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June 25, 1984

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

Attention: Ms. E. G. Adensam, Chief
Licensing Branch No. 4

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

Dear Mr. Denton:

On or about June 27, 1984, Duke Power Company will file Revision 11 to the Catawba FSAR. This revision will include changes that resulted from a recent meeting with the Staff on preoperational testing and Technical Specifications. In addition to miscellaneous updates, Revision 11 will also include:

1 - Response to SER Confirmatory Item 17 (Section 3.6.2.4.3 and Table 6.2.4-1)

2 - Updated resumés for plant personnel (Table 13.1.3-1)

3 - Previously submitted revisions to preoperational testing (Section 14.2), Annulus Ventilation System (Sections 6.2, 9.4, 15.0, 15.4 and 15.6), Boron Dilution Analysis (Section 15.4.6) and Post-Accident Sampling (Question 281.9)

4 - Updated system descriptions

a) ECCS (Section 6.3)

b) Nuclear Service Water (Section 9.2.1)

c) Component Cooling (Section 9.2.2)

d) Nuclear Sampling System (Section 9.3.2.2.1)

e) Chemical and Volume Control (Section 9.3.4)

f) Control Area Ventilation (Section 9.4.1)

g) Containment Purge Ventilation (Section 9.4.5)

h) Condensate and Feedwater (Section 10.4.7)

i) Steam Generator Blowdown (Section 10.4.8)

j) Auxiliary Feedwater (Section 10.4.9)

APERTURE CARD DISTRIBUTION
DRAWINGS TO C. FILES

B001
1/1

The attached revised FSAR pages are being transmitted prior to the filing of the formal amendment in order to allow the Staff additional time for review.

Very truly yours,

Hal B. Tucker ew

Hal B. Tucker

ROS/php

Attachment

cc: (w/o attachment)
Mr. James P. O'Reilly, Regional Administrator
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1.7 DRAWINGS AND OTHER DETAILED INFORMATION

1.7.1 ELECTRICAL INSTRUMENTATION AND CONTROL DRAWINGS

All safety related electrical instrumentation and control drawings for the Catawba Nuclear Station are listed in Table 1.7.1-1. These drawings are provided under separate cover in the Catawba Electrical Schematics books.

These drawings are submitted for initial review of the FSAR and have not been updated to reflect subsequent changes in plant design.

Q 430.8 Figure 1.7.1-1 provides the symbols used in the electrical instrumentation and control drawings.

1.7.2 PIPING AND INSTRUMENTATION DIAGRAMS

Two large-scale copies of each piping and instrumentation diagram included in the Catawba FSAR have been provided to the NRC. Table 1.7.2-1 lists each diagram and provides a cross-reference between the drawing number and the FSAR figure number.

Figures 1.7.2-1 through 1.7.2-3 provide the symbols and abbreviations used in the piping and instrumentation diagrams.

Table 1.8-1 (Page 11)
Regulatory Guides

1.0 General

All austenitic stainless steel welding shall conform to the fabrication requirements of the contractual American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section III, and to the Duke Power Company Quality Assurance Program. All new welding procedures and welding procedure qualifications shall conform to the requirements of the latest edition of the ASME, Boiler and Pressure Vessel Code, Section IX. Requirements other than those stated herein shall not be considered mandatory.

2.0 Welding Filler Material

2.1 All bare welding filler material, including consumable inserts, shall meet the requirements of ASME/SFA 5.9 including applicable addendum and shall contain delta ferrite content of 5 to 20%.

All coated products and submerged arc electrodes shall meet the applicable ASME/SFA requirements and shall contain delta ferrite content of 5 to 20%. Delta ferrite determinations for SFA 5.4 type 16-8-2 weld metal or for filler metal used for weld metal cladding are not required.

2.2 Each heat and lot of filler material shall be verified for delta ferrite content. Delta ferrite determinations for consumable inserts, electrodes, rod or wire filler metal used with the gas tungsten arc welding process, and deposits made with the plasma arc welding process shall be predicted from their chemical composition using an applicable constitutional diagram to demonstrate compliance. Delta ferrite determination shall be made for all other processes using an applicable constitutional diagram with the weld metal chemical composition taken from an undiluted weld deposit. For the submerged arc welding process, a ferrite determination shall be made for each electrode and flux combination. The delta ferrite content of the weld deposit pad shall be in the range of 5 to 20%.

2.3 A certified chemical test report shall accompany each Heat or Lot of material and shall be verified to meet the above requirements prior to issuance of the material for welding. This documentation shall be retained at the job site.

3.0 Traceability

3.1 For ASME Section III Class 1, 2, and 3 welds; each Lot and Heat of filler material shall be readily identifiable and traceable to the specific joint for which it was used, by actual field documentation.

4.0 Welding Procedure

Specific welding procedures shall be identified for each joint to be welded. The interpass temperature shall be restricted to 350°F maximum to control sensitization.

5.0 Inspection Welds

5.1 All welds shall be visually inspected for cracks and other unacceptable defects.

5.2 All ASME Section III Class 1 circumferential butt welds (excluding welds 1 inch NPS and less) shall be inspected by radiography and the liquid penetrant method. All ASME Section III Class 2 circumferential butt welds (greater than 1 inch NPS) shall be inspected by radiography. All ASME Section III Class 3 circumferential butt welds (greater than 4 inches NPS) shall be inspected by the liquid penetrant method. All nondestructive examinations shall be performed in the manner required by the ASME Code. Microfissuring of the magnitude considered to be detrimental to the structural integrity of weldments will be within the sensitivity levels of the NDE methods employed, and shall be rejected and treated as similar types of defects in accordance with the ASME Code's acceptance criteria.

5.3 Other "in process" weld inspections shall be performed (such as verification of welding procedure parameters, welder qualification, joint identification, etc.) in accordance with ASME Section III and Section IX Code requirements and additional requirements of the Duke Power Company Construction Department Quality Assurance Procedures.

Regulatory Guide 1.32

Criteria for Safety-Related Electric Power Systems from Nuclear Power Plants (Safety Guide 32, 8/72).

Discussion

The design of the Class 1E onsite power systems complies with the recommendations of Regulatory Guide 1.32 as discussed in Section 8.3.1.2.5 and 8.3.2.2.4.

Regulatory Guide 1.33

Quality Assurance Program Requirements (Operation) (Revision 2, 2/78).

Discussion

The quality assurance program for Catawba complies with the requirements of Regulatory Guide 1.33 as discussed in Section 13.5.1.1 and Chapter 17.

their correct position. These procedures require verification of the operability of a redundant system prior to the removal of any safety-related system from service, verification of the operability of all safety-related systems when they are returned to service, and notification of and action by the Shift Supervisor and reactor operators whenever any safety-related system is removed from or returned to service. Formal checklists are used to provide assurance that all valves in these safety-related systems are properly aligned. These procedures also require independent verification of proper valve alignment and source of power to those valves that are important to safety in safety-related systems.

A removal and restoration procedure governs the repositioning of valves in safety-related systems following maintenance activities or other non-normal activities which require valve movement. A formal checklist provides assurance that the repositioned safety-related valves are properly aligned following these activities. This procedure also requires independent verification of proper valve alignment and source of power to those valves that are important to safety in safety-related systems.

Notification of and action by the Shift Supervisor and reactor operators whenever any safety-related system is removed from or returned to service is accomplished by the use of red tags and the red tag logbook, white tags and the white tag logbook, out of service stickers, and the 1.47 bypass panel. Log entries denoting the removal and restoration are made in the Reactor Operator's Log. All of the above documents are reviewed during shift turnovers as required by the turnover procedure.

I.C.7 NSSS VENDOR REVIEW OF PROCEDURES

See Sections 13.5 and 14.2.3.2.

I.C.8 PILOT MONITORING OF SELECTED EMERGENCY PROCEDURES FOR NEAR-TERM OPERATING LICENSE APPLICANTS

Station emergency procedures will be available for review by the NRC as described in Section 13.5.

I.D.1 CONTROL ROOM DESIGN

A description and results of the control room review were provided in the document "Response to Supplement 1 to NUREG-0737" which was submitted on April 14, 1983 by letter from H. B. Tucker to H. R. Denton.

I.G.1 TRAINING DURING LOW-POWER TESTING

See Table 14.2.12-2, Natural Circulation Verification Test abstract.

Response to TMI Concerns

The Catawba Work Request Program governs all maintenance activities performed at Catawba. These work requests describe the maintenance to be performed and the procedures for performing it. Upon completion of the maintenance all work requests are entered into the corporate computer. This program provides for portable historical records of all maintenance performed on safety-related systems.

C.1.17

The design of Catawba Nuclear Station does not feature safety injection initiation on coincident pressurizer level and pressure signals. Safety injection is initiated whenever the low pressurizer pressure trip setpoint is reached independent of pressurizer level (See Section 7.3).

II.K.2 COMMISSION ORDERS ON B&W PLANTS

II.K.2.13 THERMAL MECHANICAL REPORT - EFFECT OF HIGH-PRESSURE INJECTION ON VESSEL INTEGRITY FOR SMALL-BREAK LOSS-OF-COOLANT ACCIDENT WITH NO AUXILIARY FEEDWATER

Q 440.T.8

WCAP-10019 which addresses the NRC requirements of detailed analysis of the thermal-mechanical conditions in the reactor vessel during recovery from small breaks with an extended loss of all feedwater was submitted to the NRC on December 30, 1981 (OG-66). This WCAP was developed under the sponsorship of the Westinghouse Owners Group (WOG). On March 23, 1982 WOG letter OG-68 was submitted to the NRC which described the additional effort underway to resolve NRC comments and questions concerning WCAP-10019. Results of the program to date show that operating plants can withstand the limiting transients for the expected life of their vessels. Since WCAP-10019 only addresses operating plants, an additional effort is underway to address NTOL plants.

II.K.2.17 POTENTIAL FOR VOIDING IN THE REACTOR COOLANT SYSTEM DURING TRANSIENTS

Q 440.T.2

Westinghouse (in support of the Westinghouse Owners Group) has performed a study which addresses the potential for void formation in Westinghouse designed nuclear steam supply systems during natural circulation cooldown/depressurization transients. This study has been submitted to the NRC by the Westinghouse Owners Group (Letter OG-57, dated April 20, 1981, R. W. Jurgensen (Chairman, Westinghouse Owners Group) to P.S. Check (NRC)) and is applicable to Catawba Nuclear Station.

In addition, the Westinghouse Owners Group has developed a natural circulation cooldown guideline that takes the results of the study into account so as to preclude void formation in the upper head region during natural circulation cooldown/depressurization transients, and specifies those conditions under which upper head voiding may occur. These Westinghouse Owners Group generic guidelines have been submitted to the NRC (Letter OG-64, dated November 30, 1981, R. W. Jurgensen (Chairman, Westinghouse Owners Group) to D. G. Eisenhut (NRC)). The generic guidance developed by the Westinghouse Owners Group (augmented as appropriate with plant specific considerations) will be utilized in the implementation of Catawba plant specific operating procedures.

Reactor Vessel Level Instrumentation System

5. ESE-50C RVLIS-86 Microprocessor
6. ESE-53 Plant Safety Monitoring System Electronics

REFERENCE ITEM L IMPLEMENTATION SCHEDULE

The RVLIS will be installed prior to fuel load. It will become fully operational after Phase II work is completed by Westinghouse. This will be before initial criticality. The Phase II work (i.e., final calibration) cannot be performed without actual flow data being taken with pumps running and full core in place.

REFERENCE ITEM M ICC OPERATING PROCEDURES

Duke Power plans to upgrade the Catawba emergency operating procedures based upon the Emergency Response Guidelines (ERG) developed by the Westinghouse Owners Group. The RVLIS will be incorporated into procedures according to these guidelines.

LIST OF TABLES

2.1.3 POPULATION DISTRIBUTION

Population within 50 mi (80.4 km) of Catawba is based on the 1970 census. Population distributions for 1980, 1981 (initial expected year of plant startup), and by decade to 2020 are based on projections made by the United States Department of Commerce, Bureau of Economic Analysis (Reference 1 and 2). Though 2021 is the year of expected end of plant life, the year 2020 is used for end of plant life population distribution.

The disaggregation of the 1970 census county subdivisions into each radial sector is based on road densities, population accumulations, land usage, and general area information. The population distribution within 5 mi (8 km) of the site is based on an actual house count performed in 1971. The distribution of the projected populations is based on the ratio of the distributed 1970 populations within each radial sector to the total county population. An additional house count within 5 mi (8 km) of the site made in December 1977, is used to establish an adjusted distribution within Mecklenburg County, North Carolina and York County, South Carolina. The December 1977 population within 5 miles (8 km) is shown on Table 2.1.3.-1.

2.1.3.1 Population Within 10 Miles

Figure 2.1.3-1 identifies places of significant population groupings within 10 mi (16.1 km) of the station. Table 2.1.3-2 gives 1970 population distribution within ten miles. Projected population distributions by census decade (1980 through 2020) and for 1981 are shown on Tables 2.1.3-3 through 2.1.3-8.

2.1.3.2 Population Between 10 and 50 Miles

Places of significant population groupings in the area from 10 mi (16.1 km) to 50 mi (80.5 km) of the station are shown on Figure 2.1.3-2. Tables 2.1.3-9 through 2.1.3-15 detail the 1970 and projected population distributions.

2.1.3.3 Transient Population

Transient population within 5 mi (8 km) of Catawba Nuclear Station is primarily recreational on and along the shores of Lake Wylie. Industrial facilities in the northeastern quadrant and in the southeastern quadrant are the major sources of transient population between 5 and 10 mi (8 to 16.1 km). Carowinds Theme Park, located approximately 8 mi (12.8 km) to the east-northeast, is the largest recreational area within 50 mi (80.5 km) of the site. Carowinds expected attendance in 1978 is 1,150,000 with a daily average attendance of 11,058. The projected increase in attendance to the year 2020 is insignificant (Reference 3).

Tables 2.1.3-16 and 2.1.3-17 show 1977 seasonal and average daily recreational transient population distribution within 10 mi (16.1 km) of the station. Table 2.1.3-18 shows the daily industrial transient population distribution within 10 mi (16.1 km) of the site.

No large industries or businesses to provide job opportunities are located within 5 mi (8 km) of the site. A reduction of daily population in the vicinity of the station due to workers commuting to population centers where job opportunities exist is expected.

2.1.3.4 Low Population Zone

The nearest boundary of Rock Hill, the closest population center, is located 5.8 miles (9.3 km) south-southeast of the site.

Due to the relatively low population density in the vicinity of the site and the size of Rock Hill, the Low Population Zone is an area extending from the Reactor Building's centerlines to a radius of 20,000 feet (6096 m). The Low Population Zone distance is well within the limits of Section 100.11(a) of 10 CFR Part 100.

Figures 2.1.3-3 and 2.1.3-4 show the topographic features and the transportation routes and facilities, including all industries and institutions within the Low Population Zone and to a distance of 5 mi (8 km). There are no prisons or hospitals within 5 mi (8 km) of the station.

Current and projected permanent population distributions by sector and 1 mi (1.6 km) radii to 5 mi (8 km) are shown on Tables 2.1.3-1 through 2.1.3-8. The seasonal recreational transient population and daily industrial transient population for each sector to 5 miles (8 km) are shown on Tables 2.1.3-16 and 2.1.3-18 respectively. The peak daily transient population distribution within 5 mi (8 km) of the site is shown on Table 2.1.3-19.

The annual, seasonal, and peak day attendance, and location of recreational areas and facilities within 5 mi (8 km) are shown on Table 2.1.3-20. The daily attendance and location of the two schools and two industries within 5 mi (8 km) of the site are listed on Table 2.1.3-21.

2.1.3.5 Population Center

The nearest population center, as defined in 10 CFR Part 100 is Rock Hill, South Carolina with a 1970 population of 33,846 and a population density of approximately 2380 people per square mile. The city of Rock Hill dominates the 5 to 10 mile south-southeast sector. The 1970 population density for the 5 to 10 mile south-southeast sector is 2087 people per square mile. There are no population groupings, including transient population, nearer the site having population distributions or densities higher than those in the 5 to 10 mile south-southeast sector. Of the adjacent 4 to 5 mile sectors, the south-southeast sector has the highest population density with 265 people per square mile. Therefore, the political boundary of Rock Hill, 5.8 mi (9.3 km) south-southeast of the Reactor Building's centerlines, is the nearest population center. Figure 2.1.3-5 shows population centers within 100 miles of the site.

2.1.3.6 Population Density

Figure 2.1.3-6 compares the cumulative projected population distributions within 50 mi (80.5 km) for the year of initial expected plant startup (1981) with a constant population density of 500 people per square mile. Figure 2.1.3-7 is a comparison of the cumulative projected population distribution within 50 mi (80.5 km) for the year 2020 (end of plant life is 2021) with a constant population density of 1000 people per square mile.

Table 2.1.3-4
1981 Projected Population Distribution
(Initial Expected Year of Plant Start-up)
0-10 Miles (0-16.1 km)

SECTOR	0-1 MILE	1-2 MILES	2-3 MILES	3-4 MILES	4-5 MILES	5-10 MILES	TOTAL
N	4	56	55	912	420	277	1,724
NNE	6	42	200	427	302	898	1,875
NE	0	51	66	103	125	3,950	4,295
ENE	3	55	27	112	173	880	1,250
E	3	27	17	114	333	527	1,021
ESE	23	106	921	817	119	6,430	8,416
SE	0	34	271	751	416	6,865	8,337
SSE	3	31	303	414	717	31,383	32,851
S	20	30	111	303	405	2,830	3,699
SSW	10	50	212	263	318	702	1,555
SW	9	15	76	61	101	327	589
WSW	0	17	47	44	50	1,284	1,442
W	3	23	3	69	90	715	903
WNW	0	79	24	79	89	3,640	3,911
NW	0	81	29	44	253	326	733
NNW	0	40	25	126	101	724	1,016
TOTAL	84	737	2,387	4,639	4,012	61,758	73,617

Table 2.1.3-11
1981 Projected Population Distribution
(Initial Expected Year of Plant Start-up)
0-50 Miles (0-80.4 km)

SECTOR	0-10 MILES	10-20 MILES	20-30 MILES	30-40 MILES	40-50 MILES	TOTAL
N	1,724	31,598	12,796	10,199	26,295	82,612
NNE	1,875	31,713	21,882	21,578	16,955	94,003
NE	4,295	113,691	79,296	60,903	23,350	281,535
ENE	1,250	116,351	40,773	7,584	13,592	179,550
E	1,021	4,260	26,165	14,082	8,669	54,197
ESE	8,416	2,770	9,388	9,300	8,157	38,031
SE	8,337	4,112	21,826	10,688	7,095	52,058
SSE	32,851	5,744	5,722	8,319	1,326	53,962
S	3,699	3,876	2,740	2,602	5,783	18,700
SSW	1,555	1,305	15,189	2,027	2,868	22,944
SW	589	1,092	2,288	17,641	7,784	29,394
WSW	1,442	6,903	2,772	6,091	23,197	40,405
W	903	3,102	5,810	28,273	81,063	119,151
WNW	3,911	4,311	18,217	38,571	27,834	92,844
NW	733	13,645	22,566	12,956	9,029	58,929
NNW	1,016	93,921	17,835	27,748	50,642	191,162
TOTAL	73,617	438,394	305,265	278,562	313,639	1,409,477

Table 3.2.2-2 (Page 1)

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
AD	Standby Shutdown Diesel System										
	Pumps	D	NNS	-	-	SSF	-	-	-	-	-
	Valves	D	NNS	B31.1.0	-	YD,SSF	-	-	-	-	-
AS	Auxiliary Steam System										
	Valves (Note 22)	D	NNS	B31.1.0	X	AB	-	X	X	-	-
BB	Steam Generator Blowdown System										
	Steam Generator Blowdown Tank	D	NNS	VIII	-	TB	P	-	-	-	-
	Steam Generator Blowdown Pump	D	NNS	-	-	TB	P	-	-	-	-
	Steam Generator Blowdown Recovery HX	D	MNS	VIII	-	TB	P	-	-	-	-
	Steam Generator Blowdown Demineralizers	D	MNS	VIII	-	TB	P	-	-	-	-
	Valves	D	2,NNS	III-2,	X	C,TB	P	X	X	X	X
	Steam Generator Blowdown Demineralizer Prefilters	D	MNS	VIII	-	TB	P	-	-	-	-
BW	Steam Generator Wet Layup Recirculation										
	Isolation Valves (CA System)	D	2	III-2	X	DH	-	X	X	X	X
	Isolation Valves (BB System)	D	NNS	B31.1.0	X	DH	-	X	X	-	-
CA	Auxiliary Feedwater System										
	Auxiliary Feedwater Pumps (Motor Driven)	D	3	III-3	X	AB	-	X	X	X	X
	Aux. Feedwater Pumps (Turbine Driven)	D	3	III-3	X	AB	-	X	X	X	X
	Aux. FDWP Turb. Lube Oil Cooler	D	3	III-3	X	AB	-	X	X	X	X
	Valves	D	2	III-2	X	C, DH	-	X	X	X	X
		D	3	III-3	X	AB	-	X	X	X	X
		D	NNS	B31.1.0	X	AB	-	X	X	-	-
CF	Feedwater System										
	Valves	D,W	2	III-2	X	C,DH	-	X	X	X	X
CM	Condensate System										
	Valves (Note 22)	D	NNS	B31.1.0	X	AB	P	X	X	-	-
CS	Condensate Storage System										
	Valves (Note 22)	D	NNS	B31.1.0	X	AB	-	X	X	-	-

3.6.2.4.3 Residual Heat Removal Recirculation Line Penetration

Residual heat removal recirculation line penetrations are of the cold-penetration type. (See Figure 3.6.2-6)

Design requirements for these penetrations are as follow:

a) The recirculation line is an extension of Containment up through the first valve.

b) These valves are Safety Class 2 and are conservatively designed (600 psig design pressure) to withstand the containment design pressure of 15 psig.

c) Valves are located in an accessible area for maintenance during the post-accident period.

d) Expansion joints are utilized in the penetration design.

The stress analysis for the two recirculation lines between containment and their sump isolation valves shows that the stress in these sections is below values that would require postulation of breaks occurring if this pipe were normally in use (i.e., stress does not exceed 0.4 ($1.2S_H + S_A$)). For this reason it is acceptable not to provide guard pipe for these sections of piping (see SRP 6.2.4 Acceptance Criteria 6.e.). Any postulated leakage from the valve bonnet via the valve stem is contained via a leakoff that is directed to the Recycle Holdup Tank (the RHT is equipped with a diaphragm that would contain any gases released from solution). The valves themselves are designed to withstand 600 psig at 400°F which is well in excess of values to which they would be exposed after an accident (approximately 36 psig, 190°F).

3.6.2.4.4 Access for Periodic Examination

A description of the method of providing access to permit periodic examinations of process pipe welds within the protective assembly as required by the plant inservice inspection program is discussed in Section 6.6.

3.6.2.5 Summary of Dynamic Analyses Results

MEB Q103 A summary of postulated circumferential and longitudinal break locations is shown on Figures 3.6.2-9 to 3.6.2-207.

MEB Q108 A summary of the dynamic analyses, resulting from postulated pipe breaks in high-energy piping systems, is comprised of the following information:

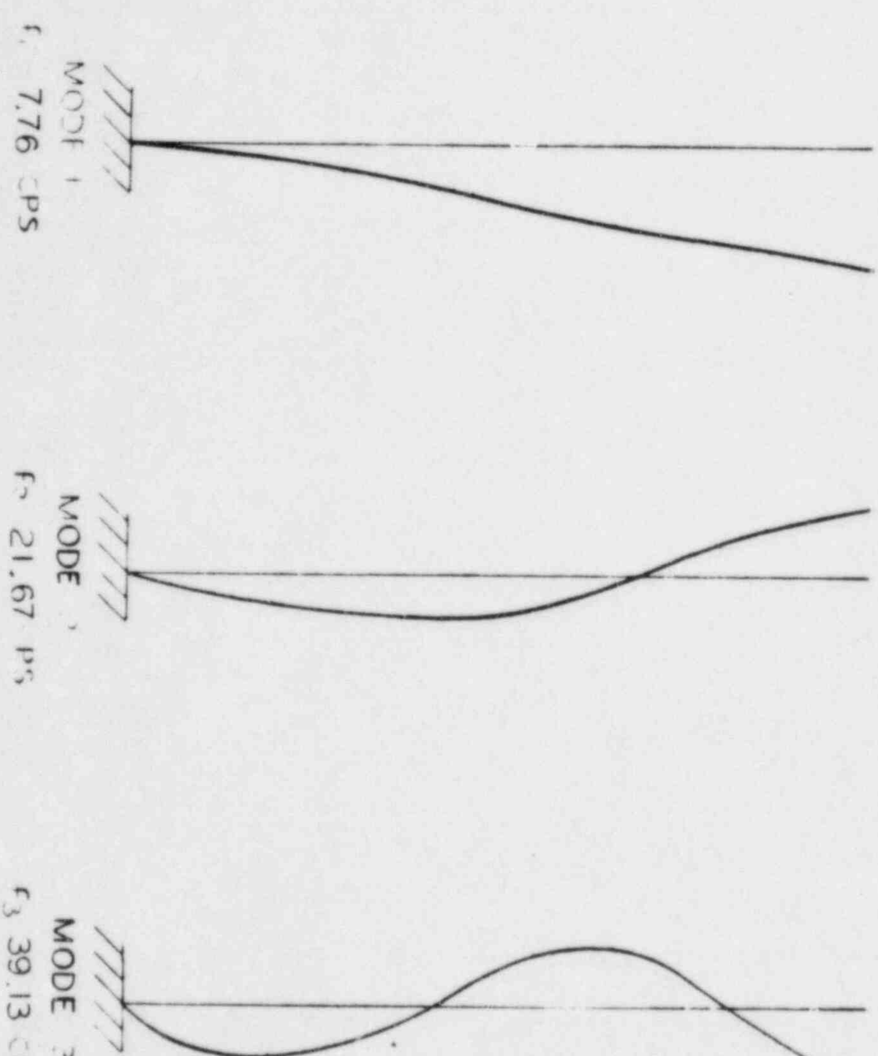
a) System pipe routing - Figures 3.6.2-9 thru 3.6.2-207

b) Location of postulated breaks - Figures 3.6.2-9 thru 3.6.2-207

c) Location of postulated pipe rupture restraints - Figures 3.6.2-9 thru 3.6.2-207 (Jet barriers are located near target to intercept jet)

d) Summary of protection requirements - Table 3.6.2-4.

e) Summary of combined stresses at break locations - Table 3.6.2-4.



CONTAINMENT INTERIOR
STRUCTURE FIRST FOUR
HORIZONTAL MODE SHAPES
EAST-WEST DIRECTION

CATAWBA NUCLEAR STATION

Figure 3.7.2-15

Rev. 11

No unique or untried construction techniques are used in fabricating the containment vessel. The same construction procedures are used that have been successfully employed at McGuire Nuclear Station which is identical in shape and size.

3.8.2.7 Testing and Inservice Inspection Requirements

3.8.2.7.1 Preoperational Testing and Inspection

(A) Structural Testing

The containment shell, personnel airlocks and equipment hatch are inspected and tested in accordance with the ASME Boiler and Pressure Vessel Code, Section III, Subsection NE. Penetrations are pressure tested as required for class NC in accordance with Section III of the 1974 ASME Code including addenda through the Summer of 1974.

(B) Leakage Rate Tests

Bottom Liner Plate: The bottom liner plate welds are inspected, prior to placing fill concrete, in accordance with the following:

1. Dye penetrant examinations are performed in accordance with Section V of the ASME Boiler and Pressure Vessel Code.

2. Upon completion of the dye penetrant test, the weld seams are covered with test channels and pressure tested. All detected leaks are repaired and retested. The leak test channel layout is shown in Figure 3.8.2-8.

Personnel Air Locks and Equipment Hatch: The personnel air locks are pressurized and a Type B leak rate test is performed as described in Section 6.2.6.

The double o-ring compression seals in the equipment hatch are tested for leakage as specified in Section 6.2.1.6.

Containment Leakage Rate Test: Upon completion erection including all penetrations, personnel air locks, equipment hatch, bottom liner plate and structural testing, a leakage rate test is performed on the containment as described in Section 6.2.6.

3.8.2.7.2 Operational Surveillance

3.8.2.7.2.1 Structural Integrity

The containment shell is protected by the Reactor Building from adverse environmental conditions. In addition, under operating conditions, the shell does not experience design pressure and temperature load cycling. It is therefore contemplated that additional structural testing of the containment shell other than the initial structural test is not necessary.

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Manual and motor operated valves have backseats to facilitate repacking and to limit stem leakage when the valves are open. Leakage connections are provided where required by valve size and fluid conditions.

5.4.7.2.3 Control

Each inlet line to the RHRS is equipped with a pressure relief valve sized to relieve the combined flow of all the charging pumps at the relief valve set pressure. These relief valves also protect the system from inadvertent overpressurization during plant cooldown or startup. Each valve has a relief flow capacity of 900 gpm at a set pressure of 450 psig. An analysis has been conducted to confirm the capability of the RHRS relief valve to prevent overpressurization in the RHRS. All credible events were examined for their potential to overpressurize the RHRS. These events included normal operating conditions, infrequent transients, and abnormal occurrences. The analysis confirmed that one relief valve has the capability to maintain the RHRS maximum pressure within code limits.

Each discharge line from the RHRS to the RCS is equipped with a pressure relief valve to relieve the maximum possible back-leakage through the valves separating the RHRS from the RCS. Each valve has a relief flow capacity of 20 gpm at a set
Q pressure of 600 psig. These relief valves are located in the ECCS (See Figures
440.15 5.4.7-1 and 5.4.7-2).

The fluid discharged by the suction side relief valves is collected in the pressurizer relief tank. The fluid discharged by the discharge side relief valves is collected in the recycle holdup tank of the boron recycle system.

The design of the RHRS includes two motor-operated gate isolation valves in series on each inlet line between the high pressures RCS and the lower pressure RHRS. They are closed during normal operation and are only opened for residual heat removal during a unit cooldown after the RCS pressure is reduced to 385 psig or lower and RCS temperature is reduced to approximately 350°F. During a unit startup the inlet isolation valves are shut after drawing a bubble in the pressurizer and prior to increasing RCS pressure above 385 psig. These isolation valves are provided with both "prevent-open" and "auto-closure" interlocks which are designed to prevent possible exposure of the RHRS to normal RCS operating pressure. The two inlet isolation valves in each subsystem are separately and independently interlocked with pressure signals to prevent their being opened whenever the RCS pressure is greater than approximately 425 psig. The two inlet isolation valves in each subsystem are also separately and independently interlocked with pressure signals to automatically shut if RCS pressure increases to
Q 600 psig during a plant startup.
440.15

The use of two independently powered motor-operated valves in each of the two inlet lines, along with two independent pressure interlock signals for each function assures a design which meets applicable single failure criteria. Not only more than one single failure but also different failure mechanisms must be postulated to defeat the function of preventing possible exposure of the RHR system to normal RCS operating pressure. These protective interlock designs,

Component Description

Pumps

The Containment Spray System flow is provided by two centrifugal type pumps driven by electric motors. The motors, which can be powered either normally or from an emergency source are direct coupled and non-overloading to the end of the pump curve. The design head of the Containment Spray Pumps is sufficient to ensure rated capacity with a minimum level in the Refueling Water Storage Tank or the containment sump when pumping against a head equivalent to the sum of the design pressure of the containment, the elevational head between the pump discharge and the uppermost spray nozzles, and the equipment and piping friction losses. Manufacturer performance testing of each pump yielded 3400 gpm flow at a head of 400 ft. See Table 6.2.2-1 for additional design parameters and Figure 6.2.2-2 characteristic curves.

The residual heat removal pumps which also provide flow to the Containment Spray System are described in Section 5.4.7 and 6.3. Each residual heat removal pump will provide about 2000 gpm for upper containment spray.

The containment spray pumps are vertical shaft pumps. Pump motor parameters are as follows:

Motor horsepower	500
Service factor	1.25
Motor voltage	4000
Phase	3
cycle	60

Heat Exchangers

The Containment spray heat exchangers are of the vertical shell and U-tube type with tubes welded to the tube sheet. Borated water from either the refueling water storage tank or the containment sump circulates through the tube side. Design parameters are presented in Table 6.2.2-2.

Piping

All Containment Spray System piping in contact with borated water is austenitic stainless steel. All piping joints are welded except for the flanged connection at the pump and relief valves.

Spray Nozzles and Ring Headers

Each pair of containment spray headers provides approximately 3400 gpm and contain a total of approximately 223 hollow cone ramp bottom nozzles, each of which is capable of a design flow of 15.2 gpm with a 40 psi differential pressure. These nozzles have a 3/8 inch spray orifice and are not subject to clogging by particles up to 1/4 inch in maximum dimension. The nozzles produce a mean drop

As an added precaution, the refueling water storage tank is kept heated between 70°-100°F. This operating condition is stated in Technical Specification 3.5.4.

The Containment Air Release and Addition System takes care of small differences in containment pressure relative to atmospheric pressure, and is described in Section 9.5.9.

CALCULATION OF MAXIMUM REVERSE PRESSURE DIFFERENTIAL

The LOTIC-2 computer model was used to calculate the reverse differential pressure across the operating deck. In order to calculate a maximum reverse differential pressure the following assumptions were made:

1. The dead-ended compartment volumes adjacent to the lower compartment, fan and accumulator rooms, pipe trenches, etc., were assumed to be swept of air during the initial blowdown. This is a very conservative assumption, since this will maximize the air mass forced into the upper ice bed and upper compartment, thus raising the compression pressure. In addition, it will minimize the mass of the non-condensables in the lower compartment. With this modeling the dead-ended volume is included with that of the lower compartment, (See Figure 6.2.1-10), resulting in a 3 volume simulation of the Containment.

2. The minimum containment temperatures are assumed in the various subcompartments. This will maximize the air mass forced into the upper containment. It will also increase the heat removal capability of the cold lower compartment structures.

3. A temperature of 100°F is assumed in the RWST. This will help raise the upper containment temperature and pressure higher for a longer period of time.

4. The upper containment spray flow rates used were runout flows.

5. The containment geometry is the same as that used in the minimum pressure analysis for ECCS purposes.

6. The Westinghouse ECCS model (See WCAP-8339, Reference 4) was used for heat transfer to the structure.

7. The mass and energy releases used are based on the analysis presented in WCAP-8479. (Reference 5)

8. Ice condenser doors are assumed to act as check valves, allowing flow only into the ice condenser.

9. Flow resistance across operating deck is 0.0072 ft^{-4}.

With these assumptions the maximum reverse pressure differential across the operating deck was calculated to be 0.65 psi. The following plots have been provided:

vided in Table 6.2.3-3. The structural outline of the Reactor Building is furnished in Figure 3.8.1-1. Additional plans and sections are shown in Figures 1.2.2-8 through 1.2.2-16.

6.2.3.3 Design Evaluation

The results of an analysis of the functional capability of the Annulus Ventilation System to depressurize and maintain a uniform negative pressure of ≥ 0.5 in. H_2O in the annulus following a design basis accident are provided in Table 6.2.3-2.

The pressure, temperature, and mass of annulus air is calculated by the Fortran IV program CANVENT for the entire accident transient, including the steady state conditions prior to the initiating event. The containment is divided into three regions, where standard equations of heat transfer are applied. No heat or mass transfer between regions is assumed except in the annulus. The steady state, pre-accident temperatures are determined by an interactive process until successively calculated temperatures differ by less than some small predetermined amount. The post-DBA transient conditions are calculated using the finite differences technique.

The following assumptions are made for simplification and/or conservatism:

1) The containment is divided into three regions. The temperature of each region is uniform within that region.

2) There are no temperature gradients in the vertical or circumferential directions. Thus, the model is one dimensional with heat transfer occurring only in the radial directions.

3) All physical properties (e.g., heat capacity, thermal conductivity, emissivity, and density) are independent of temperature, except the density of air in the annulus.

4) The air in the annulus behaves as an ideal gas and is uniformly mixed.

5) The air in the annulus has a transmissivity of unity. Therefore, energy is transfered to and from the air only by natural convection.

6) Radiative heat transfer occurs between the concrete reactor building and the steel containment building. The surfaces are treated as gray bodies with a parallel, flat plate geometry,

7) The equation for the heat transfer coefficient for the upper containment to annulus air, treating the dome as a horizontal plate, is $h = .22\ (\Delta t)^{1/3}$. Similarly, treating the ice condenser and lower containment sections as vertical plates, the heat transfer coefficient to annulus air is $h = .19\ (\Delta t)^{1/3}$.

8) For the transfer of heat from the containment air to the containment shell, a heat transfer coefficient that increases linearly in time from 8 Btu/hr -

ft^2 - °F to some maximum value is assumed, followed by exponential decay at a rate of .025 sec^{-1} to some long-term value. The steady-state calculations are based on the natural convection heat transfer coefficients previously mentioned.

9) Circulation of refrigerating air in the ice condenser air ducts ceases at the initiation of the accident. Therefore, before the accident, heat is transferred to the refrigerating air by forced convection; whereas, after the accident the mechanism is natural convection. The use of a forced convection heat transfer coefficient is eliminated by assuming the ice condenser walls are at the same temperature as the refrigerating air.

10) The annulus ventilation fan comes on instantaneously at full speed at a time determined by signal response times and fan characteristics. Partial flow before this time is not considered. At a later time, the fan flow capacity is decreased 15% due to an increased differential pressure across the annulus filter train.

11) A portion of the annulus ventilation fan flow is exhausted to the atmosphere and the remainder is returned to the annulus. The full fan flow is exhausted until the annulus pressure is reduced to -1.0 inches w.g. From that point, the amount of air exhausted is that amount required to maintain the annulus pressure at -1.0 inches w.g.

12) Leakage of air across the concrete reactor building will be a maximum at -1.0 inches w.g. This leakage is conservatively assumed to exist whenever the annulus is at a negative pressure. No credit is taken for out leakage when the annulus pressure is greater than zero.

13) Thermal contact resistances are neglected.

14) For each of the three regions, heat transfer areas are lumped into one of three categories based on the inside radius of the containment shell, the midpoint of the annulus, and the midpoint of the reactor building. This is assumed in order to avoid the continuous variation of area with radius associated with cylindrical geometry.

15) Outside temperatures remain unchanged during the course of the accident. For steady-state calculations, the surface of the reactor building is at the outside temperature. For the post-accident transient, the Reactor Building is considered an adiabatic wall.

16) The expansion of the containment shell, due to the pressure and temperature increase within, is calculated assuming each region is freestanding and independent of any other region.

6.2.3.4 Tests and Inspections

Preoperational and periodic tests are described in Chapter 14 and the Technical Specifications respectively.

their adequacy under these conditions.

Air or motor-operated valves are used for the automatic isolation valves. Air-operated valves are designed to assume the position of greater safety upon loss of air. Motor-operated valves are powered from the emergency power sources.

Remote manual control of the automatically actuated Containment isolation valves is provided.

Automatic valves are installed in lines that must be immediately isolated after an accident. Those lines which must remain in service after an accident have at least one remote manual valve.

Hot and cold penetration design and analyses are presented in Section 3.6.2.4, Mechanical Penetrations. Special penetrations such as main steam, main feed-water, and sump recirculation line penetrations are described in detail under this section.

The integrity of the isolation valves system and connecting lines under the dynamic forces resulting from inadvertent closure while at operating conditions (e.g., main steam lines) is assured by the performance of static and dynamic analysis on the piping, valves and restraints.

The supports and restraints are applied such that integrity is assured and pipe stresses and support reactions are within allowable limits. Valves, in nonsafety-related systems where function permits, are normally positioned closed to minimize any release following a design basis event. Those valves that are required to change position following a design basis event are equipped with valve operators to move the valve rapidly.

Containment isolation valves and operators inside the Containment are designed to withstand a maximum integrated radiation dose of 2×10^8 rads during the life of the plant.

Containment isolation valves that are located inside the Containment are designed to function under the pressure-temperature conditions of both normal operation and that during the design basis event. The pressure-temperature condition used for valve design under normal operation is 14.7 psia and 120°F. The pressure-temperature condition used for valve external design under accident conditions is 15 psig and 300°F.

6.2.4.2.2 Containment Valve Injection Water System

The Containment Valve Injection Water System (NW) is shown in Figure 6.2.4-2. It prevents leakage of containment atmosphere past certain gate valves used for containment isolation following a LOCA by injecting seal water at a pressure exceeding containment accident pressure between the two seating surfaces of the flex wedge valves. The system consists of two independent, redundant trains; one supplying gate valves that are powered by the A train diesel and the other supplying gate valves powered by the B train diesel. This separation of trains prevents the possibility of both containment isolation valves not sealing due to a single failure.

Each train consists of a surge chamber which is filled with water and pressurized with nitrogen. One main header exits the chamber and splits into several headers. A solenoid valve is located in the main header before any of the branch headers which will open after 60 second delay on ST signal. Each of the headers supply injection water to containment isolation valves located in the same general location, and close on the same engineered safety signal. A solenoid valve is located in each header which supplies seal water to valves closing on SP signal. These solenoid valves open after a 60 second delay on SP signal. Since a ST signal occurs before a SP signal, the solenoid valve located in the main header will already be injecting water to Containment isolation valves closing on ST signal. This leaves an open path to the headers supplying injection water on SP signal. The delay for the solenoid valves opening is to allow adequate time for the slowest gate valve to close, before water is injected into the valve seat.

Individual solenoid valves are provided for the NI and NS containment isolation valves receiving seal water injection. Following a postulated accident one or more of the NI or NS containment isolation valves may be open. These solenoid valves will receive a signal to open, following a ST signal and once its associated containment isolation valve has closed. If the containment isolation valve subsequently opens, its associated NW solenoid valve closes. Thus after a ST signal, the NW solenoid valve will be open when its containment isolation valve is closed and vice versa.

One header for each train penetrates the Containment. The NW Containment isolation valve on the outside of the Containment opens on ST signal, allowing seal water to be injected to those containment isolation valves located inside the Containment. Inside Containment, solenoid valves isolate the headers that supply injection water to those valves closing on SP signal. The solenoid valves open after a 60 second delay on SP signal.

Makeup water is provided from the Demineralized Water Storage Tank for testing and adding water to the surge chamber during normal plant operation. Assured water is provided from the essential header of the Nuclear Service Water System. This supply is assured for at least 30 days following a postulated accident. If the water level in the surge chamber drops below the low-low level or if the surge chamber nitrogen pressure drops below the low-low pressure after a ST signal, a solenoid valve in the supply line from the Nuclear Service Water System will automatically open and remains open, assuring makeup to the NW system at a pressure greater than 110% of peak Containment accident pressure.

The NW system is designed to meet all Regulatory and Testing requirements set forth in Paragraph III-C of 10CFR50, Appendix J and ASME Code Section IX.

6.2.4.3 Design Evaluation

The Containment structure and the Containment penetrations form an essentially leak-tight barrier. Allowable leak rates from the Containment under design pressure condition are discussed in Section 6.2.1. Testing provisions and performance are also discussed in Section 6.2.1. Whenever practicable, isolation valves outside Containment which are normally open and required to close on a signal to isolate the Containment are designed to fail closed.

In determining potential bypass leak paths following a LOCA, a liquid seal between two isolation valves is not assumed. Rather, the liquid seal is maintained by the line terminating in a seismic Class 1 tank or normally closed valve. Neither is it assumed that liquid pressure in the "sealed lines" will always equal or exceed containment pressure. No single failure will prevent bypass leakage control including failure of one safety channel of isolation valves to close. Through line leakage is still precluded since no seal is assumed between the two isolation valves. Following isolation valve closure, design valve leakage rates will be sufficiently low to preclude loss of liquid seals.

In order that no single, credible failure or malfunction will result in loss of isolation capability, the closed piping systems, both inside and outside the Containment, and various types of isolation valves provide a double barrier.

The isolation valve and actuators are located as close as practical to the Containment and protected from missile damage. This minimizes the potential hazards that could be experienced by the system.

The integrity of the isolation valve system and connecting lines under the dynamic forces resulting from inadvertent closure under operating conditions is assured, based upon required static and dynamic analysis.

The supports and restraints are applied such that pipe stresses and support reactions are within allowable limits as defined in Section 3.9.2.

Two trains of injection water are provided in the Containment Valve Injection Water System. This will prevent the loss of injection water or loss of sealing capability should one train of Containment isolation valves fail to close. Makeup water can be assured from the Nuclear Service Water System for 30 days following the postulated LOCA.

6.2.4.4 Testing and Inspection

Each valve is designed to be tested periodically during normal operation or during shutdown conditions to verify its operability and ability to meet closing requirements.

A program of test inspection requirements for containment isolation is presented in the Technical Specifications. Similar tests are performed prior to operation as discussed in Chapter 14.

Gate valves served by the Containment Valve Injection Water System do not receive a conventional Type C leak rate test using air as a test medium.

The Containment Isolation valves served by the Containment Valve Injection Water System together with the NW systems are tested simultaneously. Containment isolation valves are leak rate tested by injecting seal water from the Containment Valve Injection Water System to the containment isolation valves (Note that one to all Containment Isolation valves can be tested simultaneously so that effect on plant operation and radiation exposure can be minimized. With the containment isolation valve closed, the leakage is determined by measuring flow rate of seal water out of the containment valve injection water surge chamber. The leakage rate from all containment isolation valves is totaled for each train. The total leakage from each train should not exceed Technical Specifications. To assure that seal water is infact taking place, seal water flow is verified with the containment valve in the open positions and then seal water flow is verified to.be reduced when the containment isolation valve is closed. This alternate to Type C leak rate testing with air is allowed by NRC 10CFR50, Appendix J, Paragraph III-C.

TABLE 6.2.1-2

Catawba Ice Condenser Design Parameters

Reactor Containment Volume (Net free volume, ft^3)(1)	
Upper Compartment	670,100
Lower Compartment (Active)	273,218
Lower Compartment (Dead Ended)	71,779
Ice Condenser	97,348
Upper Plenum	47,000
Lower Plenum	25,000
Total Volume	1,184,445
NSSS Power, MWt	3,427
Tech Spec Weight of Ice in Condenser, lbs.	2,368,652

(1) These volumes (employed in the LOTIC analyses) use a maximum designed ice mass of 2.45×10^6 pounds and an air compression ratio at initial blowdown conditions.

Table 6.2.3-2 (Page 1)

Annulus Conditions vs. Time Following Design Basis Accident

TIME (SEC)	ANNULUS TEMP (°R)	ANNULUS PRESSURE (IN. WATER)	PURGE FLOW RATE (CFM)	RECIRCULATION FLOW (CFM)	LOWER CONTAINMENT[1] TEMPERATURE (°R)
1.	498.94	0.550	0.	0.	690.33
2.	498.95	0.570	0.	0.	690.33
3.	498.96	0.598	0.	0.	690.33
4.	498.97	0.632	0.	0.	690.33
5.	498.98	0.671	0.	0.	690.33
6.	498.99	0.716	0.	0.	690.33
7.	499.00	0.764	0.	0.	690.33
8.	499.01	0.816	0.	0.	690.33
9.	499.02	0.871	0.	0.	690.33
10.	499.03	0.929	0.	0.	690.33
11.	499.05	0.988	0.	0.	690.33
12.	499.06	1.049	0.	0.	690.33
13.	499.08	1.111	0.	0.	690.33
14.	499.09	1.174	0.	0.	690.33
15.	499.11	1.239	0.	0.	690.33
16.	499.13	1.304	0.	0.	690.33
17.	499.16	1.369	0.	0.	690.33
18.	499.18	1.436	0.	0.	690.33
19.	499.21	1.503	0.	0.	690.33
20.	499.23	1.571	0.	0.	690.33
21.	499.27	1.639	0.	0.	690.33
22.	499.30	1.708	0.	0.	690.33
23.	499.33	1.650	9000.	0.	690.33
24.	499.37	1.592	9000.	0.	690.33
25.	499.41	1.534	9000.	0.	690.33
26.	499.45	1.475	9000.	0.	690.33
27.	499.50	1.416	9000.	0.	690.33
28.	499.54	1.357	9000.	0.	690.33
29.	499.59	1.298	9000.	0.	690.33
30.	499.65	1.239	9000.	0.	690.33
31.	499.70	1.181	9000.	0.	690.33

Table 6.2.3-2 (Page 2)

Annulus Conditions vs. Time Following Design Basis Accident

TIME (SEC)	ANNULUS TEMP (°R)	ANNULUS PRESSURE (IN. WATER)	PURGE FLOW RATE (CFM)	RECIRCULATION FLOW (CFM)	LOWER CONTAINMENT[1] TEMPERATURE (°R)
32.	499.75	1.124	9000.	0.	690.33
33.	499.81	1.067	9000.	0.	690.33
34.	499.87	1.010	9000.	0.	690.33
35.	499.93	0.954	9000.	0.	690.33
36.	500.00	1.898	9000.	0.	690.33
37.	500.06	0.843	9000.	0.	690.33
38.	500.13	0.789	9000.	0.	690.33
39.	500.19	0.734	9000.	0.	690.33
40.	500.26	0.681	9000.	0.	690.33
41.	500.33	0.627	9000.	0.	690.33
42.	500.41	0.574	9000.	0.	690.33
43.	500.48	0.522	9000.	0.	690.33
44.	500.55	0.470	9000.	0.	690.33
45.	500.63	0.418	9000.	0.	690.33
46.	500.71	0.371	9000.	0.	690.33
47.	500.79	0.325	9000.	0.	690.33
48.	500.86	0.279	9000.	0.	691.16
49.	500.94	0.234	9000.	0.	691.97
50.	501.03	0.189	9000.	0.	692.76
51.	501.11	0.145	9000.	0.	693.54
52.	501.19	0.101	9000.	0.	694.30
53.	501.27	0.058	9000.	0.	695.05
54.	501.36	0.015	9000.	0.	695.79
55.	501.44	-0.014	9000.	0.	695.48
56.	501.52	-0.037	9000.	0.	695.19
57.	501.60	-0.060	9000.	0.	694.89
58.	501.68	-0.084	9000.	0.	694.61
59.	501.75	-0.107	9000.	0.	694.33
60.	501.83	-0.130	9000.	0.	694.05
61.	501.91	-0.153	9000.	0.	694.30
62.	501.99	-0.176	9000.	0.	694.54

Table 6.2.3-2 (Page 3)

Annulus Conditions vs. Time Following Design Basis Accident

TIME (SEC)	ANNULUS TEMP (°R)	ANNULUS PRESSURE (IN. WATER)	PURGE FLOW RATE (CFM)	RECIRCULATION FLOW (CFM)	LOWER CONTAINMENT[1] TEMPERATURE (°R)
63.	502.08	-0.198	9000.	0.	694.78
64.	502.16	-0.220	9000.	0.	695.02
65.	502.24	-0.243	9000.	0.	695.25
66.	502.32	-0.264	9000.	0.	695.48
67.	502.41	-0.291	9000.	0.	695.70
68.	502.49	-0.317	9000.	0.	695.92
69.	502.58	-0.343	9000.	0.	696.14
70.	502.66	-0.369	9000.	0.	696.36
71.	502.75	-0.394	9000.	0.	696.57
72.	502.83	-0.420	9000.	0.	696.78
73.	502.92	-0.445	9000.	0.	696.73
74.	503.01	-0.470	9000.	0.	696.41
75.	503.09	-0.495	9000.	0.	696.10
76.	503.18	-0.520	9000.	0.	695.79
77.	503.27	-0.545	9000.	0.	695.48
78.	503.36	-0.570	9000.	0.	695.18
79.	503.45	-0.595	9000.	0.	694.89
80.	503.53	-0.620	9000.	0.	694.59
81.	503.62	-0.645	9000.	0.	694.30
82.	503.71	-0.669	9000.	0.	694.02
83.	503.80	-0.694	9000.	0.	693.74
84.	503.89	-0.718	9000.	0.	693.46
85.	503.98	-0.743	9000.	0.	693.18
86.	504.07	-0.767	9000.	0.	692.91
87.	504.16	-0.792	9000.	0.	692.64
88.	504.25	-0.816	9000.	0.	692.37
89.	504.34	-0.841	9000.	0.	692.11
90.	504.44	-0.865	9000.	0.	691.85
91.	504.53	-0.889	9000.	0.	691.59
92.	504.62	-0.914	9000.	0.	691.34
93.	504.71	-0.938	9000.	0.	691.09

Table 6.2.3-2 (Page 4)

Annulus Conditions vs. Time Following Design Basis Accident

TIME (SEC)	ANNULUS TEMP (°R)	ANNULUS PRESSURE (IN. WATER)	PURGE FLOW RATE (CFM)	RECIRCULATION FLOW (CFM)	LOWER CONTAINMENT[1] TEMPERATURE (°R)
94.	504.80	-0.962	9000	0	690.84
95.	504.89	-0.987	9000	0	690.59
96.	504.99	-1.000	7436	1564	690.35
97.	505.08	-1.000	7285	1715	690.11
98.	505.17	-1.000	7283	1717	689.87
99.	505.26	-1.000	7282	1718	689.63
100.	505.35	-1.000	7280	1720	689.40
150.	509.93	-1.000	7026	1974	679.96
200.	514.28	-1.000	6724	2276	680.35
250.	518.34	-1.000	6367	2633	682.52
300.	522.11	-1.000	6011	2989	684.00
350.	525.59	-1.000	5658	3342	682.79
400.	528.76	-1.000	5311	3689	682.09
450.	531.64	-1.000	4983	4017	681.96
500.	534.24	-1.000	4680	4320	681.85
550.	536.57	-1.000	4402	4598	681.75
600.	538.67	-1.000	4158	4842	681.65
650.	540.54	-1.000	3871	5129	674.10
700.	542.18	-1.000	3600	5400	667.11
750.	543.57	-1.000	3334	5666	662.85
800.	544.73	-1.000	3106	5894	661.04
850.	545.68	-1.000	2937	6063	659.35
900.	546.46	-1.000	2772	6228	657.75
950.	547.09	-1.000	2631	6369	656.23
1000.	547.60	-1.000	2521	6479	656.49
1100.	548.35	-1.000	2380	6620	657.26
1200.	548.88	-1.000	2302	6698	657.95
1300.	549.29	-1.000	2259	6741	658.19
1400.	549.62	-1.000	2220	6780	657.82
1500.	549.90	-1.000	2193	6807	657.48
1600.	550.13	-1.000	2172	6828	657.16

Table 6.2.3-2 (Page 5)

Annulus Conditions vs. Time Following Design Basis Accident

TIME (SEC)	ANNULUS TEMP (°R)	ANNULUS PRESSURE (IN. WATER)	PURGE FLOW RATE (CFM)	RECIRCULATION FLOW (CFM)	LOWER CONTAINMENT[1] TEMPERATURE (°R)
1700.	550.32	-1.000	2156	6844	656.86
1800.	550.47	-1.000	2113	6887	652.85
1900.	550.52	-1.000	2049	6951	649.06
2000.	550.46	-1.000	1984	7016	645.46
2100.	550.30	-1.000	1951	7049	644.91
2200.	550.09	-1.000	1945	7055	644.39
2300	549.88	-1.000	1958	7042	643.89
2400.	549.69	-1.000	1972	7028	643.41
2500.	549.54	-1.000	1995	7005	642.95
2600.	549.43	-1.000	2024	6976	642.52
2700.	549.37	-1.000	2052	6948	642.09
2800.	549.36	-1.000	2078	6922	641.69
2900.	549.40	-1.000	2105	6895	642.40
3000.	549.50	-1.000	2096	6904	643.04
3100.	549.52	-1.000	1994	7006	641.98
3200.	549.38	-1.000	1948	7052	640.96
3300.	549.17	-1.000	1926	7074	639.97
3400.	548.92	-1.000	1920	7080	639.01
3500.	548.68	-1.000	1925	7075	638.65
3600.	548.45	-1.000	1937	7063	638.31
3700.	548.24	-1.000	1952	7048	637.97
3800.	548.06	-1.000	1965	7035	637.65
3900.	547.91	-1.000	1978	7022	637.33
4000.	547.78	-1.000	2075	6925	637.02
4100.	548.40	-1.000	3001	5999	640.23
4200.	550.26	-1.000	3368	5632	643.35
4300.	552.57	-1.000	3440	5560	646.40
4400.	554.90	-1.000	3300	5700	649.39
4500.	557.06	-1.000	3180	5820	652.30
4600.	558.97	-1.000	3052	5948	655.15
4700.	560.65	-1.000	2935	6065	657.94

Table 6.2.3-2 (Page 6)

Annulus Conditions vs. Time Following Design Basis Accident

TIME (SEC)	ANNULUS TEMP (°R)	ANNULUS PRESSURE (IN. WATER)	PURGE FLOW RATE (CFM)	RECIRCULATION FLOW (CFM)	LOWER CONTAINMENT[1] TEMPERATURE (°R)
4800.	562.11	-1.000	2841	6159	660.67
4900.	563.41	-1.000	2778	6222	663.35
5000.	564.61	-1.000	2734	6266	665.31
5500.	569.05	-1.000	2479	6521	665.67
6000.	571.17	-1.000	2266	6734	666.01
6500.	572.04	-1.000	2216	6784	666.17
7000.	572.57	-1.000	2190	6810	665.20
7500.	572.91	-1.000	2180	6820	664.30
8000.	573.21	-1.000	2178	6822	663.46
8500.	573.49	-1.000	2179	6821	662.67
9000.	573.77	-1.000	2180	6820	661.93
9500.	574.06	-1.000	2181	6819	661.22
10000.	574.34	-1.000	2182	6818	660.56
11000.	574.89	-1.000	2183	6817	659.32
12000.	575.43	-1.000	2184	6816	658.18
13000.	575.95	-1.000	2185	6815	657.14
14000.	576.44	-1.000	2185	6815	656.17
15000.	576.92	-1.000	2186	6814	655.28
16000.	577.37	-1.000	2186	6814	654.44
17000.	577.80	-1.000	2187	6813	653.65
18000.	578.20	-1.000	2187	6813	652.90
19000.	578.58	-1.000	2187	6813	652.20
20000.	578.94	-1.000	2187	6813	651.53
30000.	581.45	-1.000	2188	6812	646.25
40000.	582.58	-1.000	2187	6813	642.51
50000.	582.93	-1.000	2186	6814	639.60
60000.	582.88	-1.000	2184	6816	637.23
70000.	582.61	-1.000	2183	6817	635.22
80000.	582.25	-1.000	2181	6819	633.48
90000.	581.84	-1.000	2179	6821	631.95
100000.	581.42	-1.000	2178	6822	630.57

Table 6.2.3-2 (Page 7)

Annulus Conditions vs. Time Following Design Basis Accident

TIME (SEC)	ANNULUS TEMP (°R)	ANNULUS PRESSURE (IN. WATER)	PURGE FLOW RATE (CFM)	RECIRCULATION FLOW (CFM)	LOWER CONTAINMENT[1] TEMPERATURE (°R)
110000.	581.66	-1.000	2183	6817	630.57
120000.	581.99	-1.000	2184	6816	630.57
130000.	582.36	-1.000	2185	6815	630.57
140000.	582.72	-1.000	2187	6813	630.57
150000.	583.07	-1.000	2188	6812	630.57
160000.	583.42	-1.000	2189	6811	630.57
170000.	583.77	-1.000	2191	6809	630.57
180000.	584.13	-1.000	2192	6808	630.57
190000.	584.47	-1.000	2193	6807	630.57
200000.	584.81	-1.000	2194	6804	630.57
250000.	586.41	-1.000	2200	6800	630.57
300000.	587.85	-1.000	2205	6795	630.57

[1] The lower containment temperature shown is not a calculated value but is input from straight line approximations. See Figure 6.2.1-6 for the calculated lower compartment temperatures for a LOCA.

Table 6.2.3-3 (Page 1)

Dual Containment Characteristics

I.	Secondary Containment Design Information			
	A.	Free Volume, ft^3		484,090
	B.	Pressure, inches of water, gauge		
		1. Normal Operation		0.0
		2. Postaccident		$\leq$ -0.5
	C.	Leak Rate at Postaccident Pressure (weight %/day)		0.2
	D.	Exhaust Fans		See Figure 9.4.9-1
	E.	Filters		See Figure 9.4.9-1
II.	Transient Analysis			
	A.	Initial Conditions		
		1. Pressure, inches of water, gauge		0.0
		2. Temperature, °F		81.1
		3. Outside Air Temperature, °F		95
		4. Thickness of Secondary Containment, in		
			Wall	36
			Dome	27
		5. Thickness of Primary Containment, in		
			Wall	0.75
			Dome	0.688
	B.	Thermal Characteristics		
		1. Primary Containment Wall		
		a. Coefficient of Thermal Expansion, 1/°F		8.4E-06
		b. Modulus of Elasticity, psi		2.9E+07
		c. Thermal Conductivity, Btu/hr-ft-°F		25
		d. Specific Heat, Btu/lb-°F		0.113
		2. Secondary Containment Wall		
		a. Thermal Conductivity, Btu/hr-ft-°F		0.92
		b. Specific Heat, Btu/lb-°F		0.21

TABLE 6.2.4-1 (Page 12)

Containment Isolation Valve and Actuator Data

22. During the injection phase of safety injection, these valves are closed. Water from the refueling water storage tank (FWST) provides approximately 48 feet of head on these valves (~ 20.8 psig). This head will preclude any leakage through this penetration. During the recirculation phase of safey injection, these valves are open to provide flow to ND pump suction.

23. The main steam, feedwater, auxiliary feedwater, sample and blowdown lines are all connected to the secondary side of the steam generator which is kept at a higher pressure than the primary side soon after a LOCA occurs. Any leakage between the primary and secondary sides of the steam generator is directed inward to the containment.

24. Deleted

25. Deleted

26. These valves are sealed against leakage by the Containment Valve Injection Water System as discussed in Section 6.2.4.4.

27. Type B test performed per 10 CFR 50, Appendix J.

28. Deleted

29. This system is required to be in operation during the Type A test in order to maintain the unit in a safe condition. Therefore, this penetration will not be vented and drained.

30. This penetration is a part of a closed system inside containment. All piping inside containment is seismic Category 1 and therefore not subject to rupture as a result of a LOCA. This penetration will not be drained and vented for the Type A test.

31. Valve closes on receipt of a high radiation or high relative humidity signal.

32. This penetration is effectively water sealed against any leakage directed out of containment by the residual heat removal pumps discharge pressure.

33. This penetration is effectively water sealed against any leakage directed out of containment by the centrifugal charging pumps discharge pressure.

34. An effective fluid seal on these penetrations, provided by the suction sources to the residual heat removal pumps during and following an accident.

35. This penetration is left open during an accident to provide flow from the centrifugal charging pumps to the reactor vessel.

TABLE 6.2.4-1 (Page 13)

Containment Isolation Valve and Actuator Data

36. An effective fluid seal on these penetrations prevents any leakage directed out of containment. Residual upper head injection accumulator water left after injection is sufficient to provide sealing fluid at ~8 gph if leakage of the hydraulic operated gate valves is assumed. In addition there would be approximately 9,000lb (120,000 scf) of N_2 after all the water was consumed. In any event the water and gas accumulators compose a closed, normally pressurized system during normal operation. Significant leakage through the boundary during normal operation results in detectable loss of water or nitrogen or both and would result in identification and repair to eliminate such leakage. Both water level (in the VHI surge tan) and pressure are indicated and alarmed in the control room. Valves 1NI255B and 1NI258A will be isolable and will be Type C tested.

37. System presents a Seismic Category I closed pressure boundary to the containment atmosphere following a LOCA and is not a part of the reactor coolant system pressure boundary. In addition, the outside containment isolation valve for each penetration is supplied by the Containment Valve Injection Water System as discussed in Section 6.2.4.4, which provides a seal against any leakage through the valve.

38. These penetrations are in use during and following an accident to provide Containment Valve Injection Water System flow to certain containment isolation valves. In the event that the containment isolation valve on these penetrations should fail to open, an effective water seal would be maintained on the penetration at a pressure $>$ Pa by the Containment Valve Injection Water Surge Chamber.

39. These penetrations will either be in use following an accident, or will be sealed against leakage by a water seal against the outside of the penetrations. In addition, the following steps are taken to provide additional assurance of penetration integrity:

    a. The outside containment isolation valves are supplied by the Containment Valve Injection Water Systems, as discussed in Section 6.2.4.4, which provides a seal against leakage.

    b. The check valves which provide the inside isolation, are tested per Technical Specification 4.4.7.2.2, which requires a water leak test for Reactor Coolant System Pressure Isolation Valves.

    The use of the above features to assure the integrity of these penetrations avoids the necessity of installing block valves in the injection flow path. Such valves would add an increased probability of flow path blockage during an accident.

TABLE 6.2.4-1 (Page 14)

Containment Isolation Valve and Actuator Data

40. The leakage through these lines will be included in the results of the Type A test.

41. Valves remain open during accident. Type C test is performed to verify integrity of tubing and instrumentation.

42. The containment isolation valves in this penetration which received a sealing fluid from the NW system will not be tested as a part of the Type C leak rate test program. The other containment isolation valve(s) will be Type C tested.

43. This penetration is not vented for Type A test but the leakage calculated by Type C test performed on "reverse" check valve is added to Type A test results. The exemption and alternative have been requested and granted by NRC.

44. These penetrations are left open during an accident in order to provide reactor coolant pump seal water flow from the centrifugal charging pumps.

45. The outside containment isolation gate valve receives a sealing fluid from the NW system if it is closed after a phase A isolation signal. When the isolation valve opens in the course of performing its safety function a solenoid in the sealing fluid supply lines closes.

a. Centrifugal charging pumps (CCP's) start.

b. Valves in the CCP's suction header isolate the volume control tank and align to the refueling storage tank.

c. LLD to cold leg.

d. Normal charging path valves close.

e. The safety injection pumps start.

f. The residual heat removal pumps start.

g. Refueling water storage tank recirculation is terminated and the make-up line to the spent fuel pool is isolated.

2. Automatic switchover of the residual heat removal pumps (RHRP's) from injection mode to recirculation involves the following.

   a. The suction valves from the sump open when 2 of 4 low level transmitters indicate a low level in the RWST in conjunction with an "S" signal.

   b. The isolation valves from the refueling water storage tank close after the sump valves are open.

3. Manual switchover of the suction of the safety injection pumps and the centrifugal charging pumps requires the following interlocks be satisified.

   a. The containment recirculation sump isolation valve is open.

   b. The RHRP's suction lines must be isolated from the reactor coolant system.

   c. The safety injection pumps miniflow line must be closed.

4. The manual switchover of the containment spray pumps require the following interlocks be satisified.

   a. The containment recirculation sump isolation valve is open.

   b. The line from the refueling water storage tank to the pump suction line is closed.

6.3.2.2 Equipment and Component Descriptions

The component design and operating conditions are specified as the most severe conditions to which each respective component is exposed during either normal plant operation, or during operation of the ECCS. For each component these conditions are considered in relation to the code to which it is designed. By designing the components in accordance with applicable codes, and with due consideration for the design and operating conditions, the fundamental assurance of structural integrity of the ECCS components is maintained. Components of the ECCS are designed to withstand the appropriate seismic loadings in accordance with their safety class as given in Table 3.2.2-2.

Pertinent design and operating parameters for the components of the ECCS are given in Table 6.3.2-1. The codes and standards to which the individual components of the ECCS are designed are listed in Table 3.2.2-1.

The major mechanical components of the ECCS follow.

Cold Leg Injection Accumulators

The accumulators are pressure vessels partially filled with borated water and pressurized with nitrogen gas. During normal operation each accumulator is isolated from the Reactor Coolant System (RCS) by two check valves in series.

Should the RCS pressure fall below the accumulator pressure, the check valves open and borated water is forced into the RCS. Each accumulator is attached to one of the cold legs of the RCS. Mechanical operation of the swing-disc check valves is the only action required to open the injection path from the accumulators to the core via the cold leg.

Connections are provided for remotely adjusting the level and boron concentration of the borated water in the accumulator during normal plant operation when required. Accumulator water level may be adjusted either by draining to the reactor coolant drain tank or by pumping borated water from the refueling water storage tank to the accumulator. Samples of the solution in the accumulators are taken periodically for checks of boron concentration.

Accumulator pressure is provided by a supply of nitrogen gas, and can be adjusted as required during normal plant operation; however, the accumulators are normally isolated from this nitrogen supply. Gas relief valves on the accumulators protect them from pressures in excess of design pressure.

The accumulators are located within the containment but outside of the secondary shield wall which protects them from missiles.

Accumulator gas pressure is monitored by indicators and alarms. The operator can take action when required to maintain plant operation within the requirements of the technical specification covering accumulator operability.

Residual Heat Removal Pumps

The residual heat removal pumps are started automatically on receipt of an "S" signal. The residual heat removal pumps deliver water to the RCS from the refueling water storage tank during the injection phase and from the containment sump during the recirculation phase. Each residual heat removal pump is a single stage vertical centrifugal pump.

A minimum flow bypass line is provided for the pumps to recirculate and return the pump discharge fluid to the pump suction should these pumps be started with their normal flow paths blocked. Once flow is established to the RCS, the bypass line is automatically closed. This line prevents deadheading of the pumps and permits pump testing during normal operation.

The residual heat removal pumps are discussed further in Section 5.5.7. A pump performance curve is given in Figure 6.3.2-6.

Centrifugal Charging Pumps

The charging pumps are started automatically on receipt of an "S" signal and are automatically aligned to take suction from the refueling water storage tank during injection. During recirculation, suction is provided from the residual heat removal pump and heat exchangers.

These pumps deliver flow to the RCS at the prevailing RCS pressure. Each centrifugal charging pump is a multistage diffuser design, barrel-type casing with vertical suction and discharge nozzles. A minimum flow bypass line is provided on each pump. An "S" signal closes valves to isolate the normal charging line and volume control tank and opens the charging pump/refueling water storage tank suction valves to align the high head portion of the ECCS for injection. The charging pumps may be tested during power operation in a normal charging alignment.

A pump performance curve for the centrifugal charging pump is presented in Figure 6.3.2-7.

Safety Injection Pumps

The safety injection pumps are started automatically on receipt of an "S" signal. These pumps deliver water to the RCS from the refueling water storage tank during the injection phase and from the containment sump via the residual heat removal pumps and heat exchangers during the recirculation phase. Each high head safety injection pump is driven directly by an induction motor.

A minimum flow bypass line is provided on each pump discharge to recirculate flow to the refueling water storage tank in the event that the pumps are started with the normal flow paths blocked. This line also permits pump testing during normal plant operation. Two parallel valves in series with a third, downstream in a common header, are provided in this line. These valves are manually closed from the control room as part of the ECCS realignment from the injection to the recirculation mode. A pump performance curve is shown in Figure 6.3.2-8.

Residual Heat Exchangers

The residual heat exchangers are conventional shell and U-tube type units. During normal cooldown operation, the residual heat removal pumps recirculate reactor coolant through the tube side while component cooling water flows

Loss of one pump or one flow path will not prevent hot leg recirculation since two redundant flow paths are available for use.

6.3.2.6 Protection Provisions

The provisions taken to protect the system from damage that might result from dynamic effects are discussed in Section 3.6. The provisions taken to protect the system from missiles are discussed in Section 3.5. The provisions to protect the system from seismic damage are discussed in Sections 3.7, 3.9 and 3.10. Thermal stresses on the RCS are discussed in Section 5.2.

6.3 2.7 Provisions For Performance Testing

Test lines are provided for performance testing of the ECCS system as well as individual components. These test lines and instrumentation are shown in Figures 6.3.2-1 thru 6.3.2-5. Additional information on testing can be found in Section 6.3.4.2.

6.3.2.8 Manual Actions

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 re-align the system for the cold leg recirculation mode of operation, and, after approximately 15 hours, for the hot leg recirculation mode of operation. These actions are delineated in Table 6.3.2-7.

The chanreover from the injection mode to recirculation mode is initiated automatically and completed manually by operator action from the main control room. Protection logic is provided to automatically open the two Containment recirculation sump isolation valves and automatically close the two RHR/RWST isolation valves (FW27A and FW55B) when two of four refueling water storage tank level channels indicate a refueling water storage tank level less than a predetermined level in conjunction with the initiation of the engineered safeguards actuation signal ("S" signal). This automatic action aligns the two residual heat removal pumps to take suction from the containment sump and to deliver directly to the RCS. 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 charging pumps and the two safety injection pumps continue to take suction from the refueling water storage tank, following the above automatic action, until manual operator action is taken to align these pumps in series with the residual heat removal pumps.

The refueling water storage tank level protection logic consists of four level channels with each level channel assigned to a separate process control protection set. Four refueling water storage tank level transmitters provide level signals to corresponding normally de-energized level channel bistables. Each level channel bistable would be energized on receipt of a refueling water storage tank level signal less than the predetermined 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, provide the actuation signal to automatically open the corresponding containment sump isolation valves.

A lower refueling water storage tank level signal is also alarmed to inform the operator to initiate the manual action required to realign the charging and safety injection 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 the residual heat removal pump A discharge flow would be used to provide suction to the two charging pumps which would also deliver directly to the RCS cold legs. A portion of the discharge flow from residual heat removal pump B would be used to provide suction to the two safety injection pumps which would also deliver directly to the RCS cold legs. As part of the manual switchover procedure (Table 6.3.2-7), the suctions of the safety injection and charging pumps are cross connected so that one residual heat removal pump can deliver flow to the Reactor Coolant System and both safety injection and charging pumps, in the event of the failure of the other residual heat removal pump.

See Section 7.5 for process information available to the operator in the control room following an accident.

The consequences of the operator failing to act altogether will be loss of high head safety injection pumps and charging pumps.

6.3.3 PERFORMANCE EVALUATION

Acc.dents which require ECCS operation

1. The accidental depressurization of the main steam system.

2. A loss of reactor coolant from small ruptured pipes or from cracks in large pipes.

3. A major reactor coolant system pipe rupture (LOCA).

4. A major secondary system pipe rupture.

5. A steam generator tube rupture.

Accidental Depressurization of the Main Steam System

The most severe core conditions resulting from an accidential depressurization of the main steam system are associated with an inadvertent opening of a single steam dump, relief or safety valve.

In the event of an accidental depressurization of the main steam system, the Safety Injection System is actuated by any of the following:

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

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

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

4. Manual actuation.

A safety injection signal will rapidly close all feedwater control valves, trip the main feedwater pumps, and close the feedwater pump discharge valves.

Following the actuation signal, the suction of the charging pumps is diverted from the volume control tank to the refueling water storage tank. The valves isolating the injection header are automatically opened. The charging pumps force boric acid solution from the RWST, through the header and injection line and into the cold legs of each loop. The safety injection pumps also start automatically but provide no flow when the RCS is at normal pressure. The passive injection systems and the low head system also provide no flow at normal RCS pressure.

Results and Conclusions of Accidental Depressurization of Main Steam System

The assumed steam release is typical of the capacity of any single steam dump relief or safety valve. The boric acid solution provides sufficient negative reactivity to maintain the reactor well below criticality. The cooldown for this case is more rapid than the case of steam release from all steam generators through one steam dump, relief, or safety valve. 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 steam generators. Since the transient occurs over a period of about five minutes, the neglected stored energy is likely to have a significant effect in slowing the cooldown. The analysis shows that after reactor trip, assuming a stuck rod cluster control assembly, with offsite power available, and assuming a single failure in the ESF, there will be no consequential damage to the core or RCS.

Loss of Reactor Coolant from Small Ruptured Pipes or from Cracks in Large Pipes Which Actuate Emergency Core Cooling System

A loss of coolant accident is defined as a rupture of the Reactor Coolant System piping or of any line connected to the system. Ruptures of small cross section will cause expulsion of the coolant at a rate which can be accommodated by the charging pumps. For such a break the charging pumps would maintain an operational water level in the pressurizer permitting the operator to execute an orderly shutdown.

The maximum break size for which the normal makeup system can maintain the pressurizer level is obtained by comparing the calculated flow from the RCS through

1. The calculated peak fuel element clad temperature provides margin to the requirement of 2200°F.

2. The amount of fuel element cladding that reacts chemically with water or steam does not exceed 1 percent of the total amount of Zircaloy in the reactor.

3. The clad temperature transient is terminated at a time when the core geometry is still amenable to cooling. The cladding oxidation limits of 17 percent are not exceeded during or after quenching.

4. The core temperature is reduced and decay heat is removed for an extended period of time, as required by the long-lived radioactivity remaining in the core.

Major Secondary System Pipe Rupture

The steam release arising from a rupture of a main steam pipe would result in energy removal from the RCS causing a reduction of coolant temperature and pressure. In the presence of a negative moderator temperature coefficient, the cooldown results in a reduction of core shutdown margin. There is an increased possibility that the core will become critical and return to power. A return of power following a steam pipe rupture is a potential problem. The core is ultimately shut down by the boric acid injection delivered by the Safety Injection System.

| Minimum capability for injection of the boric acid (2,000 ppm) solution is assumed corresponding to the most restrictive single failure in the safety injection system.

The actual modeling of the Safety Injection System in MARVEL is described in WCAP-7909. The calculated transient delivery times for the borated water are listed in Table 15.1.2-1. In all cases, 2,000 ppm safety injection from the RWST is preceded by the 2000 ppm boron, which is swept from the lines.

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 12 seconds, the valves are assumed to be in their final position and the pump is assumed to be at full speed. This delay, described above, is inherently included in the modeling.

In cases where offsite power is not available, an additional 12 second delay is assumed to start the diesels and to load the necessary safety injection equipment onto them.

Results and Conclusions of Major Secondary System Pipe Rupture

The analysis has shown that assuming a stuck RCCA with or without offsite power, and assuming a single failure in the engineered safeguards the core remains in place and intact. Radiation doses will not exceed 10CFR100 guidelines.

Upper Head Injection Test Line Pressure

A local pressure indicator is provided to monitor pressure in the test line when the injection line check valves are tested for back leakage during plant startup.

SIS Test Line Pressure

Pressure in this line is measured by a locally mounted pressure indicator.

Residual Heat Removal Pump Discharge Pressure

Residual heat removal discharge pressure for each pump is indicated in the control room. A high pressure alarm is actuated by each channel.

6.3.5.3 Flow Indication

Charging Pump Injection Flow

Total charging pump injection flow is measured by a meter mounted in the common 4" injection header between the charging pump discharge and the individual cold leg injection lines. Readout is provided on the main control board.

Safety Injection Pump Header Flow

Flow through the safety injection pump header is indicated in the control room.

Residual Heat Removal Return Line Flow

Flow through each residual heat removal injection and recirculation header leading to the reactor cold legs is indicated in the control room. This instrumentation also controls total RHR flow during cooldown.

SIS Test Line Flow

Local indication of safety injection test line flow is provided.

Residual Heat Removal Hot Leg Injection Flow

The return flow from the residual heat removal loop to the reactor hot legs is indicated in the control room.

Safety Injection Pump Minimum Flow

A flow indicator is installed in the safety injection pump minimum flow line.

Residual Heat Removal Pump Minimum Flow

A flowmeter installed in each residual heat removal pump discharge header provides control for the valve located in the pump minimum flow line.

Table 6.3.2-1 (Page 4)

Emergency Core Cooling System
Component Parameter

Upper Head Injection Accumulators

Number: gas filled	1
liquid filled	1
Design pressure, psig	1800
Design temperature, °F	300
Operating temperature, °F	70-100
Minimum temperature for pressurization, °F	60
Nominal operating pressure, psia	1250
Minimum operating pressure, psia	1200
Total volume, ft^3 (nominal)	1800
Boron concentration in liquid filled tank, ppm; maximum	2100
minimum	1900
Gas in gas filled tank	Nitrogen

Upper Head Injection Surge Tank

Number	1
Design pressure, psig	1800
Design temperature, °F	300
Operating temperatures, °F	70-100
Nominal pressure, psia	1000
Useable volume, ft^3	35
Total volume, ft^3 approx.	55

Table 6.3.2-3 (Page 1)

Motor Operated Isolation Valves In ECCS

Function	Valve I.D.	Interlocks	Automatic Features	Position Indication	Alarms
Cold Leg Accumulator Isolation Valves	1NI54A 1NI65B 1NI76A 1NI88B	None	Opens (if closed) on S. Opens (if closed) on NC pressure greater than P-11. Power to valve operator removed during plant normal power operation	MCB	Yes-Out of Position
NI Pump Suction from FWST	1NI100B 1NI103A 1NI125B	None	None. Power to valve 1NI100B operator removed during plant normal power operation	MCB	Yes-Out of Position
ND Suction from FWST	1FW27A (1FW55B)	Cannot be opened unless the following are closed. Sump valve 1NI185A (1NI184B), auxiliary spray valve 1NS43A (1NS38B), ND discharge to CCP (NI Pump) suction valve 1ND28A (1NI136B) and NS pump suction from containment sump valve 1NS18A (1NS1B).	Valve closes when valve 1NI185A (1NI184B) reaches its full open position.	MCB	Yes-Out of Position
ND Pump Discharge to CCP (NI Pump) Suction	1ND28A (1FW55B)	Cannot be opened unless NI pump miniflow isolated (valves 1NI115 and 1NI144A, or 1NI147B closed) ND to NC	None	MCB	Yes-Out of Position

TABLE 6.3.2-5 (Page 1)

FAILURE MODE AND EFFECTS ANALYSIS - EMERGENCY CORE

COOLING SYSTEM - ACTIVE COMPONENTS

	Component	Failure Mode	ECCS Operation Phase	*Effect on System Operation	**Failure Detection Method	Remarks
1.	Motor operated gate valve 1NV188A (1NV189B analogous)	Fails to close on demand.	Injection - cold legs of RC loops.	Failure reduces redundancy of providing VCT discharge isolation. No effect on safety for system operation; isolation valves 1NV189B and check valve 1NV229 provide backup tank discharge isolation.	Valve position indication (open to closed position change) at MCB. Valve close position monitor light and alarm for group monitoring of components at MCB.	Valve is electrically interlocked with isolation valve 1NV252A. Valves closes on actuation by a SI "S" signal providing isolation valve 1NV-252A is at a full open position.
2.	Motor operated gate valve 1NV252A (1NV253B analogous)	Fails to open on demand.	Injection - cold legs of RC loops.	Failure reduces redundancy of providing fluid flow from RWST to suction of CCP's. No effect on safety for system operation. Valve (1NV253B) opens to provide backup flow path to suction of CCP's.	Valve position indication (closed to open position change) at MCB. Valve open position monitor light and alarm for group monitoring of components at MCB.	Valve is electrically interlocked with the instrumentation that monitors fluid level of the VCT. Valve opens upon actuation by an "S" signal or upon acutation by a "Low-Low-Level" VCT signal.
3.	Centrifugal charging pump A (pump B analogous)	Fails to deliver working fluid.	Injection and recirculation cold legs of RC loops.	Failure reduces redundancy of providing emergency coolant to the RCS at prevailing incident RCS pressure Fluid flow from CCP "A" will be lost. Minimum flow requirements at prevailing high RCS pressures will be met by CCP "B" delivery.	CCP discharge header flow (1NVP6080) at MCB. Open pump switchgear circuit breaker indication at MCB. Circuit breaker close position monitor light for group monitoring of components at MCB. Common breaker alarm at MCB.	One CCP used for normal charging of RCS during plant operation. Pump circuit breaker aligned to close on actuation by an "S" signal.

* See list at end of table for definition of acronyms and abbreviations used.

** As part of plant operation, periodic tests, surveillance inspections and instrument calibrations are made to monitor equipment and performance. Failures may be detected during such monitoring of equipment in addition to detection methods noted.

TABLE 6.3.2-5 (Page 3)

	Component	Failure Mode	ECCS Operation Phase	*Effect on System Operation	**Failure Detection Method	Remarks
		b. Fails closed.	Injection - cold legs of RC loops.	b. Failure results in an insufficient fluid flow through RHR pump A for a small LOCA or steam line break resulting in possible pump damage. If pump becomes inoperative, minimum flow requirements for LHSI will be met by RHR pump B delivering working fluid to RCS.	b. Valve position indication (closed to open position change) at MCB. RHR pump return line to cold legs flow indication (1NDP5190) at MCB.	
8.	Residual heat removal pump A (Pump B analogous)	Fails to deliver working fluid.	Injection - cold legs of RC loops.	Failure reduces redundancy of providing emergency coolant to the RCS from the RWST at low RCS pressure. Fluid flow from RHR pump A will be lost. Minimum flow requirements for LHSI will be met by RHR pump B delivering working fluid.	RHR pump return line to cold legs flow indication (1NDP5190) and low flow alarm at MCB. RHR pump discharge pressure (1NDP-5090) at MCB. Open pump switchgear circuit breaker indication at MCB. Circuit breaker close position monitor light for group monitoring of components at MCB. Common breaker trip alarm at MCB.	The RHR pump is sized to deliver reactor coolant through the RHR heat exchanger to meet plant cooldown and startup operations. The pump circuit breaker is aligned to close on actuation by an "S" signal.

TABLE 6.3.2-5 (Page 4)

Component	Failure Mode	ECCS Operation Phase	*Effect on System Operation	**Failure Detection Method	Remarks
9. Safety Injection pump A, (Pump B analogous)	Fails to deliver working fluid.	Injection - cold legs of RC loops.	Failure reduces redundancy of providing emergency coolant to the RCS from the RWST at high RCS pressure (1520 psi). Fluid flow from SI pump A will at MCB. be lost. Minimum flow requirements for HHSI will be met by SI pump B delivering working fluid.	SI pumps discharge pressure (1NIP5440) at MCB. SI pump discharge flow (1NIP5450) at MCB. Open pump switchgear circuit breaker indication Circuit breaker close position monitor light and alarm for group monitoring of components at MCB. Common breaker trip alarm at MCB.	Pump circuit breaker aligned to close on actuation by an "S" signal.
10. Motor operated gate valve 1NI185A (1NI-184B analogous)	Fails to open on demand.	Recirculation - cold legs of RC loops.	Failure reduces redundancy of providing fluid from the Containment Sump to the RCS during recirculation. RHR pump A will not provide recirculation flow. Minimum LHSI flow requirements will be met through opening of isolation valve 1NI184B and recirculation of fluid by RHR pump B.	Same methods of detection as those stated for item #2. In addition failure may be detected through monitoring of RHR pump return line to cold legs flow indication (1NDP5190) and RHR pump discharge pressure (1NDP5090) at MCB.	Valve is actuated to open by "S" signal in coincidence with "Low-Low Level" RWST signal. Valve is electrically interlocked from being opened from MCB by isolation valves 1FW27A, 1ND2A and 1ND1B.
11. Motor operated gate valve 1FW27A (1FW55B analogous)	Fails to close on demand.	Recirculation - cold legs of RC loops.	Failure reduces redundancy of providing flow isolation of Containment Sump from RWST. No effect on safety for system operation. Check valve 1FW28 provides backup isolation.	Same methods of detection as those stated for item #1.	Valve automatically closes when 1ND185A is fully open and MCB switch is in "auto" position. Valve is electrically interlocked with isolation valves 1ND28A, 1NI185A, 1NS43A, and 1NS18. It may not be remotely opened from MCB unless these valves are closed.

TABLE 6.3.2-5 (Page 5)

	Component	Failure Mode	ECCS Operation Phase	*Effect on System Operation	**Failure Detection Method	Remarks
12.	Motor operated gate valve 1ND32A (1ND65B analogous)	Fails to close on demand.	Recirculation - cold legs of RC loops.	Failure reduces redundancy of providing RHR pump train separation for recirculation of fluid to cold legs of RCS. No effect on safety for system operation. Valve 1ND65B provides backup isolation for LHSI/RHR pump train separation.	Same methods of detection as those stated for item #1.	
13.	Motor operated globe valve 1NI147B	Fails to close on demand.	Recirculation - cold legs of RC loops.	Failure reduces redundancy of providing isolation of SI pump's miniflow line isolation from RWST. No effect on safety for system operation. Valve (1NI115A and 1NI144A) in each pump's miniflow line provide backup isolation.	Same methods of detection as those stated for item #1.	Valve is electrically interlocked with isolation valves 1ND28A and 1NI136B. It may not be opened unless these valves are closed.
14.	Motor operated globe valve 1NI115A (1NI144A analogous)	Fails to close on demand.	Recirculation - cold legs of RC loops.	Failure reduces redundancy of providing isolation of SI pump A miniflow isolation from RWST. No effect on safety for system operation. Valve 1NI147B in common miniflow line provides backup isolation.	Same methods of detection as those stated for item #1.	Same remark as that stated for item #16.

TABLE 6.3.2-5 (Page 6)

	Component	Failure Mode	ECCS Operation Phase	*Effect on System Operation	**Failure Detection Method	Remarks
15.	Motor operated gate valve 1ND28A	Fails to open on demand.	Recirculation - cold legs of RC loops.	Failure reduces redundancy of providing flow to suction of CCP's from RHR pumps. No effect on safety for system operation. Flow requirements for CCP suction will be met by flow from RHR pump B via cross-tie line and opening of isolation valve 1NI332A or 1NI333B and normally open valve 1NI334B.	Same methods of detection as those stated for item #2.	Valve is electrically interlocked with isolation valves 1NI115A, 1NI144A, 1NI147B, 1ND2A and 1ND1B, and 1NI185A. Valve cannot be opened unless valve 1NI147B or valves 1NI115A and 1NI144A are closed, and valve 1ND2A or 1ND1B is closed, and valve 1NI185A is open.
16.	Motor operated gate valve 1NI136B	Fails to open on demand.	Recirculation - cold legs of RC loops.	Failure reduces redundancy of providing flow to suction of SI pumps from RHR pumps. No effect on safety for system operation. Flow requirements for SI pump suction will be met by flow from RHR pump A via cross-tie line and opening of isolation valve 1NI332A or 1NI333B and valve 1ND28A.	Same methods of detection as those stated for item #2.	Valve is electrically interlocked with isolation valves 1NI115A, 1NI144A, 1NI147B, 1ND37A, 1ND36B, and 1NI184B. Valve cannot be opened unless valve 1NI147B or valves 1NI115A and 1NI144A are closed, and valve 1ND37A or 1ND36B is closed, and valve 1NI184B is open.
17.	Motor operated gate valve 1NI332A (1NI333B analogous)	Fails to open on demand.	Recirculation - cold legs of RC loops.	Failure reduces redundancy of providing fluid flow through cross-tie between suction of CCP's and SI pumps. No effect on safety for system operation. Valve 1NI333B opens to provide backup flow path through cross-tie line.	Same methods of detection as th se for item #2.	

	Component	Failure Mode	ECCS Operation Phase	*Effect on System Operation	**Failure Detection Method	Remarks
18.	Motor operated gate valve 1NI100B	Fails to close on demand.	Recirculation - cold legs of RC loops.	Failure reduces redundancy of providing flow isolation of SI pump suction from RWST. No effect on safety for system operation. Check valve 1NI101 provides backup isolation.	Same methods of detection as those stated for item #1.	
19.	Motor operated gate valve 1NV252A (1NV253B analogous)	Fails to close on demand.	Recirculation - cold legs of RC loops.	Failure reduces redundancy of providing flow isolation of suction of CCP's from RWST. No effect on safety for system operation. Check valve 1NV254 provides backup isolation.	Same methods of detection as those state previously for failure of item during injection phase of ECCS operation.	
20.	Residual heat removal pump A (pump B analogous)	Fails to deliver working fluid.	Recirculation - cold legs of RC loops.	Failure reduces redundancy of providing recirculation of coolant to the RCS from the Containment Sump. Fluid flow from RHR pump A will be lost. Minimum recirculation flow requirements for LHSI flow will be met by RHR pump B delivering working fluid.	Same methods of detection as those stated previously for failure of item during injection phase of ECCS operation.	
21.	Safety injection pump A, (pump B analogous)	Fails to deliver working fluid.	Recirculation - cold or hot legs of RC loops.	Failure reduces redundancy of providing recirculation of coolant to the RCS from the Containment Sump to cold legs of RC loops via RHR and SI pumps. Fluid flow from SI pump A will be lost. Minimum recirculation flow requirements for HHSI flow will be met by SI pump B delivering working fluid.	Same methods of detection as those stated previously for failure of item during injection phase of ECCS operation.	

TABLE 6.3.2-5 (Page 8)

	Component	Failure Mode	ECCS Operation Phase	*Effect on System Operation	**Failure Detection Method	Remarks
22.	Motor operated gate valve 1NI173A	Fails to close on demand.	Recirculation - hot legs of RC loops.	Failure reduces redundancy of providing recirculation of coolant from the Containment Sump to hot legs of RC loops. Fluid flow from RHR pump A will continue to flow to cold legs of RC loops. Minimum recirculation flow requirements to hot legs of RC loops will be met by RHR pump B recirculating fluid to RC hot legs via SI pumps.	Same methods of detection as those stated for item #1.	
23.	Motor operated gate valve 1ND32A	Fails to open on demand.	Recirculation - hot legs of RC loops.	Failure reduces redundancy of providing recirculation of coolant from the Containment Sump to the hot legs of RC loops. Minimum flow requirements will be met by RHR pump B recirculating fluid to RC hot legs via SI pumps.	Valve position indication (closed to open position change) at MCB. Valve close position monitor light and alarm for group monitoring of components at MCB. In addition, RHR pump discharge pressure (1NDP5090) at MCB.	
24.	Motor operated gate valve 1NI183B	Fails to open on demand.	Recirculation - hot legs of RC loops.	Same effect on system operation as that stated for item #26.	Same methods of detection as those stated for item #2. In addition, RHR pump discharge pressure (1NDP5090) at MCB.	
25.	Motor operated gate valve 1NI178B	Fails to close on demand.	Recirculation - hot legs of RC loops.	Failure reduces redundancy of providing recirculation of coolant from the Containment Sump to hot legs of RC loops. Fluid flow from RHR pump B will continue to flow to cold legs of loops. Minimum recirculation flow requirements to hot legs of RC loops will be met by RHR pump A recirculating fluid to RC hot legs.	Same methods of detection as those stated for item #1.	

TABLE 6.3.2-5 (Page 9)

	Component	Failure Mode	ECCS Operation Phase	*Effect on System Operation	**Failure Detection Method	Remarks
26.	Motor operated gate valve 1NI118A (1NI150B analogous)	Fails to close on demand.	Recirculation - hot legs of RC loops.	Failure reduces redundancy of providing flow isolation of SI pump flow to cold legs of RC loops. No effect on safety for system operation. Valve 1NI162A provides backup isolation against flow to cold legs of RC loops. If loss of train "A" power, see item 24.	Same methods of detection as those stated for item #1.	
27.	Motor operated gate valve 1NI121A (1NI152B analogous)	Fails to open on demand.	Recirculation - hot legs of RC loops.	Failure reduces redundancy of providing recirculation of coolant to the hot legs of RCS from the Containment Sump via SI pumps. Minimum recirculation flow requirements to hot legs of RC loops will be met by RHR pump A recirculating fluid from Containment Sump to hot legs of RC loops and SI pump B recirculating fluid to hot legs A and D of RC loops through the opening of isolation valve 1NI152B.	Same methods of detection as those stated for item #2. In addition, SI pump discharge pressure (1NIP5440) and flow (1NIP5450) at MCB.	
28.	Motor operated gate valve 1NI162A	Fails to close on demand.	Recirculation - hot legs of RC loops.	Failure reduces redundancy of providing flow isolation of SI pump flow to cold legs of RC loops. No effect on safety for system operation. Valves 1NI118A and 1NI150B in cross-tie line between HHSI/SI pumps provides backup isolation against flow to cold legs of RC loops. If loss of train "A" power, see item 24.	Same method of detection as that stated for item #1.	

TABLE 6.3.2-5 (Page 10)

	Component	Failure Mode	ECCS Operation Phase	*Effect on System Operation	**Failure Detection Method	Remarks
29.	Residual heat removal pump A (Pump B analogous)	Fails to deliver working fluid.	Recirculation - hot legs of RC loops.	Failure reduces redundancy of providing recirculation of coolant from the Contaiment Sump to the hot legs of RC loops. Fluid flow from RHR pump A will be lost. Minimum flow requirements to hot legs of RC loop will be met by RHR pump B recirculating fluid to RC hot legs via SI pumps.	Same method of detection as that stated previously for failure of item during injection phase of ECCS operation.	
30.	Hydraulic cylinder operated gate valve 1NI242B (1NI243A analogous)	Fails to close on demand.	Injection - upper head of pressure vessel.	Failure reduces the redundancy of isolation valves provided for UHI accumulator tank discharge line "A" to block flow of N^2 from the tank to the UHI nozzles of the RV after the injection of water to the RV. No effect on safety for system operation. Alternate isolation valve (1NI243A) in the tank discharge line closes to provide backup isolation against the flow of N^2 to the RV.	Valve position (UHI valve full closed) monitor light for group monitoring of components (containment isolation) at MCB. Valve position indication (open to closed position change) at HSP. Gag motor position indication (not gagged to gagged position change) at HSP. UHI valve hydraulic system trouble alarm at MCB.	Valve is electrically interlocked with the instrumentation that monitors fluid level (1NILS5720) of the UHI accumulator tank. Valve is energized to close upon actuation by a low water level signal. Alarm is generated if valve is closed and RCS pressure is above the "SI" unblock valve.
31.	Hydraulic cylinder operated gate valve 1NI244B (1NI245A analogous)	Fails to close on demand.	Injection - upper head of pressure vessel.	Same effect on system operation as that stated above for item #33 except applies to to UHI accumulator tank discharge line "B".	Same methods of detection as those stated above for item #33.	Same remark as that stated above for item #33 except fluid level instrumentation 1NILS5730 actuates valve to close.

Table 6.3.2-6 (Page 1)

Single Active Failure Analysis For Emergency Core Cooling System Components

Short Term Phase

Component	Malfunction	Comments
1. Pumps		
a. Centrifugal charging	Fails to start	Two provided, evaluation based on operation of one.
b. Safety injection	Fails to start	Two provided, evaluation based on operation of one.
c. Residual heat removal	Fails to start	Two provided, evaluation based on operation of one.
2. Automatically Operated Valves		
a. CCP to cold leg injection isolation	Fails to open	Two parallel lines; one valve in either line required to open.
b. Residual heat removal pump suction line from containment sump	Fails to open	Only one RHR pump required to meet LPSI flow criteria.
c. Residual heat removal pump suction line from refueling water storage tank	Fails to close	Switchover sequence allows for failure of one suction line to be isolated.
d. Centrifugal Charging Pumps		
i. Suction line from refueling water storage tank	Fails to open	Two parallel lines; only one valve in either line required to open.

Table 6.3.2-7 (Page 1)

Sequence Of Changeover Operation From Injection To Recirculation

Automatic Actions

A1. The containment recirculation sump isolation valves (1NI184B and 1NI185A) open when two out of four Refueling Water Storage Tank (FWST) level instruments indicate a FWST level less at or below the Low level setpoint in conjunction with an "S" signal.

A2. The RHR pump/FWST isolation valves in each pump suction line (1FW27A and 1FW55B) automatically closes when the corresponding containment sump valve reaches its full open position.

MANUAL ACTIONS

After these automatic actions, which complete switchover of the RHR pumps to the containment recirculation sump, the operator performs the following manual actions to complete the switchover.

M1.a. Close safety injection pump 1A recirculation line isolation valve (1NI115A).
   b. Close safety injection pump 1B recirculation line isolation valve (1NI144B).
   c. Restore power to the safety injection pumps recirculation header to FWST isolation valve (1NI147B).
   d. Close 1NI147B.

M2.a. Close the RHR Train 1A hot leg injection isolation valve (1ND32A).
   b. Close the RHR Train 1B hot leg injection isolation valve (1ND65B).

M3.a. Open the safety injection pump suction crossover from RHR isolation valve (1NI332A).
   b. Open the safety injection pump suction crossover from RHR isolation valve (1NI333B).

M4.a. Open the RHR heat exchanger 1A outlet to charging pump suction isolation valve (1ND28A).
   b. Open the RHR heat exchanger 1B outlet to safety injection pump 1B isolation valve (1NI136B).

The remaining manual actions required to complete switchover are delayed until the FWST Low-Low level is reached. At that time, the operator proceeds immediately to step M5. In the iterim period, the operator performs the following nonessential manual actions.

I1. Close the safety injection pumps suction from the FWST isolation valve (1NI100B).
I2. Close the parallel centrifugal charging pumps suction from the FWST isolation valves (1NV252A, 1NV253B).

Table 6.3.2-7 (Page 2)

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 6.3.3-2

Normal Operating Status Of Emergency Core Cooling System Components For Core Cooling

Number of Safety Injection Pumps Operable	2
Number of Charging Pumps Operable	2
Number of Residual Heat Removal Pumps Operable	2
Number of Residual Heat Exchangers Operable	2
Refueling Water Storage Tank Volume, gal (minimum)	350,000
Boron Concentration in Refueling Water Storage Tanks, Minimum, ppm	2,000
Boron Concentration in Accumulator, minimum, ppm	1,900
Number of Cold Leg Injection Accumulators	4
Minimum Accumulator Pressure, psia	406
Nominal Accumulator Water Volume, ft^3	1050
System Valves, Interlocks, and Piping Required for the Above Components which are Operable	All
Number of UHI Accumulators: Water filled	1
Gas filled	1
Nominal UHI Accumulator Pressure, psia	1250

7.2 REACTOR TRIP SYSTEM

7.2.1 DESCRIPTION

7.2.1.1 System Description

The Reactor Trip System automatically keeps the reactor operating within a safe region by shutting down the reactor whenever the limits of the region are approached. The safe operating region is defined by several considerations such as mechanical/hydraulic limitations on equipment and heat transfer phenomena. Therefore the Reactor Trip System keeps surveillance on process variables which are directly related to equipment mechanical limitations, such as pressure, pressurizer water level (to prevent water discharge through safety valves, and uncovering heaters) and also on variables which directly affect the heat transfer capability of the reactor (e.g. flow and reactor coolant temperatures). Still other parameters utilized in the Reactor Trip System are calculated from various process variables. In any event, whenever a direct process or calculated variable exceeds a setpoint the reactor will be shutdown in order to protect against either gross damage to fuel cladding or loss of system integrity which could lead to release of radioactive fission products into the containment.

The following systems make up the Reactor Trip System (see References 1, 2, and 3 for additional background information.)

1. Process Instrumentation and Control System.

2. Nuclear Instrumentation System.

3. Solid State Logic Protection System.

4. Reactor Trip Switchgear.

5. Manual Actuation Circuit.

The Reactor Trip System consists of sensors which, when connected with analog circuitry consisting of two to four redundant channels, monitor various plant parameters; and digital circuitry, consisting of two redundant logic trains, which receives inputs from the analog protection channels to complete the logic necessary to automatically open the reactor trip breakers.

Each of the two logic trains, A and B, is capable of opening a separate and independent reactor trip breaker, RTA and RTB, respectively. The trip breakers in series connect three-phase ac power from the rod drive motor-generator sets to the rod drive power cabinets, as shown on Figure 7.2.1-1, Sheet 2. During plant power operation, a dc undervoltage coil on each reactor trip breaker holds a trip plunger out against its spring, allowing the power to be available at the rod control power supply cabinets. For reactor trip, a loss of dc voltage to the undervoltage coil releases the trip plunger and trips open the breaker. Additionally the shunt trip coil is energized to independently trip open the breaker. When either of the trip breakers opens, power is interrupted to the rod drive power supply, and the control rods fall, by gravity, into the core. The rods cannot be withdrawn until the trip breakers are manually reset.

The trip breakers cannot be reset until the abnormal condition which initiated the trip is corrected. Bypass breakers BYA and BYB are provided to permit testing of the trip breakers, as discussed in Section 7.2.2.2.3.

7.2.1.1.1 Functional Performance Requirements

The Reactor Trip System automatically initiates reactor trip:

1. Whenever necessary to prevent fuel damage for an anticipated operational transient (Condition II),

2. To limit core damage for infrequent faults (Condition III),

3. So that the energy generated in the core is compatible with the design provisions to protect the reactor coolant pressure boundary for limiting fault conditions (Condition IV).

The Reactor Trip System initiates a turbine trip signal whenever reactor trip is initiated to prevent the reactivity insertion that would otherwise result from excessive reactor system cooldown and to avoid unneccessary actuation of the Engineered Safety Features Actuation System.

The Reactor Trip System provides for manual initiation of reactor trip by operator action.

7.2.1.1.2 Reactor Trips

The various reactor trip circuits automatically open the reactor trip breakers whenever a condition monitored by the Reactor Trip System reaches a preset level. To ensure a reliable system, high quality design, components, manufacturing, quality control, and testing are used. In addition to redundant channels and trains, the design approach provides a Reactor Trip System which monitors numerous system variables, therefore providing protection system functional diversity. The extent of this diversity has been evaluated for a wide variety of postulated accidents.

Table 7.2.1-1 provides a list of reactor trips which are described below.

1. Nuclear Overpower Trips

   The specific trip functions generated are as follows:

   a. Power range high neutron flux trip.

      The power range high neutron flux trip circuit trips the reactor when two of the four power range channels exceed the trip setpoint.

      There are two bistables, each with its own trip setting used for a high and low range trip setting. The high trip setting provides protection during normal power operation and is always active. The low trip setting, which provides protection during startup, can be manually bypassed when two out of the four power range channels read above approximately 10 percent power (P-10). Three out of the four channels below 10 percent automatically reinstates the trip function. Refer to Table 7.2.1-2 for a listing of all protection system interlocks.

b. Intermediate range high neutron flux trip

The intermediate range high neutron flux trip circuit trips the reactor when one out of the two intermediate range channels exceed the trip setpoint. This trip, which provides protection during reactor startup, can be manually blocked if two out of four power range channels are above approximately 10 percent power (P-10). Three out of the four power range channels below this value automatically reinstates the intermediate range high neutron flux trip. The intermediate range channels can be individually bypassed at the nuclear instrumentation racks to permit channel testing during plant shutdown or prior to startup. This bypass action is annunciated on the control board.

c. Source range high neutron flux trip

The source range high neutron flux trip circuit trips the reactor when one of the two source range channels exceeds the trip setpoint. This trip, which provides protection during reactor startup and plant shutdown, can be manually bypassed when one of the two intermediate range channels reads above the P-6 setpoint value and is automatically reinstated when both intermediate range channels decrease below the P-6 setpoint value. This trip is also automatically bypassed by two-out-of-four logic from the power range protection interlock (P-10). This trip function can also be reinstated below P-10 by an administrative action requiring manual actuation of two control board mounted switches. Each switch will reinstate the trip function in one of the two protection logic trains. The source range trip point is set between the P-6 setpoint (source range cutoff power level) and the maximum source range power level. The channels can be individually bypassed at the nuclear instrumentation racks to permit channel testing during plant shutdown or prior to startup. This bypass action is annunciated on the control board.

d. Power range high positive neutron flux rate trip

This circuit trips the reactor when a sudden abnormal increase in nuclear power occurs in two out of four power range channels. This is available for trip ~~provides DNB protection against~~ rod ejection accidents of low worth from mid-power and is always active.

e. Power range high negative neutron flux rate trip

This circuit trips the reactor when a sudden abnormal decrease in nuclear power occurs in two out of four power range channels. This trip provides protection against two or more dropped rods and is always active. Protection against one dropped rod is not required to prevent occurence of DNBR per Section 15.2.2.

Figure 7.2.1-1, Sheet 3, shows the logic for all of the nuclear overpower and rate trips.

Automatic protection is provided in case the spurious high level reduces feedwater flow sufficiently to cause low-low level in the steam generator. Automatic protection is also provided in case the spurious low level signal increases feedwater flow sufficiently to cause high level in the steam generator. A turbine trip and feedwater isolation would occur on two-out-of-four high-high steam generator water level in any loop.

7.2.2.4 Additional Postulated Accidents

Loss of plant instrument air or loss of component cooling water is discussed in Section 7.3.2.3. Load rejection and turbine trip are discussed in further detail in Section 10.2.2.

The control interlocks, called rod stops, that are provided to prevent abnormal power conditions which could result from excessive control rod withdrawal are discussed in Section 7.7.1.4.1 and listed on Table 7.7.1-1. Excessively high power operation (which is prevented by blocking of automatic rod withdrawal), if allowed to continue, might lead to safety limit (as given in Chapter 16) being reached. Before such a limit is reached, protection will be available from the Reactor Trip System. At the power levels of the rod block setpoints, safety limits have not been reached; and therefore these rod withdrawal stops do not come under the scope of safety-related system, and are considered as control systems.

7.2.3 TESTS AND INSPECTIONS

The Reactor Trip System meets the testing requirements of IEEE 338-1971, as discussed in Section 7.1.2.4. The testability of the system is discussed in Section 7.2.2.2.3. The initial test intervals are specified in Chapter 16. Written test procedures and documentation, conforming to the requirements of IEEE 338-1971, will be available for audit by responsible personnel. Periodic testing complies with Regulatory Guide 1.22 as discussed in Sections 7.1.2.4 and 7.2.2.2.3.

The redundancy concept is applied to both the analog and logic portions of the system. Separation of redundant analog channels begins at the process sensors and is maintained in the field wiring, containment vessel penetrations and analog protection racks terminating at the redundant safeguards logic racks. The design meets the requirements of Criteria 20, 21, 22, 23 and 24 of the 1971 GDC.

The variables are sensed by the analog circuitry as discussed in Reference 1 and in Section 7.2. The outputs from the analog channels are combined into actuation logic as shown on Figure 7.2.1-1, Sheets 5, 6, 7 and 8. Tables 7.3.1-1 and 7.3.1-2 give additional information pertaining to logic and function.

The interlocks associated with the Engineered Safety Features Actuation System are outlined in Table 7.3.1-3. These interlocks satisfy the functional requirements discussed in Section 7.1.2.

Manual actuation from the control board for containment isolation Phase A is provided by operating either the train A or train B containment isolation Phase A controls. Also on the control board is manual actuation of safety injection by either train A or train B controls and a manual activation of containment isolation Phase B by either train A or train B controls.

Manual controls are also provided to switch from the injection to the recirculation phase after a loss of coolant accident.

A description of the Ice Condenser System and its associated instrumentation is given in Chapter 6.

7.3.1.1.1 Function Initiation

The specific functions which rely on the Engineered Safety Features Actuation System for initiation are:

1. A reactor trip, provided one has not already been generated by the Reactor Trip System.

2. Charging pumps, safety injection pumps, residual heat removal pumps, and associated valving which provide emergency makeup water to the cold legs of the Reactor Coolant System following a loss of coolant accident.

3. Service water pumps which provide cooling water to the component cooling system heat exchangers and are thus the heat sink for containment cooling.

4. Motor driven auxiliary feedwater pumps.

5. Phase A containment isolation, whose function is to prevent fission product release. (Isolation of all lines not essential to reactor protection.)

6. Steam line isolation to prevent the continuous, uncontrolled blowdown of more than one steam generator and thereby uncontrolled Reactor Coolant System cooldown.

7. Main feedwater line isolation as required to prevent or mitigate the effect of excessive cooldown.

8. Start the emergency diesels to assure backup supply of power to emergency and supporting systems components.

9. Annulus Ventilation System actuation to maintain a negative pressure in the Annulus.

10. Containment spray actuation which performs the following functions:

ICSB Q110

a. Initiates containment air return fans (after time delay) and containment spray to reduce containment pressure and temperature following a loss of coolant or steamline break accident inside of containment.

b. Initiates Phase B containment isolation which isolates the containment following a loss of reactor coolant accident or a steam or feedwater line break within containment to limit radioactive releases. (Phase B isolation together with Phase A isolation results in isolation of all but safety injection and spray lines penetrating the containment.)

11. The Auxiliary Building Ventilation System, the Control Room Area Ventilation System, and the Diesel Building Ventilation System actuate to the following safety modes.

ICSB Q97

a. The Auxiliary Building Ventilation System aligns to the filtered exhaust mode to maintain the emergency core cooling system pump rooms at a negative pressure.

b. Diesel Building Ventilation System actuates to maintain proper ventilation of the Diesel Building for Equipment operation.

c. Control Room Area Ventilation System actuates to maintain the environment in the control room, control room area, and switchgear rooms within acceptable limits for equipment operation and post-accident habitability.

7.3.1.1.2 Analog Circuitry

The process analog sensors and racks for the Engineered Safety Features Actuation System are covered in Reference 1. Discussed in this report are the parameters to be measured including pressures, flows, tank and vessel water levels, and temperatures as well as the measurement and signal transmission considerations. These latter considerations include the transmitters, orifices and flow elements, resistance temperature detectors, as well as automatic calculations, signal conditioning, and location and mounting of the devices.

TABLE 7.3.1-2

INSTRUMENT OPERATING CONDITIONS FOR ISOLATION FUNCTIONS

NO.		FUNCTIONAL UNIT	NO. OF CHANNELS	NO. OF CHANNELS TO TRIP
1.	CONTAINMENT ISOLATION			
	a.	Automatic Safety Injection (Phase A)	See Item No. 1 (b) through (d) of Table 7.3.1-1	
	b.	Containment Pressure (Phase B)	See Item No. 2 (b) of Table 7.3.1-1	
	c.	Manual Phase A	2	1
		Phase B	See Item No. 2 (a) of Table 7.3.1-1	
2.	STEAM LINE ISOLATION			
	a.	High Steam Negative Pressure Rate	12 (3/steam line)	2/steam line in any steam line
	b.	Containment Pressure (High-High)	See Item No. 2 (b) of Table 7.3.1-1	
	c.	Safety Injection (Low steam line pressure)	See Item No. 1 (c) of Table 7.3.1-1	
	d.	Manual	1/loop*	1/loop*
3.	FEEDWATER LINE ISOLATION			
	a.	Safety Injection	See Item No. 1 of Table 7.3.1-1	
	b.	Steam Generator High-High level 2/4 on any Steam Generator	4/loop	2/loop
	c.	Low T_{avg}, interlocked with P4	See P4 on Table 7.3.1-3	

* Additionally, there will be two switches (one for train A and one for train B) that will actuate all four main steam line isolation and bypass valves at the system level.

TABLE 7.3.1-3 (Continued)

INTERLOCKS FOR ENGINEERED SAFETY FEATURES ACTUATION SYSTEM

Designation	Input		Function Performed
P-11 (CONT)	2/3 Pressurizer pressure above setpoint	(a)	Reinstates automatically safety injection and steamline isolation on low steamline pressure and automatically blocks steamline pressure rate
		(b)	Defeats manual block of safety injection actuation and steamline isolation on low steamline pressure and defeats steamline isolation on high steamline negative pressure rate
ICSB Q78		(c)	Defeats manual block of motor driven auxiliary feedwater pumps automatic starting on 2/4 low-low steam generator level and loss of both main feedwater pumps as described in Section 7.4.1.1
P-12	2/4 T_{avg} below setpoint	(a)	Blocks steam dump
		(b)	Allows manual bypass of steam dump block for the cooldown valves only
	3/4 T_{avg} above setpoint	(a)	Defeats the manual bypass of steam dump block
P-14	2/4 Steam generator water level above setpoint on any steam generator	(a)	Closes all feedwater control valves
		(b)	Trips all main feedwater pumps which closes the pump discharge valves
		(c)	Actuates turbine trip

Q 430.5 Typically, the motor control centers on the 600VAC Normal Auxiliary Power System are double fed such that if the load center which normally feeds a motor control center is unavailable, a transfer is initiated to the motor control center's alternate source. The normal and alternate load center breakers feeding double ended motor control centers are electrically interlocked to prevent paralleling the two incoming sources. A hot bus transfer, where the two incoming sources are momentarily paralleled, can be made if the controls of both load centers are placed in the manual mode and the two incoming sources are in-sync.

8.3.1.1.1.6 600VAC Station Normal Auxiliary Power System

The 600VAC Station Normal Auxiliary Power System supplies power to the non-Class 1E station related loads and station normal motor control centers. This system is shown on Figure 8.3.1-1.

The 600VAC Station Normal Auxiliary Power System consists of eight load centers, their associated transformers, and motor control centers. Six of these load centers are each fed by 1500KVA, 6900/600 volt load center transformers. The other two load centers are normally fed by separate 2000KVA, 6900/600 volt load center transformers. These two load centers are also provided with a standby transformer that serves as an alternate source in the event that one of the normal load center transformers is out of service. The incoming breakers for these load centers are electrically interlocked to prevent paralleling two sources or feeding both load centers simultaneously from the standby transformer.

Q 430.5 The load centers receiving power through 1500KVA, 6900/600 volt load center transformers, distribute power to the 600 volt station motor control centers. Typically, each motor control center is double fed such that if the load center which normally feeds a motor control center is unavailable, a transfer is initiated to the alternate source for the motor control center. The normal and alternate load center breakers feeding double ended motor control centers are electrically interlocked to prevent paralleling the two incoming sources. A hot bus transfer, where the two incoming sources are momentarily paralleled, can be made if the controls of both load centers are placed in the manual mode and the two incoming sources are in-sync.

8.3.1.1.1.7 600VAC Cooling Tower Auxiliary Power System

The 600 volt Cooling Tower Auxiliary Power System supplies power to the cooling tower fan motors and auxiliaries via the cooling tower motor control centers. This system for both units is shown on Figure 8.3.1-2.

This 600VAC system is supplied from the 13.8kV Normal Auxiliary Power System and consists of 18 motor control centers and six 13800/600 volt transformers. This system is arranged such that each transformer supplies three motor control centers.

5. Regulatory Guide 1.68, Rev. 2, Appendix A, Section 1.g.3.

6. Regulatory Guide 1.108, Rev. 1, Sections C.2.a and C.2.b.

7. Regulatory Guide 1.137, Rev. 1, Section C.1.c.

8. ANSI N195 1976, Section 6.1.

B. Periodic Testing:

Tests as described in:

1. IEEE 387-1977, Sections 6.6 & 6.7.

2. Catawba Technical Specifications, Section 4.8.1.1.2.

3. Regulatory Guide 1.108, Rev. 1, Sections C.2.a.1 thru 8, C.2.b, C.2.c, C.2.d, C.2.e, and C.3.

8.3.1.1 3.11 125VDC Diesel Control Power

A 125VDC Diesel Essential Auxiliary Power System is provided to supply power to the diesel generator control panel associated with each diesel generator. Each system consists of separate battery and battery charger units which are independent and physically separate between trains. The battery chargers are fed from 600 volt essential motor control centers and provide the necessary power for normal bus operation while maintaining the batteries fully charged. Each battery assumes its system load without interruption upon loss of the battery charger or ac power failure. A detailed description of the 125VDC Diesel Essential Auxiliary Power System is presented in Section 8.3.2.1.2.2.

8.3.1.1.4 Design Bases for Class 1E Motors

Class 1E motors are sized to operate their associated driven load continuously in accordance with the motors respective speed-torque and brake horsepower requirements.

The minimum accelerating voltage for Class 1E motors is 80% of motor rated voltage except for diesel generator auxiliary motors not required during a loss of coolant accident and Class 1E motor operators for valves. These latter two types of motors are designed to start at 90% and 85% of motor rated voltage, respectively. The diesel generator auxiliary motors which are rated 90% are listed below:

Q 430.24
(1) Diesel generator engine jacket water keep warm pump motor
(2) Diesel generator engine prelube oil pump motor

The minimum separation between redundant Class 1E wiring or between Class 1E and non-Class 1E wiring inside equipment enclosures and with potentials less than 150 volts is:

1. Six inches of free air space without barriers

2. One inch of free air space (or equivalent thermal insulation) between the wiring on both sides of a single barrier

3. One inch free air space (or equivalent thermal insulation) between two barriers (the barriers may be directly adjacent to the wiring or device)

4. 1/8 inch asbestos or equivalent thermal insulation between two barriers (the barriers may be directly adjacent to the wiring or device)

Barriers extend beyond the wiring to the extent that the straight line, free air distance between redundant wiring is a minimum of six inches.

Where wiring is completely surrounded by a single barrier (e.g. conduit, etc.), the minimum separation between that barrier and the external wiring is:

1. Two inches of free air space (or equivalent thermal insulation) for separation of redundant Class 1E wiring.

2. One inch of free air space (or equivalent thermal insulation) for separation of Class 1E and non-class 1E wiring.

Physical separation and isolation devices are used to eliminate the need for associated circuits. If a circuit is used for a non-Class 1E function and is 1) connected to a Class 1E power supply or 2) connected to a Class 1E
Q 430.29 device and physical separation from Class 1E circuits cannot be maintained, the circuit is treated as Class 1E up to and including an isolation device. The portion of the circuit that is on the Class 1E side of the isolation device is identified as Class 1E and routed only in Class 1E raceways. The portion of the circuit on the non-Class 1E side of the isolation device is routed only with non-Class 1E cables.

The only device acceptable as a power circuit isolation device is one that is automatically tripped by an accident signal generated within the same train or one that is tagged/locked open.

Electrical circuits enter the containment through penetration assemblies
Q 430.11 which are provided with integral connectors (qualification information pertaining to electrical penetrations is provided in Section 3.11.2.1.5). The cables associated with Train A circuits are routed through penetrations which contain no Train B circuits, and vice-versa. The minimum separation between penetrations carrying mutually redundant circuits is five feet in all directions.
Q 430.31 The minimum separation between Class 1E and non Class 1E penetrations is one foot six inches.

Additionally, cable insulations are applied very conservatively. The following guidelines are used in applying cable insulation ratings to various station applications.

Cable Insulation Rating	Application Rating
15,000 volt	13800 volt power cable
8,000 volt	6600 volt power cable
8,000 volt	4160 volt power cable
2,000 volt	600 volt power cable
1,000 volt	Low voltage power and control cable
600 volt	208/120 volt lighting cable
300 volt	120 volt ac and 125 volt dc instrumentation cable

8.3.1.5.2 Cable Tray Fill Criteria

The cable tray fill criterion for those trays containing power cables allows only one single layer of power cables to be routed in any tray, and, in general, separation of one-quarter the diameter of the larger cable is maintained between adjacent power cables within a tray. The cable spacing may vary between tie-down points due to cable snaking or cables entering/exiting a tray; however, if cables touch, the contact is limited to approximately two feet.

The cable tray fill criterion for those trays containing instrumentation and control cables is that the cross-sectional area of these cables will not exceed the usable cross-sectional area of the tray.

8.3.2 DC POWER SYSTEMS

8.3.2.1 System Descriptions

The following sections describe the DC Power Systems for Catawba Unit 1. Unit 2 is similar.

8.3.2.1.1 Non-Class 1E DC Power Systems

8.3.2.1.1.1 125VDC Auxiliary Control Power System

The 125VDC Auxiliary Control Power System consists of two 125 volt batteries, two normal and one standby battery charger, and two 125 volt dc distribution centers. The system is divided into two trains which supply dc power to the non-Class 1E instrumentation and controls, the operator-aid computer power inverter, and the 125VDC-120VAC auxiliary control power inverters. The 125 VDC Auxiliary Control Power System is shown on Figure 8.3.2-1.

5. The following indication is provided locally on the 125 volt dc load group equipment:

   a. Vital instrumentation and control dc distribution center bus voltage

   b. Battery leg-to-ground voltage

   c. Battery charger output current and voltage

6. Indication of the load group vital instrumentation and control dc distribution center bus voltage is provided in the control room.

8.3.2.1.2.2 125VDC Diesel Essential Auxiliary Power System

The 125VDC Diesel Essential Auxiliary Power System provides a separate and independent train of 125 volt dc power to each diesel generator. Each train consists of a 125VDC battery and a battery charger powered from its associated train of 600 volt essential auxiliary power. The 125VDC Diesel Essential Auxiliary Power System is shown in Figure 8.3.2-5.

Each battery charger normally supplies its associated diesel generator control panel loads while maintaining a float charge on its associated battery. A fuel oil booster pump motor may be connected to the system for maintenance purposes; however, it will be disconnected during normal operation. Each diesel battery is available to assume its associated loads upon the loss of its battery charger or ac power source.

Each diesel generator control panel supplies the auxiliaries of its associated diesel generator and also supplies an auctioneering diode assembly which serves as one of the power sources to a 125VDC Vital Instrumentation and Control Power System distribution center as described in Section 8.3.2.1.2.1.3.

Each of the two load groups of the 125VDC Diesel Essential Auxiliary Power System are provided with the following status indications:

1. A 125 volt DC essential power train trouble annunciator is provided in the control room for each train and is initiated by any of the following load group conditions:

   a. Battery charger output circuit breaker open
   b. Battery circuit breaker open
   c. Battery charger output voltage low
   d. Battery charger output voltage high
   e. Loss of AC input to battery charger
   f. Battery positive or negative leg ground
   g. Battery undervoltage
   h. Auctioneering diode assembly input voltage low
   i. Diesel generator control panel undervoltage

Indication of the specific condition that initiated the 125VDC train trouble alarm is provided on a local alarm module near the 125VDC diesel essential auxiliary power equipment.

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 140°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 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 140°F with one cooling train operating assuming a "normal" 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.

9.1.3.1.3 Spent Fuel Pool Dewatering Protection

System piping is arranged so that failure of any pipeline cannot drain the spent fuel pool below the water level required for radiation shielding. A water level of ten feet or more above the top of the stored spent fuel assemblies is maintained to limit direct gamma dose.

9.1.3.1.4 Spent Fuel Pool Makeup

In order to provide specified shielding and water volumes in the fuel pool during plant operation, system piping provides makeup capabilities. Borated makeup water can be supplied to the spent fuel pool from the refueling water storage tank. Demineralized water can be supplied to the pool by the Reactor Makeup Water Pumps, and emergency makeup water can be supplied to the pool from the Nuclear Service Water System. All means of makeup are manually initiated and manually terminated.

9.1.3.2 System Description

An identical Spent Fuel Cooling System, as shown in Figures 9.1.3-1 and 9.1.3-2, is provided for each unit. The system consists of two cooling loops, one purification loop, and one skimmer loop.

The fuel pool cooling pumps take suction from the spent fuel pool. These pumps circulate the water through the cooling loops and the purification loop in various combinations prior to returning the water to the spent fuel pool. The spent fuel pool heat load is transferred to the Component Cooling System by the fuel pool cooling heat exchangers. The fuel pool cooling pre-filter, demineralizer, and post-filter will adequately remove corrosion and fission products from the spent fuel pool water.

The fuel pool skimmer pump takes suction from the skimmer trough, that collects water from the spent fuel pool surface. Floating debris is removed by the fuel pool skimmer strainer and filter. Optically clear water is then discharged below the pool surface at various locations. Discharge throttling valves are provided for optimizing the spent fuel pool skimmer loop operation.

The Pool Cooling and Purification System is manually controlled from a local control panel. High temperature and low liquid level in the fuel pool and high radiation in the fuel pool area alarms are provided in the Control Room as per Regulatory Guide 1.13. Also alarmed in the Control Room is high liquid level in the fuel pool. Local gauges are provided for high differential pressure across each strainer and filter and low discharge pressure on each pump.

9.1.3.2.1 Pool Cooling Subsystem

The cooling subsystem of the Spent Fuel Pool Cooling System is a closed loop system consisting of two full-capacity pumps and two full-capacity heat exobservation of underwater operations. The purification subsystem can also remove dissolved fission products from the refueling water storage tank.

One spent fuel pool water volume can be circulated through the purification loop every 24 hours, which should be sufficient to maintain the water chemistry specified for the spent fuel pool in WCAP-7452, Rev. 1, "Chemistry Criteria and Specifications for Westinghouse Pressurized Water Reactors", dated July 3C, 1973.

The fuel pool water or refueling water is circulated by its respective pump through a fuel pool cooling pre-filter, which removes particulates, and then through the fuel pool cooling demineralizer which removes ionic material. The purified water then goes through the fuel pool cooling post filter before it is returned to the fuel pool or the refueling water storage tank.

The pool purification subsystem also consists of a spent fuel pool skimmer loop which removes floating debris from the spent fuel pool surface by use of a skimmer trough, strainer, skimmer pump, and filter. The suction and return lines of the skimmer loop are arranged so that the maximum area of surface water is circulated through the skimmer loop.

9.1.3.2.2.1 Component Description

Component design parameters are given in Table 9.1.3-1.

<u>Fuel Pool Cooling Pre-Filter</u>

Suspended particles are collected on the pre-filter instead of on the fuel pool cooling demineralizer. The disposable filter cartridge removes 98 percent of all particles 3 microns and larger.

<u>Fuel Pool Cooling Demineralizer</u>

The demineralizer is of the mixed bed type with H+ and OH- type resin which removes corrosion and fission product ionic contaminants from the spent fuel pool water or the Refueling Water System water.

<u>Fuel Pool Cooling Post-Filter</u>

Resin fines are collected on the post-filter. The disposable filter cartridge removes 98 percent of all particles 3 microns and larger.

<u>Skimmer Trough</u>

The skimmer collects water from the spent fuel pool surface. Surface skimming is optimized by adjusting the pool level.

Table 9.1.3-1 (Page 1)

System Component Design Parameters

SPENT FUEL POOL COOLING & MAINTENANCE EQUIPMENT

FUEL POOL COOLING PUMP

Number per unit	2
Type	Centrifugal
Design pressure, psig	175
Design temperature, F	200
Design flow rate, gpm	2840
Design head, ft @ design flow	275
Material of construction	SS

FUEL POOL COOLING HEAT EXCHANGER

Number per unit	2
Type	U-Tube
Heat transfer per HX at design conditions (btu/hr)	15,000,000
Flow, tube side, gpm	2310
Flow, shell side, gpm	3000
Tube side inlet temperature, F	125
Tube side outlet temperature, F	112
Shell side inlet temperature, F	100
Shell side outlet temperature, F	110
Design pressure, shell/tube, psig	150/175
Design temperature, shell/tube, F	225/225
Material of Construction, shell/tube	CS/SS

FUEL TRANSFER CANAL AIR DRIVEN UNWATERING PUMP

Number per unit	1
Type	Portable submersible air driven pump
Design pressure, psig	40
Design temperature, F	200
Design flow rate, gpm	225
Design head, ft	50
Material of Construction	SS

SPENT FUEL POOL PURIFICATION EQUIPMENT

FUEL POOL COOLING PRE-FILTER

Number per unit	2
Type	Disposable cartridge
Design pressure, psig	200
Design temperature, F	200

Table 9.1.3-1 (Page 2)

FUEL POOL COOLING PRE-FILTER (cont'd)

Design flow, gpm	265
Retention @ 5 micron and larger particle size	98%
Material of Construction	SS

FUEL POOL COOLING DEMINERALIZER

Number per unit	1
Type	Flushable
Resin type	Rohm & Haas IRA 402 anion Rohm & HASS Amberline 200 cation
Design pressure, psig	200
Design temperature, F	200
Design flow, gpm	530
Material of Construction	SS

FUEL POOL COOLING DEMIN RESIN STRAINER

Number per unit	1
Type	Cone
Design Pressure, psig	200
Design Temp, °F	200
Design Flow, gpm	530
Retention mesh	.012"
Materials of Const.	SS

FUEL POOL COOLING POST-FILTER

Number per unit	2
Type	Disposable cartridge
Design pressure, psig	200
Design temperature, F	200
Design flow rate, gpm	265
Retention @ 5 micron and larger particle size	98%
Material of Construction	SS

SPENT FUEL POOL SKIMMER EQUIPMENT

FUEL POOL SKIMMER STRAINER

Number per unit	1
Type	Basket
Design pressure, psig	20
Design temperature, F	200
Design flow, gpm	100
Perforation, dia, in	7/64
Material of Construction	SS

Table 9.1.3-1 (Page 3)

FUEL POOL SKIMMER PUMP

Number per unit	1
Type	Centrifugal
Design pressure, psig	45
Design temperature, F	200
Design flow, gpm	100
Design head, ft	55
Material of Construction	SS

Number per unit	1
Type	Disposable cartridge
Design pressure, psig	75
Design temperature, F	200
Design flow, gpm	100
Retention @ 3 micron and larger particle size	100%
Material of Construction	SS

The Nuclear Service Water System design basis is for operation under the worst initial conditions of operation. This condition is assumed to be the low probability combination of a safe shutdown earthquake (SSE) coincident with a loss of coolant accident in one unit, extended shutdown of the other unit, loss of the downstream dam, and a prolonged drought and hot weather and its effect on the Standby Nuclear Service Water Pond. In addition, the RN Pumphouse is designed to keep all valve and pump motors and other essential electrical equipment above water during the probable maximum flood (PMF) due to sudden occurrence of a rain induced failure of the upstream dam.

The RN pumps can take suction from Lake Wylie throughout the entire range of lake levels from 592.4 ft above MSL (maximum calculated flood elevation corresponding to a seismic failure of Cowans Ford Dam coincident with a Standard Project Flood) down to the maximum lake drawdown of 559.4 ft above MSL. The SNSWP is normally overflowing at 571 ft above MSL and has a minimum allowable water level of 570 ft as described in Section 9.2.5.

9.2.1.2.3 Heat Exchanger Section

Nuclear Service Water supplied by the RN pumps is used in both units to supply essential and non-essential cooling water needs or as an assured source of water for another safety-related system.

Essential components are those necessary for safe shutdown of the unit, and must be redundant to meet single failure criteria. Nonessential components, are not necessary for safe shutdown of the unit, and are not redundant. Each unit has two trains of essential heat exchangers designated A and B, and one train of nonessential heat exchangers supplied from either A or B and isolated on Engineered Safety Features actuation.

The following components or services are supplied by each essential header of the RN System. Some components are normally in operation, some are automatically supplied upon ESF actuation, and others are used when needed.

a. RN Pump Motor Cooler
b. RN Strainer Backflush
c. RN Pump Bearing Lube Injection Water
d. RN Pump Motor Upper Bearing Oil Cooler
e. Diesel Generator Engine Jacket Water Cooler
f. Diesel Generator Building Essential Fire Water
g. Diesel Generator Engine Starting Air Aftercooler
h. Component Cooling Heat Exchanger
i. Assured Auxiliary Feedwater Supply
j. Assured Fuel Pool Makeup
k. Assured KC System Makeup
l. Containment Spray Heat Exchanger

m. The Control Room Area Chiller Condensers A and B are shared between units, so they are fed by Unit 1 Essential Headers only.
n. Auxiliary Shutdown Panel Air Conditioning Unit.

The components listed below function during station normal operation but are not required for safe shutdown following a postulated Loss of Coolant accident. The Unit 1 nonessential header is fed from the Unit 1 crossover between channels 1A and 1B, and is isolated on Containment hi-hi pressure signal. There are five branches off of the 20 inch header, which are listed below.

a. Auxiliary Building Nonessential components

    1. Reciprocating Charging Pump Gear Oil Cooler

b. Emergency Line to Service Building

    1. Instrument Air Compressor
    2. Instrument Air Compressor Aftercoolers

The Recirculated Cooling Water System (KR) and the Low Pressure Service Water System (RL) normally supplies these components, but loses power on station blackout The RN System may then be aligned and the Instrument Air Compressor started to provide air following the blackout.

c. Auxiliary Building Ventilation Cooling Water

    1. Auxiliary Building Vent Units (2)
    2. Fuel Handling Area Vent Unit
    3. Radiation Area Vent Unit

d. Upper Containment Ventilation Cooling Water

    1. Upper Containment Vent Units (4)

e. Lower Containment Ventilation Cooling Water

    1. Lower Containment Vent Units (4)
    2. Incore Instrumentation Area Vent Units (2)
    3. Reactor Coolant Pump Motor Air Coolers (4)

The Containment Chilled Water System (YV) normally supplies these components but loses power on station blackout. The RN System may be aligned to supply cooling water during the blackout.

During normal station operation, flow is supplied to all the components on the nonessential header with the exception of the emergency line to the Service Building and the header to lower containment. Components served by RN have either automatic control valves modulating to maintain a predetermined setpoint or manual throttling valves preset to give a minimum required flow at pump maximum flow conditions. See Table 9.2.1-2 for flow requirements of the Nuclear Service Water System.

Essential components receiving Nuclear Service Water flow are described below:

The RN pump motors are of the totally enclosed, water cooled type which have internal water-to-air heat exchangers. Cooling water is provided to the RN pump motor coolers only when the motor is in operation. This prevents the formation of condensate in the motor internals by the passage of cold water through an idle motor. The control valves for the RN pump motor coolers are manually set.

The RN pump motor upper bearing oil coolers are supplied cooling flow only when their respective RN pumps are in operation to prevent harmful condensation from forming in the oil. The RN pump motor coolers and RN pump motor upper bearing oil cooler on each pump are located downstream. A motor operated isolation valve is interlocked to open when the pump motor starts and close when the pump motor stops.

Bearing lube injection flow is maintained to all RN pumps at all times, even though only one pump is required to meet all the normal flow requirements of both units. This water is supplied through redundant self-cleaning strainers. One strainer is supplied per train. A crossover allows a single operating RN pump to supply its own bearing lube injection flow plus that of the redundant channel RN pumps. Upon Engineered Safety Features actuation, all four pumps start and the crossover valves close, allowing each channel to supply the bearing lube requirements of its corresponding channel RN pumps.

The nuclear service water strainers backflush automatically on a time cycle unless overridden by a pre-set high pressure drop. Internal water pressure is the motive force for dislodging strained particles as a backflush drive motor turns a backwash arm past the various strainer assemblies. The discharge is released to atmospheric pressure and dumps into a trash basket outside the RN Pumphouse. Entrained trash is collected and the water is returned to the Standby Nuclear Service Water Pond, which overflows to Lake Wylie.

Diesel generator engine starting air compressor aftercooler is supplied constantly as the compressor operates periodically to maintain starting air tank pressure. Flow is set by a manual throttling valve. Cooling water is supplied to the diesel generator engine jacket water cooler only when the diesel is in operation. This is accomplished by an electric motor operated valve interlocked to open when the diesel starts, close when the diesel stops. Flow is assured to all diesel generators no matter which RN pumps are in operation by the normal valve positions identified on Figure 9.2.1-2.

Those heat exchangers in which a tube leak could allow radioactive fluid to enter the cooling water are cooled indirectly through the closed loop Component Cooling System (KC). Heat is then transferred to the RN System via the component cooling heat exchanger. The heat load provided by the RN normal loads will probably provide RN pump minimum flow requirements, but should this not be the case, one of the non-operating KC heat exchangers may be used to provide a minimum flow path.

The KC heat exchanger control valve on the non-operating KC train will receive a signal to modulate on RN pump flow. It will open upon low-flow (minimum flow) conditions, allowing the minimum flow to pass through the redundant KC heat exchanger.

The only heat exchanger which could allow radioactive liquid to be discharged to the environment in the event of a tube leak is the containment spray heat exchanger, which is only in service after a loss of coolant accident. A radiation monitor is installed at the outlet of this heat exchanger. Should a leak occur, that channel would be shut down, isolated, and repaired while the redundant channel provides the required cooling.

Both control room area chiller condensers are normally in operation, sharing the load equally. In the event of a single failure, the other chiller is sized to pick up the entire load due to a one unit LOCA and one unit shutdown simultaneously. The automatic control valves for these components are electro-hydraulically actuated and powered from the Class 1E emergency diesels. These control valves continue to modulate, maintaining control room area habitability by controlling condenser head pressure after blackout, LOCA, and earthquake.

The auxiliary shutdown panel air conditioning units also operate during normal plant operation, maintaining a controlled environment for functioning electrical equipment and assuring habitability for personnel in the event of a control room evacuation and simultaneous blackout. Their automatic control valves are self-contained and control off of condenser head pressure, making this function independent of air supply.

Unless otherwise stated in the preceding description, all automatic control valves fail open on loss of air or signal, and have travel stops to limit the maximum flow through the corresponding heat exchanger.

9.2.1.2.4 Main Discharge Section

There are two main discharge headers, extending the width of the Auxiliary Building with channel 1A and 2A components returning flow to the A header, and channel 1B and 2B components returning flow to the B header. During normal station operation when RN pumps are taking suction from Lake Wylie, discharge crossover valves are open, and all heat exchangers in operation discharge through the channel A return to Lake Wylie via the Low Pressure Service Water discharge. Automatically upon low-low pumphouse pit level (as in loss of Lake Wylie) or Engineered Safety Features Actuation in either unit, double isolation valves close on the channel A return to Lake Wylie, double isolation valves close on the discharge header crossover, and single valves open on each channel return to the SNSWP. This sequence, along with isolation of the non-essential header and supply header crossover valves ensures two independent, redundant supplies and returns, satisfying the single failure criteria. The non-essential header will only isolate on P-signal, not low-low pumphouse pit level due to a possible s-signal resulting from the containment vent units not in operation. If damage is visually assessed, the non-essential header will be manually isolated.

RN piping in each Diesel Generator Building also has discharge isolation valves that are aligned from lake discharge to SNSWP discharge on the same signals which cause the Auxiliary Building headers to align to the SNSWP.

The discharge lines to the SNSWP split and discharge flow to each "finger" of the SNSWP to assure that surface cooling will occur in all areas of the pond. An orifice is installed to create a pressure drop in the shorter of the two discharge lines to assure equal flow at both discharge points (during a simultaneous safe shutdown of both units).

9.2.1.3 Safety Evaluation

The Nuclear Service Water System is designed to withstand a safe shutdown earthquake and to prevent any single failure from curtailing normal station operation or limiting the ability of the engineered safety features to perform their functions. Sufficient pump capacity is included to provide design cooling water flow under all conditions, and the headers are arranged in such a way that loss of a header does not jeopardize unit safety. Radiation monitors are located in the systems for detection of potentially radioactive leaks. The system is designed to operate at either maximum drawdown of the lake or Standby Nuclear Service Water Pond and also at a maximum water elevation in each body. As described in Section 9.2.1.2.2, the Nuclear Service Water System is designed to withstand both probable maximum flood and the effects of a prolonged drought. Sufficient margin is provided in the equipment design to accommodate anticipated corrosion and fouling without degradation of system performance.

The RN System is designed to tolerate a loss of offsite power during a unit LOCA and/or a unit cooldown simultaneous with a loss of Lake Wylie. By adhering to strict channel A and B separation with double valving between main supply and discharge headers, both units are assured of having a source of water, two 100 percent capacity pumps, and two redundant trains of heat exchangers essential for safe shutdown. Channels A and B are connected together only at 5 places by crossover piping. Redundant motor operated isolation valves protect channel integrity and meet single failure criteria. Manual crossover isolation valves are normally closed. The RN Pumphouse crossover line provides flow to backflush the backup train's RN strainers on a time cycle to assure their cleanliness upon startup. This crossover also supplies bearing lube injection water to the backup train's RN pumps, keeping them ready to start on actuation signal. These crossover valves automatically close on safety injection signal, when the redundant RN pumps also start. Normally closed valves are provided at the outlet of the RN pump bearing lube injection strainers. Should it be necessary to isolate one strainer for maintenance, flow to all four RN pumps bearings can be temporarily maintained through the other strainer. Inside the Auxiliary Building for each unit, supply header crossover valves are normally open during safety injection signal to equalize header pressure and supply the increased heat load flow requirements to containment ventilation units as well as continued operation of the reactor coolant pump motor air coolers. Both of these crossover valves as well as nonessential header supply valves close on containment spray signal, assuring channel integrity for safe shutdown following a LOCA. Main discharge crossover valves are normally open, allowing operating heat ex-changers on all trains to discharge through the single main discharge to the Low Pressure Service Water System (RL). Upon containment spray signal these two valves close, the lake discharge isolation valves close, and redundant valves open for each channel discharge to the SNSWP.

All valves whose functions are shared between units and therefore whose operation is related to the safety of both units are provided with normal and emergency diesel power from Unit 1. These valves are listed in Table 9.2.1-3.

If a Unit 1 diesel is out of service or down for maintenance, then the shared valves normally powered from that channel are provided with manual switchover to the Unit 2 diesel of corresponding channel. In this manner, any one diesel generator can be down for maintenance and the RN System can still shut the plant down safely assuming a LOCA, seismic event blackout, and single failure.

A complete RN System single failure analysis is presented in Table 9.2.1-4.

9.2.1.4 Testing and Inspection Requirements

All system components are hydrostatically tested prior to station startup and are accessible for periodic inspection during operation. All components, switchovers, starting controls, and the integral systems required for the RN System to perform its safety related functions are tested periodically.

9.2.1.5 Instrumentation Requirements

9.2.1.5.1 General Description

RN System instrumentation and controls are shown on the system flow diagrams (Figures 9.2.1-1 through 9.2.1-12). Power to the essential, safety related valves, controls, and instrumentation for a particular RN System train are powered from the same electrical power source as the RN pump which normally supplies water to that train. Therefore, loss of one power train would result in the loss of only the instrumentation and controls associated with that particular train. Those valves common to both units which isolate the intake lines in the RN Pumphouse as well as the main discharge crossover and main discharge isolation valves are normally supplied from the corresponding channel of Unit 1 diesels, with a switchover provided to corresponding Unit 2 diesels for the case when a Unit 1 diesel is down for maintenance. Backup controls are provided at the auxiliary shutdown panel for all the devices required for safe, orderly shutdown in the event of a main control room evacuation.

9.2.1.5.2 Pressure Instrumentation

Pressure transmitters are provided on each RN pump discharge line for displaying pressures locally and at the main control room, as well as actuating main control room annunciators when pressure drops below a predetermined value. Each RN pump bearing lube injection strainer is provided with a differential pressure switch which warns the operator of high ΔP. Each RN strainer is provided with differential pressure switches to initiate backwash on high ΔP. Pressure differential indicating switches are connected across the RN Pumphouse lattice screens, and alarm in the main control room on high ΔP. That channel must then be shut down and the screens cleaned by hand. This will be very infrequent because the intake structures are located at the bottom of the lake and SNSWP, thereby eliminating floating trash. The intake bar screens also are expected to minimize clogging of the RN Pumphouse lattice screens.

Inside the Auxiliary Building, each supply header has pressure indication locally and on the main control board. Each heat exchanger is equipped with a pressure test point at the outlet to monitor tube cleanliness.

9.2.1.5.3 Flow Instrumentation

Flow elements are provided on each RN pump discharge which indicate locally and on the main control board, as well as alarm on both high and low setpoints. Local flow indication is provided for setting the design flow through all RN pump bearing lube injection line and RN pump motor coolers and upper bearing oil coolers. The manual throttling valves are then locked in place. Flow indication, both local and main control board, is provided on the containment spray heat exchanger outlets, the component cooling heat exchanger outlets, and the diesel generator engine jacket water cooler outlets. These alarm on both high and low setpoints. Local flow indication is provided on all heat exchangers whose flow is controlled by a manual throttling valve to aid in setting the design flow and also on all ventilation cooling coil lines to monitor their performance.

There is a portable flow measuring probe provided for testing to assure equal flow at both discharge points into the SNSWP. This test verifies the performance of the "short leg" pressure drop orifice described in Section 9.2.1.2.4.

9.2.1.5.4 Temperature Instrumentation

RN pump motor internal air temperature is indicated both locally (to aid in setting motor cooler outlet throttling valve) and on the main control board to alarm on high temperature. RN pump motor bearing and stator temperatures are also monitored on the plant computer. Temperature indication is provided for each channel main supply header in the main control room, and temperature test points provided at the outlet of each heat exchanger to check performance. Temperature test points are provided at both the inlet and outlet of the ventilation cooling coils. Outlet temperature of the SNSWP is monitored and alarmed on high temperature. By technical specification the station must be shut down if SNSWP temperature exceeds a given value. Refer to Chapter 16 for applicable limits.

All air actuated control valves have travel stops set to provide design flow for safe shutdown heat loads upon loss of instrument air due to station blackout with or without simultaneous LOCA. Instrument air can be restored following a blackout by manually aligning emergency supply of RN to and from the instrument air compressors and manually loading the compressors on the diesel "blackout bus". This restores air supply for RN as well as all other air actuated control valves.

9.2.1.5.5 Level Instrumentation

Two sets of level instrumentation per unit, one on each power train, are installed in the RN Pumphouse pit behind the lattice screens where the RN pumps take suction. It is this instrumentation which alarms in the control room on low level and on low-low level realigns suction from Lake Wylie to the SNSWP. This will provide qualified indication of the occurrence of loss of the downstream dam.

Level instrumentation provides indication in the the control room the levels of Lake Wylie and the SNSWP, which also has positive level markings painted on a pier for visual verification of gage reading.

9.2.1.6 Corrosion, Organic Fouling, and Environmental Qualification

No provision is made for prevention of long-term corrosion in the RN System. Allowances for such corrosion were made by increasing the wall thickness of the pump pressure boundary, piping, and the heat exchanger shells and tubes in accordance with the applicable codes. Larger pipe sizes than necessary were used for pump adequacy considering scaling.

Asiatic clam control is achieved by a series of design features and operating procedures. Intake structures take suction elevated off the bottom of the lake and SNSWP and at a velocity well below that required by the Environmental Protection Agency for wildlife protection, so large clams are not drawn into the system. A bar screen with openings 4 in. X 4 in. keeps debris from entering the intake lines and a lattice screen with 1 in. X 1 in. openings separates the forebay of the RN Pumphouse from the RN pump suction bay, providing a second level of defense. The water discharging from each RN pump passes through an RN strainer with 1/32 inch openings to strain out dirt and sand particles that could clog control valves with cavitrol trim located throughout the RN System. These screens and strainers will prevent all but the smallest clam larvae from entering the RN piping.

It is understood that Asiatic clam larvae do not permanently attach to pipe walls and grow, but nest in stagnant places such as valved off pipes and idle heat exchangers and operating heat exchangers heads in front of the tube sheet. Performance monitoring programs to verify adequate flow, and visual inspection of the intake piping and inlet heat exchanger heads during maintenance will provide early detection of any clam infestation of raw water systems. If these monitoring or inspection programs indicate any potential problems, appropriate corrective action will be taken.

9.2.2 COMPONENT COOLING SYSTEM

9.2.2.1 Design Bases

The Component Cooling System (KC) is designed for operation during all phases of plant operation and shutdown. The system serves to:

a. Remove residual and sensible heat from the Reactor Coolant System via the Residual Heat Removal System, during plant shutdown and startup.

b. Cool the letdown flow to the Chemical and Volume Control System during power operation.

c. Cool the spent fuel pool water.

d. Provide cooling to dissipate waste heat from various other primary plant components.

e. Provide cooling to engineered safeguards loads after an accident.

The component cooling pumps and heat exchangers are arranged into two separate trains of equipment in each unit subsystem, with two pumps and one heat exchanger per train. Each surge tank is connected by surge tank riser to each train of component cooling equipment. Each train of component cooling equipment supplies cooling water to a corresponding train of the following redundant engineered safety equipment:

a. Residual heat removal heat exchanger

b. Residual heat removal pump mechanical seal heat exchanger

c. Component cooling pump motor coolers (2 pumps per train)

d. Motor driven auxiliary feedwater pump motor coolers

e. Residual heat removal pump motor coolers

f. Containment spray pump motor coolers

g. Safety injection pump motor coolers

h. Safety injection pump bearing oil cooler

i. Centrifugal charging pump motor coolers

j. Centrifugal charging pump speed reducer oil cooler

k. Centrifugal charging pump bearing oil cooler

Any piping connecting the two trains of component cooling equipment is provided with two isolation valves. Where this piping is seldom used, manual isolation valves are provided and are locked closed. Where this piping is often used, motor operated isolation valves, which are actuated to close on an engineered safeguards actuation signal, are provided.

Component cooling water is also provided to the following components which are not essential to safe plant shutdown following a loss of coolant accident or steam break accident:

a. Letdown heat exchanger

b. Sealwater heat exchanger

c. Fuel pool cooling heat exchangers

d. Waste gas compressor package heat exchangers

e. Waste gas hydrogen recombiner packages

f. Sample heat exchangers

g. Recycle evaporator package evaporator condenser

h. Recycle evaporator package distillate cooler

i. Recycle evaporator package vent condenser

j. Waste evaporator package evaporator condenser

k. Waste evaporator package distillate cooler

l. Waste evaporator package vent condenser

m. Excess letdown heat exchanger

n. Reactor coolant drain tank heat exchanger

o. Reactor vessel support coolers

p. Reactor coolant pump thermal barriers

q. Reactor coolant pump motor lower bearing oil coolers

r. Reactor coolant pump motor upper bearing oil coolers

s. Steam generator blowdown heat exchangers

t. Recycle evaporator concentrate sample cooler

u. Recycle evaporator concentrate heat exchanger

v. Recycle evaporator concentrate pump A bearing cooler

w. Recycle evaporator concentrate pump B bearing cooler

x. Waste evaporator concentrate sample cooler

y. Waste evaporator concentrate heat exchanger

z. Waste evaporator concentrate pump A bearing cooler

aa. Waste evaporator concentrate pump B bearing cooler

Cooling water may be supplied to the non-essential equipment from either train of component cooling equipment and, likewise; returned to either train of component cooling equipment. Motor operated isolation valves, which are actuated to close on an engineered safeguards actuation signal, provide separation of non-essential equipment from essential equipment and component cooling equipment train separation during a Loss of Coolant Accident or Steam Break Accident.

A normally closed motor operated valve at the inlet of each residual heat removal heat exchanger is actuated to open on an engineered safety signal to assure cooling water supply to these heat exchangers during a Loss of Coolant or Steam Break Accident. A continuous supply of component cooling water is provided to the other redundant safety equipment during all modes of plant operation.

On an engineered safety signal both trains of component cooling equipment are actuated and automatically aligned to the appropriate trains of engineered safety equipment. However, only one train of component cooling equipment, i.e., two component cooling pumps and one component cooling heat exchanger, is necessary to supply minimum engineered safety requirements. During normal unit operation two pumps and one heat exchanger are required. Two pumps and one heat exchanger also provide minimum unit cooldown requirements. However, to provide unit cooldown within 20 hours four component cooling pumps and two component cooling heat exchangers are required.

Design flow rates during various unit operating modes are tabulated in Table 9.2.2-1. Typical valve lineups for various system operational modes are shown in Table 9.2.2-2.

The Nuclear Service Water System (Section 9.2.1) provides an assured source of cooling water to the component cooling heat exchangers. The Component Cooling System serves as an intermediate system and a second boundary between the Reactor Coolant System and the Nuclear Service Water System and assures that any leakage of radioactive fluid into the Component Cooling System from components being cooled is contained within the plant. A radiation monitor is placed at the discharge of each component cooling heat exchanger to detect any radioactive leaks into the Component Cooling System. Each monitor actuates an alarm and closes the appropriate component cooling surge tank atmospheric vent valve if radiation reaches a preset level above the normal background. Venting would then be accomplished through a loop seal to contain potentially radioactive gasses in the surge tanks.

The vent lines on the surge tanks are sized large enough to prevent vacuum in the tanks, should cold water from the component cooling drain sump be added to a surge tank at tis maximum temperature. Surge tank overflow is directed to the component cooling drain sumps, where it can be pumped to the mixing and settling tank in the Liquid Radwaste System for disposal.

Component cooling flow is essential to the operation of the reactor coolant pumps (KC provides cooling water to the RCP thermal barriers and oil coolers). Safety related flow instrumentation is provided on the KC supply header to RCP components to alert the operator of low KC flow. The reactor will be manually tripped if KC flow is lost and cannot be restored within 10 minutes.

The major portion of the Component Cooling System is constructed of carbon steel. Corrosion will be controlled by the addition of corrosion inhibitors to the component cooling water.

Instrumentation is provided in the cooling water lines downstream of the reactor coolant pump thermal barriers to detect high flow resulting from reactor coolant inleakage due to a ruptured thermal barrier cooling coil. Upon a high flow signal the motor operated isolation valve in the cooling water discharge line from the thermal barrier automatically closes to isolate the radioactive leak. A check valve in the cooling water line upstream each thermal barrier isolates the supply flow. Component cooling water piping at the inlet and discharge of the thermal barriers is designed to withstand reactor coolant system temperature and pressure. A relief valve in the component cooling piping downstream of the reactor coolant pumps is set to relieve at the design pressure of the reactor coolant system with a capacity equal to the maximum rate at which reactor coolant can flow through the thermal barrier break. Discharge from these relief valves is directed to the containment floor and instrument sumps in the Liquid Radwaste System.

Relief valves downstream of heat exchangers other than the reactor coolant pump thermal barriers are discharged into the component cooling drain header. They are sized to relieve the thermal expansion which would occur if the flow through the heat exchanger shell side was isolated and high temperature fluid continued to flow through the tube side.

9.2.2.3 Components

All the components for this system are located within the controlled environment of the Auxiliary and Reactor Buildings, which are seismic Category I structures that are tornado, missile, and flood protected. Component design data is listed in Table 9.2.2-3, and applicable design codes listed in Table 3.2.2-2.

All essential components are seismically designed and tested and meet ASME III class 3 codes, except containment isolation valves and reactor coolant pump thermal barrier isolation valves which are ASME III class 2. Essential components which require electrical power receive emergency power from the diesels. All essential components located in one train receive their emergency power from the corresponding train diesel.

9.2.2.3.1 Component Cooling Heat Exchangers

The four component cooling heat exchangers are of shell and straight tube type. Raw river water from the Nuclear Service Water System (Section 9.2.1) is circulated through the straight tubes while component cooling water circulates through the shell side. The heat exchangers are designed to provide the required heat transfer for the various modes of plant operation. One heat exchanger is adequate to supply minimum engineered safety features heat transfer requirements. Shell side material is carbon steel. Tube side material is inhibited admiralty.

9.2.2.3.2 Component Cooling Pumps

The eight component cooling pumps are horizontal, centrifugal units. These pumps receive electric power from normal or emergency sources. All four pumps for one unit are started automatically upon receipt of the safety injection signal.

The pumps are designed to operate with the minimum net positive suction head available as provided by the component cooling surge tanks. Minimum flow lines are also provided to protect the pumps. The minimum flow is 1000 GPM per pump.

Mechanical seals are provided to minimize leakage.

9.2.2.3.3 Component Cooling Surge Tanks

Four surge tanks, two per unit, accommodate expansion, contraction, inleakage, or outleakage of water from the system. One surge tank is aligned to each train of component cooling equipment in order to provide redundancy for a passive failure during a loss of coolant or steam break accident. If an outleakage develops while the trains are cross connected, the trains automatically isolate on low-low level in either surge tank.

9.2.2.3.4 Component Cooling Drain Sump and Pumps

The two component cooling drain sumps, one per unit, and the four component cooling drain sump pumps, two per sump, are located at the lowest point in the system. All equipment drains, low point drains, valve leakoffs, and relief valves (excluding reactor coolant pump thermal barrier relief valves) are piped to the drain sump and then pumped to the appropriate component cooling surge tank, thus minimizing makeup and waste treatment problems associated with chemically treated component cooling water.

9.2.2.3.5 Valves

Electric motor operated valves are provided on all headers to nonessential equipment to isolate and separate the two component cooling trains. Two

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valves are provided, one per train, to each nonessential header to meet active failure criteria. These valves are provided with normal and emergency power. During normal operation these valves can be opened and closed from the control room, to align the two trains to the nonessential headers. These valves will automatically close on an engineered safeguards actuation signal.

Electric motor operated valves are provided on each header to each residual heat removal heat exchanger. These valves are supplied with normal and emergency power, and can be opened and closed from the control room during normal residual heat removal operations. These valves automatically open on an engineered safeguards actuation signal.

Electric motor operated valves are located in the component cooling lines down stream of each reactor coolant pump thermal barrier. These valves close on high flow caused by a reactor coolant pump thermal barrier rupture. The inleaking reactor coolant will then be isolated between the electric motor operated valve and a check valve located in the component cooling line upstream of the reactor coolant pump thermal barrier. The design conditions for these valves and piping between these valves is the same as the Reactor Coolant System.

Electric motor operated valves are provided on each recirculation line to open on low pump flow to protect the pumps. These valves are supplied with both normal and emergency power.

Electric motor operated valves are provided on lines penetrating the containment, to close on an engineered safeguards actuation signal for containment isolation during a loss of coolant accident or steam break accident.

Control valves are provided on cooling lines downstream of most of the major components to control the flow of cooling water through the component. These valves are either controlled by flow instrumentation located in the component cooling line or temperature instrumentation located in the line of the fluid being cooled. These valves are provided with leakoffs to minimize leakage from these valves. On loss of power or instrument air these valves will fail in the open position. Travel stops are provided so that the valve will fail in a set position to provide adequate cooling water and not starve the rest of the system.

Relief valves are provided for overpressurization protection of component cooling lines. These valves are normally located close to a component, and are sized to relieve thermal expansion due to overheating of the cooling water by the component.

A relief valve is located on the return header from the reactor coolant pumps to protect against overpressurization due to a thermal barrier rupture and failure of the isolation valve to shut. The valve is sized to relieve the maximum flow of reactor coolant inleakage due to a thermal barrier rupture.

9.2.2.3.6 Piping

Component Cooling System piping is carbon steel, except for drain lines from the component cooling drain sump pumps and other lines exposed to the atmosphere which are stainless steel. Welded joints and connections are used except at components which might require removal for maintenance, where flanges are used.

9.2.2.4 Safety Evaluation

Most of the equipment, piping, and instrumentation associated with the Component Cooling System is located outside the Containment and, therefore, is available for inspection and maintenance during power operation. Replacement of a pump or heat exchanger can be performed while the other components are in service.

Sufficient cooling capacity is provided to fulfill all system requirements under normal and accident conditions. Adequate safety margins are included in the size and number of components to preclude the possibility of a component malfunction adversely affecting operation of safety features equipment. Active system components considered vital to the operation of the system are redundant. Also, any single passive failure in the system does not prevent the system from performing its design function.

In consideration of single failure criteria, the Component Cooling System contains separate flow paths to the two trains of Engineered Safety Features equipment. Any pipes connecting the separate flow paths contain two isolation valves in series.

The Nuclear Service Water System (Section 9.2.1) provides an assured source of cooling water to the component cooling heat exchangers. The Component Cooling System serves as an intermediate system and a second boundary between the Reactor Coolant System and Nuclear Service Water System and assures that any leakage of radioactive fluid from the components being cooled is contained within the station. Radiation monitors are placed in the discharge lines of the component cooling heat exchangers to detect any radioactive leaks into the Component Cooling System. To minimize the possibility of leakage from piping, valves, and equipment, welded construction is used wherever practical. Further instrumentation to detect both inleakage and outleakage is presented in Section

9.2.2.5. Normal makeup to the system is provided by the Makeup Demineralized Water System. An assured supply of makeup water is available from the Nuclear Service Water System.

A relief valve on the component cooling water return header downstream of the reactor coolant pumps is designed with a capacity equal to the maximum rate at which reactor coolant can enter the Component Cooling System from a severance type break of the reactor coolant pump thermal barrier cooling coil. The discharge from these relief valves is directed to the containment floor and equipment sumps. The relief valves on the cooling water lines downstream of other heat exchangers in the system are sized to relieve the thermal expansion occurring if the exchanger shell side is isolated and high temperature fluid continues to flow through the tube side. Discharge from these relief valves is directed to the component cooling drain sump. The set pressure for all relief valves equals the local design pressure of the component cooling piping.

The surge tanks have instrumentation which automatically separates the essential trains of component cooling equipment and isolates flow to the nonessential headers upon low-low level in either surge tank. This, combined with train separation on engineered safety signals, provides redundancy for a single passive failure in the form of outleakage anywhere in the KC System. The KC pumps are able to operate with the surge tanks empty, but the operator manually provides makeup water to the surge tank on low surge tank level. Alarms are provided for high, low, and low-low surge tank levels.

Since the system does not service any Engineered Safety Feature inside the Containment, Containment isolation valves on the component cooling lines entering and leaving the Containment are automatically closed on Containment isolation signal following a loss of coolant accident, or steam break accident.

Isolation valves on the component cooling header to the reactor coolant pumps do not close until Phase B isolation to allow cooling during a small loss of coolant accident or steam break. All other isolation valves close on Phase A isolation.

Active and passive failure analyses of pumps, heat exchangers, valves and piping are presented in Table 9.2.2-4. The safety classes of major system components are listed in Table 3.2.2-2.

The Component Cooling System is a moderate-energy piping system, see Section 3.6 regarding the analysis of postulated cracks in these systems.

9.2.2.5 Leakage Provisions

Leakage from the Component Cooling System is minimized as much as possible by extensive use of weld ends, plug valves, packless stem valves, and by the use of mechanical seals on the component cooling pumps. All drains, valve leakoffs, relief valves (excluding reactor coolant pump thermal barrier relief valves) are piped to the component cooling drain sump and pumped to the appropriate component cooling surge tank. This reduces the loss of component cooling water from the system, and the amount of makeup that otherwise would have to be added to the system. A leak in a component cooling line can be detected by a drop in surge tank level, which will actuate a low level alarm in the control room. At low-low surge tank level the trains are isolated to provide redundancy for a single passive failure.

9.2.2.6 Instrument Applications

9.2.2.6.1 Flow Instrumentation

Flow measurement is located in the outlet lines of the component cooling heat exchangers. Flow rate is given in the control room along with low flow alarm. The valves in the KC pump minimum flow lines open automatically when low flow is detected.

Flow instrumentation is located in all lines providing cooling water to a component. Flow measurement is given either in the control room, on a remote panel, or locally. Flow instrumentation in these lines is also used for low and high flow alarms and for controlling control valves where needed.

Flow is monitored in the KC header serving components on the reactor coolant pumps. Upon low flow, an alarm is given in the control room. The operator must trip the reactor if normal KC flow cannot be reestablished within 10 minutes.

9.2.2.6.2 Level Instrumentation

Surge tank level measurements are used to monitor and control the total amount of water in the system. Should there be leakage into the system, the level will rise and activate a high level alarm. If there is leakage out of the system the level will fall and a low level alarm will be actuated. At low-low level the trains automatically isolate. Level indication is given in the control room.

Component cooling drain sump level is given locally for sump level indication, and automatic sump pump operation is possible, controlled by high and low level setpoints.

9.2.2.6.3 Pressure Instrumentation

Pressure instrumentation is located in the discharge of each component cooling pump, and in each main discharge header for each train. Pressure indication is given locally and in the control room.

Pressure test points are placed in the suction piping of the component cooling pumps, at the discharge of the component cooling heat exchangers, and in the supply and discharge of all the major heat exchangers served by the system.

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TABLE 9.2.1-1 (Page 1)
SYSTEM COMPONENT DESIGN PARAMETERS

NUCLEAR SERVICE WATER PUMPS

Number per unit	2
Type	Vertical, wet pit, mixed flow with above floor discharge
Design Pressure, psig	150
Design Temperature, F	105
Design Flow, gpm	20,900
Design Head, ft.	174
Max. Flow Rate, gpm	25,800
Head at Max. Flow, ft.	130
Shutoff Head, ft.	260
Min. Flow Rate, gpm	9000 for 1 yr., 5000 for 1 wk.
Material of Construction	Carbon Steel
Motor horsepower, name plate	1000
Type	Vertical, totally enclosed, water cooled
Motor Cooler Design Temp, F	100
Motor Cooler Design Flow, gpm	40
Pump Bearing Lube Injection & Packing Flush Flow, gpm	Total 24
Pump Bearing Lube Injection & Packing Flush Cleanliness	80 Mesh Strainer
Pump Bearing Lube Injection Pressure, Minimum psig	45
Motor Upper Bearing Oil Cooler Flow, gpm	4
Submergency Reg. at Max Flow, ft.	5

NUCLEAR SERVICE WATER STRAINERS

Numper per unit	2
Type	Horizontal, continuous automatic backflush
Design Pressure, psig	150
Design Temperature, F	100
Design Flow, gpm	20,900
Strainer element type	slotted tubular stainless steel
Strainer element size openings, in.	1/32
Maximum pressure drop, psi	4
Material of construction	Carbon Steel

RN PUMP BEARING LUBE INJECTION STRAINERS

Number per station	2
Type	Self-cleaning
Design Pressure, psig	150
Design Temperature, F	100
Design flow, each - normal, gpm	92
maximum, gpm	136
Design pressure differential	
clean normal, psid	1.5
maximum, psid	3.75
65% clogged maximum, psid	7.5

TABLE 9.2.1-1 (Page 2)

Mesh Size	80 (.007")
Required retention	100%
Material of construction:	All stainless steel

NUCLEAR SERVICE WATER SYSTEM UNWATERING PUMP

Number per station	1
Type	Portable submersible pump
Design Flow, gpm	800
minimum	400
maximum	1200
Design Head, ft. at Design Flow	65
ft. at Shutoff	78
Design Pressure, psig	50
Design Temperature, F	108
Driver Type	Submersible electric motor
Casing Material	Carbon Steel
Impeller Material	Stainless Steel

Table 9.2.1-2 (Page 1)
Nuclear Service Water System Flow Rates - Unit 1
Given for Unit 1 Operating Modes - Number of Components in Operation & Total Flow in GPM

ESSENTIAL COMPONENTS	Mode 1 Normal Operation		Mode 2 Startup		Mode 3-1 Shutdown - 4 Hrs		Mode 3-2 Blackout & Shutdown - 4 Hrs		Mode 3-3 Shutdown - 20 Hrs		Mode 3-4 Blackout & Shutdown - 20 Hrs		Mode 4 Safety Injection Small LOCA or Steam Leak		Mode 5 Sump Recirc. After Cont. Spray		Mode 6 Refueling	
	No	Flow	No	Flow	No	Flow	No	Flow	No	Flow	No	Flow	No	Flow	No	Flow	No	Flow
1) Containment Spray HX	0	-	0	-	0	-	0	-	0	-	0	-	0	-	2	10000	0	-
2) Diesel Gen Engine Starting Air After-cooler	4	50	4	50	4	50	4	50	4	50	4	50	4	50	4	50	4	50
3) Diesel Gen Engine Jacket Water Cooler	0	-	0	-	0	-	2	1800	0	-	2	1800	2	1800	2	1800	0	-
4) Control Room Area Chiller Condenser	1	1400	1	1400	1	1400	1	1400	1	1400	1	1400	1	1400	1	1400	1	1400
5) Component Cooling HX	1	5000	2	10000	2	20000	2	20000	2	20000	2	20000	2	20000	2	20000	2	20000
6) Auxiliary Shutdown Complex A/C Unit	2	20	2	20	2	20	2	20	2	20	2	20	2	20	2	20	2	20
7) Nuclear Service Water Pump Motor Cooler	1	40	2	80	2	80	2	80	2	80	2	80	2	80	2	80	2	80
8) Nuclear Service Water Pump Upper Brg Inj	1	5	2	10	2	10	2	10	2	10	2	10	2	10	2	10	2	10
9) Nuclear Service Water Pump Lower Brg Inj	1	5	2	10	2	10	2	10	2	10	2	10	2	10	2	10	2	10
10) Nuclear Service Water Pump Packing Flush	1	14	2	28	2	28	2	28	2	28	2	28	2	28	2	28	2	28
11) Nuclear Service Water Pump Motor Upper Brg Oil Cooler	1	4	2	8	2	8	2	8	2	8	2	8	2	8	2	8	2	8
12) Nuclear Service Water Strainer Back-flush	2	2000	2	2000	2	2000	2	2000	2	2000	2	2000	2	2000	2	2000	2	2000
		8538		13606		23606		25406		23606		25406		25406		35406		23606

Table 9.2.1-2 (Page 2)
Nuclear Service Water System Flow Rates - Unit 1
Given for Unit 1 Operating Modes - Number of Components in Operation & Total Flow in GPM

	Mode 1 Normal Operation		Mode 2 Startup		Mode 3-1 Shutdown - 4 Hrs		Mode 3-2 Blackout & Shutdown - 4 Hrs		Mode 3-3 Shutdown - 20 Hrs		Mode 3-4 Blackout & Shutdown - 20 Hrs		Mode 4 Safety Injection Small LOCA or Steam Leak		Mode 5 Sump Recirc. After Cont. Spray		Mode 6 Refueling	
NON-ESSENTIAL COMPONENTS	No	Flow	No	Flow	No	Flow	No	Flow	No	Flow	No	Flow	No	Flow	No	Flow	No	Flow
13) NC Pump Motor Cooler	4	300	4	300	4	300	0	300	0	300	0	300	0	300	0	-	0	-
14) Low Containment Vent Unit	3	2088	3	2088	3	2088	3	2784	3	2088	3	2784	4	2784	0	-	4	2784
15) Unit Containment Vent Unit	3	330	3	330	3	330	3	440	3	330	3	440	4	440	0	-	4	440
16) Incore Instrumentation Vent Unit	2	20	2	20	2	20	2	20	2	20	2	20	2	20	0	-	2	20
17) Recip Chg Pmp Fluid Drive Oil Cooler	1	90	1	90	1	90	1	90	1	90	1	90	1	90	0	-	1	90
18) Aux Bldg Radwaste Area Supply Vent Unit	1	100	1	100	1	100	1	100	1	100	1	100	0	-	0	-	1	100
19) Fuel Handling Area Supply Vent Unit	1	140	1	140	1	140	1	140	1	140	1	140	0	-	0	-	1	140
20) Aux Bldg Supply Vent Unit	1	175	1	175	1	175	2	350	1	175	2	350	0	-	0	-	1	175
21) Emergency Supply to Inst Air Comp	0	-	0	-	0	-	3	48	0	-	3	48	0	-	0	-	0	-
22) Emergency Supply to Inst Air Comp Aftercoolers	0	-	0	-	0	-	3	90	0	-	3	90	0	-	0	-	0	-
		3243		3243		3243		4362		3243		4362		3634		0		3749
MAKEUP TO: (flow per channel)																		
23) Assured Fuel Pool Makeup (up to 500 gpm)																		
24) Auxiliary Feedwater (up to 2900 gpm)							2	2900			2	2900	2	2900	2	2900		
25) Radiation Monitor Flushes (up to 50 gpm)																		
26) Assured Component Cooling Makeup (up to 500 gpm)																		
27) Essential Fire Protection (Diesel Bldg.) (up to 200 gpm)																		
28) Total Flow Rate for All Components in Operation		11781		16849		26849		32668		26849		32668		31940		38306		27355
29) No. RN Pumps Preferred	1		1		2		2		2		2		2		2		2	
Flow Per Pump		11781		16849		13425		16334		13425		16334		15970		19153		13678
30)*Single Failure of one Unit 1 RN Pump with Alignment for Safe Shutdown Before Unit 2 Startup. Flow for Remaining Unit 1 RN Pump		11781		16849		15746		20665		15746		20665		19937		21303		16252
31) Shared Component Flow Not Required on Unit 2																		
If one Unit 2 channel operating		1500		1500		1500		1638		1500		1638		1400		1400		1500
If both Unit 2 channels operating		NA		NA		2900		3038		2900		3038		2800		2800		2900

*In the single failure case train separation is assumed.

Table 9.2.1-3

RN SYSTEM VALVES SHARED BETWEEN UNITS

Value Number	Function	Power Trained Aligned Normal	Power Trained Aligned Backup	ESF Signal Actuated From Trains
1RN1A	RN Pumphouse Pit A Isol. Valve from Lake	1A	2A	1A, 2A
1RN2B	RN Pumphouse Pit A Isol. Valve from Lake	1B	2B	1B, 2B
1RN3A	RN Pumphouse Pit A Isol. Valve from SNSWP	1A	2A	1A, 2A
1RN4B	RN Pumphouse Pit B Isol. Valve from SNSWP	1B	2B	1B, 2B
1RN5A	RN Pumphouse Pit B Isol. Valve from Lake	1A	2A	1A, 2A
1RN6B	RN Pumphouse Pit B Isol. Valve from Lake	1B	2B	1B, 2B
1RN36A	RN Pump Brg Lube Inj Water Strainer Inlet Crossover	1A	2A	1A, 2A
1RN37B	RN Pump Brg Lube Inj Water Strainer Inlet Crossover	1B	2B	1B, 2B
1RN53B	Station RN Discharge Crossover Isol.	1B	2B	1B, 2B
1RN54A	Station RN Discharge Crossover Isol.	1A	2A	1A, 2A
1RN57A	RN Discharge Isol. Valve to Low Press Service Water	1A	2A	1A, 2A
1RN843B	RN Discharge Isol. Valve to Low Press Service Water	1B	2B	1B, 2B
1RN58B	SNSWP Return B Isol.	1B	2B	1B, 2B
1RN63A	SNSWP Return A Isol.	1A	2A	1A, 2A
1RN244A	Control Room Area Chiller Cond. A Control	1A	2A	None
1RN304B	Control Room Area Chiller Cond. B Control	1B	2B	None

Table 9.2.1-4 (Page 5)
Nuclear Service Water System Failure Analysis

	COMPONENT	MALFUNCTION	COMMENT & CONSEQUENCES
15.	RN Pumphouse Intake line A from SNSWP	Collapse or plug	Use Channel B intake line from SNSWP, Pumphouse Pit B, and all Channel B heat exchangers unit repairs can be made.
16.	PN Pumphouse Shared Intake line from Lake	Collapse or plug	RN Pumphouse Pit low-low level will automatically realign to SNSWP and start all RN Pumps for temporary operation until line is repaired, or for shutdown.
17.	Either RN Strainer 1A or 2A	Rupture or plug	Isolate affected RN Strainer and RN Pump. Use another pump to satisfy cooling water requirements through normally open crossovers.
18.	Any non-safety related component	Any failure which would prevent normal operation of the component.	Isolate component and perform required maintenance.
19.	Shared discharge line to Lake Wylie	Rupture or plug	Manually align all RN Pumphouse Intake line valves and all return line isolation valves to SNSWP for temporary operation until line is repaired or for shutdown.
20.	Channel A shared return line to SNSWP	Rupture or plug	Isolated affected return line A and utilize backup train return line B until train A is repaired.
21.	Either RN Pump. Lube Injection Strainer A or B	Rupture or plug	Isolate affected RN Pump Lube Injection Strainer. Use the other lube injection strainer to satisfy lube injection requirements through available crossovers for up to 180 hours. After that, the unaffected train provides 100% redundancy.

Table 9.2.1-5 (Page 1)
Nuclear Service Water Flow Rates For Possible Combinations Of
Unit 1 and Unit 2 Operational Modes

Unit 1 Mode	Unit 1 Flow Reqd	Unit 2 * Mode	Unit 2 * Flow Reqd	Total Flow Reqd	No. Pumps Preferred	Flow Per Pump	Pumps Actuated by Ss	Flow Per Pump on Ss	Min Total Flow Reqd**	No. Pumps Reqd	Flow Per Pump
1	11781	2	15349	27130	2	13565	None				
1	11781	1	10281	22062	1	22062	None				
1	11781	3-1	23949	35730	2	17865	None				
1	11781	3-3	23949	35730	2	17865	None				
1	11781	4	29140	40921	2	20461	1A1B2A2B	10231	30318	2	15159
1	11781	5	35506	47287	3	15763	1A1B2A2B	11822	31684	2	15842
1	11781	6	24455	36236	2	18118	None				
2	16849	1	10281	27130	2	13565	None				
3-1	26849	1	10281	37130	2	18565	None				
3-3	26849	1	10281	37130	2	18565	None				
4	31940	1	10281	42221	2	21111	1A1B2A2B	10556	30218	2	15109
5	38306	1	10281	48587	3	16196	1A1B2A2B	12147	32584	2	15792
6	27355	1	10281	37636	2	18818	None				
4	31940	3-1	23949	55889	3	18630	1A1B2A2B	13973	34183	2	17092
4	31930	3-2	29630	61570	3	20524	1A1B2A2B	15393	38964	2	19482
4	31940	3-3	23949	55889	3	18630	1A1B2A2B	13973	34183	2	17092
4	31940	3-4	29630	61570	3	20524	1A1B2A2B	15393	38964	2	19482
4	31940	6	24455	56395	3	18799	1A1B2A2B	14099	34689	2	17345
3-1	26849	4	29140	55989	3	18663	1A1B2A2B	13998	34283	2	17142
3-2	32668	4	29140	61808	3	20603	1A1B2A2B	15452	39202	2	19601
3-3	26849	4	29140	55989	3	18663	1A1B2A2B	13998	34283	2	17142
3-4	32668	4	29140	61808	3	20603	1A1B2A2B	15452	39202	2	19601
6	27355	4	29140	56495	3	18832	1A1B2A2B	14124	34789	2	17395
5	38306	3-1	23949	62255	3	20751	1A1B2A2B	15564	35549	2	17775
5	38306	3-2	29630	67936	3	22646	1A1B2A2B	16984	40330	2	20165
5	38306	3-3	23949	62255	3	20751	1A1B2A2B	15564	35549	2	17775
5	38306	3-4	29630	67936	3	22646	1A1B2A2B	16984	40330	2	20165
5	38306	6	24455	62761	3	20921	1A1B2A2B	15691	36055	2	18028
3-1	26849	5	35506	62355	3	20785	1A1B2A2B	15589	35649	2	17825
3-2	32668	5	35506	68174	3	22725	1A1B2A2B	17044	40568	2	20284
3-3	26849	5	35506	62355	3	20785	1A1B2A2B	15589	35649	2	17825
3-4	32668	5	35506	68174	3	22725	1A1B2A2B	17044	40568	2	20284
6	27355	5	35506	62861	3	20954	1A1B2A2B	15716	36155	2	18078

Table 9.2.1-5 (Page 2)
Nuclear Service Water Flow Rates For Possible Combinations Of
Unit 1 and Unit 2 Operational Modes

Unit 1 Mode	Unit 1 Flow Reqd	Unit 2 * Mode	Unit 2 * Flow Reqd	Total Flow Reqd	No. Pumps Preferred	Flow Per Pump	Pumps Actuated by Ss	Flow Per Pump on Ss	Min Total Flow Reqd**	No. Pumps Reqd	Flow Per Pump
3-1	26849	3-1	23949	50798	3	16933	None		29992	2	14996
3-2	32668	3-2	29630	62298	3	20766	None		39692	2	19846
3-3	26849	3-3	23949	50798	3	16933	None		29992	2	14996
3-4	32668	3-4	29630	62298	3	20766	None		39692	2	19846
3-1	26849	3-3	23949	50798	3	16933	None		29992	2	14996
3-2	32668	3-4	29630	62298	3	20766	None		39692	2	19846
3-3	26849	3-1	23949	50798	3	16933	None		29992	2	14996
3-4	32668	3-2	29630	62298	3	20766	None		39692	2	19846
6	27355	2	15349	42704	2	21352	None				
6	27355	3-1	23949	51304	3	17102	None		30498	2	15249
6	27355	3-2	29630	56985	3	18995	None		35279	2	17640
6	27355	3-3	23949	51304	3	17102	None		30498	2	15249
6	27355	3-4	29630	56985	3	18995	None		35279	2	17640
2	16849	6	24455	41304	2	20652	None				
3-1	26849	6	24455	51304	3	17102	None		30498	2	15249
3-2	32668	6	24455	57123	3	19041	None		35417	2	17709
3-3	26849	6	24455	51304	3	17102	None		30498	2	15249
3-4	32668	6	24455	57123	3	19041	None		35417	2	17709

*Unit 2 Flow equals Unit 1 Flow minus Control Room A/C Condenser Requirement, Aux Bldg. Radwaste Area Supply Vent Unit, and Emerg. Supply to Inst. Air Compressors and Aftercoolers when applicable.

**Minimum total flow required is equal to Unit 2 flow (see note above) plus Unit 1 single train flow requirement. From Table 9.2.1-2, Line 30 (Unit 2 Mode) - Line 31 (Unit 2 Mode) + Line 30 (Unit 1 Mode) gives the minimum total flow required.

Mode:
1 Normal 100% power operation
2 Unit Startup
3-1 Fast Unit Shutdown @4 hours
3-2 Fast Unit Shutdown @4 hours with blackout
3-3 Fast Unit Shutdown @20 hours
3-4 Fast Unit Shutdown @20 hours with blackout
4 Safety Injection with small leak in NC or Steam Piping (Blackout Assumed)
5 Sump Recirculation After Containment Spray (Blackout Assumed)
6 Refueling

TABLE 9.2.2-1 (Page 1)

COMPONENT COOLING SYSTEM HEAT LOAD AND FLOW REQUIREMENTS

FOR MODE 1, UNIT STARTUP

Equipment Coded by the Component Cooling System	Number With Heat Load	Number Receiving Flow	Total Heat Load (Btu/Hr 10^6)	Total Flow (GPM)	Notes
Residual Heat Removal HXs	1	1	37.4	5000	1
Residual Heat Removal Pumps	1	2	.443	50	2
Component Cooling Pumps	4	4	.216	120	3
Auxiliary Feedwater Pumps	2	2	.136	60	3
Containment Spray Pumps	0	-	-	60	3
Safety Injection Pumps	0	2	-	80	4
Centrifugal Charging Pumps	0	2	-	140	4
Letdown HX	1	1	16.0	1000	
Sealwater HX	1	1	1.98	250	
Reciprocating Charging Pump Brg. Oil Cooler	1	1	.104	6	
Fuel Pool Cooling Pumps	1	2	.620	80	3
Fuel Pool Cooling HXs	1	1	16.96	3000	5
Recycle Evaporator Package	1	1	9.019	810	6
Waste Evaporator Package	1	1	9.019	810	6
Waste Gas Compressor Package	1	2	.134	100	
Waste Gas Hyd. Recombiner Pack.	1	2	.07	20	
Reactor Coolant Drain Tank HX	0	1	-	225	
Excess Letdown HX	1	1	5.18	250	
Reactor Vessel Support Coolers	4	4	.25	40	7
Reactor Coolant Pumps	4	4	4.80	864	8
TOTALS			102.331	12965	

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TABLE 9.2.2-1 (Page 2)

NOTES:

1. Discontinued after Reactor Coolant Pumps are started.

2. The pump motor coolers and mechanical seal heat exchanger of each pump receive cooling flow.

3. The pump motor coolers of each pump receive cooling flow.

4. The pump motor coolers and oil cooler(s) of each pump receive cooling flow.

5. Only one Fuel Pool Cooling HX is assumed to be in service. However, the Component Cooling System has sufficient capacity to place both KF HXs in service if necessary.

6. Each evaporator package consists of an evaporator condenser, vent condenser, distillate cooler, concentrate heat exchanger, concentrate sample cooler, and the concentrate pumps bearing coolers. Only one of the two concentrate pumps bearing coolers is assumed to be in service.

7. Each cooler has two flow paths.

8. The Thermal Barrier, Upper and Lower Bearing Oil Coolers of each Reactor Coolant Pump receive cooling flow.

TABLE 9.2.2-1 (Page 3)

COMPONENT COOLING SYSTEM HEAT LOAD AND FLOW REQUIREMENTS

FOR MODE 2, NORMAL UNIT OPERATION

Equipment Coded by the Component Cooling System	Number With Heat Load	Number Receiving Flow	Total Heat Load (Btu/Hr 10^6)	Total Flow (GPM)	Notes
Residual Heat Removal HXs	0	0	-	-	
Residual Heat Removal Pumps	0	2	-	50	1
Component Cooling Pumps	2	4	.108	120	2
Auxiliary Feedwater Pumps	0	2	-	60	2
Containment Spray Pumps	0	2	-	60	2
Safety Injection Pumps	0	2	-	80	3
Centrifugal Charging Pumps	0	2	-	140	3
Letdown HX	1	1	10.42	1000	4
Sealwater HX	1	1	1.98	250	
Reciprocating Charging Pump Brg. Oil Cooler	1	1	.104	6	
Fuel Pool Cooling Pumps	1	2	.620	80	2
Fuel Pool Cooling HXs	1	1	16.96	3000	
Recycle Evaporator Package	1	1	9.019	810	5
Waste Evaporator Package	1	1	9.019	810	5
Waste Gas Compressor Package	1	2	.134	100	
Waste Gas Hyd. Recombiner Pack.	1	2	.07	20	
Reactor Coolant Drain Tank HX	1	1	2.23	225	
Excess Letdown HX	0	0	-	-	
Reactor Vessel Support Coolers	4	4	.25	40	6
Reactor Coolant Pumps	4	4	4.80	864	7
TOTALS			55.714	7715	

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TABLE 9.2.2-1 (Page 4)

NOTES:

1. The pump motor coolers and mechanical seal heat exchanger of each pump receive cooling flow.

2. The pump motor coolers of each pump receive cooling flow.

3. The pump motor coolers and oil coolers of each pump receive cooling flow.

4. Heat load on the Letdown HX may vary from 6.52 x 10^6 Btu/hr to 10.42 x 10^6 Btu/hr. Normally the cooling flow is throttled to between 250 and 660 GPM. 1000 GPM would be expected if the control valve failed open.

5. Each evaporator package consists of an evaporator condenser, vent condenser, distillate cooler, concentrate heat exchanger, concentrate sample cooler, and the concentrate pumps bearing coolers. Only one of the two concentrate pumps bearing coolers is assumed to be in service.

6. Each cooler has two flow paths.

7. The thermal barrier, upper and lower bearing oil coolers of each reactor coolant pump receive cooling flow.

TABLE 9.2.2-1 (Page 5)

COMPONENT COOLING SYSTEM HEAT LOAD AND FLOW REQUIREMENTS

FOR MODE 3-1, NORMAL UNIT SHUTDOWN AT 4 HOURS

Equipment Coded by the Component Cooling System	Number With Heat Load	Number Receiving Flow	Total Heat Load (Btu/Hr 10^6)	Total Flow (GPM)	Notes
Residual Heat Removal HXs	2	2	234.36	10000	1
Residual Heat Removal Pumps	2	2	.886	50	2
Component Cooling Pumps	4	4	.216	120	3
Auxiliary Feedwater Pumps	2	2	.136	60	3
Containment Spray Pumps	0	2	-	60	3
Safety Injection Pumps	0	2	-	80	4
Centrifugal Charging Pumps	1	2	.577	140	4
Letdown HX	1	1	10.42	1000	5
Sealwater HX	1	1	1.604	250	
Reciprocating Charging Pump Brg. Oil Cooler	0	1	-	6	
Fuel Pool Cooling Pumps	0	2	-	80	3
Fuel Pool Cooling HXs	0	0	-	-	
Recycle Evaporator Package	1	1	9.019	810	6
Waste Evaporator Package	1	1	9.019	810	6
Waste Gas Compressor Packages	1	2	.134	100	
Waste Gas Hyd. Recombiner Pack.	1	2	.07	20	
Reactor Coolant Drain Tank HX	1	1	2.23	225	
Excess Letdown HX	0	0	-	-	
Reactor Vessel Support Coolers	4	4	.25	40	7
Reactor Coolant Pumps	1	4	1.20	864	8
TOTALS			270.121	14715	

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TABLE 9.2.2-1 (Page 6)

NOTES:

1. Heat load determined as follows:

Core decay heat load at 4 hours	120.21×10^6 Btu/hr
Reactor Coolant System sensible heat load (2.01×10^6 Btu/°F at 50°F/hr cooldown rate)	100.50×10^6 Btu/hr
One Reactor Coolant Pump heat input	13.65×10^6 Btu/hr
	234.36×10^6 Btu/hr

2. The pump motor coolers and mechanical seal heat exchanger of each pump receive cooling flow.

3. The pump motor coolers of each pump receive cooling flow.

4. The pump motor coolers and oil cooler(s) of each pump receive cooling flow.

5. Heat load on the Letdown HX may vary from 6.52×10^6 Btu/hr to 10.42×10^6 Btu/hr. Normally, the cooling flow is throttled to between 250 and 660 GPM. 1000 GPM would be expected if the control valve failed open.

6. Each evaporator package consists of an evaporator condenser, vent condenser, distillate cooler, concentrate heat exchanger, concentrate sample cooler, and the concentrate pumps bearing coolers. Only one of the two concentrate pumps bearing coolers is assumed to be in service.

7. Each cooler has two flow paths.

8. The thermal barrier, upper and lower bearing oil coolers of each reactor coolant pump receive cooling flow.

TABLE 9.2.2-1 (Page 7)

COMPONENT COOLING SYSTEM HEAT LOAD AND FLOW REQUIREMENTS

FOR MODE 3-2, NORMAL UNIT SHUTDOWN AT 20 HOURS

Equipment Coded by the Component Cooling System	Number With Heat Load	Number Receiving Flow	Total Heat Load (Btu/Hr 10^6)	Total Flow (GPM)	Notes
Residual Heat Removal HXs	2	2	74.75	10000	
Residual Heat Removal Pumps	2	2	.886	50	1
Component Cooling Pumps	4	4	.216	120	2
Auxiliary Feedwater Pumps	2	2	.136	60	2
Containment Spray Pumps	0	2	-	60	2
Safety Injection Pumps	0	2	-	80	3
Centrifugal Charging Pumps	1	2	.577	140	3
Letdown HX	1	1	10.42	1000	4
Sealwater HX	1	1	1.604	250	
Reciprocating Charging Pump Brg. Oil Cooler	0	1	-	6	
Fuel Pool Cooling Pumps	0	2	-	80	2
Fuel Pool Cooling HXs	0	0	-	-	
Recycle Evaporator Package	1	1	9.019	810	5
Waste Evaporator Package	1	1	9.019	810	5
Waste Gas Compressor Packages	1	2	.134	100	
Waste Gas Hyd. Recombiner Pack.	1	2	.07	20	
Reactor Coolant Drain Tank HX	1	1	2.23	225	
Excess Letdown HX	0	0	-	-	
Reactor Vessel Support Coolers	4	4	.25	40	6
Reactor Coolant Pumps	0	4	-	864	7
TOTALS			109.311	14715	

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TABLE 9.2.2-1 (Page 8)

NOTES:

1. The pump motor coolers and mechanical seal heat exchanger of each pump receive cooling flow.

2. The pump motor coolers of each pump receive cooling flow.

3. The pump motor coolers and oil cooler(s) of each pump receive cooling flow.

4. Heat load on the Letdown HX may vary from 6.52×10^6 Btu/hr to 10.42×10^6 Btu/hr. Normally the cooling flow is throttled to between 250 and 660 GPM. 1000 GPM would be expected if the control valve failed open.

5. Each evaporator package consists of an evaporator condenser, vent condenser, distillate cooler, concentrate heat exchanger, concentrate sample cooler, and the concentrate pumps bearing coolers. Only one of the two concentrate pumps bearing coolers is assumed to be in service.

6. Each cooler has two flow paths.

7. The thermal barrier, upper and lower bearing oil coolers of each reactor coolant pump receive cooling flow.

TABLE 9.2.2-1 (Page 9)

COMPONENT COOLING SYSTEM HEAT LOAD AND FLOW REQUIREMENTS

FOR MODE 3-3, UNIT SHUTDOWN AT 4 HOURS (LOCA ON OTHER UNIT)

Equipment Coded by the Component Cooling System	Number With Heat Load	Number Receiving Flow	Total Heat Load (Btu/Hr 10^6)	Total Flow (GPM)	Notes
Residual Heat Removal HXs	1	1	133.86	5000	1
Residual Heat Removal Pumps	1	2	.443	50	2
Component Cooling Pumps	2	4	.108	120	3
Auxiliary Feedwater Pumps	1	2	.068	60	3
Containment Spray Pumps	0	2	-	60	3
Safety Injection Pumps	0	2	-	60	4
Centrifugal Charging Pumps	1	2	.577	140	4
Letdown HX	1	1	10.42	1000	5
Sealwater HX	1	1	1.604	250	
Reciprocating Charging Pump Brg. Oil Cooler	0	1	-	6	
Fuel Pool Cooling Pumps	0	2	-	80	3
Fuel Pool Cooling HXs	0	0	-	-	
Recycle Evaporator Package	0	1	-	810	6
Waste Evaporator Package	0	1	-	810	6
Waste Gas Compressor Packages	1	2	.134	100	
Waste Gas Hyd. Recombiner Pack.	1	2	.07	20	
Reactor Coolant Drain Tank HX	1	1	2.23	225	
Excess Letdown HX	0	0	-	-	
Reactor Vessel Support Coolers	4	4	.25	40	7
Reactor Coolant Pumps	1	4	1.2	864	8
TOTALS			150.964	9715	

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TABLE 9.2.2-1 (Page 10)

NOTES:

1. Heat load determined as follows:

Core decay heat load at 4 hours	120.21×10^6 Btu/hr
One Reactor Coolant Pump heat input	13.65×10^6 Btu/hr
	133.86×10^6 Btu/hr

   The cooldown will proceed slowly as the decay heat load decreases.

2. The pump motor coolers and mechanical seal heat exchanger of each pump receive cooling flow.

3. The pump motor coolers of each pump receive cooling flow.

4. The pump motor coolers and oil cooler(s) of each pump receive cooling flow.

5. Heat load on the Letdown HX may vary from 6.52×10^6 Btu/hr to 10.42×10^6 Btu/hr. Normally, the cooling flow is throttled to between 250 and 660 GPM. 1000 GPM would be expected if the control valve failed open.

6. Each evaporator package consists of an evaporator condenser, vent condenser, distillate cooler, concentrate heat exchanger, concentrate sample cooler, and the concentrate pumps bearing coolers. Only one of the two concentrate pumps bearing coolers is assumed to be in service.

7. Each cooler has two flow paths.

8. The thermal barrier, upper and lower bearing oil coolers of each reactor coolant pump receive cooling flow.

Table 9.2.2-1 (Page 11)

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Table 9.2.2-1 (Page 12)

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TABLE 9.2.2-1 (Page 13)

COMPONENT COOLING SYSTEM HEAT LOAD AND FLOW REQUIREMENTS

FOR MODE 4, REFUELING

Equipment Coded by the Component Cooling System	Number With Heat Load	Number Receiving Flow	Total Heat Load (Btu/Hr 10^6)	Total Flow (GPM)	Notes
Residual Heat Removal HXs	2	2	42.97	10000	1
Residual Heat Removal Pumps	2	2	.886	50	2
Component Cooling Pumps	4	4	.216	120	3
Auxiliary Feedwater Pumps	0	2	-	60	3
Containment Spray Pumps	0	2	-	60	3
Safety Injection Pumps	0	2	-	80	4
Centrifugal Charging Pumps	0	2	-	140	4
Letdown HX	0	1	-	1000	5
Sealwater HX	0	1	-	250	
Reciprocating Charging Pump Brg. Oil Cooler	1	1	.104	6	
Fuel Pool Cooling Pumps	1	2	.620	80	3
Fuel Pool Cooling HXs	1	1	16.96	3000	6
Recycle Evaporator Package	1	1	9.019	810	7
Waste Evaporator Package	1	1	9.019	810	7
Waste Gas Compressor Packages	1	2	.134	100	
Waste Gas Hyd. Recombiner Pack.	1	2	.07	20	
Reactor Coolant Drain Tank HX	0	1	-	225	
Excess Letdown HX	0	0	-	-	
Reactor Vessel Support Packages	4	4	.25	40	8
Reactor Coolant Pumps	0	4	-	864	9
TOTALS			80.248	17715	

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NOTES:

1. Heat load is core decay heat at 4 days after zero power, at which time transfer of fuel assemblies is expected to begin.

2. The pump motor coolers and mechanical seal heat exchanger of each pump receive cooling flow.

3. The pump motor coolers of each pump receive cooling flow.

4. The pump motor coolers and oil cooler(s) of each pump receive cooling flow.

5. 1000 GPM cooling flow would be expected if the control valve failed open. Normally, with no heat load the flow would tend towards zero.

6. One Fuel Pool Cooling HX is assumed for normal refueling. Flow should be blocked to nonessential equipment with no heat load if both Fuel Pool Cooling HXs are necessary.

7. Each evaporator package consists of an evaporator condenser, vent condenser, distillate cooler, concentrate heat exchanger, concentrate sample cooler, and the concentrate pumps bearing coolers. Only one of the two concentrate pumps bearing coolers is assumed to be in service.

8. Each cooler has two flow paths.

9. The thermal barrier, upper and lower bearing oil coolers of each reactor coolant pump receive cooling flow.

TABLE 9.2.2-1 (Page 15)

COMPONENT COOLING SYSTEM HEAT LOAD AND FLOW REQUIREMENTS

FOR MODE 5-1, ENGINEERED SAFEGUARDS (SAFETY INJECTION)

Equipment Coded by the Component Cooling System	Number With Heat Load	Number Receiving Flow	Total Heat Load (Btu/Hr 10^6)	Total Flow (GPM)	Notes
Residual Heat Removal HXs	0	2	-	10000	1
Residual Heat Removal Pumps	2	2	.886	50	2
Component Cooling Pumps	4	4	.216	120	3
Auxiliary Feedwater Pumps	2	2	.136	60	3
Containment Spray Pumps	2	2	.772	60	3
Safety Injection Pumps	2	2	1.132	80	4
Centrifugal Charging Pumps	2	2	1.154	140	4
Letdown HX	0	0	-	-	
Sealwater HX	0	0	-	-	
Reciprocating Charging Pump Brg. Oil Cooler	0	0	-	-	
Fuel Pool Cooling Pumps	0	0	-	-	
Fuel Pool Cooling HXs	0	0	-	-	
Recycle Evaporator Package	0	0	-	-	
Waste Evaporator Package	0	0	-	-	
Waste Gas Compressor Packages	0	0	-	-	
Waste Gas Hyd. Recombiner Pack.	0	0	-	-	
Reactor Coolant Drain Tank HX	0	1	-	250	5
Excess Letdown HX	0	1	-	225	6
Reactor Vessel Support Coolers	0	4	-	40	7
Reactor Coolant Pumps	0	4	-	864	8
TOTALS			4.296	11889	

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NOTES:

1. Cooling flow is supplied although there is no heat load on the Residual Heat Removal HXs during the safety injection mode of operation.

2. The pump motor coolers and mechanical seal heat exchanger of each pump receive cooling flow.

3. The pump motor coolers of each pump receive cooling flow.

4. The pump motor coolers and oil cooler(s) of each pump receive cooling flow.

5. The Reactor Coolant Drain Tank HX will continue to receive cooling flow until the containment high pressure signal is received, when cooling flow is automatically secured.

6. If the Excess Letdown HX is receiving cooling flow when the safety injection signal is received, it will continue to receive cooling flow until the containment high pressure signal is received, when flow is automatically secured.

7. The Reactor Vessel Support Coolers receive cooling flow until the containment high-high pressure signal is received, when flow is automatically secured. Each cooler has two flow paths.

8. The Reactor Coolant Pumps receive cooling flow until the containment high-high pressure signal is received, when flow is automatically secured. The thermal barrier, upper and lower bearing oil coolers of each pump receive cooling flow.

TABLE 9.2.2-1 (Page 17)

COMPONENT COOLING SYSTEM HEAT LOAD AND FLOW REQUIREMENTS

FOR MODE 5-2, ENGINEERED SAFEGUARD (RECIRCULATION)

Equipment Coded by the Component Cooling System	Number With Heat Load	Number Receiving Flow	Total Heat Load (Btu/Hr 10^6)	Total Flow (GPM)	Notes
Residual Heat Removal HXs	2	2	95.03	10000	
Residual Heat Removal Pumps	2	2	.886	50	1
Component Cooling Pumps	4	4	.216	120	2
Auxiliary Feedwater Pumps	2	2	.136	60	2
Containment Spray Pumps	2	2	.772	60	2
Safety Injection Pumps	2	2	1.132	80	3
Centrifugal Charging Pumps	2	2	1.154	140	3
Letdown HX	0	0	-	-	
Sealwater HX	0	0	-	-	
Reciprocating Charging Pump Brg. Oil Cooler	0	0	-	-	
Fuel Pool Cooling Pumps	0	0	-	-	
Fuel Pool Cooling HXs	0	0	-	-	
Recycle Evaporator Package	0	0	-	-	
Waste Evaporator Package	0	0	-	-	
Waste Gas Compressor Packages	0	0	-	-	
Waste Gas Hyd. Recombiner Pack.	0	0	-	-	
Reactor Coolant Drain Tank HX	0	1	-	250	4
Excess Letdown HX	0	1	-	225	5
Reactor Vessel Support Coolers	0	4	-	40	6
Reactor Coolant Pumps	0	4	-	864	7
TOTALS			99.326	11889	

NOTES:

1. The pump motor coolers and mechanical seal heat exchanger of each pump receive cooling flow.

2. The pump motor coolers of each pump receive cooling flow.

3. The pump motor coolers and oil cooler(s) of each pump receive cooling flow.

4. The Reactor Coolant Drain Tank HX will continue to receive cooling flow until the containment high pressure signal is received, when cooling flow is automatically secured.

5. If the Excess Letdown HX is receiving cooling flow when the safety injection signal is received, it will continue to receive cooling flow until the containment high pressure signal is received, when flow is automatically secured.

6. The Reactor Vessel Support Coolers receive cooling flow until the containment high-high pressure signal is received, when flow is automatically secured. Each cooler has two flow paths.

7. The Reactor Coolant Pumps receive cooling flow until the containment high-high pressure signal is received, when flow is automatically secured. The thermal barrier, upper and lower bearing oil coolers of each pump receive cooling flow.

Table 9.2.2-2 (Page 1)

COMPONENT COOLING SYSTEM VALVE ALIGNMENT FOR VARIOUS MODES OF OPERATION

Valve Number	Mode of Operation 1	2	3-1	3-2	3-3	4	5-1	5-2	Figure	Loc.
1KC1A	0	0	0	0	0	0	(1)	(1)	9.2.2-1	C-6
1KC3A	0	0	0	0	0	(2)	(3)	(3)	9.2.2-1	C-6
1KC50A	0	0	0	0	0	0	(1)	(1)	9.2.2-1	K-7
1KC230A	0	0	0	0	0	(2)	(3)	(3)	9.2.2-1	K-7
1KC56A	(4)	X	0	0	(4)	0	(5)	(5)	9.2.2-2	E-4
1KC18B	0	0	0	0	0	(2)	(3)	(3)	9.2.2-1	C-9
1KC2B	0	0	0	0	0	0	(1)	(1)	9.2.2-1	C-9
1KC53B	0	0	0	0	0	0	(1)	(1)	9.2.2-1	K-8
1KC228B	0	0	0	0	0	(2)	(3)	(3)	9.2.2-1	K-8
1KC81B	(4)	X	0	0	(4)	0	(5)	(5)	9.2.2-2	E-11
1KC148	(4,6)	(4)	X	X	X	(4,6)	-	-	9.2.2-3	G-9
1KC155	(4,6)	(4)	X	X	X	(4,6)	-	-	9.2.2-3	G-12
1KC225*	0	0	0	0	0	0	-	-	9.2.2-7	G-8
1KC252*	0	0	0	0	0	0	-	-	9.2.2-7	G-6
1KC463*	0	0	0	0	0	0	-	-	9.2.2-7	G-2
1KC477*	0	0	0	0	0	0	-	-	9.2.2-7	F-4
1KC320A	0	0	0	0	0	0	(7)	(7)	9.2.2-4	B-10
1KC332B	0	0	0	0	0	0	(7)	(7)	9.2.2-4	E-2
1KC333A	0	0	0	0	0	0	(7)	(7)	9.2.2-4	G-2
1KC305B	0	X	X	X	X	X	(8)	(8)	9.2.2-4	D-13
1KC315B	0	X	X	X	X	X	(8)	(8)	9.2.2-4	L-13
1KC338B	0	0	0	0	0	0	(3)	(3)	9.2.2-4	D-12
1KC424B	0	0	0	0	0	0	(3)	(3)	9.2.2-4	L-5
1KC425A	0	0	0	0	0	0	(3)	(3)	9.2.2-4	L-7

* On Unit 1 only.

Table 9.2.2-2 (Page 2)

Nonmenclature: 0 - open

X - closed

- - downstream of a closed valve

Valves listed in this table are isolation valves which are regularly manipulated to align the system for its various modes of operation. All other isolation valves should remain in the position indicated on the flow diagrams except for changes required for maintenance, or emergency situations.

NOTES:

1. Closes on S-signal (Safety Injection Signal).
2. Normally open, but closed when both fuel pool cooling HXs are used in refueling.
3. Closes on P-signal (High-High Containment Pressure Signal).
4. Valve may be open or closed, depending on which train (or heat exchanger) is in operation and which is serving as backup.
5. Opens on S-signal (Safety Injection Signal).
6. Both fuel pool cooling HXs may be in operation. See Note 2.
7. Normally open, closes on T-signal (High Containment Pressure Signal).
8. Normally closed, closes on T-signal (High Containment Pressure Signal) if open.

Table 9.2.2-3 (Page 1)

Component Cooling System Component Design Data

COMPONENT COOLING PUMPS

Number per unit	4
Type	Centrifugal
Design Pressure, psig	150
Design Temperature, F	200
Design Flow, gpm	3760
Design Head, ft.	200
Max. Flow Rate, gpm	4940
Shutoff Head, ft.	243.5
Minimum Flow Rate, gpm	1000
NPSH Required At Design Flow, Ft.	13.7
Material of Construction	Carbon Steel

COMPONENT COOLING HEAT EXCHANGERS

Number per Unit	2
Design Pressure, psig	150
Design Temperature, F	200
Estimated UA, BTU/HR F	6.82×10^6
Design Flow (Shell Side), LB/HR	3.242×10^6
Design Flow (Tube Side), LB/HR	5.000×10^6
Shell Side Inlet Temp., F	172
Shell Side Outlet Temp., F	110
Tube Side Inlet Temp., F	90
Tube Side Outlet Temp., F	130.4
Max. Pressure Loss, psi	15
Shell Side Fouling Factor	.0005
Tube Side Fouling Factor	.002
Shell Side Material	Carbon Steel
Tube Side Material	Inhibited Admiralty

COMPONENT COOLING SURGE TANK

Number per Unit	2
Total Volume per tank, gal	3925
Normal Water Volume per tank, gal	2500
Normal Pressure, psig	0
Design Pressure, psig	15
Design Temperature, F	200
Material of Construction	304 Stainless Steel

All sample lines are provided with a local sample valve in the sample room sink. The sample sink is located in a hooded enclosure which is equipped with an exhaust ventilator. The work area around the sink and enclosure is large enough for sample collection and storage of radiation monitoring equipment.

Shielding is provided where required for personnel protection (refer to Section 12.1). Local instrumentation is provided to permit manual control of sampling operations and to assure that the samples are at suitable temperature and pressures before diverting flow to the sample sink.

Sample heat exchangers are provided to cool samples from the reactor coolant loops, residual heat removal loops, pressurizer steam and liquid spaces, and the steam generator blowdown lines. A delay coil is provided for decay of short-lived radionuclides present in the reactor coolant loop samples. In the sample room manually controlled valves are provided to reduce pressure. Sample vessels are provided to obtain degassed reactor coolant liquid and dissolved gas samples for laboratory analysis.

A gaseous sample from the volume control tank in the chemical and volume control system is collected in a sample vessel.

The steam generator blowdown sample lines are taken off the blowdown lines as close to the steam generator as practical in order to provide representative samples and satisfactory radioactivity control. The steam generator upper shell sample lines are taken directly off the steam generator. They are tied, along with the blowdown sample lines, into common steam generator sample lines to the sample room. The sample line flow from each steam generator is cooled by a sample heat exchanger. Downstream of the sample heat exchanger each sample line separates into 3 paths. One path connects all four sample lines together for manual sampling at the primary sample sink. Another path connects all four sample lines together and directs the flow through a radiation monitor. The flow from the radiation monitor is directed to the condensate storage tank of the Condensate Storage System. Individual lines are provided for each steam generator sample header, directing flow to the conventional sampling panel.

Each line contains an air operated isolation valve which will automatically close on a signal from the radiation monitor. Containment isolation valves are provided in each of the steam generator sample lines and are arranged so that the operator may select sample flow from either the upper shell or the blowdown line of each steam generator. These valves close automatically on the safety injection signal. The ability to obtain a manual sample in the primary sample sink for identifying the responsible steam generator following a radiation monitor alarm is provided.

The principal components of the system are the sample heat exchangers, delay coil, sample vessels and the sample sink. Component safety classifications and codes are listed in Table 3.2.2-2. Component design is as follows:

Sample Heat Exchangers

Sample heat exchangers are provided to cool samples originating from the pressurizer, the reactor coolant loops, the residual heat removal loops and the steam generator blowdown sample lines. The samples flow through the tube side and water from the Auxiliary Building Cooling System (YN) circulates through the shell side.

Delay Coil

A delay coil, consisting of coiled tubing, is provided in the high pressure sample line from the reactor coolant loops. The delay coil has sufficient length to provide at least a 40 second sample transit time within the Containment. An additional 20 seconds transit time is provided from the Containment to the sample sink. The delay allows for decay of the short lived isotope N16 to a level that permits normal access to the sample room.

Sample Vessels

Sample vessels are provided in the sample lines from the pressurizer, the reactor coolant loops and the volume control tank to obtain liquid and gas samples for laboratory analysis.

Sample Sink

Two sample sinks are provided in each sample room. One sink includes all the samples which require heat exchangers or sample vessels plus the accumulator sample lines. The second sink includes all the other sample lines. Both sinks drain to the waste feed tank of the Liquid Radwaste System.

The sinks are located in a hooded enclosure which is supplied with a continuously running exhaust fan. The fan discharges to the unit vent. The enclosure is penetrated by the sample lines, and a demineralized water line for each sink. Manual valves, for sample lines discharge isolation and flow control, are mounted on panels above each sink.

Each sample is listed in Table 9.3.2-1 giving the sampled system, sample location, and system design temperature and pressure. All sample lines originating inside the containment are safety class 2 through the containment to the outside isolation valve. From the outside isolation to the sample sink the piping is non nuclear safety, but is adequately shielded. Sample lines originating at the reactor coolant lines are safety class 2. A 0.236 id connection is required to change from safety class 1 to safety class 2. Sample lines originating at the pressurizer are safety class 1 until a flow restrictor transition piece where the piping becomes safety class 2. All sample lines originating outside the containment are the same safety class until the root valve or closed isolation valve where the piping class changes to non nuclear safety. All piping safety class boundaries meet the ANS1 N18.2 Code.

The Post-Accident Sampling System is discussed in the response to Question 281.9.

9.3.2.2.2 Conventional Sampling System

The Conventional Sampling System, as shown on Figures 9.3.2-6 through 9.3.2-10 is designed to allow random grab samples and/or continuous monitoring of the leaks. The Chemical and Volume Control System also removes excess lithium from the reactor coolant, keeping the lithium concentration within the desired limits of pH control.

The Chemical and Volume Control System provides a means for adding chemicals to the Reactor Coolant System, controlling the pH of the coolant during initial startup and subsequent operation, scavenging oxygen from the coolant during startup, and controlling the oxygen level of the reactor coolant due to radiolysis during all operation subsequent to startup. The Chemical and Volume Control System is capable of maintaining the oxygen content and pH of the reactor coolant within limits specified in Table 5.2.3-4 during all operation subsequent to startup.

9.3.4.1.4 Reactivity Control

The Chemical and Volume Control System regulates the concentration of chemical neutron absorber (boron) in the reactor coolant to control reactivity changes resulting from the change in reactor coolant temperature between cold shutdown and hot full-power operation, burnup of fuel and burnable poisons, buildup of fission products in the fuel, and xenon transients.

Reactor Makeup Control

1. The Chemical and Volume Control System is capable of borating the Reactor Coolant System through either one of three flow paths: (a) through blender to VCT, (b) through blender to charging pump, and (c) directly to charging pumps.

2. The amount of boric acid stored in the Chemical and Volume Control System always exceeds that amount required to borate the Reactor Coolant System to cold shutdown concentration assuming that the control assembly with the highest reactivity worth is stuck in its fully withdrawn position. This amount of boric acid also exceeds the amount required to bring the reactor to hot shutdown and to compensate for subsequent xenon decay.

Boron Thermal Regeneration

The Chemical and Volume Control System is designed to control the changes in reactor coolant boron concentration to compensate for the xenon transients during load follow operations without adding makeup for either boration or dilution. This is accomplished by the boron thermal regeneration process which is designed to allow load follow operations as required by the design load cycle.

9.3.4.1.5 Emergency Core Cooling

The centrifugal charging pumps in the Chemical and Volume Control System serve as the high-head safety injection pumps in the Emergency Core Cooling System. Other than the centrifugal charging pumps and associated piping and valves, the Chemical and Volume Control System is not required to function during a and dilution operations, especially during load follow, part or all of the letdown flow heading for the volume control tank may be directed to the Boron Recycle System via the diversion valve. Hydrogen (from the Hydrogen Bulk Storage System) is continuously supplied to the volume control tank where it mixes with fission gases which are stripped from the reactor coolant in the gas space. The contaminated hydrogen is vented back to the Waste Gas System. The partial pressure of the hydrogen gas mixture in the volume control tank determines the concentration of hydrogen dissolved in the reactor coolant for control of oxygen produced by radiolysis of water in the core.

Three charging pumps (one positive displacement pump, and two centrifugal charging pumps) are provided to take suction from the volume control tank and return the purified reactor coolant to the Reactor Coolant System through the charging line. Charging flow is handled by either of the charging pumps. Normally, charging flow is handled by the single positive displacement reciprocating charging pump which is equipped with suction and discharge pulsation dampeners. These dampeners relieve the stress which is exerted on the piping from the positive displacement reciprocating charging pump. The charging flow splits into two paths which provide reactor coolant pump seal injection and Reactor Coolant System charging. The bulk of the charging flow is pumped back to the Reactor Coolant System through the tube side of the regenerative heat exchanger raising the charging flow to a temperature approaching the reactor coolant temperature. The flow is then injected into a cold leg of the Reactor Coolant System. Two charging paths are provided from a point downstream of the regenerative heat exchanger for rapid boration of the system. A flow path is also provided from the regenerative heat exchanger outlet to the pressurizer spray line. A motor operated valve in the spray line is available to provide auxiliary spray to the vapor space of the pressurizer. A line from the RHR System also supplies pressurizer spray. This line was added in order to handle a temperature transient which exists at the pressurizer nozzle. Pressurizer spray under normal operation is supplied by the RHR System. This provides a means of cooling the pressurizer near the end of unit cooldown, when the reactor coolant pumps, which normally provide the driving head for the pressurizer spray, are not operating.

A portion of the charging flow is directed to the reactor coolant pumps (nominally 8 gpm per pump) through a seal water injection filter. The flow is directed downward to a point between the pump shaft bearing and the thermal barrier cooling coil. Here the flow splits and a portion (nominally 5 gpm per pump) enters the Reactor Coolant System through the labyrinth seals and thermal barrier. The remainder of the flow is directed upward along the pump shaft, cooling the lower bearing, and to the number 1 seal leakoff. The number 1 seal leakoff flow discharges to a common manifold, exits from the containment, and then passes through the seal water return filter and the seal water heat exchanger to the volume control tank. A very small portion of the seal flow leaks through to the number 2 seal. A number 3 seal provides a final barrier to leakage to Containment atmosphere. The number 2 and 3 seal leakoff flows are discharged to the reactor coolant drain tank in the Liquid Radwaste System.

A standpipe is provided to assure a backpressure of at least 7 feet of water on the number 3 seal and warn of excessive number 2 seal leakage. The first outlet from the standpipe has an orifice to permit normal number 2 seal leakage to flow to the reactor coolant drain tank; excessive number 2 leakage results in a rise in standpipe level and eventual overflow to the reactor coolant drain tank via a second overflow connection.

An alternate letdown path from the Reactor Coolant System is provided in the event that the normal letdown path is inoperable. Reactor coolant can be discharged from a cold leg to flow through the tube side of the excess letdown heat exchanger where it is cooled by component cooling water. Downstream of the heat exchanger a remote-manual control valve controls the letdown flow. The flow normally joins the number 1 seal discharge manifold and passes through the seal water return filter and heat exchanger to the VCT. The flow can also be directed to the reactor coolant drain tank. When the normal letdown line is not available, the normal purification path is also not in operation. Therefore, this alternate condition would allow continued power operation for a limited period of time, dependent on Reactor Coolant System chemistry and activity. The excess letdown flow path is also used to provide additional letdown capability during the final stages of unit heatup. This path removes some of the excess reactor coolant due to expansion of the system as a result of the Reactor Coolant System temperature increase. In this case, the excess letdown is diverted to the reactor coolant drain tank.

Surges in Reactor Coolant System inventory due to load changes are accommodated for the most part in the pressurizer. The volume control tank provides surge capacity for reactor coolant expansion not accommodated by the pressurizer. If the water level in the volume control tank exceeds the normal operating range, a proportional controller modulates a three way valve downstream of the reactor coolant filter to divert a portion of the letdown to the Boron Recycle System. If the high-level limit in the volume control tank is reached, an alarm is actuated in the control room and the letdown flow is completely diverted to the Boron Recycle System.

The Boron Recycle System receives and processes reactor coolant effluent for reuse of the boric acid and purified water. The system decontaminates the effluent by means of demineralization and gas stripping, and uses evaporation to separate and recover the boric acid and reactor makeup water.

Low level in the volume control tank initiates makeup from the reactor makeup control system. If the reactor makeup control system does not supply sufficient makeup to keep the volume control tank level from falling to a lower level, a low alarm is actuated. Manual action may correct the situation or, if the level continues to decrease, an emergency low level signal from the two level channels causes the suction of the charging pumps to be transferred to the refueling water storage tank.

A boron concentration measurement system is provided, by the use of a boron meter, to monitor the boron content of the reactor coolant in the letdown line. The boron concentration is indicated in the main control room.

The boric acid is stored in two boric acid tanks. Two boric acid transfer pumps are provided with one pump normally aligned for service and the second pump in reserve. On a demand signal by the reactor makeup controller, the pump starts and delivers boric acid to the suction header of the charging pumps. The pump can also be used to recirculate the boric acid tank fluid.

All portions of the Chemical and Volume Control System which normally contain concentrated boric acid solution (4 weight percent boric acid) are required to be located within a heated area in order to maintain solution temperature at ≥ 65°F. If a portion of the system which normally contains concentrated boric acid solution is not located in a heated area, it is provided with some other means (e.g. heat tracing) to maintain solution temperature at ≥ 65°F.

The reactor makeup water pumps, taking suction from the reactor makeup water storage tank, are employed for various makeup and flushing operations throughout the systems. One of these pumps starts on demand from the reactor makeup controller and provides flow to the suction header of the charging pumps or the volume control tank.

During reactor operation, changes are made in the reactor coolant boron concentration for the following conditions:

1. Reactor startup - boron concentration must be decreased from shutdown concentration to achieve criticality.

2. Load follow - boron concentration must be either increased or decreased to compensate for the xenon transient following a change in load.

3. Fuel burnup - boron concentration must be decreased to compensate for fuel burnup and the buildup of fission products in the fuel.

4. Cold shutdown - boron concentration must be increased to the cold shutdown concentration.

The Boron Thermal Regeneration System is normally used to control boron concentration to compensate for xenon transients during load follow operations. Boron thermal regeneration can also be used in conjunction with dilution operations of the Reactor Makeup Control System to reduce the amount of effluent to be processed by the Boron Recycle System. A description of the Boron Thermal Regeneration System is given in Section 9.3.6.

The Reactor Makeup Control System can be set up for the following modes of operation:

line. Temperature indication is provided on the main control board. If the outlet temperature from the heat exchanger is excessive, a high temperature alarm is actuated and a temperature controlled valve diverts the letdown directly to the volume control tank.

9.3.4.2.3.5 Excess Letdown Heat Exchanger

The excess letdown heat exchanger cools reactor coolant letdown flow. The excess letdown heat exchanger can be employed either when normal letdown is temporarily out of service to maintain the reactor in operation or it can be used to supplement maximum letdown during the final stages of heatup. The letdown flows through the tube side of the unit and component cooling water is circulated through the shell. All surfaces in contact with reactor coolant are austenitic stainless steel and the shell is carbon steel. All tube joints are welded.

A temperature detector measures temperature of excess letdown downstream of the excess letdown heat exchanger. Temperature indication and high temperature alarm are provided on the main control board.

A pressure sensor indicates the pressure of the excess letdown flow downstream of the excess letdown heat exchanger and excess letdown control valve. Pressure indication is provided on the main control board.

9.3.4.2.3.6 Seal Water Heat Exchanger

The seal water heat exchanger is designed to cool fluid from three sources: reactor coolant pump #1 seal water returning to the Chemical and Volume Control System, reactor coolant discharged from the excess letdown heat exchanger, and centrifugal charging pump bypass flow. Reactor coolant flows through the tube side of the heat exchanger and component cooling water is circulated through the shell. The design flow rate is equal to the sum of the excess letdown flow, maximum design reactor coolant pump seal leakage, and bypass flow from one centrifugal charging pump. The unit is designed to cool the above flow to the temperature normally maintained in the volume control tank. All surfaces in contact with reactor coolant are austenitic stainless steel and the shell is carbon steel.

9.3.4.2.3.7 Volume Control Tank

The volume control tank provides surge capacity for part of the reactor coolant expansion volume not accommodated by the pressurizer. When the level in the tank reaches the high level setpoint, the remainder of the expansion volume is accommodated by diversion of the letdown stream to the Boron Recycle System. It also provides a means for introducing hydrogen into the coolant to maintain the required equilibrium concentration of 25-35 cc hydrogen (at STP per kilogram of water) and is used for degassing the reactor coolant. It also serves as a head tank for the charging pumps.

A spray nozzle located inside the tank on the letdown line nozzle provides liquid-to-gas contact between the incoming fluid and the hydrogen atmosphere in the tank.

A remotely operated vent valve, discharging to the Waste Gas System permits continuous removal of gaseous fission products which are stripped from the reactor coolant and collected in this tank. Relief protection, gas space sampling, and nitrogen purge connections are also provided. The tank also accepts the seal water return flow from the reactor coolant pumps.

Volume control tank pressure and temperature are monitored with indication given in the Control Room. Alarm is given in the Control Room for high and low pressure conditions and for high temperature.

Two level channels govern the water inventory in the volume control tank. These channels provide local and remote level indication, level alarms, level control, makeup control, and emergency makeup control.

If the volume control tank level rises above the normal operating range, one channel provides an analog signal to the proportional controller which modulates the three-way valve downstream of the reactor coolant filter to maintain the volume control tank level within the normal operating band. The three-way valve can split letdown flow so that a portion goes to the Boron Recycle System and a portion to the volume control tank. The controller would operate in this fashion during a dilution operation when reactor makeup water is being fed to the volume control tank from the reactor makeup control system.

If the modulating function of the channel fails and the volume control tank level continues to rise, the high level alarm alerts the operator to the malfunction and the letdown flow can be manually diverted to the holdup tanks. If no action is taken by the operator and the tank level continues to rise, the full letdown flow is automatically diverted.

During normal power operation, a low level in the volume control tank initiates automatic makeup which injects a pre-selected blend of boric acid and water into the charging pump suction header. When the volume control tank is restored to normal, automatic makeup stops.

If the automatic makeup fails or is not aligned for operation and the tank level continues to decrease, a low level alarm is actuated. Manual action may correct the situation or, if the level continues to decrese, an emergency low level signal from both channels opens the stop valves in the refueling water supply line and closes the stop valves in the volume control tank outlet line.

9.3.4.2.3.8 Boric Acid Tanks

Two boric acid tanks are shared by the two units. During normal operation, one tank supplies boric acid solution for each unit. Each tank is designed to store sufficient boric acid solution for a cold shutdown from full power operation immediately following refueling with the most reactive control rod not inserted, plus operating margins.

The concentration of boric acid solution in storage is maintained between 4 and 4.4 percent by weight. Periodic manual sampling and corrective action, if necessary, assures that these limits are maintained. Therefore, measured amounts of boric acid solution can be delivered to the reactor coolant to control the concentration.

A temperature sensor provides temperature measurement of each tank's contents. Temperature indication is provided as well as high and low temperature alarms which are indicated on the main control board.

Two level detectors indicate the level in each boric acid tank. Level indication with high, low, and low-low level alarms is provided on the main control board. The low-low level alarm is set to alarm when the tank level drops below the minimum level required to assure that sufficient boric acid solution is available to reach cold shutdown with the most reactive rod stuck out.

9.3.4.2.3.9 Batching Tank

The batching tank is used for mixing a makeup supply of boric acid solution for transfer to the boric acid tanks. The tank may also be used for solution storage. A boric acid batching tank pump is used to transfer the batching tanks contents to the boric acid tanks.

A local sampling point is provided for verifying the solution concentration prior to transferring it out of the tank. The tank is provided with an agitator to improve mixing during batching operations and a steam jacket for heating the boric acid solution.

9.3.4.2.3.10 Chemical Mixing Tank

The primary use of the chemical mixing tank is in the preparation of caustic solutions for pH control and hydrazine solution for oxygen scavenging.

9.3.4.2.3.11 Mixed Bed Demineralizers

Two flushable mixed bed demineralizers assist in maintaining reactor coolant purity. A lithium-form cation resin and hydroxyl-form anion resin are charged into the demineralizers. The anion resin is converted to the borate form during operation. Both types of resin remove fission and corrosion products.

The resin bed is designed to provide a decontamination factor of ten for most fission products (exceptions are cesium, yttrium, and molybdenum).

Each demineralizer has sufficient capacity for approximately one core cycle with one percent defective fuel rods. One demineralizer serves as a standby unit for use if the operating demineralizer becomes exhausted during operation.

A temperature sensor measures temperature of the letdown flow downstream of the letdown heat exchanger and controls the letdown flow to the mixed bed demineralizers by means of a three-way valve. If the letdown temperature exceeds the allowable resin operating temperature, (approximately 140°F), the flow automatically bypasses the demineralizers. Temperature indication and high alarm are provided on the main control board. The air operated three-way valve failure mode directs flow to the volume control tank.

Because of the possibility of loss of resin through the inlet of this demineralizer during the process in which resin is removed, a resin strainer has been installed in the inlet piping.

9.3.4.2.3.12 Cation Bed Demineralizers

A flushable cation resin bed in the hydrogen form is located downstream of the mixed bed demineralizers and is used intermittently to control the concentration of excess of Li^7 which builds up in the coolant from the B^{10} (n,α) Li^7 reaction. The demineralizer also has sufficient capacity to maintain the cesium-137 concentration in the coolant below 1.0 ∂Ci/cc with 1 percent defective fuel. The resin bed is designed to reduce the concentration of ionic isotopes, particularly cesium, yttrium, and molybdenum by a minimum factor of 10.

Because of the possibility of loss of resin through the inlet of this demineralizer during the process in which resin is removed, a resin strainer has been installed in the inlet piping.

The cation bed demineralizer has sufficient capacity for approximately one core cycle with one percent defective fuel rods.

9.3.4.2.3.13 Reactor Coolant Filters

Two reactor coolant filters are located on the letdown line. One filter is located upstream of the mixed bed demineralizers, and the second is located upstream of the volume control tank. The filters collect resin fines and particulates from the letdown stream. The design flow capacity of each filter is greater than the maximum purification flow rate.

Two local differential pressure indicators are provided for each reactor coolant filter.

9.3.4.2.3.14 Seal Water Injection Filters

Two seal water injection filters are located in parallel in a common line to the reactor coolant pump seals; they collect particulate matter that could be harmful to the seal faces. Each filter is sized to accept flow in excess of the normal seal water flow requirements.

A differential pressure indicator monitors the pressure drop across each seal water injection filter and gives local indication with high differential pressure alarm on the main control board.

9.3.4.2.3.15 Seal Water Return Filter

The filter collects particulates from the reactor coolant pump seal water return and from the excess letdown flow. The filter is designed to pass flow in excess of the sum of the excess letdown flow and the maximum design leakage from the reactor coolant pump seals.

A local differential pressure indicator is provided.

9.3.4.2.3.16 Boric Acid Filter

The boric acid filter collects particulates from the boric acid solution and reactor makeup water for the reactor coolant makeup circuit. The blender consists of a conventional pipe-tee fitted with a perforated tube insert. The blender decreases the pipe length required to homogenize the mixture for taking representative local sample. A sample point is provided in the piping just downstream of the blender.

9.3.4.2.3.17 Letdown Controls

Two letdown orifices and a control valve are arranged in parallel and serve to reduce the pressure of the letdown stream to a value compatible with the letdown heat exchanger design. One of the orifices and the control valve are sized such that either can pass normal letdown flow; the other orifice can pass less than the normal letdown flow. One or both standby letdown controls may be used with the normally operating control valve in order to increase letdown flow such as during reactor heatup operations and maximum purification. This arrangement also provides a full standby capacity for control of letdown flow. The letdown controls are placed in and taken out of service by remote manual operation of their respective isolation valves.

A flow monitor provides indication in the control room of the letdown flow rate and high alarm to indicate unusually high flow.

A low pressure letdown controller controls the pressure downstream of the letdown heat exchanger to prevent flashing of the letdown liquid. Pressure indication and high pressure alarm are provided on the main control board.

After the Residual Heat Removal System is placed in service and the reactor coolant pumps are shut down, further cooling of the pressurizer liquid is accomplished by charging through the auxiliary spray line from the Residual Heat Removal System. Coincident with unit cooldown, a portion of the reactor coolant flow is diverted from the Residual Heat Removal System to the Chemical and Volume Control System for cleanup. Demineralization of ionic radioactive impurities and stripping of fission gases reduce the reactor coolant activity level sufficiently to permit personnel access for refueling or maintenance operations.

9.3.4.3 Safety Evaluation

The classification of structures, components and systems is presented in Section 3.2. A further discussion on seismic design categories is given in Section 3.7. Conformance with NRC General Design Criteria for the plant systems, components and structures are important to safety as presented in Section 3.1.

9.3.4.3.1 Reactivity Control

Any time that the plant is at power, the quantity of boric acid retained and ready for injection always exceeds that quantity required for the normal cold shutdown assuming that the control assembly of greatest worth is in its fully withdrawn position. This quantity always exceeds the quantity of boric acid required to bring the reactor to hot shutdown and to compensate for subsequent xenon decay. An adequate quantity of boric acid is also available in the refueling water storage tank to achieve cold shutdown.

When the reactor is subcritical; i.e., during cold or hot shutdown, refueling and approach to criticality, the neutron source multiplication is continuously monitored and indicated. Any appreciable increase in the neutron source multiplication, including that caused by the maximum physical boron dilution rate, is slow enough to give ample time to start a corrective action to prevent the core from becoming critical (the boron dilution accident is discussed in Section 15.4.6). The rate of boration, with a single boric acid transfer pump operating, is sufficient to take the reactor from full power operation to 1 percent shutdown in the hot condition, with no rods inserted, in less than 90 minutes. In less than 90 additional minutes, enough boric acid can be injected to compensate for xenon decay, although xenon decay below the equilibrium operating level will not begin until approximately 25 hours after shutdown. Additional boric acid is employed if it is desired to bring the reactor to cold shutdown conditions.

Two separate and independent flow paths are available for reactor coolant boration; i.e., the charging line and the reactor coolant pump seal injection line. A single failure does not result in the inability to borate the Reactor Coolant System.

If the normal charging line is not available, charging to the Reactor Coolant System is continued via reactor coolant pump seal injection, by the standby makeup pump, at the rate of approximately 5 gpm to each reactor coolant pump.

Table 9.3.2-2

Temperature and Pressure Reduction for Samples in the Conventional Systems Sample Panel

Sample	Rough Cooling	Pressure Regulated	Final Cooling
S. G. "A" Blowdown Sample		X	X
S. G. "B" Blowdown Sample		X	X
S. G. "C" Blowdown Sample		X	X
S. G. "D" Blowdown Sample		X	X
Final Feedwater Sample	X	X	X
Hotwell Pump Discharge Sample		X	X
Polish Demineralizer Main Effluent Sample		X	X
Heater Drain C1 H. P. Sample	X	X	X
Heater Drain C2 H. P. Sample	X	X	X
Upper Surge Tank Sample	X		
Main Steam Sample A	X		
Main Steam Sample B	X		
Main Steam Sample C	X		
Main Steam Sample D	X		

Table 9.3.2-3

Types of Analyses Provided in the Conventional Systems Sampling Panel

Samples	Grab Sample	Specific Conductivity	Cation Conductivity	Sodium	PH	Oxygen	Hydrazine	Silica
S. G. "A" Blowdown Sample	X		X	X	X			X
S. G. "B" Blowdown Sample	X		X	X	X			X
S. G. "C" Blowdown Sample	X		X	X	X			X
S. G. "D" Blowdown Sample	X		X	X	X			X
Final Feedwater Sample	X	X	X		X	X	X	X
Hotwell Pump Discharge Sample	X	X		X	X	X		X
Polish Deminerlizer Main Influent Sample								X
Polish Demineralizer Main Effluent Sample				X				X
Heater Drain C1 H. P. Sample	X							X
Heater Drain C2 H. P. Sample	X							X
Upper Surge Tank Sample	X							
Main Steam Sample A	X							
Main Steam Sample B	X							
Main Steam Sample C	X							
Main Steam Sample D	X							

TABLE 9.3.4-3 (Page 4)

Failure Mode and Effects Analysis Chemical and Volume Control System
Active Components - Normal Plant Operation and Load Follow

Component	Failure Mode	CVCS Operation Function	*Effect on System Operation and Shutdown	**Failure Detection Method	Remarks
	b. Fails open	b. Charging and Volume Control - letdown flow.	b. Failure has no effect on CVCS operation during normal plant operation and load follow. However, under accidents conditions requiring containment isolation, failure reduces the redundancy of providing isolation of normal letdown line.	b. Valve position indication (open to closed position change) at CB.	
4. Air diaphragm operated globe valve 1NV18	a. Fails open.	a. Boron Concentration Control - boron thermal regeneration (boration).	a. Failure inhibits use of BTRS for load follow operation (boration) due to low temperature of letdown flow entering BTRS demineralizers. Alternate boration of reactor coolant for load follow is possible using RMCS of CVCS. No effect on operations to bring reactor to hot standby condition.	a. Letdown heat exchanger tube discharge flow (1NVFT5530) and pressure (1NVP5570) indications at CB and BTR demineralizer inlet flow temperature indication (1NRP-5020) at CB, if BTRS is in operation.	1. Valve is designed fail "open" and is electrically wired so the electrical trical solenoid of the air diaphragm operator is energized to close the valve. 2. BTRS operation is not required in operations of CVCS systems used to bring the reactor to hot standby condition.
	b. Fails closed.	b. Boron Concentration Control - boron therm l regeneration (boration).	b. Failure inhibits use of BTRS for load follow operation (boration) due to loss of temperature control of letdown flow entering BTRS demineralizers.	b. Same method of detection as those stated for item #1, failure mode "Fails closed" except no "closed to open position change" indication at CB.	

Failure Mode and Effects Analysis Chemical and Volume Control System
Active Components - Normal Plant Operation and Load Follow

Component	Failure Mode	CVCS Operation Function	*Effect on System Operation and Shutdown	**Failure Detection Method	Remarks
22. Air diaphragm operated globe valve 1NR93	a. Fails closed.	a. Boron Concentration Control - boron thermal regeneration.	a. Failure inhibits use of BTRS for load follow operation (boration) due to flow isolation of shell side of letdown reheat heat exchanger. Alternate boration of reactor coolant for load follow may be accomplished using RMCS of CVCS. No effect on operattion to bring reactor to not standby condition.	a. RCS boron level when sampling letdown flow. If BTRS is operating, BTRS operation indication 'borate) at CB and letdown reheat heat exchanger outlet temperature indication (1NRP5020) at CB.	1. Same remarks as those stated for item #7.
	b. Fails open.	b. Boron Concentration Control - boron storage.	b. Failure inhibits use of BTRS for load follow operation (dilution) due to passage of CVCS letdown flow through tube side of letdown reheat heat exchanger. Alternate dilution of reactor coolant may be accomplished using RMCS of CVCS. No effect on operation to bring reactor to hot standby condition.	b. RCS boron level when sampling letdown flow. If BTRS is operating, BTRS operation indication (dilute) at CB and letdown reheat heat exchanger outlet temperature indication (1RNP5020) at CB.	
23. Air diaphragm operated globe valve 1NV123B (1NV122B analogous)	a. Fails closed.	a. Charging and Volume Control - letdown flow.	a. Failure inhibits use of the excess letdown fluid system of the CVCS as an alternate system that may	a. Valve position indication (closed to open position change) at CB and excess letdown heat exchanger outlet pres-	1. Same remark as that stated for item #7 in regard to valve design.

TABLE 9.3.4-3 (Page 23)

Failure Mode and Effects Analysis Chemical and Volume Control System
Active Components - Normal Plant Operation and Load Follow

Component	Failure Mode	CVCS Operation Function	*Effect on System Operation and Shutdown	**Failure Detection Method	Remarks
	b. Fails closed.	b. Charging and Volume Control - charging flow.	b. Same effect on system operation as that stated for item #28, failure mode "Fails closed".	b. Same method of detection as those stated above for item #28, failure mode "Fails closed".	
30. Motor operated globe valve 1NV203A (1NV-202B analogous)	a. Fails open.	a. Charging and Volume Control - charging flow and seal water flow.	a. Failure has no effect on CVCS operation during normal plant operation and load follow. However, under accident condition requiring isolation of centrifugal charging pump miniflow line, failure reduces redundancy of providing isolatin of miniflow to suction of pumps via seal water heat exchanger.	a. Valve position indication (open to closed position change) at CB.	1. Constant displacement charging pump is normally used to deliver charging and seal water flow.
	b. Fails closed.	b. Charging and Volume Control - charging flow and seal water flow.	b. Failure blocks miniflow to VCT via seal water heat exchanger. Normal charging flow and seal water flow prevents deadheading of pumps when used. Boration of RCS to a hot standby concentration level and makeup of coolant during operations to bring reactor to hot standby condition is still possible.	b. Valve position indication (closed to open position change) at CB; group monitoring light (valve closed) and alarm at CB; and charging and seal water flow indication (1NVP5630) and high flow alarm at CB.	

TABLE 9.3.4-3 (Page 25)

Failure Mode and Effects Analysis Chemical and Volume Control System
Active Components - Normal Plant Operation and Load Follow

Component	Failure Mode	CVCS Operation Function	*Effect on System Operation and Shutdown	**Failure Detection Method	Remarks
32. Air diaphragm operated globe valve 1NV39A	a. Fails closed.	a. Charging and Volume Control - charging flow.	a. Failure reduces redundancy of charging flow paths to RCS. No effect on CVCS operations during normal plant operation, load follow, or hot standby operation. Normal charging flow path remains available for charging flow.	a. Valve position indication (closed to open position change) at CB.	1. Same remark as that stated for item #4 in regard to design of valve.
	b. Fails open.	b. Charging and Volume Control - charging flow.	b. Same effect on system operation and shutdown as that stated above for item #31, failure mode "Fails open" if alternate charging line is in use.	b. Valve position indication (open to closed position change) at CB.	
33. Motor operated globe valve 1NV37A	a. Fails open.	a. Charging and Volume Control - charging flow.	a. Failure results in inadvertent operation of auxiliary spray that results in a reduction of PRZ pressure during normal plant operation and load follow. PRZ heaters operate to maintain required PRZ pressure. Boration of RCS to a hot standby concentration level and makeup of coolant during operation to bring reactor to hot standby condition is still possible.	a. Valve position indication (open to closed position change) at CB and PRZ pressure recording (1NCCR5160) and low pressure alarm at CB.	

TABLE 9.3.4-3 (Page 26)

Failure Mode and Effects Analysis Chemical and Volume Control System
Active Components - Normal Plant Operation and Load Follow

Component	Failure Mode	CVCS Operation Function	*Effect on System Operation and Shutdown	**Failure Detection Method	Remarks
	b. Fails closed.	b. Charging an Volume Control - charging flow.	b. Failure has no effect on CVCS operation during normal plant operation, load follow and hot standby operation. Valve may be used during cold shutdown operation to activate auxiliary spray for cooling down the pressurizer after operation of RHRS.	b. Valve position indication (closed to open position change) at CB.	
34. Relief Valve 1NV205	a. Fails open.	a. Charging and Volume Control - charging flow.	a. Failure results in a portion of seal water return flow and centrifugal charging pump miniflow being bypassed to VCT. Boration of RCS to a hot standby concentration level and maekup of coolant during operations to bring reactor to hot standby condition is still possible.	a. Local pressure indication (1NVPG5550 and 1NVPG5560) in discharge line of centrifugal charging pumps.	1. Radioactive fluid contained.
35. Relief Valve 1NV305	a. Fails open.	a. Charging and Volume Control - charging flow and seal water flow.	a. Failure results in a portion of charging flow and seal water from constant displacement pump being bypassed to VCT. No effect on normal plant	a. Local pressure indication (1NVPG5540) in discharge line of constant displacement pump.	1. Constant displacement pump may be flow isolation by closing of manual gate valves in discharge and suction lines of pump.

9.4 AIR CONDITIONING, HEATING COOLING AND VENTILATION SYSTEMS

9.4.1 CONTROL ROOM AREA VENTILATION

9.4.1.1 Design Bases

The Control Room Area Ventilation and Air Conditioning Systems are designed to maintain the environment in the control room, control room area, and switchgear rooms, as indicated on Figures 9.4.1-1 thru 9.4.1-10 within acceptable limits for the operation of unit controls, for maintenance and testing of the controls as required, and for uninterrupted safe occupancy of the control room area during post-accident shutdown. Refer to Section 6.4 for further information regarding control room habitability.

The control room, and other support areas as shown on Figures 9.4.1-1 thru 9.4.1-4 are designed to maintain approximately 74°F and 50 percent maximum relative humidity. The battery room is designed to maintain approximately 80°F. The mechanical equipment room is designed to maintain a maximum temperature. of 100°F. All other areas, as shown on Figures 9.4.1-1 thru 9.4.1-4 are designed to maintain a maximum temperature of 85°F. These conditions are maintained continuously during all modes of operation for the protection of instrumentation and controls, and for the comfort of the operators. Outdoor design temperatures meet or exceed those given in Table No. 1, Chapter 23 of the ASHRAE 1977 Fundamentals Handbook.

Continuous pressurization of the control room and the control room area is provided to prevent entry of dust, dirt, smoke, and radioactivity originating outside the pressurized zones. Pressurization is maintained slightly positive relative to the pressure outdoors and in surrounding buildings.

Outdoor air for pressurization is taken from either of two locations such that a source of uncontaminated air is available regardless of wind direction. One fresh air intake is located at the intersection of column lines DD and 45, and the other is at the intersection of column lines DD and 69. Both intakes are at elevation 594+0. Each intake is located on the outside of the Reactor Building diametrically opposed to that unit's vent. Normally air is taken from both intakes. All outside air is filtered as described in Section 12.3.3.

Each outside air intake location is monitored for the presence of radioactivity, chlorine, and products of combustion. Isolation of the outside air intake occurs automatically upon indication of high radiation level, high chlorine concentration or smoke concentration in the intake. Should both intakes close, the operator will override the intake monitors and by inspection of the control room readouts select the least contaminated intake. This will ensure pressurization of the control room at all times.

Each outside air intake is provided with a tornado isolation damper to prevent depressurization of the control room and the control room area during a tornado having a maximum wind speed of 360 mph, a translational velocity of 70 mph and

The Fuel Area Ventilation System will operate whenever irradiated fuel handling operations above or in the fuel pool are in progress.

The Fuel Handling Area Ventilation System is located completely within a Seismic Category I structure and all essential components (exhaust filter trains, exhaust fans, exhaust ductwork) are fully protected from floods and tornado missile damage. The outside air intake opening for the ventilating air supply unit is protected by missile shields above and in front of the opening.

9.4.2.2 System Description

The Fuel Handling Area Ventilating System is shown on Figures 9.4.2-1, -2, and -3, and consists of the following components: (per unit basis)

1. One 100 percent capacity ventilation supply air handling unit and associated dampers and ductwork.
2. Two 100 percent capacity Exhaust Systems complete with filter trains and associated fans, dampers, ductwork, supports and control systems.

Outside air is supplied to the fuel handling area by a supply system consisting of one 100 percent capacity fan with heating and cooling coils, filter section and associated ductwork. The air handling unit supplies approximately 26,200 cfm. The filter section contains filters having an efficiency of approximately 30 percent based on the ASHRAE test method with atmospheric dust in accordance with ASHRAE Standard 52.68. This portion of the system has no standby capacity.

The Fuel Handling Area Ventilation Exhaust System for each unit consists of four-50 percent capacity filter trains. This portion of the Fuel Handling Area Ventilation System is an engineered safety feature. Each filter train is constructed as described in Section 12.3.3. Two 50 percent capacity filter trains are paired to operate as a single 100 percent capacity exhaust system with the two sets of filter trains receiving separate emergency power. Total exhaust flow is approximately 33,130 cfm.

Each of the 50 percent capacity filter trains is equipped with a bypass section. The normal mode of operation for the filter trains is in the bypass position. Radiation detection is provided in the duct system header, upstream of the filter train inlet to monitor radioactivity. Upon indication of high radioactivity in the exhaust duct system, the bypass dampers will automatically close and the filter train inlet dampers will automatically open to direct air flow through the filter trains. Any time irradiated fuel handling takes place, the exhaust air flow is directed through the filter trains. The operator will manually switchover from the bypass mode to the filter mode from the control room. Air from the Fuel Handling Area Exhaust System is directed to the unit vent, where it is monitored before release to the atmosphere.

The Fuel Handling Area Ventilation Supply and Exhaust Systems are designed such that a minimum of ten air changes per hour over the fuel pool are afforded to continuously purge the area of heat, humidity, and particulate matter.

During normal plant operation the air flow rate through each filter train is approximately 30,000 cfm. During accident conditions the air flow rate through each filter train is reduced to 6,540 cfm (Unit 1 side) minimum and 6,230 (Unit 2 side) minimum.

The Auxiliary Building Filtered Exhaust System filter trains are described in Section 12.3.3.

9.4.3.2.4 Auxiliary Shutdown Panel Rooms Air-Conditioning System

The Auxiliary Shutdown Panel Rooms Air-Conditioning System is shown on Figures 9.4.3-2, 9.4.3-6, and 9.4.3-7.

The four auxiliary shutdown panel rooms are located on floor elevation 543+0 of the Auxiliary Building. A separate 100 percent capacity air conditioning unit is provided to serve each of the four rooms. The system is designed to maintain a maximum temperature of 78°F and a minimum temperature of 65°F. Electrical power to the air conditioning units is provided from the electrical power train associated with the room it serves. This assures the availability of at least one train of the auxiliary shutdown panel rooms.

The air conditioning units are of the self-contained design utilizing water from the Nuclear Service Water System for condenser water. The Nuclear Service Water System is described in Section 9.2.1. Each air conditioning unit has a filter section consisting of filters having an efficiency of approximately 30 percent based on the ASHRAE test method in accordance with ASHRAE Standard 52.68. The auxiliary shutdown panel room air conditioning units are controlled by room thermostats.

9.4.3.2.5 Radwaste Area Ventilation System

Outside air is supplied to the hot machine shop, waste shipping, drum storage, and laundry areas of the radwaste area by one 100 percent capacity air handling unit consisting of a filter section, hot water preheat and service water cooling coils, (non-nuclear safety related) centrifugal fan, zone electric duct heaters and associated ductwork. The filter section contains prefilters and final filters having efficiencies of approximately 30 percent and 45 percent respectively based on the ASHRAE test method in accordance with ASHRAE Standard 52.68. A cooling water three-way mixing valve is provided to maintain space temperature. The hot water coil tempers the incoming air and is controlled by a leaving air temperature controller. Electric duct heaters controlled by zone thermostats maintain zone conditions.

Outside air is supplied to the office, personnel decontamination, and lab areas by two 50 percent capacity air handling units consisting of chilled water cooling and hot water preheat coils, filter sections, centrifugal fans, zone electric duct heaters, and associated ductwork.

The filter section contains prefilters and final filters having efficiencies of approximately 30 percent and 85 percent respectively based on the ASHRAE test method in accordance with ASHRAE Standard 52.68. A cooling water three-way mixing valve is provided for each air handling unit. The hot water preheat coil tempers the incoming air and is controlled by a leaving air temperature controller. Electric duct heaters controlled by zone thermostats maintain space temperatures.

The Diesel Building Ventilation System is designed to maintain the building temperature between 60°F minimum and 110°F maximum when the diesel is not operating, and between 60°F minimum and 120°F maximum when the diesel is operating. Outdoor design temperatures meet or exceed those given in Table No. 1, Chapter 23 of the ASHRAE 1977 Fundamentals Handbook.

All essential fans, dampers, ductwork, and supports are designed to withstand the safe shutdown earthquake.

Essential electrical components required for ventilation of the Diesel Building during accident conditions are connected to emergency Class 1E standby power.

The Diesel Building Ventilation System is located completely within a Seismic Category I structure. The ventilation air supply and exhaust openings are fully protected from tornado missile damage.

9.4.4.2 System Description

The Diesel Building Ventilation System is shown on Figure 9.4.4-1 and consists of the following subsystems:

1. Normal Ventilation System
2. Emergency Ventilation System

The Normal Ventilation System for each diesel enclosure consists of one 100 percent capacity fan, shutoff damper, electric duct heater, filter section and associated ductwork. The filter section contains filters having an efficiency of approximately 30 percent based on the ASHRAE test method with atmospheric dust in accordance with ASHRAE Standard 52.68. The Normal Ventilation System has no standby capacity and operates only during normal plant operation (diesel off-cycle). The normal ventilation fan will be cycled off and the shutoff damper closed when its associated diesel is started, either for test purposes or by an Engineered Safety Features Actuation signal.

The Emergency Ventilation System for each diesel enclosure consists of two 50 percent capacity fans, ductwork, and modulating return air and outside air dampers arranged to maintain space temperature between 60°F and 120°F when the diesel is operating. As the space temperature rises, proportioning controls are provided to modulate the outdoor air dampers toward the open postion and the return air dampers toward the closed position. Excess make-up air to the diesel enclosure is relieved through automatic (pressure-operated) relief dampers.

Q 430.89 The enclosures containing the diesel generator starting and control circuits meet NEMA 12 standards (drip and dust proof). These enclsoures protect the electrical equipment from dust and other contaminants.

9.4.4.3 Safety Evaluation

The Diesel Building Ventilation System automatically maintains a suitable environment in each diesel enclosure under all operating conditions. Since the Diesel Building Ventilation System is duplicated for each diesel, a single failure will not impair the safety function.

9.4.5 CONTAINMENT PURGE VENTILATION SYSTEM

9.4.5.1 Design Bases

The Containment Purge Ventilation System is designed to maintain the environment of the containment within acceptable limits for personnel access during inspection, testing, maintenance and refueling operations; and to limit the release of any contamination to the environment.

The design bases include provisions to:

1. Clean up containment purge exhaust during refueling.
2. Supply fresh air for contamination control when the containment is or will be occupied.
3. Supply fresh air for contamination control when the incore instrumentation room is or will be occupied.
4. Exhaust containment air to the outdoors through the purge exhaust filter trains whenever the Purge Air Supply System is operated.
5. Assure isolation of the system penetrations in the containment vessel.

Only Item 5 above is a safety-related function.

Each containment penetration for the Purge Ventilation Supply and Exhaust Subsystems is provided with two isolation valves, one on each side of the containment wall. This meets the single failure criterion. See Section 6.2.4 "Containment Isolation Systems" for a complete description of the penetration assemblies including isolation valves.

The Containment Purge Ventilation System is not an Engineered Safety Feature.

9.4.5.2 System Description

The Containment Purge Ventilation System is shown on Figure 9.4.5-1 and -2, and consists of the following subsystems: (per unit basis)

1. Containment Purge Supply System
2. Containment Purge Exhaust System
3. Incore Instrumentation Room Purge Supply System
4. Incore Instrumentation Room Purge Exhaust System

Outside air is supplied to the Containment by the Containment Purge Supply sys-System. The system consists of two 50 percent capacity air handling units. Total supply capacity is approximately 25,000 cfm. Each air handling unit consists of a filter section, hot water heating coil, shutoff damper, and fan. The filter section contains filters having an efficiency of approximately 30 percent based on the ASHRAE test method with atmospheric dust in accordance with ASHRAE Standard 52.68. This equipment is located outside the Reactor Building in the Auxiliary Building at elevation 611+0. There is one supply duct penetration through the Reactor Building wall into the annulus area. There are four purge air supply penetrations through the containment vessel, two to the upper compartment and two to the lower compartment. Two normally closed isolation valves at each penetration through the containment vessel provide containment isolation. One normally closed isolation damper at the Reactor Building wall provides annulus isolation.

Purge air is exhausted from the containment through the Containment Purge Exhaust System to the unit vent where it is monitored for radioactivity level by the unit vent monitor prior to release to the atmosphere. The Containment Purge Exhaust System consist of two 50 percent capacity filter trains and fans. Total exhaust capacity is approximately 25,000 cfm. This equipment is located outside the Reactor Building in the Auxiliary Building at elevation 594+0. There is one purge exhaust duct penetration through the Reactor Building wall from the annulus area. There are three purge exhaust penetrations through the containment vessel, two from the upper compartment and one from the lower compartment. Two normally closed isolation valves at each penetration through the containment vessel provide containment isolation. One normally closed isolation damper at the Reactor Building wall provides annulus isolation.

The upper compartment purge exhaust ductwork is arranged to draw exhaust air into a plenum around the periphery of the refueling canal, effecting a ventilation sweep of the canal during the refueling process. The lower compartment purge exhaust ductwork is arranged so as to sweep the reactor well during the refueling process (see Figure 9.4.5-2).

The Incore Instrumentation Room Purge Supply System consists of one 100 percent capacity air handling unit. Supply capacity is approximately 1,000 cfm. The air handling unit consists of a filter section, hot water heating coil, and fan. The filter section contains filters having an efficiency of approximately 30 percent based on the ASHRAE test method with atmospheric dust in accordance with ASHRAE Standard 52.68. This equipment is located outside the Reactor Building in the Auxiliary Building at elevation 594+0. There is one purge supply penetration through the Reactor Building wall and one through the containment vessel. Two normally closed isolation valves at the containment penetration provide containment isolation. One isolation damper at the Reactor Building wall provides annulus isolation.

The Incore Instrumentation Room Purge Exhaust System consists of one 100 percent capacity filter train and fan. Exhaust capacity is approximately 1,000 cfm. Purge air is exhausted to the unit vent where it is monitored for radioactivity level by the unit vent monitor prior to release to the atmosphere. This equipment is located in the Auxiliary Building at elevation 594+0. There is one purge exhaust penetration through the Reactor Building wall and one through the containment vessel. Two normally closed isolation valves at the penetration through the containment vessel provide containment isolation. One isolation damper at the Reactor Building wall provides annulus isolation.

During normal operation, purge air is supplied to reduce potentially high airborne radioactivity concentrations only when sustained periods of containment access are required. This is expected to be four times per year - twice with the reactor in the hot standby condition and twice with the reactor at cold shutdown. Purging of the containment during refueling will last approximately four weeks, while the other three purges are expected to last less than three days each. Purging of the incore instrumentation room will be as necessary for access during inspection, testing, and maintenance.

The containment purge supply fans, purge exhaust fans, and filter trains are controlled in two trains. The controls are designed to have simultaneous starting and stopping of the matching supply and exhaust equipment. Controls are also provided to reduce purge flow rate. The controls for the Incore Instrumentation Room Purge System are designed to have simultaneous starting and stopping of the supply and exhaust equipment. The controls are also designed to initiate an automatic shutdown and containment isolation upon receipt of a containment isolation signal.

The containment purge exhaust system filter trains are described in Section 12.3.3.

9.4.5.3 Safety Evaluation

Each Containment Purge Ventilation System supply and exhaust penetration through the containment vessel is equipped with two normally closed isolation valves, each connected to separate control trains. A failure in one train will not prevent the remaining isolation valve from providing the required isolation capability. The isolation valves and containment penetrations are the only portions of the Containment Purge Ventilation System that are engineered safety features, and are discussed in Section 6.2.4. Design specifications for the purge system isolation valves are presented in Table 9.4.5-1.

The containment purge exhaust system is isolated on high radiation or high relative humidity signals. Relative humidity is controlled and monitored upstream of the containment purge exhaust filter trains. Electric preheaters maintain $\leq$ 70% relative humidity.

Since containment purge system operation is intermittent, relative humidity is monitored in the vicinity of the carbon adsorbers. Carbon adsorbers are heated as necessary to maintain a suitable "storage" environment ($\leq$ 70% relative humidity). High carbon adsorber bed relative humidity is alarmed.

A fuel handling accident inside the containment has been analyzed assuming the Purge System is in operation during refueling operations. This analysis is described in Section 15.7.4.

9.4.5.4 Inspection and Testing Requirements

The nonessential components are not normally in operation and are accessible for periodic inspection. Essential components and controls are tested during preoperational tests and periodically thereafter as required by the Technical Specifications.

9.4.6.2 System Description

The Containment Ventilation System is shown on Figures 9.4.6-1, -2 and -3 and are composed of the following subsystems:

1. Lower Containment Ventilation System
2. Control Rod Drive Mechanism (CRDM) Ventilation System
3. Incore Instrumentation Room Ventilation System
4. Upper Containment Ventilation System
5. Containment Auxiliary Charcoal Filter System
6. Containment Chilled Water System

The Lower Compartment Ventilation System consists of four 33 1/3 percent capacity fan-coil units, associated dampers, a common plenum and ductwork system. The four fan-coil units are located in two annular concrete chambers around the periphery of the lower compartment. Three of the fan-coil units are normally required to operate to maintain conditions in the lower compartment with one unit on standby. Lower compartment air passes directly through each active fan-coil unit where it is cooled and supplied to the various areas of the lower compartment through a common duct distribution system as shown in Figure 9.4.6-1. Vane-axial booster fans are provided to ensure design air flow to the pipe tunnel in the lower extremity of the lower compartment and to the instrumentation area under the reactor vessel. A cooling water throttling valve for each fan-coil unit is automatically controlled by area thermostats located near the return air openings to each fan-coil unit and set to maintain the lower compartment temperature at 100°F. Backdraft dampers are provided in the discharge duct of each fan-coil unit to prevent back-flow through the standby unit.

The Control Rod Drive Mechanism (CRDM) Ventilation System consists of four 33 1/3 percent capacity vane-axial fans and associated dampers and ductwork. Three fans will normally operate with one on standby. The CRDM fans, located in the lower compartment outside the primary shield wall, pull the cooling air through the CRDM shroud and return it to the intake side of the active lower compartment fan-coil units through a common duct system. Each CRDM ventilating fan is provided with a backdraft damper located in the duct on the discharge of the fan to prevent back-flow through the standby fan.

The incore instrumentation room is a dead-ended space in the lower compartment of the containment. The Incore Instrumentation Room Ventilation System consists of two 100 percent capacity fan-coil units and common duct distribution system, located inside the conditioned space. One fan coil unit will normally operate with the other on standby. A cooling water throttling valve for each fan coil unit is automatically controlled by return air thermostats set to maintain the instrumentation room at 90°F. Backdraft dampers are provided in the discharge duct of each fan coil unit to prevent back-flow through the standby unit.

The Upper Compartment Ventilation System consists of four 33 1/3 percent capacity fan-coil units and associated return air fans located in the upper compartment. Three fan-coil units with their respective return air fans are required to operate to maintain conditions in the upper compartment during normal reactor operation with one fan-coil unit and associated return air fan on standby. A cooling water throttling valve for each fan-coil unit is automatically controlled by return air thermostats set to maintain the upper compartment at 90°F.

The Containment Auxiliary Charcoal Filter System consists of two 50 percent capacity fan-filter units and associated ductwork located in the lower compartment for reduction of airborne contamination. The number of containment auxiliary charcoal filter units in operation (one or two) depends on the airborne activity levels observed. With the addition of booster fans, inlet plenums and temporary ductwork, airborne contamination generated during maintenance may be exhausted to and filtered by these units.

Each containment auxiliary charcoal filter train consists of the following components.

1. Prefilter section containing filters having an efficiency of approximately 75 percent based on the ASHRAE test method with atmospheric dust in accordance with ASHRAE Standard 52.68.
2. High efficiency filter section containing filter having an efficiency of approximately 99.97 percent in removing 0.3 micron particles when tested with dioclylphtalate (DOP) smoke in accordance with the Instruction Manual for the installation, operation and maintenance of penetrometer, Filter Testing, DOP, Q107, Manual No. 136-300-175A, dated January, 1965, U. S. Army Edgewood Arsenal.
3. Carbon Adsorber section of the carbon tray design in accordance with AACC-CS-8T.

The Containment Chilled Water System consists of three 50 percent capacity centrifugal water chillers and chilled water pumps, associated piping and valves. Major equipment is located in an adjacent yard structure. The system supplies a lower compartment header serving the lower compartment and incore instrumentation room fan-coil units and the reactor coolant pump motor heat exchangers as shown in Figures 9.4.6-2 and 3. The Containment Chilled Water System is not available on the Blackout Power System. During a loss of offsite power, the Containment Chilled Water System is isolated and cooling water is supplied by the Nuclear Service Water System.

9.4.6.3 Safety Evaluation

The Containment Ventilation System provides adequate capacity to assure that proper temperature levels are maintained in the containment under operating conditons. Sufficient redundancy is included to assure proper operation of the system with one active component out of service.

The Containment Ventilation System is so arranged that all components of each subsystem are located wholly in the upper or lower compartment eliminating the need for ductwork penetrating the divider barrier thus enhancing the barrier integrity.

The Containment Ventilation System is not considered an engineered safety feature and no credit has been taken for the operation of any subsystem or component in analyzing the consequences of any accident.

radioisotopes following a LOCA by filtering and recirculating a large volume of annulus air relative to the volume discharged for negative pressure maintenance; and (3) provide long-term fission product removal capacity by decay and filtration.

This system is provided with two independent, 100 percent capacity ventilation filter systems complete with fans, filters, dampers, ductwork, supports and control systems for each unit. This meets the single failure criteria. Switchover between redundant trains is accomplished manually by the operator. Electrical and control component separation is maintained between trains.

All essential system components, including fans, filter trains, dampers, ductwork, and supports are designed to withstand the Safe Shutdown Earthquake.

Essential electrical components required for ventilation of the annulus during accident conditions are connected to emergency Class 1E standby power.

9.4.9.2 System Description

The Annulus Ventilation System is shown on Figure 9.4.9-1 and consists of redundant ventilation subsystems for each unit. Each ventilation subsystem consists of a filter train, fan, dampers, associated ductwork, supports and control systems. The Annulus Ventilation System filter trains are described in Section 12.3.3.

The Annulus Ventilation System functions to discharge sufficient air from the annulus to effect a negative pressure with respect to the containment and the atmosphere 60 seconds following a LOCA. Subsequent to attaining a negative pressure, additional air is discharged as necessary to maintain the pressure at or below -0.5 inches water gauge. In order to mix the inleakage in as large a volume as possible, a large flow of air is displaced from the upper level of the annulus and passed through the filter train before being returned to the annulus at a low level. Both the suction and return air flow is accomplished using ring-type distribution headers in the annulus.

The Annulus Ventilation System is activated by the safety injection signal (Ss). Upon receipt of this signal the recirculation dampers and discharge dampers are aligned to exhaust 9000 cfm to the unit vent until the annulus negative pressure is $\geq$0.5 inches water gauge. The recirculation dampers and discharge dampers then modulate to exhaust air as required to maintain the annulus negative pressure at -0.5 inches water gauge.

Computer code CANVENT has been developed by Duke Power Company to analyze the thermal effects of a loss-of-coolant accident (LOCA) in a Westinghouse "ice condenser" containment. CANVENT is capable of evaluating the following factors:

(a) Steady state (pre-LOCA) radial temperature distributions corresponding to fixed outside Reactor Building and inside containment temperatures.

(b) Radial temperature distributions in the steel containment and concrete Reactor Building during post-LOCA transient.

Redundant valves feed the Auxiliary Building fire protection header.

Fixed Water Sprinkler Systems are provided for the following areas in the Auxiliary Building:

a. RHR pump rooms

b. Component cooling water pumps (733+0 and 750+0)

c. Centrifugal Charging pump rooms

d. Charcoal filters in all Auxiliary Building filter trains.

e. Auxiliary feedwater pump rooms. The Reactor Building fire protection header is pressurized by activation of a remote manual valve located in the Auxiliary Building.

f. Battery Room Corridor (554 + 0)

g. Cable Room Corridor (574 + 0)

Reactor Building fire protection consists of manual hose stations and fixed water sprinklers on separate headers to protect charcoal filters and each of the reactor coolant pumps as well the pipe corridor of the Reactor Building. Fixed water sprinklers are provided in the annulus.

The Diesel Generator Buildings are protected by automatic CO_2 Systems with appropriate personnel alarms to warn of pending discharge. Manual hose stations, supplied from the Nuclear Service Water System, are also provided in the Diesel Generator Building.

The Turbine, Service and Administration Building fire protection is provided from manual hose stations and automatic sprinkler or deluge systems in the following areas:

a. On the turbine mezzanine and basement floors

b. Main turbine piping

c. Main turbine oil tank

d. Main turbine oil transfer tank

e. Oil purifiers

f. Feedwater pump turbines

g. Hydrogen seal oil units

the pressurized fuel oil return from the bypass headers to the day tank. The main circulation headers are fitted with a relief valve which prevents the engine fuel oil pressure from exceeding 40 psig and which discharges back to the day tank.

The day tank is surrounded by a fire wall which serves as a containment in the event of leaks or ruptures. The containment drain line is isolated by a normally closed, solenoid-operated valve. A high level signal from a level transmitter located within the containment opens this valve, allowing the oil to drain to the suction side of the lube oil transfer pump which is simultaneously activated and delivers the oil to a waste oil storage tank.

Q 430.63 An inspection program outlined in the Technical Specification ensures that the quality of the fuel oil delivered to the site and stored on site is maintained.

To prevent settling, stratification and deterioration of the fue. .il during extended periods, a system is provided to recirculate or transfer filtered fuel oil. Four fuel oil tanks (two half capacity storage tanks per redundant diesel) are centrally located and integrally connected with normally closed isolation valves and check valves to prevent backfilling and possible contamination of fuel oil between tanks. A manually operated, positive displacement recirculation pump takes suction from the flush mounted sample connection on the bottom of the storage tank and discharges the fuel oil at a rate of 25 gpm through a simplex filter with alternate bypass line to the storage tank fill connection. The simplex filter has a particle removal rating of 25 microns. The filtering and recirculation process is performed on a tank by tank basis with the frequency of operation dependent on the results of the fuel oil inspection program outlined in the Technical Specification. Since two half capacity storage tanks are provided per diesel, one tank will be aligned to supply fuel oil to its respective diesel while isolating the second tank through administrative control. The contents of the isolated storage tank would be filtered and recirculated. Prior to realigning the tank to its respective diesel, a period of not less than 24 hours is required to allow any stirred sediment to settle.

Q 430.61

Q 430.67

Q 430.62 Should the recirculation system be operating in the event of a LOCA, a redundant, safety related interlock is provided to shutdown the recirculation pump to prevent possible stirring of sediment. A redundant safety related interlock is also provided to shutdown the recirculation pump should the fuel oil in the storage tanks drop below Technical Specifications level to preclude loss of fuel oil in the event of a recirculation system pipe rupture.

Q 430.67 Fuel oil amenders are added as necessary to extend oil life by preventing oxidation, stratification, etc. A sample is used to inspect the oil for water content or degradation and if degradation is determined, the oil may be pumped out for disposal. Accumulated water in the fuel oil storge tanks will be removed by the recirculation system through a sample connection provided on the recirculation pump discharge as required by the Technical Specifications.

Q 430.60 The day tank vent and fuel oil storage tank vents and fill connections which are exposed outdoors, are protected from tornado missiles due to the construction of the vents using heavy gauge pipe. Should a tornado missile strike a vent or fill connection the pipe will bend without crimping to relieve the impact load. The day tank vent terminates 4 feet above grade elevation and the fuel oil storage tank fill and vent lines terminate 3 feet and 1'-7" respectively above grade elevation to prevent entrance of water. Q 430.68 Each fill connection is provided with a locking dust cap and each vent line is down turned. The storage tanks can be filled and vented through the manway should the fill or vent lines become impaired.

9.5.4.2.2 Component Descriptions

Fuel is recirculated within the storage facility to prevent deterioration at the rate of 25 gpm at 32 psi by a recirculation pump. The pump is driven by a 3 HP, 575 volt, 3 phase, 60 Hz motor whose power source is the 600 VAC Unit Normal Auxiliary Power Supply (Section 8.3.1.1.1.5).

The fuel oil booster pump is designed to deliver fuel oil to the engine during the startup period (approximately 11 seconds) at 8 gpm. The pump is driven by a 2 HP, 120 volt DC motor whose power source is the 125VDC Diesel Essential Auxiliary Power System (Section 8.3.1.1.3.11).

9.5.4.2.3 Instrumentation and Alarms

Q 430.58 Each diesel generator engine is provided with sufficient instrumentation to monitor the operation of the fuel oil system. All alarms are seperately annunciated on the local diesel engine control panel which also signals a general diesel trouble alarm in the control room. There are two redundant safety related interlocks provided on the fuel oil recirculation system. One interlock is provided to shutdown the recirculation pump in the event of a LOCA. The second interlock is provided to shutdown the recirculation pump should the fuel oil level in the storage tanks drop below Technical Specifications level. The fuel oil system is provided with the following instrumentation and alarms:

Fuel oil storage tanks -

Low level and high level annunciators
Tech spec low-low level alarm
Level indication, 0-100%
The capability for use of a stick gauge to measure the fuel oil level

tanks the vent and fill lines terminate 3 feet and 1'-7" respectively above grade elevation. The fill connection is provided with a locking dust cap and the vent is down turned.

Each diesel is provided with a 700 gallon capacity lube oil sump tank. The sump tank has a normal operating volume of 600 gallons and is equipped with a low level alarm which is set approximately 6¼ inches below the normal operating level. From the low level alarm point to the minimum operating level there are approximately 400 gallons. With an established oil consumption rate of 1.2 gallons per hour at full load, this volume is sufficient to operate the diesel in excess of seven days without requiring replenishment.

Q 430.62 Should it become necessary to make additions of lube oil to the diesel, lube oil is available in an 8,000 gallon storage tank located underground and outside the Diesel Building. A manually operated, positive displacement clean lube oil pump takes suction from the storage tank and discharges lube oil through a simplex filter (particle removal rating of 17 microns) to the intended diesel. The pump suction is raised 6 inches above the storage tank floor to prevent any accumulated water from entering the diesel lube oil sump tank. Q 430.86 Accumulated water in the bottom of the storage tank is removed through a sample connection flush on the bottom of storage tank.

The lube oil in the clean lube oil storage tank is inspected monthly to determine the purity of the oil. Parameters monitored include viscosity, neutralization number, and percentage of water. Any accumulated water detected in the bottom of the storage tank will be removed. If degradation of the oil is detected, the oil may be pumped out for disposal.

Q 430.81

Lubricating oil leakage is detected by:

1. Routine surveillance
2. Low lube oil sump levels alarm
3. Low lube oil pressure and alarm

System leakage into the lube oil system through the jacket water is minimized by the normal operating pressure of the lube oil being higher than the jacket water pressure. Oil leakage from the diesel is collected in a sump in the diesel room.

Q 430.86 The truck fill connection for clean lubricating oil is locked and is keyed differently from other fill connections. Administrative controls govern the issuance of this key.

Q
430.82 The periodic testing and maintenance of all diesel engine lube oil system instruments is controlled by the Preventive Maintenance Recall program. This program insures that instruments are periodically calibrated and tested, assuring reliability.

9.5.7.3 Safety Evaluation

The Diesel Generator Engine Lube Oil System is a Duke Class C piping system with the exception of the Clean and Used Lube Oil Transfer System which is a Duke Class G piping system. The two systems are seperated by Duke Class C isolation valves. The diesel engine and engine mounted components are constructed in accordance with IEEE Standard 387. The off engine essential equipment and components and the nonessential (i.e., Clean and Used Lube Oil Transfer System) equipment and components are designed in accordance with the requirements of the codes listed in Table 3.2.2-2. Each diesel generator
Q
430.62 unit is housed separately in a Seismic Category I structure which forms half of the Diesel Building, and the units themselves are fully independent and redundant for each nuclear unit.

The results of a failure modes and effects analysis are presented in Table 9.5.7-1.

The exterior of carbon steel tanks and other underground carbon steel components is sandblasted to a SSPC-SP10-63, Near White Metal Blast Cleaning. A coal tar epoxy coating which meets the requirements of Corps of Engineers
Q
430.86 Specification C-200 and Government Specification MIL-P-23236 is applied to exterior surfaces at a dry film thickness of 16 mils. This coal tar epoxy is also applied to the exterior of stainless steel piping.

In addition to being coated, the external surfaces of buried metallic piping and tanks are protected from corrosion by an impressed current cathodic protection system in accordance with NACE Standard RP-01-69 (1972 Revision) Periodic monitoring, as described by the maintenance procedure, will remove any accumulated moisture from the tanks.

Q
430.85 The governor lube oil coolers on the diesel generator engines (Delaval RV 16-4) are located at an elevation below the governor lube oil level, thereby, not affecting the starting reliability of the engines.

Q
430.61 The interior of the clean lube oil storage tank is not coated since the presence of lube oil will act as a deterrent to internal corrosion. During the surveillance intervals for sampling the lube oil in the storage tanks, as outlined per the Technical Specification, any accumulated water will be removed.

9.5.7.4 Tests and Inspections

System components and piping are tested to pressures designated by appropriate codes. Inspection and functional testing are performed prior to initial operation; thereafter the system will be tested in accordance with the Technical Specifications.

i) Loss of Cake
If the "Essential Power Circuit" fails indicating a loss of condensate motive power, or the individual filter effluent flow reaches a preset low-low minimum before the holding pump starts, an alarm will sound and the unit must be backwashed and precoated.

j) Programmer Malfunction
When any automatically sequenced valve or pump fails to provide a correct feedback within a preset adjustable time, an alarm will sound.

k) High backwash tank level
Alarm on high backwash tank level.

l) Low backwash tank level
Alarm on low backwash tank level and trip the backwash tank pumps.

m) High decant monitor tank level
Alarm on high decant monitor tank level.

n) Low decant monitor tank level
Alarm on low decant monitor tank level and trip the backwash decant pump.

10.4.7 CONDENSATE AND FEEDWATER SYSTEMS

10.4.7.1 Design Bases

The Condensate and Feedwater Systems are designed to return condensate from the condenser hotwells through the condensate polishing demineralizers and the regenerative feedwater heating cycle to the steam generators while maintaining proper water inventories throughout the cycle.

The entire Condensate System is non safety-related. The portions of th Feedwater System that are required to mitigate the consequences of an accident and allow safe shutdown of the reactor are safety-related. The safety-related portions of the system are designed in accordance with the following design bases: Q 410.2

1) The system is designed such that failure of a feedwater supply line coincident with a single active failure will not prevent safe shutdown of the reactor.

2) The system components are designed to withstand the effects of and perform their safety functions during a safe shutdown earthquake.

3) Components and piping are designed, protected from, or located to protect against the effects of high and moderate energy pipe rupture, whip, and jet impingement.

4) The system is designed such that adverse environmental conditions such as tornados, floods, and earthquakes will not impair its safety function.

f) Three stages of intermediate pressure feedwater heaters (C, D, and E)

g) Piping, valves, and instrumentation.

The hotwell pumps take suction from the condenser hotwell. During normal operation, two hotwell pumps will be operating with the third on standby. After the hotwell pumps, the condensate flows to the condensate polishing demineralizers. Normally, four of the five polishers will be in operation with the fifth on standby. Downstream of the condensate polishing demineralizers, the condensate is divided equally between the three condenser steam air ejectors where it is used as a coolant in the CSAE inner and after condensers. All three ejectors are normally in service with each air ejector removing noncondensable gases from one of the three condenser shells. After the CSAE's the condensate flows in parallel through the gland steam condenser and the blowdown recovery heat exchangers. The condensate then passes through two stages of low pressure feedwater heating to the suction of the condensate booster pumps.

During normal operation, two condensate booster pumps will be in operation with the third on standby. Downstream of the condensate booster pumps, the condensate passes through three stages of intermediate pressure feedwater heating before combining with the C heater drain pump flow and discharging to the suction of the feedwater pumps.

The Feedwater System consists of:

a) Two 50% capacity steam generator feedwater pumps

b) Two stages of high pressure feedwater heaters (A and B)

c) Piping, valves, and instrumentation.

The pumps casings are made of ASTM-A296-CA6NM steel. The impellers are constructed from ASTM-A315-CA15 steel. The heaters have shells of carbon steel and tubing of stainless steel. The piping is carbon steel.

Normally, both feedwater pumps will be operating with each pump handling half the feedwater flow. Downstream of the feedwater pumps, the feedwater passes through two stages of high pressure feedwater heating to a final feedwater header where the final feedwater temperature is equalized. The feedwater is then admitted to the steam generators through 4 steam generator feedwater lines, each of which contains a feedwater control valve and a feedwater flow nozzle. Feedwater flow to the individual steam generators is controlled by a three element feedwater control system using feedwater flow, steam generator water level, and main steam flow as control parameters for steam generator feedwater control valves (1CF28, 1CF37, 1CF46, and 1CF55).

The Auxiliary Feedwater System is the assured source of feedwater to the steam generators during accident conditions. The primary safety function of the Feedwater System is to isolate the steam generators on a feedwater isolation signal. A feedwater isolation signal initiates isolation of each steam generator in order to:

1) rapidly terminate feedwater flow and steam blowdown inside the containment following a main steam or feedwater line break inside the containment,

2) prevent loss of steam generator water inventory due to a pipe rupture outside the containment, and

3). prevent overfilling the steam generators should the normal means of controlling steam generator level malfunction. Q 410.2

Feedwater isolation is actuated by any one of the following signals:

1) safety injection,

2) reactor trip coincident with low reactor coolant average temperature,

3) steam generator level high-high.

A feedwater isolation signal closes the feedwater isolation valves (CF33, 42, 51, 60), feedwater reverse purge valves (CF87, 88, 89, 90), feedwater control valves (CF28, 37, 46, 55), feedwater control bypass valves (CF30, 39, 48, 57), feedwater preheater bypass valves (CA149, 150, 151, 152), feedwater bypass tempering flow valves (CA185, 186, 187, 188), and feedwater pump discharge isolation valves (CF10, 17). In addition, a safety injection signal or a steam generator high-high water level signal will trip the feedwater pumps.

The Auxiliary Feedwater System is discussed in Section 10.4.9, and the supply of condensate available for emergency purposes is discussed in Sections 9.2.6 and 10.4.9.

10.4.7.3 Safety Evaluation

The safety-related portion of the Feedwater System is designed in accordance with the design bases presented in Section 10.4.7.1. The system has been analyzed to assure it meets these bases. Any failure in the non-safety class portions of the Condensate and Feedwater Systems does not prevent safe shutdown of the reactor. Q 410.2

The Condensate and Feedwater System is designed to automatically maintain the water level in the steam generators during steady state and transient operating

g) Steam generator feedwater control valves
Feedwater flow to the individual steam generators will be controlled by a three element feedwater control system using feedwater flow, steam generator water level, and main steam flow as control parameters for steam generator feedwater control valves 1CF28, 1CF37, 1CF46, and 1CF55.

h) Steam generator feedwater control valve bypass valves
The bypass valves around the steam generator feedwater control valves will be manually controlled by the operator from the control room at low load.

i) Hotwell low level
Normal hotwell makeup control valve 1CS47 will open on low hotwell level. Hotwell recirculation makeup control valves 1CS33 and 1CS57 will open on low-low hotwell level.

j) Hotwell high level
Hotwell high level control valve 1CM33 will open on high hotwell level. This valve will also be controlled off of high hotwell pump discharge pressure.

10.4.8 STEAM GENERATOR BLOWDOWN SYSTEM

10.4.8.1 Design Bases

The design bases for the Steam Generator Blowdown System are:

a. Maintain proper steam generator shell side water chemistry (see Table 10.3.5-1) by removing non-volatile materials due to condenser tube leaks, primary to secondary tube leaks, and corrosion that would otherwise become more concentrated in the shell side of the steam generators.

b. Size all equipment to handle the maximum allowable blowdown flowrate from all steam generators simultaneously. Maximum allowable blowdown flowrate is specified by the steam generator manufacturer based on steam generator blowdown nozzle errosion condiserations.

c. Provide equipment and flowpath to allow purification and recovery of steam generator blowdown for reuse in the condensate cycle.

d. Provide equipment and flowpath to allow discarding of blowdown. are not in use.

e. Provide a continuous sample for measurement of the radioactivity and conductivity of the steam generator blowdown.

f. Isolate the blowdown lines leaving the containment on a containment isolation signal and on an auxiliary feedwater automatic start signal.

g. Seismic quality group classifications, and code requirements of the Steam Generator Blowdown System and components are provided in Table 3.2.2-2.

10.4.8.2 System Description

A separate Steam Generator Blowdown System (BB) serves each of the two units at Catawba. The separate units' BB Systems are similar but do differ slightly and are shown on Figures 10.4.8-1, 10.4.8-2, 10.4.8-3, 10.4.8-4.

The BB System is used in conjunction with the Condensate System (CM) to maintain proper secondary side water chemistry. Non-volatile solids resulting from corrosion, steam generator tube leaks, or condenser tube leaks tend to concentrate in the steam generators. The BB System is designed to control the concentration of these impurities by continuously removing a portion of fluid from the shell side of the steam generators. This blowdown is either discarded or purified for makeup to the CM System.

The BB System consists of the following:

a. One steam generator blowdown tank
b. Two 100% capacity steam generator blowdown pumps
c. Two 100% capacity steam generator blowdown recovery heat exchangers
d. Two 100% capacity steam generator blowdown demineralizer prefilters
e. Two 100% capacity steam generator blowdown demineralizers
f. Piping, valves, and instrumentation

The blowdown tank, pumps, demineralizer prefilters, and the shell of the blowdown recovery heat exchangers are constructed of carbon steel. The blowdown demineralizer and the blowdwon recovery heat exchanger tubes are stainless steel. System piping and valves consist of carbon steel and stainless steel. Table 10.4.8-2 presents the BB System component design data. System safety class requirements are presented in Table 3.2.2-2.

The BB System begins at the steam generator blowdown nozzles where blowdown flow is extracted from the steam generators. The blowdown is withdrawn from just above the steam generator tube sheets by internal blowdown headers. The Unit 1 BB System connects to both of two blowdown nozzles on each steam generator. The Unit 2 BB System connects to one of two available blowdown nozzles on each steam generator. This difference results from different model steam generators being used in the two units and the different internal blowdown header design associated with each model steam generator.

On Unit 1, the piping from each blowdown nozzle contains a globe valve which is used to balance flow between the two blowdown nozzles on each steam generator. Downstream of these globe valves, the two lines from each steam generator join into a common header. On Unit 2, the piping connects to just one nozzle per steam generator, and an isolation valve is provided. The blowdown header from each steam generator then runs from inside containment, out through containment isolation valves, and eventually to the steam generator blowdown tank in the Turbine Building. Two parallel blowdown flow control valves per header are provided to control blowdown flow rate from each steam generator. These valves are located close to the blowdown tank and are positioned manually by the operator from the Control Room. Maximum allowable blowdown flowrates are specified in Table 10.4.8-1. During most modes of operation, the fluid in the blowdown headers will be two-phase.

Downstream of the blowdown flow control valves, the blowdown flashes to the steam generator blowdown tank. The blowdown tank separates the water and steam phases of the blowdown. The steam phase is normally routed to the "D" heater extraction lines to recover thermal energy and conserve condensate.

Alternately, the steam from the blowdown tank can be vented to atmosphere. Blowdown tank pressure will ride on the pressure of the receiver of discharge since the steam is cascaded from the tank to the discharge receiver. The blowdown tank is protected from overpressurization by a safety valve located on top of the tank. "D" heaters and "D" heater extraction lines are protected from overpressurization from the blowdown tank by a safety valve located in the steam vent line near "D" heaters. Blowdown tank level is automatically controlled by valve BB39 which is located downstream of the blowdown demineralizers.

The water which is separated from the flashed fluid in the blowdown tank is pumped from the tank by one of two 100% capacity blowdown pumps. Each blowdown pump provides its own seal water from the pump discharge through a seal water cooler. The blowdown pumps are provided minimum flow protection by a common flow element and control loop which modulates valve BB86 on low flow to maintain 100 gpm through an operating pump. This minimum flow path discharges back to the blowdown tank.

Blowdown pump discharge is routed to the blowdown recovery heat exchangers. Two 100% capacity heat exchangers are provided with one normally in use and the other isolated but available as an alternate. The blowdown recovery heat exchangers are regenerately cooled by flow from the Condensate System (CM) to recover thermal energy and reduce blowdown temperature to a point suitable for demineralization or discharge to the turbine building sump. Normally, blowdown will be cooled, demineralized, and discharged to the condenser hotwell to conserve condensate quality water. However, a bypass line is provided upstream of the heat exchangers to allow bypass flow around the prefilters and demineralizers and allow blowdown pump discharge directly to the turbine building sump. A bypass is also provided downstream of the heat exchangers to bypass flow around the prefilters and demineralizers and directly t the turbine building sump after being cooled by the blowdown recovery heat exchangers. These bypass lines join into a common header and intersect the common demineralizer effluent line upstream of valve BB39.

Downstream of the blowdown recovery heat exchangers, blowdown flow is routed to two 1005 capacity demineralizer prefilters, which serve to remove corrosion products from the blowdown stream. These cartridge type filters are arranged in parallel with one normally in operation and one isolated. The prefilters will become highly radiactive during plant operation with any steam generator tube leaks and are shielded accordingly.

Downstream of the blowdown demineralizer prefilters, blowdown flow is routed to two 100% capacity mixed bed demineralizers. The blowdown demineralizers are arranged in parallel with one normally in operation and one isolated. The blowdown demineralizers are nonregenerative, i.e., when the ion exchange capacity of the bead resins is depleted, the resins will be discharged and replaced with new resins. The demineralizers are designed for manual operation during all operating modes. Run length between resin replacement will vary depending on operating conditions but should normally be between one and three months. The demineralizers will become highly radioactive during plant operation with any steam generator tube leaks. Shielding is provided around the demineralizers. All normally used valves, instrumentation and controls are located outside of the shield walls to minimize operator exposure to radiation. Resin traps are provided in the demineralizer effluent lines to catch any resins resins released due to faulted demineralizer resin retention strainers. The resin traps are located within the demineralizer shield walls to provide radiation shielding if the released resins are radioactive.

Instrument air and demineralized water is supplied to the demineralizers for use in resin fill, resin mix, slow fill, and resin removal modes of operation. Pressure regulators, valves, and instrumentation are provided to control instrument air and demineralized water supply during these operating modes. The resins which are removed from the demineralizers following depletion can be sluiced to the condensate polishing demineralizer backwash tank or to a portable cask liner located near the polishers.

Downstream of the blowdown demineralizers, the individual effluent lines join into a common header. This header joins with the demineralizer bypass header upstream of blowdown tank level control valve BB39. BB39 automatically modulates to regulate flow from the blowdown tank to maintain tank level at set point. Downstream of BB39 the flow path splits and blowdown can be routed to either the condenser hotwell or the turbine building sump. Normally, blowdown will be routed through a blowdown recovery heat exchanger, a prefilter, a demineralizer, and discharged to the condenser hotwell. However, during operation with high blowdown impurities or the blowdown demineralizers unavailable, it may be desirable or necessary to bypass the demineralizers and route the blowdown to the Turbine Building sump for disposal.

Motor operated or pneumatic isolation valves are provided at various points throughout the system to allow blowdown flow path determination from the Control Room. Containment isolation valves are provided for each steam generator blowdown header at the containment penetrations. These containment isolation valves automatically close on a phase A containment isolation signal or an auxiliary feedwater auto-start signal.

Samples are taken from the BB System at several points by the Nuclear Sampling System (NM) and conventional Sampling System (CT). Local grab samples are also provided at various points through the system.

The NM System takes samples of each steam generator's shell side water in the vicinity of the downcomer and also samples blowdown from each steam generator blowdown header. Radiation monitor 1EMF34 located in the NM System continuously monitors steam generator blowdown fluid and will automatically close the blowdown flow control valves BB24, 65, 73, 156, 157, 158, 159, blowdown tank steam vent to atmosphere isolation valve BB27, and blowdown pump discharge to Turbine Building sump isolation valve BB48 if activity of the blowdown fluid is too great. Blowdown can be continued during periods of high activity by overriding the radiation monitor, opening the blowdown flow control valves, and routing blowdown tank steam and water to the "D" heaters and condenser hotwell, respectively.

The Liquid Radwaste System (WL) has a connection to each steam generator blowdown header upstream of the containment isolation valves. These connections are piped to the steam generator drain pump which can be used to drain the steam generators. The WL System is normally isolated from the BB System by two WL isolation valves per line which are locked closed.

The Steam Generator Wet Lay-up Recirculation System (BW) is connected to each steam generator blowdown header in the doghouse downstream of the containment isolation valves. The BW System is normally isolated from the BB System by isolation valves which are locked closed. During steam generator wet lay-up recirculation, water will be recirculated through the steam generators by pumping into the steam generators through the blowdown headers and withdrawing water through the auxiliary feedwater nozzles.

The BB System contain Duke Class B, F and G piping. Class B piping is provided inside containment and through containment penetrations. Class F piping is provided in the doghouse and Auxiliary Building, and Class G piping is provided in the Turbine Building. The presence of Duke Class B (ASME Section III-Class 2) piping and the system containment isolation function requires the system to be designated "Nuclear Safety Related."

10.4.8.3 Safety Evaluation

The Steam Generator Blowdown System is designed to operate manually and on a continuous basis as required to maintain acceptable steam generator secondary side water chemistry. The presence of ASME Section III - Class 2 piping and the system containment isolation function requires the sytem to be desingated "Nuclear Safety Related". All blowdown lines which penetrate the Containment are isolated automatically upon containment isolation signal and auxiliary feedwater automatic start signal. The portion of the system inside the containment and the portion utilized as containment isolation are designed in accordance with applicable safety class requirements. A failure analysis is presented in Table 10.4.8-3.

The Steam Generator Blowdown System is designed to prohibit radioactive discharge to the environment from the blowdown liquid. During times of abnormally high primary-to-secondary leakage, blowdown is terminated by the radiation monitors. At this point the operator analyzes the situation and aligns the Steam Generator Blowdown System in the proper mode of operation.

In addition to the Condensate Cleanup System, Component Cooling System, and Containment Isolation System, the Steam Generator Blowdown System also interfaces with the Steam Generator Wet Layup System (BW). The BW System is used to maintain satisfactory secondary side water chemistry during periods of wet layup.

The primary and secondary water chemistry specifications are given in Tables 10.4.8-4 and 10.4.8-5, respectively, to show the compatibility with primary-to-secondary system pressure boundary material. This subject is discussed extensively in Section 5.4.2.1.

10.4.8.4 Tests and Inspections

The equipment will be tested by the manufacturer in accordance with the various applicable code requirements. Proper operation fo the System is verified during unit startup. During normal operation of system, periodic checks of operating conditions will detect any deterioration in the performance of system components.

The Containment Isolation valves are functionally tested per the Catawba Nuclear Station Pump and Valve Inservice Testing Program.

10.4.8.5 Instrumentation Applications

10.4.8.5.1 Flow Instrumentation

Flow instrumentation is provided in each of the blowdown lines to give control room indication of each steam generator blowdown flow. Flow rate can be set in the control room by adjusting a manual loader which throttles blowdown control valves in each of the blowdown lines to the desired flow rate.

Flow instrumentation is provided in the steam generator blowdown pumps discharge header to open the valve in the recirc line if flow becomes too low. Also flow instrumentation is provided in this line to indicate flowrate to the BB demineralizers or Turbine Building sump. Flow instrumentation is provided in the Blowdown tank steam vent line to indicate steam flowrate leaving the tank.

10.4.8.5.2 Level Instrumentation

Level instrumentation is provided in the steam generator blowdown tank to throttle the control valve located in the steam generator blowdown pump discharge header to keep a set level in the tank. If the level becomes too high, each of the blowdown flow control valves is automatically shut. If the level becomes too low, blowdown tank level control valve BB39 is automatically closed and the steam generator blowdown pumps are tripped. Local level indication is given.

10.4.8.5.3 Pressure Instrumentation

Pressure instrumentation is provided on the steam generator blowdown tank to provide pressure indication and high pressure alarm and trip.

Pressure instrumentation is provided in the discharge of each steam generator blowdown pump to give local indication of pump discharge pressure.

Differential pressure is indicated and high differential pressure is alarmed across the BB demineralizer prefilters, BB demineralizers, and BB demineralizer resin traps.

10.4.8.5.4 Temperature Instrumentation

Temperature instrumentation is provided in each blowdown line to give control room indication of blowdown temperature. Blowdown temperature to the BB demineralizers is indicated and high temperature gives an alarm. High-high temperature isolates the BB demineralizers from flow.

10.4.9 AUXILIARY FEEDWATER SYSTEM

10.4.9.1 Design Bases

The Auxiliary Feedwater System (CA) assures sufficient feedwater supply to the steam generators (S/G), in the event of loss of the Condensate/Feedwater System, to remove energy stored in the core and primary coolant. The CA System may also be required in some other circumstances such as evacuation of the main control room or cooldown after a loss-of-coolant accident for a small break, including maintaining a water level in the steam generators following such a break.

The two units are provided with separate CA Systems.

The CA System is designed to start automatically in the event of loss of offsite electrical power, trip of both main feedwater pumps, safety injection signal, or low-low S/G water level; any of which may result in, coincide with, or be caused by a reactor trip. The CA System will supply sufficient feedwater to maintain the reactor at hot standby for two hours followed by cooldown of the Reactor Coolant System (NC) to the temperature at which the Residual Heat Removal System (ND) may be operated.

Three CA pumps are provided, powered from separate and diverse power sources. Two full capacity motor driven pumps are powered from two separate trains of emergency on-site electrical power, each normally supplying feedwater to two steam generators. One full capacity turbine driven pump, supplying feedwater to two steam generators, is driven from steam contained in either of the two steam generators. Only one of the three CA pumps must function to supply the minimum total feedwater requirements to at least two intact steam generators at a pressure corresponding to the lowest S/G safety relief valve set pressure plus 3% accumulation at the S/G CA nozzles. Design data for the CA pumps are shown in Tables 10.4.9-1 and 10.4.9-2. A minimum of 240,000 gallons feedwater supply is required for the design basis hot standby followed by normal cooldown to conditions at which the ND System may be operated.

For a transient or accident condition, the minimum CA flow must be delivered within one minute of any actuation signal to start the CA pumps. The minimum flow is considered the flow delivered only to steam generators effective in cooldown and does not include flow delivered to a steam generator involved in a feedline or CA line break. The minimum flowrate is established by Westinghouse on the basis of providing adequate protection for the core and to assure orderly cooldown. There are two minimum CA flow requirements, depending upon the severity of the initiating event. This is based upon the more stringent and conservative acceptance criteria for more probable events such as loss of normal feedwater or station blackout than for more unlikely events such as fire, sabotage, control room evacuation, loss of all A.C. power, feedline break. For standard plant 412, Westinghouse has determined minimum CA flow requirements of 600 GPM @ 120°F for loss of normal feedwater and 470 GPM @ 120°F for more severe events or for plant cooldown following a period of hot standby. Maximum CA temperature at Catawba may reach 138°F based on maximum operating condenser pressure of 243 inches Hg volume. The Westinghouse requirements based on 120°F are adjusted to the basis of 138°F. Based on a supply temperature of 138°F, minimum CA flow requirements are 613 GPM for loss of normal feedwater and 480 GPM for more severe events or for plant cooldown following a period of hot standby.

Standards for nuclear safety related systems are met for the CA System except for the condensate quality feedwater sources. The nuclear safety related portion of the CA System is designed for seismic and single failure requirements. The CA System will provide the required flow to two or more steam generators regardless of any single active or passive failure in the long term. Safety classifications of the Auxiliary Feedwater System components are presented in Table 3.2.2-2.

The use of redundancy, diversity, and separation has been incorporated into the design of the CA System to ensure its capability to function. Redundancy is provided by using two full capacity motor driven pumps and one full capacity turbine driven pump. Diversity is provided by using several water sources, two types of pump drivers, and adequate valving for source selection, isolation, and cross-connection. Separation is provided with separated power, instrumentation, and control subsystems with appropriate measures precluding interaction between subsystems. Independent piping subsystems are incorporated into the design and protected at interconnection points with appropriate isolation and/or check valves. All of the necessary instrumentation, controls, and valves for the motor driven CA pumps are powered by the train of emergency A.C. electrical power associated with each pump. The controls for the turbine driven pump are also powered by a third emergency D.C. electrical power supply. Separation, diversity, and redundancy are provided throughout the design of the CA System to allow the system to perform its safety-related function in the event of a single failure coincident with a secondary pipe break and the loss of offsite electrical power.

For the postulated non-seismic event of loss of all offsite and all onsite emergency A.C. electrical power, the CA System will perform its safety related function with the limitation that no single failure that would prevent the single A.C. power independent turbine driven pump subsystem from functioning occurs during this limiting event.

Design features and operational precautions are provided to preclude the possibility of hydraulic instability (water hammer) in both the CA System and the Condensate/Feedwater System during all anticipated operating transients. The conditions necessary to produce water hammer in the main feedwater piping and/or steam generators must occur simultaneously as either low S/G temperature and extremely low S/G level (below the level which initiates the CA System) or low S/G temperature and low S/G pressure. Although piping and

valve, and a check valve. The turbine and motor driven pump discharge lines to each individual steam generator join into a single line outside containment. These individual lines penetrate the containment and enter each steam generator through the auxiliary feedwater nozzle. Piping and valves are provided to allow interconnection between each steam generator main feedwater line and the corresponding auxiliary feedwater nozzle to allow feeding the steam generators through the auxiliary feedwater nozzles during some modes of operation. These lines, the main feedwater bypass line and the main feedwater tempering flow line, are safety related at their intersection with the CA System and contain safety related valves. Failure of these lines and valves has been postulated in accordance with safety evaluation criteria and does not prevent the CA System from performing its safety related function. The main feedwater bypass line is provided to allow main feedwater to feed the steam generators
Q 410.32 through the auxiliary feedwater nozzles during hot standby, startup, low power operation, and cooldown. This is done in an effort to minimize the possibility of steam generator water hammer during these modes of operation. The main feedwater tempering flow line is provided to allow main feedwater to feed the steam generators through the auxiliary feedwater nozzles during normal operation. A small tempering flow is provided to the auxiliary nozzles at all times when the main feedwater bypass line is isolated, except when a feedwater isolation signal is activated. This flow cools the inner surfaces of the auxiliary nozzles and adjacent connecting piping and maintains the water temperature in the piping connecting to the nozzles at approximately feedwater temperature, which should cause the thermal stresses induced in the nozzles and connecting pipe to be reduced when main feedwater flow is transferred to the auxiliary nozzles. Isolation valves in the main feedwater bypass lines and tempering flow lines close automatically on a feedwater isolation signal. During normal operation, these valves are controlled manually from the control room. The auxiliary feedwater pump discharge lines to the upper surge tank are provided for minimum flow and testing purposes. Self-contained automatic recirculation valves are provided to assure individual pump minimum flow when needed during operation.

Flow of the auxiliary feedwater to each steam generator is monitored and controlled in each of the motor driven and turbine driven pump discharge lines. Flow is modulated by air operated control valves provided in each discharge line. Upon loss of air, these valves will fail open. Valve travel stops are set at predetermined positions to provide pump runout protection and to optimize the system resistance for various accident cases.

Any condition which could cause low steam generator pressure can cause the CA pumps to operate beyond design capacity if automatic runout protection is not provided. A condition which could cause this is a steamline or feedline break or main steam system equipment malfunction which cannot be isolated. To prevent excessive runout and yet maintain at least minimum CA flow to at least two effective steam generators during the operator delay period, the following measures have been incorporated:

1. The motor operated isolation valves on the motor driven pump discharge lines to steam generators B or C will close individually and automatically if the turbine driven pump is operating and the motor driven

3. Partial or complete loss of source due to air leakage into the system from a pipe crack, or failure to isolate a depleted source.

4. Partial loss of source due to steam void formation in the suction piping caused by excessive friction loss associated with a high flow rate, failure or spurious operation of a valve causing partial closure, or bending or partial obstruction in the pipe.

The detection scheme incorporates three differential pressure switches located in the Auxiliary Building in a vertical leg of the common condensate supply pipe to all three CA pumps. Upon two out of three indication of low suction pressure, the transfer logic will be activated. The instrumentation and controls for this function meet the standards for nuclear safety related systems, including requirements for redundancy and separation. If the station normal auxiliary electrical power is available during the initiating occurrence, a maximum 30000 gallons additional condensate supply is available from the condensate storage tank. If the two makeup demineralizers are available, a maximum condensate supply of 950 GPM is available for the short term or 475 GPM for an indefinite period. Additional condensate may also be provided from condensate sources associated with the other unit, if these sources are available, operable, and a loss of normal station auxiliary electric power has not occurred.

Q 410.31 A separate plant subsystem has been incorporated into the Catawba design to allow a means of limited plant shutdown, independent from the control room and auxiliary shutdown panels. This system, known as the Standby Shutdown System, provides an alternate means to achieve and maintain a hot shutdown condition following postulated fire and sabotage events. This system is in addition to the normal shutdown capabilities available. The Standby Shutdown System (except for interfaces to existing safety related systems) is designed in accordance with accepted fire protection and security requirements and is not designed as a safety related system. The Standby Shutdown System utilizes the turbine driven CA pump to provide adequate secondary side makeup independent from all A.C. power and normal sources of water. During this mode of operation, the turbine driven subsystem operates remotely controlled from the Standby Shutdown Facility. If the turbine has not started automatically prior to the security event, it may be manually started and receives suction water from condensate sources. If condensate sources are depleted or lost, the turbine will automatically transfer suction to an independent source initiated by train A of the condensate source loss detection logic and battery-powered motor-operated valves. The independent source of water is the buried piping of the Condenser Circulating Water System, which contains sufficient water in the imbedded pipe, inaccessible for sabotage, to enable the plant to be maintained at hot standby for at least 3½ days. In this manner, sufficient CA flow may be maintained even if all normal and emergency A.C. power is lost, and all condensate and safety-grade water sources are lost due to sabotage. All components necessary for function in this manner are protected in vital, high security areas of the plant.

Provisions have been incorporated into the Catawba CA System design to allow the system to withstand the effects of a fire involving the system and nearby surroundings. The motor driven pump subsystem and the turbine driven pump subsystem are separated by 3 hour fire barriers into two fire zones. The turbine driven pump constitutes one zone, and the two motor driven pumps constitute the second zone. The instrumentation necessary for loss of condensate detection logic is separated such that train A instrumentation is located in the turbine fire zone, and the train B instrumentation is located in the motor driven pump fire zone. This measure prevents loss of supply water to a subsystem if a fire damages instrumentation in the other subsystem.

| The CA System is designed to supply 40°F to 138°F water to the S/G nozzles in the pressure range from the ND System cut-in conditions (equivalent to approximately 110 psig S/G secondary side pressure) to the relieving pressure of the lowest safety relief valve (1210 psig).

10.4.9.3 Safety Evaluation

For the design bases considerations given in Section 10.4.9.1, sufficient feedwater can be provided at required temperature and pressure even if a secondary pipe break is the initiating event, any one CA pump fails to start, and no operator action is taken for up to 30 minutes following the event. Because the Auxiliary Feedwater System is the only source of makeup water to the steam generators for decay heat removal when the Main Feedwater System becomes inoperable, it has been designed with special considerations. The use of redundancy, diversity, and separation has been incorporated into the design of the CA System to ensure its capability to function.

Redundancy is provided by using two full capacity motor driven pumps and one full capacity turbine driven pump. Diversity is provided by using several water sources, two types of pump drivers, and adequate valving for source selection, isolation, and cross-connection. Separation is provided with separated power, instrumentation and control subsystems with appropriate measures precluding interaction between subsystems. Independent piping subsystems are incorporated into the design, protected at interconnection points with appropriate isolation and/or check valves to ensure a high degree of piping separation, redundancy, and diversity. A CA System component failure analysis is presented in Table 10.4.9-3. Transients and accidents requiring the CA System to function, discussed in Chapter 15, demonstrate that the CA System satisfies the design bases described in Section 10.4.9.1.

Following a loss-of-coolant accident, the CA System may be used for supplying water to the steam generators to develop a water head and thereby prevent potential tubesheet leakage from the primary to the secondary side of the steam generators. The two motor driven pumps will be used for this purpose as steam for the turbine driven pump may or may not be available. In the event of failure of one of the motor driven pumps, the water supply to two of the steam generators would be temporarily unavailable. By opening the crossconnection valves between the motor driven pump discharge lines, the one operating motor driven pump may be used to fill and maintain level in all four steam generators.

Table 10.4.8-1

Maximum Allowance Blowdown Flowrate

Westinghouse has imposed restrictions on the allowable flowrate through the steam generator blowdown nozzles. Exceeding the specified maximum for an extended period of time can result in erosion or possibly mechanical vibration of the blowdown pipe inside the steam generator. As it is impractical to repair a damaged internal blowdown pipe, the specified maximum valves should be observed.

On Unit 1, maximum allowable blowdown flowrates vary with unit load and are specified as follows:

Load (%)	Max. allowable flowrate per steam generator
0	69,500 lbm/hr
50	63,400 lbm/hr
100	57,600 lbm/hr

On Unit 2, the maximum allowable blowdown flowrate per steam generator is 55,000 lbm/hr for a cummulative time of 1 year and 25,000 lbm/hr for the remainder of the steam generator service life. These maximum values apply at all loads. No such cummulative time limitations apply to the Unit 1 steam generators.

Table 10.4.8-2 (Page 1)

Steam Generator Blowdown System Component Design Parameters

STEAM GENERATOR BLOWDOWN PUMPS

Number Per Unit	2
Type	Vertical Inline
Design Pressure, PSIG	
Design Temperature, °F	
Head at Design Flow, Ft	500
Temperature of Pumped Fluid, °F	110-365
Capacity at Design Head, GPM	360

STEAM GENERATOR BLOWDOWN TANK

Number per Unit	1
Volume, Gallons (approx.)	3000
Normal Operating Pressure, PSIA	1.3-160
Design Pressure, PSIG	205
Design Temperature, °F	390
Construction Material	Carbon Steel

STEAM GENERATOR BLOWDOWN RECOVERY HEAT EXCHANGERS

Number per Unit	2
Manufacturer	Josesph Oat Corp.
Type	CGU
Tube Side:	
Design Pressure, PSIG	485
Design Temperature, °F	430
Design Flow, lbm/hr	203,000
Inlet Temperature, °F	365
Outlet Temperature, °F	130
Fouling Factor	.001
Pressure Drop at Design Flow, PSI	8.1
Material	Stainless steel
Shell Side:	
Design Pressure, PSIG	380
Design Temperature, °F	180
Design Flow, lbm/hr	1,985,000
Inlet Temperature, °F	110
Outlet temperature, °F	134.4
Fouling Factor	.0005
Pressure drop at design flow, PSI	8.8
Material	Carbon steel

Table 10.4.8-2 (Page 2)

Steam Generator Blowdown System Component Design Parameters

STEAM GENERATOR BLOWDOWN DEMINERALIZER PREFILTER

Number per Unit	2
Manufacturer	Pall Trinity
Type	Cartridge
Design Pressure, PSIG	485
Design Temperature, °F	430
Design Flow, GPM	500
Retention Size, Microns	2-10
Clean Pressure Drop at DEsign Flow, PSI	2
Cartridge Structural Design Max. Pressure Drop, PSI	75
Material of Construction	Carbon Steel

STEAM GENERATOR DEMINERALIZER

Number per Unit	2
Manufacturer	Graver
Type	Mixed-bed, non-regenerative
Design Pressure, PSIG	485
Design Temperature, °F	430
Operating Temperature, °F	130
Design Flow, GPM	500
Clean Pressure Drop at DEsign Flow, PSI	5
Flow Loading at Design Flow, GPM/ft^2	17.7
Total Resin Volume, Ft^3	85
Anion to Cation Ratio	1:1
Resin Bed Depth, in.	36
Material of Construction	Stainless Steel

STEAM GENERATOR BLOWDOWN DEMINERALIZER RESIN TRAP

Number per Unit	2
Manufacturer	Mueller
Type	Y-strainer
Design Pressure, PSIG	485
Design Temperature, °F	430
Design Flow, GPM	500
Clean Pressure Drop at Design Flow, PSI	1
Retention Size, Mesh	100
Material of Construction	Carbon Steel

Tabie 10.4.8-3 (Page 1)

Failure Analysis, Steam Generator Blowdown System

	Failure	Consequences	Action
(1)	Rupture of blowdown line between steam generator and isolation valve inside containment.	Hot water under pressure partially flashes to steam. Pressure in lower compartment increases, and vapor passes through ice beds. Water level in affected steam generator increases. Radioactivity present in steam generator remains inside containment.	Same action taken for small steam break.
(2)	Rupture of blowdown line from outside containment to flash tank.	Hot water under pressure escaped into Doghouse or Turbine Building and partially flashes to steam. Some of the radioactive material in Blowdown is carried out with building ventilation exhaust.	When the leak is discovered, the operator closes blowdown isolation valves.
(3)	Rupture of blowdown line down stream of flash tank.	Water or steam under pressure escapes into Turbine Building and water is collected by floor drains.	When the leak is discovered, the operator closes all blowdown isolation valves.
(4)	Loss if instrument air	The following valves will fail as listed below: 1BB65 Fail Close 1BB69 Fail Close 1BB24 Fail Close 1BB73 Fail Close 1BB39 Fail Open 1BB86 Fail Open 1BB27 Fail Close 1BB48 Fail Close 1BB156 Fail Close 1BB157 Fail Close 1BB158 Fail Close 1BB159 Fail Close 1BB175 Fail Open	No action is required from the operator. Blowdown will be reestablished once instrument air is obtained.

Table 10.4.8-3 (Page 2)
Failure Analysis, Steam Generator Blowdown System

Failure	Consequences	Action
	1BB178 Fail Open 1BB188 Fail Close No activity will be released to the atmosphere if a primary to secondary leak is present.	
(5) One blowdown pump is inoperable.	Second blowdown pump can be used.	Second blowdown pump is aligned for operation.

Table 10.4.9-1
Auxiliary Feedwater System
Motor Driven Pump Design Data

Quantity per Unit	2
Type	Centrifugal, Horizontal
Fluid	Water
Design temperature, °F	160
Design flow rate, GPM @ 134°F	500
Design head, ft. H_2O @ 134°F	3210
NPSH requried, at design flow, ft. H^2O @ 134°	15
Rated RPM	3600

Driver:

Type	Direct coupled, electric motor
Rated BHP	600
Rated RPM	3600
Service Factor	1.25
Power Requirements	4000 VAC, 3 Phase, 60 Hz

Table 10.4.9-2
Auxiliary Feedwater System
Turbine Driven Pump Design Data

Quantity per Unit	1
Type	Centrifugal, Horizontal
Fluid	Water
Design temperature, °F	160
Design flow rate, GPM @ 134°F	1000
Design head, ft. H_2O @ 134°F	3217
NPSH required, at design flow, ft. H_2O @ 134°F	15
Rated RPM	3600

Driver:

Type	Direct coupled, Single stage turbine
Rated BHP	1160
Rated RPM	3600
Steam inlet pressure, max/min, psig	1210 - 110
Back pressure, psig	3

The auxiliary feedwater pump turbine is qualified to Seismic Category I.

Table 10.4.9-4 (Page 2)
Auxiliary Feedwater System
Instrumentation and Control

Indicators	Control Room	Local
Condensate sources low level indicating lights	X	X
Local/remote control indicating lights	X	
Loss of condensate source indicating lights		X
Auxiliary feedwater pump loss of condensate source indicating lights		X
Auxiliary feedwater pump suction valves CA7A, CA9B, CA11A, CA15A, CA18B, CA85B, CA116A open/close position	X	X
Nuclear service water supply valves RN250A, RN310B open/close position	X	X
Auxiliary feedwater flows to A,B,C,D steam generators	X	X
Individual auxiliary feedwater pump discharge flows	X	
Main feedwater pressure	X	
Upper surge tank level	X	X
Auxiliary feedwater condensate storage tank level	X	X
Hotwell level	X	X
Condensate storage tank level	X	
Nuclear service water pond level	X	
Auxiliary feedwater pumps running lights	X	X
Auxiliary feedwater pumps automatic start defeat indicating lights	X	
Auxiliary feedwater pumps recirculation flow indicating lights	X	

Table 10.4.9-4 (Page 3)
Auxiliary Feedwater System
Instrumentation and Control

Controls	Control Room	Local
Motor driven pump A stop/start	X	X
Motor driven pump B stop/start	X	X
Turbine driven pump stop/start	X	X
Individual valve position controls for pump discharge flow control valves CA36, CA40, CA44, CA48, CA52, CA56, CA60, CA64	X	X
Individual auxiliary feedwater motor operated isolation valves CA38A, CA42B, CA46B, CA50A, CA54B, CA58A, CA62A, CA66B open/close	X	X
Local/remote control transfer switch		X
Auxiliary feedwater condensate storage tank supply valve CA6 open/close/auto	X	X
Upper surge tank supply valve CA4 open/close	X	X
Condenser hotwell supply valve CA2 open/close	X	X
Auxiliary feedwater pump suction valves CA7A, CA9B, CA11A open/close	X	X
Nuclear service water supply valves RN250A, RN310B, open/close/auto	X	X
Turbine speed control	X	X
Turbine trip and reset control	X	X
Auxiliary feedwater turbine main steam supply valves open/close	X	X
Main feedwater bypass to auxiliary feedwater nozzle isolation valves open/close	X	
Auxiliary feedwater pump suction valves CA15A, CA18B, CA85B, CA116A open/close/auto	X	X
Auto start defeat switch (motor driven pumps only)	X	

Table 10.4.9-4 (Page 4)
Auxiliary Feedwater System
Instrumentation and Control

Specific control room alarms for the Auxiliary Feedwater System:

Low hotwell level
Low upper surge tank level
Low-low auxiliary feedwater condensate storage tank level

Aux. Feedwater System Loss of Condensate source

Turbine stop valves not open
Control room control overridden by local panel control
Any auxiliary feedwater pump discharge motor operated isolation valve not open
Any nuclear service water supply valve not closed (RN250A, RN310B, CA15A, CA18B, CA85B, CA116A)
High temperature alarms for pump and driver bearings and motors
Any auxiliary feedwater pump suction valve CA7A, CA9B, CA11A not open

Low auxiliary feedwater condensate storage tank level

Low auxiliary feedwater condensate storage tank level coincident with low upper surge tank level

Less than recommended inventory in upper surge tanks

Loss of condensate source

11.2.2 SYSTEM DESCRIPTION AND FUNCTIONS

11.2.2.1 General Description

Portions of the Liquid Radwaste System common to both units (shared) are shown on Figures 11.2.2-1 through 11.2.2-9. Those portions contained separately in each unit are shown on Figures 11.2.2-10 through 11.2.2-16 for Unit 1 and 11.2.2-17 through 11.2.2-23 for Unit 2.

Of prime importance to successful Liquid Radwaste System operation is the segregation of input streams so that large quantities of water with little or no radioactivity content can be swiftly monitored and released, while small, controlled quantities of dirty, contaminated, water can be collected, processed, and recycled or released. Deaerated, recyclable water can be simply collected and re-used.

The Liquid Radwaste System, as delineated in ANSI N199, begins at the interfaces with the Reactor Coolant System pressure boundary and at the second valve in lines from other systems, or at those sumps or floor drains provided for liquid waste with the potential of containing radioactive material and terminates at the point of controlled discharge to the environment, or at the point of interface with the Solid Radwaste System, and at the point of recycle back to storage for reuse.

The Liquid Radwaste System includes all piped aqueous equipment flush and drain lines with the exception of corrosion inhibited water drains, all floor drains, decontamination sink drains, ultrasonic cleaner drains, laundry drains, and ventilation equipment drains in the Auxiliary and Reactor Buildings. The Liquid Radwaste System does not include any sanitary sewer drains whatsoever. Drains from components containing corrosion inhibited water are piped to the component cooling drain sumps in the KC System.

The WL System is designed to collect liquid wastes as follows:

a. Deaerated recyclable liquids containing fission product gases and other radioactive materials including tritium are collected in the reactor coolant drain tank in the Reactor Building or the waste drain tank in the Auxiliary Building.

b. Aerated recyclable liquids containing radioactive materials including tritium are collected in the waste evaporator feed tank.

c. Liquids from the floor drains in the Reactor Building and radiation areas of the Auxiliary Building that are potentially radioactive, but generally suited for plant discharge without treatment, are collected in the floor drain tank, either directly or via floor drain sumps A and B, the containment floor and equipment sumps A and B, and incore instrumentation sumps of both units.

d. Liquids from Auxiliary Building floor drains in areas other than radiation areas are considered clean and are collected in floor drain sumps C and D. They are discharged to the Turbine Building sump through a monitor which alarms upon detectable radioactivity, diverting the flow to the floor drain tank for processing.

The normal radioactivity concentration from the containment ventilation unit condensate drain tank is expected to be undetectable. The radioactivity setpoint for the CVUCDT monitor is 1E-6 ∂Ci/ml, the minimum concentration detectable by the monitor. The basis for this setpoint is to assure that any detectable radioactive liquids present in the CVUCDT are monitored to determine if processing by the Liquid Radwaste System is required.

11.5.1.2.1.4 Nuclear Service Water (NSW) Monitors

The nuclear service water monitors consist of two off-line gamma detectors (high range and low range) for each NSW train that continuously monitor the NSW return flow from the containment spray heat exchangers. Radioactivity in excess of a preset level in the NSW return flow from a containment spray heat exchanger is indicative of a heat exchanger tube leak (e.g., during post-LOCA recirculation of the containment sump). High NSW activity is alarmed in the control room to alert the operator to isolate the affected heat exchanger.

The normal radioactivity concentration in the NSW system is expected to be undetectable. The radioactivity setpoint for the NSW monitors is 1E-6 ∂Ci/ml, the minimum detectable by the monitors. The basis for this setpoint is to limit the activity released to the environment from the NSW system to a value as low as reasonably achievable.

11.5.1.2.1.5 Component Cooling Water Monitors

The component cooling water monitors are off-line gamma detectors that continuously monitor the component cooling water at the downstream side of the two component cooling water heat exchangers. Radioactivity in the component cooling water is indicative of primary coolant in-leakage through a heat exchanger served by the Component Cooling Water System. In the event radioactivity in excess of a preset limit is detected in a train of the Component Cooling Water System, the associated component cooling water monitor actuates an alarm in the control room and closes the vent valves of the associated component cooling water surge tank. The radioactivity alarm alerts the operator to locate and isolate the faulty heat exchanger.

The normal concentration of activity in the Component Cooling Water System varies with the amount of activated Na-24. The radioactivity setpoint for the component cooling water monitor is 1E-3 ∂Ci/ml. The basis for this setpoint is to respond to inleakage of radioactivity. The Component Cooling Water System is a closed system. This setpoint may be higher to allow for fluctuation in the concentrations of activated Na-24.

11.5.1.2.1.6 Boron Recycle Evaporator Condensate Monitor

The boron recycle evaporator condensate monitor is an off-line gamma detector that continuously monitors the recycle evaporator condensate demineralizer outlet flow. The recycle evaporator effluent normally flows to the reactor makeup water storage tank; however, if radioactivity in excess of a preset limit is detected (i.e., the effluent activity is not within the Technical Specification limits for reactor makeup water), the boron recycle evaporator condensate monitor actuates an alarm in the control room and initiates automatic realignment of the flow to the recycle evaporator feed demineralizer.

12.5.2.1.1 Laboratory Equipment

Instruments for radioactivity measurement and analysis are located in the counting room and include the following, with nominal operational characteristics as indicated:

A multi-channel gamma analyzer, using Ge(Li) or HP Ge detector with at least 12% efficiency, is used for identification and measurement of gamma emitting radionuclides in samples of reactor primary coolant, liquid and gaseous waste, airborne contaminants, etc.

Several automatic and manual alpha-beta gas flow proportional and GM counterscalers (nominal 40 cpm bkgd) are used for gross beta measurements of surface contamination.

An alpha-beta low background gas flow proportional counterscaler (nominal 1.00 cpm bkgd) is used for gross alpha measurements such as uranium or plutonium in reactor primary coolant samples or alpha contamination from surface or air samples.

A dual channel liquid scintillation counter for tritium and high energy beta counting (high efficiency) is used for measurement of tritium and high energy beta in reactor primary coolant, liquid and gaseous wastes, onsite environmental samples, etc., and for gross measurement of beta activity other than tritium.

A shielded body-burden, and thyroid-burden analyzer (sensitivities <1/10 MPOB for radionuclides of interest) is located in the Administration Building and is used for bioassay purposes (i.e. measurement of possible deposited activity), for determination of internal dose.

12.5.2.1.2 Portable Radiation Monitoring Instruments and Equipment

Portable radiation survey and monitoring instruments for daily routine use are selected to cover the entire range from background to high levels for the radiation types of concern. They are generally located in the Health Physics operations office and include the following instruments and nominal characteristics:

Beta-gamma survey meters (Geiger counters, nominal 0-100 mR/hr) used for detection of radioactive contamination on surfaces and for low level dose rate measurements.

Low and high range beta gamma ionization chamber survey meters (nominal 0 mR/hr - 1000 R/hr) used to cover the general range of dose rate measurements necessary for radiation protection purposes.

Neutron rem dosimeter instruments (nominal 0 mrem/hr - 5 rem/hr) used to measure the sum of thermal, intermediate, and fast neutron dose rates for radiation protection purposes.

Respiratory protective equipment such as full-face masks, self-contained breathing apparatus, and chemical cartridge respirators are used following the guidance of applicable approval regulations contained in NUREG 0041, Regulatory Guide 8.15 and 10CFR20.103.

Survey equipment for use in emergency situations is stored in emergency kits and is located in such areas as the Control Room and the emergency control center. Respiratory protective equipment is stored in the respiratory facility, the Control Room and the emergency control centers.

Various portable airborne gaseous, particulate, and iodine samplers are also available for routine use as well as an assortment of special purpose and emergency type radiation survey instruments (including bubblers for tritium, gas sample containers, low volume samples ~2 cfm, ~100 percent efficiency particulate filters, silver zeolite cartidges and activated charcoal cartridges). All of this equipment is normally kept in the Health Physics operations office. Necessary emergency instruments are also located in the control room and at a remote assembly point.

In addition to the portable radiation monitoring instruments, fixed monitoring instruments, i.e. beta-gamma count rate meters (Geiger counters, thin side window, 0-50,000 cpm) are available for use in the Radiation Control Area. Appropriate monitoring instruments are also available at various locations within the Radiation Control Area for contamination control purposes. Portal monitors are also utilized for personnel contamination control purposes.

12.5.2.1.3 Personnel Monitoring Equipment

Fixed monitoring instruments, i.e., beta-gamma count rate meters are located at exits from the Radiation Control Area. These instruments are intended for use to prevent any contamination on personnel, materials, or equipment from being spread into the unrestricted/secondary systems areas of the station. Appropriate monitoring instruments are also used at various maintenance locations or other work areas within the Radiation Control Area for contamination control purposes. Portal monitors are utilized as appropriate, to monitor personnel leaving the Restricted Area and to monitor persons leaving the station.

Personnel monitoring equipment consists of thermoluminescent dosimeters, (TLD's), and self-reading pocket dosimeters which are worn by those persons who ordinarily work in the Radiation Control Area, whose jobs require frequent access to this area, or whose jobs involve significant levels of radiation exposure as required by 10CFR20. In addition, wrist badges, and/or finger tabs are readily available for use for measurement of extremity dose. This personnel monitoring equipment is issued from the health physics badging area located in the Service Building. Neutron radiation monitoring for individuals will be accomplished by calculated dose equivalents obtained by neutron dose equivalent rates as measured by neutron survey instruments and known personnel occupancy times. This is in accordance with Regulatory Guide 8.14. The neutron spectrum is accounted for by a neutron survey instrument which takes into account .025 ev (thermal) to 10 Mev (fast) neutrons.

The TLD has a sensitivity of a few millirem and covers a broad range up to one thousands of rem. Personnel monitoring instrumentation is maintained, calibrated and subjected to a continuing quality control program. The QC program includes the use of a computer program that compares monthly TLD values and self-reading pocket dosimeter totals covering the same monitoring period and lists those correlations that are unacceptable so that effective retesting and replacement of equipment can be done as necessary, thus helping to maintain a high level of personnel monitoring equipment performance. Periodic NBS traceable calibrations, instrument checks and evaluations, and other manual checks are also performed. Duke Power Company also participates in NRC approved performance testing programs. Self-reading pocket dosimeters and related instruments are also subject to periodic leak test and calibration.

Personnel monitoring badges are supplied by a centralized inhouse personnel dos imetry service which meets all applicable requirements for sensitivity, range, and accuracy of measurement. Conformance with appropriate standards is also required. This service has the response capability for both routine and emergency purposes. This service is performed in accordance with Regulatory Guide 8.3.

Auxiliary counting and gamma analysis equipment and a body burden analyzer for routine screening of personnel for internal exposure are provided in the low background counting area in the Administration Building. Outside services for radiobioassay and whole body counting are utilized as required for backup and support of this program. The station equipment is sufficiently sensitive to detect in thyroid, lungs or whole body a few percent of the permissible body/organ burden for those gamma emmitting radionuclides expected. This method is in accordance with Regulatory Guide 8.9.

12.5.2.1.4 Instrument Calibration and Operational Checks

In conformance with Regulatory Guide 1.33 all of the aforementioned instruments are subjected to initial operational checks and calibration and to a continuing quality control program to assure the accuracy of all measurements of radioactivity and radiation levels.

are also used in conjunction with the above and keys are issued to authorized station personnel for access to the Radiation Control Area of the plant and to limited access areas within the Radiation Control Area, under certain conditions.

Section 12.1.1 defines the Duke Power Company overall ALARA program. Inplant procedures involving radiological conditions are written such that keeping ex- Q 471.12 posures ALARA is a major consideration. The guidance of Regulatory Guides 8.2, 8.8, and 8.10 are utilized in formulating the radiological protection program and are used in the preparation and review of operating procedures. The knowledge and experience gained from other Duke Power Company operating nuclear stations, as well as other utilities, are factored into the program, also.

All persons entering the Radiation Control Area of the station must wear the personnel monitoring equipment (TLD and/or film badges, dosimeters, etc.) prescribed by the Station Health Physicist in accordance with NRC Regulations and must comply with applicable Radiation Work Permits.

Personnel whose jobs require them to frequently enter the Radiation Control Area of the station for inspection purposes ordinarily are assigned a personnel monitoring badge and a self-reading pocket dosimeter. Personnel working under a specific Radiation Work Permit, in a job situation where a sizeable fraction of the quarterly allowable dose may be received in a relatively short period of time, are additionally assigned a high range self-reading pocket dosimeter and/or extremity monitoring equipment, depending on job conditions. Extremity monitoring equipment is issued for jobs or situations where the extremity dose is expected to be limiting or controlling or in excess of the whole body dose. High range dosimeters are issued for jobs where the dose received in a short period of time is expected to be greater than 500 mrem (the range of the usual dosimeters). In other words, the additional required personnel monitoring equipment beyond that routinely used, is job coupled and depends on radiological conditions as evaluated and determined by the Station Health Physicist for those persons working under a specific Radiation Work Permit.

Individual Occupational Radiation Exposure records are filed and retained for each individual in accordance with the recommendations of Regulatory Guide 8.7. Q 471.12 Personnel exposure and monitoring reports will be submitted in accordance with the Technical Specifications and Regulatory Guide 1.16.

The Radiation Exposure Control (REC) computer program provides useful information needed to efficiently and effectively maintain daily personnel dose records. The Radiation Exposure Control (REC) computer program maintains personnel dose information equivalent to the information required on a NRC-5 form. The Job Exposure Control computer program categorizes dose according to work group and job function. The REC program also provides a report listing those cases where poor correlation is encountered between TLD badge results and pocket dosimeter totals reported for the same time period. These computer programs Q 471.12 are designed for conformance with Regulatory Guide 1.16 and facilitate conformance with Regulatory Guides 8.2, 8.8, 8.10, and the Duke ALARA program.

Duke employees and contract service employees issued a personnel monitoring badge are given a body-burden analysis when the badge is initially issued and when employment is terminated or alternatively, when the person is transferred to a non-

Q 471.12 Personnel permitted unescorted access to the Restricted Area will be given H.P. training and a written test and will be re-evaluated annually and retrained as necessary, in accordance with Section 19.12 of 10CFR19 and Regulatory Guides 8.13, 8.27, and 1.33.

The following radiation-safety requirements are provided to ensure that adequate safeguards are used for handling and storing sealed and unsealed source, special nuclear and byproduct materials. The Station Health Physicist is notified prior to ordering radioactive sources and other such materials so that the necessary arrangements for adequate protective measures and ALARA considerations can be made. Upon receipt of radioactive material at the site, Health Physics is immediately notified. Health Physics then properly monitors, records, delivers, opens, labels or posts, and assigns a custodian, before the source is stored or used. The custodian is responsible for the safekeeping, proper use, storage, and handling of all radioactive material assigned to him. He also accounts for the material at regular intervals whenever an inventory check is made by Health Physics.

All radioactive material is stored in appropriate locations in the RCA designated by the Station Health Physicist, and is posted or labeled in accordance with 10CFR20 regulations. Sealed sources containing more than license-exempt quantities of activity are leak-tested once every six months. This testing is performed by Health Physics. The Station Health Physicist is informed of any change in storage locations or change in custodian.

The Station Health Physicist is notified prior to shipment of radioactive material from the station. All shipments are monitored to ensure proper packaging and labeling, and to complete the shipment-record forms and logs, in accordance with Department of Transportation (DOT) and NRC regulations and other requirements.

All contaminated material and equipment to be removed from the RCA or transferred to another location within the RCA for storage, repair, or use, are first monitored and tagged by Health Physics. Material or equipment sent to the hot tool crib is monitored only; however, the material is marked to designate it for contaminated use only. Handling and control of contaminated material and equipment is affected by the use of tags and labels. Contaminated material and equipment are properly packaged to prevent the spread of contamination.

Table 13.1.3-1 (Page 36)

SUMMARY OF QUALIFICATIONS FOR KEY PLANT PERSONNEL

Position	General Qualifications: Academic	General Qualifications: Experience	Nuclear Qualifications: Academic	Nuclear Qualifications: Experience
• Assistant Engineer				
R. C. Simpson	B.S.N.E., University of Virginia (5-81) E.I.T. (4-81)	Duke Power Fire Fighting School. Charlotte Fire Academy (1-84)	Nuclear Preparatory and Nuclear Fundamentals Duke Power, Technical Training Center (1-84)	Two years, Junior Engineer, Startup, Primary Systems, Catawba (7-83)
			Research Reactor Training, N.C. State University. (12-83) Introduction to Systems specific, Catawba (2-84)	Three months Assistant Engineer, Operations Procedures and Fuel Handling Catawba (6-84)

Table 13.1.3-1 (Page 38)
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Table 13.1.3-1 (Page 40a)

SUMMARY OF QUALIFICATIONS FOR KEY PLANT PERSONNEL

	General Qualifications		Nuclear Qualifications	
Position	Academic	Experience	Academic	Experience
Shift Supervisor				
Stacy S. Cooper (cont.)				Additional operating experience at McGuire Nuclear Station (through 6/82) - 3 weeks

SUMMARY OF QUALIFICATIONS FOR KEY PLANT PERSONNEL

Position	General Qualifications: Academic	General Qualifications: Experience	Nuclear Qualifications: Academic	Nuclear Qualifications: Experience
Shift Supervisor				
John M. Hill	1968 Graduated Greenville Tech. Education Center, Diploma in Air Conditioning, Refrigeration and Heating 1969 - US Navy Electrician's Mate "A" School (6 months) 1970 - US Navy Submarine School (2 months) 1978-82 Attending York Technical College Completed Duke Power Management/ Supervisor course at Lake Hickory in 1981	1968 - Electrician on USS Busnwell (AS15) Qualified Duke Power Fire Brigade (Catawba Nuclear Station)	1970 - US Navy Nuclear Power School Bainbridge, MD (6 months) 1970 - US Navy Nuclear Prototype West Milton, NY (6 months) 1975 - Westinghouse NSSS Design Training (1 week) 1975 - Nuclear Power and Nuclear Fundamentals (5 months) 1976 - Research Reactor Training at NC State (3 weeks) 1978 - Cold Certification Training for McGuire Nuclear Station (6 months) 1978 - Simulator Training (Duke Power) 1981 - Catawba Nuclear Station Specific Procedures and System Training (3 months)	1971-75 Electrical Operator, USS George Washington (SSBN 598) 1975-78 Utility Operator McGuire Nuclear Station 1978-80 NCO Catawba Nuclear Station 1980 to present Assistant Shift Supervisor Catawba Nuclear Station 1981 - 3 weeks at McGuire Nuclear Station to observe startup and plant operation Additional operating experience at McGuire Nuclear Station (through 6/82) - 3 weeks

Table 13.1.3-1 (Page 41a)

SUMMARY OF QUALIFICATIONS FOR KEY PLANT PERSONNEL

Position	General Qualifications: Academic	General Qualifications: Experience	Nuclear Qualifications: Academic	Nuclear Qualifications: Experience
Assistant Shift Supervisor				
John M. Hill (cont.)			Currently attending Catawba 5th Shift training	

Table 13.1.3-1 (Page 44a)

SUMMARY OF QUALIFICATIONS FOR KEY PLANT PERSONNEL

Position	General Qualifications: Academic	General Qualifications: Experience	Nuclear Qualifications: Academic	Nuclear Qualifications: Experience
Shift Supervisor				
Phillip J. Loss (cont.)	Received Associate of Science degree (AS) 1980, York Technical College Duke Power Management courses at Catawba Nuclear Station and Lake Hickory		Currently attending Catawba Nuclear Station 5th Shift Training (1 week of each 5 weeks on Catawba Nuclear Station Systems and other SRO training)	Performed ~ 5 Reactor/ Plant Shutdowns in Control Room at Oconee Nuclear Station Performed 1 refueling as Utility Operator 2 refuelings as Control Operator at Oconee Nuclear Station Asst. Shift Supervisor, Catawba Nuclear Station 1979-1980 9 months setting up shifts at Catawba Nuclear Station and training new operators on shift 2 years working and supervising Procedure development and review process 2 weeks at Three Mile Island as Technical Consultant Shift Supervisor at Catawba Nuclear Station 1980-Present

Table 13.1.3-1 (Page 45)

SUMMARY OF QUALIFICATIONS FOR KEY PLANT PERSONNEL

	General Qualifications		Nuclear Qualifications	
Position	Academic	Experience	Academic	Experience
Shift Supervisor				
Charlie Skinner	High School Graduate May 1963 Graduate of Machinist Mate "A" School Graduate of US Navy Air Conditioning and Refrigeration School Graduate US Navy Submarine School, Groton, Conn. (3 months) Completed course in Electronics Technology and Computer Science; DeVry Institute of Technology, Chicago, Illinois 1974 Received Associates of Applied Science degree in Business Administration from Gaston College, 1979	US Navy Health Physics training and practical experience dealing with nuclear weapons, radiochemistry and general radiation control procedures US Navy firefighting and damage control training Served aboard USS Nathan Hale SSBN 623 in the Auxiliary Machinery Division Attended US Navy training schools on propulsion and auxiliary equipment too numerous to list Worked as air conditioning and refrigeration repairman and installer 1970-1972	Completed Basic Nuclear Power School (US Navy) at Bainbridge, MD (6 months) Navy Reactor Prototype Training at S3G, Saratoga Springs, New York (6 months) Completed SRO Certification training at Zion, Illinois (3 months - 1974) Completed Catawba Specific Procedures and System Training (3 months - 1981)	Served on US Navy Nuclear submarines for 9½ years in the Machinery Division Qualified through Engineering Watch Supervisor on the submarines, USS Pollack SSN603, USS Lapon SSN661 and USS Sea Devil SSN664 Worked at McGuire Nuclear Station 4 years developing procedures for plant operation May 1974 - April 1978. UO, ANCO, NCO Assistant Shift Supervisor Supervised ice loading crews during ice loading at McGuire Nuclear Station for Unit 1 Several months as Supervisor of Document Development Group, Catawba Nuclear Station

Table 13.1.3-1 (Page 45a)

SUMMARY OF QUALIFICATIONS FOR KEY PLANT PERSONNEL

Position	General Qualifications: Academic	General Qualifications: Experience	Nuclear Qualifications: Academic	Nuclear Qualifications: Experience
Shift Supervisor				
Charlie Skinner (cont.)	Completed several Duke Power Management courses at McGuire Nuclear Station, Catawba Nuclear Station and Lake Hickory	Duke Power Fire Brigade Member at Oconee Nuclear Station and Catawba Nuclear Station Duke Power First Aid, CPR and respirator training and qualification at McGuire Nuclear Station and Catawba Nuclear Station		Extensive procedure writing and review, Catawba Nuclear Station 2 weeks at Three Mile Island as Technical Consultant during entry to natural circulation mode August 1981 to present Assigned to Special Projects Group; Scheduling, tracing and writing Operations Management Procedure and Abnormal Plant operating procedures

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Table 13.1.3-1 (Page 46a)

SUMMARY OF QUALIFICATIONS FOR KEY PLANT PERSONNEL

	General Qualifications		Nuclear Qualifications	
Position	Academic	Experience	Academic	Experience
Assistant Shift Supervisor				
Mike Janeski (cont.)			Attended CNS 5th Shift Training Completed RO Cold Certification on MNS (5 months) Classroom Simulator 1979	Assistant Shift Supervisor CNS 9/81 present 9/82

Table 13.1.3-1 (Page 47)

SUMMARY OF QUALIFICATIONS FOR KEY PLANT PERSONNEL

Position	General Qualifications: Academic	General Qualifications: Experience	Nuclear Qualifications: Academic	Nuclear Qualifications: Experience
Shift Supervisor				
Michael J. Brady	High School - 1965 Associate of Applied Science Degree - Gaston College, 1979 Completed several Duke Power Management Supervisor courses at Catawba Nuclear Station and Lake Hickory	Air Force - 1965-69 Riverbend Steam Station 1970-73 Belews Creek Steam Station 1973-75 Duke Power - 12 years Duke Power Fire Fighting School - Charlotte Fire Academy Duke Power First Aid, CPR and Respirator Training	NP/NF at Technical Training Center - 1975 RRT at Raleigh - 1975 SPS at McGuire - 1977 SRO Level Cold Certification at McGuire - 1978 SPS at Catawba - 1981	Utility Operator at McGuire 1975-78 Supplement Oconee Shift Crew during Refueling Unit #2 (6 weeks 1976) Assistant Control Operator at Catawba 1978-79 Cold Certification Observation Training at Oconee Nuclear Station (4 weeks 1978) Control Operator at Catawba 1979-80 Assistant Shift Supervisor at Catawba 1980-Present McGuire/Catawba Simulator Instructor 1981-1982

Table 13.1.3-1 (Page 56)
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Table 13.1.3-1 (Page 57)
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Table 13.1.3-1 (Page 60)

SUMMARY OF QUALIFICATIONS FOR KEY PLANT PERSONNEL

Position	General Qualifications: Academic	General Qualifications: Experience	Nuclear Qualifications: Academic	Nuclear Qualifications: Experience
Assistant Shift Supervisor				
T. Williams	3 yrs. Auburn University (1968-1972)	6 mo. Submarine Repair Shop	U.S. Naval Basic Nuclear Power School (6 mo.) 1972.	3.5 years Fast Attack Submarine E.R.S.
	Winthrop College 2 semesters (1982)	Naval Health Physics Training & Experience	U.S. Naval Prototype S/W Idaho (6 mo.)	Shipyard Overhaul and Reactor Refueling
	U.S. Navy Machinist Mate School (4 Mo.) 1972.	Duke Power Fire Brigade Training, Charlotte Academy.	Completed CNS ISS class of 8 wks. 1979.	CNS NEO 2.2 Yr. 1978-80.
	Various Naval Training Schools	Duke Power First Aid, CPR and Respiratory Training & Qualification.	Research Reactor, 2 Wk. 1979	CNS ANCO, 1 Yr. 1981.
		Duke Power Company total experience 4 yrs. Sept. 82.	Completed CNS Specific Procedures & Systems Training (3 mo.) 1981.	MNS Cold Certification observation 80 hrs., 1980.
			Attended 5th Shift Training, CNS.	MNS OJT in plant experience 1 wk. presently attending.
			Completed SRO Cold Certification on MNS 5 mo. classroom and simulator, 1980.	CNS NCO 2/82, Feb. '83.
				Asst. Shift Supv. Feb. '83 present.

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SUMMARY OF QUALIFICATIONS FOR KEY PLANT PERSONNEL

Position	General Qualifications: Academic	General Qualifications: Experience	Nuclear Qualifications: Academic	Nuclear Qualifications: Experience
Assistant Shift Supervisor				
H. Rybczyk	Received B.S. History 1971, Central Conn. State College	Qualified FBM Nuclear Submarines, 1973.	U.S. Navy Nuclear Power School (6 mo.)	Completed Navy Qualification as Engine Room Supervisor.
	Completed Duke Power Leadership Training Course	Naval Fire Fighting and Damage Control schools.	U.S. Naval Nuclear Power Prototype IDAHO (6 Mo.)	Utility Operator 1 Yr. 1978-1979.
		Duke Power Fire Fighting School (Charlotte Fire Academy).	Nuclear Preparatory (6 mo.) 1979.	Cold Certification Observation ONS (80 hrs.) 1980.
		Qualified Duke Power Fire Brigade (CNS).	Introduction to System and Specifics (ISS) 1979 (6 wks).	In plant experience MNS (3 mo.) 1981-82.
		Duke Power Multimedia First Aid, CPR, Respirator Training and Qualification.	Research Reactor Training (1 wk) 1979.	Nuclear Control Operator 1980-2/83
			Relay Training (20 hrs.) 1980.	Control Room habitability review
		Naval Health Physics Training and experience.	RO Cold Certification Training and Qualif. on McGuire 1980 (5 mo. classroom and simulator).	Asst. Shift. Supv. Feb. '83 Present.
		Total Duke experience 4.8 yrs., Sept. 1982.		

Table 13.1.3-1 (Page 64)

SUMMARY OF QUALIFICATIONS FOR KEY PLANT PERSONNEL

	General Qualifications		Nuclear Qualifications	
Position	Academic	Experience	Academic	Experience
Assistant Shift Supervisor				
H. Rybczyk			5th Shift training and training on various plant systems.	

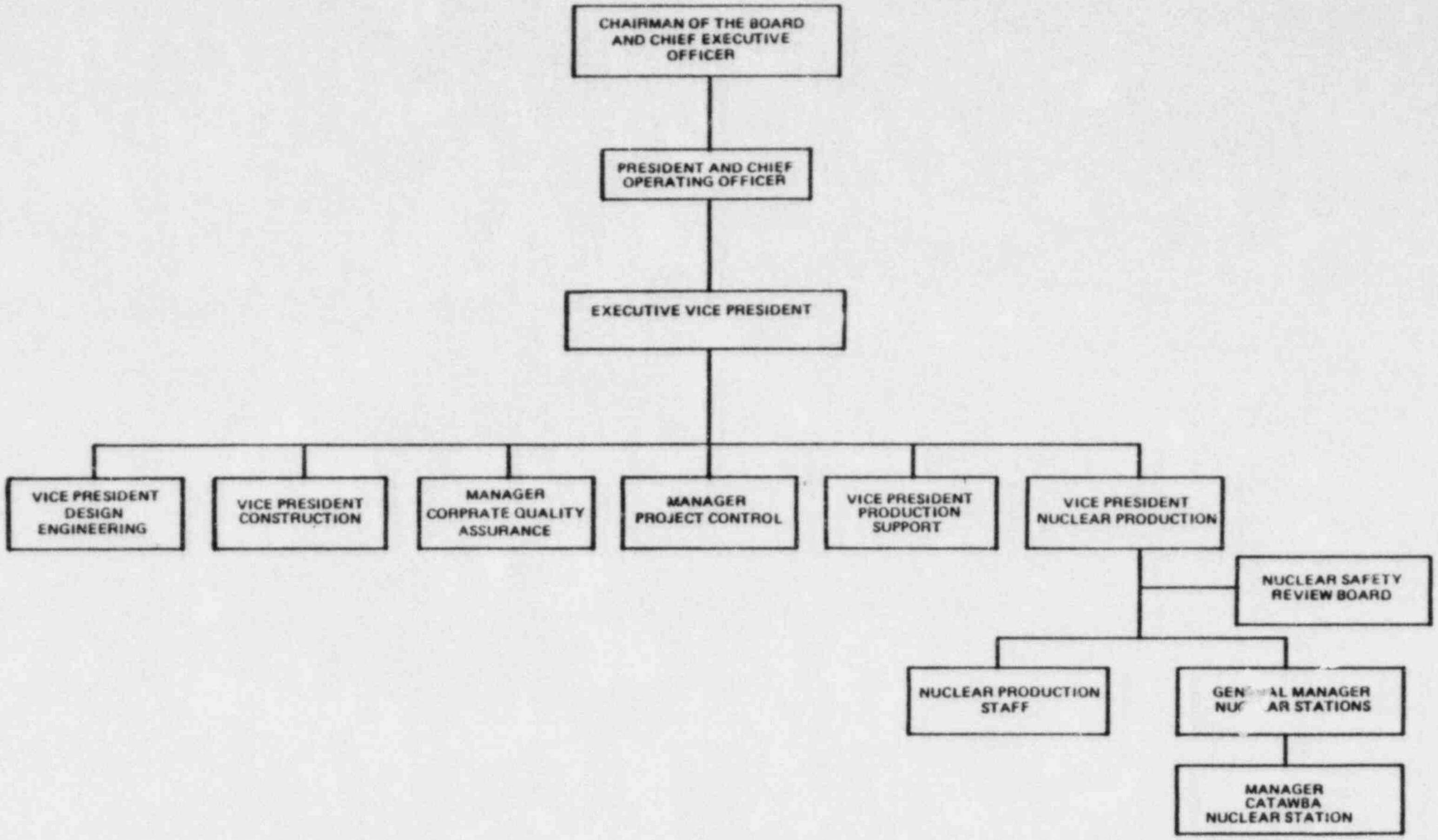
SUMMARY OF QUALIFICATIONS FOR KEY PLANT PERSONNEL

Position	General Qualifications: Academic	General Qualifications: Experience	Nuclear Qualifications: Academic	Nuclear Qualifications: Experience
Assistant Shift Supervisor				
A. Miller	US Navy Machinist Mate School 13 wks. Completed Duke Power Leadership Training Course US Naval Bearing and Lubrication School (1 wk.) 1977 US Naval Machine Tool Operator (4 wks.) 1977 US Naval Lithium Bromide Air Conditioning School (2 wks) 1978 Completed 30 hrs. toward Mechanical Engineering Technology as of Sept. 1982	Qualified on Fast Attack Submarines '76 Qualified Submarine Repair Quality Assurance Inspector For Sub Safe and Nuclear Systems while on Submarine Tender (1 yr.) Naval Health Physics Training and Experience Naval Fire Fighting School (Several wks) Nuclear Refueling Team for the Submarine (4 mo.) 1978 Coordinator for calibration of Gauges and Test Equipment (1 Yr) 1977 Ships Machinist (2 yrs)	US Naval Nuclear Power School (6 mo.) 1973 US Naval Nuclear Power Prototype SIC Center (6 mo.) 1974 Completed Nuclear Prep & Fundamentals (3 mo.) 1979 Completed Introduction to Systems and Specifics of Catawba (6 wks) Research Reactor Training (1 wk) 1979 Relay Training (2 wk) 1979 RO Cold Certification Training and Qualification on McGuire 1980 (5 mo. classroom and simulator) Systems and Procedures Specifics (3 mo) 1981	Completed Navy Engine Room Supervisor Qualification for Nuclear Submarines. Utility Operator (1 Yr.) 1978-79 ANCO 1980-1981 (1 yr.) Cold Certification Observation ONS (80 hr.) 1980 In plant experience MNS (2 mo.) Performing "CNS" Procedure Writing and Review. (1 Yr) Nuclear Control Operator CNS Jan. 1981 - Feb. 1983 Assistant Shift Supv. Feb. '83 - Present.

Table 13.1.3-1 (Page 65a)

SUMMARY OF QUALIFICATIONS FOR KEY PLANT PERSONNEL

Position	General Qualifications: Academic	General Qualifications: Experience	Nuclear Qualifications: Academic	Nuclear Qualifications: Experience
Assistant Shift Supervisor				
A. Miller (Cont'd)		Duke Power Fire Fighting Schools (Charlotte Fire Academy) Qualified Duke Power Fire Brigade (CNS) Duke Power First Aid CPR and Respirator Training and Qualification Duke Power Company (5 Yrs 9 Mos.) June 84	Fifth Shift Training - Training on various Systems.	



DUKE POWER CORPORATE ORGANIZATION

CATAWBA NUCLEAR STATION

Figure 13.1.1-1

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14.2 TEST PROGRAM (FSAR)

14.2.1 SUMMARY OF TEST PROGRAM AND OBJECTIVES

The general objectives of the initial test program at Catawba Nuclear Station is to provide assurance that:

(a) The station has been adequately designed and constructed.

(b) All contractual, regulatory and licensing requirements are satisfied.

(c) The station will not adversely affect the public health and safety.

(d) The station can be operated in a reliable, dependable manner so as to perform its intended function.

(e) Operating and emergency procedures are appropriate to the extent practicable.

(f) Personnel have acquired an appropriate level of technical expertise.

The initial test program at Catawba Nuclear Station is divided into two major portions. The first phase of testing is the preoperational test phase and includes all hot and cold functional testing required prior to fuel loading. The second phase of testing is the initial startup testing phase and includes initial fuel loading and all subsequent testing through the completion of power escalation testing.

Preoperational tests are performed following completion of construction flushing and hydrostatic testing, system turnover and initial calibration of required instrumentation. The major objective of preoperational testing is to verify that structures, systems and components essential to the safe operation of the plant are capable of performing their intended function. Summaries of these individual preoperational tests are provided in Section 14.2.12.

Preoperational testing for satisfying FSAR testing commitments will be completed prior to fuel loading. Tests currently identified which have portions of the test which may be completed following fuel loading are Spent Fuel Cooling System (Table 14.2.12-1, page 34), Rod Control System Functional Test (Table 14.2.12-1, page 7), Ice Condenser Region Functional Test (Table 14.2.12-1, page 26), and Chemical and Volume Control System Functional Test (Table 14.2.12-1, page 6). These tests will be completed prior to initial criticality. Tests currently identified which have portions of the test which may be completed during power escalation testing are Piping Systems Thermal Expansion Test (Table 14.2.12-1, page 4), Piping Systems Vibration Test (Table 14.2.12-1, pages 37 and 38), Reactor Coolant Hot Functional Test (Table 14.2.12-1, pages 3 and 3a), Feedwater and Condensate Systems Functional Test (Table 14.2.12-1, page 10), and Condenser Circulating Cooling Water Systems Functional Test (Table 14.2.12-1, page 11).

Other preoperational tests which are not required prior to fuel loading and which are not safety related, such as Administrative Building Ventilation Tests, may be completed following fuel loading. Tests (or portions of tests), for which abstracts are provided), which do not satisfy any regulatory requirement and which are not required by regulatory guides are identified in Table 14.2.12-1.

Each procedure is approved prior to use by the Station Manager; or by the Operations, Maintenance or Technical Services Superintendents as previously designated by the Station Manager. Approved safety-related test procedures which satisfy FSAR testing commitments will be made available for review 60 days prior to their intended use.

14.2.3.3 Changes to Procedures

Changes to procedures are classified as two types: minor and major. A minor change is a change to an approved procedure which corrects errors in the applicable approved procedure of a typographical or editorial nature. A major change is any change to an approved procedure determined not to be a minor change.

A minor change may be made by an individual with no special reviews or approvals. Minor changes, by definition, cannot alter the intent or methodology of the test procedure as originally approved. Because of this, minor changes require no additional review or approval. A major change to a procedure is handled in an identical manner as the original review and approval of a procedure-see Section 14.2.3.2.

14.2.3.4 Procedure Format

The format for test procedures will be uniform to the extent practicable and will consist of the following sections: Purpose, references, time required, prerequisite tests, test equipment, limits and precautions, required station (or unit) status, prerequisite system conditions, test method, data required, acceptance criteria, procedure and enclosures. Procedures are written in sufficient detail to permit qualified personnel to perform the required tasks.

Data sheets in procedures used to verify the acceptability of Engineered Safeguards pumps and fans will include all essential information to allow extrapolation of performance from test conditions to post accident design conditions. Adequate documentation is provided by the test procedure to allow determination of system operating configurations at the time test data is obtained.

14.2.4 CONDUCT OF TEST PROGRAM

14.2.4.1 Administrative Procedures

All aspects of the startup test program are conducted under appropriate administrative procedures. The use of properly reviewed and approved procedures are required for all preoperational and startup tests. The results of each preoperational test are reviewed and approved by the responsible group superintendent before they are used as the basis of continuing the test program. The results of startup testing will be reviewed and approved by the Superintendent of Technical Services prior to proceeding to the next significant power plateau. In addition, the results of each individual startup test will receive the same review as that described for preoperational tests. All modifications to safety related systems which are found necessary are reviewed and approved by the responsible group superintendent and the station manager.

Table 11.2.2-5 (Page 1)

Tanks Outside Containment Which Contain Potentially Radioactive Liquids

TANK	SYSTEM	FIGURE	LOCATION (Building - Elevation, ft)	LEVEL INDICATION	HIGH LEVEL ALARM	OVERFLOW
Volume Control	NV	9.3.4-2	AB-560	Yes	Yes	Input diverts to Recycle Holdup Tank on High Level
Boric Acid	NV	9.3.5-3	AB-560	Yes	Yes	Overflows to Waste Evaporator Feed Tank
Boron Recycle Holdup Tanks A & B	NB	9.3.5-4	AB-543	Yes	Yes	Overflows to Waste Evaporator Feed Tank Sump A
Reactor Makeup Water Storage	NB	9.3.5-7	YD	Yes	Yes	Overflows to Containment Spray and Residual Heat Removal Pump Room Sump
Upper Head Injection Water Accumulator	NI	6.3.2-5	UHI-550	*1	Yes	Overflows to Upper Head Injection Surge Tank
Upper Head Injection Surge	NI	6.3.2-5	UHI-586	Yes	Yes	Overflows to Upper Head Injection Nitrogen accumulator
Laundry and Hot Shower	WL	11.2.2-3	AB-543	Yes	Yes	Overflows via vent to Floor Drain Sump B
Waste Monitor Tanks A & B	WL	11.2.2-3 & 4	AB-543	Yes	Yes	Overflows via vent to Floor Drain Sump B

* Normally full, this status is determined by level indication in the associated surge tank

TABLE 14.2.7-1 (Page 2a)

COMPLIANCE WITH REGULATORY GUIDES

Regulatory Guide	Compliance	Affected Section(s)	Exception Taken	Justification
		App. A 4.c App. A 5.a	Pseudo-ejected-rod measurements will not be performed on Unit 2.	The calculational codes and analytical methods used for nuclear analysis of the reactor core are presented in FSAR Section 4.3.3. The validity of these codes and safety analysis assumptions for ejected rod worth will be verified as part of the extensive startup testing on Unit 1. The core design and control rods utilized on Unit 2 are identical to those for Unit 1. Control rod bank worths measurements should be sufficient to verify adequacy of ejected rod predictions. Therefore, without any gross errors in the measured bank rod worths, the Unit 2 pseudo ejected rod worth should be within the safety analysis assumptions.
		App. A 4.g A 5.z	Demonstration of proper process or effluent monitoring system response based on correlation with independent laboratory analysis will be conducted only for those monitors for which process or effuent levels exceed the minimum sensitivity of the detector.	During initial startup testing historical data has shown that process and effluent monitors may not experience levels in excess of the minimum sensitivity of the monitor. A meaningful correlation with laboratory analysis is not possible for these monitors.
		App. A 4.h A.4.r A.5.a.a.	Demonstration of the operability of reactor coolant/secondary purification and clean up systems. Formal testing will not be performed.	Refer to responses to Q640.52 items A.4.h, A.4.r., A.5.a.a.
		App. A.4.i	Specific testing to demonstrate the operability of control rod sequences and inhibit/blocking functions over the reactor power level range during low power testing will not be performed.	Refer to Q640.52 item 4.i response.
		App. A.4.j	Specific testing to demonstrate the capability of primary containment ventilation during low power testing will not be performed.	Refer to Q640.52 item 4.j response.

TABLE 14.2.7-1 (Page 3)

COMPLIANCE WITH REGULATORY GUIDES

Regulatory Guide	Compliance	Affected Section(s)	Exception Taken	Justification
1.68 Rev. 2	Partial	App. A 5	Tests and acceptance criteria will be developed to demonstrate the ability of major principal plant control systems to automatically control process variables within design limits around the nominal reference value.	Control system testing should verify proper control of process variables within the design control deadband, not over the range of design values of process variables. Proper control of process variables will be demonstrated during power escalation over the range of 0 to 100% F.P.
	Partial	App. A 5.a	Power coefficient measurements will not be performed at 100% power but will be performed at 90% power instead.	NSSS vendor does not recommend performing this test at 100% power due to potential of violating axial flux difference Technical Specification.
		App. A 5.b	Departure from nucleate boiling ratio (DNBR), maximum average planar linear heat generation rate (MAPLHGR), and minimum critical power ratio (MCPR) will not be directly verified during power escalation testing.	Axial, Radial, and Total Peaking will be directly measured and verified during power escalation testing and will be used to verify DNBR and linear heat rate margin by analysis.
	Partial	App. A 5.f	Core thermal and nuclear parameters will not be demonstrated to be in accordance with predictions following a return of the rod to its bank position.	The reactor core will be under xenon transient conditions at this time. There would be insufficient time to gather data under transient conditions. There are no NSSS vendor predictions for this configuration.
		App. A 5.g	Special testing to demonstrate control rod sequencers/withdrawal block funtions operation will not be performed.	Refer to Q640.52 item 4.i response.
		App. A 5.h	Rod drop times will not be measured at power.	Measuring rod drop times at power would require disabling all position indication for the rods in violation of plant Technical Specifications.
		App. A 5.i	Test to demonstrate incore/excore instrumentation sensitivity to detect rod misalignment will not be performed at full power.	From vendor predictions the Xenon and power distributions at 50% and 100% are similar. The performance of this test at 50% should adequately demonstrate the capability and sensitivity of incore/excore instrumentation to detect control rod misalignments equal to or less than Technical Specifications.

TABLE 14.2.7-1 (Page 3a)

COMPLIANCE WITH REGULATORY GUIDES

Regulatory Guide	Compliance	Affected Section(s)	Exception Taken	Justification
		App. A 5.k	Special testing to demonstrate ECCS operation will not be performed during low power ascension testing.	Refer to Q640.52 item 5.k response.
	Partial	App. A 5.l	Specific testing to demonstrate capabilities of RHR systems will not be performed during power ascension testing.	Refer to Q640.52 item 5.l response.
	Partial	App. A 5.m	Differential pressure measurements will not be made across the core or major reactor coolant system components.	Measured Reactor Coolant System loop flows will be compared with predicted Reactor Coolant System loop flows. Any gross deviation of actual loop or core pressure drops from predicted values will be identified by detection of the corresponding deviation of measured flow from prediction.
			Idle loop flows will not be determined during power ascension testing.	Tech. Specs. does allow for less than full flow operation.
			Specific measurements for vibration levels of reactor coolant system components will not be performed during power ascension testing.	Refer to Q640.39 and Q640.52 item 5.m responses.
		App. A 5.o	Calibration and demonstration of the response of reactor coolant system leak detection systems will not be performed during power ascension.	Refer to Q640.52 item 5.o.
		App. A.5.p	Vibration monitoring of reactor vessel internals will not be performed during power ascension testing.	Refer to Q640.39 response.
		App. A.5.q	Proper operation of failed fuel detection systems will not be performed during power ascension testing.	Refer to response Q640.52 item 5.q.
		App. A 5.r	A verification of computer inputs and performance calculations which are utilized to ensure compliance with provisions of the station operating license or accident analysis bases will be performed.	Inputs and calculations which do not serve to ensure compliance with provisions of the station operating license or accident analysis bases do not need to be verified.

Table 14.2.11-1

Preoperational and Startup Test Schedule

	Unit 1	Unit 2
Reactor Coolant System Hydro Test	Complete	2/85
Begin Hot Functional Testing	Complete	5/85
Initial Fuel Loading	6/84	10/85
Commercial Operation	3/85	9/86

REACTOR COOLANT SYSTEM HOT FUNCTIONAL TEST
Astract

Acceptance Criteria

1. Pressurizer level and pressure control during heatup, hot operation, and cooldown maintains NC system parameters within Technical Specification limits.

2. The ability to maintain charging, letdown, and seal injection flow is demonstrated through performance of the Chemical and Volume Control System Functional Test.

3. Control of reactor coolant system cooldown rate within the Technical Specification limits is demonstrated.

4. Concrete temperature adjacent to main steam line penetrations do not exceed 150°F.

5. Main steam, steam dump, and feedwater systems operate within design limits as specified by Duke Power Company Design Engineering Department System Descriptions.

6. Condenser vacuum is maintained within normal operating limits, as specified by Duke Power Company Design Engineering Department.

7. Feedwater heater controls systems and hotwell level controls function within limits as specified by Duke Power Company Design Engineering Department Specifications.

8. The main steam isolation valves close in <5 seconds, and part-stroke capability is successfully demonstrated.

9. The main steam safety valve setpoints are within the limits provided by Duke Power Company Design Engineering Department.

CHEMICAL AND VOLUME CONTROL SYSTEM FUNCTIONAL TEST
Abstract

Purpose

To demonstrate the capability of the Chemical and Volume Control System to provide required flows, pressures, temperatures, and proper flow paths for charging, letdown, seal water, and make-up to the Reactor Coolant System. To demonstrate operability of the features necessary for sampling, chemical addition and control of the primary system.

Prerequisites

The Reactor Coolant System Hot Functional Test is in progress. Chemical and Volume Control System components and piping are cleaned, flushed and hydro tested. System instrumentation and controls are available and calibrated. Component cooling and Nuclear Service Water Systems are operable to the extent required to operate the system.

The proper functioning of the sampling features may be tested prior to the Hot Functional Test, as the systems are filled and hydro tested.

Test Method

The capacities of the letdown paths and the reactor coolant filter differential pressure are measured. Letdown temperature and pressure controller responses are demonstrated. Proper operation of the excess letdown flow path is verified. Demineralizer design flow rates and pressure drops will be demonstrated during precritical testing. Charging pumps are tested for design flow rates and pressure drops. Charging pumps are tested for capability to deliver varying flow rates. Volume control tank level and pressure control indications and alarm setpoints are checked. Operational calibration and operation of the different modes of dilution and boration are verified. Flow rates within the charging, letdown, seal water and make-up flow paths are measured and verified. Emergency boration is verified along with boric acid transfer pumps discharge pressure in recirculation. Boric acid tank low level and low temperature alarms are verified. Auto-opening of INV455 (boric acid batching tank temperature control valve) upon a low temperature signal is also verified.

Operability and flow paths for sampling and chemical addition are verified by the use of normal chemistry control procedures, and successful verification is documented as a part of this test.

Acceptance Criteria

System flows, temperatures, and pressures are within limits specified by Westinghouse, and are conservative with respect to values assured in Chapter 15. Level setpoints and alarms within the flow paths tested actuate at the values specified by Westinghouse.

Sampling and chemical addition components function in accordance with design system descriptions.

Table 14.2.12-1 (Page 9)

REACTOR PROTECTION SYSTEM FUNCTIONAL TEST
Abstract

Purpose

To demonstrate the capability of the Reactor Protection System to respond properly to logic initiation signals prior to initial fuel loading.

Prerequisites

The instrument and protection systems are energized, calibrated and aligned in accordance with the test documents.

Test Method

Proper operation of the Reactor Protection System is verified under various logic conditions. Testing is performed utilizing signals or simulated signals on each of the nuclear and process protection system analog inputs in accordance with the applicable manufacturer's instruction manual. Response timing of channels is verified through insertion of signal into the sensor and measuring the time from when the process reaches its set point and the Reactor trip breakers open. The response time of the below listed protection channels will be tested.

1. Power Range Neutron Flux
2. Power Range Neutron Flux, high Negative rate
3. OTΔT
4. OPΔT
5. PZR pressure - low
6. PZR pressure - high
7. Low reactor coolant flow
8. S/G water level lo-lo
9. RCP undervoltage
10. RCP underfrequency

Acceptance Criteria

Instrument channels and solid-state logic trains for reactor protection and protection permissives function as specified by Westinghouse. Annunciators, channel status lights and permissive interlock lights function to indicate the correct status of the input signal levels.

Table 14.2.12-1 (Page 10)

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 power escalation. Manual control of feedwater pump speeds will be demonstrated during 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.

Table 14.2.12-1 (Page 11)

CONDENSER CIRCULATING WATER SYSTEMS FUNCTIONAL TEST

Abstract

Purpose

To demonstrate pre-fuel load, the proper operation of pumps and towers. To initially set flow the balance of the cooling towers.

To demonstrate during power escalation, the capability of the condenser circulating water system to supply cooling water to the main and feedwater pump turbine condensers to condense the turbine exhaust steam and to provide a sufficient heat sink for the steam dump system. This test is considered to be non-safety related.

Prerequisites

The condenser circulating water system is complete and filled. All support systems are operational to the extent necessary to perform the test. Alarms are calibrated and loop checked.

Test Method

Circulating pumps, cooling towers, and instrumentation are tested to demonstrate proper operation. System flow rates are verified where applicable. Initial flow balancing to the cooling towers will be performed by setting inlet valve open limit switches and adjustable weir levels around the cooling tower distribution flumes.

During power escalation the main and feedwater pump turbine condensers' performance parameters will be monitored to show adequate heat removal capability.

Acceptance Criteria

Circulating pumps can be started remotely and operated. Cooling tower fans can be started remotely and operated. Instrumentation functions and provides remote indication of operating conditions. Initial flows are balanced by adjustment of valve limit switches and adjustable weir levels.

Main and feedwater pump condensers maintain proper vacuum.

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)
- SI with a small LOCA or steam line break
- Refueling mode

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.

Table 14.2.12-1 (Page 16a)

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 three (3) other modes.

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 RN Pump in operation will pump the pit level down. A dynamic low level swapover to the SNSWP will be verified. For the other RN Pump, 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 are equal to or greater than the 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.

125 VDC VITAL INSTRUMENTATION AND CONTROL POWER TEST

Abstract

Purpose

To demonstrate that the 125 VDC Vital Instrumentation and Control batteries and chargers are capable of providing power during normal operation and under abnormal conditions.

Prerequisites

Battery area ventilation must be adequate. Sufficient DC loads are available to allow testing of the system.

Test Method

The system is energized for normal operation and a load equal to the maximum accident-condition steady-state dc load as measured during the Engineered Safety Features Actuation System Functional Test is applied. The capability of each battery charger to individually maintain a float charge on its associated battery, while concurrently maintaining the maximum bus dc loads, is demonstrated.

The capability of each charger to supply sufficient current to recharge a completely discharged battery within 24 hours while supplying the steady-state loads of its own load group is verified.

The capability of the system to transfer each bus from battery charger to battery power is demonstrated by de-energizing the chargers while the applicable bus is carrying its normal station loads.

A battery service test is performed in accordance with IEEE 450-1975.

The actual load on the vital buses recorded during the performance of the Engineered Safety Features Actuation System functional test is compared with the design loads for the system.

The operability of vital loads is verified at reduced system voltage by the operation of selected equipment.

Acceptance Criteria

All battery chargers provide float charge while concurrently maintaining maximum bus loads. The system responds properly to loss of normal unit power by maintaining power to the normal loads from the batteries. Batteries are capable of supplying dc power upon de-energization of their chargers. The battery capacities as determined in the battery service tests are greater than or equal to the capacity necessary to carry the vital loads during the critical period of the accident analysis.

No individual cell voltages shall reach a level of +1 volt or less during a discharge test.

Table 14.2.12-1 (Page 21a)

125 VDC VITAL INSTRUMENTATION AND CONTROL POWER TEST

<u>Abstract</u>

The battery chargers provide sufficient current to recharge a fully discharged battery within 24 hours while supplying the steady-state loads of their own load group, as described in the test method.

Table 14.2.12-1 (Page 24)

CONTAINMENT AIR RETURN AND HYDROGEN SKIMMER SYSTEM FUNCTIONAL TEST
Abstract

Purpose

To demonstrate the capability of the system to respond to an actuation signal as designed.

Prerequisites

The Containment Air Return and Hydrogen Skimmer System, solid state protection system, and associated support systems are functional to the extent required to test the system. The ice condenser inlet doors are blocked closed to prevent operation.

Test Method

Each containment air return fan and hydrogen skimmer fan is operated. Automatic operation of the Containment air return fans is verified for a simulated high-high containment pressure signal (Sp). Proper operation of the 0.25 psid permissive interlock is verified.

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Acceptance Criteria

Containment air return fan motor current and hydrogen skimmer fan current are within the limits of Technical Specification 4.6.5.6. Automatic opening of the containment air return fan damper and interlocks that prevent containment air return fan from starting with low containment pressure function as required by Technical Specification 4.6.5.2.

ANNULUS VENTILATION SYSTEM FUNCTIONAL TEST
Abstract

Purpose

To demonstrate the capability of the Annulus Ventilation System to produce and maintain a negative pressure in the annulus following a LOCA and to minimize the release of radioisotopes following a LOCA by recirculating a large volume of filtered annulus air relative to the volume discharged for negative pressure maintenance.

Prerequisites

All essential system components, including fans, filter trains, dampers, and Class 1E power systems are operational to the extent necessary to perform the test.

Test Method

Each ventilation train is operated in conjunction with its respective fan, filter train, dampers, and associated ductwork to demonstrate required capacity per ANSI N510-1980. Essential electrical components, switchovers, and starting controls are demonstrated to be functional. The ability to obtain and maintain the required negative pressure inside the annulus will be demonstrated. The acceptability of the annulus ventilation system HEPA and charcoal filters will be demonstrated per use of test procedures as specified in Regulatory Guide 1.52 Rev. 2.

Acceptance Criteria

1. Each train of the annulus ventilation system, operating independently of the other train, is capable of achieving a system flow of 9000 cfm ± 10% when tested per the requirements of ANSI N510-1980.

2. 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 9000 cfm ± 10%.

3. Laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Rev. 2 meets the laboratory testing criteria of Regulatory Position C.6.a of Regulatory Guide 1.52, Rev. 2.

4. 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 9000 cfm ± 10%.

5. The annulus ventilation system demonstrates the ability to achieve a negative pressure of greater than or equal to 0.5 in W.G. within the time period assumed by the station safety analysis. (This criteria may be verified during the Integrated ESF Test).

Table 14.2.12-1 (Page 28)

ELECTRIC HYDROGEN RECOMBINER FUNCTIONAL TEST
Abstract

Purpose

To demonstrate the capability of each electric hydrogen recombiner to achieve recombination temperatures at an air flow equal to or greater than the minimum air flow assumed in Chapter 6 of the FSAR. The test also demonstrates the proper functioning of controls, instrumentation, and indications necessary for post-accident operation.

Prerequisites

The hydrogen recombiners and associated controls are functional to the extent required to test the system.

Test Method

The electric hydrogen recombiners will be energized. Minimum acceptable heater sheath heatup rate required in order to satisfy Technical Specifications surveillance requirements will be verified. The capability of the heaters to maintain a temperature in excess of the recombination temperature as measured on the heater sheath will be verified. Air flow to each recombiner will then be measured. Following completion of the heatup test, heater resistance to ground will be verified. The results of the heatup test will be used to establish a reference power setting for use in station operating procedures.

Acceptance Criteria

A flow rate greater than or equal to the value assumed in the FSAR analysis is verified. Heater sheath heatup rate satisfies the surveillance requirement of Technical Specifications. The ability to achieve and maintain heater sheath temperatures above the hydrogen recombination temperature is verified. All controls and indications which performs a safety-related function are verified to operate as specified in Duke Power Company Design Engineering Department system descriptions, and post-heatup continuity and resistance to ground checks are satisfactory.

Table 14.2.12-1 (Page 29)

SAFETY INJECTION SYSTEM FUNCTIONAL TEST
Abstract

Purpose

To demonstrate the capability of the system to provide design flows during each of the injection phases using centrifugal charging pumps, safety injection pumps, accumulators and residual heat removal pumps. To demonstrate proper operation of all pumps and valve motors when supplied from normal offsite power or emergency power sources. To demonstrate the capability to obtain the necessary balanced flows to the Reactor Coolant System loops with the safety injection pumps running in hot leg or cold leg recirculation.

Prerequisites

For the ambient temperature portion of the test, the system is cold and the vessel head is removed. The hot temperature portion of the test is conducted during the hot functional test program. The refueling water storage tank contains sufficient water to perform the required testing, and the refueling canal is available to accept excess water drained from the Reactor Coolant System. Normal and emergency power sources are available to all safety injection equipment.

Test Method

Each pump is tested separately with water drawn from the refueling water storage tank. The overflow from the reactor vessel passes into the refueling canal. Pump head and flow are determined during this period. Pumps are then operated to determine a second point on the head/flow characteristic curve. The safety injection pumps are each run in both hot leg and cold leg recirculation modes. Flows to each branch are balanced, with each branch flow within the required range.

Each accumulator is filled and partially pressurized with the motor operated discharge valve closed. The valve is opened and the accumulators allowed to discharge into the reactor vessel. Additionally, the capability to operate the valve under maximum differential pressure conditions of maximum expected accumulator precharge pressure and zero RCS pressure is verified.

The Safety Injection System is aligned for normal power operation, with the exception that the accumulators are not pressurized. A safety injection signal ("S" signal) is manually initiated, allowing all affected equipment to actuate. Proper system alignment, flow capability and acceptable net positive suction head performance under maximum system flow conditions are demonstrated. The Safety Injection System is operated in its various modes of operation, using the Refueling Water Storage Tank as the source of water. Proper system and component response times are demonstrated in the Engineered Safety Features Actuation System Functional Test.

Table 14.2.12-1 (Page 32)

UPPER HEAD INJECTION FUNCTIONAL TEST
Astract

Purpose

To demonstrate that the upper head injection portion of the Safety Injection System is capable of performing as required.

Prerequisites

The Reactor Coolant System is cold and the reactor vessel head installed with the upper internals removed. The Reactor Coolant System water inventory is sufficiently low and the reactor coolant piping vented to minimize pressure buildup in the Reactor Coolant System during injection.

Test Method

Blowdown tests are performed by filling and pressurizing the upper head injection water and nitrogen accumulators with the isolation valves closed. The isolation valves are subsequently opened and the accumulator is allowed to discharge into the reactor vessel.

Two blowdown tests are performed - one with low accumulator pressure (about 100 psi) and one with gas pressure in the normal operating range. The low pressure test provides piping resistance information utilized in determining the level set points for isolation valves closure. The high pressure test provides verification of isolation valve operation under maximum differential pressure and verification that the required volume of water is injected into the Reactor Coolant System prior to isolation valve closure. During these tests, the proper operation of alarms, indications and controls will be verified.

| The low pressure blowdown test is performed on both units. The high pressure test is performed only on the Unit 1 UHI System.

During Reactor Coolant System cooldown from hot conditions during Hot Functional Testing, check valves operability is demonstrated by injection of small flow of water upstream of the valve.

Acceptance Criteria

The volume of water delivered to the reactor vessel is equal to or greater than the value assumed in the analysis in FSAR Section 15.6.5. Check valves are demonstrated operable at elevated temperatures.

Hydraulic isolation valve closure time is within the range assumed in the Chapter 15 analysis.

Alarms, indications and controls function as specified by Westinghouse and in the Duke Power Company Design Engineering Department system description document.

Table 14.2.12-1 (Page 33)

CONTAINMENT SPRAY SYSTEM FUNCTIONAL TEST
Abstract

Purpose

To demonstrate the capability of the system to respond to an actuation signal and to provide the required flows. Also, Containment Pressure Control Cabinet annunciator is verified on loss of control power.

Prerequisites

The refueling water storage tank is available and contains sufficient water for demonstration tests. The system is aligned to isolate the spray nozzles, obtain suction from the refueling water storage tank and recirculate water back to the refueling water storage tank.

Test Method

With the spray nozzles bypassed, the system is operated with suction from the refueling water storage tank to demonstrate design flow rates to the spray headers and to verify the pump head curve. Proper operation of the controls and interlocks associated with valves relied on to effect a transfer to the recirculation mode is demonstrated. Interlocks associated with the 0.25 psid permissive are verified to function as designed.

Proper spray nozzle performance and orientation is visually verified by blowing air through the spray ring headers and nozzles and observing the flow from the nozzles.

An unobstructed flow path is verified by the overlapping of the water flow test and the air test at the headers. Power is isolated to both trains of the Containment Pressure Control Cabinets to verify Control Room annunciators.

Acceptance Criteria

Flow nozzles are unrestricted.

Pump head vs. flow performance meets or exceeds the manufacturer's performance curve, within the error of the measurement. Pump performance in recirculation mode meets or exceeds the requirements of Technical Specification 4.6.2.b.

Interlocks which operate or prohibit operation of valves or components based upon the position of valves or containment pressure are verified to operate as designed.

System response to high-high containment pressure logic is verified during the ESF Functional Test.

Control Room annunciators actuate when control power is isolated to the Containment Pressure Control Cabinets.

SPENT FUEL COOLING SYSTEM
Abstract

Purpose

To demonstrate the capability of the system to provide the proper flow paths and flow rates required to remove decay heat from the Spent Fuel Pool. The purification capability of the system is verified by demonstrating the proper purification flow paths and flow rates.

Prerequisites

The component cooling water system is operational to the extent required to operate the Spent Fuel Cooling System.

Test Method

The spent fuel cooling pipe anti-suction holes are visually verified to be free of obstructions. Flow Paths and Flow Rates are verified for each of two cooling paths from the fuel pool through the pumps, heat exchangers, and returning to the Spent Fuel Pool. Proper operation of the Spent Fuel Pool purification and skimmer loops is also demonstrated by verifying proper flow paths. Operation of the spent fuel pool low level alarm at the proper setpoint is verified.

Acceptance Criteria

The specified flow paths are verified.

Spent fuel cooling pump performance meets or exceeds design values listed in FSAR Sectin 9.1.3. Spent fuel pool low level alarm actuates at a level equal to or higher than the value assumed in FSAR Section 15.7.4.

The anti-siphon holes are free of obstructions.

FUEL HANDLING AREA VENTILATION SYSTEM FUNCTIONAL TEST
Abstract

Purpose

To demonstrate the ability of the system to maintain the fuel handling and storage building at slightly less than atmospheric pressure, to control airborne acitvity, and to maintain a suitable temperature in the area.

Prerequisites

The system is operable to the extent required to conduct this test. The unit vent is capable of receiving air flow from the system.

Test Method

The system is operated in the normal filter train bypass mode. The ability of the system to automatically direct air flow through the filter trains upon a high radiation level in the exhaust duct system is demonstrated. The pressure in the fuel handling area is measured. The ability of the system to provide cooling and heating of the area is demonstrated by changing the temperature error signal.

Acceptance Criteria

1. Each train operating independently of the other train, is capable of achieving a flow rate of 33,130 cfm ± 10% when tested per the requirements of ANSI N510-1980.

2. Satisfactory performance of all components, controls, alarms, and interlocks required in order for the system to fulfill its required function, as described in FSAR Section 9.4.2, is demonstrated.

3. 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 each train at a flow rate of 33,130 cfm ± 10%.

4. Laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Rev. 2 meets the laboratory testing criteria of Regulatory Position C.6.a of Regulatory Guide 1.52, Rev. 2.

5. 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 each train at a flow rate of 33,130 cfm ± 10%.

6. The Fuel Handling Area Ventilation System demonstrates the ability to achieve a negative pressure of greater than or equal to 0.25 in W.G. within the Spent Fuel Storage Pool area relative to the outside atmosphere.

7. The Fuel Handling Area Ventilation System responds to changes in the temperature error signal by providing heating or cooling as appropriate, to maintain the set temperature in the fuel handling area.

NUCLEAR SERVICE WATER STRUCTURE VENTILATION SYSTEM FUNCTIONAL TEST
Abstract

Purpose

To verify that the Nuclear Service Water Structure Ventilation System can maintain the space temperature between 55°F and 104°F at design conditions.

Prerequisites

The structure and system must be complete to the extent necessary to perform the test. For the summer heat load test, the Nuclear Service Water pumps must be operable.

Test Method

The ventilation system will be operated at times when the external conditions are expected to approach the two (2) external design day conditions, 10°F and 95°F. Data will be recorded to verify that the internal environment is maintained within it's acceptable range. If the external design day conditions are not reached, the internal versus external temperature data taken during the test will be used to extrapolate to find the internal temperature which would have been reached at the design external conditions.

Design Hot Day testing will not be done to Unit Two "A" and "B" Train, and design Cold Day testing will not be done to Unit One "A" Train and Unit Two "A" and "B" Train. Instead, fan and unit heater performance data will be taken and compared with acceptable performance on either train of Unit One for Hot Day capabilities and with Unit One "B" Train for Cold Day capabilities.

Acceptance Criteria

The nuclear service water pump structure internal temperature remains between 55°F and 104°F at both the external design day conditions of 10°F and 95°F.

For those trains in which design day testing is not being done, fan and heater performance data is > -10% of the tested train.

Table 14.2.12-1 (Page 44)

EMERGENCY AC POWER SYSTEMS PREOPERATIONAL TEST
Abstract

Purpose

To demonstrate the proper operation of the essential 4160 volt, 600 volt and 125 volt A.C. power systems. To demonstrate proper operation of feeder breakers, interlocks, and alarms. To verify proper voltages at load centers during operation.

Prerequisites

The systems to be tested are completed with no outstanding deficiencies or discrepancies which could affect the test.

Test Method

For each system, the feeder breakers are operated manually, associated interlocks and alarms are verified to operate when appropriate conditions are simulated or reached during the test, voltages at load centers are measured to assure proper operation within the design range.

Acceptance Criteria

Feeder breakers, interlocks and alarms which perform a safety-related function operate in accordance with Duke Power Company Design Engineering Department System Descriptions for the appropriate systems. Voltages measured at load centers or panels are within the limits specified by Duke Power Company Design Engineering Department for the appropriate system.

Table 14.2.12-1 (Page 46)

HEAT TRACING SYSTEMS TEST
Abstract

Purpose

To demonstrate the ability of the heat tracing system to maintain proper temperature control in the various piping systems (liquid and solid wastes, chemical volume control and boron recycle).

Prerequisties

Heat tracing system installation and component checks completed. Associated systems completed to the extent necessary to allow conduct of this test.

Test Method

Energize heat tracing system.

Monitor temperatures maintained by each heat tracing circuit with the system in a static condition.

Place associated system pump in operation and establish flow path.

Monitor temperatures maintained by each heat tracing circuit.

Acceptance Criteria

Primary circuit maintains temperature 175 ± 8°F for 12% boric acid or 85 ± 5°F for 4% boric acid lines.

Backup circuit maintains temperature 160 ± 8°F for 12% boric acid lining or 70 ± 5°F for 4% boric acid lines.

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 axial 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.

2. The filter unit must be structurally sound after filter installation per applicable sections of ANSI N510-1980, Section 5, Table 2.

CONTAINMENT VENTILATION AND PURGE FUNCTIONAL TEST
Abstract

3. 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 12,500 cfm ± 10% per train.

4. 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 12,500 cfm ± 10% per train.

SEAL WATER INJECTION SYSTEM FUNCTIONAL TEST
Abstract

Purpose

To verify proper operation of the isolation valve seal water in jection system, including interlocks and alarms. To measure the overall leakoff of the system.

Prerequisites

The system is complete with no identified discrepancies which could affect the test. Valves supplied by the system are installed and operable.

Test Method

The system alarms and interlocks which perform a safety related function are tested by operation of components or simulation of sensor signals. Overall system leakoff is determined by measuring the CIV Leakages in valve subsets and then totaling the subsets to obtain an overall average.

Acceptance Criteria

Alarms and interlocks function as specified by Duke Power Company Design Engineering Department. Total train leakoff does not exceed the following makeup capacity:

For train A, $\leq$ 1.3818 gpm with tank pressure $\geq$ 45.71 psig.

For train B, $\leq$ 1.3616 gpm with tank pressure $\geq$ 45.71 psig.

INSTRUMENT AIR SYSTEM FUNCTIONAL TEST
Abstract

Purpose

To demonstrate that the system can supply instrument quality air at the design capacity. The test will also verify the correct compressor start, loading/unloading and Station Air System backup pressure setpoints. The Containment Leak Rate Test dessiccant air dryer discharge dewpoint temperature will be determined.

Prerequisites

The Instrument Air System is in normal operation.

Test Method

The start and loading/unloading pressure setpoints are verified with one compressor in "BASE," one in "STANDBY 1," and the third in "STANDBY 2." The system air pressure is lowered while pressures are recorded corresponding to compressor starts and loading. The system air pressure is then allowed to increase while pressures are recorded corresponding to the compressor's unloading. Setpoints are verified using this same procedure with compressors in each control combination.

Each compressor's flow capacity is determined by directing all the flow from the compressor through a calibrated flow orifice. The refrigerant air dryers and the CLRT air dryers discharge dewpoint temperature is determined with design air flow rate through the air dryers.

The Station Air System crossover valve is demonstrated to automatically open when Instrument Air System pressure is lowered to the design setpoint.

The Instrument Air System product air is verified to be of sufficient quality by testing of air samples taken off locations near the end of main supply headers, for a total of five samples. Samples are taken downstream of filter regulators supplying individual instrument groups. The samples are examined for particulate matter size and oil concentration.

Acceptance Criteria

The compressors start and load/unload in accordance with Duke Power Company Design Engineering Department at the correct pressures. Refrigerant and CLRT air dryers meet their maximum allowable discharge dewpoints with design flow rate. Station Air System crossover valve opens at the design setpoint ± 10%. The product air meets instrument air quality requirements as stated in the test procedure. The compressor performance meets or exceeds the acceptance flow rate specified by Duke Power Company Design Engineering Department.

Table 14.2.12-1 (Page 53)

WASTE GAS SYSTEM FUNCTIONAL TEST
Abstract

Purpose

To demonstrate the operability of the Gaseous Waste Processing System including its capability to remove and process gases from specified sources including the volume control tank, boron recycle evaporator, reactor coolant drain tank, and waste evaporator.

Prerequisites

The system is complete, with no discrepancies which would affect the test. All necessary supporting equipment is operational.

Test Method

The system will be operated to verify the flow paths from the sources through the system. Alarms and interlocks which perform a safety-related function will be verified to operate properly. The ability of the hydrogen recombiner to combine hydrogen and oxygen will be verified by operation of the recombiner.

Acceptance Criteria

Flow paths are verified to be unblocked. Alarms and interlocks function as specified by Duke Power Company Design Engineering Department.

The hydrogen recombiner successfully combines hydrogen and oxygen when operated within normal limits.

Table 14.2.12-1 (Page 54)

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%. System realigns to draw suction only from safety-related equipment rooms upon receipt of LOCA (Ss) signal and flow is 30,000 cfm ± 10%.

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% for Unit 1.

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% for Unit 1.

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, the system balance will be changed. Exhaust flows will be 30,000 cfm ± 10%.

Table 14.2.12-1 (Page 56)

REFUELING WATER SYSTEM FUNCTIONAL TEST
Abstract

Purpose

To demonstrate the operability of the refueling water storage tank heaters, in both automatic and manual modes. To demonstrate the operability of level, temperature and flow alarms.

Prerequisites

The refueling water storage tank, heaters and electrical circuits are complete with no outstanding exceptions which would affect the test.

Test Method

The operation of both sets of refueling water storage tank heaters is verified by energizing the heaters in each mode of operation. Current flow is verified to both sets of heaters. Control of the heaters in the automatic mode is verified by input of a test signal. The operation of the heaters is verified as this test signal is varied. Level, temperature and flow alarms are verified to operate in accordance with designs.

Acceptance Criteria

The heater banks are verified to energize and deenergize at the proper setpoints in each mode of operation as specified by Duke Power Company Design Engineering Department. The low recirculation flow, low recirculation line temperature, low refueling water storage tank temperature, low level, low-low level and puncture alarms all actuate as specified by Duke Power Company Design Engineering Department.

AUXILIARY SHUTDOWN PANEL TEST

Abstract

Purpose

To verify automatic valve realignment following transfer of control to auxiliary shutdown panel A (B). To demonstrate operability of auxiliary shutdown panel A (B) controls and isolation of control room following transfer of control to LOCAL. To demonstrate operability of control room controls and isolation of auxiliary shutdown panel A (B) following control transfer back to the control room.

To demonstrate that the unit can be operated from the auxiliary shutdown panels prior to loading fuel. During the Reactor Coolant System Hot Functional Test (HFT), from a hot standby condition, the ability to establish a heat transfer path to the ultimate heat sink using the Residual Heat Removal System and lowering the Reactor Coolant System temperature by 50°F is demonstrated. Instrumentation on the auxiliary shutdown panels is verified operable during this test.

Prerequisites

All systems interlocked or that can be controlled from auxiliary shutdown panel A (B) are available as required for this test.

For the demonstration portion during HFT, Hot Functional Testing is in progress with primary system at approximately 400°F.

Test Method

Prior to HFT, control is transferred to auxiliary shutdown panel A (B) and these controls are verified to be operable. All automatic interlocks are verified. Controls are verified by cycling valves and running Boric Acid Transfer Pump 1A (B). The remainder of the pumps and Pressurizer Heater Bank 1A (B) control circuits are verified operable with associated breakers in the "TEST" position. At the same time, main control room controls are verified to be isolated. Upon transfer back to the main control room, control is verified to be regained and auxiliary shutdown panel A (B) control is isolated. This is accomplished in the same manner as the previous section.

During HFT, with the primary system at approximately 400°F, control is transferred to the auxiliary shutdown panels. Also, Reactor Coolant temperature and pressure is lowered sufficiently to permit operation of the Residual Heat Removal System from the auxiliary shutdown panels. While using the Residual Heat Removal System the Reactor Coolant temperature is reduced at least 50°F.

Table 14.2.12-2 (Page 12)

Test Abstract Deleted

(This page deleted in Revision 11)

Table 14.2.12-2 (Page 27)

UNIT LOAD TRANSIENT TEST
Abstract

Purpose

To demonstrate satisfactory unit response to a 10 percent load change.

Prerequisites

The various control systems have been tested and are in automatic. All pressurizer and main steam relief and safety valves are operable. The control rods are in the maneuvering band for the power level existing at the commencement of the test. Unit conditions are stabilized and all pertinent parameters to be measured are connected to high speed recorders.

Test Method

Turbine output is manually reduced at a rate sufficient to simulate a step load change equivalent to approximately a 10 percent load decrease. After stabilization of systems, output is manually increased at a rate sufficient to simulate a step load change equivalent to approximately a 10 percent load increase. Pertinent parameters affected by a load change are measured and recorded. At various power levels, as required by the test procedure, the test is repeated.

Acceptance Criteria

Neither the turbine nor the reactor trips, and no initiation of safety injection is experienced. No pressurizer, main steam relief or safety valves lift. No operator action is required to restore conditions to steady state. Parameters affected by the load change do not incur sustained or divergent oscillations.

Table 14.2.12-2 (Page 31)

FEEDWATER TEMPERATURE VARIATION TEST
Abstract

Purpose

To demonstrate the ability of the unit to sustain a reduction in feedwater temperature from opening a feedwater heater train bypass valve. To evaluate interaction between control systems and to evaluate system responses to the transient to determine if any control system changes are required to improve transient response. This test is not required to be completed to escalate to the next testing plateau.

Prerequisites

The unit is at steady state conditions at the specified power level. Pressurizer and main steam safety valves are operable. The following systems are in the automatic mode:

1) Reactor Rod Control
2) Pressurizer Pressure Control
3) Pressurizer Level Control
4) Steam Dump Control
5) Feedwater Pump Speed Control
6) Steam Generator Level Control

Pertinent plant parameters (such as feedwater temperature, feedwater and steam flows, flux, steam generator and pressurizer levels, feedwater pump speeds) are connected to recording devices.

Test Method

The A-B heater train bypass valve is opened. Pertinent plant parameters are recorded and the data evaluated to determine control system responses to the transient.

Acceptance Criteria

Turbine generator and reactor do not trip due to Reactor Coolant System transients. Safety injection is not initiated. Main steam and pressurizer safety valves do not lift. No sustained or divergent oscillations occur in the parameters affected by the feedwater temperature variation.

Table 14.2.12-2 (Page 32)

LOSS OF CONTROL ROOM TEST
Abstract

Purpose

To demonstrate that the unit can be brought to hot standby conditions from a moderate power level using Auxiliary Shutdown Panel controls and only the minimum shift crew required for operation. To demonstrate that hot standby conditions can be maintained from outside the control room. This test is not required to be completed to escalate to the next testing plateau.

Prerequisites

Power escalation testing is in progress with the reactor at a moderate power level (10-25%) sufficiently high that plant systems are in normal configuration with the turbine - generator in operation. All personnel in the control room area not actively participating in the test as well as those performing the test are identified and their authority and responsibility documented in the test procedure.

Test Method

The control room is evacuated of normal operating personnel following the Normal Loss of Control Room operating procedure. Additional operators, not actively participating in the test, remain in the control room to monitor unit behavior. The reactor is tripped and the unit is brought to hot standby conditions using local controls and indications and maintained at this condition for at least 30 minutes. The Reactor Coolant System temperature will then be reduced by at least 50°F. Control is then transferred back to the control room and power escalation testing continued.

Acceptance Criteria

The unit is satisfactorily brought to hot standby conditions from a moderate power level and maintained at this condition for at least 30 minutes from outside the control room. The Reactor Coolant System temperature can be reduced by at least 50°F from outside the control room. Only the minimum number of personnel required to be assigned to the unit at any one time take an active part in this demonstration.

Table 14.2.12-2 (Page 37)

PRESSURIZER FUNCTIONAL TEST
Abstract

Purpose

To establish the continuous spray flow rate, determine the effectiveness of the pressurizer normal control spray and of the pressurizer heaters, and verify the response time of the pressurizer power operated relief valves.

Prerequisites

The Reactor Coolant System is at hot standby temperature and pressure. The Reactor Coolant System is lined up for normal operation in accordance with applicable operating procedures. All reactor coolant pumps are operating. Each bank of pressurizer heaters is operable.

Test Method

While maintaining pressurizer level constant, spray bypass valves are adjusted until a minimum flow is achieved which maintains less than a 125°F temperature difference between the spray line and the pressurizer steam space.

To determine pressurizer heater and spray capability, the main pressurizer spray valves are closed. All pressurizer heaters are then energized and the time to reach a 2300 psig system pressure is measured and recorded. Full spray is initiated through each spray valve individually and in parallel. Pressure versus time is recorded for each transient. The transient is terminated at a Reactor Coolant System pressure of 2000 psig by shutting the spray valves.

With the Unit at normal operating no load temperature and pressure, each PORV shall be cycled for repsonse time testing. The 2185 psig interlock closes the valve and original conditions are re-established.

This test is performed following initial fuel loading due to the need to establish the effectiveness of actual spray flow with core pressure drop acting as the driving head. This test is a prerequisite test for initial criticality.

Acceptance Criteria

For setting of continuous spray flow, the flow through each bypass valve is established such that the temperature difference between the spray line and the pressurizer steam space is less than 125°F.

For pressurizer PORV response times, each PORV reponse time is ≤ 2 seconds.

For spray and heater response tests, the response to induced transients is within limits specified in vendor guidelines.

Table 14.2.12-2 (Page 38)

SUPPORT SYSTEMS VERIFICATION TEST
Abstract

Purpose

To verify that temperatures within rooms containing engineered safety features pumps and motors are maintained within design limits during power operation by normal operation of the cooling systems serving those areas.

Prerequisites

Unit in power operation at the power level specified in the procedure.

Test Method

Temperature readings will be taken within the rooms in the auxiliary building which contain engineered safety features pumps. These readings will be compared with the design limits for these rooms.

Acceptance Criteria

Temperature readings do not exceed the design limits specified by Duke Power Company Design Engineering Department.

TABLE 15.0.12-1 (Page 1)

OFFSITE DOSES (Rem)

Accident	FSAR Section	Exclusion Area Boundary Whole Body	Exclusion Area Boundary Thyroid	Low Population Zone Whole Body	Low Population Zone Thyroid
Main Steam Line Break	15.1.5				
Case 1 (No iodine spike)		8.6E-2	7.6	4.4E-3	2.6E-1
Case 2 (Pre-spike)		7.4E-3	2.8	5.3E-4	9.6E-2
Case 3 (Coincident spike)		7.4E-3	2.4	5.3E-4	8.5E-2
Loss of Power	15.2.6				
Case 1 (No iodine spike)		4.5E-3	7.0E-2	5.9E-4	6.5E-3
Case 2 (Pre-spike)		4.5E-3	7.3E-2	5.9E-4	7.6E-3
Case 3 (Coincident spike)		4.5E-3	7.2E-2	5.9E-4	8.2E-3
Rod Ejection Accident	15.4.8				
Primary Side Release		5.1E-2	4.8	1.1E-2	2.1
Secondary Side Release		3.3E-2	1.2	1.1E-3	3.8E-2
Instrument Line Break	15.6.2				
Case 1 (No iodine spike)		1.6E-1	3.2E-1	5.1E-3	1.0E-2
Case 2 (Pre-spike)		1.8E-1	1.9E+1	6.0E-3	6.3E-1
Case 3 (Coincident spike)		1.8E-1	5.2	6.0E-3	1.7E-1
Steam Generator Tube Rupture	15.6.3				
Case 1 (No iodine spike)		6.4E-1	1.5	2.1E-2	8.8E-2
Case 2 (Pre-spike)		7.1E-1	4.4E+1	2.4E-2	1.5
Case 3 (Coincident spike)		7.0E-1	1.2E+1	2.3E-2	4.6E-1
Design Basis Accident	15.6.5				
Case 1 (With ECCS leakage)		3.0	1.2E+2	7.6E-1	5.1E+1
Case 2 (Without ECCS leakage)		3.0	1.0E+2	7.6E-1	4.6E+1
Waste Gas Decay Tank	15.7.1				
Rupture		5.0E-1	-	1.6E-2	-

3. Redundant isolation of the main feedwater lines

Q 440.66 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.

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.

Q 440.66

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.

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.

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 731 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 722 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 630 ppm (without stuck RCCA) and 448 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

Conditions at startup require the reactor to have available at least 1.30% Δk shutdown margin. The critical boron concentration is conservatively estimated to be 847 ppm for Cycle 1. The following conditions are assumed for a continuous boron dilution during startup:

Dilution flow is assumed to be a conservatively high charging flow rate (300 gpm) consistent with Reactor Coolant System operation at 2250 psia and 557°F.

A minimum water volume (9800 ft^3) in the Reactor Coolant System is used. This volume corresponds to the active volume of the Reactor Coolant System minus the pressurizer volume.

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).

Dilution During Full Power Operation

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 although only one is normally in operation). The effective reactivity addition rate is a function of the reactor coolant temperature and boron concentration. The reactivity insertion rate calculated is based on a conservative value for the critical boron concentration for Cycle 1 (847 ppm) as well as a conservative charging flowrate capacity (125 gpm).

The Reactor Coolant System volume assumed (9800 ft^3) corresponds to the active volume of the RCS excluding the pressurizer.

The operator is alerted to an uncontrolled reactivity insertion by an overtemperature ΔT trip or by the rod insertion alarms depending on whether the plant is in manual or auto rod control.

15.4.6.3 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.

15.4.6.4 Results

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 96.3 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 17.9 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 17.7 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 37.2 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 25.1 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 Startup

In the event of an unplanned approach to criticality or dilution during power escalation while in the startup mode, 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). After reactor trip there is at least 27.0 minutes for operator action prior to return to criticality.

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 other order of 65 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 27.0 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.

15.4.7.2 Analysis of Effects and Consequences

Method of Analysis

Steady state power distribution in the x-y plane of the core are calculated using the computer codes as described in Table 4.1-2. A discrete representation is used wherein each individual fuel rod is described by a mesh interval. The power distributions in the x-y plan for a correctly loaded core assembly are also given in Chapter 4 based on enrichments given in that section.

For each core loading error case analyzed, the percent deviations from detector readings for a normally loaded core are shown at all incore detector locations (see Figures 15.4.7-1 to 15.4.7-5, inclusive).

Results

The following core loading error cases have been analyzed:

Case A:

Case in which a Region 1 assembly is interchanged with a Region 3 assembly. The particular case considered was the interchange to two adjacent assemblies near the periphery of the core (see Figure 15.4.7-1).

Case B:

Case in which a Region 1 assembly is interchanged with a neighboring Region 2 fuel assembly. Two analyses have been performed for this case (see Figures 15.4.7-2 and 15.4.7-3).

In Case B-1, the interchange is assumed to take place with the burnable poison rods transferred with the Region 2 assembly mistakenly loaded into Region 1.

In Case B-2, the interchange is assumed to take place closer to core center and with burnable poison rods located in the correct Region 2 position but in a Region 1 assembly mistakenly loaded in the Region 2 positon.

Case C:

Enrichment error: Case in which a Region 2 fuel assembly is loaded in the core central position (see Figure 15.4.7-4).

Case D:

Case in which a Region 2 fuel assembly instead of a Region 1 assembly is loaded near the core periphery (see Figure 15.4.7-5.).

15.4.7.3 Environmental Consequences

There are no radiological consequences associated with inadvertent loading and operation of a fuel assembly in an improper position since activity is contained with the fuel rods and Reactor Coolant System within design limits.

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15.4.7.4 Conclusions

Fuel assembly enrichment errors would be prevented by administrative procedures implemented in fabrication.

In the event that a single pin or pellet has a higher enrichment than the nominal value, the consequences in terms of reduced DNBR and increased fuel and clad temperatures will be limited to the incorrectly loaded pin or pins.

Fuel assembly loading errors are prevented by adminstrative procedures implemented during core loading. In the unlikely event that a loading error occurs, analyses in this section confirm that resulting power distribution effects will either be readily detected by the incore moveable detector system or will cause a sufficiently small perturbation to be acceptable within the uncertainties allowed between nominal and design power shapes.

15.4.8 SPECTRUM OF ROD CLUSTER CONTROL ASSEMBLY EJECTION ACCIDENTS

15.4.8.1 Identification of Causes and Accident Description

This accident is defined as the mechanical failure of a control rod mechanism pressure housing resulting in the ejection of a rod cluster control assembly (RCCA) and drive shaft. The consequence of this mechanical failure is a rapid positive reactivity insertion together with an adverse core power distribution, possibly leading to localized fuel rod damage.

15.4.8.1.1 Design Precautions and Protection

Certain features in the Catawba units are intended to preclude the possibility of a rod ejection accident, or to limit the consequences if the accident were to occur. These include a sound, conservative mechanical design of the rod housings, together with a thorough quality control (testing) program during assembly, and a nuclear design which lessens the potential ejection worth of RCCA's, and minimizes the number of assemblies inserted at high power levels.

Mechanical Design

The mechanical design is discussed in Section 4.6. Mechanical design and quality control procedures intended to preclude the possibility of a RCCA drive mechanism housing failure are listed below:

1. Each full length control rod drive mechanism housing is completely assembled and shop tested at 4100 psi.

2. The mechanism housings are individually hydrotested after they are attached to the head adapters in the reactor vessel head, and checked during the hydrotest of the completed reactor coolant system.

3. Stress levels in the mechanism are not affected by anticipated system transients at power, or by the thermal movement of the coolant loops. Moments

induced by the design earthquake can be accepted within the allowable primary working stress range specified by the ASME Code, Section III, for Class 1 components.

4. The latch mechanism housing and rod travel housing are each a single length of forged Type-304 stainless steel. This material exhibits excellent notch toughness at all temperatures which will be encountered.

A significant margin of strength in the elastic range together with the large energy absorption capability in the plastic range gives additional assurance that gross failure of the housing will not occur. The joints between the latch mechanism housing and head adapter, and between the latch mechanism housing and rod travel housing, are threaded joints reinforced by canopy type rod welds. Administrative regulations require periodic inspections of these (and other) welds.

Nuclear Design

Even if a rupture of a RCCA drive mechanism housing is postulated, the operation of a plant utilizing chemical shim is such that the severity of an ejected RCCA is inherently limited. In general, the reactor is operated with the RCCA's inserted only far enough to permit load follow. Reactivity changes caused by core depletion and xenon transients are compensated by boron changes. Further, the location and grouping of control RCCA banks are selected during the nuclear design to lessen the severity of a RCCA ejection accident. Therefore, should a RCCA be ejected from its normal position during full power operation, only a minor reactivity excursion, at worst, could be expected to occur.

However, it may be occasionally desirable to operate with larger than normal insertions. For this reason, a rod insertion limit is defined as a function of power level. Operation with the RCCA's above this limit guarantees adequate shutdown capability and acceptable power distribution. The position of all RCCA's is continuously indicated in the control room. An alarm will occur if a bank of RCCA's approaches its insertion limit or if one RCCA deviates from its bank. Operating instructions require boration at low level alarm and emergency boration at the low-low alarm.

Reactor Protection

The reactor protection in the event of a rod ejection accident has been described in Reference 6. The protection for this accident is provided by high neutron flux trip (high and low setting) and high rate of neutron flux increase trip. These protection functions are described in detail in Section 7.2.

Effects on Adjacent Housings

Disregarding the remote possibility of the occurrence of a RCCA mechanism housing failure, investigations have shown that failure of a housing due to either longitudinal or circumferential cracking would not cause damage to adjacent housings. However, even if damage is postulated, it would not be expected to lead to a more severe transient since RCCA's are inserted in the core in symmetric patterns, and control rods immediately adjacent to worst ejected rods are not in the core when the reactor is critical. Damage to an adjacent housing could, at worst, cause that RCCA not to fall on receiving a trip signal; however, this is already taken into account in the analysis by assuming a stuck rod adjacent to the ejected rod.

15.4.8.1.2 Limiting Criteria

This event is classified as an ANS Condition IV incident. See Section 15.0.1 for a discussion of ANS classifications. Due to the extremely low probability of a RCCA ejection accident, some fuel damage could be considered an acceptable consequence.

Comprehensive studies of the threshold of fuel failure and of the threshold or significant conversion of the fuel thermal energy to mechanical energy, have been carried out as part of the SPERT project by the Idaho Nuclear Corporation (Reference 7). Extensive tests of UO_2 zirconium clad fuel rods representative of those in Pressurized Water Reactor type cores have demonstrated failure thresholds in the range of 240 to 257 cal/gm. However, other rods of a sightly different design have exhibited failures as low as 225 cal/gm. These results differ significantly from the TREAT (Reference 8) results, which indicated a failure threshold of 280 cal/gm. Limited results have indicated that this threshold decreases by about 10 percent with fuel burnup. The clad failure mechanism appears to be melting for zero burnup rods and brittle fracture for irradiated rods. Also important is the conversion ratio of thermal to mechanical energy. This ratio becomes marginally detectable above 300 cal/gm for unirradiated rods and 200 cal/gm for irradiated rods; catastrophic failure, (large fuel dispersal, large pressure rise) event for irradiated rods, did not occur below 300 cal/gm.

In view of the above experimental results, criteria are applied to ensure that there is little or no possibility of fuel dispersal in the coolant, gross lattice distortion, or severe shock waves. These criteria are:

1. Average fuel pellet enthalpy at the hot spot below 225 cal/gm for unirradiated fuel and 200 cal/gm for irradiated fuel.

2. Average clad temperature at the hot spot below the temperature at which clad embrittlement may be expected (2700°F).

3. Peak reactor coolant pressure less than that which could cause stresses to exceed the faulted condition stress limits.

4. Fuel melting will be limited to less than ten percent of the fuel volume at the hot spot even if the average fuel pellet enthalpy is below the limits of criterion 1 above.

15.4.8.2 Analysis of Effects and Consequences

Method of Analysis

The calculation of the RCCA ejection transient is performed in two stages, first an average core channel calculation and then a hot region calculation. The average core calculation is performed using spatial neutron kinetics methods to determine the average power generation with time including the various total core feedback effects, i.e., Doppler reactivity and moderator reactivity. Enthalpy and temperature transients in the hot spot are then determined by multiplying the average core energy generation by the hot channel factor and performing a fuel rod transient heat transfer calculation. The power distribution calculated without feedback is pessimistically assumed to persist throughout the transient.

A detailed discussion of the method of analysis can be found in Reference 6.

Average Core Analysis

The spatial kinetics computer code, TWINKLE, (Reference 1) is used for the average core transient analysis. This code solves the two group neutron diffusion theory kinetic equation in one, two or three spatial dimensions (rectangular coordinates) for six delayed neutron groups and up to 2000 spatial points. The computer code includes a detailed multiregion, transient fuel-clad-coolant heat transfer model for calculation of pointwise Doppler and moderator feedback effects. In this analysis, the code is used as a one dimensional axial kinetics code since it allows a more realistic representation of the spatial effects of axial moderator feedback and RCCA movement. However, since the radial dimension is missing, it is still necessary to employ very conservative methods (described below) of calculating the ejected rod worth and hot channel factor. Further descripton of TWINKLE appears in Section 15.0.11.

Hot Spot Analysis

In the hot spot analysis, the initial heat flux is equal to the nominal times the design hot channel factor. During the transient, the heat flux hot channel factor is linearly increased to the transient value in 0.1 second, the time for full ejection of the rod. Therefore, the assumption is made that the hot spot before and after ejection are coincident. This is very conservative since the peak after ejection will occur in or adjacent to the assembly with the ejected rod, and prior to ejection the power in this region will necessarily be depressed.

The hot spot analysis is performed using the detailed fuel and clad transient heat transfer computer code, FACTRAN (Reference 2). This computer code calculates the transient temperature distribution in a cross section of a metal clad UO_2 fuel rod, and the heat flux at the surface of the rod, using as input the nuclear power versus time and the local coolant conditions. The zirconium-water reaction is explicitly represented, and all material properties are represented as functions of temperature. A conservative radial power distribution is used within the fuel rod.

FACTRAN uses the Dittus-Boelter or Jens-Lottes correlation to determine the film heat transfer before DNB, and the Bishop-Sandburg-Tong correlation (Reference 9) to determine the film boiling coefficient after DNB. The BST correlation is conservatively used assuming zero bulk fluid quality. The DNB ratio is not calculated, instead the code is forced into DNB by specifying a conservative DNB heat flux. The gap heat transfer coefficient can be calculated by the code; however, it is adjusted in order to force the full power steady-state temperature distribution to agree with the fuel heat transfer design codes. Further description of FACTRAN appears in Section 15.0.11.

System Overpressure Analysis

Because safety limits for fuel damage specified earlier are not exceeded, there is little likelihood of fuel dispersal into the coolant. The pressure surge may therefore be calculated on the basis of conventional heat transfer from the fuel and prompt heat generation in the coolant.

The pressure surge is calculated by first performing the fuel heat transfer calculation to determine the average and hot spot heat flux versus time. Using this heat flux data, a THINC (Section 4.4) calculation is conducted to determine the volume surge. Finally, the volume surge is simulated in a plant transient computer code. This code calculates the pressure transient taking into account fluid transport in the reactor coolant system and heat transfer to the steam generators. No credit is taken for the possible pressure reduction caused by the assumed failure of the control rod pressure housing.

15.4.8.2.2 Calculation of Basic Parameters

Input parameters for the analysis are conservatively selected on the basis of values calculated for this type of core. The more important parameters are discussed below. Table 15.4.8-1 presents the parameters used in this analysis.

Ejected Rod Worths and Hot Channel Factors

The values for ejected rod worths and hot channel factors are calculated using either three dimensional static methods or by a synthesis method employing one dimensional and two dimensional calculations. Standard nuclear design codes are used in the analysis. No credit is taken for the flux flattening effects of reactivity feedback. The calculation is performed for the maximum allowed bank insertion at a given power level, as determined by the rod insertion limits. Adverse xenon distributions are considered in the calculation.

Appropriate margins are added to the ejected rod worth and hot channel factors to account for any calculational uncertainties, including an allowance for nuclear power peaking due to densification.

Power distributions before and after ejection for a "worst case" can be found in Reference 6. During plant startup physics testing, ejected rod worths and power distributions are measured in the zero and full power configurations and compared to values used in the analysis. It has been found that the ejected rod worth and power peaking factors are consistently overpredicted in the analysis.

Reactivity Feedback Weighting Factors

The largest temperature rises, and hence the largest reactivity feedbacks occur in channels where the power is higher than average. Since the weight of a region is dependent on flux, these regions have high weights. This means that the reactivity feedback is larger than that indicated by a simple channel analysis. Physics calculations have been carried out for temperature changes with a flat temperature distribution, and with a large number of axial and radial temperature distributions. Reactivity changes were compared and effective weighting factors determined. These weighting factors take the form of multipliers which when applied to single channel feedbacks correct them to effective whole core feedbacks for the appropriate flux shape. In this analysis, since a one dimensional (axial) spatial kinetics method is employed, axial weighting is not necessary if the initial condition is made to match the ejected rod configuration. In addition, no weighting is applied to the moderator feedback. A conservative radial weighting factor is applied to the transient fuel temperature to obtain an effective fuel temperature as a function of time accounting for the missing spatial dimension. These weighting factors have also been shown to be conservative compared to three dimensional analysis (Reference 6).

Moderator and Doppler Coefficient

The critical boron concentrations at the beginning of life and end of life are adjusted in the nuclear code in order to obtain moderator density coefficient curves which are conservative compared to actual design conditions for the plant. As discussed above, no weighting factor is applied to these results.

The Doppler reactivity defect is determined as a function of power level using a one dimensional steady-state computer code with a Doppler weighting factor of 1.0. The Doppler defect used is given in Section 15.0.4. The Doppler weighting factor will increase under accident conditions, as discussed above.

Delayed Neutron Fraction, β

Calculations of the effective delayed neutron fraction (β_{eff}) typically yield values no less than 0.70 percent at beginning of life and 0.50 percent at end of life for the first cycle. The accident is sensitive to β if the ejected rod worth is equal to or greater than β as in zero power transients. In order to allow for future cycles, pessimistic estimates of β of 0.55 percent at beginning of cycle and 0.44 percent at end of cycle were used in the analysis.

Trip Reactivity Insertion

The trip reactivity insertion assumed is given in Table 15.4.8-1 and includes the effect of one stuck RCCA. These values are reduced by the ejected rod reactivity. The shutdown reactivity was simulated by dropping a rod of the required worth into the core. The start of rod motion occurred 0.5 seconds after the high neutron flux trip point was reached. This delay is assumed to consist of 0.2 seconds for the instrument channel to produce a signal, 0.15 seconds for the trip breaker to open and 0.15 seconds for the coil to release the rods. A curve of trip rod insertion versus time was 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 re-actor pressure vessel head. The results show a rapid pressure drop and a de-crease 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.

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 rate of neutron flux increase trip. These protection functions are part of the Reactor Trip System. No single failure of the Reactor Trip 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 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.

The following conservative assumptions are used in the analysis of the release of radioactivity to the environment in the event of a postulated rod ejection accident. A summary of parameters used in the analysis is given in Table 15.4.8-2.

1. Ten percent of the gap activity is released to the containment atmosphere.

2. 50 percent of the iodines and 100 percent of the noble gases in the melted fuel are released.

3. 50 percent of the iodine released are deposited in the sump.

4. Annulus activity, which is exhausted prior to the time at which the annulus reaches a negative pressure of -0.25 in.w.g., is unfiltered.

5. ECCS leakage occurs at twice the maximum operational leakage.

6. ECCS leakage begins at the earliest possible time sump recirculation can begin.

7. Bypass leakage is 7 percent.

8. The effective annulus volume is 50 percent of the actual volume.

9. The annulus filters become fouled at 900 seconds resulting in a 15 percent reduction in flow.

10. Elemental iodine removal by the ice condenser begins at 600 seconds and continues for 3328.3 seconds with a removal efficiency of 30 percent.

11. One of the containment air return fans is assumed to fail.

12. The containment leak rate is fifty percent of the Technical Specifications limit after 1 day.

13. Iodine partition factor for ECCS leakage is 0.1 for the course of the accident.

14. No credit is taken for the auxiliary building filters for ECCS leakage.

15. The redundant hydrogen recombiners fail; therefore, purges are required for hydrogen control.

(The following assumptions apply to the secondary side analysis).

16. All the activity released is mixed instantaneously with the entire reactor coolant volume.

17. The primary to secondary leak rate is 1 gal/min.

18. The iodine partition factor is 0.1.

19. The steam release terminates in 120. seconds.

20. All noble gases which leak to the secondary side are released.

21. The primary and secondary coolant concentrations are at the maximum allowed by technical specifications.

Based on the foregoing model, the primary and secondary side releases may be calculated as well as the offsite doses. The doses, given in Table 15.4.8-2, are well below the limits of 25 rem whole body and 300 rem thyroid established in 10CFR100.

15.4.8.4 Conclusions

Even on a pessimistic basis, the analysis indicate that the described fuel and clad limits are not exceeded. It is concluded that there is no danger of sudden fuel dispersal into the coolant. Since the peak pressure does not exceed that which would cause stresses to exceed the faulted condition stress limits, it is concluded that there is no danger of further consequential damage to the Reactor Coolant System. The analyses have demonstrated that upper limit in fission product release as a result of a number of fuel rods entering DNB amounts to ten percent.

Parameters recommended for use in determining the radioactivity released to atmosphere for a rod ejection accident are given in Table 15.4.8-2. The Reactor Coolant System integrated break flow to Containment following a rod ejection accident is shown in Figure 15.4.8-5.

TABLE 15.0.6-1 (Page 2)

Trip Function	Limiting Trip Point Assumed In Analysis	Time Delays (Seconds)
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	0.0% ~~3.9%~~ of narrow range level span	2.0
High steam generator level trip of the feedwater pumps and closure of feedwater system valves, and turbine trip	93.6% of narrow range level span	2.0

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	7634
	Criticality occurs	13506
2. Dilution during cold shutdown	Dilution begins	0
	High flux at shutdown alarm occurs	2064
	Criticality occurs	3137
3. Dilution during hot shutdown	Dilution begins	0
	High flux at shutdown alarm occurs	2048
	Criticality occurs	3112
4a. Dilution during hot standby (w/o stuck rod)	Dilution begins	0
	High flux at shutdown alarm occurs	2977
	Criticality occurs	4553
4b. Dilution during hot standby (w/stuck rod)	Dilution begins	0
	High flux at shutdown alarm occurs	4002
	Criticality occurs	6233

TABLE 15.4.1-1 (Page 3)

Time Sequence of Events for Incidents which Cause Reactivity and Power Distribution Anomalies

Accident	Event	Time (sec.)
5. Dilution during startup	Power range low setpoint reactor trip due to dilution	0
	Criticality occurs (if dilution continues after trip)	1620
6. Dilution during full power operation		
a. Automatic reactor control	Operator receives low-low rod insertion limit alarm due to dilution	0
	Shutdown margin lost (if dilution continues after trip)	3900
b. Manual reactor control	Reactor trip setpoint reached for overtemperature ΔT	0
	Shutdown margin is lost (if dilution continues after trip)	1620
Rod Cluster Control Assembly Ejection		
1. Beginning-of-Life, Full Power	Initiation of rod ejection	0.0
	Power range high neutron flux setpoint reached	0.05
	Peak nuclear power occurs	0.14
	Rods begin to fall into core	0.55
	Peak fuel average temperature occurs	2.3
	Peak heat flux occurs	2.36
	Peak clad temperature occurs	2.37

TABLE 15.4.8-2 (Page 3)

Parameters for Postulated Rod Ejection Accident Analysis

		Conservative	Realistic
b.	Dose conversion assumptions	Regulatory Guides 1.4 and 1.109	same
c.	Doses (Rem)		
	Primary side		
	Exclusion area boundary		
	Whole body	5.1E-02	
	Thyroid	4.8	
	Low population zone		
	Whole body	1.1E-02	
	Thyroid	2.1	
	Secondary side		
	Exclusion area boundary		
	Whole body	3.3E-02	
	Thyroid	1.2	
	Low population zone		
	Whole body	1.1E-03	
	Thyroid	3.8E-02	

3. Annulus activity which is exhausted prior to the time at which the annulus reaches a negative pressure of -0.25 in.w.g. is unfiltered.

4. ECCS leakage begins at the earliest possible time sump recirculation can begin.

5. ECCS leakage occurs at twice the maximum operational leakage.

6. Bypass leakage is 7 percent.

7. The effective annulus volume is 50 percent of the actual volume.

8. The annulus filters become fouled at 900 seconds resulting in a 15 percent reduction in flow.

9. Elemental iodine removal by the ice condenser begins at 600 seconds and continues for 3328.3 seconds with a removal efficiency of 30 percent.

10. One of the containment air return fans is assumed to fail.

11. The containment leak rate is fifty percent of the Technical Specification limit after 1 day.

12. Iodine partition factor for ECCS leakage is 0.1 for the course of the accident.

13. No credit is taken for the auxiliary building filters for ECCS leakage.

14. The redundant hyrdogen recombiners fail; therefore, purges are required for hydrogen control.

The resulting offsite doses presented in Table 15.6.5-10 are below the limits of 25 rem whole body and 300 rem thyroid established in 10CFR100.

15.6.5.4.2 Control Room Operator Dose

The maximum postulated dose to a control room operator is determined based on the releases of a Design Basis Accident. In addition to the parameters and assumptions listed in Section 15.6.5.4.1, the following apply:

1. The control room pressurization rate is 4,000 cfm; the filtered recirculation rate is 2,000 cfm.

2. The unfiltered inleakage into the control room is 10 cfm.

3. Other assumptions are listed in Table 15.6.5-11.

TABLE 15.6.3-1

STEAM GENERATOR TUBE RUPTURE SEQUENCE OF EVENTS

Q 440.127

Event	Time (seconds)
Tube Rupture Occurs	0.0
Reactor Trip Signal	367.0
Rod Motion	369.0
Steam Generator Safety Valves Opened (assumed to stay open to maximize release)	376.0
Feedwater Terminated*	389.0
S.I. Signal	542.0
S.I. Injection	567.0
Auxiliary Feedwater Injection	602.0
Assumed that operator completes actions to isolate and equilibrate	1800.0

*The feedwater flow is throttled over 20 seconds using the FW flow control valve.

TABLE 15.6.5-10 (Page 3)

Parameters for Postulated Design Basis Accident Analysis

	Conservative	Realistic
c. Doses (Rem)		
Case 1 (With ECCS leakage)		
Exclusion Area Boundary		
Whole Body	3.0	
Thyroid	1.2E+02	
Low Population Zone		
Whole Body	7.6E-01	
Thyroid	5.1E+01	
Case 2 (Without ECCS leakage)		
Exclusion Area Boundary		
Whole Body	3.0	
Thyroid	1.0E+02	
Low Population Zone		
Whole Body	7.6E-01	
Thyroid	4.6E+01	

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	2.1E+01	
	Skin	9.0	

Response:

The isolation valves used for containment isolation of the process sampling lines are electric motor operated and therefore fail "as is." These valves are used in groups for each penetration with the isolation valves inside containment supplied by one train of safety related power while the valve outside containment receives power from the other train of safety related power. Both interior and exterior valves receive an appropriate automatic signal to close. Isolation of these lines is thus assured even with assumption of a single failure. This meets the intent of GDC60 in Appendix A to 10CFR50.

281.9 (1.9, II.B.3) Provide information that satisfies the attached proposed license conditions for post-accident sampling. (Attachment 281-1).

Response:

The Catawba Post Accident Liquid Sampling System is identical to the system reviewed and approved for the McGuire Nuclear Station (NUREG-0422) and meets the requirements of NUREG-0737, II.B.2 as discussed in the following response to Attachment 281-1:

1.0 Compliance With NUREG-0737

1.1 Each unit has a reactor coolant and a containment air sampling system. The basics of both systems are the same and both systems are remote controlled. A small sample is taken and diluted. A small portion of the diluted sample is saved, while the excess is flushed to a radwaste system. Total sampling time is approximately 1.5 hours.

1.2 a) Isotopic analysis is run at the station counting room using a portion of gas stripped from the liquid sample and diluted with inert gas and a portion of diluted liquid sample. The size of the samples and the dilution allows them to be handled and counted with the available equipment.

b) Hydrogen levels in the containment atmosphere can be determined by the hydrogen monitor located in the Auxiliary Building.

c) Dissolved gases are stripped from 150 ml pressurized sample and diluted to 1000 ml in the Post Accident Sampling Panel. The gas sample is then analyzed with a gas chromato-graph. Other gases as well as the H_2 can be determined. Results of tests performed on this function are described in the report transmitted by letter of June 28, 1982 from W. O. Parker, Jr. to H. R. Denton.

Chloride analysis can be performed on a diluted liquid sample by ion-chromatography. Currently a radiochemistry laboratory is being developed at the Physical Sciences Building to handle these analyses.

Boron is run on the diluted liquid sample by the carminic acid method.

d) In line monitoring capability as part of the sampling panel is used to determine pH and conductivity on the undiluted sample.

1.3 Reactor coolant and containment atmosphere sampling during post-accident conditions do not require an isolated auxiliary system to be placed in operation in order to use the sampling system.

1.4 Reactor coolant samples are depressurized in the sampling panel. Any gases released plus gases stripped from the sample are collected and diluted to a known volume. The diluted gas sample is then analyzed on a gas chromatograph where H_2 and O_2 are determined.

1.5 Capability of performing chloride analysis by ion-chromatography is available at the Power Chemistry Laboratory in the Physical Sciences Building of the Training and Technology facility located in Huntersville, N.C. A sample can be transported to this location and analyzed within 24 hours.

1.6 Radiation exposures are kept low through the use of distance and dilution of the sample. The sample panels are remotely controlled taking advantage of distance and the shielding of the walls. Liquid samples can be diluted 3000:1 and air samples can be diluted 10,000:1.

1.7 Boron analysis is performed on the diluted sample collected by the sampling panel. The amount of dilution is chosen to minimize radiation exposure. For the postulated 10 Ci/g extreme in the sample drawn, a 1:1000 dilution would provide protection below the 75 rem exposure to the analyst. With the limit of the carminic acid Boron Method of 0.1 ± .023 ppm, the minimum detectable concentration in the liquid sample would be 100 ± 23 ppm @ 1:1000 dilution.

1.8 Not applicable.

1.9 a) The post-accident sampling panels provide the capability to promptly obtain a liquid sample and a gas sample under reactor accident conditions as described in Regulatory Guides 1.3 or 1.4 and has the capability to dilute samples within the shield for measurement in order to reduce personnel exposure. The size of the samples and the dilution allows station personnel to analyze any liquid or gas sample with the available counting room equipment.

b) The health physics and chemistry laboratory facilities located in the Auxiliary Building provide the capability for prompt radioactivity spectrum analyses of noble gases, radioiodines, radiocesium, and non-volatile radionuclides. Highly radioactive samples are prepared at a sample preparation laboratory provided with sample shielding and a ventilation system to control airborne radioactivity. No difficulties are expected performing these analyses.

1.10 The report on Functional Testing of the Post Accident Liquid Sampling Panel (transmitted by letter of June 28, 1982 from W. O. Parker, Jr. to H. R. Denton) performed in the laboratory provides data on the accuracy, range, and sensitivity attainable by an operator. These are adequate to provide pertinent data for the radiological and chemical status of the systems sampled. Data on the accuracy, range and sensitivity attainable on the installed system will be collected during startup testing and will be documented in the Startup Report (Technical Specification 6.9).

1.11 All internal components of the air and liquid system and the sample lines are purged before the diluted samples are retrieved. The small line size in conjunction with an orifice will restrict reactor coolant flow in the event of a rupture. The size, length of line and number of bends have been kept to a minimum. Each air panel is vented to the stack vent.

2.0 Using distance and dilution, the exposure levels are kept low. The air sample is diluted 10,000:1 and the liquid samples are diluted 3,000:1. During sampling, the panels are controlled remotely.

3.0 Regulatory Guide 1.97 Revision 2 is under evaluation and a discussion of conformance will be provided in FSAR Section 1.8.

4.0 To comply with the requirements of NUREG-0737 Item II.B.3, Part 4 the Post Accident Sampling Panels (samplers) are powered from 240/120 VAC auxiliary control power system. This assures that all components associated with post accident sampling are capable of being operated within 30 minutes of an accident in which there is core degradation, and loss of offsite power assumed. Detailed description of the 240/120 VAC auxiliary power system is presented in FSAR Section 8.3.2.1.1.2.

430.18 (8.3) Explicitly identify all non-Class 1E electrical loads which are or may be powered from the Class 1E a-c and d-c systems. Also, for each load identified, provide the horsepower or kilowatt rating for that load and identify the corresponding bus number from which the load is powered.

Response:

See revised Section 8.3.1.1.2.2. Table 8.3.1-1, Sheets 2, 3 and 4 have been revised to show that the following non-Class 1E loads would be disconnected if an accident signal were initiated:

AC Emergency Lighting Panelboard
Hydrogen Ignitor Panelboard
Diesel Generator Engine Jacket Water Heater
Diesel Generator Engine Lube Oil Sump Tank Heater
Diesel Generator Engine Lube Oil Transfer Pump Motor

Each Diesel Generator is provided with a fuel oil booster pump motor which may be connected to its associated d-c system for maintenance purposes; however, it will be disconnected during normal operation.

430.19 (8.3.1.1) In Section 8.3.1.1.3.4 of the FSAR you state that the setpoint of the diesel generator overspeed trip is above the maximum engine speed on a full-load rejection. Provide the full load engine speed and maximum safe engine speed. In accordance with position C.4 of Regulatory Guide 1.9 verify that, during recovery from transients caused by step load increases or resulting from the disconnection of the largest single load, the speed of the diesel generator unit does not exceed the nominal speed plus 75 percent of the difference between nominal speed and the overspeed trip setpoint or 115 percent of nominal, whichever is lower.

Response:

See revised Section 8.3.1.1.3.4.

430.20 (8.3.1.1) Section 8.3.1.1.3.5 of the FSAR states that the load shedding feature for the Class 1E buses will remain blocked following load sequencing until the load sequencer is manually reset or diesel engine speed decreases below approximately 44%. Branch Technical Position PSB-1 in the Standard Review Plan (NUREG 0-800) requires automatic reinstatement of the load shedding feature upon completion of load sequencing. Your present design is not acceptable since it will not automatically result in load shedding upon trip of the diesel generator circuit breaker when there is no loss of diesel generator frequency.

Response:

See revised Section 8.3.1.1.3.5.

430.21 (8.3.1.1) Section 8.3.1.1.3.1 of the FSAR describes what happens when an undervoltage safety injection actuation signal is received during test of the diesel generator, but it does not describe what occurs for a loss of offsite power (LOOP).

Normally, during periodic testing of diesel generator, the diesel generator is paralleled with the offsite power system. During such a test, should a LOOP occur, a LOOP signal would probably not be generated because the D/G would attempt to provide power to the bus and to the offsite system through the closed offsite power feedbreaker. In this case, the D/G breaker will trip on overcurrent or underfrequency and in some designs the D/G breaker also locks out for this condition. To assure the continued availability of the D/G unit it is essential that the diesel generator breaker should not be locked out for such overload conditions. At the same time, the governor is shifted automatically from droop to isochronous mode and the voltage regulator to automatic mode. With the above actions complete, the diesel generator unit will be ready to accept its required load for LOOP conditions.

Verify that your Catawba diesel generator control design complies with the above.

Response:

See revised Section 8.3.1.1.3.1.

430.22 (8.3.1.1) Section 8.3.1.1.3.9 of the FSAR addresses prototype qualification testing of the Catawba diesel generator but it is not clear from the description that the testing was entirely in accordance with IEEE 387-1977 and Regulatory Guide 1.9. If the diesel generator is a type not previously qualified as a standby power source for nuclear power generating stations, it must undergo a prototype qualification test. Verify that the diesel generators for the Catawba plant have been prototype tested in accordance with IEEE 387-1977 as modified by NRC Regulatory Guide 1.9 and that these test results are available for inspection.

Response:

See revised Section 8.3.1.1.3.9.

Transamerica Delaval based qualification of 300 start test for the Catawba diesel generators on tests conducted in their facility using diesel generators for Middle South Energy's Grand Gulf Nuclear Power Station.

The following is a comparison of the main components used for the two sites:

1. Diesel engine - manufactured by Transamerica Delaval.

   The engine used in the qualification test was designed, manufactured and assembled to the same criteria as the engines for the Catawba plant. They are functionally identical.

2. Generators - manufactured by Parsons Peebles Electric Products.

   The generator used in the qualification test is electrically identical to the generator supplied for the Catawba Station. All specifications are identical for the two generators.

3. Governors - manufactured by Woodward Governor Co.

   The governor and booster used on the qualified engine is identical to that provided for the Catawba Station.

4. Voltage Regulator and Exciter - manufactured by Parson Peebles Electric Products.

   The voltage regulator - exciter systems are arranged differently on the test engine than that provided for the Catawba engine due to different contract specifications. However, the manufacturer has advised that the voltage regulator and exciter provided for the Catawba site are functionally identical to the equipment used on the test engine.

430.23 (8.3.1.1) Verify that the preoperational testing addressed in Section 8.3.1.1.3.10 of the FSAR conforms with positions C.2.a and C.2.b of Regulatory Guide 1.108.

a. Control Loads -

Essential Switchgear Control Power
Essential Load Center Control Power
Diesel Generator Load Sequencer Panel
Turbine Driven Auxiliary Feedwater Pump Control
Auxiliary Shutdown Panel Control

b. Diesel Generator Loads (Worst case) -

Field Flash
Engine Panel
Generator Panel

430.110 Section 10.4.4.1 of the FSAR indicates Catawba can accept up to 100% turbogenerator load reduction without tripping the reactor or main steam relief valve actuation. Since this allows the turbine generator to remain on line powering station loads following a loss of the offsite power system, describe the magnitude and effect of the transient and steady state voltage and frequency output of the main generator on the station loads (especially on Class 1E loads) starting with and following load reduction.

Response:

If the turbine generator is subjected to a 100% load reduction, the maximum voltage on the output of the generator is estimated to be approximately 129% of rated with the period of the excursion where voltage is above 110% of rated being approximately 3.2 seconds. The maximum frequency is estimated to be approximately 107.5% of rated. The minimum values of voltage and frequency do not exceed normal equipment ratings.

Per industry standards, power equipment such as 4 KV switchgear, 4160/600 V transformers, and 600 V switchgear is designed to withstand voltages in excess of 1.4 per unit for a duration of 60 seconds. Motors are typically subjected to hi-pot tests at 2150 volts for 575 volt motors, and 9000 volts for 4 KV motors for a duration of 60 seconds. Based on vendor information and test results, electronic equipment and control components are also capable of withstanding the transient following a 100% load rejection. The frequency excursion would result in a motor speed increase of 7½%; however, NEMA standards require that motors be designed to withstand overspeeds of 20% for short durations without damage.

The value above for maximum voltage is very conservative as it is based on initial conditions where the generator is operating 5% above rated voltage with a power factor of 0.9. Since the Catawba generators have a rated voltage approximately 5% higher than the connected transformers, the generators are not likely to be operated above rated voltage. It is also unlikely that the unit would be operating with a power factor below 0.95. Based on actual operating conditions, the maximum voltage should not exceed 122%.

Although the turbine generator is designed to accept a 100% load rejection, it is extremely unlikely that the unit will be subjected to a 100% load reduction while remaining on line powering station loads. This is especially the case since the unit is tied to the switchyard through two separate circuits which terminate in separate bays of a breaker-and-a-half arrangement.

Response:

Copies of approved test procedures for satisfying FSAR testing commitments will be made available for review by NRC regional personnel approximately 60 days prior to their intended use, and (for Unit 1) not less than 30 days prior to fuel loading for tests to be performed prior to the initial criticality and not less than 60 days prior to criticality for low power and power escalation testing, and (for Unit 2) not less than 60 days prior to fuel loading for startup testing.

640.6 (14.2.12) The initial test program should verify the capability of the off-site power system to serve as a source of power to the emergency buses. Tests should demonstrate the capability of each starting transformer to supply power (as the alternate supply) to its unit's emergency buses while carrying its maximum load of plant auxiliaries and the other unit's emergency buses (as perferred supply). Tests should also demonstrate the transfer capabilities of the unit's emergency bus feeders upon loss of one source of offsite power. These tests should be performed as early in the test program as the availability of necessary components allows. Provide descriptions of the tests that will demonstrate these capabilities.

Response:

The Unit Main Power System for each unit at Catawba, which connects the unit to the offsite power source, is described in Section 8.3. The Unit Main Power System does not utilize startup transformers. It is divided into two separate trains, each capable of supplying power to the unit 6.9 KV Auxiliary Power System. Each train contains one step-up transformer connecting the train to the 230 KV switchyard grid, and a pair of auxiliary transformers. During times when the main generator is not supplying power for in-house loads, power is supplied from the switchyard through the main step-up transformer to the pair of auxiliary transformers, to the 6.9 KV Auxiliary Power System, and on to the 4160 V vital buses. The unit main step-up transformer is sized to carry approximately one-half the full-load electrical output of the main generator, and will carry this load during normal operation. This adequately demonstrates it's ability to carry any necessary in-house loads during shutdown.

The capability of a pair of the auxiliary transformers to carry the unit's auxiliary load plus the unit emergency bus loads will be verified during the Electrical Load Capacity Test (refer to Table 14.2.12-1, page 40). This will assure that ample capacity is available with one pair of auxiliary transformers to carry one unit's engineered safety features for a DBA while supplying the loads required for a concurrent shutdown of the other unit.

The transfer of vital bus feeders upon loss of one source of offsite power will be verified during the 6900 Volt Auxiliary Power System Preoperational Test (refer to Table 14.2.12-1, page 41).

Response:

For potential for Cold Shutdown condition refer to Abstract Table 14.2.12-2, page 32 and 60.

640.33 (14.2.12.2) Your Rod Cluster Control Assembly Drop Time Test does not include retesting for drop times outside the two-sigma limit. Commit to retesting each RCCA outside this limit at least three times.

Response:

Please refer to revised Abstract, Table 14.2.12-2, page 6.

640.34 (14.2.12.2) Modify your RCCA drop time test acceptance criteria to include both hot zero power and cold temperature conditions, with both flow and no-flow conditions in the reactor coolant system in order to bound conditions under which scram might be required.

Response:

Please refer to revised Abstract, Table 14.2.12-2, page 6.

640.35 (14.2.12.2) Include demonstration of proper operating of dashpots (decelerating devices) to prevent mechanical damage during RCCA drop time testing.

Response:

Please refer to revised Abstract, Table 14.2.12-2, page 6.

640.36 (14.2.12.2) Reactor coolant system flow test must be expanded to include the following:

a) Establish that vibration levels are acceptable.

b) Determine that differential pressure across the fully loaded core and major reactor coolant system components are as predicted for all allowable combinations of pump operation.

c) Show that piping reactions to transients are as predicted.

Response:

As stated in Table 14.2.7-1, in the exception to Regulatory Guide 1.68, Revision 2, Appendix A 5.m, the differential pressure across the fully loaded core and major system components will be verified by monitoring reactor coolant flow rates during operation. Any gross differences in ΔP will be reflected by differences in observed flow rates.

1.i.2: The functional and closure time tests for containment isolation valves will be verified during the performance of the Engineered Safety Features Actuation System Functional Test (Abstract, Table 14.2.12-1, page 31). As stated in the Abstract, "Proper response of appropr ate systems and components to a containment isolation signal... is demonstrated... This testing provides response timing of valve and pump operation." In addition, individual functional testing and closure time measurements are performed for each containment isolation valve as a part of the inservice inspection program, in accordance with ASME Section XI, Article IWV.

1.i.8: This requirement is satisfied by the performance of the Engineered Safety Features Actuation System Functional Test (Abstract, Table 14.2.12-1, page 31). As stated in the abstract proper response to each of the three initiating signals will be verified, by demonstrating the initiation from the detector, through the logic to actuation of the components.

1.i.9: Refer to test Abstract for the Containment Purge Functional Test, Table 14.2.12-1, page 47.

1.i.10: The Catawba Nuclear Station design does not incorporate vacuum-breaker valves. The capability to provide air to the containment to relieve an underpressure situation is demonstrated by the Containment Air Release and Addition System Functional Test (Abstract, Table 14.2.12-1, page 48).

1.i.21: Please refer to the response to question 640.15.

1.j.3: The proper operation of the secondary system steam pressure controls will be demonstrated during the unit Reactor Coolant System Hot Functional Test, (Abstract, Table 14.2.12-1, page 3).

1.j.5: There is no RCS Leak Detection System at Catawba Nuclear Station. Technical Specification 3.4.6.1 lists systems or features used in the determination of Reactor Coolant system leakage, and Technical Specification 4.4.6.1 sets calibration and test requirements for these items. The calibrations and tests required by Technical Specification 4.4.6.1 will be performed prior to initial criticality. This will assure that the capability of the appropriate features necessary for the determination of reactor coolant system leakage has been verified, which is in line with the intent of Regulatory Guide 1.68, Revision 2, Appendix A, 1.j.5.

1.j.6: The testing to be performed on the Loose Parts Monitoring System is outlined in the response to question 492.1. This testing will be performed as a part of the normal plant surveillance program for periodic testing and calibration.

1.j.9: The testing of systems designed to maintain differential pressures to prevent leakage across boundaries as required

A-47 - Safety Implications of Control Systems

Control and safety systems at Catawba Nuclear Station have been designed with the goal of ensuring that control system failures will not prevent automatic or manual initiation and operation of any safety system equipment required for accident mitigation and/or to maintain the plant in a safe shutdown condition following any anticipated operational occurrence or accident. This has been accomplished by providing independence and physical separation between safety system trains/channels and between safety and non-safety systems. For the latter, as a minimum, isolation devices were provided. These devices preclude the propagation of non-safety system equipment faults to the protection systems. Also, to ensure that the operation of safety system equipment is not impared, the single failure criteria has been applied in the plant design.

Evaluation of control system design is being/has been done through design reviews as noted below:

1. IE Bulletin 79-27 is being addressed to insure that the loading of certain Class 1E power sources maintain the separation and independence of plant systems as designed. This bulletin is addressed in the response to ICSB question 420.01.

2. Accidents which could conceivably cause control system failures by creating a harsh environment in the area of the control equipment or by physically damaging the control equipment are being evaluated in response to IE Information Notice 79-22. This response will be included as the response to ICSB question 420.03.

3. Concern that a postulated accident might cause control system failures which would make the accident more severe than analyzed has prompted a review of such postulated failures. This response will be included as the response to ICSB question 420.04.

In addition to the reviews listed above, a wide range of bounding transients and accidents is presently being analyzed to assure that the postulated events such as steam generator overfill and overcooling events would be adequately mitigated by the safety systems. Further systematic reviews of safety systems are being performed with the goal of ensuring that control system failures will not defeat safety system action. These reviews are part of an ongoing evaluation program to qualify Class 1E plant equipment to function for all postulated service conditions to which it is subjected (NUREG-0588).

11 X 17 Figures

Remove These Pages	Insert These Pages
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TABLE 6.2.4-1

CONTAINMENT ISOLATION VALVE AND ACTUATOR DATA (PAGE 1)

Item Number	Service	Pen. No.	(1,17) Valve Arrangements	Nominal Line Size Inches	Flow Direction Relative to Containment	(7) Seismic Connections Inside	(7) Seismic Connections Outside	(6,15) Valve Number	(19) Valve Location	Type Valve & Size	(4,16) Type Actuator	(2,3) Actuation Signal	(2,3) Actuation Type	(4) Valve Position Normal	(4) Valve Position Failsafe	(4) Valve Position Shutdown	(4) Valve Position Post Accident	FSAR Figure No.	Vent And Drain For Type A Test	(18) Type C Leakage Test	Justification For Not Testing
01	Pressurizer Relief Tank Makeup	M216	B6	3	In	No	No	NC57	Inside	Check 3"	-	-	-	C	-	C	C	5.1-2	Yes	Yes (Note 42)	----
								NC56B	Outside	Gate 3"	E	T	A,R,M	C	AI	C	C				
02	Nitrogen to Pressurizer Relief Tank	M212	A1	1	In/Out	No	Yes	NC54A	Inside	Globe 1"	E	T	A,R,M	C	AI	C	C	5.1-2	Yes	Yes	----
								NC53B	Outside	Globe 1"	E	T	A,R,M	C	AI	C	C				
03	NC Pump Motor Drain Tank Pump Dischg.	M327	A4	2	Out	No	Yes	NC141	Inside	Gate 2"	HW	-	M	LC	AI	C	C	5.1-4	Yes	Yes	----
								NC142	Outside	Gate 2"	HW	-	M	LC	AI	C	C				
04	NV Letdown Line	M347	A6	2	Out	Yes	Yes	NV10A	Inside	Gate 2"	P	T	A,R	O	C	O	C	9.3.4-1	Yes	Yes (Note 42)	----
								NV11A	Inside	Gate 2"	P	T	A,R	C	C	C	C				
								NV13A	Inside	Gate 2"	P	T	A,R	C	C	C	C				
								NV15B	Outside	Globe 3"	E	T	A,R,M	O	AI	O	C				
								NV14	Inside	Relief 3"	-	600 PSIG	-	C	AI	C	C				
05	Pressurizer Aux. Spray Transient Line	M273	B2	1	In	Yes	Yes	NV861	Inside	Check 2"	-	-	-	C	-	C	C	9.3.4-1	No	No	(32)
								NV862	Outside	Globe 3"	HW	-	M	LC	-	O	C				
06	NV Charging Line	M330	B1	3	In	Yes	Yes	NV22	Inside	Check 3"	-	-	-	C	-	C	C	9.3.4-1	No	No	(33)
								NV314B	Outside	Gate 3"	E	S	A,R,M	O	AI	O	C				
07	NC Pump Seal Water Return	M256	A7	4	Out	Yes	Yes	NV89A	Inside	Gate 4"	E	T	A,R,M	O	AI	O	C	9.3.4-1	No (Note 43)	Yes (Note 42)	----
								NV90	Inside	Check 3/4"	-	-	-	C	-	-	-				
								NV91B	Outside	Gate 4"	E	T	A,R,M	O	AI	O	C				
08	NC Pump Seal Inj. Water 1A Supply	M343	D6	2	In	Yes	Yes	NV46	Inside	Check 2"	-	-	-	O	-	O	O	9.3.4-6	No	No	(44)
								NV44A	Outside	Globe 2"	E	-	-	O	AI	O	O				
09	NC Pump Seal Inj. Water 1B Supply	M339	D6	2	In	Yes	Yes	NV57	Inside	Check 2"	-	-	-	O	-	O	O	9.3.4-6	No	No	(44)
								NV55A	Outside	Globe 2"	E	-	-	O	AI	O	O				
10	NC Pump Seal Inj. Water 1C Supply	M344	D6	2	In	Yes	Yes	NV68	Inside	Check 2"	-	-	-	O	-	O	O	9.3.4-6	No	No	(44)
								NV66A	Outside	Globe 2"	E	-	-	O	AI	O	O				
11	NC Pump Seal Inj. Water 1D Supply	M350	D6	2	In	Yes	Yes	NV79	Inside	Check 2"	-	-	-	O	-	O	O	9.3.4-6	No	No	(44)
								NV77A	Outside	Globe 2"	E	-	-	O	AI	O	O				
12	Reactor Makeup Water Flush Header	M259	B1	1	In	No	No	NB262	Inside	Check 3/4"	-	-	-	C	-	-	-	9.3.5-6	Yes	Yes	----
								NB260B	Outside	Globe 1"	E	T	A,R,M	C	AI	C	C				
13	Ice Condenser Ice Blowing Air	M394	C4	5	In		Note 9	-	-	-	-	-	-	-	-	-	-	Not shown	No	Yes	----
14	Ice Condenser Ice Blowing Air	M395	C4	6	Out		Note 9	-	-	-	-	-	-	-	-	-	-	Not shown	No	Yes	----
		M371	C4	6	Out		Note 9	-	-	-	-	-	-	-	-	-	-				
15	Ice Condenser Glycol Pumps Dischg. Line	M373	B1	4	In	No	No	NF228A	Outside	Gate 4"	P	T	A,R	O	C	O	C	Not shown	No (Note 29)	Yes	----
								NF229	Inside	Check 4"	-	-	-	O	-	O	C				
16	Ice Condenser Glycol Pumps Suction Line	M372	A7	4	Out	No	No	NF233B	Inside	Gate 4"	E	T	A,R,M	O	AI	O	C	Not shown	No (Note 29)	Yes	----
								NF234A	Outside	Gate 4"	P	T	A,R	O	C	O	C				
								NF235	Inside	Check 1/2"	-	-	-	C	-	C	C				
17	Deleted																				
18	Deleted																				
19	Deleted																				
20	Containment Hydrogen Purge Inlet Blower Dischg. Line	M332	B1	4	In	Yes	No	VY15B	Outside	Gate 4"	E	T (14)	A,R,M	C	AI	C	C	6.2.5-3	Yes	Yes	----
								VY16	Inside	Check 4"	-	-	-	C	-	C	C				
21	Containment Hydrogen Purge Outlet Line	M346	A1	4	In	Yes	Yes	VY17A	Inside	Gate 4"	E	T (14)	A,R,M	C	AI	C	C	6.2.5-3	No (Note 29)	Yes	----
								VY18B	Outside	Gate 4"	E	T (14)	A,R,M	C	AI	C	C				

TABLE 6.2.4-1

CONTAINMENT ISOLATION VALVE AND ACTUATOR DATA (PAGE 7)

Item Number	Service	Pen. No.	(1,17) Valve Arrangements	Nominal Line Size Inches	Flow Direction Relative to Containment	(7) Seismic Connections Inside	Outside	(6,15) Valve Number	(19) Valve Location	Type Valve & Size		(4,16) Type Actuator	(2,3) Actuation Signal	Type	(4) Valve Position Normal	Failsafe	Shutdown	Post Accident	FSAR Figure No.	Vent And Drain For Type A Test	(18) Type C Leakage Test	Justification For Not Testing
22	ND Pump Suction A from Loop	M276	D5	12	Out	Yes	Yes	ND2A	Inside	Gate	12"	E	(10)	A,R,M	C	AI	O	C	5.4.7-1	No	No	(34)
								ND3	Inside	Relief	4"	-	450PSIG	-	C	-	C	C				
23	ND Pump Suction B from Loop	M315	D5	12	Out	Yes	Yes	ND37A	Inside	Gate	12"	E	(10)	A,R,M	C	AI	O	C	5.4.7-2	No	No	(34)
								ND38	Inside	Relief	4"	-	450PSIG	-	C	-	C	C				
24	Boron Inj. Tank Line to Cold Legs	M351	B4	4	In	No	Yes	NI9A	Outside	Gate	4"	E	S	A,R,M	C	AI	C	O	6.3.2-1	No	No	(35)
								NI10B	Outside	Gate	4"	E	S	A,R,M	C	AI	C	O				
								NI11	Inside	Globe	3/4"	D	-	R	C	C	C	C				
								NI12	Inside	Check	1"	-	-	-	C	-	C	C				
								NI3	Outside	Globe	1"	HW	-	M	C	C	C	C				
25	Nitrogen to Accumulators	M331	B1	1	In	No	No	NI48	Inside	Check	1"	-	-	-	C	-	C	C	6.3.2-2	Yes	Yes	----
								NI47A	Outside	Globe	1"	E	T	A,R,M	C	AI	C	C				
26	Safety Injection Test Line	M322	A1	3/4	In	No	No	NI95A	Inside	Globe	3/4"	E	T	A,R,M	C	AI	C	C	6.3.2-2	Yes	Yes	----
								NI96B	Outside	Globe	3/4"	E	T	A,R,M	C	AI	C	C				
								NI120B	Outside	Globe	3/4"	E	T	A,R,M	C	AI	C	C	6.3.2-3			
27	ND Crossover Dischg. to Hot Legs	M207	B5	12	In	No	Yes	NI154B	Inside	Globe	3/4"	E	T	A,R,M	C	AI	C	C	6.3.2-3	No	No	(39)
								NI183B	Outside	Gate	12"	E	-	R,M	C	AI	C	C/O				
								NI125	Inside	Check	8"	-	-	-	C	-	C	C/O				
								NI129	Inside	Check	8"	-	-	-	C	-	C	C/O				
28	NI Pump B Dischg. to Hot Legs	M320	B5	4	In	No	Yes	NI152B	Outside	Gate	4"	E	-	R,M	C	AI	C	C/O	6.3.2-3	No	No	(39)
								NI153A	Inside	Globe	3/4"	E	T	A,R,M	C	AI	C	C				
								NI156	Inside	Check	2"	-	-	-	C	-	C	C/O				
								NI159	Inside	Check	2"	-	-	-	C	-	C	C/O				
29	NI Pump A Dischg. to Hot Legs	M317	B5	4	In	No	Yes	NI121A	Outside	Gate	4"	E	-	R,M	C	AI	C	C/O	6.3.2-3	No	No	(39)
								NI122B	Inside	Globe	3/4"	E	T	A,R,M	C	AI	C	C				
								NI124	Inside	Check	2"	-	-	-	C	-	C	C/O				
								NI128	Inside	Check	2"	-	-	-	C	-	C	C/O				
30	ND HX A Dischg. to Cold Legs	M336	B5	8	In	No	Yes	NI173A	Outside	Gate	8"	E	-	R,M	O	AI	O	O	6.3.2-4	No	No	(39)
								NI174	Inside	Globe	3/4"	D	-	R,M	C	C	C	C				
								NI175	Inside	Check	6"	-	-	-	C	-	O	O				
								NI176	Inside	Check	6"	-	-	-	C	-	O	O				
31	ND HX B Dischg. to Cold Legs	M307	B5	8	In	No	Yes	NI178B	Outside	Gate	8"	E	-	R,M	O	AI	O	O	6.3.2-4	No	No	(39)
								NI179	Inside	Globe	3/4"	D	-	R,M	C	C	C	C				
								NI180	Inside	Check	6"	-	-	-	C	-	O	O				
								NI181	Inside	Check	6"	-	-	-	C	-	O	O				
32	NI Pumps A&B Dischg to Cold Legs	M352	B5	4	In	No	Yes	NI162A	Outside	Gate	4"	E	-	R,M	O	AI	C	O	6.3.2-4	No	No	(39)
								NI163	Inside	Globe	3/4"	D	-	R,M	C	C	C	C				
								NI165	Inside	Check	2"	-	-	-	C	-	C	O/C				
								NI167	Inside	Check	2"	-	-	-	C	-	C	O/C				
								NI169	Inside	Check	2"	-	-	-	C	-	C	O/C				
								NI171	Inside	Check	2"	-	-	-	C	-	C	O/C				
33	Containment Sump Recirc. Line A	M303	C1	18	Out	No	Yes	NI185A	Outside	Gate	18"	E	-	R,M	C	AI	C	C/O	6.3.2-4	No	No	(22)
34	Containment Sump Recirc. Line B	M210	C1	18	Out	No	Yes	NI184B	Outside	Gate	18"	E	-	R,M	C	AI	C	C/O	6.3.2-4	No	No	(22)
35	Upper Head Injection Line	M407	B1	12	In	Yes	Yes	NI245A	Outside	Gate	12"	E	(11)	A,R,M	O	AI	C	O/C	6.3.2-5	No	No	(36)

TABLE 6.2.4-1

CONTAINMENT ISOLATION VALVE AND ACTUATOR DATA (PAGE 3)

Item Number	Service	Pen. No.	(1,17) Valve Arrangements	Nominal Line Size Inches	Flow Direction Relative to Containment	(7) Seismic Connections Inside	Outside	(6,15) Valve Number	(19) Valve Location	Type Valve & Size	(4,16) Type Actuator	(2,3) Actuation Signal	Type	(4) Valve Position Normal	Failsafe	Shutdown	Post Accident	FSAR Figure No.	Vent And Drain For Type A Test	(18) Type C Leakage Test	Justification For Not Testing
								NI255B	Outside	Globe 2"	E	T	A,R,M	C	AI	C	C				
								NI249	Inside	Check 12"	-	-	-	C	-	C	O/C				
36	Upper Head Injection Line	M406	B1	12	In	Yes	Yes	NI258A	Outside	Globe 3/4"	E	T	A,R,M	C	AI	C	C	6.3.2-5	No	No	(36)
								NI243A	Outside	Gate 12"	E	(11)	A,R,M	O	AI	C	O/C				
								NI248	Inside	Check 12"	-	-	-	C	-	C	O/C				
37	Upper Head Injection Test Line	M454	A6	2	In	No	No	NI266A	Inside	Globe 2"	E	T	A,R,M	C	AI	C	C	6.3.2-5	Yes	Yes	----
								NI267A	Inside	Globe 2"	E	T	A,R,M	C	AI	C	C				
								NI264B	Outside	Globe 2"	E	T	A,R,M	C	AI	C	C				
								NI336	Inside	Relief 2"	-	2485 PSIG	-	C	-	C	C				
38	Containment Spray Line	M362	B1	8	In	Yes	Yes	NS32A	Outside	Gate 8"	E	P	A,R,M	C	AI	C	O	6.2.2-1	No	No	(45)
								NS33	Inside	Check 8"	-	-	-	C	-	C	O				
39	Containment Spray Line	M370	B1	8	In	Yes	Yes	NS29A	Outside	Gate 8"	E	P	A,R,M	C	AI	C	O	6.2.2-1	No	No	(45)
								NS30	Inside	Check 8"	-	-	-	C	-	C	O				
40	Containment Spray Line	M380	B1	8	In	Yes	Yes	NS15B	Outside	Gate 8"	E	P	A,R,M	C	AI	C	O	6.2.2-1	No	No	(45)
								NS16	Inside	Check 8"	-	-	-	C	-	C	O				
41	Containment Spray Line	M387	B1	8	In	Yes	Yes	NS12B	Outside	Gate 8"	E	P	A,R,M	C	AI	C	O	6.2.2-1	No	No	(45)
								NS13	Inside	Check 8"	-	-	-	C	-	C	O				
42	ND Containment Spray Line A	M369	B1	8	In	Yes	Yes	NS43A	Outside	Gate 8"	E	-	R,M	C	AI	C	C/O	6.2.2-1	No	No	(45)
								NS46	Inside	Check 8"	-	-	-	C	-	C	C/O				
43	ND Containment Spray Line B	M381	B1	8	In	Yes	Yes	NS38B	Outside	Gate 8"	E	-	R,M	C	AI	C	C/O	6.2.2-1	No	No	(45)
								NS41	Inside	Check 8"	-	-	-	C	-	C	C/O				
44	Reactor Coolant Drain Tank Gas Space to WG System	M348	A1	3/4	In/Out	No	No	WL450A	Inside	Globe 3/4"	E	T	A,R,M	O	AI	O	C	11.2.2-9	Yes	Yes	----
								WL451B	Outside	Globe 3/4"	E	T	A,R,M	O	AI	O	C				
45	Reactor Coolant Drain Tank Heat Exchanger Dischg.	M345	A9	3	Out	No	Yes	WL805A	Inside	Gate 3"	E	T	A,R,M	O	AI	O	C	11.2.2-9	No (Note 43)	Yes (Note 42)	
								WL807B	Outside	Gate 3"	E	T	A,R,M	O	AI	O	C				
								WL806	Inside	Check 1/2"	-	-	-	C	-	C	C				
46	Ventilation Unit Condensate Drain Hdr	M221	A9	6	Out	No	No	WL867A	Inside	Gate 4"	E	P (14)	A,R,M	O	AI	O	C	11.2.2-10	No (Note 43)	Yes (Note 42)	----
								WL869B	Outside	Gate 4"	E	P (14)	A,R,M	O	AI	O	C				
								WL868	Inside	Check 1"	-	-	-	C	-	C	C				
47	Cont. Floor Sump and Incore Instrumentation Sump Pump Dischg.	M374	A9	4	Out	No	No	WL825A	Inside	Gate 4"	E	T (14)	A,R,M	O	AI	O	C	11.2.2-13	No (Note 43)	Yes (Note 42)	
								WL827B	Outside	Gate 4"	E	T (14)	A,R,M	O	AI	O	C				
								WL321	Inside	Check 3/4"	-	-	-	C	-	C	C				
48	Steam Generator Drain Pump Dischg.	M359	A9	3	Out	No	No	WLA21	Inside	Gate 3"	HW	-	M	LC	-	C	C	11.2.2-15	No (Note 43)	Yes (Note 42)	
								WLA22	Inside	Check 3/4"	-	-	M	C	-	C	C				
								WLA24	Outside	Gate 3"	HW	-	M	LC	-	C	C				
49	Equipment Decontamination Line (Note 13)	M356	A4	1	In	No	No	WE20	Outside	Globe 1"	HW	-	M	LC	-	C	C	Not Shown	Yes	Yes	----
								WE22	Inside	Globe 1"	HW	-	M	LC	-	C	C				
50	Fuel Transfer Tube	C354	C2	24	None	Yes	Yes	-	Inside	Double Seal	-	-	M	C	-	O	C	9.1.3-1	No	No	(27)
								-	Inside	Blind Flange	-	-	-	-	-	-	-				
51	Refueling Water Pump Suction	M358	A4	4	Out	Yes	No	FW11	Inside	Plug 4"	HW	-	M	LC	-	C	C	9.2.7-1	Yes	Yes	----
								FW13	Outside	Plug 4"	HW	-	M	LC	-	C	C				
52	Refueling Cavity Fill Line	M377	B2	6	In	Yes	No	FW4	Outside	Gate 6"	HW	-	M	LC	-	C/O	C	9.2.7-1	Yes	Yes	----
								FW5	Inside	Check 6"	-	-	-	C	-	C/O	C				
53	Pressurizer Sample	M235	A6	1/2	Out	Yes	No	NM3A	Inside	Globe 1/2"	E	T	A,R,M	O	AI	O	C	9.3.2-1	Yes	Yes	----
								NM6A	Inside	Globe 1/2"	E	T	A,R,M	C	AI	C	C				

TABLE 6.2.4-1

CONTAINMENT ISOLATION VALVE AND ACTUATOR DATA (PAGE 4)

Item Number	Service	Pen. No.	(1,17) Valve Arrangements	Nominal Line Size Inches	Flow Direction Relative to Containment	(7) Seismic Connections Inside	Outside	(6,15) Valve Number	(19) Valve Location	Type Valve & Size	(4,16) Type Actuator	(2,3) Actuation Signal	Type	(4) Valve Position Normal	Failsafe	Shutdown	Post Accident	FSAR Figure No.	Vent And Drain For Type A Test	(18) Type C Leakage Test	Justification For Not Testing
								NM67	Inside	Relief 3/4"	-	2485 PSIG	-	C	-	C	C				
								NM78	Outside	Globe 1/2"	E	T	A,R,M	C	AI	C	C				
54	Reactor Coolant Hot Leg Sample	M310	A6	1/2	Out	Yes	Yes	NM22A	Inside	Globe 1/2"	E	T	A,R,M	O	AI	O	C	9.3.2-1	Yes	Yes	----
								NM25A	Inside	Globe 1/2"	E	T	A,R,M	C	AI	C	C				
								NM26B	Outside	Globe 1/2"	E	T	A,R,M	C	AI	C	C				
								NM68	Inside	Relief 3/4"	-	2485 PSIG	-	C	-	C	C				
55	Safety Injection Accumulator Sample	M236	A6	1/2	Out	Yes	No	NM72B	Inside	Globe 1/2"	E	T	A,R,M	C	AI	C	C	9.3.2-2	Yes	Yes	----
								NM75B	Inside	Globe 1/2"	E	T	A,R,M	C	AI	C	C				
								NM78B	Inside	Globe 1/2"	E	T	A,R,M	C	AI	C	C				
								NM81B	Inside	Globe 1/2"	E	T	A,R,M	C	AI	C	C				
								NM69	Inside	Relief 3/4"	-	700 PSIG	-	C	-	C	C				
								NM62A	Outside	Globe 1/2"	E	T	A,R,M	C	AI	C	C				
56	Steam Generator 1A Sample	M335	A6	1/2	Out	Yes	No	NM187A	Inside	Globe 1/2"	E	T	A,R,M	C	AI	C	C	9.3.2-5	No	No	(23)
								NM190A	Inside	Globe 1/2"	E	T	A,R,M	O	AI	O	C				
								NM191B	Outside	Globe 1/2"	E	T	A,R,M	O	AI	O	C				
								NM255	Inside	Relief 3/4"	-	1185 PSIG	-	C	-	C	C				
57	Steam Generator 1B Sample	M338	A6	1/2	Out	Yes	No	NM197B	Inside	Globe 1/2"	E	T	A,R,M	C	AI	C	C	9.3.2-5	No	No	(23)
								NM200B	Inside	Globe 1/2"	E	T	A,R,M	O	AI	O	C				
								NM201A	Outside	Globe 1/2"	E	T	A,R,M	O	AI	O	C				
								NM256	Inside	Relief 3/4"	-	1185 PSIG	-	C	-	C	C				
58	Steam Generator 1C Sample	M340	A6	1/2	Out	Yes	No	NM207A	Inside	Globe 1/2"	E	T	A,R,M	C	AI	C	C	9.3.2-5	No	No	(23)
								NM210A	Inside	Globe 1/2"	E	T	A,R,M	O	AI	O	C				
								NM211B	Outside	Globe 1/2"	E	T	A,R,M	O	AI	O	C				
								NM257	Inside	Relief 3/4"	-	1185 PSIG	-	C	-	C	C				
59	Steam Generator 1D Sample	M341	A6	1/2	Out	Yes	No	NM217B	Inside	Globe 1/2"	E	T	A,R,M	C	AI	C	C	9.3.2.5	No	No	(23)
								NM220B	Inside	Globe 1/2"	E	T	A,R,M	O	AI	O	C				
								NM221A	Outside	Globe 1/2"	E	T	A,R,M	O	AI	O	C				
								NM258	Inside	Relief 3/4"	-	1185 PSIG	-	C	-	C	C				
60	Component Cooling to RC Drain Tank HX	M376	B6	4	In	Yes	Yes	KC322	Inside	Check 4"	-	-	-	O	-	O	C	9.2.2-4	No	No	(37)
								KC320A	Outside	Gate 4"	E	T	A,R,M	O	AI	O	C				
61	Component Cooling from Drain Tank HX	M355	A9	4	Out	Yes	Yes	KC332B	Inside	Gate 4"	-	T	A,R,M	O	AI	O	C	9.2.2-4	No	No	(37)
								KC280	Inside	Check 1"	-	-	-	C	-	C	C				
								KC133A	Outside	Gate 4"	E	T	A,R,M	O	AI	O	C				
62	Component Cooling to Reactor Vessel Support & RCP Coolers	M328	B6	8	In	Yes	Yes	KC138B	Outside	Gate 8"	E	P	A,R,M	O	AI	O	C	9.2.2-4	No	No	(37)
								KC340	Inside	Check 8"	-	-	-	O	-	O	C				
63	Component Cooling from Reactor Vessel Support & RCP Coolers	M321	A9	8	Out	Yes	Yes	KC424B	Inside	Gate 8"	E	P	A,R,M	O	AI	O	C	9.2.2-4	No	No	(37)
								KC425A	Outside	Gate 8"	E	P	A,R,M	O	AI	O	C				
								KC279	Inside	Check 1"	-	-	-	C	-	C	C				
64	Component Cooling to Excess Letdown HX	M218	B2	4	In	Yes	Yes	KC305B	Outside	Gate 4"	E	T	A,R,M	C	AI	C	C	9.2.2-4	No	No	(37)
65	Component C[illegible]ng from Excess Letdown HX	M217	B2	4	Out	Yes	Yes	KC315B	Outside	Gate 4"	E	T	A,R,M	C	AI	C	C	9.2.2-4	No	No	(37)
66	Component Cooling to Component Cooling Drain Sump	M323	A7	2	Out	No	Yes	KC47	Inside	Check 3/4"	-	-	-	C	-	C	C	9.2.2-6	Yes	Yes	----
								KC429B	Inside	Globe 2"	E	T	A,R,M	O	AI	O	C				
								KC430A	Outside	Globe 2"	E	T	A,R,M	O	AI	O	C				

TABLE 6.2.4-1

CONTAINMENT ISOLATION VALVE AND ACTUATOR DATA (PAGE 5)

Item Number	Service	Pen. No.	(1,17) Valve Arrangements	Nominal Line Size Inches	Flow Direction Relative to Containment	(7) Seismic Connections Inside	(7) Seismic Connections Outside	(6,15) Valve Number	(19) Valve Location	Type Valve & Size	(2,3) Actuation Signal	(2,3) Actuation Type	(4) Valve Position Normal	(4) Valve Position Failsafe	(4) Valve Position Shutdown	(4) Valve Position Post Accident	FSAR Figure No.	Vent And Drain For Type A Test	(18) Type C Leakage Test	Justification For Not Testing
67	Nuclear Service Wtr. to NC Pump and Lower Cont. Vent. Units	M240	B6	12	In	Yes	Yes	RN437B	Outside	Gate 12"	P	A,R,M	O	AI	O	C	9.2.1-6	Yes	Yes (Note 42)	----
								RN438	Inside	Check 12"	-	-	O	-	O	C				
68	Nuclear Service Wtr. from NC Pump and Lower Cont Vent Units	M230	A9	12	Out	Yes	Yes	RN484A	Inside	Gate 12"	P	A,R,M	O	AI	O	C	9.2.1-7	No (Note [illegible]	Yes (Note 42)	----
								RN487B	Outside	Gate 12"	P	A,R,M	O	AI	O	C				
								RN485	Inside	Check 3/4"	-	-	C	-	C	C				
69	Nuclear Service Wtr. to Upper Cont. Vent. Units	M385	B6	6	In	Yes	Yes	RN404B	Outside	Gate 6"	P	A,R,M	O	AI	O	C	9.2.1-7	Yes	Yes (Note 42)	----
								RN405	Inside	Check 6"	-	-	O	-	O	C				
70	Nuclear Service Wtr. from Upper Cont. Vent. Units	M308	A9	6	Out	Yes	Yes	RN429A	Inside	Gate 6"	P	A,R,M	O	AI	O	C	9.2.1-6	No (Note 43)	Yes (Note 42)	----
								RN432B	Outside	Gate 6"	P	A,R,M	O	AI	O	C				
								RN430	Inside	Check 3/4"	-	-	C	-	C	C				
71	Incore Instrumentation Rm. Purge In	M213	A5	12	In	Yes	No	VP17A	Inside	Butterfly 12"	T (14)	A,R	C	C	C	C	9.4.5-1	Yes	Yes	----
								VP18B	Outside	Butterfly 12"	T (14)	A,R	LC	C	C	C				
72	Incore Instrumentation Rm. Purge Out	M140	A5	12	Out	Yes	Yes	VP19A	Inside	Butterfly 12"	T (14)	A,R	C	C	C	C	9.4.5-1	Yes	Yes	----
								VP20B	Outside	Butterfly 12"	T (14)	A,R	LC	C	C	C				
73	Upper Compartment Purge Inlet	M456	A5	24	In	Yes	No	VP1B	Outside	Butterfly 24"	T (31)	A,R	C	C	C	C	9.4.5-1	Yes	Yes	----
								VP2A	Inside	Butterfly 24"	T (31)	A,R	C	C	C	C				
74	Upper Compartment Purge Inlet	M432	A5	24	In	Yes	No	VP3B	Outside	Butterfly 24"	T (31)	A,R	C	C	C	C	9.4.5-1	Yes	Yes	----
								VP4A	Inside	Butterfly 24"	T (31)	A,R	C	C	C	C				
75	Lower Compartment Purge Inlet	M357	A5	24	In	Yes	No	VP6B	Outside	Butterfly 24"	T (31)	A,R	LC	C	C	C	9.4.5-1	Yes	Yes	----
								VP7A	Inside	Butterfly 24"	T (31)	A,R	C	C	C	C				
76	Lower Compartment Purge Inlet	M434	A5	24	In	Yes	No	VP8B	Outside	Butterfly 24"	T (31)	A,R	LC	C	C	C	9.4.5-1	Yes	Yes	----
								VP9A	Inside	Butterfly 24"	T (31)	A,R	C	C	C	C				
77	Containment Purge Exhaust	M368	A5	24	Out	Yes	Yes	VP10A	Inside	Butterfly 24"	T (31)	A,R	C	C	C	C	9.4.5-1	Yes	Yes	----
								VP11B	Outside	Butterfly 24"	T (31)	A,R	C	C	C	C				
78	Containment Purge Exhaust	M433	A5	24	Out	Yes	Yes	VP12A	Inside	Butterfly 24"	T (31)	A,R	C	C	C	C	9.4.5-1	Yes	Yes	----
								VF13B	Outside	Butterfly 24"	T (31)	A,R	C	C	C	C				
79	Containment Purge Exhaust	M119	A5	24	Out	Yes	Yes	VP15A	Inside	Butterfly 24"	T (31)	A,R	C	C	C	C	9.4.5-1	Yes	Yes	----
								VP16B	Outside	Butterfly 24"	T (31)	A,R	LC	C	C	C				
80	Steam Generator 1D Blowdown	M455	A7	4	Out	Yes	Yes	BB8A	Inside	Gate 4"	T	A,R,M	O	AI	C	C	10.4.8-1	No	No	(23)
								BB10B	Outside	Gate 4"	T	A,R,M	O	AI	C	C				
								BB52	Inside	Check 3/4"	-	-	C	-	C	C				
								BB147B	Outside	Globe 1"	T	A,R,M	C	AI	C	C				
81	Steam Generator 1A Blowdown	M142	A7	4	Out	Yes	Yes	BB56A	Inside	Gate 4"	T	A,R,M	O	AI	C	C	10.4.8-1	No	No	(23)
								BB57B	Outside	Gate 4"	T	A,R,M	O	AI	C	C				
								BB53	Inside	Check 3/4"	-	-	C	-	C	C				
								BB148B	Outside	Globe 1"	T	A,R,M	C	AI	C	C				
82	Steam Generator 1C Blowdown	M3105	A7	4	Out	Yes	Yes	BB60A	Inside	Gate 4"	T	A,R,M	O	AI	C	C	10.4.8-1	No	No	(23)
								BB61B	Outside	Gate 4"	T	A,R,M	O	AI	C	C				
								BB54	Inside	Check 3/4"	-	-	C	-	C	C				
								BB149B	Outside	Globe 1"	T	A,R,M	C	AI	C	C				
83	Steam Generator 1B Blowdown	M277	A7	4	Out	Yes	Yes	BB19A	Inside	Gate 4"	T	A,R,M	O	AI	C	C	10.4.8-1	No	No	(23)
								BB21B	Outside	Gate 4"	T	A,R,M	O	AI	C	C				
								BB55	Inside	Check 3/4"	-	-	C	-	C	C				
								BB150B	Outside	Globe 1"	T	A,R,M	C	AI	C	C				

TABLE 6.2.4-1

CONTAINMENT ISOLATION VALVE AND ACTUATOR DATA (PAGE 6)

Item Number	Service	Pen. No.	(1,17) Valve Arrangements	Nominal Line Size Inches	Flow Direction Relative to Containment	(7) Seismic Connections Inside	Outside	(6,15) Valve Number	(19) Valve Location	Type Valve & Size	(4,16) Type Actuator	(2,3) Actuation Signal	Type	(4) Valve Position Normal	Failsafe	Shutdown	Post Accident	FSAR Figure No.	Vent And Drain For Type A Test	(18) Type C Leakage Test	Justification For Not Testing
84	Containment Air Release	M386	A5	4	Out	Yes	No	VQ2A	Inside	Diaphragm 4"	D	T (14)	A,R,M	C	C	C	C	9.5.9-1	Yes	Yes	----
								[illegible]	Outside	Gate 4"	E	T (14)	A,R,M	C	AI	C	C				
85	Containment Air Addition	M204	A5	4	In	Yes	No	VQ15B	Outside	Gate 4"	E	T (14)	A,R,M	C	AI	C	C	9.5.9-1	No (Note 29)	Yes	----
								VQ16A	Inside	Diaphragm 4"	D	T (14)	A,R,M	C	C	C	C				
86	Feedwater 1A	M110	D1	18	In	Yes	No	CF33	Outside	Gate 18"	H	S	A,R	O	C	C	C	10.4.7-11	No	No	(23)
								CF91	Outside	Globe 3/4"	HW	-	-	LC	-	C	C				
								CF90	Outside	Gate 2"	D	S	A,R	C	C	C	C				
87	Feedwater 1B	M262	D1	18	In	Yes	No	CF42	Outside	Gate 18"	H	S	A,R	O	C	C	C	10.4.7-10	No	No	(23)
								CF93	Outside	Globe 3/4"	HW	-	-	LC	-	C	C				
								CF89	Outside	Gate 2"	D	S	A,R	C	C	C	C				
88	Feedwater 1C	M309	D1	18	In	Yes	No	CF51	Outside	Gate 18"	H	S	A,R	O	C	C	C	10.4.7-10	No	No	(23)
								CF95	Outside	Globe 3/4"	HW	-	-	LC	-	C	C				
								CF88	Outside	Gate 2"	D	S	A,R	C	C	C	C				
89	Feedwater 1D	M422	D1	18	In	Yes	No	CF60	Outside	Gate 18"	H	S	A,R	O	C	C	C	10.4.7-10	No	No	(23)
								CF97	Outside	Globe 3/4"	HW	-	-	LC	-	C	C				
								CF87	Outside	Gate 2"	D	S	A,R	C	C	C	C				
90	Aux. Feedwater 1A	M143	D1	4	In	Yes	Yes	CA62A	Outside	Gate 4"	E	M	R,M	O	AI	O	O	10.4.9-2	No	No	(23)
								CA66B	Outside	Gate 4"	E	M	R,M	O	AI	O	O				
								CA121	Outside	Globe 3/4"	HW	-	-	LC	-	C	C				
								CA149	Outside	Gate 4"	P	S	A,R	C(12)	C	C	C				
								BW1	Outside	Gate 2"	HW	-	-	LC	-	C	C	Not shown			
								CA185	Outside	Gate 2"	P	S	A,R	O	C	C	C				
91	Aux. Feedwater 1B	M278	D1	4	In	Yes	Yes	CA54B	Outside	Gate 4"	E	M	R,M	O	AI	O	O	10.4.9-10	No	No	(23)
								CA58A	Outside	Gate 4"	E	M	R,M	O	AI	O	O				
								CA120	Outside	Globe 3/4"	HW	-	-	LC	-	C	C				
								CA150	Outside	Gate 4"	P	S	A,R	C(12)	C	C	C				
								BW26	Outside	Gate 2"	HW	-	-	LC	-	C	C	Not shown			
								CA186	Outside	Gate 2"	P	S	A,R	O	C	C	C				
92	Aux. Feedwater 1C	M3106	D1	4	In	Yes	Yes	CA46B	Outside	Gate 4"	E	M	R,M	O	AI	O	O	10.4.9-2	No	No	(23)
								CA50A	Outside	Gate 4"	E	M	R,M	O	AI	O	O				
								CA119	Outside	Globe 3/4"	HW	-	-	LC	-	C	C				
								CA151	Outside	Gate 4"	P	S	A,R	C (12)	C	C	C				
								BW17	Outside	Gate 2"	HW	-	-	LC	-	C	C	Not shown			
								CA187	Outside	Gate 2"	P	S	A,R	O	C	C	C				
93	Aux. Feedwater 1D	M457	D1	4	In	Yes	Yes	CA38A	Outside	Gate 4"	E	M	R,M	O	AI	O	O	10.4.9-2	No	No	(23)
								CA42B	Outside	Gate 4"	E	M	R,M	O	AI	O	O				
								CA118	Outside	Globe 3/4"	HW	-	-	LC	-	C	C				
								CA152	Outside	Gate 4"	P	S	A,R	C (12)	C	C	C				
								BW10	Outside	Gate 2"	HW	-	-	LC	-	C	C	Not shown			
								CA188	Outside	Gate 2"	P	S	A,R	O	C	C	C				

TABLE 6.2.4-1

CONTAINMENT ISOLATION VALVE AND ACTUATOR DATA (PAGE 7)

Item Number	Service	Pen. No.	(1,17) Valve Arrangements	Nominal Line Size Inches	Flow Direction Relative to Containment	(7) Seismic Connections Inside	Outside	(6,15) Valve Number	(19) Valve Location	Type Valve & Size	(4,16) Type Actuator	(2,3) Actuation Signal	Type	(4) Valve Position Normal	Failsafe	Shutdown	Post Accident	FSAR Figure No.	Vent And Drain For Type A Test	(18) Type C Leakage Test	Justification For Not Testing
94	Main Steam 1A	M113	D3	34	Out	Yes	Yes	SM7	Outside	Gate 34"	P	P	A,R	O	C	O	C	10.3.2-1	No	No	(23)
								SV20	Outside	Safety 6"	-	1175 PSIG	-	C	-	C	C				
								SV21	Outside	Safety 6"	-	1190 PSIG	-	C	-	C	C				
								SV22	Outside	Safety 6"	-	1205 PSIG	-	C	-	C	C				
								SV23	Outside	Safety 6"	-	1220 PSIG	-	C	-	C	C				
								SV24	Outside	Safety 6"	-	1230 PSIG	-	C	-	C	C				
								SV19	Outside	Globe 6"	D	P	A,R	C	C	C	C				
								SM12	Outside	Globe 3"	D	P	A,R	C	C	C	C				
								SM16	Outside	Globe 2"	HW	-	-	C	-	C	C				
								SM73	Outside	Globe 1"	HW	-	-	LC	-	C	C	10.3.2-1			
								SM77A	Outside	Gate 2"	E	M	R	O	-	O	C	10.3.2-1			
								SM105	Outside	Globe 2"	HW	-	-	C	-	C	C	10.3.2-1			
								SM121	Inside	Globe 2"	HW	-	-	LC	-	C	C	10.3.2-1			
								SM143	Outside	Globe 1"	HW	-	-	C	-	C	C	10.3.2-1			
95	Main Steam 1B	M261	D3	34	Out	Yes	Yes	SM5	Outside	Gate 34"	P	P	A,R	O	C	O	C	10.3.2-1	No	No	(23)
								SV14	Outside	Safety 6"	-	1175 PSIG	-	C	-	C	C				
								SV15	Outside	Safety 6"	-	1190 PSIG	-	C	-	C	C				
								SV16	Outside	Safety 6"	-	1205 PSIG	-	C	-	C	C				
								SV17	Outside	Safety 6"	-	1220 PSIG	-	C	-	C	C				
								SV18	Outside	Safety 6"	-	1230 PSIG	-	C	-	C	C				
								SV13	Outside	Globe 6"	D	P	A,R	C	C	C	C				
								SM11	Outside	Globe 3"	D	P	A,R	C	C	C	C				
								SM72	Outside	Globe 1"	HW	-	-	LC	-	C	C	10.3.2-1			
								SM76B	Outside	Gate 2"	E	M	R	O	-	O	C	10.3.2-1			
								SM104	Outside	Globe 2"	HW	-	-	C	-	C	C	10.3.2-1			
								SM120	Inside	Globe 2"	HW	-	-	LC	-	C	C	10.3.2-1			
								SM142	Outside	Globe 1"	HW	-	-	C	-	C	C	10.3.2-1			
								SA1	Outside	Gate 6"	HW	-	-	LO	-	O	C	10.3.2-2			
								SM17	Outside	Globe 2"	HW	-	-	C	-	C	C				
96	Main Steam 1C	M393	D3	34	Out	Yes	Yes	SM3	Outside	Gate 34"	P	P	A,R	O	C	O	C	10.3.2-1	No	No	(23)
								SV8	Outside	Safety 6"	-	1175 PSIG	-	C	-	C	C				
								SV9	Outside	Safety 6"	-	1190 PSIG	-	C	-	C	C				
								SV10	Outside	Safety 6"	-	1205 PSIG	-	C	-	C	C				
								SV11	Outside	Safety 6"	-	1220 PSIG	-	C	-	C	C				
								SV12	Outside	Safety 6"	-	1230 PSIG	-	C	-	C	C				
								SV7	Outside	Globe 6"	D	P	A,R	C	C	C	C				
								SM10	Outside	Globe 3"	D	P	A,R	C	C	C	C				
								SM18	Outside	Globe 2"	HW	-	-	C	-	C	C				
								SM71	Outside	Globe 1"	HW	-	-	LC	-	C	C	10.3.2-1			
								SM75A	Outside	Gate 2"	E	M	R	O	-	O	C	10.3.2-1			
								SM103	Outside	Globe 2"	HW	-	-	C	-	C	C	10.3.2-1			
								SM119	Inside	Globe 2"	HW	-	-	LC	-	C	C	10.3.2-1			
								SM141	Outside	Globe 1"	HW	-	-	C	-	C	C	10.3.2-1			
								SA4	Outside	Gate 6"	HW	-	-	LO	-	O	C	10.3.2-2			

TABLE 6.2.4-1

CONTAINMENT ISOLATION VALVE AND ACTUATOR DATA (PAGE 8)

Item Number	Service	Pen. No.	(1,17) Valve Arrangements	Nominal Line Size Inches	Flow Direction Relative to Containment	(7) Seismic Connections Inside	(7) Seismic Connections Outside	(6,15) Valve Number	(19) Valve Location	Type Valve & Size	(2,3) Actuation Signal	(2,3) Actuation Type	(4) Valve Position Normal	(4) Valve Position Failsafe	(4) Valve Position Shutdown	(4) Valve Position Post Accident	FSAR Figure No.	Vent And Drain For Type A Test	(18) Type C Leakage Test	Justification For Not Testing
97	Main Steam 1D	M423	D3	34	Out	Yes	Yes	SM1	Outside	Gate 34"	P	A,R	O	C	O	C	10.3.2-1	No	No	(23)
								SV2	Outside	Safety 6"	1175 PSIG	-	C	-	C	C				
								SV3	Outside	Safety 6"	1190 PSIG	-	C	-	C	C				
								SV4	Outside	Safety 6"	1205 PSIG	-	C	-	C	C				
								SV5	Outside	Safety 6"	1220 PSIG	-	C	-	C	C				
								SV6	Outside	Safety 6"	1230 PSIG	-	C	-	C	C				
								SV1	Outside	Globe 6"	P	A,R	C	C	C	C				
								SM9	Outside	Globe 3"	P	A,R	C	C	C	C				
								SR19	Outside	Globe 2"	-	-	C	-	C	C				
								SM70	Outside	Globe 1"	-	-	LC	-	C	C	10.3.2-1			
								SM74B	Outside	Gate 2"	M	R	O	-	O	C	10.3.2-1			
								SM102	Outside	Globe 2"	-	-	C	-	C	C	10.3.2-1			
								SM118	Inside	Globe 2"	-	-	LC	-	C	C	10.3.2-1			
								SM140	Outside	Globe 1"	-	-	C	-	C	C	10.3.2-1			
98	Interior Fire Protection -	M316	B6	6	In	No	No	RF389B	Outside	Gate 4"	T	A,R,M	C	AI	C	C	9.5.1-4	Yes	Yes (Note 42)	----
								RF392	Inside	Check 4"	-	-	C	-	C	C				
99	Demineralized water	M337	B1	2	In	No	Yes	YM119B	Outside	Globe 2"	T	A,R,M	O	AI	O	C	9.2.3-2	Yes	Yes	----
								YM121	Inside	Check 2"	-	-	O	-	O	C				
100	Instrument Air	M220	B1	2	In	No	No	V177B	Outside	Diaphragm 2"	P	A,R,M	O	C	O	C	9.3.1-2	Yes	Yes	----
								V179	Inside	Check 2"	-		O	-	O	C				
								V1312A	Outside	Globe 2"	T	A,R,M	O	AI	O	C				
101	Station Air	M219	B1	3	In	No	Yes	V554B	Outside	Gate 3"	T	A,R,M	O	AI	O	C		Yes	Yes	----
								V556	Inside	Check 3"	-	-	C	-	O	C				
102	Breathing Air	M215	B1	2	In	No	Yes	V883B	Outside	Diaphragm 2"	T	A,R,M	O	AI	O	C	9.3.1-8	Yes	Yes	----
								V885	Inside	Check 2"	-	-	O	-	O	C				
103	Cont. Press Sensing CHI	CNIP-1N512	D4	1/4	None	None	None	Note 41	-	- -	-	-	-	-	-	-	NONE	Yes	Yes	----
104	Cont. Press Sensing CHII	CNIP-1N59	D4	1/4	None	None	None	Note 41	-	- -	-	-	-	-	-	-	NONE	Yes	Yes	----
105	Cont. Press Sensing CHIII	CNIP-1N510	D4	1/4	None	None	None	Note 41	-	- -	-	-	-	-	-	-	NONE	Yes	Yes	----
106	Cont. Press Sensing CHIV	CNIP-1N511	D4	1/4	None	None	None	Note 41	-	- -	-	-	-	-	-	-	NONE	Yes	Yes	----
107	Equipment Hatch		C2	240	None	No	No	-	Inside	Double Seal	-	-	C	-	C	C	3.8.2-2	No	No	(27)
								-	Inside	Blind Flange	-	-	-	-	-	-				
108	Personnel Hatch (NOTE 5)		C2	115	None	No	No	-	Inside	Double Seal	-	-	C	-	C	C	3.8.2-2	No	No	(27)
								-	Inside	Blind Flange	-	-	-	-	-	-				
109	Reactor Coolant Pump Motor Oil Fill	M329	A5	2	In	No	No	NC195B	Outside	Gate 2"	T	A,R,M	C	AI	C	C	5.1-4	Yes	Yes	----
								NC196A	Inside	Gate 2"	T	A,R,M	C	AI	C	C				
110	Reactor Building Sprinklers	M361	B6	6	In	No	No	RF447B	Outside	Gate 4"	T	A,R,M	C	AI	C	C	9.5.1-4	Yes	Yes (Note 42)	----
								RF448	Inside	Check 4"	-	-	C	C	C	C				
111	Containment Valve Inj. Water "A" Train	M253	B1	1	In	Yes	Yes	NW35A	Outside	Globe 1"	T	A,R,M	C	AI	C	O	6.2.4-2	No	No	(38)
								NW37	Inside	Check 1"	-	-	C	-	C	O				
112	Containment Valve Inj. Water "B" Train	M243	B1	1	in	Yes	Yes	NW105B	Outside	Globe 1"	T	A,R,M	C	AI	C	O	6.2.4-2	No	No	(38)
								NW107	Inside	Check 1"	-	-	C	-	C	O				
113	Standby Makeup Pump Discharge Line	M228	B1	2	In	No	No	NV872A	Outside	Globe 2"	T	A,R,M	C	AI	C	C	9.3.4-9	Yes	Yes	----
								NV874	Inside	Check 2"	-	-	C	-	C	C	9.3.4-9			
	Cont. Radiation Monitor	CNIP-1EMF (In)		½	Out			1MISV5230	Outside	Globe ½"	T	-	O	C	O	C	None	Yes	Yes	----
								1MISV5231	Inside	Globe ½"	T	-	O	C	O	C				
	Cont. Radiation Monitor	CNIP-1EMF (Out)		½	In			1MISV5232	Outside	Globe ½"	T	-	O	C	O	C	None	Yes	Yes	----
								1MISV5233	Inside	Globe ½"	T	-	O	C	O	C				
	ILRT Press Line	CNIP-1MI5		½	None			1MIMV6461	Outside	Globe ½"	-	-	C	-	C	C	None	No (Note 29)	Yes	----
								1MIMV6460	Inside	Globe ½"	-	-	C	-	C	C				
	ILRT Press Line	CNIP-1MI6		½	None			1MIMV6491	Outside	Globe ½"	-	-	C	-	C	C	None	No (Note 29)	Yes	----
								1MIMV6490	Inside	Globe ½"	-	-	C	-	C	C				

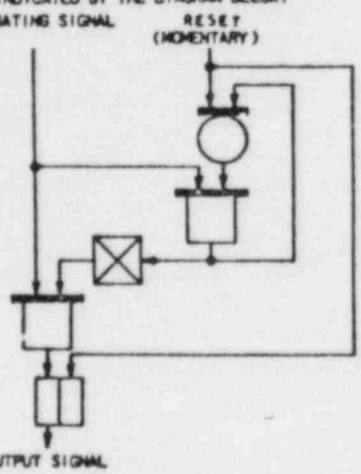
TABLE 6.2.4-1

CONTAINMENT ISOLATION VALVE AND ACTUATOR DATA (PAGE 8a)

Item Number	Service	Pen. No.	(1,17) Valve Arrangements	Nominal Line Size Inches	Flow Direction Relative to Containment	(7) Seismic Connections Inside	(7) Seismic Connections Outside	(6,15) Valve Number	(19) Valve Location	Type Valve & Size	(4,16) Type Actuator	(2,3) Actuation Signal	(2,3) Actuation Type	(4) Valve Position Normal	(4) Valve Position Failsafe	(4) Valve Position Shutdown	(4) Valve Position Post Accident	FSAR Figure No.	Vent And Drain For Type A Test	(10) Type C Leakage Test	Justification For Not Testing
								1MIMV6471	Outside	Globe ½"	HW	-	-	C	-	C	C				
	CLRT Press Line	CNIP-1M17		½	None			1MIMV6470	Inside	Globe ½"	HW	-	-	C	-	C	C	None	No (Note 29)	Yes	----
	Cont. Atmos. H_2 Concentration Level Xmitter (IN) TrainA	CNIP-1M11		½	Out			Note 41	--	--- -	-	-	-	-	-	-	-	None	Yes	Yes	----
	Cont. Atmos. H_2 Concentration Level Xmitter (OUT) TrainA	CNIP-1M13		½	In			Note 41	--	--- -	-	-	-	-	-	-	-	None	Yes	Yes	----
	Cont. Atmos. H_2 Concentration Level Xmitter (IN) TrainB	CNIP-1M12		½	Out			Note 41	--	--- -	-	-	-	-	-	-	-	None	Yes	Yes	----
	Cont. Atmos. H_2 Concentration Level Xmitter (OUT) TrainB	CNIP-1M14		½	In			Note 41	--	--- -	-	-	-	-	-	-	-	None	Yes	Yes	----
	Lower Personnel Air Lock	C100																None	No	No	(27)
	Upper Personnel Air Lock	C300																None	No	No	(27)
								11ASV5160	Outside	Globe 3/4"	E	S		O	C	O	C				
	Lower PAL Air Supply Line			3/4	In			11ACV5350	Inside	Check 3/4"	-	-		O	-	O	C	None	Yes	Yes	----
								11ACV5390	Outside	Check 3/4"	-	-		C	-	C	C				
	Lower PAL Equalization Line			3/4	None			11ACV5350	Inside	Check 3/4"	-	-		C	-	C	C	None	Yes	Yes	----
								11ASV5080	Outside	Globe 3/4"	E	S		O	C	O	C				
	Upper PAL Air Supply Line			3/4	In			11ACV5340	Inside	Check 3/4"	-	-		O	-	O	C	None	Yes	Yes	----
								11ACV5380	Outside	Check 3/4"	-	-		C	-	C	C				
	Upper PAL Equalization Line			3/4	None			11ACV5360	Inside	Check 3/4"	-	-		C	-	C	C	None	Yes	Yes	----

LOGIC SYMBOLS

SYMBOL	LOGIC FUNCTION	DESCRIPTION
	OR	A DEVICE WHICH PRODUCES AN OUTPUT ONLY WHEN ONE INPUT (OR MORE) EXISTS.
	NOT	A DEVICE WHICH PRODUCES AN OUTPUT ONLY WHEN THE INPUT DOES NOT EXIST.
	AND	A DEVICE WHICH PRODUCES AN OUTPUT ONLY WHEN EVERY INPUT EXISTS
2/3	COINCIDENCE (2 OUT OF 3 SHOWN)	A DEVICE WHICH PRODUCES AN OUTPUT WHEN THE PRESCRIBED NUMBER OF INPUTS EXIST (EXAMPLE 2 INPUTS MUST EXIST FOR AN OUTPUT).
	ADJUSTABLE TIME DELAY	A DEVICE WHICH PRODUCES AN OUTPUT FOLLOWING DEFINITE INTENTIONAL TIME DELAY AFTER RECEIVING AN INPUT.
	OFF RETURN MEMORY	A DEVICE WHICH RETAINS THE CONDITION OF OUTPUT CORRESPONDING TO THE LAST ENERGIZED INPUT, EXCEPT UPON INTERRUPTION OF POWER IT RETURNS TO THE OFF CONDITION.
	RETENTIVE MEMORY	A DEVICE WHICH RETAINS THE CONDITION OF OUTPUT CORRESPONDING TO THE LAST ENERGIZED INPUT (ALSO UPON INTERRUPTION OF POWER).
L R	RETENTIVE MEMORY WITH ACTUATION BLOCK	A DEVICE HAVING RETENTIVE MEMORY AND ACTUATION SIGNAL BLOCK LOGIC FUNCTIONS AS INDICATED BY THE DIAGRAM BELOW.



SYMBOL	LOGIC FUNCTION	DESCRIPTION
ANALOG INPUT / CONTROL LOGIC INPUT / ANALOG OUTPUT	ANALOG GATE	A DEVICE WHICH PERMITS AN ANALOG SIGNAL TO PASS IN AN ISOLATED CIRCUIT IF THE CONTROL LOGIC INPUT EXISTS.

ADDITIONAL SYMBOLS

PB 143A ← INSTRUMENT CHANNEL BISTABLE

← OUTPUT INDICATOR

BISTABLE OUTPUT IS A LOGI
PARAMETER IS GREATER THAN

BISTABLE OUTPUT IS A LOGI
PARAMETER IS LESS THAN TH

BISTABLE OUTPUT IS A LOGI
DEVIATES FROM THE NORMAL

OR OR SAME AS ABOVE
ADJUSTED SETP

OR OR SAME AS ABOVE

37 ← NON-INSTRUMENT BISTABLE

← OUTPUT INDICATOR (SAME AS EXPLAIN

A 2 ← ALARM ANNUNCIATOR (ALARMS ON THE
SUBSCRIPT SHARE A COMMON ANNUNCIA

R ← REACTOR TRIP "FIRST OUT" ANNUNCIA

T ← TURBINE TRIP "FIRST OUT" ANNUNCIA

T ← INDICATOR LAMP
A - ACTUATION SIGNAL LIGHTS, T
P - PERMISSIVE STATUS LIGHTS, B

C ← COMPUTER INPUT

LOGIC INFORMATION TRANSMISSION

ANALOG INFORMATION TRANSMISSION

I ← ANALOG DISPLAY
I - ANALOG INDICATOR, R - RECORDER
R3-RECORDER 3 PEN, R8- RECORDE

Σ ← ANALOG SUMMER

GENERAL NOTES: (FOR ALL SHEETS)

1. IN ALL LOGIC CIRCUITS, THE INDICATED ACTUATIO
EXCEPT WHERE INDICATED OTHERWISE, ALL BISTABL
DEFINED TO BE PRESENT WHEN THE BISTABLE OUTPU
2. EXCEPT WHERE INDICATED OTHERWISE, THE FOLLOWI
HAS A DUPLICATE LOCATED IN A SEPARATE CABINET
LAMPS ARE NOT REDUNDANT. MANUAL CONTROLS DO
WHERE LOGIC IS REDUNDANT. ALL INDICATO
BOTH TRAINS (WHERE LOGIC IS REDUNDANT)
3. WHENEVER A PROCESS SIGNAL IS USED FOR CO
MUST BE PROVIDED.
4. THIS SET OF DRAWINGS ILLUSTRATES THE FU
SYSTEM, INCLUDING ENGINEERED SAFEGUARDS. THE
HARDWARE IMPLEMENTATION, REFER TO THE FOLLOWI
1084W24 SOLID STATE PROTECTION SYSTEM SCH
7243D64 SOLID STATE PROTECTION SYSTEM INTE
5655D49 NUCLEAR INSTRUMENTATION SOURCE RAN
5655D50 NUCLEAR INSTRUMENTATION INTERMEDIA
5655D51 NUCLEAR INSTRUMENTATION POWER RANG
5655D52 NUCLEAR INSTRUMENTATION AUXILIARY
8757D66 PROCESS CONTROL SYSTEMS BLOCK DIAG
271C332 ELEMENTARY WIRING DIAGRAM
5. THIS SET OF DRAWINGS IS IDENTICAL FOR UNITS
"1" EXAMPLE: 1PB-468E. FOR UNIT 2 TAG NUMB

* WHEN THE MEASURED
SETPOINT VALUE.

* WHEN THE MEASURED
TPOINT VALUE.

* WHEN THE MEASURED PARAMETER
E BY MORE THAN THE SETPOINT AMOUNTS.

CEPT WITH AN AUTOMATICALLY
T

CEPT WITH REQUIRED HYSTERESIS

ABOVE)

E SHEET WITH THE SAME
WINDOW)

IP STATUS LIGHTS,
PASS STATUS LIGHTS

R2 - RECORDER 2 PEN,
POINT

F A SYSTEM OR DE ICE OCCURS WHEN A LOGIC "1" SIGNAL IS PRESENT.
ARE "DE-ENERGIZE TO ACTUATE" SUCH THAT A LOGIC 1 SIGNAL IS
OLTAGE IS OFF.
IS TRUE: ALL LOGIC CIRCUITS ARE REDUNDANT THAT IS EVERY LOGIC CIRCUIT SHOWN
ALL INSTRUMENT CHANNELS, BISTABLES, ANNUNCIATORS, COMPUTER INPUTS, AND INDICATOR
HAVE REDUNDANT ACTUATORS, BUT DO HAVE REDUNDANT CONTACTS.
AMPS, ANNUNCIATORS, AND COMPUTER INPUTS ARE CONNECTED TO
THAT A SIGNAL IN EITHER TRAIN WILL ACTUATE.
ROL AND IS DERIVED FROM A PROTECTION CHANNEL, ISOLATION

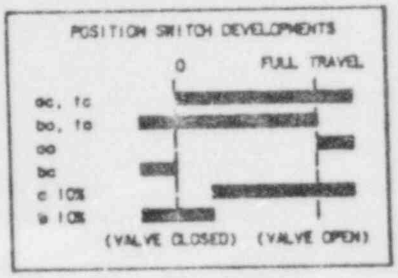
IONAL REQUIREMENTS OF THE REACTOR CONTROL AND PROTECTION
DRAWINGS DO NOT REPRESENT ACTUAL HARDWARE IMPLEMENTATION. FOR
REFERENCE DRAWINGS:
IC
NNECTION
BLOCK
RANGE BLOCK
LOCK
NNELS BLOCK

ND 2 EXCEPT FOR THE TAG NUMBERS. FOR UNIT 1 TAG NUMBERS ADD
ADD A "2". EXAMPLE: 2PB-455E.

DEVICE FUNCTION LETTERS AND NUMBERS

FB FLOW CHANNEL
LB LEVEL CHANNEL
NC NUCLEAR CHANNEL
PB PRESSURE CHANNEL
RC RADIATION CHANNEL
SB SPEED CHANNEL
TB TEMPERATURE CHANNEL
ZB POSITION CHANNEL
20 ELECTRIC OPERATED VALVE
27 UNDERVOLTAGE RELAY
33 POSITION SWITCH
SUFFIX LETTER:
ac, aa, bc, ba - LIMIT SWITCH
tc, to - TORQUE SWITCH

Also Available On
Aperture Card



52 AC CIRCUIT BREAKER
SUFFIX LETTER:
a AUXILIARY CONTACT - OPEN WHEN MAIN CONTACTS ARE OPEN
b AUXILIARY CONTACT - CLOSED WHEN MAIN CONTACTS ARE OPEN
H CELL SWITCH - CLOSED WHEN BREAKER IS IN OPERATE POSITION
63 PRESSURE SWITCH
71 LEVEL SWITCH
80 FLOW SWITCH
81 UNDERFREQUENCY RELAY

APPROVED
DUKE POWER CO.
DATE APR 1 9 1984
C. J. WYLIE
CHIEF ENGINEER
By: ELECTRICAL DIV.

QA CONDITION 1
NUCLEAR SAFETY RELATED

DOCUMENT CONTROL DATE
APR 0 9 1984
DUKE POWER COMPANY
DESIGN ENGINEERING

INDEX

TITLE	SH. NO.	SUBS									
INDEX AND SYMBOLS	1	1	2	3	4	5	6				
REACTOR TRIP SIGNALS	2	1	2	3	4	4	4				
NUCLEAR INSTR. AND MANUAL TRIP SIGNALS	3	1	2	2	2	2	3				
NUCLEAR INSTR. PERMISSIVES AND BLOCKS	4	1	1	2	3	3	3				
PRIMARY COOLANT SYSTEM TRIP SIGNALS	5	1	2	3	4	4	4				
PRESSURIZER TRIP SIGNALS	6	1	2	3	3	3	3				
STEAM GENERATOR TRIP SIGNALS	7	1	2	3	3	4	5				
SAFEGUARDS ACTUATION SIGNALS	8	1	2	3	3	3	4				
ROD CONTROLS & ROD BLOCKS	9	1	1	2	2	2	2				
STEAM DUMP CONTROL	10	1	2	3	3	4	4				
PRESSURIZER PRESSURE & LEVEL CONTROL	11	1	2	3	3	3	3				
PRESSURIZER HEATER CONTROL	12	1	2	3	3	3	3				
FEEDWATER CONTROL & ISOLATION	13	1	2	3	4	4	4				
FEEDWATER CONTROL & ISOLATION	14	1	2	3	4	4	4				
AUXILIARY FEEDWATER PUMPS STARTUP	15	1	2	3	3	3	3				
TURBINE TRIPS, RUNBACKS & OTHER SIGNALS	16	1	2	3	4	5	5				

INSTRUMENTATION AND CONTROL
SYSTEM DIAGRAMS - INDEX
AND SYMBOLS
CATAWBA NUCLEAR STATION
Figure 7.2.1-1
(1 of 16)
Revision 11

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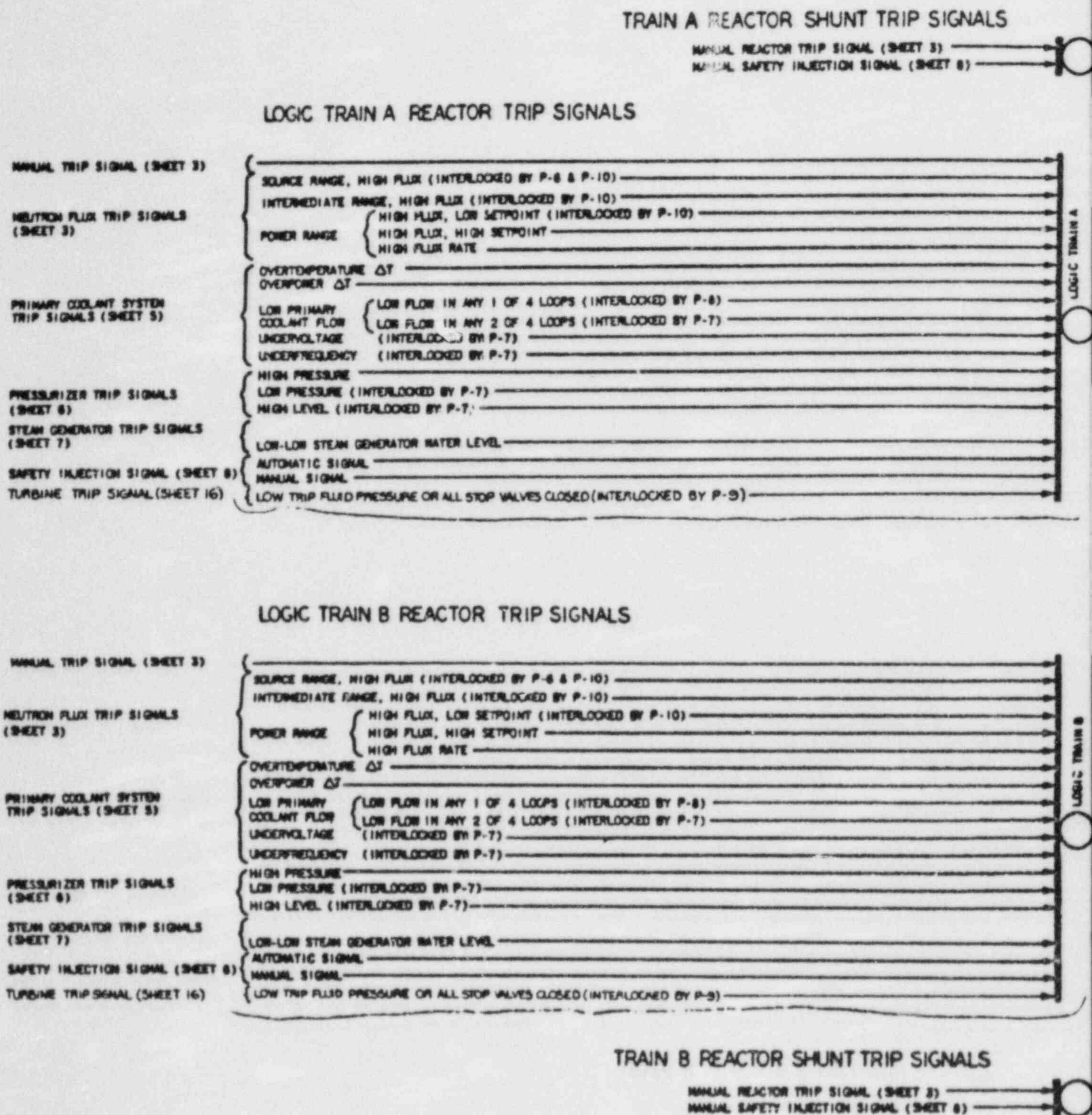
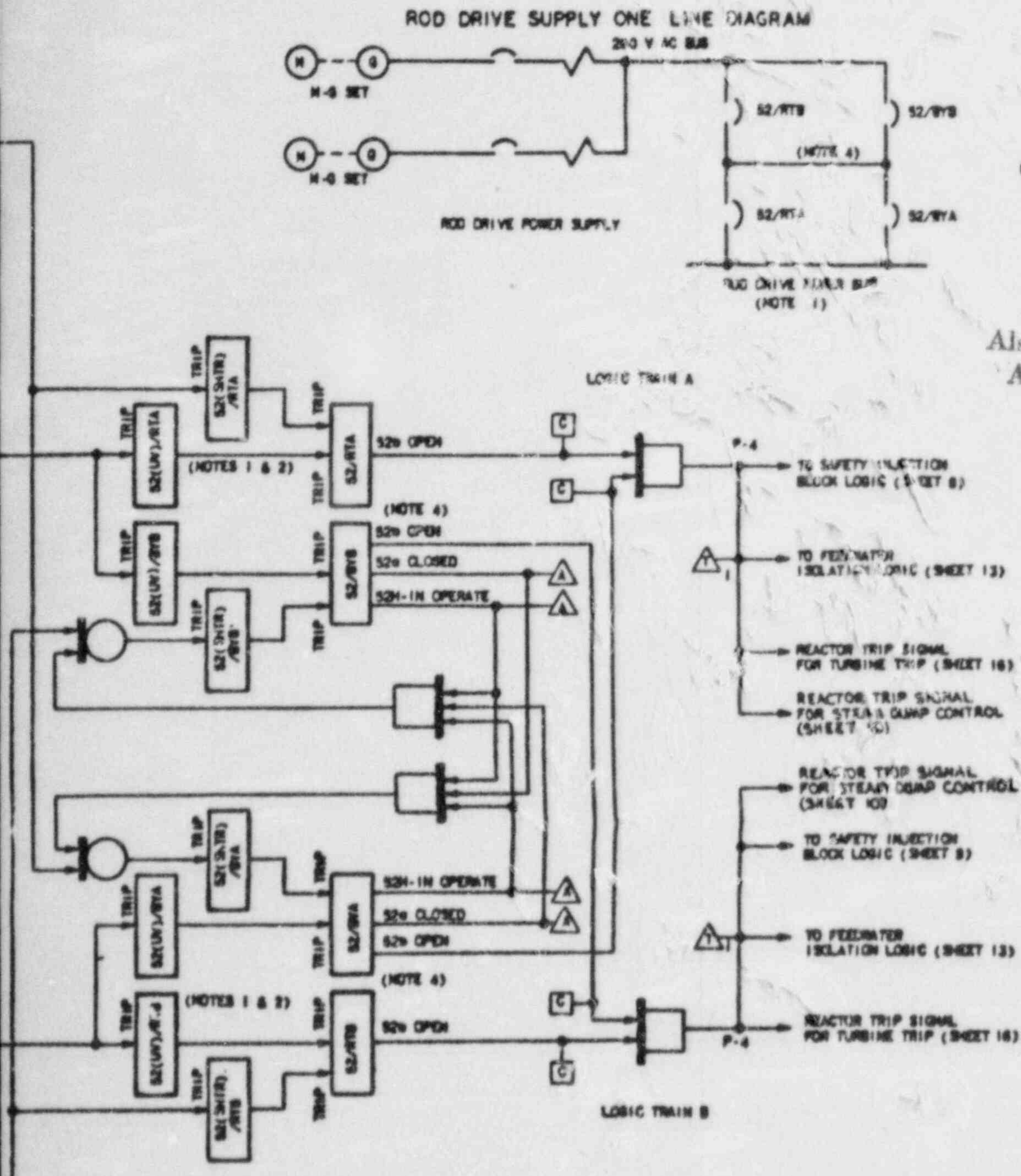
8406270190-01


TRAIN A REACTOR SHUNT TRIP SIGNALS
MANUAL REACTOR TRIP SIGNAL (SHEET 3)
MANUAL SAFETY INJECTION SIGNAL (SHEET 8)
LOGIC TRAIN A REACTOR TRIP SIGNALS
MANUAL TRIP SIGNAL (SHEET 3)
NEUTRON FLUX TRIP SIGNALS (SHEET 3)
SOURCE RANGE, HIGH FLUX (INTERLOCKED BY P-6 & P-10)
INTERMEDIATE RANGE, HIGH FLUX (INTERLOCKED BY P-10)
POWER RANGE
HIGH FLUX, LOW SETPOINT (INTERLOCKED BY P-10)
HIGH FLUX, HIGH SETPOINT
HIGH FLUX RATE
PRIMARY COOLANT SYSTEM TRIP SIGNALS (SHEET 5)
OVERTEMPERATURE ΔT
OVERPOWER ΔT
LOW PRIMARY COOLANT FLOW
LOW FLOW IN ANY 1 OF 4 LOOPS (INTERLOCKED BY P-8)
LOW FLOW IN ANY 2 OF 4 LOOPS (INTERLOCKED BY P-7)
UNDERVOLTAGE (INTERLOCKED BY P-7)
UNDERFREQUENCY (INTERLOCKED BY P-7)
PRESSURIZER TRIP SIGNALS (SHEET 6)
HIGH PRESSURE
LOW PRESSURE (INTERLOCKED BY P-7)
HIGH LEVEL (INTERLOCKED BY P-7)
STEAM GENERATOR TRIP SIGNALS (SHEET 7)
LOW-LOW STEAM GENERATOR WATER LEVEL
SAFETY INJECTION SIGNAL (SHEET 8)
AUTOMATIC SIGNAL
MANUAL SIGNAL
TURBINE TRIP SIGNAL (SHEET 16)
LOW TRIP FLUID PRESSURE OR ALL STOP VALVES CLOSED (INTERLOCKED BY P-9)
LOGIC TRAIN A
LOGIC TRAIN B REACTOR TRIP SIGNALS
MANUAL TRIP SIGNAL (SHEET 3)
NEUTRON FLUX TRIP SIGNALS (SHEET 3)
SOURCE RANGE, HIGH FLUX (INTERLOCKED BY P-6 & P-10)
INTERMEDIATE RANGE, HIGH FLUX (INTERLOCKED BY P-10)
POWER RANGE
HIGH FLUX, LOW SETPOINT (INTERLOCKED BY P-10)
HIGH FLUX, HIGH SETPOINT
HIGH FLUX RATE
PRIMARY COOLANT SYSTEM TRIP SIGNALS (SHEET 5)
OVERTEMPERATURE ΔT
OVERPOWER ΔT
LOW PRIMARY COOLANT FLOW
LOW FLOW IN ANY 1 OF 4 LOOPS (INTERLOCKED BY P-8)
LOW FLOW IN ANY 2 OF 4 LOOPS (INTERLOCKED BY P-7)
UNDERVOLTAGE (INTERLOCKED BY P-7)
UNDERFREQUENCY (INTERLOCKED BY P-7)
PRESSURIZER TRIP SIGNALS (SHEET 6)
HIGH PRESSURE
LOW PRESSURE (INTERLOCKED BY P-7)
HIGH LEVEL (INTERLOCKED BY P-7)
STEAM GENERATOR TRIP SIGNALS (SHEET 7)
LOW-LOW STEAM GENERATOR WATER LEVEL
SAFETY INJECTION SIGNAL (SHEET 8)
AUTOMATIC SIGNAL
MANUAL SIGNAL
TURBINE TRIP SIGNAL (SHEET 16)
LOW TRIP FLUID PRESSURE OR ALL STOP VALVES CLOSED (INTERLOCKED BY P-9)
LOGIC TRAIN B
TRAIN B REACTOR SHUNT TRIP SIGNALS
MANUAL REACTOR TRIP SIGNAL (SHEET 3)
MANUAL SAFETY INJECTION SIGNAL (SHEET 8)



Also Available On Aperture Card

NOTES:

1. TRIPPING THE REACTOR TRIP BREAKERS 52/RTA AND 52/RTB REDUNDANTLY DE-ENERGIZES THE ROD DRIVES. ALL FULL LENGTH CONTROL RODS AND SHUTDOWN RODS ARE THEREBY RELEASED FOR GRAVITY INSERTION INTO THE REACTOR CORE.
2. NORMAL REACTOR OPERATION IS TO BE WITH REACTOR TRIP BREAKERS 52/RTA AND 52/RTB IN SERVICE AND BY-PASS BREAKERS 52/BYA AND 52/BYB WITHDRAWN.
   DURING TEST ONE BY-PASS BREAKER IS TO BE PUT IN SERVICE AND THEN THE RESPECTIVE REACTOR TRIP BREAKER IS OPERATED UNDER A SIMULATED REACTOR TRIP SIGNAL IN THE TRAIN UNDER TEST. THE REACTOR WILL NOT BE TRIPPED BY THE SIMULATED SIGNAL SINCE THE BY-PASS BREAKER IS CONTROLLED FROM THE OTHER TRAIN. ONLY ONE REACTOR TRIP BREAKER IS TO BE TESTED AT A TIME.
3. ALL CIRCUITS ON THIS SHEET ARE NOT REDUNDANT BECAUSE BOTH TRAINS ARE SHOWN.
4. OPEN/CLOSED INDICATION FOR EACH TRIP BREAKER AND EACH BYPASS BREAKER IN CONTROL ROOM.

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INSTRUMENTATION AND CONTROL SYSTEM DIAGRAMS - INDEX AND SYMBOLS

CATAWBA NUCLEAR STATION

Figure 7.2.1-1
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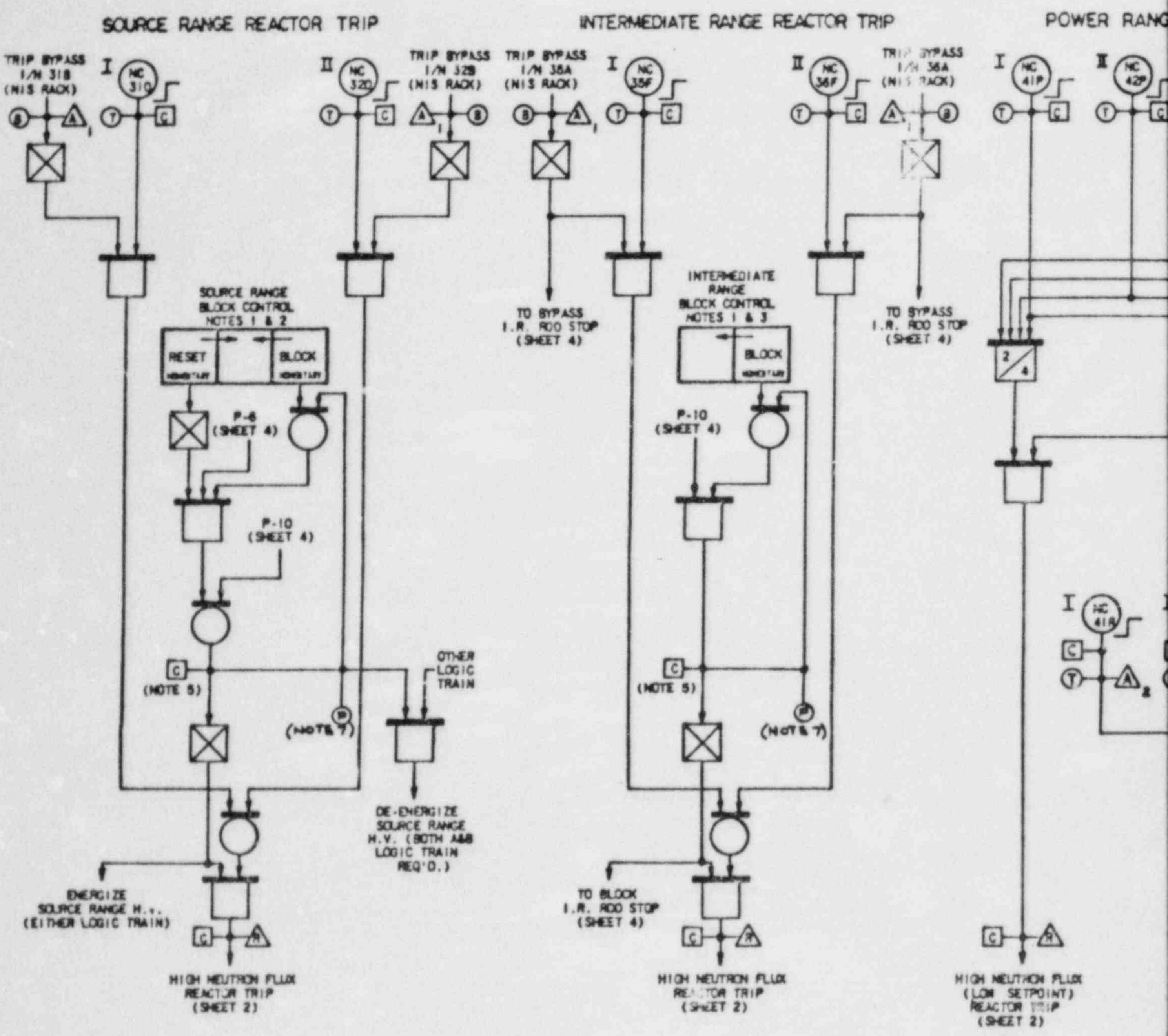

PLANT:
UNITS: 1 & 2
STATUS: APPROVE
CERTIFICATION LT

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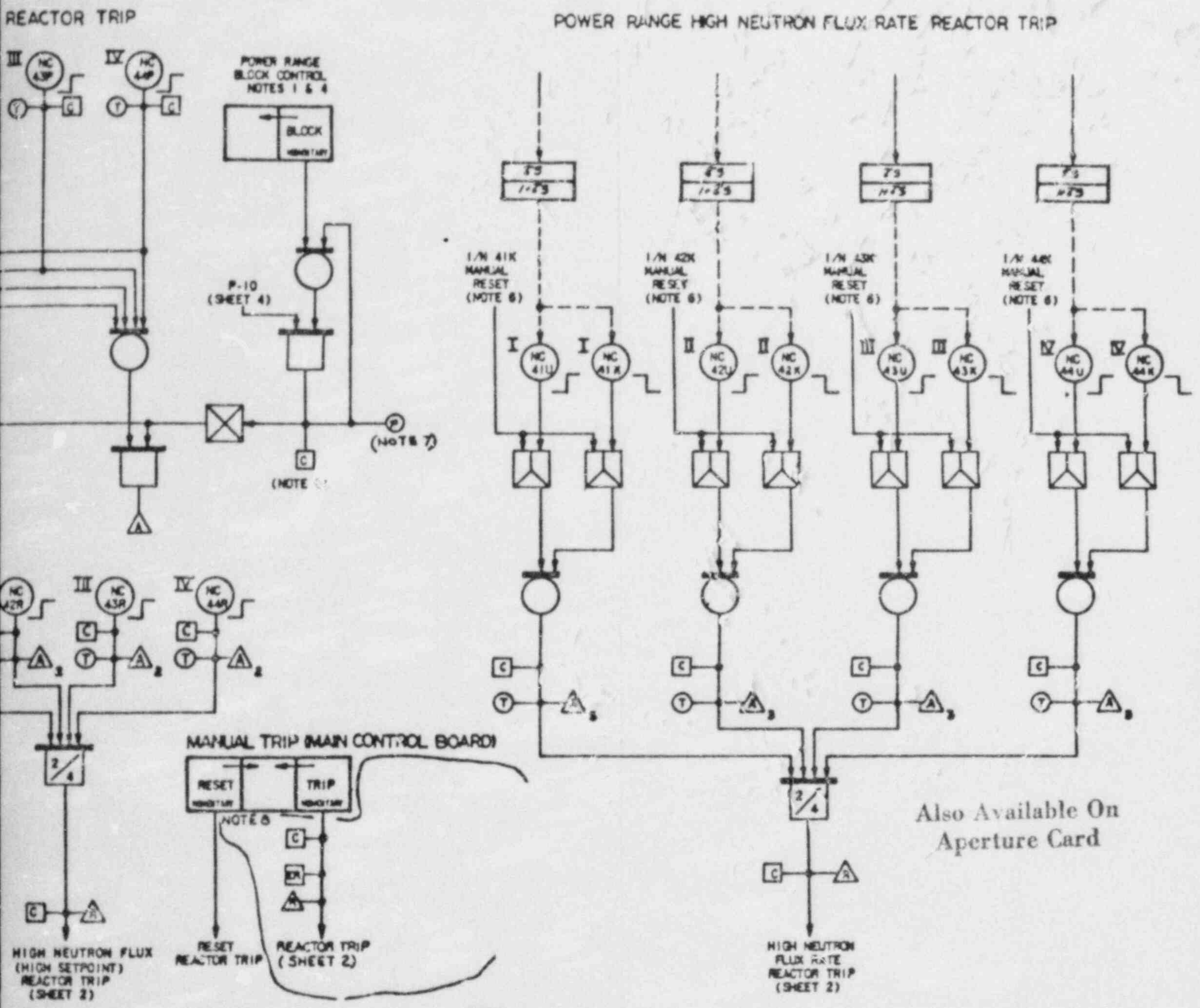

Also Available On Aperture Card

NOTES:

1. THE REDUNDANT MANUAL BLOCK CONTROLS CONSIST OF TWO CONTROLS ON THE CONTROL BOARD FOR EACH RANGE, ONE FOR EACH TRAIN.
2. I/N 33A IS IN LOGIC TRAIN A.
   I/N 33B IS IN LOGIC TRAIN B.
3. I/N 38A IS IN LOGIC TRAIN A.
   I/N 38B IS IN LOGIC TRAIN B.
4. I/N 47A IS IN LOGIC TRAIN A.
   I/N 47B IS IN LOGIC TRAIN B.
5. TWO COMPUTER INPUTS ARE CONNECTED TO THIS CIRCUIT, INDIVIDUAL FOR EACH TRAIN.
6. MANUAL RESET CONTROLS CONSIST OF FOUR MOMENTARY CONTROLS IN THE CONTROL ROOM, ONE CONTROL FOR EACH INSTRUMENT CHANNEL.
7. TWO PERMISSIVE STATUS LIGHTS ARE CONNECTED TO THIS CIRCUIT, INDIVIDUAL FOR EACH TRAIN.
8. THE REDUNDANT MANUAL TRIP CONTROLS CONSIST OF TWO CONTROLS ON THE CONTROL BOARD, ONE FOR EACH TRAIN.

DUKE POWER COMPANY
CATAWBA NUCLEAR STATION
ITEM-09

NO. CATAWBA-3608
AUTHORITY: F. J. TWOGOOD
ENGR. LTR. NO. EP/SA-43808

INSTRUMENTATION AND CONTROL SYSTEM DIAGRAMS - INDEX AND SYMBOLS

CATAWBA NUCLEAR STATION

Figure 7.2.1-1
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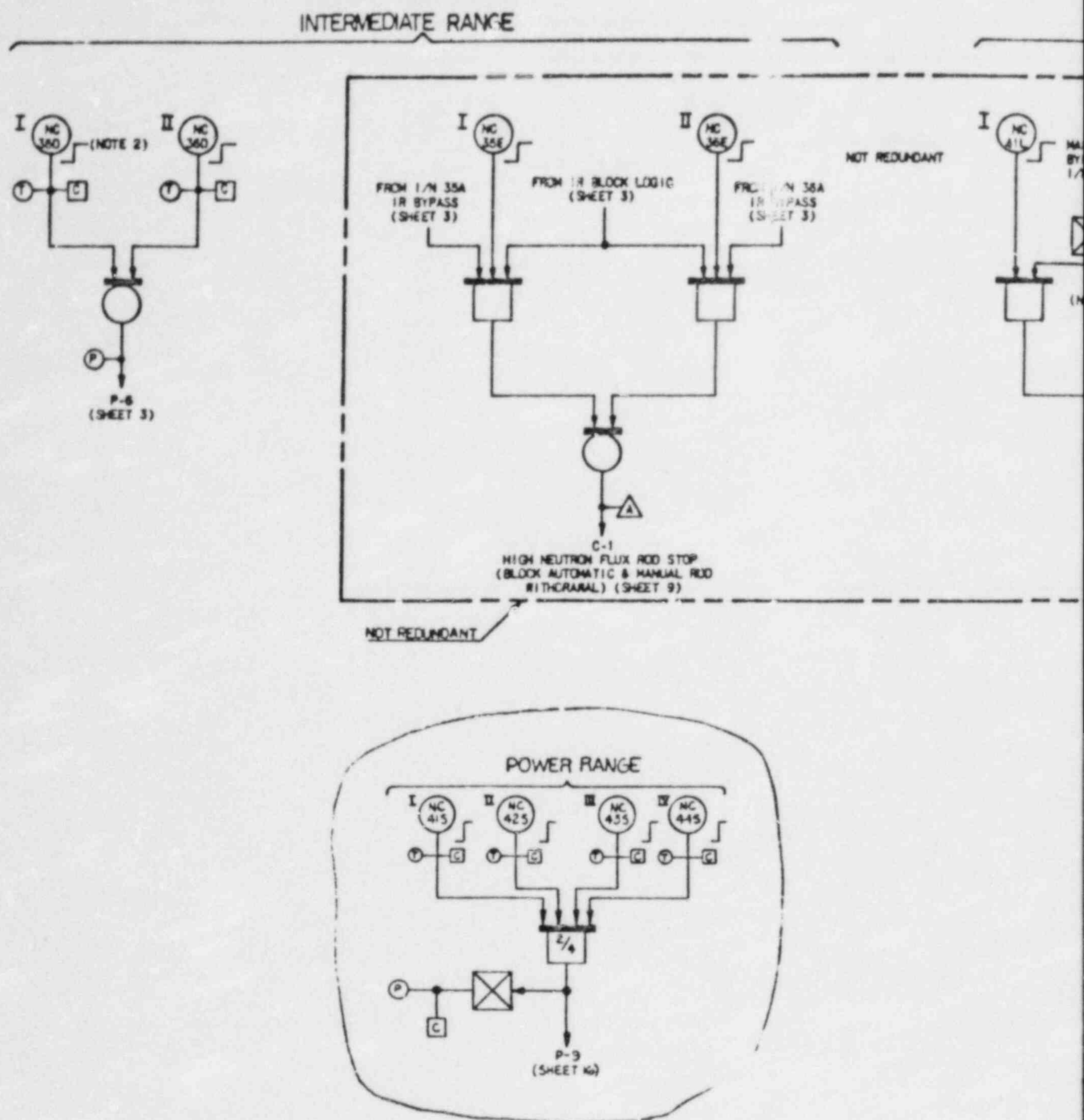
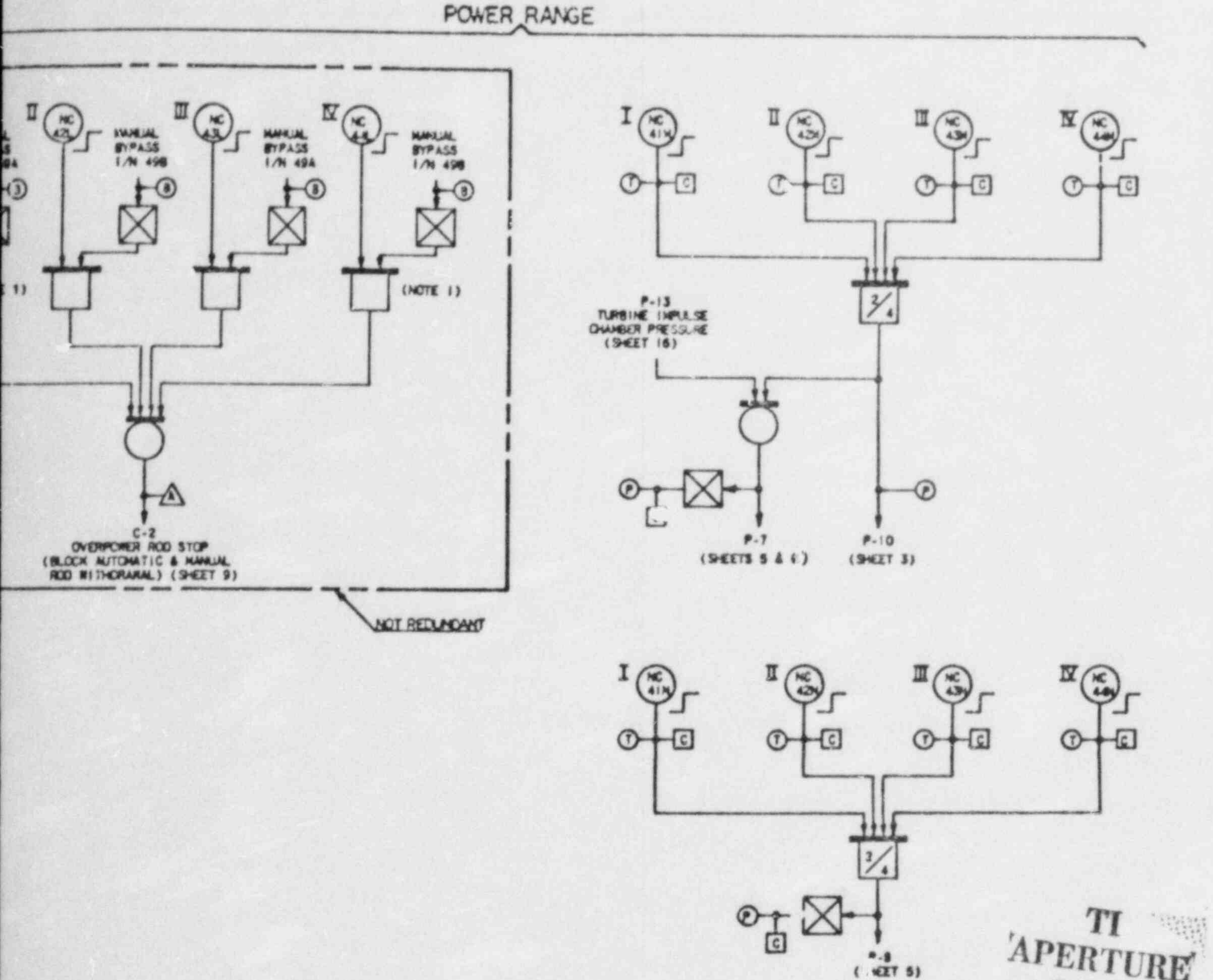
8406270190-03



INTERMEDIATE RANGE
(NOTE 2)
P-6
(SHEET 3)
FROM I/N 35A
IR BYPASS
(SHEET 3)
FROM IR BLOCK LOGIC
(SHEET 3)
NOT REDUNDANT
C-1
HIGH NEUTRON FLUX ROD STOP
(BLOCK AUTOMATIC & MANUAL ROD
WITHDRAWAL) (SHEET 9)
NOT REDUNDANT
POWER RANGE
2/4
P-9



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NOTES:

1. THE BYPASS SIGNALS ARE MADE UP BY MEANS OF TWO THREE-POSITION SWITCHES ON A NIS RACK. SWITCH I/N 49A BYPASSES EITHER NC-41L OR NC-43L. SWITCH I/N49B BYPASSES EITHER NC-42L OR NC-44L.
2. THE TWO P-6 BISTABLES NO. NC-35D AND NC-36D ARE "ENERGIZED TO ACTUATE" SUCH THAT A LOGIC 1 SIGNAL IS DEFINED TO BE PRESENT WHEN THE BISTABLE OUTPUT VOLTAGE IS ON.

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INSTRUMENTATION AND CONTROL SYSTEM DIAGRAMS - INDEX AND SYMBOLS

CATAWBA NUCLEAR STATION

Figure 7.2.1-1
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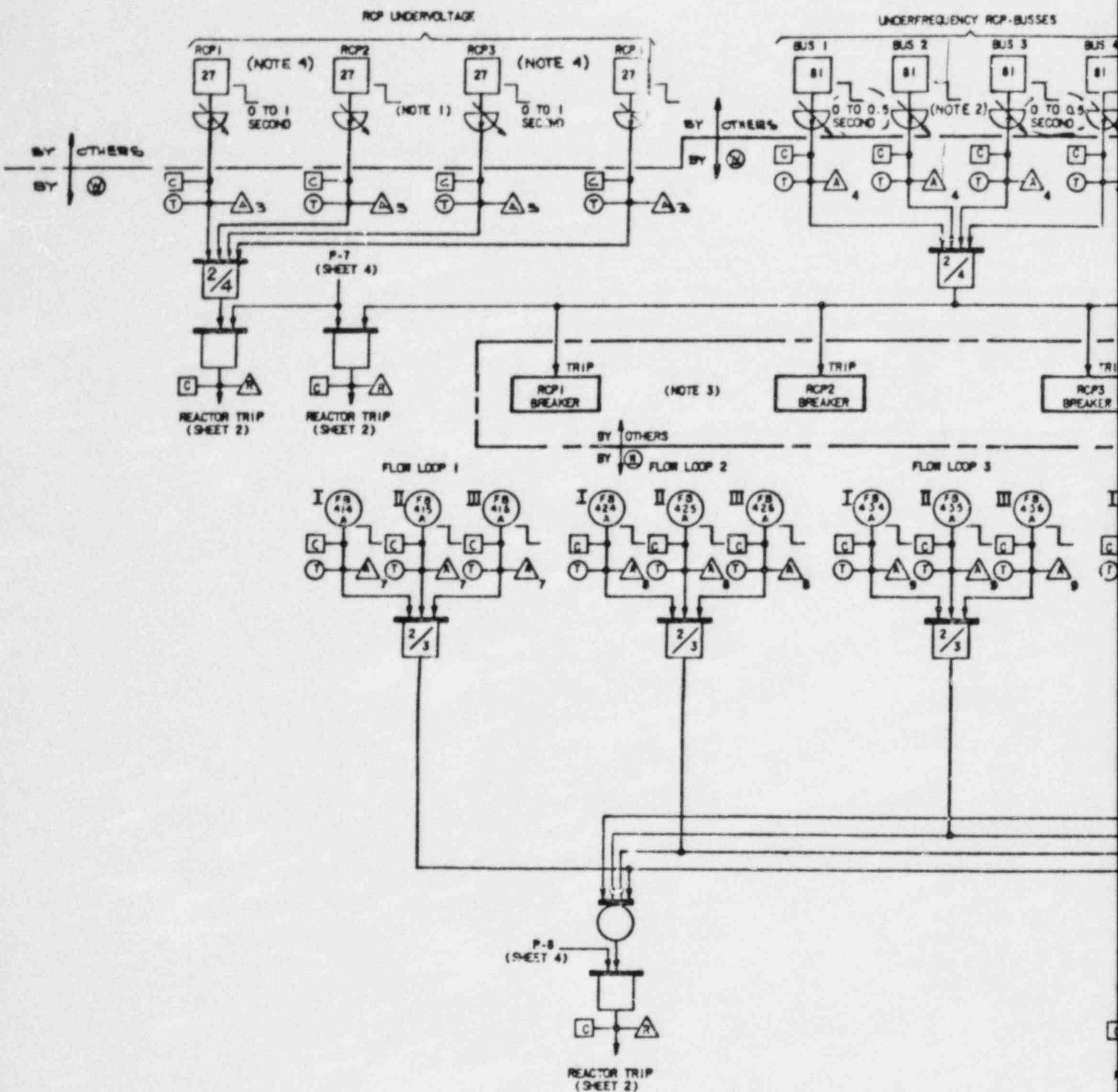
8406270190-04


RCP UNDERVOLTAGE
RCP1
RCP2
RCP3
27
(NOTE 4)
0 TO 1 SECOND
(NOTE 1)
BY OTHERS
UNDERFREQUENCY RCP-BUSSES
BUS 1
BUS 2
BUS 3
81
0 TO 0.5 SECOND
(NOTE 2)
2/4
P-7 (SHEET 4)
REACTOR TRIP (SHEET 2)
REACTOR TRIP (SHEET 2)
TRIP
RCP1 BREAKER
(NOTE 3)
RCP2 BREAKER
RCP3 BREAKER
FLOW LOOP 1
FLOW LOOP 2
FLOW LOOP 3
2/3
P-8 (SHEET 4)
REACTOR TRIP (SHEET 2)

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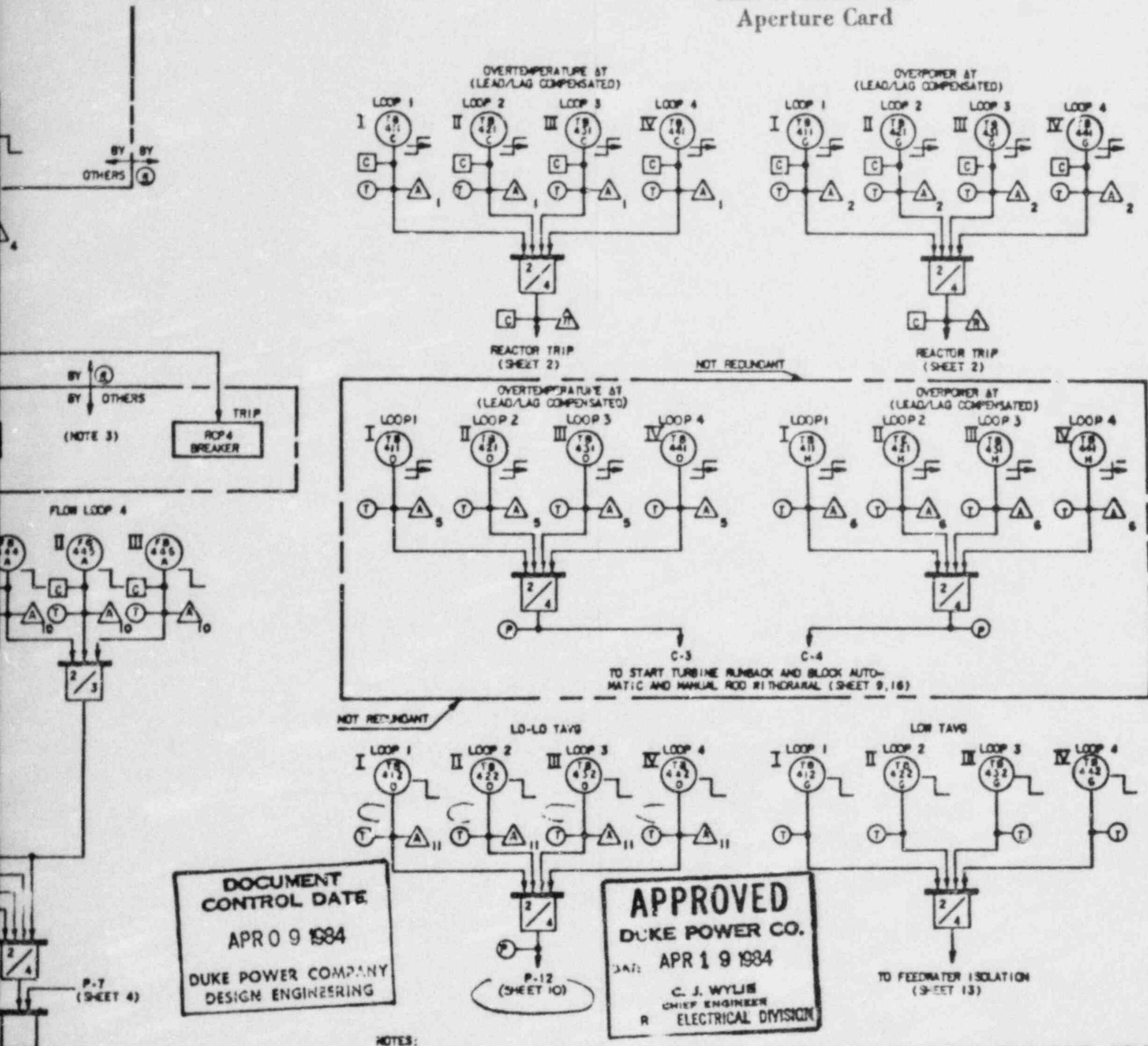

NOTES:

1. THE SETPOINT OF THE UNDERVOLTAGE RELAYS SHOULD BE ADJUSTABLE BETWEEN 60% AND 80% OF NOMINAL VOLTAGE. WITH THE ADJUSTABLE TIME DELAY SET TO ITS MINIMUM VALUE, THE UNDERVOLTAGE DETECTOR SHOULD HAVE A TIME RESPONSE OF LESS THAN 0.2 SECOND. THE ADJUSTABLE DELAY SHOULD ALLOW AN ADDITIONAL INTENTIONAL DELAY BETWEEN 0 TO 1.0 SECOND.

2. THE SETPOINT OF THE UNDERFREQUENCY RELAYS SHOULD BE ADJUSTABLE BETWEEN 54 Hz AND 58 Hz. WITH THE ADJUSTABLE TIME DELAY SET TO ITS MINIMUM VALUE, THE UNDERFREQUENCY DETECTOR SHOULD HAVE A TIME RESPONSE OF LESS THAN 0.2 SECOND. THE ADJUSTABLE DELAY SHOULD ALLOW AN ADDITIONAL INTENTIONAL DELAY BETWEEN 0 TO 0.5 SECOND.

3. THE MAXIMUM ALLOWABLE RCP BREAKER TRIP TIME DELAY IS 0.1 SECOND.

4. THE UNDERVOLTAGE SENSORS (POTENTIAL TRANSFORMERS) MUST BE LOCATED ON THE MOTOR SIDE OF THE RCP CIRCUIT BREAKERS TO DETECT THE TRIP OF THE RCP CIRCUIT BREAKERS IN ADDITION TO 80% UNDERVOLTAGE.

INSTRUMENTATION AND CONTROL SYSTEM DIAGRAMS - INDEX AND SYMBOLS

CATAWBA NUCLEAR STATION

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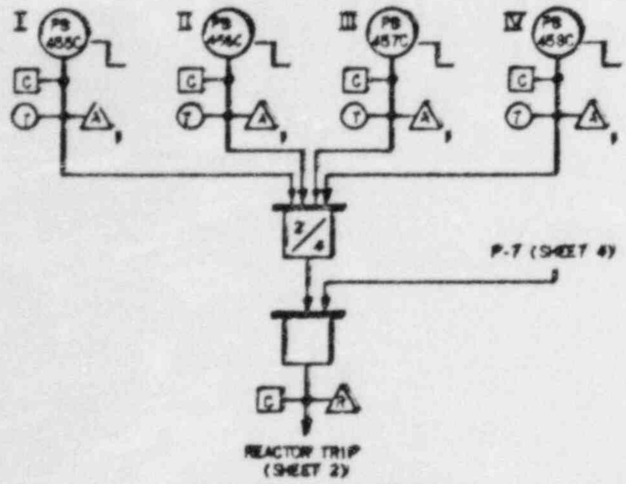
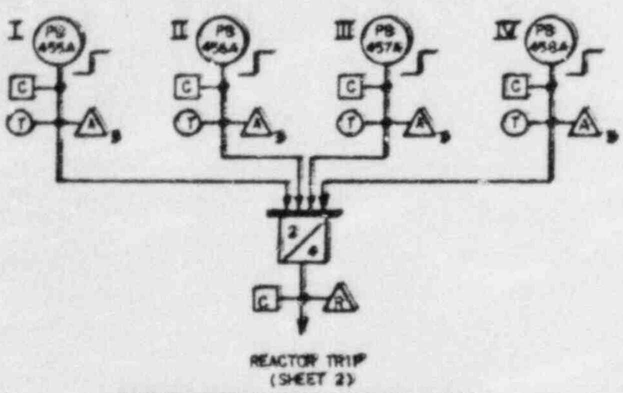
PRESSURIZER LOW PRESSURE

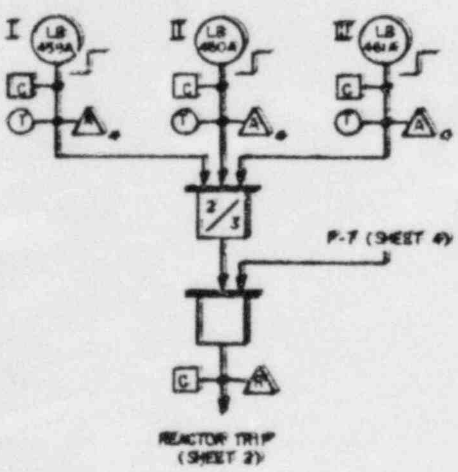
(LEAD/LAG COMPENSATED)

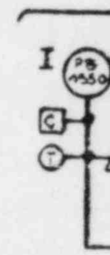


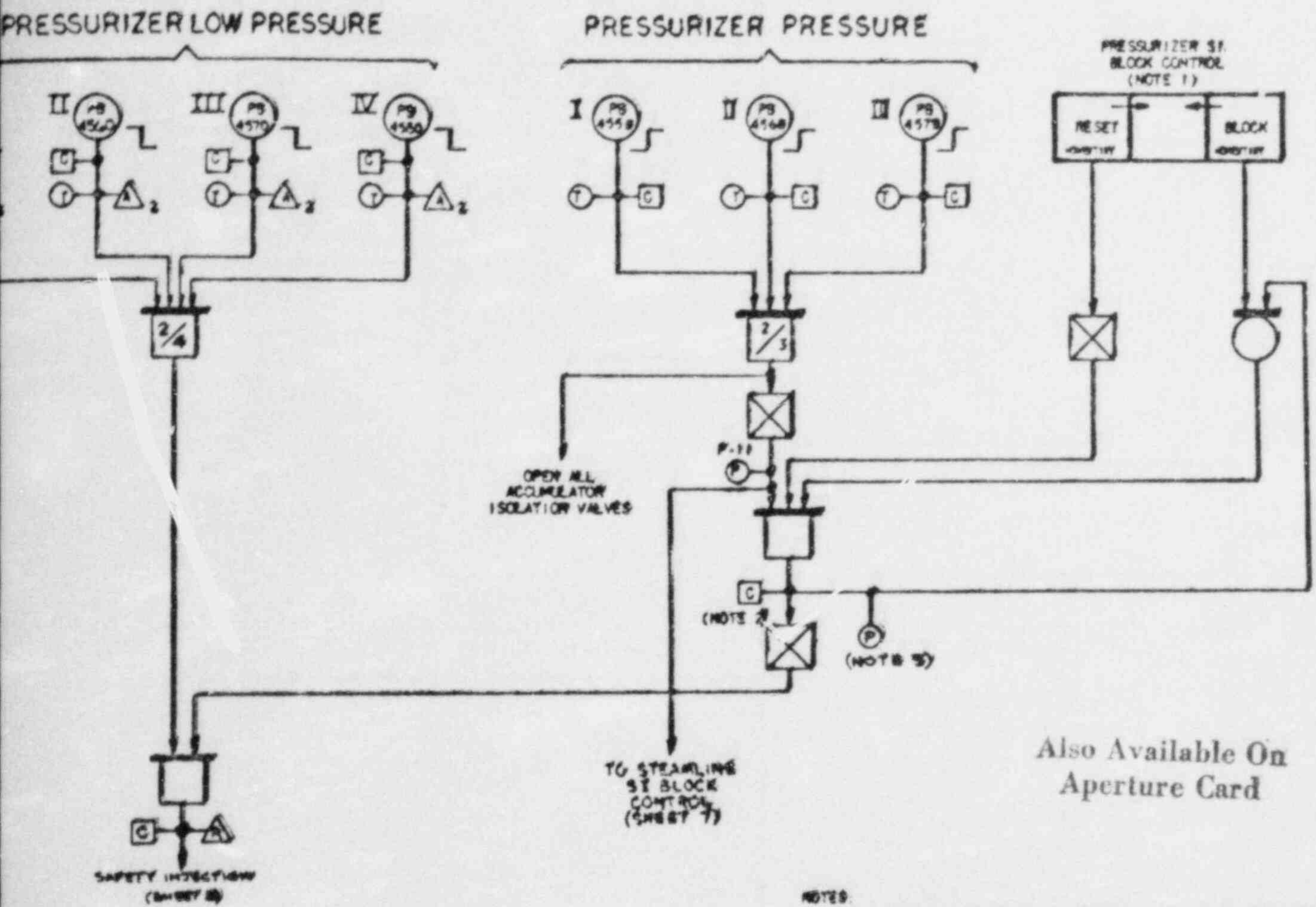
PRESSURIZER HIGH PRESSURE



PRESSURIZER HIGH WATER LEVEL







Also Available On Aperture Card

NOTES:

1. THE REDUNDANT MANUAL BLOCK CONTROL CONSISTS OF TWO CONTROLS ON THE CONTROL BOARD, ONE FOR EACH TRAIN.
2. TWO COMPUTER INPUTS ARE CONNECTED TO THIS CIRCUIT, INDIVIDUAL FOR EACH TRAIN.
3. TWO PERMISSIVE STATUS LIGHTS ARE CONNECTED TO THIS CIRCUIT, INDIVIDUAL FOR EACH TRAIN.

INSTRUMENTATION AND CONTROL SYSTEM DIAGRAMS - INDEX AND SYMBOLS

CATAWBA NUCLEAR STATION

Figure 7.2.1-1

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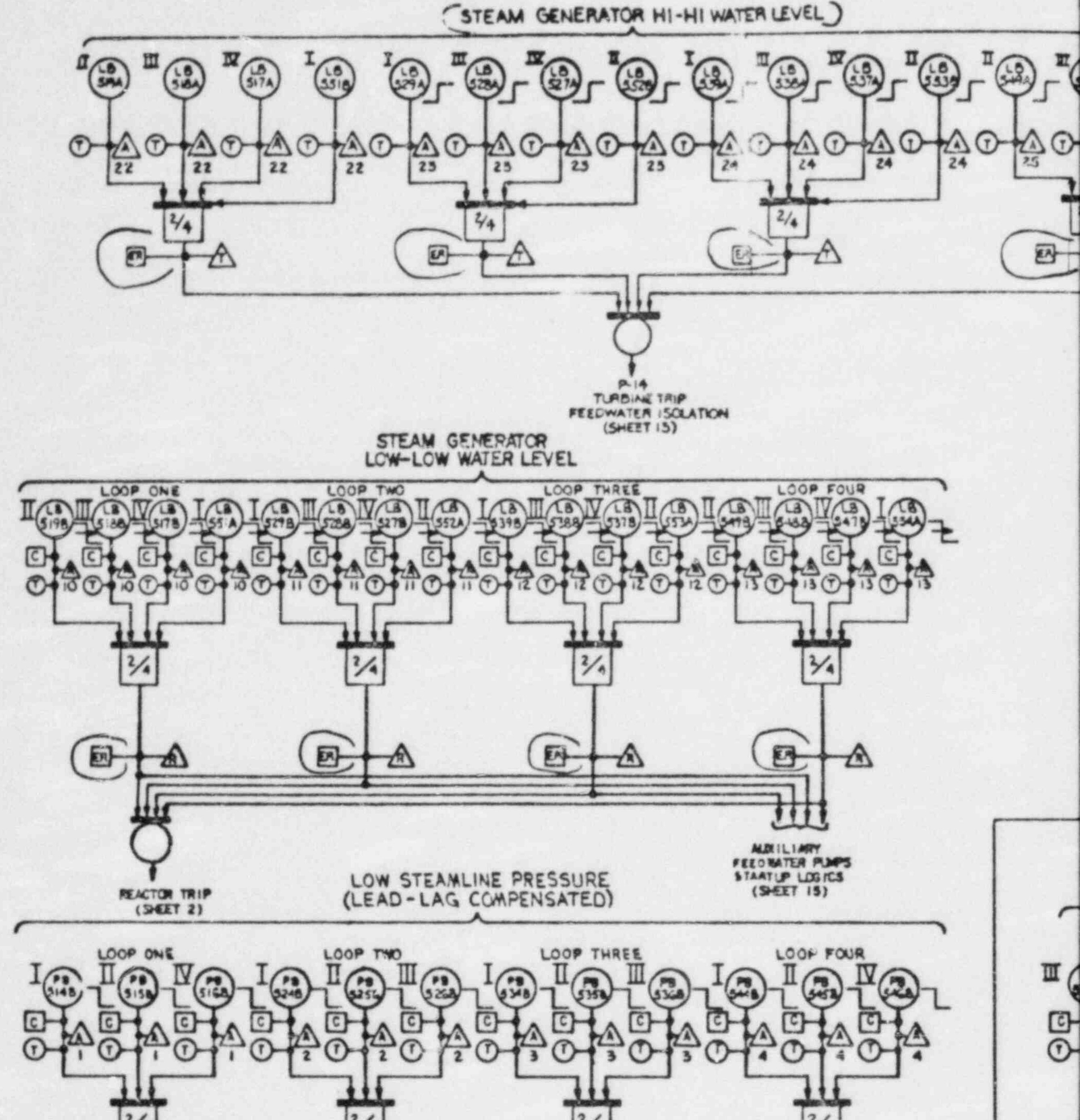
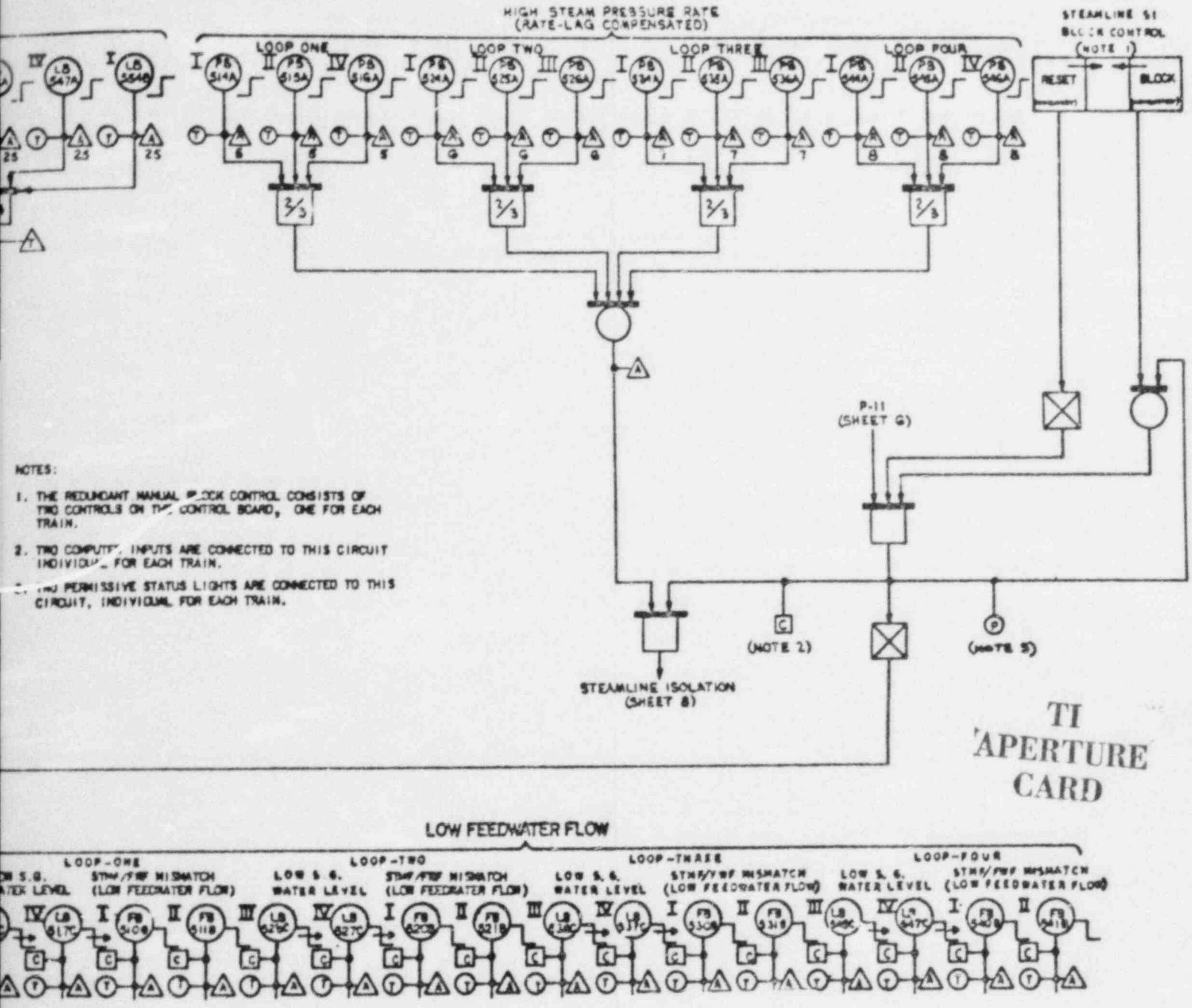

STEAM GENERATOR HI-HI WATER LEVEL
P-14
TURBINE TRIP
FEEDWATER ISOLATION
(SHEET 15)
STEAM GENERATOR
LOW-LOW WATER LEVEL
LOOP ONE
LOOP TWO
LOOP THREE
LOOP FOUR
REACTOR TRIP
(SHEET 2)
AUXILIARY
FEEDWATER PUMPS
STARTUP LOGICS
(SHEET 15)
LOW STEAMLINE PRESSURE
(LEAD-LAG COMPENSATED)
LOOP ONE
LOOP TWO
LOOP THREE
LOOP FOUR
SAFETY INJECTION AND STEAMLINE ISOLATION
(SHEET 8)



NOTES:

1. THE REDUNDANT MANUAL BLOCK CONTROL CONSISTS OF TWO CONTROLS ON THE CONTROL BOARD, ONE FOR EACH TRAIN.
2. TWO COMPUTER INPUTS ARE CONNECTED TO THIS CIRCUIT INDIVIDUAL FOR EACH TRAIN.
3. TWO PERMISSIVE STATUS LIGHTS ARE CONNECTED TO THIS CIRCUIT, INDIVIDUAL FOR EACH TRAIN.

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CATAWBA NUCLEAR STATION
Figure 7.2.1-1
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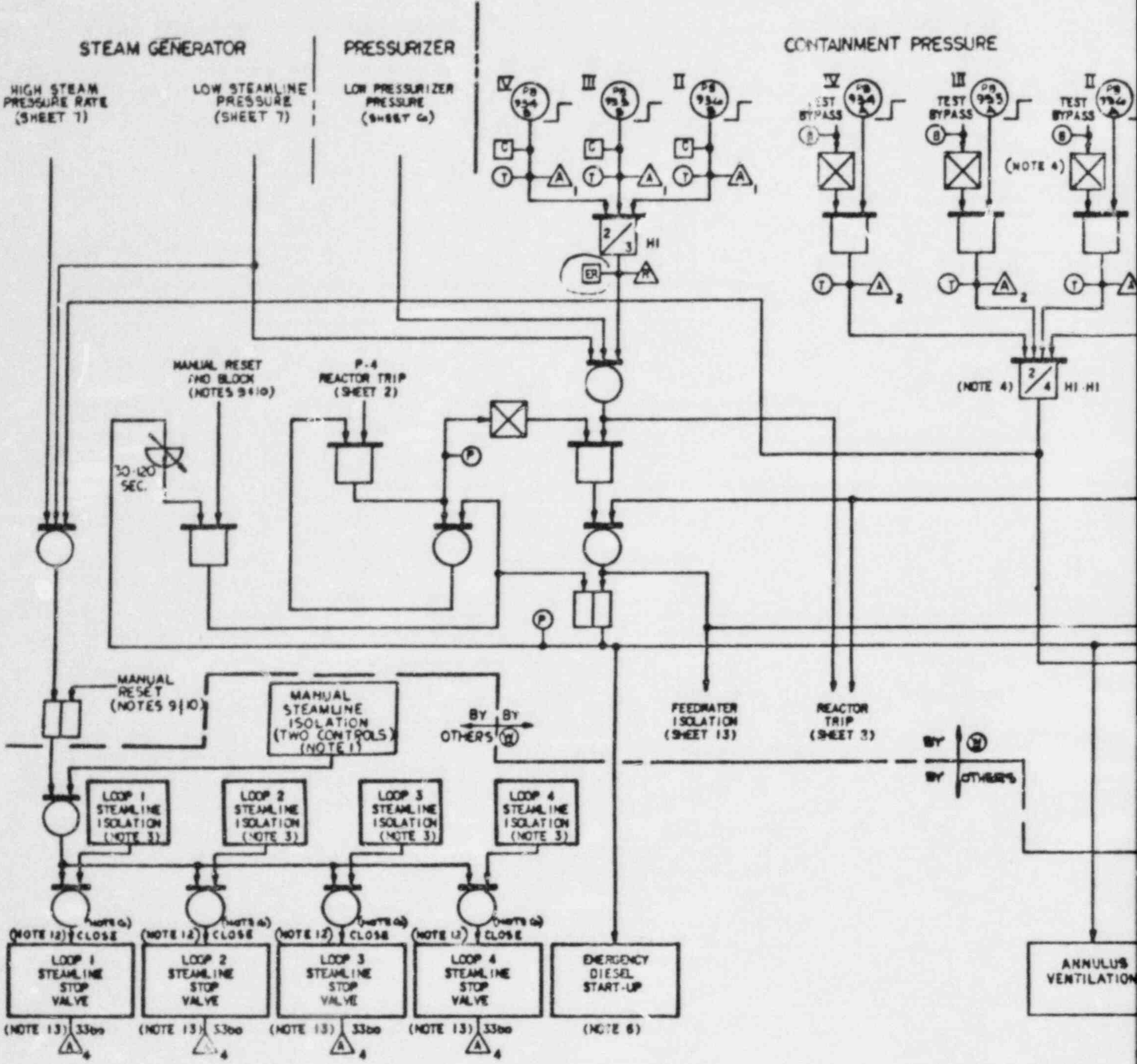
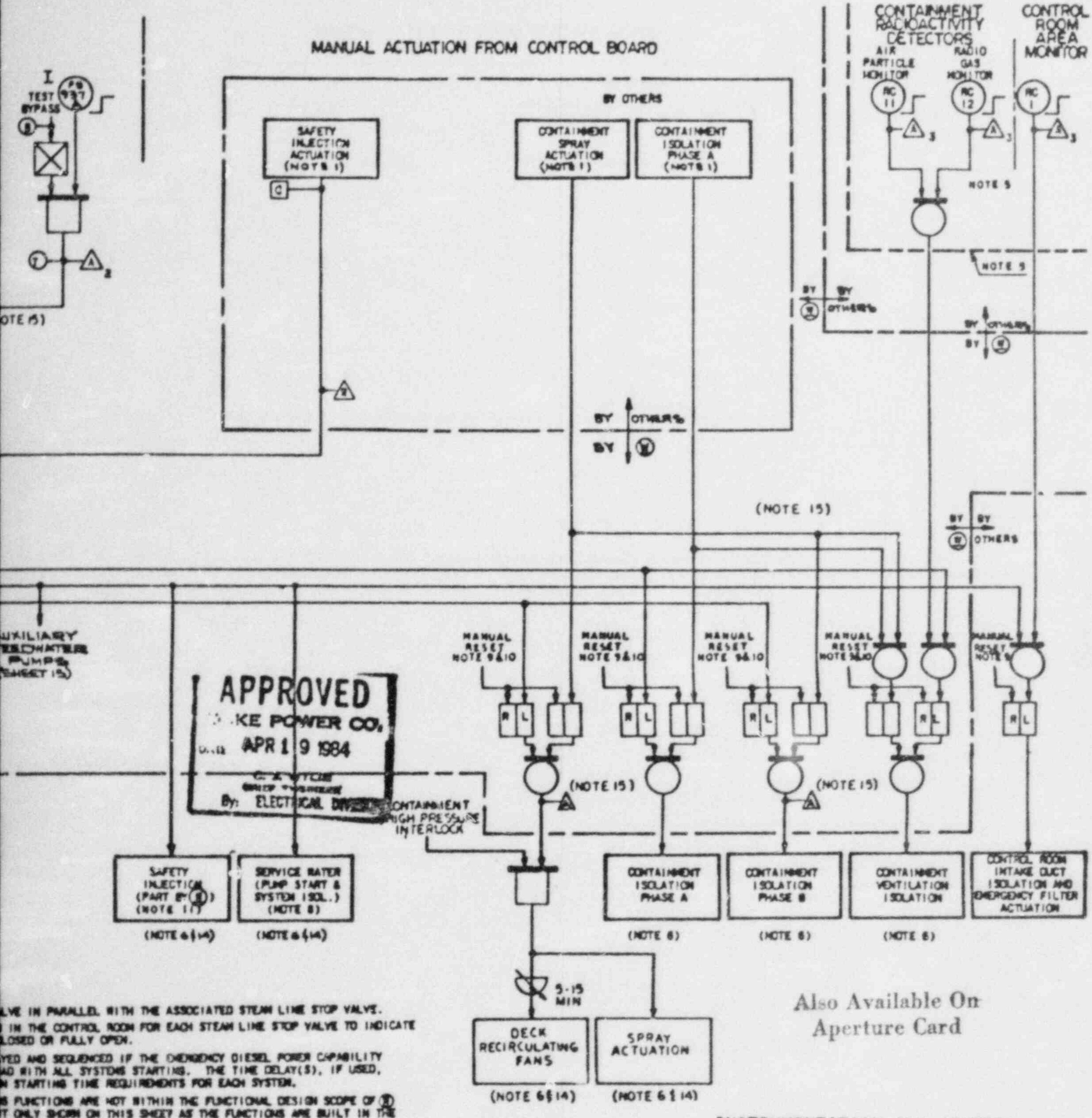
Revision 11

8406270190 -07



NOTES:

1. TWO MOMENTARY CONTROLS, ONE FOR EACH TRAIN.
3. ONE MOMENTARY CONTROL PER LOOP ON THE CONTROL BOARD.
4. CONTAINMENT PRESSURE BISTABLES FOR SPRAY ACTUATION ARE ENERGIZE-TO-ACTUATE (OTHER BISTABLES ARE DE-ENERGIZE-TO-ACTUATE).
5. ENCLOSED CIRCUITRY IS NOT PART OF THE SAFEGUARDS SYSTEM AND IS NOT REDUNDANT.
6. COMPONENTS ARE ALL INDIVIDUALLY SEALED IN (LATCHED), SO THAT LOSS OF THE ACTUATION SIGNAL WILL NOT CAUSE THESE COMPONENTS TO RETURN TO THE CONDITION HELD PRIOR TO THE ADVENT OF THE ACTUATION SIGNAL.
8. SERVICE WATER SYSTEM ISOLATION IS USED ONLY IF REQUIRED.
9. THE REDUNDANT MANUAL RESET CONSISTS OF TWO MOMENTARY CONTROLS ON THE CONTROL BOARD, ONE FOR EACH TRAIN.
10. SUPPLIED BY OTHERS.
11. NUCLEAR STEAM SUPPLY SYSTEM SEQUENCE REQUIREMENTS SPECIFIED BY (B).
12. ALSO CLOSES THE BYPASS
13. LIGHTS SHOULD BE PROVI WHEN THE VALVE IS FULL
14. THE ACTUATION MAY BE IS LESS THAN THE TOTAL MAY NOT EXCEED THE MAX
15. SOME ENGINEERED SAFEG NUCLEAR ENERGY SYSTEMS (B) SUPPLIED EQUIPMENT.



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INSTRUMENTATION AND CONTROL SYSTEM DIAGRAMS - SAFEGUARDS ACTUATION SIGNALS

CATAWBA NUCLEAR STATION

Figure 7.2.1-1
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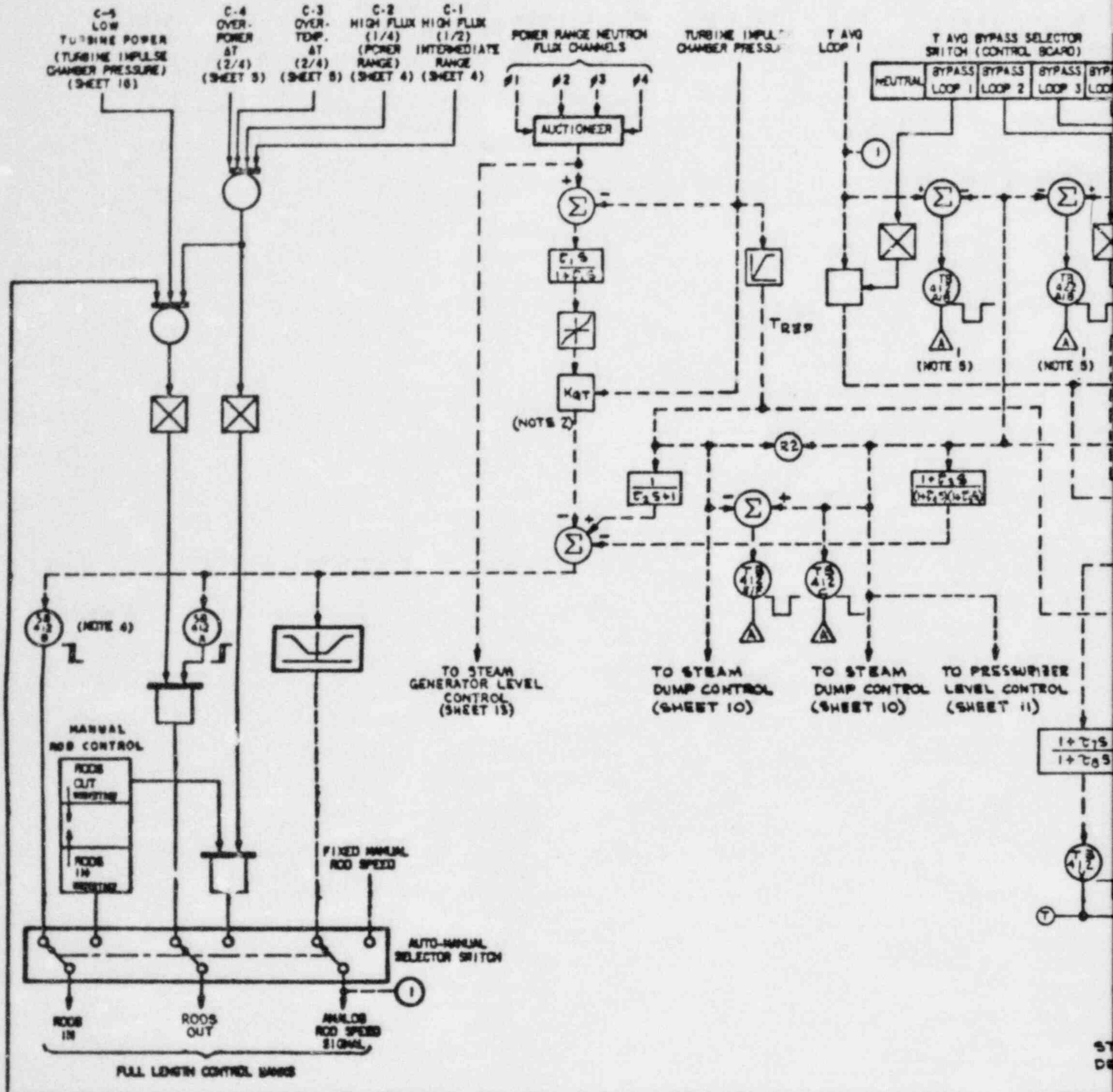

NOTES

1. ALL CIRCUITS ON THIS SHEET ARE NOT REDUNDANT.
2. KQT MAY VARY INVERSELY PROPORTIONAL TO LOAD WITH A FIXED LIMIT OR MAY VARY IN TWO DISCRETE STEPS WITH BREAK POINTS AT 30 TO 50 % AND 60 TO 80 % TURBINE LOAD.
3. THE SUMMER OUTPUTS HAVE FIXED MANUALLY ADJUSTABLE UPPER LIMITS.
4. THE ROD DIRECTION BISTABLES NO. SB-412A AND SB-412B ARE "ENERGIZED TO ACTUATE".
5. ALARM 1 AND ALARM 3 MUST HAVE REFLASH CAPABILITY.

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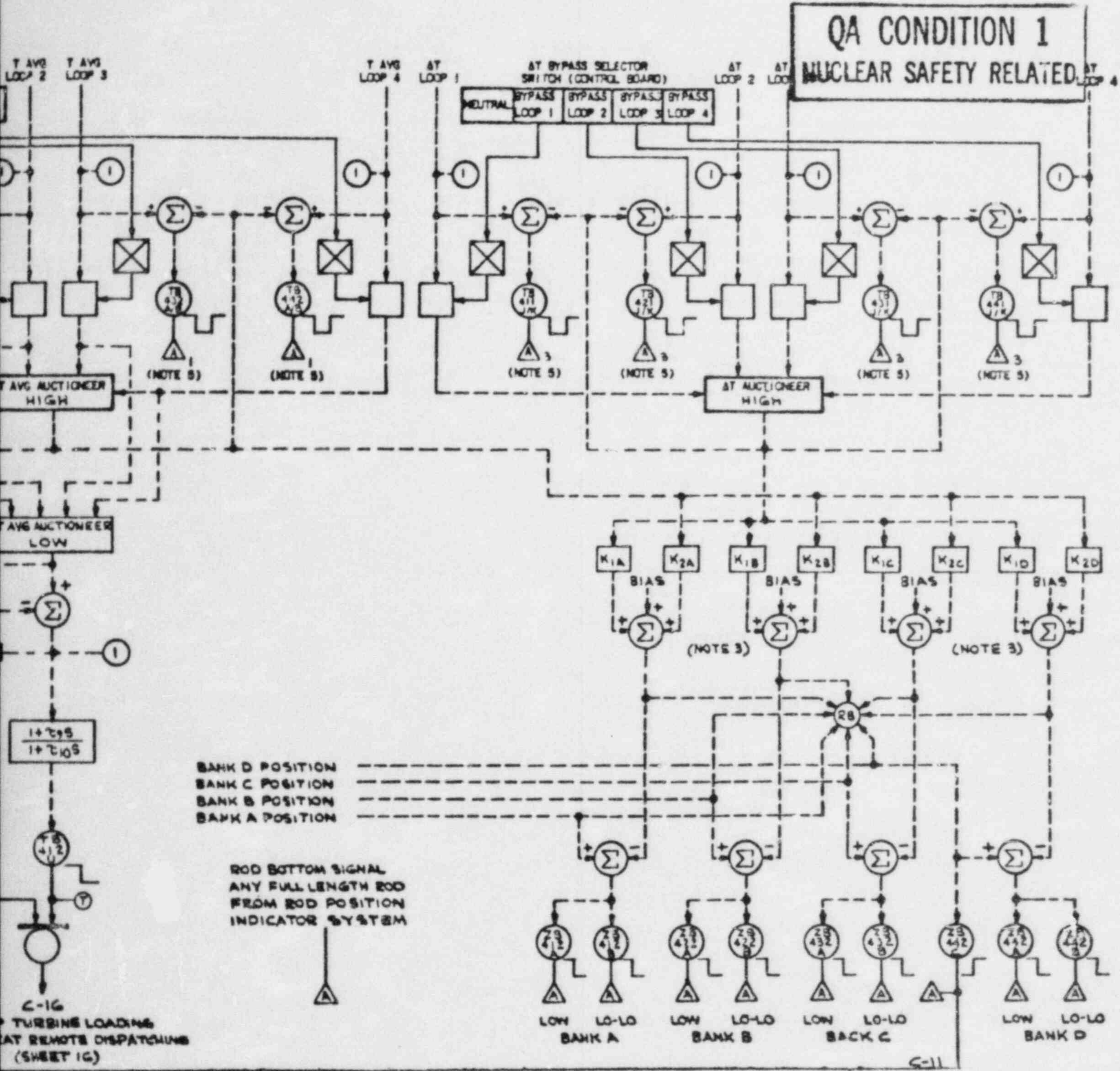

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INSTRUMENTATION AND CONTROL
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CATAWBA NUCLEAR STATION

Figure 7.2.1-1
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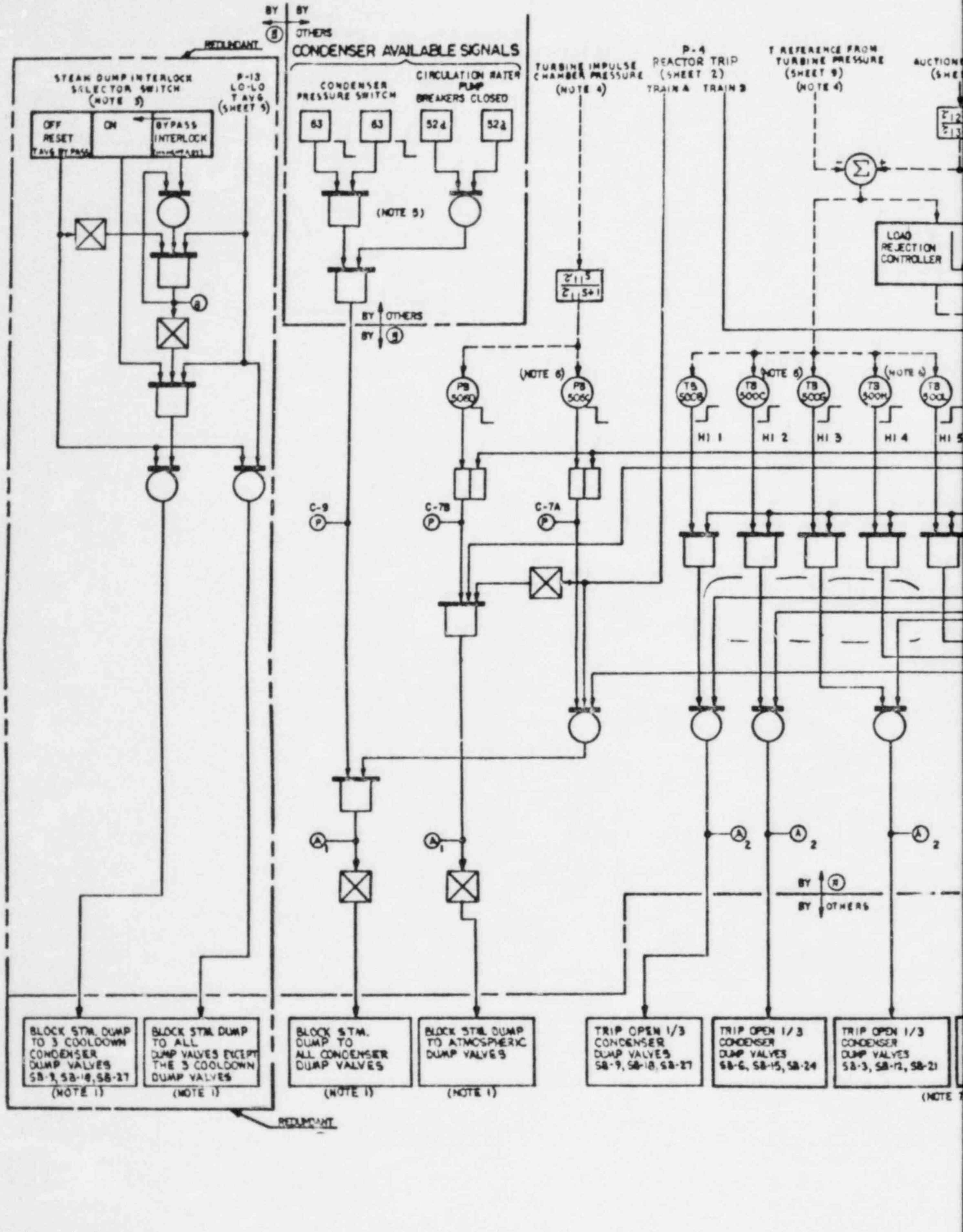
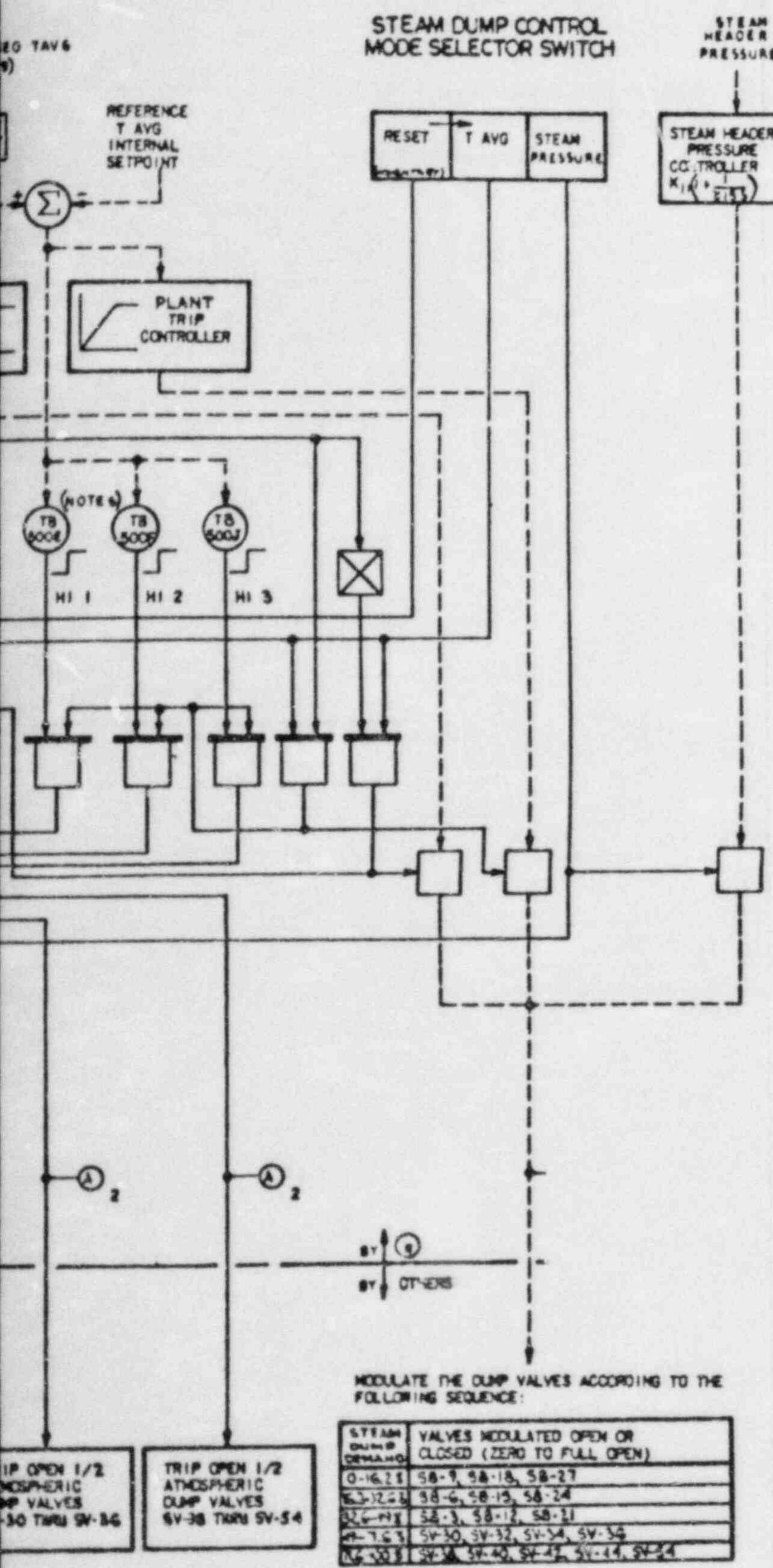
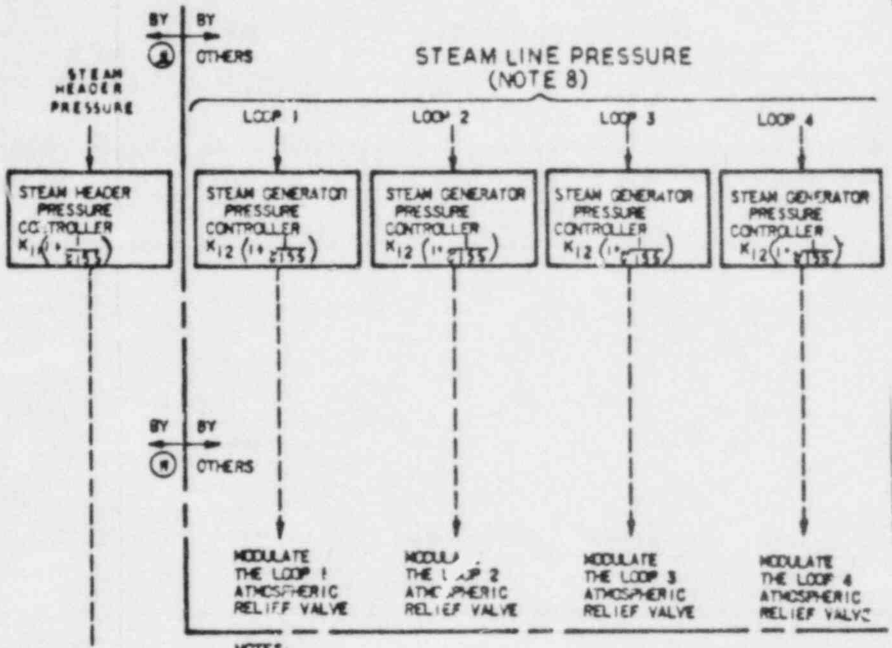


BY
BY OTHERS
REDUNDANT
CONDENSER AVAILABLE SIGNALS
STEAM DUMP INTERLOCK SELECTOR SWITCH (NOTE 3)
P-13 LO-LO T AVG (SHEET 5)
CONDENSER PRESSURE SWITCH
CIRCULATION WATER PUMP BREAKERS CLOSED
TURBINE IMPULSE CHAMBER PRESSURE (NOTE 4)
P-4 REACTOR TRIP (SHEET 2)
TRAIN A TRAIN B
T REFERENCE FROM TURBINE PRESSURE (SHEET 9) (NOTE 4)
OFF RESET
ON
BYPASS INTERLOCK
63
63
52a
52a
(NOTE 5)
LOAD REJECTION CONTROLLER
(NOTE 6)
HI 1
HI 2
HI 3
HI 4
C-9
C-7B
C-7A
BY OTHERS
BLOCK STM. DUMP TO 3 COOLDOWN CONDENSER DUMP VALVES SB-9, SB-18, SB-27 (NOTE 1)
BLOCK STM. DUMP TO ALL DUMP VALVES EXCEPT THE 3 COOLDOWN DUMP VALVES (NOTE 1)
BLOCK STM. DUMP TO ALL CONDENSER DUMP VALVES (NOTE 1)
BLOCK STM. DUMP TO ATMOSPHERIC DUMP VALVES (NOTE 1)
TRIP OPEN 1/3 CONDENSER DUMP VALVES SB-9, SB-18, SB-27
TRIP OPEN 1/3 CONDENSER DUMP VALVES SB-6, SB-15, SB-24
TRIP OPEN 1/3 CONDENSER DUMP VALVES SB-3, SB-12, SB-21
REDUNDANT





MODULATE THE DUMP VALVES ACCORDING TO THE FOLLOWING SEQUENCE:

STEAM DUMP DEMAND	VALVES MODULATED OPEN OR CLOSED (ZERO TO FULL OPEN)
0-16.2%	SB-9, SB-18, SB-27
[illegible]	SB-6, SB-15, SB-24
[illegible]	SB-3, SB-12, SB-21
[illegible]	SV-30, SV-32, SV-34, SV-36
[illegible]	SV-38, SV-40, SV-42, SV-44, SV-54

NOTES:

1. STEAM DUMP IS BLOCKED BY BLOCKING AIR TO THE DUMP VALVES AND VENTING THE DIAPHRAGMS. THE REDUNDANT LOGIC OUTPUT OPERATES TWO SOLENOID VENT VALVES IN SERIES TO REDUNDANTLY INTERLOCK THE AIR LINE BETWEEN EACH VALVE DIAPHRAGM AND ITS ASSOCIATED POSITIONER. THE NON-REDUNDANT LOGIC OUTPUT OPERATES ONE SOLENOID VENT VALVE TO INTERLOCK THE AIR LINE BETWEEN EACH VALVE DIAPHRAGM AND ITS ASSOCIATED POSITIONER. THE SOLENOID VALVES ARE DE-ENERGIZE TO VENT, CAUSING THE MAIN DUMP VALVE TO CLOSE IN FIVE SECONDS. EITHER OF THE REDUNDANT BLOCK SIGNALS OR THE NON-REDUNDANT BLOCK SIGNAL WILL BLOCK STEAM DUMP INDEPENDENT OF THE OTHER SIGNALS.
2. CIRCUITRY ON THIS SHEET IS NOT REDUNDANT EXCEPT WHERE INDICATED REDUNDANT.
3. SELECTOR SWITCH WITH THE FOLLOWING THREE POSITIONS:
   ON - SWITCH DUMP IS PERMITTED
   BYPASS-T AVG INTERLOCK IS BYPASSED FOR LO-LO T AVG. SPRING RETURN TO ON POSITION.
   OFF - STEAM DUMP IS NOT PERMITTED AND RESET T AVG BYPASS
   THE REDUNDANT INTERLOCK SELECTOR SWITCH CONSISTS OF TWO CONTROLS ON THE CONTROL BOARD, ONE FOR EACH TRAIN.
4. THE TWO ANALOG SIGNAL INPUTS COMING FROM TURBINE PRESSURE MUST COME FROM DIFFERENT PRESSURE TAPS TO MEET THE SINGLE FAILURE CRITERION.
5. THE CONDENSER AVAILABLE SIGNAL LOGIC IS TYPICAL, ACTUAL IMPLEMENTATION MAY BE DIFFERENT.
6. ALL TEMPERATURE BISTABLES ON THIS SHEET AND THE TURBINE IMPULSE CHAMBER PRESSURE BISTABLES NO. PB-506C AND PB-506D ARE "ENERGIZE TO ACTUATE".
7. LIGHTS SHOULD BE PROVIDED IN THE CONTROL ROOM FOR EACH DUMP VALVE TO INDICATE WHEN THE VALVE IS FULLY CLOSED OR FULLY OPEN.
8. THE STEAMLINE PRESSURE SIGNAL ORIGIN MUST BE DIFFERENT FROM THAT WHICH IS USED FOR THE STEAMLINE DIFFERENTIAL PRESSURE SAFETY INJECTION SIGNAL SHOWN ON SHEET 7 TO MEET THE SINGLE FAILURE CRITERION.

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CATAWBA NUCLEAR STATION

Figure 7.2.1-1
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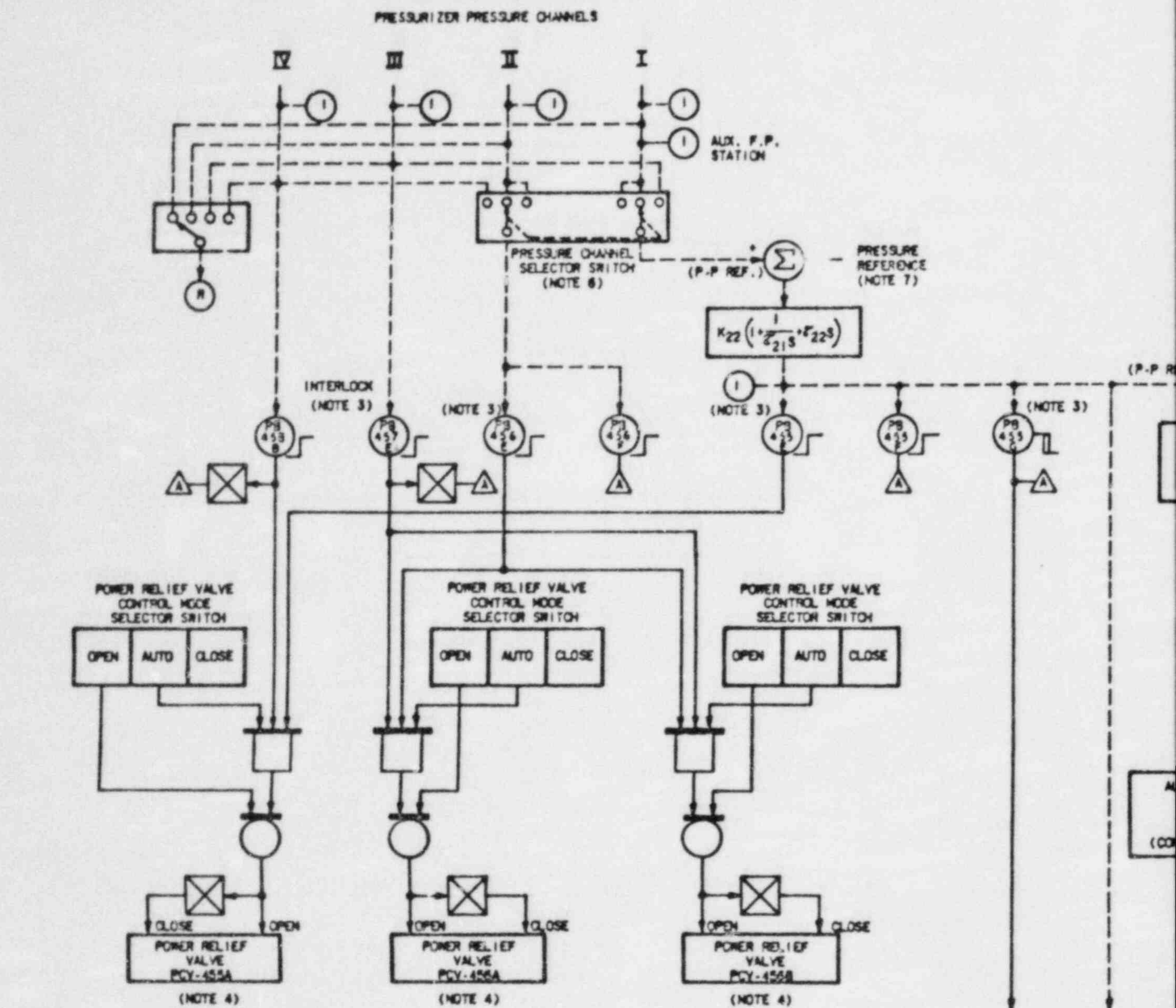
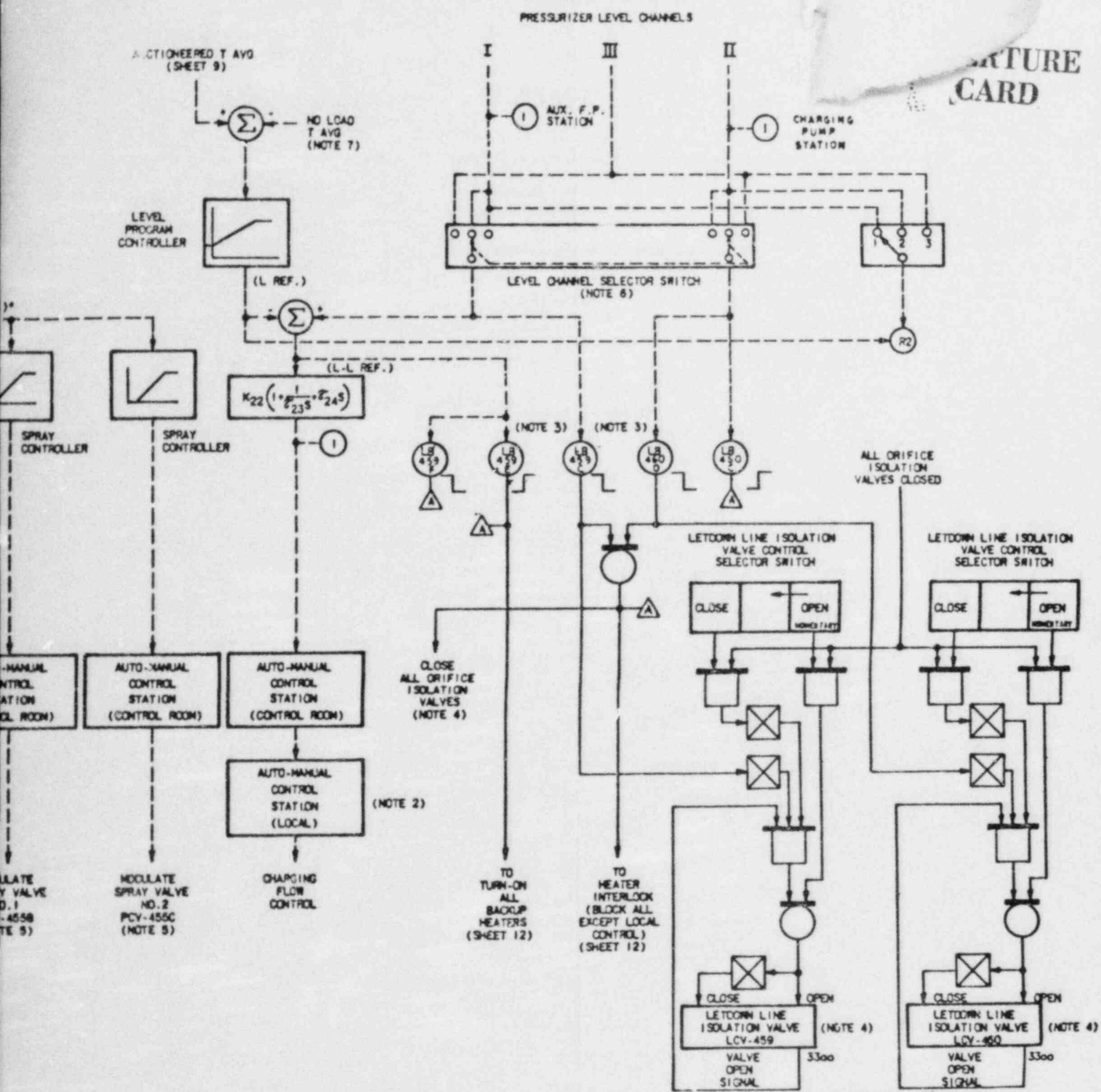
8406270190-10



NOTES:

1. ALL CIRCUITS ON THIS SHEET ARE NOT REDUNDANT.
2. LOCAL CONTROL OVERRIDES ALL OTHER SIGNALS.
   LOCAL OVERRIDE ACTUATES ALARM IN CONTROL ROOM.
3. PRESSURE BISTABLES NO. PB-455E, PB-456G, PB-456E, PB-457E, & PB-458B AND LEVEL BISTABLES NO. LB-459C, LB-459E, & LB-460D ARE ENERGIZE TO ACTUATE.
4. OPEN/SHUT INDICATION IN CONTROL ROOM.
5. A LIGHT SHOULD BE PROVIDED IN THE CONTROL ROOM FOR EACH SPRAY VALVE TO INDICATE WHEN IT IS NOT FULLY CLOSED.
6. CENTER POSITION NORMALLY SELECTED.
7. ADJUSTABLE SETPOINT WITHIN CONTROLLER.



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INSTRUMENTATION AND CONTROL SYSTEM DIAGRAMS - INDEX AND SYMBOLS

CATAWBA NUCLEAR STATION

Figure 7.2.1-1

(11 of 16)

Revision 11

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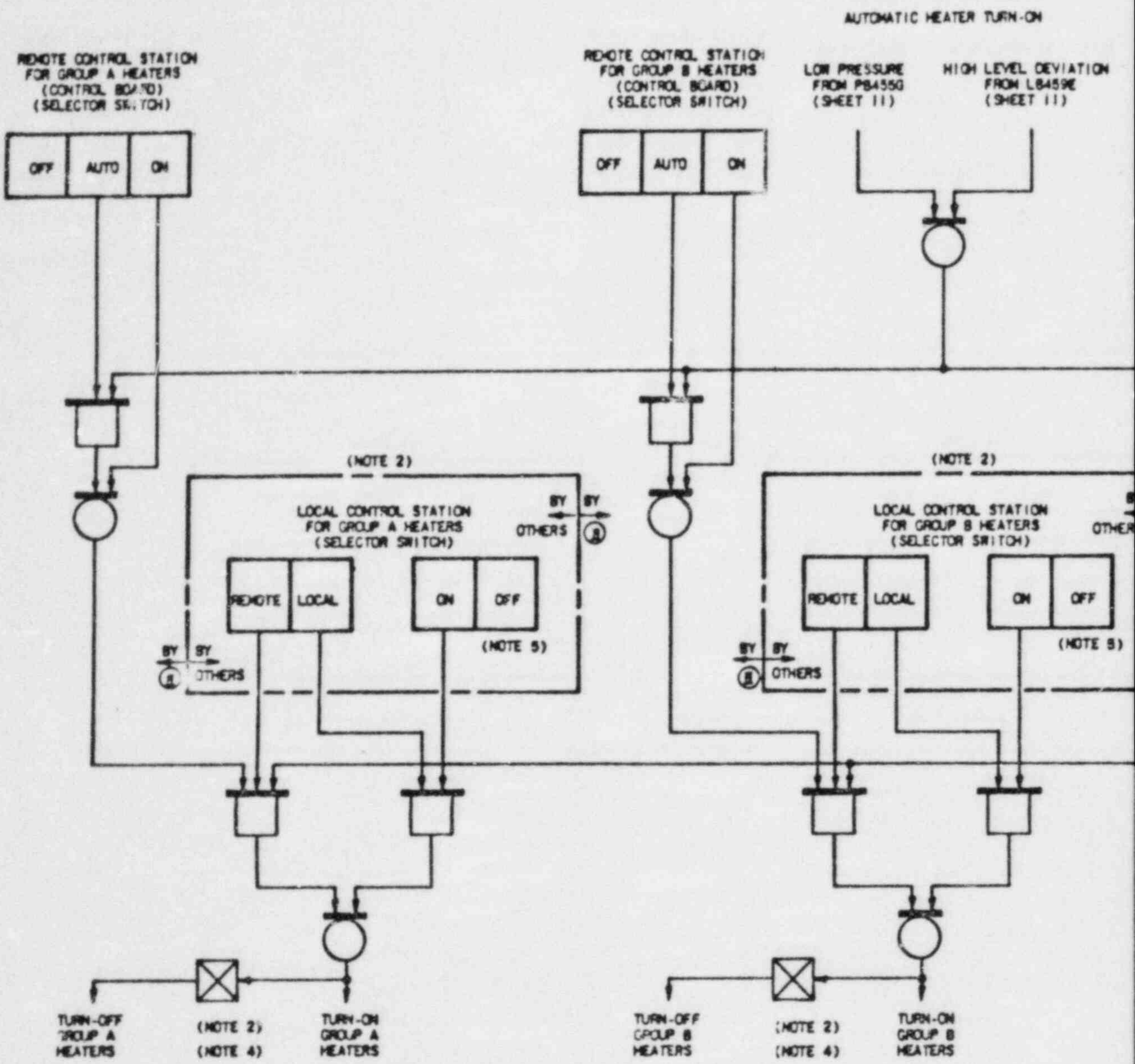
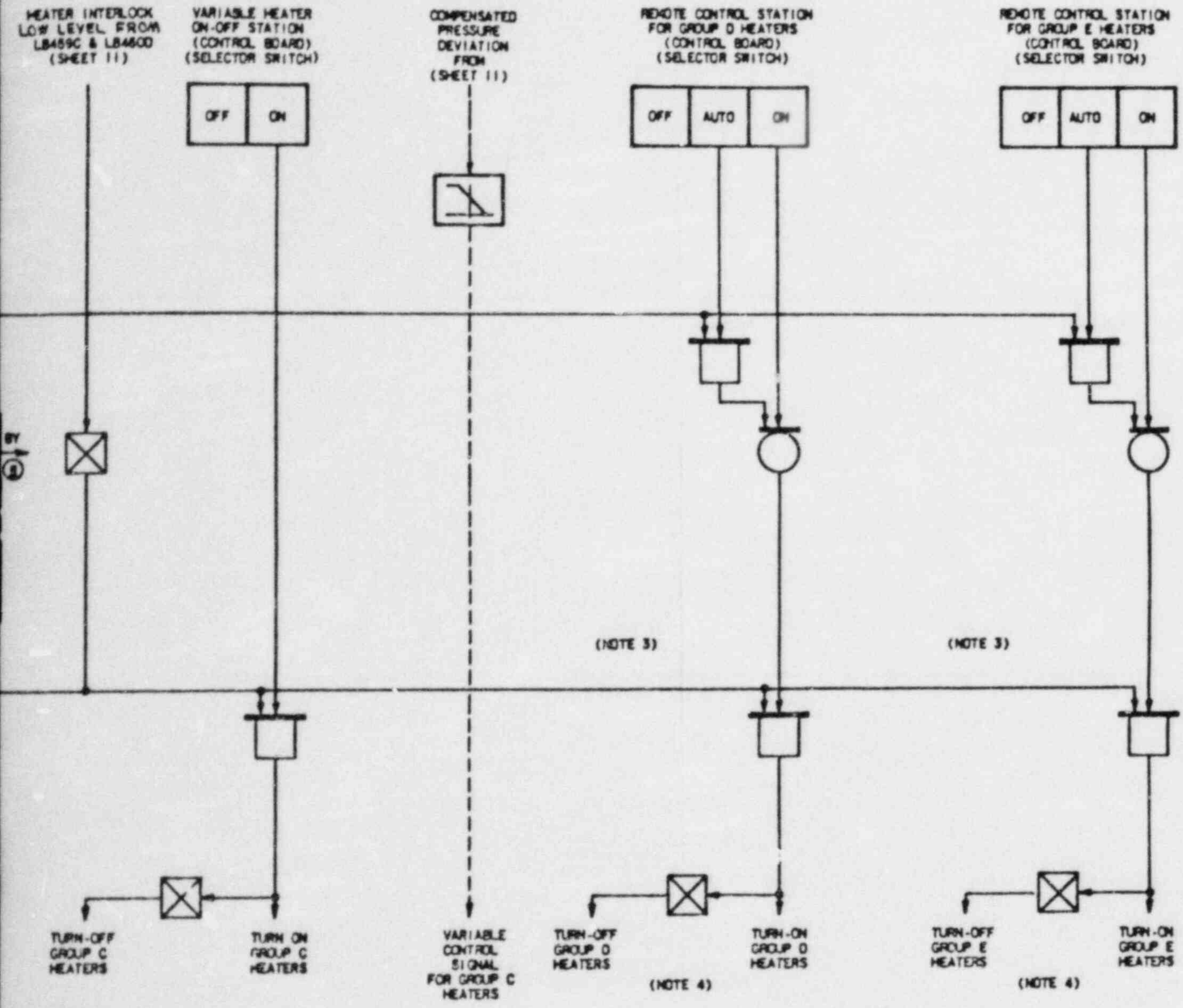


NOTES:

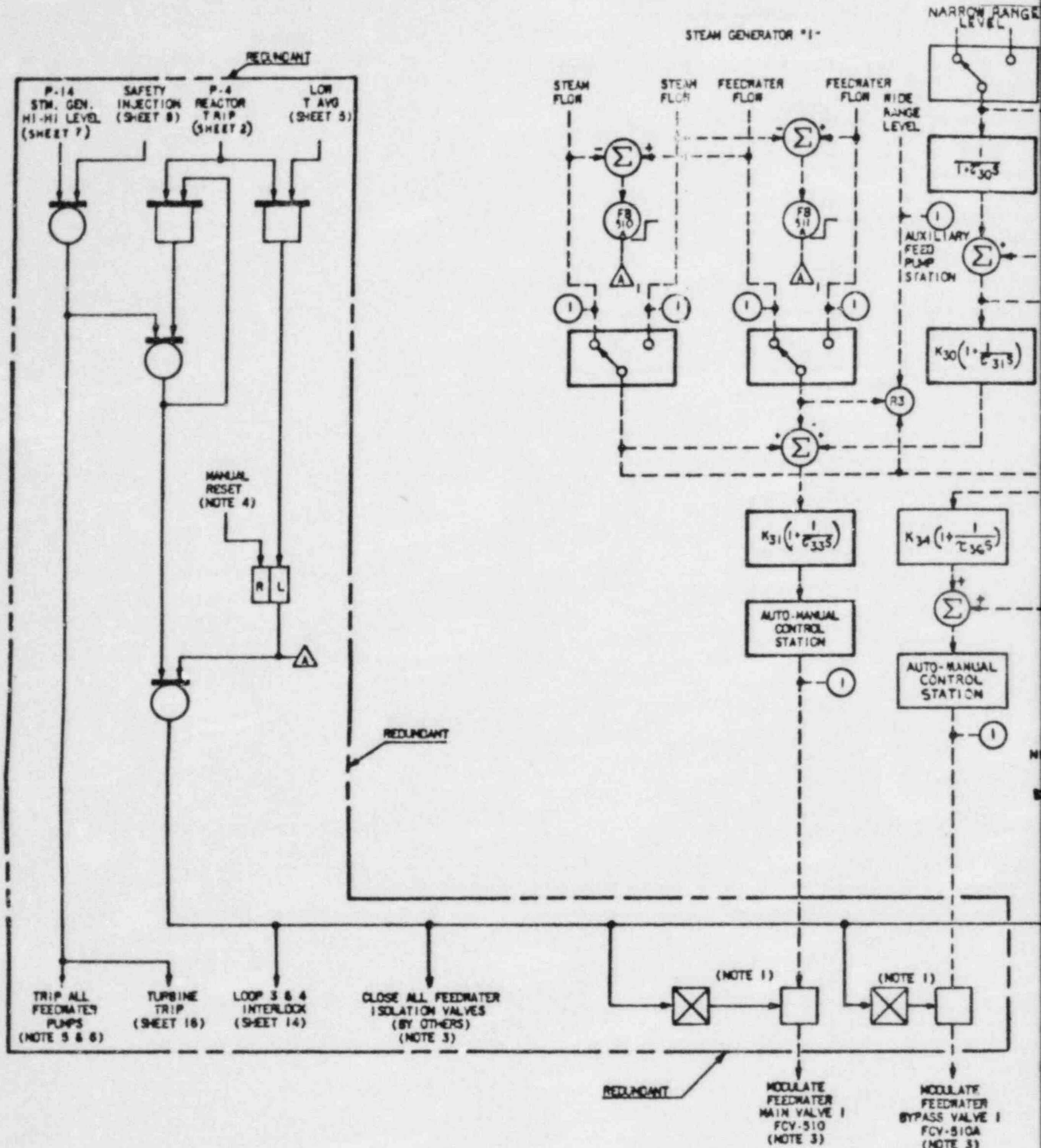
1. ALL CIRCUITS ON THIS SHEET ARE NOT REDUNDANT.
2. GROUP A AND GROUP B HEATERS MUST BE ON SEPARATE VITAL POWER SUPPLIES WITH THE LOCAL CONTROL SEPARATED SO THAT ANY SINGLE FAILURE DOES NOT DEFEAT BOTH.
3. THE NUMBER OF BACK-UP HEATER GROUPS IS TYPICAL. THE ACTUAL NUMBER OF GROUPS MAY DIFFER DEPENDING ON ELECTRICAL LOADING REQUIREMENTS.
4. BACK-UP HEATER STATUS INDICATION IN CONTROL ROOM.
5. PRECAUTIONS SHOULD BE TAKEN TO AVOID MANUAL HEATER OPERATION, WHICH WOULD CAUSE HEATER DAMAGE, IF THE WATER LEVEL UNCOVERS THE HEATERS.



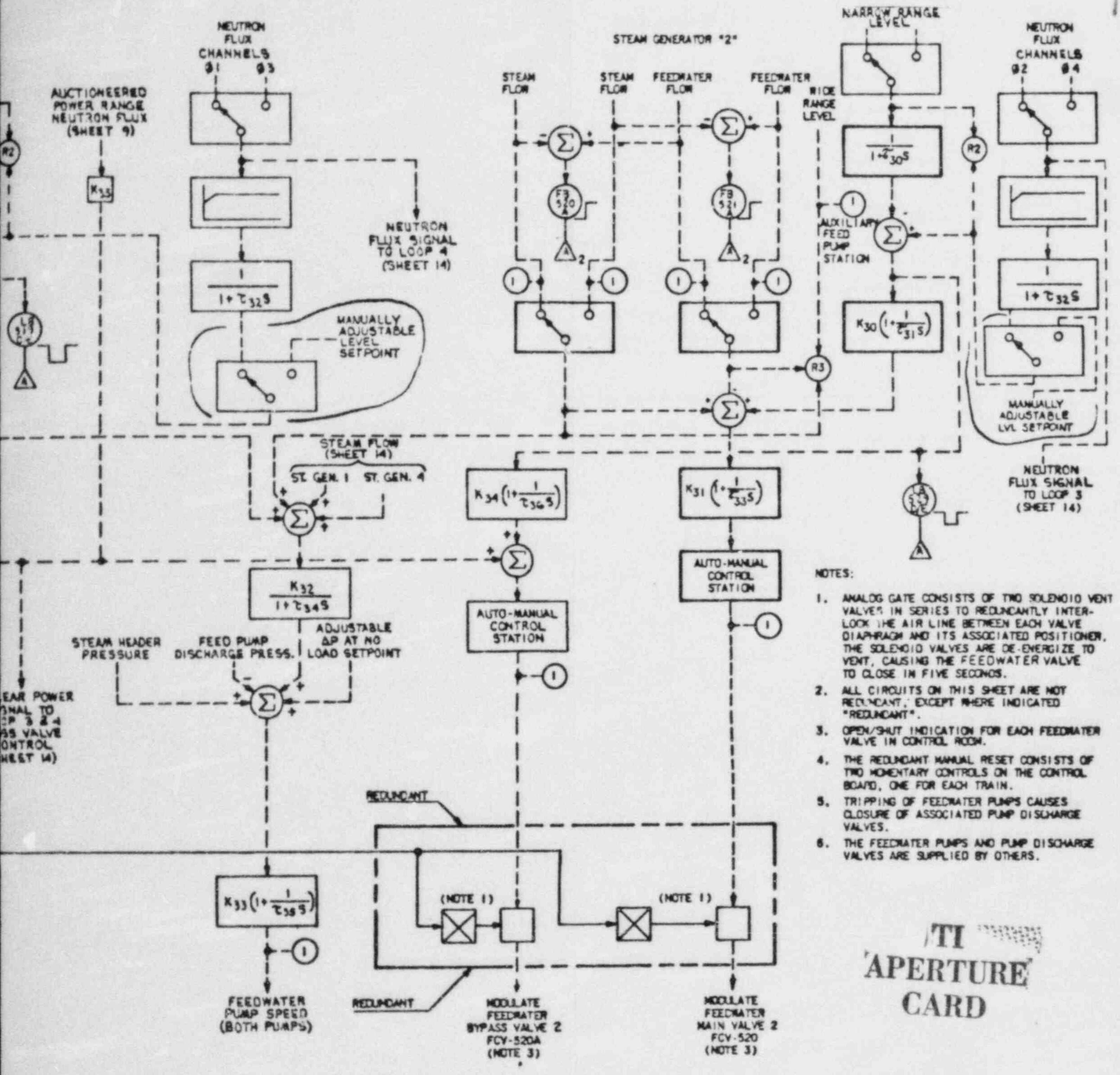
INSTRUMENTATION AND CONTROL SYSTEM DIAGRAMS - INDEX AND SYMBOLS

CATAWBA NUCLEAR STATION

Figure 7.2.1-1
(12 of 16)
Revision 11



STEAM GENERATOR "1"
NARROW RANGE LEVEL
REDUNDANT
P-14 STM. GEN. HI-HI LEVEL (SHEET 7)
SAFETY INJECTION (SHEET 8)
P-4 REACTOR TRIP (SHEET 2)
LOW T AVG (SHEET 5)
STEAM FLOW
STEAM FLOW
FEEDWATER FLOW
FEEDWATER FLOW
WIDE RANGE LEVEL
FB 510
FB 511
AUXILIARY FEED PUMP STATION
MANUAL RESET (NOTE 4)
AUTO-MANUAL CONTROL STATION
AUTO-MANUAL CONTROL STATION
REDUNDANT
(NOTE 1)
(NOTE 1)
TRIP ALL FEEDWATER PUMPS (NOTE 5 & 6)
TURBINE TRIP (SHEET 16)
LOOP 3 & 4 INTERLOCK (SHEET 14)
CLOSE ALL FEEDWATER ISOLATION VALVES (BY OTHERS) (NOTE 3)
REDUNDANT
MODULATE FEEDWATER MAIN VALVE 1 FCV-510 (NOTE 3)
MODULATE FEEDWATER BYPASS VALVE 1 FCV-510A (NOTE 3)



NOTES:

1. ANALOG GATE CONSISTS OF TWO SOLENOID VENT VALVES IN SERIES TO REDUNDANTLY INTERLOCK THE AIR LINE BETWEEN EACH VALVE DIAPHRAGM AND ITS ASSOCIATED POSITIONER. THE SOLENOID VALVES ARE DE-ENERGIZE TO VENT, CAUSING THE FEEDWATER VALVE TO CLOSE IN FIVE SECONDS.
2. ALL CIRCUITS ON THIS SHEET ARE NOT REDUNDANT, EXCEPT WHERE INDICATED "REDUNDANT".
3. OPEN/SHUT INDICATION FOR EACH FEEDWATER VALVE IN CONTROL ROOM.
4. THE REDUNDANT MANUAL RESET CONSISTS OF TWO MOMENTARY CONTROLS ON THE CONTROL BOARD, ONE FOR EACH TRAIN.
5. TRIPPING OF FEEDWATER PUMPS CAUSES CLOSURE OF ASSOCIATED PUMP DISCHARGE VALVES.
6. THE FEEDWATER PUMPS AND PUMP DISCHARGE VALVES ARE SUPPLIED BY OTHERS.

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INSTRUMENTATION AND CONTROL SYSTEM DIAGRAMS - INDEX AND SYMBOLS

CATAWBA NUCLEAR STATION

Figure 7.2.1-1 (13 of 16)
Revision 11

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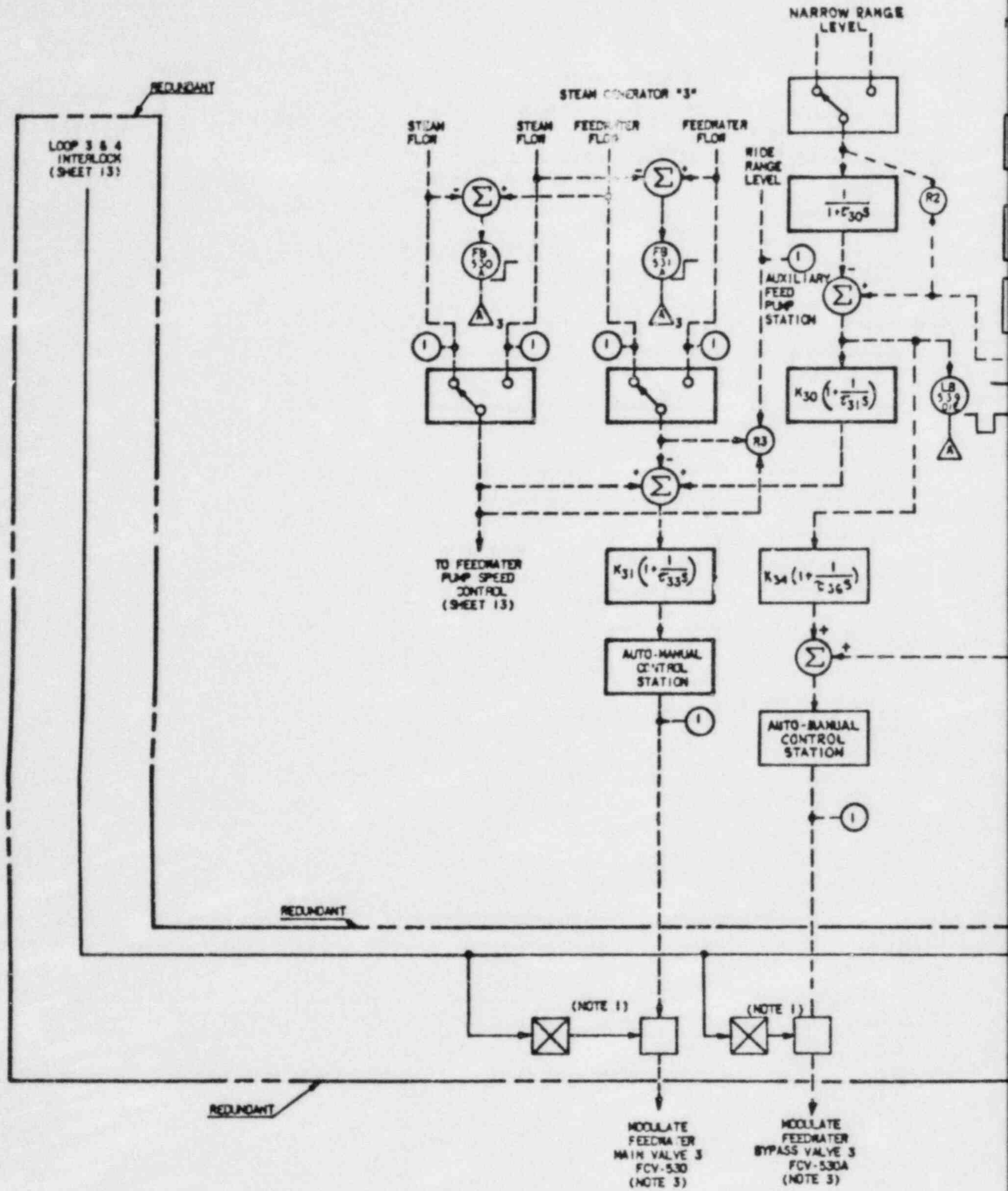
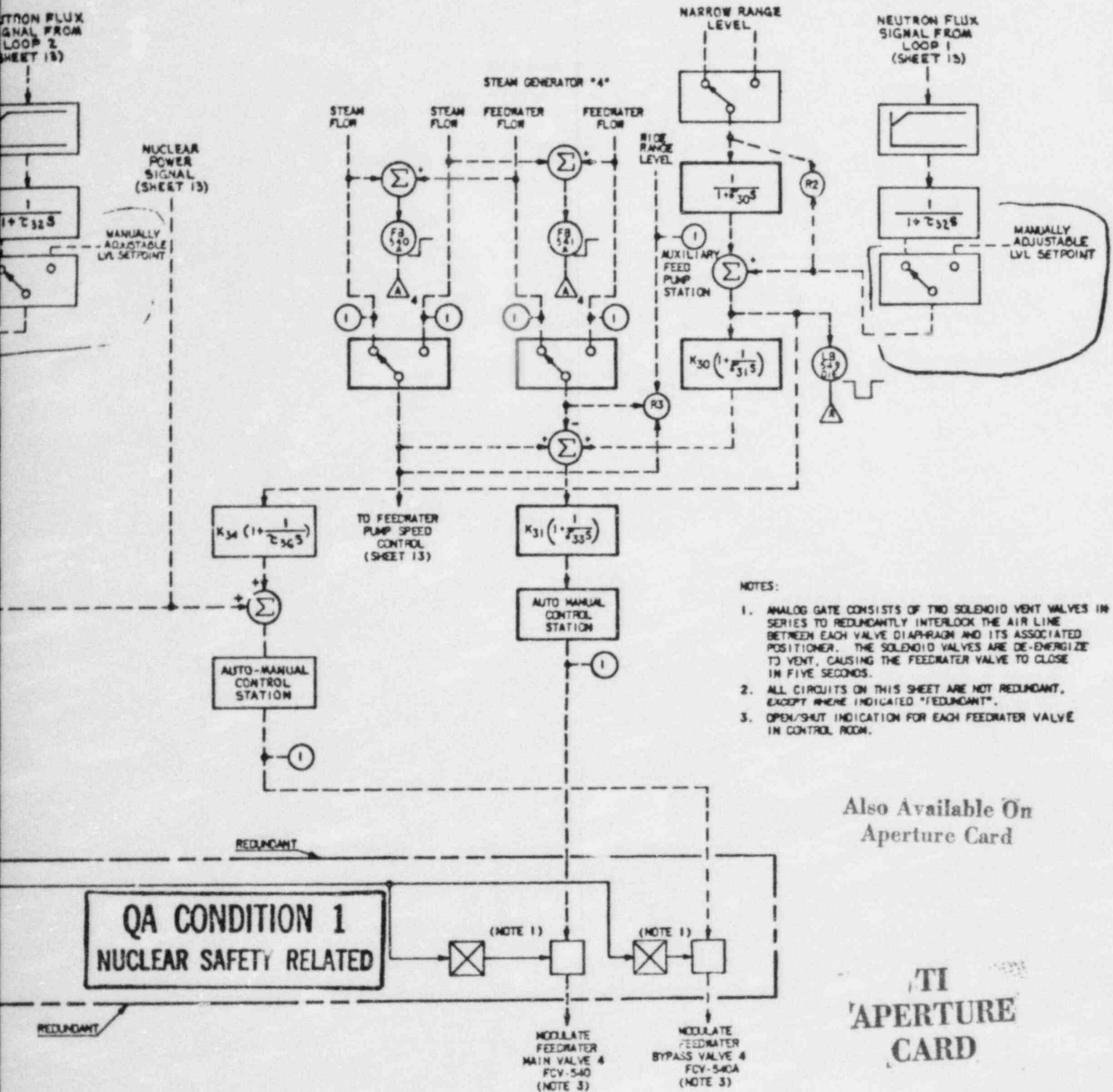


NARROW RANGE LEVEL
REDUNDANT
LOOP 3 & 4 INTERLOCK (SHEET 13)
STEAM FLOW
STEAM FLOW
FEEDWATER FLOW
WIDE RANGE LEVEL
AUXILIARY FEED PUMP STATION
TO FEEDWATER PUMP SPEED CONTROL (SHEET 13)
AUTO-MANUAL CONTROL STATION
AUTO-MANUAL CONTROL STATION
REDUNDANT
(NOTE 1)
(NOTE 1)
REDUNDANT
MODULATE FEEDWATER MAIN VALVE 3 FCV-530 (NOTE 3)
MODULATE FEEDWATER BYPASS VALVE 3 FCV-530A (NOTE 3)



NOTES:

1. ANALOG GATE CONSISTS OF TWO SOLENOID VENT VALVES IN SERIES TO REDUNDANTLY INTERLOCK THE AIR LINE BETWEEN EACH VALVE DIAPHRAGM AND ITS ASSOCIATED POSITIONER. THE SOLENOID VALVES ARE DE-ENERGIZE TO VENT, CAUSING THE FEEDWATER VALVE TO CLOSE IN FIVE SECONDS.
2. ALL CIRCUITS ON THIS SHEET ARE NOT REDUNDANT, EXCEPT WHERE INDICATED "REDUNDANT".
3. OPEN/SHUT INDICATION FOR EACH FEEDWATER VALVE IN CONTROL ROOM.

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INSTRUMENTATION AND CONTROL SYSTEM DIAGRAMS - INDEX AND SYMBOLS
CATAWBA NUCLEAR STATION
Figure 7.2.1-1
(14 of 16)
Revision 11

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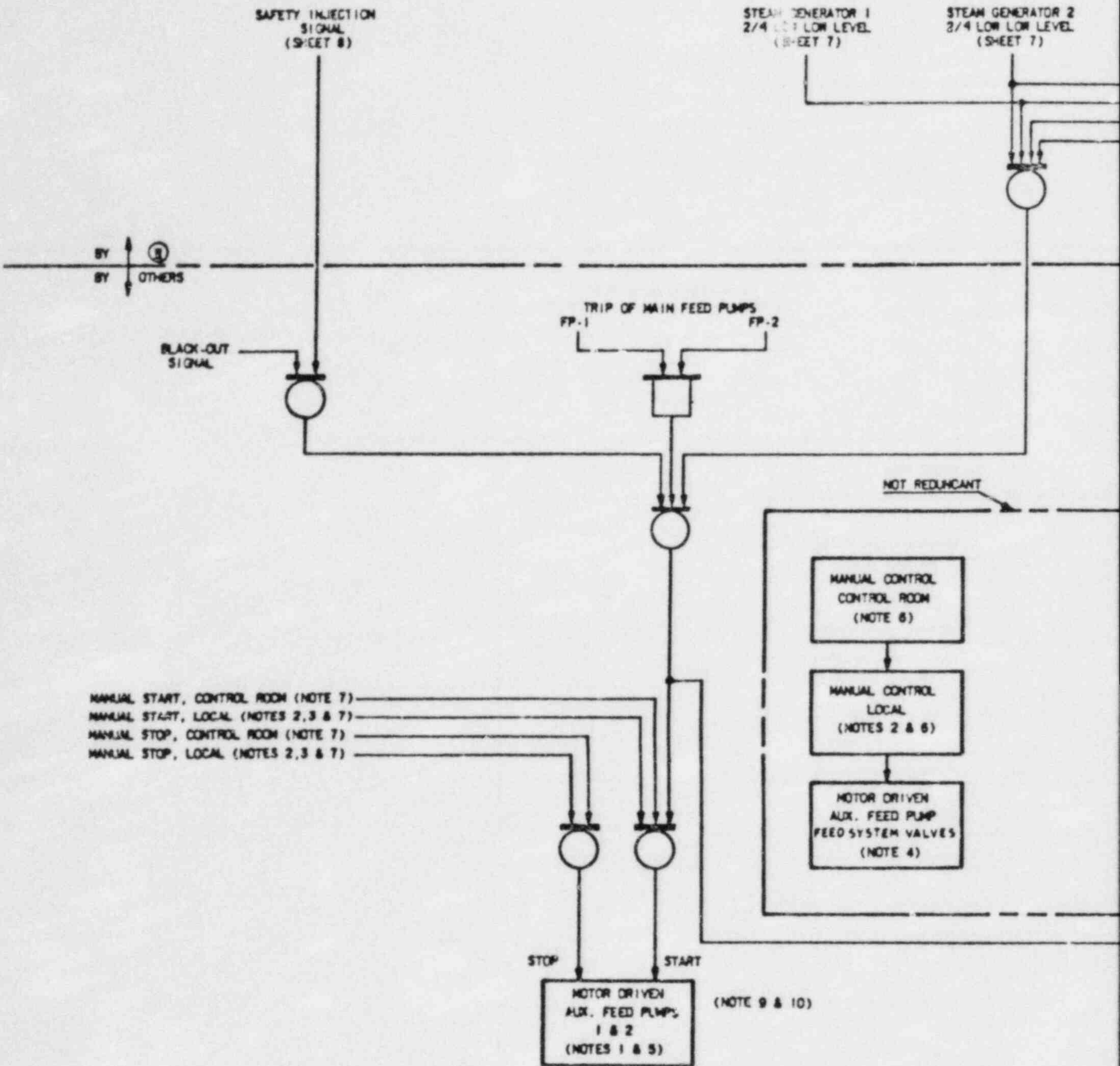

SAFETY INJECTION SIGNAL (SHEET 8)
STEAM GENERATOR 1
(SHEET 7)
STEAM GENERATOR 2 2/4 LOW LOW LEVEL (SHEET 7)
BY
BY OTHERS
TRIP OF MAIN FEED PUMPS
FP-1
FP-2
BLACK-OUT SIGNAL
NOT REDUNDANT
MANUAL CONTROL CONTROL ROOM (NOTE 6)
MANUAL CONTROL LOCAL (NOTES 2 & 6)
MOTOR DRIVEN AUX. FEED PUMP FEED SYSTEM VALVES (NOTE 4)
MANUAL START, CONTROL ROOM (NOTE 7)
MANUAL START, LOCAL (NOTES 2,3 & 7)
MANUAL STOP, CONTROL ROOM (NOTE 7)
MANUAL STOP, LOCAL (NOTES 2,3 & 7)
STOP
START
MOTOR DRIVEN AUX. FEED PUMPS 1 & 2 (NOTES 1 & 5)
(NOTE 9 & 10)

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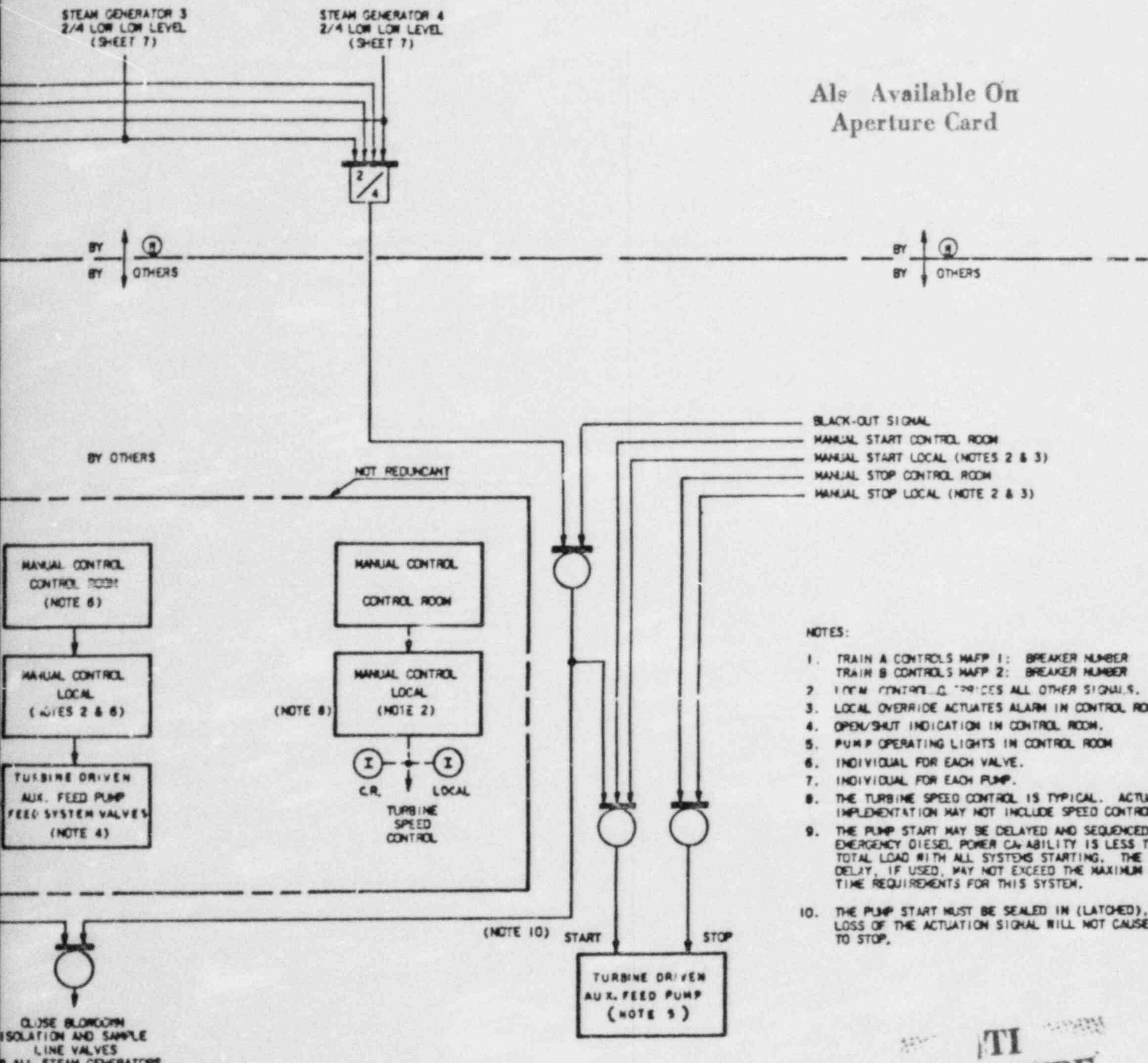

NOTES:

1. TRAIN A CONTROLS MAFP 1: BREAKER NUMBER
   TRAIN B CONTROLS MAFP 2: BREAKER NUMBER
2. LOCAL CONTROL [illegible] ALL OTHER SIGNALS.
3. LOCAL OVERRIDE ACTUATES ALARM IN CONTROL ROOM.
4. OPEN/SHUT INDICATION IN CONTROL ROOM.
5. PUMP OPERATING LIGHTS IN CONTROL ROOM
6. INDIVIDUAL FOR EACH VALVE.
7. INDIVIDUAL FOR EACH PUMP.
8. THE TURBINE SPEED CONTROL IS TYPICAL. ACTUAL IMPLEMENTATION MAY NOT INCLUDE SPEED CONTROL.
9. THE PUMP START MAY BE DELAYED AND SEQUENCED IF THE EMERGENCY DIESEL POWER CAPABILITY IS LESS THAN THE TOTAL LOAD WITH ALL SYSTEMS STARTING. THE TIME DELAY, IF USED, MAY NOT EXCEED THE MAXIMUM STARTING TIME REQUIREMENTS FOR THIS SYSTEM.
10. THE PUMP START MUST BE SEALED IN (LATCHED), SO THAT LOSS OF THE ACTUATION SIGNAL WILL NOT CAUSE THE PUMP TO STOP.

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INSTRUMENTATION AND CONTROL SYSTEM DIAGRAMS - INDEX AND SYMBOLS
CATAWBA NUCLEAR STATION
Figure 7.2.1-1
(15 of 16)
Revision 11

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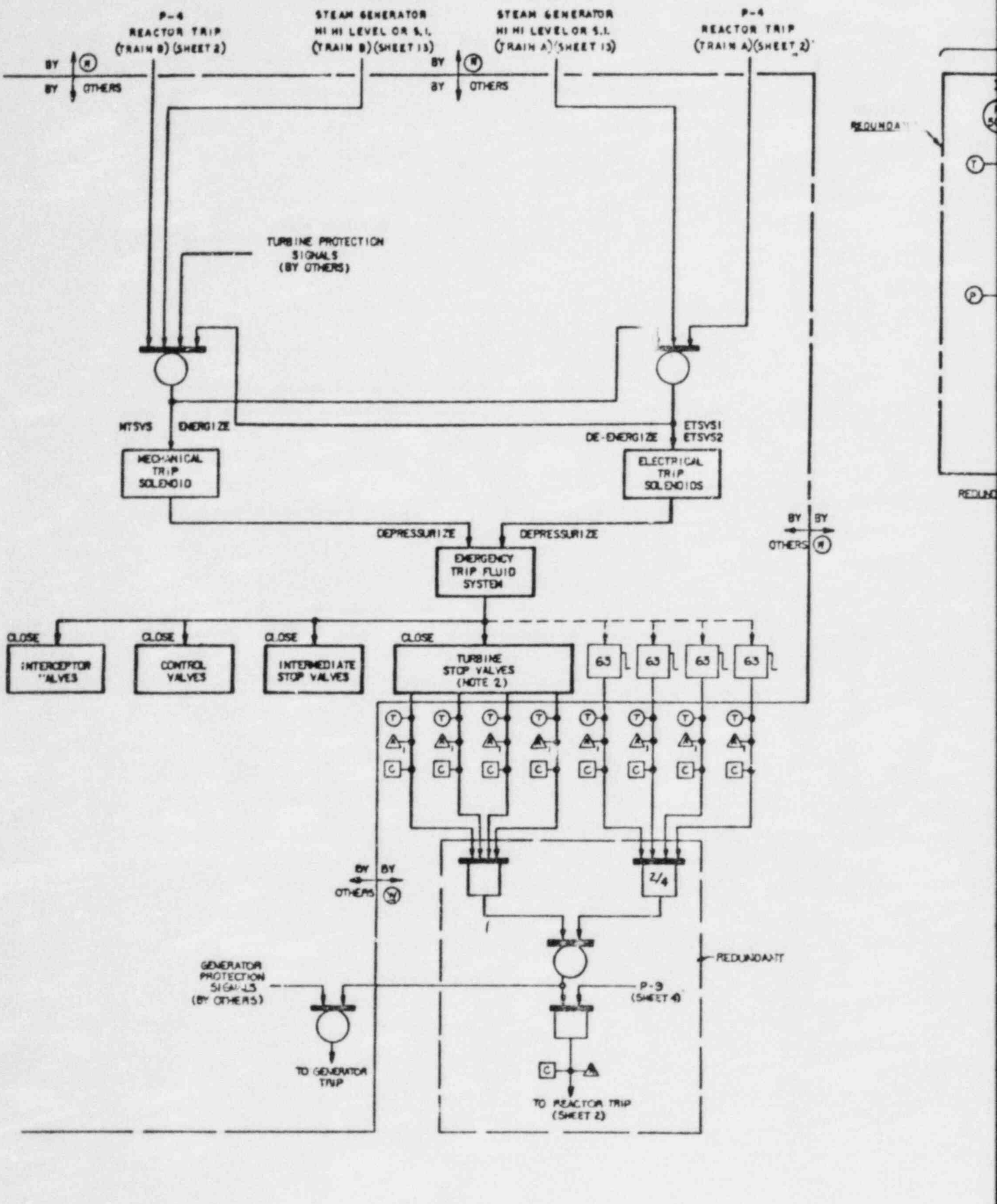
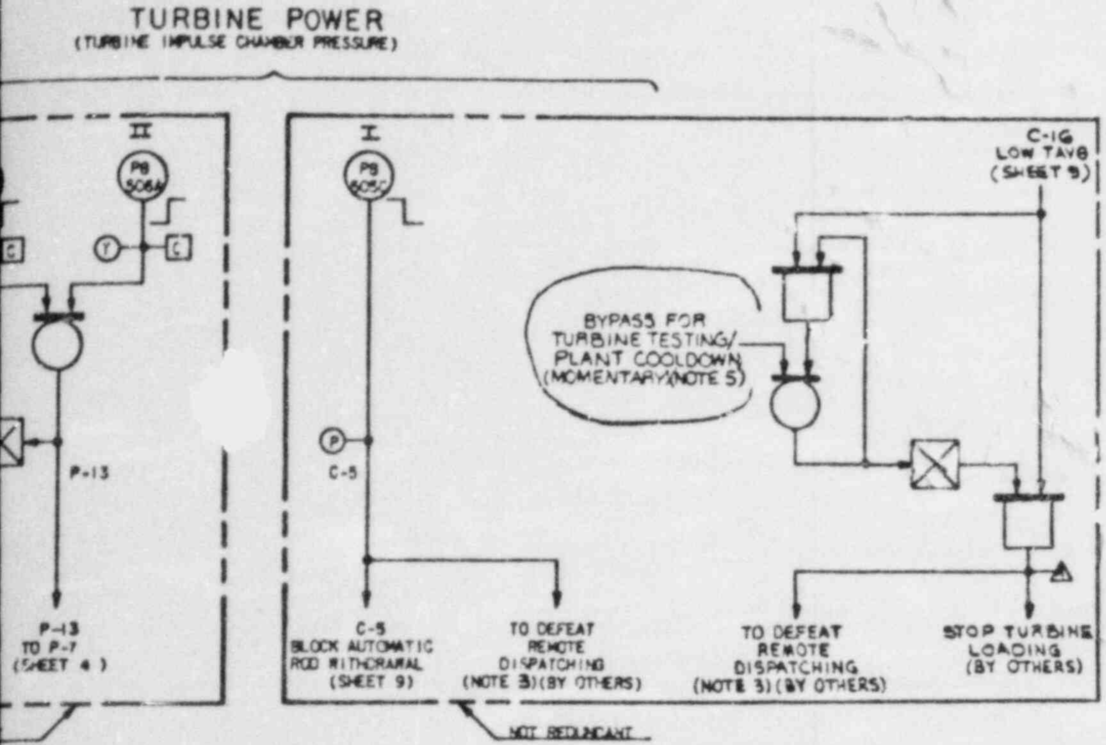

P-4
REACTOR TRIP
(TRAIN B) (SHEET 2)
STEAM GENERATOR
HI HI LEVEL OR S.I.
(TRAIN B) (SHEET 13)
STEAM GENERATOR
HI HI LEVEL OR S.I.
(TRAIN A) (SHEET 13)
P-4
REACTOR TRIP
(TRAIN A) (SHEET 2)
BY
BY OTHERS
TURBINE PROTECTION
SIGNALS
(BY OTHERS)
ENERGIZE
ETSVS1
DE-ENERGIZE
ETSVS2
MECHANICAL
TRIP
SOLENOID
ELECTRICAL
TRIP
SOLENOIDS
DEPRESSURIZE
DEPRESSURIZE
EMERGENCY
TRIP FLUID
SYSTEM
CLOSE
INTERCEPTOR
VALVES
CONTROL
VALVES
INTERMEDIATE
STOP VALVES
TURBINE
STOP VALVES
(NOTE 2)
63
2/4
OTHERS
REDUNDANT
GENERATOR
PROTECTION
SIGNALS
(BY OTHERS)
P-9
(SHEET 4)
TO GENERATOR
TRIP
TO REACTOR TRIP
(SHEET 2)



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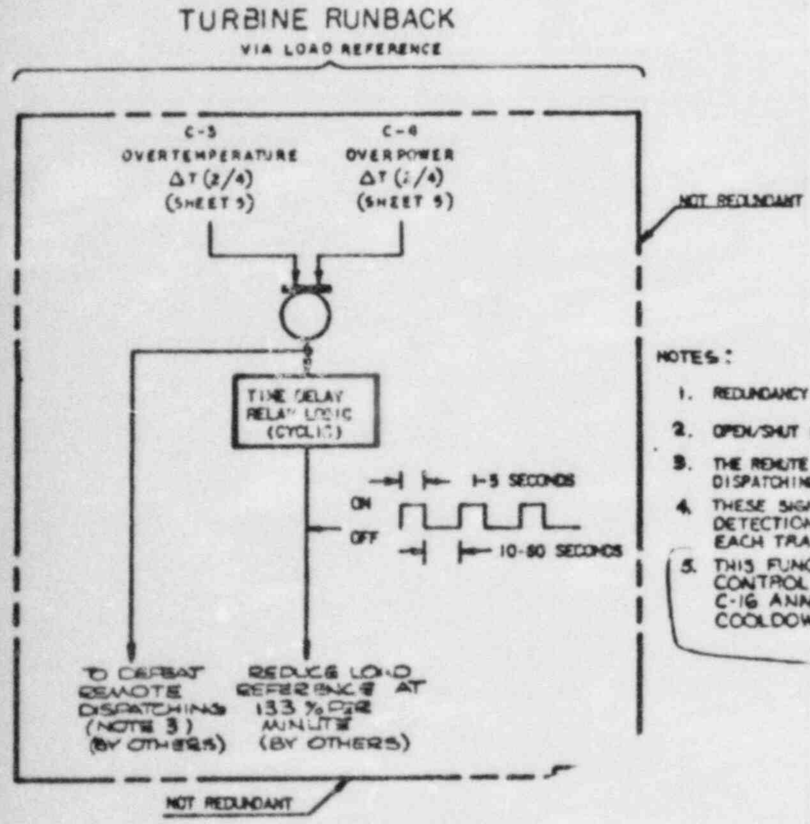

NOTES:

1. REDUNDANCY IS INDICATED IN REGARDS TO Ⓔ REQUIREMENTS ONLY.
2. OPEN/SHUT INDICATION IN CONTROL ROOM FOR EACH STOP VALVE.
3. THE REMOTE DISPATCHING IS TYPICAL. ACTUAL IMPLEMENTATION MAY NOT INCLUDE REMOTE DISPATCHING.
4. THESE SIGNALS INDICATE THE FULL CLOSED POSITION OF THE STOP VALVES. POSITION DETECTION IS ACCOMPLISHED BY TWO CONTACTS PER STOP VALVE, ONE FOR EACH TRAIN. THE LOGIC SHOWN IS FOR FOUR STOP VALVES.
5. THIS FUNCTION IS USED TO BYPASS THE REDUCED TEMPERATURE RETURN TO POWER CONTROL CIRCUITRY TO ALLOW TURBINE TESTING AND/OR TO DEFEAT THE C-16 ANNUNCIATOR SUCH AS WOULD BE REQUIRED DURING A PLANT COOLDOWN.

INSTRUMENTATION AND CONTROL
SYSTEM DIAGRAMS - INDEX AND
SYMBOLS

CATAWBA NUCLEAR STATION

Figure 7.2.1-1
(16 of 16)
Revision 11

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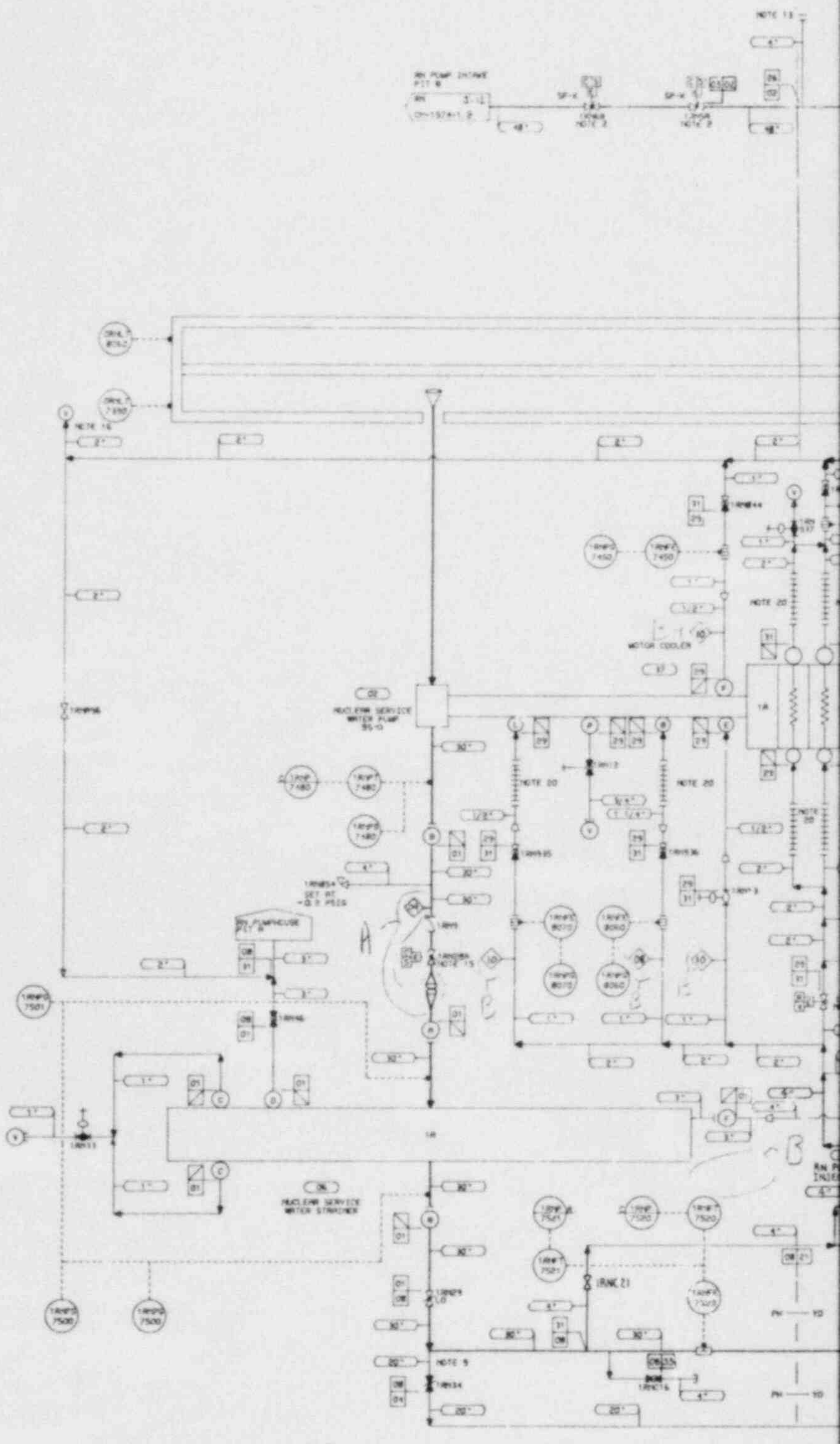

NOTES:

1.
2. ENGINEERED SAFETY SIGNAL FROM EITHER UNIT ACTIVATES THIS VALVE. EMO POWERED BY UNIT 1 DIESEL WITH SWITCHOVER TO UNIT 2 DIESEL OF CORRESPONDING CHANNEL PROVIDED. ALSO INTERLOCKED TO ACTUATE ON PIT LOW-LOW LEVEL.
3. FULL POND ELEVATION 569.5 FT. MSL. MAXIMUM DRAWDOWN 555.5 FT. MSL.
4. STANDPIPE TO EXTEND 2 FT. ABOVE LUBE WATER CONN.
5. FLOW SPREADERS.
6. 3.5"x2" OPEN AREA BETWEEN BARS OF INTAKE [illegible] SCREENS.
7. 1"x1" OPEN AREA IN SCREEN.
8. THESE VALVES TO BE QUICK OPENING PLUG VALVES WITH ELECTRIC (MOTOR OR SOLENOID) ACTUATORS ON DIRTY WATER SERVICE.
9. LOCATE 20" DRAIN LINES OFF BOTTOM OF 30" PIPE AS CLOSE AS POSSIBLE TO VALVES [illegible] AND [illegible] FOR GRAVITY DRAIN TO LAKE.
10. CONNECTION FOR NUCLEAR SERVICE WATER SYSTEM PORTABLE [illegible] PUMP [illegible] PUMPHOUSE PITS.
11. [illegible] CLOSED FOR [illegible] AND INSPECTING INTAKE LINE.
12. 8" LINE HAS NORMALLY LOCKED CLOSED [illegible], OPENED FOR UNWATERING INTAKE LINE USING AIR PRESSURE, THEN CLOSED FOR INSPECTION OF LINE.
13. 4" LINE CONNECTS TO PORTABLE 1000 SCFM AIR COMPRESSOR FOR UNWATERING INTAKE LINE.
14. EMO VALVE POWERED BY UNIT 1 [illegible] WITH SWITCHOVER TO UNIT 2 DIESEL OF CORRESPONDING CHANNEL SUPPLIED.
15. VALVES 1 & 2RN28A AND 1 & 2RN11A INTERLOCKED TO OPEN WHEN RESPECTIVE PUMP STARTS, CLOSE WHEN PUMP STOPS. THEY OPEN ON A SAFETY INJECTION SIGNAL [illegible] TO THE PUMP MOTOR STARTING.
16. SIPHON BREAK [illegible] TOP OF VENT 2 FT. ABOVE PIPING. THE VENT MUST BE THREADED TO ACCOMODATE STANDARD FIRE HOSE
17. USE TO ESTABLISH BEARING LUBE WATER BEFORE PUMP START [illegible]
18. THREADED TO ACCEPT FIRE HOSE [illegible]
19. FIRE HOSE CONNECTION [illegible]
20. [illegible]
21. NO [illegible] INSULATION REQUIRED

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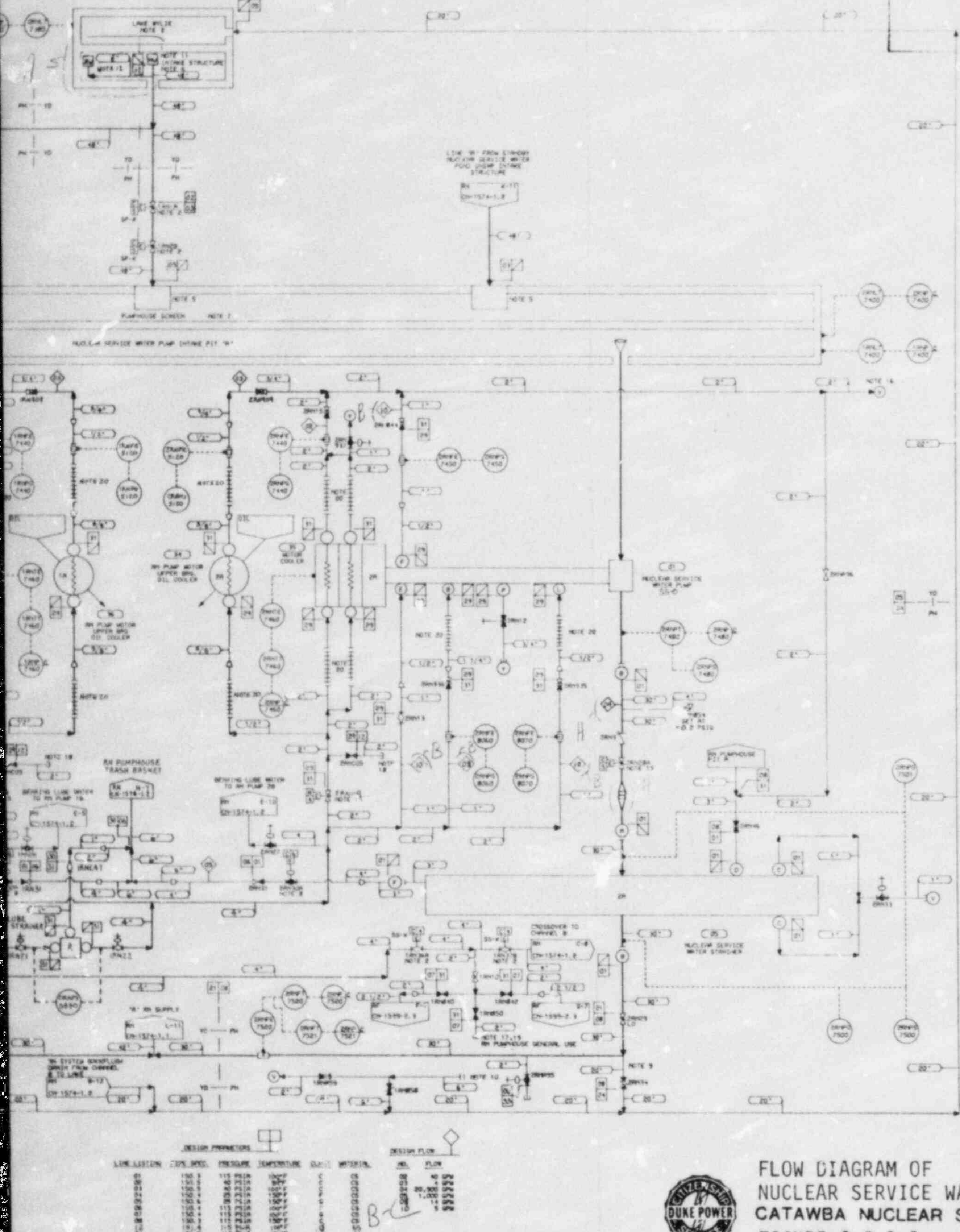

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FLOW DIAGRAM OF
NUCLEAR SERVICE WATER SYSTEM
CATAWBA NUCLEAR STATION
FIGURE 9.2.1-1
Rev. 11

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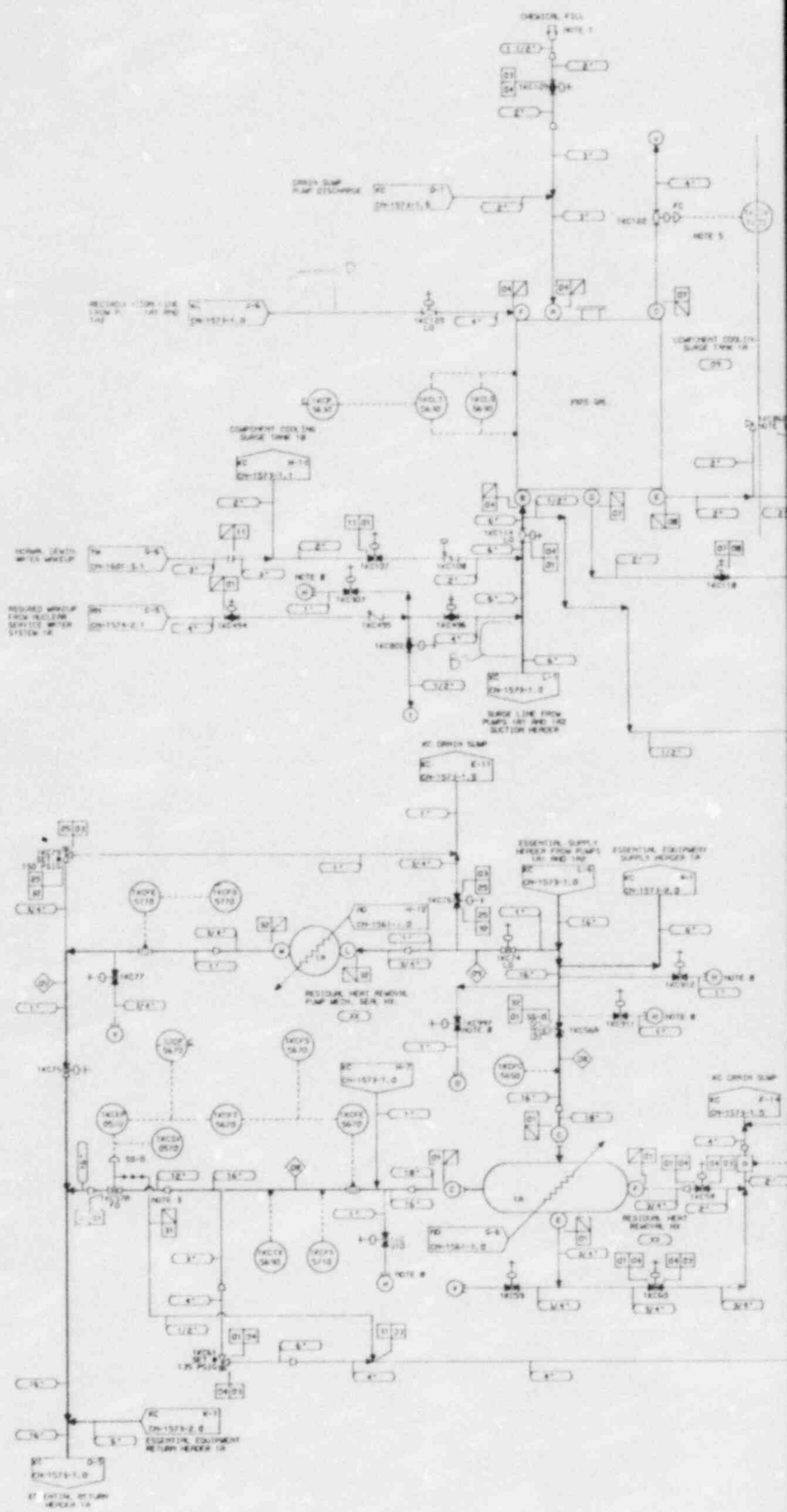
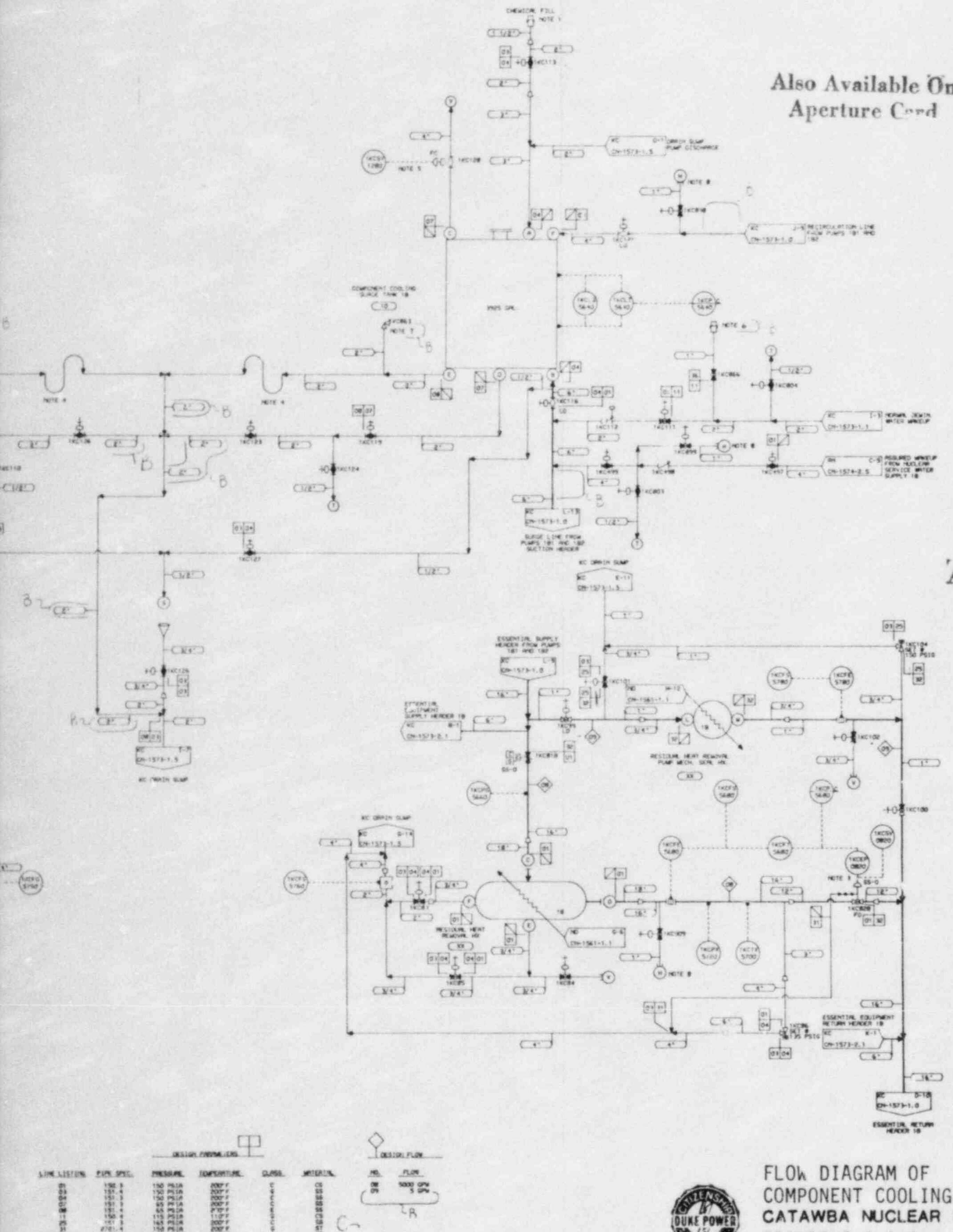


NOTES:

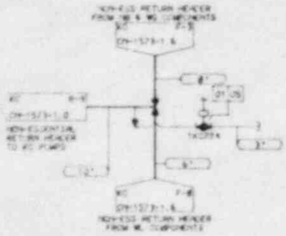
1. LOCATE CHEMICAL FILL CONNECTION AND VALVE AT A CONVENIENT POSITION FOR CONNECTING A PORTABLE PUMP.
2. NO PIPING INSULATION REQUIRED.
3. CONTROL VALVE PROVIDED WITH HANDWHEEL FOR EMERGENCY MANUAL OPERATION.
4. LOOP SEAL TO EXTEND 12 IN. ABOVE AND BELOW TANK [illegible]
5. NORMAL SURGE TANK VENT VALVE CLOSED ON HIGH RADIATION SIGNAL FROM RADIATION MONITOR AT DISCHARGE OF [illegible]
6. LOCATE [illegible] CLOSE TO COMPONENT COOLING SURGE TANK CHEMICAL FILL CONNECTION.
7. [illegible] VENT OPENING [illegible] ABOVE PIPING.

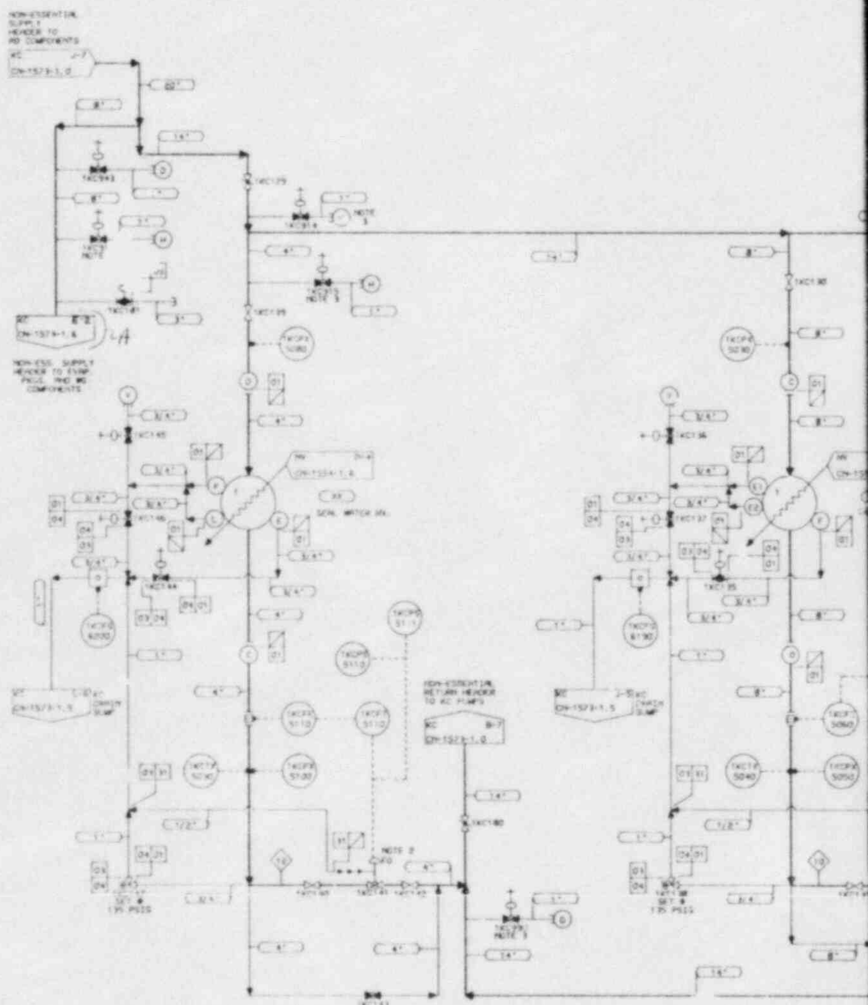
8. HIGH POINT VENTS AND LOW POINT DRAINS ADDED FOR CONSTRUCTION FLUSH AND HYDRO.



FLOW DIAGRAM OF
COMPONENT COOLING SYSTEM
CATAWBA NUCLEAR STATION
FIGURE 9.2.2-2
Rev. 11

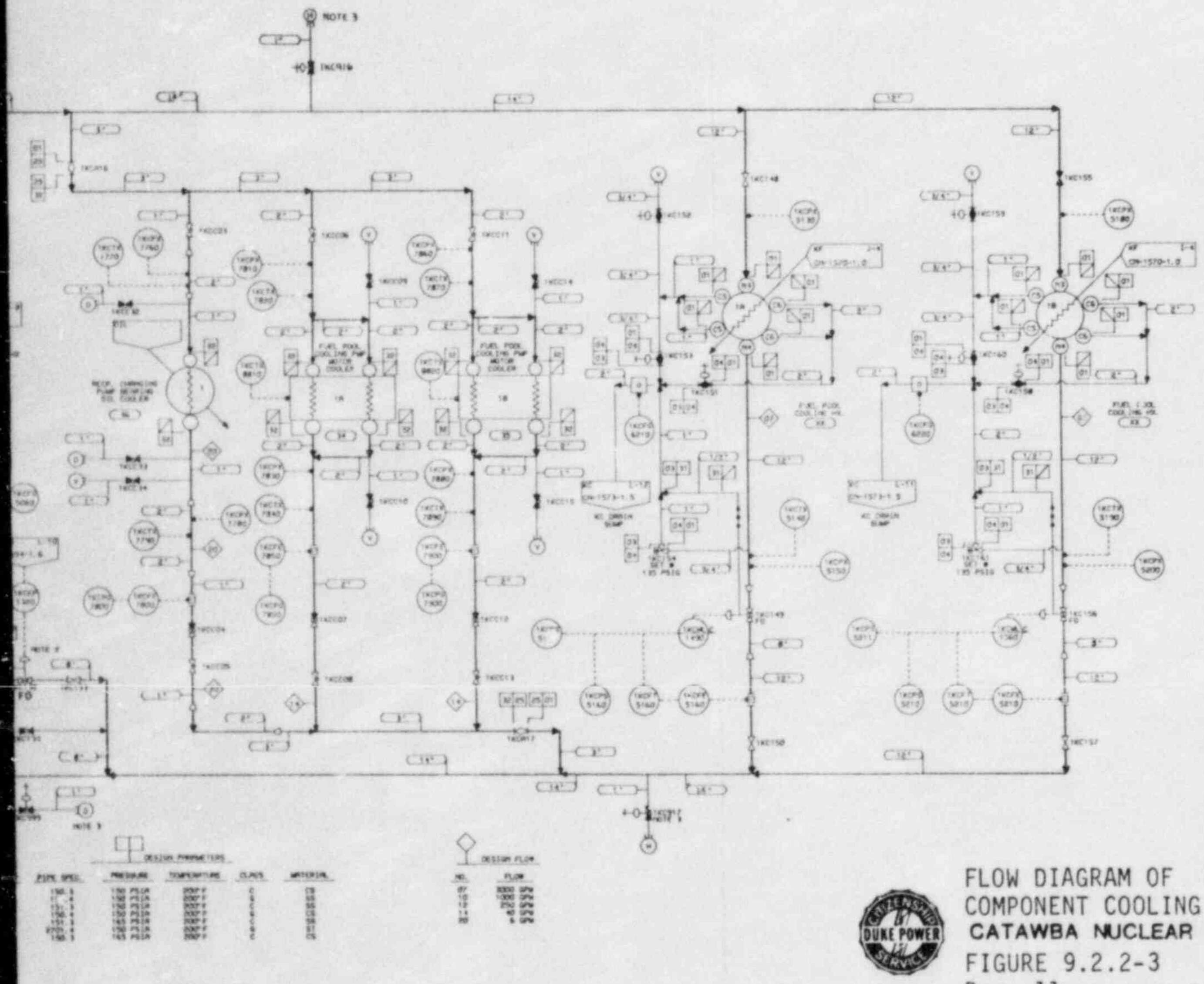
R6 - C0/15





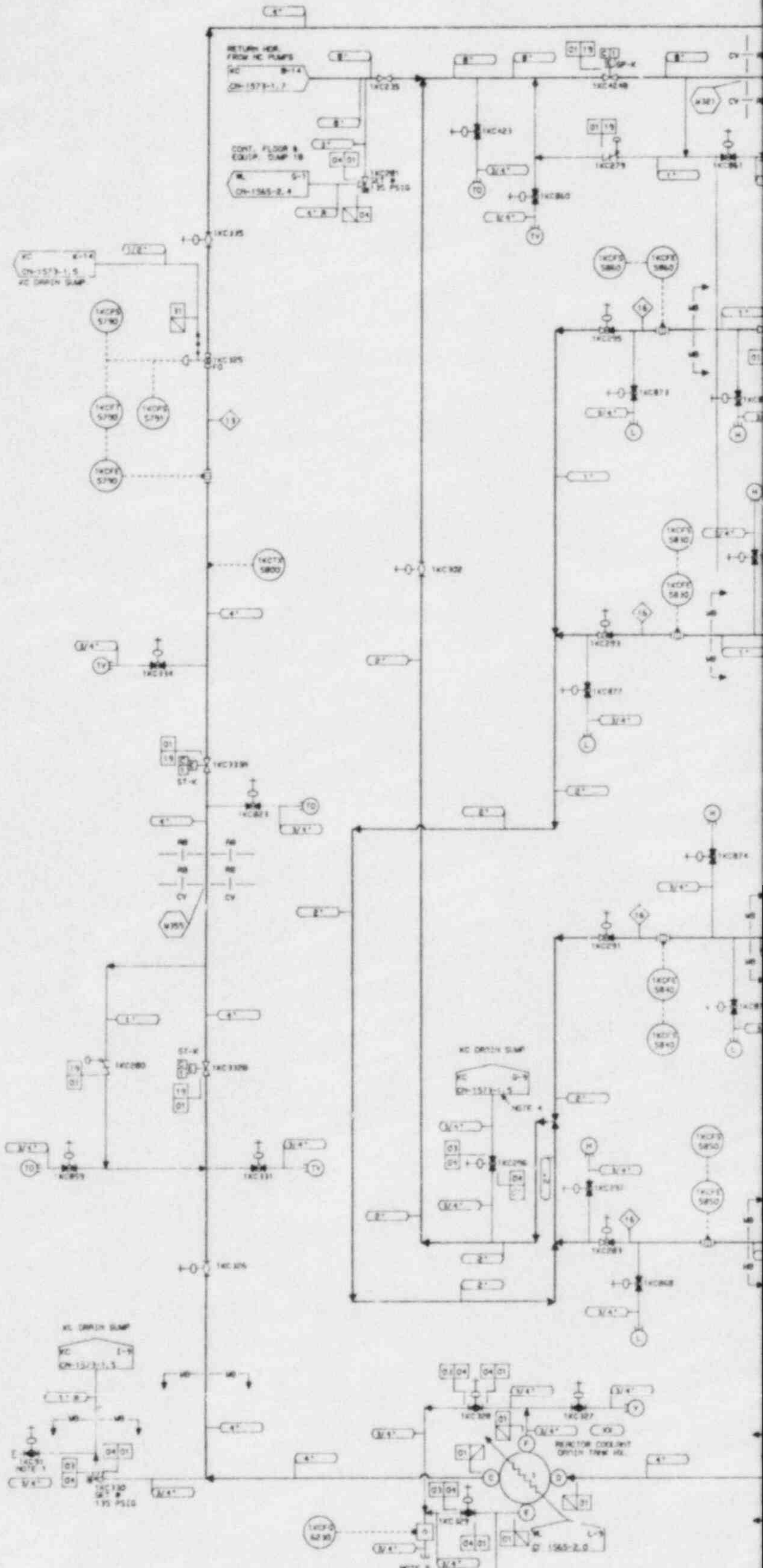
NOTES:

1. NO PIPING INSULATION REQUIRED.
2. CONTROL VALVE FITTED WITH HANDWHEEL FOR EMERGENCY MANUAL OPERATION.
3. HIGH POINT VENTS AND LOW POINT DRAINS FOR CONSTRUCTION FLUSH AND HYDRO.



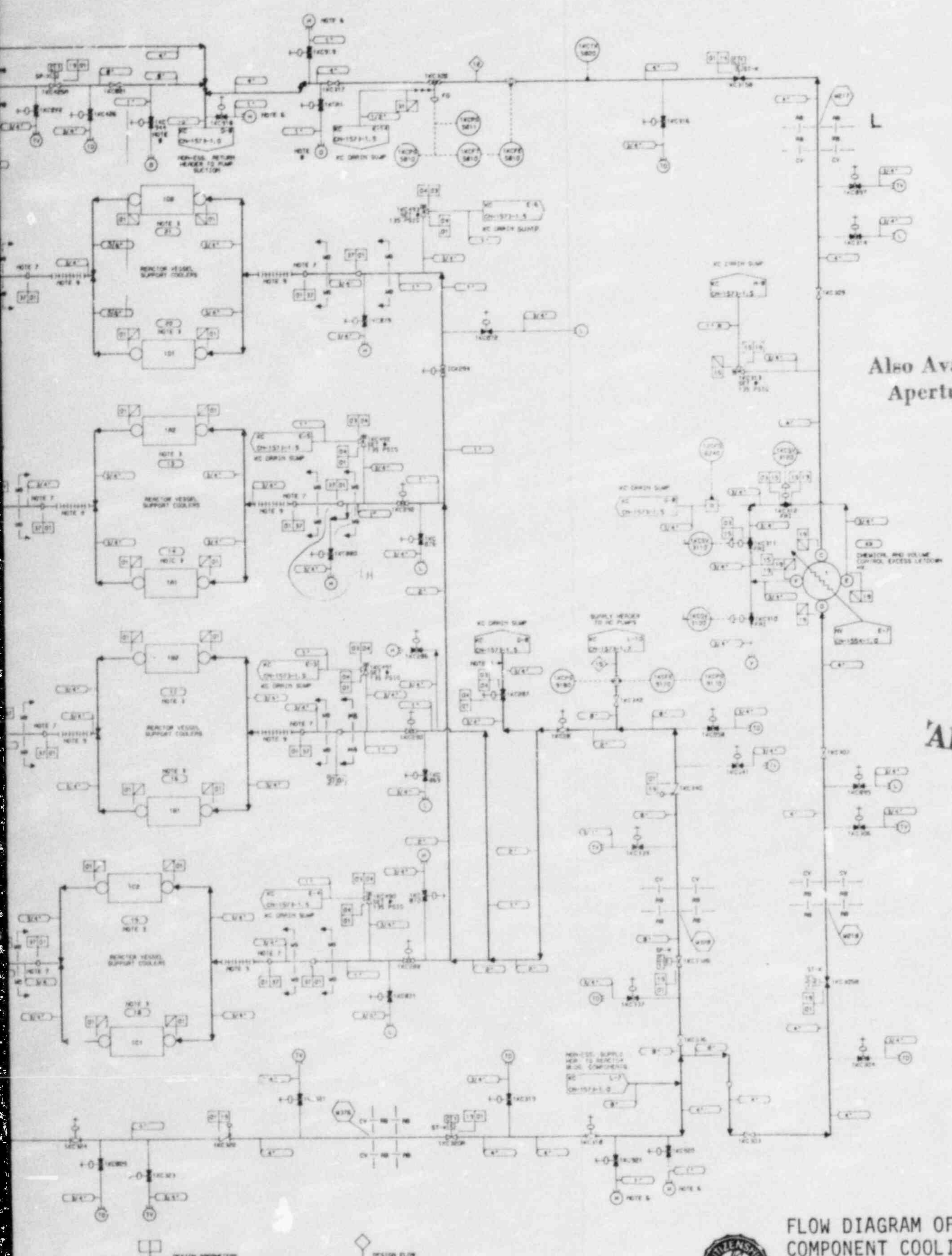
FLOW DIAGRAM OF
COMPONENT COOLING SYSTEM
CATAWBA NUCLEAR STATION
FIGURE 9.2.2-3
Rev. 11

R7-C0/18



NOTES:

1. PORTABLE PUMP DISCHARGE CONNECTION FOR DRAINING RCDT HX.
2. NO PIPING INSULATION REQUIRED.
3. SEE RV SUPPORT DRAWING CP 1070-13.
4. PLACE DRAIN AT LOW POINT IN HEADER.
5. PORTABLE PUMP SUCTION CONNECTION FOR DRAINING RCDT HX.
6. HIGH POINT VENT ADDED FOR CONSTRUCTION FLUSH AND HYDRO.
7. PIPING TO TUBING CHANGE.
8. LOW POINT DRAIN ADDED FOR CONSTRUCTION FLUSH AND HYDRO.
9. FLEX HOSE ADDED TO REDUCE THERMAL STRESS ON PIPING EXCEPT ON RETURN FROM RV SUPPORT COOLERS 1C1 & 1C2.



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FLOW DIAGRAM OF
COMPONENT COOLING SYSTEM
CATAWBA NUCLEAR STATION

FIGURE 9.2.2-4
Rev. 11

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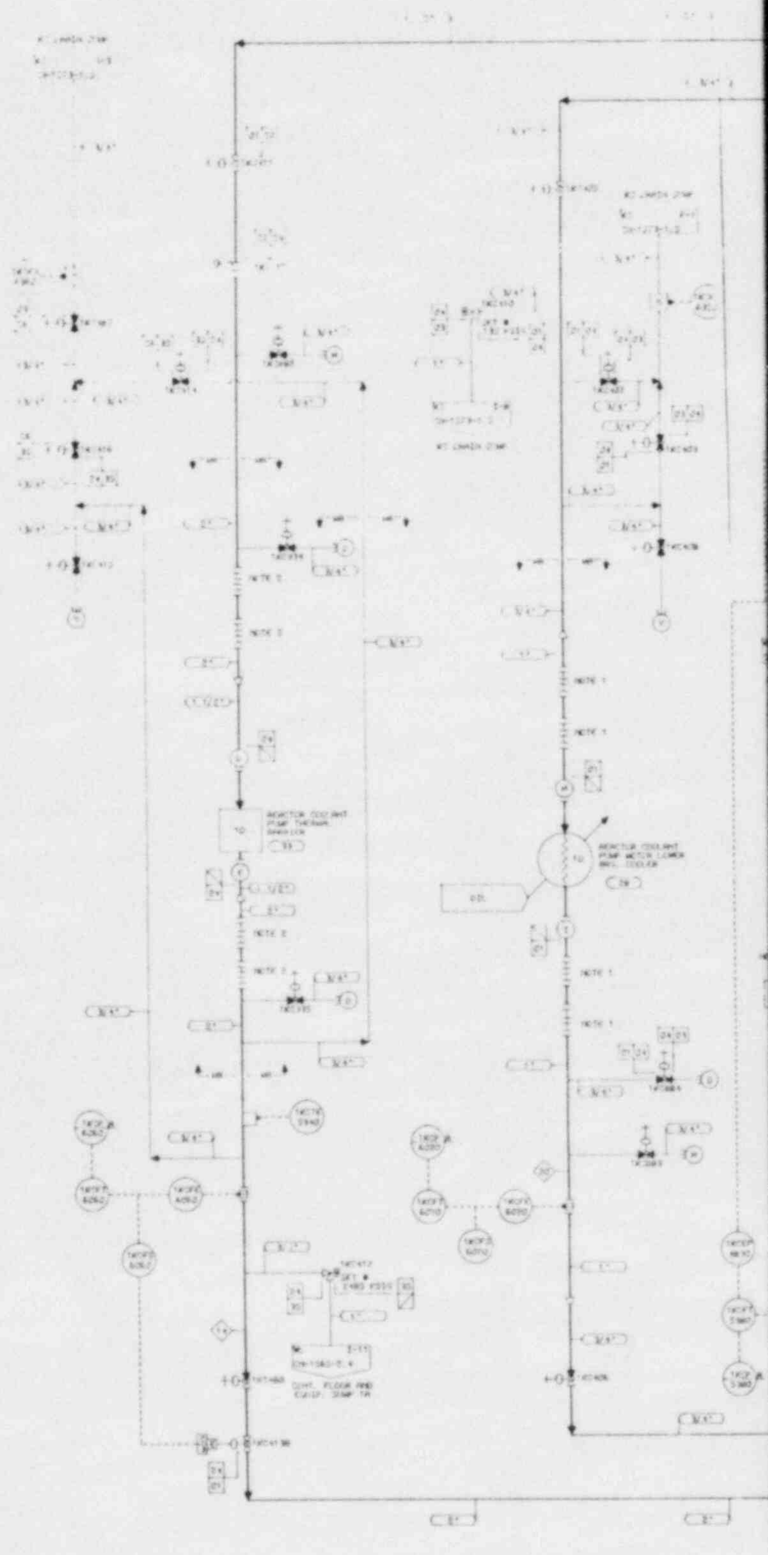
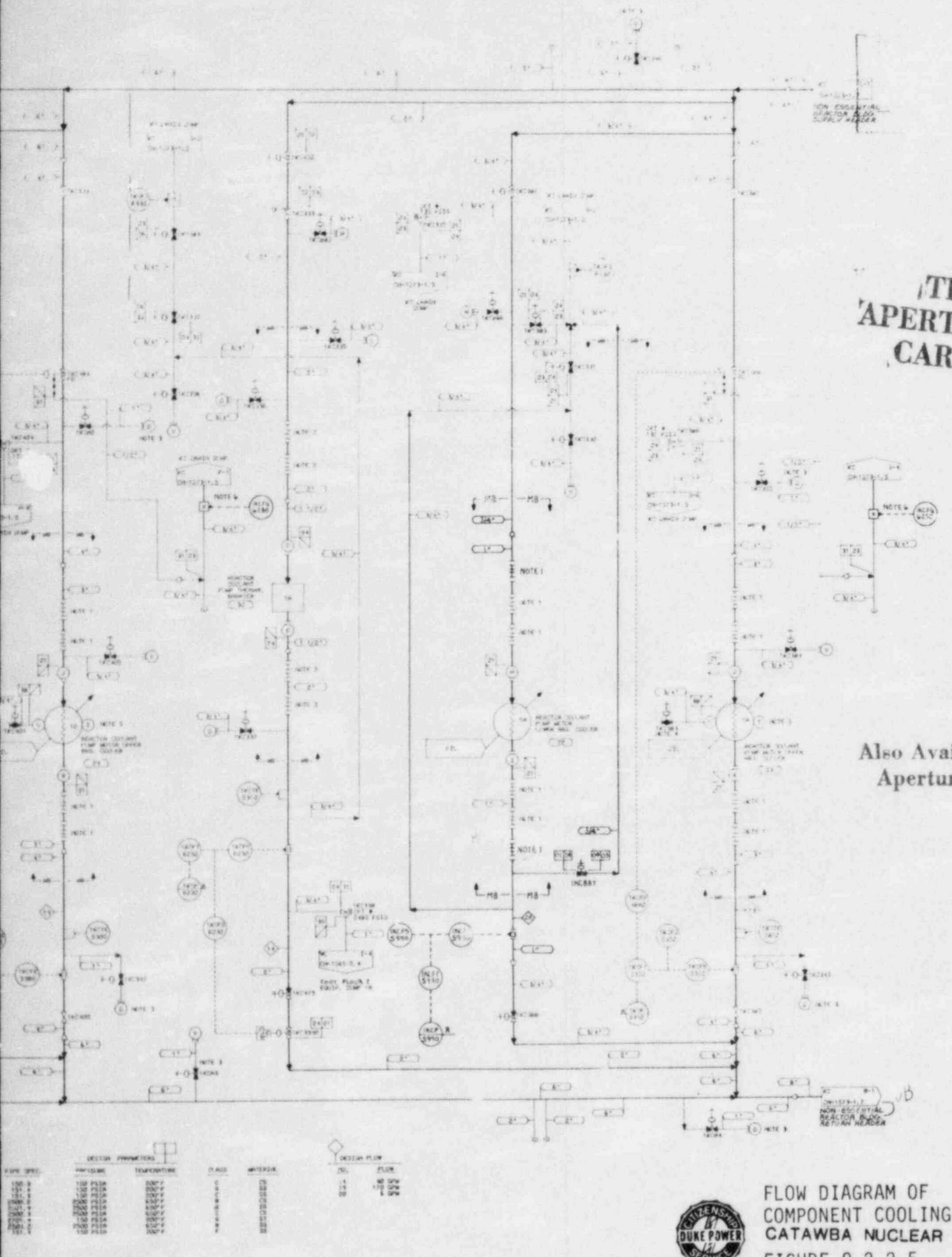


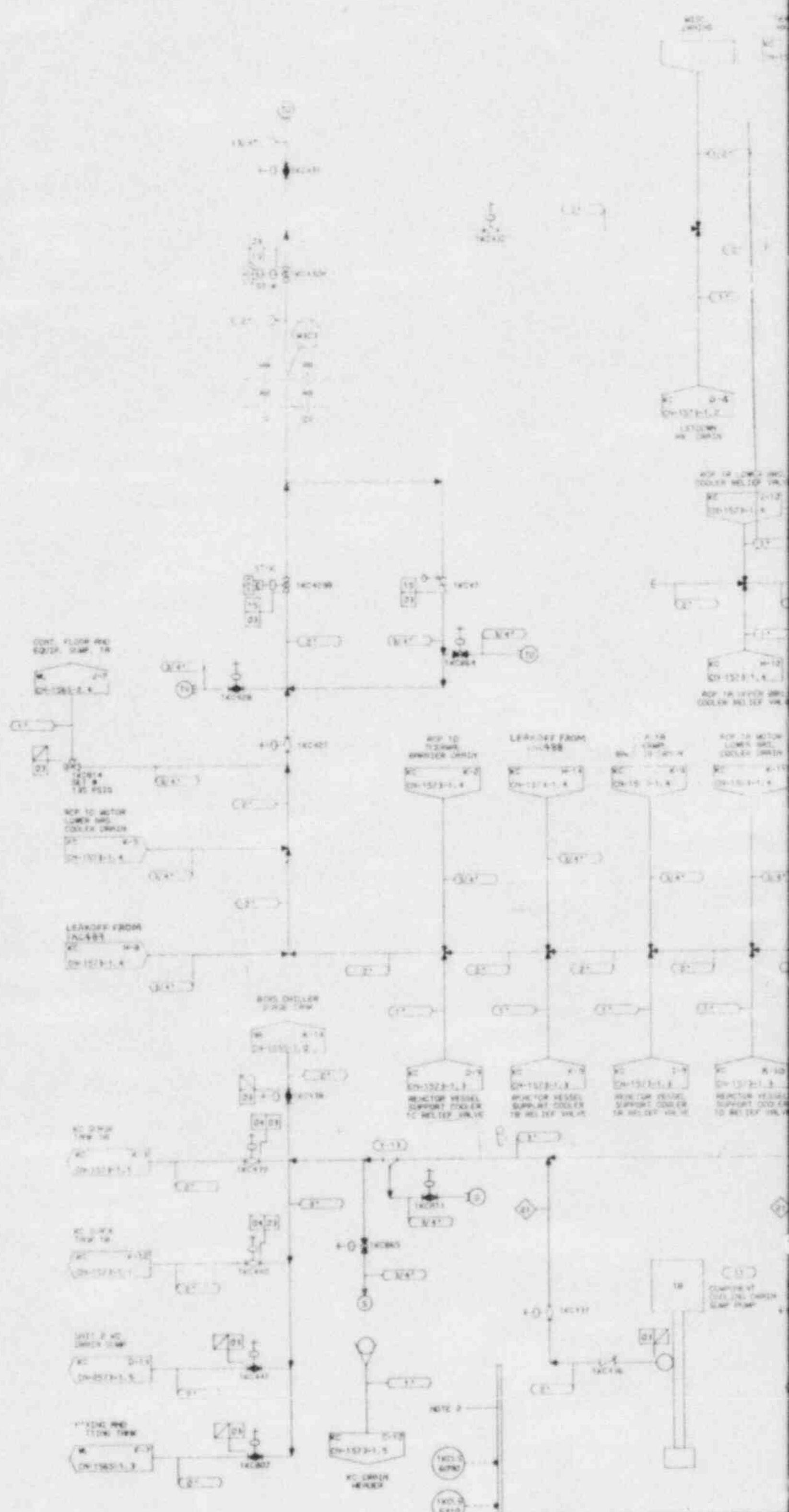
NOTES:

1. NON-CODE COMPONENT, TO BE DESIGNED, MANUFACTURED, PROCURED, & INSTALLED ACCORDING TO RULES EQUIVALENT TO ASME SECT. III CLASS 3.
2. NON-CODE COMPONENT, TO BE DESIGNED, MANUFACTURED, PROCURED, & INSTALLED ACCORDING TO RULES EQUIVALENT TO ASME SECT. III CLASS 2.
3. LOW POINT VENT OR DRAIN FOR CONSTRUCTION FLUSH AND HYDRO.
4. VALVE INSIDE OIL ENCLOSURE IS 3 1/4 IN. END TO END WITH TWO FEMALE SOW ED CONNECTIONS.
5. CONNECTION "T" ON RCP MOTOR UPPER BRG. COOLER SHOULD BE PLUGGED.
6. THE INTERNAL FLOW INDICATING MECHANISM HAS BEEN REMOVED FROM THE SIGHT GLASS.
7. NO PIPING INSULATION REQUIRED.

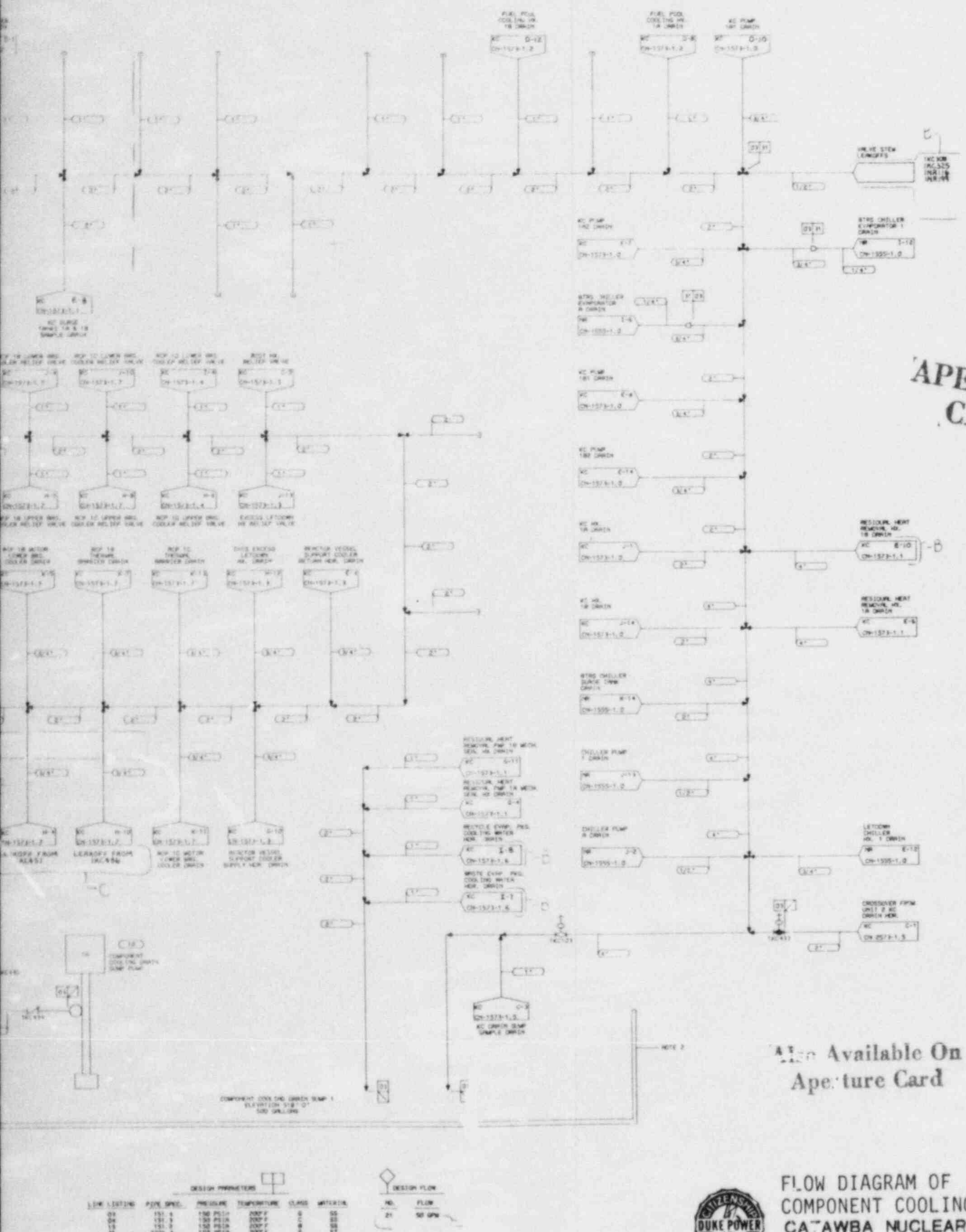


FLOW DIAGRAM OF
COMPONENT COOLING SYSTEM
CATAWBA NUCLEAR STATION
FIGURE 9.2.2-5
Rev. 11

R6 - CO/15



NOTES:
1. NO PIPING INSULATION REQUIRED.
2. 15 INCH CURBING AROUND SUMP, AND COVER OVER TOP OF SUMP.



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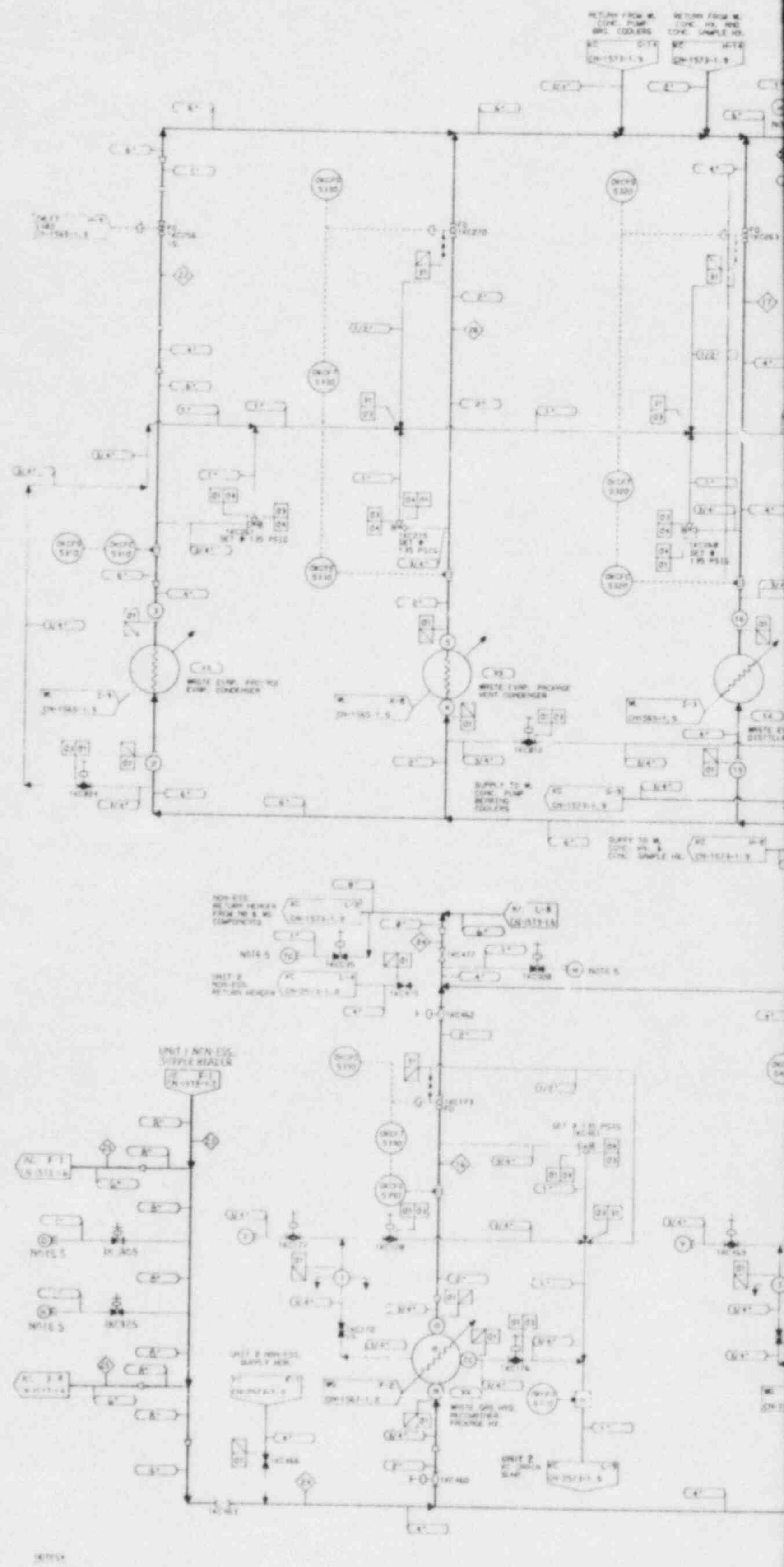
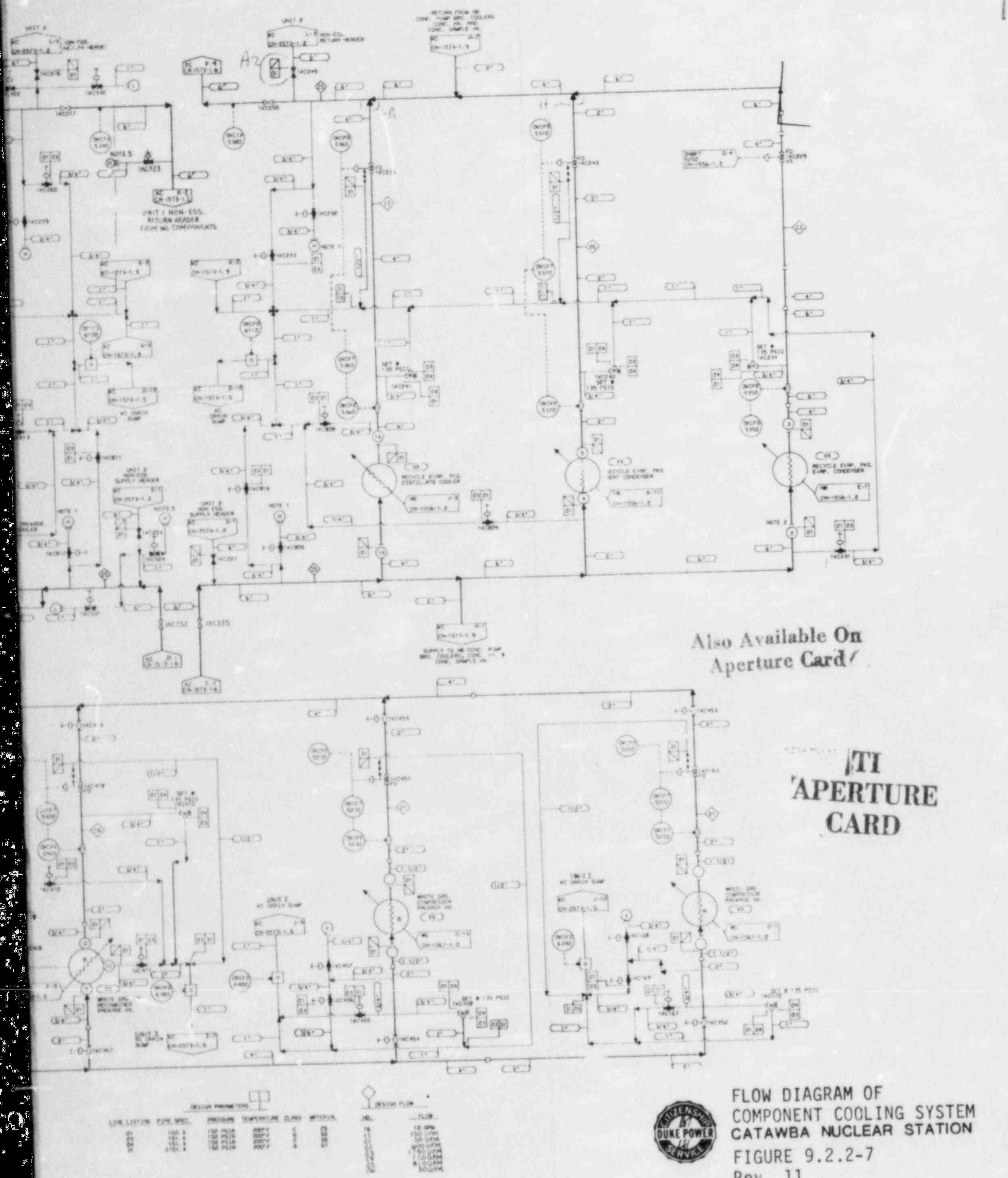
FLOW DIAGRAM OF
COMPONENT COOLING SYSTEM
CATAWBA NUCLEAR STATION
FIGURE 9.2.2-6
Rev. 11

R4 - C0/12

8406270190-22


RETURN FROM W. CONC. PUMP BRG. COOLERS
WASTE EVAP. PRE-HX EVAP. CONDENSER
WASTE EVAP. PACKAGE VENT CONDENSER
SUPPLY TO W. CONC. PUMP BEARING COOLERS
UNIT I NON-ESS. SUPPLY HEADER
UNIT II NON-ESS. SUPPLY HDR.
NOTE 5
NOTES:
1. LOCATE VENT AT HIGH POINT IN EVAPORATOR COOLING WATER HEADER.
2. LOCATE DRAIN AT LOW POINT IN EVAPORATOR COOLING WATER HEADER.
3. OPERATING CONDITIONS SHOWN ARE FOR NORMAL 100% POWER OPERATION.
4. NO PIPING INSULATION REQUIRED



FLOW DIAGRAM OF
COMPONENT COOLING SYSTEM
CATAWBA NUCLEAR STATION
FIGURE 9.2.2-7
Rev. 11

R6 - CO/13

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NOTES:

1. NON-CODE COMPONENT, TO BE DESIGNED, MANUFACTURED, PROCURED, AND INSTALLED ACCORDING TO RULES EQUIVALENT TO ASME SECT. III CLASS 3.
2. NON-CODE COMPONENT, TO BE DESIGNED, MANUFACTURED, PROCURED, AND INSTALLED ACCORDING TO RULES EQUIVALENT TO ASME SECT. III CLASS 2.
3. LOW POINT VENT OR DRAIN FOR CONSTRUCTION FLUSH AND HYDRO
4. VALVE INSIDE OIL ENCLOSURE IS 3/4 IN. END TO END WITH TWO FEMALE SCREWED ENDS.
5. CONNECTION "T" ON RCP MOTOR UPPER BRG. COOLER SHOULD BE PLUGGED.
6. THE INTERNAL FLOW INDICATING MECHANISM HAS BEEN REMOVED FROM THE SIGHT GLASS.
7. NO PIPING INSULATION REQUIRED.

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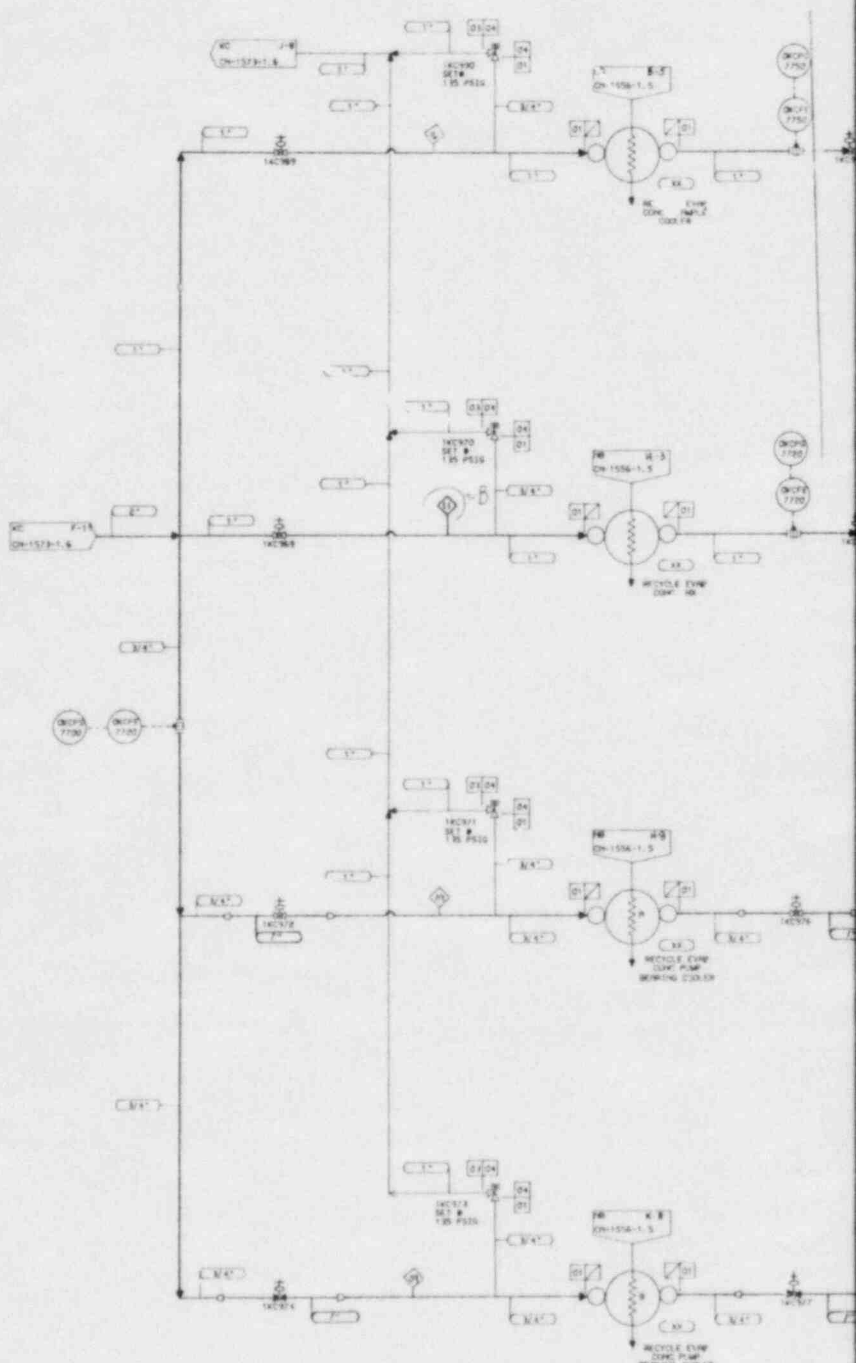
FLOW DIAGRAM OF
COMPONENT COOLING SYSTEM
CATAWBA NUCLEAR STATION
FIGURE 9.2.2-8
Rev. 11

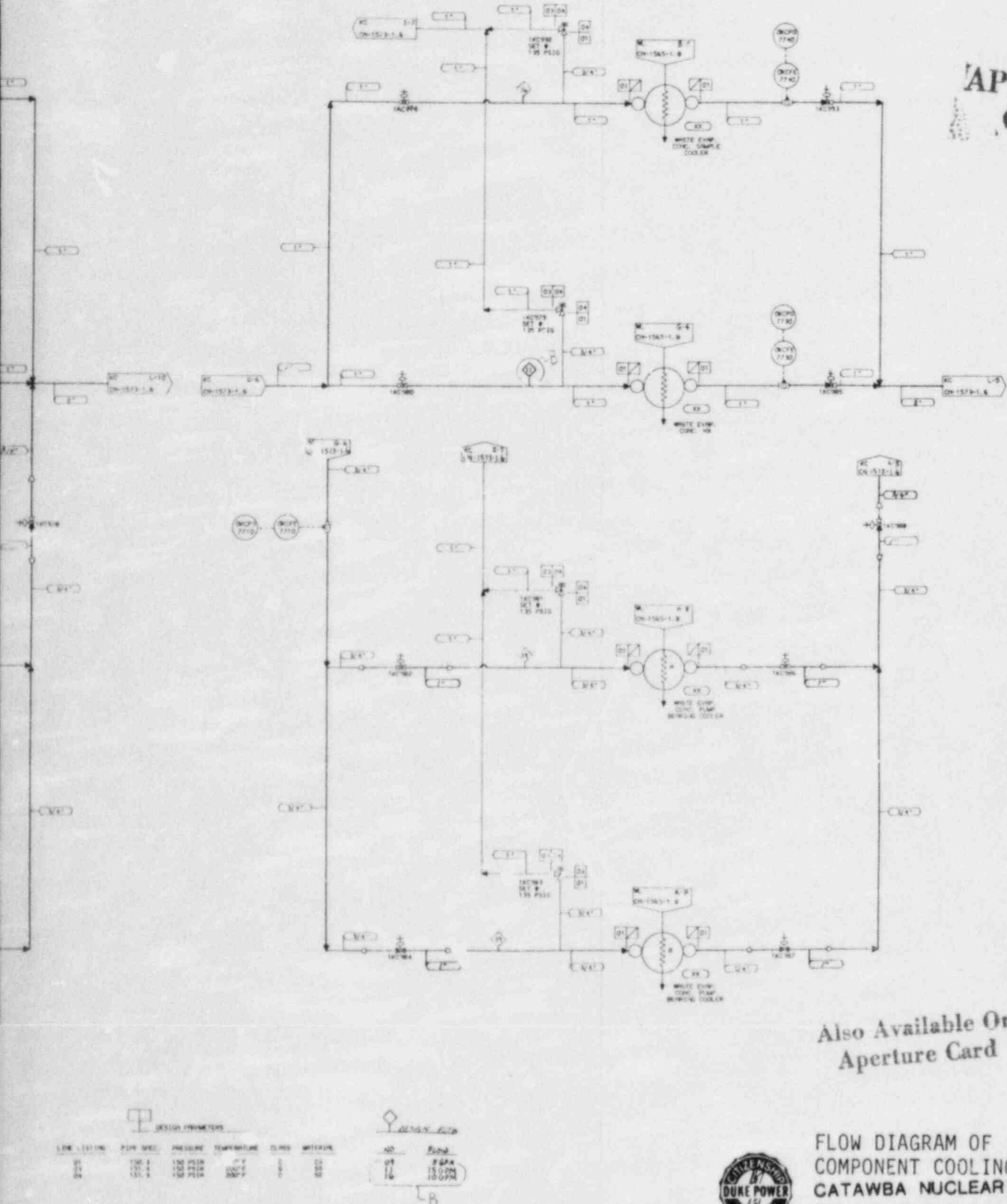
R5 - CO/14

8406270190-24



NOTES:
1. NO PIPING INSULATION REQUIRED.

TI APERTURE CARD



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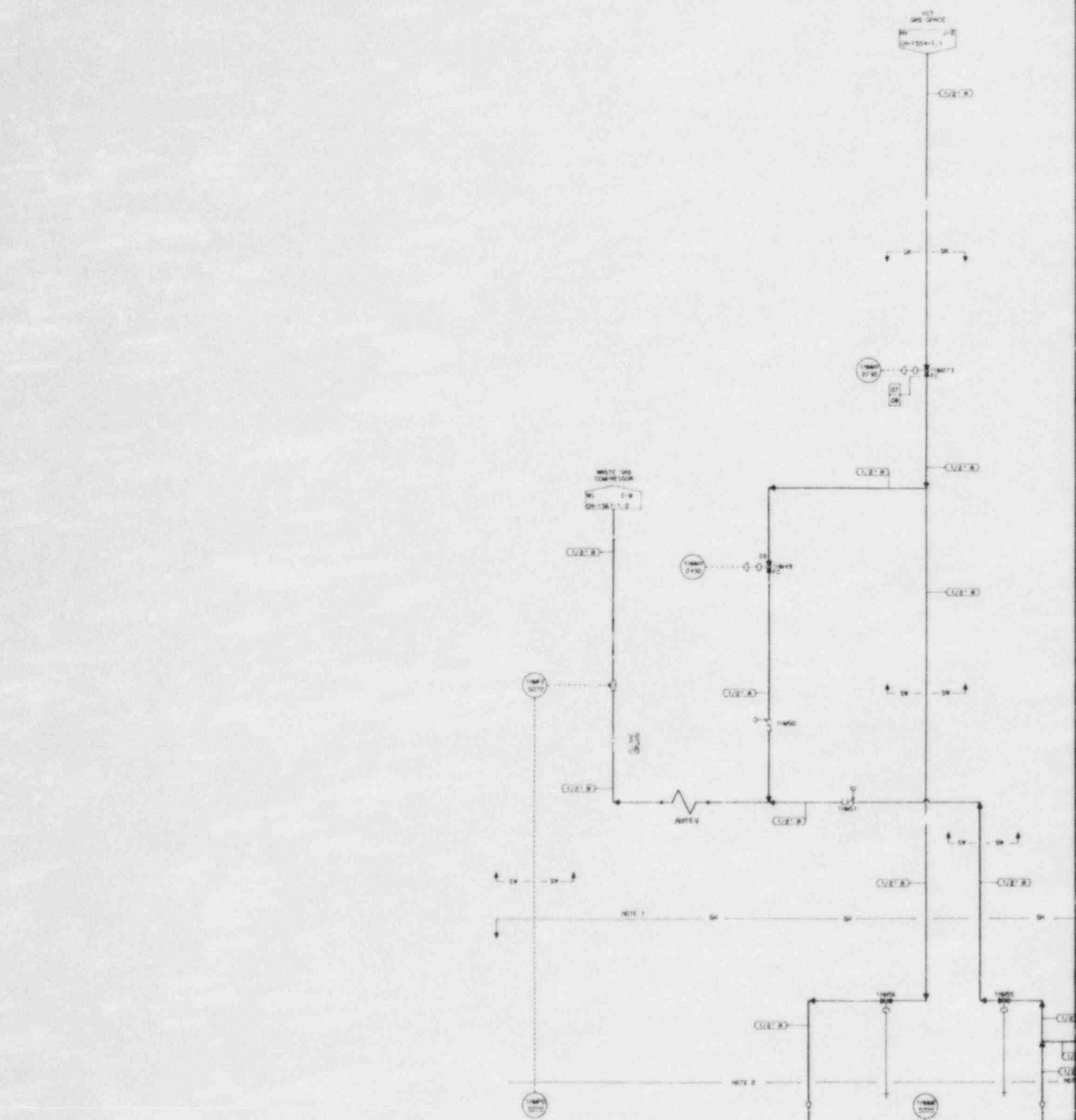
FLOW DIAGRAM OF
COMPONENT COOLING SYSTEM
CATAWBA NUCLEAR STATION
FIGURE 9.2.2-10
Rev. 11

RO - CO/04

8406270190 -25

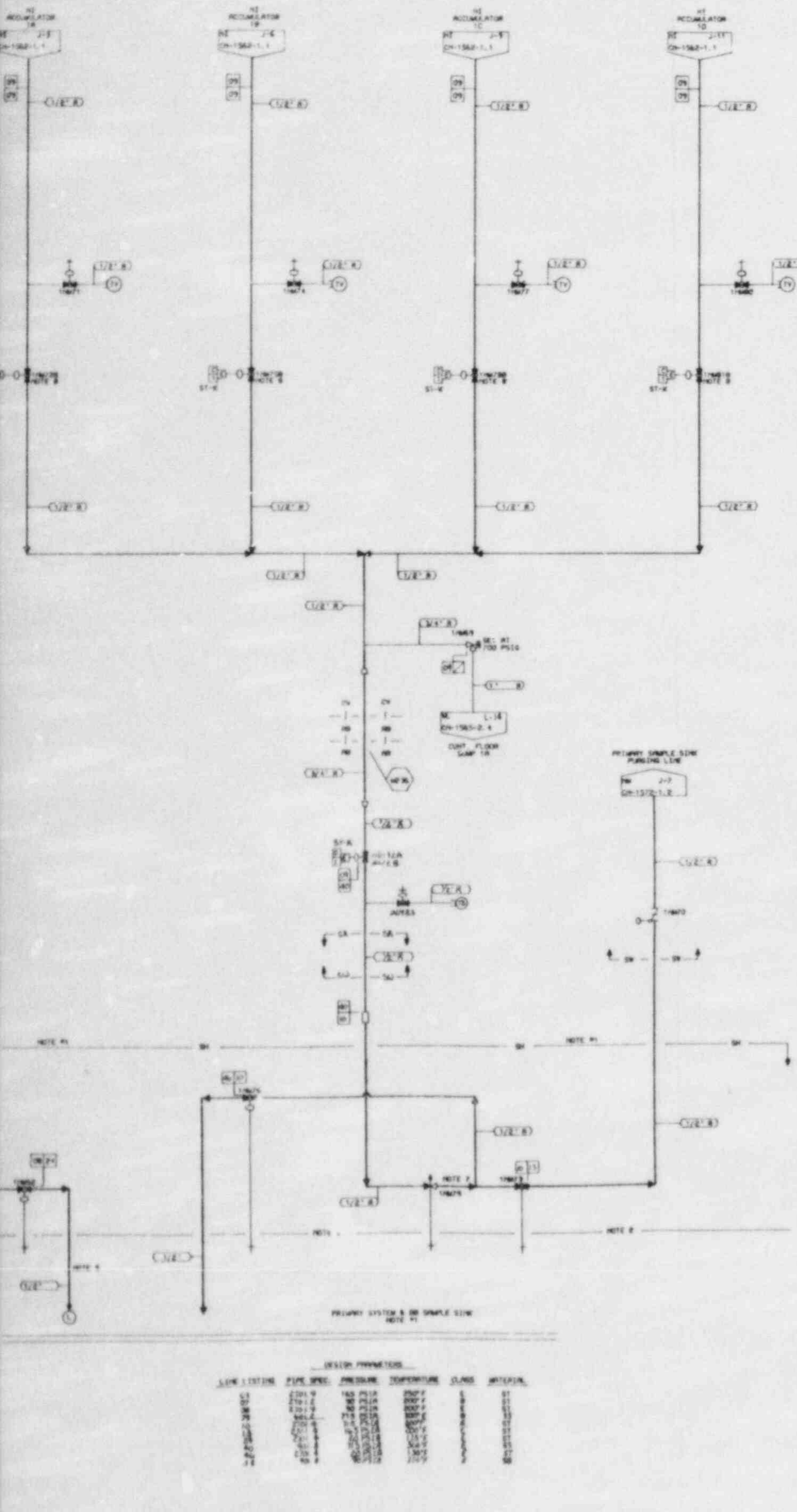


NOTES:

1. PRIMARY SYSTEMS AND STEAM GENERATOR SAMPLE SINKS, WITH SHIELDED VALVE BAFFLE AND COMMON EXHAUST HOOD, SUPPLIED AS PACKAGE BY VENDOR (SAMPLE PANEL 1 EQUIP NO. 1).
2. SHIELDED VALVE BAFFLE.
3. GAS SAMPLING DEVICE CN-1499-M142.
4. [illegible]
5. VOLUME CONTROL TANK GAS SPACE SAMPLE PIPING SHOULD BE ARRANGED SO THAT LOW POINT DRAIN MAY DISCHARGE TO SINK.
6. CONTINUATION OF PRIMARY SYSTEM SAMPLE SINK FROM CN-1378-1.5 (B-9).
7. VALVE CV NOT TO EXCEED 0.04.
8. TO BE CONTROLLED FROM SAMPLING ROOM PLUG.
9. CONTINUATION OF PRIMARY SYSTEMS SAMPLE SINK FROM CN-1378-1.0 (B-14).
10. [illegible] SUPPLIED BY NPW.

11. NO INSULATION REQUIRED ON THIS FLOW DIAGRAM.

2A



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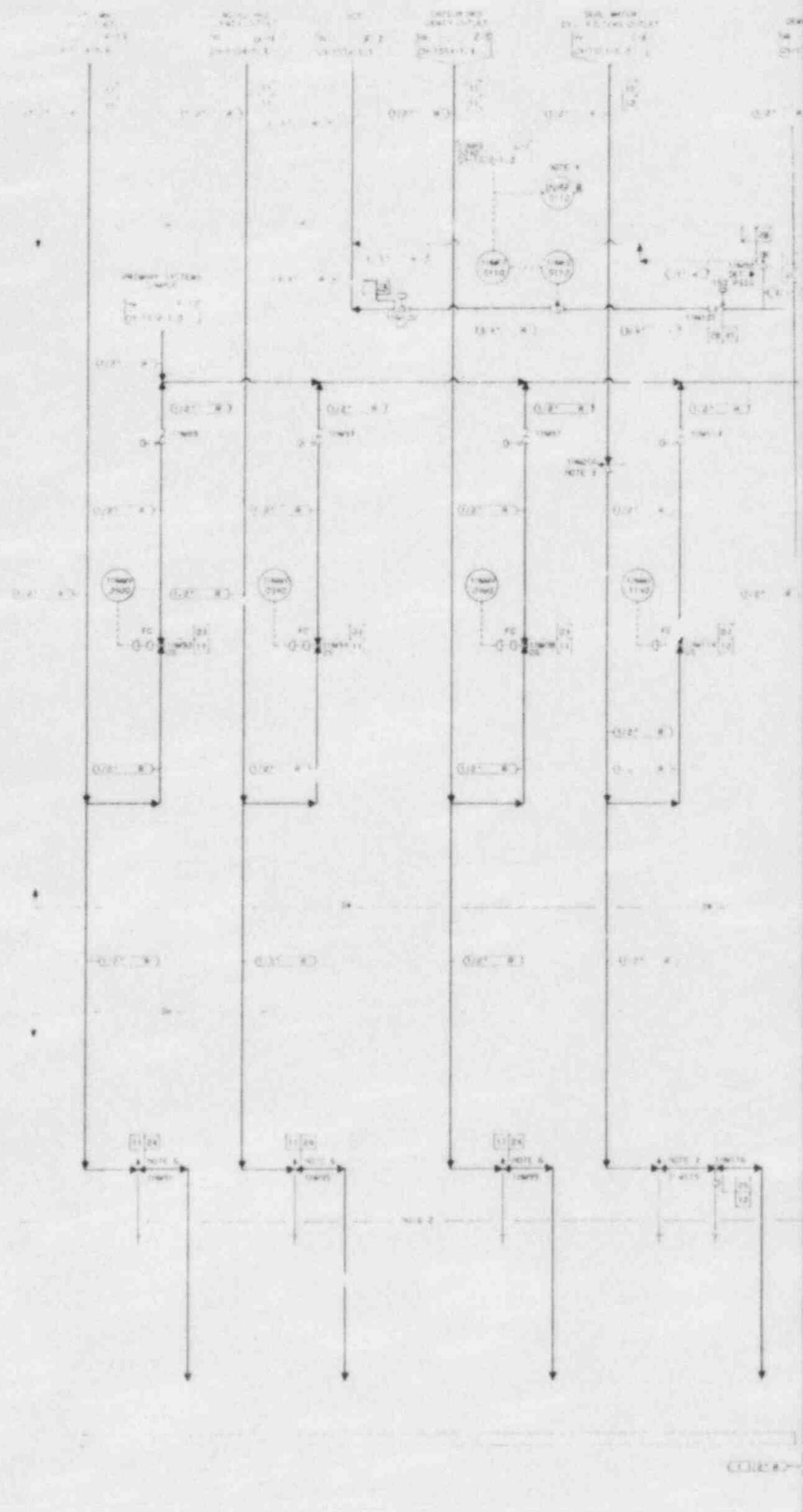
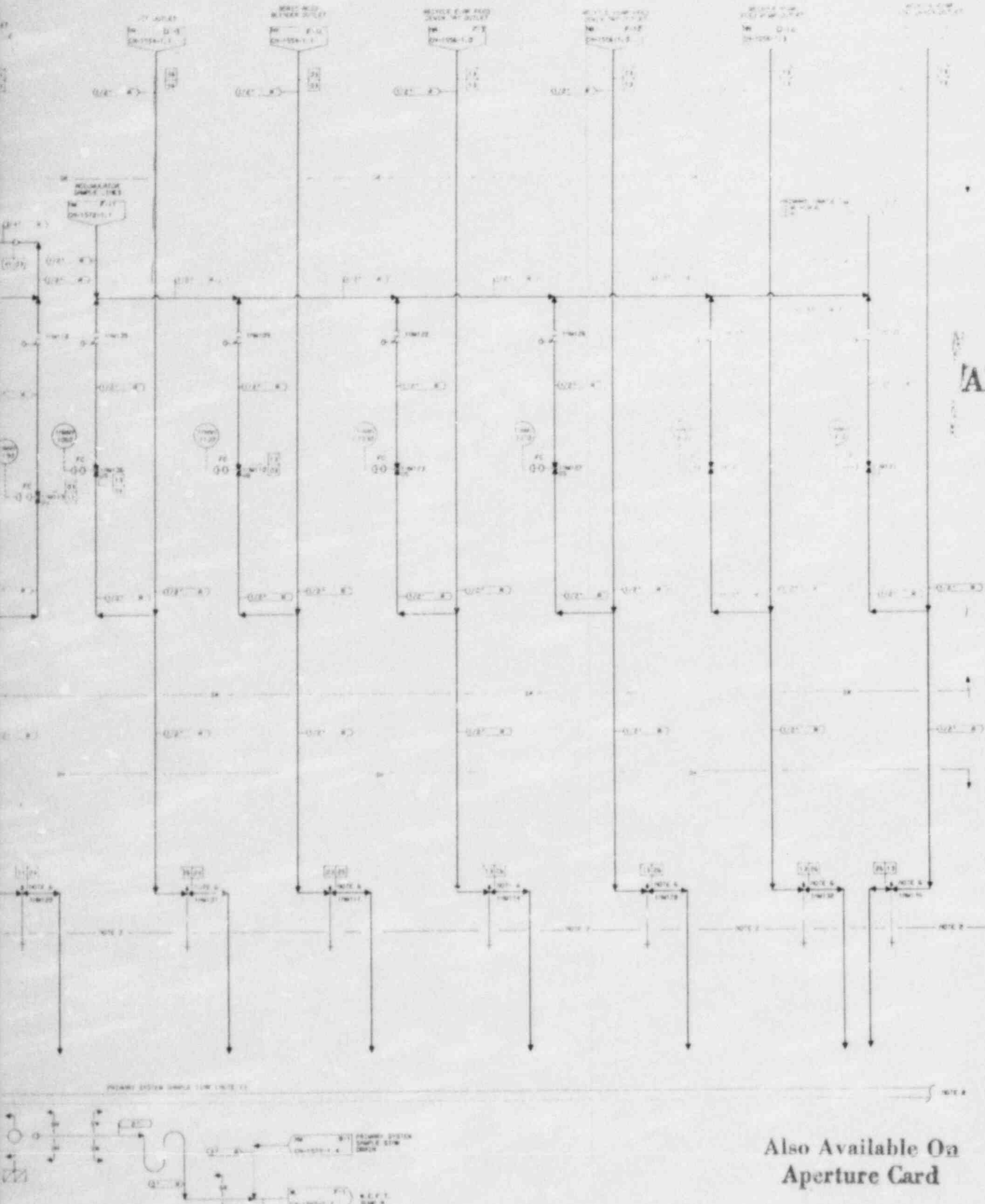
FLOW DIAGRAM OF
NUCLEAR SAMPLING SYSTEM
CATAWBA NUCLEAR STATION
FIGURE 9.3.2-2
Rev. 11

R2-CO/16

8406270190-26





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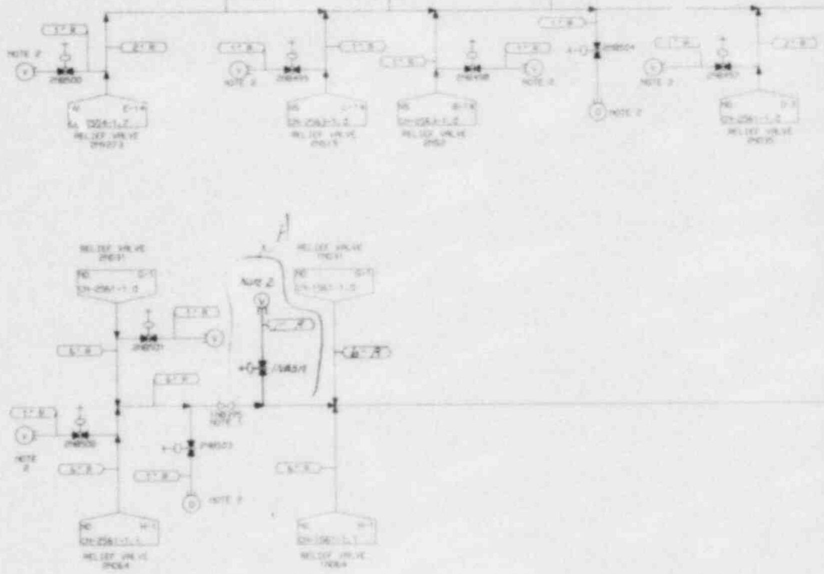
FLOW DIAGRAM OF NUCLEAR SAMPLING SYSTEM
CATAWBA NUCLEAR STATION
FIGURE 9.3.2-3
Rev. 11

R2 - CO/12

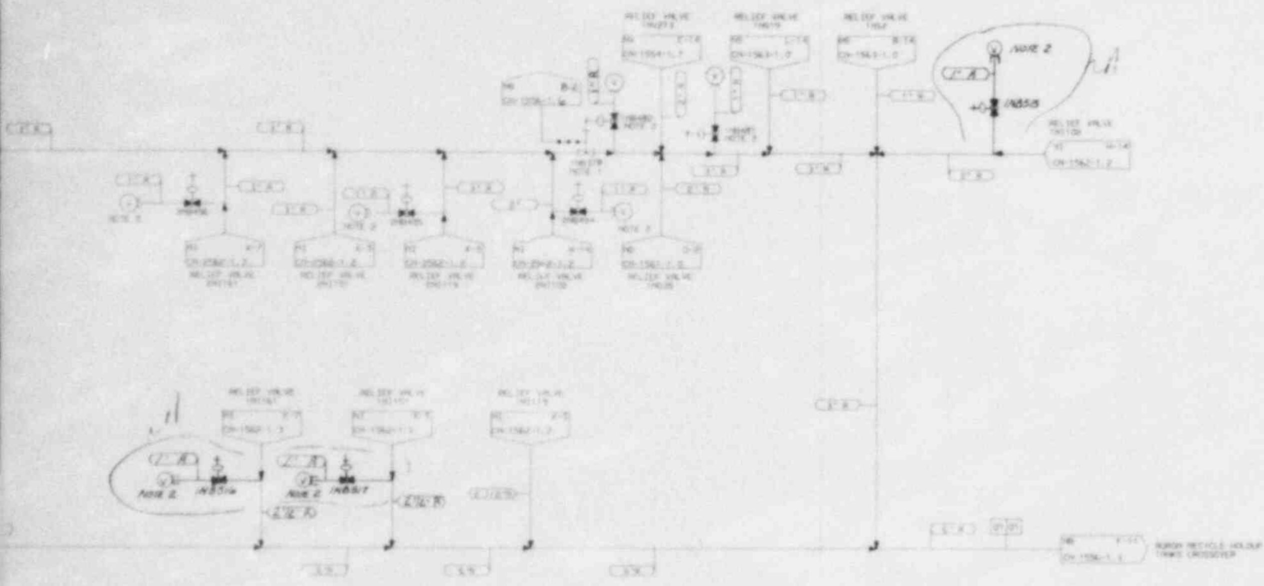
8406270190-27



[illegible] DRAWING TITLE	[illegible] DRAWING	FIGURE NO.
BORON RECYCLE SYSTEM	CN-2504-1.3	9.3.5-4
SAFETY INJECTION SYSTEM	CN-2562-1.2	6.3.2-2

NOTES:

1. VALVE IS TO SEPARATE UNIT 2 RELIEF VALVE HEADER FROM UNIT 1 FOR CONSTRUCTION PURPOSES. THIS VALVE SHOULD BE LOCKED OPEN WHEN UNIT 2 IS BROUGHT INTO OPERATION.
2. CONSTRUCTION VENTS AND DRAINS.
3. NO INSULATION REQUIRED.



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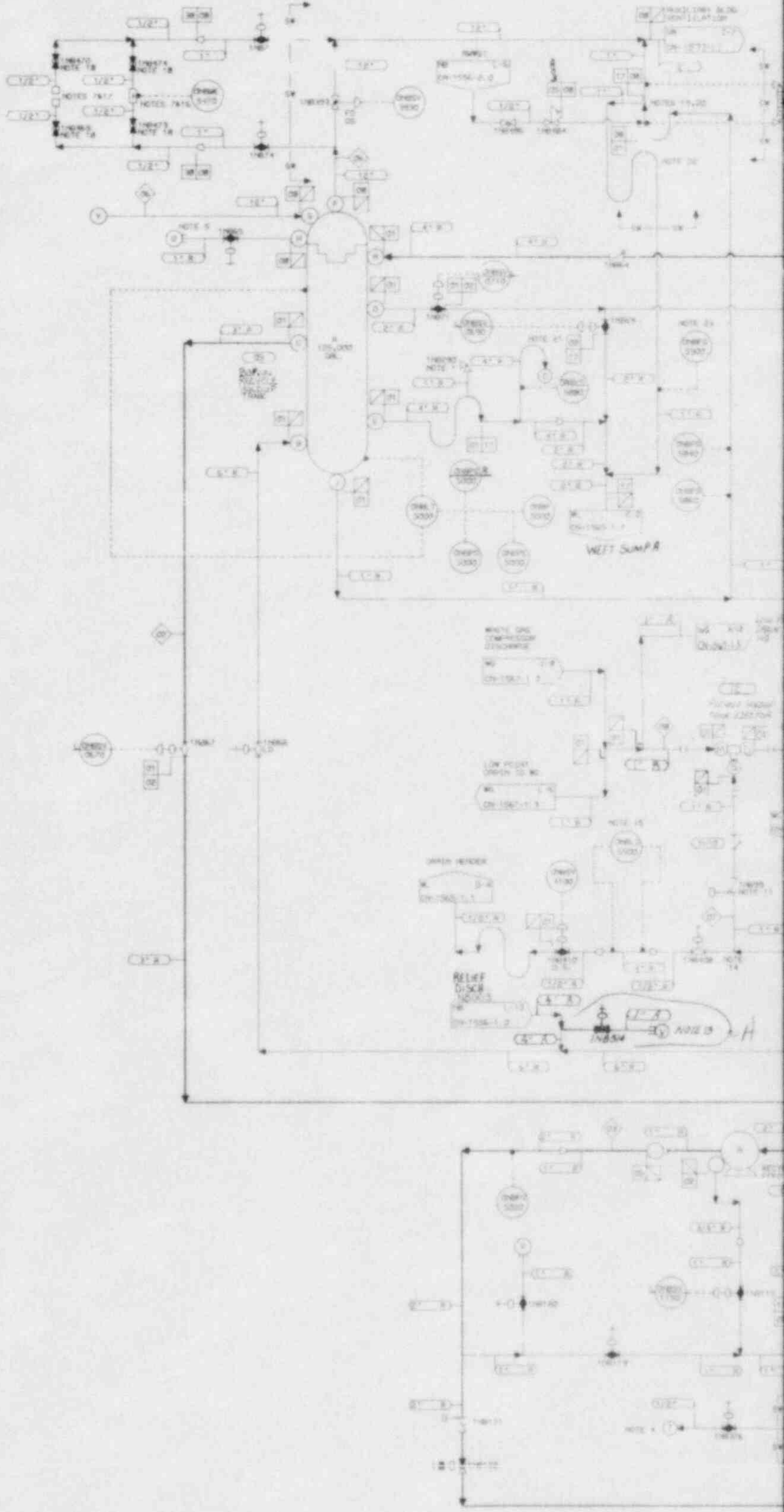
FLOW DIAGRAM OF
BORON RECYCLE SYSTEM
CATAWBA NUCLEAR STATION
Figure 9.3.5-2
Rev. 10

R7 - co/14

8406270190-28

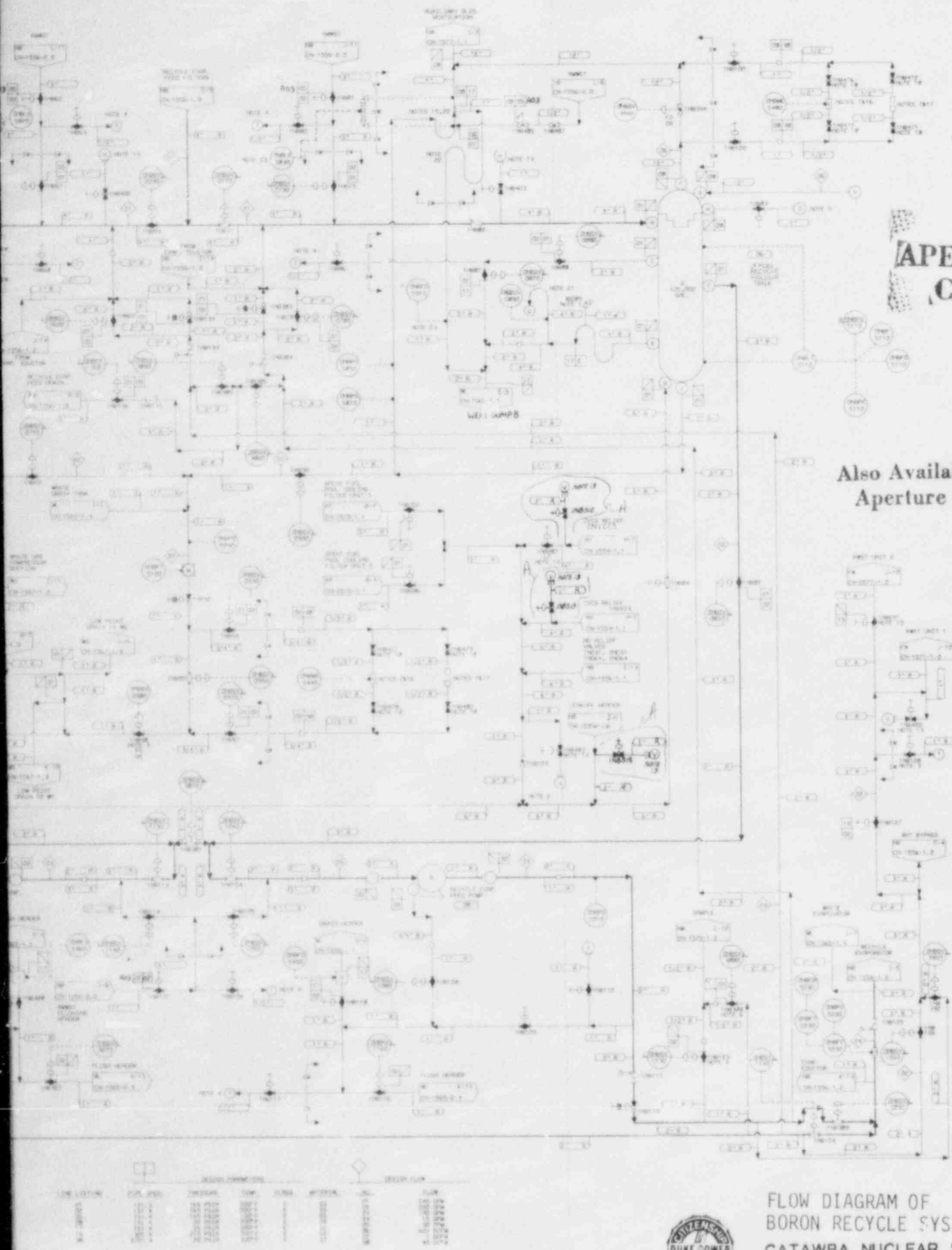


DUKE DRAWING TITLE	DUKE C. ADNG	FIGURE NO.
CHEMICAL & VOLUME CONTROL SYSTEM	CN-1554-1.1	9.3.4-1
BORON RECYCLE SYSTEM	CN-1556-1.0	9.3.4-1
BORON RECYCLE SYSTEM	CN-1556-1.1	9.3.4-2
BORON RECYCLE SYSTEM	CN-1556-1.2	9.3.4-3
BORON RECYCLE SYSTEM	CN-1556-1.4	- - -
BORON RECYCLE SYSTEM	CN-1556-2.1	9.3.4-7
LIQUID RADWASTE SYSTEM	CN-1565-1.1	11.2.2-2
LIQUID RADWASTE SYSTEM	CN-1565-1.4	11.2.2-5
LIQUID RADWASTE SYSTEM	CN-1565-2.1	11.2.2-13
WASTE GAS SYSTEM	CN-1567-1.0	11.3.2-1
WASTE GAS SYSTEM	CN-1567-1.3	11.3.2-4
SPENT FUEL COOLING SYSTEM	CN-1575-1.1	9.1.3-2
NUCLEAR SAMPLING SYSTEM	CN-1572-1.2	9.3.2-3
AUXILIARY BUILDING VENTILATION SYSTEM	CN-1577-1.0	9.4.3-1
CHEMICAL & VOLUME CONTROL SYSTEM	CN-2554-1.1	- - -
SPENT FUEL COOLING SYSTEM	CN-2575-1.1	- - -
REFUELING WATER SYSTEM	CN-2571-1.0	- - -

NOTES:

1. OVERFLOW NOZZLE TO BE LOCATED AT SAME ELEVATION AS OUTLET NOZZLE TO PUMP SUCTION. LOWER LOOP TO EXTEND 20" BELOW OVERFLOW CONNECTION AND UPPER LOOP 6" BELOW DIAPHRAGM FLANGE. LOCATE SYPHON BREAK VENT ON TOP OF UPPER LOOP.
2. ALL PIPE DOWNSTREAM OF THIS POINT IS TO BE AT SAME ELEVATION, 12" BELOW DIAPHRAGM FLANGE, TO PROVIDE FOR CROSS CONNECTION BETWEEN TANKS.
3. LOCATE VALVE CLOSE TO CONNECTION FROM WASTE GAS SYSTEM.
4. ARRANGE TELLTALE FOR EASY DRAINAGE INTO HAND CARRIED VESSEL.
5. CONDENSATE DRAIN PIPE SHOULD NOT RISE ABOVE ELEVATION OF CONNECTION PIPE TO FLOOR.
6. VALVE TO BE OPENED AND CLOSED FROM SAMPLE ROOM.
7. LOCATE SAMPLE CONNECTIONS AND VALVES FOR EASY ACCESS.
8. AIR-OPERATED PLUG VALVES FAIL-AS-IS UNLESS OTHERWISE NOTED.

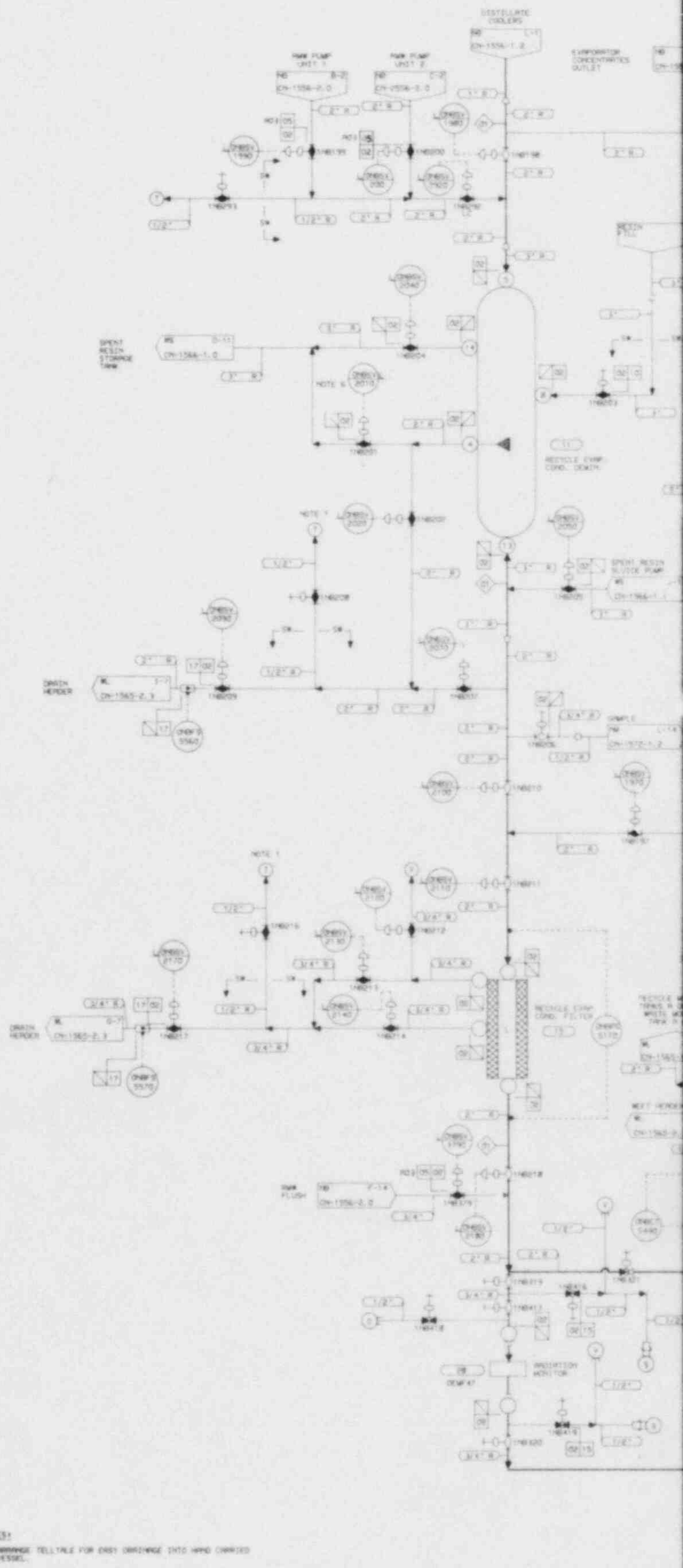
11. CHECK VALVE MUST OPEN WITH A DIFFERENTIAL PRESSURE OF 1 PSI OR LESS.
12. THIS VALVE REMAINS CLOSED UNTIL UNIT 2 IS READY FOR OPERATION. IT IS THEN LOCKED OPEN.
13. HIGH POINT VENT ADDED FOR CONSTRUCTION FLUSH AND HYDRO.
14. LOCATE AT LOW POINT IN PIPING.
15. FOUR INCH PIPE SHOULD BE AT LEAST 10 INCHES LONG LOCATED HORIZONTALLY, WITH 1/2 INCH DRAIN LINE LOCATED AT BOTTOM OF PIPE.
16. GAS CHROMATOGRAPHY OPTION.
17. PROVIDE SAMPLE TAPS WITH THREADED 1/2" TYGON HOSE CONNECTIONS.
18. VALVES ARE FURNISHED FROM INSTRUMENTATION STOCK ROOT VALVE KITS.
19. CLASS CHANGE AT [illegible] ELEVATION OF LOWER LEVEL GLASS TAP.
20. LOOP SEAL FOR PRESSURE RELIEF.
21. LOCATE TOP ¢ OF STANDPIPE AT ELV. [illegible] AND BOTTOM ¢ AT ELV. [illegible]
22. PROVIDE A MINIMUM OF 12" TOP TO BOTTOM ¢'S FOR OVERFLOW DELTA [illegible] SEAL.
23. LOCATE LOOP SEAL LEVEL GLASSES & SIGHT GLASSES OUTSIDE WHT ROOMS SO READABLE FROM [illegible] ELEVATION.



FLOW DIAGRAM OF
BORON RECYCLE SYSTEM
CATAWBA NUCLEAR STATION
Figure 9.3.5-4
Rev. 10

R7 - co/21

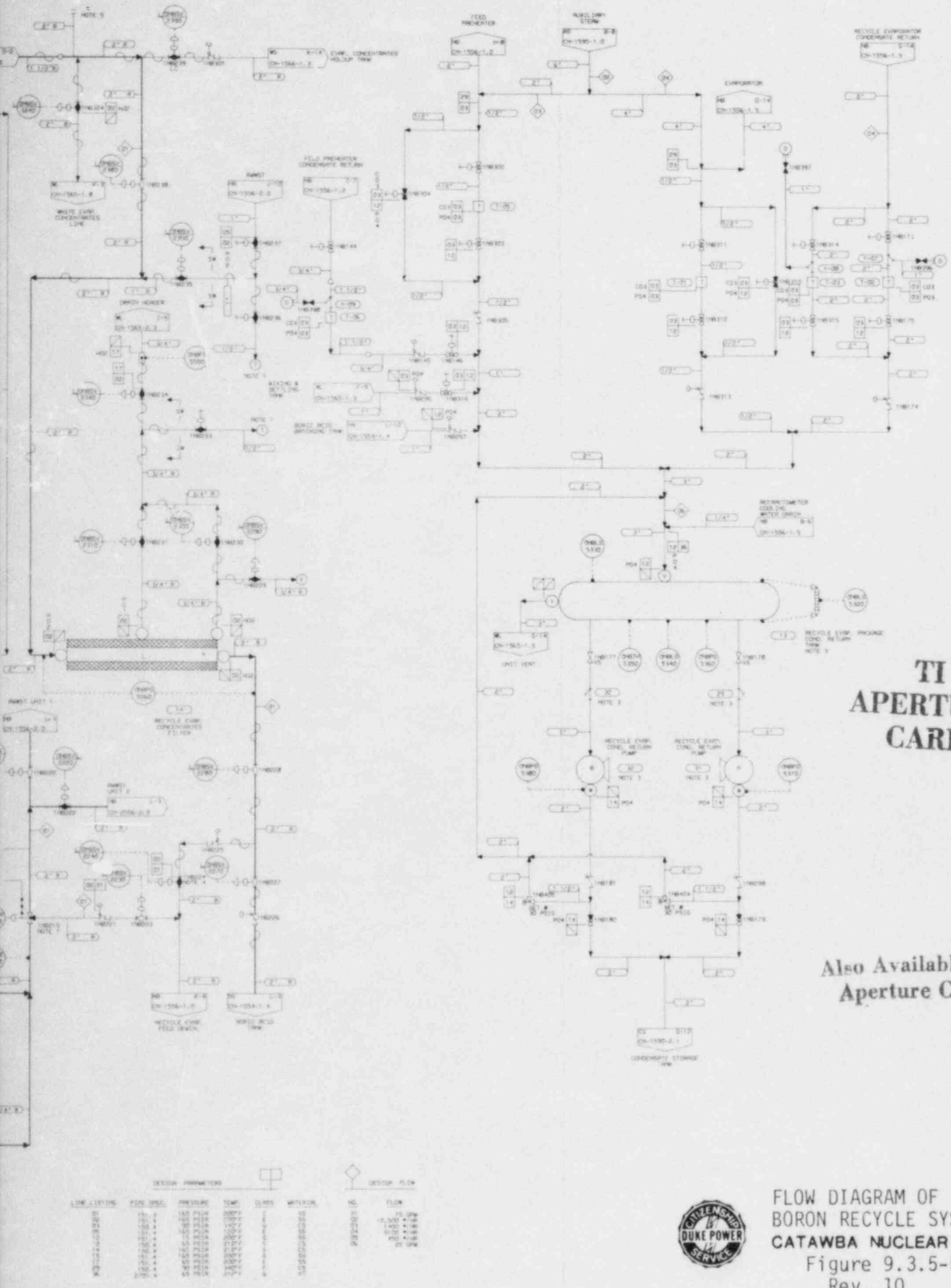
8406270190-29



DUKE DRAWING TITLE	DUKE DRAWING	FIGURE NO.
CHEMICAL & VOLUME CONTROL SYSTEM	CN-1554-1.4	9.3.4-5
BORON RECYCLE SYSTEM	CN-1556-1.0	9.3.5-1
BORON RECYCLE SYSTEM	CN-1556-1.2	9.3.5-3
BORON RECYCLE SYSTEM	CN-1556-1.5	9.3.5-6
BORON RECYCLE SYSTEM	CN-1556-2.0	9.3.5-7
LIQUID RADWASTE SYSTEM	CN-1565-1.1	11.2.2-4
LIQUID RADWASTE SYSTEM	CN-1565-1.3	11.2.2-6
LIQUID RADWASTE SYSTEM	CN-1565-1.4	11.2.2-7
LIQUID RADWASTE SYSTEM	CN-1565-1.8	11.2.2-9
LIQUID RADWASTE SYSTEM	CN-1565-2.3	11.2.2-15
SOLID RADWASTE SYSTEM	CN-1566-1.0	11.4.2-1
SOLID RADWASTE SYSTEM	CN-1566-1.1	11.4.2-2
SOLID RADWASTE SYSTEM	CN-1566-1.3	11.4.2-4
NUCLEAR SAMPLING SYSTEM	CN-1572-1.2	9.3.2-3
CONDENSATE STORAGE SYSTEM	CN-1590-2.1	10.4.7-3
AUXILIARY STEAM SYSTEM	CN-1595-1.0	---
BORON RECYCLE SYSTEM	CN2556-2.0	9.3.5-8

NOTES:

1. ARRANGE TELLTALE FOR EASY DRAINAGE INTO HAND CARRIED VESSEL.
2.
3.
4. CAUTION: SEE BORON RECYCLE SYSTEM DESCRIPTION, SECTION 7.1, PARAGRAPH D BEFORE OPENING THIS VALVE.
5. CLEAN OUT CONNECTION.
6. BUTT WELD ALL RESIN TRANSFER LINES TO ATTAIN A SMOOTH INTERIOR SURFACE.
7. VALVE FAILS TO RECYCLE EVAP. FEED DEMINERALIZERS.
8. AIR-OPERATED PLUG VALVES FAIL-AS-IS UNLESS OTHERWISE NOTED.



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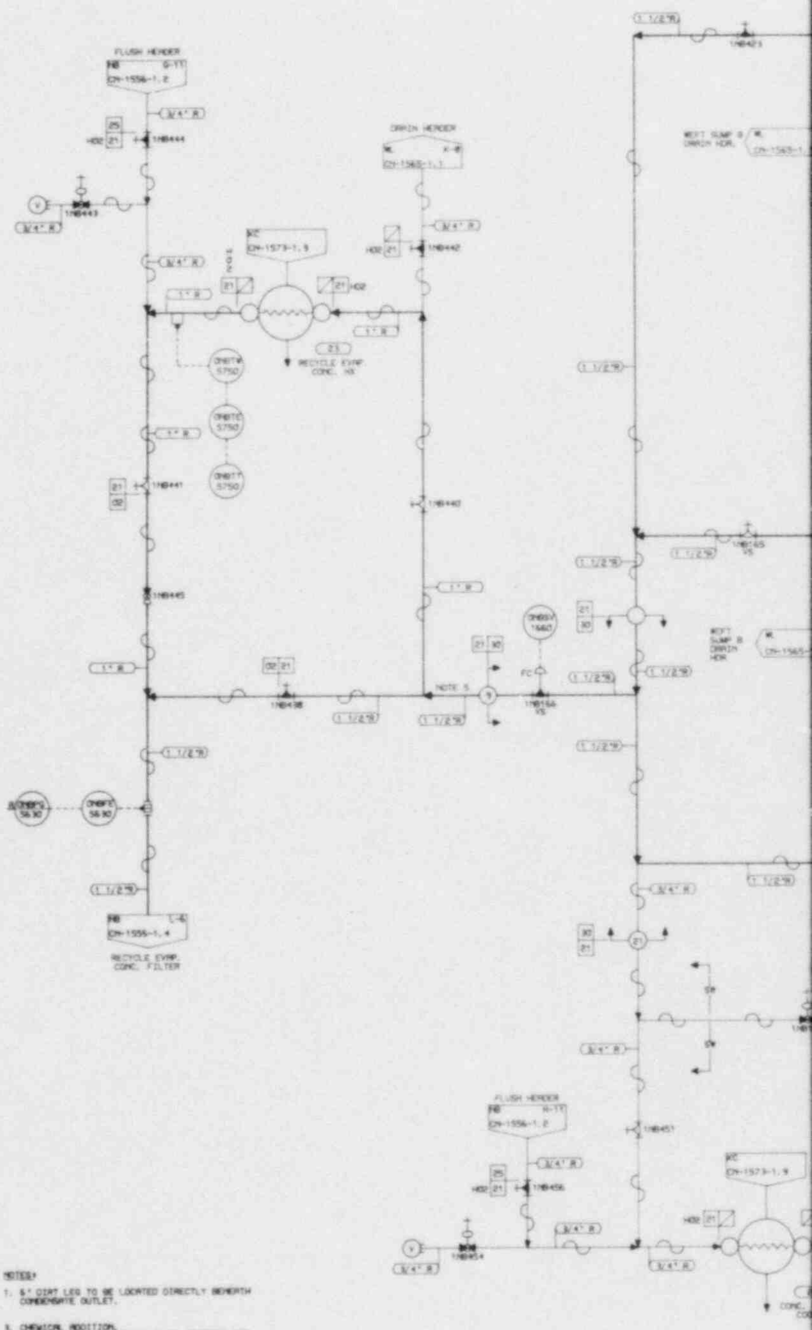
FLOW DIAGRAM OF
BORON RECYCLE SYSTEM
CATAWBA NUCLEAR STATION
Figure 9.3.5-5
Rev. 10

R-5

8406270190 -30

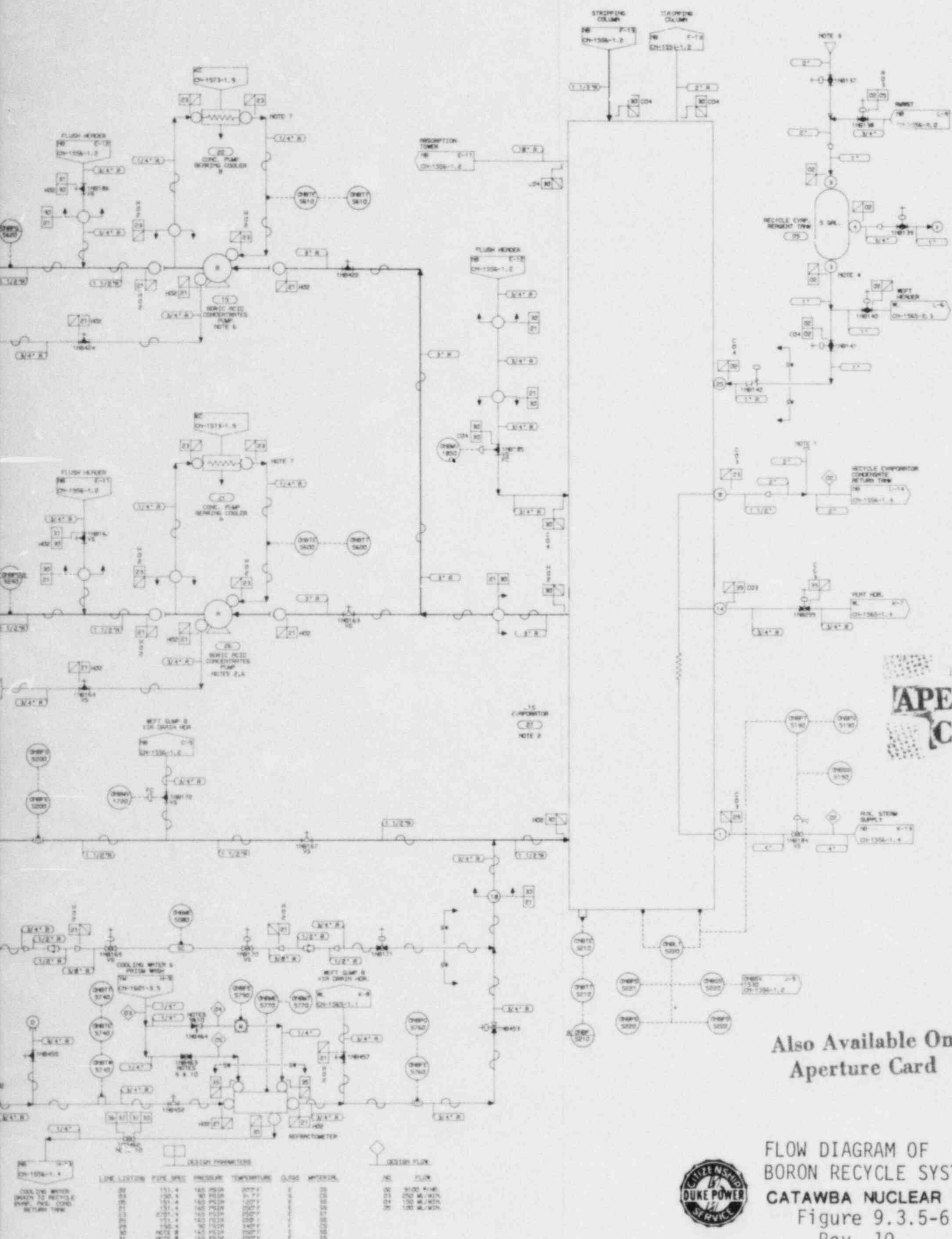
DUKE DRAWING TITLE	DUKE DRAWING	FIGURE NO.
BORON RECYCLE SYSTEM	CN-1556-1.2	9.3.5-3
BORON RECYCLE SYSTEM	CN-1556-1.4	9.3.5-5
BORON RECYCLE SYSTEM	CN-1556-2.0	9.3.5-7
LIQUID RADWASTE SYSTEM	CN-1565-1.1	11.2.2-2
LIQUID RADWASTE SYSTEM	CN-1565-1.6	11.2.2-5
LIQUID RADWASTE SYSTEM	CN-1565-2.1	11.2.2-11
COMPONENT COOLING SYSTEM	CN-1573-1.9	9.2.2-10
MAKEUP DEMINERALIZED WATER SYSTEM	CN-1601-3.5	9.2.3-6



NOTES:

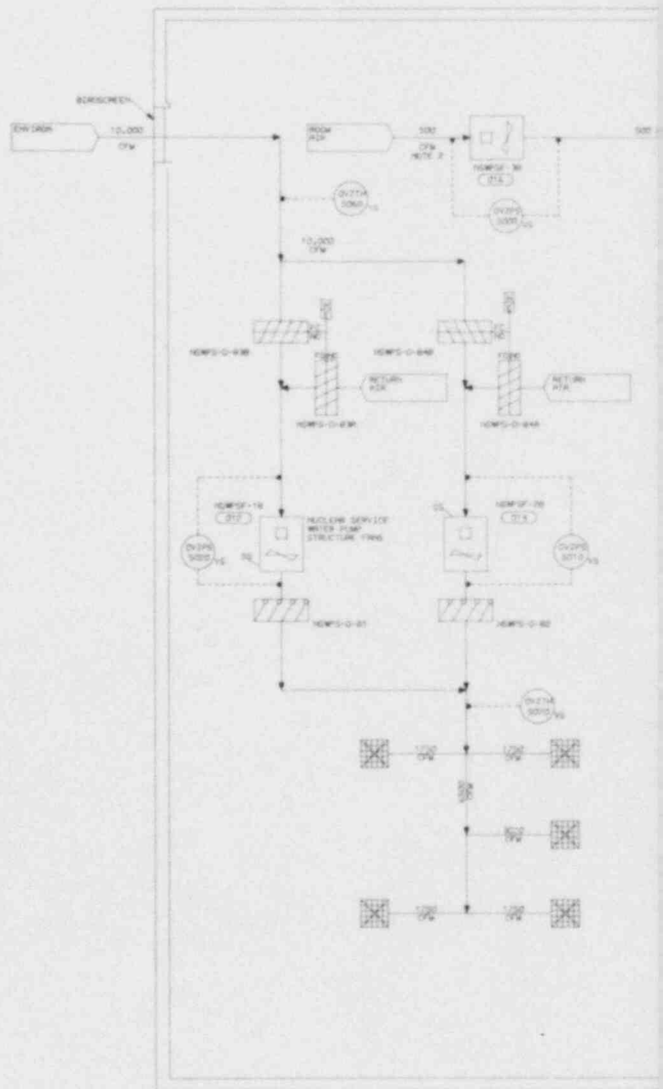
1. 6" DIRT LEG TO BE LOCATED DIRECTLY BENEATH CONDENSATE OUTLET.

3. CHEMICAL ADDITION.
4. REAGENT TANK AND PIPING TO BE ARRANGED FOR GRAVITY DRAIN TO EVAPORATOR FEED LINE.
5. HEAT TRACING SHOULD BEGIN WHERE PIPING EXITS EVAPORATOR ROOM.
6. LOCATE CONCENTRATE PUMPS ON FLOOR NEXT TO EVAPORATOR SKID.
7. THE CONC. PUMP BEARING COOLER SHOULD BE LOCATED AS CLOSE TO THE CONC. PUMP AS POSSIBLE, AND THE LENGTH OF 1/4" TUBING SHOULD BE KEPT TO A MINIMUM TO PREVENT RESTRICTION OF FLOW.
8. SEE WESTINGHOUSE EQUIPMENT SPECIFICATION NO. G-678796, REV. 2(11-16-72), PAGE 22 OF 33, DUKE FILE: CNM-1208.02-37.
9. LOCATE VALVES 1NB463, 1NB464, AND FLOW METER OUTSIDE SHIELD WALL.
10. VALVE SUPPLIED BY WPIC.



FLOW DIAGRAM OF
BORON RECYCLE SYSTEM
CATAWBA NUCLEAR STATION
Figure 9.3.5-6
Rev. 10

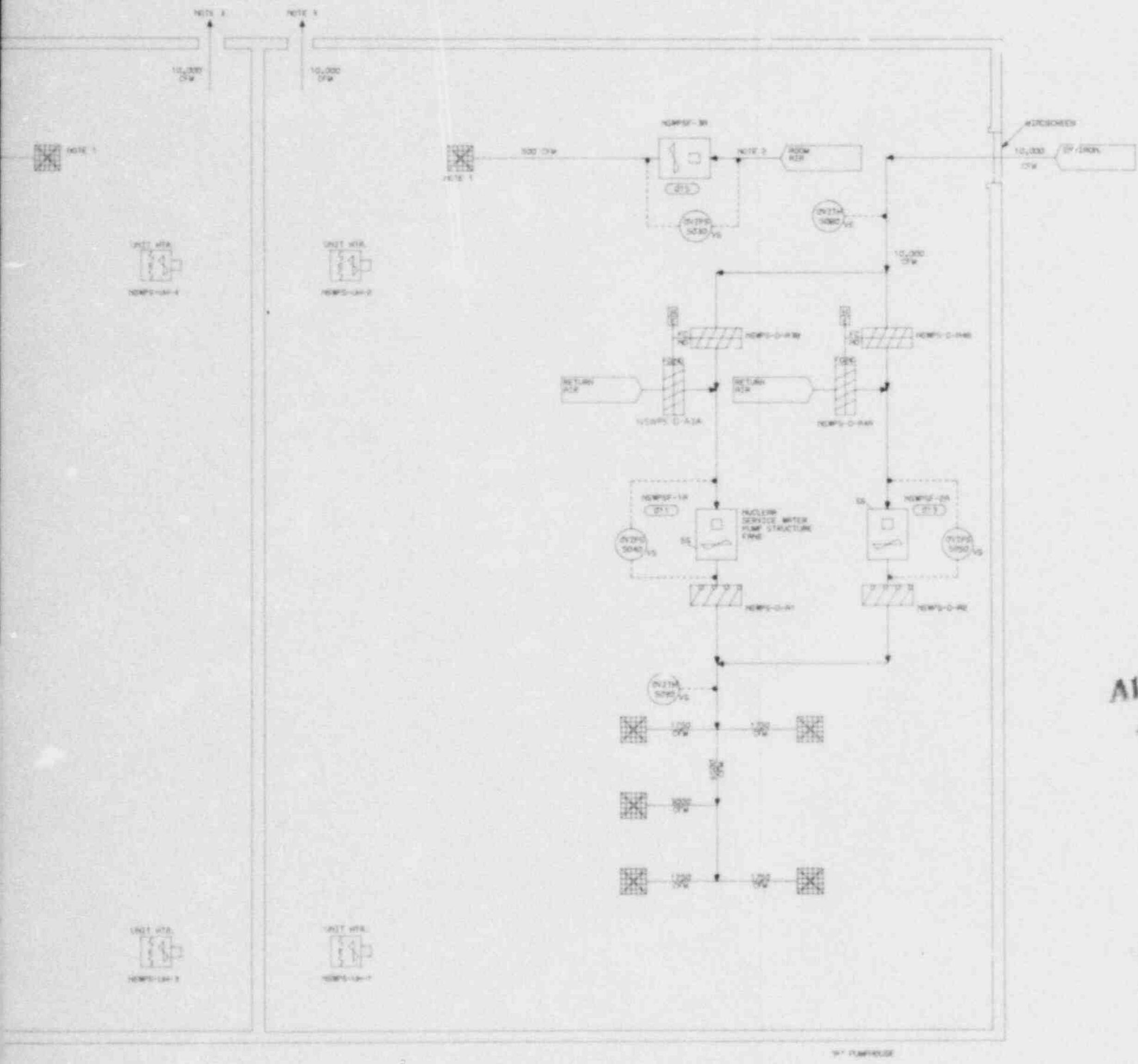
R-2



"B" PUMPHOUSE

NOTES:

1. HDMPSF-3A AND HDMPSF-3B WILL OPERATE ONLY DURING SHUTDOWN TO ALLOW ACCESSIBILITY TO THE SUMP AREA FOR MAINTENANCE.
2. HDMPSF-3A, HDMPSF-3B AND ALL RELATED DUCTWORK ARE NOT NUCLEAR SAFETY RELATED.
3. 24" CARBON STEEL PIPE.



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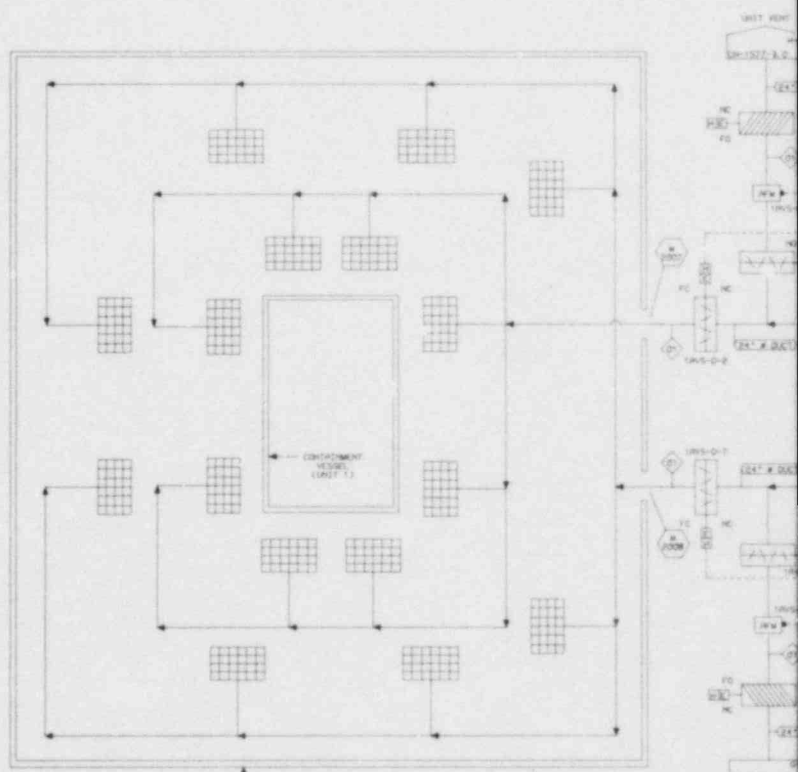
FLOW DIAGRAM OF
NUCLEAR SERVICE WATER PUMP
STRUCTURE VENTILATION SYSTEM
CATAWBA NUCLEAR STATION
Figure 9.4.8-1
Rev. 10

R-2

8406270190-32

DUKE DRAWING TITLE	DUKE DRAWING	FIGURE NO.
UNIT 1 VT STACK	CN-1577-3.0	9.4.3-3



NOTES:

1. FLOW CONDITIONS DO NOT OCCUR SIMULTANEOUSLY.
2. FOR DAMPERS, SEE DWG. CN-1565-2.3
3. SEE VALVE LISTING FOR VALVES 1VE4 AND 1VE9.
4. FLOW TOTALIZER AND DIGITAL COUNTER.

VALVE LISTING (NOTE

VALVE*	PRESSURE	TEMP
1VE4	15 PSIG	[illegible]
1VE9	15 PSIG	[illegible]

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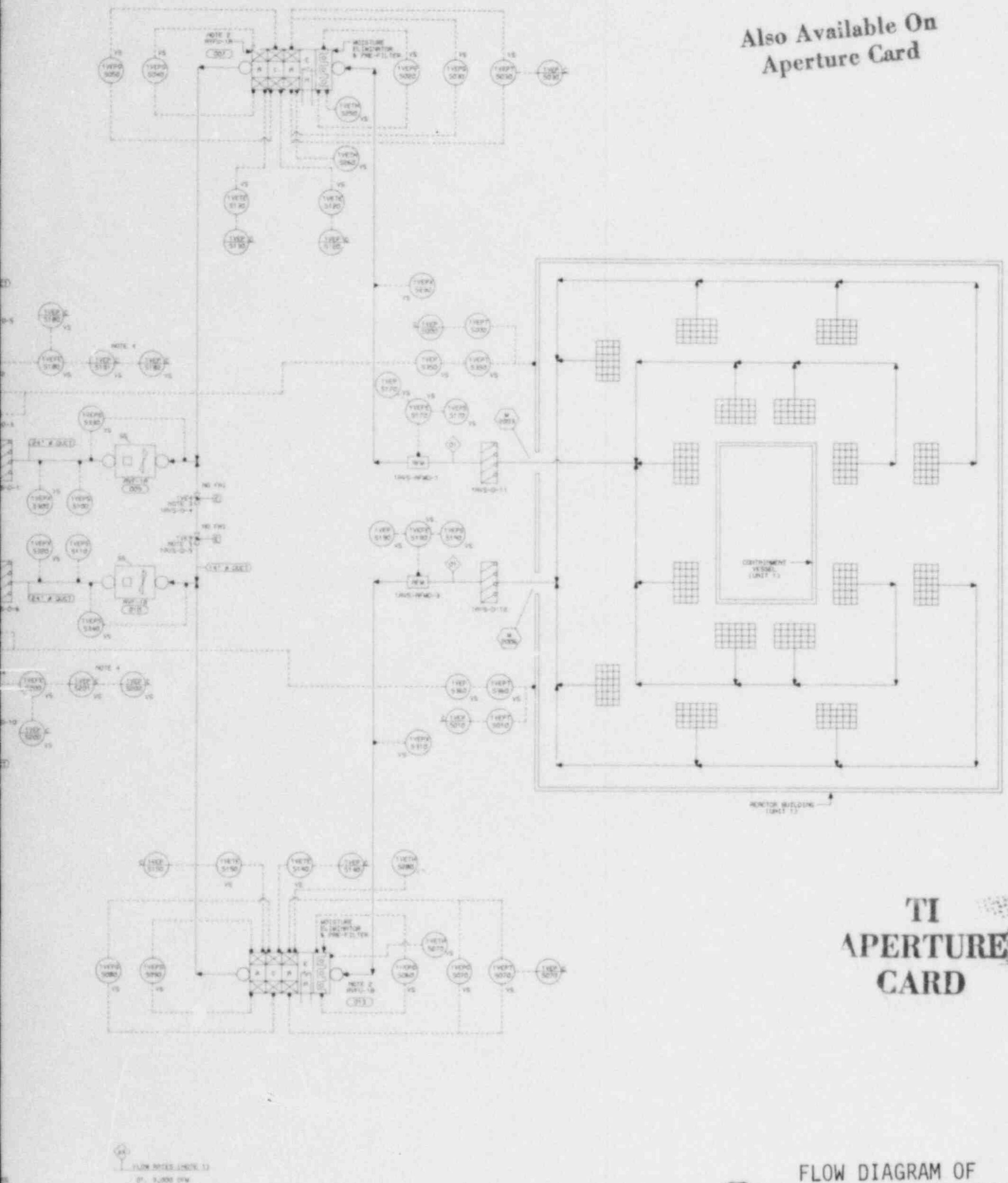

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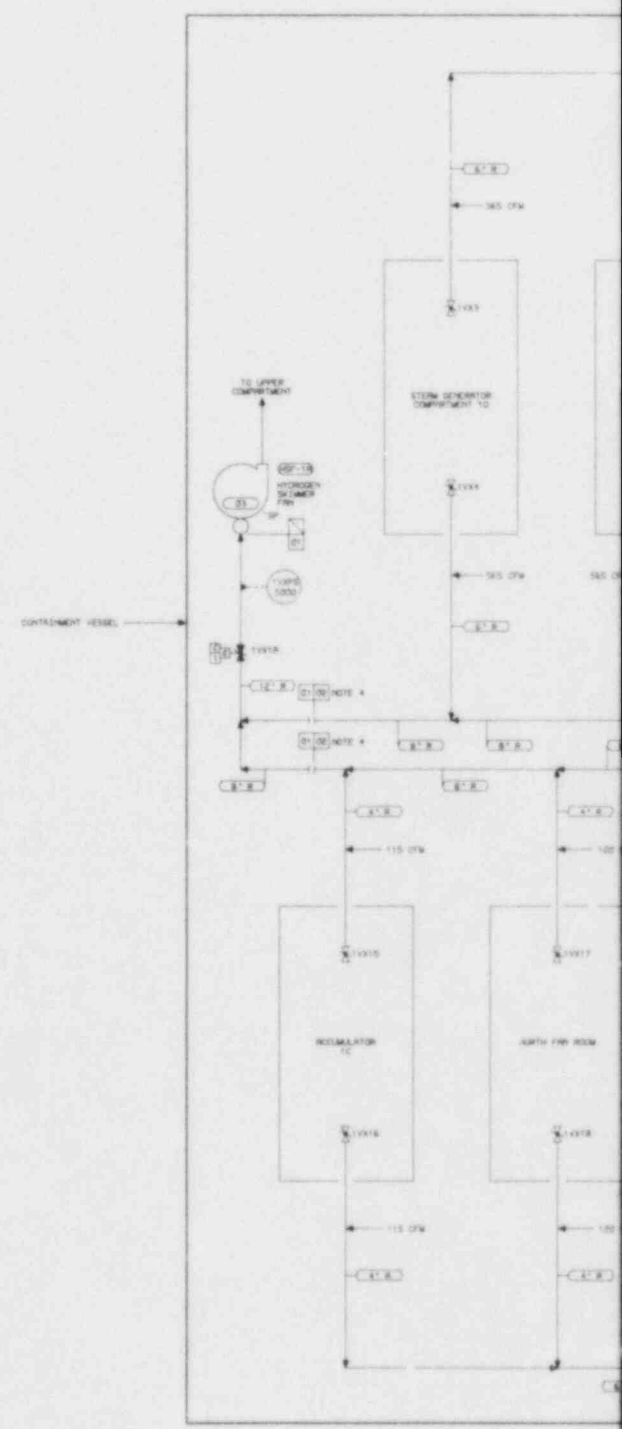
FLOW DIAGRAM OF
ANNULUS VENTILATION SYSTEM
CATAWBA NUCLEAR STATION
Figure 9.4.9-1
Rev. 10

R5 - co/14

8406270190-33



NOTES:

1. CONTAINMENT AIR RETURN FAN WILL START 10 MINUTES AFTER THE SP SIGNAL.
2. ALL PIPING CLASS "B" UNLESS OTHERWISE NOTED.

4. EMBEDDED PORTION OF PIPE IS BE CLASS H.
5. BYPASS TEST DAMPERS, TO UPPER COMPARTMENT.
6. HF SKIMMER PORTION OF VX SYSTEM IS A ANS CLASS 3 A.H. SYSTEM WHICH IS CONSTRUCTED OF PIPING MATERIALS ACCORDANCE WITH ANSI B31.1, SECTION 137.4, SUMMER 1974 ADDENDA. DESIGN PRESSURE SHALL BE 5.0 PSIG AND DESIGN TEMP. IS 300°F

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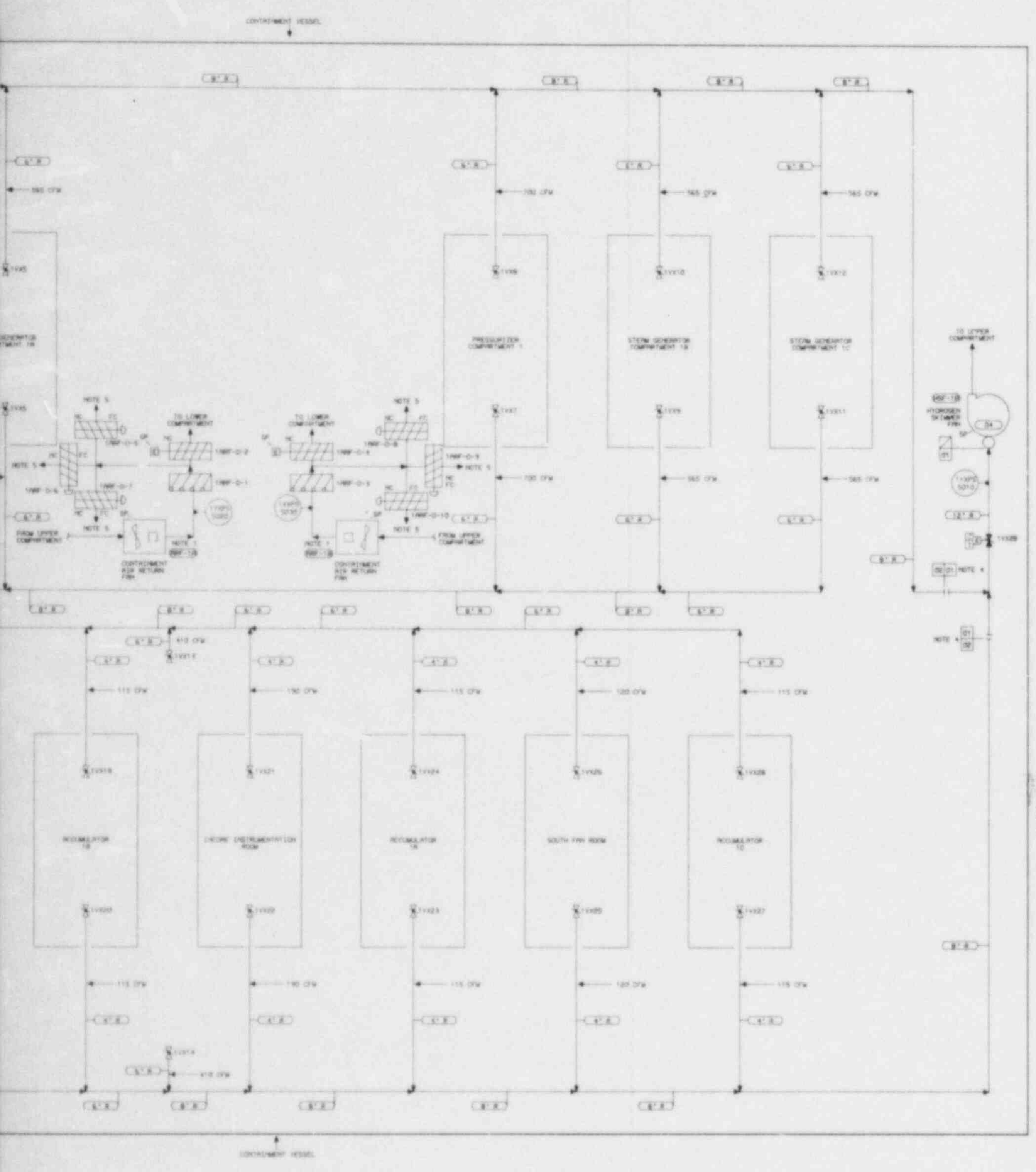

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FLOW DIAGRAM OF
CONTAINMENT AIR RETURN EXCHANCE
& HYDROGEN SKIMMER SYSTEM
CATAWBA NUCLEAR STATION
Figure 9.4.10-1
Rev. 10

R5 - co/13
8406270190-34

SEE

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*OVERSIZED DRAWINGS

(ADDITIONAL DOCUMENT PAGES FOLLOW)

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NUMBERS OF PAGES. 1

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*OVERSIZED DRAWINGS

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NUMBERS OF PAGES. 1

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*OVERSIZED DRAWINGS

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AVAILIBILITY PDR CF HOLD

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*OVERSIZED DRAWINGS

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AVAILABILITY PDR CF HOLD

NUMBERS OF PAGES. 1

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APERTURE CARD NO# 8406270232

AVAILIBILITY PDR CF HOLD

NUMBERS OF PAGES. 1

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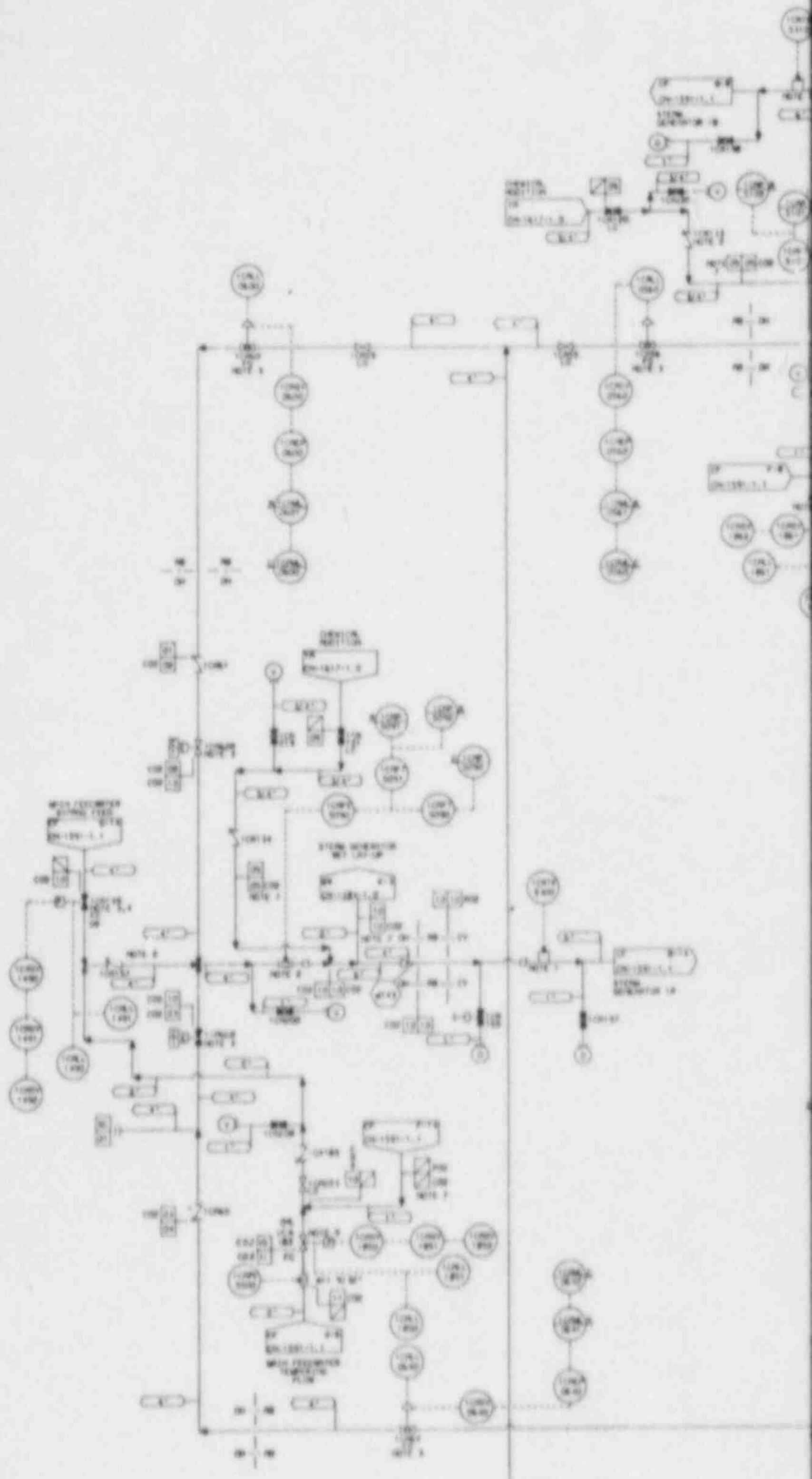

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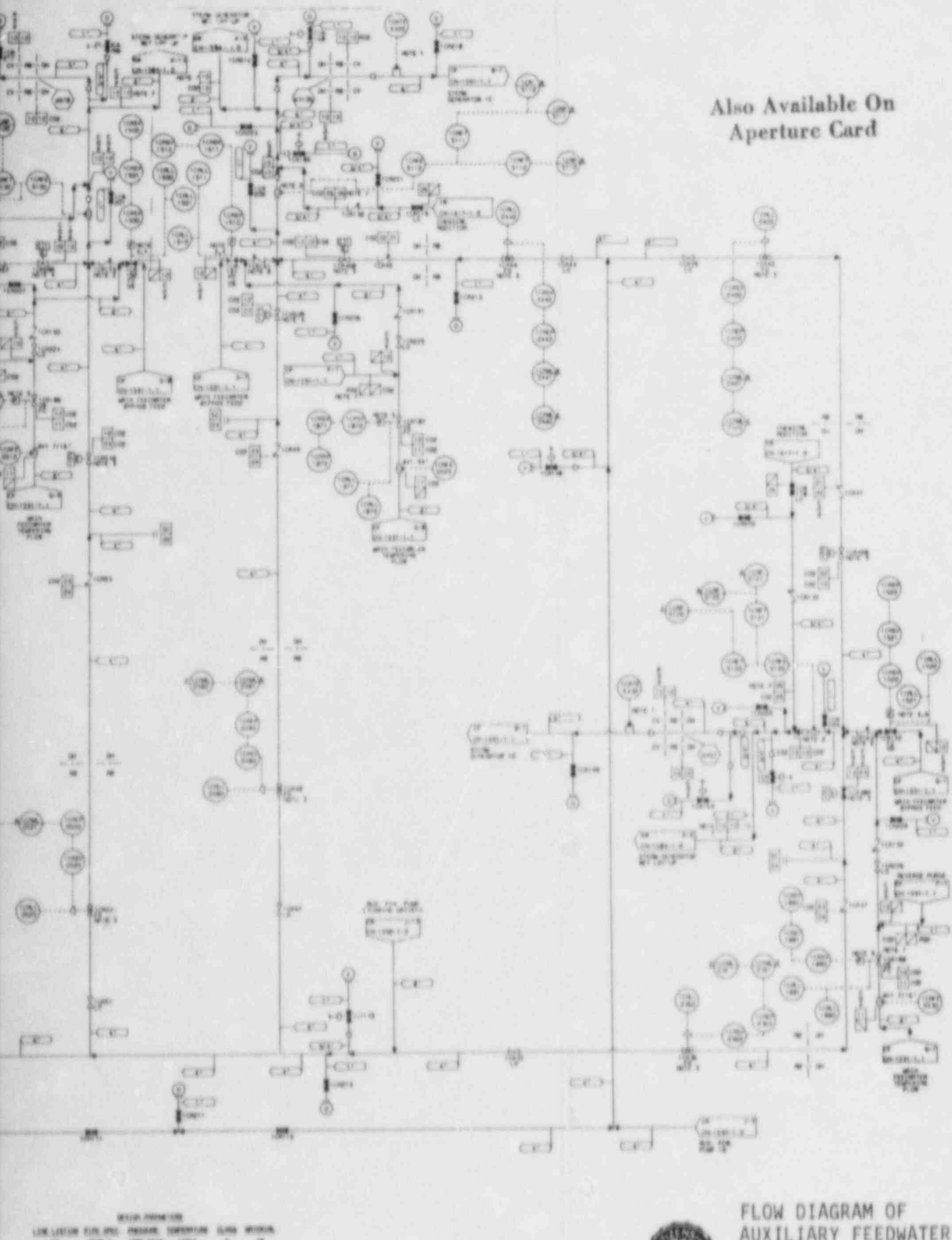
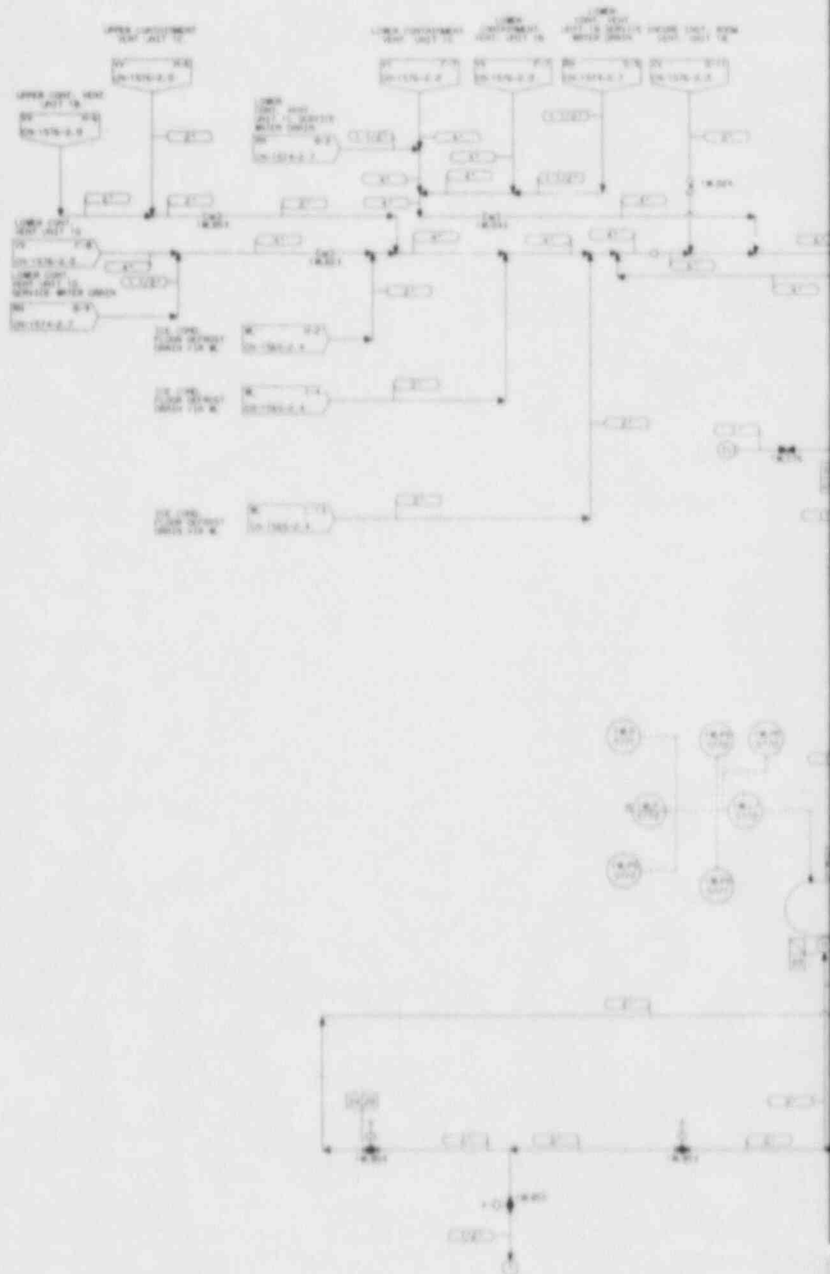


FLOW DIAGRAM OF
AUXILIARY FEEDWATER SYSTEM
CATAWBA NUCLEAR STATION
FIGURE 10.4.9-2
Rev. 11

R4

8406270232 -01



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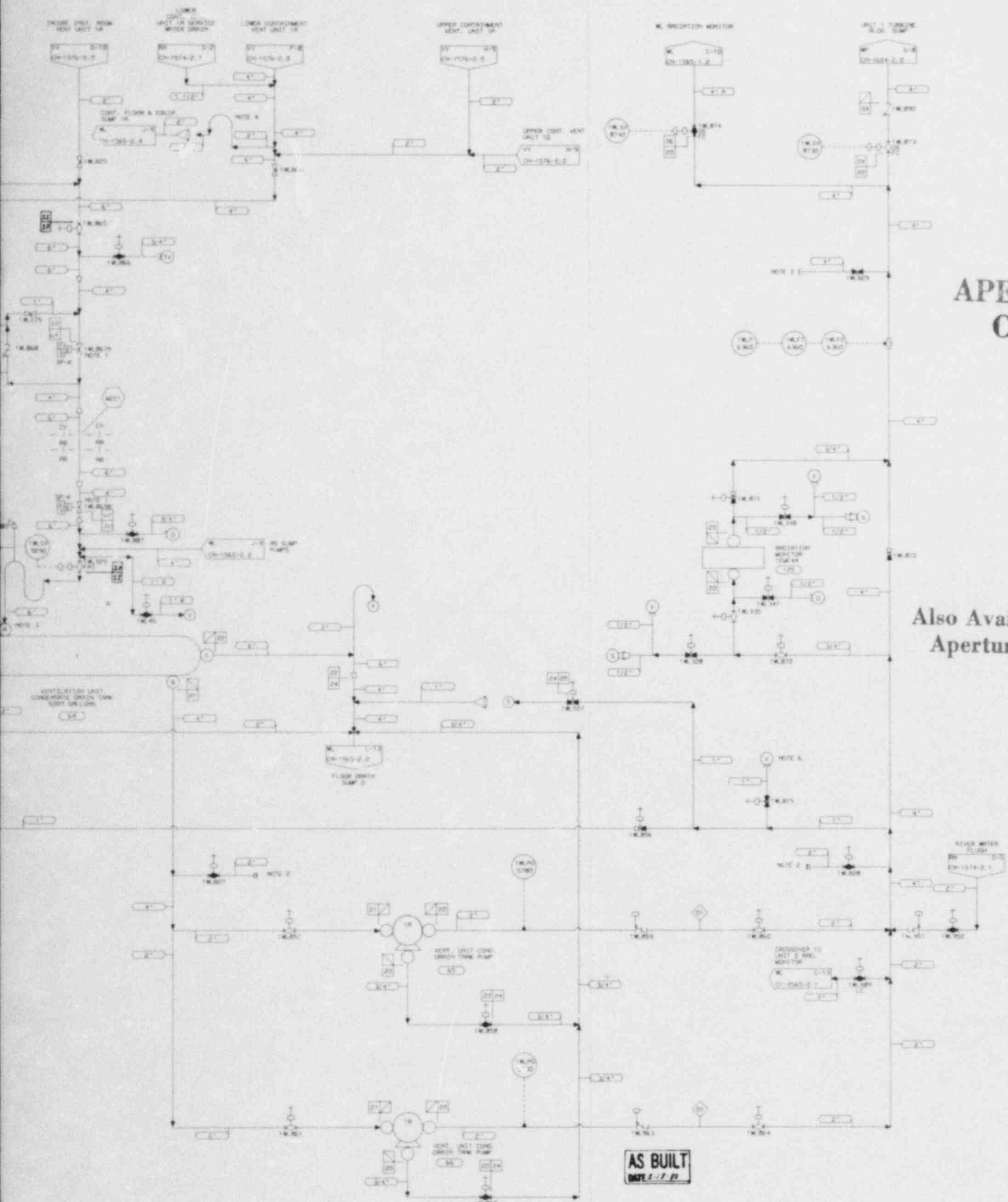
[illegible]	[illegible]	[illegible]

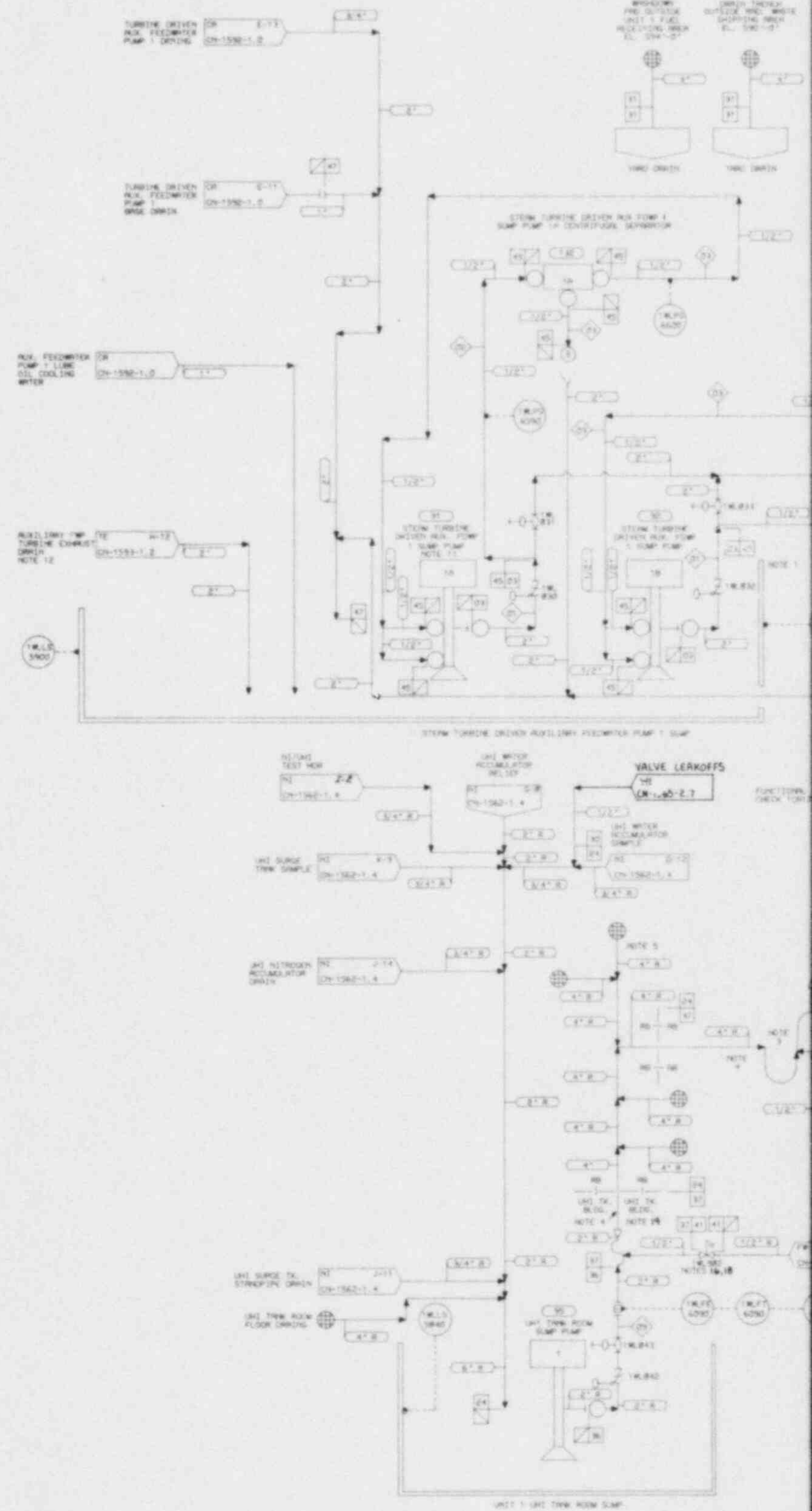
NOTES:

1. [illegible]
2. [illegible]
3. [illegible]
4. [illegible]
5. [illegible]
6. [illegible]
7. [illegible]



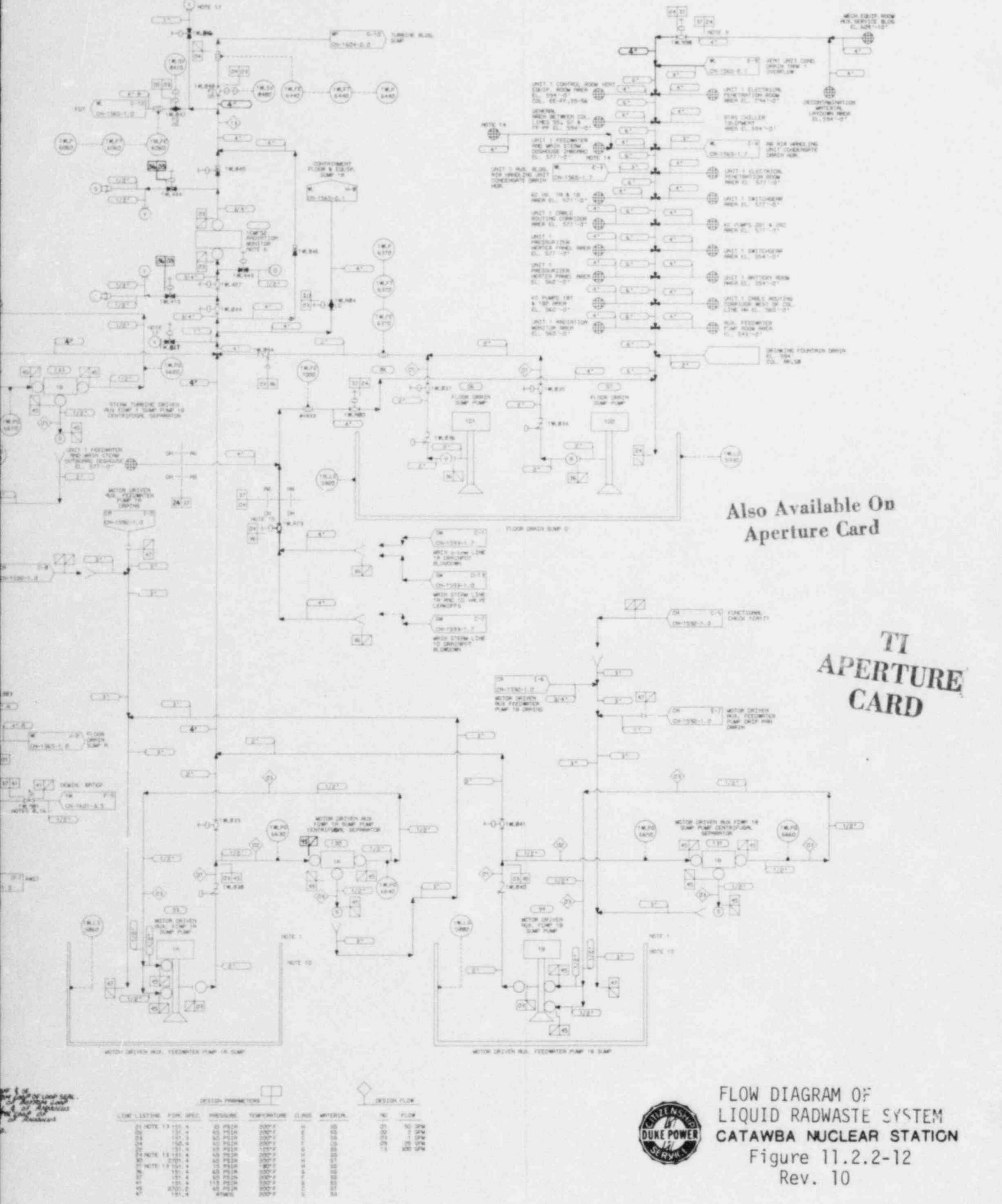
FLOW DIAGRAM OF
LIQUID RADWASTE SYSTEM
CATAWBA NUCLEAR STATION
Figure 11.2.2-11
Rev. 10

DUKE DRAWING TITLE	DUKE DRAWING	FIGURE NO.
SAFETY INJECTION SYSTEM	CN-1562-1.4	6.3.2-5
LIQUID RADWASTE SYSTEM	CN-1565-1.0	11.2.2-1
LIQUID RADWASTE SYSTEM	CN-1565-2.1	11.2.2-11
LIQUID RADWASTE SYSTEM	CN-1565-2.7	- - -
REFUELING WATER SYSTEM	CN-1571-1.0	9.2.7-1
AUXILIARY FEEDWATER SYSTEM	CN-1592-1.0	10.4.9-1
MAIN STEAM SYSTEM	CN-1593-1.7	10.3.2-8
MAKEUP DEMINERALIZED WATER SYSTEM	CN-1601-3.5	9.2.3-6
TURBINE BUILDING SUMP PUMP SYSTEM	CN-162 -2.0	- - -



NOTES:

1. 15" HIGH CURB AROUND PUMP PIT.
3. LOOP SEAL INSTALLED AS SHOWN WITH BOTTOM LOOP 12" BELOW ANNULUS DRAIN HEADER. TOP LOOP 12" ABOVE ANNULUS DRAIN HEADER.
4. PIPING IS EMBEDDED IN CONCRETE REACTOR BUILDING SLAB.
5. ANNULUS DRAIN HEADER.
6. IN ORDER TO FLUSH MONITOR, RUN TEMPORARY HOSE FROM NEAREST DEMINERALIZED WATER CONNECTION TO SUMP WHICH WAS CONTAMINATED. FILL SUMP AND ALLOW SUMP PUMPS TO FLUSH MONITOR.
7. MAY BE TURNED DOWN INTO NEAREST FLOOR DRAIN.
8. FLOAT VALVE TO BE LOCATED WITH FLOAT CENTERLINE 10" FROM BOTTOM OF BOTTOM LOOP WITH VALVE IN CLOSED POSITION.
9. AUXILIARY BUILDING WALL AT COL. LINE QQ.
10. PROVIDE OPENING IN SUMP COVER PLATE TO INSERT TEMPORARY MAINTENANCE SUMP PUMP.
11. STEAM TURBINE DRIVEN AUX. FEEDWATER PUMP PIT SUMP PUMP 1A TO BE SUPPLIED WITH BACKUP POWER FROM STANDBY SHUTDOWN FACILITY.
12. CONDENSATE DRAINS MUST DISCHARGE BELOW MINIMUM SUMP WATER LEVEL TO PREVENT EXCESSIVE FLASHING. ROUTE DRAINS CONTINUOUSLY DOWNWARD WITH NO INTERMEDIATE HIGH POINTS.
13. PS 153 MAY BE USED IN PLACE OF PS 151.X FOR EMBEDDED PIPE.
14. REPLACE STRAINER WITH CLASS F FLOW RESTRICTION PLATE WITH ID = 0.7".
15. THIS LINE AND ALL OTHERS PENETRATING TRENCH COVER SHOULD BE SEALED FOR 12 FT OF WATER
16. 1/4" VENT LINE ADDED TO MAKEUP VALVES WILL HAVE DESIGN PARAMETER *A1.
17. CONSTRUCTION VENT.
18. INSTALL VALVE SO THAT
19. INSTALL LOOP SEAL
20. NO INSULATION REQ



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FLOW DIAGRAM OF
LIQUID RADWASTE SYSTEM
CATAWBA NUCLEAR STATION
Figure 11.2.2-12
Rev. 10

R-9

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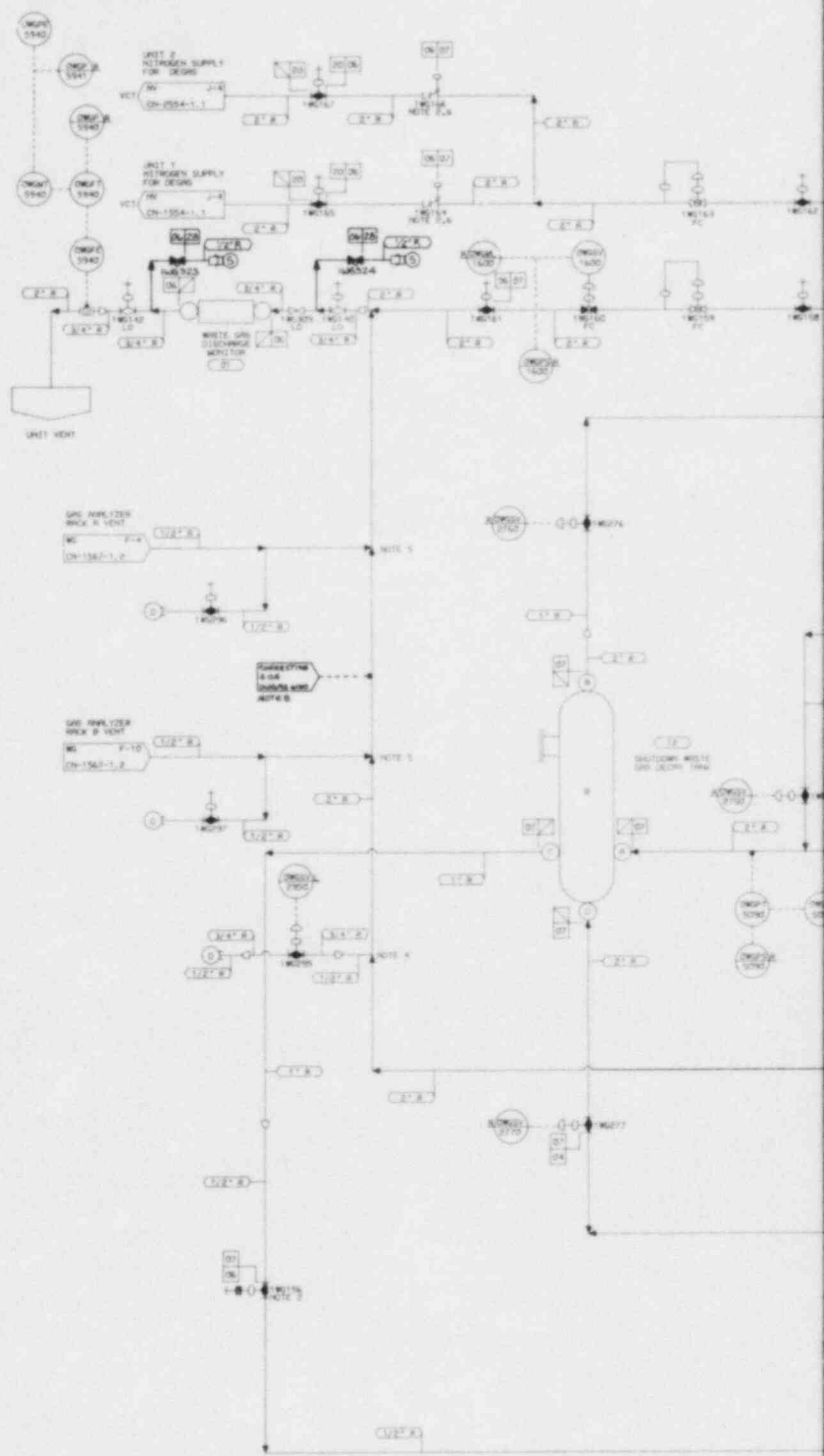
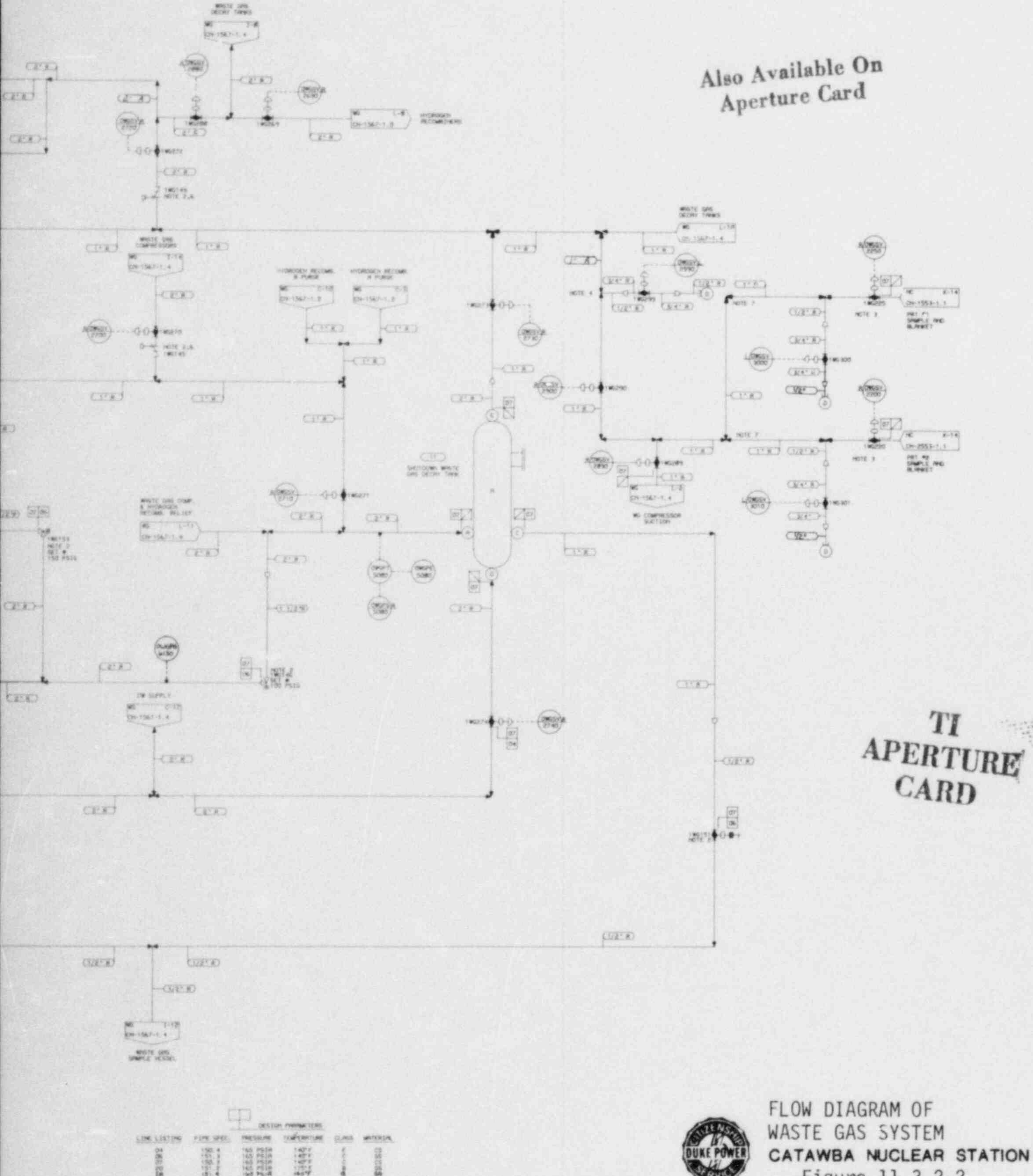


DUKE DRAWING TITLE	DUKE DRAWING	FIGURE NO.
REACTOR COOLANT SYSTEM	CN-1553-1.1	5.1-2
CHEMICAL & VOLUME CONTROL SYSTEM	CN-1554-1.1	9.3.4-2
WASTE GAS SYSTEM	CN-1567-1.3	11.3.2-1
WASTE GAS SYSTEM	CN-1567-1.2	11.3.2-3
WASTE GAS SYSTEM	CN-1567-1.4	11.3.2-5
REACTOR COOLANT SYSTEM	CN-2553-1.1	---
CHEMICAL & VOLUME CONTROL SYSTEM	CN-2554-1.1	---

NOTES:

1. AIR-OPERATED VALVES FAI UNLESS INDICATED OTHERWISE.
2. VALVE PROVIDED WITH SOFT SEAT.
3. LOW POINT DRAINS LOCATED JUST DOWNSTREAM OF VALVES 1WG220 AND 1WG205. LEAVE SUFFICIENT PIPING AFTER DRAIN VALVES TO HANDLE CONDENSATE DURING DRAINING.
4. LOW POINT DRAIN LOCATED IN VALVE GALLERY. LEAVE SUFFICIENT PIPING AFTER DRAIN VALVES TO HANDLE CONDENSATE DURING DRAINING PROCEDURE.
5. LOW POINT DRAIN IS LOCATED AT THE HYDROGEN ANALYZERS. LEAVE SUFFICIENT PIPING AFTER DRAIN VALVES TO HANDLE CONDENSATE DURING DRAINING.
6. VALVE HAS .5 TO 1.5 PSID CRACKING PRESSURE.
7. FLOW PATH OUT OF WG SYSTEM WILL BE USED TO DISCHARGE GASEOUS WASTE INTO CONTAINMENT DURING TMI-2 TYPE INCIDENT.
8. SEE INSTRUMENT DETAIL SERIES CN-1499-WG14 FOR CONNECTIONS.
9. NO INSULATION REQUIRED.



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FLOW DIAGRAM OF
WASTE GAS SYSTEM
CATAWBA NUCLEAR STATION
Figure 11.3.2-2
Rev. 10

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