. There is no decay in the auxiliary building. No liquids escape from the vault during the accident.

The evaluation of the radiation exposures resulting from the postulated accident for the design basis case is based on the maximum tank inventories given in Table 11.3-7.

The fission product accumulation and release assumptions for the expected case are identical with those used for the design basis case, with the exceptions that the tank inventories are based on operation with 0.2 percent defective fuel and the auxiliary building filter efficiency is 99 percent for iodines. The evaluation of the resulting radiation exposures for the expected case is based on the maximum tank inventories given in Table 11.3-8.

The whole body radiation doses resulting from the rupture of a volume control tank were calculated for the time period 0-2 hours using the semi-infinite cloud submersion model as discussed in earlier sections, and the inhalation thyroid doses were calculated using the models described in Reference 4. Atmospheric dispersion factors used in the

analysis are given in Tables 15.5-3 and 15.5-4, and the breathing rates used are given in Table 15.5-7. The resulting radiation exposures are listed in Table 15.5-57. As shown in the table, the individual doses are well below the guideline doses of 10 CFR 100.11.

If credit for the Auxiliary Building filters is not taken, the dose contributions from noble gases are unchanged and the dose contributions from iodines are increased by a factor of ten. The resulting thyroid doses are increased by a factor of ten from those in Table 15.5-57, and the resulting whole body doses are not significantly affected. These results are still well below the guideline doses of 10 CFR 100.11.

15.5.26.3 Conclusions

The analysis demonstrates that the acceptance criteria are met as follows:

(1) The radiation dose to the whole body and to the thyroid of an individual located at any point on the boundary of the exclusion area for the two hours immediately following the onset of the postulated fission product release are well below the dose limits of 10 CFR 100.11 as shown in Table 15.5-57.

(2) The radiation dose to the whole body and to the thyroid of an individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), are well below the dose limits of 10 CFR 100.11 as shown in Table 15.5-57.

15.5.27 REFERENCES

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TABLE 15.0-1

REGULATORY GUIDE 1.70 REVISION 1, APPLICABILITY MATRIX

Event	REG GUIDE 1.70, TABLE 15-1, REPRESENTATIVE TYPES OF EVENTS TO BE ANALYZED IN CHAPTER 15.0 OF THE SAR	15.2 Section	UFSAR SECTION 15.2 CONDITION II: FAULTS OF MODERATE FREQUENCY	15.3 Section	UFSAR SECTION 15.3 CONDITION III: INFREQUENT FAULTS	15.4 Section	UFSAR SECTION 15.4 CONDITION IV: LIMITING FAULTS	Location of Analyses or Reason Why Not Applicable
1	Uncontrolled control rod assembly withdrawal from a sub-critical condition (assuming the most unfavorable reactive conditions of the core and reactor coolant system), including control rod or temporary control device removal error during refueling.	15.2.1	UNCONTROLLED ROD CLUSTER CONTROL ASSEMBLY BANK WITHDRAWAL FROM A SUBCRITICAL CONDITION					
2	Uncontrolled control rod assembly withdrawal at the critical power (assuming the most unfavorable reactive conditions of the core and reactor coolant system) which yields the most severe results (hot at zero power, full power, etc).	15.2.2	UNCONTROLLED ROD CLUSTER CONTROL ASSEMBLY BANK WITHDRAWAL AT POWER					
3	Control rod misoperation or sequence of misoperations.	15.2.3	ROD CLUSTER CONTROL ASSEMBLY MISOPERATION					
4	Chemical and volume control system malfunction.	15.2.4	UNCONTROLLED BORON DILUTION					
5	Partial and total loss of reactor coolant flow force including trip of pumps and pump shaft seizures.	15.2.5	PARTIAL LOSS OF FORCED REACTOR COOLANT FLOW	15.3.4	COMPLETE LOSS OF FORCED REACTOR COOLANT FLOW			

TABLE 15.0-1

REGULATORY GUIDE 1.70 REVISION 1, APPLICABILITY MATRIX

Event	REG GUIDE 1.70, TABLE 15-1, REPRESENTATIVE TYPES OF EVENTS TO BE ANALYZED IN CHAPTER 15.0 OF THE SAR	15.2 Section	UFSAR SECTION 15.2 CONDITION II: FAULTS OF MODERATE FREQUENCY	15.3 Section	UFSAR SECTION 15.3 CONDITION III: INFREQUENT FAULTS	15.4 Section	UFSAR SECTION 15.4 CONDITION IV: LIMITING FAULTS	Location of Analyses or Reason Why Not Applicable
6	Start-up of an inactive reactor coolant loop or recirculating loop at incorrect temperature.	15.2.6	STARTUP OF AN INACTIVE REACTOR COOLANT LOOP					Precluded in Modes 1 and 2 due to Tech Spec 3.4.4
7	Loss of external electrical load and/or turbine stop valve closure, including, for BWRs closure of main steam isolation valve.	15.2.7	LOSS OF EXTERNAL ELECTRICAL LOAD AND/OR TURBINE TRIP					
8	Loss of normal and/or emergency feedwater flow.	15.2.8	LOSS OF NORMAL FEEDWATER					
9	Loss of all a-c power to the station auxiliaries (station blackout).	15.2.9	LOSS OF OFFSITE POWER TO THE STATION AUXILIARIES					Station Blackout is beyond design basis. Refer to UFSAR Section 8.3.1.6
10	Heat removal greater than heat generation due to (1) feedwater system malfunctions, (2) a pressure regulator failure, or inadvertent opening of a relief valve or safety valve, and (3) a regulating instrument failure.	15.2.10 15.2.12	EXCESSIVE HEAT REMOVAL DUE TO FEEDWATER SYSTEM MALFUNCTIONS EXCESSIVE LOAD INCREASE INCIDENT					Regarding (2) and (3): There are no pressure regulators or regulating instruments in the Westinghouse pressurized water reactor (PWR) design whose failure could cause heat removal greater than heat generation.

TABLE 15.0-1
REGULATORY GUIDE 1.70 REVISION 1, APPLICABILITY MATRIX

Event	REG GUIDE 1.70, TABLE 15-1, REPRESENTATIVE TYPES OF EVENTS TO BE ANALYZED IN CHAPTER 15.0 OF THE SAR	15.2 Section	UFSAR SECTION 15.2 CONDITION II: FAULTS OF MODERATE FREQUENCY	15.3 Section	UFSAR SECTION 15.3 CONDITION III: INFREQUENT FAULTS	15.4 Section	UFSAR SECTION 15.4 CONDITION IV: LIMITING FAULTS	Location of Analyses or Reason Why Not Applicable
11	Failure of the regulating instrumentation, causing for example, a power-coolant mismatch. Include reactor coolant flow controller failure resulting in increasing flow.	N/A	N/A	N/A	N/A	N/A	N/A	Reactor coolant flow controller is not a feature of the Westinghouse PWR design. Treatment of the performance of the reactivity controller in a number of accident conditions is offered in this chapter. (Chapter 15)

TABLE 15.0-1

REGULATORY GUIDE 1.70 REVISION 1, APPLICABILITY MATRIX

Event	REG GUIDE 1.70, TABLE 15-1, REPRESENTATIVE TYPES OF EVENTS TO BE ANALYZED IN CHAPTER 15.0 OF THE SAR	15.2 Section	UFSAR SECTION 15.2 CONDITION II: FAULTS OF MODERATE FREQUENCY	15.3 Section	UFSAR SECTION 15.3 CONDITION III: INFREQUENT FAULTS	15.4 Section	UFSAR SECTION 15.4 CONDITION IV: LIMITING FAULTS	Location of Analyses or Reason Why Not Applicable
12	Internal and external events such as major and minor fires, flood, storms or earthquakes.	N/A	N/A	N/A	N/A	N/A	N/A	Refer to the following Sections: 3.3 - Wind & Tornado Loadings 3.4 - Water level (flood) design 3.5 - Missile protection 3.7 - Seismic design 3.8 - Design of Class I structures 9.5.1 - Fire protection system

TABLE 15.0-1

REGULATORY GUIDE 1.70 REVISION 1, APPLICABILITY MATRIX

Event	REG GUIDE 1.70, TABLE 15-1, REPRESENTATIVE TYPES OF EVENTS TO BE ANALYZED IN CHAPTER 15.0 OF THE SAR	15.2 Section	UFSAR SECTION 15.2 CONDITION II: FAULTS OF MODERATE FREQUENCY	15.3 Section	UFSAR SECTION 15.3 CONDITION III: INFREQUENT FAULTS	15.4 Section	UFSAR SECTION 15.4 CONDITION IV: LIMITING FAULTS	Location of Analyses or Reason Why Not Applicable
13	Loss of coolant accidents resulting from the spectrum of postulated piping breaks within the reactor coolant pressure boundary and relief and safety valve blowdowns.	15.2.13	ACCIDENTAL DEPRESSURIZATION OF THE REACTOR COOLANT SYSTEM	15.3.1	LOSS OF REACTOR COOLANT FROM SMALL RUPTURED PIPES OR FROM CRACKS IN LARGE PIPES THAT ACTUATE EMERGENCY CORE COOLING SYSTEM	15.4.1	MAJOR REACTOR COOLANT SYSTEM PIPE RUPTURES (LOCA)	
14	Spectrum of postulated steam and feedwater system piping breaks inside and outside containment.	15.2.14	ACCIDENTAL DEPRESSURIZATION OF THE MAIN STEAM SYSTEM	15.3.2	MINOR SECONDARY SYSTEM PIPE BREAKS	15.4.2	MAJOR SECONDARY SYSTEM PIPE RUPTURE	
15	Inadvertent loading and operation of a fuel assembly into an improper position.			15.3.3	INADVERTENT LOADING OF A FUEL ASSEMBLY INTO AN IMPROPER POSITION			
16	Waste gas decay tank leakage or rupture.					15.4.7	RUPTURE OF A WASTE GAS DECAY TANK	
17	Failure of air ejector lines (BWR).	N/A	N/A	N/A	N/A	N/A	N/A	This applies to BWR plants only
18	Steam generator tube rupture (PWR).					15.4.3	STEAM GENERATOR TUBE RUPTURE (SGTR)	
19	Failure of charcoal or cryogenic system (BWR).	N/A	N/A	N/A	N/A	N/A	N/A	This applies to BWR plants only

TABLE 15.0-1

REGULATORY GUIDE 1.70 REVISION 1, APPLICABILITY MATRIX

Event	REG GUIDE 1.70, TABLE 15-1, REPRESENTATIVE TYPES OF EVENTS TO BE ANALYZED IN CHAPTER 15.0 OF THE SAR	15.2 Section	UFSAR SECTION 15.2 CONDITION II: FAULTS OF MODERATE FREQUENCY	15.3 Section	UFSAR SECTION 15.3 CONDITION III: INFREQUENT FAULTS	15.4 Section	UFSAR SECTION 15.4 CONDITION IV: LIMITING FAULTS	Location of Analyses or Reason Why Not Applicable
20	The spectrum of rod ejection accidents (PWR).					15.4.6	RUPTURE OF A CONTROL ROD DRIVE MECHANISM HOUSING (ROD CLUSTER CONTROL ASSEMBLY EJECTION)	
21	The spectrum of rod drop accidents (BWR).	N/A	N/A	N/A	N/A	N/A	N/A	This applies to BWR plants only
22	Break in instrument line or other lines from reactor coolant pressure boundary that penetrate containment.	N/A	N/A	N/A	N/A	N/A	N/A	No instrument lines from the RCS boundary in the DCPP design penetrate the containment. (For definition of the RCS boundary, refer to the 1972 issue of ANS N18.2, Nuclear Safety Criteria for the Design of Stationary PWR Plants.)
23	Fuel handling accident.					15.4.5	FUEL HANDLING ACCIDENT	
24	Small spills or leaks of radioactive material outside containment.	N/A	N/A	N/A	N/A	N/A	N/A	The analysis of the consequences of such small spills and leaks is included within the cases evaluated in Chapter 11, and larger leaks and spills are analyzed in Section 15.5.

TABLE 15.0-1

REGULATORY GUIDE 1.70 REVISION 1, APPLICABILITY MATRIX

Event	REG GUIDE 1.70, TABLE 15-1, REPRESENTATIVE TYPES OF EVENTS TO BE ANALYZED IN CHAPTER 15.0 OF THE SAR	15.2 Section	UFSAR SECTION 15.2 CONDITION II: FAULTS OF MODERATE FREQUENCY	15.3 Section	UFSAR SECTION 15.3 CONDITION III: INFREQUENT FAULTS	15.4 Section	UFSAR SECTION 15.4 CONDITION IV: LIMITING FAULTS	Location of Analyses or Reason Why Not Applicable
25	Fuel cladding failure (BWR, PWR) combined with steam generator leak (PWR).	N/A	N/A	N/A	N/A	N/A	N/A	The radiological consequences of this event are analyzed in Chapter 11, for the case of "Anticipated Operational Occurrences."
26	Control room uninhabitabi1ity.	N/A	N/A	N/A	N/A	N/A	N/A	Habitability of the control room following accident conditions is discussed in Chapter 6, and potential radiological exposures are reported in Section 15.5. In addition, Chapter 7 contains an analysis showing that the plant can be brought to, and maintained in, Mode 3 from outside the control room.
27	Failure or overpressurization of low pressure residual heat removal system.	N/A	N/A	N/A	N/A	N/A	N/A	Overpressurization of the residual heat removal system (RHRS) is considered extremely unlikely. PG&E reviewed possible RHRS overpressure scenarios and qualified the system for all credible high pressure transients in DCPP design change package N-049118.

TABLE 15.0-1

REGULATORY GUIDE 1.70 REVISION 1, APPLICABILITY MATRIX

Event	REG GUIDE 1.70, TABLE 15-1, REPRESENTATIVE TYPES OF EVENTS TO BE ANALYZED IN CHAPTER 15.0 OF THE SAR	15.2 Section	UFSAR SECTION 15.2 CONDITION II: FAULTS OF MODERATE FREQUENCY	15.3 Section	UFSAR SECTION 15.3 CONDITION III: INFREQUENT FAULTS	15.4 Section	UFSAR SECTION 15.4 CONDITION IV: LIMITING FAULTS	Location of Analyses or Reason Why Not Applicable
28	Loss of condenser vacuum.	N/A	N/A	N/A	N/A	N/A	N/A	This event is covered by the analyses of Section 15.2.7. Separate event analysis is not required.
29	Turbine trip with coincident failure of turbine bypass valves to open.	N/A	N/A	N/A	N/A	N/A	N/A	This event is covered by the analyses of Section 15.2.7. Separate event analysis is not required.
30	Loss of service water system.	N/A	N/A	N/A	N/A	N/A	N/A	Malfunctions of auxiliary saltwater system and component cooling water system (CCWS) are discussed in Chapter 9, Sections 9.2.7 and 9.2.2 respectively.
31	Loss of one (redundant) d-c system.	N/A	N/A	N/A	N/A	N/A	N/A	There are no significant safety-related consequences of this event.
32	Inadvertent operation of ECCS during power operation.	15.2.15	SPURIOUS OPERATION OF THE SAFETY INJECTION SYSTEM AT POWER					
33	Turbine trip with failure of generator breaker to open.	N/A	N/A	N/A	N/A	N/A	N/A	The effects of turbine trip on the RCS are presented in Section 15.2.7. Separate event analysis is not required.
34	Loss of instrument air system.	N/A	N/A	N/A	N/A	N/A	N/A	Malfunctions of this system are discussed in Section 9.3.2.

TABLE 15.0-1
REGULATORY GUIDE 1.70 REVISION 1, APPLICABILITY MATRIX

Event	REG GUIDE 1.70, TABLE 15-1, REPRESENTATIVE TYPES OF EVENTS TO BE ANALYZED IN CHAPTER 15.0 OF THE SAR	15.2 Section	UFSAR SECTION 15.2 CONDITION II: FAULTS OF MODERATE FREQUENCY	15.3 Section	UFSAR SECTION 15.3 CONDITION III: INFREQUENT FAULTS	15.4 Section	UFSAR SECTION 15.4 CONDITION IV: LIMITING FAULTS	Location of Analyses or Reason Why Not Applicable
35	Malfunction of turbine gland sealing system.	N/A	N/A	N/A	N/A	N/A	N/A	The radiological effects of this event are not significant for PWR plants. Minor leakages are within the scope of the analysis cases presented in Chapter 11.

TABLE 15.1-1

NUCLEAR STEAM SUPPLY SYSTEM POWER RATINGS

Core Rated Thermal Power	3411
Thermal power generated by the reactor coolant pumps minus heat losses to containment and letdown system [(b)]	14
Nuclear steam supply system (NSSS) thermal power output[(b)]	3425
The engineered safety features design rating (maximum calculated turbine rating)[(a)]	3570

(a) The units will not be operated at this rating because it exceeds the license ratings.
(b) As noted on Table 15.1-4, some analyses assumed a full power NSSS thermal output of 3,423 MWt, based on the previous net reactor coolant pump heat of 12 MWt. An evaluation concluded that the effect of an additional 2 MWt for NSSS is negligible such that analyses based on 3,423 MWt remain valid.

TRIP POINTS AND TIME DELAYS TO TRIP ASSUMED IN ACCIDENT ANALYSES

Trip Function	Limiting TripPoint Assumed In Analyses	Time Delay, sec
Power range high neutron flux, high setting	118%	0.5
Power range high neutron flux, low setting	35%	0.5
Power range high positive nuclear power rate	9% / 2 sec	3.0
Overtemperature ΔT	Variable, see Figure 15.1-1	7[(a)]
Overpower ΔT	Variable, see Figure 15.1-1	7[(a)]
High pressurizer pressure	2460 psia	2
Low pressurizer pressure	1860 psia	2
High pressurizer water level	100%	N/A[(f)]
Low reactor coolant flow (from loop flow detectors)	87% loop flow[(d)]	1
Undervoltage trip	[(b)]	1.5
Low-low steam generator level	8.2% of narrow range level span	2[(c)]
High steam generator level trip of the feedwater pumps and closure of feedwater system valves and turbine trips	100% of narrow range level span[(e)]	2

(a) Total time delay consists of a maximum 5-second RTD lag time constant and a maximum 2-second electronics delay

(b) A specific undervoltage setpoint was not assumed in the safety analysis.

(c) When below 50% power, a variable trip time delay is utilized as discussed in Section 7.2.2.1.5.

(d) Westinghouse letter PGE-96-582, Diablo Canyon Units 1 & 2 Evaluation of Revised Low Reactor Coolant Flow Reactor Trip Setpoint, June 27, 1996, concludes that a safety analysis setpoint of 85% loop flow is acceptable for the Locked Rotor event (Section 15.4.4) and the Partial Loss of Flow event (Section 15.2.5), for which 87% was assumed in the analysis.

(e) The analysis assumed 100% narrow range level span for conservatism. The plant setpoint analytical limit is 98.8% narrow range level span for Model Delta 54 steam generators due to void effects. Although the turbine trip is modeled for completeness it is not needed for DNBR analysis.

(f) Westinghouse Letter PGE-02-72, Diablo Canyon Units 1 and 2 Evaluation of Reactor Trip Functions for Uncontrolled RCCA Bank Withdrawal at Power, December 13, 2002, documents that a specific response time is not assumed since it is not a sensitive parameter for the generic evaluation results.

TABLE 15.1-4

SUMMARY OF INITIAL CONDITIONS AND COMPUTER CODES USED

Events	Computer Codes Utilized	Assumed Reactivity Coefficients: Moderator Temp[a], pcm/°F[d]	Assumed Reactivity Coefficients: Moderator Density[a], Δk/gm/cc	Assumed Reactivity Coefficients: Doppler[b]	Initial NSSS Thermal Power Output Assumed[c], MWt
CONDITION II					
Uncontrolled RCCA bank withdrawal from a subcritical condition	TWINKLE, THINC, FACTRAN	+5	-	Least negative defect - 954 pcm	0
Uncontrolled RCCA bank withdrawal at power	LOFTRAN	+5	0.43	Lower and Upper	3,423
RCCA misoperation	THINC, ANC, LOFTRAN	-	-	Lower	3,425
Uncontrolled boron dilution					0 and 3,423
Partial loss of forced reactor coolant flow	LOFTRAN, THINC, FACTRAN	+5	-	Upper	3,423
Startup of an inactive reactor coolant loop	LOFTRAN, FACTRAN, THINC	-	0.43	Lower	2,396
Loss of external electrical load and/or turbine trip-DNBR	LOFTRAN, RETRAN-02	+5	0.43	Lower and Upper	3,423
Loss of external electrical load and/or turbine trip - Overpressure	RETRAN-02	+5	-	Lower	3,425

TABLE 15.1-4

Events	Computer Codes Utilized	Assumed Reactivity Coefficients: Moderator Temp[a], pcm/°F[d]	Moderator Density[a], Δk/gm/cc	Doppler[b]	Initial NSSS Thermal Power Output Assumed[c], MWt
CONDITION II (Cont'd)					
Loss of normal feedwater	RETRAN-02W	0	-	Upper	3,425
Loss of offsite power to the plant auxiliaries	RETRAN-02W	0	-	Upper	3,425
Excessive heat removal due to feedwater system malfunctions	RETRAN-02W	-	0.43	Lower	3,425
Excessive load increase	LOFTRAN	-	0 and 0.43	Lower and Upper	3,423
Accidental depressurization of the reactor coolant system	LOFTRAN	+7	-	Lower	3,425
Inadvertent operation of ECCS during power operation - DNBR	LOFTRAN	+5	0.43	Lower and Upper	3,423
Inadvertent operation of ECCS during power Operation – Pressurizer Overfill	RETRAN-02	-	-	-	3,425
CONDITION III					
Loss of reactor coolant from small ruptured pipes or from cracks in large pipe which actuate emergency core cooling	NOTRUMP SBLOCTA	-	-	-	3,479
Inadvertent loading of a fuel assembly into an improper position	PHOENIX-P, ANC	-	-	-	3,483
Complete loss of forced reactor coolant flow	LOFTRAN, THINC, FACTRAN	+5	-	Upper	3,423

TABLE 15.1-4

Events	Computer Codes Utilized	Assumed Reactivity Coefficients: Moderator Temp[a], pcm/°F[d]	Assumed Reactivity Coefficients: Moderator Density[a], Δk/gm/cc	Assumed Reactivity Coefficients: Doppler[b]	Initial NSSS Thermal Power Output Assumed[c], MWt
CONDITION III (Cont'd)					
Single RCCA withdrawal at full power	ANC, THINC, PHOENIX-P	-	-	-	3,425[e]
Underfrequency accident	LOFTRAN, THINC, FACTRAN	+5	-	Upper	3,423
CONDITION IV					
Major rupture of pipes containing reactor coolant up to and including double-ended rupture of the largest pipe in the reactor coolant system (loss-of-coolant accident)	WCOBRA/TRAC HOTSPOT MONTECF	Function of moderator density. See Sec. 15.4.1	0	Function of fuel temp.	3,479
Major secondary system pipe rupture up to and including double-ended rupture (rupture of a steam pipe)	RETRAN-02W, ANC,THINC	-	Function of moderator density. See Figure 15.4.2-2.	See Figure 15.4.2-1	0.0 (Subcritical)
Major rupture of a main feedwater pipe	RETRAN-02W		0.0	Lower	3,425
Rupture of a main steam line at power	RETRAN-02W, ANC, THINC-IV		0.43	Lower	3,425
Waste gas decay tank rupture	-	-	-	-	3,577
Steam generator tube rupture	RETRAN-02W	-	0.0	Lower and Upper	3,425

TABLE 15.1-4

Events	Computer Codes Utilized	Assumed Reactivity Coefficients: Moderator Temp[a], pcm/°F[d]	Assumed Reactivity Coefficients: Moderator Density[a], Δk/gm/cc	Doppler[b]	Initial NSSS Thermal Power Output Assumed[c], MWt
CONDITION IV (Cont'd)					
Single reactor coolant pump locked rotor	LOFTRAN, THINC, FACTRAN	+5		Upper	3,423
Fuel handling accident					3,577
Rupture of a control rod mechanism housing (RCCA ejection)	TWINKLE, FACTRAN PHOENIX-P	+5.2 BOL -23.EOL	-	Least negative defect. See Table 15.4-11.	0 and 3,423

(a) Only one is used in analysis, i.e., either moderator temperature or moderator density coefficient.
(b) Reference Figure 15.1-5.
(c) Two percent calorimetric error considered where applicable.
(d) Pcm means percent mille. See footnote Table 4.3-1.
(e) Analysis only models core thermal power of 3411 MWt

TABLE 15.2-1

TIME SEQUENCE OF EVENTS FOR CONDITION II EVENTS

Accident	Event	Time, sec
Uncontrolled RCCA Withdrawal from a Subcritical Condition	Initiation of uncontrolled rod withdrawal 7.5×10^{-4} Δk/sec reactivity insertion rate from 10^{-9} of nominal power	0.0
	Power range high neutron flux low setpoint reached	9.6
	Peak nuclear power occurs	9.8
	Rods begin to fall into core	10.1
	Peak heat flux occurs	11.9
	Peak hot spot average cladding temperature occurs	12.3
Uncontrolled RCCA Withdrawal at Power		
1. Case A	Initiation of uncontrolled RCCA withdrawal at reactivity insertion rate of7.5 x 10^{-4} Δk/sec	0.0
	Power range high neutron flux high trip point reached	1.6
	Rods begin to fall into core	2.1
	Minimum DNBR occurs	3.0
2. Case B	Initiation of uncontrolled RCCA withdrawal at a reactivity insertion rate of3.0 x 10^{-5} Δk/sec	0.0

Accident	Event	Time, sec
	Overtemperature ΔT reactor trip signal initiated	31.8
	Rods begin to fall into core	33.8
	Minimum DNBR occurs	34.2
Uncontrolled Boron Dilution		
1. Dilution during refueling and startup	Dilution begins	0.0
	Operator isolates source of dilution; minimum margin to criticality occurs	~1920 or more
2. Dilution during full power operation		
a. Automatic reactor control	1.6 % shutdown margin lost	~1180
b. Manual reactor control	Dilution begins	0.0
	Reactor trip setpoint reached for high neutron flux	40
	Rods begin to fall into core	40.5
	1.6 % shutdown is lost (if dilution continues after trip)	~ 900
Partial Loss of Forced Reactor Coolant Flow		
1. All loops operating, two pumps coasting down	Coastdown begins	0.0
	Low-flow reactor trip(b)	1.43
	Rods begin to drop	2.43
	Minimum DNBR occurs	3.9
Historical *Startup of an Inactive Reactor Coolant Loop*	*Initiation of pump startup*	*0.0*
	Power reaches high nuclear flux trip	*3.2*

Accident	*Event*	*Time, sec*
	Rods begin to drop	*3.7*
	Minimum DNBR occurs	*4*
Loss of External Electrical Load-DNBR		
1. With pressurizer control (BOL)	Loss of electrical load	0.0
	High pressurizer pressure reactor trip setpoint reached	11.9
	Initiation of steam release from steam generator safety valves	12.0
	Rods begin to drop	13.9
	Peak pressurizer pressure occurs	14.5
	Minimum DNBR occurs	15
2. With pressurizer control (EOL)	Loss of electrical load	0.0
	Peak pressurizer pressure occurs	9.0
	Initiation of steam release from steam generator safety valves	12.5
	Low-low steam generator water level reactor trip	57
	Rods begin to drop	59
	Minimum DNBR occurs	(a)
3. Without pressurizer control (BOL)	Loss of electrical load	0.0
	High pressurizer pressure reactor trip point reached	6.1
	Rods begin to drop	8.1
	Minimum DNBR occurs	(a)

Accident	Event	Time, sec
	Peak pressurizer pressure occurs	9.5
	Initiation of steam release from steam generator safety valves	12.0
4. Without pressurizer control (EOL)	Loss of electrical load	0.0
	High pressurizer pressure reactor trip point reached	6
	Rods begin to drop	8
	Minimum DNBR occurs	(a)
	Peak pressurizer pressure occurs	8.5
	Initiation of steam release from steam generator safety valves	12.5
Loss of External Electrical Load-Overpressure (Peak RCS Pressure)		
1. With no pressurizer control (BOL)	Reactor Trip	9.0
	PSVs Open	9.1
	Peak RCS Pressure	9.5
	MSSVs Open	9.8
	Peak Secondary Side Pressure	16.0
Overpressure (Peak Secondary Side Pressure)		
2. With pressurizer control (BOL)	PORVs Open	3.6
	MSSVs Open	9.1
	Reactor Trip	15.1
	PSVs Open	16.3

	Peak RCS Pressure	16.5	
	Peak Secondary Side pressure	20.0	
		W/Power	W/O Power
Loss of Normal Feedwater and Loss of Offsite Power to the Station Auxiliaries	Main feedwater flow stops	0.0	0.0
	Low-low steam generator water level reactor trip	52.7	54.2
	Rods begin to drop	54.7	56.2
	Reactor coolant pumps begin to coast down	-	58.2
	Four SGs begin to receive aux feed from both motor-driven AFW pumps	112.7	114.2
	Peak water level in pressurizer occurs (post-trip)	1294	2030

Accident	Event	Time, sec
Excessive Feedwater at Full Load	One main feedwater control valve fails full open	0.0
	High-high steam generator water level is reached	33.6
	Turbine trip signal (from high-high steam generator level, turbine stop valve fully closed 0.1second later	36.0
	Reactor trip occurs from turbine trip (rod motion begins)	38.1
	Minimum DNBR occurs	39.0
	Initial pressurizer PORV opens (all PORVs closed 1.3 seconds later)	39.7
	Feedwater isolation valves closed in all four loops (from high-high steam generator level)	99.6
Excessive Load Increase		
1. Manual reactor control (BOL minimum moderator feedback)	10% step load increase	0.0
	Equilibrium conditions reached (approximate times only)	240
2. Manual reactor control (EOL maximum moderator feedback)	10% step load increase	0.0
	Equilibrium conditions reached (approximate times only)	64
3. Automatic reactor control (BOL minimum moderator feedback)	10% step load increase	0.0
	Equilibrium conditions reached (approximate times only)	150

Accident	Event	Time, sec
4. Automatic reactor control (EOL maximum moderator feedback)	10% step load increase	0.0
	Equilibrium conditions reached (approximate times only)	150
Accidental Depressurization of the Reactor Coolant System	Inadvertent opening of one pressurizer safety valve	0.0
	Overtemperature ΔT reactor trip setpoint reached	27.5
	Rods begin to drop	29.5
	Minimum DNBR occurs	29.8
Inadvertent Operation of ECCS During Power Operation - DNBR	Charging pumps begin injecting borated water	0.0
	Low-pressure trip point reached	23
	Rods begin to drop	25
Inadvertent Operation of ECCS During Power Operation - Pressurizer Overfill		
Case 1	Reactor Trip/Safety injection	0
	Pressurizer fills	583
	PSV opens	624
	Last PSV relief	720
Case 2	Reactor Trip/Safety Injection	0
	Pressurizer fills	583
	PORV opens	591
	50 PORV cycles	1,560

TABLE 15.2-1

Accident	Event	Time, sec
Case 3	Reactor Trip/Safety Injection	0
	PORV opens	77
	Pressurizer fills	864
	93 PORV cycles	1,560

(a) DNBR does not decrease below its initial value.
(b) Analysis assumed low flow setpoint of 87 percent loop flow. An evaluation concludes that 85 percent loop flow is acceptable. Refer to Table 15.1-2, footnote (d).

TABLE 15.3-1

TIME SEQUENCE OF EVENTS - SMALL BREAK LOCA

Unit 1

	2-inch	3-inch	4-inch	6-inch
Transient Initiated, sec	0	0	0	0
Reactor Trip Signal, sec	43.58	18.32	10.55	5.9
Safety Injection Signal, sec	58	26.8	16.57	8.58
Safety Injection Begins(1), sec	85	53.8	43.57	35.58
Loop Seal Clearing Occurs(2), sec	1197	514	300	110
Top of Core Uncovered(3), sec	1796	941	635	N/A
Accumulator Injection Begins, sec	N/A	1984	885	385
Top of Core Recovered, sec	6500	3170	2545	N/A
RWST Low Level, sec	1709	1689	1664	1640

Unit 2

	2-inch	3-inch	4-inch	6-inch
Transient Initiated, sec	0	0	0	0
Reactor Trip Signal, sec	44.72	18.78	10.82	6.11
Safety Injection Signal, sec	59.45	27.41	16.68	9
Safety Injection Begins(1), sec	86.45	54.41	43.68	36
Loop Seal Clearing Occurs(2), sec	1360	575	290	120
Top of Core Uncovered(3), sec	3200	722	770	N/A
Accumulator Injection Begins, sec	N/A	3050	985	400
Top of Core Recovered, sec	N/A	3215	1630	N/A
RWST Low Level, sec	1708	1690	1666	1641

(1) Safety Injection begins 27.0 seconds (SI delay time) after the safety injection signal is reached.

(2) Loop seal clearing is considered to occur when the broken loop seal vapor flow rate is sustained above 1 lbm/s.

(3) Top of core uncovery time is taken as the time when the core mixture level is sustained below the top of the core elevation.

TABLE 15.3-2

FUEL CLADDING RESULTS - SMALL BREAK LOCA

Unit 1

	2-inch	3-inch	4-inch
PCT (°F)	907	1391	1241
PCT Time (s)	2173.3	1891.7	975.8
PCT Elevation (ft)	10.75	11.25	11.00
Burst Time (s) (1)	N/A	N/A	N/A
Burst Elevation (ft) (1)	N/A	N/A	N/A
Maximum Hot Rod Transient ZrO2 (%)	0.01	0.38	0.07
Maximum Hot Rod Transient ZrO2 Elev. (ft)	10.75	11.25	10.75
Hot Rod Average Transient ZrO2 (%)	0.01	0.06	0.01

Unit 2

	2-inch	3-inch	4-inch
PCT (°F)	814	1288	1004
PCT Time (s)	4838.3	1961.8	1079.2
PCT Elevation (ft)	11.00	11.25	10.75
Burst Time (s) (1)	N/A	N/A	N/A
Burst Elevation (ft) (1)	N/A	N/A	N/A
Maximum Hot Rod Transient ZrO2 (%)	0.01	0.18	0.01
Maximum Hot Rod Transient ZrO2 Elev. (ft)	11.00	11.25	10.75
Hot Rod Average Transient ZrO2 (%)	0	0.03	0.01

(1) Burst was not predicted to occur for any break size.

TABLE 15.3-3

TIME SEQUENCE OF EVENTS FOR CONDITION III EVENTS

Accident	Event	Time, sec
Complete Loss of Forced Reactor Coolant Flow		
All loops operating, all pumps coasting down	Coastdown begins	0.0
	Rod motion begins	1.5
	Minimum DNBR occurs	3.6

TABLE 15.4.1-1A

UNIT 1 BEST ESTIMATE LARGE BREAK LOCA TIME SEQUENCE OF EVENTS FOR THE REFERENCE TRANSIENT

Event	Time (sec)
Start of Transient	0.0
Safety Injection Signal	6.0
Accumulator Injection Begins	11.0
End of Blowdown	29.0
Safety Injection Begins	33.0
Bottom of Core Recovery	37.0
Accumulator Empty	50.0
PCT Occurs	39.0
Hot Rod Quench	>300.0
End of Transient	500.0

TABLE 15.4.1-1B

UNIT 2 BEST ESTIMATE LARGE BREAK SEQUENCE OF EVENTS
FOR LIMITING PCT CASE

Event	Time (sec)
Start of Transient	0.0
Safety Injection Signal	6.0
Accumulator Injection Begins	13.0
End of Blowdown	29.0
Safety Injection Begins	33.0
Bottom of Core Recovery	37.0
Accumulator Empty	48.0
PCT Occurs	110.0
Hot Rod Quench	285.0
End of Transient	500.0

TABLE 15.4.1-2A

UNIT 1 BEST ESTIMATE LARGE BREAK LOCA ANALYSIS RESULTS

Component	Blowdown Peak	First Reflood Peak	Second Reflood Peak
$PCT^{average}$	<1485°F	<1621°F	<1486°F
$PCT^{95\%}$	<1744°F	<1900°F	<1860°F
Maximum Oxidation		<11%	
Total Oxidation		<0.89%	

TABLE 15.4.1-2B

UNIT 2 BEST ESTIMATE LARGE BREAK LOCA ANALYSIS RESULTS

	Result	Criterion
95/95 PCT	1,872°F	< 2,200°F
95/95 LMO	1.64%	< 17%
95/95 CWO	0.17%	< 1%

PCT – Peak Cladding Temperature
LMO – Local Maximum Oxidation
CWO – Core Wide Oxidation

TABLE 15.4.1-3A

UNIT 1 KEY BEST ESTIMATE LARGE BREAK LOCA PARAMETERS
AND REFERENCE TRANSIENT ASSUMPTIONS

Parameter	Reference Transient	Uncertainty or Bias
1.0 Plant Physical Description		
a. Dimensions	Nominal	ΔPCT_{MOD}
b. Flow resistance	Nominal	ΔPCT_{MOD}
c. Pressurizer location	Opposite broken loop	Bounded
d. Hot assembly location	Under limiting location	Bounded
e. Hot assembly type	17x17 V5 w/ZIRLO clad	Bounded
f. SG tube plugging level	High (15%)	Bounded[(a)]
2.0 Plant Initial Operating Conditions		
2.1 Reactor Power		
a. Core average linear heat rate	Nominal - 100% of uprated power (3411 MWt)	ΔPCT_{PD}
b. Peak linear heat rate (PLHR)	Derived from desired Technical Specifications (TS) limit and maximum baseload	ΔPCT_{PD}
c. Hot rod average linear heat rate (HRFLUX)	Derived from TS $F_{\Delta H}$	ΔPCT_{PD}

TABLE 15.4.1-3A

Parameter	Reference Transient	Uncertainty or Bias
d. Hot assembly average heat rate	HRFLUX/1.04	ΔPCT_{PD}
e. Hot assembly peak heat rate	PLHR/1.04	ΔPCT_{PD}
f. Axial power distribution (PBOT, PMID)	Figure 3-2-10 of Reference 60	ΔPCT_{PD}
g. Low power region relative power (PLOW)	0.3	Bounded[a]
h. Hot assembly burnup	BOL	Bounded
i. Prior operating history	Equilibrium decay heat	Bounded
j. Moderator Temperature Coefficient (MTC)	TS Maximum (0)	Bounded
k. HFP boron	800 ppm	Generic
2.2 Fluid Conditions		
a. T_{avg}	Max. nominal T_{avg} = 577.3°F	Nominal is bounded, uncertainty is in ΔPCT_{IC}
b. Pressurizer pressure	Nominal (2250.0 psia)	ΔPCT_{IC}
c. Loop flow	85000 gpm	ΔPCT_{MOD}[b]
d. T_{UH}	Best Estimate	0
e. Pressurizer level	Nominal (1080 ft^3)	0
f. Accumulator temperature	Nominal (102.5°F)	ΔPCT_{IC}
g. Accumulator pressure	Nominal (636.2 psia)	ΔPCT_{IC}

TABLE 15.4.1-3A

Parameter	Reference Transient	Uncertainty or Bias
h. Accumulator liquid volume	Nominal (850 ft^3)	ΔPCT_{IC}
i. Accumulator line resistance	Nominal	ΔPCT_{IC}
j. Accumulator boron	Minimum	Bounded
3.0 Accident Boundary Conditions		
a. Break location	Cold leg	Bounded
b. Break type	Guillotine	ΔPCT_{MOD}
c. Break size	Nominal (cold leg area)	ΔPCT_{MOD}
d. Offsite power	Off (RCS pumps tripped)	Bounded[(a)]
e. Safety injection flow	Minimum	Bounded
f. Safety injection temperature	Nominal (68°F)	ΔPCT_{IC}
g. Safety injection delay	Max delay (27.0 sec, with loss of offsite power)	Bounded
h. Containment pressure	Minimum based on WC/T M&E	Bounded
i. Single failure	ECCS: Loss of 1 SI train	Bounded
j. Control rod drop time	No control rods	Bounded
4.0 Model Parameters		
a. Critical Flow	Nominal (as coded)	ΔPCT_{MOD}

TABLE 15.4.1-3A

Parameter	Reference Transient	Uncertainty or Bias
b. Resistance uncertainties in broken loop	Nominal (as coded)	ΔPCT_{MOD}
c. Initial stored energy/fuel rod behavior	Nominal (as coded)	ΔPCT_{MOD}
d. Core heat transfer	Nominal (as coded)	ΔPCT_{MOD}
e. Delivery and bypassing of ECC	Nominal (as coded)	Conservative
f. Steam binding/entrainment	Nominal (as coded)	Conservative
g. Noncondensable gases/accumulator nitrogen	Nominal (as coded)	Conservative
h. Condensation	Nominal (as coded)	ΔPCT_{MOD}

(a) Confirmed by plant-specific analysis.
(b) Assumed to be result of loop resistance uncertainity.

Notes:

1. ΔPCT_{MOD} indicates this uncertainty is part of code and global model uncertainty.
2. ΔPCTPD indicates this uncertainty is part of power distribution uncertainty.
3. ΔPCTIC indicates this uncertainty is part of initial condition uncertainty.

TABLE 15.4.1-3B

UNIT 2 KEY BEST ESTIMATE LARGE BREAK LOCA PARAMETERS AND INITIAL TRANSIENT ASSUMPTIONS

Parameter	Initial Transient	Range/Uncertainty
1.0 Plant Physical Description		
a. Dimensions	Nominal	Sampled
b. Flow resistance	Nominal	Sampled
c. Pressurizer location	Opposite broken loop	Bounded
d. Hot assembly location	Under limiting location	Bounded
e. Hot assembly type	17x17 V5 + with ZIRLO™ cladding, Non-IFBA	Bounded
f. Steam generator tube plugging level	High (15%)	Bounded[(a)]
2.0 Plant Initial Operating Conditions		
2.1 Reactor Power		
a. Core average linear heat rate (AFLUX)	Nominal – Based on 100% thermal power (3468 MWt)	Sampled
b. Hot rod peak linear heat rate (PLHR)	Derived from desired Technical Specification limit F_Q = 2.7 and maximum baseload F_Q = 2.1	Sampled
c. Hot rod average linear heat rate (HRFLUX)	Derived from Technical Specification $F_{\Delta H}$ = 1.7	Sampled
d. Hot assembly average heat rate (HAFLUX)	HRFLUX/1.04	Sampled
e. Hot assembly peak heat rate (HAPHR)	PLHR/1.04	Sampled
f. Axial power distribution (PBOT, PMID)	Figure 15.4.1-15B	Sampled
g. Low power region relative power (PLOW)	0.3	Bounded[(a)]
h. Cycle burnup	~2000 MWD/MTU	Sampled
i. Prior operating history	Equilibrium decay heat	Bounded

TABLE 15.4.1-3B

Parameter	Initial Transient	Range/Uncertainty
2.0 Plant Initial Operating Conditions (continued)		
j. Moderator temperature coefficient	Technical Specification Maximum (0)	Bounded
k. HFP boron	800 ppm	Generic
2.2 Fluid Conditions		
a. T_{avg}	High Nominal T_{avg} = 577.6°F	Bounded[a], Sampled
b. Pressurizer pressure	Nominal (2250.0 psia)	Sampled
c. Loop flow	85,000 gpm	Bounded
d. Upper head fluid temperature	T_{cold}	0
e. Pressurizer level	Nominal	0
f. Accumulator temperature	Nominal (102.5°F)	Sampled
g. Accumulator pressure	Nominal (636.2 psia)	Sampled
h. Accumulator liquid volume	Nominal (850 ft^3)	Sampled
i. Accumulator line resistance	Nominal	Sampled
j. Accumulator boron	Minimum (2200 ppm)	Bounded
3.0 Accident Boundary Conditions		
a. Break location	Cold leg	Bounded
b. Break type	Guillotine (DECLG)	Sampled
c. Break size	Nominal (cold leg area)	Sampled
d. Offsite power	Loss of offsite power	Bounded[a]
e. Safety injection flow	Minimum	Bounded
f. Safety injection temperature	Nominal (68°F)	Sampled
g. Safety injection delay	Maximum delay (27.0 sec, with loss of offsite power)	Bounded

TABLE 15.4.1-3B

Parameter	Initial Transient	Range/Uncertainty
3.0 Accident Boundary Conditions (continued)		
h. Containment pressure	Bounded – Lower (conservative) than pressure curve shown in Figure 15.4.1-14B.	Bounded
i. Single failure	ECCS: Loss of one safety injection train; Containment pressure: all trains operational	Bounded
j. Control rod drop time	No control rods	Bounded
4.0 Model Parameters		
a. Critical flow	Nominal (CD = 1.0)	Sampled
b. Resistance uncertainties in broken loop	Nominal (as coded)	Sampled
c. Initial stored energy/fuel rod behavior	Nominal (as coded)	Sampled
d. Core heat transfer	Nominal (as coded)	Sampled
e. Delivery and bypassing of emergency core coolant	Nominal (as coded)	Conservative
f. Steam binding/entrainment	Nominal (as coded)	Conservative
g. Noncondensable gases/accumulator nitrogen	Nominal (as coded)	Conservative
h. Condensation	Nominal (as coded)	Sampled

[a] Per Confirmatory Study results (Section 15.4.1.1.2.5)

TABLE 15.4.1-4A

UNIT 1 SAMPLE OF BEST ESTIMATE SENSITIVITY ANALYSIS RESULTS
FOR ORIGINAL ANALYSIS (Reference 60)

Type of Study	Parameter Varied	Value	PCT Results (°F)		
			Blowdown	Reflood 1	Reflood 2
Reference Transient		See Table 15.4-3	1600	1852	1984
Confirmatory Cases	Steam Generator Tube Plugging	0%	1569	1798	1878
	Offsite Power Assumption	Available	1500	1685	1781
	Normalized Power in Outer Assemblies	0.8	1611	1805	1939
	Vessel Average Temperature	565°F	1573	1843	1871
Initial Condition	Accumulator Volume	+50 ft^3	1601	1856	1823
		–50 ft^3	1599	1863	2182
Global Models	DECLG, CD	1.0	1600	1852	1984
	SPLIT, CD	1.4	-	1596	1637
		1.6	-	1784	1799
		1.8	-	1790	1738
		2.0	-	1765	1804

TABLE 15.4.1-4B

UNIT 2 RESULTS FROM CONFIRMATORY STUDIES

Transient Description	PCT (°F) Reflood
Initial Transient (High T_{avg}, High SGTP, Low PLOW, LOOP)	1595
SGTP Confirmatory Transient (High T_{avg}, Low SGTP, Low PLOW, LOOP)	1576
T_{avg}, Confirmatory Transient (Low T_{avg}, High SGTP, Low PLOW, LOOP)	1536
PLOW Confirmatory Transient (High T_{avg}, High SGTP, High PLOW, LOOP)	1657
LOOP Confirmatory Transient (High T_{avg}, High SGTP, Low PLOW, no-LOOP)	1425
Reference Transient (High T_{avg}, High SGTP, High PLOW, LOOP)	1657

TABLE 15.4.1-5A

UNIT 1 CONTAINMENT BACK PRESSURE ANALYSIS INPUT PARAMETERS USED FOR BEST ESTIMATE LOCA ANALYSIS

Net Free Volume, cu ft	2,630,000
Initial Conditions	
Pressure, psia	14.7
Temperature, °F	85
RWST temperature, °F	35
Service water temperature, °F	45
Outside temperature, °F	33
Spray System	
Number of pumps operating	2
Runout flowrate per pump, gpm	3400
Actuation time, sec	40.8
Safeguards Fan Coolers	
Number of fan coolers operating	5
Fastest post-accident initiation of fan coolers, sec	0
Structural Heat Sinks	
Thickness, in.	Area, ft^2
42.0 concrete	65,749
12.0 concrete	24,054
24.0 concrete	14,313
12.0 concrete	48,183
12.0 concrete	15,725
108.0 concrete	20,493
30.0 concrete	33,867
1.68 steel	8,525
1.92 steel	4,015

TABLE 15.4.1-5A

Structural Heat Sinks (continued)

Thickness, in.	Area, ft^2
6.99 steel	1,771
0.5656 steel	43,396
0.088 steel	24,090
0.22 steel	10,597
0.088 steel	8,470
0.102 steel	23,438
0.071 steel	20,266
0.708 steel	26,050
0.127 steel	33,000
0.773 steel	11,004
0.375 steel	99,616
1.596 steel	1,530
1.098 steel	21,022
0.745 steel	6,755
0.96 steel	792
0.144 stainless steel	9,737
0.654 stainless steel	943
0.642 steel	1,373
3.0 steel	575
0.75 steel	17,542

TABLE 15.4.1-5B

UNIT 2 CONTAINMENT BACK PRESSURE ANALYSIS INPUT PARAMETERS USED FOR BEST ESTIMATE LBLOCA ANALYSIS

Net Free Volume	2,630,000 ft^3
Initial Conditions	
Pressure	14.7 psia
Temperature	85.0°F
RWST temperature	35.0°F
Service water temperature	48.0°F
Temperature outside containment	33.0°F
Initial spray temperature	35.0°F
Spray System	
Number of spray pumps operating	2
Post-accident spray system initiation delay	40.8 sec
Maximum spray system flow from all pumps	6,800 gal/min.
Containment Fan Coolers	
Post-accident initiation fan coolers	0.0 sec[(a)]
Number of fan coolers operating	5

(a) Bounds delay with and without LOOP

TABLE 15.4.1-7A

UNIT 1 PLANT OPERATING RANGE ALLOWED BY THE BEST-ESTIMATE LARGE BREAK LOCA ANALYSIS

Parameter		Operating Range
1.0	Plant Physical Description	
	a. Dimensions	No in-board assembly grid deformation assumed due to LOCA+DDE or LOCA + Hosgri
	b. Flow resistance	N/A
	c. Pressurizer location	N/A
	d. Hot assembly location	Anywhere in core
	e. Hot assembly type	Fresh 17X17 V5, ZIRLO, or Zircaloy cladding, 1.5X IFBA or non-IFBA
	f. SG tube plugging level	≤15%
	g. Fuel assembly type	Vantage 5, ZIRLO, or Zircaloy cladding, 1.5X IFBA or non-IFBA
2.0	Plant Initial Operating Conditions	
	2.1 Reactor Power	
	a. Core average linear heat rate	Core power ≤ 102% of 3411 MWt
	b. Peak linear heat rate	$F_Q \leq 2.7$
	c. Hot rod average linear heat rate	$F_{\Delta H} \leq 1.7$
	d. Hot assembly average linear heat rate	$\overline{P}_{HA} \leq 1.57$

TABLE 15.4.1-7A

Parameter		Operating Range
	e. Hot assembly peak linear heat rate	$F_{QHA} \leq 2.7/1.04$
	f. Axial power distribution (PBOT, PMID)	Figure 15.4.1-15A
	g. Low power region relative power (PLOW)	$0.3 \leq PLOW \leq 0.8$
	h. Hot assembly burnup	≤ 75,000 MWD/MTU, lead rod
	i. Prior operating history	All normal operating histories
	j. MTC	≤ 0 at HFP
	k. HFP boron	Normal letdown
	2.2 Fluid Conditions	
	a. Tavg	$560.0 \leq T_{ave} \leq 582.3$°F
	b. Pressurizer pressure	$2190 \leq P_{RCS} \leq 2310$ psia
	c. Loop flow	≥ 85,000 gpm/loop
	d. T_{UH}	Current upper internals
	e. Pressurizer level	Normal level, automatic control
	f. Accumulator temperature	85 ≤ accumulator temperature ≤ 120°F
	g. Accumulator pressure	$579 \leq P_{ACC} \leq 664$ psig
	h. Accumulator volume	$814 \leq V_{acc} \leq 886$ ft^3

TABLE 15.4.1-7A

Parameter		Operating Range
	i. Accumulator fL/D	Current line configuration
	j. Minimum accumulator boron	≥ 2200 ppm
3.0	Accident Boundary Conditions	
	a. Break location	N/A
	b. Break type	N/A
	c. Break size	N/A
	d. Offsite power	Available or LOOP
	e. Safety injection flow	Figure 15.4.1-13A
	f. Safety injection temperature	46 ≤ SI Temperature ≤ 90°F
	g. Safety injection delay	≤17 seconds (with offsite power) ≤ 27 seconds (with LOOP)
	h. Containment pressure	Bounded - see Figure 15.4.1-14A
	i. Single failure	Loss of one train
	j. Control rod drop time	N/A

TABLE 15.4.1-7B

UNIT 2 PLANT OPERATING RANGE ALLOWED BY THE BEST-ESTIMATE LARGE BREAK LOCA ANALYSIS

	Parameter	Operating Range
1.0	**Plant Physical Description**	
	a) Dimensions	No in-board assembly grid deformation during LOCA+DDE or LOCA + Hosgri
	b) Flow resistance	N/A
	c) Pressurizer location	N/A
	d) Hot assembly location	Anywhere in core interior (149 locations)[a]
	e) Hot assembly type	Fresh 17x17 V5+ fuel with ZIRLO™ cladding
	f) Steam generator tube plugging level	≤ 15%
	g) Fuel assembly type	17x17 V5+ fuel with ZIRLO™ cladding, non-IFBA or IFBA
2.0	**Plant Initial Operating Conditions**	
	2.1 Reactor Power	
	a) Core average linear heat rate	Core power ≤ 100.3% of 3,468 MWt
	b) Peak linear heat rate	$F_Q \leq 2.7$
	c) Hot rod average linear heat rate	$F_{\Delta H} \leq 1.7$
	d) Hot assembly average linear heat rate	$\overline{P}_{HA} \leq 1.7/1.04$
	e) Hot assembly peak linear heat rate	$F_{QHA} \leq 2.7/1.04$
	f) Axial power distribution (PBOT, PMID)	See Figure 15.4.1-15B.
	g) Low power region relative power (PLOW)	$0.3 \leq PLOW \leq 0.8$
	h) Hot assembly burnup	≤ 75,000 MWD/MTU, lead rod[a]
	i) Prior operating history	All normal operating histories
	j) Moderator temperature coefficient	≤ 0 at HFP
	k) HFP boron (minimum)	800 ppm (at BOL)
	2.2 Fluid Conditions	
	a) T_{avg}	$565 - 5°F \leq T_{avg} \leq 577.6 + 5°F$

TABLE 15.4.1-7B

	Parameter	Operating Range
	b) Pressurizer pressure	2250 - 60 psia ≤ P_{RCS} ≤ 2250 + 60 psia
	c) Loop flow	≥ 85,000 gpm/loop
	d) T_{UH}	Converted upper internals, T_{COLD} UH
	e) Pressurizer level	Nominal level, automatic control
	f) Accumulator temperature	85°F ≤ T_{ACC} ≤ 120°F
	g) Accumulator pressure	579 psia ≤ P_{ACC} ≤ 664 psia
	h) Accumulator liquid volume	814 ft^3 ≤ V_{ACC} ≤ 886 ft^3
	i) Accumulator fL/D	Current line configuration
	j) Minimum accumulator boron	≥ 2200 ppm
3.0	**Accident Boundary Conditions**	
	a) Break location	N/A
	b) Break type	N/A
	c) Break size	N/A
	d) Offsite power	Available or LOOP
	e) Safety injection flow	See Figure 15.4.1-13B.
	f) Safety injection temperature	46°F ≤ SI Temp ≤ 90°F
	g) Safety injection delay	≤ 17 seconds (with offsite power) ≤ 27 seconds (with LOOP)
	h) Containment pressure	See Figure 15.4.1-14B and raw data in Table 15.4.1-5B.
	i) Single failure	All trains operable[b]
	j) Control rod drop time	N/A

[a] 44 peripheral locations will not physically be lead power assembly.
[b] Analysis considers loss of one train of pumped ECCS.

TABLE 15.4-8

TIME SEQUENCE OF EVENTS FOR
MAJOR SECONDARY SYSTEM PIPE RUPTURES

Accident	Event	Time, sec
Steam Line Rupture @ HZP		
1. With Offsite Power Available	Main steam line ruptures	0.0
	Low steam line pressure setpoint reached	0.6
	SIS flow begins(maximum flow assumed)	2.6
	Steam line isolation occurs	8.6
	Criticality attained	36.5
	Borated water from the RWST reaches the core	~40
	Main feedwater isolation occurs	64.6
	Accumulators inject	79.0
	Peak core heat flux, minimum DNBR occurs	90.5
2. Without Offsite Power Available	Main steam line ruptures	0.0
	Low steam line pressure setpoint reached	0.6
	SIS flow begins (maximum flow assumed)	2.6
	RCPs begin to coast down	3.0
	Steam line isolation occurs	8.6
	Criticality attained	44.4
	Borated water from the RWST reaches the core	~50

TABLE 15.4-8

Accident	Event	Time, sec
	Main feedwater isolation occurs	64.6
	Peak core heat flux, minimum DNBR occurs	123.4
	Accumulators inject	129.7
Rupture of Main Feedwater Pipe (Offsite Power Available)	Feedline rupture occurs	20
	Low-low steam generator level reactor trip setpoint reached in affected steam generator	32
	Rods begin to drop	34
	Auxiliary feedwater is started	623
	Pressurizer liquid water relief begins if operator action is not assumed	2053
	Total RCS heat generation (decay heat + pump heat) decreases to auxiliary feedwater heat removal capability	5900
Rupture of Main Feedwater Pipe (Offsite Power Unavailable)	Feedline rupture occurs	20
	Low-low steam generator level reactor trip setpoint reached in affected steam generator	32
	Rods begin to drop	34
	Reactor coolant pump coastdown	36
	Auxiliary feedwater is started	632
	Peak pressurizer level after initial outsurge reached	2091

TABLE 15.4-8

Accident	Event	Time, sec
	Total RCS heat generation decreases to auxiliary feedwater heat removal capability	2200
Steam Line Rupture at Power (0.49 ft2)	Steam line ruptures	0.0
	Peak core heat flux occurs	53.1

TABLE 15.4-10

SUMMARY OF RESULTS FOR LOCKED ROTOR TRANSIENT

	4 Loops Operating Initially 1 Locked Rotor
Maximum RCS pressure, psia	2672
Maximum clad temperature, °F core hot spot	2040
Amount of Zr - H_2O at core hot spot, % by weight	0.7%

TABLE 15.4-11

TYPICAL PARAMETERS USED IN THE VANTAGE 5 RELOAD ANALYSIS OF THE ROD CLUSTER CONTROL ASSEMBLY EJECTION ACCIDENT

Time in Life	Beginning	Beginning	End	End
Generic Vantage 5 Reload Analysis Values				
Power level, %	102	0.0	102	0.0
Ejected rod worth, % Δk	0.20	0.785	0.21	0.85
Delayed neutron fraction, %	0.55	0.55	0.44	0.44
Feedback reactivity weighting	1.30	2.071	1.30	3.55
Doppler - only power defect, pcm	-955	-954	-829	-788
Trip reactivity, % Δk	4	2	4	2
F_q before rod ejection	2.60	-	2.60	-
F_q after rod ejection	6.70	13	6.50	21.50
Number of operating pumps	4	2	4	2
Generic Vantage 5 Reload Analysis Results				
Maximum fuel pellet average temperature, °F	4154	3509	3812	3408
Maximum fuel center temperature, °F	>4900 [(a)]	4025	>4800 [(a)]	3849
Maximum cladding average temperature, °F	2434	2660	2218	2632
Maximum fuel stored energy, cal/gm	183	149	165	144
Reload Analysis Evaluation Values				
Power level, %	102	0.0	102	0.0
Ejected rod worth, % Δk	0.20	0.785	0.21	0.83
Delayed neutron fraction, %	0.55	0.55	0.44	0.44
Feedback reactivity weighting	1.30	2.071	1.30	3.55
Doppler – only power defect, pcm	-995	-954	-829	-788
Trip reactivity, % Δk	4	2	4	2
F_q before rod ejection	2.60	-	2.60	-
F_q after rod ejection	6.70	13	6.50	22.50
Number of operating pumps	4	2	4	2

(a) Less than 10% fuel pellet melt (at hot spot)

TABLE 15.4-12

OPERATOR ACTION TIMES FOR DESIGN BASIS SGTR ANALYSIS

Action	Time (min)
Identify and isolate ruptured SG	10 min or RETRAN-02W calculated time to reach 38% narrow range level in the ruptured SG, whichever is longer
Operator action time to initiate cooldown	5
Cooldown	Calculated by RETRAN-02W
Operator action time to initiate depressurization	4
Depressurization	Calculated by RETRAN-02W
Operator action time to initiate SI termination	2
SI termination and pressure equalization	Calculated time for SI termination and equalization of RCS and ruptured SG pressures

TABLE 15.4-13A

TIMED SEQUENCE OF EVENTS - SGTR MTO ANALYSIS

Event	Time (sec)
SG Tube Rupture	100
Reactor Trip	274
SI Actuated	380
Turbine Driven AFW Pump Flow Isolated	700
Ruptured SG Steamline Isolation	700
Ruptured SG MDAFW Pump Flow Isolated	820
RCS Cooldown Initiated	1120
RCS Cooldown Terminated	1706
RCS Depressurization Initiated	1946
RCS Depressurization Terminated	2072
SI Terminated	2192
Break Flow Terminated	3475

TABLE 15.4-13B

TIMED SEQUENCE OF EVENTS - SGTR DOSE ANALYSIS

Event	Time (sec)
SG Tube Rupture	100
Reactor Trip	279
SI Actuated	315
Ruptured SG Isolated	953
Ruptured SG PORV Fails Open	953
Ruptured SG PORV Block Valve Closed	2753
RCS Cooldown Initiated	3053
RCS Cooldown Terminated	4424
RCS Depressurization Initiated	4664
RCS Depressurization Terminated	4839
SI Terminated	4959
Break Flow Terminated	5972

TABLE 15.4-14

MASS RELEASE RESULTS - SGTR DOSE INPUT ANALYSIS

	0 - 2 Hrs, lbm	2 - 8 Hrs, lbm
Ruptured SG		
- Condenser	294,500	0
- Atmosphere	140,200	27,000
- Feedwater	288,700	0
Intact SGs		
- Condenser	878,100	0
- Atmosphere	367,100	922,600
- Feedwater	1,476,800	961,700
Break Flow	262,200	0
Flashed Break Flow	18,150	0

Note: The 0-2 hour releases to the condenser and feedwater flows include 100 seconds of steady state operation.

TABLE 15.5-1

REACTOR COOLANT FISSION AND CORROSION PRODUCT ACTIVITIES
DURING STEADY STATE OPERATION AND PLANT SHUTDOWN OPERATION

	Operating PWR Plant (HISTORICAL)		Diablo Canyon - Design Basis Case	
Isotope	*Measured Activity Before Shutdown, mCi/gm*	*Measured Peak Shutdown Activity, mCi/gm*	Calculated Activity Before Shutdown, mCi/gm	Expected Peak Shutdown Activity, mCi/gm
I -131	*0.83*	*14.9*	2.45	43.9
Xe-133	*127.00*	*65.0*[a]	255.8	130.9[a]
Cs-134	*1.29*	*1.7*	0.198	0.26
Cs-137	*1.67*	*2.14*	0.31	0.39
Ce-144	*0.00068*	*0.0058*	0.00034	0.0029
Sr-89	*0.0033*	*0.40*	0.0026	0.32
Sr-90	*0.00057*	*0.013*	0.00013	0.003
Co-58	---	*0.95*	0.026	1.04

(a) Activity reduced from steady state level by approximately 1 day of system degasification prior to plant shutdown.

TABLE 15.5-2 (HISTORICAL)

RESULTS OF STUDY OF EFFECTS OF PLUTONIUM ON ACCIDENT DOSES

Type of Accident	*Change in 30-day Thyroid Dose, %*	*Change in 30-day Whole Body Dose, %*	*Change in 2-hour Thyroid Dose, %*	*Change in 2-hour Whole Body Dose, %*
Release from gas decay tank	*0*	*-4*	*0*	*-4*
Fuel handling accident	*+6*	*-3*	*0*	*0*
Loss of reactor primary coolant - large break	*+6*	*-3*	*+5*	*-7*
Steam generator tube rupture accident	*+6*	*-2*	*+4*	*-2*
Steam line rupture accident	*+5*	*-2*	*+5*	*-2*

TABLE 15.5-3

DESIGN BASIS POST-ACCIDENT ATMOSPHERIC DILUTION FACTORS (SEC/M^3)

	Distance from Release Point, meters[a]						
Period, hrs	800	1200	2000	4000	7000	10,000	20,000
0-8	5.29×10^{-4}	3.40×10^{-4}	1.87×10^{-5}	7.78×10^{-5}	3.59×10^{-5}	2.20×10^{-5}	8.85×10^{-6}
8-24	2.15×10^{-4}	1.10×10^{-4}	5.00×10^{-5}	1.75×10^{-5}	7.50×10^{-6}	4.75×10^{-6}	1.75×10^{-6}
24-96	7.70×10^{-5}	3.90×10^{-5}	1.75×10^{-5}	5.70×10^{-6}	2.50×10^{-6}	1.54×10^{-6}	5.50×10^{-7}
96-720	1.75×10^{-5}	8.20×10^{-6}	3.70×10^{-6}	1.35×10^{-6}	5.20×10^{-7}	3.40×10^{-7}	1.20×10^{-7}

(a) Minimum exclusion area boundary radius is 0.5 miles (approximately 800 m). Radius of low population zone is 6.2 miles (approximately 10,000 m).

TABLE 15.5-4

EXPECTED POST-ACCIDENT ATMOSPHERIC DILUTION FACTORS (SEC/M^3)

	Distance from Release Point, meters[a]						
Period, hrs	800	1200	2000	4000	7000	10,000	20,000
0-8	$5.29x10^{-5}$	$3.40x10^{-5}$	$1.87x10^{-5}$	$7.78x10^{-5}$	$3.59x10^{-6}$	$2.20x10^{-6}$	$8.85x10^{-7}$
8-24	$2.15x10^{-5}$	$1.40x10^{-5}$	$5.00x10^{-6}$	$1.75x10^{-6}$	$7.50x10^{-7}$	$4.75x10^{-7}$	$1.75x10^{-7}$
24-96	$7.70x10^{-6}$	$3.90x10^{-6}$	$1.75x10^{-6}$	$5.70x10^{-7}$	$2.50x10^{-7}$	$1.54x10^{-7}$	$5.50x10^{-8}$
96-720	$1.75x10^{-6}$	$8.20x10^{-7}$	$3.70x10^{-7}$	$1.35x10^{-7}$	$5.20x10^{-8}$	$3.40x10^{-8}$	$1.20x10^{-8}$

(a) Minimum exclusion area boundary radius is 0.5 miles (approximately 800 m). Radius of low population zone is 6.2 miles (approximately 10,000 m).

TABLE 15.5-5

ATMOSPHERIC DILUTION FACTORS
$\chi/Q \times 10^8$ sec-m^{-3}

Onshore Sector Midpoint Directions	Sector Midpoint Downwind Distance, miles					
	5	15	25	35	45	55
SSE	1.61	0.54	0.32	0.23	0.18	0.15
S	1.44	0.48	0.29	0.21	0.16	0.13
SSW	0.79	0.26	0.16	0.11	0.09	0.07
SW	0.54	0.18	0.11	0.08	0.06	0.05
WSW	0.65	0.22	0.13	0.09	0.07	0.06
W	1.08	0.36	0.22	0.15	0.12	0.10
WNW	1.19	0.40	0.24	0.17	0.13	0.11
NW	5.39	1.80	1.08	0.77	0.60	0.49
NNW	1.94	0.65	0.39	0.28	0.22	0.18

Atmospheric Dilution Factors
$\chi/Q \times 10^6$ sec-m^{-3}

	Downwind Distance, meters						
Direction	800	1200	2000	4000	7000	10,000	20,000
SE	0.75	0.47	0.19	0.087	0.050	0.035	0.018

TABLE 15.5-6

ASSUMED ONSITE ATMOSPHERIC DILUTION FACTORS (SEC/M^3)
FOR THE CONTROL ROOM

Period, hrs.	Base χ/Q[(a)] Sec/m^3	Modifying Factors f_1	f_2	f_3	f_4	f_5	f_6	Final χ/Q[(a)]
A. For The Pressurization Case								
0-8	1.084x10^{-3}	1	1	.2	1	.5	.65	7.05x10^{-5}
8-24	1.084x10^{-3}	.83	.92	.2	1	.5	.65	5.38x10^{-5}
24-96	1.084x10^{-3}	.66	.84	.2	1	.5	.65	3.91x10^{-5}
96-720	1.084x10^{-3}	.48	.67	.2	1	.5	.65	2.27x10^{-5}
B. For The Infiltration Case								
0-8	3.01x10^{-3}	1	1	.2	1	.5	.65	1.96x10^{-4}
8-24	3.01x10^{-3}	.83	.92	.2	1	.5	.65	1.49x10^{-4}
24-95	3.01x10^{-3}	.66	.84	.2	1	.5	.65	1.08x10^{-4}
96-720	3.01x10^{-3}	.48	.67	.2	1	.5	.65	6.29x10^{-5}

(a) The χ/Q calculated above do not account for credit for dual pressurization inlet and occupancy factors.

TABLE 15.5-7

BREATHING RATES[a] ASSUMED IN ANALYSIS

	Design Basis Case		Expected Case	
Period	Offsite	Onsite	Offsite	Onsite
0-8 hrs	3.47×10^{-4}	3.47×10^{-4}	2.32×10^{-4}	3.47×10^{-4}
8-24 hrs	1.75×10^{-4}	3.47×10^{-4}	2.32×10^{-4}	3.47×10^{-4}
1-30 days	2.32×10^{-4}	3.47×10^{-4}	2.32×10^{-4}	3.47×10^{-4}

(a) All breathing rates are expressed in m^3/sec. Values taken from Reference 8.

TABLE 15.5-8

POPULATION DISTRIBUTION

Onshore Sector Midpoint Directions	Sector Midpoint Downwind Distance, miles						Total Sector Population
	5	15	25	35	45	55	
SSE	1,014	4,727	2,700	5,433	1,567	697	16,138
S	1,000	4,666	2,000	4,234	466	466	12,832
SSW	1,367	20,334	7,000	4,933	1,167	1,100	35,901
SW	366	15,666	5,000	700	700	634	23,066
WSW	840	26,000	6,600	1,767	1,433	1,533	38,173
W	474	10,334	1,600	1,066	734	900	15,108
WNW	1,843	20,033	22,933	19,734	16,066	6,900	87,509
NW	0	9,700	21,334	18,666	15,334	6,000	71,034
NNW	0	0	21,333	22,267	19,133	6,500	69,233
Total Radial Population	6,904	111,460	90,500	78,800	56,600	24,730	368,944

TABLE 15.5-9

SUMMARY OF OFFSITE DOSES FROM
LOSS OF ELECTRICAL LOAD

Thyroid Doses, rem

	Site Boundary - 2 Hours	LPZ - 30 Days
10 CFR Part 100	300	300
Design basis case	0.028	0.0065
Expected case	5.2×10^{-6}	8.7×10^{-7}

Whole Body Doses, rem

	Site Boundary - 2 Hours	LPZ - 30 Days
10 CFR Part 100	25	25
Design basis case	2.3×10^{-3}	2.3×10^{-4}
Expected case	7.2×10^{-7}	6.9×10^{-8}

Population Doses, man-rem

Design basis case	0.15
Expected case	3.8×10^{-5}

TABLE 15.5-10

SUMMARY OF OFFSITE DOSES FROM
A SMALL LOSS-OF-COOLANT ACCIDENT

NO FUEL DAMAGE

Thyroid Doses, rem

	Site Boundary - 2 Hours	LPZ - 30 Days
10 CFR Part 100	300	300
Design basis case	2.0×10^{-4}	2.7×10^{-5}
Expected case	9.0×10^{-7}	1.2×10^{-7}

Whole Body Doses, rem

	Site Boundary - 2 Hours	LPZ - 30 Days
10 CFR Part 100	25	25
Design basis case	1.8×10^{-4}	5.4×10^{-5}
Expected case	4.4×10^{-6}	1.4×10^{-6}

Population Doses, man-rem

Design basis case	0.36
Expected case	0.013

TABLE 15.5-11

SUMMARY OF OFFSITE DOSES FROM
AN UNDERFREQUENCY ACCIDENT

Thyroid Doses, rem

	Site Boundary - 2 Hours	LPZ - 30 Days
10 CFR Part 100	300	300
Design basis case	0.021	0.0066
Expected case	4.0×10^{-6}	1.2×10^{-6}

Whole Body Doses, rem

	Site Boundary - 2 Hours	LPZ - 30 Days
10 CFR Part 100	25	25
Design basis case	0.0018	2.2×10^{-4}
Expected case	5.3×10^{-7}	6.6×10^{-8}

Population Doses, man-rem

Design basis case	0.15
Expected case	4.3×10^{-5}

TABLE 15.5-12

SUMMARY OF OFFSITE DOSES FROM A SINGLE ROD CLUSTER CONTROL ASSEMBLY WITHDRAWAL

Thyroid Doses, rem

	Site Boundary - 2 Hours	LPZ - 30 Days
10 CFR Part 100	300	300
Design basis case	0.12	0.043
Expected case	9.5×10^{-5}	3.4×10^{-5}

Whole Body Doses, rem

	Site Boundary - 2 Hours	LPZ - 30 Days
10 CFR Part 100	25	25
Design basis case	6.1×10^{-3}	6.7×10^{-4}
Expected case	6.5×10^{-6}	6.9×10^{-7}

Population Doses, man-rem

Design basis case	0.42
Expected case	4.3×10^{-4}

TABLE 15.5-13

CALCULATED ACTIVITY RELEASES FROM LOCA - EXPECTED CASE (CURIES)

Nuclide	0-2 hr	2-8 hr	8-24 hr	24-96 hr	4-30 Days
I-131	0.4105E-01	0.0	0.0	0.0	0.0
I-132	0.6675E-02	0.0	0.0	0.0	0.0
I-133	0.3110E-01	0.0	0.0	0.0	0.0
I-134	0.7392E-02	0.0	0.0	0.0	0.0
I-135	0.1629E-01	0.0	0.0	0.0	0.0
I-131ORG	0.1424E-01	0.3356E-01	0.4704E-01	0.1384E-01	0.1660E-03
I-132ORG	0.1780E-02	0.1556E-02	0.2210E-03	0.4311E-06	0.6136E-17
I-133ORG	0.1049E-01	0.2211E-01	0.2334E-01	0.3542E-02	0.5058E-05
I-134ORG	0.1314E-02	0.2862E-03	0.1670E-05	0.9077E-12	0.0
I-135ORG	0.5139E-02	0.8365E-02	0.4731E-02	0.1933E-03	0.1730E-08
I-131PAR	0.0	0.0	0.0	0.0	0.0
I-132PAR	0.0	0.0	0.0	0.0	0.0
I-133PAR	0.0	0.0	0.0	0.0	0.0
I-134PAR	0.0	0.0	0.0	0.0	0.0
I-135PAR	0.0	0.0	0.0	0.0	0.0
Kr-83M	0.3823E 00	0.3085E 00	0.3684E-01	0.4757E-04	0.1063E-15
Kr-65	0.5356E 01	0.1598E 02	0.4257E 02	0.9571E 02	0.8243E 03
Kr-85M	0.1750E 01	0.2889E 01	0.1689E 01	0.7387E-01	0.8775E-06
Kr-87	0.1285E 01	0.6227E 00	0.2430E-01	0.1922E-05	0.1515E-22
Kr-88	0.3503E 01	0.4192E 01	0.1180E 01	0.1097E-01	0.1648E-09
Xe-133	0.5617E 02	0.1648E 03	0.4139E 03	0.7359E 03	0.1469E 04
Xe-133M	0.9285E 00	0.2650E 01	0.6162E 01	0.8236E 01	0.5596E 01
Xe-135	0.6662E 01	0.1490E 02	0.1826E 02	0.3887E 01	0.1721E-01
Xe-135M	0.1289E 00	0.6268E-03	0.7107E-10	0.1070E-28	0.0
Xe-138	0.3957E 00	0.1035E-02	0.1840E-10	0.1979E-31	0.0

TABLE 15.5-14

CALCULATED ACTIVITY RELEASES FROM LOCA - DESIGN BASIS CASE (CURIES)

Nuclide	0-2 Hr	2-8 Hr	2-24 Hr	24-96 Hr	4-30 Days
I-131	0.2703E 02	0.0	0.0	0.0	0.0
I-132	0.3985E 02	0.0	0.0	0.0	0.0
I-133	0.6207E 02	0.0	0.0	0.0	0.0
I-134	0.7063E 02	0.0	0.0	0.0	0.0
I-135	0.5712E 02	0.0	0.0	0.0	0.0
I-131ORG	0.7340E 02	0.2170E 03	0.5561E 03	0.1070E 04	0.3227E 04
I-132ORG	0.8325E 02	0.8763E 02	0.1862E 02	0.9240E-01	0.8557E-10
I-133ORG	0.1639E 03	0.4314E 03	0.8078E 03	0.5263E 03	0.5383E 02
I-134ORG	0.9847E 02	0.2469E 02	0.2045E 00	0.2811E-06	0.2665E-31
I-135ORG	0.1411E 03	0.2838E 03	0.2668E 03	0.3148E 02	0.1834E-01
I-131PAR	0.9175E 02	0.2713E 03	0.6951E 03	0.1338E 04	0.4033E 04
I-132PAR	0.1041E 03	0.1095E 03	0.2327E 02	0.1155E 00	0.1070E-09
I-P33PAR	0.2048E 03	0.5392E 03	0.1010E 04	0.6579E 03	0.6728E 02
I-134PAR	0.1231E 03	0.3086E 02	0.2557E 00	0.3514E-06	0.3331E-31
I-135PAR	0.1764E 03	0.3548E 03	0.3335E 03	0.3935E 02	0.2293E-01
Kr-83M	0.9280E 03	0.7487E 03	0.8940E 02	0.1154E 00	0.2578E-12
Kr-85	0.6379E 02	0.1913E 03	0.5097E 03	0.1145E 04	0.9827E 04
Kr-85M	0.2823E 04	0.4660E 04	0.2723E 04	0.1191E 03	0.1413E-02
Kr-87	0.3847E 04	0.1864E 04	0.7273E 02	0.5752E-02	0.4530E-19
Kr-88	0.7090E 04	0.8484E 04	0.2388E 04	0.2220E 02	0.3333E-06
Xe-133	0.1684E 05	0.4942E 05	0.1241E 06	0.2205E 06	0.4392E 06
Xe-133M	0.4250E 03	0.1212E 04	0.2819E 04	0.3766E 04	0.2556E 04
Xe-135	0.7402E 04	0.1655E 05	0.2028E 05	0.4316E 04	0.1910E 02
Xe-135M	0.8506E 03	0.4137E 01	0.4690E-06	0.7061E-25	0.0
Xe-138	0.2504E 04	0.6552E 01	0.1164E-06	0.1252E-27	0.0

TABLE 15.5-15

THYROID DOSE - 2-HOUR - CONTAINMENT LEAKAGE - EXPECTED CASE (REM)

	Distance From Release Point, meters						
Nuclide	800	1200	2000	4000	7000	10000	20000
I-131	0.7456E-03	0.4792E-03	0.2636E-03	0.1097E-03	0.5060E-04	0.3101E-04	0.1247E-04
I-132	0.4383E-05	0.2817E-05	0.1549E-05	0.6445E-06	0.2974E-06	0.1823E-06	0.7332E-07
I-133	0.1527E-03	0.9814E-04	0.5398E-04	0.2246E-04	0.1036E-04	0.6350E-05	0.2554E-05
I-134	0.2268E-05	0.1458E-05	0.8017E-06	0.3336E-06	0.1539E-06	0.9432E-07	0.3794E-07
I-135	0.2479E-04	0.1593E-04	0.8763E-05	0.3646E-05	0.1682E-05	0.1031E-05	0.4147E-06
I-131ORG	0.2587E-03	0.1663E-03	0.9145E-04	0.3805E-04	0.1756E-04	0.1076E-04	0.4328E-05
I-132ORG	0.1169E-05	0.7514E-06	0.4132E-06	0.1719E-06	0.7933E-07	0.4862E-07	0.1956E-07
I-133ORG	0.5149E-04	0.3310E-04	0.1820E-04	0.7573E-05	0.3495E-05	0.2142E-05	0.8615E-06
I-134ORG	0.4031E-06	0.2591E-06	0.1425E-06	0.5929E-07	0.2736E-07	0.1677E-07	0.6744E-08
I-135ORG	0.7820E-05	0.5026E-05	0.2764E-05	0.1150E-05	0.5307E-06	0.3252E-06	0.1308E-06
I-131PAR	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I-132PAR	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I-133PAR	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I-134PAR	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I-135PAR	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	0.1249E-02	0.8030E-03	0.4416E-03	0.1837E-03	0.8479E-04	0.5196E-04	0.2090E-04

TABLE 15.5-17

THYROID DOSE - 30-DAY - CONTAINMENT LEAKAGE - EXPECTED CASE (REM)

	Distance From Release Point, meters						
Nuclide	800	1200	2000	4000	7000	10000	20000
I-131	0.7456E-03	0.4792E-03	0.2636E-03	0.1097E-03	0.5060E-04	0.3101E-04	0.1247E-04
I-132	0.4383E-05	0.2817E-05	0.1549E-05	0.6445E-06	0.2974E-06	0.1823E-06	0.7332E-07
I-133	0.1527E-03	0.9814E-04	0.5398E-04	0.2246E-04	0.1036E-04	0.6350E-05	0.2554E-05
I-134	0.2268E-05	0.1458E-05	0.8017E-06	0.3336E-06	0.1539E-06	0.9432E-07	0.3794E-07
I-135	0.2479E-04	0.1593E-04	0.8763E-05	0.3646E-05	0.1682E-05	0.1031E-05	0.4147E-06
I-131ORG	0.1252E-02	0.7543E-03	0.3960E-03	0.1587E-03	0.7223F-04	0.4452E-04	0.1762E-04
I-132ORG	0.2250E-05	0.1438E-05	0.7882E-06	0.3270E-06	0.1507E-06	0.9242E-07	0.3713E-07
I-133ORG	0.2091E-03	0.1280E-03	0.6797E-04	0.2751E-04	0.1257E-04	0.7734E-05	0.3074E-05
I-134ORG	0.4911E-06	0.3156E-06	0.1736E-06	0.7222E-07	0.3332E-07	0.2042E-07	0.8215E-08
I-135ORG	0.2352E-04	0.1473E-04	0.7955E-05	0.3264E-05	0.1498E-05	0.9202E-06	0.3679E-06
I-131PAR	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I-132PAR	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I-133PAR	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I-134PAR	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I-135PAR	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	0.2417E-02	0.1496E-02	0.8016E-02	0.3266E-03	0.1466E-03	0.9195E-04	0.3666E-04

TABLE 15.5-19

WHOLE BODY DOSE - 2-HOUR - CONTAINMENT LEAKAGE - EXPECTED CASE (REM)

	Distance From Release Point, meters						
Nuclide	800	1200	2000	4000	7000	10000	20000
I-131	0.3042E-06	0.1955E-06	0.1075E-06	0.4474E-07	0.2065E-07	0.1265E-07	0.5089E-08
I-132	0.2274E-06	0.1462E-06	0.8039E-07	0.3344E-07	0.1543E-07	0.9457E-08	0.3804E-08
I-133	0.4190E-06	0.2693E-06	0.1481E-06	0.6162E-07	0.2843E-07	0.1742E-07	0.7009E-08
I-134	0.1843E-06	0.1185E-06	0.6517E-07	0.2711E-07	0.1251E-07	0.7667E-08	0.3084E-08
I-135	0.4245E-06	0.2729E-06	0.1501E-06	0.6244E-07	0.2881E-07	0.1766E-07	0.7102E-08
I-131ORG	0.1055E-06	0.6784E-07	0.3731E-07	0.1552E-07	0.7163E-08	0.4389E-08	0.1766E-08
I-132ORG	0.6066E-07	0.3899E-07	0.2144E-07	0.8921E-08	0.4117E-08	0.2523E-08	0.1015E-08
I-133ORG	0.1413E-06	0.9082E-07	0.4995E-07	0.2078E-07	0.9589E-08	0.5876E-08	0.2364E-08
I-134ORG	0.3277E-07	0.2106E-07	0.1158E-07	0.4819E-08	0.2224E-08	0.1363E-08	0.5482E-09
I-135ORG	0.1339E-06	0.8608E-07	0.4734E-07	0.1970E-07	0.9089E-08	0.5570E-08	0.2241E-08
I-131PAR	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I-132PAR	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I-133PAR	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I-134PAR	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I-135PAR	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kr-83M	0.1915E-06	0.1231E-06	0.6771E-07	0.2817E-07	0.1300E-07	0.7965E-08	0.3204E-08
Kr-85	0.1469E-04	0.9439E-05	0.5192E-05	0.2160E-05	0.9967E-06	0.6108E-06	0.2457E-06
Kr-85M	0.9000E-05	0.5784E-05	0.3181E-05	0.1324E-05	0.6108E-06	0.3743E-06	0.1506E-06
Kr-87	0.4797E-04	0.3083E-04	0.1696E-04	0.7056E-05	0.3256E-05	0.1995E-05	0.8026E-06
Kr-88	0.1048E-03	0.6735E-04	0.3704E-04	0.1541E-04	0.7112E-05	0.4358E-05	0.1753E-05
Xe-133	0.1260E-03	0.8097E-04	0.4453E-04	0.1853E-04	0.8550E-05	0.5239E-05	0.2108E-05
Xe-133M	0.2658E-05	0.1708E-05	0.9396E-06	0.3909E-06	0.1804E-06	0.1105E-06	0.4447E-07
Xe-135	0.4764E-04	0.3062E-04	0.1684E-04	0.7006E-05	0.3233E-05	0.1981E-05	0.7969E-06
Xe-135M	0.8720E-06	0.5605E-06	0.3083E-06	0.1282E-06	0.5918E-07	0.3627E-07	0.1459E-07
Xe-138	0.9485E-05	0.6096E-05	0.3353E-05	0.1395E-05	0.6437E-06	0.3945E-06	0.1587E-06
TOTAL	0.3653E-03	0.2348E-03	0.1291E-03	0.5373E-04	0.2479E-04	0.1519E-04	0.6112E-05

TABLE 15.5-21

WHOLE BODY DOSE - 30-DAY - CONTAINMENT LEAKAGE - EXPECTED CASE (REM)

	Distance From Release Point, meters						
Nuclide	800	1200	2000	4000	7000	10000	20000
I-131	0.3042E-00	0.1955E-06	0.1075E-06	0.4474E-07	0.2065E-07	0.1265E-07	0.5089E-08
I-132	0.2274E-06	0.1462E-06	0.8039E-07	0.3344E-07	0.1543E-07	0.9457E-08	0.3804E-08
I-133	0.4190E-06	0.2693E-06	0.1481E-06	0.6162E-07	0.2843E-07	0.1742E-07	0.7009E-08
I-134	0.1843E-06	0.1185E-06	0.6517E-07	0.2711E-07	0.1251E-07	0.7667E-08	0.3084E-08
I-135	0.4245E-06	0.2729E-06	0.1501E-06	0.6244E-07	0.2881E-07	0.1766E-07	0.7102E-08
I-131ORG	0.5109E-06	0.3078E-06	0.1616E-06	0.6474E-07	0.2947E-07	0.1816E-07	0.7187E-08
I-132ORG	0.1167E-06	0.7463E-07	0.4090E-07	0.1697E-07	0.7822E-08	0.4796E-08	0.1927E-08
I-133ORG	0.5738E-06	0.3511E-06	0.1865E-06	0.7549E-07	0.3448E-07	0.2122E-07	0.8435E-08
I-134ORG	0.3992E-07	0.2566E-07	0.1411E-07	0.5870E-08	0.2709E-08	0.1660E-08	0.6677E-09
I-135ORG	0.4028E-06	0.2522E-06	0.1362E-06	0.5590E-07	0.2566E-07	0.1576E-07	0.6301E-08
I-131PAR	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I-132PAR	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I-133PAR	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I-134PAR	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I-135PAR	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kr-83M	0.3536E-06	0.2263E-06	0.1241E-06	0.5151E-07	0.2375E-07	0.1456E-07	0.5851E-08
Kr-85	0.2189E-03	0.1162E-03	0.5620E-04	0.2106E-04	0.9086E-05	0.5697E-05	0.2150E-05
Kr-85M	0.2744E-04	0.1717E-04	0.9267E-05	0.3800E-05	0.1744E-05	0.1071E-05	0.4283E-06
Kr-87	0.7159E-04	0.4596E-04	0.2526E-04	0.1050E-04	0,4846E-05	0.2970E-05	0.1195E-05
Kr-88	0.2446E-03	0.1553E-03	0.8472F-04	0.3503E-04	0.1612E-04	0.9891E-05	0.3968E-05
Xe-133	0.1222E-02	0.6844E-03	0.3406E-03	0.1298E-03	0.5784E-04	0.3588E-04	0.1383E-04
Xe-133M	0.2137E-04	0.1224E-04	0.6179E-05	0.2385E-05	0.1072E-05	0.6632E-06	0.2578E-06
Xe-135	0.2113E-03	0.1283E-03	0.6775E-04	0.2729E-04	0.1244E-04	0.7664E-05	0.3040E-05
Xe-135M	0.8763E-06	0.5632E-06	0.3098E-06	0.1289E-06	0.5947E-07	0.3644E-07	0.1466E-07
Xe-138	0.9510E-05	0.6112E-05	0.3362E-05	0.1399E-05	0.6454E-06	0.3955E-06	0.1591E-06
TOTAL	0.2031E-02	0.1169E-02	0.5949E-03	0.2319E-03	0.1041E-03	0.6441E-04	0.2510E-04

TABLE 15.5-23

SUMMARY OF EXPOSURE FROM CONTAINMENT LEAKAGE[a]

Thyroid Doses, rem

	EAB - 2 Hours	LPZ - 30 Days
10 CFR Part 100	300	300
Design basis case	95.9	17.7
Expected case	1.25×10^{-3}	9.20×10^{-5}

Whole Body Doses, rem

	EAB - 2 Hours	LPZ - 30 Days
10 CFR Part 100	25	25
Design basis case	5.61[b]	0.57[c]
Expected case	3.65×10^{-4}	6.44×10^{-5}

Population Doses, man-rem

Design basis case	932.1
Expected case	0.269

(a) These values correspond to the original analysis. See Table 15.5-75 for current analysis

(b) The EAB Whole Body dose of 5.61 rem is 3.69 rem gamma and 1.92 rem beta

(c) The LPZ Whole Body dose of 0.57 rem is 0.33 rem gamma and 0.24 rem beta

TABLE 15.5-24

ASSUMPTIONS USED TO CALCULATE OFFSITE EXPOSURES FROM POST-LOCA CIRCULATION LOOP LEAKAGE IN THE AUXILIARY BUILDING

	Expected Small Leakage	Expected Large Leakage	DBA Small Leakage	DBA Large Leakage
A. ECCS, Containment Fan Cooler, Containment Spray System Operation				
1. ECCS trains functioning	2	2	2	2
2. Containment fan coolers functioning	5	5	2	2
3. Containment spray system trains functioning	2	2	1	1
B. Activity Deposited in Containment Recirculation Sump Water				
1. Iodine				
1. Iodine (Core inventory base on both U-235 & PU-239 fissions)	100% of gap inventory per Table 11.1-7; (I-127, 129, rel. fract. of 0.015; I-131, 132, 133, 134, 135 rel. fract. Table 11.1-7)	100% of gap inventory per Table 11.1-7; (I-127, 129, rel. fract. of 0.015; I-131, 132, 133, 134, 135, rel. fract. Table 11.1-7)	100% of gap inventory per Regulatory Guide 1.25; (I-127, 129, rel. fract. of 0.30; I-131, 132, 133, 134, 135 rel. fract. of 0.10)	100% of gap inventory per Regulatory Guide 1.25; (I-127, 129, rel. fract. of I-131, 132, 133, 134, 135, rel. fract. of 0.10)
a. Elemental iodine inventory	100% of gap iodine inventory	100% of gap iodine inventory	99.75% of gap iodine inventory	99.75% of gap iodine inventory
(1) I-127	30.2g, 0 Ci	30.2g, 0 Ci	903g, 0 Ci	903g, 0 Ci
(2) I-129	148.5g, 0 Ci	148.5g, 0 Ci	4,445g, 0 Ci	4,445g, 0 Ci
(3) I-131, 132, 133, 134, 135	6.5g, 1.82×10^{6}Ci	6.5g, 1.82×10^{6}Ci	97g, 8.45×10^{7}Ci	97g, 8.45×10^{7}Ci

TABLE 15.5-24

ASSUMPTIONS USED TO CALCULATE OFFSITE EXPOSURES FROM POST-LOCA CIRCULATION LOOP LEAKAGE IN THE AUXILIARY BUILDING

	Expected Small Leakage	Expected Large Leakage	DBA Small Leakage	DBA Large Leakage
b. Organic iodine	0% of gap iodine inventory	0% of gap iodine inventory	0.25% of gap iodine inventory	0.25% of gap iodine inventory
(1) I-127	0.0	0.0	2g, 0 Ci	2g, 0 Ci
(2) I-129	0.0	0.0	11g, 0 Ci	11g, 0 Ci
(3) I-131, 132, 133, 134, 135	0.0	0.0	02g, 2.12×10^5 Ci	02g, 2.12×10^5 Ci
c. Total iodine	185.2g, 1.82×10^6 Ci	185.2g, 182×10^6 Ci	5.458g, 8.47×10^7 Ci	5.458g, 8.47×10^7 Ci
2. Noble Gases	0.0	0.0	0.0	0.0
Other fission products	0.0	0.0	0.0	0.0
C. Containment Recirculation Sump Decay and Cleanup				
1. Radiological decay credit	Yes	Yes	Yes	Yes
2. Cleanup credit	None	None	None	None
D. Volume of Water in Which Activity is Deposited (diluted)				
1. Reactor coolant water, gal.	93,960	93,960	93,960	93,960
2. Accumulator water, gal.	25,040	25,040	25,040	25,040

TABLE 15.5-24

ASSUMPTIONS USED TO CALCULATE OFFSITE EXPOSURES FROM POST-LOCA CIRCULATION LOOP LEAKAGE IN THE AUXILIARY BUILDING

	Expected Small Leakage	Expected Large Leakage	DBA Small Leakage	DBA Large Leakage
D. Volume of Water in Which Activity is Deposited (diluted) (Cont'd)				
3. Refueling water storage tank, gal. (Table 6.3-1)	350,000	262,030	350,000	254,220
4. Total, gal.	469,000	381,030	469,000	373,220
E. Conditions of Loop Leakage Water				
1. pH of leakage water (Figure 6.2-15)	8.8	8.4	8.5	7.85
2. Temperature of leakage water, °F	120	238	120	242
F. Loop Leakage Rate	1910 cc/hr.	50 gpm (Table 6.3-9)	1910 cc/hr	50 gpm (Table 6.3-9)
G. Duration of Loop Leakage				
1. Time after LOCA leakage begins, hr (Table 6.3-5)	0.337	0.337	0.395	24
2. Time after LOCA leakage ends, hr	720	0.837	720	24.5
3. Total duration of loop leakage, hr	719.7	0.5	719.6	0.5

TABLE 15.5-24

ASSUMPTIONS USED TO CALCULATE OFFSITE EXPOSURES FROM POST-LOCA CIRCULATION LOOP LEAKAGE IN THE AUXILIARY BUILDING

	Expected Small Leakage	Expected Large Leakage	DBA Small Leakage	DBA Large Leakage
H. Auxiliary Building Iodine Decontamination Factors				
1. Elemental iodine decontamination factor				
a. M vapor, lbm / M liquid, lbm	-	2.78×102^{-2}	-	3.22×10^{-2}
b. V vapor, ft^3/lbm / V liquid, ft^3/lbm	-	$1.60 \times 10^{+3}$	-	$1.60 \times 10^{+3}$
c. Partition coefficient, PC, (g/1) liquid / (g/1) gas	-	$7.22 \times 10^{+5}$	-	$6.77 \times 10^{+3}$
d. Partition factor, PF, (g) gas / (g) liquid	-	6.18×10^{-5}	-	7.62×10^{-3}
e. Decontamination factor, DF, (g) leak / (g) gas	1.0	$1.62 \times 10^{+4}$	1.0	$1.32 \times 10^{+2}$
2. Organic iodine decontamination factor, DF, (g) leak / (g) gas	1.0	1.0	1.0	1.0
I. Auxiliary Building Decay, Plateout, and Filter Removal				
1. Radiological decay credit	None	None	None	None
2. Plateout credit	None	None	None	None

TABLE 15.5-24

ASSUMPTIONS USED TO CALCULATE OFFSITE EXPOSURES FROM POST-LOCA CIRCULATION LOOP LEAKAGE IN THE AUXILIARY BUILDING

	Expected Small Leakage	Expected Large Leakage	DBA Small Leakage	DBA Large Leakage
I. Auxiliary Building Decay, Plateout, and Filter Removal (Cont'd)				
3. Auxiliary building filter credit	None	Yes	None	Yes
a. Iodine filter efficiency				
(1) Elemental iodine, %	0.0	99.0	0.0	90.0
(2) Organic iodine, %	0.0	85.0	0.0	70.0
(3) Particulate iodine %	0.0	99.0	0.0	90.0
b. Noble gases	0.0	0.0	0.0	0.0
J. Atmospheric Dispersion				
1. Down wind radiological decay credit	None	None	None	None
2. Atmospheric dilution factors	Table 15.5-4	Table 15.5-4	Table 15.5-4	Table 15.5-4
K. Breathing Rates	Table 15.5-7	Table 15.5-7	Table 15.5-7	Table 15.5-7

TABLE 15.5-26

PERCENTAGE OCCURRENCE OF WIND DIRECTION AND CALM WINDS EXPRESSED AS PERCENTAGE OF TOTAL HOURLY OBSERVATIONS WITHIN EACH SEASON AT THE SITE (250-FOOT LEVEL)

Wind Direction

Season [(a)]	Offshore [(b)]	Onshore [(c)]	Calm [(d)]
Annual	57%	38%	5%
Dry	55%	40%	5%
Wet	54%	42%	4%
Transitional	62%	34%	4%

(a) Dry Season - May through September
Wet Season - November through March
Transitional - April and October

(b) Offshore wind directions are defined as wind directions from northwest through east southeast measured clockwise.

(c) Onshore wind directions are defined as wind directions from southeast through west-northwest measured clockwise.

(d) Calm wind directions are defined as winds with speeds less than one 1 mph.

TABLE 15.5-27

DIABLO CANYON POWER PLANT SITE PROBABILITY OF PERSISTENCE OFFSHORE WIND DIRECTION SECTORS (250-FOOT LEVEL)

Consecutive Hours	NNE				NE				ENE				E				ESE			
	A[(a)]	D[(a)]	W[(a)]	T[(a)]	A	D	W	T	A	D	W	T	A	D	W	T	A	D	W	T
1	0.461	0.652	0.432	0.390	0.426	0.655	0.373	0.477	0.505	0.769	0.401	0.732	0.678	0.906	0.577	0.840	0.400	0.430	0.370	0.434
2	0.245	0.107	0.327	0.178	0.252	0.241	0.237	0.318	0.190	0.231	0.180	0.195	0.158	0.038	0.189	0.160	0.152	0.180	0.154	0.110
3	0.129	0.054	0.039	0.248	0.136	0.103	0.151	0.102	0.133	-	0.176	0.073	0.069	0.057	0.090	-	0.082	0.075	0.068	0.124
4	0.073	0.071	0.049	0.118	0.041	-	0.047	0.045	0.064	-	0.090	-	0.066	-	0.100	-	0.086	0.120	0.046	0.138
5	0.058	0.045	0.077	0.030	0.041	-	0.044	0.057	0.064	-	0.090	-	0.000	-	0.000	-	0.058	0.100	0.028	0.069
6	0.010	0.000	0.000	0.036	0.050	-	0.071	-	0.019	-	0.027	-	0.000	-	0.000	-	0.060	0.060	0.034	0.124
7	0.012	0.000	0.022	-	0.000	-	0.000	-	0.000	-	0.000	-	0.000	-	0.000	-	0.050	0.035	0.080	-
8	0.013	0.071	-	-	0.033	-	0.047	-	0.025	-	0.036	-	0.000	-	0.000	-	0.023	-	0.046	-
9	-	-	-	-	0.000	-	0.000	-	-	-	-	-	-	-	0.045	-	0.013	-	0.026	-
10	-	-	-	-	0.021	-	0.030	-	-	-	-	-	-	-	-	-	0.014	-	0.028	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	-	0.000	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	-	0.000	-
13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.037	-	0.074	-
14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	-	0.000	-
15	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	-	0.000	-
16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.023	-	0.046	-
17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

TABLE 15.5-27

DIABLO CANYON POWER PLANT SITE PROBABILITY OF PERSISTENCE OFFSHORE WIND DIRECTION SECTORS (250-FOOT LEVEL)

Conse- cutive Hours	NW				NNW				N				Calm			
	A	D	W	T	A	D	W	T	A	D	W	T	A	D	W	T
1	0.105	0.086	0.157	0.105	0.364	0.453	0.318	0.348	0.504	0.701	0.461	0.442	0.364	0.329	0.393	0.426
2	0.091	0.073	0.142	0.090	0.194	0.194	0.201	0.178	0.200	0.124	0.217	0.231	0.237	0.214	0.239	0.313
3	0.078	0.064	0.137	0.056	0.125	0.115	0.135	0.118	0.088	0.051	0.078	0.144	0.152	0.166	0.151	0.101
4	0.067	0.058	0.111	0.049	0.085	0.089	0.103	0.042	0.104	0.090	0.122	0.077	0.103	0.081	0.164	0.054
5	0.058	0.040	0.086	0.085	0.067	0.051	0.071	0.078	0.018	0.000	0.022	0.048	0.055	0.074	0.016	0.068
6	0.062	0.048	0.098	0.068	0.036	0.036	0.046	0.016	0.049	0.034	0.052	0.058	0.018	0.022	0.000	0.041
7	0.050	0.045	0.046	0.068	0.034	0.028	0.045	0.018	0.016	-	0.030	-	0.014	0.026	0.000	-
8	0.047	0.039	0.046	0.072	0.039	0.032	0.021	0.084	0.009	-	0.017	-	0.000	0.000	0.000	-
9	0.045	0.044	0.029	0.059	0.016	-	0.023	0.024	0.000	-	-	-	0.027	0.050	0.000	-
10	0.038	0.044	0.008	0.049	0.006	-	0.000	0.026	0.012	-	-	-	0.030	0.037	0.031	-
11	0.046	0.060	0.009	0.054	0.007	-	0.000	0.029	-	-	-	-	-	-	-	-
12	0.035	0.028	0.049	0.039	0.007	-	0.016	0.000	-	-	-	-	-	-	-	-
13	0.038	0.054	0.011	0.011	0.000	-	-	0.000	-	-	-	-	-	-	-	-
14	0.038	0.043	0.011	0.045	0.000	-	-	0.000	-	-	-	-	-	-	-	-
15	0.019	0.027	0.000	0.012	0.009	-	-	0.039	-	-	-	-	-	-	-	-
16	0.020	0.025	0.000	0.026	0.010	-	-	-	-	-	-	-	-	-	-	-
17	0.022	0.031	0.000	0.014	-	-	-	-	-	-	-	-	-	-	-	-
18	0.023	0.033	0.015	0.015	-	-	-	-	-	-	-	-	-	-	-	-
19	0.030	0.034	0.016	0.046	-	-	-	-	-	-	-	-	-	-	-	-
20	0.013	0.021	-	0.000	-	-	-	-	-	-	-	-	-	-	-	-
21	0.003	0.005	-	0.000	-	-	-	-	-	-	-	-	-	-	-	-
22	0.007	0.006	-	0.018	-	-	-	-	-	-	-	-	-	-	-	-
23	0.004	0.006	-	0.000	-	-	-	-	-	-	-	-	-	-	-	-
24	0.012	0.012	-	0.020	-	-	-	-	-	-	-	-	-	-	-	-
25	0.012	0.019	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	0.012	0.020	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	0.004	0.007	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	0.004	0.007	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	0.000	0.000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	0.000	0.000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	0.005	0.008	-	-	-	-	-	-	-	-	-	-	-	-	-	-

(a) A = Annual
D = Dry season (May through September)
W = Wet season (November through March)
T = Transitional months (April and October)

TABLE 15.5-28

ASSUMPTIONS USED TO CALCULATE ONSHORE CONTROLLED CONTAINMENT VENTING

	Expected Case	DBA Case
A. Activity Released to Containment Atmosphere		
1. Iodine	25% of gap iodine inventory	25% of core iodine inventory
a. Elemental	24.95% of gap iodine inventory	22.75% of core iodine inventory
b. Organic	0.05% of gap iodine inventory	1.0% of core iodine inventory
c. Particulate	0% of gap iodine inventory	1.25% of core iodine inventory
2. Noble gases	100% of gap inventory	100% of core inventory
3. Other fission products	None	None
B. Decay, Cleanup, and Leakage in Containment Atmosphere		
1. Radiological decay credit	Yes	Yes
2. Iodine spray cleanup		
a. Elemental	92.0 hr^{-1}	31.0 hr^{-1}[(a)]
b. Organic	0.58 hr^{-1}	0 hr^{-1}
c. Particulate	0	0
3. Filter cleanup of containment atmosphere		
a. Iodines	None	None
b. Noble gases	None	None
4. Containment leak rate	0.05%/per day	0.05%/per day

TABLE 15.5-28

ASSUMPTIONS USED TO CALCULATE ONSHORE CONTROLLED CONTAINMENT VENTING

	Expected Case	DBA Case
C. Containment Atmosphere Volume	2.68 x 10^6 cubic feet	2.68 x 10^6 cubic feet
D. Purge Schedule		
1. Time after LOCA purging begins	1968 hours, Chapter 6	672 hours, Chapter 6
2. Time after LOCA purging ends	6792 hours, remainder of 1 yr.	8088 hours, remainder of 1 yr.
E. Purge Flowrate	10 cfm, Chapter 6	25 cfm, Chapter 6
F. Filter Efficiency		
1. Iodines		
a. Elemental	99%	90%
b. Organic	85%	70%
c. Particulate	99%	90%
2. Noble gases	None	None
G. Atmospheric Dispersion		
1. Radiological decay credit	None	None
2. χ/Qs	Table 15.5-30	Table 15.5-30
H. Breathing Rates	Table 15.5-7	Table 15.5-7

(a) Although a subsequent safety evaluation showed that the Design Case coefficient of 31^{-1} (for 2600 gpm spray header flow) should be reduced to approximately 29 hr^{-1} (for 2466 gpm spray header flow), the potential offsite dose increase due to this change is extremely small and can be considered insignificant (Reference 39).

TABLE 15.5-29

ONSHORE CONTROLLED CONTAINMENT VENTING EXPOSURES

	DBA	Expected
Thyroid exposure at site boundary (800 meters), rem	2.21	9.83×10^{-25}
Whole body exposure at site boundary (800 meters), rem	0.0841	7.15×10^{-3}

TABLE 15.5-30

ATMOSHPERIC DISPERSION FACTORS FOR ONSHORE CONTROLLED CONTAINMENT VENTING (STABILITY CATEGORY D)

Distance, km	χ/Q, sec/m^3
0.8	1.437×10^{-6}
1.2	2.440×10^{-6}
2.0	1.968×10^{-6}
4.0	7.884×10^{-7}
7.0	3.135×10^{-7}
10.0	1.691×10^{-7}
20.0	6.099×10^{-8}

Meteorological Input Parameters:

Height of release = 70 meters
Mixing depth = 350 meters
Mean wind speed = 5.8 meters per second
Sigma theta = 10 degrees
Sigma phi = 3 degrees
Vertical expansion rate beta, β, = 0.9
Azimuth expansion rate alpha, α, = 0.9
$\sigma_Y = \sigma_\theta x^\delta$ and $\sigma_Z = \sigma_\phi x^\beta$

TABLE 15.5-31

CONTROL ROOM INFILTRATION ASSUMED FOR RADIOLOGICAL EXPOSURE CALCULATIONS

Leakage Path	Leakage Equation	Leakage (cfm)
A. Windows	No leakage, no windows.	0.0
B. Doors		3
C. Penetrations		
1. Ducting (external seal)	No leakage: ducting penetrations caulked to full depth and exterior surfaces sealed with FLAMEMASTIC 71A and control room will be positively pressurized.	0.0
2. Piping (external seal)	No leakage: concrete walls and floor poured with piping in place and control room will be positively pressurized.	0.0
3. Conduits and trays		
a. External seal	No leakage: space between exposed conductors and trays is sealed with B&W KAOWOOL ceramic fiber 6 inches in depth, with two coats of FLAMEMASTIC 72A, and control room will be positively pressurized.	0.0
b. Internal seal	No leakage: conduits are sealed with THIXOTROPIC silicone rubber compound, with a minimum depth of one diameter, and control room will be positively pressurized.	0.0

TABLE 15.5-31

CONTROL ROOM INFILTRATION ASSUMED FOR RADIOLOGICAL EXPOSURE CALCULATIONS

Leakage Path	Leakage Equation	Leakage (cfm)
D. Dampers	$Q = A \times q \times \Delta p$ where: Q = leakage, cfm A = damper area, square feet q = leakage per unit damper area per in. of water[a] Δp = pressure difference across damper, in. of water[b]	
1. Mode damper #2	A = 6.00 ft^2, q = 0.001 cfm/ft^2 - in. and Δp = 6.0 in. W.G.	<0.05
2. Mode damper #3	A = 1.84 ft^2, q = 0.001 cfm/ft^2 - in. and Δp = 6.0 in. W.G.	<0.05
3. Mode damper #7	A = 6.00 ft^2, q = 0.001 cfm/ft^2 - in. and Δp = 6.0 in. W.G.	<0.05
4. Mode damper #8	A = 1.78 ft^2, q = 0.001 cfm/ft^2 - in. and Δp = 6.0 in. W.G.	<0.05
E. Total		$\cong$3[c]

(a) From manufacturer's published data.
(b) Assume conservatively large value of 6 inches of water; dampers will never see a pressure differential this large.
(c) 10 cfm is conservatively assumed in the analysis.

TABLE 15.5-32

ASSUMPTIONS USED TO CALCULATE
POST-ACCIDENT CONTROL ROOM RADIOLOGICAL EXPOSURES

	DBA Case
A. Power Level	3580 MWt
B. Activity Released to Containment Atmosphere	
1. Iodine, % of core iodine inventory	25
a. Elemental, % of core iodine inventory	22.75
b. Organic, % of core iodine inventory	1.00
c. Particulate, % of core iodine inventory	1.25
2. Noble gases, % of core inventory	100
3. Other fission product	None
C. Decay, Cleanup, and Leakage in Containment Atmosphere	
1. Radiological decay included	Yes
2. Iodine spray cleanup	
a. Elemental	31 hr^{-1}[(a)]
b. Organic	0 hr^{-1}
c. Particulate	0 hr^{-1}
3. Decontamination factor (DF) cut-off for spray, elemental	100
4. Time post-LOCA spray starts	80 seconds
5. Filter cleanup of containment atmosphere	None
a. Iodines	None
b. Noble gases	None

TABLE 15.5-32

ASSUMPTIONS USED TO CALCULATE
POST-ACCIDENT CONTROL ROOM RADIOLOGICAL EXPOSURES

	DBA Case
6. Containment leakrate	
a. First 24 hours	0.1% per day
b. Remainder of accident period	0.05% per day
D. Recirculation Loop Leakage	
1. RHR leakage rate	50 gpm
2. Start of RHR leakage	24 hrs
3. Duration of RHR leakage	0.5 hr
4. Charcoal filter efficiency for release of RHR leakage	
a. Iodine filter efficiency	
(1) Elemental, %	90.0
(2) Organic, %	70.0
(3) Particulate, %	90.0
b. Noble gas filter efficiency	0.0
E. Meteorology (atmospheric dilution factors from the containment to the control room)	Table 15.5-6
F. Control Room Ventilation Flowrates	
1. Flowrate of contaminated air infiltrating into the control room	10 cfm
2. Flowrate of pressurization air into the control room	2100 cfm
3. Flowrate of recirculated control room air through cleanup filters	2100 cfm

TABLE 15.5-32

ASSUMPTIONS USED TO CALCULATE
POST-ACCIDENT CONTROL ROOM RADIOLOGICAL EXPOSURES

	DBA Case
G. Decay and Cleanup in Control Room	
1. Radiological decay included	Yes
2. Filter cleanup of pressurization air	Yes
a. Iodines	
(1) Elemental	95%
(2) Organic	95%
(3) Particulate	95%
b. Noble gases	0%
H. Control Room Complex Volume (total for Units 1 and 2)	170,000 ft^3
I. Control Room Occupancy Factors	
1. 0-24 hours	1
2. 24-96 hours	0.6
3. 96-720 hours	0.4

(a) Although a subsequent safety evaluation showed that the Design Case coefficient of 31 hr^{-1} (for 2600 gpm spray header flow) should be reduced to approximately 29 hr^{-1} (for 2466 gpm spray header flow), the potential offsite dose increase due to this change is extremely small and can be considered insignificant (Reference 39).

TABLE 15.5-33

ESTIMATED POST-ACCIDENT EXPOSURE TO CONTROL ROOM PERSONNEL

	DBA			Expected Case Accident		
Radiation Source	Gamma Exposure, rem	Beta Exposure, rem	Thyroid Exposure, rem	Gamma Exposure, rem	Beta Exposure, rem	Thyroid Exposure, rem
1. Radiation from airborne fission products postulated to enter the control room	See Table 15.5-63	See Table 15.5-63	See Table 15.5-63	---	---	---
2. Direct radiation to the control room from fission products in the containment structure	0.032	0	0	6.8×10^{-5}	0	0
3. Direct radiation to the control room from fission products in the containment leakage plume	0.022	0	0	1×10^{-5}	0	0
4. Radiation from airborne fission products in the containment leakage plume to control room personnel during egress ingress	0.0066	0.0243	4.72	1.6×10^{-5}	1.0×10^{-4}	5×10^{-6}
5. Direct radiation from fission products in the containment structure to control room personnel during egress-ingress (53 5-minute trips)	0.022	0	0	5.3×10^{-5}	0	0

TABLE 15.5-34

STEAM RELEASES FOLLOWING A MAJOR STEAM LINE BREAK

	Time Period	
	0-2 hr	2-8 hr
Steam release from ruptured pipe, lbm	171,100	-0-
Steam release from relief valves, lbm	384,000	893,000

Note: All steam releases listed above are for RSGs. OSG MSLB steam releases, which are used in the MSLB dose analysis of record, are listed in item 11 of Section 15.5.18.2.1.

TABLE 15.5-40 (HISTORICAL)

LONG-TERM ACTIVITY RELEASE FRACTIONS FOR FUEL FAILURE ACCIDENTS

Isotopes	*Release Fractions*
I-131	1.37×10^{-9}
I-132	2.51×10^{-10}
I-133	9.43×10^{-10}
I-134	1.02×10^{-10}
I-135	5.34×10^{-5}
Kr-83M	2.16×10^{-5}
Kr-85	0.98
Kr-85M	5.02×10^{-5}
Kr-87	1.51×10^{-5}
Kr-88	3.14×10^{-5}
Xe-133	1.68×10^{-3}
Xe-133M	5.52×10^{-4}
Xe-135	1.07×10^{-4}
Xe-135M	3.23×10^{-7}
Xe-138	2.89×10^{-6}

TABLE 15.5-41

ACTIVITY RELEASES FOLLOWING A LOCKED ROTOR ACCIDENT (CURIES)

Design Basis Case

Nuclide	0-2 hr	2-8 hr
I-131	8.643E-1	4.1783E0
I-132	1.121E-1	2.505E-1
I-133	7.753E-1	3.4725E0
I-134	6.086E-2	4.067E-2
I-135	3.673E-1	1.4067E0
I-131ORG	0.0	0.0
I-132ORG	0.0	0.0
I-133ORG	0.0	0.0
I-134ORG	0.0	0.0
I-135ORG	0.0	0.0
I-131PAR	0.0	0.0
I-132PAR	0.0	0.0
I-133PAR	0.0	0.0
I-134PAR	0.0	0.0
I-135PAR	0.0	0.0
Kr-83M	9.975E-1	4.281E-1
Kr-85	1.2282E1	1.6610E1
Kr-85M	4.9366E0	4.1691E0
Kr-87	3.2949E0	8.647E-1
Kr-88	8.5004E0	5.4137E0
Xe-133	2.7392E2	3.6840E2
Xe-133M	3.8638E0	5.1188E0
Xe-135	2.0293E1	2.2393E1
Xe-135M	3.026E-1	0
Xe-138	9.120E-1	0

TABLE 15.5-41 Sheet 2 of 2

ACTIVITY RELEASES FOLLOWING A LOCKED ROTOR ACCIDENT (CURIES)

	Expected Case	
Nuclide	0-2 hr	2-8 hr
I-131	1.109E-2	5.670E-2
I-132	1.223E-3	2.386E-3
I-133	8.495E-3	3.875E-2
I-134	6.708E-4	4.001E-4
I-135	3.984E-3	1.425E-2
I-131ORG	0.0	0.0
I-132ORG	0.0	0.0
I-133ORG	0.0	0.0
I-134ORG	0.0	0.0
I-135ORG	0.0	0.0
I-131PAR	0.0	0.0
I-132PAR	0.0	0.0
I-133PAR	0.0	0.0
I-134PAR	0.0	0.0
I-135PAR	0.0	0.0
Kr-83M	1.556E-2	3.770E-3
Kr-85	2.087E-1	2.379E-1
Kr-85M	7.267E-2	4.341E-2
Kr-87	5.210E-2	5.482E-3
Kr-88	1.401E-1	5.716E-2
Xe-133	2.8246E-0	3.1281E-0
Xe-133M	4.360E-2	4.702E-2
Xe-135	2.825E-1	2.366E-1
Xe-135M	5.116E-3	0
Xe-138	1.564E-2	0

TABLE 15.5-42

SUMMARY OF OFFSITE DOSES FROM A LOCKED ROTOR ACCIDENT

Thyroid Exposures, rem

	Site Boundary - 2 hours	LPZ - 30 days
10 CFR Part 100	300	300
Design basis case	0.30	0.076
Expected case	2.5×10^{-4}	6.6×10^{-5}

Whole Body Exposures, rem

	Site Boundary - 2 hours	LPZ - 30 days
10 CFR Part 100	25	25
Design basis case	1.3×10^{-2}	1.1×10^{-3}
Expected case	1.6×10^{-5}	1.3×10^{-6}

Population Doses, man-rem

Design basis case	0.32
Expected case	2.8×10^{-4}

TABLE 15.5-44

COMPOSITE SOURCE TERM FOR FUEL HANDLING ACCIDENT
IN THE FUEL HANDLING BUILDING

Isotope	Composite Source Term (Ci/assembly at shutdown)	Activity at 100 Hours After Shutdown (Ci at 100 hrs)	Pool Activity (Ci at 100 hrs)	FHB Activity Based on DF200 for Iodines (Ci at 100 hrs)
I-131	5.057E+05	3.625E+05	5.9813E+04	299.0625
I-132	7.283E+05	3.042E+05	5.0193E+04	250.965
I-133	1.032E+06	3.783E+04	6.2420E+03	31.21
I-134	1.165E+06	0	0	0
I-135	9.611E+05	2.689E+01	4.4369E+00	0.0222
Kr-83m	8.196E+04	9.554E-08	1.5764E-08	1.5764E-08
Kr-85m	1.901E+05	3.679E-02	0.0060704	0.0060704
Kr-85	6.353E+03	6.350E+03	3143.25	3143.25
Kr-87	3.828E+05	0	0	0
Kr-88	5.416E+05	1.350E-05	2.2275E-06	2.2275E-06
Kr-89	6.855E+05	0	0	0
Xe-131m	5.661E+03	5.469E+03	902.385	902.385
Xe-133m	3.187E+04	1.306E+04	2154.9	2154.9
Xe-133	9.993E+05	6.914E+05	114081	114081
Xe-135m	2.021E+05	4.264E+00	0.70356	0.70356
Xe-135	2.886E+05	1.327E+03	218.955	218.955
Xe-137	9.140E+05	0	0	0
Xe-138	9.477E+05	0	0	0

Where:

The activity/Assembly at 100 hours after shutdown = A_{100}.
Pool activity at 100 hours = $(A_{100})^{Pool}$ = A_{100} x 1.65 x release fraction
= A_{100} x 1.65 x 0.1 for iodine and noble gases except Kr-85
and
= A_{100} x 1.65 x 0.3 for Kr-85
FHB activity at 100 hours = $(A_{100})^{Pool}$ / 200 for iodine

TABLE 15.5-45

ASSUMPTIONS FOR FUEL HANDLING ACCIDENT IN THE FUEL HANDLING AREA

A.	Pre-accident Operation	
	1. Core Power	3580 MWt
B.	Highest Power Fuel Assembly Characteristics	
	1. Radial peaking factor	1.65
C.	Fuel Assembly Damage	
	1. Number of fuel rods per assembly	264
	2. Number of fuel rods ruptured per assembly	264
	3. Number of fuel assemblies damaged	1
D.	Gap Activity Fractions	
	1. Iodine	0.10
	a. Elemental	0.09975
	b. Organic	0.00025
	c. Particulate	0.0
	2. Noble gases	
	a. Other than Kr-85	0.10
	b. Kr-85	0.30
	3. Other fission products	None
E.	Gap Activity Release Fractions	
	1. Iodine	1
	2. Noble gases	1
	3. Other fission products	None
F.	Fission Product Release Depth	23 feet
G.	Spent Fuel Pool Decontamination Factors	
	1. Iodine	200
	a. Elemental	500
	b. Organic	1
	c. Particulate	None
	2. Noble gases	1
	3. Other fission products	None

TABLE 15.5-45

ASSUMPTIONS FOR FUEL HANDLING ACCIDENT IN THE FUEL HANDLING AREA

H.	Decay and Cleanup in Fuel Handling Building		
	1. Radiological decay credit	None	
	2. Radiological cleanup credit	None	
I.	Fuel Handling Building Volume	435,000 ft^3	
J.	Fuel Handling Building Filter Efficiencies	Not credited	
K.	Fuel Handling Building Exhaust Rate	40,000 cfm	
L.	Atmospheric Dispersion		
	1. Radiological decay credit	None	
	2. χ/Qs	EAB (800m) 0 to 2 hr	9.9E-4 sec/m^3
		LPZ (10 km) 0 to 8 hr	2.6E-5 sec/m^3
		8 to 24 hr	4.5E-6 sec/m^3
		24 to 96 hr	1.6E-6 sec/m^3
		96 to 720 hr	3.3E-7 sec/m^3
M.	Offsite Breathing Rates	Table 15.5-7	
N.	Offsite Power	(a)	

(a) Assumes the FHB ventilation operates continuously to maximize the FHB exhaust to the early stages of this event with or without offsite power.

TABLE 15.5-47

SUMMARY OF DOSES FROM FUEL HANDLING ACCIDENT
IN THE FUEL HANDLING AREA

	TEDE Exposures, rem	
	Site Boundary 2 - Hours	LPZ - 30 Days
Regulatory Limit	6.3	6.3
Design basis case	4.265	0.112
	Control Room	
Regulatory Limit	5	
Design basis case	0.689	

TABLE 15.5-48

DESIGN INPUTS AND ASSUMPTIONS FOR FUEL HANDLING ACCIDENTS INSIDE CONTAINMENT

Parameter	**Value**
Containment:	
Containment Free Volume (ft^3)	2.55E+06
Containment Volume above Fuel Pool (ft^3)	33600
Purge Line Flowrate to Environment (CFM)	13750
Depth of Water Above Damaged Fuel (ft)	$\geq$23
Iodine Decontamination Factors:	
Organic	1
Inorganic (Elemental)	500
Overall Effective	200
Exfiltration Rate (cfs)	2.55E+06
Duration of Release (sec)	<2.0
Time of Accident after Shutdown (hr)	100
Number of Failed Rods	264
Gap Activity Released from Damaged Rods (%):	
Kr-85	30
Noble Gases other than Kr-85	10
Iodines	10
Iodine Gap Inventory (%):	
Iorganic	99.75
Organic	0.25
Values Assumed for Generation of Inventories:	
Reactor Power (%RTP)	105
Reactor Power (MWt)	3580
Radial Peaking Factor	1.65
Dose Conversion Factors for Iodine Species (REM/Ci):	
I-131	1.08E+06
I-132	6.44E+03
I-133	1.80E+05
I-134	1.07E+03
I-135	3.13E+04

TABLE 15.5-48

DESIGN INPUTS AND ASSUMPTIONS FOR FUEL HANDLING ACCIDENTS INSIDE CONTAINMENT

Parameter	**Value**
Control Room (CR) Input Data:	
Control Room Volume (U1 +U2) (cubic feet)	170000
Flowrates (CFM)	
Flowrate of contaminated air into CR	2110
Flowrate of recirc CR air thru filters	0
CR pressurization air filter:	
Filter Depth	2 inches
Iodine Filter Efficiency:	
Elemental	95%
Organic	95%
Particulate	95%
CR Occupancy Factors:	
0 - 24 hours	1
24 -96 hours	0.6
96 - 720 hours	0.4
Atmospheric Dispersion Factors (sec/m^3):	
Control Room Pressurization:	
0 - 8 hours	7.05E-05
8 - 24 hours	5.38E-05
24 - 96 hours	3.91E-05
96 - 720 hours	2.27E-05
Control Room Infiltration :	
0 - 8 hours	1.96E-04
8 - 24 hours	1.49E-04
24 - 96 hours	1.08E-04
96 - 720 hours	6.29E-05
Exclusion Area Boundary (EAB), 800 meters:	
0 - 2 hours	5.29E-04
Low Population Zone (LPZ), 10,000 meters:	
0 - 8 hours	2.20E-05
8 -24 hours	4.75E-06
1 - 4 days	1.54E-06
4 - 30 days	3.40E-07
Control Room Breathing Rate (m^3/sec):	3.47E-04
Offsite Breathing Rates (m^3/sec):	
0 - 8 hours	3.47E-04
8 -24 hours	1.75E-04
1 - 30 days	2.32E-04

TABLE 15.5-49

ACTIVITY RELEASES FROM FUEL HANDLING ACCIDENT INSIDE CONTAINMENT (CURIES)

Design Basis Case

Nuclide	0-2 hr
I-131	299.0625
I-132	250.965
I-133	31.21
I-134	0
I-135	0.0222
Kr-83m	1.5764E-08
Kr-85m	0.0060704
Kr-85	3143.25
Kr-87	0
Kr-88	2.2275E-06
Kr-89	0
Xe-131m	902.385
Xe-133m	2154.9
Xe-133	114081
Xe-135m	0.70356
Xe-135	218.955
Xe-137	0
Xe-138	0

TABLE 15.5-50

SUMMARY OF OFFSITE DOSES FROM FUEL HANDLING ACCIDENT INSIDE CONTAINMENT

Thyroid Exposures, rem

	Control Room – 30 Days	Site Boundary - 2 Hours	LPZ - 30 Days
10 CFR Part 100	30 (GDC 19)	300	300
Design-basis case	22.31	60.62	2.52

Whole Body Immersion Exposures, rem

	Control Room – 30 Days	Site Boundary - 2 Hours	LPZ - 30 Days
10 CFR Part 100	5 (GDC 19)	25	25
Design-basis case	7.57×10^{-3}	0.43	0.018

Population Doses, man-rem

Design basis case	8.53
Expected case	3×10^{-3}

TABLE 15.5-51

ACTIVITY RELEASES FOLLOWING A ROD EJECTION ACCIDENT (CURIES)

Design Basis Case

Nuclide	0-2 hr	2-8 hr	8-24 hr	24-96 hr	4-30 Days
I-131	0.9765E-02	0.0	0.0	0.0	0.0
I-132	0.1578E-02	0.0	0.0	0.0	0.0
I-133	0.7394E-02	0.0	0.0	0.0	0.0
I-134	0.1729E-02	0.0	0.0	0.0	0.0
I-135	0.3867E-02	0.0	0.0	0.0	0.0
I-131ORG	0.0	0.0	0.0	0.0	0.0
I-132ORG	0.0	0.0	0.0	0.0	0.0
I-133ORG	0.0	0.0	0.0	0.0	0.0
I-134ORG	0.0	0.0	0.0	0.0	0.0
I-135ORG	0.0	0.0	0.0	0.0	0.0
I-131PAR	0.0	0.0	0.0	0.0	0.0
I-132PAR	0.0	0.0	0.0	0.0	0.0
I-133PAR	0.0	0.0	0.0	0.0	0.0
I-134PAR	0.0	0.0	0.0	0.0	0.0
I-135PAR	0.0	0.0	0.0	0.0	0.0
Kr-83M	0.7646E-01	0.61693-01	0.7366E-02	0.9508E-05	0.2124E-16
Kr-85	0.1066E 01	0.3193E 01	0.8511E 01	0.1912E 02	0.1641E 03
Kr-85M	0.3500E 00	0.5778E 00	0.3377E 00	0.1477E-01	0.1753E-06
Kr-87	0.2570E 00	0.1245E 00	0.4858E 02	0.3842E-06	0.3026E-23
Kr-88	0.7005E 00	0.8383E 00	0.2360E 00	0.2193E-02	0.3293E-10
Xe-133	0.1123E 02	0.3297E 02	0.8275E 02	0.1471E 03	0.2929E 03
Xe-133M	0.1857E 00	0.5299E 00	0.1232E 01	0.1646E 01	0.1117E 01
Xe-135	0.1332E 01	0.2979E 01	0.3650E 01	0.7768E 00	0.3437E-02
Xe-135M	0.2577E-01	0.1253E-03	0.1421E-10	0.2140E-29	0.0
Xe-138	0.7913E-01	0.2070E-03	0.3679E-11	0.3956E-32	0.0

TABLE 15.5-51

ACTIVITY RELEASES FOLLOWING A ROD EJECTION ACCIDENT (CURIES)

Expected Case

Nuclide	0-2 hr	2-8 hr	8-24 hr	24-96 hr	4-30 Days
I-131	0.1645E-02	0.0	0.0	0.0	0.0
I-132	0.2675E-03	0.0	0.0	0.0	0.0
I-133	0.1247E-02	0.0	0.0	0.0	0.0
I-134	0.2963E-03	0.0	0.0	0.0	0.0
I-135	0.6529E-03	0.0	0.0	0.0	0.0
I-131ORG	0.0	0.0	0.0	0.0	0.0
I-132ORG	0.0	0.0	0.0	0.0	0.0
I-133ORG	0.0	0.0	0.0	0.0	0.0
I-134ORG	0.0	0.0	0.0	0.0	0.0
I-135ORG	0.0	0.0	0.0	0.0	0.0
I-131PAR	0.0	0.0	0.0	0.0	0.0
I-132PAR	0.0	0.0	0.0	0.0	0.0
I-133PAR	0.0	0.0	0.0	0.0	0.0
I-134PAR	0.0	0.0	0.0	0.0	0.0
I-135PAR	0.0	0.0	0.0	0.0	0.0
Kr-83M	0.3823E-01	0.3085E-01	0.3684E-02	0.4757E-05	0.1063E-16
Kr-85	0.5339E 00	0.1599E 01	0.4260E 01	0.9570E 01	0.8242E 02
Kr-85M	0.1750E 00	0.2889E 00	0.1689E 00	0.7387E-02	0.8775E-07
Kr-87	0.1285E 00	0.6227E-01	0.2430E-02	0.1922E-06	0.1515E-23
Kr-88	0.3503E 00	0.4192E 00	0.1180E 00	0.1097E-02	0.1648E-10
Xe-133	0.5617E 01	0.1648E 02	0.4139E 02	0.7359E 02	0.1469E 03
Xe-133M	0.9285E-01	0.2650E 00	0.6162E 00	0.8236E 00	0.5596E 00
Xe-135	0.6662E 00	0.1490E 01	0.1826E 01	0.3887E 00	0.1721E-02
Xe-135M	0.1289E-01	0.6268E-04	0.7107E-11	0.1070E-29	0.0
Xe-138	0.3957E-01	0.1035E-03	0.1840E-11	0.1979E-32	0.0

TABLE 15.5-52

SUMMARY OF OFFSITE DOSES FROM A ROD EJECTION ACCIDENT

Thyroid Exposures, rem

	Site Boundary 2 - Hours	LPZ - 30 Days
10 CFR Part 100	300	300
Design basis case	3.3×10^{-3}	1.4×10^{-4}
Expected case	3.7×10^{-5}	1.6×10^{-6}

Whole Body Exposures, rem

	Site Boundary - 2 Hours	LPZ - 30 Days
10 CFR Part 100	25	25
Design basis case	7.3×10^{-4}	1.3×10^{-4}
Expected case	3.6×10^{-5}	6.4×10^{-6}

Population Doses, man-rem

Design basis case	0.54
Expected case	0.027

TABLE 15.5-53

SUMMARY OF OFFSITE DOSES FROM A RUPTURE OF A GAS DECAY TANK

Thyroid Exposures, rem

	Site Boundary 2 - Hours	LPZ - 30 Days
10 CFR Part 100	300	300
Design basis case	negligible	negligible
Expected case	negligible	negligible

Whole Body Exposures, rem

	Site Boundary - 2 Hours	LPZ - 30 Days
10 CFR Part 100	25	25
Design basis case	2.0	8.4×10^{-2}
Expected case	4.4×10^{-2}	1.8×10^{-3}

Population Doses, man-rem

Design basis case	55.1
Expected case	1.21

TABLE 15.5-56

SUMMARY OF OFFSITE DOSES FROM RUPTURE OF A LIQUID HOLDUP TANK

Thyroid Exposures, rem

	Site Boundary 2 - Hours	LPZ - 30 Days
10 CFR Part 100	300	300
Design basis case	1.41	0.432

Whole Body Exposures, rem

	Site Boundary - 2 Hours	LPZ - 30 Days
10 CFR Part 100	25	25
Design basis case	0.152	$6.70x10^{-3}$

TABLE 15.5-57

SUMMARY OF OFFSITE DOSES FROM RUPTURE OF A VOLUME CONTROL TANK

Thyroid Exposures, rem

	Site Boundary - 2 Hours	LPZ - 30 Days
10 CFR Part 100	300	300
Design Basis Case	3.31×10^{-5}	1.38×10^{-6}
Expected Case	4.43×10^{-8}	1.84×10^{-9}

Whole Body Exposures, rem

	Site Boundary - 2 Hours	LPZ - 30 Days
10 CFR Part 100	25	25
Design Basis Case	0.465	0.0193
Expected Case	9.27×10^{-3}	3.86×10^{-4}

Population Doses, man-rem

Design Basis Case	12.72
Expected Case	0.254

TABLE 15.5-63

POST-LOCA DOSES WITH MARGIN RECIRCULATION LOOP LEAKAGE

CONTROL ROOM OPERATOR DOSES (REM)

Pathway	Thyroid	Gamma Whole Body	Beta Skin	Notes
Containment leakage	5.96	0.0394	0.480	
RHR pump seal leakage	0.022	0.0	0.0	1
Expected recirculation loop leakage	0.85	0.00002	0.0014	
Recirculation loop leakage: 1.85 gpm, with charcoal filtration, or 0.186 gpm, with no filtration	18.45	0.0006	0.0083	2
Plume radiation (egress-ingress)	4.72	0.0066	0.0243	3
Other direct radiation pathways	0.00	0.0760	0.00	3
TOTAL CONTROL ROOM OPERATOR DOSES	30.00		-	
10 CFR PART 50 APPENDIX A, GDC 19 LIMITS	30	5	30	

OFFSITE DOSES (REM)

SITE BOUNDARY Pathway	Thyroid	Gamma Whole Body	Notes
Containment leakage	107.06	3.24	
RHR pump seal leakage	0.0	0.0	
Expected recirculation loop leakage	8.22	0.03	
Recirculation loop leakage: 1.88 gpm, with charcoal filtration, or 0.189 gpm, with no filtration	184.72	0.52	2
TOTAL SITE BOUNDARY DOSES	300.00	-	-

LPZ Pathway	Thyroid	Gamma Whole Body	Notes
Containment leakage	19.01	0.293	
RHR pump seal leakage	0.09	0.0	
Expected recirculation loop leakage	2.12	0.003	
Recirculation loop leakage: 11.07 gpm, with charcoal filtration, or 1.11 gpm, with no filtration	278.78	0.44	2
TOTAL LPZ DOSES	300.00	-	-
10 CFR PART 100 DOSE LIMITS	300	25	

Notes:
1. RHR pump seal leakage of 50 gpm for 30 minutes, starting 24 hours after the start of the LOCA, see Tables 15.5-24 and 15.5-33.
2. Additional recirculation loop leakage, existing at the start of the LOCA and continuing for 30 days.
3. Taken from Table 15.5-33.

TABLE 15.5-64

PARAMETERS USED IN EVALUATING
RADIOLOGICAL CONSEQUENCES FOR SGTR ANALYSIS

I. Source Data	
A. Core power level, MWt	3580
B. Total steam generator tube leakage, prior to accident, gpm	1.0
C. Reactor coolant activity:	
1. Accident initiated spike	The initial RC iodine activities based on 1 μCi/gram of D.E. I-131 are presented in Table 15.5-65. The iodine appearance rates based on an iodine spiking factor of 335 assumed for the accident initiated spike are presented in Table 15.5-66
2. Pre-accident spike	Primary coolant iodine activities based on 60 μCi/gram of D.E. I-131 are presented in Table 15.5-65
3. Noble gas activity	The initial RC noble gas activities based on 1% fuel defects are presented in Table 15.5-67
D. Secondary system initial activity	Dose equivalent of 0.1 μCi/gm of I-131, presented in Table 15.5-65
E. Reactor coolant mass, grams	2.27×10^{8}
F. Initial steam generator mass (each), grams	4.07×10^{7}
G. Offsite power	Lost at time of reactor trip
H. Primary-to-secondary leakage duration for intact SG, hrs	8
I. Species of iodine	100 percent elemental

TABLE 15.5-64

PARAMETERS USED IN EVALUATING
RADIOLOGICAL CONSEQUENCES FOR SGTR ANALYSIS

II. Activity Release Data	
A. Ruptured steam generator	
1. Rupture flow	See Figure 15.4.3-6b and Table 15.4-14
2. Flashed rupture flow	See Figure 15.4.3-11 and Table 15.4-14
3. Iodine scrubbing efficiency	Not Modeled
4. Total steam release, lbs	See Figure 15.4.3-9 and Table 15.4-14
5. Iodine partition coefficient	
– non-flashed	100
- flashed	1.0
B. Intact steam generators	
1. Total primary-to-secondary leakage, gpm	1.0
2. Total steam release, lbs	See Figure 15.4.3-10 and Table 15.4-14
3. Iodine partition coefficient	100
C. Condenser	
1. Iodine partition coefficient	100
D. Atmospheric dispersion factors	See Table 15.5-68

TABLE 15.5-65

IODINE SPECIFIC ACTIVITIES
IN THE PRIMARY AND SECONDARY COOLANT[a] - SGTR ANALYSIS

	Specific Activity (µCi/gm)		
	Primary Coolant		Secondary Coolant
Nuclide	1 µCi/gm	60 µCi/gm	0.1 µCi/gm
I-131	0.794	47.64	0.0794
I-132	0.204	12.24	0.0204
I-133	1.113	66.78	0.1113
I-134	0.139	8.34	0.0139
I-135	0.589	35.34	0.0589

(a) Based on 1, 60 and 0.1 µCi/gm of Dose Equivalent I-131 consistent with the DCPP Technical Specifications (Reference 22).

TABLE 15.5-66

IODINE SPIKE APPEARANCE RATES[a] - SGTR ANALYSIS
(CURIES/SECOND)

I-131	I-132	I-133	I-134	I-135
2.46	1.92	4.14	2.75	3.10

(a) The accident initiated spike appearance rate is 335 times the equilibrium appearance rate. The equilibrium appearance rate is calculated based on a total letdown flow of 143 gpm. This total is comprised of 120 gpm with perfect cleanup, a letdown flow uncertainty of 12 gpm, 10 gpm identified reactor coolant system leakage, and 1 gpm unidentified leakage from the reactor coolant system.

TABLE 15.5-67

NOBLE GAS SPECIFIC ACTIVITIES IN THE
REACTOR COOLANT[(a)] BASED ON 1% FUEL DEFECTS - SGTR ANALYSIS

Nuclide	Specific Activity (μCi/gm)
Xe-131m	2.523
Xe-133m	3.911
Xe-133	256.3
Xe-135m	0.449
Xe-135	8.663
Xe-138	0.568
Kr-85m	2.141
Kr-85	6.209
Kr-87	1.232
Kr-88	3.907

(a) Based on a 2 year fuel cycle at a core power of 3580 MWt, a 75 gpm reactor coolant system letdown flow rate, and a 90% demineralizer iodine removal efficiency.

TABLE 15.5-68

ATMOSPHERIC DISPERSION FACTORS AND BREATHING RATES - SGTR ANALYSIS

OFFSITE EXPOSURE

Time (hours)	Exclusion Area Boundary χ/Q (Sec/m^3)	Low Population Zone χ/Q (Sec/m^3)	Breathing Rate[a] (m^3/Sec)
0-2	5.29×10^{-4}	2.2×10^{-5}	3.47×10^{-4}
2-8	-	2.2×10^{-5}	3.47×10^{-4}

CONTROL ROOM EXPOSURE

Time (hours)	Control Room Filtered Pressurization χ/Q (Sec/m^3)	Control Room Unfiltered Pressurization Zone χ/Q (Sec/m^3)	Control Room Breathing Rate[a] (m^3/Sec)
0-8	7.05×10^{-5}	1.96×10^{-4}	3.47×10^{-4}
8-24	5.38×10^{-5}	1.49×10^{-4}	3.47×10^{-4}
24-96	3.91×10^{-5}	1.08×10^{-4}	3.47×10^{-4}
>96	2.27×10^{-5}	6.29×10^{-5}	3.47×10^{-4}

(a) Regulatory Guide 1.4, Revision 2, June 1974 (Note: Although revision 2 was referenced in the analysis, the breathing rates are the same as those in revision 1 which is the DCPP licensing basis)

TABLE 15.5-69

THYROID DOSE CONVERSION FACTORS[a] - SGTR ANALYSIS

Nuclide	
I-131	1.07×10^6 (Rem/Curie)
I-132	6.29×10^3 (Rem/Curie)
I-133	1.81×10^5 (Rem/Curie)
I-134	1.07×10^3 (Rem/Curie)
I-135	3.14×10^4 (Rem/Curie)

[a] International Commission on Radiological Protection Publication 30, 1979.

TABLE 15.5-70

AVERAGE GAMMA AND BETA ENERGY FOR NOBLE GASES[(a)] - SGTR ANALYSIS
(MeV/dis)

Nuclide	$\bar{E}_\gamma$	$\bar{E}_\beta$
I-131	0.38	0.19
I-132	2.2	0.52
I-133	0.6	0.42
I-134	2.6	0.69
I-135	1.4	0.43
Xe-131m	0.0029	0.16
Xe-133m	0.02	0.21
Xe-133	0.03	0.15
Xe-135m	0.43	0.099
Xe-135	0.25	0.32
Xe-138	1.2	0.66
Kr-85m	0.16	0.25
Kr-85	0.0023	0.25
Kr-87	0.79	1.3
Kr-88	2.2	0.25

(a) ENDF-223, October 1975 (Reference 36)

TABLE 15.5-71

OFFSITE RADIATION DOSES FROM SGTR ACCIDENT

	Dose (Rem)	
	Calculated Value	Allowable Guideline Value (Reference 37)
1. Accident Initiated Iodine Spike		
Exclusion Area Boundary (0-2 hr.) Thyroid CDE	27	30.5[a]
Low Population Zone (0-8 hr.) Thyroid CDE	1.5	30
2. Pre-Accident Iodine Spike		
Exclusion Area Boundary (0-2 hr.) Thyroid CDE	67	300
Low Population Zone (0-8 hr.) Thyroid CDE	3.2	300
3. Accident Initiated Iodine Spike Whole-Body Gamma Dose		
Exclusion Area Boundary (0-2 hr.) Whole Body Gamma DDE	0.2	2.5
Low Population Zone (0-8 hr.) Whole-Body Gamma DDE	0.02	2.5
4. Pre-Accident Initiated Iodine Spike Whole-Body Gamma Dose		
Exclusion Area Boundary (0-2 hr.) Whole Body Gamma DDE	0.3	25
Low Population Zone (0-8 hr.) Whole-Body Gamma DDE	0.02	25

[a] Note: A dose limit of 30.5 rem has been approved by the NRC based on OSGs. Refer to Section 15.5.20.2.1(5) for further discussion.

TABLE 15.5-72

CONTROL ROOM PARAMETERS USED IN EVALUATING RADIOLOGICAL CONSEQUENCES FOR SGTR ANA;YSIS

Control Room Isolation Signal Generated	Time of Safety Injection Signal
Delay in Control Room Isolation After Isolation Signal is Generated	35 seconds
Control Room Volume	170,000 ft^3
Control Room Unfiltered In-Leakage	10 cfm
Control Room Unfiltered Inflow	
Normal Mode	4200 cfm
Emergency Mode	0 cfm
Control Room Filtered Inflow	
Normal Mode	0 cfm
Emergency Mode	2100 cfm
Control Room Filtered Recirculation	
Normal Mode	0 cfm
Emergency Mode	2100 cfm
Control Room Filter Efficiency	95%

TABLE 15.5-74

CONTROL ROOM RADIATION DOSES FROM AIRBORNE ACTIVITY
IN SGTR ACCIDENT

	Accident Initiated Iodine Spike, rem	Pre-Accident Iodine Spike, rem	GDC 19 Guideline, rem
Thyroid CDE (0-30 days)	0.2	0.8	30
Whole Body DDE (0-30 days)	.002	.002	5
Beta Skin SDE (0-30 days)	0.09	0.09	30

TABLE 15.5-75

SUMMARY OF POST-LOCA DOSES FROM VARIOUS PATHWAYS
(DF OF 100)

THYROID DOSES, rem

	EAB - 2 hours	LPZ - 30 days
10 CFR Part 100	300	300
Containment Leakage	107.06	19.01
RHR Pump Seal (50 gpm)	0	0.09
Pre-existing leak (1910 cc/hr)	8.22	2.12
Total	115.28	21.22

WHOLE BODY DOSES, rem

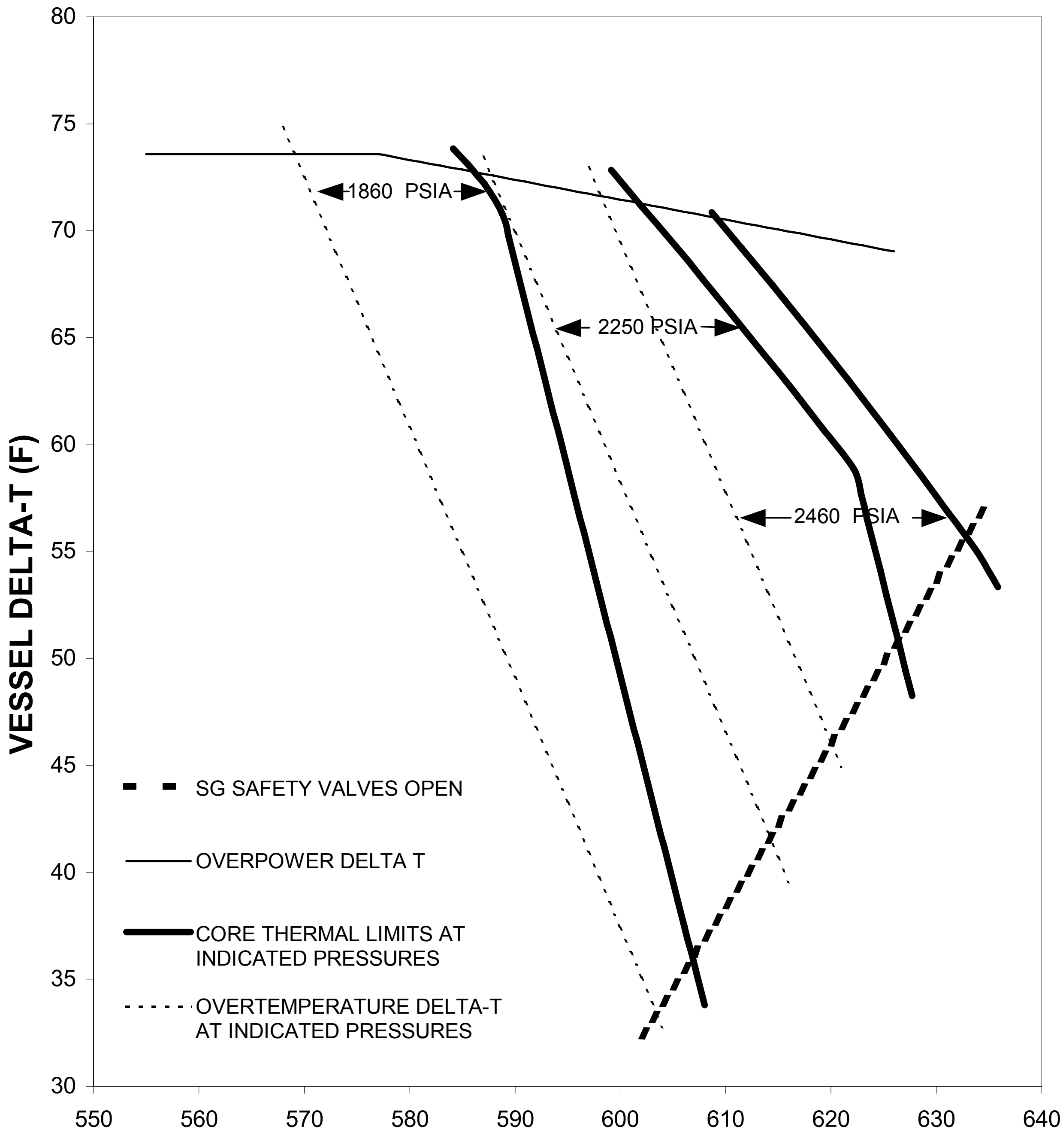
	EAB - 2 hours	LPZ - 30 days
10 CFR Part 100	25	25
Containment Leakage	3.24	0.293
RHR Pump Seal (50 gpm)	0.0	0.0
Pre-existing leak (1910 cc/hr)	0.03	0.003
Total	3.27	0.296

TABLE 15.5-76

WHOLE BODY DOSE CONVERSION FACTORS[(a)(b)]
DOSE EQUIVALENT XE-133

Nuclide	
Kr-85m	7.48E-15 (Sv m^3/Bq s)
Kr-87	4.12E-14 (Sv m^3/Bq s)
Kr-88	1.02E-13 (Sv m^3/Bq s)
Xe-133m	1.37E-15 (Sv m^3/Bq s)
Xe-133	1.56E-15 (Sv m^3/Bq s)
Xe-135m	2.04E-14 (Sv m^3/Bq s)
Xe-135	1.19E-14 (Sv m^3/Bq s)
Xe-138	5.77E-14 (Sv m^3/Bq s)

(a) Table III.1 of Federal Guidance Report 12, EPA-402-R-93-081, 1993.
(b) Note the AOR used conservative values with respect to the above.



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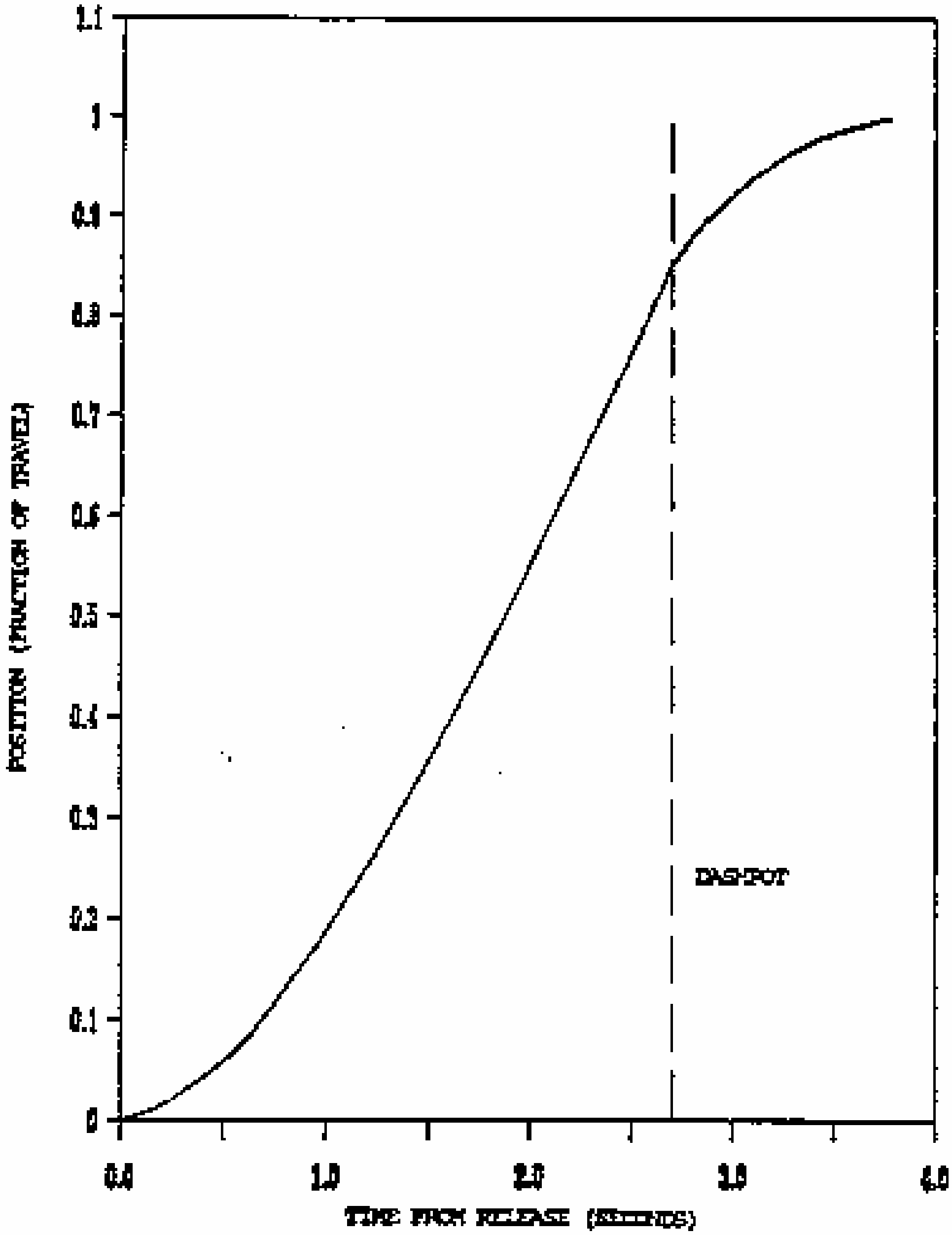
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.1-1 ILLUSTRATION OF OVERPOWER AND OVERTEMPERATURE ∆T PROTECTION



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DIABLO CANYON SITE

FIGURE 15.1-2
ROD POSITION VERSUS TIME
ON REACTOR TRIP

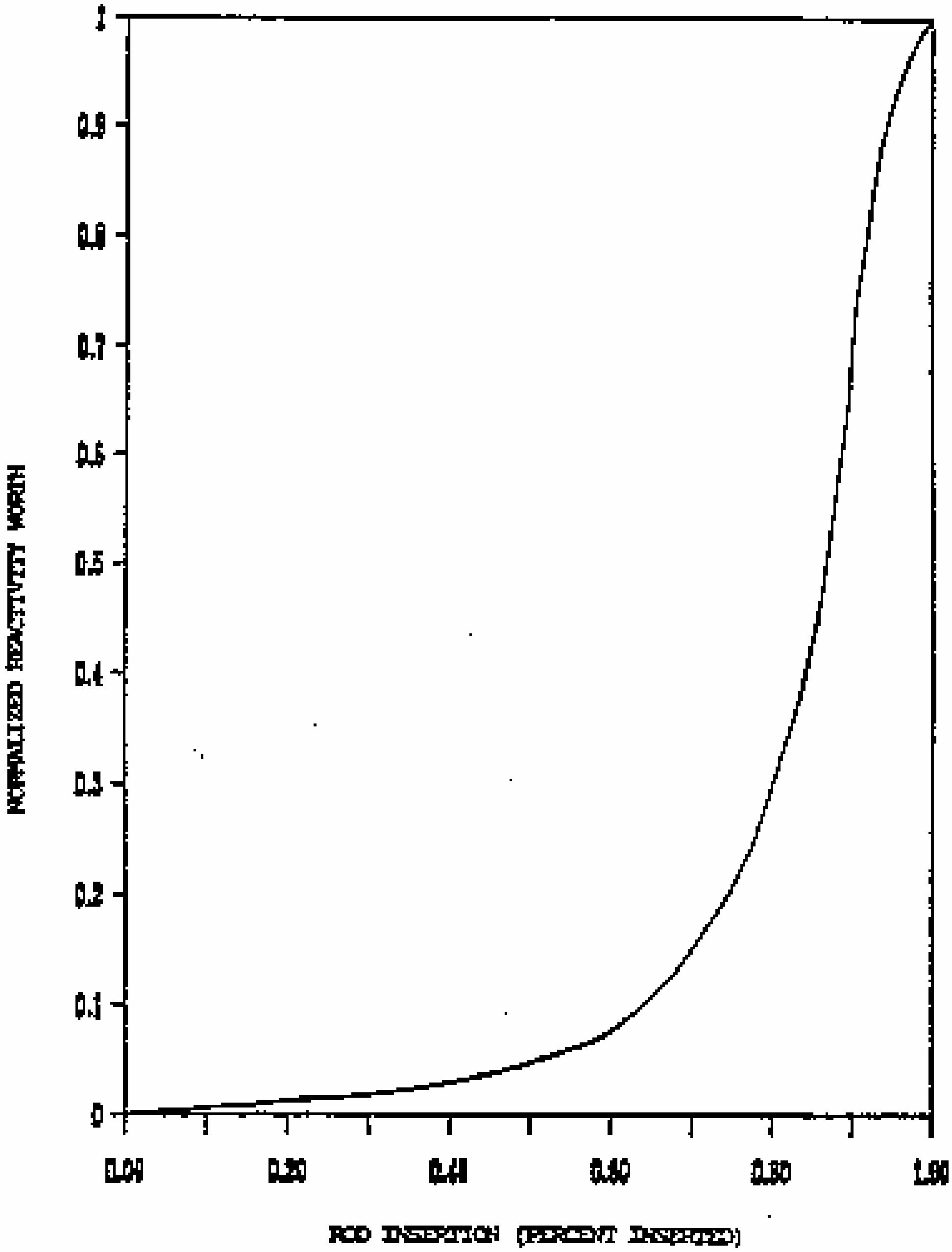

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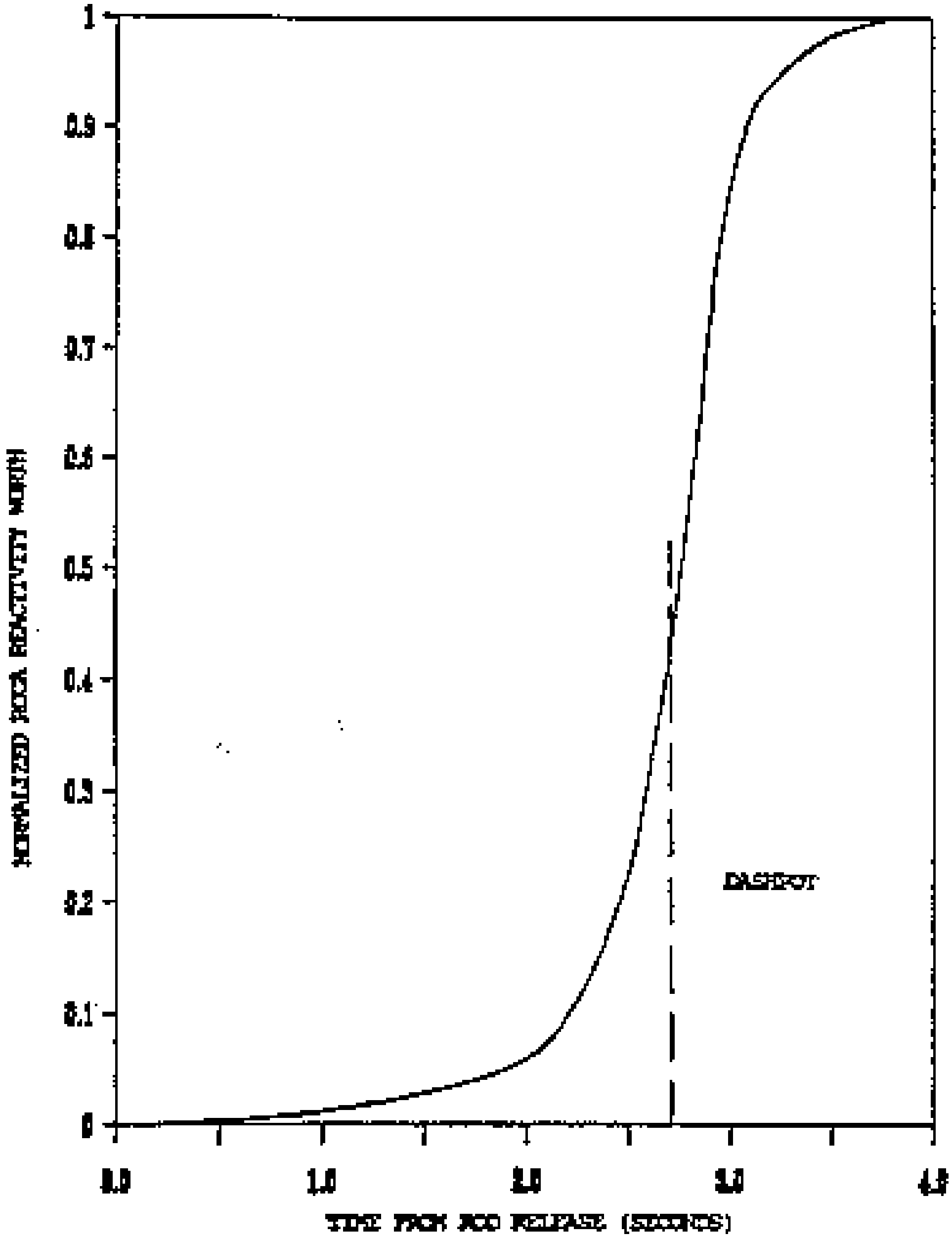
FIGURE 15.1-3
NORMALIZED RCCA REACTIVITY WORTH VERSUS PERCENT INSERTION



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UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.1-4
NORMALIZED RCCA BANK REACTIVITY WORTH VERSUS TIME AFTER TRIP

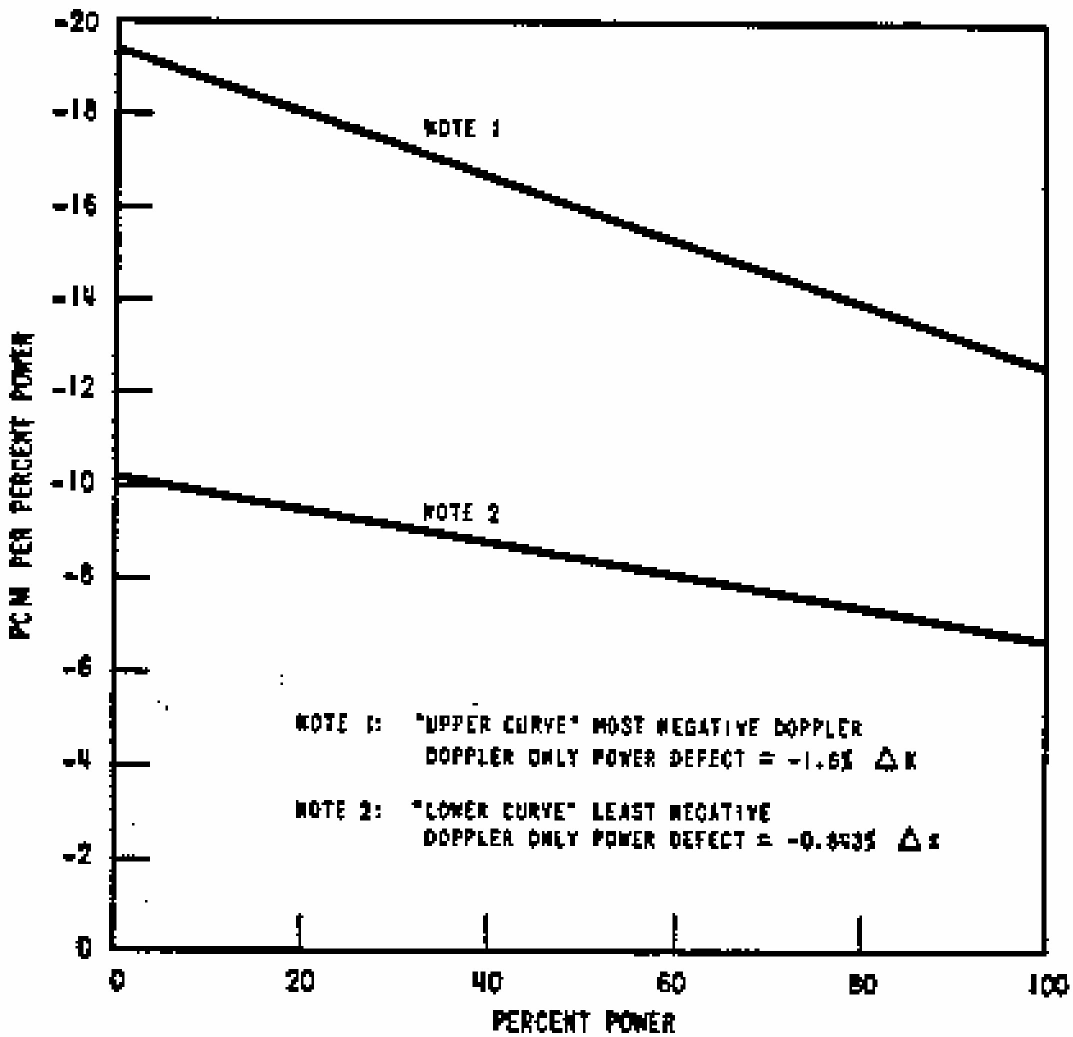

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FIGURE 15.1-5 DOPPLER POWER COEFFICIENT USED IN ACCIDENT ANALYSIS

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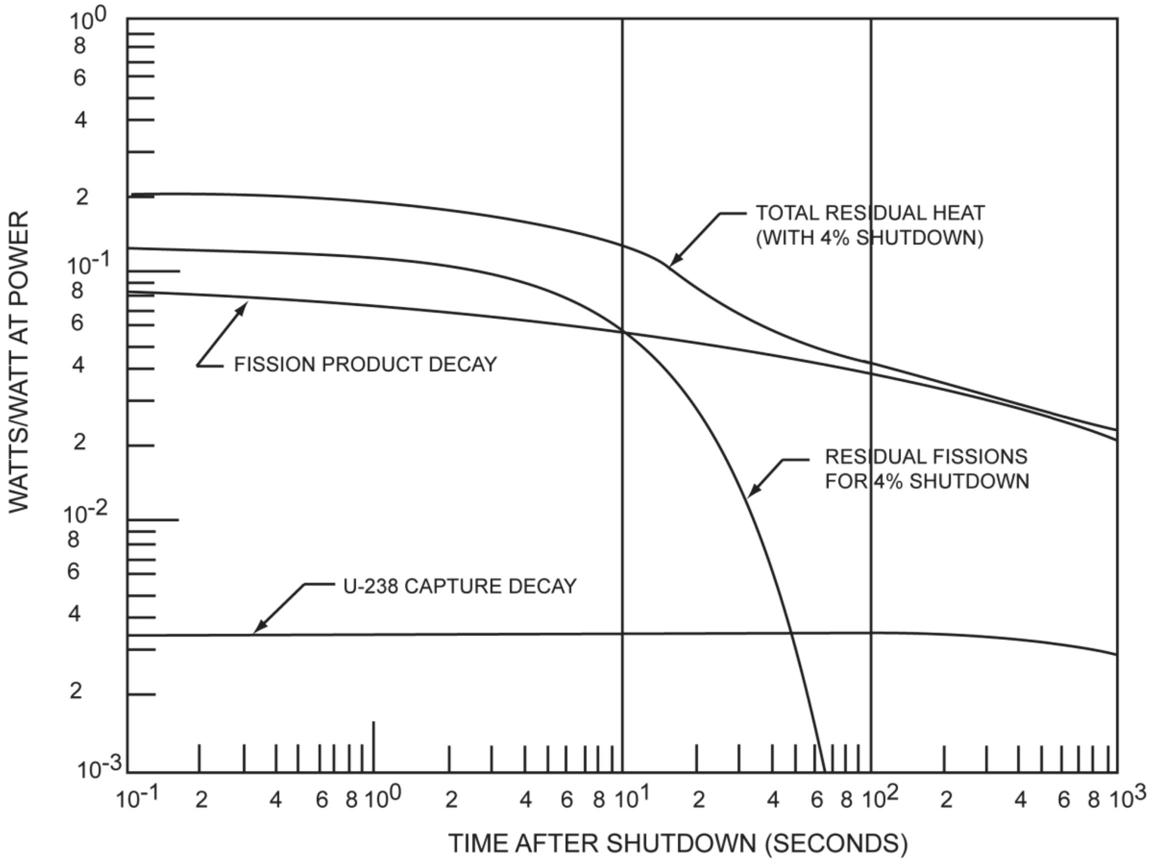

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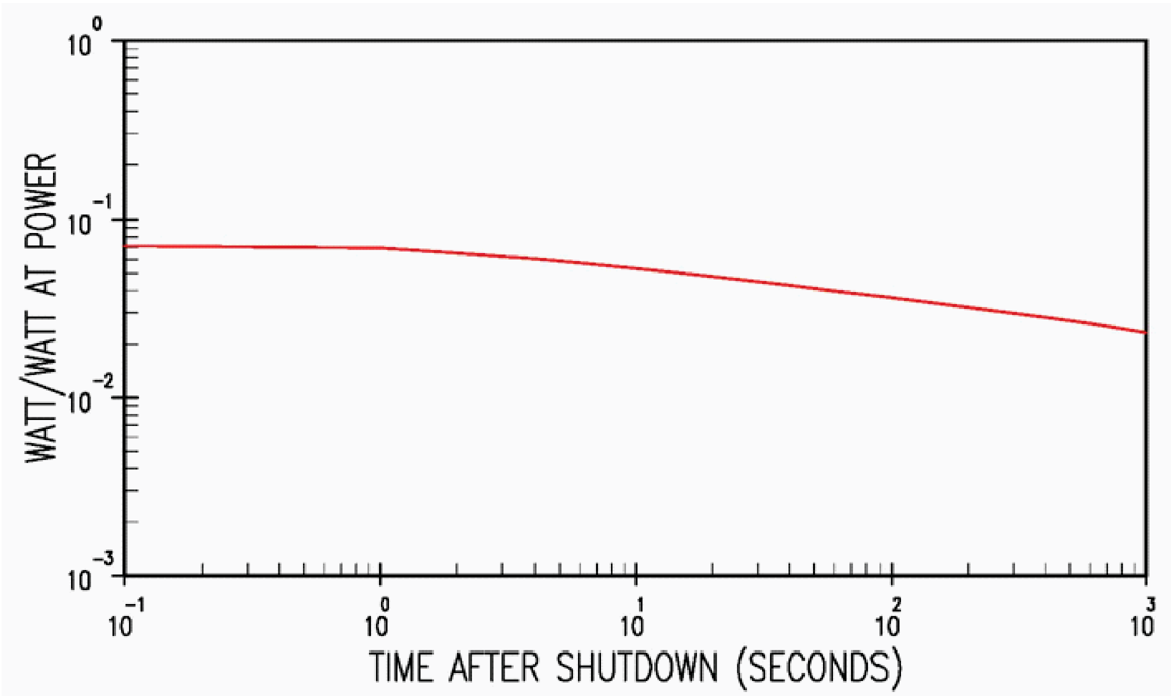
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.1-6 RESIDUAL DECAY HEAT (BEST ESTIMATE LBLOCA 1979 ANS DECAY HEAT)



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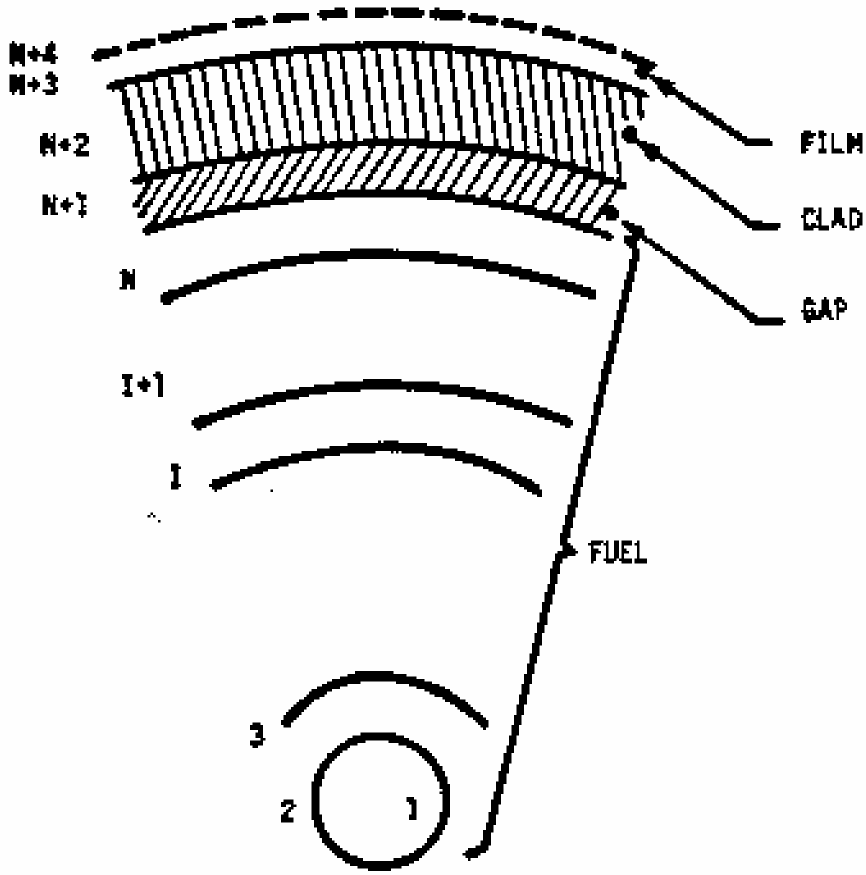
UNITS 1 AND 2 **DIABLO CANYON SITE**
FIGURE 15.1-7 **1979 ANS DECAY** **HEAT CURVE** **(USED FOR NON-LOCA ANALYSES)**



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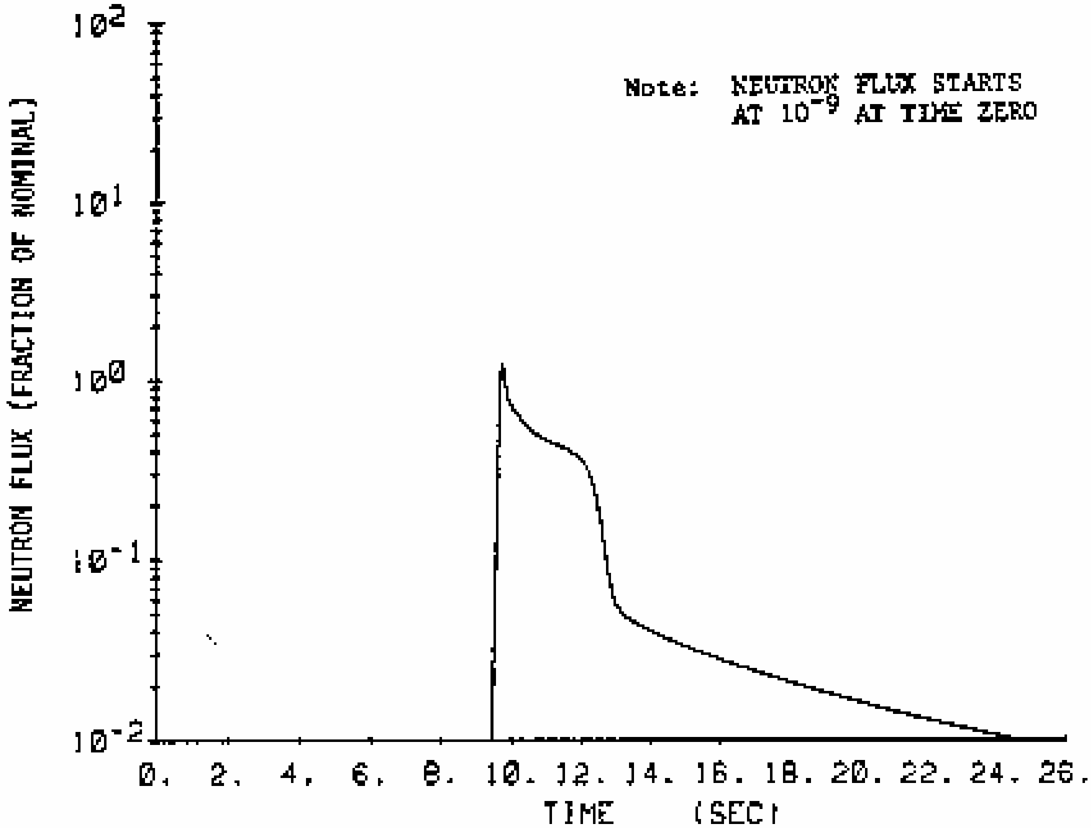
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.1-8

FUEL ROD CROSS SECTION



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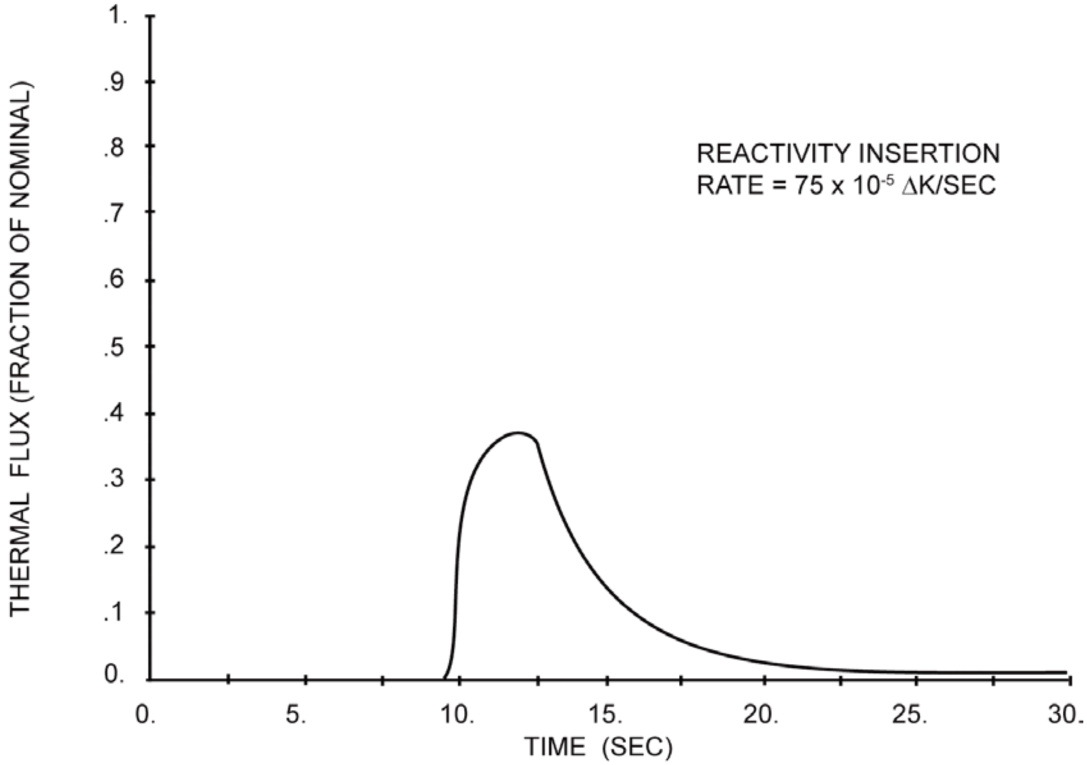
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.1-1 UNCONTROLLED ROD WITHDRAWAL FROM A SUBCRITICAL CONDITION NEUTRON FLUX VERSUS TIME



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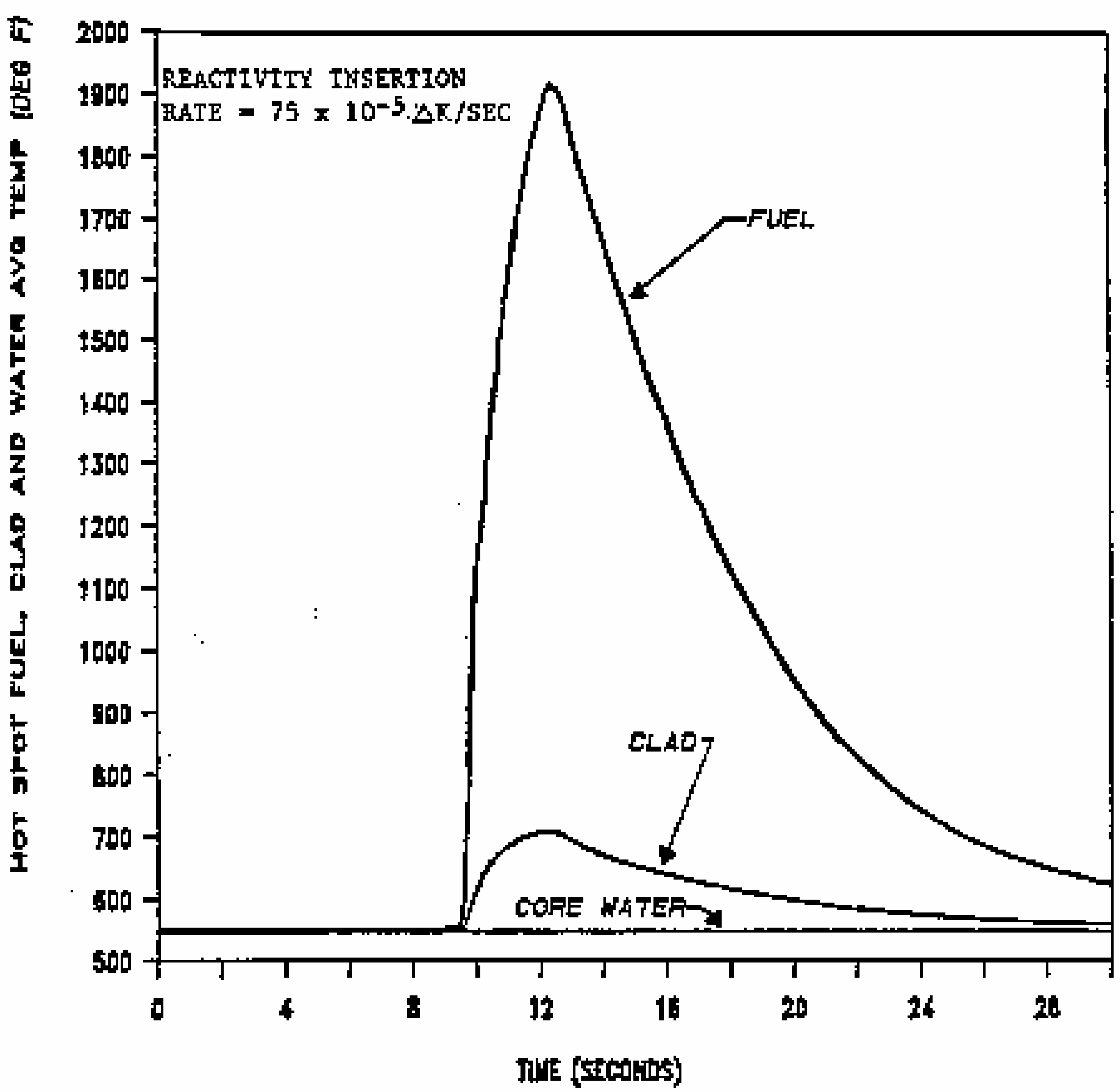
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.1-2 UNCONTROLLED ROD WITHDRAWAL FROM A SUBCRITICAL CONDITION AVERAGE CHANNEL THERMAL FLUX VERSUS TIME



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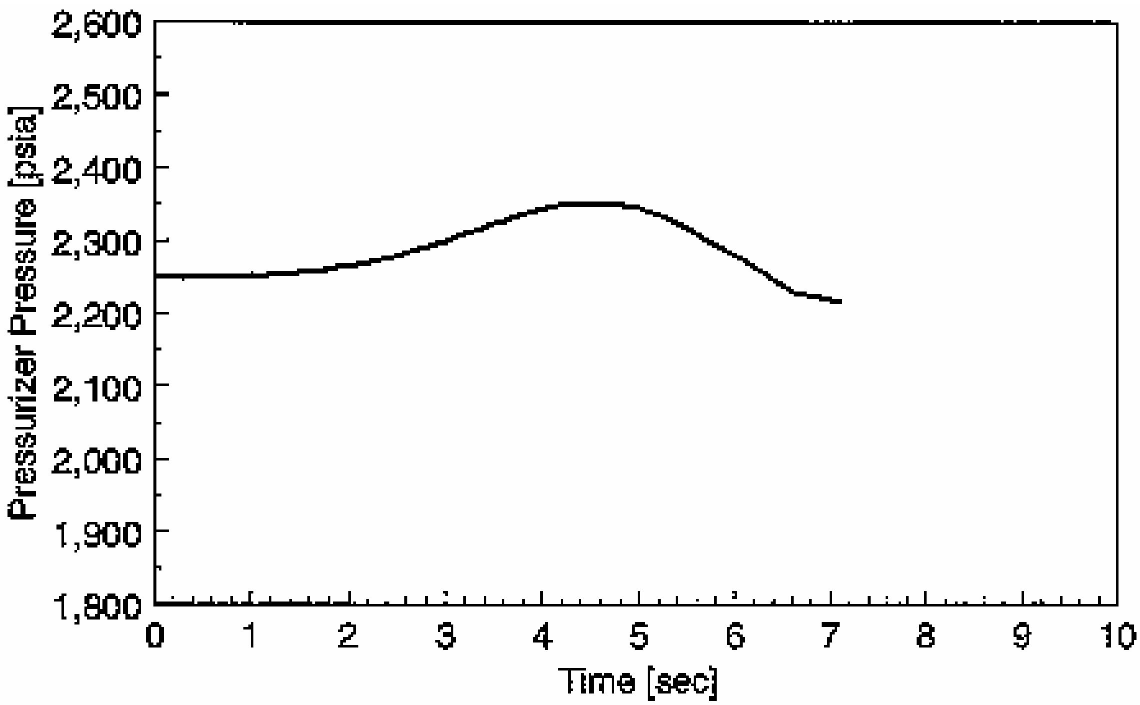
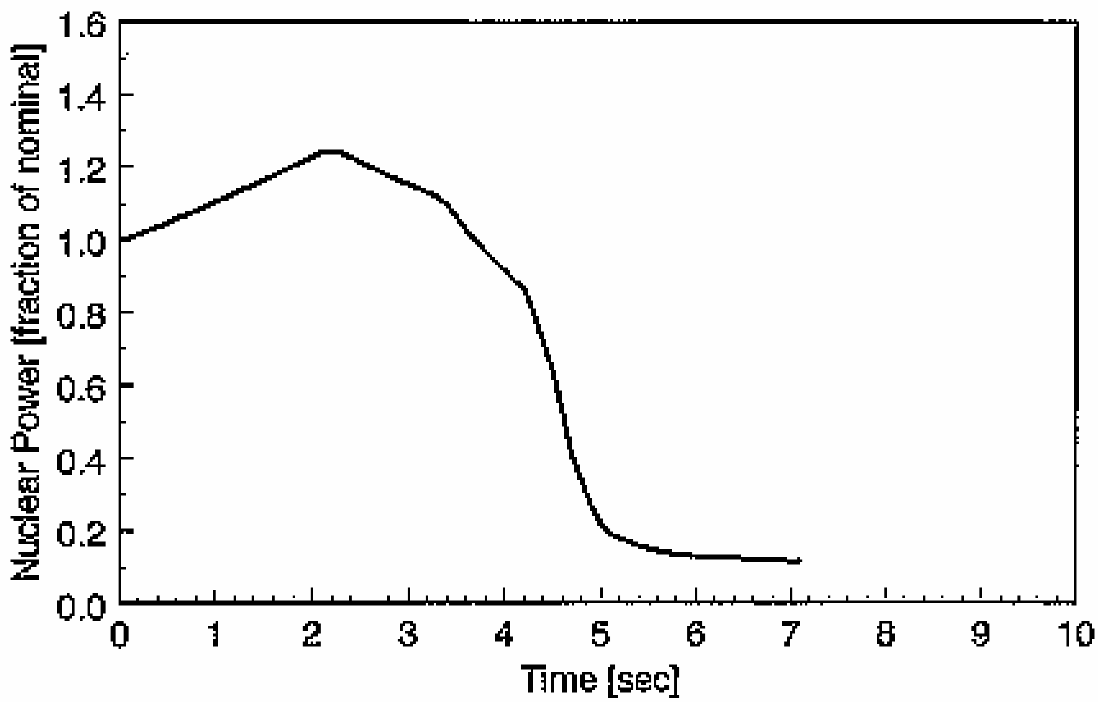
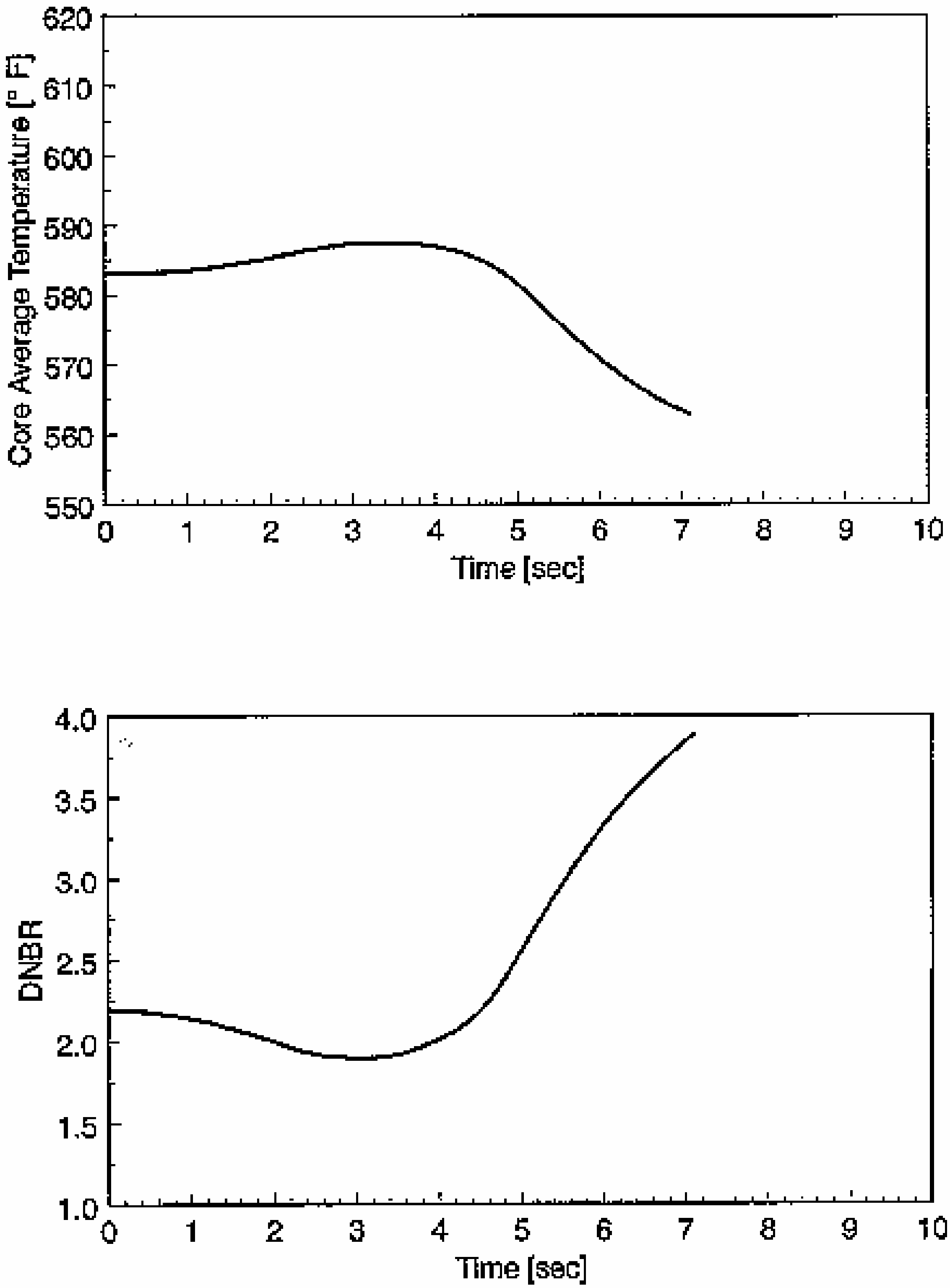
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.1-3 UNCONTROLLED ROD WITHDRAWAL FROM A SUBCRITICAL CONDITION TEMPERATURE VERSUS TIME. REACTIVITY INSERTION RATE 75 X 10^{-5} DELTA K/SEC

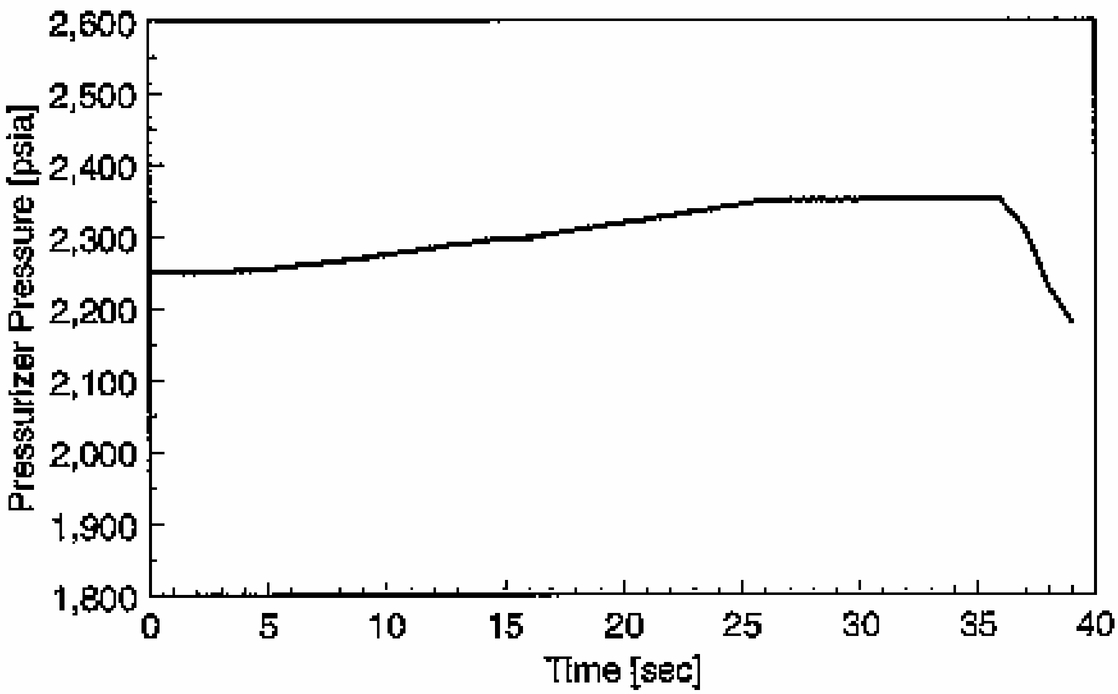


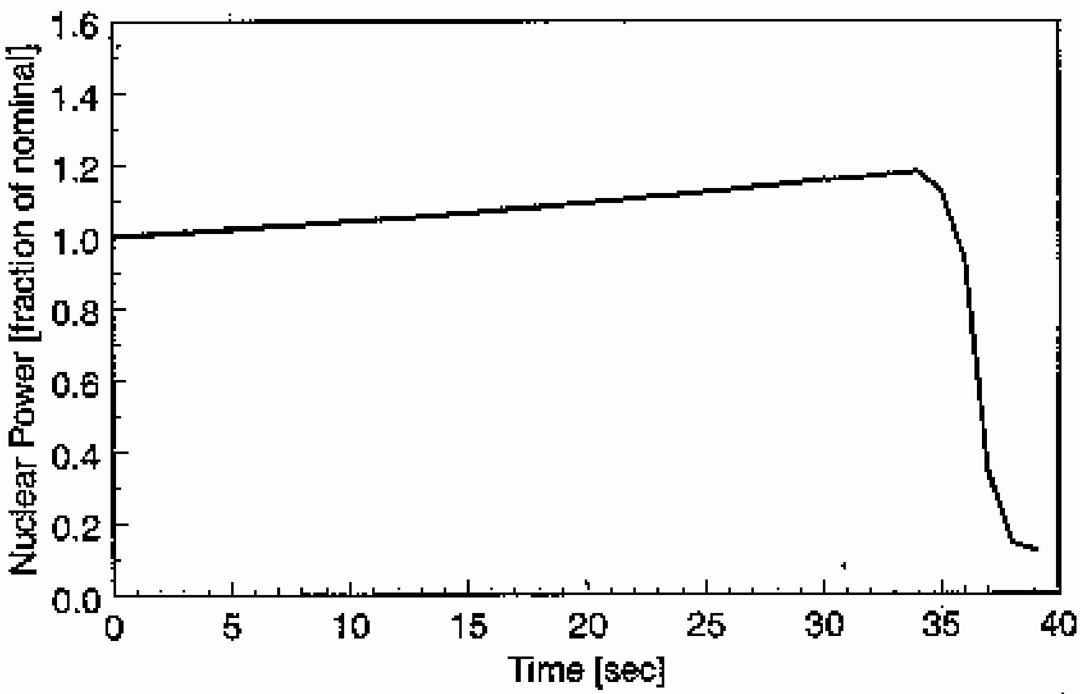


ROD WITHDRAWAL AT POWER **Minimum Feedback, 75 pcm/sec Insertion Rate**	**DIABLO CANYON UNITS 1 & 2**
	FIGURE 15.2.2-1

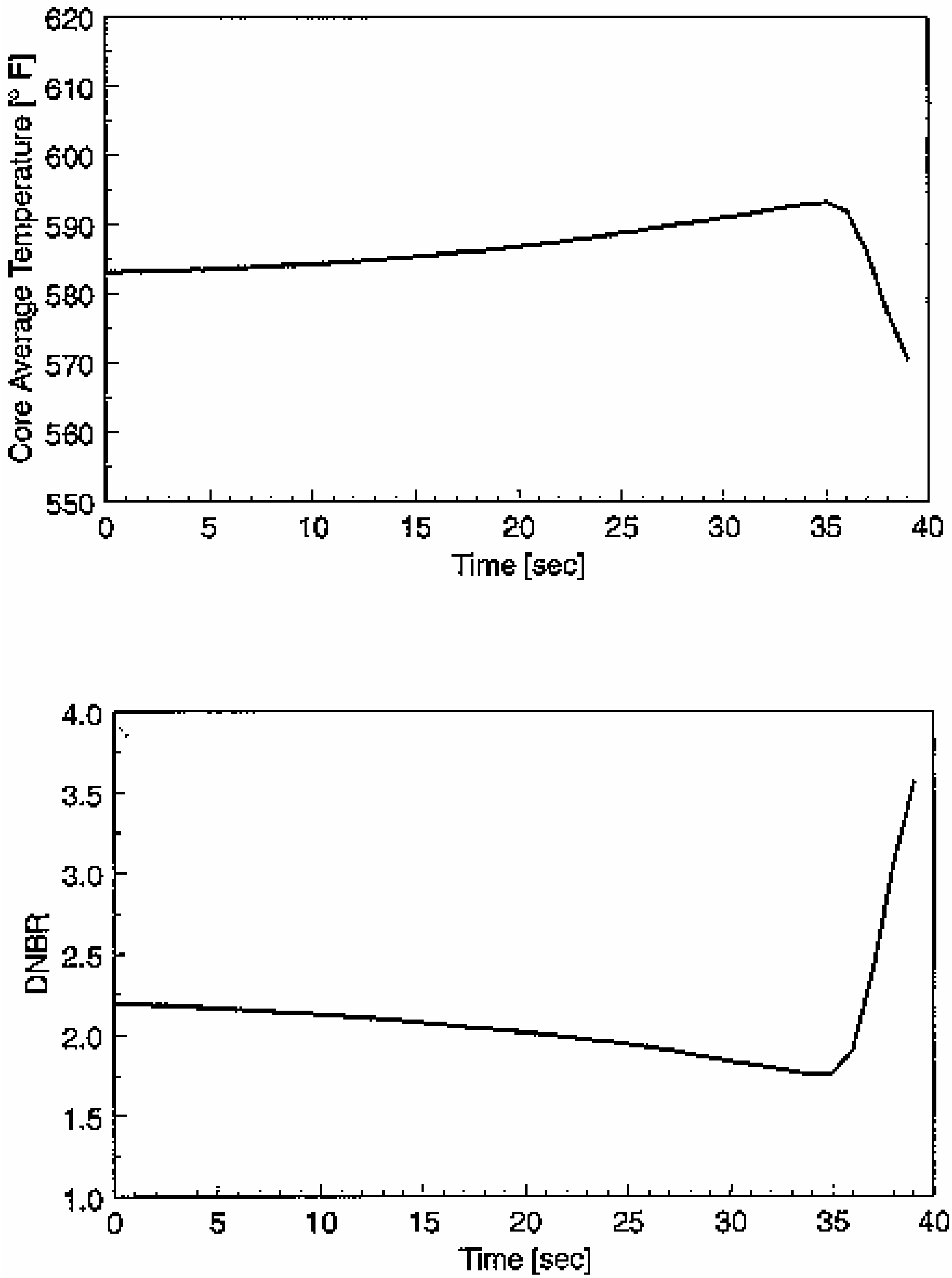


ROD WITHDRAWAL AT POWER Minimum Feedback, 75 pcm/sec Insertion Rate	DIABLO CANYON UNITS 1 & 2
	FIGURE 15.2.2-2

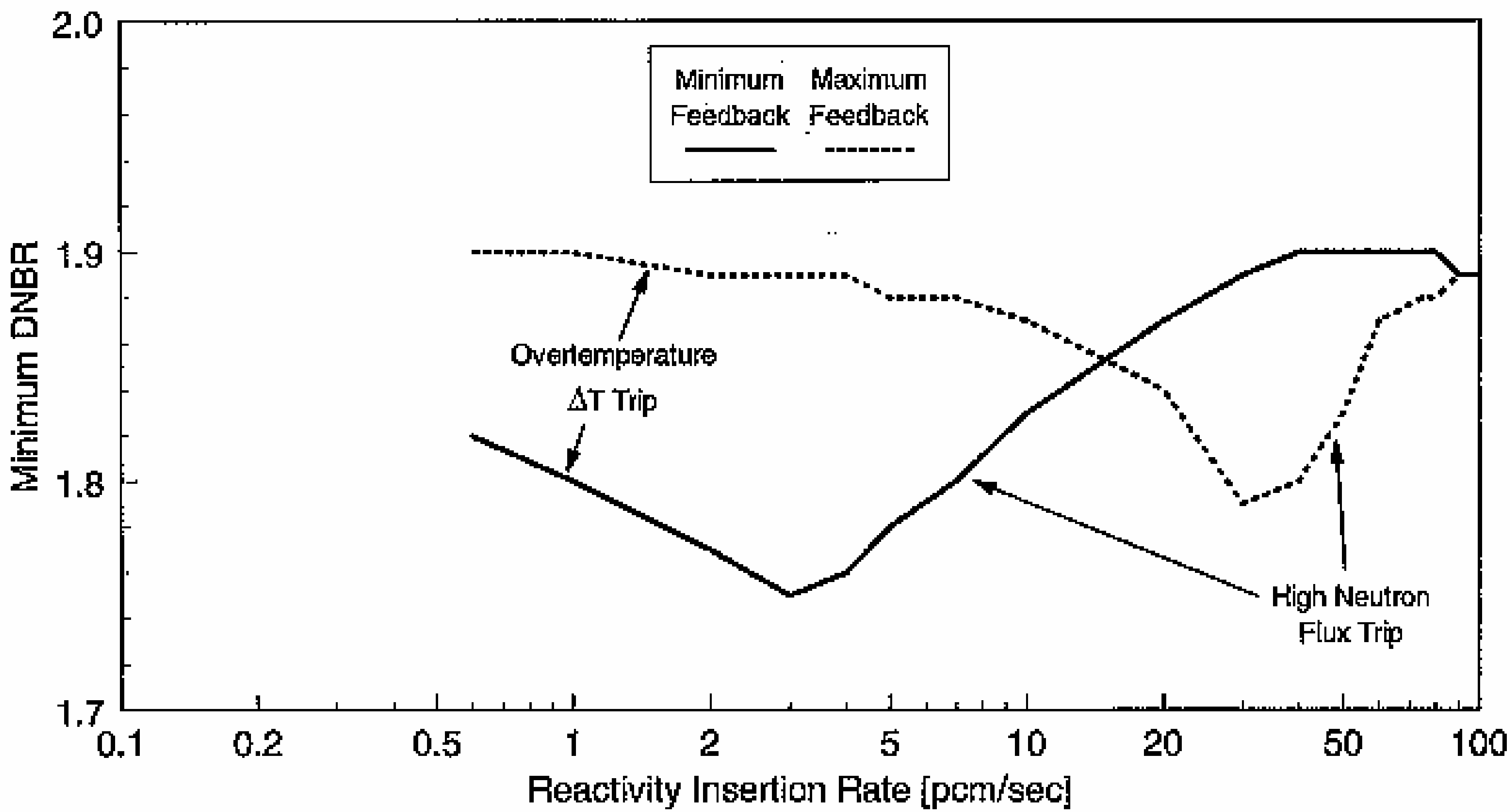




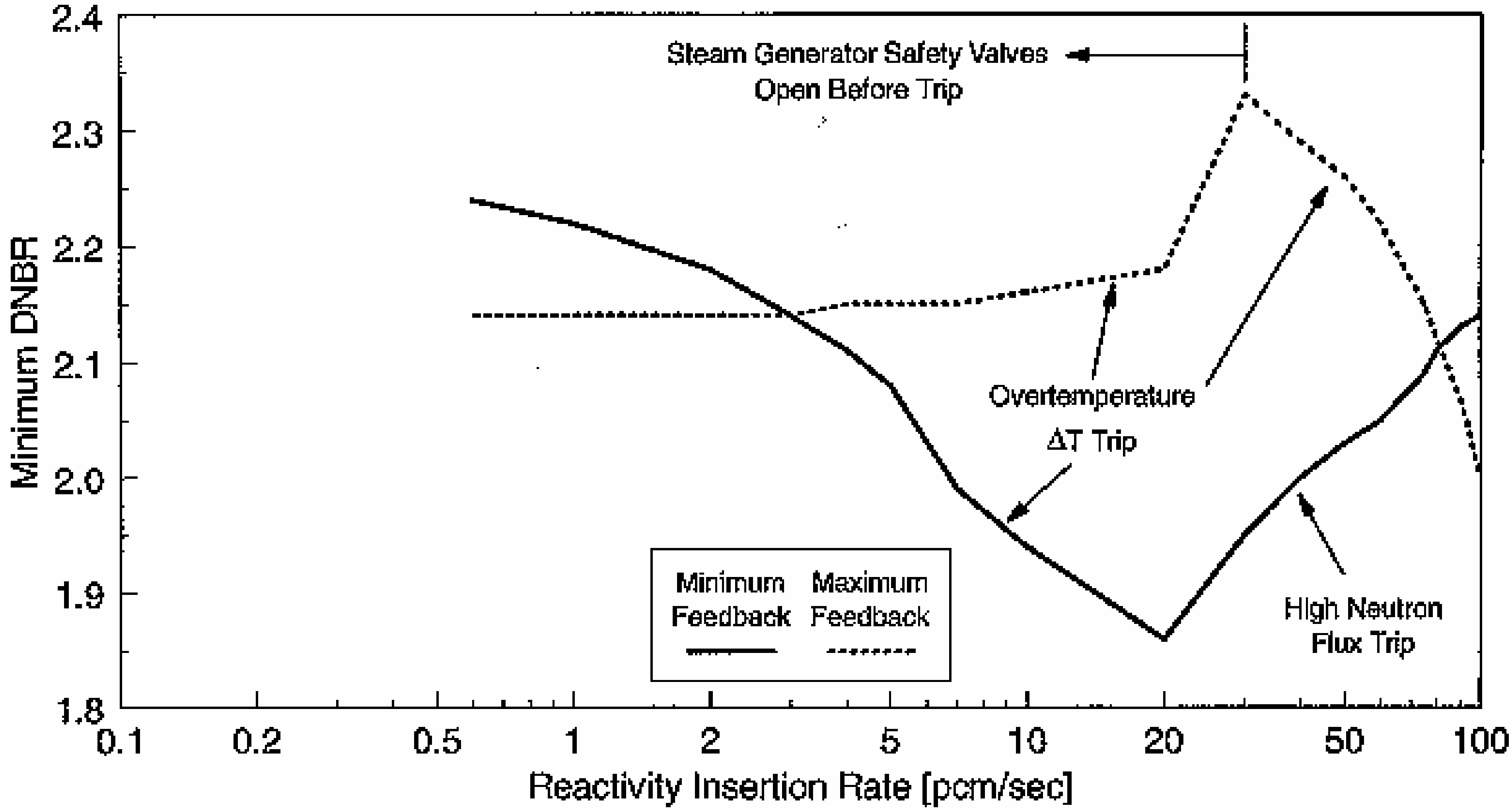
ROD WITHDRAWAL AT POWER **Minimum Feedback, 3 pcm/sec Insertion Rate**	**DIABLO CANYON UNITS 1 & 2**
	FIGURE 15.2.2-3



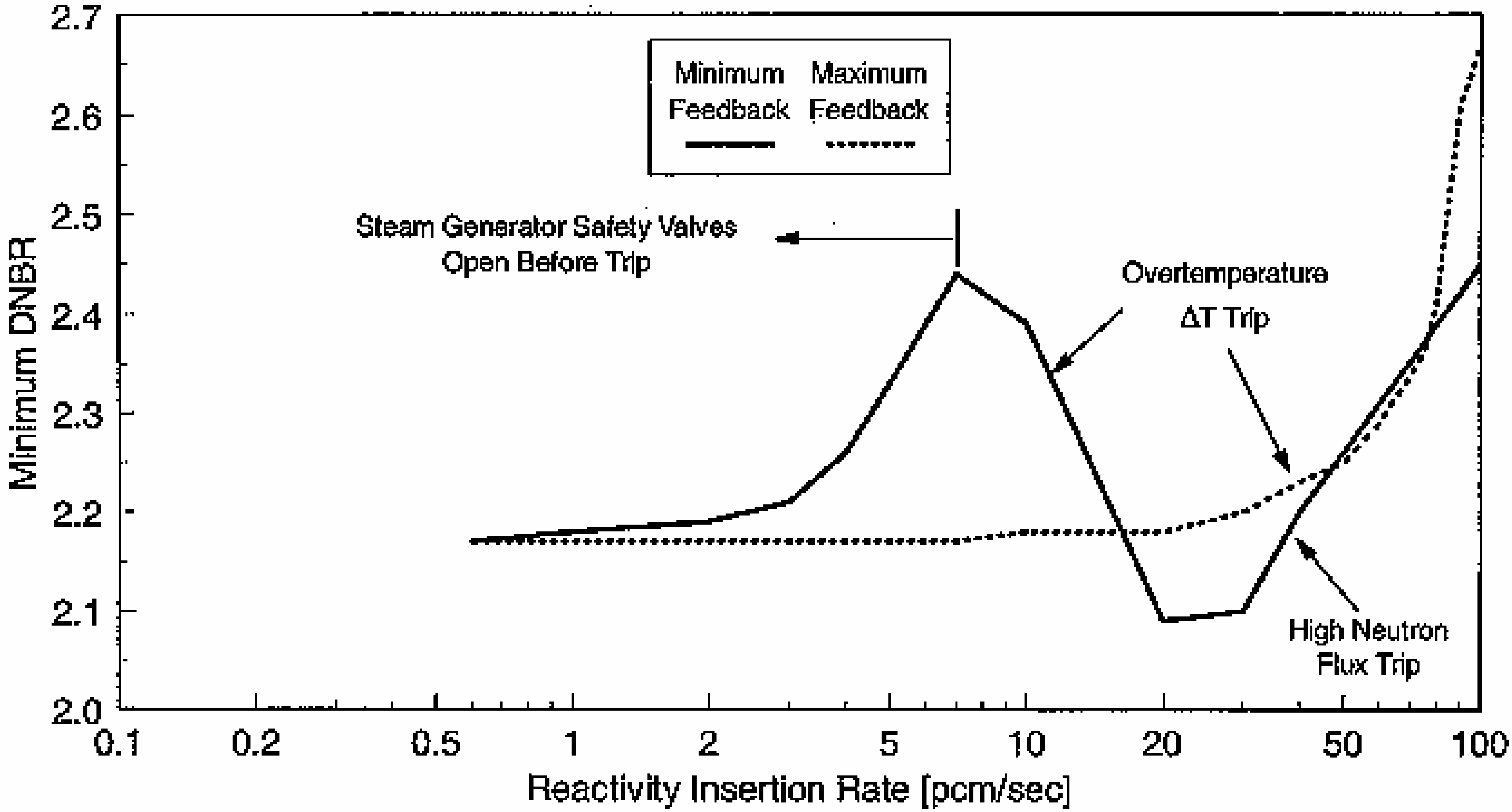
ROD WITHDRAWAL AT POWER **Minimum Feedback, 3 pcm/sec Insertion Rate**	**DIABLO CANYON UNITS 1 & 2** **FIGURE 15.2.2-4**



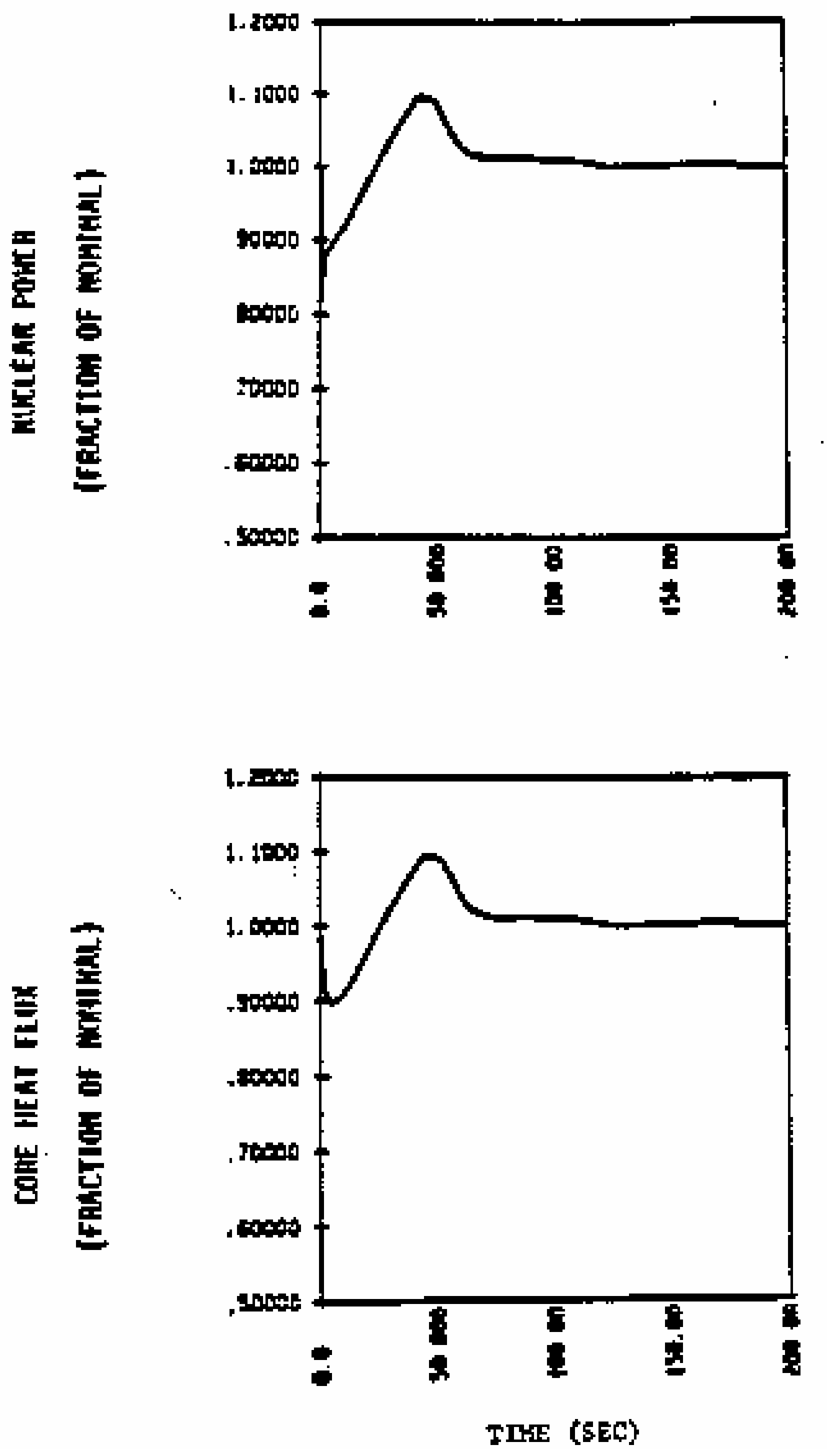
ROD WITHDRAWAL AT POWER **Reactivity Insertion Rate vs. DNBR** **For 100% Power Cases**	**DIABLO CANYON UNITS 1 & 2** **FIGURE 15.2.2-5**



ROD WITHDRAWAL AT POWER Reactivity Insertion Rate vs. DNBR For 60% Power Cases	DIABLO CANYON UNITS 1 & 2
	FIGURE 15.2.2-6



ROD WITHDRAWAL AT POWER **Reactivity Insertion Rate vs. DNBR** **For 10% Power Cases**	**DIABLO CANYON UNITS 1 & 2** **FIGURE 15.2.2-7**



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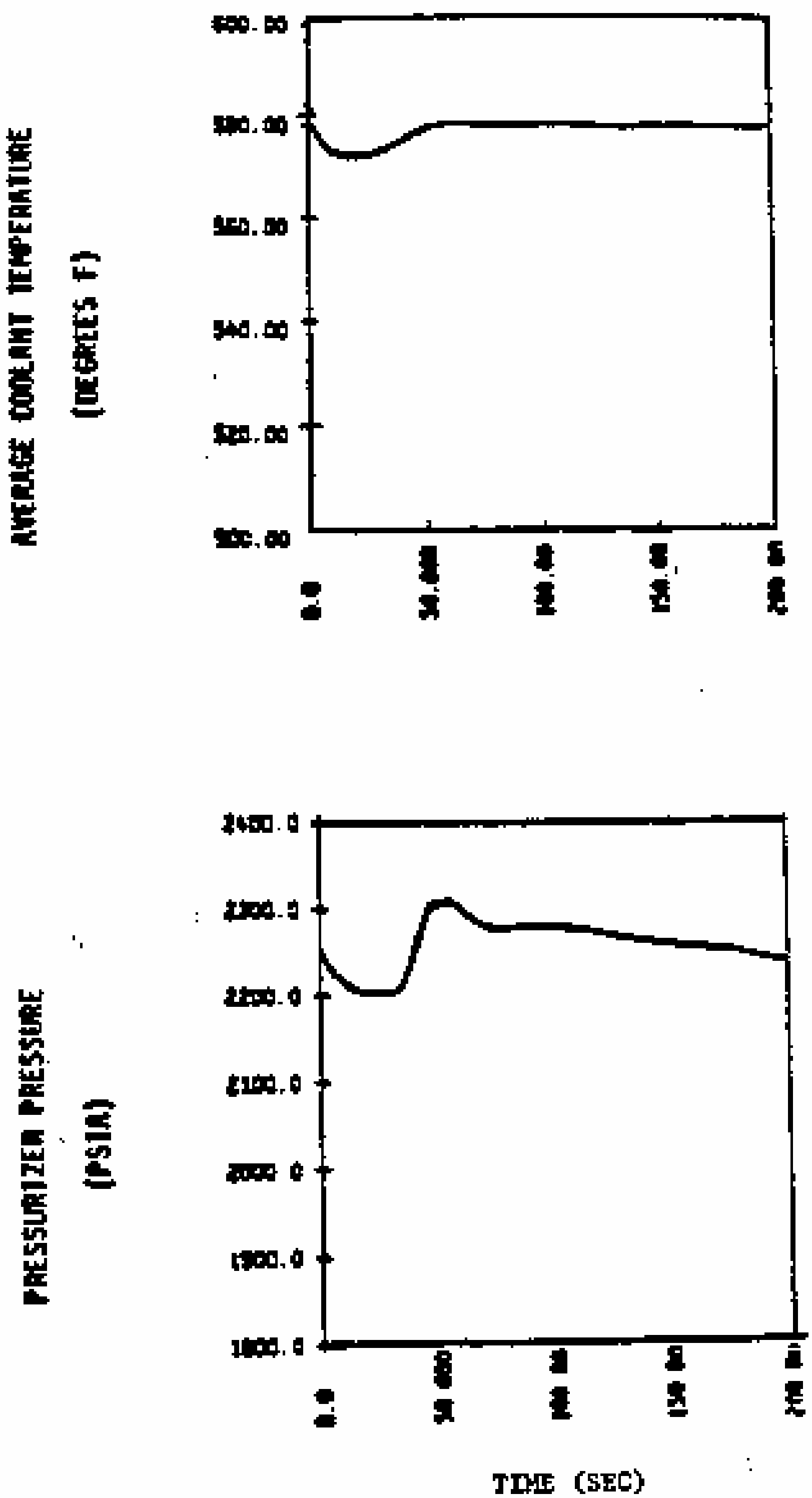
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.2.3-1
TRANSIENT RESPONSE TO DROPPED ROD CLUSTER CONTROL ASSEMBLY



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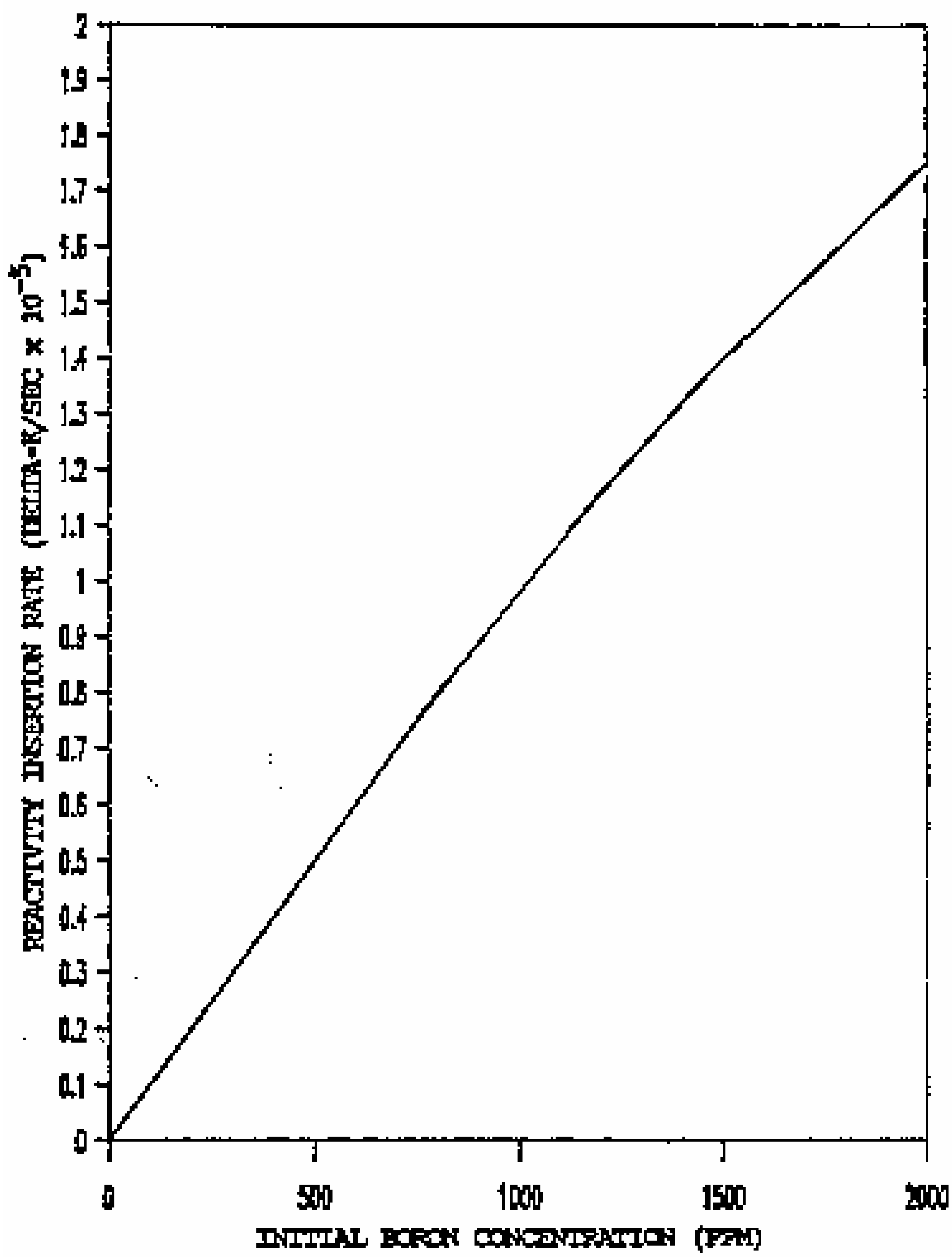
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.2.3-2
TRANSIENT RESPONSE TO DROPPED ROD CLUSTER CONTROL ASSEMBLY



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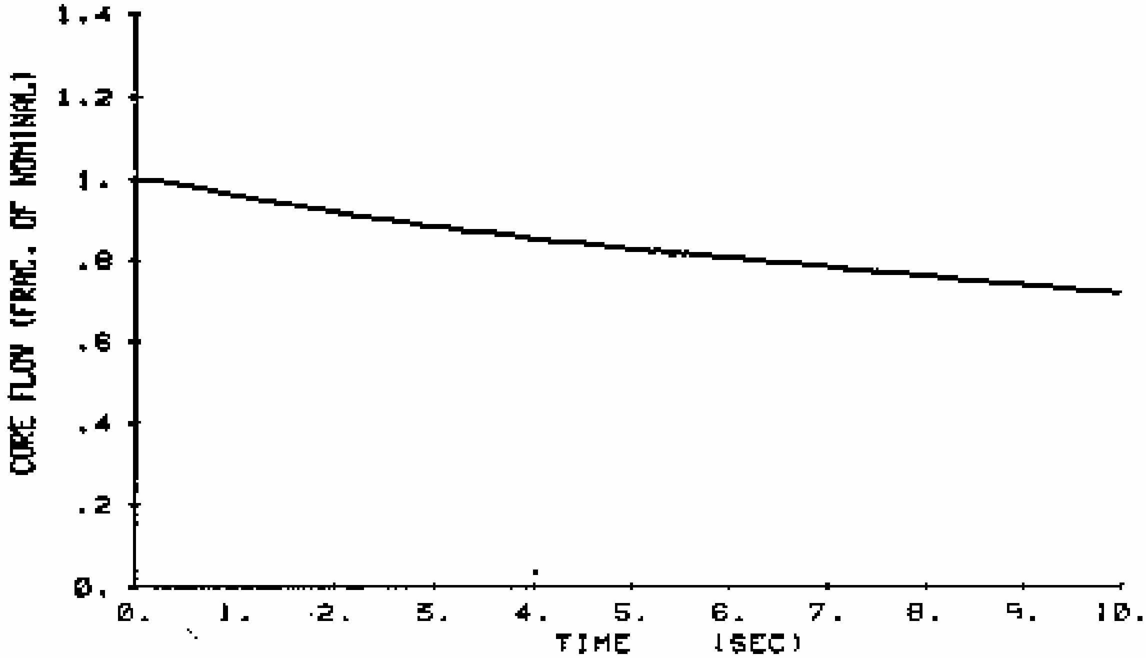
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.2.4-1
VARIATION IN REACTIVITY INSERTION RATE WITH INITIAL BORON CONCENTRATION FOR A DILUTION RATE OF 262 GPM



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UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.2.5-1
ALL LOOPS OPERATING
TWO LOOPS COASTING DOWN
CORE FLOW VERSUS TIME

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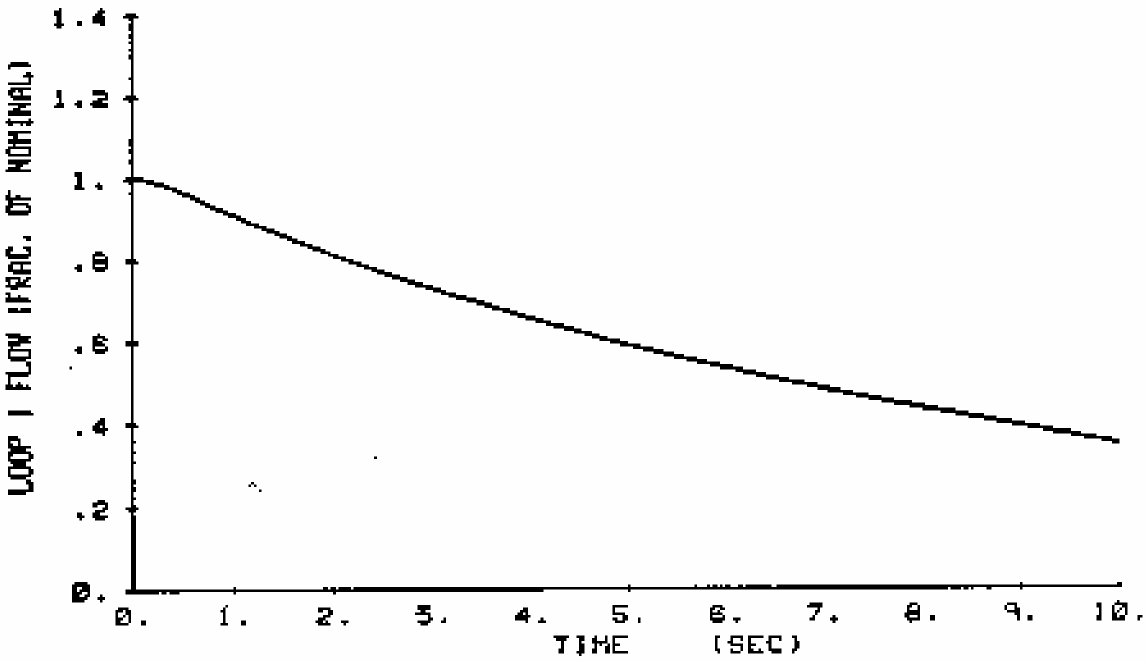

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UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.2.5-2
ALL LOOPS OPERATING
TWO LOOPS COASTING DOWN
FAILED LOOP FLOW VERSUS TIME

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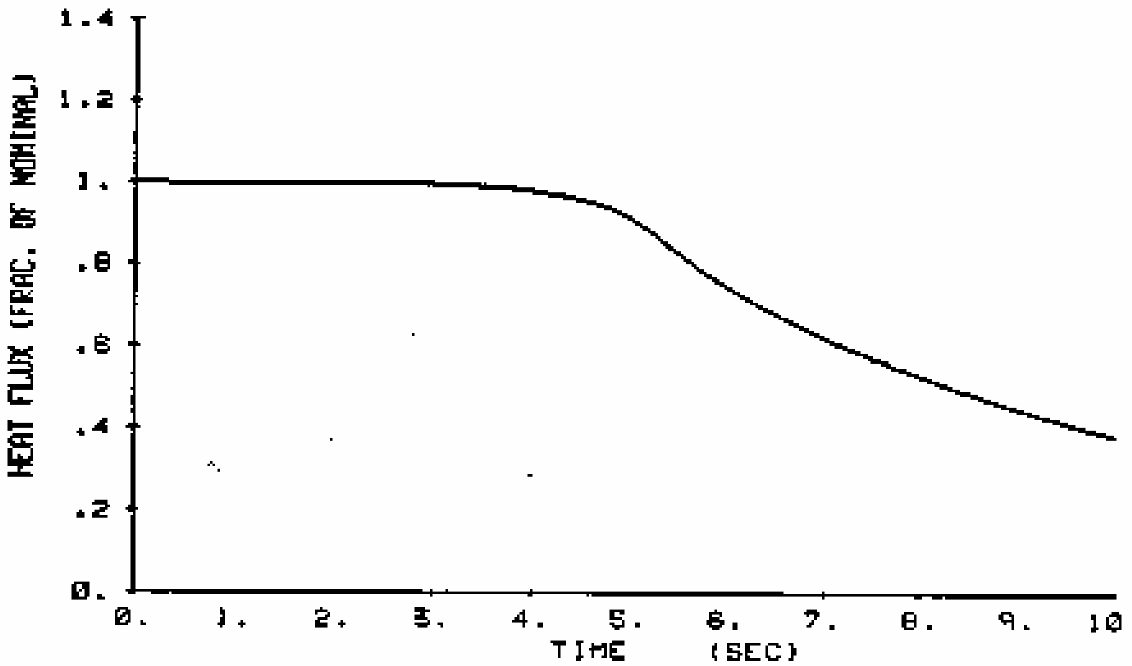

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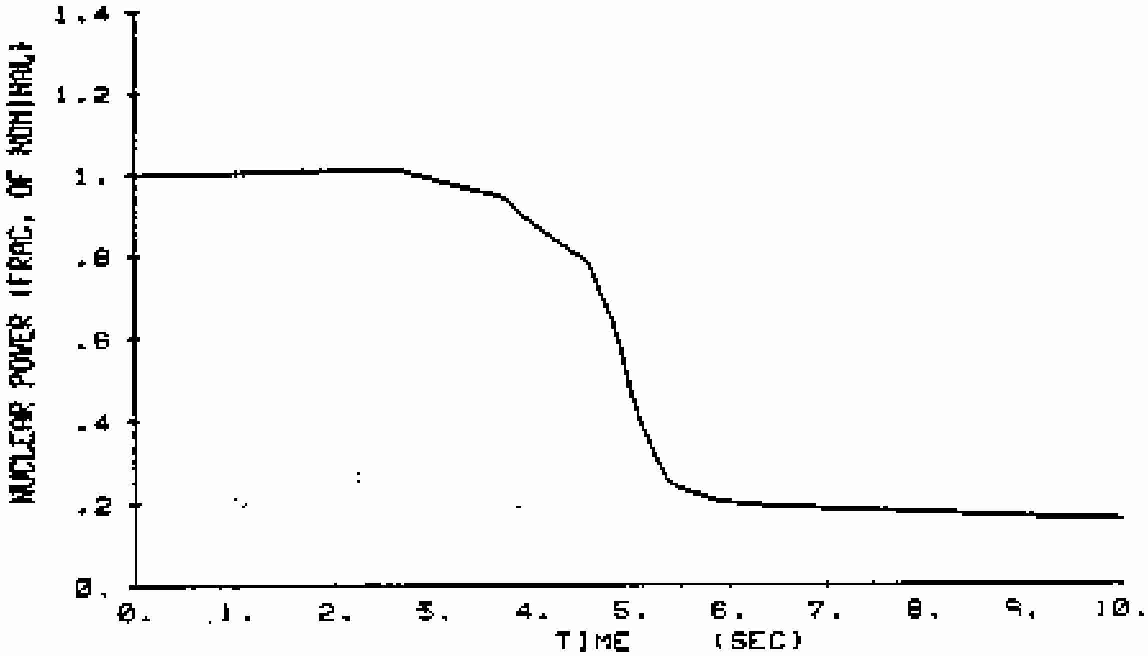
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.2.5-3
ALL LOOPS OPERATING
TWO LOOPS COASTING DOWN
HEAT FLUX VERSUS TIME

Revision 11 November 1996



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.2.5-4
ALL LOOPS OPERATING
TWO LOOPS COASTING DOWN
NUCLEAR POWER VERSUS TIME

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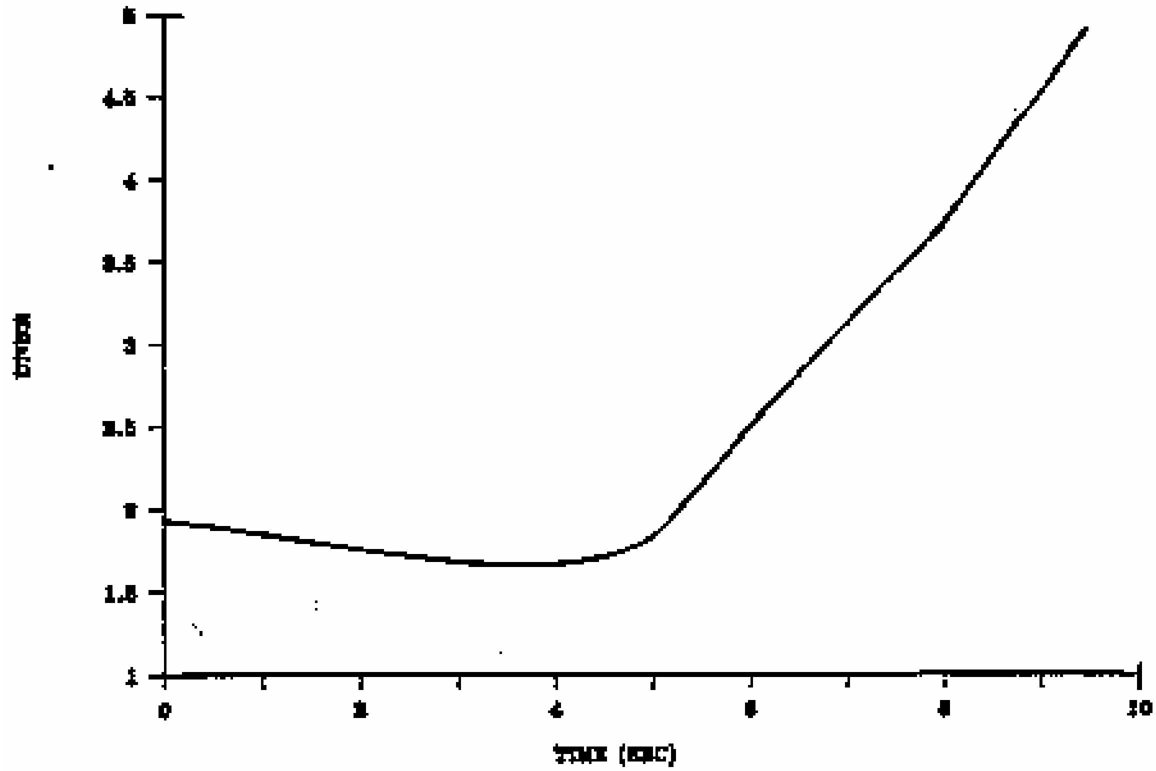
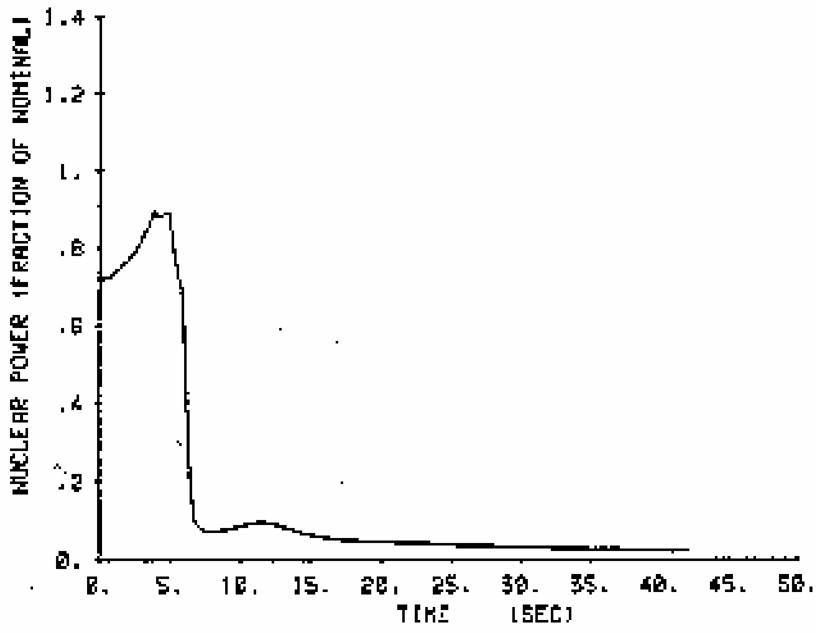


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.2.5-5
ALL LOOPS OPERATING
TWO LOOPS COASTING DOWN
DNBR VERSUS TIME

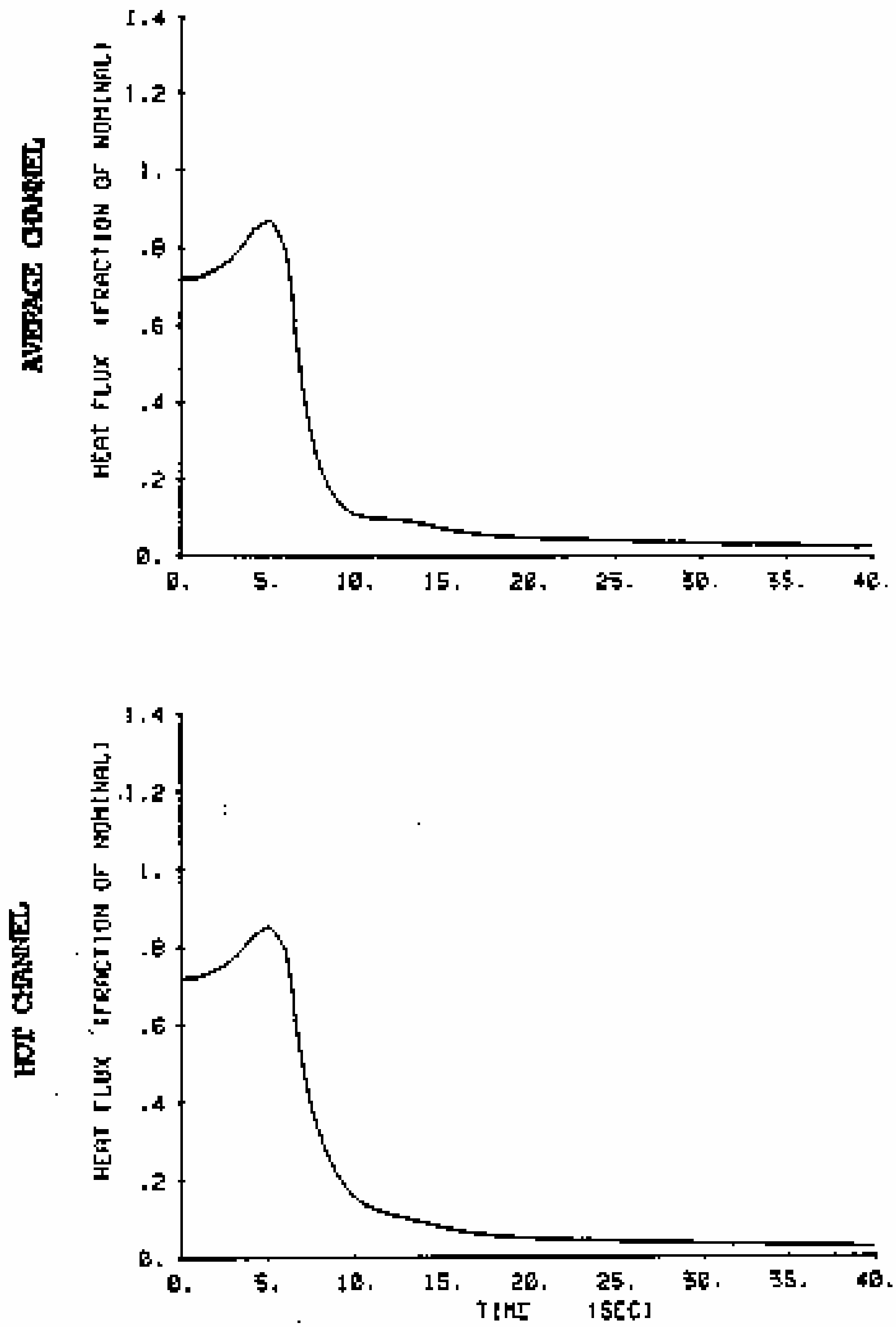


FSAR UPDATE

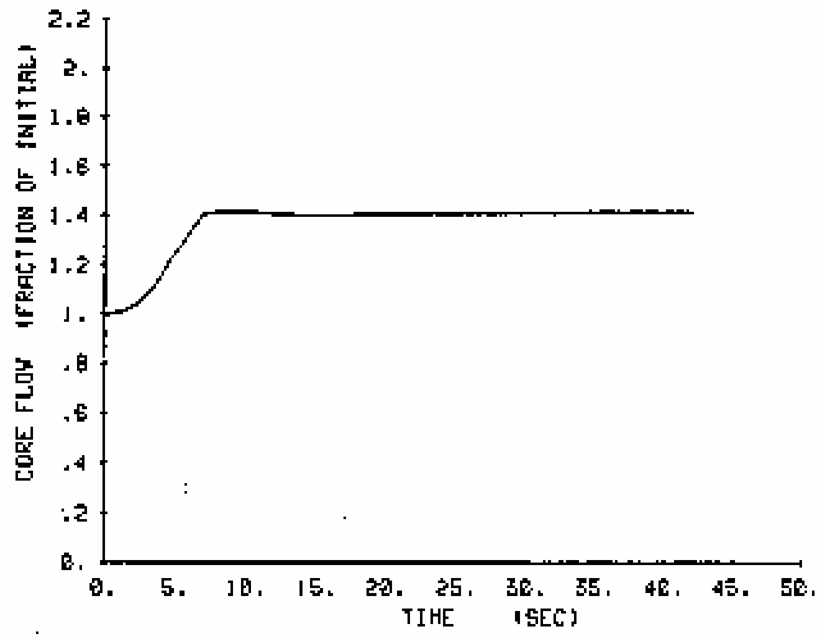
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.2.6-1

NUCLEAR POWER TRANSIENT DURING STARTUP OF AN INACTIVE LOOP



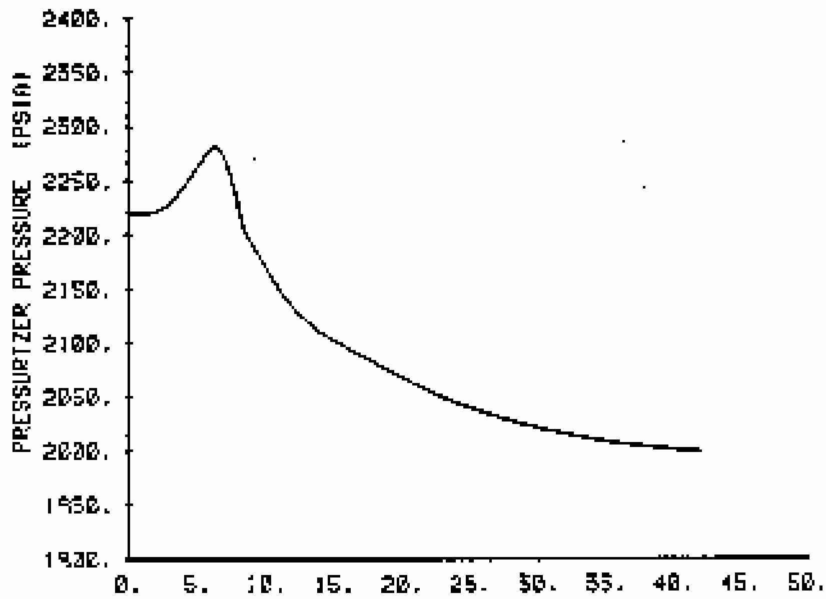
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.6-2 AVERAGE AND HOT CHANNEL HEAT FLUX TRANSIENTS DURING STARTUP OF AN INACTIVE LOOP

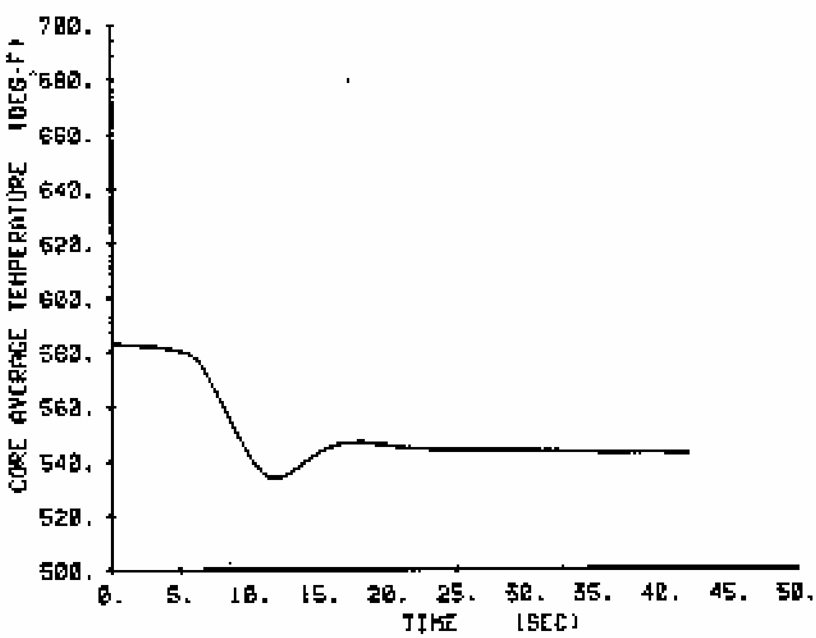


FSAR UPDATE

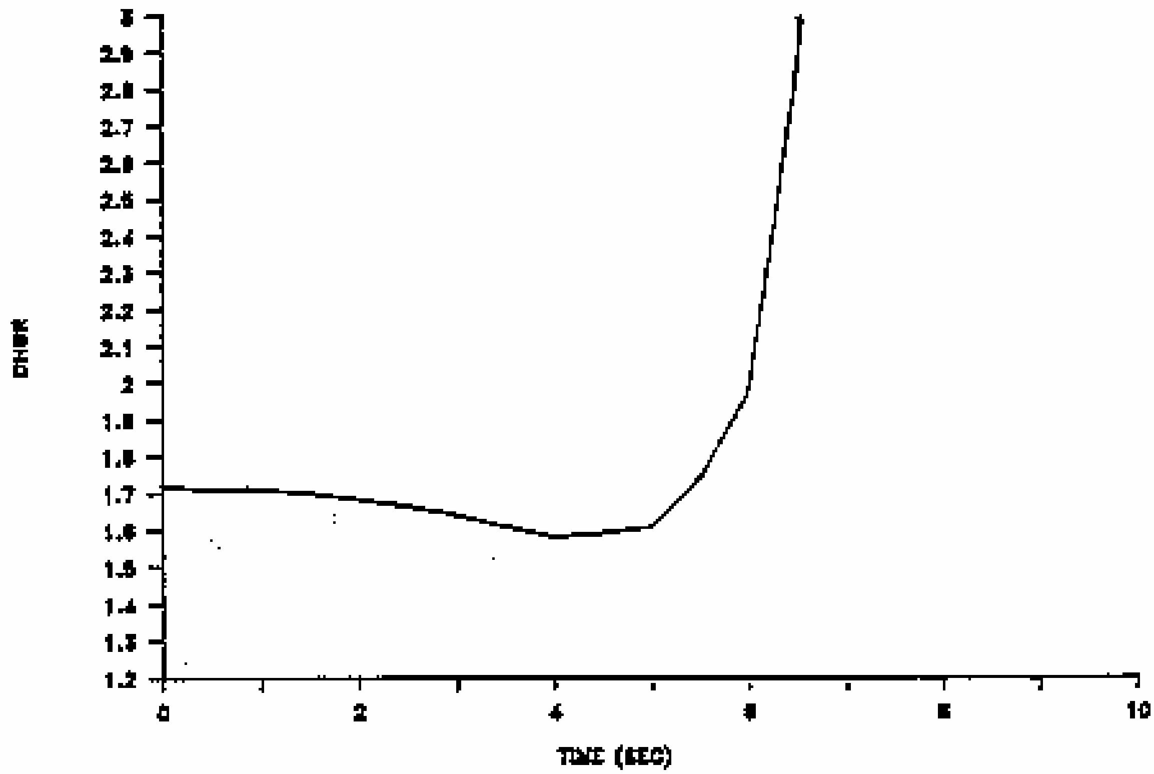
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.2.6-3
CORE FLOW DURING STARTUP OF AN INACTIVE LOOP



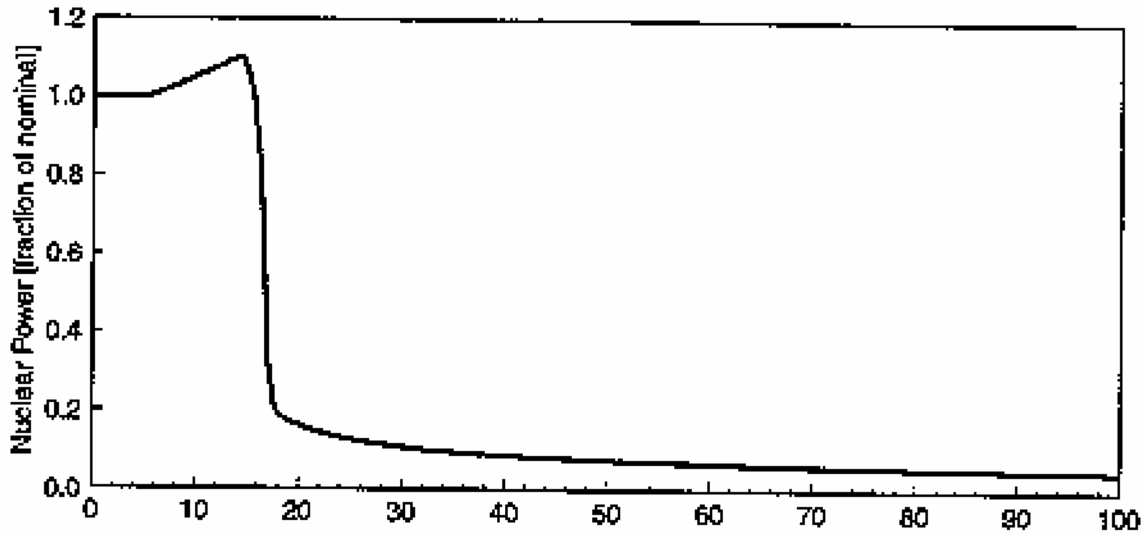


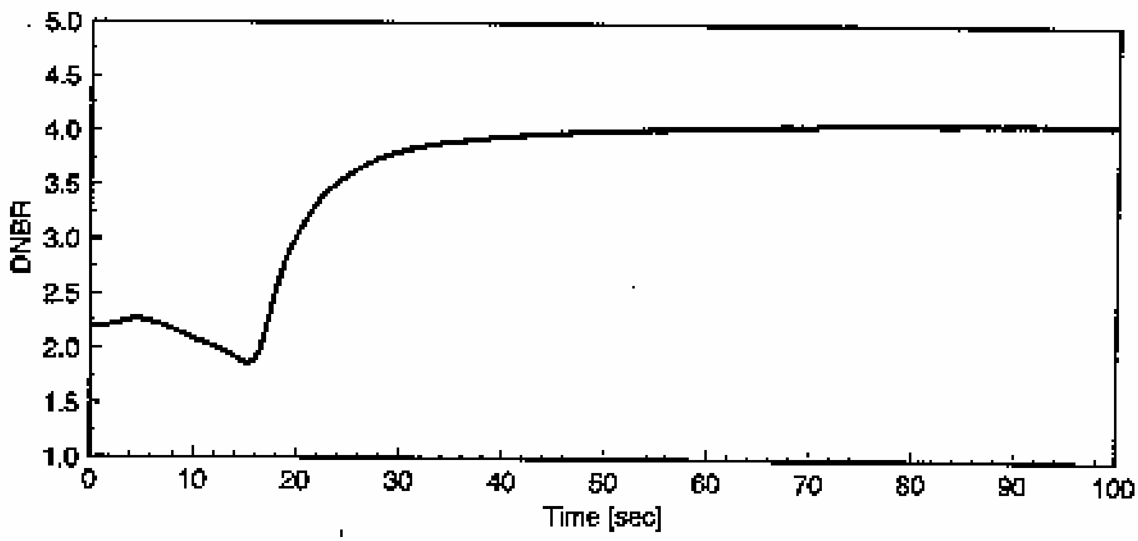
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.6-4 **PRESSURIZER PRESSURE TRANSIENT AND CORE AVERAGE TEMPERATURE TRANSIENT DURING STARTUP OF AN INACTIVE LOOP**



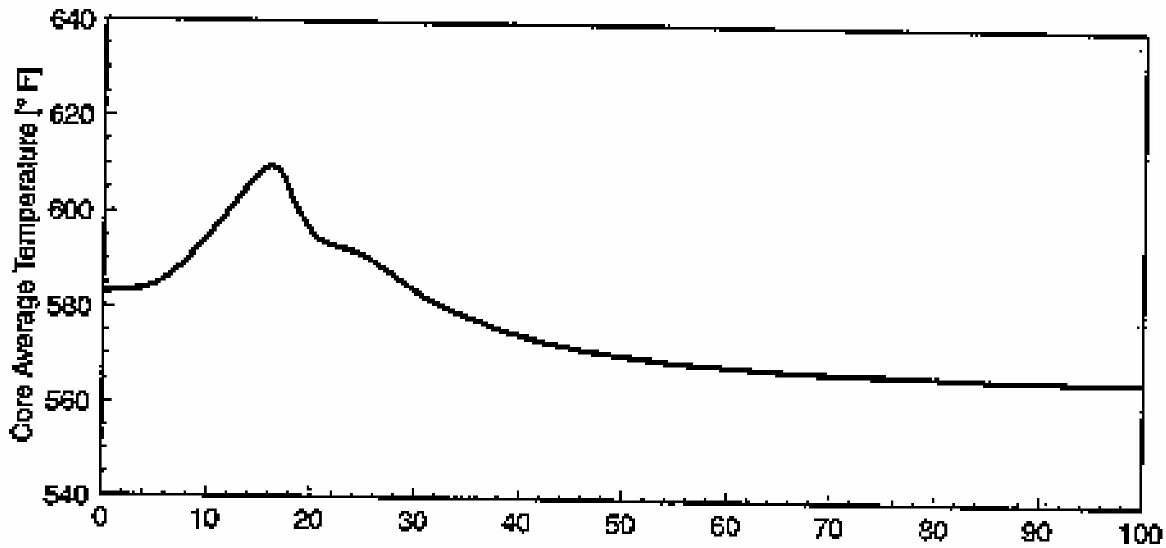
FSAR UPDATE
UNITS 1 AND 2 **DIABLO CANYON SITE**
FIGURE 15.2.6-5 **DNBR TRANSIENT** **DURING STARTUP OF AN INACTIVE LOOP**

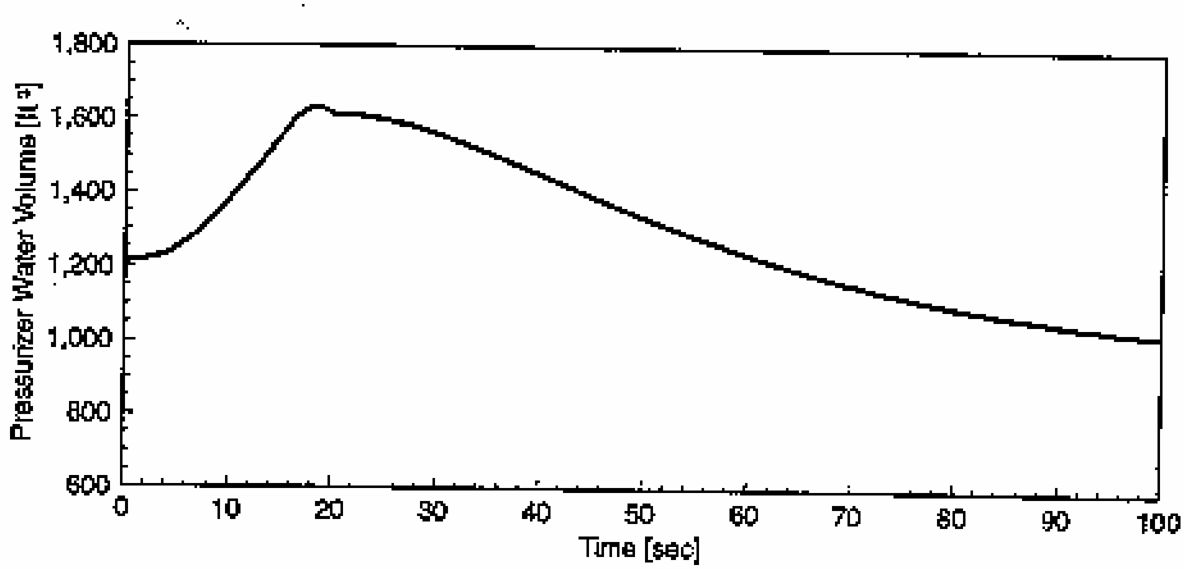
Revision 11 November 1996



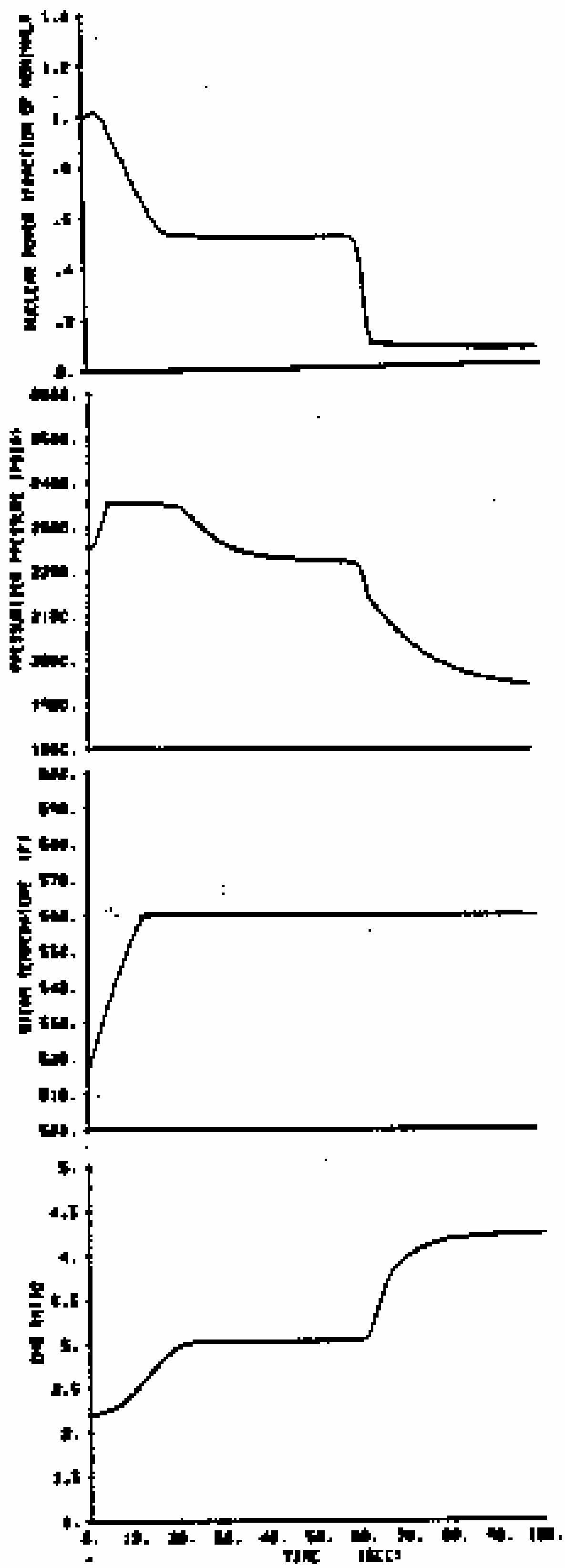


LOSS OF LOAD **With Pressurizer Spray and Power Operated Relief Valve For DNB Concern at Beginning of Life**	**DIABLO CANYON UNITS 1 & 2** **FIGURE 15.2.7-1**





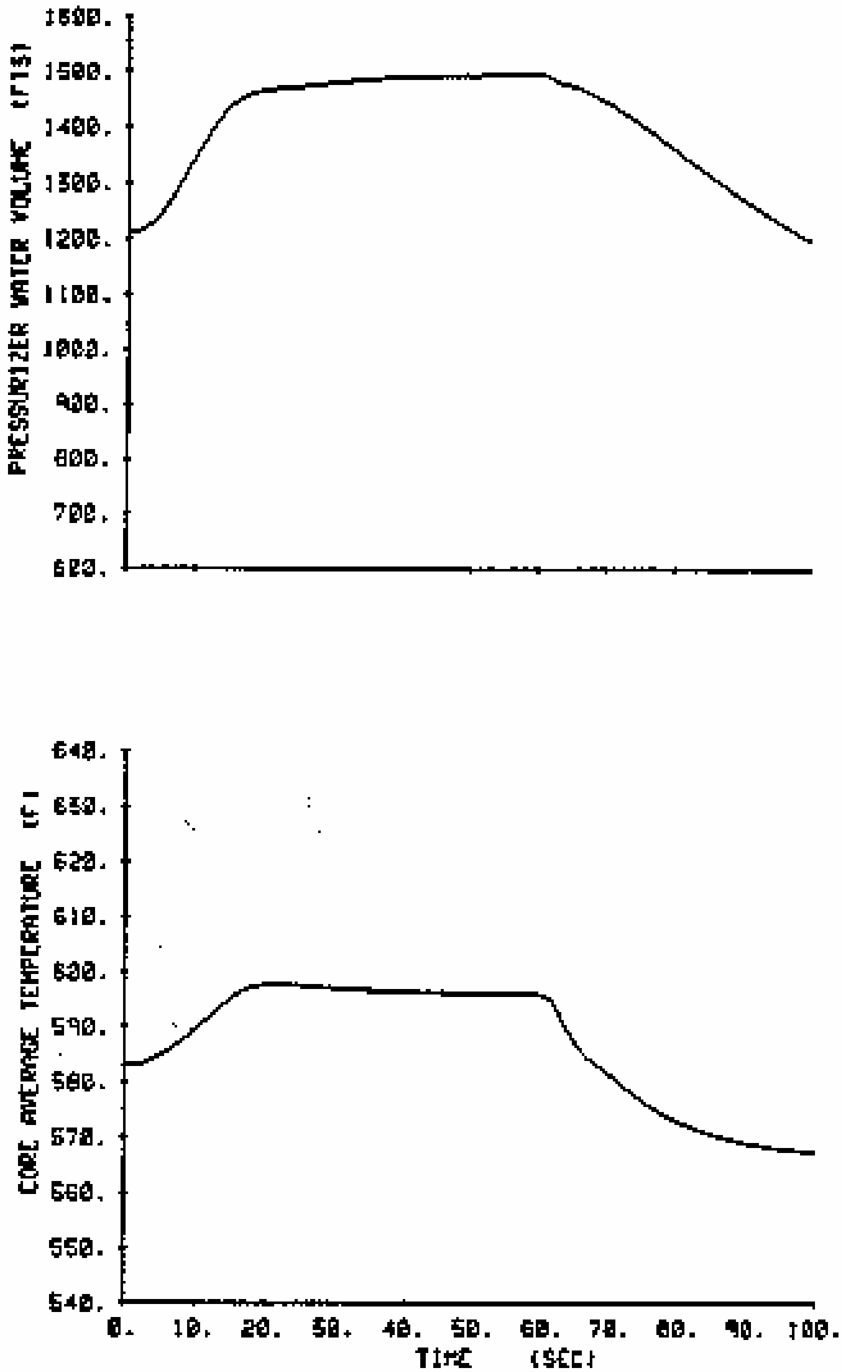
LOSS OF LOAD **With Pressurizer Spray and Power Operated Relief Valve For DNB Concern at Beginning of Life**	**DIABLO CANYON UNITS 1 & 2** **FIGURE 15.2.7-2**



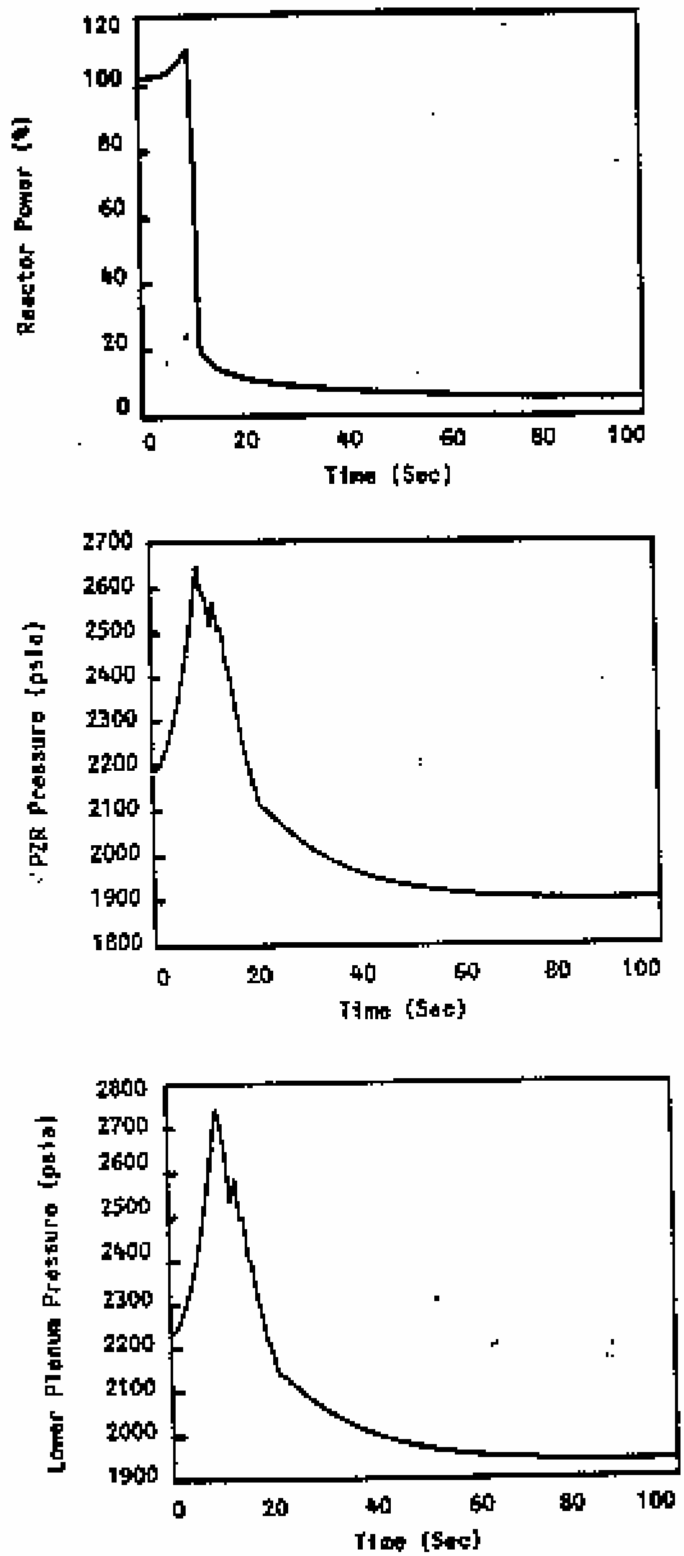
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

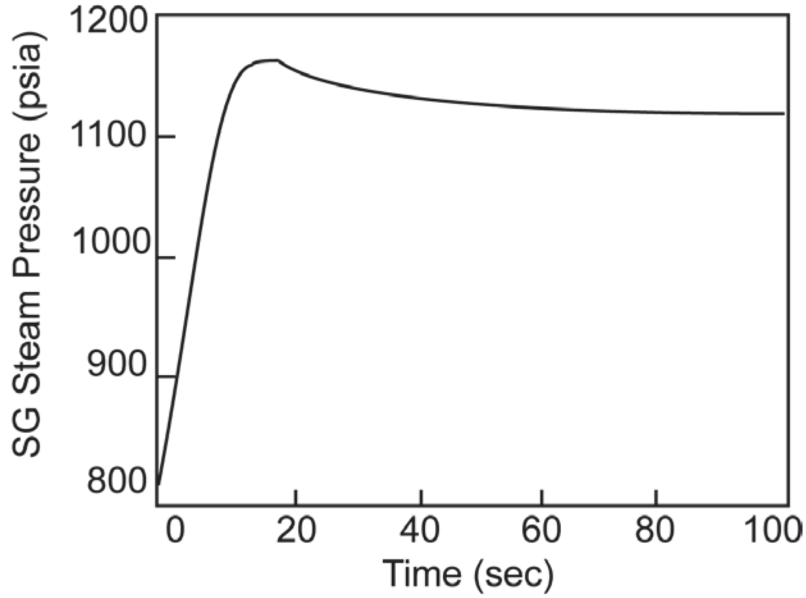
FIGURE 15.2.7-3
LOSS OF LOAD WITH PRESSURIZER SPRAY AND POWER OPERATED RELIEF VALVE FOR DNB CONCERN AT END OF LIFE

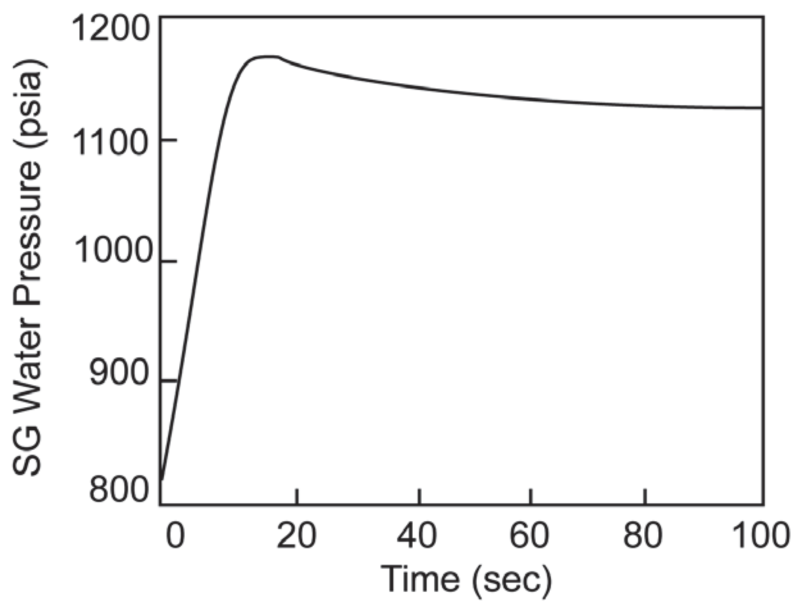


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.7-4 LOSS OF LOAD WITH PRESSURIZER SPRAY AND POWER OPERATED RELIEF VALVE FOR DNB CONCERN AT END OF LIFE



LOSS OF LOAD Without Pressurizer Spray and Power Operated Relief Valves For Overpressure Concern at Beginning of Life	DIABLO CANYON UNITS 1 & 2
	FIGURE 15.2.7-9

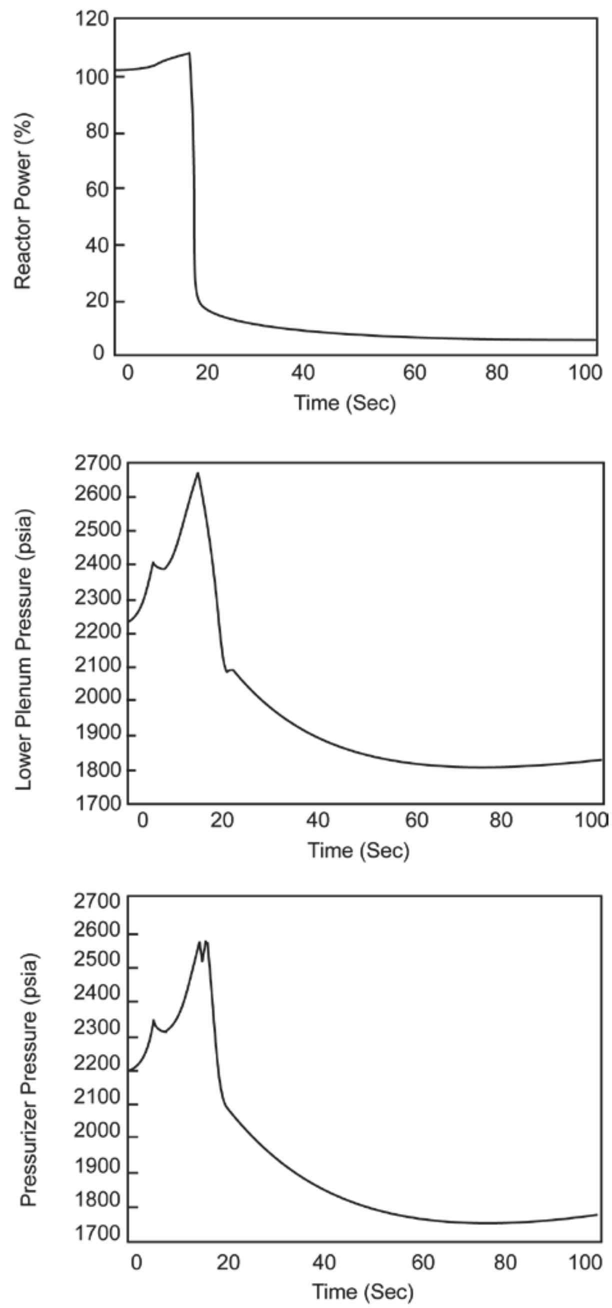




FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

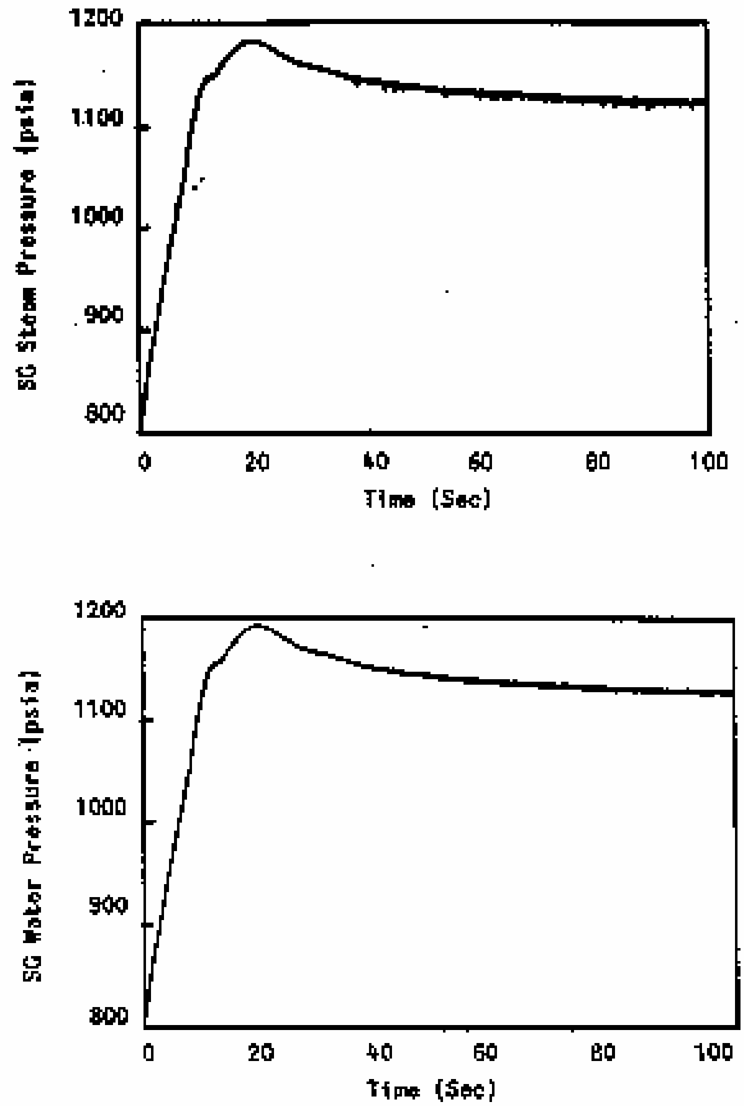
FIGURE 15.2.7-10
LOSS OF LOAD WITHOUT PRESSURIZER SPRAY AND POWER OPERATED RELIEF VALVES FOR OVERPRESSURE CONCERN AT BEGINNING OF LIFE



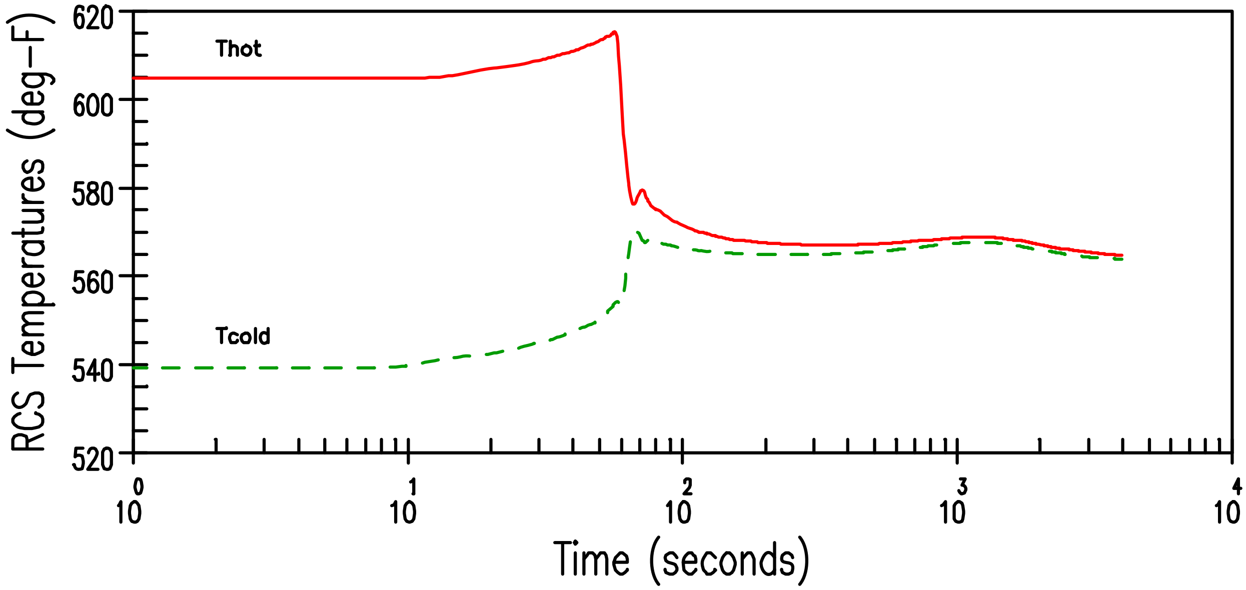
FSAR UPDATE

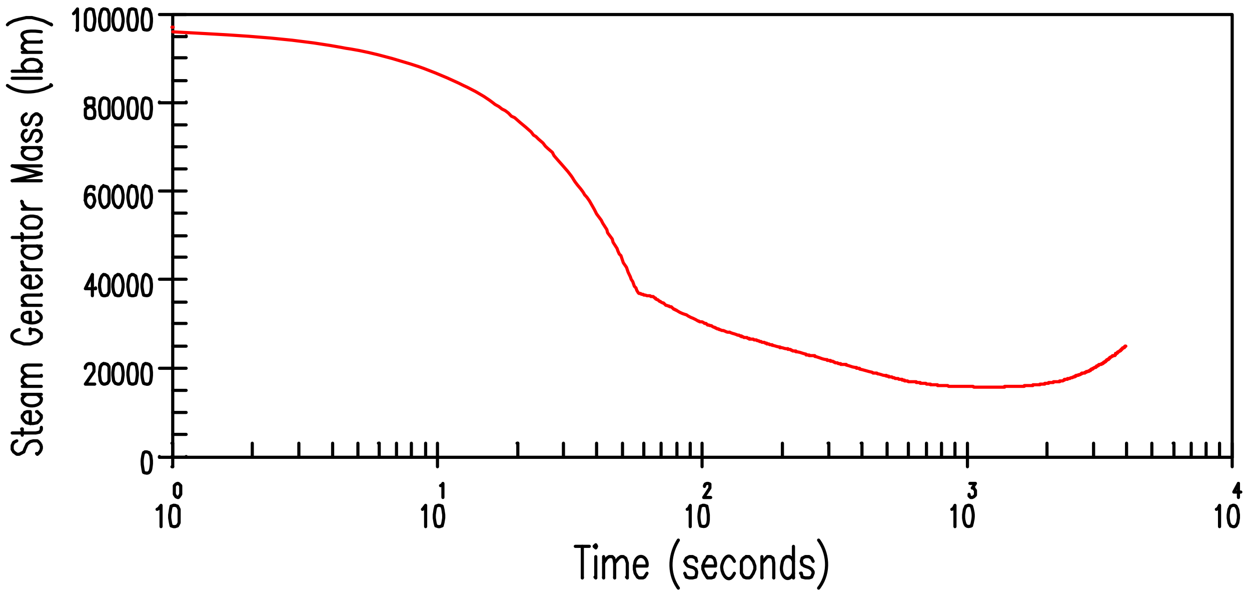
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.2.7-11
LOSS OF LOAD WITH PRESSURIZER SPRAY AND POWER OPERATED RELIEF VALVES FOR OVERPRESSURE CONCERN AT BEGINNING OF LIFE



LOSS OF LOAD With Pressurizer Spray and Power Operated Relief Valves For Overpressure Concern at Beginning of Life	DIABLO CANYON UNITS 1 & 2 FIGURE 15.2.7-12

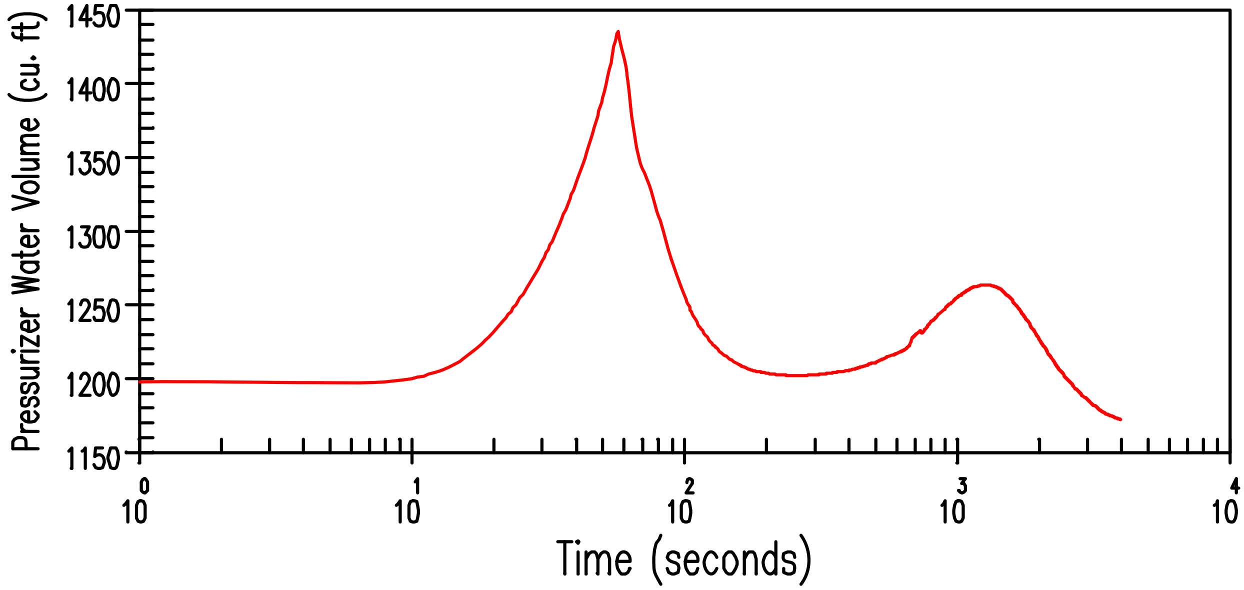


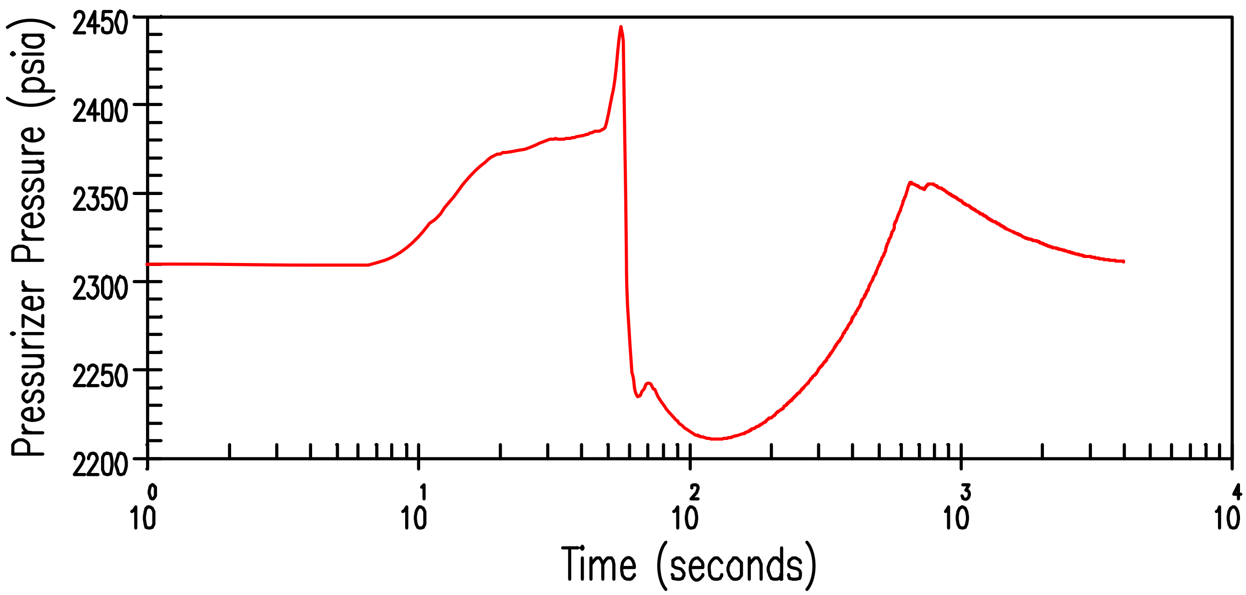


FSAR UPDATE

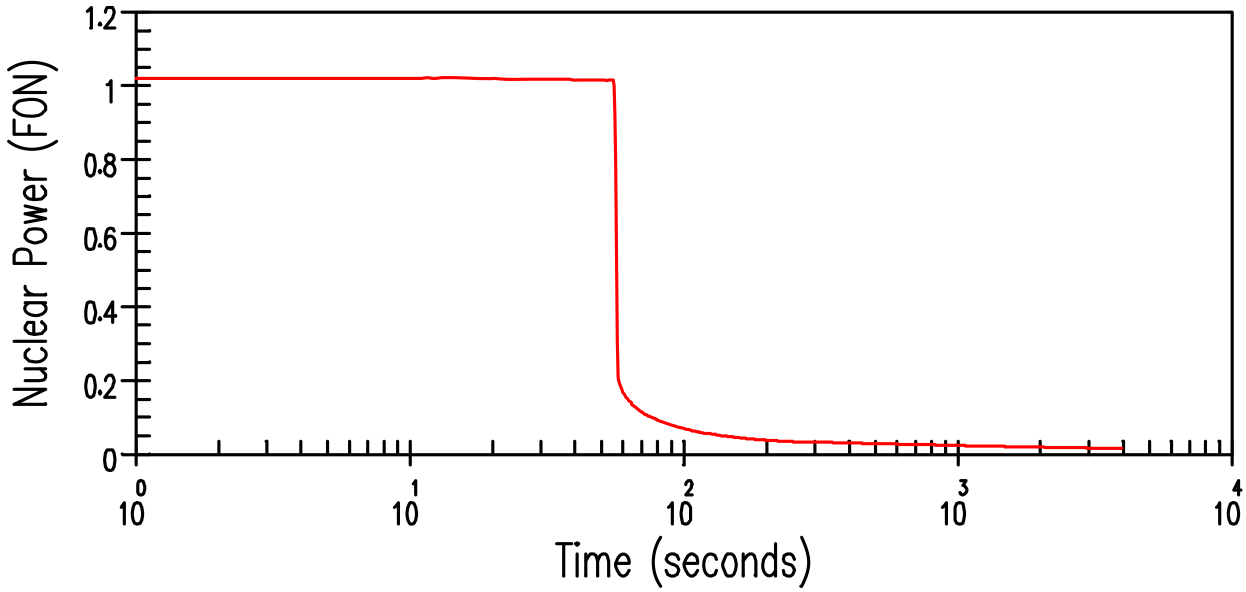
UNITS 1 AND 2
DIABLO CANYON SITE

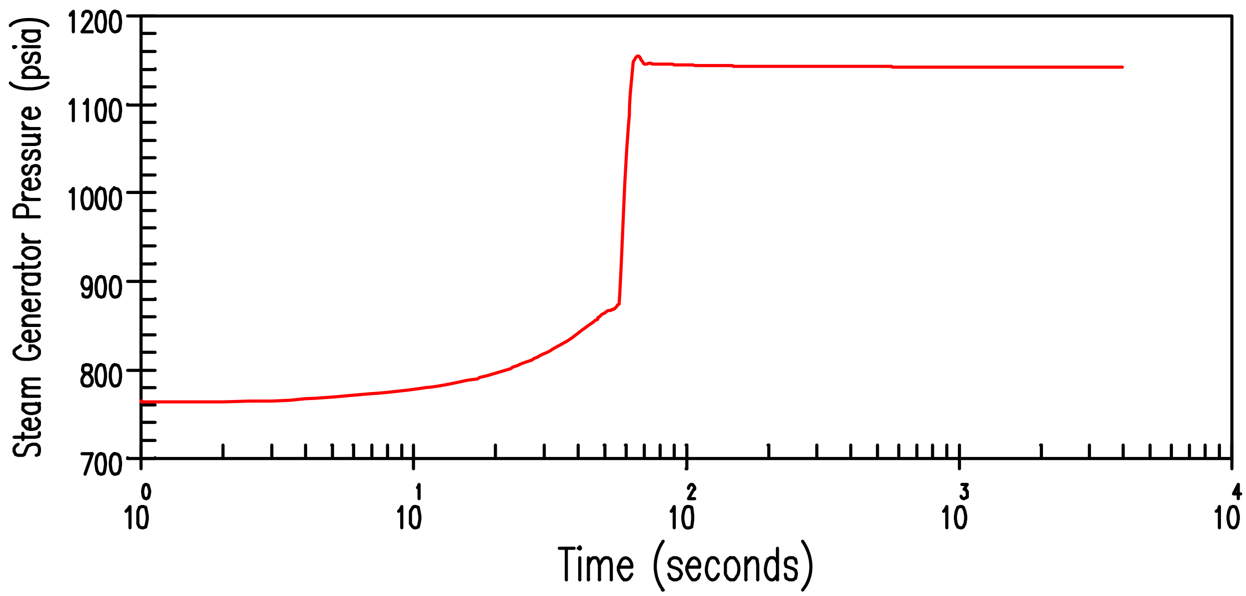
FIGURE 15.2.8-1
LOSS OF NORMAL FEEDWATER – RCS TEMPERATURES AND STEAM GENERATOR MASS TRANSIENTS



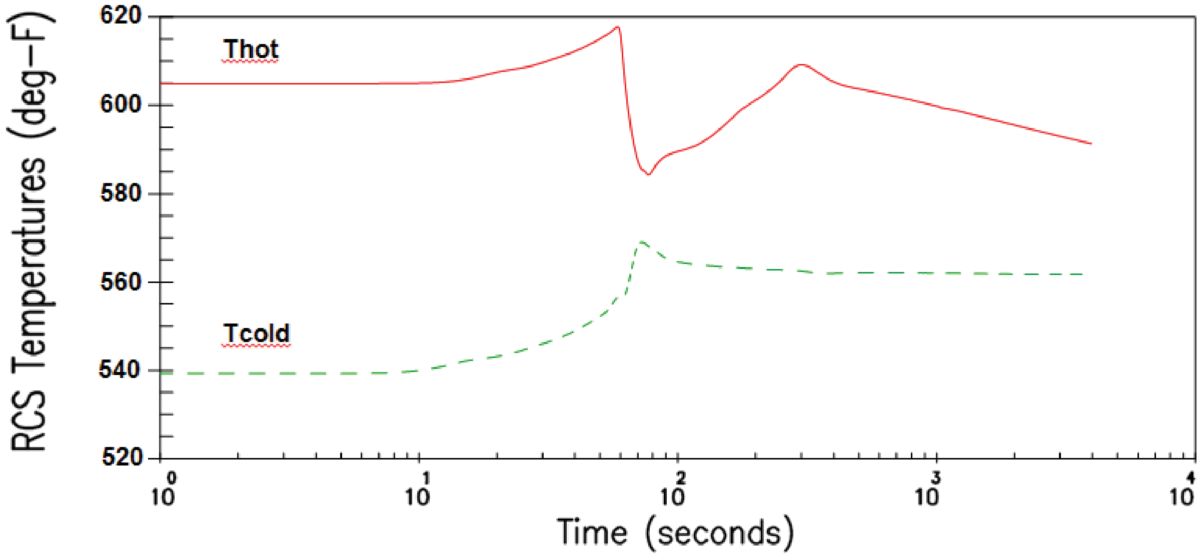


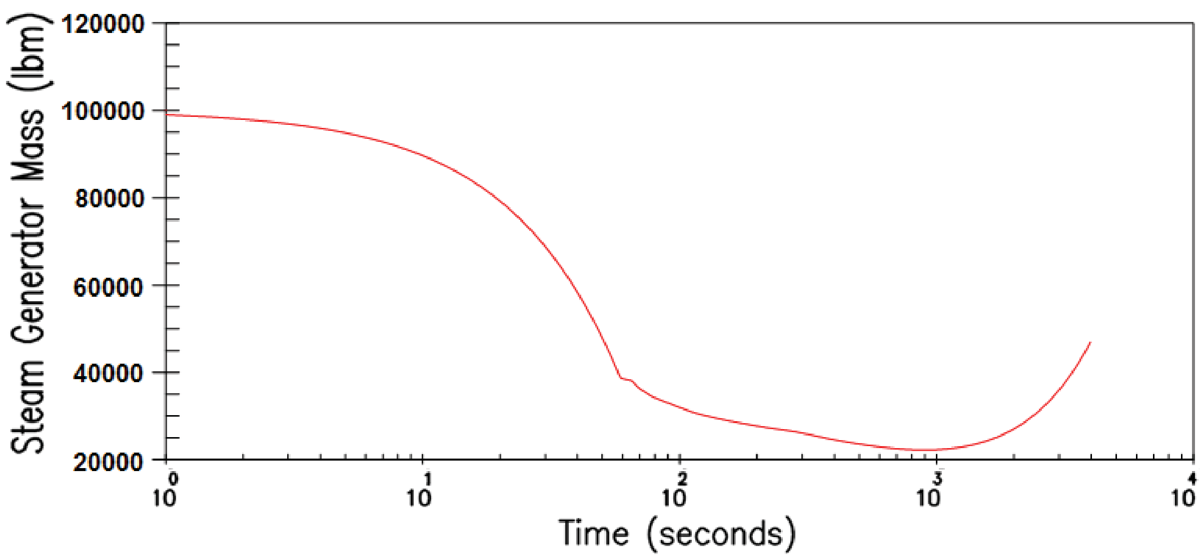
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.8-2 LOSS OF NORMAL FEEDWATER PRESSURIZER WATER VOLUME AND PRESSURIZER PRESSURE TRANSIENTS





FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.8-3 LOSS OF NORMAL FEEDWATER NUCLEAR POWER AND STEAM GENERATOR PRESSURE TRANSIENTS

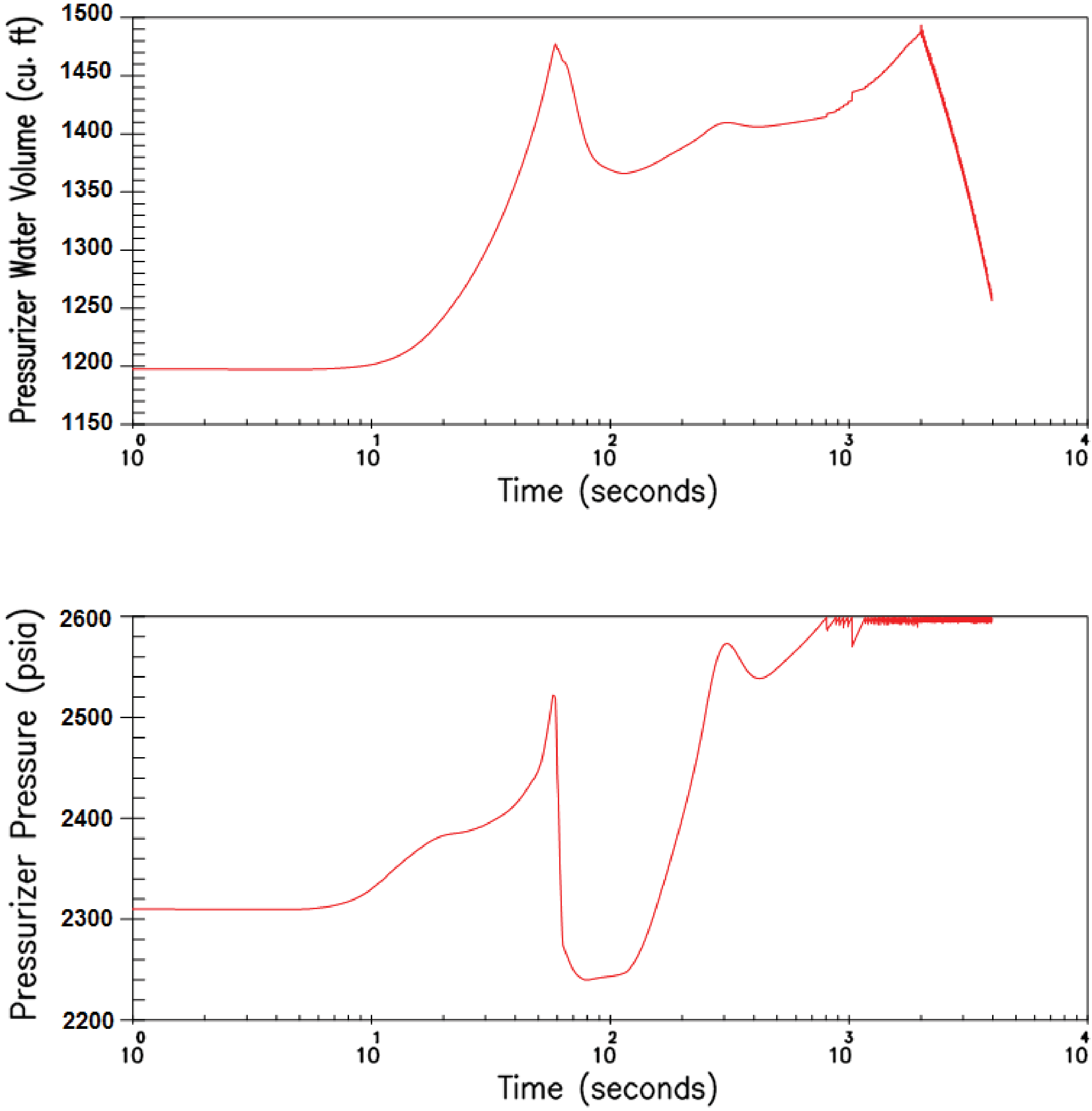




FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

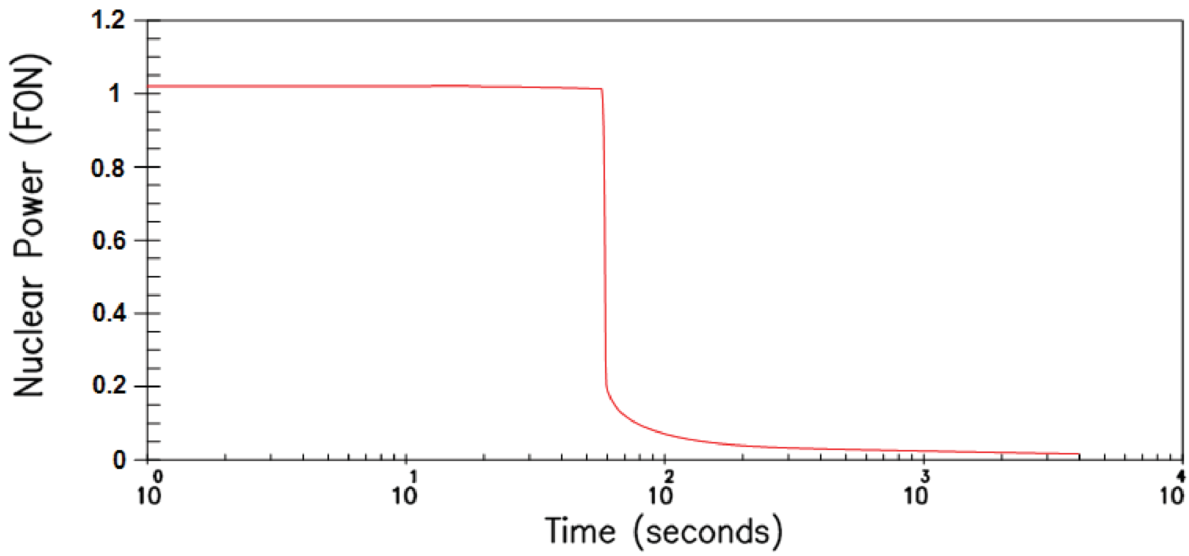
FIGURE 15.2.9-1
LOSS OF OFFSITE POWER
RCS TEMPERATURES AND STEAM GENERATOR MASS TRANSIENTS

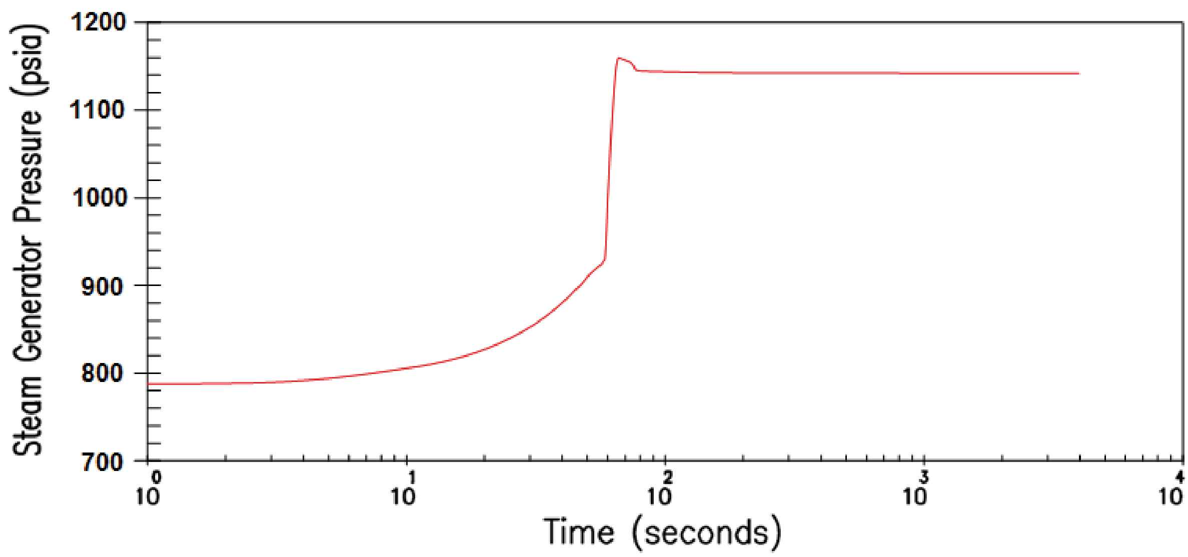


FSAR UPDATE

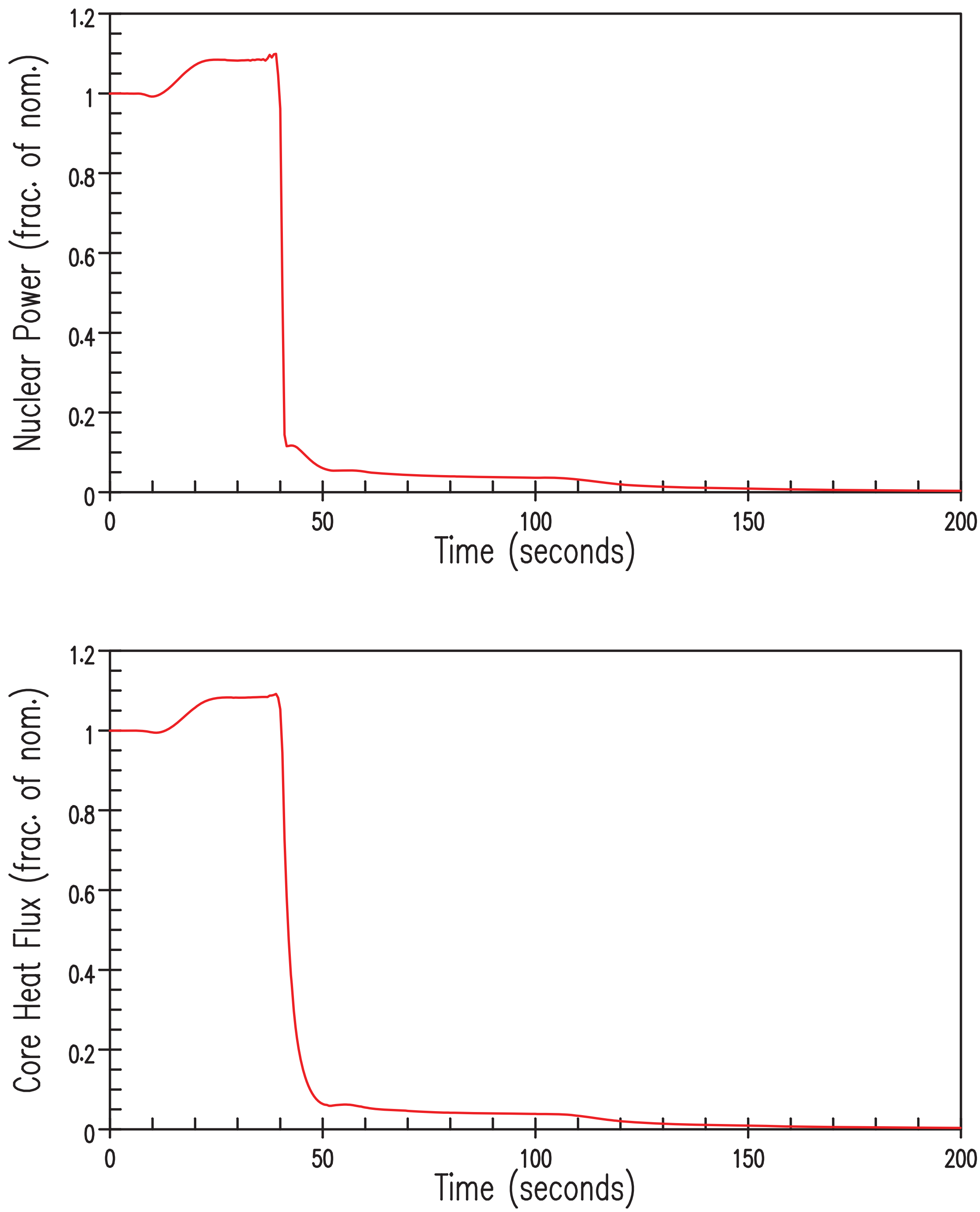
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.2.9-2
LOSS OF OFFSITE POWER
PRESSURIZER WATER VOLUME AND
PRESSURIZER PRESSURE TRANSIENTS





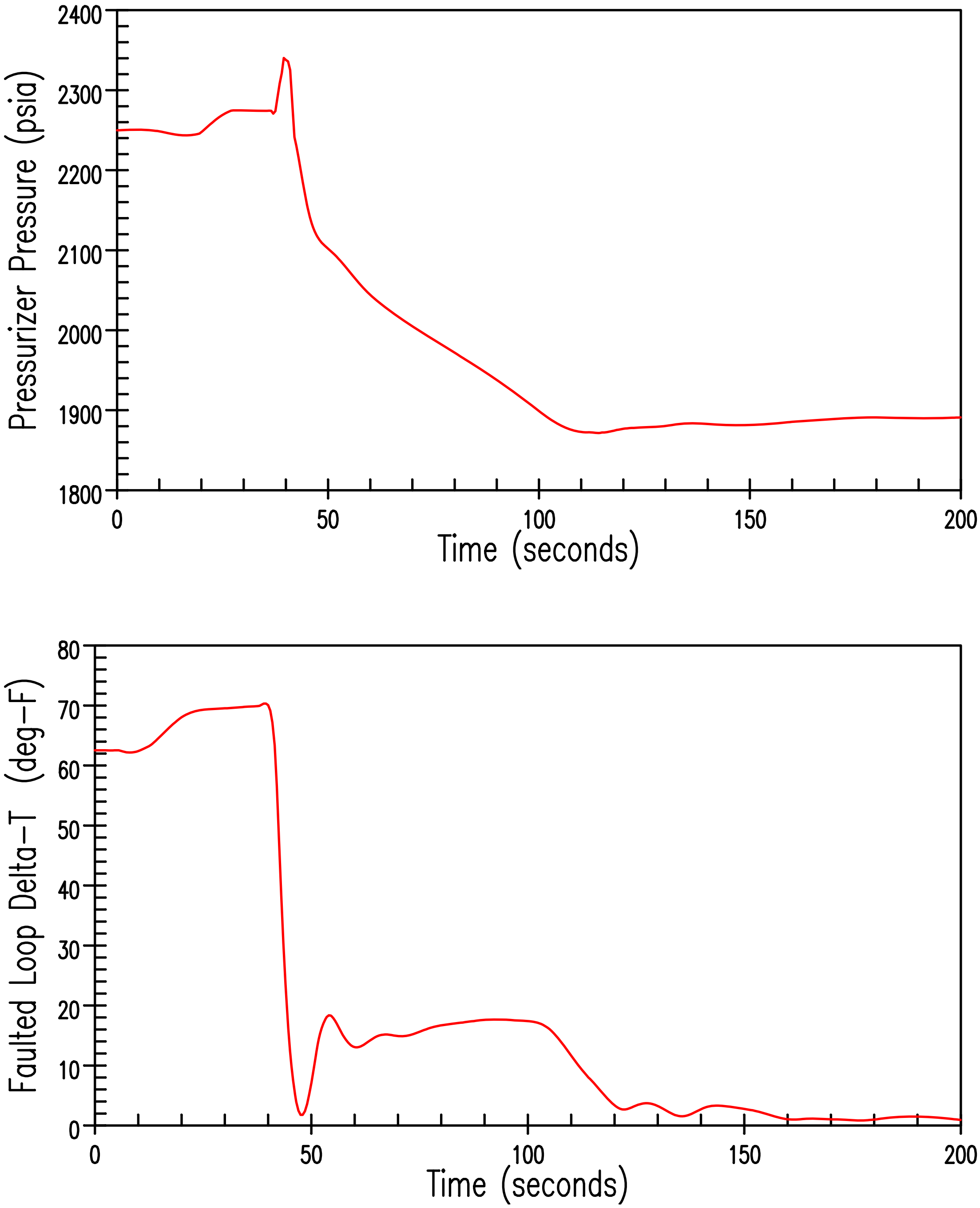
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.9-3 LOSS OF OFFSITE POWER NUCLEAR POWER AND STEAM GENERATOR PRESSURE TRANSIENTS



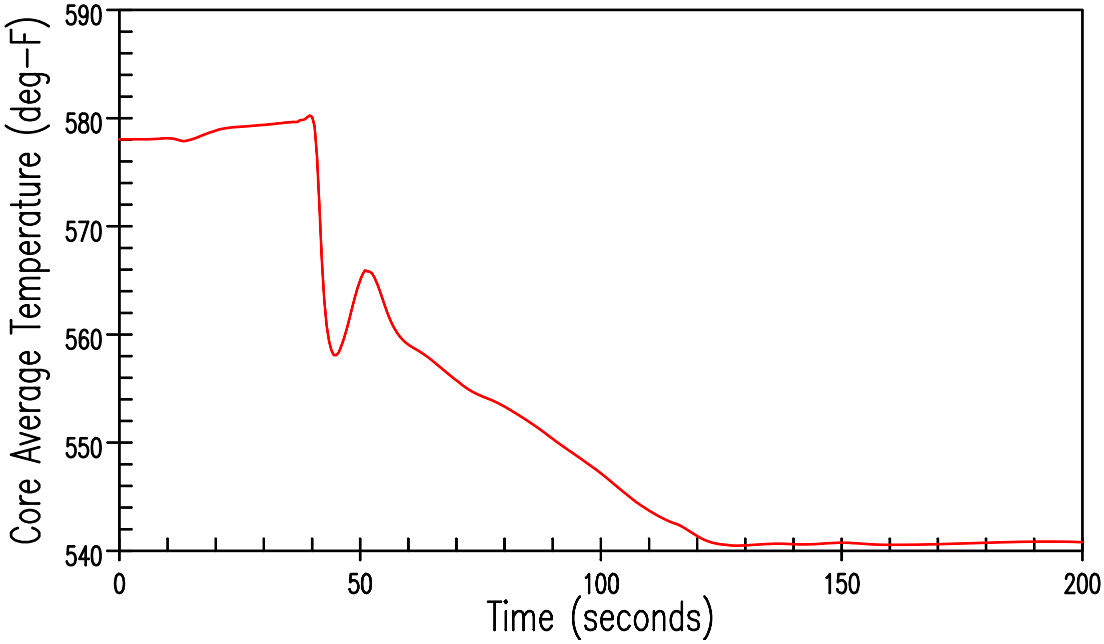
FSAR UPDATE

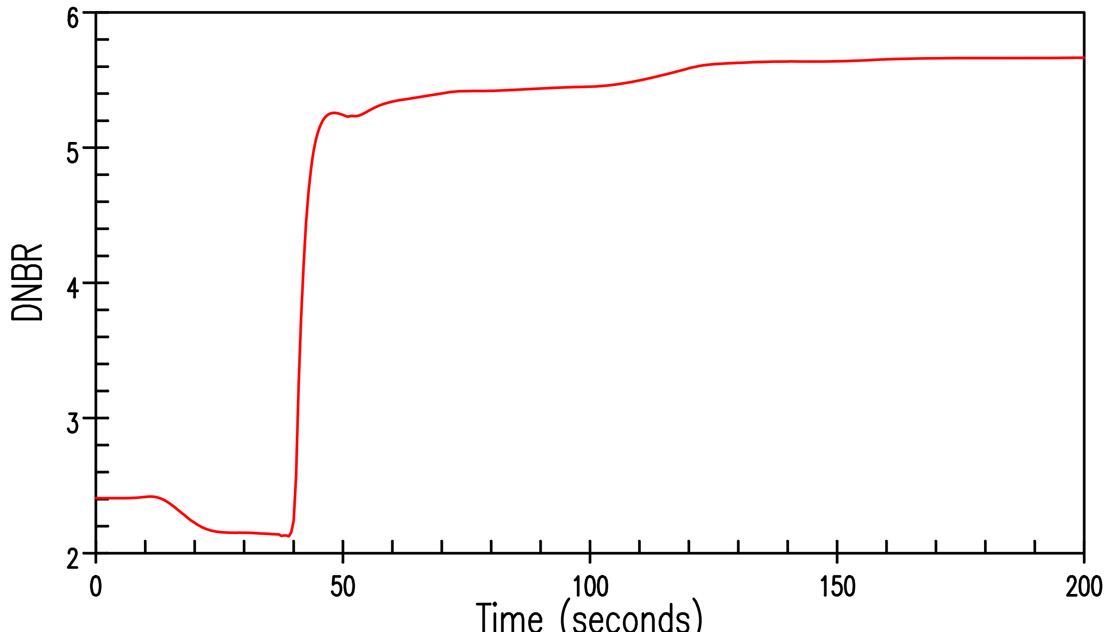
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.2.10-1
FEEDWATER CONTROL VALVE MALFUNCTION
FULL POWER, MANUAL ROD CONTROL
NUCLEAR POWER AND AVERAGE CHANNEL
CORE HEAT FLUX TRANSIENTS

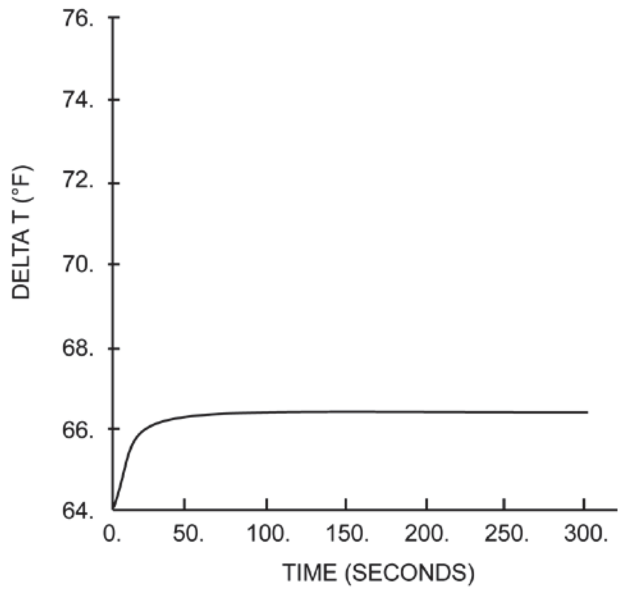


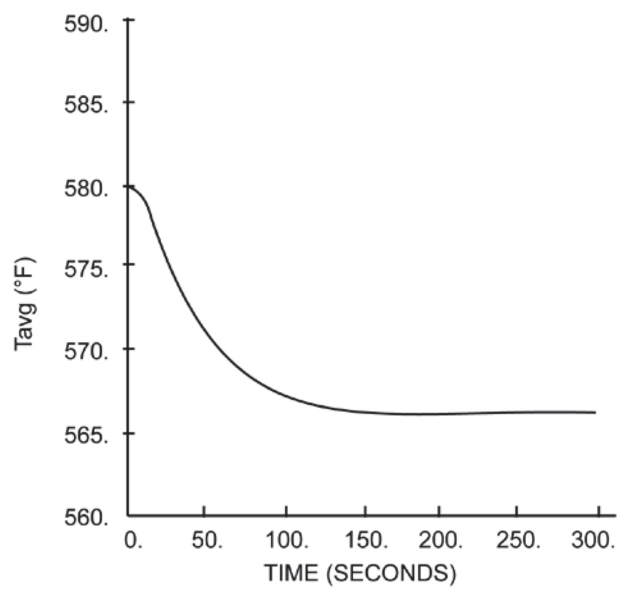
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.10-2 FEEDWATER CONTROL VALVE MALFUNCTION FULL POWER, MANUAL ROD CONTROL PRESSURIZER PRESSURE AND FAULTED LOOP DELTA-T TRANSIENTS





FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.10-3 FEEDWATER CONTROL VALVE MALFUNCTION FULL POWER, MANUAL ROD CONTROL CORE AVERAGE TEMPERATURE AND DNBR TRANSIENTS

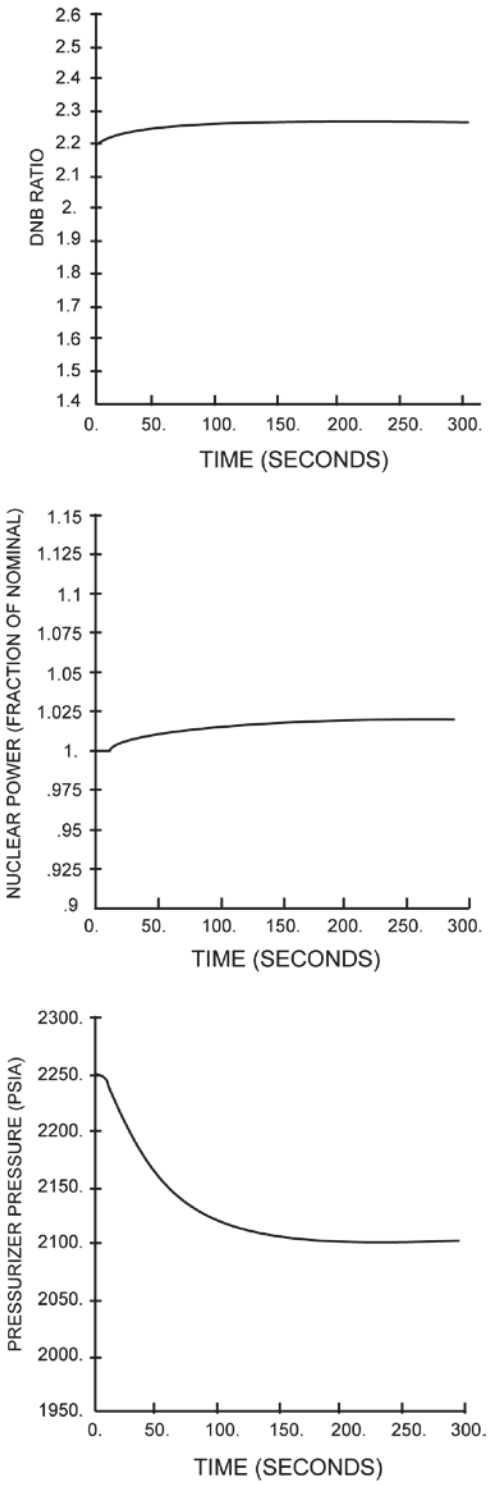




FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

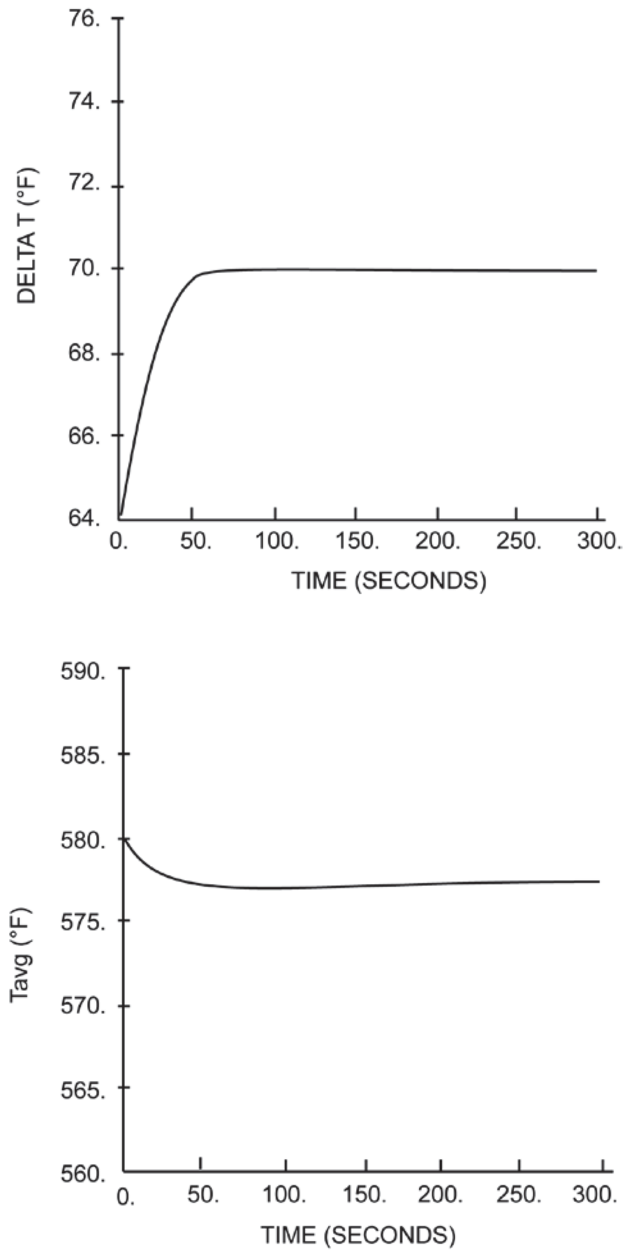
FIGURE 15.2.12-1
EXCESSIVE LOAD INCREASE WITHOUT CONTROL ACTION, BEGINNING OF LIFE, (MTC), MINIMUM FEEDBACK, DELTA-T AND TAVG AS A FUNCTION OF TIME



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

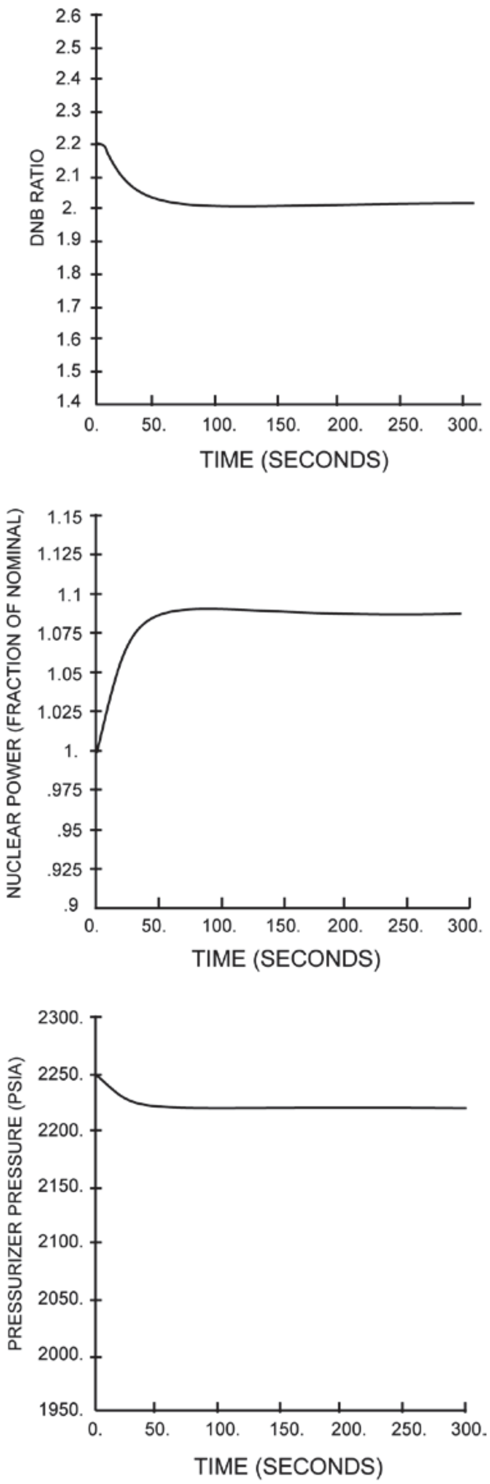
FIGURE 15.2.12-2
EXCESSIVE LOAD INCREASE WITHOUT CONTROL ACTION, BEGINNING OF LIFE, (MTC), MINIMUM FEEDBACK, DNBR, NUCLEAR POWER AND PRESSURIZER PRESSURE AS A FUNCTION OF TIME



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

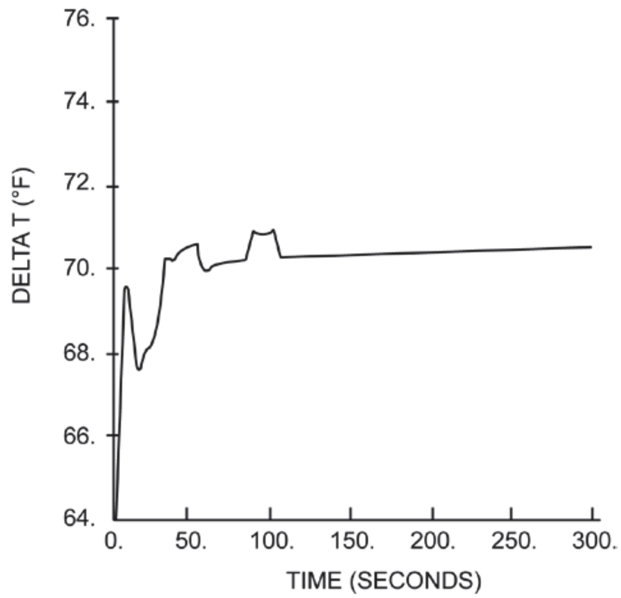
FIGURE 15.2.12-3
EXCESSIVE LOAD INCREASE WITHOUT CONTROL ACTION, END OF LIFE, (MTC), MAXIMUM FEEDBACK, DELTA-T AND TAVG AS A FUNCTION OF TIME

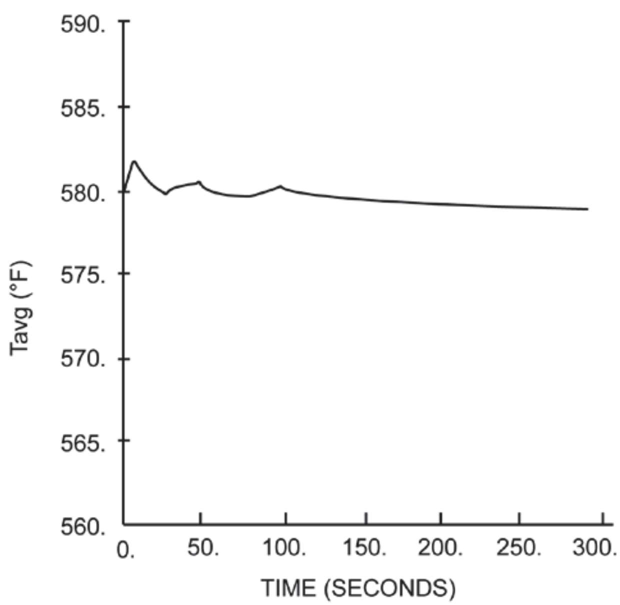


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.2.12-4
EXCESSIVE LOAD INCREASE WITHOUT CONTROL ACTION, END OF LIFE, (MTC), MAXIMUM FEEDBACK, DNBR, NUCLEAR POWER AND PRESSURIZER PRESSURE AS A FUNCTION OF TIME

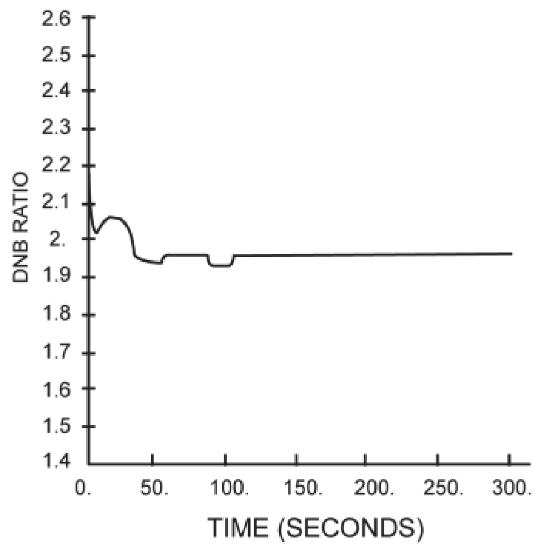


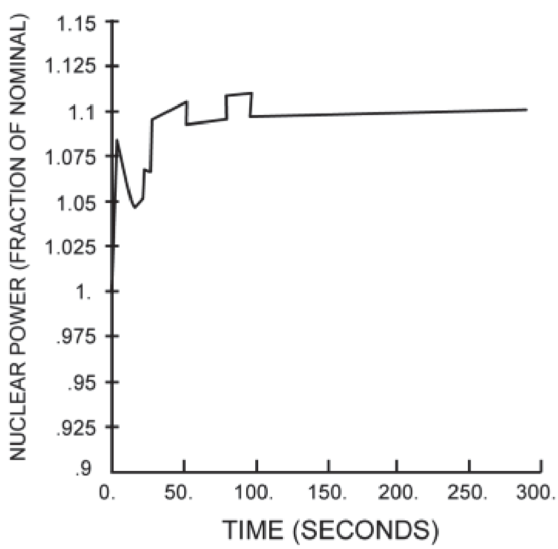


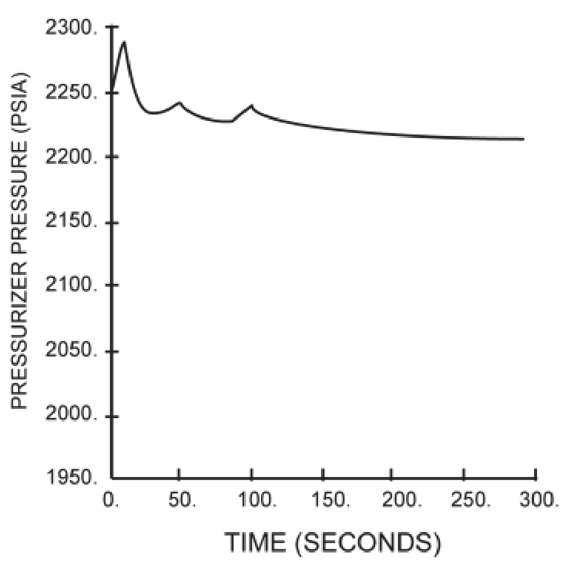
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

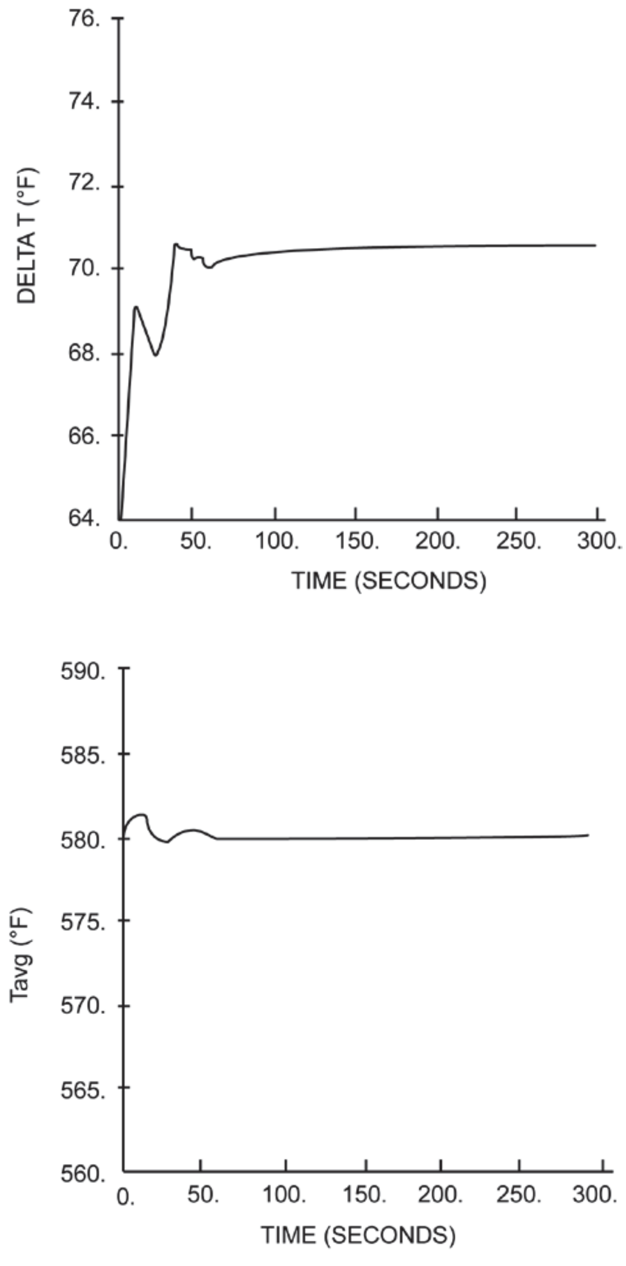
FIGURE 15.2.12-5
EXCESSIVE LOAD INCREASE WITH REACTOR CONTROL, BEGINNING OF LIFE, (MTC), MINIMUM FEEDBACK, DELTA-T AND TAVG AS A FUNCTION OF TIME







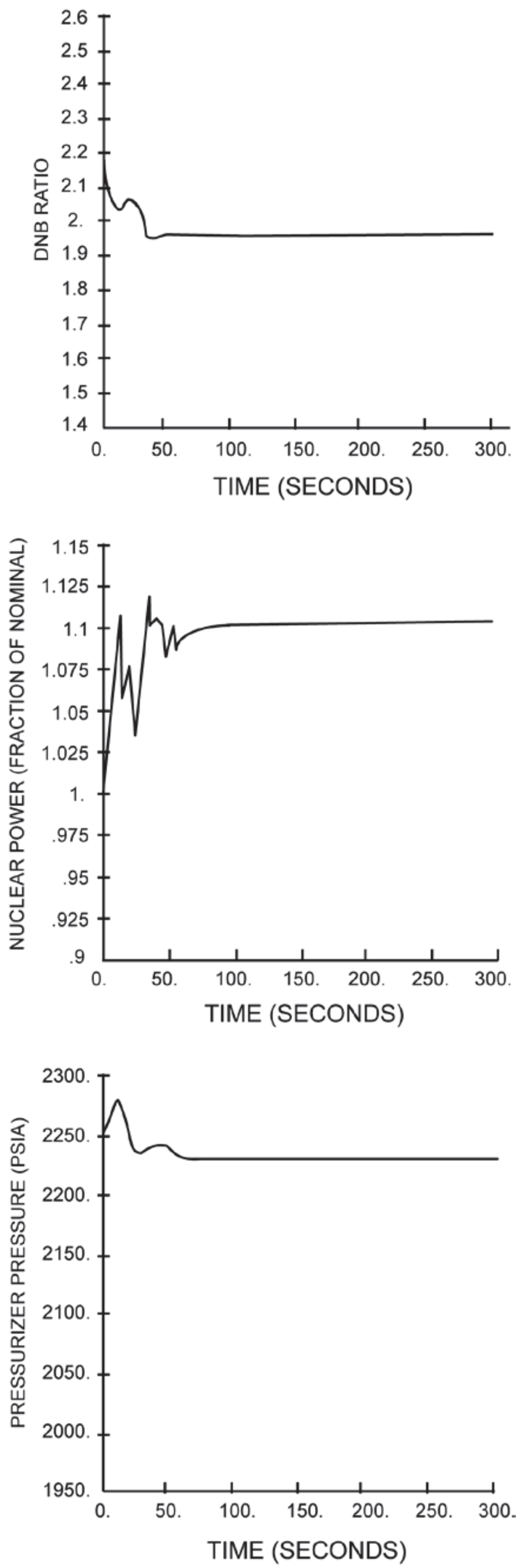
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.12-6 EXCESSIVE LOAD INCREASE WITH REACTOR CONTROL, BEGINNING OF LIFE, (MTC), MINIMUM FEEDBACK, DNBR, NUCLEAR POWER AND PRESSURIZER PRESSURE AS A FUNCTION OF TIME



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

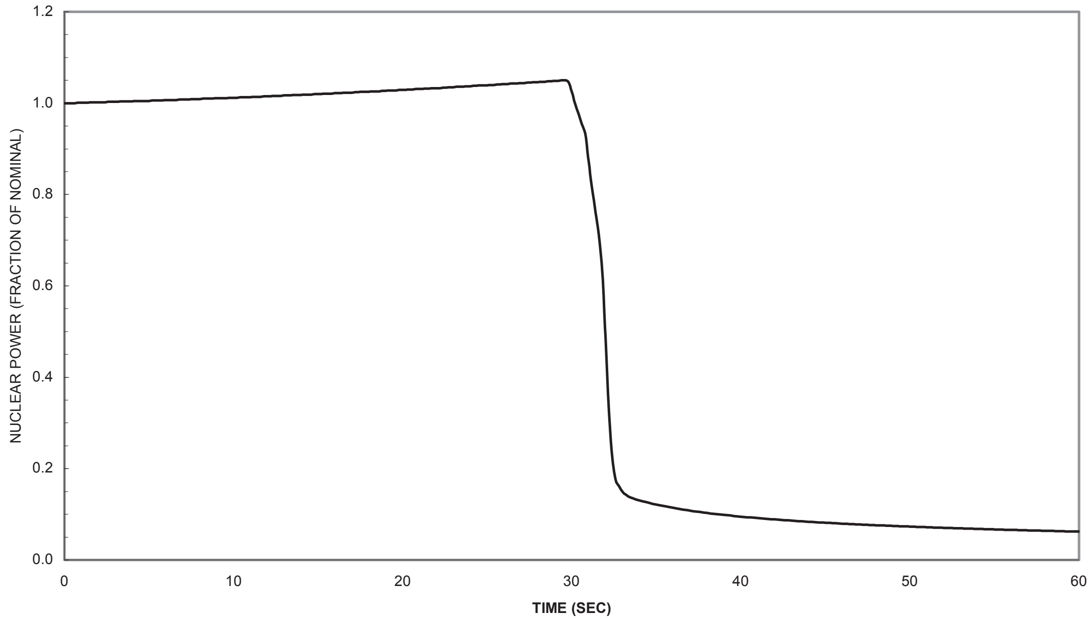
FIGURE 15.2.12-7
EXCESSIVE LOAD INCREASE WITH REACTOR CONTROL, END OF LIFE, (MTC), MAXIMUM FEEDBACK, DELTA-T AND TAVG AS A FUNCTION OF TIME

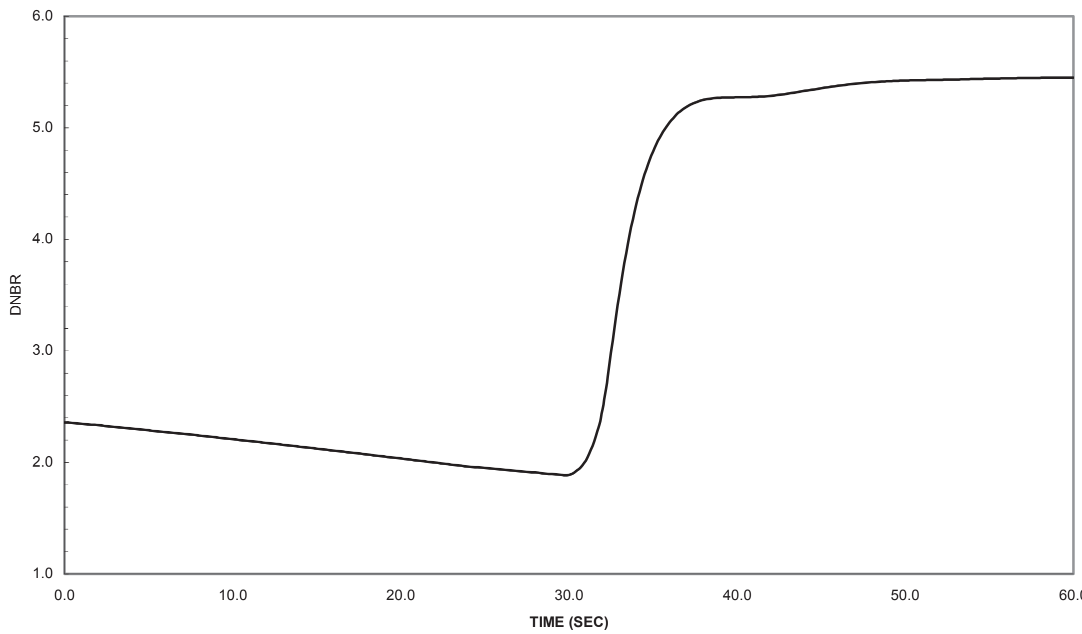


FSAR UPDATE

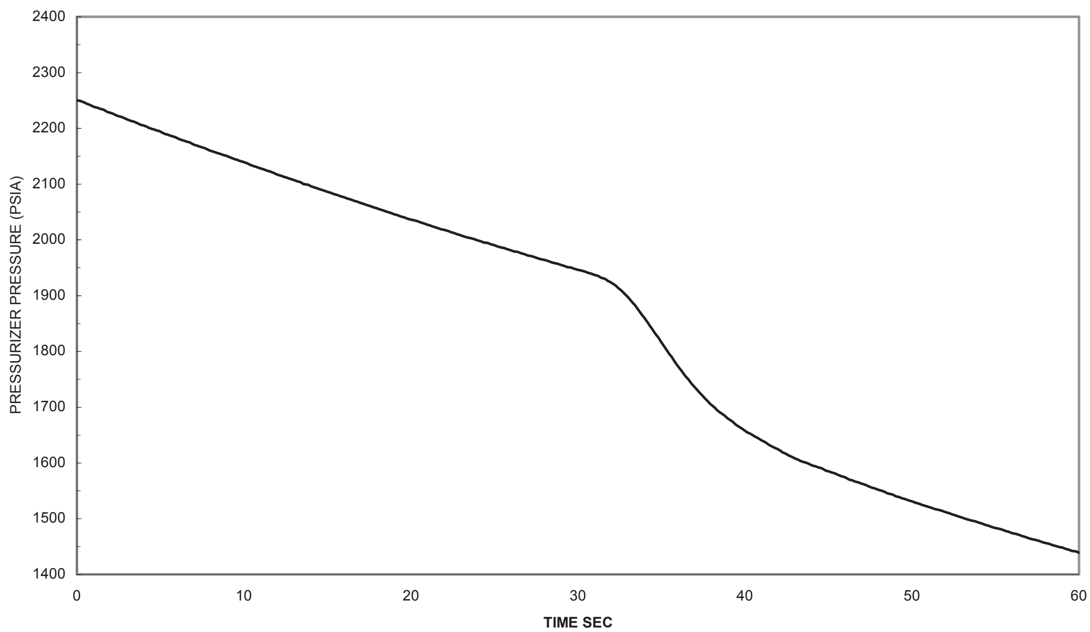
UNITS 1 AND 2
DIABLO CANYON SITE

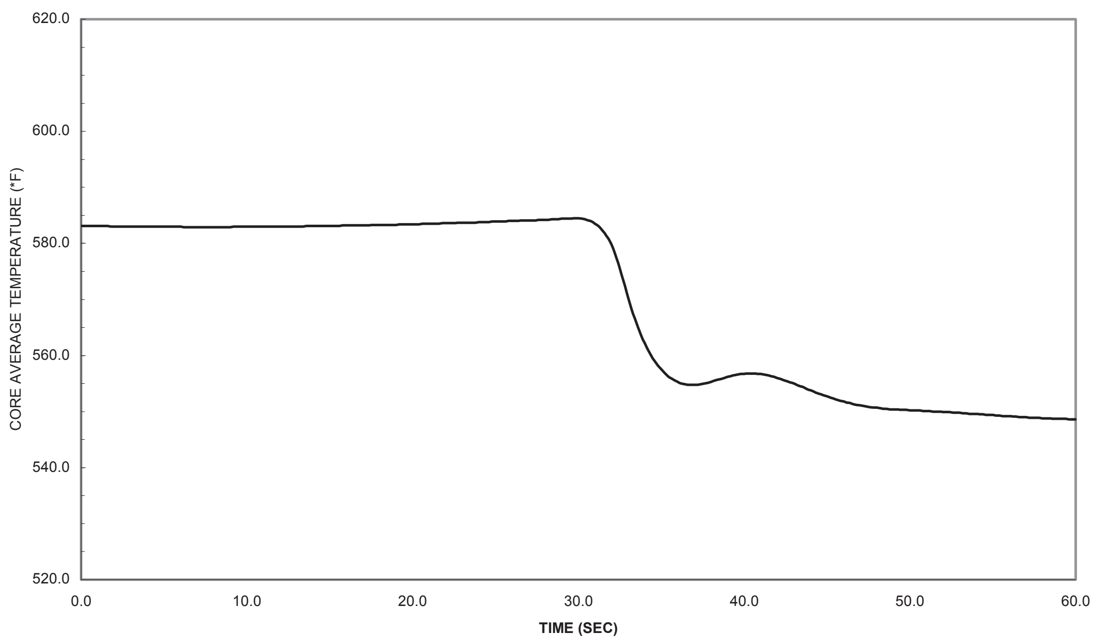
FIGURE 15.2.12-8
EXCESSIVE LOAD INCREASE WITH REACTOR CONTROL, END OF LIFE, (MTC), MAXIMUM FEEDBACK, DNBR, NUCLEAR POWER AND PRESSURIZER PRESSURE AS A FUNCTION OF TIME



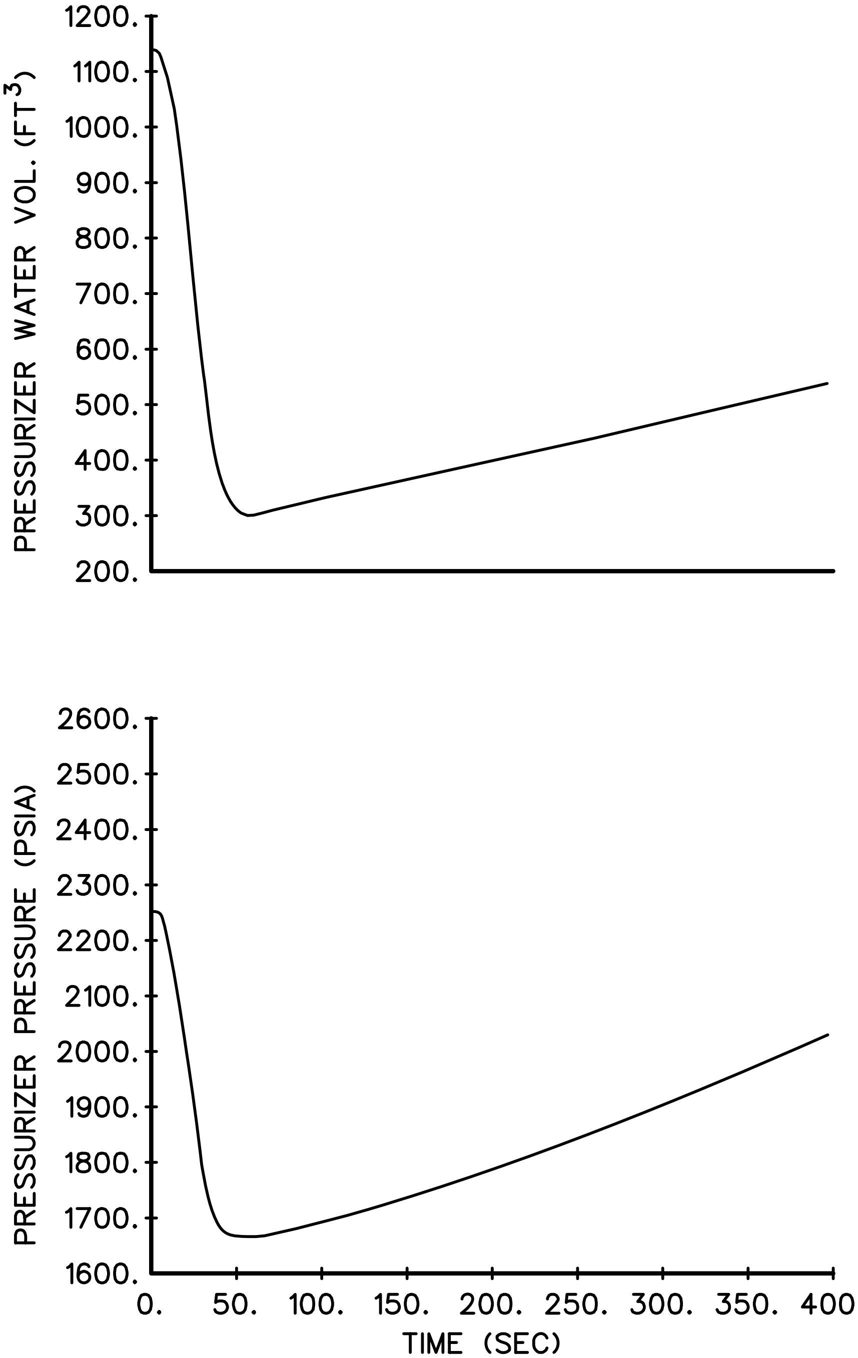


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.13-1 NUCLEAR POWER AND DNBR TRANSIENTS FOR ACCIDENTAL DEPRESSURIZATION OF THE REACTOR COOLANT SYSTEM





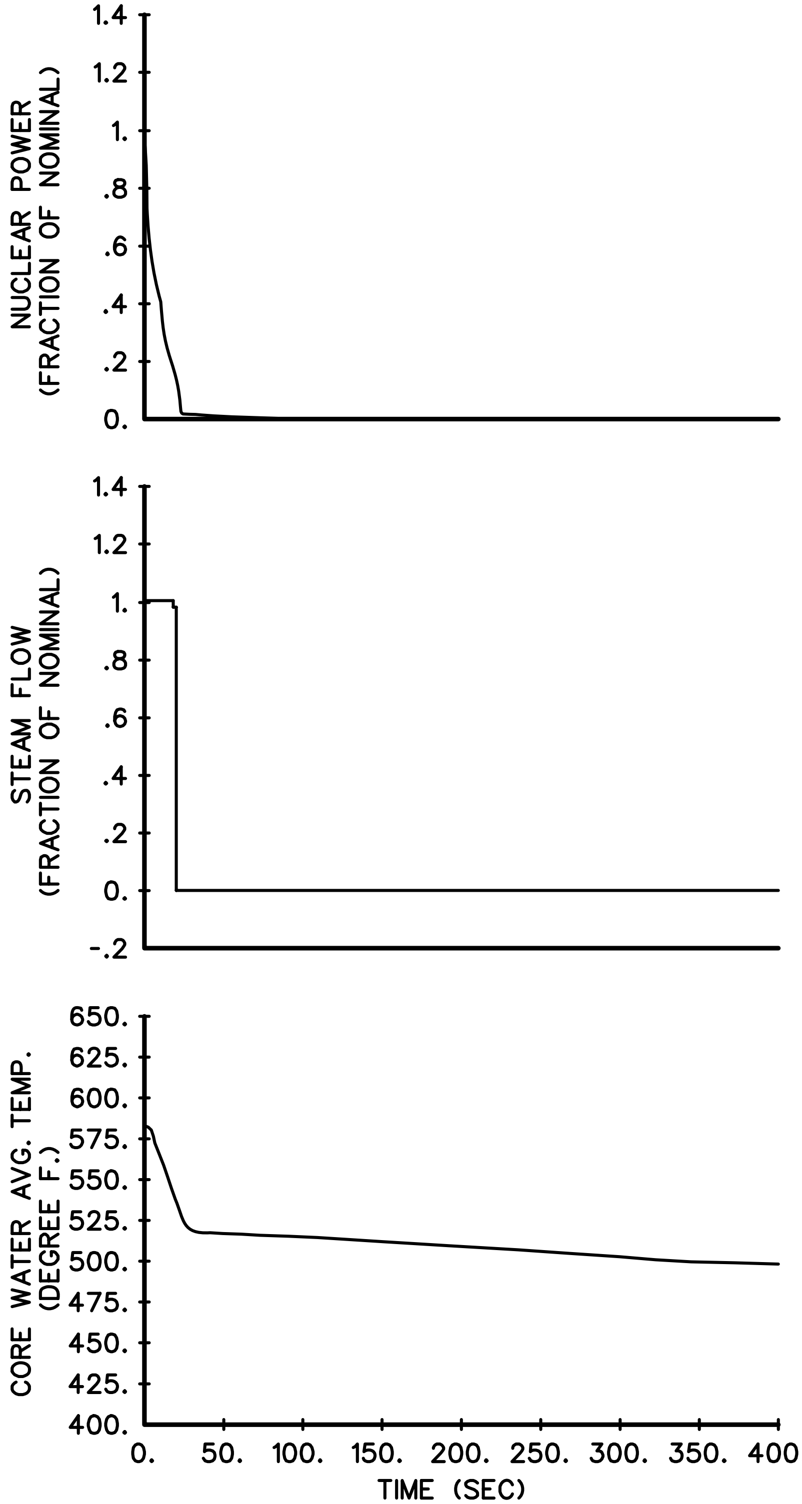
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.13-2 PRESSURIZER PRESSURE AND CORE AVERAGE TEMPERATURE TRANSIENTS FOR ACCIDENTAL DEPRESSURIZATION OF THE REACTOR COOLANT SYSTEM



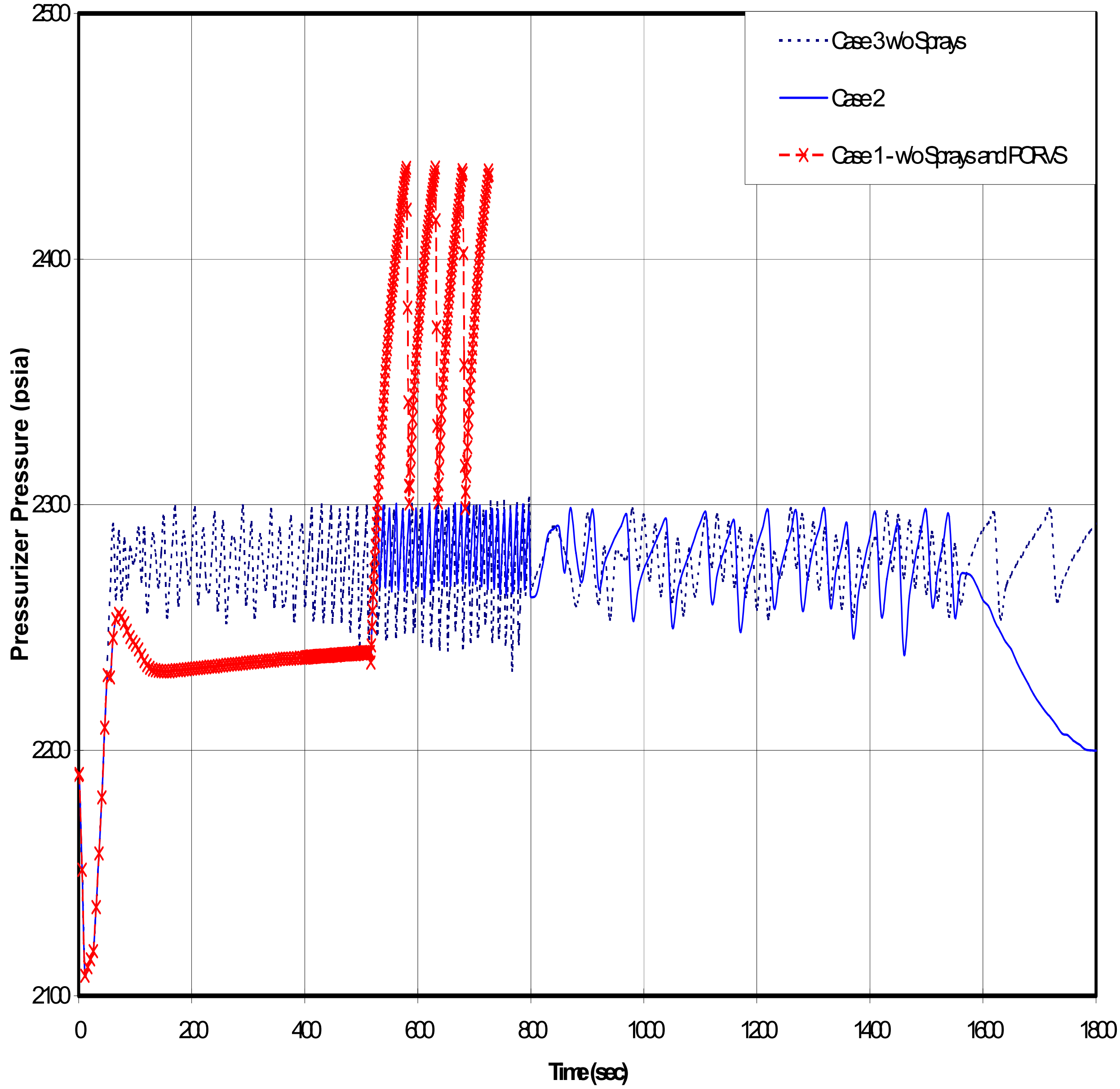
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.2.15-1
SPURIOUS ACTUATION OF SAFETY INJECTION SYSTEM AT POWER DNBR ANALYSIS – PRESSURIZER WATER VOLUME AND PRESSURIZER PRESSURE VERSUS TIME

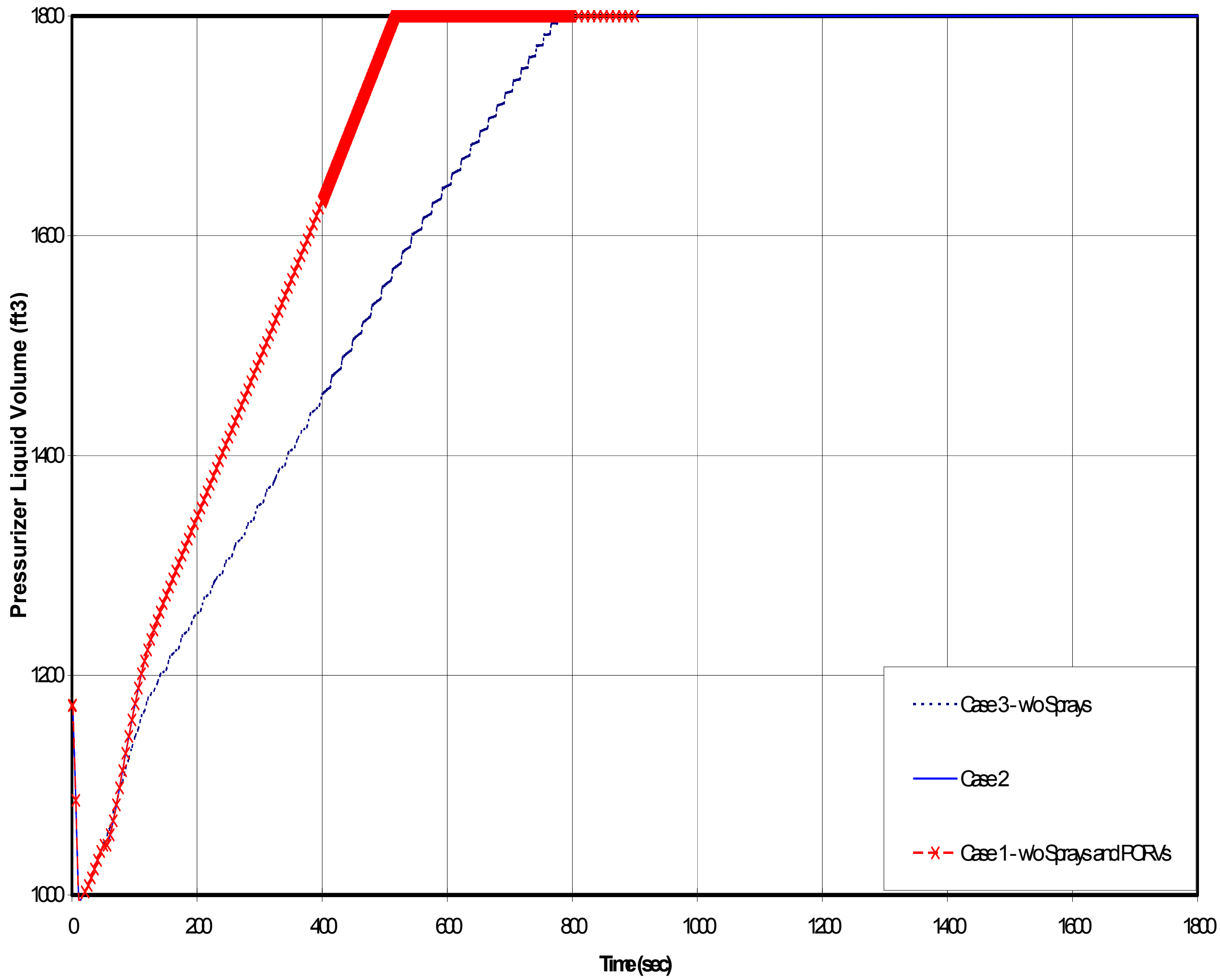


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.15-2 SPURIOUS ACTUATION OF SAFETY INJECTION SYSTEM AT POWER DNBR ANALYSIS – NUCLEAR POWER, STEAM FLOW, AND CORE WATER TEMPERATURE VERSUS TIME

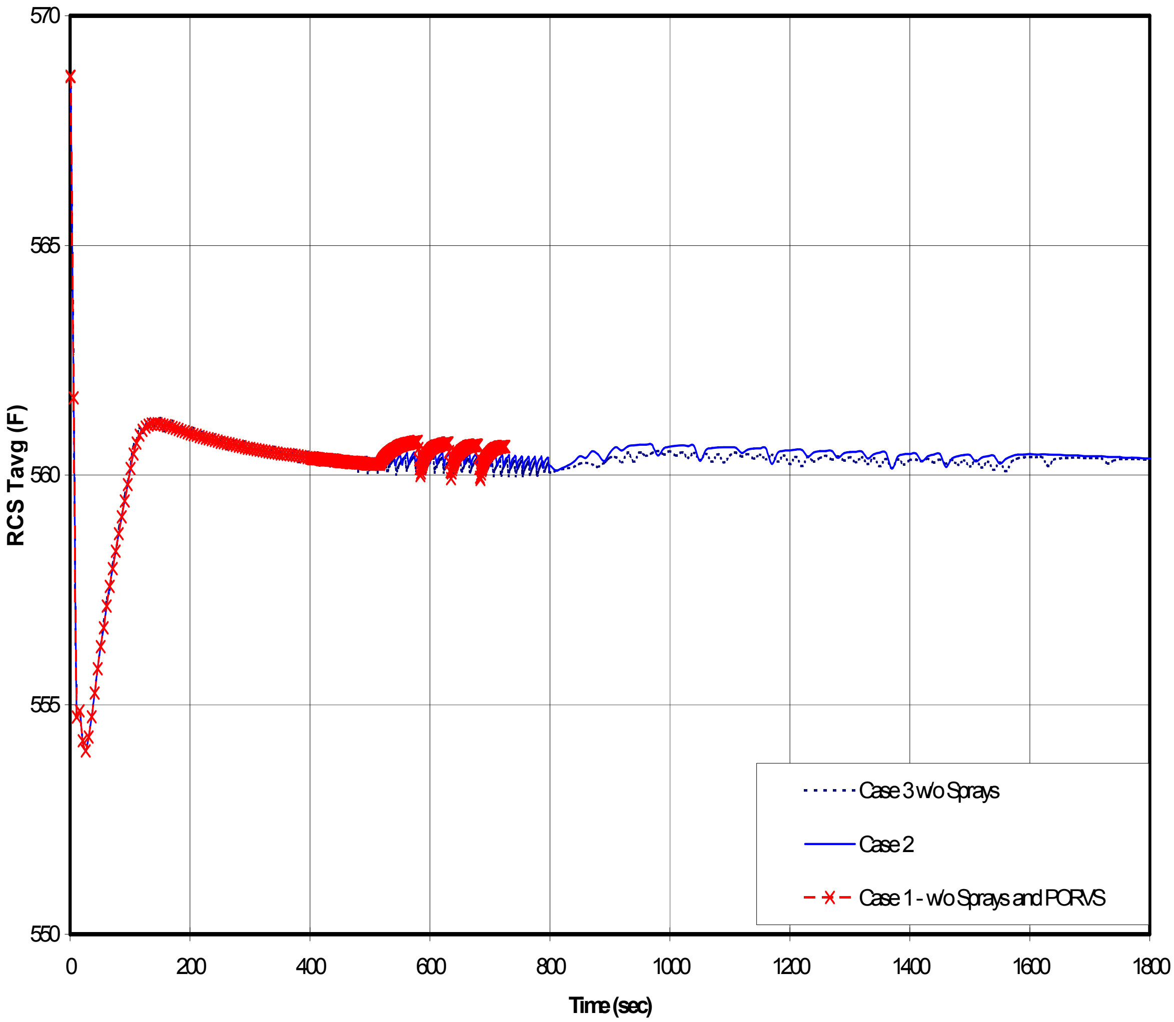


FSAR UPDATE
UNITS 1 AND 2 **DIABLO CANYON SITE**
FIGURE 15.2.15-3 **SSI PRESSURIZER OVERFILL ANALYSIS TYPICAL PRESSURIZER PRESSURE RESPONSE**

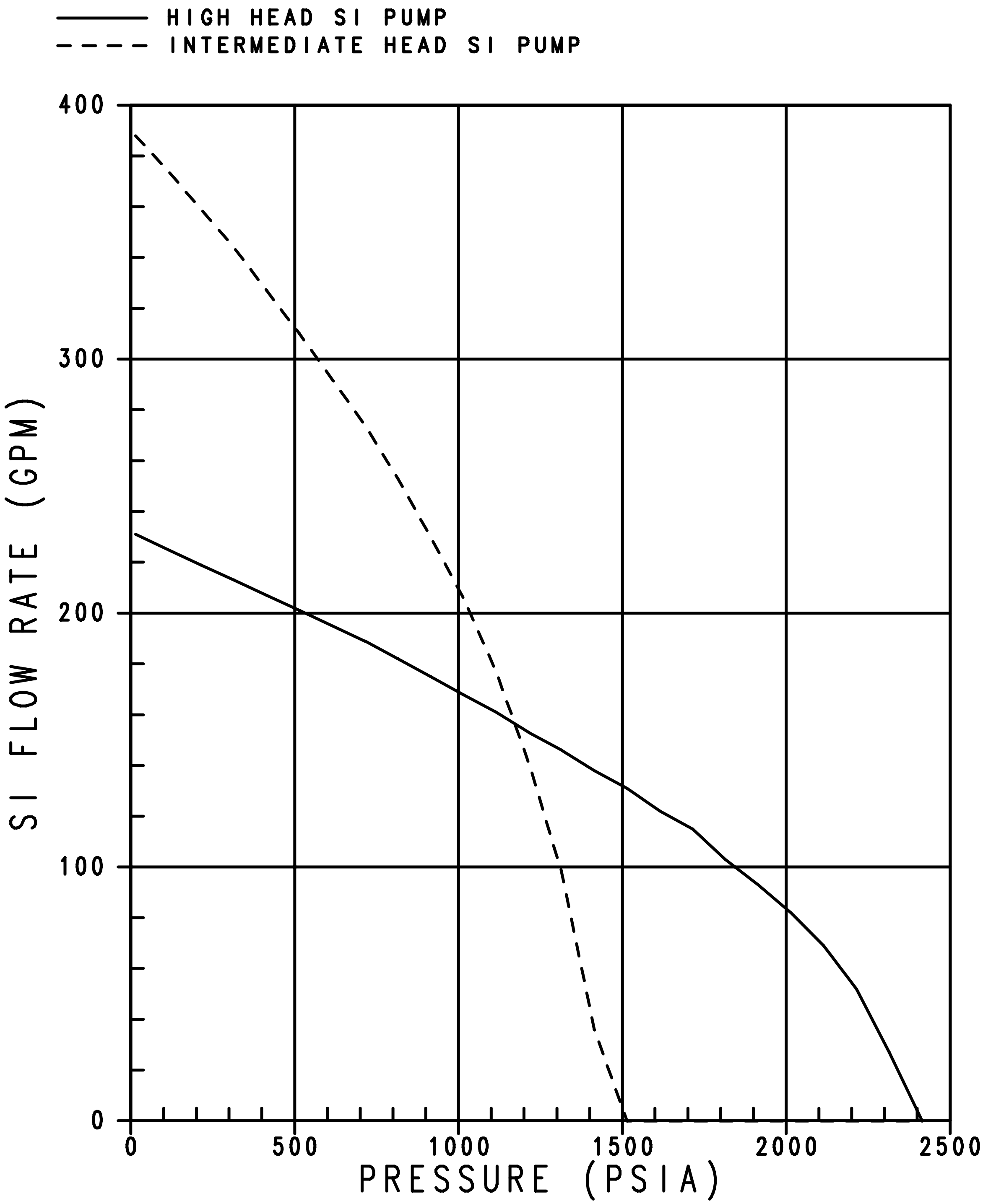
Revision 18 October 2008



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.15-4 SSI PRESSURIZER OVERFILL ANALYSIS TYPICAL PRESSURIZER LIQUID VOLUME RESPONSE



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.15-5 SSI PRESSURIZER OVERFILL ANALYSIS TYPICAL RCS AVERAGE TEMPERATURE RESPONSE



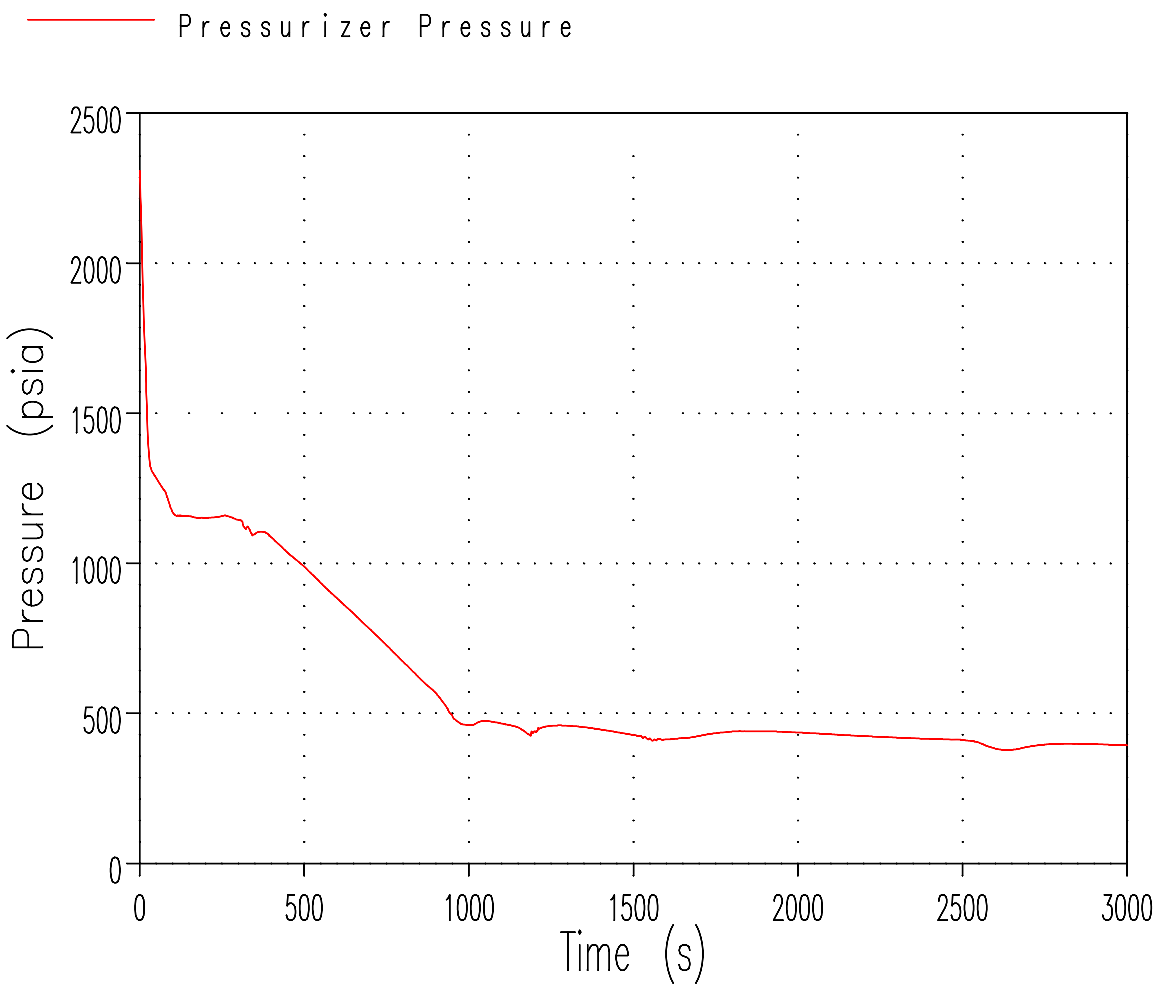
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.3-1

SAFETY INJECTION FLOW RATE FOR SMALL BREAK LOCA

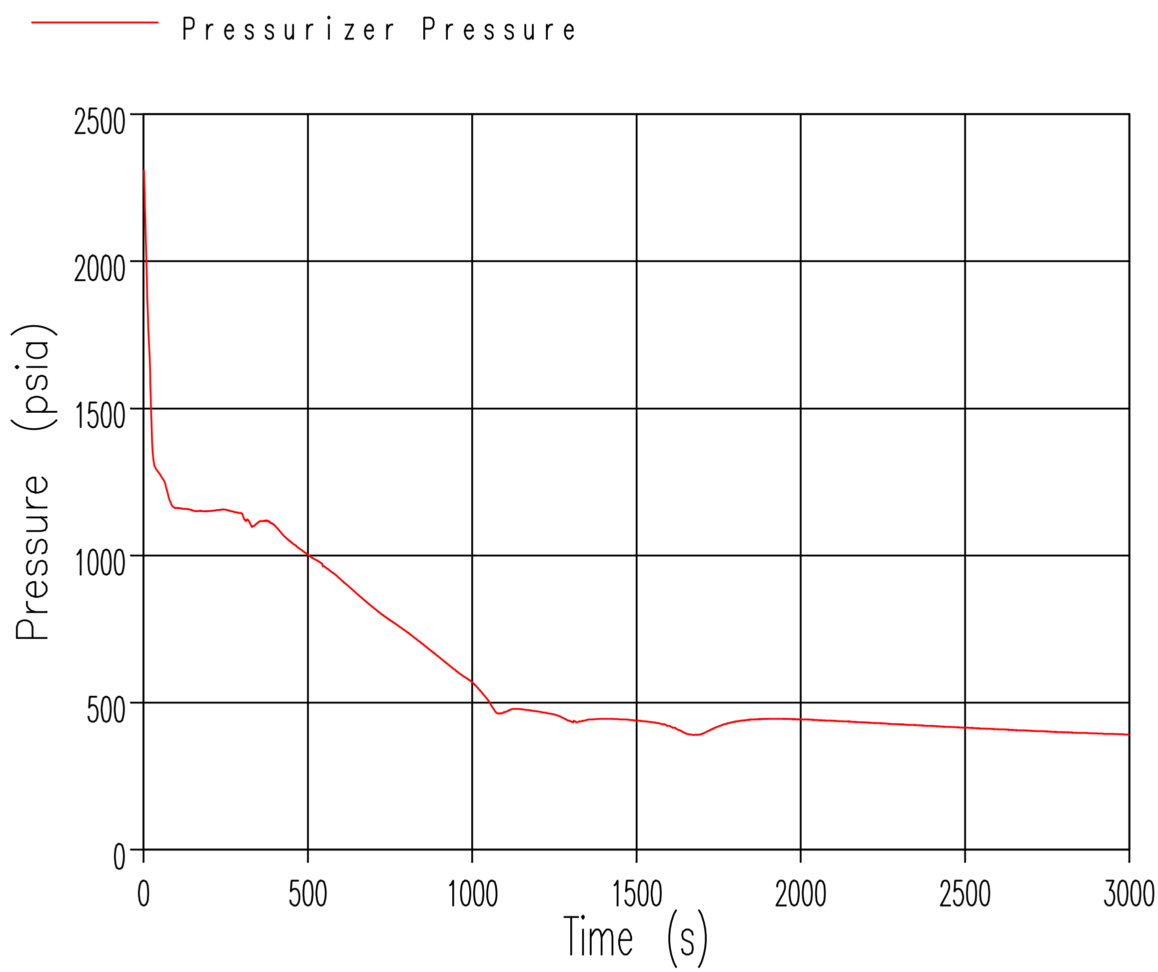
DCPP Unit 1



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.3-2 (Sheet 1 of 2) RCS DEPRESSURIZATION 4-INCH COLD LEG BREAK

Revision 21 September 2013

DCPP Unit 2



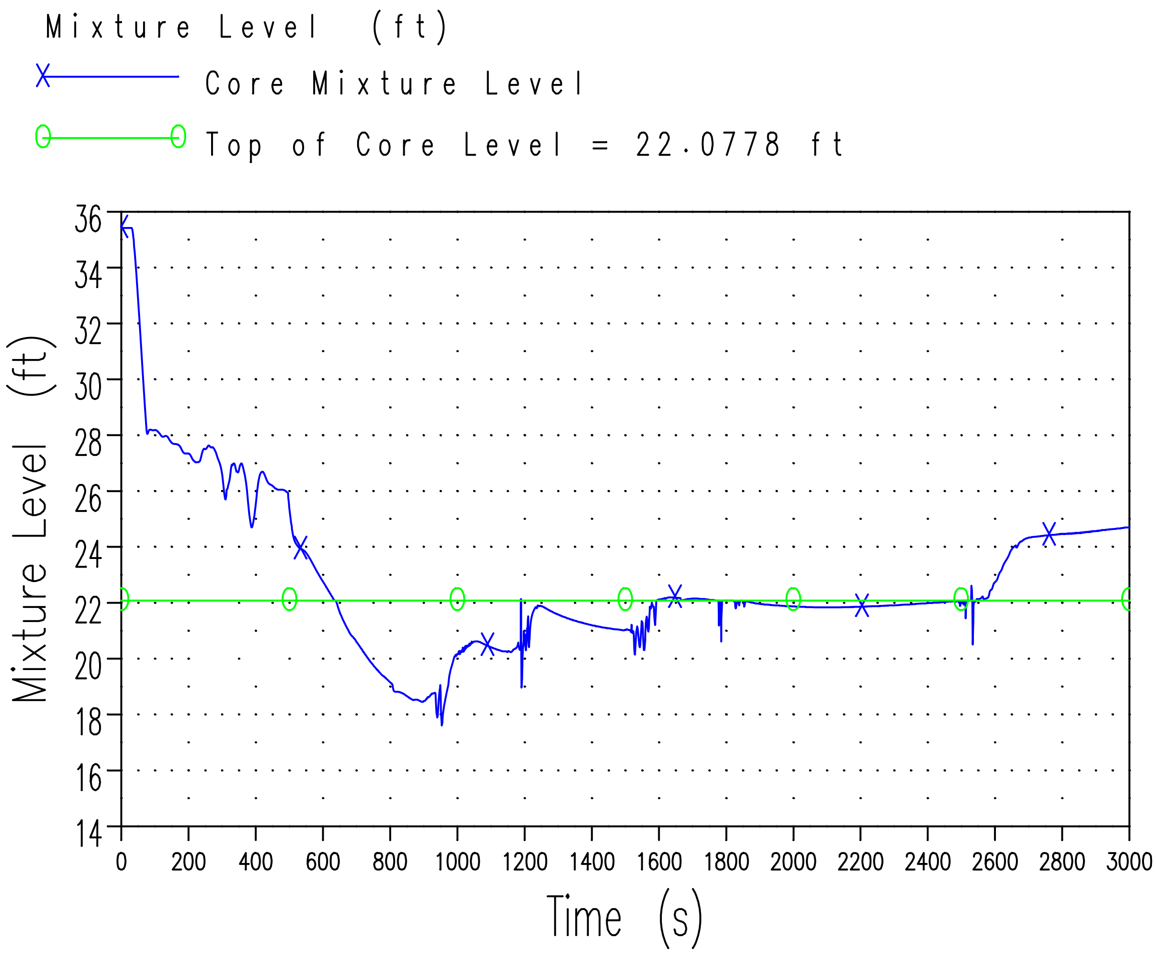
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.3-2 (Sheet 2 of 2)
RCS DEPRESSURIZATION
4-INCH COLD LEG BREAK

Revision 21 September 2013

DCPP Unit 1



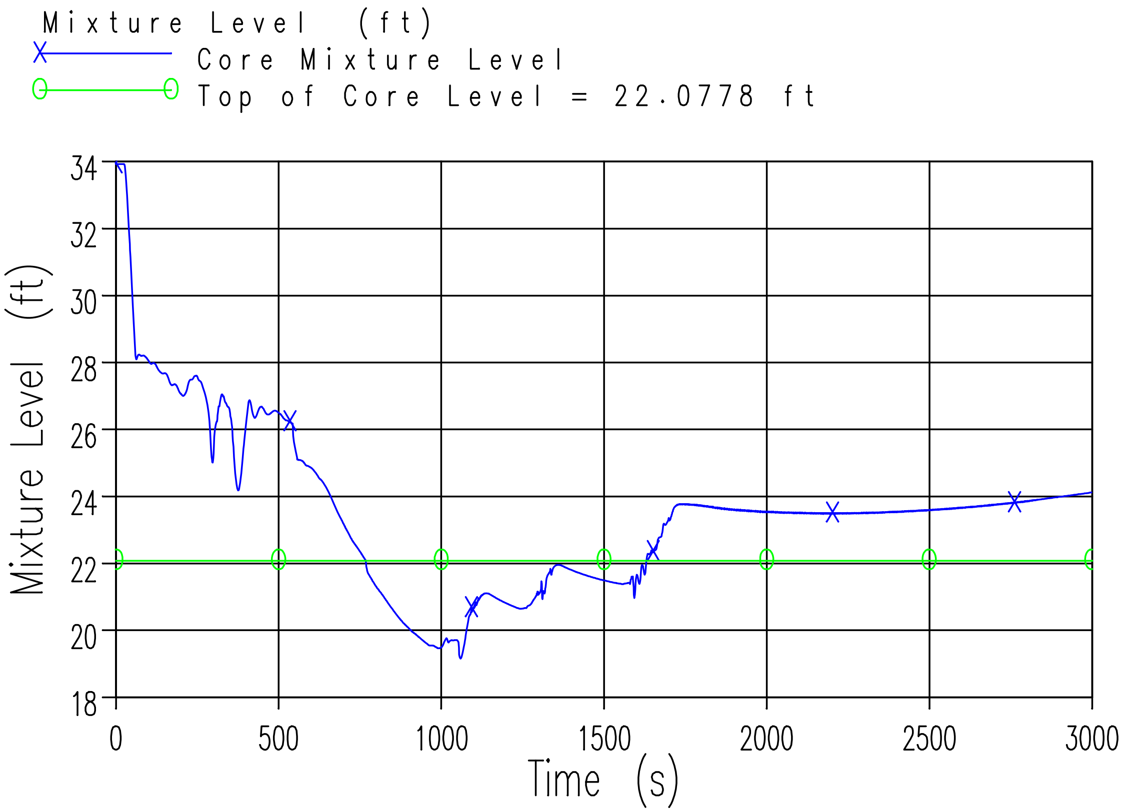
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.3-3 (Sheet 1 of 2)
CORE MIXTURE ELEVATION
4-INCH COLD LEG BREAK

Revision 21 September 2013

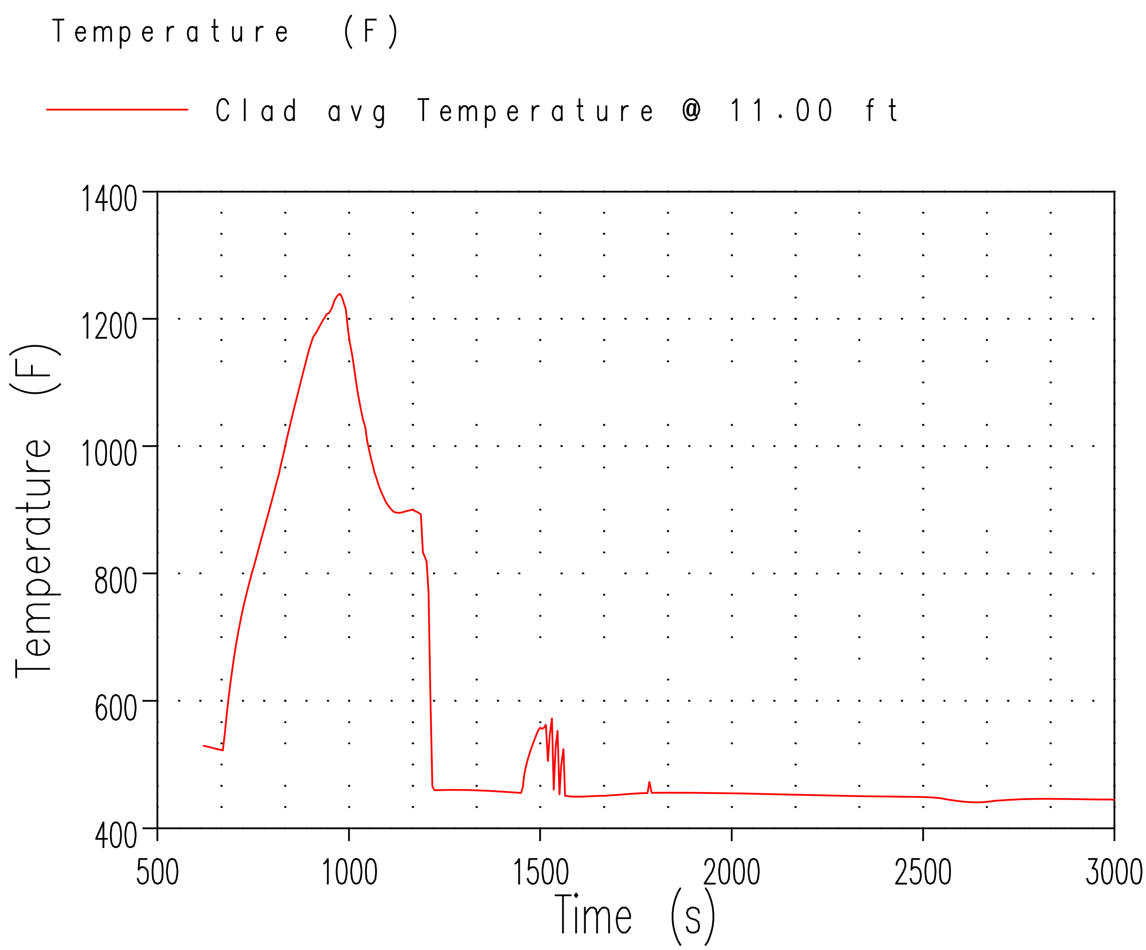
DCPP Unit 2



FSAR UPDATE
UNITS 1 AND 2 **DIABLO CANYON SITE**
FIGURE 15.3-3 (Sheet 2 of 2) **CORE MIXTURE ELEVATION** **4-INCH COLD LEG BREAK**

Revision 21 September 2013

DCPP Unit 1



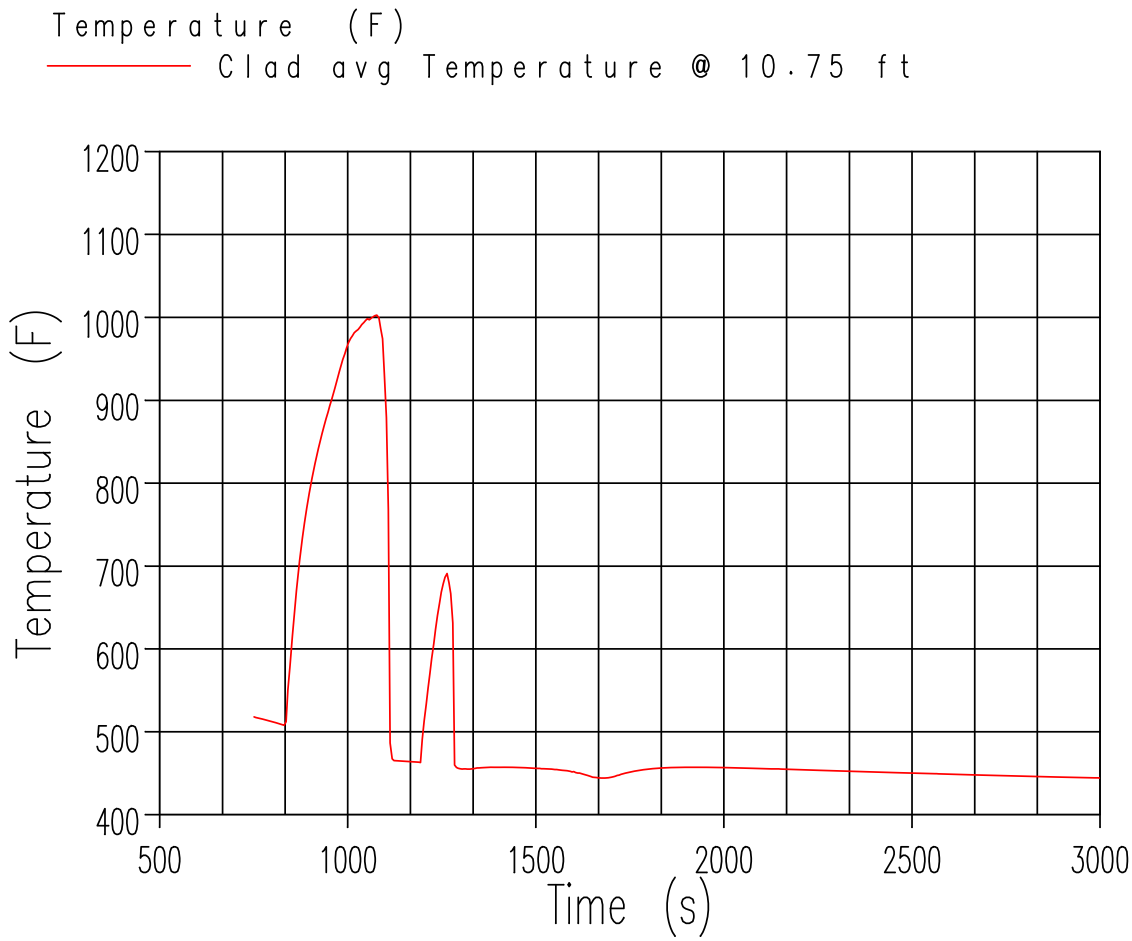
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.3-4 (Sheet 1 of 2)
CLADDING TEMPERATURE TRANSIENT
4-INCH COLD LEG BREAK

Revision 21 September 2013

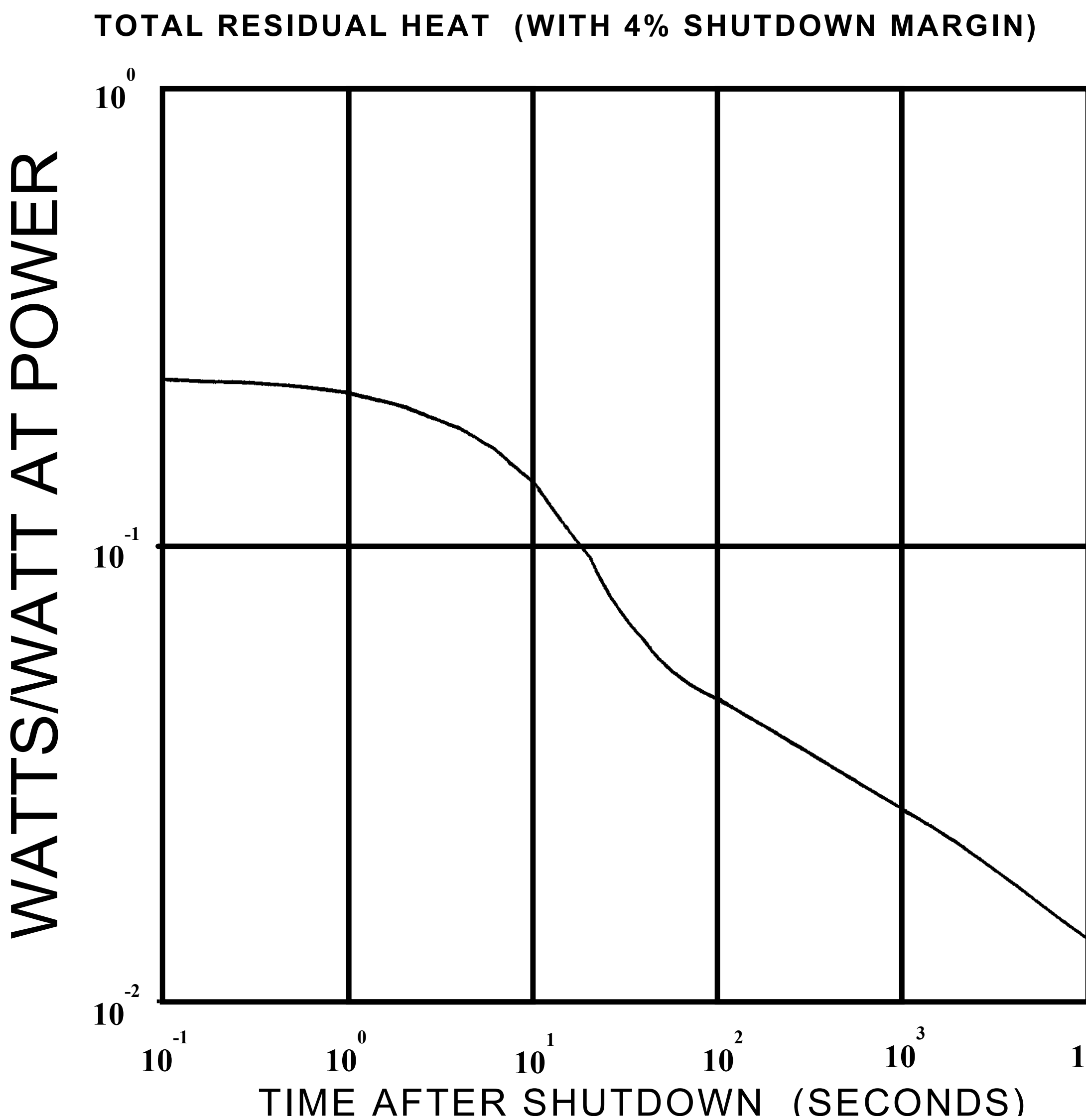
DCPP Unit 2



FSAR UPDATE

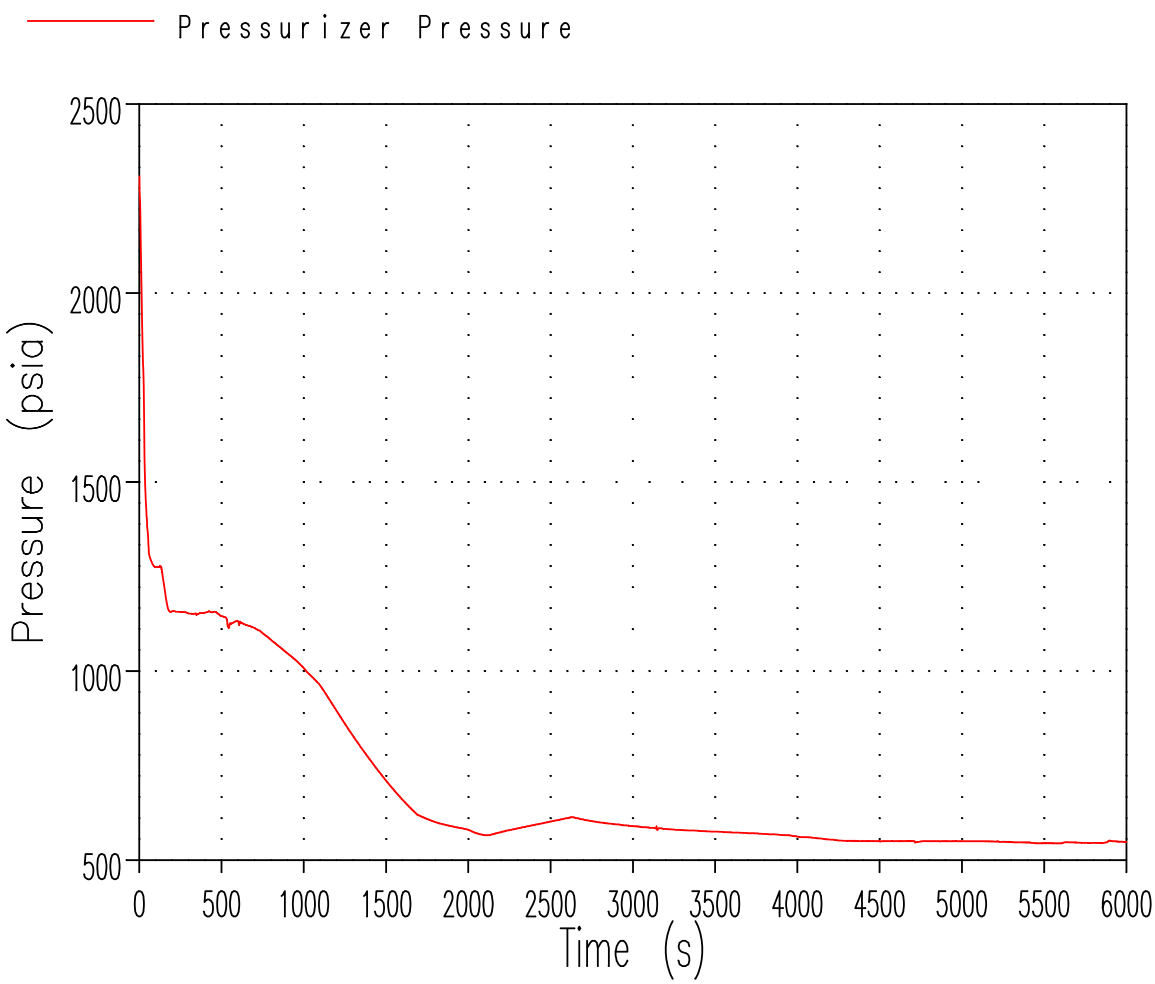
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.3-4 (Sheet 2 of 2)
CLADDING TEMPERATURE TRANSIENT
4-INCH COLD LEG BREAK



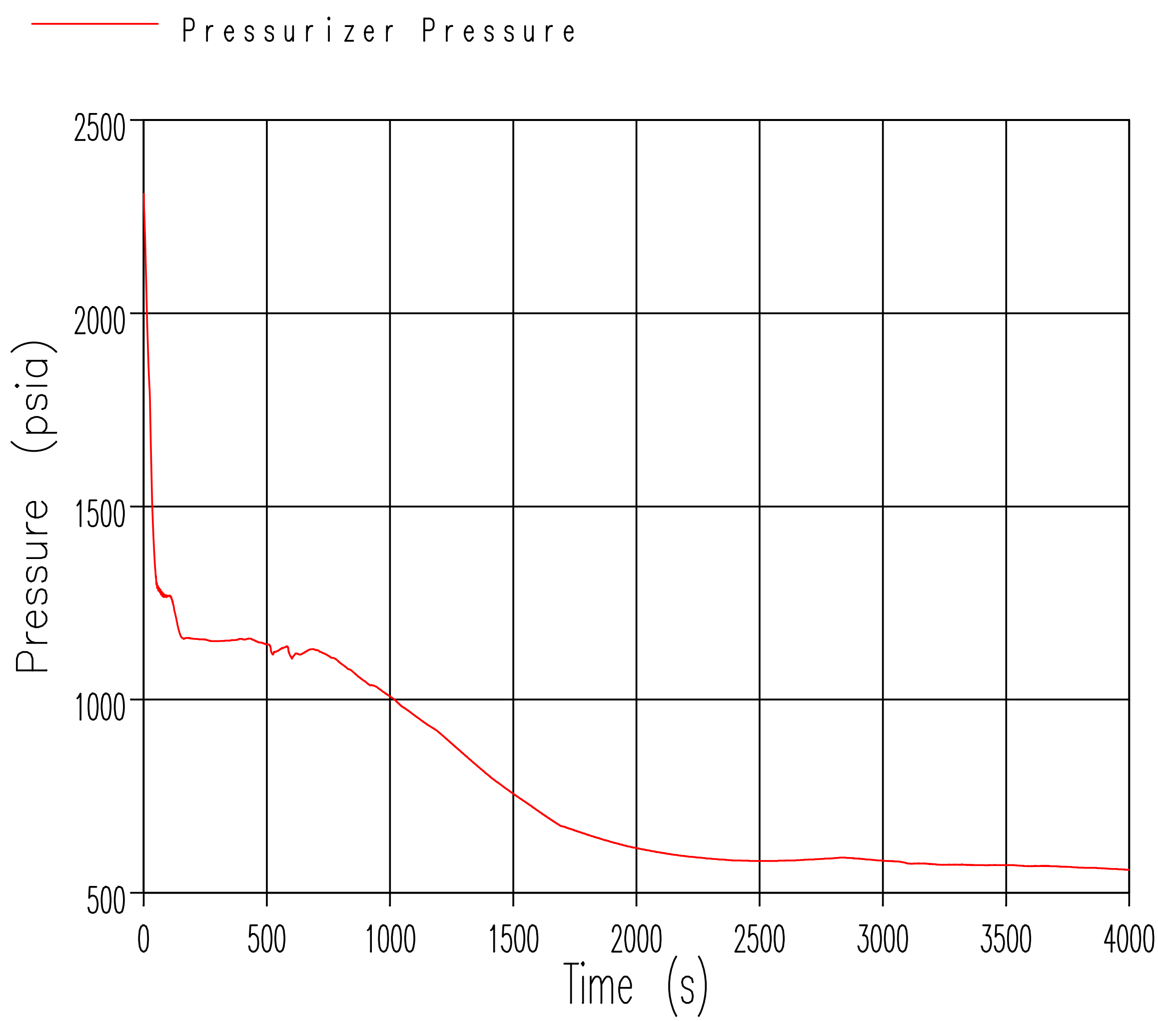
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.3-8 LOCA CORE POWER TRANSIENT

DCPP Unit 1



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.3-9 (Sheet 1 of 2) RCS DEPRESSURIZATION 3-INCH COLD LEG BREAK

DCPP Unit 2



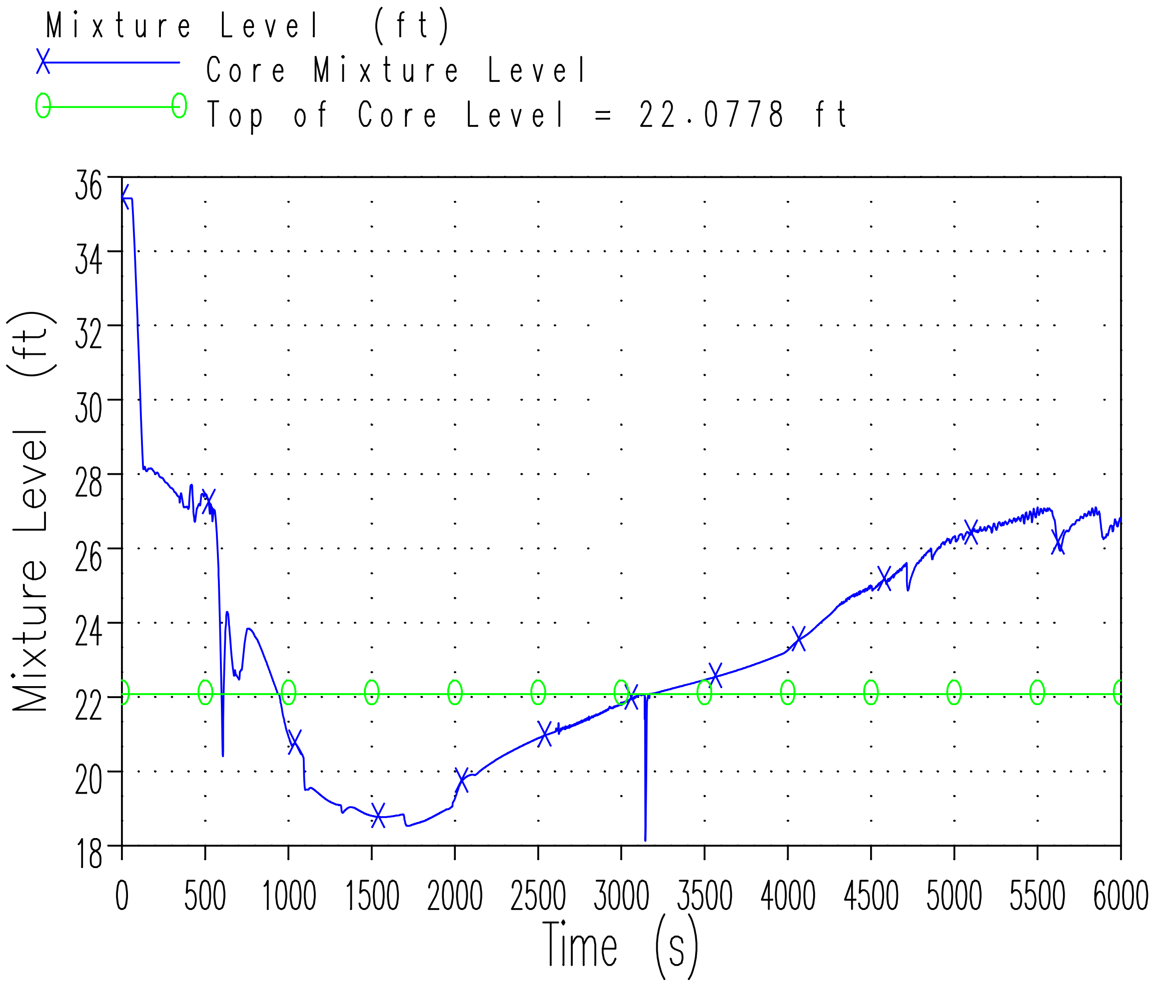
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.3-9 (Sheet 2 of 2)
RCS DEPRESSURIZATION
3-INCH COLD LEG BREAK

Revision 21 September 2013

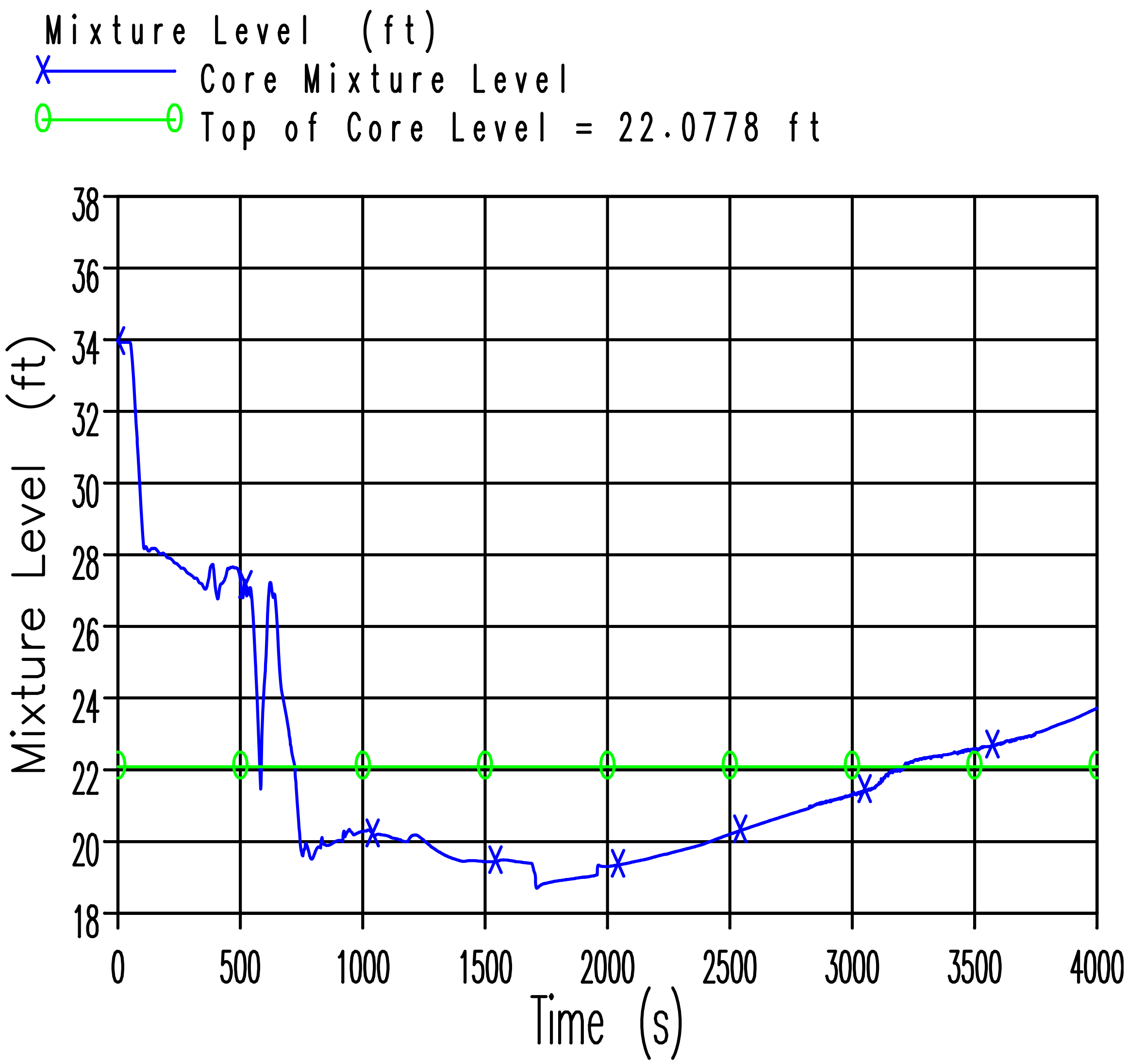
DCPP Unit 1



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.3-11 (Sheet 1 of 2) CORE MIXTURE ELEVATION 3-INCH COLD LEG BREAK

Revision 21 September 2013

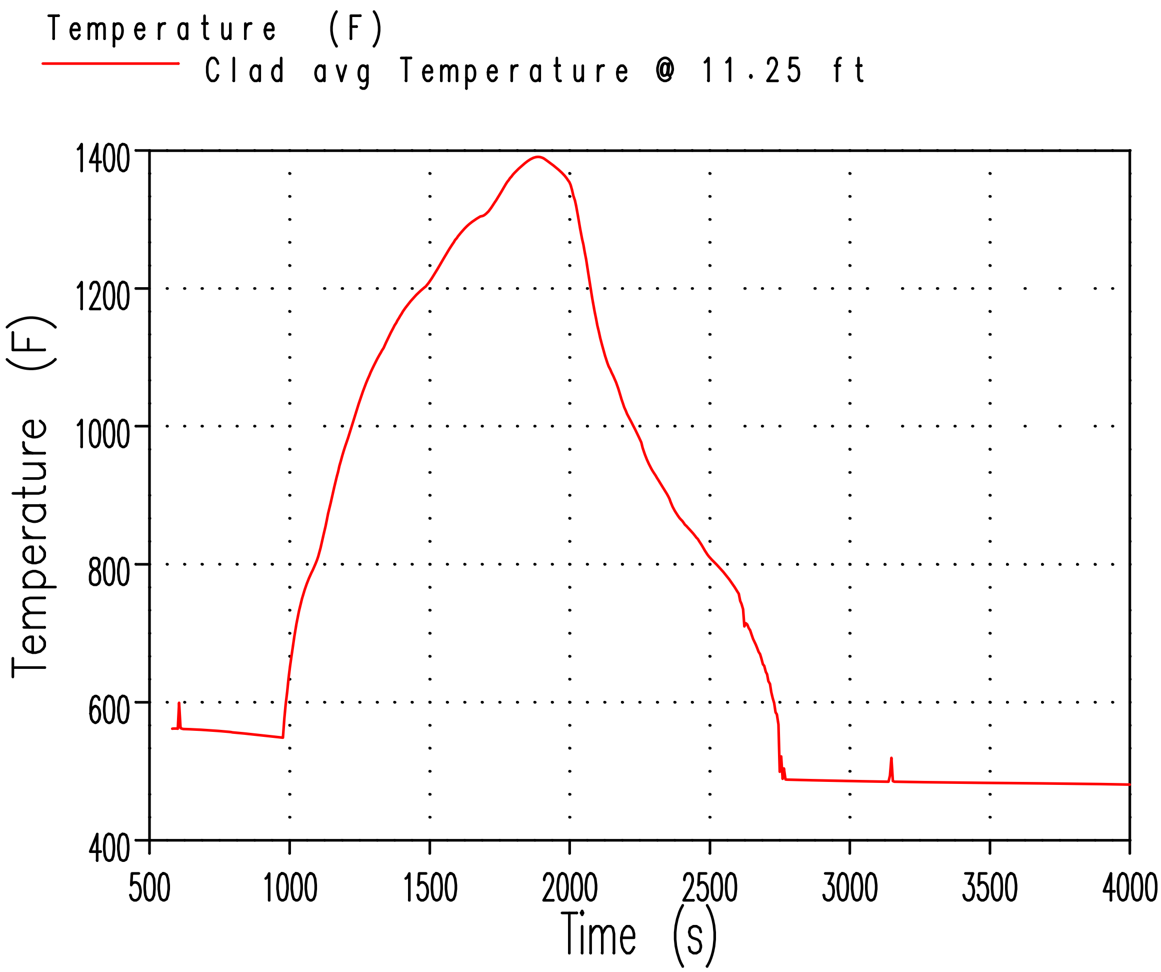
DCPP Unit 2



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.3-11 (Sheet 2 of 2) CORE MIXTURE ELEVATION 3-INCH COLD LEG BREAK

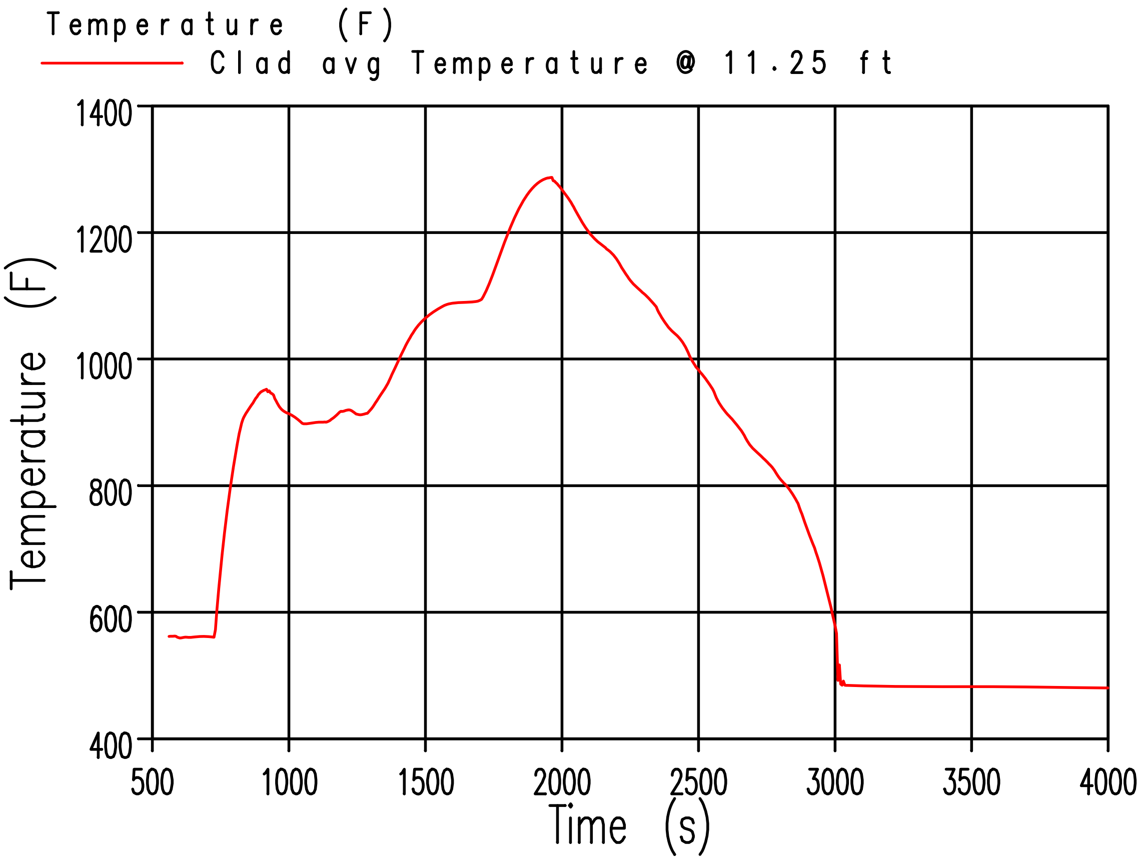
Revision 21 September 2013

DCPP Unit 1



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.3-13 (Sheet 1 of 2) CLAD TEMPERATURE TRANSIENT 3-INCH COLD LEG BREAK

DCPP Unit 2



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.3-13 (Sheet 2 of 2)
CLAD TEMPERATURE TRANSIENT
3-INCH COLD LEG BREAK

Revision 21 September 2013

4026-385

	R	P	N	M	L	K	J	H	G	F	E	D	C	B	A
1							-8.9			-7.4					
2			-5.6			-9.1		-8.5							
3								-8.2		-6.8		-4.1		0.2	
4		-7.9	-8.2					-7.7							
5					-8.4				-6.0		-3.8		-1.8		
6	-8.5		-8.4			-7.4		-5.5						-0.3	
7				-7.7			-5.0			-1.2			-1.0		
8	-7.7		-7.3		-5.9		-3.2			1.5		3.2	3.4	3.6	
9		-6.9							2.7		5.9				6.0
10					-3.4		0.7					10.6			
11	-5.3				-1.8			5.9			17.1				11.4
12						1.3			12.3			24.6			
13			0.1		0.7			7.7						23.6	
14			2.5				4.7			11.1		17.6			
15					2.1			6.5							

CASE A

THE NUMBERS REPRESENT THE PERCENT DEVIATION FROM ASSEMBLY AVERAGE POWER

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.3-15
INTERCHANGE BETWEEN
REGION 1 AND REGION 3 ASSEMBLY

Revision 21 September 2013

4026-386

	R	P	N	M	L	K	J	H	G	F	E	D	C	B	A
1					0.3			1.5							
2			3.2				0.8			3.2		6.0			
3			1.2		0.0			1.6						10.3	
4						0.0			2.9			6.5			
5	-2.2				-1.0			2.2			6.9				6.6
6					-1.7		0.5					8.8			
7		-3.2							5.2		16.7				5.4
8	-3.5		-3.4		-2.6		-0.7			11.4		11.3	5.8	4.4	
9				-3.6			-2.0			-2.3			2.2		
10	-3.8		-3.8			-3.6		-2.9						0.5	
11					-3.9				-4.3		-4.6		-1.5		
12		-2.8	-3.1					-4.5							
13								-4.8		-4.4		-2.6		1.4	
14			-0.4			-4.8		-4.8							
15							-4.8			-4.5					

CASE B-1

THE NUMBERS REPRESENT THE PERCENT DEVIATION FROM ASSEMBLY AVERAGE POWER.

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.3-16

INTERCHANGE BETWEEN REGION 1 AND REGION 2 ASSEMBLY, BURNABLE POISON RODS BEING RETAINED BY THE REGION 2 ASSEMBLY

4026-387

	R	P	N	M	L	K	J	H	G	F	E	D	C	B	A
1							1.0			1.1					
2			5.1			1.0		1.0							
3								1.1		1.1		1.9		4.9	
4		1.7	1.7					1.4							
5					1.1				1.8		1.1		0.7		
6	0.0		0.2			1.8		3.9						4.0	
7				0.0			5.2			2.2			-0.3		
8	-0.7		-0.6		0.3		5.1			1.5		-0.3	-0.6	-0.7	
9		-1.0							-1.1		-0.8				-0.9
10					-1.4		-3.1					-1.3			
11	-0.9				-1.7						-1.7				-0.9
12						-2.5			-2.9			-1.1			
13			0.7		-1.9			-2.9						2.5	
14			2.3				-2.8			-2.4		-0.8			
15					-2.1			-2.8							

CASE B-2

THE NUMBERS REPRESENT THE PERCENT DEVIATION FROM ASSEMBLY AVERAGE POWER.

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.3-17

INTERCHANGE BETWEEN REGION 1 AND REGION 2 ASSEMBLY, BURNABLE POISON RODS BEING TRANSFERRED TO THE REGION 1 ASSEMBLY

4026-388

	R	P	N	M	L	K	J	H	G	F	E	D	C	B	A
1							-2.2			-2.1					
2			2.0			-2.0		-2.1							
3								-1.5		-1.6		-1.0		2.0	
4		-0.9	-1.0					-0.4							
5					-0.4				1.2		-0.5		-1.4		
6	-2.1		-1.6			2.3		5.7						-2.0	
7				-3.2			9.7			4.4			-1.7		
8	-2.3		-1.6		1.8		13.6			5.6		-0.4	-1.6	-2.1	
9		-2.2							9.7		1.1				-2.2
10					0.3		4.5					-0.9			
11	-1.9				-0.4			1.8			-0.5				-1.9
12						-0.9			-0.6			-1.1			
13			0.4		-1.4			-1.5						2.0	
14			2.0				-2.1			-2.0		-0.9			
15					-1.9			-2.2							

CASE C

THE NUMBERS REPRESENT THE PERCENT DEVIATION FROM ASSEMBLY AVERAGE POWER.

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.3-18

ENRICHMENT ERROR: A REGION 2 ASSEMBLY LOADED INTO THE CORE CENTRAL POSITION

Revision 21 September 2013

4026-389

	R	P	N	M	L	K	J	H	G	F	E	D	C	B	A
1							-11.0			-14.0					
2			0.4			-9.2		-12.0							
3								-12.0		-14.0		-15.0		-13.0	
4		3.2	1.2					-11.0							
5					-1.5				-12.0		-15.0		-16.0		
6	9.8		7.1			-1.6		-8.0						-16.0	
7				9.2			-2.3			-12.0			-14.0		
8	20.0		17.8		10.8		0.8			-10.0		-14.0	-15.0	-16.0	
9		27.2							-5.5		-11.0				-15.0
10					20.7		5.8					-12.0			
11	42.0		X		23.6			1.9			-8.6				-13.0
12						14.0			-1.7			-8.9			
13			38.6		20.4			2.8						-7.0	
14			35.9				7.0			-3.3		-6.3			
15					15.3			2.9							

CASE D

THE NUMBERS REPRESENT THE PERCENT DEVIATION FROM ASSEMBLY AVERAGE POWER.

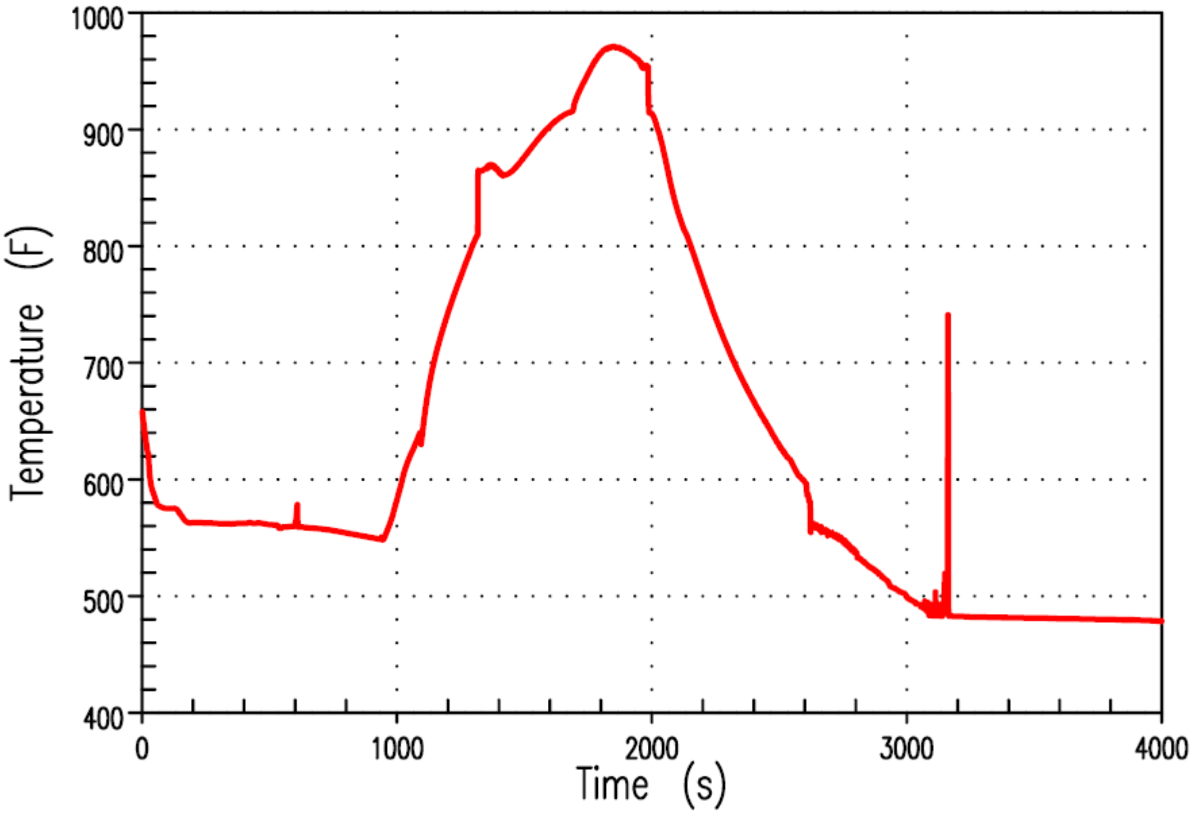
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.3-19

LOADING A REGION 2 ASSEMBLY INTO A REGION 1 POSITION NEAR CORE PERIPHERY

DCPP Unit 1

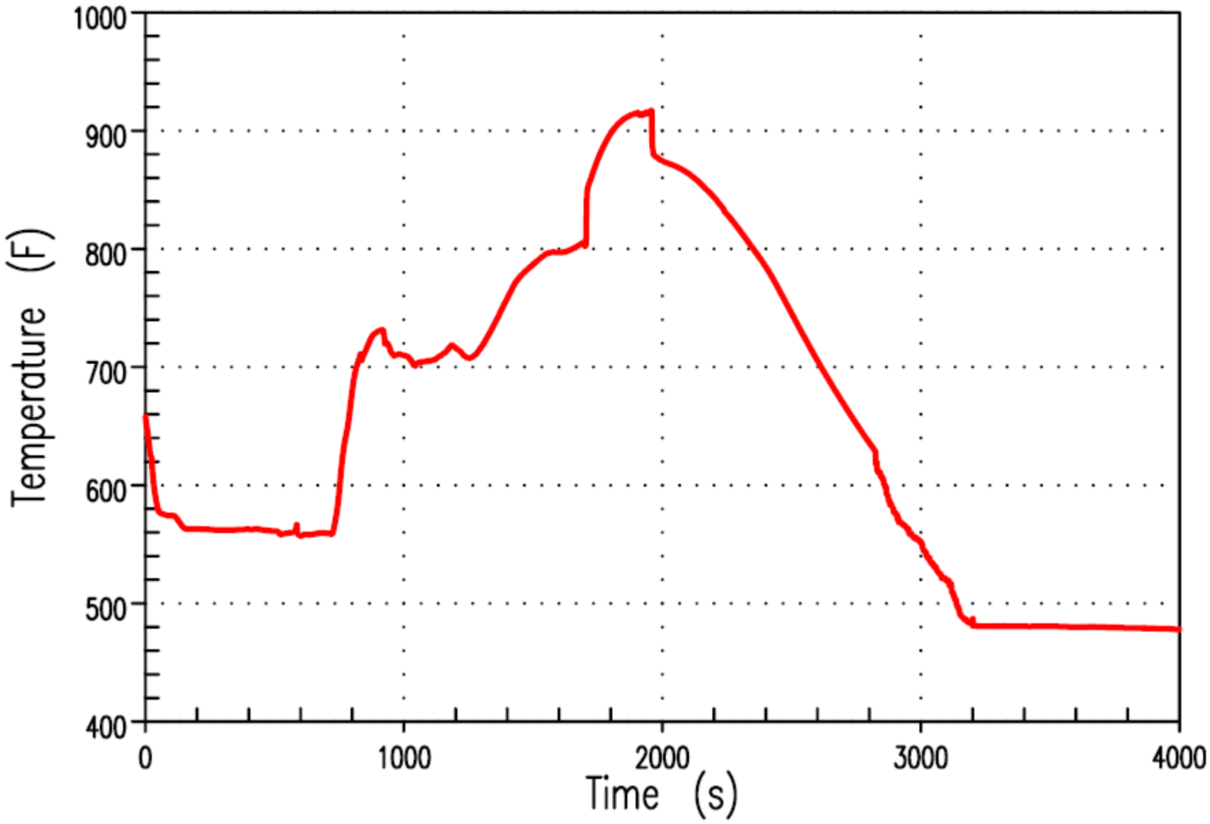


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

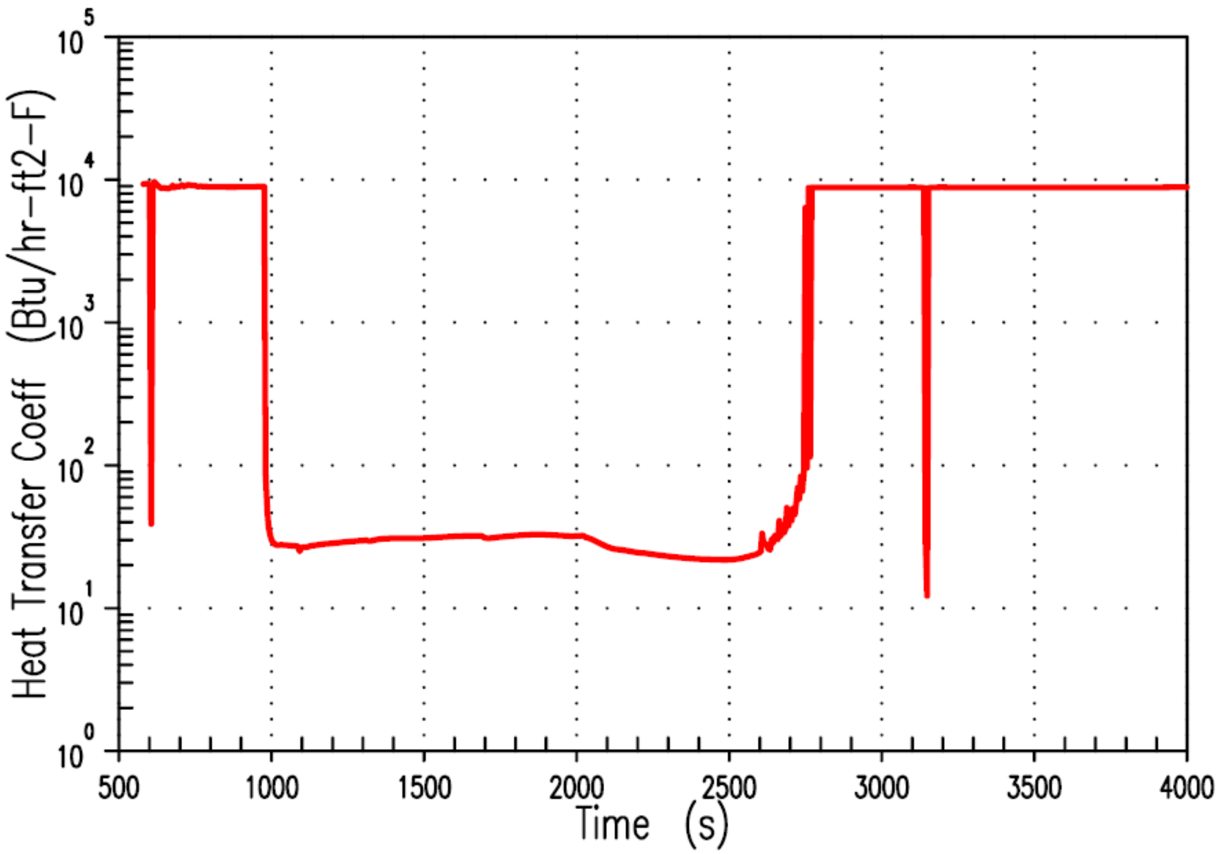
FIGURE 15.3-33 (Sheet 1 of 2)
TOP CORE NODE VAPOR TEMPERATURE
3-INCH COLD LEG BREAK

DCPP Unit 2



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.3-33 (Sheet 2 of 2) TOP CORE NODE VAPOR TEMPERATURE 3-INCH COLD LEG BREAK

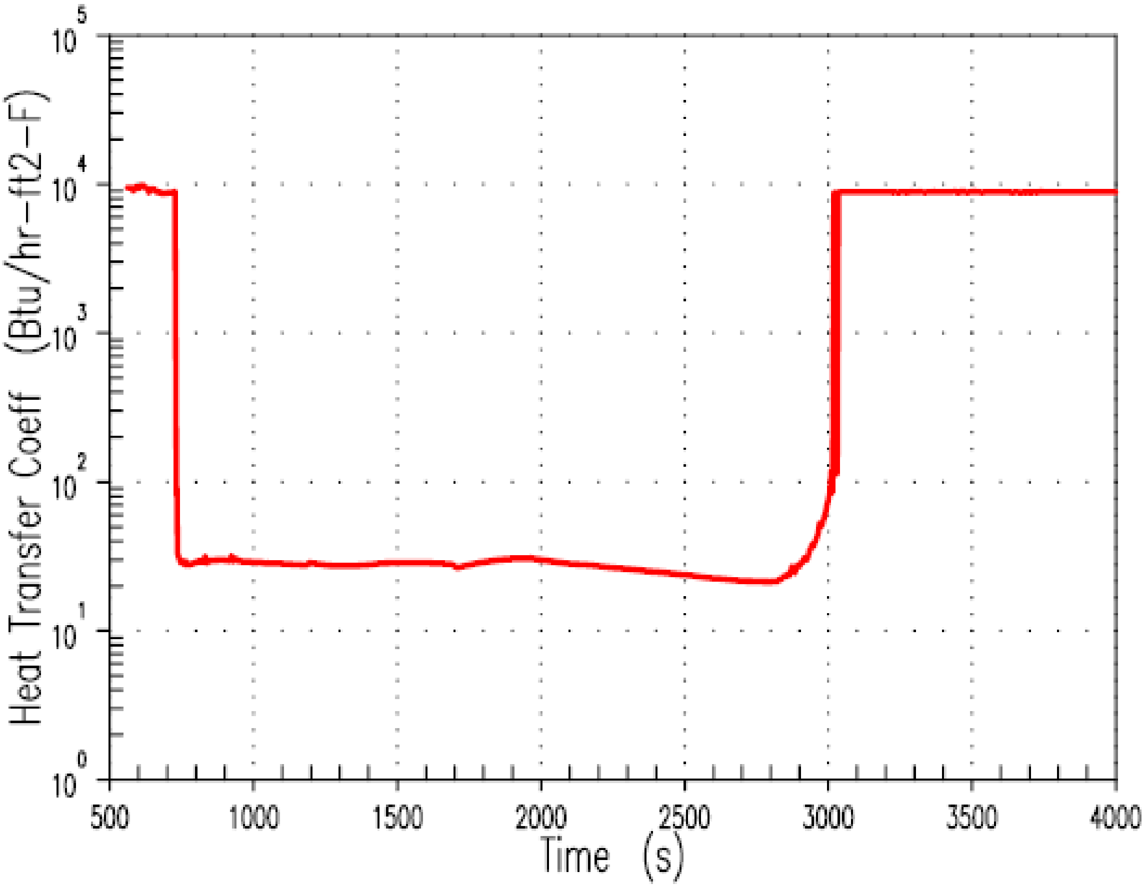
DCPP Unit 1



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.3-34 (Sheet 1 of 2) ROD FILM COEFFICIENT 3-INCH COLD LEG BREAK

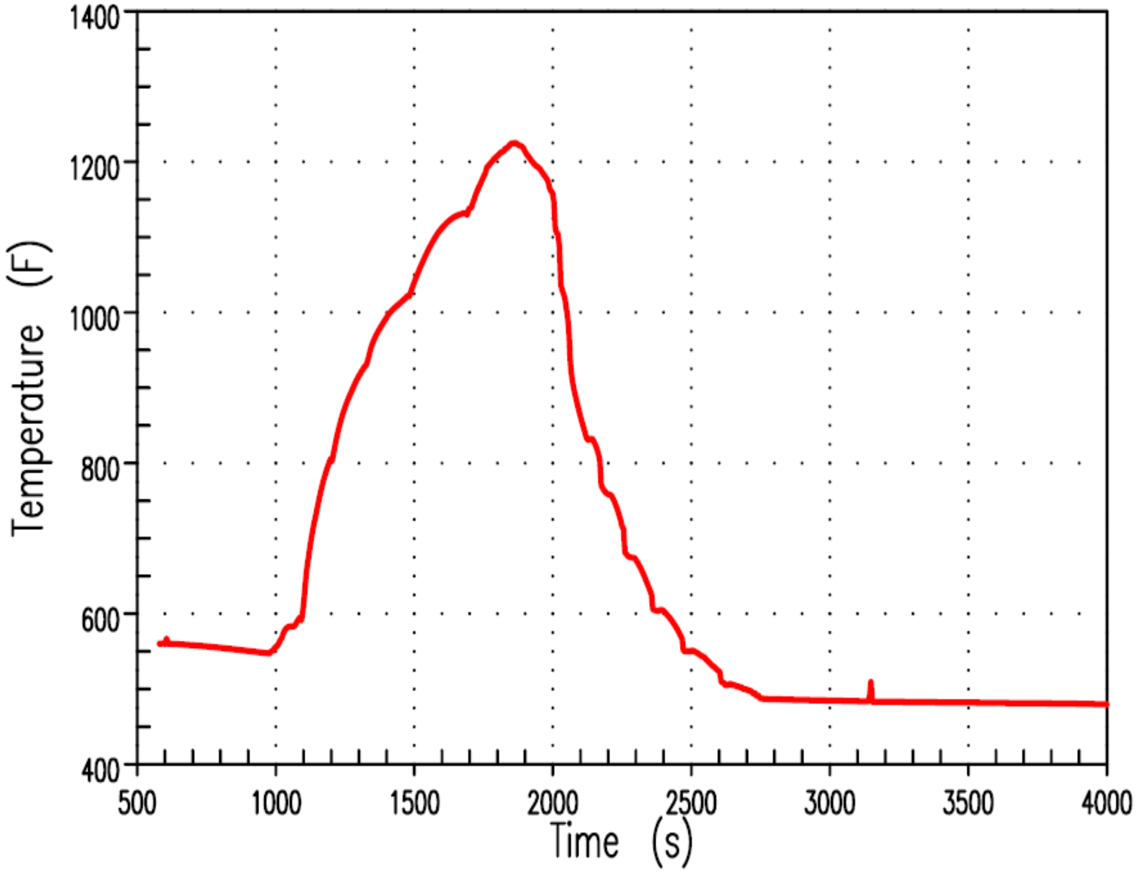
Revision 21 September 2013

DCPP Unit 2



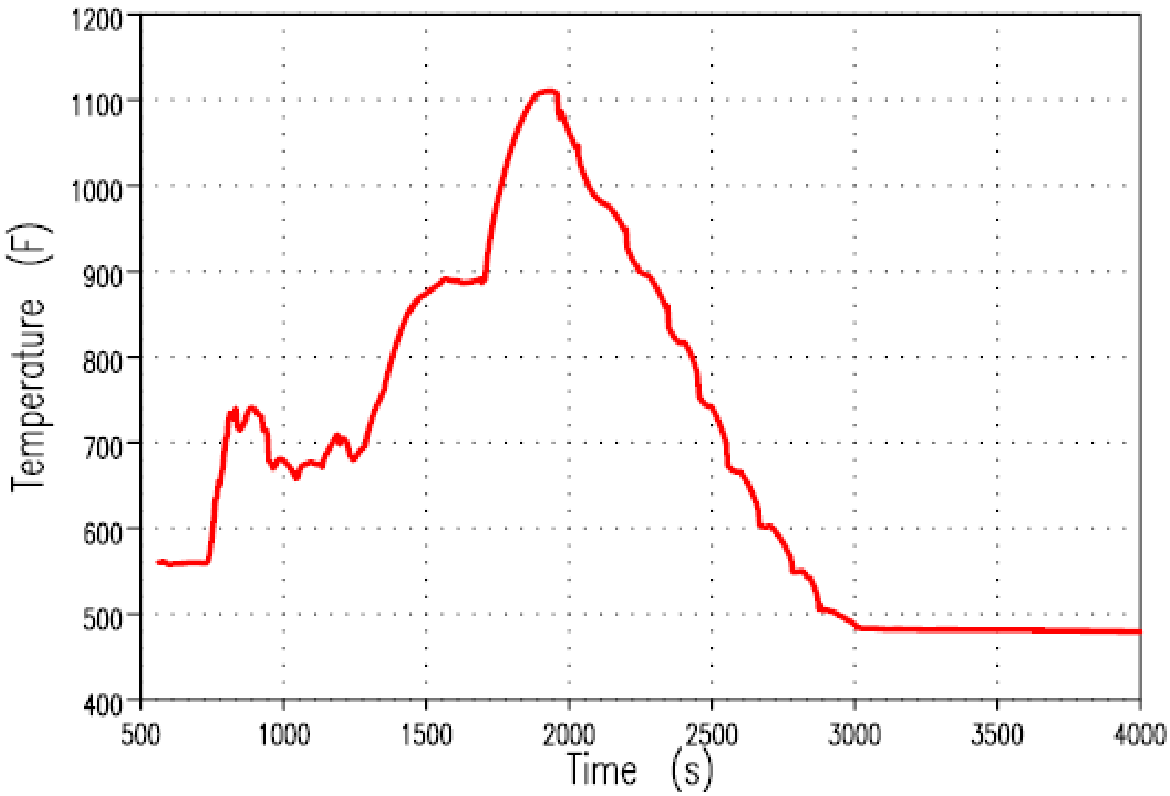
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.3-34 (Sheet 2 of 2) ROD FILM COEFFICIENT 3-INCH COLD LEG BREAK

DCPP Unit 1



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.3-35 (Sheet 1 of 2) HOT SPOT FLUID TEMPERATURE 3-INCH COLD LEG BREAK

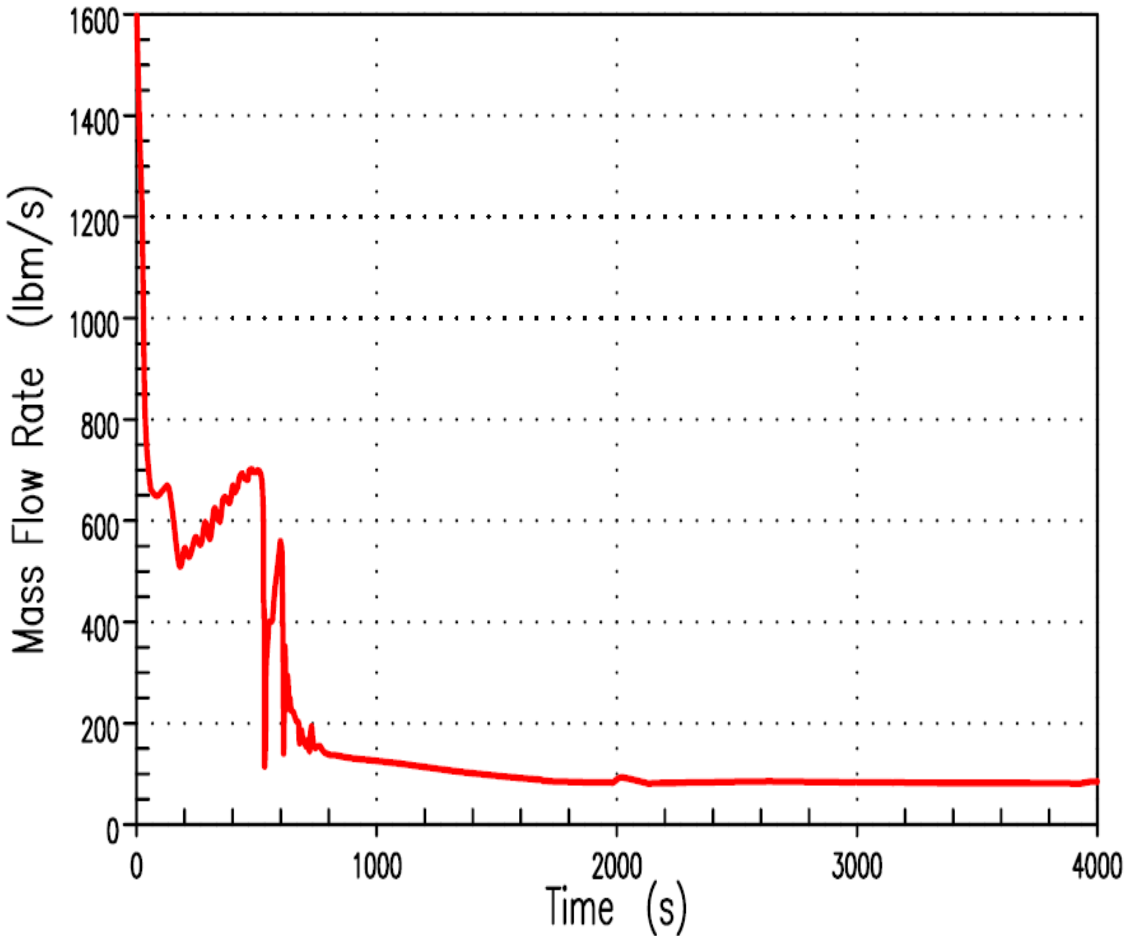
DCPP Unit 2



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.3-35 (Sheet 2 of 2) HOT SPOT FLUID TEMPERATURE 3-INCH COLD LEG BREAK

Revision 21 September 2013

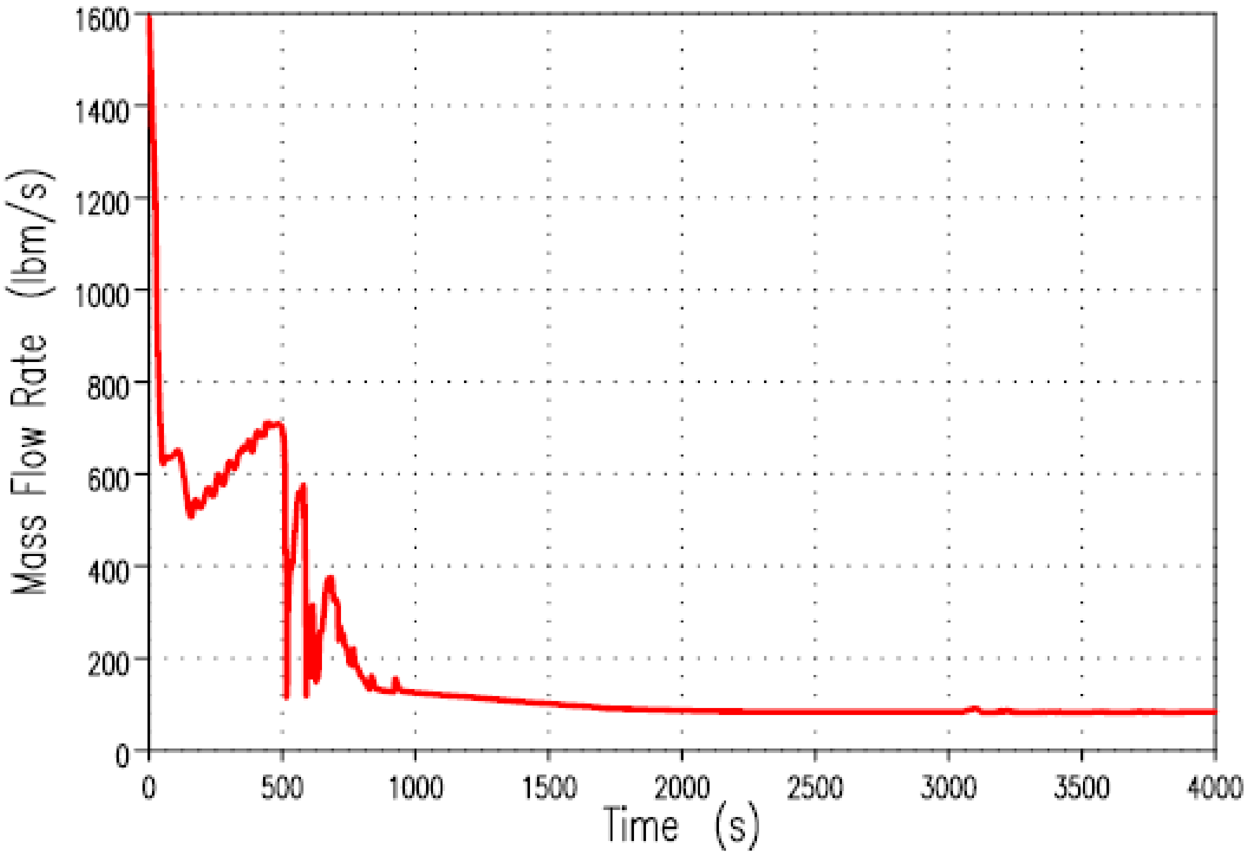
DCPP Unit 1



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.3-36 (Sheet 1 of 2) BREAK MASS FLOW 3-INCH COLD LEG BREAK

Revision 21 September 2013

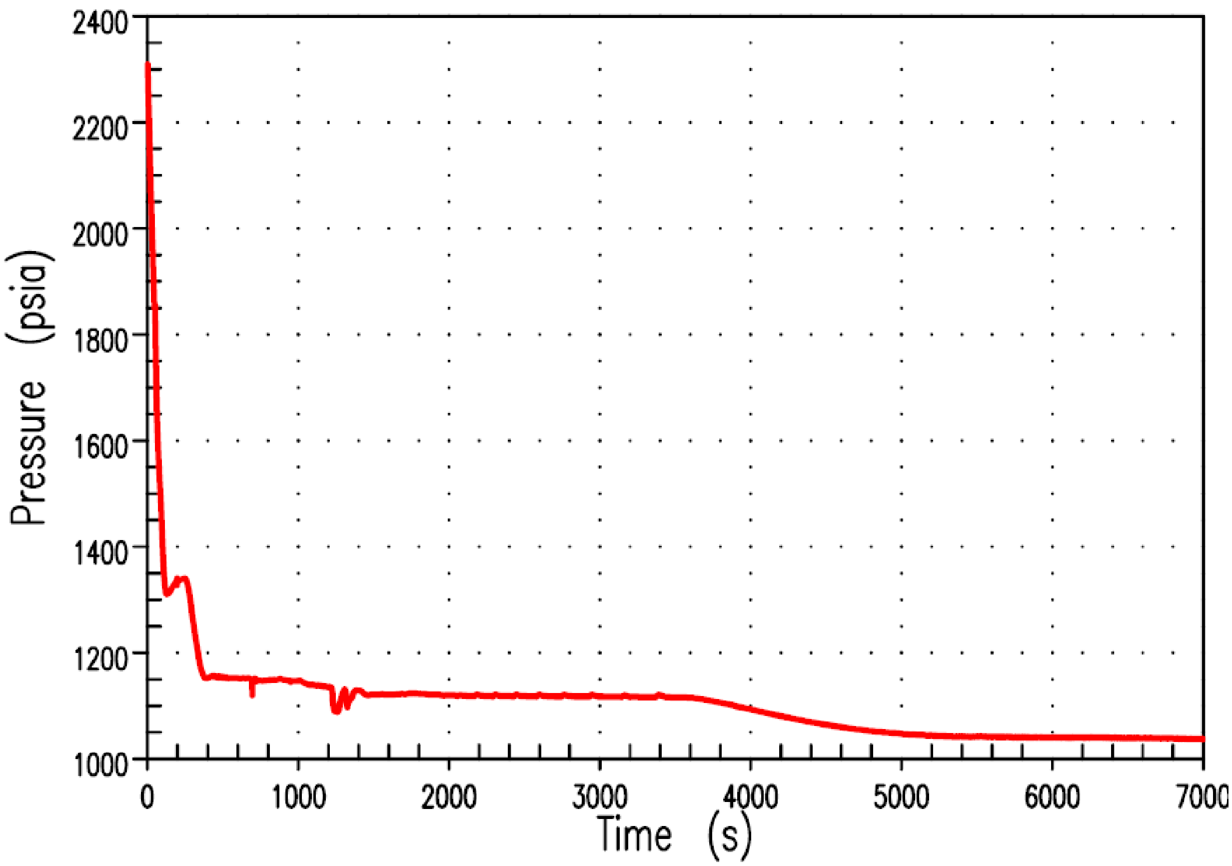
DCPP Unit 2



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.3-36 (Sheet 2 of 2) BREAK MASS FLOW 3-INCH COLD LEG BREAK

Revision 21 September 2013

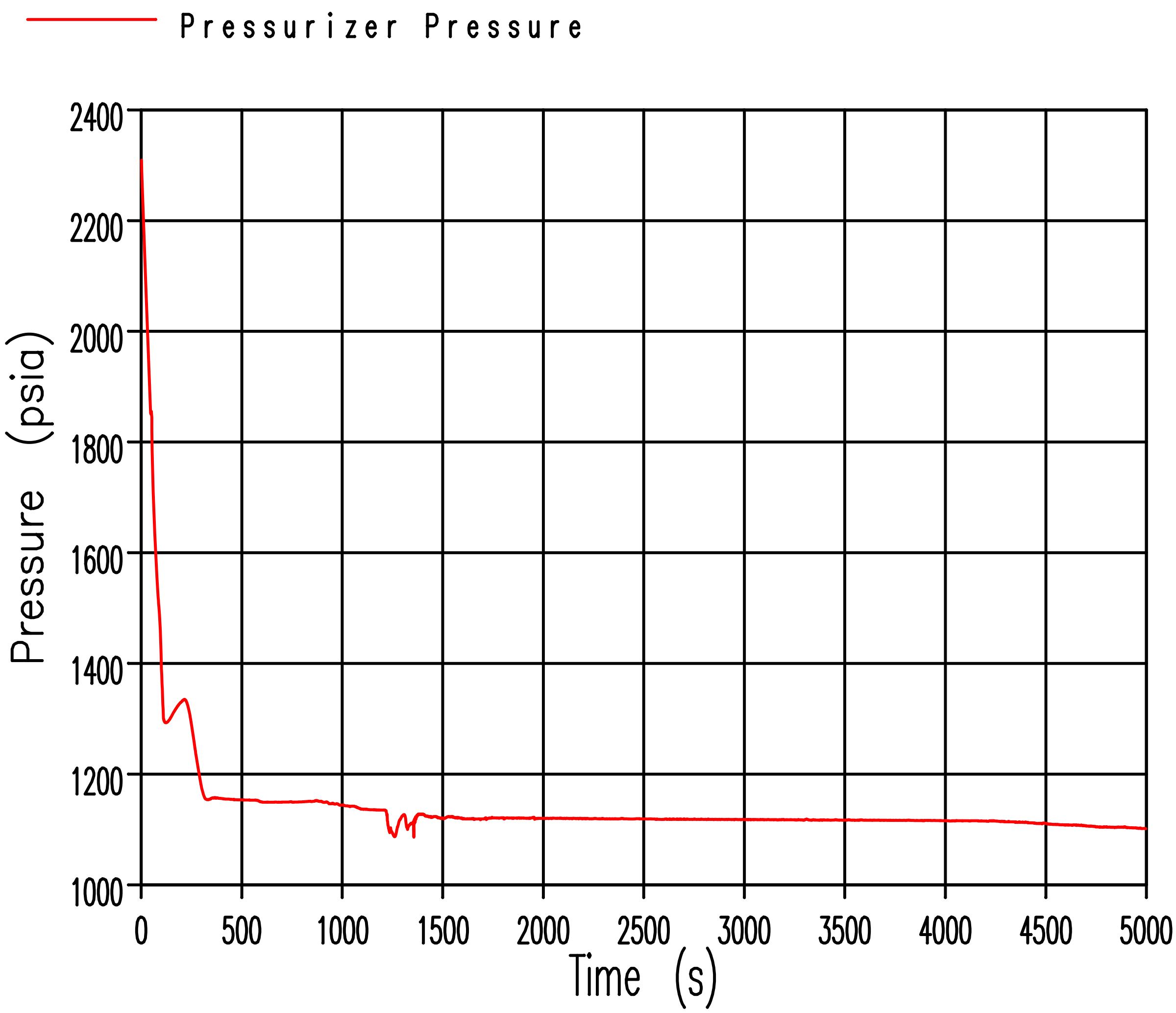
DCPP Unit 1



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.3-37 (Sheet 1 of 2) RCS DEPRESSURIZATION 2-INCH COLD LEG BREAK

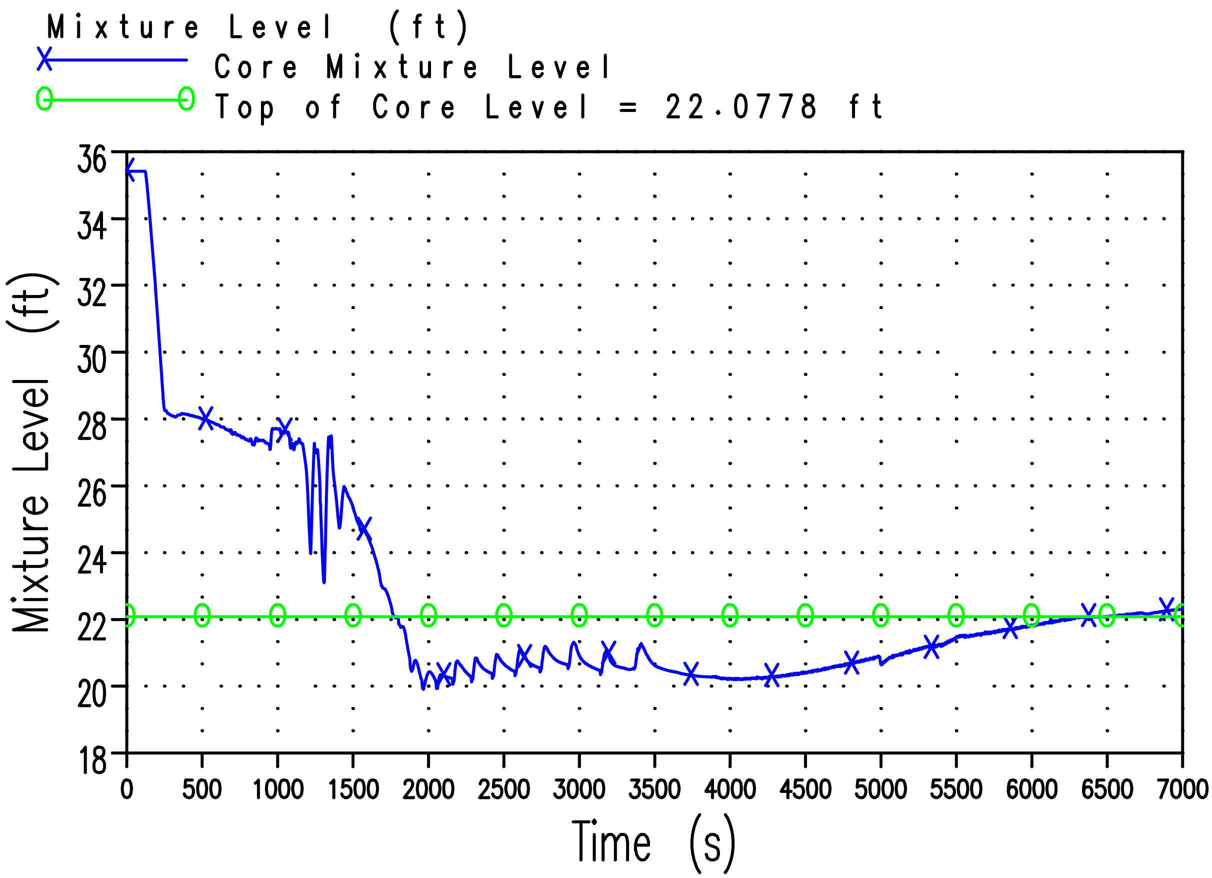
Revision 21 September 2013

DCPP Unit 2



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.3-37 (Sheet 2 of 2) RCS DEPRESSURIZATION 2-INCH COLD LEG BREAK

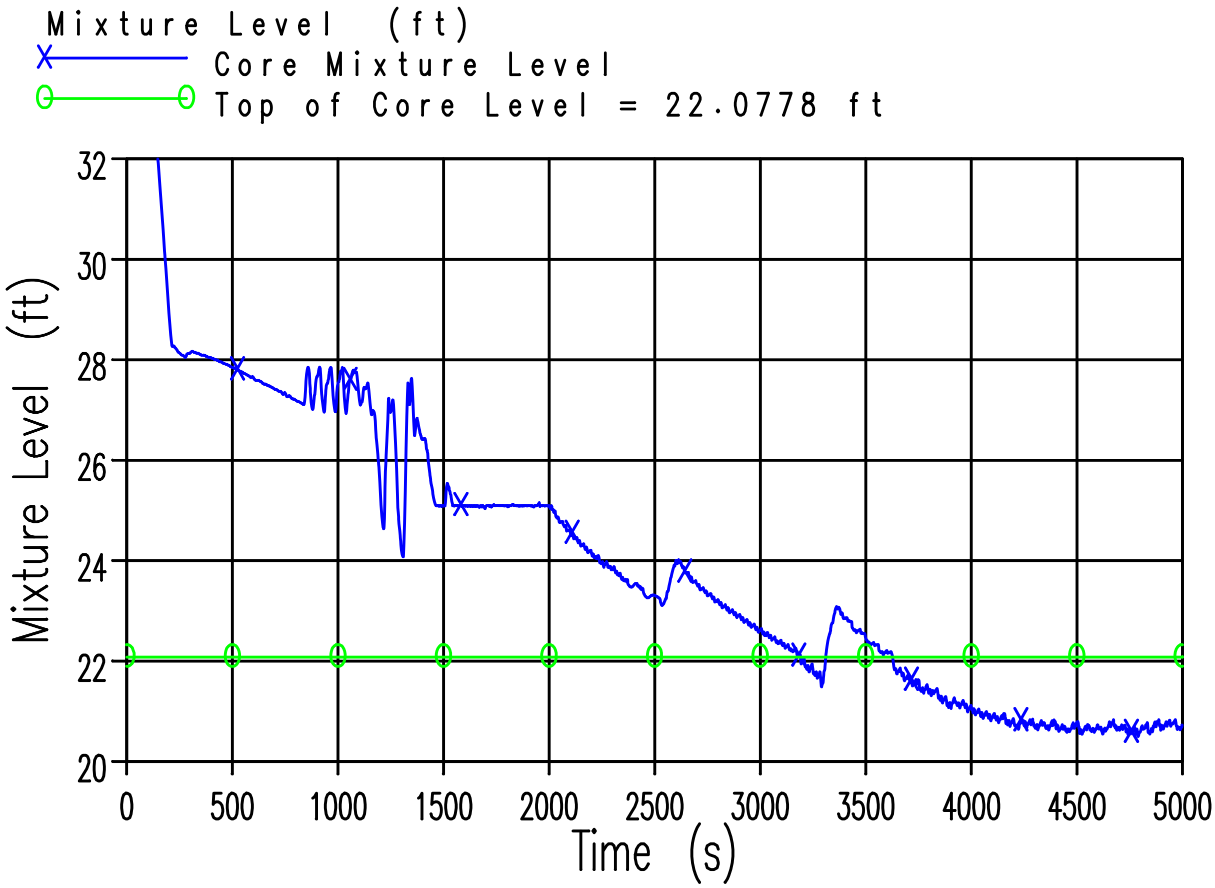
DCPP Unit 1



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.3-38 (Sheet 1 of 2) CORE MIXTURE ELEVATION 2-INCH COLD LEG BREAK

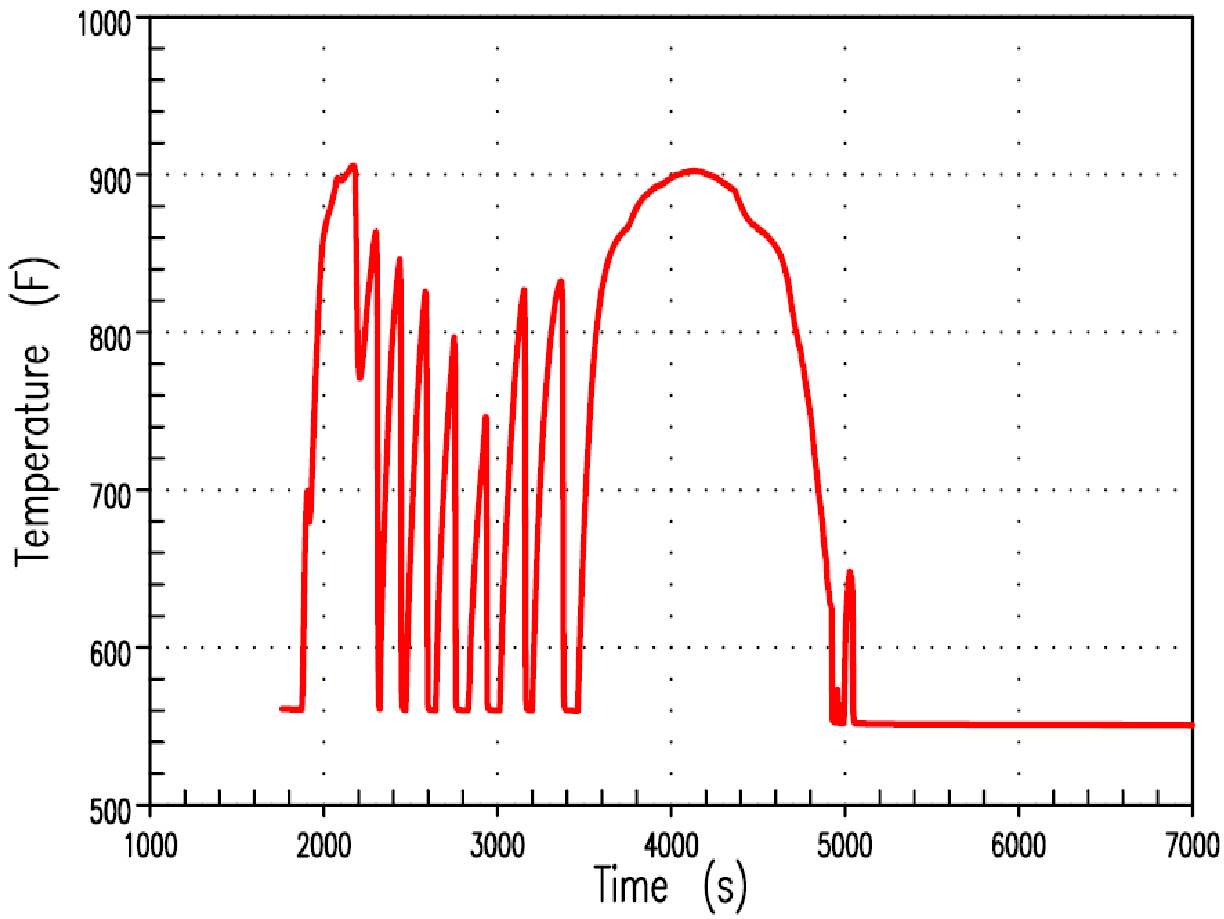
Revision 21 September 2013

DCPP Unit 2



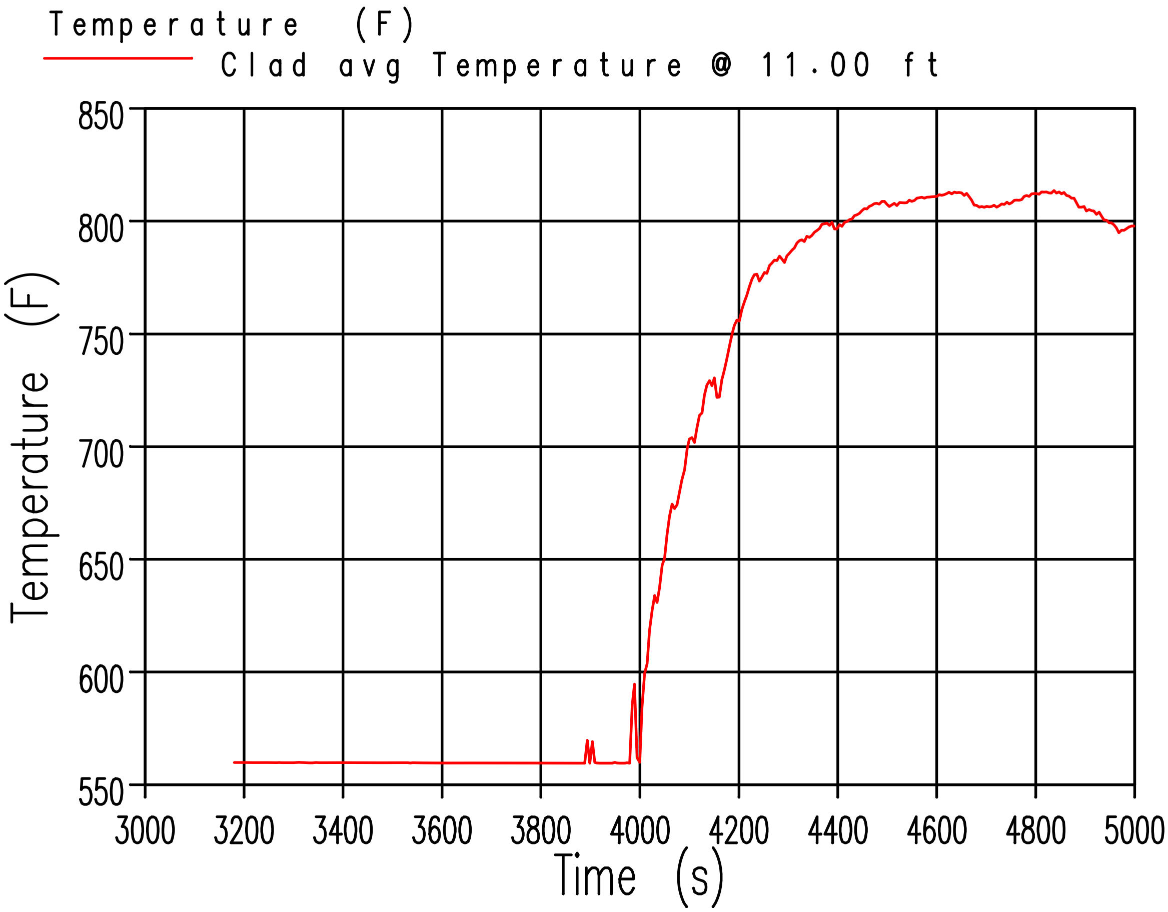
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.3-38 (Sheet 2 of 2) CORE MIXTURE ELEVATION 2-INCH COLD LEG BREAK

DCPP Unit 1



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.3-39 (Sheet 1 of 2) CLADDING TEMPERATURE TRANSIENT 2-INCH COLD LEG BREAK

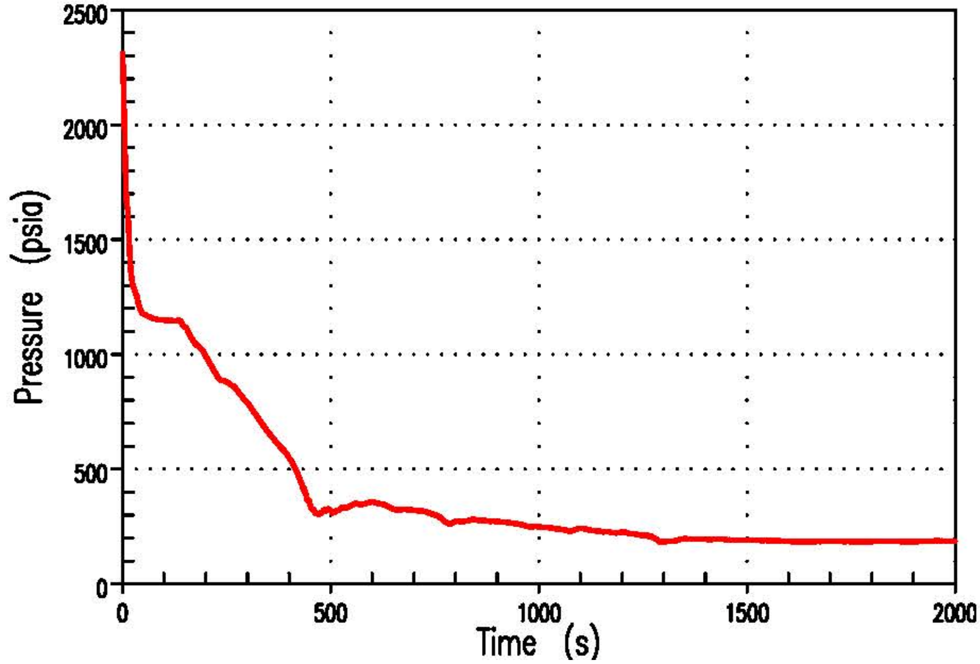
DCPP Unit 2



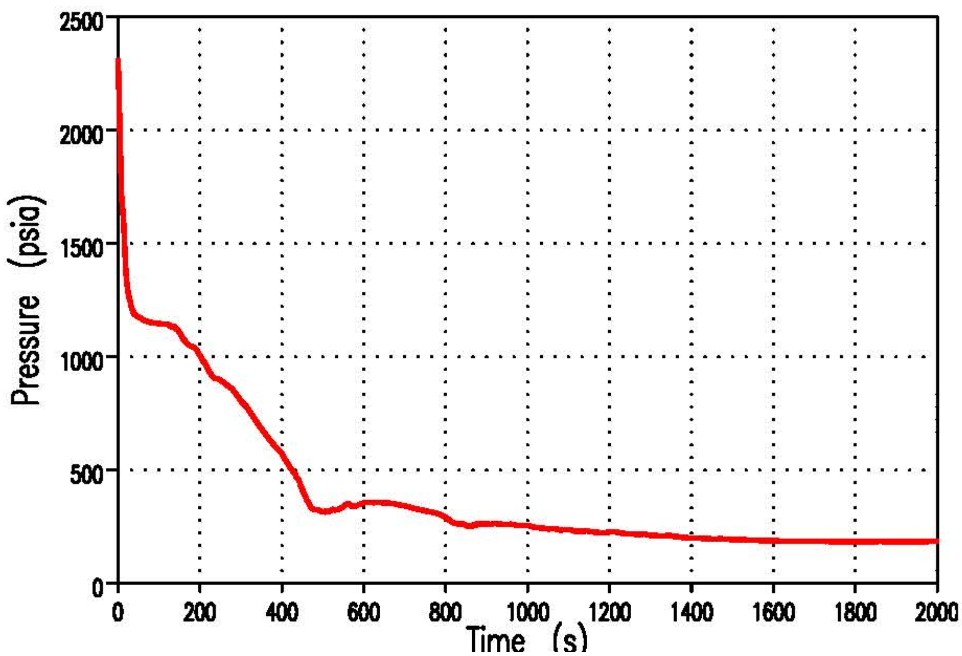
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.3-39 (Sheet 2 of 2) CLADDING TEMPERATURE TRANSIENT 2-INCH COLD LEG BREAK

Revision 21 September 2013

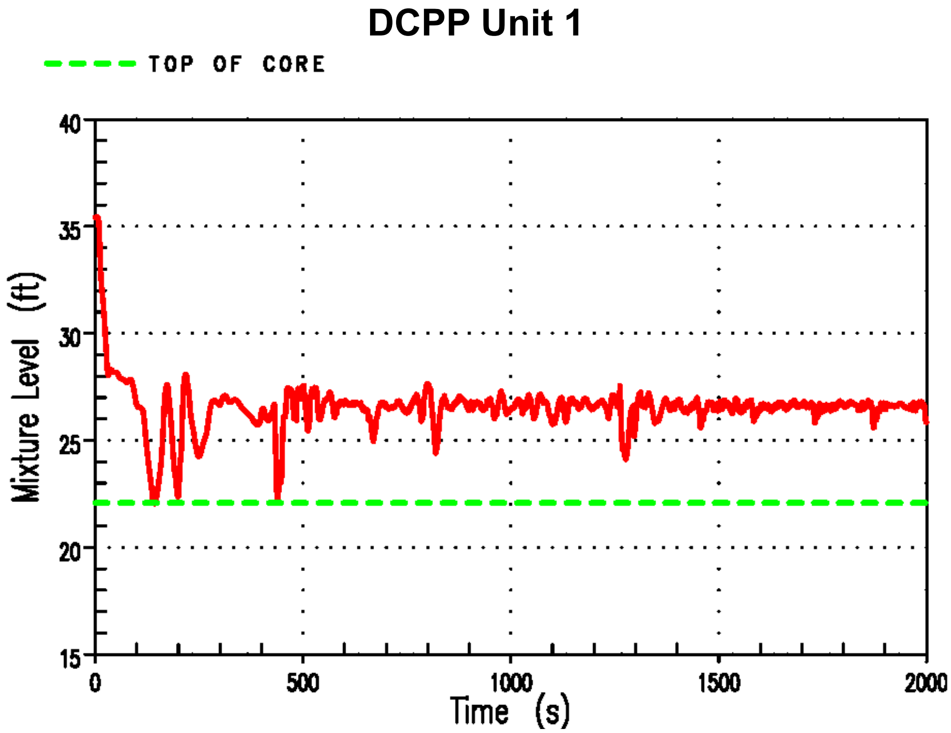
DCPP Unit 1

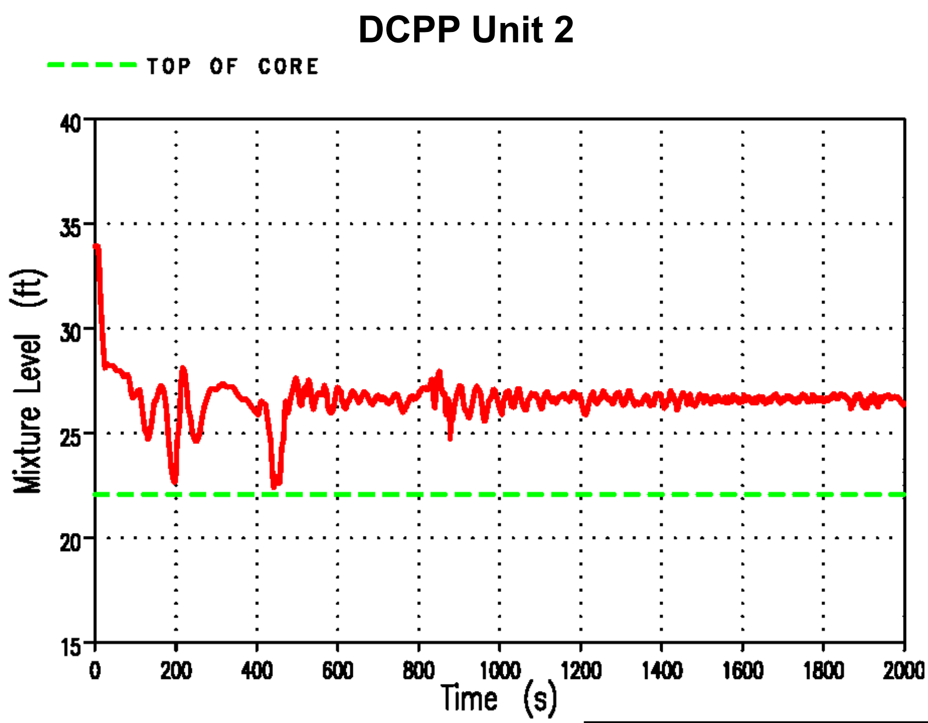


DCPP Unit 2

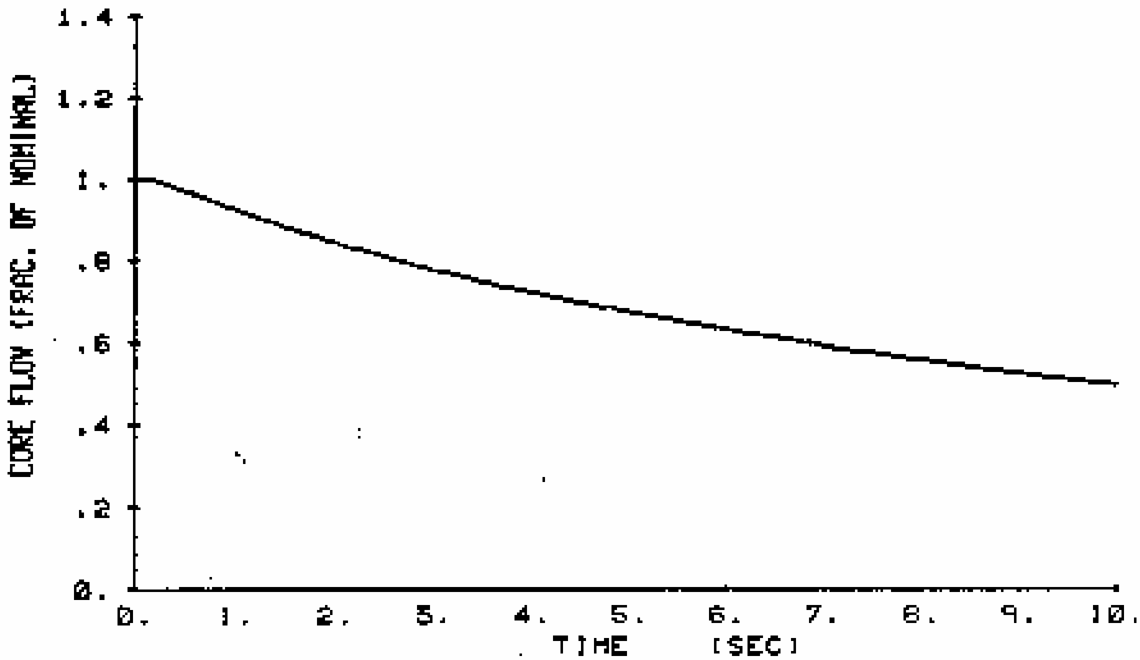


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.3-40 RCS DEPRESSURIZATION 6-INCH COLD LEG BREAK

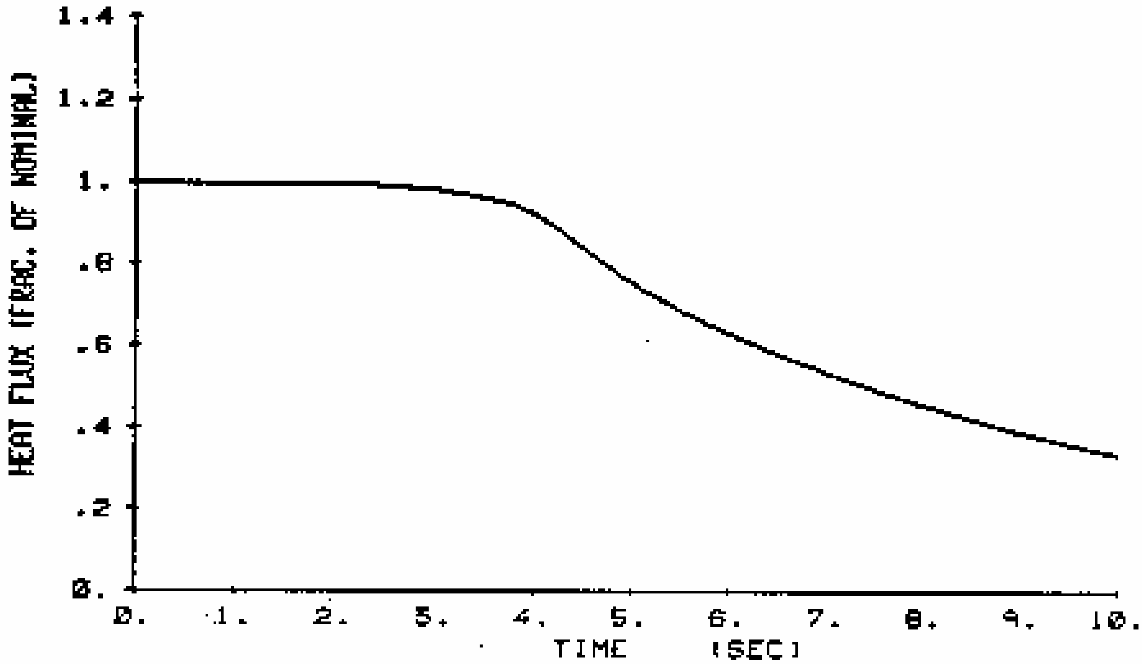




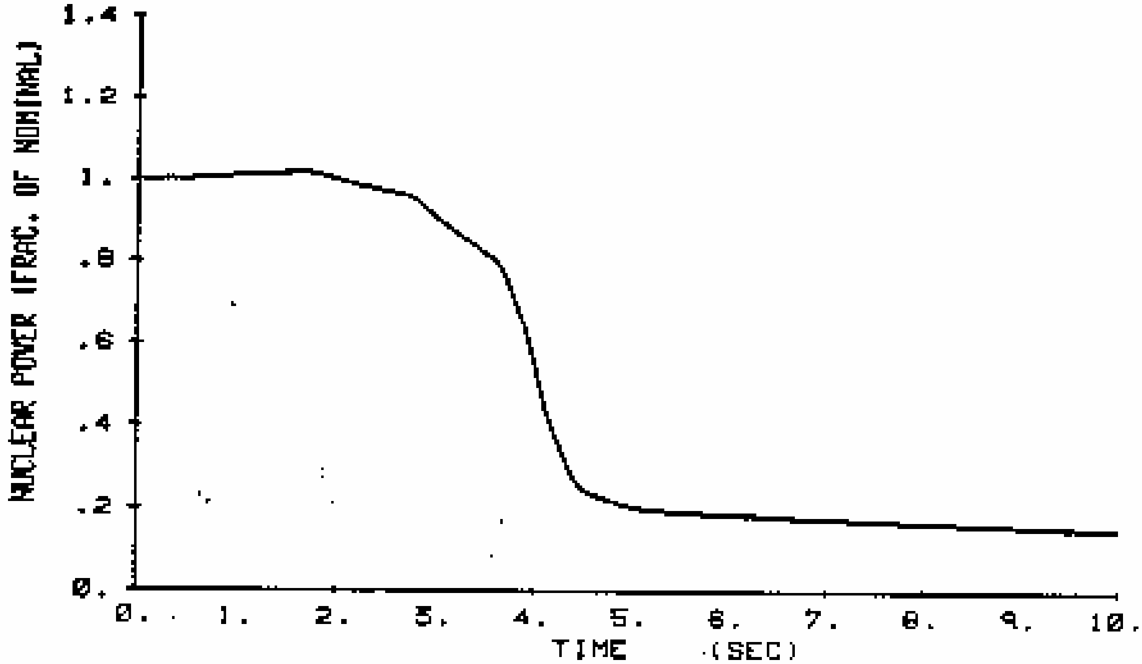
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.3-41 CORE MIXTURE ELEVATION 6-INCH COLD LEG BREAK



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.3.4-1 ALL LOOPS OPERATING ALL LOOPS COASTING DOWN FLOW COASTDOWN VERSUS TIME



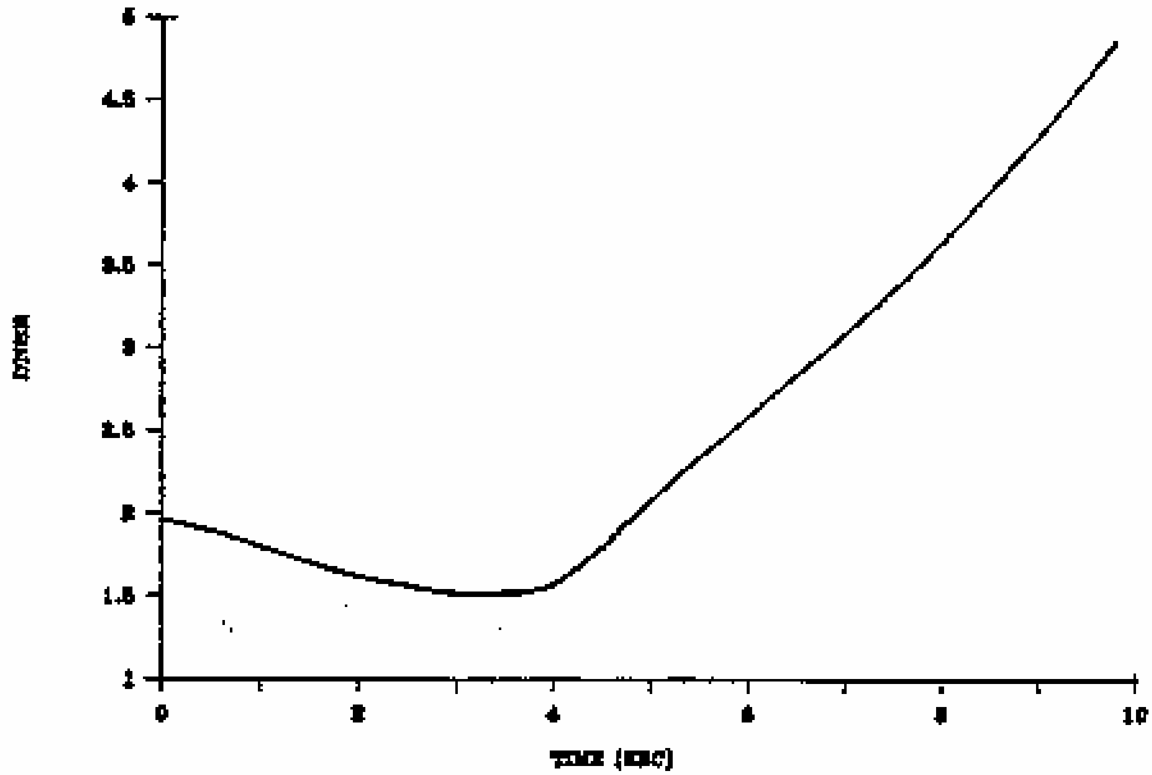
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.3.4-2 ALL LOOPS OPERATING ALL LOOPS COASTING DOWN HEAT FLUX VERSUS TIME



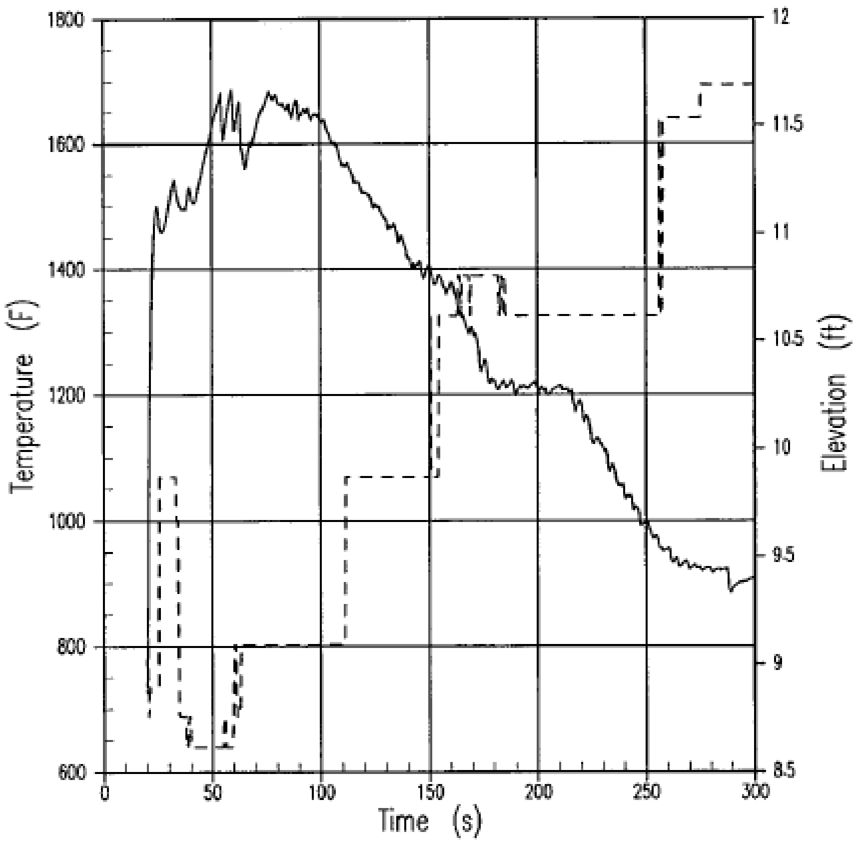
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.3.4-3
ALL LOOPS OPERATING
ALL LOOPS COASTING DOWN
NUCLEAR POWER VERSUS TIME



FSAR UPDATE
UNITS 1 AND 2 **DIABLO CANYON SITE**
FIGURE 15.3.4-4 **ALL LOOPS OPERATING** **ALL LOOPS COASTING DOWN** **DNBR VERSUS TIME**



FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1-1A REFERENCE TRANSIENT PCT AND PCT LOCATION

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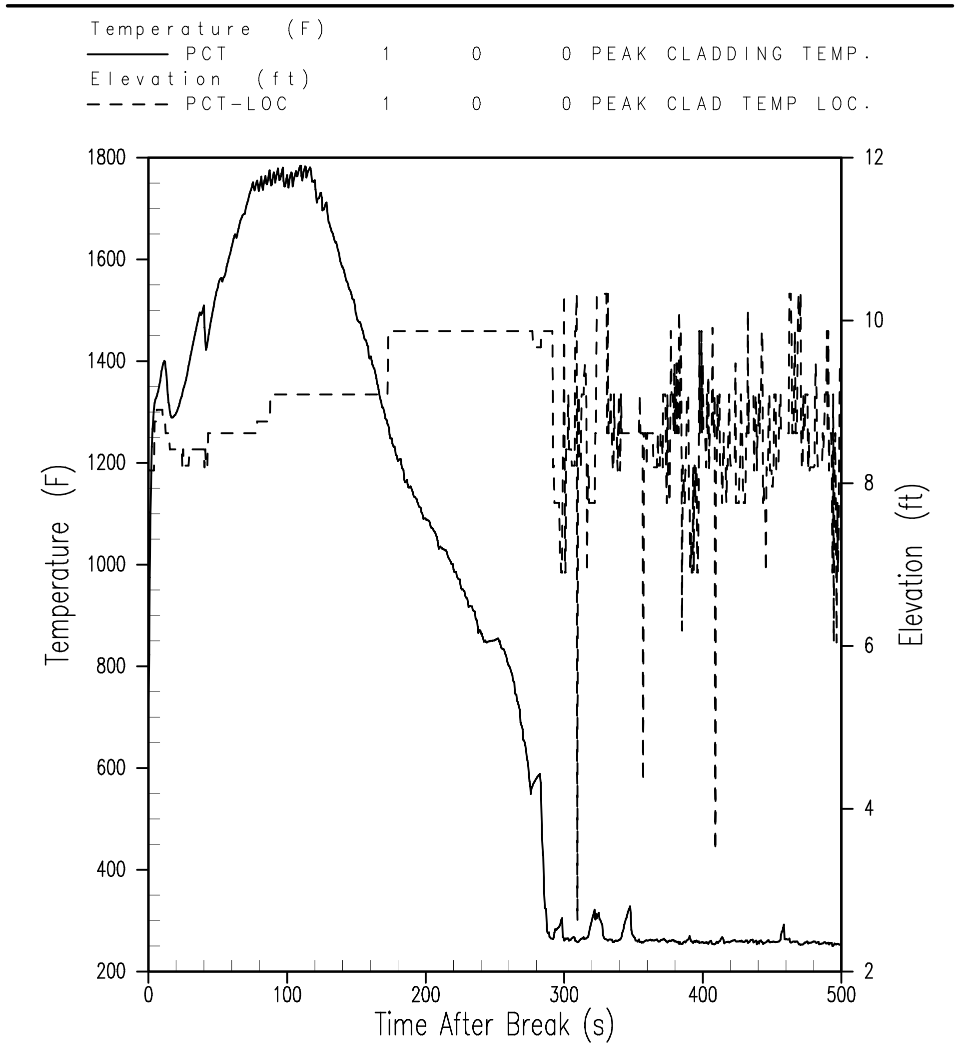


929:942:247300/18-Jul-05

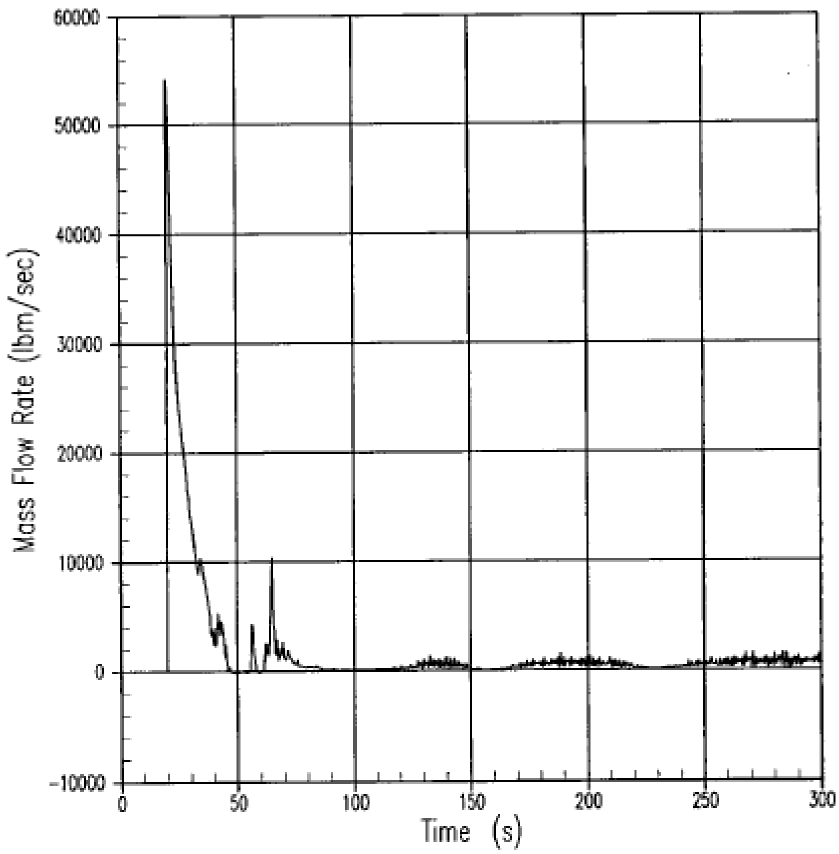
929:942:247300/18-Jul-05

FSAR UPDATE

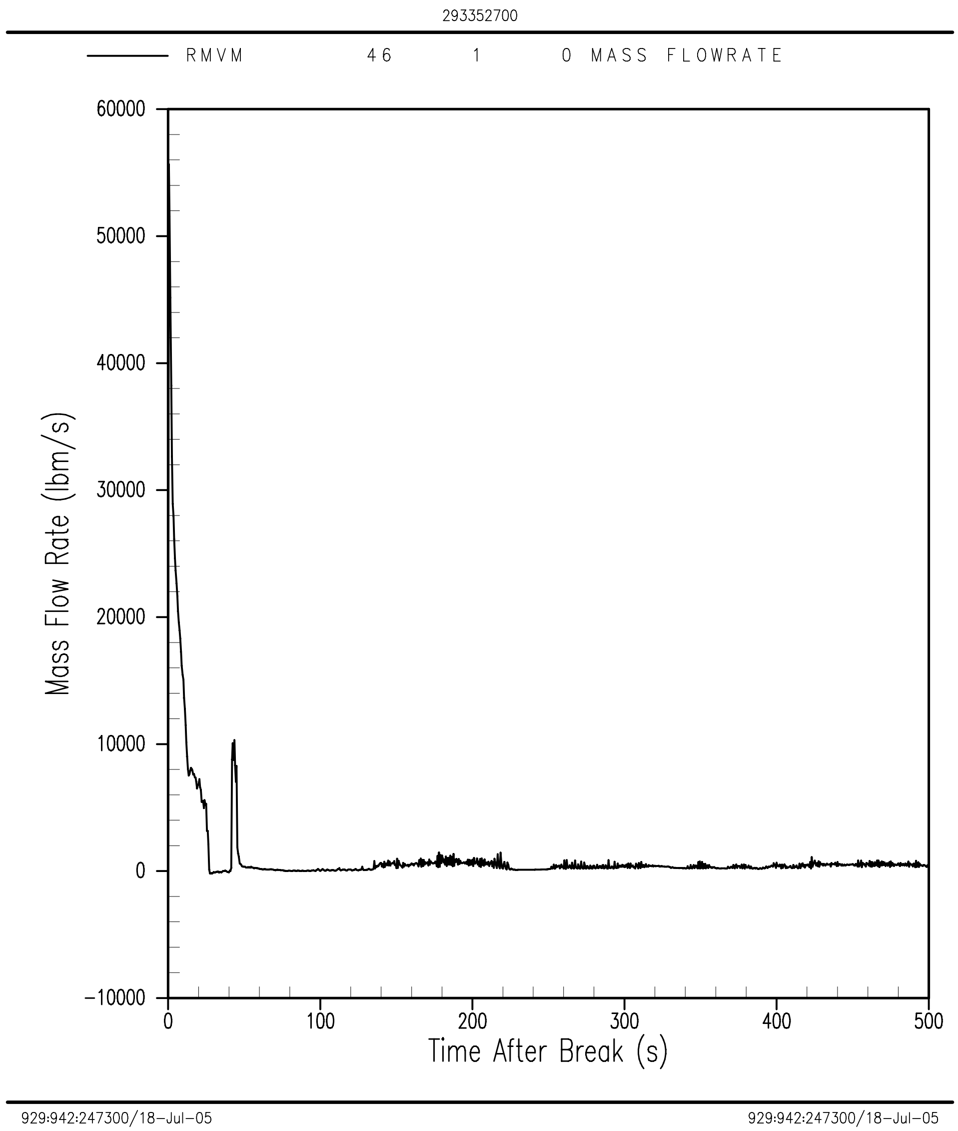
UNIT 2
DIABLO CANYON SITE

FIGURE 15.4.1-1B

LIMITING PCT CASE
AND PCT LOCATION



FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1-2A REFERENCE TRANSIENT VESSEL SIDE BREAK FLOW

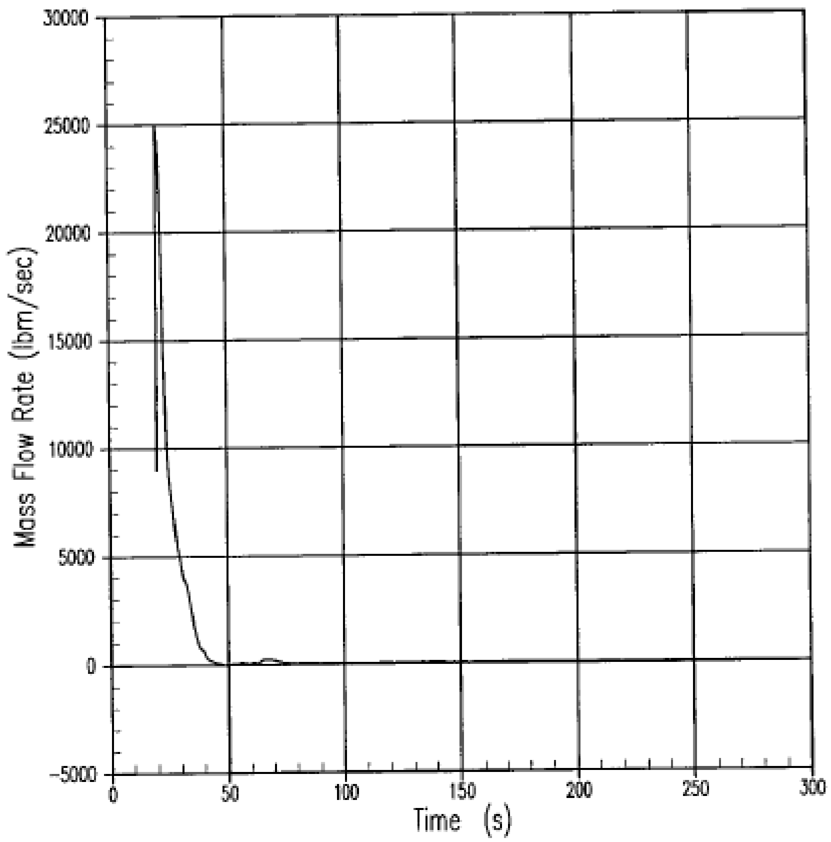


FSAR UPDATE

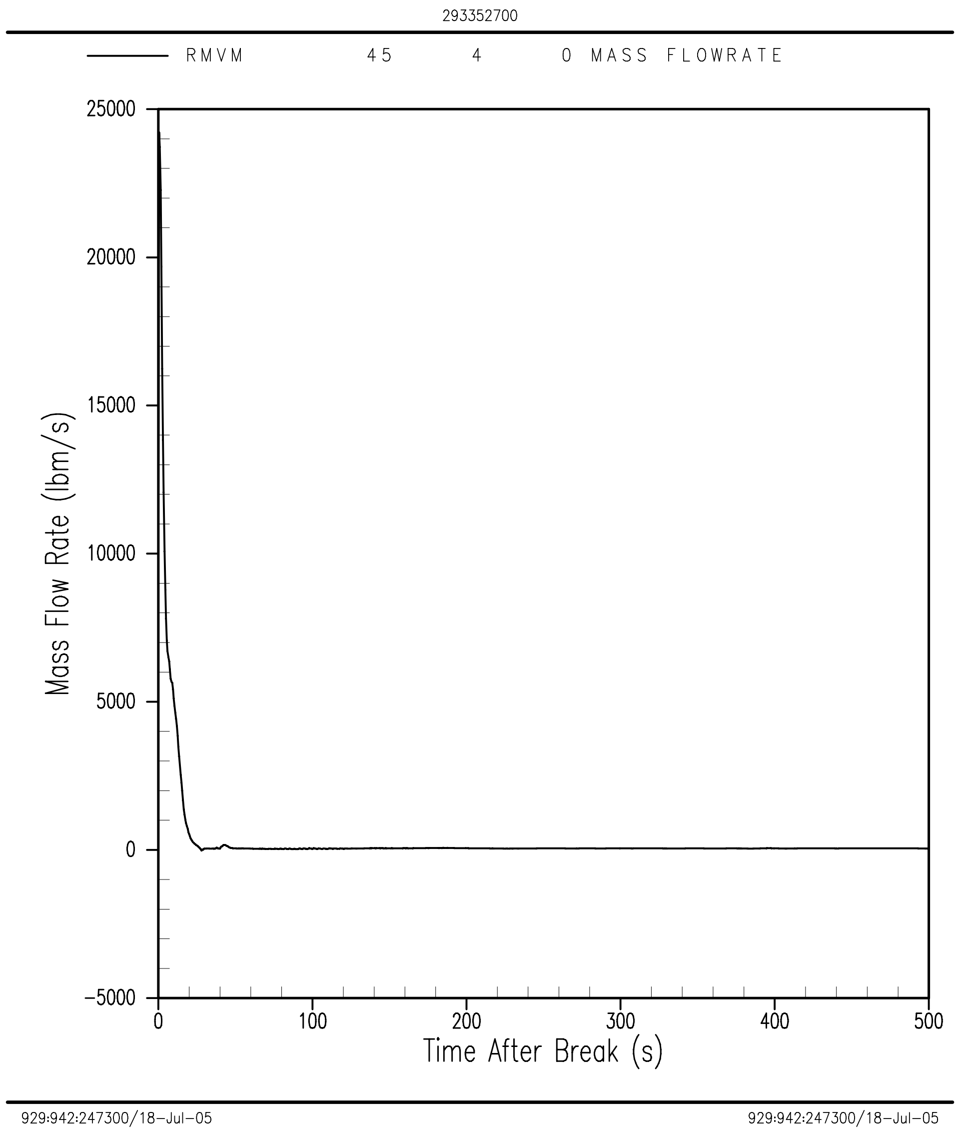
UNIT 2
DIABLO CANYON SITE

FIGURE 15.4.1-2B

LIMITING PCT CASE
VESSEL SIDE BREAK FLOW



FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1-3A REFERENCE TRANSIENT LOOP SIDE BREAK FLOW

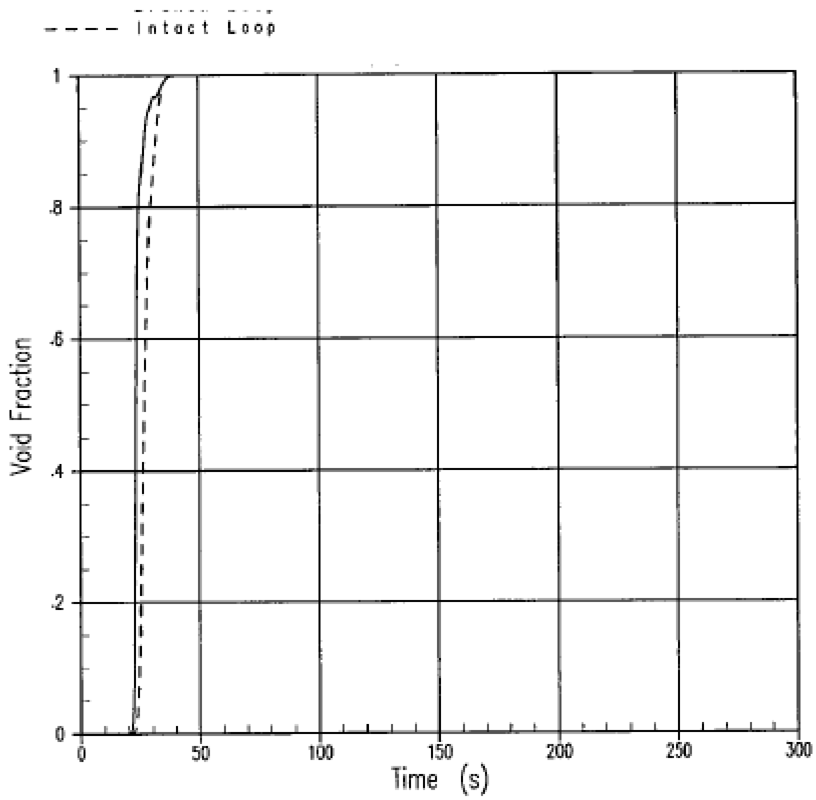


FSAR UPDATE

UNIT 2
DIABLO CANYON SITE

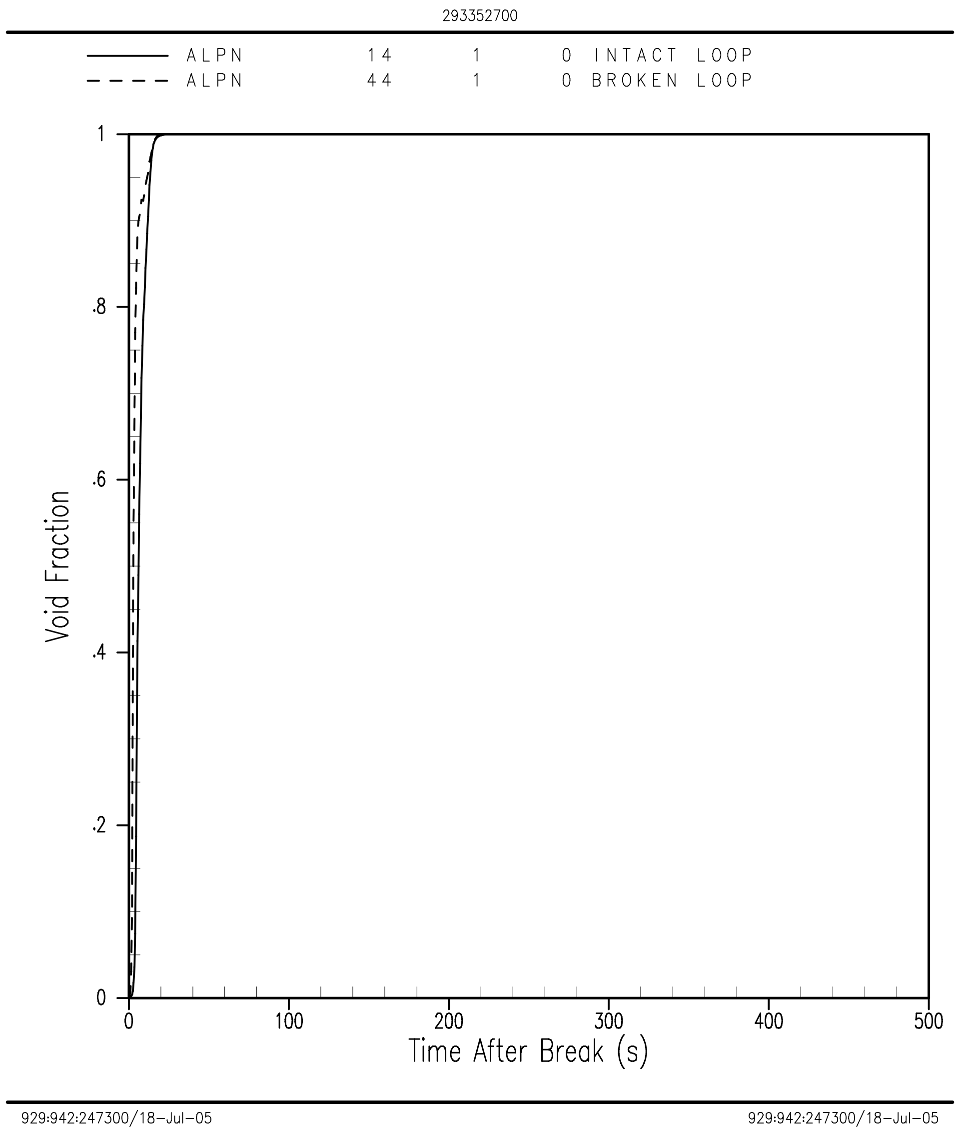
FIGURE 15.4.1-3B

LIMITING PCT CASE LOOP
SIDE BREAK FLOW

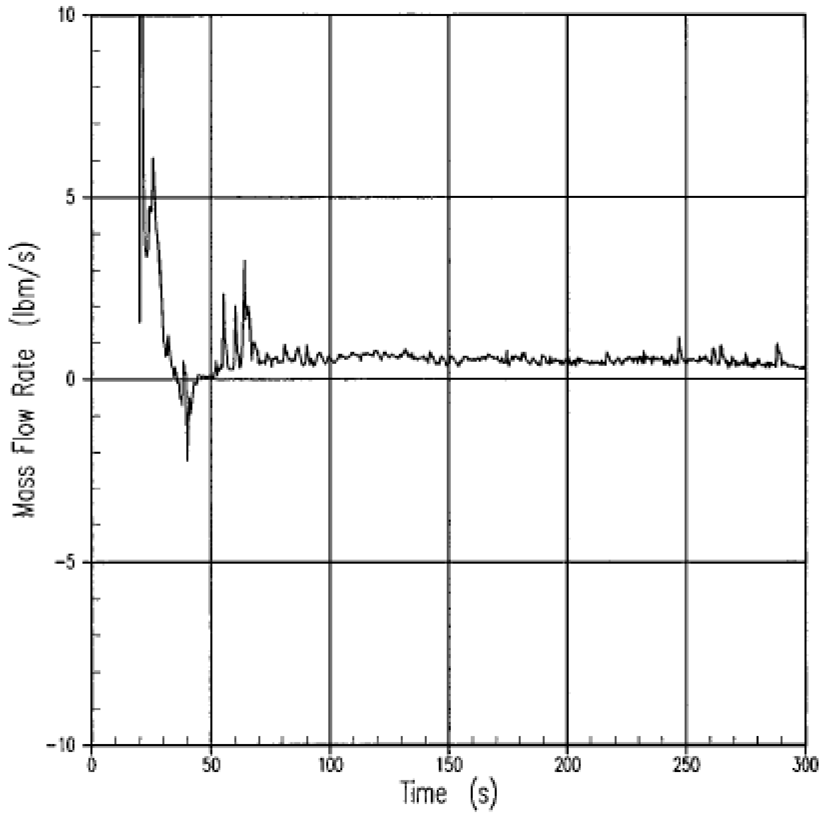


FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1-4A REFERENCE TRANSIENT BROKEN AND INTACT LOOP PUMP VOID FRACTION

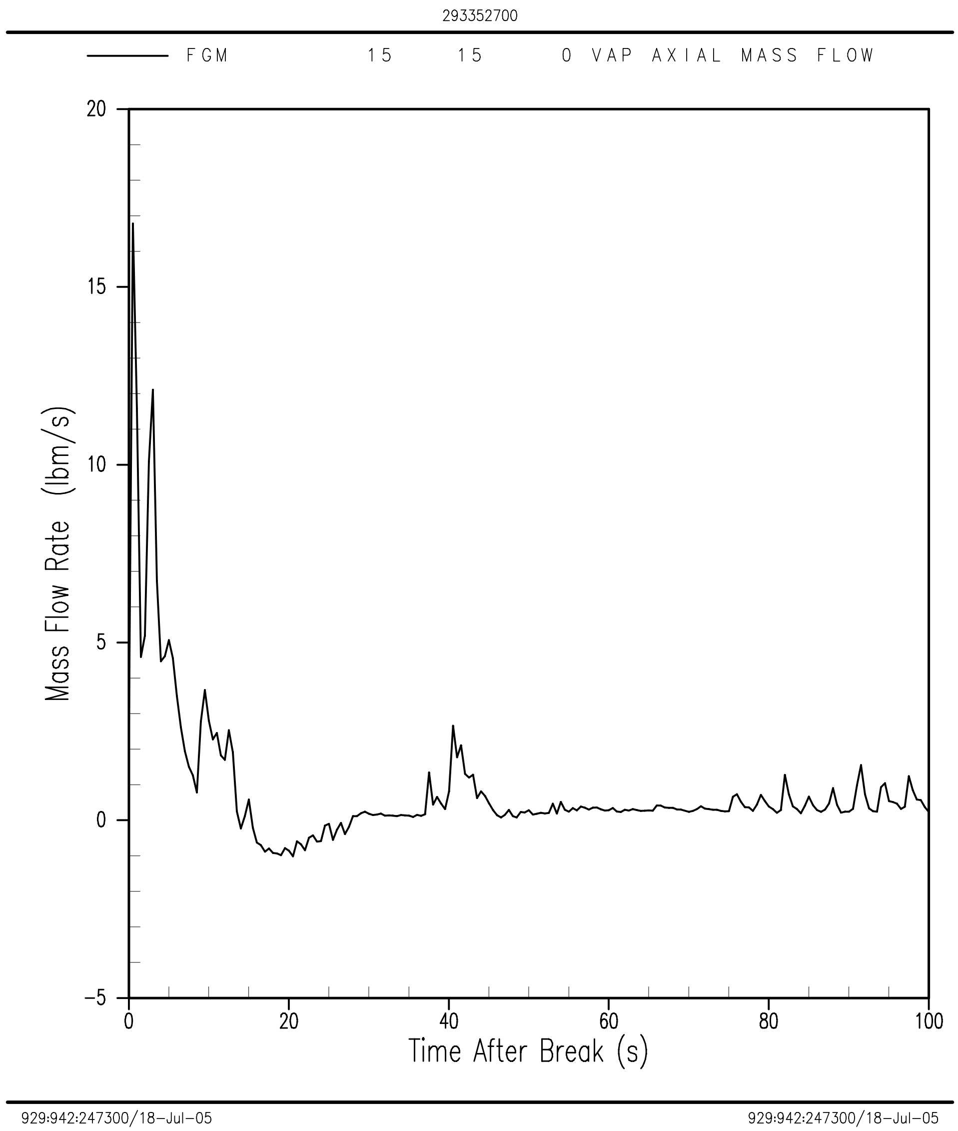
Revision 18 October 2008



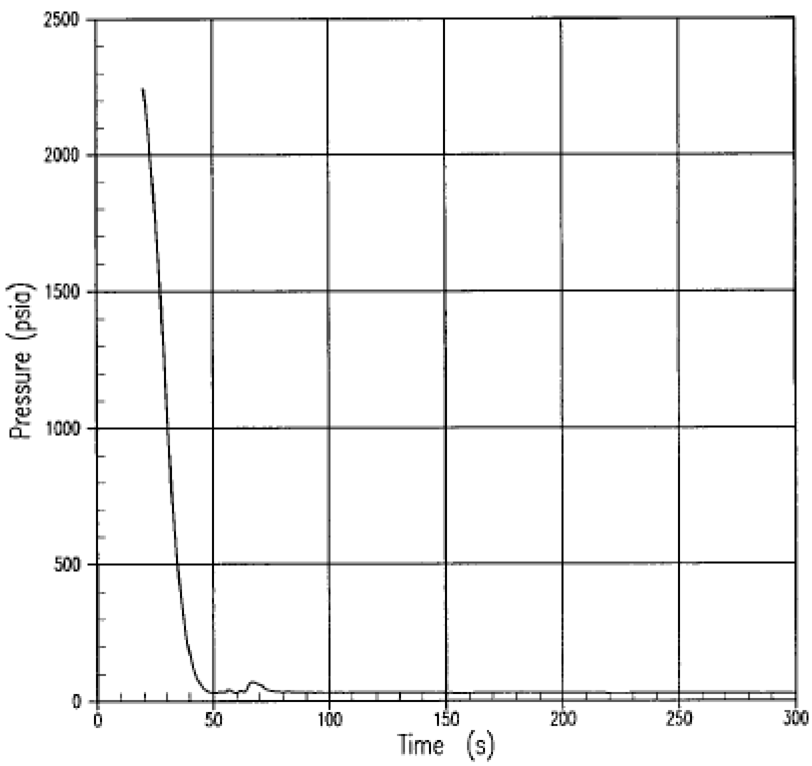
FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1-4B LIMITING PCT CASE BROKEN AND INTACT LOOP PUMP VOID FRACTION



FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1-5A REFERENCE TRANSIENT HOT ASSEMBLY/TOP OF CORE VAPOR FLOW



FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1-5B LIMITING PCT CASE HOT ASSEMBLY/TOP OF CORE VAPOR FLOW

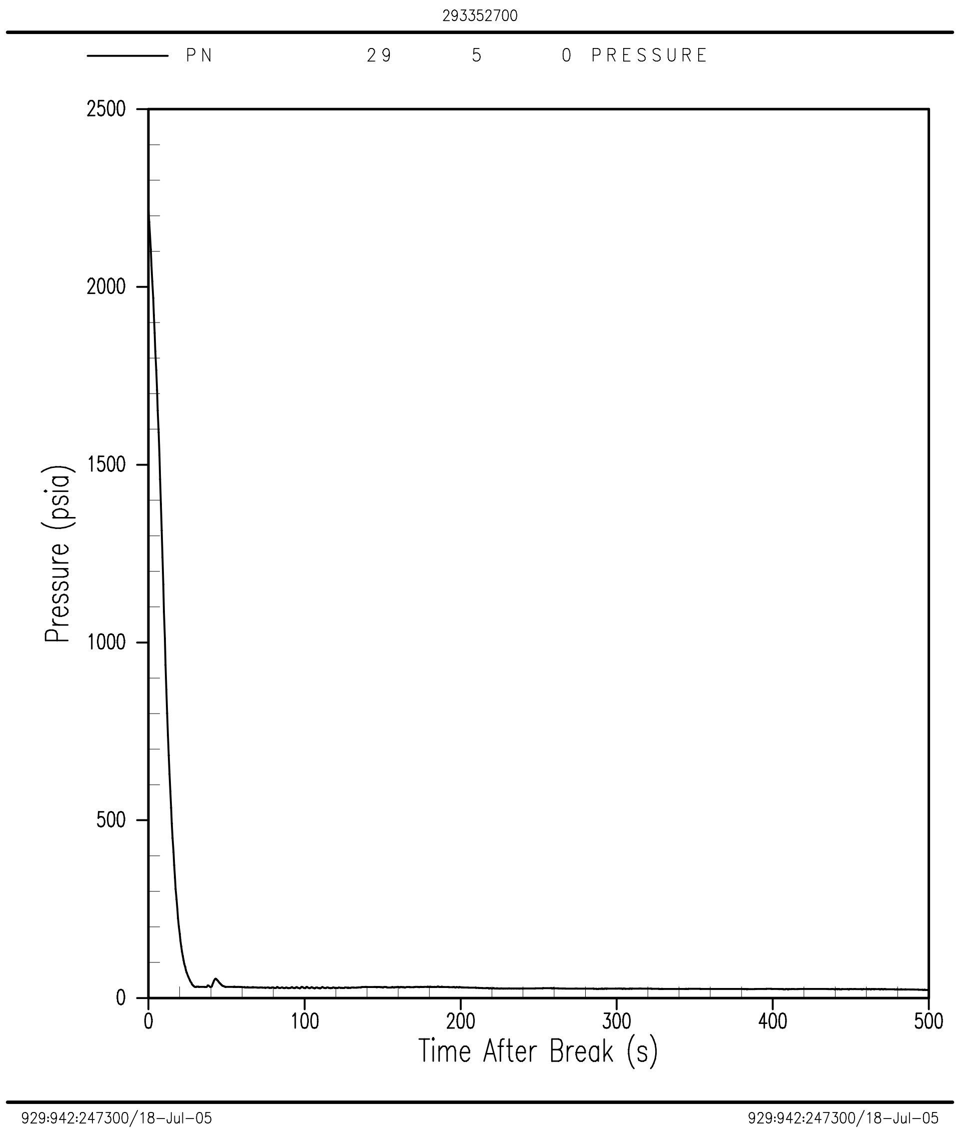


FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

FIGURE 15.4.1-6A

REFERENCE TRANSIENT
PRESSURIZER PRESSURE

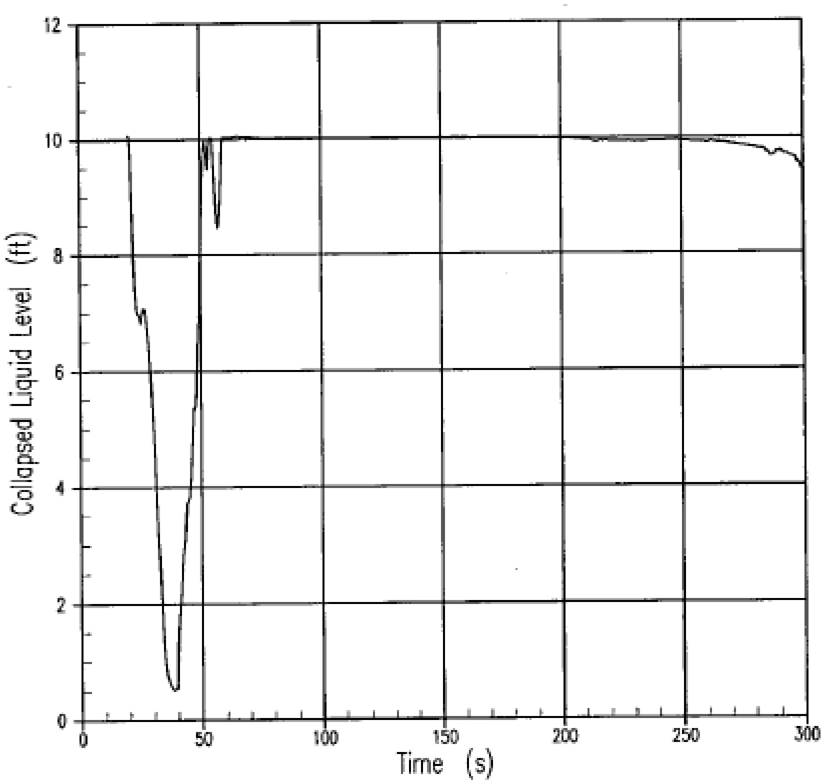


FSAR UPDATE

UNIT 2
DIABLO CANYON SITE

FIGURE 15.4.1-6B

LIMITING PCT CASE
PRESSURIZER PRESSURE



FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

FIGURE 15.4.1-7A

REFERENCE TRANSIENT
LOWER PLENUM COLLAPSED
LIQUID LEVEL

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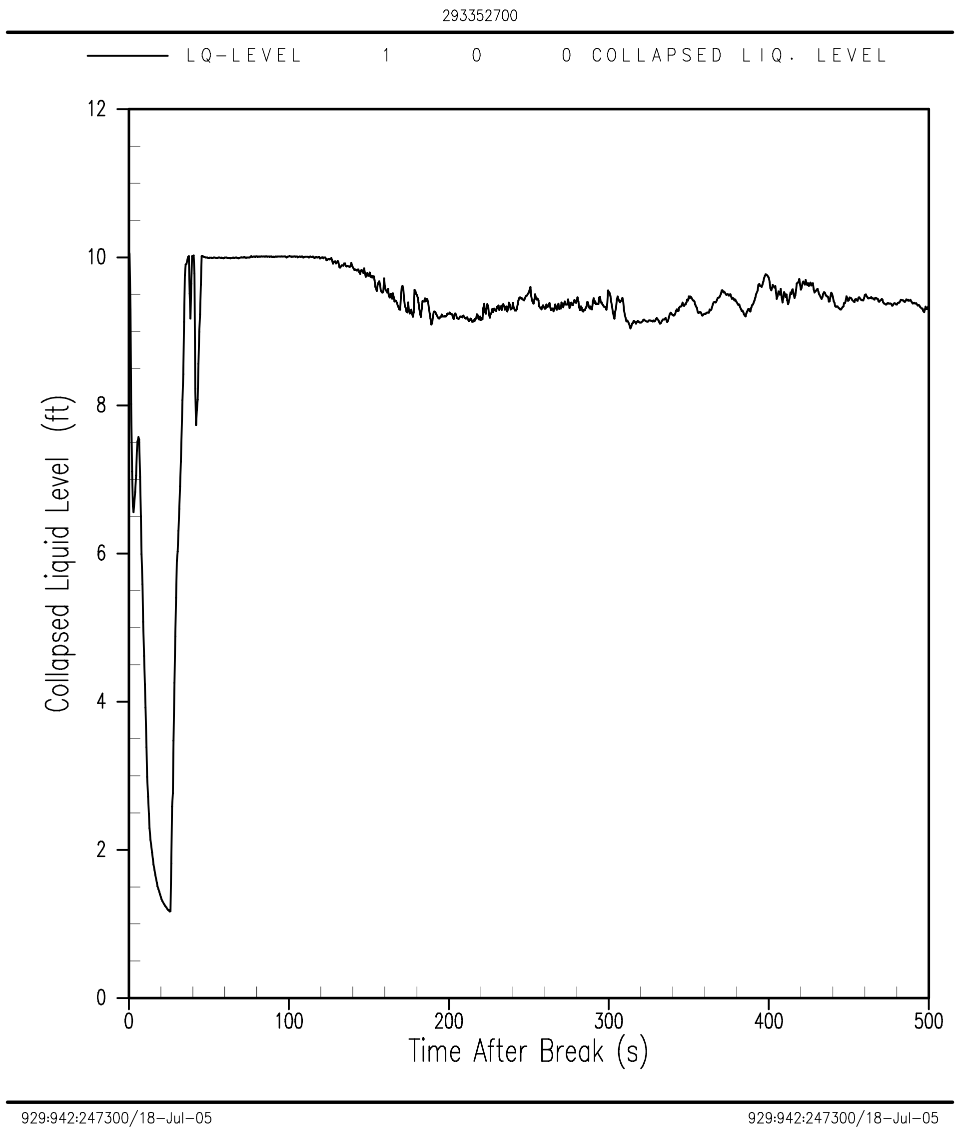
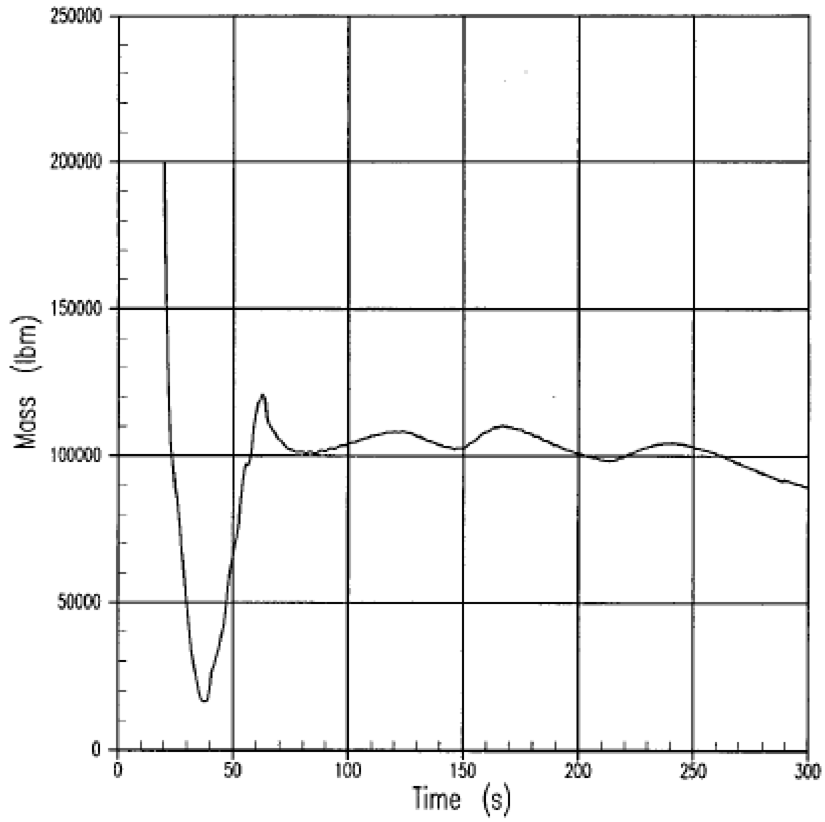
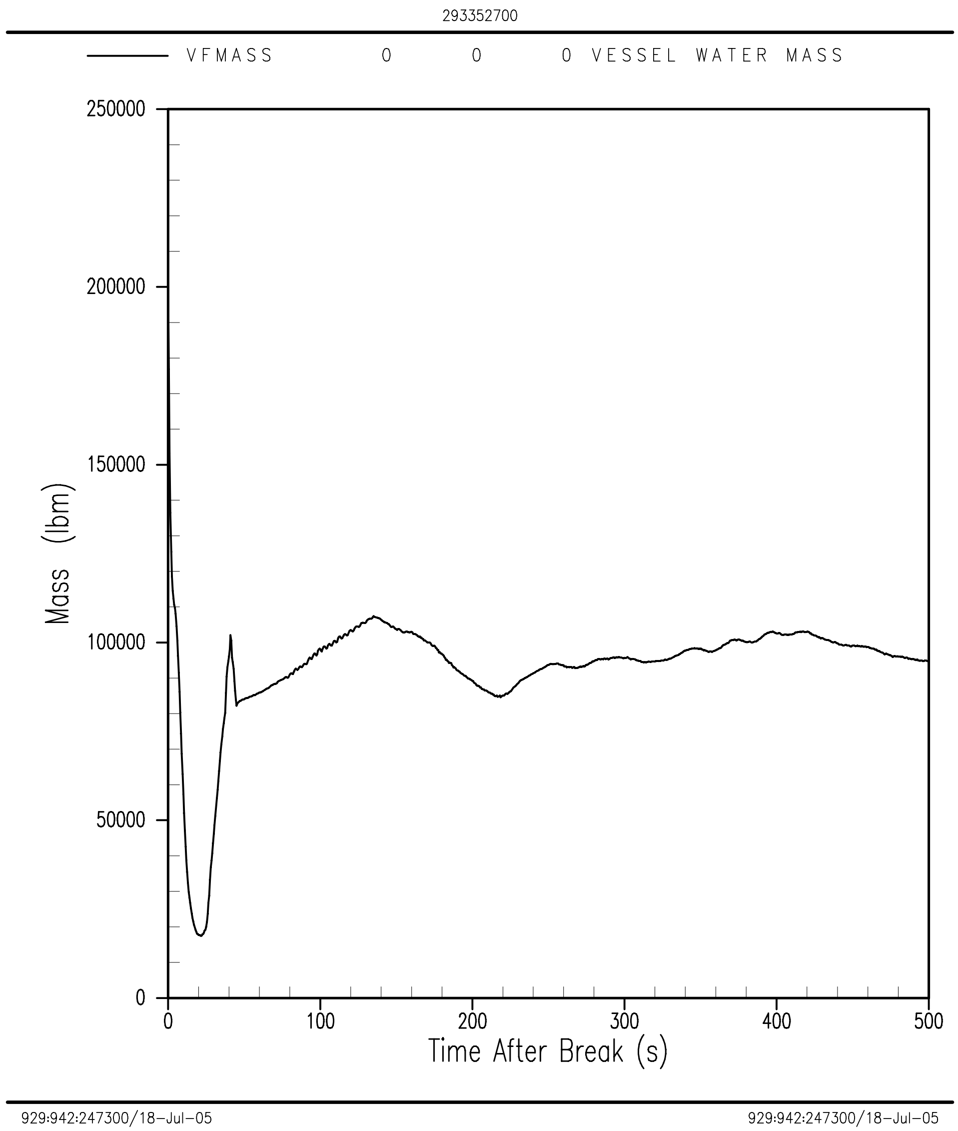


FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1-7B LIMITING PCT CASE LOWER PLENUM COLLAPSED LIQUID LEVEL



FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1-8A REFERENCE TRANSIENT VESSEL WATER MASS

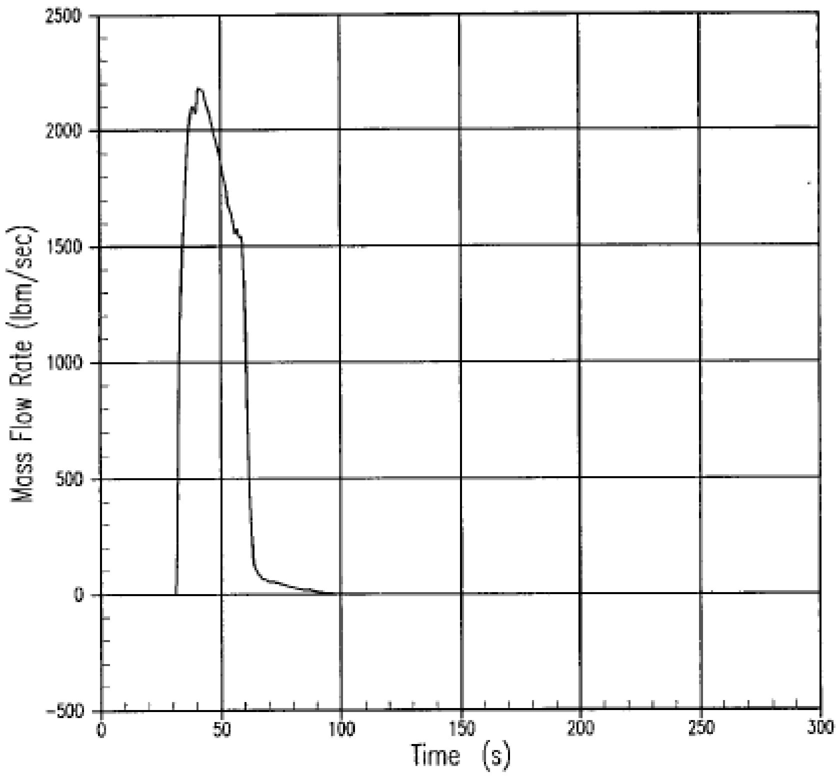


FSAR UPDATE

UNIT 2
DIABLO CANYON SITE

FIGURE 15.4.1-8B

LIMITING PCT CASE
VESSEL FLUID MASS

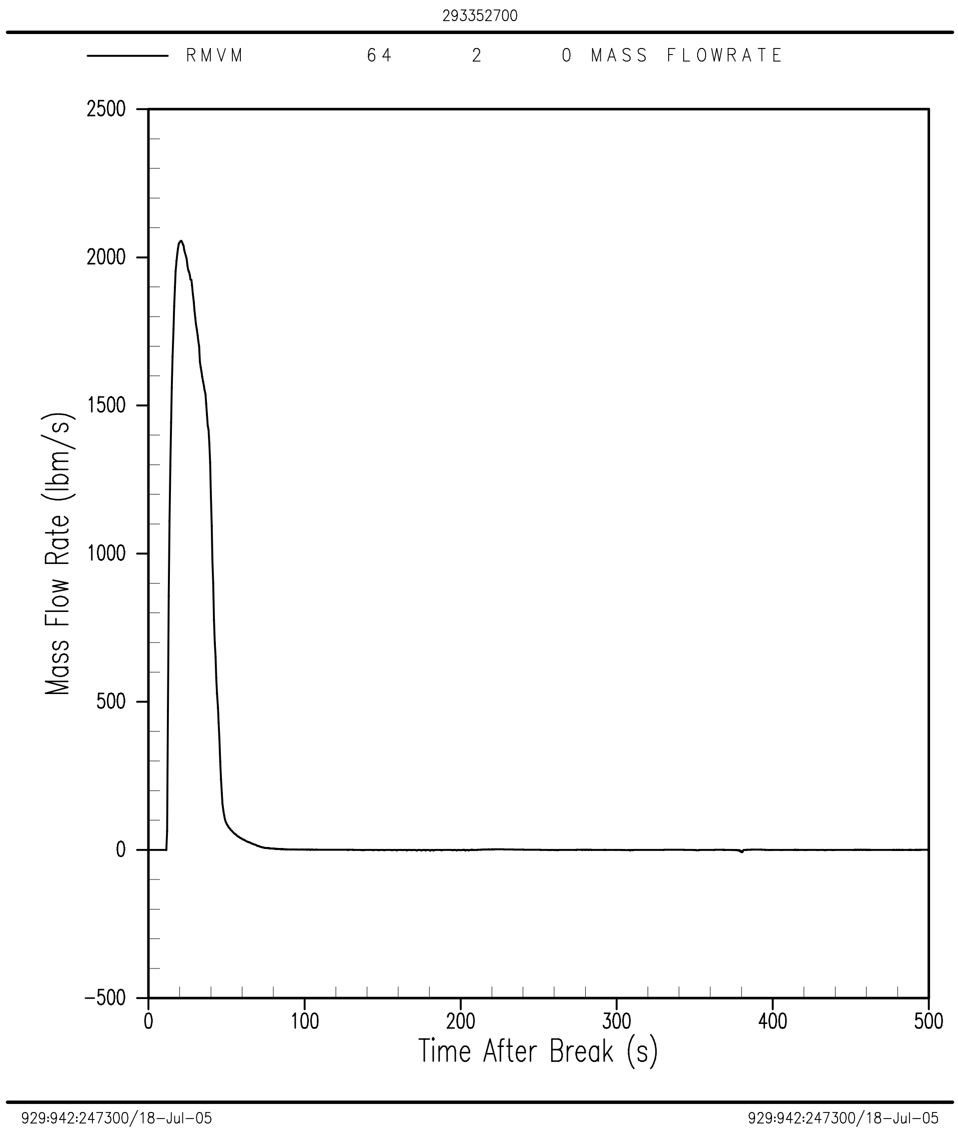


FSAR UPDATE

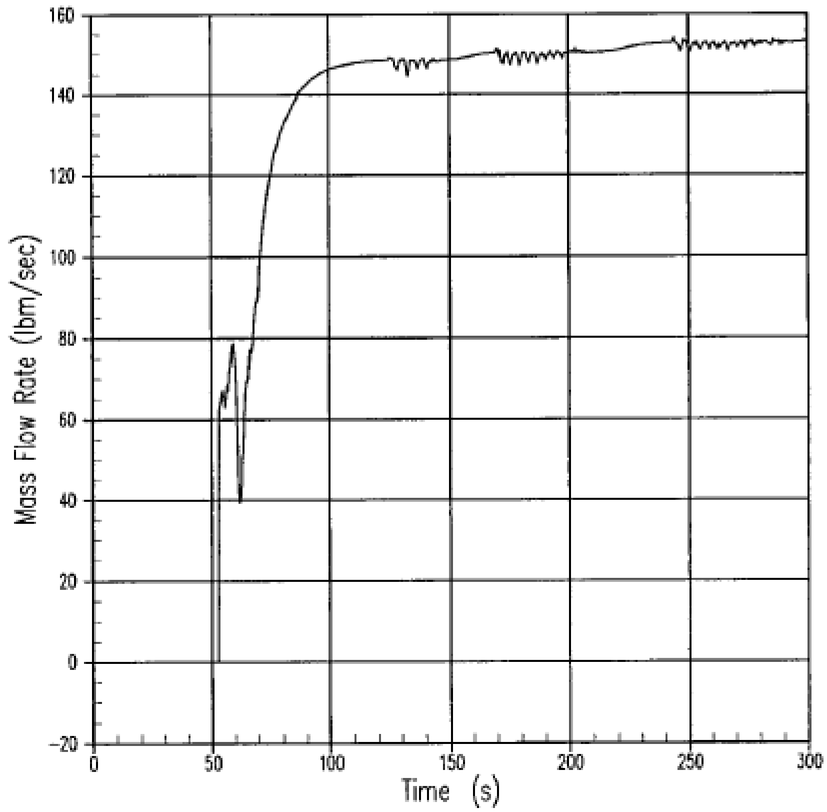
UNIT 1
DIABLO CANYON SITE

FIGURE 15.4.1-9A

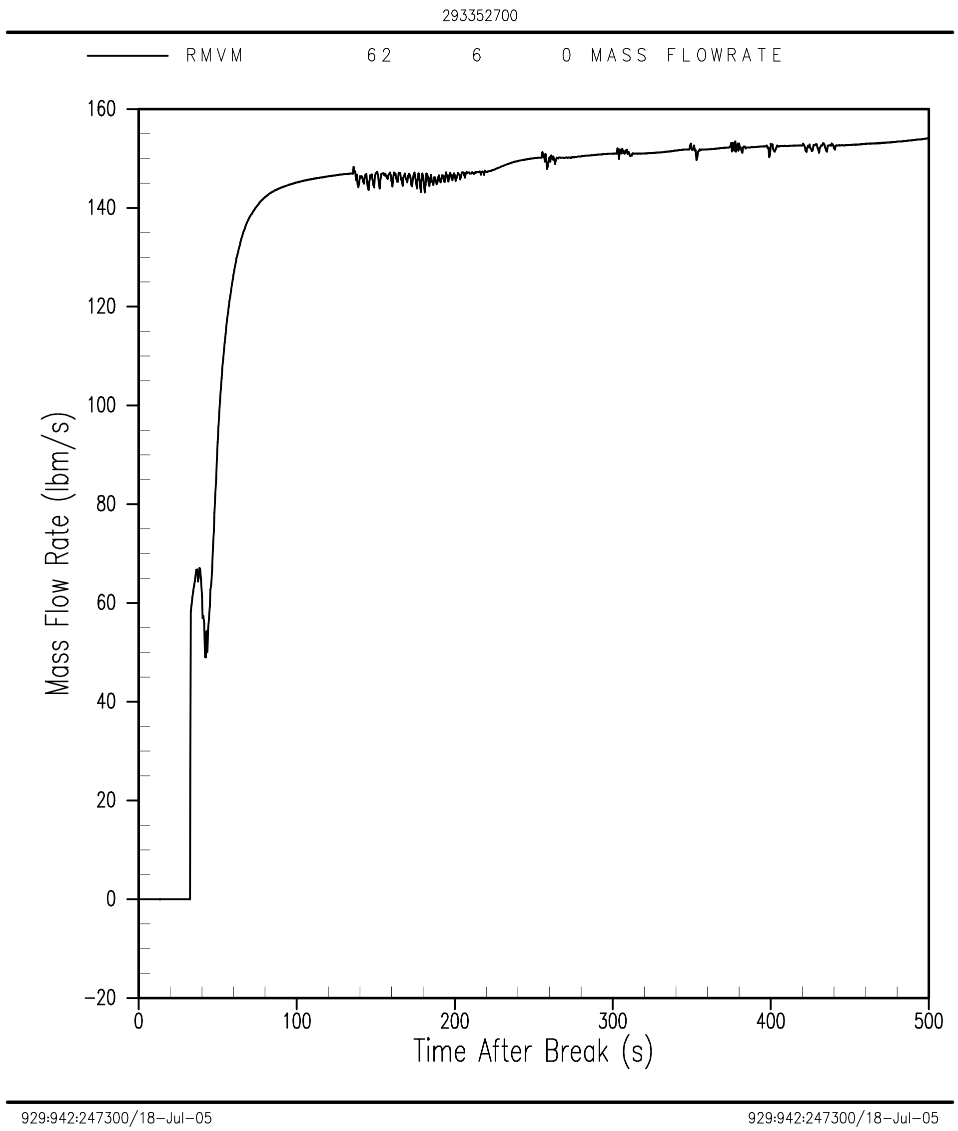
REFERENCE TRANSIENT
LOOP 1 ACCUMULATOR FLOW



FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1-9B LIMITING PCT CASE LOOP 1 ACCUMULATOR FLOW

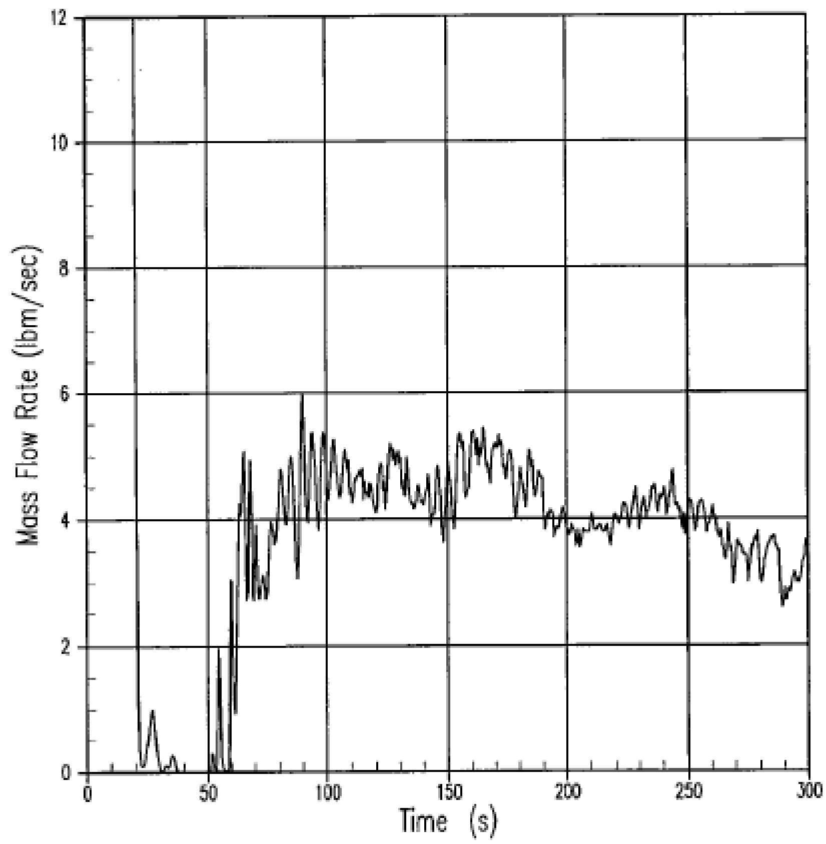


FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1-10A REFERENCE TRANSIENT LOOP 1 SAFETY INJECTION FLOW

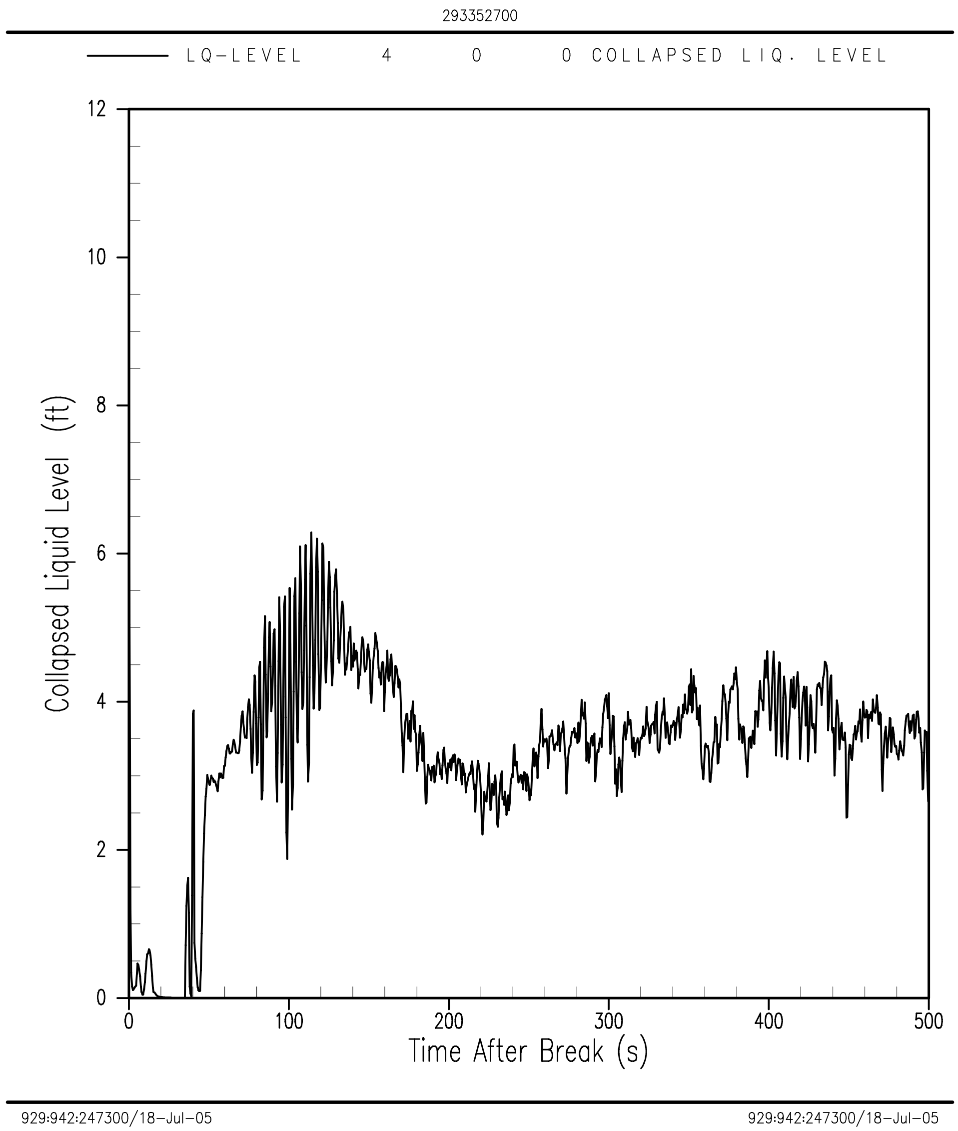


FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1-10B LIMITING PCT CASE LOOP 1 SAFETY INJECTION FLOW

Revision 18 October 2008



FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1-11A REFERENCE TRANSIENT CORE AVERAGE CHANNEL COLLAPSED LIQUID LEVEL

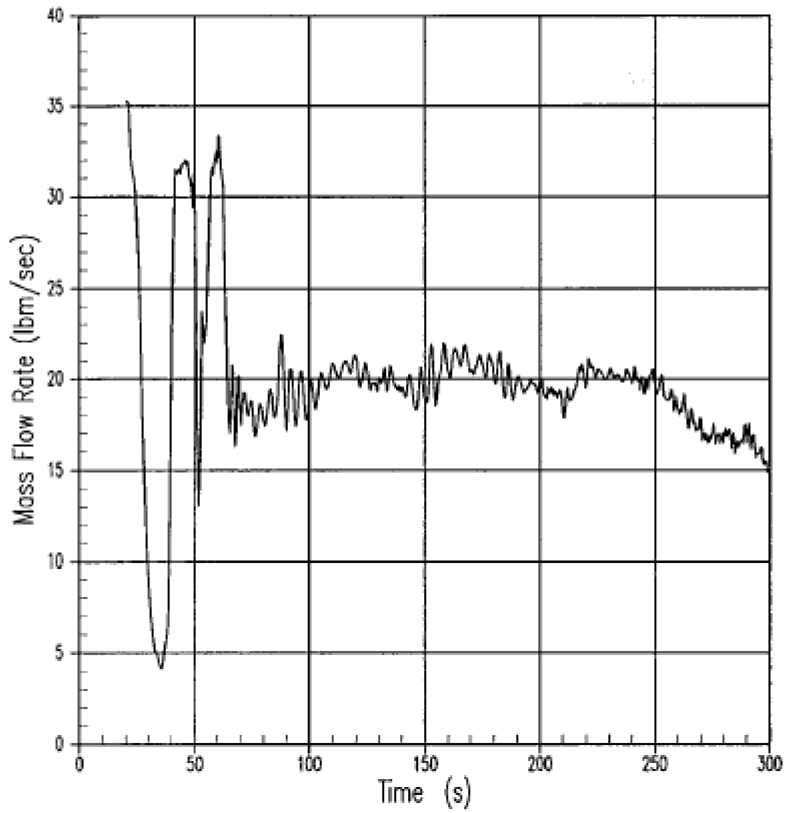


FSAR UPDATE

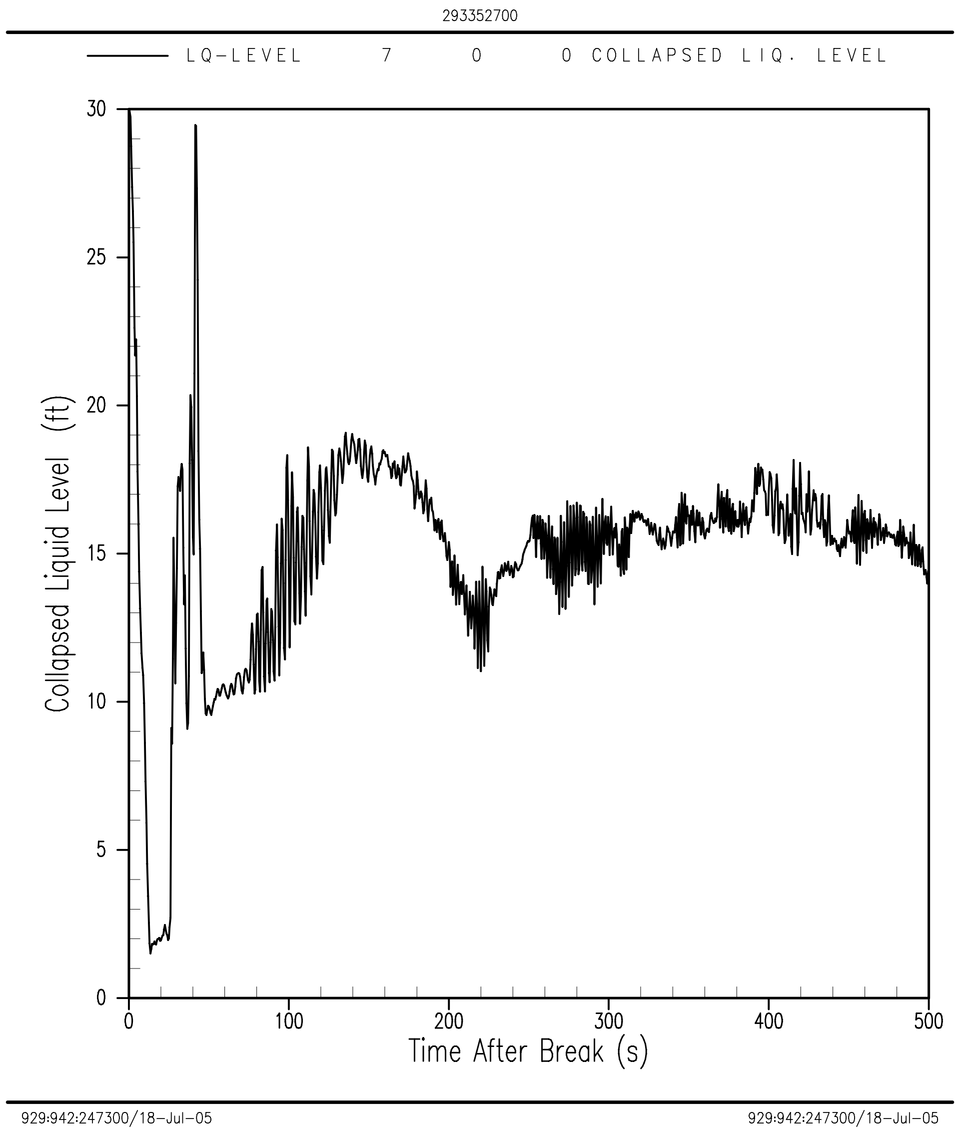
UNIT 2
DIABLO CANYON SITE

FIGURE 15.4.1-11B

LIMITING PCT CASE
CORE AVERAGE CHANNEL
COLLAPSED LIQUID LEVEL



FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1-12A REFERENCE TRANSIENT LOOP 1 DOWNCOMER COLLAPSED LIQUID LEVEL



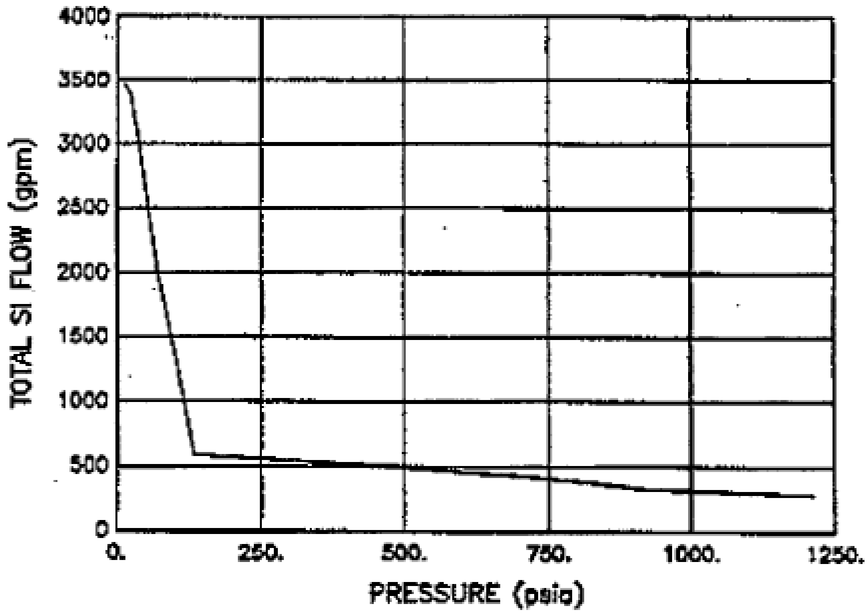
FSAR UPDATE

UNIT 2
DIABLO CANYON SITE

FIGURE 15.4.1-12B

LIMITING PCT CASE
LOOP 1 DOWNCOMER
COLLAPSED LIQUID LEVEL

Revision 18 October 2008

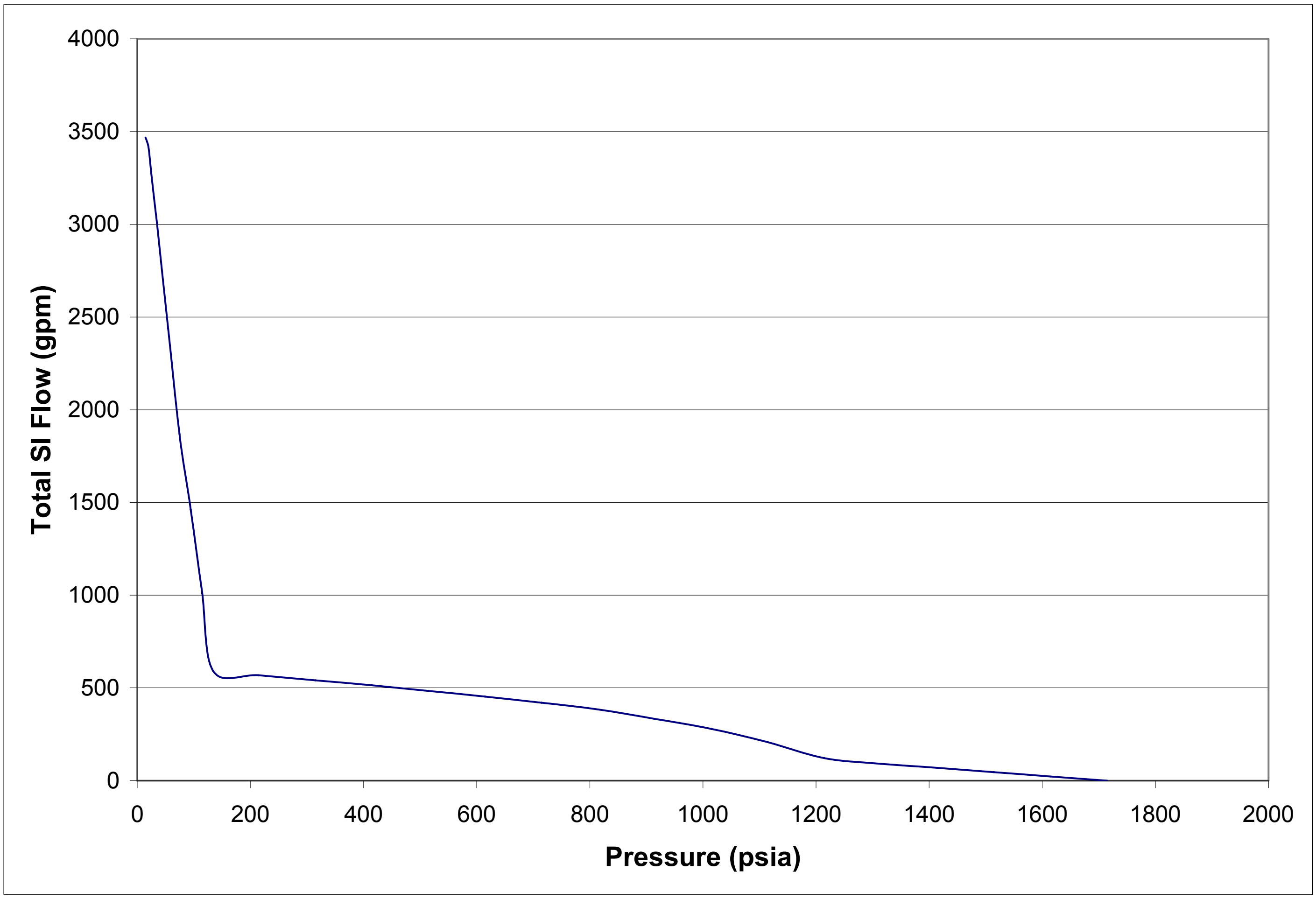


FSAR UPDATE

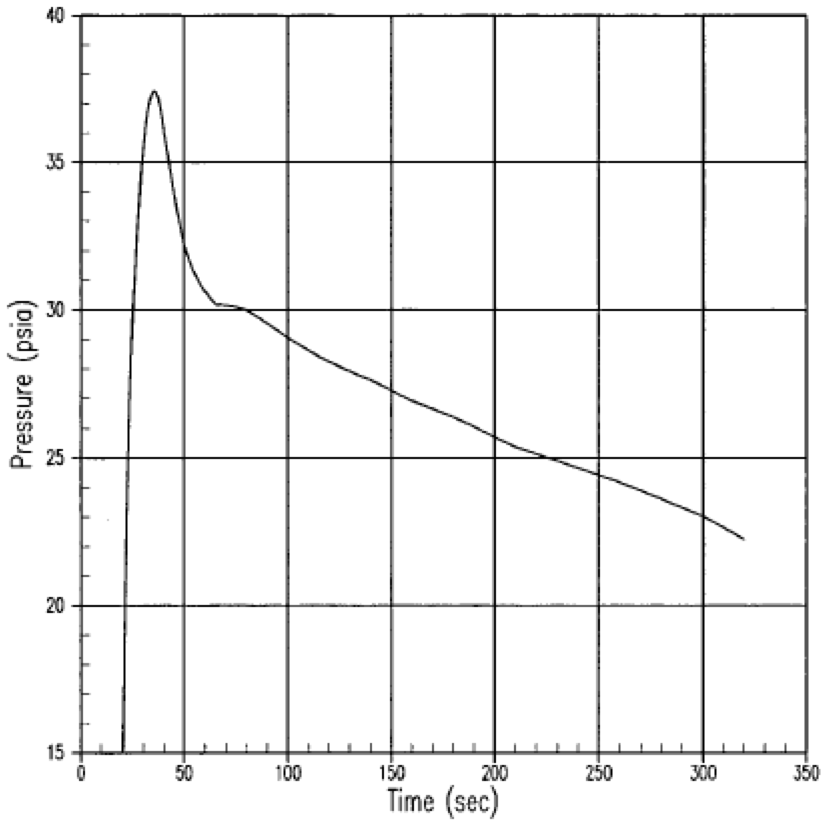
UNIT 1
DIABLO CANYON SITE

FIGURE 15.4.1-13A

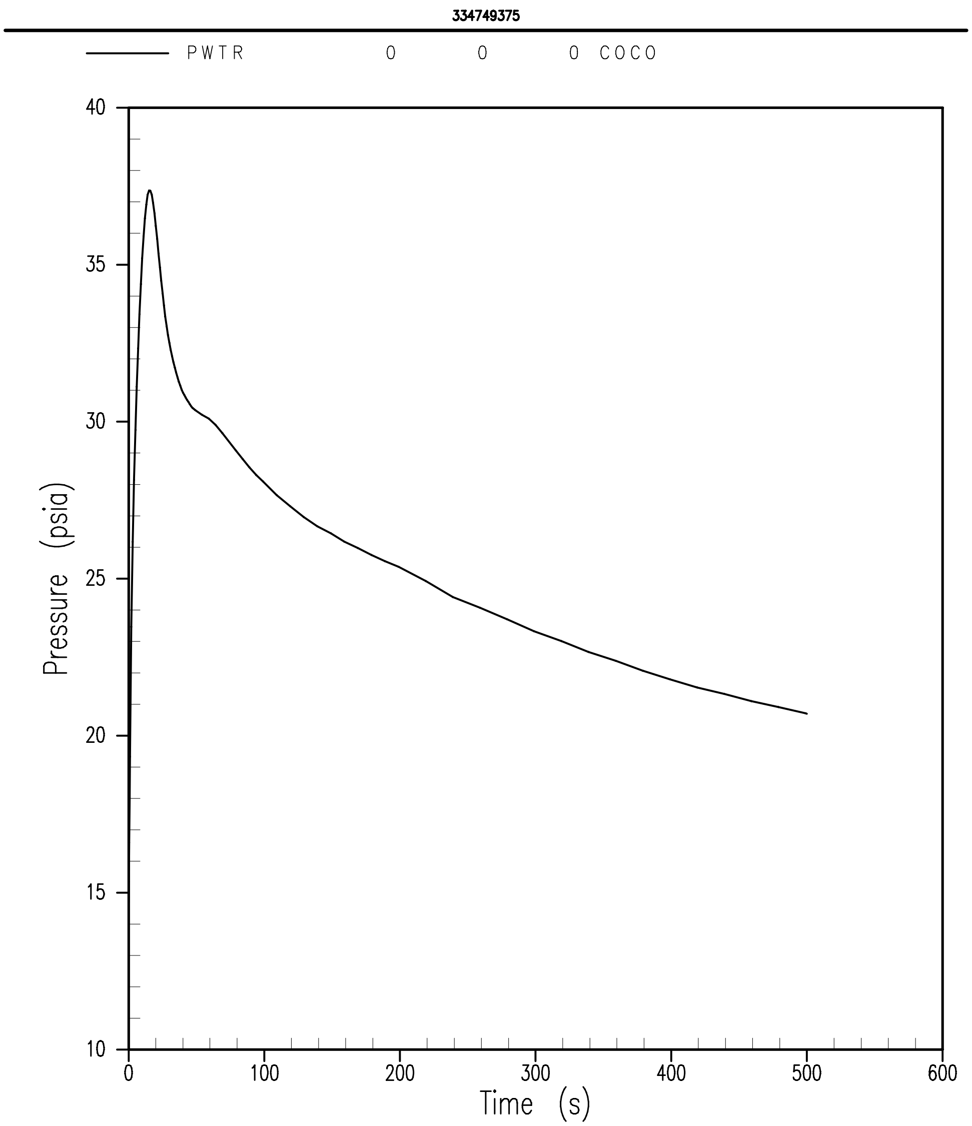
TOTAL ECCS FLOW
(3 LINES INJECTING)



FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1-13B TOTAL ECCS FLOW (3 LINES INJECTING)



FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1-14A REFERENCE TRANSIENT PRESSURE TRANSIENT



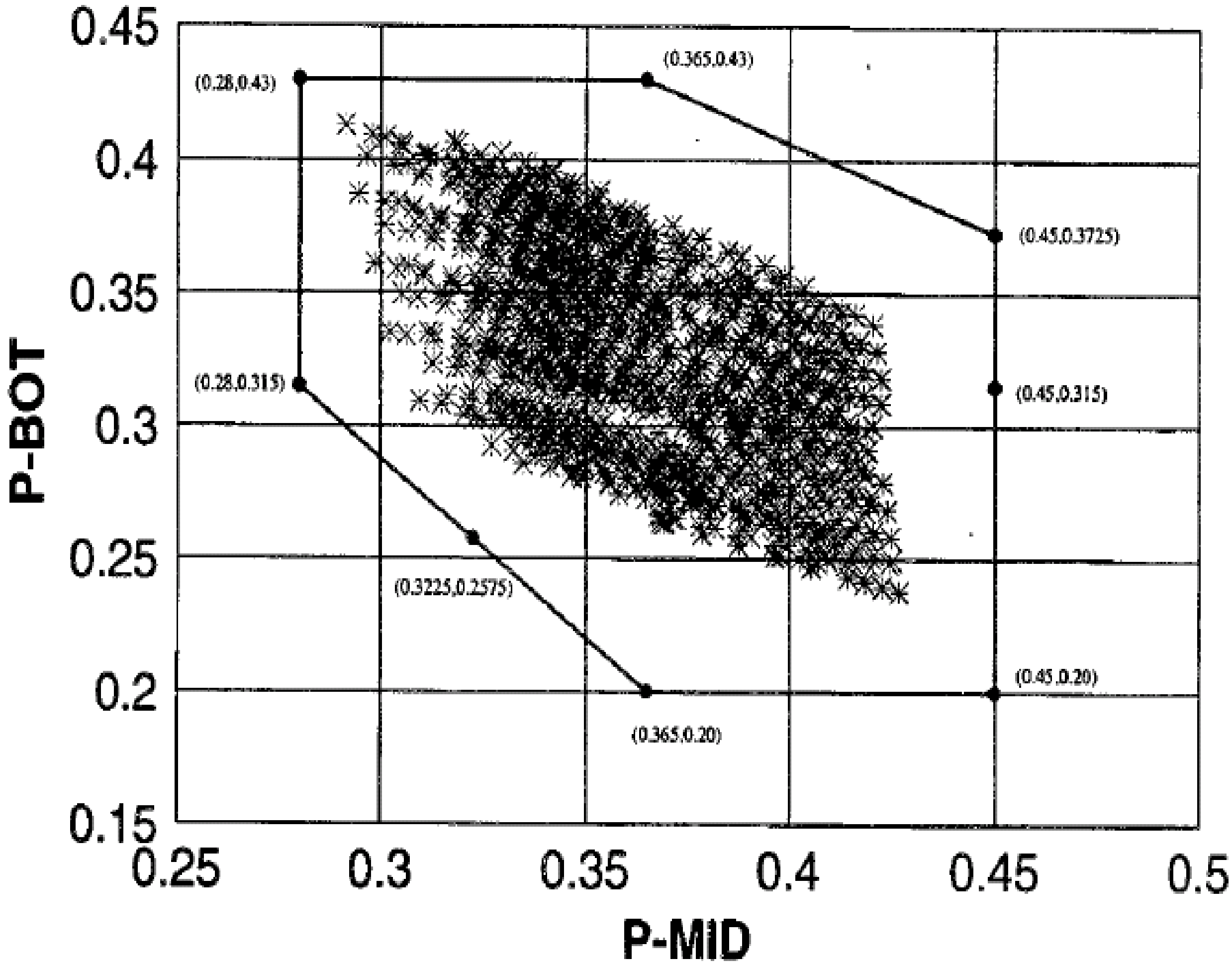
FSAR UPDATE

UNIT 2
DIABLO CANYON SITE

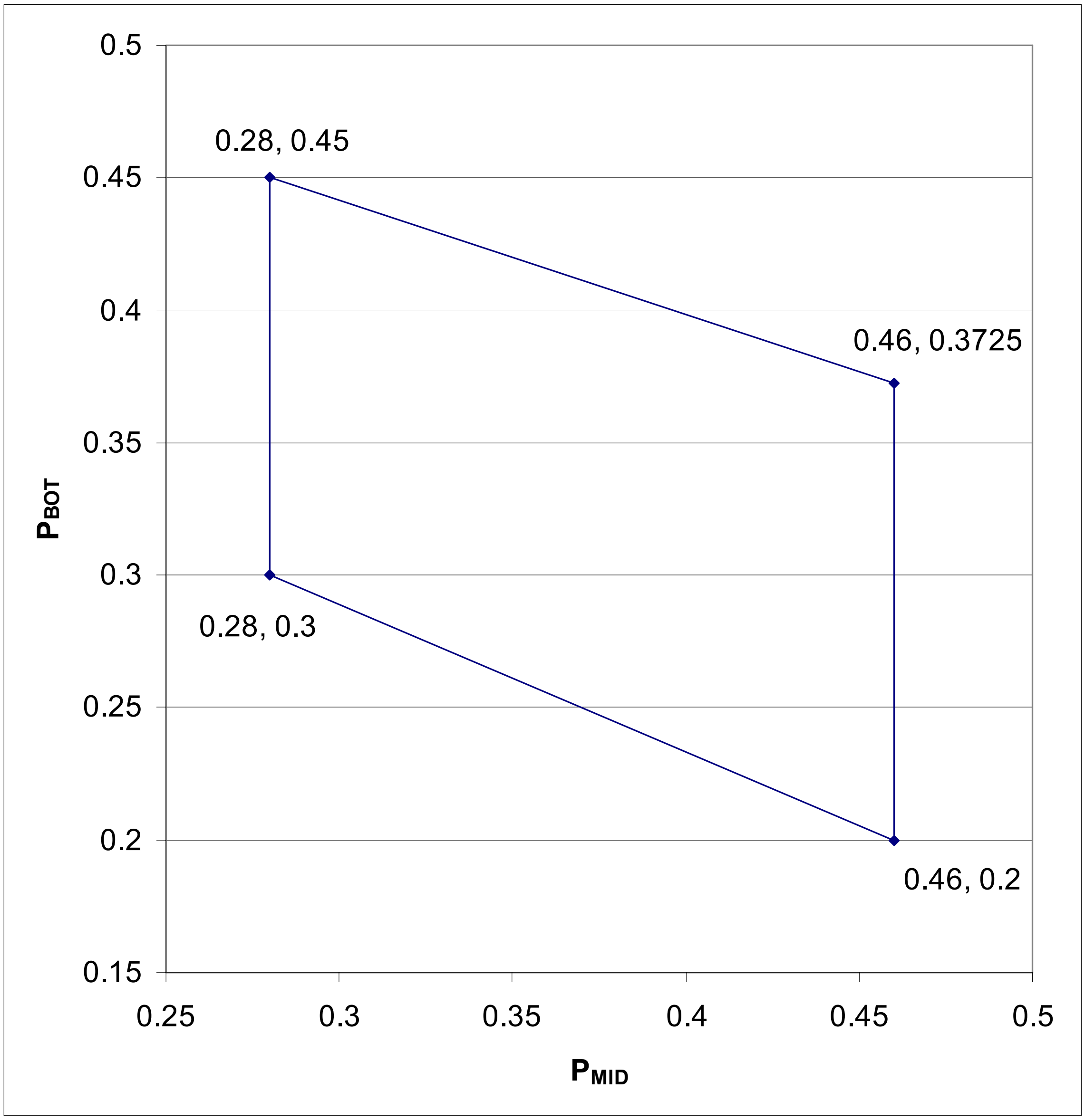
FIGURE 15.4.1-14B

LOWER BOUND COCO CONTAINMENT PRESSURE TRANSIENT

Revision 18 October 2008

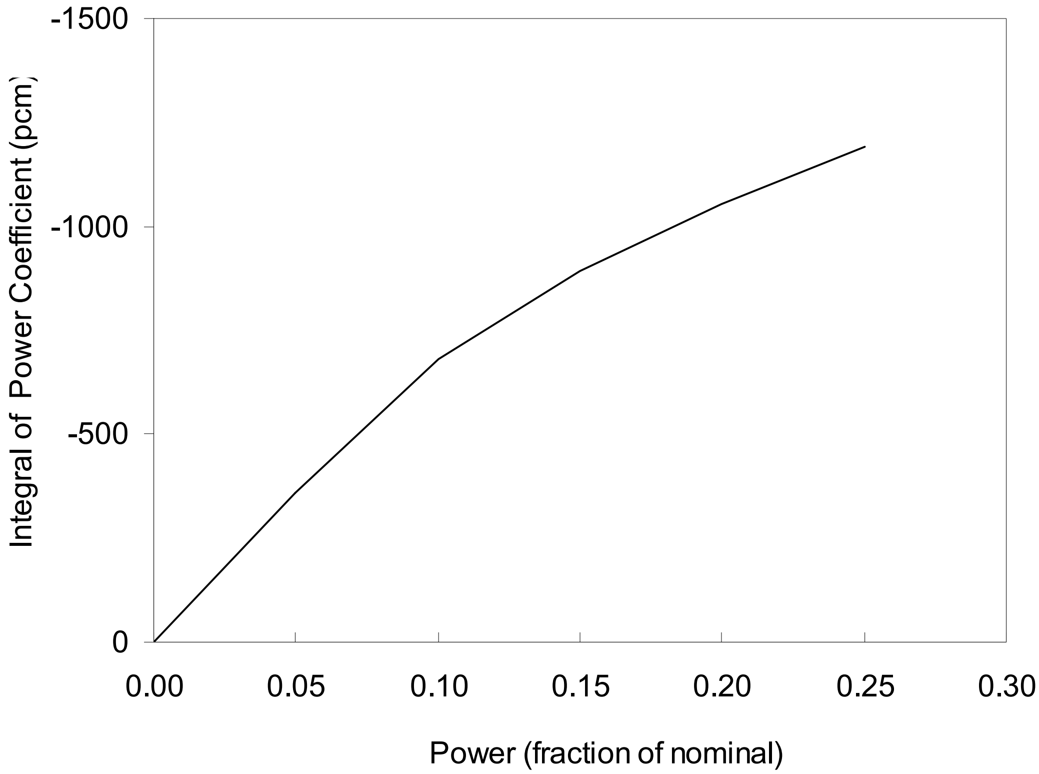


FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1-15A AXIAL POWER DISTRIBUTION LIMITS



FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1-15B AXIAL POWER DISTRIBUTION LIMITS

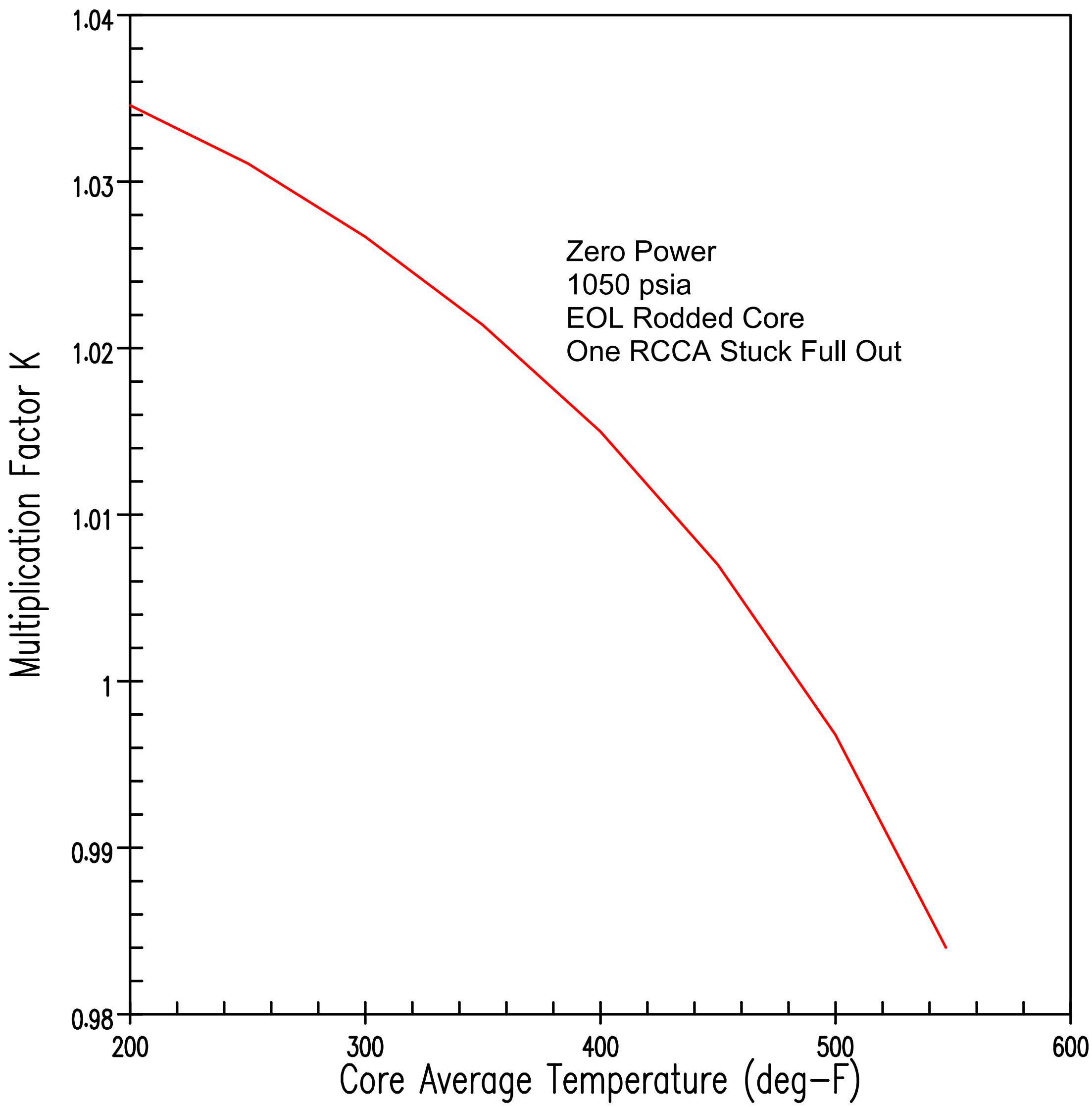
Revision 18 October 2008



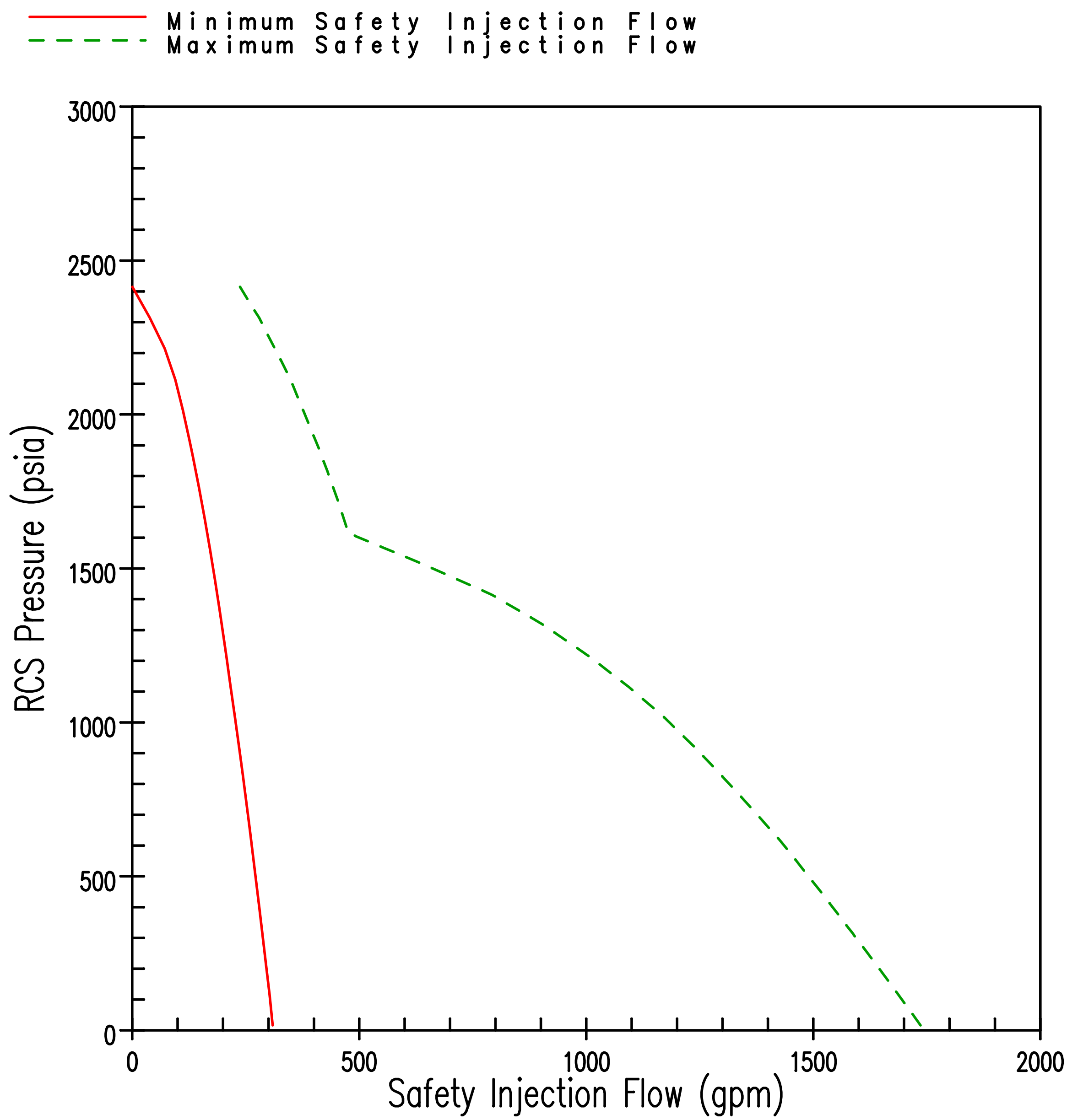
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.2-1
RUPTURE OF A MAIN STEAM LINE
VARIATION OF REACTIVITY WITH POWER AT CONSTANT CORE AVERAGE TEMPERATURE



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.2-2 RUPTURE OF A MAIN STEAM LINE VARIATION OF K_{EFF} WITH CORE AVERAGE TEMPERATURE



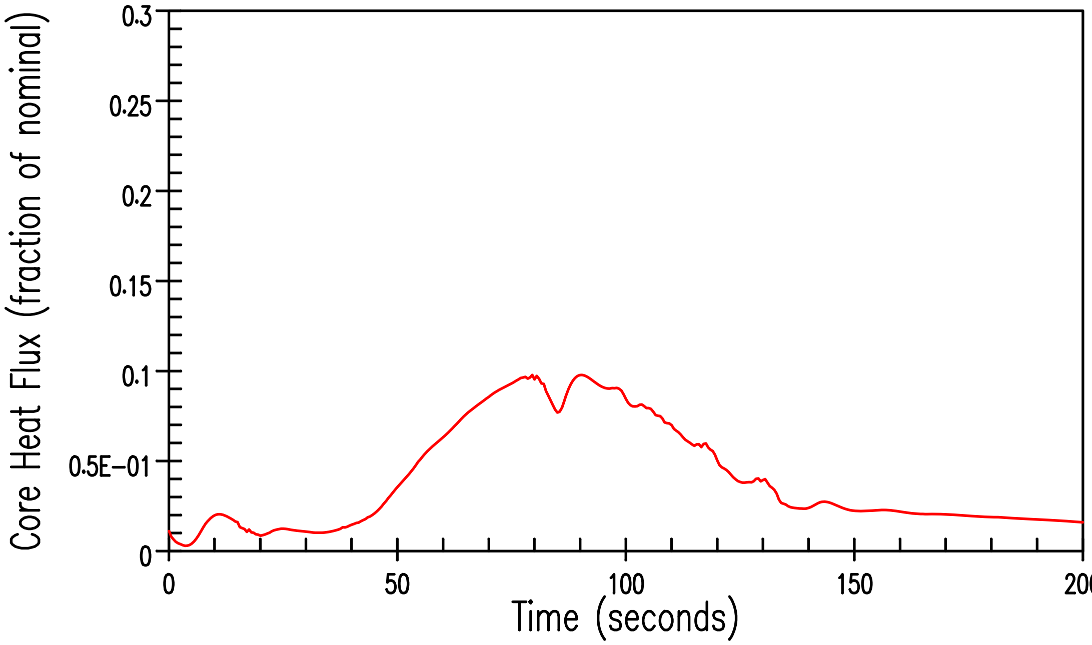
FSAR UPDATE

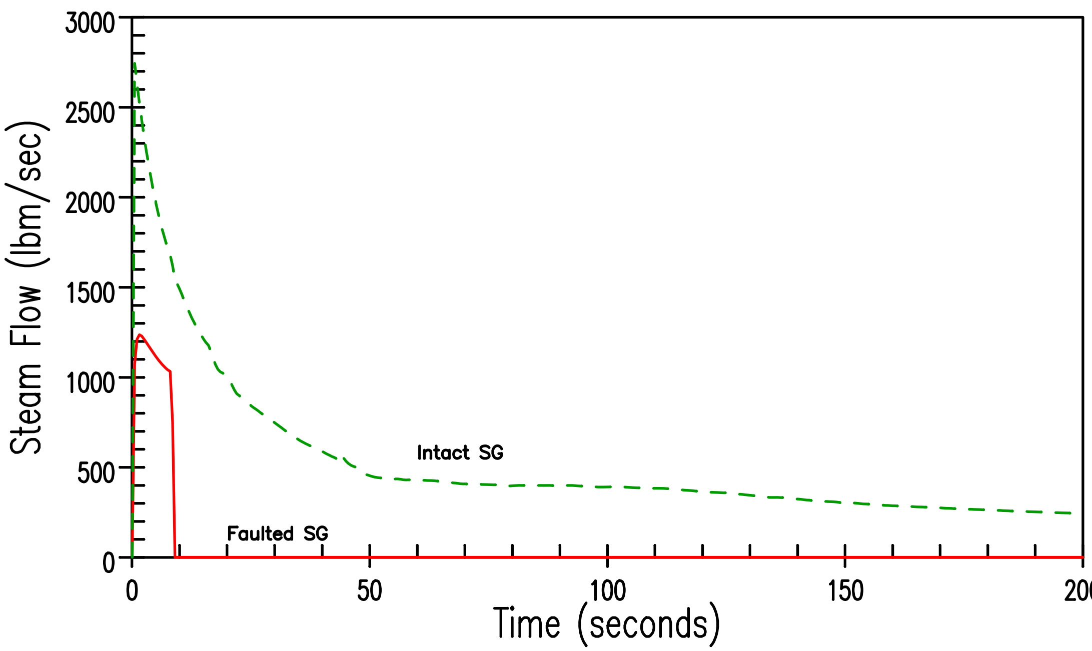
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.2-3

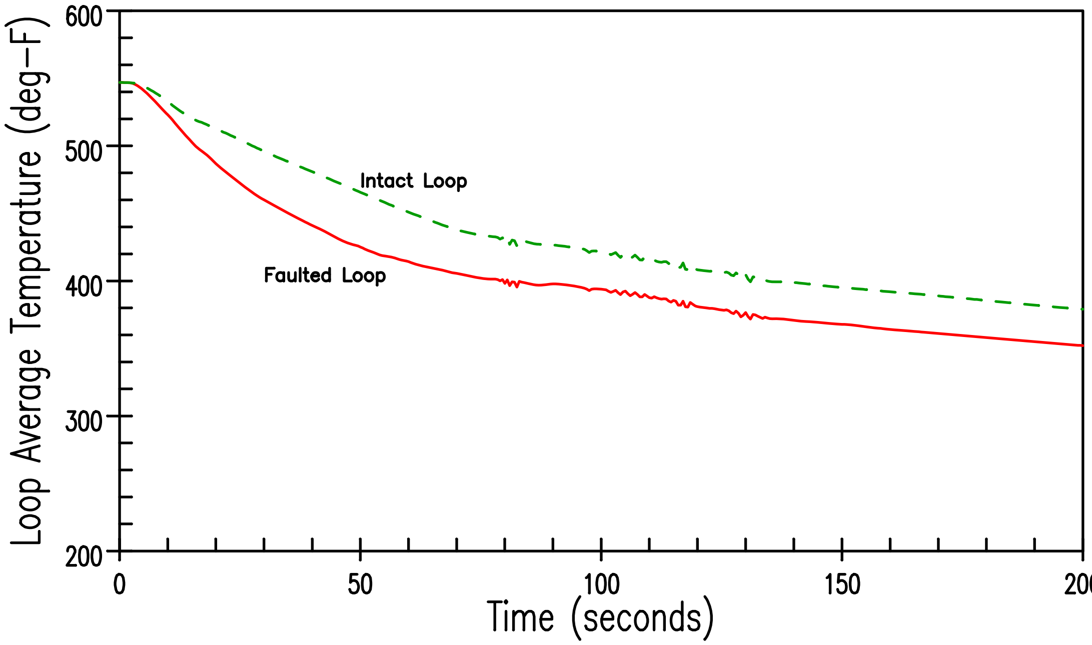
RUPTURE OF A MAIN STEAM LINE
SAFETY INJECTION CURVE

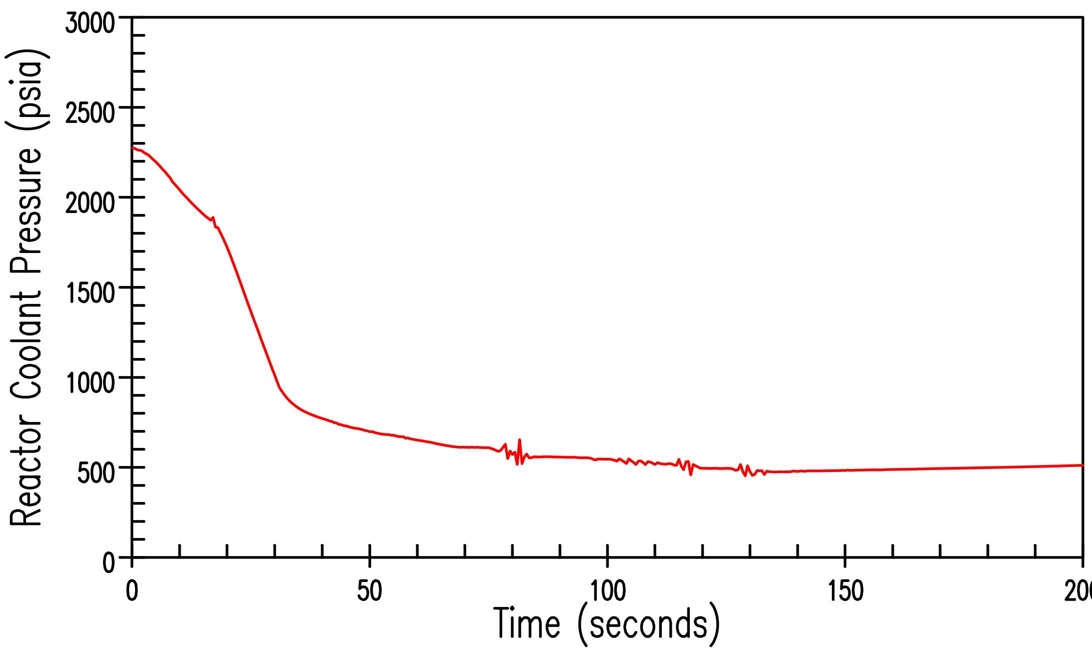
Revision 21 September 2013





FSAR UPDATE
UNITS 1 AND 2 **DIABLO CANYON SITE**
FIGURE 15.4.2-4 **RUPTURE OF A MAIN STEAM LINE** **WITH OFFSITE POWER AVAILABLE** **CORE HEAT FLUX AND** **STEAM FLOW TRANSIENTS**





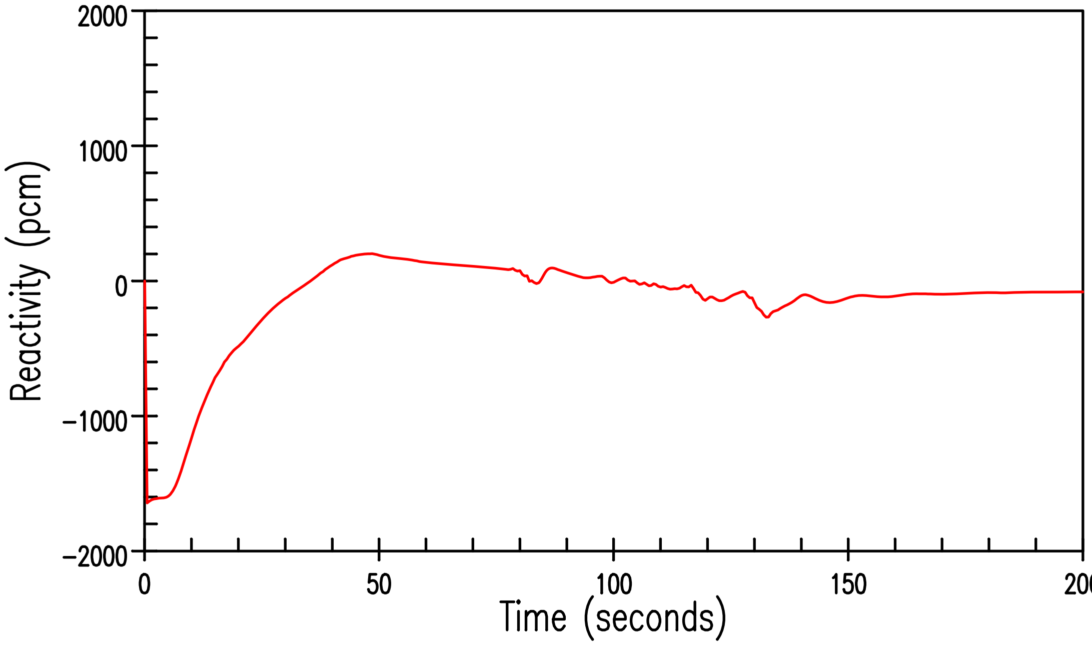
FSAR UPDATE

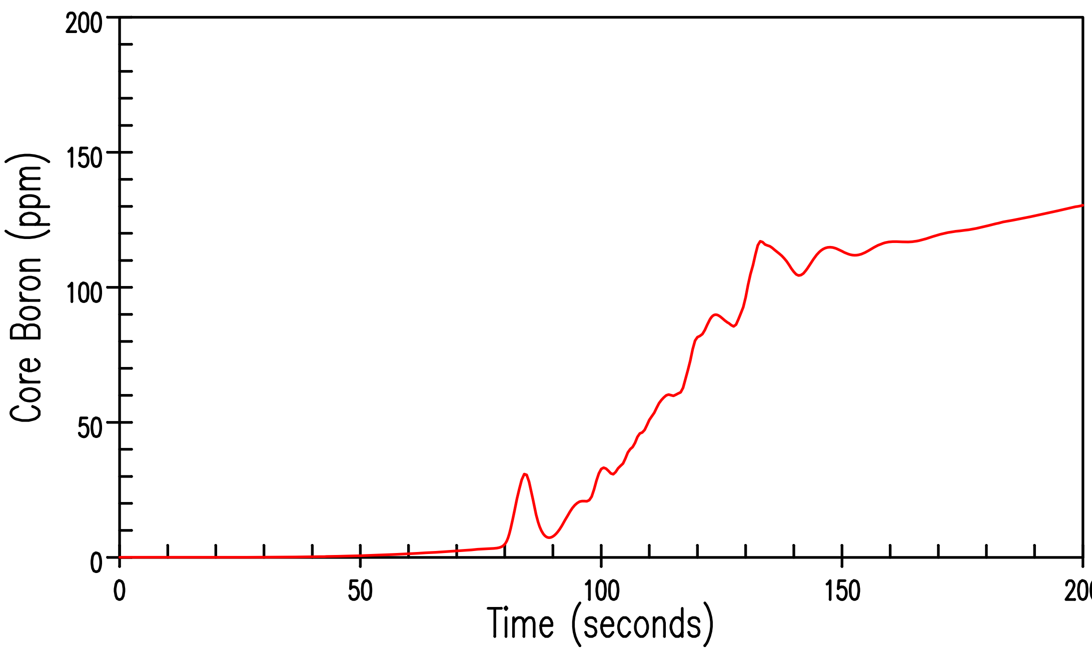
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.2-5

RUPTURE OF A MAIN STEAM LINE WITH OFFSITE POWER AVAILABLE

LOOP AVERAGE TEMPERATURE AND REACTOR COOLANT PRESSURE TRANSIENTS





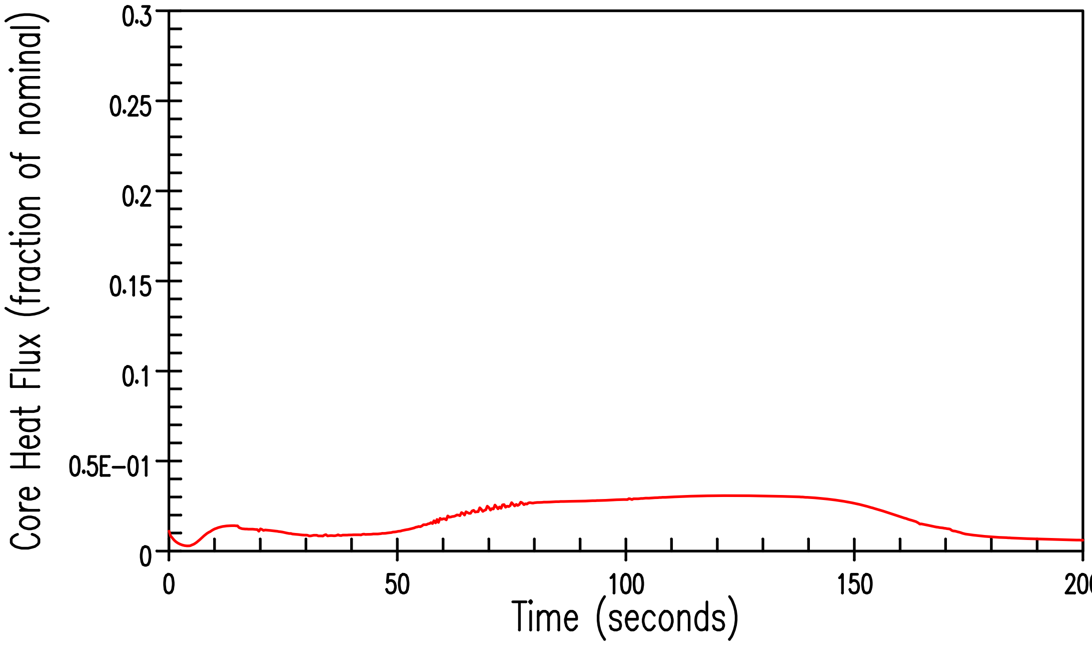
FSAR UPDATE

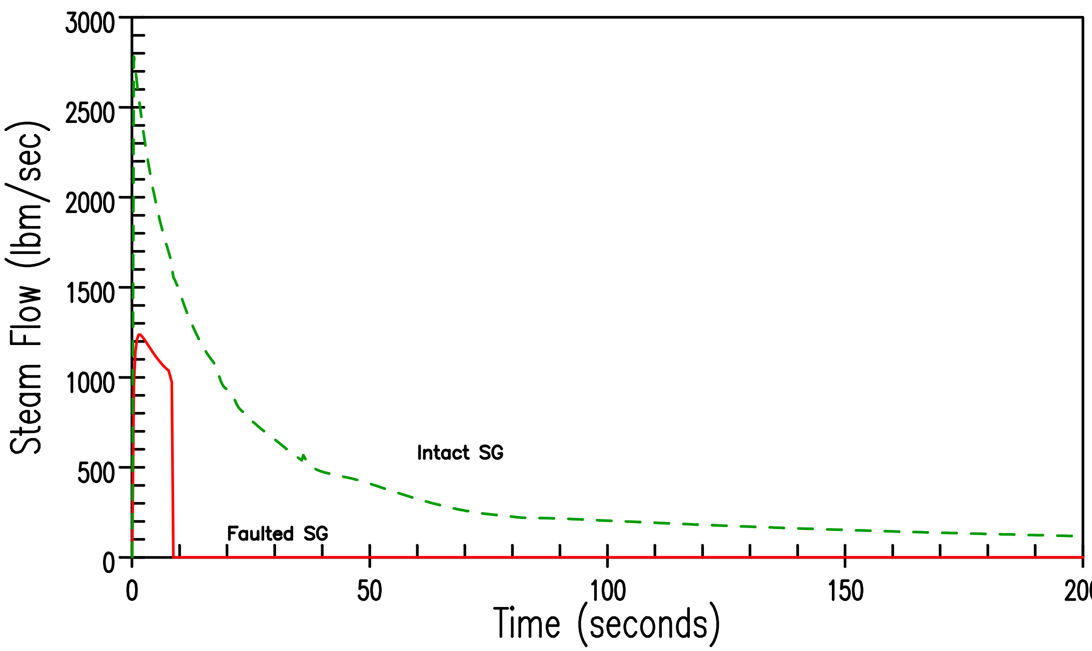
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.2-6

RUPTURE OF A MAIN STEAM LINE
WITH OFFSITE POWER AVAILABLE

REACTIVITY AND CORE BORON TRANSIENTS

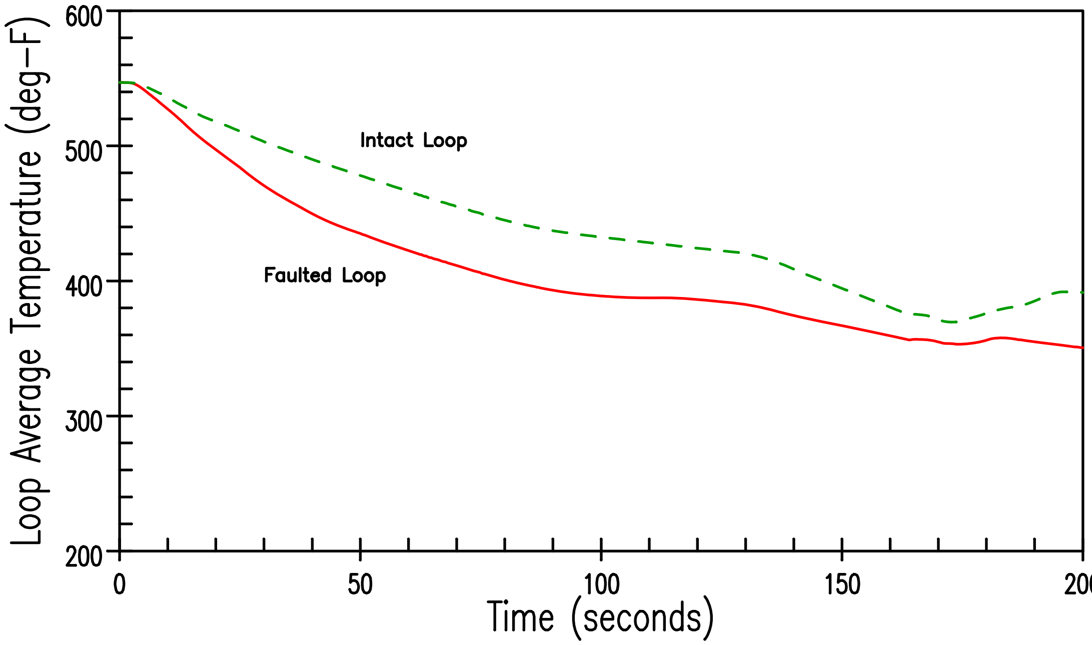


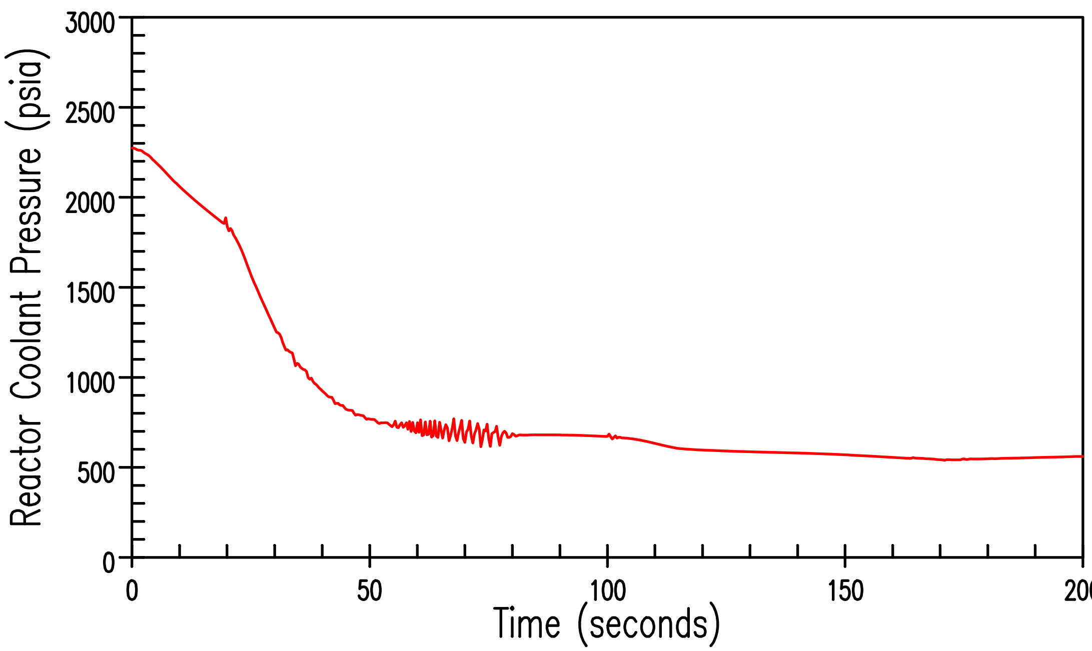


FSAR UPDATE

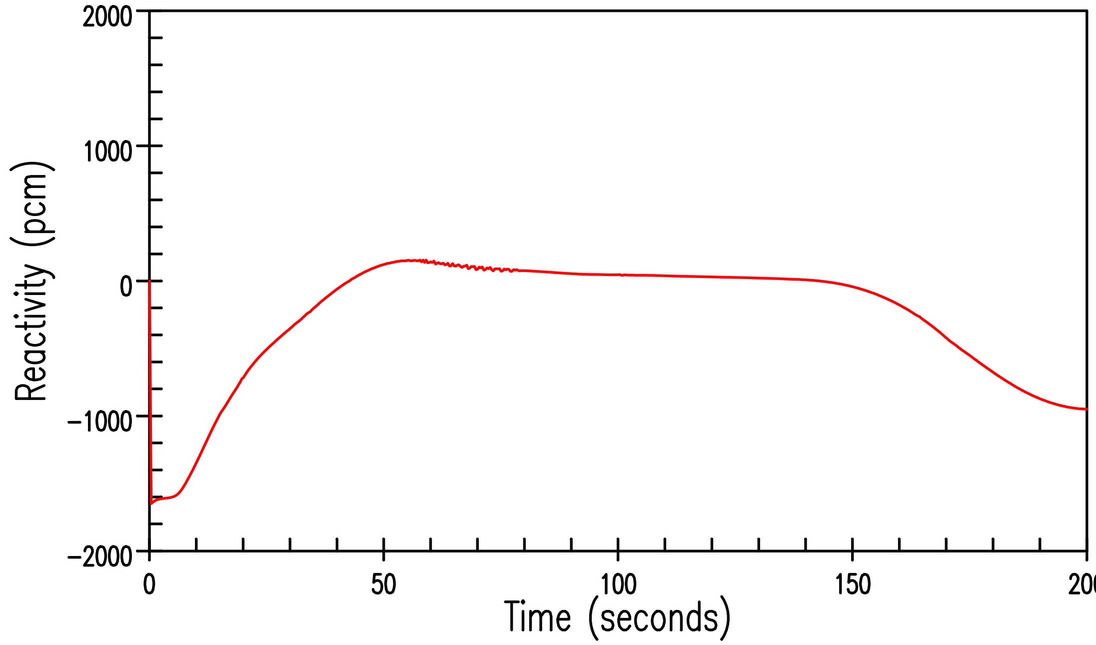
UNITS 1 AND 2
DIABLO CANYON SITE

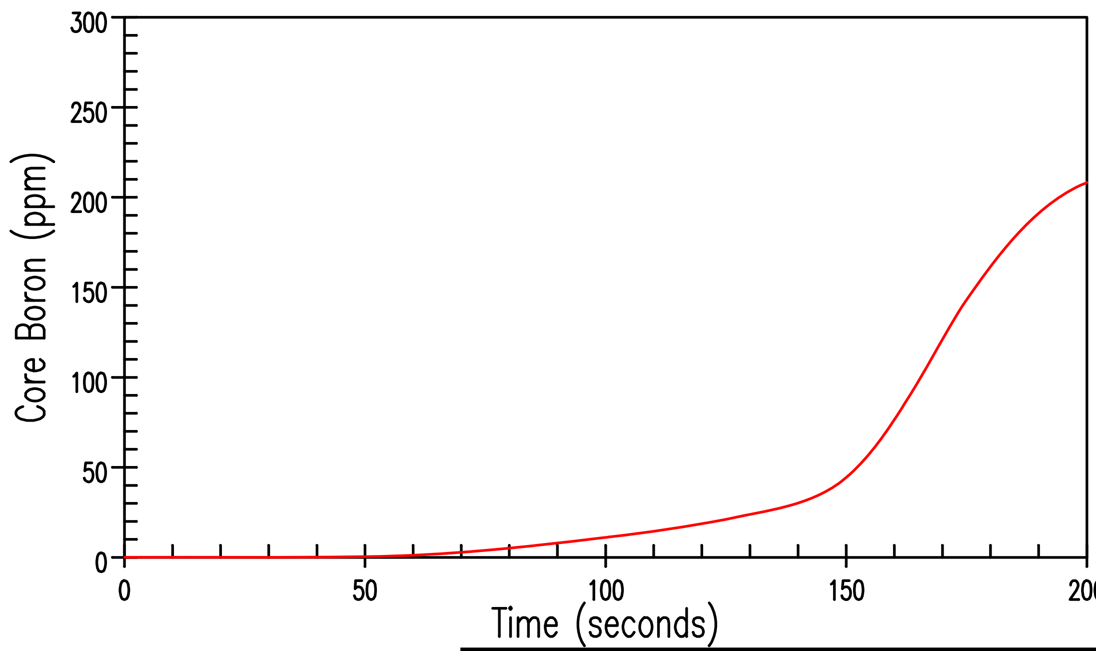
FIGURE 15.4.2-7
RUPTURE OF A MAIN STEAM LINE WITHOUT OFFSITE POWER AVAILABLE
CORE HEAT FLUX AND STEAM FLOW TRANSIENTS





FSAR UPDATE
UNITS 1 AND 2 **DIABLO CANYON SITE**
FIGURE 15.4.2-8 **RUPTURE OF A MAIN STEAM LINE WITHOUT OFFSITE POWER AVAILABLE** **LOOP AVERAGE TEMPERATURE AND REACTOR COOLANT PRESSURE TRANSIENTS**





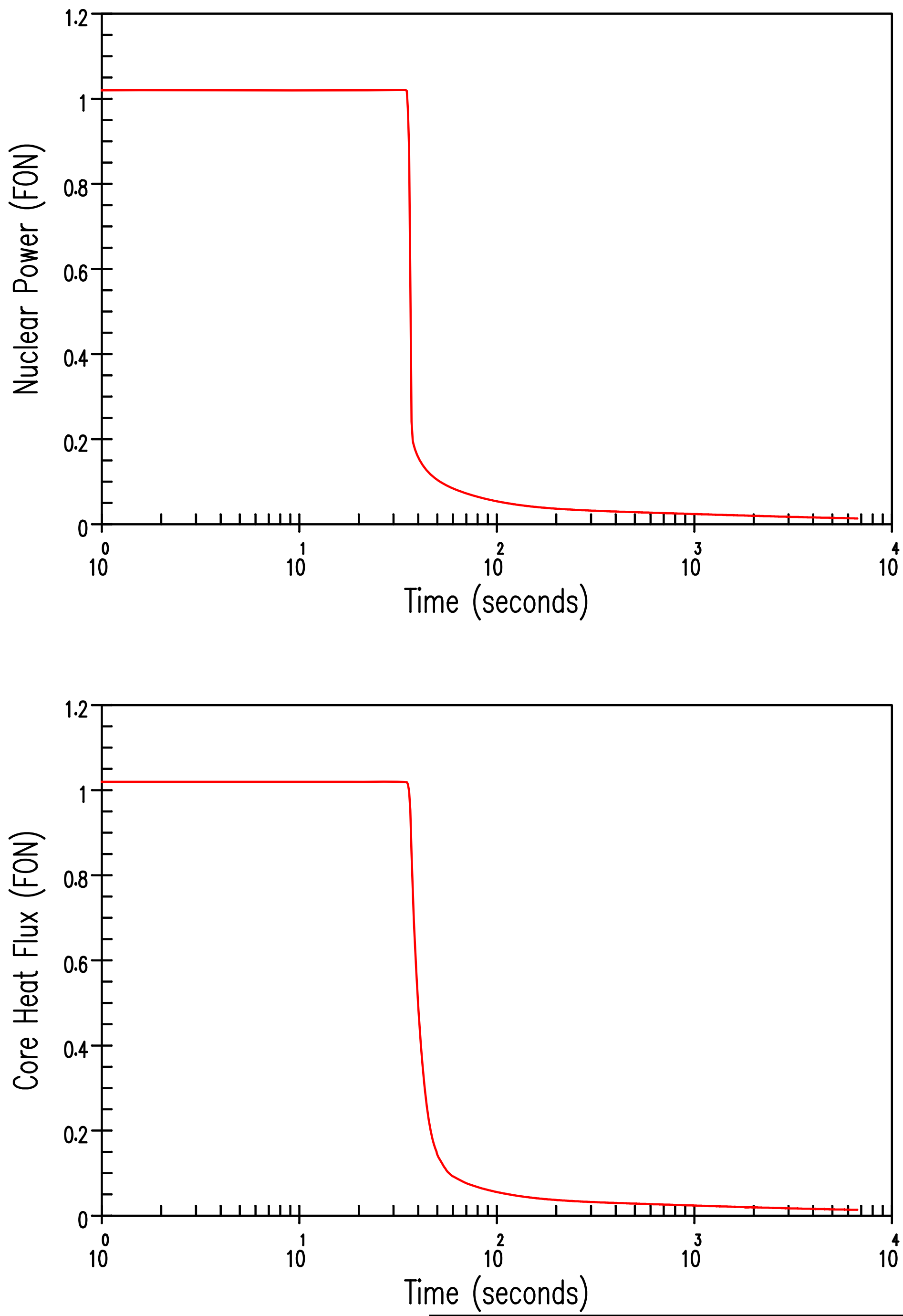
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.2-9

RUPTURE OF A MAIN STEAM LINE
WITHOUT OFFSITE POWER AVAILABLE

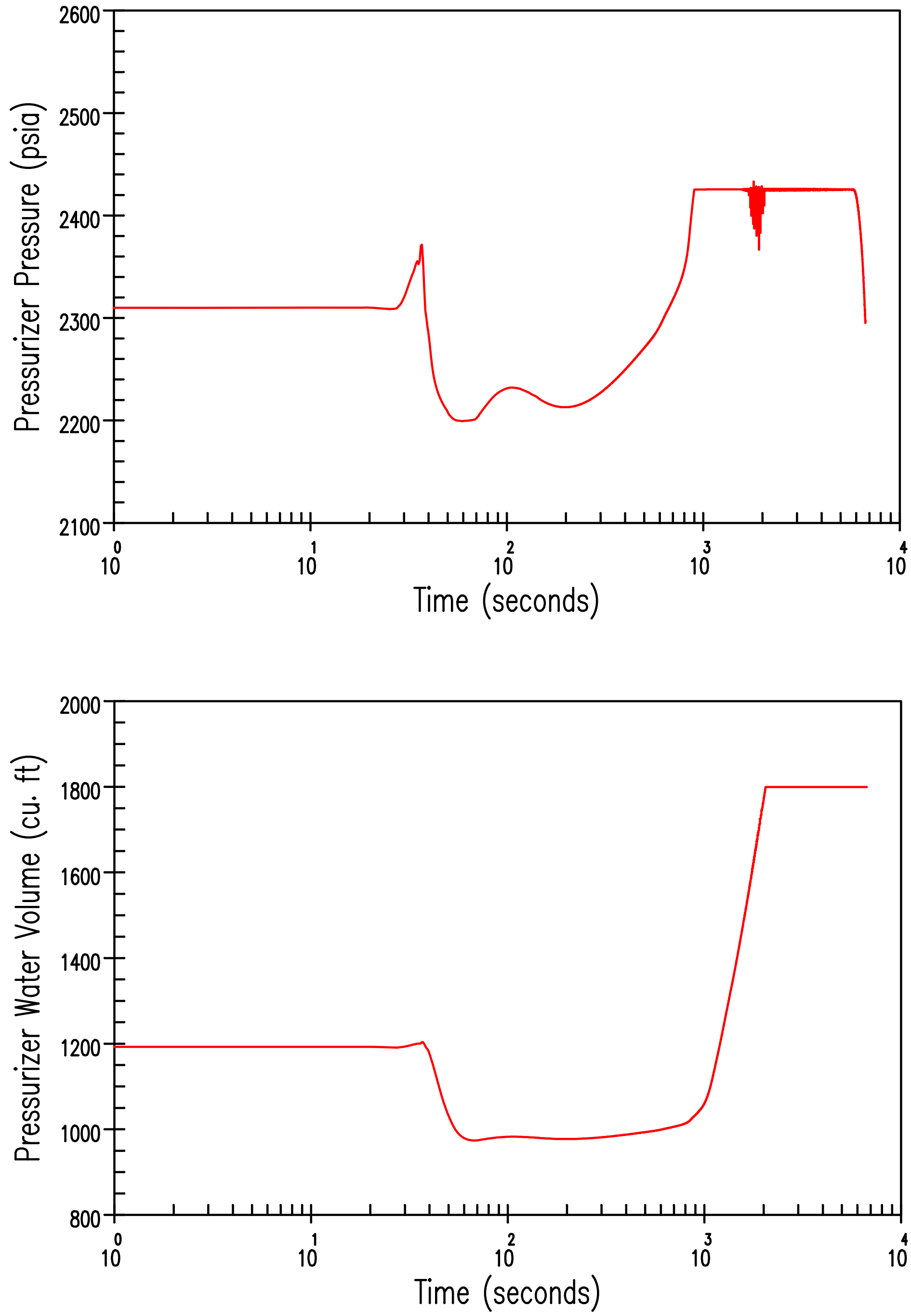
REACTIVITY AND CORE BORON TRANSIENTS



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.2-10
MAIN FEEDLINE RUPTURE
WITH OFFSITE POWER AVAILABLE
NUCLEAR POWER AND
CORE HEAT FLUX TRANSIENTS



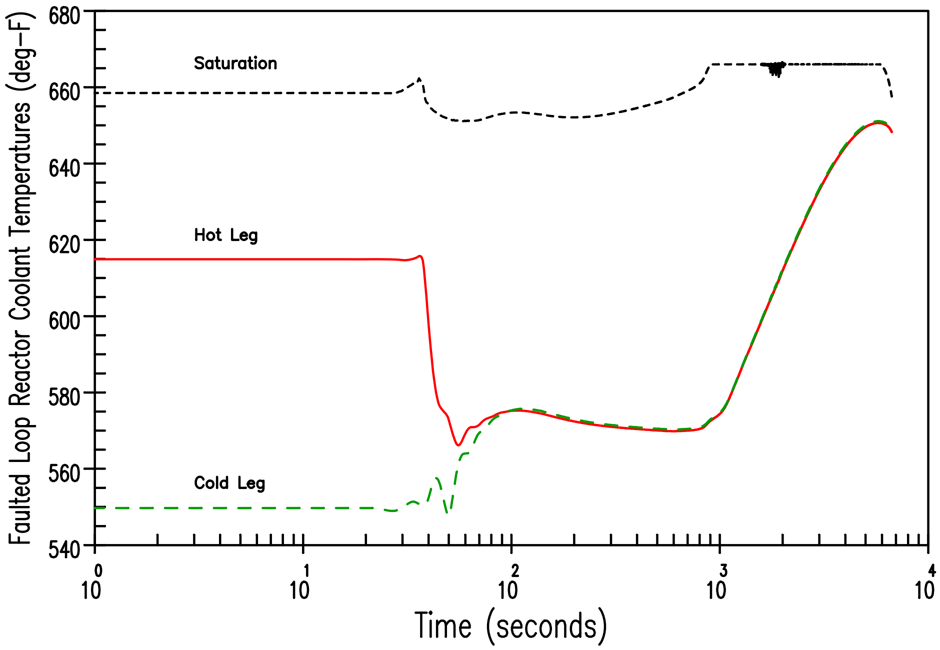
FSAR UPDATE

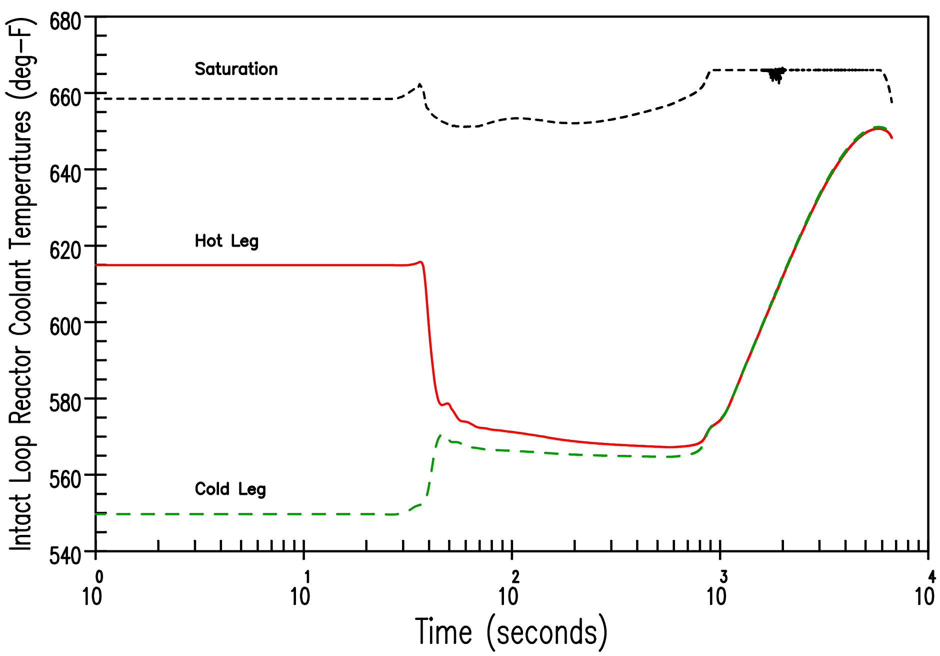
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.2-11

MAIN FEEDLINE RUPTURE
WITH OFFSITE POWER AVAILABLE

PRESSURIZER PRESSURE AND
WATER VOLUME TRANSIENTS

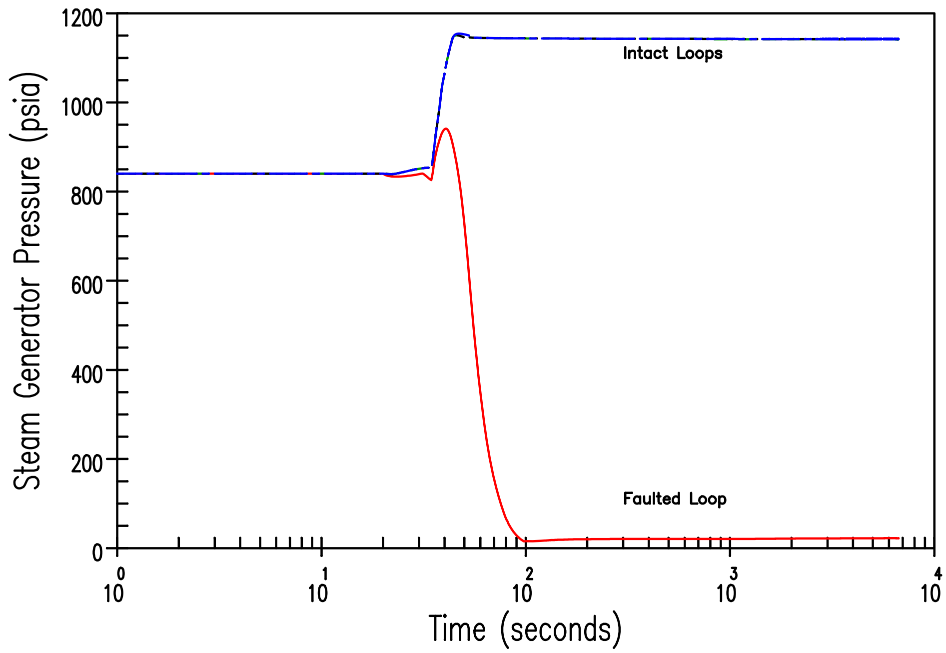


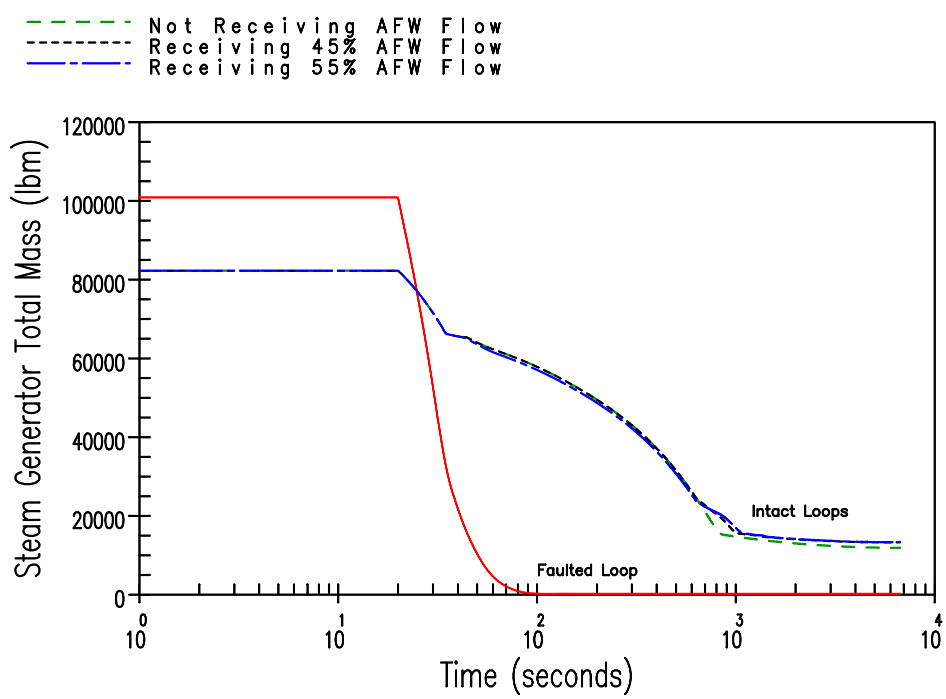


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.2-12
MAIN FEEDLINE RUPTURE
WITH OFFSITE POWER AVAILABLE
REACTOR COOLANT TEMPERATURE
TRANSIENTS FOR THE FAULTED
AND INTACT LOOPS





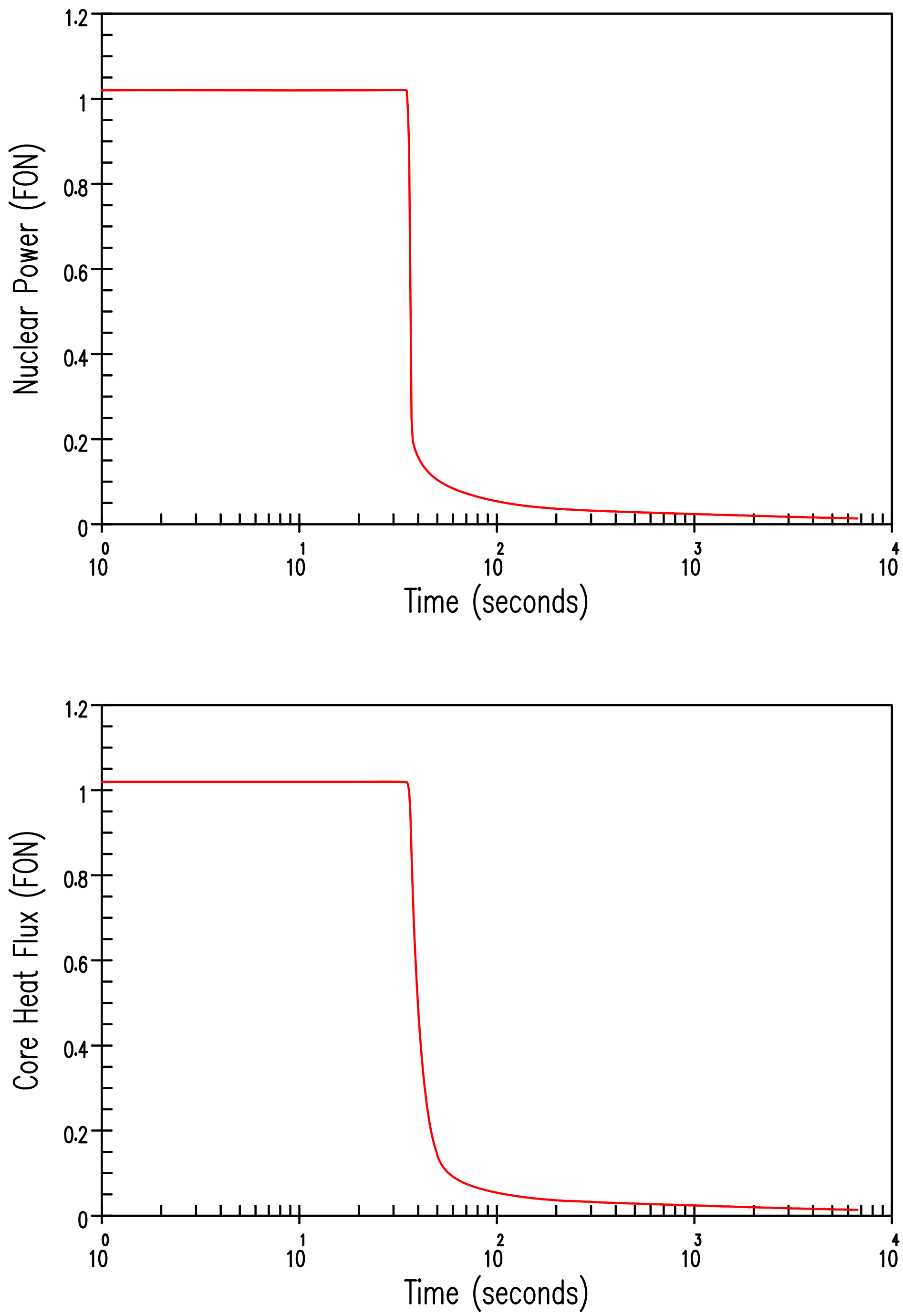
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.2-13

MAIN FEEDLINE RUPTURE
WITH OFFSITE POWER AVAILABLE

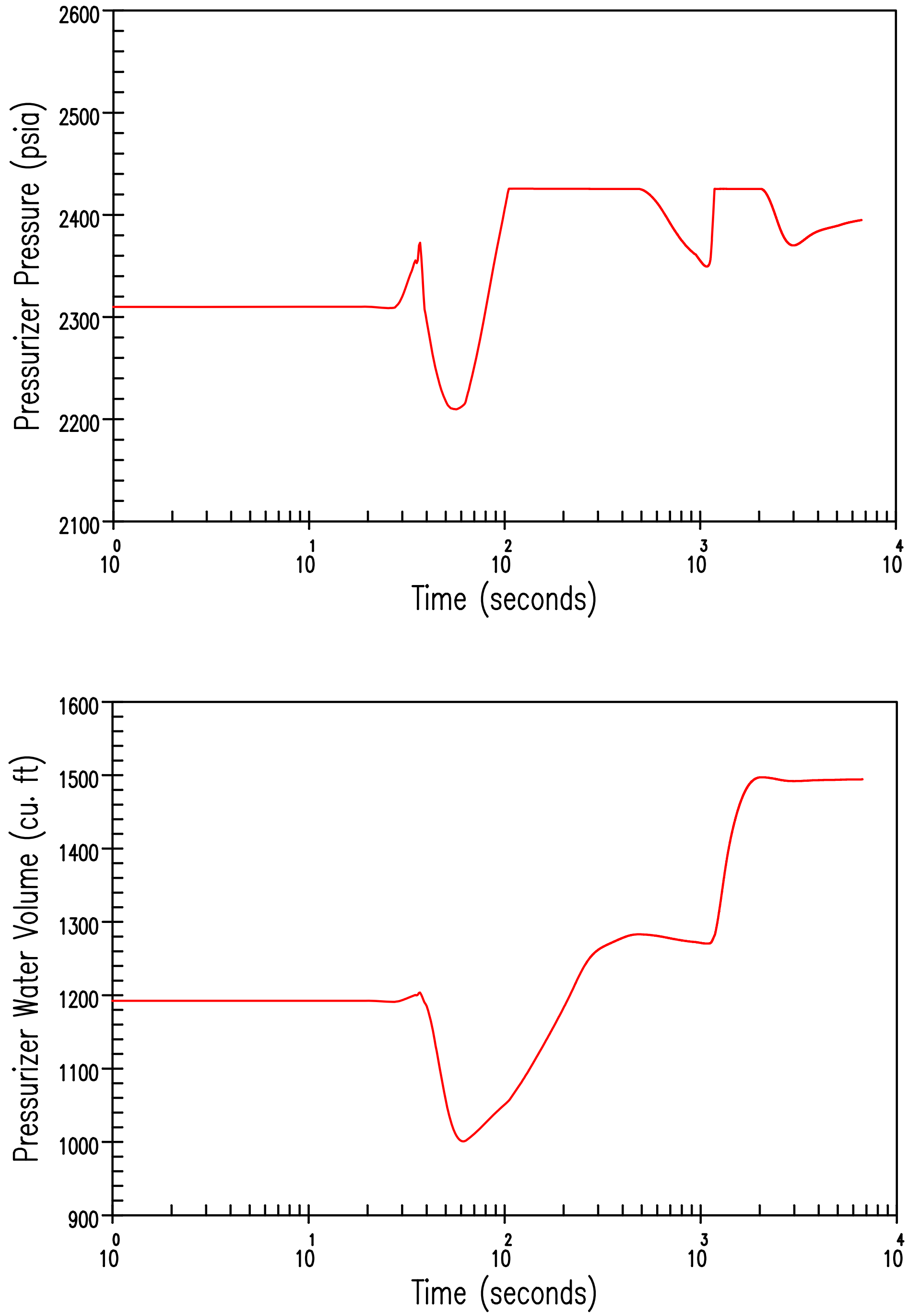
STEAM GENERATOR PRESSURE AND
TOTAL MASS TRANSIENTS



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.2-14
MAIN FEEDLINE RUPTURE
WITHOUT OFFSITE POWER AVAILABLE
NUCLEAR POWER AND
CORE HEAT FLUX TRANSIENTS



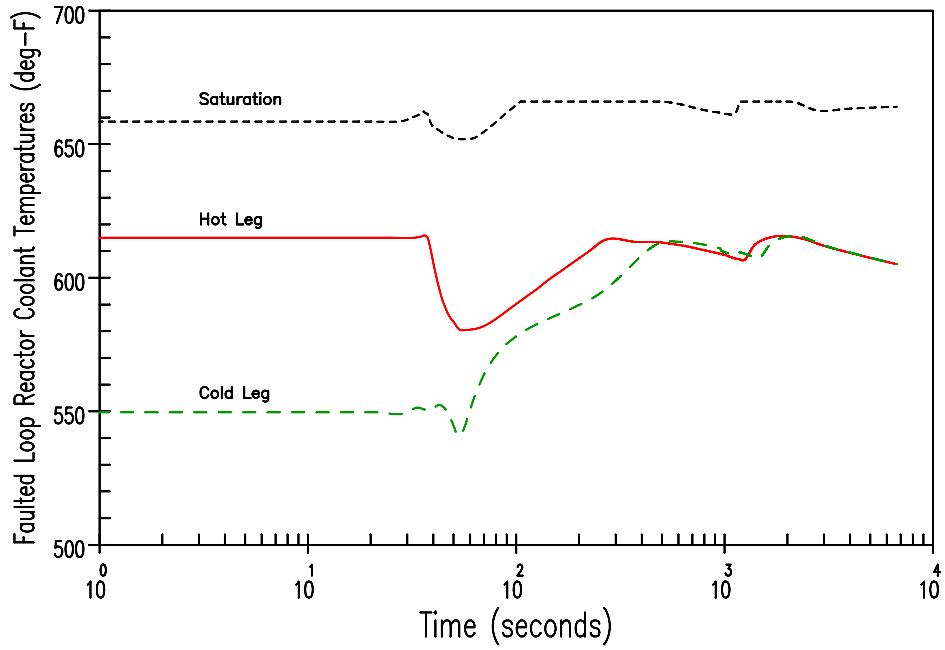
FSAR UPDATE

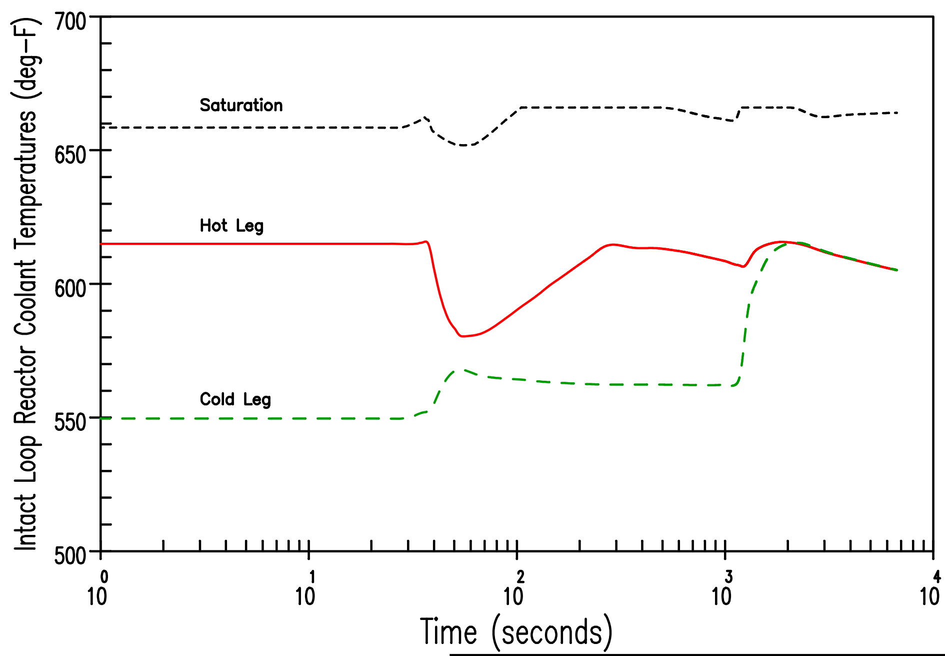
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.2-15

MAIN FEEDLINE RUPTURE
WITHOUT OFFSITE POWER AVAILABLE

PRESSURIZER PRESSURE AND
WATER VOLUME TRANSIENTS





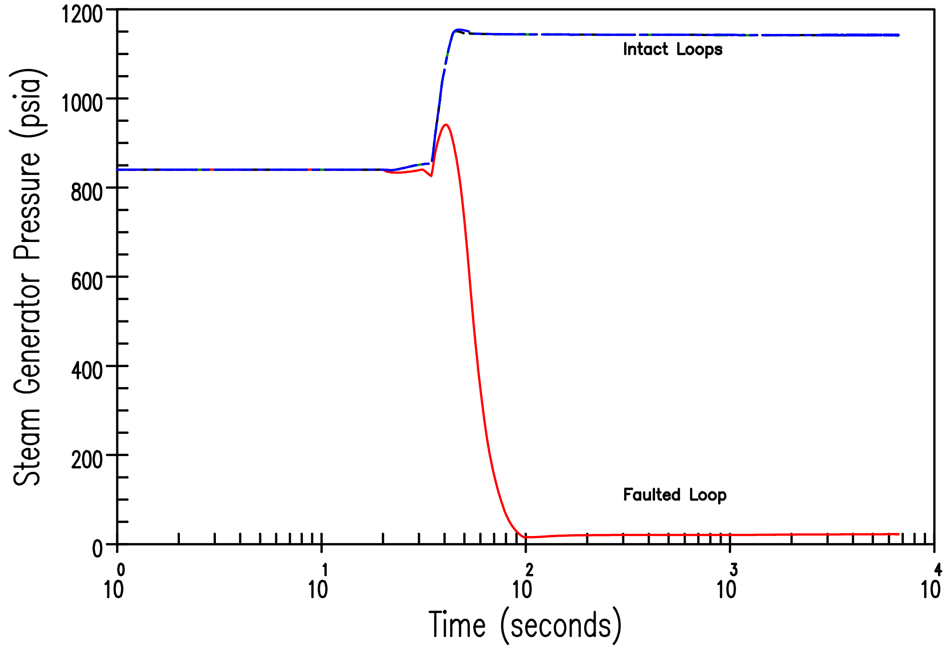
FSAR UPDATE

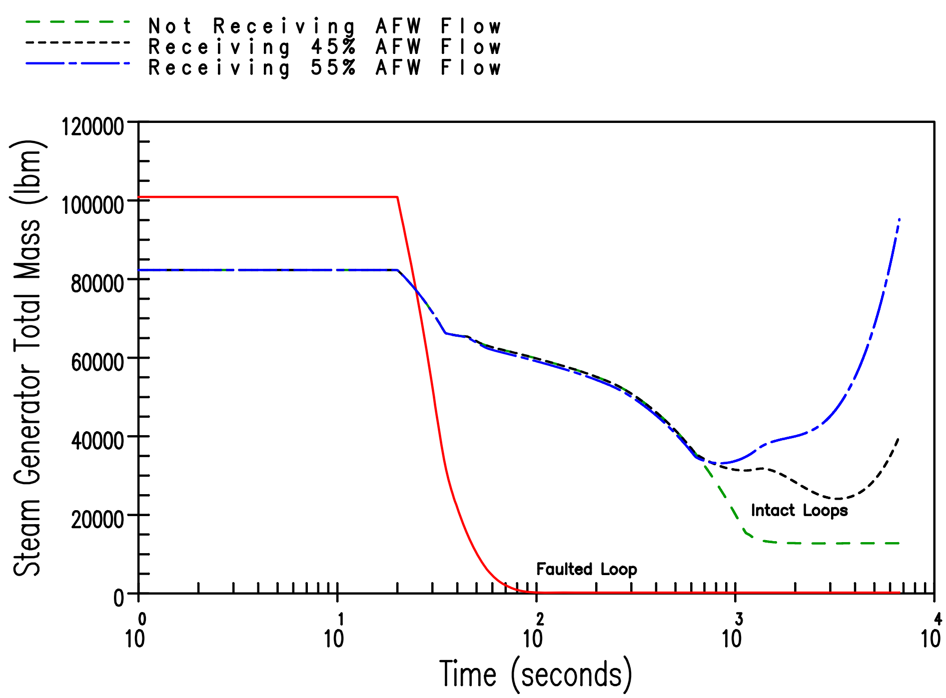
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.2-16

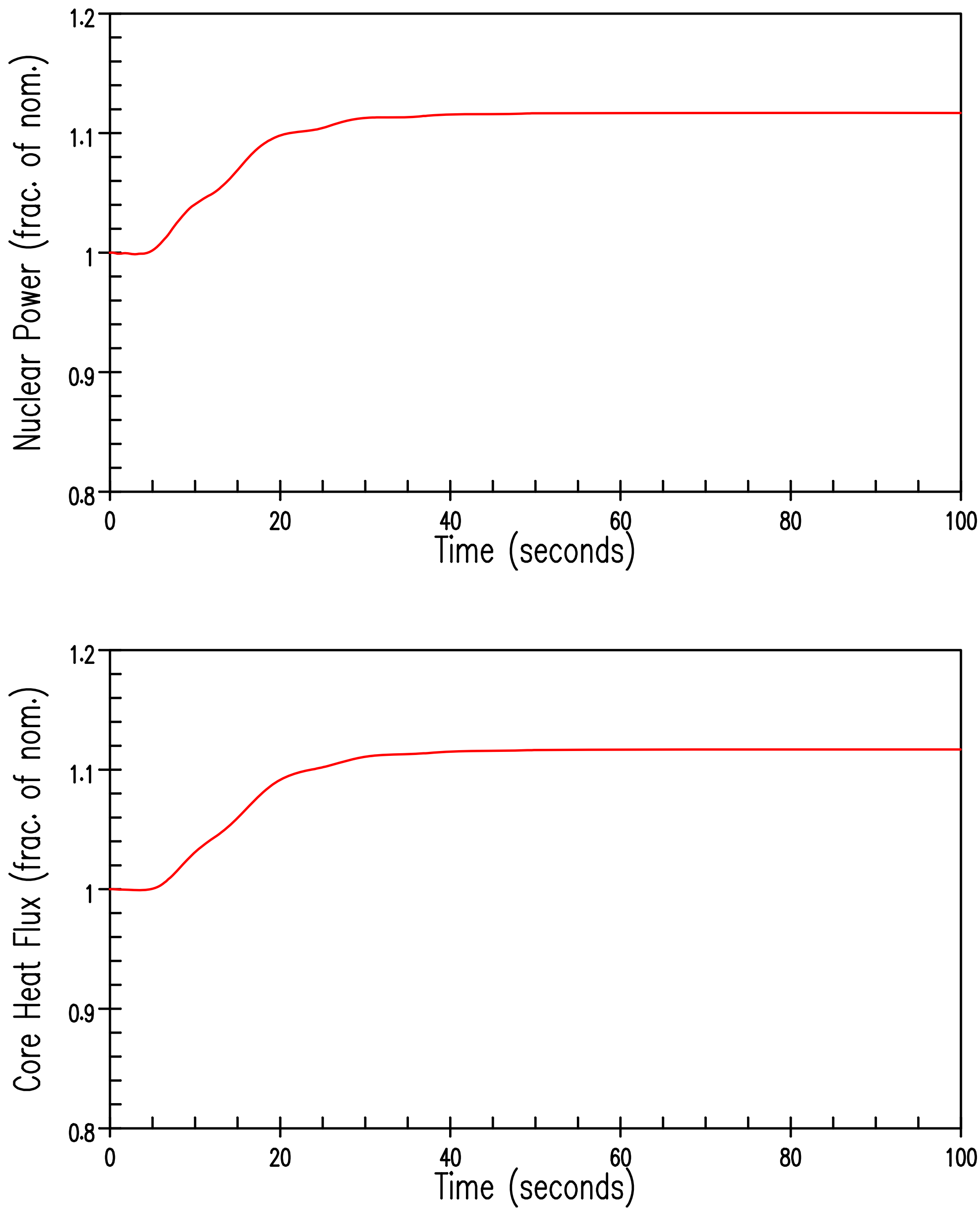
MAIN FEEDLINE RUPTURE
WITHOUT OFFSITE POWER AVAILABLE

REACTOR COOLANT TEMPERATURE
TRANSIENTS FOR THE FAULTED
AND INTACT LOOPS





FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.2-17 MAIN FEEDLINE RUPTURE WITHOUT OFFSITE POWER AVAILABLE STEAM GENERATOR PRESSURE AND TOTAL MASS TRANSIENTS



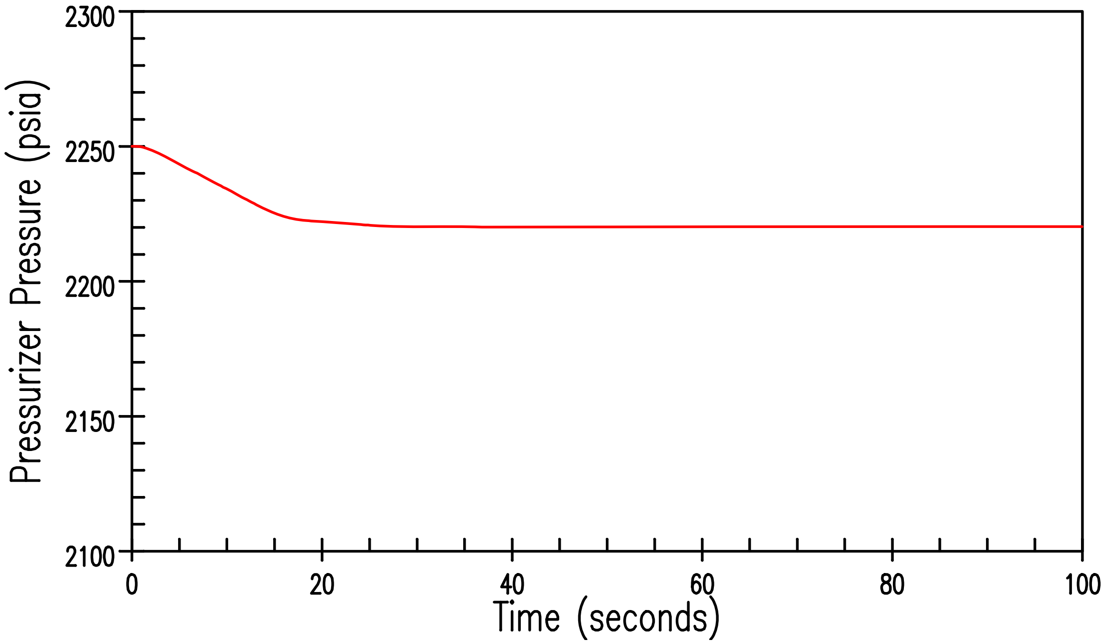
FSAR UPDATE

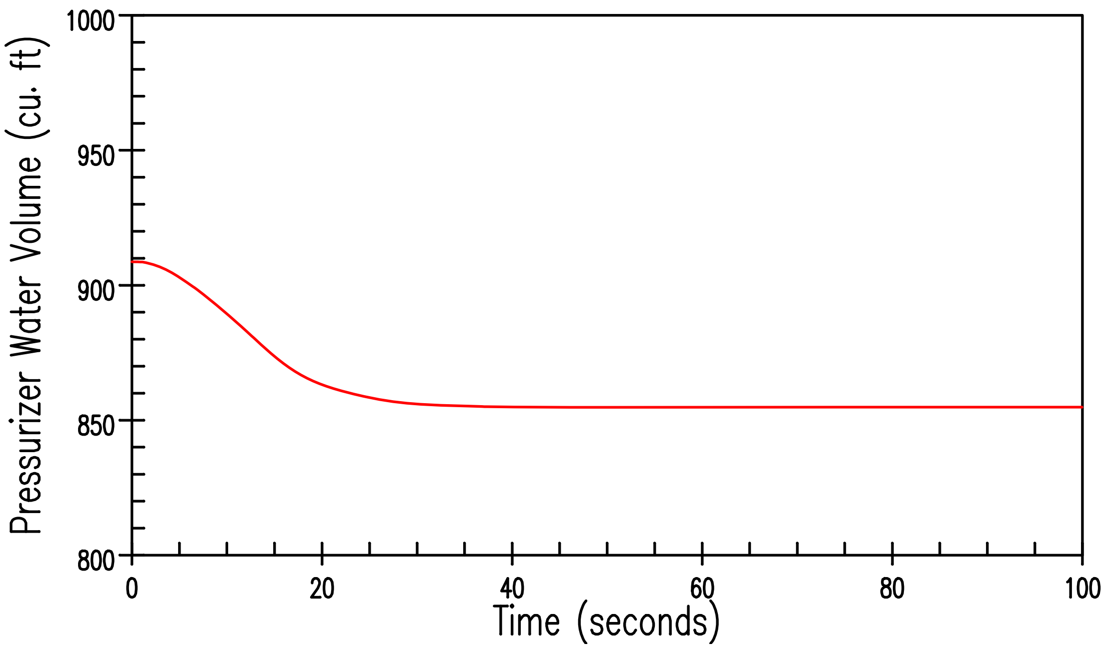
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.2-18

MAIN STEAM LINE RUPTURE AT FULL POWER, 0.49 ft^2 BREAK

NUCLEAR POWER AND CORE HEAT FLUX TRANSIENTS





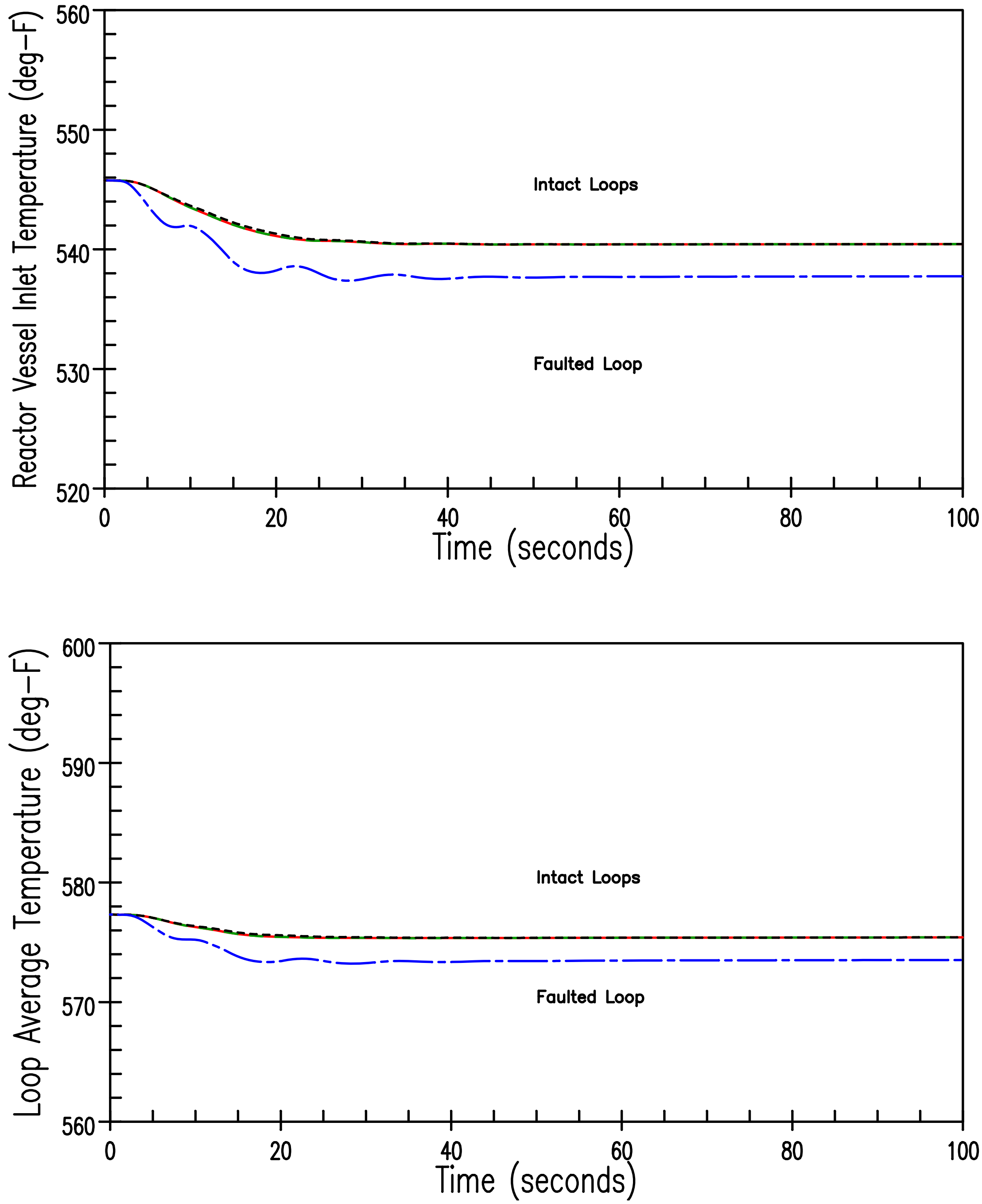
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.2-19

MAIN STEAM LINE RUPTURE AT FULL POWER, 0.49 ft^2 BREAK

PRESSURIZER PRESSURE AND WATER VOLUME TRANSIENTS



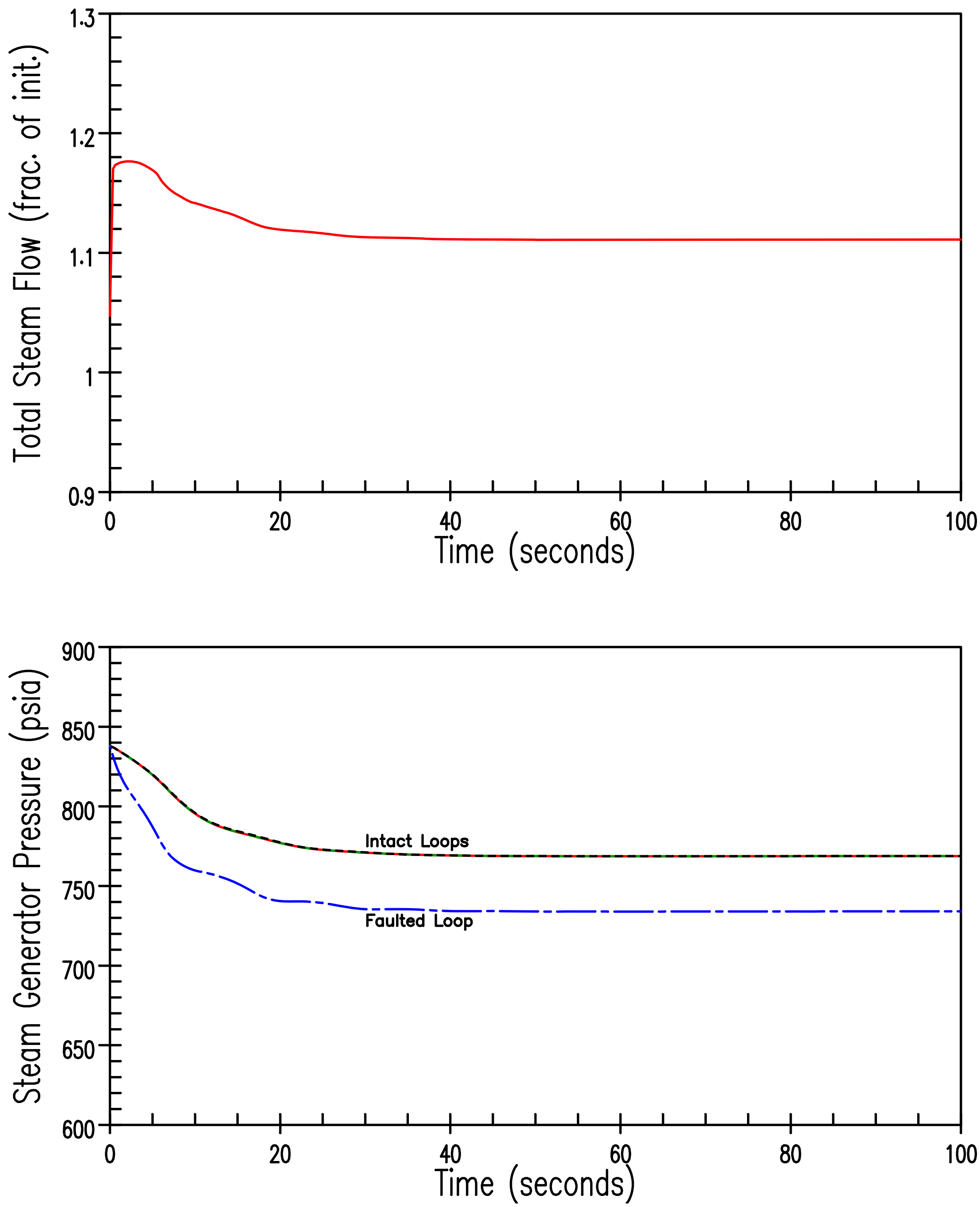
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.2-20

MAIN STEAM LINE RUPTURE AT FULL POWER, 0.49 ft^2 BREAK

REACTOR VESSEL INLET TEMPERATURE AND LOOP AVERAGE TEMPERATURE TRANSIENTS



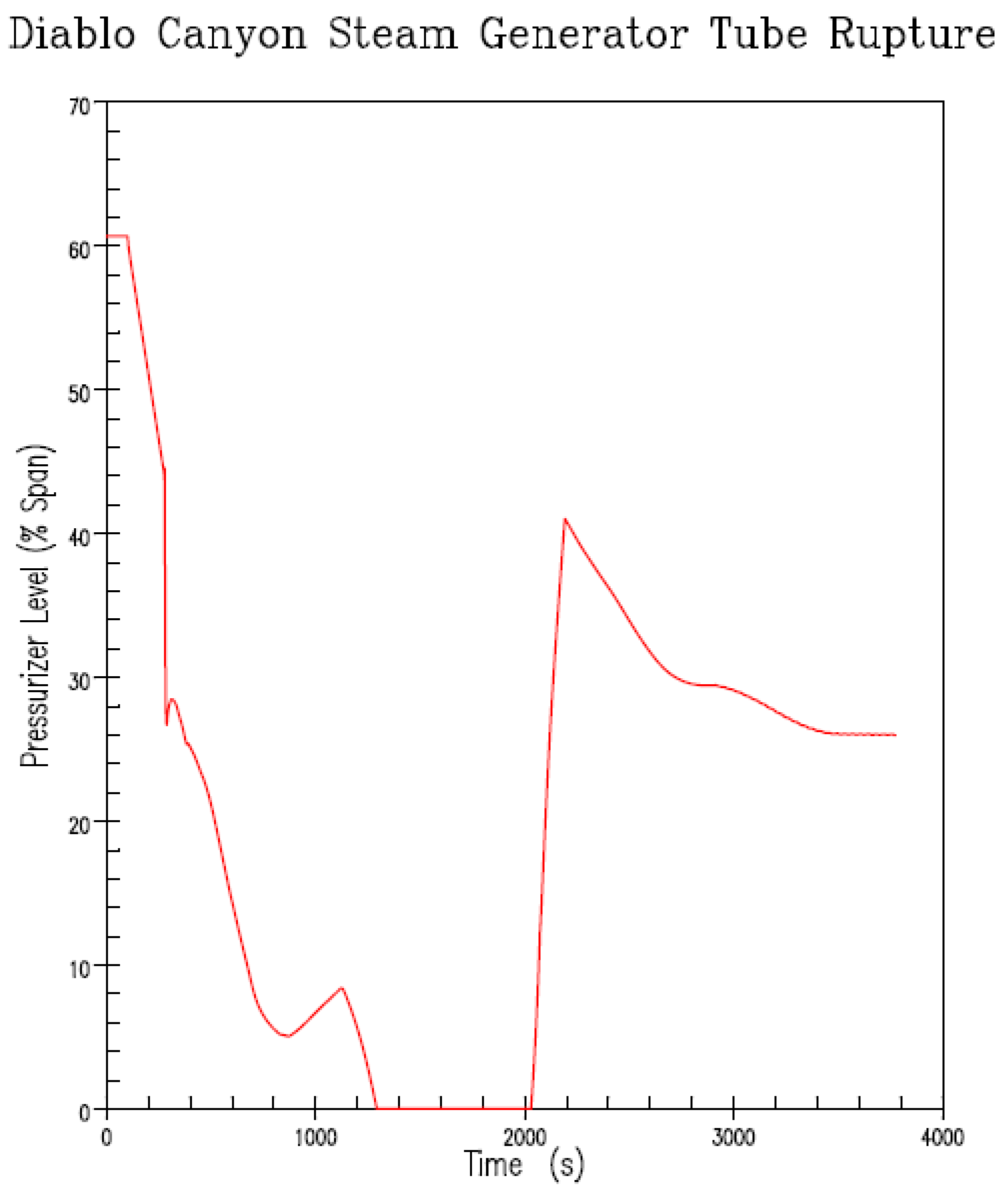
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

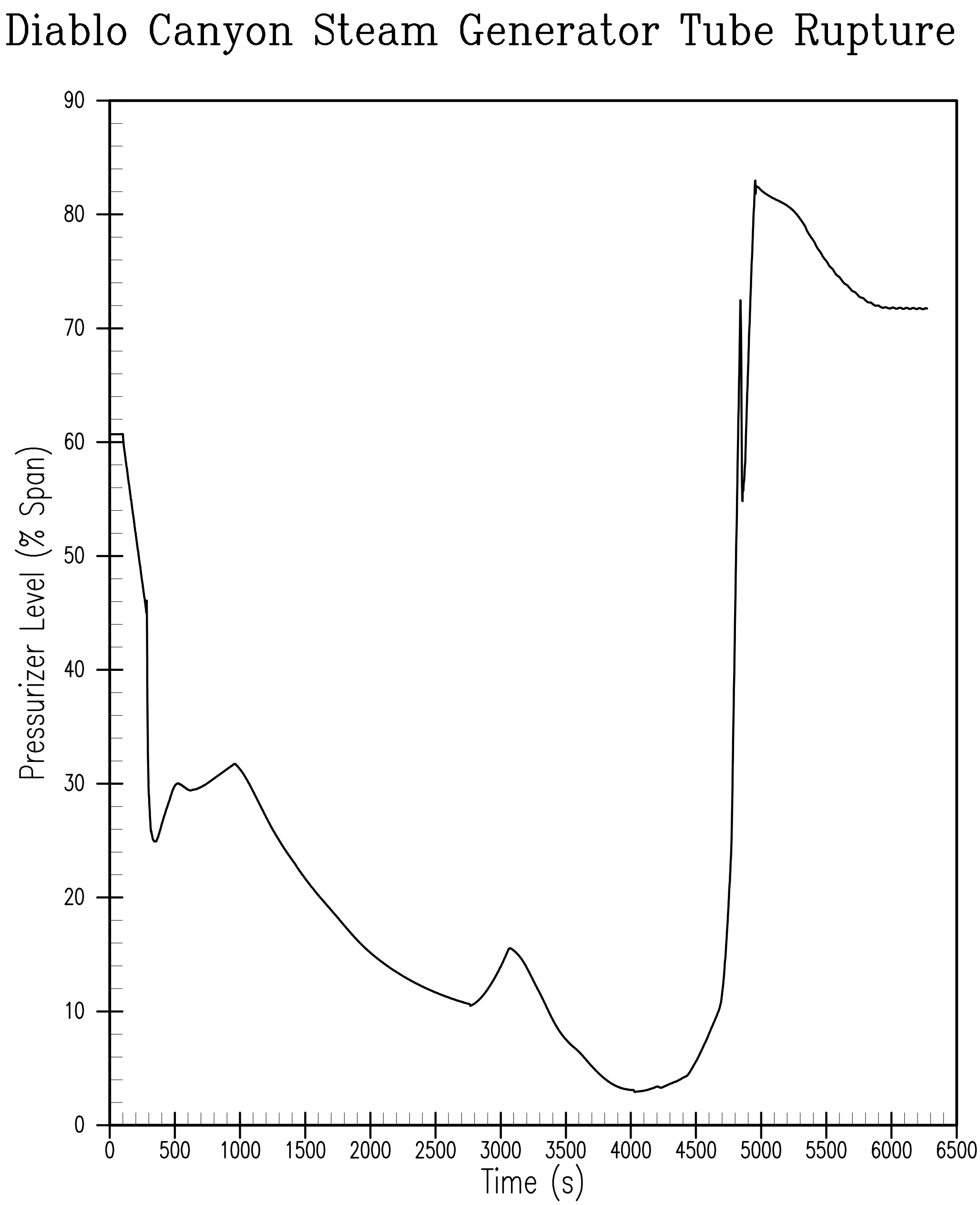
FIGURE 15.4.2-21

MAIN STEAM LINE RUPTURE AT FULL POWER, 0.49 ft^2 BREAK

TOTAL STEAM FLOW AND STEAM PRESSURE TRANSIENTS

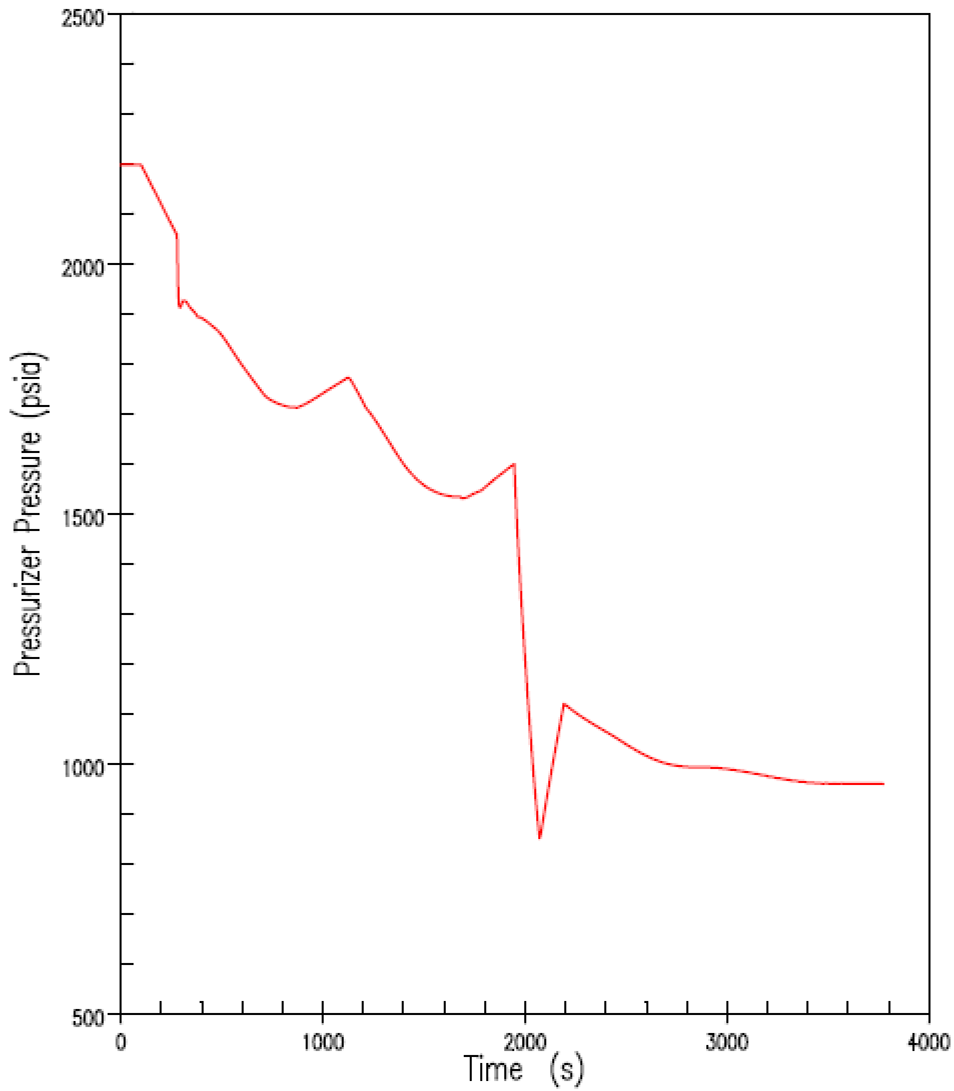


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.3-1A PRESSURIZER LEVEL SGTR MTO ANALYSIS



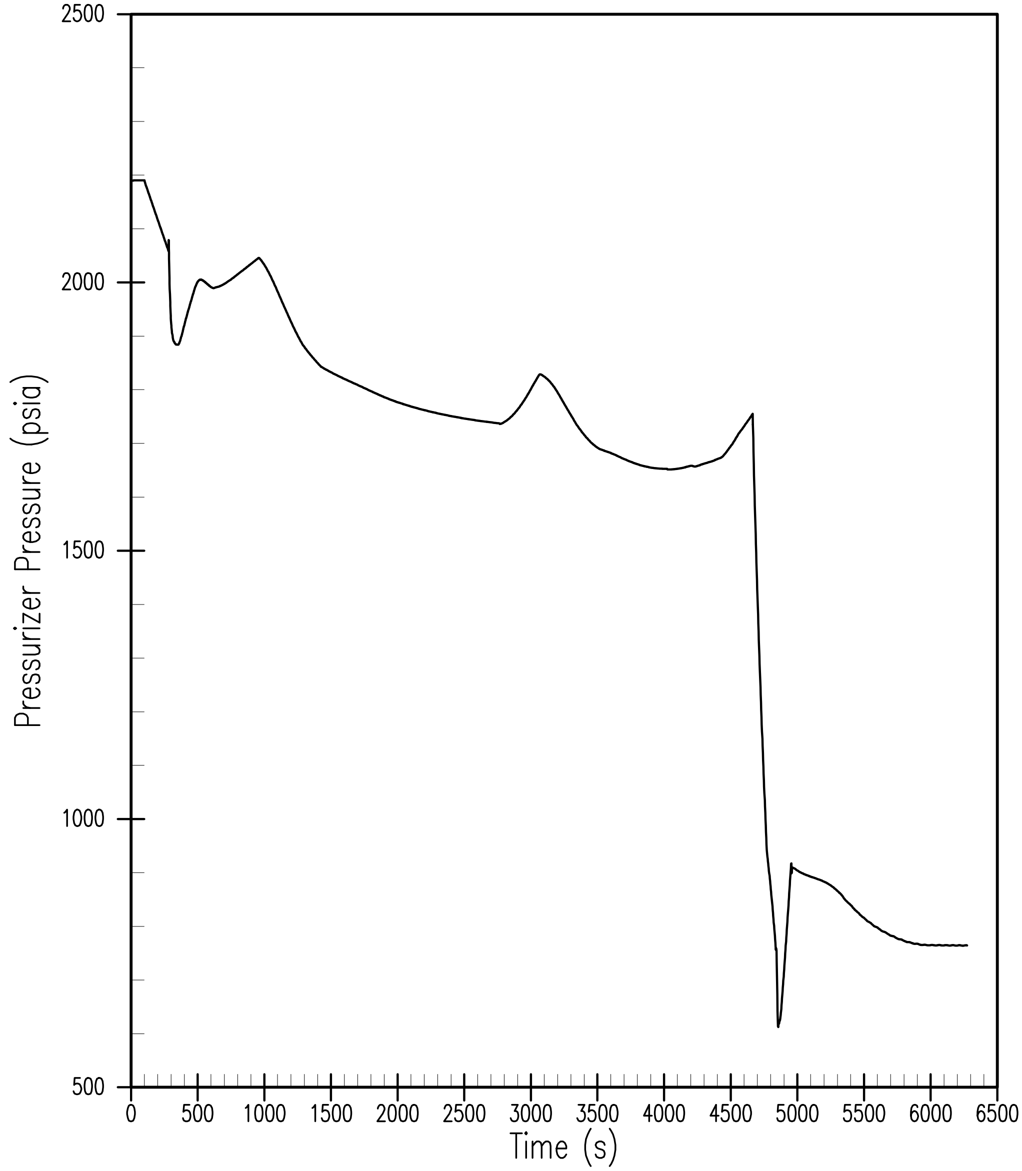
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.3-1B PRESSURIZER LEVEL SGTR DOSE INPUT ANALYSIS

Diablo Canyon Steam Generator Tube Rupture



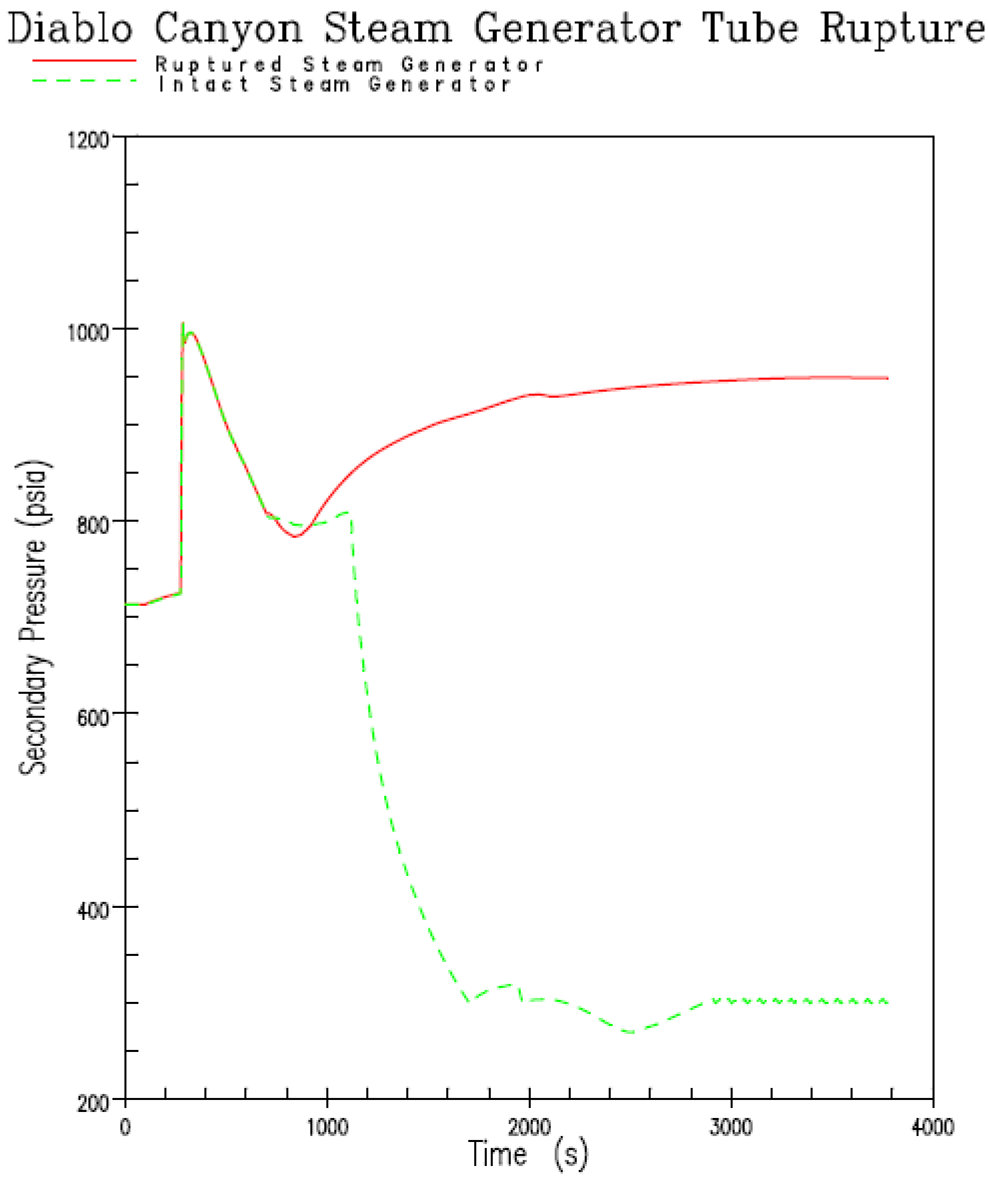
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.3-2A PRESSURIZER PRESSURE SGTR MTO ANALYSIS

Diablo Canyon Steam Generator Tube Rupture



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.3-2B PRESSURIZER PRESSURE SGTR DOSE INPUT ANALYSIS

Revision 21 September 2013

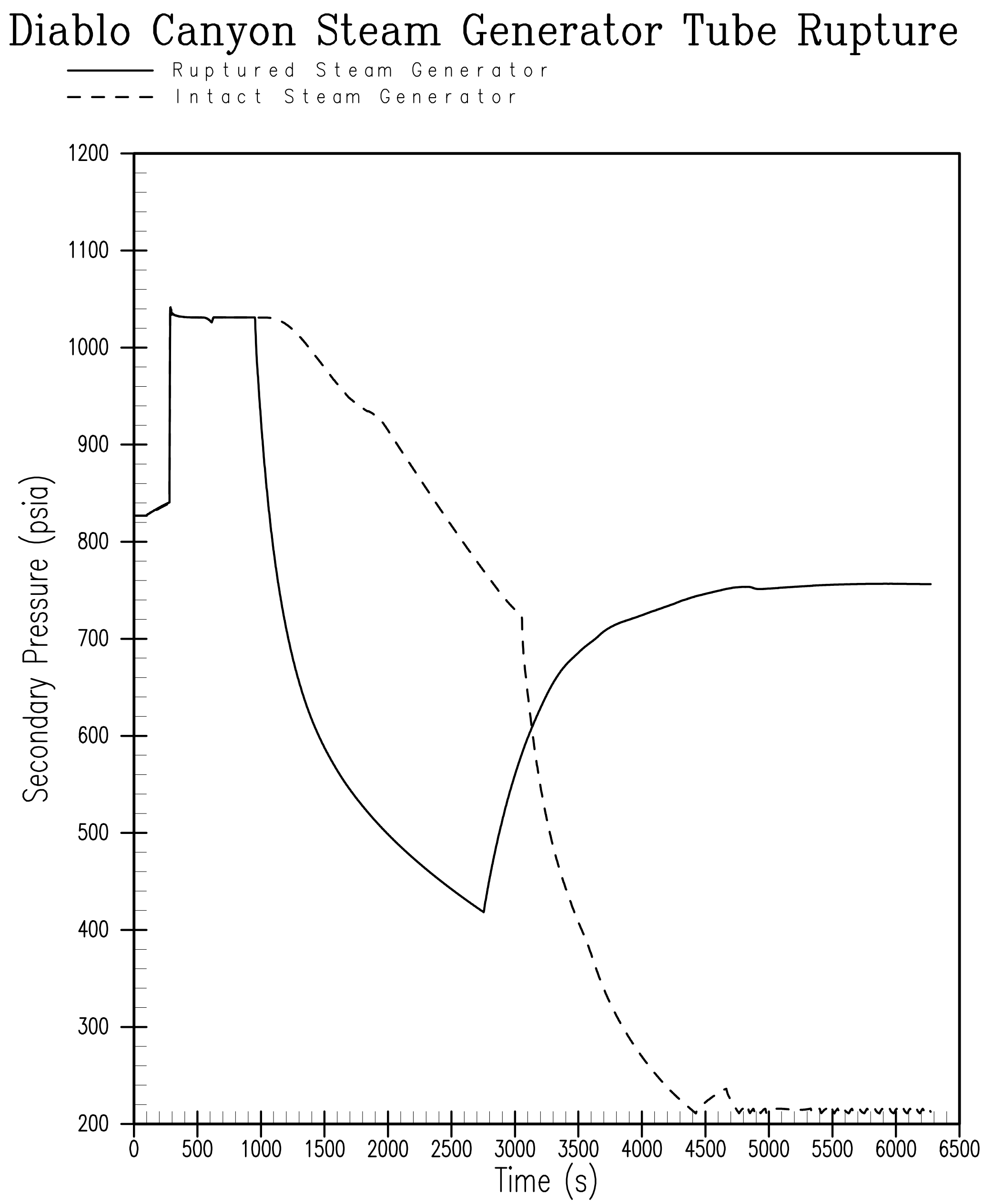


FSAR UPDATE

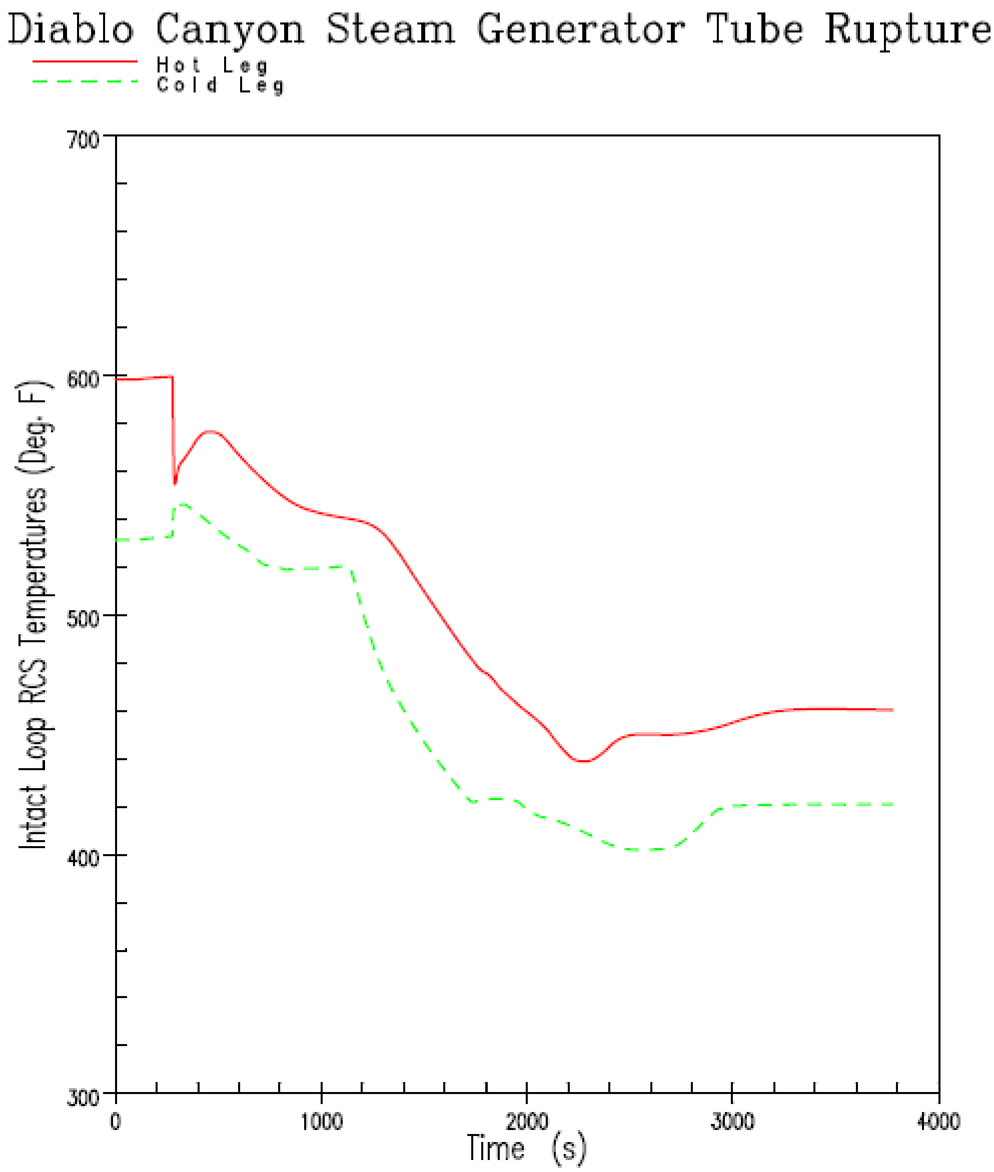
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.3-3A
SECONDARY PRESSURE
SGTR MTO ANALYSIS

Revision 20 November 2011



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.3-3B SECONDARY PRESSURE SGTR DOSE INPUT ANALYSIS

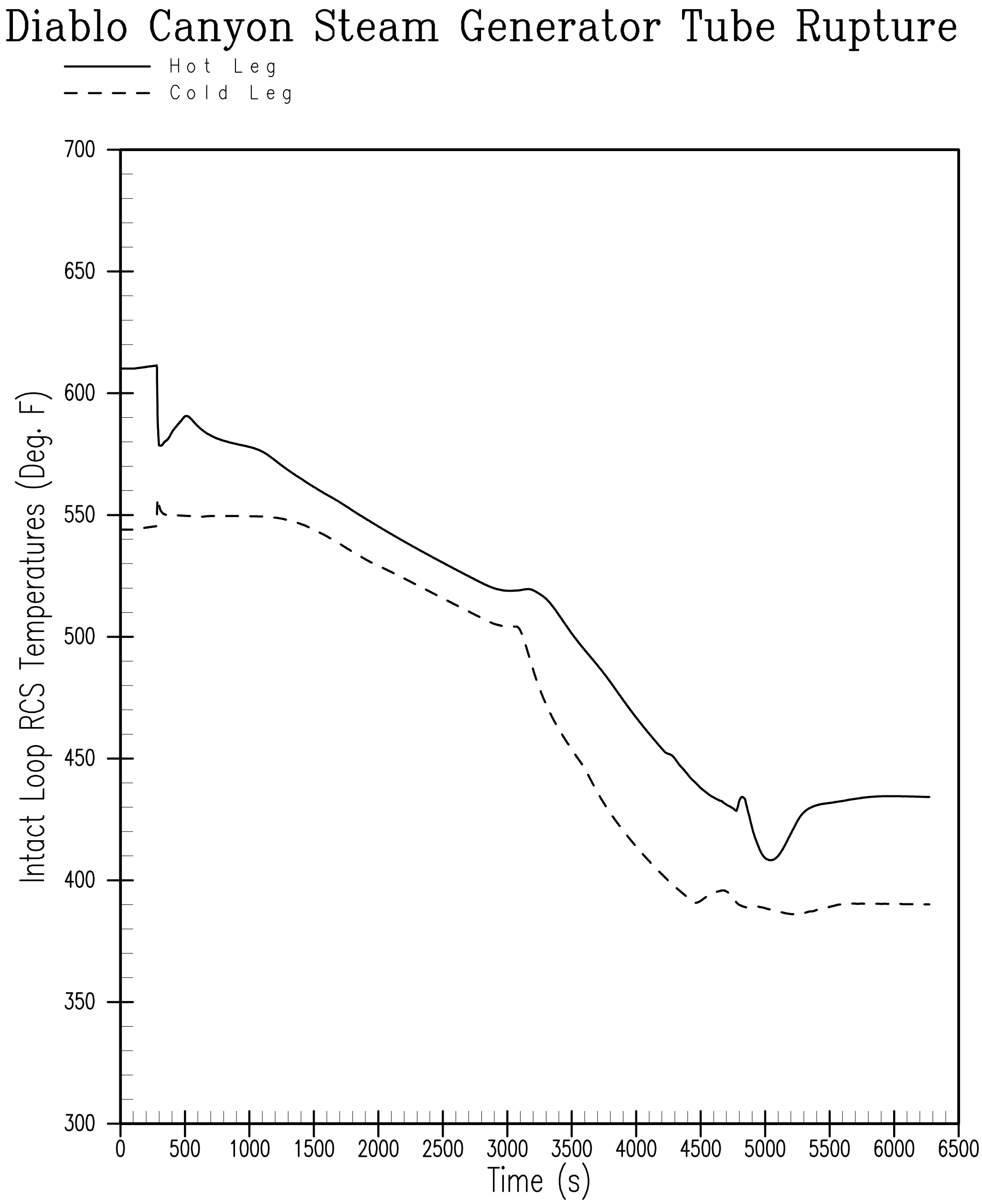


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.3-4A

INTACT LOOP HOT AND COLD LEG RCS TEMPERATURES SGTR MTO ANALYSIS

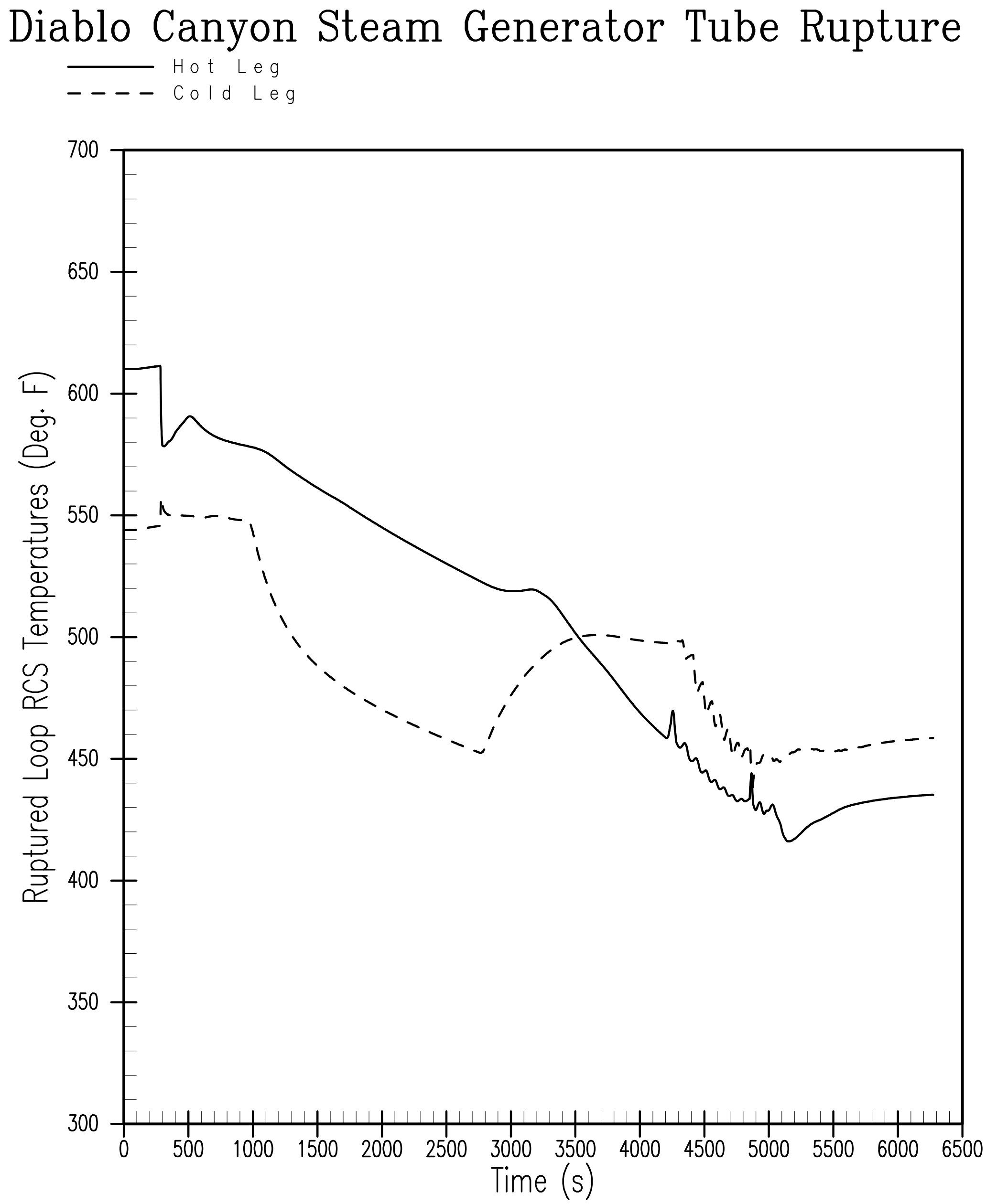


FSAR UPDATE

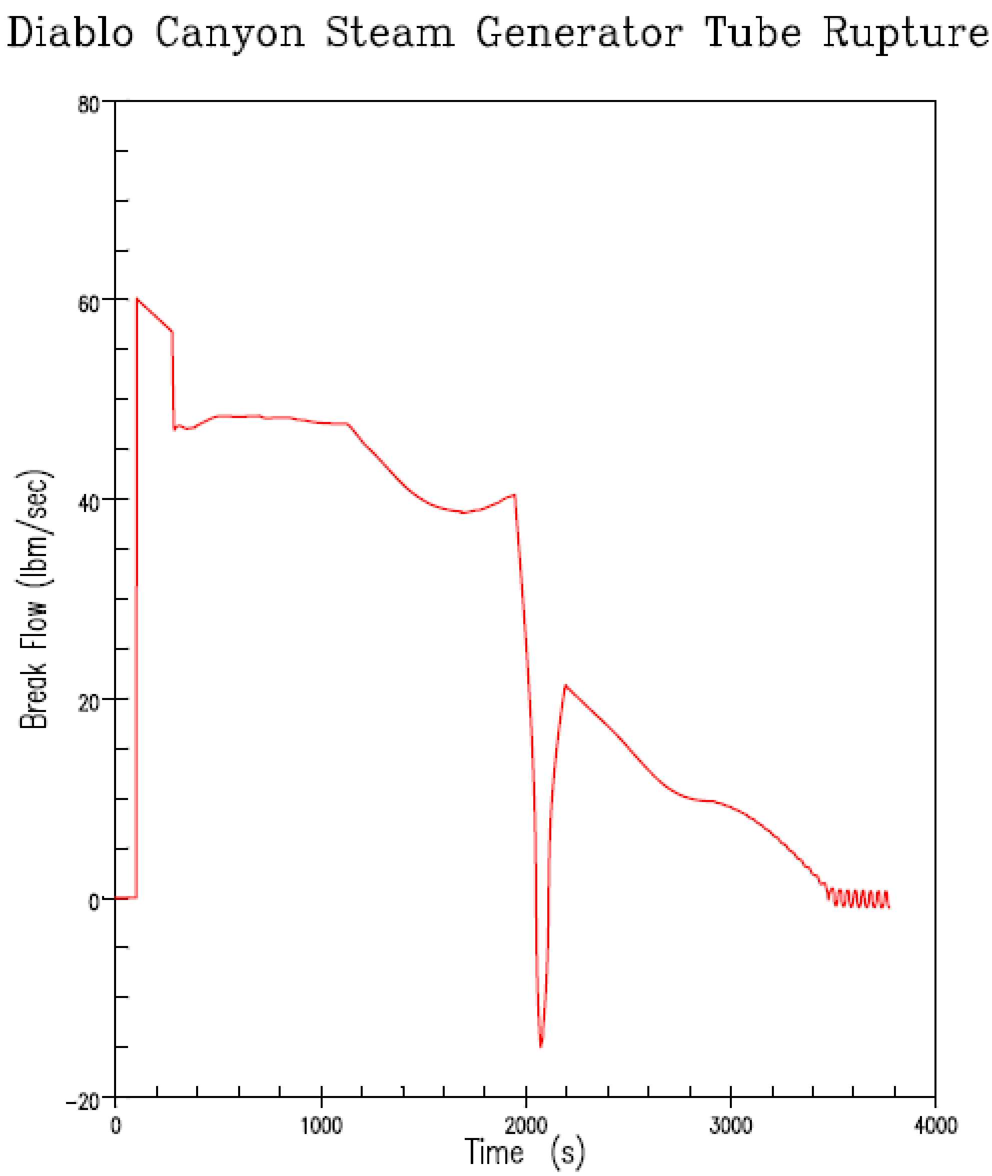
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.3-4B
INTACT LOOP HOT AND COLD LEG RCS TEMPERATURES SGTR DOSE INPUT ANALYSIS

Revision 21 September 2013



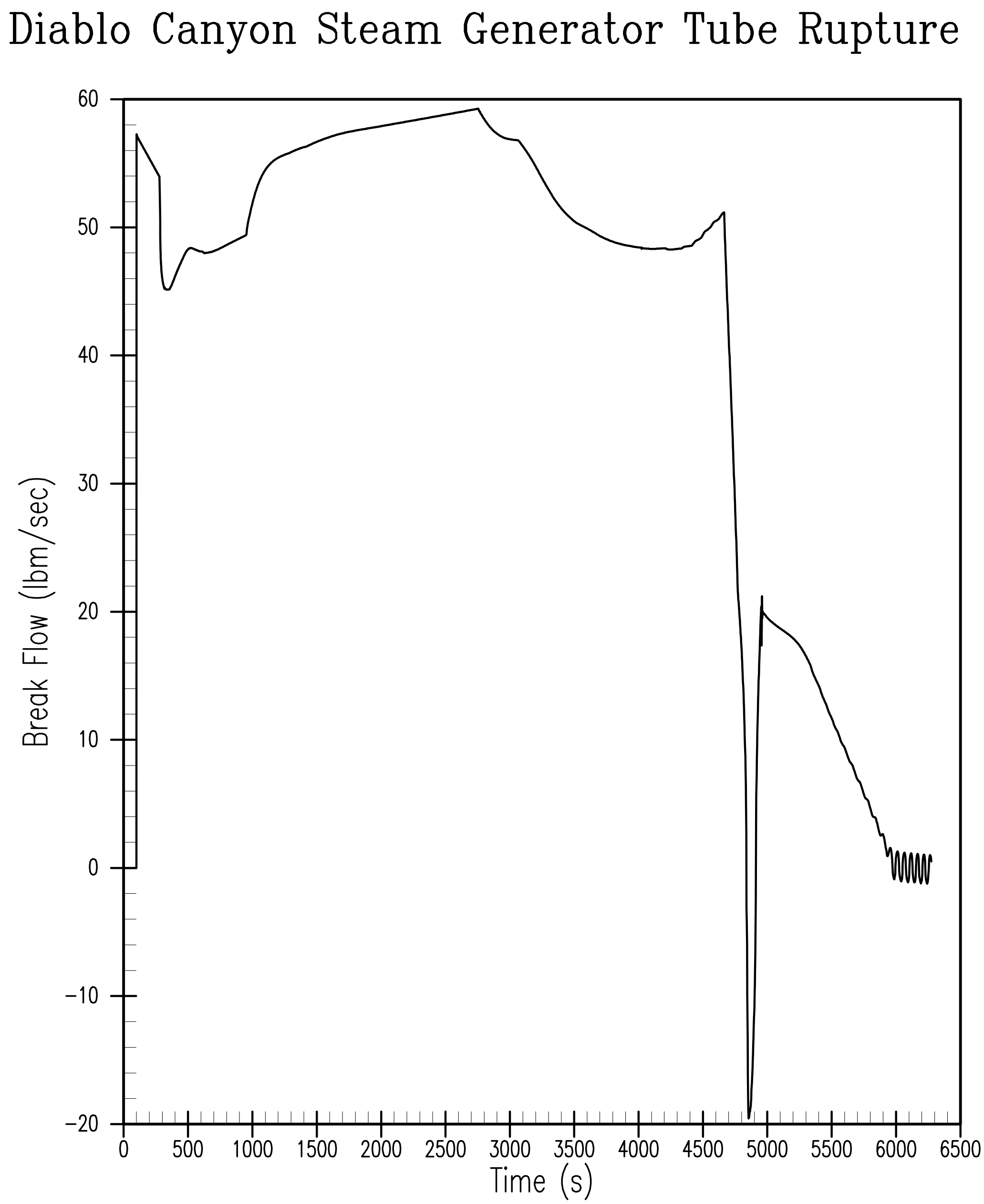
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.3-5B RUPTURED LOOP HOT AND COLD LEG RCS TEMPERATURES SGTR DOSE INPUT ANALYSIS



FSAR UPDATE

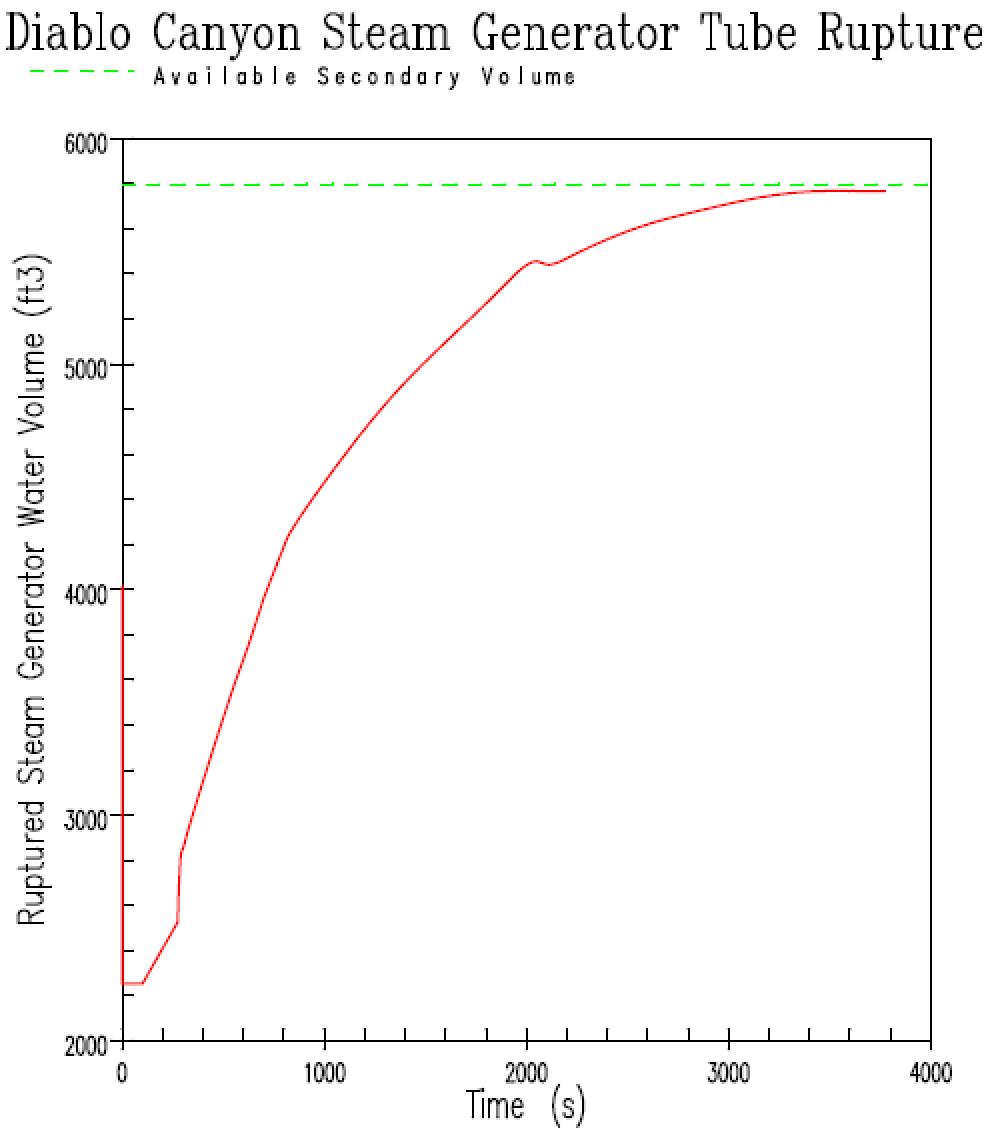
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.3-6A
PRIMARY TO SECONDARY
BREAK FLOW RATE
SGTR MTO ANALYSIS



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.3-6B PRIMARY TO SECONDARY BREAK FLOW RATE SGTR DOSE INPUT ANALYSIS

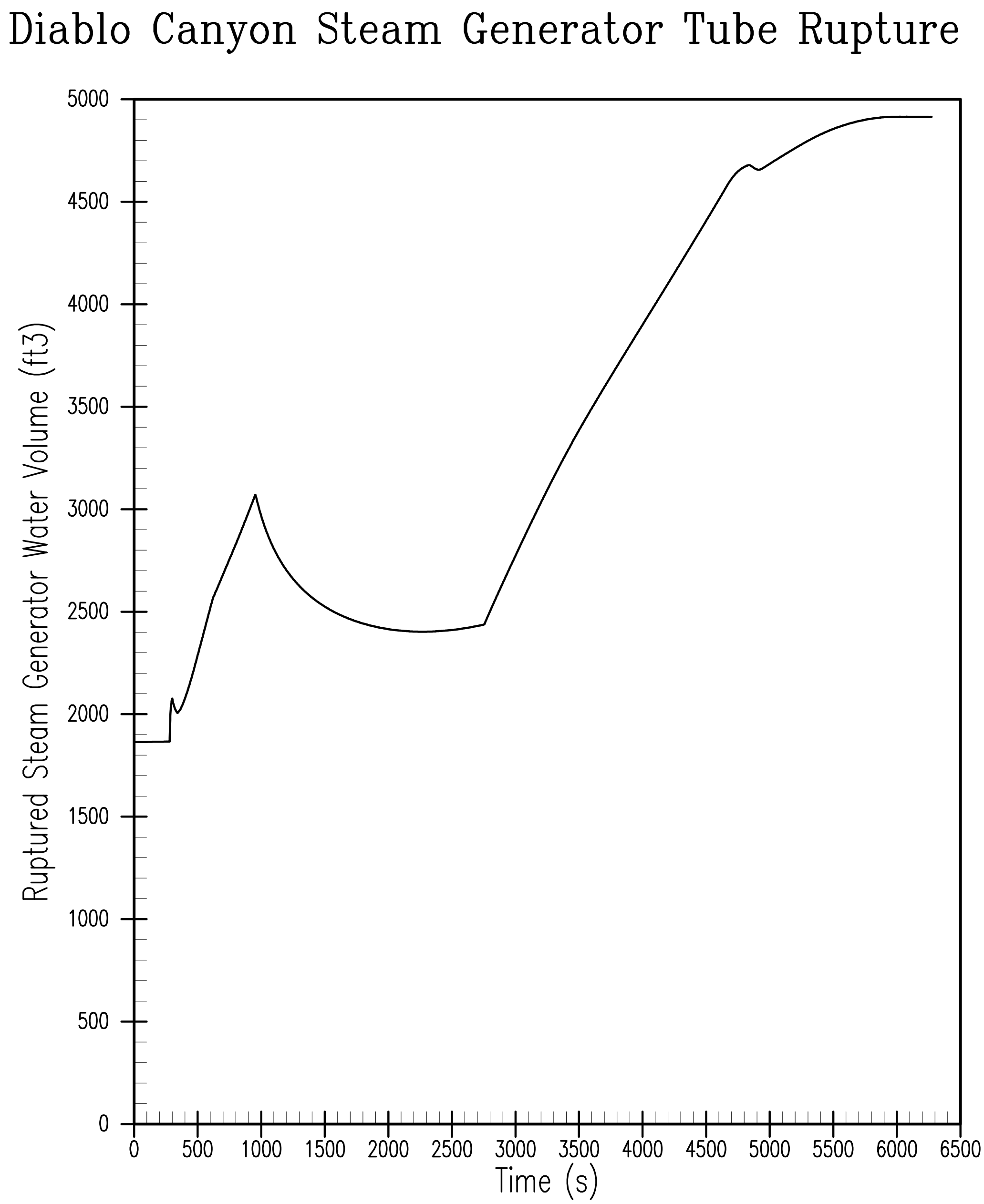
Revision 21 September 2013



FSAR UPDATE

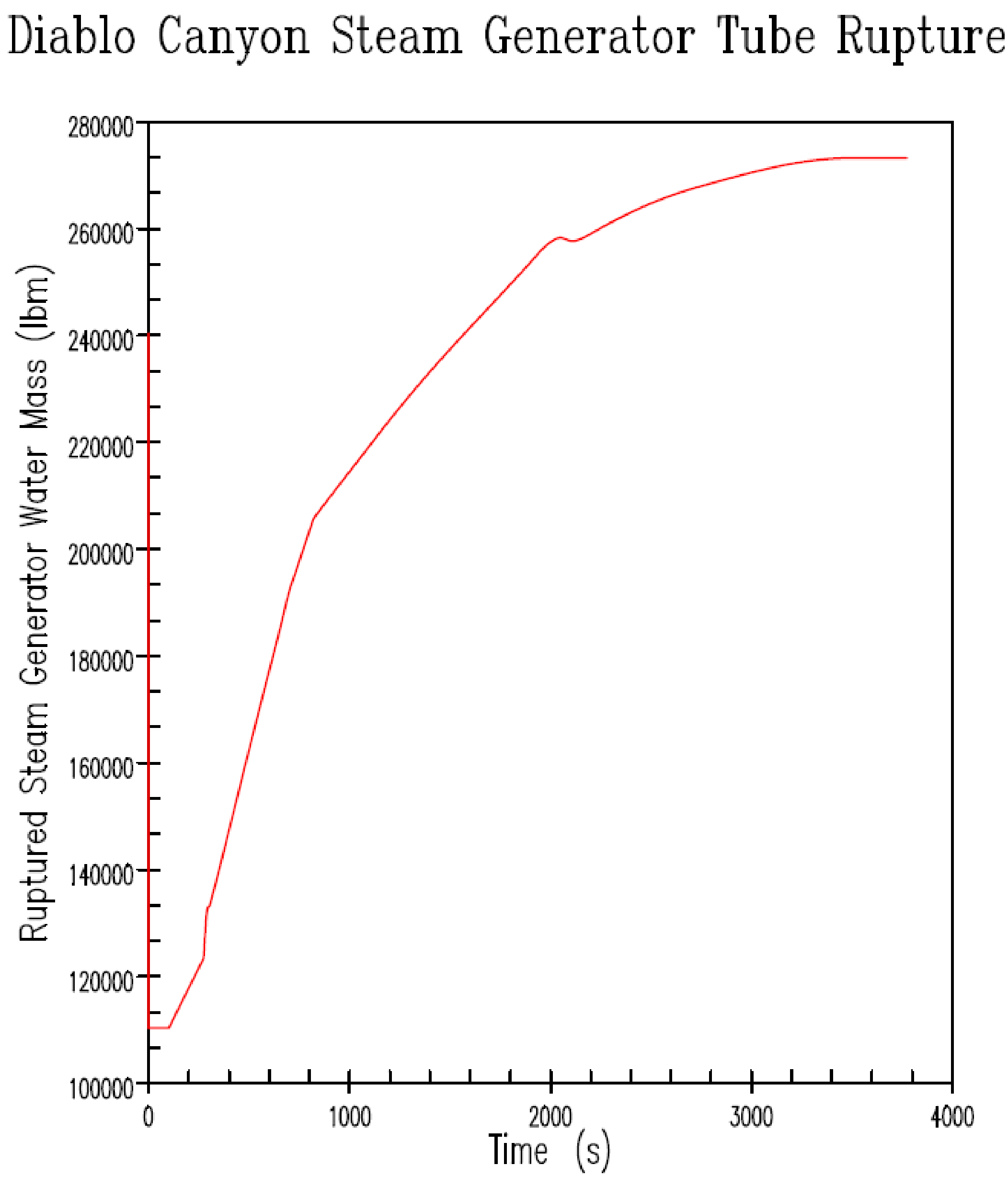
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.3-7A
RUPTURED STEAM GENERATOR WATER VOLUME SGTR MTO ANALYSIS



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.3-7B RUPTURED STEAM GENERATOR WATER VOLUME SGTR DOSE INPUT ANALYSIS

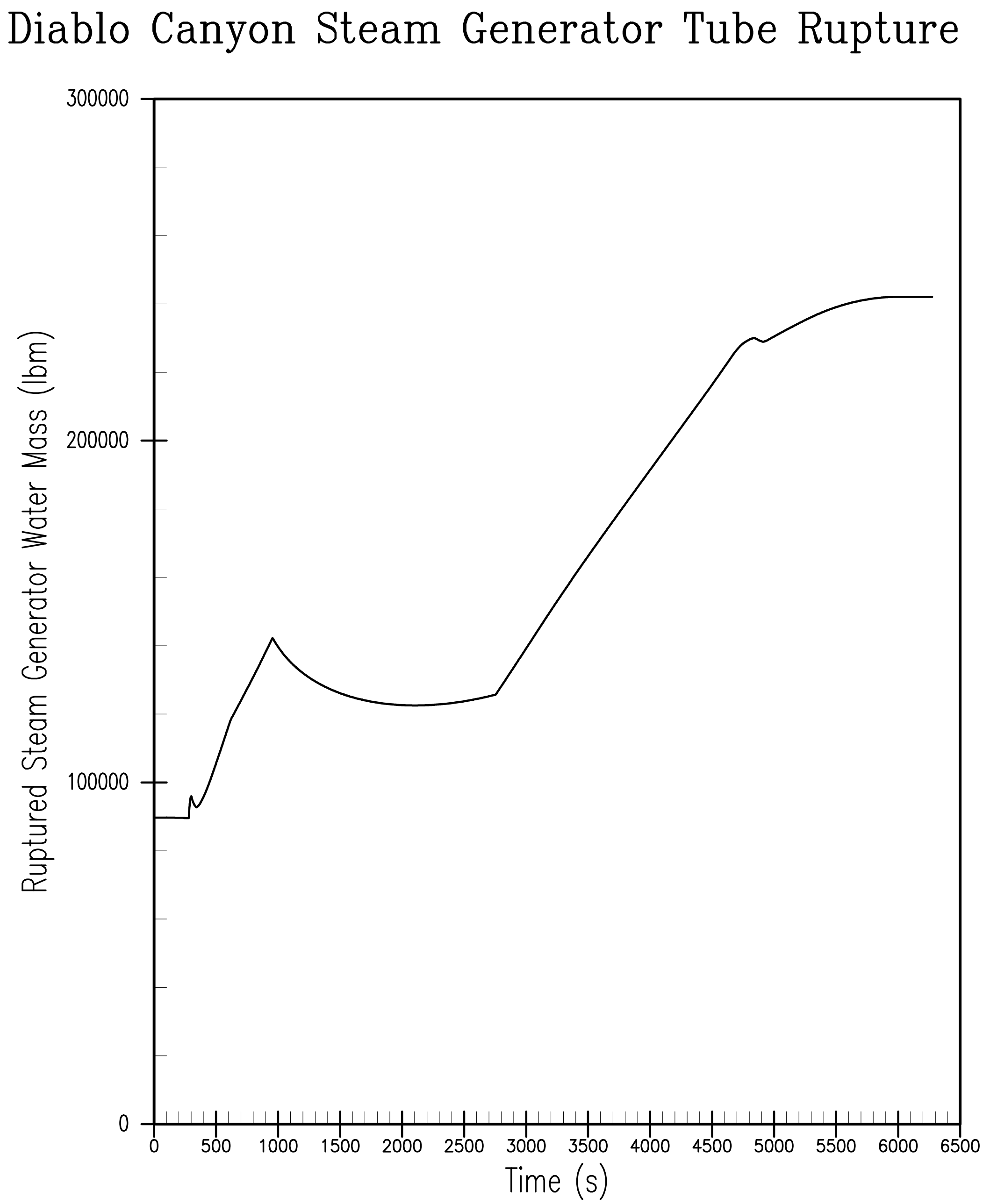
Revision 21 September 2013



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.3-8A
RUPTURED STEAM GENERATOR WATER MASS
SGTR MTO ANALYSIS

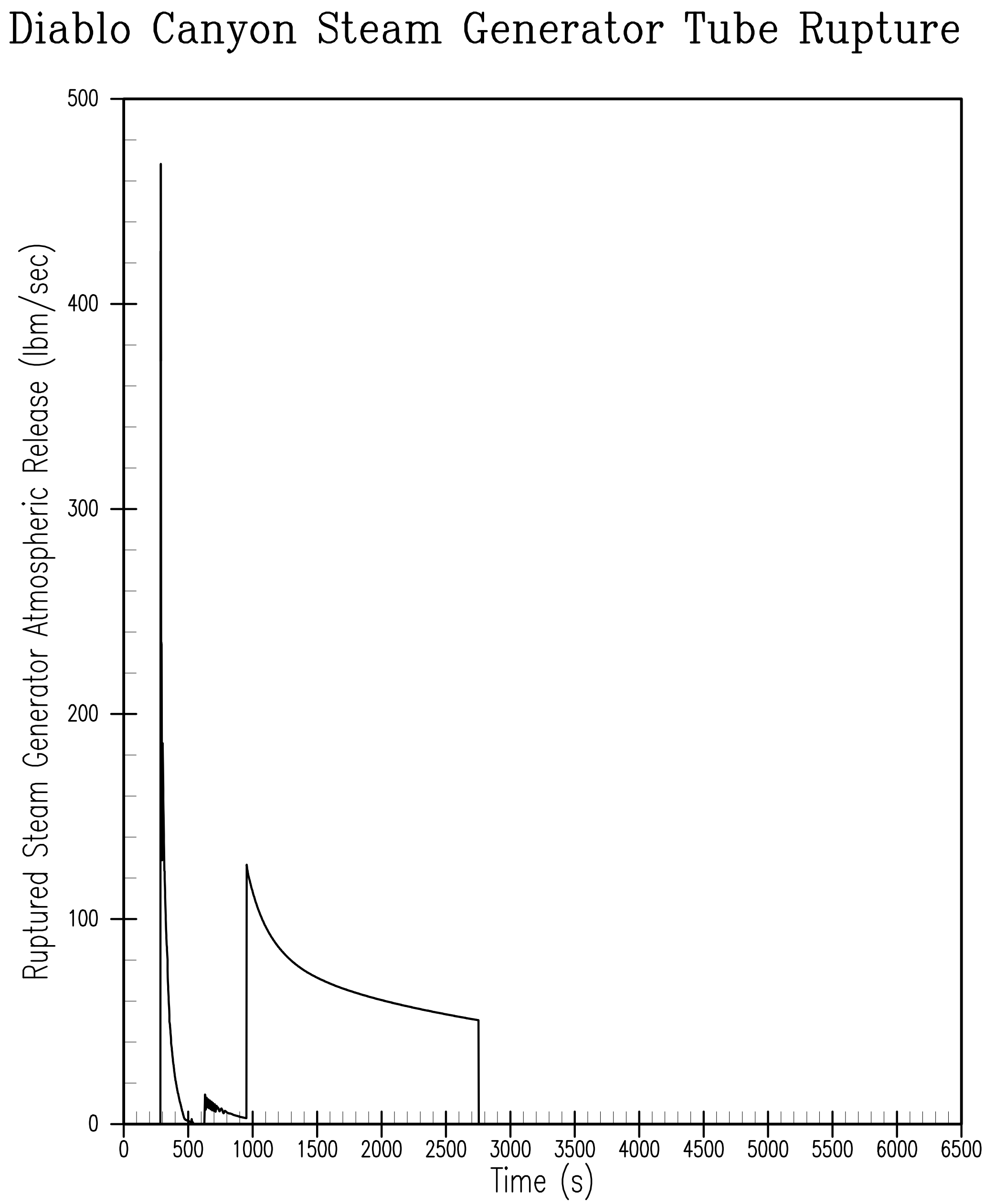


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.3-8B
RUPTURED STEAM GENERATOR WATER MASS
SGTR DOSE INPUT ANALYSIS

Revision 21 September 2013



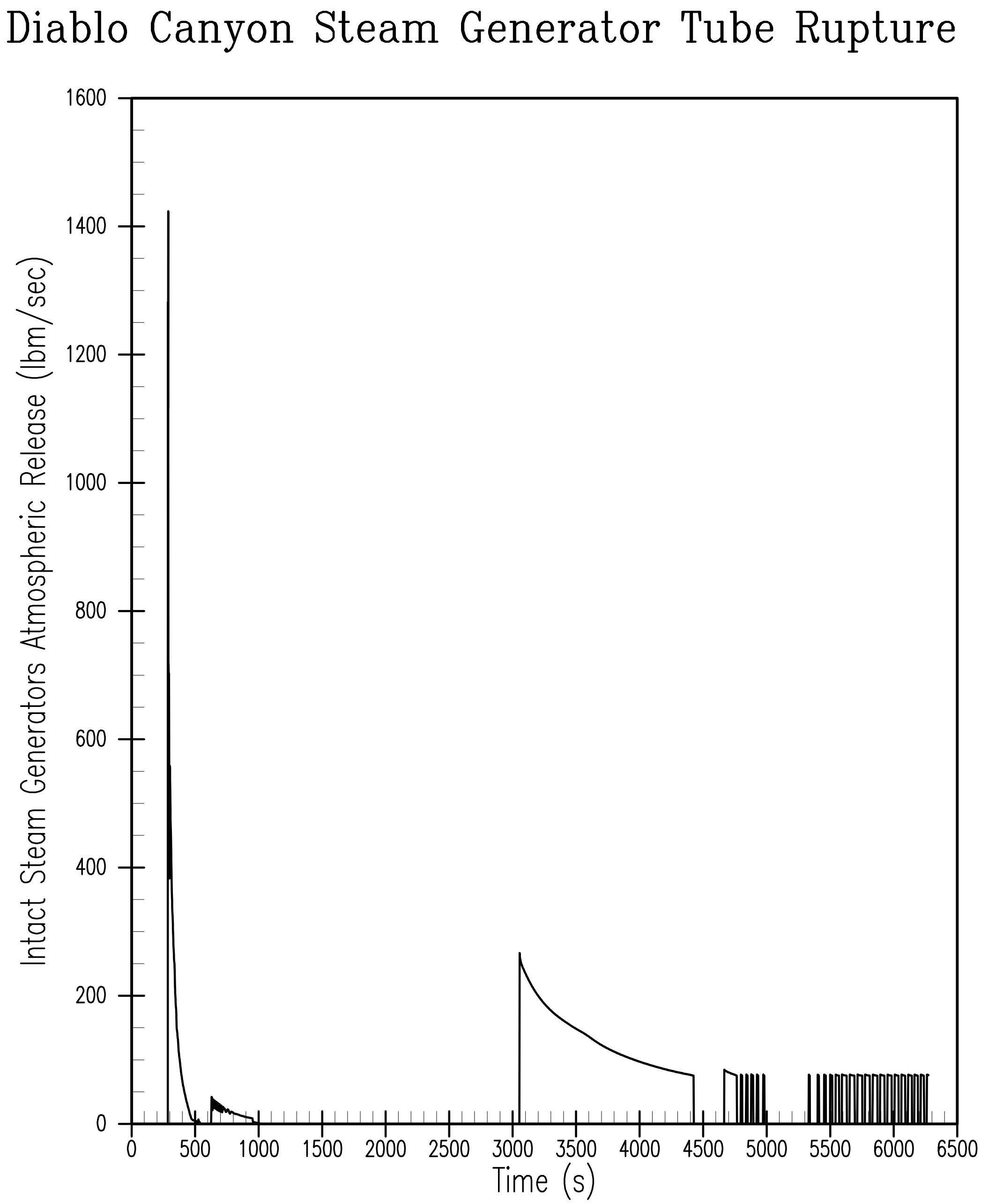
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.3-9

RUPTURED SG MASS RELEASE RATE
TO THE ATMOSPHERE
SGTR DOSE INPUT ANALYSIS

Revision 21 September 2013

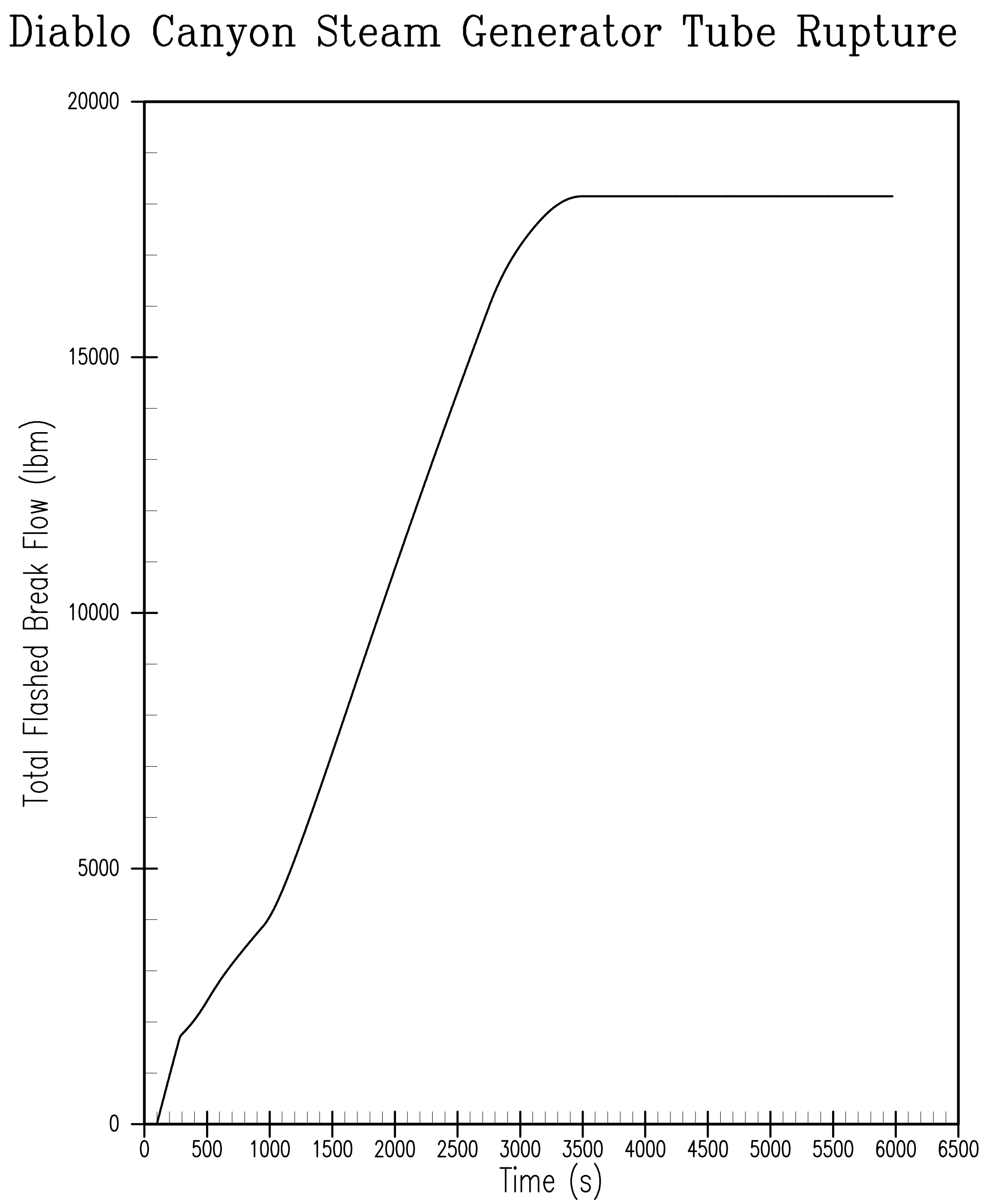


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.3-10

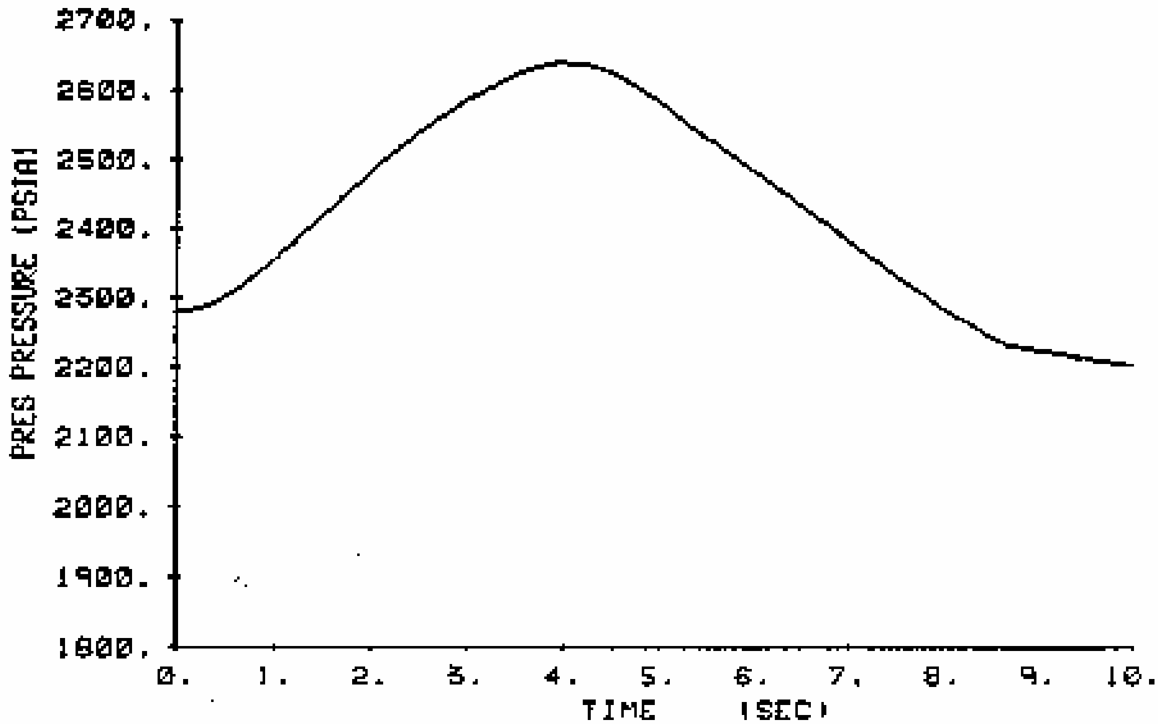
INTACT SGs MASS RELEASE RATE
TO THE ATMOSPHERE
SGTR DOSE INPUT ANALYSIS



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

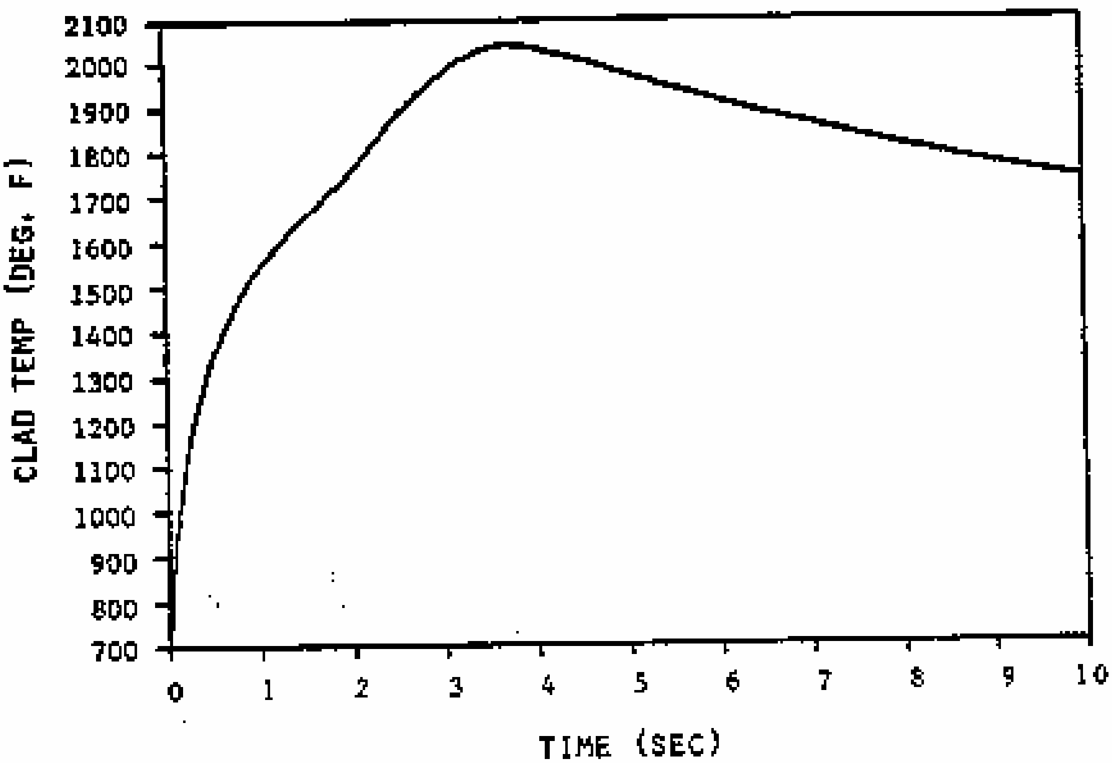
FIGURE 15.4.3-11
TOTAL FLASHED
BREAK FLOW
SGTR DOSE INPUT ANALYSIS



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

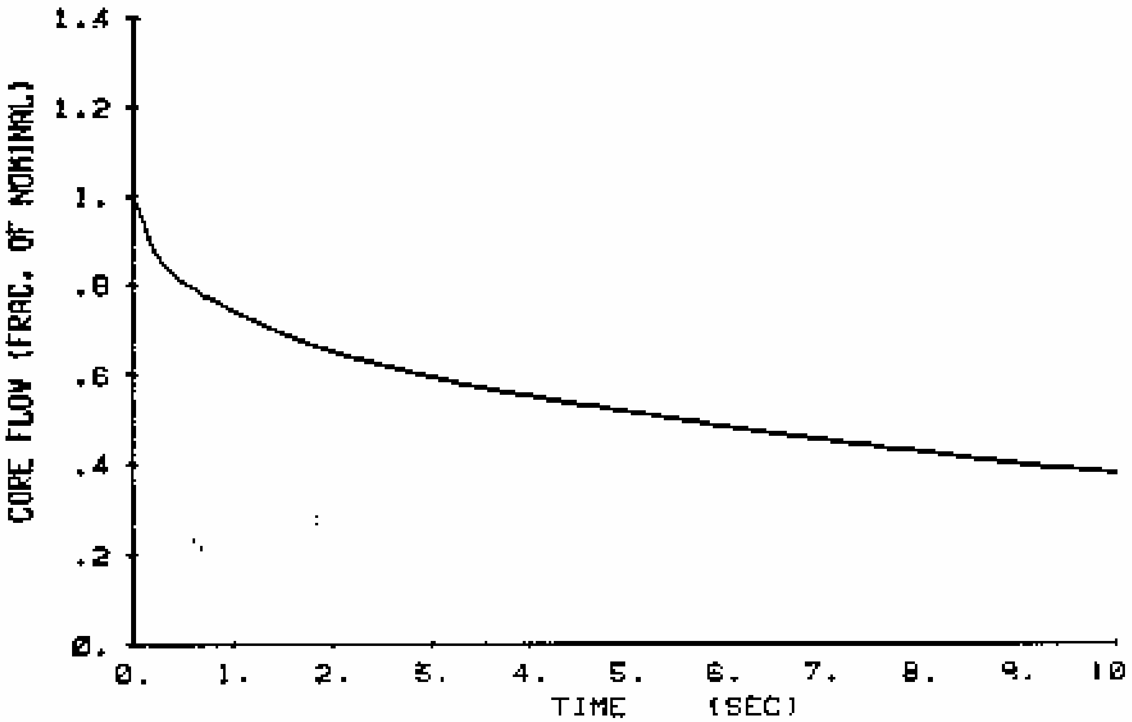
FIGURE 15.4.4-1
ALL LOOPS OPERATING
ONE LOCKED ROTOR
PRESSURE VERSUS TIME



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

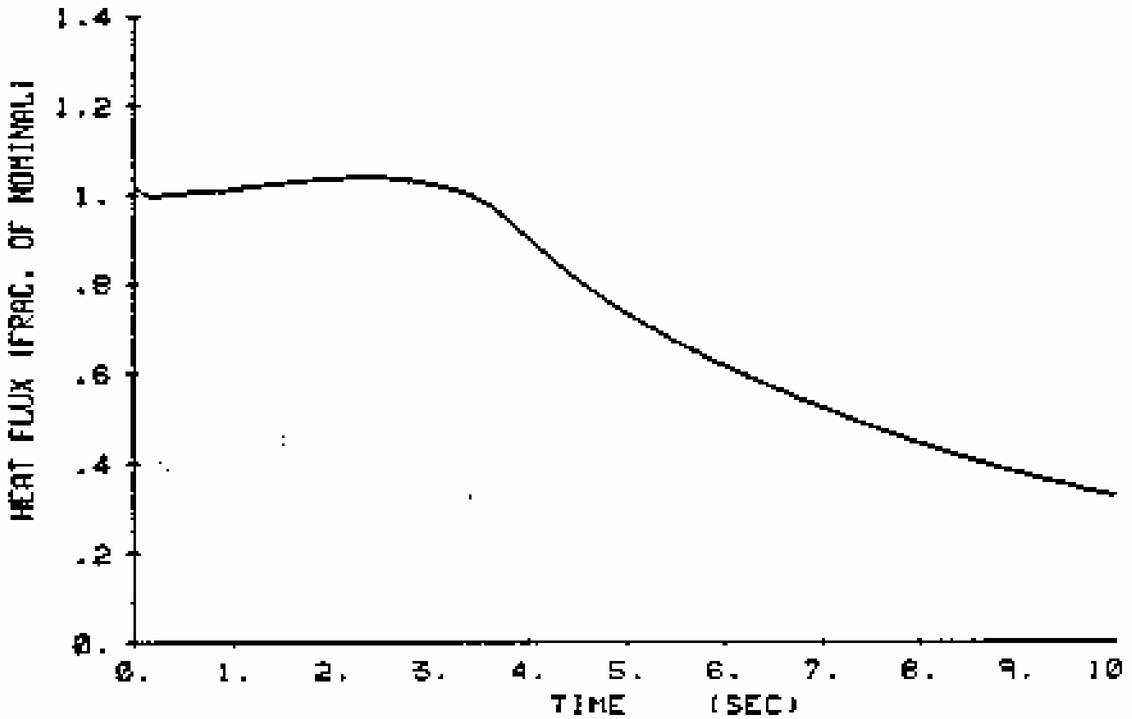
FIGURE 15.4.4-2
ALL LOOPS OPERATING
ONE LOCKED ROTOR
CLAD TEMPERATURE VERSUS TIME



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

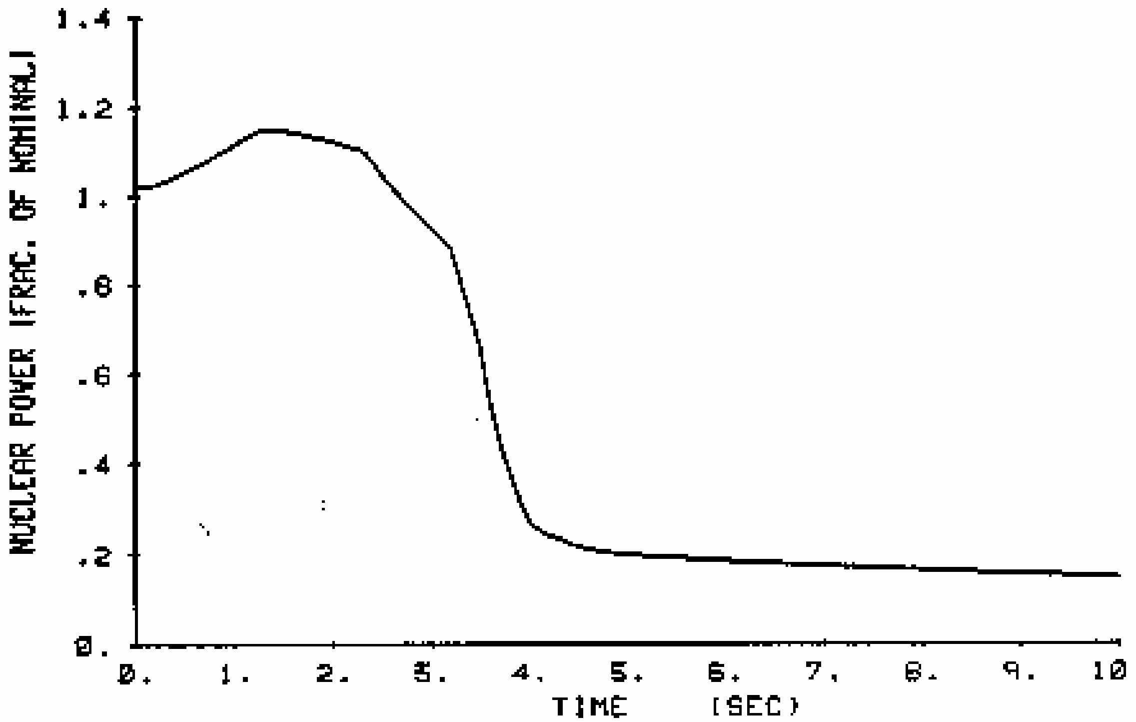
FIGURE 15.4.4-3
ALL LOOPS OPERATING
ONE LOCKED ROTOR
FLOW COASTDOWN VERSUS TIME



FSAR UPDATE

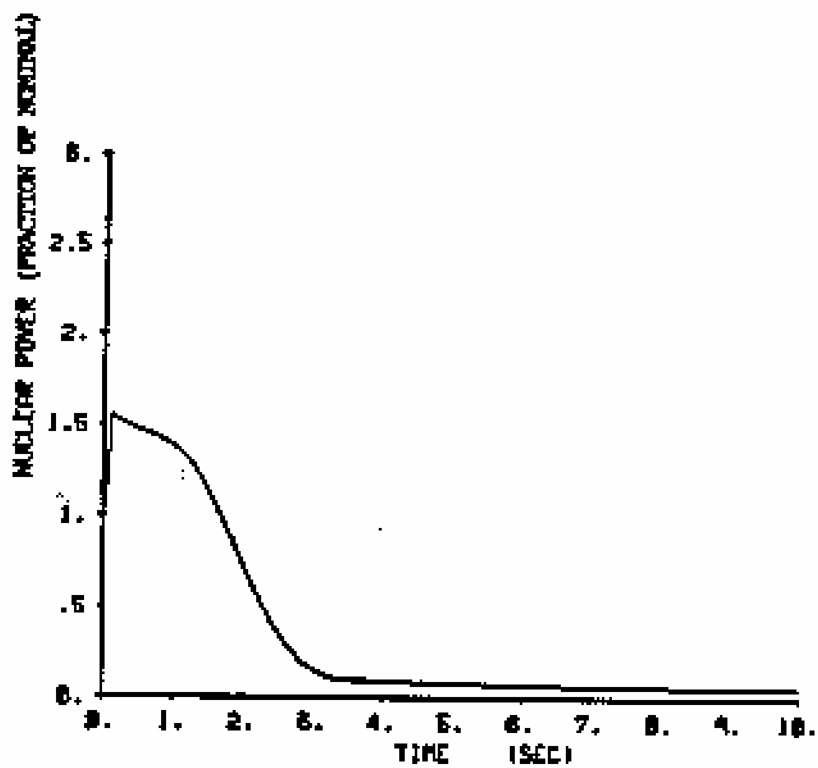
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.4-4
ALL LOOPS OPERATING
ONE LOCKED ROTOR
HEAT FLUX VERSUS TIME



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.4-5 ALL LOOPS OPERATING ONE LOCKED ROTOR NUCLEAR POWER VERSUS TIME

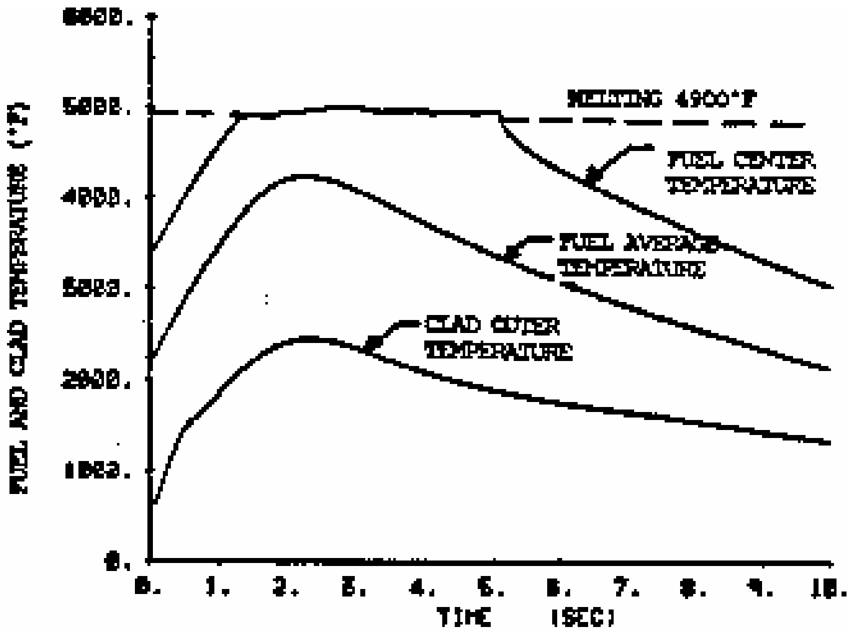
Revision 11 November 1996



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

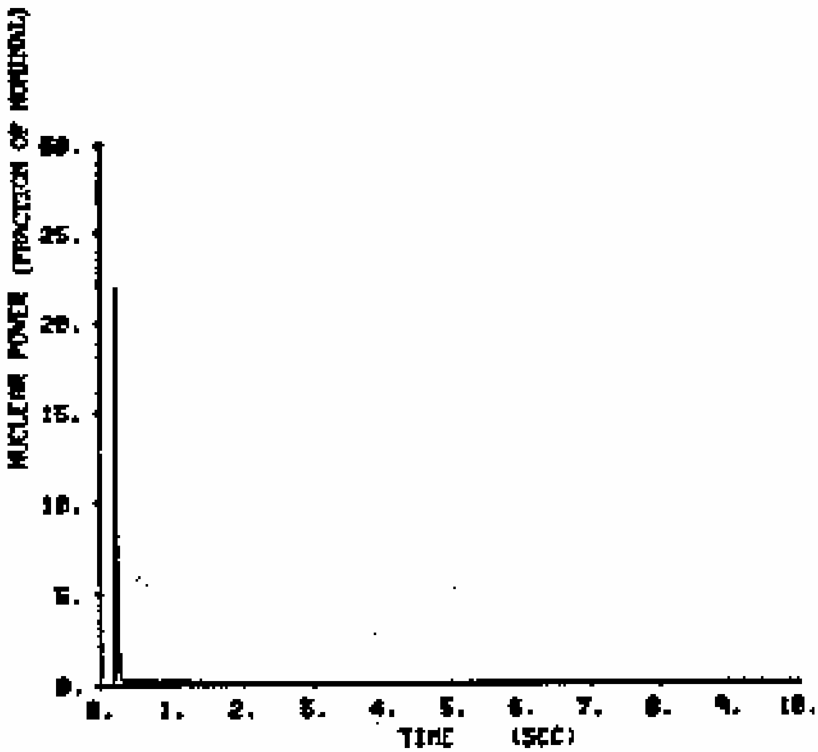
FIGURE 15.4.6-1
NUCLEAR POWER TRANSIENT, BOL, HZP, ROD EJECTION ACCIDENT



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

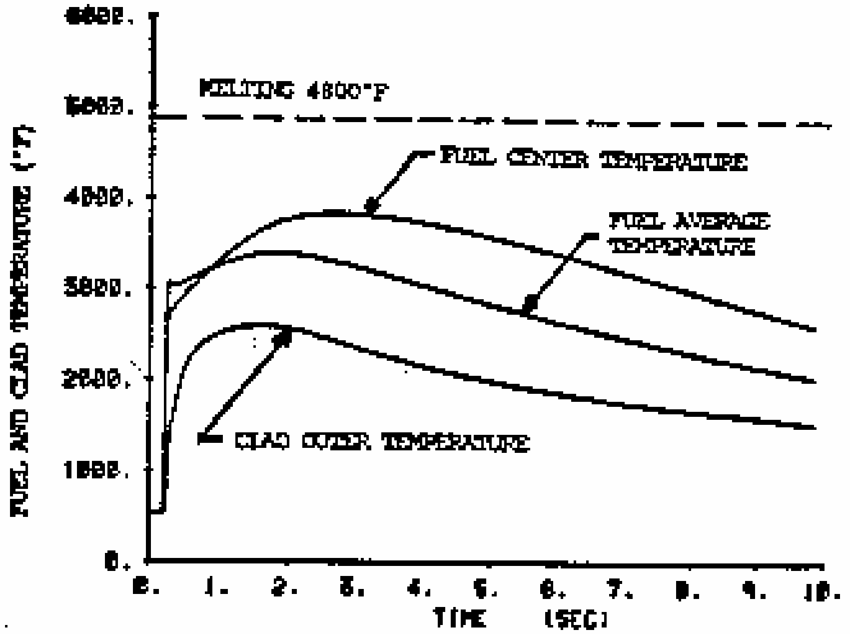
FIGURE 15.4.6-2
HOT SPOT FUEL AND CLAD TEMPERATURES VERSUS TIME, BOL, HZP, ROD EJECTION ACCIDENT



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.6-3
NUCLEAR POWER TRANSIENT, EOL, HFP, ROD EJECTION ACCIDENT

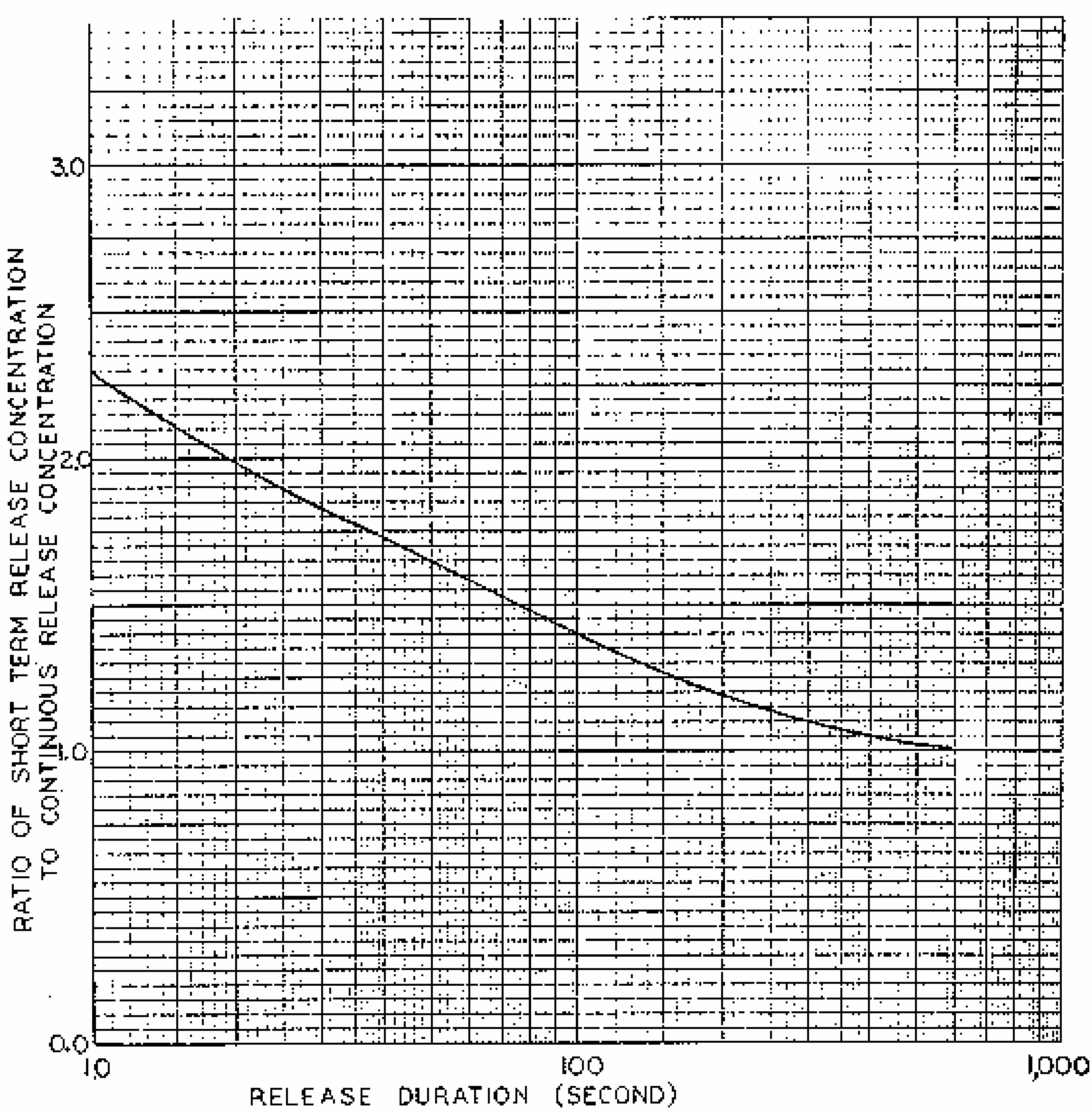


FSAR UPDATE

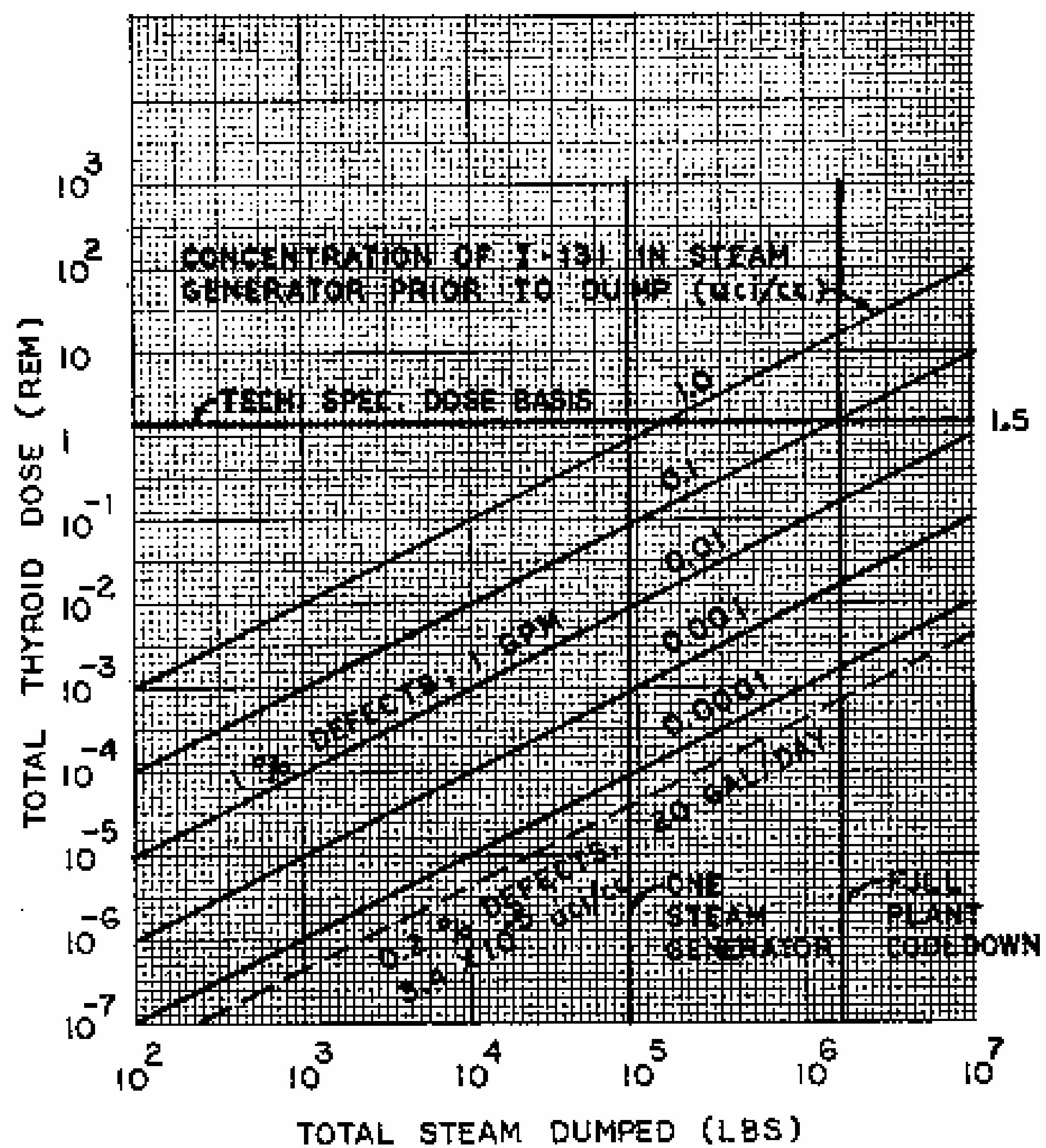
**UNITS 1 AND 2
DIABLO CANYON SITE**

FIGURE 15.4.6-4

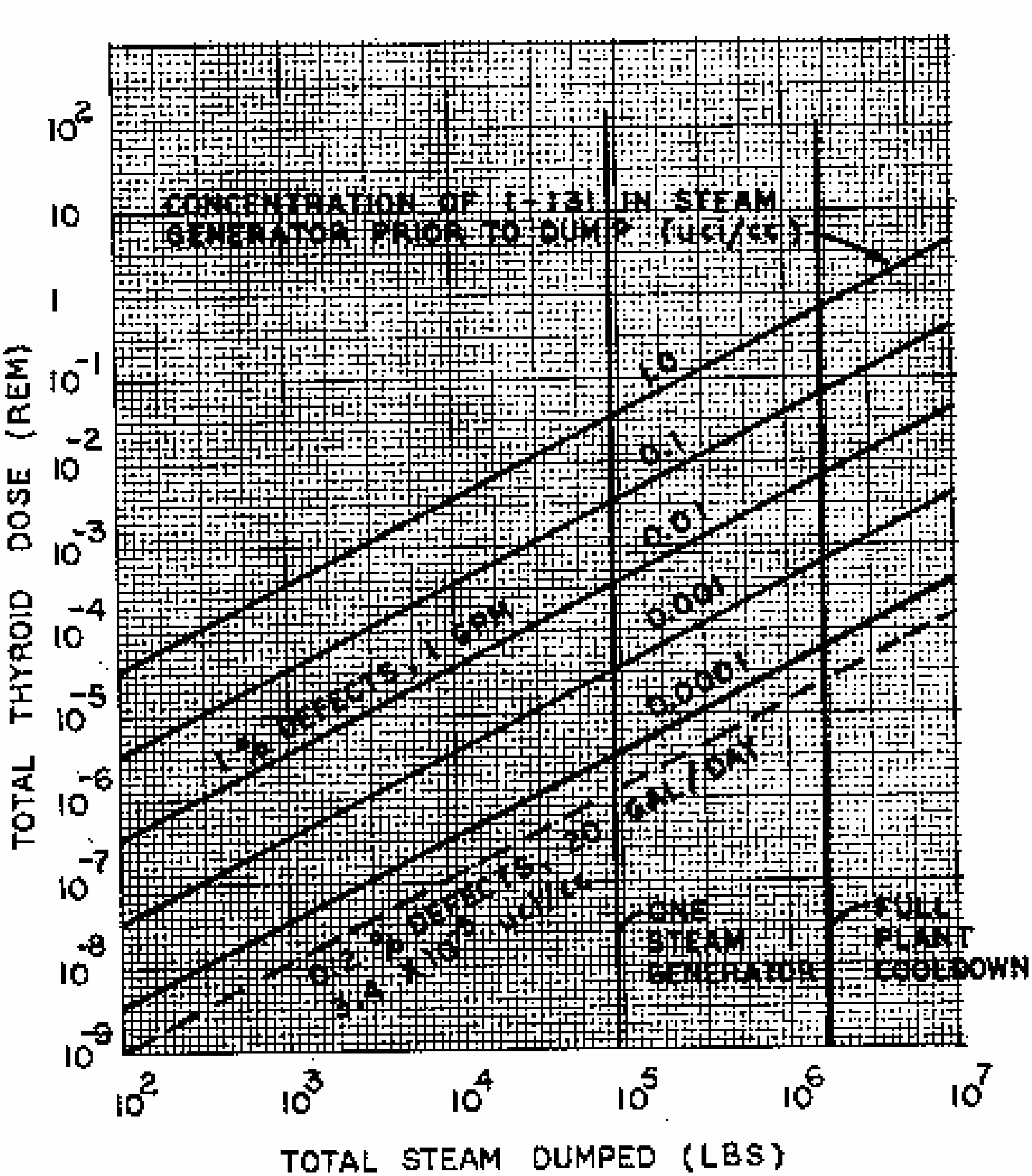
HOT SPOT FUEL AND CLAD TEMPERATURES VERSUS TIME, EOL, HZP, ROD EJECTION ACCIDENT



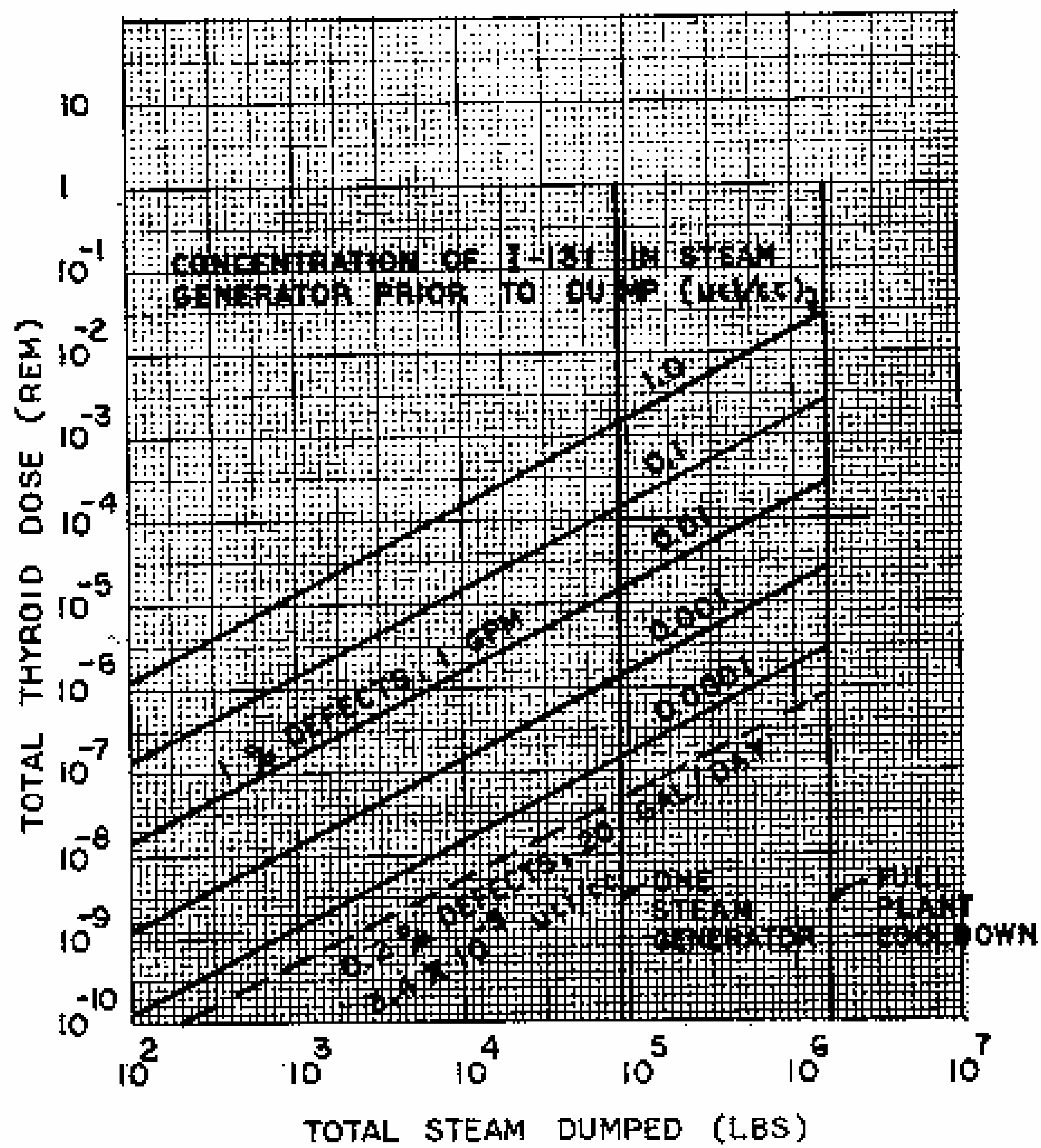
Ratio of Short-term Release Concentration to Continuous Release Concentration vs. Release Duration	DIABLO CANYON UNITS 1 & 2
	FIGURE 15.5-1



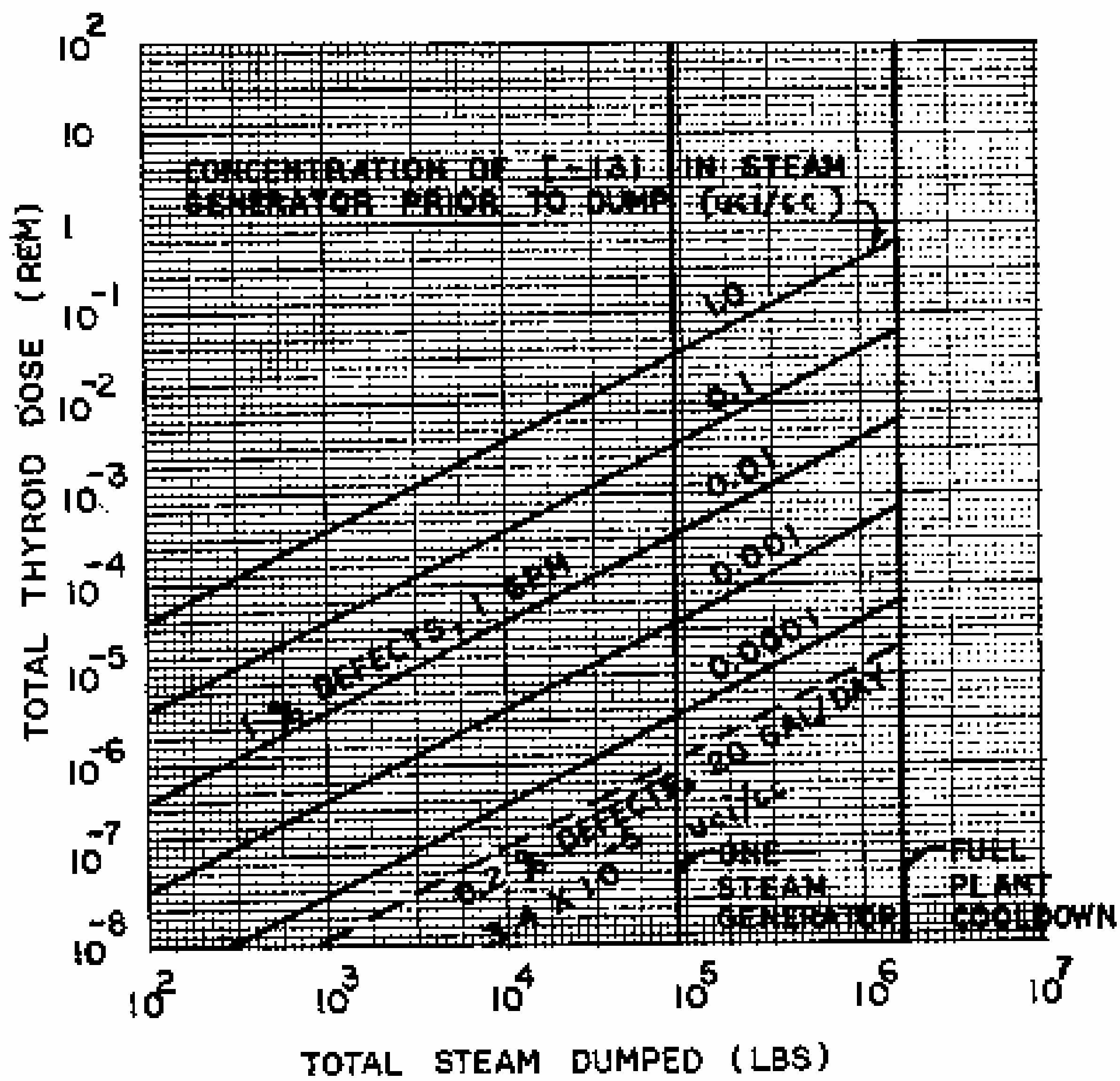
Thyroid Dose at 800 Meters Verses Weight of Steam Dumped to Atmosphere (Design Basis Case Assumptions)	DIABLO CANYON UNITS 1 & 2
	FIGURE 15.5-2



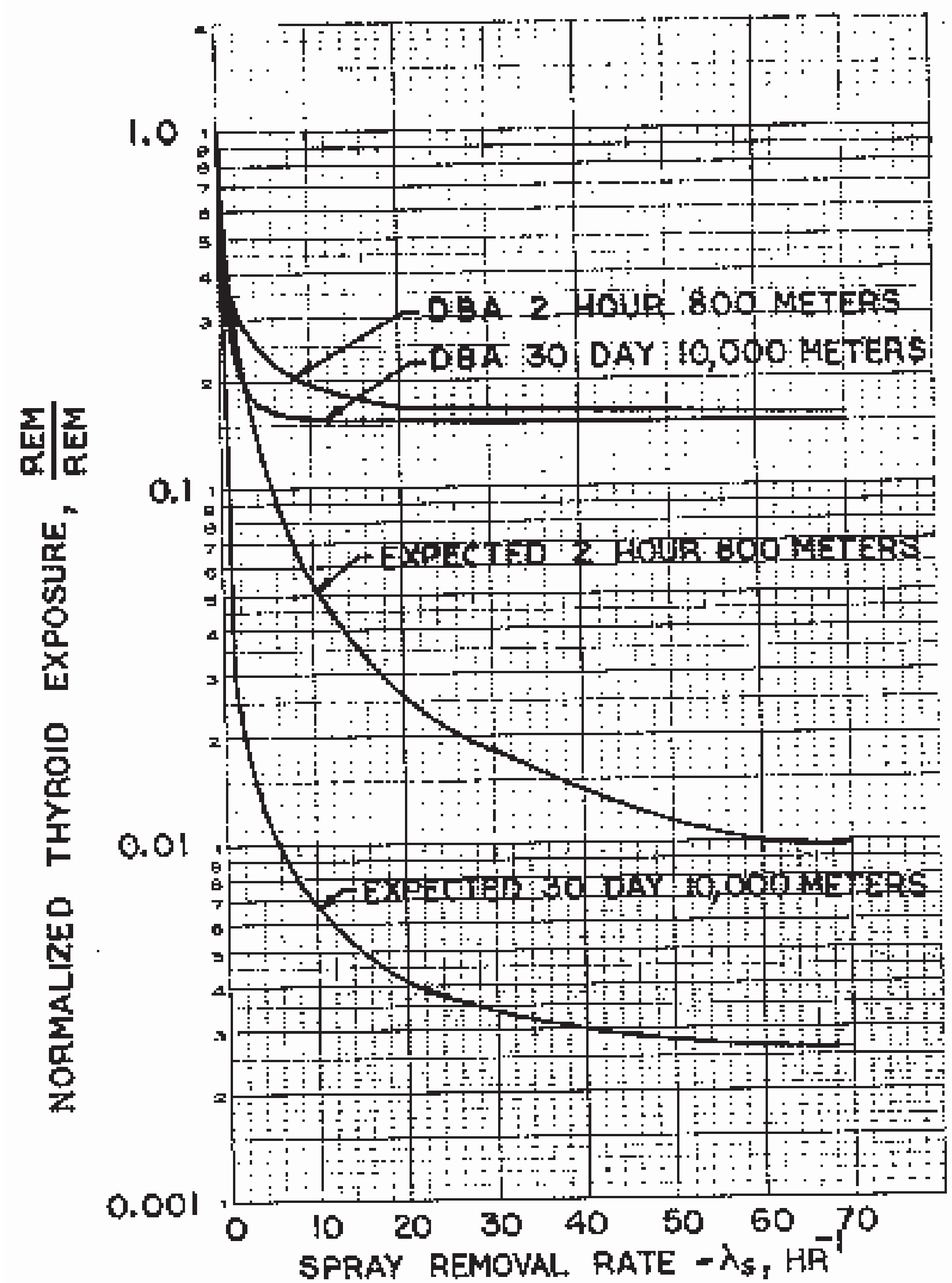
Thyroid Dose at 10,000 Meters Verses Weight of Steam Dumped to Atmosphere (Design Basis Case Assumptions)	DIABLO CANYON UNITS 1 & 2
	FIGURE 15.5-3



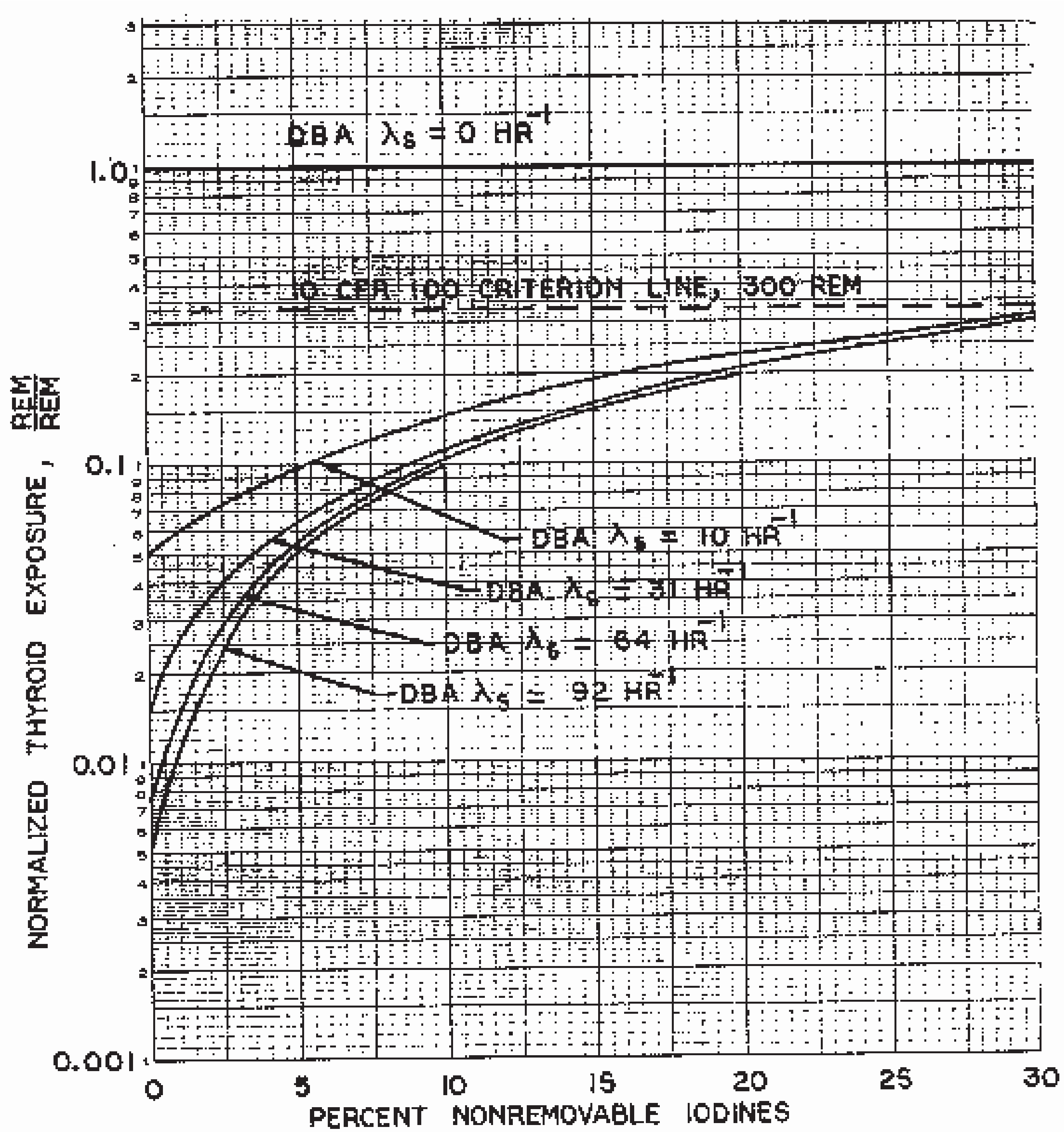
Thyroid Dose at 10,000 Meters Verses Weight of Steam Dumped to Atmosphere (Expected Case Assumptions)	**DIABLO CANYON UNITS 1 & 2**
	FIGURE 15.5-4



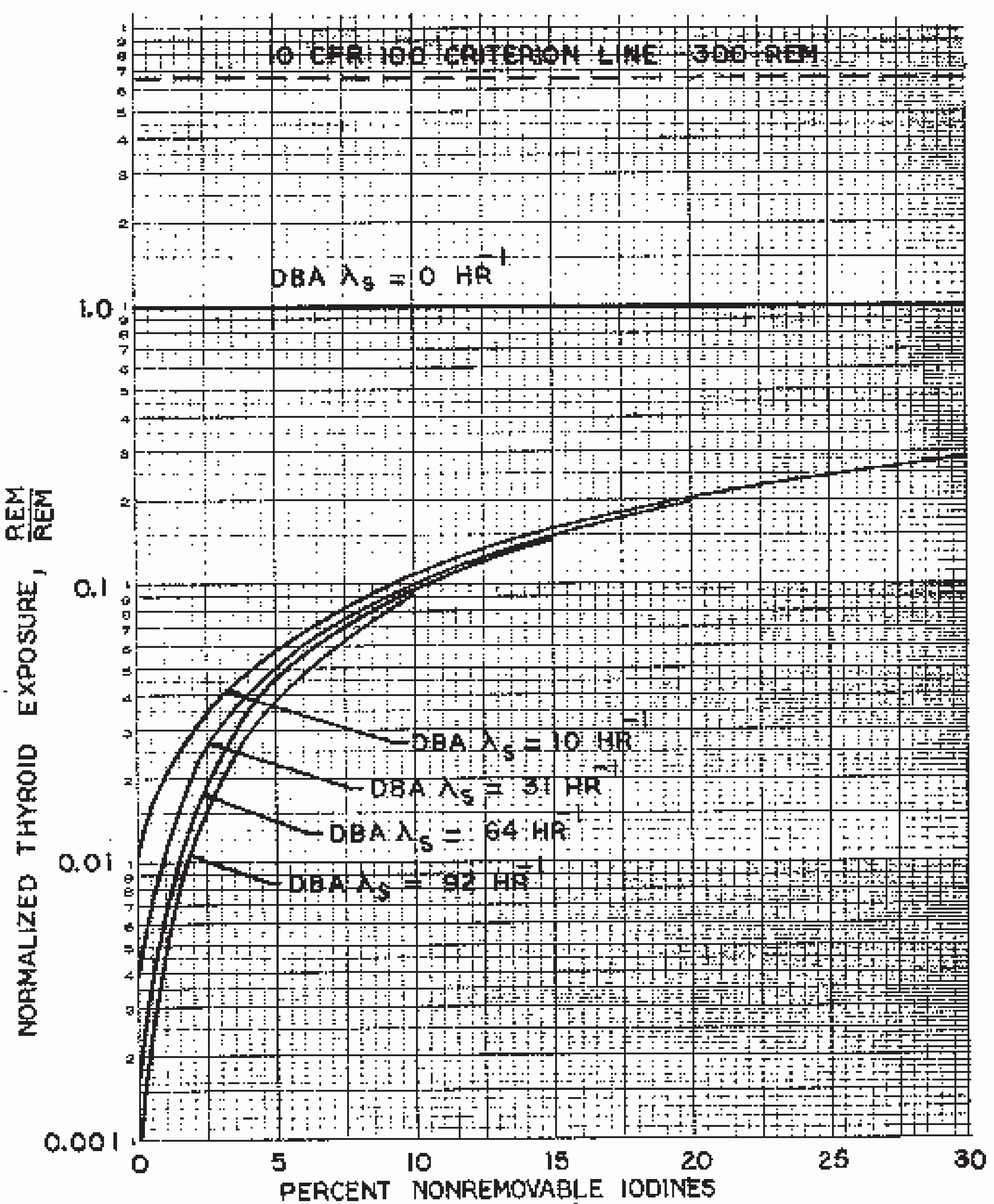
Thyroid Dose at 800 Meters Verses Weight of Steam Dumped to Atmosphere (Expected Case Assumptions)	**DIABLO CANYON UNITS 1 & 2**
	FIGURE 15.5-5



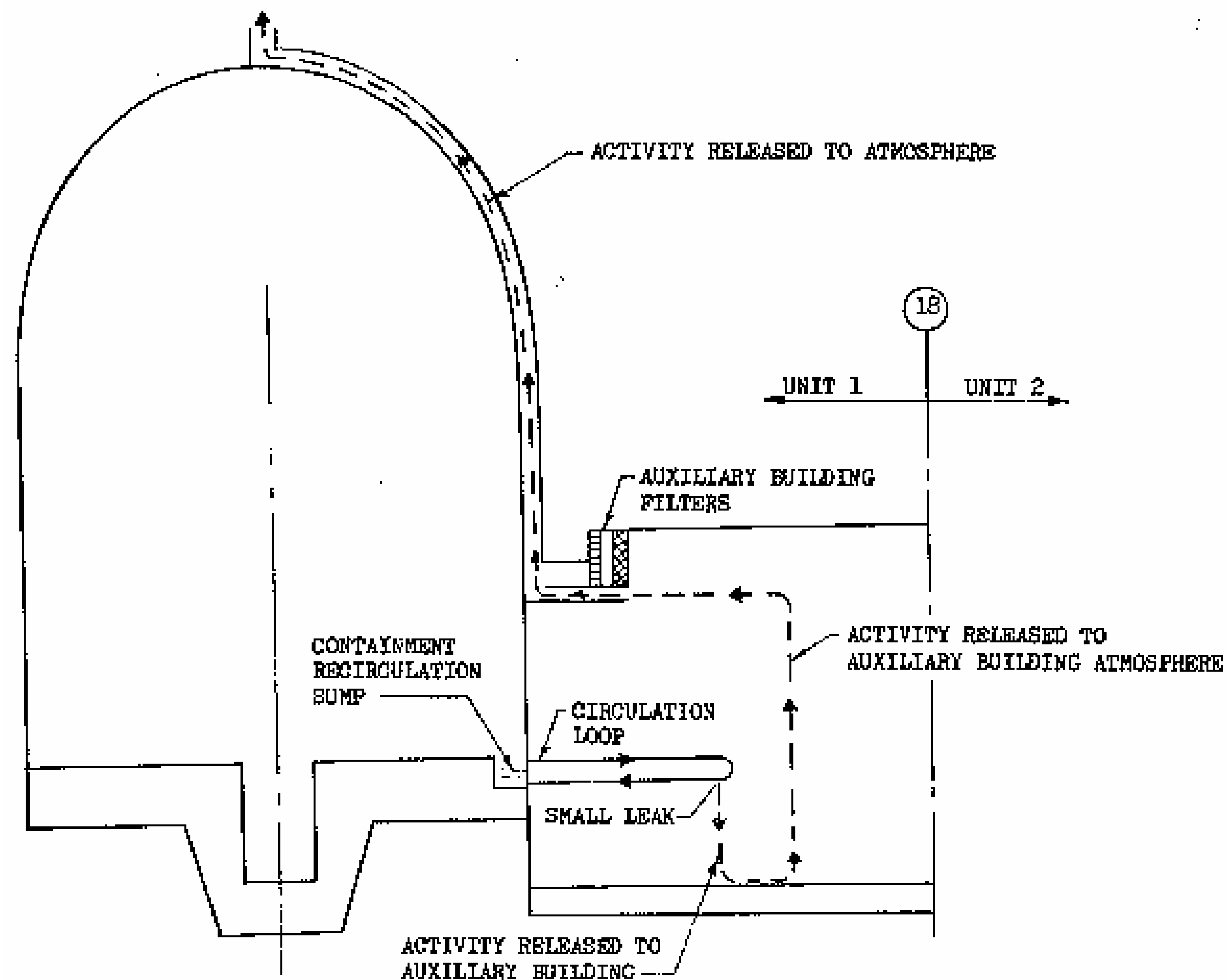
Thyroid Exposures for 15 Percent Nonremovable Iodine (Normalized to Exposures for Zero Spray Removal Constant) Historical	DIABLO CANYON UNITS 1 & 2 FIGURE 15.5-6



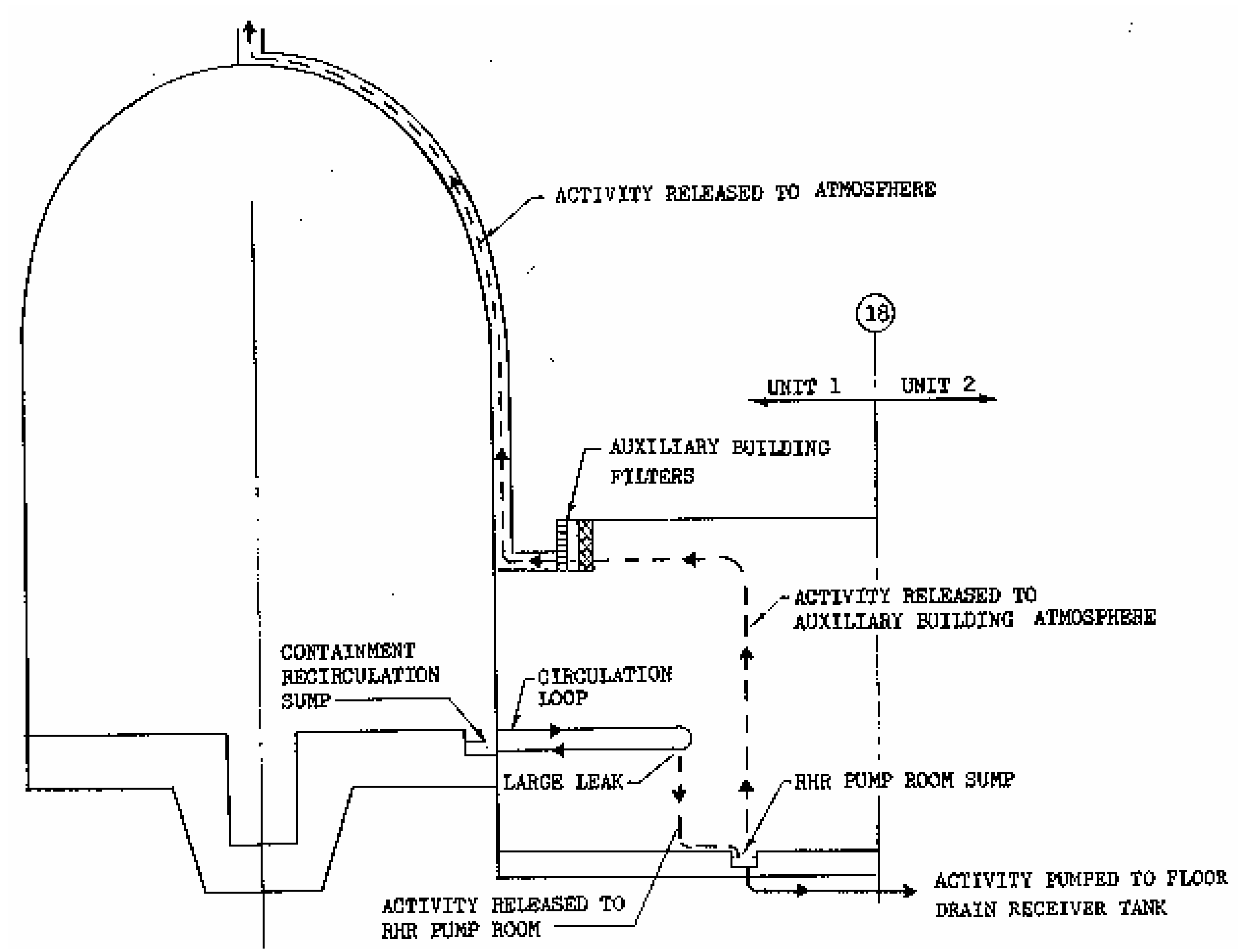
DBA 2-Hour 800-Meter Thyroid Exposures Verses Spray Removal Constant and Percent Nonremovable Iodine (Normalized to Exposures with Zero Spray Removal Constant and Zero Percent Nonremovable Iodine) Historical	DIABLO CANYON UNITS 1 & 2 FIGURE 15.5-7



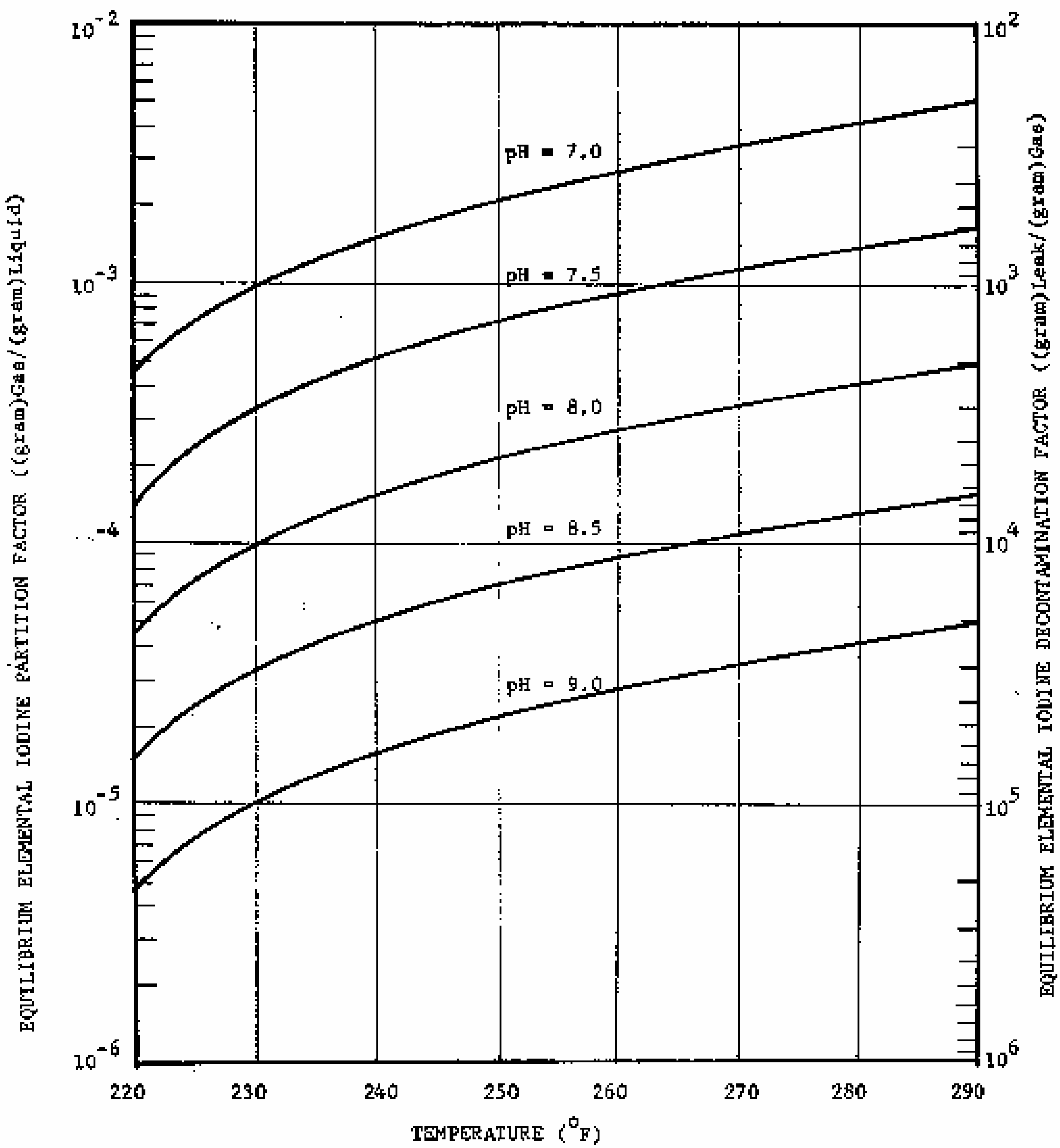
DBA 30-Hour 800-Meter Thyroid Exposures Verses Spray Removal Constant and Percent Nonremovable Iodine (Normalized to Exposures with Zero Spray Removal Constant and Zero Percent Nonremovable Iodine) Historical	**DIABLO CANYON UNITS 1 & 2** **FIGURE 15.5-8**



Containment Recirculation Sump Activity Pathway to the Atmosphere for Small Leak Case	DIABLO CANYON UNITS 1 & 2
	FIGURE 15.5-9

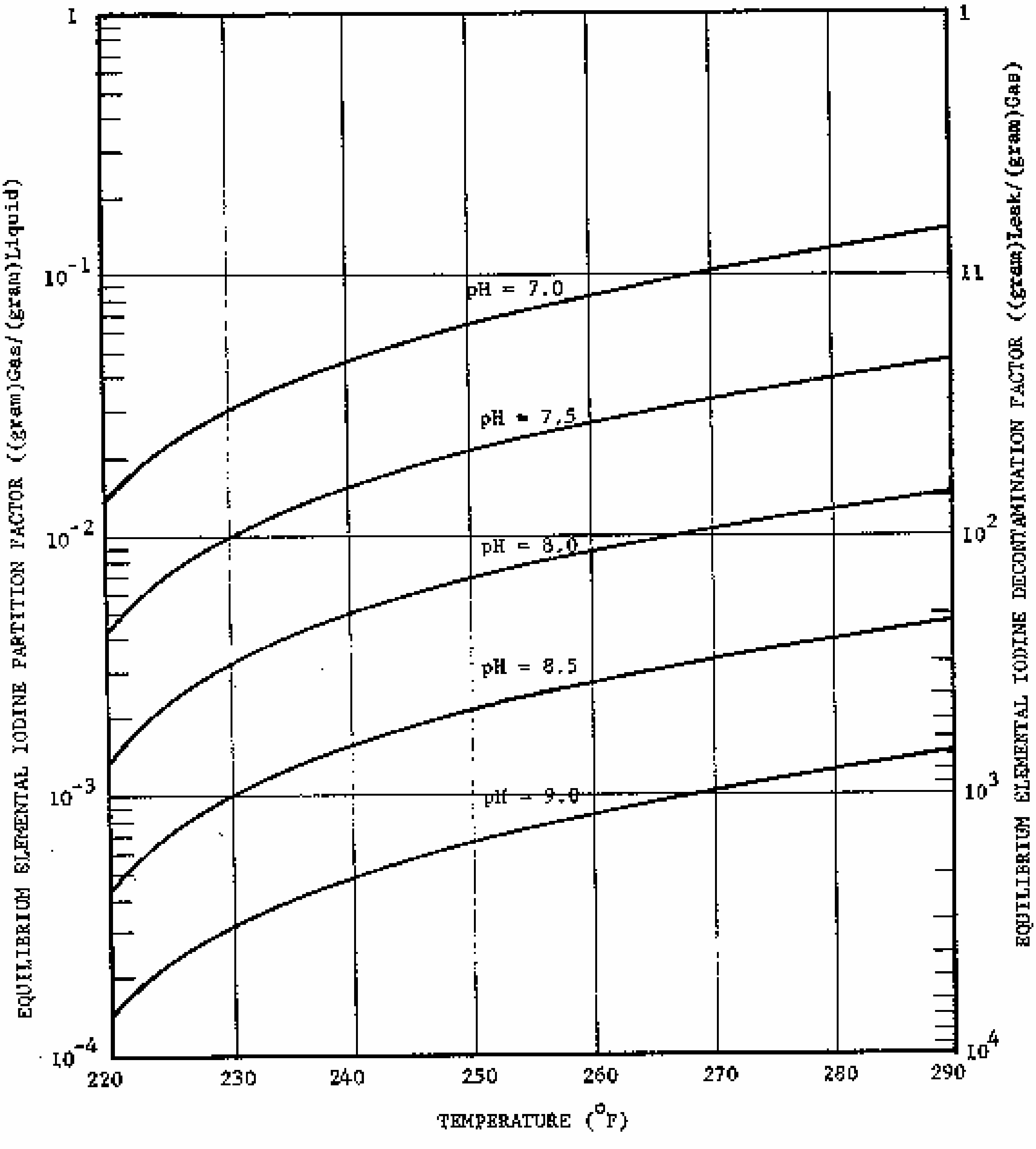


Containment Recirculation Sump Activity Pathway to the Atmosphere for Large Leak Case	DIABLO CANYON UNITS 1 & 2
	FIGURE 15.5-10



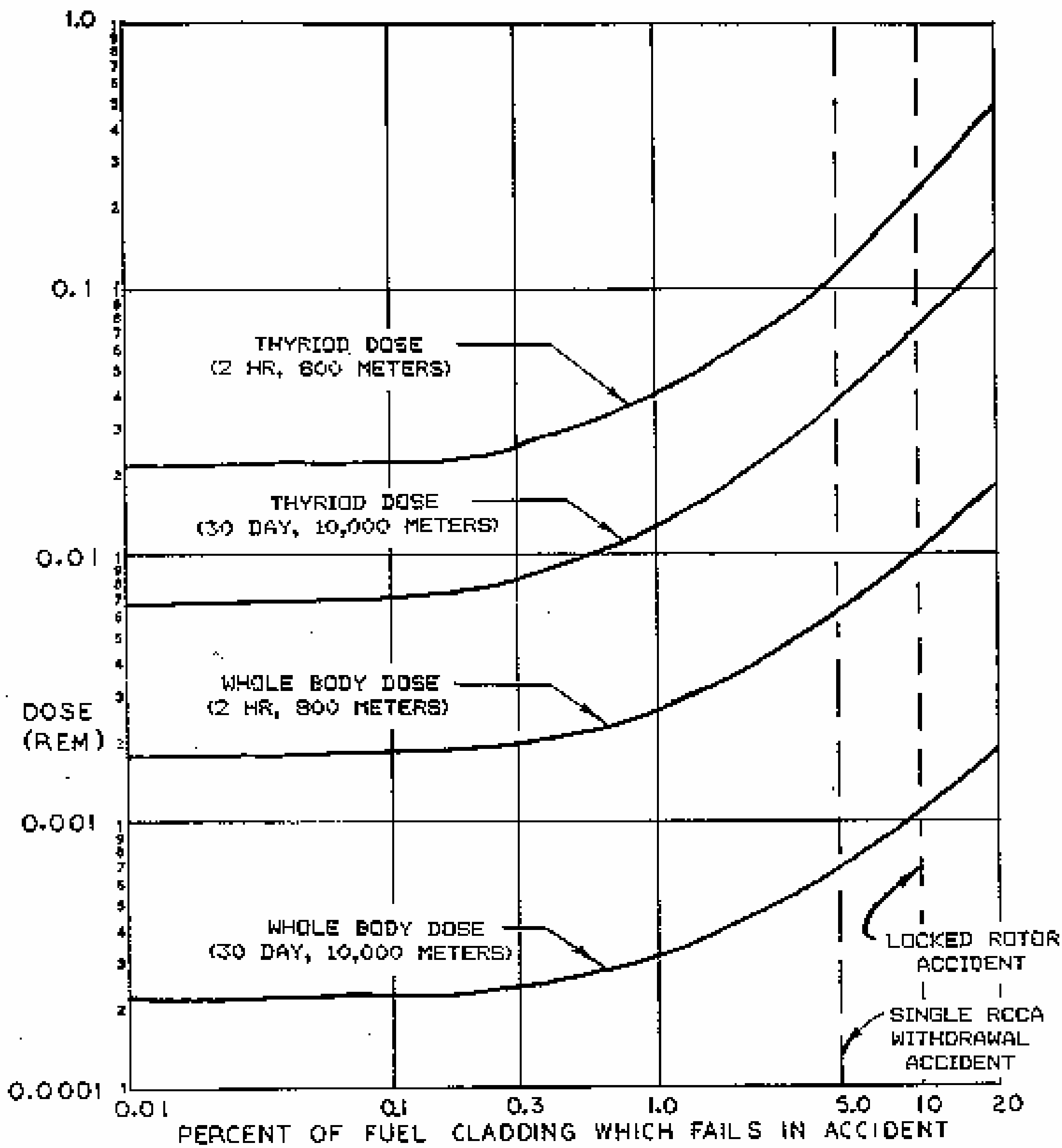
NOTE: 0.9955×10^{-6} MOLES I/LITER AND FLASHING PROCESS

Equilibrium Elemental Iodine Partition and Decontamination Factors for the Expected Case – Large Circulation Loop Leakage in the Auxiliary Building	**DIABLO CANYON UNITS 1 & 2**
	FIGURE 15.5-11

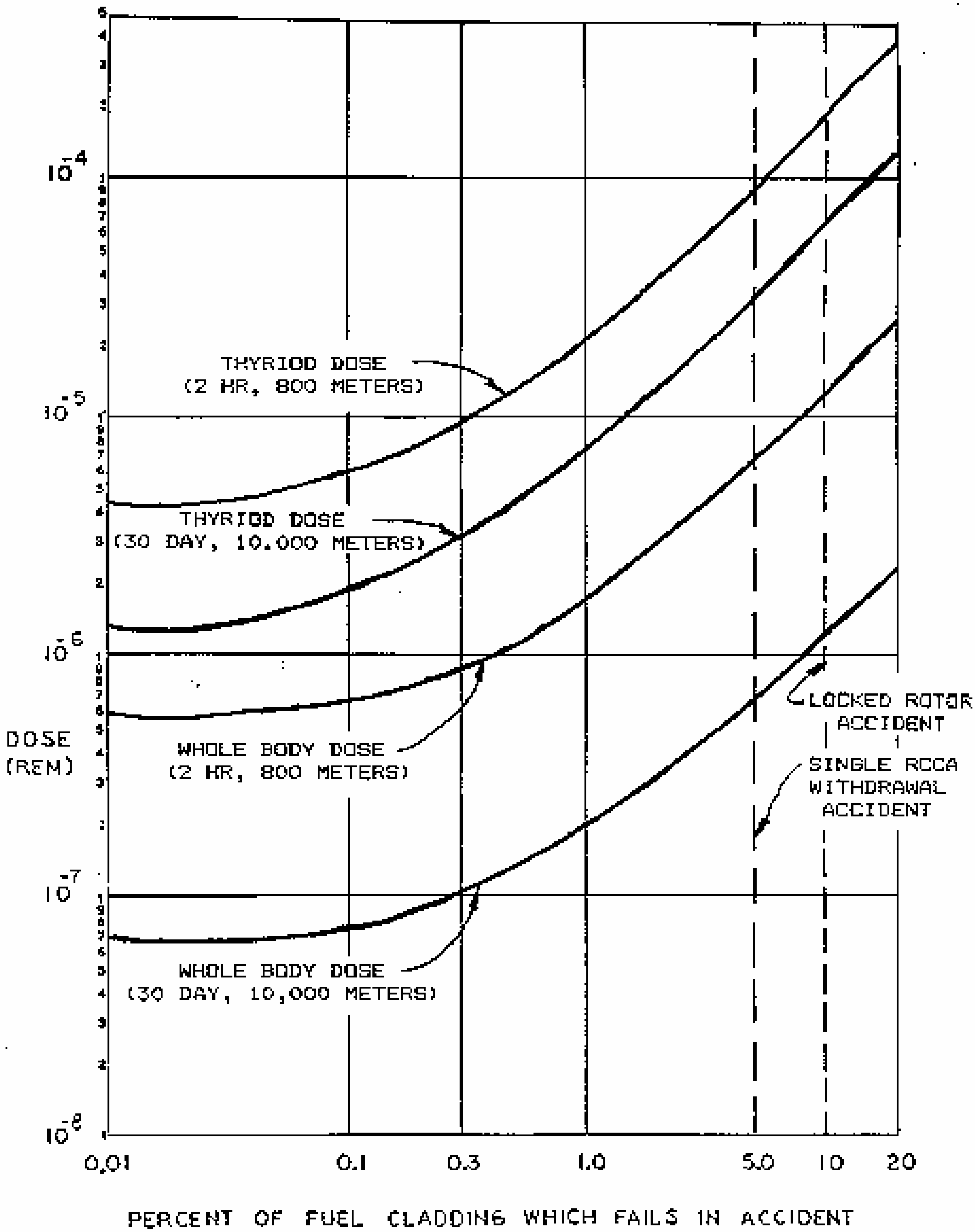


NOTE: 0.2988X10^{-4} MOLES I/LITER AND FLASHING PROCESS

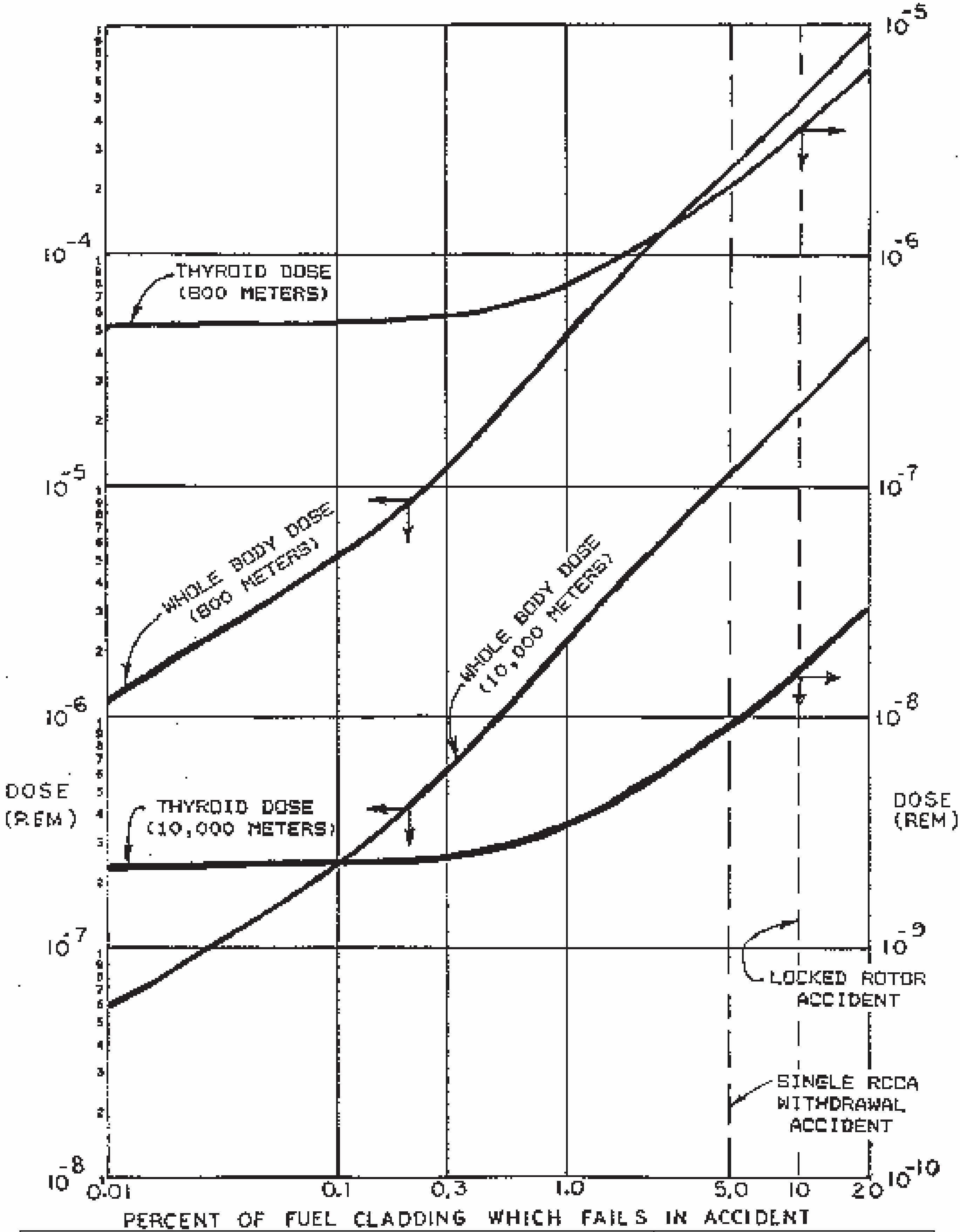
Equilibrium Elemental Iodine Partition and Decontamination Factors for the DBA Case – Large Circulation Loop Leakage in the Auxiliary Building	DIABLO CANYON UNITS 1 & 2
	FIGURE 15.5-12



Potential Radiation Exposures as a Result of Accidents Involving Failure of Fuel Cladding (Design Basis Case Assumptions)	DIABLO CANYON UNITS 1 & 2
	FIGURE 15.5-14



Potential Radiation Exposures as a Result of Accidents Involving Failure of Fuel Cladding (Expected Case Assumptions)	DIABLO CANYON UNITS 1 & 2
	FIGURE 15.5-15



Incremental Long-term Doses From Accidents Involving Failure of Fuel Cladding Historical	DIABLO CANYON UNITS 1 & 2 FIGURE 15.5-16

Chapter 16

TECHNICAL SPECIFICATIONS AND EQUIPMENT CONTROL GUIDELINES

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TECHNICAL SPECIFICATIONS AND EQUIPMENT CONTROL GUIDELINES

16.1 TECHNICAL SPECIFICATIONS AND EQUIPMENT CONTROL GUIDELINES

The Technical Specifications (TSs) for Diablo Canyon Power Plant (DCPP) are contained in Appendix A of the Operating Licenses. The TS Bases provide the bases or reasons for these technical specifications other than those covering administrative controls. In accordance with 10 CFR 50.36, the TS Bases are not part of the TS, and are included by reference in this section of the FSAR Update in accordance with 10 CFR 50.34 and 10 CFR 50.36. Changes to the TS Bases are processed in accordance with TS 5.5.14, “Technical Specifications (TS) Bases Control Program.”

The Equipment Control Guidelines (ECGs) provide administrative controls and operability requirements for selected equipment that is not addressed by the TSs. ECGs are developed when controls are required by regulatory commitments or when plant management determines that it is prudent to control equipment to maximize its availability. TSs that have been relocated to licensee controlled documents are generally transferred to ECGs. ECGs containing relocated TSs are incorporated into the FSAR Update by reference.

Similar to TSs, ECGs provide operability requirements, action statements, and surveillance requirements. If the equipment cannot be returned to service as required by the ECG, administrative review, approval, and evaluation under the plant Quality Assurance Programs is required.

Table 16.1-1 lists those DCPP ECGs that have been implemented due to relocated TSs in accordance with the NRC’s Final Policy Statement on TS Improvements and 10 CFR 50.36, which include four criteria to be used for identifying TS requirements that may be relocated to licensee controlled documents. Several license amendments were issued by the NRC related to relocated TSs as noted in Table 16.1-1. Fire Protection TSs relocated to ECGs are listed in Appendix 9.5H.

The preparation and revision process for ECGs requires evaluation under 10 CFR 50.59 or other applicable requirements. All ECGs and ECG revisions are approved by the Station Director.

TABLE 16.1-1

EQUIPMENT CONTROL GUIDELINES - TECHNICAL SPECIFICATIONS RELOCATED IN ACCORDANCE WITH NRC'S FINAL POLICY STATEMENT ON TECHNICAL SPECIFICATION IMPROVEMENTS

Number	Title	Notations
ECG 4.3	Steam Generator Pressure/Temperature Limitation	1
ECG 4.4	Instrumentation – Turbine Overspeed Protection and Turbine Trip	3, 7
ECG 7.3	Reactor Coolant System – Safety Valves Shutdown	2
ECG 7.4	Reactor Coolant System – Chemistry	2
ECG 7.5	Reactor Coolant System – Pressurizer	2
ECG 7.6	Reactor Coolant System – Structural Integrity	2
ECG 7.7	Reactor Coolant System – Reactor Vessel Head Vents	2
ECG 7.8	Accident Monitoring Instrumentation	4, 5
ECG 8.4	Reactivity Control Systems – Flow Paths – Operating	3
ECG 8.5	Reactivity Control Systems – Boration Systems – Flow Path - Shutdown	4
ECG 8.6	Reactivity Control Systems – Charging Pump - Shutdown	4
ECG 8.7	Reactivity Control Systems – Charging Pumps – Operating	4
ECG 8.8	Reactivity Control Systems – Borated Water Source – Shutdown	4
ECG 8.9	Reactivity Control Systems – Borated Water Sources – Operating	4
ECG 9.1	Accumulator Pressure and Water Level Instrumentation	8
ECG 13.2	Water Level – Spent Fuel Pool	4
ECG 17.3	Flood Protection	1

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Number	Title	Notations
ECG 19.1	Liquid Radwaste – Temporary Outdoor Tanks	4
ECG 21.3	Miscellaneous Emergency Diesel Generator (EDG) Functions	4
ECG 23.1	Area Temperature Monitoring	1
ECG 23.2	Instrumentation – Chlorine Detection System	3
ECG 23.3	Containment Ventilation System	4
ECG 23.4	Hydrogen Recombiners	4, 5
ECG 23.5	Plant Systems – Control Room Ventilation System (CRVS)	4
ECG 24.1	Explosive Gas Effluent Monitoring Instrumentation	4
ECG 24.2	Gaseous Radwaste – Explosive Gas Mixture	4
ECG 24.3	Gaseous Radwaste – Gas Storage Tanks	4
ECG 33.1	Nuclear Instrumentation – Power Distribution Monitoring System Instrumentation	6
ECG 37.2	Axial Flus Difference (AFD) Monitor Alarm	4
ECG 37.3	Quadrant Power Tilt Ratio Alarm	4
ECG 38.1	Reactor Trip System (RTS) – Instrumentation Response Times	4
ECG 38.2	Engineered Safety Features (ESF) Response Times	4
ECG 39.6	Sealed Source Contamination	1
ECG 40.1	Meteorological Instrumentation	4
ECG 41.1	Reactivity Control Systems – Position Indication System – Shutdown	3
ECG 41.2	Special Test Exceptions – Position Indication System – Shutdown	4

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Number	Title	Notations
ECG 42.1	Refueling Operations – Decay Time	4
ECG 42.2	Refueling Operations – Communications	4
ECG 42.3	Refueling Operations – Manipulator Crane	4
ECG 42.4	Refueling Operations – Crane Travel – Fuel Handling Building	4
ECG 42.5	Refueling Operations – Water Level – Reactor Vessel	4
ECG 45.2	Containment Systems – Containment Structural Integrity	3
ECG 45.3	Containment Penetration Conductor Overcurrent Protective Devices	3
ECG 48.1	Movable Incore Detectors	4
ECG 51.1	Instrumentation – Seismic Instrumentation	3
ECG 64.1	MOV Thermal Overload Protection and Bypass Devices	3
ECG 99.1	Snubbers	1

Notes:

1. Technical Specifications (TS) relocated pursuant to License Amendments (LAs) 106 (Unit 1) and 105 (Unit 2), dated July 6, 1995.
2. TS relocated pursuant to LAs 98 (Unit 1) and 97 (Unit 2), dated March 9, 1995.
3. TS relocated pursuant to LAs 120 (Unit 1) and 118 (Unit 2), dated February 3, 1998.
4. TS relocated pursuant to LAs 135 (Unit 1) and 135 (Unit 2), dated May 28, 1999.
5. TS relocated pursuant to LAs 168 (Unit 1) and 169 (Unit 2), dated May 4, 2004.
6. TS changes pursuant to LAs 164 (Unit 1) and 166 (Unit 2), dated March 31, 2004.
7. TS relocated pursuant to LAs 173 (Unit 1) and 175 (Unit 2), dated September 24, 2004.
8. TS relocated pursuant to LAs 102 (Unit 1) and 101 (Unit 2), dated May 26, 1995.

Chapter 17

QUALITY ASSURANCE

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QUALITY ASSURANCE

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QUALITY ASSURANCE

17.1 ORGANIZATION

The Pacific Gas and Electric Company's (PG&E) efforts to assure the quality and safety of its nuclear power plants and the Diablo Canyon (DC) independent spent fuel storage installations (ISFSI) is organized in a structured manner with clearly defined levels of authority, assignments of responsibility, and lines of communication. Assignment of responsibility for an item or activity includes responsibility for its quality. Figure 17.1-1 depicts the organizational structure of PG&E. The position of the quality verification (QV) organization in the utility organization is shown in Figure 17.1-2.

PG&E has assumed full responsibility to its employees, stockholders, the general public, and affected governmental regulatory agencies for the establishment and execution of the Quality Assurance (QA) Program prescribed herein, quality-related program directives, and administrative procedures. The work of executing selected portions of the QA Program may be delegated to organizations external to PG&E; however, in all such instances, PG&E retains overall responsibility.

Specific responsibilities pertaining to quality assurance matters are assigned by the QA Program and its implementing procedures and instructions to various individuals throughout PG&E. In each instance, the assignment of a responsibility to an individual includes with it a commensurate delegation of sufficient authority that the person can, in fact, fulfill that responsibility. Unless otherwise specifically prohibited, it is understood that the functions, tasks, and activities necessary to carry out a responsibility may be delegated to and performed by other qualified individuals. All delegations of functions, tasks, activities, and authority shall be documented.

Figure 17.1-2 identifies those individuals and organizational components of PG&E with direct responsibilities related to the quality of the:

- design, maintenance, and operation of DCPP, and
- design, fabrication, construction, testing, operation, maintenance, modification, and decommissioning of ISFSI structures, systems, and components (SSCs) that are important to safety.

The narrative description throughout this section is based on Figures 17.1-1 and 17.1-2.

THE BOARD OF DIRECTORS OF PG&E CORPORATION is responsible for all facets of PG&E's utility business.

THE CHAIRMAN, CEO, AND PRESIDENT, PG&E CORPORATION is accountable to the Board of Directors and establishes the corporate policies, goals, and objectives

related to all of PG&E's activities and operations. Reporting to the Chairman, CEO, and President is the President - PG&E Company.

THE PRESIDENT - PG&E is a member of the Board of Directors and is responsible for and directs the planning, distribution, and development of all the Company's energy resources and nuclear power generation. These functions include such activities as planning and development, engineering, information services, construction, and fossil and nuclear power plant and ISFSI operations. Reporting to the President – PG&E are the Senior Vice President, Chief Nuclear Officer, the Senior Vice President, Safety and Shared Services; and the Executive Vice President, Electric Operations.

THE EXECUTIVE VICE PRESIDENT – ELECTRIC OPERATIONS, through the Director – Applied Technology Services, is responsible for providing, upon request: (1) technical investigations, tests, analyses, examinations, and calibration services in support of DCPP and its ISFSI; (2) developing, evaluating, qualifying, testing, and improving welding, brazing, and heat-treating procedures required by the company; and (3) providing evaluation support of these procedures.

THE SENIOR VICE PRESIDENT – SAFETY AND SHARED SERVICES, through the Support Services Supervisor – Engineering Records Unit, is responsible for providing document services support for DCPP and the ISFSI. These services include indexing, preparing, and duplicating microfiche for the drawing control system; storing the master microfiche and drawings that cannot be microfilmed; and scanning and indexing drawings when requested. They also provide remote storage of master microfilm reels for the records management system (RMS) and storage of vendor manuals. The Senior Vice President – Safety and Shared Services, through the Manager – Nuclear Supply Chain, is responsible for administering, coordinating, planning, and operation of warehousing and procurement of materials in support of DCPP and ISFSI construction and operations, as well as for contract services.

THE SENIOR VICE PRESIDENT – CHIEF NUCLEAR OFFICER is responsible for the safe and efficient operation of the Company’s nuclear power plants. He is responsible for overall ISFSI safety and for taking measures needed to ensure acceptable performance of the ISFSI staff in designing, fabricating, constructing, testing, operating, modifying, decommissioning, and providing technical support to the ISFSI. The Senior Vice President - Chief Nuclear Officer is the corporate officer specified by the DCPP Technical Specifications who shall have corporate responsibility for overall DCPP nuclear safety and shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining, and providing technical support to DCPP to ensure nuclear safety. Reporting directly to the Senior Vice President - Chief Nuclear Officer are the Site Vice President; the Vice President Nuclear Services, the Director – Quality Verification; the Director, Compliance, Alliance, and Risk; and the Employee Concerns Program supervisor. The Senior Vice President - Chief Nuclear Officer, or his designee, as specified in administrative procedures, approves and signs official company correspondence to the U.S. Nuclear Regulatory Commission (NRC) or its representatives. The Independent Review and Audit Program, the Diablo Canyon Plant

Staff Review Committee (PSRC) and Nuclear Safety Oversight Committee (NSOC) report to the Senior Vice President – Chief Nuclear Officer. He approves revisions to the QA Program as described herein that constitute a reduction in a commitment made to the NRC. He also approves revisions to program directives.

THE SITE VICE PRESIDENT is responsible for the conduct of all onsite activities related to the safe and efficient maintenance and operation of the plant. In addition the Site Vice President is responsible for training, site services, and performance improvement. Reporting directly to the Site Vice President are the Station Director, Director Learning Services, and the Director Site Services.

THE VICE PRESIDENT NUCLEAR SERVICES is responsible for providing engineering and design services, geotechnical services, project management and nuclear fuels management. This includes configuration control, design bases defense and management, performance of modifications to DCPP, providing day-to-day technical support for DCPP operations; managing technical programs related to system and component health and long-term planning; and complying with regulatory requirements pertaining to SSCs. This includes the ISFSI. This position is responsible for reporting trend and performance status information to the Site Vice President. This position is specifically charged with development, evaluation, qualification, testing, and improvement of nondestructive examination procedures required by PG&E and for evaluation of these types of procedures that are used at DCPP by other organizations. Reporting directly to the Vice President Nuclear Services are the Director - Engineering Services; the Director Technical Services; the Director – Strategic Projects; and the Director Security and Emergency Services

The Vice President Nuclear Services is also responsible for activities related to ISFSI operation and decommissioning. He is responsible to develop, and has been delegated the necessary authority to approve and direct the implementation of those programs, procedures, and instructions required for the operation of the plant and ISFSI, within limits established by the QA Program, Technical Specifications, and administrative guidelines established by the Senior Vice President – Chief Nuclear Officer. In addition he is responsible for the specification of technical and quality requirements for the purchase of DCPP and ISFSI material and equipment and emergency planning.

THE STATION DIRECTOR is the plant manager specified in the DCPP TS, Section 5. He is responsible for operations and maintenance. Reporting directly to the Station Director are the Director - Operations Services; the Director - Maintenance Services; and the Director – Nuclear Work Management.

THE DIRECTOR - OPERATIONS SERVICES is responsible for operations. Reporting to the Director - Operations Services are the Manager - Operations; Manager – Operations Planning; Manager – Operations Performance; the Manager, Chemistry and Environmental Services; and the Manager, Radiation Protection.

THE DIRECTOR, SITE SERVICES is responsible for the overall implementation, maintenance, and continuing improvement of performance improvement processes including providing root cause analysis and trending expertise. This position through the Manager, Regulatory Services, is responsible for coordinating with the NRC for all matters relating to obtaining, maintaining, amending, revising, and otherwise changing the DCPP and ISFSI licenses. In addition, this position, through the Manager, Procedure and Document Services is responsible for implementing the quality assurance records program and provides support for the development, control, and distribution of plant procedures.

THE DIRECTOR - QUALITY VERIFICATION is responsible for management of the QA Program and for assuring that the QA Program prescribed herein, program directives, and administrative procedures are effectively implemented and complied with by all involved organizations, both internal and external to PG&E. The Chairman, CEO, and President - PG&E Corporation; the President - PG&E;; and the Senior Vice President, Chief Nuclear Officer, have given the Director, Quality Verification the organizational freedom and delegated the requisite authority to investigate any area or aspect of PG&E's operations as necessary to identify and define problems associated with establishment or execution of the QA Program. They have also delegated to the Director, Quality Verification the authority to initiate, recommend, or provide solutions for such problems to whatever management level is necessary, and to verify that effective corrective action is taken in a timely manner. This delegation includes the authority to assess, review, inspect, audit, and monitor the conduct of quality-related activities performed by or for PG&E to assure compliance with the QA Program and other regulatory requirements.

The Director - QV reports directly to the Senior Vice President - Chief Nuclear Officer and has access to the Chairman, CEO, and President - PG&E Corporation; the President - PG&E; the Site Vice President; the Vice President Nuclear Services; the Director, - Humboldt Bay Nuclear; and appropriate directors and managers for any significant quality-related problem or deficiency. He is authorized to prescribe a uniform company-wide method of performing an activity affecting quality by sponsoring or requiring the issuance of procedures when such standardization is considered desirable or essential to the effectiveness of the QA Program. Such uniform methods are contained in program directives and administrative procedures, and compliance with their requirements by all PG&E personnel is mandatory.

The Director - QV will not be responsible for any activities unrelated to responsibilities described in the QA Program that would prevent the required attention to QA matters. Further, the responsibility of the implementation of the QA Program will take precedence over the other non-QA duties.

The Director - QV shall meet the following qualification requirements: management experience through assignments to responsible positions; knowledge of QA regulations, policies, practices, and standards; and experience working in QA or related activity in reactor design, construction, or operation or in a similar highly technological industry. At

the time of initial core loading or assignment to the active position, the Director - QV shall have six years experience in implementing quality assurance, preferably at an operating nuclear plant, or operations supervisory experience. At least one year of these six years of experience shall be nuclear power plant experience in the overall implementation of the QA Program. A minimum of one year of this six-year experience requirement shall be related technical or academic training. A maximum of four years of this six-year experience requirement may be fulfilled by related technical or academic training.

The Director - QV is responsible to regularly assess and report on the status, adequacy, and effectiveness of PG&E's QA Program to the Senior Vice President - Chief Nuclear Officer and other affected PG&E management and nuclear oversight committees. He is responsible to identify, prepare, and submit for approval such changes to the QA Program prescribed herein as are necessary to maintain the QA Program up to date and in conformance with current regulatory requirements and PG&E commitments to the NRC. He is responsible for the review of all regulatory submittals as they pertain to the QA Program, and his concurrence is required prior to submittal. He is responsible for assessing and assuring that the QA Program is effectively implemented at DCPP and the ISFSI. He assures timely and effective corrective actions through audits, regular assessments, and quality assessment status reports. Reporting to the Director - QV are the quality assurance, supplier quality, project quality, and independent quality control inspection functions.

The Director - QV is responsible for providing recommendations on solutions to quality problems and performing monitoring, assessments, independent QC inspections, reviews, and audits for the areas covered by the QA Program including supplier quality. The Director - QV is also responsible for quality assurance associated with the Humboldt Bay Power Plant.

The Director - QV has the authority and responsibility to stop work should there be a serious breach of any part of the QA Program, or of technical or regulatory requirements wherein public health or safety could be involved. If stopping work would involve changing a nuclear generating unit's power level or separating such a unit from the PG&E system, the concurrence of the Senior Vice President - Chief Nuclear Officer, the Site Vice President, or the Station Director is required.

Through the conduct of assessments, audits, reviews, monitors, and independent QC inspections, the Director - QV is responsible for quality overview of:

- DCPP operating characteristics, operations, modifications, maintenance, and surveillance; and

- ISFSI design, fabrication, construction, testing, operation, modification, decommissioning, and related activities

to verify independently that these activities are performed correctly and that human errors are reduced as much as practicable.

THE EMPLOYEE CONCERNS PROGRAM SUPERVISOR reports to the Senior Vice President - Chief Nuclear Officer.

THE MANAGER - NUCLEAR SUPPLY CHAIN reports through the Director – Generation Supply Chain, to the Senior Vice President – Safety and Shared Services and is matrixed to the Director, Compliance, Alliance, and Risk. The Manager – Nuclear Supply Chain is responsible for administering, coordinating, planning, and operation of warehousing and procurement of materials in support of DCPP and ISFSI operations and construction, as well as for contract services. This position is responsible for the functions within the materials procurement group including: the procurement specialist group, warehousing operations, administrative coordination of warehouse quality control receipt inspection activities, and materials coordination.

The SENIOR MANAGER - GEOSCIENCES is responsible to the Director, Technical Services for providing geo-scientific studies; reports, and calculations (including geology, seismology, vibration ground motion studies, surface faulting, stability of subsurface materials, and slope stability) in support of DCPP and the ISFSI.

The following committees function at the managerial level within PG&E to provide review of DCPP and ISFSI design, maintenance, and operation activities.

THE NUCLEAR SAFETY OVERSIGHT COMMITTEE, which reports to the Senior Vice President - Chief Nuclear Officer, implements the Independent Review and is described in Section 17.2.3.

The mission of the NSOC is to provide an integral part of the DCPP oversight process by independently assessing the nuclear safety and performance of the station and advising the Senior Vice President - Chief Nuclear Officer on issues that could affect station performance and/or nuclear safety. The scope includes facility operations, the adequacy and implementation of all DCPP nuclear safety policies and programs, and any issues related to nuclear, radiological, industrial, and environmental safety. Based on this assessment, the NSOC will provide comments and/or recommendations to the Senior Vice President - Chief Nuclear Officer that are directed at ensuring overall excellence in Operations and overall station performance.

THE DCPP PLANT STAFF REVIEW COMMITTEE reports to the Senior Vice President - Chief Nuclear Officer and is responsible to advise the Station Director on matters related to nuclear safety. The Committee is responsible for providing timely and continuing monitoring of operating activities to assist the Station Director in keeping aware of general DCPP and ISFSI conditions and to verify that day-to-day operating activities are conducted safely and in accordance with applicable administrative controls. The Committee performs periodic reviews of DCPP and ISFSI operations and to plan future activities. In addition, the PSRC performs special reviews, investigations

or analyses, and screens subjects of special concern. PSRC functions, responsibilities, and meeting requirements are described in Section 17.2.

Administrative procedures or charters for the above committees or programs provide detailed responsibilities and functions, as well as membership, authority, and reporting requirements. The reporting relationships of the committee are identified in the organization chart on Figure 17.1-2.

Verification of conformance to established requirements (except designs) is accomplished by individuals or groups within QV who do not have direct responsibility for performing the work being verified or by individuals or groups trained and qualified in QA concepts and practices and independent of the organization responsible for performing the task. The persons and organizations performing QA and quality control functions have direct access to management levels that assure the ability to: (a) identify quality problems; (b) initiate, recommend, or provide solutions through designated channels; and (c) verify implementation of solutions. They are sufficiently free from direct pressures for cost and schedule and have the responsibility to stop unsatisfactory work and control further processing, delivery, or installation of nonconforming material. (The organizational positions with stop work authority are identified in the implementing procedures.) QV reviews and documents concurrence with all procedures and instructions that define methods for implementing the QA Program.

Each organization that supports DCPP and the ISFSI documents and maintains current a written description of its internal organization. This documentation describes the business unit or department's structure, levels of authority, lines of communication, and assignments of responsibility. Such documentation takes the form of organization charts supported by written job descriptions or other narrative material in sufficient detail that the duties and authority of each individual whose work affects quality is clear. Interfaces between organizations are described in administrative procedures or other documents controlled in accordance with the appropriate requirements of FSAR Update, Section 17.6.

The individuals assigned to the positions having a particular responsibility in program directives and administrative procedures (as described above) are the only individuals who are authorized to perform these activities. However, circumstances may arise where it is considered either necessary or desirable to have such activities, or some portion of them, actually performed by someone else. In such cases, the assigning organization retains responsibility and shall verify that the procedures and instructions to be followed in performing the work are adequate for controlling the work and meet applicable requirements. In such circumstances, the detailed procedures and instructions to be followed in performing the work are reviewed and approved by the person assigned responsibility for the work prior to the commencement of work. The purpose of such review and approval is to verify that such procedures and instructions reflect an acceptable method of performing the work and are in compliance with the requirements of the QA Program. All instances in which authority is to be delegated or support services are to be provided are documented.

Suppliers to DCPP and the ISFSI are required to conform to the PG&E QA Program or to their own program approved by PG&E. Supplier QA Programs are required to comply with the applicable portions of both 10 CFR 50, Appendix B, and 10 CFR 72, Subpart G, and the applicable regulatory documents and industry standards identified in Table 17.1-1. The quality program is defined in the contract or similar procurement document. Suppliers to PG&E are required to document their internal organizational arrangements to the extent necessary for PG&E to assure the supplier is capable of effectively managing, directing, and executing the requirements of the procurement documents. The authority and responsibility of persons and organizations who perform activities that might affect the quality of the procured items or services shall be clearly established. The Suppliers' organizational structure, levels of authority, and functional assignments of responsibility shall be such that:

(1) The QA function of formally verifying conformance to the technical and quality requirements of the procurement documents is accomplished by qualified personnel who are independent of those who performed or directly supervised the work.

(2) Personnel who perform QA functions have sufficient authority and organizational freedom to identify quality problems; to initiate, recommend, or provide solutions; to verify implementation of those solutions; and to control further processing of the items or services until proper dispositioning has occurred.

17.2 QUALITY ASSURANCE PROGRAM

17.2.1 PROGRAM APPLICABILITY

The quality of the:

- safety-related aspects of the design, construction, and operation of DCPP, and

- important-to-safety aspects related to the design, fabrication, construction, testing, operation, maintenance, modification, and decommissioning of the Diablo Canyon ISFSI structures, systems, and components (SSCs)

shall be assured through the QA Program prescribed herein, quality-related program directives, and administrative procedures. The QA Program requirements, as a minimum, apply to those DCPP SSCs classified as Design Class I in Section 3.2 of the FSAR Update. The QA Program requirements apply to Diablo Canyon ISFSI SSCs classified as important to safety in their respective ISFSI FSAR Update, Section 4.5. The applicable QA criteria are executed to an extent that is commensurate with the importance to safety.

The QA Program also applies to the following:

(1) DCPP design, construction, and operation of SSCs that prevent or mitigate the consequences of postulated accidents that could cause undue risk to the health and safety of the public. The SSCs that serve these functions are classified as Design Class I. In addition, certain QA Program requirements apply to the nonsafety-related programs discussed below to provide additional assurance that these objectives are satisfied.

(2) The design, construction, and operation of those portions of DCPP SSCs whose function is not required as above but whose failure could reduce the functioning of the above DCPP features to an unacceptable level or could incapacitate control room occupants. Certain of these SSCs are conservatively designated as Design Class I. Other nonsafety-related SSCs with seismic qualification requirements are subject to the seismic configuration control program listed below. Seismically Induced System Interaction Program requirements are governed by quality-related procedures.

(3) Activities affecting the above DCPP features.

(4) Geo-scientific studies performed by Geosciences. The Geosciences organization maintains QA Program administrative controls independent from DCPP. These administrative controls are specific to the

Geosciences organization, are reviewed and approved by the Director, QV, and comply with the requirements listed in DCPP FSAR Update, Chapter 17.

(5) Technical investigations, tests, analyses, examinations, calibration services performed at Applied Technology Services (ATS) in support of nuclear generation. This includes responsibility for the Nuclear Weld Control Manual. The ATS organization maintains QA Program administrative controls independent from DCPP. These administrative controls are specific to the ATS organization, are reviewed and approved by the Director, QV, and comply with the requirements listed in DCPP FSAR Update, Chapter 17

(6) Managerial and administrative controls to ensure safe operation of the ISFSI, both prior to issuance of a license and throughout the life of the licensed activity.

(7) Activities that provide confidence that ISFSI SSCs will perform satisfactorily in service, including activities that determine that physical characteristics and quality of materials or components adhere to predetermined requirements.

In addition, the QA Program includes requirements that apply to the following DCPP and ISFSI nonsafety-related programs:

Program	DCPP	ISFSI
(1) Fire Protection	X	
(2) Emergency Preparedness	X	X
(3) Security	X	X
(4) Radiation Protection	X	X
(5) Radiological Monitoring and Controls Program	X	
(6) ISFSI Radiological Environmental Monitoring		X
(7) Environmental Monitoring	X	
(8) Radioactive Waste Management	X	X
(9) Fitness for Duty	X	
(10) Regulatory Guide 1.97, Category 2 and 3 Instrumentation	X	

Program	DCPP	ISFSI
(11) Seismic Configuration Control	X	
(12) Anticipated Transient Without Scram Mitigation System Actuation Circuitry (AMSAC) Equipment	X	
(13) Diverse and Flexible Coping Strategy (FLEX) Equipment	X	

17.2.2 PROGRAM CONTROL

The status and adequacy of this QA Program shall be regularly monitored, and it shall be revised as necessary to improve its effectiveness or to reflect changing conditions.

The Director - Quality Verification (QV), is responsible for the preparation, issue, interpretation, and control of this QA Program, and for concurring with changes to quality-related program directives and administrative procedures that propose a change to the QA Program as it is described in a commitment to a regulatory agency. The Director - QV, is responsible to assure the requirements set forth in this QA Program, quality-related program directives, and administrative procedures are in compliance with current regulatory requirements and PG&E commitments to the NRC as shown in Table 17.1-1. Proposed changes to program directives are also approved by the Senior Vice President - Chief Nuclear Officer.

The QA Program documents, including any changes, supplements, or appendices, are issued and maintained as controlled documents. Changes to the QA Program as described herein that do not reduce commitments shall be included in the periodic updates required by 10 CFR 50.71. Proposed changes to this QA Program that reduce commitments are reviewed and concurred with in writing by the Director - QV, and are approved by the Senior Vice President - Chief Nuclear Officer, or his designee, prior to being submitted to and approved by the NRC in accordance with 10 CFR 50.54 prior to issue for use.

Implementation of the QA Program is accomplished through separately issued procedures, instructions, and drawings. Each vice president, director, and manager is responsible for the establishment and implementation of detailed procedures and instructions prescribing the activities for which he is responsible. Such documents are derived from the requirements and reflect the responsibilities specified in the QA Program. Activities affecting quality are accomplished in accordance with these instructions, procedures, and drawings. All personnel are instructed that compliance with those requirements, and the requirements of the QA Program, is mandatory.

Questions or disputes involving interpretations of QA Program requirements, or of the commitments and requirements upon which it is based, are referred to the Director -

QV, for resolution. Questions or disputes involving the responsibilities defined in this chapter and program directives are referred to the Senior Vice President - Chief Nuclear Officer. Questions or disputes involving other quality matters are resolved by referring the matter in a timely manner to successively higher levels of management until, if necessary, the matter reaches that level which has direct authority over all contesting parties.

Personnel who perform functions addressed by the QA Program are responsible for the quality of their work. They are indoctrinated, trained, and appropriately qualified to assure that they have achieved and maintained suitable proficiency to perform those functions. Qualifications of such personnel are in accordance with applicable codes, standards, and regulatory requirements.

The Director - QV, or his designated representative, regularly reports to the Senior Vice President - Chief Nuclear Officer, responsible company management, and NSOC on the effectiveness of the QA Program as it relates to DCPP and ISFSI design, maintenance, and operation of DCPP and the ISFSI. Such reports are based on the results of audits, reviews, inspections, tests, and other observations of activities as prescribed by the QA Program.

Annually, the Director - QV, shall report to the Senior Vice President - Chief Nuclear Officer, on the effectiveness of the QA Program and results of the Audit Program. The report shall include an evaluation of compliance with current regulatory requirements and commitments to the NRC.

17.2.3 INDEPENDENT REVIEW AND AUDIT PROGRAM

The QA Program includes an independent review, implemented by NSOC. This function provides an independent review of DCPP and ISFSI changes, tests, and procedures, which constitute a change to the DCPP facility or ISFSI as described in the DCPP FSAR Update or ISFSI FSAR Update. In addition, the independent review function will verify that reportable events are investigated in a timely manner and corrected in a manner that reduces the probability of recurrence of such events; and detect trends that may not appear to a day-to-day observer.

The individuals assigned responsibility for independent reviews shall be qualified in specific disciplines. These individuals shall collectively have the experience and competence required to review activities in the following areas:

(1) DCPP and ISFSI operations

(2) Nuclear engineering

(3) Chemistry and radiochemistry

(4) Metallurgy

(5) Nondestructive testing

(6) Instrument and control

(7) Radiological safety

(8) Mechanical and electrical engineering

(9) Administrative controls

(10) Quality assurance practices

(11) Other appropriate fields

NSOC shall report to and advise the Senior Vice President - Chief Nuclear Officer, on those areas of responsibility specified in the sections below.

Composition – Membership shall include a chairman and a minimum of four members, of whom no more than a minority are members of the onsite operating organization. The NSOC Chair shall have a minimum of 6 years of professional level managerial experience in the power field and NSOC members shall have a minimum of 5 years of professional level experience in the power field.

The NSOC Chair and all members shall have qualifications that meet or exceed the requirements and recommendations of Section 4.7 of ANSI/ANS 3.1 1978.

An individual may possess competence in more than one specialty area.

Consultants: Consultants shall be used as determined by the NSOC Chair to provide expert advice to NSOC.

Meeting Frequency: NSOC shall meet at least twice a year.

Quorum: A quorum of NSOC is necessary for the performance of the NSOC function required by the QA Program. A quorum shall be a majority (one-half or more) of the members, but no less than four (including the Chair). No more than a minority of the quorum shall have line responsibility for operation of the plant.

Review: NSOC shall review:

(1) The evaluations for: (a) changes to procedures, equipment, or systems, and (b) tests or experiments completed under the provision of 10 CFR 50.59 or 10 CFR 72.48, to verify that such actions did not require prior NRC approval

(2) Proposed changes to procedures, equipment, or systems, that require prior NRC approval as defined in 10 CFR 50.59 or 10 CFR 72.48

(3) Proposed tests or experiments that require prior NRC approval as defined in 10 CFR 50.59 or 10 CFR 72.48

(4) Proposed changes to Diablo Canyon Power Plant's Technical Specifications or Operating License

(5) Proposed changes to the ISFSI Technical Specifications or licenses

(6) Violations of codes, regulations, orders, Technical Specifications, license requirements, or of internal procedures or instructions having nuclear safety significance

(7) Significant operating abnormalities or deviations from normal and expected performance of DCPP and ISFSI equipment that affect nuclear safety

(8) All reportable events

(9) All recognized indications of an unanticipated deficiency in some aspect of DCPP design or operation of safety-related SSCs that could affect nuclear safety

(10) All recognized indications of an unanticipated deficiency in some aspect of ISFSI design or operation of important-to-safety SSCs that could affect nuclear safety

(11) Meeting minutes of the PSRC.

(12) Any other matter involving safe operation of DCPP or ISFSI.

NSOC may delegate reviews of selected topics such as changes processed under 10 CFR 50.59 and 10 CFR 72.48 to specialists or subgroups. NSOC shall review summaries of delegated activities.

Records - A report documenting the scope and conclusions of each NSOC meeting shall be prepared, approved, and forwarded to the Senior Vice President - Chief Nuclear Officer.

The QA Program also includes an audit function implemented by Quality Verification. (See FSAR Update Section 17.18 for audit frequencies.) Distribution of Audit Reports shall include responsible management of both the audited and auditing organizations. The audit report shall be approved within thirty days after the post audit conference.

17.2.4 PLANT STAFF REVIEW COMMITTEE

A PSRC has been established for DCPP and the ISFSI. The committee satisfies applicable requirements of ANSI N18.7, 1976, and its activities are controlled as described below:

PSRC Function - The PSRC shall function to advise the Station Director on all matters related to nuclear safety.

Composition - The PSRC shall be composed of a minimum of 8 senior management individuals, including the chairman. PSRC membership shall include one or more individuals knowledgeable in the following areas: operations, maintenance, radiation protection, engineering, and performance improvement. The PSRC Chairman and regular PSRC members shall be appointed in writing by the Station Director. The qualifications of each PSRC member shall meet or exceed the requirements and recommendations of Section 4.7 of ANSI/ANS 3.1-1978. To maintain quality assurance and independent review independence, the Director - QV, shall not be a member of the PSRC, however, PSRC meeting notifications and review material shall be provided to the Director - QV.

Alternates - The Station Director shall designate in writing other regular members who may serve as the Acting Chairman of PSRC meetings. All alternates to regular members shall be appointed in writing by the Station Director. Alternates may be designated for specific PSRC members and shall have expertise and qualifications in the same general area as the regular PSRC member they represent. No more than two alternates shall participate as voting members in PSRC activities at any one time.

Meeting Frequency - The PSRC shall meet at least once per calendar month and as convened by the PSRC Chairman or his designated alternate.

Quorum - The minimum quorum of the PSRC necessary for performance of the PSRC responsibility and authority provisions of this QA Program shall be a majority (more than one-half) of the members of the PSRC. For purposes of the quorum, this majority shall include the Chairman or the acting chairman, and no more than two alternate members.

The PSRC shall be responsible for:

(1) Reviewing the documents listed below to verify that proposed actions do not require prior NRC approval or require a change to the Technical Specifications and recommending approval or disapproval in writing to the appropriate approval authority

  (a) Evaluations of proposed procedures and procedure changes completed under the provisions of 10 CFR 50.59 or 10 CFR 72.48

(b) Evaluations of proposed tests or experiments completed under the provisions of 10 CFR 50.59 or 10 CFR 72.48

(c) Evaluations of proposed changes or modifications to plant structures, systems, or equipment completed under the provisions of 10 CFR 50.59 or 10 CFR 72.48

(d) Evaluations of proposed changes to the following plans and programs completed under the provisions of 10 CFR 50.59, 10 CFR 72.48, or other applicable regulations:

1. Security Plan
2. Emergency Plan
3. Process Control Program
4. Fire Protection Program

(2) Reviewing all proposed changes to the DCPP Technical Specifications and ISFSI Technical Specifications and advising the Station Director on their acceptability

(3) Investigating all violations of the DCPP Technical Specifications and the applicable ISFSI Technical Specifications including the preparation and forwarding of reports covering evaluation and recommendations to prevent recurrence to the Senior Vice President - Chief Nuclear Officer. The assessment shall include an assessment of the safety significance of each violation

(4) Reviewing all reportable events in order to advise the Station Director on the acceptability of proposed corrective actions, and forwarding of reports covering evaluation and recommendations to prevent recurrence to the Senior Vice President - Chief Nuclear Officer

(5) Reviewing significant DCPP and ISFSI operating experience or events that may indicate the existence of a nuclear safety hazard, and advising the Station Director on an appropriate course of action

(6) Reviewing the Security Plan and implementing procedures and submitting results and recommended changes to the Station Director

(7) Reviewing the Emergency Plan and implementing procedures and submitting results and recommended changes to the Station Director

(8) Reviewing any accidental, unplanned, or uncontrolled radioactive release including the preparation and forwarding of reports covering evaluation, recommendations, and disposition of the corrective action to prevent recurrence to the Senior Vice President - Chief Nuclear Officer

(9) Recommending in writing to the appropriate approval authority, approval or disapproval of the items considered under paragraphs (1) and (2), above

(10) Rendering determinations in writing with regard to whether each item considered under paragraphs (1) through (4), above, require prior NRC approval

(11) Providing written notification within 24 hours to the Senior Vice President - Chief Nuclear Officer, of disagreement between the PSRC and the Station Director; however, the Station Director shall have responsibility for resolution of such disagreements

(12) Reviewing, prior to approval, new procedures used to handle heavy loads in exclusion areas and changes directly related to methods and routes used to handle heavy loads in exclusion areas.

Records - The PSRC shall maintain written minutes of each PSRC meeting that, at a minimum, document the results of all PSRC activities performed under the responsibility and authority provisions of this QA Program section. Copies shall be provided to the Senior Vice President - Chief Nuclear Officer, and to NSOC.

17.3 DESIGN CONTROL

Design activities shall be performed in an orderly, planned, and controlled manner directed to achieving the DCPP and independent spent fuel storage installation (ISFSI) design that best serves the needs of PG&E and its customers without posing an undue risk to the health and safety of the public.

Design activities shall be controlled to assure that design, technical, and quality requirements are correctly translated into design documents and that changes to design and design documents are properly controlled. Design control procedures shall address responsibilities for all phases of design including:

(1) Responsibilities

(2) Interface control

(3) Design input

(4) Design performance

(5) Design verification

(6) Design change

Systematic methods shall be established and documented for communicating needed design information across the external and internal design interfaces, including changes to the design information, as work progresses. The interfaces between the DCPP engineering organization and other organizations, either internal or external to PG&E, performing work affecting quality of design shall be identified and documented. This identification shall include those organizations providing criteria, designs, specifications, technical direction, and technical information and shall be in sufficient detail to cover each structure, system, or component (SSC) and the corresponding design activity.

Provisions for design input shall define the technical objectives for SSCs being designed or analyzed. For the SSC being designed, or for the design services being provided (for example, design verification), design input requirements shall be determined, documented, reviewed, approved, and controlled.

Required design analyses (such as physics, stress, thermal, hydraulic, and accident analysis; material compatibility; accessibility for inservice inspection, maintenance, and repair; and ALARA considerations) shall be performed in a planned, controlled, and correct manner. PG&E procedures shall identify the review and approval responsibilities for design analyses.

The preparation and control of design documents (such as specifications, drawings, reports, and installation procedures) shall be performed in a manner to assure design inputs are correctly translated into design documents (for example, a documented check to verify the dimensional accuracy and completeness of design drawings and specifications).

PG&E shall provide for reviewing, confirming, or substantiating the design to assure that the design meets the specified design inputs. Design verification shall be performed by competent individuals or groups other than those who performed the original design, but who may be from the same department. Individuals performing the verification shall not:

(1) Have immediate supervisory responsibility for the individual performing the design. In exceptional circumstances, the designer's immediate supervisor can perform the verification provided:

   (a) The supervisor is the only technically qualified individual

   (b) The need is individually documented and approved in advance by the supervisor's management

   (c) Quality assurance audits cover frequency and effectiveness of use of supervisors as design verifiers to guard against abuse

(2) Have specified a singular design approach

(3) Have ruled out certain design considerations

(4) Have established the design inputs for the particular design aspect being verified

The results of the design verification efforts shall be documented with the identification of the verifier clearly provided. Design verification methods may include, but not be limited to, the following: design reviews, use of alternate calculations, and qualification testing. The design verification shall be identified and documented. The design verification shall be completed prior to relying upon the component system or structure to perform its function. Procedures shall assure that verified computer codes are certified for use and that their applicability is specified.

Proposed changes or modifications to ISFSI or DCPP systems or equipment that affect nuclear safety shall be designed by a qualified individual or organization, and reviewed by a qualified individual/group other than the individual/group who prepared the change or modification, but who may be from the same organization. These reviews shall include a determination as to whether additional cross-discipline reviews are necessary. If deemed necessary, they shall be performed by review personnel of the appropriate discipline(s). These reviews shall also determine whether an evaluation per 10 CFR 50.59 or

10 CFR 72.48 is necessary. If necessary, one shall be prepared and presented to the PSRC for review prior to approval.

Each DCPP and ISFSI change or modification shall be approved by the Station Director or his designee, as specified in administrative procedures, prior to implementation.

Procedures for implementing design changes, including field changes, shall assure that the impact of the change is carefully considered, required actions documented, and information concerning the change transmitted to all affected persons and organizations. These changes shall be subjected to design control measures commensurate with those applied to the original design. Design changes shall be reviewed and approved by the same organization or group that was responsible for the original design.

Document control measures shall be established for design documents that reflect the commitments of the DCPP FSAR Update and the ISFSI FSAR Update. These design documents shall include, but are not limited to, specifications, calculations, computer programs, system descriptions, the DCPP FSAR Update and ISFSI FSAR Update when used as a design document, and drawings including flow diagrams, piping and instrument diagrams, control logic diagrams, electrical single line diagrams, structural drawings for major facilities, site arrangements, and equipment locations.

Nonconforming activities such as procedure violations, deviations, or errors and deficiencies in approved design documents, including design methods (such as computer codes), shall be controlled as described in Sections 17.15 and 17.16.

17.4 PROCUREMENT DOCUMENT CONTROL

The procurement documents shall include those requirements necessary to assure that the items and services to be provided will be of the desired quality.

The procurement documents shall also include provisions for the following, as appropriate:

(1) Basic Technical Requirements - These include drawings, specifications, codes, and industrial standards with applicable revision data; test and inspection requirements; and special instructions and requirements, such as for designing, fabricating, cleaning, erecting, packaging, handling, shipping, and, if applicable, extended storage in the field.

(2) Quality Assurance Requirements - These include the requirements for the supplier to have an acceptable QA Program; provisions for access to the supplier's facilities and records for source inspection and audit when the need for such inspection and audit has been determined; and provisions for extending applicable QA Program and other requirements of procurement documents to subcontractors and suppliers, including PG&E's access to facilities and records.

(3) Documentation Requirements - These shall include records to be prepared, maintained, submitted or made available for review and instructions on record retention and disposition.

The procedures that implement procurement document control shall describe the organizational responsibilities for procurement planning; preparation, review, approval and control of procurement documents; supplier selection; bid evaluations; and review and evaluation of supplier QA Programs prior to initiation of activities affected by the program.

Procedures shall be established to review the adequacy of technical and quality assurance requirements stated in procurement documents; determine that requirements are correctly stated, inspectable, and controllable; assure adequate acceptance and rejection criteria; and provide for the preparation, review, and approval of procurement documents in accordance with QA Program requirements. The review and documented concurrence of the adequacy of quality assurance requirements stated in procurement documents shall be performed by independent personnel trained and qualified in applicable QA practices and concepts.

Changes to procurement documents shall be subject to the same control as the original document.

17.5 INSTRUCTIONS, PROCEDURES, AND DRAWINGS

Activities affecting quality shall be prescribed by and accomplished in accordance with documented procedures, instructions, and drawings.

The vice president in charge of each PG&E organizational unit that performs activities affecting quality is responsible for the establishment and implementation of instructions, procedures, or drawings prescribing such activities. Standard guidelines for the format, content, and review and approval processes shall be established and set forth in a procedure or instruction issued by that organizational unit.

The method of performing activities affecting quality shall be prescribed in documented instructions, procedures, or drawings of a type appropriate to the circumstances. This may include shop drawings, process specifications, job descriptions, planning sheets, travelers, QA manuals, checklists, or any other written or pictorial form provided that the activity is described in sufficient detail such that competent personnel could be expected to satisfactorily perform the work functions without direct supervision.

Within the constraints, limitations, or other conditions as may be imposed by the specific DCPP Technical Specifications and other license requirements or commitments, procedures prescribing a preplanned method of conducting the following aspects of DCPP operations shall be established in accordance with the applicable regulations, codes, standards, and specifications: preoperational tests, systems operations, general DCPP activities, startup, shutdown, power operations and load changing, process monitoring, fuel handling, maintenance, modifications, radiation control, calibrations and tests, chemical-radiochemical control, abnormal or alarm conditions, emergency plan, tests and inspections, emergencies, and significant events.

Within the constraints, limitations, or other conditions as may be imposed by the independent spent fuel storage installation (ISFSI) Technical Specifications and other license requirements or commitments, procedures prescribing a preplanned method of conducting the activities and programs specified shall be established in accordance with the applicable regulations, codes, standards, and specifications.

In addition to the above, DCPP and ISFSI procedures and programs shall be established and controlled as described below.

(1) Written procedures shall be established, implemented, and maintained covering the activities referenced in the ISFSI Technical Specifications.

(2) Written procedures shall be established, implemented, and maintained covering the activities referenced in Specification 5.4.1 of the Diablo Canyon Power Plant's Technical Specifications.

(3) Each procedure of paragraphs (1) and (2) above, and changes thereto, and all proposed tests or experiments that affect nuclear safety shall be

reviewed and approved prior to implementation in accordance with the review and approval requirements below. Each procedure of paragraphs (1) and (2) above, as modified by Table 17.1-1, shall also be reviewed periodically as set forth in administrative procedures.

These procedure review and approval requirements apply when approving DCPP and ISFSI programs and procedures, or changes to DCPP and ISFSI programs and procedures. They also apply when approving or changing corporate procedures and procedures used by support organizations if they could have an immediate effect on DCPP and ISFSI operations or the operational status of safety-related structures, systems, or components (SSCs) or ISFSI SSCs that are important to safety. They do not apply to editorial or typographical changes.

(4) Each procedure or program required by paragraphs (1) and (2) above, and other procedures, tests, and experiments that affect nuclear safety or the treatment of radwaste, and changes thereto, shall be prepared by a qualified individual/group. Each procedure, program, test, or experiment, and changes thereto, shall be reviewed by an individual/group other than the individual/group who prepared the proposed document or change, but who may be from the same organization as the individual/group who prepared it, and shall be approved, prior to implementation, by the Station Director or his designee, as identified in administrative procedures.

(5) A responsible organization shall be assigned for each program or procedure required by paragraphs (1) and (2) above. The responsible organization shall assign reviews of proposed procedures, programs, and changes to qualified personnel of the appropriate discipline(s).

(6) Individuals responsible for the above reviews shall be knowledgeable in the document's subject area, shall meet or exceed the qualification requirements of Section 4.7.2 of ANSI/ANS 3.1-1978, and shall be designated as qualified reviewers by the Station Director or his designee for DCPP and ISFSI procedures.

(7) The reviews specified in paragraph (3) above shall include a determination as to whether additional cross-discipline reviews are necessary. If deemed necessary, they shall be performed by review personnel of the appropriate discipline(s).

(8) The reviews specified in paragraph (3) above shall also determine whether an evaluation per 10 CFR 50.59 or 10 CFR 72.48 is necessary. If necessary, one shall be prepared and presented to the PSRC for review prior to approval.

(9) Temporary changes to procedures of paragraph (1) above may be made provided:

(a) The intent of the original procedure is not altered

(b) Administrative controls for approval and timely notification or training of personnel affected by the temporary change shall be implemented.

(c) The change is documented, reviewed as described above, and approved by the appropriate approval authority within 14 days of implementation.

(10) Temporary changes to procedures of paragraph (2) above may be made provided:

(a) The intent of the original procedure is not altered

(b) The change is approved by at least two exempt staff members who meet applicable qualification requirements of ANSI/ANS 3.1, 1978, and are knowledgeable in the subject area of the procedure. For changes to procedures listed below, at least one approver shall hold a Senior Reactor Operators license. (Refer to the second exception for Regulatory Guide 1.33 in Table 17.1-1.)

1. All Operations Section procedures

2. Surveillance Test Procedures

3. Emergency Plan Implementing Procedures

4. Any other procedure if the proposed change affects equipment or system operating status

If the approving Senior Reactor Operator is not the Shift Foreman of the affected unit, that individual shall determine whether the Shift Foreman should be notified of the change immediately, and shall notify him/her if appropriate.

(c) The change is documented, reviewed as described above, and approved by the appropriate approval authority within 14 days of implementation.

17.6 DOCUMENT CONTROL

Documents and changes to documents that prescribe or verify activities affecting quality shall be controlled in a manner that precludes the use of inappropriate or outdated documents. As a minimum, controlled documents include: design documents, including documents related to computer codes; procurement documents; instructions and procedures for such activities as fabrication, construction, modification, installation, test, operation, maintenance, and inspection; as-built documents; quality assurance and quality control manuals and quality-affecting procedures; DCPP FSAR Update; Diablo Canyon Independent Spent Fuel Storage Installation FSAR Update; and nonconformance reports.

The organization responsible for establishing instructions, procedures, drawings, or other documents prescribing activities affecting quality is also responsible to develop and implement systematic methods for the control of such documents in accordance with the requirements herein. In those instances where such documents directly involve organizational interfaces, that organization with ultimate responsibility for the issuance of the documents is responsible for establishing the methods for their control.

Procedures and instructions shall assure that documents, including changes, are prepared; reviewed by a qualified individual other than the person who generated the document; approved for release by authorized personnel; distributed to the location where the activity is performed prior to commencing work; and used in performing the activity. Procedures and instructions shall require the development of as-built drawings and the removal or appropriate identification of obsolete or superseded documents.

Procedures and instructions that define methods for implementing the QA Program requirements shall be reviewed and concurred with by quality verification (QV), for compliance and alignment with the Program. Revisions to these documents shall also be reviewed and concurred with by QV if they propose a change to the QA Program as it is described in a commitment to a regulatory agency.

The controls shall identify those responsible for preparing, reviewing, approving, and issuing documents to be used. They shall also define the coordination and control of interfacing documents and shall require the establishment of current and updated distribution lists.

A document control system shall be established to identify the current revision of instructions, procedures, specifications, drawings, and procurement documents. Master lists, when utilized as an element of the document control system, shall be updated and distributed to predetermined responsible personnel.

17.7 CONTROL OF PURCHASED MATERIAL, EQUIPMENT, AND SERVICES

Supplier activities in providing purchased material, equipment, and services shall be monitored as planned and necessary to assure such items and services meet procurement document requirements.

Procedures shall describe each organization's responsibilities for the control of purchased material, equipment, and services, including the interfaces between all affected organizations.

All materials, equipment, and services shall meet the specified technical and quality requirements. Verification that a supplier can meet the specified technical and quality requirements shall be by one or a combination of the following:

(1) Evaluation of the supplier's history

(2) Evaluation of current supplier quality records

(3) Evaluation of the supplier's facilities, personnel, and implementation of a QA Program

Such evaluations shall be documented. Suppliers whose QA Programs have been found by quality verification (QV), to satisfy specified quality requirements shall be listed on the PG&E Qualified Suppliers List, which is controlled by QV.

Suppliers of commercial grade calibration services may be qualified based on their accreditation by a nationally-recognized accrediting body, as an alternative to qualification by supplier audit, commercial grade survey, or in-process surveillance.

A documented review of the suppliers' accreditation by the purchaser may be used as the qualification method, as described in PG&E commitments to NRC Regulatory Guides 1.123 and 1.144, which are documented in Table 17.1-1. This review shall include, at a minimum, all of the following:

(1) The accreditation is to ANSI/ISO/IEC 17025

(2) The accrediting body is either the National Voluntary Laboratory Accreditation Program (NVLAP) or an accrediting body recognized by NVLAP through a Mutual Recognition Agreement (MRA).

(3) The published scope of accreditation for the calibration laboratory covers the needed measurement parameters, ranges, and uncertainties.

A quality verification plan shall be established and documented that applies to each procurement and identifies the manner by which PG&E intends (with appropriate QV organization involvement) to assure the quality of the material, equipment, or service as

defined in the procurement documents and to accept those items or services from the supplier.

The quality verification plan shall identify inspection, audit, and/or surveillance activities to be performed including the characteristics or processes to be witnessed, inspected, or verified; the method of surveillance; and the extent of documentation required. The timing and sequence of the activities shall be planned to identify any system or product deficiencies before subsequent activities may preclude their disclosure.

The plan shall also be based on consideration of:

(1) Importance to DCPP and independent spent fuel storage installation safety

(2) Complexity of inspectable characteristics

(3) Uniqueness of the item or service

Supplier performance and compliance with procurement documents may be monitored by either source verification, receiving inspection, or a combination of the two. Source verification activities may consist of inspections, audits, surveillance, or a combination thereof and are conducted at the supplier's facility. When source verification activities are specified in the quality verification plan, the timing and sequence of these activities are to be delineated.

Receiving inspection activities, as required by the quality verification plan, shall be coordinated with source verification activities performed prior to shipments. If sampling is performed, it shall be in accordance with procedures and/or recognized standards. Receipt inspection shall include a review which verifies that supplier quality records required by procurement documents are acceptable and that items are properly identified and traceable to appropriate documentation.

Records of quality verification activities shall be traceable to the materials, equipment, or services to which they apply. Documentation of acceptance in accordance with the procurement quality verification plan shall be available at the site prior to installation or acceptance for use. Documentary evidence that procurement document requirements have been met shall clearly reflect each requirement. Supplier's Certificates of Conformance are periodically evaluated by audits and independent inspections or tests to assure they are valid and the results documented.

When spare or replacement parts are procured, supplier selection and quality verification activities shall be planned and implemented to verify compliance with requirements meeting or exceeding those of the original.

17.8 IDENTIFICATION AND CONTROL OF MATERIALS, PARTS, AND COMPONENTS

Materials, parts, and components shall be identified and controlled in a manner to preclude the use of incorrect or defective items.

All materials, parts, and components, including partially fabricated subassemblies, batches, lots, and consumables, shall be identified in a manner that each can be related to its applicable drawing, specification, or other technical documentation at any stage from initial receipt through fabrication, installation, repair, or modification. Controls and implementing procedures shall ensure that only correct and accepted items are used during all stages and describe the responsibilities of the involved organizations.

Physical identification of items shall be used whenever possible and practical. Controls may, however, be through physical separation, procedure, or other appropriate means. Identification may be either on the item or on records traceable to the item.

Identification marking, where employed, shall be clear, unambiguous, and indelible and its application shall not impair the function of the identified item or any other item. When an item is subdivided, the identifying marking shall be transferred to each resulting part. Markings shall not be rendered illegible by treatment, process, assembly, installation, or coating unless other means of identification and determining acceptability are provided.

Verification activities, such as inspection, shall be performed to ensure that the provisions of this policy and related implementing procedures are followed for items prior to release for fabrication, assembly, shipping, installation, and use.

When required by code, standard, or specification, traceability of materials, parts, or components to specific inspection or test records shall be provided for and verified.

17.9 SPECIAL PROCESSES

Special processes shall be controlled and performed by qualified personnel using qualified procedures or instructions in accordance with applicable codes, standards, specifications, criteria, or other special requirements.

A special process is an activity in which the quality of the result is highly dependent upon either process variables or the skill and performance of the person doing the work, and the specified quality is difficult to verify by inspection and test after the process is completed.

Special processes include, but are not limited to:

(1) Welding

(2) Heat treating

(3) Nondestructive examination

(4) Chemical cleaning

(5) Others as specified in design and procurement documents (examples are certain protective coating applications and concrete batch plant operations, which are controlled by specifications on a case-by-case basis)

The implementing instructions shall contain the criteria for assuring proper process control and shall be qualified and controlled to assure compliance with applicable codes, standards, QA procedures, and design specifications. Substantiating records of qualifications and controls shall be maintained.

17.10 INSPECTION

A comprehensive program of inspection of items and activities affecting quality shall be conducted to verify conformance with established requirements. Procedures shall describe the organizational responsibilities necessary to carry out the inspection program.

The objective of the inspection program shall be to verify the quality of the items and activities and conformance to the applicable documented instructions, procedures, and drawings for accomplishing activities affecting quality. The inspection program, including information relative to individual inspections to be performed, shall be developed based on a review of the design drawings, specifications, and other controlled documents which prescribe items and activities affecting quality. Inspections shall be performed utilizing appropriate inspection procedures and instructions together with the necessary drawings, specifications, and other controlled documents. The inspections shall be documented and evaluated.

Inspection procedures, instructions, or checklists shall provide for the following: identification of characteristics and activities to be inspected; a description of the method of inspection; identification of the individuals or groups responsible for performing the inspection operation; acceptance and rejection criteria; identification of required procedures, drawings, and specifications and revisions; recording the name of the inspector or data recorder and the results of the inspection operation; and specifying necessary measuring and test equipment including accuracy requirements. The inspection program shall include, but not be limited to, those inspections required by applicable codes, standards, specifications, and DCPP and Independent Spent Fuel Storage Installation (ISFSI) Technical Specifications. The inspection program shall also require the following during the operational phase of DCPP:

(1) Inspection of modifications, repairs, and replacements, where required to assure a suitable level of confidence that an item will perform its intended function, shall verify conformance to the original design requirements or appropriately approved equivalents

(2) Verification of the cleanness of those portions of plant safety-related systems that have been subject to potential contamination during maintenance and modification activities through an inspection performed immediately prior to closure of the portion of the system

The inspection program shall require inspection of ISFSI modifications, repairs, and replacements to be in accordance with existing design requirements.

The inspection program shall require inspection and/or test of items for each work operation where such is necessary to assure quality. If inspection of processed items is impossible or disadvantageous, indirect control by monitoring of process shall be required. Both inspection and process monitoring shall be required when control is

inadequate without both. Both inspection and process control shall be performed when required by applicable code, standard, or specification.

Mandatory quality control inspection hold points shall be identified in the inspection program. When required, the specific hold points shall be indicated in the drawings, procedures, or instructions that prescribe the work activity. Work shall not proceed beyond such hold points without the documented consent of Quality Verification.

When the inspection program permits or requires a sample of a large group of items that are amenable to statistical analysis, the sampling procedures to be used shall be based on recognized standard practices.

Inspections to verify the quality of work shall be performed by qualified individuals other than those who performed or directly supervised the activity being inspected. During the inspection, such persons shall not report directly to the immediate supervisors who are responsible for the work being inspected.

Personnel performing inspections shall be qualified in accordance with applicable regulations, codes, standards, and specifications.

Inspection records shall contain the following where applicable: a description of the type of observation, the date and results of the inspection, information related to conditions adverse to quality, inspector or data recorder identification, evidence as to the acceptability of the results, and action taken to resolve any discrepancies noted.

17.11 TEST CONTROL

A program of testing shall be conducted as necessary to demonstrate that structures, systems, and components will perform satisfactorily in service. This program shall ensure that the necessary testing is identified and performed at the appropriate time in accordance with written test procedures that incorporate or reference the requirements and acceptance limits contained in the applicable design documents.

The program shall cover all required tests, including tests prior to installation, preoperational tests, and operational tests.

The procedures that implement testing shall provide for meeting appropriate prerequisites for the test (for example, environmental conditions, specification of instrumentation, and completeness of tested item), sufficient instruction for the performance of the test, specification of any witness or hold points, acceptance and rejection criteria and limits, and the documentation of the test. The procedures shall provide for evaluation and documentation of the test results and data and their acceptability as determined by a qualified person or group.

Test records shall contain the following where applicable: a description of the type of observation, the date and results of the test, information related to conditions adverse to quality, inspector or data recorder identification, evidence as to the acceptability of the results, and action taken to resolve any discrepancies noted.

17.12 CONTROL OF MEASURING AND TEST EQUIPMENT

Organizational responsibilities shall be delineated for establishing, implementing, and assuring the effectiveness of the calibration program for measuring and test equipment (M&TE). This program shall include the generation, review, and documented concurrence of calibration procedures; the calibration of measuring and test equipment; and the maintenance and use of calibration standards.

M&TE, including reference standards, used to determine the acceptability of items or activities shall be strictly maintained within prescribed accuracy limits.

M&TE, including reference standards, shall be of suitable range, type, and accuracy to verify conformance with requirements.

Procedures for control of M&TE shall provide for the identification (labeling, codes, or alternate documented control system), recall, and calibration (including documented precalibration checks) of the M&TE. The calibration procedures shall delineate any necessary environmental controls, limits, or compensations in excess of those which may be inherent to the general program.

The calibrations shall utilize documented valid relationships to nationally recognized standards or accepted values of natural physical constants. Where national standards do not exist, the basis for the calibration shall be documented. Calibration of M&TE shall be against standards that have an accuracy of at least four times the required accuracy of the equipment being calibrated or, when this is not practical, have an accuracy that assures the equipment being calibrated will be within required tolerance and that the basis of acceptance is documented and authorized by responsible management of the PG&E organization performing that activity.

Calibrating standards have greater accuracy than standards being calibrated. Calibrating standards with the same accuracy may be used if it can be shown to be adequate for the requirements and the basis of acceptance is documented and authorized by responsible management.

The calibration intervals, whether calendar- or usage-based, shall be predetermined and documented. Indication of expiration, if feasible, will be displayed on or with the M&TE. Significant environmental or usage restrictions will be indicated on or with the equipment or be factored into the documented system used to control the issuance of the M&TE. Special calibration shall be required whenever the accuracy of the equipment is suspect.

Records shall be maintained to show that established schedules and procedures for the calibration of the M&TE have been followed. M&TE shall be identified and traceable to the calibration test data. Records of the usage of the M&TE shall be maintained to facilitate corrective action in the event of the discovery of a deficiency concerning the calibration or use of M&TE, so that measures may be taken and documented to determine the validity of previous inspections performed and of the acceptability of items inspected or tested since the previous calibration of the deficient M&TE.

17.13 HANDLING, STORAGE, AND SHIPPING

Material and equipment shall be handled, stored, and shipped in accordance with design and procurement requirements in a manner that will prevent damage, deterioration, or loss.

Special coverings, equipment, and protective environments shall be specified and provided where necessary for the protection of particular items from damage or deterioration. When such special protective features are required, their existence shall be verified and monitored as necessary to assure they continue to serve their intended function.

Special handling tools and equipment shall be provided where necessary to ensure items can be handled safely and without damage. Special handling tools and equipment shall be controlled and maintained in a manner such that they will be ready and fit to serve their intended function when needed. Such control shall include periodic inspection and testing to verify that special handling tools and equipment have been properly maintained.

Special attention shall be given to marking and labeling items during packaging, shipment, and storage. Such additional marking or labeling shall be provided as is necessary to ensure that items can be properly maintained and preserved. This shall include indication of the presence of special environments or the need for special control. Provisions shall be described for the storage of chemicals, reagents (including control of shelf life), lubricants, and other consumable materials.

Special handling, preservation, storage, cleaning, packaging, and shipping requirements are established and accomplished by suitably trained individuals in accordance with predetermined work and inspection instructions.

17.14 INSPECTION, TEST, AND OPERATING STATUS

The inspection, test, and/or operating status of material, equipment, and operating systems shall be readily apparent and verifiable.

The procedures used to indicate status shall provide means for assuring that required inspections and tests are performed in the prescribed sequence; acceptability is indicated; and nonconforming items are clearly identified throughout fabrication, installation, test, maintenance, repairs, and modification to prevent inadvertent use or operation. Items accepted and released are identified to indicate their inspection status prior to forwarding them to a controlled storage area or releasing them for installation or further work. Deviations from the prescribed sequence shall be subject to the same level of control as the generation of the original sequence to prevent the bypassing or omission of a required test or inspection.

Identification of status may be by such means as, but not limited to, tags, stamps, markings, labels, or travelers. In some instances, records traceable to the item may be used. The procedures implementing control of inspection, test, and operating status shall clearly delineate authority for the application, change, or removal of a status identifier.

17.15 CONTROL OF NONCONFORMING CONDITIONS

Items and activities that do not conform to requirements shall be controlled in a manner that will prevent their inadvertent use or installation. Technical decisions as to the disposition of each nonconforming condition shall be made by personnel with assigned authority in the relevant disciplines. The control, review, and disposition of nonconforming conditions shall be accomplished and documented in accordance with approved written procedures and instructions.

Nonconforming conditions shall be documented and affected organizations notified of such conditions. Further processing of the nonconforming conditions and other items affected by them shall be controlled in a manner to prevent their inadvertent use or installation pending a decision on their disposition.

The responsibility and authority for the disposition of nonconforming conditions shall be established and set forth in the applicable procedures and instructions for their control. The rework or repair of nonconforming items and the disposition of operational nonconforming conditions shall be accomplished in accordance with written procedures and instructions. Dispositions involving design changes shall be approved by the organization with the authority for design.

The acceptability of rework or repair of materials, parts, components, systems, or structures shall be verified by reinspecting and retesting the item as originally inspected and tested, or by a method that is at least equal to the original inspection or testing method. Reworked and repaired items shall be reinspected in accordance with applicable procedures and instructions. The acceptability of nonconforming items that have been dispositioned "repair" or "accept-as-is" shall be documented. Such documentation shall include a description of the change, waiver, or deviation that has been accepted in order to record the change and, if applicable, denote the as-built condition.

Corrective action for conditions adverse to quality shall be processed in accordance with Section 17.16.

In cases where required documentary evidence that items have passed required inspections and tests is not available, the associated materials or equipment shall be considered nonconforming. Until suitable documentary evidence is available to show that the material or equipment is in conformance, affected systems shall be considered to be inoperable and reliance shall not be placed on such systems to fulfill their intended safety functions.

Nonconforming conditions that require reporting to the NRC shall be reviewed by NSOC. Such review shall include the results of any investigations made and the recommendations resulting from such investigations to preclude or reduce the probability of recurrence of the event or circumstance.

17.16 CORRECTIVE ACTION

Each individual condition adverse to quality shall be identified, controlled, and evaluated, and a disposition shall be determined for the remedial action and corrective action as soon as practicable. These activities shall be performed consistent with Section 17.15, Control of Nonconforming Conditions.

Systematic review and evaluation of all conditions adverse to quality shall be conducted and documented. Conditions adverse to quality shall include, but not be limited to: engineering, design, and drafting errors; equipment failures and malfunctions; abnormal occurrences; deficiencies; deviations; and defective material, equipment, and services.

The review and evaluation shall include identification of quality trends, repetitive occurrences, and significant conditions adverse to quality. The quality trends and other significant review findings shall be analyzed and appropriate corrective action determined. Findings and actual or recommended corrective action shall be reported to management by the responsible organization for review and assessment.

Significant conditions adverse to quality shall be investigated to the extent necessary to assess the root causes and to determine the corrective action required to prevent recurrence of the same or similar conditions. The corrective action required for significant conditions adverse to quality shall be accomplished in a timely manner. Significant conditions adverse to quality, the cause of the condition, and the corrective action taken shall be documented and reported to management.

Significant conditions adverse to quality that are related to DCPP or Independent Spent Fuel Storage Installation (ISFSI) operations or maintenance shall be reported to NSOC. Completion of corrective actions for significant conditions adverse to quality shall be reviewed and verified by personnel having no direct responsibility for either the disposition or the corrective action taken.

Follow-up reviews shall be conducted to verify that the corrective action was properly implemented, performed in a timely manner, and that it was effective in correcting the identified condition.

Significant conditions adverse to quality shall be evaluated for reportability to the NRC in accordance with 10 CFR 21, 10 CFR 50.72, 10 CFR 50.73, 10 CFR 50.9, 10 CFR 72.74, and 10 CFR 72.75, the DCPP and ISFSI Technical Specifications, and other applicable regulations and shall be reported as required.

17.17 QUALITY ASSURANCE RECORDS

Sufficient records shall be maintained to furnish evidence of both the quality of items and activities affecting quality and to meet applicable code, standard, and regulatory requirements. The records include all documents referred to or described in the QA Program or required by implementing procedures such as operating logs, maintenance and modification procedures, related inspection results, and reportable occurrences; and other records required by the DCPP and independent spent fuel storage installation (ISFSI) Technical Specifications and Code of Federal Regulations. In addition to the records of the results of reviews, designs, fabrication, installation, inspections, calibrations, tests, maintenance, surveillances, audits, personnel qualification, special process qualification, and material analyses for PG&E quality-related activities and ISFSI structures, systems, and components that are important to safety, those of vendors, suppliers, subcontractors, and contractors shall also be maintained.

A management control system for the collection, storage, and maintenance of completed quality assurance (QA) records shall be maintained. This records management program shall be designed and implemented to assure that the QA records are complete, readily retrievable when needed, and protected from damage or destruction during storage by fire, flooding, theft, environmental conditions, or other causes.

QA records stored electronically will follow the guidance for electronic records management given in the Nuclear Information and Records Management Association (NIRMA) technical guidelines, TG 11-1998, “Authentication of Records;” TG 15-1998, “Management of Electronic Records;” TG 16-1998, “Software Configuration Management and Quality Assurance;” and TG 21-1998, “Electronic Records Protection and Restoration.” QA records will be stored on electronic media (that is, optical disk, magnetic tape, network array, etc.) meeting the requirements of the NIRMA guidelines. Alternately, records stored on optical disks may meet the requirements of Generic Letter 88-18, “Plant Record Storage on Optical Disk,” dated October 20, 1988. Information Systems will determine the appropriate electronic media. Regardless of the electronic media selected, the process must be capable of producing legible, accurate, and complete records during the required retention period.

Backup copies of in-process electronic media records will be maintained in multiple, physically-independent electronic locations. Backup copies of QA records in electronic media will be maintained in multiple, physically-independent electronic locations until such time as images of these records are created, copied, and verified on two copies of an appropriate electronic storage media. The two copies will then be stored in separate physical locations. File legibility verification will be completed on all QA records stored on electronic media by either visually verifying the file legibility or by electronically verifying exact binary file transfer.

Periodic media inspections to monitor image degradation will be conducted in accordance with the NIRMA guidelines or media manufacturers’ recommendations. These periodic inspections shall be documented.

QA records stored on electronic media will be refreshed or copied on to new media and subsequently verified if the projected lifetime of that media does not exceed the retention period of the records stored on that media. These requirements meet the intent of Generic Letter 88-18.

Detailed records for items or activities shall be specified by instructions, procedures, drawings, or specification or other documents that prescribe the item or activity and shall be generated by the organization responsible for the item or activity including PG&E and non-PG&E organizations. Each department generating QA records is responsible for transmitting those records to the records processing organization for archival purposes.

All records shall be assigned a retention period in conformance with Title 10, Code of Federal Regulations, other applicable codes, standards, and specifications.

17.17.1 DCPP LIFETIME RECORDS

The following records are retained for the duration of the unit Operating License:

(1) Records and drawing changes reflecting unit design modifications made to systems and equipment described in the FSAR Update

(2) Records of new and irradiated fuel inventory, fuel transfers, and assembly burnup histories

(3) Records of radiation exposure for all individuals entering radiation control areas

(4) Records of gaseous and liquid radioactive material released to the environs

(5) Records of transient or operational cycles for those unit components identified in FSAR Update, Table 5.2-4.

(6) Records of reactor tests and experiments

(7) Records of training and qualification for current members of the unit staff

(8) Records of in-service inspection performed pursuant to 10 CFR 50.55a

(9) Records of QA activities required by the FSAR Update, Chapter 17

(10) Records of reviews performed for changes made to procedures or equipment or reviews of tests and experiments pursuant to 10 CFR 50.59

(11) Records of PSRC and NSOC meetings

(12) Records of the Independent Review and Audit Program

(13) Records of analyses required by the Radiological Environmental Monitoring Program (Reg. Guide 4.15).

(14) Records of service lives of all hydraulic and mechanical snubbers required by the FSAR Update including the date at which the service life commences and associated installation and maintenance records

(15) Records of secondary water sampling and water quality

(16) Records of reviews performed for changes made to the Offsite Dose Calculation Manual

(17) Records of reviews performed for changes made to the Process Control Program

17.17.2 DCPP NONPERMANENT RECORDS

The following records are retained for at least five years:

(1) Records and logs of unit operation covering time interval at each power level

(2) Records and logs of principal maintenance activities, inspections, repair, and replacement of principal items of equipment related to nuclear safety

(3) All reportable events

(4) Records of surveillance activities, inspections, and calibrations required by the Technical Specifications

(5) Records of changes made to procedures required by Technical Specification 5.4.1

(6) Records of radioactive shipments

(7) Records of sealed source and fission detector leak tests and results

(8) Records of annual physical inventory of all sealed source material of record

17.17.3 DIABLO CANYON ISFSI RECORDS

Important-to-safety records shall be classified as lifetime or nonpermanent. The following records shall be maintained as required for the Diablo Canyon ISFSI:

(1) Radiation protection program and survey records

(2) Records associated with reporting defects and noncompliance)

(3) Records important to decommissioning

(4) Records of changes to the physical security plan made without prior NRC approval

(5) Records of changes, tests and experiments, and of changes to procedures described in the ISFSI FSAR Update pursuant to 10 CFR 72.48

(6) Records showing receipt, inventory, location, disposal, acquisition, and transfer of spent fuel

(7) A copy of the current inventory of spent fuel in storage at the ISFSI

(8) A copy of the current material control and accounting procedures

(9) Other records required by license conditions or by NRC rules, regulations or orders

(10) Records of the occurrence and severity of important natural phenomena that affect ISFSI design

(11) QA records (including records pertaining to the design, fabrication, erection, testing, maintenance, and use of structures, systems, and components important to safety; and results of reviews, inspections, tests, audits, monitoring of work performance, and material analyses)

(12) A copy of the current physical security plan, plus any superseded portions of the plan

(13) A copy of the current safeguards contingency plan procedures, plus any superseded portions of the procedures

(14) Operating records, including maintenance, alterations or additions made

(15) Records of off-normal occurrences and events

(16) Environmental survey records

(17) Records of employee qualifications and certifications

(18) Record copies of:

- ISFSI FSAR Updates
- Reports of accidental criticality or loss of special nuclear material
- Material status reports
- Nuclear material transfer reports
- Reports of pre-operational test acceptance criteria and results
- Procedures
- Environmental Report
- Emergency Plan

(19) Construction Records; and

(20) Records of events associated with radioactive releases.

Facilities for the temporary or permanent storage of completed QA records shall be established in predetermined locations as necessary to meet the requirements of codes, standards, and regulatory agencies. Such facilities shall be constructed and maintained so as to protect the contents from possible damage or destruction.

17.18 AUDITS

The adequacy and effectiveness of the Quality Assurance (QA) Program shall be continually monitored through a comprehensive system of internal and supplier audits. The audit system implemented by the Quality Verification (QV) organization includes all aspects of the QA Program. The audit system shall:

(1) Verify, through examination and evaluation of objective evidence, that this QA Program has been implemented as required

(2) Identify any deficiencies or nonconformances in this QA Program

(3) Verify the correction of any identified deficiencies or nonconformances

(4) Assess the adequacy and effectiveness of this QA Program

A comprehensive plan for the audit system shall be established and documented. Audit frequencies are determined by a performance-based evaluation plan. This plan uses assessment indicators to identify and schedule audits based on performance results and importance of the activity relative to safety. The plan shall identify the scope of individual audits that are to be performed, the aspects of this QA Program covered by each audit, and the schedule for performing audits. The audit system plan shall be reviewed at least semiannually, and revised as necessary, to assure that coverage and schedule reflect current activities and that audits of DCPP operational phase activities and independent spent fuel storage installation (ISFSI) activities are being accomplished in accordance with applicable requirements. Other associated activities included as part of the audit program are: indoctrination and training programs; the qualification and verification of implementation of QA programs of contractors and suppliers; interface control among the applicant and the principal contractors; audits by contractors and suppliers; corrective action, calibration, and nonconformance control systems; DCPP FSAR Update and ISFSI FSAR Update commitments; and activities associated with computer codes.

Auditors shall be independent of direct responsibility for the performance of the activities that they audit, have experience or training commensurate with the scope and complexity of their audit responsibility, and be qualified in accordance with applicable standards.

Auditing shall be initiated as early in the life of an activity as is practicable and consistent with the schedule for accomplishing the activity. In any case, auditing shall be initiated early enough to assure that this QA Program is effectively implemented throughout each activity. Individual audits shall be regularly scheduled on the basis of the status and importance of the activities, which they address.

For audits, other than those who’s scheduled frequency is mandated by regulation (such as the Safeguards Contingency Plans or the Security Program), a grace period of up to 90 days may be utilized when the urgency of other priorities makes meeting the specified

schedule dates impractical. For audit activities deferred by using a grace period, the next scheduled due date shall be based on the original schedule due date but may not exceed the original due date plus 90 days.

Audit reports shall be prepared, signed by the Audit Team Leader, and issued to responsible management of both the audited and auditing organizations.

Audits are regularly scheduled on a formal audit schedule prepared by QV. The audit schedule is reviewed regularly by the Director - QV, and the schedule is revised as necessary to assure adequate coverage as commensurate with activities and past performance. Audits are performed in accordance with approved audit plans. Such audits may be augmented by other QV assessments and independent inspections. Additional audits may be performed as requested by NSOC, the Senior Vice President - Chief Nuclear Officer, the Site Vice President, or the Director - QV.

The following areas shall be audited at least once per 24 months, or more frequently as performance dictates:

(1) The conformance of DCPP and ISFSI operation to provisions contained within the applicable Technical Specifications and applicable licenses

(2) The performance, training, and qualifications of the entire DCPP and ISFSI staff

(3) The results of actions taken to correct deficiencies occurring in DCPP and ISFSI equipment, structures, systems, or method of operation that affect nuclear safety

(4) The performance of activities required by the QA Program to meet the criteria of Appendix B, 10 CFR 50

(5) The Radiological Environmental Monitoring Program, implementing procedures, and program results

(6) The Offsite Dose Calculation Procedure and its implementing procedures

(7) The Process Control Program and implementing procedures for processing and packaging radioactive wastes

(8) The Nonradiological Environmental Monitoring Program

(9) A representative sample of routine DCPP and ISFSI procedures that are used more frequently than every two years. This audit is to ensure the acceptability of the procedures and to verify that the procedures review and revision program is being implemented effectively.

(10) The performance of activities required to be audited by ANS-3.2/ANSI N18.7-1976, Section 4.5.

(11) Review of design documents and process to ensure compliance with the FSAR Update, Section 17.3 (i.e., use of supervisors as design verifiers). In addition, QV shall sample and review specifications and design drawings to assure that the documents are prepared, reviewed, and approved in accordance with PG&E procedures and that the documents contain the necessary QA requirements, acceptance requirements, and quality documentation requirements.

(12) QV shall audit the departments that qualify personnel and procedures to assure that the process qualification activity, records, and personnel meet the applicable requirements. They shall also audit the organizations implementing special processes to provide assurance that the processes are carried out in accordance with approved procedures by qualified personnel using qualified equipment and that required records are properly maintained.

(13) The performance of activities required by the QA Program for the Radioactive Effluent Controls Program.

(14) The Radiation Protection Program, in accordance with 10 CFR 20.

(15) The Fitness for Duty Program in accordance with 10 CFR 26.41.

(16) Each element of the Physical Security Protection Program in accordance with 10 CFR 73.55(m)(1). However, changes to personnel, procedures, equipment, or facilities that potentially could adversely affect security shall be audited within 12 months of the change.

(17) Each element of the of the Safeguards Contingency Plan in accordance with 10 CFR 73 Appendix C and 10 CFR 50.54(p)(3). However, changes to personnel, procedures, equipment, or facilities that potentially could adversely affect security shall be audited within 12 months of the change.

(18) Review of the Security Training and Qualification Program in accordance with 10 CFR 73 Appendix B Section I.

(19) The Access Authorization Program in accordance with 10 CFR 73.56(n)(1)

(20) The Emergency Preparedness Program in accordance with 10 CFR 50.54(t). However, changes to personnel, procedures, equipment, or facilities that potentially could adversely affect emergency preparedness shall be audited within 12 months of the change.

(21) The Fire Protection and Loss Prevention Program. Each audit shall include the annual, biennial, and triennial topical areas described in NRC Generic Letter 82-21, and shall utilize qualified independent licensee personnel or an outside fire protection consultant. An outside fire protection consultant shall be utilized at least every third year. Performance based scheduling for this audit (at least once per 24 months, or more frequently as performance dictates) is applied under the provision of NRC Administrative Letter 95-06.

The following activities shall be audited at least once per 12 months unless specified otherwise. However, if the audit frequencies required by the governing regulations are changed, audit frequencies shall at least meet the revised minimum requirements.

(1) If a contractor's or vendor's Access Authorization Program is accepted, that contractor's or vendor's Access Authorization Program shall be audited in accordance with 10 CFR 73.56(n)(2) - at least once every 12 months.

(2) FFD services that are provided by contractor/vendor personnel who are offsite or are not under the direct daily supervision or observation of DCPP personnel and HHS-certified laboratories must be audited on a nominal 12-month frequency in accordance with 10 CFR 26.41.

Management of the audited organization shall review the audit report and respond to any quality problem reports, investigate any significant findings to identify their cause and determine the extent of corrective action required, including action to prevent recurrence. They shall schedule such corrective action and also take appropriate action to assure it is accomplished as scheduled. They shall respond to QV regarding each significant finding stating the root cause, immediate action taken, and the corrective action taken or planned to prevent recurrence. Such responses may be documented directly within electronic databases used for the corrective action program.

QV shall review the written responses to all audit findings, evaluate the adequacy of each response, assure that corrective action to prevent recurrence is identified and taken for each significant finding, and confirm that corrective action is accomplished as scheduled.

Audit records shall be generated and retained by QV for all audits.

TABLE 17.1-1

CURRENT REGULATORY REQUIREMENTS AND PG&E COMMITMENTS
PERTAINING TO THE QUALITY ASSURANCE PROGRAM

The Quality Assurance Program for DCPP and Diablo Canyon Independent Spent Fuel Storage Installation (ISFSI) described in Chapter 17 of the FSAR Update, program directives, and administrative procedures complies with the requirements set forth in the Code of Federal Regulations. In addition, it complies with the regulatory documents and industry standards listed below.
Changes to this list are not made without the review and concurrence of the Director - Quality Verification.

Reg. Guides	Date	Standard No.	Rev.	Title/Subject	Exceptions
(S.G.) 28	6/72	ANSI N45.2	1971	Quality Assurance Program Requirements for Nuclear Power Plants	
1.37	3/73	ANSI N45.2.1	1973	Quality Assurance Requirements for Cleaning Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants	Not applicable to the ISFSI.
1.38	5/77	ANSI N45.2.2	1972	Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants	Warehouse personnel will normally visually scrutinize incoming shipments for damage of the types listed in Section 5.2.1, this activity is not necessarily performed prior to unloading. Separate documentation of the shipping damage is not necessary. Release of the transport agent after unloading and the signing for receipt of the shipment provides adequate documentation of completion of the shipping damage inspection. Any damage noted will be documented and dispositioned. Persons performing this visual scrutiny are not considered to be performing an inspection function as defined under Reg. Guide 1.74; therefore they do not require certification as an inspector under Reg. Guide 1.58.

TABLE 17.1-1

Reg. Guides	Date	Standard No.	Rev.	Title/Subject	Exceptions
1.39	9/77	ANSI N45.2.3	1973	Housekeeping Requirements for Water-Cooled Nuclear Power Plants	Housekeeping zones established at the power plants differ from those described in the standard; however, PG&E is in compliance with the intent of the standard.
1.30	8/72	ANSI N45.2.4	1972	Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment	The evaluation of (data sheet) acceptability is indicated on the results and data sheets by the approval signature (paragraph 2.4). No visual examination for contact corrosion is made on breaker and starter contacts unless there is evidence of water damage or condensation. Contact resistance tests are made on breakers rated at 4 kV and above. No contact resistance test is made on lower voltage breakers or starters (paragraph 3[4]). No system test incorporates a noise measurement. If the system under test meets the test criteria, then noise is not a problem (paragraph 6.2.2).
1.94	4/76	ANSI N45.2.5	1974	Quality Assurance Requirements for Installation, Inspection, and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants	Except PG&E will not require manufacturer's certification for material suitability as inferred in ANSI N45.2.5, Sections 3.1 and 3.2 when PG&E procures: (a) material from a supplier that has a QA program that meets the relevant requirements of 10CFR50, Appendix B and the supplier is included ASME Section III (NCA-3800/NCA-4000) or on the PG&E Qualified Suppler List; or (b) material as a “Commercial-Grade” item and dedicates it in accordance with PG&E's Commercial-Grade Dedication Program. Not applicable to the ISFSI.

TABLE 17.1-1

Reg. Guides	Date	Standard No.	Rev.	Title/Subject	Exceptions
1.29	9/78	--	--	Seismic Design Classification	
1.58	9/80	ANSI N45.2.6	1978	Qualification of Nuclear Power Plant Inspection, Examination and Testing Personnel	ANSI N45. 2. 6 applies to individuals conducting independent QC inspections, examinations, and tests. ANSI/ ANS 3.1-1978 applies to personnel conducting inspections and tests of items or activities for which they are responsible (e.g., plant surveillance tests, maintenance tests, etc.). Except that inspector/examiner reevaluation due dates may be extended a maximum of 90 days. The next reevaluation due date shall be based on the original scheduled due date but shall not exceed the original due date plus 90 days. NDE personnel shall be qualified and certified in accordance with CP-189-1995. ISI ultrasonic examiners shall meet the additional requirements of ASME Section XI, Appendix VIII, 2001 Edition with no Addenda.
1.116	5/77	ANSI N45.2.8	1975	Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems	

TABLE 17.1-1

Reg. Guides	Date	Standard No.	Rev.	Title/Subject	Exceptions
1.88	10/76	ANSI N45.2.9	1974	Collection, Storage, and Maintenance of Nuclear Power Plant Quality Assurance Records	Except PG&E will comply with the 2-hour rating of Section 5.6 of ANSI N45.2.9 issued July 15, 1979. Except PG&E will also meet the intent of the guidelines for the storage of QA records in electronic media as, endorsed by Generic Letter 88-18, “Plant Record Storage on Optical Disks,” issued October 20, 1988, and Regulatory Issues Summary 2000-18, “Guidance on Managing Quality Assurance Records in Electronic Media,” issued October 23, 2000. Note: PG&E will maintain records of spent fuel and high-level radioactive waste in storage in accordance with ANSI N 45.2.9-1974 rather than 10 CFR 72.72(d). Refer to ISFSI FSAR Update, Section 9.4.2.
1.74	2/74	ANSI N45.2.10	1973	Quality Assurance Terms and Definitions	
1.64	6/76	ANSI N45.2.11	1974	Quality Assurance Requirements for the Design of Nuclear Power Plants	Except PG&E will allow the designer's immediate supervisor to perform design verification in exceptional circumstances and with the controls as described in NUREG-0800, Revision 2, July 1981.

TABLE 17.1-1

Reg. Guides	Date	Standard No.	Rev.	Title/Subject	Exceptions
1.144	1/79	ANSI N45.2.12	1977	Auditing of Quality Assurance Programs for Nuclear Power Plants	Except the scheduled date for triennial vendor audits and annual supplier evaluations may be extended a maximum of 90 days. The next scheduled due date shall be based on the original scheduled due date but shall not exceed the original due date plus 90 days. Except that the corrective action program stipulated in the QA Program may be used instead of the requirements of Section 4.5.1 as long as the appropriate time limits are applied to significant conditions adverse to quality. Also, no additional documentation is necessary if needed corrective actions are taken and verified prior to audit report issuance. See Note for Reg Guide 1.144
1.123	7/77	ANSI N45.2.13	1976	Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants	In addition to ANSI N45.2.13, Section 10.3.3, PG&E will accept items and services which are complex or involve special processes, environmental qualification, or critical characteristics which are difficult to verify upon receipt by suppliers' Certificate of Conformance if and only if the supplier has been evaluated and qualified utilizing Performance Based Supplier Audit techniques. See Note for Reg Guide 1.123

TABLE 17.1-1

Reg. Guides	Date	Standard No.	Rev.	Title/Subject	Exceptions
1.146	8/80	ANSI N45.2.23	1978	Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants	Except that auditor recertification due dates may be extended a maximum of 90 days. The next recertification due date shall be based on the original scheduled due date but shall not exceed the original due date plus 90 days. Except that in lieu of the requirements of 2.3.4 of ANSI N45.2-1978, the prospective lead auditor shall have participated in at least one nuclear quality assurance audit within the year preceding the individual's effective date of qualification.

TABLE 17.1-1

Reg. Guides	Date	Standard No.	Rev.	Title/Subject	Exceptions
1.33	2/78	ANSI N18.7	1976	Quality Assurance Program Requirements (Operation)	Except that PG&E will not perform biennial review of all DCPP and ISFSI procedures, except under the conditions described in note below (See note at end of table). Except for temporary changes to procedures, PG&E will require a review by an individual who holds a Senior Reactor Operators license only if the procedure is one of the types listed in Section 17.5 (10) of this FSAR Update. Furthermore, this individual need not be the supervisor in charge of the shift. Except that audit frequencies specified in Regulatory Guide 1.33, Revision 2, need not be met. Audits shall be performed at the frequencies specified in Section 17.18 of this FSAR Update. Except that audits and reviews of the Emergency Preparedness Program shall be performed in accordance with 10 CFR 50.54(t). Except that a grace period of up to 90 days will be allowed for audit scheduling, except where the schedule is mandated by regulation. The next schedule due date shall be based on the original scheduled date but shall not exceed the original due date plus 90 days.

Reg. Guides	Date	Standard No.	Rev.	Title/Subject	Exceptions
					Except that when purchasing commercial-grade calibration services from certain accredited calibration laboratories, the procurement documents are not required to impose a quality assurance program consistent with ANSI N45.2-1971. Alternative requirements described in FSAR Update, Section 17.7 for Regulatory Guide 1.123 may be implemented in lieu of imposing a quality assurance program consistent with ANSI N45.2-1971.
1.8	2/79	ANSI/ANS 3.1	1978	Personnel Selection and Training	Except that for the Quality Verification Director, the one year of qualifying nuclear power plant experience in the overall implementation of the Quality Assurance program can be obtained outside the Quality Assurance organizations. Except certain personnel are trained and qualified to the Institute of Nuclear Power Operations (INPO) criteria as described in the DCPP FSAR Update Chapter 13. Except that a retraining and replacement training program for the plant staff meet or exceed the requirements and recommendations of Section 5.5 of ANSI N18.1-1971 and 10 CFR Part 55. This exception is based on the NRC letter to PG&E, dated July 19, 1989, issuing License Amendments No. 43 and 42. Except that the Radiation Protection Manager's qualifications shall meet or exceed the qualifications of Regulatory Guide 1.8, Revision 2, April 1987, for the Radiation Protection Manager.

TABLE 17.1-1

Reg. Guides	Date	Standard No.	Rev.	Title/Subject	Exceptions
					Except that the person serving as the manager responsible for the independent review and audit program shall have a minimum of 6 years of professional level managerial experience in the power field. This exception is based on NRC letter to PG&E dated February 6, 1992, issuing Licensing Amendment No. 68/67. Except that the Operations Manager shall meet the requirements of the Technical Specifications. Except that the licensed reactor operators and senior reactor operators shall meet or exceed the minimum qualifications of ANSI/ANS 3.1-1993 as endorsed by Regulatory Guide 1.8, Revision 3, May 2000 with the exceptions clarified in the current revision to the Operator Licensing Examination Standards for Power Reactors, NUREG-1021, Section ES-202. This exception is based on NRC letter to PG&E dated May 26, 2006, issuing License Amendment Nos. 187/189.
4.15	2/79	--	--	Quality Assurance for Radiological Monitoring Programs (Normal Operations) - Effluent Streams and the Environment	Record retention requirements are stated in Chapter 17, Section 17.17. This Regulatory Guide does not apply to the ISFSI.

Reg. Guides	Date	Standard No.	Rev.	Title/Subject	Exceptions
BTP PCSB 9.5-1 Appendix A	5/76	--	--	Guidelines for Fire Protection for Nuclear Power Plants	The fire protection program for DCPP satisfies the requirements of GDC 3 (1967) by complying with the guidelines of Appendix A to NRC Branch Technical Position (BTP) (APCSB) 9.5-1, and with the provisions of 10 CFR 50.48 and Appendix R, Section III.G, J, L, and O, as stipulated by Operating License Condition 2.C(5) and 2.C(4) for Units 1 and 2, respectively. Approved deviations from Appendix A to BTP (APCSB) 9.5-1, and Appendix R sections are identified in Supplement Numbers 8, 9, 13, 23, 27, and 31 to the Safety Evaluation Report. Due to the absence of combustible materials within the ISFSI, other than the fuel in the onsite transporter, and based upon an analysis of a transporter fuel tank fire, it is concluded that a fire protection program is not required for the ISFSI. Thus, this BTP is not applicable.
1.26	2/76	--	--	Quality Group Classifications and Standards for Water, Steam, and Radioactive Waste Containing Components of Nuclear Power Plants	Design and construction of Diablo Canyon Power Plant started in 1965 and most of the work cannot comply with the specific requirements of Regulatory Guide 1.26, February 1976. The intent of the Regulatory Guide has been followed as shown by comparing the Reg. Guide with Table 3.2-2 in the FSAR Update and the Q-List (Reference 8 of Section 3.2). This Regulatory Guide does not apply to the ISFSI.
---	--	NCIG-01	2	Visual Weld Acceptance Criteria for Structural Welding at Nuclear Power Plants	

Reg. Guides	Date	Standard No.	Rev.	Title/Subject	Exceptions
---	--	NCIG-02	2	Sampling Plan for Visual Reinspection of Welds	
---	--	NCIG-03	1	Training Manual for Inspection of Structural Weld at Nuclear Power Plants Using the Acceptance Criteria of NCIG-01	
1.97	05/83	ANSI/ANS 4.5	1980	Instrumentation for Light-Water-Cooled Nuclear Power Plants To Assess Plant And Environs Conditions During And Following An Accident	This Regulatory Guide is not applicable to the ISFSI.

Note for Reg. Guide 1.33:

These controls replace the biennial procedure review requirement found in Section 5.2.15 of ANSI N18.7-1976.

1. All applicable DCPP and ISFSI procedures (shall)* be reviewed following an unusual incident, such as an accident, unexpected transient, significant operator error, or equipment malfunction, and following any modification to a system, as specified by Section 5.2 of ANSI N18.7/ANS 3.2, which is endorsed by Regulatory Guide 1.33.

2. Non-routine procedures (e.g. emergency operating procedures, procedures which implement the emergency plan, and other procedures whose usage may be dictated by an event) (shall)* be reviewed at least every two years and revised as appropriate.

3. Routine DCPP and ISFSI procedures that have not been used for two years (shall)* be reviewed before use to determine if changes are necessary or desirable.

* The word should has been changed to shall denoting a regulatory commitment.

<u>Note for Reg. Guide 1.144:</u>

The following interpretation is added with respect to Regulatory Guide 1.144, Section C.3.b(2):

TABLE 17.1-1

When purchasing commercial-grade calibration services from calibration laboratories accredited by a nationally-recognized body, the accreditation process and accrediting body may be credited with carrying out a portion of the Purchaser's duties of verifying acceptability and effective implementation of the calibration service supplier's quality assurance program.

Nationally-recognized accrediting bodies include the National Voluntary Laboratory Accreditation Program (NVLAP) administered by the National Institute of Standards and Technology (NIST) and other accrediting bodies recognized by NVLAP via a Mutual Recognition Agreement (MRA)

In lieu of performing an audit, accepting an audit by another licensee, or performing a commercial-grade supplier survey, a documented review of the suppliers' accreditation shall be performed by the Purchaser. This review shall include, at a minimum, verification of all the following:

(1) The accreditation is to ANSI/ISO/IEC 17025

(2) The accrediting body is either NVLAP or other Accreditation Bureau (AB) accepted as signatory (full member) to the International Laboratory Accreditation Cooperation (ILAC) through a Mutual Recognition Arrangement (MRA) e.g., American Association for Laboratory Accreditation (A2LA), ACLASS Accreditation Service (ACLASS), Laboratory, Accreditation Bureau (LAB), International Accreditation Service (IAS) or similar.

(3) The published scope of accreditation for the calibration laboratory covers the needed measurement parameters, ranges, and uncertainties.

<u>Note for Reg. Guide 1.123:</u>

The requirements of ANSI N45.2.13, Section 3.2, "Content of the Procurement Documents," Subsection 3.2.3, "Quality Assurance Program Requirements" are accepted with the following exception:

When purchasing commercial-grade services from calibration laboratories accredited by a nationally-recognized accrediting body, the procurement documents are not required to impose a quality assurance program consistent with ANSI N45.2-1971. Nationally-recognized accrediting bodies include the NVLAP administered by the NIST and other accrediting bodies recognized by NVLAP via a MRA. In such cases, accreditation may be accepted in lieu of the Purchaser imposing a QA Program consistent with ANSI N45.2-1971, provided all the following are met:

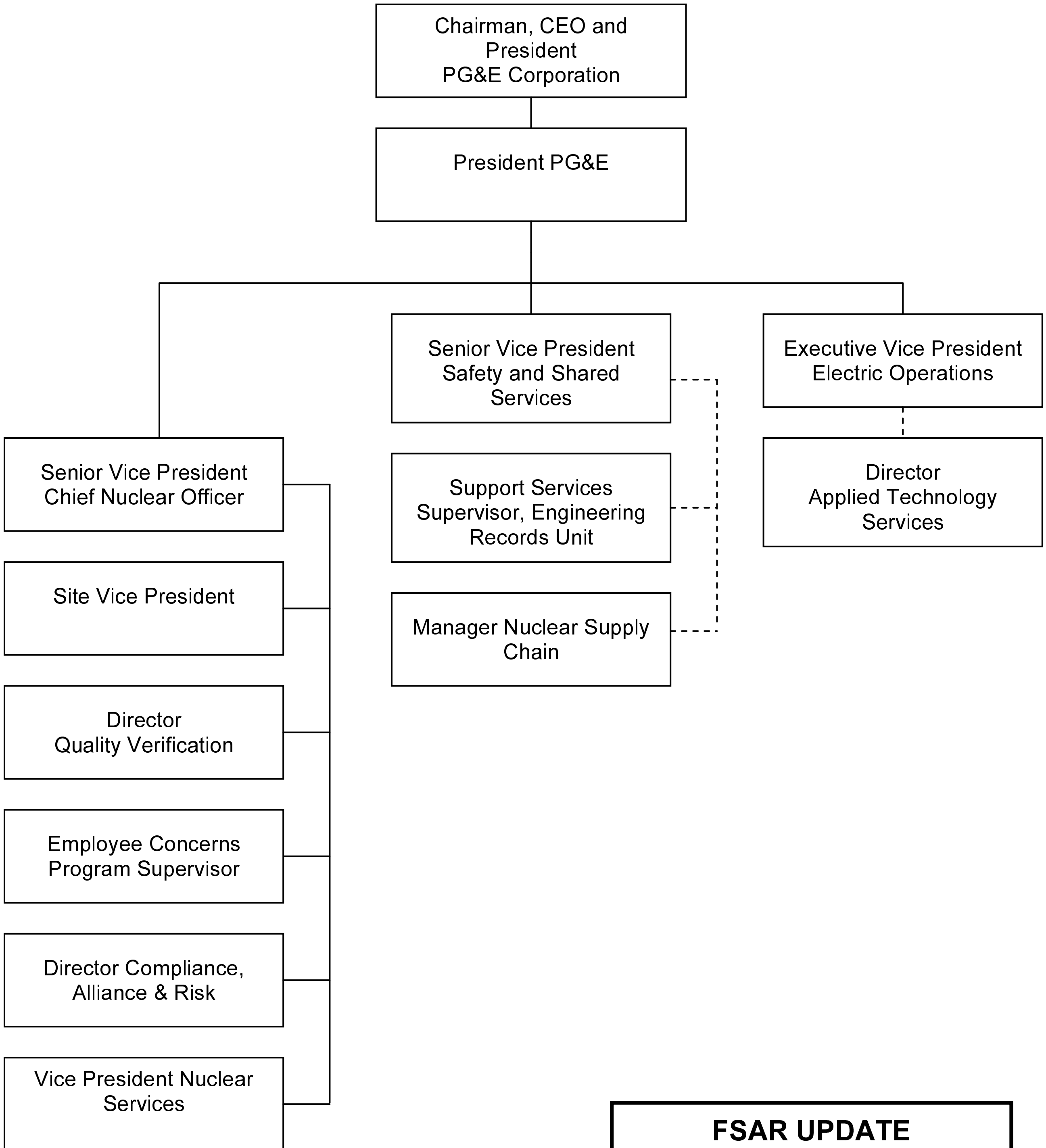
(1) The accreditation is to ANSI/ISO/IEC 17025

(2) The accrediting body is either NVLAP or other Accreditation Bureau (AB) accepted as signatory (full member) to the International Laboratory Accreditation Cooperation (ILAC) through a Mutual Recognition Arrangement (MRA) e.g., American Association for Laboratory Accreditation (A2LA), ACLASS Accreditation Service (ACLASS), Laboratory, Accreditation Bureau (LAB), International Accreditation Service (IAS) or similar.

(3) The published scope of accreditation for the calibration laboratory covers the needed measurement parameters, ranges, and uncertainties.

(4) The purchase documents impose additional technical and administrative requirements, as necessary, to satisfy DCPP QA Program and technical requirements, including the requirement that the calibration/certificate report include identification of the laboratory equipment/standard used.

(5) The purchase documents require reporting as-found calibration data when calibrated items are found to be out-of-tolerance.

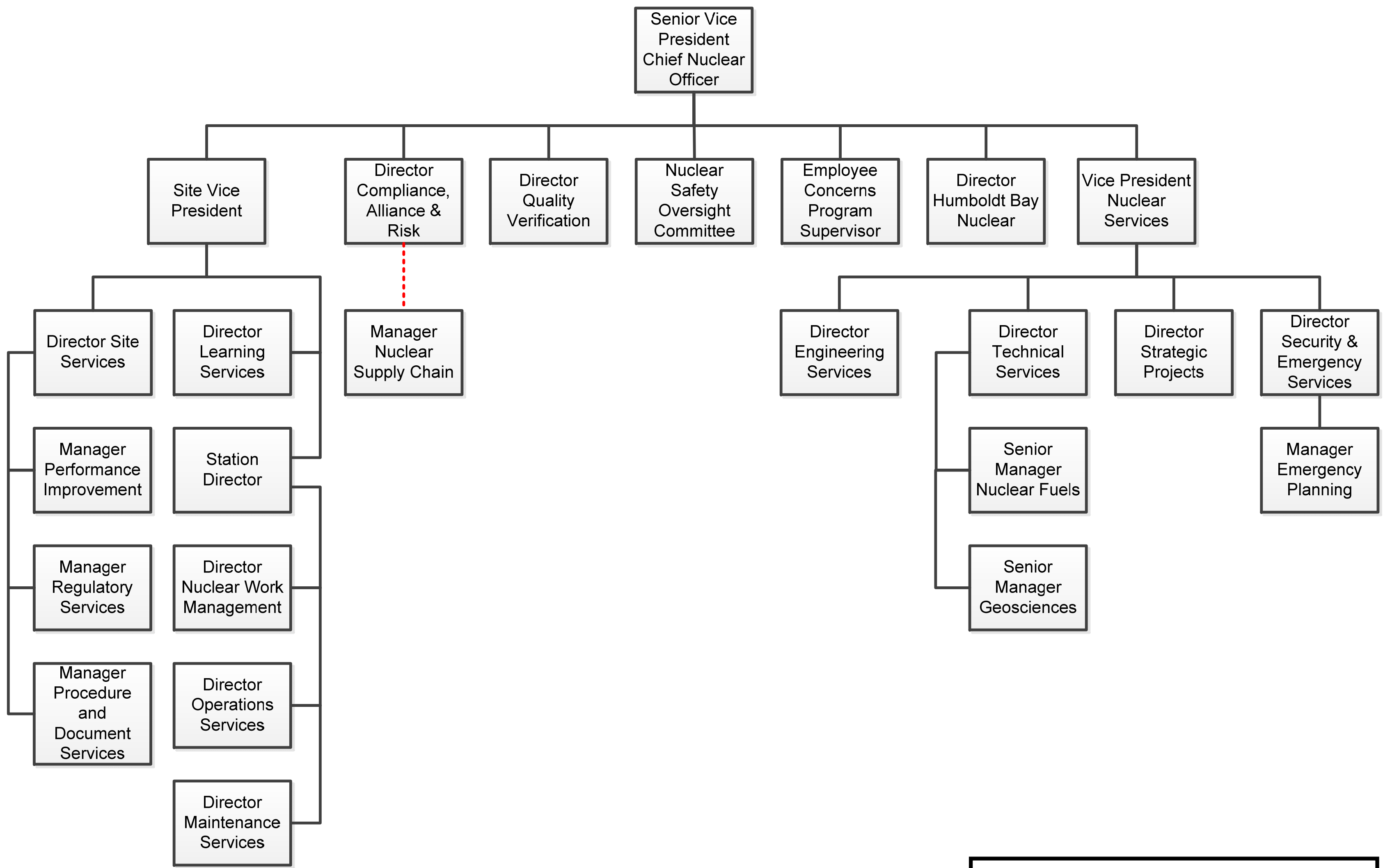


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 17.1-1
PACIFIC GAS AND ELECTRIC COMPANY UTILITY ORGANIZATION

Revision 22 May 2015



FSAR UPDATE

**UNITS 1 AND 2
DIABLO CANYON SITE**

**FIGURE 17.1-2
NUCLEAR QUALITY IN THE UTILITY ORGANIZATION**

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