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December 17, 1985

Mr. Harold R. Denton, Director
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Attention: Mr. B. J. Youngblood, Project Director
PWR Project Directorate No. 4

Re: Catawba Nuclear Station
Docket Nos. 50-413 and 50-414

Dear Sir:

Attached please find a copy of the pages affected by Revision 14 to the Catawba FSAR. This is an advance copy of the Revision and is being submitted at this time to facilitate the NRC's review of the Catawba FSAR to support licensing of Unit 2. This Revision will be submitted as Amendment 36 to the Application for Licenses for the Catawba Nuclear Station in January, 1986. Duke Power Company will also update numerous Flow Diagrams as part of Revision 14 that are not included in this package.

Revision 14 changes to the FSAR are detailed in Enclosure 1.

Very truly yours,

Hal B. Tucker/mrr

Hal B. Tucker

WLH:slb

Attachment

cc: Dr. J. Nelson Grace, Regional Administrator
U. S. Nuclear Regulatory Commission
Region II
101 Marietta Street, NW, Suite 2900
Atlanta, Georgia 30323

Dr. K. N. Jabbour (w/10 copies)
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

NRC Resident Inspector
Catawba Nuclear Station

Table 6.2.1-3	Revised Table for Peak Containment Pressure Analysis ECCS Flow Rates
Table 6.2.1-5	Revised Energy Accounting Table.
6.2.1-14A	Editorial Changes
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Table 6.2.3-1 (page 4)	Technical Clarification
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Figure 6.1.1-1	Revised Figure - Containment Sump pH vs. Time
Figure 6.2.1-5	Revised Figure - Containment Pressure vs. Time.
Figure 6.2.1-6	Revised Figure - System Temperature vs. Time.
Figure 6.2.1-7	Revised Figure - Sump Temperature vs. Time
Figure 6.2.1-8	Revised Figure - Ice Melted vs. Time
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Table 14.2.12-1 (page 16 & 16a)	Revised Test Description
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Table 15.0.6-1	Technical Clarifications
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15.4-14 thru 15.4-14a	Editorial Changes
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15.4-20a thru 15.4-23	Revised Accident Analysis
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Table 15.4.1-1 (page 2)	Revised Accident Analysis Timetable
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Questions

410-10	Revised Response to Reflect Safety Grade PORVs.
440-2 thru 440-11	These Pages Were Deleted
440-24 thru 440-27	Revised Response to Reflect Safety Grade PORVs
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440-40	Technical Clarifications
440-43 thru 440-43a	Typographical Error and Editorial Change
440-51a	Revised Table for Technical Clarifications
440-51b	Revised Response
440-52	Revised Response
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Table Q440.56-4	Revised LOCA Mitigation Description

440-65 thru 440-69	Technical Clarification and Editorial Changes
440-70 thru 440-72a	Revised Analysis Description
440-78 thru 440-78a	Revised Response
Figure Q440.74-1	This Figure Was Deleted
Figure Q440.76-1	This Figure Was Deleted
440-90	Editorial Change
440-92	Editorial Change
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440-95	Typographical Errors and an Editorial Change
440-123 thru 440-124	Revised Response to Reflect Safety Grade PORVs
440-129	Numerical Correction and a Typographical Error
440-132	Revised Response to Reflect Safety Grade PORVs
440-135	Revised Figure Reference and Revised Response & Reflect Safety Grade PORVs
440-139	Editorial Changes
470-5	Editorial Change
480-13	Technical Clarification
490-10	Technical Clarifications Numerical Corrections

Response to TMI Concerns

The design of this system significantly reduces radiation exposures during sample collection under accident conditions.

In addition to the reactor coolant sample line, a containment atmosphere sample line will be routed to a new accident level sampling panel. The containment atmosphere sample will be obtained from the hydrogen analyzer sample lines. Sample line length is minimized and large radius bends are used to minimize plate out and provide an accurate effluent sample.

Procedures for collection and transport of reactor coolant, sump water, and containment air samples under post-accident conditions have been revised to incorporate actions to be taken to minimize radiation exposures. These procedures specify the preplanning to be performed as well as modifications and approvals required prior to sample collection. The post-accident sampling systems will be tested per periodic test procedures to ensure, to a high degree of reliability, that they will be available, if required. Samples can be collected within one hour in all instances where personnel exposure does not exceed 3 rem/qtr whole body and 18 3/4 rem/qtr to the extremities. Post-accident dose assessment for sampling indicates that personnel exposures would be well below GDC-19 criteria.

II.B.4 TRAINING FOR MITIGATING CORE DAMAGE

Duke has modified the Catawba training program in order to place increased emphasis on the operation and significance of any Catawba systems or instrumentation which could be used to monitor and control accidents in which the core may be severely damaged. This additional training identified the vital instrumentation which supplies the operator with needed information in a degraded core situation. The training also identifies alternate methods of obtaining this information as well as specific instruction in the interpretation of instrument readings in degraded core situations.

Operating personnel from the station manager through the operating chain (including the Shift Engineers (STA's) to the licensed operators receive training for mitigating core damage.

II.D.1 RELIEF AND SAFETY VALVE TEST REQUIREMENTS

EPRI PWR Safety and Relief Valve Test Program will be used by Duke to respond to NRC recommendations in NUREG-0737. The Catawba valves covered by the EPRI program are pressurizer safety valves (Dresser type 6-31749A), pressurizer PORV (Control Components, Inc.), and PORV block valves (Rockwell Equiwedge gate valve).

Response to TMI Concerns

All sample selection and switching is accomplished manually by the operator from the local analyzer control panel.

ICSB Q95 | This instrumentation is provided in response to the requirements of Appendix B of NUREG-0737. Further design information is presented in Table 7.5.1-1.

Containment High Range Radiation Monitoring

Two physically and electrically separated radiation monitors are installed inside the containment. Monitor 1EMF53A is located at elevation 580', 0°17', and monitor 1EMF53B is located at elevation 580', 180°17'. These monitors are supplied by General Atomics and will feature GA detector model number RD23. Each monitor utilizes an ionization chamber to measure gamma radiation and will cover the range from 10^0 to 10^8 R/hr. No overlapping of ranges is required. Monitor sensitivity to 62 Kev is $9.8X10^{-12}$ Amps/Rad/hr and the

sensivity to 52 Kev is $9.0X10^{-12}$ Amps/Rad/hr. Seismic qualification and environmental qualification of these monitors are discussed in Sections 3.10 and 3.11, respectively.

One monitor (1EMF53A) is powered from the Train A vital instrument bus, and the other monitor (1EMF53B) is powered from the Train B vital instrument bus. Analog meters (one per train) continuously indicates monitor output in the control room. A continuous strip chart recorder (one train) is also located in the control room.

An electronic calibration of the monitors is performed every refueling outage. In addition a radiation source is used to perform an in-situ calibration of the monitor range below 10 R/hr.

II.F.2 INADEQUATE CORE COOLING INSTRUMENTS

Subcooling Monitor

The margin to saturation is calculated from Reactor Coolant System (RCS) pressure and temperature measurements. When RCS pressure is sufficiently less than 800 psig to ensure the low range pressure sensor is within its measurement span, the low range input is used. The wide range pressure inputs are used for the remaining conditions. The average of the five highest value incore thermocouples (from 40 EQ T/C's) are used to represent core exit conditions. The wide range hot leg RTD's are used to measure the loop hot leg temperatures. The plant computer performs averaging and auctioneering functions and a comparison to adjusted saturation curves (adjusted for possible measurement uncertainties) to compute margins and initiate alarms if appropriate.

The computer output consists of a CRT graphic display which plots plant pressure and temperature in relation to the computer generated adjusted saturation curve. In addition, numerical values are provided for parameters of interest such as pressure, temperatures, and subcooling margins. Program

Response to TMI Concerns

logic variables such as source for pressure value (wide or low range sensor) and containment conditions (normal (<3 psig) or degraded (>3 psig)) are also provided. Alarm status is indicated by messages on the CRT graphic display, the Alarm CRT, and by printout on the Alarm Typer. Alarms are provided at a selected margin from the adjusted saturation curve to warn of the approach to loss of adequate subcooling and again upon reaching the adjusted saturation curve to warn of the loss of adequate subcooling. Further details on this subcooling monitor are provided in Table 1.9-2.

Normal control board instrumentation for RCS temperature and pressure will be used in conjunction with a control room paper copy of the adjusted saturation curves and a written procedure to determine margin to saturation as a backup to the computer calculations.

Reactor Vessel Level Measurement

The reactor vessel level instrumentation system (RVLIS) is of Westinghouse design. The RVLIS is of standard Westinghouse design for upper head injection (UHI) reactor systems and utilizes a microprocessor for data processing. The RVLIS uses differential pressure (DP) transmitters to measure the pressure drops from the bottom of the reactor vessel to the hot legs for UHI plants and from the hot legs to the top of the reactor vessel. Under natural-circulation or no-circulation conditions, these pressure drops will provide indication of the collapsed liquid level or relative void content in the reactor vessel above and below the hot legs. Under forced-flow conditions, the pressure drops will provide indication of the vessel void content above the hot legs and the relative void content of the circulating primary coolant system fluid. Automatic compensation for changes in the temperature of the impulse lines leading from the reactor vessel and hot legs to the DP transmitters is incorporated in the system. Strap-on RTD's are mounted on the vertical runs of the impluse lines for measuring impulse-line temperatures. Automatic compensation for changes in the reactor coolant system fluid densities is also incorporated in the system. Following a hypothetical accident which causes a loss of primary coolant, the RVLIS will be used by the plant operators to assist in detecting a gas bubble or void in the reactor vessel and assist in detecting the approach to a condition of inadequate core cooling. If forced-flow conditions are maintained after the accident, the RVLIS will also be used to assist in detecting the formation of void in the circulating primary coolant system fluid. The equipment which comprises the RVLIS includes the DP transmitters, impulse lines, impluse-line RTD's, in-containment sensor bellows units, out-of-containment hydraulic isolators, and all the necessary electronic signal conditioning, processing and display equipment. A technical description of the system appears in Westinghouse's manual entitled, "RVLIS - Summary Report, December, 1980."

An item-by-item discussion of NUREG-0737, II.F.2, is provided in Table 1.9-3.

Response to TMI Concerns

Westinghouse model was submitted to the NRC in a letter (NS-EPR-2681) dated November 21, 1982, from E. P. Rahe (W) to C. O. Thomas (NRC). NRC accepted the Westinghouse model for referencing on May 21, 1985.

II.K.3.31 PLANT-SPECIFIC CALCULATIONS TO SHOW COMPLIANCE WITH 10 CFR 50.46

See II.K.3.30 above.

III.A.1.1 UPGRADE EMERGENCY PREPAREDNESS

See Section 13.3

III.A.1.2 UPGRADE EMERGENCY SUPPORT FACILITIES

See Section 13.3

III.D.1.1 PRIMARY COOLANT SOURCES OUTSIDE CONTAINMENT

A periodic leak rate test will be written for portions of systems which could carry highly radioactive fluids outside of containment following an accident. Portions of the following systems are included: Refueling Water, Safety Injection, Residual Heat Removal, Containment Spray, Containment Atmosphere Hydrogen Concentration Level Analyzer, Boron Recycle, Nuclear Sampling System, Chemical Volume and Control, Liquid Waste, and Waste Gas. This test, to be performed before startup and during each refueling outage, or at intervals not to exceed the refueling cycle, will be accomplished by pressurizing a system or part of a system and checking non-welded pipe joints, penetrations, flanges, valve separations, packing, and pump packing for leakage. Where possible, pumps included in the leak test boundary will be run so that a more accurate determination of the leak test may be made.

A separate periodic test procedure will be written to assure that excessive leakage is detected on a timely basis. This test will be run at least weekly and will require that systems carrying radioactive fluids outside of containment be visually inspected for excessive leakage. Appropriate corrective action will be taken if excessive leakage is detected.

III.D.3.3 IN-PLANT RADIATION MONITORING

See Section 12.5.3

III.D.3.4 CONTROL ROOM HABITABILITY

See Section 6.4

Table 1.9-2 (Page 1)

Information Provided on the Subcooling Monitor

Display

Information Displayed	Temperatures (Loop & Core) Pressure, Saturation Margins, % Power, Logic Variables (Pressure Sensor & Containment Condition), Alarms
Display Type (Analog, Digital, CRT)	CRT
Continuous or on Demand	DEMAND
Single or Redundant Display	SINGLE
Location of Display	CONTROL ROOM
Alarms (include setpoints)	Approaching Loss of Adequate Subcooling >0% FP 10°F; <0% FP 30°F Loss of Adequate Subcooling 0°F 0°F
Range of Display	PROGRAMMABLE
Qualifications (seismic, environmental, IEEE-279)	N/A

Calculator

Type (process computer, dedicated digital or analog calc.)	HONEYWELL HS4400 PROCESS COMPUTER
If process computer is used, specify availability. (%of time)	99.26% (1979 Average)
Single or redundant calculators	SINGLE
Selection Logic (highest T., lowest press.)	VALID TEMPERATURES VALID PRESSURE
Qualifications (seismic, environmental, IEEE-279)	N/A
Calculational Technique (Steam Tables, Functional Fit, ranges)	Functional Fit (0-700°F, 0-2500 psig)

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Table 1.9-2 (Page 2)

Information Provided on the Subcooling Monitor

Input	
Temperature (RTD's or T/C's)	T/C & RTD
Temperature (number of sensors and locations)	40 IN-CORE T/C; One wide range RTD per loop
Range of temperature sensors	T/C: 0-2300°F RTD: 0-700°F
Uncertainty* of temperature signal	<10.0°F T/C <10.0°F RTD
Qualifications (seismic, environmental, IEEE-279)	RTDs (seismic, environmental) T/Cs (seismic, environmental)
Pressure (specify instrument used)	RCS wide range press. RCS low range press.
Pressure (number of sensors and locations)	3-Reactor Coolant System
Range of Pressure sensors	(1) Low Range 0-800 PSIG (2) Wide Range 0-3000 PSIG
Uncertainty* of pressure signals	Low Range <15 psi (<125 psi)** Wide Range <63 psi (<213 psi)**
Qualifications (seismic, environmental, IEEE-279)	Wide range (seismic, environmental Low range (none)
Backup Capability	
Availability of Temp & Press	INCORE T/C-CONTROL ROOM METER WITH SELECTOR SW, HOT AND COLD LEG TEMP. (RTDs)-CONTROL ROOM RECORDER PRESSURE-CONTROL ROOM METER AND 1 CHANNEL RECORDER
Availability of Steam Tables etc.	Copy available in Control Room
Training of operators	Yes
Procedures	Yes

*Uncertainties must address conditions of forced flow and natural circulation.
**Assumed for saturation curve adjustment for degraded containment conditions (p>3 psig).

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Entire Page
Revised

Table 3.2.1-2 (Page 1)
Summary of Criteria - Equipment

Equipment	Scope	Quality Assurance Required	(Note 3) Category	Code	Location	(Note 2) Rad. Source	Seismic OBE	Seismic SSE	Tornado Wind	Tornado Missile
Cranes										
Containment Polar Crane	D	X	I	As Applicable	C	-	X	X	-	-
Cask Crane	D	X	I	As Applicable	AB	-	X	X	-	-
Cranes (Excluding Reactor Building and Fuel Handling)	D	-	III	As Applicable	-	-	-	-	-	-
Refueling Machine	W	X	I	As Applicable	C	-	X	X	-	-
Fuel Handling Machine	W	X	I	As Applicable	AB	-	X	X	-	-
Tanks										
Recycle Monitor	D	-	III	ASME VIII	AB	P	P	-	-	-
Laundry and Hot Shower	D	-	III	ASME VIII	AB	X	X	-	-	-
Waste Monitor	D	-	III	ASME VIII	AB	P	P	-	-	-
Mixing and Settling	D	-	III	ASME VIII	AB	-	-	-	-	-
Mixing and Settling Reagent	D	-	III	ASME VIII	AB	-	-	-	-	-
Floor Drain	D	-	III	ASME VIII	AB	X	X	-	-	-
Chemical Drain	D	-	III	ASME VIII	AB	X	X	-	-	-
RCP Motor Oil Drain	D	X	II	ASME VIII	C	P	P	X	-	-
Waste Gas Decay	D	X	I	ASME III	AB	X	X	X	-	-
Waste Drain	D	X	I	ASME III	AB	X	X	X	-	-
Waste Evaporator Feed	D	X	II	ASME VIII	AB	X	X	-	-	-
Vent. Unit Cond. Drain	D	X	II	ASME VIII	AB	-	-	-	-	-
Spent Resin Storage	D	X	I	ASME III	AB	X	X	X	-	-
Refueling Water Storage	D	X	I	ASME III	YD	P	P	X	X	-
Reactor Makeup Water Storage	D	-	III	ASME VIII	YD	P	P	-	X	-
Boron Recycle Holdup	D	X	I	ASME III	AB	X	X	X	See Note (4)	See Note (4)
Boric Acid	D	X	I	ASME III	AB	X	X	X	See Note (4)	See Note (4)
Fuel Oil Storage	D	X	I	ASME III	YD	-	-	X	-	-
Component Cooling Surge	D	X	I	ASME III	AB	-	-	X	-	-
Steam Gen. Blowdown	D	-	III	ASME VIII	TB	X	X	-	-	-
Backwash	D	-	III	ASME VIII	TB	-	-	-	-	-
Upper Surge	D	-	III	ASME VIII	TB	-	-	-	-	-
Condensate Storage	D	-	III	ASME VIII	TB	-	-	-	-	-
Upper Surge Dome	D	-	III	ASME VIII	TB	-	-	-	-	-
Evap. Concentrate Holdup	D	-	III	ASME VIII	AB	X	X	-	-	-
Demin. Water Storage	D	-	III	ASME VIII	SB	-	-	-	X	-
Heater Blowoff	D	-	III	ASME VIII	TB	-	-	-	-	-
"C" Heater Drain	D	-	III	ASME VIII	TB	-	-	-	-	-
RCW Storage	D	-	III	ASME VIII	SB	-	-	-	-	-
Turbine Oil Transfer	D	-	III	ASME VIII	TB	-	-	-	-	-
Fire Protection Pressurizer	D	-	III	ASME VIII	SB	-	-	-	-	-
Filtered Water	D	-	III	ASME VIII	SB	-	-	-	X	-
YT Sulfuric Acid	D	-	III	ASME VIII	YD	-	-	-	X	-
Evap. Concentrates Batch	D	-	III	ASME VIII	AB	X	X	-	-	-

Table 3.2.1-2 (Page 2)
Summary of Criteria - Equipment

Equipment	Scope	Quality Assurance Required	(Note 3) Category	Code	Location	(Note 2) Rad. Source	Seismic OBE	Seismic SSE	Tornado Wind	Tornado Missile
Aux. Boiler Blowoff	D	-	III	ASME VIII	SB	-	-	-	-	-
Clean Lube Oil Storage	D	-	III	ASME VIII	YD	-	-	-	-	-
Used Lube Oil Storage	D	-	III	ASME VIII	YD	-	-	-	-	-
Standby Shutdown Diesel Fuel Oil Storage	D	-	III	ASME VIII	YD	-	-	-	-	-
RCP Motor Oil Fill Tank	D	-		ASME VIII	YD	-	-	-	X	-
Ice Cond. Glycol Mixing and Storing	D	-	III	ASME VIII	AB	-	-	-	-	-
Ice Making Sol. Mixing	D	-	III	ASME VIII	AB	-	-	-	-	-
Instrument Air Receivers	D	-	III	ASME VIII	SB	-	-	-	-	-
Station Air Receivers	D	-	III	ASME VIII	SB	-	-	-	-	-
WC Caustic Storage	D	-	III	ASME VIII	CB	-	-	-	-	-
Chemical Addition Supply	D	-	III	ASME VIII	SB	-	-	-	-	-
Drinking Water	D	-	III	ASME VIII	SB	-	-	-	X	-
Make-up Demin. Caustic Storage	D	-	III	ASME VIII	SB	-	-	-	-	-
Vacuum Priming	D	-	III	ASME VIII	SB	-	-	-	-	-
YT Dispersant Storage	D	-	III	Note (5)	CB	-	-	-	-	-
YT Organic Bioxide Storage	D	-	III	Note (5)	CB	-	-	-	-	-
Aux. Boiler Chem. Feed	D	-	III	ASME VIII	SB	-	-	-	-	-
FWP Seal Leakoff	D	-	III	ASME VIII	TB	-	-	-	-	-
M.S. Isolation Valve	D	-	III	ASME VIII	DH	-	-	-	-	-
Radwaste Batching	D	-	III	ASME VIII	AB	X	X	-	-	-
Filtered Water Clearwell	D	-	III	ASME VIII	SB	-	-	-	-	-
Chilled Water System Compression	D	X	I	ASME III	AB	-	-	X	-	-
Aux. Boiler Chem. Feed Tank "B"	D		III	ASME VIII	SB	-	-	-	-	-
Aux Feedwater Cond. Storage	D		III	ASME VIII	SB	-	-	-	X	-
CPD Decant Monitor Tank	D		III	ASME VIII	TB	-	-	-	-	-

Symbols:
AB = Auxiliary Building
C = Containment
D = Duke
TB = Turbine Building
SB = Service Building
YD = Yard
W = Westinghouse
X = Designed For
- = Not Design For
OBE = Operating Basis Earthquake
SSE = Safe Shutdown Earthquake
DH = Dog House
CB = Chemical Building

Notes:
1. Polar crane and cask crane designed for seismic loads in unloaded condition only.
2. X = Source of radiation.
   - = No source of radiation.
   P = Possible source of radiation.
3. Category II and III Structures are not safety related.
4. Located in a Category 1 Structure which has been designed for Tornado Wind and Missiles.
5. ASTM D 3299-74 or NBS Voluntary Product Standard PS 15-69 as applicable.

Table 3.[illegible]2 (Page 5)

Summary of Criteria - Mechanical System Components

System	Component or System	(2) Scope	(3) Safety Class	(4) Code	(5) QA Reqd.	(6) Location	(7) Rad. Source	(8) Seismic OBE	(8) Seismic DBE	(9) Tornado Wind	(9) Tornado Missile
ND	Residual Heat Removal System										
	RHR Pumps	W	2	III-2	X	AB	X	X	X	X	X
	RHR Heat Exchangers (tube)	W	2	III-2	X	AB	X	X	X	X	X
	(shell)	W	3	III-3	X	AB	P	X	X	X	X
	Valves	D	1,2	III-1,2	X	C,AB	X	X	X	X	X
NF	Ice Condenser Refrigeration System										
	Ice Baskets	W	2	(10)	X	C	-	X	X	X	X
	Ice Bed Doors	W	2	(10)	X	C	-	X	X	X	X
	NF Refrigeration Units	W	NA	-	-	AB	-	-	-	X	X
	Ice Machine	W	NA	-	-	AB	-	-	-	X	X
	Air Handling Units	W	NA	(10)	-	C	P	-	-	X	X
	Valves	D	2	III-2	X	C,AB	P	X	X	X	X
	Glycol Strainers	W	NA	-	-	AB	-	-	-	X	X
	Ice Bin & Annex Cond. Units	W	NA	-	-	AB	-	-	-	X	X
	Ice Bin	W	NA	-	-	AB	-	-	-	X	X
	Ice Annex	W	NA	-	-	AB	-	-	-	X	X
	Ice Bin & Annex Air Handlers	W	NA	-	-	AB	-	-	-	X	X
	Ice Blower Package	W	NA	-	-	AB	-	-	-	X	X
	Ice Cond. Cyclone Receiver	W	NA	-	-	C	-	-	-	X	X
	Rotary Valve Assembly	W	NA	-	-	AB	-	-	-	X	X
	NF Floor Cooling Defrost Heater	W	NA	-	-	C	-	-	-	X	X
	NF Slab Cooling	W	NA	B31.1	-	C	-	X	X	X	X
	NF Glycol Bypass Strainer	W	NA	VIII	-	AB	-	-	-	X	X
	Pumps										
	NF Glycol	W	NA	-	-	AB	-	-	-	X	X
	NF Glycol Mixing & Storage	D	NA	VIII	-	AB	-	-	-	X	X
	Ice Making Solution Feed	D	NA	VIII	-	AB	-	-	-	X	X
	NF Floor Cooling	W	NNS	-	-	C	-	-	-	X	X
	Tanks										
	Glycol Mixing & Storage	D	NNS	VIII	-	AB	-	-	-	X	X
	Ice Making Solution Mixing	D	NNS	VIII	-	AB	-	-	-	X	X
	NF Glycol Expansion	W	NNS	VIII	-	C	-	-	-	X	X
NI	Safety Injection System										
	Pumps										
	Safety Injection	W	2	III-2	X	AB	X	X	X	X	X
	UHI Makeup and Testing	D	NNS	-	-	AB	-	-	-	X	X
	Tanks										
	UHI Water Accumulator	W	2	III-2	X	AB	-	X	X	X	X
	UHI Nitrogen Accumulator	W	2	III-2	X	AB	-	X	X	X	X
	UHI Surge	W	2	III-2	X	AB	-	X	X	X	X
	Accumulator	W	2	III-2	X	C	-	X	X	X	X

Table 3.2.2-2 (Page 7)

Summary of Criteria - Mechanical System Components

System	Component or System	(2) Scope	(3) Safety Class	(4) Code	(5) QA Reqd.	(6) Location	(7) Rad. Source	(8) Seismic OBE	(8) Seismic DBE	(9) Tornado Wind	(9) Tornado Missile
	Tanks										
	Volume Control	W	2	III-2	X	AB	X	X	X	X	X
	Boric Acid	D	3	III-3	X	AB	P	X	X	X	X
	Boric Acid Batching	W	NNS	VIII	X	AB	-	-	-	X	X
	Chemical Mixing	W	NNS	VIII	X	AB	-	-	-	X	X
	RCP Seal Standpipe	W	NNS	VIII	-	C	-	-	-	X	X
	Reciprocating Charging Pump Suction Pulsation Dampener	D	2	III-2	X	AB	X	X	X	X	X
	Reciprocating Charging Pump Discharge Pulsation Dampener	D	2	III-2	X	AB	X	X	X	X	X
	Demineralizers										
	Mixed Bed	W	3	III-3	X	AB	X	X	X	X	X
	Cation Bed	W	3	III-3	X	AB	X	X	X	X	X
	Filters										
	Reactor Coolant	W	2	III-2	X	AB	X	X	X	X	X
	Seal Water Return	W	2	III-2	X	AB	X	X	X	X	X
	Seal Water Injection	W	2	III-2	X	AB	X	X	X	X	X
	Boric Acid	W	3	III-2	X	AB	X	X	X	X	X
	Letdown Orifices	W	2	III-2	X	C	X	X	X	X	X
	Boric Acid Blender	W	3	III-3	X	AB	-	X	X	X	X
	Valves	D	1,2,3	III-1,2,3	X	C,AB	X	X	X	X	X
RC	Condenser Circulating Water System										
	Condenser Circulating Water Pumps	D	NA	-	-	O	-	-	-	-	-
	Valves	D	NA	-	-	TB,O	-	-	-	-	-
RF	Interior Fire Protection System										
	Valves (Note 22)	D	2,NNS,NA	III-2, B31.1, N FUL	X	TB,SB,RB,AB	-	-	-	-	-
RL	Conventional Low Pressure Service Water System										
	Pumps	D	NA	-	-	RL	-	-	-	-	-
	Strainer Pit Sump Pumps	D	NA	-	-	RL	-	-	-	-	-
	Strainers	D	NA	-	-	RL	-	-	-	-	-
	Valves	D	NA	-	-	RL,SB	-	-	-	-	-
RN	Nuclear Service Water System										
	NSW Pumps	D	3	III-3	X	RN	-	X	X	X	X
	NSW Strainers	D	3	III-3	X	RN	-	X	X	X	X
	RN Pump Brg. Lube Inj. Strainer	D	3	III-3	X	RN	-	X	X	X	X
	Valves	D	2,3	III-2,3	X	RN,AB,O,C	-	X	X	X	X

Summary of Criteria - Mechanical System Components

System	Component or System	(2) Scope	(3) Safety Class	(4) Code	(5) QA Reqd.	(6) Location	(7) Rad. Source	(8) Seismic OBE	(8) Seismic DBE	(9) Tornado Wind	(9) Tornado Missile
VN	Diesel Generator Engine Air and Exhaust System										
	Intake Filter	D	(18)	(18)	-	DB	-	(18)	X	X	X
	Intake Silencers	D	(18)	(18)	X	DB	-	(18)	X	X	X
	Exhaust Silencers	D	(18)	(18)	X	DB	-	(18)	X	X	X
	Valves	D	3	III-3	X	DB	-	X	X	X	X
VP	Containment Purge and Containment Ventilation System										
	Containment Purge Air Handling Units	D	NNS	-	-	AB	P	-	-	X	X
	Containment Purge Air Exhaust Fans	D	NNS	-	-	AB	P	X	X	X	X
	Containment Purge Air Exhaust Filters	D	NNS	-	-	AB	P	X	X	X	X
	Incore Instr. Room Purge Exhaust Air Handling Unit	D	NNS	-	-	AB	P	X	X	X	X
	Incore Instr. Purge Supply Air Handling Unit	D	NNS	-	-	AB	P	-	-	X	X
	Valves	D	2	III-2	X	AB,C	P	X	X	X	X
VQ	Containment Air Release and Addition System										
	Filters	D	NNS	-	-	AB	P	-	-	X	X
	Valves	D	2	III-2	X	AB,C	P	X	X	X	X
	Fans	D	NA	-	-	AB	P	-	-	X	X
VV	Containment Ventilation System										
	Upper Containment Ventilation Units	D	NNS	-	-	C	P	-	-	X	X
	Upper Containment Return Air Fans	D	NNS	-	-	C	P	-	-	X	X
	CRDM Vent Fans	D	NNS	-	-	C	P	-	-	X	X
	Lower Containment Vent Units	D	NNS	-	-	C	P	-	-	X	X
	Containment Aux. Charcoal Filter Units	D	NNS	-	-	C	P	-	-	X	X
	Containment Aux. Charcoal Filter Unit Fans	D	NNS	-	-	C	P	-	-	X	X
	Incore Instr. Room Ventilation Units	D	NNS	-	-	C	P	-	-	X	X
VX	Containment Air Return and Hydrogen Skimmer System										
	Air Return Fans	D	2	AMCA(12)	X	C	X	X	X	X	X
	Hydrogen Skimmer Fans	D	2	AMCA(14)	X	C	X	X	X	X	X
	Valves	D	2	III-2	X	C	X	X	X	X	X
VY	Containment Hydrogen Sample & Purge System										
	Containment Hydrogen Purge Inlet Blower	D	NNS	(10)		RB	-	-	-	X	X
	Post Accident Elec. Hydrogen Recombiner Pkg.	W	2	(20)	X	C	X	X	X	X	X

Summary of Criteria - Mechanical System Components

System	Component or System	(2) Scope	(3) Safety Class	(4) Code	(5) QA Reqd.	(6) Location	(7) Rad. Source	(8) Seismic OBE	(8) Seismic DBE	(9) Tornado Wind	(9) Tornado Missile
	Laundry and Hot Shower	W	NNS	VIII	-	AB	P	-	-	X	X
	Sump Pump Brg. Lube Inj. Separators	D	3	III-3	X	AB	X	X	X	X	X
	Demineralizers										
	Waste Evap Condensate	W	NNS	VIII	-	AB	X	-	-	X	X
	Waste Monitor Tank	W	NNS	VIII	-	AB	X	-	-	X	X
	Reactor Coolant Drain Tank Heat Exchanger (tube)	W	2	III-2	X	C	X	X	X	X	X
	(shell)	W	3	III-3	X	C	P	X	X	X	X
	Filters										
	Floor Drain Tank	W	NNS	VIII	-	AB	X	-	-	X	X
	Laundry and Hot Shower Carbon	D	NNS	VIII	-	AB	X	-	-	X	X
	Laundry and Hot Shower Primary	W	NNS	VIII	-	AB	X	-	-	X	X
	Laundry and Hot Shower Secondary	D	NNS	VIII	-	AB	X	-	-	X	X
	Waste Evap. Cond.	W	NNS	VIII	-	AB	X	-	-	X	X
	Waste Evap. Feed Filter A	W	NNS	VIII	-	AB	X	-	-	X	X
	Waste Evap. Feed Filter B	D	NNS	VIII	-	AB	X	-	-	X	X
	Waste Monitor Tank	W	NNS	VIII	-	AB	X	-	-	X	X
	Waste Evap. Cond. Return Unit	D	NA	VIII	-	AB	X	-	-	X	X
	Waste Evaporator Pkg.	W	NNS (23)	VIII	-	AB	X	-	-	X	X
	Valves	D	2,3,NNS	III-3, B31.1.0	X	AB	X	X	X	X	X
WN	Diesel Generator Room Sump Pump System										
	Diesel Generator Room Sump Pumps	D	3	III-3	X	DB	-	X	X	X	X
	Valves	D	3,NA	III-3	X,-	AB,DB	-	X	X	X	X
WP	Turbine Building Sump Pump System										
	Valves (Note 22)	D	NNS	B31.1	-	TB	P	-	-	-	-
WS	Solid Radwaste System										
	Tanks										
	Spent Resin Storage Tank	D	3	III-3	X	AB	X	X	X	X	X
	Evaporator Concentrates Holdup	D	NNS	D100	-	AB	X	-	-	X	X
	Evaporator Concentrates Batch	D	NNS	VIII (21)	-	AB	X	-	-	X	X
	Chemical Drain Tank	D	NNS	VIII	X	AB	X	-	-	X	X
	Binder Storage	D	NNS	VIII	-	B	X	-	-	X	X
	Radwaste Batching	D	NNS	VIII	-	AB	X	-	-	X	X
	Pumps										
	Spent Resin Sluice	W	NNS	-	-	AB	X	-	-	X	X
	Chemical Drain Tank	W	NNS	-	-	AB	X	-	-	X	X
	Binder	D	NNS	-	-	O	-	-	-	-	-
	Spent Resin Sluice Filter	W	3	III-3	X	AB	X	X	X	X	X
	Hydraulic Compactor	D	NNS	-	-	AB	P	-	-	X	X
	Valves	D	3	III-3	X	AB	X	X	X	X	X
			NNS	B31.1	X	AB	X	X	X	X	X

3.10 SEISMIC QUALIFICATION OF SEISMIC CATEGORY I INSTRUMENTATION AND ELECTRICAL EQUIPMENT

This section presents information to demonstrate that instrumentation and electrical equipment classified as seismic Category I is capable of performing designed safety-related functions in the event of an earthquake.

Seismic Category I instrumentation and electrical equipment is identified in Tables 3.10-1 and 3.10-2 for Catawba Units 1 and 2, respectively. Electrical equipment that is not designed to seismic Category I criteria and whose structural failure could affect the operation of seismic Category I equipment is located, physically restrained, or structurally designed, such that its postulated structural failure during seismic conditions does not prevent Category I electrical equipment from performing its safety function.

3.10.1 SEISMIC QUALIFICATION CRITERIA

3.10.1.1 Qualification Standards

The methods of meeting the general requirements for seismic qualification of Category I instrumentation and electrical equipment as described by General Design Criteria (GDC) 1, 2, and 23 are described in Section 3.1. The general methods of implementing the requirements of Appendix B to 10 CFR Part 50 are described in Chapter 17.

The seismic Category I instrumentation and electrical equipment and their supports, as listed in Table 3.10-1 are qualified in accordance with the procedures and documentation requirements of IEEE 344-1971. The recommendations of Regulatory Guide 1.100 are not applicable to Catawba based on the implementation date of the guide. However, methods similar to those described in IEEE 344-1975 are used in the qualification of instrumentation and electrical equipment as detailed in Sections 3.10.2.1 and 3.10.2.2.

The seismic acceleration levels used in the seismic qualification tests and analyses are selected to envelope the plant specific levels defined in Section 3.7.

3.10.1.2 Acceptance Criteria

Seismic qualification must demonstrate that Category I instrumentation and electrical equipment is capable of performing designated safety-related functions during and after an earthquake of magnitude up to and including the Safe Shutdown Earthquake (SSE). Any spurious actuation must not result in consequences adverse to safety. The qualification must also demonstrate the structural integrity of mechanical supports and structures at the OBE level. Some permanent mechanical deformation of supports and structures is acceptable at the SSE level provided that the ability to perform the designated safety-related functions is not impaired.

3.10.2 METHODS AND PROCEDURES FOR QUALIFYING INSTRUMENTATION AND ELECTRICAL EQUIPMENT

3.10.2.1 NSSS Equipment

The seismic qualification of safety-related electrical equipment within the NSSS scope of supply is demonstrated by testing, analysis, or a combination of these methods in accordance with IEEE 344-1971. The choice of qualification method employed by Westinghouse for a particular item of equipment is based upon many factors including; practicability, complexity of equipment, economics, and availability of previous seismic qualification. The qualification method employed for a particular item of equipment is identified on Tables 3.10-1 and 3.10-2.

3.10.2.1.1 Seismic Qualification by Type Test

From 1969 to mid-1974 Westinghouse seismic test procedures employed single axis sine beat inputs in accordance with IEEE 344-1971 to seismically qualify equipment. The input form selected by Westinghouse was chosen following an investigation of building responses to seismic events as reported in Reference 1. In addition, Westinghouse has conducted seismic retesting of certain items of equipment as part of the Supplemental Qualification Program (Reference 2). This retesting was performed at the request of the NRC Staff on agreed selected items of equipment employing multi-frequency, multi-axis test inputs (Reference 3) to demonstrate the conservatism of the original sine beat test method with respect to the modified methods of testing for complex equipment recommended by IEEE 344-1975. The original single axis sine beat testing (Reference 4) and the additional retesting completed under the Supplemental Test Program has been the subject of generic review by the NRC Staff.

3.10.2.1.2 Seismic Qualification by Analysis

The structural integrity of safety-related motors is demonstrated by a static seismic analysis in accordance with IEEE 344-1971. Should analysis fail to show the resonant frequency to be significantly greater than 33 HZ, a test is performed to establish the motor resonant frequency. Motor operability during a seismic event is demonstrated by calculating critical deflections, loads and stresses under various combinations of seismic, gravitational and operational loads. The worst case (maximum) calculated values are tabulated against the allowable values. On combining these stresses, the most unfavorable possibilities are considered in the following areas; 1) maximum rotor deflection, 2) maximum shaft stresses, 3) maximum bearing load and shaft slope at the bearings, 4) maximum stresses in the stator core welds, 5) maximum stresses in the stator core to frame welds, 6) maximum stresses in the motor mounting bolts and, 7) maximum stresses in the motor feet.

The analytical models employed and the results of the analysis are described in the qualification reference.

3.10.2.2 Balance of Plant Equipment

The seismic qualification of safety-related electrical equipment within Duke's scope of supply is demonstrated by testing, analysis, or a combination of these methods. When testing is performed, the input excitation normally employed is random, multifrequency biaxial similar to that described in IEEE 344-1975. In the event other input excitations are employed, they are selected in accordance with the requirements of IEEE 344-1971. Satisfactory operation of seismic Category I instrumentation and electrical equipment is verified both during and after testing. When testing is not practical, qualification is by analysis.

When seismic qualification of instrumentation and electrical equipment and supports is verified by testing, the test response spectrum (TRS) envelopes the required response spectrum (RRS) for all frequencies from 1 to 33 HZ. All equipment that is tested is verified to be operational during and after the test.

When seismic qualification of equipment and supports is by analysis, all stresses in critical members are verified to be less than the applicable allowable stresses. Seismically sensitive components located in the analyzed equipment are seismically qualified by testing for the localized motion at the component mounting location.

The method of qualification for each item of equipment is identified in Table 3.10-1, and Table 3.10-2.

3.10.3 METHODS AND PROCEDURES FOR QUALIFYING SUPPORTS OF INSTRUMENTATION AND ELECTRICAL EQUIPMENT

The seismic qualification of the supports for Category I electrical equipment is demonstrated by testing, analysis, or a combination of these methods. The preferred method of qualification for these supports is to test the support with the equipment as described above. When testing is not practical, qualification of supports is by static and/or dynamic analysis depending on the natural frequency of the support. In both testing and analysis procedures, the possible amplified design loads for vendor supplied equipment are considered as follows:

1. The support is tested with the actual components mounted or with the component loads simulated.

2. Analysis of the support includes the component loads.

3.10.4 RESULTS OF TESTS AND ANALYSES

The results of the seismic tests and analyses that ensure the criteria established in Section 3.10.1 have been satisfied, employing the qualification methods described in Section 3.10.1 and 3.10.3, are provided in individual seismic qualification reports. These reports are referenced in Table 3.10-1.

TABLE 3.10-1 (Page 1)

Catawba Unit 1

ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	MODEL	QUALIFICATION METHOD	QUALIFICATION REFERENCE
I. Instrumentation and Control Equipment				
1. Transmitter - Pressurizer Pressure	Barton (NSSS)	763 (Lot 2)	Test	WCAP-9885 (CNM-1399.03-318)
2. Transmitter - Pressurizer Level	Barton (NSSS)	764 (Lot 2)	Test	WCAP-9885 (CNM-1399.03-318)
3. Transmitter - Steam Generator Level (N/R)	Barton (NSSS)	764 (Lot 2)	Test	WCAP-9885 (CNM-1399.03-318)
4. Transmitter - RCS Flow	Veritrak (NSSS)	76	Test	WCAP-8687, Sup. 2, E04B (CNM-1399.03-331)
	Tobar	32 DP	Test	WCAP-8687, Sup. 2, E04C, Rev. 1 (CNM-1299.03-0003)
5. Transmitter - RCS Pressure (W/R)	Barton (NSSS)	764 (Lot 2)	Test	WCAP-9885 (CNM-1399.03-318)
6. Transmitter - Steam Line Pressure	Veritrak (NSSS)	76	Test	WCAP-8687, Sup. 2, E02B (CNM-1399.03-332)
	Tobar	32 DP	Test	WCAP-8687, Sup. 2, E04C, Rev. 1 (CNM-1299.03-0003)
7. Transmitter - Turbine Impulse Pressure	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2 E02B (CNM-1399.03-332)
8. Transmitter - Containment Pressure (N/R)	Barton	386A	Test	Wyle Test Report 43904-2 (MCM-1393.00-0019)

TABLE 3.10-1 (Page 2)

Catawba Unit 1

ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	MODEL	QUALIFICATION METHOD	QUALIFICATION REFERENCE
9. Transmitter - Containment Pressure (W/R)	Rosemount	1153DB6	Test	Wyle Test Report 45353-1 (Appendix IV to Rosemount Qual Report 108026) (CNM-1210.04-262)
10. Transmitter - Pressurizer Level-Low Temp.	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
11. Transmitter - Steam Generator Level (W/R)	Barton	764	Test	Barton Report R3-764-9 (CNM-1210.04-261)
12. Transmitter - Main Feedwater Flow	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
	Tobar	32 DP	Test	WCAP 8687, Sup. 2, E04C, Rev. 1 (CNM-1299.03-0003)
13. Transmitter - Main Steam Flow	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
14. Transmitter - Residual Heat Removal Heat Exchanger Outlet Flow	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
15. Transmitter - Boron Injection Flow	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
16. Transmitter - Safety Injection Pump Discharge Flow	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)

TABLE 3.10-1 (Page 3)

Catawba Unit 1

ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	MODEL	QUALIFICATION METHOD	QUALIFICATION REFERENCE
17. Transmitter - Containment Spray Pump Discharge Flow	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
18. Transmitter - Boric Acid Blender Discharge Flow	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
19. Transmitter - NV Charging Line Flow	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
20. Transmitter - NV Letdown Flow	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
21. Transmitter - RC Pump Seal Water Flow	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
22. Transmitter - RC Pump Seal Leakoff Flow	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
23. Transmitter - Emergency Boration Flow	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
24. Transmitter - Letdown Chill HX Shell Discharge Flow	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
25. Transmitter - Chill Surge Tank Level	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)

TABLE 3.10-1 (Page 4)

Catawba Unit 1

ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	MODEL	QUALIFICATION METHOD	QUALIFICATION REFERENCE
26. Transmitter - Boron Thermal Regen. System Flow Rate	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
27. Transmitter - Residual Heat Removal Loop Return Flow	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
28. Transmitter - Reactor Coolant Drain Tank Pump Discharge Header Flow	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
29. Transmitter - Reactor Coolant Drain Tank Recirculation Flow	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
30. Transmitter - Nuclear Volume Control Tank Vent Pressure	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E02B (CNM-1399.03-332)
31. Transmitter - Nuclear Volume Charging Header Pressure	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E02B (CNM-1399.03-332)
32. Transmitter - Nuclear Volume Excess Letdown HX Outlet Pressure	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E02B (CNM-1399.03-332)

TABLE 3.10-1 (Page 5)

Catawba Unit 1

ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	MODEL	QUALIFICATION METHOD	QUALIFICATION REFERENCE
33. Transmitter - Nuclear Volume Letdown Pressure & Control	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E02B (CNM-1399.03-332)
34. Transmitter - Pressurizer Relief Tank Pressure	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E02B (CNM-1399.03-332)
35. Transmitter - Steam Generator Steam Header Pressure	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E02B (CNM-1399.03-332)
36. Transmitter - Steam Generator Inlet Steam Header Pressure	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E02B (CNM-1399.03-332)
37. Transmitter - Residual Heat Removal Pump Discharge Pressure	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E02B (CNM-1399.03-332)
38. Transmitter - Upper Head Injection Surge Tank Pressure	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E02B (CNM-1399.03-332)
39. Transmitter - Safety Injection Pump Discharge Pressure	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E02B (CNM-1399.03-332)
40. Transmitter - Boron Injection Tank Pressure	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E02B (CNM-1399.03-332)

TABLE 3.10-1 (Page 6)

Catawba Unit 1

ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	MODEL	QUALIFICATION METHOD	QUALIFICATION REFERENCE
41. Transmitter - Safety Injection System Accumulator Tank Pressure	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E02B (CNM-1399.03-332)
42. Transmitter - Reactor Coolant Drain Tank Pressure	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E02B (CNM-1399.03-332)
43. Transmitter - Boric Acid Tank Level	Rosemount	1153DB	Test	Wyle Test Report 45353-1 (CNM-1210.04-262)
44. Transmitter - ESF Filters Differential Pressure	Foxboro	N-E13DL	Test	Wylie Test Report No. 45592-4 (CNM-1211.00-1792)
45. Transmitter - Containment Sump Level	Barton	386A	Test	Wyle Test Report 43904-2 (MCM-1393.00-0019)
46. Transmitter - RWST Level	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
	Tobar	32DP2	Test	WCAP 8687, Sup. 2, E04C, Rev. 1 (CNM-1299.03-0003)
47. Transmitter MDA FWP Disch. Flow	Barton	386A	Test	Wyle Test Report 43904-2 (MCM-1393.00-0019)

TABLE 3.10-1 (Page 7)

Catawba Unit 1

ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	MODEL	QUALIFICATION METHOD	QUALIFICATION REFERENCE
48. Transmitter - TDAFWP Disch Flow	Rosemount	1153DB5	Test	Wyle Test Report 45353-1 Appendix IV to Rosemount Qual Report 108026 (CNM-1210.04-262)
49. Transmitter - AFW Flow to SG	Barton	764	Test	Barton Report R3-764-9 (CNM-1210.04-261)
50. Transmitter - NW Surge Chamber Lvl	Barton	386A	Test	Wyle Test Report 43904-2 (MCM-1393.00-0019)
51. Transmitter - Annulus Press.	Barton	386A	Test	Wyle Test Report 43904-2 (MCM-1393.00-0019)
52. Transmitter - (capacitance probe) RN Pump Intake Pit Lvl	Robertshaw	158-B2-B1 721-A3-CX-33	Test	Wyle Test Report 44789-1 (CNM-1393.00-0003)
53. RTD - RCS Temperature (W/R)	RdF Corp. (NSSS)	21205	Test	WCAP 8567, Sup. 2, E06A (CNM-1399.03-328)
54. RTD - RCS Temperature (N/R)	RdF Corp. (NSSS)	21204	Test	WCAP 8687, Sup. 2, E05A (CNM-1399.03-327)
55. Platinum Resistance Temp. Detector & Sheath	Weed	--	Test	CCL Report No. A-489-82 (MCM-1211.00-1645)
56. Pressure Controller	Love Controls	54	Test	CCL Report No. A-489-82 (MCM-1211.00-1645) (CNM-1211.00-2003)

TABLE 3.10-1 (Page 8)

Catawba Unit 1

ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	MODEL	QUALIFICATION METHOD	QUALIFICATION REFERENCE
57. Temperature Controller	Love Controls	54	Test	CCL Report No. A-489-82 (MCM-1211.00-1645) (CNM-1211.00-2003)
58. Pressure Transmitter	Rosemount	1152	Test	Rosemount Report No. 38019 (CNM-1211.00-1778)
59. Temperature Switch	United Electric	800	Test	CCL Report No. A-489-82 (MCM-1211.00-1645) (CNM-1211.00-2003)
60. Chlorine Detector	Wallace & Tiernan	50-125D	Test	Wyle Lab Report 44945-1 (CNM-1393.00-0007)
61. Differential Pressure Switch	Penn	P67CA-1	Test	CCL Report No. A-489-82 (MCM-1211.00-1645) (CNM-1211.00-2003)
62. Differential Pressure Switch	Barton	288A	Test	Wyle Lab Report 43950-1 (MCM-1393.00-0007)
63. Differential Pressure Switch	Barton	580 Series	Test	Barton Report R3-580A-9
64. Differential Pressure Switch	Solon	7PSIIDW	Test	CCL Report No. A-489-82 (MCM 1211.00-1645)
65. Level Switches	Magnetrol	A103F-3X-Y-MPG-TDM	Test	Wyle Lab Report 44945-1 (CNM-1393.00-0007) Duke QTF Report TR-053

TABLE 3.10-1 (Page 9)

Catawba Unit 1

ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	MODEL	QUALIFICATION METHOD	QUALIFICATION REFERENCE
66. Stem Mounted Limit Switches (Valve/Damper)	NAMCO	EA170 EA180	Test Test	NAMCO Report No. QTR 107 Dated 3/11/81 (CNM 1205.19-0040) NAMCO Report No. QTR 106 Dated 9/2/81, Rev. 3 (CNM 1205.19-0042) NAMCO Report No. QTR111 Dated 10/1/81 (CNM-1205.19-0039)
67. PAM Recorders	Westinghouse (NSSS)	Optimac	Test	WCAP 8687, Sup. 2, E15A (CNM-1399.03-325)
68. PAM Indicators	Westinghouse (NSSS)	VX252	Test	WCAP 8687, Sup. 1, E14A (CNM-1399.03-333)
69. Excore Neutron Detectors (Power Range)	Westinghouse (NSSS)	WL-23686	Test/Analysis	Later
70. RVLIS	Westinghouse (NSSS)		Later	Later
71. RTD RCS-WR T_{cold} to SSF	Conax	7D56-10000-01	Test	IPS-799 (CNM-1336.02-0004)

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Catawba Unit 1

ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	MODEL	QUALIFICATION METHOD	QUALIFICATION REFERENCE
II. Protection System Equipment				
1. Process Protection Cabinets[1]	Westinghouse (NSSS)	7300	Test/Analysis	WCAP 7817, WCAP 8828 (CNM-1399.08-66) (CNM-1399.03-320)
2. Nuclear Instrumentation System (NIS) Cabinets	Westinghouse (NSSS)		Test/Analysis	WCAP 7817, WCAP 8830 (CNM-1399.08-66) (CNM-1399.04-100)
3. Solid-State Protection System	Westinghouse (NSSS)	SSPS	Test/Analysis	WCAP 7817, WCAP 8673 (CNM-1399.08-66) (CNM-1399.08-71)
4. Reactor Trip Switchgear	Westinghouse (NSSS)	DS416	Test	WCAP 8687, Sup. 2, E20B (CNM-1399.40-13)
5. Engineered Safeguards Test Cabinet	Westinghouse (NSSS)		Test/Analysis	WCAP 7817 (CNM-1399.03-66)
6. Auxiliary Relay Racks	Westinghouse (NSSS)		Analysis	Westinghouse Report Dated 8/79 (CNM-1399.03-0065)
7. Auxiliary Safeguards Cabinet	Westinghouse (NSSS)		Test/Analysis	WCAP 7817 (CNM-1399.03-66)

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Catawba Unit 1

ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	QUALIFICATION METHOD	QUALIFICATION REFERENCE
III. Motors			
1. Safety Injection Pump	Westinghouse, Buffalo (NSSS)	Analysis	Westinghouse LMD Report
2. Residual Heat Removal Pump	Westinghouse, Buffalo (NSSS)	Analysis	Westinghouse LMD Report
3. Centrifugal Charging Pump	Westinghouse, Buffalo (NSSS)	Analysis	Westinghouse LMD Report
4. Boron Injection Recirc. Pump	Westinghouse, Buffalo (NSSS)	Analysis	Crane Seismic Analysis Report
5. Boric Acid Transfer Pump	Westinghouse, Buffalo (NSSS)	Analysis	Crane Seismic Analysis Report
6. Nuclear Service Water Pump	Westinghouse, Buffalo	Test/Analysis	Westinghouse Seismic Shop Order # 74F/8635 (CNM-1318.20-15)
7. Auxiliary Feedwater Pump	Westinghouse, Buffalo	Test/Analysis	Westinghouse Seismic Shop Order # 75F32986 (CNM-1318.16-0036)
8. Component Cooling Water Pump	Westinghouse, Buffalo	Test/Analysis	Westinghouse Seismic Shop Order # 74F18653 (CNM-1318.22-0020)
9. Containment Spray Pump	Westinghouse, Buffalo	Test/Analysis	Westinghouse Seismic Shop Order # 74F18673 (CNM-1318.25-0024)

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Catawba Unit 1

ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	QUALIFICATION METHOD	QUALIFICATION REFERENCE
10. Fuel Pool Cooling Pump	Westinghouse, Buffalo	Test/Analysis	Westinghouse Seismic Shop Order No: 74F12700 (CNM-1318.23-00-0020)
11. Nuclear Service Water Strainer	Westinghouse (Motor Vendor) R. P. Adams Co. (Strainer Vendor)	Analysis	WCAP 9112 (CNM-1218.02-39) Seismic Analysis dated 1/23/80 (CNM-1218.02-38)
12. Containment Air Return Fan	Reliance/Joy	Test/Analysis	Joy Mfg. Report X-604 (CNM-1211.00-1009) Reliance NUC-9 (CNM-1211.00-1010) Joy Mfg. Report S-168 dated 10/10/78 (CNM-1211.00-275)
13. Hydrogen Skimmer Fan	Reliance/Joy	Test/Analysis	Joy Mfg. Report X-604 (CNM-1211.00-1009) Reliance NUC-9 (CNM-1211.00-1010) Joy Mfg Report S-247 dated 2/27/80 (CNM-1211.00-756)

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Catawba Unit 1

ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	QUALIFICATION METHOD	QUALIFICATION REFERENCE
14. Annulus Ventilation Fan	Reliance/Joy	Test/Analysis	Joy Mfg. Report S-134 dated 3/23/78 (CNM-1211.00-123) Joy Mfg. Report S-247 dated 2/27/80 (CNM-1211.00-756) Joy Mfg Report X604 (CNM 1211.00-1009) Reliance NUC-9 (CNM1211.00-1010)
15. Control Room Area Press. Filter Train Fan	Reliance/Joy	Test/Analysis	Seismic Report 78-R-29 dated 7/1/78 (CNM-1211.00-0947)
16. Control Room Area Chilled Water Pump	Reliance	Test/Analysis	Reliance 78-A-58 (CNM-1310.10-8) NUS Report 3250 (CNM-1211.00-1519)
17. Control Room Area	Carrier	Test/Analysis	NUS Report TR-78-24 (CNM-1211.00-1526) (CNM-1211.00-1519) CCL Report No. A-228-79 (CNM 1211.00-71)

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Catawba Unit 1

ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	QUALIFICATION METHOD	QUALIFICATION REFERENCE
18. Control Room Area Air Handling Unit Fan	Reliance (Motor) Bahnson (AHU)	Test/Analysis	Reliance 78B-1-78A (CNM-1320.53-37) CCL Report No. A-182-78 (CNM-1211.00-634 001, 002, 003, 004) CCL Report No. A-160-78-02 (CNM-1211.00-229)
19. Control Room Air Handling Unit Fan	Reliance (Motor) Carrier (AHU)	Test/Analysis	Reliance 78-A-57 (CNM-1320.53-39) CCL Report No. A-179-78 (CNM-1211.00-423) (CNM-1211.00-1826)
20. Switchgear Room Air Handling Unit Fan	Reliance (Motor) Carrier (AHU)	Test/Analysis	Reliance 78-A-56 (CNM-1320.53-38) CCL Report No. A-179-78 (CNM-1211.00-423)
21. Fuel Handling Area Exhaust Fan	Reliance Zurn/Clarage	Test/Analysis	Reliance 78-A-59 (CNM-1320.53-35) Clarage Report SQ-15 (CNM-1211.00-422)
22. Auxiliary Bldg. Filtered Exhaust Fan	Reliance Zurn/Clarage	Test/Analysis	Reliance 78-1-65 (CNM-1320.53-36) Clarage Report SQ-14 (CNM-1211.00-421)

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Catawba Unit 1

ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	QUALIFICATION METHOD	QUALIFICATION REFERENCE
23. Battery Room Exhaust Fan	Reliance/Joy	Test/Analysis	Joy Mfg. Report S-136 dated 3/23/78 (CNM-1211.00-0125) Joy Mfg Report X-604 (CNM-1211.00-1009) Reliance NUC-9 (CNM-1211.00-1010)
24. Diesel Generator System Vent Fan	Reliance/Joy	Test/Analysis	Joy Mfg. Report S-135 dated 3/23/78 (CNM-1211.00-124) Joy Mfg Report X-604 (CNM-1211.1009) Reliance NUC-9 (CNM-1211.1010)
25. Nuclear Service Water Pump Structure Fan	Reliance/Joy	Test/Analysis	Joy Mfg. Report S-255 dated 4/1/80 (CNM-1211.00-1009) Joy Mfg Report X-604 (CNM-1211.1009) Reliance NUC-9 (CNM-1211.1010)
26. Containment Spray & Residual Heat Removal Pump Room Sump Pump	Reliance	Test/Analysis	Reliance 77-A-44 (CNM-1320.59-33)
27. Steam Turbine & Motor Driven Aux. Feedwater Pump Pit Sump Pump	Reliance	Test/Analysis	Reliance 77-A-45 (CNM-1320.59-34)

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Catawba Unit 1

ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	QUALIFICATION METHOD	QUALIFICATION REFERENCE
28. Diesel Generator Rm Sump Pump	Reliance	Test/Analysis	Reliance 77-A-46 (CNM-1320.59-31)
29. Auxiliary Bldg. Ground-water Drainage Sump Pump	Reliance	Test/Analysis	Reliance 77-A-49 (CNM-1320.59-32)

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Catawba Unit 1

ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	MODEL	QUALIFICATION METHOD	QUALIFICATION REFERENCE
IV. Valve/Damper Operators				
1. Motor Operators[2] (MSIV)	Atwood & Morrill		Test	A & M Test Report 201-39500 (CNM-1205.12-0009)
2. Motor Operators[2] (FWIV)	Borg-Warner		Test	Borg-Warner Test Report 1736 (CNM-1205.12-8)
3. Motor Operators[2]	Limitorque	SMB	Test	Limitorque-Report B0058 (CNM-1205.19-1)
4. Motor Operators[2]	Rotork	NA1 NA2	Test	Rotork TR116 (11/73) (CNM-1205.19-6) Rotork TR404 (7/12/77) (CNM-1205.19-14) Rotork 20689 (12/1/70) (CNM-1205.19-22) Rotork TR4605 (3/2/72) (CNM-1205.19-23) Rotork N7/1 (5/15/70) (CNM-1205.19-21) Rotork 43979-1, Rev. A (12/19/78) (CNM-1205.19-11) Wylie 43979-1 (CNM 1211.00-1076) American Warming Calc. No. 80343-301 (CNM-1211.00-771) American Warming Calc. No. 80343-30A (CNM-1211.00-2005)

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Catawba Unit 1

ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	MODEL	QUALIFICATION METHOD	QUALIFICATION REFERENCE
5. Motor Operators	ITT General Controls	NH90 Series	Test/Analysis	ITT Report No. 730.1.140 (CNM-1211.00-1182) AWV 80343-312 (CNM-1211.00-803) AWV 80343-310 (CNM-1211.00-804) Ruskin Calc. 1009 (CNM-1211.00-510) Ruskin Calc. 1040 (CNM-1211.00-1356) PAPCO E80-36 (CNM-1211.00-885) PAPCO E1439-1 (CNM-1211.00-1147) PAPCO E80-26 (CNM-1211.00-967) Ruskin Calc. 1025 (CNM-1211.00-1037)
6. Motor Operators	Barber Coleman	MA 418	Test	Wylie TR No. 43516-1 (CNM-1211.00-1038) Ruskin Calc. No. 1009 (CNM-1211.00-510) Ruskin Calc. No. 1040 (CNM-1211.00-1356)
7. Solenoid Operators	Valcor	V70900-21-3	Test	Valcor Test Reports QR 70900-21-1 and -3 MR 70900-21-3-2

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Catawba Unit 1

ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	MODEL	QUALIFICATION METHOD	QUALIFICATION REFERENCE
8. Solenoid Operators	Westinghouse		Test	Westinghouse AESD Report
9. Solenoid Operators	ASCO	NP8316 Series	Test	ASCO Report AQS21678/TR and Wyle Lab Report 44549-1 (MCM-1210.04-117-1)
10. 3-Way Solenoid Operators	ASCO	NP8300 Series	Test	ASCO Report AQR-67368 (CNM-1211.00-1780)
11. Solenoid Operators	Valcor	V70900-39-3-1	Test	Valcor Test Report MR 70900-39-3-1 (CNM-1210.04-309)

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Catawba Unit 1

ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	QUALIFICATION METHOD	QUALIFICATION REFERENCE
V. Power System Equipment			
1. Diesel Electric Generating Units	Delaval	Test/Analysis	Delaval 75017-705 (CNM-1301.00-285)
2. Diesel Starting Air Compressor Motors	Reliance	Test/Analysis	Reliance 77-A-40 (CNM-1320.56-8)
3. Diesel Generator Auxiliaries	Subvendors		Delaval 75017-705 (CNM-1301.00-285)
- Engine Control Panel	Delaval	Test	
- Generator Control Panel	RTE/Delta	Test	
- Motor-Driven Before & After Lube Oil Pump	Siemens/Allis	Analysis	(CNM-1301.00-249 B/A Lube Oil Pump Only)
- Diesel Battery	Nife, Inc.	Test	
- Diesel Battery Charger	Power Conversion Products	Test	
- Neutral Grounding Cabinet	E. P. Portec	Test	
- Governor EGB Actuator	Woodward	Analysis	
- Governor Servo Booster	Woodward	Analysis	
- Magnetic Pick-up	Airpax	Analysis	
- Fuel Oil Booster Pump	Westinghouse	Analysis	(CNM-1301.00-248)
4. Diesel Generator Fuel Oil Booster Pump Motor Starters	Nelson Electric	Test/Analysis	Nelson Electric T-700-101 (CNM-1314.01-0245)
5. 4160 Volt Essential Switchgear	Brown Boveri Electric	Test/Analysis	Gould 33-50465 (CNM-1312.02-00-0066)

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Catawba Unit 1

ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	QUALIFICATION METHOD	QUALIFICATION REFERENCE
6. 600 Volt Essential Load Center Switchgear	Brown Boveri Electric	Test/Analysis	Gould 33-50583 (CNM-1312.06-53)
7. 600 Volt Essential Motor Control Centers	Nelson Electric	Test/Analysis	Nelson Electric T1035.36 & .37 (CNM-1314.01-0242) (CNM-1314.01-0243)
8. 4160/600 Volt Essential Load Center Transformers	Westinghouse	Test/Analysis	Westinghouse Gen. Order Number: CH18615 MPS Order No: C46767 (CNM-1312.06-0056)
9. 120VAC Essential Panelboard Transformers	Square D (Sorgel)	Test/Analysis	Wyle Test Report 43205-1 (CNM-1308.03-0011)
10. 125VDC Vital Instr. & Control Batteries	Gould	Test/Analysis	Wyle Test Report No. 42795-1 (MCM-1356.01-05) Gould 064563-D (CNM-1356.01-09) Gould GB-3454 (CNM-1356.01-1 & 12)
11. 125VDC Vital Instr. & Control Battery Chargers	Solidstate Controls, Inc.	Test	Wyle Test Report No. 44000-1 (CNM-1356.05-0018)
12. Vital Instr. & Control Static Inverters	Solidstate Controls, Inc.	Test	Wyle Test Report No. 44000-1 (CNM-1358.03-0041)

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Catawba Unit 1

ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	QUALIFICATION METHOD	QUALIFICATION REFERENCE
13. 125VDC Vital I & C Auctioneering Diode Assemblies	Power Conversion	Test	Wyle Test Report No. 44304-1 (CNM-1359.00-0001)
14. 125VDC Vital I & C Distribution Centers	Nelson Electric	Test/Analysis	Nelson Electric T1035.36 (CNM-1314.01-0242)
15. 125VDC & 120VAC Vital I & C Power Panelboards	Nelson Electric	Test/Analysis	Nelson Electric T-600.103 (CNM-1314.01-0244)
16. Electric Penetrations	D. G. O'Brien, Inc.	Test	D. G. O'Brien, Inc. Test Reports ER247 App. D, ER-252 App. K CNM-1361.00-0015 CNM-1361.00-0016 CNM-1361.00-0049
17. Electric Penetrations	Conax Corporation	Test/Analysis	Conax Corporation Test Report IPS-1037 (CNM-1361.00-0048)
18. RCP Switchgear Potential Transformers	Brown Boveri Electric	Test/Analysis	Gould 33-52420 (CNM-1312.07-28)

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Catawba Unit 1

ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	QUALIFICATION METHOD	QUALIFICATION REFERENCE
VI. Panels and Cabinets Including Components			
1. HVAC Control Panel	MCC Powers	Test/Analysis	Patel Report PEI TR-81-13 (CNM-1211.00-1470) Patel Report PEI TR-840800-1 (CNM-1211.00-1842)
2. Reactor Coolant Pump Power Monitor Panel	Frank Electric/Duke	Test	Wyle Test Report 44816-1 (CNM-1393.00-0004)
3. Monitor Light Cabinets	Beta	Test	Wyle Test Report 44331-1 (CNM-1346.01-111)
4. UHI Hydraulic Service Panels	Westinghouse	Analysis	Westinghouse Report dated 12/75 (CNM-1399.03-321)
5. Auxiliary Shutdown Panel HVAC Supply Unit	CVI	Analysis	Hissong Report HC-1174-1 (CNM-1211.00-943)
6. Auxiliary Feedwater Turbine Panel	Frank Electric/Duke	Test	Wyle Test Report 44891-1 (CNM-1393.00-0005)
7. Auxiliary Shutdown Panel	Frank Electric/Duke	Test	Wyle Test Report 44891-2 (CNM-1393.00-0006)
8. Main Control Board	Frank Electric/Duke	Test/Analysis	Duke Seismic Reports (CNC-1381.05-00-0029) (CNC-1381.05-00-0046)

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Catawba Unit 1

ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	QUALIFICATION METHOD	QUALIFICATION REFERENCE
9. Diesel Generator Load Sequencer Panel	Duke	Test	Wyle Test Report 45303-1 (CNM-1393.00-0010)
10. Nuclear Service Water Cabinets	Duke	Test	Wyle Test Report 44424-1 (CNM-1393.00-0001)
11. Miscellaneous Equipment Enclosures*	Duke	Test/Analysis	Later

*Includes: IC Cabinets
Terminal Boxes
Area Terminal Cabinets
Local Control Panels

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Catawba Unit 1

ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	MODEL	QUALIFICATION METHOD	QUALIFICATION REFERENCE
VII. Other Equipment				
1. Radiation Monitors	General Atomic	RD-23	Test	G.A. Test Report E-254-960 (CNM-1346.05-60)
2. Safety Valve Position Indication	TEC	914	Test/Analysis	TEC Report 517-TR-01,02,03 (CNM-1346.17-0012)
3. Hydrogen Analyzers	Teledyne Analytical	225 CM	Test/Analysis	Teledyne Analytical Test Report 58541
4. Electric Hydrogen Recombiner System	Westinghouse/B Sturtevant (NSSS)		Test/Analysis	WCAP-7709L Sup. 1-4 WCAP-7820 Sup. 1-4 (MCM-1399.36-0004)
5. ESF Filter Train Fire Protection System	Alison		Test	Wyle Test Report 45155-1 (CNM-1211.00-1559)
6. Electric Heater and Control Control Panel	Indeeco		Test/Analysis	CCL Report No. A-447-82-01 (CNM-1211.00-1544)
7. Cable Tray/Support System	Metal Products/Duke		Test/Analysis	CNC-1139.14-13-003

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Catawba Unit 2

ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	MODEL	QUALIFICATION METHOD	QUALIFICATION REFERENCE
I. Instrumentation and Control Equipment				
1. Transmitter - Pressurizer Pressure	Barton (NSSS)	763 (Lot 2)	Test	WCAP-9885 (CNM-1399.03-318)
2. Transmitter - Pressurizer Level	Barton (NSSS)	764 (Lot 2)	Test	WCAP-9885 (CNM-1399.03-318)
3. Transmitter - Steam Generator Level (N/R)	Barton (NSSS)	764 (Lot 2)	Test	WCAP-9885 (CNM-1399.03-318)
	Rosemount	1153HD4PB	Test	Wyle Test Report 45592-3
4. Transmitter - RCS Flow	Veritrak (NSSS)	76	Test	WCAP-8687, Sup. 2, E04B (CNM-1399.03-331)
	Rosemount	1153HD5PB	Test	Wyle Test Report 45592-3
5. Transmitter - RCS Pressure (W/R)	Barton (NSSS)	764 (Lot 2)	Test	WCAP-9885 (CNM-1399.03-318)
6. Transmitter - Steam Line Pressure	Veritrak (NSSS)	76	Test	WCAP-8687, Sup. 2, E02B (CNM-1399.03-332)
7. Transmitter - Turbine Impulse Pressure	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2 E02B (CNM-1399.03-332)
8. Transmitter - Containment Pressure (N/R)	Barton	386A	Test	Wyle Test Report 43904-2 (MCM-1393.00-0019)

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ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	MODEL	QUALIFICATION METHOD	QUALIFICATION REFERENCE
9. Transmitter - Containment Pressure (W/R)	Rosemount	1153DB6	Test	Wyle Test Report 45353-1 (Appendix IV to Rosemount Qual Report 108026) (CNM-1210.04-262)
10. Transmitter - Pressurizer Level-Low Temp.	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
11. Transmitter - Steam Generator Level (W/R)	Barton	764	Test	Barton Report R3-764-9 (CNM-1210.04-261)
12. Transmitter - Main Feedwater Flow	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
	Rosemount	1153DB6PB	Test	Wyle Test Report 45353-1, Appendix III to Rosemount Qual. Report 108026
13. Transmitter - Main Steam Flow	Tobar	32DP2212/64312	Test	WCAP 8687, Sup. 2, E04C, Rev. 1 (CNM-1299.03-0003)
14. Transmitter - Residual Heat Removal Heat Exchanger Outlet Flow	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
15. Transmitter - Boron Injection Flow	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
16. Transmitter - Safety Injection Pump Discharge Flow	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)

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ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	MODEL	QUALIFICATION METHOD	QUALIFICATION REFERENCE
17. Transmitter - Containment Spray Pump Discharge Flow	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
18. Transmitter - Boric Acid Blender Discharge Flow	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
19. Transmitter - NV Charging Line Flow	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
20. Transmitter - NV Letdown Flow	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
21. Transmitter - RC Pump Seal Water Flow	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
22. Transmitter - RC Pump Seal Leakoff Flow	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
23. Transmitter - Emergency Boration Flow	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
24. Transmitter - Letdown Chill HX Shell Discharge Flow	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
25. Transmitter - Chill Surge Tank Level	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)

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ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	MODEL	QUALIFICATION METHOD	QUALIFICATION REFERENCE
26. Transmitter - Boron Thermal Regen. System Flow Rate	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
27. Transmitter - Residual Heat Removal Loop Return Flow	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
28. Transmitter - Reactor Coolant Drain Tank Pump Discharge Header Flow	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
29. Transmitter - Reactor Coolant Drain Tank Recirculation Flow	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)
30. Transmitter - Nuclear Volume Control Tank Vent Pressure	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E02B (CNM-1399.03-332)
31. Transmitter - Nuclear Volume Charging Header Pressure	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E02B (CNM-1399.03-332)
32. Transmitter - Nuclear Volume Excess Letdown HX Outlet Pressure	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E02B (CNM-1399.03-332)

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ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	MODEL	QUALIFICATION METHOD	QUALIFICATION REFERENCE
33. Transmitter - Nuclear Volume Letdown Pressure & Control	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E02B (CNM-1399.03-332)
34. Transmitter - Pressurizer Relief Tank Pressure	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E02B (CNM-1399.03-332)
35. Transmitter - Steam Generator Steam Header Pressure	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E02B (CNM-1399.03-332)
36. Transmitter - Steam Generator Inlet Steam Header Pressure	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E02B (CNM-1399.03-332)
37. Transmitter - Residual Heat Removal Pump Discharge Pressure	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E02B (CNM-1399.03-332)
38. Transmitter - Upper Head Injection Surge Tank Pressure	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E02B (CNM-1399.03-332)
39. Transmitter - Safety Injection Pump Discharge Pressure	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E02B (CNM-1399.03-332)

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ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	MODEL	QUALIFICATION METHOD	QUALIFICATION REFERENCE
40. Transmitter - Boron Injection Tank Pressure	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E02B (CNM-1399.03-332)
41. Transmitter - Safety Injection System Accumulator Tank Pressure	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E02B (CNM-1399.03-332)
42. Transmitter - Reactor Coolant Drain Tank Pressure	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E02B (CNM-1399.03-332)
43. Transmitter - Boric Acid Tank Level	Rosemount	1153DB	Test	Wyle Test Report 45353-1 (CNM-1210.04-262)
44. Transmitter - ESF Filters Differential Pressure	Foxboro	N-E13DL	Test	Wylie Test Report No. 45592-4 (CNM-1211.00-1792)
45. Transmitter - Containment Sump Level	Barton	386A	Test	Wyle Test Report 43904-2 (MCM-1393.00-0019)
46. Transmitter - RWST Level	Veritrak (NSSS)	76	Test	WCAP 8687, Sup. 2, E04B (CNM-1399.03-331)

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ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	MODEL	QUALIFICATION METHOD	QUALIFICATION REFERENCE
47. Transmitter MDA FWP Disch. Flow	Barton	386A	Test	Wyle Test Report 43904-2 (MCM-1393.00-0019)
48. Transmitter - TDAFWP Disch Flow	Rosemount	1153DB5	Test	Wyle Test Report 45353-1 Appendix IV to Rosemount Qual Report 108026 (CNM-1210.04-262)
49. Transmitter - AFW Flow to SG	Barton	764	Test	Barton Report R3-764-9 (CNM-1210.04-261)
50. Transmitter - NW Surge Chamber Lvl	Barton	386A	Test	Wyle Test Report 43904-2 (MCM-1393.00-0019)
51. Transmitter - Annulus Press.	Barton	386A	Test	Wyle Test Report 43904-2 (MCM-1393.00-0019)
52. Transmitter - (capacitance probe) RN Pump Intake Pit Lvl	Robertshaw	158-B2-B1 721-A3-CX-33	Test	Wyle Test Report 44789-1 (CNM-1393.00-0003)
53. RTD - RCS Temperature (W/R)	RdF Corp. (NSSS)	21205	Test	WCAP 8567, Sup. 2, E06A (CNM-1399.03-328)
54. RTD - RCS Temperature (N/R)	RdF Corp. (NSSS)	21204	Test	WCAP 8687, Sup. 2, E05A (CNM-1399.03-327)
55. Platinum Resistance Temp. Detector & Sheath	Weed	--	Test	CCL Report No. A-489-82 (MCM-1211.00-1645)

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ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	MODEL	QUALIFICATION METHOD	QUALIFICATION REFERENCE
56. Pressure Controller	Love Controls	54	Test	CCL Report No. A-489-82 (MCM-1211.00-1645) (CNM-1211.00-2003)
57. Temperature Controller	Love Controls	54	Test	CCL Report No. A-489-82 (MCM-1211.00-1645) (CNM-1211.00-2003)
58. Pressure Transmitter	Rosemount	1152	Test	Rosemount Report No. 38019 (CNM-1211.00-1778)
59. Temperature Switch	United Electric	800	Test	CCL Report No. A-489-82 (MCM-1211.00-1645) (CNM-1211.00-2003)
60. Chlorine Detector	Wallace & Tiernan	50-125D	Test	Wyle Lab Report 44945-1 (CNM-1393.00-0007)
61. Differential Pressure Switch	Penn	P67CA-1	Test	CCL Report No. A-489-82 (MCM-1211.00-1645) (CNM-1211.00-2003)
62. Differential Pressure Switch	Barton	288A	Test	Wyle Lab Report 43950-1 (MCM-1393.00-0007)
63. Differential Pressure Switch	Barton	580 Series	Test	Barton Report R3-580A-9

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ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	MODEL	QUALIFICATION METHOD	QUALIFICATION REFERENCE
64. Differential Pressure Switch	Solon	7PSIIDW	Test	CCL Report No. A-489-82 (MCM 1211.00-1645)
65. Level Switches	Magnetrol	A103F-3X-Y-MPG-TDM	Test	Wyle Lab Report 44945-1 (CNM-1393.00-0007) Duke QTF Report TR-053
66. Stem Mounted Limit Switches (Valve/Damper)	NAMCO	EA170 EA180	Test Test	NAMCO Report No. QTR 107 Dated 3/11/81 (CNM 1205.19-0040) NAMCO Report No. QTR 106 Dated 9/2/81, Rev. 3 (CNM 1205.19-0042)
67. PAM Recorders	Westinghouse (NSSS)	Optimac	Test	WCAP 8687, Sup. 2, E15A (CNM-1399.03-325)
68. PAM Indicators	Westinghouse (NSSS)	VX252	Test	WCAP 8687, Sup. 1, E14A (CNM-1399.03-333)
69. Excore Neutron Detectors (Power Range)	Westinghouse (NSSS)	WL-23686	Test/Analysis	Later
70. RVLIS	Westinghouse (NSSS)		Later	Later
71. RTD RCS-WR T_{cold} to SSF	Conax	7D56-10000-01	Test	IPS-799 (CNM-1336.02-0004)

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ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	MODEL	QUALIFICATION METHOD	QUALIFICATION REFERENCE
II. Protection System Equipment				
1. Process Protection Cabinets[1]	Westinghouse (NSSS)	7300	Test/Analysis	WCAP 7817, WCAP 8828 (CNM-1399.08-66) (CNM-1399.03-320)
2. Nuclear Instrumentation System (NIS) Cabinets	Westinghouse (NSSS)		Test/Analysis	WCAP 7817, WCAP 8830 (CNM-1399.08-66) (CNM-1399.04-100)
3. Solid-State Protection System	Westinghouse (NSSS)	SSPS	Test/Analysis	WCAP 7817, WCAP 8673 (CNM-1399.08-66) (CNM-1399.08-71)
4. Reactor Trip Switchgear	Westinghouse (NSSS)	DS416	Test	WCAP 8687, Sup. 2, E20B (CNM-1399.40-13)
5. Engineered Safeguards Test Cabinet	Westinghouse (NSSS)		Test/Analysis	WCAP 7817 (CNM-1399.03-66)
6. Auxiliary Relay Racks	Westinghouse (NSSS)		Analysis	Westinghouse Report Dated 8/79 (CNM-1399.03-0065)
7. Auxiliary Safeguards Cabinet	Westinghouse (NSSS)		Test/Analysis	WCAP 7817 (CNM-1399.03-66)

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ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	QUALIFICATION METHOD	QUALIFICATION REFERENCE
III. Motors			
1. Safety Injection Pump	Westinghouse, Buffalo (NSSS)	Analysis	Westinghouse LMD Report
2. Residual Heat Removal Pump	Westinghouse, Buffalo (NSSS)	Analysis	Westinghouse LMD Report
3. Centrifugal Charging Pump	Westinghouse, Buffalo (NSSS)	Analysis	Westinghouse LMD Report
4. Boron Injection Recirc. Pump	Westinghouse, Buffalo (NSSS)	Analysis	Crane Seismic Analysis Report
5. Boric Acid Transfer Pump	Westinghouse, Buffalo (NSSS)	Analysis	Crane Seismic Analysis Report
6. Nuclear Service Water Pump	Westinghouse, Buffalo	Test/Analysis	Westinghouse Seismic Shop Order # 74F/8635 (CNM-1318.20-15)
7. Auxiliary Feedwater Pump	Westinghouse, Buffalo	Test/Analysis	Westinghouse Seismic Shop Order # 75F32986 (CNM-1318.16-0036)
8. Component Cooling Water Pump	Westinghouse, Buffalo	Test/Analysis	Westinghouse Seismic Shop Order # 74F18653 (CNM-1318.22-0020)

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ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	QUALIFICATION METHOD	QUALIFICATION REFERENCE
9. Containment Spray Pump	Westinghouse, Buffalo	Test/Analysis	Westinghouse Seismic Shop Order # 74F18673 (CNM-1318.25-0024)
10. Fuel Pool Cooling Pump	Westinghouse, Buffalo	Test/Analysis	Westinghouse Seismic Shop Order No: 74F12700 (CNM-1318.23-00-0020)
11. Nuclear Service Water Strainer	Westinghouse (Motor Vendor) R. P. Adams Co. (Strainer Vendor)	Analysis	WCAP 9112 (CNM-1218.02-39) Seismic Analysis dated 1/23/80 (CNM-1218.02-38)
12. Containment Air Return Fan	Reliance/Joy	Test/Analysis	Joy Mfg. Report X-604 (CNM-1211.00-1009) Reliance NUC-9 (CNM-1211.00-1010) Joy Mfg. Report S-168 dated 10/10/78 (CNM-1211.00-275)
13. Hydrogen Skimmer Fan	Reliance/Joy	Test/Analysis	Joy Mfg. Report X-604 (CNM-1211.00-1009) Reliance NUC-9 (CNM-1211.00-1010) Joy Mfg Report S-247 dated 2/27/80 (CNM-1211.00-756)

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ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	QUALIFICATION METHOD	QUALIFICATION REFERENCE
14. Annulus Ventilation Fan	Reliance/Joy	Test/Analysis	Joy Mfg. Report S-134 dated 3/23/78 (CNM-1211.00-123) Joy Mfg. Report S-247 dated 2/27/80 (CNM-1211.00-756) Joy Mfg Report X604 (CNM 1211.00-1009) Reliance NUC-9 (CNM1211.00-1010)
15. Control Room Area Press. Filter Train Fan	Reliance/Joy	Test/Analysis	Seismic Report 78-R-29 dated 7/1/78 (CNM-1211.00-0947)
16. Control Room Area Chilled Water Pump	Reliance	Test/Analysis	Reliance 78-A-58 (CNM-1310.10-8) NUS Report 3250 (CNM-1211.00-1519)
17. Control Room Area Chiller	Carrier	Test/Analysis	NUS Report TR-78-24 (CNM-1211.00-1526) (CNM-1211.00-1519) CCL Report No. A-228-79 (CNM 1211.00-71)

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ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	QUALIFICATION METHOD	QUALIFICATION REFERENCE
18. Control Room Area Air Handling Unit Fan	Reliance (Motor) Bahnson (AHU)	Test/Analysis	Reliance 78B-1-78A (CNM-1320.53-37) CCL Report No. A-182-78 (CNM-1211.00-634 001, 002, 003, 004) CCL Report No. A-160-78-02 (CNM-1211.00-229)
19. Control Room Air Handling Unit Fan	Reliance (Motor) Carrier (AHU)	Test/Analysis	Reliance 78-A-57 (CNM-1320.53-39) CCL Report No. A-179-78 (CNM-1211.00-423) (CNM-1211.00-1826)
20. Switchgear Room Air Handling Unit Fan	Reliance (Motor) Carrier (AHU)	Test/Analysis	Reliance 78-A-56 (CNM-1320.53-38) CCL Report No. A-179-78 (CNM-1211.00-423)
21. Fuel Handling Area Exhaust Fan	Reliance Zurn/Clarage	Test/Analysis	Reliance 78-A-59 (CNM-1320.53-35) Clarage Report SQ-15 (CNM-1211.00-422)
22. Auxiliary Bldg. Filtered Exhaust Fan	Reliance Zurn/Clarage	Test/Analysis	Reliance 78-1-65 (CNM-1320.53-36) Clarage Report SQ-14 (CNM-1211.00-421)

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ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	QUALIFICATION METHOD	QUALIFICATION REFERENCE
23. Battery Room Exhaust Fan	Reliance/Joy	Test/Analysis	Joy Mfg. Report S-136 dated 3/23/78 (CNM-1211.00-0125) Joy Mfg Report X-604 (CNM-1211.00-1009) Reliance NUC-9 (CNM-1211.00-1010)
24. Diesel Generator System Vent Fan	Reliance/Joy	Test/Analysis	Joy Mfg. Report S-135 dated 3/23/78 (CNM-1211.00-124) Joy Mfg Report X-604 (CNM-1211.1009) Reliance NUC-9 (CNM-1211.1010)
25. Nuclear Service Water Pump Structure Fan	Reliance/Joy	Test/Analysis	Joy Mfg. Report S-255 dated 4/1/80 (CNM-1211.00-0877) Joy Mfg Report X-604 (CNM-1211.1009) Reliance NUC-9 (CNM-1211.1010)
26. Containment Spray & Residual Heat Removal Pump Room Sump Pump	Reliance	Test/Analysis	Reliance 77-A-44 (CNM-1320.59-33)

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ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	QUALIFICATION METHOD	QUALIFICATION REFERENCE
27. Steam Turbine & Motor Driven Aux. Feedwater Pump Pit Sump Pump	Reliance	Test/Analysis	Reliance 77-A-45 (CNM-1320.59-34)
28. Diesel Generator Rm Sump Pump	Reliance	Test/Analysis	Reliance 77-A-46 (CNM-1320.59-31)
29. Auxiliary Bldg. Groundwater Drainage Sump Pump	Reliance	Test/Analysis	Reliance 77-A-49 (CNM-1320.59-32)

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ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	MODEL	QUALIFICATION METHOD	QUALIFICATION REFERENCE
IV. Valve/Damper Operators				
1. Motor Operators[2] (MSIV)	Atwood & Morrill		Test	A & M Test Report 201-39500 (CNM-1205.12-0009)
2. Motor Operators[2] (FWIV)	Borg-Warner		Test	Borg-Warner Test Report 1736 (CNM-1205.12-8)
3. Motor Operators[2]	Limitorque	SMB	Test	Limitorque-Report B0058 (CNM-1205.19-1)
4. Motor Operators[2]	Rotork	NA1 NA2	Test	Rotork TR116 (11/73) (CNM-1205.19-6) Rotork TR404 (7/12/77) (CNM-1205.19-14) Rotork 20689 (12/1/70) (CNM-1205.19-22) Rotork TR4605 (3/2/72) (CNM-1205.19-23) Rotork N7/1 (5/15/70) (CNM-1205.19-21) Rotork 43979-1, Rev. A (12/19/78) (CNM-1205.19-11) Wylie 43979-1 (CNM 1211.00-1076) American Warming Calc. No. 80343-301 (CNM-1211.00-771) American Warming Calc. No. 80343-30A (CNM-1211.00-2005)

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ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	MODEL	QUALIFICATION METHOD	QUALIFICATION REFERENCE
5. Motor Operators	ITT General Controls	NH90 Series	Test/Analysis	ITT Report No. 730.1.140 (CNM-1211.00-1182) AWV 80343-312 (CNM-1211.00-803) AWV 80343-310 (CNM-1211.00-804) Ruskin Calc. 1009 (CNM-1211.00-510) Ruskin Calc. 1040 (CNM-1211.00-1356) PAPCO E80-36 (CNM-1211.00-885) PAPCO E1439-1 (CNM-1211.00-1147) PAPCO E80-26 (CNM-1211.00-967) Ruskin Calc. 1025 (CNM-1211.00-1037)
6. Motor Operators	Barber Coleman	MA 418	Test	Wylie TR No. 43516-1 (CNM-1211.00-1038) Ruskin Calc. No. 1009 (CNM-1211.00-510) Ruskin Calc. No. 1040 (CNM-1211.00-1356)
7. Solenoid Operators	Valcor	V70900-21-3	Test	Valcor Test Reports QR 70900-21-1 and -3, MR 70900-21-3-2

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ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	MODEL	QUALIFICATION METHOD	QUALIFICATION REFERENCE
8. Solenoid Operators	Westinghouse		Test	Westinghouse AESD Report
9. Solenoid Operators	ASCO	NP8316 Series	Test	ASCO Report AQS21678/TR and Wyle Lab Report 44549-1 (MCM-1210.04-117-1)
10. 3-Way Solenoid Operators	ASCO	NP8300 Series	Test	ASCO Report AQR-67368 (CNM-1211.00-1780)
11. Solenoid Operators	Valcor	V70900-39-3-1	Test	Valcor Test Report MR 70900-39-3-1 (CNM-1210.04-309)

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ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	QUALIFICATION METHOD	QUALIFICATION REFERENCE
V. Power System Equipment			
1. Diesel Electric Generating Units	Delaval	Test/Analysis	Delaval 75017-705 (CNM-1301.00-285)
2. Diesel Starting Air Compressor Motors	Reliance	Test/Analysis	Reliance 77-A-40 (CNM-1320.56-8)
3. Diesel Generator Auxiliaries	Subvendors		Delaval 75017-705 (CNM-1301.00-285)
- Engine Control Panel	Delaval	Test	
- Generator Control Panel	RTE/Delta	Test	
- Motor-Driven Before & After Lube Oil Pump	Siemens/Allis	Analysis	(CNM-1301.00-249 B/A Lube Oil Pump Only)
- Diesel Battery	Nife, Inc.	Test	
- Diesel Battery Charger	Power Conversion Products	Test	
- Neutral Grounding Cabinet	E. P. Portec	Test	
- Governor EGB Actuator	Woodward	Analysis	
- Governor Servo Booster	Woodward	Analysis	
- Magnetic Pick-up	Airpax	Analysis	
- Fuel Oil Booster Pump	Westinghouse	Analysis	(CNM-1301.00-248)
4. Diesel Generator Fuel Oil Booster Pump Motor Starters	Nelson Electric	Test/Analysis	Nelson Electric T-700-101 (CNM-1314.01-0245)
5. 4160 Volt Essential Switchgear	Brown Boveri Electric	Test/Analysis	Gould 33-50465 (CNM-1312.02-00-0066)

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ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	QUALIFICATION METHOD	QUALIFICATION REFERENCE
6. 600 Volt Essential Load Center Switchgear	Brown Boveri Electric	Test/Analysis	Gould 33-50583 (CNM-1312.06-53)
7. 600 Volt Essential Motor Control Centers	Nelson Electric	Test/Analysis	Nelson Electric T1035.36 & .37 (CNM-1314.01-0242) (CNM-1314.01-0243)
8. 4160/600 Volt Essential Load Center Transformers	Westinghouse	Test/Analysis	Westinghouse Gen. Order Number: CH18615 MPS Order No: C46767 (CNM-1312.06-0056)
9. 120VAC Essential Panel-board Transformers	Square D (Sorgel)	Test/Analysis	Wyle Test Report 43205-1 (CNM-1308.03-0011)
10. 125VDC Vital Instr. & Control Batteries	Gould	Test/Analysis	Wyle Test Report No. 42795-1 (MCM-1356.01-05) Gould 064563-D (CNM-1356.01-09) Gould GB-3454 (CNM-1356.01-1 & 12)
11. 125VDC Vital Instr. & Control Battery Chargers	Solidstate Controls, Inc.	Test	Wyle Test Report No. 44000-1 (CNM-1356.05-0018)
12. Vital Instr. & Control Static Inverters	Solidstate Controls, Inc.	Test	Wyle Test Report No. 44000-1 (CNM-1358.03-0041)

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TABLE 3.10-2 (Page 22)

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ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	QUALIFICATION METHOD	QUALIFICATION REFERENCE
13. 125VDC Vital I & C Auctioneering Diode Assemblies	Power Conversion	Test	Wyle Test Report No. 44304-1 (CNM-1359.00-0001)
14. 125VDC Vital I & C Distribution Centers	Nelson Electric	Test/Analysis	Nelson Electric T1035.36 (CNM-1314.01-0242)
15. 125VDC & 120VAC Vital I & C Power Panelboards	Nelson Electric	Test/Analysis	Nelson Electric T-600.103 (CNM-1314.01-0244)
16. Electric Penetrations	D. G. O'Brien, Inc.	Test	D. G. O'Brien, Inc. Test Reports ER247 App. D, ER-252 App. K CNM-1361.00-0015 CNM-1361.00-0016 CNM-1361.00-0049
17. Electric Penetrations	Conax Corporation	Test/Analysis	Conax Corporation Test Report IPS-1037 (CNM-1361.00-0048)
18. RCP Switchgear Potential Transformers	Brown Boveri Electric	Test/Analysis	Gould 33-52420 (CNM-1312.07-28)

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TABLE 3.10-2 (Page 23)

Catawba Unit 2

ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	QUALIFICATION METHOD	QUALIFICATION REFERENCE
VI. Panels and Cabinets Including Components			
1. HVAC Control Panel	MCC Powers	Test/Analysis	Patel Report PEI TR-81-13 (CNM-1211.00-1470) Patel Report PEI TR-840800-1 (CNM-1211.00-1842)
2. Reactor Coolant Pump Power Monitor Panel	Frank Electric/Duke	Test	Wyle Test Report 44816-1 (CNM-1393.00-0004)
3. Monitor Light Cabinets	Beta	Test	Wyle Test Report 44331-1 (CNM-1346.01-111)
4. UHI Hydraulic Service Panels	Westinghouse	Analysis	Westinghouse Report dated 12/75 (CNM-1399.03-321)
5. Auxiliary Shutdown Panel HVAC Supply Unit	CVI	Analysis	Hissong Report HC-1174-1 (CNM-1211.00-943)
6. Auxiliary Feedwater Turbine Panel	Frank Electric/Duke	Test	Wyle Test Report 44891-1 (CNM-1393.00-0005)
7. Auxiliary Shutdown Panel	Frank Electric/Duke	Test	Wyle Test Report 44891-2 (CNM-1393.00-0006)
8. Main Control Board	Frank Electric/Duke	Test/Analysis	Duke Seismic Reports (CNC-1381.05-00-0029) (CNC-1381.05-00-0046)

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ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	QUALIFICATION METHOD	QUALIFICATION REFERENCE
9. Diesel Generator Load Sequencer Panel	Duke	Test	Wyle Test Report 45303-1 (CNM-1393.00-0010)
10. Nuclear Service Water Cabinets	Duke	Test	Wyle Test Report 44424-1 (CNM-1393.00-0001)
11. Miscellaneous Equipment Enclosures*	Duke	Test/Analysis	Later

*Includes: IC Cabinets
Terminal Boxes
Area Terminal Cabinets
Local Control Panels

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ELECTRICAL EQUIPMENT SEISMIC QUALIFICATION

EQUIPMENT CATEGORY & DESCRIPTION	EQUIPMENT VENDOR	MODEL	QUALIFICATION METHOD	QUALIFICATION REFERENCE
VII. Other Equipment				
1. Radiation Monitors	General Atomic	RD-23	Test	G.A. Test Report E-254-960 (CNM-1346.05-60)
2. Safety Valve Position Indication	TEC	914	Test/Analysis	TEC Report 517-TR-01,02,03 (CNM-1346.17-0012)
3. Hydrogen Analyzers	Teledyne Analytical	225 CM	Test/Analysis	Teledyne Analytical Test Report 58541
4. Electric Hydrogen Recombiner System	Westinghouse/B Sturtevant (NSSS)		Test/Analysis	WCAP-7709L Sup. 1-4 WCAP-7820 Sup. 1-4 (MCM-1399.36-0004)
5. ESF Filter Train Fire Protection System	Alison		Test	Wyle Test Report 45155-1 (CNM-1211.00-1559)
6. Electric Heater and Control Control Panel	Indeeco		Test/Analysis	CCL Report No. A-447-82-01 (CNM-1211.00-1544)
7. Cable Tray/Support System	Metal Products/Duke		Test/Analysis	CNC-1139.14-13-003

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and Volume Control System (CVCS) as a system in the analysis of transients presented in Chapter 15. Information on the capabilities of the CVCS is provided in Section 9.3.4. The adverse boron dilution possibilities due to the operation of the CVCS are investigated in Section 15.4.6. Prior proper operation of the CVCS has been presumed as an initial condition to evaluate transients and appropriate Technical Specifications have been prepared to ensure the correct operation or remedial action.

4.6.5 EVALUATION OF COMBINED PERFORMANCE

The evaluation of the steam line break, feedwater line break and loss of coolant accident which presume the combined actuation of the Reactor Trip System to the CRDS and the SIS are presented in Section 15.1.5, 15.2.8, and 15.6.5. Reactor trip signals and safety injection signals for these events are generated from functionally diverse sensors and actuate diverse means of reactivity control, i.e., control rod insertion and injection of soluble poison.

Non-diverse but redundant types of equipment are only utilized in the processing of the incoming sensor signals into appropriate logic which initiates the protective action. This equipment is described in detail in Section 7.2 and 7.3. In particular, note that protection from equipment failures is provided by redundant equipment and periodic testing. Effects of failures of this equipment have been extensively investigated as reported in Reference 4. This FMEA verifies that any single failure will not have a deleterious effect upon the Engineering Safety Features Actuation System. Adequacy of the Emergency Core Cooling System and SIS performance under faulted conditions is verified in Section 6.3.

5.0 REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

5.1 SUMMARY DESCRIPTION

The Reactor Coolant System (RCS) shown in Figures 5.1-1, 5.1-2 and 5.1-3 consists of four similar heat transfer loops connected in parallel to the reactor pressure vessel. Each loop contains a reactor coolant pump, steam generator and associated piping and valves. In addition, the system includes a pressurizer, pressurizer relief and safety valves, a pressurizer relief tank interconnecting piping, and instrumentation necessary for operational control. All the above components are located in the Containment building.

During operation, the RCS transfers the heat generated in the core to the steam generators where steam is produced to drive the turbine generator. Borated demineralized water is circulated in the RCS at a flow rate and temperature consistent with achieving the reactor core thermal-hydraulic performance. The water also acts as a neutron moderator and reflector, and as a solvent for the neutron absorber used in chemical shim control.

The RCS pressure boundary provides a barrier against the release of radioactivity generated within the reactor, and is designed to ensure a high degree of integrity throughout the life of the plant.

RCS pressure is controlled by the use of the pressurizer where water and steam are maintained in equilibrium by electrical heaters and water sprays. Steam can be formed (by the heaters) or condensed (by the pressurizer spray) to minimize pressure variations due to contraction and expansion of the reactor coolant. Spring-loaded safety valves and power operated relief valves from the pressurizer provide for steam discharge to the pressurizer relief tank, where the steam is condensed and cooled by mixing with water.

The extent of the RCS is defined as:

1. The reactor vessel including control rod drive mechanism housings.
2. The reactor coolant side of the steam generators.
3. Reactor coolant pumps.
4. A pressurizer attached to one of the reactor coolant loops.
5. Safety and relief valves.
6. The pressurizer relief tank.
7. The interconnecting piping, valves and fittings between the principal components listed above.
8. The piping, fittings and valves leading to connecting auxiliary or support systems up to and including the second isolation valve (from the high pressure side) on each line.

5.2.2.9 System Reliability

The reliability of the pressure relieving devices is discussed in Section 4 of Reference 2.

5.2.2.10 Testing and Inspection

Testing and inspection of the overpressure protection components are discussed in Section 5.4.13.4 and Chapter 14.

5.2.3 MATERIALS SELECTION, FABRICATION, AND PROCESSING

5.2.3.1 Material Specifications

Material specifications used for the principal pressure retaining applications in each component comprising the Reactor Coolant Pressure Boundary (RCPB) are listed in Table 5.2.3-1 for ASME Class I Primary Components and Table 5.2.3-2 for ASME Class 1 and 2 Auxiliary Components. Tables 5.2.3-1 and 5.2.3-2 also include the unstabilized austenitic stainless steel material specifications used for the components in systems required for reactor shutdown and for emergency core cooling.

The unstablized austenitic stainless steel material for the reactor vessel internals which are required for emergency core cooling for any mode of normal operation or under postulated accident conditions and for core structural load bearing members are listed in Table 5.2.3-3.

All of the materials utilized conform to the material specification requirements and include the special requirements of applicable ASME Code Rules.

In some cases, Table 5.2.3-2 may not be inclusive of the material specifications used in the listed applications. However, the listed specifications are representative of those materials utilized.

The welding materials used for joining the ferritic base materials of the RCPB, conform to, or are equivalent to, ASME Material Specifications SFA 5.1, 5.2, 5.5, 5.17, 5.18 and 5.20. They are tested and qualified to the requirements of ASME Section III.

The welding materials used for joining the austenitic stainless steel base materials of the RCPB conform to ASME Material Specifications SFA 5.4 and 5.9. They are tested and qualified according to the requirements of ASME Section III.

The welding materials used for joining nickel-chromium-iron alloy in similar base material combination and in dissimilar ferritic or austenitic base material combination conform to ASME Material Specifications SFA 5.11 and 5.14. They are tested and qualified to the requirements of ASME Section III.

5.2.3.2 Compatibility with Reactor Coolant

5.2.3.2.1 Chemistry of Reactor Coolant

In addition to the Technical Specifications, the primary coolant chemistry specification will be derived from NSSS vendor specifications and EPRI Primary

Water Chemistry Guidelines. Operating guidelines will be addressed in CP/O/A/8800/05 - Chemistry Procedure for Recording and Management of Data.

The incore instrumentation room sump is located under the reactor vessel in the tunnel area, where no leakage is expected under normal conditions. Therefore, an alarm is actuated in the control room if this pump ever starts. A flow integrator is provided on the combined sump pump discharge for periodic monitoring with an accuracy of one gpm, as recommended by Regulatory Guide 1.45, position C2.

5.2.5.2.3.2 Containment Airborne Monitor

The containment airborne monitor continuously monitors the gaseous, iodine, and air particulate activity levels in the containment atmosphere, as described in Section 11.5.1.2.2.2. Unidentified leakage is detected and, to the extent practicable, quantified by these monitors with response times dependent upon the sum of the time for the leakage to mix with the containment volume and the time of transit from the point of leakage, the unidentified leakage rate, the identified baseline leakage rate, and the amount of gaseous fission product activity in the coolant for the gas monitor. In addition, for the iodine and particulate monitors, response times depend on the amount of corrosion and fission product activity in the coolant, the fraction of iodines and particulates which escape into the containment atmosphere, the amount of plate out on containment surfaces, and the collection rate of the filter mechanism. The amount of fission product inventory in the reactor coolant depends on the fraction of failed fuel, fission product inventory in the core, fission product escape rates, and reactor coolant processing history. Table 5.2.5-1 presents information on the sensitivity of the monitors.

Q 410.9

The containment airborne radiation monitoring system will remain functional during and following a safe shutdown earthquake, as recommended in Regulatory Guide 1.45, position C6.

5.2.5.2.3.3 Containment Ventilation Unit Condensate Drain Tank (CVUCDT)

The quantity and activity of the CVUCDT contents will also be an indicator of excessive leakage from the Reactor Coolant System. A sudden increase in the flow rate of ventilation unit condensate indicates an increase in the relative humidity of the containment atmosphere. Such an increase in clean condensate flow in the absence of containment purge is unusual and indicates leakage from a non-radioactive system. Increased radioactivity, as indicated by an alarm from the off-line gamma detector located in the CVUCDT pump discharge, results in system isolation and implies reactor coolant leakage. A high level in the CVUCDT also actuates a control room alarm and, along with radioactivity measurements, quantifies the leak.

5.2.5.2.3.4 Humidity Detectors

Two humidity detectors (one each at the inlets to the upper and lower air handling units) are installed within the Containment on Unit two. The humidity detectors provide information on changes in dewpoint and relative humidity.

TABLE 5.2.3-4 (Page 1)

REACTOR COOLANT CHEMISTRY SPECIFICATION

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5.4.2 STEAM GENERATOR

5.4.2.1 Steam Generator Materials

5.4.2.1.1 Selection and Fabrication of Materials

All pressure boundary materials used in the steam generator are selected and fabricated in accordance with the requirements of Section III of the ASME code. A general discussion of materials specifications is given in Section 5.2.3, with types of materials listed in Tables 5.2.3-1 and 5.2.3-2. Fabrication of Reactor Coolant Pressure Boundary materials is also discussed in Section 5.2.3, particularly in Sections 5.2.3.3 and 5.2.3.4.

Testing has justified the selection of corrosion resistant thermally treated Inconel-600, a nickel-chromium-iron alloy, for the steam generator tubes (SB-163). The channel head divider plate is Inconel (SB-168). The interior surfaces of the reactor coolant channel heads and nozzles are clad with austenitic stainless steel. The primary side of the tube sheet is weld clad with Inconel. The tubes are hydraulically expanded for the full depth of the tube sheet after the ends are seal welded to the tube sheet cladding. The recessed fusion welds are performed in compliance with Sections III and IX of the ASME Code and are thoroughly inspected before each tube is expanded.

Code cases used in material selection are discussed in Section 5.2.1. The extent of conformance with Regulatory Guides 1.84 and 1.85 is also discussed there.

During manufacture, cleaning is performed on the primary and secondary sides of the steam generator in accordance with written procedures which follow the guidance of Regulatory Guide 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants," and the ANSI Standard N45.21-1973, "Cleaning of Fluid Systems and Associated Components for Nuclear Power Plants". Onsite cleaning and cleanliness control are done by the applicant. Westinghouse recommendations for cleaning are given in Westinghouse process specifications, as discussed in Section 5.2.3.4.

The fracture toughness of the materials is discussed in Section 5.2.3.3. Adequate fracture toughness of ferritic materials in the RCPB is provided by compliance with Appendix G of 10CFR50 and with Article NB-2300 of Section III of the ASME Code. Per the discussion in Section 5.4.2.3, consideration of fracture toughness is only necessary for materials in Class 1 components.

5.4.2.1.2 Steam Generator Design Effects on Materials

Several features are employed to control the regions where deposits would tend to accumulate hydraulically. To avoid extensive crevice areas at the tube sheet, the tubes are hydraulically expanded to the secondary surface of the tube sheet, where their ends are seal welded to the Inconel cladding on the primary side of the tube sheet. A flow distribution plate located below the preheat section encourages recirculating flow to sweep the tube sheet before turning upward through the tube bundle. This plate also serves to separate the tube sheet from the colder feedwater entering at the preheat section. A separate auxiliary feedwater nozzle provided in the upper shell avoids introducing cold water into the preheat section, and, thus, maximizes the integrity of steam generator materials.

5.4.2.1.3 Compatibility of Steam Generator Tubing with Primary and Secondary Coolants

As mentioned in Section 5.4.2.1.1, corrosion tests of thermally treated Inconel 600, which subjected the steam generator tubing material to simulated steam generator water chemistry, have indicated that the loss due to general corrosion over the 40 year plant life is insignificant compared to the tube wall thickness. Testing to investigate the susceptibility of heat exchanger construction materials to stress corrosion in caustic and chloride aqueous solutions has indicated that thermally treated Inconel-600 has excellent resistance to general corrosion in severe operating water conditions. Many reactor years of successful operation have shown the same low general corrosion rates as indicated by the laboratory tests. Refer to Section 9.3.2.2.2, concerning methods used to monitor secondary coolant purity.

Recent operating experience, however, has revealed areas on secondary surfaces where localized corrosion rates were significantly greater than the low general corrosion rates. Both intergranular stress corrosion and tube wall thinning were experienced in localized areas, although not at the same location or under the same environmental conditions (water chemistry, sludge composition).

To eliminate these localized areas of corrosion over the long term operation of the unit, it was decided that the use of phosphates for steam generator control would be eliminated. The adoption of the All Volatile Treatment (AVT) control program will minimize the possibility for recurrence of the tube wall thinning phenomenon related to phosphate chemistry control. Successful AVT operation requires maintenance of low concentrations of impurities in the steam generator water, thus reducing the potential for formation of highly concentrated solutions in low flow zones, the precursor of the corrosion mechanisms. By restriction of the total alkalinity in the steam generator and prohibition of extended operation with free alkalinity, the AVT program will minimize the recurrence of intergranular corrosion in localized areas due to excessive levels of free caustic.

Localized steam generator tube diameter reductions were first discovered during the April 1975 steam generator inspection at the Surry Unit No. 2 plant. This discovery was evidenced by eddy current signals, resembling those produced by dents, and by difficulty in passing the standard eddy current probe through the tubes at the intersections with the support plates. Subsequent to the initial finding, steam generator inspections at other operating plants revealed indications of denting to various degrees.

Denting is a term which describes a group of related phenomena resulting from corrosion of carbon steel in the crevices formed between the tubes and the tube support plates. The term "denting" has been applied to the secondary effects which include:

1. Tube diameter reduction

2. Tube support plate hole dilation

3. Tube support plate flow hole distortion, flow slot hourglassing

4. Tube support plate expansion

5. Tube leakage

6. Wrapper distortion

The mechanism which produces the effects cited involves an acid chloride environment in the tube crevices, in sequence, the process appears to occur as follows:

The crevice betweeen the tube and the support plate is blocked as a result of deposition of chemical species present in the bulk water, including phosphate compounds, secondary system corrosion products and minimal tube corrosion products. Once plugged the annulus provides a site for concentration of various nominally soluble contaminants, such as chlorides, sulfates, etc. Recent studies indicate that in the absence of non-volatile, alkalizing species, there may exist the potential for production of an acid solution by hydrolysis of such compounds as magnesium chloride, nickel phosphate, copper-chloride, various ferrous salts, etc. In an acid chloride solution, the corrosion film on the carbon steel is converted from protective in character, to a thick, non-protective oxide which assumes a laminar configuration subject to disruption due to the volume mismatch between the oxide and the base metal. The buildup of the thick oxide in the nominal 14 mil radial gap between the tube and the support plate causes sufficient force to be exerted against the tube to cause plastic deformation locally. The reaction to these forces can cause distortion of the circulation holes in the plate, both the flow holes between the tubes and the central flow slots between the inlet and outlet halves of the tube bundle. In the most extreme cases as corrosion proceeds and in-plate forces accumulate, the entire plate increases in diameter and the ligaments between the holes in the plate may crack. Ovalization of the tubes at the intersections results in high strains, leading to tensile stress on the tube ID and possible leakage by intergranular stress corrosion cracking. A similar result may occur at the apex of first row; i.e., the smallest radius U-bends, if sufficient distortion of the top support plate flow slots occurs, resulting in leg displacement, ovalization, and high strains.

The tube leakage and support plate effects do not pose a safety problem with respect to release of radioactivity or effects on accident calculations, but the frequency of leakage and resultant repair shutdowns does present an economic concern to the operators. The utilization of preventive plugging therefore serves to maintain availability and to permit orderly planning for long-term corrective action.

The occurrence of denting has thus far been associated exclusively with plants having a history of chloride contamination due to condenser leakage. However, it has recently been noted that Maine Yankee and Millstone Point 2, non-Westinghouse plants which have used AVT exclusively, have apparently incurred denting also; sea water is used for cooling the condensers at both of these plants.

Research into the causes of denting was initiated shortly after the discovery of the denting condition. Initially dented tubes were removed for laboratory examination. Subsequently tube support plate samples containing sections of tubing were also removed for analysis from operating plants.

The initial hard data on the nature of the denting phenomenon were derived from these tube/support plate samples which revealed the thick oxide buildup, the tube diameter reduction, and chemical makeup of the crevice-filling materials. It was observed that there was only minor corrosive attack on the tube material, approximately 0-2 mil circumferential thinning, and that the crevice contained a thick layer of almost pure magnetite (Fe_3O_4); other chemical constituents included Inconel-metal-phosphate corrosion products close to the tube, and general secondary system contaminants between the Fe_3O_4 and the phosphate layer. There was evidence of copper deposits and the oxide was laced with chlorides.

Armed with those general observations, a series of crevice-with-contaminants test geometrics were evaluated; denting was produced first in reverse as "bulging" when a carbon steel plug was inserted into an Inconel tube to form the crevice; later heated crevice assemblies with heat transfer were shown to be effective dent simulators; finally denting in model boilers equipped with plant-type geometrical configurations was demonstrated. While pure, uncontaminated AVT environments have to date been found to be innocuous, it has been shown that the PO_4 to AVT transition was unnecessary to initiate the denting process. Only the presence of acid chloride solutions has been found to be a common factor. Nickel chloride, ferrous or cupric chloride solutions have been shown to be corrosive, and have also produced measurable denting. Thus far, test data indicate that phosphates, calcium hydroxide, and borates seem to retard the dent process; morpholine, among the common volatile amines, shows a beneficial effect on the corrosion rate of carbon steel.

Model boiler tests have been used to evaluate the adequacy of the AVT chemistry specifications adopted in 1974. The guidelines appear to be adequate to preserve tube integrity with one significant alteration: operation with containment ingress must be limited. Operation with strict AVT specifications will maintain the most functional steam generator environment.

Operating experience, verified in numerous steam generator inspections, indicates that the tube degradation associated with phosphate water treatment is not occurring where only AVT has been utilized. Adherence to the AVT chemical specifications and close monitoring of the condenser integrity will aid in the continued good performance of the steam generator tubing.

Increased margin against stress corrosion cracking has been obtained by employing thermally treated Inconel-600 tubing. Laboratory testing has shown that the thermally treated Inconel-600 tubing is compatible with the AVT environment. Isothermal corrosion testing in high purity water has shown that thermally treated Inconel-600 exhibiting normal microstructures tested at normal engineering stress levels does not suffer integrannular stress corrosion cracking in extended high temperature exposure. Thermal treatment of Inconel tubes has been shown to be particularly effective in resisting caustic corrosion. Tubing used in the model D5 Steam Generator is thermally treated in accordance with a laboratory derived treatment process.

A comprehensive program of steam generator inspections, including the requirements of Regulatory Guide 1.83, should provide for detection and correction of any unanticipated degradation that might occur in the steam generator tubing.

Water purity in the secondary system, especially in the steam generators, is maintained within specified limits in order to minimize corrosion and to minimize corrosion of steam generator heat transfer surfaces. The quality of the feedwater

exposed to the units is controlled by properly operating the polishing demineralizers as well as maintaining condenser vacuum.

In addition, the Steam Generator Blowdown System is designed to maintain the correct shell side water chemistry by removing non-volatile materials due to steam generator tube leaks, corrosion or condenser tube leaks. The blowdown system also provides a normal path for the steam generator blowdown fluid to the inlet of the condensate polishing demineralizer for purification and reuse in the condensate cycle.

The Condensate Cleanup System is designed to remove dissolved and suspended impurities which can cause corrosion damage to secondary system equipment. The condensate polishing demineralizers are also used to remove impurities which could enter the system due to a condenser circulating water tube leak.

Yet another method used to clean operating steam generators of corrosion causing secondary side deposits is sludge lancing. This procedure is one in which a hydraulic jet, which is inserted through an access opening (inspection port), loosens deposits which are then removed by means of a suction pump. Sludge lancing can be performed when the need is indicated by the results of steam generator tube inspection.

A number of design changes have been incorporated in the Model D5 steam generator for Catawba Unit 2 that were not included for the Model D3 steam generator for Unit 1. These changes have been incorporated to reduce the consequences of adverse secondary side environmental conditions and hence improve overall steam generator reliability.

The tube support plates used in the Model D5 will be ferritic stainless steel which has been shown in laboratory tests to be resistant to corrosion in the AVT environment. When corrosion of ferritic stainless steel does occur, the volume of the corrosion products is equivalent to the volume of the consumed material. The support plates will also be designed with broached tube holes rather than drilled holes. The broached tube hole design promotes high velocity flow along the tube sweeping any impurities away from the support plate location.

Additional measures are incorporated in the Model D5 design to prevent areas of dryout in the steam generator and accumulations of sludge in low velocity areas. Modifications to the wrapper have increased water velocities across the tubesheet. A flow distribution baffle is provided which forces the low flow area to the center of the bundle. Increased capacity blowdown pipes have been added to enable continuous blowdown of the steam generators at a high volume. The intakes of these blowdown pipes are located below the center cutout section of the flow distributed baffle in the low velocity region where sludge may be expected to accumulate. Continuous blowdown provides maximum protection against inleakage of impurities from the condenser.

Another feature of the Model D5 generator that helps prevent tube damage is the higher circulation ratio. Increased circulation flow is vital for proper thermal hydraulic performance and also for control of the inventory of corrosion products, erosion products, and impurities (sludge) at the tube sheet. A high circulation flow results in increased fluid velocity into the tube bundle region which sweeps these undesirable products into the tube lane where this sludge is readily removed by the blowdown system.

5.4.2.1.4 Cleanup of Secondary Side Materials

Several methods are employed to clean operating steam generators of corrosion causing secondary side deposits. Sludge lancing, a procedure in which a hydraulic jet inserted through an access opening (inspection port) loosens deposits which are removed by means of a suction pump, can be performed when the need is indicated by the results of Steam Generator tube inspection. Blowdown procedures are performed as deemed necessary by regular water chemistry testing. The location of the blowdown piping suction, adjacent to the tube sheet and in a region of relatively low flow velocity, facilitates the removal of impurities that have accumulated on the tube sheet.

5.4.2.2 Steam Generator Inservice Inspection

The steam generator is designed to permit inservice inspection of Class 1 and 2 components, including individual tubes. The design aspects that provide access for inspection and the proposed inspection program comply with the edition of Section XI of the ASME Code, Division 1, "Rules for Inspection and Testing of Components of Light-Water-Cooled Plants", required by 10CFR50.55a, paragraph g. A number of access openings make it possible to inspect and repair or replace a component according to the techniques specified. These openings include four manways, two of them for access to both sides of the reactor coolant channel head and two of them for inspection and maintenance of the steam dryers, and four 2 inch inspection ports located just above the tube sheet surface. The steam generator also has five 6 inch handholes and two 2.5 inch instrument openings for additional access through the secondary side pressure boundary.

Inservice inspection of Class I components includes that of individual Steam Generator tubes. Equipment and access openings provided make it possible to detect and locate tubes with a wall defect penetrating 20% or more. Recommendations for such a program, including description of equipment, baseline and internals of inspection, criteria for selection, methods of recording, and actions to be taken if a defect is found, are given in Regulatory Guide 1.83, "Inservice Inspection of Pressurizer Water Reactor Steam Generator Tubes". Regulatory Guide 1.121, "Basis for Plugging Degraded Steam Generator Tubes", provides recommendations concerning tube plugging. Supplementary information, including tube plugging criteria, can be found in the Technical Specifications.

5.4.2.3 Design Bases

Steam generator design data are given in Table 5.4.2-1. Code classifications of the steam generator components are given in Section 3.2. Although the ASME classification for the secondary side is specified to be Class 2, the current philosophy is to design all pressure retaining parts of the steam generator, and thus both the primary and secondary pressure boundaries, to satisfy the criteria specified in Section III of the ASME Code for Class 1 components. The design stress limits, transient conditions and combined loading conditions applicable to the steam generator are discussed in Section 3.9.1. Estimates of radioactivity levels anticipated in the secondary side of the steam generators during normal operation, and the bases for the estimates are given in Chapter 11. The accident analysis of a steam generator tube rupture is discussed in Chapter 15.

The internal moisture separation equipment is designed to ensure that moisture carryover does not exceed 0.25 percent by weight under the following conditions:

1. Steady state operation up to 100 percent of full load steam flow, with water at the normal operating level.

2. Loading or unloading at a rate of five percent of full power steam flow per minute in the range from 15 percent to 100 percent of full load steam flow.

3. A step load change of ten percent of full power in the range from 15 percent to 100 percent full load steam flow.

The water chemistry on the reactor side is selected to provide the necessary boron content for reactivity control and to minimize corrosion of Reactor Coolant System surfaces. The water chemistry of the steam side and its effectiveness in corrosion control are discussed in Chapter 10. Compatibility of steam generator tubing with both primary and secondary coolants is discussed further in Section 5.4.2.1.3.

The steam generator design is evaluated to minimize the possibility of mechanical failure or flow induced vibration. Tube support adequacy is discussed in Section 5.4.2.5.3. The tubes and tube sheet are analyzed in WCAP-7832 (Reference 2) and confirmed to withstand the maximum accident loading condition as it is defined in Section 3.9.1. Further consideration is given in Section 5.4.2.5.4 to the effect of tube wall thinning on accident condition stresses.

The preheat section of the steam generator is arranged to provide the maximum amount of counter flow feasible and, therefore, more efficient heat transfer.

A separate auxiliary feedwater nozzle is provided in the upper shell in order to avoid introducing cold water into the possibly hot and empty preheat section. The integrity of the Steam Generator design is, thus, maximized.

5.4.2.4 Design Description

The steam generator shown in Figure 5.4.2-1 is a vertical shell and U-tube evaporator with integral moisture separating equipment.

On the primary side, the reactor coolant flows through the inverted U-tubes, entering and leaving through nozzles located in the hemispherical bottom head of the steam generator. The head is divided into inlet and outlet chambers by a vertical divider plate extending from the head to the tube sheet.

Steam is generated on the shell side, flows upward and exits through the outlet nozzle at the top of the vessel. During normal operation, feedwater flows through a flow restrictor, directly into the counter flow preheat section and is heated almost to saturation temperature before entering the boiler section. For the Model D5 Steam Generators, a portion of the feedwater enters the system through the auxiliary nozzle in the upper shell, reducing the magnitude of feedwater flow into the preheat section. Subsequently the water-steam mixture flows upward through the tube bundle and into the steam drum section, where individual centrifugal moisture separators remove most of the entrained water from the steam. The steam continues to the secondary separators for further moisture

removal, increasing its quality to a minimum of 99.75 percent. The moisture separators recirculate the separated water through the annulus between the shell and tube bundle wrapper via the space formed by the disflow then combines with the already preheated water-steam mixture for another passage through the steam generator. Dry steam exits through the outlet nozzle which is provided with a steam flow restrictor, described in Section 5.4.4.

5.4.2.5 Design Evaluation

5.4.2.5.1 Forced Convection

The limiting case for heat transfer capability is the "nominal 100 percent design" case. The steam generator effective heat transfer coefficient is based on the coolant conditions of temperature and flow for this case, and includes a conservative allowance for tube fouling. Adequate tube area is selected to ensure that the full design heat removal rate is achieved.

5.4.2.5.2 Natural Circulation Flow

The driving head created by the change in coolant density as it is heated in the core and rises to the outlet nozzle initiates convection circulation. This circulation is enhanced by the fact that the steam generators, which provide a heat sink, are at a higher elevation than the reactor core which is the heat source. Thus natural circulation is assured for the removal of decay heat during hot shutdown in the unlikely event of loss of forced circulation.

5.4.2.5.3 Mechanical and Flow Induced Vibration Under Normal Operation

In the design of Westinghouse steam generators, the potential for tube wall degradation attributable to mechanical or flow induced excitation has been thoroughly evaluated. The evaluation included detailed analyses of the tube support systems for various mechanisms of tube vibration.

The primary cause of tube vibration in heat exchangers is hydrodynamic excitation due to secondary fluid flow on the outside of the tubes. In the range of normal steam generator operating conditions, the effects of primary fluid flow inside the tubes and mechanically induced tube vibration are considered to be negligible.

To evaluate flow induced tube vibration in the preheater region of the tube bundle, Westinghouse undertook an extensive program employing data from operating plants, full and partial scale model tests and analytical tube vibration models. Operating plant data consisted of tube wear data from pulled tube evaluations and eddy current tests, and tube motion data from accelerometers installed inside selected tubes. Model testing generated tube wear data, flow velocity distributions, tube motion parameters and flow induced tube vibration forcing functions. The tube vibration analyses applied the forcing functions to produce tube motion data. The results of this evaluation were consistent with the early operating experience of preheat steam generators.

On the basis of an extensive model test and analysis program, Westinghouse designed, verified and implemented a modification to the steam generator to reduce tube vibratory response to preheater inlet flow excitation. Additionally, the magnitude of the flow forcing function was reduced thru implementation of

a preheater flow bypass arrangement in the feedwater system. The verification of the performance of the modifications in reducing tube excitation and response was done with input from a full scale test under simulated conservative flow and tube support conditions.

Fatigue of the tubes in the preheater region which are subject to flow induced excitation is not a concern since the maximum resultant stresses in the tube are below the endurance limit of the material.

For areas of the tube bundle other than the preheater, parallel flow analyses were performed to determine the vibratory deflections. These analyses indicate that the flow velocities are sufficiently low such that they result in negligible fatigue and vibratory amplitudes. The support system, therefore, is deemed adequate with regard to parallel flow excitation.

To evaluate cross flow at the exit of the downcomer flow to the tube bundle and at the top of the bundle in the U-bend area, Westinghouse performed an experimental research program of cross flow in tube arrays with the specific parameters of the steam generator. Air and water model tests were employed. The results of this research indicate that these regions of the bundle are not subject to the vortex shedding mechanism of tube excitation. Vortex shedding was found not to be a significant mechanism in these two regions for the following reasons:

A. Flow turbulence in the downcomer and tube bundle inlet region inhibit the formation of Von Karman vorticies.

B. Both axial and cross flow velocity components exist on the tubes. The axial flow component disrupts the Von Karman vortices.

This research program was also the basis for evaluation of the fluidelastic mechanism due to cross flow at the tubesheet. The evaluation showed the adequacy of the tube support arrangement.

Flow turbulence can result in some tube excitation in these regions. This excitation is of little concern, however, since:

A. Maximum stresses in the tubes are at least an order of magnitude below the fatigue endurance limit of the tube material, and

B. Tube support arrangements preclude significant vibratory motion.

In summary, tube vibration has been thoroughly evaluated. Mechanical and primary flow excitation are considered negligible. Secondary flow excitation has been evaluated. From this evaluation, it is concluded that if tube vibration does occur, the magnitude will be limited. Tube fatigue due to the vibration is judged to be negligible. Any tube wear resulting from the tube vibration would be limited and would progress slowly. This allows use of a periodic tube inservice inspection program for detection and follow of any tube wear. This inservice inspection program, in conjunction with tube plugging criteria, provides for safe operation of the steam generators.

5.4.2.5.4 Allowable Tube Wall Thinning Under Accident Conditions

An evaluation is performed to determine the extent of tube wall thinning that can be tolerated under accident conditions. Under such a postulated design basis accident, vibration is of short enough duration that the endurance problem is insignificant. The results of a study made on "D series" (.75 inch nominal diameter, .043 inch nominal thickness) tubes under accident loading are discussed in WCAP-7832 (Reference 2) and show that a minimum wall thickness of .026 inches would have a maximum faulted condition stress (i.e., due to combined LOCA and Safe Shutdown Earthquake loads) that is less than the allowable limit. This thickness is .010 inches less than the minimum steam generator tube wall thickness .039 reduced to .036 inches by the assumed general corrosion and erosion loss of .003 inches.

The corrosion rate is based on a conservative weight loss rate for Inconel tubing in flowing 629°F primary side reactor coolant fluid. The weight loss, when equated to a thinning rate and projected over a 40 year plant life with appropriate reduction after initial exposure, is equivalent to 0.083 mils thinning. The assumed corrosion rate of 3 mils leaves a conservative 2.917 mils for general corrosion thinning on the secondary side.

The steam generator tubes, existing originally at their minimum wall thickness and reduced by a very conservative general corrosion loss, still provide quite an adequate safety margin. Thus, it can be concluded that the ability of the steam generator tubes to withstand accident loadings is not affected by the maximum corrosion rate assumed.

Regulatory Guide 1.121, Basis For Plugging Degraded PWR Steam Generator Tubes, Revision 0, August 1976, presents detailed analytical and loading criteria to be used in determing the plugging limit as defined in the steam generator surveillance requirements section of the Technical Specifications. Westinghouse considers some of these criteria unnecessarily conservative and, in some cases, unworkable. Detailed comments to this guide were transmitted to the NRC on November 22, 1977 by Westinghouse Letter NS-CE-1282 from C. Eicheldinger to S. J. Chilk.

Position C.1

Westinghouse interprets the term "Unacceptable defects" to apply to those imperfections resulting from service induced mechanical or chemical degradation of the tube walls which have penetrated to a depth in excess of the Plugging Limit.

Positions C.2.a(2) and C.2.a(4)

Westinghouse will use a 200 percent margin of safety based on the following definition of tube failure. Westinghouse defines tube failure as plastic deformation of a crack to the extent that the sides of the crack open to a non-parallel, elliptical configuration. This 200 percent margin of safety compares favorably with the 300 percent margin requested by the NRC against gross failure.

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TABLE 5.4.2-1

STEAM GENERATOR DESIGN DATA

	Unit 1	Unit 2
Design Pressure, reactor coolant side, psig	2485	2485
Design Pressure, steam side, psig	1185	1185
Design Temperature, reactor coolant side, °F	650	650
Design Temperature, steam side, °F	600	600
Total Heat Transfer Surface Area, ft^2	48,000	48,165
Maximum Moisture Carryover, wt percent	0.25	0.25
Overall Height, ft-in	67-8	67-8
Number of U-Tubes	4674	4570
U-Tube Nominal Diameter, in.	.750	.750
Tube Wall Nominal Thickness, in.	.043	.043
Number of Manways	4	4
Inside Diameter of Manways, in.	16	16
Number of Inspection Ports		
2.0" Dia.	4	-
2.5" Dia.	-	2
6.0" Dia.	-	5
Design Fouling Factor	0.00010	0.00010
Preheat Section	0.00010	0.00010

test program (Reference 1) performed by Westinghouse considered spray and core cooling solutions of the design chemical compositions, as well as the design chemical compositions contaminated with corrosion and deterioration products which may be transferred to the solution during recirculation. The effects of sodium (free caustic), chlorine (chloride), and fluorine (fluoride) on austenitic stainless steels were considered. Based on the results of this investigation, as well as testing by ORNL and others, the behavior of austenitic stainless steels in the post DBA environment will be acceptable. No cracking is anticipated on any equipment even in the presence of postulated levels of contaminants, provided the core cooling and spray solution pH is maintained at an adequate level. The inhibitive properties of alkalinity (hydroxyl ion) against chloride cracking and the inhibitive characteristic of boric acid on fluoride cracking have been demonstrated.

Information concerning the degree to which the materials used comply with Regulatory Guides 1.31, 1.37, and 1.44 are discussed in Section 5.2.3.4.

6.1.1.2 Composition, Compatibility, and Stability of Containment and Core Spray Coolants

The vessels used for storing ESF coolants include the cold leg accumulators, one of the upper head injection accumulators, the upper head injection surge tank and the refueling water storage tank.

The cold leg and upper head injection accumulators are carbon steel clad with austenitic stainless steel and the UHI surge tank is austenitic stainless steel. Because of the corrosion resistance of these materials, significant corrosive attack on the storage vessels is not expected.

The cold leg accumulators and the UHI surge tank are filled with borated water and pressurized with nitrogen gas. Whereas, one of the UHI accumulators is filled with boric acid and the second, in series with the first, is pressurized with nitrogen gas. The nominal boron concentration, as boric acid, is 2000 ppm. Samples of the solution in the accumulators and surge tank are taken periodically for checks of boron concentration. Principal design parameters of the accumulators and surge tank are listed in Table 6.3.2-1.

The refueling water storage tank is a source of borated cooling water for injection. The nominal boron concentration, as boric acid, is 2000 ppm, which is below the solubility limit at freezing. The temperature of the refueling water is maintained above 70°F. Principal design parameters of the refueling water storage tank are given in Section 9.1.

The method of establishing containment spray and recirculation sump pH following a LOCA is discussed in Sections 6.2.2 and 6.2.3. Information concerning hydrogen release by the corrosive gas concentrations within the containment following a LOCA is discussed in Section 6.2.5.

6.1.1.2.1 Post Accident Chemistry

The soluble acids and bases identified within the containment are boric acid and sodium tetraborate. Boron in the form of boric acid is present in the reactor coolant system, accumulators and refueling water storage tank. Boron and sodium hydroxide in the form of sodium tetraborate are present in the ice.

Boron in the form of boric acid (H_3BO_3) is found in the reactor coolant system (2000 ppm), in the accumulators and refueling water storage tank (2100 ppm).

Sodium tetraborate ($Na_2B_4O_2$) is an additive in the ice of the ice condenser. Sodium tetraborate ice consists of sodium hydroxide, NaOH, boric acid, H_3BO_3 and water combined as follows:

$$2NaOH+4H_3BO_3 \rightarrow Na_2B_4O_7+7H_2O$$

The ice bed holds approximately 2.13×10^6 pounds of ice having a minimum boron concentration, per Technical Specifications, of 1800 ppm. The NaOH/B ratio is 1.85. Hence, there are 3834 pounds of boron and 7093 pounds of sodium hydroxide contained in the ice.

6.1.1.2.2 Final Post Accident Chemistry

A time history of the pH of the containment sump, following a design basis accident, has been estimated for a minimum and maximum pH case, and is presented in Figure 6.1.1-1. The sump pH reaches 8.0 in less than 5 minutes and remains in the range of 8.0 to 9.0 for the duration of the accident. Thus, stress-corrosion cracking of austenitic stainless steel components and excessive hydrogen generation by corrosion of aluminum and galvanized components is avoided.

The assumptions used in the calculations are presented in Table 6.1.1-2. The pH is determined using the titration curves for boric acid with sodium hydroxide presented in WCAP-7153-A (Reference 2).

6.1.2 ORGANIC MATERIALS

6.1.2.1 Coatings and Paint in Westinghouse Scope

Quantification of significant amounts of protective coatings on Westinghouse supplied components located inside the Containment building is given in Table

Table 6.1.1-2 (Page 1)

PARAMETERS OF FINAL POST-ACCIDENT CHEMISTRY

Parameters	CASE 1 Maximum pH Case		CASE 2 Minimum ph Case	
	Value	Reference	Value	Reference
1. RHR pump flow rate, 2 trains (gpm)	6,000	FSAR, Table 5.4.7-2	6,000	FSAR, Table 5.4.7-2
2. SI pump flow rate, 2 trains (gpm)	800	FSAR, Table 6.3.2-1	800	FSAR, Table 6.3.2-1
3. Spray pump flow rate, 2 trains (gpm)	6,800	FSAR, Table 6.2.2-1	6,800	FSAR, Table 6.2.2-1
4. RWST boron concentration (ppm)	2,000	Tech. Spec. Page 3/4 5-11	2,100	Tech. Spec. Page 3/4 5-11
5. Accumulator boron concentration (ppm)	1,900	Tech. Spec. Page 3/4 5-1 & 5-3	2,100	Tech. Spec. Page 3/4 5-1 & 5-3
6. RCS boron concentration (ppm)	0		2,000	
7. RWST volume (gallons)	350,000	Tech. Spec. Page 3/4 1-12	363,513	FSAR, Table 6.3.3-2
8. (1) Upper Head Injection & (4) Cold Leg Accumulators, Total volume (gallons)	44,813	Tech. Spec. Page 3/4 5-1 & 5-3	46,085	Tech. Spec. Page 3/4 5-1 & 5-3
9. RCS volume (gallons)	88,070	FSAR, Table 5.1-1	88,070	FSAR, Table 5.1-1

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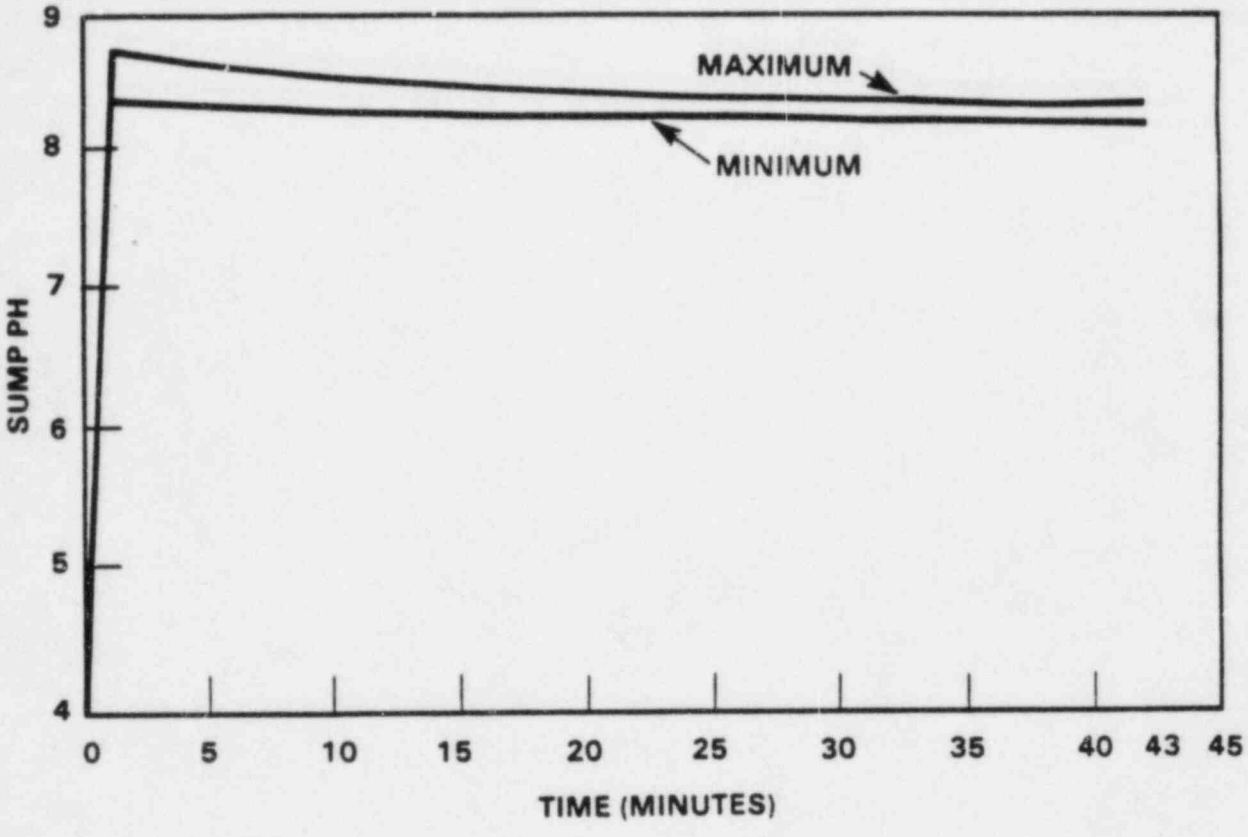
Table 6.1.1-2 (Page 2)

PARAMETERS OF FINAL POST-ACCIDENT CHEMISTRY

Parameters	CASE 1 Maximum pH Case		CASE 2 Minimum ph Case	
	Value	Reference	Value	Reference
10. RWST volume for RHR and SI Switch-over (gallons)	138,049	Tech. Spec. Page 3/4 3-31	138,049	Tech. Spec. Page 3/4 3-31
11. Ice boron concentration	1,800	Tech. Spec. Page 3/4 6-33	2,000	FSAR, Page 6.7-54

12. Ice Melt curve from FSAR, Figure 6.2.1-8, Revision 8



CONTAINMENT SUMP pH
VS. TIME

CATAWBA NUCLEAR STATION

Figure 6.1.1-1

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$$P_3 = 15.0\ (1.33)^{1.13} + 0.4$$

$$P_3 = 21.17 \text{ psia or } 6.17 \text{ psig}$$

This peak compression pressure includes a pressure increase of 0.4 psi from steam bypass through the deck. The effect of the dead-ended compartment volumes is to trap additional air and thus reduce the compression ratio and the above calculated peak pressure.

Sensitivity To Blowdown Energy

The sensitivity of the upper compartment compression pressure peak versus the amount of energy released is shown in Figure 6.2.1-4. This figure shows the magnitude of the peak compression pressure versus the amount of energy released in terms of percentage of Reactor Coolant System energy release. These data are based on test results in which each of the tests were run at 110 percent and 200 percent of the initial blowdown rate equivalent to the maximum coolant pipe break flow.

These test results indicate the very large capacity of the ice condenser for additional amounts of energy with only a small effect on compression peak pressure. For example, during testing, 100 percent energy release gave a pressure of about 6.8 psig, while an increase up to 220 percent energy release gave an increase in peak pressure of only about 2 psi. It is also important to note that maldistribution of steam into different sections of the ice condenser would not cause even the small increase in peak pressure that is shown in Figure 6.2.1-4. For every section of the ice condenser which may receive more energy than that of the average section, there are other sections which receive less energy. Thus, the compression pressure in the upper compartment would be indicated by the test performance based on 100 percent energy release, rather than either the maximum energy release section or the minimum energy release section.

Long Term Containment Pressure Analysis

Early in the ice condenser development program it was recognized that there was a need for modeling of long term ice condenser Containment performance. It was realized that the model would have to have capabilities comparable to those of the dry Containment (COCO) model. These capabilities would permit the model to be used to solve problems of Containment design and optimize the Containment and safeguards systems. This has been accomplished in the development of the LOTIC-1 code (Reference 1).

The model of the Containment consists of five distinct control volumes, the upper compartment, the lower compartment, the portion of the ice bed from which the ice has melted, the portion of the ice bed containing unmelted ice, and the deadended compartments. The ice condenser control volume with unmelted ice is further subdivided into six subcompartments to allow for maldistribution of break flow to the ice bed.

The conditions in these compartments are obtained as a function of time by the use of fundamental equations solved through numerical techniques. These equations are solved for three distinct phases in time. Each phase corresponds to a distinct physical characteristic of the problem. Each of these phases has a unique set of simplifying assumptions based on test results from the ice condenser test facility. These phases are the blowdown period, the depressurization period, and the long term.

The most significant simplification of the problem is the assumption that the total pressure in the Containment is uniform. This assumption is justified by the fact that after the initial blowdown of the Reactor Coolant System, the remaining mass and energy released from this system into the Containment are small and very slowly changing. The resulting flow rates between the control volumes will also be relatively small. These small flow rates then are unable to maintain significant pressure differences between the compartments.

In the control volumes, which are always assumed to be saturated, steam and air are assumed to be uniformly mixed and at the control volume temperature. The air is considered a perfect gas, and the thermodynamic properties of steam are taken from the ASME steam table.

The condensation of steam is assumed to take place in a condensing node located, for the purpose of calculation, between the two control volumes in the ice storage compartment.

Containment Pressure Calculation

The following are the major input assumptions used in the LOTIC-1 analysis for the pump suction pipe rupture case with the steam generators considered as an active heat source for the Catawba Nuclear Station Containment:

1. Minimum safeguards are employed in all calculations, e.g., one of two spray pumps and one of two spray heat exchangers; one of two RHR pumps providing flow to the core and one of two RHR heat exchangers; one of two safety injection pumps and one of two centrifugal charging pumps; and one of two air return fans.

2. 2.132×10^6 lbs. of ice initially in the ice condenser.

3. The blowdown, reflood, and post reflood mass and energy releases described in Section 6.2.1.3 are used.

4. Blowdown and post-blowdown ice condenser drain temperatures of 190°F and 130°F are used. (These numbers are based on Reference 2.)

5. Nitrogen from the accumulators in the amount of 5870 lbs. is input to the calculations.

6. Initial nuclear service water temperature of 86.5°F is used on the spray heat exchanger and the component cooling heat exchanger. See Section 9.2.5 for service water temperature transient.

7. The air return fan is effective 10 minutes after the transient is initiated.

8. No maldistribution of steam flow to the ice bed is assumed.

9. No ice condenser bypass is assumed. (This assumption depletes the ice in the shortest time and is thus conservative.)

10. The initial conditions in the Containment are a temperature of 100°F in the lower and dead-ended volumes and a temperature of 75°F in the upper volume. All volumes are at a pressure of 0.3 psig.

11. Pump flow rates versus time given in Table 6.2.1-3 were used.

12. Containment structural heat sinks are assumed with conservatively low heat transfer rates. (See Table 6.2.1-4).

13. The operation of one Containment spray heat exchanger UA = 2.9×10^6 (Btu/Hr-°F) for containment cooling and the operation of one RHR heat exchanger UA = 1.91×10^6 (Btu/Hr-°F) for core cooling.

14. The air return fan returns air at a rate of 40,000 cfm from the upper to lower compartment.

15. An active sump volume of 96,807 ft^3 is used.

16. The minimum time at which the RHR pumps can be diverted to the RHR sprays is specified in the plant operating procedures as 50 minutes after the accident. A discussion of the core cooling capability of the ECCS is given in Section 6.3.1 for this mode of operation.

With these assumptions, the heat removal capability of the Containment is sufficient to absorb the energy releases and still keep the maximum calculated pressure well below design.

The following plots are provided for the limiting case, DEPSG break:

Figure 6.2.1-5, Containment pressure transient

Figure 6.2.1-6, Upper and lower compartment temperature transients

Figure 6.2.1-7, Active sump temperature transient

Figure 6.2.1-8, Ice melt transient

Table 6.2.1-5 gives an energy accounting at various points in the transient.

As can be seen from Figure 6.2.1-5 the maximum calculated Containment pressure is 13.3 psig, occurring at approximately 4595 seconds.

h. A series of large break cases (1.4 sq. ft. double ended rupture) were run to determine the limiting case break. Blowdowns assuming no secondary side valve failure and failures of the feedline and main steamline isolation valves were analyzed using LOTIC-3 at the 0, 30, 70 and 102 percent power levels. In addition, a series of small breaks were analyzed with LOTIC-3 assuming the same failures as above:

0.4 ft^2 split at 0 power
0.86 ft^2 split at 102% power
0.908 ft^2 split at 70% power
0.942 ft^2 split at 30% power

i. The mass and energy releases for the limiting breaks are given in Section 6.2.1.4. These rates are considerably less than the RCS double-ended breaks, and their total integrated energy is not sufficient to cause ice bed meltout. The containment pressure transients generated for the previously presented double ended pump suction RCS break are considerably more severe.

j. The heat transfer coefficients to the containment structures are based on the work of Tagami. An explanation of their manner of application is given in References 6 and 7.

k. A conservative ice mass was assumed. Previous parameter studies show that the ice mass may be varied from 2.0 to 2.45 million pounds of ice without altering the temperature and pressure transients for steamline breaks and that no sensitivity exists to the initial compartment temperature ranges given in the Technical Specifications.

Results

The limiting case among the double-ended steamline breaks, which is the 1.4 ft^2 rupture occuring at 102% power with feedline isolation valve failure, gave a calculated peak temperature of 308.5°F. The temperature transient for this break is given in Figure 6.2.1-15. The most severe transient in terms of superheat temperature duration for the small breaks is the 0.40 ft^2 steamline split rupture occuring at 0% power with the assumption of a main steamline isolation valve failure. The temperature transient for this case is presented in Figure 6.2.1-16. The limiting peak temperature of 327.7°F is a result of the 0.86 ft^2 steamline split rupture, occuring at 102% power with main steamline isolation valve failure (presented in Figure 6.2.1-17.)

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Fluid Impingement on Condenser Doors

Refer to Section 3.6 for a discussion of the design provisions made to preclude the direct impingement of a stream of fluid from high-energy lines in the lower compartment upon the ice condenser lower inlet doors.

Normal Containment Ventilation

Refer to Section 9.4.6, Containment Ventilation System, for Normal Containment Ventilation.

b. Steam Plant Piping Blowdown

The contribution to the mass and energy releases from the secondary plant steam piping is included in the mass and energy release calculations. For all ruptures, the steam piping volume blowdown begins at the time of the break and continues at a uniform rate until the entire piping inventory is released. The flow rate is determined using the Moody correlation, the pipe cross-sectional area, and the initial steam pressure. Following the piping blowdown, reverse flow from the intact steam generators continues until the times presented in Table 6.2.1-68 to simulate the reverse steam generator flow prior to steamline isolation.

The blowdown model is further discussed in References 18 and 19.

6.2.1.4.3 Single Failure Analysis

The following single failures were evaluated to determine the limiting set of conditions for this analysis:

a. Failure of a main steam isolation valve increases the volume of steam piping which is not isolated from the break. When all valves operate, the piping volume capable of blowing down is located between the steam generator and the first isolation valve. If this valve fails, the volume between the break and the isolation valves in the other steamlines including safety and relief valve headers and other connecting lines will feed the break.

b. Failure of a diesel generator would result in the loss of one containment safeguards train resulting in minimum heat removal capability.

c. Failure of a feedwater isolation valve could only result in additional inventory in the feedwater line which would not be isolated from the steam generator. The mass in this volume can flash into the steam generator and exit through the break. Both the feedwater isolation valve and the feedwater regulating valve close in no more than 5 seconds, precluding the pumping of any additional feedwater into the steam generator. The additional line volume available to flash into the steam generator is that between the feedwater isolation valve and the feedwater regulating valve, including all headers and connecting lines.

The resultant mass and energy release rates for the limiting steam pipe break are presented in Table 6.2.1-61.

6.2.1.5 Minimum Containment Pressure Analysis for Performance Capability Studies of Emergency Core Cooling System

The containment pressure analysis is performed with the LOTIC-2 code (Reference 3). The transient pressure computed by the LOTIC-2 code can be input to the WREFLOOD code for the purpose of computing the reflood transient.

The Containment Spray System initially operates independently of other engineered safety features. For extended operation in the recirculation mode, water can be supplied to the residual spray headers through the Residual Heat Removal pumps and Residual Heat Removal exchangers. One Containment spray system train, supplemented by one residual spray train, when required, provides adequate heat removal capability to limit Containment pressure below design (see Section 6.2.1.3). Residual spray is initiated only after switchover to the recirculation mode and no earlier than 50 minutes after initiation of the LOCA. At this time one ND pump can provide sufficient residual spray as well as adequate core flow via the high head (one centrifugal charging and one safety injection) pumps. (See Section 6.3.3 for the performance evaluation of the ND pumps in their core cooling function).

An analysis has been made of all active components of the system to show that the failure of any single active component will not prevent fulfilling the design function. This analysis is summarized in Table 6.2.2-3. A single failure in the Residual Heat Removal System will not prevent long-term use of the spray system. The analyses of the loss-of-coolant accident presented in Chapter 15 reflect the single failure analysis. Each of the spray trains provides complete backup for the other.

An analysis of the spray return drains located in the refueling canal has been made to show that they are adequately sized for a maximum RHR and containment spray flow. It was shown that a water head of less than 4 feet in the refueling canal is sufficient to establish a steady-state drainage between the upper and lower compartment. This water head is well within the capacity of the refueling canal.

The passive portion of the spray systems located within the containment are designed to withstand, without loss of functional performance, a post accident containment environment and to operate without benefit of maintenance. The spray headers which are located in the upper containment volume are separated from the reactor and primary coolant loops by the operating deck and inner wall of the ice bed. These spray headers are therefore protected from missiles originating in the lower compartment.

In accordance with Regulatory Guide 1.1, the plant and piping layout of the Containment Spray System ensures that the pump net positive suction head (NPSH) requirements are met at maximum runout conditions with the Containment Spray Pumps taking suction from either the refueling water storage tank or the containment sump. The NPSH available from the containment sump is calculated using the maximum credible sump water temperature (190°F) with no credit taken for containment overpressure or height of water in the containment sump.

A Failure Mode and Effects Analysis of the Containment Spray System is provided as Table 6.2.2-4.

This evaluation shows that the Containment Spray System can withstand expected conditions during the 40-year life of the plant without loss of capability to perform the required safety functions. Specifically, the system achieved this by having been designed to meet applicable General Design Criteria as follows:

Table 6.2.1-3

ECCS and Spray Flows Rates[1] Assumed in Peak Containment Pressure Calculation

Interval (sec.)	ECCS Flow from RWST	Spray Flow from RWST	ECCS Flow from Sump	Spray Flow from Sump	Auxiliary Spray Flow from Sump
0-45	0	0	0	0	0
45-1683	4898[2]	3400	0	0	0
1683-1855.9	1036	3400	3862	0	0
1856-2824.9	0	3400	3373	0	0
2825-2889.9	0	0	3373	0	0
2890-2999.9	0	0	3373	3400	0
3000-End of Transient	0	0	1182	3400	1575

[1]All flow rates are in gpm

[2]This assumes 3862 gpm from the Residual Heat Removal pump plus 594 gpm from the Safety Injection pump and 442 gpm from the Centrifugal charging pump.

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Table 6.2.1-5

Energy Accounting

Double Ended Pump Suction Guillotine

HEAT SINK	APPROX. END OF BLOWDOWN (12 sec)	APPROX. END OF REFLOOD (163 sec)	APPROX. ICEBED MELT OUT (2805 sec)	APPROX. PEAK PRESSURE (4595 sec)
*Ice Bed Removal	2.03×10^8	3.07×10^8	5.72×10^8	$.72 \times 10^8$
*Structural Heat Sinks	1.87×10^7	5.12×10^7	5.93×10^7	9.12×10^7
*RHR Heat Exchanger	0.0	0.0	1.357×10^7	6.8×10^7
*Spray Heat Exchanger	0.0	0.0	8.19×10^6	8.53×10^7
Energy Content of Sump	1.803×10^8	2.428×10^8	6.756×10^8	6.715×10^8
Ice Melted, pounds	0.65×10^6	1.07×10^6	2.132×10^6	2.132×10^6

*Integrated Energies, Btu

Table 6.2.1-14A

Containment Sump Volume Vs. Time

Peak Containment Pressure Transient

Time (sec.)	Volume (ft^3)
51.2	20,295
74.1	22,382
129.3	26,814
175.1	29,621
361.4	36,438
594.1	42,901
617.6	43,544
653.5	44,500
705.8	45,893
785.6	48,000
873.2	50,282
970.7	52,799
1080.6	55,609
1425.3	64,215
1733.4	71,701
2030.8	77,472
2413.1	84,675
2674.5	85,718
3074.5	87,250
3397.1	88,436
3442.2	88,598
3608.2	89,194
3805.2	89,847
3928.3	90,122

End of Transient

Table 6.2.1-20

Peak Differential Pressure - 2 Node Steam Generator Enclosure

Nodes	Differential Pressure (psi)	Time (sec)
Across Enclosure Walls		
1 to Upper Compartment	13.8	3.37
2 to Upper Compartment	12.0	3.38

Table 6.2.1-43 (Page 1)

DEPSG Max SI

Broken Loop Equilibration

USE THE POST REFLOOD TABLE TO 571. SECONDS

ASSUMED CALCULATED CONTAINMENT PRESSURE AT 571. SECONDS = 13.5 PSIG

ADDITIONAL FRACTION TO BE REMOVED FROM THE BROKEN LOOP STEAM GENERATOR

(15.0 - 13.5) / 15.0 = .100

TIME REQUIRED TO EQUILIBRATE = (.100)X(7900000)/(40141.) = 19.7 SECONDS

DURATION - 571. TO 591. SECONDS

Broken Loop Depressurization

BROKEN LOOP DEPRESSURIZATION TIME = 3600. SECONDS

ENERGY TO BE REMOVED = 7900000. X (1.0- .100) = 7100000. BTUS

HEAT REMOVAL RATE = 7100000./3600.= 1976. BTU/SEC

MASS BOILOFF RATE = 1976./957.6 = 2.1 LBM/SEC

ENERGY ADDITION RATE = 2.1 X 1158. = 2389. BTU/SEC

DURATION - 591. TO 4191. SECONDS

Table 6.2.1-43 (Page 2)

DEPSG Max SI

Intact Loop Equilibration

USE THE POST REFLOOD TABLE TO 1736. SECONDS

ASSUMED CALCULATED CONTAINMENT PRESSURE AT 1736. SECONDS = 12.0 PSIG

ADDITIONAL FRACTION TO BE REMOVED FROM THE INTACT LOOP STEAM GENERATOR

(15.0 - 12.0) / 15.0 = .200

TIME REQUIRED TO EQUILIBRATE = (.200)X(41000000)/(31075.X3) = 87.9 SECONDS

DURATION - 1736. TO 1824. SECONDS

Intact Loop Depressurization

INTACT LOOP DEPRESSURIZATION TIME = 2367. SECONDS

ENERGY TO BE REMOVED = 41000000. X (1.0- .200) = 32800000. BTUS

HEAT REMOVAL RATE = 32800000./2367.= 13855. BTU/SEC

MASS BOILOFF RATE = 13855./958.9 = 14.4 LBM/SEC

ENERGY ADDITION RATE = 14.4 X 1157. = 16718. BTU/SEC

DURATION - 1824. TO 4191. SECONDS

Table 6.2.1-43 (Page 3)

DEPSG Max SI

Summary of the Releases

BETWEEN 161. AND 571. SECONDS TABLE 6.2.1-39 SHOULD BE USED

BETWEEN 571. AND 591. SECONDS THE POST REFLOOD RELEASES ARE

MASS RATE = 140.8

ENERGY RATE = 164924.

BETWEEN 591. AND 1736. SECONDS THE FOLLOWING RELEASES SHOULD BE ADDED TO THOSE IN TABLE 6.2.1-39

MASS RATE = 2.1

ENERGY RATE = 2389.

BETWEEN 1736. AND 1824. SECONDS THE POST REFLOOD RELEASES ARE

MASS RATE = 77.8

ENERGY RATE = 90568.

BETWEEN 1824. AND 4191. SECONDS THE RELEASES ARE A FUNCTION OF THE DECAY HEAT AND THE DEPRESSURIZATION RELEASES BELOW

MASS RATE = 16.5

ENERGY RATE = 19107.

FROM 4191. SECONDS THE RELEASES ARE ONLY A FUNCTION OF DECAY HEAT.

Table 6.2.1-44 (Page 1)

DEPSG Min SI

Broken Loop Equilibration

USE THE POST REFLOOD TABLE TO 273. SECONDS

ASSUMED CALCULATED CONTAINMENT PRESSURE AT 273. SECONDS = 13.5 PSIG

ADDITIONAL FRACTION TO BE REMOVED FROM THE BROKEN LOOP STEAM GENERATOR

(15.0 - 13.5) / 15.0 = .100

TIME REQUIRED TO EQUILIBRATE = (.100)X(7900000)/(125516.) = 6.3 SECONDS

DURATION - 273. TO 279. SECONDS

Broken Loop Depressurization

BROKEN LOOP DEPRESSURIZATION TIME = 3600. SECONDS

ENERGY TO BE REMOVED = 7900000. X (1.0- .100) = 7100000. BTUS

HEAT REMOVAL RATE = 7100000./3600.= 1976. BTU/SEC

MASS BOILOFF RATE = 1976./957.6 = 2.1 LBM/SEC

ENERGY ADDITION RATE = 2.1 X 1158. = 2389. BTU/SEC

DURATION - 279. TO 3879. SECONDS

Table 6.2.1-44 (Page 2)

DEPSG Min SI

Intact Loop Equilibration

USE THE POST REFLOOD TABLE TO 1743. SECONDS

ASSUMED CALCULATED CONTAINMENT PRESSURE AT 1743. SECONDS = 12.0 PSIG

ADDITIONAL FRACTION TO BE REMOVED FROM THE INTACT LOOP STEAM GENERATOR

(15.0 - 12.0) / 15.0 = .200

TIME REQUIRED TO EQUILIBRATE = (.200)X(40900000)/(30963.X3) = 88.0 SECONDS

DURATION - 1743. TO 1831. SECONDS

Intact Loop Depressurization

INTACT LOOP DEPRESSURIZATION TIME = 2048. SECONDS

ENERGY TO BE REMOVED = 40900000. X (1.0- .200) = 32700000. BTUS

HEAT REMOVAL RATE = 32700000./2048.= 15972. BTU/SEC

MASS BOILOFF RATE = 15972./958.9 = 16.7 LBM/SEC

ENERGY ADDITION RATE = 16.7 X 1157. = 19272. BTU/SEC

DURATION - 1831. TO 3879. SECONDS

Table 6.2.1-44 (Page 3)

DEPSG Min SI

Summary of the Releases

BETWEEN 163. AND 273. SECONDS TABLE 6.2.1-40 SHOULD BE USED

BETWEEN 273. AND 279. SECONDS THE POST REFLOOD RELEASES ARE

MASS RATE = 292.1

ENERGY RATE = 340494.

BETWEEN 279. AND 1743. SECONDS THE FOLLOWING RELEASES SHOULD BE ADDED TO THOSE IN TABLE 6.2.1-40

MASS RATE = 2.1

ENERGY RATE = 2389.

BETWEEN 1743. AND 1831. SECONDS THE POST REFLOOD RELEASES ARE

MASS RATE = 90.0

ENERGY RATE = 104731.

BETWEEN 1831. AND 3879. SECONDS THE RELEASES ARE A FUNCTION OF THE DECAY HEAT AND THE DEPRESSURIZATION RELEASES BELOW

MASS RATE = 18.7

ENERGY RATE = 21661.

FROM 3879. SECONDS THE RELEASES ARE ONLY A FUNCTION OF DECAY HEAT.

Table 6.2.1-48 (Page 1)

Double Ended Pump Suction Guillotine Max SI

Mass Balance

		(EOB)	(EOE)	(EOF)	(EOFIL)
TIME (SECONDS)	0.00	24.00	160.89	575.89	1735.89
	MASS (1000) LB				
AVAILABLE					
INITIAL RCS AND ACC	755.72	755.72	755.72	755.72	755.72
ADDED MASS					
PUMPED INJECTION	0.00	0.00	151.61	802.79	2622.95
TOTAL ADDED	0.00	0.00	151.61	802.79	2622.95
TOTAL AVAILABLE	755.72	755.72	907.33	1558.51	3378.66
DISTRIBUTION					
REACTOR COOLANT	496.15	32.58	115.70	115.70	115.70
ACCUMULATOR	259.57	219.80	0.00	0.00	0.00
TOTAL CONTENTS	755.72	252.38	115.70	115.70	115.70
EFFLUENT					
BREAK FLOW	0.00	503.33	595.98	654.12	752.70
ECCS SPILL	0.00	0.00	195.65	788.69	2510.25
TOTAL EFFLUENT	0.00	503.33	791.63	1442.80	3262.96
TOTAL ACCOUNTABLE	755.72	755.72	907.33	1558.51	3378.66

Table 6.2.1-48 (Page 2)

Energy Balance

		(EOB)	(EOE)	(EOF)	(EOFIL)
TIME (SECONDS)	0.00	24.00	160.89	575.69	1735.89
	ENERGY (1000000 BTU)				
AVAILABLE					
IN RCS, ACC, S GEN	855.46	855.46	855.46	855.46	855.46
ADDED ENERGY					
PUMPED INJECTION	0.00	0.00	13.34	70.65	230.82
DECAY HEAT	0.00	7.81	28.76	75.19	173.32
HEAT FROM SECONDARY	0.00	-.57	-.57	7.26	16.99
TOTAL ADDED	0.00	7.24	41.53	153.10	421.12
TOTAL AVAILABLE	855.46	862.70	897.00	1008.56	1276.59
DISTRIBUTION					
REACTOR COOLANT	299.79	6.58	17.67	17.67	17.67
ACCUMULATOR	22.84	19.34	0.00	0.00	0.00
CORE STORED	26.97	5.76	4.02	4.02	4.02
THIN METAL	19.96	15.86	7.78	7.78	7.78
THICK METAL	33.02	33.02	25.87	25.87	25.87
STEAM GENERATOR	452.88	454.66	379.64	326.55	220.21
TOTAL CONTENTS	855.46	535.21	434.98	381.89	275.54
EFFLUENT					
BREAK FLOW	0.00	327.49	444.80	513.83	628.58
ECCS SPILL	0.00	0.00	17.22	112.84	372.46
TOTAL EFFLUENT	0.00	327.49	462.02	626.67	1001.04
TOTAL ACCOUNTABLE	855.46	862.70	897.00	1008.56	1276.59

Table 6.2.1-49 (Page 1)

Double Ended Pump Suction Guillotine Min SI

Mass Balance

		(EOB)	(EOE)	(EOF)	(EOFIL)
TIME (SECONDS)	0.00	24.00	163.20	278.20	1743.20
	MASS (1000) LB)				
AVAILABLE					
INITIAL RCS AND ACC	755.72	755.72	755.72	755.72	755.72
ADDED MASS					
PUMPED INJECTION	0.00	0.00	43.05	118.11	1074.27
TOTAL ADDED	0.00	0.00	43.05	118.11	1074.27
TOTAL AVAILABLE	755.72	755.72	798.77	873.83	1829.99
DISTRIBUTION					
REACTOR COOLANT	496.15	32.58	116.95	116.95	116.95
ACCUMULATOR	259.57	219.80	0.00	0.00	0.00
TOTAL CONTENTS	755.72	252.38	116.95	116.95	116.95
EFFLUENT					
BREAK FLOW	0.00	503.33	596.20	631.30	796.90
ECCS SPILL	0.00	0.00	85.61	125.58	916.14
TOTAL EFFLUENT	0.00	503.33	681.82	756.87	1713.04
TOTAL ACCOUNTABLE	755.72	755.72	798.77	873.83	1829.99

Table 6.2.1-49 (Page 2)

Double Ended Pump Suction Guillotine Min SI

Energy Balance

		(EOB)	(EOE)	(EOF)	(EOFIL)
TIME (SECONDS)	0.00	24.00	163.20	278.20	1743.20
	ENERGY (1000000 BTU)				
AVAILABLE					
IN RCS, ACC, SI GEN	855.46	855.46	855.46	855.46	855.46
ADDED ENERGY					
PUMPED INJECTION	0.00	0.00	3.79	10.39	94.54
DECAY HEAT	0.00	7.81	29.07	43.38	173.87
HEAT FROM SECONDARY	0.00	-.57	-.57	1.60	16.99
TOTAL ADDED	0.00	7.24	32.29	55.37	285.39
TOTAL AVAILABLE	855.46	862.70	887.75	910.83	1140.85
DISTRIBUTION					
REACTOR COOLANT	299.79	6.58	17.82	17.82	17.82
ACCUMULATOR	22.84	19.34	0.00	0.00	0.00
CORE STORED	26.97	5.76	4.02	4.02	4.02
THIN METAL	19.96	15.86	7.78	7.78	7.78
THICK METAL	33.02	33.02	25.77	25.77	25.77
STEAM GENERATOR	452.88	454.66	379.71	352.67	217.32
TOTAL CONTENTS	855.46	535.21	435.10	408.06	272.71
EFFLUENT					
BREAK FLOW	0.00	327.49	445.12	486.51	679.27
ECCS SPILL	0.00	0.00	7.53	16.26	188.88
TOTAL EFFLUENT	0.00	327.49	452.65	502.77	868.15
TOTAL ACCOUNTABLE	855.46	862.70	887.75	910.83	1140.85

Table 6.2.1-50 (Page 1)

0.6 Double Ended Pump Suction Guillotine

Mass Balance

		(EOB)	(EOE)	(REC)
TIME (SECONDS)	0.00	28.00	162.73	1500.00
	MASS (1000 LB)			
AVAILABLE				
INITIAL RCS AND ACC	755.72	755.72	755.72	755.72
ADDED MASS				
PUMPED INJECTION	0.00	0.00	149.02	3462.92
TOTAL ADDED	0.00	0.00	149.02	3462.92
TOTAL AVAILABLE	755.72	755.72	904.74	4218.64
DISTRIBUTION				
REACTOR COOLANT	496.15	32.73	115.85	115.85
ACCUMULATOR	259.57	217.04	0.00	0.00
TOTAL CONTENTS	755.72	249.77	115.85	115.85
EFFLUENT				
BREAK FLOW	0.00	505.95	596.82	726.08
ECCS SPILL	0.00	0.00	192.07	3376.71
TOTAL EFFLUENT	0.00	505.95	788.89	4102.78
TOTAL ACCOUNTABLE	755.72	755.72	904.74	4218.63

Table 6.2.1-50 (Page 2)

0.6 Double Ended Pump Suction Guillotine

Energy Balance

TIME (SECONDS)	0.00	(EOB) 28.00	(EOE) 162.73	(REC) 1500.00
	ENERGY (1000000 BTU)			
AVAILABLE				
IN RCS, ACC, S GEN	855.46	855.46	855.46	855.46
ADDED ENERGY				
PUMPED INJECTION	0.00	0.00	13.11	304.74
DECAY HEAT	0.00	8.91	29.35	155.43
HEAT FROM SECONDARY	0.00	-18.63	-18.63	-18.63
TOTAL ADDED	0.00	-9.72	23.84	441.54
TOTAL AVAILABLE	855.46	845.74	879.30	1297.00
DISTRIBUTION				
REACTOR COOLANT	299.79	6.72	17.81	17.81
ACCUMULATOR	22.84	19.10	0.00	0.00
CORE STORED	26.97	5.29	4.02	4.02
THIN METAL	19.96	15.51	7.78	7.78
THICK METAL	33.02	33.02	25.96	12.96
STEAM GENERATOR	452.88	440.91	366.79	358.89
TOTAL CONTENTS	855.46	520.55	422.35	401.46
EFFLUENT				
BREAK FLOW	0.00	325.19	440.05	598.39
ECCS SPILL	0.00	0.00	16.90	297.15
TOTAL EFFLUENT	0.00	325.19	456.95	895.54
TOTAL ACCOUNTABLE	855.46	845.74	879.30	1297.00

Table 6.2.1-51 (Page 1)

Three Foot Squared Pump Suction Split

Mass Balance

		(EOB)	(EOE)	(REC)
TIME (SECONDS)	0.00	42.50	176.04	1500.00
	MASS (1000 LB)			
AVAILABLE				
INITIAL RCS AND ACC	755.72	755.72	755.72	755.72
ADDED MASS				
PUMPED INJECTION	0.00	0.00	156.01	3447.51
TOTAL ADDED	0.00	0.00	156.01	3447.51
TOTAL AVAILABLE	755.72	755.72	911.73	4203.23
DISTRIBUTION				
REACTOR COOLANT	496.15	51.46	136.59	136.59
ACCUMULATOR	259.57	204.98	0.00	0.00
TOTAL CONTENTS	755.72	256.44	136.59	136.59
EFFLUENT				
BREAK FLOW	0.00	499.27	585.55	713.22
ECCS SPILL	0.00	0.00	189.59	3353.42
TOTAL EFFLUENT	0.00	499.27	775.14	4066.64
TOTAL ACCOUNTABLE	755.72	755.72	911.73	4203.23

Table 6.2.1-51 (Page 2)

Three Foot Squared Pump Suction Split

Energy Balance

TIME (SECONDS)	0.00	(EOB) 42.50	(EOE) 176.04	(REC) 1500.00
	ENERGY (1000000 BTU)			
AVAILABLE				
IN RCS, ACC, S GEN	855.46	855.46	855.46	855.46
ADDED ENERGY				
PUMPED INJECTION	0.00	0.00	13.73	303.38
DECAY HEAT	0.00	14.17	33.77	158.09
HEAT FROM SECONDARY	0.90	-27.79	-27.79	-27.79
TOTAL ADDED	0.00	-13.62	19.71	433.68
TOTAL AVAILABLE	855.46	841.84	875.17	1289.14
DISTRIBUTION				
REACTOR COOLANT	299.79	10.16	21.41	21.41
ACCUMULATOR	22.84	18.04	0.00	0.00
CORE STORED	26.97	5.51	4.02	4.02
THIN METAL	19.96	14.48	7.78	7.78
THICK METAL	33.02	33.02	26.01	12.96
STEAM GENERATOR	452.88	437.73	367.18	359.04
TOTAL CONTENTS	855.46	518.94	426.39	405.22
EFFLUENT				
BREAK FLOW	0.00	322.91	432.09	588.82
ECCS SPILL	0.00	0.00	16.68	295.10
TOTAL EFFLUENT	0.00	322.91	448.77	883.92
TOTAL ACCOUNTABLE	855.46	841.84	875.17	1289.14

Table 6.2.1-52 (Page 1)

Double Ended Hot Leg Guillotine

Mass Balance

		(EOB)	(EOE)	(REC)
TIME (SECONDS)	0.00	20.50	120.20	1500.00
	MASS (1000 LB)			
AVAILABLE				
INITIAL RCS AND ACC	755.72	755.72	755.72	755.72
ADDED MASS				
PUMPED INJECTION	0.00	0.00	99.54	3923.65
TOTAL ADDED	0.00	0.00	99.54	3923.65
TOTAL AVAILABLE	755.72	755.72	855.26	4679.37
DISTRIBUTION				
REACTOR COOLANT	496.15	41.85	124.95	124.95
ACCUMULATOR	259.57	226.42	0.00	0.00
TOTAL CONTENTS	755.72	268.27	124.95	124.95
EFFLUENT				
BREAK FLOW	0.00	487.45	628.03	764.15
ECCS SPILL	0.00	0.00	102.29	3790.27
TOTAL EFFLUENT	0.00	487.45	730.31	4554.42
TOTAL ACCOUNTABLE	755.72	755.72	855.26	4679.37

Table 6.2.1-52 (Page 2)

Double Ended Hot Leg Guillotine

Energy Balance

TIME (SECONDS)	0.00	(EOB) 20.50	(EOE) 120.20	(REC) 1500.00
	ENERGY (1000000 BTU)			
AVAILABLE				
IN RCS, ACC, S GEN	855.46	855.46	855.46	855.46
ADDED ENERGY				
PUMPED INJECTION	0.00	0.00	8.76	345.28
DECAY HEAT	0.00	7.78	23.84	155.74
HEAT FROM SECONDARY	0.00	-.57	-.57	-.57
TOTAL ADDED	0.00	7.21	32.03	500.45
TOTAL AVAILABLE	855.46	862.67	887.49	1355.91
DISTRIBUTION				
REACTOR COOLANT	299.79	8.73	19.82	19.82
ACCUMULATOR	22.84	19.92	0.00	0.00
CORE STORED	26.97	6.75	4.02	4.02
THIN METAL	19.96	16.16	7.78	7.78
THICK METAL	33.02	33.02	27.51	12.95
STEAM GENERATOR	452.88	448.48	369.35	367.12
TOTAL CONTENTS	855.46	533.07	428.48	411.69
EFFLUENT				
BREAK FLOW	0.00	329.60	450.01	610.68
ECCS SPILL	0.00	0.00	9.00	333.54
TOTAL EFFLUENT	0.00	329.60	459.01	944.22
TOTAL ACCOUNTABLE	855.46	862.67	887.49	1355.91

Table 6.2.1-53 (Page 1)

Double Ended Cold Leg Guillotine

Mass Balance

TIME (SECONDS)	0.00	(EOB) 21.50	(EOE) 361.27	(REC) 1500.00
	MASS (1000 LB)			
AVAILABLE				
INITIAL RCS AND ACC	755.72	755.72	755.72	755.72
ADDED MASS				
PUMPED INJECTION	0.00	0.00	516.06	2262.79
TOTAL ADDED	0.00	0.00	516.06	2262.79
TOTAL AVAILABLE	755.72	755.72	1271.78	3018.51
DISTRIBUTION				
REACTOR COOLANT	496.15	21.18	104.35	104.35
ACCUMULATOR	259.57	161.32	0.00	0.00
TOTAL CONTENTS	755.72	182.49	104.35	104.35
EFFLUENT				
BREAK FLOW	0.00	508.33	607.88	709.17
ECCS SPILL	0.00	64.89	559.56	2204.99
TOTAL EFFLUENT	0.00	573.23	1167.43	2914.16
TOTAL ACCOUNTABLE	755.72	755.72	1271.78	3018.51

Table 6.2.1-53 (Page 2)

Double Ended Cold Leg Guillotine

Energy Balance

TIME (SECONDS)	0.00	(EOB) 21.50	(EOE) 361.27	(REC) 1500.00
	ENERGY (1000000 BTU)			
AVAILABLE				
IN RCS, ACC, S GEN	855.46	855.46	855.46	855.46
ADDED ENERGY				
PUMPED INJECTION	0.00	0.00	45.41	199.13
DECAY HEAT	0.00	6.16	51.62	153.93
HEAT FROM SECONDARY	0.00	-.57	-.57	-.57
TOTAL ADDED	0.00	5.59	96.46	352.48
TOTAL AVAILABLE	855.46	861.05	951.92	1207.94
DISTRIBUTION				
REACTOR COOLANT	299.79	4.31	15.84	15.84
ACCUMULATOR	22.84	14.20	0.00	0.00
CORE STORED	26.97	15.20	4.02	4.02
THIN METAL	19.96	16.06	7.78	7.78
THICK METAL	33.02	33.02	19.63	12.95
STEAM GENERATOR	452.88	457.30	411.23	399.53
TOTAL CONTENTS	855.46	540.09	458.51	440.13
EFFLUENT				
BREAK FLOW	0.00	315.25	444.17	573.78
ECCS SPILL	0.00	5.71	49.24	194.04
TOTAL EFFLUENT	0.00	320.96	493.41	767.81
TOTAL ACCOUNTABLE	855.46	861.05	951.92	1207.94

TABLE 6.2.1-55

Catawba Reflood Mass and Energy Release DEPSG Min SI

TIME	FLOODING		CARRYOVER	CORE	DOWNCOMER	FLOW	INJECTION			
	TEMP	RATE	FRACTION	HEIGHT	HEIGHT	FRACTION	TOTAL	ACCUMULATOR	SPILL	ENTHALPY
SECONDS	DEGREE F	IN/SEC		FT	FT		(CUBIC FEET PER SECOND)			BTU/LBM
0.00	249.89	0.000	0.000	0.00	0.00	2.50	0.0	0.0	0.0	88.00
.30	246.35	45.166	0.000	.63	.02	.270	111.9	101.4	0.0	88.00
.39	244.29	52.762	.000	1.01	-.15	.476	111.5	101.0	0.0	88.00
.41	243.81	53.487	.003	1.10	-.20	.596	111.4	100.9	0.0	88.00
.61	242.54	1.634	.184	1.36	-.08	.608	110.1	99.6	0.0	88.00
1.80	242.76	2.246	.351	1.50	2.17	.646	103.3	93.0	0.0	88.00
6.73	241.95	3.460	.671	2.00	9.46	.664	74.5	65.4	0.0	88.00
12.00	239.06	4.477	.746	2.50	13.73	.664	45.4	37.4	0.0	88.00
17.01	235.95	4.722	.767	2.97	15.23	.663	27.6	20.0	0.0	88.00
17.35	235.76	4.721	.768	3.00	15.27	.664	26.9	19.3	0.0	88.00
23.01	232.89	4.608	.777	3.50	15.67	.665	21.9	14.2	0.0	88.00
29.02	236.56	4.458	.782	4.00	15.91	.667	21.0	13.2	0.0	88.00
32.01	229.59	4.376	.783	4.24	16.00	.668	21.5	13.6	2.8	88.00
35.35	228.63	4.259	.784	4.50	16.00	.669	23.1	15.0	4.9	88.00
42.08	227.04	4.041	.786	5.00	16.00	.671	24.8	16.5	7.5	88.00
49.22	225.66	3.828	.787	5.50	16.00	.673	25.7	17.2	9.3	88.00
56.80	224.40	3.619	.788	6.00	16.00	.675	26.1	17.5	10.7	88.00
64.86	223.21	3.415	.789	6.50	16.00	.677	26.4	17.6	11.9	88.00
73.45	222.05	3.213	.789	7.00	16.00	.678	26.6	17.5	12.9	88.00
82.60	220.87	3.016	.790	7.50	16.00	.680	26.6	17.4	13.8	88.00
92.38	219.69	2.823	.790	8.00	16.00	.681	26.6	17.3	14.6	88.00
102.84	218.50	2.635	.790	8.50	16.00	.682	26.5	17.0	15.3	88.00
114.08	217.32	2.450	.790	9.00	16.00	.683	26.3	16.7	15.9	88.00
126.16	216.15	2.270	.789	9.50	16.00	.684	26.1	16.4	16.4	88.00
139.20	215.04	2.093	.788	10.00	16.00	.684	25.8	16.0	16.9	88.00

Table 6.2.1-55 (Page 2)

ENERGY BALANCE

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Table 6.2.1-56

Basis For Analysis

Plant Model	4 loop, 12 ft core
Core Power (License Application)	3411 Mwt
Engineered Safeguards Design Rating	3579 Mwt
Nominal Inlet Temperature	560.6°F
Nominal (Vessel) Outlet Temperature	618.2°F
Steam Pressure	1000 psia
Rod Array	17 X 17
Total Accumulator Mass	259,649 lbm
Accumulator Temperature	120°F
Assumed Containment Design Pressure*	29.7 psia
Pumped Injection (assumed for Froth)	
Minimum	652.67 lbm/sec
Maximum	1569.1 lbm/sec

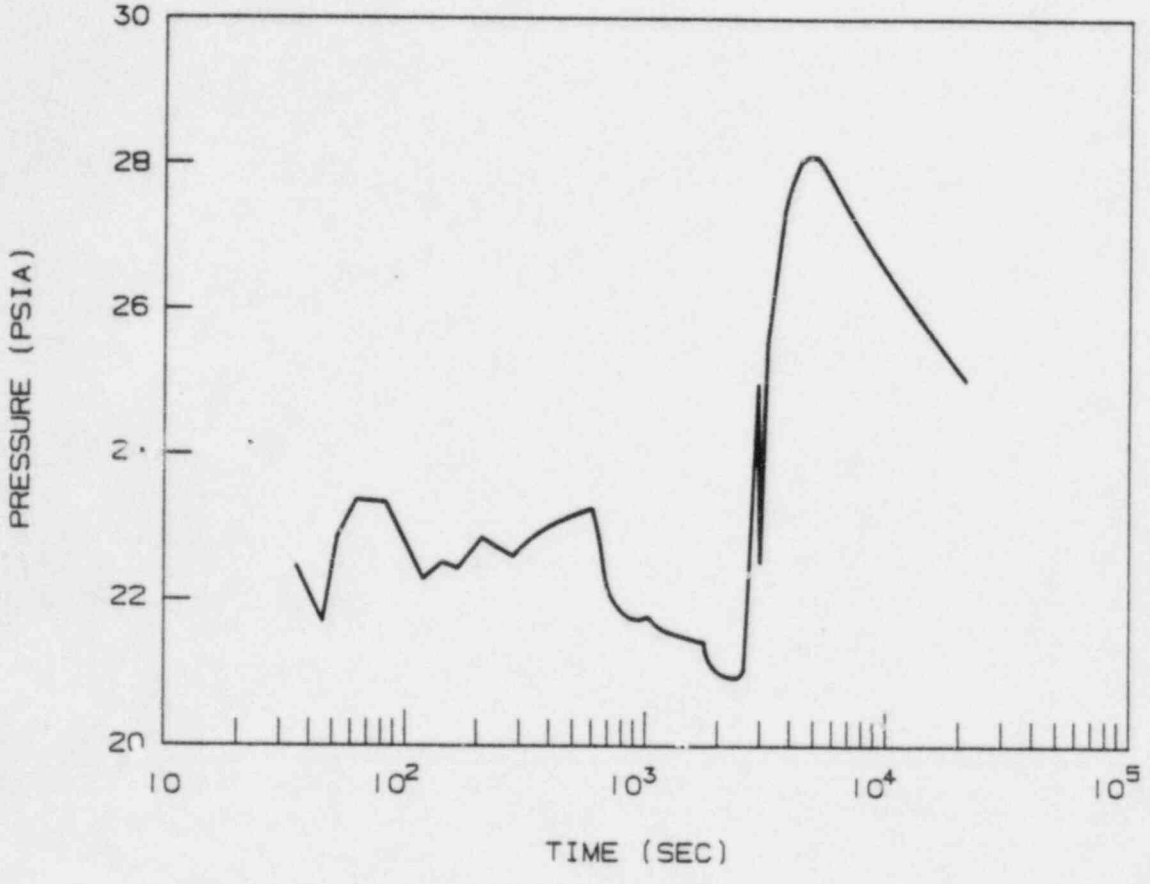
Table 6.2.1-66 (Page 1)

Containment Structural Heat Sinks

STRUCTURE	MATERIAL TYPE/THICKNESS (SEE NOTE 2)	SURFACE AREA (ft^2) (SEE NOTE 2)	COATING (SEE NOTE 1)	THERMAL CONDUCTIVITY (Btu/ft.hr°F)
A) Upper Compartment				
Containment Vessel Dome	11/16" Carbon Steel	20744.9	A	32
Crane Wall	1' - 6" Concrete	10178.4	B	1.05
Ice Condenser	1' - 0" Concrete	15422.5	B	1.05
Operating	1' - 3" Concrete	1720.7	C	1.05
CRDM Missile	1' - 6" Concrete	762.5	C	1.05
CRDM Gate	1' - 6" Concrete	655.0	C	1.05
Pressurizer Doghouse	1' - 0" Concrete	1635.3	B	1.05
Steam Generator Doghouse				
Walls	1' - 0" Concrete	1928.	B	1.05
	1' - 6" Concrete	482.	B	
Shell	3/8" Carbon Steel	3235.3	A	32.
Dome	3/8" Carbon Steel	1584.2	A	32.
Dome Slab	1' - 0" Concrete	893.1	C	1.05

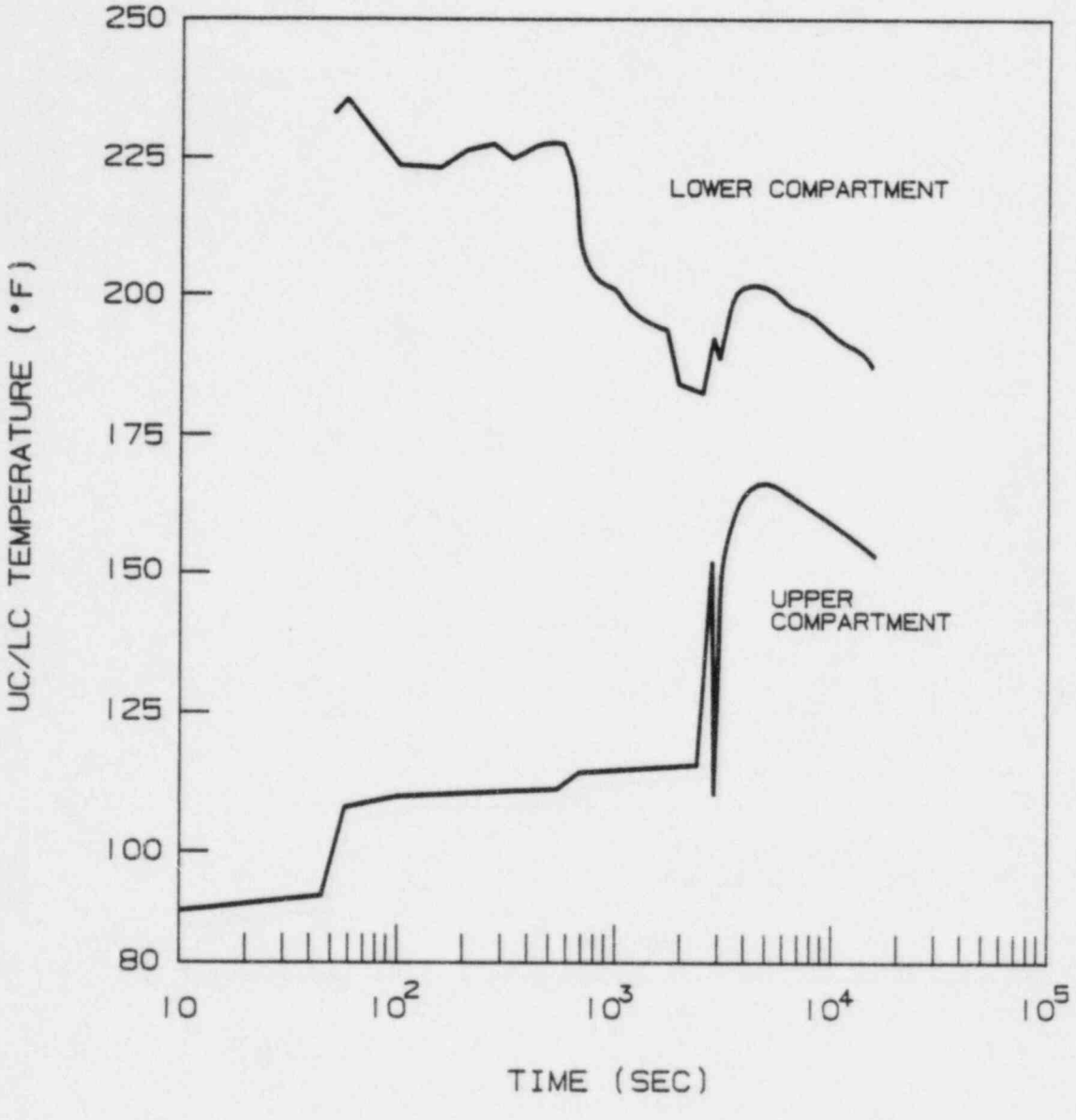
Potential Bypass Leak Paths Through Containment Isolation Valves

Penetration Item Number	Service (Note 1)	Process Fluid	Design Features to Prevent Bypass Leakage										Remarks	Potential Bypass Leakage Path (Note 2)
				Attached Closed Systems (Note 2)										
			Essential (Note 7)	Presents a Seismic Category 1 Closed Pressure Boundary to Containment Atmosphere Following a LOCA	Presents a Seismic Category 1 Closed Pressure Boundary to Environment Following a LOCA	Designed to Quality Group B or C Standards	Design Pressure Equals or Exceeds Containment Design Pressure (Note 4)	Design Temperature Equals or Exceeds Containment Design Temperature (Note 4)	Protected from Effects of Pipe Whip, Missiles, and Jet Forces Resulting From a LOCA	Pressure Boundary Maintained During Normal Plant Operation	Both Valves Served by Seal Water System	Leakage Path Terminates in Annulus		
61	Comp. Cooling from Drain Tank HX	Water	No	X	X	C/C	X		X	X	X			No
62	Comp. Cooling to Reactor Vessel Support & RCP Coolers	Water	Note 10	X	X	C/C	X			X				Yes
63	Comp. Cooling from Reactor Vessel Support & RCP Coolers	Water	Note 10	X	X	C/C	X			X	X			No
64	Comp. Cooling to Excess Letdown HX		No	X	X	B/C	X		X	X				No
65	Comp. Cooling from Excess Letdown HX	Water	No	X	X	B/C	X		X	X				No
66	Comp. Cooling to Component Cooling Drain Sump	Water	No				X			X				Yes
67	Nuclear Service Wtr. to NC Pump and Lower Cont. Vent. Units	Water	Note 10				X			X				Yes
68	Nuclear Service Wtr. from NC Pump & Lower Cont. Vent. Units	Water	Note 10				X			X	X			Yes
69	Nuclear Service Wtr. to Upper Cont. Vent.Units In	Water	Note 10				X			X				Yes
70	Nuclear Service Wtr. to Upper Cont. Vent. Units Out	Water	Note 10				X			X	X			Yes
71	Incore Instrumentation Rm Purge In	Air	No				X	X		X				Yes
72	Incore Instrumentation Rm. Purge Out	Air	No				X	X		X			Ducting extends through incore instrument room filter trains	Yes
73-74	Upper Compartment Purge Inlet	Air	No				X	X		X				Yes
75-76	Lower Compartment Purge Inlet	Air	No				X	X		X				Yes
77-79	Containment Purge Exhaust	Air	No				X	X		X			Seismic duct extends through containment purge filter trains	Yes



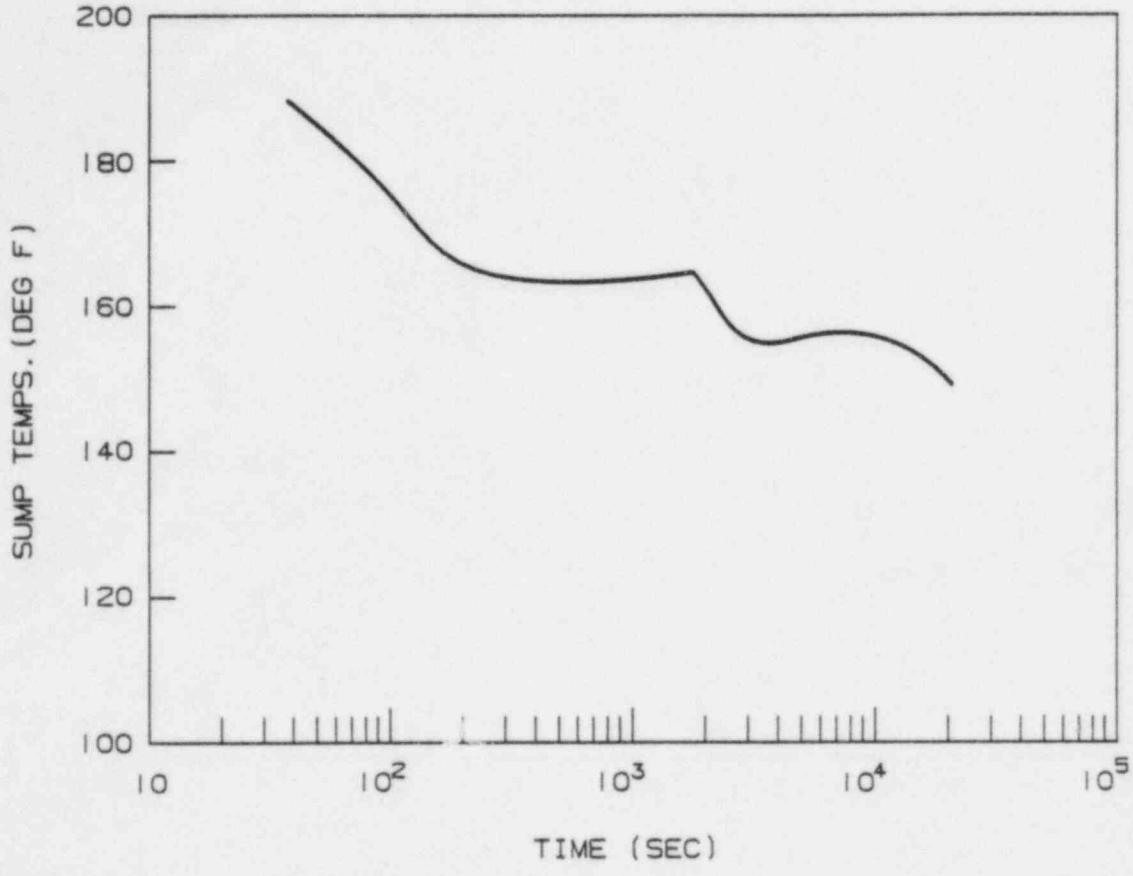
CONTAINMENT PRESSURE
TRANSIENT -- ICE MASS
2.132×10^6 POUNDS
CATAWBA NUCLEAR STATION
Figure 6.2.1-5

REVISION 14

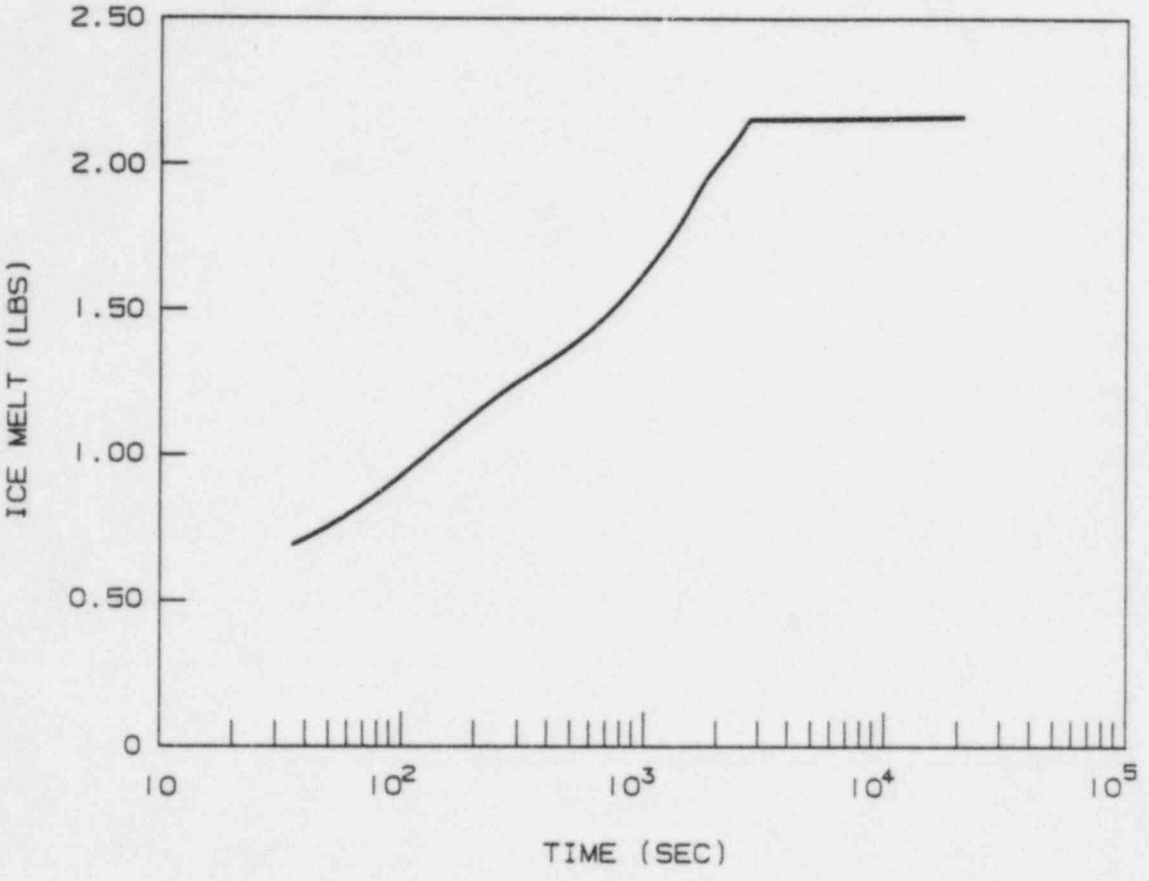


SYSTEM TEMPERATURE, UPPER
AND LOWER COMPARTMENTS
ICE MASS 2.132 x 10^6 POUNDS
CATAWBA NUCLEAR STATION

Figure 6.2.1-6
REVISION 14



ACTIVE SUMP TEMPERATURE
TRANSIENT ICE MASS
2.132×10^6 POUNDS
CATAWBA NUCLEAR STATION
Figure 6.2.1-7
REVISION 14



ICE MELT TRANSIENT ICE
MASS 2.132 x 10^6 POUNDS

CATAWBA NUCLEAR STATION
Figure 6.2.1-8
REVISION 14

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Figure 6.2.1-8A

Sequence Of Changeover Operation From Injection To Recirculation

M5.a. Stop containment spray pump 1A.
M5.b. Stop containment spray pump 1B.

M6.a. Open the containment spray heat exchanger 1A inlet isolation valve (1RN144A).
b. Open the containment spray heat exchanger 1A outlet isolation valve (1RN148A).
c. Close the containment spray pump 1A suction from FWST isolation valve (1NS20A).
d. Open the containment spray pump 1A suction from containment sump isolation valve (1NS18A).

M7.a. Start containment spray pump 1A.

M8.a. Open the containment spray heat exchanger 1B inlet isolation valve (1RN225B).
b. Open the containment spray heat exchanger 1B outlet isolation valve (1RN229B).
c. Close the containment spray pump 1B suction from FWST isolation valve (1NS3B).
d. Open the containment spray pump 1B suction from containment sump isolation valve (1NS1B).

M9.a. Start containment spray pump 1B.

To establish RHR spray, the following steps must be taken and are performed no earlier than 50 minutes post-LOCA.

M10. Close the RHR header 1A to the RCS cold legs isolation valve (1NI173A).

M11. Open the RHR pump 1A discharge to containment spray header isolation (1NS43A).

M12. Close the RHR header 1B to RCS cold legs isolation valve (1NI178B).

M13. Open the RHR pump 1B discharge to containment spray header isolation valve (1NS38B).

Table 8.3.1-1

Catawba Nuclear Station
Maximum Loads To Be Supplied From One Of The Redundant Engineered Safety Power Distribution Systems

SEQUENCE NO. AND INITIATION TIME	EQUIPMENT NAME	(a) LOCATION	SYSTEM	VOLTAGE	CONNECTED PER DIESEL	REQ'D. FOR LOCA	REQ'D. FOR BLACKOUT	REMARKS
No. 10 (cont'd)	Tech. Support Center Condensing Unit	SB	VH	600	30.75 KW	--	30.75 KW	1-30.75KW/Station Train A SMXE
	Tech. Support Center Lighting Transformer	SB	ELN	600	45.0 KVA	--	45.0 KVA	1-45.0KVA/Station Train A SMXE
	Tech. Support Center Duct Heaters	SB	VH	600	15 KW	--	15 KW	1-3.5KW/Station Train A SMXE
	Tech. Support Center Air Handling Unit	SB	VH	575	7.5 HP	--	7.5 HP	1-7.5HP/Station Train A SMXE
	Subtotal Train A Seq. # 10(d)						45.0 KVA 21.0 KW 116.5 HP	
	Equivalent Subtotal						237.88 KVA 214.10 KW 258.29 HP	

9.1.3 SPENT FUEL POOL COOLING AND PURIFICATION

The Spent Fuel Pool Cooling System (KF) is designed to remove heat from the spent fuel pool and maintain the purity and optical clarity of the pool water during fuel handling operations. The purification loop provides an alternate means for removing impurities from either the refueling cavity/transfer canal water during refueling or the refueling water storage tank water following refueling.

9.1 3.1 Design Bases

KF System design parameters are given in Table 9.1.3-1.

9.1.3.1.1 Spent Fuel Pool Cooling

An identical KF System with two trains is provided for each unit. They are designed to remove the decay heat from the spent fuel assemblies stored in the pool. The KF System will maintain:

1. Pool water temperature less than 150°F with one cooling train operating assuming a "nominal" heat load of 17.0×10^6 Btu/hr. "Nominal" heat load is 1/3 core with full irradiation and 7 days decay, one full core of open spaces, and the remainder of the pool filled with fully irradiated fuel from previous yearly refuelings.

2. Pool water temperature less than 150°F with two cooling trains operating assuming a "maximum" heat load of 39.0×10^6 Btu/hr. "Maximum" heat load is a full core discharge consisting of 1/3 core irradiated 11 days and decayed 7 days, 1/3 core irradiated one full cycle and decayed 7 days, 1/3 core irradiated two full cycles and decayed 7 days; plus 1/3 core fully irradiated and decayed 25 days with the remainder of the pool filled with fuel from previous yearly refuelings.

In order to maintain flexibility for the possible use of the fuel pool for fuel other than from Catawba the KF System also is designed to maintain:

1. Pool water temperature less than 150°F with one cooling train operating assuming a "nominal" heat load of 20.6×10^6 Btu/hr.

2. Pool water temperature less than 150°F with two cooling trains operating assuming a "maximum" heat load of 42.7×10^6 Btu/hr.

9.1.3.1.2 Water Purification

The system demineralizer and filters are designed to maintain adequate purification to permit unrestricted access to the spent fuel storage area for plant personnel, provide means for purifying transfer canal and refueling pool water during refueling, and provide purification capability for the refueling water storage tank. The KF System also maintains the optical clarity of the spent fuel pool water surface by use of the skimmer trough, strainers, and skimmer filters.

Table 9.3.1-1 (Page 6)

Compressed Air Systems

Component Design Parameters

BREATHING AIR COMPRESSORS

Manufacturer	Sullair
Quantity	2 per Station
Type	Rotory Screw
Model	RAS-75
Number of Stages	One
Design Capacity	330 CFM
Design Discharge Pressure	115 PSIG
Design Brake Horsepower	75 HP

BREATHING AIR RECEIVERS

Manufacturer	NASH
Quantity	2 per Station
Volume	49.5 ft^3
Design Pressure	115 PSIG
Design Temperature	120°F

by station operating personnel. See Section 6.2.4.4 and the Inservice Pump and Valve Testing Program (per ASME Section XI, IWP/IWV) for the testing and inspection of the main steam isolation valves.

10.3.5 WATER CHEMISTRY

10.3.5.1 Effect of Water Chemistry on the Radioactive Iodine Partition Coefficient

As a result of the basicity of the secondary side water, the radioiodine partition coefficients for both the steam generator and the air ejector system are decreased (i.e., a greater portion of radioiodine remains in the liquid phase). However, the lack of data on the exact iodine species and concentrations present prevents a quantitative determination of the coefficient decrease for these systems. The partition coefficients used for site boundary dose calculations are those given in NUREG 0017. For the steam generators, a partition coefficient of 0.01 was used while for the main condenser air ejector the partition coefficients used were 0.15 for volatile iodine species and zero for non-volatile species, assuming 5% of the iodine species are volatile.

10.3.5.2 Secondary Side Water Chemistry

Water purity in the secondary system, and in the steam generators in particular, is maintained within specified limits in order to minimize corrosion and to minimize fouling of steam generator heat transfer surfaces.

10.3.5.2.1 Treatment

All volatile treatment (AVT) is provided by the chemical addition of hydrazine for oxygen scavenging and ammonia for maintaining pH.

In addition, powdered resin demineralizers are used for condensate polishing, and an air removal section in the condenser is used to remove oxygen from the feedwater.

10.3.5.2.2 Monitoring

Samples are collected from the steam generators, condensate and feedwater. Instrumentation is provided to monitor pH, conductivity, silica, hydrazine, sodium, and oxygen. Current operating guidelines will be derived from vendor recommendations and the current revision of the SGOG PWR Secondary Water Chemistry Guidelines, Chapter 2. Operating guidelines will be addressed in CP/O/A/8800/05 - Chemistry Procedure for Recording and Management of Data.

Q 281.1

10.3.5.2.3 Controlling Chemistry

Operating the polishing and steam generator blowdown demineralizers properly and maintaining condenser vacuum will control the quality of feedwater. In addition, blowdown of the steam generators is used to maintain chemistry limits. The chemistry guidelines addressed in Section 10.3.5.2.2 will be used as the controlling chemistry criteria. High purity makeup water (Specifications Table 10.3.5-2) and chemical additives are added as needed.

Table 10.3.5-1

Limiting AVT Specifications for Power Operations

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radioactivity setpoint for the unit vent iodine monitor is 7E-6 µCi/ml, based on the methodology and parameters in the Offsite Dose Calculation Manual and a unit vent exhaust flow of 160,000 CFM. For periods when the exhaust flow rate varies significantly from 160,000 CFM, the setpoint for the iodine monitor will be recalculated.

In addition to the off-line monitors, a unit vent high range monitor employing an ion chamber for gross gamma detection is attached to the unit vent. The detector is sensitive to the 80 Kev energy range of noble gases and is shielded to minimize the count rate contribution of extraneous sources. Unit vent high range gross gamma activity in excess of a preset limit is alarmed in the control room. A typical setpoint for the unit vent high range monitor is 10 R/hr, the minimum practical setpoint due to hardware limitations.

11.5.1.2.2.2 Containment Airborne Monitor

The containment airborne monitor continuously monitors the gaseous, iodine, and air particulate activity levels in the containment atmosphere.

Leakage to the containment volume from the Reactor Coolant System results in airborne activity that may be released to the environment during purge operations. Containment airborne activity may also result in personnel exposure during periods of containment access. The containment airborne monitor; therefore, monitors for the presence and, to the extent possible, the magnitude of reactor coolant leakage and quantitatively analyzes airborne activity released to the environment by the Containment Purge System.

The containment airborne monitor consists of a sample pump that draws a single 4SCFM sample stream through a moving airborne particulate filter, a charcoal bed iodine monitor, and a gas monitoring chamber, and then returns the air sample to the containment. The sample flow is delivered to the detector through a manifold of solenoid-operated sample valves operated from the control room. The sample valves provide the capability to monitor various locations within the containment with a minimum number of containment penetrations. The containment areas sampled include the upper containment, lower containment, and the incore instrumentation room.

Containment air particulate activity in excess of a preset limit is alarmed in the control room. A typical air particulate activity setpoint for the containment air particulate monitor is 1E-8 µCi/ml. The setpoint is determined in the same manner as Unit Vent per ODCM and adjusted for differences between 160,000 vs. 30,100 cfm exhaust values. Setpoint is tied directly to Exclusion Area Boundary (EAB) dose.

The normal gaseous activity concentrations expected in the containment are provided in Table 12.2.2-4. Containment gaseous activity in excess of a preset limit actuates an alarm in the control room and automatically terminates containment purge. The gaseous activity setpoint for the containment gaseous activity

automatically initates isolation of the affected air intake. A typical gaseous activity setpoint for the control room air intake monitors is 1.7E-4 µCi/ml, a 2 mR/hr submersion dose in a semi-infinite Xe-133 cloud.

11.5.1.2.2.6 Waste Gas Discharge Monitor

The waste gas discharge monitor continuously monitors the gaseous activity released to the environment from the waste gas decay tanks. The waste gas decay tanks contain radioactive noble gases that, after laboratory analysis, may be released through the unit vent on a controlled basis.

The setpoint for the waste gas discharge monitor is based on the concentration of the tank to be discharged, as determined by laboratory analysis. Waste gas discharge radioactivity in excess of a preset limit indicates an improper discharge valve line up or possible valve leakage from a source of high gaseous activity. The discharge is automatically terminated and an alarm is initiated in the control room when the preset level of gaseous activity is detected in the waste gas discharge flow.

11.5.1.2.2.7 Condenser Air Ejector Exhaust Monitor

The condenser air ejector exhaust monitor continuously monitors the gaseous activity released to the unit vent from the condenser air ejector exhaust. The condenser air ejector exhaust may contain airborne radioactivity in the event of a primary to secondary leak in the steam generator.

The normal concentration of gaseous activity expected from the condenser air ejector exhaust is 8E-5 µCi/ml, assuming the steam concentrations of Table 11.1.1-4. Gaseous activity in the condenser air ejector exhaust which exceeds a preset limit is alarmed in the control room. A typical gaseous activity setpoint for the condenser air ejector exhaust monitor is 3 times normal background.

11.5.1.2.2.8 Containment High Range Monitors

The containment high range monitors consists of two physically and electrically separated ion chambers located inside the Reactor Containment to measure high range gamma radiation. In the event high gamma activity is detected inside the containment, the containment high range monitors will automatically terminate discharge flow from the containment sump pumps and containment ventilation unit drain header, and will actuate an alarm in the control room.

A typical setpoint for the containment high range monitors is 100R/hr, selected as being low in the LOCA range but high enough to avoid spurrious trips.

Seismic and environmental qualification of these monitors are discussed in Section 3.10 and 3.11, respectively.

TABLE 11.5.1-1 (Page 1)

Liquid Process Radiation Monitoring Equipment

Monitor Identification	Detector Type	Sensitivity(1)	Max. Detectable Concentration	Range Counts/Min.	Typical Setpoint	Design Service
Turbine Building sump monitor (EMF31)	NaI Scintillator	$3X10^{-8}$ µCi/ml I-31 $2X10^{-8}$ µCi/ml Co-60 $3X10^{-8}$ µCi/ml Cs-137	$2X10^{-2}$ µCi/ml I-131 $1X10^{-2}$ µCi/ml Co-60 $2X10^{-2}$ µCi/ml Cs-137	10^{1} - 10^{7}	10^{-6} µCi/ml	Normal operation gross gamma
Steam generator water sample monitor (EMF34)	NaI Scintillator GM Tube	$3X10^{-8}$ µCi/ml I-131 $2X10^{-8}$ µCi/ml Co-60 $3X10^{-8}$ µCi/ml Cs-137	$1X10^{3}$ µCi/ml I-131 $8X10^{1}$ µCi/ml Co-60 $2X10^{2}$ µCi/ml Cs-137	10^{1} - 10^{7} 10^{1} - 10^{6} (2)	10^{-6} µi/ml	Normal operation gross gamma
Containment Ventilation Unit Condensate Drain Monitor (EMF44)	NaI Scintillator GM Tube	$3X10^{-8}$ µCi/ml I-131 $2X10^{-8}$ µCi/ml Co-60 $3X10^{-8}$ µCi/ml Cs-137	$1X10^{3}$ µCi/ml I-131 $8X10^{1}$ µCi/ml Co-60 $2X10^{2}$ µCi/ml Cs-137	10^{1} - 10^{7} 10^{1} - 10^{6} (2)	10^{-6} µCi/ml	Normal operation gross gamma
Nuclear service water monitor (EMF45)	NaI Scintillator GM Tube	$3X10^{-8}$ µCi/ml I-131 $2X10^{-8}$ µCi/ml Co-60 $3X10^{-8}$ µCi/ml Cs-137	$1X10^{3}$ µCi/ml I-131 $8X10^{1}$ µCi/ml Co-60 $2X10^{2}$ µCi/ml Cs-137	10^{1} - 10^{7} 10^{1} - 10^{6} (2)	10^{-6} µCi/ml	Normal and Post LOCA gross gamma
Component cooling water monitor (EMF46)	NaI Scintillator	$3X10^{-8}$ µCi/ml I-131 $2X10^{-8}$ µCi/ml co-60 $3X10^{-8}$ µCi/ml Cs-137	$2X10^{-2}$ µCi/ml I-131 $1X10^{-2}$ µCi/ml Co-60 $2X10^{-2}$ µCi/ml Cs-137	10^{1} - 10^{7}	10^{-3} µCi/ml	Normal operation gross gamma
Boron recycle evaporator condensate monitor (EMF47)	NaI Scintillator	$3X10^{-8}$ µCi/ml I-131 $2X10^{-8}$ µCi/ml Co-60 $3X10^{-8}$ µCi/ml Cs-137	$2X10^{-2}$ µCi/ml I-131 $1X10^{-2}$ µCi/ml Co-60 $2X10^{-2}$ µCi/ml Cs-137	10^{1} - 10^{7}	10^{-3} µCi/ml	Normal operation gross gamma
Reactor coolant monitor (EMF48)	NaI Scintillator	$6X10^{-4}$ µCi/ml Ba-133	$1X10^{3}$ µCi/ml Ba-133	10^{1} - 10^{7}	(Refer to 11.5.1.2.1.7)	Normal operation gross gamma

TABLE 11.5.1-1 (Page 2)

Liquid Process Radiation Monitoring Equipment

Monitor Identification	Dectector Type	Sensitivity(1)	Max. Detectable Concentration	Range Counts/Min.	Typical Setpoint	Design Service
Waste liquid discharge monitor (EMF49)	NaI Scintillator GM Tube	$5X10^{-7}$ µCi/ml I-131	$1X10^{3}$ µCi/ml I-131	10^{1} - 10^{7} 10^{1} - 10^{6} (2)	(Refer to 11.5.1.2.1.8)	Normal operation gross gamma
		$3X10^{-7}$ µCi/ml Co-60	$8X10^{1}$ µCi/ml Co-60			
		$6X10^{-7}$ µCi/ml Cs-137	$2X10^{2}$ µCi/ml Cs-137			
Clean area floor drains discharge monitor (EMF52)	NaI Scintillator	$3X10^{-8}$ µCi/ml I-131	$2X10^{-2}$ µCi/ml I-131	10^{1} - 10^{7}	10^{-6} µCi/ml	Normal operation gross gamma
		$2X10^{-8}$ µCi/ml Co-60	$1X10^{-2}$ µCi/ml Co-60			
		$3X10^{-8}$ µCi/ml Cs-137	$2X10^{-2}$ µCi/ml Cs-137			

(1) The sensitivity is for the single radionuclide listed; in the event mixtures of radionuclides are present, the sensitivity will vary. Sensitivity will also vary with background radiation and contamination buildup.

(2) High range (shielded)

TABLE 11.5.1-2 (Page 1)

Airborne Process Radiation Monitoring Equipment

Monitor Identification	Detector Type	Sensitivity[1]	Max. Detectable Concentration	Range Counts/Min.	Typical Setpoint	Design Service
Unit vent particulate monitor (EMF35)	Plastic Beta Scintillator - GM Tube	$9X10^{-11}$ µCi/ml Sr-90[2] $2X10^{-10}$ µCi/ml Co-60 $4X10^{-10}$ µCi/ml Cs-137	$8X10^{-2}$ µCi/ml Co-60[2] $7X10^{-1}$ µCi/ml Cs-137	10^{1} - 10^{7} 10^{1} - 10^{6} (4)	$7X10^{-7}$ µCi/ml	Normal operation beta-gamma
Unit vent gas monitor (EMF36)	Plastic Beta Scintillator - GM Tube	$1X10^{-7}$ µCi/ml Kr-85 $3X10^{-7}$ µCi/ml Xe-133	$4X10^{3}$ µCi/ml Kr-85 $2X10^{2}$ µCi/ml Xe-133	10^{1} - 10^{7} 10^{1} - 10^{6} (4)	$2X10^{-2}$ µCi/ml	Normal operation beta-gamma
Unit vent iodine monitor (EMF37)	NaI Scintillator	$2X10^{-11}$ µCi/ml I-131[3]	$3X10^{-5}$ µCi/ml I-131[3]	10^{1} - 10^{7}	$7X10^{-6}$ µCi/ml	Normal operation gross gamma
Unit vent high high range monitor (EMF54)	Ion Chamber	$3X10^{0}$ µCi/ml Xe-133[5]	$5X10^{7}$ µCi/ml Xe-133	10^{0} - 10^{8} R/hr	5 R/hr	Post LOCA gross gamma
Containment air particulate monitor (EMF38)	Plastic Beta Scintillator - GM Tube	$2X10^{-10}$ µCi/ml Sr-90[2] $2X10^{-10}$ µCi/ml Co-60 $7X10^{-10}$ µCi/ml Cs-137	$8X10^{-2}$ µCi/ml Co-60[2] $7X10^{-1}$ µCi/ml Cs-137	10^{1} - 10^{7}	10^{-8} µCi/ml	Normal operation beta-gamma
Containment gas monitor (EMF39)	Plastic Beta Scintillator - GM Tube	$1X10^{-7}$ µCi/ml Kr-85 $3X10^{-7}$ µCi/ml Xe-133	$4X10^{3}$ µCi/ml Kr-85 $2X10^{2}$ µCi/ml Xe-133	10^{1} - 10^{7} 10^{1} - 10^{6} (4)	10^{-4} µCi/ml	Normal operation beta-gamma
Containment Iodine monitor (EMF40)	NaI Scintillator	$3X10^{-11}$ µCi/ml I-131[3]	$3X10^{-5}$ µCi/ml I-131[3]	10^{1} - 10^{7}	10^{-8} µCi/ml	Normal operation gross gamma
Auxiliary Building ventilation monitor (EMF41)	Plastic Beta Scintillator	$1X10^{-7}$ µCi/ml Kr-85 $3X10^{-7}$ µCi/ml Xe-133	$1X10^{-1}$ µCi/ml Kr-85 $3X10^{-1}$ µCi/ml Xe-133	10^{1} - 10^{7}	10^{-4} µCi/ml	Normal operation beta
Fuel Building ventilation monitor (EMF42)	Plastic Beta Scintillator	$1X10^{-7}$ µCi/ml Kr-85 $3X10^{-7}$ µCi/ml Xe-133	$1X10^{-1}$ µCi/ml Kr-85 $3X10^{-1}$ µCi/ml Xe-133	10^{1} - 10^{7}	10^{-4} µCi/ml	Normal operation beta
Control Room Air intake monitor (EMF43)	Plastic Beta Scintillator	$1X10^{-7}$ µCi/ml Kr-85 $3X10^{-7}$ µCi/ml Xe-133	$1X10^{-1}$ µCi/ml Kr-85 $3X10^{-1}$ µCi/ml Xe-133	10^{1} - 10^{7}	10^{-4} µCi/ml	Normal operation beta
Waste gas discharge monitor (EMF50)	Plastic Beta Scintillator - GM Tube	$1X10^{-7}$ µCi/ml Kr-85 $3X10^{-7}$ µCi/ml Xe-133	$4X10^{3}$ µCi/ml Kr-85 $2X10^{2}$ µCi/ml Xe-133	10^{1} - 10^{7} 10^{1} - 10^{6}	(Refer to 11.5.1.2.2.6)	Normal operation beta-gamma

TABLE 11.5.1-2 (Page 2)

Airborne Process Radiation Monitoring Equipment

Monitor Identification	Detector Type	Sensitivity(1)	Max. Detectable Concentration	Range Counts/Min.	Typical Setpoint	Design Service
Condenser air ejector exhaust monitor (EMF33)	Plastic Beta Scintillator	$1X10^{-7}$ µCi/ml Kr-85 $3X10^{-7}$ µCi/ml Xe-133	$1X10^{-1}$ µCi/ml Kr-85 $3X10^{-1}$ µCi/ml Xe-133	10^{1} - 10^{7}	10^{-6} µCi/ml	Normal operation beta
Containment high range monitor (EMF53)	Ion Chamber	$2X10^{2}$ µCi/ml Xe-133 (5)	$5X10^{7}$ µCi/ml Xe-133	10^{0} - 10^{8} R/hr	10^{2} R/hr	Post LOCA gross gamma
Technical Support Center air intake monitor (EMF55)	Plastic Beta Scintillator	$2X10^{-7}$ µCi/ml Kr-85 $2X10^{-7}$ µCi/ml Xe-133	$1x10^{-1}$ µCi/ml Kr-85 $2X10^{-1}$ µCi/ml Xe-133	10^{1} - 10^{7}	10^{-4} µCi/ml	Normal operation beta

(1) The sensitivity is for the single radionuclide listed; in the event mixtures of radionuclides are present, the sensitivity will vary. Sensitivity will also vary with background radiation and contamination buildup.

(2) Based on 15 minute buildup on filter.

(3) Based on 1 hour buildup on charcoal cartridge.

(4) High range (shielded)

(5) Sensitivity value corresponds to typical setpoint listed.

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Design Criteria 19, 63, and 64, and Regulatory Guides 8.2 and 8.8. A discussion of compliance with Regulatory Guide 1.97 is provided in Section 7.1.2. The Area Radiation Monitoring System has no associated control functions.

12.3.4.1.1 Description

The Area Radiation Monitoring System consists of gamma-sensitive detectors, signal conditioning and readout instrumentation, radiation level alarm sensing logic, audible and visual alarm devices, and outputs available for recording. Geiger-Mueller detectors, each with a range of 10^{-1} to 10^{4} mR/hr, are used in 29 area radiation monitoring channels. Eight Geiger-Mueller detectors, each with a range of 10^{-2} to 10^{3} R/hr and four ion chambers, each with a range of 10^{-1} to 10^{4} R/hr, are installed in high-level monitoring channels. The location, sensitivity, range, and accuracy for each detector are shown in Table 12.3.4-1.

All supporting equipment for the detectors (i.e., analyzer/rate meter modules, annunciators, power supplies, auxiliary relays, module test pulse generators, etc.) is located in the control room, except for the supporting equipment associated with the technical support center monitor which is located in the Technical Support Center.

The majority of the Area Radiation Monitoring System is powered from the 240/120 VAC Auxiliary Control Power System (Section 8.3.2). The technical support center monitor is powered from the 120 VAC Technical Support Center Power System.

12.3.4.1.2 Locations and Criteria

The location of the low-level area radiation monitors is based on the potential for significant radiation levels in an area and the expected occupancy of that area. The locations of the monitors are provided in Table 12.3.4-1.

Areas of the plant with high occupancy but little or no radiation potential (e.g., Turbine Building) and areas with high radiation potential but no occupancy (e.g. pipe chases) do not meet the above criteria and are not monitored.

The eight high level Geiger-Mueller radiation monitors are located adjacent to the main steam lines to detect secondary radioactivity due to a steam generator tube rupture.

The location of the four high-level ion chamber radiation monitors is based on the potential for radioactivity accumulation in the reactor coolant filters to exceed the shielding capacity of the spent filter transfer cask.

12.3.4.1.3 Alarms and Indicators

Each detector, except the technical support center detector, is provided with an audible and visual alarm in the control room. The technical support center monitor is provided with an audible and visual alarm locally in the Technical Support Center. Additionally, each low-level area monitor (with the exception

SUMMARY OF QUALIFICATIONS FOR KEY PLANT PERSONNEL

	General Qualifications		Nuclear Qualifications	
Position	Academic	Experience	Academic	Experience
Operations Superintendent				
H. B. Barron	BSNE, 1972 University of Virginia			Junior Engineer Oconee Nuclear Station (June 1972) Initial Fuel Loading, Units 1&2, Oconee Nuclear Station Startup and Physics Testing, Units 2&3 Oconee Nuclear Station Reactor Operators License, Oconee Nuclear Station, 1973 Reactor Engineer, McGuire Nuclear Station (Feburary, 1974) Performance Engineer, McGuire Nuclear Station (August, 1975) Operating Engineer, McGuire Nuclear Station (January, 1978) SRO License McGuire Nuclear Station, 1981

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SUMMARY OF QUALIFICATIONS FOR KEY PLANT PERSONNEL

	General Qualifications		Nuclear Qualifications	
Position	Academic	Experience	Academic	Experience
Operations Superintendent				
H. B. Barron (cont.)				Milestone Manager, Catawba Nuclear Station (December, 1984) Operations Superintendent Catawba Nuclear Station (June, 1985)

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FEEDWATER AND CONDENSATE SYSTEMS FUNCTIONAL TEST
Abstract

Purpose

To demonstrate the ability of these systems to provide a steady, properly regulated supply of feedwater flow to the steam generators during normal and upset conditions. To demonstrate the operability of the secondary Chemical Addition and Sampling Systems. This test is considered to be non-safety related.

Prerequisites

Support systems necessary to operate the condensate and feedwater systems are sufficiently in service. Steam generators are in service at hot standby temperature and pressure conditions for applicable portions of the procedure.

Test Method

Feedwater flow rates will be varied with the bypass feedwater control valves in manual to demonstrate manual control of steam generator levels during hot functional testing. Feedwater flow rates will be varied with the main feedwater control valves in manual to demonstrate manual control of steam generator levels during Hot Functional Testing and/or power escalation. Manual control of feedwater pump speeds will be demonstrated during Hot Functional Testing and/or power escalation. Operability of the feedwater heaters and feedwater heater drains will be verified during power escalation. The ability to obtain samples at designated points in the system and to add chemicals to control feedwater chemistry are verified by the use of normal station chemistry procedures.

Acceptance Criteria

Valve operations which are required to supply the required flows are demonstrated by operating the required valves from the Control room. The proper response to feedwater isolation as described in Section 10.4.7.2 is verified.

Doghouse high water level alarms actuate in Control room upon simulation of high water level.

Samples are obtained from the feedwater and condensate systems. Chemical Addition capability is verified to be operable.

NUCLEAR SERVICE WATER SYSTEM FUNCTIONAL TEST
Abstract

Purpose

To verify acceptable pump performance by obtaining at least three points on the head/capacity curve and verifying against acceptance criteria.

Balance system flows to individual components with manually balanced flows to assure minimum acceptable cooling flow to each essential component in each of the following modes of operation:

Sump recirculation after containment spray (limiting mode, essential flows)
Blackout and shutdown after 4 hours (limiting mode, non-essential flows)

Balance return flows to each finger of the Standby Nuclear Service Water Pond (SNSWP) during the Unit 2 functional test.

Verify Nuclear Service Water System (RN) pump motor cooler inlet isolation valve interlocks.

Verify strainer backwash on simulated high strainer ΔP and associated alarms.

Verify proper dynamic response (including setpoints) of the RN System to lake isolation and resulting low level swapover to the SNSWP - generic demonstration to be performed for one train only (not performed on Unit 2).

The following alarms are verified during the course of the test:

RN pit level alarms
RN System low flow alarms
RN essential header pressure alarms

Proper system response at the proper setpoint is verified for a simulated low intake pit level for the train not used for the actual dynamic swapover at low intake pit level (this verification is performed for both trains of Unit 2).

Prerequisites

All components and essential instrumentation of the Nuclear Service Water System are installed and operational. Portions of the components served by the Nuclear Service Water System are installed and operational.

Test Method

The Nuclear Service Water Pumps will be run singularly to allow data to be collected in order to evaluate their performance.

NUCLEAR SERVICE WATER SYSTEM FUNCTIONAL TEST

Abstract

With each RN Pump in operation with its respective train of components, manual throttling valves and control valve travel stops will be set. The RN System will be lined up for its Sump Recirculation After Containment Spray mode (Mode 5). Then, flows will be verified and others set with the RN System lined up for the blackout and shutdown after 4 hours mode.

The RN System will be lined up with its return flow to the SNSWP. Verification that the flow to each finger of the pond is balanced will be performed during the Unit 2 functional test. With each RN train in normal operation, the RN pump motor cooler inlet isolation valves will be verified to have opened. Also, a strainer simulated high ΔP will be given to verify initiation of an automatic strainer backwash.

The Lake Wylie source of cooling water will be isolated from the RN Pump Pit. The Unit 1 RN Pump in operation will pump the pit level down. A dynamic low level swapover to the SNSWP will be verified. For the other Unit 1 RN Pump and both Unit 2 RN pumps, a simulated low pit level will be given to verify proper system response.

Essential alarms and annunciators initiated during any of the above tests will be verified.

Acceptance Criteria

Each nuclear service water pump develops less than or equal to 226 feet of head after adjustment for instrumentation error at a minimum flow of 9000 gpm ± 1.9%. Flows to essential components correspond to the nominal values listed in FSAR Table 9.2.1-2 for modes 3-2, 4, 5, and 6.

Each nuclear service water pump motor cooler inlet isolation valve interlock allows valve to open upon pump start.

Dynamic swapover is accomplished as described in FSAR Section 9.2.1.2.1, for the pump and pit tested. (Unit 1 only)

EMERGENCY DIESEL GENERATOR FUNCTIONAL TEST
Abstract

Purpose

To demonstrate that the emergency diesel generators are capable of automatically providing the required power to equipment vital to safe reactor shutdown under emergency conditions, and other equipment necessary to maintain the plant in a safe condition during loss of power conditions.

Prerequisites

Diesel generator support systems are operational. Switching relays are calibrated and all normal bus protection is operational. Diesel generator area ventilation and fire protection are functional. The portion of this test involving automatic starting and loading tests performed immediately following the 24-hour run will be run concurrently with the Engineered Safeguards Functional Test.

Test Method

Automatic diesel generator starting is demonstrated for a simulated safety injection signal and for a simulated loss of normal power signal. Diesel generator loading is demonstrated for a simulated loss of normal power signal and diesel generator sequenced loading is demonstrated for the combined safety injection and loss of normal power simulated signals.

Diesel generator full-load-carrying capability is demonstrated by loading the diesel generator to $\geq$ 5600kW but $\leq$ 5750kW for an interval of not less than 24 hours. During the 24 hour run demonstration, the ability to swap from one fuel oil filter to the other is demonstrated along with the ability to swap from one fuel oil strainer to the other. Automatic diesel generator starting and loading is again demonstrated for a combined safety injection and for a loss of normal power simulated signals, immediately following the 24 hour run. Simultaneous starting of both diesel generators will be demonstrated.

Diesel generator load rejection will be demonstrated at $\geq$ 5600 kW but $\leq$ 5750kW load and at a load equivalent to the largest sequenced load. The ability to transfer the emergency load to offsite power will be demonstrated. Diesel generator emergency response is demonstrated not to be impaired during testing. Diesel generator emergency reliability is demonstrated by means of any 35 consecutive valid tests with no failures.

These demonstrations are accomplished for each of the two generators utilizing only one at a time, except as noted above. In addition, the manual operation of the generators is verified by loading each generator to its qualified load rating.

DIESEL GENERATOR FUEL OIL SYSTEM FUNCTIONAL TEST
Abstract

Purpose

To demonstrate the capability of the system to provide an adequate fuel supply to the emergency diesel generators for operation under loaded conditions.

Prerequisites

The electrical and fire protection systems are in service to the extent of conducting fuel oil transfer demonstrations in a safe manner. The emergency diesel generators must be available to operate loaded to the capacity required under post accident conditions as described in Chapter 8 of the FSAR.

Test Method

With both diesel fuel oil day tanks at least one-half full, the diesel generators are started and brought to the qualified rated load condition. The units are operated for a sufficient length of time to measure the fuel consumption rate from each day tank.

Acceptance Criteria

System operation including alarms and controls function as specified in the manufacturer's operating manual. Fuel oil consumption rates at qualified rated load are such that the fuel oil day tank would provide greater than one hour's fuel supply.

CONTAINMENT INITIAL INTEGRATED LEAK RATE TEST AND STRUCTURAL INTEGRITY TEST
Abstract

Purpose

To verify the structural integrity of the Containment and to verify that the integrated leak rate from the Containment does not exceed the maximum allowable leakage.

Prerequisites

The Containment is operational and penetration local leak rate testing has been completed to the greatest extent possible. All systems inside Containment which have containment isolation valves identified as Potential Bypass Leakage Paths in Table 6.2.3-1, are vented and drained except for the following:

System	Reason
Ice Condenser glycol supply and return (M372 and M373)	Ice Condenser is in operation (Unit 1 only - Unit 2 test is performed prior to ice load)
Containment Air Release Line (VQ M204)	Turbine Flowmeter (For Imposed Leak Rate Test) is installed on this penetration.
Containment Hydrogen Sample and Purge (VY M346)	Containment Relief Valve is installed on this penetration.
ILRT Test Pressure sensing lines (3 penetrations)	Lines are open to monitor containment pressure during test.
Chemical and Volume Control System (NV M256) Nuclear Service Water System (RN M230, M308) Liquid Waste System (WL M345, M221, M374, M359) Component Cooling Water System (KCM321)	These penetrations are exempted from the venting and draining requirements since the containment isolation valves are supplied by the Seal Water Injection (NW) System. Exemption was approved in Supplement 3 to the Catawba SER.

Test Method

Closure of containment isolation valves is accomplished by the means provided for normal operation of the valves. The Containment is strength tested at 110 to 115 percent of the design internal pressure and an integrated leak rate test is conducted at not less than the calculated peak accident pressure. Testing is performed in accordance with 10CFR50, Appendix J. The test duration is at least ten (10) hours preceded by a period for stabilization of containment conditions. In order to verify the test methods, a supplemental leak test is performed by imposing a known leak rate on the containment.

CONTAINMENT VENTILATION AND PURGE FUNCTIONAL TEST
Abstract

Purpose

To demonstrate the capability of the Containment Ventilation System to provide containment air recirculation, control rod drive mechanism cooling and containment purging.

Prerequisites

A cooling water supply is available for the fan-cooling units of the system. For testing portions of the system as applicable, the control rod drive mechanisms are capable of being energized, and plant conditions are established as required.

Test Method

Actual expected building heat loads are simulated during Reactor Coolant System Hot Functional Testing and data is taken to demonstrate the capability of the Containment Ventilation System to provide for containment recirculation and heat removal, by testing operation of the fans, centrifugal water chillers and the cooling coils, and by ensuring adequate flow is delivered to components and areas inside Containment as required.

Data will also be taken to verify that the control rod drive mechanisms shroud ventilation units are capable of maintaining temperatures within the shroud within design limits.

The capability of the containment purge exhaust filtration units to provide filtration is verified by testing of the filtration units.

Proper operation of the containment purge supply and purge exhaust equipment is demonstrated in normal and refueling modes.

Proper operation of Containment Ventilation and Purge System instrumentation, interlocks, and alarms which perform a safety-related function is verified.

Acceptance Criteria

1. The Containment Ventilation System components function in accordance with Duke Power Company Design Engineering Department System Descriptions. Adequate ventilation flow is provided to containment areas to maintain or limit temperatures to design valves. System interlocks, instrumentation and alarms operate as described in Duke Power Company Design Engineering Department System Descriptions.

CONTAINMENT AIR RELEASE AND ADDITION SYSTEM FUNCTIONAL TEST
Abstract

Purpose

To verify the proper operation of the fans and air addition and discharge valves. To verify the operation of interlocks and alarms associated with the system. To verify capability of the filtration units.

Prerequisites

System is complete with no discrepancies which would affect the test. For the portion of the test indicated in the test method, unit Reactor Coolant System Hot Functional Test and/or Power Escalation Testing is in progress.

Test Method

Containment Air Release Fans are verified as being able to provide design flow. In order to simulate the pressure differential caused by a normal filter train (since at the time of this portion of the test, filters will not be installed) an obstruction will be placed in the filter train.

Flow will be established from containment to the unit vent. Maximum ΔP from lower to upper containment created by system operation is designed to be less than the amount required to open the ice condenser doors. This will be verified by the absence of an annunciator alarm indicating that an ice condenser door is open. This verification will be performed during power escalation and/or hot functional testing.

During Hot Functional Testing Heat-up and Cooldown (Unit 7 only), the high and low pressure annunciator alarms will be verified and proper opening and closing of unit vent and air addition valves verified (This verification will be performed prior to HFT for Unit 2). The capability of filtration units will be tested in accordance with ANSI N510-1980.

During Hot Functional Testing and/or power escalation, the ability of the system to control containment pressure will be verified.

Acceptance Criteria

Fan capacity is 200 SCFM ± 20% with normal filter pressure drop. All ice condenser doors remain closed with either containment air release train operating in the air release mode. Containment Pressure alarm is received at the high and low containment pressure setpoint ± 0.05 psig. Containment pressure air release valve and containment air addition valve close at the correct containment pressure ± 0.05 psig.

The filtration units demonstrate an efficiency of 99.0% or greater, when tested in accordance with ANSI N510-1980.

The system functions to maintain containment pressure within Technical Specifications limits.

AUXILIARY BUILDING FILTERED EXHAUST AND SHUTDOWN VENTILATION TEST

Abstract

Purpose

To verify proper operation of alarms, interlocks and controls. To verify the capability of the filtration units to fulfill their design function.

Prerequisites

The system is complete with no outstanding discrepancies which would affect the test. Supporting systems are complete to the extent necessary to operate the system.

Test Method

The system will be operated in both normal and LOCA (Ss) modes. Flow rates will be verified during operation. Switchover on receipt of a simulated LOCA (Ss) signal will be verified. Proper operation of alarms and interlocks will be verified by simulation of the appropriate conditions or injection of simulated sensor signals. Filtration units will be tested to verify their capabilities in accordance with ANSI N510-1980.

Acceptance Criteria

System alarms and interlocks function as specified by Duke Power Company Design Engineering Department. Filtered exhaust flow rate is 30,000 cfm ± 10% per fan. System realigns to draw suction only from safety-related equipment rooms upon receipt of LOCA (Ss) signal and flow is $\geq$ 6450 cfm per fan.

HEPA filter banks demonstrated an efficiency of greater than or equal to 99.0% when they are tested in-place in accordance with ANSI N510-1980 while operating the system at a flow rate of 30,000 cfm ± 10% per fan.

Charcoal absorbers remove greater than or equal to 99.0% of a halogenated hydrocarbon refrigerant test gas when they are tested in accordance with ANSI N510-1980 while operating at a flow rate of 30,000 cfm ± 10% per fan.

For the interim flow balance for this system, the Unit 2 filtered exhaust fans will exhaust 30,000 cfm + 0% - 35%. Once the interim barrier is removed or the Unit 2 RCA is established the system balance will be changed prior to Unit 2 entering Mode 4. Exhaust flows will be 30,000 cfm ± 10% per fan.

RTD BYPASS FLOW VERIFICATION
Abstract

Purpose

To determine the flowrate necessary to achieve the required reactor coolant transport time in each RTD bypass loop (time from NC loop to last RTD well), to verify that the coolant transport times are acceptable and to verify the low flow alarm setpoint and reset for the total RTD bypass flow in each reactor coolant loop.

Prerequisites

For portions of the test other than the piping measurements, the reactor is in the hot standby condition with all reactor coolant pumps running. All RTD bypass loop flow measurement channels are calibrated and in service.

Test Method

The flow required to achieve the required reactor coolant transport time is determined by accurately measuring and recording the lengths of installed piping from the bypass loop inlet connections on each reactor coolant loop to the last downstream RTD of both the cold and hot leg bypass loops, and then calculating the flow necessary to achieve less than or equal to 1.0 second transport time. The total bypass flowrate is then measured with both loops in service, and the actual bypass loop transport time is calculated. The low flow alarm setpoint is verified by sequentially throttling the hot and cold leg manifold isolation valves in each loop and noting the flow when the alarm point(s) are reached.

Acceptance Criteria

The RTD bypass loop transport time is less than or equal to 1.0 second or if greater, is noted for comparison with results from unit trip testing at 100 percent power. The low flow alarm actuates at 90 ± 2.0 percent of full bypass loop flow.

ZERO POWER PHYSICS TEST
Abstract

Purpose

To verify the basic nuclear characteristics of the reactor core through the following measurements:

(a) Nuclear instrumentation overlap verification.
(b) Onset of nuclear heat.
(c) All rods out critical boron concentration.
(d) Isothermal temperature coefficient.
(e) Differential and integral worth of the sequenced control banks.
(f) Differential boron worth at hot zero power.
(g) Integral control rod worth with one stuck rod.
(h) Ejected rod cluster control assembly worth at hot zero power.

Prerequisites

The Reactor Coolant System is in the hot zero power condition with the reactor critical with the neutron flux level in the source range as established in the initial criticality sequence. Reactor Coolant System temperature is being maintained. Required signals for data collection and recording are available.

Test Method

(a) The neutron flux level will be increased by outward control rod motion and the nuclear instrumentation overlap recorded. Adjustments will be made as necessary to insure minimum overlap of at least one decade exists between the source-intermediate range instrumentation.

(b) The neutron flux level will be increased by outward control rod motion until temperature feedback effects are noted. The upper limit for zero power physics testing is defined as approximately one decade below this level.

(c) The all rods out, critical boron concentration is determined by measuring the just critical boron concentration with Bank D near the fully withdrawn position. The amount of reactivity held down by Bank D is then dynamically determined by withdrawal of Bank D, noting the amount of reactivity inserted and converting this value to an equivalent amount of boron.

(d) The isothermal temperature coefficient for various boron concentrations is obtained by dynamically measuring the reactivity change due to a temperature change in the primary system.

(e) The sequenced bank differential rod worth is determined by either borating the Reactor Coolant System while withdrawing the control banks or by diluting the Reactor Coolant System while inserting the control banks to maintain nominal system criticality. For Unit 2, Rod Swap technique may be utilized for determination of control rod worths. Integral worth is then determined from the differential reactivity data.

16. Chemical and Volume Control System malfunction that results in a decrease in the boron concentration in the reactor coolant (Section 15.4.6).

17. Inadvertent operation of the Emergency Core Cooling System during power operation (Section 15.5.1).

18. Chemical and Volume Control System malfunction that increases reactor coolant inventory (Section 15.5.2).

19. Inadvertent opening of a pressurizer safety or relief valve (Section 15.6.1).

20. Break in instrument line or other lines from reactor coolant pressure boundary that penetrate Containment (Section 15.6.2).

15.0.1.3 Condition III - Infrequent Faults

By definition Condition III occurrences are faults which may occur very infrequently during the life of the plant. They will be accommodated with the failure of only a small fraction of the fuel rods although sufficient fuel damage might occur to preclude resumption of the 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 or Containment barriers. For the purposes of this report the following faults are included in this category:

1. Steam system piping failure (minor) (Section 15.1.5).

2. Complete loss of forced reactor coolant flow (Section 15.3.2).

3. Rod cluster control assembly misoperation (system malfunction or operator error) (Section 15.4.3).

4. Inadvertent loading and operation of a fuel assembly in an improper position (Section 15.4.7).

5. Loss of coolant accidents resulting from a spectrum of postulated piping breaks within the reactor coolant pressure boundary (small break) (Section 15.6.5).

6. Radioactive gas waste system leak or failure (Section 15.7.1).

7. Radioactive liquid waste system leak or failure (Section 15.7.2).

8. Postulated radioactive releases due to liquid tank failures (Section 15.7.3).

15.0.3 PLANT CHARACTERISTICS AND INITIAL CONDITIONS ASSUMED IN THE ACCIDENT ANALYSES

15.0.3.1 Design Plant Conditions

Table 15.0.3-1 lists the principal power rating values which are assumed in analyses performed in this report. Two ratings are given:

1. The guaranteed NSSS thermal power output. This power output includes the thermal power generated by the reactor coolant pumps.

2. The engineered safety features design rating. The NSSS supplied engineered safety features are designed for thermal power higher than the guaranteed value in order not to preclude realization of future potential power capability. This higher thermal power value is designated as the engineered safety features design rating. This power output includes the thermal power generated by the reactor coolant pumps.

Where initial power operating conditions are assumed in accident analyses, the guaranteed NSSS thermal power output is assumed. Where demonstration of adequacy of the Containment and engineered safety features are concerned, the engineered safety features design rating is assumed. Allowance for errors in the determination of the steady-state power level is made as described in Section 15.0.3.2. The thermal power values used for each transient analyzed are given in Table 15.0.3-1. In all cases where the 3581 megawatt thermal (MWt) rating is used in an analysis, the resulting transients and consequences are conservative compared to using the 3427 MWt rating.

The values of other pertinent plant parameters utilized in the accident analyses are given in Tables 15.0.3-3 and 15.0.3-4.

15.0.3.2 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 4. This procedure is known as the "Improved Thermal Design Procedure" and is discussed more fully in Section 4.4.

For accidents which are not DNB limited, or for which the Improved Thermal Design Procedure is not employed, the initial conditions are obtained by adding the maximum steady state errors to rated values. The following conservative steady state errors were assumed in the analysis:

1.	Core power	±2 percent allowance for calorimetric error
2.	Average Reactor Coolant System temperature	±4°F allowance for controller deadband and measurement error and steam generator fouling penalty

3.	Pressurizer pressure	±30 pounds per square inch (psi) allowance for steady state fluctuations and measurement error

Table 15.0.3-2 summarizes the initial conditions and computer codes used in the accident analyses.

events, such as the loss of reactor coolant from cracks or ruptures in the Reactor Coolant System, do not depend on reactivity feedback effects. The values assumed for these coefficients are given in Table 15.0.3-2. Reference is made in that table to Figure 15.0.4-1 which shows, as a function of power, the upper and lower bound Doppler power coefficients used in the transient analysis. The justification for the use of conservatively large versus small reactivity coefficient values is treated on an event-by-event basis. In some cases conservative combinations of parameters are used to bound the effects of core life, although these combinations may not represent possible realistic situations.

This time was based on a preliminary value for B_4C rod cluster control assemblies. The final safety analysis value is 3.30 seconds. As transients are reanalyzed for various reasons the 3.30 second drop time will be used. The complete loss of flow reanalysis in Section 15.3.2 used the final value.

15.0.5 ROD CLUSTER CONTROL ASSEMBLY INSERTION CHARACTERISTICS

The negative reactivity insertion following a reactor trip is a function of the position versus time characteristic of the rod cluster control assemblies and of 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, approximately 85 percent of the rod cluster travel. The rod cluster control assembly position versus time characteristic assumed in the accident analyses is shown in Figure 15.0.5-1. The rod cluster control assembly insertion time to dashpot entry was taken as 3.05 seconds. Drop time testing requirements are specified in the plant Technical Specifications, and the initial startup test verified that either safety analysis assumption is conservative. This time was based on a preliminary value for B_4C rod cluster control assemblies. The final safety analysis value is 3.30 seconds. As transients are reanalyzed for various reasons, the 3.30 second drop time will be used. The complete loss of flow reanalysis in Section 15.3.2 used the final value.

Figure 15.0.5-2 shows the fraction of total negative reactivity insertion versus normalized rod position for a core where the axial distribution is skewed to the lower region of the core. An axial distribution which is skewed to the lower region of the core can arise from an unbalanced xenon distribution. This curve is used to compute the negative reactivity insertion versus time following a reactor trip, which is input to all point kinetics core models used in transient analyses. The bottom skewed power distribution itself is not input into the point kinetics core model.

There is inherent conservatism in the use of Figure 15.0.5-2 in that it is based on a skewed flux distribution which would exist relatively infrequently. For cases other than those associated with unbalanced xenon distributions, significant negative reactivity would have been inserted due to the more favorable axial distribution existing prior to trip.

The normalized rod cluster control assembly negative reactivity insertion versus time is shown in Figure 15.0.5-3. The curve shown in this figure was obtained from Figures 15.0.5-1 and 15.0.5-2. A total negative reactivity insertion following a trip of 4 percent $\Delta K/K$ 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 Table 4.3.2-3. For Figures 15.0.5-1 and 15.0.5-2, the rod cluster control assembly drop time is normalized to 3.05 seconds, unless otherwise noted for a particular event.

The normalized rod cluster control assembly negative reactivity insertion versus time curve for an axial power distribution skewed to the bottom (Figure 15.0.5-3) is used in those transient analyses for which a point kinetics core model is used.

Where special analyses require use of three dimensional or axial one dimensional core models, the negative reactivity insertion resulting from the reactor trip is calculated directly by the reactor kinetics code and is not separable from the other reactivity feedback effects. In this case, the rod cluster control assembly position versus time of Figure 15.0.5-1 is used as code input.

15.0.6 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 mechanisms to release the rod cluster control assemblies 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 15.0.6-1. Reference is made in that table to Overtemperature and Overpower ΔT trip shown in Figure 15.0.3-1.

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. Nominal trip setpoints are specified in the plant Technical Specifications. During plant startup tests, it will be demonstrated that actual instrument time delays are equal to or less than the assumed values. Additionally, protection system channels are calibrated and instrument response times determined periodically in accordance with the Technical Specifications.

15.0.7 INSTRUMENTATION DRIFT AND CALORIMETRIC ERRORS - POWER RANGE NEUTRON FLUX

The instrumentation drift and calorimetric errors used in establishing the power range high neutron flux setpoint are presented in Table 15.0.7-1.

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 which would be required to control feedwater flow.

15.0.8 PLANT SYSTEMS AND COMPONENTS AVAILABLE FOR MITIGATION OF ACCIDENT EFFECTS

The NSSS is designed to afford proper protection against the possible effects of natural phenomena, postulated environmental conditions and dynamic effects of the postulated accidents. In addition, the design incorporates features which minimize the probability and effects of fires and explosions. Reference 12 discusses the quality assurance program which has been implemented to assure that the NSSS will satisfactorily perform its assigned safety functions. The incorporation of these features in the NSSS, coupled with the reliability of the design, ensures that the normally operating systems and components listed in Table 15.0.8-1 will be available for mitigation of the events discussed in Chapter 15. In determining which systems are necessary to mitigate the effects of these postulated events, the classification system of ANSI-N18.2-1973 is utilized. The design of "systems important to safety" (including protection systems) is consistent with IEEE Standard 379-1972 and Regulatory Guide 1.53 in the application of the single failure criterion.

In the analysis of the Chapter 15 events, control system action is considered only if that action results in more severe accident results. No credit is taken for control system operation if that operation mitigates the results of an accident. For some accidents, the analysis is performed both with and without control system operation to determine the worst case. The pressurizer heaters are not assumed to be energized during any of the Chapter 15 events.

15.0.9 FISSION PRODUCT INVENTORIES

15.0.9.1 Inventory in the Core

The fission product radiation sources considered to be released from the fuel to the containment following a maximum credible accident are based on the assumptions stated in TID-14844 (Reference 1), namely 100 percent of the noble gases, 50 percent of the halogens and a core power level of 3565 MWt.

The time-dependent fission product inventories in the reactor core are calculated by the ORIGEN Code (Reference 2) using a data library based on END F/B-IV (Reference 3). The core inventories are shown in Table 15.0.9-1.

The Equilibrium Appearance Rate of Iodines in the RCS due to conservative and realistic fuel defects are shown in Table 15.0.9-2.

15.0.9.2 Inventory in the Fuel Pellet Clad Gap

The radiation sources associated with a gap-activity-release accident are based on the assumptions that the fission products in the space between the fuel pellets and the cladding of all fuel rods in the core are released as a result of cladding failure.

The gap activities were determined using the model suggested in Regulatory Guide 1.25. Specifically, ten percent of the iodine and noble gas activity (except Kr-85, I-127 and I-129 which are 30 percent) is accumulated in the fuel-clad gap. The gap inventories are shown in Table 15.0.9-1.

(pressure, flow, temperature, and density). The code uses a fuel model which exhibits the following features simultaneously:

1. A sufficiently large number of radial space increments to handle fast transients such as rod ejection accidents.

2. Material properties which are functions of temperature and a sophisticated fuel-to-clad gap heat transfer calculation.

3. The necessary calculations to handle post-DNB transients: film boiling heat transfer correlations, zircaloy-water reaction and partial melting of the materials.

FACTRAN is further discussed in Reference 9.

15.0.11.2 LOFTRAN

The LOFTRAN program is used for studies of transient response of a PWR system to specified perturbations in process parameters. LOFTRAN simulates a multi-loop system by a model containing reactor vessel, hot and cold leg piping, steam generator (tube and shell sides) and the pressurizer. 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 high neutron flux, Overtemperature ΔT, Overpower 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 Emergency Core Cooling System, including the accumulators and upper head injection, is also modeled.

LOFTRAN is a versatile program which 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 DNBR based on the input from the core limits illustrated on Figure 15.0.3-1. The core limits represent the minimum value of DNBR as calculated for typical or thimble cell.

LOFTRAN is further discussed in Reference 10.

15.0.11.3 TWINKLE

The TWINKLE program is a multi-dimensional 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 multi-region fuel-clad-coolant heat transfer model for calculating pointwise Doppler and moderator feedback effects. The code handles up to 2000 spatial points, and performs its own

REFERENCES FOR SECTION 15.0

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6. Bordelon, F. M., et al., "SATAN-VI Program: Comprehensive Space-Time Dependent Analysis of Loss of Coolant," WCAP-8302 (Proprietary), and WCAP-8306 (Non-Proprietary), June 1974.

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10. Risher, D. H., Jr. and Barry, R. F., "TWINKLE - A Multi-Dimensional Neutron Kinetics Computer Code," WCAP-7979-P-A (Proprietary), and WCAP-8028-A (Non-Proprietary), January 1975.

Table 15.0.3-3

Nominal Values of Pertinent Plant Parameters

Utilized In The Accident Analyses

Thermal output of NSSS (MWt)	See Table 15.0.3-1
Core inlet temperature (°F)	560.6
Vessel average temperature (°F)	590.8
Reactor Coolant System pressure (psia)	2250
Reactor coolant flow per loop (gpm)	93,300
Total reactor coolant flow (10^6 lb/hr)	138.3
Steam flow from NSSS (lb/hr)	15,140,000
Steam pressure at steam generator outlet (psia)	1000
Maximum steam moisture content (%)	0.25
Assumed feedwater temperature at steam generator inlet (°F)	440
Average core heat flux (Btu/hr-ft^2)	197,200

Table 15.0.3-4

Nominal Values of Pertinent Plant Parameters

Utilized In The Accident Analyses

(Using The Improved Thermal Design Procedure)

Thermal output of NSSS (MWt)	See Table 15.0.3-1
Core inlet temperature (°F)	561.6
Vessel average temperature (°F)	590.8
Reactor Coolant System pressure (psia)	2250
Reactor coolant flow per loop (gpm)	96,900
Total Reactor Coolant flow (10^6 lb/hr)	143.4
Steam flow from NSSS (lb/hr)	15,140,000
Steam pressure at steam generator outlet (psia)	1000
Maximum steam moisture content (%)	0.25
Assumed feedwater temperature at steam generator inlet (°F)	440
Average core heat flux (Btu/hr-ft^2)	197,200

Table 15.0.6-1

Trip Points and Time Delays To Trip

Assumed In Accident Analyses

Trip Function	Limiting Trip Point Assumed in Analysis	Time Delays (Seconds)
Power range high neutron flux, high setting	118%	0.5
Power range high neutron flux, low setting	35%	0.5
High neutron flux, P-8	85%	0.5
Overtemperature ΔT	Variable see Figure 15.0.3-1	6.0*
Overpower ΔT	Variable see Figure 15.0.3-1	6.0*
High pressurizer pressure	2410 psig***	2.0
Low pressurizer pressure	1921 psig***	2.0
Low reactor coolant flow (from loop flow detectors)	87% loop flow	1.0
Undervoltage trip	68% nominal	1.5
Turbine trip	Not applicable	2.0
Low-low steam generator level	**	4.0
High steam generator level feedwater pump trip, feedwater isolation, and turbine trip	93.6% of narrow range level span***	2.0

*Total time delay (including RTD bypass loop fluid transport delay effect, bypass loop piping thermal capacity, RTD time response, and trip circuit, channel electronics delay) from the time the temperature difference in the coolant loops exceeds the trip setpoint until the rods are free to fall.

**The numerical setpoint assumed for this trip function varies depending on the accident being analyzed. The values used are given in the descriptions of the various accidents.

***The discrepancies between the values and those given the Catawba Nuclear Station Setpoint Methodology document are addressed in a June 25, 1984 letter from H. B. Tucker (Duke Power) to H. R. Denton (NRC).

Table 15.0.6-1 (page 2)

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Table 15.0.8-1 (Page 1)

Plant Systems And Equipment Available For
Transient And Accident Conditions

	Incident	Reactor Trip Functions	ESF Actuation Functions	Other Equipment	ESF Equipment
15.1	INCREASE IN HEAT REMOVED BY THE SECONDARY SYSTEM				
ICSB Q99	Feedwater system malfunctions that result in an increase in feedwater flow	Lo-lo steam generator level, power range high flux, OTΔT, OPΔT, turbine trip, manual	Feedwater isolation, main feedwater pump trip, and turbine trip on hi-hi steam generator level	Feedwater isolation valves	-
	Excessive increase in secondary steam flow	Power range high flux (low), OTΔT, OPΔT, turbine trip, manual	-	Pressurizer safety valves, steam generator safety valves	-
	Inadvertent opening of a steam generator relief or safety valve	SIS, low pressurizer pressure, power range high flux (low), OPΔT, manual	Low pressurizer pressure, low compensated steamline pressure hi-hi containment pressure, high negative steamline pressure rate, manual	Feedwater isolation valves, main steam valves isolation	Auxiliary Feedwater System, Safety Injection System

Table 15.0.8-1 (Page 2)

	Incident	Reactor Trip Functions	ESF Actuation Functions	Other Equipment	ESF Equipment
	Steam system piping failure	SIS, low pressurizer pressure, power range high flux (low), OPΔT, manual	Low pressurizer pressure, low compensated steamline pressure, hi-hi containment pressure, high negative steamline pressure rate, manual	Feedwater isolation valves, main steam valves isolation	Auxiliary Feedwater System, Safety Injection System Essential Auxiliary Power System
15.2	DECREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM				
	Loss of external electrical load/ turbine trip	High pressurizer pressure, OTΔT, high pressurizer level, lo-lo steam generator level, manual	Steam generator lo-lo level	Pressurizer safety valves, steam generator safety valves	-
	Loss of non-emergency AC power to the station auxiliaries	Steam generator lo-lo level, manual	Steam generator lo-lo level	Steam generator safety valves	Auxiliary Feedwater System, Essential Auxiliary Power System
	Loss of normal feedwater flow	Steam generator lo-lo level, manual	Steam generator lo-lo level	Steam generator safety valves	Auxiliary feedwater System

Table 15.0.8-1 (Page 3)

	Incident	Reactor Trip Functions	ESF Actuation Functions	Other Equipment	ESF Equipment
	Feedwater System pipe break	Steam generator lo-lo level, SIS, manual	High containment pressure, steam generator lo-lo water level, low compensated steam line pressure	Main steam isolation valves, feedline isolation valves, pressurizer safety valves, steam generator safety valves	Auxiliary Feedwater System, Safety Injection System, Essential Auxiliary Power System
15.3	DECREASE IN REACTOR COOLANT SYSTEM FLOW RATE				
	Partial and complete loss of forced reactor coolant flow	Low flow, under-voltage, under-frequency, manual	-	Steam generator safety valves	-
	Reactor coolant pump shaft seizure (locked rotor)	Low flow, manual	-	Pressurizer safety valves, steam generator safety valves	-

Table 15.0.8-1 (Page 4)

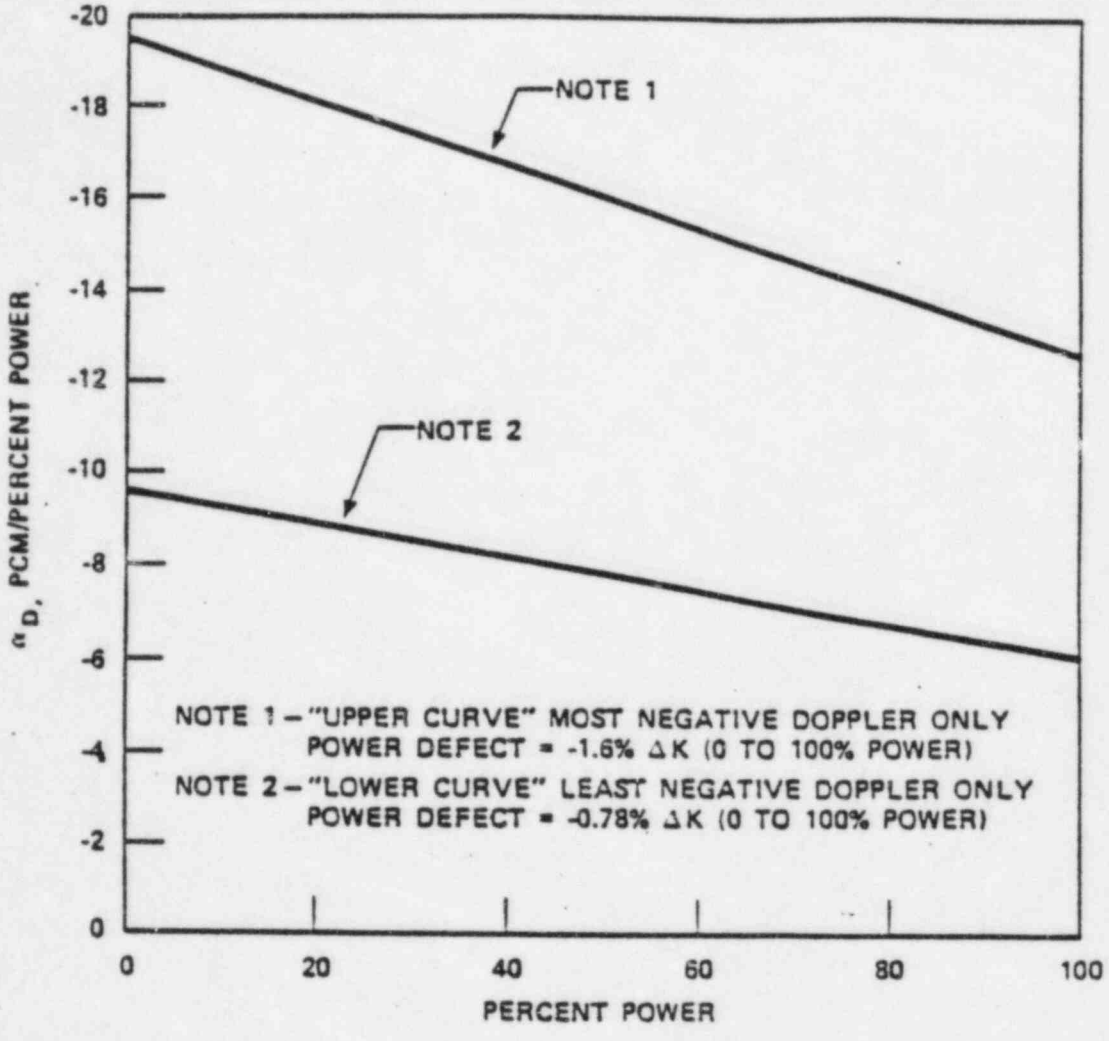
	Incident	Reactor Trip Functions	ESF Actuation Functions	Other Equipment	ESF Equipment
15.4	REACTIVITY AND POWER DISTRIBUTION ANOMALIES				
	Uncontrolled rod cluster control assembly bank withdrawal from a subcritical or low power startup condition	Power range high flux (low), power range high flux (high), intermediate range high flux, source range high flux, manual	-	-	-
	Uncontrolled rod cluster control assembly bank withdrawal at power	Power range high flux (high), OTΔT, OPΔT, high pressurizer pressure, high pressurizer level, manual	-	Pressurizer safety valves, steam generator valves	-
	Rod cluster control assembly misalignment	Power range negative flux rate, OTΔT, manaul	-	-	-
ICSB Q99	Startup of an inactive reactor coolant loop at an incorrect temperature	Low flow coincident with power range high flux exceeding 3-loop P-8 setpoint, manual	-	Low insertion limit annunciators for boration	-

Table 15.0.8-1 (Page 5)

	Incident	Reactor Trip Functions	ESF Actuation Functions	Other Equipment	ESF Equipment
	Chemical and Volume Control System malfunction that results in a decrease in boron concentration in the reactor coolant	Power range high flux (low), OTΔT, manual	-	Low insertion limit annunciators for boration	-
	Spectrum of rod cluster control assembly ejection accidents	Power range high flux, high positive flux rate, manual	-	-	-
15.5	INCREASE IN REACTOR COOLANT INVENTORY				
	Inadvertent operation of the ECCS during power operation	Low pressurizer pressure, SIS, manual	-	-	Safety Injection System
15.6	DECREASE IN REACTOR COOLANT INVENTORY				
	Inadvertent opening of a pressurizer safety or relief valve	Pressurizer low pressure, OTΔT, manual	-	-	-

Table 15.0.8-1 (Page 6)

Incident	Reactor Trip Functions	ESF Actuation Functions	Other Equipment	ESF Equipment
Steam generator tube failure	Pressurizer low pressure, OTΔT, manual	Pressurizer low pressure	Steam generator safety and/or relief valves, main steam isolation valves	Safety Injection System, Auxiliary Feedwater water System, Essential Auxiliary Power System
Loss of coolant accidents resulting from the spectrum of postulated piping breaks within the reactor coolant pressure boundary	Pressurizer low pressure, OTΔT, manual	Pressurizer low pressure, Containment high pressure	Steam generator safety and/or relief valves	Safety Injection System, Auxiliary Feedwater System, Containment Heat Removal System, Essential Auxiliary Power System



DOPPLER POWER COEFFICIENT
USED IN ACCIDENT
ANALYSIS
CATAWBA NUCLEAR STATION

Figure 15.0.4-1

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15.1.2 FEEDWATER SYSTEM MALFUNCTION CAUSING AN INCREASE IN FEEDWATER FLOW

15.1.2.1 Identification of Causes and Accident Description

Addition of excessive feedwater will cause an increase in core power by decreasing reactor coolant temperature. Such transients are attenuated by the thermal capacity of the secondary plant and of the Reactor Coolant System (RCS). The overpower - overtemperature protection (neutron overpower, overtemperature and overpower ΔT trips) prevents any power increase which could lead to a DNBR less than the limit valve.

An 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 coefficient of reactivity.

Continuous addition of excessive feedwater is prevented by the steam generator high-high level trip, which closes the feedwater valves.

An increase in normal feedwater flow is classified as an ANS Condition II event, fault of moderate frequency. See Section 15.0.1 for a discussion of ANS Condition II events.

Plant systems and equipment which are available to mitigate the effects of the accident are discussed in Section 15.0.8 and listed in Table 15.0.8-1.

15.1.2.2 Analysis of Effects and Consequences

Method of Analysis

The excessive heat removal due to a feedwater system malfunction transient is analyzed by using the detailed digital computer code LOFTRAN (Reference 1). This code simulates a multi-loop 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 demonstrate plant behavior in the event that excessive feedwater addition occurs due to a control system malfunction or operator error which allows a feedwater control valve to open fully. Two cases are analyzed as follows:

1. Accidental opening of one feedwater control valve with the reactor just critical at zero load conditions assuming a conservatively large negative moderator temperature coefficient.

2. Accidental opening of one feedwater control valve with the reactor in manual control at full power.

This accident is analyzed with the Improved Thermal Design Procedure as described in Reference 5. Plant characteristics and initial conditions are discussed in Section 15.0.3. The reactivity insertion rate following a feedwater system malfunction is calculated with the following assumptions:

1. Initial reactor power, pressure, and RCS temperature are assumed to be at their nominal values. Uncertainties in initial conditions are included in the limit DNBR as described in Reference 5.

2. For the feedwater control valve accident at full power, one feedwater control valve is assumed to malfunction resulting in a step increase to 149 percent of nominal feedwater flow to one steam generator.

3. For the feedwater control valve accident at zero load condition, a feedwater control valve malfunction occurs which results in an increase in flow to one steam generator from zero to 206 percent of the nominal full load value for one steam generator.

4. For the zero load condition, feedwater temperature is at a conservatively low value of 70°F.

5. No credit is taken for the heat capacity of the RCS and steam generator thick metal in attenuating the resulting plant cooldown.

6. The feedwater flow resulting from a fully open control valve is terminated by a steam generator high-high level trip signal which closes all feedwater control and isolation valves, trips the main feedwater pumps, and trips the turbine.

Plant characteristics and initial conditions are further discussed in Section 15.0.3.

Normal reactor control systems and Engineered Safety Systems are not required to function. The Reactor Protection System may function to trip the reactor due to overpower or turbine trip conditions. No single active failure will prevent operation of the Reactor Protection System. A discussion of ATWT considerations is presented in Reference 2.

Results

In the case of an accidental full opening of one feedwater control valve with the reactor at zero power and the above mentioned assumptions, the maximum reactivity insertion rate is less than the maximum reactivity insertion rate analyzed in Section 15.4.1, "Uncontrolled Rod Cluster Control Assembly Bank Withdrawal from a Subcritical or Low Power Startup Condition," and therefore the results of the analysis are not presented here. It should be noted that if the incident occurs with the unit just critical at no load, the reactor may be tripped by the power range high neutron flux trip (low setting) set at approximately 25 percent of nominal full power.

The full power case (maximum reactivity feedback coefficients, manual rod control) gives the largest reactivity feedback and results in the greatest

power increase. Assuming the reactor to be in the automatic rod control mode results in a less severe transient. The rod control system is, therefore, not required to function for an excessive feedwater flow event.

When the steam generator water level in the faulted loop reaches the high-high level setpoint, all feedwater isolation valves and feedwater pump discharge valves are automatically closed and the main feedwater pumps are tripped. This prevents continuous addition of the feedwater. In addition, a turbine trip is initiated.

Following turbine trip, with automatic rod control, the reactor will be tripped on low-low steam generator water level signal. If the reactor were in the automatic control mode, the control rods would be inserted at the maximum rate following turbine trip, and the ensuing transient would then be similar to a loss of load (turbine trip event) as analyzed in Section 15.2.3.

Transient results, see Figures 15.1.2-1 and 15.1.2-2, show the increase in nuclear power and ΔT associated with the increased thermal load on the reactor. Following the turbine trip and feedwater isolation on the steam generator high-high level signal the reactor reaches a new stabilized condition at a reduced power level consistent with the reactivity parameters assumed to maximize the initial increase in code power. The reactor is tripped on low-low steam generator water level if no action is taken by the operator to terminate the reduced power operation. The DNB ratio does not drop below the limit value. Following the reactor trip, the plant approaches a stabilized condition; standard plant shutdown procedures may then be followed to further cool down the plant.

Since the power level rises during the excessive feedwater flow incident, the fuel temperatures will also rise until after reactor trip occurs. The core heat flux lags behind the neutron flux response due to the fuel rod thermal time constant, hence the peak value does not exceed 118% of its nominal value (i.e., the assumed high neutron flux trip setpoint). The peak fuel temperature will thus remain well below the fuel melting temperature.

The transient results show that DNB does not occur at any time during the excessive feedwater flow incident; thus, the ability of the primary coolant to remove heat from the fuel rod is not reduced. The fuel cladding temperature therefore does not rise significantly above its initial value during the transient.

The calculated sequence of events for this accident is shown in Table 15.1.2-1.

15.1.2.3 Conclusions

The results of the analysis show that the DNB ratios encountered for an excessive feedwater addition at power are above the limiting value hence, no fuel or clad damage is predicted. Additionally, it has been shown that the reactivity insertion rate which occurs at no load conditions following excessive feedwater addition is less than the maximum value considered in the analysis of the rod withdrawal from a subcritical condition analysis.

A conservative limit on the turbine valve opening is assumed, and all cases are analyzed without credit being taken for pressurizer heaters.

This accident is analyzed with the Improved Thermal Design Procedure as described in Reference 5. Plant characteristics and initial conditions are discussed in Section 15.0.3. Initial reactor power, pressure, and RCS temperature are assumed to be at their nominal values. Uncertainties in initial conditions are included in the limit DNBR as described in Reference 5.

Plant characteristics and initial conditions are further discussed in Section 15.0.3.

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 many 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.

Results

Figures 15.1.3-1 through 15.1.3-4 illustrate the transient with the reactor in the manual control mode. As expected, for the 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 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. For these cases, the plant rapidly reaches a stabilized condition at the higher power level. Normal plant operating procedures would then be followed to reduce power.

Figures 15.1.3-5 through 15.1.3-8 illustrate the transient assuming the reactor is in the automatic control mode and no reactor trip signals occur. Both the minimum and 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.

The excessive load increase incident is an overpower transient for which the fuel temperatures will rise. Reactor trip may not occur for some 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 does not 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.

The calculated sequence of events for the excessive load increase incident is shown on Table 15.1.2-1.

15.1.3.3 Environmental Consequences

There will be no radiological consequences associated with this event and activity is contained within the fuel rods and reactor coolant system within design limits.

15.1.3.4 Conclusions

The analysis presented above shows that for a ten percent step load increase, the DNBR remains above the limit value thereby precluding fuel or clad damage. The plant reaches a stabilized condition rapidly following the load increase.

15.1.4 INADVERTENT OPENING OF A STEAM GENERATOR RELIEF OR SAFETY VALVE

15.1.4.1 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 performed assuming a rupture of a main steam line are given in Section 15.1.5.

The steam release as a consequence of this accident results in an initial increase in steam flow which 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 an insertion of positive reactivity.

The analysis is performed to demonstrate that the following criterion is satisfied:

> Assuming a stuck rod cluster control assembly, with offsite power available, and assuming a single failure in the Engineered Safety Features System, there will be no consequential damage to the core or Reactor Coolant System after reactor trip for a stream release equivalent to the spurious opening, with failure to close, of the largest of any single steam dump, relief, or safety valve.

Accidental depressurization of the secondary system is classified as an ANS Condition II event. See Section 15.0.1 for a discussion of Condition II events.

The following systems provide the necessary protection against an accidental depressurization of the Main Steam System.

1. Safety Injection System actuation from any of the following:

   a. Two-out-of-three low steamline pressure signals in any one loop

b. Two-out-of-four low pressurizer pressure signals.

c. Two-out-of-three high containment pressure signals.

2. The overpower reactor trips (neutron flux and ΔT) and the reactor trip occurring in conjunction with receipt of the safety injection signal.

3. Redundant isolation of the main feedwater lines

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Sustained high feedwater flow would cause additional cooldown. Therefore, in addition to the normal control action which will close the main feedwater valves following reactor trip, a feedwater isolation signal will rapidly close all feedwater control valves and back up feedwater isolation valves, trip the main feedwater pumps, and close the feedwater pump discharge valves.

4. Trip of the fast-acting steam line stop valves (designed to close in less than 5 seconds) on:

a. Two-out-of-three low steamline pressure signals in any one loop.

b. Two-out-of-four high-high containment pressure signals.

c. Two-out-of-three high negative steamline pressure rate signals in any one loop (used only during cooldown and heatup operations).

Plant systems and equipment which are available to mitigate the effects of the accident are also discussed in Section 15.0.8 and listed in Table 15.0.8-1.

15.1.4.2 Analysis of Effects and Consequences

Method of Analysis

The following analyses of a secondary system steam release are performed for this section.

1. A full plant digital computer simulation using the LOFTRAN Code (Reference 1) to determine RCS temperature and pressure during cooldown, and the effect of safety injection.

2. Analyses to determine that there is no damage to the core or reactor coolant system.

The following conditions are assumed to exist at the time of a secondary steam system release:

1. End-of-life shutdown margin at no-load, equilibrium xenon conditions, and with the most reactive rod cluster control assembly stuck in its fully withdrawn position. Operation of rod cluster control assembly banks during core burnup is restricted in such a way that addition of positive

reactivity in a secondary system steam release accident will not lead to a more adverse condition than the case analyzed.

2. A negative moderator coefficient corresponding to the end-of-life rodded core with the most reactive rod cluster control assembly in the fully withdrawn position. The variation of the coefficient with temperature and pressure is included. The K_{eff} versus temperature at 1000 psi corresponding to the negative moderator temperature coefficient used is shown in Figure 15.1.4-1.

3. Minimum capability for injection of high concentration boric acid solution corresponding to the most restrictive single failure in the Safety Injection System. This corresponds to the flow delivered by one charging pump delivering its full contents to the cold leg header. No credit is taken for the low concentration boric acid which must be swept from the safety injection lines downstream of the refueling water storage tank prior to the delivery of concentrated boric acid (2,000 ppm from the refueling water storage tank) to the reactor coolant loops.

4. The case studied is a steam flow of 270 pounds per second at 1200 pounds per square inch absolute (psia) with offsite power available. This is the maximum capacity of any single steam dump, relief, or safety valve. Initial hot shutdown conditions at time zero are assumed since this represents the most conservative initial condition.

   Should the reactor be just critical or operating at power at the time of a steam release, the reactor will be tripped by the normal overpower protection 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 release 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, since the initial steam generator water inventory is greatest at no-load, the magnitude and duration of the RCS cooldown are less for steam line release occurring at power.

5. In computing the steam flow, the Moody Curve (Reference 3) for f(L/D) = 0 is used.

6. Perfect moisture separation in the steam generator is assumed.

Results

The calculated time sequence of events for this accident is listed in Table 15.1.2-1.

The results presented are a conservative indication of the events which would occur assuming a secondary system steam release since it is postulated that all of the conditions described above occur simultaneously.

Figures 15.1.4-2 and 15.1.4-3 show the transient results for a steam flow of 270 lb/sec at 1200 psia.

The assumed steam release is typical of the capacity of any single steam dump, relief, or safety valve. Safety injection is initiated automatically by low pressurizer pressure. Operation of one centrifugal charging pump is assumed. Boron solution at 2,000 ppm enters the RCS from the refueling storage water tank (RWST) providing sufficient negative reactivity to prevent core damage.

The transient is quite conservative with respect to cooldown, since no credit is taken for the energy stored in the system metal other than that of the fuel elements or the energy stored in the other steam generators. Since the transient occurs over a period of about 5 minutes, the neglected stored energy is likely to have a significant effect in slowing the cooldown.

15 1.4.3 Environmental Consequences

The inadvertent opening of a single steam dump relief or safety valve can result in steam release from the secondary system. If steam generator leakage exists coincident with the failed fuel conditions, some activity will be released.

15.1.4.4 Conclusions

The analysis shows that the criteria stated earlier in this section are satisfied. For an accidental depressurization of the main steam system, the DNB design basis as stated in Section 4.4 is met and system design limits are exceeded.

15.1.5 STEAM SYSTEM PIPING FAILURE

15.1.5.1 Identification of Causes and Accident Description

The steam release arising from a rupture of a main steam line would result in an initial increase in steam flow which 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 an insertion of positive reactivity. If the most reactive rod cluster control assembly (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 line rupture is a potential problem mainly because of the high power peaking factors which 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 Safety Injection System.

The analysis of a main steam line rupture is performed to demonstrate that the following criteria are satisfied:

Assuming a stuck RCCA with or without offsite power, and assuming a single failure in the engineered safety features, the core remains in place and intact. Radiation doses do not exceed the guidelines of 10CFR100.

Although DNB and possible clad perforation following a steam pipe rupture are not necessarily unacceptable, the following analysis, in fact, shows that no DNB occurs for any rupture assuming the most reactive assembly stuck in its fully withdrawn position. The DNBR design basis is discussed in Section 4.4.

A major steam line rupture is classified as an ANS Condition IV event. See Section 15.0.1 for a discussion of Condition IV events.

Effects of minor secondary system pipe breaks are bounded by the analysis presented in this section. Minor secondary system pipe breaks are classified as Condition III events, as described in Section 15.0.1.3.

The major rupture of a steam line is the most limiting cooldown transient and is analyzed at zero power with no decay heat. Decay heat would retard the cooldown thereby reducing the return to power. A detailed analysis of this transient with the most limiting break size, a double ended rupture, is presented here.

The following functions provide the protection for a steam line rupture:

1. Safety Injection System actuation from any of the following:

   a. Two-out-of-three low steamline pressure signals in any one loop.

   b. Two-out-of-four low pressurizer pressure signals.

   c. Two-out-of-four high Containment pressure signals.

2. The overpower reactor trips (neutron flux and ΔT) 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, in addition to the normal control action which will close the main feedwater valves a feedwater isolation signal will rapidly close all feedwater control valves and back up feedwater isolation valves, trip the main feedwater pumps, and close the feedwater pump discharge valves.

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4. Trip of the fast acting steam line stop valves (designed to close in less than 5 seconds) on:

a. Two-out-of-three low steam line pressure signals in any one loop.

b. Two-out-of-three high-high containment pressure signals.

c. Two-out-of-three high negative steam line pressure rate signals in any one loop (used only during cooldown and heatup operations.

Fast-acting isolation valves are provided in each steam line; these valves will fully close within 10 seconds of a large break in the steam line. For breaks downsteam 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 experience an uncontrolled blowdown even if one of the isolation valves fails to close. A description of steam line isolation is included in Chapter 10.

Steam flow is measured by monitoring dynamic head in nozzles located in the throat of the steam generator. The effective throat area of the nozzles is 1.4 square feet, which is considerably less than the main steam pipe area; thus, the nozzles also serve to limit the maximum steam flow for a break at any location.

Table 15.1.5-1 lists the equipment required in the recovery from a high energy line rupture. Not all equipment is required for any one particular break, since the requirements will vary depending upon postulated break location and details of balance of plant design and pipe rupture criteria as discussed elsewhere in this application. Design criteria and methods of protection of safety-related equipment from the dynamic effects of postulated piping ruptures are provided in Section 3.6.

15.1.5.2 Analysis of Effects and Consequences

Method of Analysis

The analysis of the steam pipe rupture has been performed to determine:

1. The core heat flux and RCS temperature and pressure resulting from the cooldown following the steam line break. The LOFTRAN CODE (Reference 1) 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, has been used to determine if DNB occurs for the core conditions computed in item 1 above.

Studies have been performed to determine the sensitivity of steamline break results to various assumptions (Reference 4). Based upon this study, the following conditions were assumed to exist at the time of the main steam line break accident:

1. End-of-life shut down margin at no-load, equilibrium xenon conditions, and the most reactive RCCA 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. A negative moderator coefficient corresponding to the end-of-life rodded core with the most reactive RCCA in the fully withdrawn position. The variation of the coefficient with temperature and pressure has been included. The K_{eff} versus temperature at 1000 psi corresponding to the negative moderator temperature coefficient used is shown in Figure 15.1.4-1. The effect of power generation in the core on overall reactivity is shown in Figure 15.1.5-1.

   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. Further, it was conservatively assumed that the core power distribution was uniform. These two conditions cause underprediction of the reactivity feedback in the high power region near the stuck rod. To verify the conservatism of this method, the reactivity as well as the power distribution was checked for the limiting statepoints for the cases analyzed.

   This core analysis 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 nonuniform 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 determined that the reactivity employed in the kinetics analysis was always larger than the reactivity calculated including the above local effects for the statepoints. These results verify conservatism; i.e., underprediction of negative reactivity feedback from power generation.

3. Minimum capability for injection of boric acid (2,000 ppm from the RWST) solution corresponding to the most restrictive single failure in the Safety Injection System. The Emergency Core Cooling System consists of three systems: 1) the passive accumulators, 2) the Residual Heat Removal System, and 3) the Safety Injection System. Only the Safety Injection System and the accumulators are modeled for the steam line break accident analysis.

   The actual modeling of the Safety Injection System in LOFTRAN is described in Reference 1. The flow corresponds to that delivered by one charging pump delivering its full flow to the cold leg header. No credit has been taken for the low concentration borated water, which must be swept from the lines downsteam of the RWST prior to the delivery of high concentration boric acid to the reactor coolant loops.

   For the cases where offsite power is assumed, the sequence of events in the Safety Injection System is the following. After the generation of

the safety injection signal (appropriate delays for instrumentation, logic, and signal transport included), the appropriate valves begin to operate and the high head safety injection pump starts. In 10 seconds, the valves are assumed to be in their final position and the pump is assumed to be at full speed. The volume containing the low concentration borated water is swept before the 2,000 ppm water reaches the core. This delay, described above, is inherently included in the modeling.

In cases where offsite power is not available, an additional 10 second delay is assumed to start the diesels and to load the necessary safety injection equipment onto them.

4. Design value of the steam generator heat transfer coefficient including allowance for fouling factor.

5. Since the steam generators are provided with integral flow restrictors with a 1.4 square foot throat area, any rupture with a break area greater than 1.4 square feet, regardless of location, would have the same effect on the NSSS as the 1.4 square foot break. The following 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, full reactor coolant flow with offsite power available.

   b. Case (a) with loss of offsite power simultaneous with the steam line break and initiation of the safety injection signal. Loss of offsite power results in reactor coolant pump coastdown.

6. Power peaking factors corresponding to one stuck RCCA and non-uniform core inlet coolant temperatures are determined at end of core life. 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 upon the core power, temperature, pressure, and flow, and, thus, are different for each case studied.

   The core parameters used for each of the two cases correspond to values determined from the respective transient analysis.

   Both cases above assume initial hot standby conditions at time zero since this represents the most pessimistic 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.

7. In computing the steam flow during a steam line break, the Moody Curve (Reference 3) for f(L/D) = 0 is used.

8. The Upper Head Injection (UHI) is simulated. The actuation pressure for the UHI is near the saturation pressure for the inactive coolant in the upper head. The insurge of cold UHI water keeps this inactive coolant from flashing and from retarding the pressure decrease. The effect of UHI is a faster pressure decrease which in turn permits more safety injection flow into the core. These effects are very small and results are not significantly affected.

Results

The calculated sequence of events for both cases analyzed is shown on Table 15.1.2-1.

The results presented are a conservative indication of the events which would occur assuming a steamline rupture since it is postulated that all of the conditions described above occur simultaneously.

Core Power and Reactor Coolant System Transient

Figures 15.1.5-2 through 15.1.5-4 show the RCS transient and core heat flux following a main steamline rupture (complete severance of a pipe) at initial no-load condition (case a).

Offsite power is assumed available so that full reactor coolant flow exists. The transient shown assumes an uncontrolled steam release from only one steam generator. Should the core be critical at near zero power when the rupture occurs the initiation of safety injection by low steam line pressure will shut down the reactor. Steam release from more than one steam generator will be prevented by automatic trip of the fast acting isolation valves in the steamlines by low steamline pressure signals, high-high containment pressure signals, or high negative steamline pressure rate signals. Even with the failure of one valve, release is limited to no more than 10 seconds for the other steam generators while the one generator blows down. The steam line stop valves are designed to be fully closed in less than 5 seconds from receipt of a closure signal.

As shown in Figure 15.1.5-3 the core attains criticality with the RCCAs inserted (with the design shutdown assuming one stuck RCCA) shortly after boron solution at 2,000 ppm enters the RCS. The continued addition of boron results in a peak core power significantly lower than the nominal full power value.

The calculation assumes the boric acid is mixed with, and diluted by, the water flowing in the RCS prior to entering the reactor core. The concentration after mixing depends upon the relative flow rates in the RCS, from the UHI, and in the Safety Injection System. The variation of mass flow rate in the RCS due to water density changes is included in the calculation as is the variation of flow rate in the Safety Injection System due to changes in the RCS pressure. The Safety Injection System flow calculation includes the line losses in the system as well as the pump head curve.

Figures 15.1.5-5 through 15.1.5-7 show the salient parameters for case b, which corresponds to the case discussed above with additional loss of offsite power at the time the safety injection signal is generated. The Safety Injection System delay time includes 10 seconds to start the diesel in addition to 10 seconds to start the safety injection pump and open the valves. Criticality is achieved later and the core power increase is slower than in the similar 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. The peak power remains well below the nominal full power value.

It should be noted that following a steamline 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 of loss of offsite power this heat is removed to the atmosphere via the steamline safety valves.

Margin to Critical Heat Flux

A DNB analysis was performed for both of these cases. It was found that both cases has a minimum DNBR greater than the limit value.

15.1.5.3 Environmental Consequences

The postulated accidents involving release of steam from the secondary system do not result in a release of radioactivity unless there is leakage from the RCS to the secondary system in the steam generators. A conservative analysis of the potential offsite doses resulting from this accident is presented considering equilibrium operation based upon a 1 gpm steam generator leak rate prior to the postulated accident. Two postulated cases are analyzed:

Case 1: There is a pre-existing iodine spike.

Case 2: There is a coincident iodine spike.

The primary and secondary coolant activities correspond to limits set by Technical Specifications prior to the accident.

The following assumptions and parameters are used to calculate the activity release and offsite dose for a postulated steam line break:

1. Prior to the accident, an equilibrium activity of fission products exists in the primary and secondary systems caused by a primary-to-secondary leakage in steam generators.

2. The total primary-to-secondary leak rate for the duration of the accident is 1.0 gpm, with 0.347 gpm (500 gal/day) in the defective steam generator and 0.653 gpm in the nondefective steam generators.

3. Offsite power is lost.

4. The initial steam release for the defective steam generators terminates in 30 minutes, the steam release from the nondefective steam generators continues for eight hours.

5. All noble gases which leak to the secondary side are released via the steam release.

6. The iodine partition factor in the defective steam generator is 1.

7. The iodine partition factor in the nondefective steam generator is 0.01.

8. For Case 1, the iodine concentrations are assumed to be the maximum permitted for full power operation.

9. For Case 2, the iodine spike occurs at the onset of the accident and continues for the duration of the accident. Spike concentrations are determined by increasing the equilibrium appearance rate in the coolant by a factor of 500.

10. Other assumptions are listed in Table 15.1.5-2.

Based on the foregoing model, the thyroid and whole body doses are calculated at the exclusion area boundary and the low population zone. The results are presented in Table 15.1.5-2.

REFERENCES FOR SECTION 15.1

1. Burnett, T. W. T., et al., "LOFTRAN Code Description", WCAP-7907-P-A (Proprietary) and WCAP-7907-A (Non-Proprietary), April, 1984.

2. "Westinghouse Anticipated Transients Without Trip Analysis", WCAP-8330, August 1974.

3. Moody, F. S., "Transactions of the ASME, Journal of Heat Transfer", Figure 3, page 134, February 1965.

4. Hollingsworth, S. D. and Wood, D. C., "Reactor Core Response To Excessive Secondary Steam Releases", WCAP-9226 (Proprietary) and WCAP-9227 (Non-Proprietary), January 1978.

5. Chelemer, H., Boman, L. H., Sharp, D. R., "Improved Thermal Design Procedures", WCAP-8567, July, 1975.

Time Sequence of Event for Incidents Which Cause an Increase in Heat Removal By The Secondary System

Accident	Event	Time (sec.)
Excessive Feedwater flow at full power	One main feedwater control valve fails fully open	0.0
	High-High steam generator water level signal generated	89.2
	Turbine trip occurs due to high-high steam generator level	92.2
	Minimum DNBR occurs	92.2
	Feedwater isolation valves close	96.2
	Low-low steam generator level reactor trip setpoint reached	167
Excessive Increase in Secondary Steam Flow		
1. Manual Reactor Control (Minimum moderator feedback)	10% step load increase	0.0
	Equilibrium conditions reached (approximate time only)	100
2. Manual Reactor Control (Maximum moderator feedback)	10% step load increase	0.0
	Equilibrium conditions reached (approximate time only)	50
3. Automatic Reactor Control (Minimum moderator feedback)	10% step load increase	0.0

TABLE 15.1.5-2 (Page 1)

Parameters for Postulated Main Steam Line Break Accident Analysis

			Conservative	Realistic
1.	Data and assumptions used to estimate radioactive source from postulated accidents			
	a. Power level (MWt)		3565.	3565.
	b. Steam generator tube leak rate prior to accident and initial 8 hours following accident (gpm)		1.	0.008
	c. Offsite power		Not available	Available
2.	Data and assumptions used to estimate activity released			
	a. Iodine partition factor for initial steam release		1.	1.
	b. Iodine partition factor for nondefective steam generators		0.01	0.01
	c. Iodine partition factor in condenser during accident		-	0.15
	d. Initial steam release from defective steam generator (lb)	(0-30 min)	175700.	175700.
	e. Steam release from three nondefective steam generators (lb)	(0-2 hr)	403650.	403650.
		(2-8 hr)	968638.	968638.
3.	Dispersion data			
	a. Distance to exclusion area boundary (m)		762.	762.
	b. Distance to low population zone (m)		6096.	6096.
	c. χ/Q at exclusion area boundary (sec/m^3)		5.5E-04	1.3E-04
	d. χ/Q at low population zone (sec/m^3)		1.8E-05	6.2E-06
4.	Dose data			
	a. Method of dose calculations		Regulatory Guide 1.4	Same

Table 15.1.5-2 (Page 2)

Parameters for Postulated Main Steam Line Break Accident Analysis

		Conservative	Realistic
b.	Dose conversion assumptions	Regulatory Guides 1.4, 1.109	Same
c.	Doses (Rem)		
	Case 1 (With pre-existing iodine spike) Exclusion area boundary		
	Whole body	1.03E-02	
	Thyroid	4.22	
	Low population zone		
	Whole body	9.38E-04	
	Thyroid	3.23E-01	
	Case 2 (With coincident iodine spike)		
	Exclusion area boundary		
	Whole body	1.26E-02	
	Thyroid	3.32	
	Low population zone		
	Whole body	2.29E-03	
	Thyroid	5.77E-01	

TABLE 15.1.5-2 (Page 3)

Parameters for Postulated Main Steam Line Break Accident Analysis

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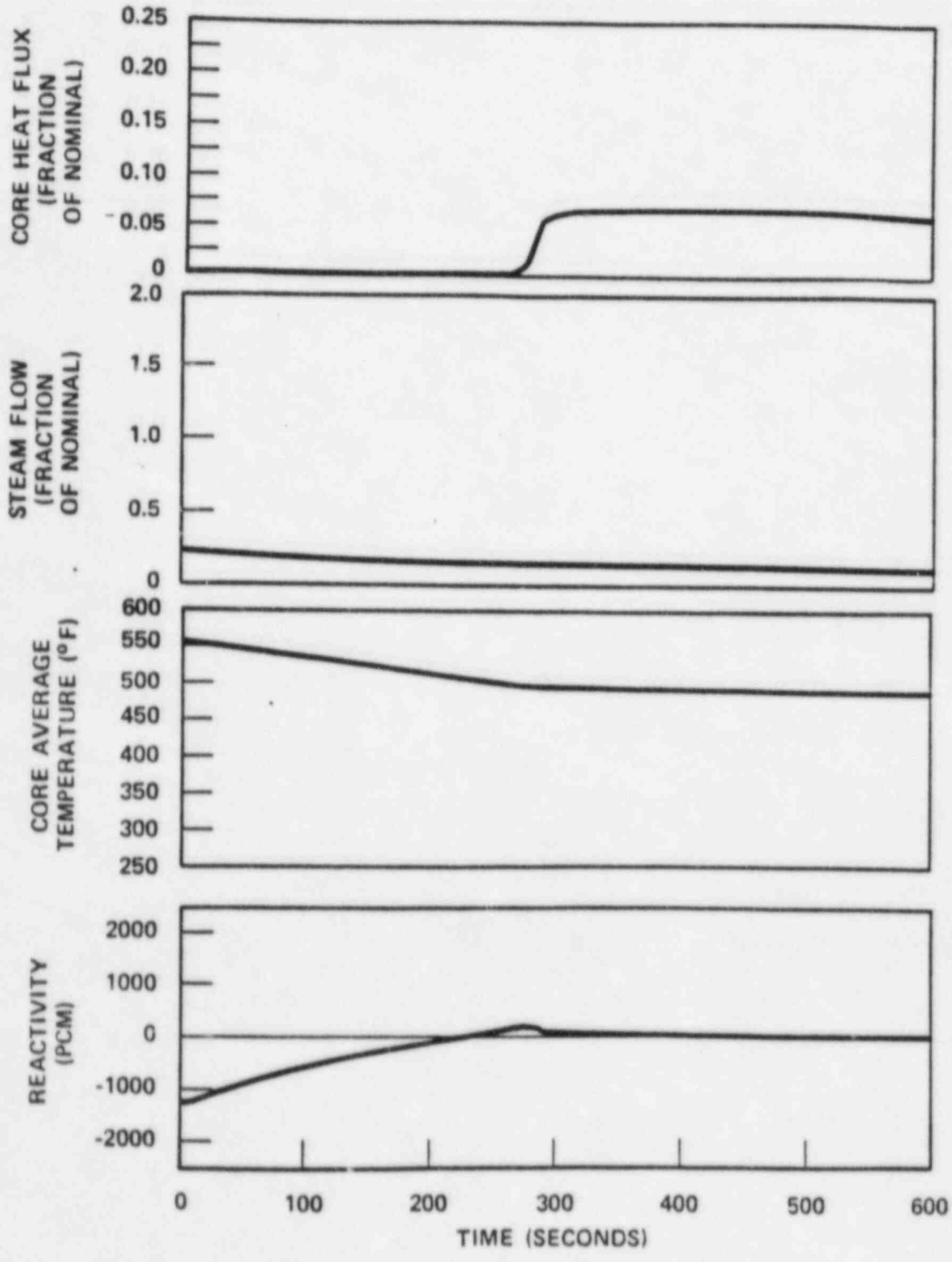
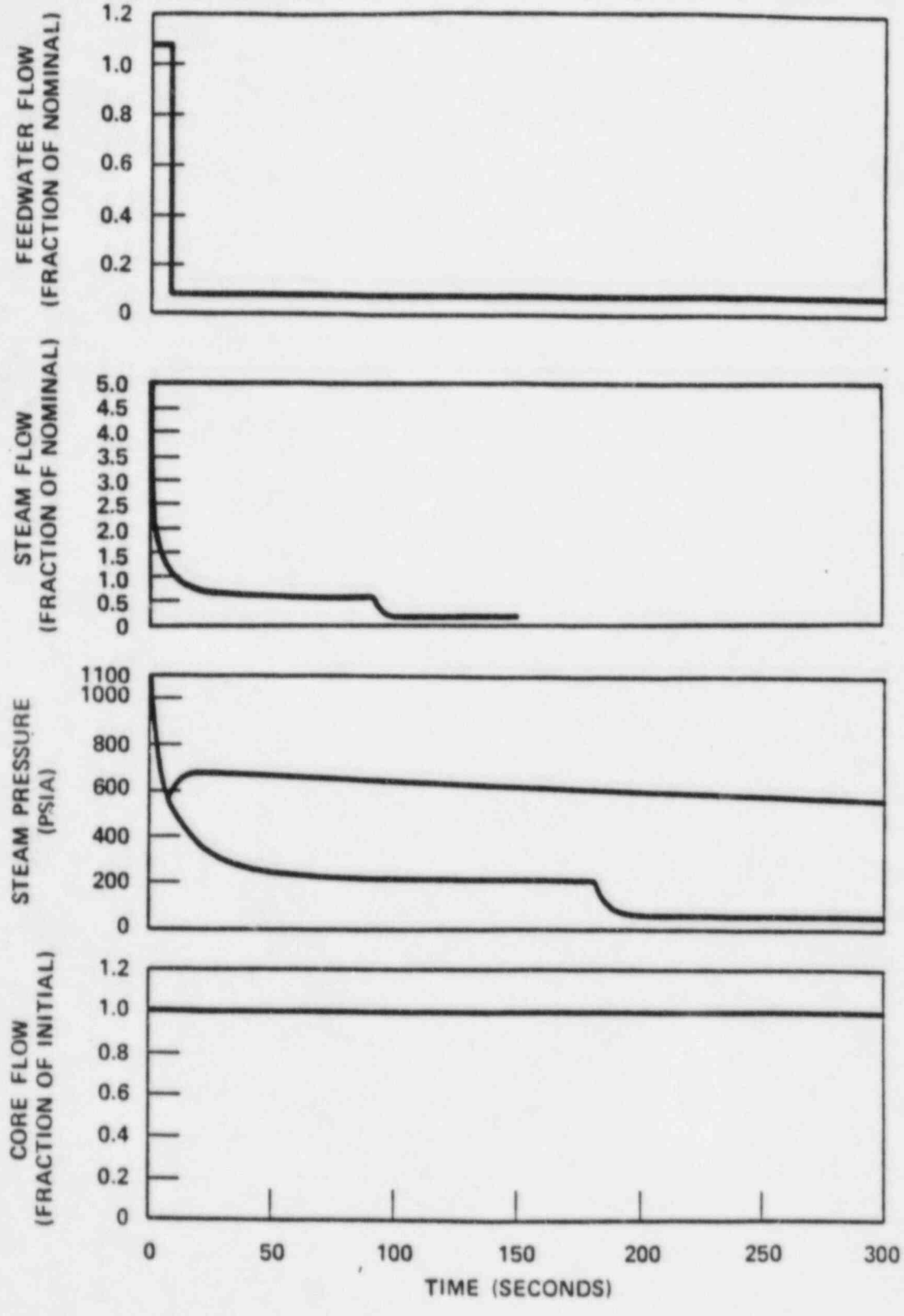


FAILURE OF A STEAM GENERATOR SAFETY OR DUMP VALVE

CATAWBA NUCLEAR STATION

Figure 15.1.4-2

Rev. 14



1.4 FT.^{2} STEAM LINE RUPTURE
OFFSITE POWER AVAILABLE
CATAWBA NUCLEAR STATION
Figure 15.1.5-4
Rev. 14

15.2.3.2 Analysis of Effects and Consequences

Method of Analysis

In this analysis, the behavior of the unit is evaluated for a complete loss of steam load from 100 percent of full power primarily to show the adequacy of the pressure relieving devices and also to demonstrate core protection margins. The reactor is not tripped until conditions in the RCS result in a trip. No credit is taken for steam dump. Main feedwater flow is terminated at the time of turbine trip, with no credit taken for auxiliary feedwater to mitigate the consequences of the transient.

The turbine trip transients are analyzed by employing the detailed digital computer program LOFTRAN (Reference 3). The program simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The program computes pertinent plant variables including temperatures, pressures, and power level.

This accident is analyzed with the Improved Thermal Design Procedure as described in Reference 6. Plant characteristics and initial conditions are discussed in Section 15.0.3.

Major assumptions are summarized below:

1. Initial operating conditions - initial reactor power, pressure and RCS temperatures are assumed to be at their nominal values. Uncertainties in initial conditions are included in the limit DNBR as described in WCAP-8567.

2. Moderator and Doppler Coefficients of Reactivity - the turbine trip is analyzed with both maximum and minimum reactivity feedback. The maximum feedback cases assume a large negative moderator temperature coefficient and the most negative Doppler power coefficient. The minimum feedback cases assume a least negative moderator temperature coefficient and the least negative Doppler coefficients. (See Figure 15.0.4-1).

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 minimum and maximum reactivity feedback are analyzed:

to actuate the safety valves so the primary system pressure remains substantially below the 110% design value. The Steam Generator Safety Valves limit the secondary steam conditions to saturation at the safety valve setpoint.

Figures 15.2.3-3 and 15.2.3-4 show the response for the total loss of steam load with a large negative moderator temperature coefficient. All other plant parameters are the same as the above. The DNBR increases throughout the transient and never drops below its initial value. Pressurizer relief valves and steam generator safety valves prevent overpressurization in primary and secondary systems, respectively. The pressurizer safety valves are not actuated for this case.

In the event that feedwater flow is not terminated at the time of turbine trip for this case, flow would continue under automatic control with the reactor at a reduced power. The operator would take action to terminate the transient and bring the plant to a stabilized condition. If no action were taken by the operator the reduced power operation would continue until the condenser hotwell was emptied. A low-low steam generator water level reactor trip would be generated along with auxiliary feedwater initiation signals. Auxiliary feedwater would then be used to remove decay heat with the results less severe than those presented in Section 15.2.7, Loss of Normal Feedwater Flow.

The turbine trip accident was also studied assuming the plant to be initially operating at full power with no credit taken for the pressurizer spray, pressurizer power-operated relief valves, or steam dump. The reactor is tripped on the high pressurizer pressure signal. Figures 15.2.3-5 and 15.2.3-6 show the transients with a least negative moderator coefficient. The neutron flux remains essentially constant at full power until the reactor is tripped. The DNBR never goes below the initial valve throughout the transient. In this case the pressurizer safety valves are actuated, and maintain system pressure below 110% of the design value.

Figures 15.2.3-7 and 15.2.3-8 are the transients with maximum reactivity feedback with the other assumptions being the same as in the preceding case. Again, the DNBR increases throughout the transient and the pressurizer safety valves are actuated to limit primary pressure.

Reference 1 presents additional results of analysis for a complete loss of heat sink including loss of main feedwater. This analysis shows the overpressure protection that is afforded by the pressurizer and steam generator safety valves.

15.2.3.3 Environmental Consequences

The radiological consequences resulting from atmospheric steam dump will be less severe than the steamline break event analyzed in Section 15.1.5.3 since no fuel damage is postulated to occur.

15.2.3.4 Conclusions

Results of the analyses, including those in Reference 1, show that the plant design is such that a turbine 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 limit value. The applicable acceptance criteria as listed in Section 15.0.1 have been met. The above analysis demonstrates the ability of the NSSS to safely withstand a full load rejection.

15.2.4 INADVERTENT CLOSURE OF MAIN STEAM ISOLATION VALVES

Inadvertent closure of the main steam isolation valves would result in a turbine trip. Turbine trips are discussed in Section 15.2.3.

15.2.5 LOSS OF CONDENSOR VACUUM AND OTHER EVENTS CAUSING A TURBINE TRIP

Loss of condenser vacuum is one of the events that can cause a turbine trip. Turbine trip initiating events are described in Section 15.2.3. A loss of condenser vacuum would preclude the use of steam dump to the condenser; however, since steam dump is assumed not to be available in the turbine trip analysis, no additional adverse effects would result if the turbine trip were caused by loss of condenser vacuum. Therefore, the analysis results and conclusions contained in Section 15.2.3 apply to loss of condenser vacuum. In addition, analyses for the other possible causes of a turbine trip, as listed in Section 15.2.3.1 are covered by Section 15.2.3. Possible overfrequency effects due to a turbine overspeed condition are discussed in Section 15.2.2.1 and are not a concern for this type of event.

15.2.6 LOSS OF NON-EMERGENCY AC POWER TO THE STATION AUXILIARIES

15.2.6.1 Identification of Causes and Accident Description

A complete loss of non-emergency AC power may result in the loss of all power to the plant auxiliaries, i.e., the reactor coolant pumps, condensate pumps, etc. The loss of power may be caused by a complete loss of the offsite grid accompanied by a turbine generator trip at the station, or by a loss of the onsite AC distribution system.

This transient is more severe than the turbine trip event analyzed in Section 15.2.3 because for this case the decrease in heat removal by the secondary system is accompanied by a flow coastdown which further reduces the capacity of the primary coolant to remove heat from the core. The reactor will trip:

4. Reactor trip occurs on steam generator low-low narrow range level, assumed to be at 49.9%. No credit is taken for immediate release of the control rod drive mechanisms caused by a loss of offsite power.

5. The worst single failure in the auxiliary feedwater system occurs. 491 gpm of auxiliary feedwater is delivered to two steam generators.

6. Secondary system steam relief is achieved through the steam generator safety valves.

The assumptions used in the analysis are essentially identical to the loss of normal feedwater flow incident (Section 15.2.7) except that power is assumed to be lost to the reactor coolant pumps at the time of reactor trip.

Plant characteristics and initial conditions are further discussed in Section 15.0.3.

Results

The transient response of the RCS following a loss of ac power is shown in Figures 15.2.6-1 through 15.2.6-4. The calculated sequence of events for this event is listed in Table 15.2.3-1.

The first few seconds after the loss of power to the reactor coolant pumps will closely resemble a simulation of the complete loss of flow incident (see Section 15.3.2), i.e., core damage due to rapidly increasing core temperatures is prevented by promptly tripping the reactor. After the reactor trip, stored and residual decay heat must be removed to prevent damage to either the RCS or the core.

The LOFTRAN code results show that the natural circulation flow available is sufficient to provide adequate core decay heat removal following reactor trip and RCP coastdown.

15.2.6.3 Environmental Consequences

The postulated accidents involving release of steam from the secondary system will not result in a release of radioactivity unless there is leakage from the Reactor Coolant System to the secondary system in the steam generator. A conservative analysis of the potential offsite doses resulting from this accident is presented assuming primary to secondary leakage. This analysis incorporates assumptions of 1 percent defective fuel and existence of a 1 gpm steam generator leak rate prior to the postulated accident for a time sufficient to establish equilibrium specific activity levels in the secondary system. Three postulated cases are analyzed:

Case 1 (No iodine spike)

Case 2 (With pre-existing iodine spike)

Case 3 (With coincident iodine spike)

15.2.7.2 Analysis of Effects and Consequences

Method of Analysis

A detailed analysis using the LOFTRAN Code (Reference 3) is performed in order to obtain the plant transient following a loss of normal feedwater. The simulation describes the plant thermal kinetics, RCS including the natural circulation, pressurizer, steam generators and feedwater system. The digital program computes pertinent variables including the steam generator level, pressurizer water level, and reactor coolant average temperature.

Assumptions made in the analysis are:

1. The plant is initially operating at 102 percent of the Engineered Safety Features design rating.

2. A conservative core residual heat generation based upon long term operation at the initial power level preceding the trip.

3. Reactor trip occurs on steam generator low-low narrow range level, assumed to be at 49.9%.

4. The worst single failure in the auxiliary feedwater system occurs. 491 gpm of auxiliary feedwater is delivered to two steam generators.

5. Secondary system steam relief is achieved through the steam generator safety valves.

The loss of normal feedwater analysis is performed to demonstrate the adequacy of the reactor protection and engineered safeguards systems (e.g., the Auxiliary Feedwater System) in removing long term decay heat and preventing excessive heatup of the RCS with possible resultant RCS overpressurization or loss of RCS water.

As such, the assumptions used in this analysis are designed to minimize the energy removal capability of the system and to maximize the possibility of water relief from the coolant system by maximizing the coolant system expansion, as noted in the assumptions listed above.

For the loss of normal feedwater transient, the reactor coolant volumetric flow remains at its normal value and the reactor trips via the low-low steam generator level trip. The reactor coolant pumps may be manually tripped at some later time to reduce heat addition to the RCS.

An additional assumption made for the loss of normal feedwater evaluation is that only the pressurizer safety valves are assumed to function normally. Operation of the valves maintains peak RCS pressure at or below the actuation setpoint (2500 psia) throughout the transient.

Plant characteristics and initial conditions are further discussed in Section 15.0.3.

Plant systems and equipment which are necessary to mitigate the effects of a loss of normal feedwater accident are discussed in Section 15.0.8 and listed in Table 15.0.8-1. Normal reactor control systems are not required to function. The Reactor Protection System is required to function following a loss of normal feedwater as analyzed here. The Auxiliary Feedwater System is required to deliver a minimum auxiliary feedwater flowrate. No single active failure will prevent operation of any system required to function. A discussion of ATWT considerations is presented in Reference 2.

Results

Figures 15.2.7-1 through 15.2.7-4 show the significant plant parameters following a loss of normal feedwater.

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 level trip, at least one auxiliary feedwater pump is automatically started, reducing the rate of water level decrease.

The capacity of the Auxiliary Feedwater System is such that the water level in the steam generators being fed does not recede below the lowest level at which sufficient heat transfer area is available to dissipate core residual heat without water relief from the RCS safety valves. Figure 15.2.7-2 shows that at no time is there water relief from the pressurizer.

The calculated sequence of events for this accident is listed in Table 15.2.3-1. As shown in Figures 15.2.7-1 and 15.2.7-2, the plant approaches a stabilized condition following reactor trip and auxiliary feedwater initiation. Plant procedures may be followed to further cool down the plant.

15.2.7.3 Environmental Consequences

If steam dump to the condenser is assumed to be lost, heat removal from the secondary system would occur through the steam generator power relief valves or safety valves. Since no fuel damage is postulated to occur, radiological consequences resulting from this transient would be less severe than the steamline break accident analyzed in Section 15.1.5.3.

15.2.7.4 Conclusions

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 auxiliary feedwater capacity is such that reactor coolant water is not relieved from the pressurizer relief or safety valves.

the functioning of various control and safety systems. Sensitivity studies presented in Reference 5 illustrate that the most limiting feedwater line ruptures are the double ended rupture of the largest feedwater line, occurring at full power with and without loss of offsite power, with no credit taken for pressurizer control. These cases are analyzed below.

The following provides the necessary protection for a main feedwater 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:

      1. 2/3 low steam line pressure in any loop.

      2. 2/3 high containment pressure

   Chapter 7 contains a description of the actuation system.

2. An Auxiliary Feedwater System to provide an assured source of feedwater to the steam generators for decay heat removal. Section 10.4.9 contains a description of the Auxiliary Feedwater System.

15.2.8.2 Analysis of Effects and Consequences

Method of Analysis

A detailed analysis using the LOFTRAN Code (Reference 3) is performed in order to determine the plant transient following a feedwater line rupture. The code describes the plant thermal kinetics, RCS including natural circulation, pressurizer, steam generators and feedwater system, and computes pertinent variables including the pressurizer pressure, pressurizer water level, and reactor coolant average temperature.

The cases analyzed assume a double ended rupture of the largest feedwater pipe at full power. Major assumptions made in the analyses are as follows:

1. The plant is initially operating at 102 percent of engineered safeguards power.

2. Initial reactor coolant average temperature is 4.0°F above the nominal value, and the initial pressurizer pressure is 30 psi above its nominal value.

3. No credit is taken for the pressurizer power operated relief valves or pressurizer spray.

4. Initial pressurizer level is at the nominal programmed value plus 5 percent (error); initial steam generator water level is at the nominal value plus 5 percent in the faulted steam generator and at the nominal value minus 5 percent in the intact steam generators.

5. No credit is taken for the high pressurizer pressure reactor trip.

6. Main feedwater flow to all steam generators is assumed to be lost at the time the break occurs (all main feedwater spills out through the break).

7. The worst possible break area is assumed. This maximizes the blowdown discharge rate following the time of trip, which maximizes the resultant heatup of the reactor coolant.

8. A conservative feedline break discharge quality is assumed prior to the time the reactor trip occurs, thereby maximizing the time until the trip setpoint is reached. After the trip occurs, a saturated liquid discharge is assumed until all the water inventory is discharged from the affected steam generator. This minimizes the heat removal capability of the affected steam generator.

9. Reactor trip is assumed to be initiated at 17 percent of narrow range span below the adjusted low-low level trip setpoint in the faulted steam generator.

10. The Auxiliary Feedwater System is actuated by the low-low steam generator water level signal. The Auxiliary Feedwater System is assumed to supply a total of 492 gallons per minute (gpm) to the two unaffected steam generators, including allowance for possible spillage through the main feedwater line break. A 60 second delay was assumed following the low-low level signal to allow time for startup of the emergency diesel generators and the auxiliary feedwater pumps. An additional 115 seconds was assumed before the feedwater lines were purged and the relatively cold (134°F) auxiliary feedwater entered the unaffected steam generators.

11. No credit is taken for heat energy deposited in RCS metal during the RCS heatup.

12. No credit is taken for charging or letdown.

13. Steam generator heat transfer area is assumed to decrease as the shell side liquid inventory decreases.

14. Conservative core residual heat generation is assumed based upon long term operation at the initial power level preceding the trip.

15. No credit is taken for the following potential protection logic signals to mitigate the consequences of the accident:

a. High pressurizer pressure.
b. Overtemperature ΔT.
c. High pressurizer level.
d. High Containment pressure.

Receipt of a low-low steam generator water level signal in at least one steam generator starts the motor driven auxiliary feedwater pumps, which then deliver auxiliary feedwater flow to the steam generators. The turbine driven auxiliary feedwater pump is initiated if the low-low steam generator water signal is reached in at least two steam generators. Similarly, receipt of a low steam line pressure signal in at least one steam line initiates a steam line isolation signal which closes the main steam line isolation valves in all steam lines. This signal also gives a safety injection signal which initiates flow of borated water into the RCS. The amount of safety injection flow is a function of RCS pressure.

Emergency operating procedures following a secondary system line rupture call for the following actions to be taken by the reactor operator:

1. Isolate feedwater flow spilling out the break of ruptured steam generator and align system so level in intact steam generators recovers.

2. Stop the safety injection pumps if:

   a. Wide range reactor coolant pressure is stable or increasing.

   b. Pressurizer water level is on span.

   c. RCS is adequately subcooled.

   d. Steam generator narrow range level indication exists in at least one steam generator or sufficient auxiliary feedwater is being injected into the steam generators to provide an adequate heat sink.

Subsequent to recovery of level in the intact steam generators, the plant operating procedures will be followed in cooling the plant to hot shutdown conditions.

Plant characteristics and initial conditions are further discussed in Section 15.0.3.

No reactor control systems are assumed to function. The Reactor Protection System is required to function following a feedwater line rupture as analyzed here. No single active failure will prevent operation of this system. A discussion of ATWT considerations is presented in Reference 2.

The engineered safety systems assumed to function are the Auxiliary Feedwater System and the Safety Injection System. For the Auxiliary Feedwater System, the worst case configuration has been used, i.e., two intact steam generators receive auxiliary feedwater following the break. The turbine driven auxiliary

feedwater pump is assumed to fail. One motor driven auxiliary feedwater pump has been assumed to spill its entire flow out the break. The second motor driven pump delivers 492 gpm to the two intact steam generators. Only one train of safety injection has been assumed to be available.

For the case without offsite power there will be a flow coastdown until flow in the loops reaches the natural circulation value. The natural circulation capability of the RCS has been shown in Section 15.2.6, for the loss of AC non-emergency power transient, to be sufficient to remove core decay heat following

reactor trip. Pump coastdown characteristics are demonstrated in Sections 15.3.1 and 15.3.2 for single and multiple reactor coolant pump trips, respectively.

A detailed description and analysis of the Safety Injection System is provided in Section 6.3. The Auxiliary Feedwater System is described in Section 10.4.9.

Results

Calculated plant parameters following a major feedwater line rupture are shown in Figures 15.2.8-1 through 15.2.8-10. Results for the case with offsite power available are presented in Figures 15.2.8-1 through 15.2.8-5. Results for the case where offsite power is lost are presented in Figures 15.2.8-5 through 15.2.8-10. The calculated sequence of events for both cases analyzed are listed in Table 15.2.3-1.

The system response following the feedwater line rupture is similar for both cases analyzed. Results presented in Figures 15.2.8-2 and 15.2.8-4 (with offsite power available) and Figures 15.2.8-7 and 15.2.8-9 (without offsite power) show that pressures in the RCS and main steam system remain below 110 percent of the respective design pressures. Pressurizer pressure increases until reactor trip occurs on low-low steam generator water level. Pressure then decreases, due to the loss of heat input, until the Safety Injection System is actuated on low steam line pressure in the ruptured loop. Coolant expansion occurs due to reduced heat transfer capability in the steam generators; the pressurizer safety valves open to maintain primary pressure at an acceptable value. Addition of the safety injection flow aids in cooling down the primary and helps to ensure that sufficient fluid exists to keep the core covered with water.

Figures 15.2.8-1 and 15.2.8-6 show that following reactor trip, the plant remains subcritical.

RCS pressure will be maintained at the safety valve setpoint until safety injection flow is terminated by the operator, as mentioned in Section 15.2.8.2. The reactor core remains covered with water throughout the transient, as water relief due to thermal expansion is limited by the heat removal capability of the Auxiliary Feedwater System and makeup is provided by the Safety Injection System.

The major difference between the two cases analyzed can be seen in the plots of hot and cold leg temperatures, Figure 15.2.8-3 (with offsite power available) and Figure 15.2.8-8 (without offsite power). It is apparent from the initial portion of the transient (~200 seconds), that the case without offsite power results in higher temperatures in the hot leg. For longer times, however, the case with offsite power results in a more severe rise in temperature until the coolant pumps are turned off and the Auxiliary Feedwater System is realigned. The pressurizer fills for the case with power due to the increased coolant expansion resulting from the pump heat addition; hence, water is relieved for the case with power. As previously stated, however, the core remains covered with water for both cases.

REFERENCES FOR SECTION 15.2

1. Mangan, M. A., "Overpressure Protection for Westinghouse Pressurized Water Reactors", WCAP-7769, October 1971.

2. "Westinghouse Anticipated Transients Without Trip Analysis", WCAP-8330, August 1974.

3. Burnett, T. W. T., et al., "LOFTRAN Code Description", WCAP-7907-P-A (Proprietary) and WCAP-7907-A (Non-Proprietary), April, 1984.

4. Hargrove, H. G., "FACTRAN-A Fortran-IV Code for Thermal Transients in a UO_2 Fuel Rod", WCAP-7908, June 1972.

5. Lang, G. E., Cunningham, J. B., "Report on the Consequences of a Postulated Main Feedline Rupture", WCAP-9230, January 1978.

Table 15.2.3-1 (Page 5)

Time Sequence Of Events For Incidents Which Cause A Decrease

In Heat Removal By The Secondary System

Accident	Event	Time (sec)
Loss of Non-Emergency AC Power	Main feedwater flow stops	10
	Low-low steam generator level reactor trip	60
	Rods begin to drop	62
	Reactor coolant pumps begin to coast down	64
	Peak water level in pressurizer occurs	65
	Auxiliary feedwater pumps start	120
	Two steam generators begin to receive auxiliary feedwater from one motor driven pump	196
	Core decay heat decreases to auxiliary feedwater heat removal capacity	~ 770
Loss of Normal Feedwater Flow	Main feedwater flow stops	10
	Low-low steam generator level reactor trip	51
	Rods begin to drop	53
	Auxiliary feedwater pumps start	111
	Two steam generators begin to receive auxiliary feedwater from one motor-driven pump	188

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Revised

Table 15.2.3-1 (Page 6)

Time Sequence Of Events For Incidents Which Cause A Decrease

In Heat Removal By The Secondary System

Accident	Event	Time (sec)
Loss of Normal Feedwater Flow (Cont'd)	Core decay heat plus pump heat decreases to auxiliary feedwater heat removal capacity	~ 4370
	Peak water level in pressurizer occurs	4446
Feedwater System Pipe Break		
1. With offsite power available	Main feedline rupture occurs	10
	Low-low steam generator level trip setpoint reached in ruptured steam generator	31
	Rods begin to drop	33
	Auxiliary feedwater pumps start	91
	Two steam generators begin to receive auxiliary feedwater from one motor driven pump	168
	Low steam line pressure setpoint reached in ruptured steam generator	247
	All main steam line isolation valves close	254
	Steam generator safety valve setpoint reached in intact steam generators	454

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Revised

Table 15.2.3-1 (Page 7)

Time Sequence Of Events For Incidents Which Cause A Decrease In Heat Removal By The Secondary System

Accident	Event	Time (sec)
Feedwater System Pipe Break		
1. With offsite power available (Cont'd)	Pressurizer water relief begins	1476
	Core decay heat plus pump heat decreases to auxiliary feedwater heat removal capacity	~ 3850
2. Without offsite power	Main feedline rupture occurs	10
	Low-low steam generator level reactor trip setpoint reached in ruptured steam generator	31
	Rods begin to drop, power lost to the reactor coolant pumps	33
	Auxiliary feedwater pumps start	91
	Two steam generators begin to receive auxiliary feedwater from one motor driven pump	168
	Low steam line pressure setpoint reached in ruptured steam generator	256
	All main steam line isolation valves close	263

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Table 15.2.3-1 (Page 8)

Time Sequence Of Events For Incidents Which Cause A Decrease

In Heat Removal By The Secondary System

Accident	Event	Time (sec)
Feedwater System Pipe Break		
2. Without offsite power (Cont'd)	Steam generator safety valve setpoint reached in intact steam generators	568
	Core decay heat decreases to auxiliary feedwater heat removal capacity	~ 960

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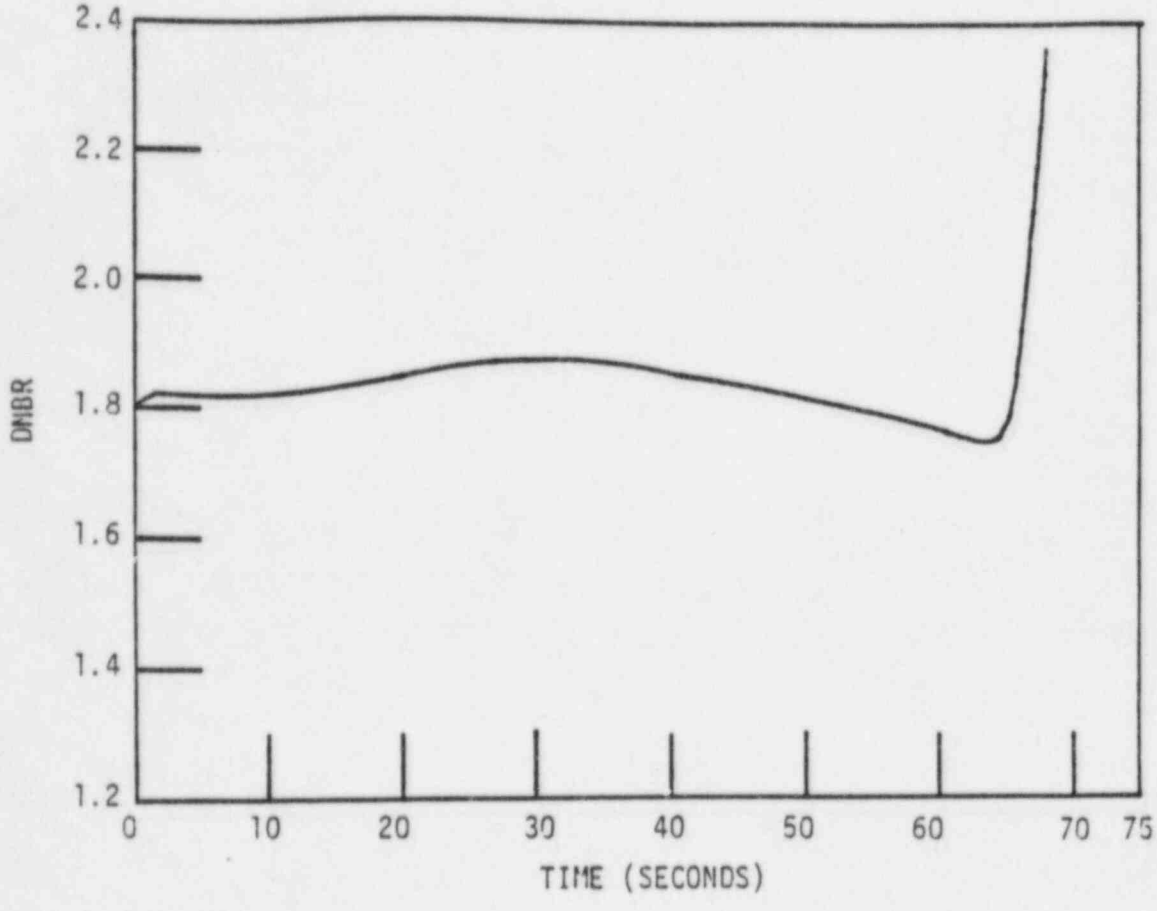
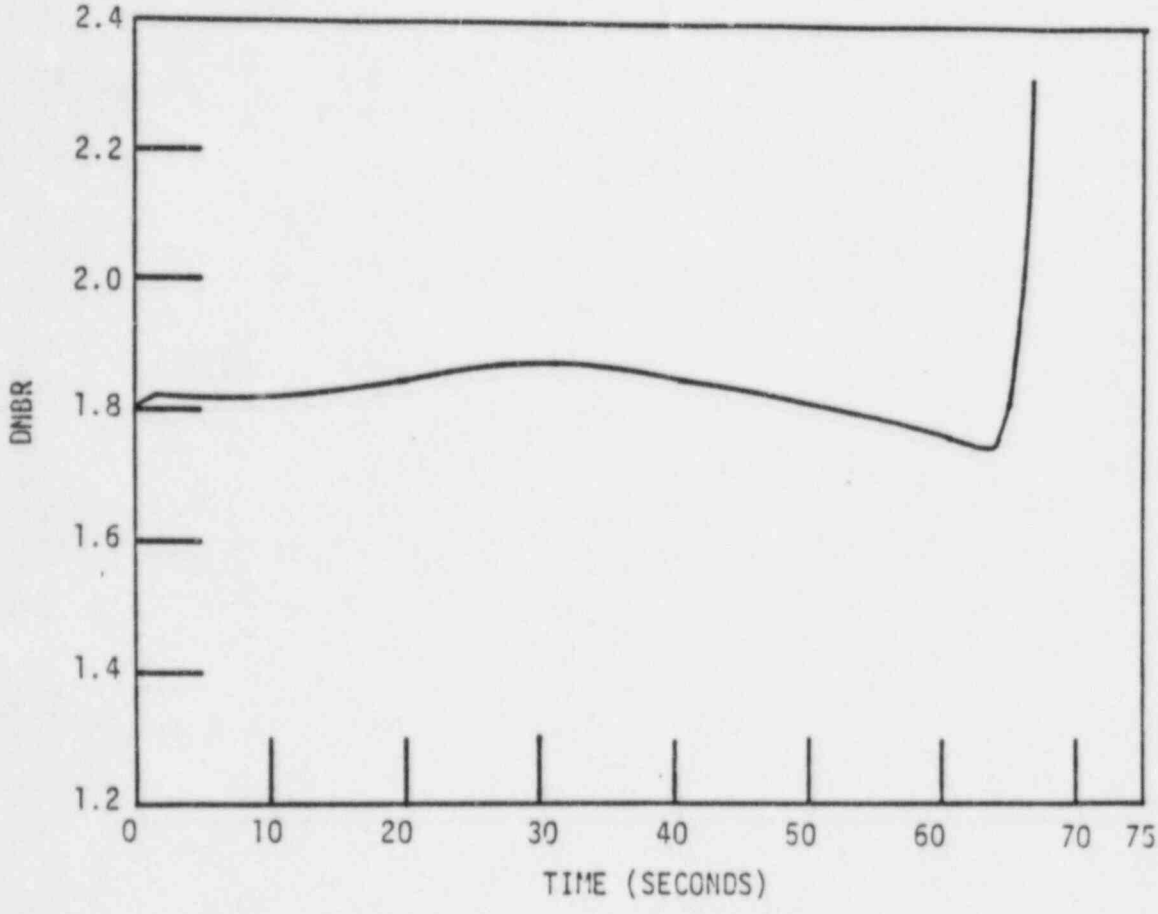
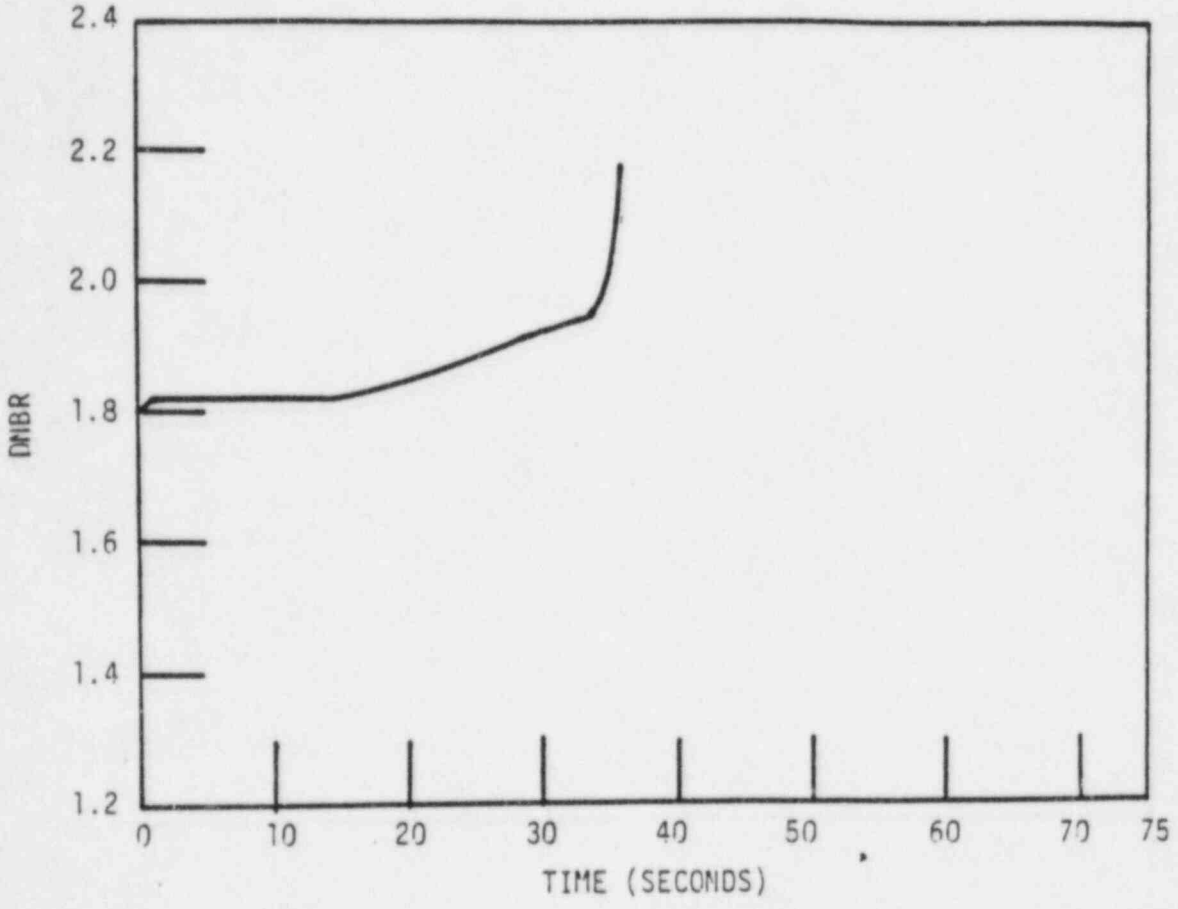


DNBR VERSUS TIME FOR
LOSS OF NON-EMERGENCY
AC POWER
CATAWBA NUCLEAR STATION
Figure 15.2.6-4

Rev. 14
New Figure



DNBR VERSUS TIME
FOR LOSS OF
NORMAL FEEDWATER
CATAWBA NUCLEAR STATION
Figure 15.2.7-4
Rev. 14
New Figure



DNBR VERSUS TIME FOR
FEEDLINE RUPTURE
WITH OFFSITE
POWER AVAILABLE
CATAWBA NUCLEAR STATION
Figure 15.2.8-5
Rev. 14

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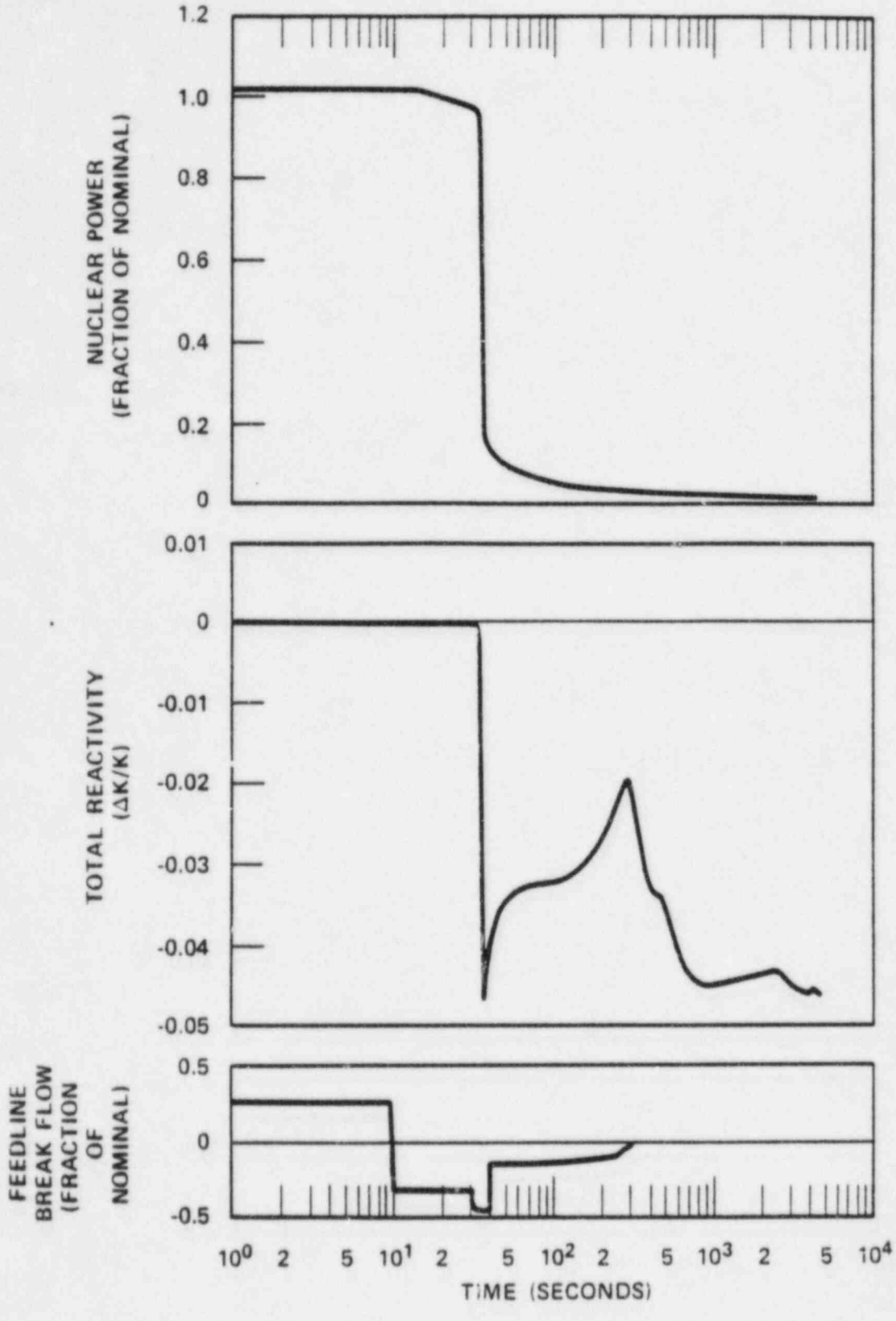

NUCLEAR POWER TRANSIENT, TOTAL CORE REACTIVITY TRANSIENT, AND FEEDLINE BREAK FLOW TRANSIENT FOR MAIN FEEDLINE RUPTURE WITHOUT OFFSITE POWER AVAILABLE

CATAWBA NUCLEAR STATION

Figure 15.2.8-6

Rev. 14

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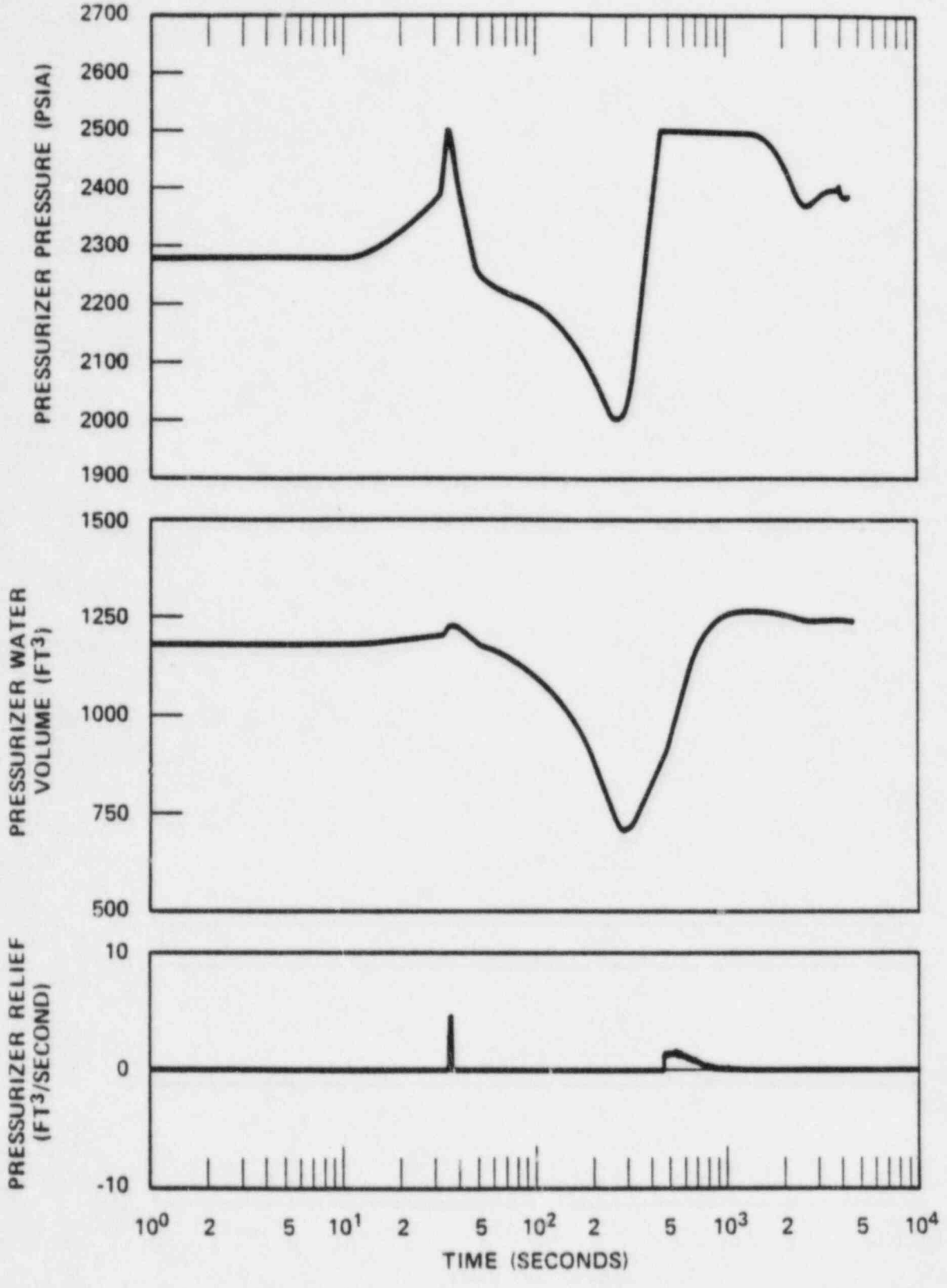

PRESSURIZER PRESSURE, WATER VOLUME, AND RELIEF RATE FOR MAIN FEEDLINE RUPTURE WITHOUT OFFSITE POWER AVAILABLE

CATAWBA NUCLEAR STATION

Figure 15.2.8-7

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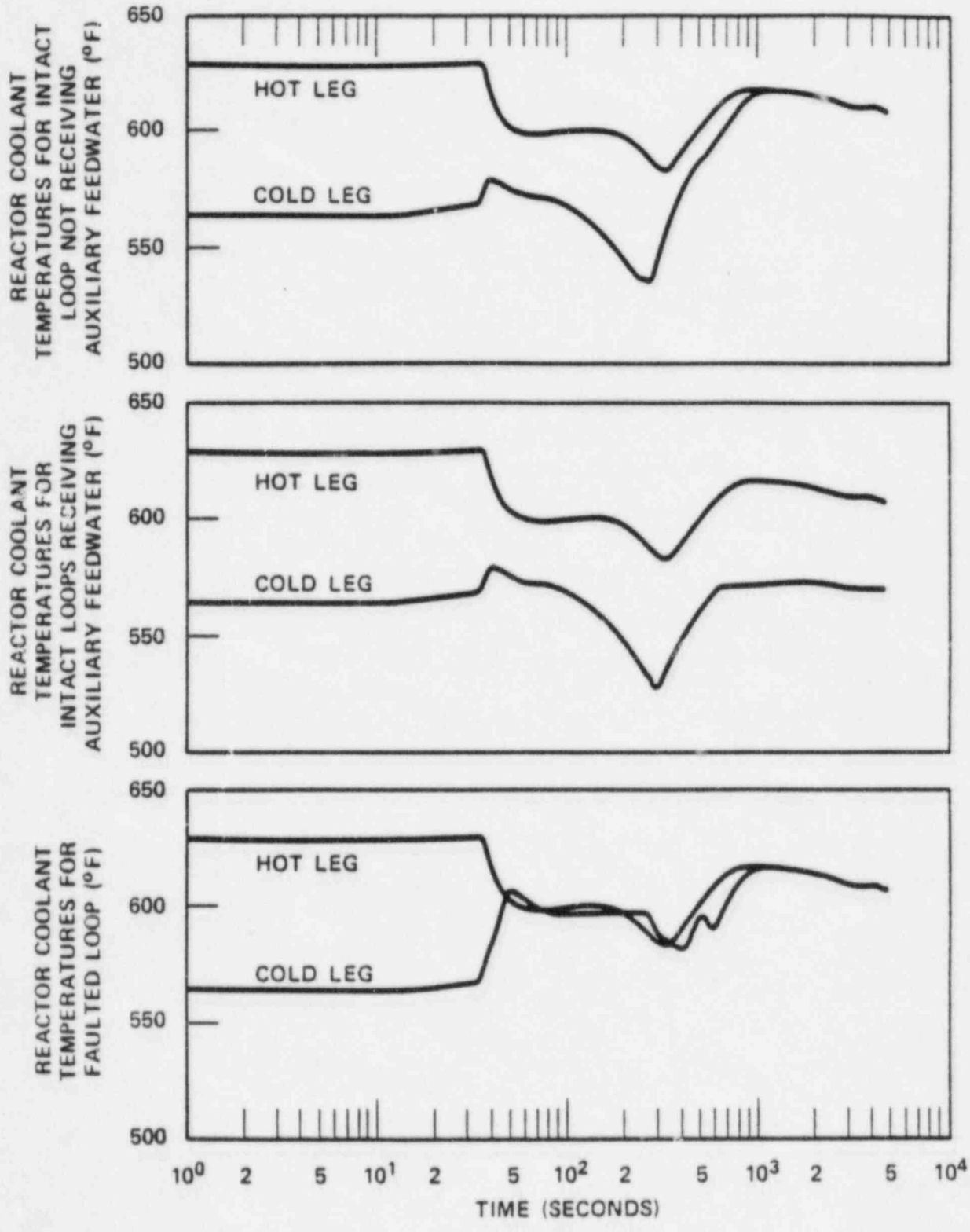

REACTOR COOLANT TEMPERATURE TRANSIENTS FOR THE FAULTED AND INTACT LOOPS FOR MAIN FEEDLINE RUPTURE WITHOUT OFFSITE POWER AVAILABLE

CATAWBA NUCLEAR STATION

Figure 15.2.8-8

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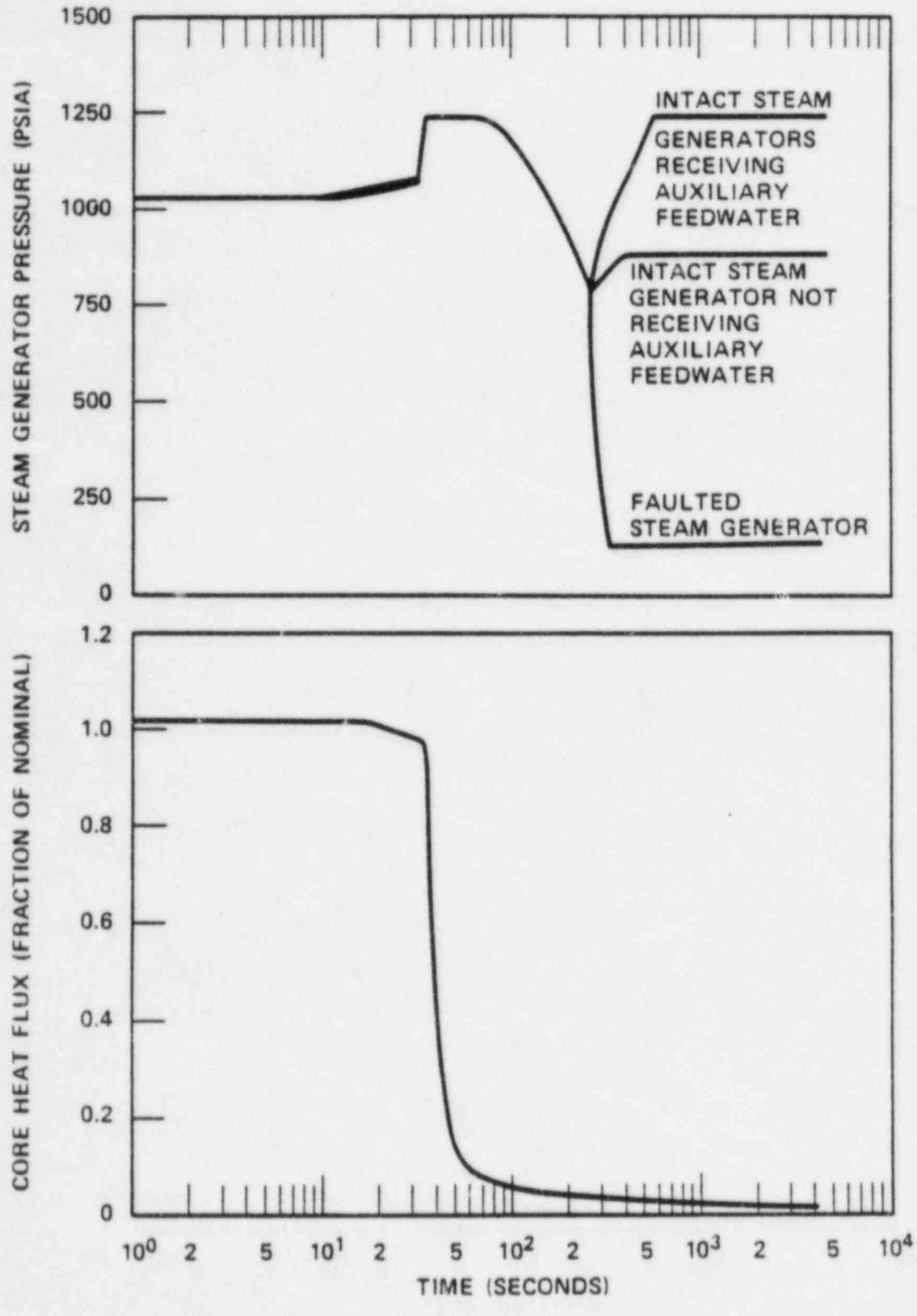
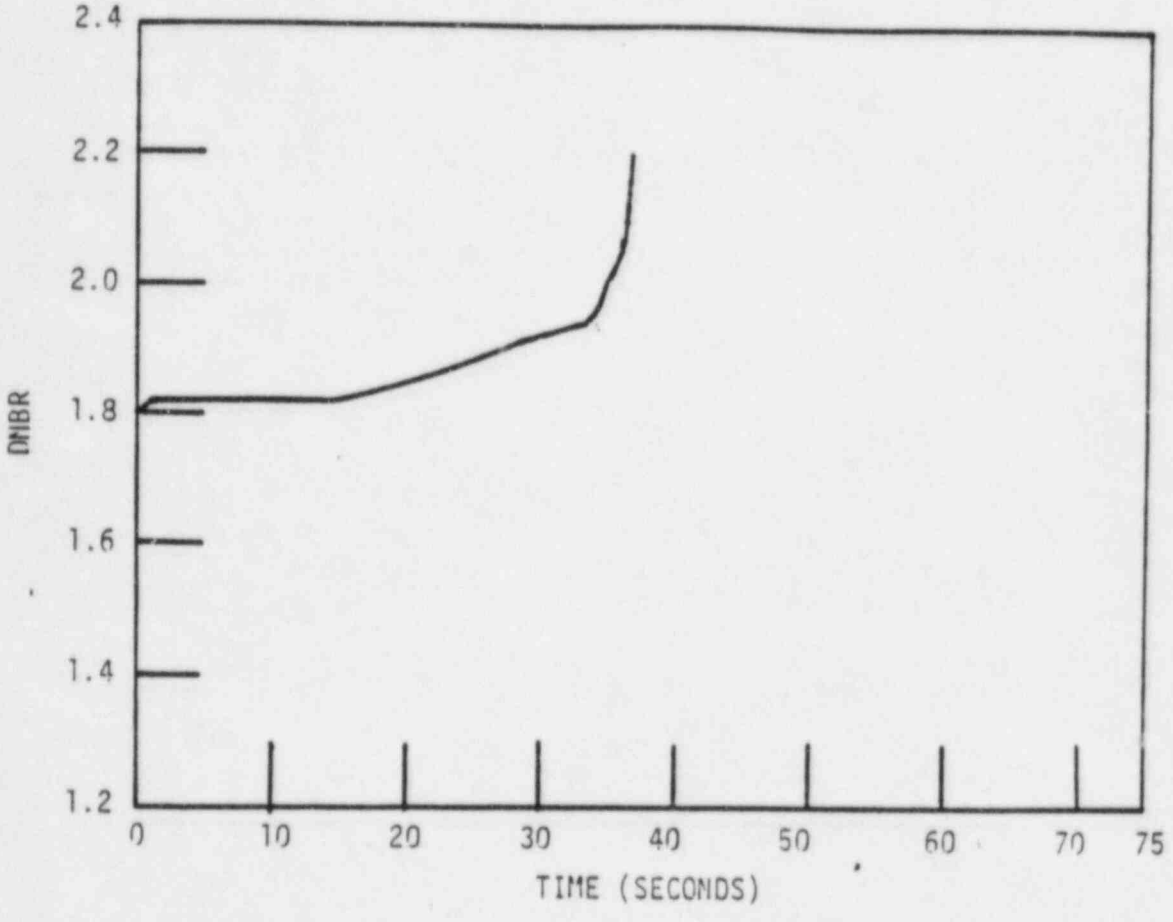


STEAM GENERATOR PRESSURE
AND CORE HEAT FLUX TRANSIENTS
FOR MAIN FEEDLINE RUPTURE
WITHOUT OFFSITE POWER AVAILABLE
CATAWBA NUCLEAR STATION

Figure 15.2.8-9
Rev. 14



DNBR VERSUS TIME FOR
FEEDLINE RUPTURES
WITHOUT OFFSITE
POWER AVAILABLE
CATAWBA NUCLEAR STATION
Figure 15.2.8-10
Rev. 14
New Figure

1. Loss of one pump with four loops in operation.
2. Loss of one pump with three loops in operation.

This transient is analyzed by three digital computer codes. First, the LOFTRAN Code (Reference 1) is used to calculate the loop and core flow during the transient, the time of reactor trip based on the calculated flows, the nuclear power transient, and the primary system pressure and temperature transients. The FACTRAN Code (Reference 2) is then used to calculate the heat flux transient based on the nuclear power and flow from LOFTRAN. Finally, the THINC Code (see Section 4.4) is used to calculate the DNBR during the transient based on the heat flux from FACTRAN and flow from LOFTRAN. The "R" grid spacer factor is applied to the W-3 correlation. The DNBR transients presented represent the minimum of the typical or thimble cell.

This accident is analyzed with the Improved Thermal Design Procedure as described in Reference 4. Plant characteristics and initial conditions are discussed in Section 15.0.3.

Initial Conditions

Initial reactor power, pressure, and RCS temperature are assumed to be at their nominal values. Uncertainties in initial conditions are included in the limit DNBR as described in Reference 4. With three loops operating, the maximum power level (including errors) allowed for three-loop operation is assumed.

Reactivity Coefficients

A conservatively large absolute value of the Doppler-only power coefficient is used (see Figure 15.0.4-1). This is equivalent to a total integrated Doppler reactivity from 0 to 100 percent power of 0.016 ΔK.

The least negative moderator temperature coefficient (see Figure 15.0.5-1) is assumed since this results in the maximum core power during the initial part of the transient when the minimum DNBR is reached.

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.

Plant systems and equipment which are necessary to mitigate the effects of the accident are discussed in Section 15.0.8 and listed in Table 15.0.8-1. No single active failure in any of these systems or equipment will adversely affect the consequences of the accident.

Results

Figures 15.3.1-1 through 15.3.1-4 show the transient response for the loss of one reactor coolant pump with four loops in operation. Figure 15.3.1-4 shows the DNBR to be always greater than the limit value.

The following signals provide the necessary protection against a complete loss of flow accident:

1. Reactor coolant pump power supply undervoltage or underfrequency.
2. Low reactor coolant loop flow.

The reactor trip on reactor coolant pump undervoltage is provided to protect against conditions which can cause a loss of voltage to all reactor coolant pumps, i.e., station blackout. 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 power grid. Reference 3 provides analyses of grid frequency disturbances and the resulting Nuclear Steam Supply System protection requirements which are generally applicable to the Catawba units.

The reactor trip on low primary coolant loop flow is provided to protect against loss of flow conditions which affect only one reactor coolant loop. This function is generated by two out of three low flow signals per reactor coolant loop. Above Permissive 8, low flow in any loop will actuate a reactor trip. Between approximately 10 percent power (Permissive 7) and the power level corresponding to Permissive 8, low flow in any two loops will actuate a reactor trip.

15.3.2.2 Analysis of Effects and Consequences

Two cases have been analyzed:

1. Loss of four pumps with four loops in operation.
2. Loss of three pumps with three loops in operation.

This transient is analyzed by three digital computer codes. For case 1, the loop and core flows are calculated by the LOFTRAN code (Reference 1) based on the measured flow coastdown data taken during the Unit 1 startup test. For case 2, the LOFTRAN Code is used to calculate the loop and core flow during the transient. For both cases, LOFTRAN is used to calculate the time of reactor trip based on the flows, the nuclear power transient, and the primary system pressure and temperature transients. The FACTRAN Code (Reference 2) is then used to calculate the heat flux transient based on the nuclear power and flow from LOFTRAN. Finally, the THINC Code (see section 4.4) is used to calculate the DNBR during the transient based on the heat flux from FACTRAN and flow from LOFTRAN. The DNBR transients presented represent the minimum of the typical or thimble cell.

The method of analysis and the assumptions made regarding initial operating conditions and reactivity coefficients are identical to those discussed in Section 15.3.1, except that following the loss of power supply to all pumps at power, a reactor trip is actuated by either reactor coolant pump power supply undervoltage or underfrequency.

REFERENCES FOR SECTION 15.3

1. Burnett, T. W. T, et al., "LOFTRAN Code Description", WCAP-7907-P-A (Proprietary) and WCAP-7907-A (Non-Proprietary), April, 1984.

2. Hargrove, H. G., "FACTRAN - A Fortran - IV Code for Thermal Transients in a UO_2 Fuel Rod", WCAP-7908, June 1972.

3. Baldwin, M. S., Merrian, M. M., Schenkel, H. S. and Van De Walle, D. J., "An Evaluation of Loss of Flow Accidents Caused by Power System Frequency Transients in Westinghouse PWRs", WCAP-8424, Revision 1, June 1975.

4. Chelemer, H., Boman, L. H., Sharp, D. R., "Improved Thermal Design Procedures", WCAP-8567, July, 1975.

TABLE 15.3.1-1 (Page 2)

Time Sequence of Events for Incidents
Which Result in a Decrease in Reactor Coolant
System Flow

Accident	Event	Time (sec.)	
		Four Loop operation	Three Loop operation
Reactor Coolant Pump Shaft Seizure (Locked Rotor)	Reactor coolant pump undervoltage trip point reached	0.	0.
	Rods begin to drop	1.5	1.5
	Minimum DNBR occurs	3.6	3.7
	Rotor on one pump locks	0.	0.
	Low flow trip point reached	0.03	0.05
	Rods begin to drop	1.03	1.05
	Maximum RCS pressure occurs	4.0	4.8
	Maximum clad temperature occurs	3.7	4.1

Table 15.3.3-2 (Page 1)

Parameters for Postulated Locked Rotor Analysis

		Conservative
1.	Data and assumptions used to estimate radioactive source from postulated accident	
	a. Power Level (MWt)	3565
	b. Percent of fuel defected	1
	c. Total steam generator tube leak rate during accident and initial 8 hours	1 gpm
	d. Activity released to reactor coolant from failed fuel	0% of gap inventory
	e. Offsite Power	Not available
	f. Reactor coolant activity prior to accident	Primary and Secondary Activity During Normal Operations (Table 11.1.1-4)
2.	Data and assumptions used to estimate activity released	
	a. Iodine partition factor	.1
	b. Initial steam release from 4 steam generators	515,247 lb (0-2 hr) 1,040,910 lb (2-8 hr)
	c. Duration of plant cooldown by secondary system after accident, (hrs)	8
3.	Dispersion data	
	a. Distance to exclusion area boundary (m)	762
	b. Distance to low population zone (m)	6096
	c. X/Q at exclusion area boundary (sec/m^3)	5.5E-04
	d. X/Q at low population zone (sec/m^3)	1.8E-05
4.	Dose data	
	a. Method of dose calculations	Regulatory Guide 1.4
	b. Dose conversion assumptions	Regulatory Guides 1.4 & 1.109

15.4 REACTIVITY AND POWER DISTRIBUTION ANOMALIES

A number of faults have been postulated which could result in reactivity and power distribution anomalies. Reactivity changes could be caused by control rod motion or ejection, boron concentration changes, or addition of cold water to the reactor core region. Power distribution changes could be caused by control rod motion, misalignment, or ejection, or by static means such as fuel assembly mislocation. These events are discussed in this section. Detailed analyses are presented for the most limiting of these events.

Discussions of the following incidents are presented in Section 15.4:

1. Uncontrolled Rod Cluster Control Assembly Bank Withdrawal from a Subcritical or Low Power Startup Condition

2. Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power

3. Rod Cluster Control Assembly Misoperation

4. Startup of an Inactive Reactor Coolant Pump at an Incorrect Temperature

5. Chemical and Volume Control System Malfunction that Results in a Decrease in Boron Concentration in the Reactor Coolant

6. Inadvertent Loading and Operation of a Fuel Assembly in an Improper Position

7. Spectrum of Rod Cluster Control Assembly Ejection Accidents

Items 1, 2, 4, and 5 are considered to be ANS Condition II events, Item 6 an ANS Condition III event, and item 7 an ANS Condition IV event. Item 3 entails both Condition II and III events. Section 15.0.1 contains a discussion of ANS classifications.

15.4.1 UNCONTROLLED ROD CLUSTER CONTROL ASSEMBLY BANK WITHDRAWAL FROM A SUBCRITICAL OR LOW POWER STARTUP CONDITION

15.4.1.1 Identification of Causes and Accident Description

A rod cluster control assembly (RCCA) withdrawal accident is defined as an uncontrolled addition of reactivity to the reactor core caused by withdrawal of RCCA's resulting in a power excursion. Such a transient could be caused by a malfunction of the Rod Control System. This could occur with the reactor either subcritical, hot zero power or at power. The "at power" case is discussed in Section 15.4.2.

Although the reactor is normally brought to power from a subcritical condition by means of RCCA withdrawal, initial startup procedures with a clean core call for boron dilution. The maximum rate of reactivity increase in the case of boron dilution is less than that assumed in this analysis (see Section 15.4.6, "Chemical and Volume Control System Malfunction that Results in a Decrease in Boron Concentration in the Reactor Coolant").

This accident is analyzed with the Improved Thermal Design Procedure as described in Reference 3. Plant characteristics and initial conditions are discussed in Section 15.0.3. In order to obtain conservative results for an uncontrolled rod withdrawal at power accident, the following assumptions are made:

1. Initial reactor power, pressure, and RCS temperatures are assumed to be at their nominal values. Uncertainties in initial conditions are included in the limit DNBR as described in Reference 3.

2. Reactivity Coefficients - Two cases are analyzed:

   a. Minimum Reactivity Feedback. A least negative moderator coefficient of reactivity is assumed corresponding to the beginning of core life. 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 and a large (in absolute magnitude) negative Doppler power coefficient are assumed.

3. 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. The delays for trip actuation are assumed to be the maximum values.

4. The RCCA trip insertion characteristic is based on the assumption that the highest worth assembly is stuck in its fully withdrawn position.

5. The maximum positive reactivity insertion rate is greater than that for the simultaneous withdrawal of the combinations of the two control banks having the maximum combined worth at maximum speed.

6. Pressurizer pressure control is assumed to be available. The limiting criterion for this transient is minimum DNBR. Maintaining lower RCS pressures will result in a lower DNBR. Therefore pressure control availability is conservative.

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.

Plant systems and equipment which are available to mitigate the effects of the accident are discussed in Section 15.0.8 and listed in Table 15.0.8-1. No single active failure in any of these systems or equipment will adversely offset the consequences of the accident. A discussion of ATWT considerations is presented in Reference 5.

Results

Figures 15.4.2-1 through 15.4.2-3 show the transient response for a rapid RCCA withdrawal incident 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, only small changes in T_{avg} and pressure result and margin to DNB is maintained.

The transient response for a slow RCCA withdrawal from full power is shown in Figures 15.4.2-4 through 15.4.2-6. 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 greater than the limit value.

Figure 15.4.2-7 shows the minimum DNBR as a function of reactivity insertion rate from initial full power operation for minimum and maximum reactivity feedback. 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 channels. The minimum DNBR is never less than the limit value.

Figures 15.4.2-8 and 15.4.2-9 shows the minimum DNBR 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 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 limit value.

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 15.4.2-8, for example, it is noted that:

1. For high reactivity insertion rates (i.e., between $\sim 2 \times 10^{-4}$ δK/sec and 1.0×10^{-3} δK/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 DNB ratio 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 Reactor Coolant System average temperature and pressure This trip circuit is described in detail in Chapter 7; however, it is important in this context 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 Reactor Coolant System in response to power increases.

3. With further decrease in reactivity insertion rate, the overtemperature ΔT and high neutron flux trips become equally effective in terminating the transient (e.g., at $\sim 2 \times 10^{-4}$ $\delta K/sec$ reactivity insertion rate).

   For reactivity insertion rates between $\sim 2 \times 10^{-4}$ $\delta K/sec$ and $\sim 6 \times 10^{-5}$ $\delta K/sec$ the effectiveness of the overtemperature ΔT trip increases (in terms of increased minimum DNB ratio) 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 $\sim 6 \times 10^{-5}$ $\delta K/sec$, 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 sink for the Reactor Coolant System, sharply decreases the rate of increase of Reactor Coolant System average temperature. This decrease in rate of increase of the average coolant system temperature during the transient is accentuated by the lead-lag compensation causing the overtemperature ΔT trip setpoint to be reached later with resulting lower minimum DNB ratios.

Figures 15.4.2-7, 15.4.2-8 and 15.4.2-9 illustrate minimum DNBR 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 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 centerline temperature will remain below the fuel melting temperature.

Since DNB does not 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 on Table 15.4.1-1. 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.

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. The transient response, nuclear peaking factor analysis, and DNB design basis confirmation are performed in accordance with the methodology described in Reference 10.

b. Statically Misaligned RCCA

Steady state power distribution 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 to calculate the DNBR.

Results

a. One or more Dropped RCCAs

Single or multiple dropped RCCAs within the same group result in a negative reactivity insertion which may be detected by the power range negative neutron flux rate trip circuitry. If detected, the reactor is tripped within approximately 2.5 seconds following the drop of the RCCAs. The core is not adversely affected during this period, since power is decreasing rapidly. Following reactor trip, normal shutdown procedures are followed. The operator may manually retrieve the RCCA by following approved operating procedures.

For those dropped RCCAs which do not result in a reactor trip, 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 15.4.3-1 and 15.4.3-2 show a typical transient response to a dropped RCCA (or RCCAs) in automatic control. Uncertainties in the initial condition are included in the DNB evaluation as described in Reference 3. In all cases, the minimum DNBR remains above the limit value:

b. Dropped RCCA Bank

A dropped RCCA bank typically results in a reactivity insertion greater than 500 pcm which will be detected by the power range negative neutron flux rate trip circuitry. The reactor is tripped within approximately 2.5 seconds following the drop of a RCCA Bank. The core is not adversely affected during this period, since power is decreasing rapidly. Following reactor trip, normal shutdown procedures are followed to further cool down the plant.

c. 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. Any action required of the operator to maintain the plant in a stabilized condition will be in a time frame in excess of ten minutes following the incident.

The insertion limits in the technical specifications may vary from time to time depending on a number of limiting criteria. It is preferable, therefore, to analyze the misaligned RCCA case at full power for a position of the control bank as deeply inserted as the criteria on minimum DNBR and power peaking factor will allow. The full power insertion limits on control bank D must then be chosen to be above that position and will usually be 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 limit value. This case is analyzed assuming the initial reactor power, pressure, and RCS temperatures are at their nominal values including uncertainties (as given in Table 15.0.3-3) but with the increased radial peaking factor associated with the misaligned RCCA.

DNB calculations have not been performed specifically for RCCAs missing from other banks. However, power shape calculations have been done as required for the RCCA ejection analysis. Inspection of the power shapes shows that the DNB and peak kw/ft situation is less severe than the bank D case discussed above, assuming insertion limits on the other banks equivalent to a bank D full-in insertion limit.

For RCCA misalignments with one RCCA fully inserted, the DNBR does not fall below the limit value. This case is analyzed assuming the initial reactor power, pressure, and RCS temperatures are at their nominal values, including uncertainties (as given in Table 15.0.3-4) 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 corrdsponds 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 a RCCA group misalignment condition by the operator, the operator is required to take action as required by the plant Technical Specifications and operating procedures.

2. Single RCCA Withdrawal

Method of Analysis

Power distributions within the core are calculated using the computer codes as described in Table 4.1-2. The peaking factors are then used by THINC to calculate the DNBR for the event. The case of the worst rod withdrawn from bank D inserted at the insertion limit, with the reactor initially at full power, was analyzed. This incident is assumed to occur at beginning-of-life since 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.

Results

For the single rod withdrawal event, two cases have been considered as follows:

a. 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 withdrawing RCCA. In terms of the overall system response, this case is similar to those presented in Section 15.4.2. However, the increased local power peaking in the area of the withdrawn RCCA results in lower minimum DNBR's than for the withdrawn bank cases. Depending on initial bank insertion and location of the withdrawn RCCA, automatic reactor trip may not occur fast enough to prevent the minimum core DNBR from failing below the limit value. Evaluation of this case at the power and coolant conditions 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 limit value is 5 percent.

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 loop flow when the power range neutron flux exceeds the P-8 setpoint. The P-8 setpoint is conservatively assumed to be 85% of rated power which corresponds to the nominal setpoint plus 9% for nuclear instrumentation errors.

Plant systems and equipment which are available to mitigate the effects of the accident are discussed in Section 15.0.8 and listed in Table 15.0.8-1. No single active failure in any of these systems or equipment will adversely affect the consequences of the accident.

Results

The results following the startup of an idle pump with the above listed assumptions are shown in Figures 15.4.4-1 through 15.4.4-5. 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 limit value.

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 the increase in reactor coolant flow and, 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 on Figure 15.4.4-1.

The calculated sequence of events for this accident is shown on Table 15.4.1-1. The transient results illustrated in Figures 15.4.4-1 through 15.4.4-5 indicate that a stabilized plant condition, with the reactor tripped, is approached rapidly. Plant cooldown may subsequently be achieved by following normal shutdown procedures.

15.4.4.3 Environmental Consequences

There would be minimal radiological consequences associated with startup of an inactive reactor coolant loop at an incorrect temperature. Therefore, this event is not limiting. The reactor trip causes a turbine trip and heat may be removed from the secondary system through the steam generator power relief valves or safety valves. Since no fuel damage is postulated to occur from this transient, the radiological consequences associated with this event would be less severe than the steamline break event analyzed in Section 15.1.5.

15.4.4.4 Conclusions

The transient results show that the core is not adversely affected. There is considerable margin to the limiting DNBR. Thus, no fuel or clad damage is predicted.

actuated to warn the operator if boric acid or demineralized water flow rates deviate from preset values as a result of system malfunction.

This event is classified as an ANS Condition II incident (an incident of moderate frequency) as defined in Section 15.0.1.

15.4.6.2 Analysis of Effects and Consequences

Method of Analysis

To cover all phases of the plant operation, boron dilution during refueling, cold shutdown, hot standby, startup, and power operation are considered in this analysis.

Dilution During Refueling

An uncontrolled boron dilution accident cannot occur during refueling as a result of a reactor coolant makeup system malfunction. This accident is prevented by administrative controls which isolate the Reactor Coolant System from the potential source of unborated water.

Q 440.89 Valves 1NV231, 1NV237, 1NV241, 1NV244, and 1NV240 in the CVCS will be locked closed during refueling operations. These valves will block the flow paths which could allow unborated makeup to reach the reactor coolant system. Any makeup which is required during refueling will be borated water supplied from the refueling water storage tank.

The most limiting alternate source of uncontrolled boron dilution would be the inadvertent opening of a valve in the Boron Thermal Regeneration System (BTRS). For this case highly borated RCS water is depleted of boron as it passes through the BTRS and is returned via the volume control tank. The following conditions are assumed for an uncontrolled boron dilution during refueling:

Technical Specifications require the reactor to be borated to a concentration of 2000 ppm at refueling. The critical boron concentration is conservatively estimated to be 765 ppm for Cycle 1.

Dilution flow is assumed to be 120gpm. This is assumed although normally neither the reactor makeup system nor the BTRS is operated at refueling conditions.

Mixing of the reactor coolant is accomplished by the operation of one residual heat removal pump.

A minimum water volume (3588 ft^3) in the RCS is used. This is the minimum volume of the RCS for residual heat removal system operation.

Dilution During Cold Shutdown

Conditions at cold shutdown require the reactor to be shut down by at least 1.0% Δk. The critical boron concentration is conservatively estimated to be 765 ppm for Cycle 1. The following conditions are assumed for an uncontrolled boron dilution during cold shutdown:

Dilution flow is assumed to be 120 gpm.

Mixing of the reactor coolant is accomplished by the operation of one residual heat removal pump.

A minimum water volume (3588 ft^3) in the RCS is used. This is the minimum volume of the RCS for residual heat removal system operation.

Dilution During Hot Shutdown

Conditions at hot shutdown require the reactor to be shut down by at least 1.3% Δk. The critical boron concentration is conservatively estimated to be 786 ppm for Cycle 1. The following conditions are assumed for an uncontrolled boron dilution during hot shutdown:

Dilution flow is assumed to be 120 gpm.

Mixing of the reactor coolant is accomplished by the operation of one residual heat removal pump.

A minimum water volume (3588 ft^3) in the RCS is used. This is the minimum volume of the RCS for residual heat removal system operation.

Dilution During Hot Standby

Conditions at hot standby require the reactor to have available at least 1.30% Δk shutdown margin. This mode of operation is analyzed both with and without the most reactive rod cluster control assembly (RCCA) stuck out of the core. The stuck rod case is assumed to occur immediately after a reactor trip and is therefore analyzed at no-load conditions. The case with no stuck rod is analyzed at 350°F which is conservative since this is the lowest permissible temperature in this mode. The critical boron concentrations are conservatively estimated to be 569 ppm (without stuck RCCA) and 579 ppm (with stuck RCCA) for Cycle 1. The following conditions are assumed in each case for a continuous boron dilution during hot standby:

1. Dilution flow is assumed to be output of two reactor makeup water pumps (240 gpm).

2. A minimum water volume (9029 ft^3) in the Reactor Coolant System is used. This corresponds to the active volume of the Reactor Coolant System while on natural circulation, i.e., the reactor vessel upper head and the pressurizer are not included.

Dilution During Startup

Prior to startup, the Reactor Coolant System is filled with borated (approximately 2000 ppm) water from the refueling water storage tank.

Core monitoring is by external BF_3 detectors. Mixing of the reactor coolant is accomplished by operation of the reactor coolant pumps.

The operator is alerted to an uncontrolled reactivity insertion by a reactor trip at the Power Range High Neutron Flux low setpoint (nominally 25% RTP).

In the analysis, a conservatively high dilution flow capacity for the two primary water makeup pumps is considered (300 gal/min). The volume of the reactor core (9800 ft^3) is the active volume of the Reactor Coolant System excluding the pressurizer. The critical boron concentration at which shutdown margin is lost is 1150 ppm.

Dilution at Power

With the unit at power and the Reactor Coolant System at pressure, the dilution rate is limited by the capacity of the charging pumps (analysis is performed assuming all charging pumps are in operation for manual rod control, 300 gal/min, although only one is normally in operation). For automatic rod control at power, a flow capacity of 125 gal/min is assumed. The effective reactivity addition rate is a function of the reactor coolant temperature and boron concentration.

The Reactor Coolant System volume assumed (9800 ft^3) is the active volume of the RCS excluding the pressurizer.

The reactivity insertion rate calculated is based on a conservatively high value for the expected critical boron concentration at power at which shutdown margin is lost (1150 ppm).

The operator is alerted to an uncontrolled reactivity insertion by an over temperature delta-T trip or by the rod insertion alarms depending on whether the plant is in manual or automatic rod control.

15.4.6.3 Conclusions

The results presented above show that there is adequate time for the operator to manually terminate the source of dilution flow. Following termination of the dilution flow, the reactor will be in a stable condition. The operator can then initiate reboration to recover the shutdown margin.

Results

The calculated sequence of events is shown in Table 15.4.1-1.

Dilution During Refueling

During refueling, an inadvertent dilution from the reactor makeup water system is prevented by administrative controls which isolate the RCS from the potential source of unborated makeup water.

The most limiting conditions for an inadvertent dilution from either the BTRS or the reactor makeup water system occurs with the RCS drained to 26" above the borrom ID of the reactor vessel inlet nozzles. The high flux at shutdown alarm, set at $\sqrt{10}$ times the background flux level measured by the source range nuclear instrumentation, is available at these conditions to alert the operator that a dilution event is in progress.

For this case, the operator has 92.2 minutes from the high flux at shutdown alarm to recognize and terminate the dilution before shutdown margin is lost and the reactor becomes critical.

Dilution During Cold Shutdown

While in cold shutdown, the high flux at shutdown alarm, set at $\sqrt{10}$ times the background flux level measured by the source range nuclear instrumentation, is available to alert the operator that a dilution event is in progress.

During the cold shutdown mode while operating on the residual heat removal system (RHRS) with the RCS drained to 26" above the bottom ID of the reactor vessel inlet nozzles, the operator has 17.1 minutes from the high flux at shutdown alarm to recognize and terminate the uncontrolled reactivity insertion before shutdown margin is lost and the reactor becomes critical.

Dilution During Hot Shutdown

While in hot shutdown, the high flux at shutdown alarm, set at $\sqrt{10}$ times the background flux level measured by the source range nuclear instrumentation, is available to alert the operator that a dilution event is in progress.

During the hot shutdown mode, the operator has 15.2 minutes from the high flux at shutdown alarm to recognize and terminate the uncontrolled recativity insertion before shutdown margin is lost and the reactor becomes critical.

Dilution During Hot Standby

While in hot standby, the high flux at shutdown alarm, set at $\sqrt{10}$ times the background flux level measured by the source range nuclear instrumentation, is available to alert the operator that a dilution event is in progress.

For the case with a stuck rod, the operator has 15.4 minutes from the high flux at shutdown alarm to recognize and terminate the uncontrolled reactivity insertion before shutdown margin is lost and the reactor becomes critical.

For the case without a stuck rod, the operator has 21.8 minutes from the high flux at shutdown alarm to recognize and terminate the uncontrolled reactivity insertion before shutdown margin is lost and the reactor becomes critical.

Dilution During Startup

Dilution during startup is bounded by dilution at power with manual rod control and therefore there is adequate time (greater than 65 min) for the operator to recognize the high count rate signal and manually terminate the source of dilution.

Dilution During Full Power Operation

1. With the reactor in automatic control, the power and temperature increase from boron dilution results in insertion of the rod cluster control assemblies and a decrease in the shutdown margin. The rod insertion limit alarms (low and low-low settings) provide the operator with adequate time (of the order of 156.0 minutes) to determine the cause of dilution, isolate the primary grade water source, and initiate reboration before the total shutdown margin is lost due to dilution.

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 overtemperature ΔT trip setpoint. The boron dilution accident in this case is essentially identical to rod cluster control assembly withdrawal accident. The maximum reactivity insertion rate for boron dilution is approximately .90 pcm/sec and is within the reange of insertion rates analyzed. Prior to the overtemperature ΔT trip, an overtemperature ΔT alarm and turbine runback would be actuated. There is adequate time available (of the order of 65.0 minutes) 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.

15.4.6.4 Environmental Consequences

There would be minimal radiological consequences associated with a Chemical and Volume Control System malfunction that results in a decrease in boron concentration in the reactor coolant event. The reactor trip causes a turbine-trip, and heat is removed from the secondary system through the steam generator power relief valves or safety valves. Since no fuel damage occurs from this transient, the radiological consequences associated with this event are less severe than the steamline break event analyzed in Section 15.1.5.

15.4.7 INADVERTENT LOADING AND OPERATION OF A FUEL ASSEMBLY IN AN IMPROPER POSITON

15.4.7.1 Identification of Causes and Accident Description

Fuel and core loading errors such as can arise from the inadvertent loading of one or more fuel assemblies into improper positions, loading a fuel rod during manufacture with one or more pellets of the wrong enrichment or the loading of 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. Also included among possible core loading errors is the inadvertent loading of one or more fuel assemblies requiring burnable poison rods into a new core without burnable poison rods.

Any error in enrichment, beyond the normal manufacturing tolerances, can cause power shapes which are more peaked than those calculated with the correct enrichments. There is a 5 percent uncertainty margin included in the design value of power peaking factor assumed in the analysis of Condition I and Condition II transients. The incore system of moveable flux detectors which is used to verify power shapes at the start of life is capable of revealing any assembly enrichment error or loading error which 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. During core loading, the identification number will be checked before each assembly is moved into the core. Serial numbers read during fuel movement are subsequently recorded on the loading diagram as a further check on proper placing after the loading is completed.

The power distortion due to any combination of misplaced fuel assemblies would significantly raise peaking factors and would be readily observable with incore flux monitors. In addition to the flux monitors, 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.

This event is classified as an ANS Condition III incident (an infrequent incident) as defined in Section 15.0.1.

used which assumed that insertion to the dashpot does not occur until 3.05 seconds after the start of fall. The choice of such a conservative insertion rate means that there is over one second after the trip point is reached before significant shutdown reactivity is inserted into the core. This is a particularly important conservatism for hot full power accidents.

The minimum design shutdown available for this plant at HZP may be reached only at end of life in the equilibrium cycle. This value includes an allowance for the worst stuck rod, adverse xenon distribution, conservative Doppler and moderator defects, and an allowance for calculational uncertainties. Physics calculations for this plant have shown that the effect of two stuck RCCA's (one of which is the worst ejected rod) is to reduce the shutdown by about an additional one percent Δk. Therefore, following a reactor trip resulting from an RCCA ejection accident, the reactor will be subcritical when the core returns to HZP.

Depressurization calculations have been performed for a typical four-loop plant assuming the maximum possible size break (2.75 inch diameter) located in the reactor pressure vessel head. The results show a rapid pressure drop and a decrease in system water mass due to the break. The safety injection system is actuated on of low pressurizer pressure within one minute after the break. The reactor coolant system pressure continues to drop and reaches saturation (1100 to 1300 psi depending on the system temperature) in about two to three minutes. Due to the large thermal inertia of primary and secondary system, there has been no significant decrease in the reactor coolant system temperature below no-load by this time, and the depressurization itself has caused an increase in shutdown margin by about 0.2 percent Δk due to the pressure coefficient. The cooldown transient could not absorb the available shutdown margin until more than ten minutes after the break. The addition of borated (2000 ppm) safety injection flow starting one minute after the break is much more than sufficient to ensure that the core remains subcritical during the cooldown.

Reactor Protection

As discussed in Section 15.4.8.1.1, reactor protection for a rod ejection is provided by high neutron flux trip (high and low setting) and high neutron flux rate trip. These protection functions are part of the Reactor Protection System. No single failure of the Reactor Protection system will negate the protection functions required for the rod ejection accident, or adversely affect the consequences of the accident.

Results

Cases are presented for both beginning and end of life at zero and full power.

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 calculated to be 0.23 percent Δk and 5.90 respectively. The peak hot

spot clad average temperature was 2353°F. The peak hot spot fuel center temperature reached melting, conservatively assumed at 4900°F. However, melting was restricted to less than 10% of the pellet.

2. Beginning of Cycle, Zero Power

   For this condition, control bank D was assumed to be fully inserted and banks B and C were at their insertion limits. The worst ejected rod is located in control bank D and has a worth of 0.78 percent Δk and a hot channel factor of 11.5. The peak hot spot clad temperature reached 2597°F, the fuel center temperature was 4030°F.

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 calculated to be 0.25 percent Δk and 6.40 respectively. This resulted in a peak clad average temperature of 2228°F. The peak hot spot fuel temperature reached melting conservatively assumed at 4800°F. However, melting was restricted to less than 10% of the pellet.

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 0.90 percent Δk and 20.0 respectively. The peak clad average and fuel center temperatures were 2553 and 3791°F. The Doppler weighting factor for this case is significantly higher than for the other cases due to the very large transient hot channel factor.

A summary of the cases presented above is given in Table 15.4.8-1. The nuclear power and hot spot fuel and clad temperature transients for the worst cases (end of life, full and zero power) are presented in Figures 15.4.8-1 through 15.4.8-4. (Beginning of life full power and beginning of life zero power).

The calculated sequence of events for the worst case rod ejection accidents, as shown in Figures 15.4.8-1 through 15.4.8-4, is presented in Table 15.4.1-1. For all cases, reactor trip occurs very early in the transient, after which the nuclear power excursion is terminated. As discussed previously in Section 15.4.8.2.2, the reactor will remain subcritical following reactor trip.

The ejection of an RCCA constitutes a break in the Reactor Coolant System, located in the reactor pressure vessel head. The effects and consequences of loss of coolant accidents are discussed in Section 15.6.5. Following the RCCA ejection, the operator would follow the same emergency instructions as for any other loss of coolant accident to recover from the event.

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 (Reference 6).

Pressure Surge

A detailed calculation of the pressure surge for an ejection worth of one dollar at beginning of life, hot full power, indicates that the peak pressure does not exceed that which would cause stress to exceed the faulted condition stress limits (Reference 6). Since the severity of the present analysis does not exceed the "worst case" analysis, the accident for this plant will not result in an excessive pressure rise or further damage to the Reactor Coolant System.

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 differential expansion tending to bow the midpoint of the rods toward the hotter side of the rod. Calculations have indicated that this bowing would result in a negative reactivity effect at the hot spot since Westinghouse cores are under-moderated, and bowing will tend to increase the under-moderation at the hot spot. Since the 17 x 17 fuel design is also under-moderated, the same effect would be observed. 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 the 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 analysis.

15.4.8.3 Environmental Consequences

A conservative analysis for a postulated rod ejection accident is performed to determine the resulting radiological consequences. The analysis is based on a instantaneous fission product release to the reactor coolant of the gap activity from 10 percent of the fuel rods in the core plus the activity from an assumed 0.25 percent core melt.

Prior to the postulated rod ejection accident, it is assumed that the plant is operating at equilibrium levels of radioactivity in the primary and secondary systems with 1 percent fuel defects and a steam generator tube leak rate of 1 gpm. Following the accident, two activity release paths contribute to the total radiological consequences. The first release path is via containment leakage resulting from release of activity from the primary coolant to the containment. The second path is the contribution of contaminated steam in the secondary system dumped through the relief valves, since offsite power is assumed to be lost.

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2. Hargrove, H. G., "FACTRAN - A Fortran-IV Code for Thermal Transients in a UO_2 Fuel Rod", WCAP-7908, June 1972.

3. Chelemer, H., Boman, L. H., Sharp, D. R., "Improved Thermal Design Procedures", WCAP-8567, July 1975.

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8. Liimataninen, R. C. and Testa, F. J., "Studies in TREAT of Zircaloy-2-Clad, UO_2-Core Simulated Fuel Elements", ANL-7225, January - June 1966, p. 177, November 1966.

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10. Morita, T., et al., "Dropped Rod Methodology for Negative Flux Rate Trip Plants", WCAP-10297-P-A (Proprietary)and WCAP-10298-A (Non-Proprietary), June 1983.

Table 15.4.1-1 (Page 2)

Time Sequence of Events for Incidents which Cause Reactivity and Power Distribution Anomalies

Accident	Event	Time (sec.)
	Rods begin to fall into core	66.2
	Minimum DNBR occurs	67.1
Startup of an inactive reactor coolant loop at an incorrect temperature	Initiation of pump startup	1.0
	Power reaches P-8 trip setpoint	13.4
	Rods begin to drop	13.9
	Minimum DNBR occurs	15.0
CVCS Malfunction that results in a decrease in the boron concentration in the reactor coolant		
1. Dilution during refueling	Dilution begins	0
	High flux at shutdown alarm occurs	7362
	Criticality occurs	12896
2. Dilution during cold shutdown	Dilution begins	0
	High flux at shutdown alarm occurs	1986
	Criticality occurs	3012
3. Dilution during hot shutdown	Dilution begins	0
	High flux at shutdown alarm occurs	1787
	Criticality occurs	2701
4a. Dilution during hot standby (w/o stuck rod)	Dilution begins	0
	High flux at shutdown alarm occurs	2525
	Criticality occurs	3833
4b. Dilution during hot standby (w/stuck rod)	Dilution begins	0
	High flux at shutdown alarm occurs	1840
	Criticality occurs	2764

Table 15.4.8-2 (Page 1)

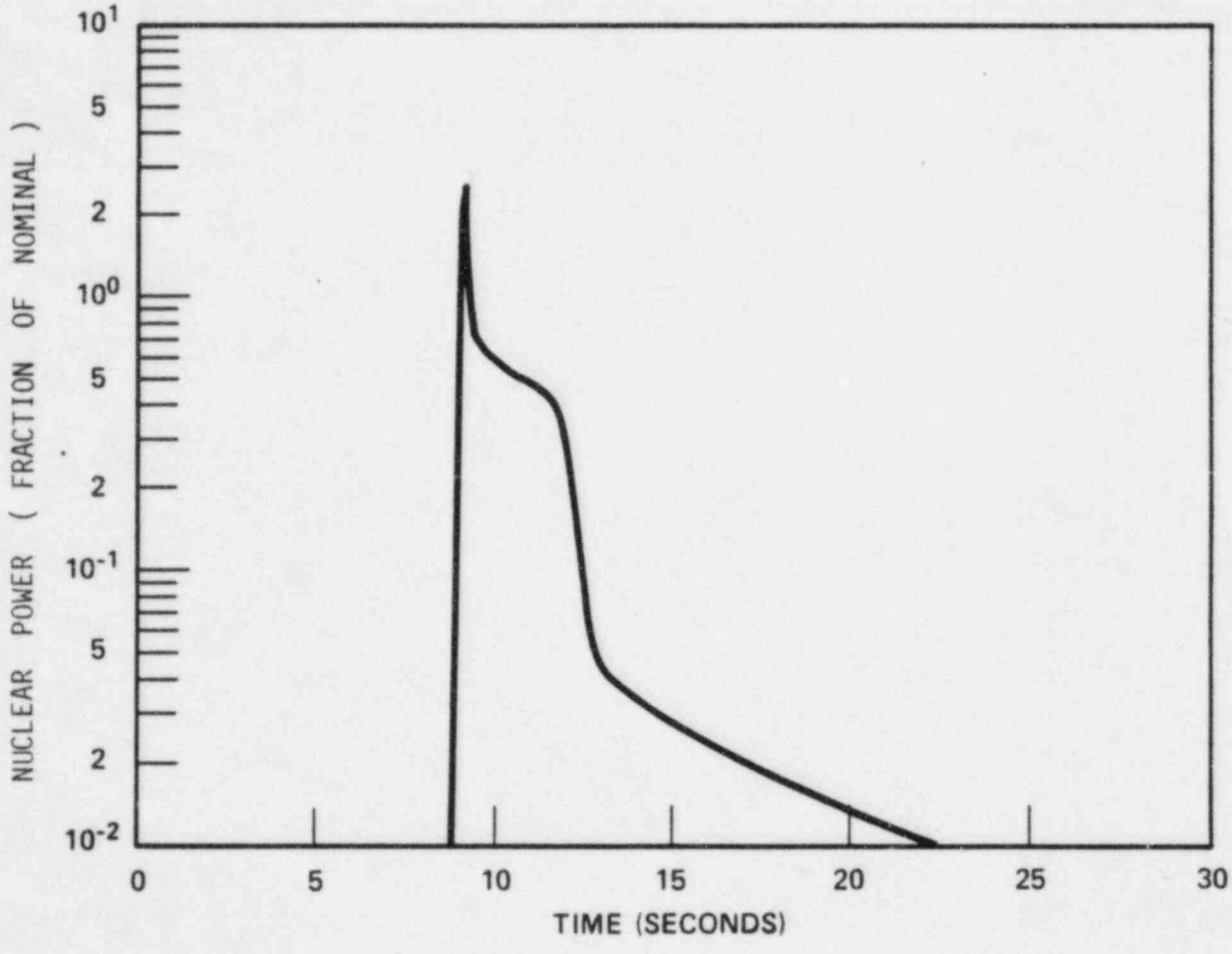
Parameters for Postulated Rod Ejection Accident Analysis

		Conservative	Realistic
1.	Data and assumptions used to estimate radioactive source from postulated accidents		
	a. Power level (MWt)	3565.	3565.
	b. Percent of fuel defected	1.	0.12
	c. Steam generator tube leak rate prior to and during steam dump (gpm)	1.	0.008
	d. Failed fuel	10 percent of fuel rods in core	same
	e. Activity released to reactor coolant from failed fuel and available for release		
	Noble gases	10 percent of core gap inventory	same
	Iodines	10 percent of core gap inventory	same
	f. Melted fuel	0.25 percent of core	0.
	g. Activity released to reactor coolant from melted fuel and available for release to containment		
	Noble gases	0.25 percent of core inventory	0.
	Iodines	0.125 percent of core inventory	0.
	h. Iodine Fractions (organic, elemental, and particulate)	Regulatory Guide 1.4	same
2.	Data and assumptions used to estimate activity released		
	a. Containment Free volume (ft^3)	1.015E+06	same

Table 15.4.8-2 (Page 2)

Parameters for Postulated Rod Ejection Accident Analysis

		Conservative	Realistic
b.	Containment leak rate	0.2 percent of containment volume per day, $0 \leq t \leq 24$ hr	0.05 percent of containment vol- per day, $0 \leq t \leq 24$ hr
		0.1 percent of containment volume per day, tJ24 hr	0.025 percent of containment vol- per day, tJ24 hr
c.	Bypass leakage fraction	0.07	0.07
d.	Iodine partition factor for steam release	0.1	-
e.	Offsite power	Lost	-
f.	Steam dump from relief valves (lb)	44500.	-
g.	Duration of dump from relief valves (sec)	120.	-
3.	Dispersion data		
a.	Distance to exclusion area boundary (m)	762.	762.
b.	Distance to low population zone (m)	6096.	6096.
c.	x/Q at exclusion area boundary (sec/m^3)		
	0-2 hrs	5.5E-04	1.3E-04
d.	x/Q at low population zone (sec/m^3)		
	0-8 hrs	1.8E-05	6.2E-06
	8-24 hrs	1.2E-05	5.4E-06
	1-4 days	4.3E-06	2.5E-06
	4+days	1.2E-06	9.7E-07
4.	Dose data		
a.	Method of dose calculation	Regulatory Guide 1.77	same

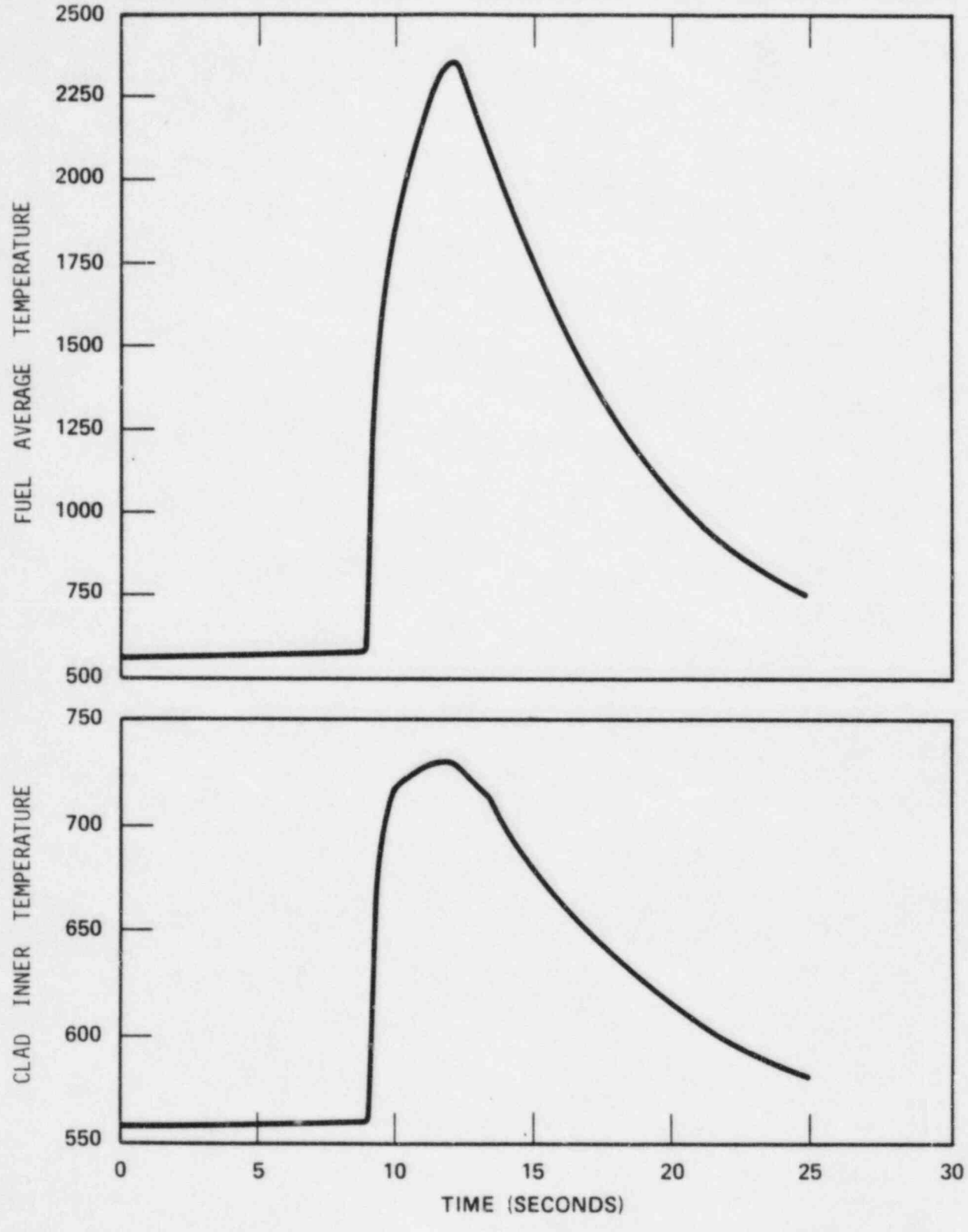


NEUTRON FLUX TRANSIENT FOR
UNCONTROLLED ROD WITHDRAWAL
FROM A SUBCRITICAL CONDITION

CATAWBA NUCLEAR STATION

Figure 15.4.1-1

Rev. 14

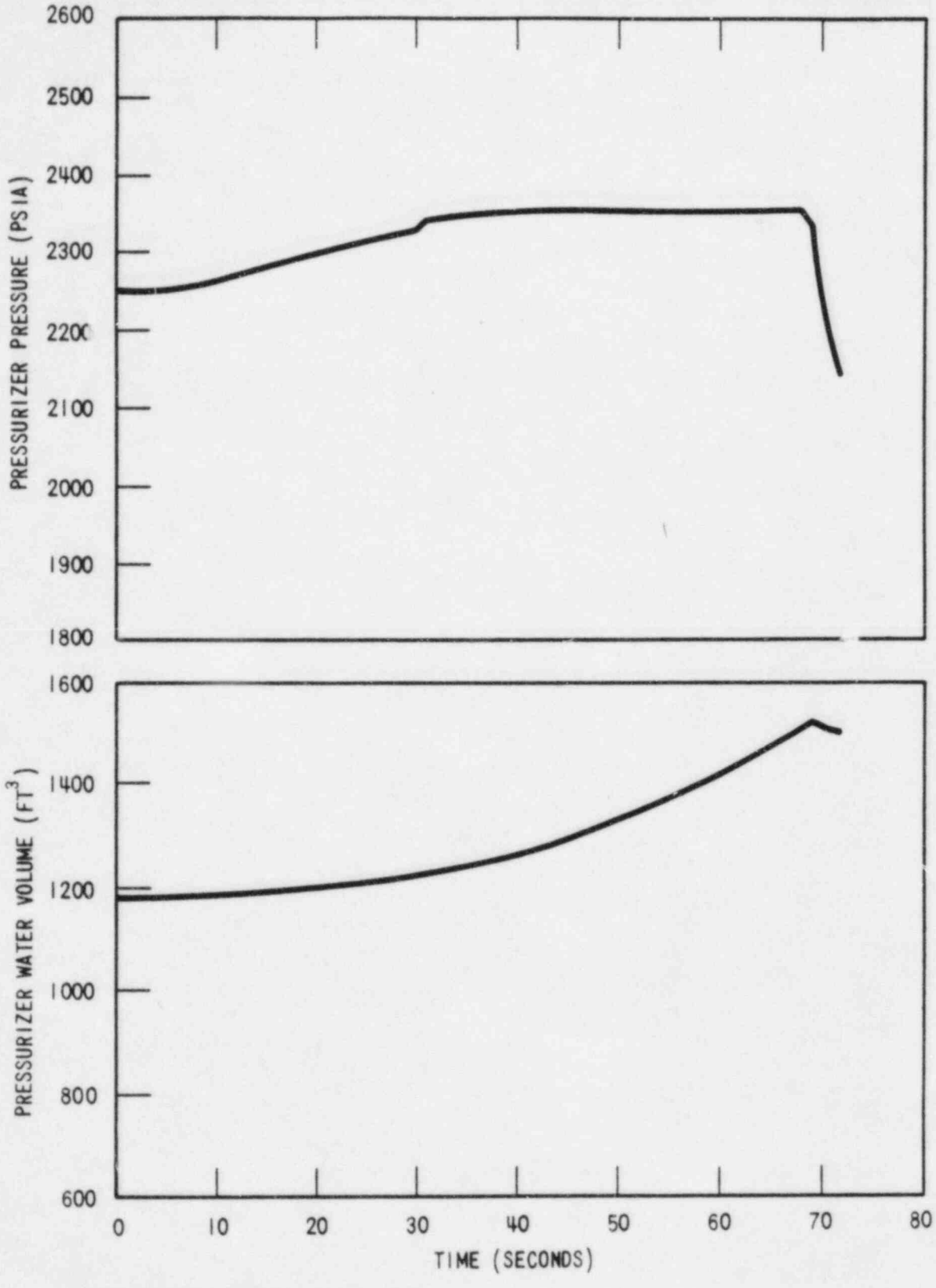


FUEL AND CLAD TEMPERATURE TRANSIENTS FOR UNCONTROLLED ROD WITHDRAWAL FROM A SUBCRITICAL CONDITION

CATAWBA NUCLEAR STATION

Figure 15.4.1-3

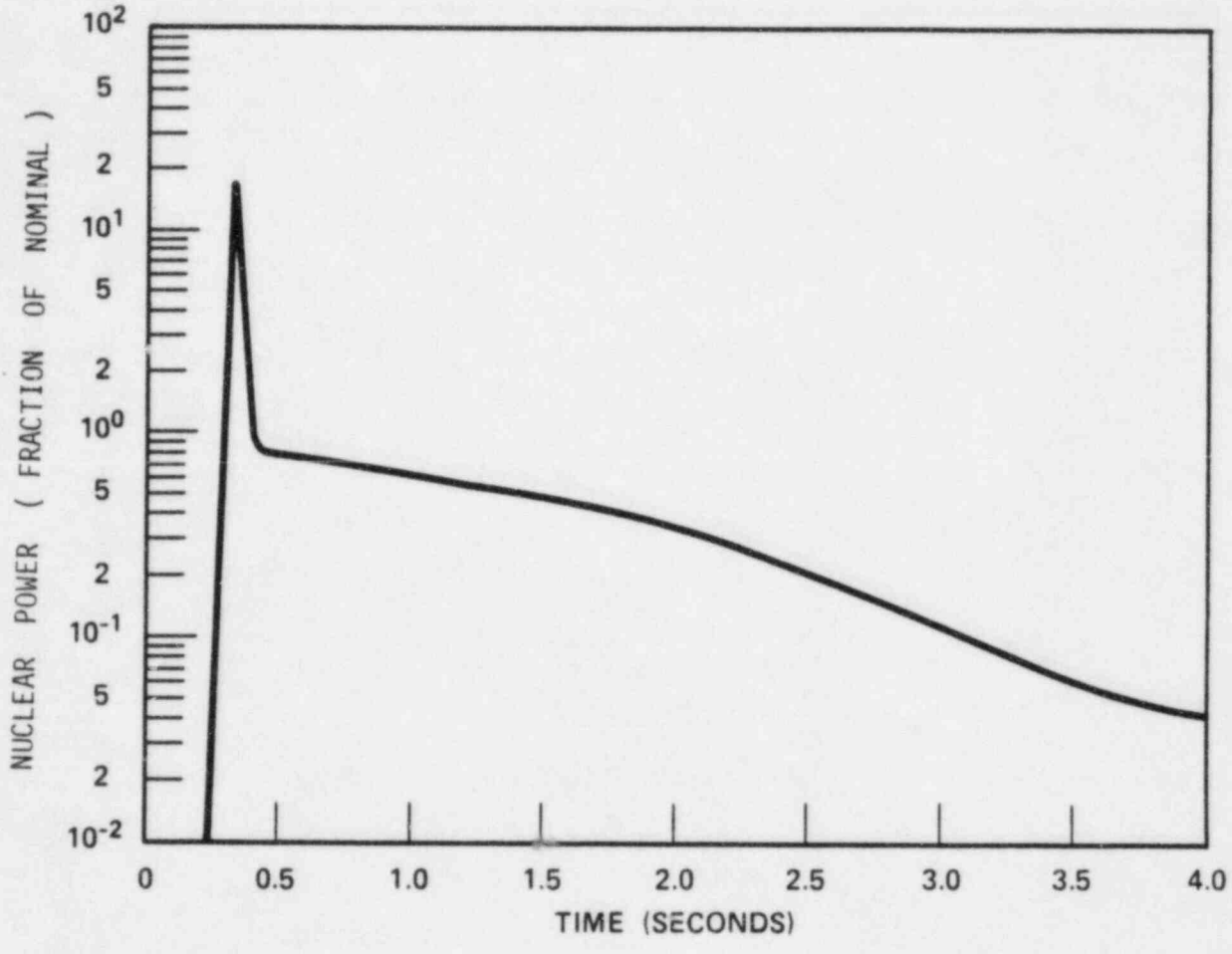
Rev. 14



UNCONTROLLED RCCA WITHDRAWAL FROM FULL POWER WITH MINIMUM REACTIVITY FEEDBACK (2 PCM/ SEC WITHDRAWAL RATE)

CATAWBA NUCLEAR STATION

Figure 15.4.2-5
Rev. 14



NUCLEAR POWER TRANSIENT,
BOL HZP, ROD EJECTION ACCIDENT

CATAWBA NUCLEAR STATION

Figure 15.4.8-3
Rev. 14

15.5 INCREASE IN REACTOR COOLANT INVENTORY

A number of events have been postulated which could result in an increase in Reactor Coolant System inventory. Detailed analyses are presented for two such events which have been identified as limiting cases.

Discussions of the following events are presented in this section:

1. Inadvertent Operation of Emergency Core Cooling System During Power Operation

2. Chemical and Volume Control System Malfunction That Increases Reactor Coolant Inventory

3. A number of BWR Transients (Not applicable to Catawba)

The above are considered to be ANS Condition II events. Section 15.0.1 contains a discussion of ANS classifications and applicable acceptance criteria.

15.5.1 INADVERTENT OPERATION OF EMERGENCY CORE COOLING SYSTEM DURING POWER OPERATION

15.5.1.1 Identification of Causes and Accident Description

Spurious Emergency Core Cooling System (ECCS) operation at power could be caused by operator error or a false electrical actuation signal. A spurious signal may originate from any of the safety injection actuation channels as described in Section 7.3.

Following the actuation signal, the suction of the coolant charging pumps is diverted from the volume control tank to the refueling water storage tank. The charging pumps then force highly concentrated (2,000 ppm) boric acid solution from the refueling water storage tank through the header and injection line and into the cold leg of each loop. The safety injection pumps also start automatically but provide no flow when the Reactor Coolant System is at normal pressure. The passive accumulators and the low head system also provide no flow at normal Reactor Coolant System pressure.

A Safety Injection System (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. If a reactor trip is generated by the spurious SIS signal, the operator should determine if the spurious signal was transient or steady state in nature. The operator must also determine if the safety injection signal should be blocked. For a spurious occurrence, the operator would stop the safety injection and maintain the plant in the hot standby condition. If the ECCS actuation instrumentation must be repaired, future plant operation will be in accordance with the Technical Specifications.

If the Reactor Protection System does not produce an immediate trip as a result of the spurious SIS signal, the reactor experiences a negative reactivity excursion due to the injected boron causing a decrease in reactor power. The power mismatch causes a drop in T_{avg} and consequent coolant

shrinkage. Pressurizer pressure and water level drop. Load will decrease due to the effect of reduced steam pressure on load after the turbine throttle valve is fully open. 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 which affects initial boron concentration, rate of change of boron concentration, Doppler and moderator coefficients.

Recovery from this second case is made in the same manner as described for the case where the SIS signal results directly in a reactor trip. The only difference is the lower T_{avg} and pressure associated with the power mismatch during the transient. The time at which reactor trip occurs is of little concern for this transient. At lower loads coolant contraction will be slower resulting in a longer time to trip.

This event is classified as a Condition II incident (an incident of moderate frequency) as defined in Section 15.0.1.

15.5.1.2 Analysis of Effects and Consequences

Method of Analysis

The spurious operation of the Safety Injection System is analyzed by employing the detailed digital computer program LOFTRAN (Reference 1). The code simulates the neutron kinetics, Reactor Coolant System, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, steam generator safety valves, and the effect of the Safety Injection System. 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. Analysis of several cases has shown that the results are relatively independent of time to trip.

A typical transient is presented representing minimum reactivity feedback. Results with maximum reactivity feedback are similar except that the transient is slower. For calculational simplicity, zero injection line purge volume was assumed in this analysis, thus the boration transient begins immediately when the appropriate valves are opened. This accident is analyzed with the Improved Thermal Design Procedure as described in Reference 2. Plant characteristics and initial conditions are further discussed in Section 15.0.3.

The assumptions are as follows:

1. Initial Operating Conditions

   The initial reactor power, pressure, and Reactor Coolant System temperatures are assumed at their nominal values. Uncertainties in initial conditions are included in the limit DNBR as described in Reference 2.

REFERENCES FOR SECTION 15.5

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kinetics, Reactor Coolant System, 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 as described in Reference 2. Plant characteristics and initial conditions are discussed in Section 15.0.3.

In order to give conservative results in calculating the DNBR during the transient, the following assumptions are made:

1. Initial reactor power, pressure, and RCS temperatures are assumed to be at their nominal values. Uncertainties in initial conditions are included in the limit DNBR as described in Reference 2.

2. A least negative moderator coefficient of reactivity is assumed. The spatial effect of void due to local or subcooled boiling is not considered in the analysis with respect to reactivity feedback or core power shape.

3. A large (absolute value) Doppler coefficient of reactivity such that the resultant amount of positive feedback is conservatively high in order to retard any power decrease due to moderator reactivity feedback.

Plant systems and equipment which are necessary to mitigate the effects of a Reactor Coolant System depressurization caused by an inadvertent safety valve opening are discussed in Section 15.0.8 and listed in Table 15.0.8-1.

Normal reactor control systems are not required to function; however, the rod control system is assumed to be in the automatic mode in order to hold the core at full power longer and thus delay the trip. This is a worst-case assumption; if the reactor were in manual control, an earlier trip could occur on low pressurizer pressure. The Reactor Protection System functions to trip the reactor on the appropriate signal. No single active failure will prevent the Reactor Protection System from functioning properly.

Results

The system response to an inadvertent opening of a pressurizer safety or relief valve is shown on Figures 15.6.1-1 and 15.6.1-2. Figure 15.6.1-1 illustrates the nuclear power transient following the depressurization. Nuclear power is maintained at the initial value until reactor trip occurs on low pressurizer pressure. The pressure decay transient and average temperature transient following the accident are given in Figure 15.6.1-2. Pressure drops more rapidly while core heat generation is reduced via the trip, and then slows once saturation temperature is reached in the hot leg. The DNBR decreases initially, but increases rapidly following the trip, as shown in Figure 15.6.1-1. The DNBR remains above the limit value throughout the transient.

The calculated sequence of events for the inadvertent opening of a pressurizer safety valve incident is shown on Table 15.6.1-1.

Case 2: There is a pre-existing iodine spike at the time the accident occurs. The reactor coolant concentrations are the maximum permitted for full power operation.

Case 3: There is a coincident iodine spike at the time the accident occurs. The iodine concentrations are found by increasing the equilibrium appearance rate in the coolant by 500.

Other assumptions and parameters are found in Table 15.6.2-1.

Based on the foregoing model, the doses to the thyroid and whole body are calculated at exclusion area boundary and the low population zone. The results appear in Table 15.6.2-1. Therefore, the radiological consequences resulting from failure of the 3 inch CVCS letdown line is not expected to exceed a small fraction of the 10 CFR 100 dose limits.

15.6.3 STEAM GENERATOR TUBE RUPTURE

15.6.3.1 Identification of Causes and Accident Description

The accident examined is the complete severance of a single steam generator tube for a UHI 4-Loop plant. This event is considered an ANS Condition IV event, a limiting fault (see Section 15.0.1). 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 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 safety and/or power operated relief valves.

In view of the fact that the steam generator tube material is Inconel-600 and is a highly ductile material, it is considered that the assumption of a complete severance is somewhat conservative. 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 which exceed the limits established in the Technical Specifications is not permitted during the unit operation.

The operator is expected to determine that a steam generator tube rupture has occurred, and to identify and isolate the faulty steam generator 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 faulty unit. The recovery procedure can be carried out on a time scale which 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.

Immediately apparent symptoms of a tube rupture accident such as falling pressurizer pressure and level and increased charging pump flow are also

symptoms of small steam line breaks and loss of coolant accidents. It is therefore important for the operator to determine that the accident is a rupture of a steam generator tube in order that he may carry out the correct recovery procedure. The accident under discussion can be identified by the following method. In the event of a complete tube rupture, the reactor coolant system pressure decreases, Figure 15.6.3-2, and the condenser air ejector radiation and/or steam generator blowdown radiation monitors exhibit abnormally high readings. If the containment pressure, containment radiation and containment recirculation sump level exhibit normal readings, then a steam generator tube rupture is diagnosed to have occurred.

Consideration of the indications provided at the control board, together with the magnitude of the break flow, leads to the conclusion that the accident diagnostics and isolation procedure can be completed within 30 minutes of accident initiation for the design basis event.

Note that break sizes smaller than complete severance of a tube, with less break flow from primary to secondary, exhibit a slower rise in steam generator water level, and an increased time interval for actuation of the blowdown line radiation monitor and the condenser air ejector radiation monitor. Therefore more time may be available to the operator to diagnose the accident and take steps to isolate the faulted steam generator.

If normal operation of the various plant control systems is assumed, 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 steam flow/feedwater flow mismatch occurs as feedwater flow to the affected steam generator is reduced as a result of primary coolant break flow to that unit.

2. Decrease in RCS pressure (Figure 15.6.3-2) due to continued loss of reactor coolant inventory leads to a reactor trip signal on low pressurizer pressure or overtemperature ΔT. Resultant plant cooldown (Figure 15.6.3-3) following reactor trip leads to a rapid decrease in pressurizer level (Figure 15.6.3-6), and a safety injection signal, initiated by low pressurizer pressure, follows soon after reactor trip. The safety injection signal automatically terminates normal feedwater supply and initiates auxiliary feedwater addition.

3. The steam generator blowdown liquid monitor and/or the condenser air ejector radiation monitor will alarm, indicating a sharp increase in radioactivity in the secondary system and will automatically terminate steam generator blowdown.

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 station blackout (loss of offsite power), as assumed in the transients presented in this section, the steam dump valves automatically close to protect the condenser. The

steam generator pressure (Figure 15.6.3-4) rapidly increases resulting in steam discharge to the atmosphere through the steam generator safety and/or power operated relief valves. In Figure 15.6.3-7 the steam flow is presented as a function of time. The flow is constant initially until reactor trip, followed by turbine trip, which results in a large decrease in flow, but a rapid increase in steam pressure to the safety valve setpoint.

5. Following reactor trip, the continued action of the auxiliary feedwater supply and borated safety injection flow (supplied from the RWST) provide a heat sink which absorbs the decay heat.

6. Safety injection flow results in increasing pressurizer water level (Figure 15.6.3-6), the rate of increase depending upon the amount of auxiliary equipment operating.

Steam generator tube failure is classified as an ANS Condition IV event, a limiting fault. See Section 15.0.1 for a discussion of Condition IV events.

15.6.3.2 Analysis of Effects and Consequences

Method of Analysis

Mass and energy balance calculations are performed to determine primary to secondary mass release and to determine the amount of steam vented from each of the steam generators, using LOFTRAN (Reference 1).

In estimating the mass transfer from the RCS through the broken tube the following assumptions are made:

1. Reactor trip occurs automatically as a result of overtemperature ΔT. Loss of offsite power occurs at reactor trip.

2. Following the initiation of the safety injection signal, two centrifugal pumps are actuated and are assumed in the analyses to continue to deliver flow for 30 minutes.

3. After reactor trip break flow reaches equilibrium when incoming safety injection flow is balanced by outgoing break flow as shown in Figure 15.6.3-1. The resultant break flow is assumed to persist from plant trip until 30 minutes after the accident. No operator actions are assumed.

4. The steam generators are controlled at the safety valve setting rather than the power operated relief valve setting.

5. The operator identifies the accident type and terminates steam relief from the faulted steam generator within 30 minutes of accident initiation.

The above assumptions, suitably conservative for the design basis tube rupture, are made to maximize doses and do not explicitly model operator actions for recovery.

Results

Figure 15.6.3-1 illustrates the flow rate that would result through the ruptured steam generator tube. The previous assumptions lead to an estimate of 102,259 pounds for the total amount of reactor coolant transferred to the secondary side of the faulted steam generator as a result of a tube rupture accident. The integrated steam flow is 55,420 pounds released through the safety valves.

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Figure 15.6.3-2 Reactor Coolant System Pressure
Figure 15.6.3-3 Reactor Coolant System Temperature
Figure 15.6.3-4 Steam Generator Pressure (For Faulted Steam Generator)
Figure 15.6.3-5 Steam Generator Temperature (For Faulted Steam Generator)
Figure 15.6.3-6 Pressurizer Water Volume
Figure 15.6.3-7 Steam Generator Flow

The DNB calculations performed with LOFTRAN (Reference 1) indicate that DNB limits are met.

In Table 15.6.3-1 the sequence of events are presented. These events are the normal plant response to the normal plant setpoints. Loss of offsite power at reactor trip and no operator actions were assumed.

15.6.3.3 Environmental Consequences

The postulated accidents involving release of steam from the secondary system do not result in a release of radioactivity unless there is leakage from the RCS to the secondary system in the steam generators. A conservative analysis of the postulated steam generator tube rupture assumes the loss of offsite power and involves the release of steam from the secondary system caused by a turbine trip in conjection with loss of main steam dump capabilities, and subsequent venting to the atmosphere. A conservative analysis of the potential offsite doses resulting from this accident is presented assuming primary to secondary leakage. This analysis incorporates assumptions of 1 percent defective fuel and steam generator leakage of 1 gpm prior to the postulated accident for a time sufficient to establish equilibrium specific activities in the secondary system. Three postulated cases are analyzed:

Case 1 - No iodine spike

Case 2 - Pre-existing iodine spike

Case 3 - Coincident iodine spike

a. 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. However, no credit is taken in the LOCA analysis for boron content of the injection water. In addition, the insertion of control rods to shut down the reactor is neglected in the large break analysis.

b. Injection of borated water provides for heat transfer from the core and prevents excessive clad temperatures.

Description of Large Break LOCA Transient

The sequence of events following a large break LOCA are presented in Figure 15.6.5-1.

Before the break occurs, the unit is in an equilibrium condition, i.e., the heat generated in the core is being removed via the secondary system. During blowdown, heat from fission product decay, hot internals and the vessel continues to be transferred to the reactor coolant. At the beginning of the blowdown phase, the entire RCS contains subcooled liquid which transfers heat from the core by forced convection with some fully developed nucleate boiling. Thereafter, the core heat transfer is based on local conditions with transition boiling and forced convection to steam as the major heat transfer mechanisms.

The heat transfer between the Reactor Coolant System and the secondary system may be in either direction depending on the relative temperatures. In the case of continued heat addition to the secondary, secondary system pressure increases and the main steam safety valves may actuate to limit the pressure. Makeup water to the secondary side is automatically provided by the auxiliary feedwater system. The SIS actuates a feedwater isolation signal which isolates normal feedwater flow by closing the main feedwater isolation valves and also initiates emergency feedwater flow by starting the auxiliary feedwater pumps. The secondary flow aids in the reduction of Reactor Coolant System pressure.

When the Reactor Coolant System pressure falls below approximately 1250 psia the upper head injection accumulators begin to inject borated water directly into the reactor upper head region. This water is directed from the upper head directly to all but 8 peripheral assemblies in the core via the RCC guide tubes and UHI support columns. This flow provides additional core cooling during the blowdown phase of the transient. A detailed description of the interactions of UHI water and those effects on the blowdown and subsequent reflood transients is given in Reference 4.

When the Reactor Coolant System depressurizes to approximately 400 psia, the accumulators begin to inject borated water into the reactor coolant loops.

Since the loss of offsite power is assumed, the reactor coolant pumps are assumed to trip at the inception of the accident. The effects of pump coastdown are included in the blowdown analysis.

The blowdown phase of the transient ends when the RCS pressure (initially assumed at 2280 psia) falls to a value approaching that of the containment atmosphere. Prior to or at the end of the blowdown, the mechanisms that are responsible for the bypassing of emergency core cooling water injection into the RCS are calculated not to be effective. At this time (called end of bypass) refill of the reactor vessel lower plenum begins. Refill is complete when emergency core cooling water has filled the lower plenum of the reactor vessel which is bounded by the bottom of the fuel rods (called bottom of core recovery time, BOC).

The reflood phase of the transient is defined as the time period lasting from the end of refill until the reactor vessel has been filled with water to the extent that the core temperature rise has been terminated. From the later stage of blowdown and then the beginning of reflood, the safety injection accumulator tanks rapidly discharge borated cooling water into the RCS, contributing to the filling of the reactor vessel downcomer. The downcomer water elevation head provides the driving force required for the reflooding of the reactor core.

The low head and high head safety injection pumps aid in the filling of the downcomer and subsequently supply water to maintain a full downcomer and complete the reflooding process. The safety injection pumped flow as a function of pressure is given in Table 15.6.5-6 for the large and small break cases.

Continued operation of the ECCS pumps supplies water during long-term cooling. Core temperatures have been reduced to long-term steady-state levels associated with dissipation of residual heat. After the water level of the refueling water storage tank (RWST) reaches a minimum allowable value, coolant for long-term cooling of the core is obtained by switching to the cold leg recirculation phase of operation in which spilled borated water is drawn from the containment sumps by the low head safety injection (RHR) pumps and returned to the RCS cold legs. The Containment Spray System continues to operate to further reduce containment pressure. Approximately 15 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.

Description of Small Break LOCA Transient

Ruptures of small cross section will cause expulsion of the coolant at a rate which can be accommodated by the charging pumps. These pumps would maintain an operational water level in the pressurizer permitting the operator to execute an orderly shutdown. The coolant which would be released to the containment contains the fission products existing at equilibrium.

The maximum break size for which the normal makeup system can maintain the pressurizer level is obtained by comparing the calculated flow from the Reactor Coolant System through the postulated break against the charging pump makeup flow at normal Reactor Coolant System pressure, i.e., 2250 psia. A makeup flow rate from one centrifugal charging pump is typically adequate to sustain pressurizer level at 2250 psia for a break through a 0.375 inch diameter hole. This break results in a loss of approximately 17.25 lb/sec.

The bases used to select the numerical values that are input parameters to the analysis have been conservatively determined from extensive sensitivity studies (Reference 4). In addition, the requirements of Appendix K regarding specific model features were met by selecting models which provide a significant overall conservatism in the analysis. The assumptions made pertain to the conditions of the reactor and associated safety system equipment at the time that the LOCA occurs and include such items as the core peaking factors, the containment pressure, and the performance of the ECCS system. Decay heat generated throughout the transient is also conservatively calculated as required by Appendix K, 10CFR50.46.

The worst break (C_D = 1.0) was run with a variation in UHI accumulator volume delivery for the perfect (1043 ft^3) and imperfect mixing case (877 ft^3) assumptions. The delivered volume considered in the analyses encompasses the volume delivery band (156 ft^3) associated with UHI delivery uncertainties at a 95 percent probability level.

Cases presented herein provide the results of a conservative application of this range of values. In addition, UHI volume deliveries for each case presented herein will differ somewhat due to variation in UH. flowrate during the time of isolation valve closure and be dependent on discharge coefficient assumed.

The imperfect mixing case was analyzed to develop a low delivery volume since the upper head drains earlier in the transient and subsequently voids the lower plenum and core. The imperfect mixing case was also run at a higher pressure (1300) than the perfect mixing case (1200) to allow for uncertainty in the accumulator setpoint pressure. Similarly, the high pressure for the imperfect mixing case represents the most conservative case since the smaller accumulator volume would be delivered in a shorter amount of time and earlier in the blowdown transient, thereby providing for a longer core heatup time.

15.6.5.3.3 Results

Large Break Results

Based on the results of the LOCA sensitivity studies (Reference 4), the limiting large break was found to be double-ended cold leg guillotine (DECLG). Therefore, only the DECLG break is considered in the large break ECCS performance analysis. Calculations were performed for a range of Moody break discharge coefficients (C_D). The results of these calculations are summarized in Tables 15.6.5-2 through 15.6.5-5.

The mass and energy release data for the break resulting in the highest calculated peak cladding temperature is presented in Section 6.2.1.5.

Figures 15.6.5-4 through 15.6.5-63 present the parameters of principal interest from the large break ECCS analyses. For all cases analyzed, transients of the following parameters are presented:

REFERENCES FOR SECTION 15.6

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10. Porsching, T. A., et. al., "FLASH-4: A Fully Implicit FORTRAN-IV Program for the Digital Simulation of Transients in a Reactor Plant", WAPD-TM-84, Bettis Atomic Power Laboratory, March 1969.

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12. Skwarek, R., W. J. Johnson, P. E. Meyer, "Westinghouse Emergency Core Cooling System Small Break October 75 Model", WCAP-8970 (Proprietary) and WCAP-8971 (Non-Proprietary), January 1979.

13. Docherty, P. J., et al, "Report on Small Break Accidents for Westinghouse Nuclear Steam Supply System (NSSS) With Upper Head Injection (UHI)", WCAP-9639 (Non-Proprietary), December 1979.

TABLE 15.6.5-1

Input Parameters Used in the ECCS Analysis

Core Power* (mwt)	3411
Peak Linear Power (Includes 102% factor) kW/ft	
Large Break	12.88
Small Break	12.22
Total Peaking Factor, F_Q	2.32
Axial Peaking Factor, F_Z	1.495
Power Shape	
Large Break	Chopped Cosine
Small Break	See Figure 15.6.5-79
Fuel Assembly Array	17 x 17 (optimized)
Cold Leg Accumulator Water Volume (nominal) (Ft^3/accumulator)	1050
Cold Leg Accumulator Tank Volume (nominal) (Ft^3/accumulator)	1350
Cold Leg Accumulator Gas Pressure (minimum) (psia)	400
UHI Accumulator injected volume (ft^3)	
Perfect mixing case	1043
Imperfect mixing case	877
Small breaks	860
UHI Accumulator initial pressure	
Perfect mixing case and small breaks (psia)	1200
Imperfect mixing case (psia)	1300
Safety Injection Pumped Flow ($\geq$ 10 inch)	See Table 15.6.5-6
Safety Injection Pumped Flow ($<$ 10 inch)	See Table 15.6.5-6
Containment Parameters	0 psig (See text for additional details)
Initial Loop Flow (lb/sec)	9961
Vessel Inlet Temperature (°F)	561.6
Vessel Outlet Temperature (°F)	620.0
Reactor Coolant Pressure, psia	2280
Steam Pressure (psia)	1000
Steam Generator Tube Plugging Level (%)	0

Notes:

* Two percent is added to this power to account for calorimetric error.

Table 15.6.5-3

Large Break LOCA

Time Sequence Of Events

Imperfect Mixing

	$C_{D_{DECLG}} = 1.0$ (sec)	$C_{D_{DECLG}} = 0.8$ (sec)	$C_{D_{DECLG}} = 0.6$ (sec)	$C_{D_{DECLG}} = 0.4$ (sec)
Start	0.0	0.0	0.0	0.0
Reactor Trip Signal	0.8	0.778	0.795	0.823
UHI Accumulator Injection	2.2	*	*	*
Safety Injection Signal	4.8	4.9	5.0	5.3
Cold Leg Accumulator Injection	13.4	15.1	17.7	23.3
UHI Accumulator Injection Complete	19.4	*	*	*
Pump Injection	29.8	29.9	30.0	30.3
End of Bypass	48.8	45.8	47.5	55.7
Bottom of Core Recovery	70.2	67.5	68.9	76.4
Cold Leg Accumulator Empty	112.2	115.0	118.8	126.6

* Not available

Table 15.6.5-5

Large Break LOCA Results

Fuel Cladding Data

Imperfect Mixing

RESULTS	C_D = 1.0 DECLG	C_D = 0.8 DECLG	C_D = 0.6 DECLG	C_D = 0.4 DECLG
Peak Clad Temperature (°F)	1992	2110	2144	2006
Peak Clad Temperature Location (ft)	7.5	7.5	7.5	7.5
Local Zr/H_2O Reaction (max), (%)	4.0	5.9	6.5	4.1
Local Zr/H_2O Location, (ft)	7.5	7.5	7.5	7.5
Total Zr/H_2O Reaction, (%)	<0.3	<0.3	<0.3	<0.3
Hot Rod Burst Time, (sec)	108.2	64.0	64.0	77.0
Hot Rod Burst Location, (ft)	6.25	5.75	6.5	5.5

Table 15.6.5-10 (Page 1)

Parameters for Postulated Design Basis Accident Analysis

		Conservative	Realistic
1.	Data and assumptions used to estimate radioactive source from postulated accidents		
	a. Power Level	3565.	3565.
	b. Fail fuel	100% of fuel rods in core	2% of fuel rods in core
	c. Activity released to reactor coolant from failed fuel and available for release		
	Noble gases	100% of core activity	2% of core activity
	Iodines	50% of core activity	2% of core activity
	d. Iodine fractions (organic, elemental, and particulate)	Regulatory Guide 1.4	same
2.	Data and assumptions used to estimate activity released		
	a. Containment free volume		
	Upper containment volume (ft^3)	6.70E+05	same
	Lower containment volume (ft^3)	3.45E+05	same
	Total containment free volume (ft^3)	1.015E+06	same
	b. Iodine activity released to containment	25%	same
	c. Containment leak rate	0.2% of containment volume per day, $0 \leq t \leq 24$ hr	0.05% of containment volume per day, $0 \leq t \leq 24$ hr
		0.1% of containment volume per day, $t > 24$ hr	0.025% of containment volume per day, $t > 24$ hr
	d. Bypass leakage fraction	0.07	0.07
	e. Annulus ventilation iodine filter efficiency	95%	99%

Table 15.6.5-11 (Page 1)

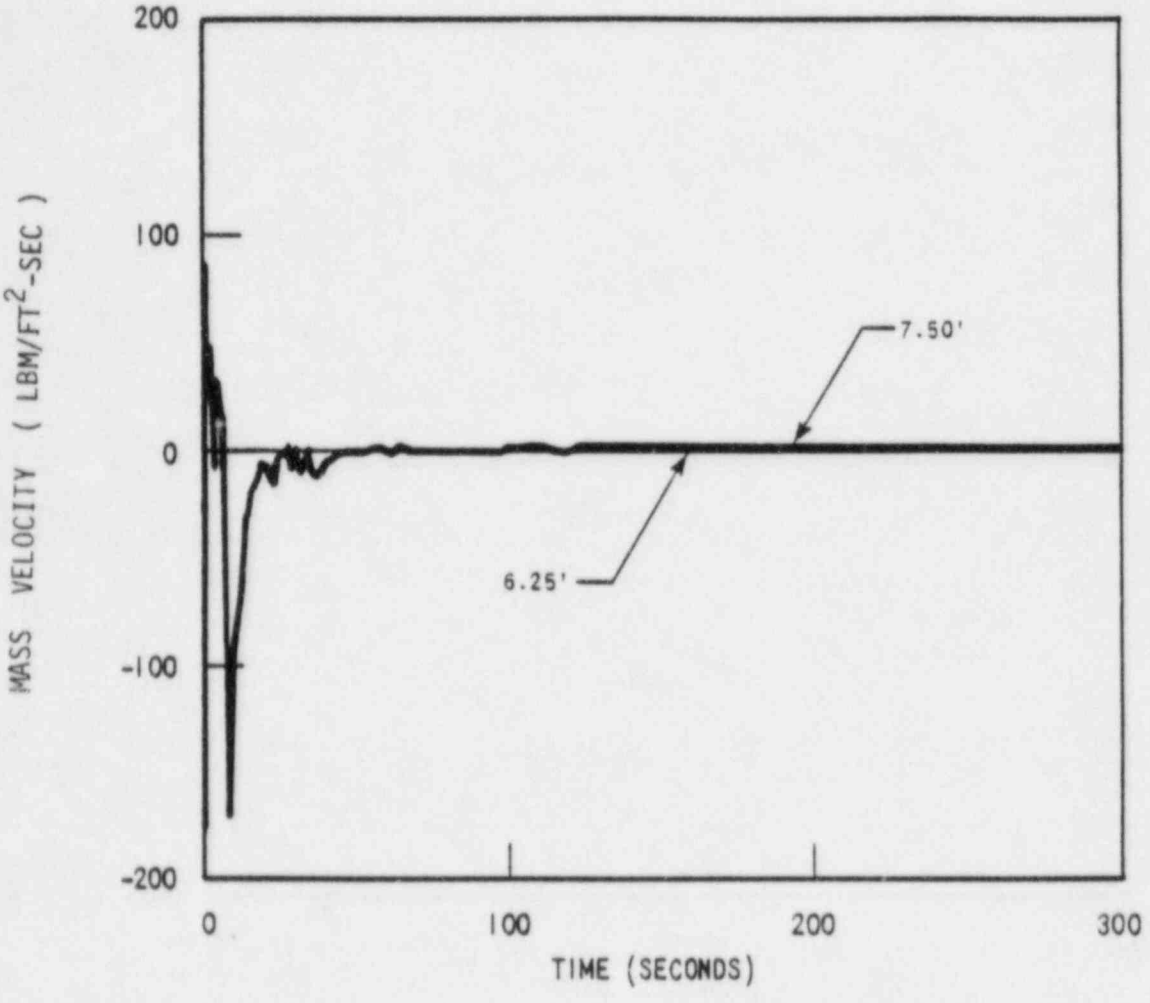
Parameters for Postulated Design Basis Accident Control Room Analysis

		Conservative	Realistic
1.	Data and assumptions used to estimate radioactive source from postulated accidents		Realistic case not analyzed
	a. Power Level	3565.	
	b. Failed fuel	100% of fuel rods in core	
	c. Activity released to reactor coolant from failed fuel and available for release		
	Noble gases	100% of core activity	
	Iodines	50% of core activity	
	d. Iodine fractions (organic, elemental, and particulate)	Regulatory Guide 1.4	
2.	Data and assumptions used to estimate activity released		
	a. Containment free volume (ft^3)	1.015E+06	
	b. Iodine activity released to containment	25%	
	c. Containment leak rate	0.2% of containment volume per day, $0 \leq t \leq 24$ hr	
		0.1% of containment volume per day, $t > 24$ hr	
	d. Bypass leakage fraction	0.07	
	e. Control room pressurization rate (cfm)	4000.	
	f. Control room filtered recirculation rate (cfm)	2000.	
	g. Control room unfiltered in-leakage (cfm)	10.	
	h. Control room volume (ft^3)	8.92E+04	
	i. Control room pressurization and recirculation removal efficiencies for iodine	99%	

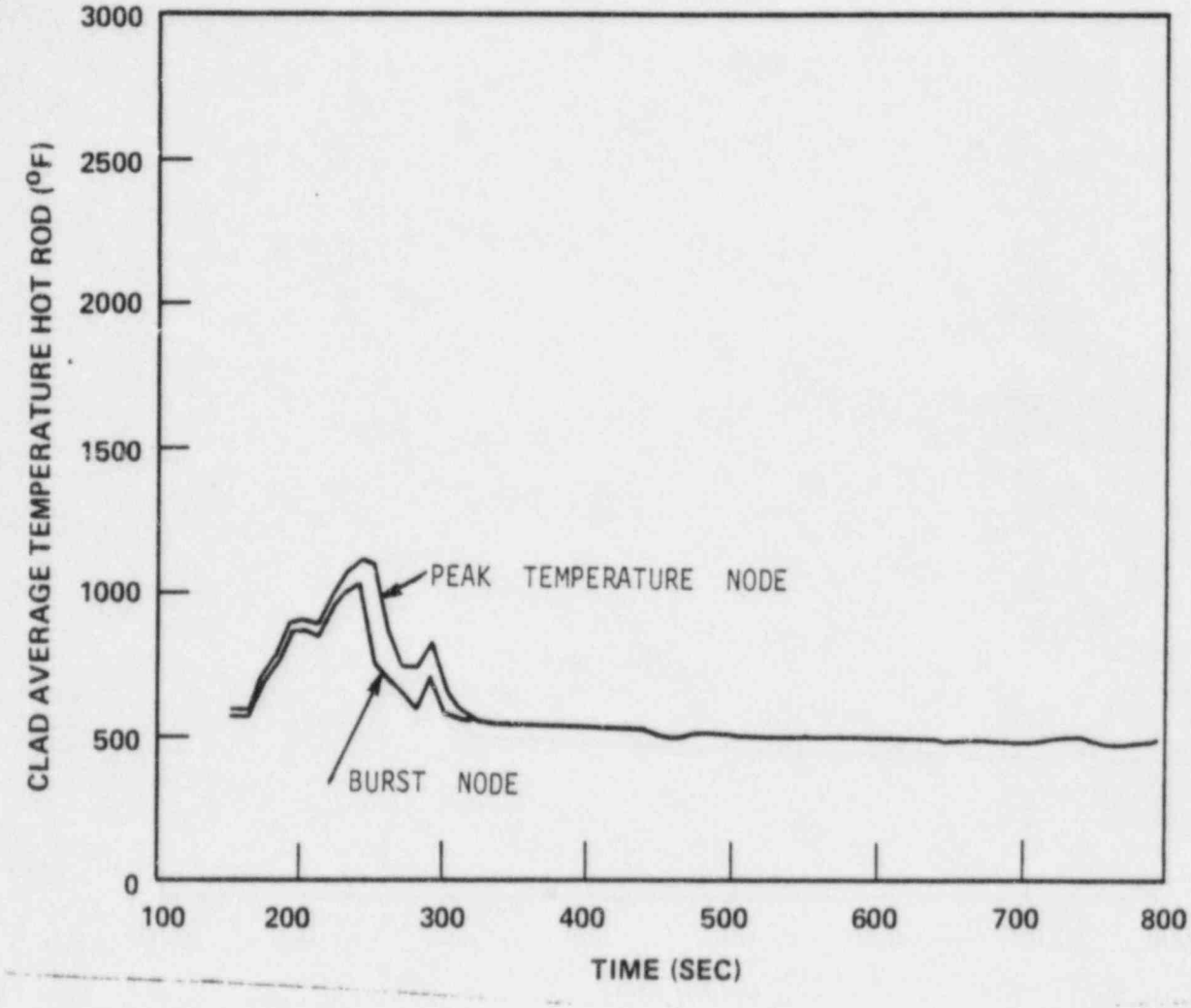
Table 15.6.5-11 (Page 2)

Parameters for Postulated Design Basis Accident Control Room Analysis

		Conservative	Realistic
3.	Dispersion data		
	a. Control room intake χ/Q (sec/m^3)		
	0-8 hrs	9.9E-04	
	8-24 hrs	7.2E-04	
	1-4 days	5.1E-04	
	4 + days	2.8E-04	
4.	Dose data		
	a. Method of dose calculations	Standard Review Plan 6.4	
	b. Dose conversion assumptions	Regulatory Guides 1.4, 1.109	
	c. Doses (Rem)		
	Whole body	4.6E-01	
	Thyroid	2.6E+01	
	Skin	9.0	



MASS VELOCITY - DECLG
(C_D = 1.0)
IMPERFECT MIXING
CATAWBA NUCLEAR STATION
Figure 15.6.5-10
Rev. 14

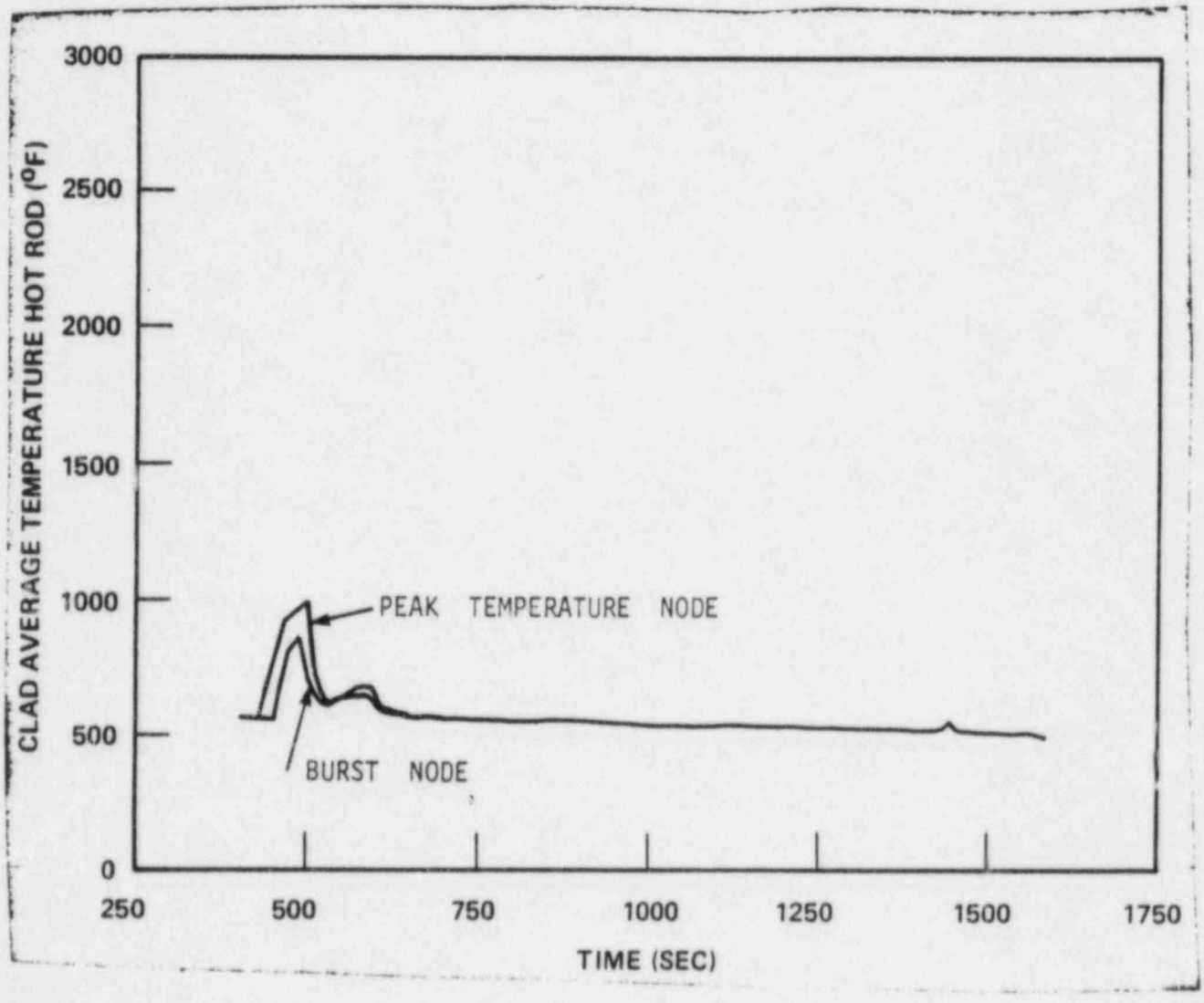


HOT SPOT CLAD TEMPERATURE
6 INCH SMALL BREAK

CATAWBA NUCLEAR STATION

Figure 15.6.5-91

Rev. 14



HOT SPOT CLAD TEMPERATURE
4 INCH SMALL BREAK

CATAWBA NUCLEAR STATION

Figure 15.6.5-92

Rev. 14

410.19 (9.2.6) Provide drawings that indicate the relationship of the auxiliary feedwater condensate storage tank to the condensate storage system and to the auxiliary feedwater system. FSAR Figures 9.2.6-3 and 10.4.9-1 concerning this tank and system do not agree.

Response:

See revised Figure 9.2.6-3.

410.20 (9.3.1) Provide additional information concerning the discussion in FSAR Section 9.3.1.3 which describes the need for air operated valve operation in the event of a control room evacuation coincident with a station blackout in order to bring the station to a hot standby condition from the auxiliary shutdown panel. Describe any special provisions made to assure the reliable delivery of instrument air to these valves under this coincident event. Identify the valves requiring this capability.

Response:

There are no air operated valves that are required to be operable from the auxiliary shutdown complex. The valves fail to an acceptable position on loss of air to maintain hot standby. For this reason instrument air is not required.

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normal and accident conditions. Additionally, the unit can be maintained safely at hot standby for an extended period of time from outside the control room. A list of instrumentation and controls and a description of the remote shutdown panels is in Section 7.4.

440.20 (App. 5-A) The auxiliary spray valve fails closed on loss of air or power. In this case you indicate the valve may be opened by using a portable compressed air or nitrogen bottle supply. Specify the seismic category of this valve, the operator, and controls. Describe the procedures for opening the valve with portable compressed air or nitrogen bottle supply. Discuss the availability of this equipment and communication with the control room.

If the spray valve is stuck closed as a result of mechanical failure, you state the pressurizer power operated relief valves may be used to depressurize the RCS. Provide the justification and procedures for using these valves for depressurization. Include in the discussions the effect on the RCS for only offsite power or onsite power available, single failures including common failures, seismic classification of components and controls for valve operators, and the effect of discharged fluid that could lead to discharge to the containment via the pressurizer relief tank.

Response:

The safety grade means of RCS depressurization will be accomplished by discharge of steam from the pressurizer via the PORV's. These valves (and operators) and suitable safety grade N_2 supplies to the air piston actuator will be available to assure operability from the main control room assuming worst single failure. This capability will be available on Unit 2 prior to initial criticality and for Unit 1 after the modifications are made during the first refueling. The pressurizer auxiliary spray valve (tag number 1NV37A shown on Figure 9.3.4-1) has been changed from an air operated valve to an electric motor operated valve. It is an active valve and is powered from a train A essential power source.

440.21 (App. 5-A) This appendix states that "should boration without letdown prove impractical due to any combination of plant conditions or equipment failures, letdown can be achieved by discharging RCS inventory via the pressurizer power operated relief valves or the reactor vessel head vent valves." Identify the factors that would make boration without letdown impractical. Provide the justification and procedures for using the pressurizer power operated relief valves or the reactor vessel head vent valves for letdown. Consideration should be given to single failures including common mode failures such as loss of power or air, safe shutdown earthquake, the effect on the RCS for only offsite power or onsite power available, and the effect of discharged fluid that could lead to a discharge to the containment and prevent access to the containment.

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of offsite power, for which recovery involves a controlled cooldown of the Reactor Coolant System, the plant can be placed in and maintained in (for an extended period of time) a safe hot standby condition using safety grade systems only. In this condition, decay heat removal is via the emergency feedwater system and the steam generator safety valves.

In the event of a loss of offsite power, the reactor coolant pumps and main condenser are not operable. Therefore, the plant will be maintained in the safe hot standby condition until offsite power, and thus operability of this equipment, is restored. Once offsite power is restored, the operator can either return the plant to power operation or can conduct a normal plant cooldown. However, if the operator feels that it is desirable to cool the plant down, it can be cooled down to cold shutdown conditions without offsite power.

The cold shutdown capability of the plant has been evaluated in order to demonstrate how the plant can be maintained in a safe hot standby condition while necessary manual actions as allowed by the recommended implementation for Class 2 plants, are taken to achieve cold shutdown conditions following the most limiting single failure. Under such conditions, the plant is capable of achieving RHRS operation conditions (approximately 350°F, 425 psia) in approximately 36 hours. Note that two of the Pressurizer PORV's (for the RCS depressurization function) and the Steam Generator PORV's (for heat removal from Hot Standby to 350°F) have been upgraded to safety grade. (Unit 1 valves will be upgraded during the first refueling.)

To accomplish the cooldown without offsite power requires that four critical functions be performed. These are circulation of the reactor coolant, removal of residual heat, boration, and depressurization.

For the first stage of the cooldown (hot standby to 350°F) circulation of the reactor coolant is accomplished by natural circulation, with the reactor core as the heat source and the steam generators as the heat sink. In the second stage (< 350°F), circulation of the reactor coolant is performed by the residual heat removal (RHR) pumps.

For the first stage of cooldown, removal of residual heat utilizes the emergency feedwater system and steam released thru the steam generators to bring the reactor coolant temperature from hot standby to 350°F. Steam is initially released thru the steam generator safety valves, as a result of the turbine and reactor trip, in order to maintain hot standby. Steam release for cooldown to 350°F occurs via the steam generator PORV's. In the second stage, heat removal is via the RHR system, the component cooling water system, and the service water system.

Boration is accomplished using a portion of the chemical and volume control system consisting of the boric acid tanks and pumps, the centrifugal charging pumps, and piping and valves from the boric acid tanks to the reactor coolant system.

Depressurization can be accomplished by a number of methods. Credit is being taken for use of the Pressurizer PORV's to release steam to the Pressurizer Relief Tank.

Makeup for contraction during the cooldown can be provided either from the reactor makeup water storage tank and the boric acid tanks, or from the refueling water storage tank.

The plant design provides the capability for conducting natural circulation cooldown tests if required. However, because of the great similarity in design between all Westinghouse pressurized water reactors, Catawba can reference those tests conducted at other units rather than conducting such tests on Catawba. However, specific procedures for cooling down using natural circulation will be prepared prior to startup.

Table 6.3.2-3 indicates that the containment sump isolation valves cannot be opened unless RHR to RCS, and RWST outlet valves are closed. This is not consistent with Table 6.3.2-7 which indicates the RWST valves are closed after the sump valves are open. This should be clarified.

Response:

Table 6.3.2-3 is correct as is. When two of four RWST level channels indicate a RWST level less than the low level setpoint in conjunction with an "S" signal, the two containment sump isolation valves are automatically opened to realign the two RHR pumps to take suction from the sump for the start of the recirculation mode. The RHR pumps continue to operate during this switchover.

The "S" signal is specifically required as an integral part of this interlock to prevent an automatic opening of these sump isolation valves (and the consequential spilling of RWST contents into the containment) during a refueling operation when the RWST water level may be decreased below the RWST low level setpoint.

This interlock provides for the retention of the "S" signal by a latching relay. The retention of this signal is required since the emergency procedures may instruct the operator to reset the "S" signal prior to the generation of the RWST low level setpoint signal.

A two position manual reset switch is provided on the main control board to permit the operator to remove this actuation signal in the event that the corresponding sump valve must be closed and retained in a closed position to terminate a leak (passive failure) in the RHR pump suction or discharge piping or to perform maintenance on the corresponding RHR pump during post-LOCA recirculation.

This interlock permits the sump valves to be opened automatically following a LOCA when the RWST/RHR suction valves are open. The automatic circuit therefore bypasses the block which prevents these valves from being opened by the operator during normal operations when the RWST/RHR isolation valves are open.

440.36 (6.3) Discuss the potential for deadheading ECCS pumps. Consider the effects of single failures.

Response:

Pumps used in the ECCS mode are the residual heat removal, safety injection and charging pumps. Following an "S" signal, all of these pumps would start and flow from each would be provided to the reactor coolant system as the system pressure drops below the shutoff head of the pump.

To prevent deadheading, the residual heat removal pumps are provided with miniflow lines. A valve located in each miniflow line, which is controlled by the flow indicator at the pump discharge, opens when the discharge flow is less than 500 gpm and closes when the flow exceeds 1000 gpm.

The safety injection pumps are also provided with miniflow lines. These miniflow paths recirculate water from the discharge of the pumps back to the RWST. As part of the switchover from injection to cold leg recirculation, the operator is instructed to close the valves in these lines to prevent containment sump water being pumped to the RWST. These valves are not closed on initiation of an "S" signal.

Miniflow recirculation paths are also provided for the charging pumps. The pump deadheading problem is a valid concern for the charging pumps as operating these pumps at or above their shutoff head would lead to failure of the pumps due to overheating. The miniflow path for the centrifugal charging pumps is opened and closed by the operator according to specific guidelines in the various emergency procedures. The valves in this path are normally open and do not change state on a safety injection signal. The operator is reminded to reopen the valves if Reactor Coolant System pressure increases above 2000 psig. This is done to prevent deadheading the pumps. The operator is instructed to close the valves only if Reactor Coolant System pressure is less than 1500 psig and the charging pumps are expected to remain aligned for safety injection, i.e., the criteria for stopping or realigning these pumps are not about to be satisfied. This is done to provide additional safety injection flow at lower pressures where pump deadheading is not a concern.

A single active failure analysis for Catawba is discussed in Table 6.3.2-5 and Table 6.3.2-6.

440.37 (6.3) Provide the detailed procedures and methods for maintaining the ECCS lines in a filled condition to prevent water hammer. How have the effects of water hammer been considered in the design of the ECCS?

Response:

Proper initial fill and venting of the ECCS ensures that water hammer will not occur in ECCS lines. In addition, the head of water provided by the RWST further ensures the lines will remain full and water hammer concerns will not develop. High point vents in the ECCS lines are provided to ensure means for proper venting of lines and pumps. Fill and venting procedures for the ECCS ensure removal of air from the system to prevent the possibility of a water hammer if injection flow is initiated. The refueling water storage tank (RWST) location/configuration ensures that the Technical Specification limit for the

RWST low water level is above the emergency core cooling system (ECCS) high point required to maintain water solid ECCS lines.

Further the existence of high point vents and the positive head of water provides means by which the operator can confirm water solid ECCS lines.

Technical Specifications surveillance required periodic operation of the RHR system and leak testing of ECCS check valves. These requirements are incorporated into plant surveillance test procedures which se methods developed during startup and preoperational testing.

440.38 (6.3) What are your procedures for resetting the ECCS after a safety injection signal?

Response:

The Catawba emergency procedures were derived from the Westinghouse Owners Group Emergency Response Guidelines which consider various accidents and multiple failures. Appropriate criteria for the termination and reinitiation of safety injection have been developed for each situation. An example of such criteria is given in the response to Question 440.43.

440.39 (6.3, 15.0) What are the initiation and completion of action times of the ECCS components that were used in the Chapter 15 analysis with and without offsite power? What are the bases for these times and will they all be verified during preoperational testing?

Response:

The following action times for ECCS were assumed in Chapter 15 non-LOCA analysis.

2 Second Delay - Logic Delay

10 Second Delay - This delay only used for loss of offsite power cases. This delay simulates the time required to start diesel generators and loading of SI pumps.

10 Second Ramp - SI flow is brought up to full flow over a 10 second ramp. This simulates bringing SI pumps to full speed and aligning valves.

These items are verified by the procedures in the Technical Specifications.

The large break ECCS performance analysis performed for Catawba assumed the loss of offsite power and initiation of safety injection flow 25 seconds after receipt of a pressurizer low pressure signal. The 25 second time is a conservative estimate of the delay associated with safety injection water flow delivery. Individual delay times are summarized below:

Action	Time Delay after SI Setpoint is Reached
Setpoint Reached	0 sec
Safeguards Signal Generated	2.0 sec

1. The ECCS process flow diagrams of high pressure and low pressure systems including piping flow rates with all pumps running, and,

2. The total pumped ECCS flow rate distribution to the intact loops as well as the broken loop with the worst single failure in the ECCS.

Response:

NOTE: The clarifying statement below accompanies the Westinghouse process flow diagram furnished with this response.

The response to question 440.41 has been included as a new FSAR figure, which is Figure 6.3.2-9 and the accompanying clarifying notes.

The Westinghouse process flow diagram was developed for illustrative purposes only and is not intended to represent the flow rates used by Westinghouse in the various accident analyses. For the cold leg injection mode, it illustrates best estimate system performance based on maximum ECCS safeguards (both trains of ECCS components) operating. The system operating conditions presented are based on the assumption that the RCS is fully depressurized and is in equilibrium with the containment at zero psig.

Flow rates to the RCS are provided in Chapter 15.0, where appropriate, for the accident analyses. The accident analyses flow rates are developed from certified pump performance curves and calculated system resistance based on plant piping layouts. Minimum ECCS safeguards flow rates are determined by degrading the weakest certified pump performance curves by 5% and assuming that the injection line with the lowest resistance spills to containment (to maximize spill).

Loss-of-coolant accidents (LOCA) are discussed in Section 15.6.5. For small break LOCA's, the most limiting single active failure is failure of an emergency power train which results in loss of one complete train of ECCS components. The minimum delivered ECCS flow available to the RCS is based on this single failure. For large break LOCA's, the most limiting single failure for purposes of LOCA analyses is the one which produces the lowest containment pressure. The lowest containment pressure would be obtained only if all containment spray pumps and fan coolers operated subsequent to the postulated LOCA. Therefore, for the purposes of large break LOCA analyses, the most limiting single failure would be the loss of one RHR pump. However, the large break LOCA analyses assume both a conservative containment pressure, which is lower than that calculated with maximum containment safeguards, and minimum ECCS safeguards (the loss of one complete train of ECCS components, which results in the minimum delivered ECCS flow available to the RCS.

The quantity of ECCS flow delivered to the unbroken loops, as assumed in the limiting break calculations, is given in Table 15.6.5-6 for the Condition III (small break) LOCA and for the Condition IV (large break LOCA.

The High level setpoint is established sufficiently below the FWST overflow to account for instrument error (approximately 11,490 gallons) and provide warning of imminent overflow.

The Makeup level setpoint provides a volume below overflow level to conservatively account for thermal contraction level variation and minor uses (approximately 6,000 gallons) plus an allowance for instrument error (approximately 11,490 gallons). This setpoint is approximately 25,000 gallons more than the proposed Technical Specification requirement of 350,000 gallons, which provides an adequate "working allowance."

The minimum time from the initiation of a LOCA to the start of switchover to recirculation is the minimum time required to reduce FWST volume from Makeup level to the Low level. This will always exceed 11 minutes with maximum FWST outflow (reference Section 9.2.7.2.e) and most adverse level instrument errors.

The switchover procedure and level setpoints conservatively account for all relevant factors of FWST sizing while maximizing the minimum volume available for cold leg injection, placing appropriate emphasis on timely completion of manual actions of the switchover procedure, and maximizing the containment sump volume. The FWST alarms are derived from safety grade instrument loops.

440.43
(6.3, 15.6.5) Identify single failures and operator errors that would divert ECCS flow. For both large and small breaks discuss the effect of these failures on flow to the core, the containment sump water level, and conformance with the 50.46 acceptance criteria.

Response:

In both large and small break LOCA analyses for Catawba loss-of-offsite power coincident with the accident is assumed. The single failure subsequently considered is the loss of a diesel generator so that only one train of ECCS flow of the two actually present is considered to be available. Therefore, for both large and small break LOCAs ECCS flow to the core is at a conservatively low value following its automatic actuation, especially since all water delivered to the broken loop is considered to spill directly to the containment sump. Notwithstanding these conservatisms, conformance with the 10 CFR 50.46 acceptance criteria is demonstrated in the large and small break LOCA analyses. No other postulated single failure would have as great an effect on ECCS flow delivery.

The ECCS termination and reinitiation criteria provided in the Catawba Emergency Operating Procedures (EOPs) are designed to minimize any possibility of an operator error improperly or prematurely shutting off safety injection. Termination criteria for high pressure safety injection flow (HPI) following a LOCA event are as follows:

1) Reactor coolant system pressure must be increasing

2) The reactor coolant system must be subcooled

3) Pressurizer level must be on the span of the level instrument

4) An adequate heat removal capability must be provided by the steam generators

All of these criteria account for the applicable instrument errors. Reinitiation criteria are provided if safety injection is terminated too soon.

440.44
(6.3, 15.0)

Page 6.3-7 states "As the reactor coolant pressure drops below the nominal pressure in the gas accumulator (1000 psia) the membrane in the gas crossover line will tear open at a differential pressure of about 40 psi and flow will be initiated through the normally open isolation valves and injection lines into the reactor vessel." This is not consistent with some of the Chapter 15 analyses which assume a pressure of about 1250 psia. For each of the Chapter 15 analyses that take credit for UHI, show that the analysis is based on the correct UHI pressure with appropriate allowances for the minimum accumulator initiation pressures.

TABLE Q440.52-1

RESPONSE TIMES AND DISCHARGE RATES ASSUMED FOR CHAPTER 15 EVENTS

COMPONENT	RESPONSE TIME	CAPACITY
Main Steam Isolation Valves	2 second logic delay & 5 second closure time(1)	-----
Main Feed Isolation Valves	2 second logic delay & 5 second closure time(1)	-----
Pressurizer Power Operated Relief Valves	Full Open 15 psi Above Setpoint(6)	3 Valves @ 210,000. lbm/hr per valve(6)
Pressurizer Safety Valves	Full Open at 3% accumulation Above Set Pressure(2)	3 Valves @ 420000. lbm/hr per valve(5)
Steam Generator Safety Valves	Full Open at 3% Accumulation Above Set Pressure(2)	120% of Rated Full Power Steam Flow. (Rated Steam Flow = 15.14×10^6 lbm/hr)
Aux Feed Pumps	60 Second Delay Assumed with or without Offsite Power(1)	Feedline Rupture - 492 gpm to Two Intact Steam Generators(3)
		Loss of Feed W/AC 491 gpm Uniform to SG.(3)
		Loss of Feed W/O AC 491 gpm Uniform to 2 SG.(3)

NOTES:

1. Technical Specifications require verification of the response times thru tests.
2. Technical Specifications require verification that valves begin to lift at proper setpoint.
3. Technical Specifications require testing of auxiliary feed flows.
4. Valve capacity is certified by valve manufacturer using accepted industry standards.
5. Valve capacity will be verified through results from EPRI's PWR Safety & Relief Valve Test Program.
6. Valve stroke time and capacity will be verified through results from EPRI's PWR Safety & Relief Valve Test Program.

Identify the version of the codes used in the Chapter 15 analysis of the core, RCS, and secondary coolant system and reference NRC approval letters for use of these versions of the codes.

Response:

1. The LOFTRAN code version used to perform the Chapter 15 analyses is essentially the same as that described in WCAP-7907-P-A, "LOFTRAN Code Description", April, 1984.

For most of the events analyzed in Chapter 15, the plant will be in a safe and stable hot standby condition following an automatic reactor trip. This condition will in fact be similar to plant conditions following any normal, orderly shutdown of the reactor. At this point, the actions taken by the operator would be no different than those in the normal operating procedures. The exact actions taken, and the time these actions would occur, will depend on which systems are available (e.g. steam dump system, main feedwater system, etc.) and the plans for further plant operation. As a minimum, to maintain the hot standby condition, decay heat must be removed via the steam generators. The main feedwater system and the steam dump or steam line PORVs could be used for this purpose. Alternatively, the auxiliary feedwater system and the steam line safety valves may be used, both of which are safety grade systems. Although the auxiliary feedwater system may be started manually, it will be automatically actuated if needed by one of the signals shown on Figure 7.2.1-1 (sheet 15), such as low-low steam generator water level. If hot standby conditions are maintained for an extended period of time, operator action may be required to transfer the auxiliary feedwater source. The time at which such action is required will be sufficiently long after initiation of the event to permit operator action. Also, if the hot standby condition is maintained for an even longer period of time (greater than approximately 18 hours), operator action may be required to add boric acid via the CVCS to compensate for xenon decay and maintain shutdown margin. Again, the actions taken by the operator would be no different than during normal plant shutdown.

Many Chapter 15 events result in a stable condition being reached automatically following a reactor trip and only actions typical of normal operation are required from the operator. For several events involving breaks in the reactor coolant system or secondary system piping, additional requirements for operator action can be identified. (Additional information about the impact of equipment failures or erroneous operator actions may be found in WCAP-9691 "NUREG-0578 2.1.9.C, Transient and Accident Analysis.")

Steamline Break: See Table Q440.56-1

Following the hypothetical steam line break incident, a steam line isolation signal will be generated almost immediately, causing the steam line isolation valves to close within a few seconds. If the break is downstream of the isolation valves, all of which subsequently close, it will be isolated. If the break is upstream of the isolation valves, or if one valve fails to close, the break will be isolated from three steam generators while the faulted one will continue to blow down. Only the case in which one steam generator continues to blow down is discussed here since isolation of all steam generators for a downstream break will terminate the transient.

An excessive cooldown protection signal will cause main feedwater isolation to occur. The only source of water available to the faulted steam generator is then the Auxiliary Feedwater System (CA). The first required operator action is to identify the faulted steam generator and then isolate the auxiliary feedwater flow to that steam generator. Following steamline isolation, steam pressure in the steamline with the faulted steam generator will continue to fall rapidly, while the pressure stablizes in the remaining three steam lines. The indication of the different steam pressures will be available to the operator within a few seconds of the steamline isolation. This will provide the necessary information to identify the faulted steam generator so that auxiliary feedwater to it can be isolated. The operator is instructed by Emergency Operating Procedures to isolate the affected steam generator by shutting the steam generator CA isolation valve(s). Manual controls are provided in the control room for stopping and starting the CA pumps and for the control and isolation valves associated with the CA system. The means for detecting the faulted steam generator and isolating auxiliary feedwater to it requires only the use of safety grade equipment available following the break.

Following the automatic safety injection actuation and after the faulted steam generator is completely isolated, the continued operation of the safety injection system will repressurize the RCS and continue to increase the reactor coolant inventory. The second required operation action is to manually control the repressurization of the RCS by stopping the safety injection (NI) pumps and the centrifugal charging (NV) pumps. As soon as an indicated water level returns to the pressurizer, NC pressure has returned to the normal range and the NC system is sufficiently subcooled, the operator is instructed to stop the pumps, reestablish normal charging and letdown flows, and reestablish operation of the pressurizer heaters to maintain a steam bubble in the pressurizer to limit system repressurization. The pressurizer level instrumentation and manual controls for operation of the NV pumps meet the required standards for safety systems.

The removal of decay heat in the long-term (following the initial cooldown) using the remaining intact steam generators requires only the auxiliary feedwater system as a water source and the secondary system safety valves to relieve steam.

The requirements to terminate auxiliary feedwater flow to the faulted steam generator, reestablishing normal charging and letdown flows, and reestablishing operation of the pressurizer heaters can be met by simple switch actions by the operator. Thus the required actions to limit the cooldown and repressurization can be easily recognized, planned and performed within ten minutes. For decay heat removal and plant cooldown the operator has a considerably longer time period in which to respond because of the large initial cooldown associated with a steam-line break transient.

Feedwater Line Break: See Table Q440.56-2

For a feedwater line break, auxiliary feedwater is initiated automatically as is Safety Injection. For the feedline break downstream of the main feedwater isolation valves the required operator actions are similar in nature to the required actions for the steamline break.

The first required operator action is to identify the faulted steam generator and isolate CA flow to that steam generator. The primary indication to the operator will be a comparison of individual steam line pressures after steam line isolation has occurred. After identifying the faulted steam generator by shutting the steam generator CA isolation valve(s). The steam line pressure indicators and CA isolation valves are safety grade.

The operator will also control the auxiliary feedwater to provide the decay heat removal through the intact steam generators by maintaining steam generator water level. The operator can use the steam dump system or the steam generator PORVs to begin a controlled cooldown, or the unit may be maintained in hot standby by using the steam line safety valves for decay heat removal.

As soon as an indicated water level returns to the pressurizer, NC pressure has returned to the normal range and the NC system is sufficiently subcooled, the operator is instructed to stop the pumps, reestablish normal charging and letdown flows, and reestablish operation of the pressurizer heaters to maintain a steam bubble in the pressurizer to limit system repressurization. The pressurizer level instrumentation and manual controls for operation of the NV pumps meet the required standards for safety systems.

The analysis presented in Section 15.2.8 assumes a 30-minute delay until these actions occur.

Boron Dilution

Several indicators are available to the operator to determine that a boron dilution event is occurring depending on the mode neutron flux, overtemperature delta T, and rod position alarms are available. During other modes of operation, the operator relies on the high flux at shutdown alarm. Once the operator determines that a reactivity addition event is in progress, he should perform emergency boration utilizing the charging pumps. By taking this action, the operator will prevent the core from returning to criticality. After verifying that the rate of reactivity addition is being reduced, the operator should determine the source of the boron dilution and terminate it.

Operator action is required for a boron dilution event in any mode of operation. Ample operator action time (from the receipt of alarm till the core returns to criticality) is available as discussed in Section 15.4.6.

Steam Generator Tube Rupture: See Table 440.56-3

The accident examined is the complete severance of a single steam generator tube. The operator is expected to determine that a steam generator tube rupture has occurred, and to identify and isolate the faulty steam generator on a restricted time scale in order to minimize contamination of the secondary system and ensure the termination of radioactive release to the atmosphere from the faulty unit. The recovery procedure can be carried out on a time scale which ensures that break flow to the secondary system is terminated before water level in the affected steam generator rises into the main steam line. Sufficient indications and controls are provided to enable the operator to carry out these functions satisfactorily. Consideration of the indications provided at the control board, together with the magnitude of the break flow, leads to the conclusion that the isolation procedure can be completed within 30 minutes of accident initiation. Included in this 30 minute time period would be an allowance of approximately 6 minutes to trip the reactor (automatic action), 10 minutes to identify the accident as a steam generator tube rupture and 15 minutes to isolate the faulted steam generator. Preliminary diagnosis of a steam generator tube rupture can be initiated prior to reactor trip. Consequently, although it may take slightly longer than 5 minutes for automatic reactor trip to occur, identification and isolation of the affected steam generator is expected to be completed within 30 minutes.

Immediately apparent symptoms of a tube rupture accident such as falling pressurizer pressure and level and increased charging pump flow are also symptoms of small steam line breaks and loss of coolant accidents. It is therefore important for the operator to determine that the accident is a rupture of a steam generator tube in order that he may carry out the correct recovery procedure. The accident under discussion can be identified by the following method. In the event of a complete tube rupture, it will be clear soon after the trip that the level in one steam generator is rising more rapidly than in the others.

Also this accident could be identified by either a condenser air ejector exhaust high radiation alarm or a steam generator blowdown radiation alarm.

The operator carries out the following major operator actions subsequent to reactor trip which lead to isolation of the faulted steam generator and minimizing primary to secondary leakage.

1. Identification of the faulted steam generator.

2. Isolation of the faulted steam generator.

3. Subcooling of NC system fluid to 20° below the saturation temperature at the ruptured steam generator pressure.

4. Depressurization of the NC system to terminate breakflow, and

5. Terminating safety injection.

Loss of Coolant Accident: See Table 440.56-4

No manual actions are required of the operator for proper operation of the ECCS during the injection mode of operation. Only limited manual actions are required by the operator to realign the system for the cold leg recirculation mode of operation, and, at approximately 15 hours, for the hot leg recirculation mode of operation. These actions are delineated in Table 440.56-4.

The changeover from the injection mode to recirculation mode is initiated automatically and completed manually by operator action from the control room. Protection logic is provided to automatically open the two containment sump isolation valves when two of four RWST level channels indicate a RWST level less than a low level setpoint in conjunction with the initiation of the engineered safeguards actuation signal ("S" signal). This automatic action would align the two residual heat removal pumps to take suction from the containment sump and to deliver directly to the NC system. It should be noted that the residual heat removal pumps would continue to operate during this changeover from injection mode to recirculation mode.

The two NV pumps and the two NI pumps would continue to take suction from the RWST, following the above automatic action, until manual operator action is taken to align these pumps in series with the residual heat removal pumps.

The RWST low level protection logic consists of four level channels with each level assigned to a separate process control protection set. Four RWST level transmitters provide level signals to corresponding normally deenergized level channel bistables. Each level channel bistable would be energized on receipt of a RWST level signal less than the low level setpoint.

A two out of four coincident logic is utilized in both protection cabinets A and B to ensure a trip signal in the event that two of the four level channel bistables are energized. This trip signal, in conjunction with the "S" signal, provides the actuation signal to automatically open the corresponding containment sump isolation valves.

The low RWST level signal is also alarmed to inform the operator to initiate the manual action required to realign the NV and NI pumps for the recirculation mode. The manual switchover sequence that must be performed by the operator is delineated in Table 6.3.2-7. Following the automatic and manual switchover sequence, the two residual heat removal pumps would take suction from the containment sump and deliver borated water directly to the RCS cold legs. A portion of residual heat removal pumps discharge flow would be used to provide suction to the two NV pumps and the two NI pumps which would also deliver directly to the RCS cold legs. As part of the manual switchover procedure, the suctions of the NI and NV pumps are cross connected so that one residual heat removal pump can deliver flow to the RCS and both NI and NV pumps, in the event of the failure of the second residual heat removal pump.

TABLE Q440.56-1
STEAMLINE BREAK

REQUIRED OPERATOR ACTION	ALARMS TO ALERT THE OPERATOR TO INITIATE A PARTICULAR ACTION	DELAY TIME ASSUMED	INSTRUCTIONS GIVEN TO THE OPERATOR FOR PERFORMING THE REQUIRED ACTION	COMPONENTS AND INSTRUMENTATION NECESSARY TO COMPLETE INDICATED ACTION	IMPACT OF SINGLE ACTIVE COMPONENT FAILURE	IMPACT OF THE OPERATOR'S FAILURE TO TAKE ACTION OR THE OPERATOR TAKING A CLOSELY RELATED BUT ERRONEOUS ACTION
A. Identify the faulted steam generator and isolate auxiliary feedwater to that steam generator.	A. No specific alarms provided for this function. Primary indication to the operator is steamline pressure indication. A possible alarm is the steam flow - feed flow mismatch.	A. Within 10 minutes	A. Identify the faulted S/G by comparing individual steamline pressures. Terminate auxiliary feedwater to that S/G by shutting the AFW isolation valves for that S/G.	A.1 Steamline pressure indications A.2 Steam generator AFW isolation valves A.3 Steam generator level indications	None	A. Operator does not isolate AFW to any steam generator or isolates AFW to wrong steam generator: Faulted S/G will continue to blow down.
B. Reset the Safety Injection and manually control the repressurization of RCS and maintain normal pressure control.	B. No specific alarms for this purpose. Primary indications to the operator are: pressurizer level, RCS subcooling and RCS pressure. Possible alarms include: - High pressurizer level - High pressurizer pressure	B. Within 10 minutes	B. The conditions for resetting Safety Injection are given to the operator. The operator is instructed to stop the Safety Injection pumps and realign the charging pumps to reestablish normal pressurizer level control.	B.1 Pressurizer level indicators B.2 RCS subcooling monitor B.3 RCS pressure indicators B.4 High head safety injection pumps	None None None None	B1. The operator fails to terminate SI after the pressurizer level returns to the indicating range: Water relief thru pressurizer relief valves may occur. B2. The operator terminates SI before peak reactivity is reached: If criticality is attained the core power will increase until it reaches equilibrium with steam demand.

TABLE Q440.56-2
FEEDLINE BREAK

REQUIRED OPERATOR ACTION	ALARMS TO ALERT THE OPERATOR TO INITIATE A PARTICULAR ACTION	DELAY TIME ASSUMED	INSTRUCTIONS GIVEN TO THE OPERATOR FOR PERFORMING THE REQUIRED ACTION	COMPONENTS AND INSTRUMENTATION NECESSARY TO COMPLETE INDICATED ACTION	IMPACT OF SINGLE ACTIVE COMPONENT FAILURE	IMPACT OF THE OPERATOR'S FAILURE TO TAKE ACTION OR THE OPERATOR TAKING A CLOSELY RELATED BUT ERRONEOUS ACTION
A. Identify the faulted steam generator and isolate AFW to that steam generator.	A. No specific alarms for this purpose. Primary indication to the operator will be a comparison of steamline pressures. Steam flow - feed flow mismatch alarm may help	A. Within 10 minutes	A. Identify the faulted S/G by comparing individual steam line pressures. Terminate AFW flow to that S/G by shutting the AFW isolation valves for that S/G.	A.1 Steamline pressure indicators A.2 Steam generator AFW isolation valves A.3 Steam generator level indicators	None	A. Operator does not isolate AFW to any S/G or isolates AFW to isolates AFW to wrong S/G: Faulted S/G will continue to blow down.
B. Control AFW to the intact steam generators and control cooldown.	B. The operator will use individual S/G level individual to control AFW flow to each of the steam generators. High level and low level alarms are provided.	B. Within 30 minutes	B. Maintain proper S/G level in intact S/Gs. If possible, maximize AFW flow to intact S/Gs to help lower primary temperature.	B. AFW modulating valves & controls	None	B. The operator fails to modulate AFW flows to intact steam generators: overfilling of a steam generator may occur.
C. Operator terminates SI to control primary system pressure and pressurizer level.	C. Pressurizer level indication and high and low level alarms are provided.	C. Within 30 minutes	C. Reset SI and terminate SI to control primary system pressure and pressurizer level.	C.1 Safety injection and charging pump controls C.2 Pressurizer pressure indicators C.3 Pressurizer level indicators C.4 RCS subcooling indicators	None None None None	C. The operator does not terminate SI after criteria are met: Water relief thru the pressurizer relief valves may occur.

TABLE Q440.56-4 (Page 1)
LOSS OF COOLANT ACCIDENT

REQUIRED OPERATOR ACTION	ALARMS TO ALERT THE OPERATOR TO INITIATE A PARTICULAR ACTION	DELAY TIME ASSUMED	INSTRUCTIONS GIVEN TO THE OPERATOR FOR PERFORMING THE REQUIRED ACTION	COMPONENTS AND INSTRUMENTATION NECESSARY TO COMPLETE INDICATED ACTION	IMPACT OF SINGLE ACTIVE COMPONENT FAILURE	IMPACT OF THE OPERATOR'S FAILURE TO TAKE ACTION OR THE OPERATOR TAKING A CLOSELY RELATED BUT ERRONEOUS ACTION
A. Check Reactor Coolant Pump trip criteria	None Required	Time of RCP trip is a function of break size. It is assumed that RCP's are tripped upon loss of subcooling as specified in the plant procedures.	The operator is instructed to trip all RCP's when the RCS subcooling is lost and high head SI flow is verified.	A.1 RCP's A.2 RCS subcooling monitor A.3 High head SI flow indicators	If a single active failure prevents tripping RCP's the impact is discussed in WOG letter OG-117, March 9, 1984.	Discussed in WCAP-9584.
B. The operator must manually complete the changeover of the ECCS system from the injection mode to the cold leg recirculation mode.	Refer to Sections 6.3.5.4 an 9.2.6	~ 30 minutes	B.1. Verify that the containment sump isolation valves are open. B.2. Verify the isolation valve in each RHR suction line from the RWST is closed. B.3. Close the isolation valve in each SI pump miniflow line. B.4. Close the two isolation valves in the crossover line downstream of the RHR heat exchangers. B.5. Open the two parallel valves in the common suction line between the centrifugal	B.1. RWST Level Indicator: (PAMS) B.2. All valves required to be operated for the switchover sequence.	B.1. None B.2. Refer to Table 6.3.2-5.	B. The plant emergency operating procedures include instructions and verification steps to ensure proper manual realignment of the ECCS for recirculation by the operator. The failure to perform one step or the performance of one step out of order, as a single failure, should not reduce ECCS recirculation capability below minimum safeguards. Should the operator fail to take any action following automatic ECCS switchover initiation, the consequences will be the loss of the safety injection and charging pumps. The residual heat removal pumps will be

TABLE Q440.56-4 (Page 2)
LOSS OF COOLANT ACCIDENT

REQUIRED OPERATOR ACTION	ALARMS TO ALERT THE OPERATOR TO INITIATE A PARTICULAR ACTION	DELAY TIME ASSUMED	INSTRUCTIONS GIVEN TO THE OPERATOR FOR PERFORMING THE REQUIRED ACTION	COMPONENTS AND INSTRUMENTATION NECESSARY TO COMPLETE INDICATED ACTION	IMPACT OF SINGLE ACTIVE COMPONENT FAILURE	IMPACT OF THE OPERATOR'S FAILURE TO TAKE ACTION OR THE OPERATOR TAKING A CLOSELY RELATED BUT ERRONEOUS ACTION
			charging pump suction and the SI pump.			protected from damage by automatic ECCS switchover initiation. For small break LOCA in the unlikely event of losing all high head pump delivery capability this situation could lead to core uncovery and inadequate core cooling. This situation is addressed in WCAP-9691 as the loss of the Emergency Coolant Recirculation (ECR) function following a small break. LOCA Analyses have been performed for loss of high head safety injection for small LOCA which are presented in WCAP-9573. Inadequate Core Cooling procedures have been developed which would instruct the operator on the appropriate operator actions to be taken for this event.
			B.6. Open the valves in the discharge lines from the RHR heat exchangers to the suction of the centrifugal charging pumps and the SI pumps.			For large break LOCA the residual heat removal pump delivery to the RCS would be sufficient to provide adequate core cooling during recirculation.
			B.7. Close the isolation valve in the SI pump suction line from the RWST.			
			B.8. Close the two parallel isolation valves in the centrifugal charging pump suction line from the RWST.			

TABLE Q440.56-4 (Page 3)
LOSS OF COOLANT ACCIDENT

REQUIRED OPERATOR ACTION	ALARMS TO ALERT THE OPERATOR TO INITIATE A PARTICULAR ACTION	DELAY TIME ASSUMED	INSTRUCTIONS GIVEN TO THE OPERATOR FOR PERFORMING THE REQUIRED ACTION	COMPONENTS AND INSTRUMENTATION NECESSARY TO COMPLETE INDICATED ACTION	IMPACT OF SINGLE ACTIVE COMPONENT FAILURE	IMPACT OF THE OPERATOR'S FAILURE TO TAKE ACTION OR THE OPERATOR TAKING A CLOSELY RELATED BUT ERRONEOUS ACTION
C. At approximately 15 hours after the transient, the operator must manually switch over to the hot leg recirculation mode.	None Required	Long Term	C.1. Terminate RHR pump flow to the RCS cold legs and establish RHR pump flow to the RCS hot legs by: a) closing the RHR cold leg header isolation valves b) opening the two isolation valves in the RHR heat exchangers c) opening the RHR hot leg header isolation valve C.2. Terminate SI pump flow to the RCS cold legs and establish SI pump flow to the RCS hot legs by: a) stop SI pump no. 1 and close its corresponding cold leg crossover header isolation valve	Refer to Section 6.3	Refer to Table 6.3.2-5	

TABLE Q440.56-4 (Page 4)
LOSS OF COOLANT ACCIDENT

REQUIRED OPERATOR ACTION	ALARMS TO ALERT THE OPERATOR TO INITIATE A PARTICULAR ACTION	DELAY TIME ASSUMED	INSTRUCTIONS GIVEN TO THE OPERATOR FOR PERFORMING THE REQUIRED ACTION	COMPONENTS AND INSTRUMENTATION NECESSARY TO COMPLETE INDICATED ACTION	IMPACT OF SINGLE ACTIVE COMPONENT FAILURE	IMPACT OF THE OPERATOR'S FAILURE TO TAKE ACTION OR THE OPERATOR TAKING A CLOSELY RELATED BUT ERRONEOUS ACTION
			b) open its corresponding hot leg header isolation valve c) restart SI pump no. 1 d) stop SI pump No. 2 and close its corresponding cold leg crossover header isolation valve e) close the SI common cold leg header isolation valve f) open SI pump No. 2's hot leg header isolation valve g) restart SI pump No. 2			

Table Q440.59-1 (Page 1)

Plant Systems And Equipment Used For
Transient And Accident Analysis
Presented In Chapter 15

	Incident	Reactor Trip Functions	ESF Actuation Functions	Other Equipment	ESF Equipment
15.1	INCREASE IN HEAT REMOVED BY THE SECONDARY SYSTEM				
	Feedwater system malfunctions that result in an increase in feedwater flow	Lo-lo steam generator level	Feedwater isolation, main feedwater pump trip, and turbine on hi-hi steam generator level	Feedwater isolation valves	-
	Excessive increase in secondary steam flow	*Power range high flux (low)	-	-	-
	Inadvertent opening of a steam generator relief or safety valve	*SIS	Low pressurizer pressure, low compensated steam line pressure	Feedwater isolation valves, main steam isolation valves	Auxiliary Feedwater System, Safety Injection System
	Steam system piping failure	*SIS	Low compensated steam line pressure	Feedwater isolation valves, main steam isolation valves	Auxiliary Feedwater System, Safety Injection System UHI Accumulator

Table Q440.59-1 (Page 2)

Plant Systems And Equipment Used For
Transient And Accident Analysis
Presented In Chapter 15

	Incident	Reactor Trip Functions	ESF Actuation Functions	Other Equipment	ESF Equipment
15.2	DECREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM				
	Loss of external electrical load/ turbine trip	High pressurizer pressure	-	Steam generator and pressurizer safety valves	-
	Loss of non-emergency AC power to the station auxiliaries	Steam generator lo-lo level	Steam generator lo-lo level	Steam generator and pressurizer safety valves	Auxiliary Feedwater System
	Loss of normal feedwater flow	Steam generator lo-lo level	Steam generator lo-lo level	Steam generator and pressurizer safety valves	Auxiliary Feedwater System
	Feedwater System pipe break	Steam generator lo-lo level	Steam generator lo-lo water level, low compensated steam line pressure	Main steam isolation valves, feedwater isolation, steam generator and pressurizer safety valves	Auxiliary Feedwater System, Safety Injection System

Table Q440.59-1 (Page 3)

Plant Systems And Equipment Used For
Transient And Accident Analysis
Presented In Chapter 15

	Incident	Reactor Trip Functions	ESF Actuation Functions	Other Equipment	ESF Equipment
15.3	DECREASE IN REACTOR COOLANT SYSTEM FLOW RATE				
	Partial and complete loss of forced reactor coolant flow	Low flow, undervoltage	-	Steam generator safety valves	-
	Reactor coolant pump shaft seizure locked rotor	Low flow	-	Steam generator and pressurizer safety valves	-
15.4	REACTIVITY AND POWER DISTRIBUTION ANOMALIES				
	Uncontrolled rod cluster control assembly bank withdrawal from a subcritical or low power startup condition	Power range high flux (low)	-	-	-
	Uncontrolled rod cluster control assembly bank withdrawal at power	Power range high flux (high), Overtemperature ΔT	-	Steam generator and pressurizer safety valves	-

Table Q440.59-1 (Page 4)

Plant Systems And Equipment Used For
Transient And Accident Analysis
Presented In Chapter 15

	Incident	Reactor Trip Functions	ESF Actuation Functions	Other Equipment	ESF Equipment
	Rod cluster control assembly misalignment	Power range negative flux rate	-	-	-
	Startup of an inactive reactor coolant loop at an incorrect temperature	Low flow coincident with power range high flux exceeding 3-loop P-9 setpoint	-	-	-
	Chemical and volume Control System malfunction that results in a decrease in boron concentration in the reactor coolant	Overtemperature ΔT, power range high flux (low), manual	-	-	-
	Spectrum of rod cluster control assembly ejection accidents	Power range high flux	-	-	-
15.5	INCREAE IN REACTOR COOLANT INVENTORY				
	Inadvertent operation of the ECCS during power operation	Low pressurizer pressure	-	-	Safety Injection System

Table Q440.59-1 (Page 5)

Plant Systems And Equipment Used For
Transient And Accident Analysis
Presented In Chapter 15

	Incident	Reactor Trip Functions	ESF Actuation Functions	Other Equipment	ESF Equipment
15.6	DECREASE IN REACTOR COOLANT INVENTORY				
	Inadvertent opening of a pressurizer safety or relief valve	Pressurizer low pressure	-	-	-
	Steam generator tube failure		Pressurizer low pressure	Steam generator safety and/or relief valves, main steam isolation valves	Safety Injection System, Auxiliary Feedwater System, Essential Auxiliary Power System
	Loss of coolant accidents resulting from the spectrum of postulated piping breaks within the reactor coolant pressure boundary	Pressurizer low pressure	Pressurizer low pressure, containment high pressure	Steam generator safety and/or relief valves	Safety Injection System, Auxiliary Feedwater System, Containment Heat Removal System, Essential Auxiliary Power System

2) When a loss of a non-safety grade system initiates a transient by itself, it is not super imposed upon other transients unless there is a credible reason that one would cause the other.

The following non-safety grade systems and equipment are assumed operable in some analyses presented in Chapter 15.

1) Automatic rod control

2) Pressurizer pressure control (power operated relief valves and spray)

3) Main Feedwater System

AUTOMATIC ROD CONTROL

The Automatic Rod Control System is assumed to be operable in the following transient analysis:

15.1.3 Excessive increase in secondary steam flow.

15.4.3 Rod Cluster Control Assembly Misoperation

15.6.1 Inadvertent opening of a pressurizer safety or relief valve.

Analyses of the excessive increase in secondary steam flow transient are done with and without automatic rod control and are presented in Section 15.1.3. Both cases meet acceptance criteria.

For the dropped rod(s) case of Section 15.4.3 the automatic rod control system is assumed to be operable. Because of the power overshoot possibility associated with automatic control, it is conservative to assume its function for this accident.

For the inadvertent opening of a pressurizer safety or relief valve transient it is conservative to assume the automatic rod control system is operable. During this transient RCS pressure will be decreasing. Decreasing RCS pressure will cause the reactor power to decrease due to moderator density feedback. If the Automatic Rod Control System is operable it will function to maintain power and average coolant temperature, thus causing a more severe transient.

PRESSURIZER PRESSURE CONTROL
1 POWER OPERATED RELIEF VALVE & SPRAY

The Pressurizer Pressure Control System is assumed to be operable in the following transients:

15.2.3 Turbine trip

15.4.2 Uncontrolled rod cluster control assembly bank withdrawal at power

Analysis of the turbine trip event with and without pressurizer pressure control is presented in Section 15.2.3 of the FSAR. Both cases met acceptance criteria.

For the rod bank withdrawal transient it is conservative to assume pressurizer pressure control is operable. The limiting criteria for this transient is the DNB ratio. Maintaining RCS pressure low will result in lower DNB ratios.

MAIN FEEDWATER CONTROL SYSTEM

The Main Feedwater Control System is assumed to function during the following transient analyses:

15.1.1 Feedwater System malfunctions causing a reduction in feedwater temperature

15.1.2 Feedwater System malfunction causing an increase in feedwater flow

15.1.3 Excessive increase in secondary steam flow

15.1.5 Steam system piping failure

15.4.2 Uncontrolled rod cluster control assembly bank withdrawal at power

15.4.4 Startup of an inactive loop

15.5.1 Inadvertent operation of Emergency Core Cooling System during power operation

15.6.1 Inadvertent opening of a pressurizer safety or relief valve.

Loss of main feedwater flow is a Condition II occurrence by itself and is analyzed in Section 15.2.7. There is no credible reason for any of the Condition II events listed above to cause a loss of feedwater flow. Therefore, a loss of feedwater is not considered coincidently with those occurances listed above which are Condition II.

For the steamline break transient it is conservative to assume main feedwater is available. This maximizes the amount of steam generator inventory available to be blowdown and prolongs the transient.

440.63 (15.1.3) Section 15.1.3.2 states "Figures 15.1.3-5 through 15.1.3-8 illustrate the transient assuming the reactor is in the automatic control mode and no reactor trip signals occur." This statement is not consistent with the information in Figure 15.1.3-5 through 15.1.3-8 and Table 15.1.2-1 which indicate that reactor trip occurs. Explain this discrepancy and confirm that the transient response is within the acceptance criteria of Standard Review Plan Section 15.1.3.

Response:

See revised figures in Section 15.1.

440.64 (15.1.3) In Section 15.1.3.1 regarding an excessive increase in secondary system flow, you state "This accident could result from either an administrative violation, such as excessive loading by the operator,

440.73 (15.2.6) How was the natural circulation flow of the RCS determined? Describe the available data or data that you will obtain which will verify the conservatism of the analysis of the loss of nonemergency AC power accident.

Response:

Natural circulation flow used for the loss of non-emergency AC power transient presented in Section 15.2.6 was calculated by the LOFTRAN Code. LOFTRAN bases the calculation of natural circulation flow on frictional pressure losses, elevation (density) head and fluid momentum. Details of the methodology used by LOFTRAN are in Section 3.1 of the "LOFTRAN Code Description," which was transmitted to the NRC by Westinghouse letter NS-TMA-1802, dated May 26, 1978.

The natural circulation verification test is described in Table 14.2.12-2 (page 35).

440.74 (15.2.6, 15.2.7) Provide figures showing the DNBR versus time for the loss of non-emergency AC power and normal feedwater flow accidents and discuss the basis for assuming that no fuel or clad damage occurs.

Response:

See new Figures 15.2.6-4 and 15.2.7-4. The DNBR remains above the limit value thus no fuel damage will occur.

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Figure Q440.74-1

440.75 (15.2.6, 15.2.7) Table 15.2.3-1 indicates that the main feedwater flow stops at 10 seconds for the loss of AC power and normal feedwater flow transients. Provide the justification for credit taken for this feedwater flow.

Response:

The loss of AC power, loss of normal feedwater flow and the feedline rupture transients are analysed with the plant operating at a steady state condition for 10 seconds before the initiating events occur. The results for these transients are plotted on base 10 logarithmic time scales, therefore for plotting convenience the initiating events are assumed to occur at 10 seconds.

440.76 (15.2.8) Provide a plot of DNBR versus time for the feedwater system pipe break and discuss the extent of fuel damage.

Response:

See new Figures 15.2.8-5 and 15.2.8-10. The DNBR remains above the limit value, thus no fuel failures will occur.

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Figure Q440.76-1

(2) Train operators to take actions in the event of an anticipated transient without scram.

Response:

As discussed in Table 1.9-1, Item I.C.1, generic emergency procedures for ATWS have been developed by the Westinghouse Owners Group. These generic procedures have been used in developing the Catawba Emergency Procedures. Operators are trained on these Emergency Procedures.

440.99 (5.2.2, 5.4.7 5-A, 6.3) Catawba P&IDs are not sufficiently legible. Provide larger scale P&IDs (2 sets) such that flow paths discussed in Chapter 5.2.2, 5.4.7, Appendix 5 and 6.3 can each be followed by consulting one drawing for each flow function and configuration. Each functional flow path (e.g., ECCS, RHR, etc.) should be highlighted with bold lines to distinguish that path from ancillary paths.

Response:

The requested P&ID's were transmitted by letter of December 28, 1981 from W. O. Parker, Jr. to H. R. Denton.

440.100 (15.6.5) LOCA analysis results for Catawba presented in FSAR Section 15.6.5 indicate that the limiting break is a double ended cold leg guillotine (DECLG) rupture with Cd - 1.0. Previously reviewed UHI designs have identified DECLG ruptures with Cd - 0.6 as limiting. What is the reason for this difference?

Response:

The difference between the C_D = 1.0 DECLG and C_D = 0.6 DECLG results in calculated peak clad temperature (PCT) is only on the order of 50°F. The entire reason for performing LOCA cases for a spectrum of discharge coefficients is to identify for small changes in PCT such as this which particular discharge coefficient is indeed limiting.

440.101 (15.6.5) Since Catawba LOCA analyses identify a different limiting break (Cd = 1.0) than other UHI LOCA analyses do (Cd = 0.6), justify that LOCA sensitivity studies (worst type break, worst location, worst single failure, offsite power, etc.) for other analyses apply to

Response:

In the Catawba large break LOCA analysis a cold leg accumulator water volume of 1050 cubic feet per tank and a nitrogen gas pressure of 400 psia were assumed. The Catawba cold leg accumulator tank setpoints will be established to meet these requirements: a minimum possible tank water volume of 1088 cubic feet and a minimum gas pressure of 400 psia. The use of the 1050 cubic feet cold leg accumulator water volume and a gas pressure value of 400 psia in the Appendix K large break ECCS performance analysis corresponds with the analysis previously discussed and justified as appropriate in McGuire FSAR Question 212.105. The conclusion drawn therein that calculated peak clad temperature for a UHI plant DECLG perfect mixing case is unaffected by assuming maximum and minimum accumulator water delivery rate bounding conditions applies also to the Catawba limiting case (DECLG C_D = 1.0).

The blowdown transients for the limiting case breaks for the two plants are very similar in predicted accumulator performance and in bypass deficit behavior, so the impact of assuming bounding accumulator water delivery rates is virtually the same.

440.104 (5.4.7) (440.12) Your response to Question 440.12 is not acceptable. You state "the residual heat removal flow rate is throttled to about 1500 gpm through each of the residual heat removal loops." This implies both loops are operating, therefore, your postulated air entrainment event may preclude the continued use of both operating trains instead of one train. Accordingly, provide the information requested in Items 2 and 3 of Question 440.12. Describe your procedures for RHR operation when the steam generator tubes are drained.

The staff's position is that each train of the RHR will be provided with an alarm in the control room to alert the operator to RHR degradation. Provide your basis for the alarm setpoint.

Response:

Having both RHR trains in operation during Mode 5 activities, though not precluded, is unlikely. The heat load is such that one RHR loop can adequately provide all of the required cooling.

The Technical Specifications (Section 3/4.4.1.4) specifically address RCS loop drain operations and specify that both RHR trains be operable prior to draining the steam generators.

Alarms are provided in the control room to alert the operator should the unlikely situation of RHR degradation occur.

ND Pump Discharge to CCP (NI Pump) - Prevents flow of recirculation sump fluid to FWST, prevent possible overpressure of pipe during cooldown, permits alignment to supply NI & CC pumps only during recirculation.

Containment Sump Valve - The interlocks prevent the control room operator from opening the sump valves and flooding containment with fluid from the reactor coolant system or the FWST. The automatic features override the interlocks and open the valve if the FWST level is low and an "S" signal has been generated (this prevents the sump valve from opening and flooding containment during refueling as the FWST is emptied into the refueling cavity).

CCP Normal Suction - Isolates normal charging sources after FWST is available to pumps.

NC to ND Isolation Valves - Interlocks prevent flow from RCS to FWST, spill of RCS to containment sump, potentially overpressuring CCP and NI pump suction lines, spraying RCS to containment via residual spray headers. Pressure interlocks and automatic feature prevent overpressure of the ND pump suction line.

NI Pump Miniflow - Interlocks prevent recirculation sump fluid from being pumped to FWST.

NS Suction from FWST - Prevents spill of FWST fluid to containment sump via ND piping.

NS Suction from Sump - Prevents spill of FWST fluid to containment sump and prevents containment spray with reactor coolant.

Residual Containment Spray - Prevents residual containment spray with reactor coolant.

440.109
(6.3 & 15.0)
(440.29)

The response to Question 440.30 is incomplete. Feedwater pipe breaks should also be discussed. For each type of pipe break in the primary and secondary systems, provide the information requested in Question 440.30. Time response for operation reaction (credit only given from time of receipt of control room alarm from safety grade instrumentation) should be discussed, and may be based on ANSI N660 criteria when determining accident consequences. The accident description and discussions of consequences should take into consideration the available mitigating equipment as a function of pressure.

Response:

If the feedline rupture is large enough a safety injection may occur due to high containment pressure. Note that no credit is taken for this actuation in the analysis presented in Section 15.2.8.

If a smaller feedline rupture occurs while the other two automatic SI actuation signals are blocked, a low-steam generator water level alarm will be generated followed by a low-low steam generator water level signal. Auxiliary feedwater flow is initiated on receipt of low-low steam generator

The response to Question 440.36 states "miniflow recirculation paths are also provided for the charging pumps. These paths are isolated upon receipt of an "S" signal. The pump deadheading problem is a valid concern for the charging pumps as operating these pumps at or above their shutoff head would lead to failure of the pumps due to overheating. Analyses have been performed to show that adequate core cooling is provided by flow from the safety injection and residual heat removal pump."

Identify those conditions that would lead to failure of the charging pumps. Include the postulated case of a small break in which the RCS pressure remains at or near the RCS safety valve setpoint. Describe the analysis that was performed to show that adequate core cooling is provided by the safety injection and residual heat removal pumps. Show that the Chapter 15 analysis has accounted for the potential failure of the charging pumps.

Response:

The secenario leading to deadheading of the charging pumps was described in extended detail in a Westinghouse letter to the Commission:

T. M. Anderson, letter to V. Stello, subject: "Centrifugal Charging Pump Operation Following Secondary Side High Energy Line Rupture," dated May 8, 1980.

In order to prevent this scenario the charging pumps minimum flow isolation valves no longer close on an "S" signal. The minimum flow path can be isolated by the control room operator when it is certain that reactor coolant pressure is low enough to ensure pump minimum flow requirements. See the revised response to Question 440.36.

440.111
(15.0)
(440.37)

Your response to Question 440.37 is not adequate. You state "In addition, the head of water provided by the RWST further ensures the lines will remain full and water hammer concerns will not develop." This does not appear to be correct. For example, the charging pump subsystem is not aligned to the RWST during the ECCS standby condition. A small leak in this subsystem could void the charging lines. Describe the means for ensuring water hammer will not occur in the charging pump lines including specific Technical Specifications testing requirements and frequency of tests.

Response:

The ECCS lines which incorporate the charging pumps consist of:

1. RWST to charging pump suction isolation valves 1NV252A and 1NV253B -

The water head in the RWST precludes voiding in these lines due to a small leak.

2. Suction isolation valves to common suction line check valve 1NV254 -

Response:

The only valves that have power removed from their operator at a location outside the control room during normal operation and are repositioned to achieve a cold shutdown are the cold leg accumulator isolation valves.

These valves are active, ASME Section III Class 2, electric motor operated gate valves located inside containment. In order to preclude mispositioning these valves during unit operation, power is removed from these valves at the motor breakers in a readily accessible area of the Auxiliary Building. These valves are closed before the RCS pressure is reduced below the accumulator pressure as the plant is cooled from hot standby to cold shutdown. It is felt that the operator will have sufficient time before the need to achieve cold shutdown to reach the breaker locations, restore power, close the valves, and remove power. However, cold shutdown (i.e., RCS $\leq$ 200°F) can be achieved without closing the accumulator isolation valves. This would result in additional fluid that would require processing in the Boron Recycle System but no nitrogen would be injected into the RCS as long as pressure remained above approximately 155 psia.

440.135 (5.4.7) RSB 5-1 requires that Class 2 Plants "provide safety-grade dump valves, operators, and power supply, etc., so that manual action should not be required after SSE except to meet single failure." Discuss Catawba compliance with this position.

Response:

See Section 10.3.2 describing the provisions made for compliance with RSB 5-1.

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440.139
(6.3)
(440.26)

The response to Q440.26 addressed degradation of the ECCS by sump debris. It discussed types of insulation used at Catawba inside containment. We require a commitment to provide a survey quantifying the insulation by type and location prior to startup following the first refueling.

Response:

The survey will be provided as requested.

440.140
(6.3)
(440.26)
(440.104)

The response to Q440.26 did not identify alarms which would alert the operator to ECCS degradation (the response to Q440.104 mentioned alarms to alert the operator to RHR degradation, but did not identify what they were). We require that a control room alarm (audible/visual) be provided to alert the operator to ECCS degradation.

Response:

Refer to the response to Q440.133.

440.141
(6.3)
(440.106)
(440.108)

The responses to Q440.106 and 440.108 describe power removal and interlocks to prevent spurious mispositioning of valves. Identify and justify any actions outside the control room which the operator must take in a post-accident or normal cold shutdown scenario. Our position is that such actions should be performed from the control room.

Response:

The response for actions taken in the normal cold shutdown scenario is presented in response to Q440.134.

In order for the operator to switch from cold leg recirculation to hot leg recirculation there are six valves which require power be reestablished before they can be repositioned. These valves are 1NI178B, 1NI173A, 1NI152B, 1NI162A, 1NI121A, and 1NI183B. Power is removed from the operators of the last four valves at the motor breakers in a readily accessible area of the Auxiliary Building. Since these valves will not require repositioning until approximately 15 hours after the start of the accident, it is felt that the operator will have sufficient time to perform this task before the need to align for hot leg recirculation.

Valves 1NI173A and 1NI178B could require repositioning as early as one hour after the start of the accident if residual containment spray is required. For this reason, power removal/restoration capability for these valves will be added to the main control room after first refueling.

440.142 (6.3) (440.110) It is our position that the removal of automatic isolation of mini-flow to protect charging pumps from deadheading is unacceptable as a long term design and Catawba must commit to provide a plan to improve its design with automatic features.

Response:

Duke has provided the NRC with the Westinghouse generic analysis which concludes that non-automatic isolation of the mini-flow line is acceptable. It found that negligible flow degradation resulted provided the line is isolated in accordance with the emergency operating procedures. This analysis was transmitted in H. B. Tucker's letter of 10/26/83 to H. R. Denton.

440.143 (6.3) (440.34) Question 440.34 cited the SRP 6.3 "20 minutes operator response" time requirement. The response did not address the question. Provide a timetable, with time versus event (LOCA occurrance, low level setpoint reached, various operator actions, etc.) versus gallons remaining in the RWST, and justify that operator action is not required within 20 minutes (with limiting single failure) to avoid unacceptable consequences (i.e., inadequate long term cooling).

Response:

SRP 6.3 indicates that where manual actions are used that a sufficient time is available for the operator to respond. The operators do not require twenty minutes to respond. As stated in Section 9.2.7, ten minutes or more are sufficient for the operator to properly assess the situation. The response to Q440.42 stated that a minimum of 11 minutes are available before the LOW level alarm is reached and the operator begins the switchover procedure assuming the worst case instrument errors, large break LOCA, etc.

The switchover procedure and RWST level setpoints provide a consistent and conservative basis to account for all relevant factors of RWST sizing. Appropriate emphasis is placed on the timely completion of manual actions of the switchover procedure. This fully meets the intent of SRP 6.3 to provide sufficient time for operator response.

(440.129) vessel the downcomer would be relatively smaller than for most UHI plants. Justify that Catawba is not "imperfect mixing" limited as is the other "small downcomer" UHI plant.

Response:

Three additional DECLG break cases have been analyzed (C_D = 0.8, 0.6 and 0.4) assuming that imperfect mixing of UHI water occurs in the reactor vessel upper head; the results obtained are summarized in Table 15.6.5-3 and 15.6.5-5. The previously identified limiting break (C_D = 1.0 DECLG, perfect mixing) for Catawba, which produced a calculated peak clad temperature of 2155°F, remains the limiting case.

440.148 Question deleted - Issue Resolved in FSAR, Revision 6.

440.149 (15.6.3) (440.127) Table 440.3-3 and the response to Q440.56 indicate that credit has been taken for non-safety grade equipment, without applying single failure, and without loss of offsite power in the analysis of steam generator tube rupture. Provide an analysis for this event with loss of offsite power, applying single failure, and taking credit only for safety grade systems and instrumentation in the mitigation of the event.

Response:

The non-safety grade equipment referred to above were the Pressurizer PORV's and the Steam Generator PORV's. Two of the Unit 2 Pressurizer PORV's and their actuating systems have been upgraded to safety grade. They can be positioned from the control room by independent safety grade controls. Similar modifications will be implemented on Unit 1 to upgrade two of the Pressurizer PORV's and their actuating systems to safety grade during the first refueling.

All four of the Unit 2 Steam Generator PORV's including their actuating systems have been upgraded to safety grade. They can be positioned from the control room by independent safety grade controls. Similar modifications will be implemented on Unit 1 to upgrade all four of the Steam Generator PORV's and their actuating systems to safety grade during the first refueling. (See Section 10.3 for a more complete description of the Steam Generator PORV capabilities.)

440.150 (5.4.12) (440.T.7) The response to Q440.T.7 identifies the pressurizer PORVs as RCS vents per NUREG-0737, item II.B.1. Show that these "vents" are appropriately qualified.

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Response:

The pressurizer power operated relief valves (PORV's) can be used to vent the pressurizer; however, pressurizer venting has been found by analysis (Byron, Q212.159) not to be required.

(c) Submit (or reference) Operating Guidelines for use of the RCS Vent System. The guidelines shall include:

1. Methods for the operator to determine when to initiate and terminate venting, and the instrumentation needed for this determination. The guidelines should cover a wide variety of initial conditions and should consider the balance between the need for increased core cooling versus the decreased containment integrity due to increased hydrogen concentrations.

2. Detailed methods for determining the size and location of a noncondensible gas bubble.

3. Methods which may be used to vent the steam generator U-tubes.

(d) Describe the equipment used to vent the pressurizer and verify that this equipment meets the clarification requirements of NUREG-0737 Item II.B.1.

(e) What type of valve and operator is used in the head vent system? If these valves fail in position, describe how irreversible vent operation can be prevented.

Response:

(a) See Figure Q440.T.7-1

(b) 1. Design Pressure - 2500 psia
Design Temperature - 650°F

2. Piping, valves, components and supports are classified Seismic Category I and Safety Class 1 up to and including the second normally closed valve; Safety Class 2 up to and including the flow-restricting orifice.

(c) The Westinghouse Owners Group has prepared "Emergency Response Guidelines (ERG's)" in response to NUREG-0737, Item I.C.1 which were submitted for NRC review (Letter OG-61 dated July 7, 1981, R. W. Jurgensen (Chairman, Westinghouse Owners Group) to Stephen H. Hanauer (NRC)). The ERG's provide criteria for use of the RCS Vent System. The ERG's were used in developing the Catawba Emergency Procedures.

(d) The power-operated relief valves (PORV's) are used to vent the pressurizer; PORV's meet the clarification requirements of NUREG-0737, II.B.1.

(e) Head vent isolation valves are Kerotest Y-body globe valves with electric motor operators. Valves NC252B and NC253A are

471.16 This information was previously requested by Q331.3 (submitted to DL on 5/14/79). Recently, potential access and shielding problems have been noted at other ice condenser type plants. Provide additional detailed information regarding spent fuel transfer tube shielding and access controls as outlined in Regulatory Guide 1.70 (Sections 12.3.1 and 12.3.2). Provide diagrams and information which details how all portions of the Catawba 1 & 2 fuel transfer tube shielding and administrative and operational controls meet the following branch positions:

Control of Access to Spent Fuel Transfer Areas

All accessible portions of the spent fuel transfer tube and/or canal must be shielded during fuel transfer. Use of removable shielding for this purpose is acceptable. This shielding shall be such that the resultant contact radiation levels shall be no greater than 100 rads per hour. All accessible portions of the spent fuel transfer tube shall be clearly marked with a sign stating that potentially lethal radiation fields are possible during fuel transfer. If removable shielding is used for the fuel transfer tubes, it must also be explicitly marked as above. If other than permanent shielding is used, local audible and visible alarming radiation monitors must be installed to alert personnel if temporary fuel transfer tube shielding is removed during fuel transfer operations.

Response:

See Section 12.3.2.2.

471.17 The individual selected for the position of Station Health Physicist does not appear to meet the education, experience, or training criteria outlined in Regulatory Guide 1.8 or the alternative Duke positions outlined in Section 13.1.3 of the FSAR. In order for the staff to evaluate Duke's alternate selection of a "qualified" individual in

Residual containment spray operation is initiated manually when required by the operator and only if the following two criteria are met:

1. Emergency Core Cooling System and Containment Spray System are operating in the recirculation mode.

2. At least fifty minutes have passed since the initiation of the Safety Injection signal.

The Residual Spray may be required due to high containment pressure. High containment pressure would be indicated to the operator via safety-related redundant pressure indication in the control room. See Section 7.5 for description of safety-related display instrumentation.

It is not intended that RHR spray be limited to a maximum value of 1575 gpm. Therefore, no flow control elements are required to adjust to a particular flowrate.

480.16 (6.2.3) Identify all secondary containment openings such as personnel access doors and equipment hatches. Discuss the administrative control to be exercised over these openings.

Response:

Access to the annulus is under the control of the Station Operations Department. Both upper and lower doors to the annulus are kept locked and the keys are under the control of the shift supervisor. If an authorized individual must gain entry to the annulus he or she obtains the key from the shift supervisor and is "logged" in. Anytime someone is inside the annulus another person is placed at the annulus door to prevent unauthorized entry of other individuals. Station Directive 3.1.2 is the procedural document that establishes the above controls.

Also, in accordance with 10 CFR Part 50.34, paragraph c and d; 10 CFR Parts 73.46, 73.50, and 73.55 paragraph (d) 8 and as committed to in the Catawba Nuclear Station Security Plan, the upper and lower annulus doors will be locked and maintained under security card key access control. Door position indication and annunciation of door alarms is provided for in the Central and Secondary Alarm Stations.

480.17 (6.2.4) For each containment penetration, specify whether the line is essential or nonessential, in accordance with the provisions of NUREG-0737, "Clarification of TMI Action Plan Requirements," II.E.4.2, Containment Isolation Dependability.

Table Q492.7-2

MEASUREMENTS REQUIRED

	Parameter	Instrument	Function
1.	Feedwater venturi pressure differential	Rosemount ΔP guage and compatible readout	feedwater flow
2.	Feedwater temperature	Continuous lead thermocouple	feedwater enthalpy and density
			venturi thermal expansion
3.	Steam pressure	Transducer and process computer readout	steam enthalpy
4.	Reactor coolant T_{hot}	Narrow range RTD and data acquisition system or DVM readout	RCS hot leg enthalpy
5.	Reactor coolant T_{cold}	Narrow range RTD and data acquisition system or DVM readout	RCS cold leg enthalpy RCS specific volume
6.	Reactor coolant pressure	Transducer and process computer readout	RCS enthalpy and specific volume

Other information required for the calculation is as follows:

7. Feedwater venturi coefficient from vendor calibration.
8. Primary system heat losses and pump heat input obtained from calculations.

Table Q492.7-3 (Page 1)

CALORIMETRIC FLOW MEASUREMENT UNCERTAINTIES

Component	Instrument Error	Uncertainty % Power or % Flow
Secondary Power		
Feedwater Flow		
Venturi K	± 0.25% K	± 0.25%
Thermal Expansion coefficient		
Temperature	± 2.0°F	
Material	± 5.0%	± 0.06%
Density		
Temperature	± 2.0°F	± 0.09%
Pressure	± 60 psi	
DP Cell Calibration	± 0.25% of RDG	± 0.13%
DP Cell Precision Error	± 0.50%	± 0.25%
Tempering Aux. Feedwater Flow Error	± 5.0% x 0.011%/%	±0.06%
Blowdown Flow Error	± 10% x 0.017%/%	±0.17%
Feedwater Enthalpy		
Temperature	± 2.0°F	± 0.28%
Pressure	± 60 psi	
Steam Enthalpy		
Pressure	± 40 psi	± 0.15%
Moisture Carryover	± 0.25%	± 0.22%
Total Secondary Thermal Power Uncertainty	$\sqrt{\Sigma(e)^2}$	± 0.58%
Primary Enthalpy		
T_H RTD	± 1.2°F	± 2.27%
T_H Data Acquisition System or equivalent DMM	± 0.5°F	± 0.95%
T_H Readout	± 0.1°F	± 0.19%
T_H Temperature Streaming	± 1.2°F	± 2.27%
T_H Pressure Effect	± 30 psi	± 0.24%
T_C RTD	± 1.2°F	± 1.87%
T_C Data Acquisition System or equivalent DMM	± 0.5°F	± 0.79%
T_C Precision Error	± 0.1°F	± 0.16%
T_C Pressure Effect	± 30 psi	± 0.06%
Net Pump Heat Addition	± 20%	± 0.085%
Total Loop Flow Uncertainty	$\sqrt{\Sigma(e)^2}$	± 3.98%
Total Reactor Flow Uncertainty 4-loop		± 1.99%

ASSUMPTIONS

The values on page 1 are based on some specific assumptions about the instruments and readouts.

1. Feedwater flow is obtained from several readings of Rosemount differential pressure gauges installed on the feewater venturi.

2. Credit was taken for the 3 tap scoop RTD bypass loop in reducing uncertainties due to streaming.