CHAPTER 10

STEAM AND POWER CONVERSION SYSTEM

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STEAM AND POWER CONVERSION SYSTEM

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CHAPTER 10

STEAM AND POWER CONVERSION SYSTEM

10.1 SUMMARY DESCRIPTION

The steam and power conversion system is shown in Fig. 10.1-1. Typical heat balances at rated power and at turbine maximum capability are shown in Fig. 10.1-2 and 10.1-3, respectively.

The steam and power conversion system includes a six flow, tandem compound, 1,800 rpm turbine, coupled to a single, hydrogen inner-cooled generator and rotating rectifier exciter. Steam to drive the turbine is produced in steam generators taking heat from the reactor coolant system. Moisture separation and steam reheat are provided between the high and low pressure turbines. Steam is condensed in three surface-type single-pass condensers of divided water box design, and condensate is collected in the hotwell which has storage capacity equivalent to approximately 5 min full load operation.

The steam and power conversion systems shown and discussed in SWESSAR-P1 are based on a turbine cycle consisting of turbine driven feedwater pumps, six stages of feedwater heating and a single stage of steam reheat. Because of variations in site environmental conditions and economic evaluations, the turbine building design has the flexibility to allow Utility Applicants to optimize the turbine cycle. The turbine building design can accommodate motor-driven feedwater pumps, seven stages of feedwater heating, and two stages of steam reheat. The extra feedwater heater and second stage of reheat are indicated by dashed lines on Fig. 1.2-7. The electrical systems can accommodate motor-driven feedwater pumps by increasing the transformer's capacities.

The steam and power conversion systems are based on detailed design information for General Electric and Westinghouse turbine generators compatible with the reference plant power level. Turbine-generators provided by other manufacturers may result in changes to the steam and power conversion systems related to the turbine-generator. The turbine building arrangement drawings may change with respect to the width and height of the turbine building and the location and dimensions of related equipment. However, the orientation of the turbine-generator and the turbine building will remain the same with respect to the remainder of the plant. It is anticipated that such a change would have a very minimal effect on the remainder of the plant design. 8

The condensate and feedwater systems return feedwater to the steam generators through six stages of extraction heating arranged in three parallel strings.

The system provides load following capability in accordance with the NSSS Vendor's specified capability and within the turbine manufacturer's recommended limitations. Turbine bypass and atmospheric steam dump capacity accommodates more severe load rejections without reactor or turbine trip, as specified by the nuclear steam supply system (NSSS) Vendor.

The principal design and performance characteristics of the steam and power conversion system are summarized in Table 10.1-1.

Interface Requirements

Interface information of general applicability to the steam and power conversion systems, as presented in Section 10.1 of the respective NSSS Vendor's SARs is discussed in this section.

Westinghouse interface information given in RESAR-41 is addressed in Table 10.1-2.

10.1.1 Materials Considerations

Materials for Safety Class 2 and 3 portions of the steam and feedwater systems comply with ASME III Code Classes 2 and 3, respectively, and are selected for adequate corrosion resistance and fracture toughness characteristics. Fabrication specifications invoke the requirements of Regulatory Guide 1.71 as described in Section 3A.1-1.71. In addition, the use of ferritic materials for ASME III Code Classes 2 and 3 components invokes the fracture toughness requirements of NC 2300 and ND 2300 of the ASME III code.

The use of austenitic stainless steel complies with Regulatory Guide 1.44 as discussed in Section 3A.1-1.44 and the requirements for cleaning comply with Regulatory Guide 1.37, as discussed in Section 3A.1-1.37. Where non-metallic insulation is employed, requirements of Regulatory Guide 1.36, as discussed in Section 3A.1-1.36, are invoked. The fabrication of low alloy steels invoke requirements of Regulatory Guide 1.50 as described in Section 3A.1-1.50.

10.1.2 Interface Requirements

9 Interface information applicable to the steam and power conversion systems, as presented in the respective NSSS Vendor's SAR's, is discussed in Table 10.1-2.

Table 10.1-2 does not address all items listed as interface requirements because many items so listed interface requirements only if the NSSS Vendor supplies the described system. 9
Table 10.1-2 addresses as a minimum items which are, in fact, interface requirements imposed on the systems within the S&W scope of design responsibility.

TABLE 10.1-1

STEAM AND POWER CONVERSION SYSTEMS
PRINCIPAL DESIGN AND PERFORMANCE CHARACTERISTICS

Item	Design and Performance Characteristics
Turbine-Generator (Section 10.2)	
Turbine	1,800 rpm tandem compound, 6-flow, 43 or 44 in. last row blades, single stage reheat
Generator	1,800 rpm, direct coupled, hydrogen cooled
Exciter	1.0 response ratio
Overspeed Protection	a. Normal and transient speed control system
	b. Mechanical overspeed system
	c. Backup overspeed protection system
Turbine Gland Sealing	Operated with main steam or auxiliary steam. Offgas discharged to radioactive gaseous waste system.
Turbine Steam System (Section 10.2)	
Turbine Steam Piping	a. Piping provided by the turbine manufacturer: in accordance with the turbine manufacturer's standards, wherever industry codes and standards do not apply
	b. Balance of turbine steam piping: ANSI B31.1.0b-1971
Moisture-Separator/ Reheaters	ASME VIII
Main Steam System (Section 10.3)	
Main Steam Piping	*a. From each steam generator up to and including the main steam isolation valves: ASME III, Code Class 2: Seismic Category I

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*Safety related (QA Category I)

TABLE 10.1-1 (CONT)

Item	Design and Performance Characteristics
	*b. From main steam piping up to and including auxiliary feedwater pump turbine: ASME III, Code Class 3; Seismic Category I
	c. Balance of the main steam piping: ANSI B31.1.0b-1971
Main Steam Isolation Valves*	Maximum closing time as specified by the NSSS Vendor (see Table 10.3-1 for specified time): ASME III, Code Class 2; Seismic Category I
Main Steam Safety Valves and Main Steam Atmospheric Dump Valves*	Flow capacity as specified by the NSSS Vendor (see Table 10.3-1) ASME III, Code Class 2; Seismic Category I
Turbine Bypass System (Section 10.4.4)	Capacity equal to 40 percent of the maximum calculated steam generator mass flow at full load pressure. Piping: ANSI B31.1.0b-1971
Condenser (Section 10.4.1)	Conventional tubular design, deaerating type steam surface condenser, single pass with divided water box. Steam and condensate crossover ducts to equalize pressure, impingement baffles to protect the tubes, and means in the hotwell for detection of circulating water leakage are included in the design.
Condenser Evacuation System (Section 10.4.2)	Condenser air removal pumps are provided for initial condenser shell side air removal. Steam jet air ejectors maintain vacuum while removing noncondensable gases from the shells. A radiation monitor is installed in air ejector discharge line to the radioactive gaseous waste system (Section 11.3).
Circulating Water System (Section 10.4.5)	Provided by Utility-Applicant.

*Safety related (QA Category I)

TABLE 10.1-1 (CONT)

Item	Design and Performance Characteristics
Steam Generator Blowdown System (Section 10.4.8)	a. See Section 10.4.8 for details of system.
	*b. Piping and valves inside the containment structure up to and including the containment isolation valves: ASME Section III, Code Class 2
	c. All other piping: ANSI B31.1.0b 12
Auxiliary Steam System (Section 10.4.12)	Piping designed in accordance with ANSI B31.1.0b 12
Condensate and Feedwater Systems (Section 10.4.7)	a. Three one-half capacity motor-driven condensate pumps, six stages of regenerative feedwater heating, three one-third capacity turbine-driven feedwater pumps
	*b. Piping from and including the feedwater isolation valves outside the containment structure to steam generator inlets: ASME III, Code Class 2; Seismic Category I
	c. Piping from condenser up to, but not including, feedwater isolation valvesoutside the containment structure: ANSI B31.1.0b 12
Auxiliary Feedwater System* (Section 10.4.10)	a. See Section 10.4.10 for details of system.
	b. All piping up to but excluding the auxiliary feedwater containment isolation valve: ASME III,Code Class 3: Seismic Category I

TABLE 10.1-1 (CONT)

Item	Design and Performance Characteristics
	c. Piping from and including the auxiliary feedwater containment isolation valve to the feedwater system steam generator connection: ASME III, Code Class 2; Seismic Category I 12

*Safety related (QA Category I)

TABLE 10.1-2

STEAM AND POWER CONVERSION SYSTEMS
INTERFACE INFORMATION

Responses are given, whenever possible, to the SWESSAR section in which compliance with the interface item is discussed.

RESAR-41 Interface Item	SWESSAR-P1 Design
Steam and Power Conversion Systems, RESAR-41, Table 10.1-1	
Heat balance data	The values given are typical values calculated using a specific turbine cycle and heat balance. Values calculated for a different cycle will vary slightly, as seen on Fig. 10.1-2. The choice of turbine cycle is the responsibility of the Utility-Applicant/Architect-Engineer.
Instrumentation	Refer to Section 7.8.
Electrical	Refer to Section 8.4.
Main steam and feedwater isolation valve closure time	Sections 10.3.3 & 10.4.7.1, Table 10.3-1
Water chemistry	Sections 10.4.6, 10.4.7, & 10.4.8
Prevention of uncontrolled blowdown of more than one steam generator	Section 10.3.3
Maximum flow to turbine	Fig. 10.2-3
Single failure	Section 3.1.65
Instrument air	There are no steam and power conversion system valves within the NSSS Vendor's scope of design responsibility.
Uniform feedwater temperature and continuous feedwater flow	Section 10.4.7.2.
Feedwater storage capacity	Section 10.4.7.2
Main steam design pressure	Table 10.3-1

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TABLE 10.1-2 (CONT)

RESAR-41 Interface Item	SWESSAR-P1 Design	
Prevention of consequential damage from pipe breaks	Section 3.6.2	
Main steam valves' ability to stop flow in either direction	Section 10.3.3	21
Main steam safety valve capacity	Table 10.3-1	
Main steam atmospheric dump valve capacity	Table 10.3-1	
Auxiliary Feedwater System, RESAR-41, Section 6.6		
When system is required	Sections 10.4.10.2, 7.3.3.8	
Multitrain power sources and three train actuation logic	Sections 10.4.10.3, 7.8	
Minimum delivered flow and pressure	Section 10.4.10.3, Table 10.4.10-1. Auxiliary feedwater flow based on a steam pressure of 1,339 psia.	21
Maximum total delivered flow	Basis for sizing the AFST is a 2 hour hot standby followed by a 50 F per hour cooldown. Containment pressure considerations are within S&W scope of design responsibility.	
Maximum allowable time for flow delivery	Section 10.4.10.3, Table 10.4.10-1	
Maximum temperature	The maximum annulus building cubicle temperature of 120 F will give a maximum AFWST temperature of 120 F.	21
Actuation logic and operation from control room or local control station	Sections 7.8, 7.4.3.1	
Single failure	Section 3.1.65	21
AFST minimum volume	Table 10.4.10-1	

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TABLE 10.1-2 (CONT)

RESAR-41 Interface Item	SWESSAR-P1 Design	
Isolation of steam generator blowdown system	Section 7.8	21
Feedwater nozzle materials	Table 3.2.5-1, Sections 5.2, 10.1.1	

TABLE 10.1-2

STEAM AND POWER CONVERSION SYSTEMS
INTERFACE INFORMATION

Responses are given, whenever possible, to the SWESSAR section in which compliance with the interface item is discussed.

RESAR-3S Interface Item	SWESSAR-P1 Design	
Steam and Power Conversion Systems, RESAR-3S, Table 10.1-1		
Heat balance data	The values given are typical values calculated using a specific turbine cycle and heat balance. Values calculated for a different cycle will vary slightly, as seen on Fig. 10.1-2. The choice of turbine cycle is the responsibility of the Utility-Applicant/Architect-Engineer.	
Instrumentation	Section 7.8	
Electrical	Section 8.4	
Instrument air	There are no steam and power conversion system valves within the NSSS Vendor's scope of design responsibility.	
Main steam and feedwater isolation valve closure time	Section 10.3.3, Table 10.3-1, Section 10.4.7.1	28
Feedwater isolation	Section 15.1.14.3	
Maximum flow to turbine	Fig. 10.2-3	
Single failure	Section 3.1.65	
Prevention of uncontrolled blowdown of more than one steam generator	Section 10.3.3	28
Main steam safety valve capacity	Table 10.3-1	
Main steam atmospheric dump valve capacity	Table 10.3-1	
Uniform feedwater temperature and continuous feedwater flow	Section 10.4.7.2	

TABLE 10.1-2 (CONT)

RESAR-3S Interface Item	SWESSAR-P1 Design
Feedwater storage capacity	Section 10.4.7.2
Main steam design pressure	Table 10.3-1
Prevention of consequential damage from pipe breaks	Section 3.6.2
Main steam valves' ability to stop flow in either direction	Section 10.3.3
Water chemistry	Sections 10.4.6, 10.4.7, 10.4.8
Auxiliary Feedwater System, RESAR-3S, Section 6.5, Appendix 6A	
When system is required	Sections 10.4.10.2, 7.3.3.8
Multitrain power sources and two train actuation logic	Sections 10.4.10.3, 7.8
Flow rate and pressure delivered to steam generators	Section 10.4.10.3, Table 10.4.10-1 Maximum flow to any one steam generator assumed by Westinghouse in its calculation of mass and energy releases for the main steam line break is 1,380 gpm. These releases have been used in the analyses of Section 6.2.1.1.2.2. Therefore, the system layout during the detail design will assure that this value is not exceeded.
Maximum total delivered flow	Basis for sizing the AFST is a 2 hour hot standby followed by a 50 F per hour cooldown. Containment pressure considerations are within S&W scope of design responsibility.
Maximum allowable time for flow delivery	Section 10.4.10.3, Table 10.4.10-1
Maximum temperature	Table 10.4.10-1
Actuation logic and operation from control room or local control station	Sections 7.8, 7.4.3.1
Sources of auxiliary feedwater	Section 10.4.10.2
Feedwater nozzle materials	Table 3.2.5-1, Sections 5.2, 10.1.1

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TABLE 10.1-2 (CONT)

RESAR-3S Interface Item	SWESSAR-P1 Design
Condensate Storage Facilities, RESAR-3S, Section 9.2.6	
AFST minimum volume	Table 10.4.10-1. Usable volume is based on 60 gal per MWt of the reactor rating, which is the Westinghouse sizing criterion. 28

TABLE 10.1-2

STEAM AND POWER CONVERSION SYSTEMS
INTERFACE REQUIREMENTS

Requirement	B-SAR-205 Reference	SWESSAR Reference	
Power	Section 10.5.1 (Note 1)	Sections 8.4, 10.4.10.3	
Protection against wind, tornado, floods, and missiles	Sections 10.5.2 (1,2,3), 10.5.4	Sections 3.3, 3.4, 3.5	
Seismic criteria and ASME Code Class	Sections 10.5.2 (4, 5, 6, 7)	Sections 10.3.1, 10.4.7.1, 10.4.10.1	
Pipe separation, rupture, and whip	Sections 10.5.3, 10.5.5, 10.5.6, 10.5.7(2)	Section 3.6	
Mass and energy release data	Sections 10.5.5.1, 10.5.5.2	Section 15.1.14	
Independence of controls	Section 10.5.7(1, 3, 4)	Section 7.8	
Auxiliary feedwater system	Section 10.5.9 (1, 2, 4)	See Note 2.	
Turbine-generator	Section 10.5.9 (5, 6)	Section 10.2	
Turbine bypass system	Section 10.5.9 (7, 8, 9, 11, 12)	Section 10.4.4	
Modulating atmospheric dump valve	Sections 10.5.9 (10, 18), 10.5.17(3)	See Note 4.	
Feedwater system	Section 10.5.9 (13, 14, 15, 16, 17)	See Note 3.	
Monitoring	Section 10.5.10	Fig. 10.3-1, 10.4.7-1	
Operational controls	Section 10.5.11	Section 7.8, Table 10.4.10-1 (See Note 5)	37
Inspections and tests	Section 10.5.12	Sections 10.3.4, 10.4.7.4	
Chemistry and sampling	Section 10.5.13	Sections 10.4.6, 10.4.7.2	
Materials	Section 10.5.14	Sections 10.1.1	
System/component arrangement	Section 10.5.15	Sections 10.3, 10.4.7	
Radiological waste	Section 10.5.16	Chapter 11	
Overpressure protection	Sections 10.5.17(1, 2)	Section 10.3	

TABLE 10.1-2 (CONT)

Nozzle loadings	Section 10.5.18	Section 3.6

NOTES: 1. Where a B-SAR-205 reference section is listed without an accompanying item number in parentheses, it is intended that all item numbers within that section are referenced.

2. The SWESSAR-P1 design meets these requirements (reference Section 10.4.10), with the exception of the 90 F auxiliary feedwater temperature given in item 4. The auxiliary feedwater storage tank (AFST), located inside the annulus building, is subjected to the ambient temperature in the annulus building. As described in Section 9.4.2, the annulus building ventilation system maintains the temperature in the tank cubicle below 104 F.

3. The SWESSAR-P1 design meets these requirements (reference Section 10.4.7). Following a turbine trip without a reactor trip, the reactor is run back in power. As reactor power decreases, feedwater flow decreases. The storage capacity of the condenser hotwell (Section 10.4.1) is more than adequate to accommodate the feedwater/steam mass lost via release through the atmospheric dump valves during reactor runback.

4. The SWESSAR-P1 design meets these requirements (reference Section 10.3) with the following clarification. Manually operated isolation valves are provided between the steam generators and the modulating atmospheric dump valves in the SWESSAR-P1 design. These valves are normally open and are provided for maintenance of the atmospheric dump valves. The SWESSAR-P1 design includes four atmospheric dump valves, one per main steam line (i.e., two per steam generator) in lieu of B&W's requirement of one per steam generator. This design feature increases the plant's capability to accommodate main steam pressure rises during normal operating transients, particularly during valve maintenance. Should one atmospheric dump valve be isolated for maintenance, the related steam generator remains protected by the atmospheric dump valve located on the steam generator's other main steam line.

5. B-SAR-205 Section 10.5.11, paragraph 6, to be addressed in Applicant's PSAR. 37

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TABLE 10.1-2

STEAM AND POWER CONVERSION SYSTEMS

INTERFACE REQUIREMENTS

Requirement	CESSAR Reference	SWESSAR Reference
Missile, pipe whip, jet impingement protection	Sections 3.5, 3.6, 5.1.4.C.5, 5.1.4.D.4, 5.1.4.G.2, 5.1.4.L.7	Sections 3.5 and 3.6
Electric power	Refer to SWESSAR-P1	Section 8.4
Control circuitry	Refer to SWESSAR-P1	Section 7.8
Feedwater isolation	Sections 5.1.4 (G.9.) 5.1.4 (G.12.) 5.1.4 (G.15.)	Section 10.4.7
Main Steam design conditions	Section 5.1.4 (I.1)	Section 10.3.1
Main steam header arrangement	Section 5.1.4.(I.3)	Fig. 10.3-1
Main steam isolation	Sections 5.1.4 (I.4) 5.1.4 (I.5)	Section 10.3.3
Maximum turbine power	Section 5.1.4 (I.6)	Fig. 10.1-3, Section 10.3.1 (7)
Atmospheric dump valves	Sections 5.1.4 (I.7) 5.1.4 (I.8) 5.1.4 (K.2)	Table 10.3-1, Section 10.3.3
Emergency feedwater	Sections 5.1.4 (I.11) 5.1.4 (I.12) 5.1.4 (I.13) 5.1.4 (I.14) 5.1.4 (I.15) 5.1.4 (I.16) 5.1.4 (I.17) 5.1.4 (K.12) 5.1.4 (O.9) 5.1.4 (O.10)	Sections 7.8, 10.4.10 Sections 7.8, 10.4.10 Fig. 10.4.10-1, 10.4.7-2A Table 10.4.10-1 Table 10.4.10-1 Maximum temperature, Table 10.4.10-1. Minimum temperature is building temperature, Section 9.4.7.1(2). Table 10.4.10-1 Fig. 10.4.10-1 Fig. 10.4.7-2A Loop seal will be provided to prevent drainage of feedwater piping.
Main steam isolation bypass va. -	Section 5.1.4 (I.20)	Section 10.3.1 (11)
Isolation of steam paths	Section 5.1.4 (I.21)	See Note 1.
Single failure	Section 5.1.4 (L.7)	Sections 3.1.65, 10.4.10.3

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TABLE 10.1-2 (CONT)

Requirement	CESSAR Reference	SWESSAR Reference
Secondary chemistry control	Section 5.1.4 (M.2) 5.1.4 (M.9)	Sections 10.4.6, 10.4.8, 10.4.10
Blowdown processing	Section 5.1.4 (P.1) 5.1.4 (R.17)	Sections 10.4.8, 10.4.6
Main steam safety valves	Section 5.1.4 (Q.3) 5.1.4 (Q.5) 5.1.4 (Q.6)	Table 10.3-1
Turbine bypass	Section 5.1.4 (Q.8)	Section 10.4.4

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Note 1: Following a main steam line break, either all steam paths downstream of the main steam isolation valves (MSIV) will be isolated by their respective control systems following an MSIV closure signal, or the results of a blowdown through a non-isolated path will be shown to be acceptable. An acceptable maximum steam flow from a non-isolated steam path will be provided in the C-E application for Final Design Approval. Blowdown from any non-isolated path will not exceed this value.

The SWESSAR-P1 design isolates all steam paths downstream of the MSIVs by their respective control systems following an MSIV closure signal. (Reference Fig. 7.8.1-3, 10.2-1, and Section 10.2.4.) These controls are redundant, physically independent, and separated and designed to withstand a single failure.

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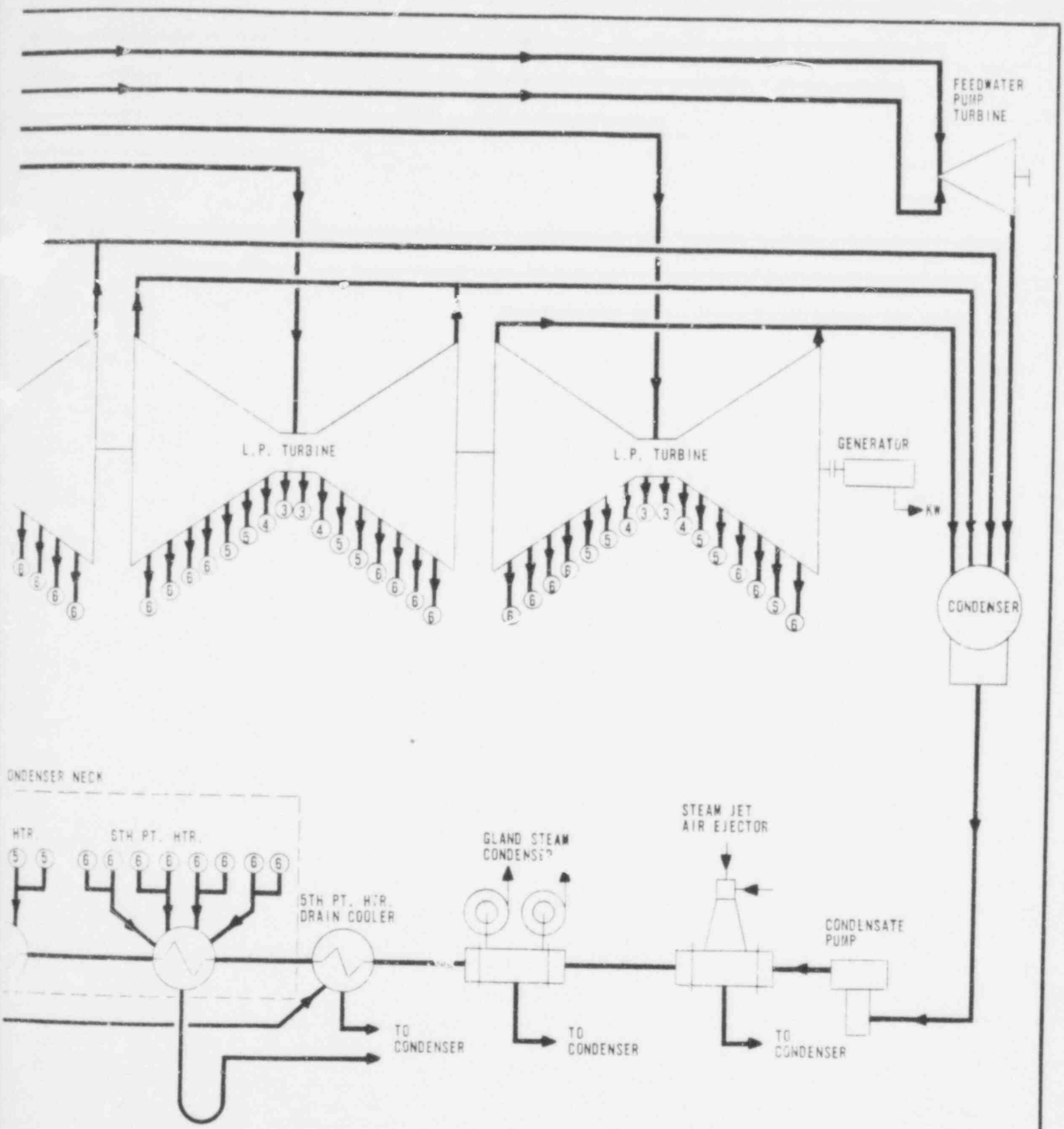

FIG. 10.1-1

TYPICAL STEAM PLANT FUNDAMENTAL DIAGRAM

PWR STANDARD PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

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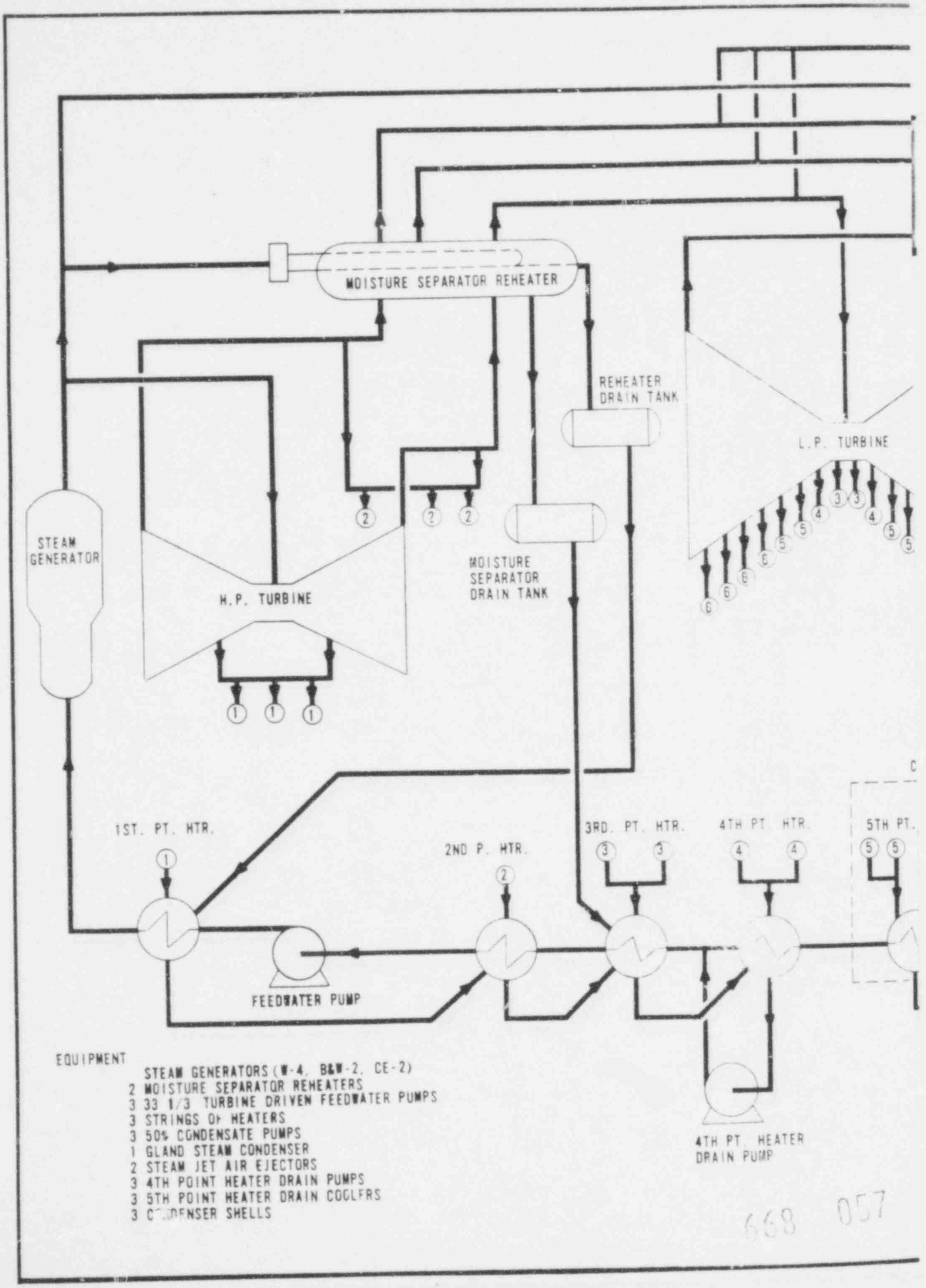
MOISTURE SEPARATOR REHEATER
REHEATER DRAIN TANK
L.P. TURBINE
STEAM GENERATOR
H.P. TURBINE
MOISTURE SEPARATOR DRAIN TANK
1ST. PT. HTR.
2ND P. HTR.
3RD. PT. HTR.
4TH PT. HTR.
5TH PT.
C
FEEDWATER PUMP
4TH PT. HEATER DRAIN PUMP
EQUIPMENT
STEAM GENERATORS (W-4, B&W-2, CE-2)
2 MOISTURE SEPARATOR REHEATERS
3 33 1/3 TURBINE DRIVEN FEEDWATER PUMPS
3 STRINGS OF HEATERS
3 50% CONDENSATE PUMPS
1 GLAND STEAM CONDENSER
2 STEAM JET AIR EJECTORS
3 4TH POINT HEATER DRAIN PUMPS
3 5TH POINT HEATER DRAIN COOLERS
3 CONDENSER SHELLS

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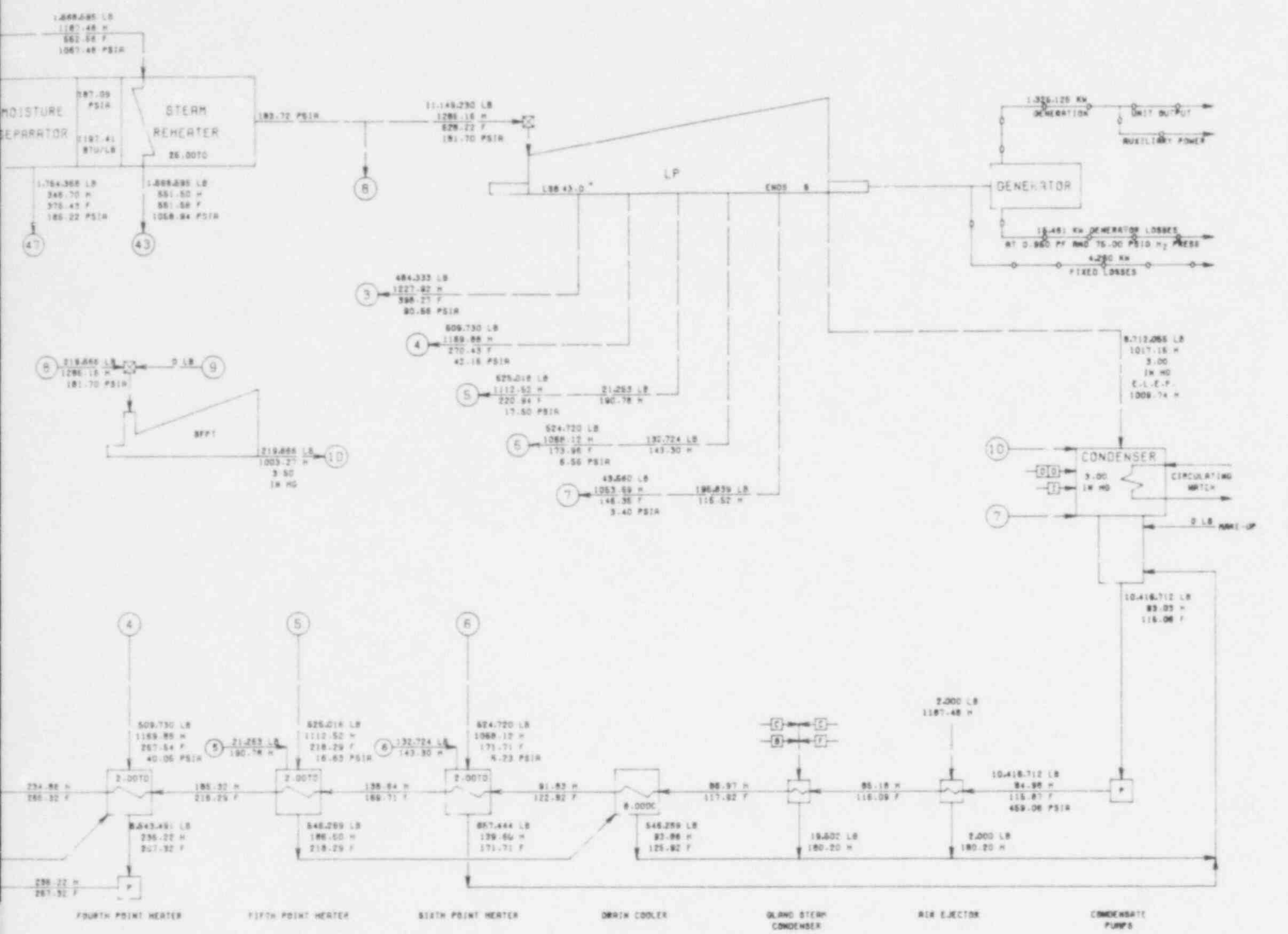


LEAKAGES

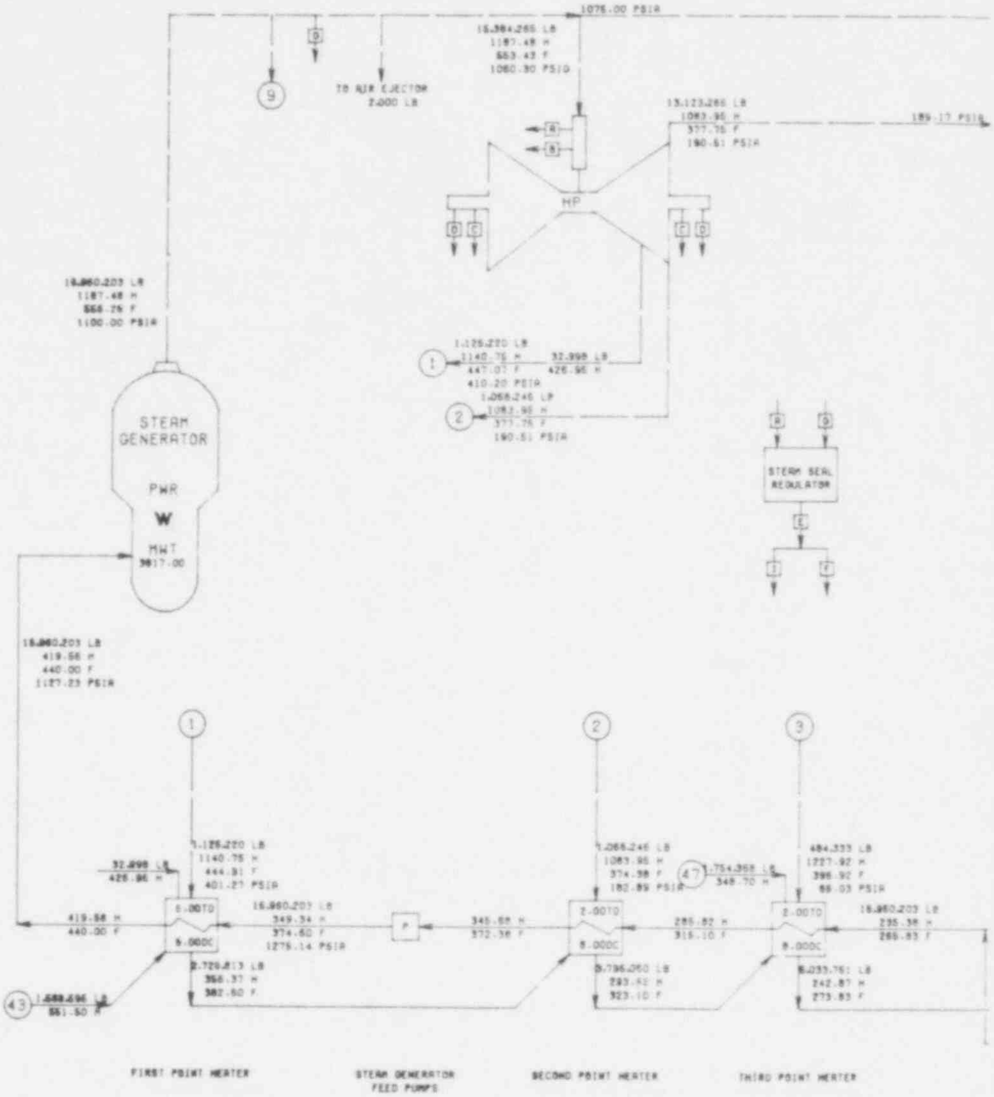
	FLOW	ENTHALPY
A	12,858	1187.48
B	2,728	1187.48
C	4,788	1083.95
D	4,788	1083.95
E	18,000	1187.48
F	7,200	1187.48
G	5,342	1187.48
H	0	-
I	10,800	1187.48

LEGEND

STEAM
WATER
POWER
LB FLOW, POUNDS PER HOUR
H ENTHALPY, BTU PER POUND
F TEMPERATURE, DEGREES F
TD TERMINAL DIFFERENCE
DC DRAIN COOLER APPROACH
KW KILOWATTS
IN HG PRESSURE, IN OF MERCURY, ABS.
PSIA PRESSURE, LB PER SQUARE IN. ABS.
THROTTLE OR INTERCEPT VALVE
CONTROL VALVE

FIG. 10.1-2
TYPICAL HEAT BALANCE
AT RATED POWER
PWR STANDARD PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

W



POOR ORIGINAL

668 059

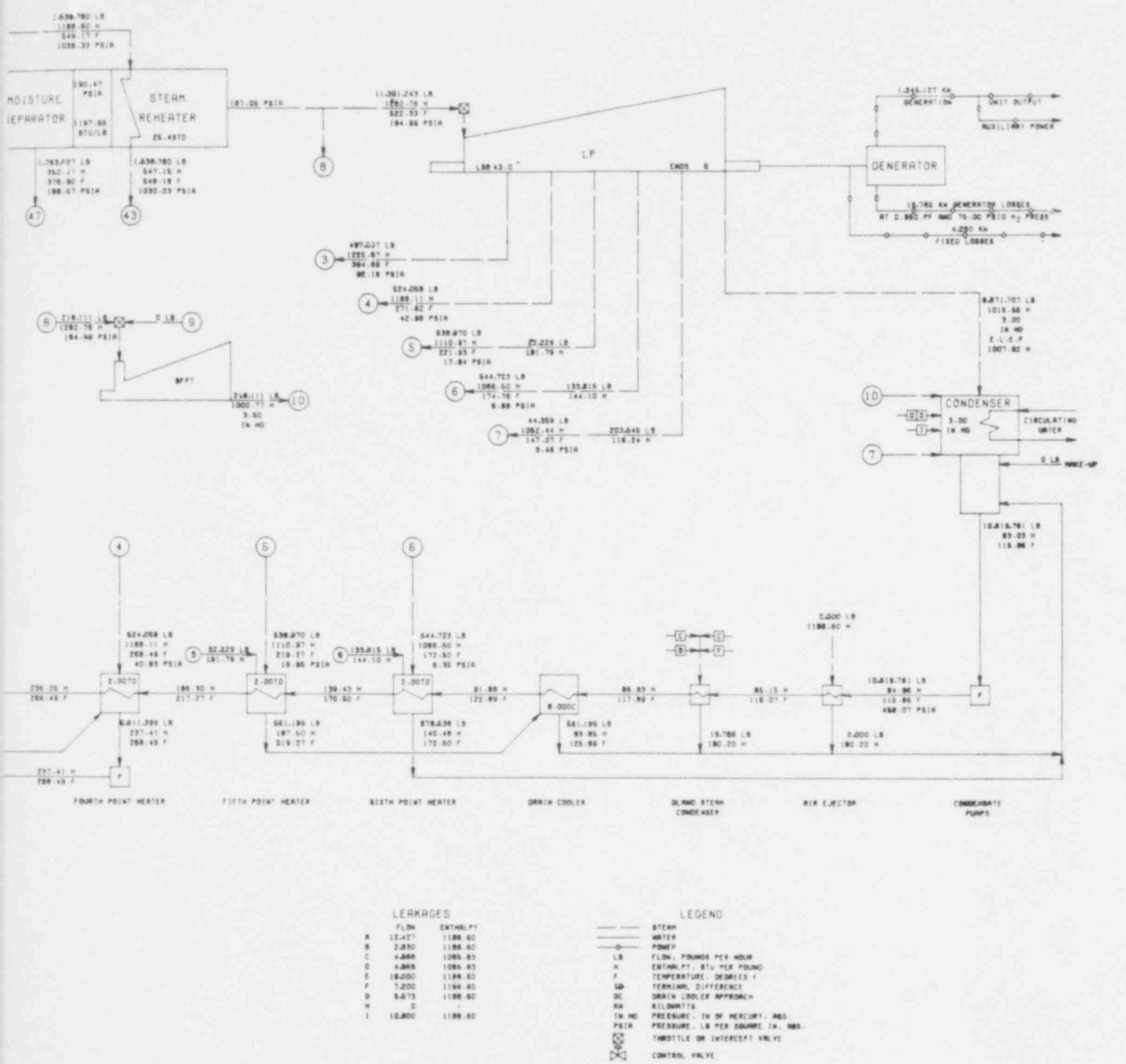


FIG. 10.1-3

TYPICAL HEAT BALANCE AT TURBINE MAXIMUM CAPABILITY

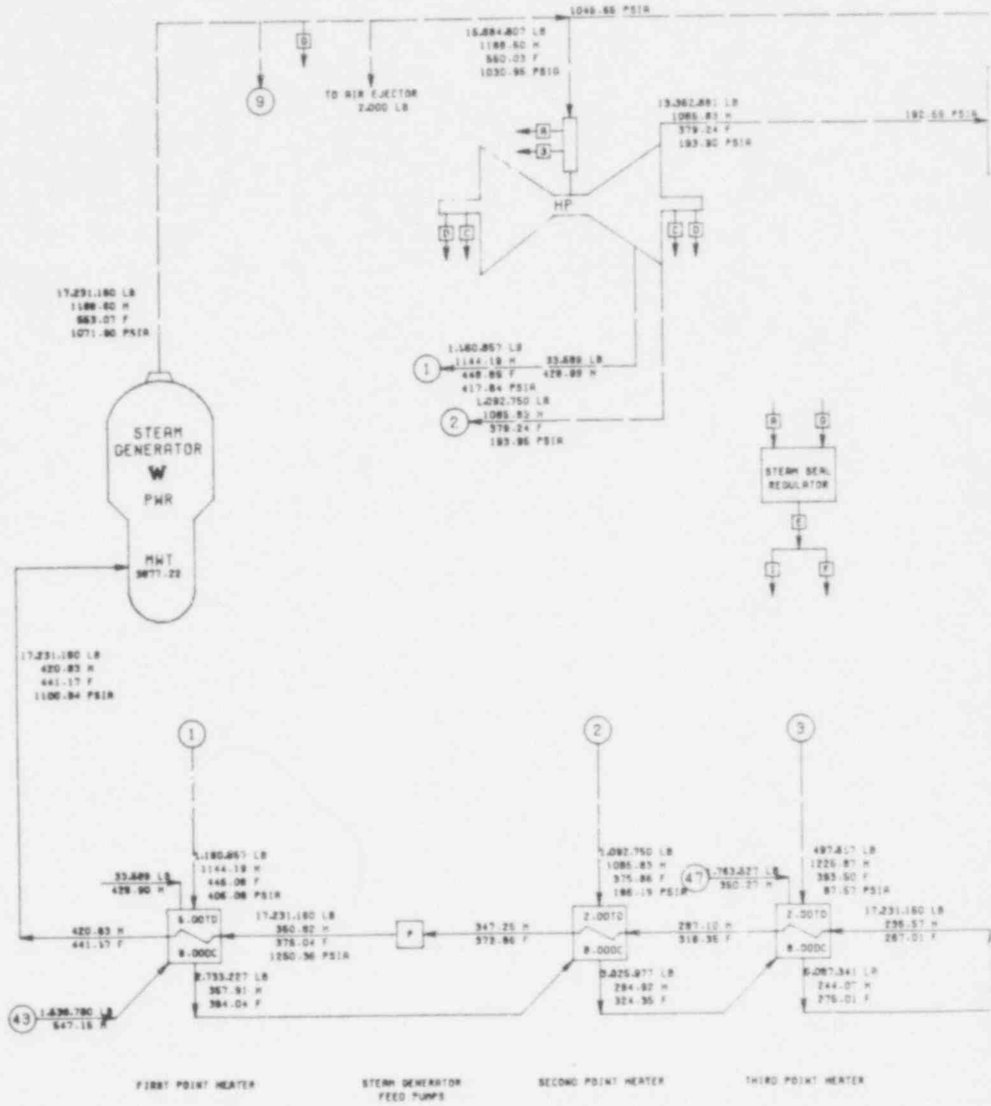
PWR STANDARD PLANT

SAFETY ANALYSIS REPORT

SWESSAR-P1

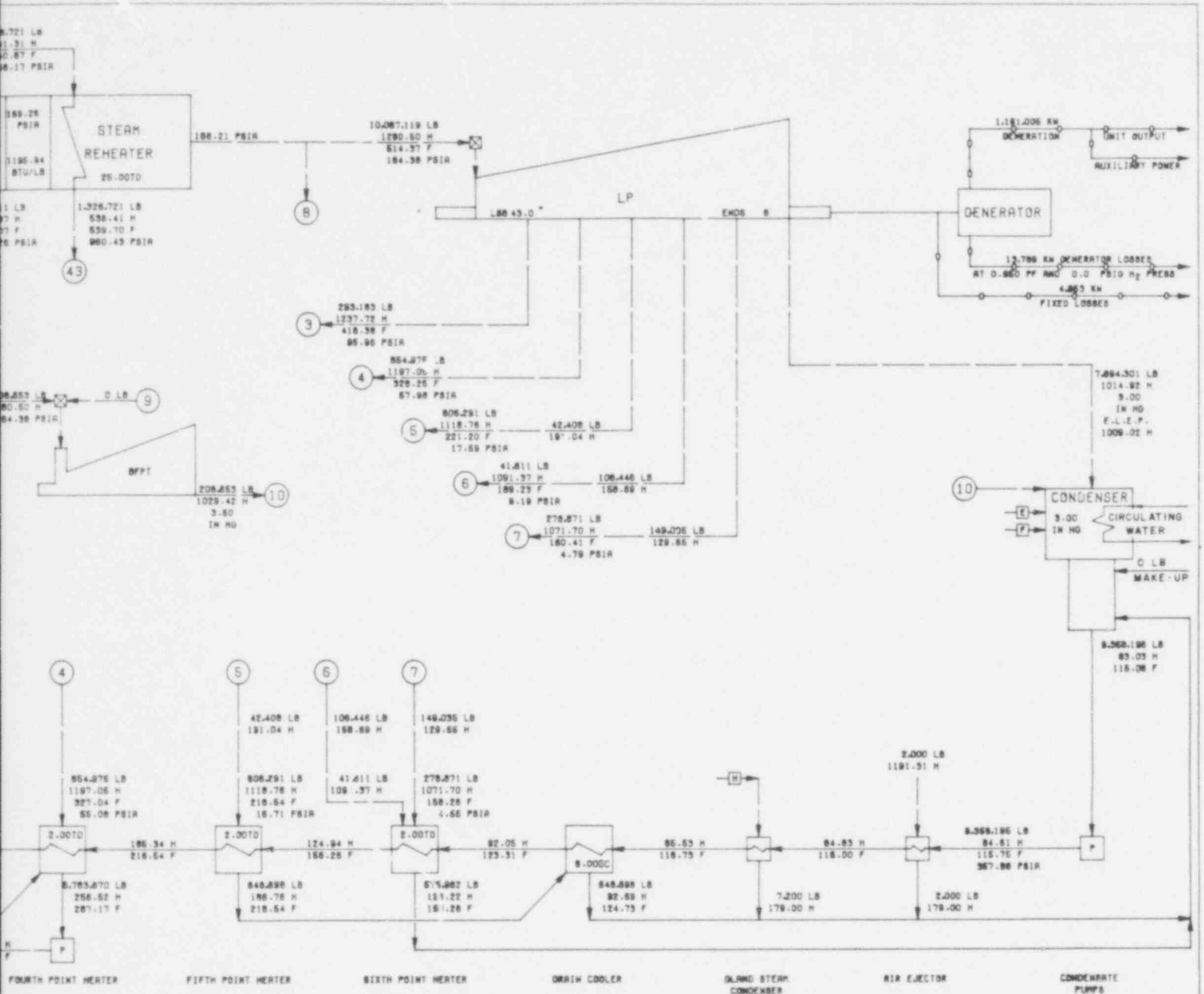
W

668 060



POOR ORIGINAL

668 001



LEGEND

——— ———	STEAM
————	WATER
——o——	POWER
LB	FLOW, POUNDS PER HOUR
H	ENTHALPY, BTU PER POUND
F	TEMPERATURE, DEGREES F
TD	TERMINAL DIFFERENCE
DC	DRAIN COOLER APPROACH
KW	KILOWATTS
IN HG	PRESSURE, IN OF MERCURY, ABS.
PSIA	PRESSURE, LB PER SQUARE IN. ABS.
⊠	THROTTLE OR INTERCEPT VALVE
⋈	CONTROL VALVE

LEAKAGES

	FLOW	ENTHALPY
A	11,840	1191.31
B	2,864	1191.31
C	13,009	1083.00
D	13,006	1083.00
E	10,800	1092.72
F	10,681	1092.72
G	0	-
H	7,200	1092.72

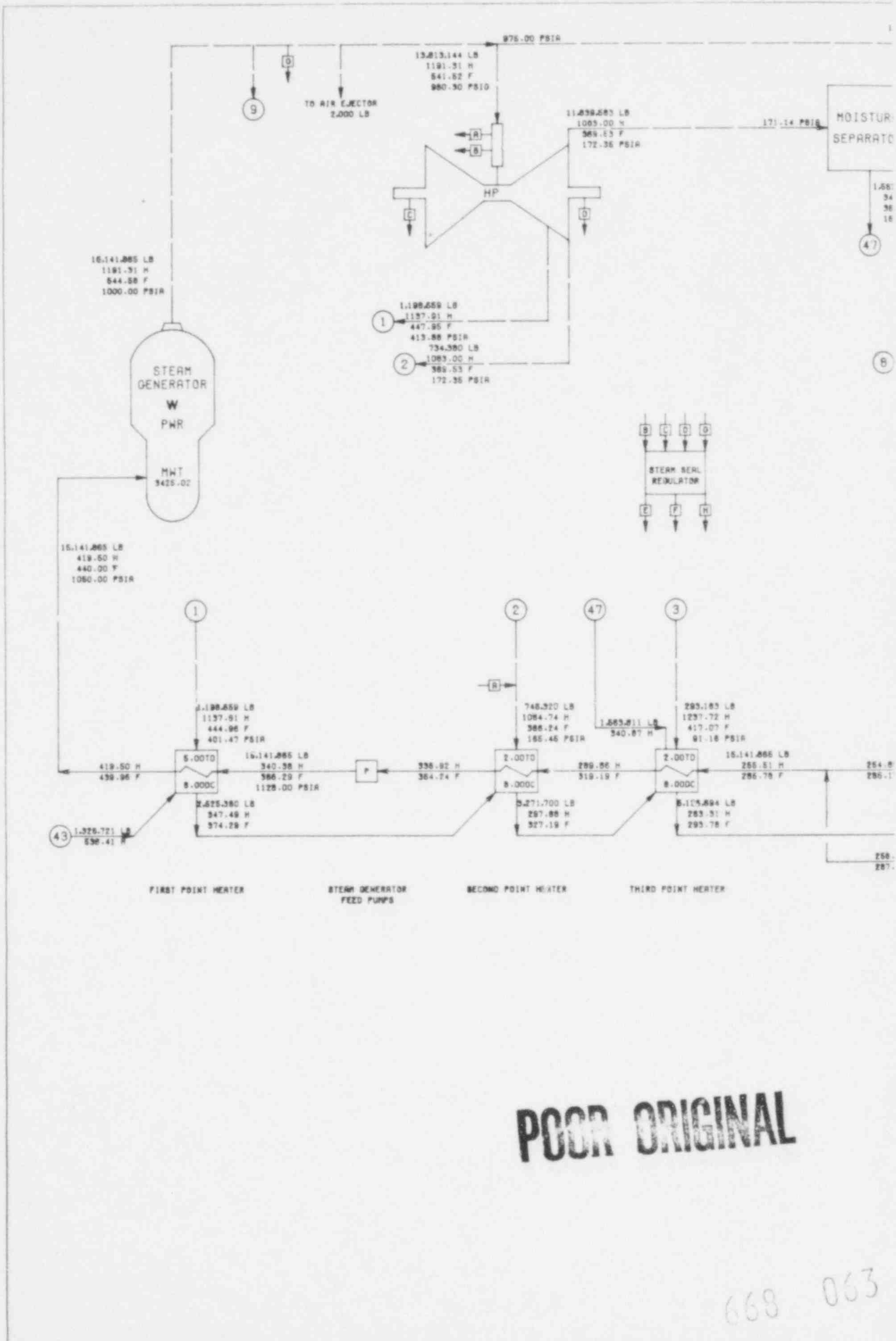
FIG. 10.1-2

TYPICAL HEAT BALANCE AT RATED POWER

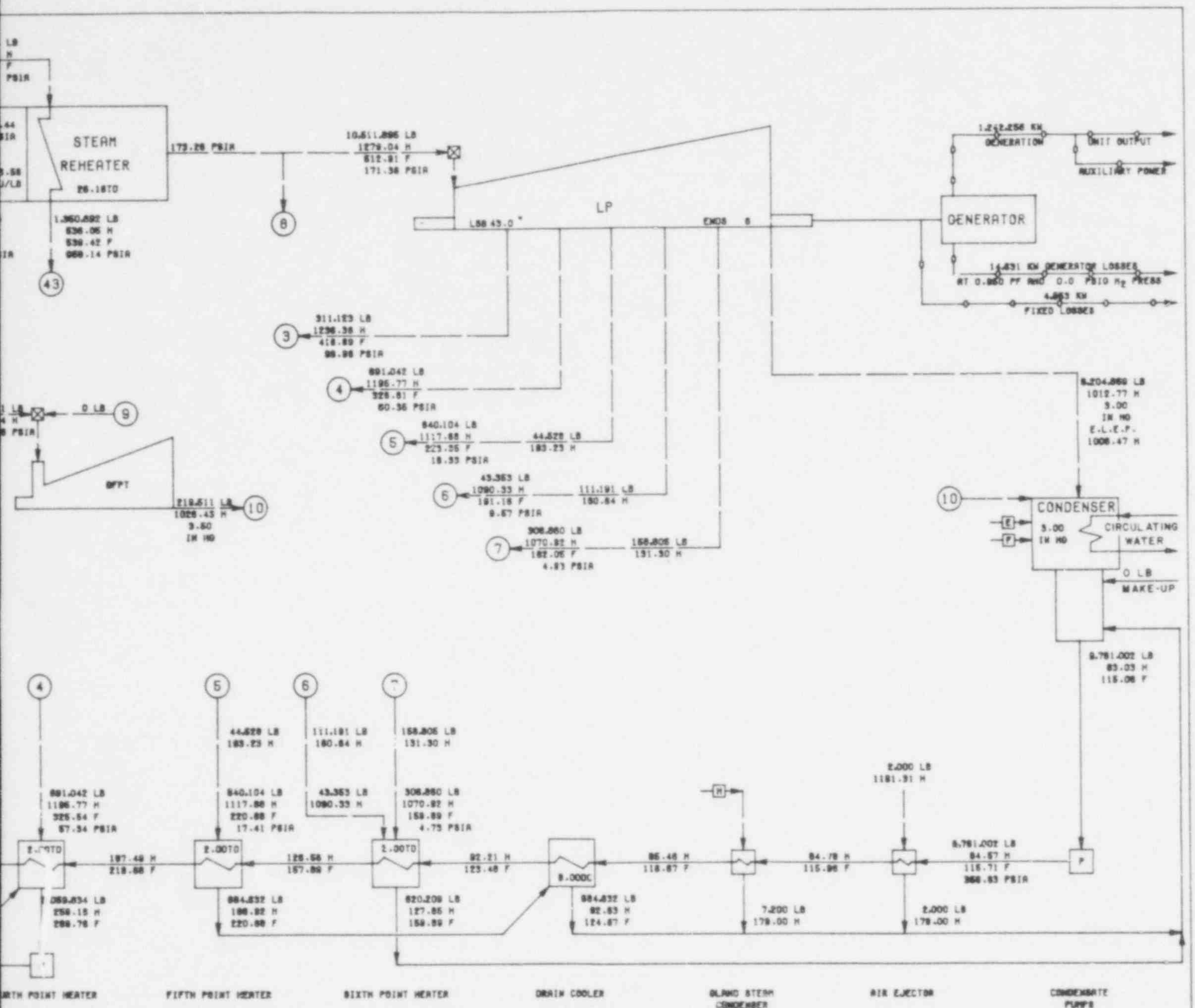
PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

W-3S

668 082



976.00 PSIA
13,813,144 LB
1191.31 H
541.52 F
980.30 PSIG
TO AIR EJECTOR
2,000 LB
11,839,583 LB
1083.00 H
369.53 F
172.36 PSIA
171.14 PSIA
MOISTURE
SEPARATOR
HP
16,141,865 LB
1191.31 H
544.58 F
1000.00 PSIA
1,198,659 LB
1137.91 H
447.95 F
413.88 PSIA
734,380 LB
1083.00 H
369.53 F
172.36 PSIA
STEAM
GENERATOR
W
PWR
MWT
3425.02
STEAM SEAL
REGULATOR
16,141,865 LB
419.50 H
440.00 F
1060.00 PSIA
1,198,659 LB
1137.91 H
444.96 F
401.47 PSIA
748,320 LB
1084.74 H
366.24 F
165.46 PSIA
1,663,811 LB
340.87 H
295,183 LB
1237.72 H
417.07 F
91.16 PSIA
419.50 H
439.96 F
5.00TD
8.000C
16,141,865 LB
340.38 H
366.29 F
1128.00 PSIA
P
338.82 H
364.74 F
2.00TD
8.000C
289.56 H
319.19 F
2.00TD
8.000C
16,141,865 LB
255.51 H
286.78 F
2,625,380 LB
347.49 H
374.29 F
3,271,700 LB
297.88 H
327.19 F
5,115,894 LB
263.31 H
293.78 F
1,926,721 LB
538.41 H
FIRST POINT HEATER
STEAM GENERATOR
FEED PUMPS
SECOND POINT HEATER
THIRD POINT HEATER
POOR ORIGINAL
668 063



LEGEND

- STEAM
- WATER
- POWER
- LB — FLOW, POUNDS PER HOUR
- H — ENTHALPY, BTU PER POUND
- F — TEMPERATURE, DEGREES F
- TD — TERMINAL DIFFERENCE
- DC — DRAIN COOLER APPROACH
- KW — KILOWATTS
- IN HG — PRESSURE, IN OF MERCURY, ABS.
- PSIA — PRESSURE, LB PER SQUARE IN. ABS.
- THROTTLE OR INTERCEPT VALVE
- CONTROL VALVE

LEAKAGES

	FLOW	ENTHALPY
A	11,810	1181.31
B	2,876	1181.31
C	13,643	1084.87
D	13,643	1084.87
E	10,800	1084.26
F	11,781	1084.28
G	0	-
H	7,200	1084.28

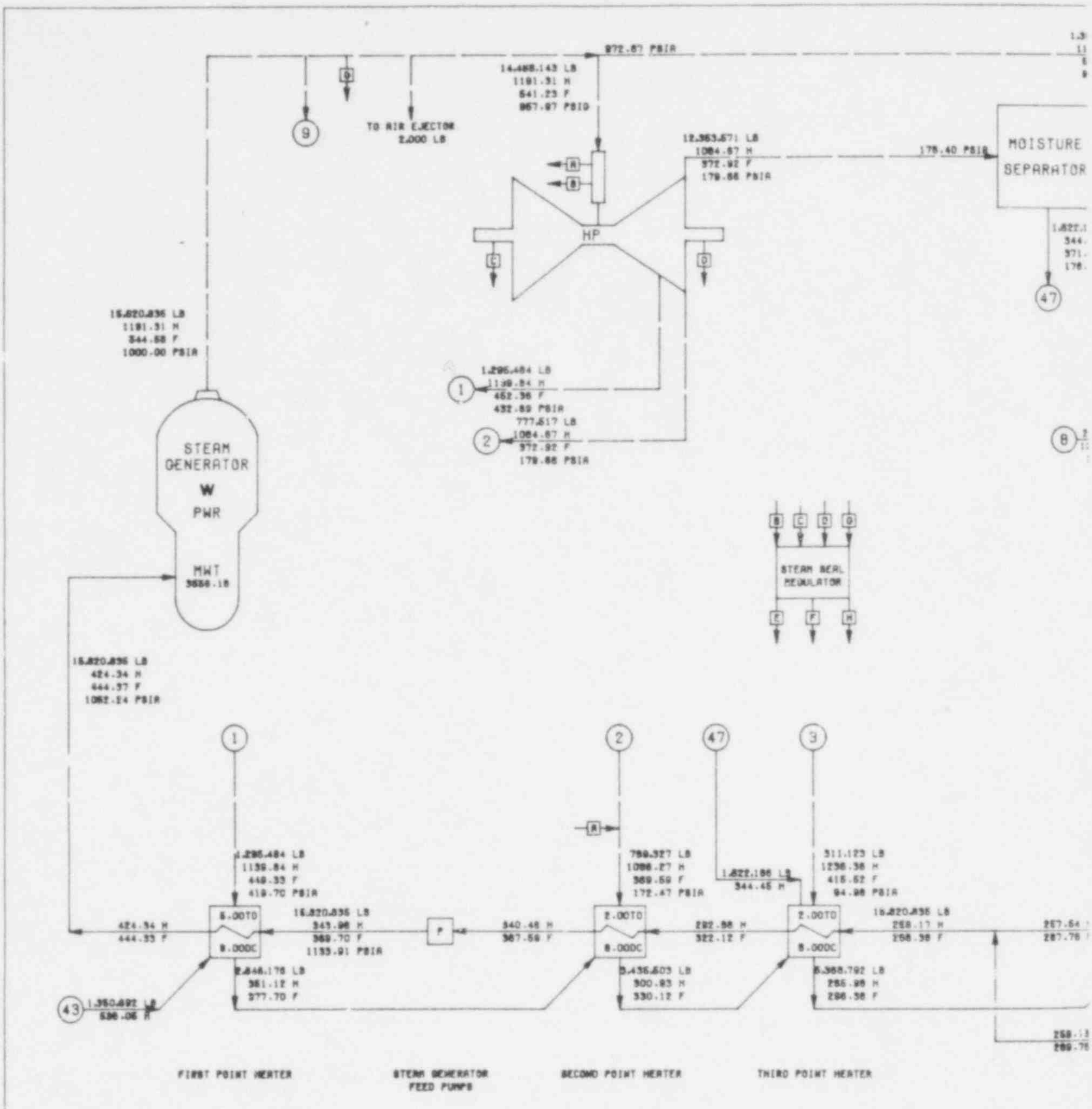
FIG. 10.1-3

TYPICAL HEAT BALANCE AT TURBINE MAXIMUM CAPABILITY

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

W-3S

668 064



POOR ORIGINAL

668 065

A heat balance at rated power for B-SAR-205 is not provided because of the different power levels the B&W NSSS is capable of providing. B&W offers NSSS thermal outputs of either 3,620 MWt or 3,820 MWt. The 3,820 MWt heat balance is provided as Fig. 10.1-3 because this is the power level used for the design of the steam and power conversion systems. 19

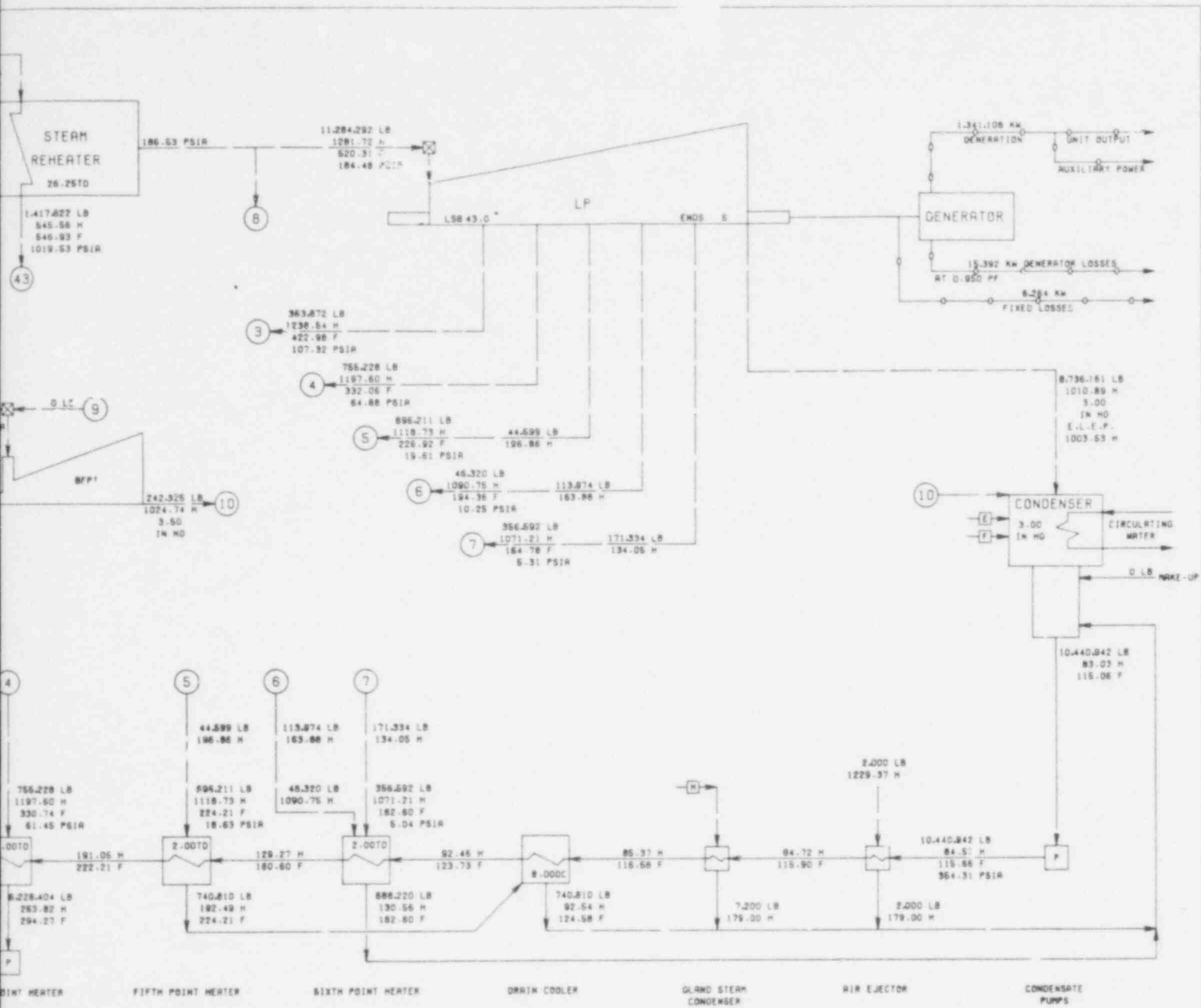
FIG. 10.1-2

TYPICAL HEAT BALANCE
AT RATED POWER

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

B&W

668 066



PER HOUR
PER POUND
DEGREES F
RENCE
APPROACH

OF MERCURY, ABS.
PER SQUARE IN. ABS.
NTERCEPT VALVE

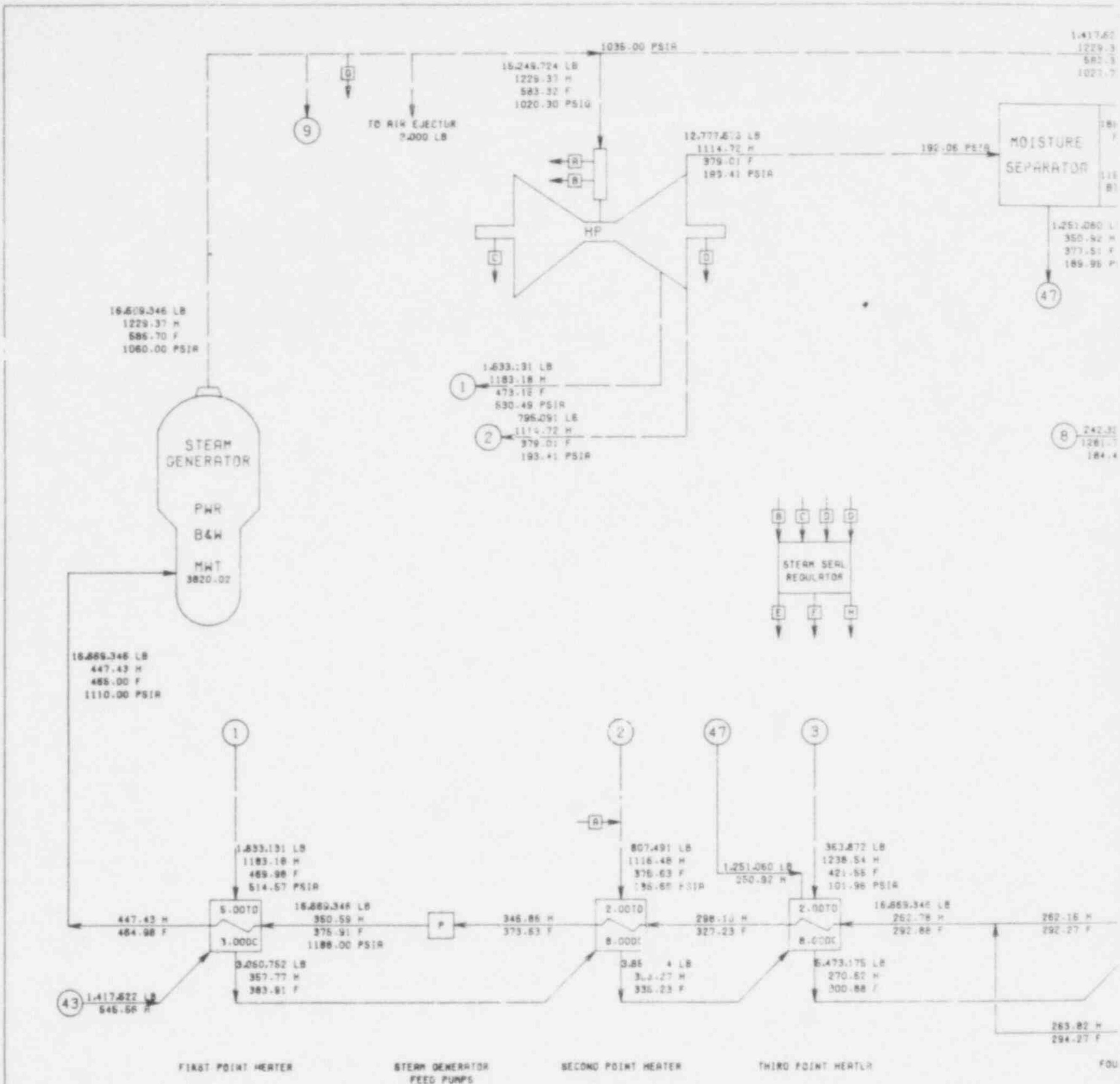
FIG. 10.1-3

TYPICAL HEAT BALANCE AT TURBINE MAXIMUM CAPABILITY

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

B&W

668 067



LEAKAGES

	FLOW	ENTHALPY
A	12.400	1229.37
B	2.850	1229.37
C	14.288	1114.72
D	14.288	1114.72
E	10.800	1125.12
F	13.425	1125.12
G	0	-
H	7.200	1125.12

LE

	STEAM
	WATER
	POWER
LB	FLOW, POL
H	ENTHALPY-
F	TEMPERATU
TD	TERMINA
DC	DRAIN COO
KW	KILOWATTS
IN HG	PRESSURE.
PSIA	PRESSURE.
	THROTTLE
	CONTROL V

POOR ORIGINAL

668 068

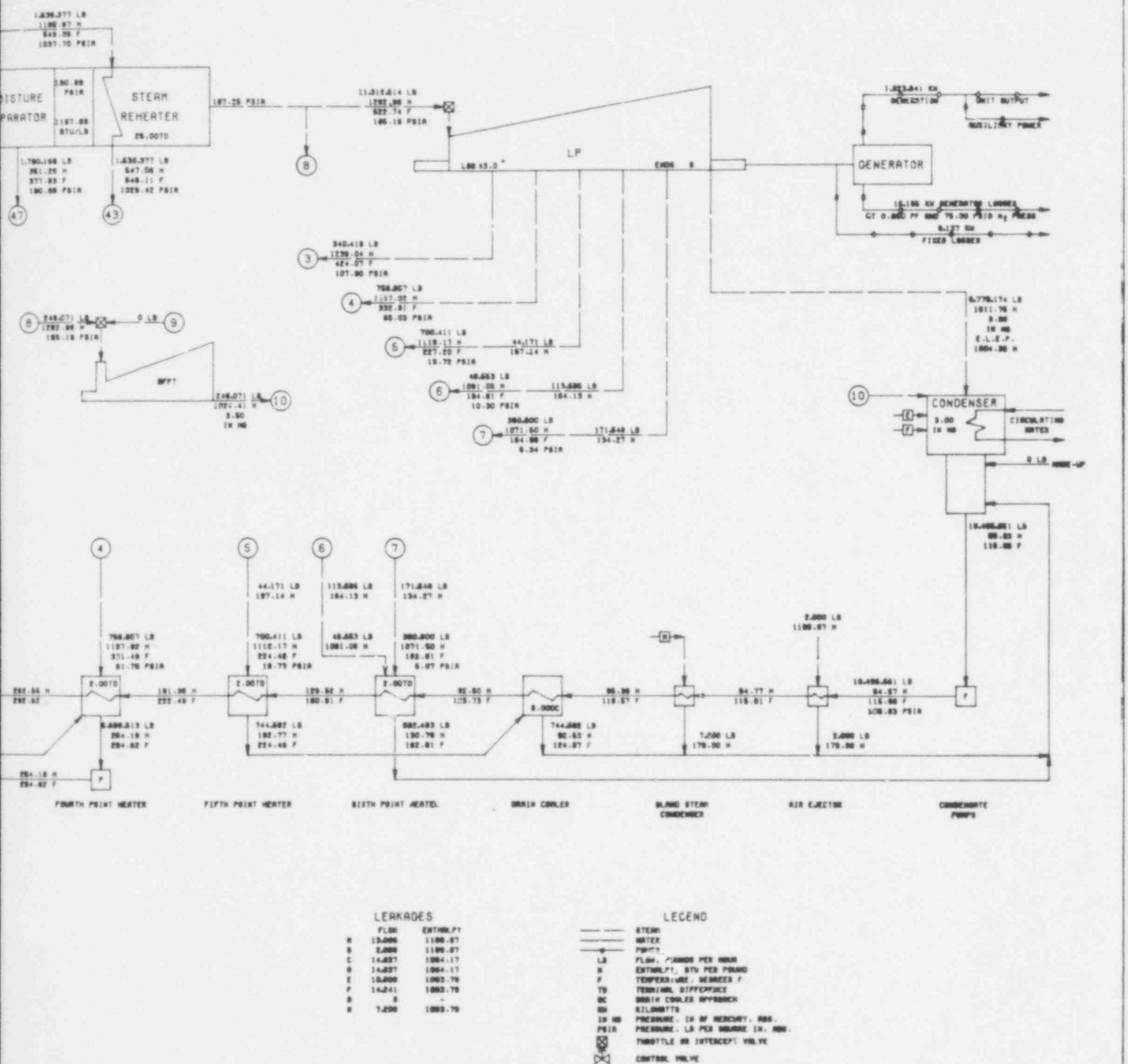


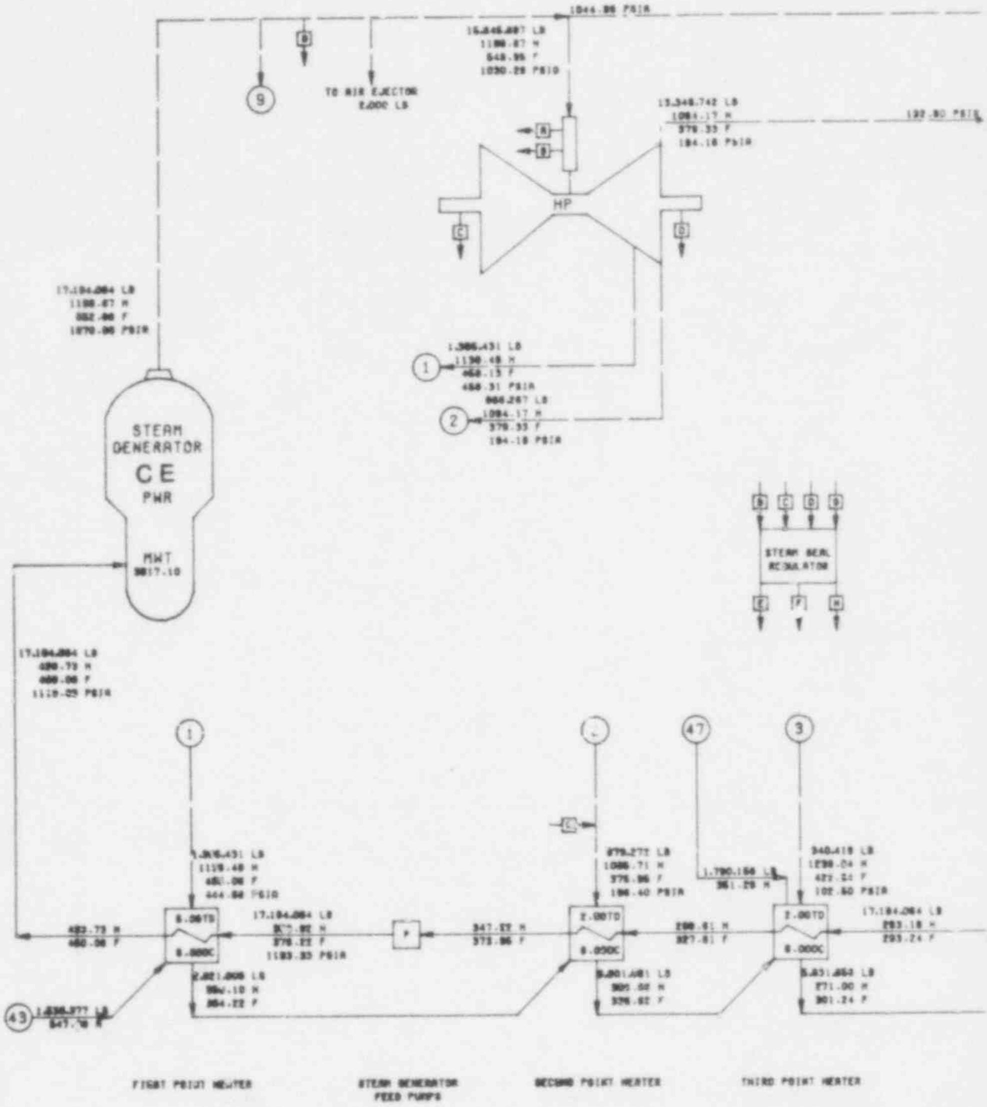
FIG. 10.1-2

TYPICAL HEAT BALANCE AT RATED POWER

PWR STANDARD PLANT
SAFETY ANALYSIS REPORT
SWESSAR-PI

CE

668 069



POOR ORIGINAL

668 070

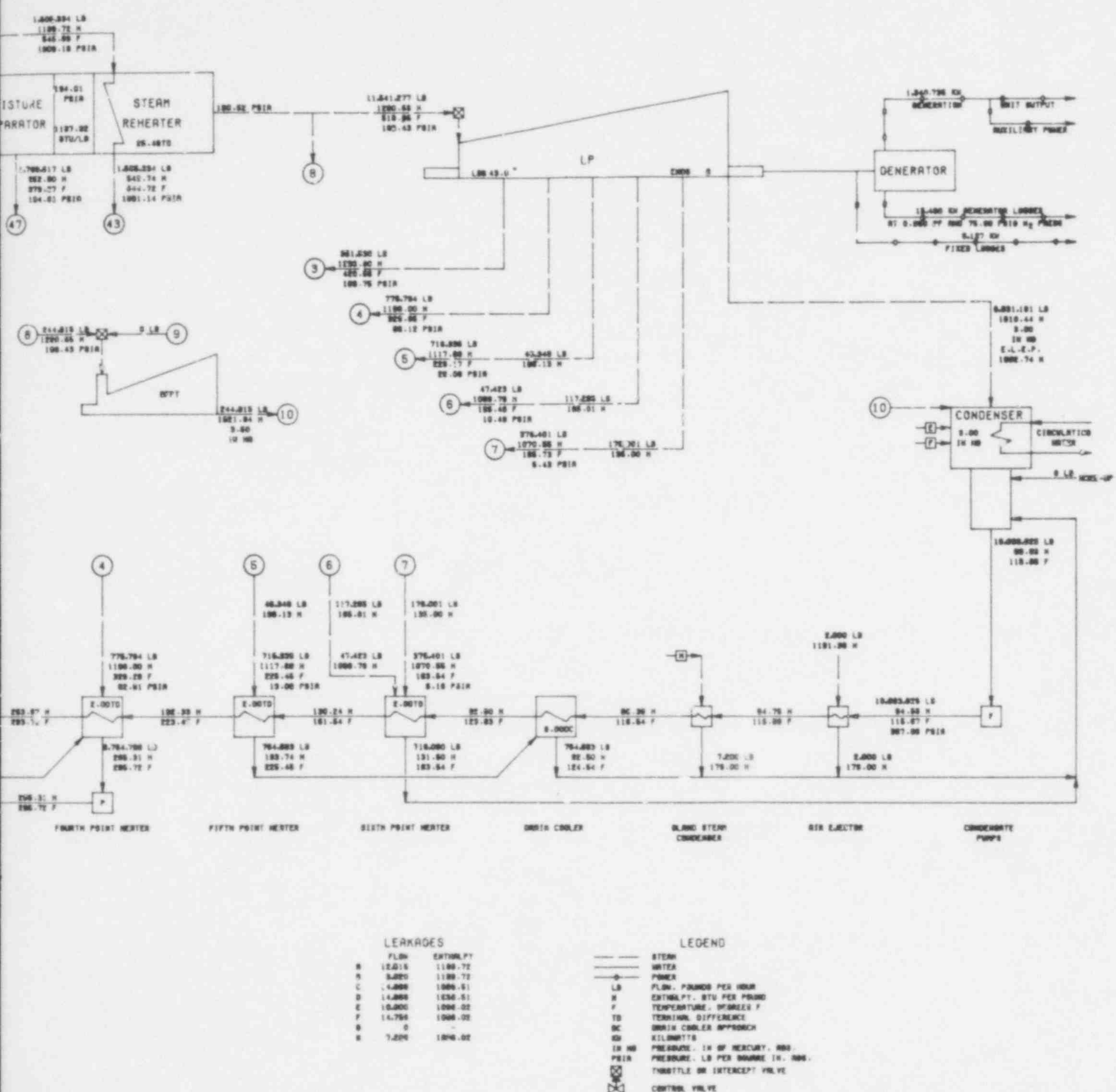
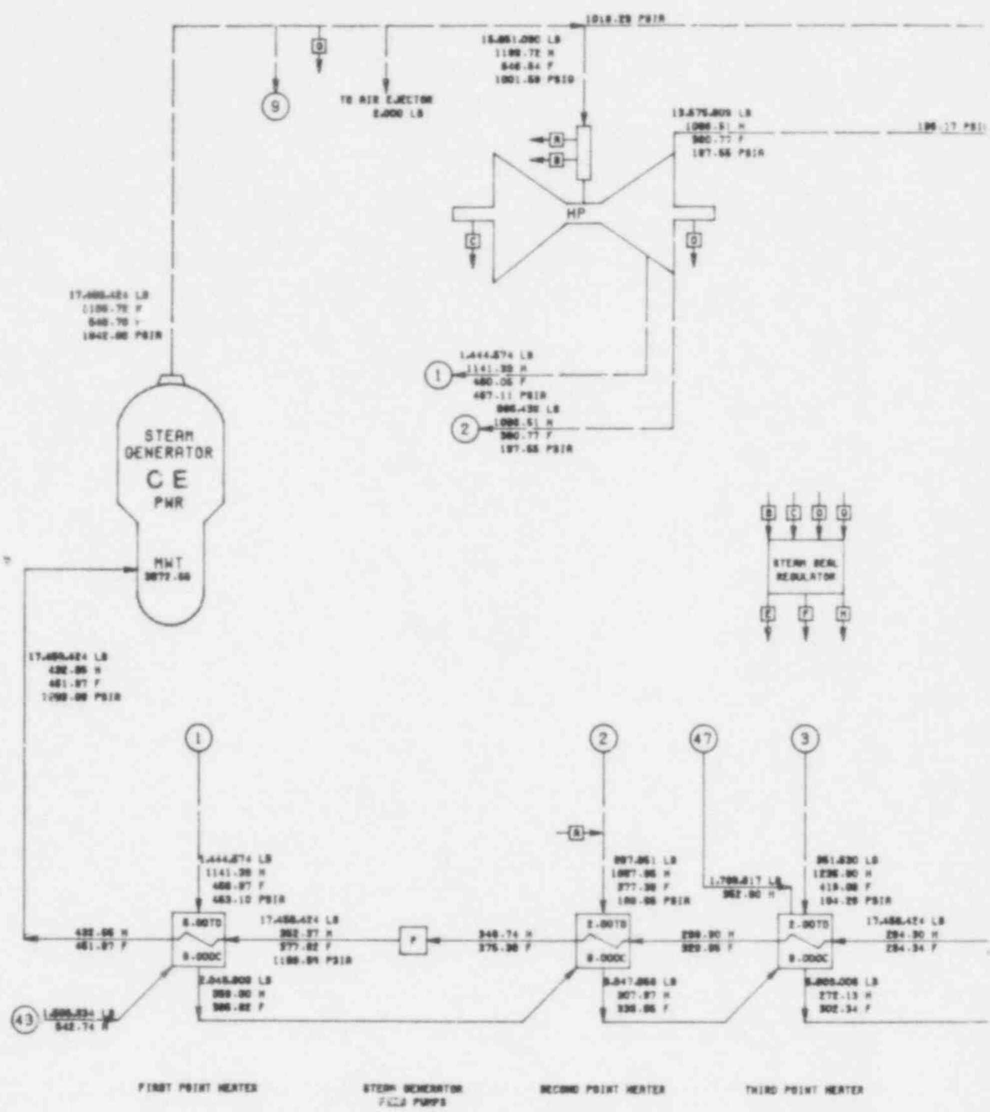


FIG. 10.1-3

TYPICAL HEAT BALANCE AT MAXIMUM CAPACITY

PWR STANDARD PLANT SAFETY ANALYSIS REPORT SWESSAR-P1

CE



POOR ORIGINAL

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10.2

668 073

10.2 TURBINE-GENERATOR AND TURBINE STEAM SYSTEM

The function of the turbine-generator and the turbine steam system is to receive steam from the main steam system (Section 10.3) and to transform the thermal energy in the steam to electrical energy.

Detailed design information and analyses of specific applicability to General Electric and Westinghouse turbine-generators are provided in the following Sections:

10.2.2.2	Turbine Control System
10.2.3	Turbine Missiles
10.4.3	Turbine Gland Sealing System
15.1.35A and 15.1.35B	Malfunction of Turbine Gland Sealing System.

Should a Utility-Applicant referencing SWESSAR specify a different turbine-generator manufacturer, the design information and analyses applicable to that manufacturer will be provided at the time of the Utility-Applicant's submittal. In addition, revised turbine building arrangement drawings will be submitted, if necessary. 8

A typical turbine steam system is shown in Fig. 10.2-1.

10.2.1 Design Bases

The design bases of the turbine-generator and the turbine steam system are:

1. The turbine shall be designed for normal operation based on steam conditions as determined by the Utility-Applicant's choice of NSSS Vendor and the main steam piping configuration. The conditions at the steam generator outlet are specified in Table 10.3-1.

2. The turbine-generator shall be designed for load following operation.

3. The turbine-generator design shall allow safe continuous operation at the maximum capability of the turbine (valves wide open condition).

4. The turbine-generator and associated steam and power conversion systems shall be capable of a 50 percent load reduction without producing a reactor trip by dumping steam into the condenser through the turbine bypass system (Section 10.4.4).

5. The turbine-generator shall be capable of increasing or decreasing electrical load at a rate consistent with the

requirements which the NSSS Vendor imposes on the turbine (Section 7.7).

6. The turbine-generator shall be built in accordance with the turbine manufacturer's standards and the industry codes that most closely approximate the conditions of turbine-generator applications.

7. The moisture separator/reheaters shall be designed and fabricated in accordance with Section VIII of the ASME Boiler and Pressure Vessel Code.

8. Generator rating, temperature rise, and insulation class shall be in accordance with the latest ANSI Standards.

10.2.2 Description

10.2.2.1 Turbine Steam System

The turbine is an 1,800 rpm, tandem compound, 6-flow, steam reheat machine with 43 in. (General Electric) or 44 in. (Westinghouse) last stage blades. The turbine consists of one double-flow high pressure cylinder and three double-flow low pressure cylinders. Steam from the main steam system, flowing through four main steam lines, passes through the turbine stop and control valves and into the high pressure turbine. Steam leaving the high pressure turbine passes through the moisture separator reheaters to the inlets of the low pressure turbines. Each of the steam lines between the reheater outlets and low pressure turbine inlets is provided with combined intercept and stop valves.

The moisture separator/reheaters are located on the operating floor on both sides of the turbine. Steam from the main steam manifold heats the exhaust steam from the high pressure turbine, while chevron type baffles remove moisture from the exhaust steam. Each moisture separator/reheater has a single stage of reheat. The moisture separators are provided with relief valves
12 which discharge to the atmosphere.

The exhaust from the three low pressure turbines passes to the condenser where it is condensed by the circulating water system (Section 10.4.5).

Turbine extraction steam, used for feedwater heating, is taken from six extraction points (see Fig. 10.1-1): one on the high pressure turbine casing, one from the exhaust of the high pressure turbine, and four from the low pressure turbine casing. Six stages of closed feedwater heaters are provided (Section 10.4.7). Motor operated block valves and power assisted nonreturn valves in the extraction piping protect against the possibility of turbine water induction or overspeed due to energy stored in the extraction steam system.

10.2.2.2 Turbine Control System

The turbine control system is capable of remote manual or automatic starting and loading of the unit at a preset rate, and holding speed and load at a preset level. The system contains valve positioning, operating, and tripping devices with provisions for testing valve operation.

Typical turbine control systems provided by the turbine manufacturers are discussed in the following sections. 8

10.2.2.2A Turbine Control System for General Electric Turbine

The turbine control system is of the electrohydraulic control (EHC) type and is organized into three major units to minimize interactions. A speed control unit compares actual turbine speed with the speed reference, or actual acceleration with the acceleration reference, and provides one speed error signal for the load control unit. The load control unit combines the speed error signal with the load reference signal, and provides limits and biases to determine desired steam flow signals for the turbine stop valves, turbine control valves, and intercept valves. Finally, the valve flow control units accurately position the appropriate valves to obtain the desired steam flows to the turbine.

Turbine-Generator Overspeed Protection Control System

Modern EHC controls incorporate the experience gained over a period of 10 years on 140 turbines using EHC control. It is a highly reliable system, employing three electrical and one mechanical speed inputs. Logic signals are redundantly processed in both electronic and hydraulic channels. Valve opening actuation is provided by a 1,600 psig hydraulic system which is totally independent of the bearing lubrication system. Valve closing actuation is provided by springs and aided by steam forces upon the reduction or relief of fluid pressure. The system is designed so that loss of hydraulic fluid pressure for any reason leads to valve closing and consequent shutdown (fail safe).

The main steam valves are provided in series arrangements: a group of stop valves actuated by either of two overspeed trip signals, followed by a group of controlling valves modulated by the speed governing system, and tripped by either overspeed trip signal.

The intermediate valves are arranged in series-pairs, an intermediate stop valve and intercept valve in one casing. The closure of either one of the two valves closes off the corresponding steam line.

A single failure of any component will not lead to destructive overspeed. A multiple failure, involving combinations of undetected electronic faults and/or mechanically stuck valves and/or hydraulic fluid contamination at the instant of load loss, would be required. The probability of such joint occurrences is extremely low, due to both the inherently high reliability of the design of the components and frequent inservice testing.

A. Speed Sensing

The EHC system provides three independent levels of speed sensing. All three are normally in operation. A minimum of two are in operation during the short period used to test the overspeed trip devices.

1. The operating speed signal is obtained from two magnetic pickups on a toothed wheel at the high pressure turbine shaft. Increase of either of the speed signals tends to close control and intercept valves. Loss of one of the speed signals transfers control to the other speed signal. Loss of both speed signals trips the emergency trip system through two redundant trip signals. The operation of both speed signals is continuously monitored by the alarm system.

2. The mechanical overspeed trip uses an unbalanced rotating ring and a stationary trip finger operating a trip valve to dump the emergency trip fluid system pressure directly upon reaching its set speed, typically 110 to 111 percent of rated speed. All stop and control valves and intermediate valves are tripped.

   The operation of the overspeed trip mechanism and the mechanical trip valve can be tested during normal operation. A test interval of once per week is recommended.

3. The electrical backup overspeed trip trips the emergency trip fluid system pressure, through two redundant trip signals, upon reaching its trip speed.

   The operation of the backup overspeed trip and the electrically operated master trip solenoid valves can be tested during normal operation. A test interval of once per week is recommended.

B. Steam Flow Controlling Valves

The General Electric turbine control system provides two independent valve groups for defense against overspeed in each admission line to the turbine. The normal speed control system closes one on moderate overspeed, and the emergency trip system closes both upon a higher overspeed or other trip signals.

All valves are testable during operation. The fast closing feature of any valve is fully operative while the valves are being tested.

Main Steam Inlets

Steam from the turbine steam system is admitted to the high pressure turbine through four main stop valves, followed by a manifold, followed by four main control valves, followed by four un-manifolded main steam inlets. The manifold ahead of the control valves permits inservice testing of the stop valves with little effect on load. Daily testing of each stop valve is recommended. The control valves can be individually tested in service at the expense of shedding up to about 15 percent of maximum load. A testing interval not exceeding one week is recommended.

The control valves are normally controlled by the redundant speed control system. In their emergency operating mode, the valves are rapidly tripped closed when fluid pressure is dumped by the fast acting solenoid valves upon power/load imbalance actuation or by either of two redundant trip valves. Both the normal operating and fast closing devices are tested while under load.

The main stop valves are normally held open by pressure in the emergency trip system (ETS). They are rapidly tripped closed by dumping the ETS pressure.

Stop valves of the stem sealed design have been used on large General Electric steam turbines since 1948. There have been over 700 turbines shipped and put in service during this period, and there has been no report of the stop valves failing to close when required to protect the turbine. Impending sticking has been disclosed by means of the daily full closed test, so that a shutdown can be made to make the necessary correction. Such incipient problems have been found only on high temperature fossil fueled units and have been due to the accumulation of an oxide layer in the stem and bushing. Oxidation is not expected at the relatively low temperatures of water cooled nuclear reactor applications. General Electric has heard of two failures of nuclear turbine stop valves to close. Both were reported to have occurred on a unit not of General Electric manufacture, and were reputed to have been due to silica buildup between the stems and bushings. General Electric believes that their stop valves are not subject to such failure, because the stem sealed design precludes the transport of steam carried impurities back along the stem. At the present writing General Electric has accumulated about 300 valve-years of service on nuclear turbine stop valves and knows of no failure to close. Calculated failure rates are based on these statistics.

Nuclear turbine control valves are similar in construction to the highly developed designs used in fossil fuel applications.

Because the operating temperature is lower, they should be significantly freer of temperature related problems, such as sticking caused by stem thermal distortion or oxidation.

At the present writing General Electric has accumulated over 450 valve years of nuclear turbine control valve service. One failure to completely close has been reported. That valve, of a design no longer used, employed a bolted down removable seat. A small piece of seat locking hardware came loose and lodged between the seat and disc, preventing closure by about 1/8 inch. The calculated failure rates used in the present study consider this failure, treating it as a complete failure in the open position.

Combined Intermediate Stop and Intercept Valves

Modern nuclear turbine cycles employ either moisture separators or moisture separator-reheaters, at 150 to 250 psia, between the high and low pressure turbine sections. The energy storage in these devices and the associated piping are sufficient to accelerate a nuclear turbine generator to higher than normal, but not catastrophic overspeed on loss of full load. Two combined intermediate valves are provided at the inlet of each low pressure casing to prevent such overspeed. Each valve contains two independently operated valve discs in series, one called an intercept valve, and the other called an intermediate stop valve.

The intercept valves are normally wide open but are closed by the speed control system upon a moderate speed increase. They are tripped closed rapidly upon removal of the ETS pressure.

The intermediate stop valves are normally open but are tripped closed rapidly upon removal of the ETS pressure.

Both valves are of the stem sealed design with its attendant reliability advantage.

Both valves, including their rapid closure devices, can be tested during normal operation with minor load perturbation. Daily testing is recommended.

Special field tests are made of new components, both to obtain design information and to confirm proper operation. Such special tests include the confirmation of the capability of controls to prevent excessive overspeed on loss of load. Design procedures take into account the effect of extra overspeed potential reulting from water in contact with hot metal flashing into steam.

The described design, inspection, and testing features substantially reduce the probability of destructive overspeed as a possible cause of failure in modern design units. The regular testing of all testable devices and circuits during operation in accordance with instruction book recommendations increases the reliability of the protection system by several orders of magnitude.

10.2.2.2B Turbine Control System for Westinghouse Turbine 8

The turbine control system is a digital electrohydraulic (DEH) control system and includes a digital computer, an analog backup system, electronic servo hardware, and hydraulic valve actuators. During automatic operation, the computer sends output signals to the servo system to position the valve actuators, which, in turn, admit steam to the turbine and thus control turbine speed and/or load. During computer maintenance, an analog backup system maintains valve position and provides simple raise and lower action. The computer and analog systems continuously track each other, allowing smooth transfer from one mode to the other.

Emergency Trip System and Overspeed Protection

A. Emergency Trip System

The emergency trip system provides a means of protection against various contingencies which might cause damage to the unit were it not immediately taken out of service. 8
Electrohydraulic in design, the system offers:

- Complete redundancy of all trip functions
- Complete on-line testability without causing or preventing a trip
- Provisions for detection and diagnosis of failed device
- Provisions for inservice maintenance
- Fail safe design

Pertinent turbine parameters are continuously monitored. If they exceed the limits of safe turbine operation, the unit shuts down. All steam valves close upon the occurrence of the following:

- Turbine overspeed
- Excessive thrust bearing wear
- Low bearing oil pressure
- Low condenser vacuum
- Low EH fluid pressure

A remote trip is also provided. The system consists of an emergency trip block and three test blocks mounted on the governor pedestal, a cabinet containing all electrical and electronic hardware, and a remote mounted trip test panel.

Trip Block

The emergency trip block contains four normally energized solenoid valves divided into two channels. When a contingency occurs, both channels are deenergized causing the turbine to trip. Only one valve per channel is necessary to trip. When testing, only one channel is deenergized at a time. This will not cause or prevent a trip since the other channel is still functional. Two additional solenoid valves associated with the overspeed protection controller circuitry are also contained in this block.

Test Blocks

The test blocks, similar in nature, provide the means of monitoring bearing oil pressure, EH fluid pressure, and condenser vacuum. Low bearing oil pressure is discussed in detail. Four pressure switches monitor bearing oil pressure with two associated with each trip channel. If at least one from each channel functions on low bearing oil pressure, contacts open dropping out relay trains in the trip cabinet which deenergize the trip solenoid valves and therefore trip the turbine. Test valves and gages for locally and remotely testing each function are included in these blocks.

Trip Cabinet

The trip cabinet contains all power supplies, relays, and additional hardware associated with the trip system. It also contains the electronics for the electrical overspeed trip channel. All purchaser connections are made to terminal strips in this cabinet.

Test Panel

The test panel contains all the lights, pushbuttons, and selector switches to test both channels of each trip function remotely. Testing is accomplished by actually changing the pressure read by each channel of the pressure trip function, by moving the position of the pickups used in sensing thrust bearing wear, or by injecting an overspeed signal into the electrical overspeed channel. Interlocks are provided to prevent testing one channel when the other channel is down. Lights on the panels indicate when a channel has tripped. Additional lights are available for monitoring all pressure switches, power supplies as well as the trip channels.

Summary of Trip Functions

Low bearing oil, low vacuum, low EH fluid are monitored by pressure switches in test blocks on the governor pedestal. Two pickup coils monitor the position of the thrust bearing collar.

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Excessive movement in either the governor end or generator end trips the unit.

Overspeed protection is provided by independent mechanical and electrical channels. If the turbine speed reaches the trip setpoint (standardly 111 percent), a spring loaded bolt located in a transverse hole in the turbine shaft flys out, dumping the autostop oil which unseats a diaphragm valve, dumping the EH fluid. The electrical overspeed channel picks up a relay which deenergizes all solenoid valves in the trip block. The occurrence of either closes all steam valves, tripping the turbine well before design speed is reached.

Purchaser remote trip can be provided with an option for on-line testing.

B. Overspeed Protection

Overspeed protection redundancy is provided in the design of the steam valves and sensing circuitry.

Valve Design

Main Inlet

Redundancy is accomplished by providing separate throttle and governor valves. 1

Reheat Inlet

Separate reheat stop and interceptor valves provide redundancy in the valving between the moisture separator reheater and the low pressure turbine.

Speed Sensing

Three electromagnetic speed sensors are located in the governor pedestal and one is located in the turning gear pedestal.

The following sensors are provided:

Mechanical Overspeed Trip Weight

This is a spring loaded bolt located in a radial drilling of the turbine stub shaft (governor pedestal). The center of gravity of the bolt is outside of the shaft center.

Electromagnetic Speed Pickups

One pickup is provided as a feedback for the main speed control channel. A speed reference (setpoint) is compared against the feedback. The governor valves are closed if the feedback has a higher value than the reference.

A second pickup feeds the overspeed protection controller (OPC). The OPC speed channel can be substituted for the main speed channel if a digital electrohydraulic (DEH) system is furnished.

A third speed pickup is used by the turbine supervisory instruments (TSI) for speed indicating and recording. The TSI speed signal is used for speed signal comparison on DEH systems.

A fourth speed pickup is used in the electrical overspeed trip device. This pickup is located in the turning gear pedestal to provide physical separation from other speed sensing devices.

There are additional pickups which are not relevant for overspeed protection. They are used for phase angle indications and spares.

Overspeed Protection Hierarchy

Main Speed Control Loop

When the circuit breaker opens, the main speed control loop calls for rated speed. Thus, when the unit exceeds rated speed, the governor valves move to the closed position.

1 Overspeed Protection Controller (Breaker Status)

If the unit carries more than 30 percent load and the main breaker opens, the governor and interceptor valves close rapidly. Speed is maintained below the overspeed trip point. The interceptor valves are oscillated between closed and partially open until the reheater steam is dissipated. Thereafter, the governor valves take over speed control and maintain household at rated speed if the control system is in automatic. The turbine generator coasts down to turning gear operation if the system is in manual.

Overspeed Protection Controller (103 Percent Speed Setpoint)

The governor and interceptor valves are closed rapidly when the unit exceeds 103 percent of rated speed. Thereafter the valves function as described above.

Mechanical Overspeed Trip Weight

If the speed reaches the setpoint of the trip weight (standardly 111 percent of rated speed), all steam valves are tripped (throttle, governor reheat stop, and interceptor valves). Speed is maintained below 120 percent of rated speed. The unit coasts down to turning gear operation.

Electrical Overspeed Trip

The electrical overspeed trip channel is independent of the control system and uses a pickup in the turning gear pedestal. When the speed reaches the trip point (standardly 111 percent of rated speed), all steam valves are tripped by energizing trip solenoids in the EH fluid lines. Speed is maintained below 120 percent of rated speed. The unit coasts down to turning gear operation. 1

10.2.2.3 Lubricating Oil System

The lubricating oil system supplies the lubrication needs of the turbine-generator. A bypass stream of lubricating oil flows continuously through an oil conditioning circuit. The lubricating oil system is described in Section 10.4.13.

10.2.2.4 Turbine Gland Sealing System

The turbine gland sealing system seals the turbine rotor between the turbine casings or the exhaust hood and the atmosphere, thus preventing leakage of air into the condenser and leakage of steam from the turbine into the turbine building. The turbine gland sealing system is described in Section 10.4.3.

10.2.2.5 Generator

The generator is sized to accept the output of the turbine. The generator is equipped with an excitation system, hydrogen control system, and a seal oil system. The generator terminals are connected to the main step-up transformer and unit station service transformers with generator isolated phase bus leads.

The generator excitation system controls the voltage of the generator. The hydrogen control system includes pressure regulators, control for the hydrogen gas, and a circuit to supply and control the CO2 used during filling and purging operations. A hydrogen seal oil system prevents hydrogen leakage through the generator shaft seals. This system includes pumps, controls, and a storage tank, and degasifies the oil before it is returned to the shaft seals.

10.2.2.6 Generator Hydrogen

A bulk hydrogen storage facility in the yard provides hydrogen for generator cooling.

An automatic pressure reducing transfer station, located outside near the bulk storage area, reduces the normally high hydrogen storage pressure to a lower hydrogen distribution system pressure. Local pressure reducing stations are provided where necessary to reduce the distribution system pressure to the pressure required by the serviced equipment.

Since the hydrogen supply is outdoors, an explosive mixture of hydrogen and oxygen cannot be formed by hydrogen leakage because of atmospheric dilution. The distribution system is of welded construction and is leak tested prior to being placed in service.

The designs of the generator and the generator cooling system and operating procedures are such that explosive mixtures are not possible under operating or maintenance conditions, including filling and purging the generator.

Purging operations will be closely supervised by responsible personnel familiar with the correct procedures. The generator is vented to the atmosphere and hydrogen is displaced under pressure
9 by CO_2 for the CO_2 storage tank in the turbine building to ensure that there is no mixing of hydrogen and air. The generator hydrogen system provides for purging and filling the generator housing, maintains the gases used in a moisture-free condition, and within predetermined limits of purity, pressure, and temperature, and gives warning of improper operation of the generator.

As indicated above, fires and explosions attributable to hydrogen are unlikely because of monitoring of the generator hydrogen system, reliable operating procedures, and location of the bulk storage facilities. In addition, the fire protection system (Section 9.5.1) provides backup to mitigate the effects of fire.

10.2.3 Turbine Missiles

An evaluation of postulated turbine missiles, in addition to discussing plant design as it pertains to protection of safety related items from the effects of turbine missiles, must take into consideration the probabilities of occurrence both of the generation of missiles and of the effects attributed to them.

Probability of Significant Damage (P4)

The probability of significant damage to plant structures, systems, and components (P4), where such damage could cause significant radiological consequences, is the product of three contributing factors:

$$P4 = P1 \times P2 \times P3$$

where:

P1 = the probability of generation and ejection of a high energy missile

P2 = the probability that a missile strikes a critical plant region, given its generation and ejection

P3 = the probability that the missile strike damages its target in a manner leading to unacceptable consequences

Probability of Generation and Ejection (P1)

A turbine missile can be caused by brittle fracture of a rotating turbine part at or near turbine operating speed, or by ductile fracture upon runaway after extensive, highly improbable control system failures. The calculation of this probability (P1) is the responsibility of the turbine manufacturer. For the purposes of P4 calculations, P1 was assumed to apply to the turbine disc for which the highest value of P2 would result.

Probability of Missile Strike (P2)

The probability of a strike on a critical plant region (P2) is a function of the energy and direction of an ejected missile and of the orientation of the turbine with respect to the critical plant regions. The arrangement of the PWR Reference Plant is such that the planes of rotation of the turbine discs do not intersect any safety related structures, systems, or components, thus minimizing the probability of significant adverse affects resulting from a turbine missile. The orientation of the turbine is shown on the plot plan, Fig. 1.2-1. Values of P2 have been calculated using a solid angle approach. 5

The turbine spins about the z-axis of the reference system shown in Fig. 10.2-2. Based on data provided by the turbine manufacturer, a postulated missile is thrown from the turbine with initial velocity V_o as shown. The variable angles required to describe the resulting motion are displayed in Fig. 10.2-2. Deflection angles δ_1 and δ_2, provided by the turbine vendor limit θ to the range:

$$\frac{\Pi}{2} - \delta_1 \leq \theta \leq \frac{\Pi}{2} + \delta_2$$

The probability that a single disc fragment strikes a critical area A_o is defined as:

$$P(A_o) = \int_{\Omega_o} f(\Omega)\, d\Omega \qquad (1)$$

where, Ω_o is the solid angle which must be subtended by the initial velocity vector for a missile to strike A.

$d\Omega$ is the differential solid angle, and

$f(\Omega)$ is the probability density function.

From Fig. 10.2-2,

$$d\Omega = \cos\phi \; d\phi \; d\psi \qquad (2)$$

Given V_0, the elevation angle ϕ necessary to hit any point on A_0 (described by r, y, and ψ in Fig. 10.2.2) is determined from classical trajectory theory as:

$$\phi = \tan^{-1}\left[\frac{1 \pm \left[1 - (rg/v_o^2)^2 - 2(yg/v_o^2)\right]^{\frac{1}{2}}}{(rg/v_o^2)}\right] \qquad (3)$$

In Eq (3), air resistance is neglected and the ± refers to high and low trajectory missiles respectively.

The probability density function $f(\Omega)$ is determined by assuming:

$f(\Omega)$ = constant = f_0 for $0 \le \beta \le 2\Pi$ and $\Pi/2 - \delta_1, \le \Theta \le \Pi/2 + \delta_2$

$f(\Omega) = o$, for all other Θ.

From probability theory it is required that

$$\int_{\text{all}\,\Omega} f(\Omega)\, d\Omega = 1$$

Therefore, $f_o = \dfrac{1}{2\Pi\,(\sin\delta_1 + \sin\delta_2)}$

The probability that n disc fragments strike a critical area A_0 is then

8 $$P2(A_o) = \frac{n}{2\Pi\,(\sin\delta_1 + \sin\delta_2)} \int_{\Omega_o} d\Omega \qquad (4)$$

A computer program has been developed to calculate the strike
8 probability using Eq (4). Following Bush[1], the analysis considers high trajectory hits on the tops of all critical targets and low trajectory hits on the sides of all critical targets. Fig. 10.2-3 and 10.2-4 represent the top and side views of an idealized target. The strike probability of the target is found by numerically integrating Eq (4), which gives

8 $$P_2 = \frac{n}{2\Pi\,(\sin\delta_1 + \sin\delta_2)} \sum_{i=1}^{n_\psi} (\cos\phi_i)(\Delta\phi_i)\Delta\Psi$$

for $\Pi/2 - \delta_1 \le \theta_i \le \Pi/2 + \delta_2$

and $P_2 = 0$

for $0 \leq \theta_i < \Pi/2 - \delta_1 \; , \; \Pi/2 + \delta_2 < \theta_i \leq \Pi$

where,

$$\theta_i = \cos^{-1} (\cos \phi_i \cos \psi_i)$$

and n_ψ = number of ground angle increments taken through the target.

From Fig. 10.2-3 and 10.2-4,

$$\Delta\psi = \frac{\psi_{max} - \psi_{min}}{n_\psi}$$

$$\psi_i = \psi_{min} + (i - \tfrac{1}{2}) \Delta\psi$$

$$\Delta\phi_i = |\phi_2^i - \phi_1^i|$$

$$\phi_i = \tfrac{1}{2} (\phi_1^i + \phi_2^i)$$

Eq (3) is used to determine $\phi_{1,2}^i$. The low and high trajectory probabilities are calculated separately and added to obtain the final probability.

Probability of Damage (P3)

The probability (P3) is a function of the energy of the missile, its angle of impact upon the affected structure, and the energy and direction of the missile after penetration of the structure. The following criteria suggested by Bush[1] were used. | 9

$$\frac{t}{\cos^2} > 6' \quad , P3 = 0.$$

And if $\alpha > 45^\circ$, P3 = 0.

where, t = thickness of reinforced concrete between the turbine and a critical component,

and α = the incidence angle (angle between the normal to the concrete and the impact velocity vector).

Otherwise, P3 = 1.

Overall Probability Calculation

Turbine missile information provided by the turbine manufacturers is listed in Table 10.2-1[2][3][4]. With this data as a basis, the strike probability (P2) was calculated for one of the units shown in Fig. 1.2-1 and tabulated in Table 10.2-2. The overall probability of turbine missile damage (P4) for a single unit is calculated in Table 10.2-3. Probability of turbine missile damage was also calculated for a two unit site, with strike probability given in Table 10.2-4 and overall probability given in Table 10.2-5. For the two unit site shown in Fig. 1.2-1, turbine A corresponds to Unit 1 and turbine B corresponds to Unit 2.

Strike probabilities in Tables 10.2-2 and 10.2-4 are given only for those areas where P3 = 1.0. Turbine-target distances and effective impact areas for a two-unit site are given in Table 10.2-6.

The Utility-Applicant's SAR will indicate whether the single unit or the two-unit site calculations are applicable. In addition, if more than two units are provided at one site, the additional probabilities will be provided in the Utility-Applicant's SAR.

Based on the values given in Tables 10.2-3 and 10.2-5, the probability (P4) of significant damage to critical plant regions due to a postulated turbine failure is sufficiently low that design of the plant against turbine missile effects need not be considered.

10.2.4 Design Evaluation

Primary protection of the main generator is provided by differential current and field failure relays. Protective relays automatically trip the turbine stop valves and electrically isolate the generator.

The turbine-generator is protected against destructive overspeed by redundant speed control systems during normal and transient conditions. If the primary system fails, either a mechanical overspeed or a backup overspeed system trips the turbine-generator.

23 To ensure system reliability, requirements will be imposed on the turbine manufacturer to design the overspeed protection systems and to provide installation instructions thereof to ensure that these systems remain operable under the most severe environmental conditions for which the turbine building is designed. In addition, requirements will be imposed to ensure complete on-line testability of both the mechanical and electrical overspeed trip systems. Connections between the turbine and the reactor protection system and between the engineered safety features actuation system (ESFAS) and the turbine trip system shall be redundant, physically independent, and separated and designed to

withstand a single failure. To ensure turbine trip and to minimize blowdown following a main steam line break, the turbine stop valves, the reheat valves, and turbine bypass valves will receive redundant steam line isolation (SLI) signals from the ESFAS. 23

The turbine-generator and related steam handling equipment systems are radioactively contaminated only when there is a steam generator tube rupture resulting in leakage of reactor coolant from the primary to the secondary side of a steam generator. Shielding of the turbine-generator systems is not required because the activity level during operation is minimal and well within safe limits. The equilibrium concentrations of various isotopes in the turbine steam system are essentially the same as the equilibrium concentrations in the main steam system. These concentrations are tabulated in Tables 11.1.3-1 and 11.1.3-2.

The design of the reinforced concrete pedestal supporting the main generator minimizes pockets on the underside in which escaped hydrogen could collect. The potential for an explosion is considered nil, since there is no high pressure gas within the building and the ventilation system prevents accumulation of any minor leakage that may occur.

10.2.5 Testing and Inspections

To ensure proper operation, the turbine stop and control valves and the combined stop and intercept valves are exercised periodically to detect valve stem sticking. During this procedure, the valves are partially closed and then reopened.

Tests to ensure operability of the overspeed trip system are performed periodically while under load. Special test provisions prevent tripping of the plant during these tests.

References for Section 10.2

1. Bush, S.H., "Probability of Damage to Nuclear Components Due to Turbine Failures," Nuclear Safety, Vol. 14, No. 3, May-June 1973.

2. General Electric Company, Memo Report - Hypothetical Turbine Missiles - Probability of Occurrence, 3/14/73.

3. Westinghouse Electric Corp., Analysis of the Probability of the Generation and Strike of Missiles from a Nuclear Turbine, March 1974.

TABLE 10.2-1

VENDOR PROVIDED TURBINE INFORMATION

	GE	Westinghouse
Annual Average Probability of Failure, P1	1.4E-8	1.7E-6
Deflection Angles		
End disc: ϑ_1 (degrees)	25	25
ϑ_2	0	0
Interior disc: ϑ_1 (degrees)	5	5
ϑ_2	5	5
Low Overspeed Condition		
Percent of normal running speed	120	120
Exit velocity, V_0 (fps)	300	300
Number of fragments, n	4	4
Fragment size (degrees)	90	90
High Overspeed Condition		
Percent of normal running speed	180	180
Exit velocity, V_0 (fps)	600	600
Number of fragments, n	3	3
Fragment size (degrees)	120	120

8

TABLE 10.2-2

STRIKE PROBABILITY (P2) FOR A SINGLE UNIT
TURBINE MANUFACTURER - GENERAL ELECTRIC, WESTINGHOUSE

NSSS Vendor - Babcock & Wilcox, Combustion Engineering, and Westinghouse (3S) 17

		Vo = 300 FPS			Vo = 600 FPS		
Critical Plant Region	Unit-Turbine	Low Trajectory	High Trajectory	Total	Low Trajectory	High Trajectory	Total
Containment Structure	1-A	0.0000E 00	0.1243E-02	0.1243E-02	0.0000E 00	0.5589E-04	0.5589E-04
Control Building	1-A	0.0000E 00	0.3313E-02	0.3313E-02	0.0000E 00	0.1535E-03	0.1535E-03
Diesel Generator Building	1-A	0.0000E 00	0.6300E-03	0.6300E-03	0.0000E 00	0.4814E-04	0.4814E-04
Fuel Oil Storage Tanks & Pump House	1-A	0.0000E 00	0.2274E-03	0.2274E-03	0.0000E 00	0.2537E-04	0.2537E-04
Fuel Storage Area	1-A	0.0000E 00	0.9818E-03	0.9818E-03	0.0000E 00	0.4559E-04	0.4559E-04
Auxiliary Feedwater Storage Tank	1-A	0.0000E 00	0.1182E-03	0.1182E-03	0.0000E 00	0.5331E-05	0.5331E-05
Total Strike Probability, P2		0.0000E 00	0.6514E-02	0.6514E-02	0.0000E 00	0.3338E-03	0.3338E-03

NSSS Vendor - Westinghouse (41) 17

Critical Plant Region	Unit-Turbine	Low Trajectory (Vo = 300 FPS)	High Trajectory (Vo = 300 FPS)	Total (Vo = 300 FPS)	Low Trajectory (Vo = 600 FPS)	High Trajectory (Vo = 600 FPS)	Total (Vo = 600 FPS)
Containment Structure	1-A	0.0000E 00	0.1243E-02	0.1243E-02	0.0000E 00	0.5589E-04	0.5589E-04
Control Building	1-A	0.0000E 00	0.3313E-02	0.3313E-02	0.0000E 00	0.1535E-03	0.1535E-03
Diesel Generator Building	1-A	0.0000E 00	0.9416E-03	0.9416E-03	0.0000E 00	0.7221E-04	0.7221E-04
Fuel Oil Storage Tanks & Pump House	1-A	0.0000E 00	0.3382E-03	0.3382E-03	0.0000E 00	0.3774E-04	0.3774E-04
Fuel Storage Area	1-A	0.0000E 00	0.9818E-03	0.9818E-03	0.0000E 00	0.4559E-04	0.4559E-04
Auxiliary Feedwater Storage Tank	1-A	0.0000E 00	0.1182E-03	0.1182E-03	0.0000E 00	0.5331E-05	0.5331E-05
Total Strike Probability, P2		0.0000E 00	0.6936E-02	0.6936E-02	0.0000E 00	0.3702E-03	0.3702E-03

TABLE 10.2-3

OVERALL PROBABILITY (P4) FOR A SINGLE UNIT

NSSS Vendor - Babcock & Wilcox, Combustion Engineering, and Westinghouse (3S) | 17

Turbine Manufacturers	P1	P2	P3	P4 = P1xP2xP3
GE				
V_0 = 300 fps	1.4E-8	6.514E-3	1.0	9.120E-11
V_0 = 600 fps	1.4E-8	3.338E-4	1.0	4.673E-12
Westinghouse				
V_0 = 300 fps	1.7E-6	6.514E-3	1.0	1.107E-08
V_0 = 600 fps	1.7E-6	3.338E-4	1.0	5.675E-10

NSSS Vendor - Westinghouse (41) | 17

Turbine Manufacturers	P1	P2	P3	P4 = P1xP2xP3
GE				
V_0 = 300 fps	1.4E-8	6.936E-3	1.0	9.710E-11
V_0 = 600 fps	1.4E-8	3.702E-4	1.0	5.183E-12
Westinghouse				
V_0 = 300 fps	1.7E-6	6.936E-3	1.0	1.179E-08
V_0 = 600 fps	1.7E-6	3.702E-4	1.0	6.293E-10

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TABLE 10.2-4

STRIKE PROBABILITY (P2) FOR A TWO-UNIT SITE
TURBINE MANUFACTURER - GENERAL ELECTRIC, WESTINGHOUSE

NSSS Vendor - Babcock & Wilcox, Combustion Engineering, and Westinghouse (3S)

Critical Plant Region	Unit-Turbine	Vo = 300 FPS Low Trajectory	Vo = 300 FPS High Trajectory	Vo = 300 FPS Total	Vo = 600 FPS Low Trajectory	Vo = 600 FPS High Trajectory	Vo = 600 FPS Total
Containment Structure	1-A*	0.0000E 00	0.2487E-02	0.2487E-02	0.0000E 00	0.1118E-03	0.1118E-03
Control Building	1-A*	0.0000E 00	0.6626E-02	0.6626E-02	0.0000E 00	0.3069E-03	0.3069E-03
Diesel Generator Building	1-A*	0.0000E 00	0.1260E-02	0.1260E-02	0.0000E 00	0.9629E-04	0.9629E-04
Fuel Oil Storage Tanks & Pump House	1-A*	0.0000E 00	0.4548E-03	0.4548E-03	0.0000E 00	0.5074E-04	0.5074E-04
Fuel Storage Area	1-A*	0.0000E 00	0.1964E-02	0.1964E-02	0.0000E 00	0.9118E-04	0.9118E-04
Auxiliary Feedwater Storage Tank	1-A*	0.0000E 00	0.2364E-03	0.2364E-03	0.0000E 00	0.1066E-04	0.1066E-04
Containment Structure**	1-B	0.9348E-02	0.1286E-02	0.1063E-01	0.5618E-02	0.5599E-04	0.5674E-02
Control Building	1-B	0.1633E-02	0.3501E-02	0.5134E-02	0.1211E-02	0.1539E-03	0.1365E-02
Diesel Generator Building	1-B	0.0000E 00	0.6168E-03	0.6168E-03	0.0000E 00	0.4831E-04	0.4831E-04
Fuel Oil Storage Tanks & Pump House	1-B	0.0000E 00	0.2409E-03	0.2409E-03	0.0000E 00	0.2545E-04	0.2545E-04
Fuel Storage Area	1-B	0.0000E 00	0.1002E-02	0.1002E-02	0.0000E 00	0.4568E-04	0.4568E-04
Auxiliary Feedwater Storage Tank	1-B	0.0000E 00	0.1182E-03	0.1182E-03	0.0000E 00	0.5331E-05	0.5331E-05
Containment Structure**	2-A	0.9348E-02	0.1286E-02	0.1063E-01	0.5618E-02	0.5599E-04	0.5674E-02
Control Building	2-A	0.0000E 00	0.3338E-02	0.3338E-02	0.0000E 00	0.1535E-03	0.1535E-03
Diesel Generator Building	2-A	0.0000E 00	0.6272E-03	0.6272E-03	0.0000E 00	0.4817E-04	0.4817E-04
Fuel Oil Storage Tanks & Pump House	2-A	0.0000E 00	0.2292E-03	0.2292E-03	0.0000E 00	0.2538E-04	0.2538E-04
Fuel Storage Area	2-A	0.0000E 00	0.1026E-02	0.1026E-02	0.0000E 00	0.4577E-04	0.4577E-04
Auxiliary Feedwater Storage Tank	2-A	0.0000E 00	0.1207E-03	0.1207E-03	0.0000E 00	0.5333E-05	0.5333E-05
Total Strike Probability, P2		0.2033E-01	0.2642E-01	0.4675E-01	0.1245E-01	0.1336E-02	0.1378E-01

* Probability multiplied by 2 to account for a missile strike on unit 2 from turbine B as well as on unit 1 from turbine A.

** The conservative assumption was made that the Westinghouse (3S) containment structure is the same height as that for B&W and C-E.

TABLE 10.2-4 (CONT)

NSSS Vendor - Westinghouse (41) 17

Critical Plant Region	Unit-Turbine	Vo = 300 FPS Low Trajectory	Vo = 300 FPS High Trajectory	Vo = 300 FPS Total	Vo = 600 FPS Low Trajectory	Vo = 600 FPS High Trajectory	Vo = 600 FPS Total
Containment Structure	1-A*	0.0000E 00	0.2487E-02	0.2487E-02	0.0000E 00	0.1118E-03	0.1118E-03
Control Building	1-A*	0.0000E 00	0.6626E-02	0.6626E-02	0.0000E 00	0.3069E-03	0.3069E-03
Diesel Generator Building	1-A*	0.0000E 00	0.1883E-02	0.1883E-02	0.0000E 00	0.1444E-03	0.1444E-03
Fuel Oil Storage Tanks & Pump House	1-A*	0.0000E 00	0.6764E-03	0.6764E-03	0.0000E 00	0.7549E-04	0.7549E-04
Fuel Storage Area	1-A*	0.0000E 00	0.1964E-02	0.1964E-02	0.0000E 00	0.9118E-04	0.9118E-04
Auxiliary Feedwater Storage Tank	1-A*	0.0000E 00	0.2364E-03	0.2364E-03	0.0000E 00	0.1066E-04	0.1066E-04
Containment Structure	1-B	0.9348E-02	0.1286E-02	0.1063E-01	0.5618E-02	0.5599E-04	0.5674E-02
Control Building	1-B	0.1633E-02	0.3501E-02	0.5134E-02	0.1211E-02	0.1539E-03	0.1365E-02
Diesel Generator Building	1-B	0.0000E 00	0.9219E-03	0.9219E-03	0.0000E 00	0.7245E-04	0.7245E-04
Fuel Oil Storage Tanks & Pump House	1-B	0.0000E 00	0.3579E-03	0.3579E-03	0.0000E 00	0.3787E-04	0.3787E-04
Fuel Storage Area	1-B	0.0000E 00	0.1002E-02	0.1002E-02	0.0000E 00	0.4568E-04	0.4568E-04
Auxiliary Feedwater Storage Tank	1-B	0.0000E 00	0.1182E-03	0.1182E-03	0.0000E 00	0.5331E-05	0.5331E-05
Containment Structure	2-A	0.9348E-02	0.1286E-02	0.1063E-01	0.5618E-02	0.5599E-04	0.5674E-02
Control Building	2-A	0.0000E 00	0.3338E-02	0.3338E-02	0.0000E 00	0.1535E-03	0.1535E-03
Diesel Generator Building	2-A	0.0000E 00	0.9476E-03	0.9476E-03	0.0000E 00	0.7225E-04	0.7225E-04
Fuel Oil Storage Tanks & Pump House	2-A	0.0000E 00	0.3404E-03	0.3404E-03	0.0000E 00	0.3776E-04	0.3776E-04
Fuel Storage Area	2-A	0.0000E 00	0.1026E-02	0.1026E-02	0.0000E 00	0.4577E-04	0.4577E-04
Auxiliary Feedwater Storage Tank	2-A	0.0000E 00	0.1207E-03	0.1207E-03	0.0000E 00	0.5333E-05	0.5333E-05
Total Strike Probability, P2		0.2033E-01	0.2812E-01	0.4845E-01	0.1245E-01	0.1482E-02	0.1393E-01

* Probability multiplied by 2 to account for a missile strike on unit 2 from turbine B as well as on unit 1 from turbine A.

TABLE 10.2-5

OVERALL PROBABILITY (P4) FOR A TWO-UNIT SITE

NSSS Vendor - Babcock & Wilcox, Combustion Engineering, and Westinghouse (3S) 17

Turbine Manufacturers	P1	P2	P3	P4 = P1xP2xP3
GE				
V_0 = 300 fps	1.4E-8	4.675E-2	1.0	6.545E-10
V_0 = 600 fps	1.4E-8	1.378E-2	1.0	1.929E-10
Westinghouse				
V_0 = 300 fps	1.7E-6	4.675E-2	1.0	7.948E-08
V_0 = 600 fps	1.7E-6	1.378E-2	1.0	2.343E-08

NSSS Vendor - Westinghouse (41) 17

Turbine Manufacturers	P1	P2	P3	P4 = P1xP2xP3
GE				
V_0 = 300 fps	1.4E-8	4.845E-2	1.0	6.783E-10
V_0 = 600 fps	1.4E-8	1.393E-2	1.0	1.950E-10
Westinghouse				
V_0 = 300 fps	1.7E-6	4.845E-2	1.0	8.237E-08
V_0 = 600 fps	1.7E-6	1.393E-2	1.0	2.368E-08

TABLE 10.2-6

TURBINE-TARGET DISTANCES AND IMPACT AREAS FOR
A TWO-UNIT SITE

NSSS Vendor - Babcock & Wilcox, Combustion Engineering and Westinghouse (3S) 17

		HIGH TRAJECTORY				LOW TRAJECTORY				
Critical Plant Region	Unit Turbine	r_{min} ft	r_{max} ft	y ft	Impact Area ft²	r ft	y_{max} ft	y_{min} ft	Impact Area ft²	
Containment Structure	1-A*	304	418	112	10000					
Control Building	1-A*	267	518	13	28200					
Diesel Generator Building	1-A*	475	609	-33	8800					
Fuel Oil Storage Tanks & Pump House	1-A*	601	720	-46	4600					
Fuel Storage Area	1-A*	322	450	-5	8300					
Auxiliary Feedwater Storage Tank	1-A*	298	333	110	960					
Containment Structure**	1-B	652	765	112	10000	612	112	-5	3000	17
Control Building	1-B	754	1002	13	28200	836	13	-5	790	
Diesel Generator Building	1-B	930	1050	-33	8800					
Fuel Oil Storage Tanks & Pump House	1-B	1007	1169	-46	4600					
Fuel Storage Area	1-B	554	660	-5	8300					
Auxiliary Feedwater Storage Tank	1-B	755	790	110	960					
Containment Structure**	2-A	652	765	112	10000	612	112	-5	3000	17
Control Building	2-A	386	600	13	28200					
Diesel Generator Building	2-A	573	709	-33	8800					
Fuel Oil Storage Tanks & Pump House	2-A	697	736	-46	4640					
Fuel Storage Area	2-A	754	862	-5	8300					
Auxiliary Feedwater Storage Tank	2-A	571	606	110	960					

**The conservative assumption was made that the Westinghouse (3S) containment structure is the same height as that for B&W and C-E. 17

669 097

TABLE 10.2-6 (CONT)

NSSS Vendor - Westinghouse (41) 17

Critical Plant Region	Unit Turbine	HIGH TRAJECTORY r_{min} ft	r_{max} ft	y ft	Impact Area ft²	LOW TRAJECTORY r ft	y_{max} ft	y_{min} ft	Impact Area ft²
Containment Structure	1-A*	304	418	112	10000				
Control Building	1-A*	267	518	13	28200				
Diesel Generator Building	1-A*	458	608	-33	13200				
Fuel Oil Storage Tanks & Pump House	1-A*	594	720	-46	6900				
Fuel Storage Area	1-A*	322	450	-5	8300				
Auxiliary Feedwater Storage Tank	1-A*	298	333	110	960				
Containment Structure	1-B	652	765	112	10000	612	112	-5	3000
Control Building	1-B	754	1002	13	28200	836	13	-5	790
Diesel Genrator Building	1-B	896	1050	-33	13200				
Fuel Oil Storage Tanks & Pump House	1-B	990	1104	-46	6900				
Fuel Storage Area	1-B	554	660	-5	8300				
Auxiliary Feedwater Storage Tank	1-B	755	790	110	960				
Containment Structure	2-A	652	765	112	10000	612	112	-5	3000
Control Building	2-A	386	600	13	28200				
Diesel Generator Building	2-A	524	683	-33	13200				
Fuel Oil Storage Tanks & Pump House	2-A	651	777	-46	6900				
Fuel Storage Area	2-A	754	862	-5	8300				
Auxiliary Feedwater Storage Tank	2-A	571	606	110	950				

*Distances and areas are the same for a missile strike on unit 2 from turbine B as those for a strike on unit 1 from turbine A.

**Refer to Fig.10.2-2 for definition of r and y. The subscripts min and max refer to minimum and maximum distance respectively.

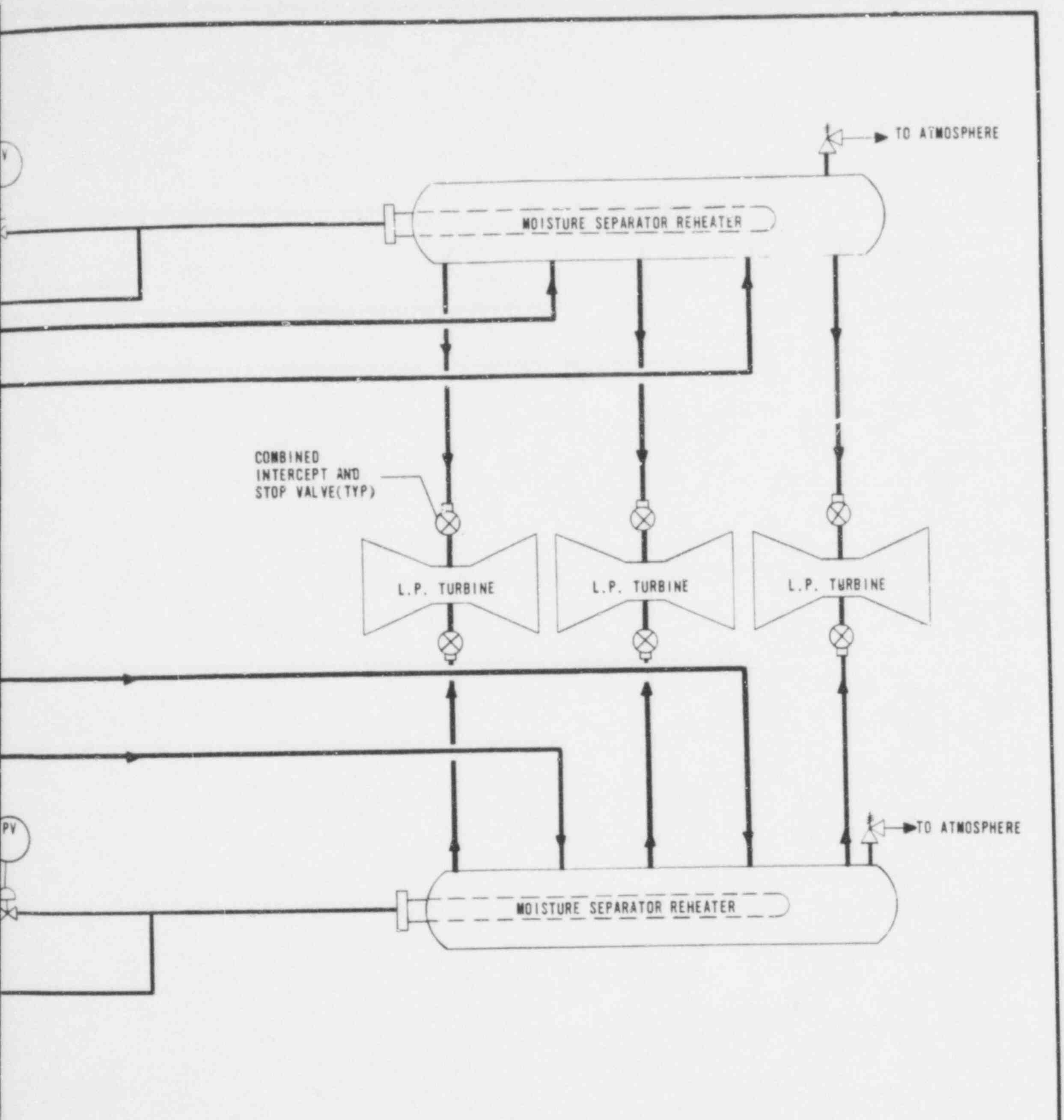

FIG. 10.2-1

TYPICAL TURBINE STEAM SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

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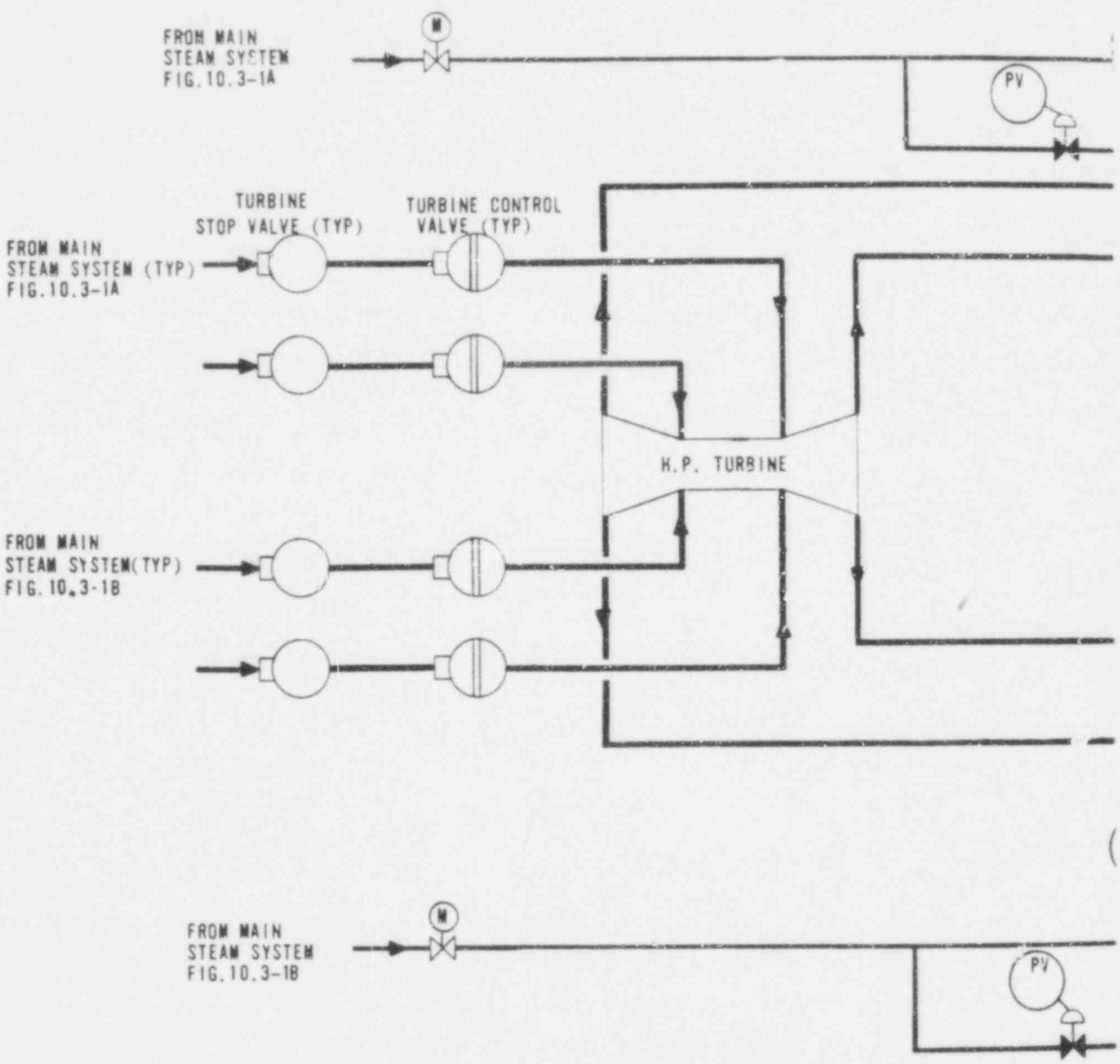

NOTE:
1. THIS SYSTEM IS NON-NUCLEAR SAFETY CLASS (NNS), LOCATED IN TURBINE BUILDING.

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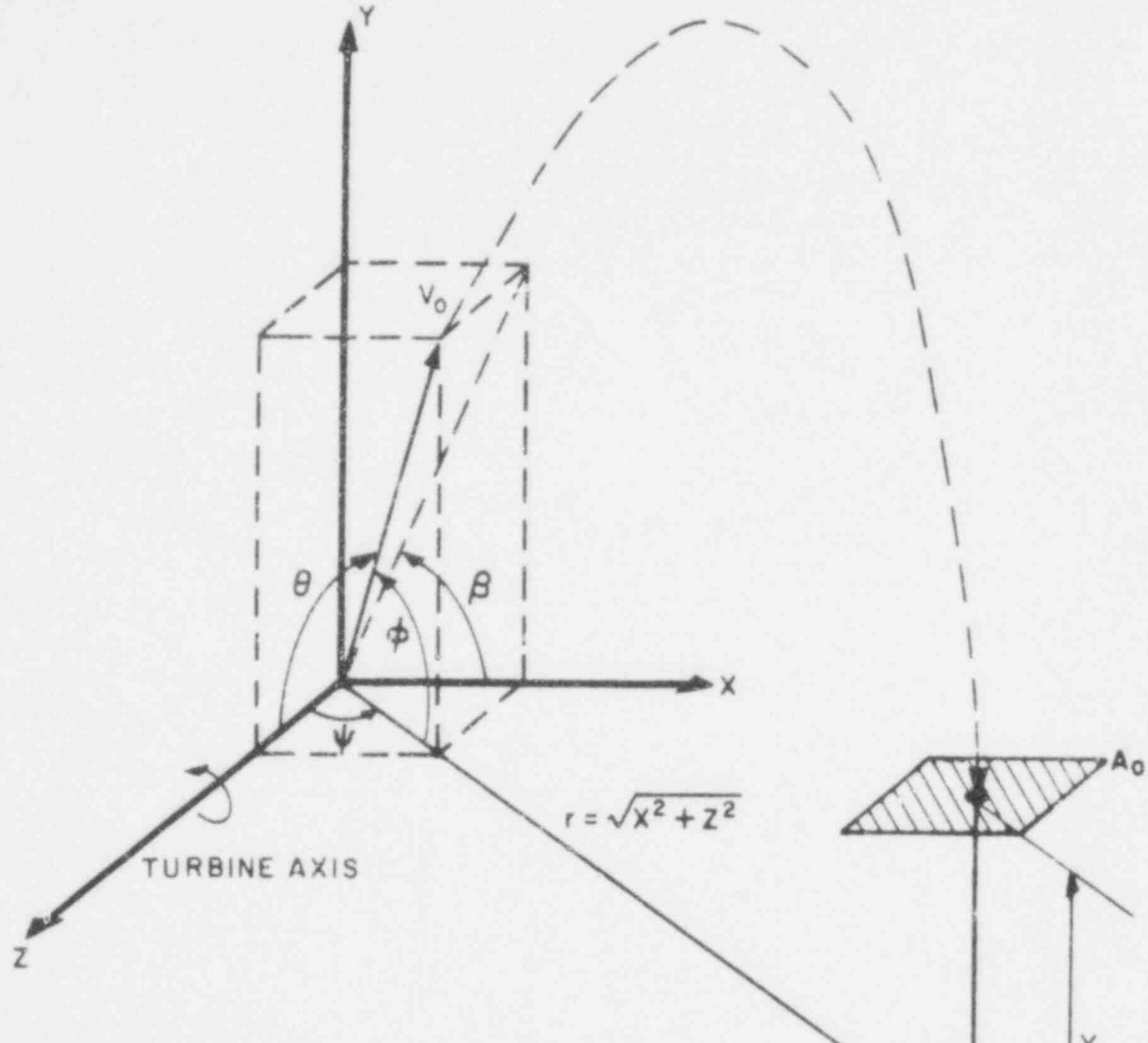

$-\pi \leq \psi \leq \pi$

$-\pi/2 \leq \phi \leq \pi/2$

$0 \leq \beta \leq 2\pi$

$\pi/2 - \delta \leq \theta \leq \pi/2 + \delta_2$

FIG. 10.2-2

TURBINE MISSILE REFERENCE SYSTEM

PWR STANDARD PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

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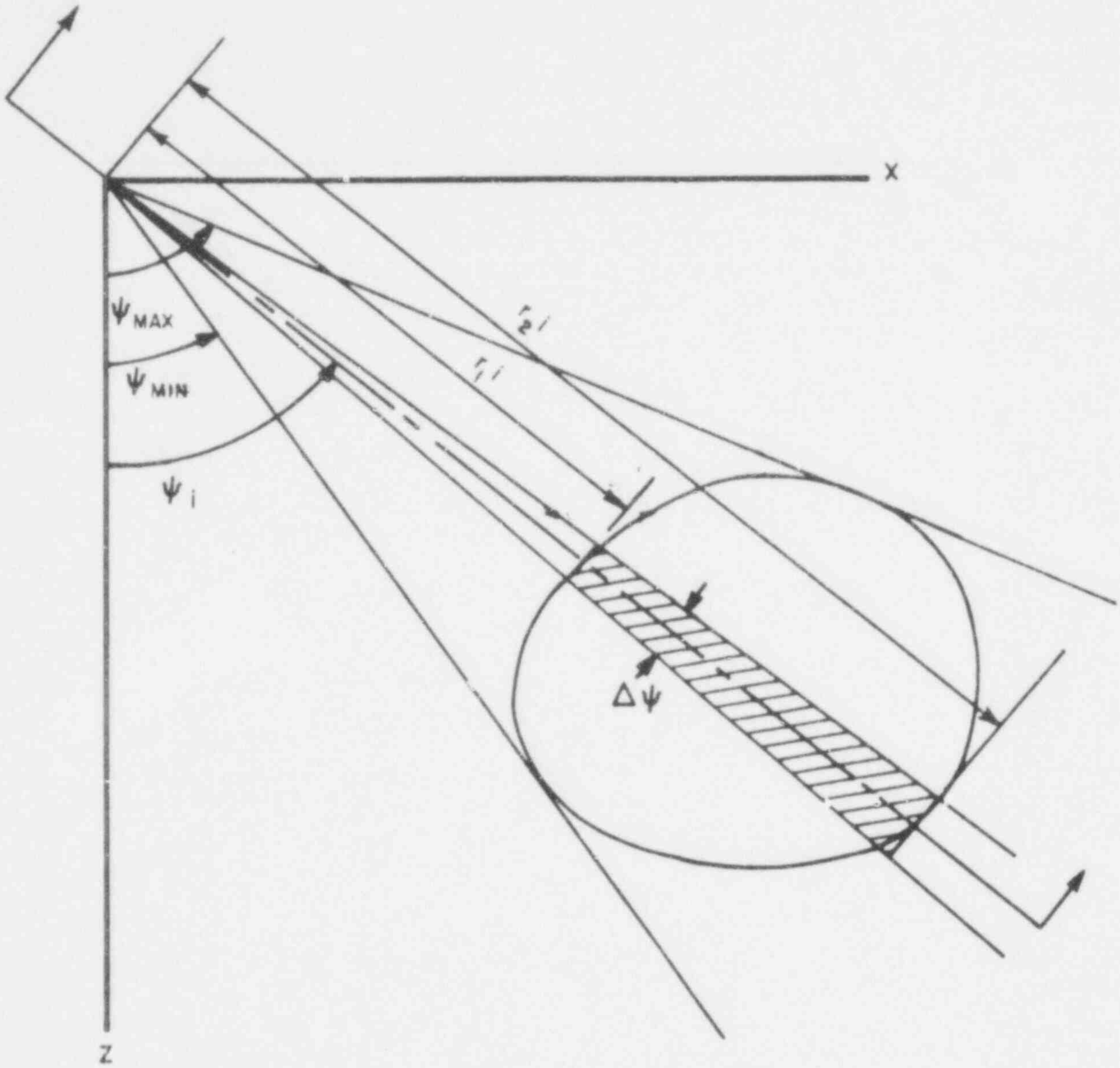

FIG. 10.2-3

TOP VIEW OF IDEALIZED TARGET

PWR STANDARD PLANT
SAFETY ANALYSIS REPORT
SWESSAR - P1

668 102

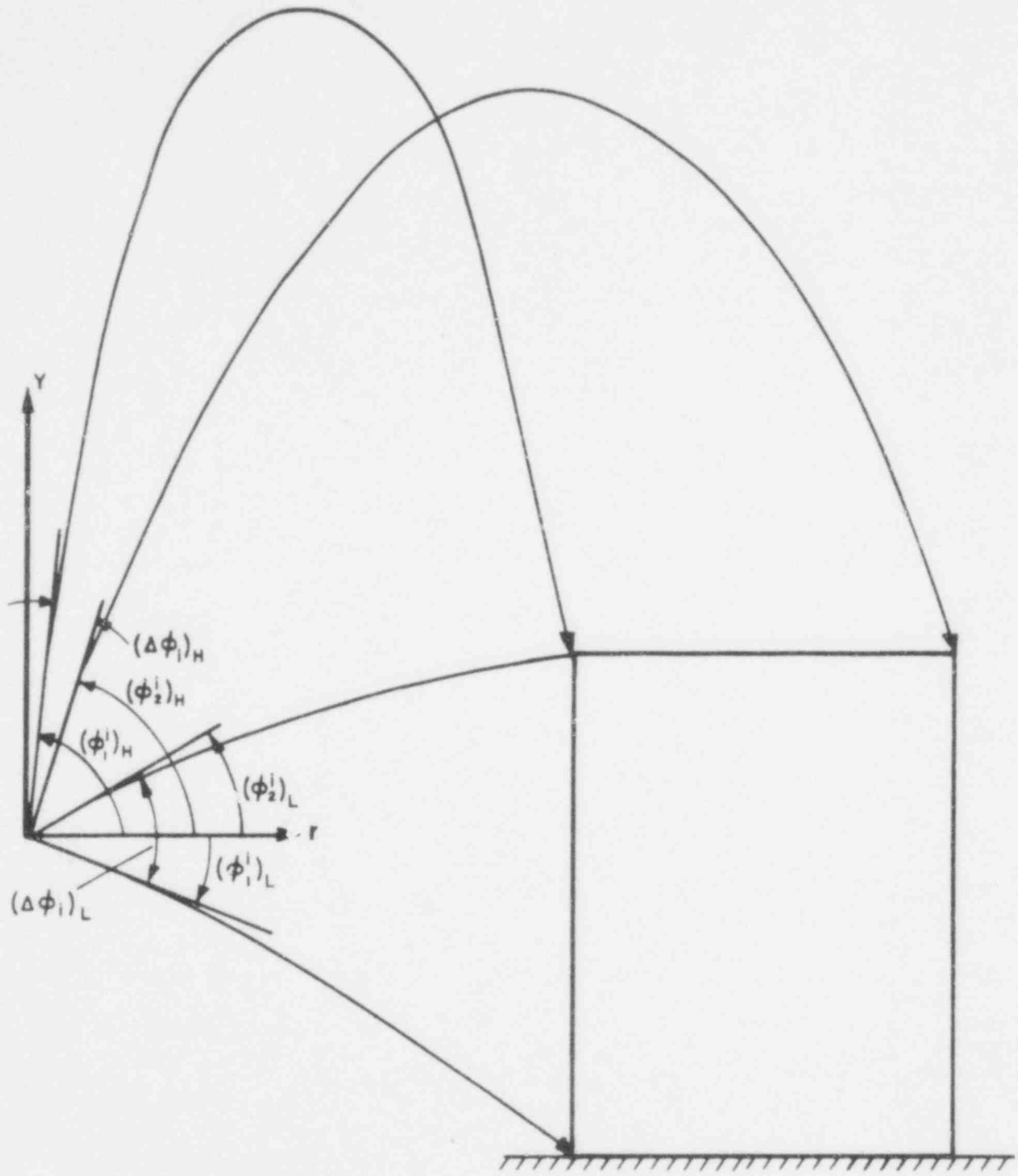

FIG. 10.2-4
SIDE VIEW OF IDEALIZED TARGET
PWR STANDARD PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

668 103

10.3

10.3 MAIN STEAM SYSTEM

The function of the main steam system is to transport steam from the steam generators in the reactor coolant system (Chapter 5) to the turbine-generator (Section 10.2).

The main steam system is shown in Fig. 10.3-1, 1A, and 1B.

10.3.1 Design Bases

The design bases for the main steam system are:

1. Those portions of the main steam system extending from the steam generators up to and including the outermost containment isolation valves are safety related and Seismic Category I, and are designated Safety Class 2.

2. The piping in the steam supply line to the auxiliary feedwater pump turbine from the motor-operated valves up to and including the turbine is also safety related and Seismic Category I, and is designated Safety Class 3.

3. The safety related portions of the main steam system are designed in accordance with ASME III, Code Class 2 (for the Safety Class 2 portions of the system) and in accordance with ASME III, Code Class 3 (for Safety Class 3 portions of the system); see Section 3.9.2 for system analysis. 33

4. The balance of the main steam system is not safety related.

5. The nonsafety related portions of the main steam system are designed in accordance with ANSI B31.1. 33

6. The following valves are considered containment isolation valves:

   Main steam isolation valves

   Main steam isolation valve bypass valves

   Motor operated valves at steam supply branch connections to the auxiliary feedwater pump turbine.

7. The main steam system shall be able to remove the heat generated in the steam generators at 105 percent rated main steam flow (i.e., valves wide open condition); reactor core power at rated flow equals 3,800 MWt.

8. The main steam system shall have design pressure and temperature equal to the design pressure and temperature of the steam side of the steam generators. (See Table 10.3-1 for actual design conditions.)

9. The main steam system design shall be such that, during normal operation, the maximum out-of-balance pressure between one steam generator and any other is as specified in Table 10.3-1.

10. The main steam system design shall ensure a supply of steam to the turbine driven auxiliary feedwater pump (Section 10.4.10) under all accident conditions which require the turbine driven pump to be in service.

11. The main steam system design shall prevent the uncontrolled blowdown of more than one steam generator following a main steam pipe break accident.

10.3.2 Description

Principal design and performance characteristics of the main steam system and its principal components are summarized in Table 10.3-1.

Steam from the steam generators flows through carbon steel pipes, through a main steam isolation valve in each main steam line, to the main steam manifold. Steam from the manifold flows through the main steam turbine stop and control valves before entering the high pressure turbine. Because of the superheated steam temperatures inherent to the B&W NSSS, two additional manifolds
19 are required upstream of the primary manifold to ensure adequate mixing and equalized temperatures at the turbine inlets.

The containment penetrations for the main steam piping are located in the main steam and feedwater valve areas of the annulus building. Two main steam pipes pass through each of the two areas, which are located 180 degrees apart. The main steam pipes are routed around the outside of the containment structure so that they are isolated from safety related systems and components. The piping is restrained from whipping following a pipe break.

The turbine steam system is discussed in Section 10.2.

Safety valves and atmospheric dump valves are provided for each steam generator immediately outside the containment structure upstream of the main steam isolation valves.

Steam piping connects the auxiliary feedwater pump turbine steam supply header to one or two main steam pipes (depending on NSSS Vendor) upstream of the main steam isolation valves. This piping and the header provide steam to drive the auxiliary feedwater pump turbine. The first valve on the turbine steam supply line is a motor operated stop-check valve when the turbine requires steam from two steam generators. When steam is only required from one steam generator, the valve is a motor operated gate valve. Two solenoid air operated control valves, mounted in parallel, admit steam to the auxiliary feedwater pump turbine.

The main steam isolation valves, safety valves, atmospheric dump valves, and supply piping up to and including the turbine-driven auxiliary feedwater pump are housed within the annulus building.

Pipes from the main steam manifold supply steam to the main feedwater pump turbines, the single stage reheat of the moisture separator reheaters (Section 10.2), the turbine gland sealing system (Section 10.4.3), the turbine bypass system (Section 10.4.4), and the auxiliary steam system (Section 10.4.12).

10.3.3 Safety Evaluation

If a steam pipe breaks downstream of the main steam isolation valves, closure of these valves stops the flow of steam from the steam generators to the ruptured pipe section. Maximum closing time for the main steam isolation valves is as specified by the NSSS Vendor (see Table 10.3-1).

Valve closure checks the sudden release of main steam, thereby preventing rapid cooling of the reactor coolant system (Chapter 5). Valve closure does not limit the supply of steam to the auxiliary feedwater pump turbine.

If a steam pipe breaks between a main steam isolation valve and a steam generator, the affected steam generator continues to blow down. The main steam isolation valves prevent blowdown from another steam generator. This, the most serious postulated steam pipe break accident, is discussed in Section 15.1.14.

The main steam system is capable of removing heat from the reactor coolant system following sudden load rejection or trip of the turbine-generator by automatically bypassing main steam to the condenser through the turbine bypass system (Section 10.4.4), or by relieving to the atmosphere through the main steam safety valves or main steam atmospheric dump valves if the turbine bypass system is unavailable. Removal of the reactor coolant system sensible heat limits the main steam pressure at or below the design pressure. The main steam safety and the safety related main steam atmospheric dump valves have flow capacities stated in Table 10.3-1.

Under certain conditions, the main steam atmospheric dump valves release reactor coolant system sensible and core decay heat to the atmosphere when the steam generators are in service. These valves operate during periods when the turbine-generator or condenser is not in service, core physics testing, turbine trip on loss of condenser vacuum, or loss of electric power. The main steam atmospheric dump valves preclude operation of the safety valves during normal operating transients by keeping the main steam pressure below the safety valve setpoints. The main steam atmospheric dump valves are not required for safety of the plant 30 because the steam generators are protected by the main steam safety valves.

In the event of a main steam pipe rupture upstream of the main steam isolation valves, the motor-operated stop-check valves in the steam supply piping to the auxiliary feedwater pump turbine prevent reverse flow of steam. This ensures that the steam supply piping to the auxiliary feedwater pump turbine inlet is continuously under steam generator pressure following a main steam rupture. All operating conditions of the auxiliary feedwater pump turbine are indicated in the control room to enable the operator to adjust the feedwater flow. Information on the auxiliary feedwater pumps is contained in Sections 10.4.10 and 16.4.8.

If the steam supply piping to the auxiliary feedwater pump turbine ruptures, the turbine driven pump is rendered inoperable. Depending on the NSSS Vendor, either one or two steam generators blow down through the ruptured pipe until the motor-operated valves in the turbine steam supply line can be closed. Flow elements upstream of the motor operated valves and interlocked with the steam admission valves are provided to detect and alarm flow into the line at any time other than when the steam admission valves are open. This flow is indicative of a pipe rupture in the steam supply line. For any pipe rupture in the turbine steam supply piping, the break area for a double ended rupture (i.e., steam flowing from both ends of the broken pipe) is less than the maximum main steam safety valve orifice size. Since the NSSS designs can accommodate the blowdown resulting from a safety valve stuck open, they can also accommodate the lesser blowdown resulting from this pipe break without excessive rapid cooling of the core. For this reason, operator action time is inconsequential, and the valves can be assumed to be manually closed after 30 minutes.

The stop-check valves, when provided, are designed in accordance with ASME III requirements. Included in the conditions of design are consideration of operating loads, earthquake loads, and dynamic system loads resulting from postulated pipe rupture, as further described in Section 3.9.2.

Valve closure due to normal, inadvertent, or spurious action is controlled and therefore results in negligible accumulated fatigue damage. The valve plug assembly is held open by system pressure, and closure is achieved through valve operator (motor) movement of the plug against system pressure.

Valve closure dynamics of the stop-check valve following postulated rupture of the piping between the steam generator and the main steam isolation valve are developed based on the methods outlined in Reference 1. Maintenance of structural integrity of the valve pressure boundary and pressure retaining parts is demonstrated for the conditions defined.

Guide 1.75 (Section 3A.1-1.75) for redundant safety related circuits.

Two parallel redundant solenoid air operated control valves automatically start the auxiliary feedwater pump turbine upon receipt of a starting signal as described in Section 7.3.3.8. Local and remote pressure indications monitor operation of the auxiliary feedwater pump turbine.

The safety related atmospheric dump valves are provided with electrohydraulic operators powered from a Class IE power supply
30 to ensure operability when required to effect controlled cooldown of the plant. The safety related atmospheric dump valves are normally under automatic control from steam generator pressure (W, W-3S, and B&W) or are manually controlled from the control room (W, W-3S, C-E, and B&W).

Pressure signals from the main steam manifold are supplied to the steam dump and feedwater pump turbine control.

A flow element is located in each auxiliary feedwater pump turbine steam supply line immediately upstream of the first valve in the supply line. The flow element is interlocked with the steam admission valve to the turbine and initiates an alarm in the control room upon detection of flow when the steam admission valves are closed.

10.3.7 Interface Requirements

Interface information applicable to the main steam system, as presented in the respective NSSS Vendor's SARs, is discussed in Table 10.1-2.

Reference for Section 10.3

1. Gwinn, J.M. "Swing-Check Valves under Trip Loads," ASME Publication 74-PVP-51.

The main steam system piping supports are analyzed for the more severe condition of either turbine trip reaction or seismic forces up to and including the main steam manifold. The main steam system piping supports from the main steam manifold to the turbine are analyzed for turbine trip forces only. The main steam system is also stress analyzed for the forces and moments which result from thermal growth. The main steam system piping within the containment structure is reviewed for possible pipe rupture. Sufficient supports and guides are provided to prevent damage to the containment liner and adjacent piping, controls, or electrical cables.

10.3.4 Inspection and Testing Requirements

All safety class valves require testing as specified in Section 16.4.2. The main steam isolation valves will be inservice tested for partial closure. In addition, containment isolation valves require testing as specified in Section 16.4.4.

The auxiliary feedwater pump turbine air operated control valves will be tested each month. Code Class 2 and 3 piping within the jurisdiction of ASME III will be inspected and tested according to Articles NC-5000 and 6000, respectively, of that code. Piping within the jurisdiction of ANSI B31.1 will be inspected and tested in accordance with paragraphs 136 and 137 of that code.

Inservice inspection will be performed as discussed in Section 16.4.2.

10.3.5 Water Chemistry

Secondary side water chemistry is discussed in Section 10.4.7.

The radioactive iodine partition coefficients for the steam generators are given in in Table 11.1.2-1.

10.3.6 Instrumentation Applications

The NSSS Vendor supplies the main steam flow, pressure, and steam generator level instrumentation for protection and control. Descriptions of the feedwater control, steam generator level, steam piping break protection, and engineered safety feature inputs are supplied by the NSSS Vendor (Chapter 7).

Redundant steam line isolation (SLI) signals ensure closure of each main steam isolation valve. A bypass valve around each main steam isolation valve also closes upon receipt of an SLI signal.

Each SLI valve has two solenoid valves in series. Each solenoid valve is powered from a separate source. These solenoid valves are physically separated and supplied by redundant electric power sources to meet the requirements of IEEE 308 and Regulatory

TABLE 10.3-1

MAIN STEAM SYSTEM
PRINCIPAL DESIGN AND PERFORMANCE CHARACTERISTICS

Item	Design and Performance Characteristics			
Main Steam System	B&W	C-E	W-41	W-3S
No-load pressure, psia	1,200	1,170	1,198	1,107
Rated Power Conditions				
pressure, psia	-	1,070	1,100	1,000
temperature, F	-	553	556	545
flow, lb/hr x 10^6	-	17.18	16.96	15.14
Turbine Maximum Capability Conditions				
pressure, psia	1,060	1,043	1,072	1,000
temperature, F	586.7	550	553	545
flow, lb/hr x 10^6	16.7	17.46	17.23	15.82
Design Conditions				
pressure, psia	1,250	1,270	1,300	1,200
temperature, F	630	575	600	600
Maximum out-of-balance pressure between one steam generator and any other, psi	5	No requirement	10	10 (35)
Main Steam Isolation Valves				
Number	4 (one on each main steam line)	4 (one on each main steam line)	4 (one on each main steam line)	4 (one on each main steam line)
Closing time, sec (max)	5 (after receipt of closure signal)	5 (after receipt of closure signal)	5 (after receipt of closure signal)	5 (after receipt of closure signal)
Main Steam Safety Valves				
Number	20 (five on each main steam line)	20 (five on each main steam line)	20 (five on each main steam line)	20 (five on each main steam line)
Total relieving capacity	112 percent maximum calculated flow at set pressure plus 3 percent accumulation of 1,200 psig	$19x10^6$ lb/hr at set pressure of 1,255 psig; maximum individual capacity of $1.9x10^6$ lb/hr at 1,000 psia	105 percent maximum calculated operating flow at 110 percent design pressure	105 percent maximum calculated operating flow at 110 percent design pressure; maximum individual capacity of $1.05x10^6$ lb/hr. (35)

668 112

TABLE 10.3-1 (CONT)

Design and Performance Characteristics

Item	B&W	C-E	W-41	W-3S	
Safety Related Atmospheric Dump Valves					
Number	4 (one on each main steam line)	4 (one on each main steam line)	4 (one on each main steam line)	4 (one on each main steam line)	
Total relieving capacity	At least 7 percent maximum expected operating flow	Minimum combined capacity of 3.5×10^5 lb/hr at 350 F; maximum individual capacity of 1.9×10^6 lb/hr.	At least 10 percent maximum operating flow at no-load pressure	At least 15 percent maximum operating flow at no-load pressure; maximum individual capacity of 1.05×10^6 lb/hr.	28 28

668 113

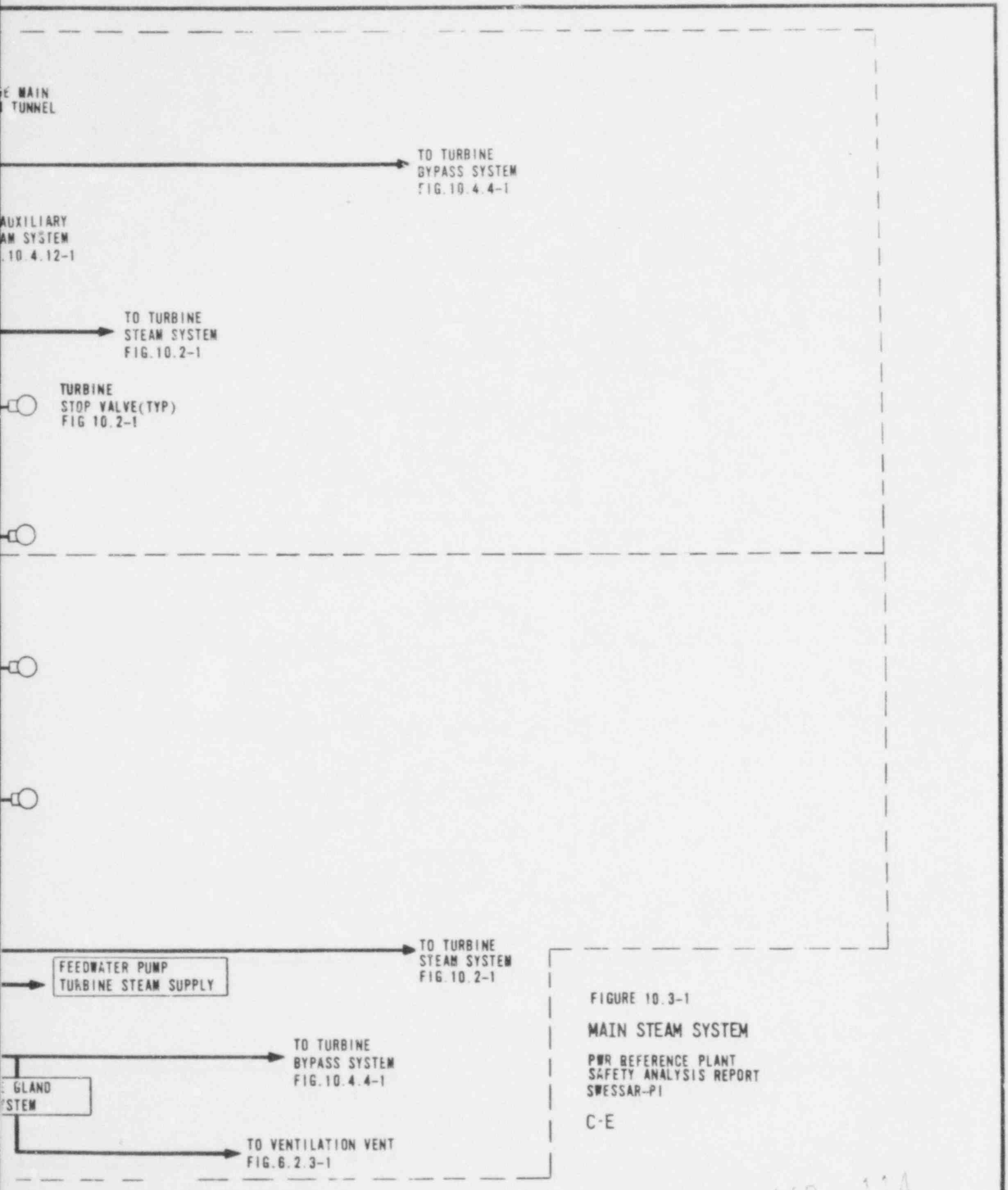

FIGURE 10.3-1

MAIN STEAM SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

C-E

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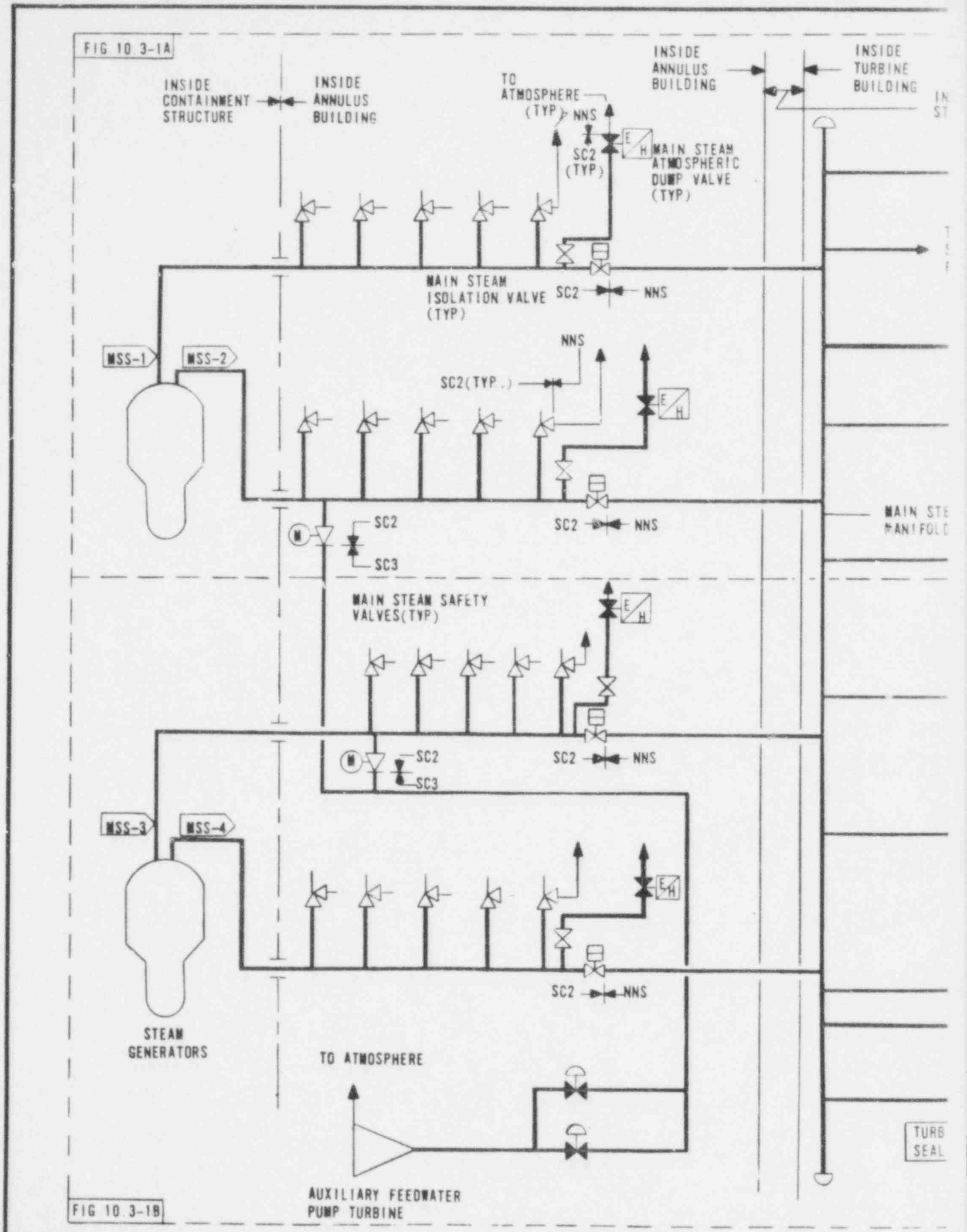

NOTES: THIS SYSTEM IS NON-NUCLEAR SAFETY CLASS (NNS) EXCEPT WHERE OTHERWISE NOTED

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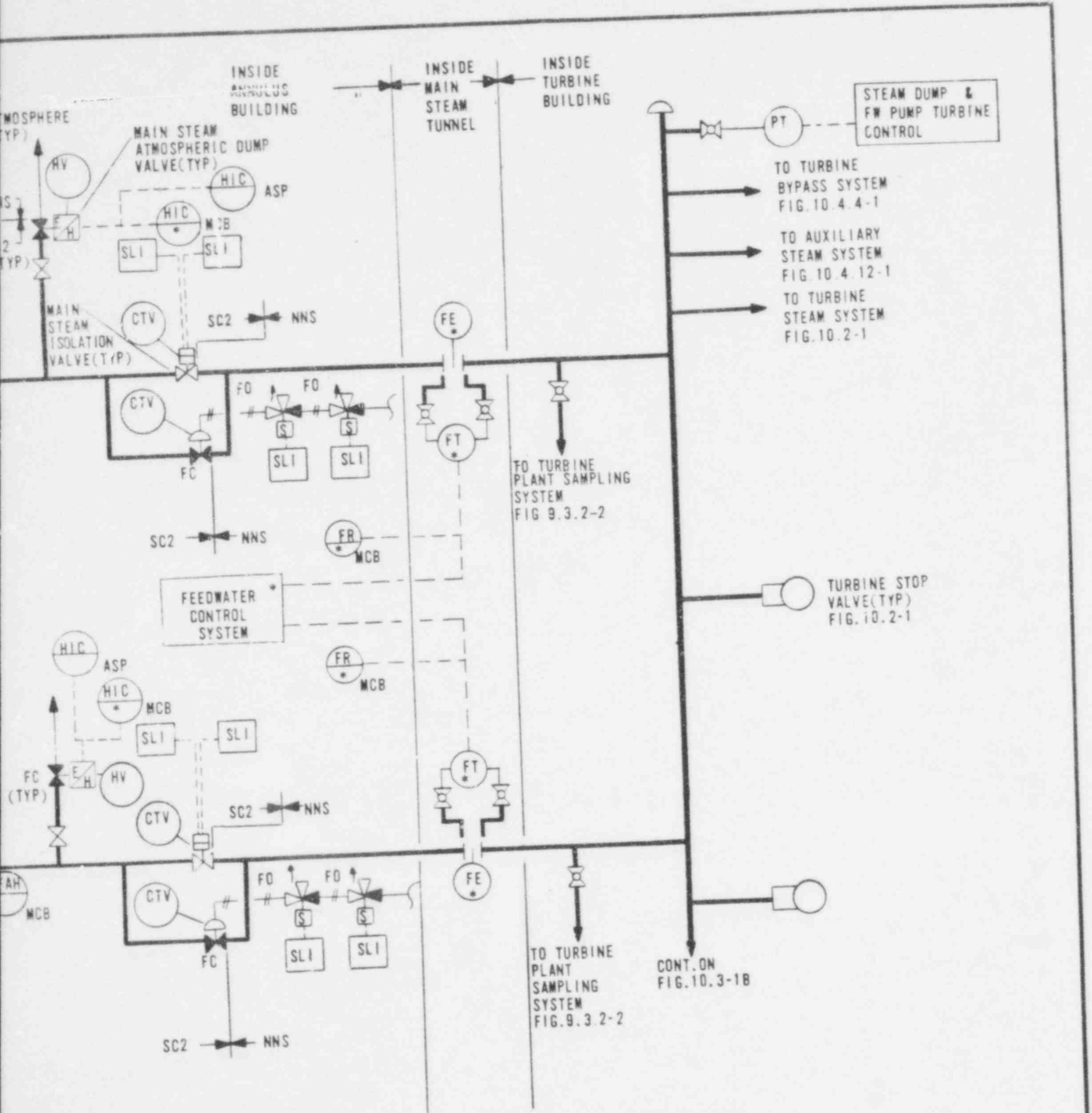
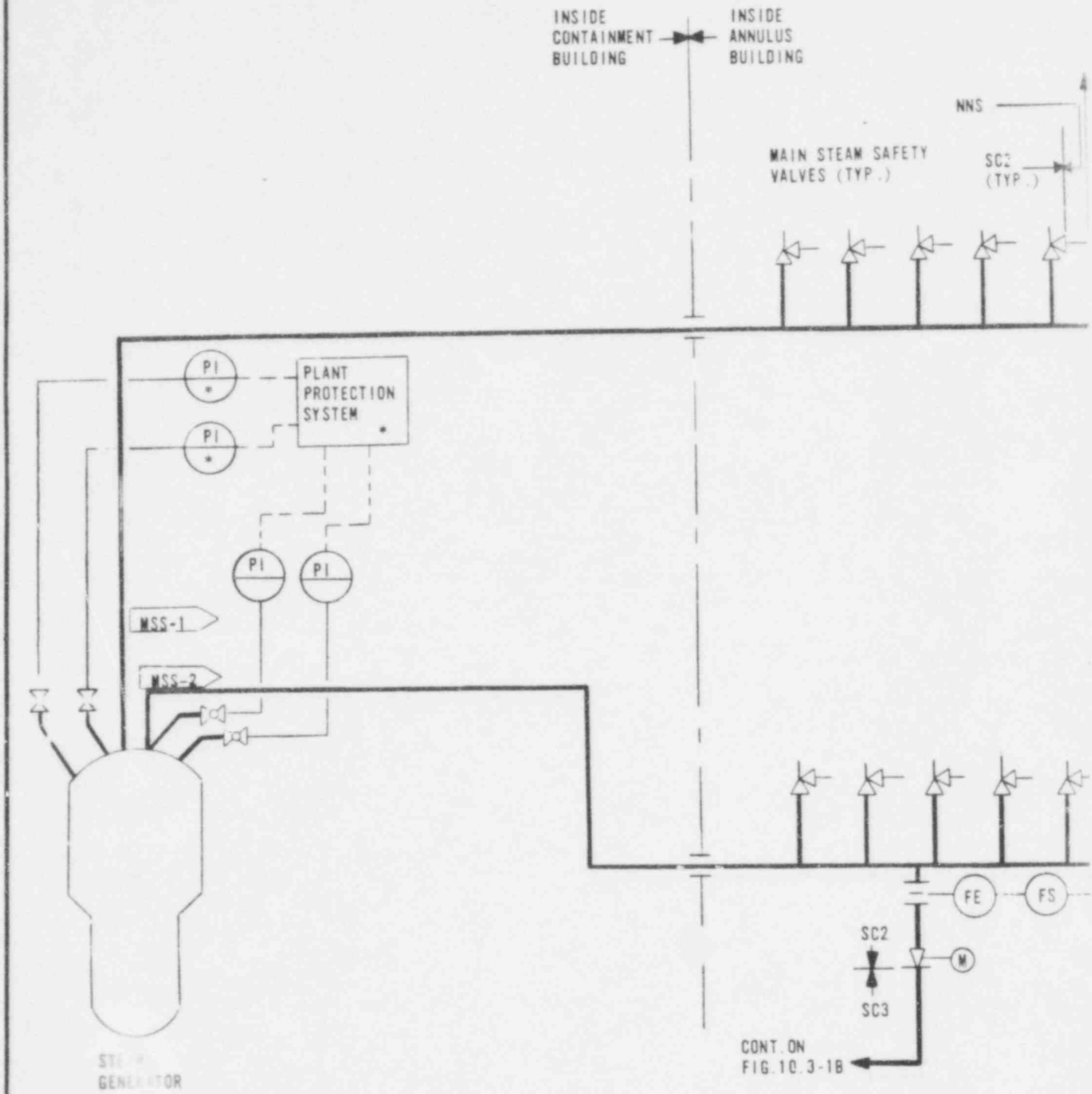


FIG.10.3-1A

MAIN STEAM SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1
C-E



NOTES:

1. THIS PORTION OF THE MAIN STEAM SYSTEM IS SAFETY CLASS 2 (SC2) EXCEPT WHERE OTHERWISE NOTED.
2. MAIN STEAM ISOLATION VALVE HAS 5 SEC. MAX. CLOSURE TIME.
3. "*" MEANS INSTRUMENT SUPPLIED BY NSSS VENDOR.

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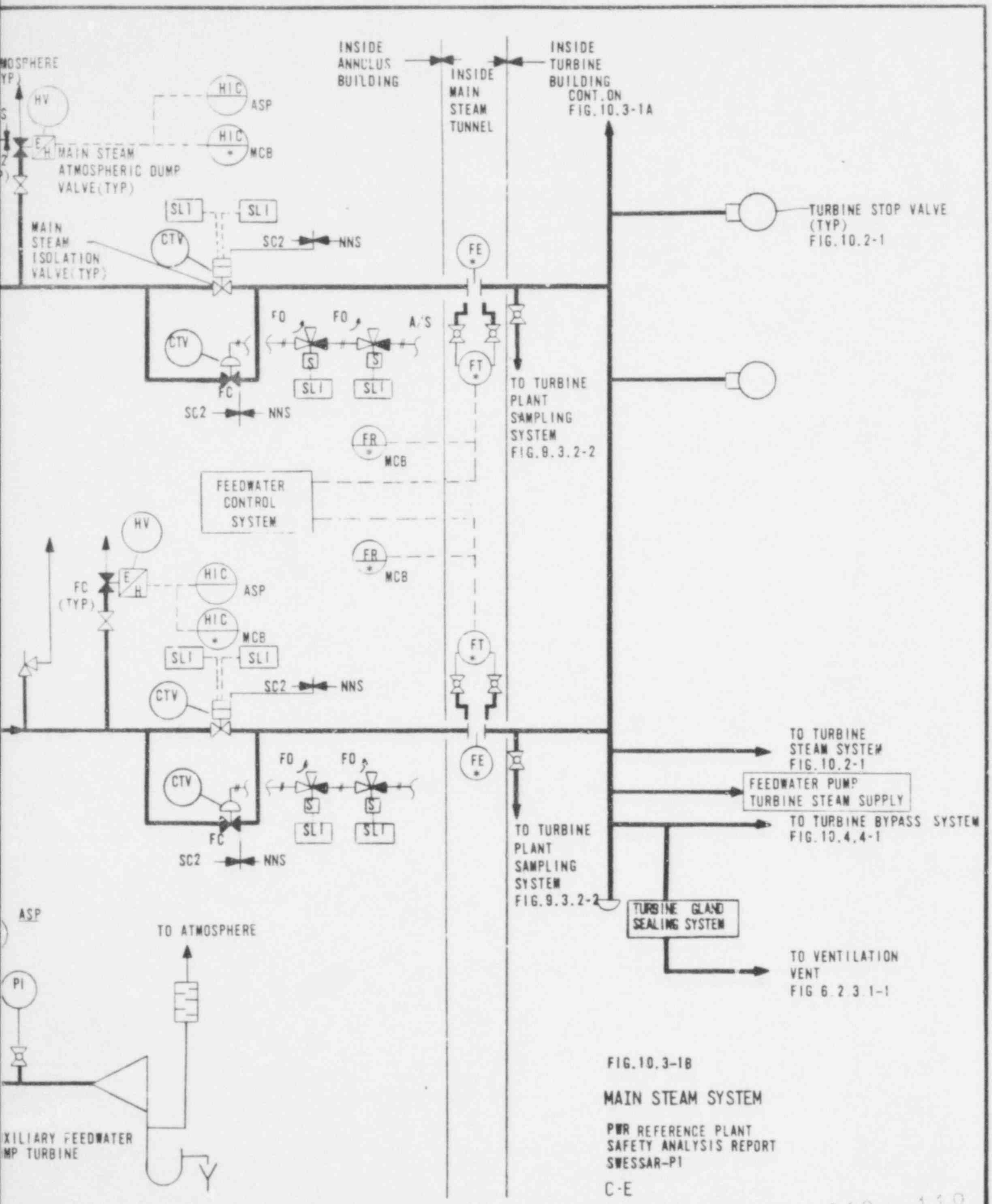


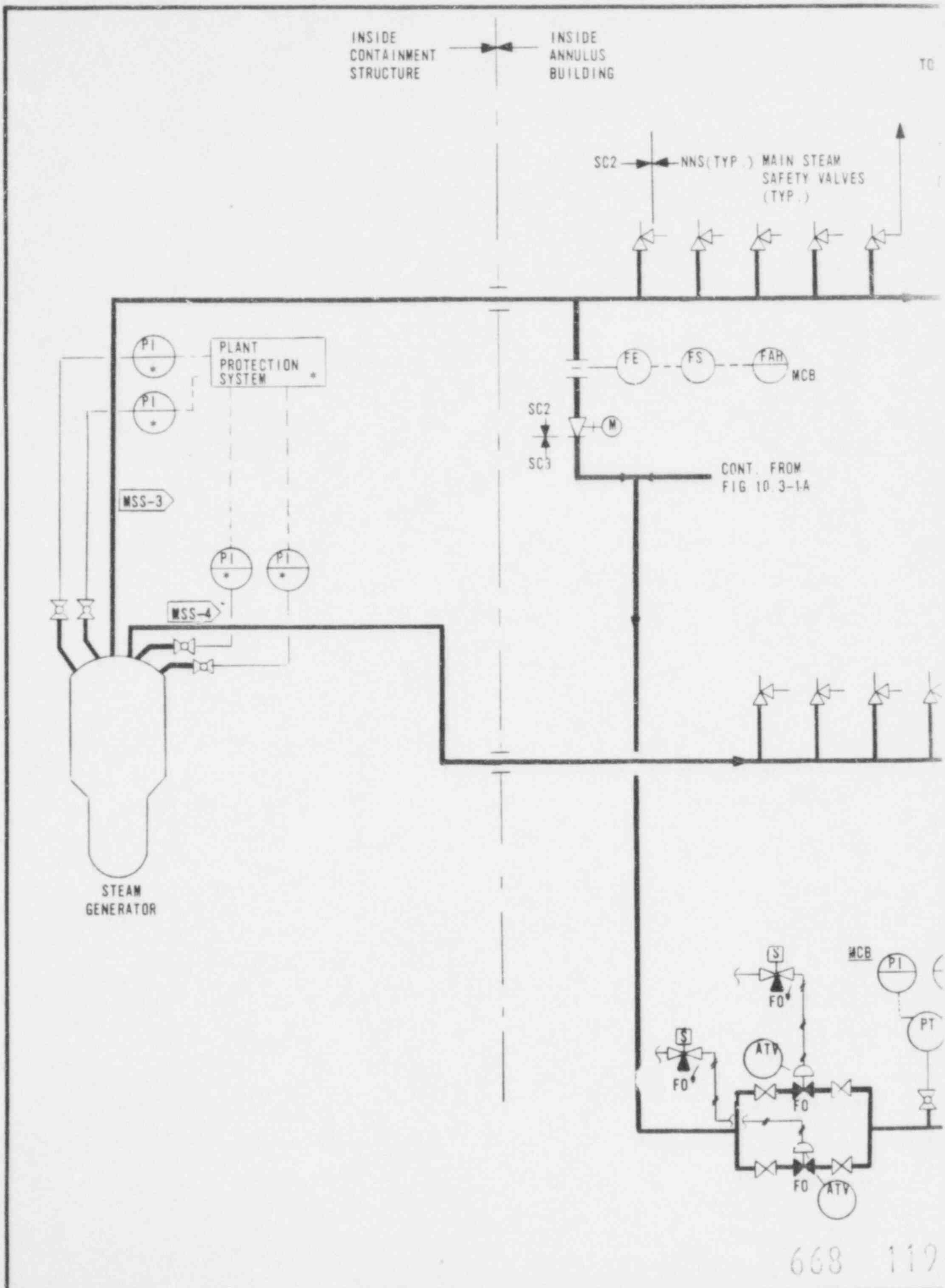
FIG. 10.3-1B

MAIN STEAM SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

C-E

668 118



INSIDE CONTAINMENT STRUCTURE
INSIDE ANNULUS BUILDING
TO
SC2
NNS(TYP.)
MAIN STEAM SAFETY VALVES (TYP.)
PI
PLANT PROTECTION SYSTEM
FE
FS
FAH
MCB
SC2
SC3
M
CONT. FROM FIG 10.3-1A
MSS-3
MSS-4
STEAM GENERATOR
MCB
PI
PT
S
FO
ATV

668 119

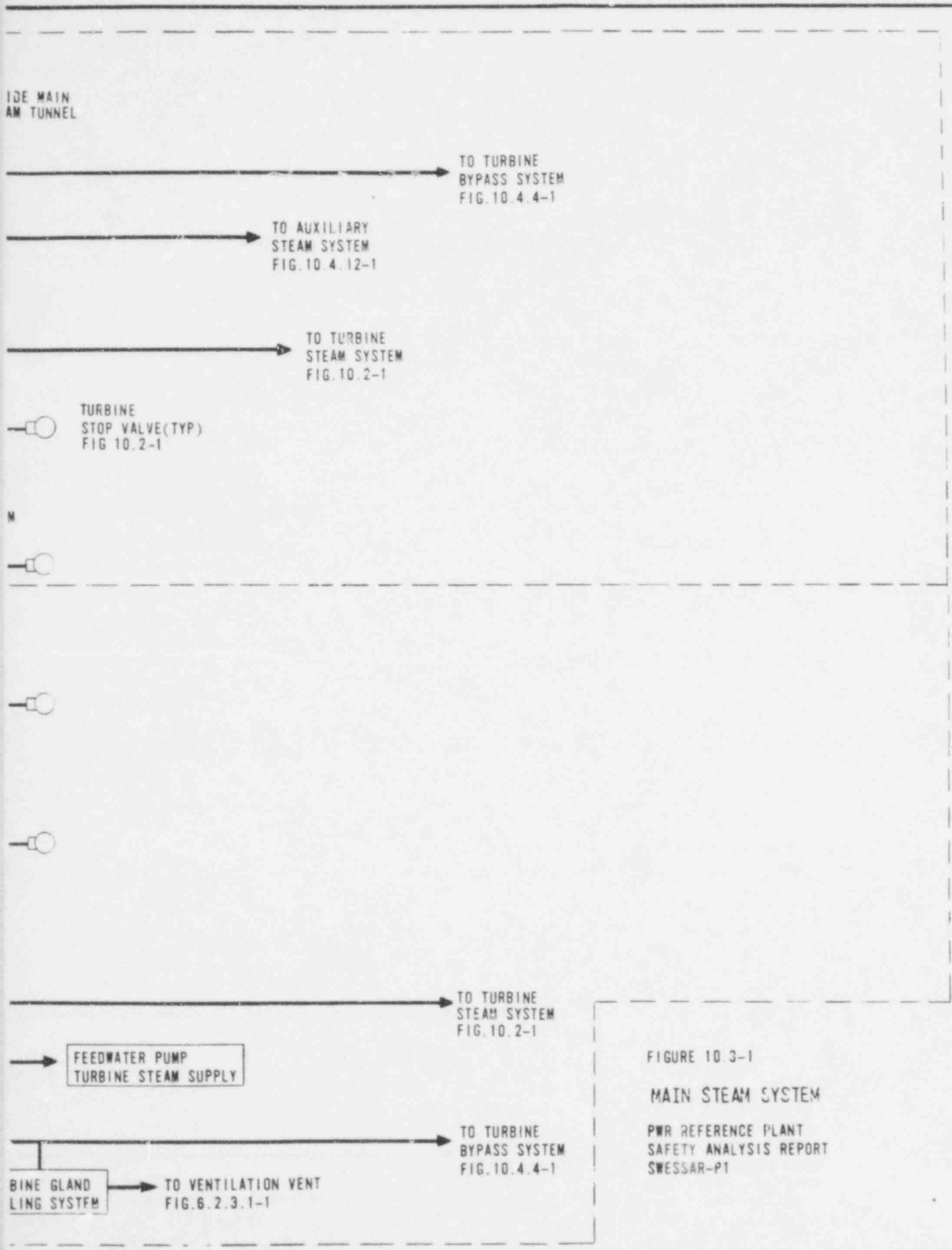


FIGURE 10.3-1

MAIN STEAM SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

W

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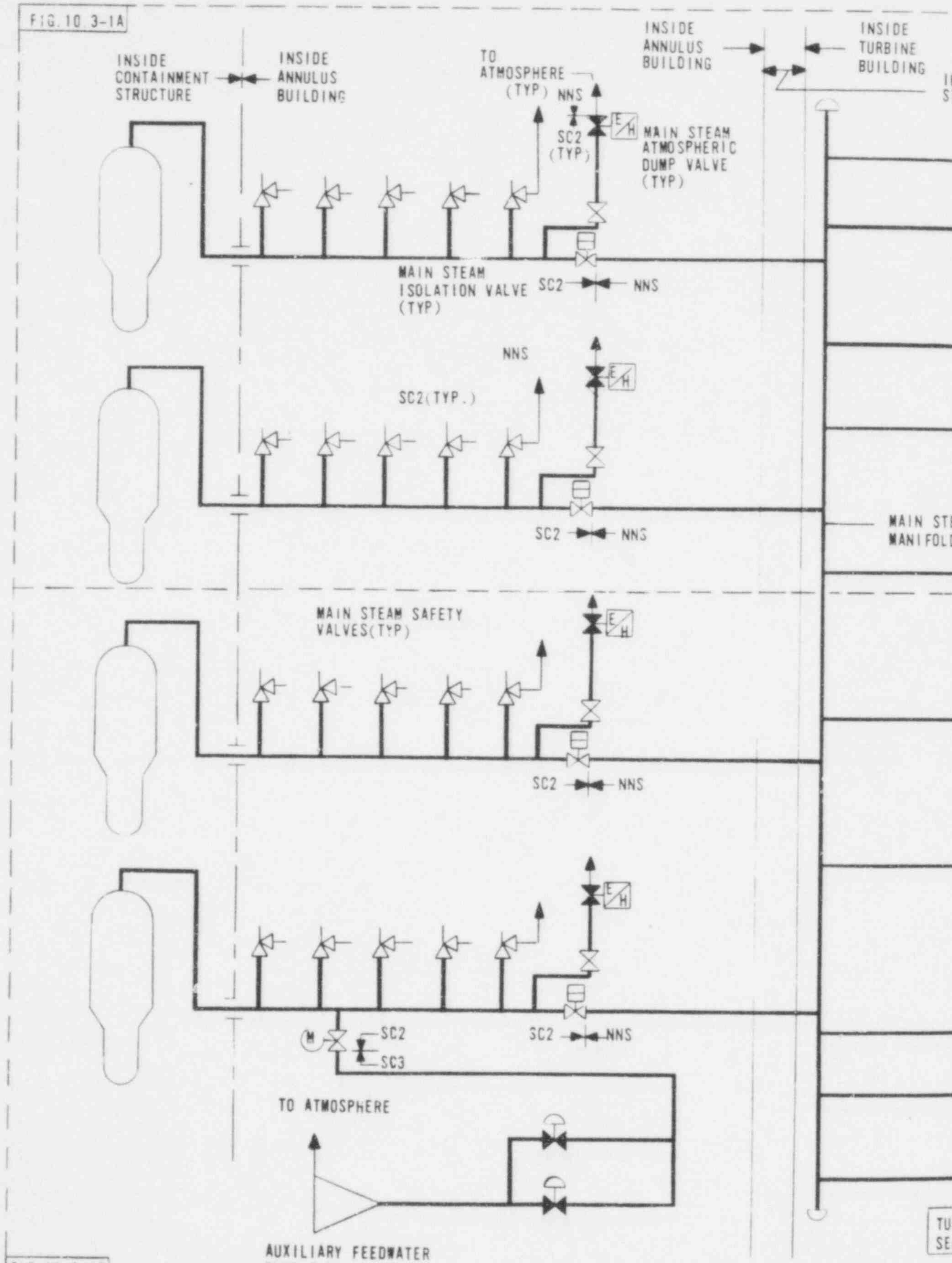
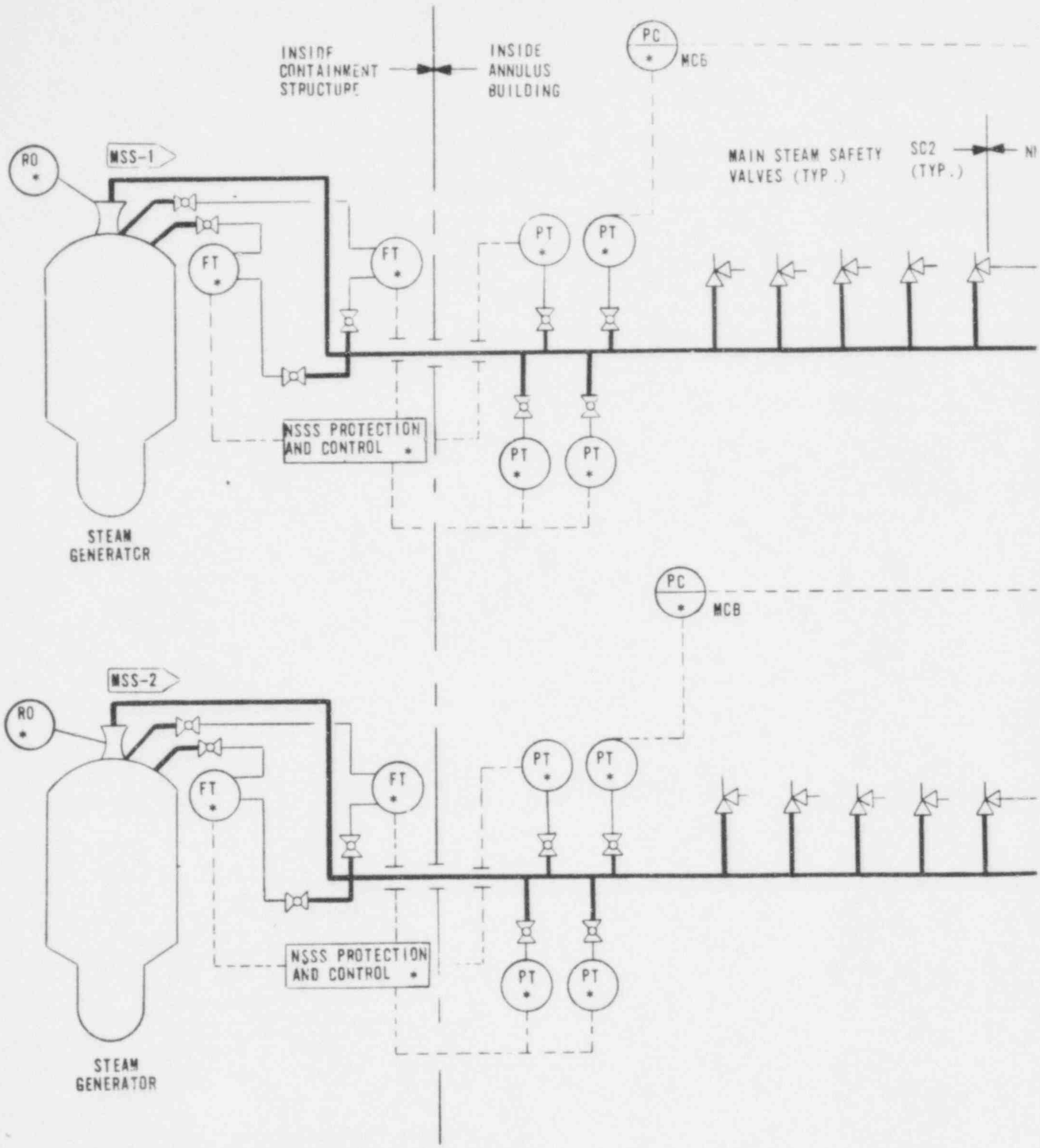


NOTES: THIS SYSTEM IS NON-NUCLEAR SAFETY CLASS (NNS) EXCEPT WHERE OTHERWISE NOTED.

668 121



NOTES:

1. THIS PORTION OF THE MAIN STEAM SYSTEM IS SAFETY CLASS 2 (SC^) EXCEPT WHERE OTHERWISE NOTED.
2. MAIN STEAM ISOLATION VALVE HAS 5 SEC. MAX. CLOSURE TIME.
3. "*" MEANS INSTRUMENTS SUPPLIED BY NSSS VENDOR.

668 122

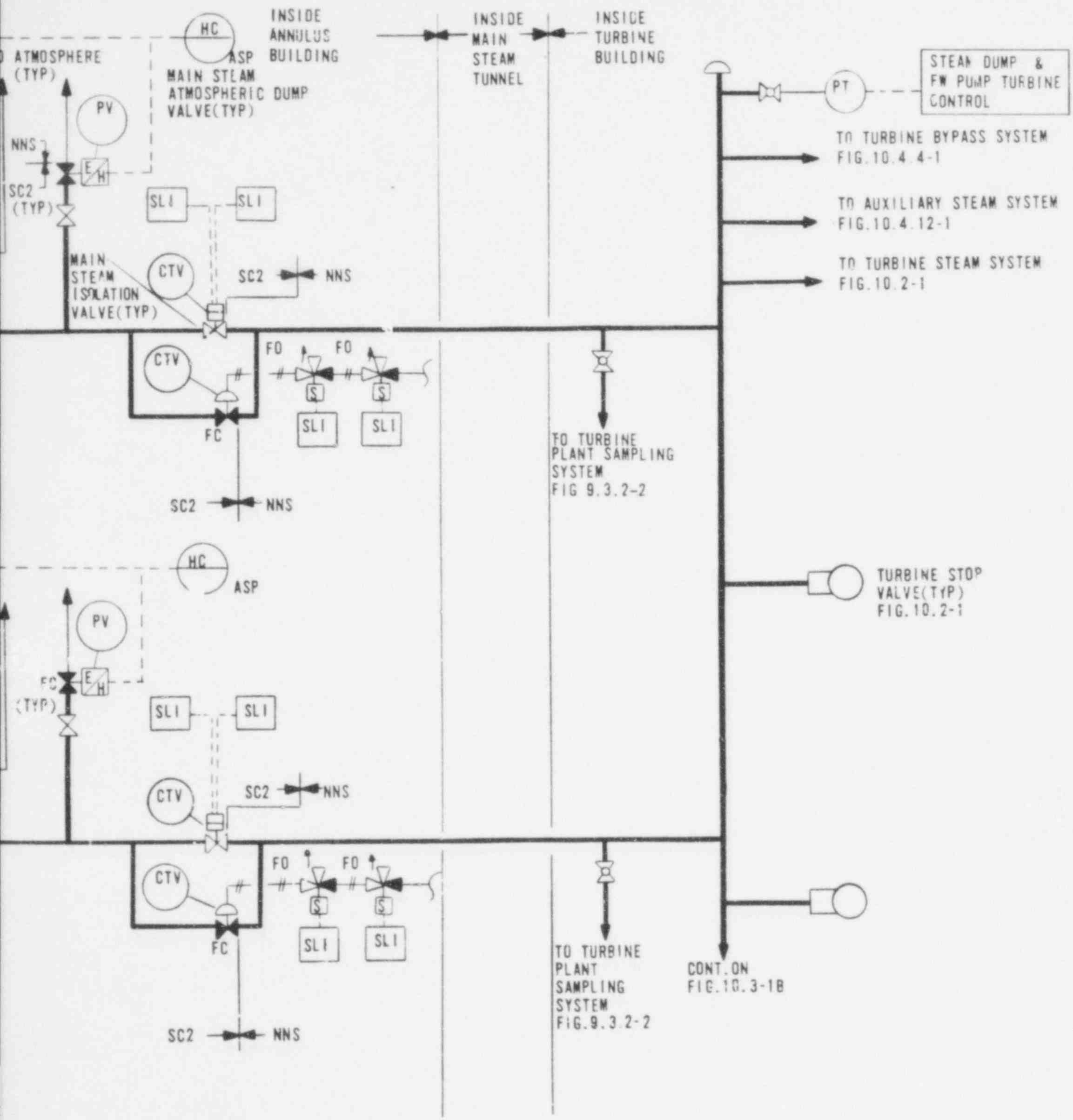


FIG.10.3-1A

MAIN STEAM SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

W 668 123

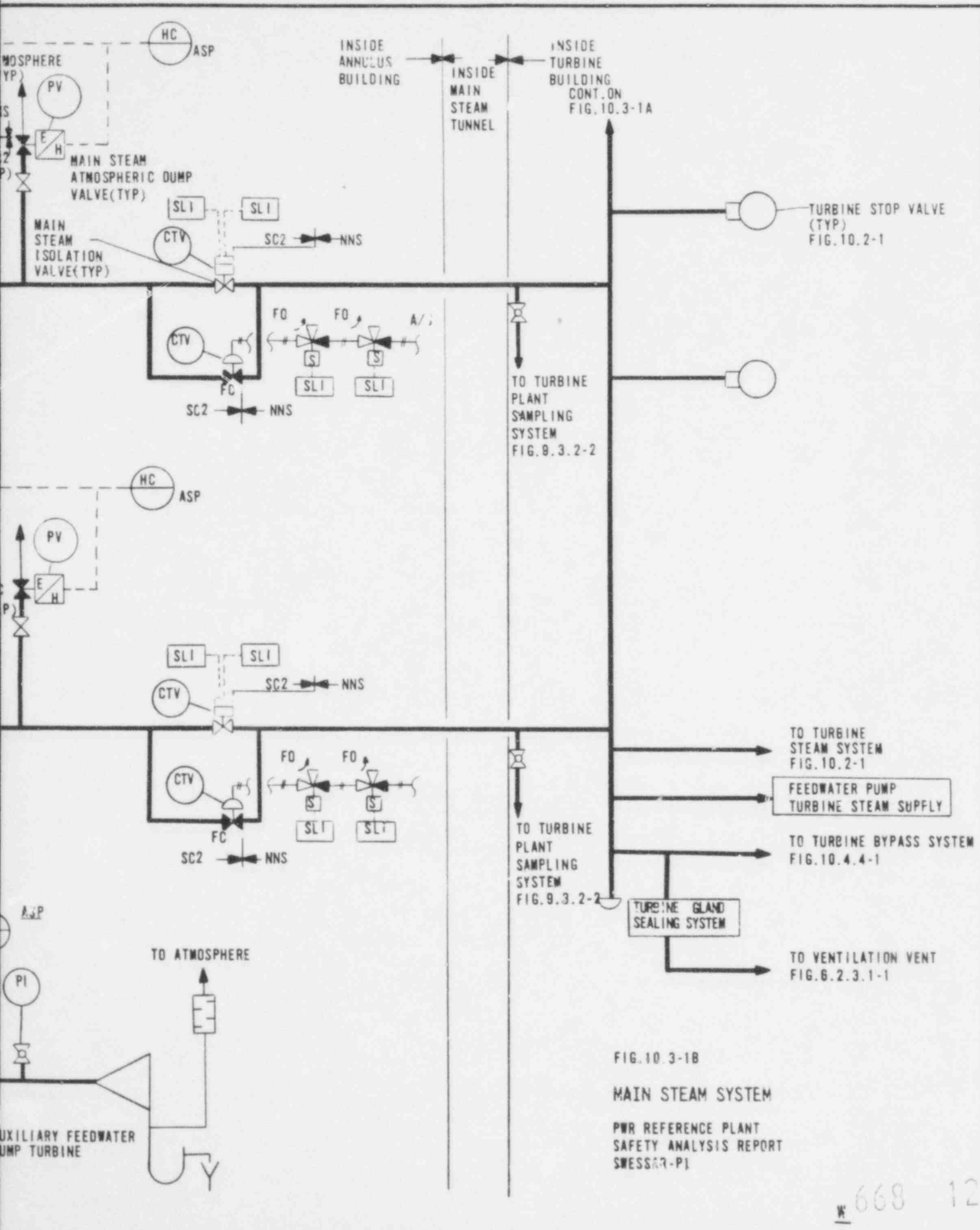
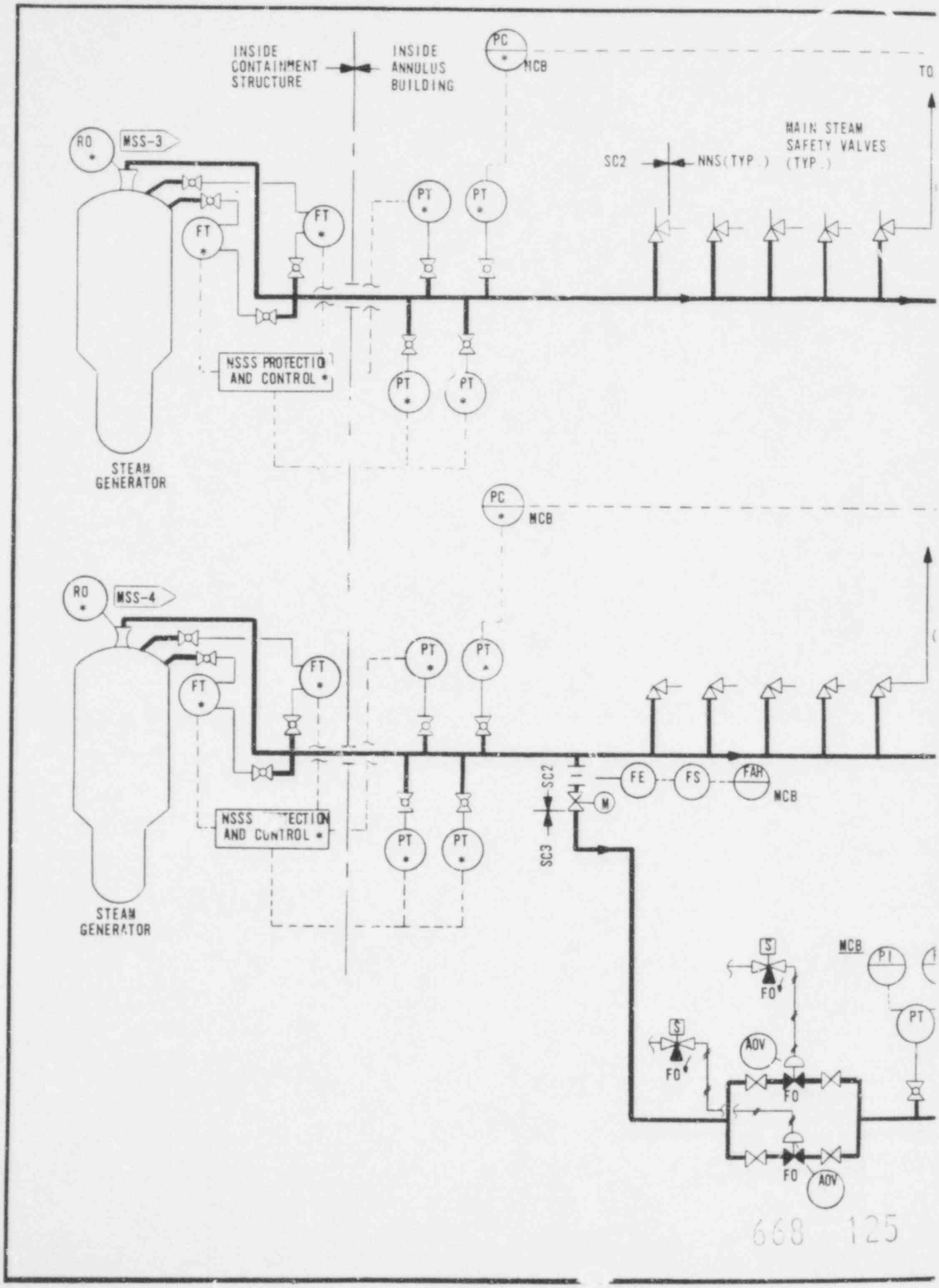


FIG. 10.3-1B

MAIN STEAM SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

668 124


INSIDE CONTAINMENT STRUCTURE
INSIDE ANNULUS BUILDING
PC
MCB
TO
RO
MSS-3
MAIN STEAM SAFETY VALVES (TYP.)
SC2
NNS(TYP.)
FT
PT
NSSS PROTECTION AND CONTROL *
STEAM GENERATOR
PC
MCB
RO
MSS-4
FT
PT
NSSS PROTECTION AND CONTROL *
SC2
SC3
M
FE
FS
FAH
MCB
STEAM GENERATOR
MCB
PI
S
FO
AOV
PT
668 125

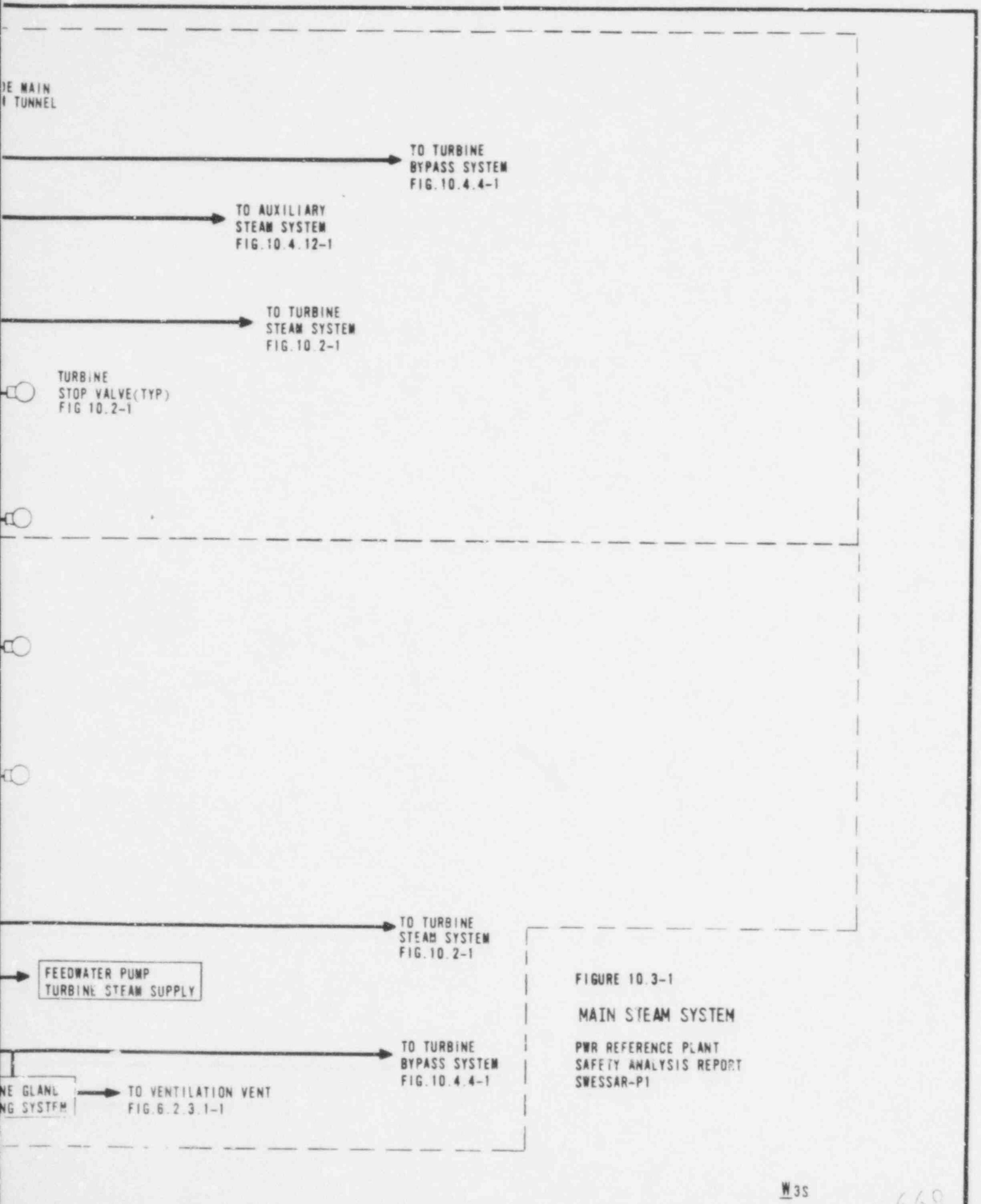


FIGURE 10.3-1

MAIN STEAM SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

W3S

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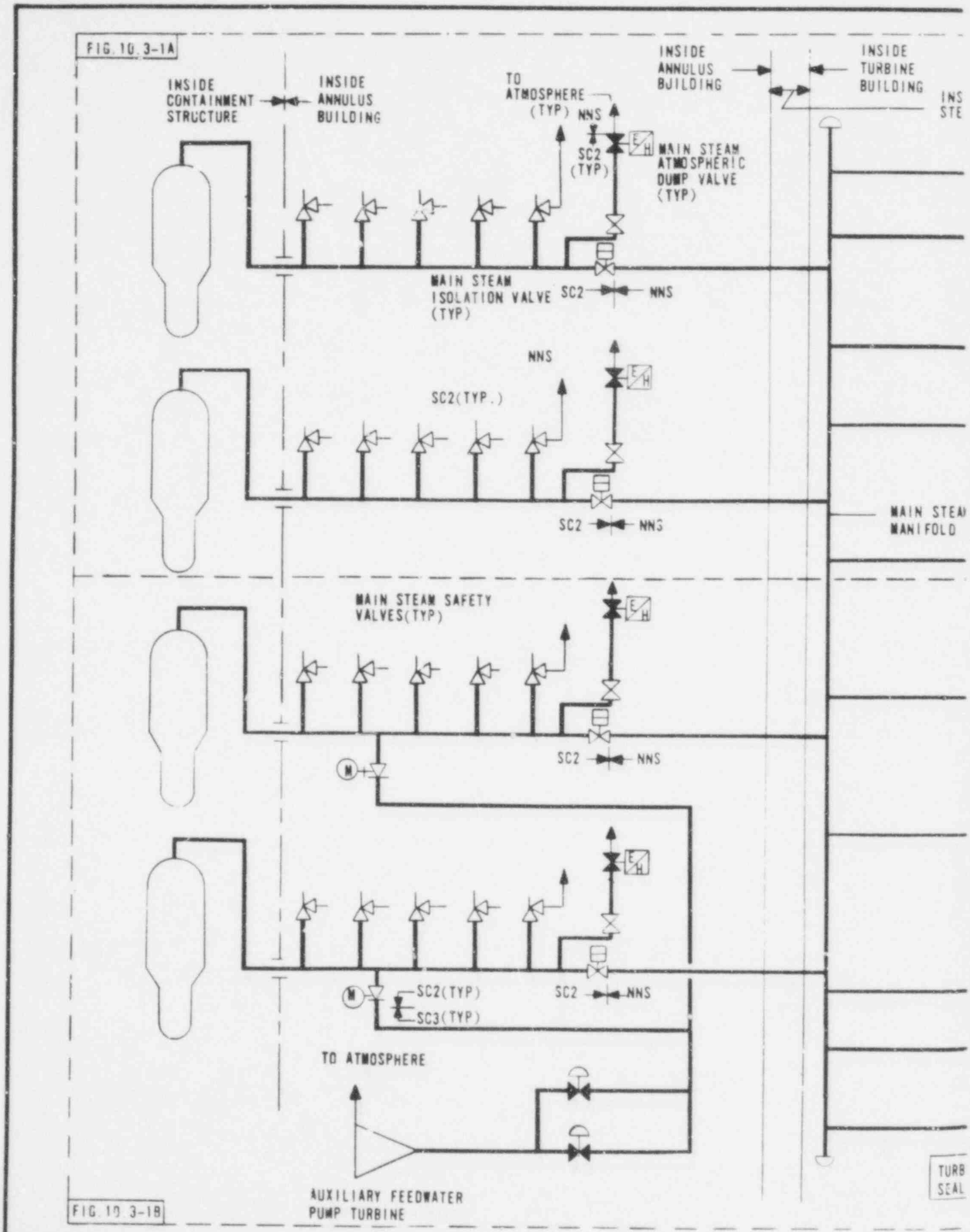


NOTES: THIS SYSTEM IS NON-NUCLEAR SAFETY CLASS (NNS) EXCEPT WHERE OTHERWISE NOTED.

668 127

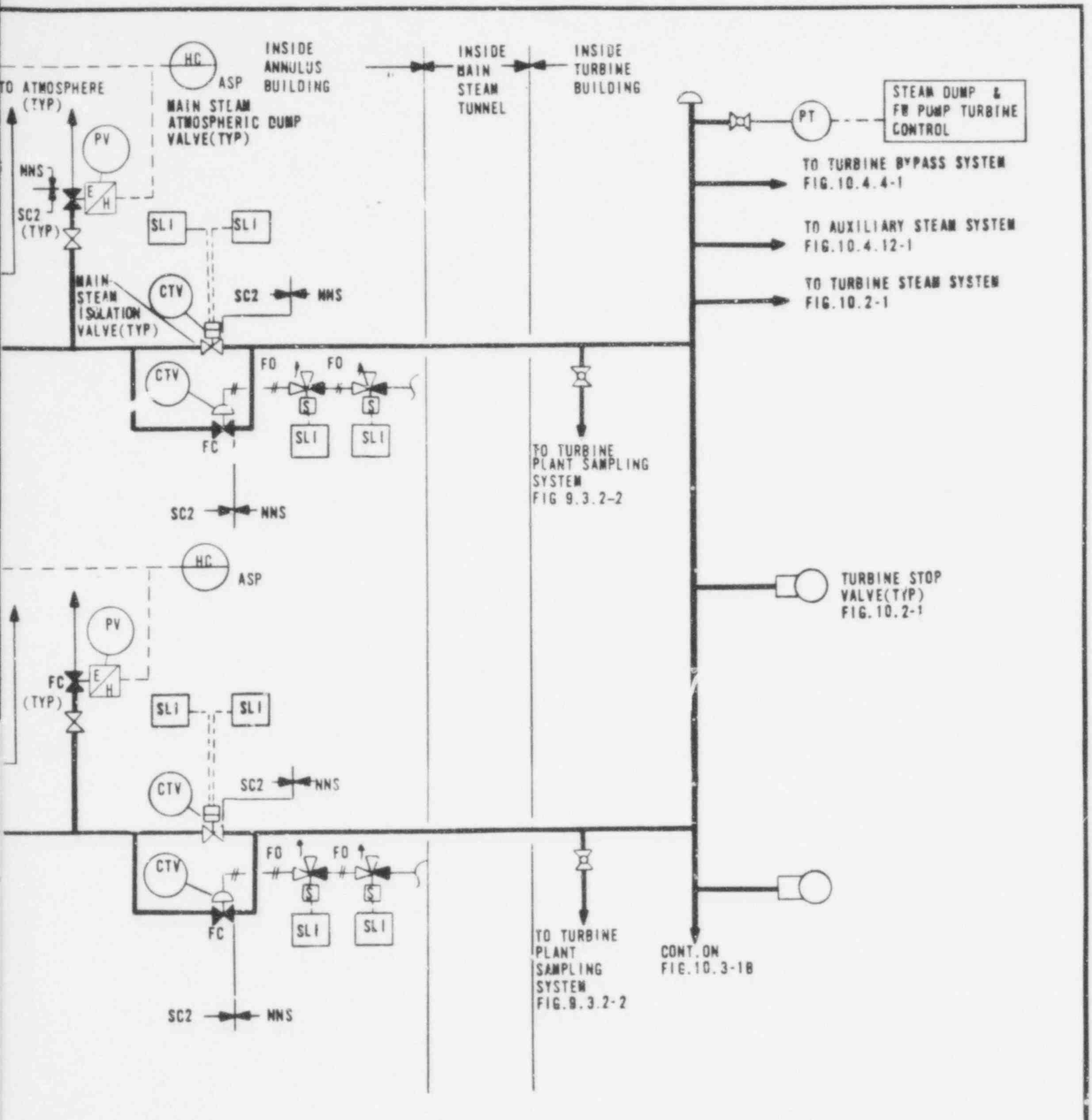


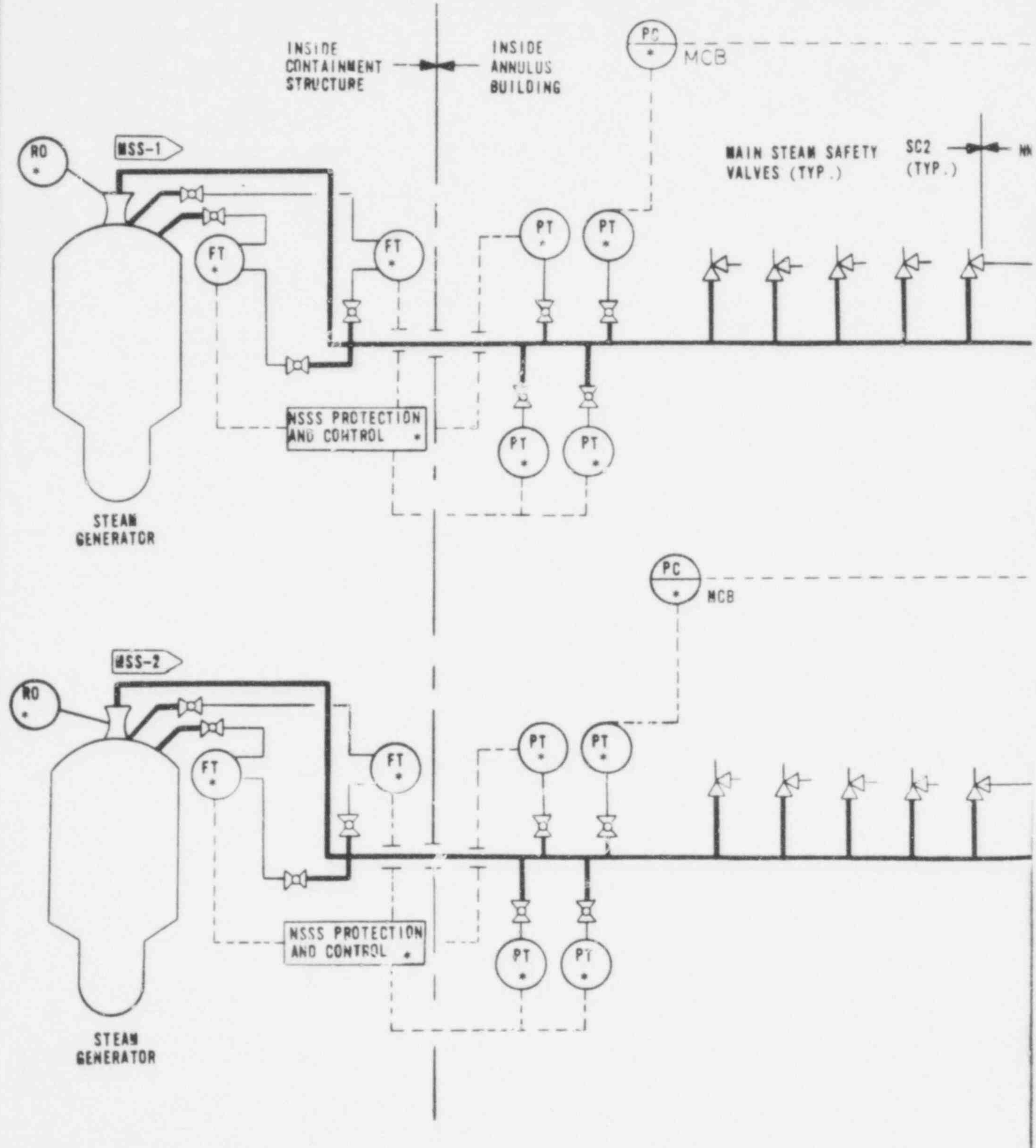
FIG.10.3-1A

MAIN STEAM SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

668 128

W 3S



NOTES:

1. THIS PORTION OF THE MAIN STEAM SYSTEM IS SAFETY CLASS 2 (SC2) EXCEPT WHERE OTHERWISE NOTED.
2. MAIN STEAM ISOLATION VALVE HAS 5 SEC. MAX. CLOSURE TIME.
3. "*" MEANS INSTRUMENTS SUPPLIED BY NSSS VENDOR.

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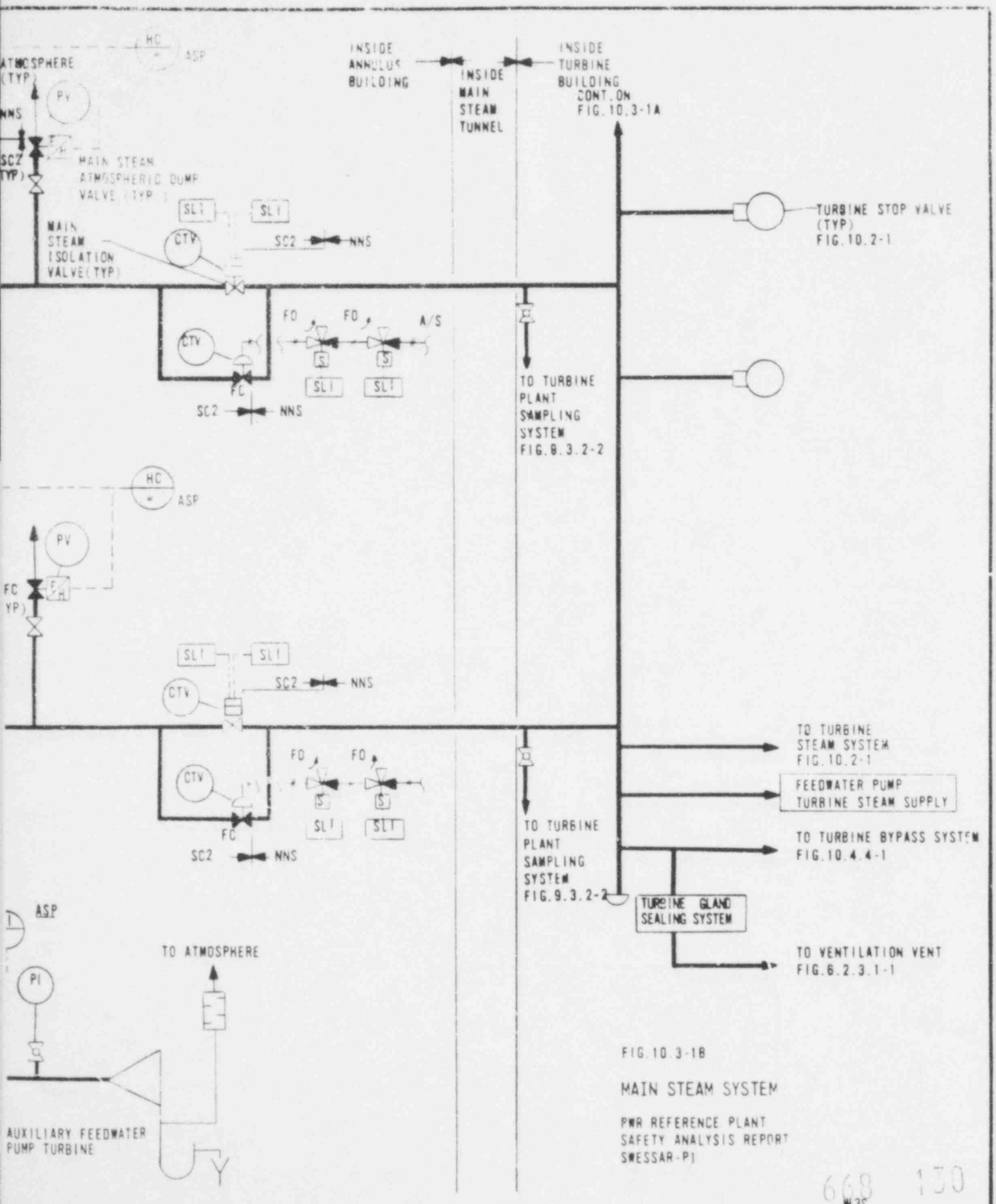


FIG. 10.3-1B

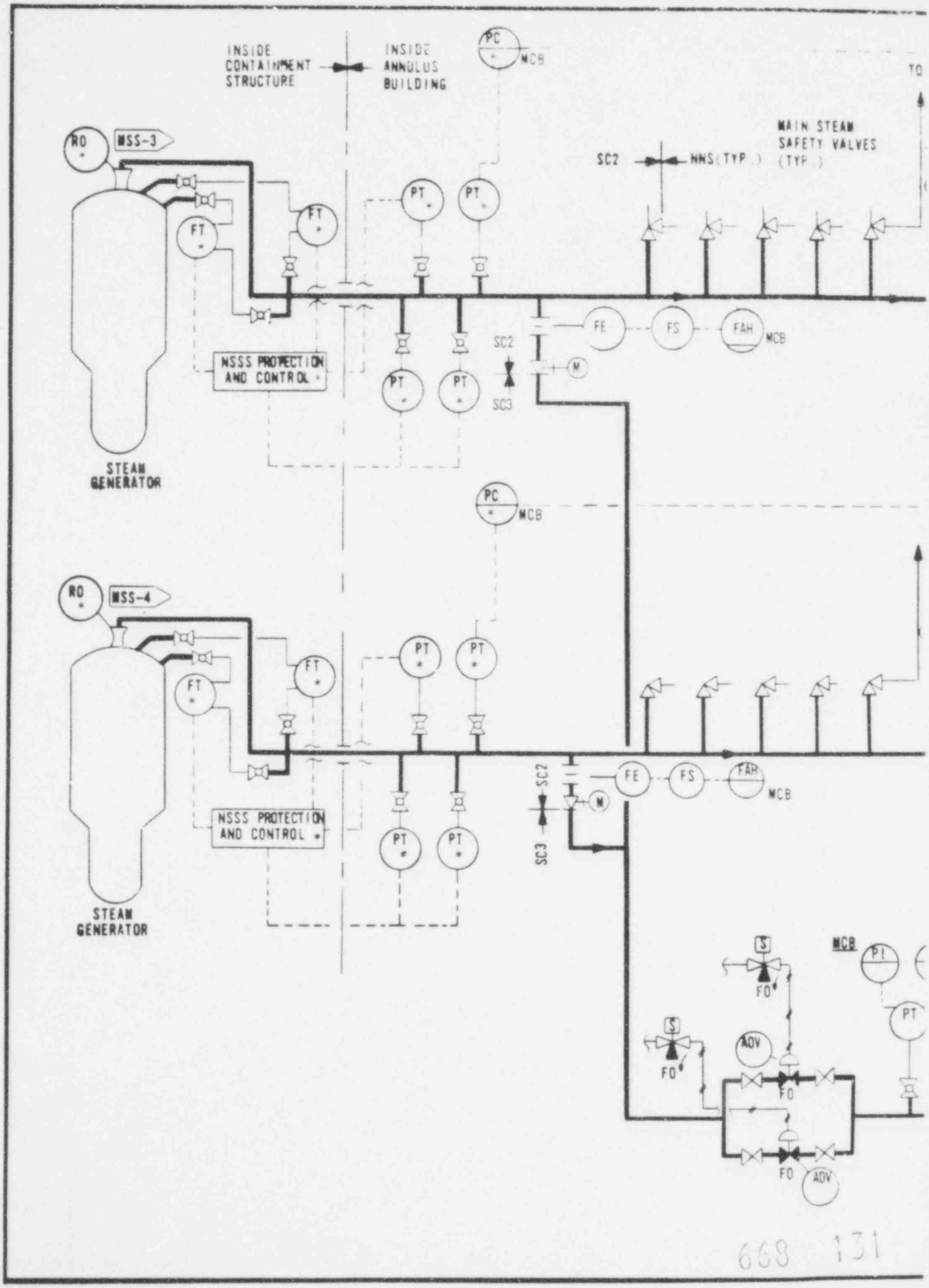
MAIN STEAM SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

668 130

W3S

AMENDMENT 30 1/28/77


INSIDE CONTAINMENT STRUCTURE
INSIDE ANNULUS BUILDING
PC
MCB
TO
MAIN STEAM SAFETY VALVES (TYP.)
SC2
NNS (TYP.)
RO
MSS-3
FT
PT
FE
FS
FAH
SC3
M
NSSS PROTECTION AND CONTROL
STEAM GENERATOR
MSS-4
S
FO
AOV
PI

668 131

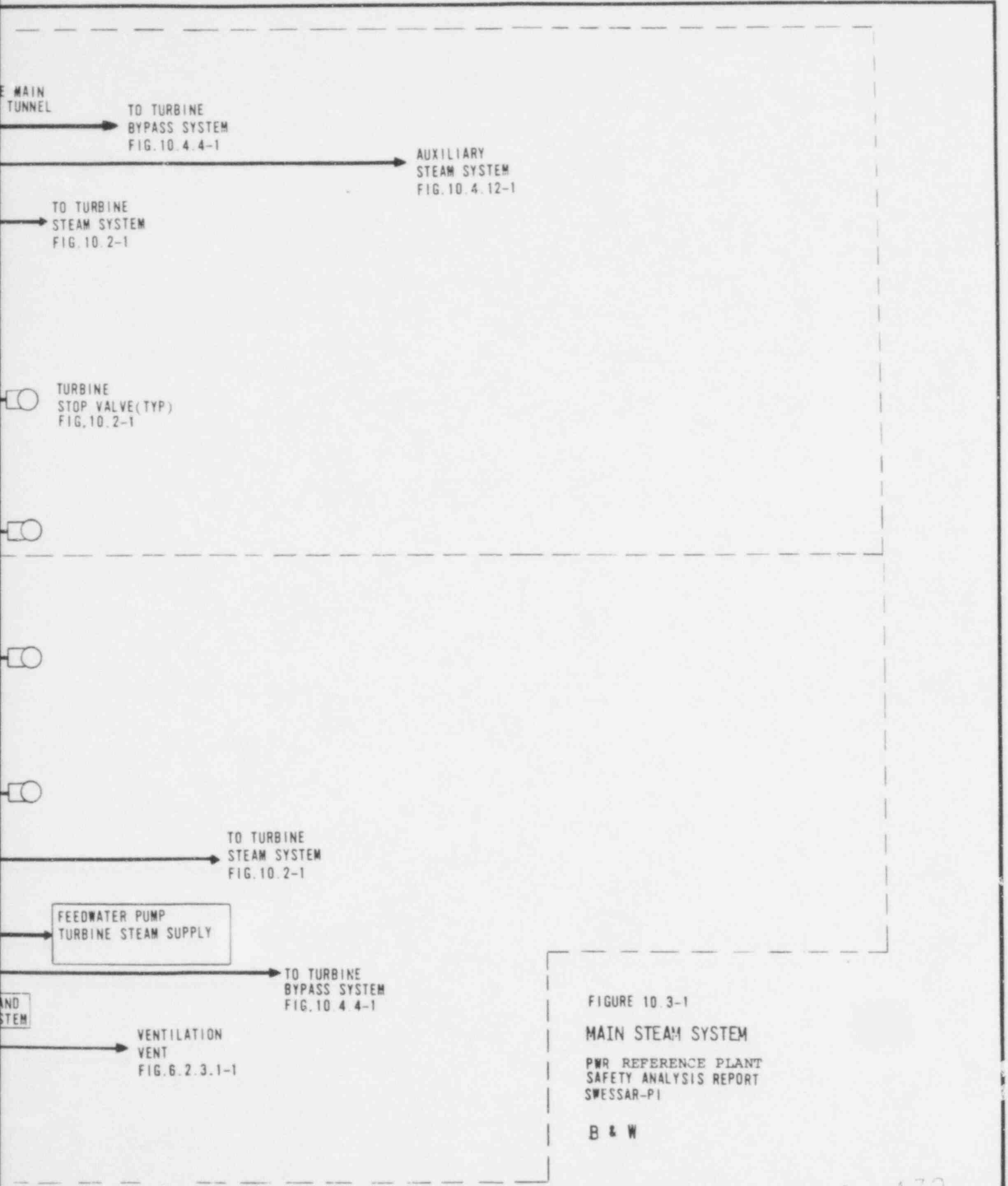


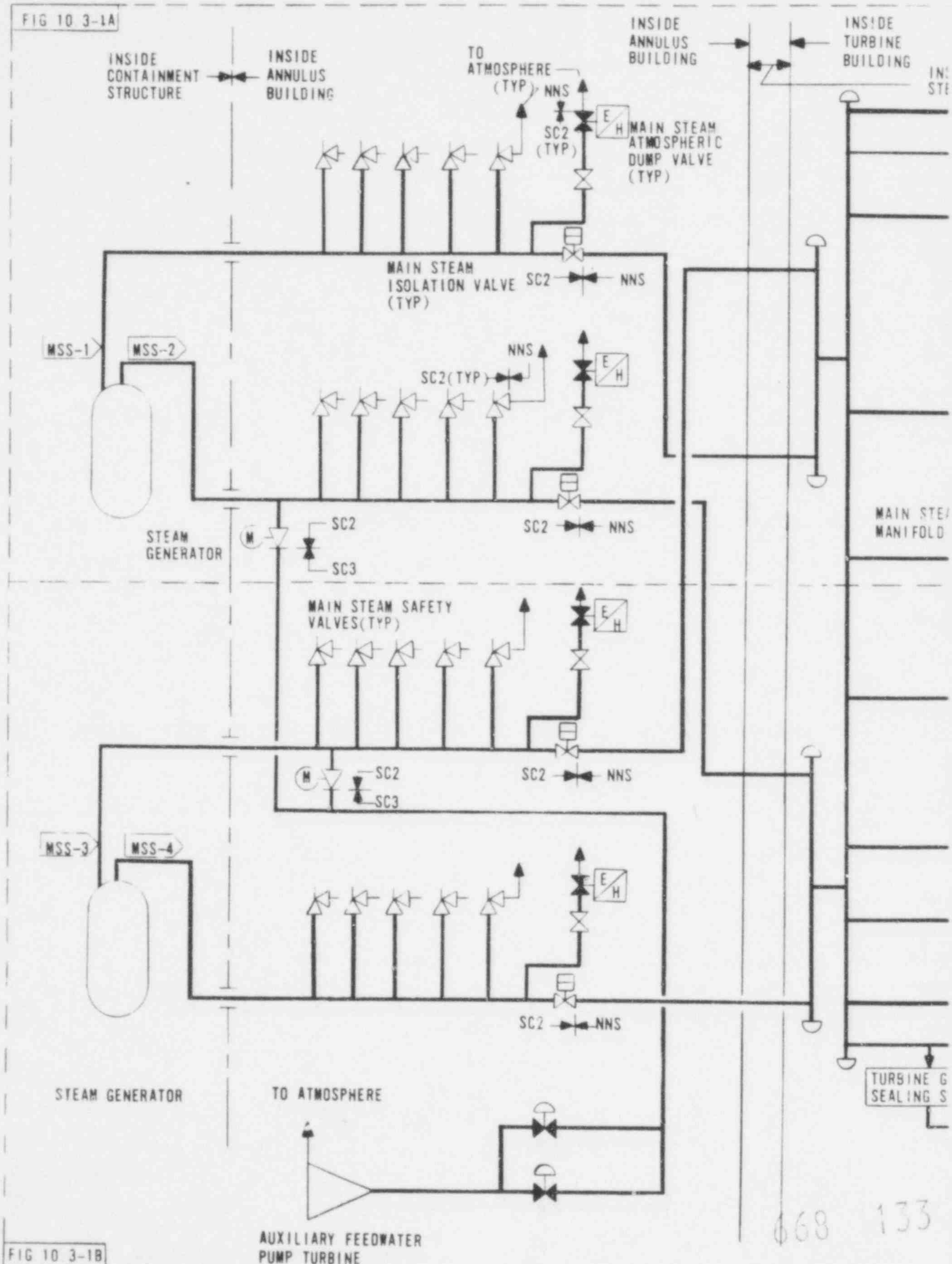
FIGURE 10.3-1

MAIN STEAM SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

B & W

668 132



NOTES THIS SYSTEM IS NON-NUCLEAR SAFETY CLASS (NNS) EXCEPT WHERE OTHERWISE NOTED

668 133

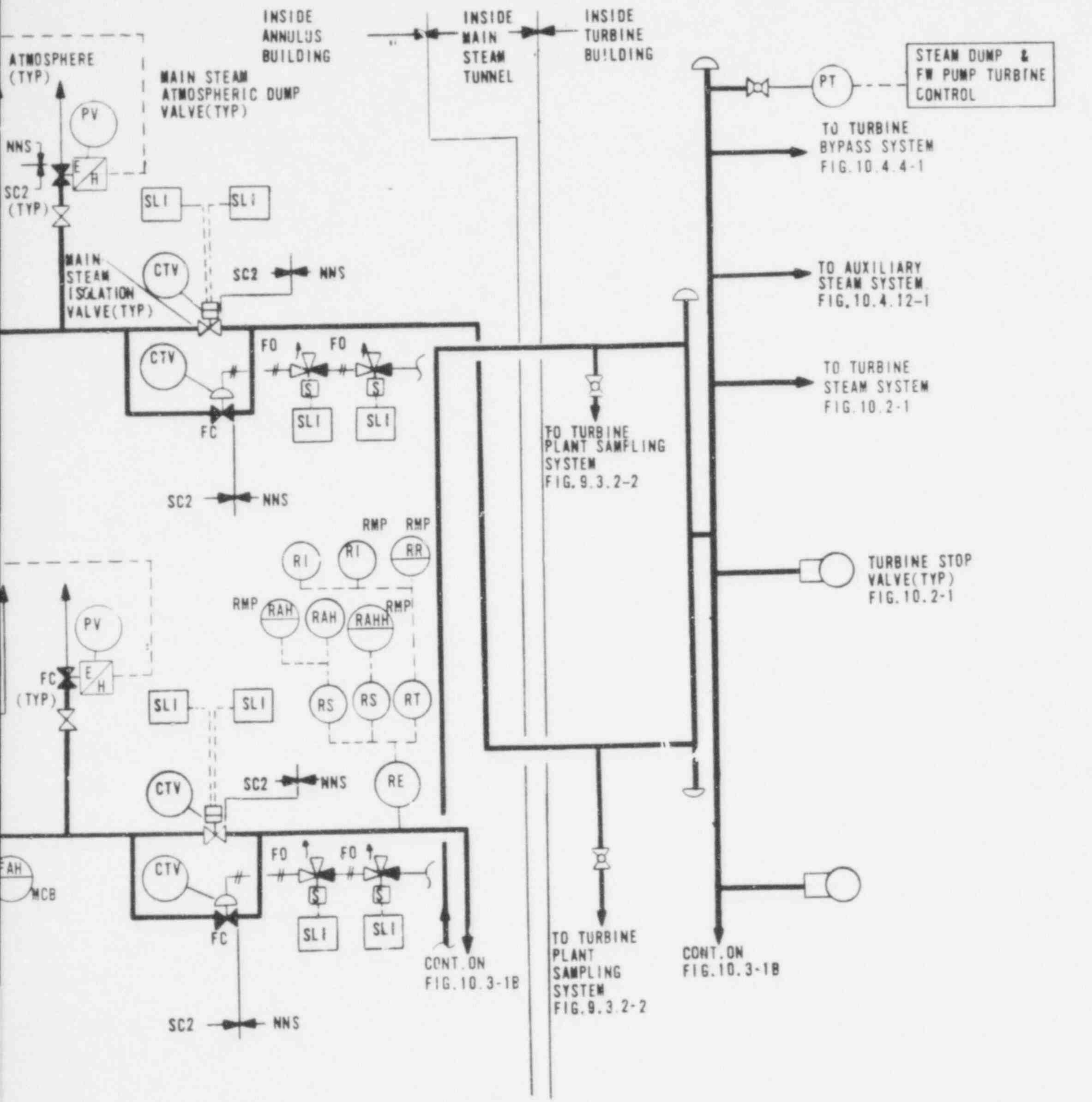


FIG.10.3-1A

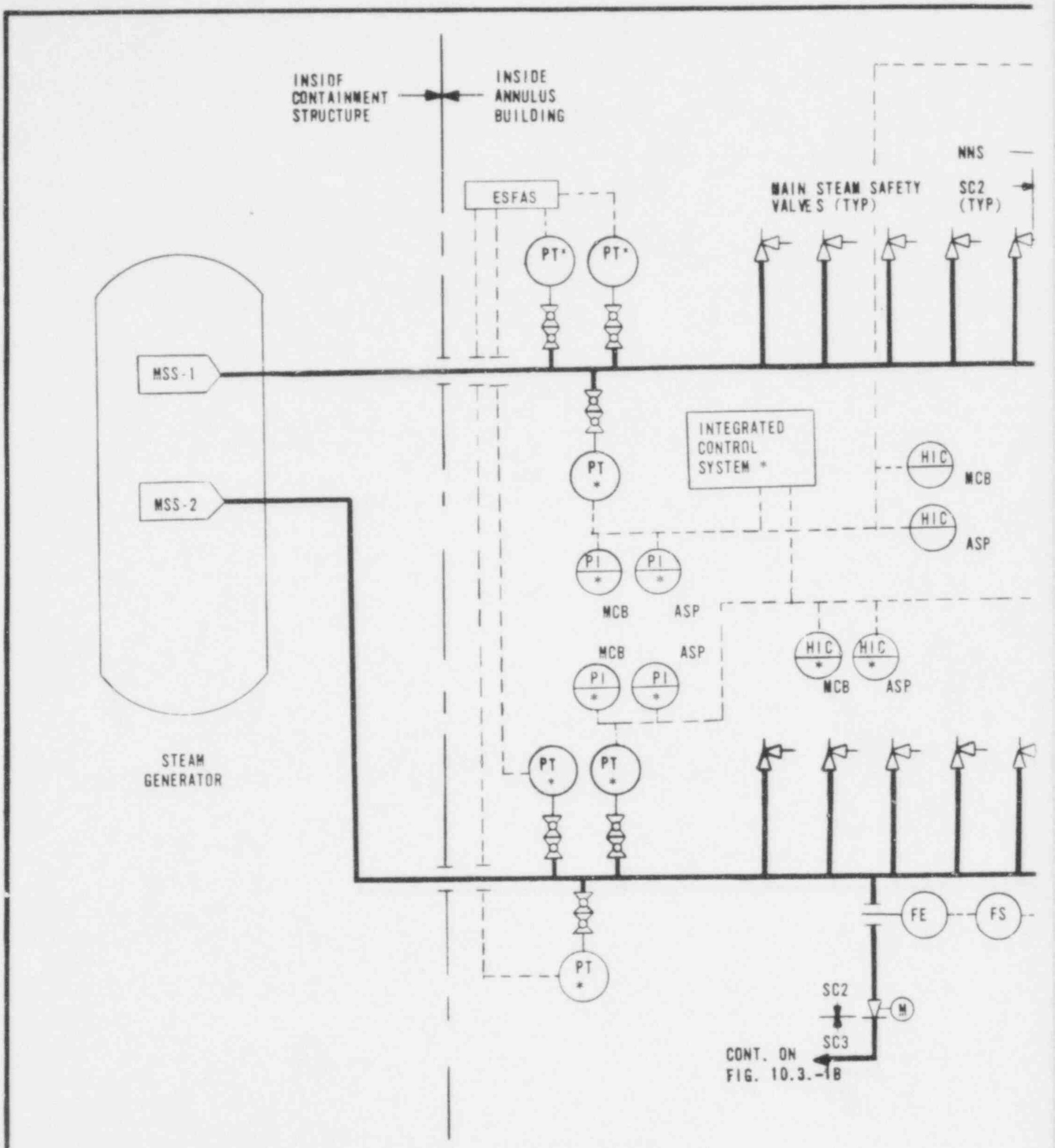
MAIN STEAM SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

B&W

668 134

AMENDMENT 30 1/28/77



NOTES:

1. THIS PORTION OF THE MAIN STEAM SYSTEM IS SAFETY CLASS 2 (SC2) EXCEPT WHERE OTHERWISE NOTED.
2. MAIN STEAM ISOLATION VALVE HAS 5 SEC. MAX. CLOSURE TIME.
3. "*" MEANS INSTRUMENT SUPPLIED BY NSSS VENDOR.

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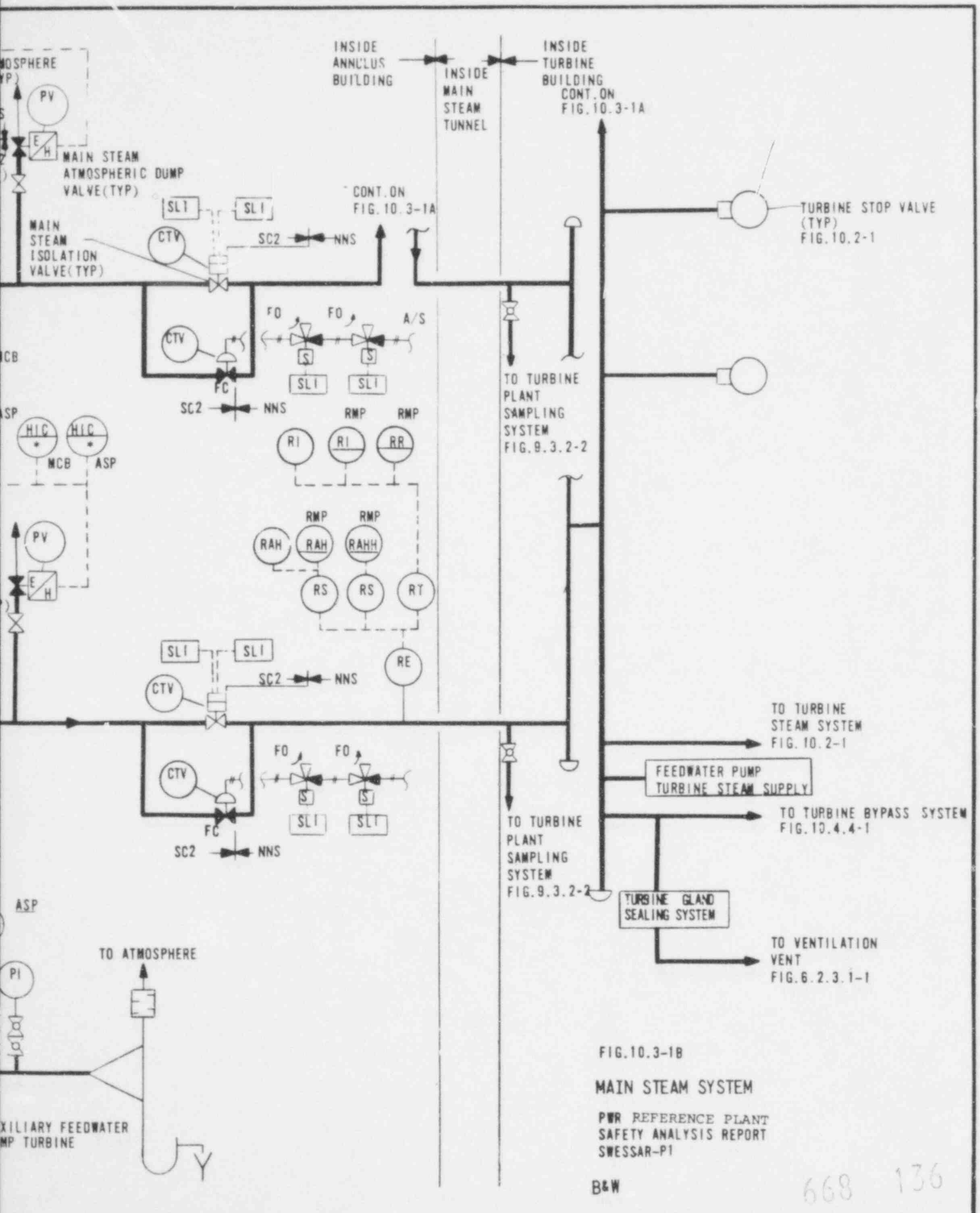


FIG. 10.3-1B

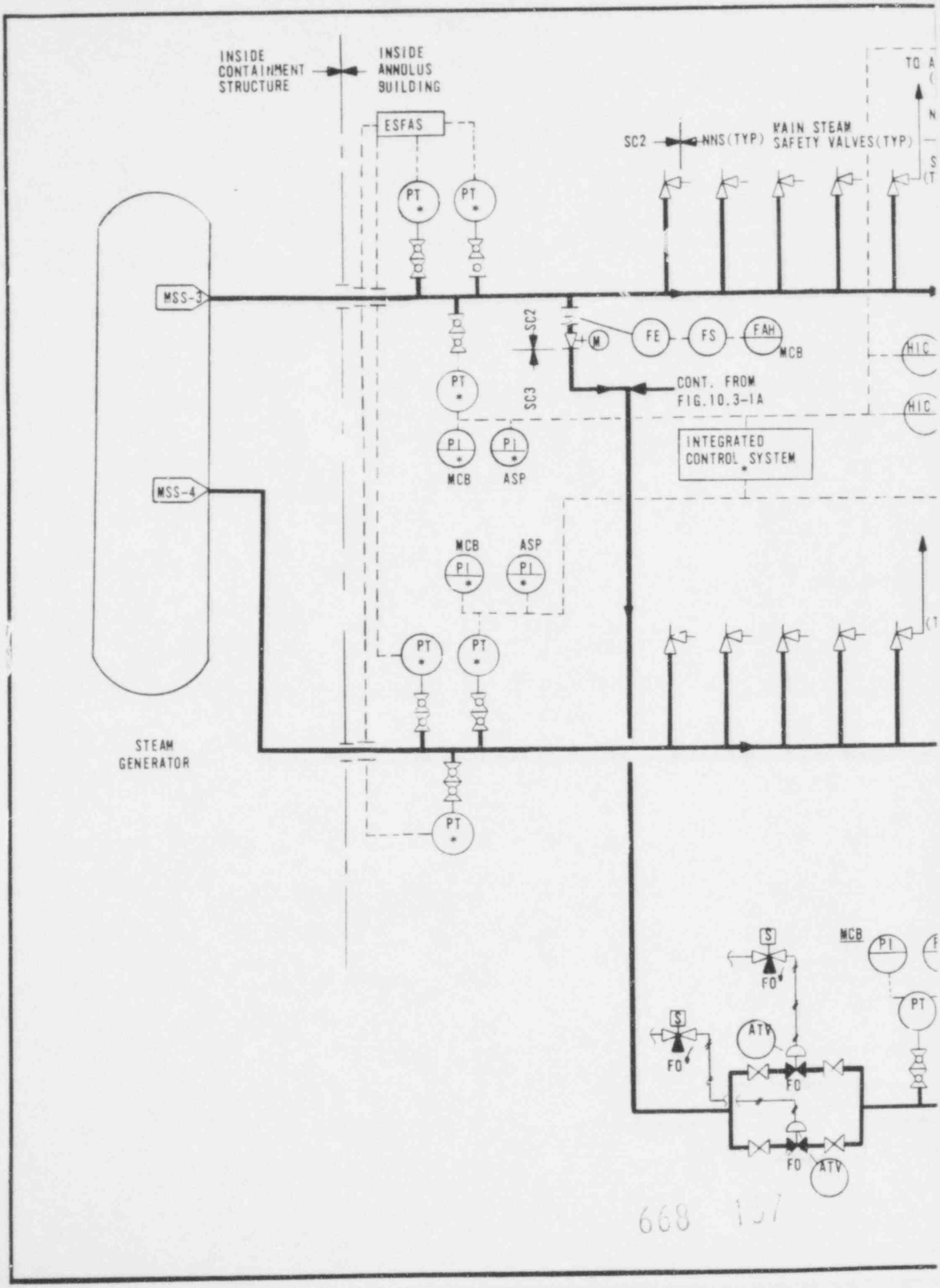
MAIN STEAM SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

B&W

668 136

AMENDMENT 30 1/28/77



INSIDE CONTAINMENT STRUCTURE
INSIDE ANNULUS BUILDING
ESFAS
SC2
NNS(TYP)
MAIN STEAM SAFETY VALVES(TYP)
TO A
PT
MSS-3
MSS-4
SC2
SC3
M
FE
FS
FAH
MCB
HIC
CONT. FROM FIG.10.3-1A
PI
MCB
ASP
INTEGRATED CONTROL SYSTEM
STEAM GENERATOR
S
FO
ATV
668 157

SYSTEM INTERFACE POINTS - MAIN STEAM SYSTEM (MSS)

ID NO.	RESAR-41	RESAR-3S	B-SAR 205	CESSAR
MSS-1-4	Main steam system from steam generator nozzles	Main steam system from steam generator nozzles	Main steam system from steam generator nozzles	Main steam system from steam generator nozzles

19

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FIG. 10.3-1C
MAIN STEAM SYSTEM
PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

10.4

10.4 OTHER FEATURES OF STEAM AND POWER CONVERSION SYSTEM

10.4.1 Main Condenser

The function of the main condenser is to condense steam from the three low pressure turbine exhausts, the three feedwater pump turbines, and from the turbine bypass system (Section 10.4.4), and to collect miscellaneous drains. The major connections to the condenser are shown in Fig. 10.4.1-1.

10.4.1.1 Design Bases

The design bases of the main condenser are:

1. The condenser shall not be safety related.

2. The condenser shall maintain normal turbine backpressure for all operating conditions. Backpressure during operation of the turbine bypass system may rise above the normal continuous range but shall remain within limits specified by the turbine manufacturer.

3. The condenser shall deaerate the turbine exhaust at all loads.

10.4.1.2 System Design

The condenser is of conventional triple shell, single-pass divided water box design having impingement baffles to protect the tubes, steam and condensate equalizing sections, and flexible expansion joints between the condenser necks and the turbine exhaust flanges. Partitioned hotwells, open at one end, with sample points in each section, and leakage collections troughs on each tube sheet are provided to detect inleakage of circulating water (Section 10.4.5). The total hotwell water storage capacity is equivalent to approximately 5 minutes of flow at full load operation.

Two feedwater heaters are located in each condenser neck.

The design equilibrium concentration of radioactivity in the condenser during normal operation for the design case of 1.0 percent failed fuel coincident with 166 gallons per day steam generator primary to secondary leakage is the same as the equilibrium concentration in the main steam system. Table 11.1.3-2 gives the concentrations for various isotopes. During shutdown, the radioactivity in the condenser decreases.

The anticipated air inleakage limit for the condenser is 52.5 scfm (W-41, C-E) or 45 scfm (W-3S, B&W), calculated using the method given in Heat Exchange Institute "Standard for Steam Surface Condensers," Sixth Edition, 1970. 19

10.4.1.3 Safety Evaluation

The condenser is designed for operation at maximum calculated plant output. Motor-operated butterfly valves are provided at the condenser outlet water boxes for maintenance. Water box vacuum breakers interlocked with the circulating water pumps protect the water boxes in the event of circulating water pump
12 trips.

The potential for hydrogen buildup in the condenser is negligible. Noncondensable gases entering the condenser are removed by the condenser evacuation system (Section 10.4.2).

Pressure relief diaphragms furnished on the turbine exhaust shell avoid buildup of excessive pressures in the condenser shell.

10.4.1.4 Testing and Inspections

Samples are taken from the condenser hotwells and from troughs mounted on the tube sheets to check the condenser for circulating water inleakage and to locate the condenser section containing the leak.

10.4.1.5 Instrumentation Applications

All instrumentation on the condenser is nonsafety related. Level controllers and level alarms on the condenser are discussed under condensate and feedwater systems (Section 10.4.7).

10.4.2 Condenser Evacuation System

The function of the condenser evacuation system is to remove noncondensable gases from the condenser shells.

The condenser evacuation system is shown in Fig. 10.4.2-1.

10.4.2.1 Design Bases

The design bases of the condenser evacuation system are as follows:

1. The condenser evacuation system shall draw the initial vacuum in the condenser shells during startup, maintain vacuum during operation, and dispose of the noncondensable gases from the condenser.

2. The condenser evacuation system is nonsafety related and is classified as nonnuclear safety (NNS).

10.4.2.2 System Design

Two steam jet air ejectors, each having a double element first stage and a single element second stage, complete with tubed inter- and after-condensers, remove noncondensable gases from the condenser shells. During normal operation, one unit operates with the other unit on standby. The steam jet air ejectors function by using steam from the auxiliary steam system (Section 10.4.12). The auxiliary steam that condenses in the steam jet air ejector condensers flows through drain traps to the condenser (Section 10.4.1). 12

Two horizontal, motor-driven condenser air removal pumps are provided for initial condenser shell side air removal.

The air removed from the condenser shells by the condenser air removal pumps is discharged to atmosphere.

The air removed from the condenser shells by the steam jet air ejectors is discharged to the radioactive gaseous waste system (Section 11.3) after passing through a radiation monitor.

10.4.2.3 Safety Evaluation

Maintaining vacuum in the condenser is necessary for operation of both the turbine bypass system (Section 10.4.4) and the turbine-generator (Section 10.2). Failure of the condenser evacuation system causes a gradual loss of vacuum in the condenser by buildup of noncondensable gases. When the pressure in the condenser creates too much of a backpressure against the turbine exhausts, the turbine-generator trips.

10.4.2.4 Testing and Inspection Requirements

Normally, one steam jet air ejector is in operation with the other on standby. The operation of these units is alternated periodically to eliminate the necessity for testing.

The condenser air removal pumps normally operate only during startup and therefore need not be tested during plant operation.

10.4.2.5 Instrumentation Applications

All instrumentation in the condenser evacuation system is non-safety related. The condenser air removal pumps are manually started from the control room prior to plant startup.

After sufficiently reducing pressure in the condenser during startup, the condenser air removal pumps are manually shut down and one steam jet air ejector is manually started. On indication of high absolute pressure in the condenser during normal operation, the second steam jet air ejector is manually started.

The steam jet air ejector discharge to the radioactive gaseous waste system is monitored for radiation level. The radiation level is recorded and a high radiation level is alarmed.

10.4.2.6 Interface Requirements

9 The Utility-Applicant shall provide a supply of domestic water to the condenser air removal pumps to be used as the compressing liquid for the pumps. This water is only required during plant startup and is not recoverable. Domestic water interface points are indicated on Fig. 10.4.2-1.

10.4.3 Turbine Gland Sealing System

The function of the turbine gland sealing system is to seal the turbine shaft (rotor) between both the turbine casings and the exhaust hoods and the atmosphere, thus preventing leakage of air into the condenser and leakage of steam from the turbine into the building.

10.4.3.1 Design Bases

The design bases of the turbine gland sealing system are:

1. The system shall not be safety related and shall be designated nonnuclear safety class (NNS).

2. The system shall seal the turbine continuously during startup and during full load operation.

3. The system shall prevent the occurrence of overpressure in the system.

10.4.3.2A System Description with General Electric Turbine

A series of spring-backed segmented packing rings are fastened in the bores of turbine shells and hoods at every point where the rotor emerges from the steam atmosphere. These rings are machined with specially designed teeth fitted with minimum radial clearance between the teeth and the turbine rotor. The small clearance and the resistance offered by the particular tooth construction so restrict the steam and air flow that it is held to a minimum.

On pressure packings, the small amount of steam that does leak past the packing teeth is piped from a leakoff passage in the packing casing to one of the stages in the turbine or to a feedwater heater. This is done so that the heat energy in the steam can be utilized more efficiently.

On vacuum packings, a very small quantity of steam leaks into the exhaust casing and discharges to the condenser.

The steam seal header pressure is held automatically by an air-operated feed valve and a direct acting unloading valve. At light loads, the steam seal feed valve supplies steam from the main steam system (Section 10.3) to the steam seal header. At higher loads, when more steam is leaking from the pressure packings than is required by the vacuum packings, the steam seal unloading valve discharges the excess to the condenser.

During cold startup, the turbine gland sealing system operates from the auxiliary steam system. During normal operation, when requiring external steam supply, the system takes steam from the main steam system.

A gland steam condenser and two motor-operated gland steam condenser exhausters maintain a slight vacuum in the system and exhaust the noncondensables to the ventilation vent (Section 6.2.3.1). The exhausters have automatically operated discharge valves for isolation and regulation. 9

10.4.3.2B System Description with Westinghouse Turbine

The turbine rotor ends are sealed by rotor glands of the labyrinth type, consisting of a number of seal strips machined into seal rings.

Steam from the main steam system is throttled to the steam seal header to seal the turbine glands during startup. As the turbine load is increased, the steam pressure inside the high pressure turbine increases and the steam leakage path is outward toward the rotor ends, thus eliminating the need to supply sealing steam to these glands. When this occurs, leakage from the high pressure glands supplies the steam sealing requirements for the low pressure glands. The leakoff steam and air mixture then flows to the gland steam condenser which is maintained at a pressure slightly below atmospheric so as to prevent the escape of steam from the ends of the glands. The gland steam condenser returns seal leakage to the main condenser as condensate. The air inleakage to the glands is exhausted from the gland steam condenser by one of two exhaust blowers to the ventilation vent (Section 6.2.3.1). 9

10.4.3.3 Safety Evaluation

An analysis of a turbine gland sealing system malfunction is given in Section 15.1.35. Exhaust for this system passes to the ventilation vent where it is monitored for possible radioactive releases. 9

10.4.3.4 Testing and Inspections

Operation of the gland steam exhausters will be alternated periodically, thus eliminating the need for periodic testing.

Other components of the system will be tested and inspected as recommended by the turbine manufacturer.

10.4.3.5 Instrumentation Applications

Instrumentation, as recommended by the turbine manufacturer to monitor system operation, is provided.

10.4.4 Turbine Bypass System

The function of the turbine bypass system is to enable the NSSS to follow a turbine-generator step load reduction up to approximately 50 percent, without causing a reactor or turbine trip, and without lifting the main steam safety valves.

The turbine bypass system is shown in Fig. 10.4.4-1.

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10.4.4.1 Design Bases

The design bases of the turbine bypass system are as follows:

1. The turbine bypass system shall not be safety related.

2. The turbine bypass system shall be designed in accordance with ANSI B31.1.0b-1971.

3. The turbine bypass system shall enable the turbine-generator (Section 10.2) to take a step load reduction up to 50 percent without causing a reactor or turbine trip and without lifting the main steam safety valves.

4. A single turbine bypass control valve sticking open shall not cause an uncontrolled plant cooldown.

10.4.4.2 System Design

On a large external electrical load decrease (up to 50 percent), the turbine bypass system relieves main steam directly to the condenser, thus preventing a reactor or turbine trip and lifting of the main steam safety valves (Section 10.3).

The turbine bypass system includes two turbine bypass headers, branching from the main steam manifold in the main steam system (Section 10.3), and individual bypass valves between the bypass header and the condenser. 9

An uncontrolled plant cooldown caused by a single valve sticking open is prevented by the use of a group of smaller valves installed in parallel instead of a single larger valve.

The full capacity of the turbine bypass system is 40 percent of maximum calculated steam flow at full load steam pressure which, together with the NSSS transient capability, meets the design requirement in 10.4.4.1(3). This steam flow is equally distributed among the three condenser shells by the preset opening sequence of the turbine bypass control valves and by use of perforated distribution piping inside the condenser. 9

After a normal shutdown of the turbine-generator leading to plant cooldown, the turbine bypass control valves are opened to release steam generated from reactor coolant system sensible heat (Chapter 5). Reactor cooldown, programmed to minimize thermal transients and based on sensible heat release, is accomplished by gradually decreasing the setpoint of a steam pressure controller. This closes the turbine bypass control valves, thus transferring the cooldown process to the residual heat removal system (Section 5.5.7).

10.4.4.3 Safety Evaluation

All or several of the turbine bypass control valves can be opened in a preset sequence if the condenser vacuum permissive interlock is satisfied.

During startup, shutdown, operator training, or physics testing, the turbine bypass control valves can be actuated remotely from the main control board.

The turbine bypass control valves are prevented from opening on loss of condenser vacuum and, in such a case, excess steam pressure is relieved to the atmosphere through the main steam safety valves and the atmospheric steam dump valves (Section 10.3). Interlocks are provided to reduce the probability of inadvertent opening of the turbine bypass control valves.

10.4.4.4 Inspection and Testing

During refueling shutdowns, the turbine bypass control valves and turbine bypass system controls will be inspected and tested for proper operation. Inservice testing for partial opening will be done periodically.

Turbine bypass system piping will be inspected and tested in accordance with paragraphs 136 and 137 of ANSI B31.1.0b-1971.

10.4.4.5 Instrumentation Applications

Manual controls and loss of condenser vacuum interlocks are provided for the turbine bypass control valves.

Automatic signals to open the turbine bypass control valves are discussed in Section 7.7 of the NSSS Vendor's SAR.

10.4.4.6 Interface Requirements

9 Interface information applicable to the turbine bypass system, as presented in the respective NSSS Vendor's SARs, is discussed in Table 10.1-2.

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10.4.5 Ci culating Water System

This system and the vacuum priming system (if required) will be described in the Utility - Applicant's SAR.

Interface requirements for the design of these systems are:

1. The systems shall not be safety related and shall be classified nonnuclear safety (NNS).

2. The circulating water system shall be physically isolated and remote from both the ultimate heat sink (Section 9.2.5) and the reactor plant service water system (Section 9.2.1), so that a failure in the circulating water system will not be able to render any part of the reactor plant service water system inoperable.

3. The type of circulating water system, the amount of heat rejected to the condenser which must be removed by the circulating water system, and the need for a vacuum priming system will be determined for the specific site and described in the Utility-Applicant's SAR.

4. Circulating water system piping interface points with the condenser are as shown on Fig. 10.4.1-1.

5. Circulating water system piping interface points with the turbine plant service water system are as shown on Fig. 10.4.11-1. 9

10.4.6 Condensate Polishing System

The function of the condensate polishing system is to remove from the condensate stream impurities resulting from condenser tube leakage to produce a high quality effluent capable of meeting feedwater and steam generator chemistry specifications.

The condensate polishing system is shown in Fig. 10.4.6-1.

10.4.6.1 Design Bases

The design bases of the condensate polishing system are:

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1. The condensate polishing system shall not be safety related and shall be classified nonnuclear safety (NNS).

2. The system shall be sized to accommodate 100 percent condensate flow.

3. The system shall maintain the condensate water chemistry in accordance with the requirements of the NSSS Vendor.

4. Sufficient demineralizer redundancy shall be provided to allow demineralizer regeneration while the system retains its normal polishing capacity.

10.4.6.2 System Description

The condensate polishing system consists of mixed-bed demineralizers in the condensate stream between the condensate pump discharge and the steam jet air ejector condensers. These 17
demineralizers are capable of handling the full condensate flow while one out of service demineralizer is being regenerated or is on standby. The resin used in the demineralizers is of the H^+–OH^- type, with the two resin types mixed in equal proportion by volume.

The number of demineralizers is dependent on the condensate flow, which in turn is dependent on the NSSS. For Westinghouse (RESAR-41), Combustion Engineering, and Babcock & Wilcox, there 17
are nine demineralizers. For Westinghouse (RESAR-3S), there are eight demineralizers.

The polisher regeneration equipment consists of a cation regeneration vessel, an anion regeneration vessel, and a resin mix and storage vessel, as well as appropriate equipment for regenerating when the polishing system is operated in the ammonia cycle. The ammonia cycle system varies among manufacturers. Selection of the specific ammonia cycle system is the responsibility of the Utility-Applicant.

A concentrated acid day tank and pumps are required to regenerate the cation resin in both the hydrogen and the ammonia cycle. A concentrated caustic day tank and pumps are also required to regenerate the anion resin in the hydrogen cycle. Recovered water, acid, and caustic tanks and pumps reduce the cost of regeneration and minimize the volumes requiring waste treatment.

The waste from the condensate polisher regeneration contains a varied mixture of dissolved and suspended solids. Wastes with a conductivity greater than 50 micromhos, i.e., high conductivity waste, are collected separately from low conductivity waste, i.e., waste with less than 50 micromhos. The suspended iron oxides that are collected from the condensate system are predominantly low conductivity waste.

High conductivity wastes are neutralized by the required reagent in a 22,000 gal neutralizing tank before transfer to a 36,000 gal storage tank. Neutralized wastes are pumped to the radioactive liquid waste system (Section 11.2) for evaporation. The evaporator distillate is returned to the low conductivity waste sump.

Low conductivity wastes are collected in a surge tank to minimize flow variations downstream from the regeneration equipment. These wastes are pumped at a rate of 75 gpm through a filter and cleanup demineralizer. The demineralized water is returned to the recovered water tank, to the condenser hotwell, or to the makeup water supplied to the system.

The solids collected in the filter are removed by high pressure air and water into a filter backwash tank located adjacent to the filter. These solids are pumped to the high conductivity waste storage tank.

The cleanup demineralizer has a bed of mixed cation and anion resins of the same size and resin ratio as the condensate polisher bed. The resin is sluiced to the polisher regeneration equipment and regenerated in the same manner as the polisher beds.

Radioactivity is concentrated in the condensate polishing system only if primary-to-secondary leakage occurs in the steam generators.

10.4.6.3 Safety Evaluation

The condensate polishing system is capable of removing, on a continuous basis, condensate impurities resulting from normal anticipated condenser tube leakage expected during operation of the plant. Based on operating experience, this leakage ranges from 0.2 to 0.5 gpm. The maximum tube leak that can be treated continuously will vary with the quality of the condenser circulating water. However, the system provides some degree of protection even during massive leaks, such as one complete tube failure when using sea water as coolant, thus affording "reaction" time to take corrective action or initiate a plant shutdown. In addition, the demineralizers provide an iodine DF of 1,000, and credit for this iodine removal capability is taken in accordance with Regulatory Guide 1.42.

Radiation shielding is provided around the condensate polishing area for personnel protection in the event of primary-to-secondary leakage.

All tanks in the system which are potentially radioactive are located in a diked area of the turbine building. Any overflow from these tanks is collected in one of three area sumps. The contents of the sumps are initially processed in the condensate

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polishing system and are then pumped to the radioactive liquid waste system for further processing.

10.4.6.4 Testing and Inspections

The condensate polishing system is in continuous operation whenever the condensate system is operating. Even with no condenser inleakage, each demineralizer will be regenerated periodically; therefore, operability of the demineralizers and the regeneration system will be demonstrated on a regular basis.

System equipment will be tested for leakage and proper automatic operation prior to initial startup of the plant. The conductivity of the condensate leaving the condenser hotwells and the demineralizer effluent is monitored continuously during plant operation, thus providing a method of evaluating system performance and determining the need for demineralizer regeneration.

10.4.6.5 Instrumentation Applications

The influent condensate to the condensate demineralizers, the effluent from each demineralizer, and the condensate returning to the condensate header are sampled by the turbine plant sampling system (Section 9.3.2). The conductivity at each location is measured and recorded continuously, and an alarm signal is provided on the condensate polishing panel to indicate high conductivity.

A differential pressure transmitter is provided to monitor the differential pressure across the condensate demineralizers. An alarm signal is provided on the main control board and on the condensate polishing panel to indicate high differential pressure.

Flow transmitters, recorders, and flow indicating totalizers are provided on the effluent of each condensate demineralizer and the condensate return piping to the condensate header.

All tanks in the system which are potentially radioactive are provided with high level indicators and alarms on the condensate polishing control panel in the turbine building. In addition, tanks which are emptied by pumping are also provided with low level indicators and alarms on the condensate polishing control panel. The potentially radioactive tanks and their level indications are listed in Table 11.2-38.

10.4.6.6 Interface Requirements

The Utility-Applicant shall select the type of ammonia cycle system that will be provided by the condensate polishing system supplier. The ammonia cycle system interfaces with the balance of the condensate polishing system as shown on Fig. 10.4.6-1B.

10.4.7 Condensate and Feedwater Systems

The function of the condensate and feedwater systems is to return condensed steam from the condenser (Section 10.4.1) and the drains from the regenerative feedwater heating cycle to the steam generators, while maintaining the water inventories throughout the systems constant. The systems automatically control the water levels in the steam generators and condenser hotwell during steady state and transient conditions.

The flow diagrams of the condensate and feedwater systems are shown in Fig. 10.4.7-1 and 10.4.7-2, respectively.

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10.4.7.1 Design Bases

The design bases of the feedwater and condensate systems are:

1. The portion of the feedwater system extending from and including the feedwater isolation valves to the steam generator inlets shall be safety related (QA Category I) and Seismic Category I. 13

2. The entire condensate system and the portions of the feedwater system upstream of the feedwater isolation valves shall be neither safety related nor Seismic Category I. 13

3. The feedwater isolation valves nearest the containment shall be categorized as containment isolation valves and, as such, shall be located as close as practical outside the containment structure.

4. The portion of the feedwater system from and including the feedwater isolation valves to the steam generator shall be designed in accordance with ASME III, Code Class 2 and is designated Safety Class 2 (SC-2). 13

5. The condensate system and the nonsafety related portions of the feedwater system shall be designed in accordance with ASME VIII and ANSI-B31.1.0b and are designated nonnuclear safety class.

6. The condensate and feedwater systems shall be isolated from the steam generators following a safety injection signal (SIS, Section 7.3) within the following time for each NSSS Vendor: 13

Babcock & Wilcox:	15 sec
Combustion Engineering:	20 sec
Westinghouse:	5 sec

10.4.7.2 System Description

Principal operating characteristics of the condensate and feedwater systems and their principal components can be found on Fig. 10.1-2.

The condensate is drawn from the condenser hotwell by three half-capacity motor driven, vertical condensate pumps, each operating at two-thirds capacity during normal operation. The pumps discharge into a common header which passes the condensate through a full flow condensate polishing system (Section 10.4.6), the steam jet air ejector condensers, and then the turbine gland steam condenser. Downstream of the gland steam condenser, condensate passes through three parallel flow paths of six stages of low pressure feedwater heating (fifth point heater drain coolers and feedwater heaters no. 6 through 2). The three flow paths are combined to ensure mixing and pressure equalization upstream of the feedwater pumps. The condenser hotwell is sized to store condensate sufficient for 5 minutes of full load operation.

The three one-third capacity turbine driven feedwater pumps take suction from the condensate system and discharge into a common header. The feedwater then passes through three high pressure feedwater heater shells (heater no. 1) in parallel. Downstream from these heaters, the feedwater piping is headered for mixing and distribution of feedwater to the steam generators through individual feedwater flow control valves. These valves are controlled by the feedwater control system (NSSS Vendor's scope).

A condensate storage tank provides storage of makeup condensate and accommodates surges within the turbine plant. Makeup flow to the condensate storage tank is automatically controlled based on water level in the condenser hotwell and the condensate storage tank. Automatic heating maintains a minimum water temperature in the condensate storage tanks of 40 F.

The condensate storage tank is sized to accommodate surges from the turbine plant when the tank level is already at its normal maximum level, thus precluding overflows from the tank.

The feedwater/condensate passing through the feedwater heaters is heated by extractions taken from the turbine steam system (Section 10.2). The feedwater heaters are horizontal, two pass, fixed tube sheet, U-tube heat exchangers. The fifth and sixth point heaters are located in the condenser neck.

Drains from the first, second, and third point heaters cascade to the shell side of the second, third, and fourth point heaters, respectively. Drains from the fourth point heaters are pumped forward into the condensate system between the third and fourth point heaters. Drains from the fifth point heaters pass through an external drain cooler in the condensate system to the condenser. Drains from the sixth point heaters and drains from the gland steam condenser and the steam jet air ejector condensers pass to the condenser. The first, second, and third point heaters have drain cooler sections.

A bypass is provided around the feedwater pumps to allow the condensate pumps to fill the steam generators during startup, when the feedwater pumps are inoperable.

21 Chemical feed equipment is provided to ensure proper chemistry control of the steam system during all modes of operation. The

primary objective is to minimize corrosion of the steam generator internals, with secondary objectives being to prevent or minimize turbine deposits due to carryover from the steam generator; to reduce corrosion in the steam/feedwater cycle; to minimize sludge deposits in the steam generator; to prevent scale deposits on the steam generator heat transfer surfaces and in the turbine; to minimize feedwater oxygen content; and to minimize the potential for the formation of free caustic or acid in the steam generators.

These objectives are met by system chemistry control after sampling, including comprehensive continuous sampling and laboratory analysis, chemical injection at selected points, normally continuous blowdown from each steam generator (for W41, W3S, and CE only), and chemical protection of the steam generator and feedwater train internals during outages. 21

Chemicals for oxygen scavenging and pH control are added to the condensate system downstream from the condensate demineralizers. This allows good mixing in the condensate/feedwater systems prior to the entrance of the feedwater into the steam generator.

Chemicals for oxygen scavenging and pH control can be added to the feedwater and/or auxiliary feedwater systems to allow manual addition of chemicals to the steam generators during startup and shutdown conditions when addition to the condensate system is either not effective or not sufficient. For example, addition to auxiliary feedwater is required during startup and during wet layup of the steam generators when chemicals are required in great quantities.

Chemical solutions are mixed and stored in covered tanks. The solutions are pumped from the tanks into the appropriate system by positive displacement pumps with adjustable strokes.

10.4.7.3 Safety Evaluation

The condensate and feedwater systems are capable of operation at full load with one condensate pump out of service and at partial load with one feedwater pump out of service.

A loss of normal feedwater flow results in a reduced capability for steam generator heat removal. Such a loss could result from a pipe break, pump failure, valve malfunction, or loss of a-c power. In the event of such an occurrence, the auxiliary feedwater system ensures a sufficient supply of cooling water (Section 10.4.10).

Malfunction of any low pressure feedwater heater shell necessitates isolation of the flow path in which the malfunctioning feedwater heater shell is located. Two motor-operated isolation valves are provided for each train of low pressure heater shells and for each first point heater. In case of malfunction of any of the heater shells, the isolation valves are closed and a motor operated bypass valve is opened, permitting flow to be bypassed around the out-of-service feedwater heaters.

The turbine-generator loading may be reduced when less than three strings of heaters are in service.

The effects of condensate and feedwater systems equipment malfunctions on the reactor coolant system are described by the NSSS Vendor.

A bypass is provided around the feedwater pumps to allow the condensate pumps to fill the steam generators during startup, when the feedwater pumps are inoperable.

Release of radioactivity to the environment in the event of pipe rupture in the condensate or feedwater system is bounded by the release that would occur from a pipe rupture in the main steam system (Section 15.1.14).

10.4.7.4 Testing and Inspections

Piping in the condensate and feedwater systems will be hydrostatically tested during construction and all active system components such as pumps, valves, and controls will be functionally tested during startup. A bypass line with a locked closed valve is provided around the condensate polishing system for hydrostatic testing and prestartup system cleanup. Inservice inspections, as required by ASME XI, are discussed in Section 16.4.2. Samples are taken from the condenser hotwell, condensate pumps discharge, and feedwater pumps discharge to determine oxygen content, pH value, and possible contamination or deterioration. Safety class valves in the feedwater system

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require testing as specified in Section 16.4.2 (for safety class valves) and Section 16.4.4 (for containment isolation valves).

10.4.7.5 Instrumentation Applications

The condenser hotwell level is automatically controlled by high and low level controllers. The high level controller opens the valve in the condensate return line allowing condensate to return to the condensate storage tank. The low level controller opens the valve in the condensate supply line allowing condensate to pass from the condensate storage tank to the condenser hotwell. High and low levels are alarmed on the main control board.

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Low level in the condensate storage tank automatically opens the line from the demineralized water makeup system and a lower level alarms on the main control board. High level closes the makeup line and a higher level alarms on the main control board to alert the operator that makeup flow has not been stopped. The condensate storage tank level is continuously indicated on the main control board.

19 The feedwater isolation valves isolate the feedwater pump upon receipt of a feedwater isolation (FWI) signal.

Steam generator water level is controlled by steam generator water level control equipment (NSSS Vendor's scope).

Minimum condensate flow is controlled by a flow control condensate valve in a recirculation line to the condenser.

A minimum recirculation flow control valve for each feedwater pump protects against undue temperature or vibration in the feedwater pump casing at reduced pump flow.

10.4.7.6 Interface Requirements

Interface information applicable to the feedwater system, as presented in the respective NSSS Vendor's SARs, is discussed in Table 10.1-2.

10.4.8 Steam Generator Blowdown System

The steam generator blowdown system is used in conjunction with the chemical feed portion of the feedwater system (Section 10.4.7) and the condensate polishing system (Section 10.4.6) to control the chemical composition and solids concentration of the feedwater in the steam generators. The design of this system allows for heat recovery by use of a flash tank that returns steam to the fourth point feedwater heaters and condensate to the condenser hotwell. This system applies to an NSSS provided by either Westinghouse or Combustion Engineering. Babcock & Wilcox utilizes a once through steam generator which does not require a blowdown system.

The steam generator blowdown system is shown in Fig. 10.4.8-1.

Table 10.4.8-1 lists the design and operating conditions of the steam generator blowdown system components. The NSSS design and operating interface parameters are given in Table 10.4.8-2.

10.4.8.1 Design Bases

The design bases for the steam generator blowdown system are:

1. Piping and valves from the steam generators up to and including the containment isolation valves shall be

Safety Class 2, and shall be designed to ASME Section III, Code Class 2.

2. Other piping and equipment in the steam generator blowdown system shall be nonnuclear safety class (NNS) and shall be designed to ANSI B31.1.0b-1971 and ASME Section VIII.

3. During normal operation, the steam generators shall collectively blow down liquid continuously to the steam generator blowdown system. In the event of a major steam generator tube leak, the steam generator blowdown system shall be capable of processing the maximum expected blowdown rate.

4. The system meets the design objectives Items 6, 7, 8, 9, and 10 of Section 11.2.1.

10.4.8.2 System Description

The steam generator blowdown system consists of a flash tank and two pumps.

Each steam generator is provided with a blowdown connection. The rate of blowdown for each steam generator is controlled by flow control valves. The liquid passes through the valves and flashes in the tank.

In the flash tank, the steam is drawn off to the fourth point feedwater heaters, and the liquid is pumped to the condenser

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hotwell. One pump is normally operated. Upon high level signal in the flash tank, the second pump is started.

Individual blowdown samples may be monitored separately to determine which steam generator is leaking. The steam generator can be manually isolated by the operator, based on leakage rate, activity level, and boron concentration. The steam generator blowdown line is isolated on a containment isolation phase A (CIA) signal which closes the containment isolation valve in each blowdown line.

10.4.8.3 Design Evaluation

A failure analysis of the system components is presented in Table 10.4.8-3.

Containment isolation valves are open during normal operation and close on loss of air or on a CIA signal.

10.4.8.4 Testing and Inspections

Containment isolation valves in the steam generator blowdown system are tested monthly. In addition, containment isolation valves require testing as specified in Sections 16.4.2 and 16.4.4. 8

10.4.8.5 Instrument Applications

The radiation monitoring of the steam generator blowdown system is described under the reactor plant sampling system (Section 9.3.2). Solenoid operated pilot valves as shown on Fig. 10.4.8-1 are capable of actuation from the control room.

10.4.8.6 Interface Requirements

10.4.8.6.1 Westinghouse

The information given in RESAR 41, Section 10.4.8, and in Table 10.1-2 is not applicable since this system is supplied by S&W. The maximum blowdown rate is 1 percent of the main steam flow. The S&W blowdown system meets this requirement.

10.4.8.6.2 Combustion Engineering

In CESSAR, those portions of Section 10.4.6 that refer to the blowdown processing system are not applicable. The only requirement is that the system must handle the blowdown rate of 1 percent of the main steam flow. The S&W blowdown system meets this requirement.

10.4.8.6.3 Babcock & Wilcox

B-SAR has no blowdown system or interface requirements.

10.4.9 Turbine Plant Component Cooling System

The function of the turbine plant component cooling system is to remove heat from various nonsafety related turbine plant equipment.

The turbine plant component cooling system is shown in Fig. 10.4.9-1.

10.4.9.1 Design Bases

The design bases of the turbine plant component cooling system are:

1. The system shall not be safety related and shall be designated nonnuclear safety class (NNS).

2. The system shall supply cooling water at a maximum temperature of 105 F to the components served by this system.

3. The system shall transfer heat to the turbine plant service water system, which is at a maximum inlet temperature of 95 F.

10.4.9.2 System Description

The principal equipment served by the turbine plant component cooling system is as follows:

1. Turbine lubricating oil coolers (Section 10.2)

2. Electrohydraulic fluid coolers (Section 10.2)

3. Instrument air compressors and aftercoolers (Section 9.3.1)

4. Generator stator water coolers (Section 10.2)

5. Fourth point heater drain pump coolers (Section 10.4.7)

6. Exciter air cooler (Section 10.2)

7. Hydrogen coolers (Section 10.2)

8. Feedwater pump coolers (Section 10.4.7)

9. Condensate pump motor thrust bearing coolers (Section 10.4.7) 12

12 10. Turbine plant sample coolers (Section 9.3.2)

11. Turbine plant sample cooling bath makeup (Section 9.3.2)

Turbine plant component cooling water is pumped through shell and tube type heat exchangers where it is cooled by turbine plant service water. The cooled water then passes to the components listed above.

Three 50 percent capacity pumps and three 50 percent capacity heat exchangers are provided. This capacity is based on the maximum heat load which could occur during normal plant operation with a service water inlet temperature of 95 F. At other times, each heat exchanger and pump are capable of supplying more than 50 percent of the required cooling capacity.

The system is a closed loop. Variations in volume, due to temperature changes, are accommodated by a surge tank located at the pump suctions. The surge tank is at the high point of the system, and provides a net positive suction head for the pumps.

The entire system and the equipment cooled by the system are located in the turbine building.

Cooling water return piping from each component contains valves for control. The valves are either manually operated, positioned before plant startup, or automatic air-operated type, positioned by pressure or temperature control signals originating in the cooled system.

Relief valves are provided on all equipment which might be overpressurized by a combination of closed cooling water inlet and outlet valves, and heat input from the isolated equipment.

The surge tank level is automatically controlled and the tank capacity is sufficient to accommodate minor system surges and thermal swell. The surge tank is provided with a low level alarm to alert the operator to either a possible malfunction of the makeup valve or system leakage.

Makeup is supplied from the demineralized water makeup system (Section 9.2.3). An air-operated valve in the supply piping is automatically controlled from a surge tank level switch.

A chemical addition tank is connected to the pump discharge piping. To add chemicals to the system, the tank is isolated, drained, and filled with the desired chemicals. The tank isolation valves are then opened and the discharge pressure of the operating pump forces water through the tank, injecting the mixture into the common return line from the equipment served and
12 the pumps. The desired water chemistry is obtained by the addition of appropriate chemicals for corrosion inhibition and pH control.

10.4.9.3 Safety Evaluation

The low pressure, high temperature, and surge tank low level alarms alert the operator to malfunctions in the system. If a malfunction causing low pressure, high temperature, or low level is not corrected, components and systems served by the system may be inadequately cooled, requiring the operator to shut down the affected component or system to prevent damage.

During normal operation, two pumps and two heat exchangers can accommodate the heat removal load. The third pump and heat exchanger are spares, in the event of a pump or heat exchanger failure. All pumps and heat exchangers are rotated in service on a scheduled basis.

10.4.9.4 Testing and Inspections

During the life of the plant, all portions of the system are either in continuous or intermittent operation, and performance tests will not be required. Components are accessible for visual inspections conducted periodically and following installation of spare parts or piping modifications to confirm normal operation of the system. Routine prestartup inspections will be performed in addition to periodic observation and monitoring of the system parameters during operation.

10.4.9.5 Instrumentation Applications

Instrumentation and controls monitor system parameters and alert the operator to any component malfunction. Process variables of components required on a continuous basis for the startup, operation, or shutdown of the system are controlled from, and indicated and alarmed in, the control room. Those variables which require minimal operator attention are indicated locally.

Motor control switches and indicating lights for the pumps are provided on the main control board.

Electrically operated valves have controls and position indication in the control room.

Pressure and temperature indicators in the control room monitor the system. A low pressure alarm in the system warns the operator of any major leak in the system. The operator manually starts the third pump upon a motor trip alarm of one of the operating pumps.

Surge tank level is maintained by automatic control of the makeup control valve. High and low level alarms in the control room warn the operator of a failed makeup control valve or of a major leak in the system.

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10.4.10 Auxiliary Feedwater System

The function of the auxiliary feedwater system is to ensure a sufficient supply of cooling water to the steam generators so they can act as heat sinks for sensible and decay heat removal from the reactor core under loss of power, feedwater line malfunction, or main steam line break conditions.

The auxiliary feedwater system is shown in Fig. 10.4.10-1.

10.4.10.1 Design Bases

The design bases of the auxiliary feedwater system are:

1. The system shall be safety related (QA Category I) and Seismic Category I.

2. The system, from and including the containment isolation valves and up to the connections with the steam
3 generators or the feedwater system, is designated Safety Class 2 and shall be designed in accordance with ASME III, Code Class 2.

3. The system, up to but not including the containment isolation valves, is designated Safety Class 3 and shall be designed in accordance with ASME III, Code Class 3.

4. The auxiliary feedwater storage tank (AFST) shall contain, as a minimum, sufficient water to hold the reactor at hot shutdown for two hours, followed by an
3 orderly cooldown consistent with the NSSS Vendor's requirements until the pressure at which the residual heat removal system starts operating has been reached.

5. The system shall deliver sufficient auxiliary feedwater
3 to the steam generators following loss of normal feedwater to prevent lifting of the pressurizer relief valves caused by temperature and pressure buildup in the reactor coolant system.

6. The system shall deliver auxiliary feedwater against a steam generator pressure corresponding to the main steam safety valves set pressure plus accumulation.

7. The system shall include the capability of being controlled from the auxiliary shutdown panel following the unlikely event of control room inaccessibility.

10.4.10.2 System Description

Principal design and performance characteristics of the auxiliary feedwater system and its principal components are summarized in Table 10.4.10-1.

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The entire system is housed within the annulus building and containment structure and consists of auxiliary feedwater pumps, the AFST, and associated piping and valves.

The auxiliary feedwater pumps supply an emergency source of feedwater to the steam generators. The pumps ensure safe shutdown of the reactor in the event of a turbine-generator trip with complete loss of a-c power and also supply water to the steam generators in the event of a safety injection signal to remove core sensible and decay heat. The pumps are on standby service with only periodic startups to ensure operability and reliability (Section 16.4.8).

The auxiliary feedwater pumps can be started either automatically as described in Section 7.3.3.8 or manually from the main control board. In addition, the pumps can be started manually from the auxiliary shutdown panel. Each auxiliary feedwater pump normally takes suction through a separate supply line from the tornado and missile protected AFST.

Feedwater is pumped by the auxiliary feedwater pumps to each steam generator through control valves. Flow is monitored in each supply line to the steam generators. Each control valve can be manually adjusted from the control room as dictated by the steam generator water level and auxiliary feedwater flow rate. The control valves can also be manually adjusted from the auxiliary shutdown panel. In the event of a loss of power, these valves fail as is. The control valves are equipped with handwheels for manual operation, if necessary. 13

The auxiliary feedwater is discharged, depending on the NSSS Vendor, either directly to the steam generators or to the steam generators through connections in the feedwater piping inside the containment structure. This arrangement prevents loss of the auxiliary feedwater should a feedwater pipe break upstream of its containment isolation valve.

Each auxiliary feedwater pump, when operating, recirculates a specified flow back to the AFST. The pumps are sized to supply their rated capacities plus this minimum recirculation and wear allowance. The continuous recirculation eliminates the need for redundant recirculation controls, which would normally be required to ensure reliability of pumps which operate intermittently. Cooling water for each pump (and for the turbine oil cooler of the turbine-driven pump) is supplied from an extraction point on the first stage of the associated pump. This provides a guaranteed source of cooling water under all operating conditions.

The turbine drive receives steam from the main steam piping upstream of the main steam isolation valves (Section 10.3), thus ensuring that steam supply piping to the turbine drive is at main steam pressure and temperature whenever operation of the turbine 13 driven pump is required. Steam traps are provided to remove condensate.

Each motor-driven auxiliary feedwater pump receives power from a separate emergency electrical bus.

The AFST has sufficient capacity to satisfy the design bases of the auxiliary feedwater system. The condensate storage tank provides a nonsafety related source of water to the AFST for longer periods of hot shutdown. When the motor operated valve in the line connecting the two tanks is opened, water will drain by gravity into the AFST. Makeup connections to the AFST are provided from the demineralized water makeup system (Section 9.2.3). The long term emergency water supply is provided by connections to the pump suction lines from the reactor plant service water system (Section 9.2.1).

During plant startup, when main steam pressure is low, the auxiliary feedwater pumps provide feedwater to the steam generators by drawing suction from the AFST thus enabling sufficient steam to be produced to start up the main feedwater pumps.

10.4.10.3 Safety Evaluation

Each auxiliary feedwater pump has sufficient capacity to remove sensible and decay heat from the reactor core. One pump is always available in the event of the loss of one emergency bus. The turbine-driven pump can be used for sensible and decay heat removal as long as adequate steam is available. An ample supply of steam for the turbine drive is available provided at least one steam generator is providing steam to the turbine drive and the associated main steam piping up to the main steam isolation valve is intact. The need for sensible and decay heat removal is reduced to a level where the residual heat removal system can be used before the main steam pressure decreases to the point where the turbine-driven pump can not operate adequately.

Table 10.4.10-1 states the times allowed by the NSSS Vendors before the required auxiliary feedwater flow must be delivered to the steam generators. Based on investigations of the time required for the diesel generators to reach operating speed, the diesel generator loading sequence, and the time required for the auxiliary feedwater pumps to reach operating speed, the auxiliary feedwater pumps are able to deliver the required flow in less
19 than the times allowed by the NSSS Vendors.

The auxiliary feedwater pump flows and AFST capacities, shown in Table 10.4.10-1, are based on the requirements of the NSSS Vendors. Therefore, the auxiliary feedwater system has the capacity to accommodate the full spectrum of secondary system pipe breaks.

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Redundant piping flow paths ensure the required flow for adequate decay heat removal, assuming a single failure.

Controls on the auxiliary shutdown panel ensure that the reactor can be brought to hot shutdown should the control room become uninhabitable (Section 7.4).

The tornado and missile protected AFST meets Seismic Category I requirements and is available under all accident conditions.

Isolation of the containment structure from the auxiliary feedwater lines can be performed under administrative control after the AFST is exhausted.

The reactor plant service water system provides an emergency long term source of water to the suctions of the motor driven auxiliary feedwater pumps. Three 8 in. pipes connect to the pump suction lines. To prevent contamination of the auxiliary feedwater system, a spool piece is included at the auxiliary feedwater end of the piping, with a blind flange normally in 15
place. The spool piece is 8 in. diameter and approximately 1 ft long, and is stored alongside the pipe at the point of intersection. Service water is only required in the long term, after both the AFST and the condensate storage tank (if available) have been drained. Assuming that the condensate storage tank is not available, the spool piece must be installed before the AFST is emptied. The spool piece weighs approximately 100 lb, and can be installed by two workers in less than one hour. The shortest time in which the AFST would be emptied is approximately seven hours, for the Westinghouse RESAR-41 NSSS. (Other NSSS storage capacities result in longer time periods.) This 15
period allows more than adequate time for installation of the spool piece.

The consequences of component failure are presented in Table 10.4.10-2.

10.4.10.4 Testing and Inspection Requirements

The auxiliary feedwater pumps, their drives, and the pump discharge valves will be tested once a month, the pumps being tested as specified in Section 16.4.2. Steam is admitted to the turbine drive, and the motor drives are energized during these tests. Flow is established by recirculating auxiliary feedwater to the AFST. Following the completion of the test, the auxiliary feedwater pumps are shut off and the motor operated valves leading to the feedwater lines are opened. Safety class valves require testing as specified in Section 16.4.2 (for safety class valves) and Section 16.4.4 (for containment isolation valves).

10.4.10.5 Instrumentation Applications

The AFST is provided with redundant remote level indication and low level alarm on the main control board and indication on the auxiliary shutdown panel.

A normally closed air operated valve in the pipe connecting the condensate storage tank to the AFST is opened upon low level in the AFST or can be manually opened following a loss of power.

High level in the AFST closes the valve to ensure that the AFST does not overflow. 13

Auxiliary feedwater control valves are normally open and can be remote manually modulated to maintain level in the steam generators.

Auxiliary feedwater pump starting signals are given in Section 7.3.3.8.

Flow indicators in the control room monitor system operation. 13

10.4.10.6 Interface Requirements

Interface information applicable to the auxiliary feedwater system, as presented in the respective NSSS Vendor's SARs, is discussed in Table 10.1-2.

10.4.11 Turbine Plant Service Water System

The function of the turbine plant service water system is to remove heat from various nonsafety related plant equipment and to dissipate that heat to the environment.

The turbine plant service water system is shown in Fig. 10.4.11-1.

10.4.11.1 Design Bases

The design bases of the turbine plant service water system are:

1. The system shall not be safety related and shall be designated nonnuclear safety class (NNS).

2. The system shall supply cooling water at a maximum temperature of 95 F to the components served by the system.

10.4.11.2 System Description

The principal equipment served by the turbine plant service water system are:

1. Turbine plant component cooling heat exchangers (Section 10.4.9).

2. Mechanical refrigeration units (Section 9.2.8).

The major portion of the turbine plant service water system consists of three 50 percent capacity pumps and three self-cleaning strainers, along with the necessary piping and valves.

The source of turbine plant service water will be discussed in the Utility-Applicant's SAR.

During normal operation and normal plant cooldown conditions, two pumps discharge through the components listed above and then into the circulating water discharge.

Cooling water lines from each component contain valves for controlling flow. The valves are of the automatic air-operated type, positioned by temperature signals originating in the cooled system.

In addition to the above equipment, two 100 percent capacity recirculation pumps and appropriate instrumentation are provided
9 for cold weather operation of each set of mechanical refrigeration units. Operation of the recirculation loop ensures an inlet service water temperature sufficiently high to enable proper operation of the mechanical refrigeration units.

10.4.11.3 Safety Evaluation

The low pressure alarm alerts the operator to malfunctions in the system. If a malfunction causing low pressure is not corrected, components and systems served by the system may be inadequately cooled, requiring the operator to shut down the affected component or system. No safety functions will be impaired by this component or system shutdown, because no safety related function is dependent on the system.

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The low temperature alarm on the mechanical refrigeration units inlet alerts the operator of a low temperature which may cause improper operation of the units. Following the alarm, the

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operator will manually start one of the recirculation pumps to raise the inlet service water temperature.

The high temperature alarm alerts the operator to shut down the operating recirculation pump.

During normal operation, two pumps can accommodate the heat removal load. The third pump is a spare so that in the event of a pump failure, a replacement component is available. The third pump is rotated in service on a scheduled basis.

10.4.11.4 Testing and Inspections

During the life of the plant, all portions of the system except the mechanical refrigeration units recirculation pumps are either in continuous or intermittent operation, and performance tests are not required. The recirculation pumps will be tested periodically when recirculation is not required. When recirculation is required, the second pump will be rotated in service on a scheduled basis. Components are accessible for visual inspections conducted periodically and following installation of spare parts or piping modifications to confirm normal operation of the system. Routine prestartup inspections will be performed in addition to periodic observation and monitoring of the system parameters during operation.

10.4.11.5 Instrumentation Applications

Instrumentation and controls monitor system parameters and alert the operator to any component malfunction. Process variables of components required on a continuous basis for the startup, operation, or shutdown of this system are controlled from, and indicated and alarmed in, the control room. Those variables which require minimal operator attention are indicated locally.

Motor control switches and indicating lights for the pumps are provided on the main control board.

Pressure and temperature indicators in the control room monitor the system. A low pressure alarm in the system warns the operator of a major leak in the system or a failure of an operating pump. The operator manually starts the third pump upon a motor trip alarm of one of the operating pumps.

When the inlet service water temperature to the mechanical refrigeration units is too low to permit proper operation of the units, a recirculation pump is started and the service water discharge valve throttled to maintain a sufficiently high service water temperature. Low and high temperature alarms alert the operator to either start or stop a recirculation pump.

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10.4.11.6 Interface Requirements

9 The source of turbine plant service water will be discussed in Section 10.4.11 of the Utility Applicant's SAR. This water source interfaces with the balance of the turbine plant service water system as indicated on Fig. 10.4.11-1.

10.4.12 Auxiliary Steam and Condensate System

The functions of the auxiliary steam and condensate system are to supply heating steam throughout the plant to various heating and processing equipment, and to recover the condensed steam from the equipment served.

The auxiliary steam and condensate system is shown in Fig. 10.4.12-1.

10.4.12.1 Design Bases

The design bases of the auxiliary steam and condensate system are:

1. The system shall not be safety related.

2. Piping for this system shall be designed in accordance with ANSI B31.1.0-1971 and shall be designated nonnuclear safety class (NNS).

3. The system shall provide steam to the equipment requiring it both during normal operation and during plant shutdown.

4. The system shall have the capability to remove radioactive contaminants carried over from the equipment served.

10.4.12.2 System Description

The auxiliary steam and condensate system is capable of supplying the auxiliary steam requirements of two nuclear power plants located adjacent to one another. The auxiliary boiler building and the equipment contained therein and the steam supply to the domestic hot water tank in the service building will be shared between the two plants.

When one plant is shut down, auxiliary steam from the operating plant will be provided to the shutdown plant through a connection between the auxiliary steam supply headers of the two plants. A connection is also provided to return condensate from the shutdown plant to the operating plant to maintain fluid inventories in each plant.

For a single nuclear power plant, the system will be complete, as shown in Fig. 10.4.12-1 except the steam and condensate connections to the second plant will not be provided.

The auxiliary steam supply header for each nuclear power plant normally receives its steam requirements from one of three sources. During normal operation, the steam is supplied from low pressure turbine extraction steam. When extraction steam pressure is too low, steam is supplied from the main steam manifold, through a pressure reducing valve. When main steam pressure is too low, or during plant shutdown, steam is supplied either from the adjacent operating nuclear power plant or by the auxiliary boilers if there is only one nuclear power plant or if the second nuclear power plant is also shut down.

Auxiliary steam is used by and condensed in the equipment listed below:

1. Auxiliary boiler deaerator

2. Boron evaporator reboiler (Section 9.3.7)

3. Degasifier feed preheater (Section 11.3)

4. Waste evaporator reboiler (Section 11.2)

5. Boric acid batch tank (if required by NSSS Vendor) (Section 9.3.4)

6. Domestic hot water tank (Section 9.2.4)

7. Laundry waste evaporator (Section 11.2)

8. Building heating heat exchangers (Section 9.4.7)

9. Demineralized water storage tank heater (Section 9.2.3)

10. Condensate storage tank heater (Section 10.4.7)

11. Steam jet air ejectors (Section 10.4.2)

12. Turbine gland seal steam system (Section 10.4.3)

13. Steam generator blowdown system (Section 10.4.8)

The condensate from the boron evaporator reboiler, the degasifier feed preheater, the waste evaporator reboiler, the boric acid batch tank (if heating steam to this component is required by the NSSS Vendor), the laundry waste evaporator, and the steam generator blowdown system are collected in the annulus building auxiliary condensate receiver. On high level in the condensate receiver, the auxiliary condensate is pumped by one of two 100 percent capacity pumps to the condenser via the condensate system (Section 10.4.7). 12

The condensate from the building heating heat exchangers, the turbine gland sealing system, the demineralized water storage tank heater, and the condensate storage tank heater is collected in the turbine building auxiliary condensate receiver. On high level in the condensate receiver, the condensate is pumped by one of two 100 percent capacity pumps to the condenser via the condensate system. 12

The condensate from the steam jet air ejectors drains to the condenser (see Section 10.4.2). A line from the condensate pumps

12 discharge, containing a flow limiting device, connects to the turbine building auxiliary condensate receiver.

12 The device is sized such that the mass flow passing from the condensate system to the auxiliary condensate receiver is the same as the auxiliary steam flow to the steam jet air ejectors.

When auxiliary steam is supplied from a second nuclear power plant, the condensate collected in the auxiliary condensate receivers will be pumped directly to the condenser of the plant which is operating. When the auxiliary boilers are operating, the condensate will be pumped to the auxiliary condensate tank in the auxiliary boiler building.

The auxiliary boiler condensate tank provides the source of auxiliary feedwater for the auxiliary boilers. On low level in the auxiliary boiler condensate tank, makeup is provided from the demineralized water makeup system (Section 9.2.3). On high level in the tank, the condensate is pumped by one of two 100 percent capacity pumps either to the condenser of either plant, depending on system fluid inventories, or to the auxiliary boiler deaerator, should low level be indicated in the deaerator.

When operation of the auxiliary boilers is required, auxiliary boiler feedwater is pumped by one of two 100 percent capacity pumps from the auxiliary boiler deaerator.

Blowdown from the auxiliary boilers flows to the auxiliary boiler blowdown tank. The portion of the blowdown which flashes into steam passes to the ventilation vent (Section 6.2.3.1).

Pressure in the turbine building auxiliary condensate receiver, the auxiliary boiler condensate tank, and the auxiliary boiler blowdown tank is equalized through interconnecting vent lines. Pressure in the auxiliary boiler deaerator is relieved to the same vent line through a restricting orifice. The vent lines combine and relieve to the radioactive gaseous waste system. The annulus building auxiliary condensate receiver also vents to the radioactive gaseous waste system.

The drain and overflow from the auxiliary boiler blowdown tank flow to the aerated portion of the reactor plant vents and drains system (Section 9.3.3).

Two packaged water tube auxiliary boilers are provided for low load and shutdown operation. Each auxiliary boiler is equipped with controls and indication for automatic operation.

10.4.12.3 Safety Evaluation

Together, the auxiliary boilers can accommodate a normal plant shutdown with normal building heating being provided. With loss of one auxiliary boiler, the other auxiliary boiler can accommodate a normal plant shutdown and an orderly plant startup.

with building heating to 40 F being provided. The auxiliary steam header is protected from malfunction of the pressure reducing valve by a safety valve. 3

10.4.12.4 Testing and Inspections

The auxiliary steam and condensate system is normally in continuous operation, and thus performance tests are not required. Visual inspections will be conducted following system maintenance to confirm normal operation of the systems.

10.4.12.5 Instrumentation Applications

Each auxiliary boiler is provided with automatic combustion controls, burner controls, and a three element feedwater control system. Safety valves on the auxiliary boilers are set at the design pressure of the auxiliary boilers. Control valves in the auxiliary steam lines to the various heaters regulate the temperature in the equipment being serviced. A relief valve on the boric acid batch tank jacket protects the batch tank.

The level in the auxiliary boiler condensate tank is maintained by modulating a level control valve to control condensate flow to the auxiliary boiler deaerator and to the condenser. Level switches in the auxiliary condensate receivers and the auxiliary boiler condensate tank shut off the associated pump when the low level boiler switch settings are reached.

Level controls maintain condensate level in the steam-to-water heat exchanger shells to improve heat transfer and allow subcooling of the condensate.

10.4.13 Lubricating Oil System

The functions of the lubricating oil system are to receive, store, purify, cool, and provide lubricating oil to the bearings of the main turbine-generator and the feedwater pump turbines, to provide oil to the generator hydrogen seal oil system, and to provide high pressure oil to the turbine control system (if required by the turbine manufacturer).

10.4.13.1 Design Bases

The design bases of the lubricating oil system are:

1. The system shall not be safety related and shall be designated nonuclear safety class (NNS).

2. The system shall furnish lubricating oil to the thrust and journal bearings of the main turbine and the feedwater pump turbines.

668 178

3. The system shall supply oil to the generator hydrogen seal oil system.

4. The system shall supply high pressure oil to the turbine control system (if required by the turbine manufacturer).

5. The system shall reclaim used oil from the equipment supplied by the system.

6. The system shall purify a side stream of oil on a continuous bypass basis.

7. The lubricating oil shall be maintained at a temperature compatible with the requirements of the turbine manufacturer.

10.4.13.2 System Description

The lubricating oil system consists of two integrated sections (1) the turbine-generator lubricating oil section which includes the bearing oil pumps, turbine lubricating oil reservoir, and the oil coolers; and (2) the lubricating oil conditioning and storage circuit consisting of clean and used oil storage tanks, an oil purifier, and a motor driven transfer pump. The pump is a positive displacement type, capable of two-speed operation to accomplish both the transfer and circulation requirements.

The clean and used oil storage tanks are located inside a fireproof room equipped with a trap drain, water sprays, and vent fans. The pumps and piping are arranged so that oil can be processed from the turbine lubricating oil reservoir or either of the storage tanks. The processed oil can be returned to either of the storage tanks or to the turbine lubricating oil reservoir as required. Vapor extractors purge oil fumes from the reservoir and exhaust them to the atmosphere outside the turbine building.

Lubricating oil to the turbine-generator is normally supplied from a turbine shaft driven pump. An a-c motor driven turning-gear oil pump supplies bearing lubrication for startup, shutdown, and standby operation when a-c power is available. A d-c motor driven bearing oil pump, operated from the normal station battery, ensures bearing lubrication in the event a-c power fails.

Turbine lubricating oil coolers, located in the turbine lubricating oil reservoir, remove heat generated in the turbine-generator bearings and transfer it to the turbine plant component cooling system (Section 10.4.9).

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10.4.13.3 Safety Evaluation

In the event plant a-c power fails, the turbine-generator safely comes to rest using the backup d-c bearing oil pump. The normal station battery provides an uninterrupted source of power to operate this pump.

10.4.13.4 Tests and Inspections

The d-c bearing oil pump will be tested periodically. Other components will be tested in accordance with turbine vendor recommendations.

10.4.13.5 Instrumentation Applications

Turbine-generator bearing oil pressure and temperatures are indicated both locally and in the control room. Low pressure and high temperature alarms are provided in the control room. Alarms also announce low oil level in the turbine lubricating oil reservoir.

Table 10.4.7-1 is deleted. 8

668 101

TABLE 10.4.8-1

STEAM GENERATOR BLOWDOWN SYSTEM
COMPONENT DESIGN AND PERFORMANCE CHARACTERISTICS

Flash Tank	
Number	1
Capacity, gpm	380
Design pressure, psig	100/full vacuum
Design temperature, F	350
Material of construction	Carbon steel
Flash Tank Pumps	
Number	2
Capacity, gpm	380
Design pressure, psig	115
Design temperature, F	350
Material of construction	Carbon steel

7

TABLE 10.4.8-2

NSSS DESIGN AND OPERATING INTERFACE PARAMETERS

NSSS Vendor	Number of Steam Generators	Expected Blowdown Flow	Design Blowdown Flow
Westinghouse-41	4	60 gpm	360 gpm
Westinghouse-3S	4	60 gpm	360 gpm
Combustion Engineering	2	150 gpm	375 gpm
Babcock & Wilcox		not applicable	

20

668 103

TABLE 10.4.8-3

CONSEQUENCES OF COMPONENT FAILURES,

STEAM GENERATOR BLOWDOWN SYSTEM

Components	Malfunctions	Comments and Consequences	
System valves	Loss of air or electric power	All air operated valves fail closed on loss of air or electric power.	
Flash tank	Rupture	A relief valve prevents overpressure of the tank.	7
Pump	Failure	The pumps are each full capacity so that system integrity is ensured.	

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TABLE 10.4.10-2

CONSEQUENCES OF COMPONENT FAILURES
AUXILIARY FEEDWATER SYSTEM

Components	Malfunctions	Comments and Consequences	
Auxiliary feedwater pumps	Pump casing ruptures.	Each pump can be isolated by suction and discharge isolation valves. Full system capability can be retained by using any one pump.	
	Pump fails to start. Either motor-driven pump fails to start.	One pump can be used to achieve full system capability to bring the plant to hot shutdown conditions and to remove residual heat for core protection.	9
System valves	Improper position	Should any single valve be improperly positioned, full system capability can be retained by using any one pump.	9
	Failure to operate	System capability, in the event of a failure of the control valve on the discharge of any one of the pumps, is retained by using any one of the other pumps.	9
Electrical supply	Diesel generator fails to operate.	Failure of one diesel generator does not prevent operation of another motor-driven pump or the turbine-driven pump, any one of which can provide sufficient cooling water for all accident conditions.	9

668 185

TABLE 10.4.10-3 has been deleted. 9

668 186

TABLE 10.4.10-1

AUXILIARY FEEDWATER SYSTEM
COMPONENT DESIGN AND PERFORMANCE CHARACTERISTICS

Item	Design and Performance Characteristics			
Turbine-Driven Auxiliary Feedwater Pump	B&W	C-E	W-41	W-3S
Number	1	1	1	1
Design pressure, psia	1,700	1,900	1,900	1,900
Design temperature, F	120	120	120	120
Required flow to steam generators, gpm	1,235	875	500	940
Total developed head, ft	3,100	3,527	3,360	3,300
Design flow of pumps, gpm	1,660	1,186	693	1,275
Motor-Driven Auxiliary Feedwater Pumps				
Number	2	2	3	2
Design pressure, psia	1,800	1,900	1,900	1,900
Design temperature, F	120	120	120	120
Required flow to steam generators, gpm	620	438	500	470
Total developed head, ft	3,100	3,495	3,332	3,300
Design flow of pumps, gpm	820	581	665	625
Auxiliary Feedwater Storage Tank (AFST)				
Number	1	1	1	1
Capacity, gal	200,000	225,000	250,000	214,000
Design pressure, psia	Atmospheric	Atmospheric	Atmospheric	Atmospheric
Design temperature, F	140	140	140	140
Time allowed before required flow must be delivered to steam generators.	Within 40 sec from receipt of signal	Within 45 sec from receipt of signal	Within 60 sec from initiating signal	Within 60 sec from initiating signal 35

668 107

TABLE 10.4.10-2

CONSEQUENCES OF COMPONENT FAILURES
AUXILIARY FEEDWATER SYSTEM

Components	Malfunctions	Comments and Consequences
Auxiliary feedwater pumps	Pump casing ruptures.	Each pump can be isolated by suction and discharge isolation valves. Full system capability can be retained by using any combination of two pumps.
	Turbine-driven pump fails to start.	Two motor-driven pumps can be used to achieve full system capability to bring the plant to hot shutdown conditions and to maintain steam generator level.
	Either motor-driven pump fails to start.	The second motor-driven pump can be used to remove residual heat for core protection. The turbine-driven pump can maintain steam generator water level.
System valves	Improper position	Should any single valve be improperly positioned, full system capability can be retained by using either of the other two pumps.
	Failure to operate	System capability, in the event of a failure of the control valve on the discharge of any one of the pumps, is retained by using either of the other two pumps.
Electrical supply	Diesel generator fails to operate.	Failure of one diesel generator does not prevent operation of the second motor-driven pump or the turbine-driven pump which can provide sufficient cooling water for all accident conditions.

668 190

TABLE 10.4.10-2

CONSEQUENCES OF COMPONENT FAILURES
AUXILIARY FEEDWATER SYSTEM

Components	Malfunctions	Comments and Consequences
Auxiliary feedwater pumps	Pump casing ruptures.	Each pump can be isolated by suction and discharge isolation valves. Full system capability can be retained by using any combination of two pumps.
	Turbine-driven pump fails to start.	Two motor-driven pumps can be used to achieve full system capability to bring the plant to hot shutdown conditions and to maintain steam generator level.
	Either motor-driven pump fails to start.	The second motor-driven pump can be used to remove residual heat for core protection. The turbine-driven pump can maintain steam generator water level.
System valves	Improper position	Should any single valve be improperly positioned, full system capability can be retained by using either of the other two pumps.
	Failure to operate	System capability, in the event of a failure of the control valve on the discharge of any one of the pumps, is retained by using either of the other two pumps.
Electrical supply	Diesel generator fails to operate.	Failure of one diesel generator does not prevent operation of the second motor-driven pump or the turbine-driven pump which can provide sufficient cooling water for all accident conditions.

668 189

TABLE 10.4.10-2

CONSEQUENCES OF COMPONENT FAILURES
AUXILIARY FEEDWATER SYSTEM

Components	Malfunctions	Comments and Consequences	
Auxiliary feedwater pumps	Pump casing ruptures.	Each pump can be isolated by suction and discharge isolation valves. Full system capability can be retained by using any combination of two pumps.	6
	Turbine-driven pump fails to start.	Two motor-driven pumps can be used to achieve full system capability to bring the plant to hot shutdown conditions and to maintain steam generator level.	
	Either motor-driven pump fails to start.	The second motor-driven pump can be used to remove residual heat for core protection. The turbine-driven pump can maintain steam generator water level.	6
System valves	Improper position	Should any single valve be improperly positioned, full system capability can be retained by using either of the other two pumps.	
	Failure to operate	System capability, in the event of a failure of the control valve on the discharge of any one of the pumps, is retained by using either of the other two pumps.	
Electrical supply	Diesel generator fails to operate.	Failure of one diesel generator does not prevent operation of the second motor-driven pump or the turbine-driven pump which can provide sufficient cooling water for all accident conditions.	

668 190

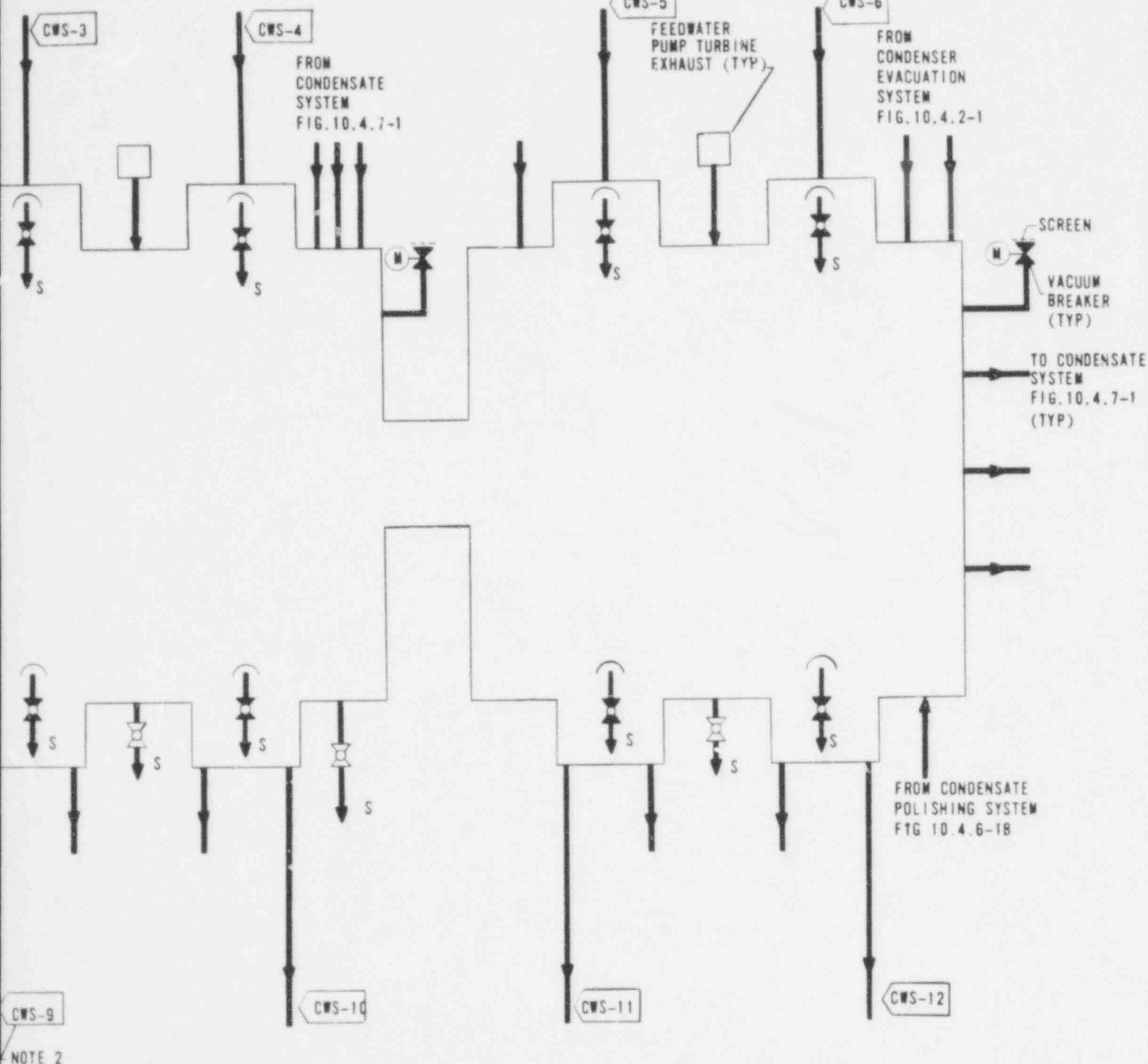
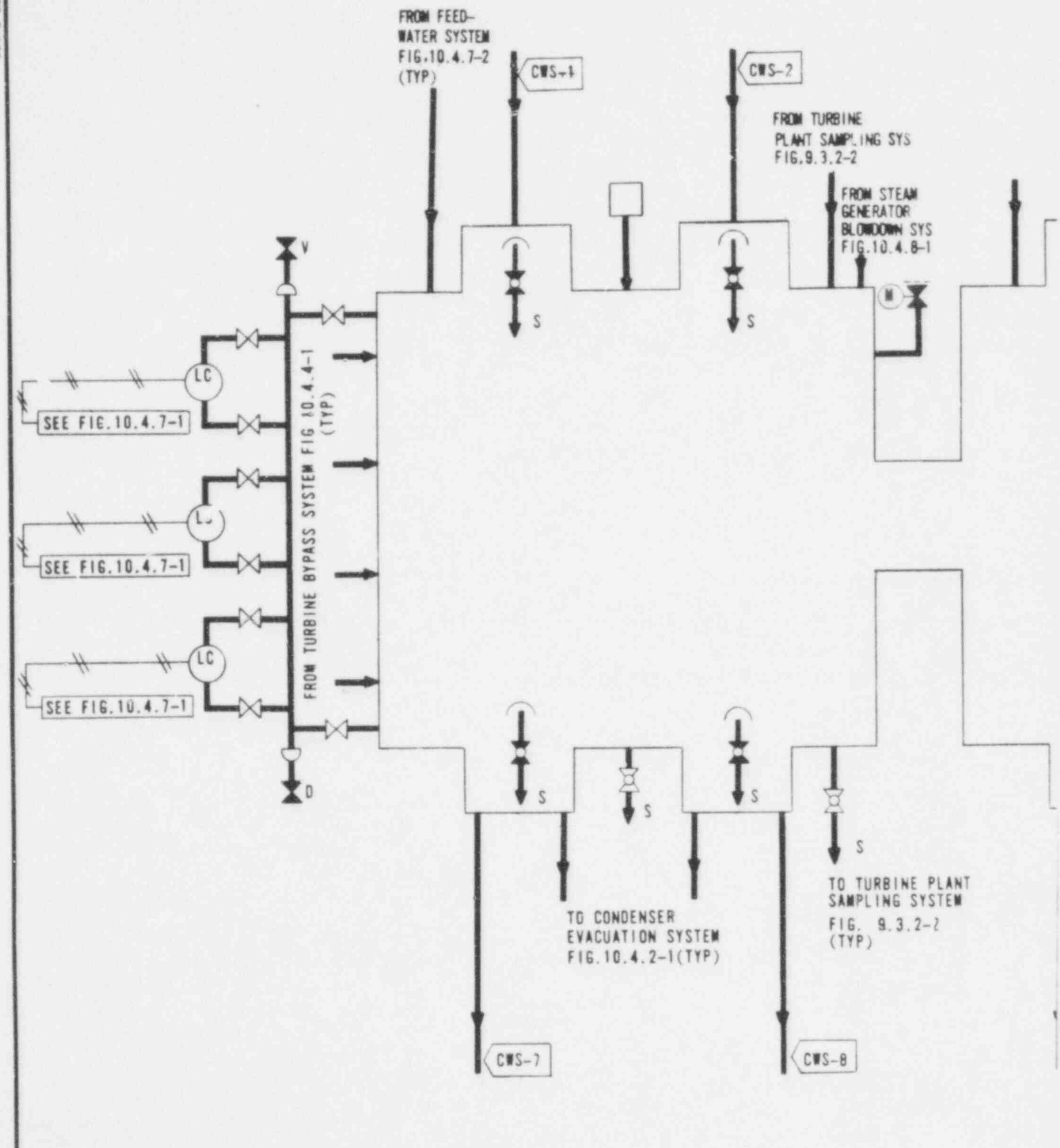


FIG.10.4.1-1

CONDENSER

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

668 191



NOTE:

1. THIS SYSTEM IS NON-NUCLEAR SAFETY CLASS (NNS) LOCATED IN TURBINE BUILDING.

2. SYSTEM INTERFACE POINTS CWS-1 THRU 6/CWS-7 THRU 12 ARE WITH CIRCULATING WATER SYSTEM INLETS/OUTLETS. SEE UTILITY APPLICANT'S SAR, SECTION 10 4.5.

668 192

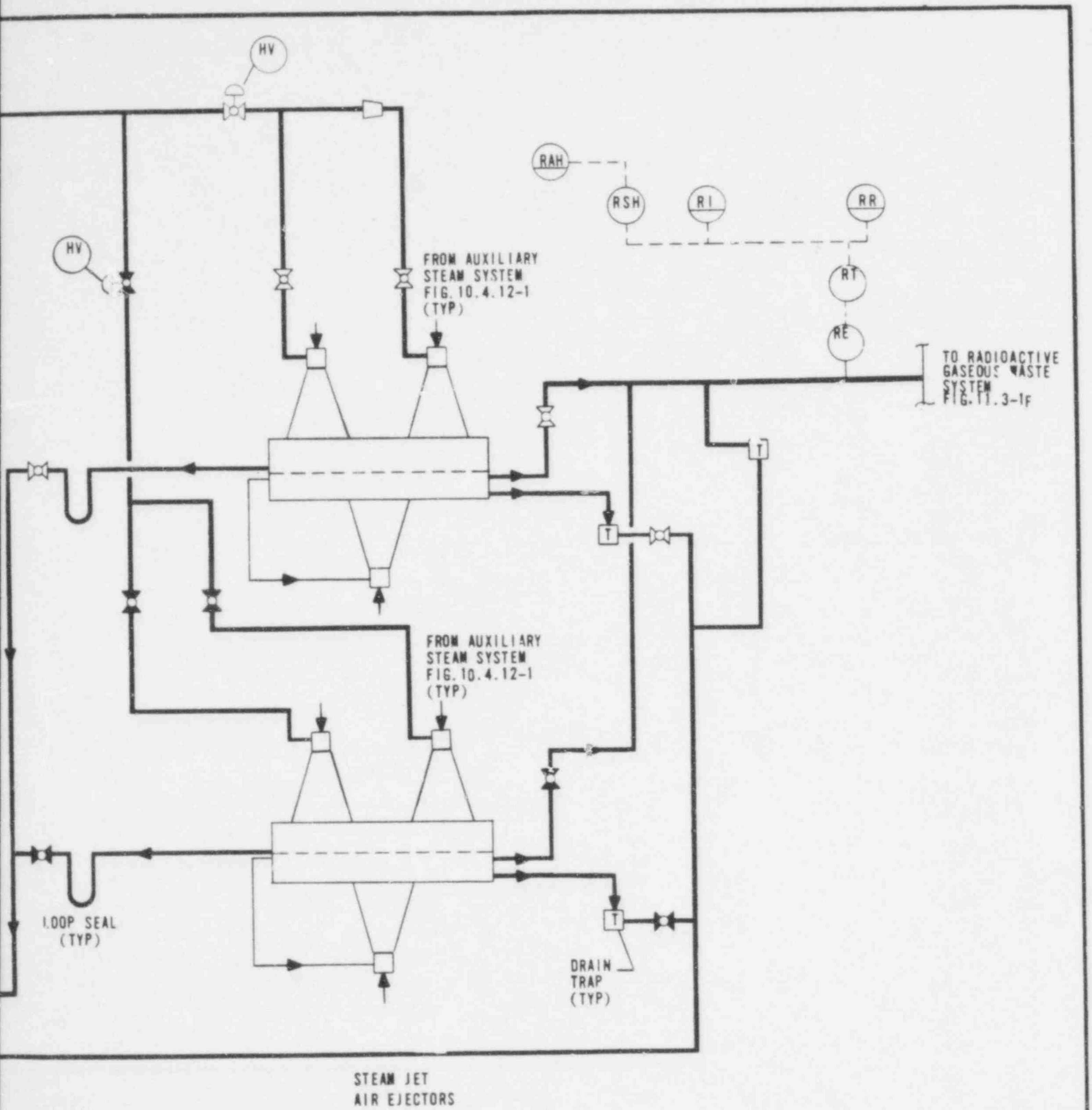
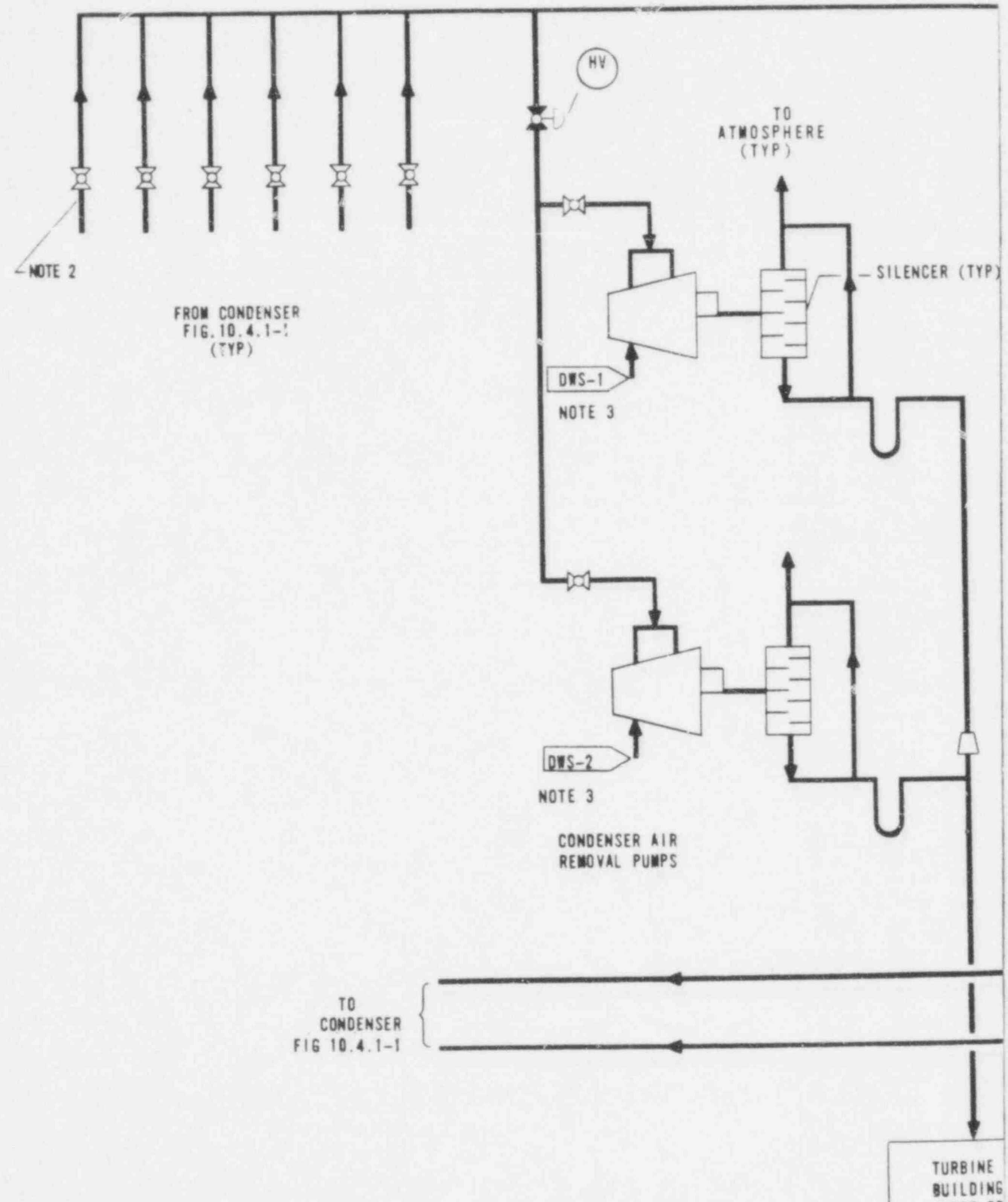


FIG. 10.4.2-1

CONDENSER EVACUATION SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P4

668 193



NOTE:

1. THIS SYSTEM IS NON-NUCLEAR SAFETY CLASS (NNS). LOCATED IN TURBINE BUILDING.
2. NUMBER OF CONDENSER CONNECTIONS TO BE DETERMINED BY CONDENSER MANUFACTURER.
3. SYSTEM INTERFACE POINTS DWS-1&2 ARE DOMESTIC WATER SUPPLY PROVIDED BY UTILITY APPLICANT.

668 194

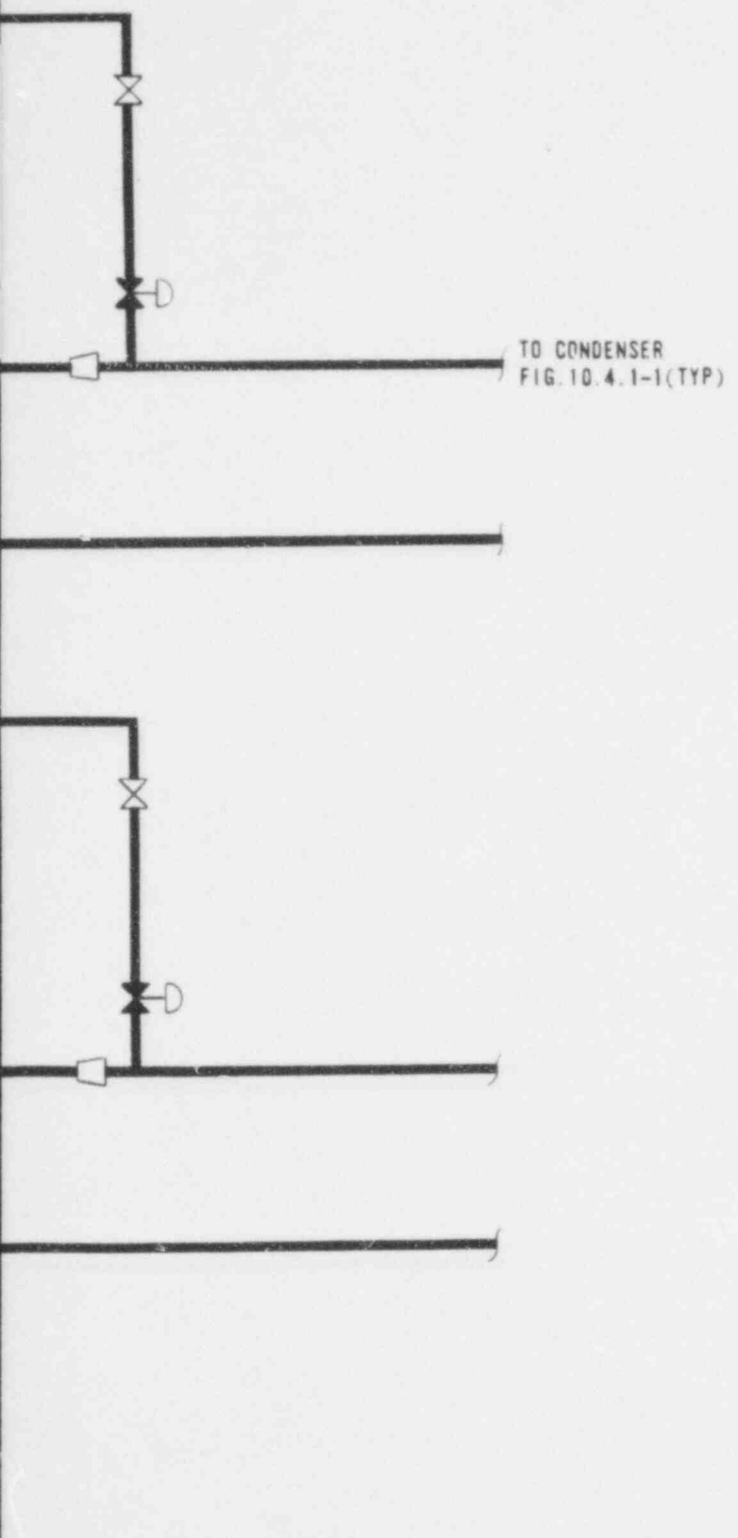
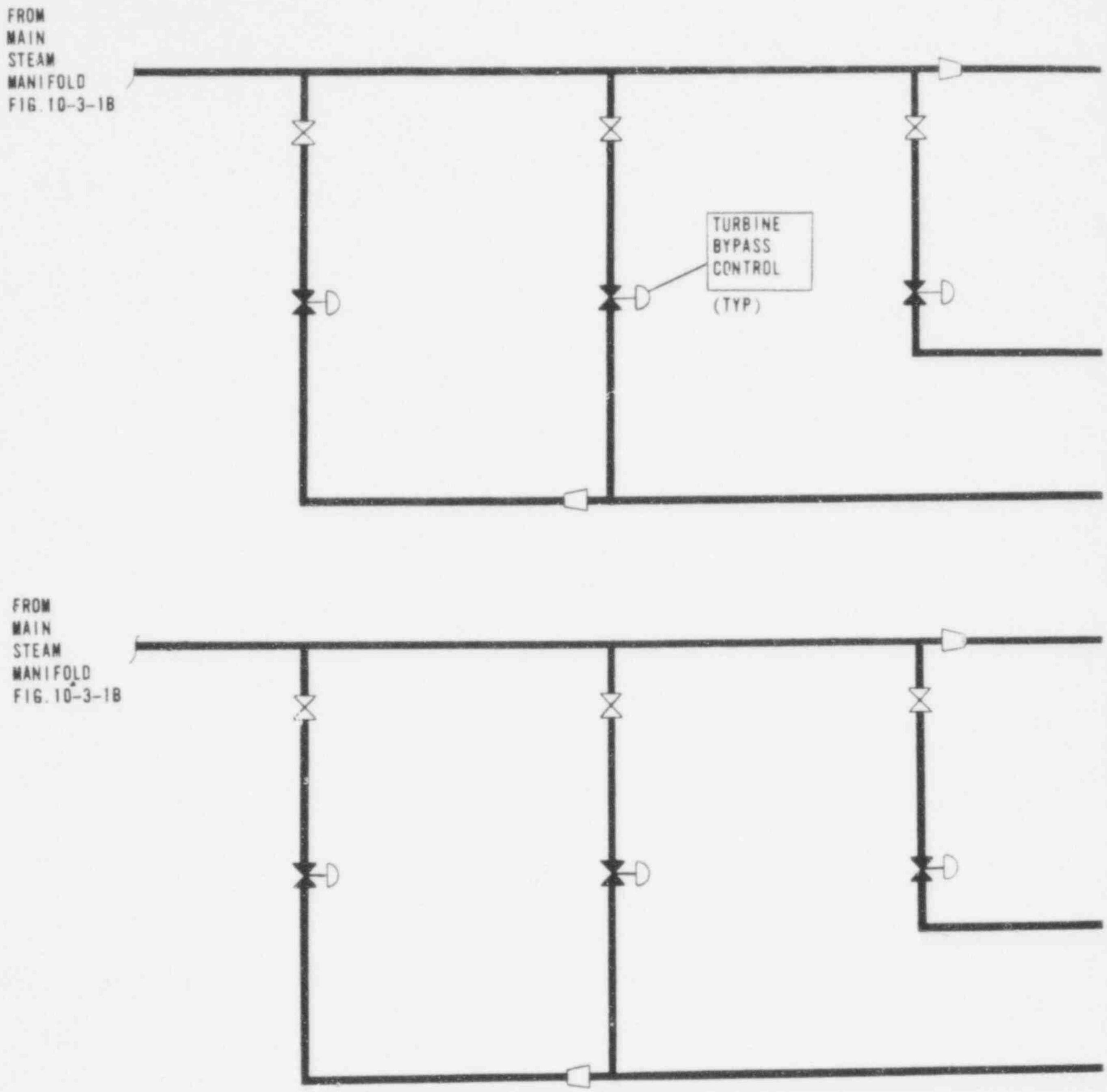


FIG 10.4.4-1

TURBINE BYPASS SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

668 195



NOTE:

1. THIS SYSTEM IS NON-NUCLEAR SAFETY CLASS (NNS), LOCATED IN TURBINE BUILDING.

668 196

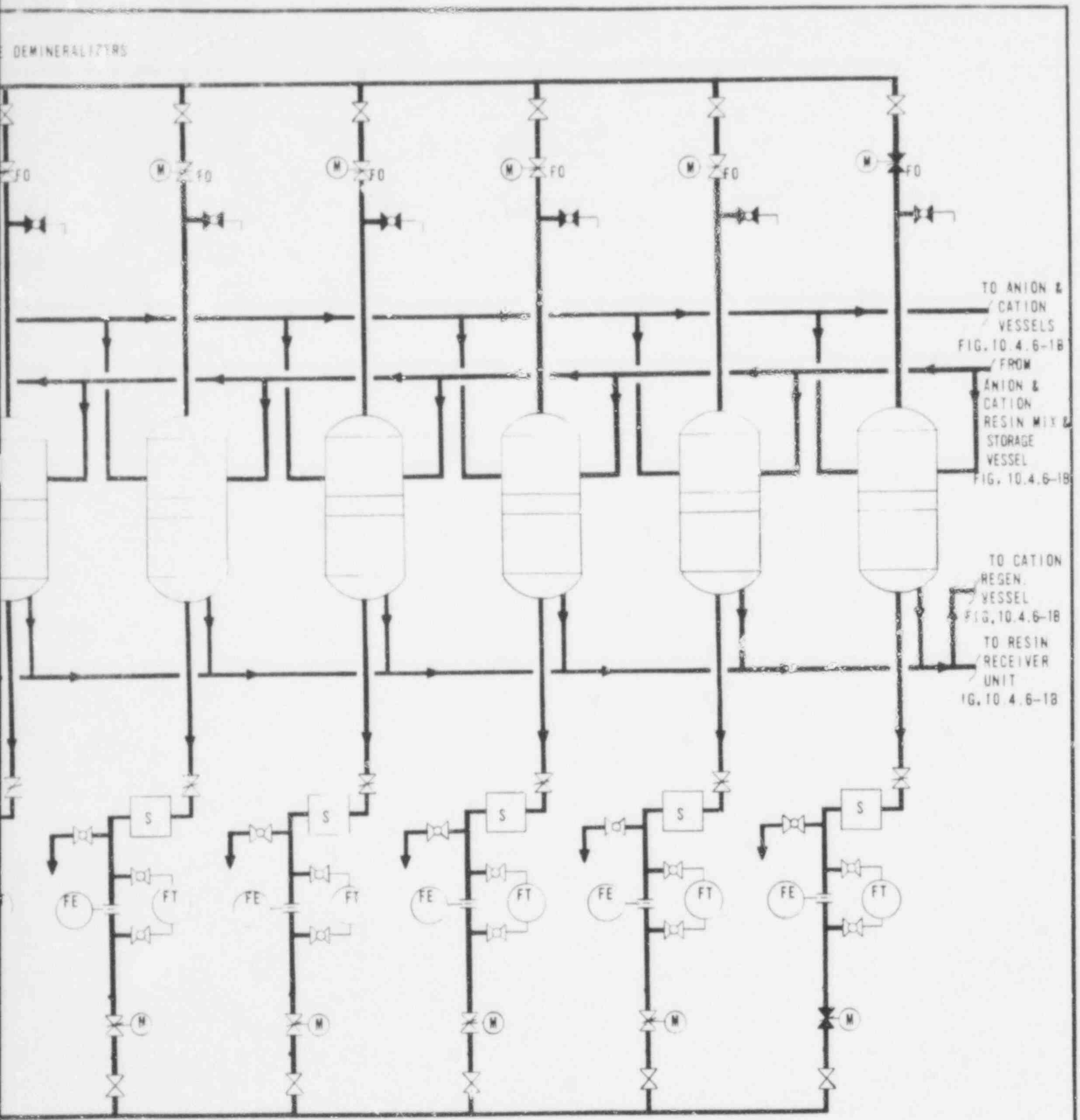
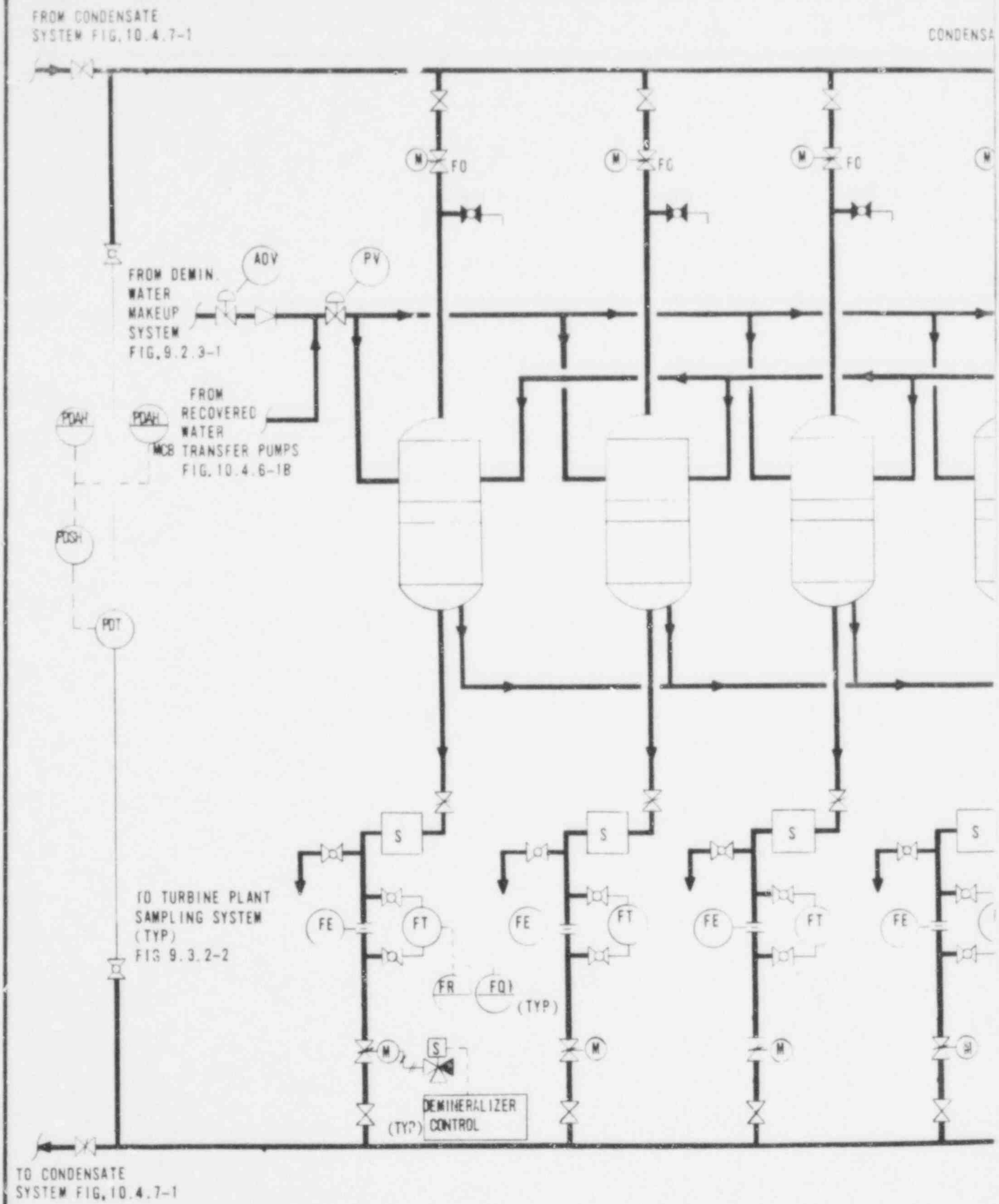


FIGURE 10.4.6-1A

CONDENSATE POLISHING SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1 668 197



NOTE:

1. THIS SYSTEM IS NON-NUCLEAR SAFETY CLASS (NNS) LOCATED IN TURBINE BUILDING.
2. NUMBER OF DEMINERALIZERS IS DEPENDENT ON CONDENSATE FLOW. REFER TO SECTION 10.4.6.2 FOR NUMBER FOR EACH NSSS.

668 198

BRUNING 44-122 21039

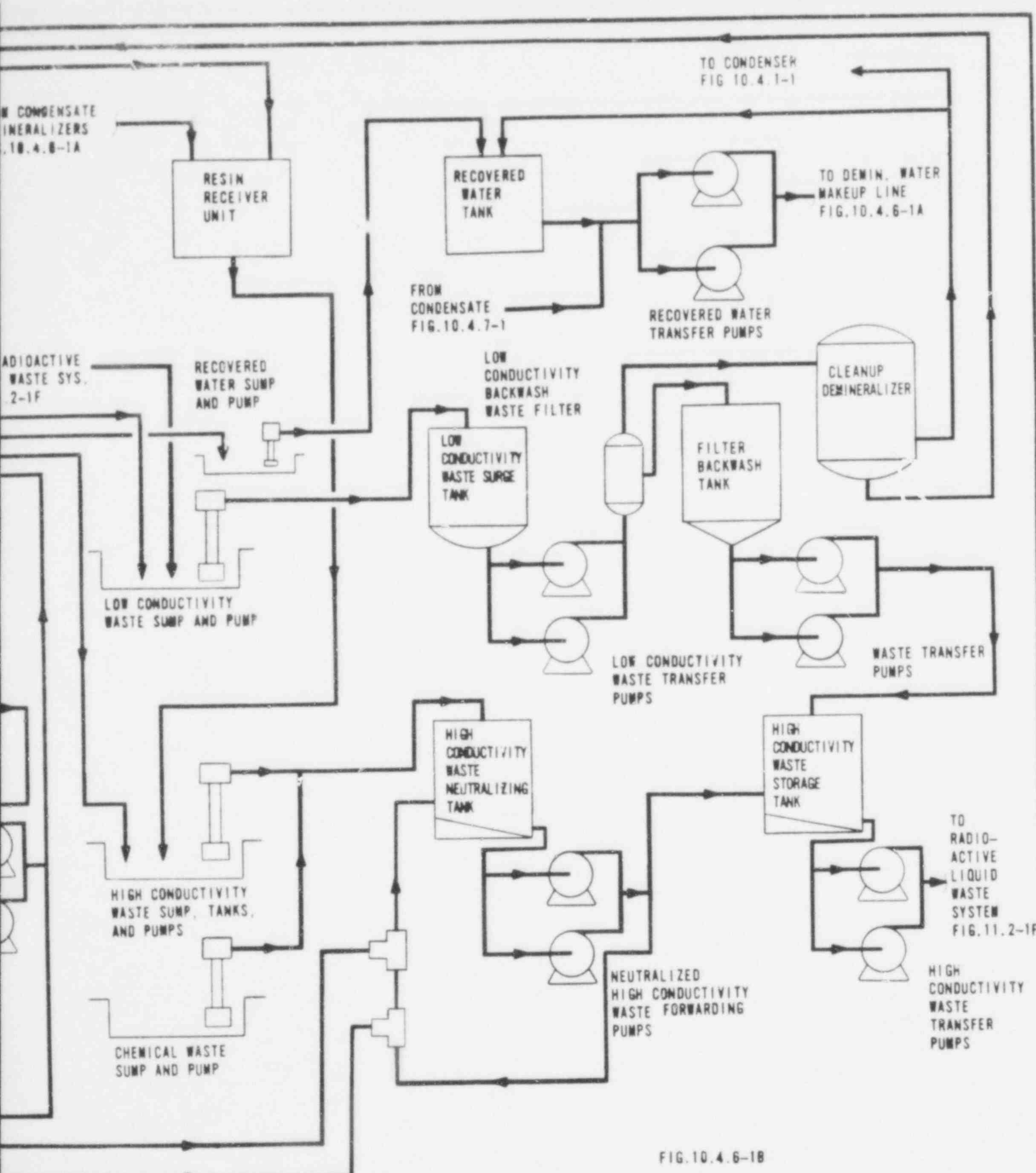
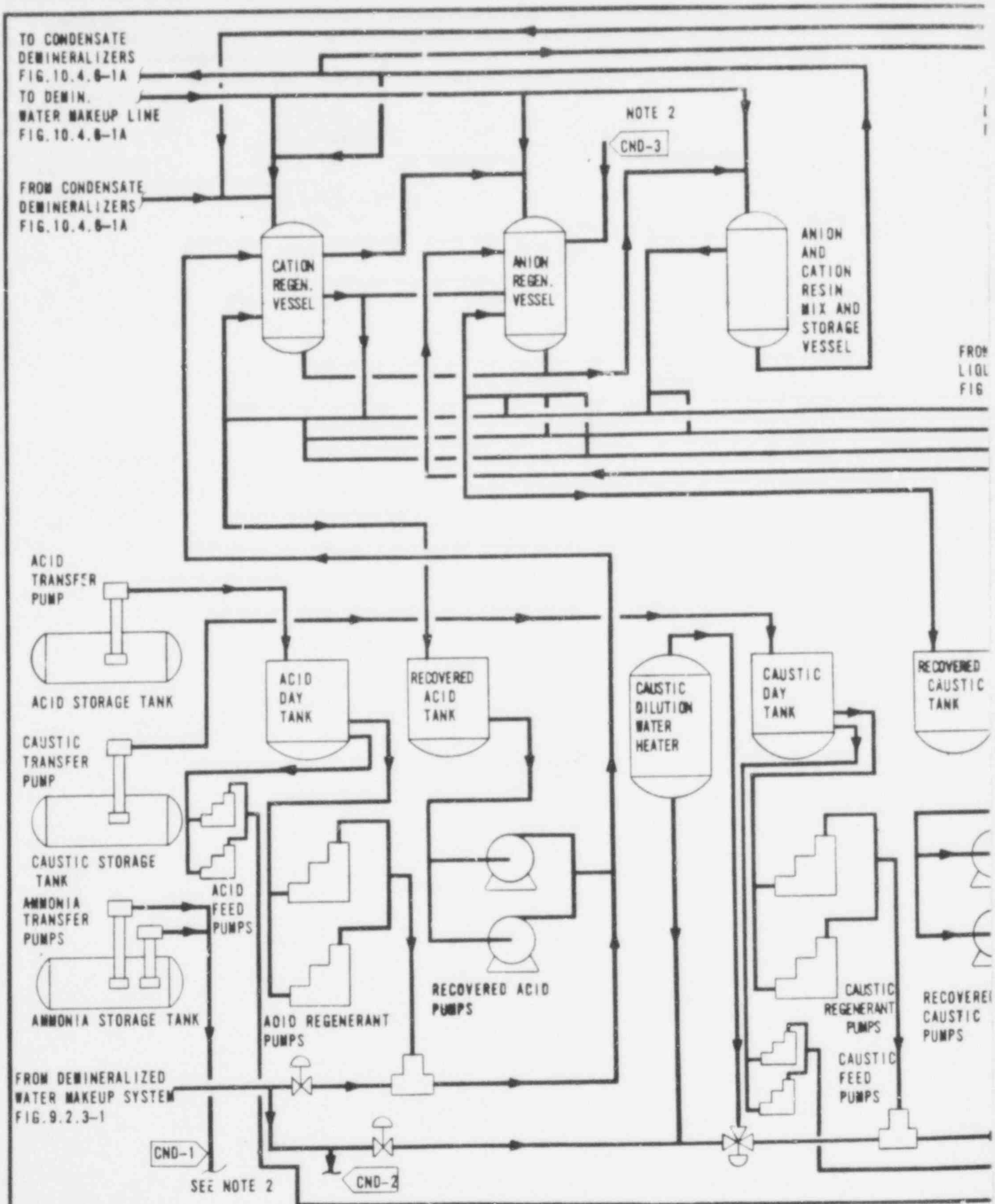


FIG.10.4.6-1B

CONDENSATE POLISHING SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

668 199



NOTES:

1. THIS SYSTEM IS NON-NUCLEAR SAFETY CLASS (NNS) LOCATED IN THE TURBINE BUILDING.
2. SYSTEM INTERFACE POINTS CND-1 THRU 3 ARE TO/FROM ONE OF THE THREE SYSTEMS AVAILABLE FOR THE AMMONIA CYCLE. SELECTION OF THIS SYSTEM IS THE RESPONSIBILITY OF THE UTILITY-APPLICANT.

668 200

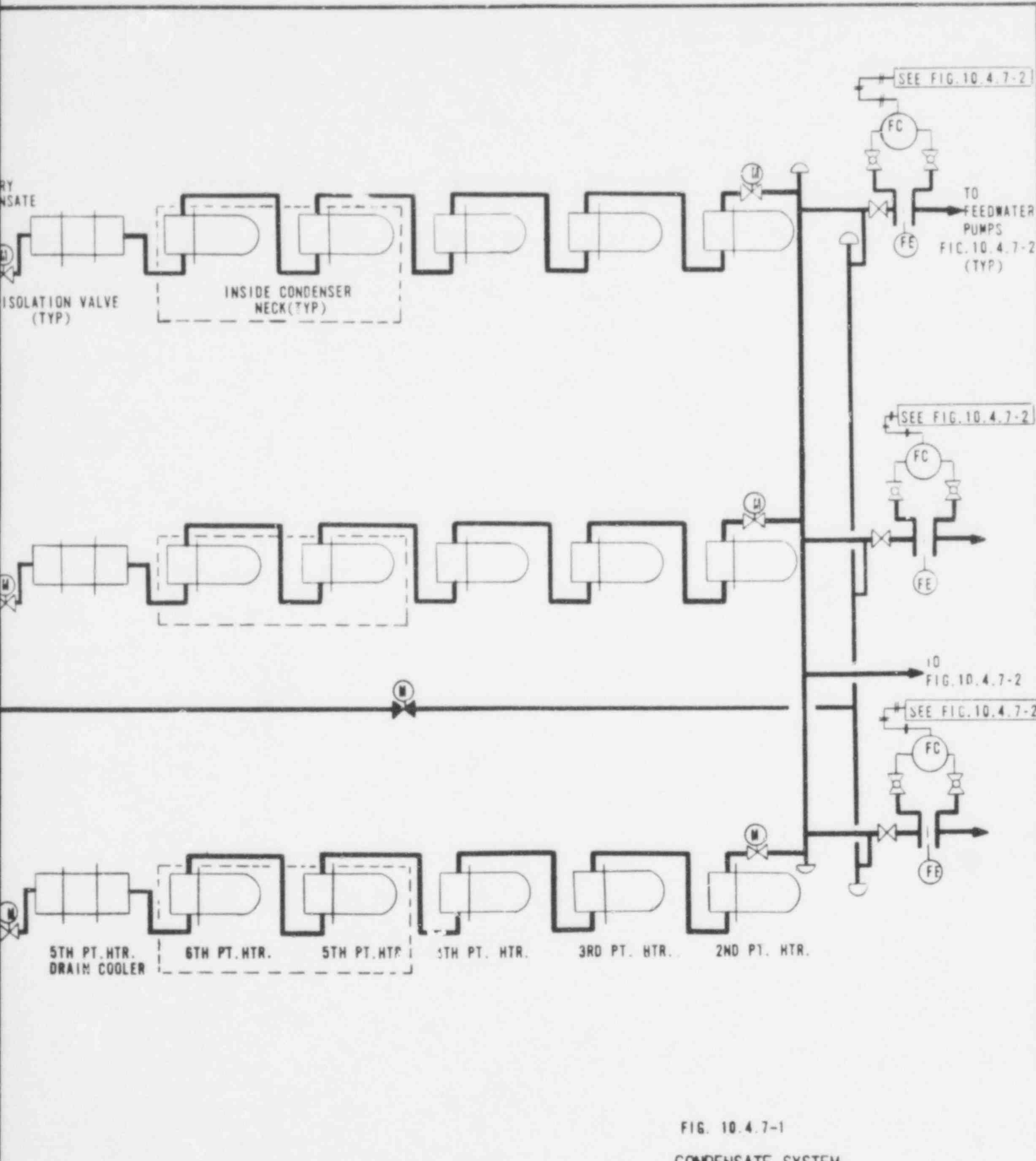


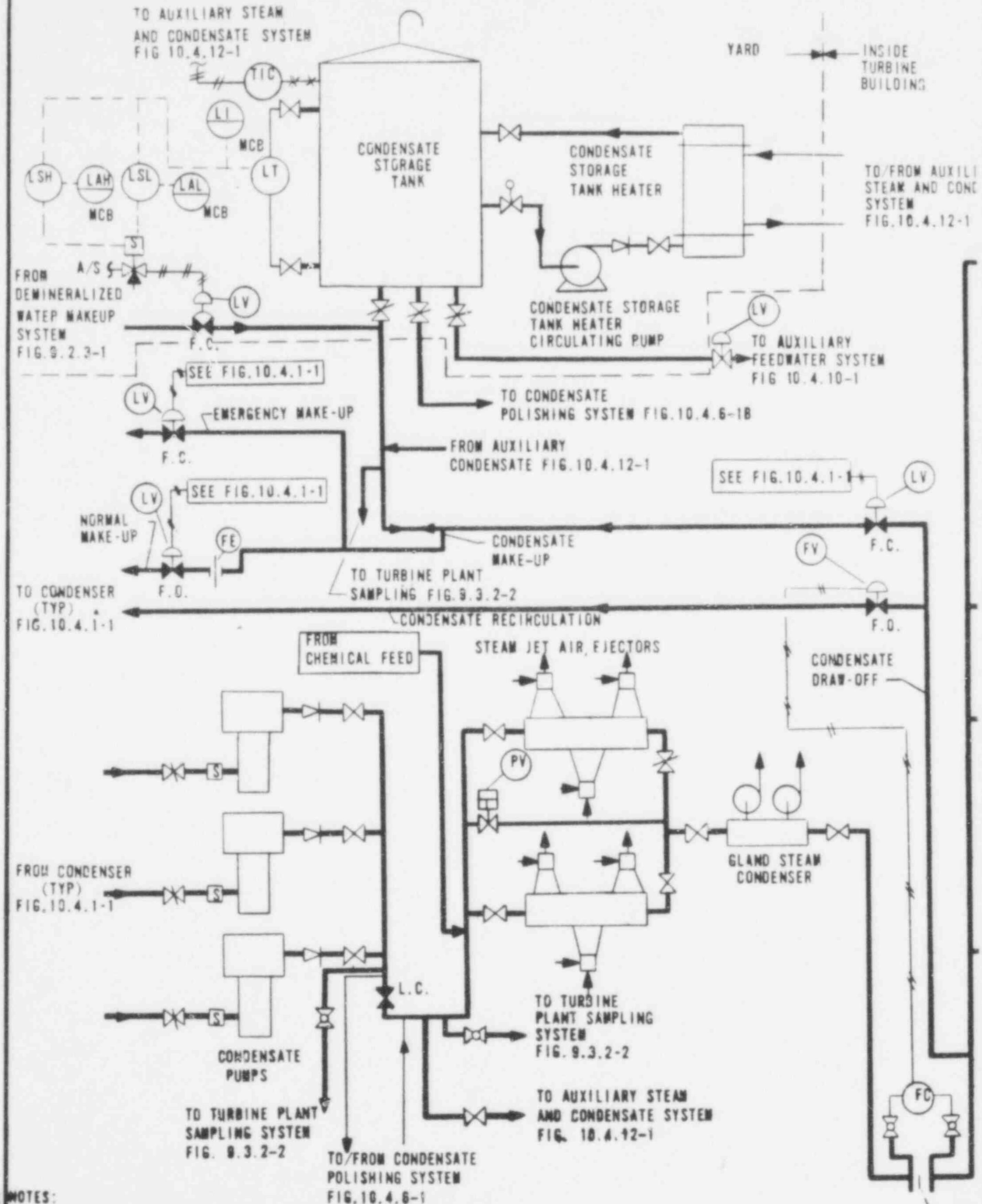
FIG. 10.4.7-1

CONDENSATE SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

668 201

AMENDMENT 12 6/16/75



NOTES:

1. THIS SYSTEM IS NON-NUCLEAR SAFETY CLASS (NNS), LOCATED IN TURBINE BUILDING.

DRAWING 44-122 21039

668 202

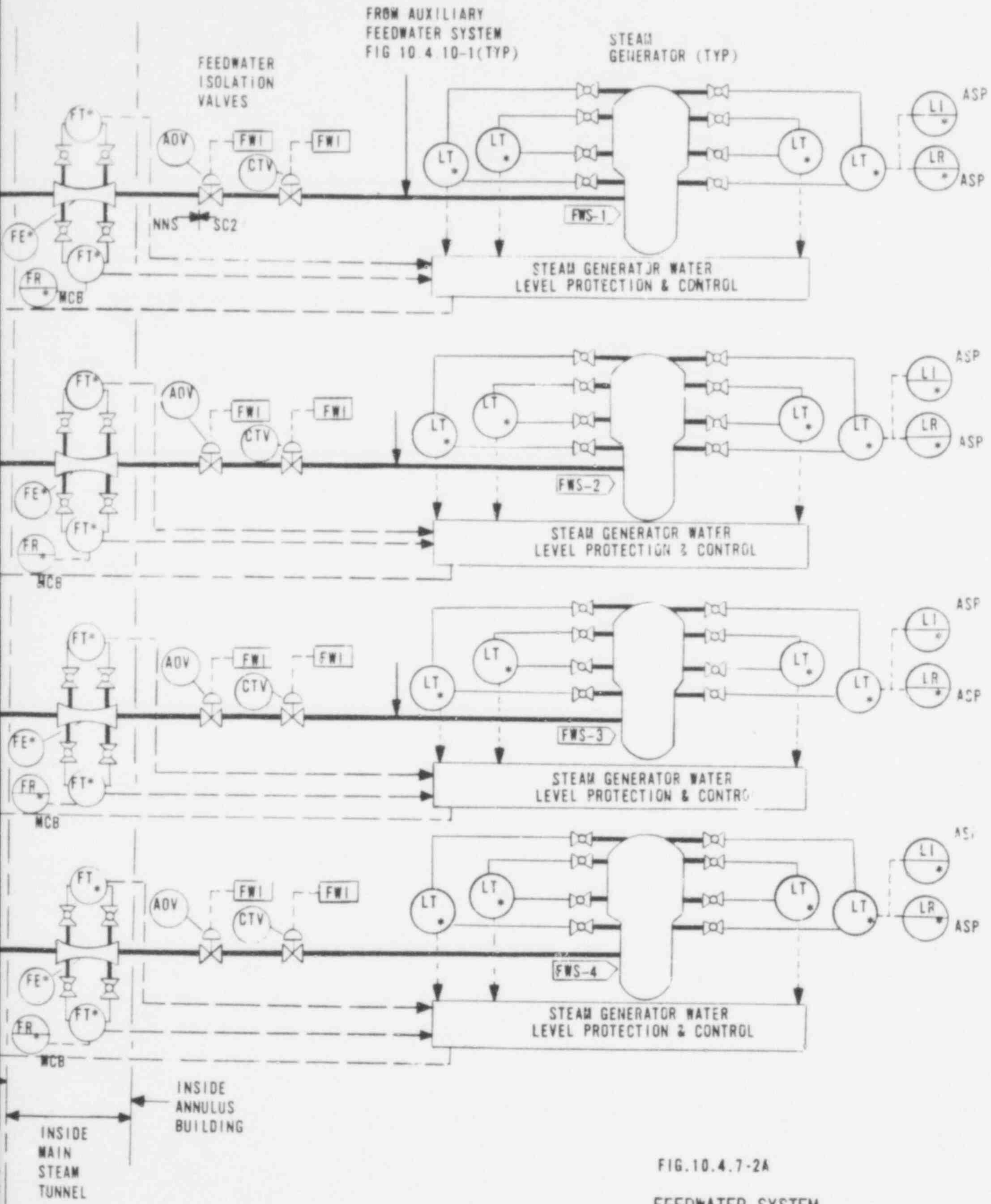
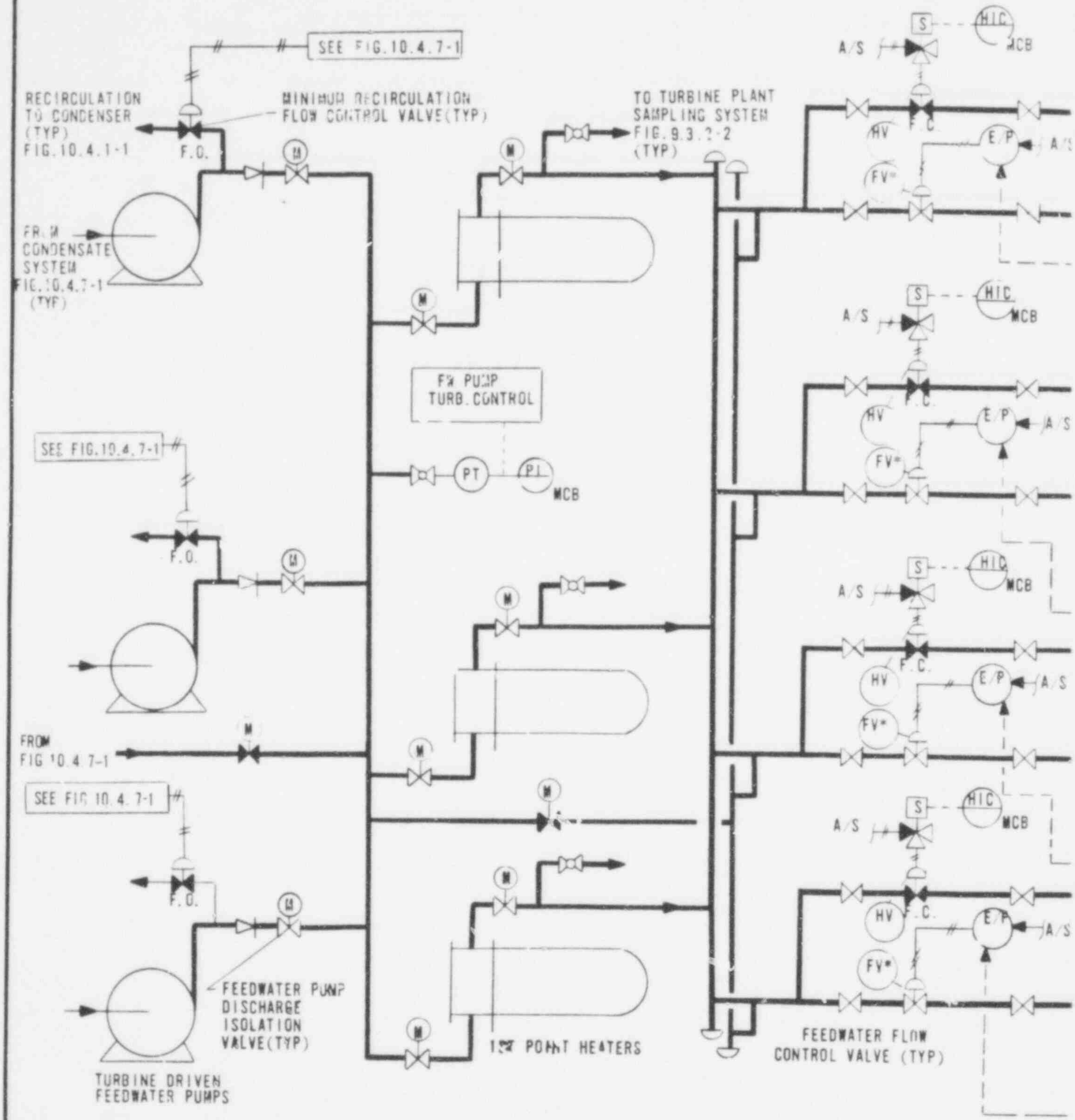


FIG.10.4.7-2A

FEEDWATER SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

W 668 203



NOTES:

1. THIS SYSTEM IS NON-NUCLEAR SAFETY CLASS (NNS) EXCEPT WHERE OTHERWISE NOTED.
2. "*" INDICATES INSTRUMENT SUPPLIED BY NSSS VENDOR.

668 204

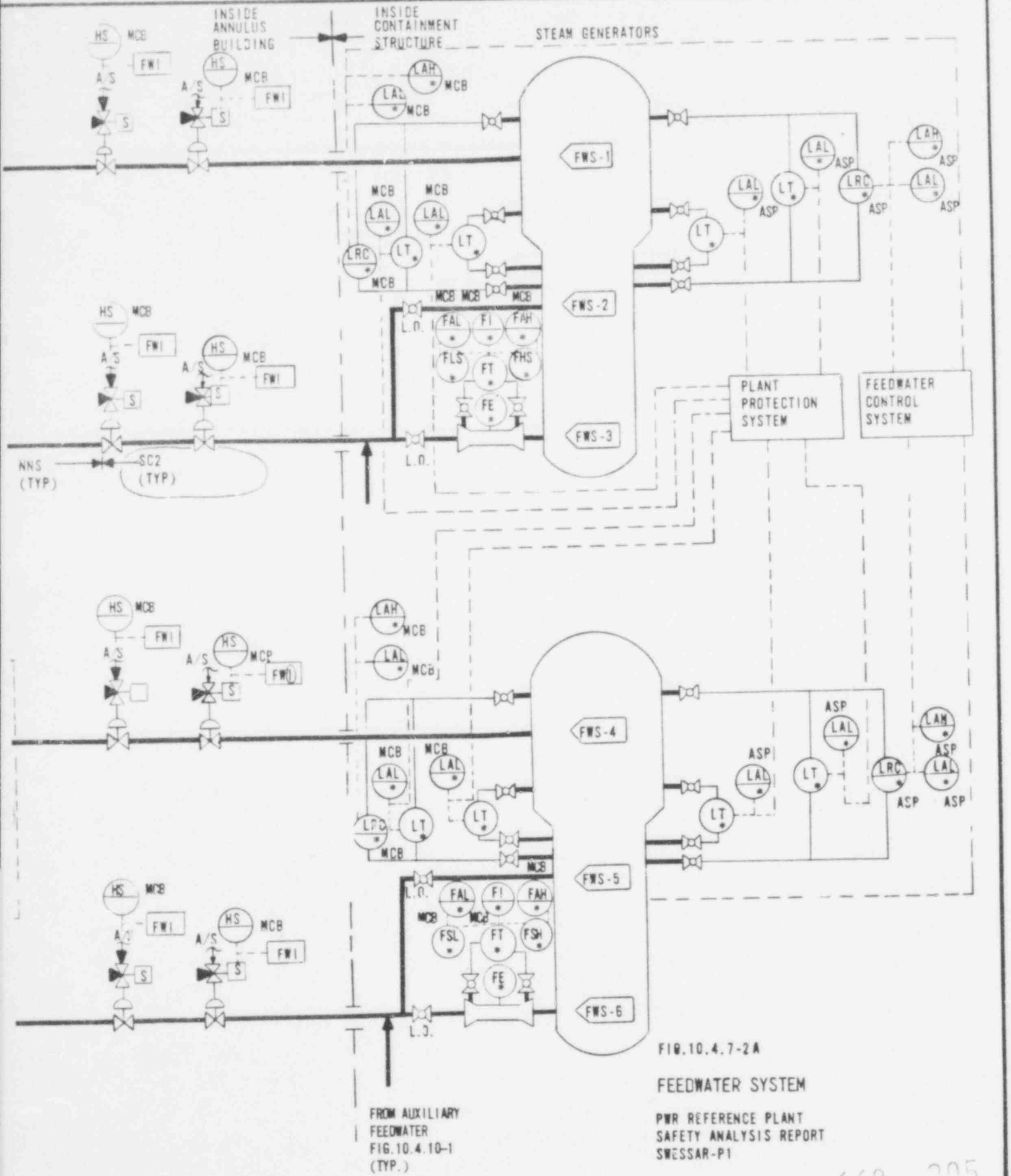


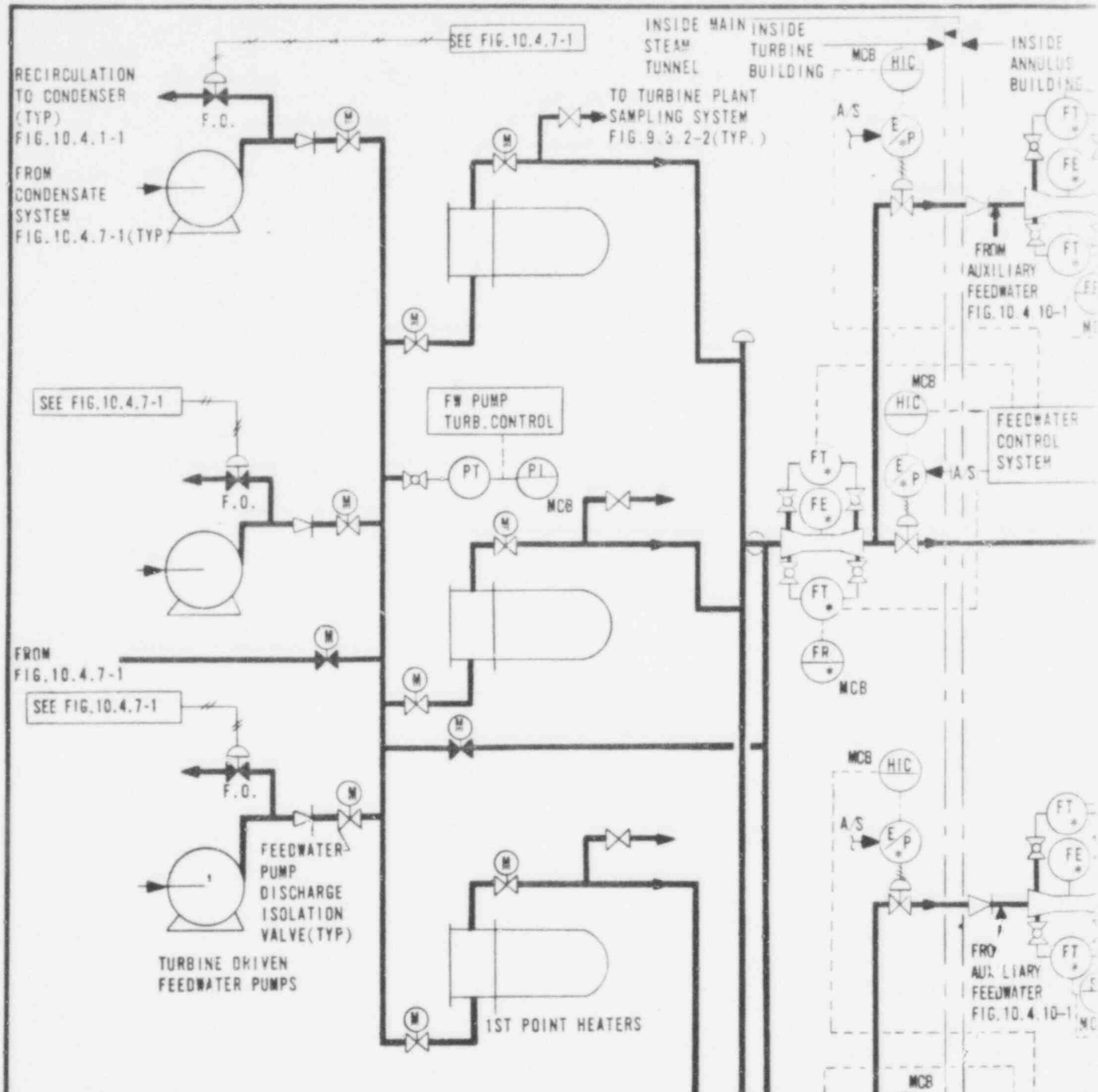
FIG.10.4.7-2A

FEEDWATER SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

CE

668 205



NOTES:

1. THIS SYSTEM IS NON-NUCLEAR SAFETY CLASS (NNS) EXCEPT WHERE OTHERWISE NOTED.
2. "*" INDICATES INSTRUMENT SUPPLIED BY NSSS VENDOR.

POOR ORIGINAL

668 206

BRUNING 44-122 21039

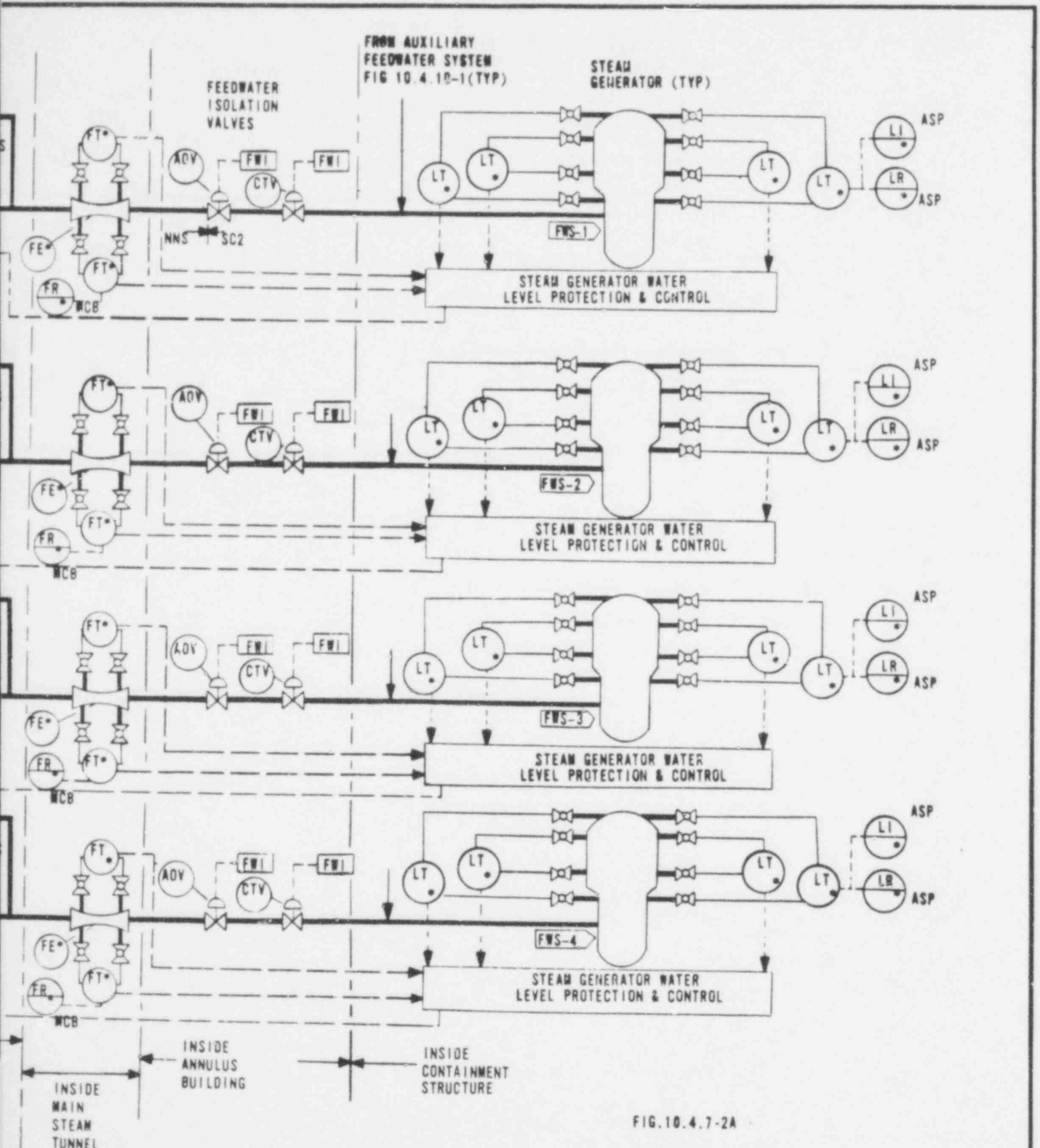


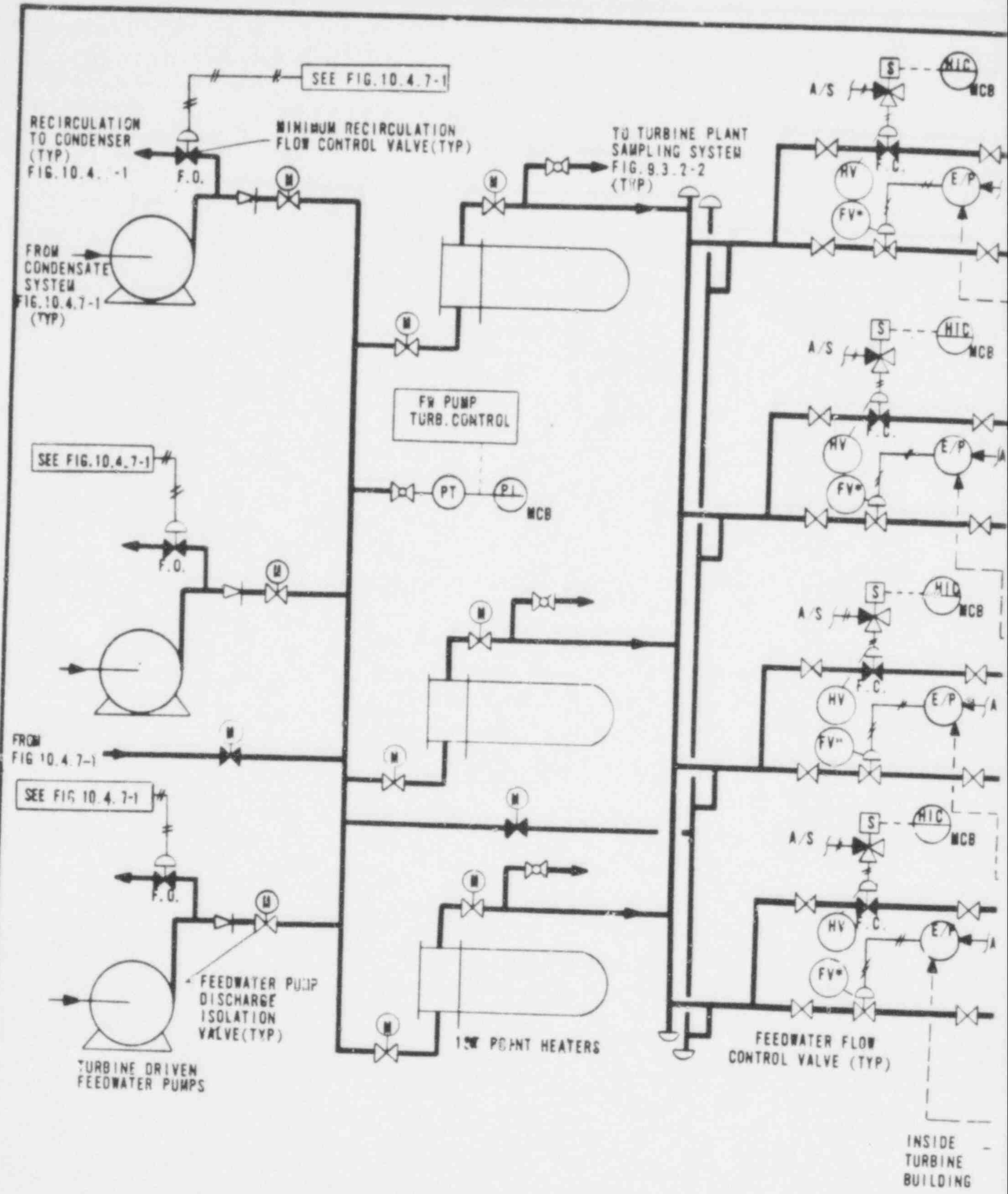
FIG.10.4.7-2A

FEEDWATER SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

668 207

W3S



NOTES:

1. THIS SYSTEM IS NON-NUCLEAR SAFETY CLASS (NNS) EXCEPT WHERE OTHERWISE NOTED.
2. "*" INDICATES INSTRUMENT SUPPLIED BY NSSS VENDOR.

668 208

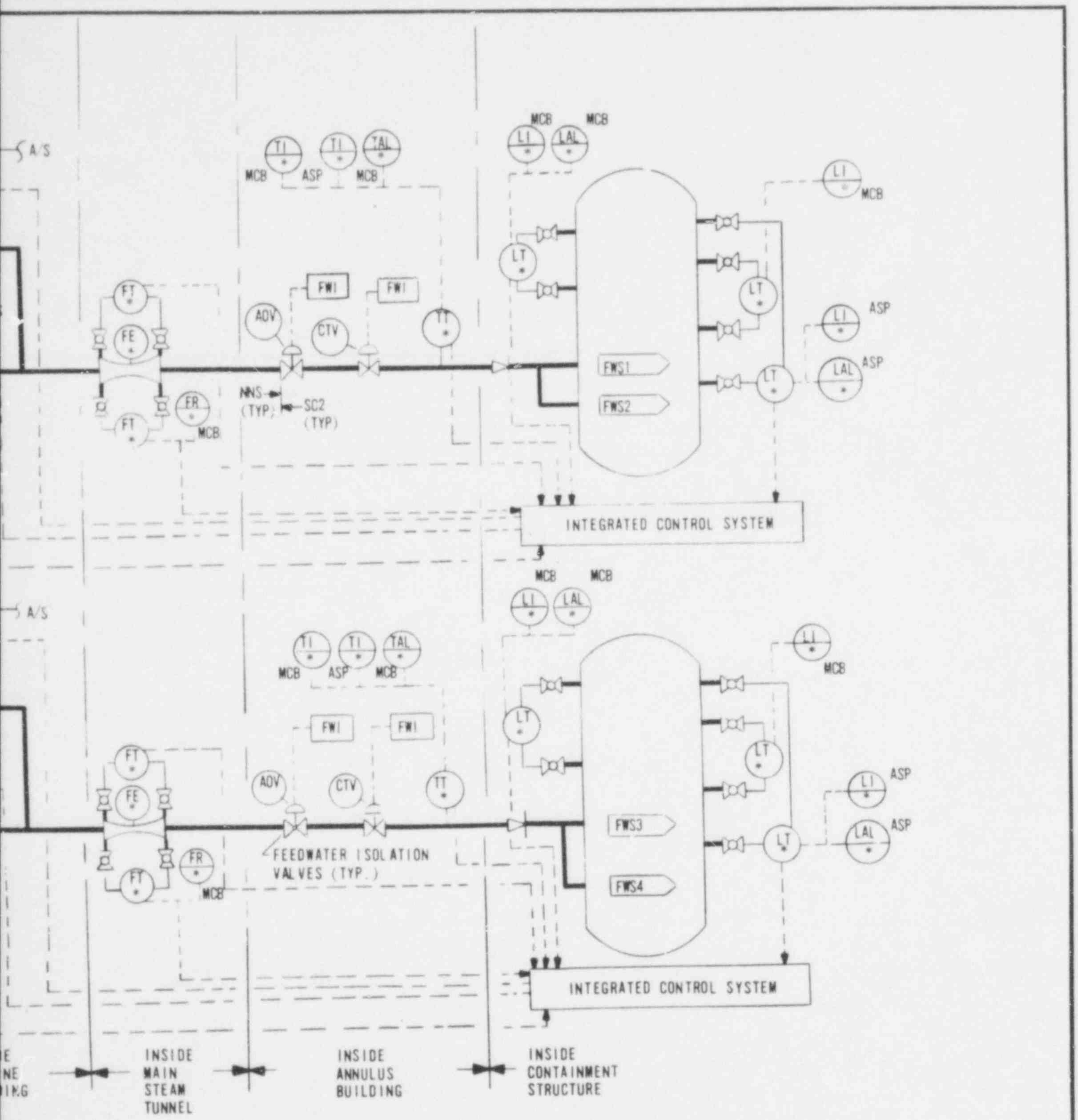


FIG. 10.4.7-2A

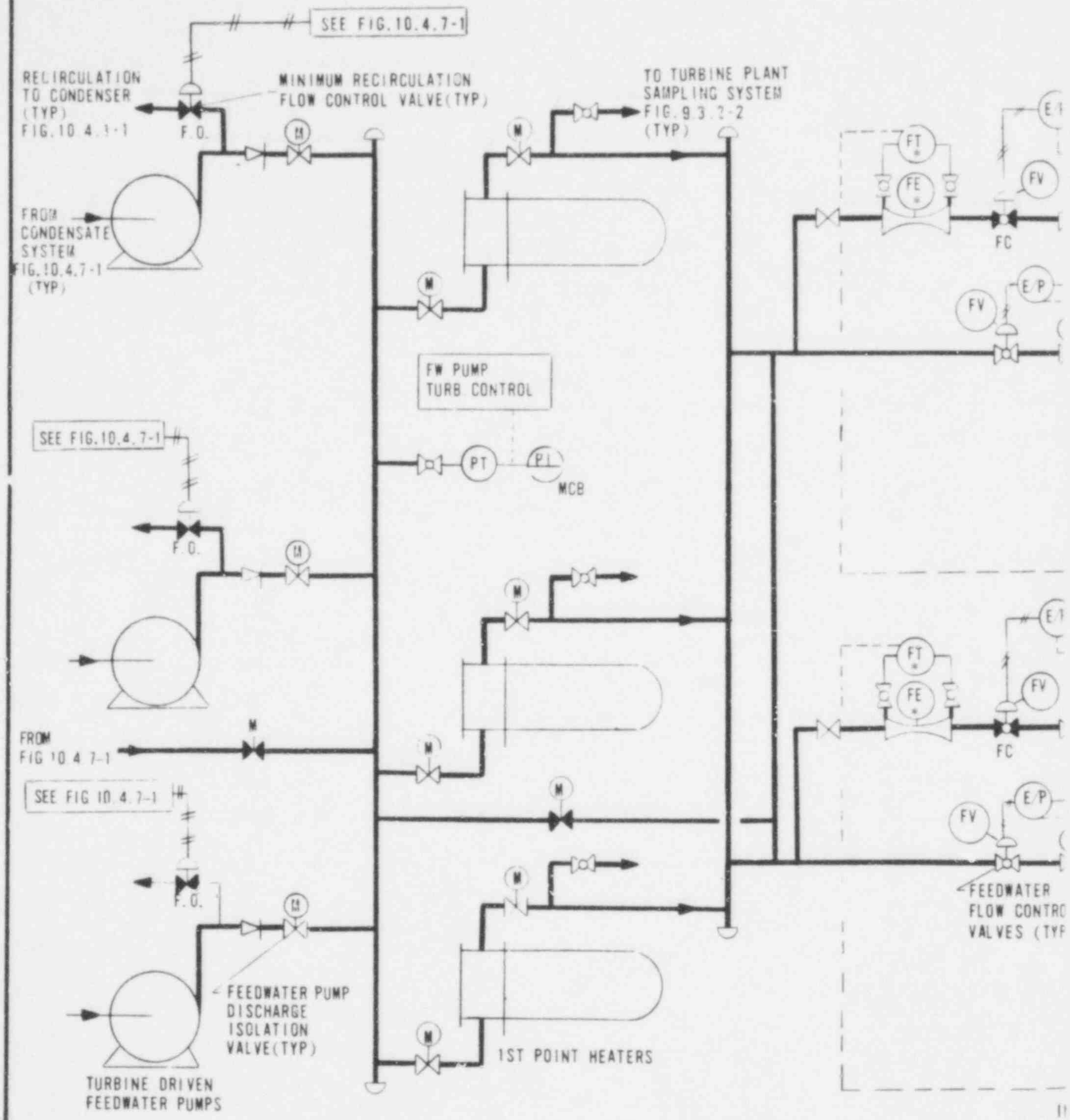
FEEDWATER SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

B & W

668 209

AMENDMENT 19 12/12/75



NOTES:

1. THIS SYSTEM IS NON-NUCLEAR SAFETY CLASS (NNS) EXCEPT WHERE OTHERWISE NOTED.
2. "*" INDICATES INSTRUMENT SUPPLIED BY NSSS VENDOR.

668 210

SYSTEM INTERFACE POINTS - FEEDWATER SYSTEM (FWS)

ID NO.	RESAR-41	RESAR-3S	B-SAR 205	CESSAR
FWS-1-4	Feedwater system to steam generator nozzles	Feedwater system to steam generator nozzles	Feedwater system to steam generator nozzles	Feedwater system to steam generator nozzles
FWS-5-6	Not Applicable	Not Applicable	Not Applicable	Feedwater system to steam generator nozzles

FIG. 10.4.7-2B

FEEDWATER SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

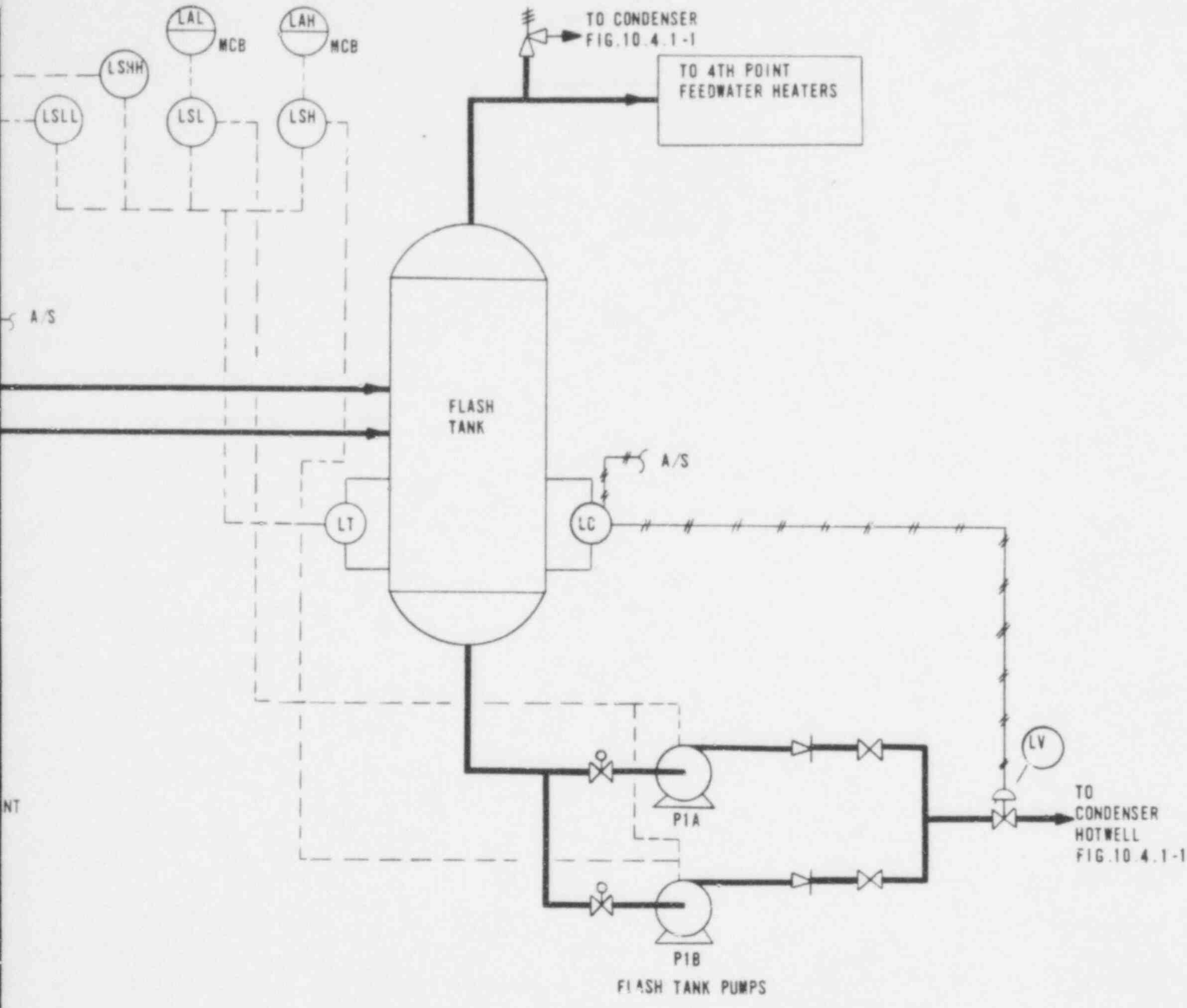


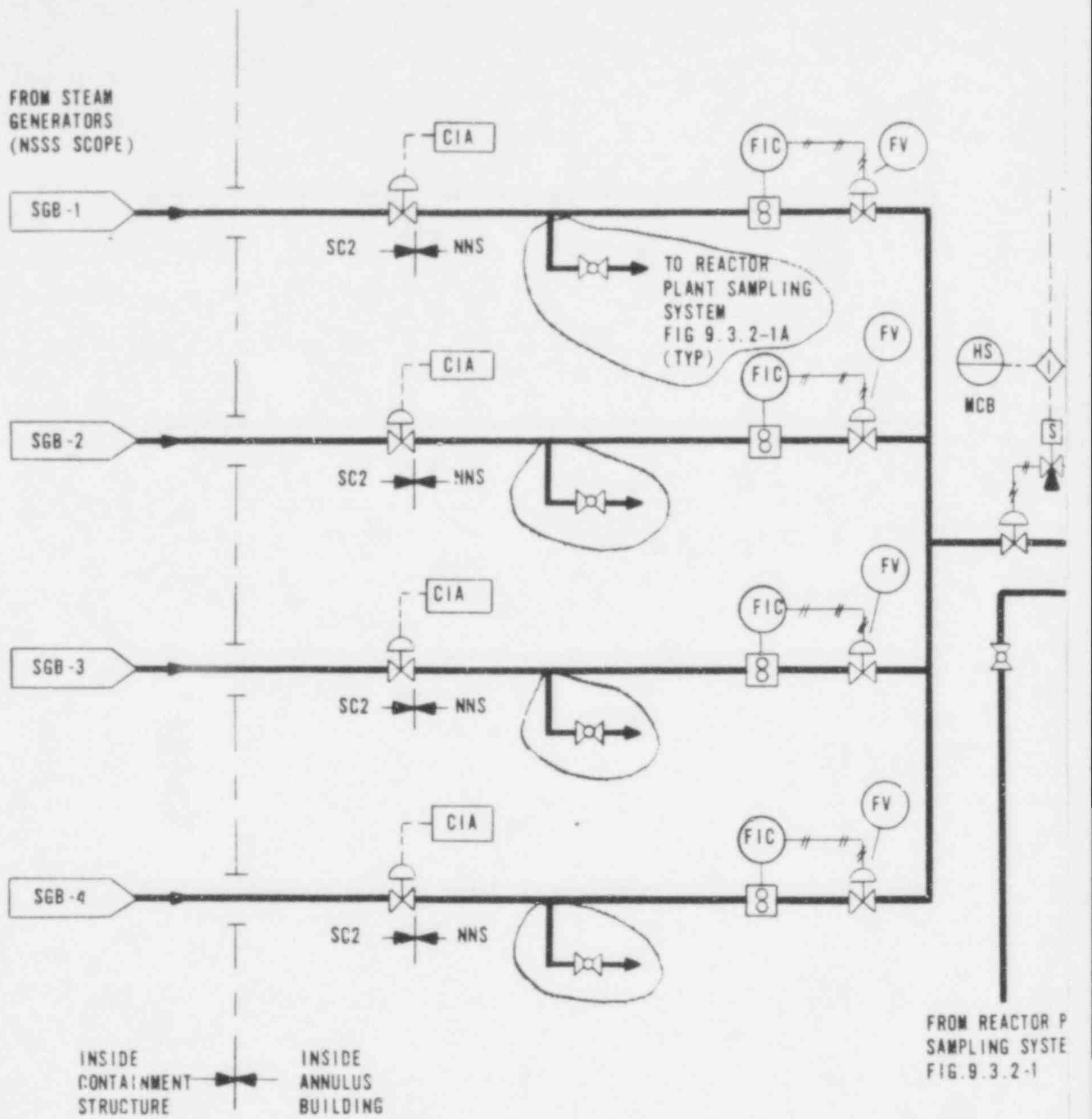
FIG.10.4.8-1A

STEAM GENERATOR BLOWDOWN SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

668 212

W



NOTE:

1. THIS SYSTEM IS NON-NUCLEAR SAFETY CLASS (NNS), EXCEPT WHERE OTHERWISE NOTED.

668 213

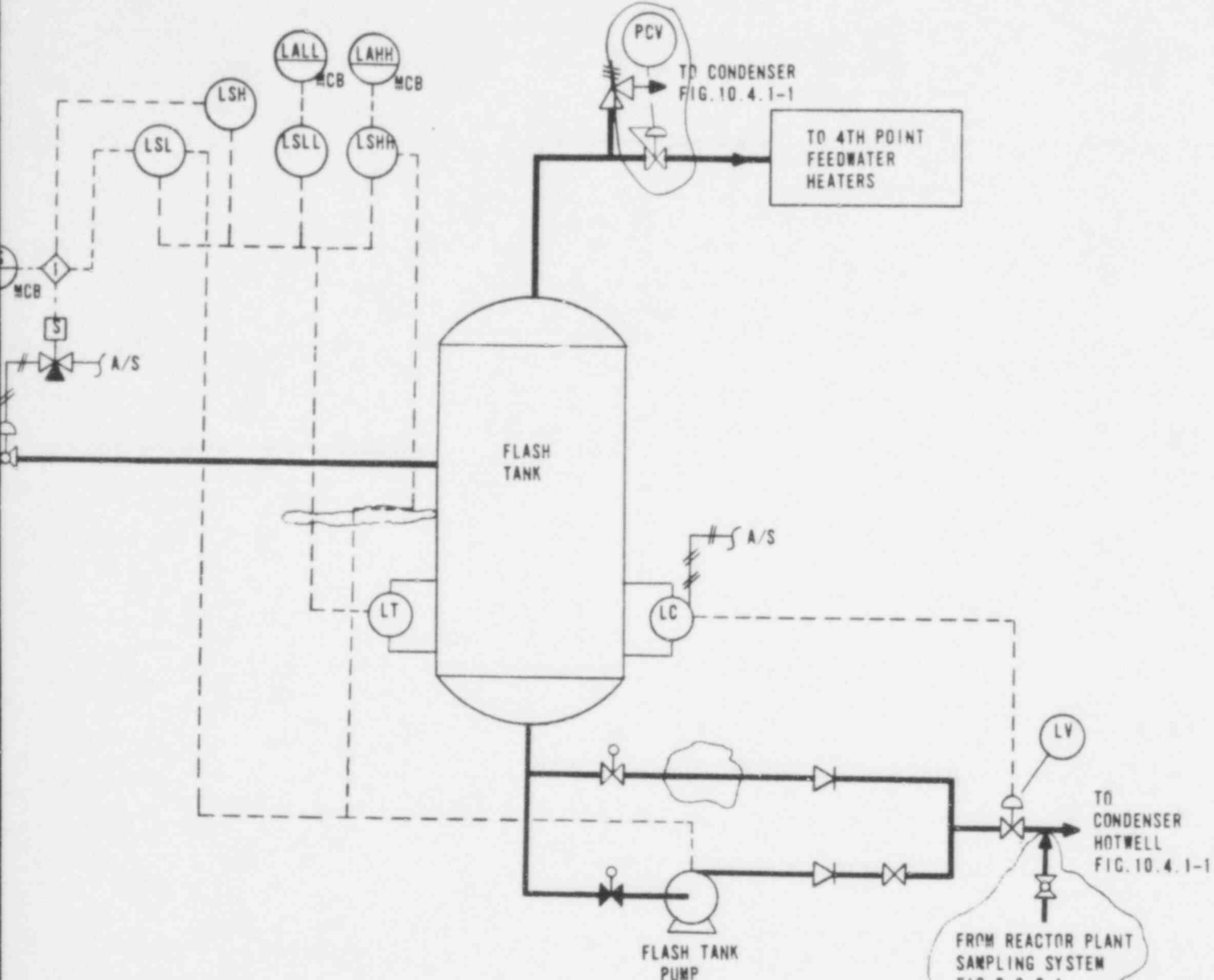


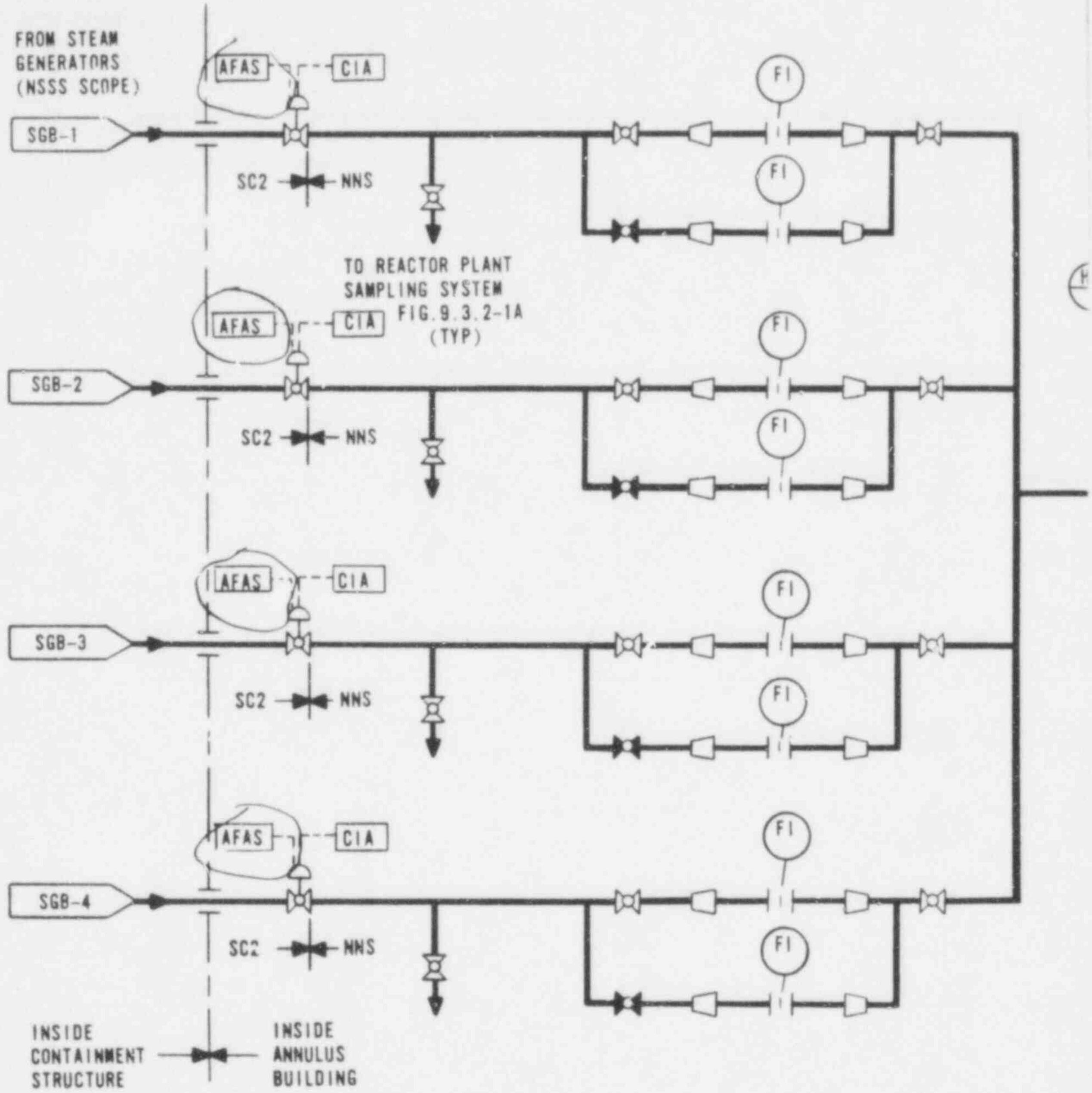
FIG.10.4.8-1A

STEAM GENERATOR BLOWDOWN SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

668 214

W3S



NOTES:

1. THIS SYSTEM IS NON-NUCLEAR SAFETY CLASS (NNS) EXCEPT WHERE OTHERWISE NOTED.

668 215

RUNING 44-122 21039

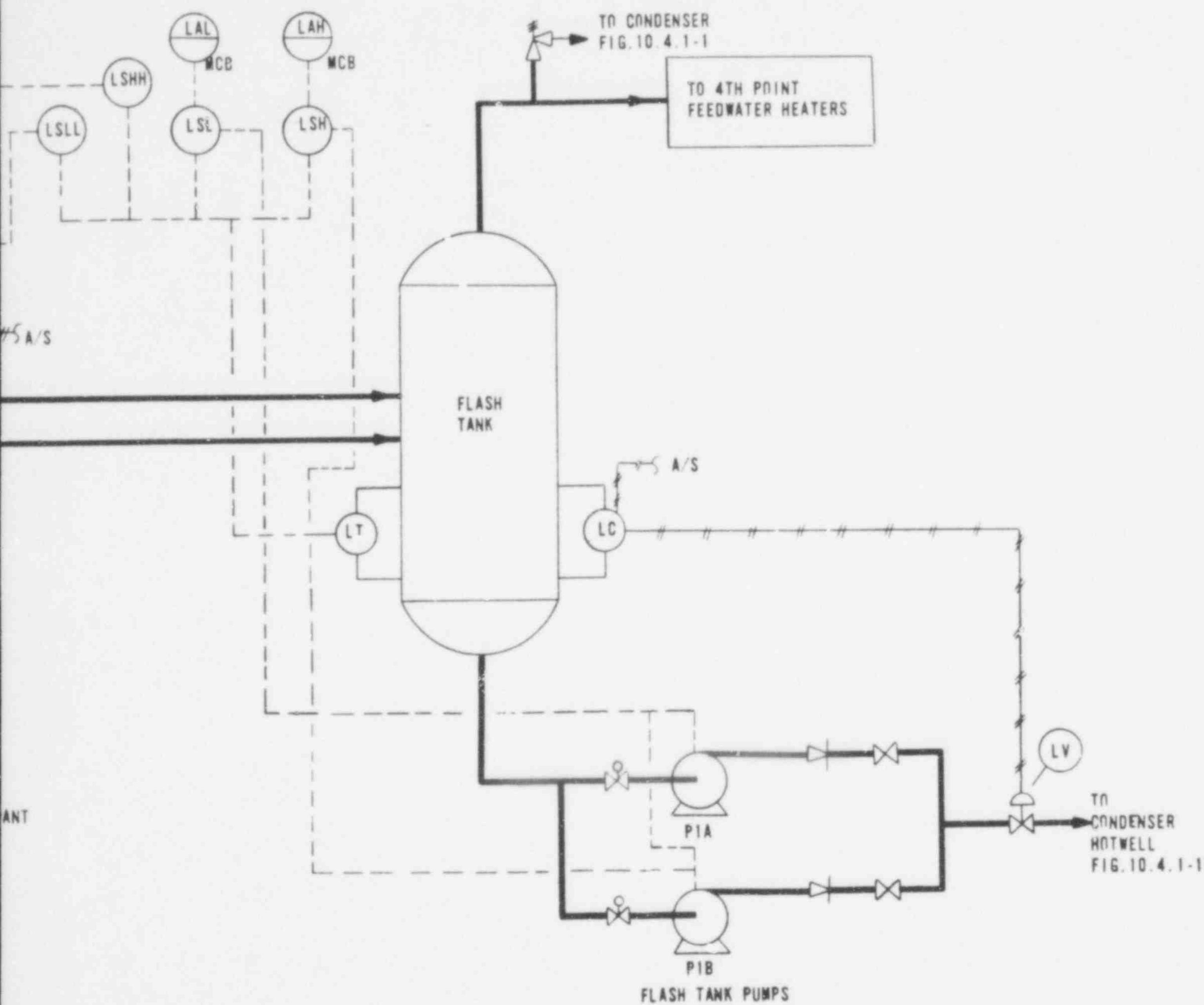


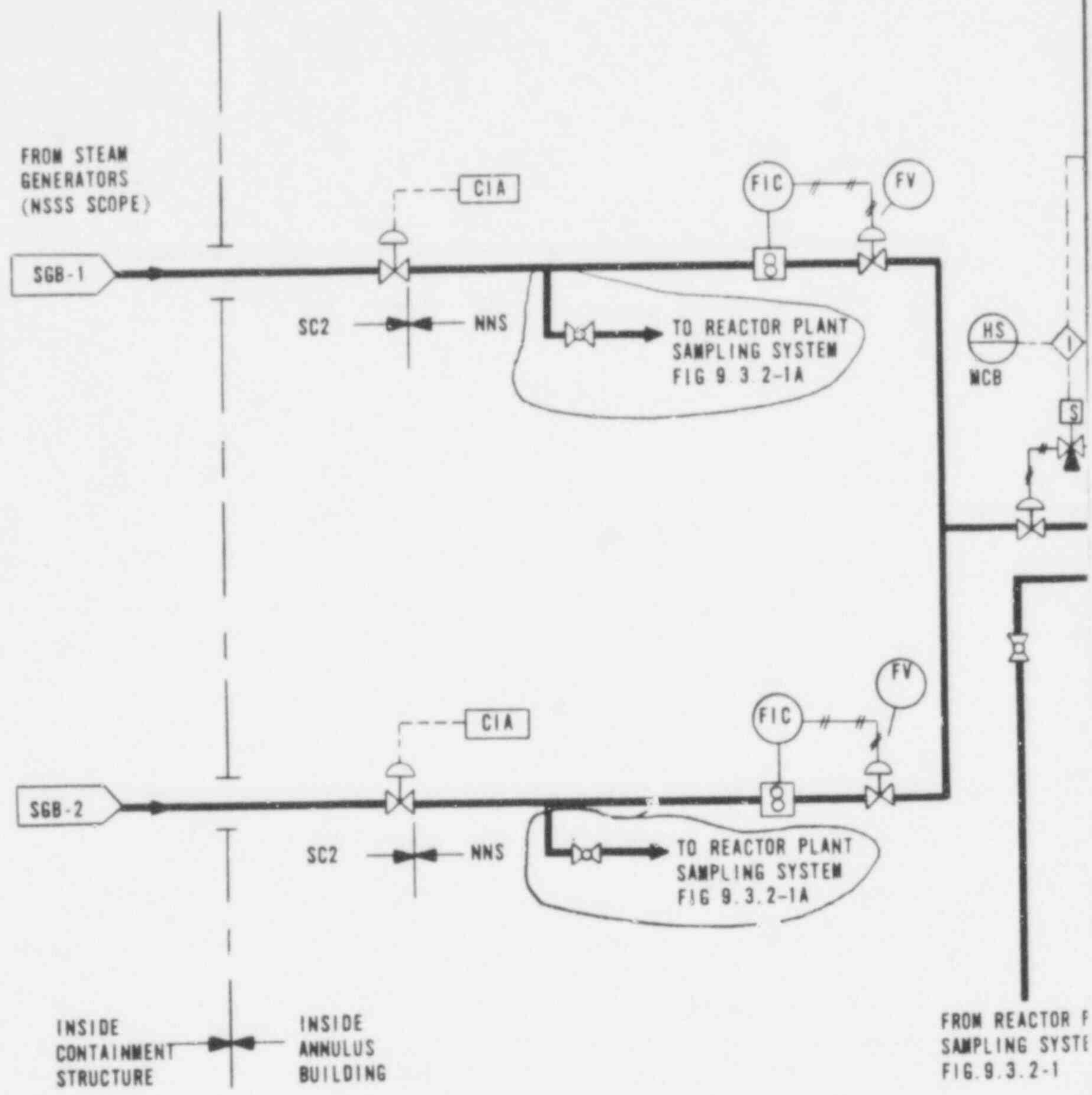
FIG. 10.4.8-1A

STEAM GENERATOR BLOWDOWN SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

CE

668 216



NOTES:

1. THIS SYSTEM IS NON-NUCLEAR SAFETY CLASS (NNS), EXCEPT WHERE OTHERWISE NOTED.

668 217

DRAWING 44-122 21030

SYSTEM INTERFACE POINTS - STEAM GENERATOR BLOWDOWN SYSTEM (SGB)

ID No.	RESAR-41	RESAR-3S	B-SAR 205	CESSAR
SGB-1-2	From point downstream of blowdown line pipe tee into steam generator blowdown system (Fig. 10.4-1, sheet 1)	From point downstream of blowdown line pipe tee into steam generator blowdown system (Fig. 10.4-1, sheet 1)	NA	From point downstream of blowdown line pipe tee into steam generator blowdown system (Fig. 10.4.8-3)
SGB-3-4	From point downsteam of blowdown line pipe tee into steam generator blowdown system (Fig. 10.4-1, sheet 1)	From point downstream of blowdown line pipe tee into steam generator blowdown system (Fig. 10.4-1, sheet 1)	NA	NA

20

FIG. 10.4B-1B
STEAM GENERATOR BLOWDOWN SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

668 218

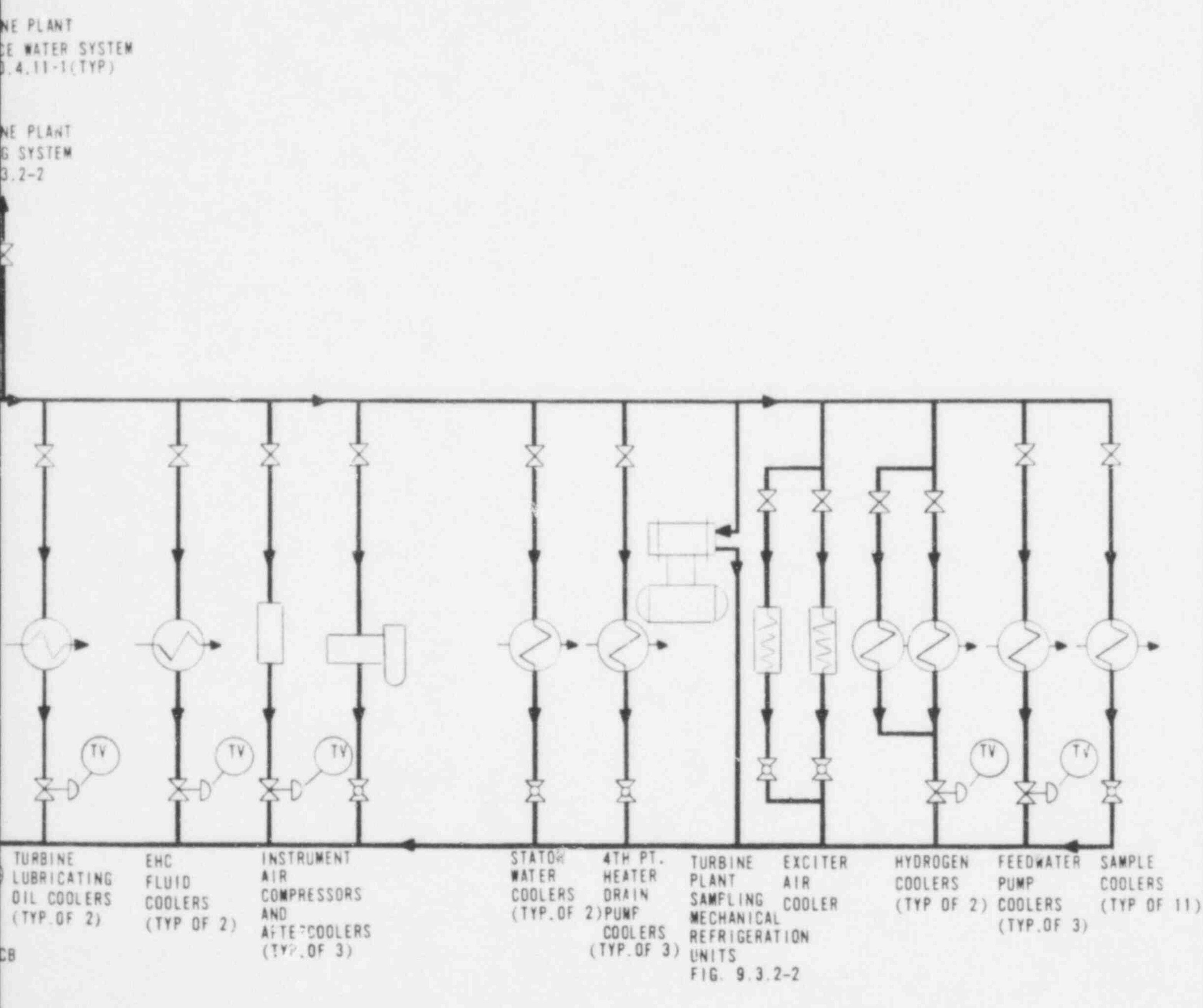
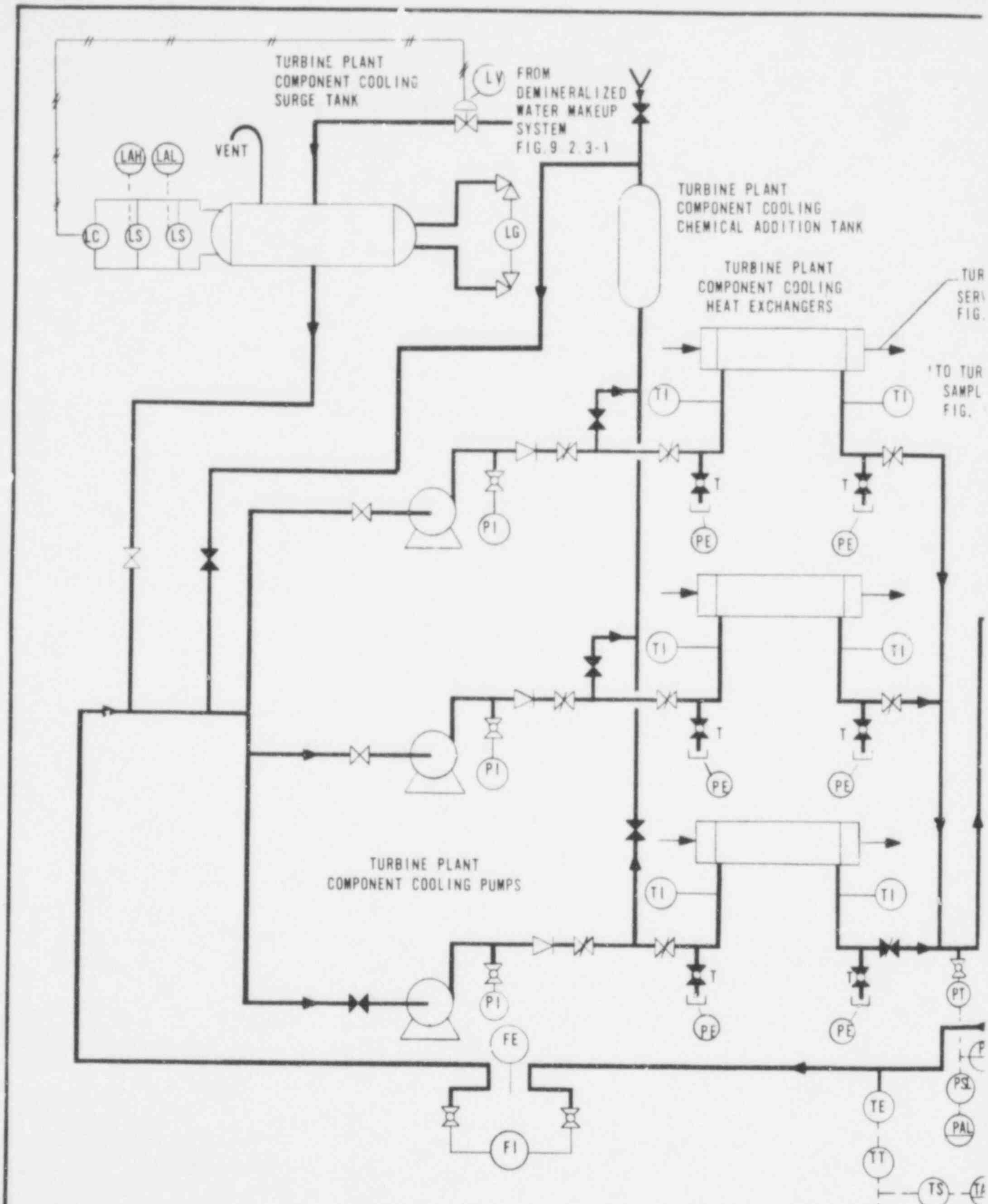


FIG. 10.4.9-1

TURBINE PLANT COMPONENT COOLING SYSTEM

PWR STANDARD PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

668 219



NOTE:

1. THIS SYSTEM IS NON-NUCLEAR SAFETY CLASS (NNS) LOCATED IN TURBINE BUILDING.

668 220

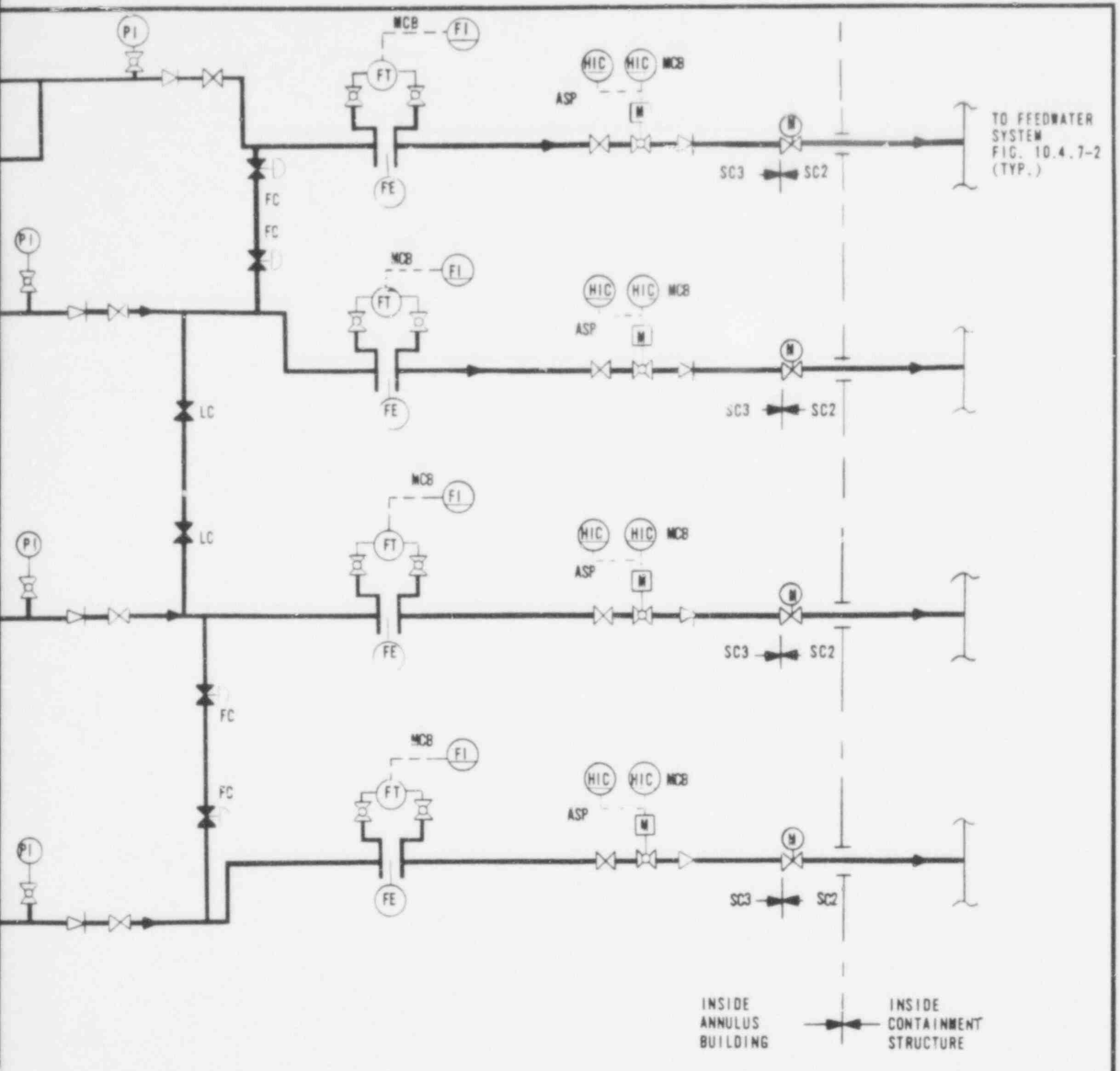


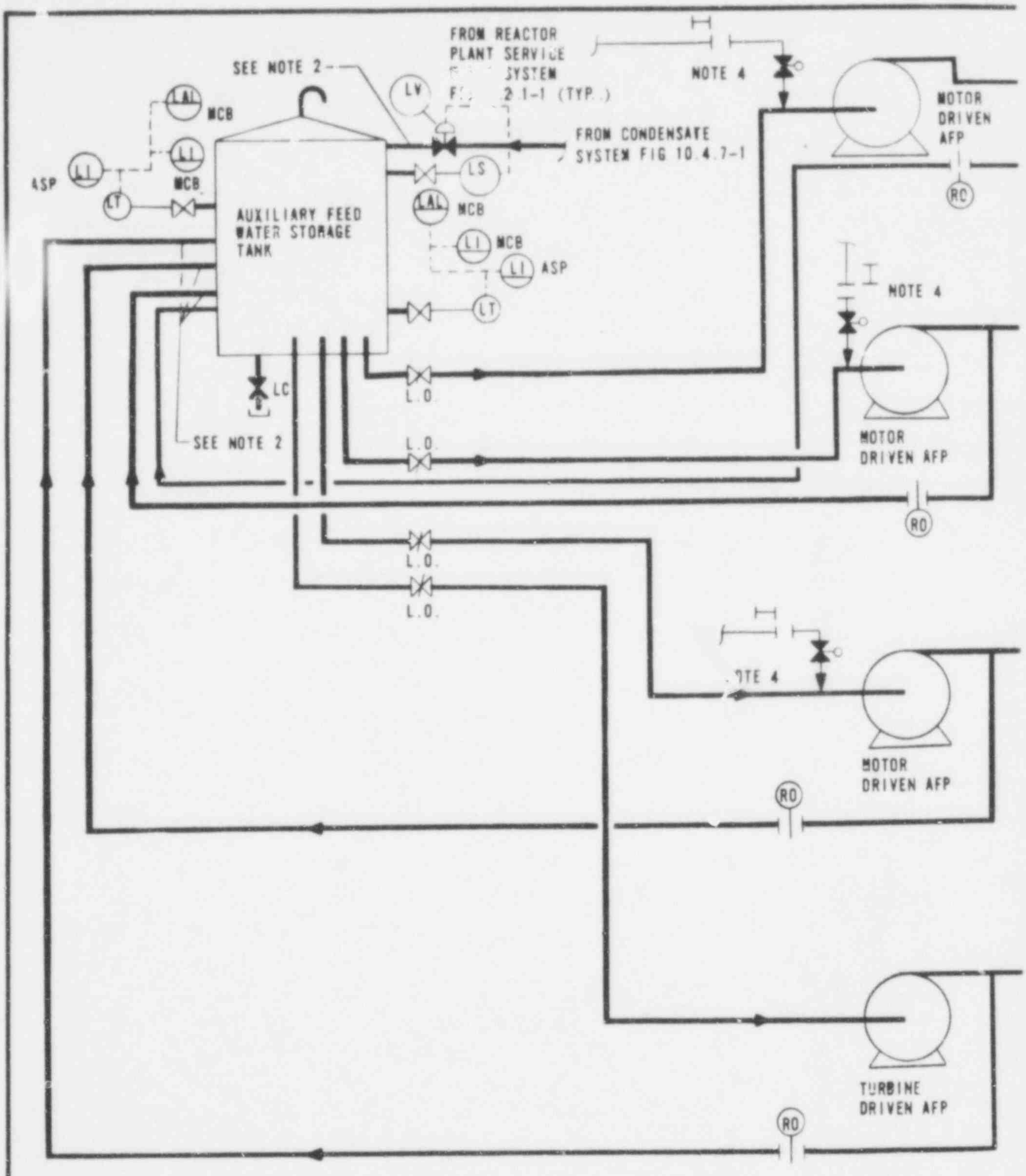
FIG. 10.4.10-1A

AUXILIARY FEEDWATER SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

668 22

W



NOTES:

1. AFP DENOTES AUCILIARY FEEDWATER PUMP
2. RETURN LINES ABOVE TANK WATER LEVEL
3. THIS SYSTEM IS SAFETY CLASS 3 (SC3) EXCEPT WHERE OTHERWISE NOTED.
4. SPOOL PIECE TO BE ADDED WHEN NEEDED.

BRUNING 44-122 21039

668 222

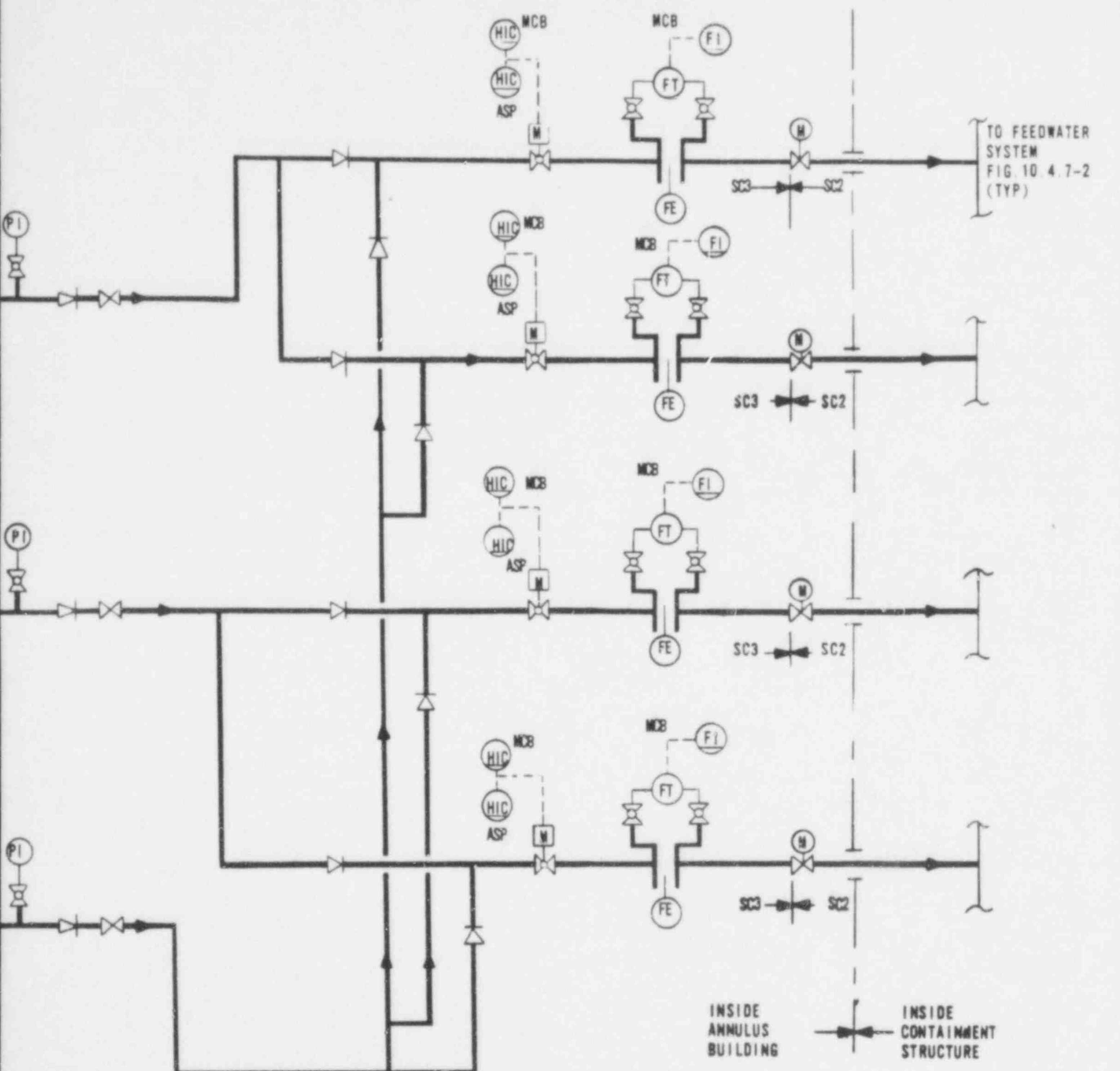


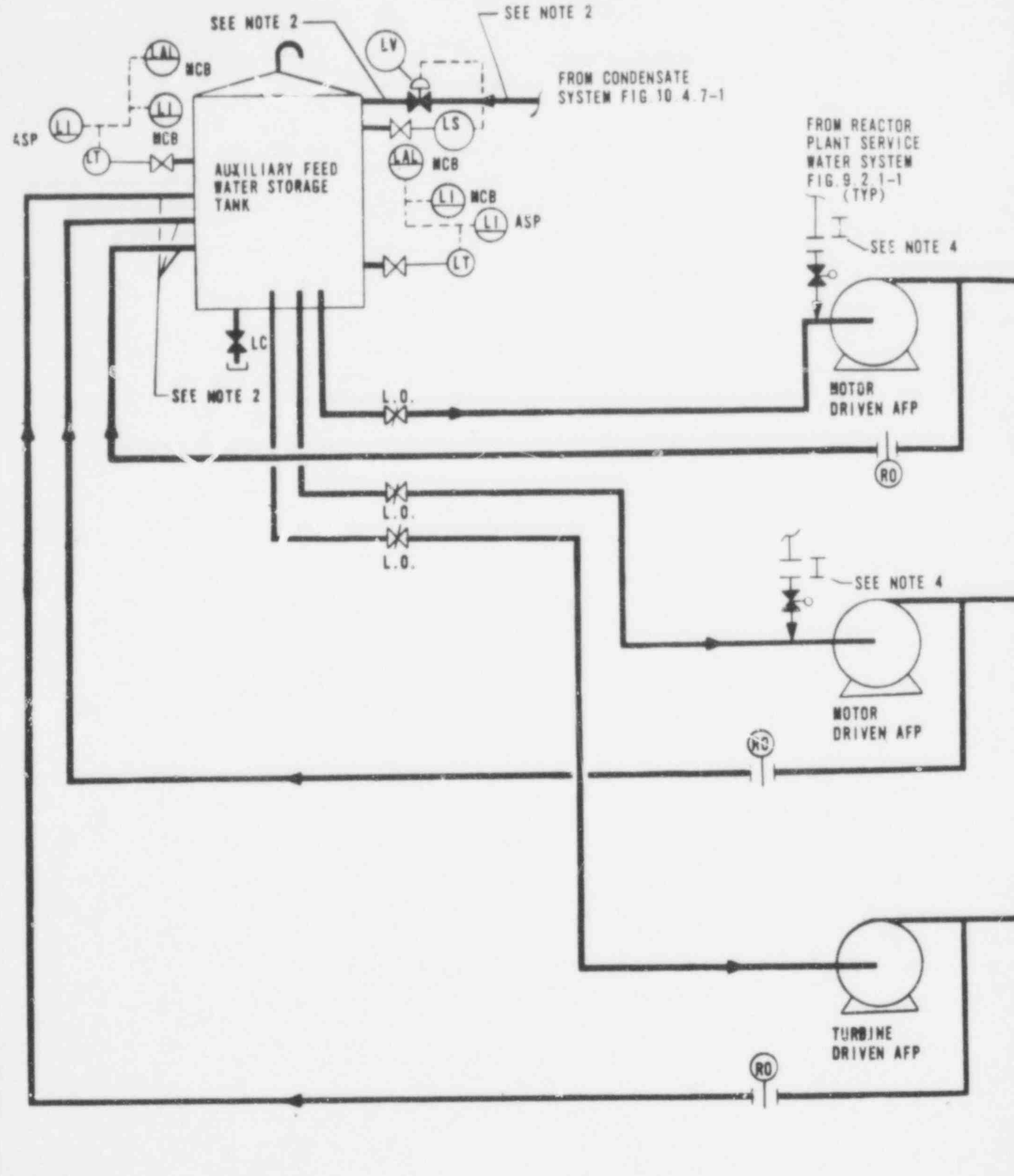
FIG. 10.4.10-1A

AUXILIARY FEEDWATER SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

R 3S

668 223



NOTES:

1. AFP DENOTES AUXILIARY FEEDWATER PUMP
2. RETURN LINES ABOVE TANK WATER LEVEL
3. THIS SYSTEM IS SAFETY CLASS 3 (SC3) EXCEPT WHERE OTHERWISE NOTED.
4. SPOOL PIECE TO BE ADDED WHEN NEEDED.

DRAWING 44-122 21030

668 224

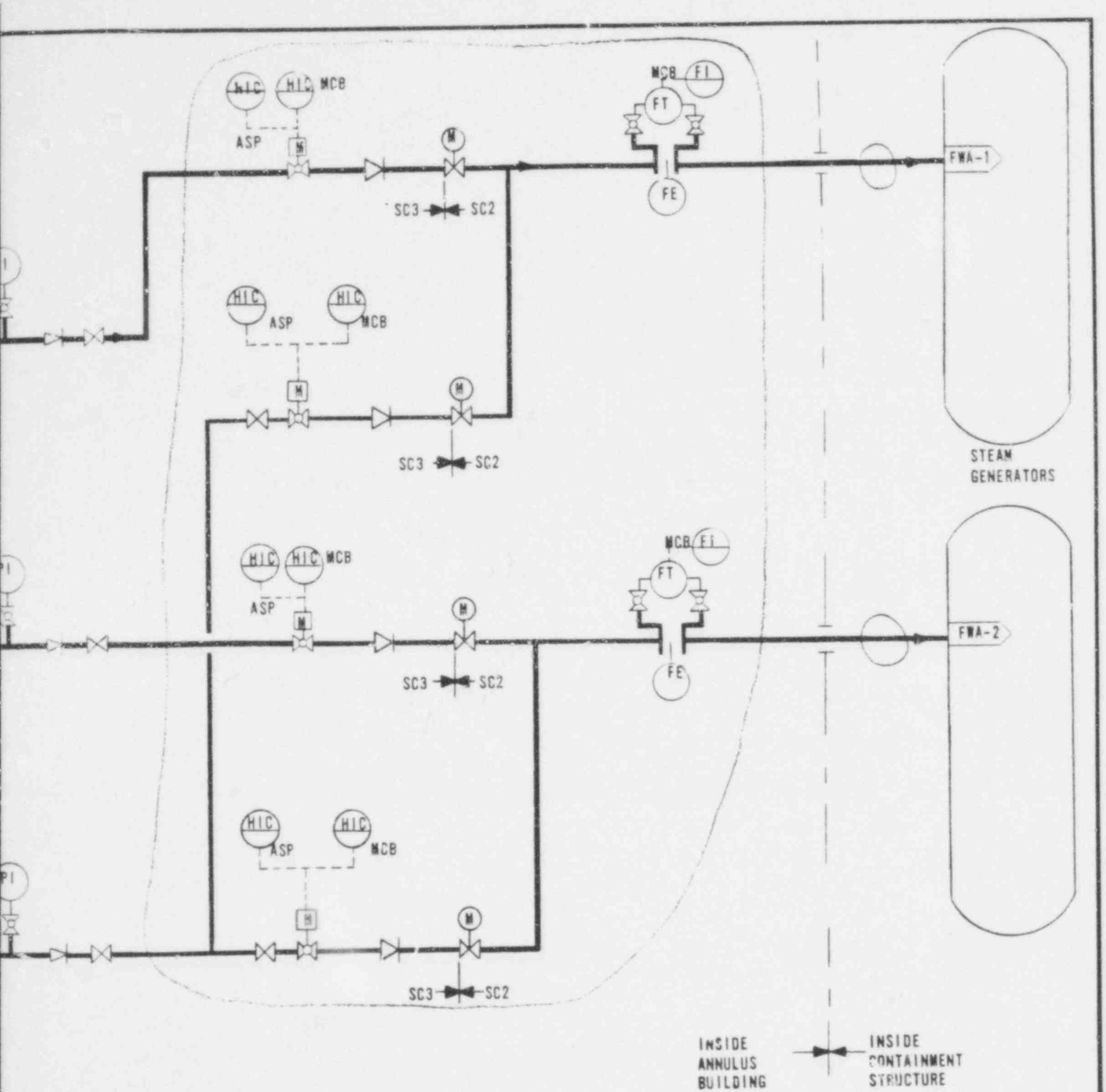


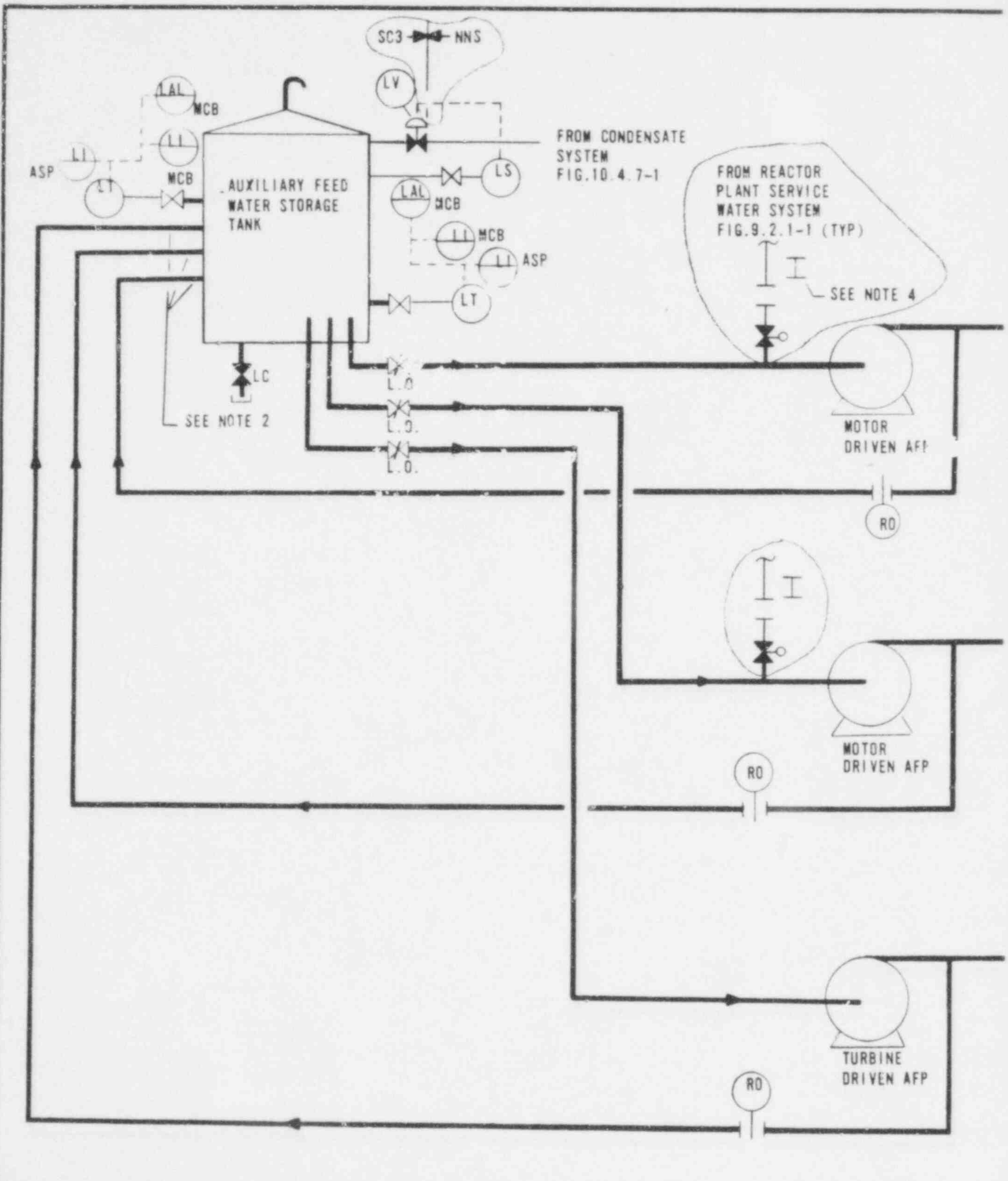
FIG. 10.4.10-1A

AUXILIARY FEEDWATER SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

B&W

668 225



NOTES:

1. AFP DENOTES AUXILIARY FEEDWATER PUMP.
2. RETURN LINES ABOVE TANK WATER LEVEL.
3. THIS SYSTEM IS SAFETY CLASS 3 (SC3) EXCEPT WHERE OTHERWISE NOTED.
4. SPOOL PIECE TO BE ADDED WHEN NEEDED.

BRUNING 44 122 21039

668 226

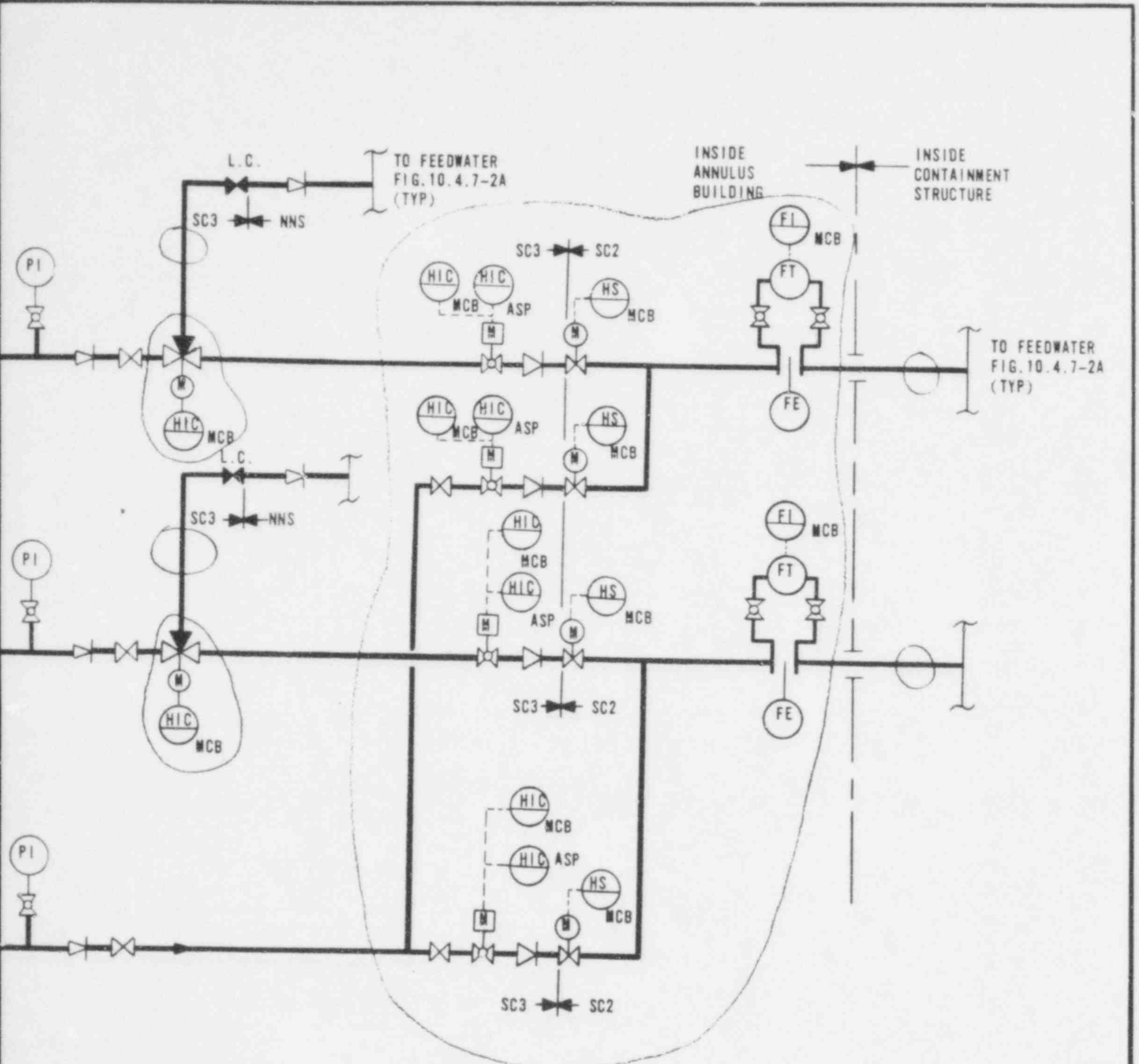


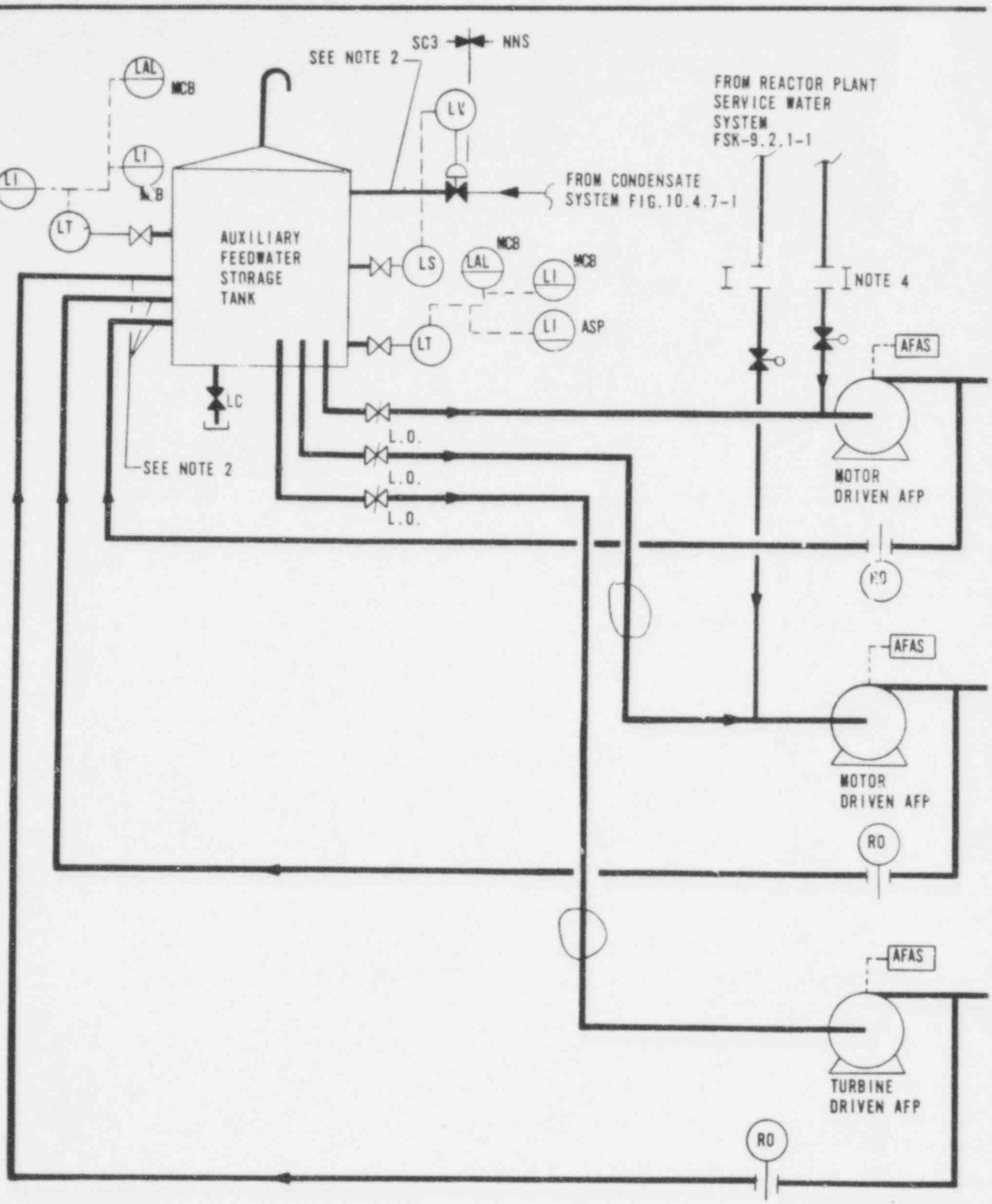
FIG.10.4.10-1

AUXILIARY FEEDWATER SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

CE

668 227



NOTES:

1. AFP DENOTES AUXILIARY FEEDWATER PUMP
2. RETURN LINES ABOVE TANK WATER LEVEL.
3. THIS SYSTEM IS SAFETY CLASS 3 (SC3) UNLESS OTHERWISE NOTED.
4. SPOOL PIECES WILL BE ADDED WHEN NEEDED.

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SYSTEM INTERFACE POINTS - AUXILIARY FEEDWATER SYSTEM

ID NO.	RESAR-41	RESAR-3S	B-SAR 205	CESSAR
FWA-1-2	Not Applicable	Not Applicable	Auxiliary feedwater system to steam generator nozzles	Not Applicable

19

668 229

FIG 10.4.10-1B
AUXILIARY FEEDWATER SYSTEM
PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

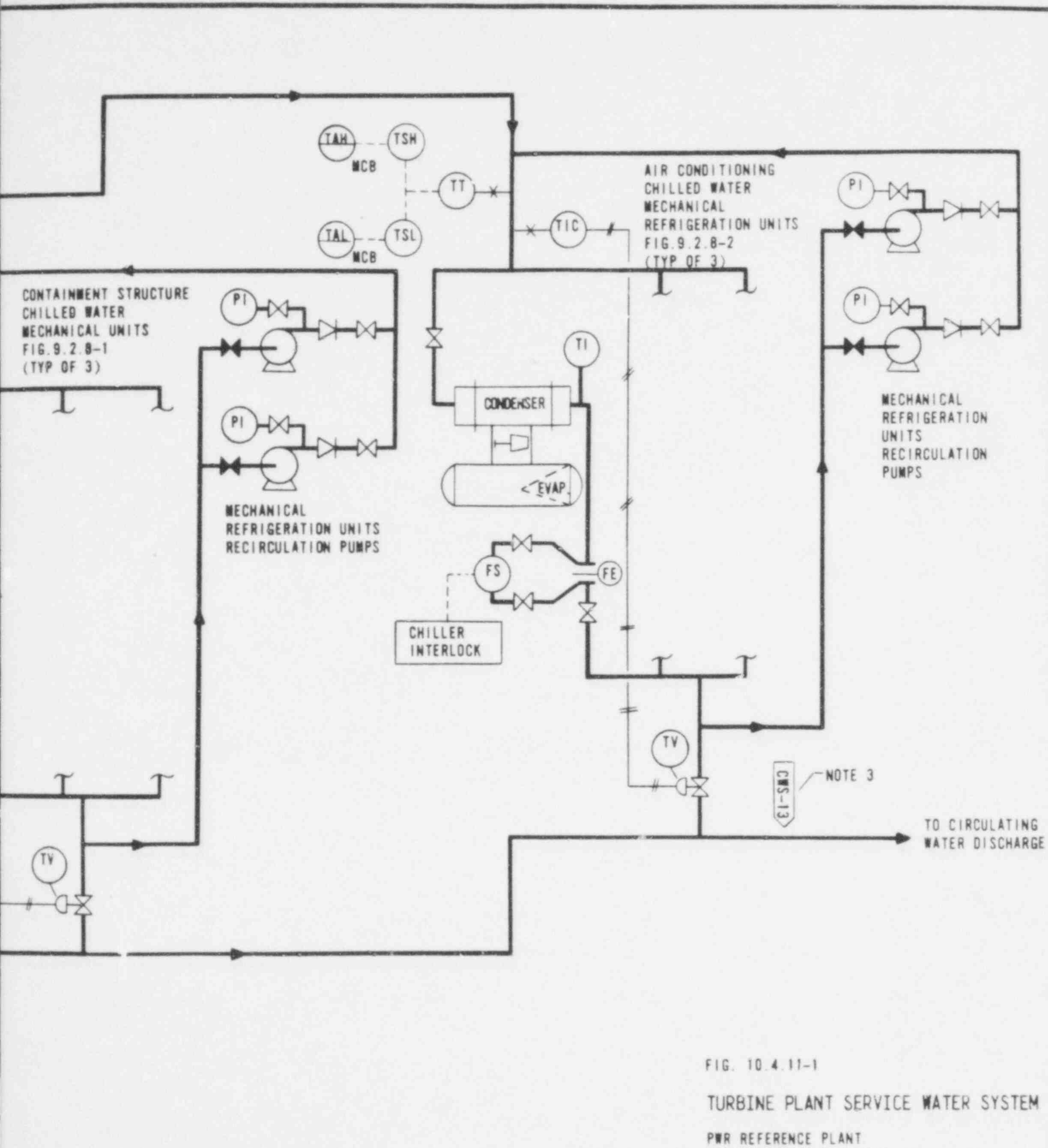


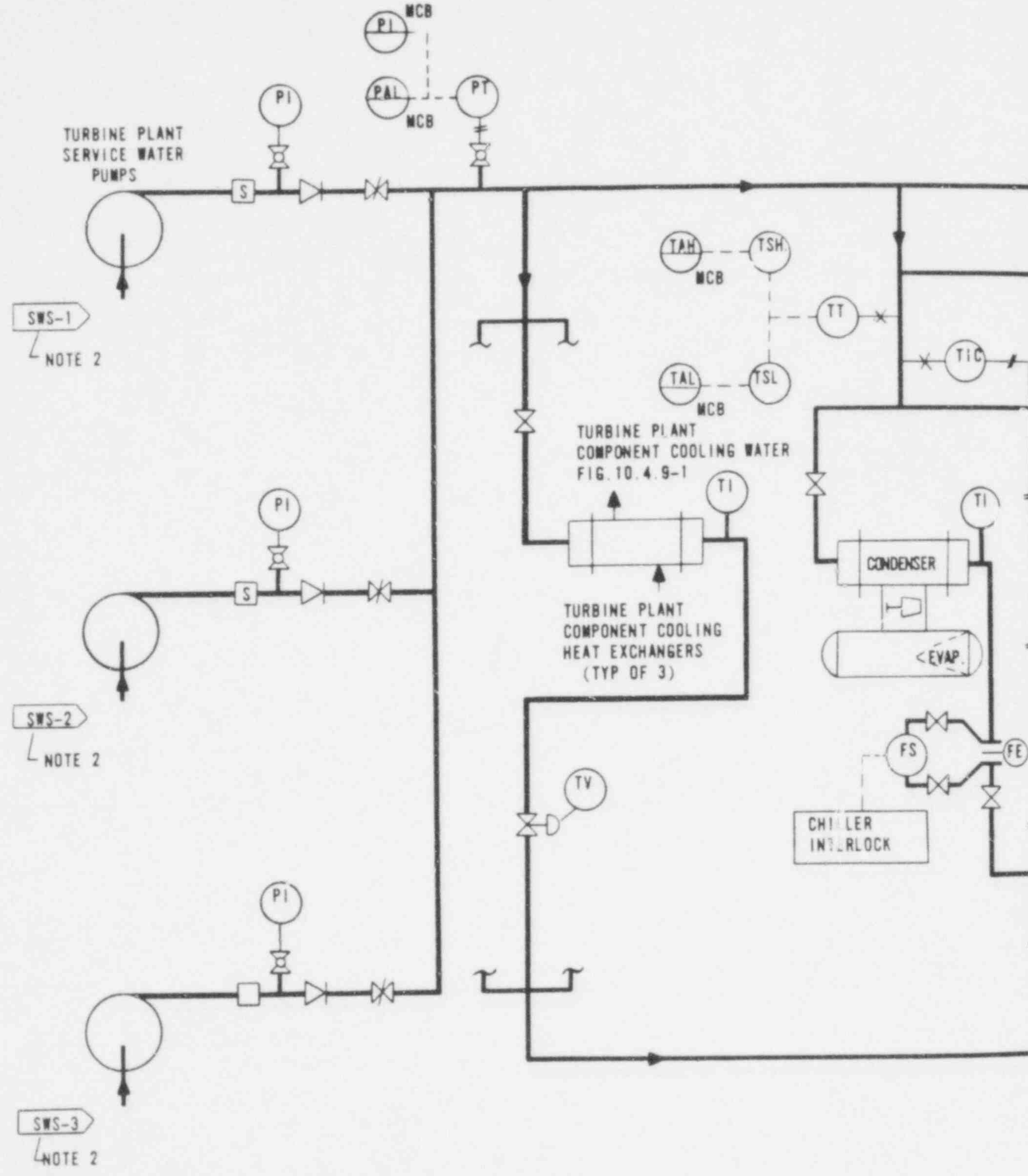
FIG. 10.4.11-1

TURBINE PLANT SERVICE WATER SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

668 230

DRAWING 44-122 21039



NOTES:

1. THIS SYSTEM IS NON-NUCLEAR SAFETY CLASS (NNS).
2. SYSTEM INTERFACE POINTS SWS-1 THRU 3 ARE WITH TURBINE PLANT SERVICE WATER SOURCE. SEE UTILITY APPLICANT'S SAR, SECTION 10.4.11.
3. SYSTEM INTERFACE POINT CWS-13, IS WITH CIRCULATING WATER SYSTEM. SEE UTILITY APPLICANT'S SAR, SECTION 10.4.5.

668 231

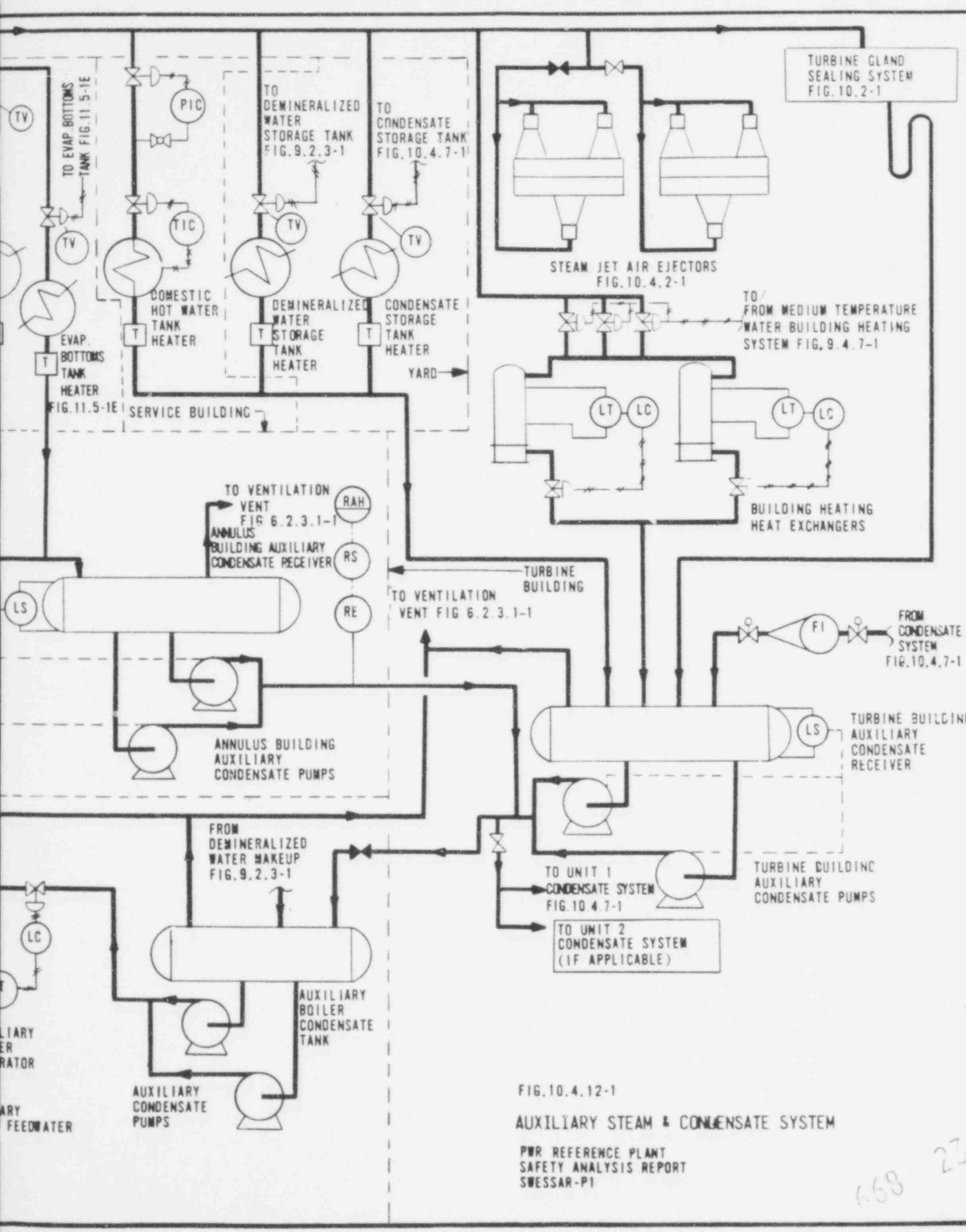
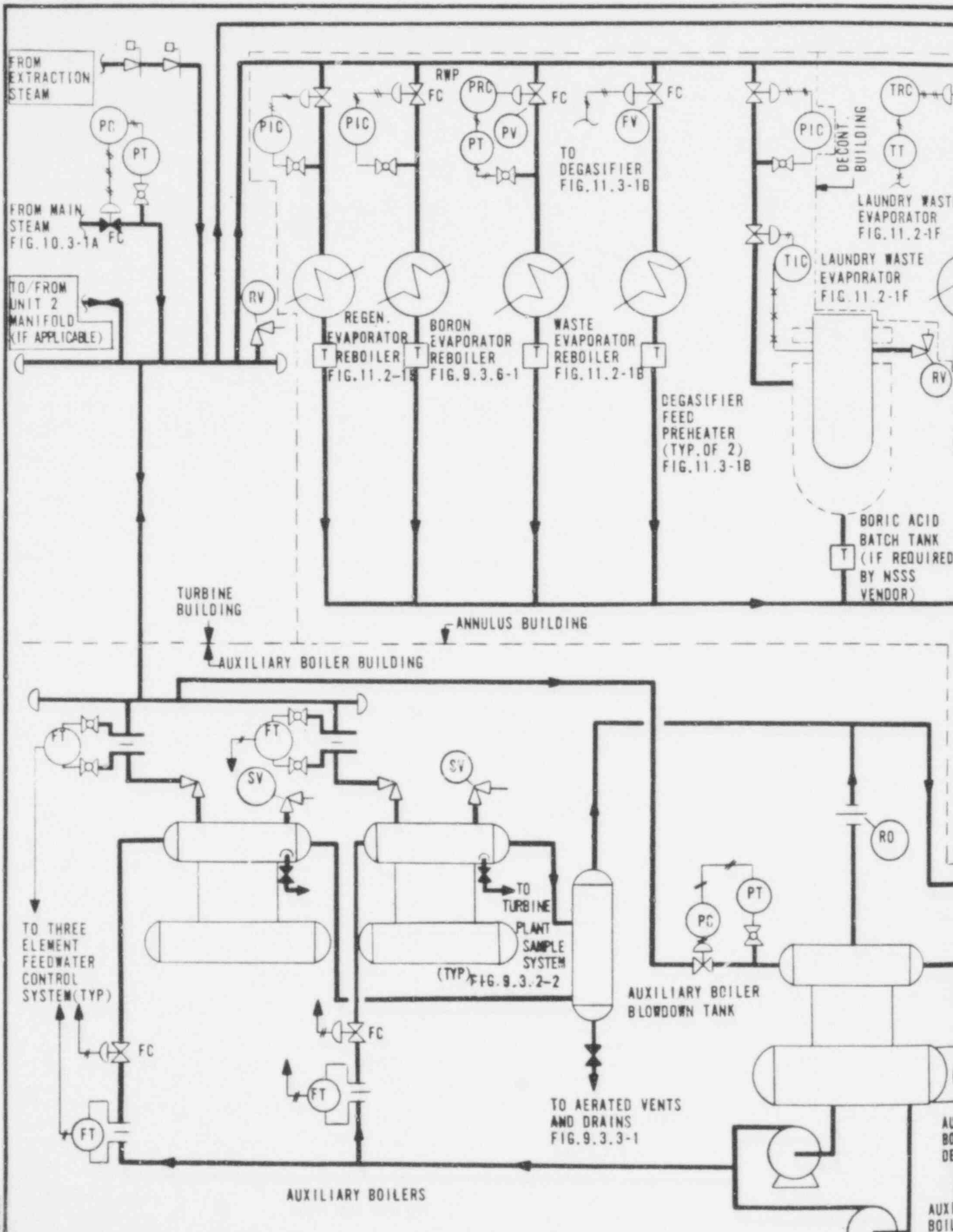


FIG. 10.4.12-1

AUXILIARY STEAM & CONDENSATE SYSTEM

PWR REFERENCE PLANT
SAFETY ANALYSIS REPORT
SWESSAR-P1

468 237



NOTE: THIS SYSTEM IS NON-NUCLEAR SAFETY CLASS (NNS).

668 233