Public Service
Electric and Gas
Company

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Senior Vice President - Nuclear Operations

OCT 14 1998
LR-N980493

United States Nuclear Regulatory Commission
Document Control Desk
Washington, DC 20555

Gentlemen:

UPDATED FINAL SAFETY ANALYSIS REPORT, REVISION 17
SALEM GENERATING STATION UNITS 1 AND 2
DOCKET NOS. 50-272 and 50-311

Public Service Electric and Gas Company (PSE&G) hereby submits Revision No. 17 to the Salem Generating Station Updated Final Safety Analysis Report (UFSAR) in accordance with the requirements of 10CFR50.71(e).

Revision No. 17 to the Salem UFSAR contains identified text, table and figure changes required to reflect the plant configuration as of April 16, 1998, six months prior to this submittal. In addition, there are corrections of typographical errors and general editorial changes. Details regarding each change are attached to facilitate your review.

The previous revision to the Salem UFSAR was issued on January 31, 1998 both to reflect configuration changes resulting from the Unit 2 extended outage and to satisfy the 24 month maximum revision limit. This revision, Revision 17, reflects configuration changes resulting from the Unit 1 extended outage and reestablishes Salem Unit 1 as the lead plant for planned updates of the Salem UFSAR.

Should there be any questions with regard to this submittal, please do not hesitate to contact us.

Sincerely,

Louis F Storz

A053

Attachments:

- Affidavit
- Summary of Salem UFSAR Revision 17 Changes
- Salem UFSAR Revision No. 17

C Document Control Desk - Original & ten copies

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Senior Vice President - Nuclear Engineering (N19)
Director - QA/NT/EP (120)
Director - Licensing / Regulation and Fuels (N21)
General Manager - Salem Operations (S05)
Manager - Nuclear Review Board (N38)
Manager - Joint Owners/Ext Aff Interface (N28)
Licensing Operational Manager - Salem (N21)
J. Keenan, Esq. (N21)

(w/ attachments except Salem UFSAR Revision No. 17):
Records Management
Microfilm
File Nos. 1.2.1, 2.1.3

REF: LR-N980493

STATE OF NEW JERSEY)
) SS
COUNTY OF SALEM)

L. F. Storz, being duly sworn, states that he is Senior Vice President - Nuclear Operations of Public Service Electric and Gas Company, that he is authorized on the part of said Company to sign and file with the Nuclear Regulatory Commission this certification; and, that in accordance with 10 CFR50.71 (e)(2), the information contained in the attached letter and Updated Final Safety Analysis Report accurately presents changes made since the previous submittal, necessary to reflect information and analyses submitted to the Commission or prepared pursuant to Commission requirement; and, contains an identification of changes made under the provisions of 10 CFR50.59 but not previously submitted to the Commission.

Subscribed and Sworn to

before me this 14th day of

October, 1998

Louis F. Storz

LOUIS F. STORZ

Deloris D. Hadden

DELORIS D. HADDEN
Notary Public of New Jersey
My Commission Expires
03-29-2000

ATTACHMENT 1

Summary of Salem UFSAR Revision 17 Changes

Salem UFSAR Changes Approved for Incorporation in Revision 17

10/12/98

CN Number	Affected Sections	Affected Pages/Figures/Tables	Description	Initiating or Ref. Document
SSAR 94-041	15.2	15.2-55 15.2-56 15.2-57 15.2-58 15.2-59 F15.2-45 F15.2-46 T15.2-1 Sh 7	Reanalysis of Inadvertent Safety Injection at Power transient - Unit 2 only	DCPs 2EC-3617 and 1EC-3696, AR 961016246 CRCA 01, Fuels Eval. DS 1.8-0005; CR 951208266, DEF DES-94-0042
	5.5	5.5-48 5.5-55 5.5-57		
	A	A-6 A-8		
	New SAR Pages:	F15.2.14-1 through -5		
SSAR 95-028	3.2 3.8	3.2-2 3.8-74 3.8-80 3.8-82	Clarification of the Service Water Intake Structure seismic class 1 classification	PR 951221127, DEF DES-94-00114
SSAR 95-062	8.1	8.1-10	Revision of 28 volt DC Logic System breaker protection	DCP 1EE-0116
SSAR 95-088	3.8	F3.8-37 F3.8-38	Replacement of containment airlock valves	DCP 1EE-0130
SSAR 96-068	10.2	10.2-6 10.2-6a	Adds an additional means for turbine runback as a result of a main feedwater pump trip on Unit 2	DCP 2EC-3306 PKG 1
SSAR 96-076	11.4	11.4-19 T11.4-4 SH 1	Unit 2 Fuel Handling Area Ventilation System - addition of an automatic initiation of exhaust fans on a high radiation signal from RMS	DCP 2EC-3559 PKG 1, LCR S96-08B
	8.3	T8.3-6		
	9.1	9.1-3b		
	9.4	9.4-18		

CN Number	Affected Sections	Affected Pages/Figures/Tables	Description	Initiating or Ref. Document
SSAR 96-084	10.3	F10.3-1B Sh 1	Digital Feedwater Control System	DCP 2EC-3178 Pkg 1, 1EC-3206 PKG 1
		F10.3-1B Sh 2		
	10.4	F10.4-5A Sh 3		
	15.2	15.2-37		
	15.4	15.4-44		
	7	7-ix		
	7.2	7.2-25		
		F7.2-2		
		F7.2-7		
		T7.2-1 Sh 3		
		T7.2-1 Sh 4		
		T7.2-1 Sh 5		
		T7.2-1 Sh 6		
	7.3	T7.3-1 Sh 1		
		T7.3-1 Sh 2		
	7.7	7.7-10		
		7.7-9		
	New SAR Pages:	Figures 7.7-7, 7.7-8, 7.7-9		
SSAR 96-087	10.2	10.2-6	Main Generator - revise low stator winding, rectifier, and bushing water flow logic to "2 out of 3"	DCP 2EC-3471 PKG 1
SSAR 96-092	11.4	11.4-10	Radiation Monitoring System Channel 1R41 replacement (plant vent)	DCP 1EC-3244 PKG 1
		11.4-16		
		11.4-3		
		11.4-4		
		11.4-8		
		11.4-9		
		F11.4-2		
		T11.4-1 SH 3		
	3A	3A-8		
	A	A-52		
SSAR 96-107	3.8	3.8-16	Update of UFSAR for structural adequacy of containment structure and liner for effects of Main Steam Line Break	CR 950721135
		3.8-19		
		3.8-20		
		3.8-24		
		3.8-28		
		3.8-4		
		3.8-5		
		3.8-82		

CN Number	Affected Sections	Affected Pages/Figures/Tables	Description	Initiating or Ref. Document
SSAR 96-112	10.3 10.4	10.3-18 F10.3-3 Sh 2 10.4-11 F10.4-18B Sh 2 F10.4-5B Sh 1 F10.4-5B Sh 2 F10.4-5B Sh 3 F10.4-6B Sh 5	Ethanolamine (ETA) Chemistry and corrosion sample points	DCP 2EX-3533
SSAR 96-117	3.8	3.8-77a 3.8-82	Spent Fuel Pool structure and liner update for latest structural evaluations	CR 951207356 CRCA 2
SSAR 96-126	3.6 9.4	3.6-36a 3.6-42 F3.6-28 F9.4-2B SH 3	Provide protection for Turbine Driven Aux Feed pump enclosure by adding blowout panels, removing and installing dampers, and adding temperature switches	DCP 2EC-3522 PKG 1
SSAR 96-153	5.5	T5.5-1 SH 4	RHR suction pressure change from 450 psig to 600 psig for piping between valves 2RH75 and 2RH76	CR 960911067
SSAR 96-211	15.4	15.4-114	Correction of Feedwater regulator valve delay time for the steam line break accident	CR 960722187
SSAR 97-002	5.1 5.6 7.7	F5.1-6a sh 1 5.6-4 7.7-21	Install new RVLIS wide range midloop indication.	DCP 1EC-3531
SSAR 97-006	10.3 10.4	10.3-5 10.4-18	Replacement of steam traps with orifice/strainer assemblies.	DCP 1EC-3495 pkg 1, DCP 2EC-3407 pkg 1
SSAR 97-011	9.3	9.3-1	Denote 1SAE1 as both total closure and constant pressure controls.	DCP 1EC-3651 Pkg. 1, Pkg 2, Pkg 3

CN Number	Affected Sections	Affected Pages/Figures/Tables	Description	Initiating or Ref. Document
SSAR 97-018	10.4 11.3 2.2 6.4	10.4-19 11.3-5 2.2-10 T2.2-2 Sh 1 T2.2-2 Sh 2 6.4-3	Addition of nitrogen purge/blanket to the Auxiliary Feed Water storage tank	DCP 2EC-3570 pkg 1
SSAR 97-026	3.6	3.6-35 3.6-41 3.6-43 F3.6-28	Pipe break vent panel to be fixed closed with venting function provided by new vent penthouse.	DCP 1EC-3474
SSAR 97-027	10.3 3.6	10.3-12 3.6-44	Pressure relief vent panels for the Inner and Outer Penetration Areas are being modified by DCP 1EC-3475	DCP 1EC-3475
SSAR 97-030	2.4 6.3 8.3 9.2	F2.4-3 T6.3-13 Sh 1 F8.3-4 9.2-6b F9.2-1A Sh 2 F9.2-3	Revise UFSAR to reflect installation of new Service Water Pumps. Includes UFSAR update information from SSAR's 96-202, 96-203, 97-031, 97-040 , & 97-041.	DCP 1EC-3409
SSAR 97-035	7.5	T7.5-1 sh 2 T7.5-1 sh 3 T7.5-2 sh 10 T7.5-2 sh 9	Correction of data connected to the replacement of the Salem Unit 1 Series 51 Steam Generators with Model F Steam Generators.	DCP 1EE-0367
SSAR 97-036	8.3 9.5	F8.3-5 Sh 1 9.5-38	DCP 1EC-3385 exchanges the normal and backup power supplies for emergency lighting inverters 1INV1A15Y, 1INV1B16Y and 1INV1C12Y	DCP 1EC-3385 pkg 2

CN Number	Affected Sections	Affected Pages/Figures/Tables	Description	Initiating or Ref. Document
SSAR 97-045	11.2	11.2-10 11.2-4 F11.2-1B Sh 2 T11.2-1 T11.2-3 Sh 1	Addition of a filtration unit to the Liquid Radwaste System	DCP 1EC-3622
SSAR 97-062	3.5	3.5-22 3.5-5	Information provided for steel missile barriers.	DCP 2EC-3590 pkg 14
SSAR 97-068	5.6 7.1 7.2 7.3 7.7	5.6-3 5.6-4 7.1-11 7.1-13 7.2-12 7.2-39 7.3-29 T7.3-5 Sh 10 T7.3-5 Sh 12 T7.3-5 Sh 14 T7.3-5 Sh 2 T7.3-5 Sh 4 T7.3-5 Sh 6 T7.3-5 Sh 8 7.7-6 7.7-7 F7.7-2	Removes a section of the UFSAR that describes the use of a Hi Tave signal from a Hagan instrument loop being replaced by an NUS instrument loop.	DCP 1EC-3523 pkg 1
SSAR 97-075	6.3	6.3-32	Add description of anti-sweat insulation to be installed on 3" & 3/4" dia. uninsulated service water piping on CFCUs in Unit 1 Containment.	DCP 1EE-0348 pkg 1
SSAR 97-093	15.4	15.4-110 F15.4-100 F15.4-91 F15.4-98 T15.4-22 T15.4-24	Revise Section 15.4.8 to reflect the impact of the recent license amendments increasing the CFCU response time from 45 to 60 seconds.	DCPs 1EC-1914A, 2EC-1915A, 1EC-2032 and 2EC-2032
SSAR 97-104	6.2	F6.2-34 T6.2-10 Sh 5 T6.2-12 Sh 3	Revise UFSAR in accordance with DCP 1EC-3687	DCP 1EC-3687

CN Number	Affected Sections	Affected Pages/Figures/Tables	Description	Initiating or Ref. Document
SSAR 97-105	7.2	7.2-32 F7.2-4	Implement changes to pressurizer pressure circuits.	DCP 1EC-3696
	7.5	7.5-4		
SSAR 97-109	1.2	F1.2-1	Delete Waste Evaporator Building and add Service Water Accumulator Enclosure.	DCP 1EC-3668 pkg 7, GL 96-06

CN Number	Affected Sections	Affected Pages/Figures/Tables	Description	Initiating or Ref. Document
SSAR 97-110	4	4-iii	Update of Salem UFSAR Chapter 4 for fuel upgrade (to Vantage+) and typical reload cycle information.	LCR 94-07, CRCA 960416212
		4-vii		
		4-viii		
		4-x		
		4-xi		
		4-xii		
		4-xiii		
		4-xiv		
		4-xv		
		4-xvi		
		4-xvii		
		4-xviii		
	4.1	4.1-1		
		4.1-2		
		4.1-3		
		4.1-4		
		T4.1-1 Sh 1		
		T4.1-1 Sh 2		
		T4.1-1 Sh 3		
		T4.1-1 Sh 4		
		T4.1-1 Sh 5		
		T4.1-2 Sh 1		
	4.2	4.2-10		
		4.2-11		
		4.2-12		
		4.2-13		
		4.2-13a		
		4.2-13b		
		4.2-13c		
		4.2-13d		
		4.2-14		
		4.2-17		
		4.2-2		
		4.2-24		
		4.2-25		
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		4.2-27		
		4.2-28		
		4.2-4		
		4.2-5		
		4.2-7		
		4.2-8		
		4.2-83		
		4.2-9		
		F4.2-1		
		F4.2-11		
		F4.2-2A		
		F4.2-3		

CN Number	Affected Sections	Affected Pages/Figures/Tables	Description	Initiating or Ref. Document
		F4.2-3A		
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		F4.2-7		
		F4.2-9		
	4.3	4.3-10		
		4.3-11		
		4.3-12		
		4.3-13		
		4.3-15		
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		4.3-47		
		4.3-48		
		4.3-49		
		4.3-5		
		4.3-50		
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		4.3-54		
		4.3-55		
		4.3-56		

CN Number	Affected Sections	Affected Pages/Figures/Tables	Description	Initiating or Ref. Document
		4.3-57		
		4.3-58		
		4.3-61		
		4.3-9		
		F4.3-10A		
		F4.3-10B		
		F4.3-11A		
		F4.3-11B		
		F4.3-12A		
		F4.3-12B		
		F4.3-13		
		F4.3-14		
		F4.3-15		
		F4.3-16		
		F4.3-17		
		F4.3-18		
		F4.3-19		
		F4.3-1A		
		F4.3-1B		
		F4.3-2		
		F4.3-20		
		F4.3-21		
		F4.3-22		
		F4.3-23		
		F4.3-24		
		F4.3-25		
		F4.3-26A		
		F4.3-26B		
		F4.3-27A		
		F4.3-27B		
		F4.3-28A		
		F4.3-28B		
		F4.3-29A		
		F4.3-29B		
		F4.3-3		
		F4.3-30A		
		F4.3-30B		
		F4.3-31A		
		F4.3-31B		
		F4.3-32A		
		F4.3-32B		
		F4.3-33A		
		F4.3-33B		
		F4.3-34A		
		F4.3-34B		
		F4.3-35A		
		F4.3-35B		
		F4.3-36		

CN Number	Affected Sections	Affected Pages/Figures/Tables	Description	Initiating or Ref. Document
		F4.3-37		
		F4.3-38		
		F4.3-39		
		F4.3-40		
		F4.3-41		
		F4.3-42		
		F4.3-43		
		F4.3-44		
		F4.3-4A		
		F4.3-4B		
		F4.3-5A		
		F4.3-5B		
		F4.3-6A		
		F4.3-6B		
		F4.3-7A		
		F4.3-7B		
		F4.3-8A		
		F4.3-8B		
		F4.3-9A		
		F4.3-9B		
		T4.3-1 Sh 1		
		T4.3-1 Sh 2		
		T4.3-1 Sh 3		
		T4.3-2 Sh 1		
		T4.3-2 Sh 2		
		T4.3-2 Sh 3		
		T4.3-3A		
		T4.3-3B		
	4.5	4.5-1		
		4.5-2		
		4.5-2A		
		4.5-2B		
		4.5-2C		
		4.5-2D		
		4.5-2E		
		4.5-2F		
		4.5-2G		
		4.5-2H		
		4.5-2I		
		4.5-2J		
		4.5-2K		
		4.5-2L		
		4.5-3		
		4.5-3A		
		4.5-3B		
		4.5-3C		
		4.5-3D		
		4.5-3E		

CN Number	Affected Sections	Affected Pages/Figures/Tables	Description	Initiating or Ref. Document
		4.5-3F 4.5-3G 4.5-3H 4.5-3I 4.5-3J 4.5-3K 4.5-3L 4.5-3M		
	New SAR Pages:	T4.5-1, T4.5-2, F4.5-1, F4.5-2, F4.5-3, F4.5-4		
SSAR 97-112	8.3 9.2	T8.3-6 F9.2-1A sh 6	Revise UFSAR to reflect decrease in 125V DC battery profile and removal of high CFCU outlet water radiation console alarm.	DCP 1EC-3668 pkg 10
SSAR 97-115	10.4 8.3 9.2	F10.4-17A T8.3-5 T8.3-6 F9.2-11 Sh 6	Increase in 28 VDC/125 VDC battery profiles and changes to demin water makeup and auxiliary feedwater P&IDs.	DCP 1EC-3519, pkg 1
SSAR 97-123	5.5	5.5-3	Revise the UFSAR description of the RCP vibration monitoring system to reflect new equipment.	DCP 1EC-3647
SSAR 97-124	7.6	7.6-5	Revise description of relief valve action to include auto and manual modes of operation.	DCP 1EC-3607
SSAR 97-127	6.2	F6.2-17 F6.2-26 F6.2-38 F6.2-44 T6.2-10 sh 3 T6.2-10 sh 8 T6.2-12 sh 3	Revise UFSAR to incorporate DCP 1EC-3718	DCP 1EC-3718
SSAR 97-129	10.4 11.3 2.2 6.4	10.4-19 11.3-5 2.2-10 6.4-3	Addition of nitrogen purge blanket for Aux. Feed Water Storage Tank.	DCP 1EC-3640

CN Number	Affected Sections	Affected Pages/Figures/Tables	Description	Initiating or Ref. Document
SSAR 97-130	6.3	6.3-9	Revise Mode 4 Hot Leg Recirculation to be applicable to both units.	
SSAR 97-133	13.1	13.1-10 13.1-11 13.1-15 13.1-18 13.1-8a 13.1-9 F13.1-8a F13.1-8b F13.1-8e T13.1-1 sh 1	Eliminates Director- Salem Operations position. Shifts reporting relationships for Salem Operations and changes management title for Salem Chemistry. Also changes station succession of authority.	
SSAR 97-136	New SAR Pages:	Table 6.3-6	Revision to RWST Draindown Analysis for Unit 1	
SSAR 97-138	New SAR Pages:	T4.5-1, F4.5-1, F4.5-2	Update of Salem 1 Cycle 1 information to reflect current cycle.	DS1.8-0042, DS1.8-0043
SSAR 97-139	5.2 5.5 6.2 6.3 9.3	5.2-70 5.5-28 5.5-33 T5.5-2 sh 1 6.2-59 F6.2-30 F6.2-33 F6.2-4A T6.2-10 sh 1 T6.2-12 sh 1 6.3-20 6.3-21 F6.3-1A sh 2 F6.3-1A sh 3 F6.3-2 F9.3-4A sh 3 F9.3-6A sh 2	Revise piping at the outlet of valve 1 PR 25 in accordance with Minor Modification S97-174.	Minor Mod S97-174
SSAR 97-142	5.2	5.2-4	Add clarification note on applicability and control of code cases to the ASME Boiler & Pressure Vessel Code.	

CN Number	Affected Sections	Affected Pages/Figures/Tables	Description	Initiating or Ref. Document
SSAR 98-001	8.3	8.3-6	Reflects the UPRATING of the 115 VAC Vital Instrument Bus Inverters from 10kVa to 12kVa	
	New SAR Pages:	Figure 8.3-5 Sht. 1		
SSAR 98-002	9.4	9.4-45 9.4-46	Revise Service Water Intake Structure minimum design temperature from 60F to 40F.	
SSAR 98-005	13.1	13.1-1	Adds position for Executive Vice President - NBU, position will perform duties of CNO/PNBU in his absence.	
	New SAR Pages:	Figure 13.1-2		
SSAR 98-006	3A	3A-6	Revise statement of conformance for Reg. Guide 1.16	
SSAR 98-007	9.4	9.4-42	Provide description of outside air temperature basis used in SPAV system performance calculations.	
SSAR 98-011	9.4	9.4-3	Revised descriptions for CREACS Single Filtration Train Alignment.	
	New SAR Pages:	9.4-4b,9.4-4d, & 9.4-4f		
SSAR 98-013	4.2	4.2-46 4.2-51 4.2-52 4.2-67 4.2-68 4.2-69 4.2-70 4.2-71 4.2-78	Replacement of Westinghouse Rod Cluster Control Assemblies in each Salem Unit with Frematome assimblies manufactured from different materials as noted in FSAR.	DCP's 1EC-3446 & 2EC-3334
	New SAR Pages:	Tables: 4.1-1 (3&4 of 5); 4.3-1 (2&3 of 3) Figures: 4.2-14; 4.2-15		

CN Number	Affected Sections	Affected Pages/Figures/Tables	Description	Initiating or Ref. Document
SSAR 98-015			Table 5.2-8 revised to reform valve design parameters	DCP 2EC-3650/01
	New SAR Pages:	Table 5.2-8		
SSAR 98-016	13.1	13.1-9	Aligns both stations succession of authority and responsibility for overall operation in the event of an unexpected contingency.	
SSAR 98-017	9.3	9.3-9	To describe accumulator purge to locations other than the VCT.	
SSAR 98-019	17.2	17.2-24	ORGANIZATIONAL NAME CHANGE FOR UFSAR UPDATE RESPONSIBILITY.	
SSAR 98-020	13.5	13.5-1 13.5-2 13.5-2a 13.5-2b 13.5-2c 13.5-2d	This proposed change will align Hope Creek Section 13.5.1, Administrative Procedures and Salem Section 13.5, Plant Procedures (in part)	

CN Number	Affected Sections	Affected Pages/Figures/Tables	Description	Initiating or Ref. Document
SSAR 98-027	17.2	17.2-12 17.2-13 17.2-19 17.2-2 17.2-20 17.2-21 17.2-23 17.2-25 17.2-26 17.2-28 17.2-29 17.2-37 17.2-4 17.2-40 17.2-6 F17.2-1	Org change moving QA Mat'l & Supplier Plant Support from QA into the Nuclear Procurement & Material Management Organization and transferring the responsibility for review of special process procedures from QA and the General Manager to a qualified specialist.	
	New SAR Pages:	17.2-4a, 17.2-7i		

10/16/98

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Public Service
Electric and Gas
Company

Louis F. Storz

Senior Vice President - Nuclear Operations

Public Service Electric and Gas Company P.O. Box 236, Hancocks Bridge, NJ 08038 609-339-5700

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Gentlemen:

UPDATED FINAL SAFETY ANALYSIS REPORT, REVISION 17
SALEM GENERATING STATION UNITS 1 AND 2
DOCKET NOS. 50-272 and 50-311

Public Service Electric and Gas Company (PSE&G) hereby submits Revision No. 17 to the Salem Generating Station Updated Final Safety Analysis Report (UFSAR) in accordance with the requirements of 10CFR50.71(e).

Revision No. 17 to the Salem UFSAR contains identified text, table and figure changes required to reflect the plant configuration as of April 16, 1998, six months prior to this submittal. In addition, there are corrections of typographical errors and general editorial changes. Details regarding each change are attached to facilitate your review.

The previous revision to the Salem UFSAR was issued on January 31, 1998 both to reflect configuration changes resulting from the Unit 2 extended outage and to satisfy the 24 month maximum revision limit. This revision, Revision 17, reflects configuration changes resulting from the Unit 1 extended outage and reestablishes Salem Unit 1 as the lead plant for planned updates of the Salem UFSAR.

Should there be any questions with regard to this submittal, please do not hesitate to contact us.

Sincerely,

Louis F. Storz

Attachments:

- Affidavit
- Summary of Salem UFSAR Revision 17 Changes
- Salem UFSAR Revision No. 17

C Document Control Desk - Original & ten copies

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Senior Vice President - Nuclear Engineering (N19)
Director - QA/NT/EP (120)
Director - Licensing / Regulation and Fuels (N21)
General Manager - Salem Operations (S05)
Manager - Nuclear Review Board (N38)
Manager - Joint Owners/Ext Aff Interface (N28)
Licensing Operational Manager - Salem (N21)
J. Keenan, Esq. (N21)

(w/ attachments except Salem UFSAR Revision No. 17):
Records Management
Microfilm
File Nos. 1.2.1, 2.1.3

REF: LR-N980493

STATE OF NEW JERSEY)
) SS
COUNTY OF SALEM)

L. F. Storz, being duly sworn, states that he is Senior Vice President - Nuclear Operations of Public Service Electric and Gas Company, that he is authorized on the part of said Company to sign and file with the Nuclear Regulatory Commission this certification; and, that in accordance with 10 CFR50.71 (e)(2), the information contained in the attached letter and Updated Final Safety Analysis Report accurately presents changes made since the previous submittal, necessary to reflect information and analyses submitted to the Commission or prepared pursuant to Commission requirement; and, contains an identification of changes made under the provisions of 10 CFR50.59 but not previously submitted to the Commission.

Subscribed and Sworn to

before me this 14th day of

October, 1998

Louis F. Storz
LOUIS F. STORZ

Deloris D. Hadden
DELORIS D. HADDEN
Notary Public of New Jersey
My Commission Expires
03-29-2000

ATTACHMENT 1

Summary of Salem UFSAR Revision 17 Changes

Salem UFSAR Changes Approved for Incorporation in Revision 17

10/12/98

CN Number	Affected Sections	Affected Pages/Figures/Tables	Description	Initiating or Ref. Document
SSAR 94-041	15.2	15.2-55 15.2-56 15.2-57 15.2-58 15.2-59 F15.2-45 F15.2-46 T15.2-1 Sh 7	Reanalysis of Inadvertent Safety Injection at Power transient - Unit 2 only	DCPs 2EC-3617 and 1EC-3696, AR 961016246 CRCA 01, Fuels Eval. DS 1.8-0005; CR 951208266, DEF DES-94-0042
	5.5	5.5-48 5.5-55 5.5-57		
	A	A-6 A-8		
	New SAR Pages:	F15.2.14-1 through -5		
SSAR 95-028	3.2 3.8	3.2-2 3.8-74 3.8-80 3.8-82	Clarification of the Service Water Intake Structure seismic class 1 classification	PR 951221127, DEF DES-94-00114
SSAR 95-062	8.1	8.1-10	Revision of 28 volt DC Logic System breaker protection	DCP 1EE-0116
SSAR 95-088	3.8	F3.8-37 F3.8-38	Replacement of containment airlock valves	DCP 1EE-0130
SSAR 96-068	10.2	10.2-6 10.2-6a	Adds an additional means for turbine runback as a result of a main feedwater pump trip on Unit 2	DCP 2EC-3306 PKG 1
SSAR 96-076	11.4 8.3 9.1 9.4	11.4-19 T11.4-4 SH 1 T8.3-6 9.1-3b 9.4-18	Unit 2 Fuel Handling Area Ventilation System - addition of an automatic initiation of exhaust fans on a high radiation signal from RMS	DCP 2EC-3559 PKG 1, LCR S96-08B

CN Number	Affected Sections	Affected Pages/Figures/Tables	Description	Initiating or Ref. Document
SSAR 96-084	10.3	F10.3-1B Sh 1	Digital Feedwater Control System	DCP 2EC-3178 Pkg 1, 1EC-3206 PKG 1
		F10.3-1B Sh 2		
	10.4	F10.4-5A Sh 3		
	15.2	15.2-37		
	15.4	15.4-44		
	7	7-ix		
	7.2	7.2-25		
		F7.2-2		
		F7.2-7		
		T7.2-1 Sh 3		
		T7.2-1 Sh 4		
		T7.2-1 Sh 5		
		T7.2-1 Sh 6		
	7.3	T7.3-1 Sh 1		
		T7.3-1 Sh 2		
	7.7	7.7-10		
		7.7-9		
	New SAR Pages:	Figures 7.7-7, 7.7-8, 7.7-9		
SSAR 96-087	10.2	10.2-6	Main Generator - revise low stator winding, rectifier, and bushing water flow logic to "2 out of 3"	DCP 2EC-3471 PKG 1
SSAR 96-092	11.4	11.4-10	Radiation Monitoring System Channel 1R41 replacement (plant vent)	DCP 1EC-3244 PKG 1
		11.4-16		
		11.4-3		
		11.4-4		
		11.4-8		
		11.4-9		
		F11.4-2		
		T11.4-1 SH 3		
	3A	3A-8		
	A	A-52		
SSAR 96-107	3.8	3.8-16	Update of UFSAR for structural adequacy of containment structure and liner for effects of Main Steam Line Break	CR 950721135
		3.8-19		
		3.8-20		
		3.8-24		
		3.8-28		
		3.8-4		
		3.8-5		
		3.8-82		

CN Number	Affected Sections	Affected Pages/Figures/Tables	Description	Initiating or Ref. Document
SSAR 96-112	10.3 10.4	10.3-18 F10.3-3 Sh 2 10.4-11 F10.4-18B Sh 2 F10.4-5B Sh 1 F10.4-5B Sh 2 F10.4-5B Sh 3 F10.4-6B Sh 5	Ethanolamine (ETA) Chemistry and corrosion sample points	DCP 2EX-3533
SSAR 96-117	3.8	3.8-77a 3.8-82	Spent Fuel Pool structure and liner update for latest structural evaluations	CR 951207356 CRCA 2
SSAR 96-126	3.6 9.4	3.6-36a 3.6-42 F3.6-28 F9.4-2B SH 3	Provide protection for Turbine Driven Aux Feed pump enclosure by adding blowout panels, removing and installing dampers, and adding temperature switches	DCP 2EC-3522 PKG 1
SSAR 96-153	5.5	T5.5-1 SH 4	RHR suction pressure change from 450 psig to 600 psig for piping between valves 2RH75 and 2RH76	CR 960911067
SSAR 96-211	15.4	15.4-114	Correction of Feedwater regulator valve delay time for the steam line break accident	CR 960722187
SSAR 97-002	5.1 5.6 7.7	F5.1-6a sh 1 5.6-4 7.7-21	Install new RVLIS wide range midloop indication.	DCP 1EC-3531
SSAR 97-006	10.3 10.4	10.3-5 10.4-18	Replacement of steam traps with orifice/strainer assemblies.	DCP 1EC-3495 pkg 1, DCP 2EC-3407 pkg 1
SSAR 97-011	9.3	9.3-1	Denote 1SAE1 as both total closure and constant pressure controls.	DCP 1EC-3651 Pkg. 1, Pkg 2, Pkg 3

CN Number	Affected Sections	Affected Pages/Figures/Tables	Description	Initiating or Ref. Document
SSAR 97-018	10.4 11.3 2.2 6.4	10.4-19 11.3-5 2.2-10 T2.2-2 Sh 1 T2.2-2 Sh 2 6.4-3	Addition of nitrogen purge/blanket to the Auxiliary Feed Water storage tank	DCP 2EC-3570 pkg 1
SSAR 97-026	3.6	3.6-35 3.6-41 3.6-43 F3.6-28	Pipe break vent panel to be fixed closed with venting function provided by new vent penthouse.	DCP 1EC-3474
SSAR 97-027	10.3 3.6	10.3-12 3.6-44	Pressure relief vent panels for the Inner and Outer Penetration Areas are being modified by DCP 1EC-3475	DCP 1EC-3475
SSAR 97-030	2.4 6.3 8.3 9.2	F2.4-3 T6.3-13 Sh 1 F8.3-4 9.2-6b F9.2-1A Sh 2 F9.2-3	Revise UFSAR to reflect installation of new Service Water Pumps. Includes UFSAR update information from SSAR's 96-202, 96-203, 97-031, 97-040 , & 97-041.	DCP 1EC-3409
SSAR 97-035	7.5	T7.5-1 sh 2 T7.5-1 sh 3 T7.5-2 sh 10 T7.5-2 sh 9	Correction of data connected to the replacement of the Salem Unit 1 Series 51 Steam Generators with Model F Steam Generators.	DCP 1EE-0367
SSAR 97-036	8.3 9.5	F8.3-5 Sh 1 9.5-38	DCP 1EC-3385 exchanges the normal and backup power supplies for emergency lighting inverters 1INV1A15Y, 1INV1B16Y and 1INV1C12Y	DCP 1EC-3385 pkg 2

CN Number	Affected Sections	Affected Pages/Figures/Tables	Description	Initiating or Ref. Document
SSAR 97-045	11.2	11.2-10 11.2-4 F11.2-1B Sh 2 T11.2-1 T11.2-3 Sh 1	Addition of a filtration unit to the Liquid Radwaste System	DCP 1EC-3622
SSAR 97-062	3.5	3.5-22 3.5-5	Information provided for steel missile barriers.	DCP 2EC-3590 pkg 14
SSAR 97-068	5.6 7.1 7.2 7.3 7.7	5.6-3 5.6-4 7.1-11 7.1-13 7.2-12 7.2-39 7.3-29 T7.3-5 Sh 10 T7.3-5 Sh 12 T7.3-5 Sh 14 T7.3-5 Sh 2 T7.3-5 Sh 4 T7.3-5 Sh 6 T7.3-5 Sh 8 7.7-6 7.7-7 F7.7-2	Removes a section of the UFSAR that describes the use of a Hi Tave signal from a Hagan instrument loop being replaced by an NUS instrument loop.	DCP 1EC-3523 pkg 1
SSAR 97-075	6.3	6.3-32	Add description of anti-sweat insulation to be installed on 3" & 3/4" dia. uninsulated service water piping on CFCUs in Unit 1 Containment.	DCP 1EE-0348 pkg 1
SSAR 97-093	15.4	15.4-110 F15.4-100 F15.4-91 F15.4-98 T15.4-22 T15.4-24	Revise Section 15.4.8 to reflect the impact of the recent license amendments increasing the CFCU response time from 45 to 60 seconds.	DCPs 1EC-1914A, 2EC-1915A, 1EC-2032 and 2EC-2032
SSAR 97-104	6.2	F6.2-34 T6.2-10 Sh 5 T6.2-12 Sh 3	Revise UFSAR in accordance with DCP 1EC-3687	DCP 1EC-3687

CN Number	Affected Sections	Affected Pages/Figures/Tables	Description	Initiating or Ref. Document
SSAR 97-105	7.2	7.2-32 F7.2-4	Implement changes to pressurizer pressure circuits.	DCP 1EC-3696
	7.5	7.5-4		
SSAR 97-109	1.2	F1.2-1	Delete Waste Evaporator Building and add Service Water Accumulator Enclosure.	DCP 1EC-3668 pkg 7, GL 96-06

CN Number	Affected Sections	Affected Pages/Figures/Tables	Description	Initiating or Ref. Document
SSAR 97-110	4	4-iii	Update of Salem UFSAR Chapter 4 for fuel upgrade (to Vantage+) and typical reload cycle information.	LCR 94-07, CRCA 960416212
		4-vii		
		4-viii		
		4-x		
		4-xi		
		4-xii		
		4-xiii		
		4-xiv		
		4-xv		
		4-xvi		
		4-xvii		
		4-xviii		
	4.1	4.1-1		
		4.1-2		
		4.1-3		
		4.1-4		
		T4.1-1 Sh 1		
		T4.1-1 Sh 2		
		T4.1-1 Sh 3		
		T4.1-1 Sh 4		
		T4.1-1 Sh 5		
		T4.1-2 Sh 1		
	4.2	4.2-10		
		4.2-11		
		4.2-12		
		4.2-13		
		4.2-13a		
		4.2-13b		
		4.2-13c		
		4.2-13d		
		4.2-14		
		4.2-17		
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		4.2-5		
		4.2-7		
		4.2-8		
		4.2-83		
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		F4.2-11		
		F4.2-2A		
		F4.2-3		

CN Number	Affected Sections	Affected Pages/Figures/Tables	Description	Initiating or Ref. Document
		F4.2-3A		
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	4.3	4.3-10		
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		4.3-57		
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		4.3-61		
		4.3-9		
		F4.3-10A		
		F4.3-10B		
		F4.3-11A		
		F4.3-11B		
		F4.3-12A		
		F4.3-12B		
		F4.3-13		
		F4.3-14		
		F4.3-15		
		F4.3-16		
		F4.3-17		
		F4.3-18		
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		F4.3-1A		
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		F4.3-26A		
		F4.3-26B		
		F4.3-27A		
		F4.3-27B		
		F4.3-28A		
		F4.3-28B		
		F4.3-29A		
		F4.3-29B		
		F4.3-3		
		F4.3-30A		
		F4.3-30B		
		F4.3-31A		
		F4.3-31B		
		F4.3-32A		
		F4.3-32B		
		F4.3-33A		
		F4.3-33B		
		F4.3-34A		
		F4.3-34B		
		F4.3-35A		
		F4.3-35B		
		F4.3-36		

CN Number	Affected Sections	Affected Pages/Figures/Tables	Description	Initiating or Ref. Document
		F4.3-37		
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		F4.3-39		
		F4.3-40		
		F4.3-41		
		F4.3-42		
		F4.3-43		
		F4.3-44		
		F4.3-4A		
		F4.3-4B		
		F4.3-5A		
		F4.3-5B		
		F4.3-6A		
		F4.3-6B		
		F4.3-7A		
		F4.3-7B		
		F4.3-8A		
		F4.3-8B		
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		F4.3-9B		
		T4.3-1 Sh 1		
		T4.3-1 Sh 2		
		T4.3-1 Sh 3		
		T4.3-2 Sh 1		
		T4.3-2 Sh 2		
		T4.3-2 Sh 3		
		T4.3-3A		
		T4.3-3B		
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CN Number	Affected Sections	Affected Pages/Figures/Tables	Description	Initiating or Ref. Document
		4.5-3F 4.5-3G 4.5-3H 4.5-3I 4.5-3J 4.5-3K 4.5-3L 4.5-3M		
	New SAR Pages:	T4.5-1, T4.5-2, F4.5-1, F4.5-2, F4.5-3, F4.5-4		
SSAR 97-112	8.3 9.2	T8.3-6 F9.2-1A sh 6	Revise UFSAR to reflect decrease in 125V DC battery profile and removal of high CFCU outlet water radiation console alarm.	DCP 1EC-3668 pkg 10
SSAR 97-115	10.4 8.3 9.2	F10.4-17A T8.3-5 T8.3-6 F9.2-11 Sh 6	Increase in 28 VDC/125 VDC battery profiles and changes to demin water makeup and auxiliary feedwater P&IDs.	DCP 1EC-3519, pkg 1
SSAR 97-123	5.5	5.5-3	Revise the UFSAR description of the RCP vibration monitoring system to reflect new equipment.	DCP 1EC-3647
SSAR 97-124	7.6	7.6-5	Revise description of relief valve action to include auto and manual modes of operation.	DCP 1EC-3607
SSAR 97-127	6.2	F6.2-17 F6.2-26 F6.2-38 F6.2-44 T6.2-10 sh 3 T6.2-10 sh 8 T6.2-12 sh 3	Revise UFSAR to incorporate DCP 1EC-3718	DCP 1EC-3718
SSAR 97-129	10.4 11.3 2.2 6.4	10.4-19 11.3-5 2.2-10 6.4-3	Addition of nitrogen purge blanket for Aux. Feed Water Storage Tank.	DCP 1EC-3640

CN Number	Affected Sections	Affected Pages/Figures/Tables	Description	Initiating or Ref. Document
SSAR 97-130	6.3	6.3-9	Revise Mode 4 Hot Leg Recirculation to be applicable to both units.	
SSAR 97-133	13.1	13.1-10 13.1-11 13.1-15 13.1-18 13.1-8a 13.1-9 F13.1-8a F13.1-8b F13.1-8e T13.1-1 sh 1	Eliminates Director- Salem Operations position. Shifts reporting relationships for Salem Operations and changes management title for Salem Chemistry. Also changes station succession of authority.	
SSAR 97-136	New SAR Pages:	Table 6.3-6	Revision to RWST Draindown Analysis for Unit 1	
SSAR 97-138	New SAR Pages:	T4.5-1, F4.5-1, F4.5-2	Update of Salem 1 Cycle 1 information to reflect current cycle.	DS1.8-0042, DS1.8-0043
SSAR 97-139	5.2 5.5 6.2 6.3 9.3	5.2-70 5.5-28 5.5-33 T5.5-2 sh 1 6.2-59 F6.2-30 F6.2-33 F6.2-4A T6.2-10 sh 1 T6.2-12 sh 1 6.3-20 6.3-21 F6.3-1A sh 2 F6.3-1A sh 3 F6.3-2 F9.3-4A sh 3 F9.3-6A sh 2	Revise piping at the outlet of valve 1 PR 25 in accordance with Minor Modification S97-174.	Minor Mod S97-174
SSAR 97-142	5.2	5.2-4	Add clarification note on applicability and control of code cases to the ASME Boiler & Pressure Vessel Code.	

CN Number	Affected Sections	Affected Pages/Figures/Tables	Description	Initiating or Ref. Document
SSAR 98-001	8.3	8.3-6	Reflects the UPRATING of the 115 VAC Vital Instrument Bus Inverters from 10kVa to 12kVa	
	New SAR Pages:	Figure 8.3-5 Sht. 1		
SSAR 98-002	9.4	9.4-45 9.4-46	Revise Service Water Intake Structure minimum design temperature from 60F to 40F.	
SSAR 98-005	13.1	13.1-1	Adds position for Executive Vice President - NBU, position will perform duties of CNO/PNBU in his absence.	
	New SAR Pages:	Figure 13.1-2		
SSAR 98-006	3A	3A-6	Revise statement of conformance for Reg. Guide 1.16	
SSAR 98-007	9.4	9.4-42	Provide description of outside air temperature basis used in SPAV system performance calculations.	
SSAR 98-011	9.4	9.4-3	Revised descriptions for CREACS Single Filtration Train Alignment.	
	New SAR Pages:	9.4-4b,9.4-4d, & 9.4-4f		
SSAR 98-013	4.2	4.2-46 4.2-51 4.2-52 4.2-67 4.2-68 4.2-69 4.2-70 4.2-71 4.2-78	Replacement of Westinghouse Rod Cluster Control Assemblies in each Salem Unit with Frematome assimblies manufactured from different materials as noted in FSAR.	DCP's 1EC-3446 & 2EC-3334
	New SAR Pages:	Tables: 4.1-1 (3&4 of 5); 4.3-1 (2&3 of 3) Figures: 4.2-14; 4.2-15		

CN Number	Affected Sections	Affected Pages/Figures/Tables	Description	Initiating or Ref. Document
SSAR 98-015			Table 5.2-8 revised to reform valve design parameters	DCP 2EC-3650/01
	New SAR Pages:	Table 5.2-8		
SSAR 98-016	13.1	13.1-9	Aligns both stations succession of authority and responsibility for overall operation in the event of an unexpected contingency.	
SSAR 98-017	9.3	9.3-9	To describe accumulator purge to locations other than the VCT.	
SSAR 98-019	17.2	17.2-24	ORGANIZATIONAL NAME CHANGE FOR UFSAR UPDATE RESPONSIBILITY.	
SSAR 98-020	13.5	13.5-1 13.5-2 13.5-2a 13.5-2b 13.5-2c 13.5-2d	This proposed change will align Hope Creek Section 13.5.1, Administrative Procedures and Salem Section 13.5, Plant Procedures (in part)	

CN Number	Affected Sections	Affected Pages/Figures/Tables	Description	Initiating or Ref. Document
SSAR 98-027	17.2	17.2-12 17.2-13 17.2-19 17.2-2 17.2-20 17.2-21 17.2-23 17.2-25 17.2-26 17.2-28 17.2-29 17.2-37 17.2-4 17.2-40 17.2-6 F17.2-1	Org change moving QA Mat'l & Supplier Plant Support from QA into the Nuclear Procurement & Material Management Organization and transferring the responsibility for review of special process procedures from QA and the General Manager to a qualified specialist.	
	New SAR Pages:	17.2-4a, 17.2-7i		

Salem Generating Station
Revision 17

INSERT INSTRUCTIONS

REMOVE	INSERT
VOL 1	
List of Current Pages	List of Current Pages
F1.2-1	F1.2-1
2.2-9/2.2-10	2.2-9/2.2-10
T2.2-2 SH 1 OF 2	T2.2-2 SH 1 OF 2
F2.4-3	F2.4-3
3.2-1/3.2-2	3.2-1/3.2-2
3.5-5/3.5-6	3.5-5/3.5-6
3.5-7/3.5-8	3.5-7/3.5-8
3.5-21d/3.5-22	3.5-21d/3.5-22
3.6-43/3.6-44	3.6-43/3.6-44
F3.6-28	F3.6-28
VOLUME 2	
3.8-3/3.8-4	3.8-3/3.8-4
3.8-5/3.8-6	3.8-5/3.8-6
3.8-15/3.8-16	3.8-15/3.8-16
3.8-19/3.8-20	3.8-19/3.8-20
3.8-21/3.8-22	3.8-21/3.8-22
3.8-23/3.8-24	3.8-23/3.8-24
3.8-27/3.8-28	3.8-27/3.8-28
3.8-73/3.8-74	3.8-73/3.8-74
3.8-77/3.8-78	3.8-77/3.8-78
---	3.8-78a/3.8-78b
3.8-79b/3.8-80	3.8-79b/3.8-80
3.8-81/3.8-82	3.8-81/3.8-82
F3.8-37	F3.8-37
F3.8-38	F3.8-38
T3.10-1 SH 1 OF 9	T3.10-1 SH 1 OF 9
3A-5/3A-6	3A-5/3A-6
3A-7b/3A-8	3A-7b/3A-8
4-iii/4-iv	4-iii/4-iv
4-vii/4-viii	4-vii/4-viii
4-ix/4-x	4-ix/4-x

4-xi/4-xii	4-xi/4-xii
4-xiii/4-xiv	4-xiii/4-xiv
4-xv/4-xvi	4-xv
4-xvii/4-xviii	---
4.1-1/4.1-2	4.1-1/4.1-2
4.1-3/4.1-4	4.1-3/4.1-4
T4.1-1 SH 1 OF 5 SH 2 OF 5 SH 3 OF 5 SH 4 OF 5 SH 5 OF 5	T4.1-1 SH 1 OF 5 SH 2 OF 5 SH 3 OF 5 SH 4 OF 5 SH 5 OF 5
T4.1-2 SH 1 OF 2	T4.1-2 SH 1 OF 2
4.2-1/4.2-2	4.2-1/4.2-2
4.2-3/4.2-4	4.2-3/4.2-4
4.2-5/4.2-6	4.2-5/4.2-6
4.2-7/4.2-8	4.2-7/4.2-8
4.2-9/4.2-10	4.2-9/4.2-10
4.2-11/4.2-12	4.2-11/4.2-12
4.2-13/4.2-13a	4.2-13/4.2-13a
4.2-13b/4.2-13c	4.2-13b/4.2-13c
4.2-13d/4.2-14	4.2-13d/4.2-14
4.2-17/4.2-18	4.2-17/4.2-18
4.2-23/4.2-24	4.2-23/4.2-24
4.2-25/4.2-26	4.2-25/4.2-26
4.2-27/4.2-28	4.2-27/4.2-28
4.2-45/4.2-46	4.2-45/4.2-46
4.2-51/4.2-52	4.2-51/4.2-52
4.2-67/4.2-68	4.2-67/4.2-68
4.2-69/4.2-70	4.2-69/4.2-70
4.2-71/4.2-72	4.2-71/4.2-72
4.2-77/4.2-78	4.2-77/4.2-78
4.2-83	4.2-83
F4.2-14	F4.2-14
F4.2-15	F4.2-15
4.3-1/4.3-2	4.3-1/4.3-2
4.3-3/4.3-4	4.3-3/4.3-4
4.3-5/4.3-6	4.3-5/4.3-6
4.3-9/4.3-10	4.3-9/4.3-10

4.3-11/4.3-12	4.3-11/4.3-12
4.3-13/4.3-14	4.3-13/4.3-14
4.3-15/4.3-16	4.3-15/4.3-16
4.3-17/4.3-18	4.3-17/4.3-18
4.3-19/4.3-20	4.3-19/4.3-20
4.3-21/4.3-22	4.3-21/4.3-22
4.3-23/4.3-24	4.3-23/4.3-24
4.3-25/4.3-26	4.3-25/4.3-26
4.3-27/4.3-28	4.3-27/4.3-28
4.3-29/4.3-30	4.3-29/4.3-30
4.3-31/4.3-32	4.3-31/4.3-32
4.3-33/4.3-34	4.3-33/4.3-34
4.3-35/4.3-36	4.3-35/4.3-36
4.3-37/4.3-38	4.3-37/4.3-38
4.3-39/4.3-40	4.3-39/4.3-40
4.3-41/4.3-42	4.3-41/4.3-42
4.3-43/4.3-44	4.3-43/4.3-44
4.3-45/4.3-46	4.3-45/4.3-46
4.3-47/4.3-48	4.3-47/4.3-48
4.3-49/4.3-50	4.3-49/4.3-50
4.3-51/4.3-52	4.3-51/4.3-52
4.3-53/4.3-54	4.3-53/4.3-54
4.3-55/4.3-56	4.3-55/4.3-56
4.3-57/4.3-58	4.3-57/4.3-58
4.3-61	4.3-61
T4.3-1 SH 1 OF 3 SH 2 OF 3 SH 3 OF 3	T4.3-1 SH 1 OF 3 SH 2 OF 3 SH 3 OF 3
T4.3-2 SH 1 OF 3 SH 2 OF 3 SH 3 OF 3	T4.3-2 SH 1 OF 2 SH 2 OF 2 ---
T4.3-3A	T4.3-3
T4.3-3B	---
F4.3-1A	F4.3-1
F4.3-1B	---
F4.3-8A	F4.3-8
F4.3-8B	---
F4.3-9A	F4.3-9

F4.3-9B	---
F4.3-10A	F4.3-10
F4.3-10B	---
F4.3-12A	F4.3-12
F4.3-12B	---
F4.3-13	F4.3-13
F4.3-14	F4.3-14
F4.3-15	F4.3-15
F4.3-16	F4.3-16
F4.3-26A	F4.3-26A
F4.3-26B	F4.3-26B
F4.3-27A	F4.3-27
F4.3-27B	---
F4.3-28A	F4.3-28
F4.3-28B	---
F4.3-30A	F4.3-30
F4.3-30B	---
F4.3-31A	F4.3-31
F4.3-31B	---
F4.3-32A	F4.3-32
F4.3-32B	---
F4.3-33A	F4.3-33
F4.3-33B	---
F4.3-34A	F4.3-34
F4.3-34B	---
F4.3-35A	F4.3-35
F4.3-35B	---
4.5-1/4.5-2	4.5-1/4.5-2
4.5-2A/4.5-2B	---
4.5-2C/4.5-2D	---
4.5-2E/4.5-2F	---
4.5-2G/4.5-2H	---
4.5-2I/4.5-2J	---
4.5-2K/4.5-2L	---
4.5-3	---
4.5-3A/4.5-3B	---
4.5-3C/4.5-3D	---
4.5-3E/4.5-3F	---

4.5-3G/4.5-3H	---
4.5-3I/4.5-3J	---
4.5-3K/4.5-3L	---
4.5-3M	---
---	T4.5-1
---	T4.5-2
---	F4.5-1
---	F4.5-2
VOLUME 3	
F5.1-6A SH 1 OF 3 SH 2 OF 3 SH 3 OF 3	F5.1-6A SH 1 OF 3 SH 2 OF 3 SH 3 OF 3
F5.1-6B SH 1 OF 3	F5.1-6B SH 1 OF 3
5.2-3/5.2-4	5.2-3/5.2-4
5.2-69/5.2-70	5.2-69/5.2-70
T5.2-8 SH 1 OF 2	T5.2-8 SH 1 OF 2
5.5-3/5.5-4	5.5-3/5.5-4
5.5-27/5.5-28	5.5-27/5.5-28
5.5-33/5.5-34	5.5-33/5.5-34
5.5-47/5.5-48	5.5-47/5.5-48
5.5-55/5.5-56	5.5-55/5.5-56
5.5-57/5.5-58	5.5-57/5.5-58
T5.5-1 SH 4 OF 4	T5.5-1 SH 4 OF 4
T5.5-2 SH 1 OF 2	T5.5-2 SH 1 OF 2
F5.5-2A SH 1 OF 2 SH 2 OF 2	F5.5-2A SH 1 OF 2 SH 2 OF 2
F5.5-2B SH 1 OF 2 SH 2 OF 2	F5.5-2B SH 1 OF 2 SH 2 OF 2
5.6-3/5.6-4	5.6-3/5.6-4
6.2-59/6.2-59a	6.2-59/6.2-59a
T6.2-10 SH 1 OF 12 SH 3 OF 12 SH 5 OF 12 SH 8 OF 12	T6.2-10 SH 1 OF 12 SH 3 OF 12 SH 5 OF 12 SH 8 OF 12
T6.2-12 SH 1 OF 3 SH 3 OF 3	T6.2-12 SH 1 OF 3 SH 3 OF 3

F6.2-4A	F6.2-4A
F6.2-4B	F6.2-4B
F6.2-19	F6.2-19
F6.2-22	F6.2-22
F6.2-29	F6.2-29
F6.2-30	F6.2-30
F6.2-33	F6.2-33
F6.2-34	F6.2-34
6.3-9/6.3-10	6.3-9/6.3-10
6.3-19/6.3-20	6.3-19/6.3-20
6.3-21/6.3-22	6.3-21/6.3-22
6.3-31/6.3-32	6.3-31/6.3-32
6.3-33b/6.3-34	6.3-33b/6.3-34
6.3-35/6.3-36	6.3-35/6.3-36
6.3-36a/6.3-36b	6.3-36a/6.3-36b
6.3-36c/6.3-36d	6.3-36c/6.3-36d
T6.3-6 SH 1 OF 3 SH 2 OF 3 SH 3 OF 3	T6.3-6 SH 1 OF 3 SH 2 OF 3 SH 3 OF 3
T6.3-13 SH 1 OF 2	T6.3-13 SH 1 OF 2
F6.3-1A SH 1 OF 4 SH 2 OF 4 SH 3 OF 4	F6.3-1A SH 1 OF 4 SH 2 OF 4 SH 3 OF 4
F6.3-1B SH 2 OF 4 SH 3 OF 4 SH 4 OF 4	F6.3-1B SH 2 OF 4 SH 3 OF 4 SH 4 OF 4
F6.3-2	F6.3-2
6.4-3/6.4-4	6.4-3/6.4-4
VOLUME 4	
7-ix	7-ix
7.1-11/7.1-12	7.1-11/7.1-12
7.1-13/7.1-14	7.1-13/7.1-14
7.2-25/7.2-26	7.2-25/7.2-26
T7.2-1 SH 3 OF 7 SH 4 OF 7 SH 5 OF 7 SH 6 OF 7	T7.2-1 SH 3 OF 7 SH 4 OF 7 SH 5 OF 7 SH 6 OF 7
F7.2-2	F7.2-2
F7.2-7	F7.2-7

7.3-29/7.3-30	7.3-29/7.3-30
T7.3-1 SH 1 OF 2 SH 2 OF 2	T7.3-1 SH 1 OF 2 SH 2 OF 2
T7.3-5 SH 2 OF 15 SH 4 OF 15 SH 6 OF 15 SH 8 OF 15 SH 10 OF 15 SH 12 OF 15 SH 14 OF 15	T7.3-5 SH 2 OF 15 SH 4 OF 15 SH 6 OF 15 SH 8 OF 15 SH 10 OF 15 SH 12 OF 15 SH 14 OF 15
7.5-3/7.5-4	7.5-3/7.5-4
T7.5-1 SH 2 OF 4 SH 3 OF 4	T7.5-1 SH 2 OF 4 SH 3 OF 4
T7.5-2 SH 9 OF 11 SH 10 OF 11	T7.5-2 SH 9 OF 11 SH 10 OF 11
7.6-5/7.6-6	7.6-5/7.6-6
7.7-9/7.7-10	7.7-9/7.7-9a
---	7.7-9b/7.7-10
7.7-21/7.7-21a	7.7-21/7.7-21a
T7.7-2 SH 1 OF 2 SH 2 OF 2	T7.7-2 SH 1 OF 2 SH 2 OF 2
---	F7.7-7
---	F7.7-8
---	F7.7-9
8.1-9/8.1-10	8.1-9/8.1-10
8.3-5b/8.3-6	8.3-5b/8.3-6
F8.3-3B	F8.3-3B
F8.3-4	F8.3-4
F8.3-4A	F8.3-4A
F8.3-5 SH 1 OF 2	F8.3-5 SH 1 OF 2
F8.3-6 SH 1 OF 2 SH 2 OF 2	F8.3-6 SH 1 OF 2 SH 2 OF 2
F8.3-7	F8.3-7
F8.3-8 SH 1 OF 2 SH 2 OF 2	F8.3-8 SH 1 OF 2 SH 2 OF 2
T9.1-4 SH 6 OF 6	T9.1-4 SH 6 OF 6
9.2-6a/9.2-6b	9.2-6a/9.2-6b

F9.2-1A SH 1 OF 6 SH 2 OF 6 SH 3 OF 6 SH 4 OF 6 SH 5 OF 6 SH 6 OF 6 ---	F9.2-1A SH 1 OF 7 SH 2 OF 7 SH 3 OF 7 SH 4 OF 7 SH 5 OF 7 SH 6 OF 7 SH 7 OF 7
F9.2-1B SH 1 OF 6 SH 5 OF 6	F9.2-1B SH 1 OF 6 SH 5 OF 6
F9.2-2B	F9.2-2B
F9.2-3	F9.2-3
F9.2-4A SH 1 OF 3	F9.2-4A SH 1 OF 3
F9.2-4B SH 2 OF 3	F9.2-4B SH 2 OF 3
F9.2-11 SH 5 OF 7 SH 6 OF 7	F9.2-11 SH 5 OF 7 SH 6 OF 7
VOLUME 5	
9.3-1/9.3-2	9.3-1/9.3-2
9.3-9/9.3-10	9.3-9/9.3-10
F9.3-1A SH 1 OF 4 SH 3 OF 4	F9.3-1A SH 1 OF 4 SH 3 OF 4
F9.3-2A SH 1 OF 3 SH 2 OF 3	F9.3-2A SH 1 OF 3 SH 2 OF 3
F9.3-2B SH 1 OF 3 SH 2 OF 3	F9.3-2B SH 1 OF 3 SH 2 OF 3
F9.3-3A SH 1 OF 4 SH 2 OF 4 SH 3 OF 4	F9.3-3A SH 1 OF 4 SH 2 OF 4 SH 3 OF 4
F9.3-4A SH 3 OF 3	F9.3-4A SH 3 OF 3
F9.3-4B SH 1 OF 3 SH 3 OF 3	F9.3-4B SH 1 OF 3 SH 3 OF 3
F9.3-5A SH 1 OF 2	F9.3-5A SH 1 OF 2
F9.3-6A SH 1 OF 3 SH 2 OF 3 SH 3 OF 3	F9.3-6A SH 1 OF 3 SH 2 OF 3 SH 3 OF 3
F9.3-6B SH 1 OF 3 SH 2 OF 3	F9.3-6B SH 1 OF 3 SH 2 OF 3
9.4-3/9.4-4	9.4-3/9.4-4
9.4-4a/9.4-4b	9.4-4a/9.4-4b

9.4-4c/9.4-4d	9.4-4c/9.4-4d
9.4-4e/9.4-4f	9.4-4e/9.4-4f
9.4-41/9.4-42	9.4-41/9.4-42
9.4-45/9.4-46	9.4-45/9.4-46
F9.4-1A	F9.4-1A
F9.4-1B	F9.4-1B
F9.4-2A SH 1 OF 3 SH 2 OF 3 SH 3 OF 3	F9.4-2A SH 1 OF 3 SH 2 OF 3 SH 3 OF 3
F9.4-3B	F9.4-3B
F9.4-4A SH 2 OF 3 SH 3 OF 3	F9.4-4A SH 2 OF 3 SH 3 OF 3
F9.4-4B SH 2 OF 3	F9.4-4B SH 2 OF 3
F9.4-6A	F9.4-6A
F9.4-6B	F9.4-6B
9.5-37/9.5-38	9.5-37/9.5-38
10.2-5/10.2-6	10.2-5/10.2-6
10.2-6a/10.2-6b	10.2-6a/10.2-6b
F10.2-1 SH 1 OF 3 SH 2 OF 3 SH 3 OF 3	F10.2-1 SH 1 OF 3 SH 2 OF 3 SH 3 OF 3
F10.2-2A SH 1 OF 3 SH 2 OF 3 SH 3 OF 3	F10.2-2A SH 1 OF 3 SH 2 OF 3 SH 3 OF 3
F10.2-2B SH 1 OF 3 SH 2 OF 3 SH 3 OF 3	F10.2-2B SH 1 OF 3 SH 2 OF 3 SH 3 OF 3
F10.2-3 SH 1 OF 2	F10.2-3 SH 1 OF 2
F10.2-4 SH 1 OF 4 SH 4 OF 4	F10.2-4 SH 1 OF 4 SH 4 OF 4
10.3-17/10.3-18	10.3-17/10.3-18
F10.3-1A SH 1 OF 6 SH 2 OF 6 SH 3 OF 6 SH 4 OF 6 SH 5 OF 6 SH 6 OF 6	F10.3-1A SH 1 OF 6 SH 2 OF 6 SH 3 OF 6 SH 4 OF 6 SH 5 OF 6 SH 6 OF 6
F10.3-1B SH 2 OF 6 SH 3 OF 6 SH 6 OF 6	F10.3-1B SH 2 OF 6 SH 3 OF 6 SH 6 OF 6

VOLUME 6	
10.4-11/10.4-12	10.4-11/10.4-12
10.4-17/10.4-18	10.4-17/10.4-18
10.4-19/10.4-20	10.4-19/10.4-20
F10.4-1 SH 1 OF 2	F10.4-1 SH 1 OF 2
F10.4-3A SH 1 OF 5 SH 2 OF 5 SH 3 OF 5 SH 4 OF 5 SH 5 OF 5	F10.4-3A SH 1 OF 5 SH 2 OF 5 SH 3 OF 5 SH 4 OF 5 SH 5 OF 5
F10.4-3B SH 1 OF 4 SH 2 OF 4 SH 4 OF 4	F10.4-3B SH 1 OF 4 SH 2 OF 4 SH 4 OF 4
F10.4-5A SH 1 OF 3 SH 2 OF 3 SH 3 OF 3	F10.4-5A SH 1 OF 3 SH 2 OF 3 SH 3 OF 3
F10.4-5B SH 1 OF 3 SH 2 OF 3 SH 3 OF 3	F10.4-5B SH 1 OF 3 SH 2 OF 3 SH 3 OF 3
F10.4-6A SH 4 OF 6 SH 5 OF 6	F10.4-6A SH 4 OF 6 SH 5 OF 6
F10.4-6B SH 5 OF 6	F10.4-6B SH 5 OF 6
F10.4-17A	F10.4-17A
F10.4-17B	F10.4-17B
F10.4-18B SH 2 OF 2	F10.4-18B SH 2 OF 2
11.2-3/11.2-4	11.2-3/11.2-4
11.2-9/11.2-10	11.2-9/11.2-10
T11.2-1	T11.2-1
T11.2-3 SH 1 OF 2	T11.2-3 SH 1 OF 2
F11.2-1A SH 1 OF 5 SH 2 OF 5 SH 3 OF 5	F11.2-1A SH 1 OF 5 SH 2 OF 5 SH 3 OF 5
F11.2-1B SH 1 OF 3 SH 2 OF 3 SH 3 OF 3	F11.2-1B SH 1 OF 3 SH 2 OF 3 SH 3 OF 3
11.3-5/11.3-6	11.3-5/11.3-6
F11.3-1A SH 1 OF 3 SH 3 OF 3	F11.3-1A SH 1 OF 3 SH 3 OF 3

F11.3-1B SH 1 OF 3	F11.3-1B SH 1 OF 3
11.4-3/11.4-4	11.4-3/11.4-4
11.4-7/11.4-8	11.4-7/11.4-8
11.4-9/11.4-10	11.4-9/11.4-10
T11.4-1 SH 3 OF 4	T11.4-1 SH 3 OF 4
F11.4-2	F11.4-2
13-i/13-ii	13-i/13-ii
13.1-1/13.1-1a	13.1-1/13.1-1a
13.1-9/13.1-10	13.1-9/13.1-10
13.1-11/13.1-12	13.1-11/13.1-12
13.1-15/13.1-16	13.1-15/13.1-16
13.1-18a/13.1-18b	13.1-18a/13.1-18b
T13.1-1	T13.1-1
F13.1-2	F13.1-2
F13.1-8a	F13.1-8a
F13.1-8b	F13.1-8b
F13.1-8e	F13.1-8e
13.5-1/13.5-2	13.5-1/13.5-2
13.5-2a/13.5-2b	13.5-2a/13.5-2b
13.5-2c/13.5-2d	13.5-2c/13.5-2d
VOLUME 7	
15-v/15-vi	15-v/15-vi
15-xvii/15-xviii	15-xvii/15-xviii
15.2-37/15.2-38	15.2-37/15.2-38
15.2-55/15.2-56	15.2-55/15.2-56
15.2-57/15.2-58	15.2-57/15.2-58
15.2-59/15.2-60	15.2-59/15.2-60
15.2-60a/15.2-60b	15.2-60a/15.2-60b
15.2-61/15.2-62	15.2-61/15.2-62
T15.2-1 SH 8 OF 8	T15.2-1 SH 8 OF 8
15.4-109/15.4-110	15.4-109/15.4-110
15.4-113/15.4-114	15.4-113/15.4-114
15.4-115/15.4-116	15.4-115/15.4-116
T15.4-22	T15.4-22
T15.4-23	T15.4-23

T15.4-24	T15.4-24
17.2-1/17.2-2	17.2-1/17.2-2
17.2-3/17.2-4	17.2-3/17.2-4
17.2-4a/17.2-4b	17.2-4a/17.2-4b
17.2-5/17.2-6	17.2-5/17.2-6
17.2-7h/17.2-7i	17.2-7h/17.2-7i
17.2-11/17.2-12	17.2-11/17.2-12
17.2-19/17.2-20	17.2-19/17.2-20
17.2-21/17.2-22	17.2-21/17.2-22
17.2-23/17.2-24	17.2-23/17.2-24
17.2-25/17.2-26	17.2-25/17.2-26
17.2-27/17.2-28	17.2-27/17.2-28
17.2-29/17.2-30	17.2-29/17.2-30
17.2-37/17.2-38	17.2-37/17.2-38
17.2-39/17.2-40	17.2-39/17.2-40
A-5/A-6	A-5/A-6
A-7/A-8	A-7/A-8
A-51/A-52	A-51/A-52

LIST OF CURRENT PAGES

MASTER TABLE OF CONTENTS

PSE&G
CONTROL
COPY # SFSR0005

LIST OF CURRENT PAGES

SECTION 1

LIST OF CURRENT PAGES (Cont)

LIST OF CURRENT PAGES

SECTION 2

Page T=Table F=Figure	Revision Number
2-i	6
2-ii	11
2-iii	16
2-iv	6
2-v	6
2-vi	6
2-vii	16
2-viii	16
2-ix	6
2-x	6
2-xi	6
2-xii	6
2-xiii	6
2.1-1	6
2.1-2	6
2.1-3	6
2.1-4	6
2.1-5	6
2.1-6	6
2.1-7	6
2.1-8	6
2.1-9	6
2.1-10	6
2.1-11	6
2.1-12	6
2.1-13	6
2.1-14	6

Page T=Table F=Figure	Revision Number
2.1-15	6
2.1-16	6
2.1-17	6
2.1-18	6
2.1-19	6
2.1-20	6
2.1-21	6
2.1-22	6
2.1-23	6
2.1-24	6
2.1-25	6
2.1-26	6
2.1-27	6
2.1-28	6
T 2.1-1	
Sh 1	6
Sh 2	6
T 2.1-2	6
T 2.1-3	6
T 2.1-4	
Sh 1	6
Sh 2	6
T 2.1-5	6
T 2.1-6	6
T 2.1-7	6
T 2.1-8	6
T 2.1-9	
Sh 1	6
Sh 2	6
Sh 3	6

Page T=Table F=Figure	Revision Number
T 2.1-10	
Sh 1	6
Sh 2	6
Sh 3	6
T 2.1-11	6
T 2.1-12	6
F 2.1-1	6
F 2.1-2	6
F 2.1-3	6
F 2.1-4	6
F 2.1-5	6
F 2.1-6	6
F 2.1-7	6
F 2.1-8	6
F 2.1-9	6
F 2.1-10	6
F 2.1-11	6
F 2.1-12	6
F 2.1-13	6
F 2.1-14	6
F 2.1-15	6
F 2.1-16	6
F 2.1-17	6
F 2.1-18	6
2.2-1	6
2.2-2	6
2.2-3	6
2.2-4	6
2.2-5	6

LIST OF CURRENT PAGES (Cont)

Page T=Table F=Figure	Revision Number
2.3A-13	6
2.3A-14	6
2.3A-15	6
2.3A-16	6
2.3A-17	6
2.3A-18	6
2.3A-19	6
2.3A-20	6
2.3A-21	6
2.3A-22	6
2.3A-23	6
2.3A-24	6
2.3A-25	6
2.3A-26	6
2.3A-27	6
2.3A-28	6
2.3A-29	6
2.3A-30	6
2.3A-31	6
2.3A-32	6
2.3A-33	6
2.3A-34	6
2.3A-35	6
2.3A-36	6
2.3A-37	6
2.3A-38	6
2.3A-39	6
2.3A-40	6
2.3A-41	6

LIST OF CURRENT PAGES (Cont)

Page T=Table F=Figure	Revision Number
T 2.4-3	
Sh 1	6
Sh 2	6
Sh 3	6
Sh 4	6
T 2.4-4	
Sh 1	6
Sh 2	6
T 2.4-5	
Sh 1	6
Sh 2	6
Sh 3	6
F 2.4-1	6
F 2.4-2	15
F 2.4-3	17
F 2.4-4	6
F 2.4-5	6
F 2.4-6	6
F 2.4-7	6
F 2.4-8	6
F 2.4-9	6
F 2.4-10	6
F 2.4-11	6
2.5-1	6
2.5-2	6
2.5-3	6
2.5-4	6
2.5-5	6

LIST OF CURRENT PAGES (Cont)

LIST OF CURRENT PAGES

SECTION 3

Page T=Table F=Figure	Revision Number
3-i	12
3-ii	16
3-iii	6
3-iv	13
3-v	6
3-vi	6
3-vii	16
3-viii	6
3-ix	6
3-x	15
3-xi	14
3-xii	16
3-xiii	6
3-xiv	6
3-xv	6
3-xvi	6
3-xvii	7
3-xviii	6
3-xix	6
3-xx	13
3-xxi	16
3.1-1	12
3.1-2	12
3.1-3	12
3.1-4	16
3.1-5	12
3.1-6	12

LIST OF CURRENT PAGES (Cont)

Page T=Table F=Figure	Revision Number
3.1-7	12
3.1-8	12
3.1-9	12
3.1-10	16
3.1-11	12
3.1-12	12
3.1-13	12
3.1-14	12
3.1-15	12
3.1-16	12
3.1-17	12
3.1-18	12
3.1-19	12
3.1-20	12
3.1-21	12
3.1-22	12
3.1-23	12
3.1-24	12
3.1-25	12
3.1-26	12
3.1-27	12
3.1-28	12
3.1-29	12
3.1-30	12
3.1-31	12
3.1-32	12
3.1-33	12
3.1-34	12
3.1-35	12
3.1-36	12

LIST OF CURRENT PAGES (Cont)

Page T=Table F=Figure	Revision Number
3.1-37	12
3.1-38	12
3.1-39	12
3.1-39a	12
3.1-39b	12
3.1-40	12
3.1-40a	7
3.1-40b	7
3.1-41	6
3.1-42	6
3.1-43	6
3.1-44	6
3.1-45	6
3.1-46	6
3.1-47	6
3.1-48	6
3.1-49	13
3.1-49a	9
3.1-49b	9
3.1-50	6
3.1-51	6
3.1-52	6
3.1-53	6
3.1-54	6
3.1-55	6
3.2-1	6
3.2-2	17
3.2-3	6
3.2-4	6
3.2-5	6
3.2-6	8

LIST OF CURRENT PAGES (Cont)

Page T=Table F=Figure	Revision Number
3.2-7	6
3.2-8	6
3.3-1	6
3.3-2	6
F 3.3-1	6
F 3.3-2	6
F 3.3-3	6
F 3.3-4	6
F 3.3-5	6
3.4-1	15
3.4-2	6
3.4-3	6
3.4-4	6
3.4-5	16
3.4-6	6
F 3.4-1	6
F 3.4-2	6
F 3.4-3	6
F 3.4-4	6
3.5-1	14
3.5-2	6
3.5-3	15
3.5-4	16
3.5-5	17
3.5-6	17
3.5-7	17
3.5-8	17

Page T=Table F=Figure	Revision Number
3.5-9	6
3.5-10	6
3.5-11	7
3.5-12	16
3.5-13	16
3.5-14	6
3.5-15	16
3.5-16	16
3.5-17	16
3.5-18	16
3.5-19	16
3.5-20	16
3.5-21	16
3.5-21a	16
3.5-21b	16
3.5-21c	16
3.5-21d	16
3.5-22	17
T 3.5-1	16
T 3.5-2	16
T 3.5-3	16
F 3.5-1	9
F 3.5-2	9
F 3.5-3	6
F 3.5-4	6
F 3.5-5	6
F 3.5-6	6
F 3.5-6A	16
F 3.5-7	16
3.6-1	7
3.6-2	7
3.6-3	7
3.6-4	6
3.6-5	6
3.6-6	6

LIST OF CURRENT PAGES (Cont)

Page T=Table F=Figure	Revision Number
3.6-7	6
3.6-8	7
3.6-9	16
3.6-9a	16
3.6-9b	7
3.6-10	7
3.6-11	7
3.6-12	16
3.6-13	7
3.6-14	7
3.6-15	6
3.6-16	6
3.6-17	16
3.6-18	16
3.6-19	16
3.6-20	6
3.6-21	16
3.6-21a	16
3.6-21b	16
3.6-22	16
3.6-23	16
3.6-24	16
3.6-25	6
3.6-26	16
3.6-27	16
3.6-28	16
3.6-29	6
3.6-30	16
3.6-31	15
3.6-32	6
3.6-33	6
3.6-34	6

LIST OF CURRENT PAGES (Cont)

Page T=Table F=Figure	Revision Number
F 3.7-1	6
F 3.7-2	6
F 3.7-3	6
F 3.7-4	6
F 3.7-5	6
F 3.7-6	6
F 3.7-7	6
F 3.7-8	6
F 3.7-9	6
F 3.7-10	6
F 3.7-11	6
F 3.7-12	6
F 3.7-13	6
3.8-1	6
3.8-2	16
3.8-3	6
3.8-4	17
3.8-5	17
3.8-6	6
3.8-7	6
3.8-8	6
3.8-9	6
3.8-10	6
3.8-11	6
3.8-12	6
3.8-13	6
3.8-14	6
3.8-15	6
3.8-16	17

LIST OF CURRENT PAGES (Cont)

Page T=Table F=Figure	Revision Number
3.8-77	15
3.8-78	17
3.8-78a	17
3.8.78b	17
3.8-79	16
3.8-79a	16
3.8-79b	16
3.8-80	17
3.8-81	6
3.8-82	17
T 3.8-1	6
T 3.8-2	6
T 3.8-3	6
T 3.8-4	6
T 3.8-5	6
T 3.8-6	6
T 3.8-7	6
T 3.8-8	6
T 3.8-9	6
T 3.8-10	6
T 3.8-11	
Sh 1	6
Sh 2	6
F 3.8-1	6
F 3.8-2	9
F 3.8-3	6
F 3.8-4	9
F 3.8-5	9
F 3.8-6	9
F 3.8-7	9
F 3.8-8	6
F 3.8-9	9
F 3.8-10	9
F 3.8-11	6

LIST OF CURRENT PAGES (Cont)

LIST OF CURRENT PAGES

SECTION 4

Page T=Table F=Figure	Revision Number
4-i	11
4-ii	6
4-iii	17
4-iv	11
4-v	11
4-vi	6
4-vii	17
4-viii	17
4-ix	17
4-x	17
4-xi	17
4-xii	17
4-xiii	17
4-xiv	17
4-xv	17
4.1-1	17
4.1-2	17
4.1-3	17
4.1-4	17
T 4.1-1	
Sh 1	17
Sh 2	17
Sh 3	17
Sh 4	17
Sh 5	17

LIST OF CURRENT PAGES (Cont)

Page T=Table F=Figure	Revision Number
4.2-21	6
4.2-22	6
4.2-23	11
4.2-24	17
4.2-25	17
4.2-26	17
4.2-27	17
4.2-28	17
4.2-28a	11
4.2-28b	11
4.2-29	6
4.2-30	8
4.2-31	6
4.2-32	6
4.2-33	6
4.2-34	6
4.2-35	6
4.2-36	6
4.2-37	6
4.2-38	6
4.2-39	11
4.2-40	11
4.2-40a	11
4.2-40b	11
4.2-41	6
4.2-42	6
4.2-43	6
4.2-44	6
4.2-45	11
4.2-46	17

LIST OF CURRENT PAGES (Cont)

Page T=Table F=Figure	Revision Number
4.2-47	11
4.2-48	6
4.2-49	11
4.2-50	11
4.2-51	17
4.2-52	17
4.2-53	11
4.2-54	16
4.2-55	16
4.2-56	11
4.2-57	13
4.2-58	13
4.2-58a	13
4.2-58b	13
4.2-59	6
4.2-60	6
4.2-61	6
4.2-62	6
4.2-63	6
4.2-64	6
4.2-65	11
4.2-66	11
4.2-67	17
4.2-68	17
4.2-69	17
4.2-70	17
4.2-71	17
4.2-72	11
4.2-73	11
4.2-74	6
4.2-75	6
4.2-76	6

LIST OF CURRENT PAGES (Cont)

Page T=Table F=Figure	Revision Number
F 4.2-21	6
F 4.2-22	6
F 4.2-23	6
F 4.2-24	6
F 4.2-25	6
4.3-1	6
4.3-2	17
4.3-3	17
4.3-4	17
4.3-5	17
4.3-6	6
4.3-7	6
4.3-8	6
4.3-9	17
4.3-10	17
4.3-11	17
4.3-12	17
4.3-13	17
4.3-14	6
4.3-15	17
4.3-16	17
4.3-17	17
4.3-18	17
4.3-19	17
4.3-20	17
4.3-21	17
4.3-22	17
4.3-23	17
4.3-24	17

LIST OF CURRENT PAGES (Cont)

LIST OF CURRENT PAGES (Cont)

Page T=Table F=Figure	Revision Number
4.3-55	17
4.3-56	17
4.3-57	17
4.3-58	17
4.3-59	6
4.3-60	6
4.3-61	17
T 4.3-1	
Sh 1	17
Sh 2	17
Sh 3	17
T 4.3-2	
Sh 1	17
Sh 2	17
T 4.3-3	17
T 4.3-4	6
T 4.3-5	6
T 4.3-6	6
T 4.3-7	6
T 4.3-8	6
T 4.3-9	6
T 4.3-10	6
T 4.3-11	6
F 4.3-1	17
F 4.3-2	6
F 4.3-3	6
F 4.3-4A	6

LIST OF CURRENT PAGES (Cont).

Page T=Table F=Figure	Revision Number
4.4-10	6
4.4-11	6
4.4-12	6
4.4-13	7
4.4-14	11
4.4-15	11
4.4-15a	11
4.4-15b	11
4.4-16	11
4.4-17	11
4.4-17a	11
4.4-17b	11
4.4-18	6
4.4-19	6
4.4-20	6
4.4-21	11
4.4-21a	11
4.4-21b	11
4.4-22	11
4.4-23	11
4.4-24	11
4.4-25	6
4.4-26	11
4.4-27	11
4.4-28	11
4.4-29	6
4.4-30	11
4.4-31	11
4.4-32	6
4.4-33	6
4.4-34	11
4.4-35	6
4.4-36	6
4.4-32	6
4.4-33	6
4.4-34	11

Page T=Table F=Figure	Revision Number
4.4-35	6
4.4-36	6
4.4-37	6
4.4-38	11
4.4-39	6
4.4-40	6
4.4-41	6
4.4-42	6
4.4-43	6
4.4-44	6
4.4-45	6
4.4-46	6
4.4-47	6
4.4-48	6
4.4-49	6
4.4-50	6
4.4-51	6
4.4-52	11
4.4-53	6
4.4-54	11
4.4-55	6
4.4-56	6
4.4-57	6
4.4-58	6
4.4-59	6
4.4-60	6
4.4-61	6
4.4-62	6
4.4-63	6
4.4-64	6
4.4-65	6
4.4-66	11
4.4-66a	11
4.4-66b	15

LIST OF CURRENT PAGES (Cont)

Page T=Table F=Figure	Revision Number
T 4.4-1	
Sh 1	11
Sh 2	15
Sh 3	11
Sh 4	11
T4.4-2	
Sh 1	11
Sh 2	11
T 4.4-3	11
T 4.4-4	6
F 4.4-1	6
F 4.4-2	6
F 4.4-3	6
F 4.4-4	6
F 4.4-5A	11
F 4.4-5B	11
F 4.4-6	6
F 4.4-7	6
F 4.4-8	6
F 4.4-9	6
F 4.4-10	6
F 4.4-11	6
F 4.4-12	6
F 4.4-13	6
F 4.4-14	6
F 4.4-15	6
F 4.4-16	6
F 4.4-5A	11
F 4.4-5B	11
F 4.4-6	6
F 4.4-7	6
F 4.4-8	6
F 4.4-9	6
F 4.4-10	6
F 4.4-11	6

LIST OF CURRENT PAGES

SECTION 5

Page T=Table F=Figure	Revision Number
5-i	6
5-ii	6
5-iii	7
5-iv	7
5-v	7
5-vi	6
5-vii	14
5-viii	9
5-ix	6
5-x	12
5-xa	7
5-xb	7
5-xi	6
5-xii	6
5-xiii	7
5-xiv	7
5.1-1	6
5.1-2	13
5.1-2a	13
5.1-2b	13
5.1-3	6
5.1-4	6
5.1-5	6
5.1-6	6
5.1-7	16
5.1-8	6
5.1-9	6
T 5.1-1	
Sh 1	7
Sh 2	15

LIST OF CURRENT PAGES (Cont)

Page T=Table F=Figure	Revision Number
5.2-38	6
5.2-39	6
5.2-40	6
5.2-41	6
5.2-42	12
5.2-43	15
5.2-43a	15
5.2-43b	15
5.2-44	6
5.2-45	6
5.2-46	6
5.2-47	6
5.2-48	6
5.2-49	7
5.2-50	6
5.2-51	6
5.2-52	15
5.2-53	6
5.2-54	7
5.2-55	10
5.2-56	7
5.2-56a	7
5.2-56b	7
5.2-57	10
5.2-57a	10
5.2-57b	10
5.2-58	6
5.2-59	6
5.2-60	6
5.2-61	6
5.2-62	6
5.2-63	16

Page T=Table F=Figure	Revision Number
5.2-64	6
5.2-65	6
5.2-66	6
5.2-67	6
5.2-68	6
5.2-69	16
5.2-70	17
5.2-71	16
5.2-72	16
5.2-73	16
5.2-74	6
5.2-75	7
T 5.2-1	15
T 5.2-2	6
T 5.2-3	
Sh 1	7
Sh 2	16
T 5.2-4	16
T 5.2-5	
Sh 1	15
Sh 2	7
T 5.2-6	6
T 5.2-7	
Sh 1	7
Sh 2	7
T 5.2-8	
Sh 1	17
Sh 2	14
T 5.2-9A	9
T 5.2-9B	16

LIST OF CURRENT PAGES (Cont)

LIST OF CURRENT PAGES

SECTION 6

Page T=Table F=Figure	Revision Number
6.2-34	6
6.2-35	6
6.2-36	6
6.2-37	16
6.2-38	6
6.2-39	6
6.2-40	12
6.2-41	6
6.2-42	6
6.2-43	6
6.2-44	16
6.2-45	6
6.2-46	6
6.2-47	6
6.2-48	6
6.2-49	6
6.2-50	15
6.2-51	6
6.2-52	16
6.2-53	16
6.2-54	6
6.2-55	16
6.2-56	6
6.2-57	6
6.2-58	16
6.2-59	17
6.2-59a	16
6.2-59b	16
6.2-60	16
6.2-61	16
6.2-62	14
6.2-63	6

LIST OF CURRENT PAGES (Cont)

Page T=Table F=Figure	Revision Number
6.2-64	6
6.2-65	16
6.2-66	16
6.2-67	16
6.2-68	6
6.2-69	6
6.2-70	6
6.2-71	6
6.2-72	6
6.2-73	6
6.2-74	6
6.2-75	6
6.2-76	13
6.2-76a	13
6.2-76b	13
6.2-77	6
6.2-78	6
6.2-79	6
6.2-80	6
6.2-81	6
6.2-82	6
6.2-83	6
6.2-84	13
6.2-85	16
T 6.2-1	6
T 6.2-2	6
T 6.2-3	6
T 6.2-4	
Sh 1	6
Sh 2	6
T 6.2-5	6
T 6.2-6	16

LIST OF CURRENT PAGES (Cont)

LIST OF CURRENT PAGES (Cont)

Page T=Table F=Figure	Revision Number
F 6.2-30	17
F 6.2-31	16
F 6.2-32	16
F 6.2-33	17
F 6.2-34	17
F 6.2-35	6
F 6.2-36	6
F 6.2-37	6
F 6.2-38	6
F 6.2-39	16
F 6.2-40	16
F 6.2-41	16
F 6.2-42	16
F 6.2-43	16
F 6.2-44	14
F 6.2-45	12
F 6.2-45A	6
F 6.2-45B	6
F 6.2-45C	16
F 6.2-45D	16
F 6.2-45E	6
F 6.2-46	6
F 6.2-47	6
F 6.2-48	6
F 6.2-49	6
F 6.2-50	6
F 6.2-51	6
F 6.2-52	6
F 6.2-53	6

LIST OF CURRENT PAGES (Cont)

LIST OF CURRENT PAGES

SECTION 7

Page T=Table F=Figure	Revision Number
7-i	6
7-ii	15
7-iii	13
7-iv	16
7-v	14
7-va	10
7-vb	15
7-vi	6
7-vii	14
7-viii	13
7-ix	17
7.1-1	6
7.1-2	6
7.1-3	6
7.1-4	6
7.1-5	6
7.1-6	6
7.1-7	6
7.1-8	6
7.1-9	6
7.1-10	6
7.1-11	17
7.1-12	16
7.1-13	17
7.1-14	16

LIST OF CURRENT PAGES (Cont)

LIST OF CURRENT PAGES (Cont)

Page T=Table F=Figure	Revision Number
F 7.2-1	6
F 7.2-2	17
F 7.2-3	6
F 7.2-4	15
F 7.2-5	16
F 7.2-6	6
F 7.2-7	17
7.3-1	6
7.3-2	6
7.3-3	6
7.3-4	16
7.3-5	16
7.3-6	6
7.3-7	16
7.3-8	6
7.3-9	6
7.3-10	13
7.3-10a	13
7.3-10b	13
7.3-11	6
7.3-12	6
7.3-13	11
7.3-14	6
7.3-15	8
7.3-16	15
7.3-16a	8
7.3-16b	8
7.3-17	6
7.3-18	6
7.3-19	6

LIST OF CURRENT PAGES (Cont)

LIST OF CURRENT PAGES (Cont)

LIST OF CURRENT PAGES (Cont)

Page T=Table F=Figure	Revision Number
Sh 35	16
Sh 36	16
Sh 37	16
Sh 38	16
Sh 39	16
Sh 40	16
Sh 41	16
Sh 42	16
Sh 43	16
Sh 44	16
Sh 45	16
Sh 46	16
Sh 47	16
T 7.3-5	
Sh 1	16
Sh 2	17
Sh 3	16
Sh 4	17
Sh 5	16
Sh 6	17
Sh 7	16
Sh 8	17
Sh 9	16
Sh 10	17
Sh 11	6
Sh 12	17
Sh 13	16
Sh 14	17
Sh 15	16

LIST OF CURRENT PAGES (Cont)

LIST OF CURRENT PAGES (Cont)

Page T=Table F=Figure	Revision Number
T 7.5-4	
Sh 1	15
Sh 2	16
Sh 3	15
Sh 4	16
Sh 5	16
T 7.5-5	
Sh 1	6
Sh 2	16
Sh 3	16
7.6-1	11
7.6-1a	11
7.6-1b	10
7.6-2	11
7.6-2a	10
7.6-2b	10
7.6-3	6
7.6-4	6
7.6-5	17
7.6-6	16
7.6-7	6
7.6-8	16
F 7.6-1	6
7.7-1	6
7.7-2	6
7.7-3	16
7.7-4	6
7.7-5	6
7.7-6	16

LIST OF CURRENT PAGES (Cont)

LIST OF CURRENT PAGES

SECTION 8

Page T=Table F=Figure	Revision Number
8-i	16
8-ii	14
8-iii	16
8-iv	16
8.1-1	14
8.1-2	14
8.1-3	16
8.1-4	14
8.1-5	10
8.1-5a	10
8.1-5b	10
8.1-6	6
8.1-7	16
8.1-8	16
8.1-9	16
8.1-10	17
8.1-11	16
8.1-11a	16
8.1-11b	16
8.1-12	16
8.2-1	6
8.2-2	6
8.2-3	15
8.2-4	15
F 8.2-1	15
F 8.2-2	14
8.3-1	6
8.3-2	16
8.3-3	15

LIST OF CURRENT PAGES (Cont)

Page T=Table F=Figure	Revision Number
F 8.3-1	15
F 8.3-2	16
F 8.3-2a	15
F 8.3-3A	16
F 8.3-3B	17
F 8.3-4	17
F 8.3-4A	17
F 8.3-4b	16
F 8.3-4c	14
F 8.3-5	
Sh 1	17
Sh 2	16
F 8.3-6	
Sh 1	17
Sh 2	17
F 8.3-7	17
F 8.3-8	
Sh 1	17
Sh 2	17

LIST OF CURRENT PAGES

SECTION 9

Page T=Table F=Figure	Revision Number
9-i	6
9-ii	6
9-iii	13
9-iv	6
9-v	16
9-vi	16
9-vii	13
9-viii	13
9-ix	13
9-x	6
9-xi	15
9-xia	15
9-xib	15
9-xii	16
9-xiii	8
9-xiv	13
9.1-1	6
9.1-2	6
9.1-3	15
9.1-3a	15
9.1-3b	16
9.1-4	15
9.1-4a	15
9.1-4b	15
9.1-5	15
9.1-6	15
9.1-7	15
9.1-8	15
9.1-9	15

LIST OF CURRENT PAGES (Cont)

Page T=Table F=Figure	Revision Number
T 9.1-2	
Sh 1	16
Sh 2	12
Sh 3	12
T 9.1-3	6
T 9.1-4	
Sh 1	15
Sh 2	6
Sh 3	6
Sh 4	6
Sh 5	15
Sh 6	17
F 9.1-1	16
F 9.1-2A	15
F 9.1-2B	15
F 9.1-3	15
F 9.1-3A	15
F 9.1-3B	15
F 9.1-3C	15
F 9.1-3D	15
F 9.1-3E	15
F 9.1-3F	15
F 9.1-4A	16
F 9.1-4B	16
F 9.1-5	6
F 9.1-6	6
F 9.1-7	6
F 9.1-8	6
F 9.1-9	6
9.2-1	16
9.2-2	16
9.2-3	16
9.2-4	15

LIST OF CURRENT PAGES (Cont)

LIST OF CURRENT PAGES (Cont)

Page T=Table F=Figure	Revision Number
F 9.2-8	6
F 9.2-9	6
F 9.2-10	6
F 9.2-11	
Sh 1	15
Sh 2	15
Sh 3	15
Sh 4	15
Sh 5	17
Sh 6	17
Sh 7	16
9.3-1	17
9.3-2	15
9.3-3	15
9.3-4	15
9.3-5	15
9.3-6	6
9.3-7	6
9.3-8	6
9.3.9	17
9.3-10	6
9.3-11	6
9.3-12	6
9.3-13	6
9.3-14	13
9.3-15	13
9.3-15a	13
9.3-15b	13
9.3-16	6
9.3-17	6
9.3-18	6

Page T=Table F=Figure	Revision Number
9.3-19	6
9.3-20	6
9.3-21	14
9.3-22	13
9.3-23	14
9.3-24	6
9.3-25	6
9.3-26	6
9.3-27	6
9.3-28	13
9.3-29	14
9.3-30	14
9.3-31	6
9.3-32	16
9.3-33	16
9.3-34	6
9.3-35	9
9.3-36	6
9.3-37	14
9.3-38	14
9.3-39	14
9.3-39a	14
9.3-39b	12
9.3-40	14
9.3-41	6
9.3-42	6
9.3-43	6
9.3-44	6
9.3-45	6
9.3-46	6

LIST OF CURRENT PAGES (Cont)

LIST OF CURRENT PAGES (Cont)

Page T=Table F=Figure	Revision Number
9.5-24	13
9.5-25	13
9.5-26	13
9.5-27	13
9.5-28	13
9.5-29	13
9.5-30	13
9.5-31	13
9.5-32	13
9.5-33	13
9.5-34	13
9.5-35	13
9.5-36	14
9.5-37	16
9.5-38	17
9.5-39	15
9.5-40	16
9.5-41	16
9.5-42	14
9.5-43	16
9.5-44	15
9.5-45	16
9.5-46	16
F 9.5-1	13
F 9.5-2	
Sh 1	16
Sh 2	16
Sh 3	16

LIST OF CURRENT PAGES

SECTION 10

LIST OF CURRENT PAGES (Cont)

LIST OF CURRENT PAGES (Cont)

Page T=Table F=Figure	Revision Number
T 10.3-1	12
T 10.3-2	12
F 10.3-1A	
Sh 1	17
Sh 2	17
Sh 3	17
Sh 4	17
Sh 5	17
Sh 6	17
F 10.3-1B	
Sh 1	16
Sh 2	17
Sh 3	17
Sh 4	16
Sh 5	16
Sh 6	17
F 10.3-2	15
F 10.3-3	
Sh 1	16
Sh 2	16
10.4-1	15
10.4-2	16
10.4-3	16
10.4-4	16
10.4-5	16
10.4-6	6
10.4-7	6
10.4-8	16
10.4-9	16

Page T=Table F=Figure	Revision Number
10.4-10	6
10.4-11	17
10.4-12	6
10.4-13	16
10.4-14	6
10.4-15	6
10.4-16	6
10.4-17	16
10.4-18	17
10.4-19	17
10.4-20	14
10.4-21	14
10.4-22	6
10.4-23	14
10.4-24	14
10.4-25	6
10.4-26	6
10.4-27	16
T 10.4-1	
Sh 1	13
Sh 2	6
Sh 3	6
Sh 4	6
T 10.4-2	16
T 10.4-3	6
T 10.4-4	6
T 10.4-5	
Sh 1	6
Sh 2	6
T 10.4-6	6

LIST OF CURRENT PAGES

SECTION 11

Page T=Table F=Figure	Revision Number
11-i	16
11-ii	6
11-iii	6
11-iv	16
11-v	6
11-vi	15
11-vii	6
11.1-1	16
11.1-2	16
11.1-3	16
11.1-4	16
11.1-5	16
11.1-6	16
11.1-7	6
11.1-8	6
11.1-9	6
11.1-10	16
11.1-11	16
T 11.1-1	16
T 11.1-2	16
T 11.1-3	16
T 11.1-4	16
T 11.1-5	16
T 11.1-6	16
T 11.1-7	
Sh 1	16
Sh 2	16

LIST OF CURRENT PAGES (Cont)

Page T=Table F=Figure	Revision Number
T 11.2-3	
Sh 1	17
Sh 2	15
T 11.2-4	
Sh 1	14
Sh 2	14
T 11.2-5	14
T 11.2-6	
Sh 1	6
Sh 2	6
T 11.2-7	
Sh 1	6
Sh 2	6
T 11.2-8	
Sh 1	6
Sh 2	6
Sh 3	6
T 11.2-9	6
F 11.2-1A	
Sh 1	17
Sh 2	17
Sh 3	17
Sh 4	13
Sh 5	13
F 11.2-1B	
Sh 1	17
Sh 2	17
Sh 3	17

LIST OF CURRENT PAGES (Cont)

LIST OF CURRENT PAGES (Cont)

LIST OF CURRENT PAGES

SECTION 12

Page T=Table F=Figure	Revision Number
12-i	16
12-ii	16
12-iii	7
12.1-1	6
12.1-2	6
12.1-3	6
12.1-4	6
12.1-5	6
12.1-6	6
12.1-7	6
12.1-8	7
12.1-9	16
12.1-10	16
12.1-11	16
12.1-12	16
12.1-13	16
12.1-14	15
T 12.1-1	6
T 12.1-2	6
T 12.1-3	6
T 12.1-4	6
T 12.1-5	6

LIST OF CURRENT PAGES (Cont)

LIST OF CURRENT PAGES

SECTION 13

LIST OF CURRENT PAGES (Cont)

LIST OF CURRENT PAGES

SECTION 14

LIST OF CURRENT PAGES (Cont)

LIST OF CURRENT PAGES

SECTION 15

Page T=Table F=Figure	Revision Number
15-i	6
15-ii	6
15-iii	6
15-iv	15
15-v	17
15-vi	16
15-vii	16
15-viia	16
15-viib	10
15-viii	15
15-ix	16
15-x	16
15-xi	16
15-xii	15
15-xiii	16
15-xiiia	7
15-xiiib	7
15-xiv	11
15-xv	11
15-xvi	15
15-xvii	17
15-xviii	15
15-xix	15
15-xixa	15
15-xixb	15
15-xx	15
15-xxi	15
15-xxii	15

LIST OF CURRENT PAGES (Cont)

Page T=Table F=Figure	Revision Number
15-xxiii	15
15-xxiiia	16
15-xxiiib	11
15-xxiv	15
15-xxiva	15
15-xxivb	11
15-xxv	16
15-xxvi	6
15-xxvii	15
15-xxviii	15
15-xxix	9
15.1-1	6
15.1-2	16
15.1-3	6
15.1-4	6
15.1-5	6
15.1-6	6
15.1-7	6
15.1-8	6
15.1-9	11
15.1-10	7
15.1-10a	7
15.1-10b	7
15.1-11	15
15.1-12	16
15.1-13	16
15.1-14	16

Page T=Table F=Figure	Revision Number
15.1-15	6
15.1-16	6
15.1-17	6
15.1-18	6
15.1-19	15
15.1-20	6
15.1-21	6
15.1-22	6
15.1-23	11
15.1-24	16
15.1-25	6
15.1-26	11
T 15.1-1	6
T 15.1-2	
Sh 1	11
Sh 2	16
Sh 3	15
Sh 4	10
T 15.1-3	13
T 15.1-4	6
T 15.1-5	16
T 15.1-6	16
F 15.1-1	6
F 15.1-2	11
F 15.1-3	11
F 15.1-4	11
F 15.1-5	11
F 15.1-6	6
F 15.1-7	6
F 15.1-8	6

Page T=Table F=Figure	Revision Number
15.2-53	15
15.2-54	15
15.2-55	17
15.2-56	17
15.2-57	17
15.2-58	17
15.2-59	17
15.2-60	17
15.2-60a	17
15.2-60b	16
15.2-61	16
15.2-62	17
T 15.2-1	
Sh 1	16
Sh 2	16
Sh 3	16
Sh 4	16
Sh 5	16
Sh 6	16
Sh 7	16
Sh 8	17
T 15.2-2	15
T 15.2-3	6
F 15.2-1	16
F 15.2-2	16
F 15.2-3	16
F 15.2-4	6
F 15.2-5	6
F 15.2-6	6
F 15.2-7	6
F 15.2-8	6
F 15.2-9	6
F 15.2-10	6

Page T=Table F=Figure	Revision Number
F 15.2-11	
Sh 1	15
Sh 2	15
F 15.2-12	6
F 15.2-13	11
F 15.2-14	11
F 15.2-15	11
F 15.2-16	11
F 15.2-17	11
F 15.2-18	11
F 15.2-19	6
F 15.2-20	6
F 15.2-21	6
F 15.2-22	6
F 15.2-23	6
F 15.2-24	6
F 15.2-25	6
F 15.2-26	6
F 15.2-27	6
F 15.2-28	6
F 15.2-29a	15
F 15.2-29b	15
F 15.2-29c	15
F 15.2-29d	15
F 15.2-29e	15
F 15.2-29f	15
F 15.2-30	6
F 15.2-31	6
F 15.2-32	6
F 15.2-33	6
F 15.2-34	6
F 15.2-35	6

LIST OF CURRENT PAGES (Cont)

Page T=Table F=Figure	Revision Number
15.4-1	15
15.4-2	15
15.4-2a	15
15.4-2b	15
15.4-3	15
15.4-3a	15
15.4-3b	15
15.4-4	16
15.4-5	15
15.4-6	15
15.4-7	15
15.4-8	15
15.4-9	10
15.4-10	10
15.4-11	10
15.4-12	10
15.4-13	10
15.4-14	10
15.4-15	10
15.4-16	16
15.4-17	16
15.4-18	16
15.4-18a	16
15.4-18b	16
15.4-19	16
15.4-20	16
15.4-21	16

LIST OF CURRENT PAGES (Cont)

Page T=Table F=Figure	Revision Number
15.4-22	16
15.4-22a	16
15.4-22b	16
15.4-23	16
15.4-24	16
15.4-25	16
15.4-26	16
15.4-27	16
15.4-28	16
15.4-29	16
15.4-30	16
15.4-31	16
15.4-32	15
15.4-33	15
15.4-34	9
15.4-35	15
15.4-36	15
15.4-37	9
15.4-38	16
15.4-39	16
15.4-40	16
15.4-41	16
15.4-42	16
15.4-43	15
15.4-44	15
15.4-45	15
15.4-46	15
15.4-47	15

LIST OF CURRENT PAGES (Cont)

Page T=Table F=Figure	Revision Number
15.4-109	6
15.4-110	17
15.4-111	15
15.4-112	15
15.4-113	15
15.4-114	17
15.4-115	17
15.4-116	15
15.4-117	15
15.4-118	15
15.4-119	15
15.4-120	15
15.4-121	16
15.4-122	13
15.4-123	15
15.4-124	15
15.4-125	15
15.4-126	15
15.4-127	6
15.4-128	9
15.4-129	6
15.4-130	16
T 15.4-1	
Sh 1	15
Sh 2	15
Sh 3	16
T 15.4-2	
Sh 1	15
Sh 2	15
T 15.4-3	
Sh 1	15
Sh 2	15
Sh 3	15

LIST OF CURRENT PAGES (Cont)

Page T=Table F=Figure	Revision Number
F 15.4-1	15
F 15.4-2	15
F 15.4-3	15
F 15.4-4A	15
F 15.4-4B	15
F 15.4-4C	15
F 15.4-5	15
F 15.4-6	15
F 15.4-7A	15
F 15.4-7B	15
F 15.4-7C	15
F 15.4-8	15
F 15.4-9	15
F 15.4-10A	15
F 15.4-10B	15
F 15.4-10C	15
F 15.4-11	15
F 15.4-12	15
F 15.4-13A	15
F 15.4-13B	15
F 15.4-14	15
F 15.4-15	15
F 15.4-16A	15
F 15.4-16B	15
F 15.4-17	15

Page T=Table F=Figure	Revision Number
F 15.4-35	15
F 15.4-36	15
F 15.4-37A	15
F 15.4-37B	15
F 15.4-38	15
F 15.4-39	15
F 15.4-40A	15
F 15.4-40B	15
F 15.4-40C	15
F 15.4-41	15
F 15.4-42	15
F 15.4-43A	15
F 15.4-43B	15
F 15.4-43C	15
F 15.4-44	15
F 15.4-45	15
F 15.4-46A	15
F 15.4-46B	15
F 15.4-47	15
F 15.4-47A	16
F 15.4-47B	16
F 15.4-47C	16
F 15.4-48	16
F 15.4-49	9
F 15.4-50A	16
F 15.4-50B	16
F 15.4-50C	16

LIST OF CURRENT PAGES

SECTION 16

Page T=Table F=Figure	Revision Number
16-1	6

LIST OF CURRENT PAGES

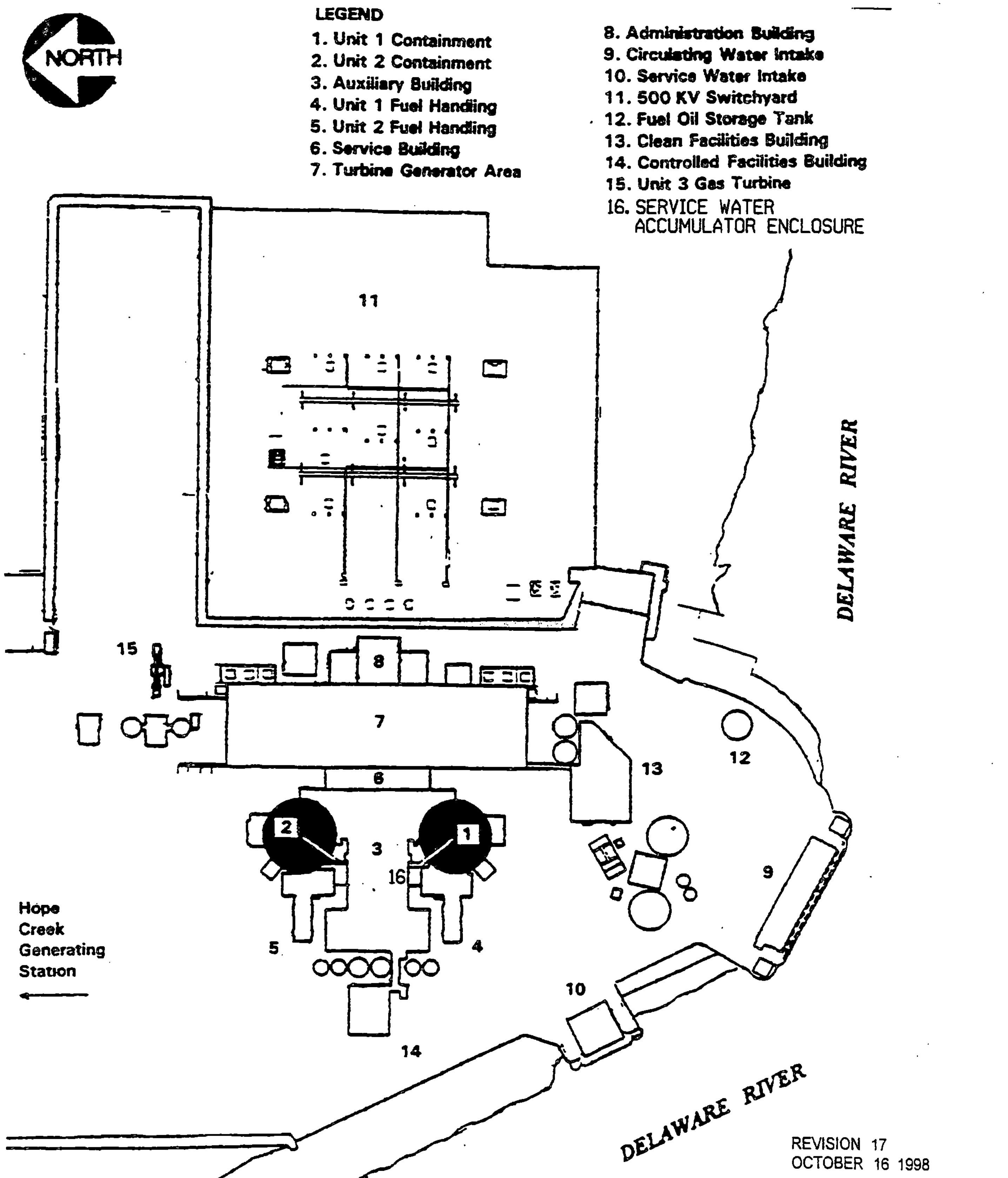
SECTION 17

Page T=Table F=Figure	Revision Number
17-i	16
17-ii	9
17-iii	6
17-iv	16
17.1-1	6
17.2-1	16
17.2-2	17
17.2-3	16
17.2-4	17
17.2-4a	17
17.2-4b	16
17.2-5	17
17.2-6	17
17.2-6a	16
17.2-6b	16
17.2-7	16
17.2-7a	16
17.2-7b	16
17.2-7c	16
17.2-7d	16
17.2-7e	16
17.2-7f	16
17.2-7g	16
17.2-7h	16
17.2-7i	17
17.2-7j	16
17.2-8	15
17.2-8a	14
17.2-8b	11
17.2-9	15
17.2-10	10
17.2-11	15
17.2-12	17

Page T=Table F=Figure	Revision Number
17.2-13	16
17.2-14	15
17.2-15	16
17.2-15a	16
17.2-15b	13
17.2-16	16
17.2-17	9
17.2-18	15
17.2-19	17
17.2-20	17
17.2-21	17
17.2-22	16
17.2-23	17
17.2-24	17
17.2-25	17
17.2-26	17
17.2-27	13
17.2-28	17
17.2-29	17
17.2-30	9
17.2-31	11
17.2-32	15
17.2-33	16
17.2-34	15
17.2-35	16
17.2-36	16
17.2-37	17
17.2-38	16
17.2-39	16
17.2-40	17
17.2-41	15
T 17.2-1	
Sh 1	16
Sh 2	16
Sh 3	9
Sh 4	6
Sh 5	9

LIST OF CURRENT PAGES

APPENDIX A



PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

General Site Plan

Updated FSAR

FIG. 1.2-1

2.2.3.2 Hazardous Chemicals - Onsite

Regulatory Guide 1.78, Paragraph C.2 states that hazardous chemicals such as those indicated in Table C-1 of the Guide, must be included in the analysis if they are frequently shipped within a 5 mile radius of the plant. The Guide also defines frequent shipments as being 50 or more trips per year for barge traffic, 10 or more trips per year for truck traffic, and specifies in Paragraph C.1, that chemicals stored or situated at distances greater than 5 miles from the facility need not be considered.

Following is the analysis of control room habitability during a postulated hazardous chemical release occurring either on the site or within a 5 mile radius of the plant. As indicated in Section 2.2, the Salem site is located in a rural area with no major manufacturing or chemical plants located within 5 miles of the site. The only major transportation route within 5 miles of the plant is the Delaware River, with the Intracoastal Waterway passing 1 mile west of the site.

The SGS uses a sodium hypochlorite biocide system, thus eliminating an onsite chlorine hazard. The control room is equipped with smoke and combustible detectors located in the air conditioning unit ducts. These detectors provide alarms in the control room in the event of smoke or combustible hazards present. The control room is equipped with radiation detectors which provide annunciation, automatically isolate the control room, and initiate emergency ventilation in the pressurized mode. The site was reviewed to identify potentially hazardous chemicals which may impact control room habitability during a postulated release. The site includes the SGS, HCGS, and deliveries to and near the site. Hazardous chemicals which may impact control room habitability are identified as sulfuric acid, nitrogen, ammonium hydroxide, hydrazine, sodium hydroxide, and helium. Fire fighting agents such as carbon dioxide and halon are discussed later in this section. The basis for identification was the chemical's physical properties, toxicity and/or asphyxiant threshold levels, and storage quantities and locations.

Table 2.2-2 presents the chemicals stored onsite or shipped by the site on the Delaware River which are identified in Regulatory Guide 1.78, Table C-1. Table 6.4-3 in Section 6.4 provides information on the control room ventilation system, as required by Regulatory Guide 1.78, Paragraph C.7. As can be seen from Table 2.2-2, the hazardous chemicals stored onsite are sulfuric acid, nitrogen, ammonium hydroxide, hydrazine, sodium hydroxide, and helium.

As previously mentioned, several chemicals are stored onsite that are considered hazardous. Sulfuric acid is stored in 4,000 and 2,250 gallon tanks in the SGS Turbine Buildings and it is stored in 16,000 gallon tanks at the HCGS. Calculations indicated that the toxicity limit found in Regulatory Guide 1.78 will not be exceeded in the control rooms during a postulated release at any of the sources.

Liquid nitrogen and nitrogen stored as a compressed gas is stored at various locations onsite. According to the criteria contained in Regulatory Guide 1.78, the largest single source should be evaluated for its impact on control room habitability. The sources evaluated at the SGS are the portable nitrogen tube trailers located in various areas throughout the SGS yard area and the (2) 3000 gallon tanks located behind Unit No. 1 & 2 Auxiliary Buildings. In addition to these sources, liquid nitrogen is also stored in 9,000 gallon tanks at the HCGS. Calculations indicated that the oxygen depletion is negligible in the control rooms during a postulated release at any of the significant sources.

Chemicals used as fire-fighting agents were evaluated. Carbon dioxide is stored on the 84 foot elevation of each of the Auxiliary Buildings. It is also stored at the HCGS. Calculations indicated that the toxicity limit established in Regulatory Guide 1.78 as well as asphyxiation levels would not be exceeded during

TABLE 2.2-2

HAZARDOUS CHEMICALS STORED ONSITE

Name of Chemical	Sulfuric Acid	Nitrogen	Ammonium Hydroxide	Hydrazine	Sodium Hydroxide	Helium	Carbon Dioxide	Halon	Sodium Hypochlorite
Type of Source	Onsite	Onsite	Onsite	Onsite	Onsite	Onsite	Onsite	Onsite	Onsite
Human Detection Threshold (mg/m^3)	1.0	N/A	3.5	3.5	N/A	N/A	N/A	N/A	N/A
Maximum Allowable 2-minute Limit (mg/m^3)	2.0	Asphyxi-ant	70.0	0.04	2.0	Asphyxi-ant	Asphyxi-ant	Asphyxi-ant	N/A
Largest Single Container of Chemical (gallons)	1) 4000 (Unit 1) 2) 2250 (Unit 2)	1) 9000 (Hope Creek) (2) 3000 Salem	1) 3000	1) 300	1) 4000 (Unit 1) 2) 2250 (Unit 2)	1) 150 lbs	1) 2 tons	1) 310 lbs	1) 88,000
Maximum Continuous Release Rate (g/s)	Approx. Zero	Instant-aneous	450	0.53	Approx zero	Instant-aneous	Instant-aneous	Instant-aneous	Approx. zero
Vapor Pressure (mmHg)	Approx. zero	N/A	450@ 115°F	35@ 115°F	Approx zero	N/A	N/A	N/A	Approx. zero

3.2 CLASSIFICATION OF STRUCTURES, COMPONENTS, AND SYSTEMS

Certain structures, components, and systems of a nuclear power plant are considered important because they perform safety functions required to avoid or mitigate the consequences of abnormal operational transients or accidents. This section discusses the classification of structures, components, and systems according to the importance of the safety function they perform. In addition, design requirements are placed upon such equipment to ensure the proper performance of safety actions when required.

3.2.1 Seismic Classification

3.2.1.1 Definition of Seismic Design Classifications

Structures and equipment have been divided into three classes for the purpose of establishing the seismic design requirements. Each structure, system, component, and parts thereof are classified in accordance with the following definitions.

Class I

Those structures and components, including instruments and controls, whose failure might cause or increase the severity of a loss-of-coolant accident or result in an uncontrolled release of excessive amounts of radioactivity. Also, those structures and components vital to safe shutdown and isolation of the reactor.

Class II

Those structures and components which are important to reactor operation but not essential to safe shutdown and isolation of the reactor, and whose failure could not result in the release of substantial amounts of radioactivity.

Class III

Those structures and components which are not related to reactor operation or containment.

Seismic design measures for these three classifications are described in Sections 3.7 and 5.2.

3.2.1.2 Seismic Classification of Structures, Systems, and Components

The classifications which follow are intended, by example, to convey the application of the seismic classification definitions.

Class I

The following list establishes a general category of Class I items:

Structures:

1. Containment (including penetrations and air locks, the concrete shield, and the interior structures)

2. Fuel Handling Building

3. Control Room

4. Auxiliary Building

5. Service Water Intake Structure

The cumulative probability of missile strikes on all the unprotected components and openings for each of the two Salem units was determined to be less than 10^{-6}, which is acceptable per the guidance provided in Regulatory Guide 1.117 and SRP Section 2.2.3.

Penetrations into steel barriers are calculated using equations developed based on tests conducted at the Stanford Research Institute, summarized in Reference 7. The equation for penetration can be written in the form

$$\left(\frac{e}{d}\right)^2+\frac{3}{128}\left(\frac{B}{d}\right)\left(\frac{e}{d}\right)=\frac{0.0452 D \upsilon_0^2}{S_s}$$

where

e	=	perforation thickness (in)
d	=	effective projectile diameter (in)
B	=	width of plate between rigid supports (in)
D	=	w/d^3, where w = missile weight in pounds
υ_0	=	missile striking velocity (ft/sec)
S_s	=	ultimate tensile strength of steel target (psi)

The value of e calculated using the above equation is multiplied by 1.25 when designing steel barriers

t_d = 1.25 e

Steel missile barriers are designed using the following allowable ductility ratios:

Flexural members	$\mu d \leq 10.0$
Columns with slenderness ratio (l/r) less than or equal to 20	$\mu d \leq 1.3$
Columns with slenderness ratio (l/r) greater than 20	$\mu d \leq 1.0$
Members subjected to tension	$\mu d \leq 0.5 \frac{e_u}{e_y}$

where e_u = ultimate strain

e_y = yield strain

3.5.2.3 Safety Assurance Against Tornado Missile Induced Damages

Category I systems outside the Category I buildings that may be damaged by tornado or secondary missiles are the refueling water storage and auxiliary feedwater storage tanks and systems. Sufficient precautions have been taken to assure a safe shutdown of the reactor and to maintain it in a safe condition.

3.5.2.3.1 Backup Water Sources for Category I Water Storage Tanks

In the event that the integrity of Category I storage tanks are violated due to tornado induced missiles, sufficient backup water sources are available to assure a safe shutdown of the reactor.

Primary system makeup requirements during cooldown are normally accomplished by the Chemical and Volume Control System (CVCS), providing makeup water from the primary water storage tank. In the event that the primary water storage tank is the affected tank, primary system makeup can be provided by transferring water to the Reactor Coolant System from the three 8500 cubic foot capacity holdup tanks or the spent fuel pool via the CVCS. Approximately 24,000 gallons of water are required to maintain the level in the Reactor Coolant System in the transition from full power operation to cold shutdown. Removable borated water (31,000 gallons) is available in the spent fuel pool above the spent fuel pool pump suction line. In addition, another 13,000 gallons of borated water is available above the spent fuel pool pump suction line in the fuel transfer pool.

Feedwater system makeup requirements during cooldown are normally supplied from the Main Feedwater System, providing makeup water from the condenser. In the event the Main Feedwater System becomes inoperable, the Auxiliary Feedwater System is placed in operation and feedwater makeup is supplied from the auxiliary feed storage tank. This Category I tank is adequately protected from the effects of earthquakes, tornado, wind loads, and floods. Backup water sources for the auxiliary feedwater pumps are the two demineralized water storage tanks (500,000 gallon capacity each), the two fire protection and domestic water storage tanks (350,000 gallon capacity each), and the station Service Water System.

Because of the chloride content of the water (approximately 6000 ppm), the Service Water System would be used for this purpose only as a last resort in the event that other water sources become unavailable. The Service Water System will be used for decay heat removal as necessary, only until the normal or backup water sources are again made available.

Backup water supply from the demineralized water storage tanks is readily available, upon filling and venting the associated suction piping. The fill process is accomplished using local/manual valves. Automatic vent valves are provided to ensure the line is properly filled. Once filled the alternate suction stops, AF52's are opened from the Main Control Room to place this backup source of water in service. The fire protection and domestic water storage tanks can be used as a backup water source in the event that the demineralized water storage tanks become unavailable. Fire protection and domestic water can be provided to the auxiliary feed pumps only when a spool piece has been connected by station personnel. The Service Water System can be used as a backup water source in the event that the other water sources become unavailable. Service water can be provided to the auxiliary feed pumps only when a spool piece has been connected by station personnel. The time required to connect the spool piece is less than 30 minutes. Operations involving alignment of normal and alternate sources of water to the auxiliary feedwater pumps are covered by station procedure.

The backup water sources from the CVCS holdup tanks, the spent fuel pool, and the Service Water System are located in buildings/structures designed to withstand tornado induced missiles. The water storage tanks are located in different areas of the station site (refer to the arrangement drawings in Section 5). Although not specifically designed to withstand tornado induced missiles, the separated locations of the various tanks preclude the possibility that all tanks would be rendered unavailable due to tornado induced missiles. The systems which are required to bring the unit to a safe shutdown are enclosed in tornado protected buildings/structures and capable of being powered by the standby AC power systems.

Plant Shutdown Operating Procedures

In the unlikely event that a breach of any of the primary water sources were to occur (refueling water storage tank, auxiliary feedwater storage tank, or primary water storage tank), station operating personnel would start to shut down and cool the reactor below 350°F, using normal plant shutdown operating procedures. These procedures initiate immediate decay heat removal by steam dump to the condenser. As feedwater in the secondary plant cycle absorbs heat from the reactor coolant through the steam generators, it is converted to steam, giving up heat to the circulating water in the condenser. Hot shutdown can be maintained with Auxiliary Feedwater System operation and main steam atmospheric relief valves. Boration can be accomplished via the charging pumps, boric acid tanks, and boric acid transfer pumps. In the event the Auxiliary Feed Storage Tank is unavailable, transfer to one of the backup water sources (previously discussed in this section) is accomplished by station procedure. No automatic water supply switchover is provided. The backup water sources for the Auxiliary Feedwater System water sources are addressed in the Technical Specifications (except for the service water backup source).

The unit would be maintained in a hot shutdown condition until station operating personnel have assessed operating conditions, damage, and availability of water sources to attain cold shutdown. Necessary repairs would be made and alternate water supplies provided as necessary for the CVCS to maintain Reactor Coolant System inventory and proceed to bring the unit to a cold shutdown condition.

Shutdown procedures would be accomplished in as normal a fashion as operating conditions permit utilizing alternate water sources as necessary. The methodology would be dependent upon the extent of tornado missile damage as determined by operating personnel in their assessment of plant conditions.

The arrangement of the service intake structure, service water pumps and piping is discussed in Section 9.2. The service water pumps are located within the service intake structure, which is seismic Category I and designed to be tornado missile proof. The piping is buried below grade, thereby protected from tornado missiles.

Indication is provided in the control room for all outdoor water storage tanks. Upon indication of loss of water from all outdoor water storage tanks such that they become unavailable for auxiliary feedwater supply (tornado induced failure), personnel would be dispatched to install the spool piece connection between the Service Water and Auxiliary Feedwater Systems.

It has been determined by actual demonstration that two men can install the spool piece in 13 minutes. The installation requires no special tools and involves removing two blind flanges and bolting the spool piece in place. The spool piece is stored at the connection point.

An analysis was performed to determine the time period following a loss of ac power and main and auxiliary feedwater flow before the core becomes uncovered. The pertinent assumptions used in the analysis are as follows:

1. All ac power lost at time of incident

2. Rods assumed to begin dropping into core 2 seconds following incident

3. ANS standard decay heat curve assumed

4. Pressurizer relief and safety valves operative

5. Initial power is 1.02 times rated power

6. Loss of all main and auxiliary feedwater following incident.

The calculation was subdivided into the following areas:

1. Heat required to raise primary to saturation temperature

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3.5.5 References for Section 3.5

1. MSTG-1-P, "Criteria for Low Pressure Nuclear Turbine Disc Inspection," June 1981.

2. Topical Reports WSTG-1-P and NP, "Procedures for Estimating the Probability of Steam Turbine Disc Rupture From Stress Corrosion Cracking," May 1981.

3. Topical Report WSTG-2-P and NP, "Missile Energy Analysis Methods for Nuclear Steam Turbines," May 1981.

4. CT-25243, "Turbine Missile Report (Heavy Disc - Keyplate Design LP's)" Revision 0, November 1985.

5. Westinghouse Report WSTG-4-P, "Analysis of the Probability of the Generation of Missiles from Fully Integral Nuclear Low Pressure Rotors," October, 1984.

6. Westinghouse Technical Report TM-95185, "Overspeed Analysis for Public Service Electric and Gas - Salem 2 Fully Integral Rotors Dated August 15, 1995"

7. W. B. Cottrell and A. W. Savolainen, "U.S. Reactor Containment Technology," ORNL-NSIC-5, Vol. 1, Chapter 6, Oak Ridge National Laboratory.

safety injection pump motors from the steam environment following a postulated rupture of this pipe, the pipe is entirely sleeved within this room. The sleeving design is shown on Figures 3.6-29 and 3.6-21. No significant modifications were required, other than moving the letdown line several inches to preclude sleeve interference.

The Waste Evaporator Room, located on Elevation 100 feet, contains a portion of the high energy steam line to the auxiliary feedwater pump turbine which is described in Section 3.6.5.6. Pipe break locations, selected on the basis of the criteria presented in Section 3.6.4.3.2, are sleeved and restrained in order to prevent whip and limit the steam mass flow rates from the postulated breaks. In order to preclude the detrimental effects of steam flooding and jet impingement, a steel plate enclosure is provided around this pipe where it passes through this room. A new vent opening in the floor of the room within the enclosure was provided to vent the steam flow from the postulated breaks to the pipe alley below. These modifications are shown on Figures 3.6-28 and 3.6-29.

The Pipe Alley, located on Elevation 84 feet, contains portions of both the high energy CVCS letdown lines and the steam line to the auxiliary feedwater pump turbine. Pipe break locations, selected on the basis of the criteria presented in Section 3.6.4.3.2, are restrained to prevent whip. Although the pipe alley does not contain any safety-related equipment, sealing (or backdraft dampers) is provided to prevent steam from entering any areas not specifically designed to accommodate the steam environment. A wall opening to the penetration area provides atmospheric venting via the penetration area vent penthouse.

The Piping Penetration Areas (Elevations 78 feet and 100 feet) contain portions of all of the high energy systems listed in Section 3.6.1. Pipe break locations, selected on the basis of the criteria presented in Section 3.6.4.3.2 were restrained as necessary to prevent unacceptable pipe whip and fluid impingement. In order to maintain the internal pressure of the penetration areas within acceptable limits following the postulated main steam and feedwater system ruptures, the inboard and outboard penetration area venting panels were increased from 100 ft^2 to 650 ft^2 by raising their roofs to Elevation 141 feet. However, certain venting panels have obstructions and are not fully operational. Considering all obstructions, the net available venting areas are: 337 ft^2 for the inboard penetration area, and 391 ft^2 for the outboard penetration area. Design calculations have confirmed that the present net available venting area maintains the internal pressure of the penetration areas within previously established design limits as discussed in section 3.6.5.2.2. Certain Elevation 100-foot and 78-foot penetration area walls and floor sections were sealed in order to confine the environmental effects of the postulated breaks, and some localized impingement protection was added in order to accommodate the postulated breaks.

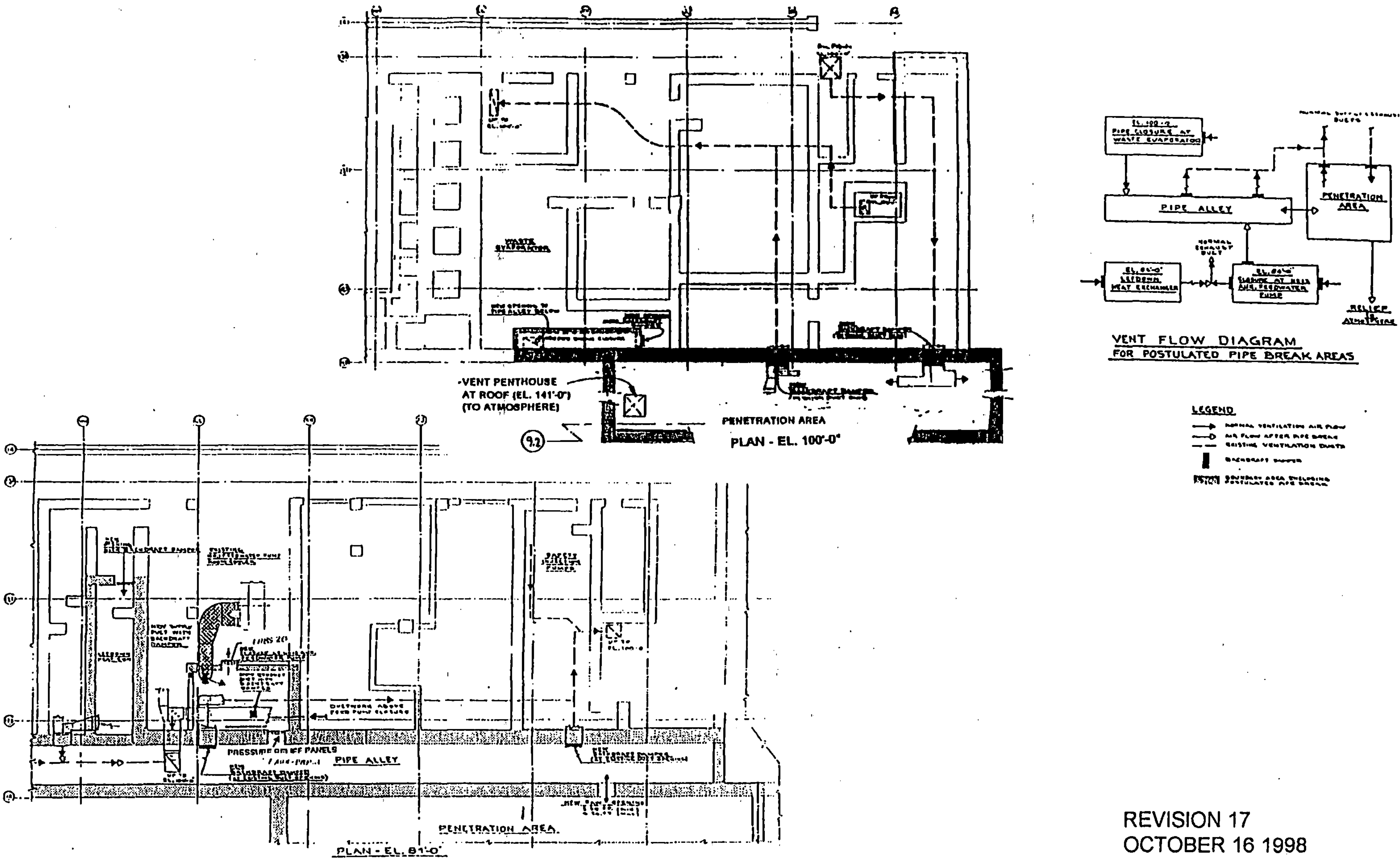
3.6.5.11 Design Criteria for Encapsulation Sleeves

In some instances, encapsulation of portions of the high energy piping systems was used to limit break mass flow rates and, hence, preclude any unacceptable effects of pipe rupture. In these cases, the encapsulation sleeves are designed and installed in accordance with the following criteria:

1. The encapsulation sleeves are designed and supported in a manner which will not introduce significant strain concentrations on the encapsulated section of piping.

2. The piping beyond the encapsulation sleeves is provided with restraints or anchors which restrict its axial displacement and motion within the sleeves following a postulated circumferential pipe break.

3. The encapsulation sleeves are designed (a) to withstand the dynamic forces of internal pressurization resulting from the escape of high energy fluid at the postulated pipe break location, assuming complete pipe severance and axial separation to the extent permitted by the pipe restraints, and (b) to restrict the flow at the open ends of the sleeve to a level required to preclude compartment pressurization beyond the allowable



REVISION 17
OCTOBER 16 1998

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	No.1 Unit Auxiliary Building - Ventilation Design for Pipe Break
	Updated FSAR FIG. 3.6-28

flooding to a height of 20.9 feet above grade, the dead weight will be a minimum of 1.6 times the buoyant force. Therefore, the highest water conditions in the river will present no hazard to the flotation of the containment.

Internal structures consist of equipment supports, polar crane gantry, shielding, reactor cavity and canal for fuel transfer, miscellaneous concrete and steel for floors and stairs.

A 3-foot thick concrete ring wall serving as a partial radiation shield surrounds the Reactor Coolant System (RCS) components and supports the polar-type reactor containment crane. A 3 to 5-foot thick reinforced concrete floor covers the RCS compartments. Removable concrete plugs are provided to permit crane access to the reactor coolant pumps. The four steam generators, pressurizer, and various pipes penetrate the floor. Stairs provide access to the areas below the floor.

The refueling canal connects the reactor cavity with the fuel transport tube to the spent fuel pool. The floor and walls of the canal are concrete, with walls and shielding water providing the equivalent of 6 feet of concrete. The floor is 4.5-feet thick. The concrete walls and floor are lined with 1/4-inch thick stainless steel plate. The linings provide a leakproof membrane that is resistant to abrasion and damage during fuel handling operations.

3.8.1.2 Design Codes

The Containment Building has been designed under the following codes:

1. Building Code Requirements for Reinforced Concrete, ACI 381-63.

2. AISC Manual of Steel Construction, 6th Edition or later edition, as applicable.

3. ASME Boiler and Pressure Vessel Code, Section III, Section VIII, and Section IX (Applicable portions) - 1968.

3.8.1.3 Design Loads and Loading Combinations

The following loads are considered to act upon the containment structure creating stresses within the component parts:

1. Dead load

   The dead load consists of the weight of the complete structure as shown in the construction drawing. To provide for variations in the assumed dead load, the coefficient for dead load components is adjusted by ±5 percent as indicated in the various cases of loading combinations.

2. Live load

   Live load consists of snow or construction loads on the dome and also the weight of major components or equipment in the containment. A construction load of 50 pounds per square foot, which is more severe than the snow load, is used in dome design.

3. Internal Pressure

   The internal pressure transient used for the containment design and its variation with time is shown on the pressure-temperature transient curve, Figure 3.8-11. For the free volume of 2,620,000 cubic feet within the containment, the design pressure is 47 psig. This pressure transient is more severe than those calculated for various LOCAs and Main Steam Line Breaks (MSLB) which are presented in Section 15.

4. Thermal

Thermal expansion stresses due to an internal temperature increase caused by a LOCA have been considered. This temperature and its variation with time is shown on the pressure-temperature transient curve, Figure 3.8-11. The maximum temperature at the uninsulated section of the liner under accident conditions is 246°F. For the 1.25 times and 1.50 times design pressure loading conditions given in Section 3.8.1.4.1, the corresponding liner temperature will be 285°F and 306°F, respectively. The pressure-temperature transient curves for these loading conditions are shown on Figures 3.8-12 and 3.8-13, respectively. The maximum operating temperature is 120°F.

For the Main Steam Line Breaks (MSLB), Figure 15.4-100 provides the containment pressure and temperature transients for the limiting temperature case. The governing peak temperature is 351.3°F.

5. Buoyancy

Uplift due to buoyant forces created by the displacement of ground water by the structure has been considered. Computations are based on normal ground water being at grade level and flood water at 20.9 feet above grade during a hypothetical hurricane.

6. Seismic Load

The site seismology and ground response spectra are described in Section 2. Seismic design criteria for structures and equipment are described in Sections 3.7 and 3.8.1.4.2.

7. Wind Load

A wind load of 30 pounds per square foot, equivalent to 108 mph, was applied to structures and found to be less critical than the Operational Basis Earthquake (OBE) load.

8. Tornado

The Reactor Containment, Fuel Handling, and Auxiliary Buildings have been checked to withstand a tornado loading based on a peripheral wind velocity of 300 miles per hour and a translational velocity of 60 mph.

Simultaneous with wind loading, an atmospheric pressure drop of 3 psig for all Class I structures has been considered.

The shape factor, C, for the dome is 0.4 and for the cylinder, 0.5. No gust factor is applied. For additional information on tornado loadings, see Section 3.3.2.

9. Test Pressure

The test pressure for the containment structure is 115 percent of the design pressure or 54 psig.

10. Negative Pressure

Loading from an internal negative pressure of 3.5 psig has been considered. A pressure of this magnitude would result from the combined effects of: cooling of the containment volume 70°F below the temperature at which

3.8.1.4 Design and Analysis Procedures

The containment structure has been analyzed to determine stresses, moments, shear, and deflections due to the static and dynamic loads.

3.8.1.4.1 Static Analysis

The containment structure has been analyzed and designed for all loading conditions combined with load factors as outlined in Section 3.8.1.3.

Mathematically, the dome and cylinder are treated as thin-walled shell structures which result in a membrane analysis. Since the thickness of the dome and cylinder is small in comparison with the radius of curvature (cylinder 1/15.5, dome 1/20), the stress due to pressure and wind or earthquake can be calculated by assuming that they are uniformly distributed across the thickness.

In general, membrane stresses are carried by the reinforcement. Some are carried by the steel liner, but none by the concrete unless they are compressive stresses.

Manual analysis of the containment structure, based on "Theory of Plates and Shells," by Timoshenko and Woinowsky-Krieger (1) and "Theory of Elasticity," by Timoshenko and Goodier (2), have been performed to obtain shears, moments, and stresses within the structure as the basis of our preliminary design for reinforcements and liner plate.

An independent three-dimensional axisymmetric modal analysis using the finite element method was made by Conrad Associates (3) to ascertain that the design of the containment structure was adequate.

The manual shell analyses calculations and the "Conrad Associates" design review report are submitted separately.

The design includes the consideration of both primary and secondary stresses. The design limit for tension members (i.e., the capacity required for the design load) is based upon the yield stress of the reinforcing steel. The load factors used in the design primarily provide for a safety margin on the load assumptions.

The capacity reduction factor "ø" is provided for the possibility that small adverse variations in material strengths, workmanship, dimensions, and control, while individually within required tolerances and the limits of good practice, occasionally may combine to result in under capacity. For tension members, the factor "ø" is established as 0.95. The factor "ø" is 0.90 for flexure and 0.85 for diagonal tension, bond, and anchorage. For the liner steel the factor "ø" is 0.95 for tension, 0.90 for compression and shear.

The detailed design has been reviewed by Conrad Associates' finite element computer program to verify its safety. Stress values for rebars and liner plates at various locations for all loading combinations involving LOCA are given in Tables 3.8-1 through 3.8-10. The designation of main reinforcement pattern for the containment structure is shown on Figures 3.8-14 and 3.8-15.

Seismic reinforcing consists of diagonal bars at 45° to the horizontal plane each way, extended from mat to the lower portion of the dome. They are designed to resist the lateral shear under earthquake such that the horizontal component per foot of diagonals will be equal to the maximum value of the shear flow. Although, in the cylinder, the liner and the concrete have some capacity available to resist the seismic shears, no credit was taken for the capacity. Dowel action of the main bars was also neglected.

The containment structure has also been evaluated for increase in design loads due to the postulated MSLBs. The evaluation shows that for the design of the containment structures LOCA is the governing condition.

condition. Under other cases of critical loading combinations involving LOCA the maximum tensile stress in the liner plate is 27.5 ksi, with 14 percent extra safety margin. The maximum interaction coefficient for biaxial compression and shear in the liner plate under critical load combinations involving LOCA is 0.902 with approximately 10 percent extra safety margin.

The listed stresses in Tables 3.8-1 through 3.8-9 have already taken account of the capacity reduction factors, ø. In other words, the stresses have been divided by the appropriate ø, 0.95 for tension, 0.90 for flexure, and 0.85 for shear, etc.

The combined biaxial compression and shear in the liner plate have been examined by the following interaction formula:

$$\frac{\sigma_x + \sigma_z}{\sigma_{x0} + \sigma_{z0}} + (T/T_0)^2 \leq 1$$

where:

σ_x, σ_z = hoop and meridional stresses in liner plates

σ_{xo}, σ_{z0} = maximum allowable stress in hoop and meridional direction (critical buckling stress or the yield stress)

T = shear stress in the liner plate

T_o = maximum allowable shear stress

The resulting interaction coefficients for Operating, LOCA, and Test conditions are listed in Table 3.8-10.

The containment liner has also been evaluated for the increased containment temperature of 351.3°F and the concurrent pressure due to the postulated MSLBs. The evaluation shows that the liner in the uninsulated portion tends to yield locally at EL.120'-0"; however, the total design forces at this local section can be carried by the containment reinforcing steel alone, without using the liner as a strength element. The corresponding strains in the liner at this section are low relative to the allowable liner strain values specified in Table CC-3720-1 of 1995 ASME B&PV Code, Section III, Division 2 (Reference 6) for maintaining leaktight integrity of the liner. Thus, both strength and leaktight integrity of the containment are assured.

S. B. Batdorf and M. Stein in their paper "Critical Combinations of Shear and Direct Stress for Simply Supported Rectangular Flat Plates" (NACA Technical Note 1223, 1947), obtained the critical stress combination for the case of shear and simultaneous uniaxial compressive stresses as:

$$(\tau/\tau 0)^2 + \sigma/\sigma 0 = 1$$

For biaxial compression, Timoshenko and Gere in their "Theory of Elastic Stability" defined the allowable biaxial compression in the form of:

$$xo + yo = \frac{\pi^2 \ E_h{}^2}{3_a 2_{(1-v)}}$$

Modifying The Batdorf and Stein expression to include the biaxial effect we have used the following equation to check the interaction stability:

$$(\tau/\tau 0)^2 + \frac{(x + y)}{(x0 + y0)} = 1$$

The edge condition was assumed to be simple supported which is more conservative.

Base Mat

In designing the base mat, the slab is considered to be a circular plate of constant thickness, t. The loads are imposed upon the slab by the exterior cylinder wall, the central circular crane wall and, to a lesser degree, by the equipment. The soil reaction pressure was found in a conventional manner by treating the slab, which is 16-feet thick, as a rigid mat.

The mat is then analyzed as a plate subjected to soil pressures and supported by a circular wall symmetrical with respect to the center of the mat. The supporting walls are considered as either simply supporting the mat or partially fixed. The exterior cylinder wall has been considered partially fixing the mat; the crane wall is a simple support.

The containment base mat is analyzed as a rigid circular plate subjected to loadings from the axisymmetric exterior cylinder wall, crane wall, interior walls, and equipment acting around an equivalent circle. The soil pressure is found in a conventional manner without the benefit of its elastic deformation. Manual analysis was based on the ACI Paper, Title No. 63-63, "Analysis of Circular and Annular Slab for Chimney Foundation," by Kuang-Han Chu and Omar F. Afandi. A finite element program was used to check the rebar under five loading combinations. Since the mat is covered by a 2 to 5-foot thick concrete slab, and also the lower 34-feet of cylinder liner is insulated, the thermal effect on the mat has been neglected.

The design of the base mat reinforcement has been reviewed for five load combinations at three different mat sections. The maximum radial, tangential, vertical, and shear stresses at these sections are shown on Figures 3.8-16 through 3.8-20. The stresses shown in these figures are integrated over the thickness of the slab and transformed to forces per unit length of circumference. These forces are then distributed to the top and bottom reinforcing bars at the section under investigation. The resulting stresses in the bars are all under 30 ksi.

The maximum tangential shear under DBE for the interior structure at top of reactor pit is 7600k. The shear is transmitted through the pit wall at Elevation 76 feet and then bearing against the base mat. The unit shear is 73 psi and bearing is 42 psi, both well within allowable values.

Five static load analyses consisting of dead load, buoyancy, internal pressure, thermal, and tornado loadings have been performed for the containment structure. The complete report by Conrad Associates (3) and manual design calculations are kept on file by Public Service Electric & Gas (PSE&G). They are summarized as follows.

Dead Load Analysis

Finite element model is used to perform the dead load analysis. Static secant moduli are used in representing the soil stiffness under dead load. For the vertical load, only horizontal restraints are imposed at side boundaries of the soil system. Stresses, moments, and shears at containment wall and mat are shown on Figures 3.8-21, 3.8-22, and 3.8-23.

Buoyancy Analysis

Normal ground water table for the site is at Elevation 96 feet. For design purpose it is considered to be at 6 inches above the plant grade level, Elevation 99 feet-6 inches. Under hurricane condition the water level could be expected to rise to Elevation 120.4 feet; however, since the direction of the hydrostatic pressure is so small it does not create a critical loading combination.

The result of the buoyancy-induced stresses in the containment vessel are very small and are confined to the lower portion of the structure. No plot is given because it does not affect the design.

Internal Pressure Analysis

The internal pressure transients used for the containment design and its variation with time are shown on Figures 3.8-11 through 3.8-13. For the free volume of 2,620,000 cubic feet within the containment, the design pressure is 47 psig. The maximum temperature at the uninsulated section of the liner under the accident condition is 246°F. For 1.25 times and 1.5 times design pressure loading conditions, the corresponding liner temperatures are 285°F and 306°F, respectively. Static pressure loads are used in design, since the pressure increase is very gradual from the transient curve.

Thermal Analysis

The thermal gradients in the containment wall under operating and accident conditions are shown on Figure 3.8-24. Both loadings are analyzed for the containment structure.

The analytical model employed by Conrad Associates (3) for finite element thermal analysis is an axisymmetric assemblage of solids of revolution. Each segment across the containment wall consists of ten elements to represent the thermal gradient through the wall thickness.

Orthotropic material properties are used to represent the variable shell area in the hoop and meridional directions.

Due to the one-dimensional nature of the reinforcing bars, Poisson's ratio was set equal to zero in the plane of the equivalent steel shell.

For accident loading, the concrete is assumed to be totally cracked in the hoop and meridional directions, but uncracked in the radial direction.

For operating loading, concrete is assumed to be uncracked.

The liner plate is modeled as a thin isotropic steel shell with an elastic modulus of 28,000 ksi and a Poisson's ratio of 0.3. Between the liner plate and the concrete containment shell a thin element, 0.01-feet thick, is introduced to facilitate modeling of the discontinuity in temperature occurring at the liner-to-concrete interface under accident conditions.

A fixed boundary is introduced at the foundation mat. Thermal stresses and strains are not likely to develop in the thick mat which has excellent insulating properties.

Stresses under operating and accidental thermal loadings involving LOCA are shown on Figures 3.8-25 through 3.8-30.

Tornado and Tornado Generated Missile Analysis

Three tornado wind distributions were investigated in the Category I structural design as shown on Figure 3.8-31. In combination with the static forces produced by the 360 mph maximum wind, a 3 psig atmospheric pressure drop was specified for the containment structure.

Evaluations of structural adequacy against tornado wind loads and tornado missiles are given in Sections 3.3.2 and 3.5.2, respectively.

3.8.1.4.2 Dynamic Analysis

The containment structure seismic analysis was performed through (a) lumped mass model manual analysis, using average response spectra ground input, and (b) a finite element modal analysis, using time history ground input. The detailed report from Conrad Associates (3) and the independent manual calculations are kept on file by PSE&G.

The computer analysis yields a slightly higher result in accelerations, shears, and moments in comparison with the manual analysis. The most conservative results are used in design.

The seismic analysis of the containment structure by the finite element method is performed by computer using a step-by-step direction integration procedure. Studies have been made to establish free field soil boundary condition. The model used in the analysis is shown on Figure 3.7-13.

The El Centro ground motion of May 18, 1940, was recommended by Dames and Moore as the most appropriate motion for the site. Its

4. Shielding requirements

5. Design basis accident requirements

6. Flood conditions due to maximum probable hurricane

7. Internal missile generation

The stresses of concrete, reinforcing steel, and liner plate under various loading combinations are as described in Section 3.8.1.4.

The containment integrity evaluation, including the containment pressure transients and safety margin, are presented in Section 15.

3.8.1.5.1 Fracture Prevention of Containment Pressure Boundary

The containment pressure boundary parts, which do not rely on concrete structures to provide the pressure retaining capability, are constructed in accordance with the material, design, fabrication, and installation requirements of the ASME Code, Section III, 1968 Edition. The Code requirements took into consideration procedures for prevention of brittle failures and fracture propagations in containment pressure boundaries. These procedures include Charpy V notch tests of plate materials, sufficient margins in the design allowables, preheat of steel plates, and postweld heat treatment of penetration assemblies.

3.8.1.6 Materials, Quality Control, and Special Construction Techniques

3.8.1.6.1 Liner Plate

A welded steel liner of thicknesses varying from 1/4 inch to 1/2 inch is anchored to the inside face of the concrete shell with

1/2-inch diameter studs to ensure containment leak tightness. This containment liner is designed to carry a portion of the membrane force from the different combinations of loading; however, for conservatism it is not counted on in the resistance to lateral shear.

The out-of-roundness tolerance of the liner shall not exceed plus or minus 2 inches from the true diameter of 140 feet.

The lower 34 feet of cylinder liner is insulated, except locally around liner penetrations and around interferences with other commodities, to prevent buckling of the liner due to restricted growth under a rise in temperature.

The membrane tension and the combined stress of biaxial compression and shear in the liner plate are described in Section 3.8.1.4.1.

Our computations for the liner plate indicate that there would be no inelastic buckling of the plates.

Under stress, the variation in plate thickness would cause small differential movements between the liner and the concrete. Also, the shrinkage cracks in the concrete would have the same result. Soft corks are placed around the studs adjoining the liner plate to allow differential movement between the liner and the concrete.

The stud anchors are designed such that their failure in shear or tension will not break the leak tight integrity of the liner plate. Tests will be made to verify this criterion. Even if stud failure developed, it would be random in nature. This would not impair the liner integrity, nor would it cause progressive failure. The design load per anchor is low, and if an anchor should fail, the load it would have carried would be easily distributed to the adjacent anchor.

Tensile and shear tests were conducted on the liner plate studs. Three tensile and three shear test assemblies approximating as accidental eccentricity. For information concerning the extent to which the internal structure and its walls are capable of withstanding the stresses resulting from the accidental eccentricity, see Section 3.7.

The following structures are removable; provisions have been made to prevent them from becoming missiles.

Hatch covers at Elevation 130 feet

They are 4-foot thick massive concrete blocks bolted down to the slab to withstand any uplift pressure.

Missile shield over Reactor Vessel

It is a concrete slab 17 feet x 17 feet x 1 foot with a 1-inch steel plate at bottom face to stop missiles coming from the reactor vessel head. It is secured to prevent it from becoming a missile.

Lead blocks at Elevation 100 feet in fuel transfer canal area and at Elevation 89 feet-6 inches to 95 feet-10 inches transfer chamber

They are for radiation protection for the gap between containment exterior wall and interior structure. Blocks are held in place by angle frames and steel plates to hold them during earthquake motion.

Hatch cover over fuel transfer chamber at Elevation 100 feet

It is a steel enclosure filled with poured lead. It is laterally restrained, subject to no jet force and could never become a missile.

3.8.4 Other Category I Structures

3.8.4.1 Summary Description

The Category I structures other than the containment structures are listed in Section 3.2. They are Auxiliary Building, Fuel Handling Buildings, Service Water Intake Structure, Class I water tank foundations, and the Class I equipment supports.

The orientation of the principal structures is shown on Figure 3.8-56. The general arrangements of Containment Buildings, Auxiliary Building, and Fuel Handling Buildings are shown in Section 5.

3.8.4.2 Design Codes

Category I structures were designed under the following codes:

1. Building Code Requirements for Reinforced Concrete, ACI 318-63.

2. AISC Manual of Steel Construction, 6th Edition or later edition, as applicable.

3.8.4.3 Loads and Loading Combinations

Loads and load combinations for Category I structures under SSE or tornado conditions are similar to those of the containment except for LOCA pressure and temperature loadings. The working stress design method was used for operating and OBE conditions. (No load factor was used for OBE loadings.) For combination of containment loadings and load symbols, see Section 3.8.1.3.

The safety against sliding, overturning, and flotation for all Category I structures under all loading combinations are within the limits set by the SRP 3.8.5.

Masonry Walls

For the loading criteria for non-structural masonry walls see Section 3.8.4.5.1.

3.8.4.4 Design and Analysis Procedures

The Category I structures have been designed based on ACI 318-63 "Working Stress Design," for normal operating load plus OBE and "Ultimate Strength Design," for normal loads plus DBE or tornado. In the working stress design under OBE the allowable stresses are one-third above the normal applicable code working stresses. Wind stresses are found to be less critical than those generated for an OBE. Load factors of unity have been used in the ultimate design under DBE or tornado loading. The stress of reinforcing steel under ultimate strength design has been kept under 0.9 Fy. The capacity reduction factor "ø" as described in Section 3.8.1.4.1 for concrete stress is applicable for all Category I structures. A coefficient "k" of 0.85 for 3500 psi concrete has been used in addition to "ø" for equivalent rectangular concrete stress distribution.

During the design phase of the reracking which was implemented in 1994, the Spent Fuel Pool was reanalyzed for increased fuel storage capacity. The following is the list of items incorporated in the analysis:

1) The "ultimate strength" design method based on NUREG-0800, Standard Review Plan 3.8.4, Rev. 1, 1981 was used.

2) The plant design spectra, given in Salem UFSAR, for DBE and OBE events were broadened, per provisions of Reg. Guide 1.122 and used.

3) The response spectrum method was used to determine the self-excitation loading on the pool structure.

4) The pool structure was modelled in three dimensions via a 3-D finite element model.

5) The thermal gradient across the pool slab and the pool walls was computed using finite element method. Thus, the effect of interaction between the ambient, pool water, and grade temperatures is fully incorporated in the analysis.

6) The pressure on the lower portion of the wall during a seismic event undergoes a cyclic pulsation due to the hydrodynamic coupling between racks and the pool walls. This loading was quantified using Whole Pool Multi-Rack analysis. This loading was included in the analysis.

7) Analyses have been performed that evaluate the spent fuel pool structure (reinforced concrete as well as the stainless steel liner and its anchors) for a boiling pool condition. The acceptance criteria used for these evaluations was ACI 359 (ASME Code Section III Division 2, Reference 7). The spent fuel pool structure, including the liner and its anchors, was shown to meet all requirements of this code for a boiling pool condition. Analyses were also performed for the spent fuel pool liner and its anchors for a maximum normal pool temperature of 150°F. The liner and its anchors were shown to meet the acceptance criteria of ACI 359. Thermal cycling of the liner and its anchors was evaluated and shown to not be a concern.

Steel members inside the Category I structures are designed in accordance with the AISC Manual of Steel Construction (Sixth Edition or later edition, as applicable).

Seismic design criteria are described in Section 3.7. Tornado and tornado generated missile design is described in Sections 3.3.2 and 3.5.2.

Four independent seismic analyses, similar to those for the Containment Building, have been performed for the 1) Auxiliary Building, 2) Fuel Handling Building, 3) Service Water Intake Structure, and 4) Outer Penetration Building. Conservative results have been utilized for the building design. The time history computer analysis calculations are kept on file with PSE&G. Specifically, the information for the Auxiliary Building and the Fuel Handling Building has been provided in the Reference 3 report, while the information for the Service Water Intake Structure and Outer Penetration Building has been provided in the Reference 5 report.

The loading combinations used for Category I (seismic) steel structures other than containment are as follows:

Working stress design

1. D + L + I + H

   Allowable stresses in accordance with AISC Manual of Steel Construction

2. D + L + I + H + E

   Allowable stresses are one-third above the normal allowable stresse.

Ultimate strength design

1. D + L + I + H + E'

2. D + L + I + H + T

The stress in the ultimate strength design has been kept under 0.9 Fy

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3.8.4.5 Materials, Quality Control, and Special Construction Techniques

3.8.4.5.1 Masonry Walls

There is no masonry block construction in the Containment and Fuel Handling Building. In the Auxiliary Building and penetration area, removable block walls are reinforced with steel bars and also anchored to the slab. These provisions are used to prevent the wall from collapsing under earthquake forces; however, they are not considered as major shear walls to carry the lateral forces for the building.

All of the masonry walls that have been installed within (and between) Category I structures and adjacent to Category I tanks have been re-evaluated for seismic loadings and are found to be within the following two groups:

1. Those walls whose collapse would endanger or affect in any way the safety of any Category I structure

2. Those walls whose collapse would not affect the safety of any Category I structure

A structural analysis has been performed on each of the walls whose collapse would affect any of the Category I structures to determine the shear and bending stresses to assess their margin of safety.

For the re-evaluation and analysis, the masonry wall field testing and inspection, the design for the corrective action, the structural steel reinforcing, and the drawings, see "Report on Re-evaluation of Masonry Walls," dated November 28, 1980, which was submitted to the NRC on December 10, 1980. Corrective actions for those masonry walls which do not meet the NRC criterion (1.33 times allowable ACI shear or tensile stress for mortar when the wall is subjected to out of plane bending during an SSE) are detailed in a PSE&G letter (Liden to Varga) dated December 8, 1982.

3.8.5 Foundations

3.8.5.1 Description

All major Category I structure foundations, except the tank foundations, are built on top of lean concrete fill, which in turn bears on the Vincetown formation at approximately Elevation 30 feet. The actual elevation of top Vincetown was established by visual inspection and additional borings after the excavation was completed. The Service Water Intake Structure was constructed within a steel sheet cofferdam. The material within the cofferdam has been removed down to the Vincetown formation and all the less compact materials on top of the formation were removed and replaced with tremie concrete to the bottom of the mat. The Category I water storage tank foundation is a 3-foot concrete mat serving as the top of a pipe trench. The trench foundation rests on compacted backfill brought up from the top of the lean concrete fill at Elevation 79 feet.

The profile of the principal plant structures, cofferdams, and subsurface formations are shown on Figure 3.8-56. A summary of foundations for plant structures is given in Table 3.8-11.

Seismic separation joints for building foundation mats adjacent to each other are provided to allow independent motion of each building under earthquake conditions.

3.8.5.2 Applicable Codes, Standards, and Specifications

All foundations were designed according to all of the applicable sections of the same codes, standards, and specifications as the buildings and structures which they support. These are listed in Sections 3.8.1.2, 3.8.3.2, and 3.8.4.2.

3.8.5.3 Loads and Load Combinations

All foundations were designed according to all of the applicable loads and load combinations as the buildings and structures which they support. These are listed in Sections 3.8.1.3, 3.8.3.3, and 3.8.4.3.

3.8.5.4 Design and Analysis Procedures

The containment base mat is analyzed as a rigid circular plate subjected to loadings from the axisymmetric exterior cylinder wall, crane wall, interior walls, and equipment acting around an equivalent circle. The soil pressure is found in a conventional manner without the benefit of its elastic formation. Our manual analysis was based on the ACI Paper, Title No. 63-63, "Analysis of Circular and Annular Slab for Chimney Foundation," by Kuang-Han Chu and Omar F. Afandi. A finite element program was used to check the rebar under five loading combinations. Since the mat is covered by 2 to 5-feet thick of concrete slab and also the lower 34 feet of cylinder liner is insulated, the thermal effect on the mat has been neglected.

The Service Water Intake Structure and Category I water tank foundation seismic design has been based on the manual dynamic model analyses using the average response spectra as the ground motion input.

Other Category I structure foundation mats were designed for all loading combinations as described in Section 3.8.4.3.

3.8.6 References for Section 3.8

1. Timoshenko and Woinowsky-Kriegar, "Theory of Plates and Shells," McGraw-Hill, 1959.

2. Timoshenko and Goodier, "Theory of Elasticity," McGraw-Hill, 1951.

3. "Structural Analysis of Containment Vessel - Salem Nuclear Generating Station," Conrad Associates, Van Nuys, California, 1970.

4. Maugh, L. C., "Statically Indeterminate Structures," John Wiley and Sons, New York, New York, 1946.

5. VTD 320237-01, "Design Basis Response Analysis of the Salem Nuclear Generating Station Structures," EQE Final Report, January, 1995.

6. 1995 ASME Boiler & Pressure Vessel Code, Section III, Division 2, Code for Concrete Reactor Pressure Vessels and Containments.

7. ACI 359-95 (ASME Boiler and Pressure Vessel Code Section III Division 2), "Code for Concrete Reactor Vessels and Containments."

TABLE 3.10-1
SUMMARY OF SEISMIC QUALIFICATIONS
FOR SAFETY-RELATED EQUIPMENT

Equipment	Method	Results
Control Console	Test & Dynamic Analysis	Simultaneous Time History Test[1] producing accelerations greater than design basis earthquake (DBE). Test results were acceptable. Accelerations at the device location were determined by T-H dynamic analysis.
Nuclear Instrumentation System Cabinet; Process Control Equipment Cabinets; Solid State Protection Actuation Cabinet	Test Single Axis	Sine Beat Test with electrical funcations of the equipment monitored.
12 KVA (Unit 1) 10 KVA (Unit 2) Vital Bus UPS	Triaxial Multifrequency Random Motion Test	Single axis Sine Sweep Resonance search test in front-to-back, side-to-side, and vertical axes followed by 30 second duration Triaxial Multifrequency Random Motion test. The specimen was subjected to 5 Operating Basis Earthquake (OBE) tests and one Design Basis Earthquake (DBE) test.
Auxiliary Control System Terminal and Relay Cabinets	Test Single Axis	Single axis Sine Sweep Resonance search test in front-to-back, side-to-side, and vertical axes followed by 30 second duration Triaxial Multifrequency Random Motion test. The equipment functioned satisfactorily.

Regulatory Guide 1.8 - PERSONNEL SELECTION AND TRAINING, 9/75 (endorses ANSI-N18.1-1971)

The Salem Station will conform to the Regulatory Guide with the following exceptions:

1. The Operations Manager either shall hold an SRO License, or shall have held an SRO license for a similar unit (PWR), per Amendments 110/89.
2. Licensed Operator qualifications and training shall be in accordance with 10CFR55, per Amendments 136/111.

Qualification requirements for the Nuclear Review Board personnel performing the onsite independent review function and SORC members are described in Section 17.2 of the UFSAR.

Regulatory Guide 1.9 - SELECTION, DESIGN, AND QUALIFICATION OF DIESEL GENERATOR SET CAPACITY FOR STANDBY POWER SUPPLIES

The Salem Station design conforms with the intent of the Regulatory Guide as indicated in Section 8.

Regulatory Guide 1.10 - MECHANICAL (CADWELD) SPLICES IN REINFORCING BARS OF CATEGORY I CONCRETE STRUCTURES

Although NRC Regulatory Guide 1.10 was withdrawn by the NRC on July 21, 1981, SGS commitments, as stated below, are not affected by this withdrawal.

The Salem Station design conforms with the intent of the Regulatory Guide as described in Section 3.8.

Regulatory Guide 1.11 - INSTRUMENT LINES PENETRATING PRIMARY REACTOR CONTAINMENT

The Salem Station design conforms with the intent of Regulatory Guide 1.11 and General Design Criterion (GDC) 55 for instrument lines. Both containment pressure and RVLIS isolation inside containment is provided by a sealed bellows arrangement. The containment pressure bellows are located immediately adjacent to the inside containment wall. The RVLIS bellows are located near the process pressure sources at the RCS hot legs, in the seal table room and in the reactor cavity. Outside containment isolation for containment pressure is provided by the diaphragm in the pressure transmitter connected to the bellows by a sealed, fluid filled tube. Outside containment isolation for RVLIS is provided by sealed, fluid filled isolators that convey RCS pressure to DP transmitters. The justification for these special arrangements results from the importance of containment pressure and RVLIS indication during accident conditions.

Regulatory Guide 1.12 - INSTRUMENTATION FOR EARTHQUAKES

The Salem Station design conforms with the intent of the Regulatory Guide as described in Section 3.7.

Regulatory Guide 1.13 - SPENT FUEL STORAGE FACILITY DESIGN BASIS

The Spent Fuel Cooling System design conforms with the intent of the Regulatory Guide as discussed in Section 9.1. The design of the Fuel Handling System conforms to the recommendations of Regulatory Guide 1.13.

Regulatory Guide 1.14 - REACTOR COOLANT PUMP FLYWHEEL INTEGRITY

The Salem Station design conforms with the intent of the Regulatory Guide.

Regulatory Guide 1.15 - TESTING OF REINFORCING BARS FOR CATEGORY I CONCRETE STRUCTURES

Although NRC Regulatory Guide 1.15 was withdrawn by the NRC on July 21, 1981, SGS commitments, as stated below, are not affected by this withdrawal.

The Salem Station design generally conforms with the intent of the Regulatory Guide as discussed in Section 3.8. However, instead of one full diameter specimen from each bar size tested for each 50 tons, or fraction thereof, of rebar produced from each heat as required by the Regulatory Guide, two specimens for each 25 tons or less of heat have been taken for testing. If any of the four specimens failed to meet the specification, the entire heat was rejected. It is believed that this procedure is as conservative as that of the Regulatory Guide.

Regulatory Guide 1.16 - REPORTING OF OPERATING INFORMATION

Information will be reported as indicated in the Regulatory Guide, with the exception of the information provided in the Monthly Operating Report. The Monthly Operating Report information will be reported as indicated in Generic Letter 97-02.

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For BATCH MODE gaseous releases the quantification of the activity discharged should be based on the sampling of the gas decay tank and all purges prior to discharge.

GASEOUS ABNORMAL RELEASES should be treated as a BATCH mode release, evaluated as they occur, and reported to the NRC isotopically every 6 months. In the event that there are no ABNORMAL RELEASES, the quantity of activity discharged for purposes of reporting to the NRC under the "uniformity" requirements should be based on the monthly vent grab sample for "continuous mode" releases, and on gas decay tank samples and containment purge samples for "batch mode releases." An ABNORMAL RELEASE will be considered to have occurred whenever channel R16, channel 1R41D, or 2R41C is in the alarm state. ABNORMAL RELEASE as defined in 10CFR50.72 for 4-hour reporting requirement is defined as two times the Maximum Permissible Concentration at the site boundary, averaged over 1 hour.

It currently is not feasible to implement those portions of the Regulatory Guide listed in Table 3A-1.

Regulatory Guide 1.22 - PERIODIC TESTING OF PROTECTION SYSTEM ACTUATION FUNCTIONS

The Salem Station Protection System is designed in accordance with IEEE Standard 279-1971. Safety actuation circuitry is provided with a capability for testing with the reactor at power. The protection system design complies with the Regulatory Guide. Under the present design, there are protection functions which are not tested at power. These are described in Section 7. Additionally, the following manual functions are not tested at power:

1. Generation of a reactor trip by tripping the reactor coolant pump breakers

2. Generation of reactor trip by tripping the turbine

TABLE OF CONTENTS (Cont)

TABLE OF CONTENTS (Cont)

TABLE OF CONTENTS (Cont)

LIST OF TABLES

LIST OF TABLES (Cont)

LIST OF FIGURES

LIST OF FIGURES (Cont)

LIST OF FIGURES (Cont)

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SECTION 4

REACTOR

4.1 SUMMARY DESCRIPTION

This chapter describes the following: 1) the mechanical components of the reactor and reactor core including the fuel rods and fuel assemblies, reactor internals, and the control rod drive mechanisms, 2) the nuclear design, and 3) the thermal-hydraulic design.

The reactor core is comprised of an array of fuel assemblies which are similar in mechanical design and fuel enrichment. The Salem Unit 1 and 2 cores may consist of any combination of standard (STD), Vantage 5H, and Vantage+ fuel assemblies as described in Section 4.2.1.2. The most significant difference between the Vantage+ fuel and the others is the application of Zirlo™ cladding, guide thimble and instrument tubes in the Vantage+ fuel design. The Vantage+ fuel assembly is a modification of the NRC-approved Vantage 5H fuel assembly design (Reference 1). A detailed description and evaluation of the Vantage+ features is provided in Reference 2.

The core is cooled and moderated by light water at a pressure of 2250 psia in the Reactor Coolant System. The moderator coolant contains boron as a neutron absorber. The concentration of boron in the coolant is varied as required to control relatively slow reactivity changes including the effects of fuel burnup. Additional boron, in the form of burnable absorber rods and/or IFBAs, may be employed in the core to establish the desired initial reactivity.

Two hundred and sixty-four fuel rods are mechanically joined in a square array to form a fuel assembly. The fuel rods are supported in intervals along their length by grid assemblies which maintain the lateral spacing between the rods throughout the design life of the assembly. The grid assembly consists of an "egg-crate" arrangement of interlocked straps. The straps contain spring fingers and dimples for fuel rod support as well as coolant mixing vanes. The fuel rods consist of slightly enriched uranium dioxide ceramic cylindrical pellets contained in slightly cold worked Zircaloy-4 or Zirlo™ tubing which is plugged and seal welded at the ends to encapsulate the fuel. All fuel rods are pressurized with helium during fabrication to reduce stresses and strains and to increase fatigue life. In addition, the Zirlo^{TM} fuel rods will be oxide coated at the lower end for additional protection against fretting.

The center position in the assembly is reserved for the in-core instrumentation, while the remaining 24 positions in the array are equipped with guide thimbles joined to the grids and the top and bottom nozzles. Depending upon the position of the assembly in the core, the guide thimbles are used as core locations for rod cluster control assemblies, neutron source assemblies, and burnable absorber rods. The remaining guide thimbles may be fitted with plugging devices to limit bypass flow. The use of plugging devices is optional.

The bottom nozzle is a box-like structure which serves as a bottom structural element of the fuel assembly and directs the coolant flow distribution to the assembly.

The top nozzle assembly functions as the upper structural element of the fuel assembly in addition to providing a partial protective housing for the rod cluster control assembly or other core components.

The rod cluster control assemblies each consist of a group of individual absorber rods fastened at the top end to a common hub or spider assembly. These assemblies have rods containing absorber material to control the reactivity of the core under operating conditions.

The control rod drive mechanisms are of the magnetic latch type. The latches are controlled by three magnetic coils. They are so designed that upon a loss of power to the coils, the rod cluster control assembly is released and falls by gravity to shut down the reactor.

The components of the reactor internals are divided into three parts consisting of the lower core support structure (including the entire core barrel and thermal shield), the upper core support structure and the in-core instrumentation support structure. The reactor internals support the core, maintain fuel alignment, limit fuel assembly movement, maintain alignment between the fuel assemblies and control rod drive mechanisms, direct coolant flow past the fuel elements and to the pressure vessel head, provide gamma and neutron shielding, and provide guides for the in-core instrumentation.

The nuclear design analyses and evaluation establish physical locations for control rods and burnable absorbers, and physical parameters such as fuel enrichments and boron concentration in the coolant such that the reactor core has inherent characteristics which, together with corrective actions of the Reactor Control, Protection and Emergency Cooling Systems provide adequate reactivity control even if the highest reactivity worth rod cluster control assembly is stuck in the fully withdrawn position. The design also provides for inherent stability against diametral and azimuthal power oscillations.

The thermal-hydraulic design analyses and evaluation establish coolant flow parameters which assure that adequate heat transfer is assured between the fuel cladding and the reactor coolant. The thermal design takes into account local variations in fuel rod dimensions, power generation, flow distribution, and mixing. The mixing vanes incorporated in the fuel assembly spacer grid design induces additional flow mixing between the various flow channels within a fuel assembly as well as between adjacent assemblies.

Instrumentation is provided in and out of the core to monitor the nuclear, thermal-hydraulic, and mechanical performance of the reactor and to provide inputs to automatic control functions.

The reactor core design together with corrective actions of the Reactor Control, Protection and Emergency Cooling Systems can meet the reactor performance and safety criteria specified in Section 4.2.

To illustrate the effects of the change in fuel design, Table 4.1-1 presents principal nuclear, thermal-hydraulic, and mechanical design parameters for the Salem 17 x 17 STD, Vantage 5H, and Vantage+ fuel assemblies.

The effects of fuel densification were evaluated(1).

The analytical techniques employed in the core design are tabulated in Table 4.1-2. The loading conditions considered in general for the core internals and components are tabulated in Table 4.1-3. Specific or limiting loads considered for design purposes of the various components are listed as follows: fuel assemblies in Section 4.2.1.1.2; reactor internals in Section 4.2.2.3 and Table 5.1-10; neutron absorber rods, burnable absorber rods, neutron source rods, and thimble plug assemblies (if used) in Section 4.2.3.1.3; control rod drive mechanisms in Section 4.2.3.1.4.

4.1.1 Reference for Section 4.1

1. Davidson, S.L. (Ed.), et al., "Vantage 5H Fuel Assembly Reference Core Report," WCAP-10444-P-A and Appendix A, September 1985; Addendum 2-A, March 1986; Addendum 2-A, April 1988.

2. Davidson, S.L., Nuhfer, D.L. (Eds.), "Vantage+ Fuel Assembly Refernece Core Report," WCAP-12610-P-A, April 1995.

3. Hellman, J. M. (Ed.), "Fuel Densification Experimental Results and Model for Reactor Application," WCAP-8218-P-A (Proprietary) and WCAP-8219-A (Nonproprietary), March 1975.

TABLE 4.1-1

THERMAL AND HYDRAULIC DESIGN

Reactor Core Heat Output, MWt	3411	
Reactor Core Heat Output, 10^6 Btu/hr	11,642	
Heat Generated in the Fuel, %	97.4	
Nominal System Pressure, psia	2250	
Assumed Initial System Pressure for DNB Transients, psia	2220 2250	(STDP(1)) (RTDP(2))
Minimum DNBR for Design Transients	STD V-5H(3) V-5H(4)	1.30 (STDP(1)) 1.36 (STDP(1)) 1.24 (RTDP(2))
DNB Correlation	STD V-5H(3)	W-3 "R" Grid WRB-1
Coolant Flow		
Total Thermal Design Flow Rate, 10^6 lb/hr	125.2(5) 127.2(6)	
Effective Flow Rate for Heat Transfer, 10^6 lb/hr	116.2(5) 118.0(6)	
Effective Flow Area for Heat Transfer, ft^2	STD V-5H(3)	51.1 51.3
Average Velocity Along Fuel Rods, ft/sec	STD V-5H(3)	14.2 14.1
Average Mass Velocity, 10^6 lb/hr-ft^2	2.27(5) 2.30(6)	

THERMAL AND HYDRAULIC DESIGN

Coolant Temperature	
Nominal Inlet, °F	543.2[2,5] 530.7[2,6]
Average Rise in Vessel, °F	69.4[2,5] 70.6[2,6]
Average Rise in Core, °F	74.2[2,5] 75.5[2,6]
Average in Core, °F	582.3[2,5] 570.3[2,6]
Average in Vessel, °F	577.9[2,5] 566.0[2,6]
Heat Transfer	
Active Heat Transfer Surface Area, ft^2	59,700
Heat Flux Hot Channel Factor, F_Q	2.40
Average Heat Flux, $Btu/hr\text{-}ft^2$	189,800
Maximum Heat Flux for Normal Operation, $Btu/hr\text{-}ft^2$	455,500
Average Thermal Output, kW/ft	5.45
Maximum Thermal Output for Normal Operation, kW/ft	13.1
Peak Linear Power for Determination of Protection Setpoints, kW/ft	22.0
Peak Fuel Center Temperature at Maximum Thermal Output for Maximum Overpower Trip Point, °F	<4700

TABLE 4.1-1 (Continued)

THERMAL AND HYDRAULIC DESIGN

Fuel Assemblies		
Design	RCC Canless	
Number of Fuel Assemblies	193	
UO_2 Rods per Assembly	264	
Rod Pitch, in	0.496	
Overall Dimension, in	8.426 x 8.426	
Weight of Fuel (as UO_2) in Core, lbs	222,739	
Weight of Zircaloy in Core, lbs	All STD	50913
	All V5H	52541
	All V+	53142
Number of Grids per Assembly	STD	8 Type R (Inconel)
	V5H	2 Type R (Inconel)
		6 Type Z (Zircaloy-4)
	V+	2 Type R (Inconel)
		6 Type Z (Zirlo^{TM})
Loading Technique	3 Region Non-uniform	
Fuel Rods		
Number in Core	50,952	
Outside Diameter, in	0.374	
Diametral Gap, in	0.0065	
Clad Thickness, in	0.0225	
Clad Material	STD, V5H	Zircaloy-4
	V+	Zirlo^{TM}

TABLE 4.1-1 (Continued)

THERMAL AND HYDRAULIC DESIGN

Fuel Pellets		
Material	UO_2 Sintered	
Density, % of Theoretical	95	
Diameter, in	0.3225	
Length, in	STD	0.530
	V-5H(3)	0.370
Rod Cluster Control Assemblies		
Neutron Absorber	Ag-In-Cd	
Cladding Material	Type 316L Ionnitride Surface	
Clad Thickness, in	0.0185	
Number of Clusters	53	
Number of Absorbers per Cluster	24	
Core Structure		
Core Barrel, ID / OD, in	148.0 / 152.5	
Thermal Shield, ID / OD, in	158.5 / 164.0	
Nuclear Design Parameters:		
Structure Characteristics		
Core Diameter, in (Equivalent)	132.7	
Core Average Active Fuel Height, in	143.7	

TABLE 4.1-1 (Continued)

THERMAL AND HYDRAULIC DESIGN

Reflector Thickness and Composition	
Top - Water Plus Steel, in	~10
Bottom - Water Plus Steel, in	~10
Side - Water Plus Steel, in	~15
H_2O/U, Molecular Ratio, Lattice (cold)	2.41

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(1) Standard Thermal Design Procedure.

(2) Revised Thermal Design Procedure.

(3) Also valid for V+ assemblies without Intermediate Flow Mixing Vanes.

(4) To offset the effects of rod bow and provide some generic margin, this has been conservatively increased to a DNBR Safety Limit value of 1.34 for typical channels and 1.33 for thimble channels.

(5) For analyses where high average core temperature is bounding.

(6) For analyses where low average core temperature is bounding.

TABLE 4.1-2

ANALYTIC TECHNIQUES IN CORE DESIGN

Analysis	Technique	Computer Code	Section Referenced
Mechanical Design of Core Internals			
Loads, Deflections, and Stress Analysis	Static and Dynamic Modeling	Blowdown code, FORCE, Finite element structural analysis code, and others	
Fuel Rod Design			
Fuel Performance Characteristics (temperature, internal pressure, clad stress, etc.)	Semi-empirical thermal model of fuel rod with consideration of fuel density changes, heat transfer, fission gas release, etc.	Westinghouse fuel rod design model	4.2.1.3.1 4.3.3.1 4.4.2.2 4.4.3.4.2
Nuclear Design			
1) Cross Sections and Group Constants	Microscopic data	Modified ENDF/B library	4.3.3.2
	Macroscopic constants for homogenized core regions	LEOPARD/CINDER type or PHOENIX-P	4.3.3.2
	Group constants for control rods with self-shielding	HAMMER-AIM or PHOENIX-P	4.3.3.2
2) X-Y and X-Y-Z Power Distributions, Fuel Depletion, Critical Boron Concentrations, x-y and X-Y-Z Xenon Distributions, Reactivity Coefficients	2-Group Diffusion Theory	TURTLE (2-D) or ANC(2-D or 3-D)	4.3.3.3
3) Axial Power Distributions Control Rod Worths, and Axial Xenon Distribution	1-D, 2-Group Diffusion Theory	PANDA or APOLLO	4.3.3.3

4.2 MECHANICAL DESIGN

The plant conditions for design are divided into four categories in accordance with their anticipated frequency of occurrence and risk to the public: Condition I - Normal Operation; Condition II - Incidents of Moderate Frequency; Condition III - Infrequent Incidents; Condition IV - Limiting Faults.

The reactor is designed so that its components meet the following performance and safety criteria:

1. The mechanical design of the reactor core components and their physical arrangement, together with corrective actions of the Reactor Control, Protection, and Emergency Cooling Systems (when applicable) assure that:

   a. Fuel damage* is not expected during Condition I and Condition II events. It is not possible, however, to preclude a very small number of rod failures. These are within the capability of the Plant Cleanup System and are consistent with the plant design bases.

   b. The reactor can be brought to a safe state following a Condition III event with only a small fraction of fuel rods damaged* although sufficient fuel damage might occur to preclude resumption of operation without considerable outage time.

   c. The reactor can be brought to a safe state and the core can be kept subcritical with acceptable heat transfer geometry following transients arising from Condition IV events.

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* Fuel damage as used here is defined as penetration of the fission product barrier (i.e., the fuel rod clad).

2. The fuel assemblies are designed to accommodate expected conditions for design for handling during assembly inspection and refueling operations and shipping loads.

3. The fuel assemblies are designed to accept control rod insertions in order to provide the required reactivity control for power operations and reactivity shutdown conditions.

4. All fuel assemblies have provisions for the insertion of in-core instrumentation necessary for plant operation.

5. The reactor internals, in conjunction with the fuel assemblies, direct reactor coolant through the core to achieve acceptable flow distribution and to restrict bypass flow so that the heat transfer performance requirements can be met for all modes of operation. In addition, the internals provide core support and distribute coolant flow to the pressure vessel head so that the temperature differences between the vessel flange and head do not result in leakage from the flange during the Condition I and II modes of operation. Required inservice inspection can be carried out as the internals are removable and provide access to the inside of the pressure vessel.

4.2.1 Fuel

4.2.1.1 Design Bases

The fuel rod and fuel assembly design bases are established to satisfy the general performance and safety criteria presented in Section 4.2 and specific criteria noted below. The same design bases apply to the 17 x 17 standard (STD), 17 x 17 Vantage 5H and 17 x 17 Vantage+ fuel assemblies.

4.2.1.1.1 Fuel Rods

The integrity of the fuel rods is ensured by designing to prevent excessive fuel temperatures, excessive internal rod gas pressures due to fission gas releases, and excessive cladding stresses and strains. This is achieved by designing the fuel rods so that the following conservative design bases are satisfied during Condition I and Condition II events over the fuel lifetime:

1. Fuel Pellet Temperatures - The center temperature of the hottest pellet is to be below the melting temperature of the UO_2 (melting point of 5080°F(1) unirradiated and reducing by 58°F per 10,000 MWD/MTU). While a limited amount of center melting can be tolerated, the design conservatively precludes center melting. A calculated centerline fuel temperature of 4700°F has been selected as an overpower limit to assure no fuel melting. This provides sufficient margin for uncertainties, as described in Sections 4.4.1.2 and 4.4.2.10.1.

2. Internal Gas Pressure - The internal gas pressure of the lead rod in the reactor will be limited to a value below that which would cause (a) the diametral gap to increase due to outward clad creep during steady-state operation, and (b) extensive departure from nucleate boiling (DNB) propagation to occur.

3. Clad Stress - The effective clad stresses are less than that which would cause general yield of the clad. While the clad has some capability for accommodating plastic strain, the yield strength has been accepted as a conservative design basis.

4. Clad Tensile Strain - The clad tangential strain range is less than one percent. The clad strain design basis addresses slow transient strain rate mechanisms where the clad effective stress never reaches the yield

strength due to stress relaxation. The 1 percent strain limit has been established based upon tensile and burst test data from irradiated clad. Irradiated clad properties are appropriate due to irradiation effects on clad ductility occurring before strain-limiting fuel clad interaction during a transient event can occur.

5. Strain Fatigue - The cumulative strain fatigue cycles are less than the design strain fatigue life. This basis is consistent with proven practice.

Radial, tangential, and axial stress components due to pressure differential and fuel clad contact pressure are combined into an effective stress using the maximum-distortion-energy theory. The von Mises' criterion is used to evaluate if the yield strength has been exceeded. The von Mises' criterion states that an isotropic material under multiaxial stress will begin to yield plastically when the effective stress (i.e., combined stress using maximum-distortion-energy theory) becomes equal to the material yield stress in simple tension as determined by an uniaxial tensile test. Since general yielding is to be prohibited, the volume average effective stress determined by integrating across the clad thickness increased by an allowance for local nonuniformity effects before it is compared to the yield strength. The yield strength correlation is that appropriate for irradiated clad since the irradiated properties are attained at low exposure whereas the fuel/clad interaction conditions which can lead to minimum margin to the design basis limit always occurs at much higher exposure.

The detailed fuel rod design established such parameters as pellet size and density, clad-pellet diametral gap, gas plenum size, and helium pressure. The design also considers effects such as fuel density changes, fission gas release, clad creep, and other physical properties which vary with burnup.

Irradiation testing and fuel operational experience has verified the adequacy of the fuel performance and design bases. This experience and testing are discussed in References 2 and 3. Fuel experience and testing results, as they become available, are used to improve fuel rod design and manfacturing processes and assure that the design bases and safety criteria are satisfied.

The safety evaluation of the fuel rod internal pressure design basis is presented in Reference 4.

4.2.1.1.2 Fuel Assembly Structure

Structural integrity of the fuel assemblies is assured by setting limits on stresses and deformations due to various loads and by determining that the assemblies do not interfere with the functioning of other components. Three types of loads are considered.

1. Nonoperational loads such as those due to shipping and handling

2. Normal and abnormal loads which are defined for Conditions I and II

3. Abnormal loads which are defined for Conditions III and IV.

These criteria are applied to the design and evaluation of the top and bottom nozzles, the guide thimbles, the grids, and the thimble joints.

The design bases for evaluating the structural integrity of the fuel assemblies are:

1. Nonoperational 4g axial and 6g lateral loading with dimensional stability.

2. Normal Operation (Condition I) and Incidents Moderate Frequency (Condition II).

   For the normal operating (Condition I) and upset conditions (Condition II), the fuel assembly component structural design criteria are classified into two material categories, namely, austenitic steels and Zircaloy. The stress categories and strength theory presented in the ASME Boiler and Pressure Vessel Code, Section III, are used as a general guide. The maximum shear-theory (Tresca criterion) for combined stresses is used to determine the stress intensities for the austenitic steel components. The stress intensity is defined as the numerically largest difference between the various principal stresses in a three-dimensional field. The allowable stress intensity value for austenitic steels, such as nickel-chromium-iron alloys, is given by the lowest of the following:

   a. 1/3 of the specific minimum tensile strength or 2/3 of the specified minimum yield strength at room temperature

   b. 1/3 of the tensile strength or 90 percent of the yield strength at temperature but not to exceed 2/3 of the specified minimum yield strength at room temperature.

The stress limits for the austenitic steel components follow:

Stress Intensity Limits

Categories	Limit
General Primary Membrane Stress Intensity	Sm
Local Primary Membrane Stress Intensity	1.5 Sm
Primary Membrane plus Bending Stress Intensity	1.5 Sm
Total Primary plus Secondary Stress Intensity	3.0 Sm

The Zircaloy and ZIRLO^{TM} structural components which consist of guide thimble and fuel tubes are in turn subdivided into two categories because of material differences and functional requirements. The fuel tube design criteria are covered separately in Section 4.2.1.1.1. The maximum stress theory is used to evaluate the guide thimble design. The maximum stress theory assumes that yielding due to combined stresses occur where one of the principal stresses are equal to the simple tensile or compressive yield stress. The Zircaloy and ZIRLO^{TM} unirradiated properties are used to define the stress limits.

Abnormal loads during Conditions III and IV - worst case represented by combined seismic and blowdown loads.

1. Deflections of components cannot interfere with the reactor shutdown or emergency cooling of the fuel rods.

2. The fuel assembly component stresses under faulted conditions are evaluated using primarily the methods outlined in Appendix F of the ASME Pressure Vessel Code Section 3. Since the current analytical methods utilize elastic analysis, the stress allowables are defined as the smaller value of 2.4 Sm or 0.70 Su for primary membrane and 3.6 Sm or 1.05 Su for primary membrane plus primary bending. For the austenitic steel fuel assembly components, the stress intensity is defined in

accordance with the rules described in the previous section for normal operating conditions. For the Zircaloy and ZIRLO™ components the stress limits are set at two-thirds of the material yield strength, Sy, at reactor operating temperature. This results in Zircaloy stress intensity limits being the smaller of 1.6 Sy or 0.70 Su for primary membrane and 2.4 Sy or 1.05 Su for primary membrane plus bending. For conservative purposes, the Zircaloy and ZIRLO™ unirradiated properties are used to define the stress limits. The grid component strength criteria are based on experimental tests. The grid component strength criterion is based on the lower 95 percent confidence level on the true mean from distribution of grid crush strength data at temperature.

4.2.1.2 Design Description

Fuel assembly and fuel rod design data are given in Table 4.3-1. Two hundred sixty-four fuel rods, twenty-four guide thimble tubes, and one instrumentation thimble tube are arranged within a supporting structure to form a fuel assembly. The instrumentation thimble is located in the center position and provides a channel for insertion of an in-core neutron detector if the fuel assembly is located in an instrument core position. The guide thimbles provide channels for insertion of either a rod cluster control assembly, a neutron source assembly, a burnable absorber assembly or a plugging device (if used), depending on the position of the particular fuel assembly in the core. Figure 4.2-1 shows a cross section of a fuel assembly array, and Figure 4.2-2 shows a standard fuel assembly full length view. The fuel rods are loaded into the fuel assembly structure so that there is clearance between the fuel rod ends and the top and bottom nozzles.

The Vantage 5H fuel assembly design is shown in Figure 4.2-2a. The design changes from the 17 x 17 STD design to the Vantage 5H design include reduced guide thimble and instrumentation tube diameters, and replacement of the six intermediate (mixing vane) Iconel grids with Zircaloy grids. The debris filter bottom nozzle (DFBN) design has been incorporated into the Vantage 5H fuel assembly. The DFBN is similar to the standard bottom nozzle design except that it is thinner and has a new pattern of smaller flow holes. The DFBN helps to minimize passage of debris particles that could cause fretting damage to fuel rod cladding.

The Vantage+ assembly skeleton is identical to that previously described for Vantage 5H except for those modifications necessary to accommodate intended fuel operation to higher burnup levels. The Vantage+ assembly skeleton is made of low cobalt material and the spring height is slightly increased for the reduction in fuel assembly height. The modifications consist of the use of ZIRLO™ guide thimbles as necessary, and small skeleton dimensional alterations to provide additional fuel assembly and rod growth space at the extended burnup levels. The Vantage+ fuel assembly is 0.200 inch shorter than the Vantage 5H assembly. The grid centerline elevations of the Vantage+ are identical to those of the Vantage 5H assembly, except for the top grid. The Vantage+ top grid has been moved down by the same 0.200 inch. However, since the Vantage+ fuel is intended to replace either the Westinghouse LOPAR or the Vantage 5H, the Vantage+ exterior assembly envelope is equivalent in design dimensions, and the functional interface with the reactor internals is also equivalent to those of previous Westinghouse fuel designs. Also, the Vantage+ fuel assembly is designed to be mechanically and hydraulically compatible with the LOPAR and Vantage 5H, and the same functional requirements and design criteria as previously established for the Westinghouse Vantage 5H fuel assembly remain valid for the Vantage+ fuel assembly (Reference 18). The Vantage+ fuel assembly design parameters are provided in Table 4.1-1. Figure 4.2-2A compares the Vantage+ and the Vantage 5H fuel assembly designs.

Each fuel assembly is installed vertically in the reactor vessel and stands upright on the lower core plate, which is fitted with alignment pins to locate and orient the assembly. After all fuel assemblies are set in place, the upper support structure is installed. Alignment pins, built into the upper core plate, engage and locate the upper ends of the fuel assemblies. The upper core plate then bears downward against the fuel assembly top nozzle via the holddown springs to hold the fuel assemblies in place.

4.2.1.2.1 Fuel Rods

The Vantage+ fuel rod represents a modification to the Vantage 5H fuel rod in cladding of ZIRLO™ as compared to Zircaloy-4. ZIRLO™ is a zirconium alloy similar to Zircaloy-4, which has been specifically developed to enhance corrosion resistance. The Vantage 5H and Vantage+ fuel rods contain enriched uranium dioxide fuel pellets, and Integral Fuel Burnable Absorber (IFBA) coating on some of the fuel pellets. Schematics of the fuel rods are shown in Figures 4.2-3 and 4.2-3A.

The Vantage+ fuel rod has the same wall thickness as the Vantage 5H. The Vantage+ fuel rod length is shorter to provide the required fuel rod growth room. To offset the reduction in plenum length the Vantage+ fuel rod has a variable pitch plenum spring. The variable pitch plenum spring provides the same support as the Vantage 5H plenum spring, but with less spring turns which means less spring volume. The bottom end plug has an internal grip feature to facilitate rod loading on both designs (Vantage+ and Vantage 5H) and provides appropriate lead-in for the removable top nozzle reconstitution feature. The Salem Vantage+ fuel rod also has an oxide coating at the bottom end. The extra layer of oxide coating provides additional rod fretting wear protection.

The Salem Vantage 5H and Vantage+ fuel uses a standardized fuel pellet design which is a refinement to the chamfered pellet design. The standard design helps to improve manufacturability while maintaining or improving performance (e.g., improved pellet chip resistance during manufacturing and handling).

The Vantage 5H and Vantage+ IFBA coated fuel pellets are identical to the enriched uranium dioxide pellets except for the addition of a thin boride coating on the pellet cylindrical surface. Coated pellets occupy the central portion of the fuel column. The number and pattern of IFBA rods within an assembly vary depending on specific application. The ends of the coated and uncoated pellets are dished to allow for greater axial expansion at the pellet centerline and void volume for fission gas release.

To avoid overstressing of the cladding or seal welds, void volume and clearances are provided within the rods to accommodate fission gases released from the fuel, differential thermal expansion between the cladding and the fuel, and fuel density changes during burnup. Shifting the fuel within the cladding during handling or shipping prior to core loading is prevented by a stainless steel helical spring which bears on top of the fuel. At assembly the pellets are stacked in the cladding to the required fuel height, the spring is then inserted into the top end of the fuel tube and the end plugs pressed into the ends of the tube and welded. All fuel rods are internally pressurized with helium during the welding process in order to minimize compressive clad stresses and creep due to coolant operating pressures. Fuel rod pressurization is dependent on the planned fuel burnup as well as other fuel design parameters and fuel characteristics (particularly densification potential).

4.2.1.2.2 Fuel Assembly Structure

The fuel assembly structure consists of a bottom nozzle, top nozzle, guide thimbles, and grids, as shown on Figures 4.2-2 and 4.2-2A.

Bottom Nozzle

The bottom nozzle is a box-like structure which serves as a bottom structural element of the fuel assembly and directs the coolant flow distribution to the assembly. The square nozzle is fabricated from Type 304 stainless steel and consists of a perforated plate and four angle legs with bearing plates as shown on Figure 4.2-2. The legs form a plenum for the inlet coolant flow to the fuel assembly. The plate itself acts to prevent a downward ejection of the fuel rods from the fuel assembly. The bottom nozzle is fastened to the fuel assembly guide tubes by locked screws which penetrate through the nozzle and mate with an inside fitting in each guide tube.

The debris filter bottom nozzle (DFBN) design has been introduced into the Salem fuel assemblies to help reduce the possibility of fuel rod damage due to debris-induced fretting. The Vantage+ fuel assembly has a low cobalt stainless steel DFBN. The DFBN design incorporates a modified flow hole size and pattern, as described below, and a decreased nozzle height and thinner top plate to accommodate the high burnup fuel rods. The DFBN retains the design reconstitution feature which facilitates easy removal of the nozzle from the fuel assembly.

The relatively large flow holes in a conventional bottom nozzle are replaced with a new pattern of smaller flow holes in the DFBN. The holes are sized to minimize passage of debris particles large enough to cause damage. The holes were also sized to provide sufficient flow area, comparable pressure drops, and continued structural integrity of the nozzle. Tests to measure pressure drop and demonstrate structural integrity have been performed to verify that the DFBN is totally compatible with the current design.

Coolant flow through the fuel assembly is directed from the plenum in the bottom nozzle upward through the penetrations in the plate to the channels between the fuel rods. The penetrations in the plate are positioned between the rows of the fuel rods.

Axial loads (holddown) imposed on the fuel assembly and the weight of the fuel assembly are transmitted through the bottom nozzle to the lower core plate. Indexing and positioning of the fuel assembly is controlled by alignment holes in two diagonally opposite bearing plates which mate with locating pins in the lower core plate. Any lateral loads on the fuel assembly are transmitted to the lower core plate through the locating pins.

Top Nozzle

The top nozzle assembly functions as the upper structural element of the fuel assembly in addition to providing a partial protective housing for the rod cluster control assembly or other components. It consists of an adapter plate, enclosure, top plate, and pads. The integral welded assembly has holddown springs mounted on the assembly as shown on Figure 4.2-2. The springs and bolts are made of Inconel 718 and Inconel 600, respectively, whereas other components are made of Type 304 stainless steel.

Vantage+ and Vantage 5H fuel assemblies use the reconstitutable top nozzle (RTN). The RTN design for the Vantage 5H fuel assembly differs from the conventional design in two ways: 1) a groove is provided in each thimble thru-hole in the nozzle plate to facilitate attachment and removal, and; 2) the nozzle plate thickness is reduced to provide additional axial space for fuel rod growth. Additional details of this design feature, the design bases and evaluation of the reconstitutable top nozzle are given in Section 2.3.2 in Reference 15.

The square adapter plate is provided with round and obround penetrations to permit the flow of coolant upward through the top nozzle. Other round holes are provided to accept sleeves which are welded to the adapter plate and mechanically attached to the thimble tubes. The ligaments in the plate cover the tops of the fuel rods and prevent their upward ejection from the fuel assembly. The enclosure is a sheet metal shroud which sets the distance between the adapter plate and the top plate. The top plate has a large square hole in the center to permit access for the control rods and the control rod spiders. Holddown springs are mounted on the top plate and are fastened in place by bolts and clamps located at two diagonally opposite corners. On the other two corners, integral pads are positioned which contain alignment holes for locating the upper end of the fuel assembly.

Guide and Instrument Thimbles

The guide thimbles are structural members which also provide channels for the neutron absorber rods, burnable poison rods, or neutron source assemblies. Each one is fabricated from Zircaloy-4 or ZIRLO™ tubing having two different diameters. The larger diameter at the top provides a relatively large annular area to permit rapid insertion of the control rods during a reactor trip as well as to accommodate the flow of coolant during normal operation. Four holes are provided on the thimble tube above the dashpot to reduce the rod drop time. The lower portion of the guide thimbles has a reduced diameter to produce a dashpot action near the end of the control rod travel during normal operation and to accommodate the outflow of water from the dashpot during a reactor trip. The dashpot is closed at the bottom by means of an end plug which is provided with a small flow port to avoid fluid stagnation in the dashpot volume during normal operation. The top end of the guide thimble is fastened to a tubular insert by three expansion swages. The insert engages into the top nozzle and is secured into position by the lock tube. The lower end of the guide thimble is fitted with an end plug which is then fastened into the bottom nozzle by a locked screw.

Fuel rod support grids are fastened to the guide thimble assemblies to create an integrated structure. Since welding of the Inconel grid and Zircaloy thimble is not possible, the fastening technique depicted on Figures 4.2-5 and 4.2-9 is used for all but the top and bottom grids in a fuel assembly.

An expanding tool is inserted into the inner diameter of the Zircaloy or Zirlo^{TM} thimble tube to the elevation of the zircaloy sleeves that have been welded to the Zircaloy middle grid assemblies. The four-lobed tool forces the thimble and sleeve outward to a predetermined diameter, thus joining the two components.

The top grid-to-thimble attachment for the Vantage 5H and Vantage+ assemblies is shown on Figure 4.2-7. The Zircaloy or ZIRLO^{TM} thimbles are fastened to the top nozzle inserts by expanding the members as shown on Figure 4.2-7. The inserts then engage the top nozzle and are secured into position by the insertion of lock tubes.

The bottom grid assembly is joined to the STD or Vantage 5H assembly as shown on Figure 4.2-11. The stainless steel insert is spotwelded to the bottom grid and later captured between the guide thimble end plug and the bottom nozzle by means of a stainless steel thimble screw.

The described methods of grid fastening are standard and have been used successfully since the introduction of Zircaloy guide thimbles in 1969.

The central instrumentation thimble of each fuel assembly is constrained by seating in counterbores in each nozzle. This tube is a constant diameter and guides the incore neutron detectors. This thimble is expanded at the top and mid grids in the same manner as the previously discussed expansion of the guide thimbles to the grids.

With the exception of an increased length above the dashpot, the Vantage+ guide thimbles are identical to those in the Vantage 5H design. The Vantage+ and Vantage 5H guide thimble ID provides adequate clearance for the control rods and sufficient diametral clearance for burnable absorber rods and source rods.

The Vantage+ and Vantage 5H instrumentation tube diameter has sufficient diametral clearance for the flux thimble to traverse the tube without binding.

Grid Assemblies

The fuel rods, as shown on Figures 4.2-2 and 4.2-2A, are supported laterally at intervals along their length by grid assemblies which maintain the lateral spacing between the rods throughout the design life of the assembly. Each fuel rod is afforded lateral support at six contact points within each grid by the combination of support dimples and springs. The grid assembly consists of individual slotted straps interlocked and welded in an "egg-crate" arrangement to join the straps permanently at their points of intersection. The straps contain spring fingers, support dimples, and mixing vanes.

The grid material of the Vantage+ fuel assembly is Zirlo^{TM} (mid-grids) and Inconel 718 (end-grids). The magnitude of the grid restraining force on the fuel rod is set high enough to minimize possible fretting, without overstressing the cladding at the points of contact between the grids and fuel rods. The grid assemblies also allow axial thermal expansion of the fuel rods without imposing restraint sufficient to develop buckling or distortion of the fuel rods.

Two types of grid assemblies are used in each fuel assembly. One type, with mixing vanes projecting from the edges of the straps into the coolant stream, is used in the high heat flux region of the fuel assemblies to promote mixing of the coolant. The other type, located at the ends the assembly, does not contain mixing vanes on the internal straps. The outside straps on all grids contain mixing vanes which, in addition to their mixing function, aid in guiding the grids and fuel assemblies past projecting surfaces during handling or during loading and unloading of the core.

During 1989, snag-resistant grids were introduced. These grids contain outer grid straps which are modified to help prevent assembly hangup from grid strap interference during fuel assembly removal. This was accomplished by changing the grid strap corner geometry and the addition of guide tabs on the outer grid strap.

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4.2.1.3 Design Evaluation

4.2.1.3.1 Fuel Rods

The fuel rods are designed to assure the design bases are satisfied for Condition I and II events. This assures that the fuel performed, and safety criteria (Section 4.2.1.1) are satisfied.

Materials - Fuel Cladding

The desired fuel rod cladding is a material which has a superior combination of neutron economy (low absorption cross section), high strength (to resist deformation due to differential pressures and mechanical interaction between fuel and clad), high corrosion resistance (to coolant, fuel, and fission products), and high reliability. Zircaloy-4 and ZIRLO™ have this desired combination of cladding properties. There is considerable pressurized water reactor (PWR) operating experience on the capability of Zircaloy as a cladding material (2). Clad hydriding has not been a significant cause of clad perforation since current controls on fuel-contained moisture levels were instituted.

Metallographic examination of irradiated commercial fuel rods have shown occurrences of fuel/clad chemical interaction. Reaction layers of <1 mil in thickness have been observed between fuel and clad at limited points around the circumference. Westinghouse metallographic data indicates that this interface layer remains very thin even at high burnup. Thus, there is no indication of propagation of the layer and eventual clad penetration.

Stress corrosion cracking is another postulated phenomenon related to fuel/clad chemical interaction. Out-of-reactor tests have shown that in the presence of high clad tensile stress, relatively large concentrations of iodine, or cadmium in solution in liquid cesium can stress corrode zirconium alloy tubing and lead to eventual clad cracking. Extensive post irradiation examination has

3. Internal pressure as a function of fission gas release, rod geometry, and temperature distribution

These effects are evaluated using an overall fuel rod design model (References 5, 6, 17) which include appropriate modifications for time dependent fuel densification. With these interacting factors considered, the model determines the fuel rod performance characteristics for a given rod geometry, power history, and axial power shape. In particular, internal gas pressure, fuel and cladding temperatures, and cladding deflections are calculated. The fuel rod is divided lengthwise into several sections and radially into a number of annular zones. Fuel density changes, cladding stresses, strains and deformations, and fission gas releases are calculated separately for each segment. The effects are integrated to obtain the internal rod pressure. The initial rod internal pressure is selected to delay fuel/clad mechanical interaction and to avoid the potential for flattened rod formation. Clad flattening for Salem Nuclear Generating Station (SNGS) fuel is evaluated using the models described (7).

The gap conductance between the pellet surface and the cladding inner diameter is calculated as a function of the composition, temperature, and pressure of the gas mixture, and the gap size or contact pressure between clad and pellet. After computing the fuel temperature of each pellet annular zone, the fractional fission gas release is assessed using an empirical model derived from experimental data (5) (17). The total amount of gas released is based on the average fractional release within each axial and radial zone and the gas generation rate which, in turn, is a function of burnup. Finally, the gas released is summed over all zones and the pressure is calculated.

The model shows good agreement in fit for a variety of published and proprietary data on fission gas release, fuel temperatures, and clad deflections (5) (17). Included in this spectrum are variations in power, time, fuel density, and geometry. The in-pile fuel temperature measurements' comparisons used are shown in References 5 and 17.

Typical fuel clad inner diameter and the fuel pellet outer diameter as a function of exposure are presented on Figure 4.2-4. The cycle-to-cycle changes in the pellet outer diameter represent the effects of power changes as the fuel is moved into different positions as a result of refueling. The gap size at any time is merely the difference between clad inner diameter and pellet outer diameter. Total clad-pellet surface contact occurs near the end of Cycle 2. The figure represents hot fuel dimensions for a fuel rod operating at the power level shown on Figure 4.2-6. Figure 4.2-6 illustrates representative fuel rod internal gas pressure and linear power for the lead burnup rod vs. irradiation time. In addition, it outlines the typical operating range of internal gas pressures which is applicable to the total fuel rod population within a region. The "best estimate" fission gas release model was used in determining the internal gas pressures as a function of irradiation time.

The clad stresses at a constant local fuel rod power are low. Compressive stresses are created by the pressure differential between the coolant pressure and the rod internal gas pressure. Because of the prepressurization with helium, the volume average effective stresses are always less than ~10,000 psi at the pressurization level used in this fuel rod design. Stresses due to the temperature gradient are not included in this average effective stress because thermal stresses are, in general, negative at the clad inner diameter and positive at the clad outer diameter and their contribution to the clad volume average stress is small. Furthermore, the thermal stress decreases with time during steady-state operation due to stress relaxation. The stress due to pressure differential is highest in the minimum power rod at the beginning of life (BOL) (due to low internal gas pressure) and the thermal stress is highest in the maximum power rod (due to steep temperature gradient).

Both hydrided and nonhydrided Zircaloy-4 cladding were tested.

2. A biaxial fatigue experiment in gas autoclave on unirradiated Zircaloy-4 cladding both hydrided and nonhydrided.

3. A fatigue test program on irradiated cladding from the CVTR and Yankee Core V conducted at Battelle Memorial Institute.

The results of these test programs provided information of different cladding conditions including the effect of irradiation, hydrogen level, and temperature.

The Westinghouse design equations followed the concept for the fatigue design criterion according to Section 3 of the ASME Boiler and Pressure Vessel code; namely:

1. The calculated pseudo-stress amplitude (S_a) has to be multiplied by a factor of 2 in order to obtain the allowable number of cycles (N_f).

2. The allowable cycles for a given S_a is 5 percent of N_f, or a safety factor of 20 on cycles.

The lesser of the two allowable number of cycles is selected. The cumulative fatigue life fraction is then computed as:

$$\sum_{1}^{k} \frac{n_k}{N_{fk}} \leq 1$$

where: n_k = number of diurnal cycles of mode k.

The potential effects of operation with waterlogged fuel are discussed in Section 4.4.3.6. Waterlogging is not considered to be a concern during operational transients.

4.2.1.3.2 Fuel Assembly Structure

Stresses and Deflections

The potential sources of high stresses in the assembly are avoided by the design. For example, stresses in the fuel rod due to thermal expansion and Zircaloy or ZIRLO™ irradiation growth are limited by the relative motion of the rod as it slips over the grid spring and dimple surfaces. Clearances between the fuel rod ends and nozzles are provided so that Zircaloy or ZIRLO™ irradiation growth will not result in end interferences. As another example, stresses due to holddown springs in opposition to the hydraulic lift force are limited by the deflection characteristic of the springs. Stresses in the fuel assembly caused by tripping of the rod cluster control assembly have little influence on fatigue because of the small number of events during the life of an assembly. Welded joints in the fuel assembly structure are considered in the structural analysis of the assembly. Appropriate material properties of welds are used to ensure the design bases are met. Assembly components and prototype fuel assemblies made from production parts have been subjected to structural tests to verify that the design bases requirements are met.

The fuel assembly design loads for shipping have been established at 4 g axial and 6 g lateral. Probes are permanently placed into the shipping cask to monitor and detect fuel assembly displacements that would result from loads in excess of the criteria. Past history and experience have indicated that loads which exceeded the allowable limits rarely occur. Exceeding the limits requires reinspection of the fuel assembly for damage. Tests on various fuel assembly components such as the grid assembly, sleeves, inserts, and structure joints have been performed to assure that the shipping design limits do not result in impairment of fuel assembly function.

Dimensional Stability

The Vantage 5H Mechanical Test Program description and results are given in Reference 16 and are considered to applicable to Vantage+ as the two assemblies are structurally essentially identical.

The coolant flow channels are established and maintained by the structure composed of grids and guide thimbles. The lateral spacing between fuel rods is provided and controlled by the support dimples of adjacent grid cells. Contact of the fuel rods on the dimples is assured by the clamping force provided by the grid springs. Lateral motion of the fuel rods is opposed by the spring force and the internal moments generated between the spring and the support dimples. Grid testing is discussed in Reference 10.

No interference with control rod insertion into thimble tubes will occur during a postulated loss-of-coolant accident (LOCA) transient due to fuel rod swelling, thermal expansion, or bowing. In the early phase of the transient following the coolant break, the high axial loads which potentially could be generated by the difference in thermal expansion between fuel clad and thimbles are relieved by slippage of the fuel rods through the grids. The relatively low drag force restraint on the fuel rods will only induce minor thermal bowing not sufficient to close the fuel rod-to-thimble tube gap. This rod-to-grid slip mechanism occurs simultaneously with control rod drop.

Vibration and Wear

The effect of the flow induced vibration on the V5H and Vantage+ fuel assembly and individual fuel rods is minimal. The cyclic stress range associated with deflections of such small magnitude is insignificant and has no effect on the structural integrity of the fuel rod.

The conclusion that the effect of flow induced vibrations on the fuel assembly and fuel rod is minimal is based on test results and analysis documented in Reference 11.

The reaction on the grid support due to vibration motions is also correspondingly small and much less than the spring preload. Firm contact is therfore maintained. No significant wear of the cladding or grid supports is expected during the life of the fuel assembly, based on out-of-pile flow tests, performance of similarly designed fuel in operating reactors (2), and design analyses.

Clad fretting and fuel rod vibration have been experimentally investigated as shown in Reference 11.

No significant guide thimble tube wear due to flow-induced vibration of the control rods is predicted. Based on a conservative wear analyses, Westinghouse concluded that the integrity of the guide tube is maintained during normal operation, accident conditions, and nonoperational loading condition for at least 250 weeks (> 3 cycles) of fuel assembly operation. The Nuclear Regulatory Commission (NRC) has concluded (12) that the Westinghouse analyses probably accounts for all the major variables in the wear process. However, the NRC requested additional confirmatory information supporting the absence of significant thimble wear (no wear hole formation) for the 17 x 17 fuel assembly design. Examination of 1434 guide thimble tubes in six fuel assemblies examined at Salem Unit 1 shows no wear hole formation. Four of the assemblies had control rods in the parked position (7 1/2 inches into the guide thimble) for Cycle 1, and two assemblies had control rods parked for Cycles 1 and 2. The parked position of the control rods has the greatest potential for causing guide thimble wear due to flow induced vibrations. The results of this surveillance program satisfy the NRC request to verify the wear analysis conclusion of no wear holes.

Evaluation of the Reactor Core for Limited Displacement RPV Inlet and Outlet Nozzle Breaks

The STD fuel assembly response resulting from the most limiting main coolant pipe break was analyzed using time history numerical techniques. Since the resulting vessel motion induces primarily lateral loads on the reactor core, a finite element model similar to the seismic model described in Reference 10 was used to assess the fuel assembly deflections and impact forces.

The reactor core finite element model which simulates the fuel assembly interaction during lateral excitation consists of fuel assemblies arranged in a planer array with inter-assembly gaps. For the Salem Station, 15 fuel assemblies which correspond to the maximum number of assemblies across the core diameter were used in the mode. The fuel assemblies and the reactor baffle support are represented by single beam elements as shown on Figure 4.2-25. The time history motion for the upper and lower core plates and the barrel at the upper core plate elevation are simultaneously applied to the simulated reactor core model as illustrated on Figure 4.2-25. The three time history motions were obtained from the time history analysis of the reactor vessel and internals finite element model.

The fuel assembly response, namely the displacements and grid impact forces, were obtained from the reactor core model using the core plate and barrel motions resulting from a reactor coolant pump outlet double ended break. The maximum fuel assembly deflection which occurred in a peripheral fuel assembly was approximately 0.67 inch. The fuel assembly stresses resulting from this deflection indicated significant safety margins compared to the allowable values. The grid maximum impact force for both the seismic and lateral blowdown accident conditions occurred at the peripheral fuel assembly locations adjacent to the baffle wall. The grid impact forces were appreciably lower for fuel assembly locations inward from the peripheral fuel. For the lateral blowdown case, only a small (outer) portion of the core experienced significant grid impact forces.

The maximum grid impact force obtained from the limiting rupture break was found to be approximately 68 percent of the minimum grid strength (using the 95 x 95 value as determined by tests at reactor operating safe shutdown temperatures). The maximum square-root-of-the-sum-of-the-squares combination of the pipe rupture and safe shutdown earthquake loads for the limiting grid location was found to be approximately 74 percent of the minimum grid strength.

The major components that determine the structural integrity of the fuel assembly are the grids. Mechanical testing and analysis of the Vantage 5H Zircaloy grid and fuel assembly have demonstrated that the Vantage 5H structural integrity under seismic/LOCA loads will provide margins comparable to the STD 17 x 17 fuel assembly design and will meet all design bases.

Since the Vantage+ assembly is structurally similar to that of Vantage 5H, the seismic and LOCA analysis for the Vantage 5H assembly are applicable to Vantage+ assembly. The use of ZIRLO^{TM} guide thimbles will not affect the seismic and LOCA loads.

4.2.1.3.3 Operational Experience

Westinghouse has had considerable experience with Zircaloy-clad fuel since its introduction in the Jose Cabrera plant in June 1968. This experience is extensively described in Reference 2.

Dynamic Analysis: The cyclic stresses due to dynamic loads and deflections are combined with the stresses imposed by loads from component weights, hydraulic forces, and thermal gradients for the determination of the total stresses of the Reactivity Control System.

4.2.3.1.2 Material Compatibility

Materials are selected for compatibility in a PWR environment, for adequate mechanical properties at room and operating temperature, for resistance to adverse property changes in a radioactive environment, and for compatibility with interfacing components.

4.2.3.1.3 Reactivity Control Components

The reactivity control components are subdivided into two categories:

1. Permanent devices used to control or monitor the core

2. Temporary devices used to control or monitor the core.

The permanent type components are the rod cluster control assemblies, control rod drive assemblies, neutron source assemblies, and thimble plug assemblies. Although the thimble plug assembly does not directly contribute to the reactivity control of the reactor, it is presented as a Reactivity Control System component in this document because it can be used to restrict bypass flow through those thimbles not occupied by absorber, source, or burnable absorber rods.

The temporary component is the burnable absorber assembly. The design bases for each of the mentioned components are in the following paragraphs.

Absorber Rods

The following are considered design conditions under Subsections NG and NB of the ASME Boiler and Pressure Vessel Code Section III.

1. The external pressure equal to the Reactor Coolant System operating pressure

2. The wear allowance equivalent to 1,000 reactor trips

3. Bending of the rod due to a misalignment in the guide tube

4. Forces imposed on the rods during rod drop

5. Loads caused by accelerations imposed by the control rod drive mechanism

6. Radiation exposure for maximum core life

7. Temperature effects at operating conditions

The absorber material temperature shall not exceed its melting temperature (1470°F for Ag-In-Cd absorber material)(14).

Burnable Absorber Rods

The burnable absorber rod clad is designed using Subsections NG and NB of the ASME Boiler and Pressure Vessel Code, Section III, 1973 as a general guide for Conditions I and II. For abnormal loads during Conditions III and IV, Code stresses are not considered limiting. Failures of the burnable absorber rods during these conditions must and drive rod while maintaining trip times at or below required limits. In the following paragraphs, each reactivity control component is described in detail.

4.2.3.2.1 Reactivity Control Components

Rod Cluster Control Assembly

The rod cluster control assemblies are divided into two categories: control and shutdown. The control groups compensate for reactivity changes due to variations in operating conditions of the reactor, i.e., power and temperature variations. Two criteria have been employed for selection of the control groups. First, the total reactivity worth must be adequate to meet the nuclear requirements of the reactor. Second, in view of the fact that some of these rods may be partially inserted at power operation, the total power peaking factor should be low enough to ensure that the power capability is met. The control and shutdown groups provide adequate shutdown margin which is defined as the amount by which the core would be subcritical at hot shutdown if all rod cluster control assemblies are tripped assuming that the highest worth assembly remains fully withdrawn and assuming no changes in xenon or boron concentration.

A rod cluster control assembly comprises a group of individual neutron absorber rods fastened at the top end to a common spider assembly, as illustrated on Figure 4.2-14.

The absorber material used in the control rods is silver-indium-cadmium single piece absorber rod which is essentially "black" to thermal neutrons and has sufficient additional resonance absorption to significantly increase its worth. The alloy is in the form of extruded rods which are sealed in stainless steel tubes to prevent the rods from coming in direct contact with the coolant. In construction, the silver-indium-cadmium rods are inserted into cold-worked stainless steel tubing which is then sealed at the bottom and the top by welded Type 308L stainless steel end plugs as shown on Figure 4.2-15. Sufficient diametral and end clearance is provided to accommodate relative thermal expansions. The cladding surface has been ion-nitrided for hardening and corrosion resistance.

The bottom plugs are made bullet-nosed to reduce the hydraulic drag during reactor trip and to guide smoothly into the dashpot section of the fuel assembly guide thimbles. The upper end plug is threaded for assembly to the spider and is machined with a reduced diameter shank to provide flexibility to the joint for any misalignment condition.

The spider assembly is a one-piece machined casting in the form of a central hub with radial vanes containing cylindrical fingers from which the absorber rods are suspended. Handling detents and detents for connection to the drive rod assembly are machined into the upper end of the hub. A coil spring inside the spider body absorbs the impact energy at the end of a trip insertion. A centerpost which holds the spring and its retainer is threaded into the hub within the skirt and welded to prevent loosening in service. The spider casting material is CF3M cast 316 stainless steel.

The absorber rods are fastened securely to the spider assembly as shown in Figure 4.2-15 to assure trouble free service. The threaded end of the upper end plug is inserted into the bottom of the spider boss hole. A nut is tightened on and welded to the spider boss to prevent loosening. A lock pin is inserted into the aligned holes of the spider base and upper end plug and welded to prevent the end plug and rod from backing off.

The overall length is such that when the assembly is withdrawn through its full travel the tips of the absorber rods remain engaged in the guide thimbles so that alignment between rods and thimbles is always maintained. Since the rods are long and slender, they are relatively free to conform to any small misalignments with the guide thimble.

(e.g., Cl^- control in the coolant). The current design type reactivity controls have been in service for more than 10 years with no apparent degradation of construction materials.

With regard to the materials of construction exhibiting satisfactory resistance to adverse property changes in a radioactive environment, it should be noted that on work on breeder reactors in current design, similar materials are being applied. At high fluences the austenitic materials increase in strength with a corresponding decreased ductility (as measured by tensile tests) but energy absorption (as measured by impact tests) remains quite high. Corrosion of the materials exposed to the coolant is quite low and proper control of Cl^- and O_2 in the coolant will prevent the occurrence of stress corrosion. All of the austenitic stainless steel base materials used are processed and fabricated to preclude sensitization.

Analysis of the rod cluster control assemblies shows that if the drive mechanism housing ruptures, the rod cluster control assembly will be ejected from the core by the pressure differential of the operating pressure and ambient pressure across the drive rod assembly. The ejection is also predicted on the failure of the drive mechanism to retain the drive rod/rod cluster control assembly position. It should be pointed out that a drive mechanism housing rupture will cause the ejection of only one rod cluster control assembly with the other assemblies remaining in the core.

Ejection of a burnable absorber or thimble plug assembly (if used) is conceivable based on the postulation that the holddown bar fails and that the base plate and burnable absorber rods are severely deformed. In the unlikely event that failure of the holddown bar occurs, the upward displacement of the burnable absorber assembly only permits the base plate to contact the upper core plate. Since this displacement is small, the major portion of the borosilicate glass tubing remains positioned within the core. In the case of the thimble plug assembly, the thimble plugs will partially remain in the fuel assembly guide thimbles thus maintaining a majority of the desired flow impedance. Further displacement or complete ejection would necessitate the square base plate and burnable absorber rods be forced, thus plastically deformed, to fit up through a smaller diameter hole. It is expected that this condition requires a substantially higher force or pressure drop than that of the holddown bar failure.

Experience with control rods, burnable absorber rods, and source rods is discussed in Reference 2.

The mechanical design of the reactivity control components provides for the protection of the active elements to prevent the loss of control capability and functional failure of critical components. The components have been reviewed for potential failure and consequences of a functional failure of critical parts. The results of the review are summarized below.

Rod Cluster Control Assembly

1. The basic absorbing material is sealed from contact with the primary coolant and the fuel assembly and guidance surfaces by a high quality stainless steel clad.

Potential loss of absorber mass or reduction in reactivity control material due to mechanical or chemical erosion or wear is therefore reliably prevented.

2. A breach of the cladding for any postulated reason does not result in serious consequences. The absorber material, silver-indium-cadmium, is relatively inert and would still remain remote from high coolant velocity regions. Rapid loss of material resulting in significant loss of reactivity control material would not occur.

3. The individually clad absorber rods are doubly secured to the retaining spider finger by a threaded top end plug secured by a nut welded to the finger and a welded lock pin.

   It should also be noted that in several instances of control rod jamming caused by foreign particles, the individual rods at the site of the jam have borne the full capacity of the CRDM and higher impact loads to dislodge the jam without failure. The guide tube card/guide thimble arrangement is such that large loads are required to buckle individual control rods. The conclusion to be drawn from this experience is that this joint is extremely insensitive to potential mechanical damage. A failure of the joint would result in the insertion of the individual rod into the core. This results in reduced reactivity which is a fail safe condition. Further information is given in Reference 2.

4. The spider is a one-piece machined casting and includes the radial vanes and fingers. Reliability is increased by not using brazed joints. Casting allows the rod holes to be drilled to the positional tolerances prior to assembly to ensure the rods will align with the guide cards.

5. The spider hub being of a one-piece machined casting is very rugged and of extremely low potential for damage. It is difficult to postulate any condition to cause failure. Should some unforeseen event cause fracture of the hub above the vanes, the lower portion with the vanes and rods attached would insert by gravity into the core causing reactivity decrease. The rod could then not be removed by the drive line, again a fail safe condition. Fracture below the vanes cannot be postulated since all loads, including scram impact, are taken above the vane elevation.

6. The rod cluster control rods are provided a clear channel for insertion by the guide thimbles of the fuel assemblies. All fuel rod failures are protected against by providing this physical barrier between the fuel rod and the intended insertion channel. Distortion of the fuel rods by bending cannot apply sufficient force to damage or significantly distort the guide thimble. Fuel rod distortion by swelling, though precluded by design, would be terminated by fracture before contact with the guide thimble occurs. If such were not the case, it would be expected that a force reaction at the point of contact would cause a slight deflection of the guide thimble. The radius of curvature of the deflected shape of the guide thimbles would be sufficiently large to have a negligible influence on rod cluster control insertion.

Burnable Absorber Assemblies

The burnable absorber assemblies are static temporary reactivity control elements. The axial position is assured by the holddown assembly which bears against the upper core plate. Their lateral position is maintained by the guide thimbles of the fuel assemblies.

The individual rods are shouldered against the underside of the retainer plate and securely fastened at the top by a threaded nut which is then locked in place. The square dimension of the retainer plate is larger than the diameter of the flow holes through the core plate. Failure of the holddown bar or spring pack therefore does not result in ejection of the burnable absorber rods from the core.

The only incident that could potentially result in ejection of the burnable absorber rods is a multiple fracture of the retainer plate. This is not considered credible because of the light loads borne by this component. During normal operation the loads borne by the plate are approximately 5 lbs per rod, or a total of 100 lbs. distributed at the points of attachment. Even a multiple fracture of the retainer plate would result in jamming of the plate segments against the upper core plate, again preventing ejection. Excessive reactivity increase due to burnable poison ejection is therefore prevented.

The same type of stainless steel clad used on rod cluster control rods is also used on the burnable absorber rods. In this application there is even less susceptibility to mechanical damage since these are static assemblies. The guide thimbles of the fuel assembly afford the same protection from damage due to fuel rod failures as that described for the rod cluster control rods.

The consequences of clad breach are also similarly small. The absorber material is borosilicate glass which is maintained in position by a central hollow tube. In the event of a hole developing in the clad for any postulated reason the expected consequence is only the loss of the helium produced by the absorption process into the primary coolant. The glass is chemically inert and remains remote from high coolant velocities; therefore significant loss of absorber material resulting in reactivity increase is not expected.

At 70°F the inside diameter of the coil stack is 7.308/7.298 inches. The outside diameter of the latch housing is 7.260/7.270 inches.

Thermal expansion of the mechanism due to operating temperature of the CRDM results in minimum inside diameter of the coil stack being 7.310 inches at 222°F and the maximum latch housing diameter being 7.302 inches at 532°F.

Under the extreme tolerance conditions listed above, it is necessary to allow time for a 70°F coil housing to heat during a replacement operation.

Four coil stack assemblies were removed from four hot CRDMs mounted on 11.035-inch centers on a 550°F test loop, allowed to cool, and then replaced without incident as a test to prove the proceeding.

Coil Fit in Coil Housing

Control rod drive mechanism and coil housing clearances are selected so that coil heatup results in a close or tight fit. This is done to facilitate thermal transfer and coil cooling in a hot CRDM.

4.2.3.4 Tests, Verification, and Inspections

4.2.3.4.1 Reactivity Control Components

Tests and inspections are performed on each reactivity control component to verify the mechanical characteristics. In the case of the rod cluster control assembly, prototype testing has been conducted, and both manufacturing test/inspections and functional testing at the plant site are performed.

During the component manufacturing phase, the following requirements apply to the reactivity control components to assure the proper functioning during reactor operation:

1. All materials are procured to specifications to attain the desired standard of quality.

2. All clad/end plug welds are checked for integrity by visual inspection and X-ray, and are helium leak checked. All the seal welds in the neutron absorber rods, burnable poison rods, and source rods are checked in this manner.

3. To assure proper fitup with the fuel assembly, the rod cluster control, burnable poison, and source assemblies are installed in the fuel assembly and checked for binding in the dry condition.

   The rod cluster control assemblies (RCCA) are functionally tested following core loading, but prior to criticality to demonstrate reliable operation of the assemblies. Each assembly is operated (and tripped) one time at no flow/cold conditions and one time at full flow/hot conditions. In addition, selected assemblies, amounting to about 15 to 20 percent of the total assemblies are operated at no-flow/operating temperature conditions and full flow/ambient conditions. Also the slowest rod and the fastest rod are tripped 10 times at no-flow/ambient conditions and at full flow/operating temperature conditions. Thus each assembly is tested a

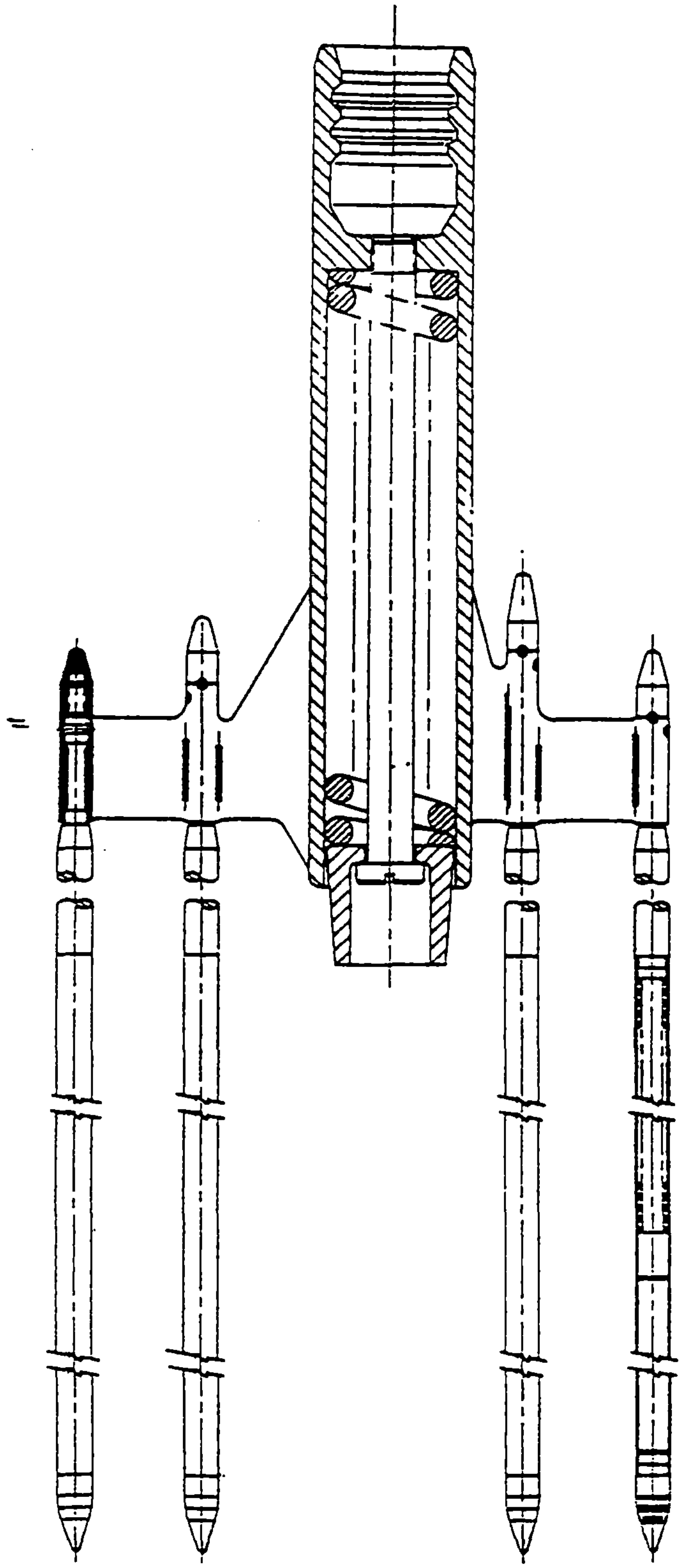
14. Cohen, J., "Development and Properties of Silver Base Alloys as Control Rod Materials for Pressurized Water Reactors," WAPD-214, December 1959.

15. Davidson, S. L. (Ed.), et al, "Vantage 5 Fuel Assembly Reference Core Report," WCAP-10444-P-A, September 1985.

16. Davidson, S. L. (Ed.), et al, "Vantage 5H Fuel Assembly," WCAP-10444-P-A, Addendum 2-A, February 1989.

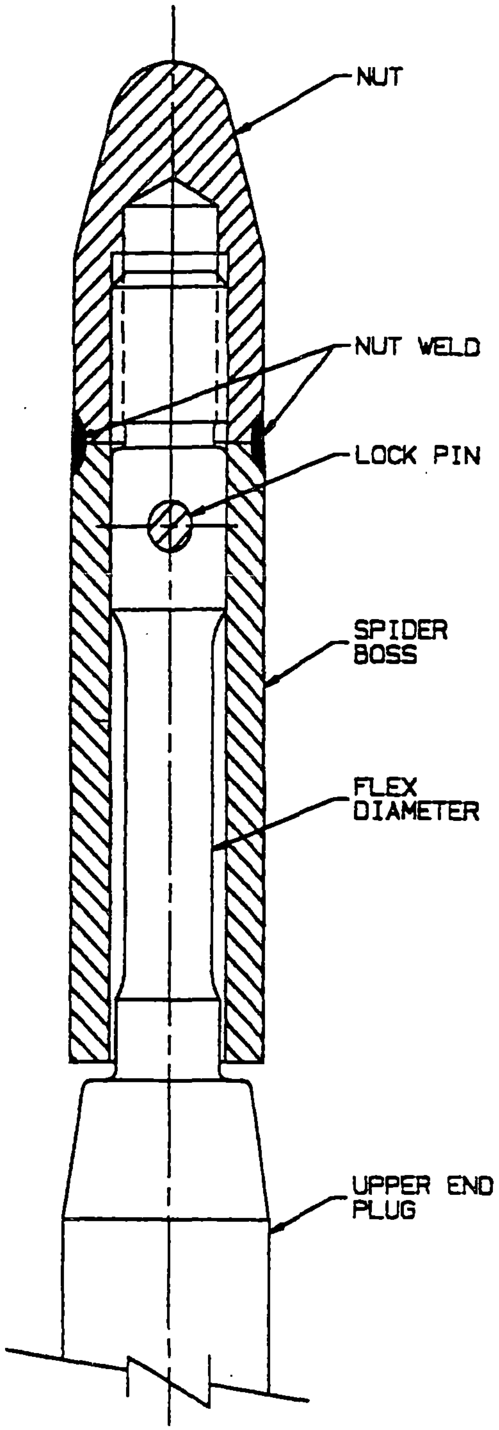
17. Weiner, R. A., "Improved Fuel Rod Performance Models for Westinghouse Fuel Rod Design and Safety Evaluation," WCAP-10851-P-A, August 1988.

18. Letter from A. C. Thadani, (NRC) to S. R. Tritch (Westinghouse), "Acceptance for Referencing of Topical Report WCAP-12610 'Vantage+ Fuel Assembly Reference Core Report'," July 1, 1991.

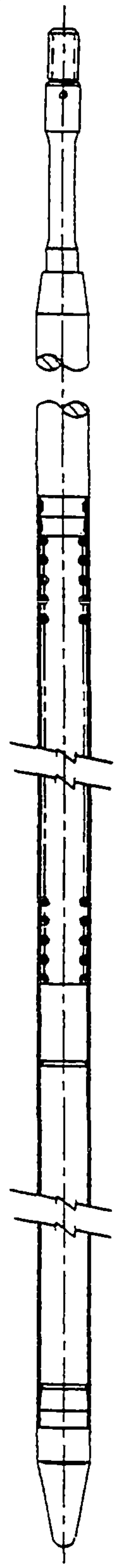


REVISION 17
OCTOBER 16 1998

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Full Length Rod Cluster Control Assembly Outline
	Updated FSAR FIG.4.2-14



Flex Joint



Control Rod

REVISION 17
OCTOBER 16 1998

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Full Length Absorber Rod
	Updated FSAR FIG. 4.2-15

4.3 NUCLEAR DESIGN

4.3.1 Design Bases

This section describes the design bases and functional requirements used in the nuclear design of the Fuel and Reactivity Control System and relates these design bases to the General Design Criteria (GDC) in 10CFR50 Appendix A. Where appropriate, supplemental criteria such as the Final Acceptance Criteria for Emergency Core Cooling Systems are addressed. Before discussing the nuclear design bases, it is appropriate to briefly review the four major categories ascribed to conditions of plant operation.

The full spectrum of plant conditions is divided into four categories, in accordance with the anticipated frequency of occurrence and risk to the public:

1. Condition I - Normal Operation,
2. Condition II - Incidents of Moderate Frequency,
3. Condition III - Infrequent Faults,
4. Condition IV - Limiting Faults.

In general, the Condition I occurrences are accommodated with margin between any plant parameter and the value of that parameter which would require either automatic or manual protective action. Condition II incidents are accommodated with, at most, a shutdown of the reactor with the plant capable of returning to operation after corrective action. Fuel damage* is not expected during Condition I and Condition II events. It is not possible, however,

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* Fuel damage as used here is defined as penetration of the fission product barrier (i.e., the fuel rod clad).

to preclude a very small number of rod failures. These are within the capability of the plant cleanup system and are consistent with the plant design basis.

Condition III incidents shall not cause more than a small fraction of the fuel elements in the reactor to be damaged, although sufficient fuel element damage might occur to preclude immediate resumption of operation. The release of radioactive material due to Condition III incidents should not be sufficient to interrupt or restrict public use of these areas beyond the exclusion radius. Furthermore, a Condition III incident shall not, by itself, generate a Condition IV fault or result in a consequential loss of function of the Reactor Coolant System (RCS) or reactor containment barriers.

Condition IV occurrences are faults that are not expected to occur but are defined as limiting faults which must be designed against. Condition IV faults shall not cause a release of radioactive material that results in an undue risk to public health and safety.

The core design power distribution limits related to fuel integrity are met for Condition I occurrences through conservative design and maintained by the action of the Control System. The requirements for Condition II occurrences are met by providing an adequate protection system which monitors reactor parameters. The Control and Protection Systems are described in Section 7, and the consequences of Condition II, III, and IV occurrences are given in Section 15.

4.3.1.1 Fuel Burnup

Basis

The fuel rod design basis is described in Section 4.2. The nuclear design basis is to install sufficient reactivity in the fuel to attain the average region discharge burnup values given in reference 28. The above, along with the design basis in Section 4.3.1.3, Control of Power Distribution, satisfies GDC-10.

Discussion

Fuel burnup is a measure of fuel depletion which represents the integrated energy output of the fuel (MWD/MTU) and is a convenient means for quantifying fuel exposure criteria.

The core design lifetime or design discharge burnup is achieved by installing sufficient initial excess reactivity in each fuel region and by following a fuel replacement program (such as that described in Section 4.3.2) that meets all safety-related criteria in each cycle of operation.

Initial excess reactivity installed in the fuel, although not a design basis, must be sufficient to maintain core criticality at full power operating conditions throughout cycle life with equilibrium xenon, samarium, and other fission products present. The end-of-design cycle life is defined to occur when the chemical shim concentration is essentially zero with control rods present to the degree necessary for operational requirements. In terms of chemical shim boron concentration this represents approximately 10 ppm with no control rod insertion.

A limitation on initial installed excess reactivity is not required other than as is quantified in terms of other design bases such as core negative reactivity feedback and shutdown margin discussed below.

4.3.1.2 Negative Reactivity Feedbacks (Reactivity Coefficient)

Basis

The fuel temperature coefficient will be negative and the moderator temperature coefficient of reactivity will be non-positive for power operating conditions, thereby providing negative reactivity feedback characteristics. The design basis meets GDC-11.

Discussion

When compensation for a rapid increase in reactivity is considered, there are two major effects. These are the resonance absorption effects (Doppler) associated with changing fuel temperature and the spectrum effect resulting from changing moderator density. These basic physics characteristics are often identified by reactivity coefficients. The use of slightly enriched uranium ensures that the Doppler coefficient of reactivity is negative. This coefficient provides the most rapid reactivity compensation. The core is also designed to have an overall negative moderator temperature coefficient of reactivity so that average coolant temperature or void content provides another, slower compensatory effect. Nominal power operation is permitted only in a range of overall non-positive moderator temperature coefficient. The non-positive moderator temperature coefficient can be achieved through use of fixed burnable absorber, integral fuel burnable absorber (IFBA) and/or control rods by limiting the reactivity held down by soluable boron.

Burnable absorber content (quantity and distribution) is not stated as a design basis other than as it relates to accomplishment of a non-positive moderator temperature coefficient at power operating conditions discussed above.

4.3.1.3 Control of Power Distribution

Basis

The nuclear design basis is that, with at least a 95 percent confidence level:

1. The fuel will not be operated at greater than 13 kW/ft under normal operating conditions including an allowance

of 2 percent for calorimetric error and including densification effects.

2. Under abnormal conditions including the maximum overpressure condition, the fuel peak power will not cause melting as defined in Section 4.4.1.2.

3. The fuel will not operate with a power distribution that violates the departure from nucleate boiling (DNB) design basis (i.e., the DNB ratio (DNBR) shall not be less than the safety limit, as discussed in Section 4.4.1) under Condition I and II events including the maximum overpower condition.

4. Fuel management will be such as to produce rod powers and burnups consistent with the assumptions in the fuel rod mechanical integrity analysis of Section 4.2.

The above basis meets GDC-10.

Discussion

Calculation of extreme power shapes which affect fuel design limits is performed with proven methods and verified frequently with measurements from operating reactors. The conditions under which limiting power shapes are assumed to occur are chosen conservatively with regard to any permissible operating state.

To ensure that the axial profile meets with the linear heat rate limit and the DNB limit, ex-core detector signals are used to provide a top to bottom flux difference, ΔI, which is input, through $F(\Delta I)$, into both the overpower ΔT and overtemperature ΔT trip points.

Even though there is good agreement between measured peak power calculations and measurements, a nuclear uncertainty margin is applied to calculated peak local power. Such a margin is provided both for the analysis of normal operating states and for anticipated transients.

4.3.1.4 Maximum Controlled Reactivity Insertion Rate

Basis

The maximum reactivity insertion rate due to withdrawal of rod cluster control assemblies or by boron dilution is limited. This limit, expressed as a maximum reactivity change rate (75 pcm/sec)* is set such that peak heat generation rate and DNBR do not exceed the maximum allowable at overpower conditions. This satisfies GDC-25.

The maximum reactivity worth of control rods and the maximum rates of reactivity insertion employing control rods are limited so as to preclude rupture of the coolant pressure boundary or disruption of the core internals to a degree which would impair core cooling capacity due to a rod withdrawal or ejection accident (See Section 15).

Following any Condition IV event (rod ejection, steamline break, etc.) the reactor can be brought to the shutdown condition and the core will maintain acceptable heat transfer geometry. This satisfies GDC-28.

Discussion

Reactivity addition associated with an accidental withdrawal of a control bank (or banks) is limited by the maximum rod speed (or travel rate) and by the worth of the bank(s). For this reactor the maximum control rod speed is 45 inches per minute and the maximum rate of reactivity change considering two control banks moving is less than 75 pcm per second.

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* 1 pcm = 10^{5} $\Delta\rho$ (See footnote Table 4.3-2)

Discussion

The core is designed so that diametral and azimuthal oscillations due to spatial xenon effects are self-damping and no operator action or control action is required to suppress them. The stability of diametral oscillations is so great that this excitation is highly improbable. Convergent azimuthal oscillations can be excited by prohibited motion of individual control rods. Such oscillations are readily observable and alarmed, using the ex-core long ion chambers. Indications are also continuously available from in-core thermocouples and loop temperature measurements. Moveable in-core detectors can be activated to provide more detailed information. In all presently proposed cores these horizontal plane oscillations are self-damping by virtue of reactivity feedback effects designed into the core.

However, axial xenon spatial power oscillations may occur late in core life. The control bank and ex-core detectors are provided for control and monitoring of axial power distributions. Assurance that fuel design limits are not exceeded is provided by reactor overpower ΔT and overtemperature ΔT trip functions which use the measured axial power imbalance as an input.

4.3.1.7 Anticipated Transients Without Trip

The effects of anticipated transients with failure to trip are not considered in the design bases of the plant. Analysis has shown that the likelihood of such a hypothetical event is negligibly small. Furthermore, analysis of the consequences of a hypothetical failure to trip following anticipated transients has shown that no significant core damage would result and system peak pressures would be limited to acceptable values and no failure of the RCS would result (1).

4.3.2 Description

4.3.2.1 Nuclear Design Description

The reactor cores consist of a specified number of fuel rods which are held in bundles by spacer grids and top and bottom fittings. The fuel rods are constructed of Zircaloy or Zirlo™ cylindrical tubes containing UO_2 fuel pellets. The bundles, known as fuel assemblies, are arranged in a pattern which approximates a right circular cylinder.

Each fuel assembly contains a 17 x 17 rod array composed of 264 fuel rods, 24 rod cluster control (RCC) thimbles and an in-core instrumentation thimble. Figure 4.2-1 shows a cross sectional view of a 17 x 17 fuel assembly and the related RCC locations. Further details of the fuel assembly are given in Section 4.2.1.

For initial core loading, the fuel rods within a given assembly have the same uranium enrichment in both the radial and axial planes. Fuel assemblies of three different enrichments are used in the initial core loadings to establish a favorable radial power distribution. Two regions consisting of two lower enrichments are interspersed so as to form a checkerboard pattern in the central portion of the core. The third region is arranged around the periphery of the core and contains the highest enrichment. The enrichments for the first cores are shown in Table 4.3-1.

A typical reload pattern is a low leakage loading pattern. A low leakage loading pattern has either burned (depleted) or fresh (feed) assemblies arranged on the core periphery. The reload cores are normally designed to be able to operate approximately eighteen months between refuelings. The current cycles' loading patterns for both Salem Units are shown in Section 4.5.

The core average enrichment is determined by the amount of fissionable material required to provide the desired cycle energy requirements. The physics of the burnout process is such that operation of the reactor depletes the amount of fuel available due to the absorption of neutrons by the U-235 atoms and their subsequent fission. The rate of U-235 depletion is directly proportional to the power level at which the reactor is operated. In addition, the fission process results in the formation of fisson products, some of which readily absorb neutrons. These effects, depletion and the buildup of fission products, are partially offset by the buildup of plutonium shown on Figure 4.3-1 for the 17 x 17 fuel assembly, which occurs due to the non-fission absorption of neutrons in U-238. Therefore, at the beginning of any cycle a reactivity reserve equal to the depletion of the fissionable fuel and the buildup of fission product poisons over the specified cycle life must be "built" into the reactor. This excess reactivity is controlled by boron dissolved in the primary coolant and burnable absorbers.

The concentration of boric acid in the primary coolant is varied to provide control and to compensate for long-term reactivity requirements. The concentration of the soluble neutron absorber is varied to compensate for reactivity changes due to fuel burnup, fission product poisoning including xenon and samarium, burnable absorber depletion, and the cold-to-operating moderator temperature change. Using its normal makeup path, the Chemical and Volume Control System (CVCS) is capable of inserting negative reactivity at a rate of approximately 30 pcm/min when the reactor coolant boron concentration is 1000 ppm and approximately 35 pcm/min when the reactor coolant boron concentration is 100 ppm. The peak burnout rate for xenon is 25 pcm/min. Rapid transient reactivity requirements and safety shutdown requirements are met with control rods.

As the boron concentration is increased, the moderator temperature coefficient becomes less negative. The use of a soluable absorber alone would result in a positive moderator coefficient at beginning-of-life (BOL). Therefore, burnable absorbers are used to reduce the soluble boron concentration sufficiently to ensure that the moderator temperature coefficient is non-positive for power operating conditions. During operation the absorber content in the burnable absorbers is depleted thus adding positive reactivity to offset some of the negative reactivity from fuel depletion and fission product buildup. The depletion rate of the burnable absorbers is not critical since chemical shim is always available and flexible enough to cover any possible deviations in the expected burnable absorber depletion rate. Figure 4.3-2 is a graph of a typical core depletion with burnable absorbers.

In addition to reactivity control, the burnable absorbers, both discrete and internal, are strategically located to provide a favorable radial power distribution. Reload loading patterns utilize various burnable absorber distributions. These are determined on a cycle-specific basis. The current cycles' burnable absorber loading patterns are shown in Section 4.5.

Tables 4.3-1 through 4.3-3 contain a summary of the reactor core design parameters for a typical fuel cycle, including reactivity coefficients, delayed neutron fraction, and neutron lifetimes. Some of these parameters change on a reload basis. The current values or allowable range of values may be found in the appropriate Reload Safety Evaluation (RSE) or Nuclear Design Report (NDR). A list of applicable RSEs and NDRs, by unit and cycle, is given in Section 4.5. The RSE is a cycle-specific document which evaluates the fuel assembly design and core loading pattern configuration for plant safety. The NDR is a cycle-specific document which includes such information as power distributions, reactivity coefficients, boron and control rod worths under a variety of plant operating conditions. There is sufficient information in the RSE and NDR to permit an independent calculation of the nuclear performance characteristics of the core.

4.3.2.2 Power Distribution

The accuracy of power distribution calculations has been confirmed through approximately one thousand flux maps during some 20 years of operation under conditions very similar to those expected for the plant described herein. Details of this confirmation are given in Reference 2 and in Section 4.3.2.2.7.

4.3.2.2.1 Definitions

Power distributions are quantified in terms of hot channel factors. These factors are a measure of the peak pellet power within the reactor core and the total energy produced in a coolant channel and are expressed in terms of quantities related to the nuclear or thermal design, namely:

Power density is the thermal power produced per unit volume of the core (kW/liter).

Linear power density is the thermal power produced per unit length of active fuel (kW/ft). Since fuel assembly geometry is standardized, this is the unit of power density most commonly used. For all practical purposes it differs from kW/liter by a constant factor which includes geometry effects and the fraction of the total thermal power which is generated in the fuel rod.

Average linear power density is the total thermal power produced in the fuel rods divided by the total active fuel length of all rods in the core.

Local heat flux is the heat flux at the surface of the cladding (Btu-ft^{-2}-hr^{-1}). For nominal rod parameters this differs from linear power density by a constant factor.

Rod power or rod integral power is the length integrated linear power density in one rod (kW).

Average rod power is the total thermal power produced in the fuel rods divided by the number of fuel rods (assuming all rods have equal length).

The hot channel factors used in the discussion of power distributions in this section are defined as follows:

F_Q, Heat Flux Hot Channel Factor, is defined as the maximum local heat flux on the surface of a fuel rod divided by the average fuel rod heat flux, allowing for manufacturing tolerances on fuel pellets and rods.

$F^N Q$, Nuclear Heat Flux Hot Channel Factor, is defined as the maximum local fuel rod linear power density divided by the average fuel rod linear power density, assuming nominal fuel pellet and rod parameters.

$F^E Q$, Engineering Heat Flux Hot Channel Factor, is the allowance on heat flux required for manufacturing tolerances. The engineering factor allows for local variations in enrichment, pellet density and diameter, surface area of the fuel rod, and eccentricity of the gap between pellet and clad.

Combined statistically the net effect is a factor of 1.03 to be applied to fuel rod surface heat flux.

$F^N_{\Delta H}$, Nuclear Enthalpy Rise Hot Channel Factor, is defined as the ratio of the integral of linear power along the rod with the highest integrated power to the average rod power.

Manufacturing tolerances, hot channel power distribution and surrounding channel power distributions are treated explicitly in the calculation of the departure from nucleate boiling ratio described in Section 4.4.

It is convenient for the purposes of discussion to define subfactors of F_Q; however, design limits are set in terms of the total peaking factor.

F_Q = Total peaking factor or heat flux hot-channel factor

$$= \frac{\text{Maximum kW/ft}}{\text{Average kW/ft}}$$

without densification effects

$$F_Q = F_Q^N \times F_Q^E$$

$$= \max[F_{XY}^N \times P(z)] \times F_U^N \times F_Q^E$$

where:

F_Q^N and F_Q^E are defined above.

F_U^N = the measurement uncertainty associated with a full core flux map with moveable detectors.

F_{XY}^N = ratio of peak power density to average power density in the horizontal plane of peak local power.

P(Z) = ratio of the power per unit core height in the horizontal plane at height Z to the average value of power per unit core height.

4.3.2.2.2 Radial Power Distribution

The power shape in horizontal sections of the core at full power is a function of the fuel and burnable absorber loading patterns and the presence or absence of a single bank of control rods. Thus, at any time in the cycle a horizontal section of the core can be characterized as unrodded or with group D control rods. These two situations combined with burnup effects determine the radial power shapes which can exist in the core at full power. The effect on radial power shapes of power level, xenon, samarium, and moderator density effects are considered also but these are quite small. The effect of non-uniform flow distribution is negligible. While radial power distributions in various planes of the core are often illustrated, the core radial enthalpy rise distribution as determined by the integral of power up each channel is of greater interest. Figures 4.3-3 through 4.3-7 show representative low leakage radial power distributions for one eighth of the core for representative operating conditions. These conditions are (1) Hot Full Power (HFP) at BOL - unrodded - no xenon, (2) HFP at BOL - unrodded - equilibrium xenon, (3) HFP at BOL - Bank D in - equilibrium xenon, (4) HFP at Middle-of-Life (MOL) - unrodded - equilibrium xenon, and (5) HFP at EOL - unrodded - equilibrium xenon.

The radial power distribution, and hence radial enthalpy rise distribution, changes on a cycle-specific basis. The appropriate NDR should be referenced. See Section 4.5 for the current cycles' predicted radial enthalpy distribution.

Since the position of the hot channel varies from time to time a single reference radial design power distribution is selected for DNB calculations. This reference power distribution is chosen conservatively to concentrate power in one area of the core, minimizing the benefits of flow redistribution. Assembly powers are normalized to core average power.

4.3.2.2.3 Assembly Power Distribution

Since the detailed power distribution surrounding the hot channel varies based on within-assembly design features and time in life, a conservatively flat assembly power distribution is assumed in the DNB analysis, described in Section 4.4, with the rod of maximum integrated power artificially raised to the design value of $F^N_{\Delta H}$. The design value of $F^N_{\Delta H}$ is determined during the RSE. The current cycles' $F^N_{\Delta H}$ value is given in Section 4.5. Care is taken in the nuclear design of all fuel cycles and all operating conditions to ensure that a flatter assembly power distribution does not occur with limiting values to $F^N_{\Delta H}$.

4.3.2.2.4 Axial Power Distribution

The shape of the power profile in the axial or vertical direction is largely under the control of the operator through either the manual operation of the control rods or automatic motion of control rods responding to manual operation of the CVCS. Nuclear effects which cause variations in the axial power shape include moderator density, Doppler effect on resonance absorption, spatial xenon, burnable absorbers, and burnup. Automatically controlled variations in total power output and control rod motion are also important in determining the axial power shape at any time. Signals are available to the operator from the ex-core ion chambers which are long ion chambers outside the reactor vessel running parallel to the axis of the core. Separate signals are taken from the top and bottom halves of the chambers. The difference between top and bottom signals from each of four pairs of detectors is displayed on the control panel and called the flux difference, ΔI. Calculations of core average peaking factor for many plants and measurements from operating plants under many operating situations are associated with either ΔI or axial offset in such a way that an upper bound can be placed on the peaking factor. For these correlations axial offset is defined as:

$$\text{axial offset} = \frac{\Phi_t - \Phi_b}{\Phi_t + \Phi_b}$$

and Φ_t and Φ_b are the top and bottom detector readings.

Representative axial power shapes from Reference 3 for BOL, MOL, and EOL conditions are shown on Figures 4.3-8 through 4.3-10.

These figures cover a wide range of axial offset including values not permitted at full power.

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4.3.2.2.6 Limiting Power Distribution

According to the ANS classifications of plant conditions (See Section 15), Condition I occurrences are those which are expected frequently or regularly in the course of power operation, maintenance, or maneuvering of the plant. As such, Condition I occurrences are accommodated with margin between any plant parameter and the value of that parameter which would require either automatic or manual protective action. In as much as Condition I occurrences occur frequently or regularly, they must be considered from the point of view of affecting the consequences of fault conditions (Conditions II, III, and IV). In this regard, analysis of each fault condition described is generally based on a conservative set of initial conditions corresponding to the most adverse set of conditions which can occur during Condition I operation.

The list of steady state and shutdown conditions, permissible deviations (such as one coolant loop out of service) and operational transients is given in Section 15. Implicit in the definition of normal operation is proper and timely action by the reactor operator. That is, the operator follows recommended operating procedures for maintaining appropriate power distributions and takes any necessary remedial action when alerted to do so by the plant instrumentation. Thus, as stated above, the worst or limiting power distribution which can occur during normal operation is to be considered as the starting point for analysis of Condition II, III, and IV events.

Improper procedural actions or errors by the operator are assumed in the design as occurrences of moderate frequency (Condition II). Some of the consequences which might result are listed in Section 15.1. Therefore, the limiting power shapes which result from such Condition II events are those power shapes which deviate from the normal operating condition at the recommended axial offset band, e.g., due to lack of proper action by the operator during a xenon transient following a change in power level brought about by control rod motion. Power shapes which fall in this category are used for determination of the reactor protection system setpoints so as to maintain margin to overpower or DNB limits.

The means for maintaining power distributions within the required hot channel factor limits are described in the Core Operating Limit Report (COLR). A complete discussion of power distribution control in Westinghouse Pressurized Water Reactors (PWRs) is included in Reference 5. Detailed information on the design constraints on local power density in a Westinghouse PWR, on the defined operating procedures and on the measures taken to preclude exceeding design limits is presented in the Westinghouse topical report on peaking factors (Reference 6). The following paragraphs summarize these reports and describe the calculations used to establish the upper bound on peaking factors.

The calculations used to establish the upper bound on peaking factors, F_Q and $F^N_{\Delta H}$, include all of the nuclear effects which influence the radial and/or axial power distributions throughout core life for various modes of operation including load follow, reduced power operation, and axial xenon transients.

Radial power distributions are calculated for the full power condition, and fuel and moderator temperature feedback effects are included for the average enthalpy plane of the reactor. The steady state nuclear design calculations are done for normal flow with the same mass flow in each channel and flow redistribution effects neglected. The effect of flow redistribution is calculated explicitly where it is important in the DNB analysis of accidents. The effect of xenon on radial power distribution is small (compare Figures 4.3-3 and 4.3-4, respectively) but is included as part of the normal design process. Radial power distributions are relatively fixed and easily bounded with upper limits.

The core average axial profile, however, can experience significant changes which can occur rapidly as a result of rod motion and load changes and more slowly due to xenon distribution. For the study of points of closest approach to axial power distribution limits, several thousand cases are examined. Since the properties of the nuclear design dictate what axial shapes can occur, boundaries on the limits of interest can be set in terms of the parameters which are readily observed on the plant. Specifically, the nuclear design parameters which are significant to the axial power distribution analysis are:

1. Core power level

2. Core height

3. Coolant temperature and flow

4. Coolant temperature program as a function of reactor power

5. Fuel cycle lifetimes

6. Rod bank worths

7. Rod bank overlaps

8. Burnable absorber length and placement

Normal operation of the plant assumes compliance with the following conditions:

1. For Unit 1, control rods in a single bank move together with no individual rod insertion differing by more than 12 steps from the bank demand position. For Unit 2, control rods in a single bank move together with no individual rod insertion differing by more than 12 steps above 85% RTP or more than 18 steps at or below 85% RTP from the bank demand position.

2. Control banks are sequenced with overlapping banks.

3. The control bank insertion limits are not violated.

4. Axial power distribution procedures, which are given in terms of flux difference control and control bank position, are observed.

The axial power distribution procedures referred to above are part of the required operating procedures which are followed in normal operation. They require control of the axial offset (flux difference divided by fractional power) at all power levels within a permissible operating band of a target value corresponding to the equilibrium full power value. In the first cycle, the target value changes from about -10 percent to 0 percent linearly through the life of the cycle. Target values in a reload cycle vary based on previous cycle length and number of fresh assemblies. These cycle-specific target values are available in the appropriate NDR. Section 4.5 contains a list. This minimizes xenon transient effects on the axial power distribution since the procedures essentially keep the xenon distribution in phase with the power distribution.

Calculations are performed for normal operation of the reactor including load following maneuvers. Beginning, middle, and end-of-cycle conditions are included in the calculations. Different histories of operation are assumed prior to calculating the effect of load follow transients on the axial power distribution. These different histories assume base loaded operation and extensive load following. The calculated points have been synthesized from axial calculations combined with radial factors appropriate for rodded and unrodded planes. The calculated values have been increased by a factor of 1.05 for conservatism and a factor of 1.03 for the engineering factor, F_Q^E.

Figure 4.3-11 represents these results as an upper bound envelope on local power density versus elevation in the core. It should be emphasized that this envelope is a conservative representation of the bounding values of local power density. Expected values are considerably smaller and, in fact, less conservative bounding values may be justified with additional analysis or surveillance requirements.

Finally, as previously discussed, this upper bound envelope is based on procedures of load follow which require the operator to operate within an allowed deviation from a target equilibrium value of axial flux difference, observing certain D bank insertion limits. These procedures are detailed in Technical Specifications and are predicated only upon ex-core surveillance supplemented by the normal monthly full core map requirement and by computer based alarms on deviation and time of deviation from the allowed flux difference band.

Allowing for fuel densification effects, the average kW/ft for both Units 1 and 2 is 5.44. From Figure 4.3-11, the conservative upper bound value of normalized local power density, including allowances for densification effects, is 2.40 corresponding to a peak local power density of 13.3 kW/ft at 102 percent power for Units 1 and 2.

To determine Reactor Protection System setpoints, with respect to power distributions, three categories of events are considered, namely rod control equipment malfunctions, operator errors of commission, and operator errors of omission.

The first category comprises uncontrolled rod withdrawal (with rods moving in the normal bank sequence) for full length rod banks. Also included are motions of the full length rod banks below their insertion limits, which could be caused, for example, by uncontrolled dilution or primary coolant cooldown. Power distributions were calculated throughout these occurrences assuming short-term corrective action, that is no transient xenon effects were considered to result from the malfunction. The event was assumed to occur from typical normal operating situations which did include normal xenon transients. It was further assumed in determining the power distributions that total power level would be limited by reactor trip to below 118 percent. Since the study is to determine protection limits with respect to power and axial offset, no credit was taken for trip setpoint reduction due to flux difference. Results are given on Figure 4.3-12 in units of kW/ft. The peak power density which can occur in such events, assuming reactor trip at or below 118 percent, is less than that required for centerline melt including uncertainties and densification effects. The second category, also appearing in Figure 4.3-12, assumes that the operator mis-positions the full length rod bank in violation of the insertion limits and creates short-term conditions not included in normal operating conditions.

The third category assumes that the operator fails to take action to correct a flux difference violation. Representative results shown on Figure 4.3-13 are F_Q multiplied by 102 percent power including an allowance for calorimetric error. The figure shows that provided the assumed error in operation does not continue for a period which is long compared to the xenon time constant, the maximum local power does not exceed 22.0 kW/ft including the above factors. However, the COLR restrict ΔI at 102 percent power such that the peak linear power density is less than 18 kW/ft. These events are considered Condition II events.

It should be noted that a reactor overpower accident is not assumed to occur coincident with an independent operator error.

Analyses of possible operating power shapes show that the appropriate hot channel factors F_Q and $F^N_{\Delta H}$ for peak local power density and for DNB analysis at full power are the values given in the COLR. The current unit and cycle's COLR is given in Section 4.5. Typical values are given in Table 4.3-2.

F_Q can be increased with decreasing power as shown in the Technical Specifications. Increasing $F^N_{\Delta H}$ with decreasing power is permitted by the DNB protection setpoints and allows radial power shape changes with rod insertion to the insertion limits as described in Section 4.4.3.2. It has been determined that provided the above Conditions I through IV are observed, the Technical Specification limits are met.

When a situation is possible in normal operation which could result in local power densities in excess of those assumed as the pre-condition for a subsequent hypothetical accident, but which would not itself cause fuel failure, administrative controls and alarms are provided for returning the core to a safe condition. These alarms are described in detail in Sections 7 and 16.

4.3.2.2.7 Experimental Verification of Power Distribution Analysis

This subject is discussed in depth in Reference 2. A summary of this report is given here.

In a measurement of peak local power density, F_Q, with the moveable detector system described in Section 7.6, the following uncertainties have to be considered:

1. Reproducibility of the measured signal

2. Errors in the calculated relationship between detector current and local flux

3. Errors in the calculated relationship between detector flux and peak rod power some distance from the measurement thimble.

The appropriate allowance for 1 above has been quantified by repetitive measurements made with several inter-calibrated detectors by using the common thimble features of the In-core Detector System. This system allows more than one detector to access any thimble. Errors in category 2 above are quantified to the extent possible, by using the fluxes measured at one thimble location to predict fluxes at another location which is also measured. Local power distribution predictions are verified in critical experiments on arrays of rods with simulated guide thimbles, control rods, burnable poisons, etc. These critical experiments provide quantification of error of types 2 and 3 above.

Reference 2 describes critical experiments performed at the Westinghouse Reactor Evaluation Center and measurements taken on two Westinghouse plants with In-core Detector Systems of the same type as used in the plant described herein. The report concludes that the uncertainty associated with the peak nuclear heat flux factor, F_Q, is 4.58 percent at the 95 percent confidence level with only 5 percent of the measurements greater than the inferred value. This is the equivalent of a 2σ limit on a normal distribution and is the uncertainty to be associated with a full core flux map with moveable detectors reduced with a reasonable set of input data incorporating the influence of burnup on the radial power distribution. The uncertainty is usually rounded up to 5 percent.

In comparing measured power distributions (or detector currents) against the calculations for the same situation, it is not possible to subtract out the detector reproducibility. Thus a comparison between measured and predicted power distributions has to include some measurement error. Such a comparison is given on Figure 4.3-14 for one of the maps used in Reference 2. Since the first publication of the report, hundreds of maps have been taken on these and other reactors. The results confirm the adequacy of the 5 percent uncertainty allowance on the calculated F_Q.

A similar analysis for the uncertainty in $F_{\Delta H}$ (rod integral power) measurements results in an allowance of 3.60 percent at the equivalent of a 2σ confidence level. For historical reasons, an 8 percent uncertainty factor is allowed in the nuclear design basis; that is, the predicted rod integrals at full power must not exceed the design $F_{\Delta H}$ less 8 percent. This 8 percent may be reduced in final design to 4 percent to allow a wider range of acceptable axial power distributions in the DNB analysis and still meet the design bases of Section 4.3.1.3.

A measurement in the second cycle of a 121 assembly, 12 foot core is compared with a simplified one dimensional core average axial calculation on Figure 4.3-15. This calculation does not give explicit representation to the fuel grids.

The accumulated data on power distributions in actual operation is basically of three types:

1. Much of the data is obtained in steady state operation at constant power in the normal operating configuration.

2. Data with unusual values of axial offset have been obtained in the past as part of the multi-point ex-core detector calibration exercise which is performed monthly.

3. Special tests have been performed in load follow and other transient xenon conditions which have yielded useful information on power distributions.

These data are presented in detail in Reference 6. Figure 4.3-16 contains a summary of measured values of F_Q as a function of axial offset for five plants from that report.

4.3.2.2.8 Testing

A very extensive series of physics tests is performed on first cores. These tests are described in Section 14. Since not all limiting situations can be created at BOL, the main purpose of the tests is to provide a check on the calculational methods used in the predictions for the conditions of the test. Tests performed at the beginning of each reload cycle are limited to verification of steady state power distributions.

4.3.2.2.9 Monitoring Instrumentation

The adequacy of instrument numbers, spatial deployment, required correlations between readings and peaking factors, calibration and errors are described in References 2, 5, and 6. The relevant conclusions are summarized here in Section 4.3.2.2.7.

Provided the limitations given in Section 4.3.2.2.6 on rod insertion and flux difference are observed, the Ex-core Detector System provides adequate monitoring of power distributions.

Further details of specific limits on the observed rod positions and flux difference are given in the COLR (See Section 4.5).

Limits for alarms, reactor trip, etc. are given in the Technical Specifications. Descriptions of the systems provided are given in Section 7.7.

4.3.2.3 Reactivity Coefficients

The kinetic characteristics of the reactor core determine the response of the core to changing plant conditions or to operator adjustments made during normal operation, as well as the core response during abnormal or accidental transients. These kinetic characteristics are quantified in reactivity coefficients. The reactivity coefficients reflect the changes in the neutron multiplication due to varying plant conditions such as power, moderator, or fuel temperatures, or less significantly due to a change in pressure or void conditions. Since reactivity coefficients change during the life of the core, ranges of coefficients are employed in transient analysis to determine the response of the plant throughout life. The results of such simulations and the reactivity coefficients used are presented in Section 15. The analytical methods and calculational models used in calculating the reactivity coefficients are given in Section 4.3.3. These models have been confirmed through extensive testing of more than thirty cores similar to the plant described herein; results of these tests are discussed in Section 4.3.3. Quantitative information for calculated reactivity coefficients, including fuel Doppler coefficient, moderator coefficients (density, temperature, pressure, void) and power coefficient is given in the following sections.

4.3.2.3.1 Fuel Temperature (Doppler) Coefficient

The fuel temperature (Doppler) coefficient is defined as the change in reactivity per degree change in effective fuel temperature and is primarily a measure of the Doppler broadening of U-238 and Pu-240 resonance absorption peaks. Doppler broadening of other isotopes such as U-236, Np-237 etc. are also considered but their contributions to the Doppler effect is small. An increase in fuel temperature increases the effective resonance absorption cross sections of the fuel and produces a corresponding reduction in reactivity.

The fuel temperature coefficient is calculated by performing two-group three-dimensional calculations using ANC (Reference 31). The fuel temperature coefficient is calculated by subtracting the MTC from the ITC from HZP to HFP.

A typical Doppler temperature coefficient is shown on Figure 4.3-17 as a function of the effective fuel temperature (at BOL and EOL conditions). The effective fuel temperature is lower than the volume averaged fuel temperature since the neutron flux distribution is non-uniform through the pellet and gives preferential weight to the surface temperature. A typical Doppler-only contribution to the power coefficient, defined later, is shown on Figure 4.3-18 as a function of relative core power. The integral of the differential curve on Figure 4.3-18 is the Doppler contribution to the power defect and is shown on Figure 4.3-19 as a function of relative power. The Doppler-only power coefficient and defects were calculated using three-dimensional ANC (Reference 31). The Doppler coefficient becomes more negative as a function of life as the Pu-240 content increases, thus increasing the Pu-240 resonance absorption but less negative as the fuel temperature changes with burnup as described in Section 4.3.3.1. The upper and lower limits of Doppler coefficient used in accident analyses are given in Section 15. The Doppler-only coefficient and defect change slightly on a cycle-specific basis. The appropriate NDR should be referenced for the current cycle's information (see Section 4.5).

4.3.2.3.2 Moderator Coefficients

The moderator coefficient is a measure of the change in reactivity due to a change in specific coolant parameters such as density, temperature, pressure, or void. The coefficients so obtained are moderator density, temperature, pressure, and void coefficients.

Moderator Density and Temperature Coefficients

The moderator temperature (density) coefficient is defined as the change in reactivity per unit change in the moderator temperature (density). Generally, the effect of the changes in moderator density as well as the temperature are considered together. An increase in moderator density results in more moderation and hence an increase in reactivity. Therefore, the moderator density coefficient is positive. As temperature increases, density decreases (for a constant pressure); hence the moderator temperature coefficient becomes more negative. An increase in coolant temperature, keeping the density constant, leads to a hardened neutron spectrum and results in an increase in resonance absorption in U-238, Pu-240 and other isotopes. The hardened spectrum also causes a decrease in the fission-to-capture ratio in U-235 and Pu-239. Both of these effects make the moderator temperature coefficient more negative. Since water density changes more rapidly with temperature as temperature increases, the moderator temperature (density) coefficient becomes more negative (positive) with increasing temperature.

The soluble boron used in the reactor as a means of reactivity control also has an effect on moderator density coefficient since the soluble boron poison density as well as the water density is decreased when the coolant temperature rises. A decrease in the soluble poison concentration introduces a positive component in the moderator temperature coefficient.

Thus, if the concentration of soluble poison is large enough, the net value of the coefficient may be positive. With the burnable absorbers present, however, the initial hot boron concentration is sufficiently low that the moderator temperature coefficient is negative at operating temperatures. The effect of control rods is to make the moderator coefficient more negative by reducing the required soluble boron concentration and by increasing the "leakage" of the core.

With burnup, the moderator temperature coefficient becomes more negative primarily as a result of boric acid dilution but also to an extent from the effects of the buildup of plutonium and fission products.

The moderator coefficient is calculated for the various plant conditions discussed above by performing two-group three-dimensional calculations, varying the moderator temperature (and density) by about ± 5°F about each of the mean temperatures. The moderator temperature coefficient is shown as a function of core temperature and boron concentration for the unrodded and rodded core on Figures 4.3-20 through 4.3-22. The temperature range covered is from cold (68°F) to about 600°F. The contribution due to Doppler coefficient (because of change in moderator temperature) has been subtracted from these results. Figure 4.3-23 shows the hot, full power moderator temperature coefficient plotted as a function of first cycle lifetime for the just critical boron concentration condition based on the design boron letdown condition.

The moderator coefficients presented here are calculated on a corewise basis, since they are used to describe the core behavior in normal and accident situations when the moderator temperature changes can be considered to affect the whole core. Moderator temperature coefficients change on a cycle-specific basis. The appropriate NDR should be referenced for the current cycle's information (see Section 4.5).

Moderator Pressure Coefficient

The moderator pressure coefficient relates the change in moderator density, resulting from a reactor coolant pressure change, to the corresponding effect on neutron production. This coefficient is of much less significance in comparison with the moderator temperature coefficient. A change of 50 psi in pressure has approximately the same effect on reactivity as a half-degree change in moderator temperature. This coefficient can be determined from the moderator temperature coefficient by relating change in pressure to the corresponding change in density. The moderator pressure coefficient is negative over a portion of the moderator temperature range at beginning-of-life (-0.004 pcm/psi, BOL) but is always positive at operating conditions and becomes more positive during life (+0.3 pcm/psi, EOL).

Moderator Void Coefficient

The moderator void coefficient relates the change in neutron multiplication to the presence of voids in the moderator. In a PWR this coefficient is not very significant because of the low void content in the coolant. The core void content is less than one-half of one percent and is due to local or statistical boiling. The void coefficient at BOL varies from 50 pcm/percent void at low temperatures to -250 pcm/percent void at EOL and at operating temperatures. The negative void coefficient at operating temperature becomes more negative with fuel burnup.

4.3.2.3.3 Power Coefficient

The combined effect of moderator temperature and fuel temperature change as the core power level changes is called the total power coefficient and is expressed in terms of reactivity change per percent power change. A typical plot of the power coefficient at BOL and EOL conditions is given on Figure 4.3-24. It becomes more negative with burnup reflecting the combined effect of moderator and fuel temperature coefficients with burnup. A typical plot of the power defect (integral reactivity effect) at BOL and EOL is given on Figure 4.3-25. The power coefficient and defect change on a cycle-specific basis. The appropriate NDR should be referenced for the current cycle (see Section 4.5).

4.3.2.3.4 Comparison of Calculated and Experimental Reactivity Coefficients

Section 4.3.3 describes the comparison of calculated and experimental reactivity coefficients in detail. Based on the data presented there, the accuracy of the current analytical model is:

± 0.2 percent $\Delta\rho$ for Doppler and power defect

± 2 pcm/°F for the moderator coefficient

Experimental evaluation of the calculated coefficients are done during the physics startup tests described in Section 14.

4.3.2.3.5 Reactivity Coefficients Used in Transient Analysis

Table 4.3-2 gives the representative ranges for the reactivity coefficients used in transient analysis. The exact values of the coefficient used in the analysis depend on whether the transient of interest is examined at the BOL or EOL, whether most negative or the most positive (least negative) coefficients are appropriate, and whether spatial nonuniformity must be considered in the analysis. Conservative values of coefficients, considering various aspects of analysis, are used in the transient analysis. This is described in Section 15.

The values listed in Table 4.3-2 and illustrated on Figures 4.3-17 through 4.3-25 apply to a typical reload cycle. The coefficients appropriate for use in subsequent cycles depend on the core's operating history, the number and enrichment of fresh fuel assemblies, the loading pattern of burned and fresh fuel, the number and location of any burnable absorber rods, etc. The need for a reevaluation of any accident in a subsequent cycle is contingent upon whether or not the coefficients for that cycle fall within the identified range used in the analysis presented in Section 15. Control rod requirements for typical Unit 1 and Unit 2 reload cores are given in Table 4.3-3.

4.3.2.4 Control Requirements

To ensure the shutdown margin stated in the Technical Specifications under conditions where a cooldown to ambient temperature is required, concentrated soluble boron is added to the coolant. Typical boron concentrations for several core conditions are listed in Table 4.3-2. For all core conditions including refueling, the boron concentration is well below the solubility limit. The RCCAs are employed to bring the reactor to the hot shutdown condition. The minimum required shutdown margin is given in the Technical Specifications.

The ability to accomplish the shutdown for hot conditions is demonstrated in Table 4.3-3 by comparing the difference between the RCCA's reactivity available with an allowance for the worst stuck rod with that required for control and protection purposes. The shutdown margin includes an allowance of 10 percent for analytic uncertainties (see Section 4.3.2.4.9). The largest reactivity control requirement appears at the EOL when the moderator temperature coefficient reaches its peak negative value as reflected in the larger power defect.

The control rods are required to provide sufficient reactivity to account for the power defect from full power to zero power and to provide the required shutdown margin. The reactivity addition resulting from power reduction consists of contributions from Doppler, moderator temperature, flux redistribution, and reduction in void content as discussed below.

4.3.2.4.1 Doppler

The Doppler effect arises from the broadening of U-238 and Pu-240 resonance peaks with an increase in effective pellet temperature. This effect is most noticeable over the range of zero power to full power due to the large pellet temperature increase with power generation.

4.3.2.4.2 Variable Average Moderator Temperature

When the core is shut down to the hot, zero power condition, the average moderator temperature changes from the equilibrium full load value determined by the steam generator and turbine characteristics (steam pressure, heat transfer, tube fouling, etc) to the equilibrium no load value, which is based on the steam generator shell side design pressure. The design change in temperature is conservatively increased by 4°F to account for the control dead band and measurement errors.

Since the moderator coefficient is negative, there is a reactivity addition with power reduction. The moderator coefficient becomes more negative as the fuel depletes because the boron concentration is reduced. This effect is the major contributor to the increased requirement at EOL.

4.3.2.4.3 Redistribution

During full power operation the coolant density decreases with core height, and this, together with partial insertion of control rods, results in less fuel depletion near the top of the core. Under steady state conditions, the relative power distribution will be slightly asymmetric towards the bottom of the core. On the other hand, at hot zero power conditions, the coolant density is uniform up the core, and there is no flattening due to Doppler. The result will be a flux distribution which at zero power can be skewed toward the top of the core.

The reactivity insertion due to the skewed distribution is calculated with an allowance for the most adverse effects of xenon distribution.

4.3.2.4.4 Void Content

A small void content in the core is due to nucleate boiling at full power. The void collapse coincident with power reduction makes a small reactivity contribution.

4.3.2.4.5 Rod Insertion Allowance

At full power, the control bank is operated within a prescribed band of travel to compensate for small periodic changes in boron concentration, changes in temperature, and very small changes in the xenon concentration not compensated for by a change in boron concentration. When the control bank reaches either limit of this band, a change in boron concentration is required to compensate for additional reactivity changes. Since the insertion limit is set by a rod travel limit, a conservatively high calculation of the inserted worth is made which exceeds the normally inserted reactivity.

4.3.2.4.6 Burnup

Excess reactivity is installed at the beginning of each cycle to provide sufficient reactivity to compensate for fuel depletion and fission products throughout the cycle. This reactivity is controlled by the addition of soluble boron to the coolant and by burnable absorbers. The soluble boron concentration for several core configurations, and unit boron worths are given in Table 4.3-2. Since the excess reactivity for burnup is controlled by soluble boron and/or burnable absorbers, it is not included in control rod requirements.

4.3.2.4.7 Xenon and Samarium Poisoning

Changes in xenon and samarium concentrations in the core occur at a sufficiently slow rate, even following rapid power level changes, that the resulting reactivity change is controlled by changing the soluble boron concentration.

4.3.2.4.8 pH Effects

Changes in reactivity due to a change in coolant pH, if any, are sufficiently small in magnitude and occur slowly enough to be controlled by the Boron System. Further details are available in Reference 8.

4.3.2.4.9 Experimental Confirmation

Following a normal shutdown, the total core reactivity change during cooldown with a stuck rod has been measured on a 121 assembly, 10-foot high core, and a 121 assembly, 12-foot high core. In each case, the core was allowed to cool down until it reached criticality simulating the steamline break accident. For the 10-foot core, the total reactivity change associated with the cooldown was overpredicated by about 0.3 percent $\Delta\rho$ with respect to the measured result. This represents an error of about 5 percent in the total reactivity change and is about half the uncertainty allowance for this quantity. For the 12-foot core, the difference between the measured and predicted reactivity change was an even smaller 0.2 percent $\Delta\rho$. These measurements and others demonstrate the ability of the methods described in Section 4.3.3 to accurately predict the total shutdown reactivity of the core.

4.3.2.5 Control

Core reactivity is controlled by means of a chemical poison dissolved in the coolant, RCCAs, and burnable absorber rods as described below.

4.3.2.5.1 Chemical Poison

Boron in solution as boric acid is used to control relatively slow reactivity changes associated with:

1. The moderator temperature defect in going from cold shutdown at ambient temperature to the hot operating temperature at zero power

2. The transient xenon and samarium poisoning, such as that following power changes or changes in RCC position

3. The excess reactivity required to compensate for the effects of fissile inventory depletion and buildup of long-life fission products

4. The burnable absorber depletion

Typical boron concentrations for various core conditions are presented in Table 4.3-2.

4.3.2.5.2 Rod Cluster Control Assemblies

Fifty-three RCCAs are employed. These are used for shutdown and for control purposes to offset fast reactivity changes associated with:

1. The required shutdown margin in the hot zero power, stuck rod condition

2. The reactivity compensation as a result of an increase in power above hot zero power (power defect including Doppler, and moderator reactivity changes)

3. Unprogrammed fluctuations in boron concentration, coolant temperature, or xenon concentration (with rods not exceeding the allowable rod insertion limits)

4. Reactivity ramp rates resulting from load changes

The allowed control bank reactivity insertion is limited at full power to maintain shutdown capability. As the power level is reduced, control rod reactivity requirements are also reduced and more rod insertion is allowed. The control bank position is monitored and the operator is notified by an alarm if the limit is approached. The determination of the insertion limit uses conservative xenon distributions and axial power shapes. In addition, the RCCA withdrawal pattern determined from these analyses is used in determining power distribution factors and in determining the maximum worth of an inserted RCCA ejection accident. For further discussion refer to the Technical Specifications on rod insertion limits.

Power distribution, rod ejection, and rod misalignment analyses are based on the arrangement of the shutdown and control groups of the RCCAs shown on Figures 4.3-26A and B. All shutdown RCCAs are withdrawn before withdrawal of the control banks is initiated. In going from zero to 100 percent power, control banks A, B, C, and D are withdrawn sequentially. The limits of rod positions are provided in the COLR (see Section 4.5). Further discussion on the basis of rod insertion limits are provided in the Technical Specifications.

4.3.2.5.3 Burnable Absorbers

The burnable absorbers provide partial control of the excess reactivity available during the fuel cycle. In doing so, the moderator temperature coefficient is prevented from being positive at normal operating conditions. They perform this function by reducing the requirement for soluble poison in the moderator at the beginning of the fuel cycle as described previously. The burnable absorber rod pattern in the core together with the number of rods per assembly is shown in Section 4.5 for each Unit's current cycle. The boron in the burnable absorbers is depleted with burnup but at a sufficiently slow rate so that the resulting critical concentration of soluble boron is such that the moderator temperature coefficient remains non-positive at all times for power operating conditions.

4.3.2.5.4 Peak Xenon Startup

Compensation for the peak xenon buildup is accomplished using the Boron Control System. Startup from the peak xenon condition is accomplished with a combination of rod motion and boron dilution.

The boron dilution may be made at any time, even during the shutdown period, provided the shutdown margin is maintained.

4.3.2.5.5 Load Follow Control and Xenon Control

During load follow maneuvers, power changes are accomplished using control rod motion and dilution or boration by the Boron System as required. Control rod motion is limited by the control rod insertion limits as provided in the COLR (see Section 4.5) and discussed previously in this section. Reactivity changes due to the changing xenon concentration can be controlled by rod motion and/or changes in soluble boron concentration.

4.3.2.5.6 Burnup

Control of the excess reactivity for burnup is accomplished using soluble boron and/or burnup absorbers. The boron concentration must be limited during operating conditions to ensure the moderator temperature coefficient is non-positive. Sufficient burnable absorber is installed at the beginning of a cycle to give the desired cycle lifetime without exceeding the boron concentration value which would yield a positive MTC per Technical Specifications. The practical minimum boron concentration is 10 ppm.

4.3.2.6 <u>Control Rod Patterns and Reactivity Worth</u>

The RCCAs are designated by function as the control groups and the shutdown groups. The terms "group" and "bank" are used synonymously throughout this report to describe a particular grouping of control assemblies. The RCCA pattern is displayed on Figures 4.3-26A and B which is not expected to change during the life of the plant. The control banks are labeled A, B, C, and D and the shutdown banks are labeled SA, SB, SC, and SD. Each bank, although operated and controlled as a unit, is comprised of two subgroups. The axial position of the RCCAs may be controlled manually or automatically. The RCCAs are all dropped into the core following actuation of reactor trip signals.

Two criteria have been employed for selection of the control groups. First, the total reactivity worth must be adequate to meet the requirements specified in Table 4.3-3. Second, in view of the fact that these rods may be partially inserted at power operation, the total power peaking factor should be low enough to ensure that the power capability requirements are met. Analyses indicate that the first requirement can be met either by a single group or by two or more banks whose total worth equals at least the required amount. The axial power shape would be more peaked following movement of a single group of rods worth 3 to 4 percent $\Delta\rho$; therefore, four banks (described as A, B, C, and D on Figures 4.3-26A and B) each worth approximately 1 percent $\Delta\rho$ have been selected.

The position of control banks for criticality under any reactor condition is determined by the concentration of boron in the coolant. On an approach to criticality, boron is adjusted to ensure that criticality will be achieved with control rods above the insertion limit set by shutdown and other considerations (See the Technical Specifications).

Early in the cycle there may also be a withdrawal limit at low power to maintain a negative moderator temperature coefficient. Usual practice is to adjust boron to ensure that the rod position lies within the so-called maneuvering band, that is such that an escalation from zero power to full power does not require further adjustment of boron concentration.

Ejected rod worths are given in Section 15.3.1.6 for several different conditions. Experimental confirmation of these worths can be found by reference to startup test reports (9).

Allowable deviations due to misaligned control rods are discussed in the Technical Specifications.

A representative calculation for two banks of control rods withdrawn simultaneously (rod withdrawal accident) is given on Figure 4.3-27.

Calculation of control rod reactivity worth versus time following reactor trip involves both control rod velocity and differential reactivity worth. The rod position versus time of travel after rod release assumed is given on Figure 4.3-28 for Vantage+ fuel. The drop time to the dashpot increases from 2.2 to 2.7 seconds for Vantage 5H and Vantage+ fuel, with the other times increasing proportionately. For nuclear design purposes, the reactivity worth versus rod position is calculated by a series of steady state calculations at various control rod positions assuming all rods out of the core as the initial position in order to minimize the initial reactivity insertion rate. Also, to be conservative, the rod of highest worth is assumed stuck out of the core and the flux distribution (and thus reactivity importance) is assumed to be skewed to the bottom of the core. The result of these calculations is shown on Figure 4.3-29.

The shutdown groups provide additional negative reactivity to assure an adequate shutdown margin. Shutdown margin is defined as the amount by which the core would be subcritical at hot shutdown if all RCCAs are tripped, but assuming that the highest worth assembly remains fully withdrawn and no changes in xenon or boron take place. The loss of control rod worth due to the material irradiation is negligible since only D bank rods may be in the core under normal operating conditions.

The values given in Table 4.3-3 show that the available reactivity in withdrawn RCCAs provides the design basis minimum shutdown margin allowing for the highest worth cluster to be at its fully withdrawn position. An allowance for uncertainty in the calculated worth of N-1 rods is made before determination of the shutdown margin.

4.3.2.7 Criticality of Fuel Assemblies

Criticality of fuel assemblies outside of the reactor is precluded by adequate design of fuel transfer and fuel storage facilities and by administrative control procedures. This section identifies those criteria important to criticality safety analyses.

New fuel is generally stored in fuel storage facilities with no water present but which are designed so as to prevent accidental criticality even if unborated water is present.

In the analysis for the storage facilities, the fuel assemblies are assumed to be in their most reactive condition, namely fresh or undepleted and with no control rods or removable neutron absorbers present. Assemblies cannot be closer together than the design separation provided by the storage facility except in special cases such as in fuel shipping containers where analyses are carried out to establish the acceptability of the design. The mechanical integrity of the fuel assembly is assumed and no credit is taken for neutron absorption properties of the storage facility unless specifically included in the design. For full flooding with unborated water, the fuel assembly spacing of the facility provides essentially full nuclear isolation, and k_{eff} for the array is no greater than k_{eff} for the single most reactive fuel assembly. The criterion for full flooding is $k_{eff} \leqq 0.95$.

The fuel assembly (17 x 17 fuel rods) of standard design and 3.5 w/o enriched uranium oxide, without a control rod or burnable absorbers, fully flooded and reflected with cold clean water, has a k_{eff} of about 0.85. Two such fuel assemblies spaced 1 inch apart with parallel axes 9.5 inches apart have a k_{eff} of about 0.99. Three such fuel assemblies spaced 1 inch apart with parallel axes would be supercritical.

An infinite number of dry fuel assemblies of this design would have a k_{eff} < 0.80.

4.3.2.8 Stability

4.3.2.8.1 Introduction

The stability of the PWR cores against xenon-induced spatial oscillations and the control of such transients are discussed extensively (References 5, 10, 11, 12). A summary of these reports is given in the following discussion and the design bases are given in Section 4.3.1.6.

In a large reactor core, xenon-induced oscillations can take place with no corresponding change in the total power of the core. The oscillation may be caused by a power shift in the core which occurs rapidly by comparison with the xenon-iodine time constants. Such a power shift occurs in the axial direction when a plant load change is made by control rod motion and results in a change in the moderator density and fuel temperature distributions. Such a power shift could occur in the diametral plane of the core as a result of abnormal control action.

Due to the negative power coefficient of reactivity, PWR cores are inherently stable to oscillations in total power. Protection against total power stabilities is provided by the Control and Protection System as described in Chapter 7. Hence, the discussion on the core stability will be limited here to xenon-induced spatial oscillations.

4.3.2.8.2 Stability Index

Power distributions, either in the axial direction or in the X-Y plane, can undergo oscillations due to perturbations introduced in the equilibrium distributions without changing the total core power. The overtones in the current PWRs, and the stability of the core against xenon-induced oscillations can be determined in terms of the eigenvalues of the first flux overtones. Writing, either in the axial direction or in the X-Y plane, the eigenvalue, ϵ, of the first flux harmonic as

$\varepsilon = b + ic,$ (Reference 10)

then b is defined as the stability index and $T = 2\pi/C$ as the oscillation period of the first harmonic. The time-dependence of the first harmonic $\delta\phi$ in the power distribution can now be represented as

$$\delta\phi(t) = A\, e^{\varepsilon t} = a e^{bt} \cos ct,$$ (Reference 12)

where A and a are constants. The stability index can also be obtained approximately by:

$$b = \frac{1}{T} \ln \frac{A_n + 1}{A_n}$$

where A_n, A_{n+1} are the successive peak amplitudes of the oscillation and T is the time period between the successive peaks.

4.3.2.8.3 Prediction of the Core Stability

The stability of the core described herein (i.e., with 17 x 17 fuel assemblies) against xenon-induced spatial oscillations is expected to be equal to or better than that of earlier designs. The prediction is based on a comparison of the parameters which are significant in determining the stability of the core against the xenon-induced oscillations, namely (1) the overall core size is unchanged and spatial power distributions will be similar, (2) the moderator temperature coefficient is expected to be similar, and (3) the Doppler coefficient of reactivity is expected to be similar at full power.

Analysis of both the axial and X-Y xenon transient tests, discussed in Section 4.3.2.8.5, shows that the calculational model is adequate for the prediction of core stability.

4.3.2.8.4 Stability Measurements

Axial Measurements

Two axial xenon transient tests conducted in a PWR with a core height of 12 feet and 121 fuel assemblies are reported in Reference 13, and will be briefly discussed here. The tests were performed at approximately 10 percent and 50 percent of cycle life.

Both a free-running oscillation test and a controlled test were performed during the first test. The second test at mid-cycle consisted of a free-running oscillation test only. In each of the free-running oscillation tests, a perturbation was introduced to the equilibrium power distribution through an impulse motion of the control bank D, and the subsequent oscillation was monitored to measure the stability index and the oscillation period. In the controlled test conducted early in the cycle, the part-length rods were used to follow the oscillations to maintain an axial offset (AO) within the prescribed limits. The AO of power was obtained from the ex-core ion chamber readings (which had been calibrated against the in-core flux maps) as a function of time for both free-running tests as shown on Figure 4.3-30.

The total core power was maintained constant during these spatial xenon tests, and the stability index and the oscillation period were obtained from a least-square fit of the AO data in the form of Equation 2. The AO of power is the quantity that properly represents the axial stability in the sense that it essentially eliminates any contribution from even order harmonics including the fundamental mode. The conclusions of the tests are the following:

1. The core was stable against induced axial xenon transients both at the core average burnups of 1550 MWD/MTU and 7700 MWD/MTU. The measured stability indices are $-0.041\ hr^{-1}$ for the first test (Curve 1 of

Figure 4.3-30) and -0.014 hr^{-1} for the second test (Curve 2 of Figure 4.3-30). The corresponding oscillation periods are 32.4 hours and 27.2 hours, respectively.

2. The reactor core becomes less stable as fuel burnup progresses and the axial stability index was essentially zero at 12,000 MWD/MTU.

Measurements in the X-Y Plane

Two X-Y xenon oscillation tests were performed at a PWR plant with a core height of 12 feet and 157 fuel assemblies. The first test was conducted at a core average burnup of 1540 MWD/MTU and the second at a core average burnup of 12900 MWD/MTU. Both of the X-Y xenon tests show that the core was stable in the X-Y plane at both burnups. The second test shows that the core became more stable as the fuel burnup increased and all Westinghouse PWRs with 121 and 157 assemblies are expected to be stable throughout their burnup cycles.

In each of the two X-Y tests, a perturbation was introduced to the equilibrium power distribution through an impulse motion of one RCCA located along the diagonal axis. Following the perturbation, the uncontrolled oscillation was monitored using the moveable detector and thermocouple system and the ex-core power range detectors. The quadrant tilt difference is the quantity that properly represents the diametral oscillation in the X-Y plane of the reactor core in that the differences of the quadrant average powers over two symmetrically opposite quadrants essentially eliminates the contribution to the oscillation from the azimuthal mode. The quadrant tilt difference data were fitted in the form of Equation 2 through a least-square method. A stability index of -0.076 hr^{-1} with a period of 29.6 hours was obtained from the thermocouple data shown on Figure 4.3-31.

It was observed in the second X-Y xenon test that the PWR core with 157 fuel assemblies had become more stable due to an increased fuel depletion, and the stability index was not determined.

4.3.2.8.5 Comparison of Calculations with Measurements

The analysis of the axial xenon transient tests was performed in an axial slab geometry using a flux synthesis technique. The direct simulation of the AO data was carried out using the PANDA Code (Reference 14). The analysis of the X-Y xenon transient tests was performed in an X-Y geometry using a modified TURTLE code (Reference 7). Both the PANDA and TURTLE codes solve the two-group time-dependent neutron diffusion equation with time-dependent xenon and iodine concentrations. The fuel temperature and moderator density feedback is limited to a steady state model. All the X-Y calculations were performed in an average enthalpy plane.

The basic nuclear cross sections used in this study were generated from a unit cell depletion program which was evolved from the codes LEOPARD (Reference 15) and CINDER (Reference 16). The detailed experimental data during the tests including the reactor power level, enthalpy rise, and the impulse motion of the control rod assembly, as well as the plant follow burnup data, were closely simulated in the study.

The results of the stability calculation for the axial tests are compared with the experimental data in Table 4.3-4. The calculations show conservative results for both of the axial tests with a margin of approximately 0.01 hr^{-1} in the stability index.

An analytical simulation of the first X-Y xenon oscillation test shows a calculated stability index of -0.081 hr^{-1}, in good agreement with the measured value of -0.076 hr^{-1}. As indicated earlier, the second X-Y xenon test showed that the core had become more stable compared to the first test and no evaluation of the stability index was attempted. This increase in the core stability in the X-Y plane due to increased fuel burnup is due mainly to the increased magnitude of the negative moderator temperature coefficient.

Previous studies of the physics of xenon oscillations, including three-dimensional analysis, are reported in the series of topical reports (References 10, 11, 12). A more detailed description of the experimental results and analysis of the axial and X-Y xenon transient tests is presented in Reference 13 and Section 1 of Reference 17.

4.3.2.8.6 Stability Control and Protection

The Ex-core Detector System is utilized to provide indications of xenon-induced spatial oscillations. The readings from the ex-core detectors are available to the operator and also form part of the protection system.

Axial Power Distribution

For maintenance of proper axial power distributions, the operator is instructed to maintain an axial offset within a prescribed operating band, based on the ex-core detector readings. Should the axial offset be permitted to move far enough outside this band, the protection limit will be reached and the power will be automatically cut back.

Twelve-foot PWR cores become less stable to axial xenon oscillations as fuel burnup progresses. However, free xenon oscillations are not allowed to occur except for special tests. The full length control rod banks present in all modern Westinghouse PWRs are sufficient to dampen and control any axial xenon oscillations present. Should the axial offset be inadvertently permitted to move far enough outside the control band due to an axial xenon oscillation, or any other reason, the protection limit on axial offset will be reached and the power will be automatically cut back.

Radial Power Distribution

The core described herein is calculated to be stable against X-Y xenon induced oscillations at all times in life.

The X-Y stability of large PWRs has been further verified as part of the startup physics test program for PWR cores with 193 fuel assemblies. The measured X-Y stability of the cores with 157 and 193 assemblies was in good agreement with the calculated stability discussed in Sections 4.3.2.8.4 and 4.3.2.8.5. In the unlikely event that X-Y oscillations occur, backup actions are possible and would be implemented, if necessary, to increase the natural stability of the core. This is based on the fact that several actions could be taken to make the moderator temperature coefficient more negative, which will increase the stability of the core in the X-Y plane.

Provisions for protection against nonsymmetric perturbations in the X-Y power distribution that could result from equipment malfunctions are made in the protection system design. This includes control rod drop, rod misalignment, and asymmetric loss-of-coolant flow.

A more detailed discussion of the power distribution control in the PWR cores is presented in Reference 5.

4.3.2.9 Vessel Irradiation

A brief review of the methods and analyses used in the determination of neutron and gamma ray flux attenuation between the core and the pressure vessel is given below. A more complete discussion is given in the pressure vessel irradiation and surveillance program.

The materials that serve to attenuate neutrons originating in the core and gamma rays, from both the core and structural component consist of the core baffle, core barrel, the neutron pads, and associated water annuli, all of which are within the region between the core and the pressure vessel.

In general, few-group neutron diffusion theory codes are used to determine fission power density distributions within the active core, and the accuracy of these analyses is verified by in-core measurements on operating reactors. Region and rodwise power sharing information from the core calculations is then used as source information in two-dimensional transport calculations which compute the flux distributions through the reactor.

The neutron flux distribution and spectrum in the various structural components varies significantly from the core to the pressure vessel. Representative values of the neutron flux distribution and spectrum are presented in Table 4.3-5. The values listed are based on time averaged equilibrium cycle reactor core parameters and power distributions, and thus, are suitable for long-term nvt projections and for correlation with radiation damage estimates.

The irradiation surveillance program utilizes actual test samples to verify the accuracy of the calculated fluxes at the vessel.

4.3.3 Analytical Methods

Calculations required in nuclear design consist of three distinct types, which are performed in sequence:

1. Determination of effective fuel temperatures

2. Generation of macroscopic few-group parameters

3. Space-dependent, few-group diffusion calculations

These calculations are carried out by computer codes which can be executed individually; however, at Westinghouse most of the codes required have been linked to form an automated design sequence which minimizes design time, avoids errors in transcription of data, and standardizes the design methods.

4.3.3.1 Fuel Temperature (Doppler) Calculations

Temperatures vary radially within the fuel rod depending on the heat generation rate in the pellet; the conductivity of the materials in the pellet, gap, and clad; and the temperature of the coolant.

The fuel temperatures for use in most nuclear design Doppler calculations are obtained from a simplified version of the Westinghouse fuel rod design model described in Section 4.2.1.3.1, which considers the effect of radial variation of pellet conductivity, expansion-coefficient and heat generation rate, elastic deflection of the clad, and a gap conductance which depends on the initial fill gas, the hot open gap dimension, and the fraction of the pellet over which the gap is closed. The fraction of the gap assumed closed represents an empirical adjustment used to produce good agreement with observed reactivity data at BOL. Further gap closure occurs with burnup and accounts for the decrease in Doppler defect with burnup which has been observed in operating plants. For detailed calculations of the Doppler coefficient, a more sophisticated temperature model is used which accounts for the effects of fuel swelling, fission gas release, and plastic clad deformation.

Radial power distributions in the pellet as a function of burnup are obtained from LASER (Reference 18) calculations.

The effective U-238 temperature for resonance absorption is obtained from the radial temperature distribution by applying a radially dependent weighting function. The weighting function was determined from REPAD (Reference 19) Monte Carlo calculations of resonance escape probabilities in several steady state and transient temperature distributions. In each case a flat pellet temperature was determined which produced the same resonance escape probability as the actual distribution. The weighting function was empirically determined from these results.

The effective Pu-240 temperature for resonance absorption is determined by a convolution of the radial distribution of Pu-240 number densities from LASER burnup calculations and the radial weighting function. The resulting temperature is burnup dependent, but the difference between U-238 and Pu-240 temperatures, in terms of reactivity effects, is small.

The effective pellet temperature for pellet dimensional change is that value which produces the same outer pellet radius in a virgin pellet as that obtained from the temperature model. The effective clad temperature for dimensional change is its average value.

The temperature calculational model has been validated by plant Doppler defect data as shown in Table 4.3-6 and Doppler coefficient data as shown on Figure 4.3-32. Stability index measurements also provide a sensitive measure of the Doppler coefficient near full power (see Section 4.3.2.8). It can be seen that Doppler defect data is typically within 0.2 percent $\Delta\rho$ of prediction.

4.3.3.2 Macroscopic Group Constants

There are two lattice codes which have been used for the generation of macroscopic group constants needed in the spatial, few-group diffusion codes. One is a version of the LEOPARD and CINDER codes, which has historically been the source of the macroscopic group constants. The other is PHOENIX-P, which is used in present reload designs (Reference 30).

Macroscopic few-group constants and analogous microscopic cross sections (needed for feedback and microscopic depletion calculations) were previously generated for fuel cells by a version of the LEOPARD (Reference 15) and CINDER (Reference 16) codes, which are linked internally and provide burnup dependent cross sections. Normally a simplified approximation of the main fuel chains is used; however, where needed, a complete solution for all the significant isotopes in the fuel chains from Th-232 to Cm-244 is available (Reference 20). Fast and thermal cross section library tapes contain microscopic cross sections taken for the most part from the ENDF/B (Reference 21) library, with a few exceptions where other data provide better agreement with critical experiments, isotopic measurements, and plant critical boron values. The effect on the unit fuel cell of non-lattice components in the fuel assembly is obtained by supplying an appropriate volume fraction of these materials in an extra region which is homogenized with the unit cell in the fast (MUFT) and thermal (SOFOCATE) flux calculations. In the thermal calculation, the fuel rod, clad, and moderator are homogenized by energy-dependent disadvantage factors derived from an analytical fit to integral transport theory results.

Group constants for discrete burnable absorber cells, guide thimbles, instrument thimbles, and interassembly gaps are generated in a manner analogous to the fuel cell calculation. Reflector group constants are taken from infinite medium LEOPARD calculations. Baffle group constants are calculated from an average of core and radial reflector microscopic group constants for stainless steel.

Group constants for control rods are calculated in a linked version of the HAMMER (Reference 22) and AIM (Reference 23) codes to provide an improved treatment of self shielding in the broad resonance structure of these isotopes at epithermal energies than is available in LEOPARD. The Doppler broadened cross sections of the control rod materials are represented as smooth cross sections in the 54-group LEOPARD fast group structure and in 30 thermal groups. The four-group constants in the rod cell and appropriate extra region are generated in the coupled space-energy transport HAMMER calculation. A corresponding AIM calculation of the homogenized rod cell with extra region is used to adjust the absorption cross sections of the rod cell to match the reaction rates in HAMMER. These transport-equivalent group constants are reduced to two-group constants for use in space-dependent diffusion calculations. In discrete X-Y calculations only one mesh interval per cell is used, and the rod group constants are further adjusted for use in this standard mesh by reaction rate matching the standard mesh unit assembly to a fine-mesh unit assembly calculation.

Validation of the cross section method is based on analysis of critical experiments as shown in Table 4.3-7, isotopic data as shown in Table 4.3-8, plant critical boron (C_B) values at HZP, BOL, as shown in Table 4.3-9 and at HFP as a function of burnup as shown on Figures 4.3-33 through 4.3-35. Control rod worth measurements are shown in Table 4.3-10.

Confirmatory critical experiments on discrete burnable absorbers are described in Reference 24.

PHOENIX-P has been approved by the USNRC as a lattice code for the generation of macroscopic and microscopic few group cross sections for PWR analysis (Reference 30). PHOENIX-P is a two-dimensional, multigroup, transport-based lattice code capable of providing all necessary data for PWR analysis. Since it is a dimensional lattice code, PHOENIX-P does not rely on predetermined spatial/spectral interaction assumptions for the heterogeneous fuel lattice and can provide a more accurate multigroup flux solution than versions of LEOPARD/CINDER.

The solution for the detailed spatial flux and energy distribution is divided into two major steps in PHOENIX-P (Reference 30). First, a two-dimensional fine energy group nodal solution is obtained, coupling individual subcell regions (pellet, clad, and moderator) as well as surrounding pins, using a method based on Carlvik's collision probability approach and heterogeneous response fluxes which preserve the heterogeneity of the pin cells and their surroundings. The nodal solution provides an accurate and detailed local flux distribution, which is then used to homogenize the pin cells spatially to fewer groups.

Then, a standard S4 discrete ordinates calculation solves for the angular distribution, based on the group-collapsed and homogenized cross-sections from the first step. These S4 fluxes normalize the detailed spatial and energy nodal fluxes, which are then used to compute reaction rates, power distributions and to deplete the fuel and burnable absorbers. A standard B1 calculation evaluates the fundamental mode critical spectrum, providing an improved fast difusion coefficient for the core spatial codes.

PHOENIX-P employs a 42 energy group library derived mainly from END/B-V files. This library was designed to capture the integral properties of the multigroup data properly during group collapse and to model important resonance parameters properly. It contains all neutronics data necessary for modeling fuel, fission products, cladding and structural materials, coolant, and control and burnable absorber materials present in the PWRs.

Group constants for burnable absorber cells, control rod cells, guide thimbles and instrumentation thimbles, or other non-fuel cells, can be obtained directly from PHOENIX-P without any adjustments such as those required in the cell or ID lattice codes.

4.3.3.3 Spatial Few-Group Diffusion Calculations

Historically, spatial few-group diffusion calculations consisted primarily of two-group X-Y calculations using an updated version of the TURTLE code and two-group axial calculations using an updated version of the PANDA code.

Discrete X-Y calculations (1 mesh per cell) were carried out to determine critical boron concentrations and power distributions in the X-Y plane. An axial average in the X-Y plane was obtained by synthesis from unrodded and rodded planes. Axial effects in unrodded depletion calculations were accounted for by the axial buckling, which varies with burnup and is determined by radial depletion calculations which are matched in reactivity to the analogous R-Z depletion calculation. The moderator coefficient is evaluated by varying the inlet temperature in the same X-Y calculations used for power distribution and reactivity predictions.

Validation of the reactivity calculations is associated with the validation of the group constants themselves, as discussed in Section 4.3.3.2. Validation of the Doppler calculations is associated with the fuel temperature validation discussed in Section 4.3.3.1. Validation of the moderator coefficient calculations is obtained by comparison with plant measurements at hot zero power conditions as shown in Table 4.3-11.

Axial calculations are used to determine differential control rod worth curves (reactivity versus rod insertion) and axial power shapes during steady state and transient xenon conditions (flyspeck curve). Group constants are obtained from the three-dimensional nodal model by flux-volume weighting on an axial slice-wise basis. Radial bucklings are determined by varying parameters in the buckling model while forcing the one-dimensional model to reproduce the axial characteristics (axial offset, mid-plane power) of the three-dimensional model.

Recent few-group spatial calculations have input PHOENIX-P supplied two-group cross-sections to the Advanced Nodal Code (ANC). ANC is a two-group, two or three-dimensional nodal code capable of determining typical nuclear design analyses, such as critical boron concentrations, average assembly and pin powers, control rod worths, reactivity coefficients, assembly and pin burnups and axial power distributions. Through the use of advanced nodal techniques, ANC is able to produce solutions similar to the fine mesh, finite difference diffusion theory codes such as TURTLE/TORTISE. ANC has been benchmarked against TORTISE (an improved version of TURTLE) for normal and off-normal conditions, such as ejected rod, stuck rod and dropped rod (Reference 31). The qualification of the PHOENIX-P/ANC methodology against measured data is given in Reference 30.

Validation of the spatial codes for calculating power distributions involves the use of in-core and ex-core detectors and is discussed in Section 4.3.2.2.7.

Based on comparison with measured data it is estimated that the accuracy of current analytical methods is:

± 0.2 percent $\Delta\rho$ for Doppler defect
± 2 x 10^{-5}/°F for moderator coefficient
± 50 ppm for critical boron concentration with depletion
± 3 percent for power distributions
± 0.2 percent $\Delta\rho$ for rod bank worth
± 4 pcm/step for differential rod worth
± 0.5 pcm/ppm for boron worth
± 0.1 percent $\Delta\rho$ for moderator defect

4.3.4 References for Section 4.3

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23. Flatt, H. P. and Baller, D. C., "AIM-5, A Multigroup, One Dimensional Diffusion Equation Code," NAA-SR-4694, March 1960.

24. Barry, R. F., "Nuclear Design of Westinghouse Pressurized Water Reactors with Burnable Poison Rods," WCAP-7806, December 1971.

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29. Henderson, W. B., "Results of the Control Rod Worth Program," WCAP-9217, October 1977.

30. Nguyen, T. Q. et al., "Qualification of the PHOENIX-P/ANC Nuclear Design System for Pressurized Water Reactor Cores," WCAP-11596-P-A, June 1988.

31. Liu, Y. S., et al., "ANC: A Westinghouse Advanced Nodal Computer Code," WCAP-10966-A, September 1986.

TABLE 4.3-1

REACTOR CORE DESCRIPTION

<u>Active Core</u>		
Equivalent Diameter, in.	132.7	
Core Average Active Fuel Height, First Core (Hot), in.	143.7	
Height-to-Diameter Ratio	1.09	
Total Cross Section Area, ft^2	96.06	
H_2O/U Molecular Ratio, Lattice (Cold)	2.41	
<u>Reflector Thickness and Composition</u>		
Top - Water plus Steel, in.	~10	
Bottom - Water plus Steel, in.	~10	
Side - Water plus Steel, in.	~15	
<u>Fuel Assemblies</u>		
Number	193	
Rod Array	17 x 17	
Rods per Assembly	264	
Rod Pitch, in.	0.496	
Overall Transverse Dimensions, in.	8.426 x 8.426	
Fuel Weight (as UO_2), lb	222,739	
Zircaloy Weight, lb	53,142	
Number of Grids per Assembly	2-R type	(top/bottom)
	6-Z type	(middle)
Composition of Grids	INC718	top/bottom
	Zircaloy-4	middle (V5H)
	Zirlo^{TM}	middle (V+)
Weight of Grids (Effective in Core), lb	2324	
Number of Guide Thimbles per Assembly	24	
Composition of Guide Thimbles	Zircaloy-4	(V5H)
	Zirlo^{TM}	(V+)

TABLE 4.3-1 (Cont.)

REACTOR CORE DESCRIPTION

Diameter of Guide Thimbles (upper part), in.	0.442 ID x 0.474 OD
Diameter of Guide Thimbles (lower part), in.	0.397 ID x 0.429 OD
Diameter of Instrument Guide Thimbles, in.	0.442 ID x 0.474 OD
<u>Fuel Rods</u>	
Number	50,952
Outside Diameter, in.	0.374
Diameter Gap, in.	0.0065
Clad Thickness, in.	0.0225
Clad Material	Zircaloy-4 (V5H) Zirlo^{TM} (V+)
<u>Fuel Pellets</u>	
Material	UO_2 Sintered
Density	95
Fuel Enrichments w/o[(1)]	<u>Typical Reload</u>
Region 1	4.0
Region 2	4.4
Region 3A	4.0
Region 3B	4.4
Diameter, in.	0.3225
Length, in.	0.530
Mass of UO_2 Per Foot of Fuel Rod, lb/ft	0.364
<u>Rod Cluster Control Assemblies</u>	
Neutron Absorber	Ag-In-Cd
Composition, percent	80, 15, 5
Diameter, in.	0.381
Density, lb/in.	0.367
Clad Material	Type 316L, Ionnitride Surface

(1) Typical reload values. Current values are given in the appropriate NDR (See Section 4.5).

TABLE 4.3-1 (Cont.)

REACTOR CORE DESCRIPTION

Clad Thickness, in.	0.0185
Number of Clusters, full length	53
Number of Absorber Rods per Cluster	24
Full Length Assembly Weight (dry), lb	149
<u>Burnable Absorber Rods</u>[(1)]	
Material	Borosilicate Glass
Outside Diameter, in.	0.381
Inner Tube, OD, in.	0.1815
Clad Material	Stainless Steel
Inner Tube Material	Stainless Steel
Boron Loading (w/o B_2O_3 in glass rod)	12.5
Weight of Boron - 10 per foot of rod, lb/ft	0.00419
<u>Integral Fuel Burnable Absorber</u>	
Material	ZrB_2
Content	2.350 mg B^{10}/in.
<u>Excess Reactivity</u>	
Maximum Fuel Assembly k (Cold, Clean Unborated Water)[(2)]	1.48
Maximum Core Reactivity (Cold, Zero Power, Beginning of Cycle)[(3)]	1.200

(2) Based on 5.0 w/o with negative reactivity holddown equivalent to 32 1.5X IFBA pins.

(3) Typical reload value. This parameter is cycle-specific and is a function of energy requirements and number of burnable absorbers used.

TABLE 4.3-2

NUCLEAR DESIGN PARAMETERS

Core Average Linear Power, kW/ft, including densification effects	5.44
Total Heat Flux Hot Channel Factor, F_Q including densification effects	2.40
Nuclear Enthalpy Rise Hot Channel Factor,[1]	
$F^N_{\Delta H}$	1.65
Reactivity Coefficients	
Doppler Coefficient	See Figures 4.3-17 and 4.3-18
Moderator Temperature Coefficient at Operating Conditions, pcm/°F(2)	0 to -44
Boron Coefficient in Primary Coolant, pcm/ppm	-16 to -8
Rodded Moderator Density Coefficient at Operating Conditions, pcm/gm/cc	$\leq +0.52 \times 10^5$

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(1) Cycle-specific values based on accident analysis. The Core Operating Limits Report (COLR) contains the current cycle limits (See Section 4.5).

(2) Note: 1 pcm = (percent mille) 10^{-5} $\Delta\rho$ where $\Delta\rho$ is calculated from two statepoint values of k_{eff} by ln (k_2/k_1).

TABLE 4.3-2 (Cont'd)

NUCLEAR DESIGN PARAMETERS

<u>Delayed Neutron Fraction and Lifetime</u>

β_{eff} BOL, (EOL)	0.0075 (0.0044)

<u>Control Rod Worths</u>

Rod Requirements	See Table 4.3-3
Maximum Bank Worth, pcm	< 2000
Maximum Ejected Rod Worth	See Chapter 15

<u>Boron Concentrations</u>(3)

Refueling CB, ARI (K<0.95)	> 1820
Shutdown (K=0.99) with ARI, HZP	971
Shutdown (K=0.99) with ARO, HZP	1914
To control at HZP, ARO, (K=1.0)	1741
To control at HFP, ARO, (K=1.0):	
0 MWD/MTU, No Xenon	1556
150 MWD/MTU, Eq Xenon	1206
1000 MWD/MTU, Eq Xenon	1224

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(3) Typical reload values. Current cycle values are given in the appropriate NDR. See Section 4.5.

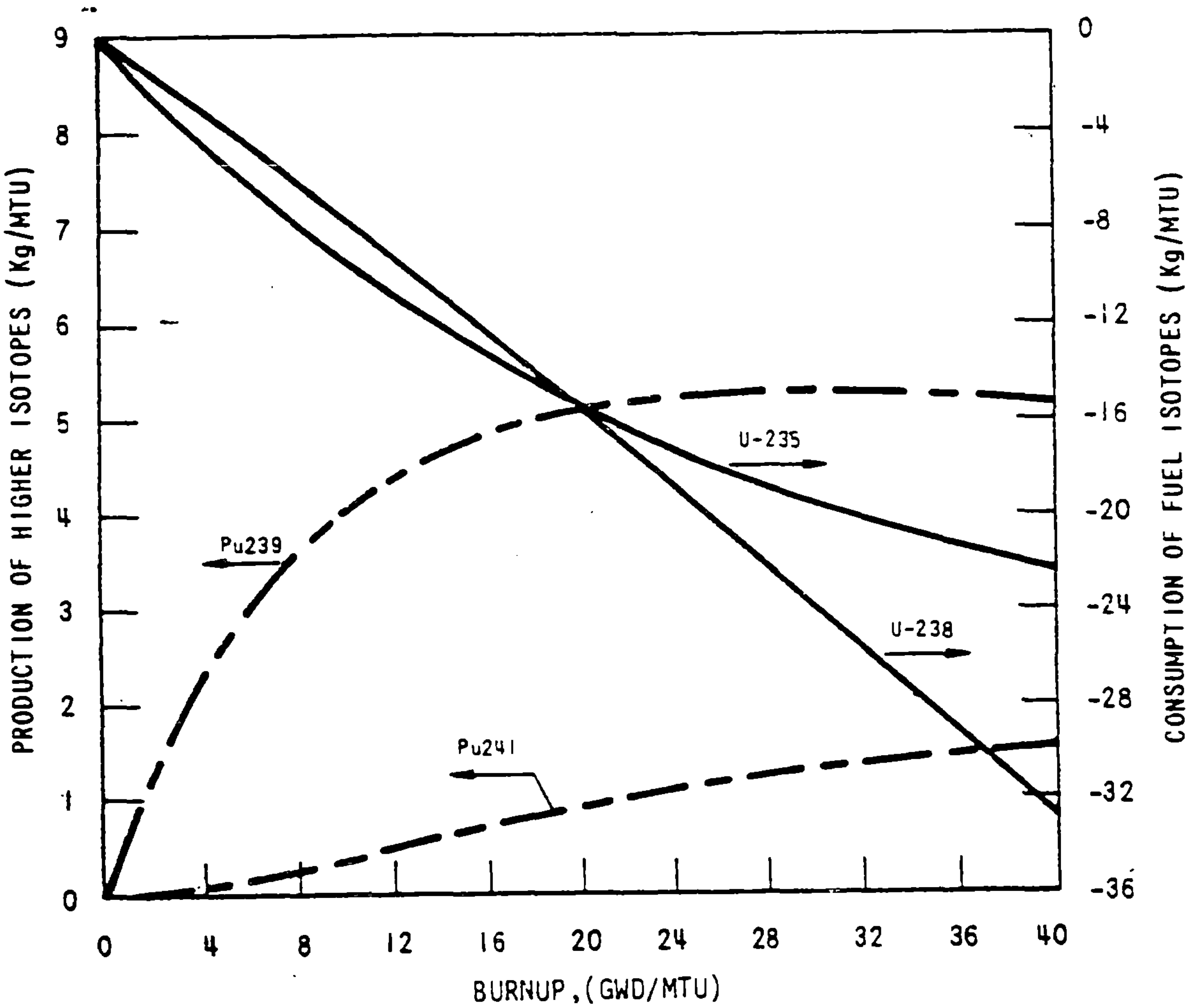
TABLE 4.3-3

REACTIVITY REQUIREMENTS FOR ROD CLUSTER CONTROL ASSEMBLIES

Reactivity Effects, Percent	Beginning-of-Life[1]	End-of Life[1]
1. Control requirements		
Fuel temperature (Doppler), %Δp	1.32	1.30
Moderator temperature, %Δp	0.11	1.25
Void, %Δp	0.01	0.05
Redistribution, %Δp	0.50	0.85
Rod Insertion Allowance, %Δp	0.50	0.50
2. Total Control, %Δp	2.44	3.95
3. Estimated Rod Cluster Control Assembly Worth (53 Rods)		
a. All full length assemblies inserted, %Δp	8.595	8.00
b. All but one (highest worth) assemblies inserted, %Δp	6.85	6.30
4. Estimated Rod Cluster Control Assembly credit with 10 percent adjustment to accomodate uncertainties (3b - 10 percent), %Δp	6.17	5.67
5. Shutdown margin available (4-2), %Δp	3.73	1.72[2]

(1) Typical reload values. See Section 4.5 for current cycle-specific values.

(2) The design basis minimum shutdown is 1.6 percent.



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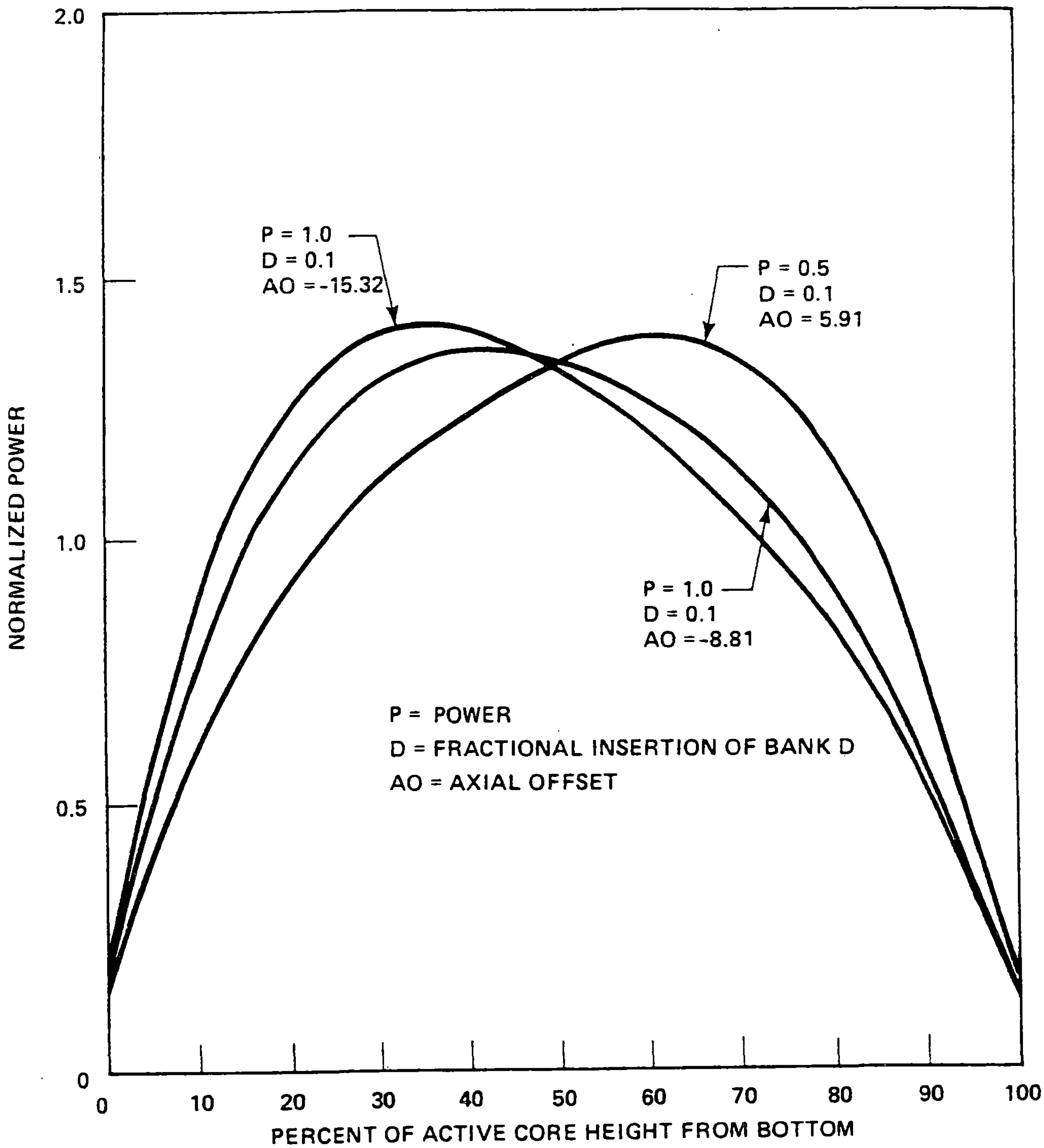
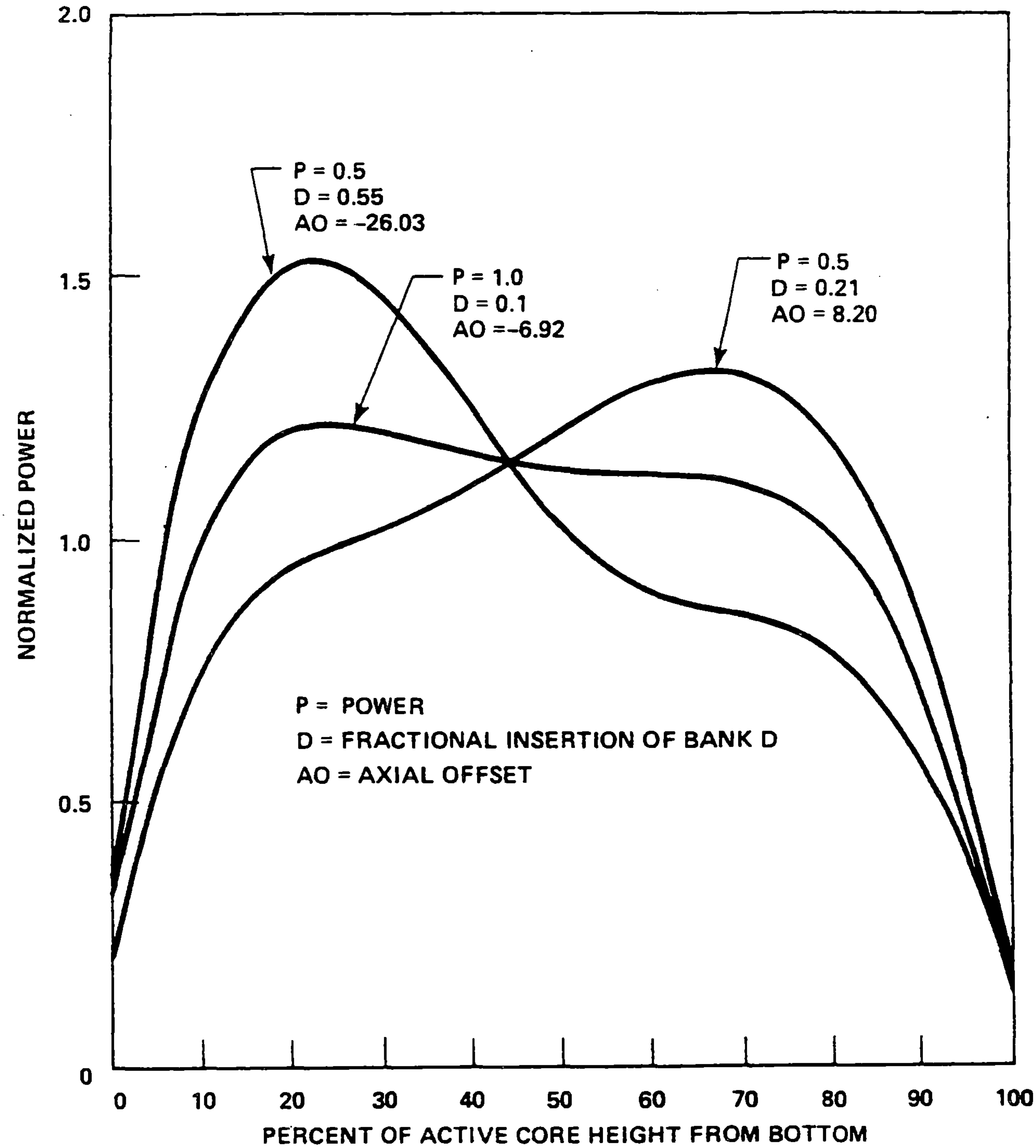
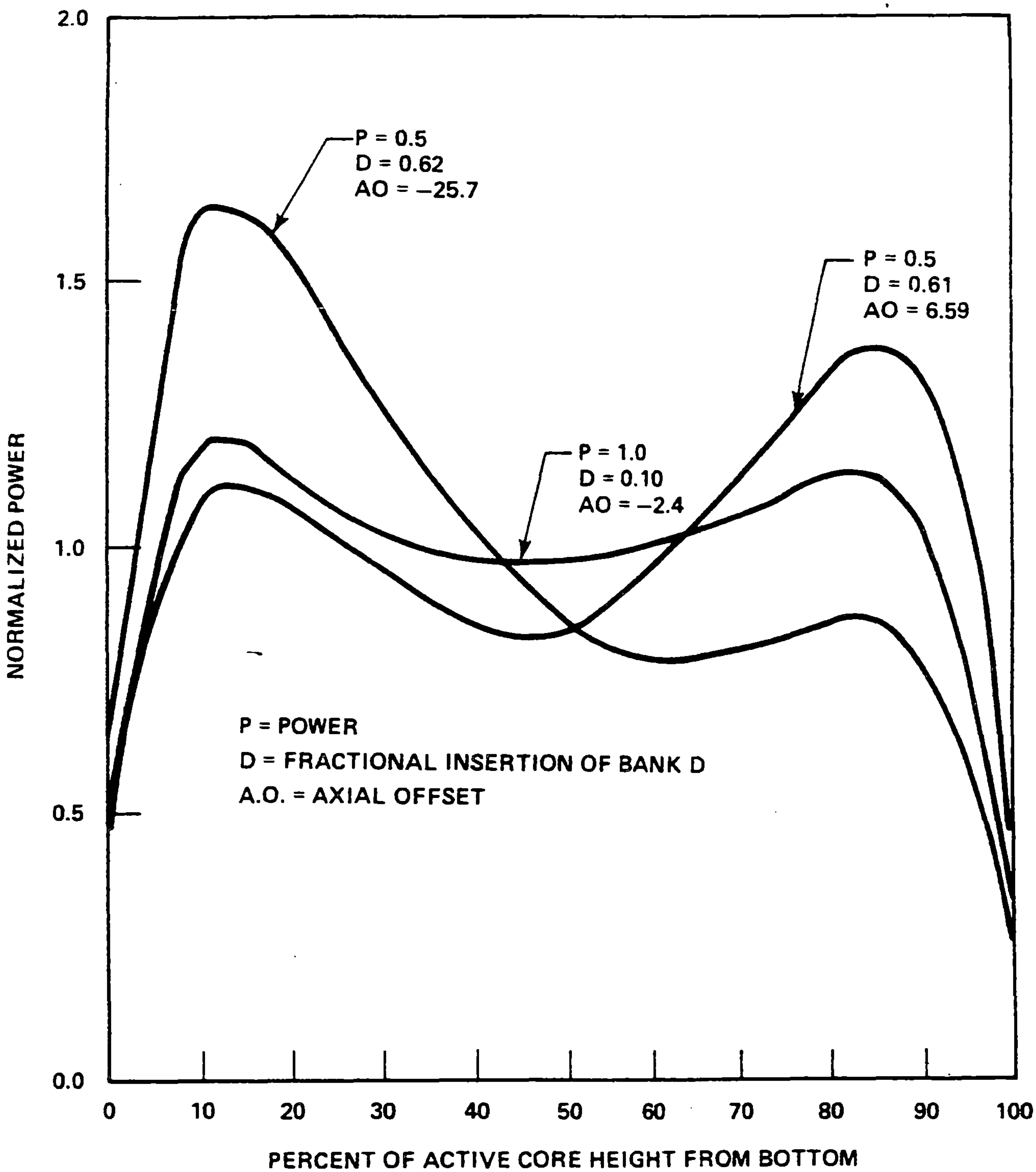
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Production and Consumption of Higher Isotopes
	Updated FSAR Fig 4.3-1



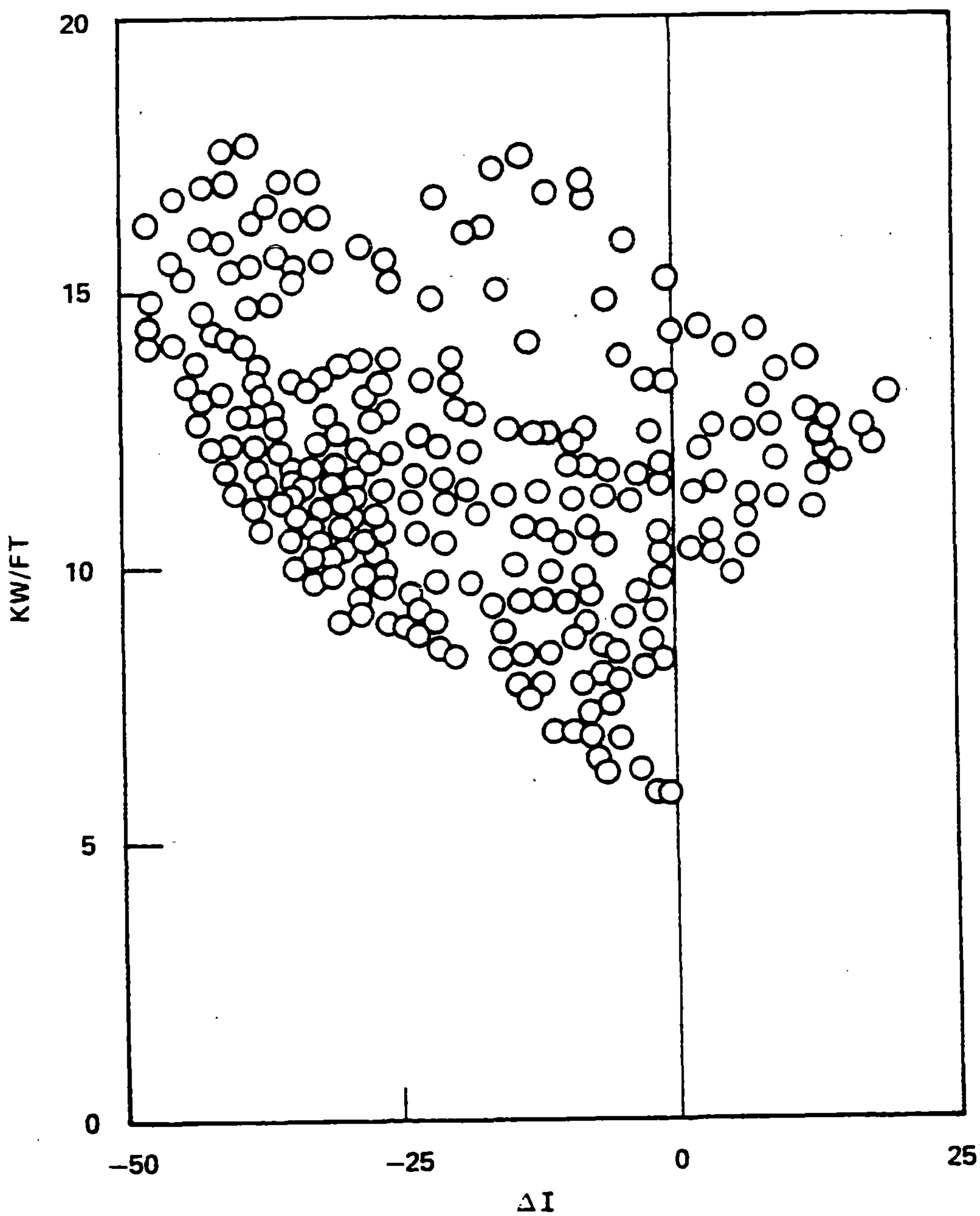
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Typical Axial Power Shapes Ocurring at Beginning of Life	
	Updated FSAR	Fig 4.3-8



PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Typical Axial Power Shapes Ocurring at Middle of Life
	Updated FSAR Fig 4.3-9



PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Typical Axial Power Shapes Ocurring at End of Life
	Updated FSAR — Fig 4.3-10



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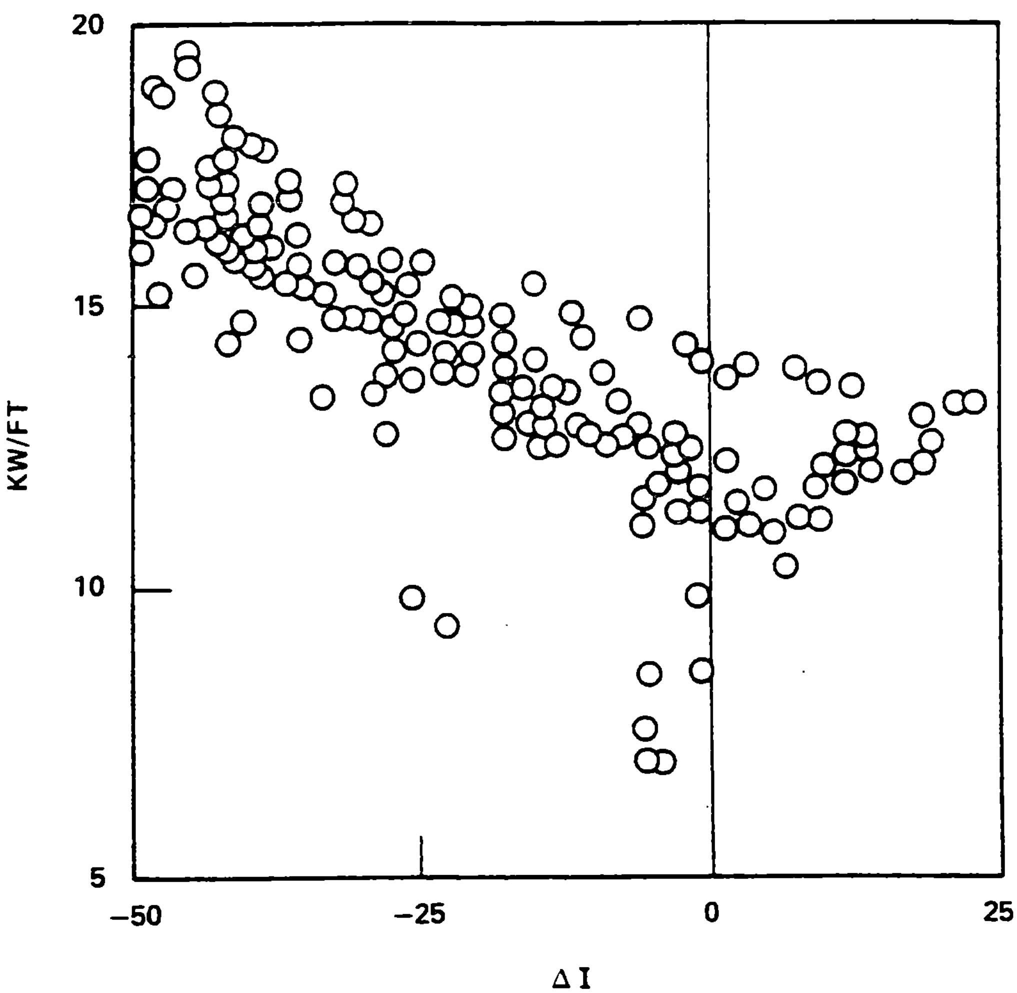
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Peak Power Density During Control Rod Malfunction Overpower Transients
	Updated FSAR Fig 4.3-12



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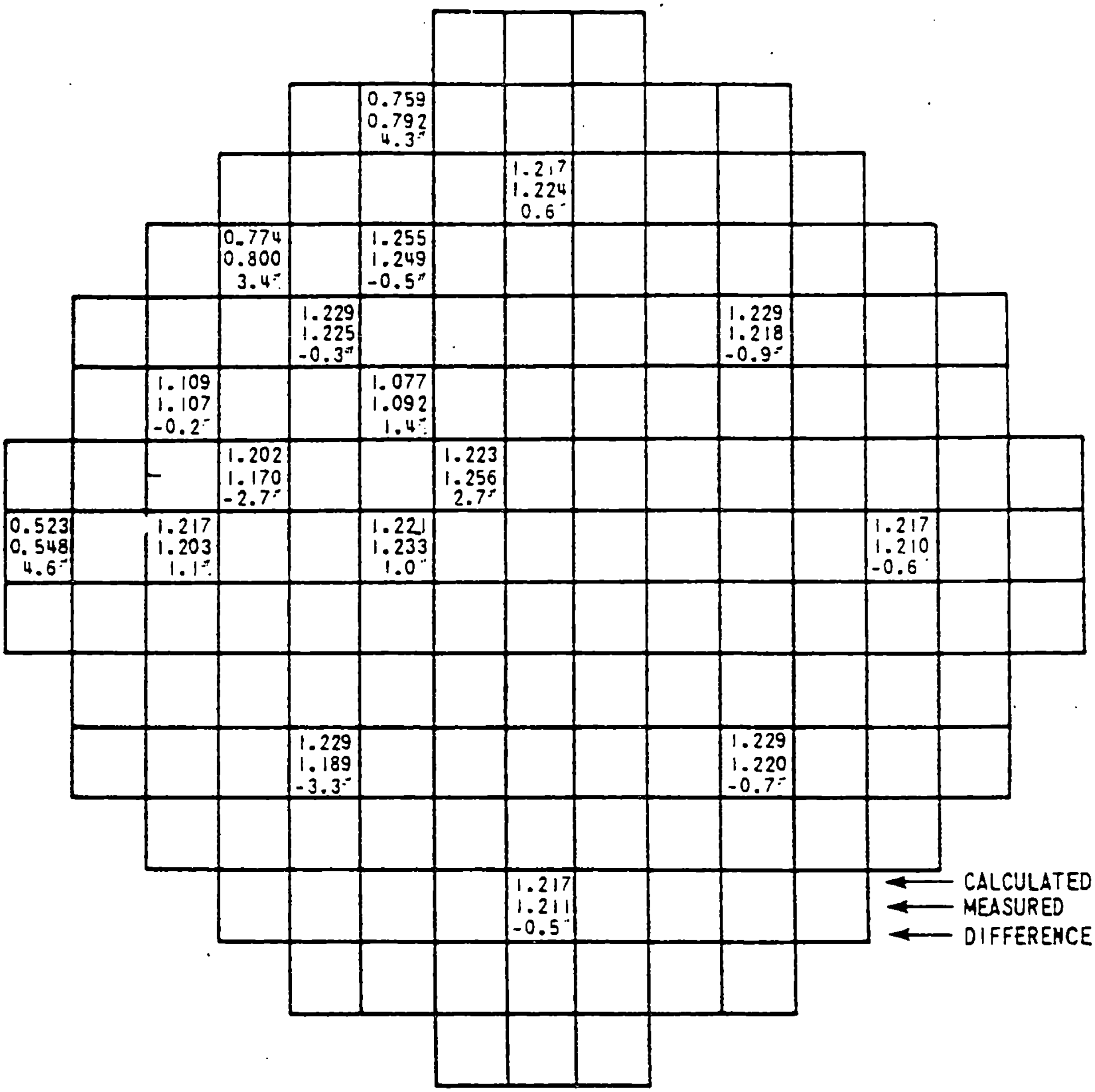
PUBLIC SERVICE ELECTRIC AND GAS COMPANY **SALEM NUCLEAR GENERATING STATION**	Peak Linear Power During Boration/Dilution Overpower Transients
	Updated FSAR — Fig 4.3-13



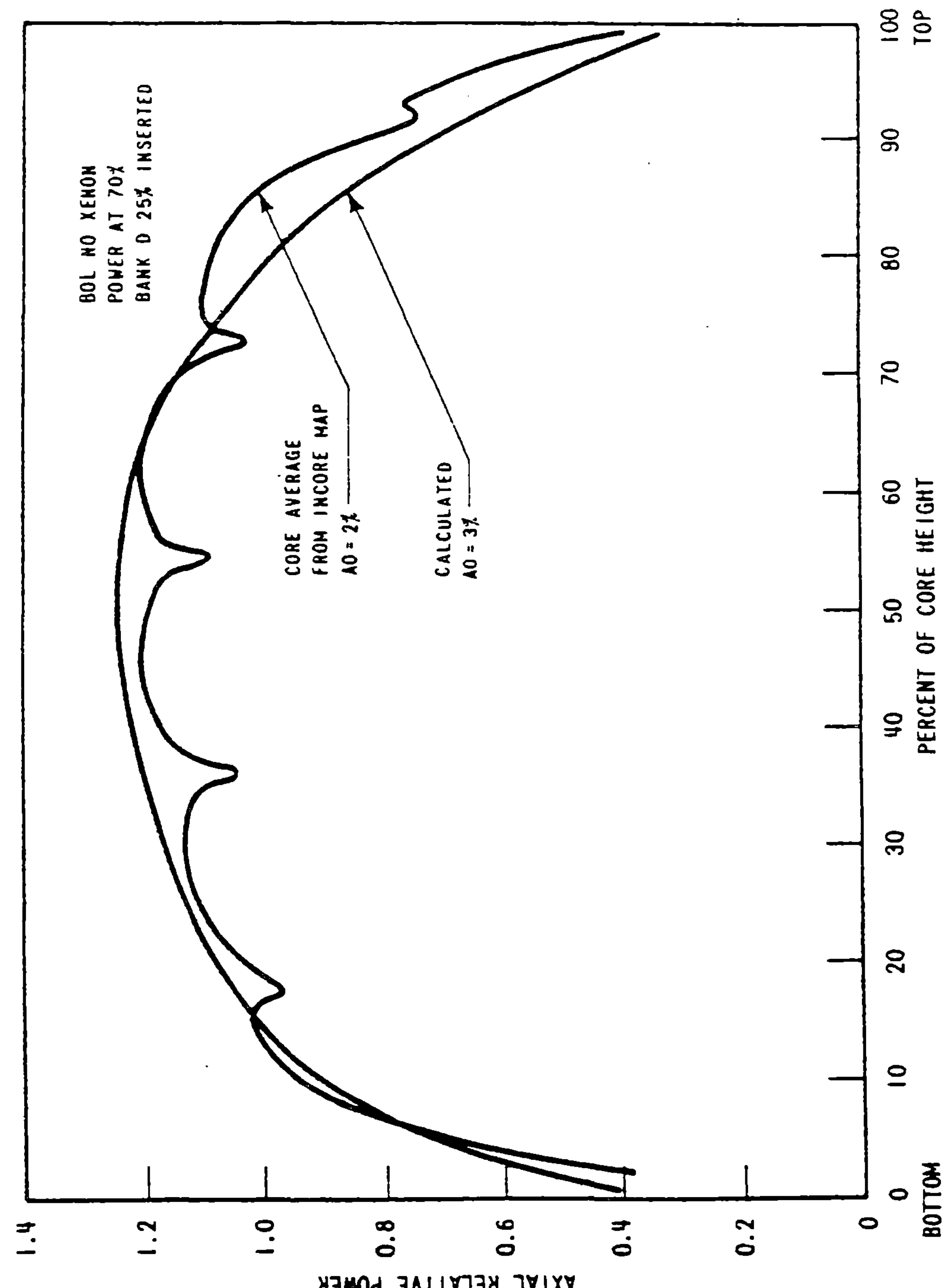
PEAKING FACTORS

$\bar{F}_z$ = 1.5

$F^N_{\Delta H}$ = 1.357

F^N_Q = 2.07 LOCATED AT M-8 SOUTH

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Comparison Beetween Calculated and Measured Relative Fuel Assembly Power Distribution
	Updated FSAR — Fig 4.3-14



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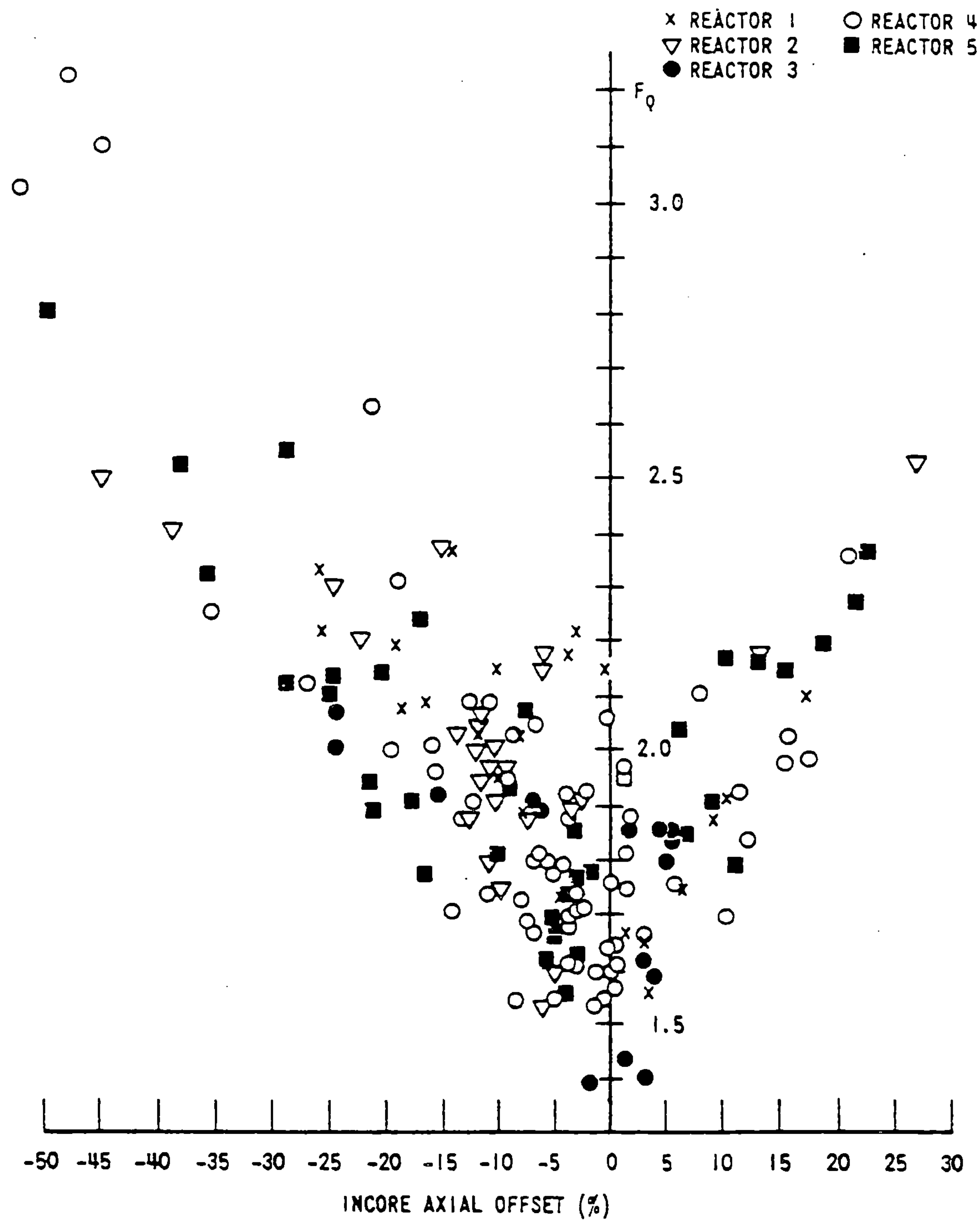
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Comparison of Calculated and Measured Axial Shape
	Updated FSAR Fig 4.3-15



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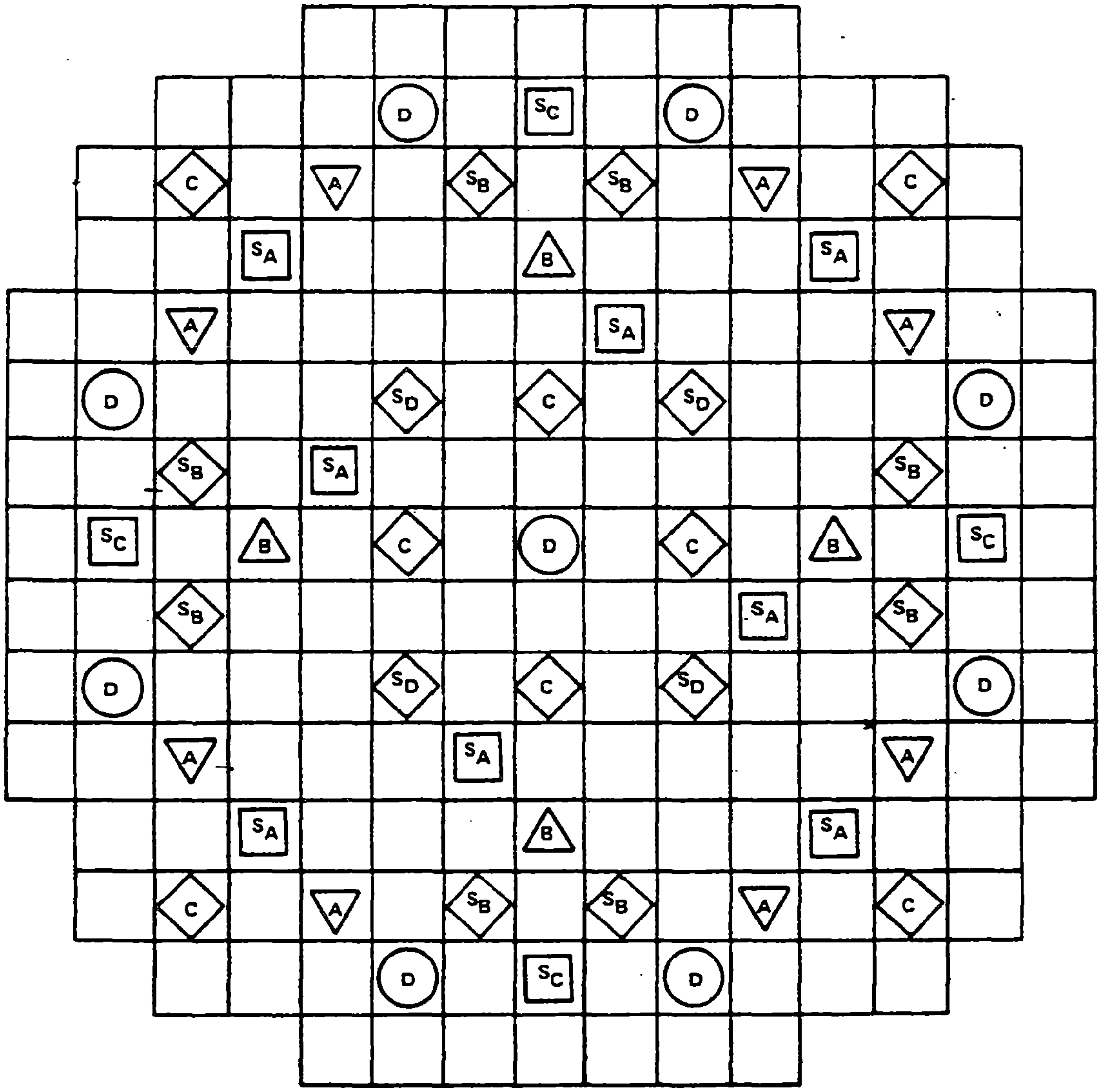
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Measured Values of F_Q for Full Power Rod Configuration
	Updated FSAR — Fig 4.3-16



	FUNCTION	NUMBER OF ROD CLUSTERS
SHUTDOWN BANK	S_A	8
SHUTDOWN BANK	S_B	8
SHUTDOWN BANK	S_C & S_D	4 & 4
CONTROL BANK	A	8
CONTROL BANK	B	4
CONTROL BANK	C	8
CONTROL BANK	D	9

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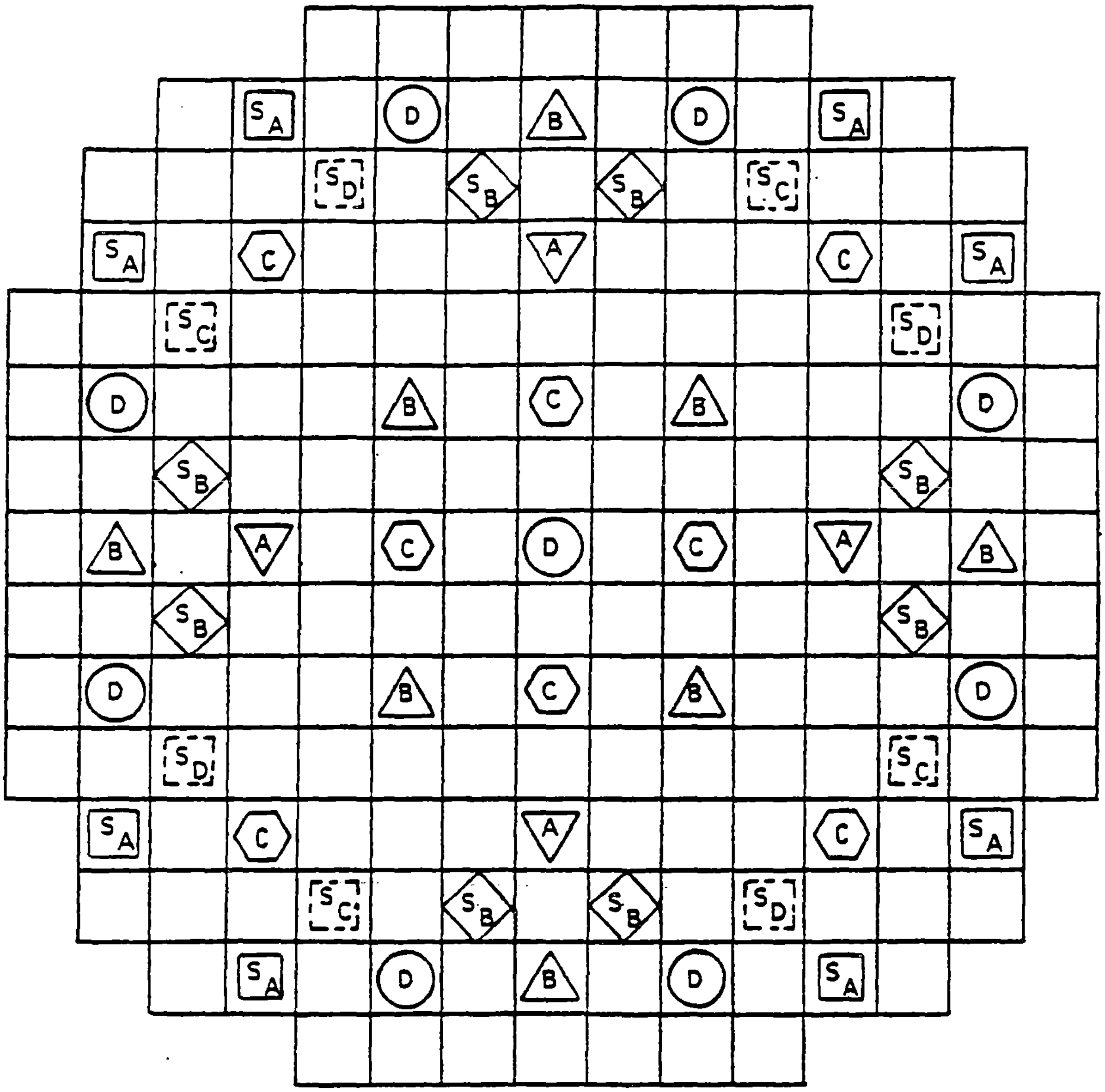
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Rod Cluster Control Assembly Pattern - Unit 1
	Updated FSAR Fig 4.3-26A



TYPE OF ROD CLUSTER	FUNCTION & SYMBOL	NUMBER OF ROD CLUSTERS
SHUTDOWN BANK	S_A	8
SHUTDOWN BANK	S_B	8
SHUTDOWN BANK	S_C & S_D	4 & 4
CONTROL BANK	A	4
CONTROL BANK	B	8
CONTROL BANK	C	8
CONTROL BANK	D	9

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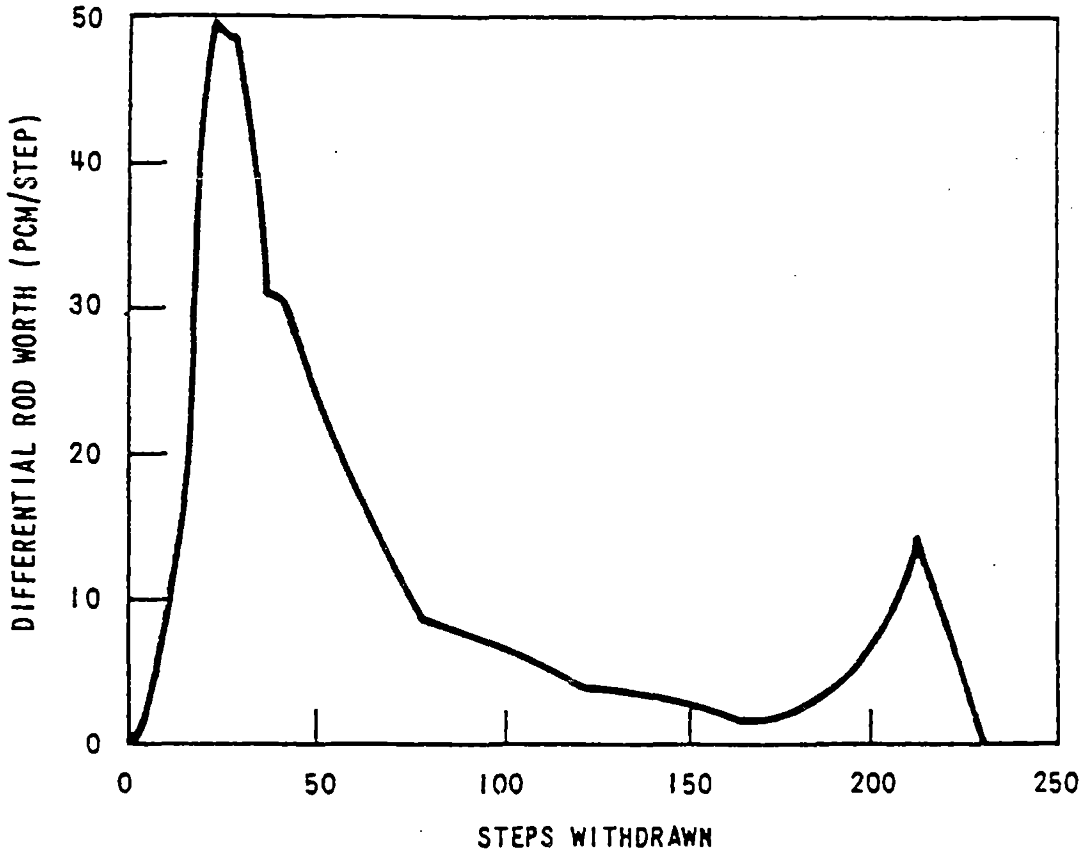
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Rod Cluster Control Assembly Pattern Unit 2
	Updated FSAR Fig 4.3-26B



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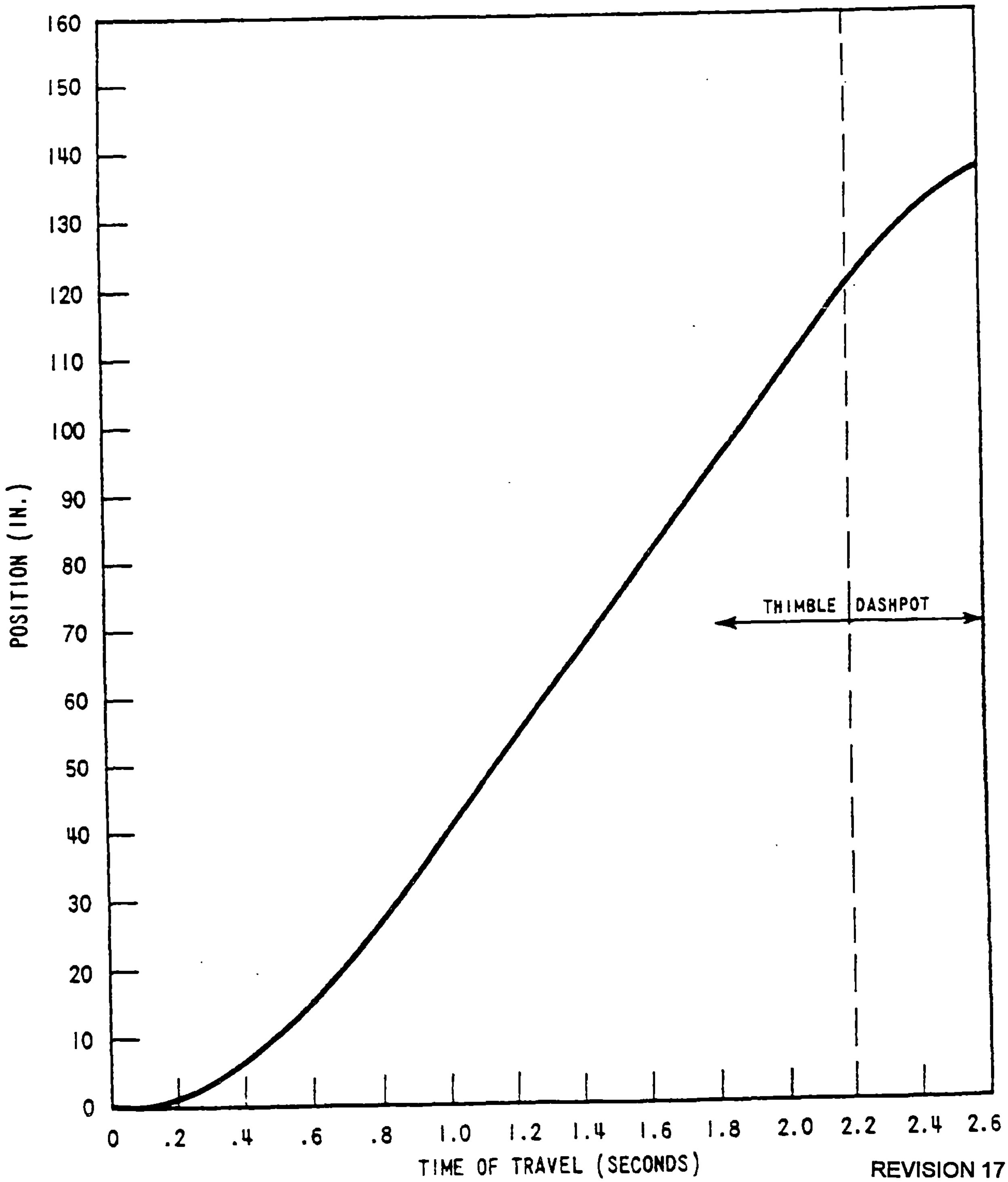
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Accidental Simultaneous Withdrawal of 2 Control Banks EOL, HZP, Banks D & B Moving in the Same Plane
	Updated FSAR Fig 4.3-27



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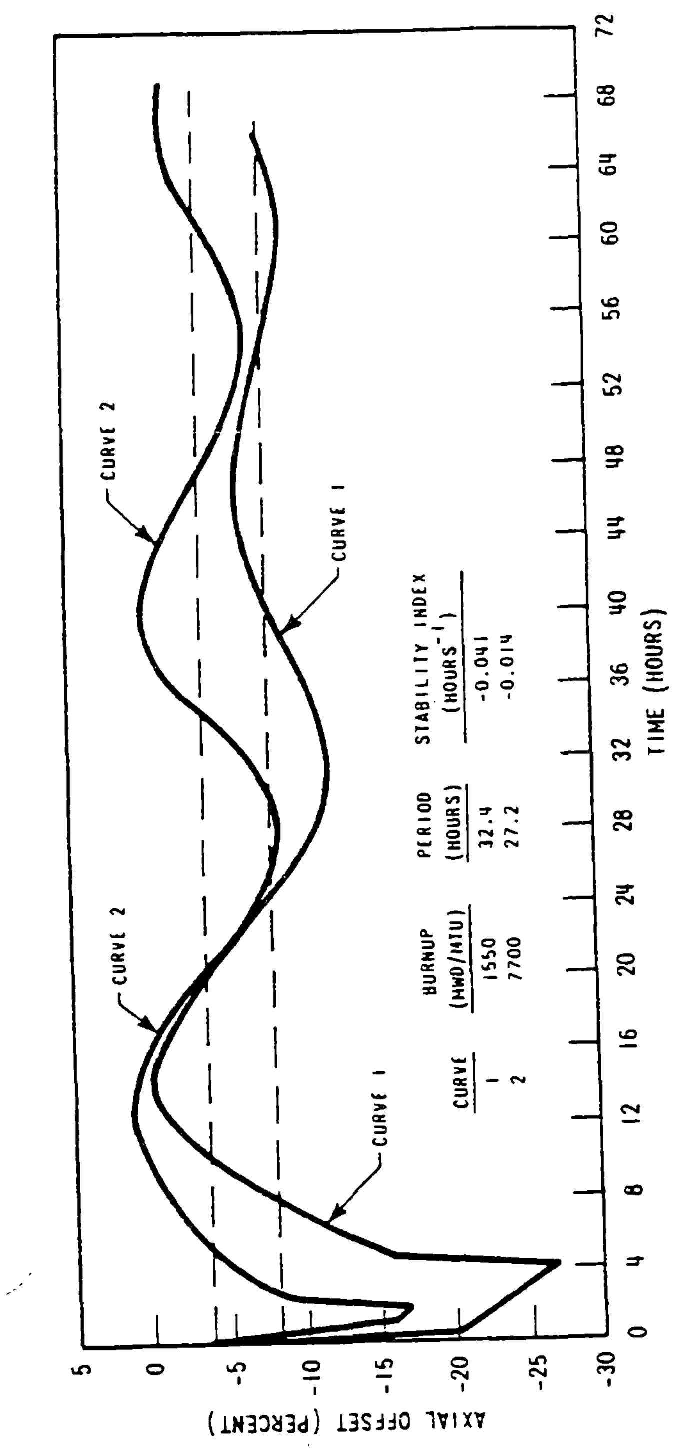
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Design Trip Curve	
	Updated FSAR	Fig 4.3-28



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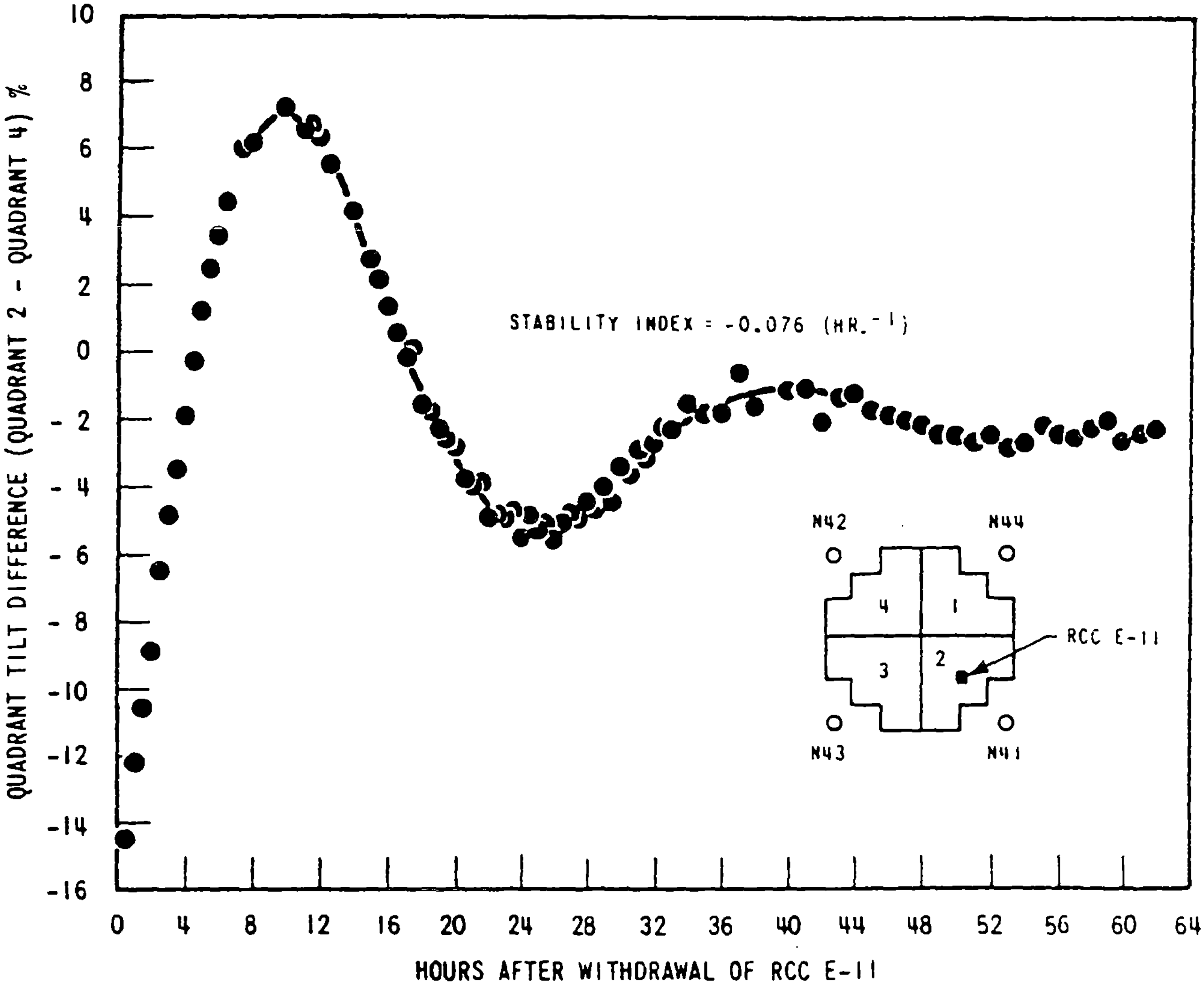
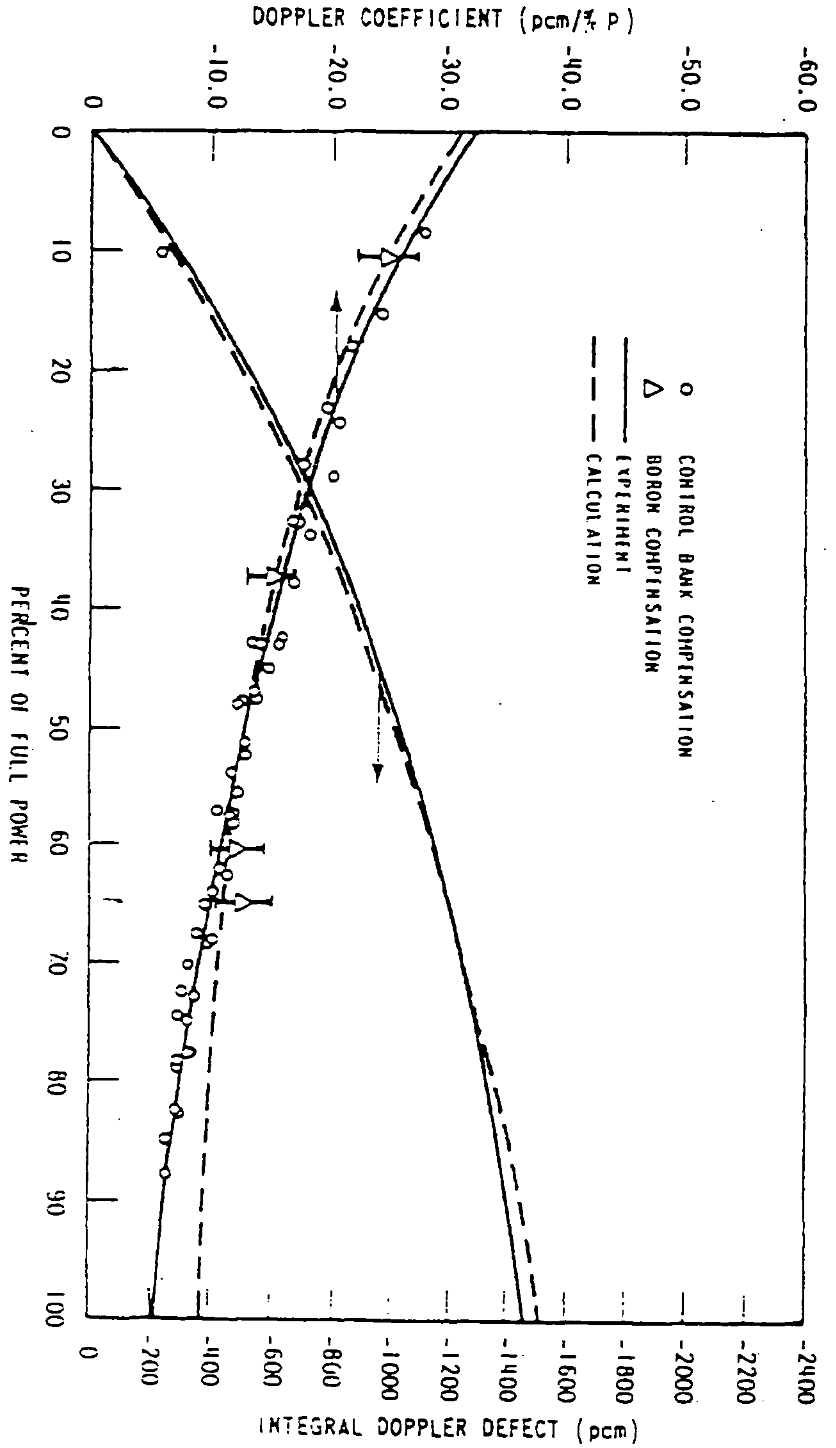
PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Axial Offset vs Time - PWR Core With a 12-Ft height and 121 Assemblies
	Updated FSAR Fig 4.3-30



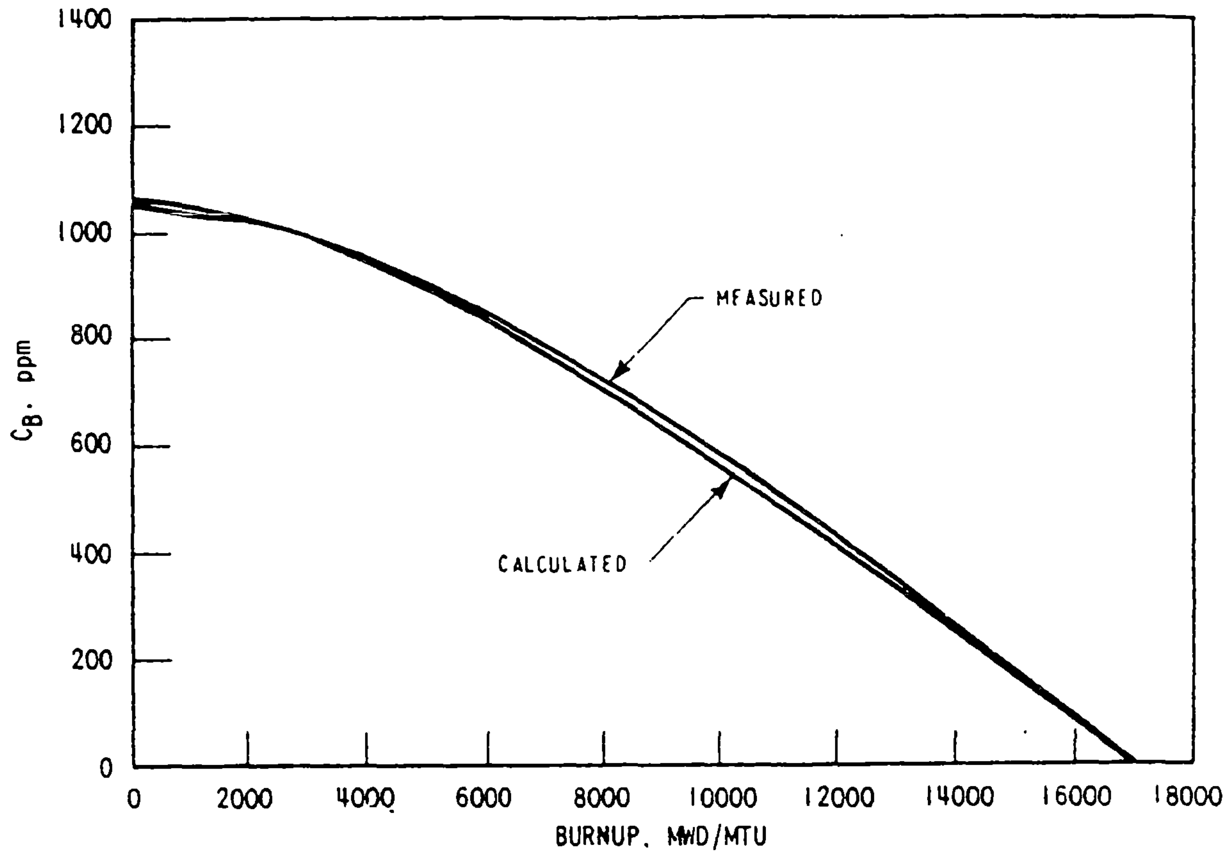
REVISION 17
OCTOBER 16 1998

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	XY Xenon Test Thermocouple Response Quadrant Tilt Difference vs Time
	Updated FSAR — Fig 4.3-31



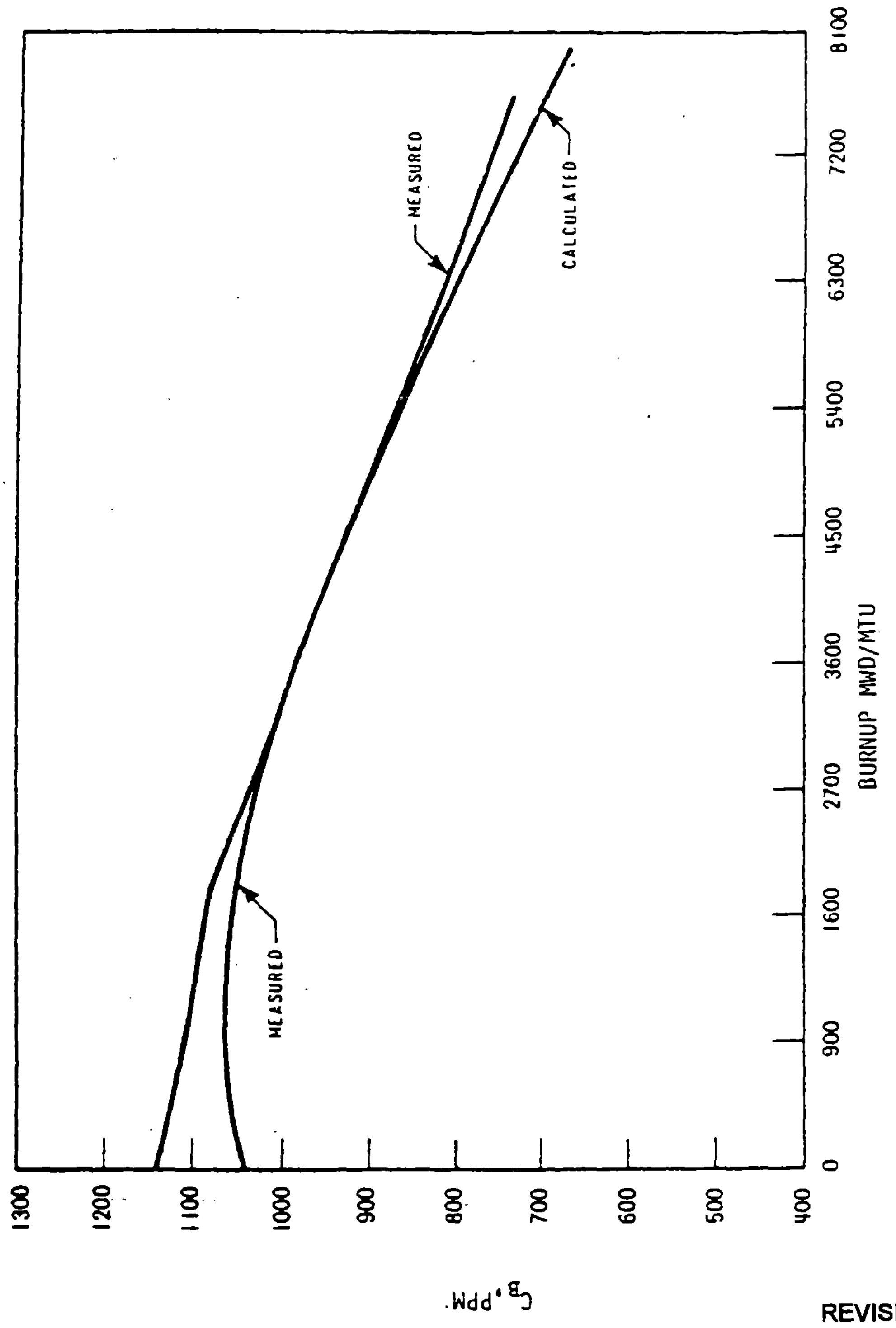
REVISION 17
OCTOBER 16 1998

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Calculated and Measured Doppler Defect and Coefficients at BOL,Two Loop Plant, 121 Assemblies 12-Ft Core
	Updated FSAR FIG.4.3-32



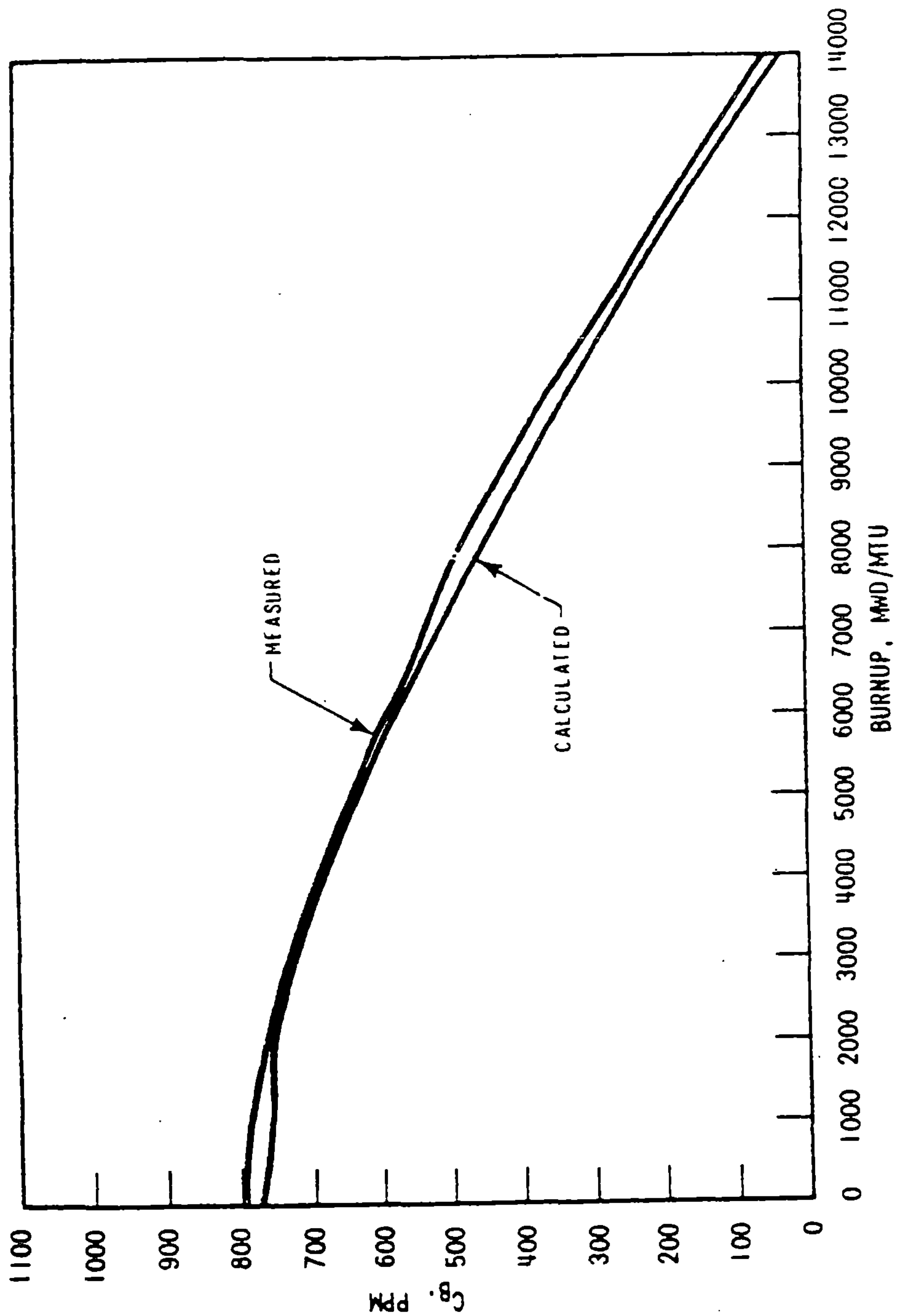
REVISION 17
OCTOBER 16 1998

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Comparison of Calculated and Measured Boron Concentration for 2-Loop Plant, 121 Assemblies, 12-Ft Core
	Updated FSAR Fig 4.3-33



REVISION 17
OCTOBER 16 1998

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Comparison of Calculated and Measured C_B 2-Loop with 121 Assemblies, 12-Ft Core	
	Updated FSAR	Fig 4.3-34



REVISION 17
OCTOBER 16 1998

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Comparison of Calculated and Measured C_B 3-Loop with 157 Assemblies, 12-Ft Core	
	Updated FSAR	Fig 4.3-35

4.5 RELOAD ANALYSES

A Reload Safety Evaluation (RSE) is performed for each cycle using methodology described in Reference 1. Based on this methodology, those events analyzed and reported in the Salem UFSAR, as well as limits given in the Technical Specification or Core Operating Limits Report (COLR) that could potentially be affected by the fuel reload are addressed. These UFSAR analyses and limits contain assumptions which involve parameters whose values are core design dependent. Hence, those parameters sensitive to reload core designs are considered, i.e., core criticality, power distributions, shutdown margin, etc. In addition, changes in fuel assembly design (mechanical, nuclear, and thermal-hydraulic) that could potentially affect the events analyzed are also addressed. The RSE results are used as input into the 10CFR50.59 process to determine if an Unresolved Safety Question (USQ) exists or a Technical Specification needs to be modified for a specific reload cycle.

As part of the Reload Safety Evaluation process, the values for the parameters defined in the COLR are determined. The COLR contains specific parameter values which were previously contained in the Technical Specifications: Beginning and End of Cycle Moderator Temperature Coefficients, Moderator Temperature Surveillance Limit, Control Rod Insertion Limits, Axial Flux Difference Range, Heat Flux Hot Channel Factor ($F_Q(z)$), and Nuclear Enthalpy Rise Hot Channel Factor ($F_{\Delta H}$).

The Nuclear Design Report (NDR) is a cycle-specific document which contains the best estimate predictions of the reload's nuclear characteristics, feed (fresh) fuel assembly nuclear design information and loading pattern configuration. Typical nuclear characteristics consist of radial power distributions, average assembly burnups, boron concentrations, reactivity coefficients, boron and control rod worths. Typical fuel assembly design information includes feed region cross sectional drawing and grid axial locations, assembly enrichments, burnable absorber types, including core locations and within assembly placement. NDR data is used to support plant operation and to compare measured and predicted plant data.

Table 4.5.1 contains a list, by cycle, of applicable RSEs, COLRs, and NDRs for Salem Unit 1. Table 4.5.2 contains the equivalent information for Unit 2. This list is updated for each new reload cycle.

The current Salem Unit 1 cycle's loading pattern and burnable absorber configuration, from the NDR or Core Loading Plan, are given as Figures 4.5-1 and 4.5-2, respectively. The current Salem Unit 2 cycle's loading pattern and burnable absorber configuration are given as Figures 4.5-3 and 4.5-4, respectively.

4.5.1 References for Section 4.5

1. Davidson, S. L., (Ed.), et. al., "Westinghouse Reload Safety Evaluation Methodology," WCAP-9273-NP-A, July 1985.

TABLE 4.5-1

SALEM UNIT 1
RSE, COLR, AND NDR REFERENCE LIST

Cycle	RSE (1)	COLR (2)	NDR (3)
1			NFVD-WW-97012-00 WCAP-8458
2	NFVD-WW-97008-00		NFVD-WW-97017-00/01 WCAP-9497
3			NFVD-WW-97014-00 WCAP-9827
4	NFVD-WW-97009-00		NFVD-WW-97015-00 WCAP-10017
5	NFVD-WW-97010-00		NFVD-WW-97016-00 WCAP-10242
6	NFVD-WW-97011-00		NFVD-WW-97013-00 WCAP-10597
7	NFU-VTDWW 86-004-01		NFU-VTDWW 86-006-003 WCAP-11077
8	NFU-VTDWW 87-014-00		NFU-VTDWW 87-015-00 WCAP-11616
9	NFU-VTDWW 89-028-01		NFU-VTDWW 89-029-00 WCAP-12198
10	NFU-VTDWW 91-042-01		NFU-VTDWW 91-043-00 WCAP-12838
11	NFU-VTDWW 92-064-00		NFU-VTDWW 92-060-00 WCAP-13380
12	NFU-VTDWW 93-073-01		NFU-VTDWW 93-074-00 WCAP-13873
13	NFU-VTDWW 97-018-00	NFS-0163	NFU-VTDWW 97-020-00 WCAP-14997

(1) PSE&G issued document number. Not available for Cycles 1 and 3.
(2) Prior to Cycle 13, PFLR was issued instead of COLR.
(3) PSE&G issued document number and vendor document number (for cross-reference purposes only).

TABLE 4.5-2

SALEM UNIT 2
RSE, COLR, AND NDR REFERENCE LIST

Cycle	RSE (1)	COLR (2)	NDR (3)
1			NFVD-WW-97005-00 WCAP-9374
2	NFVD-WW-97003-00		NFVD-WW-97006-00 WCAP-10248
3	NFVD-WW-97004-00		NFVD-WW-97007-00 WCAP-10790
4	NFU-VTDWW 86-008-01		NFU-VTWW86-009-00 WCAP-11218
5	NFU-VTDWW 88-022-02		NFU-VTDWW 88-024-00 WCAP-11920
6	NFU-VTDWW 90-034-00		NFU-VTDWW 90-036-00 WCAP-12534
7	NFU-VTDWW 92-059-00		NFU-VTDWW 92-057-00 WCAP-13214
8	NFU-VTDWW 93-068-00		NFU-VTDWW 93-070-00 WCAP-13739
9	NFU-VTDWW 94-100-00		NFU-VTDWW 94-109-00 WCAP-14199
10	NFU-VTDWW 96-151-01		NFUVD-WW 97001-01 WCAP-14669

(1) PSE&G issued document number. Not available for Cycle 1.
(2) Prior to Cycle 11, PFLR was issued instead of COLR.
(3) PSE&G issued document number and vendor document number (for cross-reference purposes only).

	R	P	N	M	L	K	J	H	G	F	E	D	C	B	A
1					13B AA58	12 M67	14A AB27	12 M74	14A AB08	12 M69	13B AA55				
2			12 M14	12 M21	15B AC34	14B AB33	15B AC36	14B AB39	15B AC38	14B AB47	15B AC36	12 M47	12 M62		
3		12 M17	15A AC53	15B AC42	13B AA51	15B AC49	14B AB44	13B AA41	14B AB41	15B AC31	13B AA49	15B AC44	15A AC54	12 M43	
4		12 M41	15B AC45	14A AB30	15A AC58	13A AA20	13A AA05	14A AB13	13A AA12	13A AA02	15A AC60	14A AB11	15B AC46	12 M13	
5	13B AA61	15B AC27	13B AA48	15A AC51	13A AA13	15A AC18	13A AA32	13B AA60	13A AA34	15A AC20	13A AA16	15A AC62	13B AA47	15B AC38	13B AA57
6	12 M31	14B AB48	15B AC32	13A AA36	15A AC21	14A AB02	15A AC02	14A AB20	15A AC04	14A AB01	15A AC26	13A AA23	15B AC50	14B AB35	12 M70
7	14A AB09	15B AC89	14B AB42	13A AA24	13A AA35	15A AC05	13A AA11	15A AC27	13A AA01	15A AC06	13A AA39	13A AA29	14B AB40	15B AC90	14A AB26
8	12 M59	14B AB43	13B AA46	14A AB06	13B AA68	14A AB15	15A AC17	14A AB12	15A AC28	14A AB05	13B AA64	14A AB22	13B AA44	14B AB46	12 M50
9	14A AB19	15B AC91	14B AB51	13A AA38	13A AA37	15A AC07	13A AA09	15A AC19	13A AA18	15A AC01	13A AA08	13A AA19	14B AB37	15B AC85	14A AB23
10	12 M76	14B AB50	15B AC51	13A AA33	15A AC24	14A AB04	15A AC08	14A AB28	15A AC03	14A AB03	15A AC25	13A AA17	15B AC83	14B AB38	12 M15
11	13B AA66	15B AC39	13B AA42	15A AC53	13A AA21	15A AC22	13A AA40	13B AA59	13A AA26	15A AC23	13A AA22	15A AC57	13B AA50	15B AC33	13B AA54
12		12 M75	15B AC47	14A AB17	15A AC54	13A AA04	13A AA03	14A AB24	13A AA28	13A AA30	15A AC59	14A AB14	15B AC41	12 M16	
13		12 M73	15A AC55	15B AC48	13B AA45	15B AC84	14B AB52	13B AA52	14B AB45	15B AC52	13B AA43	15B AC43	15A AC56	12 M51	
14			12 M60	12 M32	15B AC40	14B AB49	15B AC92	14B AB36	15B AC87	14B AB34	15B AC35	12 M44	12 M27		
15					13B AA63	12 M58	14A AB07	12 M37	14A AB25	12 M35	13B AA53				

90°

0°

LEGEND

R ID	Region Identifier Fuel Assembly Identifier

Fuel Assembly Orientation

- ● Reference Hole
- ○ Core Pin Hole
- ⁄ Holdown Bar

NOTE: Figures are Top View

REVISION 17
OCTOBER 16 1998

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Salem Unit 1 Cycle 13 Loading Pattern
	Updated FSAR FIG. 4.5-1

Row	R	P	N	M	L	K	J	H	G	F	E	D	C	B	A
1					24WD	24WD				24WD	24WD				
2			24WD	24WD	64I	RCCA	8P 64I	RCCA	8P 64I	RCCA	64I	24WD	24WD		
3		24WD	RCCA 16I	8P 64I	RCCA	12P 104I	RCCA	1PSA 3THP	RCCA	12P 104I	RCCA	8P 64I	RCCA 16I	24WD	
4		24WD	8P 64I	RCCA	8P 64I			RCCA			8P 64I	RCCA	8P 64I	24WD	
5	24WD	64I	RCCA	8P 64I		12P 80I			RCCA	12P 80I		8P 64I	RCCA	64I	24WD
6	24WD	RCCA	12P 104I		12P 80I	RCCA	12P 64I	RCCA	12P 64I	RCCA	12P 80I		12P 104I	RCCA	24WD
7		8P 64I	RCCA		RCCA	12P 64I		12P 80I		12P 64I			RCCA	8P 64I	
8		RCCA	4SSA	RCCA		RCCA	12P 80I	RCCA	12P 80I	RCCA		RCCA	4SSA	RCCA	
9		8P 64I	RCCA			12P 64I		12P 80I		12P 64I	RCCA		RCCA	8P 64I	
10	24WD	RCCA	12P 104I		12P 80I	RCCA	12P 64I	RCCA	12P 64I	RCCA	12P 80I		12P 104I	RCCA	24WD
11	24WD	64I	RCCA	8P 64I		12P 80I	RCCA			12P 80I		8P 64I	RCCA	64I	24WD
12		24WD	8P 64I	RCCA	8P 64I			RCCA			8P 64I	RCCA	8P 64I	24WD	
13		24WD	RCCA 16I	8P 64I	RCCA	12P 104I	RCCA	1PSA 3THP	RCCA	12P 104I	RCCA	8P 64I	RCCA 16I	24WD	
14			24WD	24WD	64I	RCCA	8P 64I	RCCA	8P 64I	RCCA	64I	24WD	24WD		
15					24WD	24WD				24WD	24WD				

90°

0°

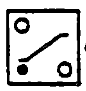
LEGEND

TYPE	COMPONENT TYPE
###I	NUMBER OF FRESH IFBA RODS

CORE COMPONENT TYPES

RCCA - CONTROL OR SHUTDOWN RCCA
##P - NUMBER OF RODLETS IN PYREX ASSEMBLY
#SSA - NUMBER OF RODLETS ON SECONDARY SOURCE ASSEMBLY
#PSA - NUMBER OF PRIMARY SOURCE RODLETS
##WD - NUMBER OF DAMPER RODS
#THP - NUMBER OF THIMBLE PLUGS

Fuel Assembly Orientation



• Reference Hole
O Core Pin Hole
/ Holdown Bar

NOTE: Figures are Top View

COMPONENT ORIENTATION SHOWN IN TABLE 2

REVISION 17
OCTOBER 16 1998

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Salem Unit 1 Cycle 13 Burnable Absorber Configuration

Updated FSAR

FIG. 4.5-2

Design Temperature

The design temperature for each component was selected to be above the maximum coolant temperature in that component under all normal and anticipated transient load conditions. The design and operating temperatures of the respective system components are listed in Tables 5.2-3 through 5.2-8.

Seismic Loads

The seismic loading conditions were established by the operational basis earthquake (OBE) and design basis earthquake (DBE). The former was selected to be typical of the largest probable ground motion based on the site seismic history. The latter was selected to be the largest potential ground motion at the site based on seismic and geological factors and their uncertainties.

For the OBE loading condition, the Nuclear Steam Supply System (NSSS) is designed to be capable of continued safe operation. Therefore, for this loading condition, critical structures and equipment needed for this purpose are required to remain operable. The seismic design for the DBE is intended to provide a margin in design that assures capability to shut down and maintain the nuclear facility in a safe condition. In this case, it is only necessary to ensure that the RCS components do not lose their capability to perform their safety function. This has come to be referred to as the "no-loss-of-function" criteria and the loading condition as the "design basis earthquake" loading condition.

The criteria adopted for allowable stresses and stress intensities in vessels and piping subjected to normal loads plus seismic loads are defined in Section 3.

Design and construction practices in accordance with these criteria assure the integrity of the RCS under seismic loading. The combination of seismic loads with operating and pipe rupture loads for the design of the RCS support structures and their respective allowable stresses are given in Table 5.5-3.

5.2.1.3 Compliance with 10CFR50.55a

All pressure-containing components of the RCS were designed, fabricated, inspected, and tested in conformance with the applicable codes listed in Table 5.2-9.

The RCS is classified as Class I for seismic design, requiring that there will be no loss-of-function of such equipment in the event of the assumed DBE ground acceleration acting in the horizontal and vertical directions simultaneously, when combined with the RCS steady-state stresses.

5.2.1.4 Applicable Code Cases

NOTE:

The use of Code Cases during construction was governed by the paragraphs below. Use of Code Cases for inservice inspections and repair or replacement activities is governed by either the Inservice Inspection Program or the NBU Repair Program. Please refer to these programs for Code Case applicability or incorporation of new Code Cases into these programs. New Code Cases must be reviewed for acceptability against the current revision of Regulatory Guides 1.84, 1.85, or 1.147; as applicable.

Code cases applied in the RCS design are listed in Table 5.2-9.

5.2.1.5 Design Transients

The RCS and its components are designed to accommodate 10-percent of full power step changes in plant load and 5-percent of full power per minute ramp changes over the range from 15-percent full power up to and including but not exceeding 100-percent of full power without reactor trip. The RCS can accept a complete loss-of-load from full power with reactor trip. In addition, the steam dump system makes it possible to accept a 50-percent loss of external load from full power without reactor trip.

All components in the RCS are designed to withstand the effects of cyclic loads due to reactor system temperature and pressure changes. These cyclic loads are introduced by normal power changes, reactor trip, and startup and shutdown operations. The number of thermal and loading cycles used for design purposes and their bases are given in Table 5.2-10. During unit startup and

A preliminary estimate of the leakage can be obtained from the rate of condensate flow increase during the transient; a better estimate can be made from the steady state condensate flow at equilibrium conditions. The device alarms on a 0.06 gpm condensate flow rate, which indicates that a 1 gpm or larger leak has been developing for about 5 minutes.

The system can be checked during reactor shutdown.

5.2.7.1.5 Intersystem Leakage Detection

The following provisions are available for the detection of intersystem leakage from the RCS:

1. Radiation monitors are provided for the Steam Generator Blowdown System, each Main Steam Line (Unit 2) and condenser air removal effluent line which alert the operator to reactor coolant leakage into the Main Steam and Feedwater Systems from steam generator tube leaks.

2. Radiation monitors are provided for the Component Cooling System to detect reactor coolant leakage into the system from the Residual Heat Removal System. Surge tank level is also an indicator for leakage detection.

3. The accumulators are isolated from the RCS by two check valves. They are also provided with a remote manual valve. Leakage would be detected by level and pressure changes in the accumulators.

4. The charging/boron injection tank line is isolated from the RCS by two check valves and normally closed remote manual valves. Leakage from the RCS would be detected by pressure changes in the line.

5. The Residual Heat Removal System and SIS are isolated from the RCS by two check valves and normally closed remote manual valves. Leakage would cause operation of the relief valves which discharge to the containment sump.

RCS leakage can also be detected by level changes in the volume control tank, as well as by RCS water inventory balances, which are performed periodically. The indications identified above are provided, with appropriate alarms, in the control room.

5.2.7.2 Indication in Control Room

Positive indications in the control room of leakage of coolant from the RCS to the lower containment compartment are provided by equipment which permits continuous monitoring of the lower containment compartment air activity and humidity, and condensate run-off from the fan coolers. This equipment provides indication of normal background which is indicative of a basic level of leakage from primary systems and components. Any increase in the observed parameters are an indication of change within the lower containment compartment, and the equipment provided is capable of monitoring this change. The basic design criterion is the detection of deviations from normal containment environmental conditions including air particulate activity, radiogas activity, humidity, condensate, and in addition, in the case of gross leakage, the liquid inventory in the process systems and containment sump.

5.2.8 Inservice Inspection Program

Preservice and inservice inspection for Class 1, 2, and 3 components are in accordance with the rules of 10CFR50.55(a), Paragraph (g) to the extent practical. Relief from the applicable ASME Section XI inspection requirements have been transmitted to the NRC through the Inservice Inspection Program Long Term Plans and Testing Programs.

TABLE 5.2-8

PRESSURIZER VALVES DESIGN PARAMETERS

PRESSURIZER SPRAY CONTROL VALVES

Number of Valves	2/Unit
Design Pressure	2485 psig
Design Temperature	650°F
Design Flow (valves full open, each)	400 gpm
Fluid Temperature	545°F
Position (after failure of actuating force)	Closed

SAFETY VALVES

1. VALVE PARAMETERS

Number of Valves	3/Unit
Manufacturer	Crosby Valve and Gage Co.
Type	Crosby HB-BP-86 6M6 Safety Valve (Steam Internals)
Point	2485 psig
Size	6" Inlet x 6" Outlet Orifice Size $= 2.154$ (3.644 sq. in.^{2})
Rated Capacity (Saturated Steam)	420,000 lb/hr each
Design Pressure and Temp.	2485 psig and 650°F
Constant Back Pressure	
Normal	3-5 psig
Developed	350 psig
Inlet Flange Rating	1500 #ASA
Discharge Flange Rating	600 #ASA

2. INLET PIPING PARAMETERS

Diameter	6" Sch 160	
Length	Unit 1	Unit 2
Loop 3	14.553'	12.054'
Loop 4	12.873'	12.241'
Loop 5	12.309'	11.719'

POWER OPERATED RELIEF VALVES

Number of Valves	2/Unit
Manufacturer	Copes-Vulcan Division
Type	Diaphragm Operated Relief Valve
Set Point	2315 psig

The motor is an air-cooled, Class B thermelastic epoxy-insulated, squirrel cage induction motor. The rotor and stator are of standard construction and are cooled by air. Six resistance temperature detectors are located throughout the stator to sense the winding temperature. The top of the motor consists of a flywheel and an anti-reverse rotation device.

The internal parts of the motor are cooled by air. Integral vanes on each end of the rotor draw air in through cooling slots in the motor frame. This air passes through the motor with particular emphasis on the stator end turns. It is then exhausted to the containment environment.

Each of the RCPs is equipped for continuous monitoring of RCP shaft and frame vibration levels. Shaft vibration is measured by two relative shaft probes mounted on top of the pump seal housing. The probes, one in line with the pump discharge and the other perpendicular to the pump discharge, are mounted in the same horizontal plane near the pump shaft. Frame vibration is measured by two velocity seismoprobes located 90 degrees apart in the same horizontal plane and mounted at the top of the motor support stand. Proximeters and converters convert the probe signals to linear output, which is displayed on monitor meters in the control room. The Salem Unit 2 monitor meters automatically indicate the highest output from the relative probes and seismoprobes; manual selection allows monitoring of individual probes. The Salem Unit 1 monitor bargraphs indicate the output from the relative probes and seismoprobes. Indicator lights on both units display caution and danger limits of vibration.

All parts of the pump in contact with the reactor coolant are austenitic stainless steel, except for seals, bearings, and special parts.

The pump internals, motor, and motor stand can be removed from the casing as a unit without disturbing the reactor coolant piping. The flywheel is available for inspection by removing the flywheel cover.

5.5.1.3 Design Evaluation

5.5.1.3.1 Pump Performance

The RCPs are sized to deliver flow at rates that equal or exceed the required flow rates. Initial RCS tests confirm the total delivery capability, providing assurance of adequate forced circulation coolant flow prior to initial plant operation. The performance characteristics are shown on Figure 5.1-5.

The reactor trip system ensures that pump operation is within the assumptions used for loss-of-coolant flow analyses, and also assures that adequate core cooling is provided to permit an orderly reduction in power if flow from a RCP is lost during operation.

An extensive test program has been conducted to develop the controlled leakage shaft seal for pressurized water reactor (PWR) applications. Long-term tests were conducted on less than full-scale prototype seals as well as on full-size seals. Operating plants continue to demonstrate the satisfactory performance of the controlled leakage shaft seal pump design.

The support of the stationary member of the Number 1 seal (seal ring) is such as to allow large deflections, both axial and tilting, while still maintaining its controlled gap relative to the seal runner. Even if all the graphite were removed from the pump bearing, the shaft could not deflect far enough to cause opening of the controlled leakage gap. The "spring-rate" of the hydraulic forces associated with the maintenance of the gap is high enough to ensure that the ring follows the runner under very rapid shaft deflections.

Testing of pumps with the Number 1 seal entirely removed, which puts full system pressure on the Number 2 seal, shows that relatively small leakage rates would be maintained for a period of time which is sufficient to secure the pump. Even if the Number 1

Design data for the RHR System components described below are listed in Table 5.5-1.

Residual Heat Exchanger

Two residual heat exchangers are installed in the system. Each exchanger is designed to remove one-half of the residual heat load. The installation of two exchangers assures that the heat removal capacity of the RHR System is only partially lost if one exchanger fails or becomes inoperative. Two exchangers also allow maintenance of one exchanger while the other unit is in operation.

The residual heat exchangers are of the shell and U-tube type. Reactor coolant circulates through the tubes, while component cooling water circulates through the shell. The tubes are welded to the tube sheet to prevent leakage of reactor coolant.

RHR Pumps

Two identical pumps are installed in the RHR System. Each pump is sized to deliver sufficient reactor coolant flow through the residual heat exchangers to meet the plant cooldown requirements. The use of two pumps, installed in parallel, assures that pumping capacity is only partially lost should one pump become inoperative. This also allows maintenance on one pump while the other pump is in operation. In addition to the RHR duty, the pumps are used for transfer of refueling water before and after a refueling operation.

The two RHR pumps are vertical, centrifugal units with mechanical seals to prevent reactor coolant leakage to the atmosphere. All pump parts in contact with reactor coolant are austenitic stainless steel or equivalent corrosion-resistant material.

RHR Valves

The valves used in the RHR System are constructed of austenitic stainless steel or equivalent corrosion-resistant material.

Manual isolation valves are provided to isolate equipment for maintenance. Throttle valves are provided for remote manual control of residual heat exchanger tube side flow, and for remote manual control of bypass flow. Check valves prevent reverse flow through the RHR pumps.

Isolation of the RHR System is achieved with two remotely-operated series stop valves in the line from the RCS to the RHR pump suction and by two check valves in series in each line from the RHR pump discharge to the RCS, plus a remotely-operated stop valve in each discharge line. Overpressure in the RHR System is relieved through a relief valve to the containment sump.

Valves that perform a modulating function are equipped with two sets of packing and an intermediate leakoff connection that discharges to the Waste Disposal System.

Manually-operated valves have backseats to facilitate repacking and to limit the steam leakage when the valves are open. Leakoff connections are provided where required by valve size and fluid conditions.

RHR Piping

RHR piping is austenitic stainless steel. Piping joints and connections are welded except where flanged connections are required to facilitate maintenance.

5. Boration with only safety-grade systems assuming single failure.

Compliance is not required since the station can be maintained in a safe hot standby condition while any required manual actions are taken.

6. Provisions for collection and containment of RHR pressure relief discharge.

The RHR relief valves discharge to the containment sump.

7. Additional tests to study mixing of the added borated water and cooldown under natural circulation conditions with and without a single failure of an atmospheric dump valve.

Salem Generating Station is similar to Diablo Canyon Power Station in design, both being Westinghouse PWRs. Due to the similarity of the two stations, no special tests will be conducted by the Salem Unit to establish boron mixing and cooldown capability under natural circulation since Diablo Canyon Station has committed to perform these tests. The results of the tests on Diablo Canyon will be applicable for Salem.

8. Specific operational procedures for cooldown under natural circulation.

Salem Generating Station will generate specific operational procedures that will enable the operators to bring the station from hot standby condition to cold shutdown status using the systems and operating functions given in Item 9 (Cold Shutdown Scenario).

9. Seismic Category I auxiliary feedwater supply for at least 4 hours at hot shutdown plus cooldown to RHR cut-in based on longest time (for only onsite or offsite power and assuming worst single failure).

   A long-term source of auxiliary feedwater is provided by a connection to the Seismic Category I Service Water System.

Cold Shutdown Scenario (Assuming Loss of All Nonseismic Category I Equipment)

The safe shutdown design basis of the Salem Units is hot standby. The station can be maintained in a safe hot standby condition while manual actions are taken to permit achievement of cold shutdown conditions following an SSE with loss of offsite power. Under such conditions the station is capable of achieving RHR initiation conditions (approximately 350°F, 375 psig) in approximately 36 to 48 hours, including the time required for any manual actions. To achieve and maintain cold shutdown, four key functions must be performed. These are: (1) circulation of the reactor coolant, (2) removal of residual heat, (3) boration and makeup, and (4) depressurization.

Circulation of Reactor Coolant

Circulation of the reactor coolant has two stages in a cooldown from hot standby to cold shutdown. The first stage is from hot standby to 350°F. During this stage, circulation of the reactor coolant is provided by natural circulation with the reactor core as the heat source and steam generators as the heat sink. Steam release from the steam generators is initially via the steam generator safety valves and occurs automatically as a result of turbine and reactor trip. Steam release for cooldown is via the steam generator power-operated relief valves which are operated manually with their handwheels. The steam generator power-operated relief valves are accessible for local operation.

4. The steam volume is large enough to prevent water relief through the safety valves following a loss-of-load with the high water level initiating a reactor trip.

5. The pressurizer does not empty following reactor trip and turbine trip.

6. The safety injection signal is not activated during reactor trip and turbine trip.

5.5.10.2 <u>Design Description</u>

5.5.10.2.1 Pressurizer Surge Line

The pressurizer surge line connects the pressurizer to one reactor coolant loop hot leg. The line enables continuous volume pressure adjustments between the RCS and the pressurizer.

The surge line is sized to limit the pressure drop during the maximum anticipated surge to less than the difference between the maximum allowable pressure in the reactor vessel and the loops (at the point of highest pressure) and the pressure in the pressurizer at the maximum allowable accumulation with the code safety valves discharging.

The surge line and the thermal sleeves at each end are designed to withstand the thermal stresses resulting from volume surges of relatively hotter or colder water which may occur during operation.

5.5.10.2.2 Pressurizer

The pressurizer is a vertical, cylindrical vessel with hemispherical top and bottom heads constructed of carbon steel, with austenitic stainless steel cladding on all surfaces exposed to the reactor coolant.

The surge line nozzle and electric heaters are installed in the bottom head. The heaters can be removed for maintenance or replacement. A thermal sleeve is provided to minimize stresses in the surge line nozzle. A screen at the surge line nozzle and baffles in the lower section of the pressurizer prevents an insurge of cold water from flowing directly to the steam/water interface and also assists mixing.

The spray line nozzle and relief and safety valve connections are located in the top head of the vessel. Spray flow is modulated by automatically controlled air-operated valves. The spray valves can also be operated manually by a switch in the control room.

A small, continuous spray flow is provided through a manual bypass valve around the power-operated spray valves to assure that the pressurizer liquid is homogenous with the coolant and to prevent excessive cooling of the spray piping.

During an outsurge from the pressurizer, the flashing of water to steam and the generation of steam by automatic actuation of the heaters keep the pressure above the minimum allowable limit. During an insurge from the RCS, the Spray System, which is fed from two cold legs, condenses steam in the vessel to prevent the pressurizer pressure from reaching the setpoint of the power-operated relief valves for normal design transients. Heaters are energized on high water level during insurge to heat the sub-cooled surge water that enters the pressurizer from the reactor coolant loop.

Power-operated relief valves (PORVs) provide the means for pressurizer venting and a procedure for such an application is included within the Station Emergency Instructions for "natural circulation." Pressurizer vent paths have been evaluated and shown not to result in inadvertent opening or failure to close after initial opening.

The PORVs are set to open before the pressurizer safety valves. Relief through the PORVs can limit the pressurizer pressure to levels below the pressurizer safety valve setpressure, and thereby avoid opening (or challenging) the pressurizer safety valves.

5.5.13 Safety and Relief Valves

5.5.13.1 Design Bases

The capacity of the pressurizer safety valves accommodates the maximum surge resulting from complete loss of load. By the opening of the steam generator safety valves when steam pressure reaches the steam side safety setting, this objective is met without reactor trip or any operator action.

The RCS uses pressure control equipment in addition to the ASME Code safety valves. Although this pressure control equipment is not required by the ASME Code, it is used to assist in maintaining the RCS within the normal operating pressure.

The pressurizer PORVs are designed to limit pressurizer pressure to a value below the high pressure reactor trip setpoint. They are designed to fail to the closed position on loss of air supply. The PORVs are equipped with air accumulators, and will remain operable for some time following loss of the Control Air System, as long as there is sufficient air pressure in the accumulators.

The pressurizer PORVs are not required to open in order to prevent the overpressurization of the RCS. Failure of the PORVs to open results in higher reactor coolant pressures, but does not result in overpressurization of the system. In fact, the opening of the PORVs is a conservative assumption for the departure-from- nucleate-boiling limited transients by tending to keep the primary system pressure down.

The pressurizer spray control valves are also utilized to control pressurizer pressure variations. During an insurge, the Spray System, which is fed from the cold legs, condenses steam in the pressurizer to prevent the pressure from reaching the setpoint of the PORVs.

5.5.13.2 Design Description

The pressurizer safety valves are totally enclosed pop-type valves. The valves are spring-loaded, self-activated and with back-pressure compensation designed to prevent system pressure from exceeding the design pressure by more than 110 percent, in accordance with the ASME Boiler and Pressure Code, Section III. The set pressure of the valves is 2485 psig.

The 6-inch pipes connecting the pressurizer nozzles to their respective code safety valves are shaped in the form of a loop seal. Condensate, as a result of normal heat losses to the ambient will drain back to the pressurizer liquid space through the normally open safety valve drain lines. If the pressurizer pressure exceeds the set pressure of the safety valves, they will start lifting, and the water from the seal will discharge during the accumulation period. A temperature indicator in the safety valve discharge manifold alerts the operator to the passage of steam due to leakage or valves lifting.

The pressurizer is equipped with PORVs which limit system pressure for a large power mismatch and thus prevent actuation of the fixed high pressure reactor trip. The relief valves are operated automatically or by remote manual control. The operation of these valves also limits the undesirable opening of the spring-loaded safety valves.

5.5.13.3 Design Evaluation

The pressurizer safety valves prevent RCS pressure from exceeding 110 percent of system design pressure, in compliance with the ASME Code, Section III. Safety valve position is monitored by limit switches which alarm in the Control Room when any valve is not in the fully closed position.

The pressurizer PORVs prevent actuation of the reactor high pressure trip for all design transients up to and including the design step load decreases with steam dump. The relief valves also limit opening of the spring-loaded safety valves. The opening of any pressurizer PORV is annunciated in the control room.

The Salem PORVs, PORV block valves and associated downstream piping have been evaluated for operation under water-solid conditions, and have been found to be adequate. The PORVs can be relied upon to prevent challenges to the pressurizer safety valves when the pressurizer is water-solid. Administrative controls (procedures) are placed upon the PORV block valves to prevent their closure when the pressurizer is water-solid.

Westinghouse has completed a generic study (2) of PORV reliability and concluded that PORVs are adequately reliable so as not to require automatic block valve closure. Public Service Electric & Gas (PSE&G) has determined that the information provided in the generic report is applicable to the Salem Generating Station. Accordingly, automatic isolation of the PORVs is not provided.

5.5.14 Reactor Coolant System Component Supports

5.5.14.1 Description

Reactor vessel supports are assemblages of plates built up to seat the reactor vessel nozzle shoes. There are four shoe supports for each reactor vessel. The support assemblages are air cooled by negative pressure ducts that draw the air away from the space surrounding the vessel through vent holes drilled in the multiple plates. For support details, see Figure 5.5-3.

The steam generator supports are shown on Figure 5.5-4. The weight of the steam generator is transferred through four steel columns at its base to the supporting frame. The steam generator penetrates the operating floor of the Containment Building. The elevation of the operating floor is approximately at the center of gravity of the steam generator. It is supported at the floor by two sets of snubbers and bumper blocks which resist the horizontal forces and overturning moments generated from pipe rupture or earthquake motion. The supporting frame has its upper bay braced in both directions. The lower bay consists of two parallel planar trusses which are pin-hinged at the top and bottom to allow for thermal displacement. The horizontal forces at the base of the steam generator are transferred through combined truss and frame action to the lower bay of the support structure. The primary loop piping provides lateral support for the frame in the direction normal to the plane of the trusses. Lateral restraint for blowdown is provided at the top of the support structure by two struts connected to the reactor shield wall. The struts are in two bolted sections with gaps for free thermal travel and adjustment.

The RCP supports as shown on Figure 5.5-5 also consist of an upper and lower section. The upper section is a welded steel assembly and is constructed to accommodate the bolts of the feet of the RCP. The lower section is composed of two parallel planar trusses, pin-hinged at the top and bottom to provide for thermal expansion. Lateral support in the direction normal to the plane of the trusses is provided by the primary loop piping. Blowdown restraint is provided at the top of the supporting structure by struts connected to the shield wall. The struts are in bolted sections with gaps for free thermal travel and adjustment.

The steam generator and RCP supports are anchored to the containment base slab by heavy welded steel frames embedded in the concrete and tied to the base mat by 6 and 4 inch diameter bolts, 18.5 feet long. Typical details for the embedded steel for equipment supports are shown on Figure 5.5-6.

The pressurizer also penetrates the operating floor of the reactor containment. Stop lugs are embedded in the floor slab to provide the lateral support for the pressurizer at its mid-height. The

Piping and Valves

	Pump Suction	Pump Discharge
Residual heat removal loop (piping and valves in isolated loop):		
Design pressure, psig	450*	600
Design temperature, °F	400	400
Residual loop isolation valves and piping:		
Design pressure, psig		2,485
Design temperature, °F		650

* Unit 2 piping downstream of 2RH75 & 76 are designed to 600 psig.

TABLE 5.5-2

RESIDUAL HEAT REMOVAL SYSTEM FAILURE ANALYSIS

Component	Malfunction	Comments and Consequences
1. Residual heat removal pumps	Rupture of a pump casing	The casing and shell are designed for 600 psi and 400°F. The pump is protected from overpressurization by two normally closed valves in the pump suction line and by an open relief line, containing a relief valve, back to the containment sump. The pump is inspectable and is located in the Auxiliary Building protected against credible missiles. Rupture is considered unlikely but in any event the pump can be isolated.
2. Residual heat removal pump	Pump fails to start	One operating pump furnishes half of the flow required to meet design cooldown rate. This increases the time necessary for plant cooldown.
3. Residual heat removal pump	Motor operated valve on pump suction is closed	This is prevented by prestartup and startup and operational checks.
4. Residual heat removal pump	Stop valve on discharge line closed or check valve sticks closed	Stop valves are locked open. Prestartup and operational checks confirm position of valves.
5. Remote operated valves inside containment in pump suction line	Valve fails to open	In the improbable event that one of the remote operated valves on the suction line to the residual heat removal pumps is inoperable, an attempt will be made to open it manually. If this is impossible, the plant will be cooled to about 280°F with steam dump from the steam generators, while additional recovery actions could be implemented based on plant's abnormal and emergency operating procedures, equipment availability and resources.

Temperatures in the pressurizer safety and relief valve discharge lines are measured and indicated. An increase in a discharge line temperature is an indication of leakage through the associated valve. An alarm is actuated on high temperature.

The fluid temperatures in each spray line are measured and indicated. Alarms from these signals are actuated by low spray water temperature. Alarm conditions indicate insufficient flow in the spray lines through the manual throttle valves.

The temperature of the water in the pressurizer relief tank is indicated over a range of 50°F to 350°F, and an alarm, actuated by a high temperature, informs the operator that cooling of the tank contents is required.

The temperature in the leakoff line from the reactor vessel flange O-ring seal leakage monitor connections is indicated. An increase in temperature above ambient is an indication of O-ring seal leakage. High temperature actuates an alarm.

5.6.3 Pressure

Four pressurizer pressure transmitters provide signals for individual indicators in the control room, for actuation of a low pressure trip, for high pressure reactor trip, and for alarms. One of the four signals may be selected by the operator for display on a pressure recorder. Three transmitters provide independent low pressure signals for safety injection initiation and for safety injection signals to allow manual block during plant shutdown and automatic unblock during plant startup. In addition, these pressure transmitters provide inputs for pressurizer heater, spray valve, and power-operated relief valve (PORV) control.

Two narrow range differential pressure transmitters connected to the RCS sample line on the No. 1 hot leg and on the No. 3 hot leg are installed to monitor RCS level during Mid-Loop operation. A wide range differential pressure transmitter is connected on the No. 3 hot leg to monitor RCS level during midloop operation, reduced inventory and vacuum fill.

Two wide-range transmitters provide pressure indication over the full operating range. The indicators serve as a guide to the operator during plant startup and shutdown and also provide the open permissive signals and automatic closure signals for the RHR loop isolation valves interlock circuit.

Two local pressure indicators are provided for operator reference during shutdown. They are located in two separate loops and are provided with maximum (drag) pointers to indicate the maximum pressure attained since the last resetting of the pointers.

A pressurizer relief tank (PRT) pressure transmitter provides a signal to close valve PCV-472 on high pressure should it be open when a safety valve lifts discharging steam into the PRT.

5.6.4 Pressurizer Water Level

Three pressurizer liquid level transmitters provide signals for use in the Reactor Control and Protection System, and the Chemical and Volume Control System (CVCS). Each transmitter provides an independent high water level signal that is used to actuate an alarm and, upon two out of the three transmitter signals, will cause a reactor trip. The transmitters may also provide independent low water level signals that will activate an alarm. Each transmitter also provides a signal for a level indicator that is located on the main control board.

In addition, any of the three level transmitters may be selected for display on a level recorder located on the main control board.

Two of the three transmitters may be selected to provide an alarm when the liquid level falls to the fixed low level setpoint. The

3. Safety injection recirculating suction line from the containment sump to the suction of the RHR pumps. Redundant isolation protection is provided by normally closed motor operated valves inside protective chambers outside of containment and the closed system (RHR) outside the containment.

4. Containment pressure instrument lines (see below).

5. The main feedwater lines are provided with one stopcheck valve (BF22) outside containment. On Unit 2, these valves include remote-manual motor operators.

6. RHR pump discharge to cold leg Safety Injection. Redundant isolation is provided by the remote manual (SJ49) valves located outside containment and the RHR closed system outside containment. This is considered an acceptable isolation barrier per the "other defined basis" in ANSI N271-1976. This standard is endorsed by Regulatory Guide 1.141.

7. ECCS relief line discharge to the containment sump. Redundant isolation is provided by a check valve inside containment (PR25) and the closed system outside the containment as defined in UFSAR Sections 6.2.2 and 6.3.

8. Service Water system to and from the Containment Fan Coil Units. Redundant isolation is provided by remote manual valves outside containment and the closed Nuclear Class III system inside containment. Original system design complied with AEC General Design Criteria #53 and the system meets the definition for a Safety Class 2 system.

9. Component Cooling to and from the Excess Letdown Heat Exchanger. Redundant isolation is provided by automatic isolation valves outside containment and the closed Nuclear Class III system inside containment. Original system design complied with AEC General Design Criteria #53 and the system meets the definition for a Safety Class 2 system.

10. Main Steam supply lines to the Auxiliary Feed Pump Turbine, Radiation Monitors and the Steam Safety Valves support struts. These essential system branch lines off the Main Steam penetrations only utilize a single isolation barrier being the closed system inside containment. The calculated release through these paths is already bounded by the accident analysis for a primary to secondary leak and a complete blowdown of the Steam Generator.

Instrument Lines

Instrument lines which penetrate the containment are the following:

1. The containment pressure instrument used to initiate safeguards consists of four instrument lines penetrating the containment. Each line consists of a sealed, filled measuring system whose isolation consists of a diaphragm-type sensor which separates the containment atmosphere from the seal fluid and another diaphragm in the transmitter which separates the seal from the atmosphere outside the containment.

2. The containment air sample radiation monitor normal inlet and outlet sample lines are each equipped with two automatic trip valves, one inside and one outside the containment, which close upon receipt of a containment isolation phase A signal. The backup inlet and outlet sample lines are normally closed and under administrative control with two remote operated isolation valves, one inside and one outside the containment for each line.

TABLE 6.2-10
CONTAINMENT ISOLATION - MAJOR PIPING PENETRATIONS

Figure	Service	Class	Status N	Status S	Status I	Inside Containment Valve(s)	Inside Containment Type	Inside Containment Pwr	Inside Containment Signal	Outside Containment Valve(s)	Outside Containment Type	Outside Containment Pwr	Outside Containment Signal	Auto Isol. Time (Sec)	Fluid	Temp.
6.2-17	Gas Analyzer from Pressurizer Relief Tank	B	Int.	Closed	Closed	1PR17 #	Auto-trip	A	T	1PR18 #	Auto-trip	B	T	≤10	Gas	Cold
6.2-17	Primary Water Supply to Pressurizer Relief Tank	B	Int.	Closed	Closed	1WR81 #	Non-return	N/A	N/A	1WR80 #	Auto-trip	B	T	≤10	Liquid	Cold
6.2-17	Nitrogen Supply to Pressurizer Relief Tank	B	Int.	Closed	Closed	1NT26 #	Non-return	N/A	N/A	1NT25 #	Auto-trip	B	T	≤10	Gas	Cold
6.2-18	Pressurizer Dead Weight Calibrator	B	Closed	Closed	Closed	Note 9	-	-	-	1SS900 1SS901	Manual Manual	N/A N/A	N/A N/A	N/A	Liquid	Cold
6.2-19	Relief Lines to Containment Sump	D	Int.	Closed	Closed	1PR25 #	Non-return	N/A	N/A	Closed System	-	-	-	N/A	Liquid	Cold
6.2-20	CVCS Letdown Line	B	Open	Open	Closed	1CV3 # 1CV4 # 1CV5 #	Auto-trip	B \$ A C	T T T	1CV7 #	Auto-trip	B \$	T	≤10	Liquid	Hot
6.2-20	CVCS Charging Line	B	Open	Open	Closed	1CV74 #	Non-return	N/A	N/A	1CV68 # 1CV69 #	Auto-trip	B C	SI SI	≤10	Liquid	Hot
6.2-21	Reactor Coolant Pump Seal Water Supply	D	Open	Open	Open	11-14CV99 #	Non-return	N/A	N/A	Closed System	-	-	-	N/A	Liquid	Cold

TABLE 6.2-10 (Continued)

Figure	Service	Class	Status N	Status S	Status I	Inside Containment Valve(s)	Inside Containment Type	Inside Containment Pwr-Signal		Outside Containment Valve(s)	Outside Containment Type	Outside Containment Pwr-Signal		Auto Isol. Time (Sec)	Fluid	Temp.
6.2-24	Reactor Coolant Pump Thermal Barrier Cooling Water Discharge	B	Open	Open	Closed	1CC190 #	Auto-trip	A	P	1CC131 #	Auto-trip	C	P	≤10	Liquid	Cold
			Closed	Closed	Closed	1CC208 #	Non-return	N/A	N/A							
6.2-25	Gas Analyzer from RCDT	B	Int.	Int.	Closed	1WL96 #	Auto-trip	C	T	1WL97 #	Auto-trip	B	T	≤10	Gas	Cold
6.2-25	N2 Supply to RCDT	B	Open	Open	Closed	1WL98 #	Auto-trip	C	T	1WL108 #	Auto-trip	B	T	≤10	Gas	Cold
6.2-25	Reactor Coolant Drain Tank Vent	B	Open	Open	Closed	1WL98 #	Auto-trip	C	T	1WL99 #	Auto-trip	B	T	≤10	Gas	Cold
6.2-26	Reactor Coolant Drain Tank Pump Discharge	B	Int.	Int.	Closed	1WL12 #	Auto-trip	C	T	1WL13 #	Auto-trip	B	T	≤10	Liquid	Hot
		B	N/A	N/A	N/A	1WL476	Relief	N/A	N/A							
6.2-27	Accumulator N2 Supply	B	Closed	Closed	Closed	1NT34 #	Non-return	N/A	N/A	1NT32 #	Auto-trip	D	T	≤10	Gas	Cold
6.2-28	Safety Injection Test line	B	Closed	Closed	Closed	1SJ123 #	Auto-trip	A	T	1SJ53 # 1SJ60 #	Auto-trip	D B	T T	≤10 ≤10	Liquid Liquid	Cold Cold
6.2-29	RHR Outlets to Safety Injection System	D	Open	Open	Open	-	-	-	-	11SJ49 12SJ49 & Closed System	(2)Rem. Manual	A B	N/A	Note 14	Liquid	Cold
6.2-30	Safety Injection Pumps Outlet to Cold Legs and Test Line	D	Open	Open	Open	11-14SJ144	Non-return	N/A	N/A	1SJ135	Rem. Manual	B	N/A	Note 14	Liquid	Cold
			Closed	Closed	Closed	1SJ158	Rem. Manual	B	N/A							

* For Unit 2 Only

TABLE 6.2-10 (Continued)

Figure	Service	Class	Status N	Status S	Status I	Inside Containment Valve(s)	Inside Containment Type	Inside Containment Pwr	Inside Containment Signal	Outside Containment Valve(s)	Outside Containment Type	Outside Containment Pwr	Outside Containment Signal	Auto Isol. Time (Sec)	Fluid	Temp.
6.2-34	Sample Line from Accumulators	B	Closed	Closed	Closed	1SS103 #	Auto-trip	A	T	1SS27 #	Auto-trip	B	T	$\leq$10	Liquid	Hot
		B	Closed	Closed	Closed	1SS653*	Relief	N/A	N/A							
6.2-34	Sample Line from Hot Legs	B	Closed	Closed	Closed	1SS104 #	Auto-trip	A	T	1SS33 #	Auto-trip	D	T	$\leq$10	Gas	Cold
6.2-34	Sample Line from Pressurizer Liquid	B	Closed	Closed	Closed	1SS107 #	Auto-trip	A	T	1SS49 #	Auto-trip	B	T	$\leq$10	Liquid	Cold
6.2-34	Sample Lines from S/G Blowdown	C	Open	Closed	Closed	Closed System	-	-	-	11-14SS94	Auto-trip	B	T	$\leq$10	Liquid	Hot
6.2-35	Containment Pressure Instruments	A	Open	Open	Open	Note 7	-	-	-	- -	-	-	-		(Filled system)	
6.2-36	Containment Air Monitor Normal Inlet	B	Open	Open	Closed	1VC11 #	Auto-trip	B	T	1VC12 #	Auto-trip	A	T	$\leq$10	Gas	Cold
6.2-36	Containment Air Monitor Backup Inlet	B	Closed	Closed	Closed	1VC13 #	Rem. Manual	C	N/A	1VC14 #	Rem. Manual	C	N/A	Note 14	Gas	Cold
6.2-36	Containment Air Monitor Normal Outlet	B	Open	Open	Closed	1VC7 #	Auto-trip	B	T	1VC8 #	Auto-trip	A	T	$\leq$10	Gas	Cold
6.2-36	Containment Air Monitor Backup Outlet	B	Closed	Closed	Closed	1VC9 #	Rem. Manual	C	N/A	1VC10 #	Rem. Manual	C	N/A	Note 14	Gas	Cold

* for Unit 1 only

TABLE 6.2-10 (Continued)

Figure	Service	Class	Status N	Status S	Status I	Inside Containment Valve(s)	Inside Containment Type	Inside Containment Pwr-Signal		Outside Containment Valve(s)	Outside Containment Type	Outside Containment Pwr-Signal		Auto Isol. Time (Sec)	Fluid	Temp.
6.2-40 through 6.2-43	Auxiliary Feed- water Supply Turbine Driven	C	Open Open Open Open	Int. Int. Int. Int.	Open Open Open Open	Closed System	-	-	-	11AF11 12AF11 13AF11 14AF11	Rem. Manual	C C C C	N/A	Note 14	Liquid	Cold
6.2-40 through 6.2-43	Auxiliary Feed- water Supply Motor Driven	C	Closed Closed Closed Closed	Int. Int. Int. Int.	Open Open Open Open	Closed System	-	-	-	11AF21 12AF21 13AF21 14AF21	Rem. Manual	B B A A	N/A	Note 14	Liquid	Cold
6.2-44	Reactor Cavity Sump Discharge	B	Int.	Int.	Closed	1WL16 #	Auto- trip	C	T	1WL17 #	Auto- trip	B	T	≤10	Liquid	Cold
	to Waste Disposal	B	N/A	N/A	N/A	1WL478	Relief	N/A	N/A							
6.2-45	Fire Protection Water Supply	B	Closed	Closed	Closed	1FP148 #	Non- return	N/A	N/A	1FP147 #	Auto- trip	C	T	≤10	Liquid	Cold
6.2-45	Refueling Canal Supply	B	Closed	Closed	Closed	1WL190 #	Manual	N/A	N/A	1SF36 #	Manual	N/A	N/A	N/A	Liquid	Cold
6.2-45	Refueling Canal Discharge	B	Closed	Closed	Closed	1WL191 #	Manual	N/A	N/A	1SF22 #	Manual	N/A	N/A	N/A	Liquid	Cold
6.2-45A	Post LOCA Atmosphere Sample	B	Closed	Closed	Int.	11VC19 #	Rem. Manual	A	N/A	11VC17 #	Rem. Manual	A	N/A	Note 14	Gas	Cold
		B	Closed	Closed	Int.	11VC20 #	Rem. Manual	A	N/A	11VC18 #	Rem. Manual	A	N/A	Note 14	Gas	Cold
		B	Closed	Closed	Int.	12VC20 #	Rem. Manual	C	N/A	12VC18 #	Rem. Manual	C	N/A	Note 14	Gas	Cold
		B	Closed	Closed	Int.	12VC19 #	Rem. Manual	C	N/A	12VC17 #	Rem. Manual	C	N/A	Note 14	Gas	Cold

* For Unit 2 Only

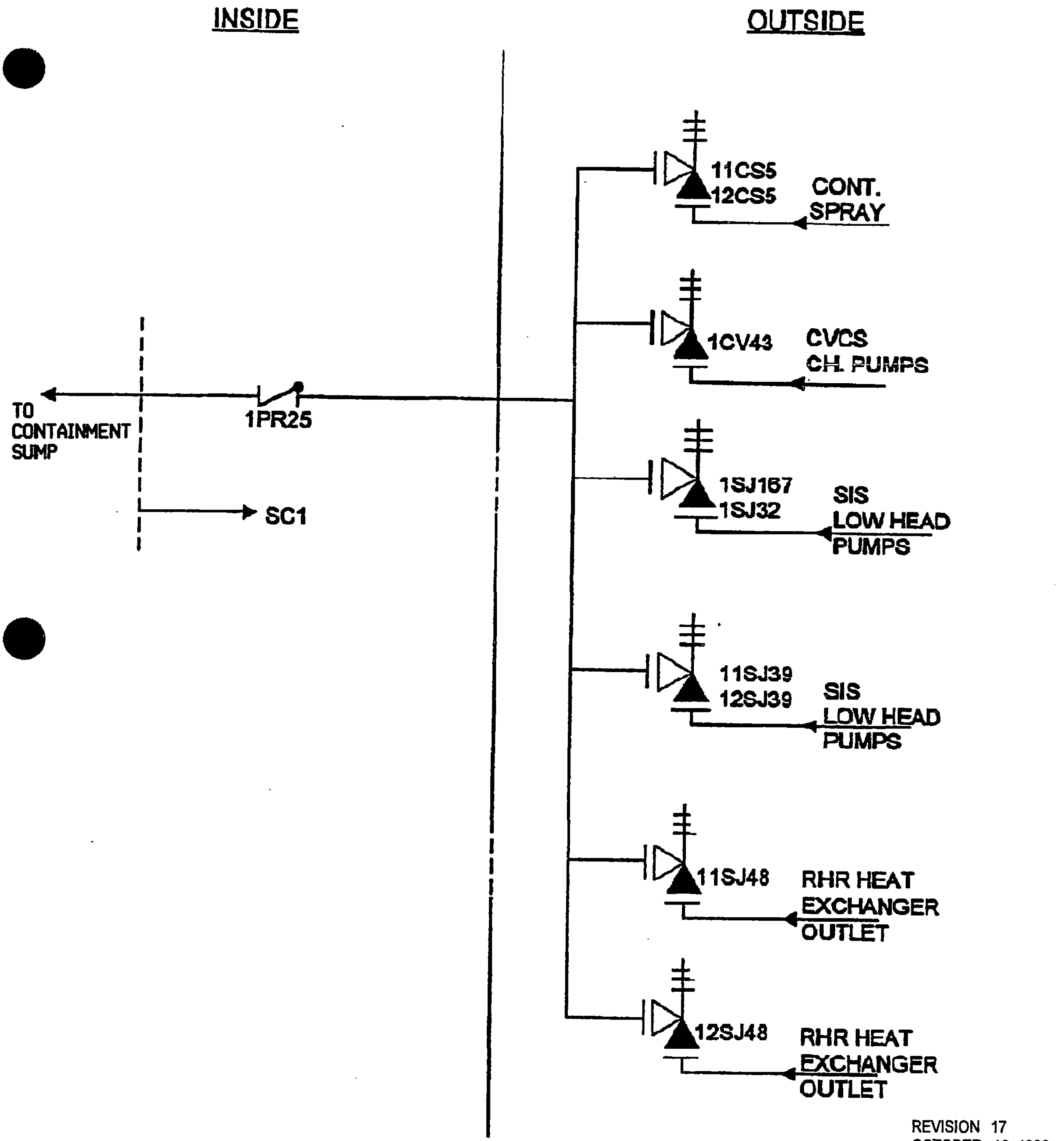
TABLE 6.2-12

CONTAINMENT ISOLATION VALVES
SUBJECT TO TYPE C LEAK RATE TESTING

Valve Number		Function
1.	1PR17	Pressurizer Relief Tank - Gas Analyzer Connection
2.	1PR18	Pressurizer Relief Tank - Gas Analyzer Connection
3.	1NT25	Pressurizer Relief Tank - N_2 Connection
4.	1NT26	Pressurizer Relief Tank - N_2 Connection
5.	1WR80	Pressurizer Relief Tank - Primary Water Connection
6.	1WR81	Pressurizer Relief Tank - Primary Water Connection
7.	1PR25	Containment Sump - ECCS Relief Line Connection
8.	1CV3	CVCS - Letdown Line
9.	1CV4	CVCS - Letdown Line
10.	1CV5	CVCS - Letdown Line
11.	1CV7	CVCS - Letdown Line
12.	1CV68	CVCS - Charging Line
13.	1CV69	CVCS - Charging Line
14.	1CV74	CVCS - Charging Line
15.	1CV284	CVCS - RCP Seals
16.	1CV296	CVCS - RCP Seals
17.	1CV116	CVCS - RCP Seals
18.	1CV215	Component Cooling - Excess Letdown Heat Exchanger
19.	1CV113	Component Cooling - Excess Letdown Heat Exchanger
20.	1CC118	Component Cooling - RCP Cooler
21.	1CC119	Component Cooling - RCP Cooler
22.	1CC187	Component Cooling - RCP Cooler
23.	1CC186	Component Cooling - RCP Cooler
24.	1CC136	Component Cooling - RCP Cooler
25.	1CC190	Component Cooling - RCP Cooler
26.	1CC208	Component Cooling - RCP Cooler
27.	1CC131	Component Cooling - RCP Cooler
28.	1WL96	RC Drain Tank - Gas Analyzer Connection
29.	1WL97	RC Drain Tank - Gas Analyzer Connection
30.	1WL98	RC Drain Tank - Vent Header Connection
31.	1WL99	RC Drain Tank - Vent Header Connection
32.	1WL108	RC Drain Tank - N_2 Connection
33.	1WL12	RC Drain Tank Pumps
34.	1WL13	RC Drain Tank Pumps
35.	1NT32	Accumulator N_2 Supply
36.	1NT34	Accumulator N_2 Supply
37.	1SJ123	Safety Injection System Test Line
38.	1SJ53	Safety Injection System Test Line
39.	1SJ60	Safety Injection System Test Line

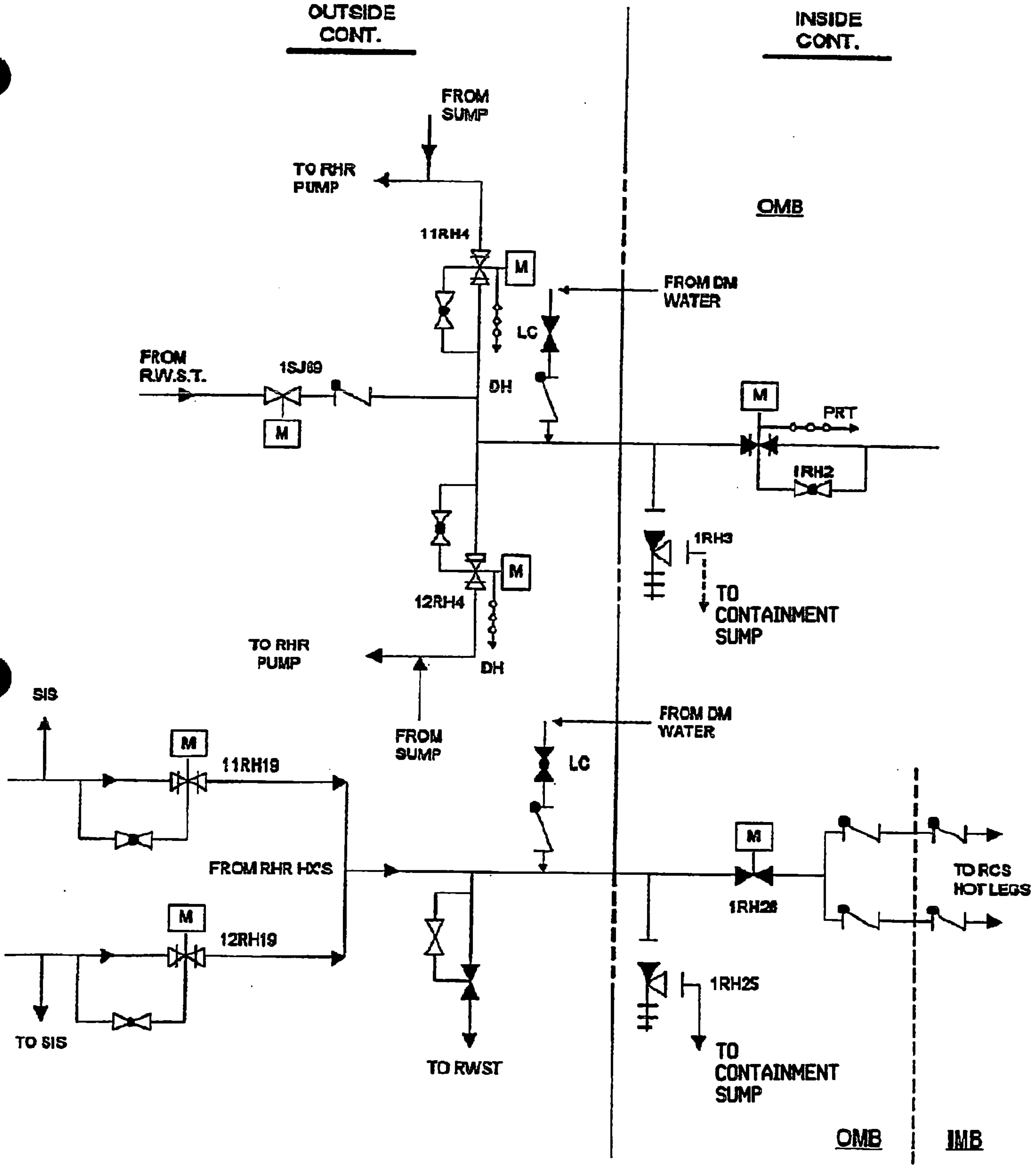
Valve Number		Function
83.	1SA262	Containment Pressure Test Instrumentation
84.	1SA264	Containment Pressure Test Instrumentation
85.	1SA265	Containment Pressure Test Instrumentation
86.	1SA267	Containment Pressure Test Instrumentation
87.	1SA268	Containmnent Pressure Test Instrumentation
88.	1SA270	Containment Pressure Test Instrumentation
89.	11SS181	Post LOCA RCS Sampling
90.	11SS182	Post LOCA RCS Sampling
91.	11SS188	Post LOCA RCS Sampling
92.	11SS189	Post LOCA RCS Sampling
93.	13SS181	Post LOCA RCS Sampling
94.	13SS182	Post LOCA RCS Sampling
95.	13SS184	Post LOCA RCS Sampling
96.	13SS185	Post LOCA RCS Sampling
97.	11VC17	Post LOCA Atmospheric Sampling
98.	11VC18	Post LOCA Atmospheric Sampling
99.	11VC19	Post LOCA Atmospheric Sampling
100.	11VC20	Post LOCA Atmospheric Sampling
101.	12VC17	Post LOCA Atmospheric Sampling
102.	12VC18	Post LOCA Atmospheric Sampling
103.	12VC19	Post LOCA Atmospheric Sampling
104.	12VC20	Post LOCA Atmospheric Sampling
105.	11CA360	Instrument Air Supply
106.	12CA360	Instrument Air Supply
107.	1CA1714	Airlock Seal Test Supply
108.	1CA1715	Airlock Seal Test Supply
109.	11CV99	RCP Seal Injection
110.	12CV99	RCP Seal Injection
111.	13CV99	RCP Seal Injection
112.	14CV99	RCP Seal Injection
113.	1WL476	Containment Penetration Piping Overpressure Relief
114.	1WL478	Containment Penetration Piping Overpressure Relief
115.	1SS653	Containment Penetration Piping Overpressure Relief

NOTE: Valve designations are shown for Unit No. 1 although Unit No. 2 is similar (e.g., 1PR17 would be 2PR17 for Unit No. 2) unless otherwise noted.



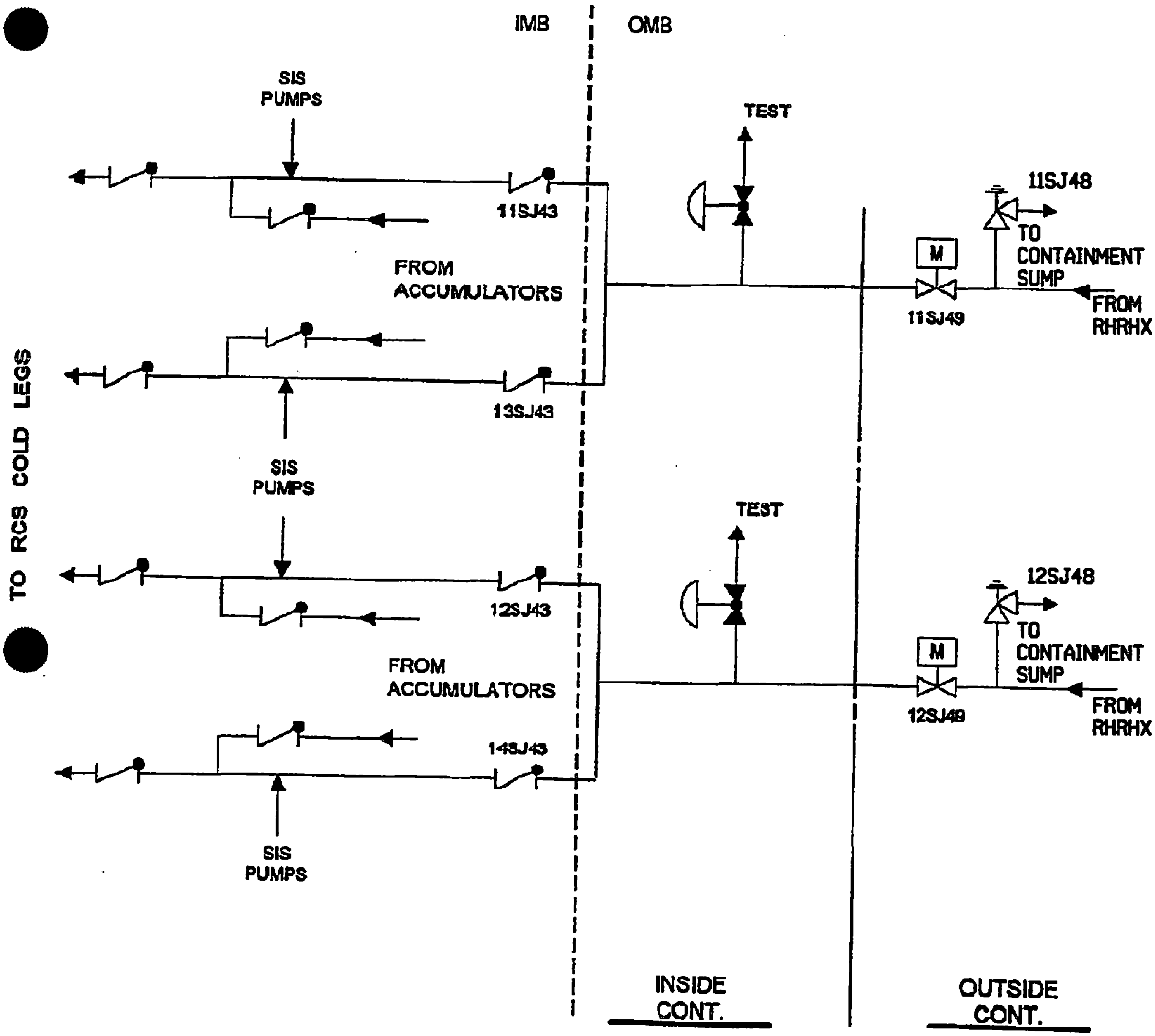
REVISION 17
OCTOBER 16 1998

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	CONTAINMENT ISOLATION RELIEF LINES TO CONTAINMENT SUMP
	Updated FSAR FIG. 6.2-19



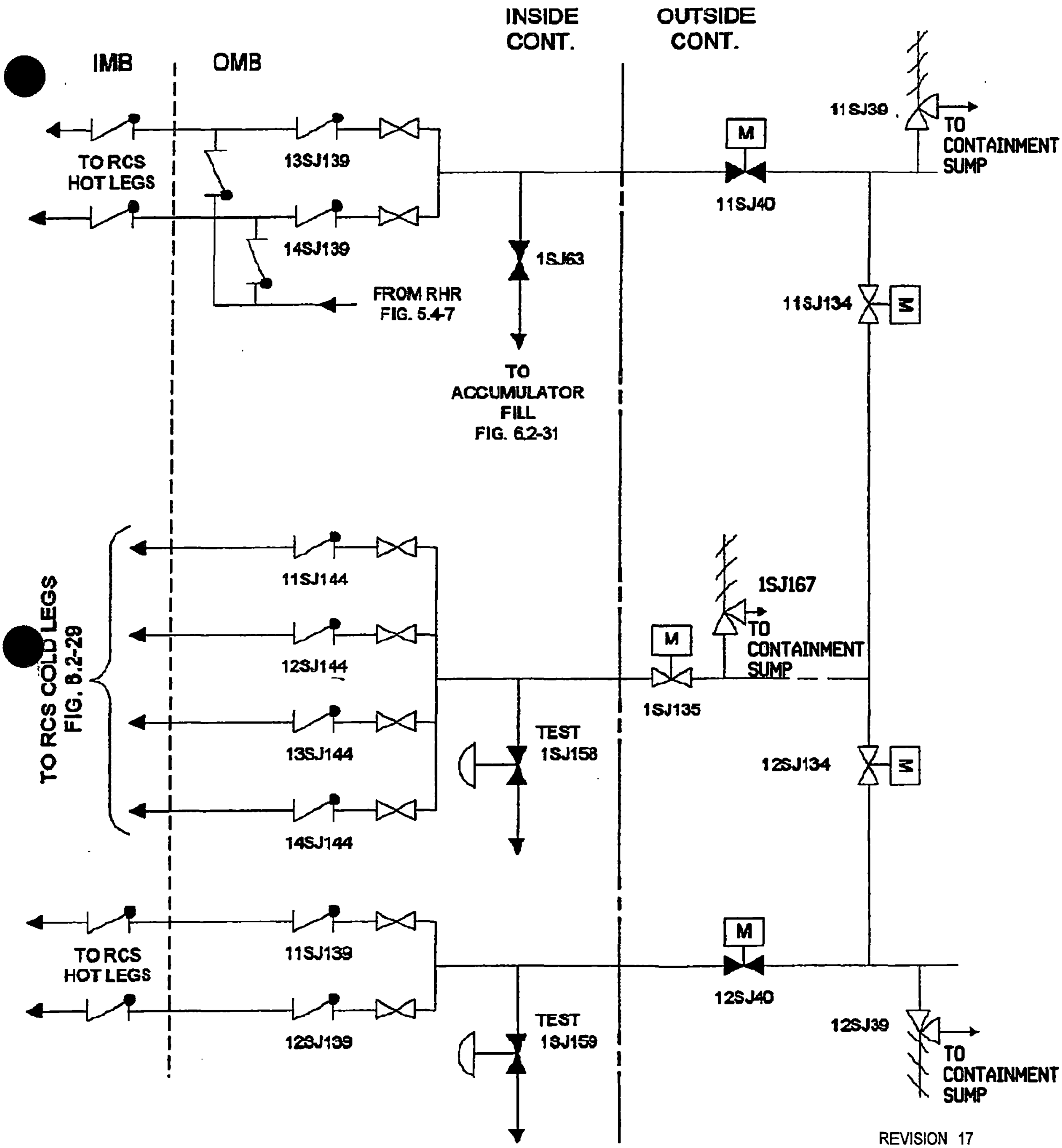
REVISION 17
OCTOBER 16 1998

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	CONTAINMENT ISOLATION RESIDUAL HEAT REMOVAL CONNECTIONS
	Updated FSAR FIG. 6.2-22



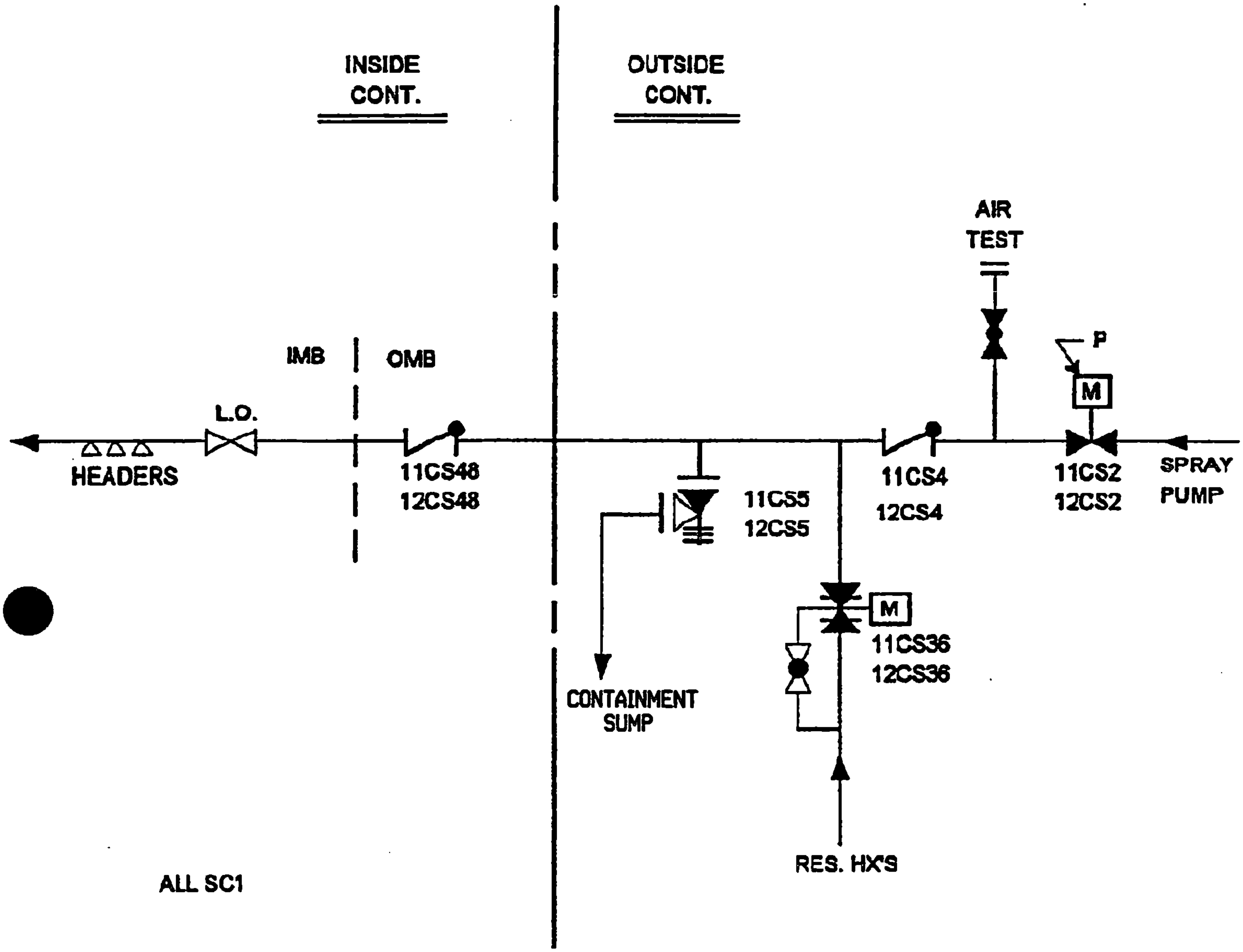
REVISION 17
OCTOBER 16 1998

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	CONTAINMENT ISOLATION RHR SAFETY INJECTION CONNECTIONS
	Updated FSAR FIG. 6.2-29



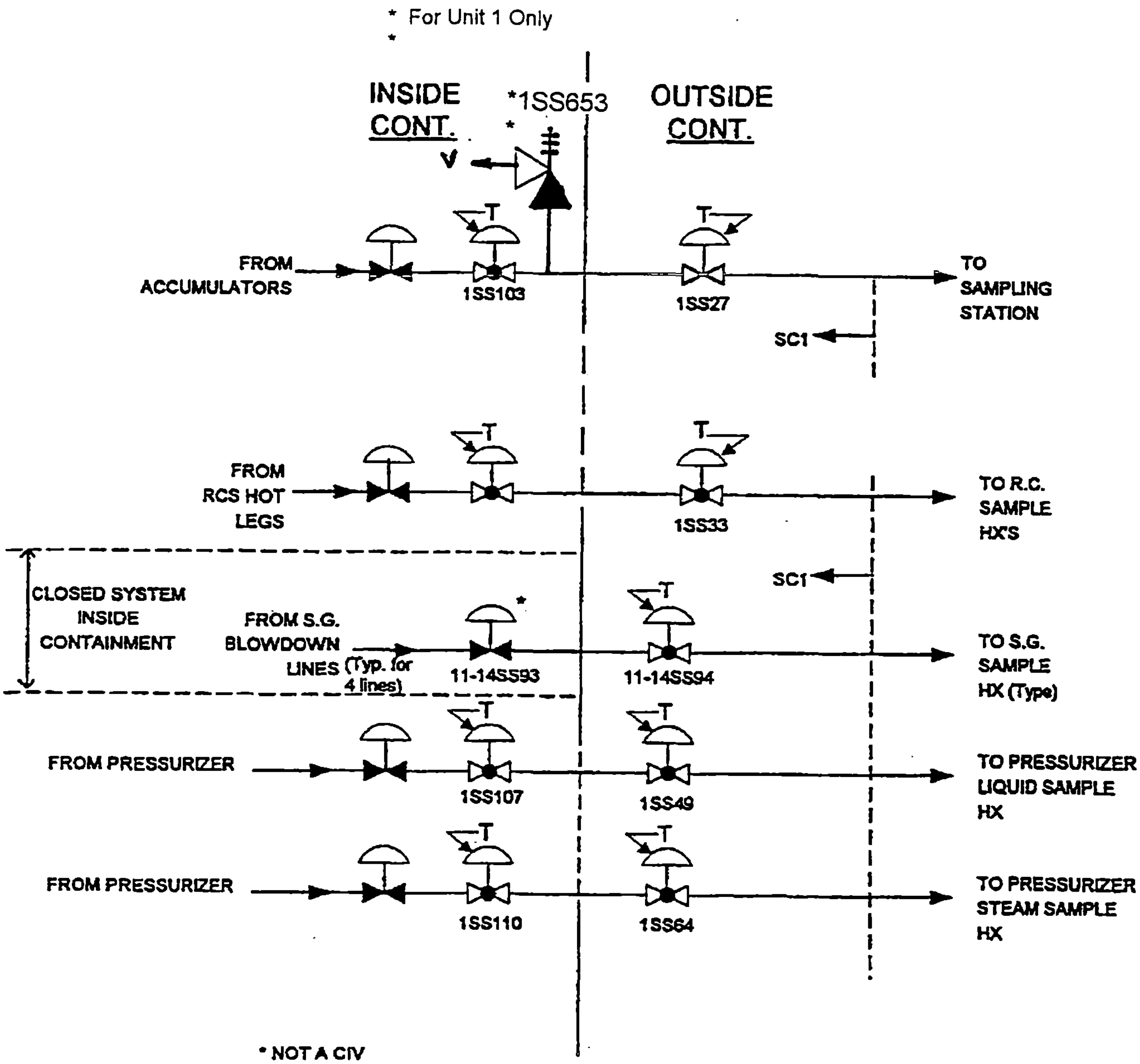
REVISION 17
OCTOBER 16 1998

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	CONTAINMENT ISOLATION SAFETY INJECTION PUMP CONNECTIONS
	Updated FSAR — FIG. 6.2-30



REVISION 17
OCTOBER 16 1998

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	CONTAINMENT ISOLATION CONTAINMENT SPRAY SYSTEM
	Updated FSAR FIG. 6.2-33



REVISION 17
OCTOBER 16 1998

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Containment Isolation - Reactor Coolant, Steam Generator, Pressurizer, Accumulator Sampling
	Updated FSAR FIG.6.2-34

the RCS pressure is still in excess of the shutoff head of the RHR pumps at the onset of recirculation.

NRC issued Information Notice 87-63 which identified the possibility of unintended flow paths during the recirculation modes of operation which could increase RHR pump maximum flow potential. With "loop around" flow considered, the highest RHR pump flow was calculated to occur during the cold leg recirculation mode of operation following a postulated failure of one of two operating RHR pumps.

At approximately 14.0 hours after the switchover to cold leg recirculation, hot leg recirculation will be initiated to assure termination of boiling. To ensure adequate flow performance, simultaneous flow delivery to the RCS cold legs and RCS hot legs are required. At a minimum, one safety injection pump is required to be aligned and operated in a hot leg recirculation flow mode. For a LOCA during Mode 4, with RCS cold leg temperature <312°F, a SI pump may not be available for the hot leg recirculation. In this instance, the RHR flowpath through RH26 would be utilized to provide hot leg recirculation.

Since the injection phase of the accident is terminated before the RWST is completely emptied, all pipes are kept filled with water before recirculation is initiated. Water level indication and alarms on the RWST inform the operator that sufficient water has been injected into the containment to allow initiation of recirculation with the RHR pumps and to provide ample warning to terminate the injection phase while the operating pumps still have adequate NPSH. Two level indicators are provided in the containment sump to provide backup indication that injection can be terminated and recirculation initiated.

Redundancy in the external recirculation loop is provided for by the inclusion of duplicate charging, safety injection, and RHR pumps and residual heat exchangers. Inside the containment, the High Pressure Injection System is divided into two separate flow trains. For cold leg recirculation, the charging pumps deliver to all four cold legs and the safety injection pumps also deliver to all four cold legs by separate flow paths. For hot leg recirculation, each safety injection pump delivers through separate paths to two reactor coolant loops.

The low head pumps take suction through separate lines from the containment sump and discharge through separate paths to the RCS. The sump design provides sufficient flow area over the trash curb ahead of the sump and adequate NPSH for the RHR pumps to operate in the recirculation mode.

The low flow velocity across the containment floor approaching the sump permits the bulk of the debris denser than water to settle to the floor of the containment rather than enter the sump.

Perforated plates prevent entrance of other suspended matter of a size that could jeopardize the Recirculation System. A weir in the sump prevents floating debris from entering the sump.

The sump isolation valves are located in small steel-lined controlled leakage compartments. This arrangement contains any isolation valve leakage and assures that leakage during long-term recirculation will not impair the integrity of the containment or recirculation system.

The containment sump is described in Section 6.3.2.2. Special attention is paid to the design, materials, and fabrication of the sump, the suction piping, guardpipes, and isolation valves to provide assurance that the sump and piping will remain functional under the accident environment and continue to provide suction for the long-term recirculation.

A sample connection is provided in the RHR System to remotely sample recirculated liquid in the sample room during post-accident operations. Additives can be supplied to the sump through the existing plant design features within 48 hours from switchover to cold leg recirculation mode, if measurements indicate the sump liquid is outside the desired pH range of 7.0 to 10.0. A minimum sump liquid pH of 7.0 will minimize the potential for chloride induced stress corrosion cracking of stainless steel components (Reference 3). Note: Branch Technical Position MTEB 6.1 supports a lower limit of 7.0.

6.3.2.2 Equipment and Component Description

The major components of the ECCS are described below.

Accumulators

The accumulators are pressure vessels containing borated water and pressurized with nitrogen gas. During normal operation, each accumulator is isolated from the RCS by two check valves in series. Should the RCS pressure fall below the accumulator pressure, the check valves open and borated water is forced into the RCS. One accumulator is attached to each of the cold legs of the RCS. Mechanical operation of the swing disc check valves is

6. Penetrant inspection in accordance with Paragraph N-627 of Section III of the ASME Code of all welds and all hot or cold formed parts

7. A hydrostatic test duration of not less than 30 minutes

8. The witnessing of hydro and penetrant tests by a qualified inspector

9. A thorough final inspection of the unit for workmanship and the absence of any gouge marks or other scars that could act as stress concentration points

10. A review of the radiographs and of the certified chemical and physical test reports for all material used in the unit.

The residual heat exchangers are conventional vertical shell and U-tube type units. The tubes are seal welded to the tube sheet. The shell connections are flanged to facilitate shell removal for inspection and cleaning of the tube bundle. Each unit has a SA 515GR70 carbon steel shell, SA-213 TP-304 stainless steel tubes, SA-240 Type 304 stainless steel channel, SA-240 Type 304 stainless steel channel cover and a tube sheet of forged steel SA-105 GR.III with 1/4-inch minimum TP-304 weld overlay.

Valves (General)

Design features employed to minimize valve leakage include the following:

1. Other valves that are normally open, except those valves which perform a control function, are provided with backseats to limit stem leakage.

2. Normally closed globe valves are installed with recirculation fluid pressure under the seat to prevent stem leakage of recirculated (radioactive) water.

3. Relief valves are enclosed, i.e., they are provided with a closed bonnet and discharge to a closed system or the containment sump.

4. Control and motor operated valves (3 inches and above) exposed to recirculation flow have double packed stuffing boxes and stem leakoff connections to the Waste Processing System.

All parts of valves used in the SIS in contact with borated water are austenitic stainless steel or equivalent corrosion-resistant material. The motor operators on the injection line isolation valves are capable of rapid operation. All valves required for initiation of safety injection or isolation of the system have remote limit position indication in the control room.

Valving is specified for exceptional leak tightness. All valves, except those which perform a control function, are provided with backseats that are capable of limiting leakage to less than 1.0 cc per hour per inch of stem diameter, assuming no credit taken for valve packing. Those valves that are normally open are backseated. Normally closed globe valves are installed with recirculation flow under the seat to prevent leakage of recirculated water through the valve stem packing. Relief valves discharge to an enclosed system or the containment sump. Control and motor-operated valves, 3 inches and above that are exposed to recirculation, are provided with double-packed stuffing boxes and stem leakoff connections which are piped to the Equipment Drain System.

The check valves that isolate the ECCS from the RCS are installed near the reactor coolant piping to reduce the probability of an injection line rupture causing a LOCA.

Portions of the ECCS piping are protected by relief valves. The relieving capacity of these valves is based on a flow several times greater than the expected leakage rate through the check valves. The valves relieve to the pressurizer relief tank.

The RHR System is protected by four relief valves: one on the header from the RCS to the pumps, two on the cold leg injection headers, and one on the hot leg return header.

These valves discharge to the containment sump.

The gas relief valves on the accumulators protect them from pressures in excess of the design value.

Motor-Operated Valves

The pressure containing parts (body, bonnet, and discs) of the motor-operated valves employed in the SIS are designed per criteria established by the ANSI B16.5 or MSS SP66 specifications. The materials of construction for these parts are procured per ASTM A182, F316 or A351, GR CF8M, or CF8. All material in contact with the primary fluid, except the packing, is austenitic stainless steel or equivalent corrosion-resistant material. The pressure-containing cast components are radiographed in accordance with ASTM E-94 and the acceptance standard as outlined in ASTM E-71. The body, bonnet, and discs are liquid penetrant inspected in accordance with ASME Pump and Valve Code. The liquid penetrant acceptable standard is outlined in the ASME Pump and Valve Code.

When a gasket is employed, the body-to-bonnet joint is designed per ASME Code Section VIII and/or ANSI B16.5 with a fully trapped, controlled compression, spiral wound gasket with provisions for seal welding, or of the pressure seal design with provisions for seal welding. The body-to-bonnet bolting and nut materials are procured per ASTM A193 and A194, respectively, or equivalent.

The entire assembled unit is hydrotested as outlined in MSS SP-61 with the exception that the test is maintained for a minimum period of 30 minutes. Any leakage is cause for rejection. The seating design is of the Darling parallel disc design, the Crane flexible wedge design, or the equivalent. These designs have the feature of releasing the mechanical holding force during the first increment of travel. Thus, the motor operator has to work only against the frictional component of the hydraulic unbalance on the disc and the packing box friction. The discs are guided throughout the full disc travel to prevent chattering and provide ease of gate movement. The seating surfaces are hard faced (Stellite No. 6 or equivalent) to prevent galling and reduce wear.

The stem material is ASTM A276, Type 316, Condition B or precipitation hardened 17-4 PH stainless procured and heat treated to Westinghouse Specifications. These materials are selected because of their corrosion resistance, high tensile properties, and their resistance to surface scoring by the packing. The valve stuffing box of motor-operated valves having leakoff is designed with a lantern ring leak-off connection with a minimum of a full set of packing below the lantern ring; a full set of packing is defined as a depth of packing equal to 1 1/2 times the stem diameter. The experience with this stuffing box design and the selection of packing and stem materials have been very favorable in both conventional and nuclear power plants.

The motor operator is extremely rugged and is noted throughout the power industry for its reliability. The unit incorporates a "hammer blow" feature that allows the motor to impact the discs away from the fore or backseat upon opening or closing. This "hammer blow" feature not only impacts the disc but allows the motor to attain its operational speed.

Each valve is assembled, hydrostatically tested, seat-leakage tested (fore and back), operationally tested, cleaned and packaged per specifications. All manufacturing procedures employed by the

2. The majority of containment sump screening consists of two-level horizontal screens.

Blockage of drains and containment sump screens will not be caused by circulation materials following an accident. Because of the structural nature of the insulation, large quantities of this material would not be dislodged from pipes in which breaks could occur or from surrounding pipes due to jet impingement. Reflective, totally encapsulated, and semi-encapsulated materials are designed to withstand severe loadings. Only the material directly adjacent to a high energy pipe break would be dislodged from the pipe. Although material directly in the path of a jet stream may become saturated, the lagging or strapping system will keep it on all insulated surfaces.

The following is a summary of insulation materials used inside containment:

Reflective: This is an all-metallic stainless steel insulation. This material is used on the RCS.

Encapsulated: This is a ceramic fiber insulation "cera-blanket" totally enclosed in a rigid stainless steel structure. This material is used on the ECCS piping and equipment in the containment.

Semi-Encapsulated: This application of "cera-blanket" insulation utilizes an outer heavy gage stainless steel surface with an interior surface of formed stainless steel foil or heavy gage stainless steel channels and straps (panel insulation). Foil-enclosed insulation is used for heat retention on Nuclear Class 3 piping and equipment while panel insulation is used on the steam generators.

Min "K":	This is a high-efficiency powder-like insulation totally enclosed in stainless steel. Small amounts of this insulation are used on the RCS where physical arrangement does not permit the use of thicker reflective insulation.
Fiberglass:	This is a fibrous insulation covered by stainless steel and a vapor barrier used to prevent sweating of cold water systems (Component Cooling and Service Water).
Fiberglass With Blanket:	This fibrous glass insulation is enclosed in woven fibrous glass fabric between two layers of fiberglass scrim sewn to the insulation. This material is used on the Pressurizer. On most areas of the Pressurizer where this material is used, this insulation is covered with a stainless steel jacket or a stainless steel mesh.
Calcium Silicate:	This rigid solid insulation is used on straight portions of the Feedwater and Main Steam Systems. This material is also covered with stainless steel. Welds in these systems are covered with encapsulated insulation.
Mineral Wool:	This fibrous insulation is applied to the lower 34 feet of the containment liner and is also covered with stainless steel lagging and a vapor barrier.
Fiberglass Blanket:	This fiberglass blanket material is jacketed with fiberglass fabric impregnated with silicone. This insulation is used as anti-sweat insulation on Service Water piping of 3" & 2" dia. at CFCUs in the Containment Building Units 1 & 2.

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6.3.2.6 Coolant Quantity

The minimum storage volume for the accumulators is given in Table 6.3-2. The total volume of the RWST is 400,000 gallons. At the minimum volume permitted by the Technical Specifications (364,500 gallons) approximately 313,000 gallons for Unit 1 and 313,000 gallons for Unit 2 are available to the ECCS pumps.

The RWST volume must be sufficient to support operator action time following the SI actuation and during the switchover alignment to cold leg recirculation. Following an SI actuation, all ECCS pumps (RHR, Charging/Safety Injection and Safety Injection) are automatically started. If the containment High-High setpoint is reached, the Containment Spray pumps are also automatically started with all pumps initially taking suction from the RWST. This time period is termed the injection phase of the RWST draindown. When the RWST reaches the low level setpoint, the operator begins to take action to switchover from the injection phase to the containment sump recirculation phase. During this switchover phase, the RHR pump suction is re-aligned to the containment sump and the charging/safety injection pump and safety injection pump suction are aligned to the RHR pump discharge. One of the two operating CS pumps is also stopped upon entering the switchover phase to reduce the outflow from the RWST. When the RWST reaches the low-low level alarm, the second CS pump is stopped. The RWST low-low level setpoint must also support NPSH requirements for all ECCS pumps and CS pumps taking suction on the RWST. Once the ECCS is aligned for containment recirculation, the RHR pump discharge may then be cross-tied to the containment spray header to provide containment recirculation spray flow after all CS pumps are stopped.

In addition, the amount of water during the injection phase of a LOCA must be sufficient to provide adequate RHR NPSH in the containment sump. The RWST volume to meet this requirement is 193,000 gallons.

The available RWST water volume for the injection phase is the minimum volume between the Technical Specification requirement and the RWST low level setpoint. The available RWST water volume for the switchover phase is the minimum volume between the RWST low level setpoint and the RWST low-low level setpoint. These minimum volumes account for instrument accuracy in the RWST level channels which are used by the operators to monitor RWST inventory. The following water volumes are available:

	Salem 1	Salem 2
Injection Phase	207,800 gallons	204,500 gallons
Switchover Phase	105,200 gallons	108,500 gallons
Total	313,000 gallons	313,000 gallons

Injection Phase

The available RWST water volume for the injection phase provides sufficient time for the operators to proceed through the Emergency Operating Procedures (EOPs) to the point where switchover to cold leg recirculation may be required. Following an SI actuation with a containment high-high signal, the RHR pumps, charging pumps, SI pumps and CS pumps are all started automatically, taking suction on the RWST. The highest drain rate for the RWST occurs with all pumps operating for a design basis large break LOCA when the RCS is rapidly depressurized to containment pressure and the RHR pumps inject flow to the RCS cold legs. ECCS pump flow rates vary with the RWST level and the RCS/containment pressures. Significantly conservative assumptions are used in determining the RWST drain flow rates as follows:

(1) The RCS and Containment pressure average approximately 10 psig for the first 5 minutes following SI actuation. This is based on the minimum RCS/containment pressures calculated in the LOCA PCT analysis. The LOCA PCT analysis for minimum RCS/containment pressures predict conservatively low RCS/containment pressures based on maximum pump flow delivery similar to those used in the RWST draindown evaluation.

(2) After the first 5 minutes, the RCS/containment pressures are conservatively assumed to be 0 psig.

(3) The RHR pumps inject to the RCS in the same lines as the accumulators. Since the accumulators are at a higher pressure than the RHR pumps, the RHR pumps do not inject to the RCS until the accumulator pressures decrease. An average time period of 45 seconds for accumulator blowdown is assumed based on the LOCA analysis, during which time the RHR pumps do not drain down the RWST.

(4) The pump flowrates are based on the maximum expected flow with the maximum allowable pump curves and conservative modeling of the piping and component resistances. The charging pump and SI pump flows are based on the balancing criteria provided in the Technical Specification.

Based on these assumptions for pump flow rates and the available RWST water volume during the injection phase (207,800 gallons for Unit 1 and 204,500 gallons for Unit 2), the RWST low level alarm will be reached in 12.9 minutes (Unit 1) and 12.5 minutes (Unit 2). This time is sufficient for the operators to proceed through the EOPs and begin switchover to containment recirculation. The RWST water volume required for RHR pump NPSH is also met.

Switchover Phase

Additional water storage is required in the RWST to accommodate the operator actions necessary to align the ECCS pump suctions from the RWST to the containment sump. The required operator actions for Salem 1 and 2 are provided in Table 6.3-6. The switchover is similar for both units with one exception. Salem Unit 1 requires a manual transfer while Salem Unit 2 is semi-automatic. This means that for Salem Unit 1, the RHR pumps are manually stopped, the RHR pump suctions are re-aligned to the containment sump and the RHR pumps re-started. For Salem Unit 2, the semi-automatic switchover is armed and the RHR pump suction is automatically switched from the RWST to the containment sump without stopping the RHR pumps.

The time available for operators to complete the switchover is dependent on the flow rate out of the RWST and the available RWST volume. A conservative analysis was performed to show that sufficient water is provided in the RWST to complete the switchover for all RCS break sizes assuming a limiting single failure while maintaining long term cooling consistent with the 10CFR50.46 analysis of record. The available water volume is that contained between the RWST low level and the RWST low-low level, taking into account instrument inaccuracies. At the RWST low-low level, all pumps taking suction on the RWST would be stopped to protect the pumps. Three limiting break sizes have been specifically evaluated for the Salem 1 and 2 switchover.

Large Break LOCA - The design basis large break LOCA produces the lowest RCS pressure and the highest RWST draindown rate, which results in the limiting time for RWST drain down during switchover to containment recirculation. All pumps are assumed to inject to a 0 psig back pressure. To maintain long term core cooling, one RHR pump injecting to two RCS cold legs (with one leg spilling to the containment and one leg delivering flow to the core) is sufficient to maintain long term core cooling.

Small Break LOCA - The RWST drain down time for a small break LOCA is longer since the RCS pressure remains above the RHR pump discharge pressure. This provides the operator with additional time to complete the switchover and align the charging pumps and SI pumps to cold leg recirculation. To maintain long term core cooling, one charging pump and one SI pump (each delivering to 4 cold legs with one leg spilling to the containment) is sufficient to maintain long term core cooling.

Accumulator Line Small Break LOCA - Due to the break location, the drain down time for an accumulator line small break LOCA is similar to that of a Large Break LOCA. The RHR pumps inject to the RCS through the accumulator line. With a break in the accumulator line, the RHR pumps spill directly to the containment even if the RCS pressure is above the RHR pump cut off head. This increases the RWST outflow and therefore reduces the time available for the operator to complete the recirculation alignment. To maintain long term core cooling, one charging pump and one SI pump (each delivering to 4 cold legs with one line spilling to the containment) is sufficient to maintain long term core cooling.

Each of these breaks have been evaluated with a limiting single failure to determine the minimum RWST drain down times. The limiting single failure for Salem Unit 1 is one RHR pump failing to stop on demand. This results in the failed (running) RHR pump continuing to draw down the RWST. The limiting single failure for Salem Unit 2 is the RWST/RHR isolation valve (RH4) failing to close (with all buses available) during semi-automatic switchover. This results in draining of the RWST to the sump as the ECCS pumps continue to draw down the RWST during switchover. Additional assumptions used in the RWST drain down evaluation are as follows:

(1) The containment pressure is assumed to be 0 psig. This maximizes containment spray flow and RHR pump flow for the large break LOCA and accumulator line small break LOCA.

(2) The RCS pressure is assumed to be 0 psig for the large break LOCA. For the small break LOCA, the RCS pressure is assumed to be above the RHR pump cut in pressure. For the accumulator line small break LOCA, the RCS pressure is also assumed to be above the RHR cut-in pressure, but one injection line is spilling to the containment pressure of 0 psig.

(3) All pumps are operating in an alignment that maximizes outflow from the RWST.

(4) For Salem Unit 2, during the semi-automatic switchover, both the RWST/RHR isolation valve (RH4) and the containment sump isolation valve (SJ44) are open at the same time. This creates a direct path from the RWST to the containment sump. Valve RH4 has a maximum allowable stroke time of 2 minutes and valve SJ44 has a maximum allowable stroke time of 17 seconds. The valves are assumed to be fully open during the stroke time to conservatively maximize the RWST drain flow. With the failure of one RH4 valve to close, this drain path exists for the entire duration of the switchover for one of the containment sump lines. This drainage path also exists for the small break LOCA even though the RHR pumps are not injecting directly into the RCS. This results in reduced switchover times for Salem Unit 2 small break LOCA when compared to Salem Unit 1. Salem Unit 1 has an interlock between valves RH4 and SJ44 such that the containment sump isolation valve (SJ44) can not be open unless the RWST/RHR isolation valve (RH4) is closed. This interlock precludes a direct drainage path from the RWST to the containment sump for Salem Unit 1.

Unit 1 Analysis of Manual Switchover

For Unit 1, manual switchover from the RWST to the containment sump is initiated at an RWST level of 15.2 feet (RWST low or low-backup alarm setpoint). Two significant operator actions are modeled in the RWST drain down evaluation. This simplified approach provides clearer training guidelines rather than modeling each specific operator action in the RWST to containment sump switchover. The first timed operator action is initiating a close on the RHR pump suction valves from RWST valves (RH4). As shown in Table 6.3-6, once the operator reaches this step, the RHR pumps have been stopped (or isolated) and one containment spray pump is about to be stopped (if two are running). The second significant time modeled is the time at which the RWST low-low level alarm is reached for the limiting large break LOCA. The Charging/SI and SI pumps must have their suctions re-aligned to the RHR pump(s) before reaching the RWST low-low level alarm.

The available times for operator actions to ensure that long term cooling will be maintained consistent with the 10CFR50.46 analysis for Unit 1 are:

Initiate Close RH4s	Complete Switchover
4 minutes	11.7 minutes

For the limiting design basis large break LOCA, the time to complete switchover is sufficient for the required operator actions.

Unit 2 - Semi-Automatic Switchover

For Salem Unit 2, the semi-automatic switchover is armed and the RHR pump suction is automatically switched from the RWST to the containment sump without stopping the RHR pumps. Three significant operator actions are modeled in the RWST drain down evaluation. Again, this simplified approach provides clearer training guidelines rather than modeling each specific operator action in the RWST to containment sump switchover. The first is closing the SJ69 valve within a maximum of 25.5 seconds. This is the common RWST suction line valve to the RHR pumps. If an RH4 valve failed to close, closure of the SJ69 would assure positive isolation of the RWST and stop any further draining of the RWST directly to the containment sump. The second significant time modeled is the time at which a containment spray pump must be stopped (if two are running). The third time modeled is the time at which the RWST low-low level alarm is reached for the small break (accumulator line) LOCA. The Charging/SI and SI pumps must have their suctions re-aligned to the RHR pump(s) before reaching the RWST low-low level alarm during the small break LOCA.

For the design basis LOCA, one RHR pump provides adequate cooling flow. When the semi-automatic switchover is armed, the suction of the RHR pumps is automatically switched from the RWST to the containment sump, ensuring adequate cooling flow is available. This makes the design basis LOCA less limiting with respect to switchover time. Therefore, available operator action times are dictated by the small break LOCA. For small break LOCA (accumulator line small break LOCA is limiting), the time to complete switchover is sufficient for the required operator actions.

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TABLE 6.3-6

SEQUENCE OF CHANGEOVER OPERATION INJECTION TO RECIRCULATION

The following sequence of operations is used when terminating the injection mode and starting the recirculation mode when low level is reached in the RWST. Note: Because initiating events in MODES 3 and 4 may start at lower pressures and temperatures, the steps/sequences below may vary slightly:

	Unit 1	Unit 2
1.	Confirm Minimum Sump Level	Confirm Minimum Sump Level
1.a	N/A	Enable Semi-Automatic Switchover
2.	Reset SEC, SI and Motor Control Centers	N/A
2.a	N/A	Remove Lockouts for SJ69, 68 and 67
3.	Stop RHR Pumps 11 and 12	N/A
3.a	Close RHR Cross-tie Valves (RH19)	N/A
3.b	Ensure both RHR pumps have stopped	N/A
3.c	Remove Lockouts for SJ44, 69, 68, and 67 valves	N/A
3.d	If an RHR pump fails to stop, remove lockout for failed pumps' RHR Cold Leg Isolation valve (SJ49) and close valve	N/A
3.e	Close RWST/RHR Isolation Valves (RH4)	N/A
3.f	Stop one CS pump, if two are operating	N/A
3.g	N/A	Verify SJ44 Valves Open
3.h	N/A	Start RHR pumps 21 and 22
3.i	N/A	Close SJ69 Valve
3.j	N/A	Reset SI, SEC and Motor Control Centers
3.k	N/A	Stop one CS pump
3.l	N/A	Close RHR Cross-tie Valves (RH19)
4.	Determine Diesel Loading	Determine Diesel Loading
5.	Ensure that at least 2 CC pumps are operating	Ensure that at least 2 CC pumps are operating
5.a	Open CCW water supply to RHR Heat Exchanger valves (CC16)	Ensure CCW water supply to RHR Heat Exchanger valves (CC16) Open

TABLE 6.3-6 (Cont.)
SEQUENCE OF CHANGEOVER OPERATION INJECTION TO RECIRCULATION

6.	Open Containment Sump Isolation Valves (SJ44)	N/A
6.a	Open RHR Cold Leg Isolation Valves (SJ49)	N/A
6.b	Restart RHR pumps 11 and 12	N/A
7.	Close SI Pump miniflow isolation valves (SJ67 and SJ68)	Close SI Pump miniflow isolation valves (SJ67 and SJ68)
7.a	Open RHR pump discharge to Charging pumps and SI pumps isolation valves (SJ45)	Open RHR pump discharge to Charging pumps and SI pumps isolation valves (SJ45)
7.b	Open cross-tie between Charging pumps and SI pumps suction isolation valve (SJ113) Open	Ensure cross-tie between Charging pumps and SI pumps suction isolation valve (SJ113) Open
7.c	Start Charging pumps and SI pumps	Start Charging pumps and SI pumps

Note: Switchover for long-term core cooling flow is complete at this time.

8.	Isolate RWST from SI, C/SI and RHR pumps	Isolate RWST from SI, C/SI and RHR pumps
8.a	Remove lockout for RWST/SI pump isolation valve SJ30	Remove Lockout for RWST/SI pump isolation valve SJ30
8.b	Close RWST/Charging pump isolation valves (SJ1 and SJ2)	Close RWST/Charging pump isolation valves (SJ1 and SJ2)
8.c	Close RWST/Common Suction valve (SJ69)	N/A
8.d	Close RWST/SI pump isolation valve (SJ30)	Close RWST/SI pump isolation valves (SJ30)
8.e	Place RH29 valves in "Manual" and close valves	Place RH29 valves in "Manual" and close valves
9.	When the RWST low-low level is reached, perform the following:	When the RWST low-low level is reached, perform the following:
9.a	Stop the operating CS pump	Stop the operating CS pump
9.b	Close the RHR pump to RCS cold leg isolation valve (SJ49)	Close the RHR pump to RCS cold leg isolation valve (SJ49)
9.c	Open RHR supply to Containment Spray, valve (CS36)	Open RHR supply to Containment Spray, valve (CS36)

SEQUENCE OF CHANGEOVER OPERATION INJECTION TO RECIRCULATION

Note: The Emergency Core Cooling System is now aligned for cold leg recirculation with recirculation containment spray as follows:

1. RHR Pump 12 (22) is delivering from the recirculation sump directly to the spray header and to the suction of charging pumps through valve SJ45.

2. RHR Pump 11 (21) is delivering from the recirculation sump directly to the cold legs via valve SJ49 and to the suction of the safety injection pumps via valve SJ45.

3. Recirculation spray is established when RHR supply to Containment Spray, valve CS36, is open.

The sequence of operations for change-over from the cold leg recirculation phase to the hot leg recirculation phase is as follows:

Close the spray header isolation valve (12CS36).
Close isolation valve (12SJ49).
Stop safety injection pump number 11.
Close the safety injection pump cross-tie isolation valve (11SJ134).
Open hot leg isolation valve (11SJ40).
Start safety injection pump number 11.
Stop safety injection pump number 12.
Close the cold leg isolation valve (1SJ135) and close the safety injection pump cross-tie isolation valve (12SJ134).
Open hot leg isolation valve (12SJ40)
Start safety injection pump number 12.

The safety injection pumps are now aligned for the hot leg recirculation as follows:

a. RHR pump number 12 is delivering from the recirculation sump to the centrifugal charging pumps which are delivering to the cold legs.

b. RHR pump number 11 is delivering from the recirculation sump to the suction header of the safety injection pumps and to the Reactor Coolant System through the cold leg injection header.

c. Number 11 and 12 safety injection pumps are delivering to the Reactor Coolant System through individual hot leg injection headers.

TABLE 6.3-13

NET POSITIVE SUCTION HEADS FOR
POST-ACCIDENT OPERATIONAL PUMPS

Pump	Elevation	Flow and Condition	Suction Source and Elevation	Minimum Available NPSH	Required NPSH	Maximum Water Temperature
Safety Injection	86'-3"	675 gpm runout	RWST 101'-8"	31.3'	22'	100°F
Centrifugal Charging	87'-5"	560 gpm runout	RWST 101-8"	38'	23'	100°F
Residual Heat Removal	46'-10"	1 pump operating 4500 gpm runout flow	RWST 101'-8"	63.3'	19.5'	100°F
Residual Heat Removal	46'-10"	2 pumps operating 3000 gpm/pump rated flow	RWST 101'-8"	53.2'	11'	100°F
Containment Spray	86'-3"	2600 gpm rated flow	RWST 101'-8"	29.9'	10'	100°F
Component Cooling	86'-0"	4600 gpm rated flow	Head Tank 128'	40'	14'	135°F
Service Water	Impeller Suction 72'-3" Pump Dis. 94'-0"	10,875 gpm rated flow	Plant Intake Water Level 76'	34'	29'	90°F

As previously mentioned, several chemicals are stored onsite that are considered hazardous. Sulfuric acid is stored in 4,000 and 2,250 gallon tanks in the SGS Turbine Buildings and it is stored in 16,000 gallon tanks at the HCGS. Calculations indicated that the toxicity limit found in Regulatory Guide 1.78 will not be exceeded in the control rooms during a postulated release at any of the sources.

Liquid nitrogen and nitrogen stored as a compressed gas is stored at various locations onsite. According to the criteria contained in Regulatory Guide 1.78, the largest single source should be evaluated for its impact on control room habitability. The sources evaluated at the SGS are the portable nitrogen tube trailers located in various areas throughout the SGS yard area and the (2) 3000 gallon tanks located behind Unit No. 1 & 2 Auxiliary Buildings. In addition to these sources, liquid nitrogen is also stored in 9,000 gallon tanks at the HCGS. Calculations indicated that the oxygen depletion is negligible in the control rooms during a postulated release at any of the significant sources.

Chemicals used as fire-fighting agents were evaluated. Carbon dioxide is stored on the 84 foot elevation of each of the Auxiliary Buildings. It is also stored at HCGS. Calculations indicated that the toxicity limit established in Regulatory Guide 1.78 as well as asphyxiation levels would not be exceeded during postulated releases at the significant sources. The Halon storage vessels are relatively small and do not contain the volume of Halon required to cause asphyxiation in the control rooms, therefore, a postulated release will not pose a danger to the control rooms.

Ammonium hydroxide is stored in a 3000 gallon vessel in the SGS Unit No. 1 Turbine Building. Evaluations concluded that the control rooms would remain habitable during a postulated release at the storage tank. The shipments to the site are considered "frequent" and are discussed in Section 2.2.3.3.

Hydrazine is stored in a 300 gallon vessel also in the Unit No. 1 side of the SGS Turbine Building. The calculations indicated that the control room concentrations will not exceed toxicity limits established in 29CFR Part 1910.1000, Subpart Z during a postulated release.

Aqueous sodium hydroxide is stored in various quantities and vessels at both the SGS and HCGS. Upon a release, sodium hydroxide vapors may form locally at the spill, but the physical properties of this chemical preclude the formation of a plume that will travel in the control room air intakes. The vapor pressure of aqueous sodium hydroxide is very low, especially as the concentration is increased. During a postulated release, mostly water will evaporate from the liquid pool, leaving the solid sodium hydroxide behind. The solid form of sodium hydroxide poses no danger to the control room due to its physical properties.

Helium is stored in 150 lb cylinders at both the SGS and HCGS. It is much lighter than air and upon a postulated failure of one of the cylinders, the helium would disperse rapidly into the atmosphere and not form a continuing plume.

Tables 6.4-3 and 6.4-4 summarize data on the Control Room Ventilation System, which is described in detail in Section 9.4.1.

LIST OF FIGURES (Cont)

Table 3.10-1 contains all the safety-related electrical equipment that requires seismic qualification.

7.1.2.6 Conformance and Exceptions to IEEE Standard 323-1971

The safety-related equipment is type tested to substantiate the adequacy of design. This is the preferred method as indicated in IEEE Standard 323-1971, "IEEE Trial-Use Standard Guide for Qualifying Class I Electric Equipment for Nuclear Power Generating Stations." Type tests already performed (References 4, 8, 10) in accordance with criteria standards established at the time of the construction permit, may not conform to the format guidelines set forth in IEEE Standard 323-1971.

7.1.2.7 Conformance to IEEE Standard 336-1971

Installation, inspection, and testing activities for instrumentation and electric equipment are in accordance with IEEE Standard 336-1971, "IEEE Standard Installation, Inspection and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations." The overall quality assurance program is described in Section 17.

7.1.2.8 Conformance to 10CFR50.62

The AMSAC conforms to the requirements of 10CFR50.62 as discussed in Section 7.8.

7.1.3 Control Room Design Review

A preliminary design review assessment of the Salem Unit 2 Control Room was undertaken in the spring of 1980 by Public Service Electric & Gas in conjunction with human factors personnel from Essex Corporation. It was concluded in the preliminary review that "the design of the Salem 2 Control Room, which was repeatedly developed through the use of mockups and operator walk-throughs, evidences a high level of concern for the capabilities and limitations of the human operator, with some notable exceptions." The authors cautioned that the human engineering discrepancies and conclusions were tentative pending further evaluation and analysis. A detailed control room design review (DCRDR) (11) was subsequently undertaken. The DCRDR was performed for Units 1 and

2 in accordance with the intent of NUREG-0700 (12). The DCRDR process was divided into the following major steps:

1. Operating Experience Review
2. Control Room Inventory
3. Control Room Survey
4. System Function Review and Task Analysis
5. Verification of Task Performance Capabilities
6. Validation of Control Room Functions and Integrated Performance Capabilities

Design review team members assessed the identified and prioritized human engineering discrepancies (HEDs) and recommended corrective actions, if applicable, for the resolution of each. Recommendations for HED resolution were developed for all significant HEDs using the resources of the DCRDR team and other specialists (e.g., Plant Engineering and Operating Departments). These recommendations took into account the impact of the correction on operating effectiveness, system safety, acceptability of design, and consistency with present Control Room characteristics.

A list of all HEDs requiring plant changes appears in Section 3.1.1 of the DCRDR report (11). All HEDs identified during the review are listed in Volume 2 of the same report.

A re-evaluation of human factors issues affected by the changes in the general arrangement of the Control Room(s) undertaken in 1996 has been conducted. The human factors issues affected by the changes include lighting, control room colors, sound propagation, task analyses, relocation of communications devices and information systems, adequacy of storage locations and traffic flow within the control room. The results of this review are contained in Reference 13.

7.1.4 References for Section 7.1

1. Lipchak, J. B. and Stokes, R. A., "Nuclear Instrumentation System," WCAP-7380-L (Proprietary) December 1970 and WCAP-7669 (Nonproprietary), April 1971.

2. "Controls and Electrical Drawings for Safety-Related Equipment," Volumes 1 through 4, Salem Nuclear Generating Station, Units 1 and 2, Public Service Electric and Gas Company, July 1973.

3. Burnett, T. W. T., "Reactor Protection System Diversity in Westinghouse PWRs," WCAP-7306, April 1969.

4. Vogeding, E. L., "Seismic Testing of Electrical and Control Equipment," WCAP-7397-L (Proprietary), January 1970 and WCAP-7817 (Nonproprietary), December 1971.

5. Vogeding, E. L., "Seismic Testing of Electrical and Control Equipment (WCID Process Control Equipment)," WCAP-7397-L, Supplement 1 (Proprietary), January 1971 and WCAP-7817, Supplement 1 (Nonproprietary), December 1971.

6. Potochnik, L. M., "Seismic Testing of Electrical and Control Equipment (Low Seismic Plants)," WCAP-7817, Supplement 2, December 1971.

7. Vogeding, E. L., "Seismic Testing and Electric and Control Equipment (Westinghouse Solid State Protection System) (Low Seismic Plants)," WCAP-7817, Supplement 3, December 1971.

8. "Test Report - Nuclear Instrumentation System Isolation Amplifier," WCAP-7819, Revision 1, January 1972.

9. Deleted

10. Locante, J., "Environmental Testing of Engineered Safety Features Related Equipment (NSSS - Standard Scope)," WCAP-7410-L, Volume 1 (Proprietary), December 1970 and WCAP-7744, Volume 1 (Nonproprietary), August 1971.

11. "Public Service Electric & Gas Co.," Salem Generating Station, Units 1 and 2, Detailed Control Room Design Review, Volumes 1 and 2, December 1983.

12. USNRC, NUREG-0700, "Guidelines for Control Room Design Reviews."

13. "Public Service Electric & Gas Co.," Salem Generating Station, Units 1 and 2, Supplemental Control Room Human Factors Design Review in Support of DCP 1EC-3360.

Low-Low Steam Generator Water Level Trip

The purpose of this trip is to prevent a loss of the reactor's heat sink in the case of a sustained steam/feedwater flow mismatch of insufficient magnitude to cause a low feedwater flow reactor trip. The trip is actuated on two-out-of-the-three low-low water level signals in any steam generator.

7.2.2.6 Reactor Coolant Flow Measurement

Elbow taps are used on each of the four loops in the Primary Coolant System as an instrument device that indicates the status of the reactor coolant flow. The basic function of this device is to provide information as to whether or not a reduction in flow rate has occurred. The correlation between flow reduction and elbow tap read-out has been well established by the following equation: $\Delta P/\Delta P_0 = (\dot{w}/\dot{w}_0)^2$, where ΔP_0 is the referenced pressure differential with the corresponding referenced flow rate $\dot{w}0$ and ΔP is the pressure differential with the corresponding referenced flow rate $\dot{w}$. The full flow reference point is established during initial plant startup. The low flow trip point is then established by extrapolating along the correlation curve. The technique has been well established in providing core protection against low coolant flow in Westinghouse PWR plants. The expected absolute accuracy of the channel is within ± 10 percent and field results have shown the repeatability of the trip point to be within ± 1 percent. The analysis of the loss of flow transient presented in Section 15 assumes instrumentation error of ± 3 percent.

7.2.3 System Evaluation

7.2.3.1 Reactor Protection System and Departure from Nucleate Boiling

The following is a description of how the Reactor Protection System prevents departure from nucleate boiling (DNB).

The plant variables affecting the DNBR are:

1. Thermal power

2. Coolant flow

3. Coolant temperature

4. Coolant pressure

5. Core power distribution

Figure 7.2-1 illustrates the core limits for which DNBR for the hottest fuel rod is 1.3 and shows the overpower and overtemperature ΔT reactor trips locus as a function of Tavg and pressure. This illustration is derived from the inlet temperature versus power relationships.

Reactor trips for a fixed high pressurizer pressure and for a fixed low pressurizer pressure are provided to limit the pressure range over which core protection depends on the overpower and overtemperature ΔT trips.

Reactor trips on nuclear overpower and low reactor coolant flow are provided for direct, immediate protection against rapid changes in these parameters. However for all cases in which the calculated DNBR approaches 1.3, a reactor trip on overpower and/or overtemperature ΔT would also be actuated.

TABLE 7.2-1 (Cont)

Reactor Trip	Coincidence Circuitry and Interlocks	Comments
	Description-Protective Action For Interlocks).	
11. Turbine-generator trip	2/3 low auto stop oil pressure (interlocked with P-9) or all stop valves closed	(Anticipatory trip of the reactor. No credit taken in accident analysis.)
12. Low-low steam generator water level	2/3, per loop	
13. Intermediate range neutron flux	1/2, manual block permitted by P-10	Manual block and automatic reset
14. Source range neutron flux	1/2, manual block permitted by P-6, interlocked with P-10	Manual block and automatic reset
15. High flux rate trips	2/4, no interlocks	Positive and negative high flux rate trips provided

TABLE 7.2-1 (Cont.)

Reactor Trip	Coincidence Circuitry and Interlocks	Comments
16. Containment pressure (Note 1)	Coincidence of 2/3 containment high pressure or 1/2 manual	Actuates all non-essential process lines containment isolation trip valves- ation Phase A
	Coincidence of 2/4 containment Hi-Hi pressure or 2/2 manual	Actuates all remaining trip valves (except those required for operation of engineered safeguard systems)
17. High containment activity	High activity signal, from either air particulate detector or radiogas detector, or 1/2 manual	Closes containment purge supply, exhaust ducts and all others necessary to isolate containment atmosphere
Engineered Safeguards Systems Actuation		
18. Safety injection signal (S)	See Item 10	
19. Containment spray signal (P)	See second part of item 16	
20. NaOH addition	Containment Spray Actuation Signal	

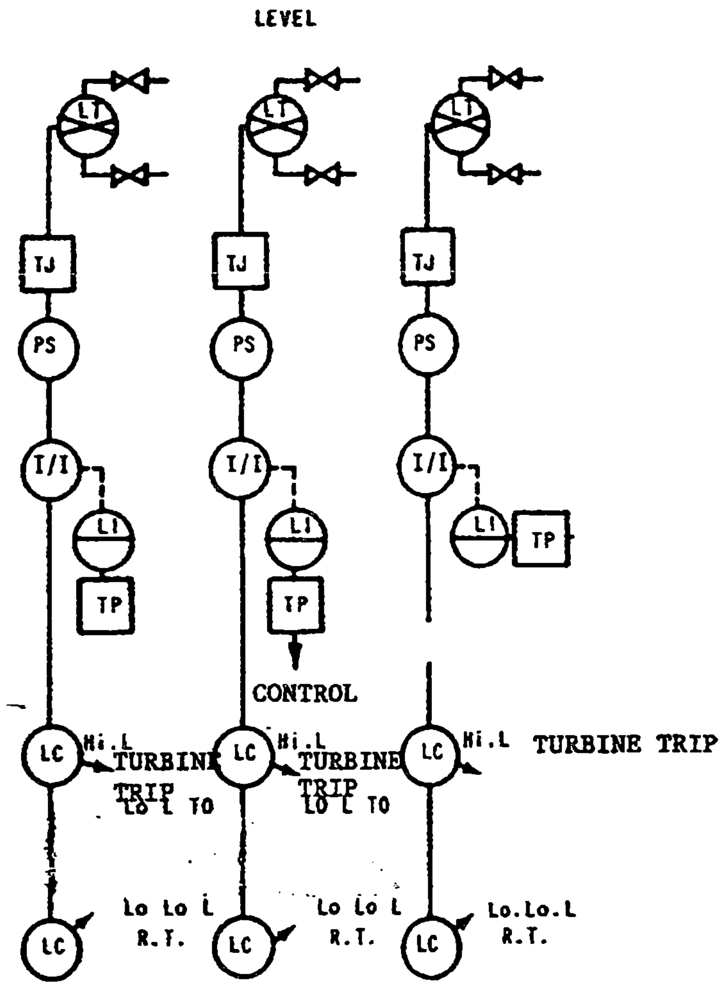
Reactor Trip	Coincidence Circuitry and Interlocks	Comments
Steam Lines Isolation Actuation		
21. Steam flow	High steam line flow in 2 out of 4 lines coincident with either low-low T_{avg} in 2 out of 4 loops or low steam pressure in 2 out of 4 lines	
Containment pressure (Note 1)	2/4 Hi-Hi containment pressure	
22. Manual (per steam line)	1/1 per steam line	
Auxiliary Feedwater Actuation		
23. Turbine driven pump	Coincidence of 2/3 low-low level in any two steam generators; undervoltage 1/2 twice on RCP busses; or manual (local and remote)	2/3 high level in steam generator trips main feedwater pumps

TABLE 7.2-1 (Cont.)

Reactor Trip	Coincidence Circuitry and Interlocks	Comments
24. Motor drive pumps	2/3 low level in any steam generator: or trip of both main feedwater pumps, or safeguards sequence signal, or blackout sequence signal, or manual (local and remote)	Safeguards automatic loading signal blocks manual start
Main Feedwater Isolation		
25. Close main feedwater control valves (fast closure) and feedwater bypass valves and feedwater inlet stop valves	Actuated by: 1. Safety injection (See No. 10) 2. 2/3 Hi-Hi level in steam generator 3. Low actioneered T_{avg} and reactor trip	

NOTE 1: Definition of "S", "T", and "P" signals:

Signal	Initiated by:	Action
"S"	Safety injection signal	Actuates safety injection
"T"	Safety injection signal	Actuates containment isolation Phase A (All non-essential process lines)



REVISION 17
OCTOBER 16 1998

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Steam Generator Level Control and Protection System	
	Updated FSAR	FIG. 7.2-7

Each 125 V dc circuit is protected by Class 1E, 15 amp circuit breakers which will trip open if short circuits are caused by the flooding of components in the containment. Power to the entire circuit would be lost. All components on the if their loss was acceptable.

Each 115 V ac circuit providing power to the process group racks and protection racks is also protected by Class 1E, 15 amp circuit breakers. However, in this case the entire circuit will not be lost due to flooding of components in part of the circuits. Each individual process or protection control/indication loop is provided with its own fuse protected power supply. The development of faults from flooding of components in the loop would blow the fuses and thereby isolate that portion of the circuit. Other functions powered from that particular circuit would not be affected.

In the analysis of 115 V ac circuits only those devices which would become submerged were examined as to function and need. Non-submerged components of the circuit will not be affected by the flooding. In the case of submerged devices in the 115 V ac circuit, it may be possible that total loss of control power will not occur, and that some control loops would provide anomalous indication or control. This has been examined and those devices which are required to operate properly do so for the required time period prior to submergence. Once submerged their functions are not required, and any improper operation would not be detrimental to the necessary safety functions following a LOCA.

Each 230 V motor control center circuit is provided with Class 1E circuit breakers. The control circuit power developed from a 230/115 V transformer is protected by fuses. Any isolation valves will have performed their function prior to becoming submerged. The reactor nozzle support vent fans are tripped during an accident. These power circuits are protected during flooding conditions since voltage to the devices is removed by open motor starter contacts.

Design Changes

During the course of the review two instances were discovered which required a redesign to assure that the Emergency Core Cooling Systems can be operated effectively. They are described below:

1. Position interlock circuits for valves 1SJ67 and 1SJ68, although not flooded, were found to be on 125 V dc circuits which are affected by the flooding of other components. The position interlock circuit of 1SJ67 was on circuit 13 of the 1CCDC distribution cabinet and the position interlock circuit of 1SJ68 was on circuit 13 of the 1AADC distribution cabinet. Coincident flooding of components in portions of the circuits could trip the circuit breakers, thereby losing the interlock capability for opening 11SJ45 and 12SJ45. The power circuit for the 1SJ67 and 1SJ68 position interlocks was changed to circuits which cannot be affected by flooding.

2. The containment sump level instruments provide backup indication for initiating the recirculation phase of an accident and are above the flood level. However, two junction boxes, JN106 and JN108, used for the routing of the indication circuits, were located below the flood level. This situation could have caused anomalous indication to the operator and possibly affected his response to accident conditions. These two junction boxes were raised above the flood level.

In summary, with incorporation of the design changes, the entire analysis demonstrates that flooding within the containment will not adversely affect the safe operation of the plant following a

TABLE 7.3-1

PROCESS INSTRUMENTATION FOR RPS AND ESF ACTUATION

Parameter	Transmitter Sensors	Read-out	Power	Prot/Safeguards Use	Taps
Reactor Coolant Temperature	8 RTDs	C.B. Meter	Ext.	Δ trips, T_{avg} permissives	1 each
Pressurizer Pressure	4 Transmitters	C.B. Meter	Ext.	Hi/Lo Pressure Trips, SIS	3 (Top Level) One Shared
Pressurizer Level	3 ΔP Transmitters	C.B. Meter	Ext.	R. T.	3 (Top Level) 3 (Bottom Level)
Steam Flow	8 ΔP Transmitters	C.B. Meter	Ext.	SIS	1 Pair Each
Steam Pressure	12 Transmitters	C.B. Meter	Ext.	SIS, Steam Line Isolation	1 Each

TABLE 7.3-1 (Cont)

Parameter	Transmitter Sensors	Read-out	Power	Prot/Safeguards Use	Taps
Steam Generator Level	12 ΔP Transmitters	C.B. Meter	Ext.	Low Level trip	1 Pair Each
Reactor Coolant Flow	12 ΔP Transmitters	C.B. Meter	Ext.	Low Flow Trip	1 High Pressure Shared/Loop 1 Low Pressure Each
Containment Pressure	4 Transmitters	C.B. Meter	Ext.	SIS (3) Spray (4) Cont. Isol.	4
Turbine 1st Stage Pressure	2 Transmitters	C.B. Meter	Ext.	Set Point Programs and Turbine Power Permissives	1 Each

*C.B. is Control Board

TABLE 7.3-5 (Cont)

Component	Function	Control Gr. Affiliation	Accident/Safety Requirements	Analysis	Results/Effects
PT-188 (Panel 237)	No. 11 Reactor Coolant Pump Seal Water Diff. Pressure	Process Gr. 1 Rack 21	None	N/A	None
FIT-159A (Local)	No. 11 Reactor Coolant Pump Seal Leakoff Flow	Process Gr. 1 Rack 21	None	N/A	None
FIT-159B (Local)	No. 11 Reactor Coolant Pump Seal Leakoff Flow	Process Gr. 1 Rack 21	None	N/A	None

CIRCUIT PROTECTION - ENTIRE 115V AC CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER.
INDIVIDUAL PROCESS/PROTECTION CONTROL AND INDICATION LOOPS PROVIDED WITH THEIR OWN FUSE PROTECTED POWER SUPPLY.

Component	Function	Control Gr. Affiliation	Accident/Safety Requirements	Analysis	Results/Effects
FT-444 (Panel 447-1K)	No. 14 Reactor Coolant Loop Flow	Protection Channel I Rack 3	Provides input to reactor trip logic, not required for long term accident conditions	Same analysis as for PT-414 above	None - Safety func- is performed

CIRCUIT PROTECTION - ENTIRE 115V AC CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER.
INDIVIDUAL PROCESS/PROTECTION CONTROL AND INDICATION LOOPS PROVIDED WITH THEIR OWN FUSE PROTECTED POWER SUPPLY.

TABLE 7.3-5 (Cont)

Component	Function	Control Gr. Affiliation	Accident/Safety Requirements	Analysis	Results/Effects
PT-936B (Panel 234)	Accumulator Pressure No. 12	Process Gr. 2 Rack 16	Required during injection phase for up to 5 minutes following an accident	Instrument will function for the required time period prior to flooding - Panel 234 is located at E1.78' with the instrument approx. 4' up from the bottom	Safety function will be performed
LT-934B (Panel 234)	Accumulator Level No. 12	Process Gr. 2 Rack 16	RG 1.97 Category 3 (EQ not required)	Instrument will function for the required time period prior to any flooding	None
PT-121 (Panel 241)	Excess Let-down Pressure	Process Gr. 2 Rack 16	None	N/A	None
E/P Converter(Panel 241)	Control for Valve 1CV132	Process Gr. 2 Rack 16	None	N/A	None
FIT-158A (Local)	No. 12 Reactor Coolant Pump Seal Leakoff Flow	Process Gr. 2 Rack 16	None	N/A	None
FIT-158B (Local)	No. 12 Reactor Coolant Pump Seal Leakoff Flow	Process Gr. 2 Rack 16	None	N/A	None

CIRCUIT PROTECTION - ENTIRE 115V AC CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER.
INDIVIDUAL PROCESS/PROTECTION CONTROL AND INDICATION LOOPS PROVIDED WITH THEIR OWN FUSE PROTECTED POWER SUPPLY.

TABLE 7.3-5 (Cont.)

Component	Function	Control Gr. Affiliation	Accident/Safety Requirements	Analysis	Results/Effects
FT-445 (Panel 447)	No. 14 Reactor Coolan Loop Flow	Protection Channel II Rack 7	Provides input to reactor trip logic, not required for long term accident conditions	Same analysis as for PT-415 above	None - Safety func- is performed

CIRCUIT PROTECTION - ENTIRE 115V AC CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER.
INDIVIDUAL PROCESS/PROTECTION CONTROL AND INDICATION LOOPS PROVIDED WITH THEIR OWN FUSE PROTECTED POWER SUPPLY.

TABLE 7.3-5 (Cont.)

Component	Function	Control Gr. Affiliation	Accident/Safety Requirements	Analysis	Results/Effects
PT-186 (Panel 241)	No. 13 Reactor Coolant Pump Seal Water Diff. Pressure	Process Gr. 3 Rack 24	None	N/A	None
FIT-157A (Local)	No. 13 Reactor Coolant Pump Seal Leakoff Flow	Process Gr. 3 Rack 24	None	N/A	None
FIT-157B (Local)	No. 13 Reactor Coolant Pump Seal Leakoff Flow	Process Gr. 3 Rack 24	None	N/A	None

CIRCUIT PROTECTION - ENTIRE 115V AC CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER.
INDIVIDUAL PROCESS/PROTECTION CONTROL AND INDICATION LOOPS PROVIDED WITH THEIR OWN FUSE PROTECTED POWER SUPPLY.

TABLE 7.3-5 (Cont.)

Components	Function	Control Gr. Affiliation	Accident/Safety Requirements	Analysis	Results/Effects
FT-446 (Panel 447-1M)	No. 14 Reactor Coolant Loop Flow	Protection Channel III Rack 12	Provides input to reactor trip logic, not required for long term accident conditions	Same analysis as FT-416 above	None - Safety function is performed

CIRCUIT PROTECTION - ENTIRE 115V AC CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER.
INDIVIDUAL PROCESS/PROTECTION CONTROL AND INDICATION LOOPS PROVIDED WITH THEIR OWN FUSE PROTECTED POWER SUPPLY.

Component	Function	Control Gr. Affiliation	Accident/Safety Requirements	Analysis	Results/Effects
PT-183 (Panel 240)	No. 14 Reactor Coolant Pump Seal Water Diff. Pressure	Process Gr. 4 Rack 27	None	N/A	None
E/P Converter (Panel 241)	Control for Valve 1NT35	Process Gr. 4 Rack 28	None	N/A	None
FIT-156A (Local)	No. 14 Reactor Coolant Pump Seal Leakoff Flow	Process Gr. 4 Rack 28	None	N/A	None
FIT-156B (Local)	No. 14 Reactor Coolant Pump Seal Leakoff Flow	Process Gr. 4	None	N/A	None

CIRCUIT PROTECTION - ENTIRE 115V AC CIRCUIT PROTECTED BY CLASS 1E 15 AMP CIRCUIT BREAKER.
INDIVIDUAL PROCESS/PROTECTION CONTROL AND INDICATION LOOPS PROVIDED WITH THEIR OWN FUSE PROTECTED POWER SUPPLY.

lights on the main control console pushbutton stations and loss of control voltage alarms in the Auxiliary Alarm System. The spray additive tank valve, 1CS14, also has an "off-normal" position alarm on the overhead annunciator.

Any equipment taken out of service for maintenance or other purposes is under the administrative control of the plant operating personnel, which includes logging of unavailable equipment and covering the control station with a plastic cover.

Bypasses of the Solid State Protection System (SSPS) outputs associated with the spray system are described below.

In general, if any analog channel in the ESF Actuation System is taken out of service for any reason, the channel is placed in the tripped mode, and a channel trip status light is lit in the Control Room. In addition, an alarm will sound and an associated annunciator panel light will be lit. This holds true for the containment pressure channel associated with safety injection and steam line isolation functions. The channel bistable output relays associated with the containment spray function are not tripped, to reduce the possibility of inadvertent actuation, but are bypassed for test and maintenance purposes. An alarm indicating a bypassed condition is provided for each channel.

The plant design includes one or a combination of the following indications to show the operator the status of plant systems and to highlight the existence of an incorrect configuration:

1. Indication lights (red-open and green-closed) at the push-button control station for valves.

2. A separate monitor light indication grouped with lights for other devices having a similar function such that the lights in the group are all on or are all off to provide for quick operator evaluation of systems status

during the injection or recirculation mode of a Loss-of-Coolant Accident (LOCA).

3. Auxiliary annunciation redundant to the above indications which serves to alert the operator of the improper state, relative to plant conditions, of a critical device (pump, valve, etc.).

By looking at equipment status indications, an operator can determine if components in the ESF Systems have been isolated or bypassed.

The following alarms have been provided in the Control Room to indicate test of bypass for ESF Systems:

Spray channel comparator tripped (4 alarms)

Spray channel comparator on test (4 alarms)

Solid state protection Train A trouble

Solid state protection Train B trouble

Solid state protection Train A on test

Solid state protection Train B on test

Reactor protection channel on test (4 alarms)

Nuclear instrument channel on test

Rod position indication on test

Safeguards Equipment Control Systems on test (3 alarms)

NIS loss of detector of compensation voltage (5 alarms)

1 (2) PR1 CHANNEL UNSAFE (comparator on test)

1 (2) PR2 CHANNEL UNSAFE (comparator on test)

1 (2) PR1 1/2 TRIP (channel comparator tripped)

1 (2) PR2 1/2 TRIP (channel comparator tripped)

TABLE 7.5-1 (Cont'd)

Parameter	Channel Available	Range	Accuracy	Indicator/ Recorder	Purpose
OPERATIONAL OCCURRENCES (Cont.)					
6. Steam generator water level (wide range)	1/steam generator	0-100%	Refer to Applicable Loop Accuracy Calculation	All channels recorded	Ensure maintenance of reactor heat sink.
7. Steam generator water level (narrow range)	3/steam generator	0-100%	Refer to Applicable Loop Accuracy Calculation	All channels indicated; the channels used for control are recorded	Ensure maintenance of reactor heat sink.
ACCIDENT CONDITIONS					
1. Containment pressure	4	0-115% of design pressure (-5 to +55 psig)	±5.5% of full span	All four are indicated; two are also recorded	Monitor post-LOCA containment conditions.
	2	(-15 to +165 psig)		Both are recorded	
2. Refueling water storage tank water level	2	0-100% of (48 ft/H_2O)	±3% of level span	Both are indicated and alarmed	Ensure that water is flowing to the safety injection system after a LOCA and determine when to shift from injection to recirculation mode.

TABLE 7.5-1 (Cont.)

Parameter	Channels Available	Range	Accuracy	Indicator/ Recorder	Purpose
ACCIDENT CONDITIONS (Cont.)					
3. Steam generator water level (narrow range)	3/steam generator	0-100%	Refer to Applicable Loop Accuracy Calculation	All channels indicated; the channels used for control are recorded	Detect steam generator tube rupture; monitor steam generator water level following a steam line break.
4. Steam generator water level (wide range)	1/steam generator	0-100%	Refer to Applicable Loop Accuracy Calculation	All channels are recorded	Detect steam generator tube rupture; monitor steam generator water level following a steam line break.
5. Steam line pressure	3/steam line	0-1200 psig	±7.5% of full scale	All channels are indicated	Monitor steam line pressures following steam generator tube rupture or steam line break.
6. Pressurizer water level	3	Entire distance between taps (526"/H2O)	Indicate the level is somewhere between 0 and 100 of span	All three indicated and one is for recording	Indicate that coolant inventory restored in pressurizer following cooldown after team generator tube rupture or steam line break.
7. Containment hydrogen level	2	0-10% vol	2% of full scale	Both channels are recorded	NUREG 0737
8. Containment area monitors (high range)	2	1-107R/hr		Both channels are recorded	NUREG 0737

TABLE 7.5-2 (Cont.)

Parameter	No. of Channels Available	Range	Accuracy	Indicator/ Recorder	Notes
CONTAINMENT SYSTEM					
Containment pressure	4	0 - 115 of design pressure (-5 to +55 psig)	±5.5% of full span	All 4 channels indicated and 2 are also recorded.	
FEEDWATER AND STEAM SYSTEMS					
1. Auxiliary feedwater flow	1/steam line	0-250000 PPH		All channels indicated	One channel to measure the flow to each steam generator
2. Steam generator level (narrow range)	3/steam generator	0-100%	Refer to Applicable Loop Accuracy Calculation	All channels indicated. The channels used for control are recorded.	
3. Steam generator level (wide range)	1/steam generator	0-100%	Refer to Applicable Loop Accuracy Calculation	All channels recorded.	

Parameter	No. of Channels Available	Range	Accuracy	Indicator/ Recorder	Notes
FEEDWATER AND STEAM SYSTEMS					
4. Programmed steam generator level signal	1/steam generator	0-100%	Refer to Applicable Loop Accuracy Calculation	All channels indicated.	
5. Main feedwater flow	2/steam generator	0 to 120% of maximum calculated flow	±5%	All channnels indicated. The channels used for control are recorded.	
6. Magnitude of signal controlling main and bypass feedwater control valves	1/main 1/bypass	0 to 100% of valve opening	±1.5%	All channels indicated	1. One channel for each main and bypass feedwater control valve 2. OPEN/SHUT indication is provided in the control room for each main and bypass feedwater control valve.

7.6.3.2 System Design and Operation

The POPS is a two-train system which uses separate and independent pressure transmitters to open two pressurizer relief valves if RCS pressure exceeds a preset value of 375 psi. This automatic action takes place provided the system has been armed by placing two keylocked pushbuttons in the "ON" position. The system is required to be armed whenever the RCS is below 312°F.

Each relief valve is actuated by its own logic output relay, which is energized by a bistable device. The bistable is energized if RCS pressure exceeds the setpoint. Existing pressure sensors are used to develop the signal for valve actuation. These are the same sensors which provide the open permissive interlock function of the RHR System.

The operation of the POPS is governed by two administratively controlled, keylocked pushbuttons which perform three functions. When the RCS temperature is less than 312°F, the system is armed by depressing the "ON" pushbutton for each POPS train. This action opens the motor-operated valves upstream of the relief valves and provides an alarm permissive to indicate that the POPS is armed should temperature increase above 312°F. In this mode of operation, the relief valve will automatically open if RCS pressure exceeds 375 psi. Actuation of the relief valve is alarmed in the Control Room.

When RCS temperature is above 312°F, the "OFF" pushbutton for each POPS train is depressed. This action removes the opening permissive from the relief valve, removes the opening signal from its associated motor-operated valve, and provides an alarm input to indicate that the system is disarmed should RCS temperature fall below 312°F.

When POPS is armed and in the AUTO mode, if either relief valve is opened by POPS, it will remain open until the system pressure falls below 375 psi.

A testing provision in the POPS circuitry allows for test opening of the relief valves prior to use of the system below 312°F. The "TEST" pushbutton, when depressed, will operate the relief valve provided that the associated motor-operated valve is closed. Other portions of the POPS can be tested in a manner similar to other protection system functions.

The existing power operated relief valves (PORVs) are utilized for overpressure protection at low temperature in Units 1 and 2.

7.6.3.3 Design Evaluation

The POPS is designed as a "protection grade" system in accordance with the applicable portions of IEEE Standard 279-1971. The use of proven devices provides assurance that the system is compatible with other Protection System equipment. The use of administrative controls to arm the POPS is considered acceptable due to the expected infrequent need for overpressure protection at low temperature.

The POPS relief valves protect the RCS from pressure transients which could exceed the limits of Appendix G to 10CFR50 when one or more RCS cold leg temperature is at or below 312°F. Either POPS has adequate relieving capacity to protect the RCS from overpressurization as a result of the limiting heat input or mass input cases: (1) the start of an idle Reactor Coolant Pump with the secondary water temperature of the steam generator less than or equal to 50°F above RCS cold leg temperature or (2) the start of an Intermediate Head Safety Injection pump and its injection into a water solid RCS, or the start of a High Head Safety Injection pump in conjunction with a running Positive Displacement charging pump and injection into a water solid RCS. The resultant limiting RCS peak pressure has been calculated to be 452 psig (Reference 1). A number of provisions for prevention of pressure transients below P-7 (when the RCS temperature is below 312°F) presently exists in the Technical Specifications.

In order to cause an unwanted relief valve opening at normal operating pressures, an operator would have to erroneously arm the POPS system. This would require bypassing the administrative control of the key associated with the keylocked pushbutton condensed by the spray reduces the pressurizer pressure. A small continuous spray is normally maintained to reduce thermal stresses and thermal shock and to help maintain uniform water chemistry and temperature in the pressurizer.

Two power relief valves limit system pressure for large load reduction transients.

Spring-loaded safety valves limit system pressure should a complete loss of load occur without direct reactor trip or turbine bypass.

7.7.2.5 Pressurizer Level Control

The water inventory in the RCS is maintained by the CVCS. During normal plant operation, the pressurizer level is controlled by the charging-flow controller which controls the positive displacement charging-pump speed to produce the flow demanded by the pressurizer-level controller. The pressurizer water level is programmed as a function of coolant average temperature. The pressurizer water level decreases as the load is reduced from full load. This is the result of coolant contraction following programmed coolant temperature reduction from full power to low power. The programmed level is designed to match as nearly as possible the level changes resulting from the coolant temperature changes. To permit manual control of pressurizer level during startup and shutdown operations, the charging flow can be manually regulated from the main control room.

7.7.2.6 Steam Generator Water Level Control

The steam generator water level is controlled by a digital microprocessor controlled steam generator feedwater control system termed the advanced digital feedwater control system (ADFCS). The ADFCS provides automatic control of the programmed level in the steam generators without the need for operator intervention over the range of power operation. This range of operation extends from the point at which the transition is made from feeding via the auxiliary feedwater system to feeding via the main feedwater system on the bypass control valve (approximately 2-3% power) up to full power. One control system operates on both the main and bypass feedwater control valves without the need for manual action to switch operating modes or switch between valves.

The basic control system functional design is similar to the original analog feedwater control system; however, a number of features have been added to improve the performance of the system. Functional block diagrams of the system are shown in Figures 7.7-7, 7.7-8, and 7.7-9. A feedwater temperature-dependent gain has been added to the narrow-range level regulator as shown in Figures 7.7-7 and 7.7-8. The response of steam generator water level to changes in feedwater flow is a function of feedwater temperature. At low feedwater temperatures and low power levels the level response exhibits more of the classical shrink/swell effect. This non-minimum-phase response is a destabilizing influence on the feedback control system. Therefore the control system lowers the gain at low feedwater temperature to preserve stability and increases the gain at high feedwater temperature to improve the response of the system. Derivative action has also been added to the level controller to provide some anticipatory action based on the rate of change of level.

The flow regulator has a high-power mode and a low-power mode which is shown in Figure 7.7-8. This is necessary because the feedwater flow and steam flow signals are not usable at low power levels. The switching between these two modes is done automatically within the system and is performed in a bumpless manner without the need for operator action. At low power levels a load index is used as a feedforward signal to anticipate the need for changes in feedwater flow in advance of an actual change in level. The wide-range steam generator water level measurement is used for this purpose. This signal changes with plant load and also leads the response of the narrow-range measurement. The high-power load regulator uses the standard steam-flow-feed-flow mismatch input. However, the loop steam flow signal is compensated with high-pass filtered loop average steam flow to improve the response of the system to steam-flow-induced transients, such as a large load change. Initially, during a large load change, there is a rapid decrease in steam flow. If the compensation on steam flow were not present, this would cause the control system to close the feedwater control valve, which is opposite to the desired response. As was the case with the low-power mode load index, the feed flow and steam flow signals will automatically be switched in and out of the system. This mode switching is performed independently of which valve (main or bypass) is being used for control.

An additional unique feature of the control system design is the valve lift calculator or the "linearization circuit." The block diagram of this part of the system is shown in Figures 7.7-8 and 7.7-9. The output of the flow regulator is a demanded feedwater flow. The relationship between changes in valve position and changes in feedwater flow is highly nonlinear. It depends on the valve flow characteristic, pressure drop across the system, and system hydraulic characteristics. The linearization circuit calculates the amount that the control valve(s) must be moved to accomplish the change in flow demanded by the control system. The valve lift calculator operates on both the main and bypass control valves and is independent of the control mode. The bypass and main control valves are stroked open sequentially with some overlap. Either of the valves may be operated in manual while leaving the other valve in auto as shown in Figure 7.7-9. The valves are closely coupled through the algorithms in the valve demand portion of the system in order to minimize disturbances on the process (flow and level).

As the plant is taken from low power to high power, the bypass and main control valves are opened sequentially. Before the bypass valve reaches its nominal full-open condition, the control system begins to open the main valve from its full-closed position. As the plant increases in power, the feedwater flow demand increases and the main and bypass valves operate in a "split-range" fashion with both valves continuing to open as controlled by the system's valve sequencing logic. As flow demand is increased the main and bypass valves continue to open until a predetermined position on the main valve is reached at which point the bypass valve will begin to close as a function of flow demand. The system's valve sequencing logic will continue to close the bypass valve until it reaches the full-closed position and the main valve will open to compensate for the decrease in the bypass valve demand. During a power decrease, the main valve will begin to close until a predetermined position is reached on the main valve at which time the bypass valve will open while the main valve is continuing to close. The main valve will continue to close and the bypass valve will begin to close after it has reached its full-open position. The normal sequence described above can be altered by placing either or both of the valves in manual control.

The feedwater control system includes signal validation for input signals to reduce the probability of a failed sensor causing an upset condition in the plant. The input channel signal validation configuration is shown in Figure 7.7-7. When three channels of a variable are available, the median signal select method is used. In this method, the middle value of the three input values is used as the input to the control algorithms. This will prevent high or low failures of a single input from affecting the control system. When two input channels of a variable are available, an arbitration method is used. In this method, the two inputs are compared, and if they agree to within a certain criterion, they are averaged and the result is sent to the control algorithms. If the two channels disagree significantly, they are compared to an estimate of the variable, which is calculated using other process measurements. The primary input that is closest to the estimate is used in the control system.

The signal validation feature of the feedwater control system allowed elimination of the low feedwater flow reactor trip that was incorporated into the original design of the plant. WCAP-13502 provides justification for elimination of the trip (Reference 1).

A summary of the signals input to the advanced digital feedwater control system is as follows:

Process Variable	Number of Channels
Narrow-range steam generator water level	12, 3/loop
Wide-Range steam generator water level	4, 1/loop
Steam flow	12, 3/loop
Feedwater flow	12, 3/loop
Feedwater temperature	4, 1/loop
Steam generator pressure	4, 1/loop
Turbine first stage pressure	2
Feedwater header pressure	3
Valve position	8, 1/valve

Continued delivery of feedwater to the steam generators is required as a sink for the heat stored and generated in the reactor coolant following a reactor trip and turbine trip. An override signal closes the feedwater valves when the average coolant temperature is below a given temperature.

Following a turbine trip, the feedwater regulating valves are closed at approximately a uniform rate, decreasing flow to a low percent of full flow at about one minute after the trip. This provides an optimum heat sink. Subsequently, the operator remotely controls the valves to maintain steam generator water level. Manual override of the Feedwater Control System is available at all times.

7.7.2.7 Steam Dump Control

The Steam Dump System is designed to relieve steam from the steam generators to the condenser to reduce the sensible heat in the primary system in the event of load reduction not exceeding 50 percent.

The bypass system can accommodate 40 percent of full load flow, which, in conjunction with the 10-percent load follow capability of the Reactor Control System, enables the Nuclear Steam Supply System to accept a 50-percent load rejection from full load without reactor trip. All steam dump steam flows to the main condenser via the bypass lines.

When a load rejection occurs, if the difference between the required temperature setpoint of the RCS and the actual average temperature exceeds a predetermined amount, a signal will actuate the load rejection steam dump controller.

7.7.2.11 Residual Heat Removal Performance Monitoring System

The residual heat removal performance monitoring system provides an early warning of loss of decay heat removal capabilities. The system includes:

1. Two independent narrow range continuous Reactor Coolant System level indications and wide range RCS level indication whenever the RCS is in a reduced inventory (mode 5 or 6). The narrow level range monitored is from Elevation 97' to Elevation 91.1'. The wide range level is monitored from elevation 97 feet to 109.5 feet. The wide range midloop level is used while reactor vessel level is above the narrow range midloop level indication.

2. Other monitoring capability:
    a. RHR pump discharge flow
    b. RHR pump discharge pressure
    c. RHR pump suction pressure
    d. RHR pump motor current

    The system is shown on the RCS and RHR system drawings (Figures 5.1-6B and 5.5-2B).

The system is designed to accurately monitor water level while the RHR system is operating with the RCS drained to the mid level of the RPV nozzles. This level allows draining of the steam generators but establishes a very narrow operating level over which the RHR pumps will have adequate NPSH. The Reactor Vessel Level Indicating System (Figure 5.5-2B) provides a wide range level indication but is not accurate enough for the purposes described in NRC Generic Letter 88-17.

The testing design criteria is the same as used for instruments that are connected to full reactor temperature and pressure. The channel design and physical location of the transmitters prevent any physical damage from a refueling seal failure even though the system is not specifically designed to function while flooded or over this range. The low side of the level transmitter is connected to the pressurizer and can be manually aligned to measure the static water level in the vessel with or without pressure in the vessel.

The system is not required for safe shutdown, and is used only during cold shutdown, therefore, it is not safety related. However, it is designed, installed, and maintained as if it were safety related.

7.7.2.12 Seismic Monitoring Instrumentation

The operability of the seismic monitoring instrumentation ensures that sufficient capability is available to promptly determine the magnitude of a seismic event and evaluate the response of those features important to safety. This capability is required to permit comparison of the measured response to that used in the design basis for the facility. Accordingly, the seismic monitoring instrumentation shown in Table 7.7-3 should be maintained operable by the performance of the channel check, channel calibration and channel functional tests at the frequencies shown in Table 7.7-4. Additionally, each of the above seismic monitoring instruments actuated during a seismic event shall be restored to operable status within 24 hours and a channel calibration performed within 5 days following the seismic event. Data should be retrieved from actuated instruments and analyzed to determine the magnitude of the vibratory ground motion.

7.7.2.13 Meteorological Monitoring Instrumentation

The operability of the meteorological instrumentation ensures that sufficient meteorological data is available for estimating potential radiation doses to the public as a result of routine or accidental release of radioactive materials to the atmosphere. This capability is required to evaluate the need for initiating protective measures to protect the health and safety of the public. Accordingly, the meteorological monitoring instrumentation shown in Table 7.7-5 should be maintained operable by the performance of the channel check and channel calibration tests at the frequencies shown in Table 7.7-6.

7.7.3 System Design Evaluation

7.7.3.1 Unit Stability

The Rod Control System is designed to limit the amplitude and the frequency of continuous oscillation of coolant average temperature about the Control System setpoint within acceptable values. Continuous oscillation can be induced by the introduction of a feedback control loop with an effective loop gain which is either too large or too small with respect to the process transient response, i.e., instability induced by the control system itself. Because stability is more difficult to maintain at low power under automatic control, no provision is made to provide automatic control below 15 percent of full power.

The Control System is designed to operate as a stable system over the full range of automatic control throughout core life.

7.7.3.2 Step Load Changes Without Steam Dump

A typical power control requirement is to restore equilibrium conditions, without a trip, following a plus or minus 10 percent step change in load demand, over the 15 to 100 percent power range for automatic control. The design must necessarily be based on conservative conditions and a greater transient capability is expected for actual operating conditions. A load demand greater than full power is prohibited by the turbine control load limit devices.

TABLE 7.7-2

OVERHEAD ANNUNCIATOR GROUPINGS

The alarm groupings are as follows:

<u>DISPLAY A</u>
- ANNUNCIATOR
- TEST/TROUBLE ALARMS
- MISCELLANEOUS
- FIRE PROTECTION

<u>DISPLAY B</u>
- MISCELLANEOUS WATER SYSTEMS
- VITAL DC
- VITAL INVERTERS
- MISCELLANEOUS ELECTRICAL
- SERVICE WATER

<u>DISPLAY C</u>
- WASTE DISPOSAL
- LEAK DETECTION
- AUXILIARY COOLING
- CONTAINMENT

<u>DISPLAY D</u>
- ECCS
- REACTOR COOLANT SYSTEM

<u>DISPLAY E</u>
- CHEMICAL AND VOLUME CONTROL SYSTEM
- PRESSURIZER
- NUCLEAR INSTRUMENTATION SYSTEM
- ROD CONTROL

<u>DISPLAY F</u>
- REACTOR TRIP
- SAFETY INJECTION
- TURBINE TRIP

<u>DISPLAY G</u>
- MAIN STEAM
- TURBINE AND CONDENSER
- FEEDWATER
- TURBINE AUXILIARY COOLING

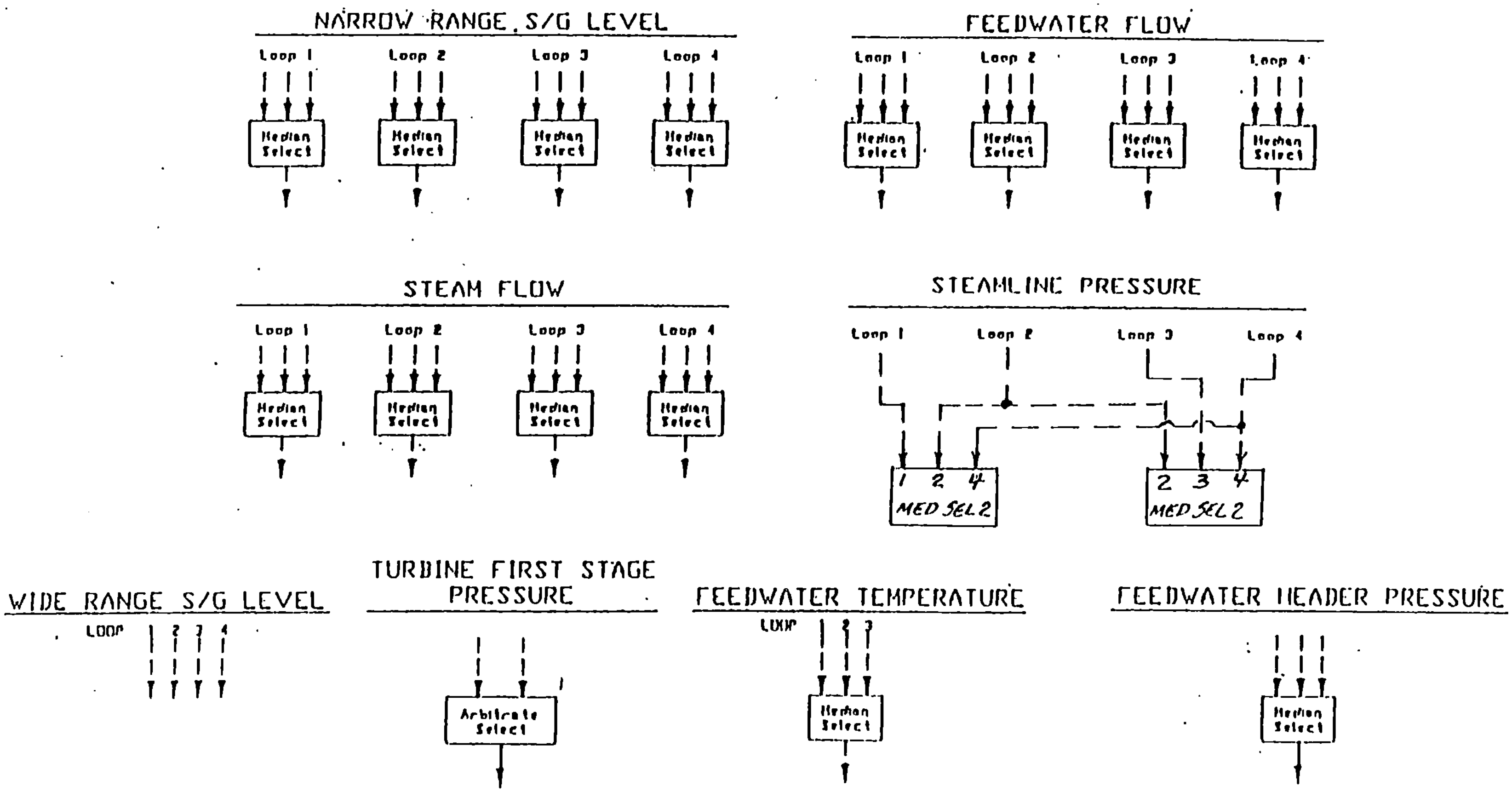
TABLE 7.7-2 (Cont.)

DISPLAY H
- MAIN GENERATOR
- 25KV TRANSFORMERS

DISPLAY J
- VITAL AC
- DIESEL GENERATORS
- GROUP BUSES

DISPLAY K
- CIRCULATING WATER
- 13KV SYSTEM
- 500KV SYSTEM

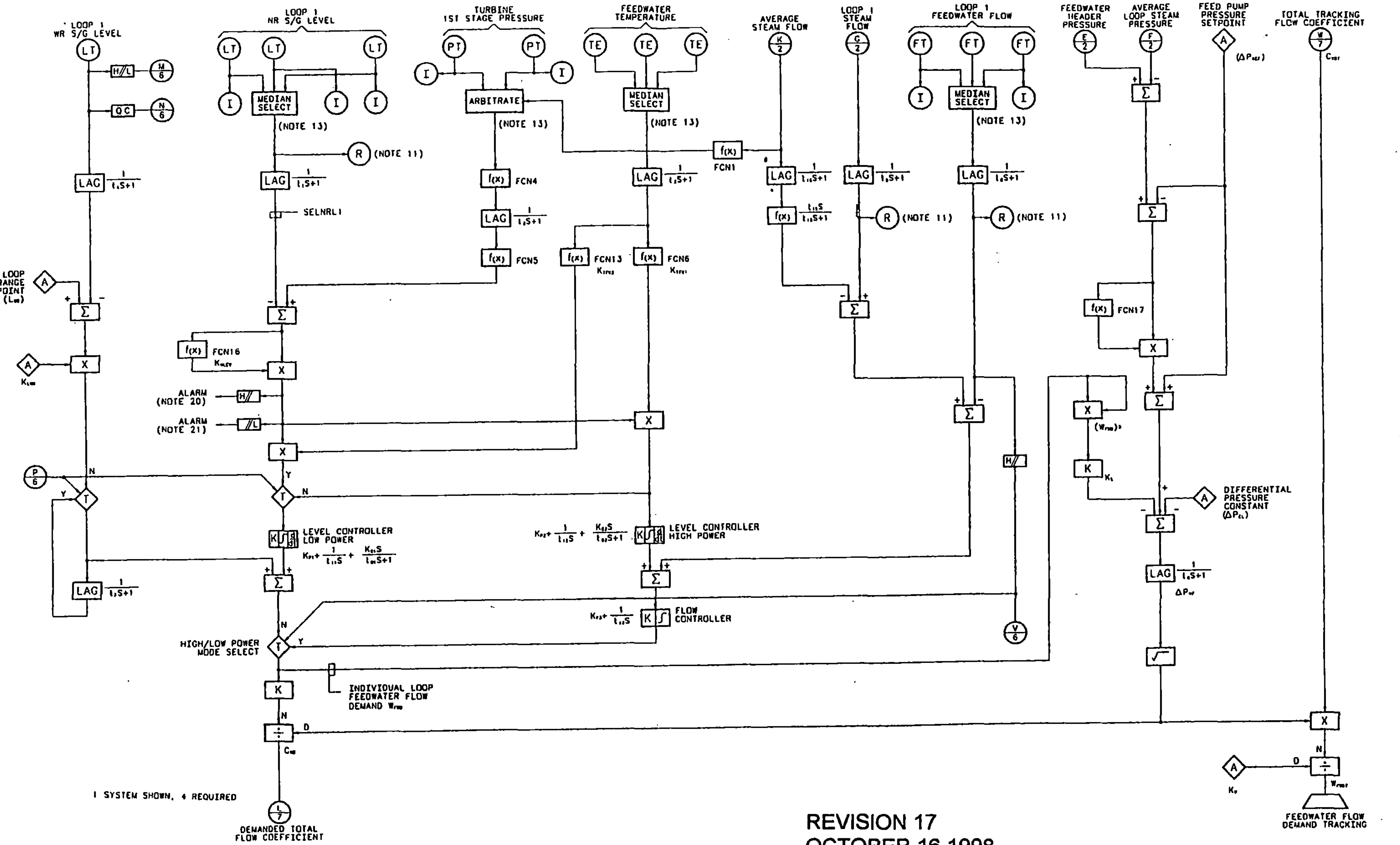
INPUT SIGNAL VALIDATION SCHEME FOR SALEM
ADVANCED DIGITAL FEEDWATER CONTROL SYSTEM



NOTE: ON INPUT SIGNALS FOR WIDE RANGE S/G LEVEL AND STEAMLINE PRESSURE, AN INPUT SIGNAL QUALITY CHECK AND SIGNAL RANGE CHECK IS PERFORMED.

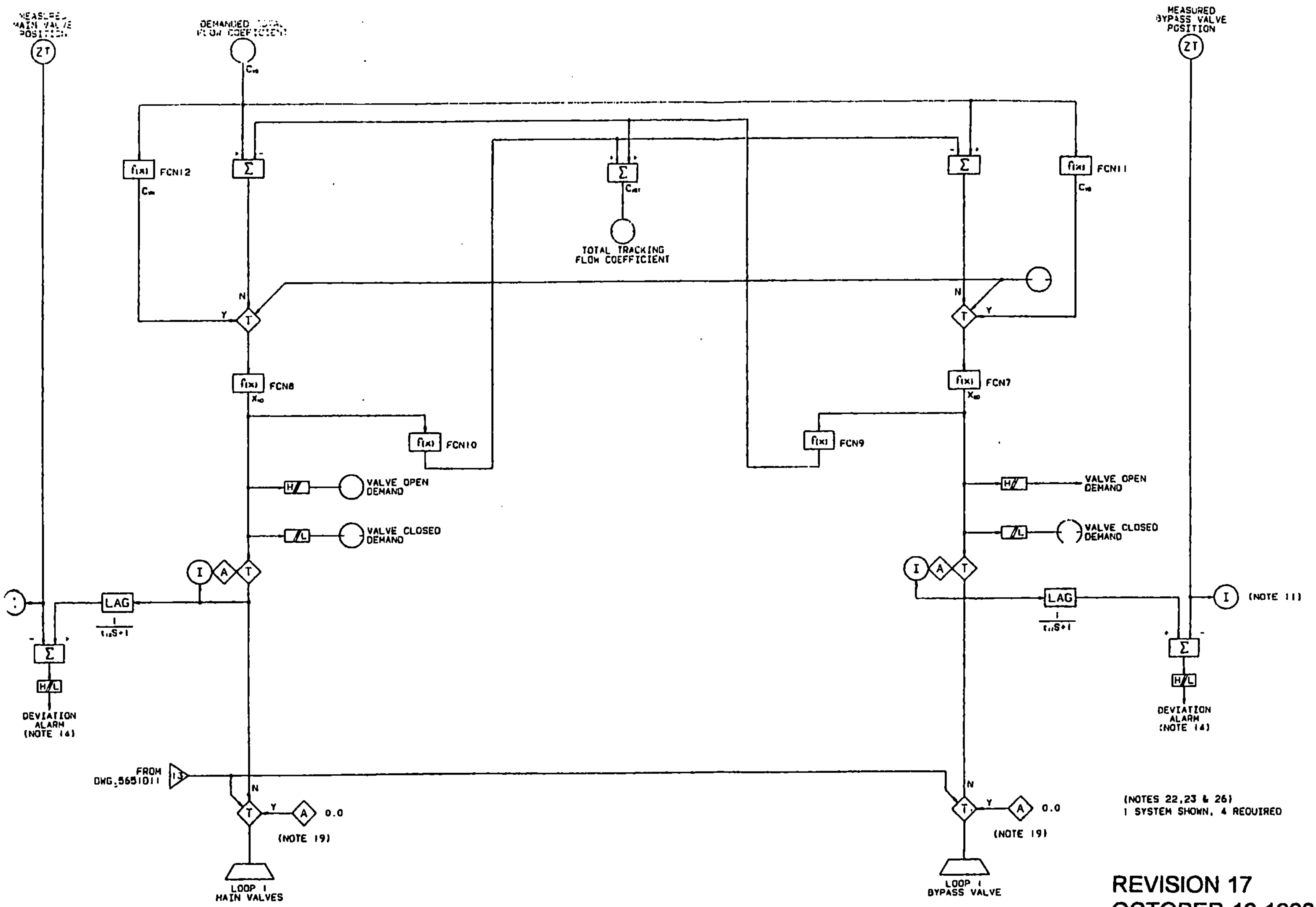
REVISION 17
OCTOBER 16 1998

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Advanced Digital Feedwater Control System Input Signal Validation Scheme
	Updated FSAR FIG.7.7-7



REVISION 17
OCTOBER 16 1998

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Advanced Digital Feedwater Control System Feedwater Control Functional Logic With Algorithms
	Updated FSAR FIG. 7.7-8



REVISION 17
OCTOBER 16 1998

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Advanced Digital Feedwater Control System Feedwater Control Valve Linerization Functional Block Diagram
	Updated FSAR — FIG. 7.7-9

8.1.4.2.5 Separation in Control Areas and Components

Limited Hazard Areas

Limited hazard areas at Salem are considered to be the Relay Rooms, Elevation 100' and Control Equipment Rooms, Elevation 122'. The required physical separation of cables in free air is designated as 1" horizontal and 3" vertical for instrumentation and control cables and 6" horizontal and 12" vertical for low voltage power cables less than 2/0 AWG.

Control Boards, Panels and Racks

The control boards, panels, and relay racks have been designed to provide independence and separation necessary to fulfill the single failure requirement of IEEE Standard 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations."

Control Console

The control console is a free standing unit that is totally enclosed including a dropped floor with a steel bottom plate. All cables entering the console pass through sealing bushings installed in the steel bottom plate on 6-inch centers. Up to eight cables may pass through a numbered sealing bushing; however, only cables of the same separation designation are permitted in a single bushing. Safety-related and nonsafety-related cables may be assigned to the same bushing in accordance with the criteria stated above.

Once in the console, cables are assigned to a four-section cable lattice arrangement with supports which have a minimum center to center distance of 1 7/8 inches and are 2 inches high. Cables go through the lattice to the plug-in instruments. The lattice is assigned separation designations and is also divided horizontally into a numbered grid system. Each cable is assigned a separation designation, a bushing, and a lattice position number. Therefore, the location and path of each cable in the console is individually defined. Installed cables are fastened to the lattice supports.

The plug-in cables terminate at the rear of the console-mounted equipment. All pushbutton stations and vertical indicators plug into identical steel housings which have a rear-mounted receptacle for the plug-in cable.

The steel housings provide physical separation for adjacent pushbutton stations or indicators. There are no exposed terminations associated with the control stations and indicators.

Each pushbutton station has functions associated with one separation designation. The minimum center-to-center distance between the double barriered control station housings is 1 1/2 inches and is based on the use of low voltage controls and special teflon insulated plug-in cables. This minimum distance occurs at the entrance to plug-in modules containing terminations which are enclosed in a steel housing. From the modules, the cables are separated in the lattice system described above which provides for specific routing of the cables to the floor bushings. Redundant cables are "fanned out" from the modules to achieve a greater separation as soon as practical; however, the separation is never less than 1 1/2 inches, center to center. Safety-related wiring other than the plug-in cables is run in conduit.

The reactor trip switches' wiring is not of plug-in cable construction. Reactor trip wiring is run in conduit (using two separate paths for the two trains) from the entrance to the console up to the switches. Wiring for redundant functions is separated by using the front and rear decks of the multi-deck switch.

Each circuit in the 28-V dc Logic System is protected by circuit breakers. Current overload tests have been performed on the multi-conductor plug-in cable based upon the calculated current which would occur if the circuit protection failed to interrupt a short circuit due to failures in the pushbutton control stations. These tests showed that a fault occurring in a pushbutton control station could not cause a fire in the console space.

Within the console, color coding is used to identify the cables and connectors associated with each of the four safety-related and nonsafety-related channels.

The new trip setpoint of 95.1 percent is based upon the results of detailed analyses of the Salem Generating Station electrical distribution system transient response characteristics. Those analyses indicate that, at the PSE&G bulk power system voltage minimum expected value and for a LOCA on one Salem unit and a concurrent orderly shutdown of the other unit, vital bus voltage will recover to a worst-case value of ≈97 percent. The minimum allowable trip value and trip setpoint are derived using the 90-percent minimum motor terminal voltage requirement as a starting point and then applying appropriate allowances required by Regulatory Guide 1.105.

Group bus undervoltage protection (68 percent of nominal) will automatically trip the reactor coolant and condensate pump 4-kV breakers upon sensing an undervoltage (i.e., loss of voltage) condition on its respective 4-kV group bus (1E, 1F, 1G, and 1H) using 1/1 logic taken once.

8.3.1.3 460- and 230-Volt Systems

The 460-V Auxiliary System feeds most motors from 20 to 300 hp. The 230-V System feeds smaller loads and, for convenience of operation, a few motors larger than 15 hp. The 4160-V System feeds the 460-V and 230-V systems via 4160-460-V and 4160-240-V transformers.

The 460-V and 230-V Vital Bus Systems are divided into three bus sections which correlate to their respective 4160-V vital buses.

8.3.1.4 115-V ac Instrumentation Power

Four 12-kVA 115-V ac vital instrument buses for Unit 1 and four 10-kVA 115-V ac vital instrument buses for Unit 2 (1/2 A,B,C & D) receive power from individual Uninterruptible Power Supplies (UPS) to form redundant channels for reactor control and protection instrumentation and safety-related equipment. Each vital instrument bus UPS's Rectifier receives normal source, vital 230-V ac power, converts (rectifies ac/dc) it to dc power, and then converts (inverts dc/ac) it to ac power. In the event of a 230-V ac power loss or an UPS's Rectifier malfunction, 125-V dc vital station battery power will automatically supply power to the UPS's Inverter, via the UPS's actioneering circuit, to maintain uninterruptible ac output power.

Each UPS also contains a 12-kVA Unit 1, 10-kVA Unit 2 ac Line Regulator and Static Switch that receives alternate source, vital 230-V ac power from the same normal source vital 230-V ac bus. In the event of an UPS's Inverter malfunction, the Static Switch senses a loss of Inverter output voltage and automatically fast transfers the associated vital instrument bus loads to the ac Line Regulator 115-V ac output. When the UPS's Inverter voltage returns to normal, the Static Switch will automatically return the associated vital instrument bus loads to the Inverter output.

Table 8.3-1 depicts channel designations for each vital instrument bus power feed. The 115-V ac Control Power System for Units 1 and 2 is illustrated on Figure 8.3-5.

TABLE 9.1-4 (Cont)

OVERHEAD HANDLING SYSTEMS			HEAVY LOAD			
Description	Rated Capacity (ton)	Location (ft)	Description	Weight (lb)	Drop Height (ft)	Safety Related Equipment/ Components Involved in Dropped Lift
			Service Water Pump	12,047	1 in the yard	
			Service Water Pump Motor	13,200	1 in the yard	
900 Series American Crawler Crane	225	Intake Structure and Outside Yard	Traveling Screens	17,325	12	
			Fish Gate	3,000	12	

buses. The pumps for each unit are mounted in two individual dewaterable cells of the intake structure with three pumps to a cell. The intake structure, shown on Figure 9.2-3, is physically apart from the turbine condenser circulating water pump intake. The pumps are arranged to afford adequate submergence during the lowest credible water level elevation of 76.0 feet. The motors are protected from flooding by the pump room compartments which are watertight to Elevation 126'-0" with wave run-up protection to Elevation 128'-0", and which contain sump pumps. Automatic traveling water screens are provided at each intake cell and combine with full-depth trash racks to filter debris from the incoming flow. A mobile mechanical trash rake unit is provided to maintain unobstructed passageways at the trash racks. Two-foot-wide fish-escape passages are located abreast of the traveling screens to minimize the entrapment of fish in the individual intake cells. The primary method to prevent organic buildup in the heat exchangers and piping is by injecting sodium hypochlorite into each of the six service water headers. Additionally or alternately, sodium hypochlorite may be injected at the suction of each service water pump. Each pump discharges to an automatic, self-cleaning strainer and check valve prior to entering the compartment supply header.

The SWS intake structure is located about 200 yards from the Delaware River shipping channels. It is expected that shipping will not approach the intake since the channel is marked by buoys and lights. Due to the large distance between the intake and the shipping channel, vessels which may be adrift can be secured, anchored, or grounded before coming into the vicinity of the intake. In the event that small unattended barges do drift into the vicinity of the intake, marine dock bumpers have been installed to prevent damage to the structure.

The six service water pumps for each unit are arranged in groups of three pumps each, and each group of pumps for one unit is installed in alternate watertight compartments inside the intake structure, as indicated on Figures 9.2-1A and B. Each service water pump is recessed approximately 50 feet from the river face of the intake. Based on the above, damage or blockage to two adjacent compartments of the intake can occur without cutting off the supply of service water to each unit.

In the event that a river borne oil spill occurs which could affect the service water intake, floating oil spill booms will be installed as needed to protect the two end cell fish-escape passages opening to the river to prevent oil from entering the intake at any river water level above 81 feet. A curtain wall at Elevation 81 feet extending across the entire intake structure, except in the fish escape passages, prevents any oil from entering the intake at any river level above this elevation. Lowest recorded river water level is 83 feet-1 inch. The vertical turbine type service water pumps take suction at Elevation 71'-6" for Johnston Pump Co. pumps, which is below the minimum credible river water level of 76 feet. Based on the above, oil floating on the river surface will not be drawn into the pumps. Should the river water level drop below elevation 81 feet with water borne oil present, the plant would be shut down.

The SWS is designed for Class I (seismic) conditions except for the turbine area service water piping outside of the service water intake structure, which is of non-Class I (seismic) design. The Class I (seismic) service water piping inside the service water intake structure which supplies the turbine area is provided with two motor-operated valves, SW-20 and SW-26, in series, to isolate the non-Class I (seismic) portion of the system upon receipt of a safety injection signal or a blackout. The two motor-operated valves in series are powered from separate vital buses to ensure isolation of the non-Class I (seismic) portion of the SWS.

9.3 PROCESS AUXILIARIES

9.3.1 Compressed Air System

The Compressed Air System provides the station with a reliable supply of clean, oil free air which is directed to various locations for services as required. The system is illustrated on Figures 9.3-1A and B.

9.3.1.1 Design Bases

The system provides a reliable supply of clean, oil free, dry air at temperatures and pressures suitable for use as control air and for containment penetration cooling, as well as for miscellaneous services and maintenance.

The Compressed Air System is designed such that any single failure will not result in loss of function.

9.3.1.2 System Description

9.3.1.2.1 General

The Compressed Air System is supplied by three motor-driven, oil free, centrifugal compressors which draw air from the atmosphere. The intakes of the air compressors are located to avoid drawing in toxic or corrosive gases. Each compressor has a capacity of 4000 scfm at 110 psig discharge pressure. One compressor is typically running to satisfy the normal requirements of station air and control air for both units as well as to supply containment penetration cooling air for both units. A second compressor serves as standby. A third compressor is available when required. Each compressor is furnished with a 1000-hp motor, intake filter-silencer, blow-off silencer and total closure controls, constant pressure controls for 1SAE1 and 1SAE2 only, intercoolers, aftercooler, and moisture separator. The compressors discharge into two independent service air headers, with an air receiver tied to each header.

The station air header for each unit is supplied from either of the two service air headers. This station air header provides operating and service requirements at various locations.

The containment penetration cooling system for each unit is furnished with two supply lines. The normal supply is taken from the station air header and the backup supply from either of the two service air headers.

9.3.1.2.2 Control Air

The Control Air System for each unit consists of a dual header arrangement as shown on Figures 9.3-2A and B. This control air for each unit is supplied through two distinct parallel paths. One path is supplied from the Unit 1 Station Air System and the other is supplied from the Unit 2 Station Air System. Control air for the safety-related portions is automatically backed up by an emergency control air compressor. Control air is fed from the Station Air System through heatless, desiccant-type air dryers.

The dual station service air headers are fed by three 100-percent capacity air compressors, any one of which can supply the total service and control air requirements for both units.

In addition to the normal air supply from the service air headers, each system has an emergency control air compressor complete with its own dryer and accessories to supply the safety-related headers. The emergency control air for either system may be directed to supply air for the opposite system through a valved connection. Each emergency control air compressor motor is energized from the standby ac power supply. The Emergency Control Air System is designated Class I (seismic) and is located in a Class I (seismic) structure.

Each emergency control air compressor has a capacity of 500 scfm at 110 psig and is driven by a 125-hp motor. Accessory equipment includes an independent heatless desiccant-type air dryer, intake filter, silencer, intercooler, aftercooler, moisture separator, inlet control valve, relief valve and automatic condensate trap and drain. The emergency control air compressors with teflon piston rings and stainless steel cylinder liners. Cooling of the emergency control air compressors is provided from the safety-related Chilled Water System. In the event that the Chilled Water System is not available, the Service Water System (SWS) serves as a backup.

Operational or test data that verify the functional reliability of the emergency control air compressors were not initially available although stress analysis calculations by the manufacturer indicated that the compressor could withstand both operational and seismic loadings simultaneously.

9.3.2.2.2 Operation

Sampling System equipment is located inside the Auxiliary Building with most of it in the Sampling Room. All sample lines from inside the containment have remotely operable valves.

Reactor coolant loop liquid, pressurizer liquid, pressurizer steam and steam generator blowdown samples originate inside the containment and flow through separate sample lines to the sampling room. A delay is provided by the length of the reactor coolant sample lines to provide sufficient elapsed time for N-16 decay. The samples pass through the containment to the Auxiliary Building, and into the Sampling Room, where they are cooled (pressurizer steam samples condensed and cooled) in the sample heat exchangers. The sample stream pressure is reduced by a manual throttling valve located downstream of each sample pressure vessel. The sample stream is purged to the volume control tank in the CVCS until sufficient volume has passed to permit collection of a representative sample. After sufficient purging, the sample pressure vessel is isolated for laboratory analysis of the contents or degassed, depending on the analysis required.

Alternately, these liquid samples may be collected by bypassing the sample pressure vessels. After sufficient volume has passed to the volume control tank to permit collection of a representative sample, a portion of the sample flow is diverted to the sample sink where the sample is collected.

Samples from the accumulators in the SIS pass through the containment, to the Auxiliary Building, and into the Sampling Room. The sample stream is purged until sufficient volume has passed to permit collection of a representative sample. After sufficient purging, samples are obtained at the sample sink.

The reactor coolant samples originating from the RHRS have remote operated, normally closed air-operated sampling valves located close to the sample sources. The sample lines from these sources are connected to the sample lines coming from the reactor coolant loops at a point upstream of the sample heat exchanger. Samples from this source can be collected either in the sample pressure vessel or at the sample sink as with reactor coolant loop samples.

Liquid samples originating at the CVCS letdown line at the mixed bed demineralizer inlet and outlet headers are purged directly to the volume control tank. Samples are obtained by diverting a portion of the flow to the sample sink. If the pressure is low in the letdown line, the purge flow is directed to the Waste Disposal System (WDS).

The sample line from the gas space of the volume control tank delivers gas samples to the volume control tank sample pressure vessel in the Sampling Room. Purge flow for these samples is discharged to the vent header in the WDS.

The steam generator blowdown samples originate from locations inside the containment, flowing through lines to the sampling area in the Auxiliary Building. Each line is equipped with a manual valve close to the source, a remote air-operated valve downstream of the manual valve, an automatic containment boundary isolation valve located outside the containment and manual valves located inside the sampling area for component isolation, flow control and routing. These sample lines also contain a sample heat exchanger for cooling. A blowdown sample from each steam generator is reduced in pressure and is continuously monitored for radioactivity level, pH, and conductivity.

The steam generator samples originate from locations outside the containment, flowing through lines to the sampling area in the Auxiliary Building. Each line is provided with a manual valve close to the source and manual valves located inside the sampling area for component isolation and flow control. These sample lines also contain a sample heat exchanger for condensing and cooling.

Each CREACS filter unit will draw in 1000 scfm of outside air mixing with 7000 scfm recirculated air from the CRE. The total of 2000 scfm makeup air ensures that the CRE is pressurized to greater than 1/8 inwc differential between adjacent rooms. The recirculated air and outside makeup air is filtered through HEPA and charcoal filters to remove airborne radionuclides and is cooled by a cooling coil. The CAACS operates in Mode 3 recirculating air to control room areas outside the CRE. The CAACS and CREACS automatically actuates upon an accident signal (SI or high radiation) and selects the preferred emergency intake.

In the event that the automatic selection of the preferred intake is unavailable, the operator can manually place the CREACS into Mode 4 service with the preferred emergency intake selected to any unit at power or shutdown.

Single Filtration Train Alignment

The control area ventilation system has provisions to allow for a single CREACS train to be out of service for maintenance. In this alignment, a single CREACS filter train is capable of providing ample cooling, filtering of recirculated and makeup air, and pressurization of the CRE to ensure continuous occupancy of personnel in the control room. In this standby alignment, one CREACS train on one unit is isolated and the other train is aligned (using manual dampers) for cooling the entire CRE with the CREACS train in standby. In this alignment, while in the standby condition, the CAACS fans on the side where CREACS is aligned continues to supply cooling to its respective Electrical Equipment Room/Relay Room (EER/RR) as well as the entire CRE. On the side where the CREACS is isolated, the CAACS supplies only it's respective EER/RR. If an accident were to occur, the system would automatically align as described in the Accident Pressurized Mode (Mode 4) except one CREACS train is now aligned to supply the entire CRE. The manual dampers (VHE1058, VHE1130, VHE1133 and VHE1141) when positioned ensure that a total of 2200 scfm of makeup air is provided and that supply air is distributed throughout the CRE. Return damper CAA17 on the CREACS unit aligned to the Single Filtration Train mode is administratively controlled to the open position. With both units in modes 1-4, the air intake dampers must remain capable of automatic actuation to the non-accident unit upon receipt of a Safety Injection (SI) or a High Radiation signal.

SYSTEM CONTROLS

Both Units 1 and 2 control room ventilation systems are designed to initiate Mode 4 operation automatically upon any one of the following signals:

(1) Safety Injection signal from Unit 1

(2) Safety Injection signal from Unit 2

(3) High outside air activity from Unit 1 control room intake monitor

(4) High outside air activity from Unit 2 control room intake monitor

The automatic selection of emergency intake dampers that open during Mode 4 operation is based on the following:

(1) Safety Injection or control room intake high radiation signal from Unit 1 will open emergency intake dampers on Unit 2 (Unit 1 remain closed).

(2) Safety Injection or control room intake high radiation signal from Unit 2 will open emergency intake dampers on Unit 1 (Unit 2 remain closed).

The following monitoring devices are provided for the control room ventilation system:

(1) Smoke detectors are provided to detect trace amounts of combustion products

(2) Two safety related outside air activity monitors per intake monitor air entering the control room supply duct are beta scintillation type detectors with a range of 10^1 - 10^7 cpm. These monitors have an instrument failure alarm, indication in the control room, and alarm to the control room. The control room alarm is also used for automatic initiation of Mode 4 to isolate and pressurize the CRE.

(3) One non-safety related area monitor per unit is mounted in the control room. These monitors are GM type detectors with a range of 10^{-1} - 10^4 mR/hr (Unit 1) and 10^{-1} - 10^6 mR/hr (Unit 2). These monitors have an instrument failure alarm, local readout, and alarm to the control room. This monitor serves to provide indication only in the control room.

(4) Chilled water control valve (CH168) will be permanently in full open (fail-safe) position during all CAACS modes of operation.

The dampers actuated in the CAACS and CREACS are pneumatically controlled and have position indicators for vital automatic dampers in the control room. The dampers required to operate during Mode 4 conditions are designed to fail to their designated position upon loss of control air or power. These dampers automatically actuate to the designated positions upon signals from the Solid State Protection System (SSPS) and the radiation monitoring system (RMS). All vital dampers can also be operated manually at the damper.

The control room ventilation system has provisions to allow the operators to manually initiate the CAACS and CREACS to any of the operating modes from the control room.

9.4.1.3 System Design Evaluation

9.4.1.3.1 CREACS Single Failure Design

The CREACS ventilation design has been evaluated for single failure vulnerabilities and impacts on control room habitability requirements during an accident.

The CAACS and CREACS designs provide for redundant pneumatically operated isolation dampers (with manual backup operators) and controls for isolating the outside environment from the control room areas. These dampers are designed to fail to their designated positions for Mode 4 accident operation as described in 9.4.1.2. In addition, each unit's emergency intakes are provided with dual parallel flow paths, each with redundant pneumatically operated dampers in series with a manual isolation damper for maintenance. These pneumatic dampers are provided with redundant actuation signals and are supplied from separate control air headers to ensure that emergency makeup air is supplied to pressurize the CRE during an accident.

Dampers not providing isolation from the outside environment are single pneumatically operated dampers. Dampers relied upon during emergency conditions are provided with redundant actuation signals and are spring loaded to their fail safe positions upon a loss of control air or power (CAA14, CAA17, and CAA20). These dampers are also provided with manual backup operators and position indicators in the control room.

Operation of required dampers, valves and fans during an emergency condition is ensured by providing redundant controls. Each unit consists of two trains of controls circuitry supplied from separate vital control power and control air sources. The control scheme is designed such that on a loss of control power or air, the CAACS and CREACS will fail safe to the designated position for Mode 4 operation. Each unit's controls are initiated from redundant trains of SSPS and control room intake radiation monitors.

Each CREACS filtration train is provided with two 100% capacity supply fans supplied by the standby A/C power supply. In the event that one fan fails to start, a safety related flow switch located downstream of the fan discharge duct will start the standby supply fan. Control switches located in the control room are provided to allow the operators to select the lead and standby emergency fans. In the event maintenance is required on a filter unit, the operators manually place the system in the standby alignment condition for a single CREACS filtration train operation. In the Maintenance mode, a single CREACS filtration train is capable of providing adequate cooling, removal of airborne activity, and pressurization of the CRE during the course of an accident for long term occupancy. While in the Maintenance mode, CREACS return damper CAA17 is administratively blocked open.

9.4.1.3.2 Shared Systems, Structures, or Components

Since the SGS Unit 1 and 2 control rooms are common, the ventilation design and operating modes for CAACS and CREACS are evaluated for impacts for shared system design (GDC 5). The following areas of the ventilation design were evaluated:

(1) Supply Distribution Plenum to CRE
(2) Outside Emergency Intake Plenum
(3) Unit 1 and 2 CREACS supplying CRE
(4) Single Filtration Train operation (Maintenance mode)
(5) Ventilation Control Circuitry
(6) Control Room Intake Radiation Monitors

Supply Distribution Plenum to CRE

This supply distribution plenum and associated manual dampers are designed to Class I (seismic) criteria. This common supply plenum serves to distribute air to the rooms within the CRE.

Outside Emergency Intake Plenums

The emergency air intake plenums for each unit is cross-connected by a common ductwork to allow each unit's CREACS or a single unit's CREACS the ability to draw outside makeup air from the selected or preferred intake. The emergency air intake and distribution plenums are designed to Class I (seismic) criteria. The emergency air intake plenums for each unit are designed with dual parallel flow paths, each flow path consisting of a redundant series of dampers actuated by redundant controls. The sources of power and control air for each unit's intake dampers are not shared between units.

CREACS Supplying CRE

Normally, during an emergency condition, both units CREACS will operate simultaneously, each CREACS supplying cool filtered air to the CRE to maintain habitability requirements.

Single Filtration Train Operation

In the event that one of the CREACS filtration trains is out of service for maintenance, the operators manually place the system in the standby alignment condition to a single filtration train operation (Maintenance mode). A single CREACS train is capable of providing adequate air to cool the CRE and ensure control room habitability requirements are met during an accident without impairing the capacity of the onsite power supply.

Ventilation Control Circuitry

The controls for actuating the CAACS and CREACS to the accident mode of operation (Mode 4) and for single filtration train alignment are shared between Unit 1 and 2 control area ventilation control circuitry. This is based upon each unit's train of control circuitry being electrically interlocked with the opposite unit's controls. This interlock enables the opposite unit's CAACS and CREACS controls to automatically initiate to Mode 4 operation. This interlock is electrically isolated and separated from the other unit's control power. The pneumatic controls are completely separated and are not cross-connected between units. Each unit's actuation controls are redundant, and electrically and physically separated. The interlock between units is electrically isolated and is only interconnected to the same division or train on the opposite unit. The control power and air sources are not shared between units, and therefore, the capacities are not impaired.

Control Room Intake Radiation Monitors

The radiation monitors monitor both unit's intake and provide actuation functions to Unit 1 and 2 ventilation controls and are considered shared. These monitors are redundant and safety related. A monitor is located in each unit and is capable of monitoring normal makeup air on each unit's intake plenums. Therefore, each unit's intake plenum consist of redundant detectors from separate radiation monitors located in different units. The power sources to these monitors are not shared between units and the actuating functions to both unit's ventilation controls are separated and isolated.

Conclusion

The shared ductwork is designed to seismic I criteria and will maintain its safety function during an accident.

The capacity of the onsite power sources are not impaired by the sharing of the control area ventilation system. In the cases evaluated herein, the power sources for the ventilation equipment (fans) and controls (relays, solenoids, damper actuators) are not shared between Units 1 and 2. In fact, the sharing is based on the function of the SSC being shared between the units, in which case, provisions in the design ensures for adequate separation and isolation between units SSC and redundancy of the shared SSC, such that the safety function is not impaired per GDC-5 criteria.

9.4.1.3.3 Detection of Adverse or Dangerous Environment Conditions

The control room is provided with smoke detectors and radiation detectors located in the control room and in the normal intake plenums. The smoke detectors monitor for trace amounts of combustion and alarm to the control room. Redundant radiation monitors are provided that monitor the normal incoming makeup air to the control room areas for airborne radioactivity. A radiation monitor is also provided in each control room that serves to provide radiation levels in the area. Human detection by the control room operators is also relied upon for the detection of other hazardous conditions (e.g., smoke, ammonia, etc.).

9.4.1.3.4 Capability to Exclude Contaminants

The CAACS and CREACS is designed to cope with preventing the entry of contaminants by operating in the following modes:

(1) CAACS in Normal operation (Mode 1) with outside makeup air maintains a positive pressure inside the control room areas and the CRE during normal operation and use of minimum leakage dampers, minimum leakage penetrations, weather stripped doors, and absence of outside windows to limit infiltration of air, smoke or airborne radioactivity from other rooms in the control area and Auxiliary Building. The CAACS does not use exhaust fans and relies on the supply fan pressure to deliver air flow into the room areas. With this design, minimizing leakage in the rooms and makeup air, the control room areas can be maintained at a positive pressure limiting entry of contaminants.

(2) Full recirculation (Mode 3) of CAACS and CREACS with the outside environment isolated due to smoke, toxic gas, or hazardous chemical released outside the control room. This mode is initiated manually by the operator upon detection.

(3) CREACS pressurizing (Mode 4) the CRE and CAACS in full recirculation for radiological accident. This mode can be initiated automatically or manually.

9.4.1.3.5 Capability for Removal of Contamination

The CREACS filtration train consists of a High Efficiency Particulate Air (HEPA) and charcoal filters. The HEPA filters have a removal efficiency of 95% and the charcoal filters have a removal efficiency for radioiodine of 95%. The Unit 1 and 2 CREACS filtration units will automatically be placed in service during a radiological accident, filtering recirculated air from the CRE and makeup air from outside the control room. In addition, a single CREACS filtration train, when operated in the Maintenance mode, is capable of providing adequate removal of airborne contaminants during an accident to ensure the doses in the CRE are within the limits of GDC 19 criteria.

9.4.1.3.6 Removal of Contamination by Purging

Purging of the control room areas is provided by the operators manually initiating the system to the Mode 2 operation. In this mode, all of the normal outside air intake plenum dampers go open, providing 100% outside air to be drawn into the control room areas. Exhaust dampers go open to allow the contaminants to be expelled to the outside environment. The CREACS is isolated and in standby in this mode.

9.4.1.3.7 Capability of Ensuring Ambient Room Temperatures

The control area ventilation system has adequate capacity to ensure ambient temperatures in the rooms are maintained within limits during normal and emergency conditions. A system air balance was performed and adjustments made for the required design values. A chiller capacity test was performed on one of the chillers. A system balance on the CWS was performed. Inspection on the CREACS coils was performed. These tests reasonably demonstrate the capability of the system to remove the heat loads during normal and emergency conditions to maintain the control room areas and the CRE within temperature limits.

9.4.1.3.8 Capability for Single CREACS Filtration Train

In the event that one of the unit's CREACS filtration trains require maintenance, the operators manually place the system in the standby alignment condition to operate with a single CREACS filter train (Maintenance mode). Once the CREACS unit is in the Maintenance mode, an automatic initiation will initiate accident pressurized and will pressurize the CRE and maintain control room habitability during the course of an accident within GDC 19 limits.

Each system will automatically shut down if carbon dioxide fire protection flooding is initiated for the space.

If the ambient temperature in a diesel generator compartment or Control Room exceeds 110°F or goes below 40°F, the condition is alarmed in the Unit Control Room.

9.4.5.3 Design Evaluation

The heating and ventilating of the diesel generator area is predicated on outdoor temperature limits of 0°F in winter and 95°F in summer. For the Salem site, these values satisfy more than 99 percent of the conditions experienced annually. There is, therefore, a conservative margin in the heating and ventilating systems to assure that the design temperatures for the spaces can be maintained. Heaters are provided in the Lube Oil System and in the Jacket Water System to assure each diesel generator is maintained at a temperature at which it can be started in 10 seconds. This condition is satisfied for an outside temperature of 0°F and an inside ambient temperature of 40°F.

The Ventilation Systems for the diesel generator areas are independent, physically separated and powered from separate sources. Each system is provided with its own controls.

In the event of a fire in one space, the Ventilation System for that space is automatically de-energized and does not feed air to the fire. The other diesel generators are available with full ventilation.

The CO_2 system contacts, that interpose the ventilation systems, are bypassed by the operation of switches in the Control Room if a station seismic event is detected.

9.4.5.4 Tests and Inspections

All equipment and components of the diesel generator area Ventilation Systems are subject to a program of tests and inspections.

9.4.6 Switchgear and Penetration Area (SPAV) Ventilation System

9.4.6.1 Design Basis and Criteria

The Switchgear and Penetration Area Ventilation (SPAV) System is designed to maintain safe levels of temperature and cleanliness in the rooms served. Standby equipment is included in the system to assure the maintenance of these design conditions. The system is seismic Class I. The seismic design and analysis methodologies used to qualify all ductwork and the contained equipment are described is Section 3.8.4.4.1. The Ventilation System is designed to maintain the areas served by this system between a temperature range of 65°F-110°F except for the following areas:

El. 64' Security Battery Room	115°F
El. 64' Elevator Machinery Room	115°F
El. 84' Main Corridor	115°F
El. 84' Unit 1 Switchgear Room	115°F

The design basis outdoor air temperature is 0°F (winter) and 95°F (summer). A 10°F daily temperature variation may be used for summer operations, in accordance with ASHRAE methodology. These temperature values satisfy more than 99 percent of the conditions experienced at the site area annually.

9.4.6.2 System Description

9.4.6.2.1 General Description

An independent Ventilation System is provided for each unit's Switchgear Rooms which are located on Elevations 84 feet and 64 feet, Mechanical Penetration Area (El. 100'), and the Electrical Penetration Area (El. 78') of the Auxiliary Building. The SPAV System consists of a supply air roll filter and enclosure, three supply air fans, two Penetration Area exhaust fans, two return/exhaust fans, recirculation duct, supply and exhaust ducts, and control dampers. Most of the equipment is located in the penetration areas at Elevation 100 feet of each unit. All ventilated areas and equipment are enclosed in seismic Class I structures. The Switchgear Ventilation System is shown on Figures 9.4-6A and B.

9.4.7 Service Water Intake Structure Ventilation

9.4.7.1 Design Bases

The Ventilation Systems are designed to limit the temperature of each compartment and/or Control Room to 110°F during ambient conditions of 95°F with all equipment operating. The unit heaters are sized to limit the temperature in the areas to a nominal 60°F in the winter during ambient condition of 0°F. Reliable operation of the service water pumps, their controls and instrumentation is assured for a temperature range of 40°F-110°F.

The ventilation capacity for each service water intake structure compartment and Control Room is based on the calculated waste heat released.

The exhaust fans (12,000 and 32,000 cfm capacity) and their controls and instrumentation are designed to Class I (seismic) criteria and can be powered from the Standby AC Power System. The air intake penthouse, supply and exhaust dampers are of non-seismic construction. The seismic design and analysis methodologies used to qualify all ductwork and the contained equipment are described in Section 3.8.4.4.1.

9.4.7.2 System Description

9.4.7.2.1 General Description

The service water intake structure for both units consists of four service water intake compartments, each with its own Control Room. Each of these compartments is provided with an independent, once-through Ventilation System.

The service water intake structure Ventilation Systems are designed to start automatically and limit the maximum room temperature when the service water pumps are operating.

The Ventilation System for each compartment consists of an outside air intake penthouse, power-operated intake and exhaust dampers, and two exhaust fans discharging to the outdoors.

Local unit heaters assure an adequate minimum temperature in the spaces during cold weather when no pumps are in operation.

9.4.7.2.2 System Operation

The service water intake structure Ventilating Systems operate automatically in response to compartment and/or Control Room temperatures.

The Ventilation Systems operate as follows: on a small rise in temperature, the smaller of two exhaust fans starts and discharges to the outdoors. The supply air from the outdoors is modulated by room thermostats to provide the design compartment or Control Room temperature. On a greater rise in temperature, the larger fan starts, its intake damper opens and more air is induced to flow through the compartments. When a system is shut down, its exhaust fans stop and the supply and exhaust air dampers return by spring action to their closed positions.

Prior to the ambient temperature in compartments or Control Rooms exceeding 110°F or going below 40°F, the condition is alarmed in the Control Room.

9.4.7.3 <u>Design Evaluation</u>

The heating and ventilating of the service water intake structure area is predicted on outdoor temperature limits of 0°F in winter and 95°F in summer. For the Salem site, these values satisfy more than 99 percent of the conditions experienced annually. This is, therefore, a conservative margin in the Heating and Ventilating Systems to assure that the design temperatures for the spaces can be maintained.

9.5.2.2 Telephone System

Ten telephones are located in each Control Room. One of them is a direct line to the Load Dispatcher; one is a direct line to the NRC; two are for use with the Centrex Instrument; two are for general purpose use; and four are for NETS. Direct lines are also provided in the Administration Building Conference Room and tie in directly to the New Jersey Bell Telephone Company. These lines are for emergency use and insure communications between the Conference Room and the Telephone Company.

9.5.2.3 Closed Circuit Television System

A closed circuit television system provides intermittent television monitoring of equipment inside containment. Portable underwater television equipment is provided for the Fuel Handling Building and for scanning the inside of large vessels.

Each Containment Building has three television cameras mounted on the containment liner, 120 degrees apart, at an elevation of approximately 205 feet. Each containment camera has a zoom lens and a pan and tilt control unit. A switch is located in the control room for turning the lights in the containment on and off.

Underwater equipment consists of four underwater cameras each with its own zoom lens, pan and tilt unit and 9-inch monitor. Two sets of portable lights are provided for underwater illumination. Monitors and camera controls are mounted on a movable television table.

Video tape recorders are provided with any of the television cameras.

9.5.2.4 Radio Repeater System

A system of portable transceivers and fixed repeaters is provided for the fire brigade.

9.5.3 Lighting System

The Lighting System provides necessary illumination for day-to-day plant operation and adequate illumination for safe shutdown and personnel safety.

9.5.3.1 Emergency Lighting

Power for emergency lighting within the plant is distributed by Lighting Distribution Panels (LDP) 1ELD and 1ELC (2ELD and 2ELC for Unit 2). Lighting Distribution Panels 1ELD (2ELD for Unit 2) contains two separate distribution buses. One bus within LDP 1ELD (2ELD) is supplied either from Lighting Inverter 11 (21) or from 230 V ac vital bus 1A (2A) through a lighting transformer (located inside the inverter enclosure). A bus transfer switch in the output of inverter 11 (21) automatically switches from the inverter output to ac vital bus 1A (2A) if a loss of inverter output power is sensed. Lighting Inverter 11 (21) is powered by battery 1A (2A). The second bus within LPD 1ELD (2ELD) is supplied in a similar manner from Lighting Inverter 12 (22), 230 V ac vital bus 1B (2B), battery 1B (2B), and a bus transfer switch. LDP 1ELC (2ELC) is powered from lighting inverter 13 (23) and 230 V ac vital bus 1C (2C) with automatic switchover accomplished by a bus transfer switch in the same way as described above. Lighting Distribution Panels, 1ELD-A, 1ELD-B, and 1ELC for Unit 1 are normally powered by 230V AC, 3 phase vital buses, 1SWGR1AY, 1SWGR1BY, and 1SWGR1CY through lighting transformers located within the inverter enclosure. The backup power for these LPD's are inverters 11, 12, and 13 which are fed from 125V DC sources, 1SWGR1ADC, 1SWGR1BDC, and 1SWGR1CDC, respectively. Lighting Distribution Panels 2ELD-A, 2ELD-B, and 2ELC for Unit 2 are normally powered by 230V AC, 3 phase vital busses 2SWGR2AY, 2SWGR2BY, and 2SWGR2CY through transformers located within the inverter. The backup power for these LDPs are inverters 21, 22, and 23 which are fed from 125V DC sources 2SWGR2ADC, 2SWGR2BDC, and 2SWGR2CDC, respectively. A bus transfer switch in the output of the inverter will automatically transfer to the inverter output upon the loss of the normal 230V AC vital bus supply.

Areas of the plant requiring operator access for safe shutdown are provided with self-contained emergency lights. These units are battery powered and have an 8-hour capacity. Those self contained emergency light battery supports that are required to meet seismic integrity are designed to withstand seismic forces.

3. Low vacuum trip

4. Thrust bearing trip

5. Electrical solenoid trip actuated by:

   a. Reactor trip
   b. Generator electrical trips
   c. Manual trip from Control Room
   d. Loss of electro-hydraulic system control voltage
   e. Electrical overspeed trip

6. Manual trip lever located at the turbine

7. Loss of primary/secondary 24 V dc power

8. High-high steam generator water level or safety injection

The mechanical overspeed trip mechanism consists of an eccentric weight mounted on the end of the turbine shaft, which is balanced in position by a spring until the speed reaches approximately 103 percent of rated speed. Centrifugal force then overcomes the spring force and the weight flies out striking a trigger which actuates the overspeed trip valve and releases the protection system fluid (autostop oil) to drain. The resulting decrease in autostop pressure causes the governor emergency trip valve to dump the hydraulic fluid to a drain, thereby closing the turbine stop and control valves and the reheat stop and interceptor valves.

The autostop dump valve is also tripped when any one of the previously mentioned protective devices is actuated.

In addition to these devices, other protective features of the Turbine and Steam System are:

1. Turbine trip following a reactor trip

2. Automatic load runback initiated by overpower or overtemperature ΔT

3. MSIV in each steam generator steam line

4. Safety and relief valves in each steam generator steam line

5. Safety valves mounted on the moisture separator-reheater vessels

6. Extraction line nonreturn valves

7. Automatic load runback initiated by generator stator water turbine runback (Unit 2).

8. Automatic load runback initiated by main feedwater pump trip.

A trip of the turbine generator, when unit load is greater than a present limit, initiates a reactor trip to prevent excessive reactor coolant temperature and pressure.

Automatic turbine load runback is initiated by an approach to an overpower or overtemperature condition. This will prevent high power operation which might lead to an overpower or overtemperature ΔT trip.

For Unit 2, an automatic turbine load runback can also be initiated by an input from the generator stator water turbine runback schemes. Generator runback is initiated by 2 out of 3 logic for low water pressure, 2 out of 3 logic for outlet water temperature, 2 out of 3 logic for low stator winding water flow, 2 out of 3 logic for low rectifier water flow or 2 out of 3 logic for low bushing water flow when the No. 2 voltage regulator is in the automatic permissive for runback condition. Stator current is monitored during this runback. Stator current must be less than 79% of rated load at the 2 minute mark and less than 23% of rated load at the 3.5 minute mark or a main turbine trip will be initiated. This will prevent damage to the Generator winding.

An automatic turbine load runback can also be initiated by a trip of either main feedwater pump when turbine power is greater than 70%.

The extraction nonreturn valves are closed through an air pilot valve which is actuated by the loss of autostop oil pressure when the turbine generator is tripped.

An electrical speed limiting device is incorporated in the Electro-Hydraulic Control System. This mechanism dumps the operating fluid from the turbine governor and intercept valves allowing spring pressure to close the valves. When turbine speed decreases, and the overspeed condition clears, the signal is removed and the valves reopen. This is not considered a turbine trip, but rather a speed limiting device to prevent an overspeed condition which would result in a turbine trip.

To prevent potential damage to the turbine due to the generator motoring, an electrical reverse power device interlocked with the turbine trip signal is incorporated. This protective measure ensures that the turbine is tripped before the generator circuit breakers are open, and provides the 30 seconds delay between the turbine trip and the generator trip upon detection of motoring condition.

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and supply restraint against undesired motion. Where necessary, the valve operator has also been restrained to limit seismically induced motions.

10.3.4 Inspection and Testing Requirements

The MSIVs (MS167) and automatic drain stop valves (MS7) shall be tested periodically as set forth in the Technical Specifications.

The main steam drain traps are periodically tested to ascertain their proper functioning and, hence, prevent any unnecessary water accumulations.

Removable insulation panels have been provided at welds in the Main Steam System between the steam generator and the MSIVs in order to accommodate volumetric and surface weld examination as specified by periodic inservice inspection requirements.

A functional test of the turbine governor control valves is performed periodically and can be made while the unit is carrying load. The purpose of this test is to ensure proper operation of the turbine stop valves, control valves, reheat stop valves, and interceptor valves.

The controls and protective devices associated with system components, including steam generator safety valves, are tested as set forth in the Technical Specifications.

The valves cannot be tested while the plant in operating.

10.3.5 Water Chemistry

10.3.5.1 Chemical Feed System

The Chemical Feed System is shown on Figure 10.3-3. Chemical feed equipment is provided to add hydrazine and ammonium hydroxide for Unit 1, and hydrazine and ammonium hydroxide and/or alternate amine for Unit 2 to the discharge of each condensate pump. In addition, equipment is available to feed a solution of hydrazine and ammonium hydroxide for Unit 1, and hydrazine and ammonium hydroxide and/or alternate amine for Unit 2 to the inlet main and auxiliary feedwater line of each steam generator.

Hydrazine is added to the Condensate System and the main and auxiliary feedwater system for control of residual oxygen. Ammonium hydroxide and/or alternate amine is added for corrosion and pH control and minimizes metal pickup through the cycle.

The chemical solutions are prepared with demineralized water and stored in covered tanks. All chemicals are injected by motor-driven positive displacement pumps with both manual and/or automatic control.

10.3.5.2 Secondary Water Chemistry Control Program

The Secondary Water Chemistry Control Program is designed to limit the corrosion of the tubing and internals of the steam generators. The basis of the program is to control the levels of the critical parameters in the steam generator bulk water such that maximum protection to the steam generators is provided and tube integrity is maintained.

Protection of the steam generator tubing is accomplished by maintaining the water quality of the condensate and condensate polishing effluent and adjusting the blowdown on each of the four steam generators. The feedwater and steam generator bulk water treatment consists of introducing ammonium hydroxide and/or alternate amine for pH control and hydrazine for oxygen scavenging. This treatment is recommended by industry guidelines.

The CPS is designed to handle a normal and a maximum continuous flow of 22,000 gpm and 24,000 gpm, respectively, with five of the six demineralizers operating in parallel.

A pH range of 8.8 - 9.4, is recommended by the EPRI Chemworks model for Salem Unit 2 with alternate amine chemistry (ETA). While using ammonia only for pH control a range of 8.8 - 9.2 is recommended by EPRI. However, sodium levels in the feedwater become extremely critical in this pH range since sodium may be converted to sodium hydroxide. Sodium hydroxide, if carried over into the steam generators, will increase the possibility of caustic embrittlement of steel and stress corrosion cracking of Inconel components of the steam generator.

The operator is alerted to (partial) bypass of the CPS when valve 1(2)CN-109 is open and either valve 11(21)CN-108, 12(22)CN-108 or 13(23)CN-108 are not fully shut (valves are shown on Figures 10.4-5A and B).

10.4.7 Condensate and Feedwater Systems

10.4.7.1 Main Condensate and Feedwater System

10.4.7.1.1 System Description

The Steam Generator Feedwater and Condensate System is shown on Figures 10.4-5A and B. Condensate is withdrawn from the condenser hotwells through a common suction header by three motor-driven, multi-stage, vertical centrifugal condensate pumps rated at 8000 gpm and 575 psi TDH. These pumps discharge into a common header which carries the condensate into the first five stages of feedwater heating. A low flow recirculation line is provided on the discharge of each condensate pump to maintain a minimum flow of 1800 gpm for pump protection. The vertical motors are located at an elevation above the highest recorded river water level.

Two, one-half capacity, high speed, barrel-type feed pumps take suction from a common header receiving feedwater from the discharge of the No. 5 heater. These feed pumps discharge into a common header, through the No. 6 high pressure feedwater heater and into a collecting header. Feedwater then flows through one line into the steam generator inlet header which is located outside the containment.

Feedwater enters the containment vessel through four lines penetrating the containment wall, one line feeding each steam generator. Feedwater flow control valve, motor-operated stop check valve, and isolation valves are installed in each steam generator feedwater line outside the containment. Each feedwater control valve is positioned by its own three-element control of feedwater flow to maintain steam generator level during startup and low power operation. All feedwater piping downstream from, and including, the isolating motor operated stop check valve is designed to meet Class I seismic requirements. A low flow recirculation line is provided on the discharge of each steam generator feed pump to maintain a minimum flow of 2300 gpm at design conditions for pump protection.

Each steam generator feed pump is designed for a capacity of 18,600 gpm and total developed head of 884 psi. These design conditions were based on the maximum calculated turbine load plus allowance for pump wear and steam generator blowdown.

Each steam generator feed pump is driven by a variable speed steam turbine with throttle steam supplied from the reheater outlet for normal two pump operation and from the Main Steam System during periods of low load. During startup, steam is supplied from the station heating steam system. Each steam generator feed pump turbine exhausts separately into one of the three condenser shells.

The Feedwater Heating System utilizes six stages of closed feedwater heaters. All feedwater heaters are horizontal "U" tube, one-third size units, (three strings) with each heater string capable of satisfactory operation at 150 percent of its design feedwater flow. The feedwater heaters and piping are arranged to turbine-driven pump is taken from two of the four main steam lines upstream of the MSIVs. Separate isolation valves are provided for these connections. The motor driven pumps receive power from the 4 KV vital buses. The Auxiliary Feedwater System is designed as a Class 1E Safety Grade System.

The turbine-driven auxiliary feed pump, rated at 880 gpm (plus 100 gpm continuous recirculation flow), and 1550 psi, and the motor-driven auxiliary feed pumps, rated at 440 gpm and 1300 psi*, receive suction from the 220,000-gallon auxiliary feedwater storage tank.

Each motor-driven pump discharges to two steam generators with a normally isolated cross-connect line joining the motor-driven pump discharge headers. The turbine-driven pump feeds all four steam generators. Feedwater flow is controlled from the Control Room by remotely operated flow control valves in the supply lines to each steam generator. For Units 1 and 2, reduced capacity trim has been installed on all eight flow control valves (AF11 and AF21) to limit the maximum flow under certain plant conditions. Safety grade indication of auxiliary feedwater flow to each steam generator is provided in the Control Room.

The AFW System circuits and initiation signals receive power from unit vital buses. System initiation signals and circuits are designed for complete testing.

The AFW pumps are capable of being started in either the manual or automatic mode. Manually, the pumps can be started at their local control panel or from the main Control Room. Manual start circuits are designed for single failure, and failure of the automatic initiation signals or circuits will not affect the capability for manual starting.

Automatic initiation signals and circuits are designed to prevent system malfunction for a single failure.

* No. 22 motor driven auxiliary feedwater pump rated at 450 gpm and 1175 psi.

The motor-driven auxiliary feedwater pumps are started automatically by any of the following conditions: loss of offsite power, loss of main feedwater system, safeguards sequence signal, or low-low level signal from any one steam generator.

When either of these pumps are started automatically, a signal is sent to close Steam Generator Blowdown and Sampling Systems' isolation valves. The isolation signal to the Sampling System isolation valves can be bypassed by the use of a keylock switch located on the control room console. This bypass capability allows control room operators to open the Sampling System isolation valves when sampling is required by the EOPs in the event that a faulted steam generator with a low-low level condition is experienced.

For the pumps to start in automatic mode, the REMOTE-LOCAL MANUAL switch located on the local panel must be in the REMOTE position.

The motor-driven auxiliary feedwater pumps are among the loads included in the diesel generator's automatic loading sequence.

The turbine-driven auxiliary feedpump is started automatically by any of the following conditions: low-low level in two of the four steam generators or undervoltage on the reactor coolant pump group buses using 1/2 twice logic. For the pump to start in the automatic mode, the REMOTE-LOCAL MANUAL switch located on the local panel must be in the REMOTE position.

When the turbine-driven pump is started automatically, Steam Generator Blowdown System valves and Sampling System valves are automatically closed. The isolation signal to the Sampling System isolation valves can be bypassed by the use of a keylock switch located on the control room console. This bypass capability allows control room operators to open the Sampling System isolation valves when sampling is required by the EOPs in the event that a faulted steam generator with a low-low level condition is experienced.

The steam supply line up to the stop-start valve is continuously warmed by main steam. Traps and/or strainers/orifices are provided to ensure that condensate is removed from turbine steam piping. The turbine is a single inlet, single stage unit of rugged design such that water impingement will not impair its operation.

Each of the two motor-driven pumps is provided with a minimum flow recirculation system to prevent damage to the pumps from low flow. In order to prevent a runout of the motor-driven pumps the steam generator level control valves (AF21s) are throttled back when pump discharge pressure drops below 1350 psig and are closed at

1150 psig*. This runout protection feature can be overridden in the Control Room. The steam turbine driven pump is protected from operation with insufficient flow by a continuous recirculation flow. The required margin of 100 gpm is built into the pump rated flow.

All auxiliary feed pumps normally take suction from the auxiliary feed storage tank. The tank is adequately protected from the effects of earthquakes, tornado wind loads, and floods. A safety grade, automatic low pressure trip is provided as backup protection for each pump in the event that tornado missile damage to the auxiliary feedwater storage tank results in loss of suction pressure. To protect against spurious activation, this trip will be made operable only during "tornado warnings" issued by the National Weather Service. The tank has sufficient capacity to allow residual heat removal for 8 hours. Backup water sources for the auxiliary feed pumps are the two demineralized water storage tanks (500,000 gallons capacity each), the two fire protection and domestic water storage tanks (350,000 gallons capacity each) and the station Service Water System, which must first have a spool piece installed. The quality of water from these sources is lower and is therefore intended for use only in the event of emergency situations. See Section 10.4.7.2.4 for an evaluation of service water usage in the AFW System.

The Unit 1 & Unit 2 auxiliary feedwater storage tanks are provided with a nitrogen purge/blanket system in order to control the dissolved oxygen concentration in the water. Each nitrogen purge/blanket system is provided with a dedicated nitrogen source.

The AFW tank has low and low-low level alarms which alert the operator to align pump suction to an alternate source. An alarm is also received when AFW Storage Tank level is approaching the minimum required volume by the Technical Specifications. Plant emergency instructions caution the operator to monitor the AFW water supply while in use. The low level alarm sounds at a level of 100,000 gallons and the low-low level alarm sounds at 30,000 gallons. The AFW tank has redundant channels of level indication. In addition, the demineralized water makeup

* Setpoints for the control valves for No. 22 motor driven pump (Valves 21 & 22AF21) are 1200 psig and 1000 psig, respectively.

supply valve to the AFW storage tank can be opened from the Control Room. In order to provide assurance that inadvertent failure (or closure) of the suction valve from the AFW storage tank will not result in a degraded condition of the AFW System, the valve was first radiographed to ensure an open flow path and the yoke bushing and stem were then drilled and pinned in the open position. The handwheel was removed with the valve stem left in place to provide visual indication that the valve is open.

There is adequate redundancy in the AFW System to provide reactor cooldown capability when necessary. Each pump has the capacity to remove heat from the steam generators at a sufficient rate to prevent over-pressurization of the RCS and to maintain steam generator levels to prevent thermal cycling. Once the normal steam generator level is re-established the AFW System can cool down the RCS at a rate of 50°F/hr. Feedwater flow can be stopped when the reactor coolant has been cooled to approximately 350°F and 400 psig at which time the RHR System is used to continue the cooldown process.

The pumps, drives, valves, tanks, piping and appurtenances within the AFW System have been designed as Seismic Category I components.

The AFW System piping and components are designed to the following codes and standards:

Aux. Feed System Piping	ANSI B31.1*
Aux. Feed Storage Tank	ASME Section III, sub-section N.D.
Aux. Feed Pump (except No 22 Aux Feed Pump)	ASME Section III
No. 22 Aux. Feed Pump	Hydraulic Institute
Aux. Feed System Valves	ASME Section III

*The Aux. Feed System piping is designed to ANSI B31.1; material fabrication, inspections, and quality control conform to ANSI B31.7, 1969 Edition. Where not possible to comply to ANSI B31.7, the requirements of ASME III-1973 which incorporated ANSI B31.7, were adhered to. Additionally, to upgrade material to original plant requirements, additional NDE requirements will be imposed to meet PSE&G piping specification S-C-MPOO-MGS-0001, addendum XVI.

At the AFW System seismic boundary, valves AF-71 and AF-72 are not anchored with three orthogonal restraints. These valves are, however, anchored to the Seismic Category I Auxiliary Building wall. A stress review has shown that the anchors meet the intent of the system boundary definition given in NRC Generic Letter 81-14. In addition, the valves are protected from debris by a steel protective structure mounted to the Seismic Category I wall. This protective structure also provides seismic guides for additional protection of the seismic boundary valves.

2. Radioactive chemical laboratory drains

3. Hot shower drains

4. Decontamination area drains

5. CVCS demineralizer regenerant solutions and spent resins

6. Sampling System

In addition, piping has been installed to direct potential fluid leakage from valves in the following systems to the LWS: Residual Heat Removal (RHR), Safety Injection (SIS), Containment Spray, CVCS, Sampling Systems. This design minimizes the spread of highly radioactive liquid throughout the plant in the event of postuated accidents.

The LWS also collects and transfers liquids from the following sources directly to the CVCS, to the waste holdup tanks, or back to the refueling water storage tank (depending on fluid content) for processing:

1. Reactor coolant loops

2. Pressurizer relief tank

3. Reactor coolant pump secondary seals

4. Excess letdown (during startup)

5. Accumulators

6. Valve and reactor vessel flange leakoffs

7. Refueling canal drains

These liquids flow to the reactor coolant drain tank and are discharged either directly to the CVCS holdup tanks or to the waste holdup tanks by the reactor coolant drain pumps which are operated automatically by a level controller in the tank. These pumps also return water from the refueling canal and cavity to the refueling water storage tank. There is one reactor coolant drain tank with two reactor coolant drain tank pumps located inside containment.

Where possible, waste liquids drain to the waste holdup tanks by gravity flow. Other waste liquids drain to the Auxiliary Building sump tank and are discharged to the waste holdup tanks by pumps operated automatically by a level controller for the Auxiliary Building sump tank.

With the exception of the shared pumps and tanks of the Laundry and Hot Shower Drains, the Chemical Drains, Portable Filter and the Portable Demineralizer, each unit has its own Liquid Waste Disposal System. The Laundry and Hot Shower Drain Tanks and the Chemical Drain Tank are pumped to one of the Waste Hold-up Tanks or the Waste Monitor Hold-up Tank of either unit.

When a Waste Hold-up or Waste Monitor Hold-up Tank is filled, it is isolated and sampled while another tank is in service. If analysis confirms that the activity level of the tank's contents is suitable for discharge, the tank's contents may be pumped through a flow meter and a radiation monitor to the Service Water System. Tanks requiring processing before release are routed on a batch basis through a portable filter and portable demineralizer. The effluent of the portable system is returned either to the Waste Monitor Hold-up Tanks or the CVCS Monitor Tanks to be sampled, analyzed, and either reprocessed or pumped through a flow meter and a radiation monitor to the Service Water System.

Although the Waste Monitor Hold-up or CVCS Monitor Tank analysis forms the basis for recording activity releases, the radiation monitor provides surveillance over the operation by closing the discharge valve if the liquid activity exceeds a preset value.

The waste evaporator is capable of producing distillate at a rate of 16.5 gpm. A reagent tank is provided on the evaporator inlet for the introduction of chemical additives to suppress foaming and regulate pH. Distillate produced by the evaporator is continuously pumped to the waste monitor hold-up tanks or the CVCS monitor tanks.

The evaporator DF (defined as waste inlet concentration/distillate concentration) is 1×10^4.

Piping and Valves

Piping and valves which are in contact with liquid wastes are constructed of stainless steel. Piping connections are welded except where flanged connections are necessary to facilitate equipment maintenance. Isolation valves are provided to isolate each piece of equipment for maintenance, to direct the flow of waste through the system, and to isolate storage tanks for radioactive decay. Relief valves are provided for tanks containing radioactive wastes if the tanks might be over pressurized by improper operation or component malfunction.

Spent Resin Storage Tank

The spent resin storage tank retains the spent resin normally discharged from the mixed bed, evaporator feed ion exchange, spent fuel pit, and cation demineralizers. A layer of water is maintained over the resin storage to prevent resin degradation due to heat generation from decaying fission products. The contents can be removed any time by flushing with nitrogen. Resin sample connections are supplied upstream and downstream of the spent resin storage tank isolation valve. The tank is all welded austenitic stainless steel.

Waste Monitor and Waste Monitor Holdup Tanks

The Waste Monitor Tanks have been disabled and left in place. These tanks are of welded stainless steel construction.

The Waste Monitor Hold-up Tank is also a welded stainless steel tank and it serves a dual purpose. Its normal function is as a third waste holdup tank to receive abnormally large quantities of waste discharged to the system, but it can also serve as a waste monitor tank.

Portable Demineralizer

Permanent provisions have been made to the waste liquid piping, compressed air piping, and the demineralized water-restricted area piping to allow for the installation and operation of a portable system to assist processing liquid radwaste from either unit. The Unit 2 liquid waste may be processed at a higher rate due to a difference in piping configuration. The system is installed and operated in the 103' elevation of the truck bay of the Auxiliary Building. The effluent of the portable system is returned to either the Waste Monitor Holdup Tanks or the CVCS Monitor Tanks to be sampled, analyzed, and either reprocessed or disposed of. Exhausted ion exchange media is transferred to a burial site approved container after which it can be processed, classified, and shipped for disposal.

Portable Filter

Permanent provisions have been made in the demineralized water and 460 vac supply to allow for the installation and operation of a portable filtration system to assist processing liquid radwaste from either unit. The system is installed and operated in the 100' elevation of the truck bay of the Auxiliary Building. The permeate from the portable system is sent to the portable demineralizers, in place of the unprocessed liquid radwaste. If the filtration system is bypassed liquid radwaste is processed only by the portable demineralizer as described above.

11.2.4 Operating Procedures

Verification is made to ensure that dilution flow sufficient to meet the requirements of 10CFR20 is available whenever radioactive liquid wastes are released to the Plant Discharge System.

Liquid waste releases are continuously monitored for gross activity during discharges to ensure that the activity limits specified in 10CFR20 for unrestricted areas are not exceeded. The

TABLE 11.2-1

LIQUID WASTE SYSTEM PERFORMANCE DATA

Evaporator Design Life	39 years
Normal process capacity, liquids	16.5 gpm (Unit 1 only)
Evaporator load factor	
Average	Inactive
During peak week	Inactive
Annual liquid discharge(1)	
Reactor grade water	766,950 gal
Nonreactor grade water	1,572,500 gal
Total	2,339,450 gal
Activity other than tritium	0.145 curies
Tritium	690 curies
Portable Demineralizer normal Process capacity	28 gpm (Unit 1) 38 gpm Unit 2)
Portable Demineralizer Load Factor	(at 28 gpm)
Average	6 percent
During peak week	42 percent
Portable filter normal process capacity	25-40 gpm
Portable filter load factor	(at 28 gpm)
Average	6 percent
During Peak Week	42 percent

NOTES:

(1) Estimate based on Table 11.2-2.

TABLE 11.2-3

WASTE DISPOSAL COMPONENTS CODE REQUIREMENTS

Component	Code
Chemical Drain Tank	ASME VIII (4) (not code stamped)
Reactor Coolant Drain Tank	ASME III, (1) Class C
Sump Tank	ASME III, (1) Class C
Waste Holdup Tank	ASME III, (1) Class C
Waste Monitor - Holdup Tank	ASME III, (1) Class C (9)
Waste Monitor Tank	ASME III, (1) Class C (10)
Laundry and Hot Shower Tank	ASME VIII (4) (not code stamped)
Waste Evaporator Forced Circulation Concentrator	ASME VIII (5)
Waste Filter	ASME III, (1) Class C
Piping and Valves (11)	ANSI B31.7 (2) Section 1 ANSI B31.1 (3)
Spent Resin Storage Tank	ASME III, (1) Class C
Pumps and Compressors (7) (11)	ASME Draft Code for Pumps and Valves for Nuclear Power, November, 1968
Evaporator Bottoms Holdup Tank	ASME VIII (5)
Reactor Coolant Drain Tank Pumps	NNS, Class D+ (6)
Portable Demineralizer	(8)
Portable Filter	(8)

desired tank and closing the outlet valve to the reuse header. Simultaneously, one of the other tanks can be opened to the reuse header if desired, while another is discharged to atmosphere.

Before a tank is discharged to the environment, it is sampled and analyzed to determine and record the activity to be released, and then discharged to the plant vent at a controlled rate, and monitored for gross activity.

During operation, gas samples are drawn automatically from the gas decay tanks and automatically analyzed to determine their hydrogen and oxygen content. There should be no significant oxygen content in any of the tanks, and an alarm will warn the operator if any sample shows 2 percent or higher by volume of oxygen. This allows time to take required action before the combustible limits of hydrogen-oxygen mixtures are reached. Another tank is placed in service while the operator locates and eliminates the source of oxygen.

The system is controlled from a central panel in the Auxiliary Buildings. Malfunction of the system is alarmed in the Auxiliary Building, and annunciated in the Control Room. All system equipment is located in the Auxiliary Building.

The Unit 1 & Unit 2 auxiliary feedwater storage tanks are provided with a nitrogen purge/blanket system in order to control the dissolved oxygen concentration in the water. Each nitrogen purge/blanket system is provided with a dedicated nitrogen source.

The GWS process flow diagram is shown on Figure 11.3-1.

11.3.3 System Design

Gas Decay Tanks

Four welded carbon steel tanks per unit are provided to contain waste gases (hydrogen, nitrogen, and fission gases). Each tank conforms to ASME Boiler and Pressure Vessel Code Section III, Class C. Design data are as follows:

Volume, each (ft^3)	525
Design pressure (psig)	150
Design temperature (°F)	180
Operating pressure (psig)	0 - 92
Operating temperature (°F)	50 - 150
Type	Vertical cylinder

Waste Gas Compressors

There are two waste gas compressors per system to provide continuous removal of gases discharged to the vent header. Only one unit is normally in operation. The second unit is provided for backup during peak load conditions, such as when degassing the reactor coolant or for service when the first unit is down for maintenance. The compressors are water sealed, rotary, positive displacement units in which the water is used to displace and compress the gas being moved. Each compressor has a capacity of 40 cfm at 105 psig. The seal water is cooled, in a heat exchanger, by the component cooling water. Makeup water for the seal is supplied to the compressor suction from the Component Cooling System.

Each compressor contains a mechanical seal to minimize leakage of seal water.

The compressor discharges a mixture of waste gas and water into the separator. In the separator, the water is centrifuged out of the mixture and is accumulated in the bottom of the separator.

3. The Area Radiation Monitoring System monitors radiation levels in various locations of the plant to warn personnel of a deteriorating radiological condition. It is also useful in assessing the spread of radioactivity in a given area.

11.4.2.1 Radiation Monitoring System Description

11.4.2.1.1 Radiation Monitoring System - Unit 1

Except for 1R1B and 1R41A, B, C, D, the Unit 1 RMS consists of analog channels which monitor radiation levels in various plant locations and operating systems. Monitors 1R1B and 1R41A, B, C have microprocessor-based electronics and a digital control and display module in the Control Equipment Room. The output from each detector is transmitted via cables to the RMS cabinets in the Control Room area where the radiation level is indicated on a meter and preselected channels are recorded on a multipoint recorder. For area monitors, the radiation level is also indicated locally at the detector. High radiation level alarms are annunciated on the Control Room overhead annunciator and further identified at the RMS cabinets. For area monitors, a high radiation level is also alarmed at the detector location, except for area monitors located in the Control Room.

Each channel contains a completely integrated modular assembly, which includes the following.

1. Level Amplifier/Discriminator - Discriminates and amplifies the detector output to provide a discriminated and shaped pulse output to the log level amplifier.*

2. Log Level Amplifier - Accepts the shaped pulse of the level amplifier output,* performs a log integration (converts total pulse rate to a logarithmic analog signal), and amplifies the resulting output for suitable indication and recording.

* Note, monitors 1R1B and 1R41A/B/C have microprocessor based electronics that provide a direct digital conversion of detector output to CPM. 1R1B contains two channel inputs and monitors both Control Room area inlet ducts as illustrated on Figure 11.4-9.

3. Power Supplies - Individual power supplies are contained in each drawer for furnishing the positive and negative voltages for the transistor circuits, relays and alarm lights and for providing the high voltage for the detector.

4. Test-Calibration Circuitry - These circuits provide a precalibrated pulsed and/or analog signal to perform a channel test, and a solenoid operated radiation check source to verify the channel's operation. A light on the Control Room overhead annunciator indicates when any channel is in the test-calibrate mode, except 1R1B.

5. Radiation Level Meter - This meter, mounted on the assembly drawer, has a scale calibrated logarithmically from 10^1 to 10^6 counts per minute for process monitor channels and in mR/hr for area and filter monitor channels. For monitors 1R1B and 1R41A/B/C/D, the displays are digital. Preselected signals are also recorded and displayed in the Control Room area.

6. Indicating Lights - These lights indicate high radiation levels and circuit failures. A light on the Control Room overhead annunciator is actuated on a high radiation signal and a yellow light on the RMS recorder panel indicates which channel. The Control Room alarm CRT provides discriminate 1R1B channel alarms. The yellow light is not applicable for 1R1B.

7. Bistable Circuits - Two bistable circuits are provided, one to alarm on high radiation (actuation point may be set at any level over the range of the instruments) and one to alarm on loss of signal (circuit failure).

The Central Processing System provides the operator displays and alarms. It also provides for check source operation and data input for setpoints, conversion factors, etc., from the Control Room CRT. The same functions can be performed at the remote field units. The data input functions may be accomplished using two programmer printer consoles. These terminals are under administrative control to maintain proper configuration control. The safety-related radiation monitors do not accept data inputs from the Central Processing System. The safety-related monitors are controlled from the remote field units. Failure of the Central Processing System will not cause the loss of remote field unit functions. The remote monitors will continue to function normally.

The system was designed to provide for the safe operation of the plant, to assure that personnel exposure does not exceed 10CFR20 limits, and to assure that environmental releases do not exceed Technical Specification limits. The Unit 2 system was designed to meet the same requirements as the Unit 1 system. The two Radiation Monitoring Systems perform essentially the same functions. There are, however, some differences in sensitivities, detector types, and monitoring channels. The major difference between the two is that Unit 1 is primarily an analog system and Unit 2 is primarily a digital system.

11.4.2.2 Process Radiation Monitoring System Channel Description

The process monitors are utilized for monitoring process systems for potential radiation leakage and effluent discharge paths for normal releases and those following potential accidents. The monitors typically incorporate an offline liquid or gas sampling system. Some of the units monitor the process stream directly. Typical functional block diagrams of the process monitors are shown on Figures 11.4-2 through 11.4-7.

The Process Radiation Monitoring System is summarized in Tables 11.4-1 and 11.4-2 and consists of the following radiation monitoring channels. The prefix numbers indicate monitors associated with Unit 1 or Unit 2.

Control Room Area Intake Duct Monitors (1-R1B and 2-R1B)

The Control Room Intake Air Radiation Monitoring System is a shared system. The R1B monitors provide redundant functions to monitor air drawn into the Control Room through the Unit 1 and Unit 2 air intakes to the Control Room. The dual channel processors with beta scintillation detectors in each of the Unit 1 and Unit 2 Control Room intake ducts provide the redundant initiation signals to place the ventilation system into its accident-pressurized mode of operation. In addition, the monitoring system provides continuous indication and recording of the radiation levels and annunciates in the Control Room the failures of the radiation monitoring equipment and the development of warning and alarm level radiation conditions. This is a safety-related channel.

Containment - Air Particulate Monitors (1-R11A, 2-R11A, 2-R41A)

These monitors are provided to measure air particulate gamma radioactivity in the containment and to ensure that the release rate through the plant vent during purging is maintained below specified limits. High radiation level for the channel initiates closure of the containment purge supply and exhaust duct valves and pressure relief line valves (mode 6 only for Channel R11A). For Unit 1, channel R-11A takes a continuous air sample from the containment atmosphere. For Unit 2, channel 2-R11A takes a sample from the containment. The sample is drawn from the containment through a closed, sealed system and monitored by a scintillation counter-moving filter paper detector assembly. The filter paper collects 99 percent of all particulate matter greater than 1 micron in size on its constantly moving surface and is viewed by a photomultiplier-scintillation crystal combination.

The sample is returned to the containment or vent, depending on which source is being monitored. The detector assembly is in a completely enclosed housing. The detector is a hermetically sealed photomultiplier tube - scintillation crystal (NaI) combination. The filter paper has a 25-day minimum supply at normal speed. Lead shielding is provided to reduce the background level to where it does not interfere with the detector's sensitivity. The filter paper mechanism, an electro-mechanical assembly which controls the filter paper movement, is provided as an integral part of the detector unit.

Containment/Plant Vent Radioactive Gas Monitors (1-R12A, 2-R12A, 1-R41C and 2-R41D)

These monitors are provided to measure gaseous radioactivity in the containment, and to ensure that the release rate through the plant vent during purging is maintained below specified limits. High radiation level initiates closure of the containment purge supply and exhaust duct valves and pressure relief line valves. For Unit 2, high radiation level also closes the waste gas discharge valve.

For Unit 1, channel 1-R12A takes a continuous air sample from the containment atmosphere. Channel 1-41D samples only the plant vent. For Unit 2, channel 2-R12A takes a sample from the containment and channel 2-R41D from the plant vent. All samples reach the gaseous detector after passing through the air particulate monitor or an air particulate sampler (1-R41D only). The sample is constantly mixed in the fixed, shielded volume, where it is viewed by beta scintillator (except 1-R12A which is a GM tube). The sample is then returned to the source being monitored.

The detector assembly is in a completely enclosed housing containing a beta-gamma sensitive detector mounted in a constant gas volume container. Lead shielding is provided to reduce the background level to a point where it does not interfere with the detector's sensitivity.

Containment - Fixed Filter Iodine Monitor (1-R12B, 2-R12B)

Iodine is one of the more prominent isotopes requiring special surveillance. The containment monitoring system has been designed so that the sample flows first through the filter paper assembly and then through a charcoal cartridge. It is a scintillation type detector. For Unit 1, the sample is drawn from the containment for channel 1-R12B. Channel 1-R41C smaples only the plant vent. For Unit 2, channel 2-R12B takes a sample from the containment.

High radiation level initiates closure of the containment purge supply and exhaust duct valves and pressure line relief valves. The abnormal conditions are alarmed in the Control Room and Control Equipment Room. A solenoid-operated check source is provided to give an instant checkout of the system functional status.

Note

The containment radiation monitors (channels R11, R12A, and R12B) have elements common to all three channels of the particulate/noble gas/iodine monitoring assembly. These are described as follows:

1. The flow control assembly includes a pump unit and selector valves that provide a representative sample (or a "clean" sample) to the detectors.

2. The pump unit consists of:

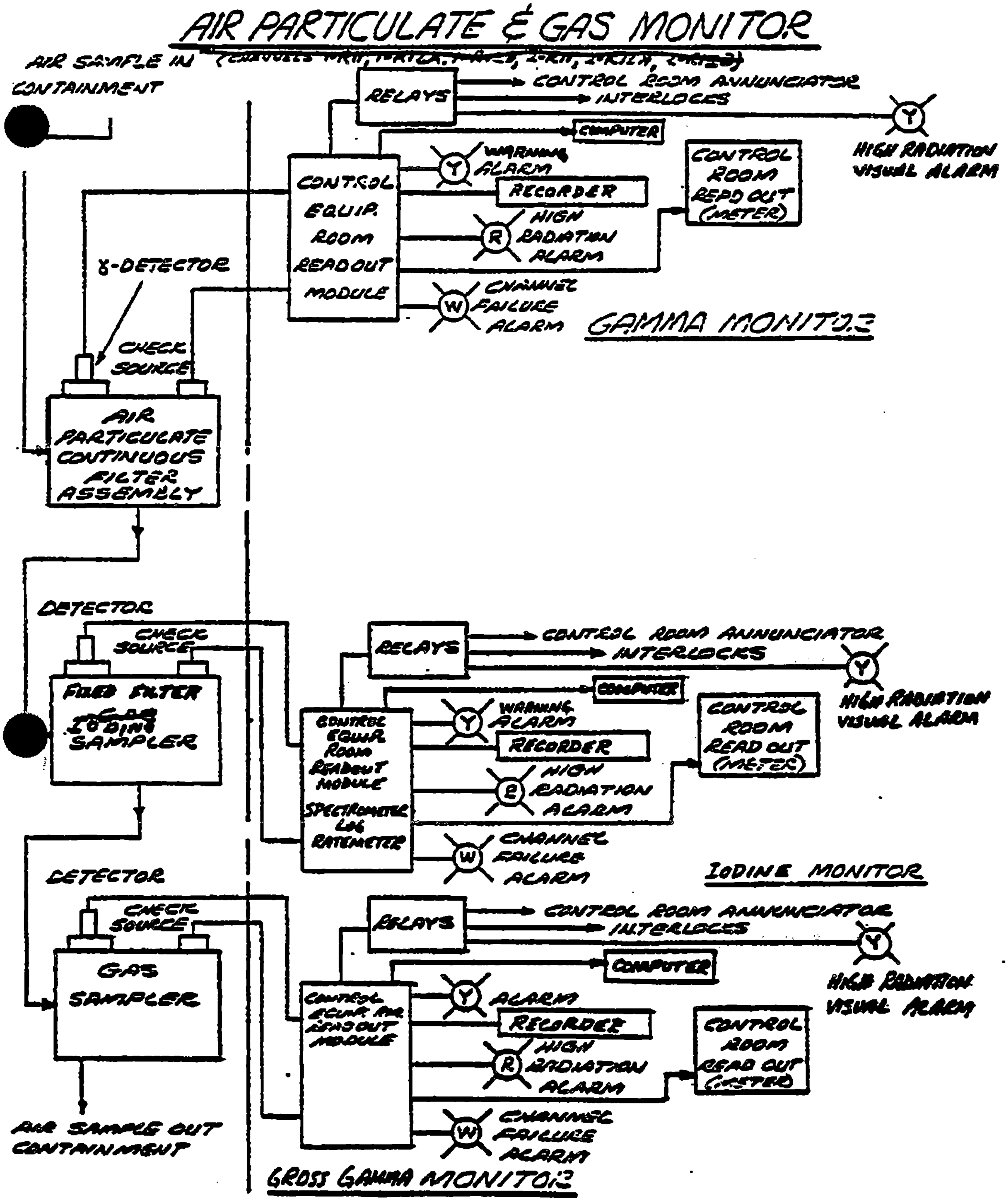
   a. A pump to obtain the air sample

   b. A flowmeter to indicate the flow rate

   c. A flow control valve to provide flow adjustment

TABLE 11.4-1 (Cont.)

Channel No.	Type of Detector	Channel Description	Minimum Detectable Level	Control Function/Interlocks
1-R36	Gamma Scintillator	Evaporator and Feed Heater Condensate	10^{-5} µCi/cc ^{137}Cs	Condensate Line Valve
1-R41A	Beta Scintillator	Plant Vent Noble Gas (Low)	10^{-7} µCi/cc ^{133}Xe	
1-R41B	Beta-Gamma Scintillator	Plant Vent Noble Gas (Inter.)	10^{-4} µCi/cc ^{133}Xe	
1-R41C	Beta-Gamma Scintillator	Plant Vent Noble Gas (High)	10^{-1} µCi/cc ^{133}Xe	
1-R41D	N/A	Plant Vent Noble Gas (composite)	N/A	Containment Ventilation Isolation Closes Waste Gas Discharge Valve
1-R45A	GM Tube	Plant Vent Shield Background	0.1 mr/hr to 10,000 mr/hr	Section 11.4.2.2, Item 15
1-R45B	GM Tube	Plant Vent Noble Gas (Inter)	0.1 mr/hr to 10,000 mr/hr	Section 11.4.2.2, Item 15



REVISION 17
OCTOBER 16 1998

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	UNIT NO. 1 AIR PARTICULATE IODINE AND GAS MONITOR (TYPICAL)
	Updated FSAR — FIG. 11.4-2

SECTION 13

CONDUCT OF OPERATIONS

TABLE OF CONTENTS

TABLE OF CONTENTS (Cont)

SECTION 13

CONDUCT OF OPERATIONS

13.1 ORGANIZATION STRUCTURE

Public Service Electric and Gas Company (PSE&G), a subsidiary of Public Service Enterprise Group, is an investor-owned public utility which provides reliable generation, transmission, and sale of gas and electric energy in the State of New Jersey. In meeting these responsibilities to its customers, PSE&G has developed experience and expertise in the design, construction, startup, and operation of both fossil and nuclear generation facilities. In continuing these commitments, PSE&G is dedicated to the safe, reliable, and efficient operation of Salem Generating Station (SGS). The organization chart shown on Figure 13.1-1 depicts the corporate structure of PSE&G.

13.1.1 Management and Technical Support Organization

Management of PSE&G's nuclear program is provided by the Chief Nuclear Officer and President - Nuclear Business Unit (CNO/PNBU). The CNO/PNBU is responsible for overseeing the direction and development of PSE&G's nuclear program and is the senior nuclear manager onsite. The CNO/PNBU is responsible for the implementation of PSE&G's nuclear program. As shown on Figure 13.1-1, the CNO/PNBU reports directly to the Company Chairman. The Executive Vice President - Nuclear Business Unit (EVP-NBU), the Senior Vice President - Nuclear Operations (SVP-NO), the Senior Vice President - Nuclear Engineering (SVP-NE), the Director Nuclear Business Support (DIR-NBS), the Director Nuclear Quality Nuclear Training and Emergency Preparedness (Director - Quality NT and EP) and the Nuclear Human Resources Manager report to the CNO & President - NBU.

Technical support for the nuclear stations is provided by the Nuclear Business Unit under the direction of the CNO/PNBU. The Nuclear Business Unit organization is discussed in Section 13.1.1.2. Table 13.1-1 provides a comparison between Nuclear Business Unit organization titles in the UFSAR and the corresponding position titles included in Section 6.0 of the Salem Technical Specifications.

13.1.1.1 Design and Operating Responsibilities

For the Salem projects, PSE&G and Westinghouse Electric Corporation jointly participated in the design and construction of each unit. The SGS is operated by PSE&G.

PSE&G provided an experienced and trained staff for the SGS to support hot functional testing, core load, and power ascension testing programs. The CNO/PNBU continues to provide an experienced and trained staff to support the continued safe, reliable, and efficient commercial operation of the SGS.

13.1.1.2 Organizational Arrangement

PSE&G dedicated the Nuclear Business Unit (NBU) to operate and support the operation of the company's nuclear generating stations. The functional responsibilities of the various positions within the Nuclear Business Unit organization are described in the following sections.

13.1.1.2.1 Chief Nuclear Officer and President - Nuclear Business Unit (CNO/PNBU)

The CNO/PNBU is responsible for the leadership, direction, management, and control of the Nuclear Business Unit . The organization chart for the office of the CNO/PNBU is shown on Figure 13.1-2. The CNO/PNBU has direct reports to assist in fulfilling the responsibilities of the position. The responsibilities of each direct report and their respective organizations are discussed in the following sections.

13.1.1.2.2 Executive Vice President - Nuclear Business Unit (EVP-NBU)

The EVP-NBU has the primary responsibility for the leadership, direction, management and control of the Nuclear Business Unit in the absence of the CNO/PNBU.

The NHRMGR advises management on the interpretation and administration of labor agreements and assures consistent department-wide adherence to company/union agreements and good labor relations practices. The NHRMGR also provides assistance and support for succession planning, personnel development, staffing, performance management, compensation, and other administrative functions.

13.1.1.2.1.7 (This Section has been deleted)

13.1.1.2.1.8 (This Section has been deleted)

13.1.2 Operating Organization

The General Manager - Salem Operations (GM-SO) is responsible for all plant organizational activities. As the senior manager located at the station, the GM-SO provides management direction and control of plant operations. In the event of an unexpected contingency, the succession of authority and responsibility for the overall operation is in the following order:

1. Operations Manager

2. Operations Superintendent - Assistant Operations Manager

3. Operations Superintendent - Staff

4. Manager - Plant Maintenance - Salem

The functional organization of the Salem Generating Station is shown on Figures 13.1-8a through 13.1-8e.

13.1.2.1 Station Management

The GM-SO reports directly to the Senior Vice President - Nuclear Operations and is responsible for the overall management, direction, and control of station activities. In fulfilling these responsibilities this individual ensures the safe and efficient operation of SGS. These functions include, but are not limited to, general administration, liaison activities with regulatory and other agencies, approving and implementing programs and procedures, and acting on matters pertaining to Company policies and practices. The GM-SO may designate an individual or group to manage special projects. The GM-SO is responsible for ensuring compliance with the requirements of the Technical Specifications, facility operating license, and all other applicable government regulations. The GM-SO also ensures the station's commitment to the NBU QA Program by maintaining a close liaison with the Manager - Quality Assessment.

13.1.2.2 Operations Department

The Operations Department is responsible for safe and efficient plant operation. The Operations Manager reports to the General Manager - Salem Operations and is responsible for managing, directing, and controlling department activities. The Operations Manager ensures that plant operation complies with the facility operating license, Technical Specifications, and all government regulations and company policies. Reporting to the Operations Manager are the Operations Superintendent - Assistant Operations Manager, Operations Superintendent - Work Management and Operations Superintendent - Staff. The Operations Manager ensures that a properly trained licensed and nonlicensed staff is available to provide safe and efficient operation, which in turn ensures plant availability and reliability.

Administratively, the Operations Manager is responsible for the approval of all operating procedures and the review of conditions adverse to quality as reported in the Corrective Action Program, reportable occurrences, and other correspondence.

The Operations Manager is assisted by the following:

1. The Operations Superintendent - Assistant Operations Manager who directs activities of the operating shift crews. One of the Operations Superintendents will be designated as the Operations Superintendent - Assistant Operations Manager.;
2. The Operations Superintendent - Work Management who directs the operation of the Work Control Center and other Operations segments interfacing with the Nuclear Maintenance Department;
3. The Operations Superintendent - Staff who provides technical and administrative support for the Operations Department. The Operations Superintendent - Staff reports to the Operations Manager.

The Operations Superintendent - Assistant Operations Manager, Operations Superintendent - Work Management or the Operations Superintendent - Staff may assume control of the department in the absence of the Operations Manager, provided they meet the qualifications.

Supervision of shift personnel is under the direction of an Operations Superintendent (OS). The OS is directly responsible for the operation of the unit. The OS has the authority to take any action necessary, including plant shutdown, to protect equipment or personnel and to act in accordance with approved procedures. During off-normal hours, the OS assumes responsibility for all plant functions in the absence of senior plant management. The OS inspects equipment to ensure that operations are conducted safely and efficiently in compliance with Technical Specifications and the operating license. The OS also ensures the review and approval of completed checkoff lists, logs, and other shift data to detect abnormal trends or potential operating problems. A Licensed Senior Reactor Operator (SRO) on shift approves removal of equipment from service and performance of safety tagging in support of the plant surveillance and maintenance program.

The OS is assisted by the Control Room Supervisor (CRS), the Work Control Center Supervisor (WCCS), and the Field Supervisor (FS). The CRS is responsible for the operation of the individual unit assigned and assumes the Command and Control function in the absence of the OS. The CRS provides direct supervision of the Control Room area and operators assigned to the specific unit. The CRS also provides primary procedural direction during normal, abnormal and emergency operating conditions. When assigned, the FS provides direct supervision to the operators assigned duty positions in the plant and other on shift operations personnel with duties outside the control room area. When assigned, the WCCS provides direct supervision of Operations personnel performing daily, on shift work control functions.

The position of Shift Technical Advisor (STA) has been established and personnel are assigned to the operating shifts. Shift manning requirements for the STA are in accordance with the administrative section of the Technical Specifications. The assigned individuals meet the experience, education and training requirements as specified in NUREG 0737 "Clarification of TMI Action Plan Requirements," "Commission Policy Statement on Engineering Expertise on Shift" (50 FR 43621, October 28, 1985, Generic Letter 86-04), and the administrative section of the Technical Specifications.

operations. Responsibilities of the Operators assigned to radwaste include the following:

1. Completing checkoff lists, logs, and other shift data associated with radwaste operations to provide continuous surveillance of the equipment assigned

2. Manipulating controls, valves, and equipment to support liquid radwaste processing and storing

3. Initiating immediate actions necessary to maintain radwaste equipment in a safe condition during normal, abnormal, and emergency operations

Shift electrician, instrumentation and control (I&C) technicians, chemistry technicians and radiation protection technicians are assigned to shift schedule and report to the Operations Superintendent. These personnel perform support functions associated with electrical, I&C, chemistry and radiation monitoring disciplines. During normal operation, they are available to perform surveillance, preventive and corrective maintenance. When periods of emergency or abnormal operating conditions exist, they are available as part of the plant emergency preparedness program for emergency response and technical assistance.

13.1.2.3 Maintenance Department

The Nuclear Maintenance Organization is described in Section 13.1.1.2.1.1. Although the Maintenance Organization will not report directly to the Plant Manager, the Plant Manager will maintain control over those activities necessary for safe operation and maintenance of the plant.

13.1.2.4 Chemistry Department

The Chemistry Superintendent re[ports to the General Manager - Salem Operations and is responsible for implementing programs to ensure plant chemistry, radiochemistry, and plant effluents monitoring are in accordance with the facility license and government regulations.

The Chemistry Department is responsible for the development and implementation of the chemistry, radiochemistry, environmental and liquid effluent monitoring programs. They are also responsible for operation of the condensate demineralizers, demineralized water makeup plant, service water chlorination, non-radioactive liquid waste disposal system, oil-wter separator and post accident sampling system.

The Chemistry Department is also responsible for the sampling and analysis of lant fluid systems, chemistry results reporting, calibration of chemistry instrumentation, evaluation of laboratory and chemisal systems operation and techniques, operation of deep bed demineralizers, plant water and chemical control systems, and maintaining the plant fluid systems and liquid effluents within established limits. The Chemistry Department organization is shown on Figure 13.1-8e.

13.1.2.5 Radiation Protection Department

The Radiation Protection Superintendent reports to the General Manager - Salem Operations and is responsible for ensuring that the conduct of the radiological safety and radiological material control program is in accordance with the facility license, government regulations, and the NBU radiation protection plan. These programs require that personnel exposure to radiation and releases of radioactive material to the environment meet ALARA requirements. The radiation protection program, organization, and various responsibilities of the Radiation Protection Department are described in Section 12. The Radiation Protection Department organization is shown on Figure 13.1-8e.

13.1.2.6 Salem Projects

The Supervisor - Salem Projects reports to the General Manager - Salem Operations and is responsible for the management of the station administrative support staff and special projects as assigned by the General Manager.

13.1.2.7 Nuclear Security

The Nuclear Security Manager reports to the General Manager - Salem Operations. Nuclear Security responsibilities and organization are addressed in the Salem - Hope Creek Security Plan.

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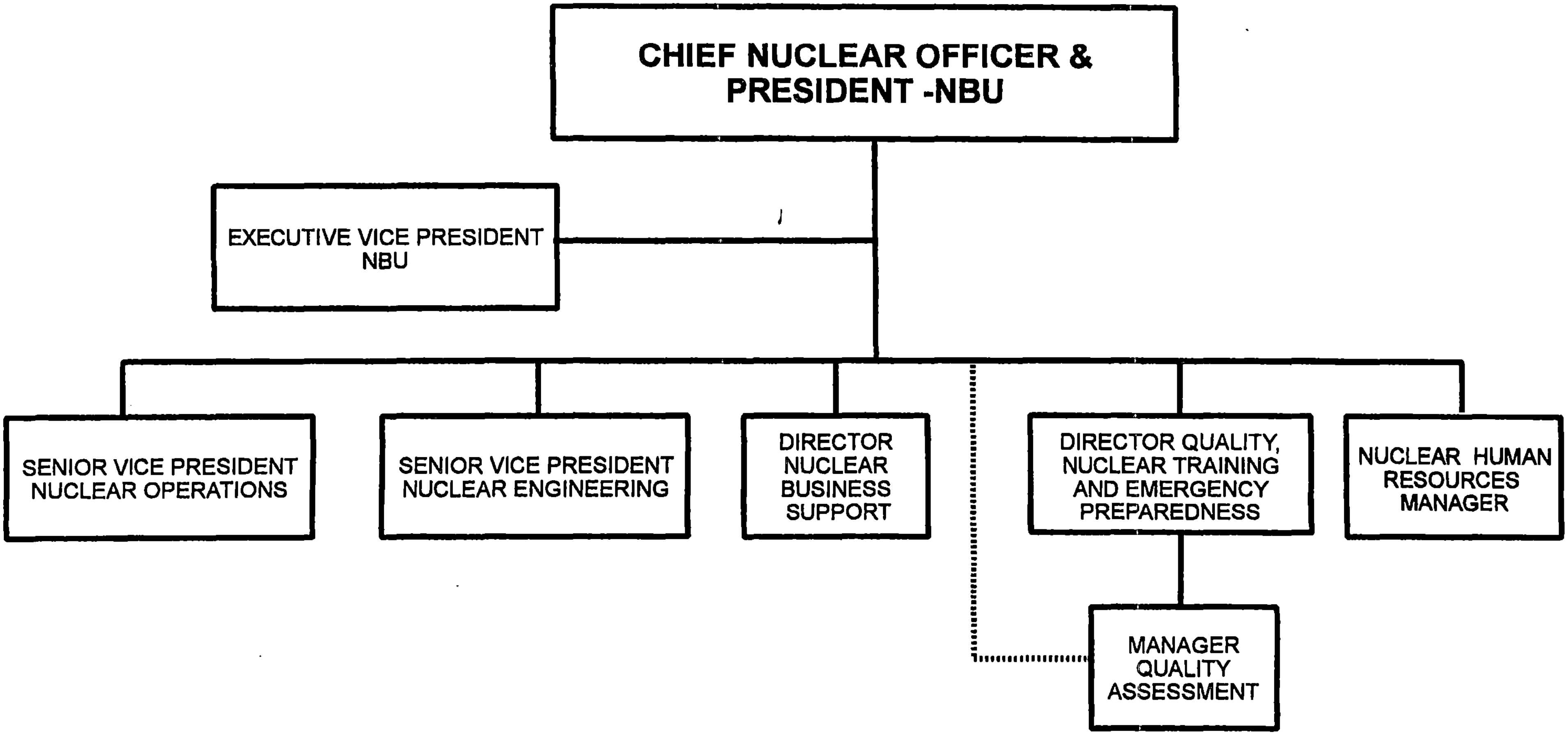
Table 13.1-1

Comparison of UFSAR Position Titles and Salem Technical Specifications
Section 6.0 Organization Titles - Listed by Exception

UFSAR Title	Technical Specification Title
Chief Nuclear Officer and President - Nuclear Business Unit	Senior Corporate Nuclear Officer
General Manager - Salem Operations	Plant Manager
Operations Superintendent	Senior Nuclear Shift Supervisor
Control Room Supervisor	Nuclear Shift Supervisor
Reactor Operator and Plant Operator	Nuclear Control Operator
Nuclear Equipment Operator or Utility Operator	Equipment Operator or Utility Operator
Radiation Protection Superintendent	Radiation Protection Manager
Radiation Protection Supervisor	Senior Supervisor - Radiation Protection
Director - Quality, Nuclear Training and Emergency Preparedness	Director - Nuclear Training and Radiological Safety
Director - Quality, Nuclear Training and Emergency Preparedness	Senior Management Position with responsibility for Independent Nuclear Safety Assessment and Quality Program oversight
Chemistry Superintendent	Chemistry Manager

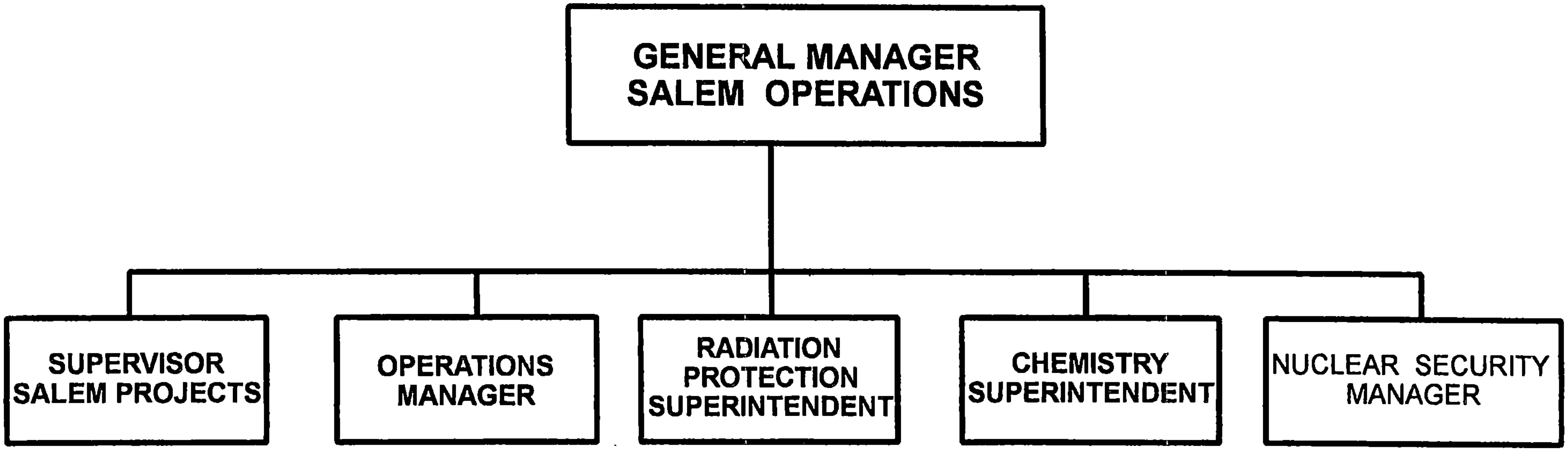


PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

NUCLEAR BUSINESS UNIT

Updated FSAR
Revision 17, October 16, 1998

Figure 13.1-2
Sheet 1 of 1

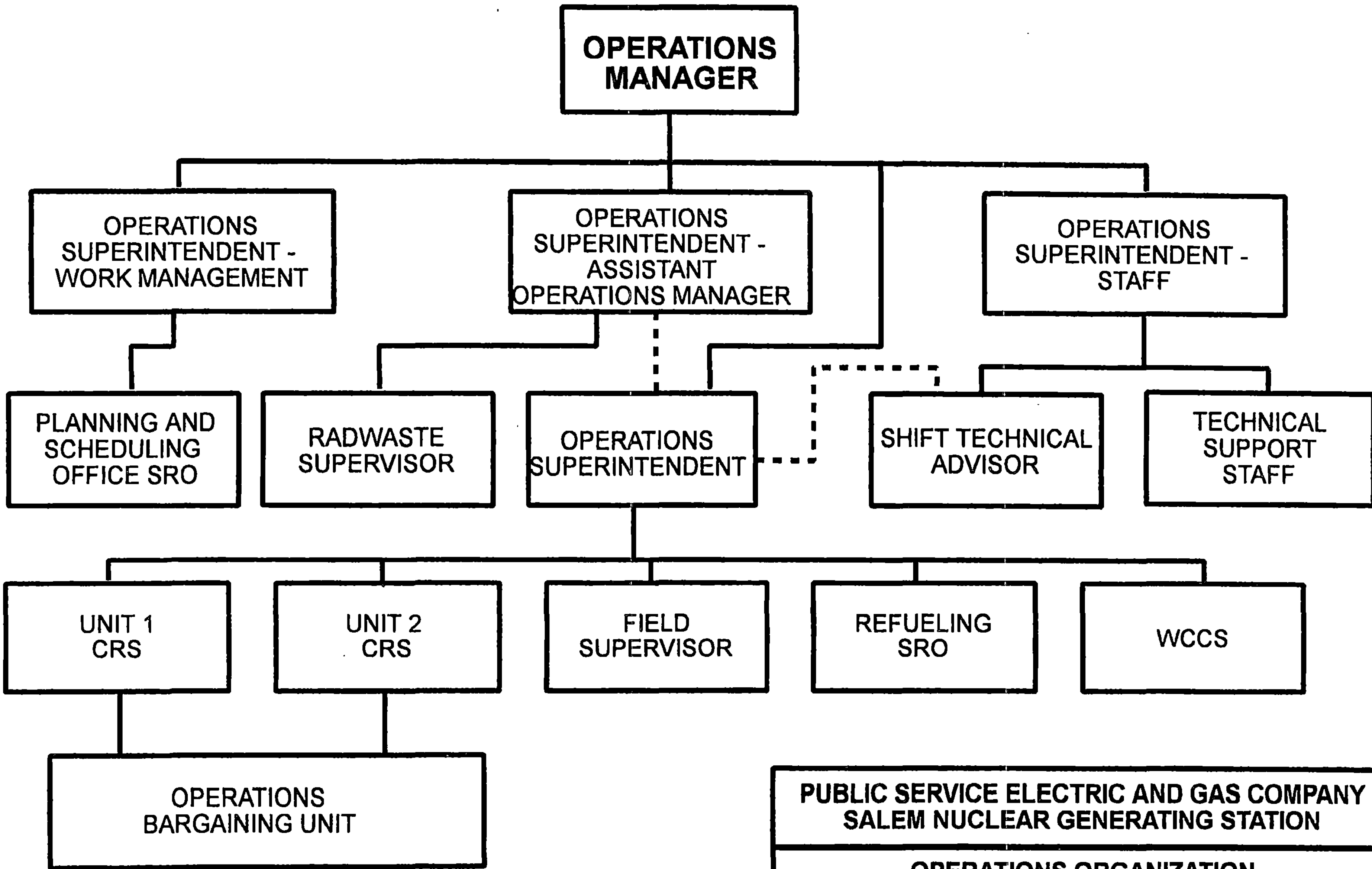


PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

SALEM ORGANIZATION
SALEM OPERATIONS
UNITS 1 & 2

Updated FSAR **Figure 13.1-8a**

Revision 17, October 16, 1998

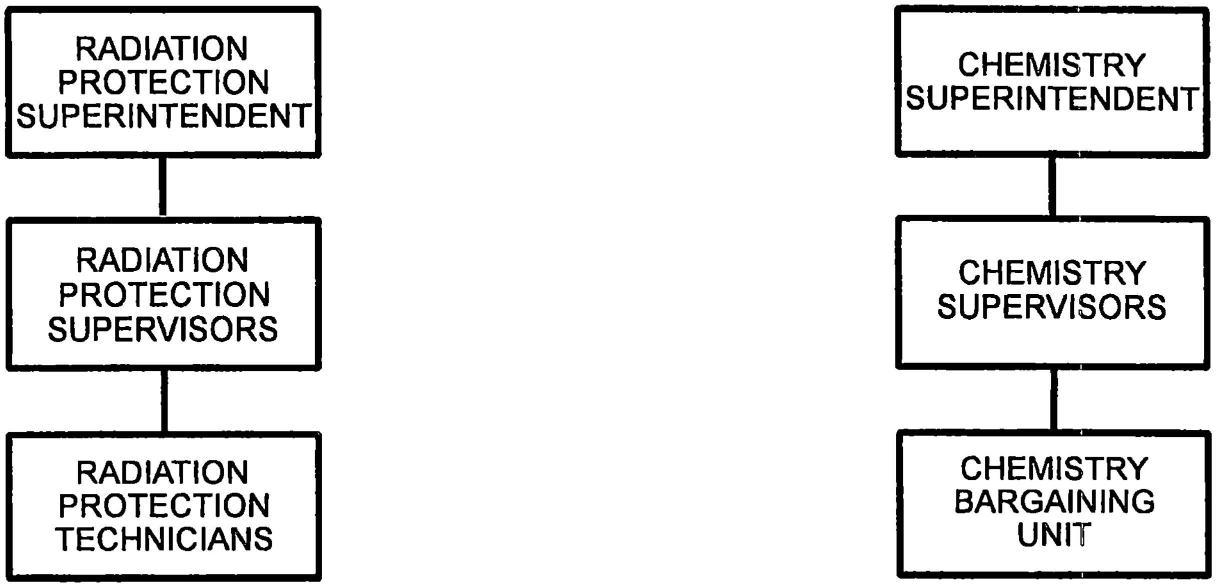


PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

OPERATIONS ORGANIZATION
STATION ORGANIZATION
OPERATIONS DEPARTMENT - UNITS 1 & 2

Updated FSAR **Figure 13.1-8b**

Revision 17, October 16, 1998



PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

SALEM ORGANIZATION
RADIATION PROTECTION DEPARTMENT
UNITS 1 & 2

Updated FSAR **Figure 13.1-8e**
Revision 17, October 16, 1998

13.5 Plant Procedures

13.5.1 Administrative Procedures

Administrative procedures define processes and programs that provide for the control of nuclear operations, and in turn incorporate regulatory requirements and commitments. There are three types of administrative procedures: 1) Nuclear Administrative Procedures (NAPs); 2) Station Administrative Procedures (SAPs); and 3) Department Administrative Procedures (DAPs).

Nuclear Administrative Procedures (NAPs) are written to provide direction in the areas that are common to all station departments as well as other organizations within the NBU. NAPs are prepared using a standard format and content, and a writers guide, which provides human factors and style guidance. NAPs are approved by the General Manager - Salem Operations.

Station Administrative Procedures (SAPs) are written to govern station specific programs and processes. SAPs are approved by the General Manager - Salem Operations and comply with all applicable requirements specified in the NAPs.

Department Administrative Procedures (DAPs) provide direction for the administrative control of specific activities that are within a department's functional area of responsibility or between departments with the same functional responsibility or that control administrative functions between a limited number of departments in the NBU. Department - specific procedures are approved by the individual department managers for Salem and comply with all applicable requirements specified in the NAPs.

Additional topics for administrative procedures may be addressed as required, and material may be shifted between specific procedures as needed.

A list of topics for NBU administrative procedures is listed below:

- Action Request Process
- Nuclear Procedure System
- Nuclear Department Organization
- Document Control Program
- Station Operations Review Committee
- Corrective Action Program

- Control of Design and Configuration Changes, Tests and Experiments
- Work Control Process
- Preventive Maintenance Program
- Records Management Program
- Technical Specification Surveillance Requirements
- Control of Temporary Modifications
- Training, Qualification and Certification
- Safety Tagging
- Monitoring the Effectiveness of Maintenance
- Minor Modification Process
- Material Control Program
- Procurement of Materials and Services
- System Cleanliness
- Measuring & Test Equipment, Lifting & Rigging and Tool Control
- Scaffolding Program
- Radiological Protection Program
- Fire Protection
- Nuclear Mutual Limited/Boiler and Machinery Insurance Program
- Inservice Inspection Program
- Code Job Packages
- Commitment Management Program

- Inspection/Housekeeping Program
- Nuclear Security Program
- Nuclear Licensing and Reporting
- Environmental Control
- Chemical Control Program
- Service Water Reliability Program
- Lubricant Program
- Fitness for Duty Program
- Vendor Information Program
- Stations Aids and Labels
- Respiratory Protection Program
- Station Performance and Reliability
- Refueling Management
- Station Testing Program
- Plant Chemistry Control
- Operating Experience Feedback Program
- Outage Management
- Action Tracking Program
- 10CFR50.59 Reviews and Safety Evaluations
- Repairs to Presure Relief Devices

- Environmental Qualification Program
- Software and Micro-processor Based Systems (Digital Systems)
- Control of On-Site Contractor Personnel
- Inservice Testing Program
- Fuel Integrity Program
- Nuclear Fuel Program
- Special Nuclear Material Control Program
- Valve Programs
- Independent Review Program
- Transient Loads
- Conduct of Infrequently Performed Tests and Evolutions

13.5.2 Station Department Manuals

Various departments within the station have manuals which contain their own pertinent operating guidelines and instructions.

The Operations Department has two manuals: the Station Plant Manual and the Operations Directives Manual. The Station Plant Manual contains the Operations Department procedures. The Operations Directives Manual contains general information, organization and responsibility guidelines, administrative and operations directives.

The Chemistry Department Manual contains Administrative Procedures, guidelines detailing department organization and responsibilities, training, general work practices, laboratory quality control, procedure generation and control instructions as well as Chemistry Department Procedures.

The Radiation Protection Department Manual contains Administrative Procedures, guidelines detailing functions and responsibilities, general work practices, training instructions and requirements, as well as department procedures.

Nuclear Maintenance administrative guidelines describe department functions and responsibilities. Nuclear Maintenance procedures contain instructions for the performance of maintenance.

Nuclear Engineering administrative guidelines describe department functions and responsibilities. Nuclear Engineering procedures contain instructions for performing engineering functions. Reactor Engineering procedures contain instructions for testing various reactor parameters.

Written Test Procedures issued for special test are not incorporated into these manuals due to their one-time nature.

Other manuals used in the station include the following: the System Descriptions, which describe the characteristics of the various Primary, Secondary, and Electrical Systems; and the Emergency Plan Implementing Procedures.

13.5.3 Operating Instructions

All operating instructions are included in the Station Plant Manual and provide initial conditions and precautions on the subject system and, where applicable, surveillance requirements.

13.5.4 Emergency Instructions

The Station Plant Manual includes those emergency instructions, with the exception of fire and medical emergency response procedures, (which are located in the Fire and Medical Emergency Response Manual), necessary to ensure that proper action is taken to handle any malfunction that may occur at either of the Salem units.

13.5.5 Preventive Maintenance

A Preventive Maintenance Program has been in effect since the initiation of plant operation and is reviewed and improved continuously. Preventive maintenance activities are based upon Technical Specification Requirements, Nuclear Regulatory Commission and other regulatory requirements, equipment vendor and

TABLE OF CONTENTS (Cont)

TABLE OF CONTENTS (Cont)

LIST OF FIGURES (Cont)

2. Two motor-driven auxiliary feedwater pumps which are started on:

   a. Low-low level in any steam generator

   b. Trip of all main feedwater pumps

   c. Any safety injection signal

   d. Loss of offsite power

   e. Manual actuation

3. One turbine-driven auxiliary feedwater pump which is started on:

   a. Low-low level in any two steam generators, or

   b. Undervoltage on any two reactor coolant pump buses

   c. Manual actuation

The motor-driven auxiliary feedwater pumps are supplied by the diesels if a loss of offsite power occurs and the turbine-driven pump utilizes steam from the secondary system. Both type pumps are designed to start within one minute even if a loss of offsite power occurs simultaneously with loss of normal feedwater. The turbine exhausts the secondary steam to the atmosphere. The auxiliary pumps take suction from the auxiliary feedwater storage tank for delivery to the steam generators.

The analysis shows that following a loss of normal feedwater, the Auxiliary Feedwater System is capable of removing the stored and residual heat thus preventing either over-pressurization of the RCS or loss of water from the reactor core.

15.2.8.2 Method of Analysis

A detailed analysis using the BLKOUT (9) Code is performed in order to obtain the plant transient following a loss of normal feedwater. The simulation describes the plant thermal kinetics, RCS including the natural circulation, pressurizer, steam generators and Feedwater System. The digital program computes pertinent variables including the steam generator level, pressurizer water level, and reactor coolant average temperature.

Major assumptions are:

1. The initial steam generator water level (in all steam generators) at the time of reactor trip is at a conservatively low level, i.e., the lower narrow range level tap.

2. The plant is initially operating at 102 percent of the engineered safeguards design rating.

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

4. A heat transfer coefficient in the steam generator associated with RCS natural circulation.

5. Only one motor-driven auxiliary feedwater pump is available one minute after the accident.

6. Auxiliary feedwater is delivered to two steam generators.

by low pressurizer pressure. The transient is quite conservative with respect to cooldown, since no credit is taken for the energy stored in the system metal other than that of the fuel elements or the energy stored in the other steam generators. Since the transient occurs over a period of about 10 minutes, the neglected stored energy is likely to have a significant effect in slowing the cooldown.

15.2.13.4 Conclusions

The analysis has shown that the criteria stated earlier in this section are satisfied, since a DNBR less than the design DNBR limit does not occur.

15.2.14 Spurious Operation of The Safety Injection System at Power

15.2.14.1 Accident Description

The Spurious Operation of the Safety Injection System (SIS) at Power is caused by either an operator error or a false electrical actuating signal.

When the SIS is actuated, charging pump suction is diverted from the Volume Control Tank to the RWST, and boric acid is pumped from the RWST to the cold leg of each reactor coolant loop. The safety injection pumps are also started automatically; but they cannot develop the head necessary to pump borated water into the reactor coolant loops when the RCS is at normal operating pressure.

The Spurious Operation of the SIS at Power is classified as a Condition II event, a fault of moderate frequency. The acceptance criteria for analysis of this event are:

1. Fuel cladding integrity shall be maintained by ensuring that the minimum DNBR remains above the applicable DNBR limit.

2. Pressure in the reactor coolant and main steam systems should be maintained below 110% of the design values.

3. A Condition II must not escalate into, or cause a more serious fault (e.g., a Condition III or Condition IV event) without other faults occurring independently.

15.2.14.2 Method of Analysis

The first criterion, that fuel cladding integrity be maintained, is shown to be satisfied by means of a safety evaluation (see Case 1 below). The remaining criteria, that the RCS and main steam system pressure limits are not exceeded, and that the event would not lead to a more serious event, are demonstreted by means of an accident analysis (see Case 2 below).

Case 1. Safety Evaluation to show that fuel cladding integrity is maintained.

If no reactor trip signal is assumed to be generated by the SI signal, then borated water from the SIS would cause core reactivity and power level to drop, and consequently, the calculated DNB ratio to rise. The calculated DNBR would increase throughtout the transient, without ever approaching its safety analysis limit value. Therefore, the Spurious Operation of the SIS at Power could not lead to any fuel damage.

Case 2. Accident Analysis to show that RCS and main steam system pressure limits are not exceeded, and that the event would not lead to a more serious event.

During a Spurious Operation of the SIS at Power event, the addition of borated water from the SIS, into the RCS, can fill the pressurizer and eventually lead to the discharge of water through the pressurizer safety valves. Since the pressurizer safety valves have not been qualified for water relief, one or more of the valves might fail to reseat completely, and thereby create an unisolatable leak from the RCS. Such a situation would be an escalation of a Condition II event into a more serious event (a small break LOCA), a violation of the third acceptance criterion.

The Spurious Operation of the SIS at Power is analyzed using the LOFTRAN [4] code. LOFTRAN simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, feedwater system, steam generator, steam generator safety valves, and the effects of the SI system. The code computes pertinent plant variables, including temperatures, pressures and power level.

The following basic assumptions were used to define and evaluate this event:

a. Initial reactor power is at its maximum value (+2%). Uncertainties are deducted from the initial RCS temperature and pressure (-5^{o}F and -50 psi). Assuming lower values of initial T_{avg} and pressure tends to reduce the time predicted to fill the pressurizer.

b. The SI signal causes the reactor to trip. Core residual decay heat generation is based upon long term operation at the initial power level.

c. Two centrifugal charging pumps and one positive displacement charging pump are in operation, with the miniflow valves open. Full SI flow begins immediately.

d. The pressurizer sprays operate at their maximum capacity. The pressurizer sprays limit the RCS pressure, permitting a higher SI delivery rate, which fills the pressurizer sooner.

e. Either the pressurizer PORV block valves are open, or they are opened by the operators before the pressurizer fills with water.

f. One of the pressurizer PORVs opens, and relieves water. The PORVs and downstream piping are qualified for this safety-related application [17,18].

15.2.14.3 Results

Fuel Cladding Integrity (evaluation)

If the SI signal does not trip the reactor and turbine, then nuclear power would decrease as borated water is added to the core. Since steam flow would be maintained, the mismatch between nuclear power and load would cause T_{avg}, pressurizer pressure, and pressurizer water volume to decrease until the low pressurizer pressure reactor trip setpoint is reached. The DNB ratio would increase, due mainly to the decrease in power and T_{avg}, and always remain above its safety limit value. Therefore, this event would not pose a challenge to fuel clad integrity.

Pressure Limits and Escalation into a More Serious Event (accident analysis)

An analysis [19] was performed for Salem Unit 2, using the LOFTRAN code. The resulting transient response plots are depicted in Figures 15.2-44, 15.2-45, and 15.2-46. A safety evaluation [20], performed for Unit 1, indicates that the Unit 2 analysis results would also be representative of the Unit 1 response.

Nuclear power, T_{avg}, pressurizer pressure, and pressurizer water volume decrease, and steam pressure increases, as the result of the reactor and turbine trips demanded by the spurious SI signal. Pressurizer pressure and pressurizer water volume begin to increase as water is added to the RCS by the SIS and the pressurizer sprays operate. Pressurizer pressure stabilizes as the pressurizer spraying limits the pressurizer pressure to within about 25 psi above its initial value. The action of the pressurizer sprays, in limiting the pressure, allows more SI water to be added to the reactor coolant system, which surges into the pressurizer. It is assumed that the operators open the PORV block valves, if they are closed, before the pressurizer fills with water. After ten minutes, the pressurizer becomes water-solid, and the pressure rapidly increases to the PORV opening setpoint (conservatively assumed to be only 100 psi above the initial pressure, or 2300 psia). Only one of the two PORVs is assumed to open and relieve water.

After ten minutes, the transient equilibrates to a relatively stable condition, wherein T_{avg} is fairly constant, the pressurizer is water-solid, and pressure is maintained at or near the PORV setpoint, as water is relieved through repeated cycling of the pressurizer PORV. The event is ultimately ended by the operators, who stop the SIS flow and re-establish normal letdown flow, as per the emergency operating procedures.

The operators will ensure that the PORV block valves are open before the pressurizer is filled, ten minutes after the initiation of the event. This action assures the availability of the PORVs to open automatically when their opening setpressure is reached.

The results of the accident analysis indicate that opening one PORV will limit the pressurizer pressure to a level that will not cause any of the pressurizer safety valves to open. As the pressurizer safety valves will not open, the event cannot escalate to a more serious event (e.g., a small break LOCA, due to the failure of a pressurizer safety valve to reseat completely).

15.2.14.4 Conclusions

The results of the Spurious Operation of the SIS at Power evaluation and analysis demonstrate that:

(1) Pressures in the reactor coolant and main steam systems are limited to less than 110% of the design values. Operating one PORV limits the pressurizer pressure to about the PORV opening setpressure, which is well below the RCS design pressure.

(2) Fuel cladding integrity is maintained. This is based upon an evaluation (Case 1), which predicts that the DNBR would always remain above the DNBR safety analysis limit value.

(3) A more serious fault would not result from the Spurious Operation of the SIS at Power event. The Case 2 analysis results show that an open pressurizer PORV will limit the pressurizer pressure to a level that will not cause any of the pressurizer safety valves to open, and thereby preclude the possibility that one or more of these valves would generate a more serious event by opening and failing to re-seat properly.

15.2.15 Turbine Generator Accidents

The likelihood of a turbine generator failure in which missiles are generated is remote. Westinghouse turbine generator units have never experienced a major structural failure of a rotating part that resulted in missiles leaving the turbine casing. A review of the records of all Westinghouse turbine generator units in operation from 1938 to 1969 is presented in Reference 14.

Catastrophic failure of turbines reported in the Appendix fall into one of two categories:

1. Failure by overstressing arising from accidental and excessive overspeed

2. Fracture because of defects in the material at speeds under the design overspeed

Contributing factors in the Westinghouse record of never having had a turbine generator run away to destructive overspeed are redundancy in the control system and routine testing of the main steam valves and the mechanical emergency overspeed protective system while the unit is carrying load. The overspeed control system for the turbine generator is described in detail in Sections 10.2.2.3 and 10.2.2.4.

The overspeed protective controller calls for fully closed main governing valves and interceptor valves at 103 percent of rated speed. In the event the turbine speed continues to increase past 103 percent of rated speed, the turbine stop and reheat stop valves, and also the main governing valves and interceptor valves will be tripped closed by both the mechanical overspeed weight and a backup electrical trip. When these valves are tripped, the turbine speed will continue to increase due to the finite valve closure time and the steam which is trapped in the turbine and piping downstream of the tripped valves. The turbine speed, however, will not exceed the design overspeed (120 percent of rated speed).

The likelihood of a failure in the second category, resulting from material defects, at speeds below design overspeed, is very small. There have been no failures of this nature in the United States since 1956. This has been attributed to improvements in design, inspection and manufacturing techniques stemming from the work of a special task force of forging suppliers and equipment manufacturers which was set up in 1955 under the auspices of the American Society for Testing and Materials to study turbine and generator rotor failures. This task force developed the high-toughness NiCrMoV material now used in all turbine rotors and discs.

Reference 14 discusses the energy levels of the external missiles which would be generated at design overspeed in the highly unlikely event that a destructive failure would occur at this speed. It should be noted that for Unit 2, shrunk-on discs do not exist, therefore the accident analysis presented in Reference 14 applies to Unit 1 only. Calculations show that all fragments generated by any postulated failure of the high pressure turbine rotor would be contained by the turbine blade rings and casing. Low pressure turbine blades which would be shed would be contained within the shell. Detailed results are shown for failure of the six low pressure turbine discs at design overspeed. Only discs 4 and 6 would generate missiles that could not be contained. The plant is designed to prevent these postulated missiles from endangering the integrity of the Containment Building, the Control Room area, the spent fuel pool and critical portions of the penetration areas. This design is presented in Section 5.6.3.

For Unit 2, the limiting component for the ruggedized rotors are the turbine blades that are attached to the one-piece rotor. The heaviest turbine blade is the last row (47") blade that weights approximately 128 lbs. A conservative comparison of the results in Reference 14 was made using the highest velocity presented (648 ft/sec) in the report. This resulted in approximately 5% of the energy calculated for the existing rotor design. The missiles identified in the report with significantly higher energy levels (12.7×10^6 to 17.8×10^6 ft/lbs) were contained within the shell. Those that exited the shell expended 9.0×10^6 and 7.7×10^6 ft/lbs of energy to penetrate. Therefore, it can be concluded that the Unit 2 limiting component (last row of blades) with approximately 1×10^6 ft/lbs of energy will be contained within the shell.

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15.2.16 References For Section 15.2

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17. Engineering Evaluation No. S-2-RC-MEE-1108, "Salem Unit 2 Evaluation of the Pressurizer PORVs for Inadvertent Safety Injection" (July 25, 1996)

18. Engineering Evaluation No. S-1-RC-MEE-1272, "Salem Unit 1 Evaluation of the Pressurizer PORVs for Inadvertent Safety Injection" (December 10, 1997)

19. Inadvertent ECCS Analysis Results, letter from J. Huckabee (Westinghouse) to E. Rosenfeld (PSE&G), PSE-96-227 (April 3, 1996)

20. FTI Replacement Steam Generator Report, Rev 1. PSBP-322933

Accident	Event	Time (sec)
Accidental Depressurization of the Main Steam System	Inadvertent opening of one main steam safety or relief valve	0
	Pressurizer empties	172
	2300 ppm boron reaches RCS loops	214
Spurious Operation of the SIS at Power	Charging pumps begin injecting borated water	0.
	Reactor/turbine trip on SI signal	0.
	Operators open the PORV block valves, if necessary	≤600.
	Pressurizer becomes water-solid	≥600.
	PORV opens and limits peak pressurizer pressure	≥610.
	Manual procedures to terminate the event are completed	≤2700.

NOTE:
(1) DNBR does not decrease below its initial value.

P_s = Steam partial pressure

P_v = Droplet vapor pressure

Pr = Prandtl number

q = Heat flow rate

Re = Reynolds number

Sc = Schmidt number

T = Droplet temperature

T_s = Steam temperature

t = Time

u = Droplet external energy

V = Velocity

ρ = Droplet density

ρ_m = Steam-air mixture density

15.4.8.1.4 Containment Pressure Response Results

The containment pressure was calculated for a spectrum of break sizes including the largest cold leg and hot leg breaks (reactor inlet and reactor outlet) and a range of pump suction breaks from 3.0 square feet up to the largest. Because of the phenomenom of reflood and post-reflood, the pump suction break location is the worst case. This conclusion is supported by studies of smaller hot leg breaks which have been shown on similar plants to less severe than the double-ended hot leg break. Cold leg breaks, on the other hand, are lower both in the blowdown peak and in the reflood pressure rise. Thus, an analysis of smaller pump suction breaks is representative of the spectrum of break sizes.

For these analyses it was assumed that the single failure occurred on a diesel generator such that one spray pump and two fan coolers failed to operate.

Figures 15.4-86 and 15.4-87 give the containment pressure transients for several break sizes and locations for the design basis case. Additional margin cases assuming entrainment continues up to the 10-foot core level were analyzed with results presented on Figures 15.4-88 and 15.4-89. The peak pressures for these cases are summarized in Table 15.4-22.

Structural heat transfer coefficients as a function of time are indicated on Figure 15.4-90.

The parameters for the containment fan coolers and spray pumps are presented in Table 15.4-24.

The DEPS results are shown on Figure 15.4-91. This transient results in the highest peak pressure of 45.4 psig. In addition, an evaluation was performed for revised safety injection pump flows. This evaluation yielded a net increase in peak pressure of 0.4 psi. Therefore, the limiting peak pressure for the DEPS case is 45.8 psig. The cases that are presented in Figures 15.4-86 through 89 were not reanalyzed for these sensitivities because the DEPS is the most limiting case.

15.4.8.2.2 Method of Analysis

The steamline break analysis performed utilized the Westinghouse containment model developed for the IEEE Standard 323-1971 Equipment Qualification Program. These models and their justification (experimental and analytical) are detailed in References 56 through 60. Some major points of the model are as follows:

a. The saturation temperature corresponding to the partial pressure of the containment vapor is used in the calculation of condensing heat transfer to the passive heat sinks and the heat removal by containment fan coolers.
b. The Westinghouse containment model utilizes the analytical approaches described in References 6 and 60 to calculate the condensate removal from the condensate film. Justification of this model is provided in References 6, 56, 59, and 60. (For large breaks, 100% revaporization of the condensate is used, and a calculated fractional revaporization due to convective heat flux is used for small breaks.)
c. The small steamline break containment analyses utilized the stagnant Tagami correlation, and the large steamline break analyses utilized the blowdown Tagami correlation with an exponential decay to the stagnant Tagami correlation. The details of these models are given in Reference 38. Justification of the use of heat transfer coefficients has been provided in References 58, 59, and 61.

A complete analysis of main steamline breaks inside containment has been performed using the LOFTRAN code and the Westinghouse containment computer code, COCO[6]. All blowdown calculations with the LOFTRAN code assumed the reactor coolant pumps were running (i.e., offsite power available), because this increases the primary to secondary heat transfer and therefore maintains higher blowdown flow rates (Reference 63, Section 3.1.7). Although this assumption is inconsistent with the delay times assumed in containment fan cooler and spray initiations, where loss of offsite power it assumed, the combined effect of these assumptions provides extra conservatism in the calculated containment conditions.

Single Failure Assumptions

Several failures can be postulated which would impair the performance of various steamline break protection systems and therefore would change the net energy releases from a ruptured line. Four different single failures were considered for each break condition resulting in a limiting transient. These were:

a. failure of a main feed regulating valve,
b. failure of a main steam isolation valve,
c. failure of the auxiliary feed water (AFW) runout protection equipment, and
d. failure of a containment safeguards train.

Details about each of the single failures and their major assumptions follow.

Feed Water Flow

There are two valves in each main feedline that serve to isolate main feed water flow following a steamline break. One is the main feed water regulator valve, which receives dual, separate train trip signals from the Plant Protection System on any safety injection signal and closes within 10 seconds (including instrument delays). The second is the feed water isolation valve that also receives dual, separate train trip signals from the reactor protection system following a safety injection signal. This valve closes within 32 seconds (including instrument delays). Additionally, the main feed water pumps receive dual, separate train trips from the protection system following a steamline break. Thus, the worst failure in this system is a failure of the main feed water regulator valve to close. This failure results in an additional 22 seconds during which feed water from the Condensate Feed System may be added to the faulted steam generator. Also, since the feed water isolation valve is upstream of the regulator valve, failure of the regulator valve results in additional feedline volume that is not isolated from the faulted steam generator. Thus, water in this portion of the lines can flash and enter the faulted steam generator.

The feed water regulating valves (main and bypass) and main feed water isolation valves, which are relied upon to terminate main feed flow to the steam generators, are exempt from seismic requirements (thus classified as Seismic Category 3). However, each valve has safety-related performance requirements, and as such receives dual, independent, safety grade, trip close signals from the protection system following a steamline rupture event. The feed water regulating valves are air-operated, fail close design, whereas the feed water isolation valves are motor operated. Since the assumed pipe break occurs inside containment in a Seismic Category I pipe, the steamline rupture is not assumed to be initiated by a seismic event. There is no requirement to assume a coincident seismic event with the hypothetical pipe rupture. Thus a seismic classification for the main feed water regulating and isolation valves is not necessary to ensure closure following a steamline break inside containment. Also, since the feed water isolation valves are only credited in the event of a single failure of the regulating valves to close, additional failure of these valves does not need to be considered.

Feed water flow to the faulted steam generator from the Main Feed Water System is calculated using the hydraulic resistances of the system piping, head/flow curves for the main feed water pumps, and the steam generator pressure decay as calculated by the LOFTRAN code. In the calculations performed to match these systems' variables, a variety of assumptions is made to maximize the calculated flows. These include:

a. No credit is taken for extra pressure drop in the feedlines due to flashing of water.
b. Feed water regulator valves in the intact loops do not change position prior to a trip signal.
c. All feed water pumps are running at maximum speed.

Calculation of feed water flashing is performed by the LOFTRAN code as described in Reference 27, Section 4.1.5 For the Salem units, the maximum volume of unisolatable feedline is 328.2 ft^3 without a main feed water regulator valve failure, and it increases to 388.4 ft^3 with a main feed water regulator valve failure.

Main Steam Isolation

Since all main steam isolation valves have closing times of no more than 12 seconds after receipt of signal (including the instrument delays), failure of one of these valves affects only the volume of the main steam and turbine steam piping which cannot be isolated from the pipe rupture.

Steam contained in the unisolatable portions of the steamlines and turbine plant was considered in the containment analyses in two ways. For the large double-ended ruptures (DERs), steam in the unisolatable steamlines is released to containment as part of the reverse flow. This is accomplished by having the reverse flow begin at the time of the break at the Moody critical flow rate for steam as established by the cross-sectional area of the steamline and the initial steam pressure. The flow is held constant at this rate for a period sufficient to purge the entire unisolated portion of the steamlines. Enthalpy of the flow is also held constant at the initial steam enthalpy. Following this period of constant flow representing purging of the steamlines, flow from the intact steam generators, as calculated by LOFTRAN, is added to the containment and continues until steamline isolation is complete.

When considering split ruptures, steam in the steamlines is included in the analysis by adding the total mass in the lines to the initial mass of steam in the faulted steam generator. This is necessary because, unlike DERs, the total break area of a split is unchanged by steamline isolation; only the source of the blowdown effluent is changed. Thus, steam flow from the piping in the intact loops is indistinguishable from steam leaving the faulted steam generator. However, by adding the water mass in the piping to the faulted steam generator mass and by having dry steam blowdowns, the steamline inventory is included in the total blowdown.

TABLE 15.4-22

PEAK PRESSURE

Assumed Break	Blowdown Peak (psig)	Peak Pressure Design Basis (psig)	Peak Pressure Margin Case (20 ft entrainment) (psig)
Double Ended Pump Suction	39.2*	45.8*	44.4
0.6 Double Ended Pump Suction	37.9	42.4	44.2
3 Ft^2 Pump Suction	37.3	42.4	44.0
Double Ended Cold Leg	37.7	38.4	39.4
Double Ended Hot Leg	39.2	39.2	39.2

*The Design Basis DEPS case was reanalyzed with fan cooler heat removal that was based on 2500 gpm service water at 95°F. The other cases were originally performed with 2500 gpm water service at 85°F and Westinghouse supplied cooling coils.

TABLE 15.4-23

EFFECTS OF SINGLE FAILURES ON CONTAINMENT ANALYSES

1. MAIN STEAM ISOLATION VALVES (1)

NOTE:

(1) Failure of main steam line isolation valve increases the unisolatable steam line volume from 542 ft^3 to 10,083 ft^3.

2. MAIN FEED LINE ISOLATION VALVE

Maximum Unisolatable Feed Line Volume Without MFIV Failure	= 328.2 ft^3
Maximum Unisolatable Feed Line Volume With MFIV Failure	= 388.4 ft^3
Closing Time of Feed Regulation Valve	= <10 sec
Closing Time of Feed Isolation Valve	= <32 sec

TABLE 15.4-24

SPRAY SYSTEM/FAN COOLER/INITIATION TIMES/SETPOINTS

Spray System

Number of Spray Trains	2
Number of Spray Trains Operating in Minimum Safeguards Analysis	1
Spray Flow Rate per Spray Train	2600 gpm

Fan Coolers

Number of Fan Coolers	5
Number of Fan Coolers Operating in Minimum Safeguards Analysis	3

Initiation Times/Setpoints

System	Containment Setpoint Used	Delay after Trip Signal (w/o offsite power available)
Spray	17.0 psig	85
Fan Coolers	6.0 psig	60

17.2 QUALITY ASSURANCE DURING THE OPERATIONS PHASE

Public Service Electric and Gas Company (PSE&G) is responsible for assuring that the operation, maintenance, refueling, and modification of the nuclear generating stations are accomplished in a manner that protects public health and safety and that is in compliance with applicable regulatory requirements. To carry out this responsibility, PSE&G developed and implemented a comprehensive Quality Assurance (QA) Program that was applicable to the design, construction, and testing phases and is now applied to the operation phase.

The Operational Quality Assurance Program is described in the Nuclear Administrative Procedures Manual. This manual establishes and documents the programs and processes that implement the QA Program.

The QA Program provides measures to assure the control of activities affecting the quality function of structures, systems, and components, to an extent consistent with their importance to safety. The Quality Assurance Program encompasses fire protection of safety-related areas and other activities enumerated in Regulatory Guide 1.33. A planned monitoring assessment and audit program assures effective implementation of the Operational Quality Assurance Program. An assessment is a direct observation of activities and review of documentation to verify compliance/conformance to specified requirements and effectiveness of processes. The program provides coordinated and centralized quality assurance direction, control, and documentation as required by Nuclear Regulatory Commission (NRC) criteria set forth in 10CFR50, Appendix B. The program provides for monitoring, assessing and auditing elements of the Fitness-For-Duty (FFD) Program as set forth in 10CFR26 and is applied to, and includes non Q-list (i.e. balance of plant) activities and services necessary to achieve safety, reliability, availability, and economy in the operation of the Salem Generating Station. Applicable NRC Regulatory Guides, codes, and standards, as well as the policy statements contained in the Nuclear Administrative Procedures Manual, are used by PSE&G organizations performing activities affecting safety to prepare appropriate implementing procedures. To assess the effectiveness of the PSE&G Quality

Assurance Program, independent auditors from outside the company audit the program every 2 years for compliance with 10CFR50, Appendix B, and other regulatory commitments. Reports of such audits are made directly to upper management.

Quality Assurance (QA) policy statements are issued by key management representatives, including the Chairman and Chief Executive Officer and the Chief Nuclear Officer and President - Nuclear Business Unit (CNO/PNBU). These policy statements are mandatory throughout the Company for nuclear facilities.

Key policy elements, as they apply to nuclear safety, include the following:

1. Nuclear safety is of the highest priority and shall take precedence over matters concerning power production.

2. The public's health and safety is the prime consideration in the conduct and support of PSE&G's nuclear operations and shall not be compromised. All decisions which could affect the health and safety of the public shall be made conservatively.

3. The Operational Quality Assurance Program is an essential part of the PSE&G commitment to safe and reliable nuclear power operation. Applicable program requirements shall be strictly adhered to in the performance of activities covered by the Operational Quality Assurance Program.

PSE&G requires its suppliers and contractors to assume responsibility for establishing and implementing Quality Assurance/Quality Verification (QA/QV) programs, as applicable, to meet 10CFR50, Appendix B. However, responsibility for the overall QA program is retained and exercised by PSE&G. Procurement Assessment (PA) reviews those programs and conducts appropriate monitoring and auditing as required to assure that the suppliers are properly implementing their QA/QV programs. The Operational QA Program verifies that requirements necessary to assure quality are properly included or referenced in procurement documents. In addition, these suppliers' procurement documents include applicable PSE&G quality assurance requirements for items and services provided by their suppliers.

17.2.1 Organization

The Operational QA Program, referred to hereafter as the QA Program, assures that adequate administrative and management controls are established for safe operation of the station.

Implementation is assured by ongoing review, monitoring, assessment and audit under the direction of the Director - Quality, Nuclear Training and Emergency Preparedness (Director - Quality, NT and EP), who reports to the Chief Nuclear Officer and President - Nuclear Business Unit (CNO/PNBU).

Implementation for the non-QA areas under the control of the Director - Quality, NT and EP is assured by the Manager - Quality Assessment.

Company organization is shown on Figures 13.1-1 through 13.1-9 and 17.2-1. Responsibilities for activities affecting quality are described in the following sections.

17.2.1.1 Nuclear Business Unit

The Chief Nuclear Officer and President - Nuclear Business Unit (CNO/PNBU) is responsible for managing and directing the nuclear activities of the company. Overall duties and responsibilities of the Nuclear Business Unit (NBU) are provided in Section 13.1. Vice Presidents, Directors and General managers reporting to the CNO/PNBU are responsible for implementation of QA requirements by their staff. These QA requirements are contained in the Nuclear Administrative Procedures Manual and individual department documents.

The CNO/PNBU regularly assesses the scope, status, adequacy, and compliance of the QA program to 10CFR50, Appendix B, through:

1. Frequent contacts in staff meetings, QA audit reports, audits by independent auditors, NRC inspection reports, department status reports.

2. An annual assessment of the QA program that is preplanned and documented. This assessment addresses the scope, status, and adequacy of the QA program. Corrective action is identified and tracked.

17.2.1.1.1 Quality Assurance

The Director - Quality, NT and EP is responsible for defining, formulating, implementing, and coordinating the QA program. The Director has been delegated the authority and has the independence to interpret quality requirements, identify quality problems and trends, and provide recommendations or solutions to quality problems for all areas except those non-QA areas under his control. The Director is responsible for approval of the QA/NSR Department Manual used during the operations phase of the nuclear stations. The Director also is responsible for verifying compliance with established requirements for the QA program through document review, inspection, monitoring, assessments and audits for all areas except those non-QA areas under his control. QA provides a centralized coordinating function for QA/QV activities applied to the operations phase.

The Director - Quality, NT and EP has the authority and responsibility to stop work, through the issuance of a Stop Work Order, when significant conditions adverse to quality require such action.

The PSE&G policies and organization structure assure that the Director - Quality, NT and EP has sufficient organizational freedom and independence to carry out his responsibilities.

The full attention of the Director will be in support of QA activities and will take precedence over his non-QA activities. In the event of a conflict, the Director will delegate all QA authority to the Manager - Quality Assurance, if necessary. The Manager - Quality Assessment has the authority to report directly to the CNO/PNBU for these matters.

The Procurement Assessment (PA) Manager, who reports to the Manager - Nuclear Procurement and Material Management (NP&MM), is responsible for the Quality Services activities provided by the PA group. The PA activities of the Manager - MP&MM will take precedence over his non-PA activities. In the event of a conflict, he will delegate all authority in the area of PA to the PA Manager if necessary.

1. The authority and responsibility to stop work, through the issuance of a Stop Work Order, when significant conditions adverse to quality requires such action.

2. The freedom and authority to directly access the Manager - Quality Assurance if the need for such access exists for any issue under his responsibility. In the event of a conflict concerning the implementation of the QA program between NP&MM and PA, the reporting line will be direct from PA to the Manager - Quality Assessment.

3. Review of engineering documents such as equipment specifications for inclusion of QA requirements.

4. Review and approves specifications for Q-listed materials, equipment and services.

5. Review of procurement documents for insertion of QA requirements.

6. Conduct of Supplier surveys audits and surveillances.

7. Evaluation of prospective and existing Supplier QA programs.

8. Monitoring/auditing of nuclear fuel fabrication.

9. Review of NBU fuel specifications for inclusion of QA requirements.

10. Perform material evaluation activities on items subject to the QA program.

Responsibilities of the Manager - Corrective Action, Emergency Preparedness and Instructional Technology (Manager - CA, EP & IT) include the following:

1. Administration of the Corrective Action program.

2. Management direction and control of all collection and trending of Corrective Action reports.

3. Performing statistical analysis trends for management.

The Manager's responsibilities relative to Emergency Preparedness and Instructional Technology are described in Section 13.1.1.2.1.4.2.

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Responsibilities and authorities of the Manager - Quality Assessment include the following:

1. The authority and responsibility to stop work, through the issuance of a Stop Work Order, when significant conditions adverse to quality requires such action.

2. The freedom and authority to directly access the CNO/PNBU if the need for such access exists for any issue under his responsibility, including those related to the non-QA areas under the control of the Director - Quality, NT and EP.

3. The responsibility and authority for verifying compliance with established requirements of the QA program through document reviews, inspections, assessments and audits of non-QA areas under the control of the Director - Quality, NT and EP. This includes the authority to interpret QA program requirements during conduct of the above activities.

4. Development and implementation of the QA Audit and Assessment Program.

5. Performing assessments of contractor activities and evaluation of emergent contractor programs and procedures.

6. Planning and scheduling of surveillances conducted within the Nuclear Business Unit.

7. Performing selected station procedure reviews and concurrence.

8. Preparation and maintenance of the QA/NSR Department Manual, the QA Program description in the UFSAR, and the Operational QA Program description in the Nuclear Administrative Procedures Manual.

9. Review of the Nuclear Administrative Procedures Manual for compliance with the Operational QA Program.

10. Performing assessments of PSE&G Program administrative and implementing procedures (as necessary, these assessments may also include station administrative and implementing procedures).

11. Conducting QA Program orientation for NBU personnel administering the training and certification program for QA personnel involved in inspection, assessments and auditing activities, maintaining the QA training plan, and maintaining QA training records.

12. Review of new regulatory requirements for QA Program impact.

13. Coordination of the commitment verification program on a selected basis.

14. Performing Code related inspections, test performance, and review of weld procedures for inclusion of QA requirements.

15. Performing design change package pre-implementation review and closure review for compliance with Inspection Hold Point (IHP) requirements.

16. Performing Performance Based Inspections.

17. Implementation of the onsite independent review.

18. Random assessments are performed on the cable system to ensure that they have been installed as specified per procedure.

19. Quality verifications are performed on field installed cables to ensure that the cables are properly installed, identified and routed as specified per procedure.

20. Monitoring/auditing of nuclear fuel installation.

21. Monitor the ability of the PA group to continuously function independently as delineated under the responsibilities of the PA Manager and perform periodic audits of PA review functions. The following provides guidance on the conduct and content of the subject audits:

    - conduct interviews, surveys, etc. of selected personnel who are involved in procurement or procurement assessment activities or who are in a position to observe these activities

    - observe selected procurement and procurement assesment activities

    - assess selected reviews, evaluations, surveys, audits, and surveillances conducted by PA personnel.

Records of NRB reviews and minutes of NRB meetings shall be maintained. Reports of reviews, meeting minutes and audit reports shall be prepared and distributed as indicated below:

a. Minutes of each NRB meeting and a report of NRB reviews performed shall be prepared and forwarded to the CNO/PNBU within 30 days following the meeting.

b. Audit reports shall be forwarded to the CNO/PNBU and management positions responsible for the areas audited within 30 days after completion of the audit exit meeting for those audits conducted by the QA Department and within 60 days after completion of the audit exit meeting for those audits conducted by an independent consultant.

17.2.1.1.2.4 Onsite Independent Review

The Manager - Quality Assessment shall be responsible for onsite independent review. The onsite independent review shall be performed by a minimum of four (4) personnel who are independent of plant management. These individuals shall report to the Manager - Quality Assessment. The Manager - Quality Assessment shall utilize the information obtained during onsite independent review as input to advise management on the overall quality and safety of operations and shall report to and advise the CNO/PNBU, through the Director - Quality, NT and EP on the results of independent reviews. For onsite independent review issues involving non-QA areas under the Director's control, the Manager - Quality Assessment has the authority to directly report the results to the CNO/PNBU.

The personnel performing onsite independent review shall function to provide: the review of plant design and operating experience for potential opportunities to improve plant safety; evaluation of plant operations and maintenance activities; and advice to management on the overall quality and safety of plant operations. The personnel shall make recommendations for revised procedures, equipment modifications, or other means of improving plant safety to appropriate station/corporate management.

Onsite independent review shall encompass:

a. Review of selected plant operating characteristics, NRC issuances, industry advisories, and other appropriate sources of plant design and operating experience information which may indicate areas for improving plant safety.

b. Review of selected facility features, equipment, and systems.

c. Review of selected procedures and plant activities including maintenance, modification, operational problems, and operational analysis.

d. Surveillance of selected plant operations and maintenance activities to provide independent verification that they are performed correctly and that human errors are reduced to as low as reasonably achievable.

The personnel performing the onsite independent review shall have: 1) at least three (3) years related experience of which at least two (2) years are nuclear related, and a Bachelor Degree in Engineering or a related field; or 2) at least eight (8) years related experience, of which at least five (5) years are nuclear related. At least fifty percent (50%) of the personnel performing the onsite independent review shall have a Bachelor Degree in Engineering or a related field. For the discipline of Operations, a senior reactor operator license or certification may be used as an alternative qualification instead of a Bachelor Degree in Engineering or a related field.

Personnel performing the onsite independent review function shall possess knowledge of nuclear power plant operation and knowledge of the discipline or activity in the assigned area of review. A single individual may be qualified to perform reviews in more than one discipline. The requisite experience may have been gained concurrently in related disciplines.

The Director-Quality, NT and EP will approve and document the qualifications of those personnel performing the onsite independent review who are qualified based on at least eight (8) years related experience.

17.2.1.2 Maplewood Testing Services

The Manager Maplewood Testing Services reports to the Director-Service Company (Servco) in the PSE&G Fossil Generation Business Unit.

Maplewood Testing Services performs calibrations, analyses, and evaluations on systems, equipment, and materials, as requested by NBU departments, and maintains compliance with its quality assurance program as approved by NBU PA.

14. Regulatory Guide 1.137, Fuel-Oil Systems for Standby Diesel Generators.

15. Regulatory Guide 1.144, Auditing of Quality Assurance Programs for Nuclear Power Plants.

16. Regulatory Guide 1.146, Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants.

17. BTP 9.5-1, Appendix A, Guidelines for Fire Protection for Nuclear Plants Docketed Prior to July 1, 1976.

Commitments to Regulatory Guides, with respect to revision level, exceptions, etc, are contained in Section 3, Appendix 3A.

The code QA requirements are used for the procurement of systems, components, and structures covered by ASME Boiler and Pressure Vessel Code B31.1 and B31.7 or evaluated to be an acceptable replacement. The standard QA program controls apply to Q-Listed code items following receipt at the station. In addition, applicable requirements of Regulatory Guide 1.38 are applied to ASME Code procurements where necessary to assure safe shipment.

Substantive changes to the QA program described herein will be submitted to the NRC within 30 days of implementation. Nonsubstantive changes will be identified in the annual UFSAR updates.

The station General Manager has instituted and will maintain a station administrative procedures (SAP) manual.

Regulatory Guide 1.33 requires that plant activities affecting quality-related items and services be conducted in accordance with written administrative controls prepared by management. The procedures and instructions by which plant activities are performed are prepared by the responsible organization as required by the Nuclear Administrative Procedures Manual, reviewed by the organization responsible for the activity, reviewed as required by QA and SORC, and approved by the department manager. Nuclear Administrative Procedures (NAPs) and station APs and all subsequent revisions thereto are reviewed by QA and SORC and are approved by the station General Manager. Procedures cannot be implemented unless the review/approval process is accomplished. The Nuclear Administrative Procedures Manual provides a means to accommodate on-the-spot changes to subtier implementing procedures. The routine practice for revising a procedure is to repeat the original review and approval sequence.

Implementation of the QA program is verified by means of independent inspections, assessments, monitoring, and audits conducted by QA.

QA and PA review and analyze problems affecting quality that occur during the operational phase. Items subject to review include:

1. Documented nonconformances occurring at the supplier's facility and those identified during receiving, storage, installation, test, and operation, e.g., Deficiency Reports, Nonconformance Reports, Work Orders, Licensee Event Reports, etc.

2. Documented corrective actions taken on conditions adverse to quality and actions to prevent recurrence on significant conditions adverse to quality.

3. NRC inspection findings, notifications, bulletins, etc.

testing will be deferred, but not beyond the point when the installation would be irreversible.

3. Tests will be performed under conditions that simulate the most adverse design conditions, as determined by analysis.

New drawings or revisions to existing drawings are prepared for inclusion into a design/configuration change by, or under the supervision of, a designer from information received from the responsible engineer, manufacturer's drawings, etc. After implementation, approved design/configuration change information is transferred onto permanent drawings by a designer or drafter and peer reviewed and initialed as being checked by another designer, drafter or responsible design supervisor. New drawings or revisions to existing drawings receive final approval by the responsible design supervisor or authorized designee.

Specifications and changes thereto for items covered by the QA program are prepared by Nuclear Engineering, and are reviewed by PA for QA content.

PA review assures that the documents are prepared, reviewed, and approved in accordance with company procedures and that the documents contain the necessary QA requirements, such as inspection and test requirements, acceptance requirements, and the extent of documenting inspection and test results .

The Station Operations Review Committee (SORC) reviews proposed changes affecting nuclear safety and makes recommendations concerning implementation of the change to the station general manager. The design change process provides for signoff of the design change by the appropriate department head for the purpose of identifying required procedure change. If the proposed modification involves a Technical Specification change or is considered by the SORC to involve an unreviewed safety question (10CFR50.59), the matter is submitted to the Nuclear Review Board (NRB) for a determination of its safety implication before a license change request is submitted for NRC approval.

During the preparation of design changes, Nuclear Business Support assigns a project manager, as necessary. The project manager leads a project team. The project team consists of members of various organizations, both internal and external to Nuclear Engineering. The project team members are responsible for providing technical and administrative input to the entire design change process, which consists of design, installation, testing, and closeout phases. The technical and administrative input is guided by the requirements of those organizations which comprise the project team. The project manager ensures that the specific requirements of each organization on the project team are considered to ensure the overall quality of the product.

For design changes important to safety, the QA representative on the project team provides input and assures that design changes include quality assurance requirements such as inspection and test requirements, acceptance requirements, test result documentation, and project team compliance with company procedures during preparation, review, and approval of design changes.

Updating of records, including drawings, blueprints, instructions technical manuals, and specifications resulting from design changes, is the responsibility of the Senior Vice President - Nuclear Engineering. Design change procedures provide for the timely update of affected drawings following design change implementation to reflect as-built configuration.

17.2.4 Procurement Document Control

Procurement documents and changes thereto for the purchase of Q-Listed material, equipment, or services are reviewed and approved by PA prior to issuance by the Purchasing Department to the prospective supplier. PA review assures that spare and replacement parts are procured using controls which are commensurate with current QA program requirements.

The review also assures that procurement documents adequately and correctly:

1. Identify applicable QA program requirements.

2. Reference applicable regulatory requirements, codes, and standards.

3. Provide right of access for source surveillance and audit by PA or its agents.

4. Provide for required supplier documentation to be submitted to PSE&G or maintained by the supplier, as appropriate.

5. Provide for PSE&G review and approval of critical procedures prior to fabrication, as appropriate.

Procurement documents require suppliers and contractors of other than commercial-grade items to provide services or components in accordance with a QA program that complies with applicable parts of 10CFR50, Appendix B. The requirement for notifying PSE&G of procurement requirements that have not been met is conveyed to the supplier through the standard warranty provision contained in each purchase order. In addition, where 10CFR21 is imposed, suppliers are required to comply with applicable reporting requirements.

17.2.5 Instructions, Procedures, and Drawings

Organizations engaged in Q-Listed activities are required to perform these activities in accordance with written and approved procedures, instructions, or drawings, as appropriate.

Simple, routine activities that can be performed by qualified personnel with normal skills do not require a detailed written procedure. Complex activities require detailed procedures. The designation of those activities requiring detailed procedures is made by cognizant department heads and, as a minimum, complies with applicable requirements of Regulatory Guide 1.33.

Procedures include, as appropriate, scope, statement of applicability, references, prerequisites, precautions, limitations, and checkoff lists of inspection requirements, in addition to the detailed steps required to accomplish the activity. Instructions, procedures, and drawings also contain acceptance criteria where appropriate.

The appropriate general manager or director is responsible for assuring that procedures are prepared, approved, and implemented in compliance with the Nuclear Administrative Procedures Manual. Documents affecting nuclear safety are reviewed by the SORC for technical content, by QA for QA requirements, and are approved by the responsible station department manager or his designee.

The Director - Nuclear Business Support is responsible for issuing specifications, drawings, blueprints, procedures and administrative and technical manuals associated with structures, systems, and components covered by the QA Program. Approved and implemented modifications and design changes are incorporated in these reference documents for the life of the station. Master lists of current editions or revisions of these documents are maintained by Nuclear Business Support and are available at the station to assure that only current and approved referenced documents are used.

QA reviews and approves selected procedures that implement the QA program, including testing, calibration, maintenance, modification, rework, and repair. Changes to these documents are also reviewed and approved. In addition, QA is responsible for review and approval of selected specifications, test procedures, and results of testing.

17.2.6 Document Control

Instructions, procedures, drawings, and changes thereto are reviewed for the inclusion of appropriate QA requirements, approved by appropriate levels of management of the PSE&G organizations producing such documents, and distributed on a timely basis to using locations. Measures are provided for the timely removal of obsolete or superseded documents from the using location. Supplier documents are controlled according to contractual agreements with suppliers.

The following is a generic listing of key documents for the operational phase, showing minimum organization responsibility for review and/or approval, including changes thereto:

1. Design specification - Nuclear Engineering, PA.

2. Design modification, manufacturing, construction, and installation drawings - Nuclear Engineering, Nuclear Maintenance, station operations.

3. Procurement documents - Initiating NBU organization, Nuclear Business Support, PA.

4. Nuclear Administrative Procedures Manual - NBU organizations responsible for implementation, QA.

5. NBU second-tier manuals, including station administrative procedures - Cognizant department head, QA.

6. Maintenance, modification, and calibration procedures for Q-Listed designated station work activities - Nuclear Maintenance.

7. Operating procedures - Station operations.

8. UFSAR - Nuclear Engineering and other NBU organizations responsible for implementing applicable sections. In addition, QA reviews subsequent changes to the UFSAR sections to the extent necessary for assuring compliance with applicable QA program requirements.

9. Maintenance, inspection, and testing instruction - NBU implementing organizations.

10. Post-modification test procedures - Nuclear Engineering.

11. Design Change Requests - Nuclear Engineering, QA.

QA involvement in the work activity includes review of work procedures prior to approval for designation of inspection hold points (see Section 17.2.10), review of completed safety-related Work Orders on a sampling basis, and periodic QA surveillance and assessment.

The establishment and maintenance of a document control system for all instructions, procedures, specifications, and drawings received from the NBU or prepared at the station for use in operating, maintaining, refueling, or modifying items and services covered by the QA program is the responsibility of the Director - Nuclear Business Support. The Nuclear Administrative Procedures Manual describes the controls for specific documents. Control of station practices is included in the administrative procedures authorized by the responsible department managers. Measures are established to assure that administrative procedures are up to date, properly authorized, changed only after the required review and approvals are obtained, and distributed to appropriate personnel. Design change procedures provide for the timely update of affected drawings, following design change implementation, to reflect as-built configuration. Computerized databases maintained by the NBU organization are used to control drawings, specifications, procedures and instructions.

Controls of software affecting nuclear safety are identified in the Nuclear Administrative Procedures Manual. These controls are based on applicable guidelines provided by the NRC and include software review and approval as well as access controls to prevent unauthorized software changes.

17.2.7 Control of Purchased Material, Equipment, and Services

PA maintains an up-to-date listing of approved suppliers of material, equipment, and services covered by the QA program. This list identifies suppliers and contractors that have demonstrated the ability to supply acceptable material, equipment, or services. The list includes manufacturers of commercial-grade items. All QA program procurements are made from approved suppliers.

The responsible engineer and PA personnel select and evaluate prospective bidders and suppliers. The responsible engineer determines the technical competence of the supplier, while PA evaluates the prospective supplier's QA program for the capability of meeting applicable requirements of 10CFR50, Appendix B, and for extending applicable program requirements to subtier suppliers.

Qualified PA personnel evaluate the prospective supplier's QA capability using one or more techniques, including but not necessarily limited to:

1. Evaluation of supplier's or contractor's procedures or manuals and changes thereto.

2. ASME code stamp approval.

3. Nuclear Utility Procurement Issues Council (NUPIC) or Nuclear Fuel Users Forum (NFUF) Audits.

4. Satisfactory past history of providing similar items.

5. Survey of supplier's facility.

The evaluations of the prospective suppliers are conducted using standard checklist form designed to include the 18 quality criteria of 10CFR50, Appendix B, as appropriate.

Surveys of suppliers' capabilities include evaluation of management systems, manufacturing processes, and adherence to QA/QV procedures. The results of supplier evaluations are documented by the appropriate checklist form and filed.

Supplier control is maintained through a planned inspection, monitoring, and audit program by PA.

PA and the responsible engineer conduct a review of the manufacturing process for complex manufactured items, such as pumps, valves, heat exchangers, vessels, electrical panels, etc. This review establishes critical inspection points and establishes a notification point program for the identified inspection or surveillance activities. The established inspection or surveillance activities are implemented by qualified PA personnel or PA agents. Commercial grade items are dedicated in accordance with recognized industry standards, e.g. EPRI NP-5652.

Monitoring of suppliers/contractors during fabrication, installation, modification, rework, repair, inspection, testing, and shipment of Q-Listed materials, equipment, and services is conducted by qualified PA personnel or PA agents at the supplier's/contractor's facility or at the generating station. Surveillances are conducted in accordance with written procedures and are designed to assure conformance with procurement requirements, in accordance with the safety significance of the item or service.

Periodic evaluations of the supplier/contractor quality program are also conducted, consistent with the importance or complexity of the item or service. Dependent upon the evaluation, additional audits or corrections by the supplier/contractor may be required. Supplier's certificates of conformance are periodically evaluated by audit, inspection, or test to assure that they are valid. Results of these audits, inspections, or tests are documented.

Where feasible, replacement parts adhere to the original design criteria (such as Nuclear Steam Supply System (NSSS) components in accordance with NSSS documentation and other code components in accordance with AWWA, AISC, SPCC, and ASME B&PV Code, editions and addenda as applicable to the component or system). This provides the intended level of safety and does not result in redesign of the system.

The requirement for appropriate supplier documentation of conformance to applicable code, standard, specification, or other quality requirements is provided by the procurement document. The supplier-provided documentation is reviewed either at the supplier's facility during source surveillance, or by Material Compliance Group during material evaluation activities. A data review checkoff is used to document the acceptability of the supplier-provided data and to identify discrepancies.

Evaluation of supplier equipment, material and services is conducted by qualified personnel to verify correct identification, appropriate documentation, and to verify that the item is acceptable and can be released for storage, installation, or use.

Nonconforming items identified by the Material Compliance Group are tagged or segregated to prevent inadvertent use. Nonconforming items are controlled as described in Section 17.2.15.

17.2.8 Identification and Control of Materials, Parts, and Components

Procurement document controls provide assurance that materials, parts, and components received can be properly identified. The identification is directly marked on the item or on records traceable to the item. The data review conducted at receiving assures that proper documentation of received items is available. Materials and items received without proper identification are tagged or segregated until satisfactory documentation and identification is obtained.

Procedures require that Q-Listed materials, parts, and components be marked or otherwise identified and that such identity be maintained either on the item or on records traceable to it throughout receipt, storage, installation, and use. Protection against use of incorrect or defective items also is provided.

Material identification and traceability is maintained for rework, repairs, and modifications throughout operation.

Identification and control of materials, parts and components are the responsibility of Nuclear Maintenance, Nuclear Engineering and Nuclear Business Support. Procurement document controls are the responsibility of PA. Receipt, storage, installation, inspection and test activities are the responsibility of Nuclear Business Support, QA, PA and Nuclear Maintenance.

17.2.9 Control of Special Processes

Special process controls provide for the use of qualified procedures, equipment, personnel, and documentation of satisfactory completion of an activity. Special processes are generally those processes where direct inspection is impossible or disadvantageous.

Procedures have been established for special processes such as welding, brazing, soldering, concreting, protective coating, cleaning, heat treating, and nondestructive examination (NDE) to assure compliance with codes and design specifications. The Senior Vice President - Nuclear Engineering is responsible for preparing special process procedures such as concreting, protective coating and cleaning, while the

General Manager - Nuclear Maintenance is responsible for preparing specifications for processes such as welding, brazing, soldering, and heat treating. Nuclear Engineering is responsible for preparing specifications for nondestructive examination (NDE). These specifications are reviewed and approved by the Nuclear Maintenance Code Assurance Code Specialist for necessary QA program requirements. QA monitoring assessments and audits assure that qualification of special processes, equipment, and personnel have been satisfactorily performed.

Procedures for implementing the requirements of the specifications are prepared either by the NBU or by supplier personnel and are reviewed by a qualified specialist with the exception of special process procedures prepared by code suppliers holding a valid certificate of authorization. A qualified specialist is a person who has certified proficiency in the area of review (e.g., personnel reviewing NDE procedures are required to have Level III certification in the subject NDE area, and personnel reviewing other procedures or reports are required to be qualified in accordance with PSE&G's Engineering Support Personnel Program).

Qualification records of procedures, equipment, and personnel associated with special processes are retained as stated in Section 17.2.17.

17.2.10 Inspection

A planned inspection program is conducted and documented by personnel appropriately qualified in accordance with Section 17.2.2. The inspection program verifies conformance to the established procedure, code, or standard, consistent with the item's or activity's importance to safety.

The inspection program for maintenance and modification activities is based upon the following three important levels of inspection:

1. Worker Checks - Quality cannot be achieved unless the worker performs the activity in a quality manner. The worker is the individual best able to control the quality of work being performed. Work steps that contain elements impacting plant equipment or systems have provisions for signoff by the worker. This worker signoff establishes accountability for the activity and is

acknowledgement that the activity has been performed as specified in the work step.

2. Supervisory Inspection - Although the work supervisor may have overall responsibility for the conduct and performance of the work activity, certain conditions at the work location require supervisory inspection to increase confidence that work activities are completed as specified through familiarity of the work activity, work group, or past experience. Supervisory inspections are established in the appropriate work procedure and accomplished through direct observation of the work activity.

3. Independent Inspection - Independent inspections are not intended to dilute or replace the responsibility of the worker check or supervisory inspection for quality of work. Independent inspections provide the maximum confidence attainable that the work activity has been performed in accordance with the overall objective. Typical guidelines for establishing independent inspections include conditions similar to the following:

   - Work activity affecting redundant equipment or potentially causing cascading failure.
   - Retest will not verify the applicable attribute.
   - Establishing a baseline in a new process or procedure.
   - It is deemed necessary to maintain confidence in the work process.

This guidance is considered by the responsible QA organization in the establishment of inspection activities.

procedures control the application and removal of tags and are designed to prevent operation of valves and/or switches that could result in personnel hazard or equipment damage.

Valve and equipment status boards or logs are maintained to indicate status.

17.2.15 Nonconforming Materials, Parts, or Components

Organizations involved in material receipt, installation, test, design modification, and other operating activities are responsible for identifying and documenting nonconformances. Nonconforming materials, where practical, are segregated to prevent installation or use until proper approvals are obtained. Materials, parts, or components that have failed in service are identified and, where practical, segregated. Procedures control the application and removal of tags.

Documentation of the nonconformance includes a description of the nonconformance, review by Operations Superintendent/Control Room Supervisor OS/CRS for Limiting Condition for Operation (LCO) applicability when appropriate and the disposition and inspection or retest requirements, as appropriate. The responsible Engineer dispositions each nonconformance report. Dispositions for repair or "use-as-is" are required to be reviewed and approved by QA prior to implementation. Rework or repair of nonconforming material, parts, or components is inspected or retested, or both, in accordance with specified test and inspection requirements established by the responsible engineering representative, based on applicable requirements. QA or PA shall verify the satisfactory completion of the disposition of nonconformances.

QA and other organizations in the NBU review nonconformance reports for quality problems, including adverse quality trends, and initiate reports to higher management, identifying significant quality problems with recommendations for appropriate action.

17.2.16 Corrective Action

Organizations involved in activities covered by the QA program are required to implement corrective action for significant conditions adverse to quality and conditions adverse to quality identified within their scope of activity. Such conditions are documented and controlled by the issuance of an action request. The QA Corrective Action Group reviews responses to action requests for adequacy and monitors these action requests through periodic summary and status reports to management.

Responses to action requests are based on the four elements of corrective action, which are:

1. Identification of cause of deficiency.

2. Action to correct deficiency and results achieved to date.

3. Action taken or to be taken to prevent recurrence.

4. Date when full compliance was or will be achieved.

For significant conditions adverse to quality, such as LERs and NRC/INPO/CMAP findings, the QA Corrective Action Group is involved in the review of such conditions and provides oversight to assure timely followup and closeout.

Items 3 and 4 are optional for conditions adverse to quality.

Proper implementation of corrective action is verified through surveillance inspection assessment or audit, as appropriate.

The appropriate general manager or director is responsible for assuring that conditions adverse to quality are promptly identified and corrected for all activities involving station operation, maintenance, testing, refueling, and modification.

Administrative procedures that govern station activities covered by the QA program provide for the timely discovery and correction of nonconformances. This includes receipt of defective material, failure or malfunction of equipment, deficiencies or deviations of equipment from design performance, and deviations from procedures. In cases of significant conditions adverse to quality, the cause of the condition is determined, and measures are established to preclude recurrence. Such events, together with corrective action taken, are documented and reported as described in Section 17.2.15. Corrective action is initiated by the responsible department head.

QA closely monitors station conditions requiring corrective action.

Repetitive deficiencies, procedure or process violations at the station that are not classified as operational incidents or reportable occurrences, or nonconformances under the QA program are documented via the issuance of an action request. This request provides a formal administrative vehicle to alert management of conditions adverse to quality that require corrective action.

17.2.17 Quality Assurance Records

Records necessary to demonstrate that activities important to quality have been performed in accordance with applicable requirements are identified and maintained in accordance with Regulatory Guide 1.88, as noted in Section 17.2.2. Records shall be considered valid only when authenticated by authorized personnel. Record types, as a minimum, comply with applicable technical specification requirements and include operating logs, maintenance and modification procedures and related inspection results and reportable occurrences.

The NBU is responsible for the permanent storage of station records. The retention period for records; permanent storage location; and methods of control, identification, and retrieval are specified by administrative procedure. Individual station department heads are responsible for submitting applicable department records to the designated location for retention.

17.2.18 Audits

Audits of PSE&G and supplier organizations that implement the QA program are performed by QA and PA to verify compliance with the applicable portions of the program, through personnel interview, observation of activities in process, and review of applicable documents and records as required. Performance based assessment should be an integral part of the auditing program and should evaluate activities on the basis of their effect on the safe and reliable operation of the facility. An annual audit schedule is developed to identify the audits to be performed and their frequency. A dominant factor in audit schedule development is performance in the subject area. Audit schedules are revised so that weak or declining areas receive increased audit coverage and strong areas receive less consistent with the audit schedule frequency requirements of the Code of Federal Regulations and the UFSAR. Audits of the selected aspects of operational phase activities are performed with a frequency commensurate with safety significance and in a manner to assure that at least biennial (2 year) audits of safety related activities are performed. A list of operational phase activities subject to the audit program is provided in Section 17.2.1.1.2.3 and in Table 17.2-1.

Audits are conducted by audit teams comprised of a certified lead auditor, certified auditors, and technical specialists (when deemed necessary).

Audits are conducted using preestablished written procedures and checklists. Areas of deficiency revealed by audits are reviewed with management and are corrected in a timely manner. Required corrective action is documented and verified. Followup action, including reaudit of deficient areas, is performed.

The audit program conducted by QA includes, but is not limited to, the following activities covered by the QA program:

1. Operation, maintenance, and modification.

2. Preparation, review, approval, and control of design, specifications, procurement and requisition documents, instructions, procedures, and drawings.

transient without SCRAM (ATWS) conditions, for pressurizer water-solid conditions due to inadvertent operation of the safety injection system events, and low temperature overpressure transients.

Incorporation of complete independence between the relief valve and block valve would negate the system's ability to meet the single failure criterion for the events identified above. The existing design, however, does incorporate the use of diverse power supplies for the PORVs and their associated block valves. The relief valves are supplied by Class 1E, 125 V dc systems while the block valves use 230 V and 115 V vital ac.

Pressurizer level indication instrument channels are powered from the vital instrument buses.

2.1.2 Relief and Safety Valve Testing

Performance Testing for BWR and PWR Relief and Safety Valves

NRC Position

Pressurized water reactor (PWR) and boiling water reactor licensees and applicants shall conduct testing to qualify the Reactor Coolant System relief and safety valves under expected operating conditions for design basis transients and accidents. The licensees and applicants shall determine the expected valve operating conditions through the use of analyses of accidents and anticipated operational occurrences referenced in Regulatory Guide 1.70, Revision 2. The single failures applied to these analyses shall be chosen so that the dynamic forces on the safety and relief valves are maximized. Test pressures shall be the highest predicted by conventional safety analysis procedures. Reactor Coolant System relief and safety valve qualification shall include qualification of associated control circuitry piping and supports as well as the valves themselves.

Response

1. Safety and Relief Valves

   Public Service Electric & Gas (PSE&G) is a participant in the Generic PWR Safety and Relief Valve Test Program implemented by the Electric Power Research Institute (EPRI) at the request of participating PWR utilities in response to the USNRC recommendations for safety and relief valve testing.

   The primary objective of the Test Program was to provide full scale test data confirming the functionability of primary system PORVs and safety valves for expected operating and accident conditions. The second objective of the program was to obtain sufficient piping thermal hydraulic load data to permit confirmation of models which may be utilized for plant unique analysis of safety and relief valve discharge piping systems. Relief valve tests were completed in August 1981 and safety valve tests were completed in December 1981. The reports prepared by EPRI documenting the Test Program results are as follows:

"Valve Selection/Justification Report"

This report documents that the selected test valves represent all participating PWR plant safety and relief valves. Salem PORVs are 2-inch NPS Copes Vulcan valves with 17-4PH plug and cage. Three-inch Copes Vulcan valves similar to the Salem valves were tested in a configuration similar to that of the Salem Station. Salem safety valves are 6M6 Crosby valves which were tested in a configuration similar to that at the Salem Station.

"Test Condition Justification Report" and the "Westinghouse Plant Condition Justification Report"

These reports document the basis and justification of the valve test conditions for all participating PWR plants. The PORV fluid conditions, safety valve fluid conditions and cold overpressurization conditions at Salem are enveloped by the test conditions.

"Safety and Relief Valve Test Report"

This report provides evidence demonstrating the functionability of the selected test valves under the selected test conditions for all participating PWR plants. Tests conducted on the relief valve have confirmed that the valve opened and closed on demand and that the valve suffered no damage that would preclude future operation. Requirements for the pressurizer power-operated relief valves are addressed in UFSAR Chapter 15.2.14, "Spurious Operation of the Safety Injection System at Power".

Although the tests indicated acceptable valve performance, test valve disassembly showed galling of the cage and plug guiding surfaces. In view of this, the internals of Salem Units 1 and 2 PORVs have been changed to 316 stellited plugs instead of 17-4PH. The Salem valves with this combination of internals have shown no indication of leakage or galling.

The safety valves were shown to open and close. The functionability of the valves to provide overpressure protection for the Final Safety Analysis Report (FSAR) events was found to be adequate (1). However, depending upon the test conditions (steam - transition - water), the valves were shown to flutter and/or chatter during loop seal discharge. The observed instability of the safety valves during loop seal discharge has been evaluated by Westinghouse and PSE&G and is not considered to be a safety concern.

Upstream piping and valve ring adjustments have been shown to have a substantial effect on valve performance. Performance of the Salem safety valves during steam discharge conditions has been judged stable through the use of a valve dynamic model developed by Continuum Dynamics, Inc. (2). The model also predicted blowdown of less than 10 percent which is considered acceptable. Liquid discharge challenges to safety valves are predicted to occur significantly less frequently than a LOCA and the consequences of such liquid discharge are much less severe; liquid discharge from the Salem safety valves has been shown to be an unlikely event (3). Thus, safety valve liquid discharge is an insignificant safety concern when compared with FSAR transient events.

2.1.8.b Increased Radiation Monitoring Range

Increased Range of Radiation Monitors

NRC Position

The requirements associated with this recommendation should be considered as advanced implementation of certain requirements to be included in a revision to Regulatory Guide 1.97, "Instrumentation to Follow the Course of an Accident," which has already been initiated, and in other Regulatory Guides, which will be promulgated in the near-term.

1. Noble gas effluent monitors shall be installed with an extended range designed to function during accident conditions as well as during normal operating conditions; multiple monitors are considered to be necessary to cover the ranges of interest.

   a. Noble gas effluent monitors with an upper range of 10^5 μCi/cc (Xe-133) are considered to be practical and should be installed in all operating plants.

   b. Noble gas effluent monitoring shall be provided for the total range of concentration extending from a minimum of 10^{-7} μCi/cc (Xe-133). Multiple monitors are considered to be necessary to cover the ranges of interest. The range capacity of individual monitors shall overlap by a factor of ten.

2. Since iodine gaseous effluent monitors for the accident condition are not considered to be practical at this time, capability for effluent monitoring of radioiodines for the accident condition shall be provided with sampling conducted by adsorption on charcoal or other media, followed by onsite laboratory analysis.

3. In containment radiation level monitors with a maximum range of 10^8 rad per hour shall be installed. A minimum of two such monitors that are physically separated shall be provided. Monitors shall be designed and qualified to function in an accident environment.

The NRC position in NUREG-0578 was subsequently modified to permit a maximum range of 10^7 R per hour for gamma - only monitoring.

The NRC position (in NUREG-0578) was subsequently modified to require noble gas effluent monitors with a range from as low as reasonably achievable to 10^5 μC/cc. In addition, the overlap requirement was deleted.

<u>Response</u>

1. Extended range noble gas monitors have been installed to meet this requirement. Post-accident samplers are located in enclosures outside of the Auxiliary Building to reduce radiation exposures to individuals obtaining post-accident plant vent samples. The detection range of extended range monitors is as follows:

   Intermediate range monitors:
   Unit 1 - 1R45B, Unit 2 - 2R45B = 1×10^{-3} to 10 μCi/cc
   Unit 1 - 1R41B, Unit 2 - 2R41B = 1×10^{-4} to 1×10^{2} μCi/cc
   High range monitors:
   Unit 1 - 1R45C, Unit 2 - 2R45C = 0.1 to 1×10^{5} μCi/cc
   Unit 1 - 1R41C, Unit 2 - 2R41C = 0.1 to 1×10^{5} μCi/cc

   Readings from these monitors are continuously available in the Control Room.

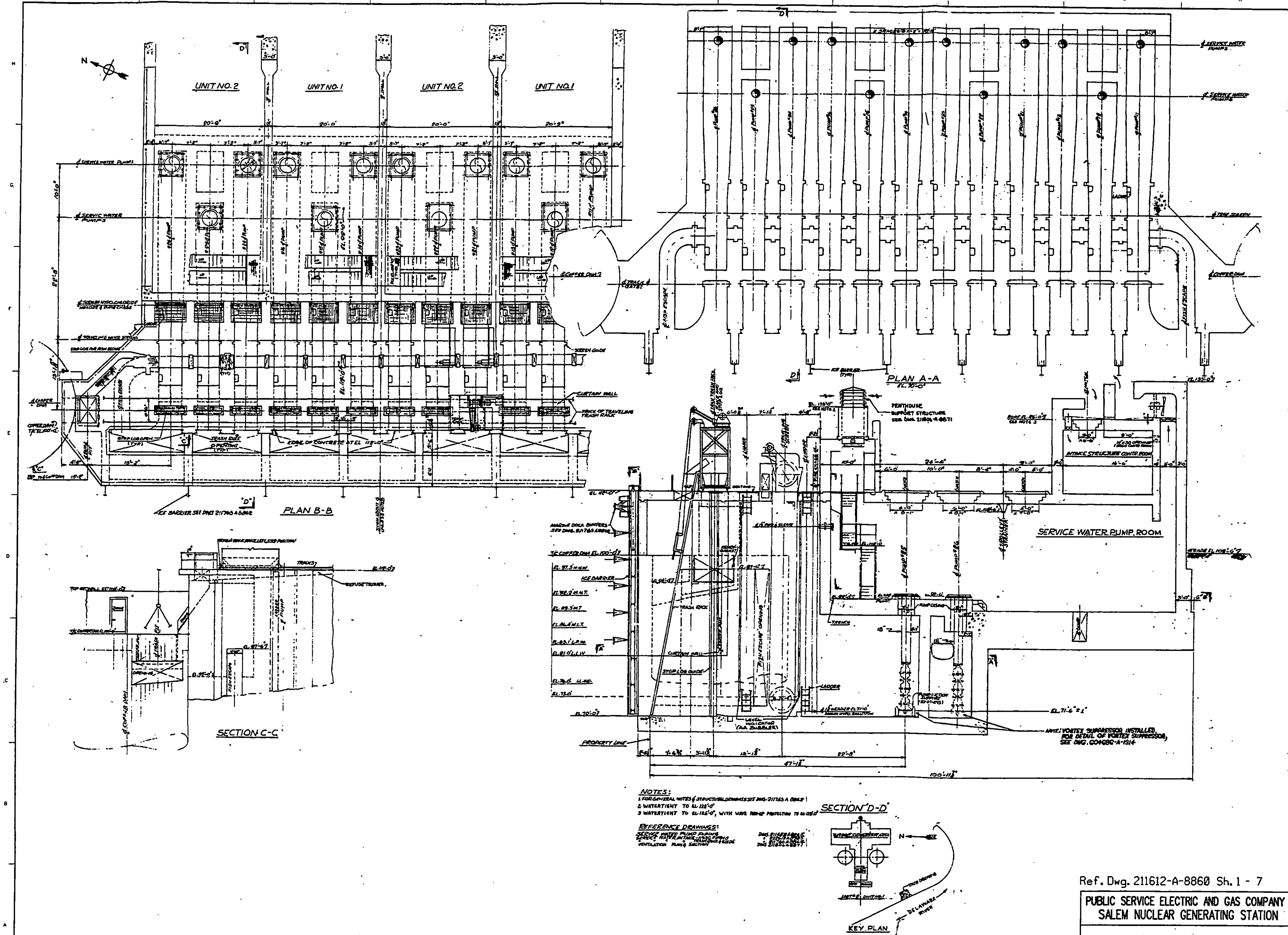
   The existing R41A noble gas monitors provide for low detection ranges (1×10^{-7} to 1×10^{1} μCi/cc) during normal plant operations.

   Channels R41B,C are assigned the Reg. Guide 1.97 extended range noble gas monitoring functions.

   High range monitors have also been installed to measure releases from the atmospheric steam relief and/or safety valves. A separate channel is installed for each of the four main steam lines of each unit. A redundant backup monitor is also provided. The range of these monitors is as follows:

Unit 1 - 1R46, A,B,C,D,E	0.1 to 5×10^{3} μCi/cc Xe-133
Unit 2 - 2R46, A,B,C,D,E	0.1 to 5×10^{3} μCi/cc Xe-133

2. The Salem R45 design provides for iodine sampling by absorption on charcoal or silver zeolite cartridges. Plant vent iodine grab samples can be obtained in the extended range monitoring enclosure to prevent personnel from receiving excessive radiation exposure.



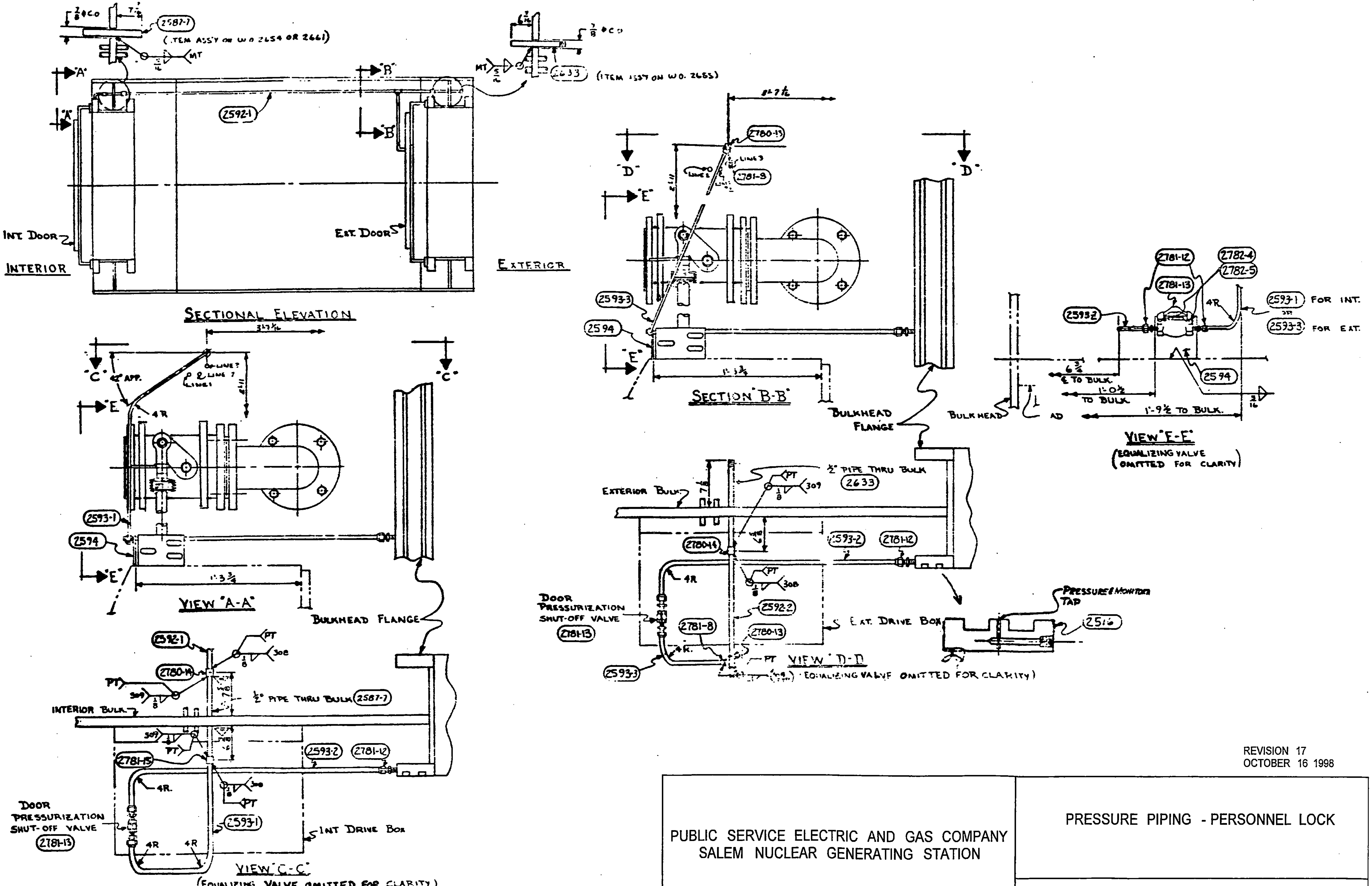
Ref. Dwg. 211612-A-8860 Sh. 1 - 7

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

SERVICE WATER INTAKE

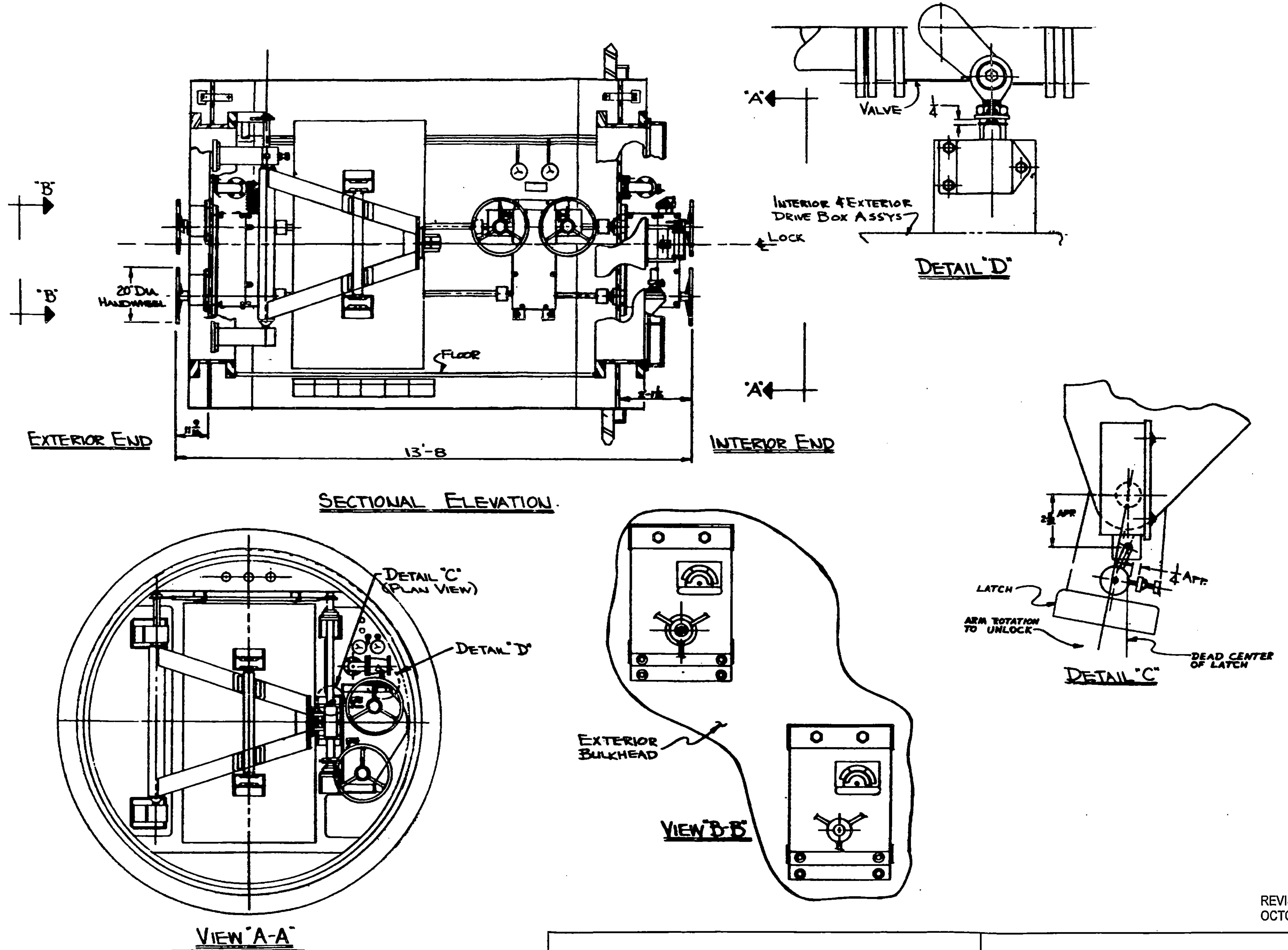
Updated FSAR — Sheet 1 of 1

Revision 17, October 16, 1998 — Fig 2.4-3



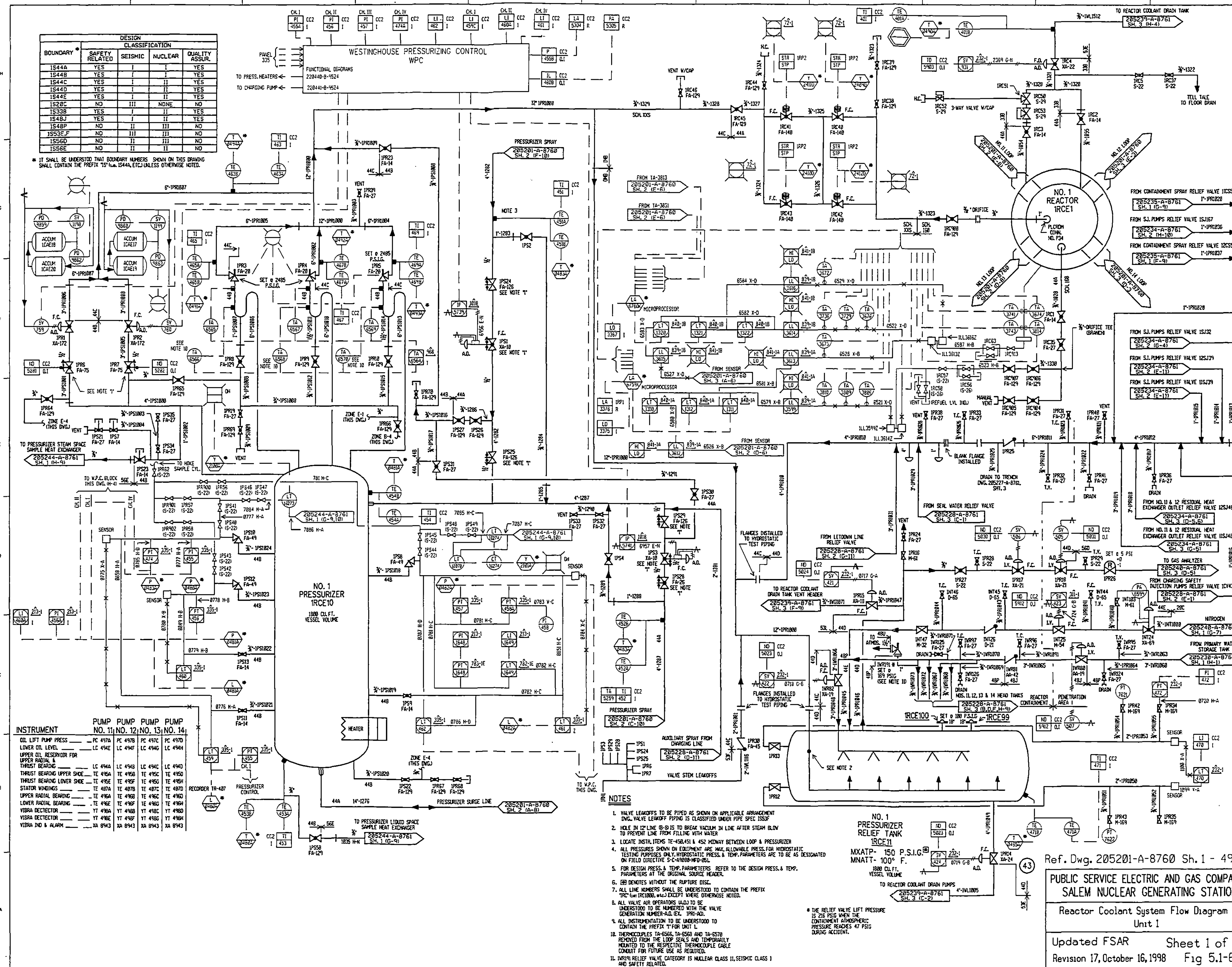
REVISION 17
OCTOBER 16 1998

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	PRESSURE PIPING - PERSONNEL LOCK
	Updated FSAR FIG. 3.8-37



REVISION 17
OCTOBER 16 1998

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	PERSONNEL LOCK
	Updated FSAR — FIG. 3.8-38



BOUNDARY *	DESIGN CLASSIFICATION: SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S44A	YES	I	I	YES
1S44B	YES	I	I	YES
1S44C	YES	I	II	YES
1S44D	YES	I	II	YES
1S44E	YES	I	II	YES
1S20C	NO	III	NONE	NO
1S33B	YES	I	II	YES
1S48J	YES	I	II	YES
1S48P	NO	II	III	NO
1S53E,F	NO	III	III	NO
1S56D	NO	II	III	NO
1S56E	NO	II	II	NO

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (i.e. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

INSTRUMENT	PUMP NO. 11	PUMP NO. 12	PUMP NO. 13	PUMP NO. 14
OIL LIFT PUMP PRESS	PC 497A	PC 497B	PC 497C	PC 497D
LOWER OIL LEVEL	LC 494E	LC 494F	LC 494G	LC 494H
UPPER OIL RESERVOIR FOR UPPER RADIAL & THRUST BEARING	LC 494A	LC 494B	LC 494C	LC 494D
THRUST BEARING UPPER SHOE	TE 495A	TE 495B	TE 495C	TE 495D
THRUST BEARING LOWER SHOE	TE 495E	TE 495F	TE 495G	TE 495H
STATOR WINDINGS	TE 407A	TE 407B	TE 407C	TE 407D
UPPER RADIAL BEARING	TE 496A	TE 496B	TE 496C	TE 496D
LOWER RADIAL BEARING	TE 496E	TE 496F	TE 496G	TE 496H
VIBRA DECTECTOR	YT 498A	YT 498B	YT 498C	YT 498D
VIBRA DECTECTOR	YT 498E	YT 498F	YT 498G	YT 498H
VIBRA IND & ALARM	XA 8943	XA 8943	XA 8943	XA 8943

NOTES

1. VALVE LEAKOFFS TO BE PIPED AS SHOWN ON APPLICABLE ARRANGEMENT DWG. VALVE LEAKOFF PIPING IS CLASSIFIED UNDER PIPE SPEC 1S53F
2. HOLE IN 12" LINE (B-8) IS TO BREAK VACUUM IN LINE AFTER STEAM BLOW TO PREVENT LINE FROM FILLING WITH WATER
3. LOCATE INSTR. ITEMS TE-450, 451 & 452 MIDWAY BETWEEN LOOP & PRESSURIZER
4. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAX. ALLOWABLE PRESS. FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESS. & TEMP. PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-05L
5. FOR DESIGN PRESS. & TEMP. PARAMETEERS REFER TO THE DESIGN PRESS. & TEMP. PARAMETERS AT THE ORIGINAL SOURCE HEADER.
6. ⊞ DENOTES WITHOUT THE RUPTURE DISC.
7. ALL LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1RC" (i.e. 1RC1000, etc.) EXCEPT WHERE OTHERWISE NOTED.
8. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 1PR1-AO).
9. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "1" FOR UNIT 1.
10. THERMOCOUPLES TA-6566, TA-6568 AND TA-6570 REMOVED FROM THE LOOP SEALS AND TEMPORARILY MOUNTED TO THE RESPECTIVE THERMOCOUPLE CABLE CONDUIT FOR FUTURE USE AS REQUIRED.
11. 1WR191 RELIEF VALVE CATEGORY IS NUCLEAR CLASS II, SEISMIC CLASS I AND SAFETY RELATED.

* THE RELIEF VALVE LIFT PRESSURE IS 216 PSIG WHEN THE CONTAINMENT ATMOSPHERIC PRESSURE REACHES 47 PSIG DURING ACCIDENT.

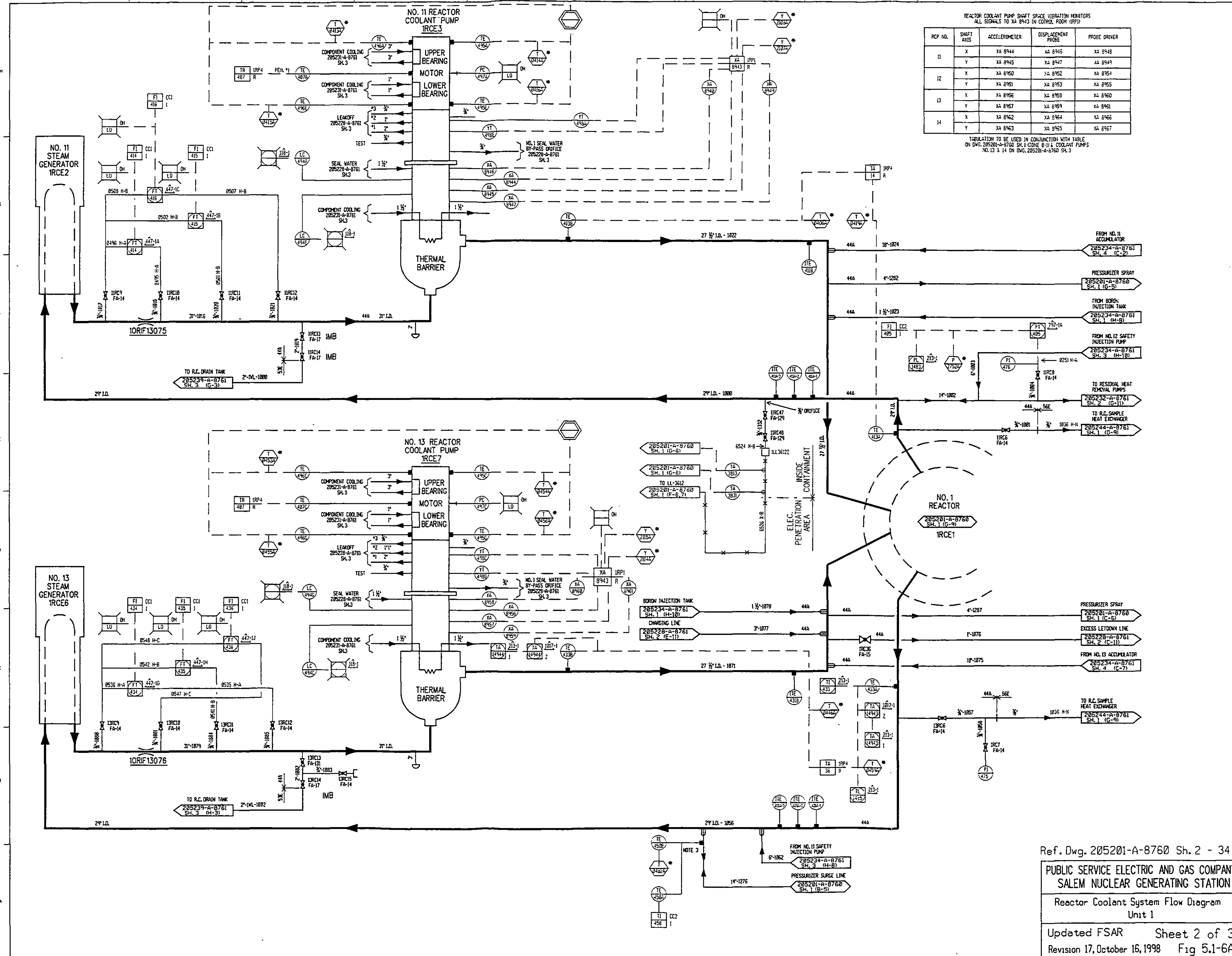
NOTE: FOR VALVE MARK NO'S NOT SHOWN ON THIS SHEET, REFER TO MMIS.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Reactor Coolant System Flow Diagram
Unit 1

Updated FSAR — Sheet 1 of 3

Revision 17, October 16, 1998 — Fig 5.1-6A



REACTOR COOLANT PUMP SHAFT SPACE VIBRATION MONITORS
ALL SIGNALS TO XA 8943 IN COTROL ROOM (1RP1)

RCP NO.	SHAFT AXIS	ACCELEROMETER	DISPLACEMENT PROBE	PROBE DRIVER
11	X	XA 8944	XA 8946	XA 8948
	Y	XA 8945	XA 8947	XA 8949
12	X	XA 8950	XA 8952	XA 8954
	Y	XA 8951	XA 8953	XA 8955
13	X	XA 8956	XA 8958	XA 8960
	Y	XA 8957	XA 8959	XA 8961
14	X	XA 8962	XA 8964	XA 8966
	Y	XA 8963	XA 8965	XA 8967

TABULATION TO BE USED IN CONJUNCTION WITH TABLE ON DWG. 205201-A-8760 SH. 1 (ZONE B-1) & COOLANT PUMPS NO. 13 & 14 ON DWG. 205201-A-8760 SH. 3

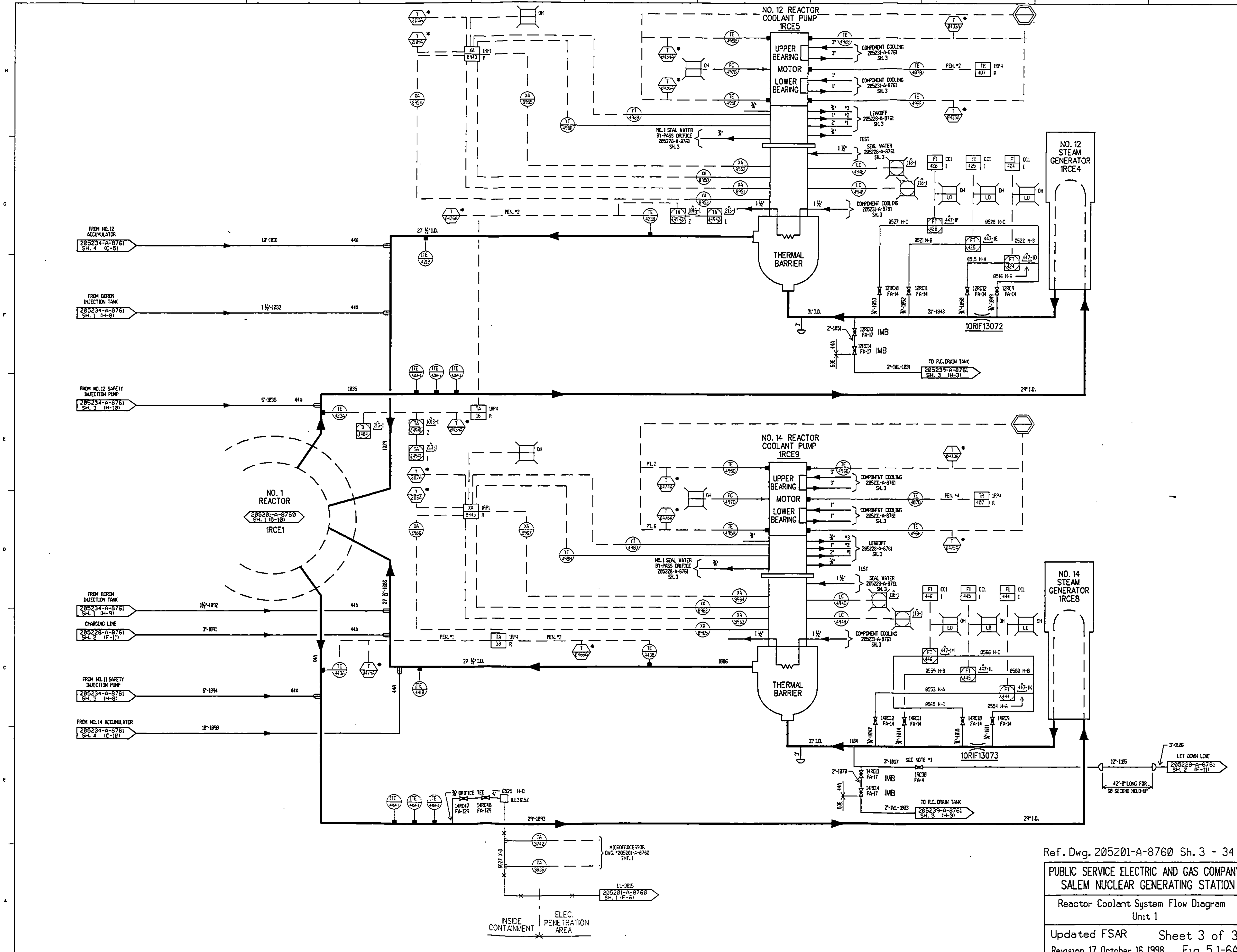
Ref. Dwg. 205201-A-8760 Sh. 2 - 34

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Reactor Coolant System Flow Diagram
Unit 1

Updated FSAR — Sheet 2 of 3

Revision 17, October 16, 1998 — Fig 5.1-6A

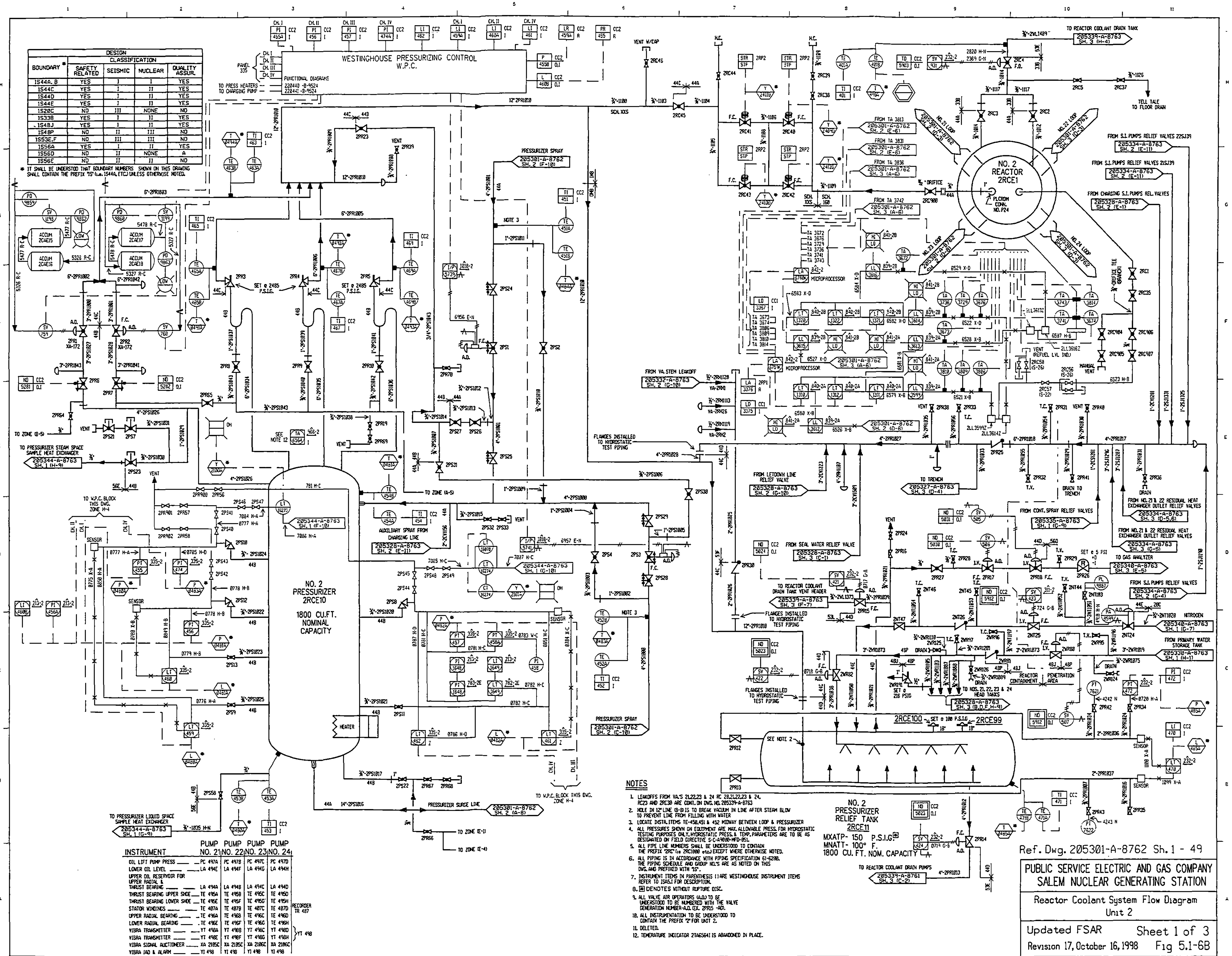


Ref. Dwg. 205201-A-8760 Sh. 3 - 34

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Reactor Coolant System Flow Diagram
Unit 1

Updated FSAR Sheet 3 of 3
Revision 17, October 16, 1998 Fig 5.1-6A



BOUNDARY *	DESIGN CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S44A, B	YES	I	I	YES
1S44C	YES	I	II	YES
1S44D	YES	I	II	YES
1S44E	YES	I	II	YES
1S20C	NO	III	NONE	NO
1S33B	YES	I	II	YES
1S48J	YES	I	II	YES
1S48P	NO	II	III	NO
1S53E,F	NO	III	III	NO
1S56A	YES	I	II	YES
1S56D	NO	II	NONE	A
1S56E	NO	II	II	NO

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (i.e. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

INSTRUMENT	PUMP NO. 21	PUMP NO. 22	PUMP NO. 23	PUMP NO. 24	
OIL LIFT PUMP PRESS	PC 497A	PC 497B	PC 497C	PC 497D	
LOWER OIL LEVEL	LA 494E	LA 494F	LA 494G	LA 494H	
UPPER OIL RESERVOIR FOR UPPER RADIAL & THRUST BEARING	LA 494A	LA 494B	LA 494C	LA 494D	
THRUST BEARING UPPER SHOE	TE 495A	TE 495B	TE 495C	TE 495D	
THRUST BEARING LOWER SHOE	TE 495E	TE 495F	TE 495G	TE 495H	
STATOR WINDINGS	TE 407A	TE 407B	TE 407C	TE 407D	RECORDER TR 407
UPPER RADIAL BEARING	TE 496A	TE 496B	TE 496C	TE 496D	
LOWER RADIAL BEARING	TE 496E	TE 496F	TE 496G	TE 496H	
VIBRA TRANSMITTER	YT 498A	YT 498B	YT 498C	YT 498D	YT 498
VIBRA TRANSMITTER	YT 498E	YT 498F	YT 498G	YT 498H	YT 498
VIBRA SIGNAL AUCTIONEER	XA 2105C	XA 2105C	XA 2106C	XA 2106C	
VIBRA IAD & ALARM	YI 498	YI 498	YI 498	YI 498	

NOTES

1. LEAKOFFS FROM VA.'S 21,22,23 & 24 RC 20,21,22,23 & 24. RC23 AND 2RC30 ARE CONT. ON DWG. NO. 205339-A-8763
2. HOLE IN 12" LINE (B-8) IS TO BREAK VACUUM IN LINE AFTER STEAM BLOW TO PREVENT LINE FROM FILLING WITH WATER
3. LOCATE INSTR. ITEMS TE-450,451 & 452 MIDWAY BETWEEN LOOP & PRESSURIZER
4. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAX. ALLOWABLE PRESS. FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESS. & TEMP. PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051.
5. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "2RC" (i.e. 2RC1000 etc.) EXCEPT WHERE OTHERWISE NOTED.
6. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6200. THE PIPING SCHEDULE AND GROUP NO.'S ARE AS NOTED ON THIS DWG. AND PREFIXED WITH "1S".
7. INSTRUMENT ITEMS IN PARENTHESIS ( ) ARE WESTINGHOUSE INSTRUMENT ITEMS REFER TO ISA5.1 FOR DESCRIPTION.
8. ⊠ DENOTES WITHOUT RUPTURE DISC.
9. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 2PR15 -AO).
10. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "2" FOR UNIT 2.
11. DELETED.
12. TEMERATURE INDICATOR 2TA6564I IS ABANDONED IN PLACE.

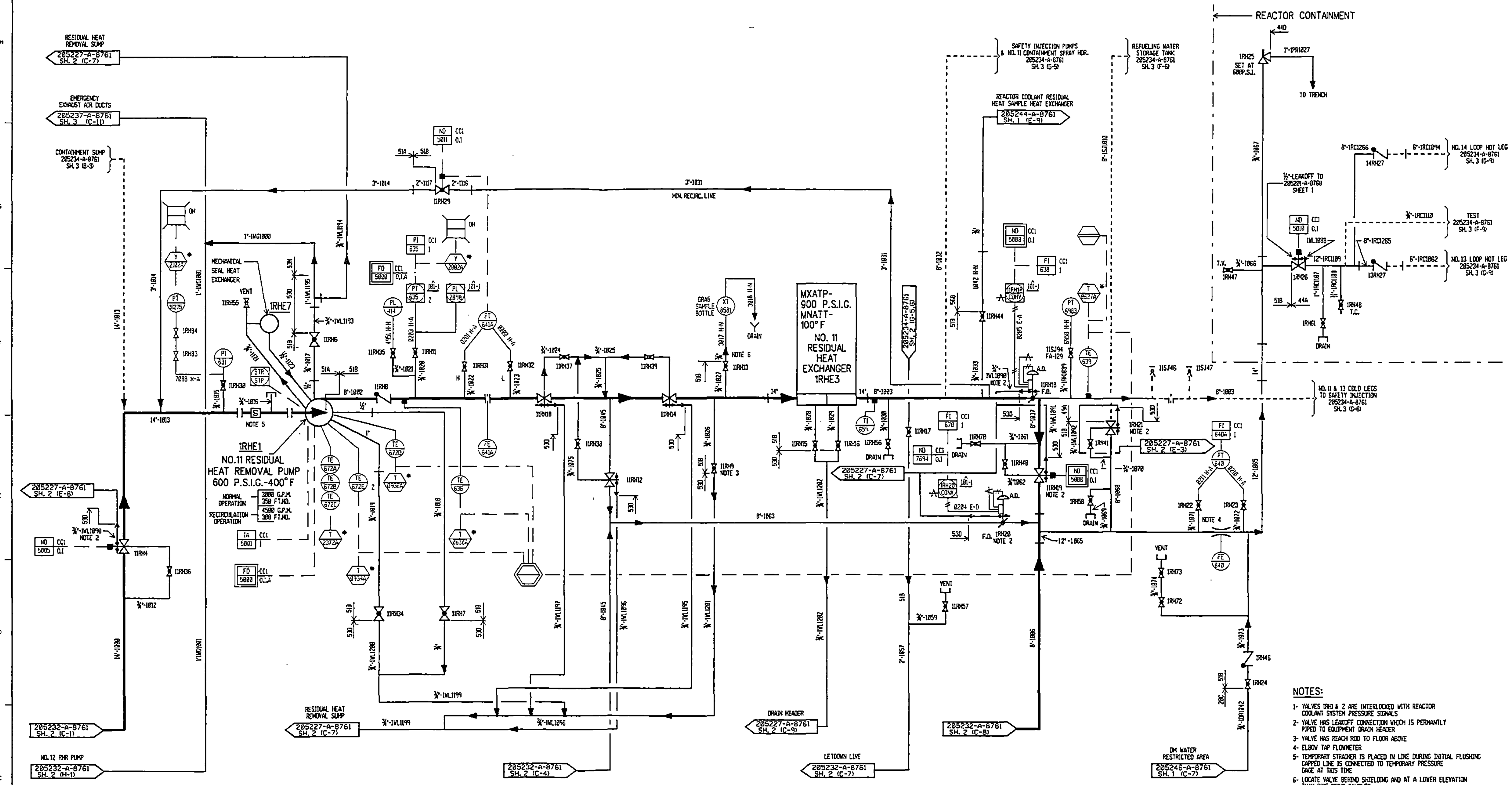
NOTE: FOR VALVE MARK NO'S. NOT SHOWN ON THIS SHEET, REFER TO MMIS.

Ref. Dwg. 205301-A-8762 Sh. 1 - 49

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Reactor Coolant System Flow Diagram
Unit 2

Updated FSAR — Sheet 1 of 3
Revision 17, October 16, 1998 — Fig 5.1-6B



NOTES:

1- VALVES 1RH1 & 2 ARE INTERLOCKED WITH REACTOR COOLANT SYSTEM PRESSURE SIGNALS
2- VALVE HAS LEAKOFF CONNECTION WHICH IS PERMANTLY PIPED TO EQUIPMENT DRAIN HEADER
3- VALVE HAS REACH ROD TO FLOOR ABOVE
4- ELBOW TAP FLOWMETER
5- TEMPORARY STRAINER IS PLACED IN LINE DURING INITIAL FLUSHING CAPPED LINE IS CONNECTED TO TEMPORARY PRESSURE GAGE AT THIS TIME
6- LOCATE VALVE BEHIND SHIELDING AND AT A LOWER ELEVATION THAN PIPE BEING SAMPLED
7- ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1RH" (i.e. 1RH1000, ETC.) EXCEPT WHERE OTHERWISE NOTED.
8- ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051.
9- ALL CONTROL VALVES TO HAVE OPEN & CLOSED LIMIT SWITCHES.
10. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 11RH18-AO).
11. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "1" FOR UNIT 1.
12. PIPING CLASS 530 WAS ORIGINALLY CLASSIFED AS NUCLEAR CLASS III. DCP 1EA-1028 RECLASSIFIES PIPING CLASS 530 TO BE NON-NUCLEAR. ANY MAINTENANCE, REPAIR AND/OR MODIFICATION HENCEFORTH SHALL COMPLY WITH THE REQUIREMENTS OF RECLASSIFIED PIPING CLASS.

DESIGN				
BOUNDARY	CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S20C	NO	III	NONE	NO
1S44A	YES	I	I	YES
1S44D	YES	I	II	YES
1S49A	YES	I	III	YES
1S51A	YES	I	II	YES
1S51B	YES	I	II	YES
1S53D	NO	III	NONE	NO
1S53N	NO	III	III	NO
1S56B	NO	II	III	NO

IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (i.e. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

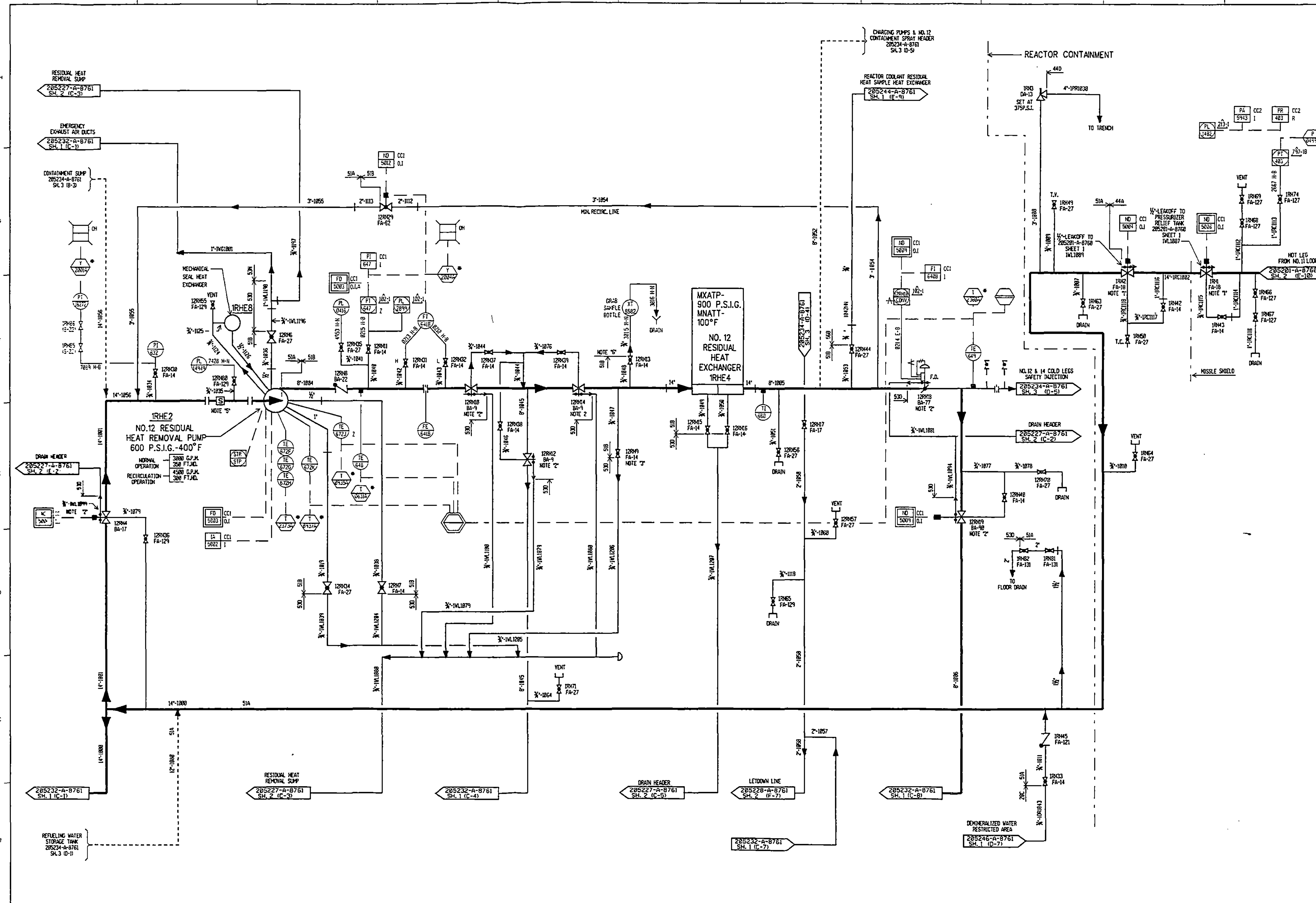
NOTE: FOR VALVE MARK NO'S NOT SHOWN ON THIS SHEET, REFER TO MMS.

Ref. Dwg. 205232-A-8761 Sh. 1 - 35

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Residual Heat Removal System
Unit 1

Updated FSAR | Sheet 1 of 2
Revision 17, October 16, 1998 | Fig 5.5-2A



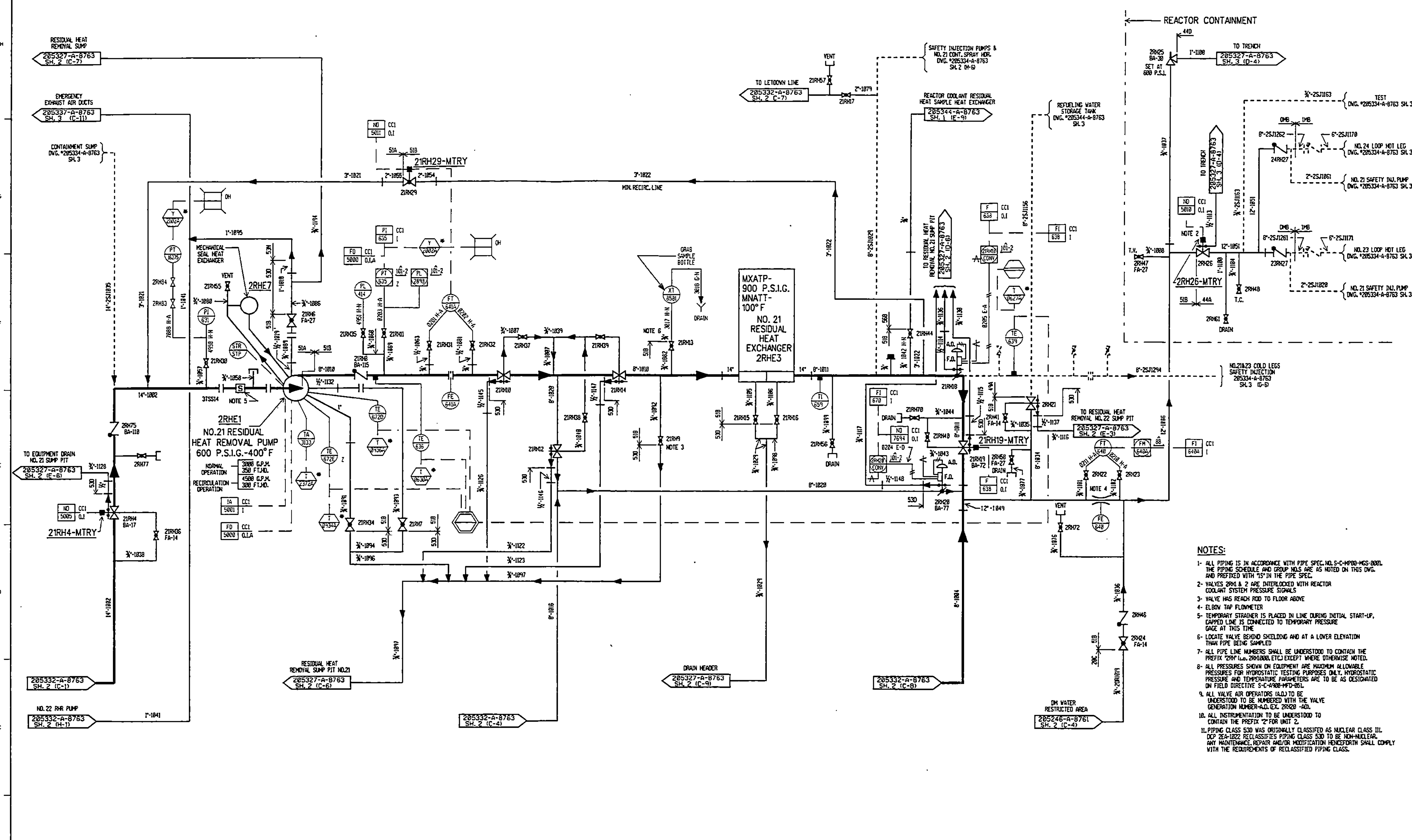
Ref. Dwg. 205232-A-8761 Sh. 2 - 34

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Residual Heat Removal System
Unit 1

Updated FSAR — Sheet 2 of 2

Revision 17, October 16, 1998 — Fig 5.5-2A



NOTES:

1- ALL PIPING IS IN ACCORDANCE WITH PIPE SPEC. NO. S-C-MP00-MGS-0001. THE PIPING SCHEDULE AND GROUP NO.S ARE AS NOTED ON THIS DWG. AND PREFIXED WITH "1S" IN THE PIPE SPEC.

2- VALVES 2RH1 & 2 ARE INTERLOCKED WITH REACTOR COOLANT SYSTEM PRESSURE SIGNALS

3- VALVE HAS REACH ROD TO FLOOR ABOVE

4- ELBOW TAP FLOWMETER

5- TEMPORARY STRAINER IS PLACED IN LINE DURING INITIAL START-UP, CAPPED LINE IS CONNECTED TO TEMPORARY PRESSURE GAGE AT THIS TIME

6- LOCATE VALVE BEHIND SHIELDING AND AT A LOWER ELEVATION THAN PIPE BEING SAMPLED

7- ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "2RH" (i.e. 2RH1000, ETC.) EXCEPT WHERE OTHERWISE NOTED.

8- ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051.

9. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 2RH20 -AO).

10. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "2" FOR UNIT 2.

11. PIPING CLASS 530 WAS ORIGINALLY CLASSIFIED AS NUCLEAR CLASS III. DCP 2EA-1022 RECLASSIFIES PIPING CLASS 530 TO BE NON-NUCLEAR. ANY MAINTENANCE, REPAIR AND/OR MODIFICATION HENCEFORTH SHALL COMPLY WITH THE REQUIREMENTS OF RECLASSIFIED PIPING CLASS.

* BOUNDARY	DESIGN CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S20C	NO	III	NONE	NO
1S44A	YES	I	I	YES
1S44D	YES	I	II	YES
1S49A	YES	I	III	YES
1S51A	YES	I	II	YES
1S51B	YES	I	II	YES
1S53D	NO	III	NONE	NO
1S53N	NO	III	III	NO
1S56B	NO	II	III	NO

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (i.e. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

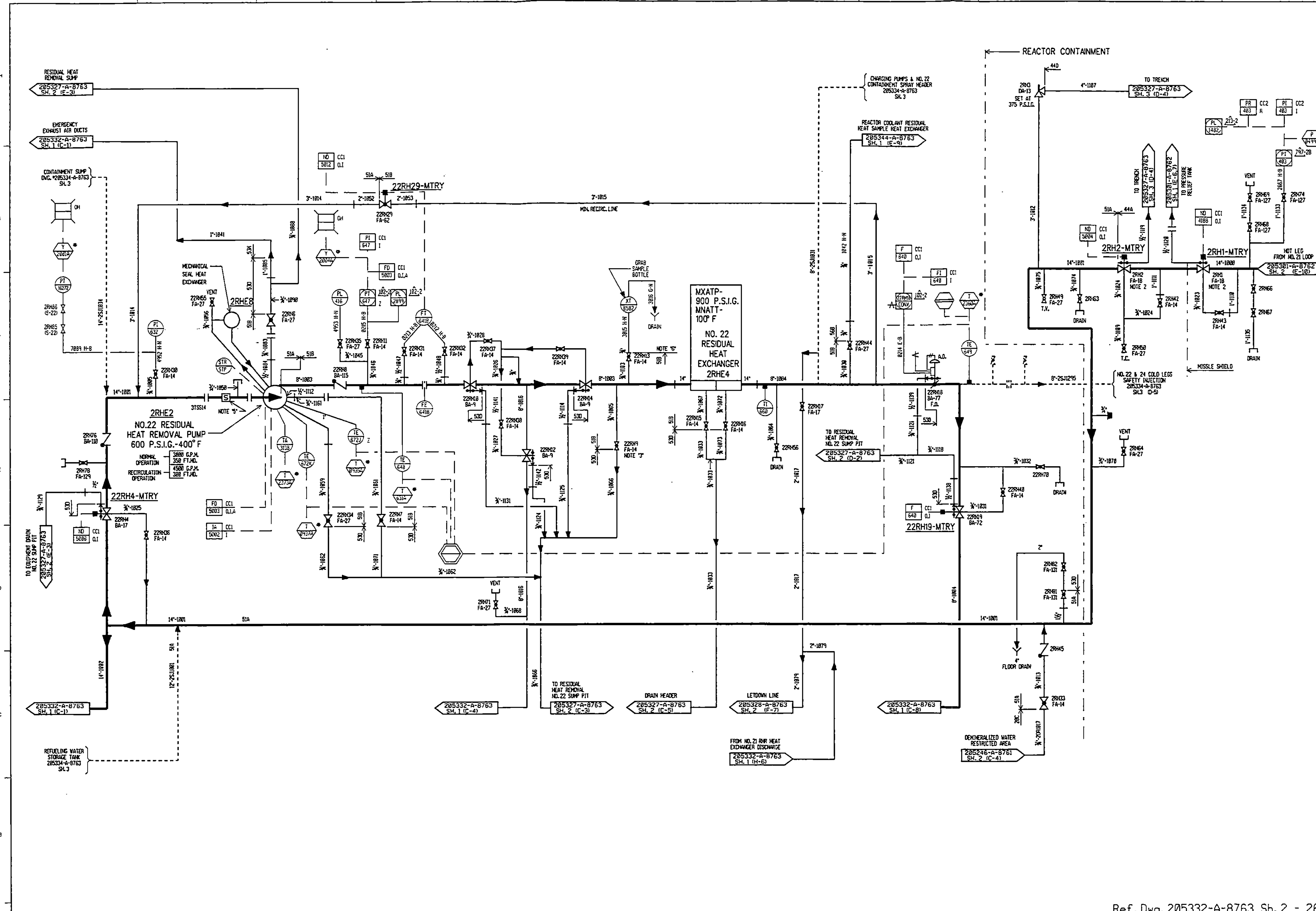
Ref. Dwg. 205332-A-8763 Sh. 1 - 28

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Residual Heat Removal System
Unit 2

Updated FSAR — Sheet 1 of 2

Revision 17, October 16, 1998 — Fig 5.5-2B

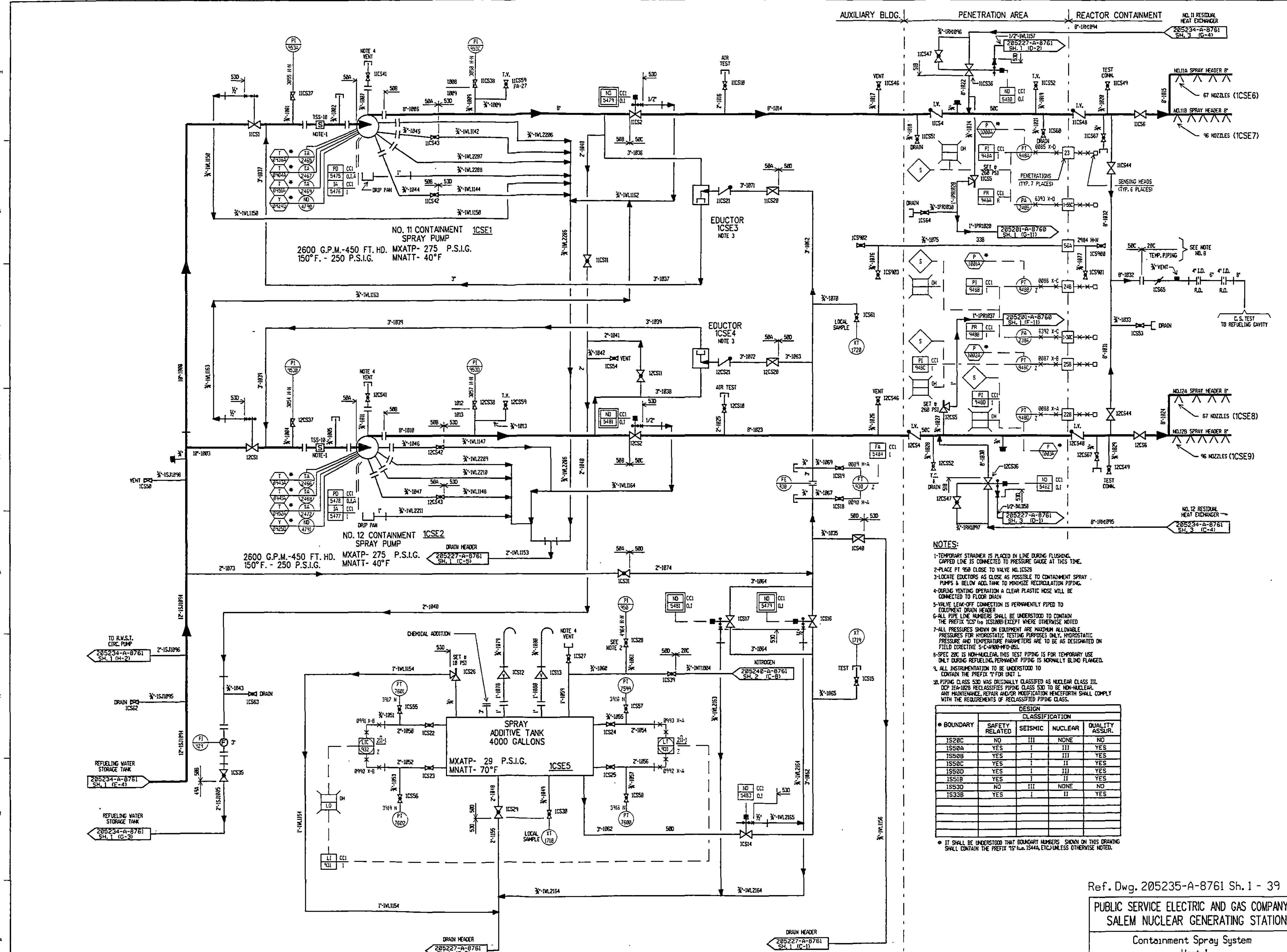


Ref. Dwg. 205332-A-8763 Sh. 2 - 26

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Residual Heat Removal System
Unit 2

Updated FSAR Sheet 2 of 2
Revision 17, October 16, 1998 Fig 5.5-2B



NOTES:

1-TEMPORARY STRAINER IS PLACED IN LINE DURING FLUSHING. CAPPED LINE IS CONNECTED TO PRESSURE GAUGE AT THIS TIME.

2-PLACE PT 950 CLOSE TO VALVE NO. 1CS28

3-LOCATE EDUCTORS AS CLOSE AS POSSIBLE TO CONTAINMENT SPRAY PUMPS & BELOW ADD. TANK TO MINIMIZE RECIRCULATION PIPING.

4-DURING VENTING OPERATION A CLEAR PLASTIC HOSE WILL BE CONNECTED TO FLOOR DRAIN

5-VALVE LEAK-OFF CONNECTION IS PERMANENTLY PIPED TO EQUIPMENT DRAIN HEADER

6-ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1CS" (i.e. 1CS1000) EXCEPT WHERE OTHERWISE NOTED

7-ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051.

8-SPEC 20C IS NON-NUCLEAR. THIS TEST PIPING IS FOR TEMPORARY USE ONLY DURING REFUELING. PERMANENT PIPING IS NORMALLY BLIND FLANGED.

9. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "1" FOR UNIT 1.

10. PIPING CLASS 530 WAS ORIGINALLY CLASSIFED AS NUCLEAR CLASS III. DCP 1EA-1028 RECLASSIFIES PIPING CLASS 530 TO BE NON-NUCLEAR. ANY MAINTENANCE, REPAIR AND/OR MODIFICATION HENCEFORTH SHALL COMPLY WITH THE REQUIREMENTS OF RECLASSIFIED PIPING CLASS.

* BOUNDARY	DESIGN CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S20C	NO	III	NONE	NO
1S50A	YES	I	III	YES
1S50B	YES	I	III	YES
1S50C	YES	I	II	YES
1S50D	YES	I	III	YES
1S51B	YES	I	II	YES
1S53D	NO	III	NONE	NO
1S33B	YES	I	II	YES

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (i.e. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

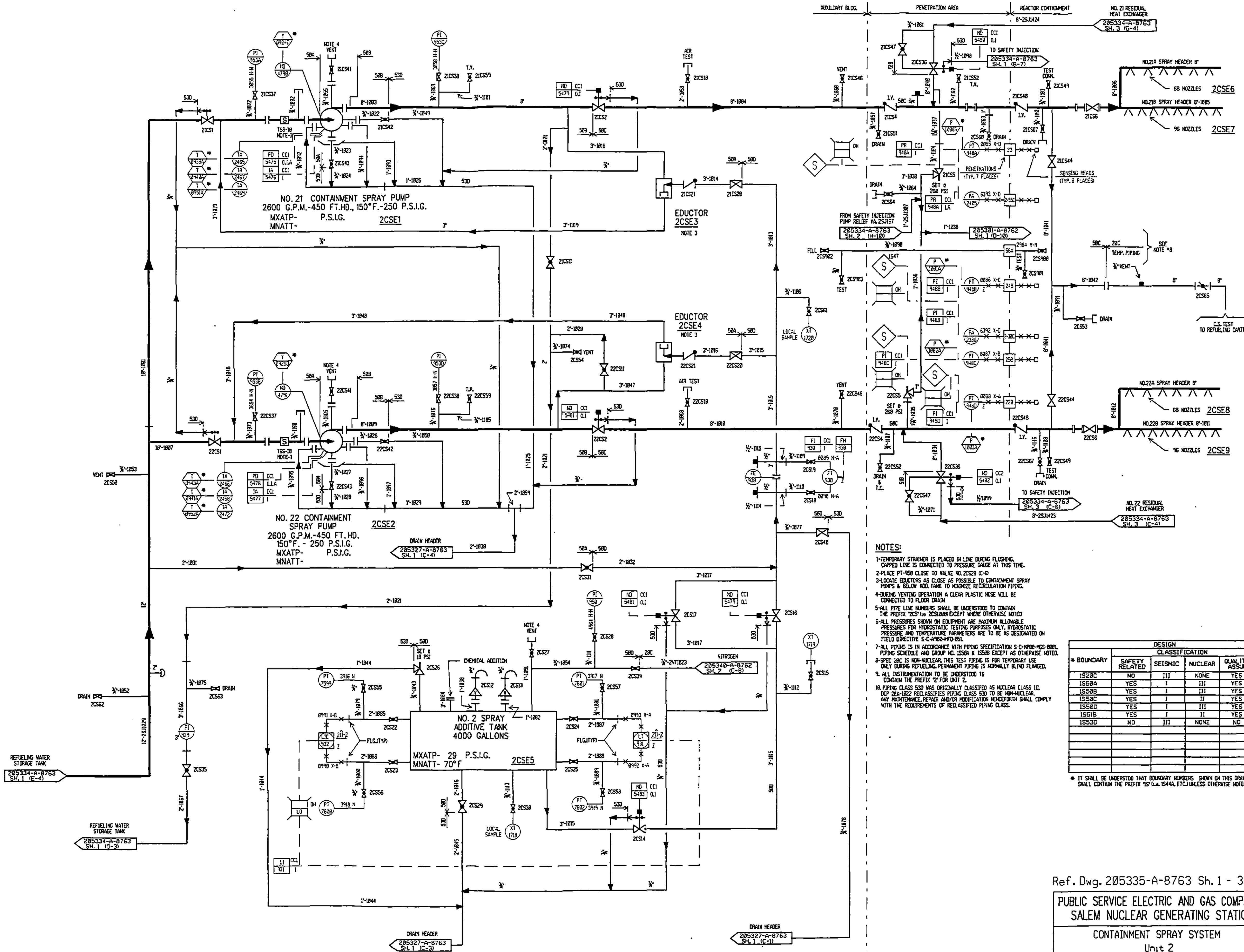
NOTE: FOR VALVE MARK NO'S. NOT SHOWN ON THIS SHEET, REFER TO MMIS.

Ref. Dwg. 205235-A-8761 Sh. 1 - 39

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Containment Spray System
Unit 1

Updated FSAR Sheet 1 of 1
Revision 17, October 16, 1998 Fig 6.2-4A



NOTES:

1-TEMPORARY STRAINER IS PLACED IN LINE DURING FLUSHING. CAPPED LINE IS CONNECTED TO PRESSURE GAUGE AT THIS TIME.

2-PLACE PT-950 CLOSE TO VALVE NO. 2CS28 (C-6)

3-LOCATE EDUCTORS AS CLOSE AS POSSIBLE TO CONTAINMENT SPRAY PUMPS & BELOW ADD. TANK TO MINIMIZE RECIRCULATION PIPING.

4-DURING VENTING OPERATION A CLEAR PLASTIC HOSE WILL BE CONNECTED TO FLOOR DRAIN

5-ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "2CS" (i.e. 2CS1000) EXCEPT WHERE OTHERWISE NOTED

6-ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051.

7-ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION S-C-MP00-MGS-0001. PIPING SCHEDULE AND GROUP NO. 1S50A & 1S50B EXCEPT AS OTHERWISE NOTED.

8-SPEC 20C IS NON-NUCLEAR. THIS TEST PIPING IS FOR TEMPORARY USE ONLY DURING REFUELING. PERMANENT PIPING IS NORMALLY BLIND FLANGED.

9. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "2" FOR UNIT 2.

10. PIPING CLASS 530 WAS ORIGINALLY CLASSIFED AS NUCLEAR CLASS III. DCP 2EA-1022 RECLASSIFIES PIPING CLASS 530 TO BE NON-NUCLEAR. ANY MAINTENANCE, REPAIR AND/OR MODIFICATION HENCEFORTH SHALL COMPLY WITH THE REQUIREMENTS OF RECLASSIFIED PIPING CLASS.

* BOUNDARY	DESIGN CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S20C	NO	III	NONE	YES
1S50A	YES	I	III	YES
1S50B	YES	I	III	YES
1S50C	YES	I	II	YES
1S50D	YES	I	III	YES
1S51B	YES	I	II	YES
1S53D	NO	III	NONE	NO

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (i.e. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

NOTE: FOR VALVE MARK NO'S NOT SHOWN ON THIS SHEET, REFER TO MMIS.

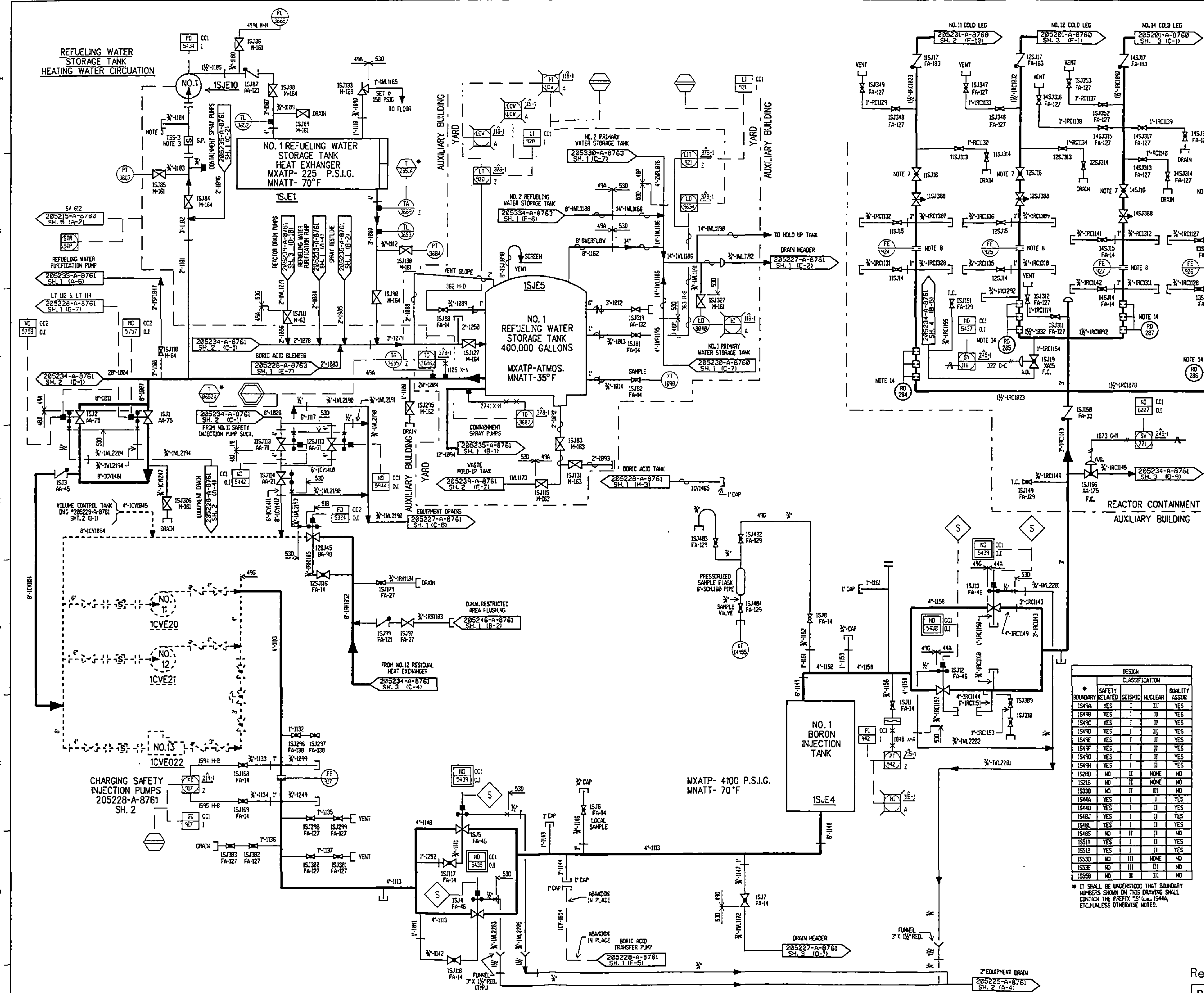
Ref. Dwg. 205335-A-8763 Sh. 1 - 36

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

CONTAINMENT SPRAY SYSTEM
Unit 2

Updated FSAR | Sheet 1 of 1

Revision 17, October 16, 1998 | Fig 6.2-4B



NOTES

1. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO AS DESIGNATED ON FIELD DIRECTIVE S-C-A9CO-MFD-05L
2. LOCATE VALVE BEHIND SHIELDING.
3. TEMPORARY STRAINER IS PLACED IN LINE DURING INITIAL FLUSHING CAPPED LINE IN CONNECTION TO A TEMPERATURE PRESSURE GAGE AT THIS TIME.
4. VALVE HAS LEAKOFF CONNECTION WHICH IS PERMANENTLY PIPED TO EQUIPMENT DRAIN HEADER. OTHER VALVES WITH LEAKOFFS CONNECTIONS (NOT SHOWN) SHALL HAVE STUBS SEALED AND CAPPED.
5. DURING ACCUMULATOR VENTING A TEMPORARY HOSE MAY BE CONNECTED TO CONTAINMENT PURGE DUCT.
6. DURING PUMP VENTING A TEMPORARY CLEAR PLASTIC HOSE MAY BE CONNECTED TO FLOOR DRAIN.
7. ADJUST VALVE IN FIELD TO LIMIT PUMP RUNOUT, THEN LOCK.
8. FLOW METERING ORIFICE TO VERIFY FLOW DURING PREOPERATIONAL TESTING.
9. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1SJ" (i.e. 1SJ1000 ETC.) EXCEPT WHERE OTHERWISE NOTED
10. ALL CONTROL VALVES HAVE OPEN & CLOSED LIMIT SWITCHES.
11. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 1SJ178-AO).
12. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "1" FOR UNIT 1.
13. PIPING CLASS 530 WAS ORIGINALLY CLASSIFED AS NUCLEAR CLASS III. DCP 1EA-1028 RECLASSIFIES PIPING CLASS 530 TO BE NON-NUCLEAR. ANY MAINTENANCE, REPAIR AND/OR MODIFICATION HENCEFORTH SHALL COMPLY WITH THE REQUIREMENTS OF RECLASSIFIED PIPING CLASS.
14. SEE DWG. 207464 FOR ORIFICE ARRANGEMENT DETAILS.
15. SEE DWG. 218269 FOR ORIFICE ARRANGEMENT DETAILS.

* BOUNDARY	DESIGN CLASSIFICATION SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR
1S49A	YES	I	III	YES
1S49B	YES	I	II	YES
1S49C	YES	I	II	YES
1S49D	YES	I	III	YES
1S49E	YES	I	II	YES
1S49F	YES	I	II	YES
1S49G	YES	I	II	YES
1S49H	YES	I	II	YES
1S20D	NO	II	NONE	NO
1S21B	NO	II	NONE	NO
1S33B	NO	II	III	NO
1S44A	YES	I	I	YES
1S44D	YES	I	II	YES
1S48J	YES	I	II	YES
1S48L	YES	I	II	YES
1S48S	NO	II	II	NO
1S51A	YES	I	II	YES
1S51B	YES	I	II	YES
1S53D	NO	III	NONE	NO
1S53E	NO	III	III	NO
1S55B	NO	II	III	NO

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (i.e., 1S44A, ETC.) UNLESS OTHERWISE NOTED.

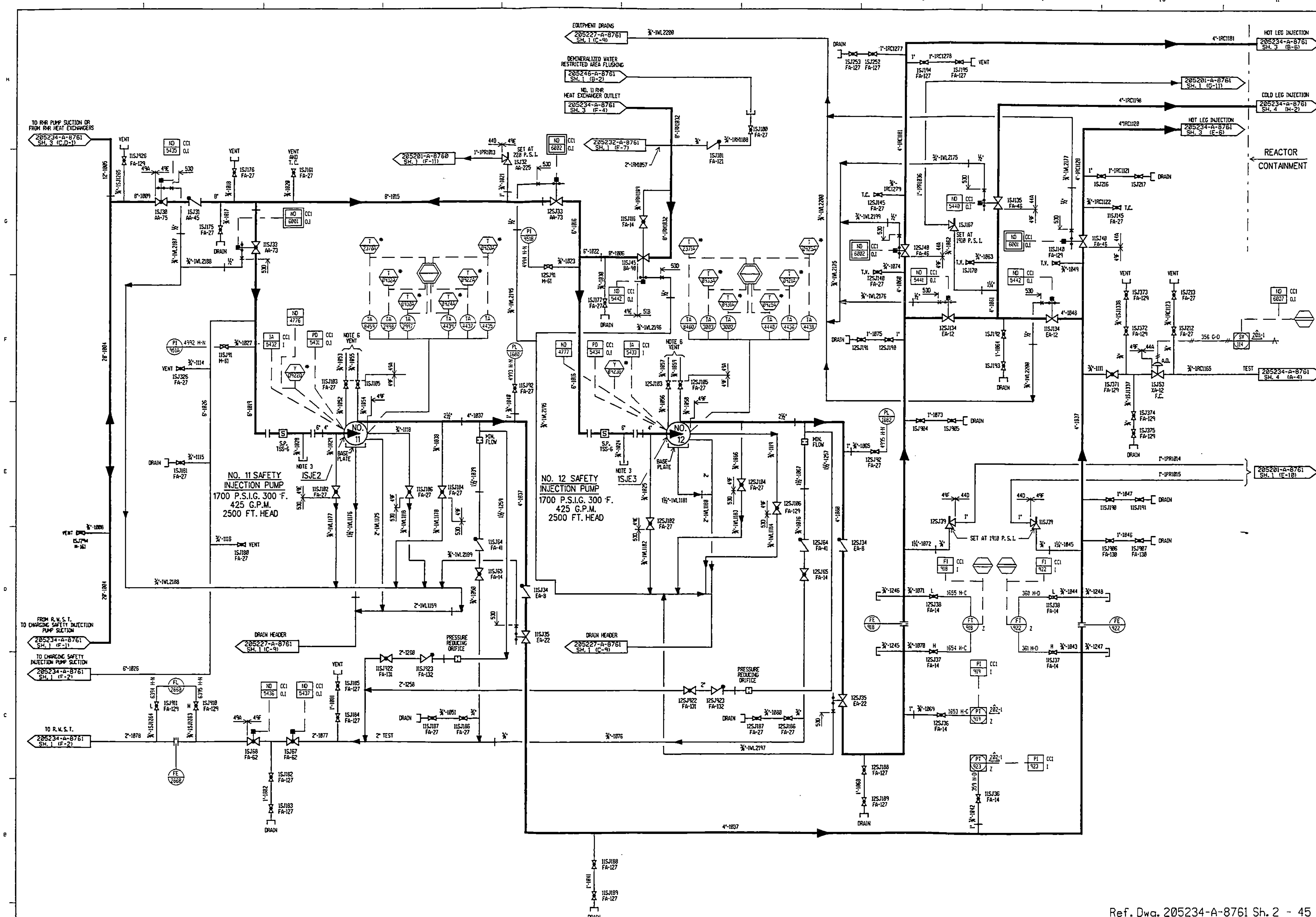
NOTE:
FOR VALVE MARK NO'S. NOT SHOWN ON THIS SHEET, REFER TO MNIS.

Ref. Dwg. 205234-A-8761 Sh. 1 - 47

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Emergency Core Cooling System
Unit 1

Updated FSAR
Sheet 1 of 4
Revision 17, October 16, 1998
Fig 6.3-1A



NOTE "B" - REV. 45
DELETED: NOTE "TO NO.1 PRESSURIZER RELIEF TANK" ABOVE OFF PAGE CONNECTORS TO DWG. 205201-A-8760 (H-4), (H,10-11), (E-11).
REVISION SUPERSEDES & INCORPORATES S97-0174, CD NO. M505/0, PKG. 01

NOTE:
FOR VALVE MARK NO'S. NOT SHOWN ON THIS SHEET, REFER TO MKIS.

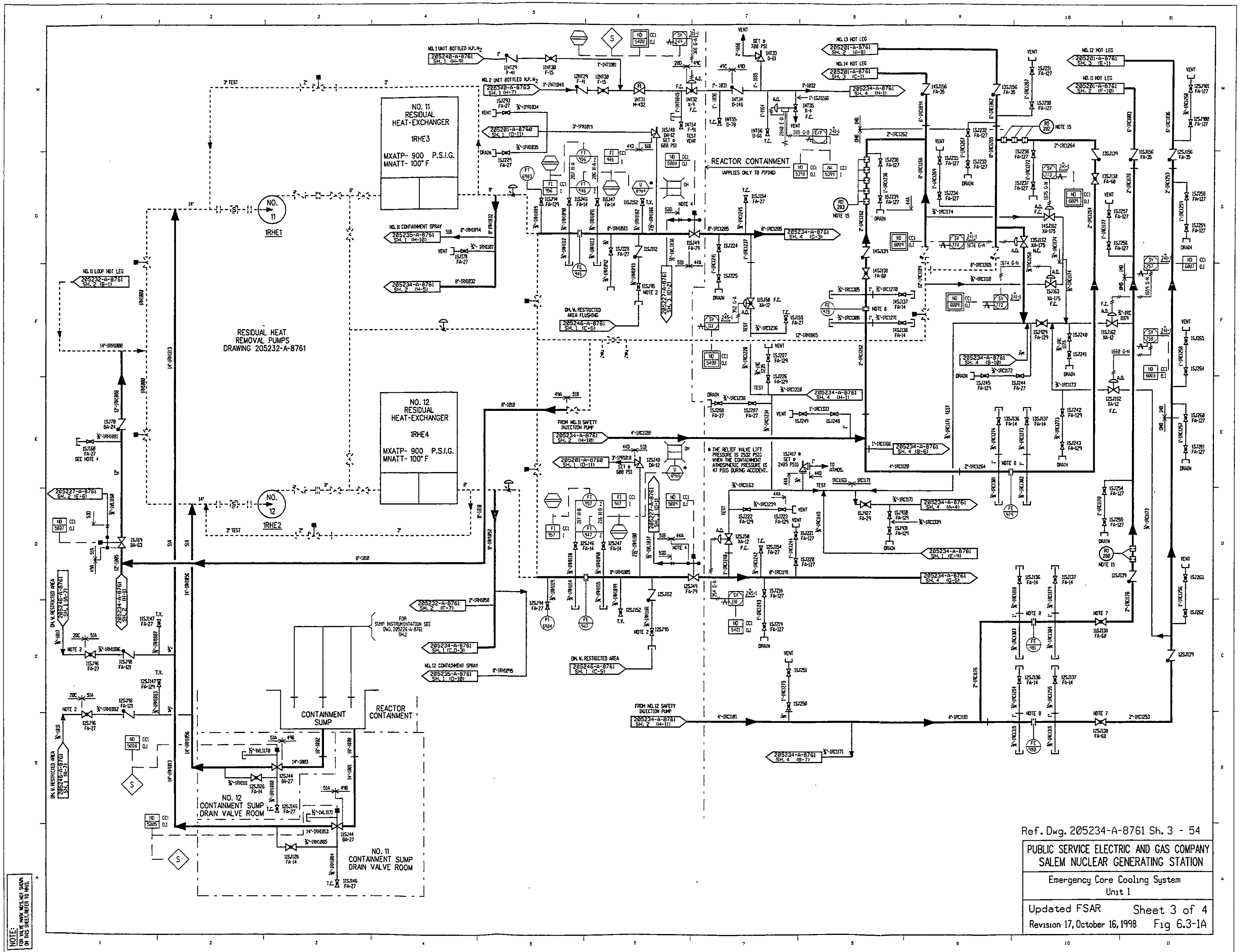
Ref. Dwg. 205234-A-8761 Sh. 2 - 45

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Emergency Core Cooling System
Unit 1

Updated FSAR — Sheet 2 of 4

Revision 17, October 16, 1998 — Fig 6.3-1A



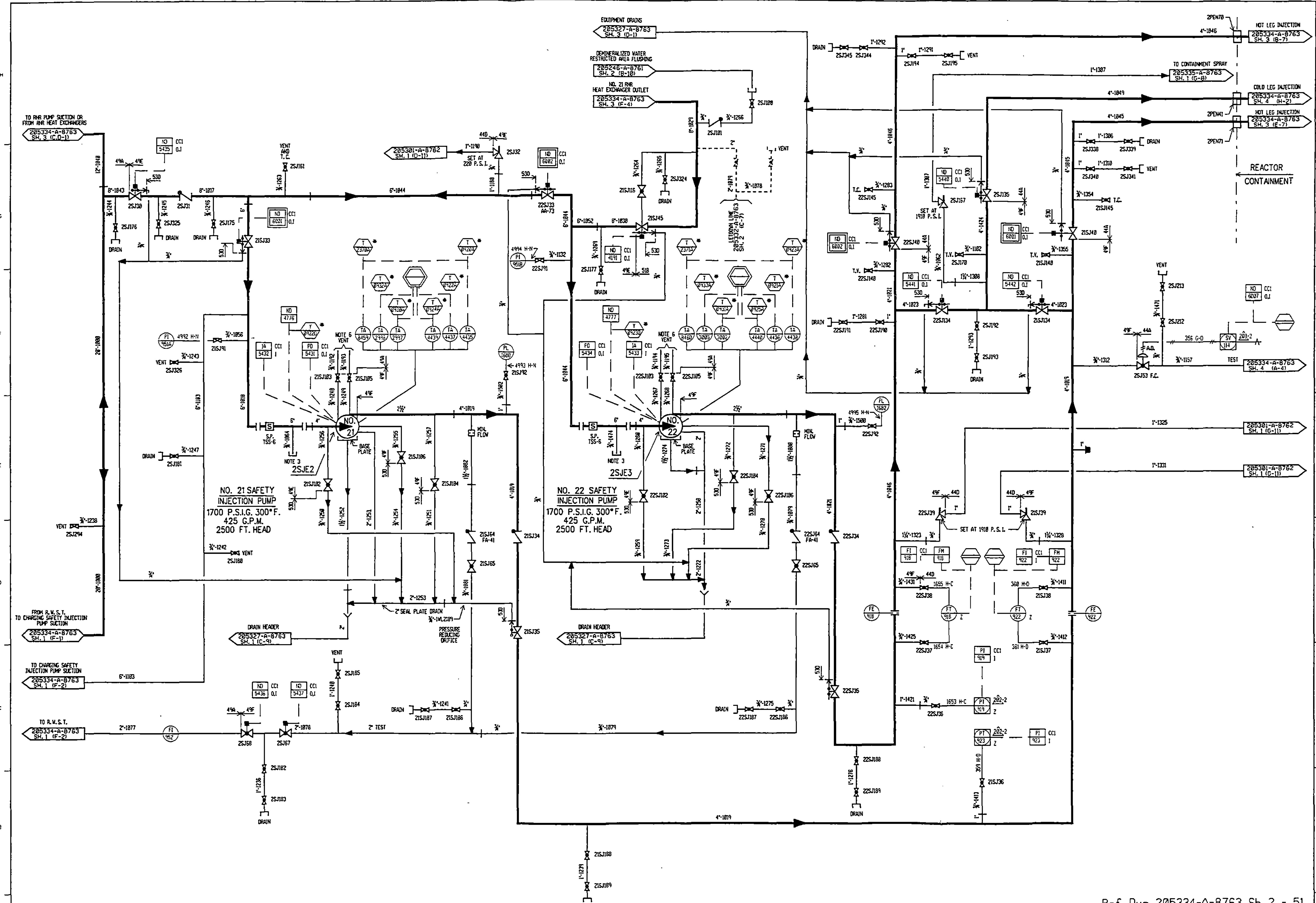
Ref. Dwg. 205234-A-8761 Sh. 3 - 54

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Emergency Core Cooling System
Unit 1

Updated FSAR — Sheet 3 of 4

Revision 17, October 16, 1998 — Fig 6.3-1A



NOTE: FOR VALVE MARK NO'S NOT SHOWN ON THIS SHEET, REFER TO MMIS.

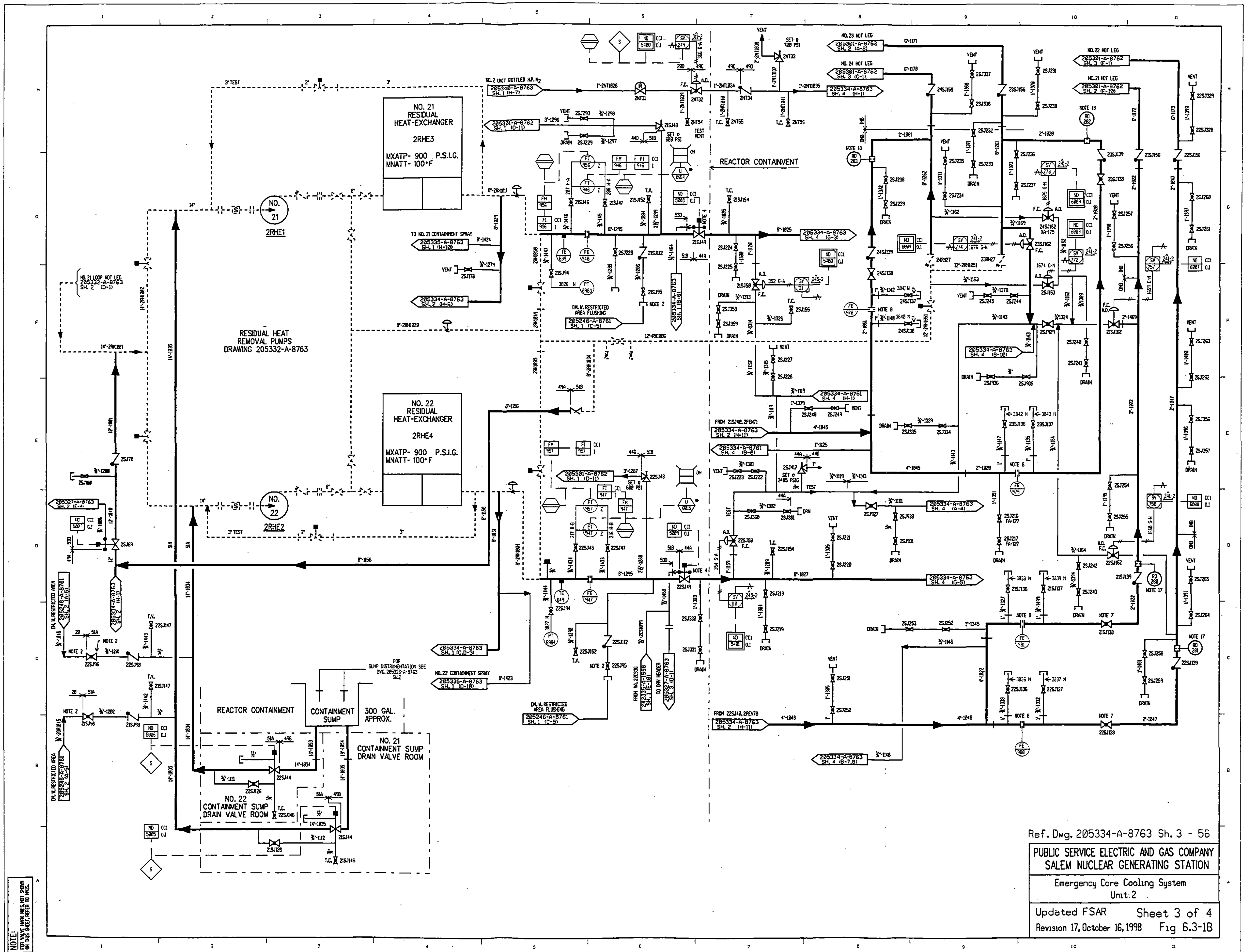
Ref. Dwg. 205334-A-8763 Sh. 2 - 51

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Emergency Core Cooling System
Unit 2

Updated FSAR — Sheet 2 of 4

Revision 17, October 16, 1998 — Fig 6.3-1B

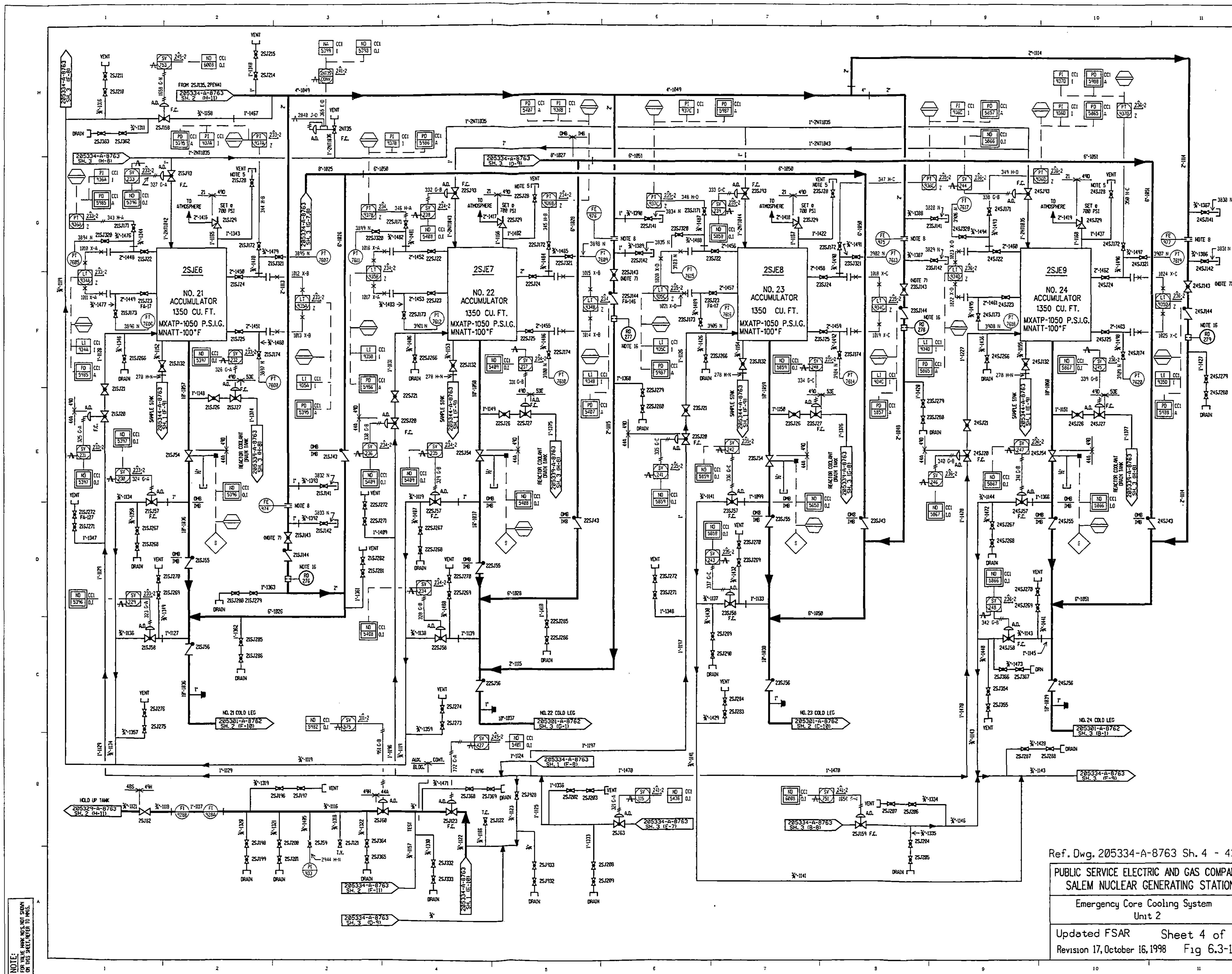


Ref. Dwg. 205334-A-8763 Sh. 3 - 56

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Emergency Core Cooling System
Unit 2

Updated FSAR Sheet 3 of 4
Revision 17, October 16, 1998 Fig 6.3-1B

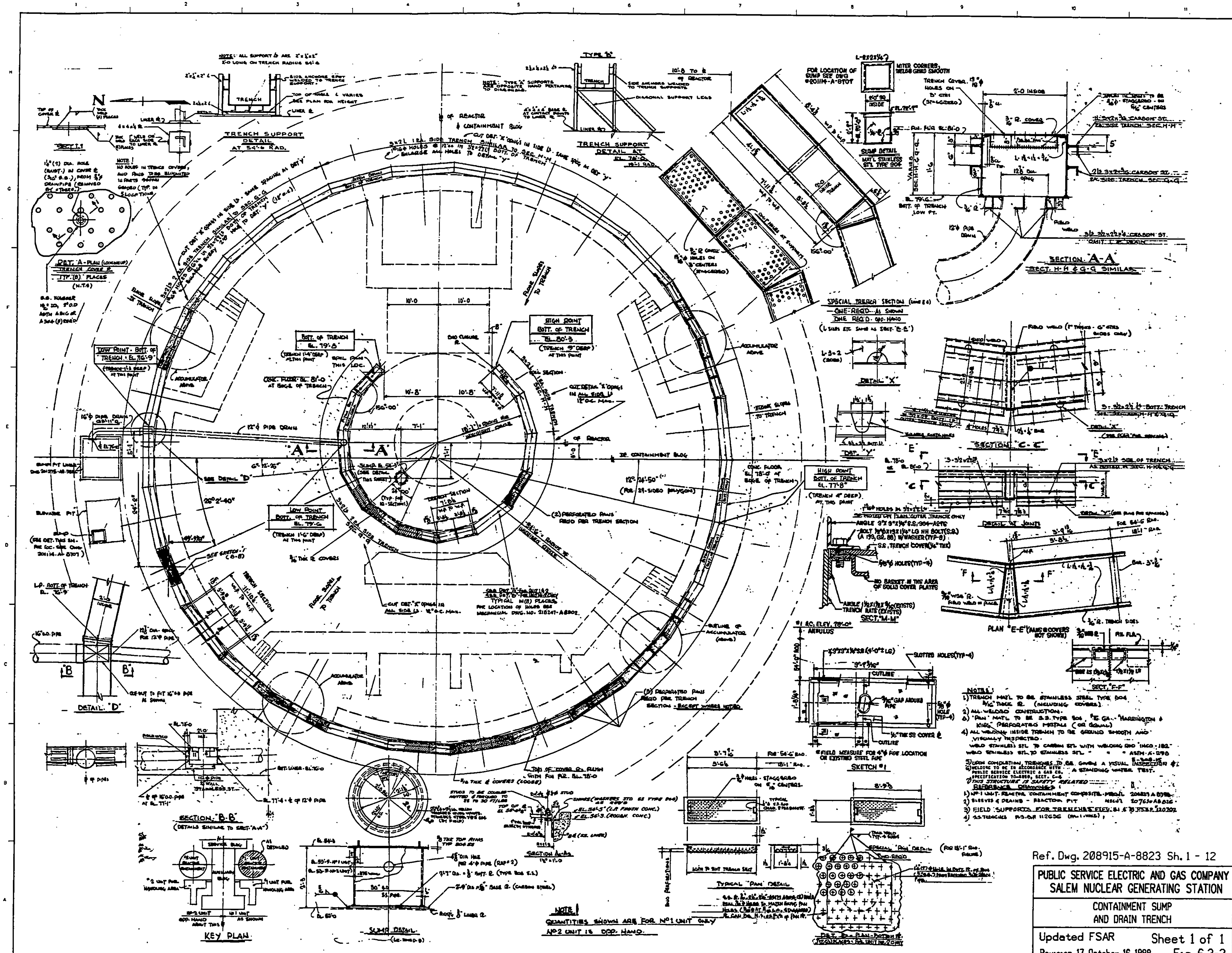


Ref. Dwg. 205334-A-8763 Sh. 4 - 43

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Emergency Core Cooling System
Unit 2

Updated FSAR Sheet 4 of 4
Revision 17, October 16, 1998 Fig 6.3-1B



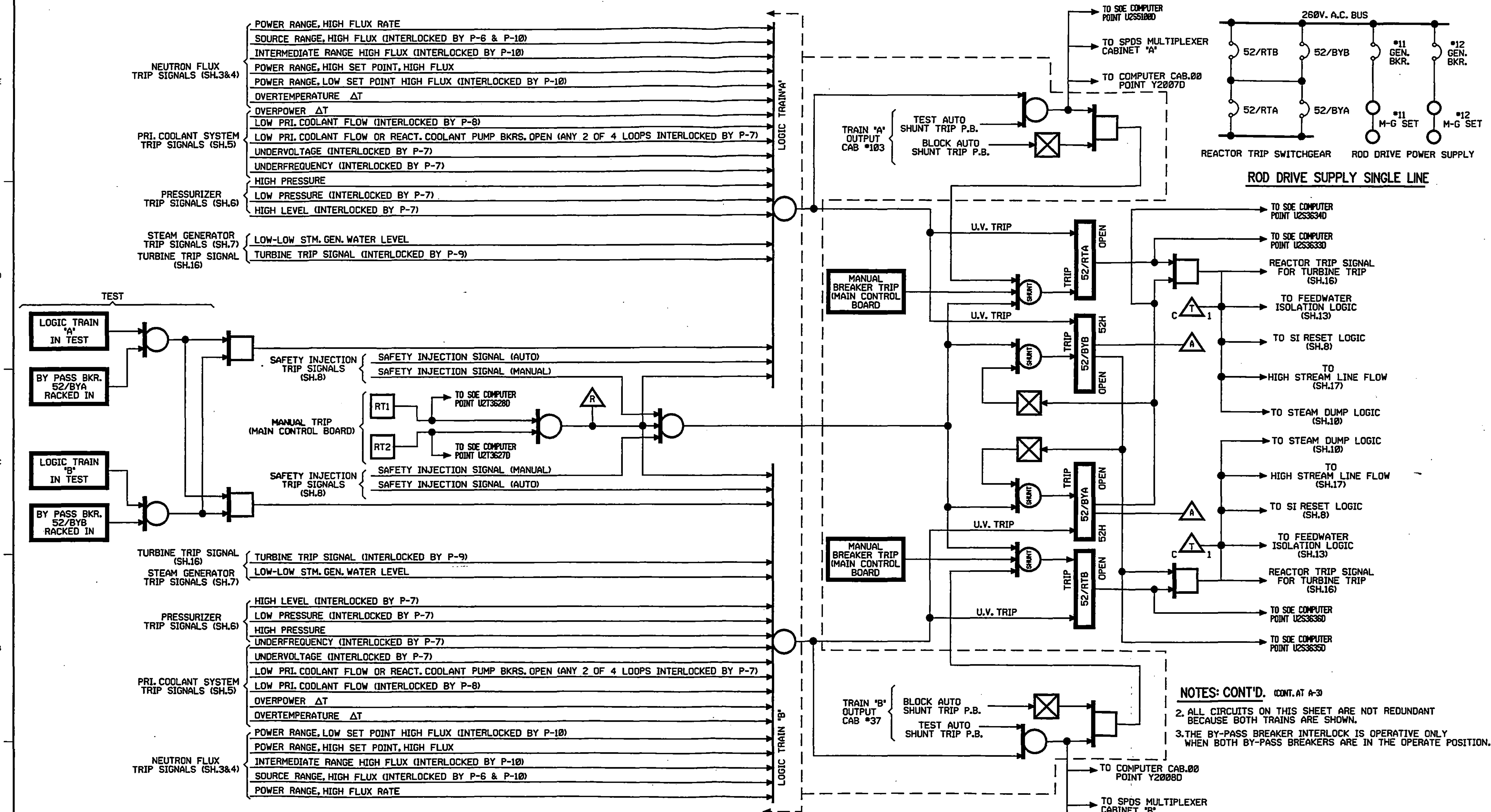
Ref. Dwg. 208915-A-8823 Sh. 1 - 12

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

CONTAINMENT SUMP
AND DRAIN TRENCH

Updated FSAR — Sheet 1 of 1

Revision 17, October 16, 1998 — Fig 6.3-2



NOTES: CONT'D. (CONT. AT A-3)

2. ALL CIRCUITS ON THIS SHEET ARE NOT REDUNDANT BECAUSE BOTH TRAINS ARE SHOWN.
3. THE BY-PASS BREAKER INTERLOCK IS OPERATIVE ONLY WHEN BOTH BY-PASS BREAKERS ARE IN THE OPERATE POSITION.

NOTES:

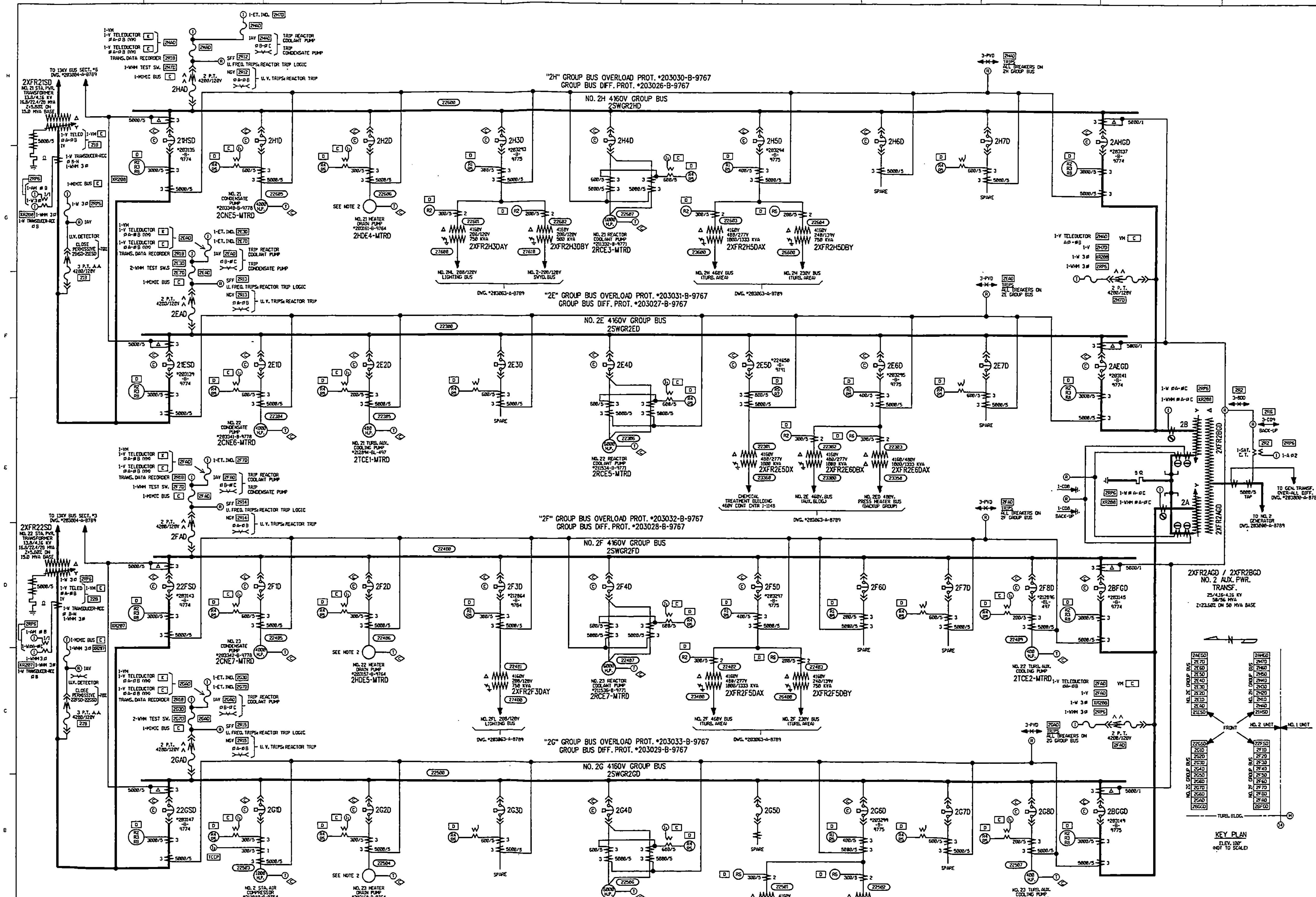
1. NORMAL REACTOR OPERATION IS TO BE WITH REACTOR TRIP BREAKERS 52/RTA AND 52/RTB IN SERVICE AND BY-PASS BREAKERS 52/BYA AND 52/BYB WITHDRAWN. DURING TEST ONE BY-PASS BREAKER IS TO BE PUT IN SERVICE AND THEN THE RESPECTIVE REACTOR TRIP BREAKER IS OPERATED USING A SIMULATED REACTOR TRIP SIGNAL IN THE TRAIN UNDER TEST. THE REACTOR WILL NOT BE TRIPPED BY THE SIMULATED SIGNAL SINCE THE BY-PASS BREAKER IS CONTROLLED FROM THE OTHER TRAIN. ONLY ONE REACTOR TRIP BREAKER IS TO BE TESTED AT A TIME. (CONT. AT B-7)

Ref. Dwg. 221051-B-9545 Sh. 1 - 11

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

REACTOR PROTECTION SYSTEM
Units 1 & 2

Updated FSAR — Sheet 1 of 1
Rev. 17, October 16, 1998 — Fig 7.2-2



MULTI-RATIO C. T.'S

– 3000-4000-5000/5 DWG. *30226-D-496

– 100-200-300-400-500-600-800-900-1000-1200/5 DWG. *30226-D-496

NOTES:

1. ALL BREAKERS ARE 1200 AMP EXCEPT MAIN BREAKERS: 2AHGD, 2AEGD, 2BFGD, 2BGGD, 21HSD, 21ESD, 22FSD & 22GSD WHICH ARE 2000 AMP.
2. THE H.P. FOR THE HEATER DRAIN PUMP MOTORS ARE 1000/1250. FOR SIZE AND LOCATION SEE MMIS.
3. DUE TO NO. 2 AUX. PWR. TRANSF. REPLACEMENT, WINDING 2B FEEDS BUS 2H & 2E, & WINDING 2A FEEDS BUS 2F & 2G.

LOCATION INDEX & ABBREV.'S

C- NO. 2 CONSOLE IN CONTROL ROOM
D- 4160V CUBICLE AT WHICH EQUIP. IS SHOWN RELAYS DESIGNATED THUS, TRIP RESPECTIVE C.B. WHERE SHOWN
K- NO. 2 COMPUTER
TCCP- TOTAL CLOSURE CONTROL PANEL
– EQUIP. DESIGNATION
– ALARM
– CONTROL
– TEMP. CONTROL
– INDICATES NODE NUMBERS FOR LOAD MANAGEMENT STUDY

RELAY & INSTR. INDEX ABBREV.'S

R — AS SHOWN
R1 – INSTANTANEOUS OVERCURRENT RELAY
R2 — VERY INVERSE OVERCURRENT RELAY
R3 – VERY INVERSE CURRENT GRD. RELAY
R4 — LONG TIME INVERSE OVERCURRENT RELAY WITH INSTANTANEOUS TRIP (Ø A & Ø C)
R5 – SHORT TIME INVERSE CURRENT GRD. RELAY
R6 — STEP TYPE INVERSE OVERCURRENT RELAY
R7 – VERY INVERSE OVERCURRENT RELAY WITH INSTANTANEOUS TRIP (Ø A & Ø C)
R8 — HIGH SPEED NON DIRECTIONAL OVER CURRENT RELAY

I — AS SHOWN
I1 – 1-AM Ø B & TRANSDUCER
I2 — 1-LOAD REGULATOR

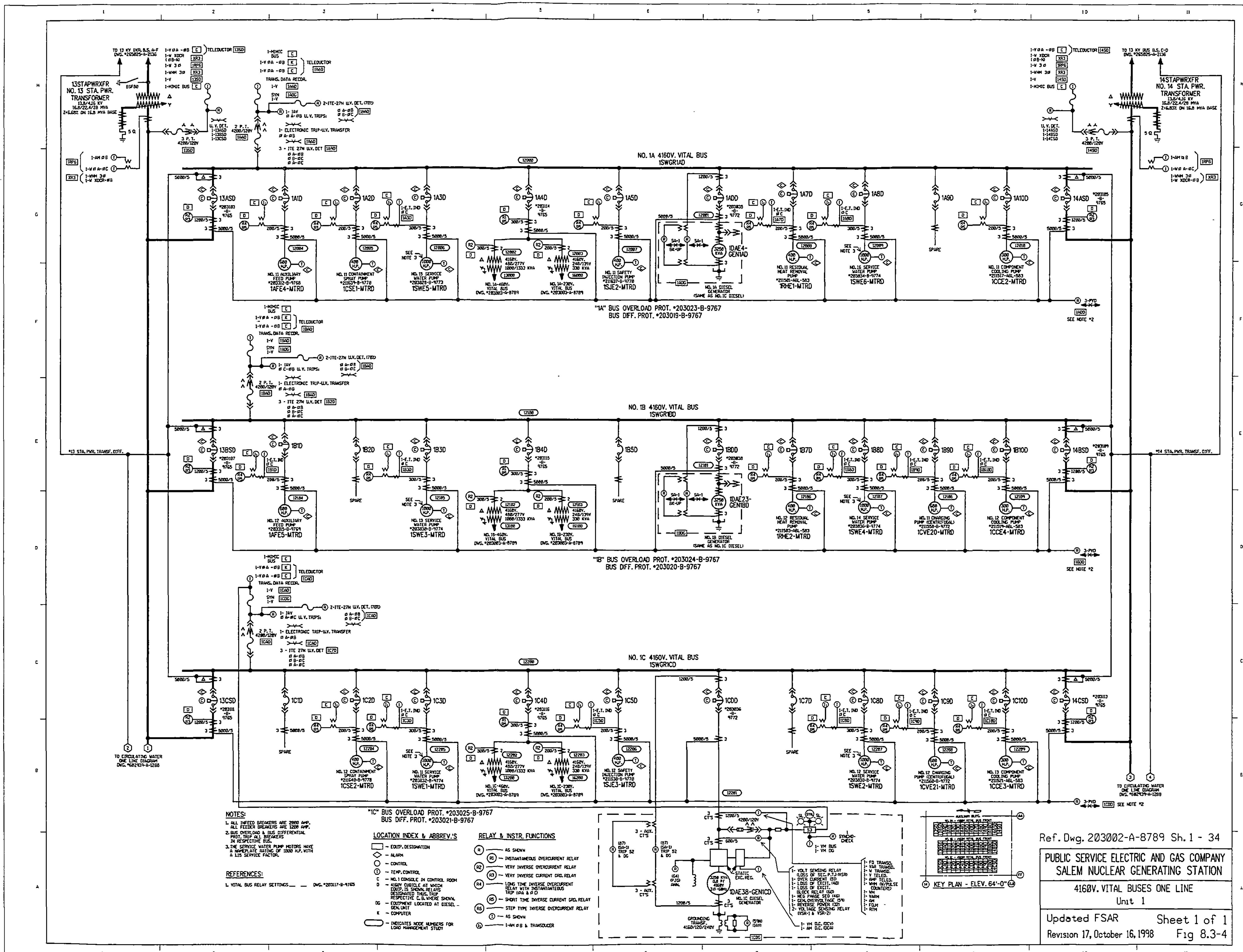
X

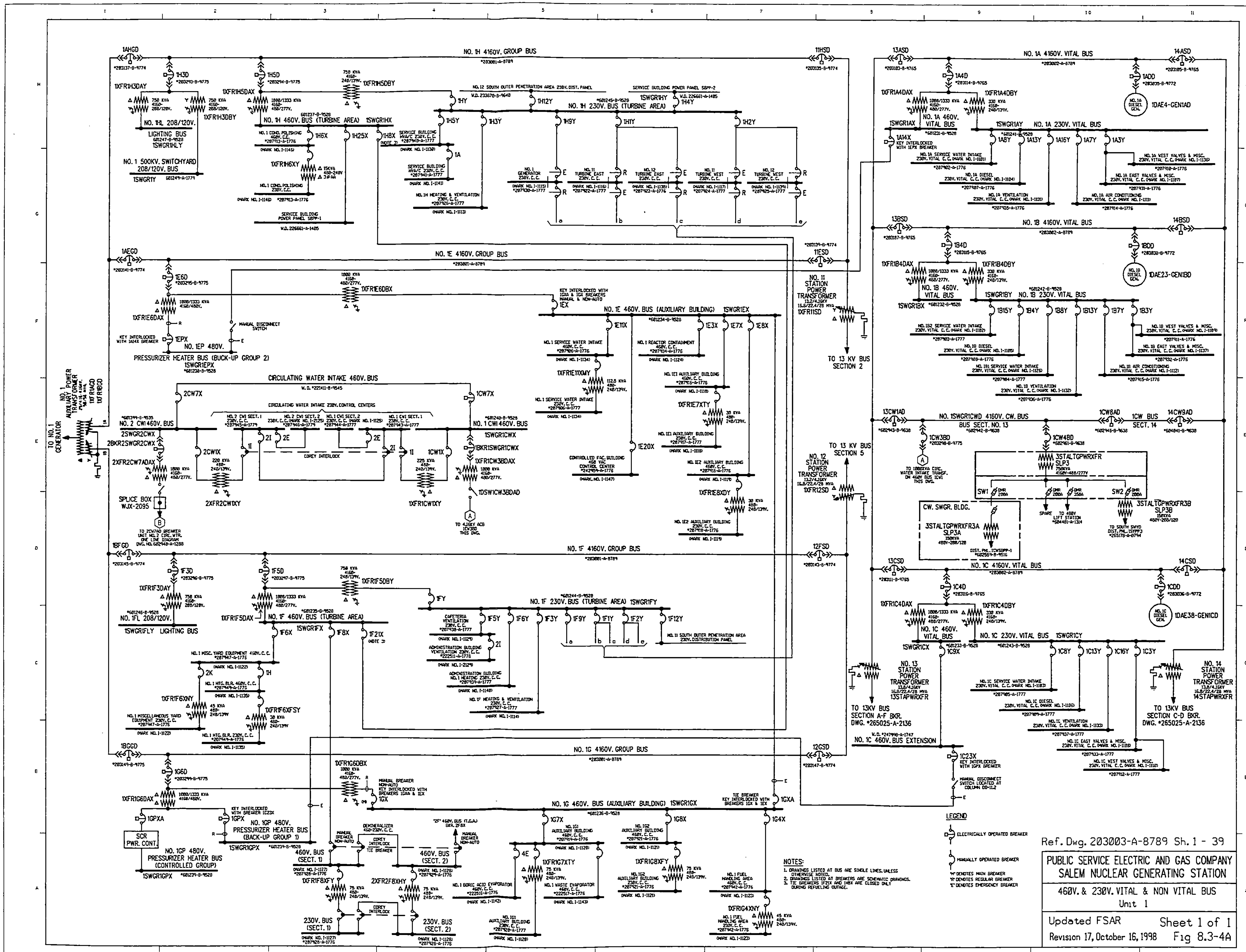
Ref. Dwg. 203062-A-8789 Sh. 1 - 26

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

4160V. GROUP BUSES ONE LINE
Unit 2

Updated FSAR — Sheet 1 of 1
Revision 17, October 16, 1998 — Fig 8.3-3B


13STAPWRXFR NO. 13 STA. PWR. TRANSFORMER
14STAPWRXFR NO. 14 STA. PWR. TRANSFORMER
NO. 1A 4160V. VITAL BUS 1SWGR1AD
"1A" BUS OVERLOAD PROT. *203023-B-9767
BUS DIFF. PROT. *203019-B-9767
NO. 1B 4160V. VITAL BUS 1SWGR1BD
"1B" BUS OVERLOAD PROT. *203024-B-9767
BUS DIFF. PROT. *203020-B-9767
NO. 1C 4160V. VITAL BUS 1SWGR1CD
"1C" BUS OVERLOAD PROT. *203025-B-9767
BUS DIFF. PROT. *203021-B-9767
NOTES:
1. ALL INFEED BREAKERS ARE 2000 AMP. ALL FEEDER BREAKERS ARE 1200 AMP.
2. BUS OVERLOAD & BUS DIFFERENTIAL PROT. TRIP ALL BREAKERS IN RESPECTIVE BUS.
3. THE SERVICE WATER PUMP MOTORS HAVE A NAMEPLATE RATING OF 1000 H.P. WITH A 1.15 SERVICE FACTOR.
REFERENCES:
1. VITAL BUS RELAY SETTINGS DWG. *203117-B-9765
LOCATION INDEX & ABBREV.'S
– EQUIP. DESIGNATION
– ALARM
– CONTROL
– TEMP. CONTROL
C – NO. 1 CONSOLE IN CONTROL ROOM
D – 4160V CUBICLE AT WHICH EQUIP. IS SHOWN. RELAYS DESIGNATED THUS. TRIP RESPECTIVE C.B. WHERE SHOWN.
DG – EQUIPMENT LOCATED AT DIESEL GEN. UNIT
K – COMPUTER
– INDICATES NODE NUMBERS FOR LOAD MANAGEMENT STUDY
RELAY & INSTR. FUNCTIONS
R – AS SHOWN
R1 – INSTANTANEOUS OVERCURRENT RELAY
R2 – VERY INVERSE OVERCURRENT RELAY
R3 – VERY INVERSE CURRENT GRD. RELAY
R4 – LONG TIME INVERSE OVERCURRENT RELAY WITH INSTANTANTEOUS TRIP (ØA & ØC)
R5 – SHORT TIME INVERSE CURRENT GRD. RELAY
R6 – STEP TYPE INVERSE OVERCURRENT RELAY
I – AS SHOWN
I1 – 1-AM ØB & TRANSDUCER
KEY PLAN - ELEV. 64'-0"
Ref. Dwg. 203002-A-8789 Sh. 1 - 34
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION
4160V. VITAL BUSES ONE LINE
Unit 1
Updated FSAR
Sheet 1 of 1
Revision 17, October 16, 1998
Fig 8.3-4



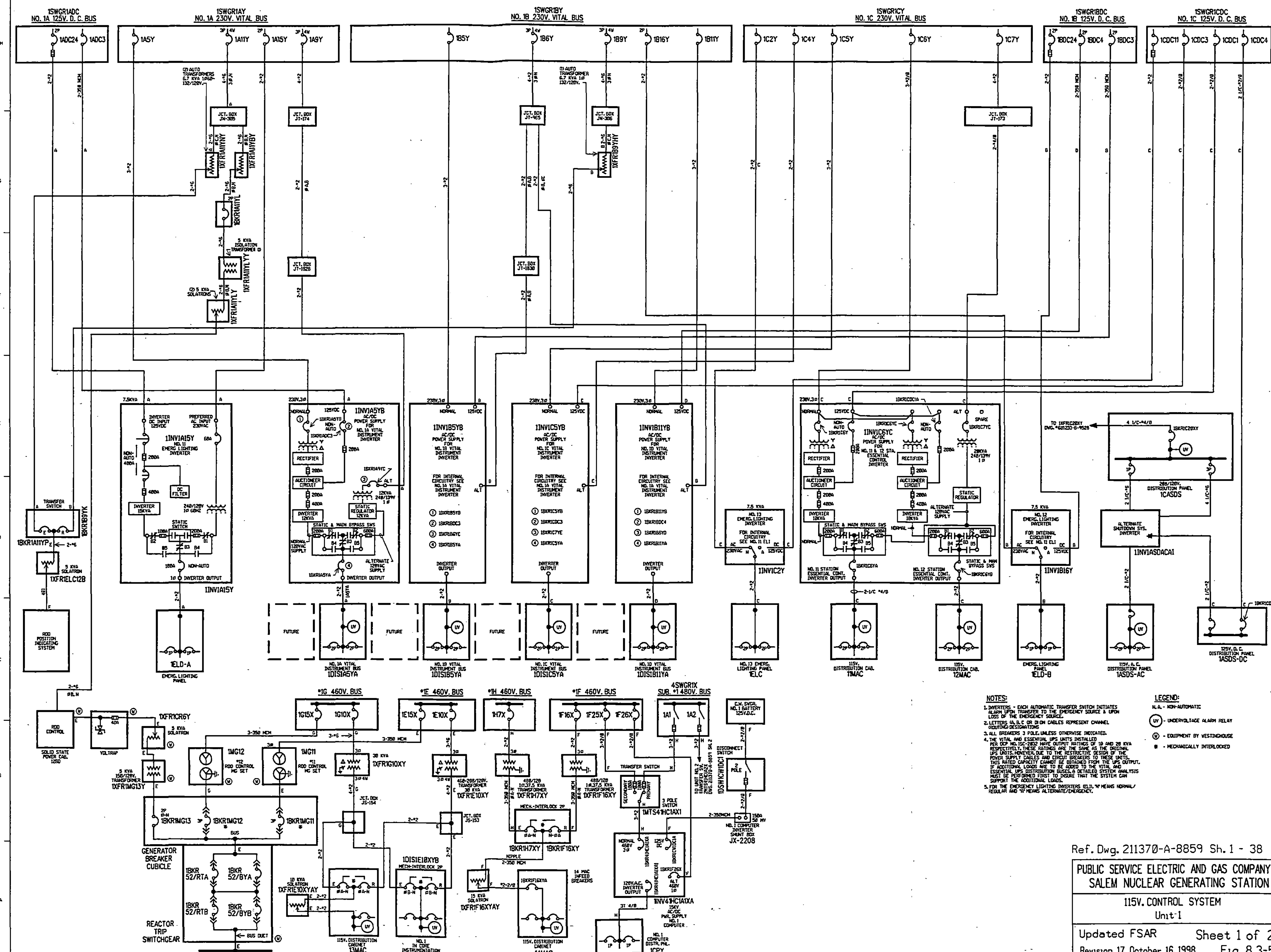
Ref. Dwg. 203003-A-8789 Sh. 1 - 39

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

460V. & 230V. VITAL & NON VITAL BUS
Unit 1

Updated FSAR
Revision 17, October 16, 1998

Sheet 1 of 1
Fig 8.3-4A



NOTES:

1. INVERTERS - EACH AUTOMATIC TRANSFER SWITCH INITIATES ALARM UPON TRANSFER TO THE EMERGENCY SOURCE & UPON LOSS OF THE EMERGENCY SOURCE.
2. LETTERS (A, B, C OR D) ON CABLES REPRESENT CHANNEL (ROUTING) DESIGNATIONS
3. ALL BREAKERS 3 POLE, UNLESS OTHERWISE INDICATED.
4. THE VITAL AND ESSENTIAL UPS UNITS INSTALLED PER DCP NO. 1SC-2032 HAVE OUTPUT RATINGS OF 10 AND 20 KVA RESPECTIVELY. THESE RATINGS ARE THE SAME AS THE ORIGINAL UPS UNITS. HOWEVER, DUE TO THE RESTRICTIVE DESIGN OF THE POWER SUPPLY CABLES AND CIRCUIT BREAKERS TO THESE UNITS, THIS RATED CAPACITY CANNOT BE OBTAINED FROM THE UPS OUTPUT. IF ADDITIONAL LOADS ARE TO BE ADDED TO THE VITAL AND ESSENTIAL UPS DISTRIBUTION BUSES, A DETAILED SYSTEM ANALYSIS MUST BE PERFORMED FIRST TO INSURE THAT THE SYSTEM CAN SUPPORT THE ADDITIONAL LOADS.
5. FOR THE EMERGENCY LIGHTING INVERTERS (ELI), "N" MEANS NORMAL/REGULAR AND "A" MEANS ALTERNATE/EMERGENCY.

LEGEND:

N.A. - NON-AUTOMATIC
UV - UNDERVOLTAGE ALARM RELAY
W - EQUIPMENT BY WESTINGHOUSE
* - MECHANICALLY INTERLOCKED

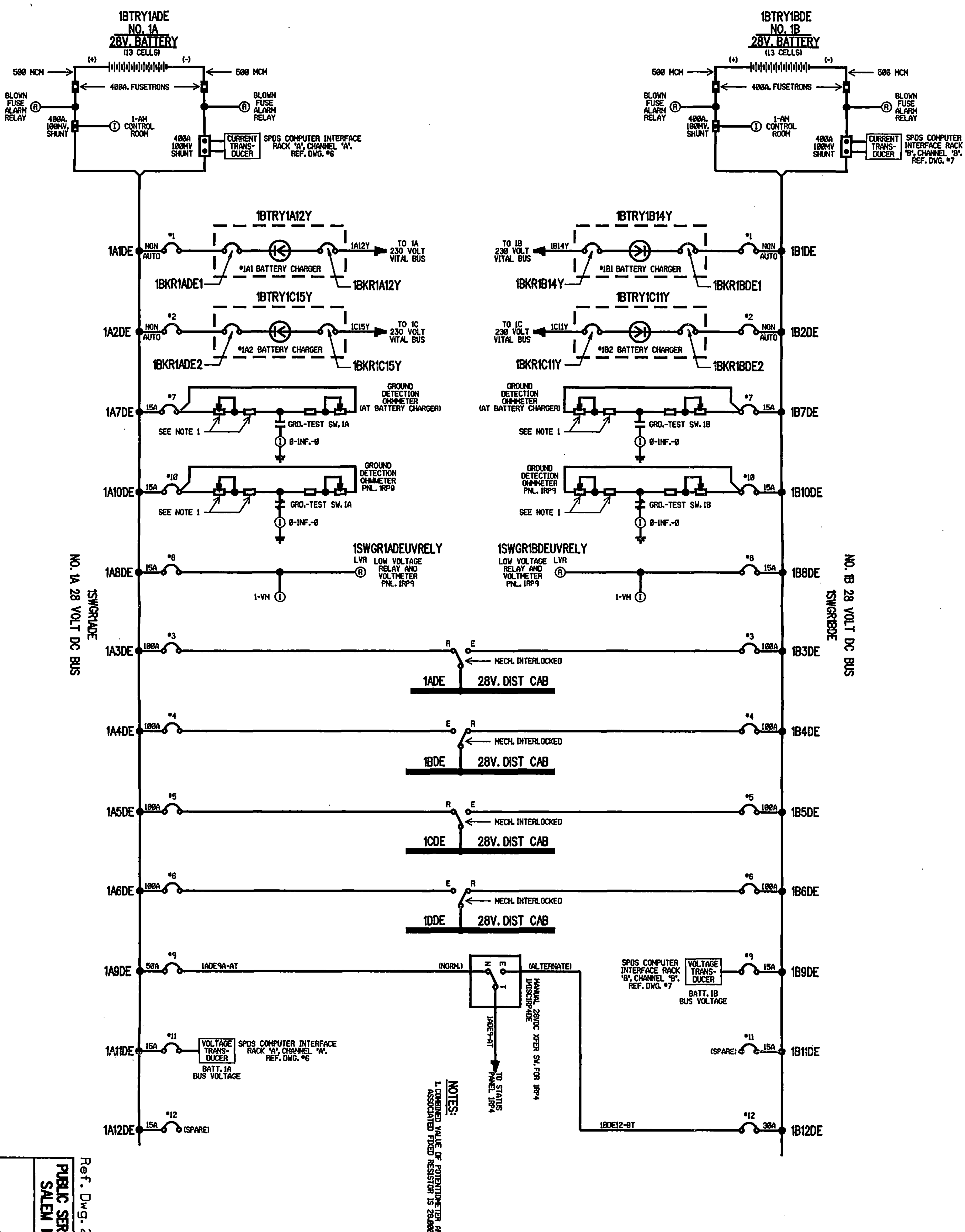
Ref. Dwg. 211370-A-8859 Sh. 1 - 38

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

115V. CONTROL SYSTEM
Unit 1

Updated FSAR
Revision 17, October 16, 1998

Sheet 1 of 2
Fig 8.3-5

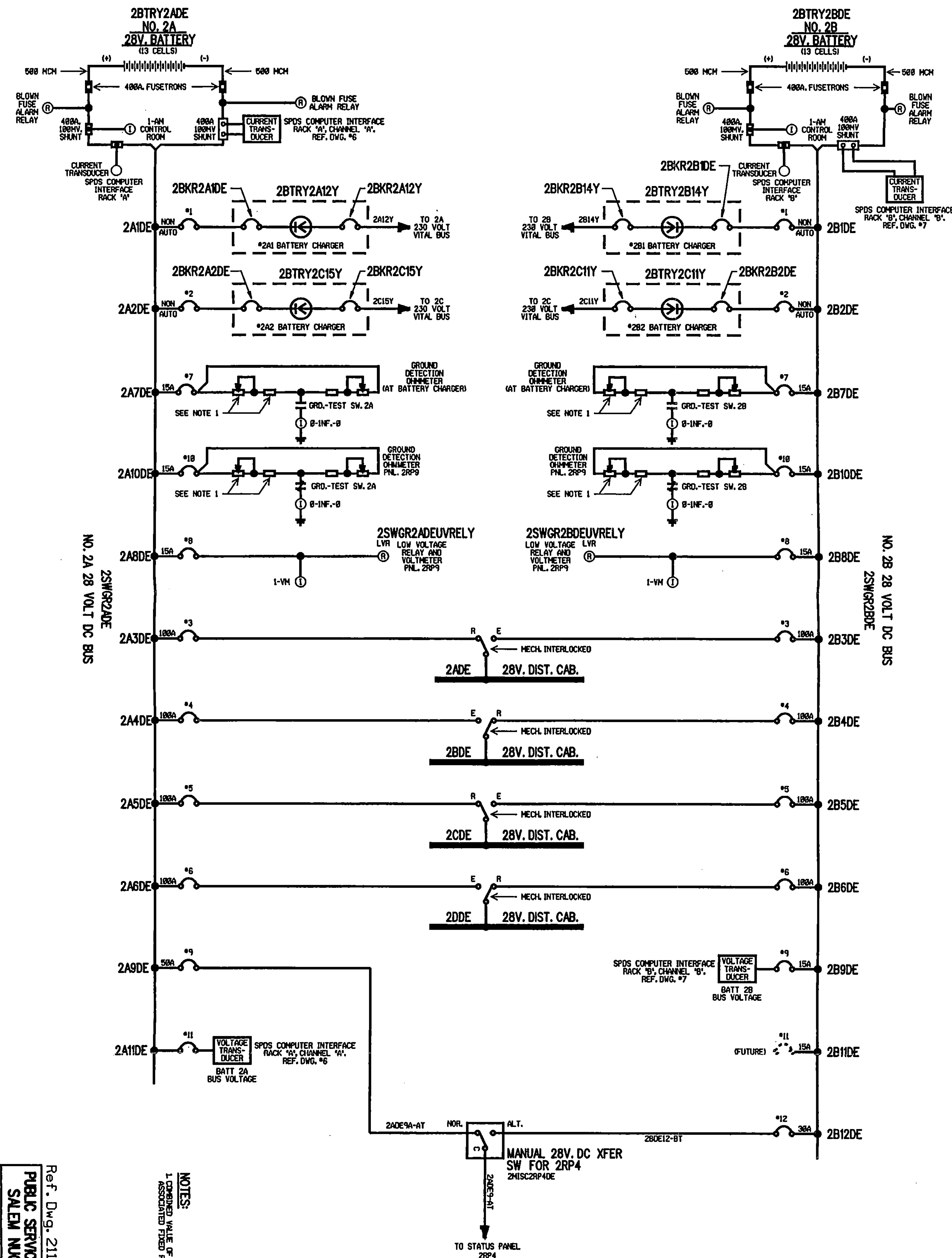


Ref. Dwg. 211357-B-9511 Sh.1 - 13

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

28 VOLT D.C. ONE LINE
Unit 1

Updated FSAR Sheet 1 of 2
Rev.17, October 16,1998 Fig 8.3-6



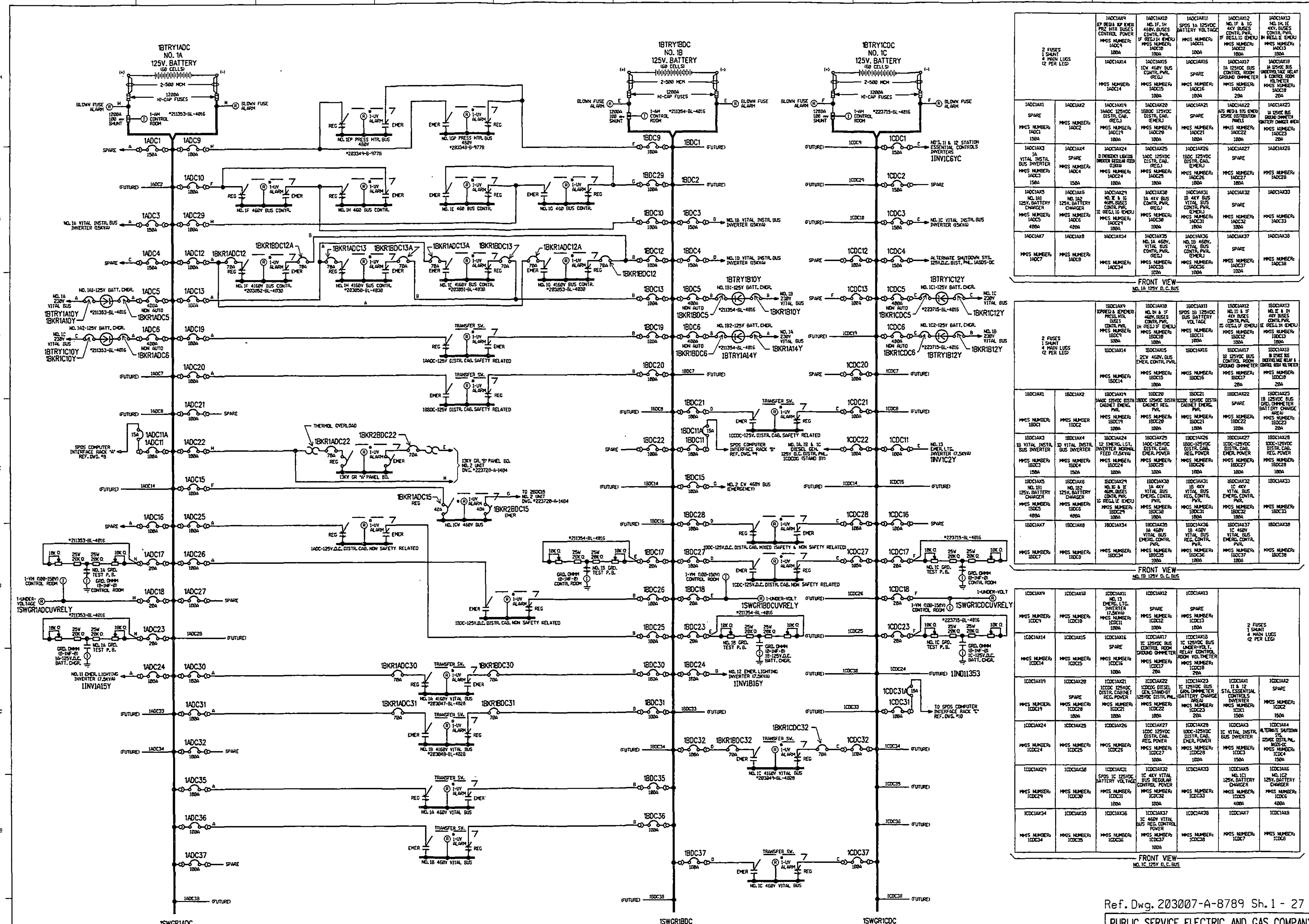
NOTES:
1. COMBINED VALUE OF POTENTIOMETER AND ASSOCIATED FIXED RESISTOR IS 20,000 Ω.

Ref. Dwg. 211357-B-9511 SH. 2 - 11

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

28 VOLT D.C. ONE LINE
Unit 2

Updated FSAR Sheet 2 of 2
Rev.17, October 16,1998 Fig 8.3-6



NOTES:

1- ALL CIRCUIT BREAKERS SHALL BE 2 POLE AND SHALL HAVE 20,000 A.D.C. MINIMUM INTERRUPTING CAPACITY.

2- MOLDED TYPE PLUG-IN CIRCUIT BREAKER

3- ● DENOTES MECH. INTERLOCKED MANUALLY OPERATED BREAKERS

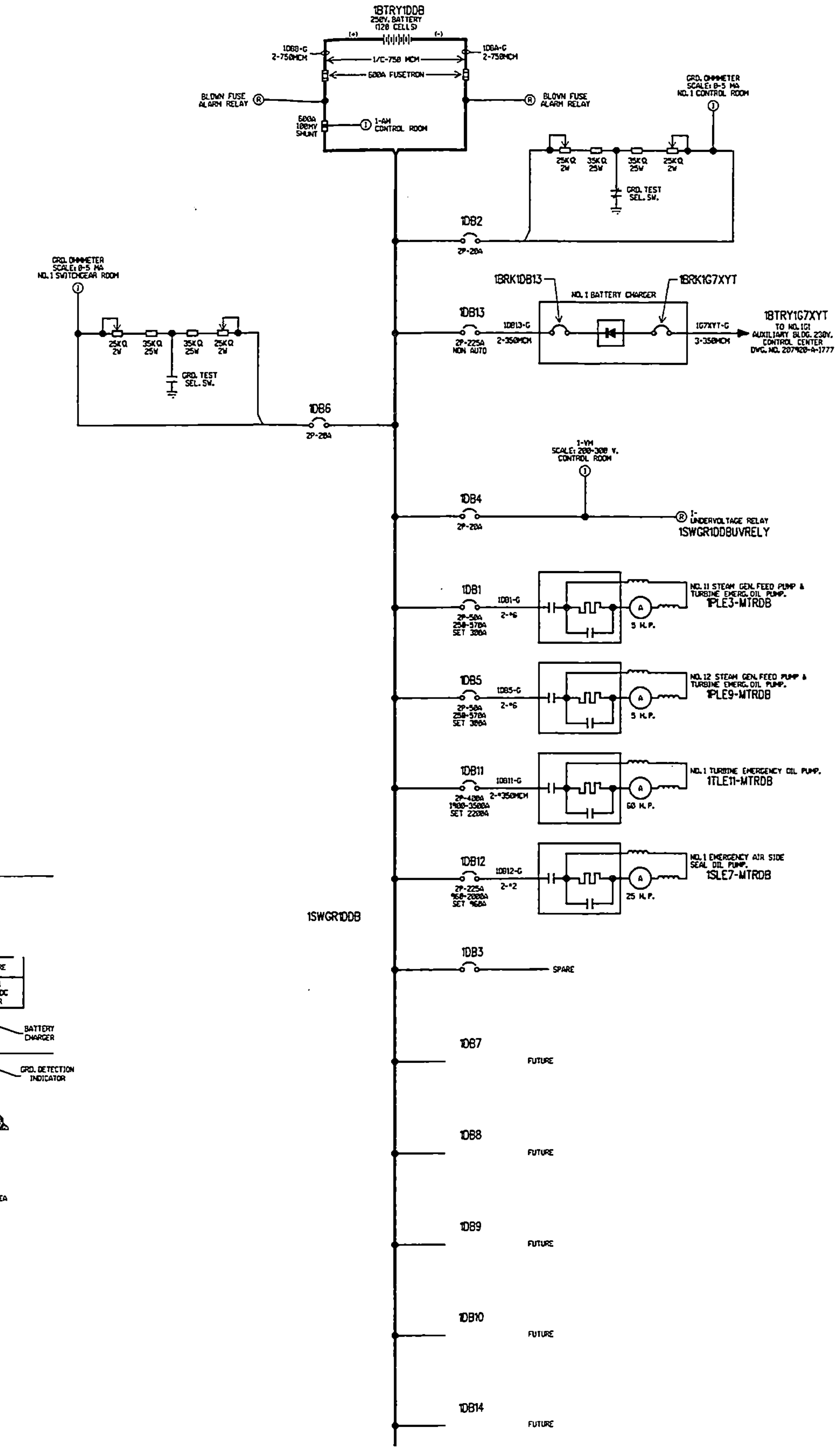
Ref. Dwg. 203007-A-8789 Sh. 1 - 27

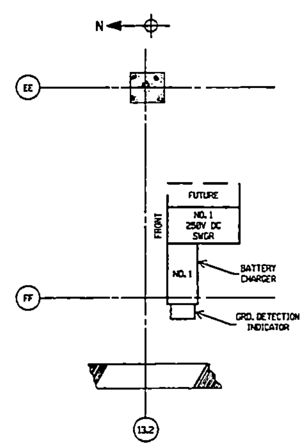
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

125 V.D.C. ONE LINE
Unit 1

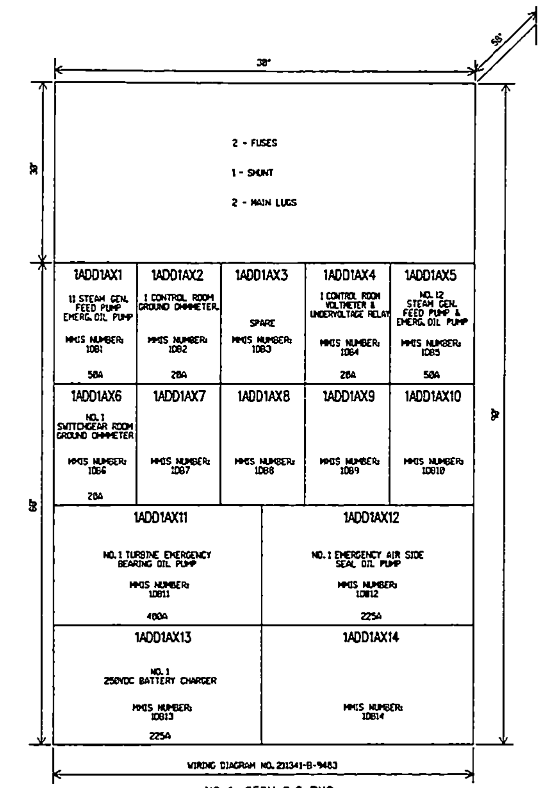
Updated FSAR — Sheet 1 of 1

Revision 17, October 16, 1998 — Fig 8.3-7





KEY PLAN
EL. 84' - AUX. BLDG. CONTROL AREA



NO. 1 250V. D.C. BUS
FRONT VIEW
(NTS)

NOTES:

1. ALL CIRCUIT BREAKERS SHALL BE 2-POLE & SHALL HAVE 20,000A. D.C. MINIMUM INTERRUPTING CAPACITY.

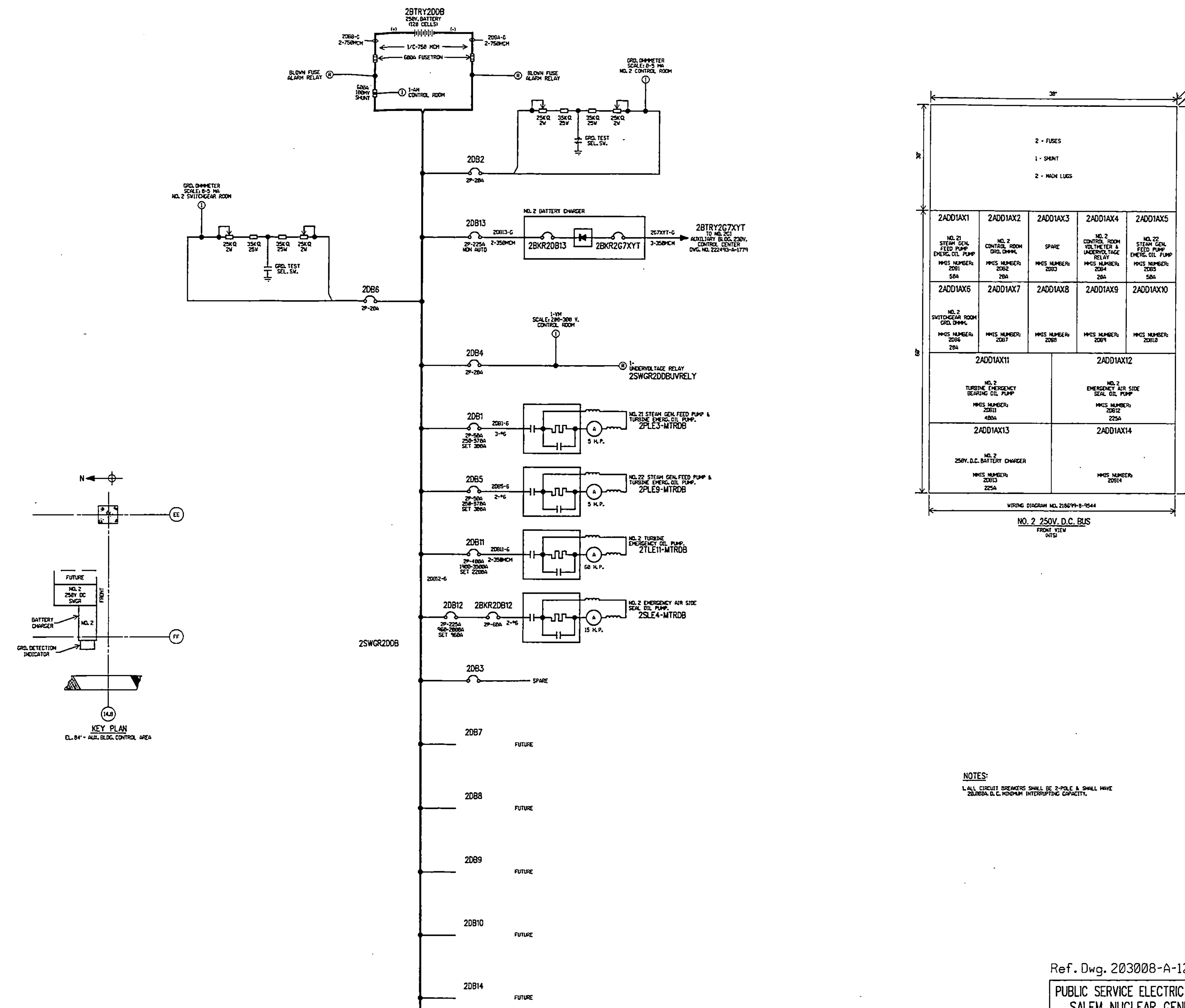
Ref. Dwg. 203008-A-1213 Sh. 1 - 10

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

250V. D.C. ONE LINE
Unit 1

Updated FSAR
Revision 17, October 16, 1998

Sheet 1 of 2
Fig 8.3-8



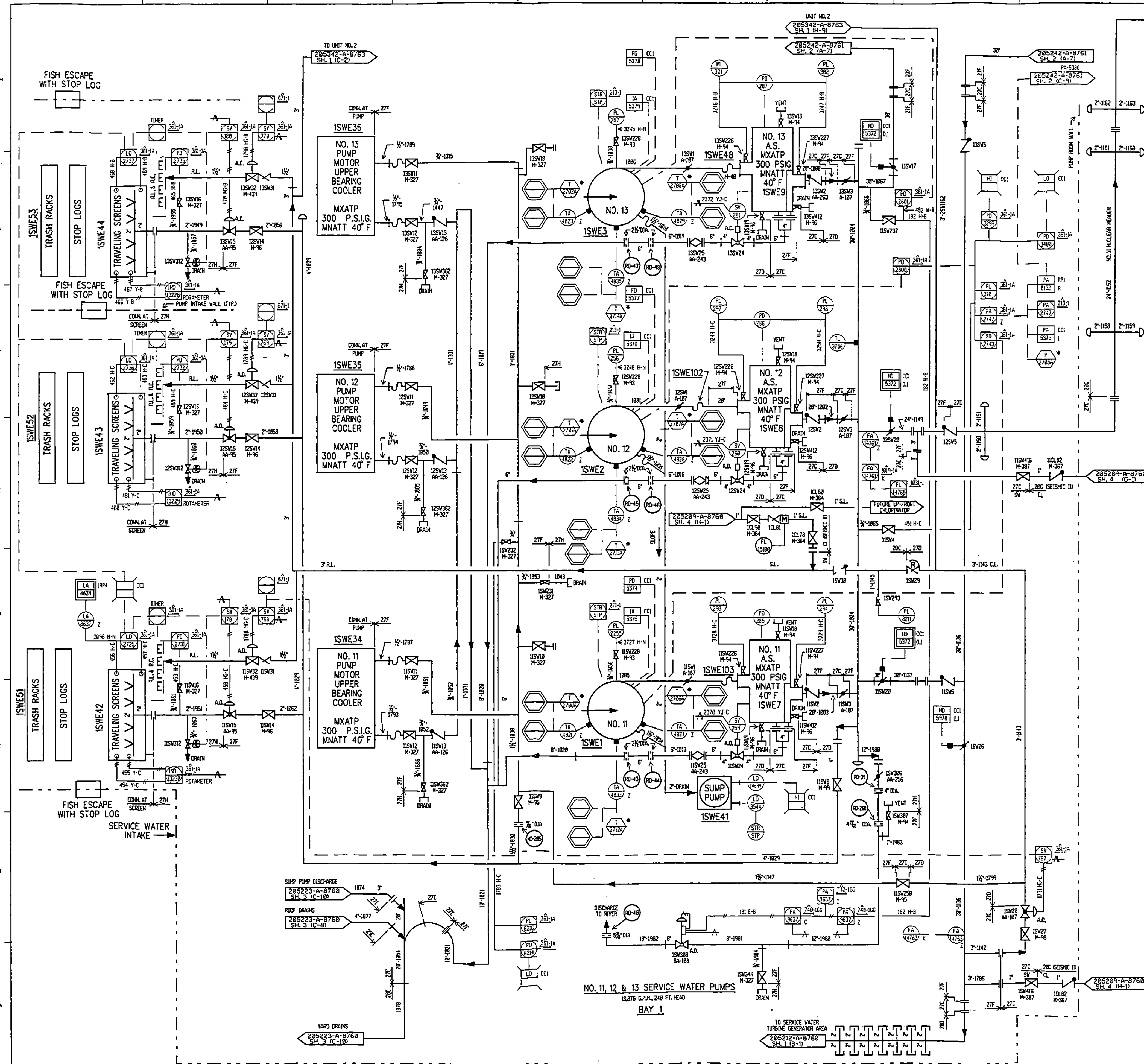
Ref. Dwg. 203008-A-1213 Sh. 2 - 11

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

250V. D. C. ONE LINE
Unit 2

Updated FSAR
Sheet 2 of 2

Revision 17, October 16, 1998
Fig 8.3-8



NOTES:

1. PIPING SCHEDULE DESIGNATIONS SHOWN ONLY FOR SEISMIC AND/OR NUCLEAR PIPING.
2. FOR DESIGN PRESSURE & TEMPERATURE PARAMETERS REFER TO THE DESIGN PRESSURE & TEMPERATURE PARAMETERS AT THE ORIGINAL SOURCE HEADER.
3. ALL PIPING NUMBERS SHALL HAVE THE PREFIX "1SW" (I.E. 1SW1000, ETC.) EXCEPT WHERE OTHERWISE NOTED.
4. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051
5. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6200. THE PIPING SCHEDULE AND GROUP NOS. ARE AS NOTED ON THIS DRAWING AND PREFIXED WITH "1S".
6.
7. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 13SW32-AO).
8. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "1" FOR UNIT 1.
9. SERVICE WATER PIPING SPEC 1S27F, 1S27G MTL 6% MOLY SS.
10. TEMPORARY STRAINER TO BE PLACED IN LINE DURING FLUSHING AND PLANT

DESIGN				
BOUNDARY *	CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S27B	YES	I	III	YES
1S27C	YES	I	III	YES
1S27D	NO	III	NONE	NO
1S27E	NO	III	NONE	NO
1S28B	YES	I	III	YES
1S28C	YES	I	III	YES
1S28D	NO	III	NONE	NO
1S29	NO	III	NONE	NO
1S27A	YES	I	II	YES
1S20C	NO	III	NONE	NO
1S27F	YES	I	III	YES
1S27G	YES	I	III	YES
1S27H	NO	III	NONE	NO
1S27I	YES	I	NONE	YES
1S27J	YES	I	II	YES
1S53D	NO	III	NONE	NO

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (I.E. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

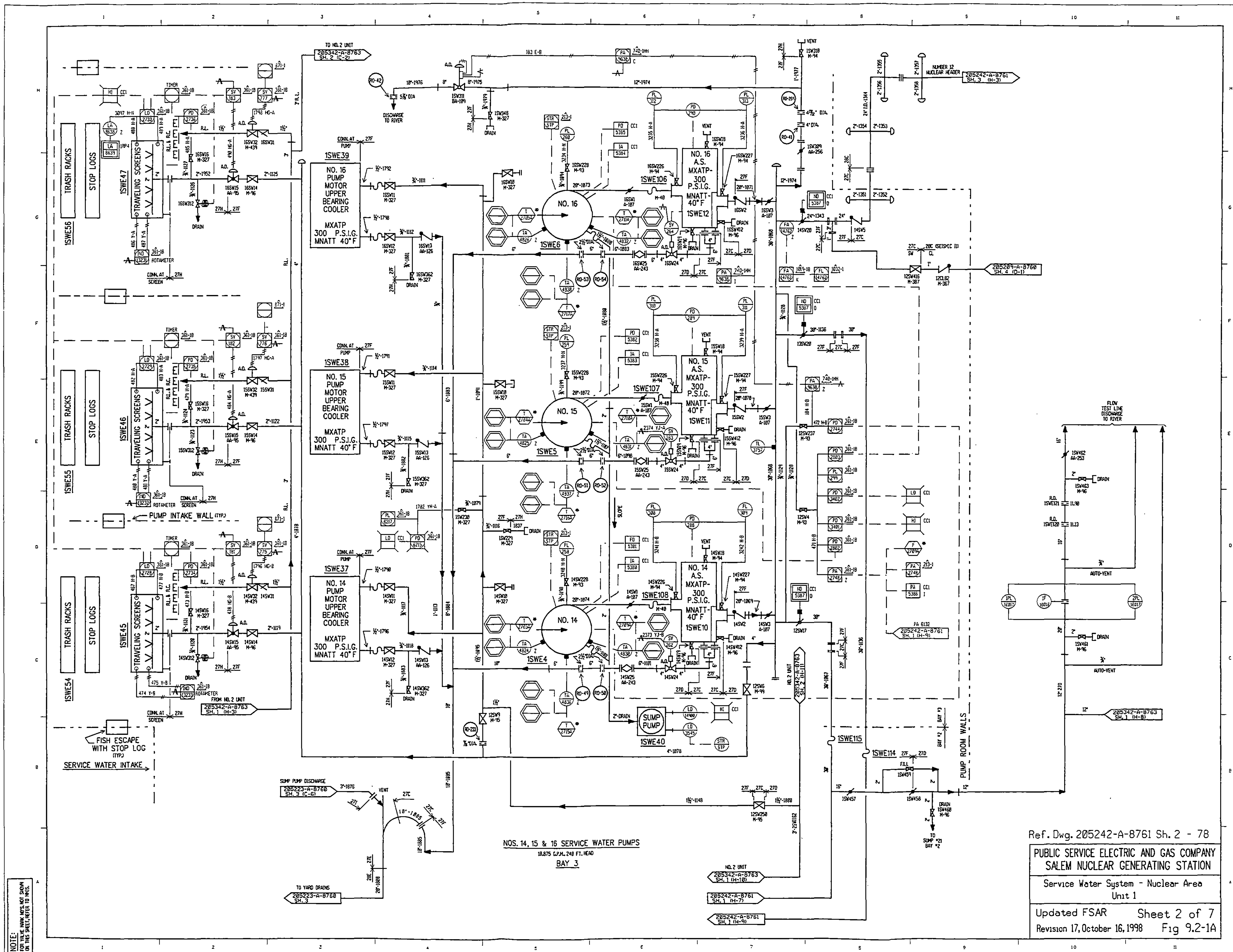
Ref. Dwg. 205242-A-8761 Sh. 1 - 81

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Service Water System - Nuclear Area
Unit 1

Updated FSAR
Sheet 1 of 7
Revision 17, October 16, 1998
Fig 9.2-1A

NOTE:

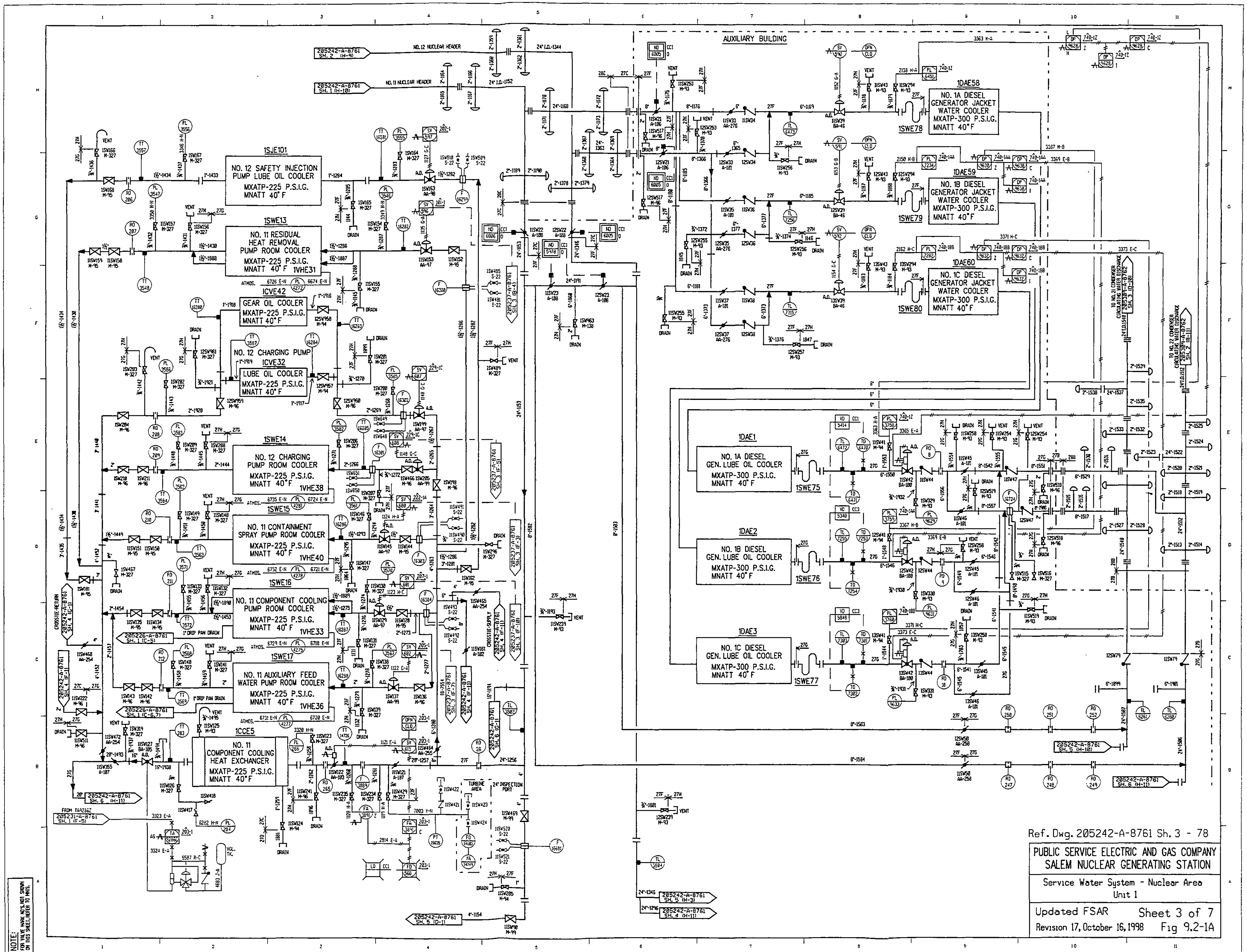


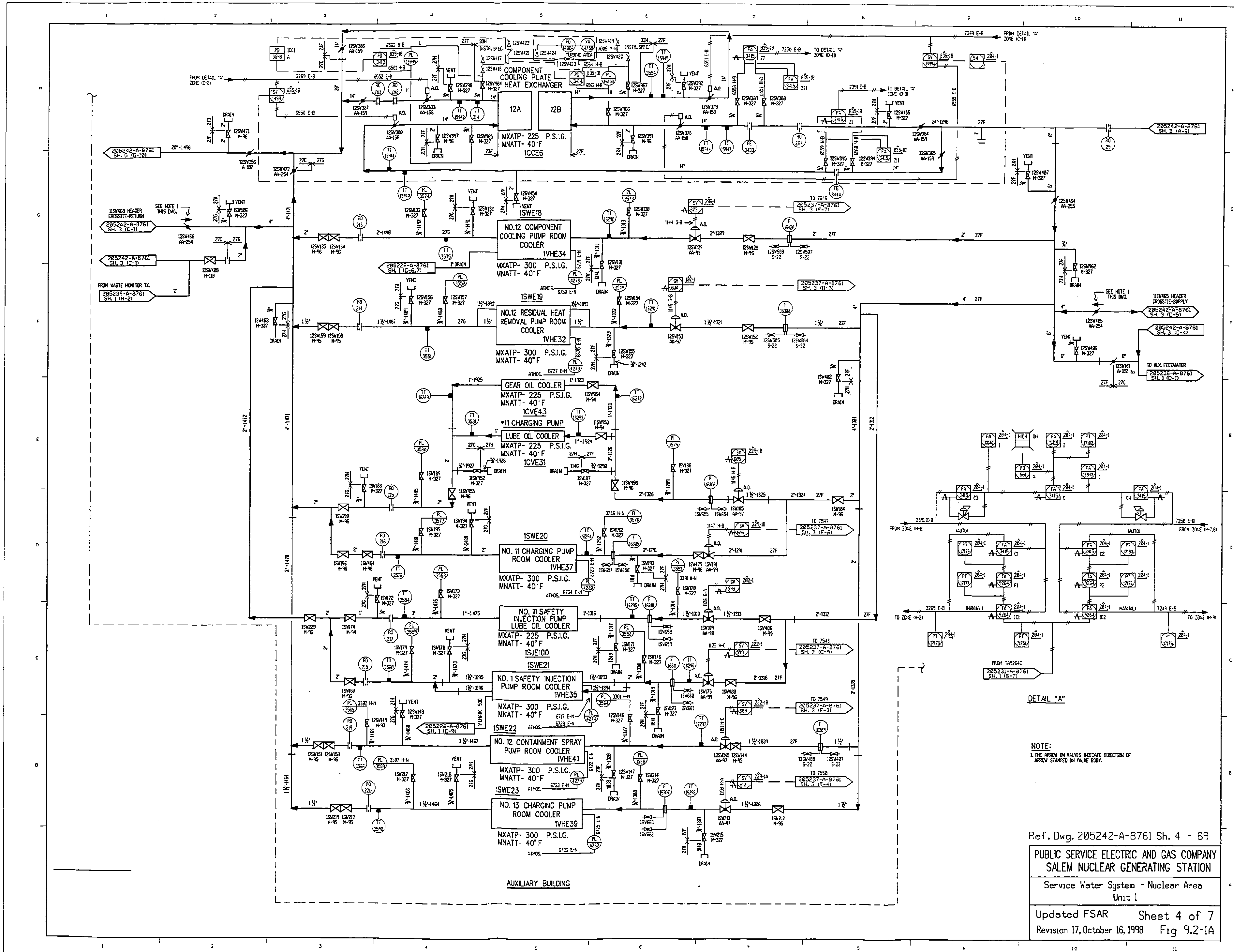
Ref. Dwg. 205242-A-8761 Sh. 2 - 78

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Service Water System - Nuclear Area
Unit 1

Updated FSAR — Sheet 2 of 7
Revision 17, October 16, 1998 — Fig 9.2-1A


AUXILIARY BUILDING
NO. 12 NUCLEAR HEADER
NO. 11 NUCLEAR HEADER
1SJE101
NO. 12 SAFETY INJECTION PUMP LUBE OIL COOLER
MXATP-225 P.S.I.G.
MNATT 40°F
1SWE13
NO. 11 RESIDUAL HEAT REMOVAL PUMP ROOM COOLER
MXATP-225 P.S.I.G.
MNATT 40°F 1VHE31
1CVE42
GEAR OIL COOLER
MXATP-225 P.S.I.G.
MNATT 40°F
NO. 12 CHARGING PUMP
1CVE32
LUBE OIL COOLER
MXATP-225 P.S.I.G.
MNATT 40°F
1SWE14
NO. 12 CHARGING PUMP ROOM COOLER
MXATP-225 P.S.I.G.
MNATT 40°F 1VHE38
1SWE15
NO. 11 CONTAINMENT SPRAY PUMP ROOM COOLER
MXATP-225 P.S.I.G.
MNATT 40°F 1VHE40
1SWE16
NO. 11 COMPONENT COOLING PUMP ROOM COOLER
MXATP-225 P.S.I.G.
MNATT 40°F 1VHE33
1SWE17
NO. 11 AUXILIARY FEED WATER PUMP ROOM COOLER
MXATP-225 P.S.I.G.
MNATT 40°F 1VHE36
1CCE5
NO. 11 COMPONENT COOLING HEAT EXCHANGER
MXATP-225 P.S.I.G.
MNATT 40°F
1DAE58
NO. 1A DIESEL GENERATOR JACKET WATER COOLER
MXATP-300 P.S.I.G.
MNATT 40°F
1SWE78
1DAE59
NO. 1B DIESEL GENERATOR JACKET WATER COOLER
MXATP-300 P.S.I.G.
MNATT 40°F
1SWE79
1DAE60
NO. 1C DIESEL GENERATOR JACKET WATER COOLER
MXATP-300 P.S.I.G.
MNATT 40°F
1SWE80
1DAE1
NO. 1A DIESEL GEN. LUBE OIL COOLER
MXATP-300 P.S.I.G.
MNATT 40°F
1SWE75
1DAE2
NO. 1B DIESEL GEN. LUBE OIL COOLER
MXATP-300 P.S.I.G.
MNATT 40°F
1SWE76
1DAE3
NO. 1C DIESEL GEN. LUBE OIL COOLER
MXATP-300 P.S.I.G.
MNATT 40°F
1SWE77
TURBINE AREA
24" INSPECTION PORT
NOTE: FOR VALVE MARK NO'S NOT SHOWN ON THIS SHEET, REFER TO MMIS.
Ref. Dwg. 205242-A-8761 Sh. 3 - 78
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION
Service Water System - Nuclear Area
Unit 1
Updated FSAR
Sheet 3 of 7
Revision 17, October 16, 1998
Fig 9.2-1A



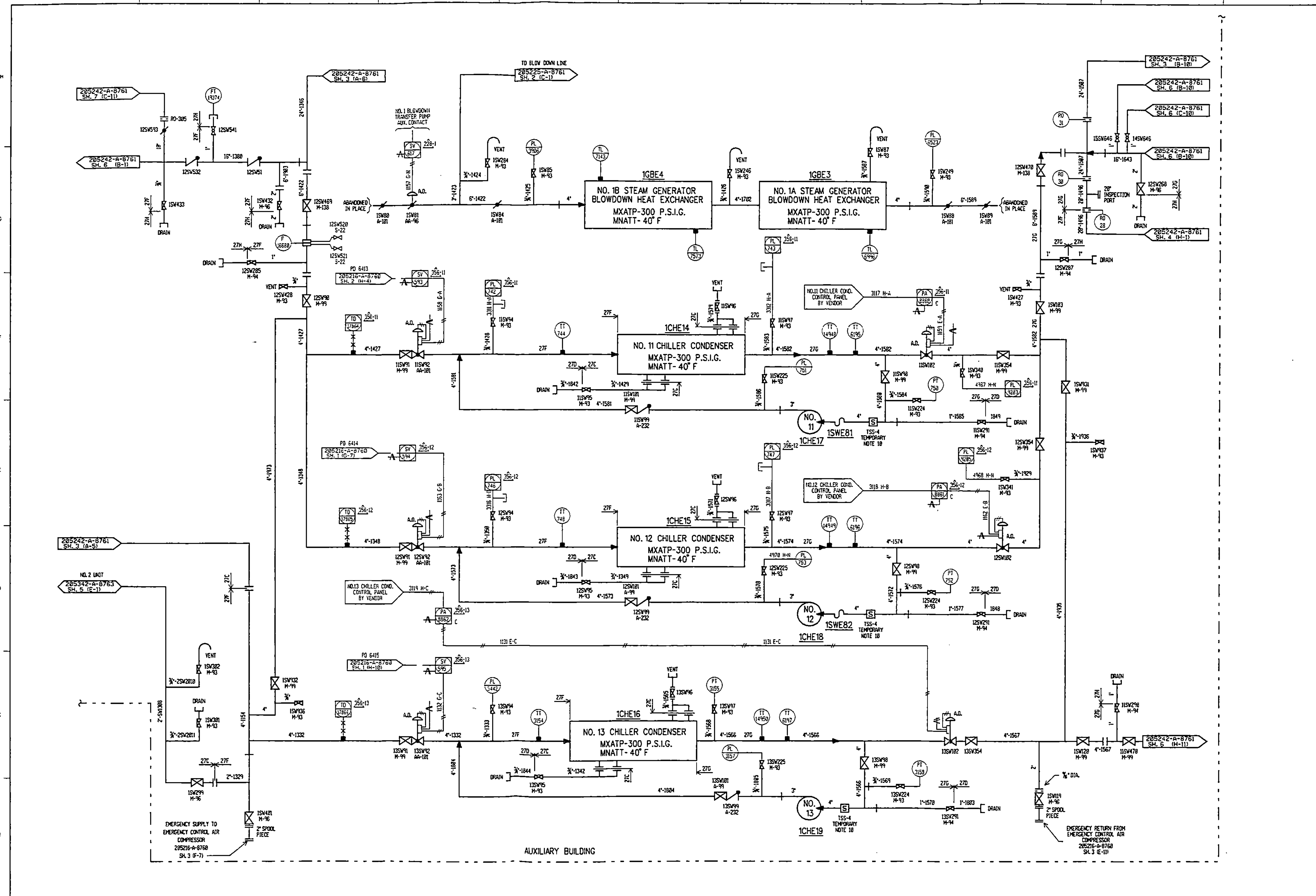
Ref. Dwg. 205242-A-8761 Sh. 4 - 69

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Service Water System - Nuclear Area
Unit 1

Updated FSAR — Sheet 4 of 7

Revision 17, October 16, 1998 — Fig 9.2-1A



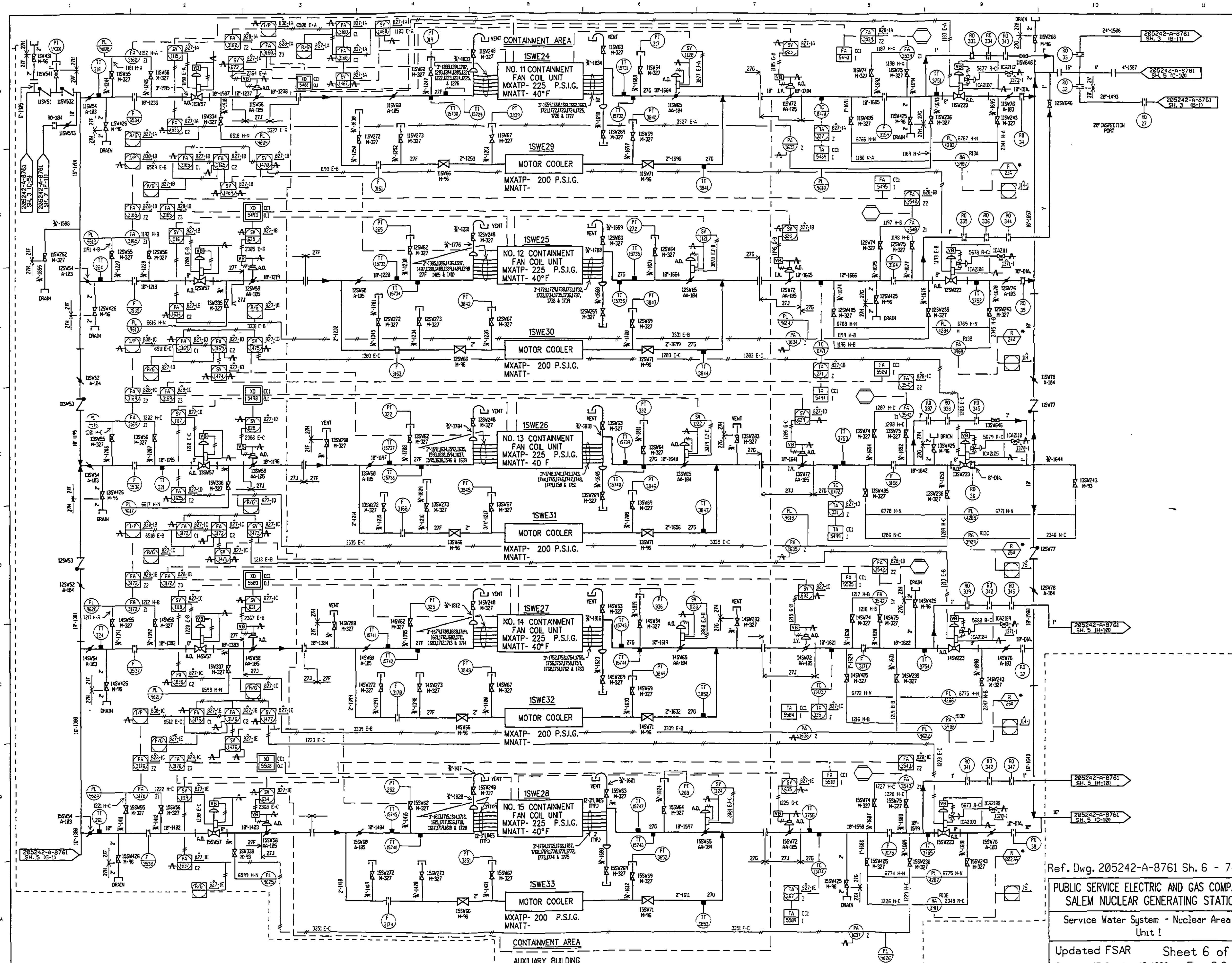
Ref. Dwg. 205242-A-8761 Sh. 5 - 65

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Service Water System - Nuclear Area
Unit 1

Updated FSAR Sheet 5 of 7
Revision 17, October 16, 1998 Fig 9.2-1A

NOTE: FOR VALVE MARK NO'S NOT SHOWN ON THIS SHEET, REFER TO 1MMS.



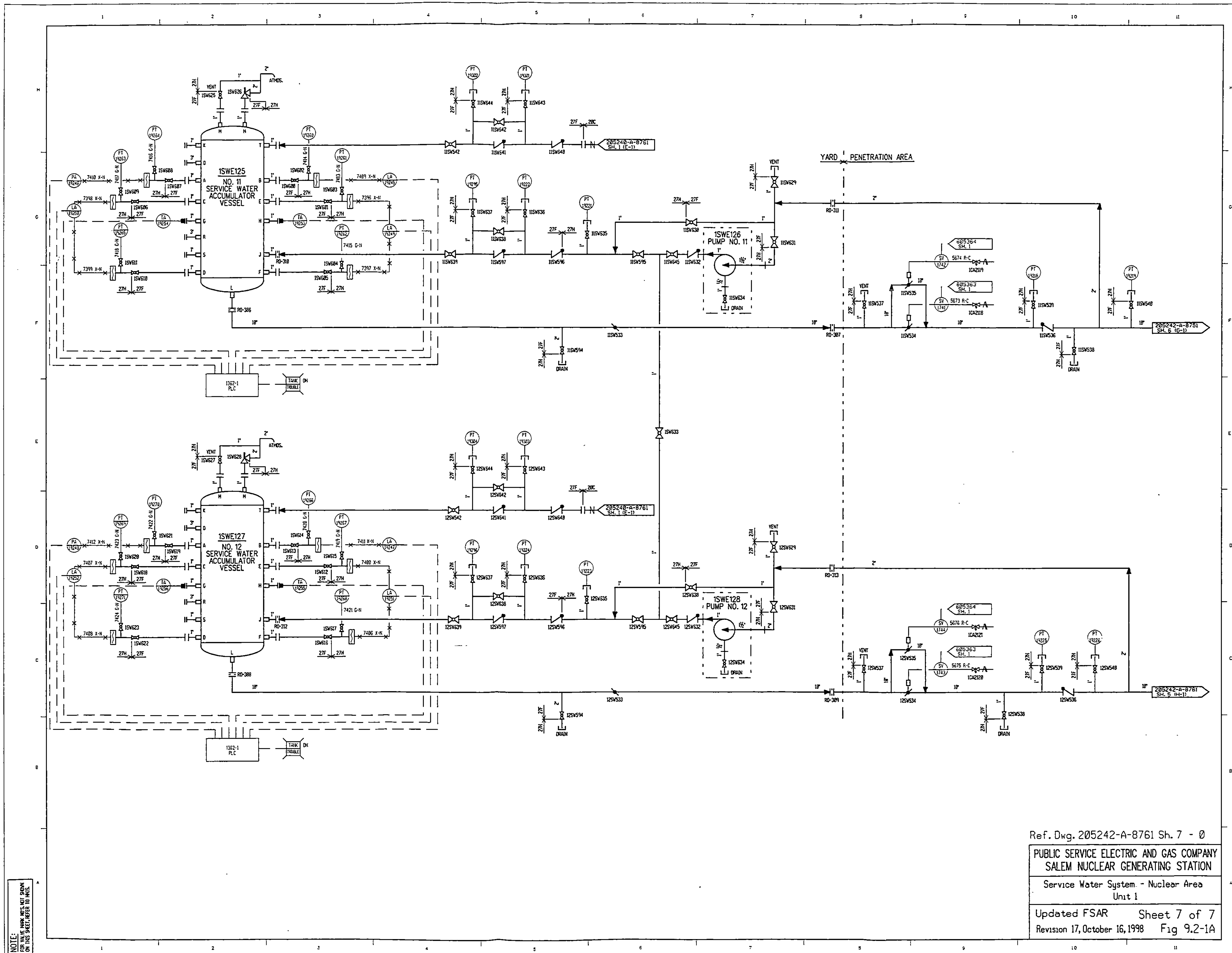
Ref. Dwg. 205242-A-8761 Sh. 6 - 74

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Service Water System - Nuclear Area
Unit 1

Updated FSAR — Sheet 6 of 7

Revision 17, October 16, 1998 — Fig 9.2-1A



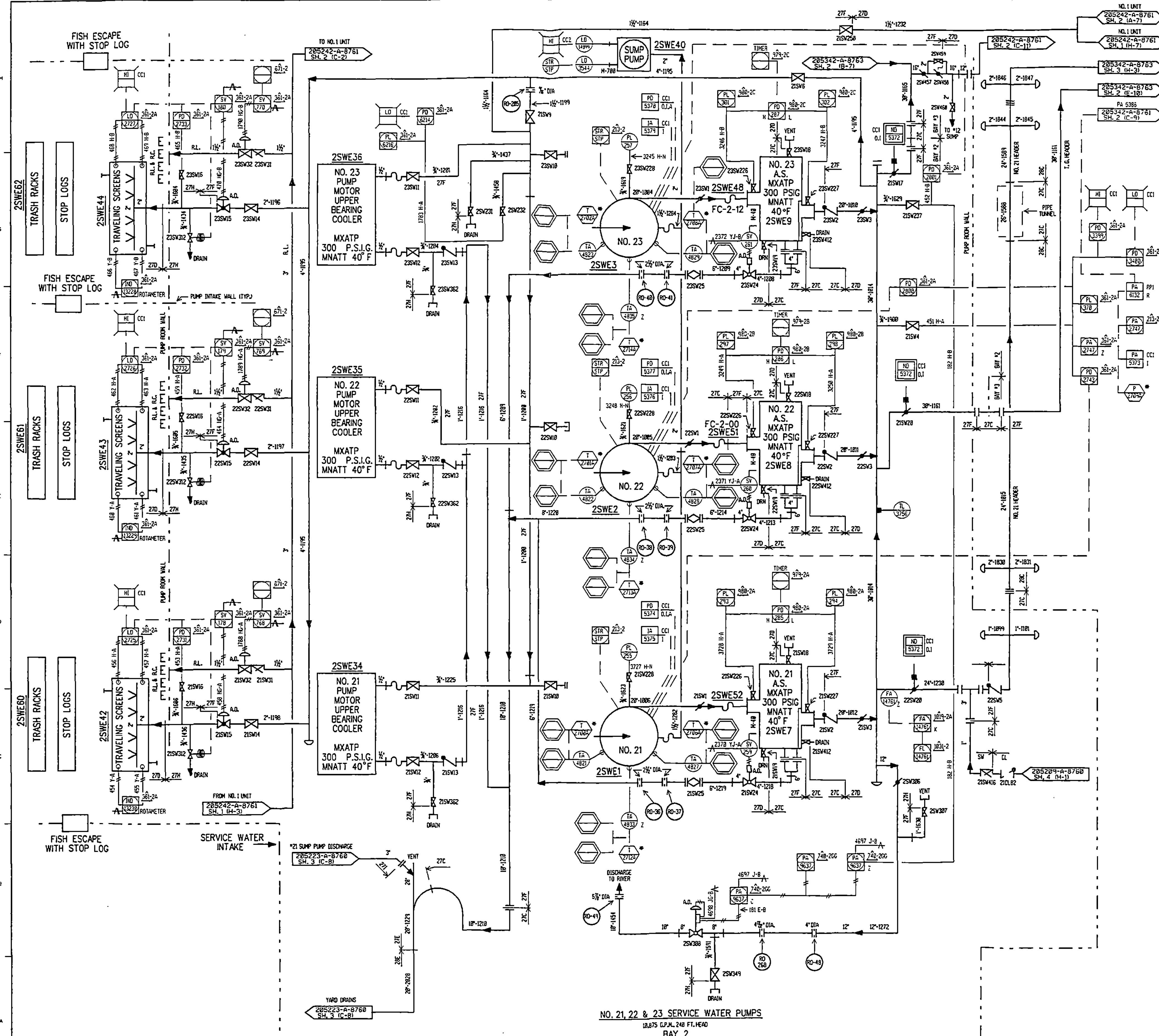
Ref. Dwg. 205242-A-8761 Sh. 7 - 0

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Service Water System - Nuclear Area
Unit 1

Updated FSAR
Revision 17, October 16, 1998

Sheet 7 of 7
Fig 9.2-1A



NOTES:

1. ALL PIPING NUMBERS SHALL HAVE THE PREFIX "2SW" (I.E. 2SW1000, ETC.) EXCEPT WHERE OTHERWISE NOTED.
2. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051
3. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6200. THE PIPING SCHEDULE AND GROUP NO'S ARE 1527 & 1528 EXCEPT AS OTHERWISE NOTED.
4. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 22SW32-AO).
5. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "2" FOR UNIT 2.
6. SW PIPING SPEC. 1S27F, 1S27G, 1S27H MTL: 6% MOLY S.S.
7. TEMPORARY STRAINER TO BE PLACED IN LINE DURING FLUSHING AND PLANT

DESIGN				
BOUNDARY *	CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S27B	YES	I	III	YES
1S27C	YES	I	III	YES
1S27D	NO	III	NONE	NO
1S27E	NO	III	NONE	NO
1S28B	YES	I	III	YES
1S28C	YES	I	III	YES
1S28D	NO	III	NONE	NO
1S29	NO	III	NONE	NO
1S27A	YES	I	II	YES
1S27F	YES	I	III	YES
1S27G	YES	I	III	YES
1S27H	NO	III	NONE	NO
1S27H	NO	III	NONE	NO
1S27J	YES	I	II	YES
1S530	NO	III	NONE	NO

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (I.E. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

NOTE: FOR VALVE MARK NO'S NOT SHOWN ON THIS SHEET, REFER TO NO. 1 UNIT.

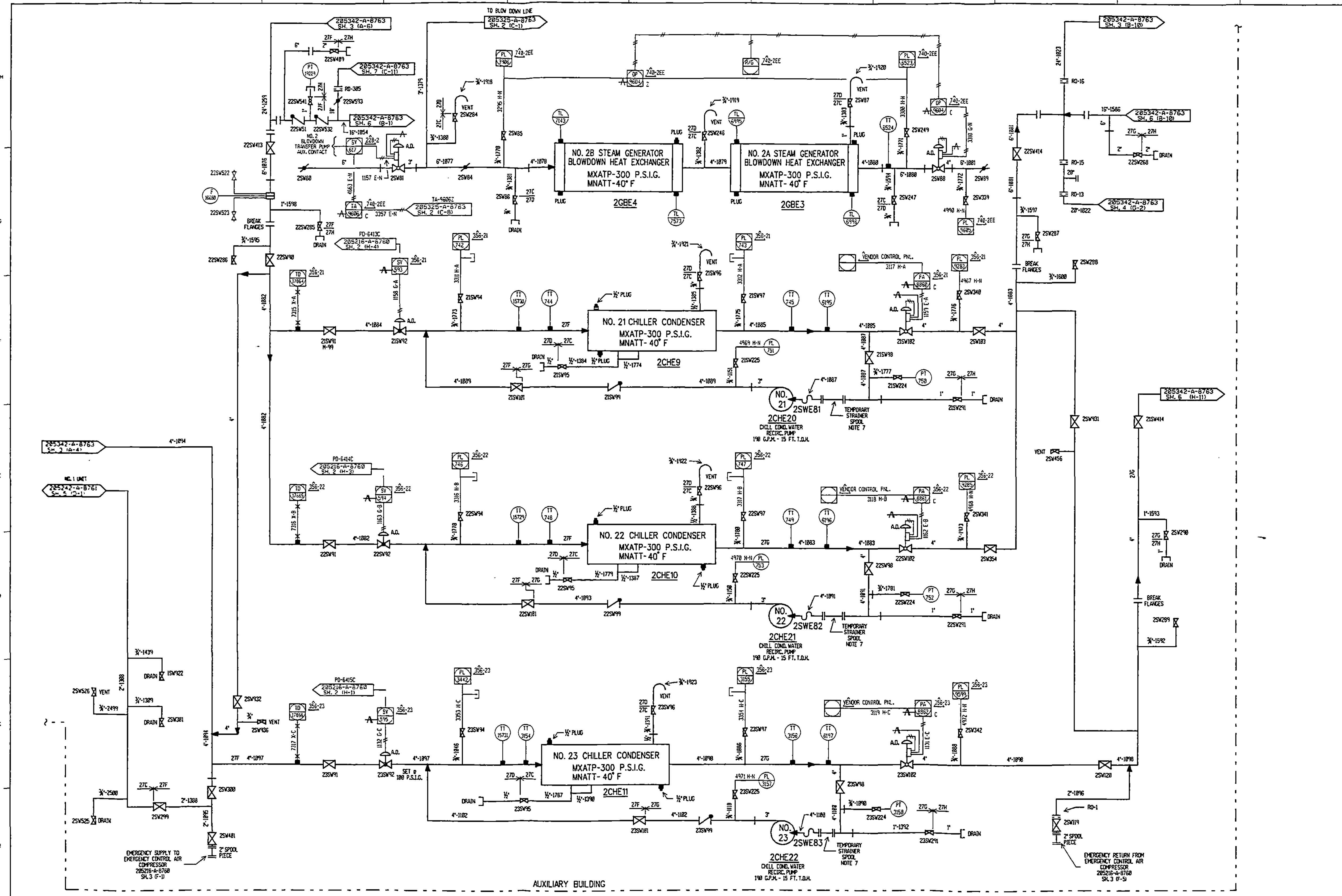
Ref. Dwg. 205342-A-8763 Sh. 1 - 66

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Service Water System - Nuclear Area
Unit 2

Updated FSAR — Sheet 1 of 6

Revision 17, October 16, 1998 — Fig 9.2-1B



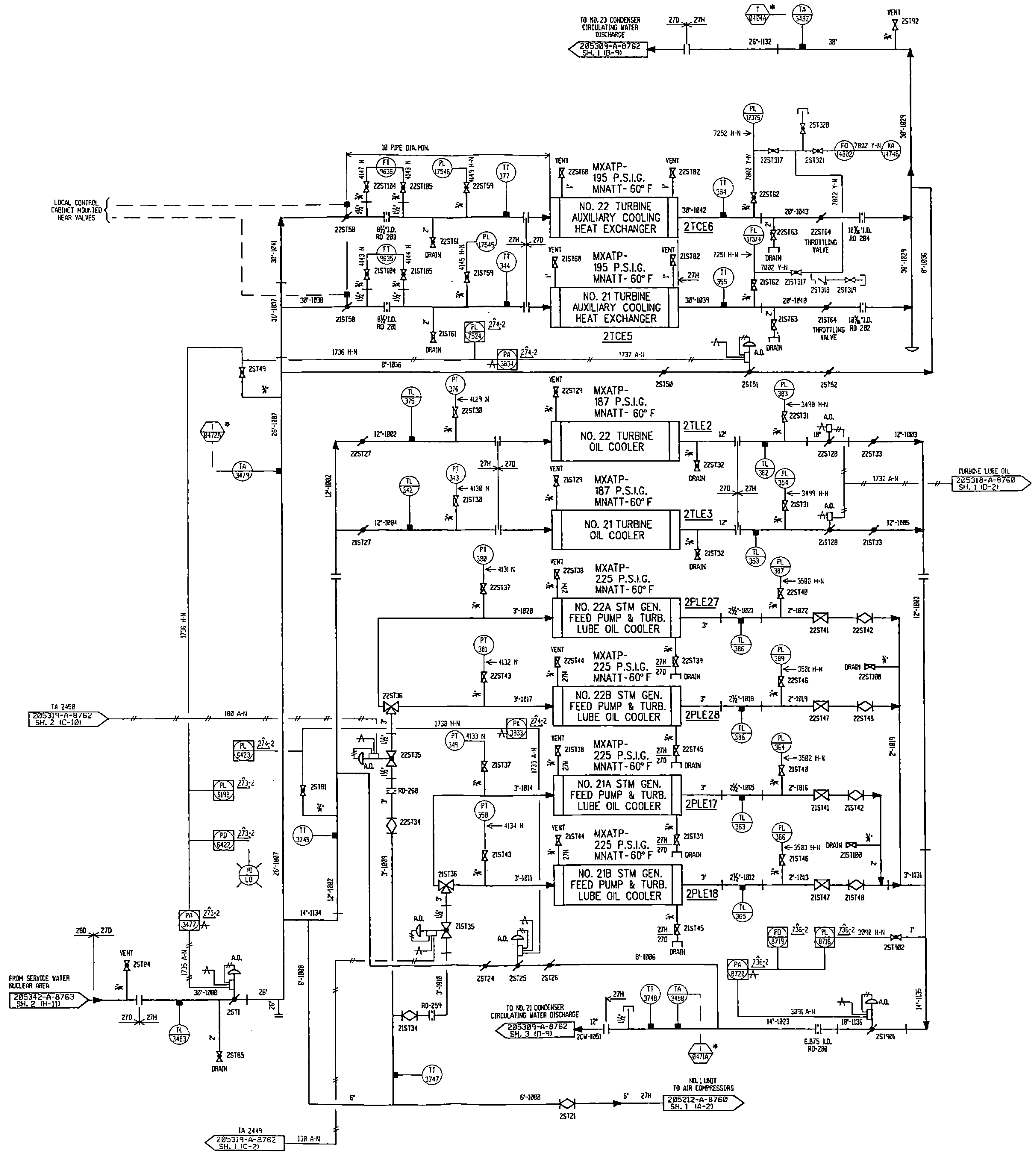
Ref. Dwg. 205342-A-8763 Sh. 5 - 54

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Service Water System - Nuclear Area
Unit 2

Updated FSAR — Sheet 5 of 6
Revision 17, October 16, 1998 — Fig 9.2-1B

NOTE: FOR VALVE MARK NO'S NOT SHOWN ON THIS SHEET, REFER TO M-MIS.



NOTES:

1. ALL PIPING, INCLUDING BRASS SECTIONS, IS IN ACCORDANCE WITH PIPE SPECIFICATION S-C-MP00-MGS-0001, PIPING SCHEDULE AND GROUP NO. 27D AND 27H EXCEPT AS OTHERWISE NOTED.
2. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051
3. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "2ST" (i.e. 2ST1000, ...etc.) UNLESS OTHERWISE NOTED.
4. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 22ST35-AO).
5. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "2" FOR UNIT 2.

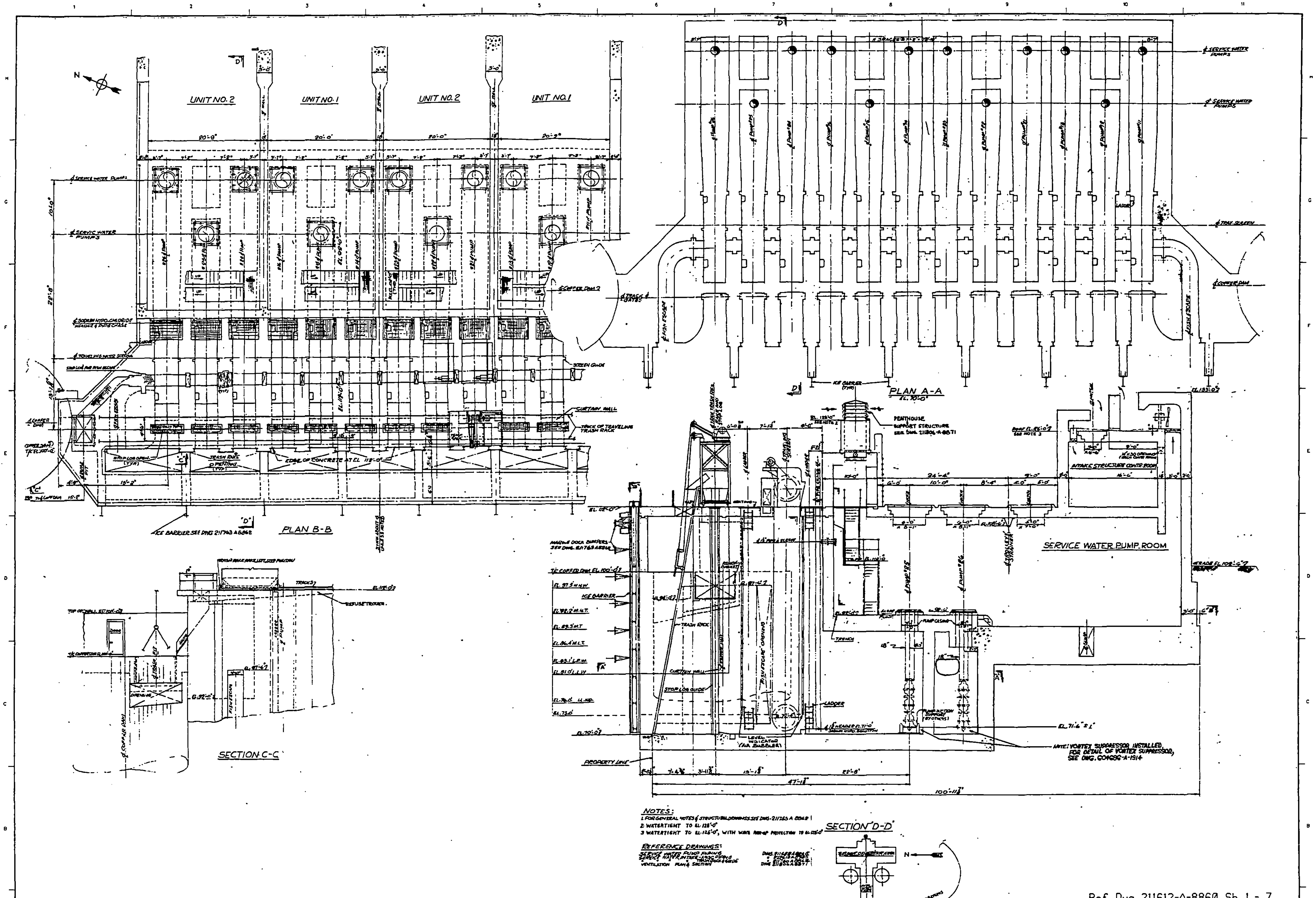
NOTE: FOR VALVE MARK NO'S. NOT SHOWN ON THIS SHEET, REFER TO MMIS.

Ref. Dwg. 205312-A-8762 Sh. 1 - 30

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

SERVICE WATER SYSTEM - TURBINE AREA
Unit 2

Updated FSAR — Sheet 1 of 1
Revision 17, October 16, 1998 — Fig. 9.2-2B

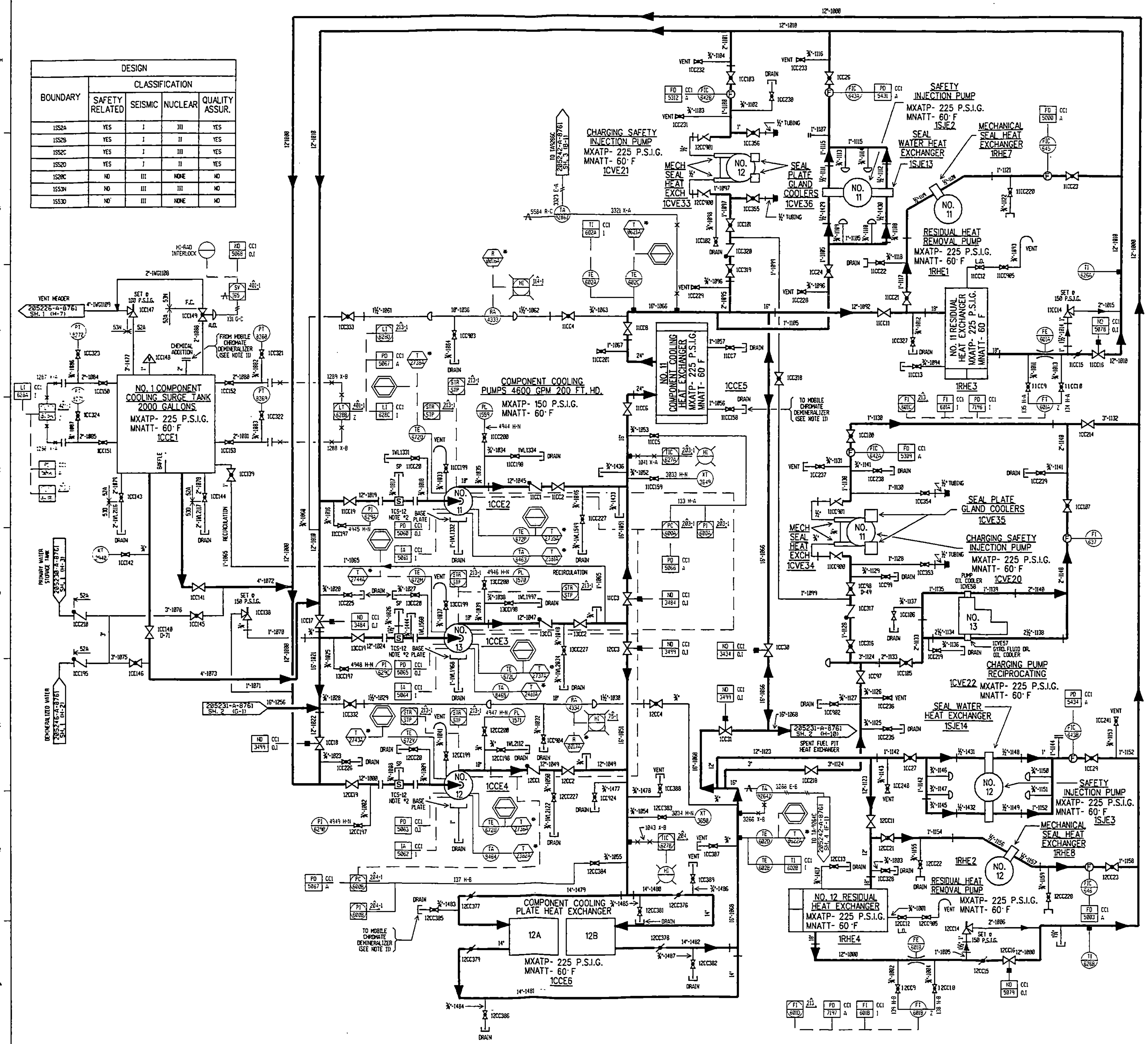


Ref. Dwg. 211612-A-8860 Sh. 1 - 7

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

SERVICE WATER INTAKE (ARRANGEMENT)

Updated FSAR
Sheet 1 of 1
Revision 17, October 16, 1998
Fig 9.2-3



BOUNDARY	DESIGN CLASSIFICATION: SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S52A	YES	I	III	YES
1S52B	YES	I	II	YES
1S52C	YES	I	III	YES
1S52D	YES	I	II	YES
1S28C	NO	III	NONE	NO
1S53N	NO	III	III	NO
1S53O	NO	III	NONE	NO

NOTES

1. THESE VALVES TO BE LOCATED OUTSIDE RADIATION SHIELD.
2. TEMPORARY STRAINER TO BE PLACED IN SPOOL PIECE DURING INITIAL FLUSHING OPERATION. STRAINER MUST BE REMOVED BEFORE PLANT START UP.
3. IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (I.E. 1S44A, ETC.) UNLESS OTHERWISE NOTED.
4. ALL PIPING SPECIFICATIONS 52A UNLESS OTHERWISE NOTED.
5. ALL VALVES SHOWN WITH CAPS OR HOSE CONNECTIONS SHALL HAVE PIPE SPEC. END AT VALVE - i.e. 52A
6. FOR PRESSURE AND TEMPERATURE PARAMETERS REFER TO THE DESIGN PRESSURE AND TEMPATURE PARAMETES AT THE ORIGINATING SOURCE HEADER.
7. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1CC" (i.e. 1CC1000 ETC.) EXCEPT WHERE OTHERWISE NOTED.
8. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051
9. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 1CC149-AO).
10. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "1" FOR UNIT 1, UNLESS OTHERWISE NOTED.
11. THESE CONNS. USED TO TRANSFER CHROMATED WATER TO & FROM THE MOBILE CHROMATE DEMINERALIZERS. TRANSFER PIPING SHOWN ON DRAWING 205246-A-8761 SHT. 1 & 2. HOSES TO BE USED TO INTERCONNECT PIPING.
12. PIPING CLASS 530 WAS ORIGINALLY CLASSIFED AS NUCLEAR CLASS III. DCP 1EA-1028 RECLASSIFIES PIPING CLASS 530 TO BE NON-NUCLEAR. ANY MAINTENANCE, REPAIR AND/OR MODIFICATION HENCEFORTH SHALL COMPLY WITH THE REQUIREMENTS OF RECLASSIFIED PIPING CLASS.

NOTE:
FOR VALVE MARK NO'S NOT SHOWN ON THIS SHEET, REFER TO MMIS.

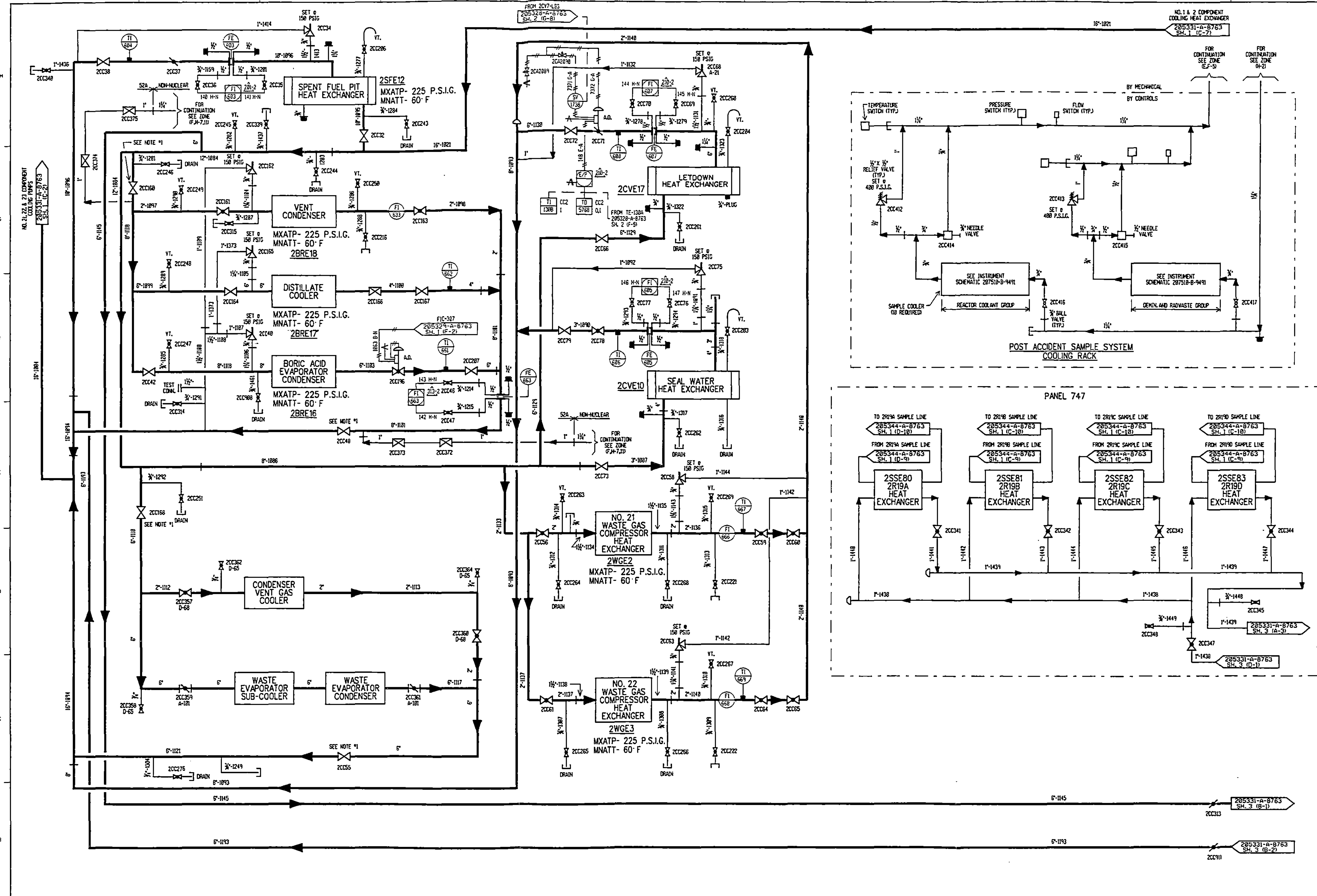
Ref. Dwg. 205231-A-8761 Sh. 1 - 57

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Component Cooling System
Unit 1

Updated FSAR
Revision 17, October 16, 1998

Sheet 1 of 3
Fig 9.2-4A



NOTE: FOR VALVE MARK NO'S NOT SHOWN ON THIS SHEET, REFER TO 9MNS.

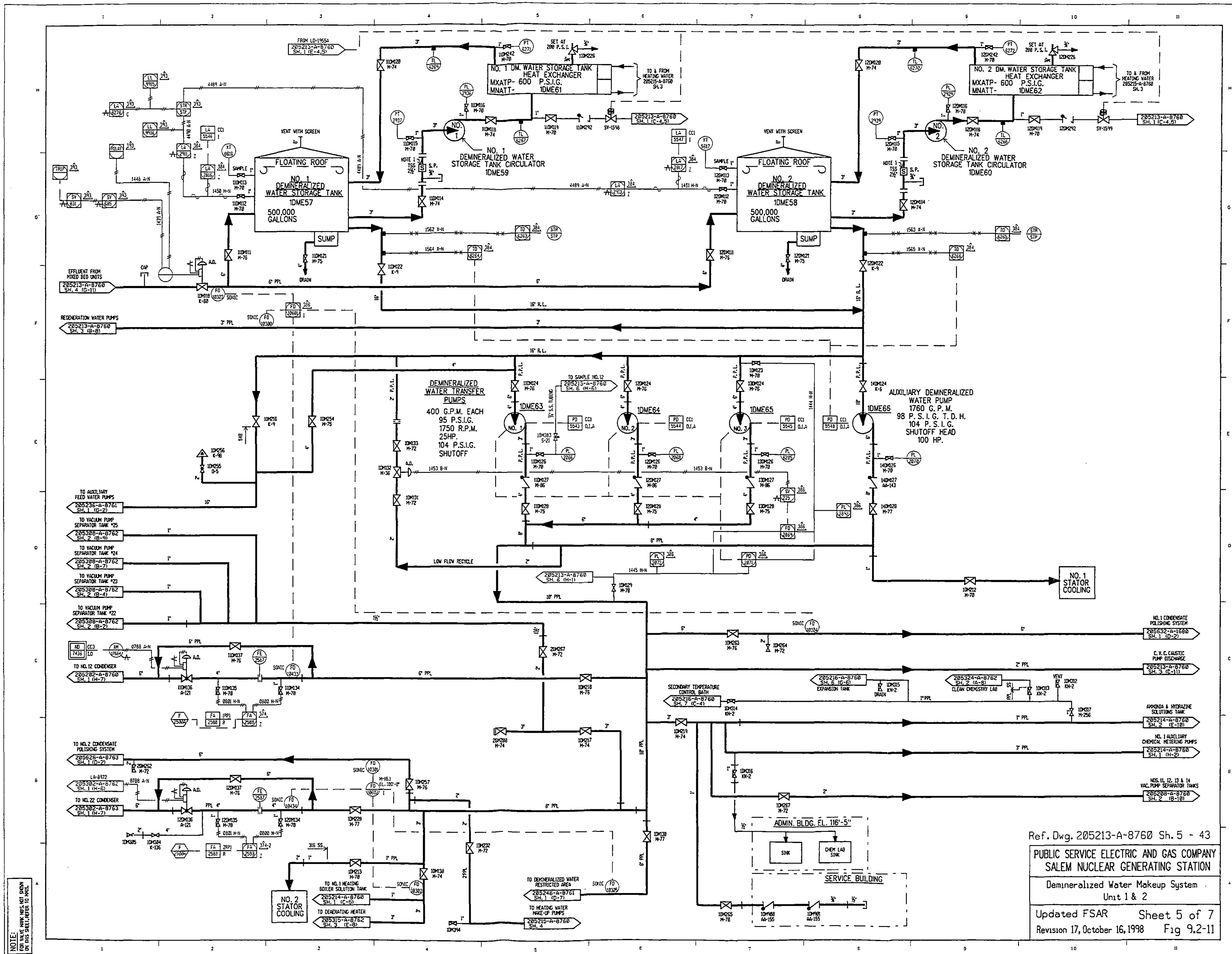
Ref. Dwg. 205331-A-8763 Sh. 2 - 37

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Component Cooling System
Unit 2

Updated FSAR — Sheet 2 of 3

Revision 17, October 16, 1998 — Fig 9.2-4B



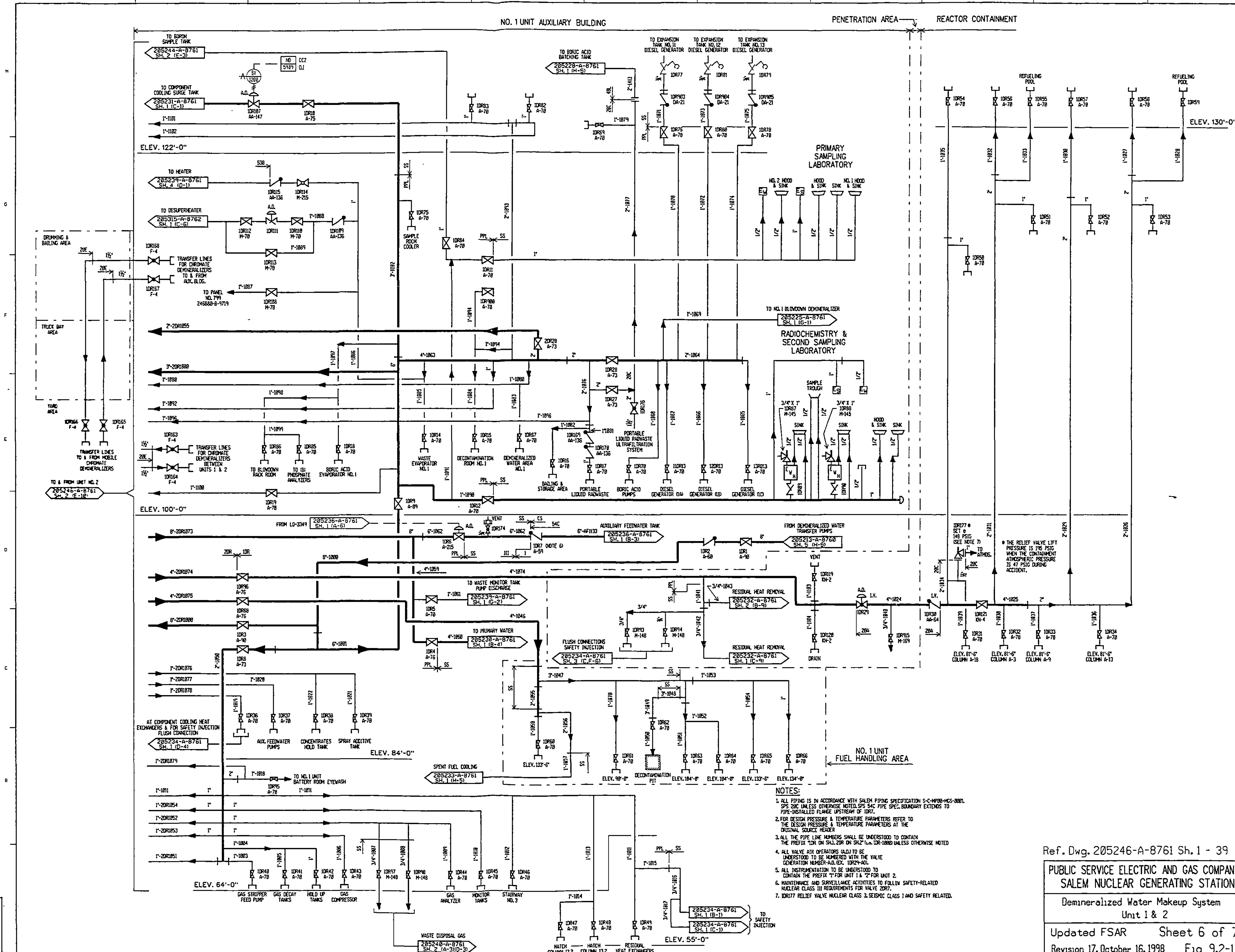
NOTE: FOR VALVE MARK NOS. NOT SHOWN ON THIS SHEET, REFER TO MMS.

Ref. Dwg. 205213-A-8760 Sh. 5 - 43

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Demineralized Water Makeup System
Unit 1 & 2

Updated FSAR Sheet 5 of 7
Revision 17, October 16, 1998 Fig 9.2-11



NOTES:

1. ALL PIPING IS IN ACCORDANCE WITH SALEM PIPING SPECIFICATION S-C-MP00-MGS-0001. SPS 20C UNLESS OTHERWISE NOTED. SPS 54C PIPE SPEC. BOUNDARY EXTENDS TO PIPE-INSTALLED FLANGE UPSTREAM OF 1DR7.
2. FOR DESIGN PRESSURE & TEMPERATURE PARAMETERS REFER TO THE DESIGN PRESSURE & TEMPERATURE PARAMETERS AT THE ORIGINAL SOURCE HEADER
3. ALL THE PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1DR ON SH.1, 2DR ON SH.2" (i.e. 1DR-1000) UNLESS OTHERWISE NOTED
4. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 1DR29-AO).
5. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "1" FOR UNIT 1 & "2" FOR UNIT 2.
6. MAINTENANCE AND SURVEILLANCE ACTIVITIES TO FOLLOW SAFETY-RELATED NUCLEAR CLASS III REQUIREMENTS FOR VALVE 2DR7.
7. 1DR177 RELIEF VALVE NUCLEAR CLASS 3, SEISMIC CLASS I AND SAFETY RELATED.

Ref. Dwg. 205246-A-8761 Sh. 1 - 39

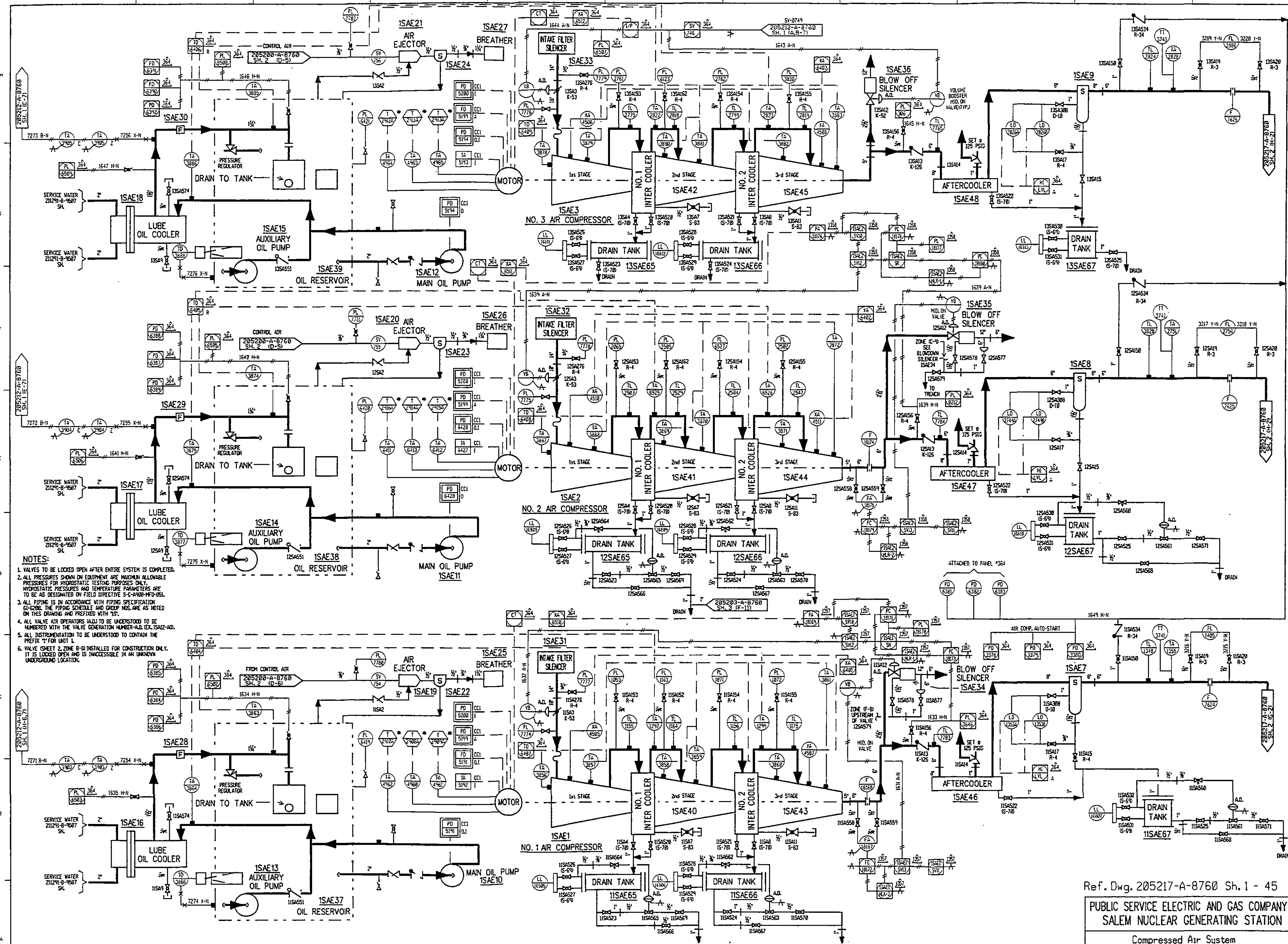
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Demineralized Water Makeup System
Unit 1 & 2

Updated FSAR — Sheet 6 of 7

Revision 17, October 16, 1998 — Fig 9.2-11

NOTE: FOR VALVE MARK NOS. NOT SHOWN ON THIS SHEET, REFER TO MMIS.



NOTES:

1. VALVES TO BE LOCKED OPEN AFTER ENTIRE SYSTEM IS COMPLETED.
2. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051.
3. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6200. THE PIPING SCHEDULE AND GROUP NOS. ARE AS NOTED ON THIS DRAWING AND PREFIXED WITH "1S".
4. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 1SA12-AO).
5. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "1" FOR UNIT 1.
6. VALVE (SHEET 2, ZONE B-8) INSTALLED FOR CONSTRUCTION ONLY. IT IS LOCKED OPEN AND IS INACCESSIBLE IN AN UNKNOWN UNDERGROUND LOCATION.

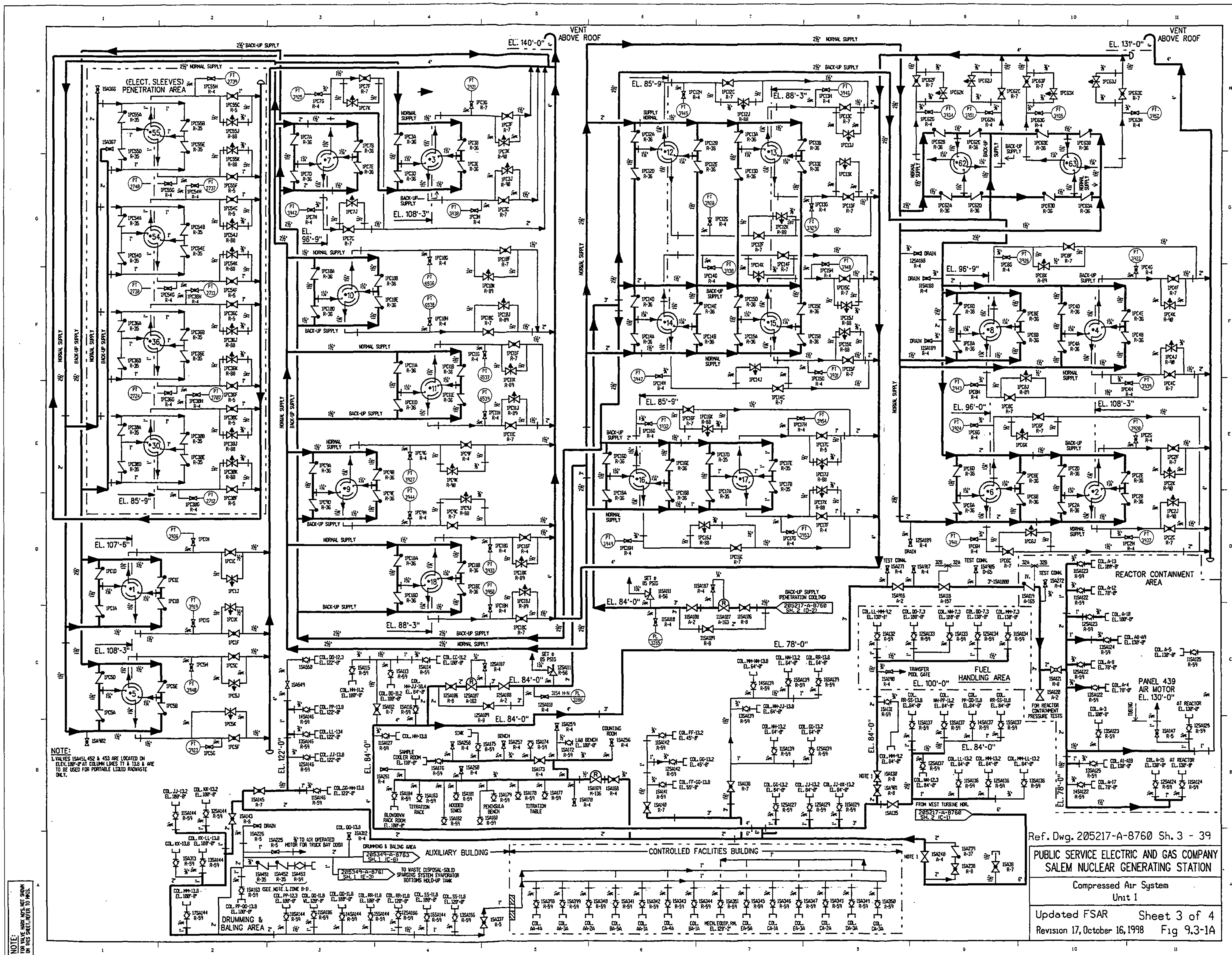
NOTE:
FOR VALVE MARK NO'S. NOT SHOWN ON THIS SHEET, REFER TO MMIS.

Ref. Dwg. 205217-A-8760 Sh. 1 - 45

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Compressed Air System
Unit 1

Updated FSAR — Sheet 1 of 4
Revision 17, October 16, 1998 — Fig 9.3-1A

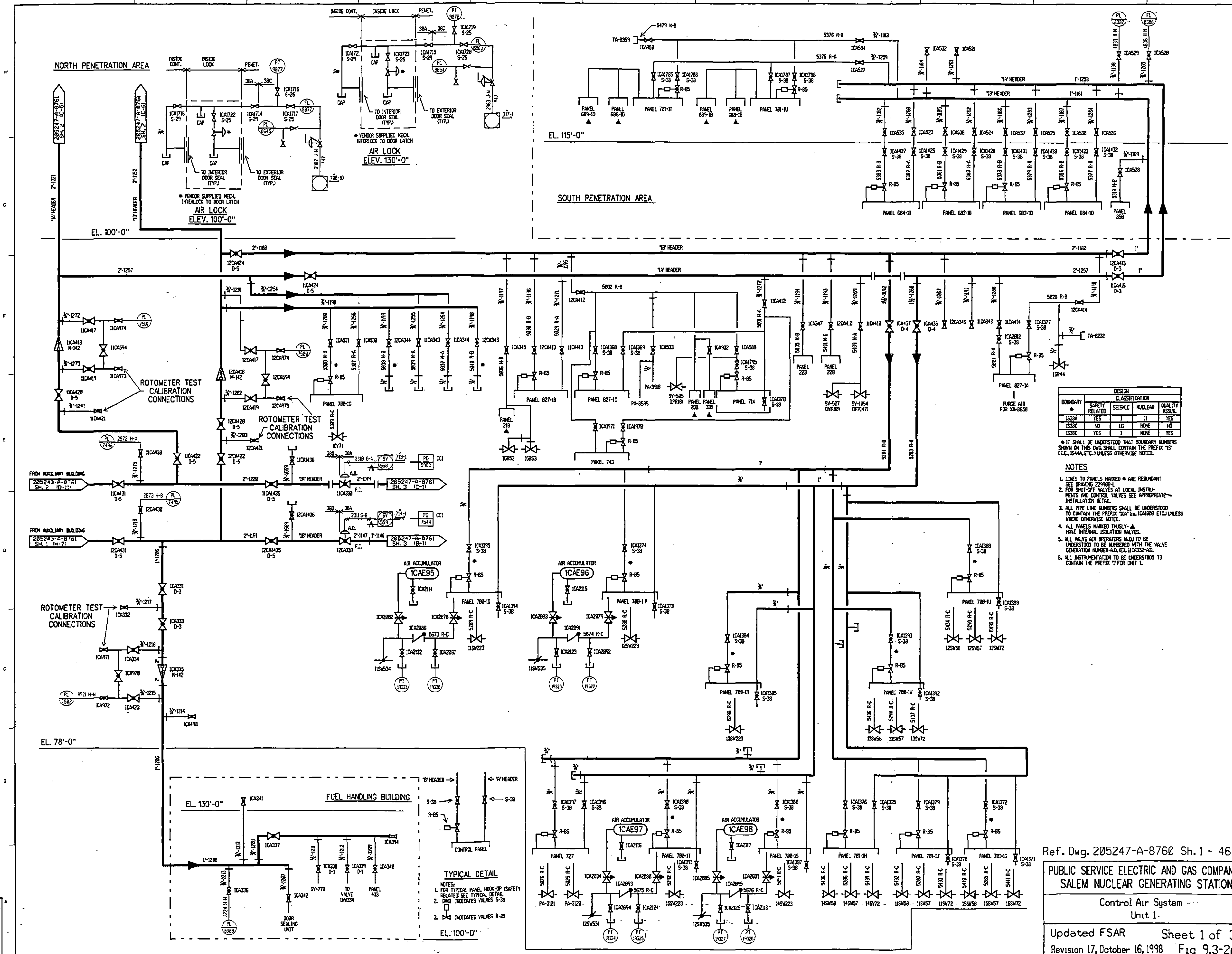


Ref. Dwg. 205217-A-8760 Sh. 3 - 39

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Compressed Air System
Unit 1

Updated FSAR Sheet 3 of 4
Revision 17, October 16, 1998 Fig 9.3-1A



BOUNDARY *	DESIGN CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S38A	YES	I	II	YES
1S38C	NO	III	NONE	NO
1S38D	YES	I	NONE	YES

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DWG. SHALL CONTAIN THE PREFIX "1S" (I.E. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

NOTES

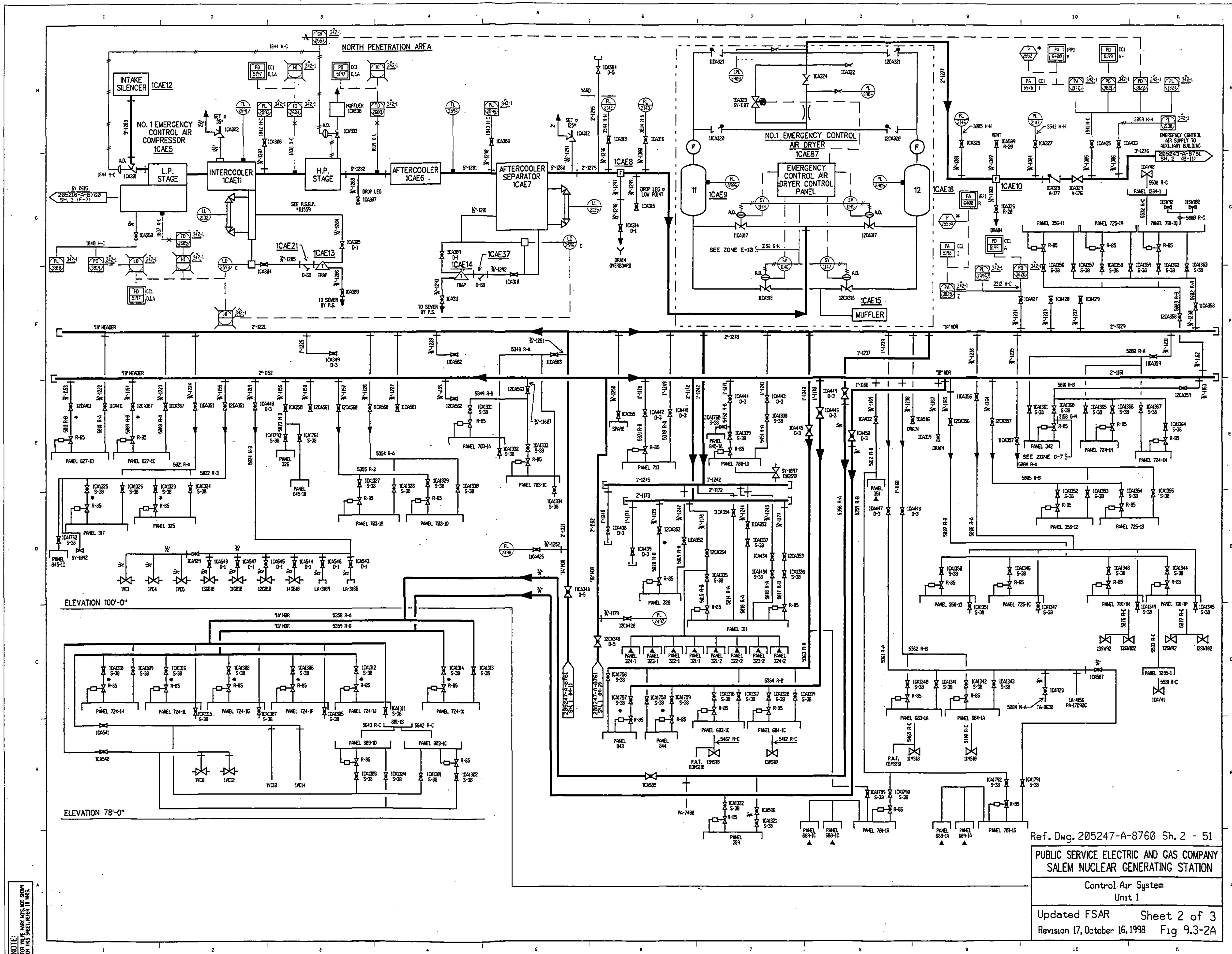
1. LINES TO PANELS MARKED * ARE REDUNDANT SEE DRAWING 229988-L
2. FOR SHUT-OFF VALVES AT LOCAL INSTRUMENTS AND CONTROL VALVES SEE APPROPRIATE INSTALLATION DETAIL
3. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1CA" (i.e. 1CA1000 ETC.) UNLESS WHERE OTHERWISE NOTED.
4. ALL PANELS MARKED THUSLY- ▲ HAVE INTERNAL ISOLATION VALVES.
5. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 11CA330-AO).
6. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "1" FOR UNIT 1.

Ref. Dwg. 205247-A-8760 Sh. 1 - 46

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Control Air System
Unit 1

Updated FSAR — Sheet 1 of 3
Revision 17, October 16, 1998 — Fig 9.3-2A



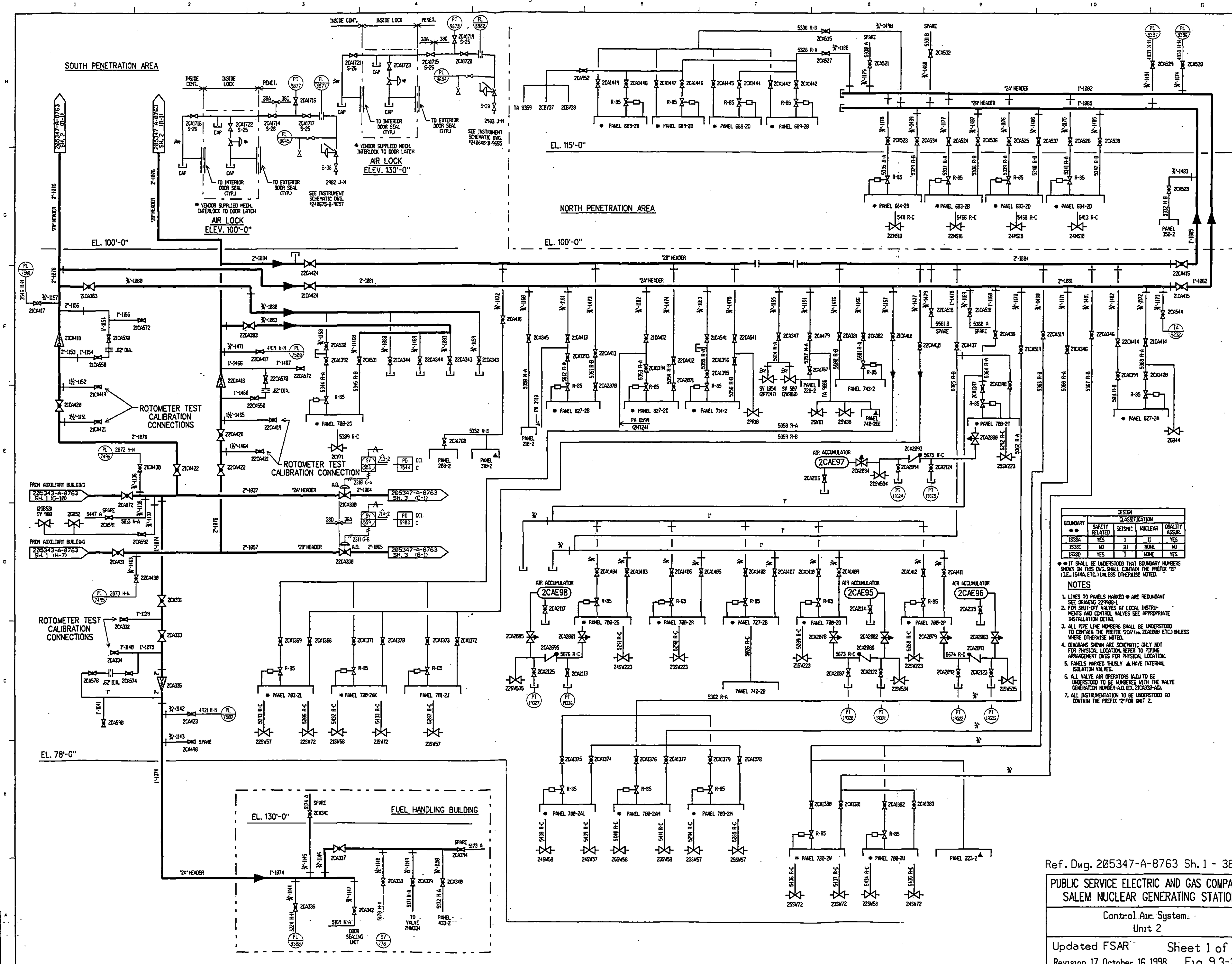
Ref. Dwg. 205247-A-8760 Sh. 2 - 51

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Control Air System
Unit 1

Updated FSAR — Sheet 2 of 3

Revision 17, October 16, 1998 — Fig 9.3-2A



DESIGN				
BOUNDARY **	CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S38A	YES	I	II	YES
1S38C	NO	III	NONE	NO
1S38D	YES	I	NONE	YES

** IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DWG. SHALL CONTAIN THE PREFIX "1S" (I.E. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

NOTES

1. LINES TO PANELS MARKED * ARE REDUNDANT SEE DRAWING 229988-L
2. FOR SHUT-OFF VALVES AT LOCAL INSTRUMENTS AND CONTROL VALVES SEE APPROPRIATE INSTALLATION DETAIL
3. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "2CA" (i.e. 2CA1000 ETC.) UNLESS WHERE OTHERWISE NOTED.
4. DIAGRAMS SHOWN ARE SCHEMATIC ONLY NOT FOR PHYSICAL LOCATION. REFER TO PIPING ARRANGEMENT DWGS FOR PHYSICAL LOCATION.
5. PANELS MARKED THUSLY ▲ HAVE INTERNAL ISOLATION VALVES.
6. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 21CA330-AO).
7. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "2" FOR UNIT 2.

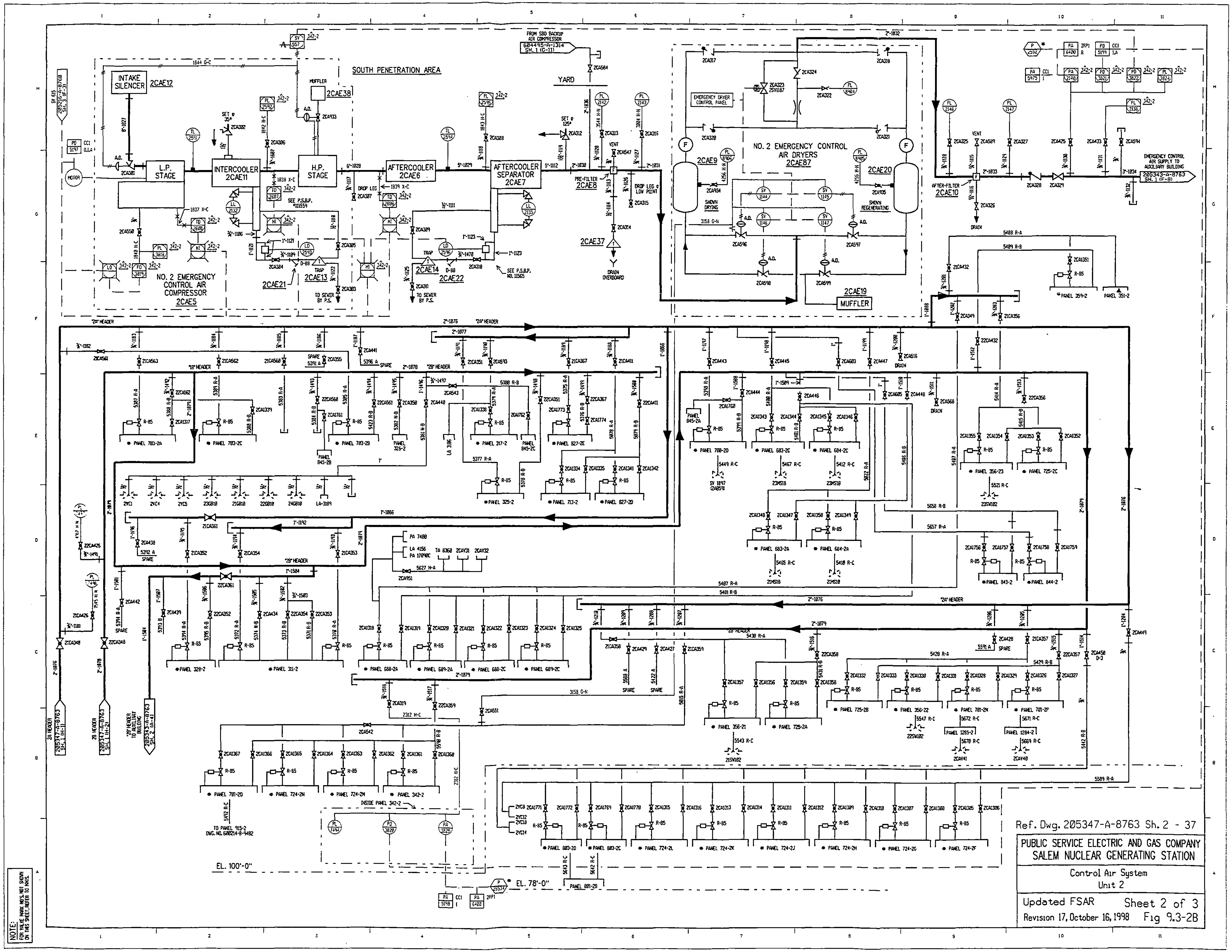
NOTE: FOR VALVE MARK NO'S NOT SHOWN ON THIS SHEET, REFER TO MMIS.

Ref. Dwg. 205347-A-8763 Sh. 1 - 38

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Control Air System
Unit 2

Updated FSAR
Sheet 1 of 3
Revision 17, October 16, 1998
Fig 9.3-2B



Ref. Dwg. 205347-A-8763 Sh. 2 - 37

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

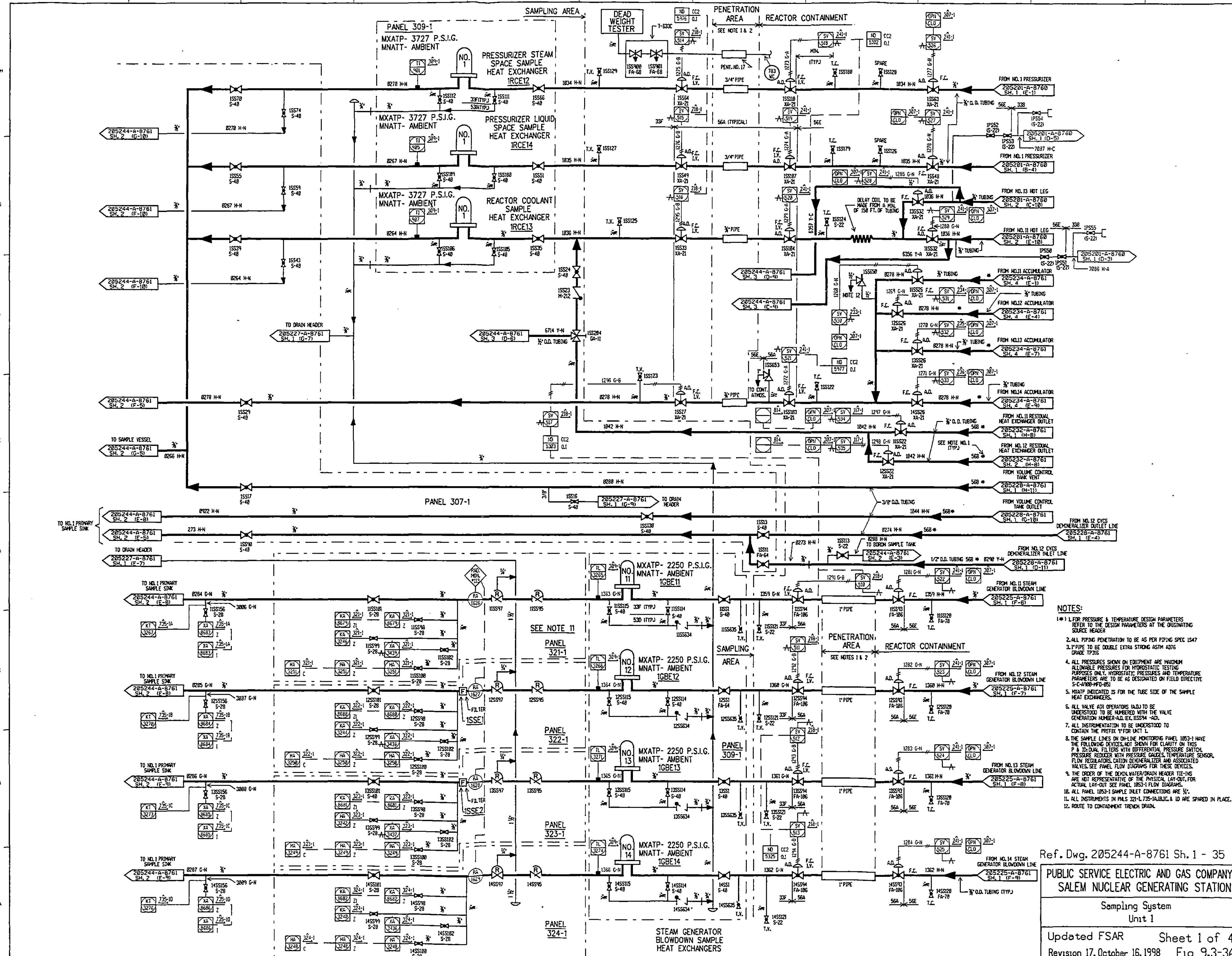
Control Air System
Unit 2

Updated FSAR

Sheet 2 of 3

Revision 17, October 16, 1998

Fig 9.3-2B



NOTES:

(*) 1. FOR PRESSURE & TEMPERATURE DESIGN PARAMETERS REFER TO THE DESIGN PARAMETERS AT THE ORIGINATING SOURCE HEADER

2. ALL PIPING PENETRATION TO BE AS PER PIPING SPEC 1S47

3. 1" PIPE TO BE DOUBLE EXTRA STRONG ASTM A376 GRADE TP316

4. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051

5. MXATP INDICATED IS FOR THE TUBE SIDE OF THE SAMPLE HEAT EXCHANGERS.

6. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 11SS94 -AO).

7. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "1" FOR UNIT 1.

8. THE SAMPLE LINES ON ON-LINE MONITORING PANEL 1053-1 HAVE THE FOLLOWING DEVICES, NOT SHOWN FOR CLARITY ON THIS P & ID: DUAL FILTERS WITH DIFFERENTIAL PRESSURE SWITCH, PRESSURE REDUCER WITH PRESSURE GAUGES, TEMPERATURE SENSOR, FLOW REGULATORS, CATION DEMINERALIZER AND ASSOCIATED VALVES. SEE PANEL FLOW DIAGRAMS FOR THESE DEVICES.

9. THE ORDER OF THE DEMIN. WATER/DRAIN HEADER TIE-INS ARE NOT REPRESENTATIVE OF THE PHYSICAL LAY-OUT, FOR ACTUAL LAY-OUT SEE PANEL 1053-1 FLOW DIAGRAMS.

10. ALL PANEL 1053-1 SAMPLE INLET CONNECTIONS ARE ¼".

11. ALL INSTRUMENTS IN PNLS 321-1, 735-1A,1B,1C, & 1D ARE SPARED IN PLACE.

12. ROUTE TO CONTAINMENT TRENCH DRAIN.

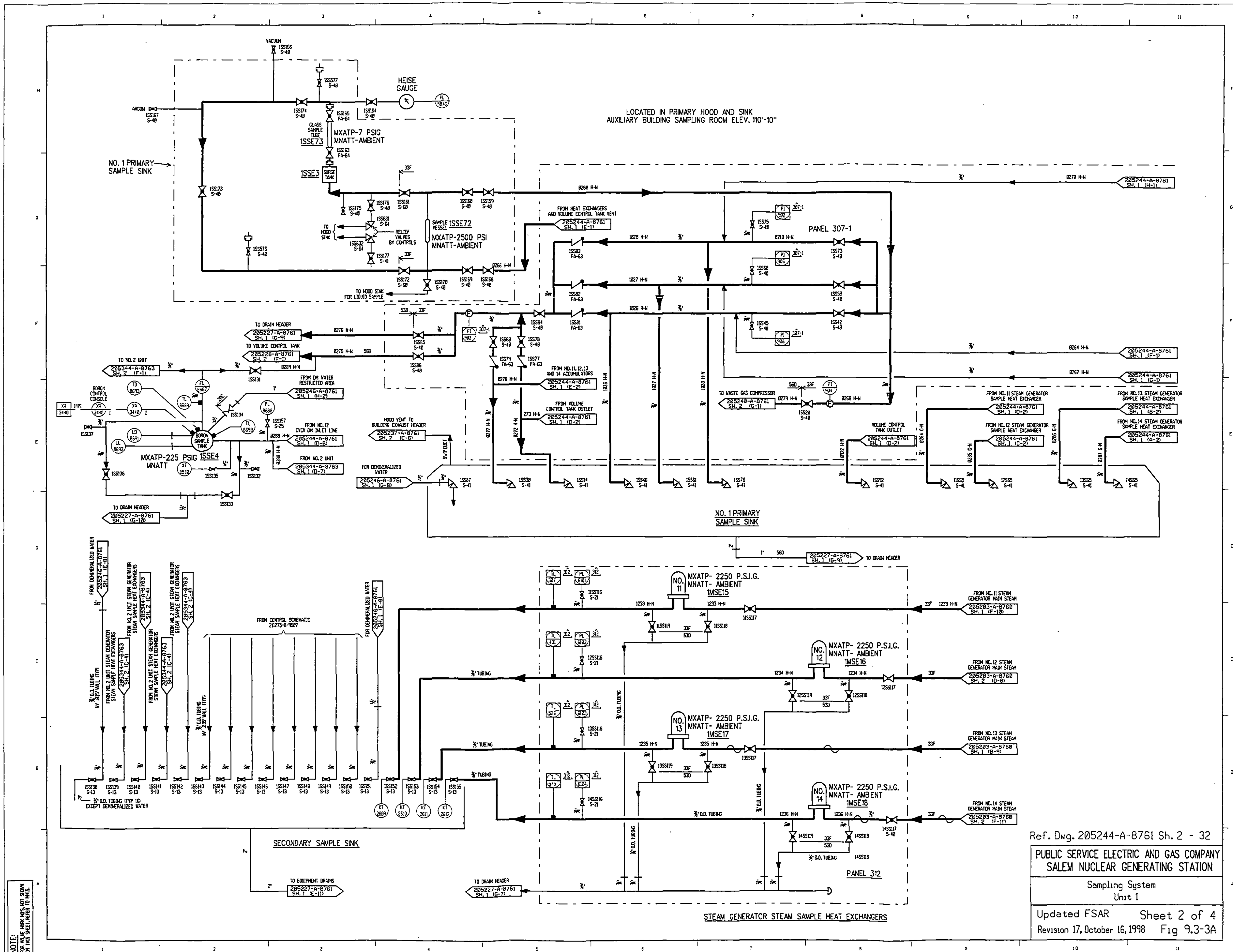
Ref. Dwg. 205244-A-8761 Sh. 1 - 35

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Sampling System
Unit 1

Updated FSAR — Sheet 1 of 4

Revision 17, October 16, 1998 — Fig 9.3-3A



Ref. Dwg. 205244-A-8761 Sh. 2 - 32

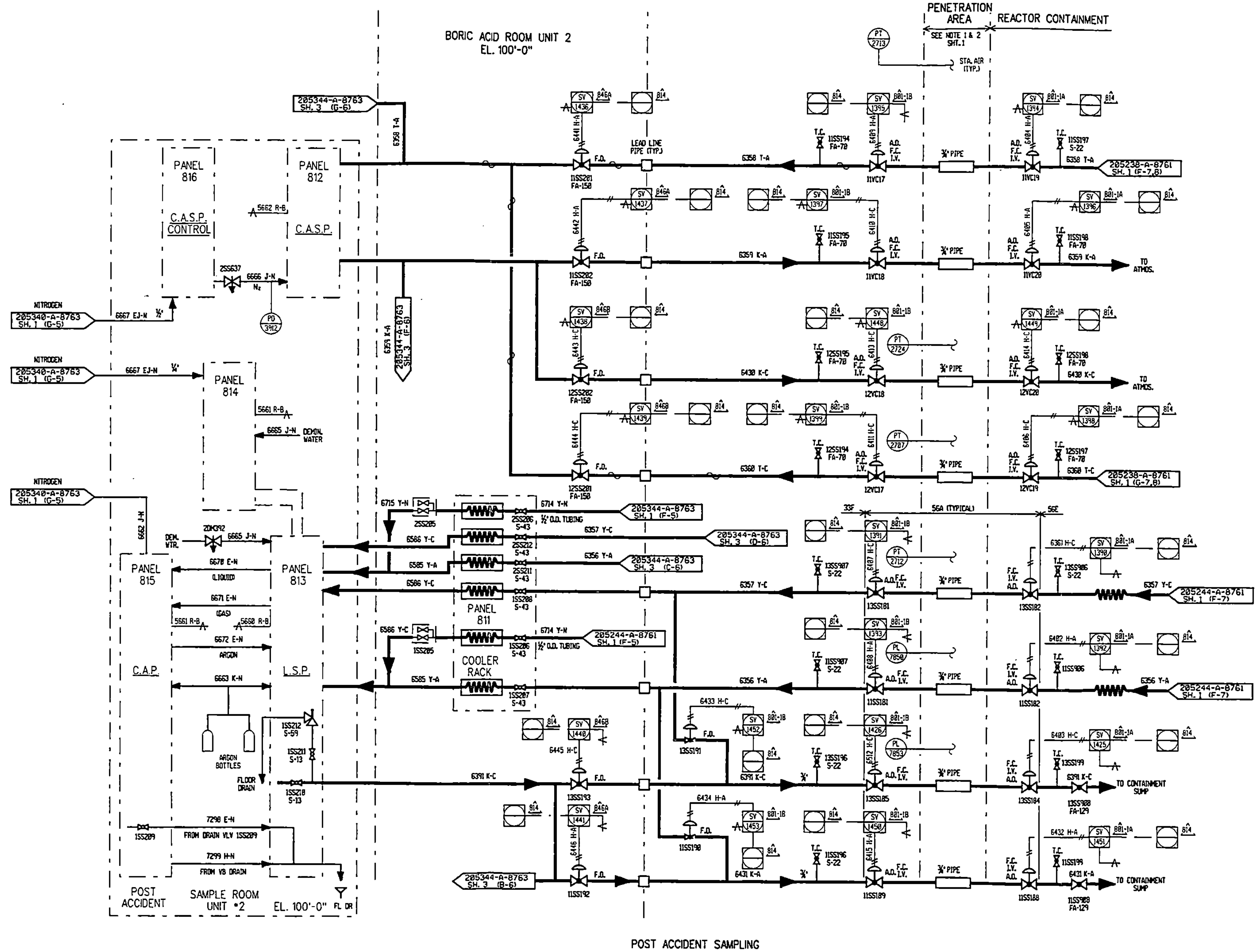
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Sampling System
Unit 1

Updated FSAR — Sheet 2 of 4

Revision 17, October 16, 1998 — Fig 9.3-3A

NOTE: FOR VALVE MARK NOS. NOT SHOWN ON THIS SHEET, REFER TO MNS.



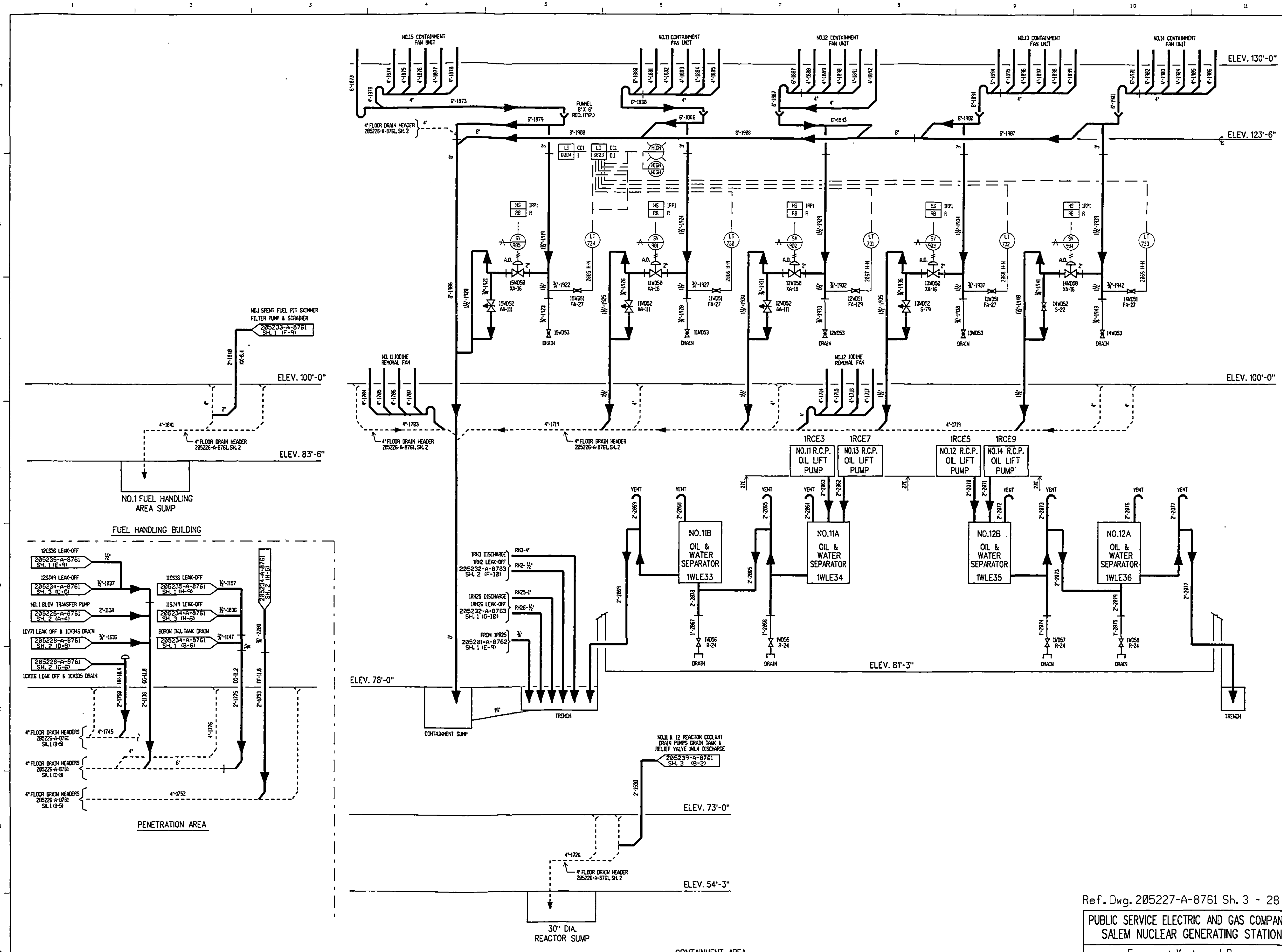
NOTE:
FOR VALVE MARK NO'S. NOT SHOWN ON THIS SHEET, REFER TO MMIS.

Ref. Dwg. 205244-A-8761 Sh. 3 - 31

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Sampling System
Unit 1

Updated FSAR
Sheet 3 of 4
Revision 17, October 16, 1998
Fig 9.3-3A



NOTE "B" - REV. 28
ADDED: SEPARATE DISCHARGE LINES FOR VALVES 1RH3,1RH2,1RH25,1RH26 AND 1PR25 (C-D,4-5).
REVISION SUPERSEDES & INCORPORATES S97-0174, CD NO. M508/B, PKG. 01

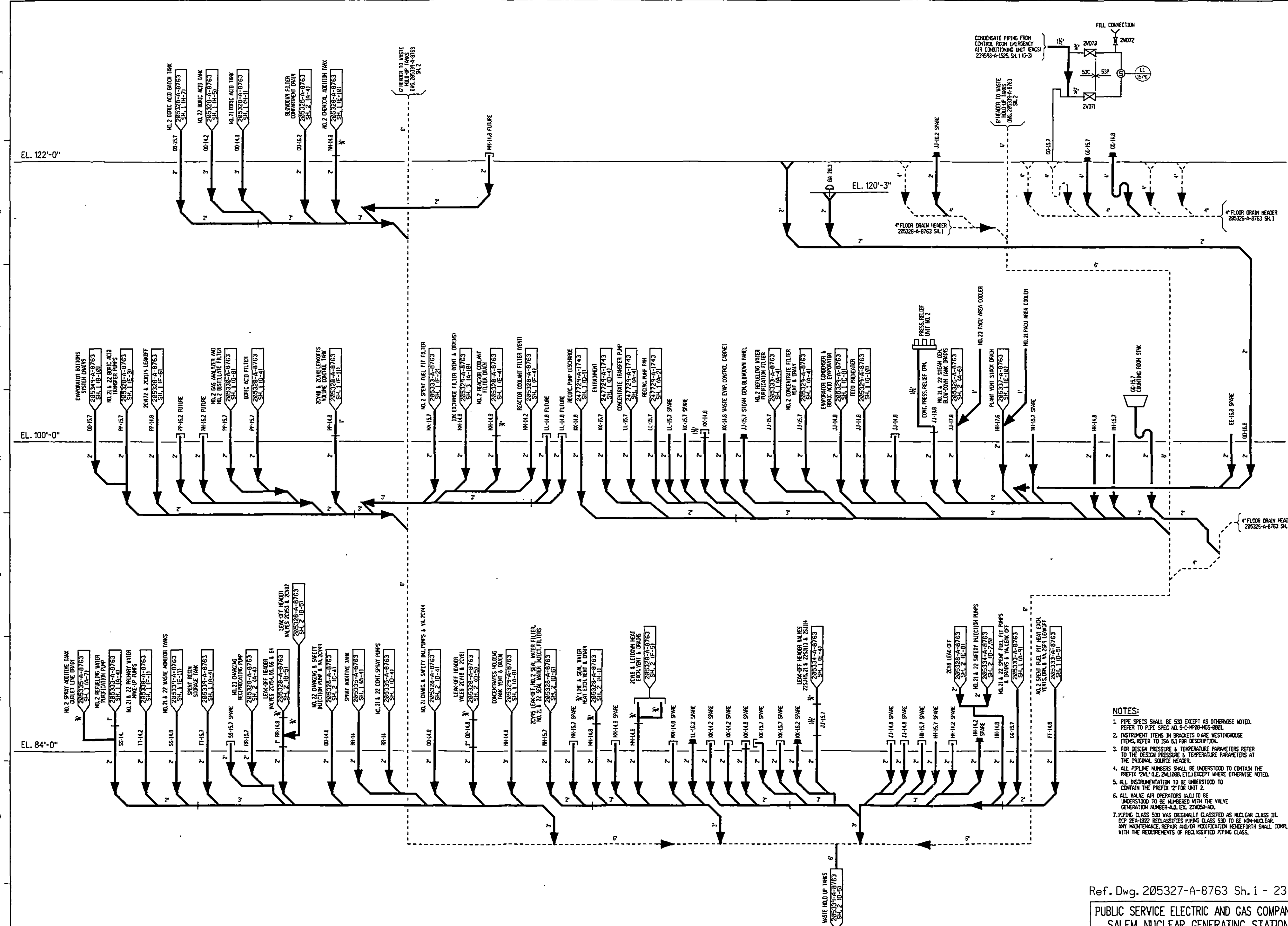
NOTE: FOR VALVE MARK NO'S NOT SHOWN ON THIS SHEET, REFER TO MASS.

Ref. Dwg. 205227-A-8761 Sh. 3 - 28

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Equipment Vents and Drains-
Unit 1

Updated FSAR Sheet 3 of 3
Revision 17, October 16, 1998 Fig 9.3-4A



NOTES:

1. PIPE SPECS SHALL BE 530 EXCEPT AS OTHERWISE NOTED. REFER TO PIPE SPEC NO. S-C-MP00-MGS-0001.
2. INSTRUMENT ITEMS IN BRACKETS [] ARE WESTINGHOUSE ITEMS, REFER TO ISA 5.1 FOR DESCRIPTION.
3. FOR DESIGN PRESSURE & TEMPERATURE PARAMETERS REFER TO THE DESIGN PRESSURE & TEMPERATURE PARAMETERS AT THE ORIGINAL SOURCE HEADER.
4. ALL PIPLINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "2WL" (I.E. 2WL1000, ETC.) EXCEPT WHERE OTHERWISE NOTED.
5. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "2" FOR UNIT 2.
6. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 23VD50-AO).
7. PIPING CLASS 530 WAS ORIGINALLY CLASSIFED AS NUCLEAR CLASS III. DCP 2EA-1022 RECLASSIFIES PIPING CLASS 530 TO BE NON-NUCLEAR. ANY MAINTENANCE, REPAIR AND/OR MODIFICATION HENCEFORTH SHALL COMPLY WITH THE REQUIREMENTS OF RECLASSIFIED PIPING CLASS.

NOTE: FOR VALVE MARK NO'S NOT SHOWN ON THIS SHEET, REFER TO M425.

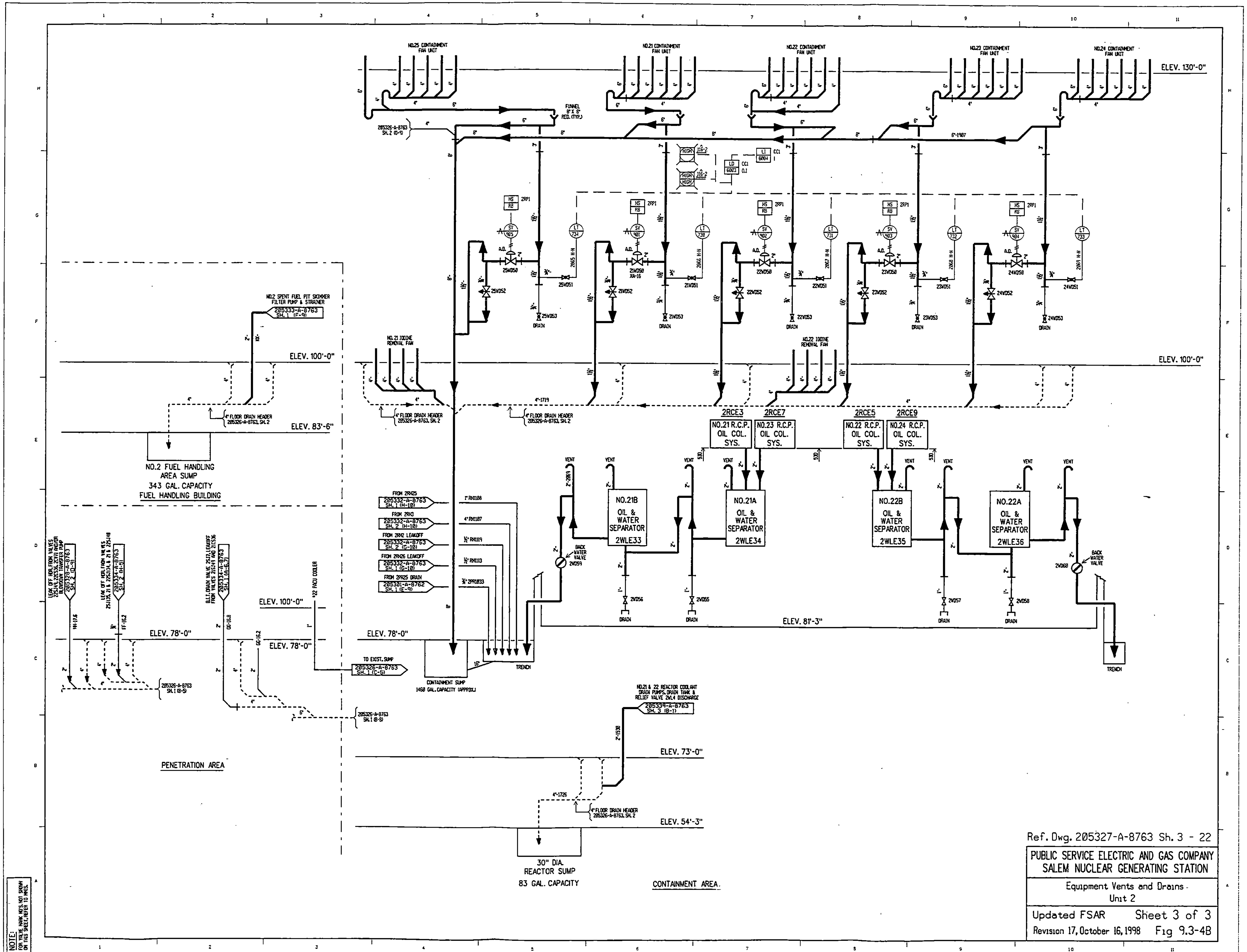
Ref. Dwg. 205327-A-8763 Sh. 1 - 23

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Equipment Vents and Drains
Unit 2

Updated FSAR — Sheet 1 of 3

Revision 17, October 16, 1998 — Fig 9.3-4B

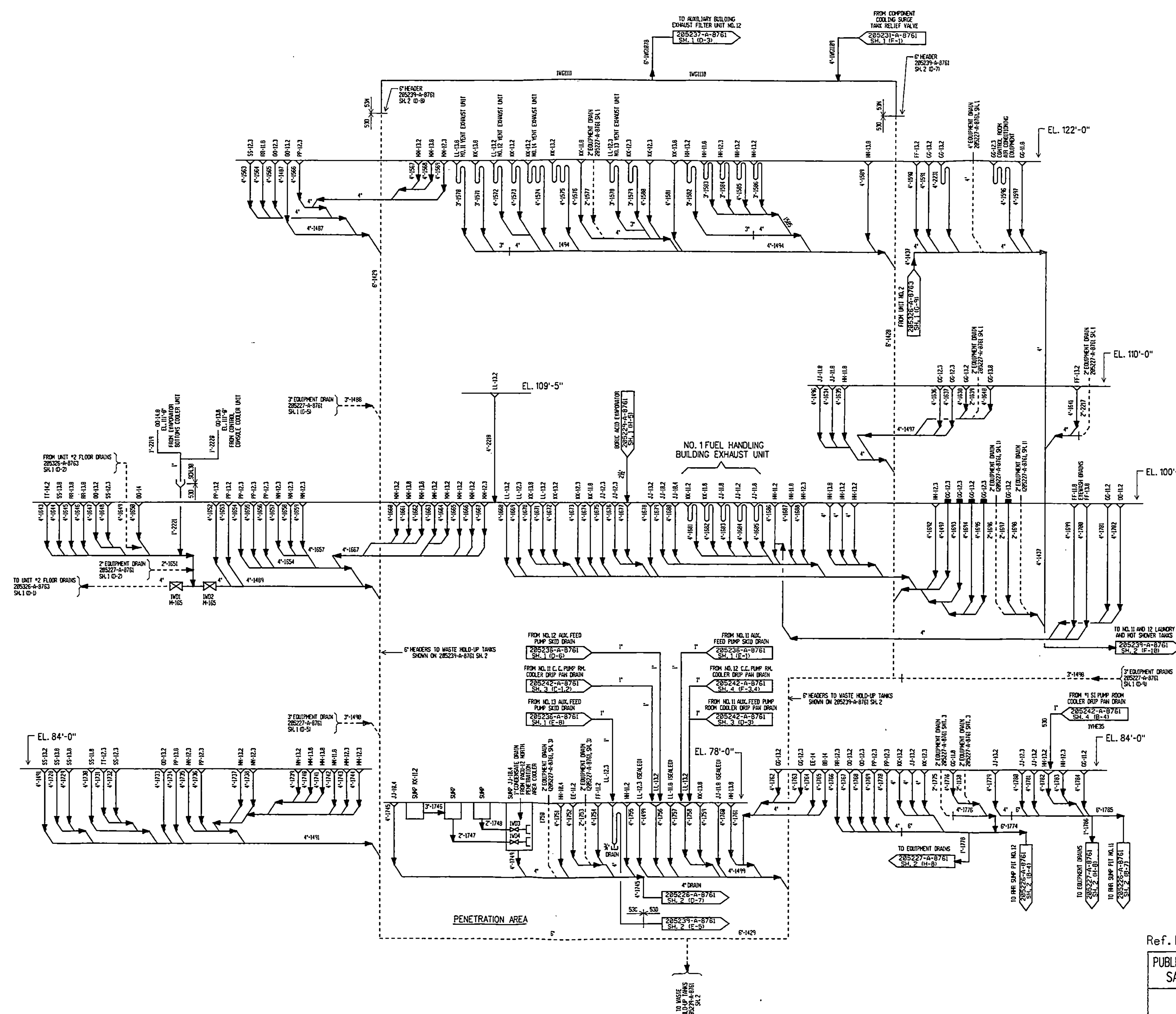


Ref. Dwg. 205327-A-8763 Sh. 3 - 22

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Equipment Vents and Drains
Unit 2

Updated FSAR Sheet 3 of 3
Revision 17, October 16, 1998 Fig 9.3-4B



NOTES

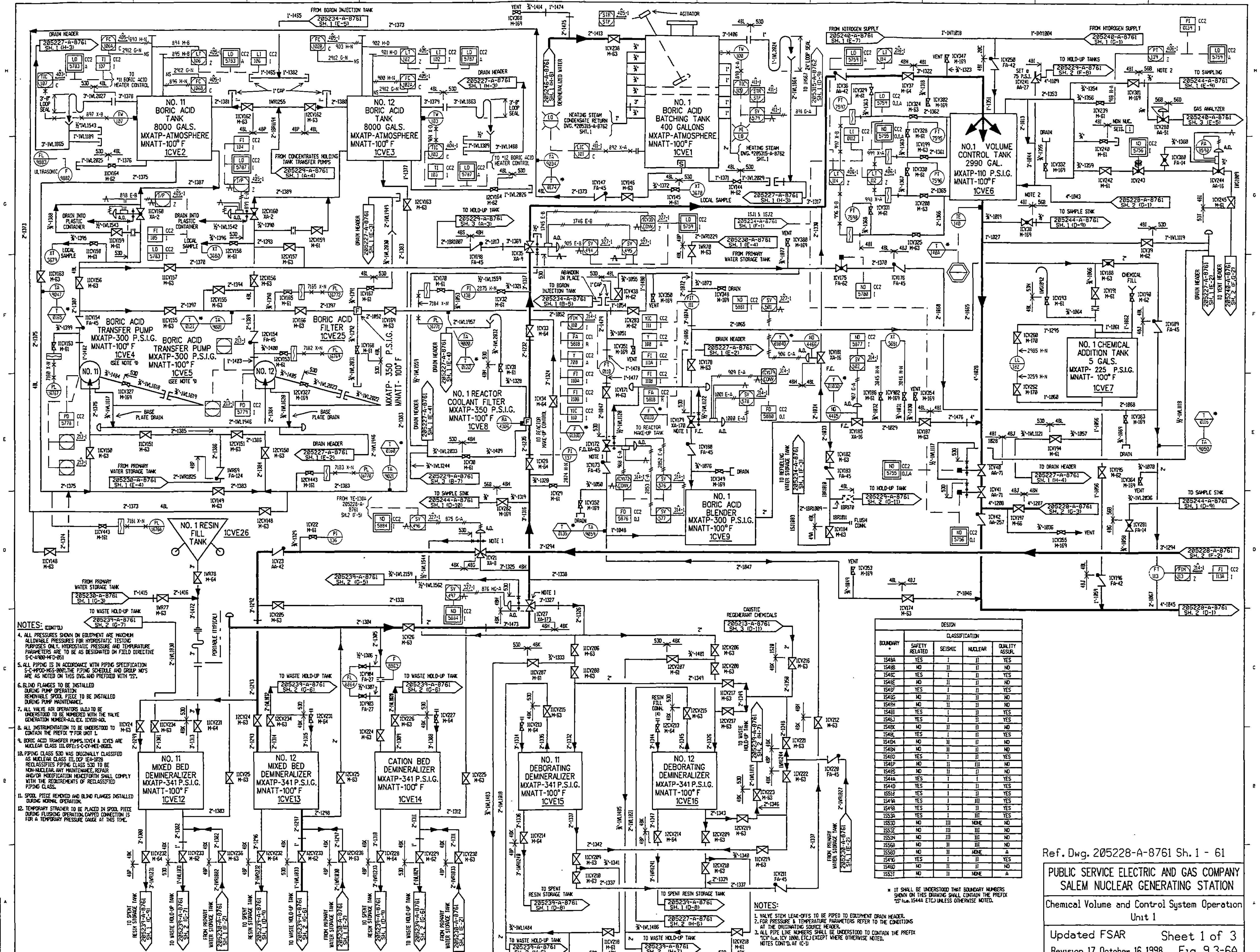
1. PIPE SPECIFICATIONS SHALL BE 530 REFER TO PIPE SPECIFICATION NO. S-C-MPOO-MGS-0001.
2. FOR DESIGN PRESSURE AND TEMPERATURE PARAMETERS REFER TO THE DESIGN PRESSURE AND TEMPERATURE PARAMETERS AT THE ORIGINAL SOURCE HEADERS.
3. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX 1WL (IE: 1WL1000, ETC.) EXCEPT WHERE OTHERWISE NOTED.
4. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "1" FOR UNIT 1.
5. PIPING CLASS 530 WAS ORIGINALLY CLASSIFED AS NUCLEAR CLASS III. DCP 1EA-1028 RECLASSIFIES PIPING CLASS 530 TO BE NON-NUCLEAR. ANY MAINTENANCE, REPAIR AND/OR MODIFICATION HENCEFORTH SHALL COMPLY WITH THE REQUIREMENTS OF RECLASSIFIED PIPING CLASS.

Ref. Dwg. 205226-A-8761 Sh. 1 - 30

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Floor Drains
Unit 1

Updated FSAR — Sheet 1 of 2
Revision 17, October 16, 1998 — Fig 9.3-5A



NOTES: (CONT'D)

4. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURE AND TEMPURATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051
5. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION S-C-MP00-MGS-0001.THE PIPING SCHEDULE AND GROUP NO'S ARE AS NOTED ON THIS DWG. AND PREFIXED WITH "1S".
6. BLIND FLANGES TO BE INSTALLED DURING PUMP OPERATION REMOVABLE SPOOL PIECE TO BE INSTALLED DURING PUMP MAINTENANCE.
7. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 1CV181-AO).
8. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "1" FOR UNIT 1.
9. BORIC ACID TRANSFER PUMPS, 1CVE4 & 1CVE5 ARE NUCLEAR CLASS III. (RFE: S-C-CV-MEE-0683).
10. PIPING CLASS 530 WAS ORIGINALLY CLASSIFED AS NUCLEAR CLASS III. DCP 1EA-1028 RECLASSIFIES PIPING CLASS 530 TO BE NON-NUCLEAR. ANY MAINTENANCE, REPAIR AND/OR MODIFICATION HENCEFORTH SHALL COMPLY WITH THE REQUIREMENTS OF RECLASSIFIED PIPING CLASS.
11. SPOOL PIECE REMOVED AND BLIND FLANGES INSTALLED DURING NORMAL OPERATION.
12. TEMPORARY STRAINER TO BE PLACED IN SPOOL PIECE DURING FLUSHING OPERATION. CAPPED CONNECTION IS FOR A TEMPORARY PRESSURE GAUGE AT THIS TIME.

DESIGN				
BOUNDARY *	CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S48A	YES	I	II	YES
1S48B	NO	II	II	NO
1S48C	YES	I	II	YES
1S48E	NO	II	II	NO
1S48F	YES	I	II	YES
1S48G	NO	II	II	NO
1S48H	NO	II	II	NO
1S48I	YES	I	II	YES
1S48J	YES	I	II	YES
1S48K	NO	II	II	NO
1S48L	YES	I	II	YES
1S48M	NO	II	II	NO
1S48N	NO	II	II	NO
1S48O	YES	I	II	YES
1S48P	NO	II	III	NO
1S48S	NO	II	II	NO
1S44A	YES	I	I	YES
1S44D	YES	I	II	YES
1S51B	YES	I	II	YES
1S49A	YES	I	III	YES
1S49B	YES	I	II	YES
1S53A	YES	I	III	YES
1S53D	NO	III	NONE	NO
1S53E	NO	III	III	NO
1S53N	NO	III	III	NO
1S56B	NO	II	III	NO
1S56D	NO	II	NONE	A
1S49G	YES	I	II	YES
1S46D	NO	II	II	NO
1S53T	NO	II	NONE	A

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (i.e. 1S44A ETC.) UNLESS OTHERWISE NOTED.

NOTES:

1. VALVE STEM LEAK-OFFS TO BE PIPED TO EQUIPMENT DRAIN HEADER.
2. FOR PRESSURE & TEMPERATURE PARAMETERS REFER TO THE CONDITIONS AT THE ORIGINATING SOURCE HEADER.
3. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1CV" (i.e. 1CV 1000, ETC.) EXCEPT WHERE OTHERWISE NOTED.

NOTES CONT'D. AT (C-1)

NOTE: FOR VALVE MARK NO'S. NOT SHOWN ON THIS SHEET, REFER TO MNIS.

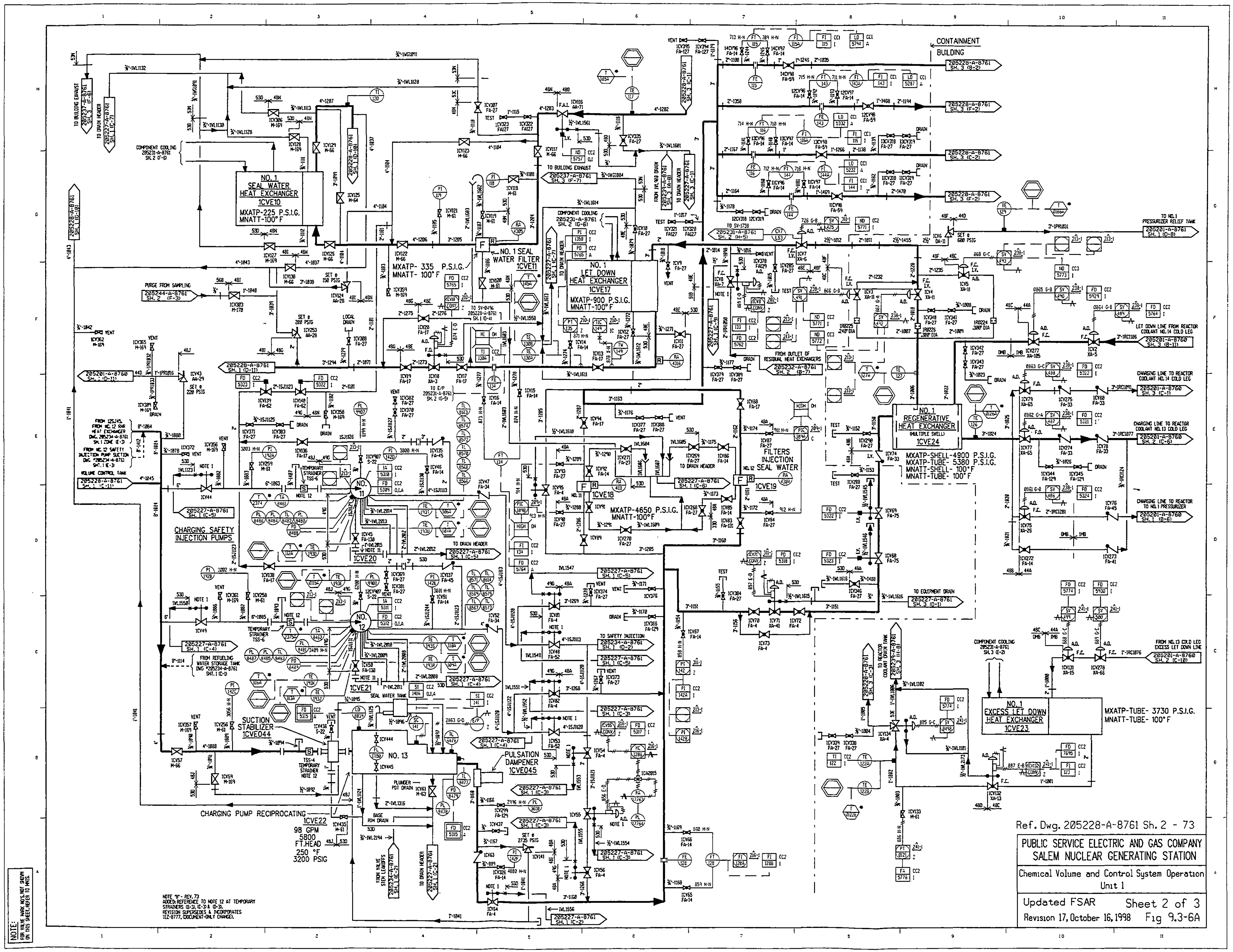
Ref. Dwg. 205228-A-8761 Sh. 1 - 61

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Chemical Volume and Control System Operation
Unit 1

Updated FSAR — Sheet 1 of 3

Revision 17, October 16, 1998 — Fig 9.3-6A



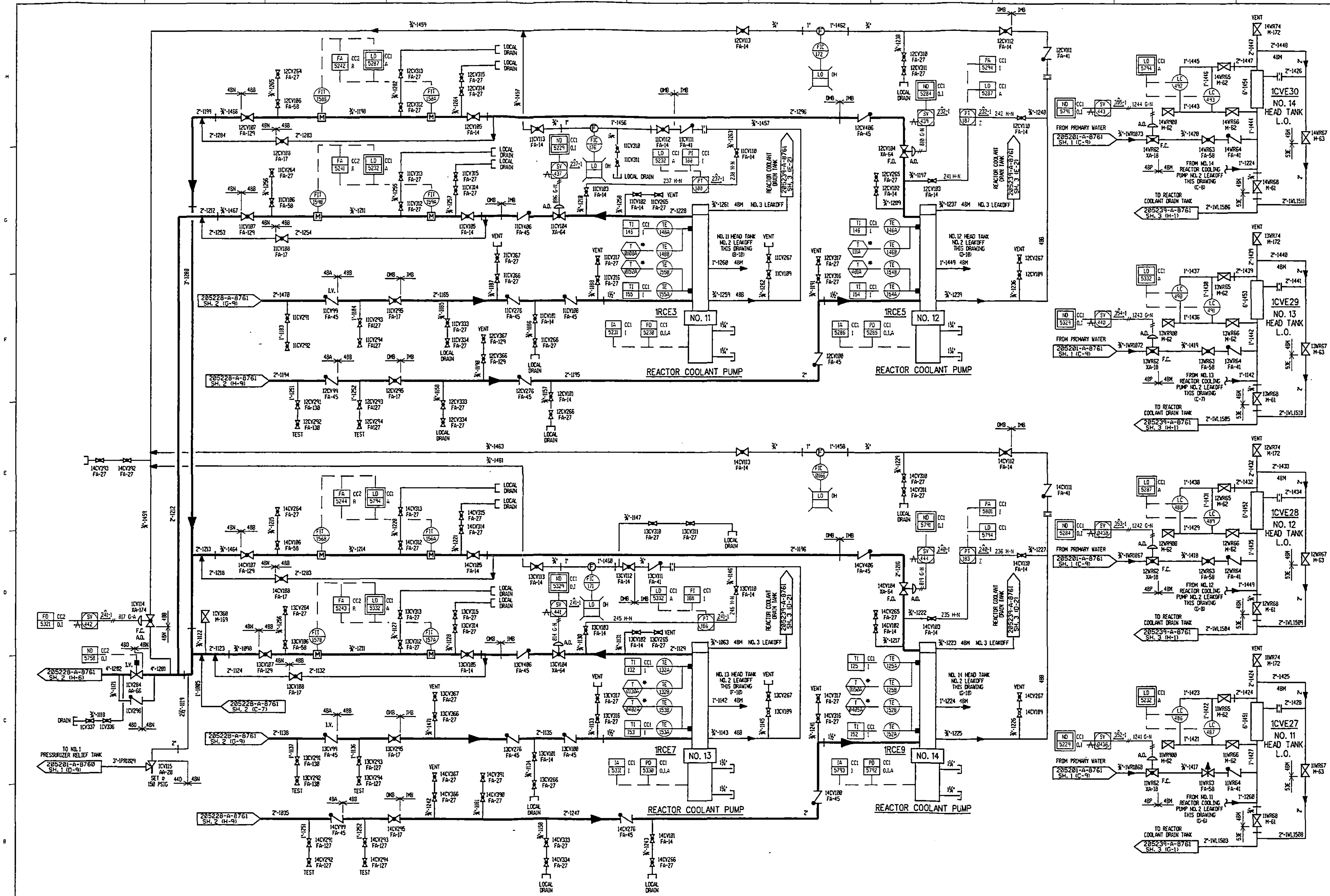
Ref. Dwg. 205228-A-8761 Sh. 2 - 73

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Chemical Volume and Control System Operation
Unit 1

Updated FSAR — Sheet 2 of 3

Revision 17, October 16, 1998 — Fig 9.3-6A



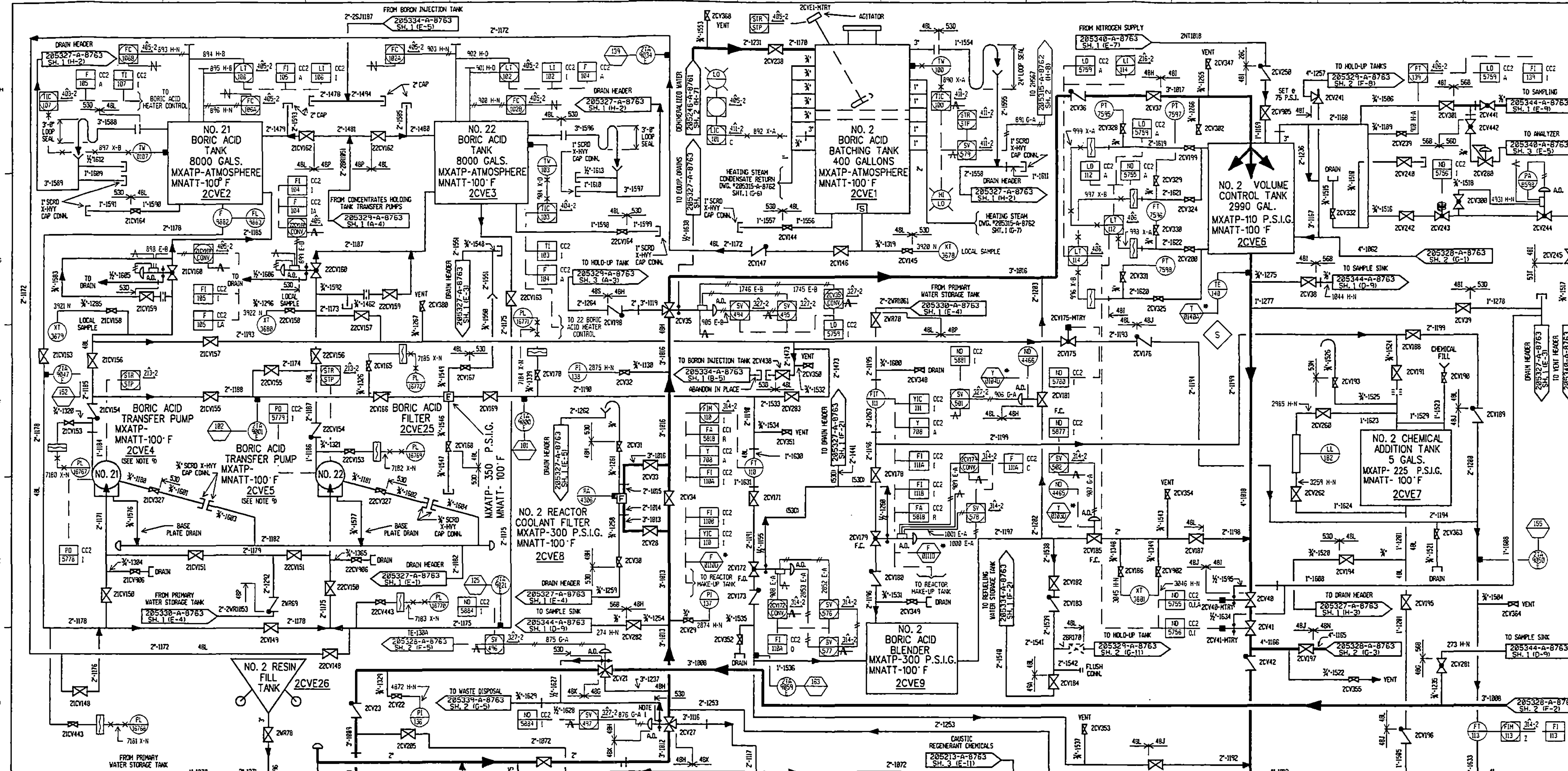
Ref. Dwg. 205228-A-8761 Sh. 3 - 45

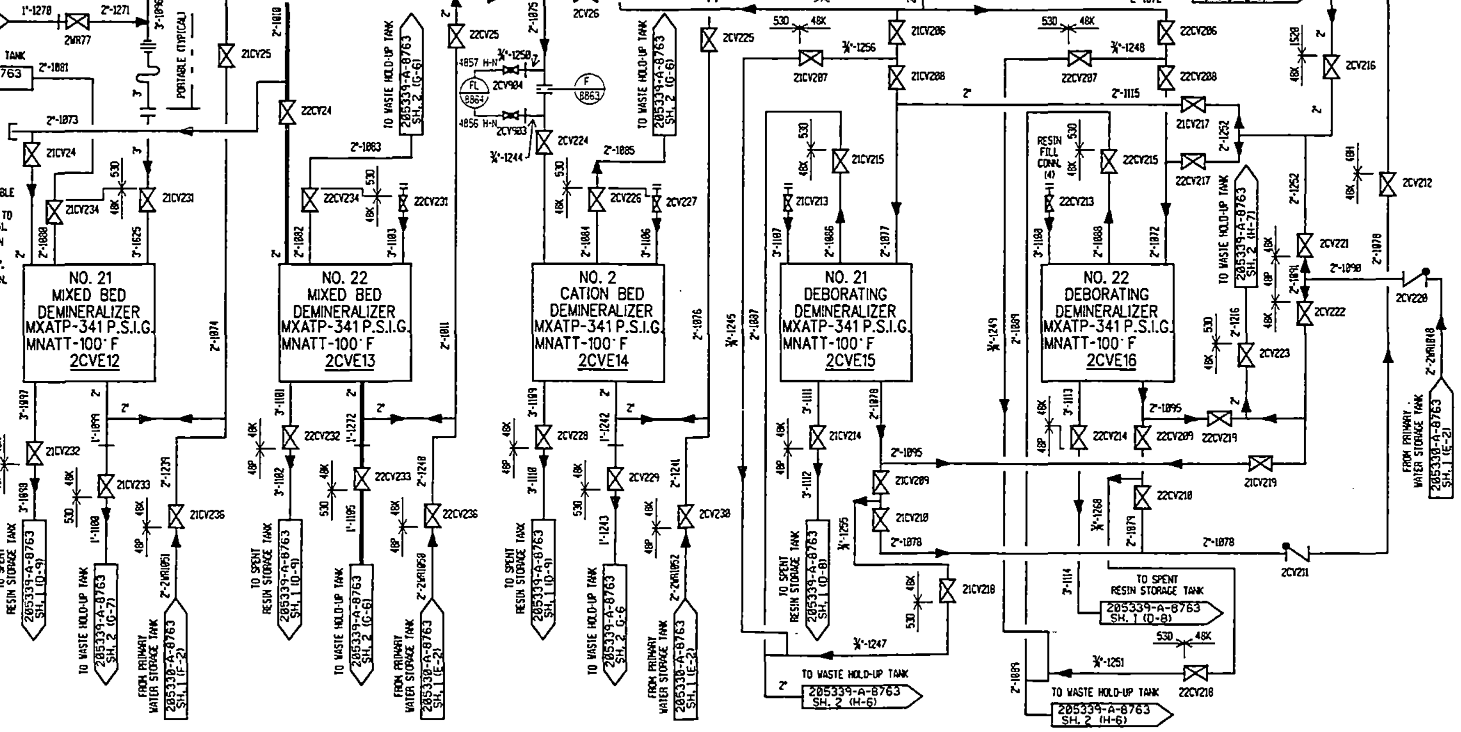
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Chemical Volume and Control System Operation
Unit 1

Updated FSAR — Sheet 3 of 3

Revision 17, October 16, 1998 — Fig 9.3-6A





NOTES:

1. VALVE STEM LEAK-OFFS TO BE PIPED TO EQUIPMENT DRAIN HEADER.
2. ALL PIPING IS IN ACCORDANCE WITH PIPING SPEC. S-C-MP00-MGS-0001. PIPING SCH. 1548A UNLESS OTHERWISE NOTED.
3. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "2CV" (i.e. 2CV 1000, ETC.) EXCEPT WHERE OTHERWISE NOTED. NOTES CONT'D. AT (B-1)

NOTES: (CONT'D.)

4. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051.
5. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION S-C-MP00-MGS-0001. THE PIPING SCHEDULE AND GROUP NO'S. ARE AS NOTED ON THIS DWG. AND PREFIXED WITH "25".
6. BLIND FLANGES SHALL BE INSTALLED FOR PUMP OPERATION. REMOVABLE SPOOL PIECE SHALL BE INSTALLED FOR PUMP MAINTENANCE.
7. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 22CV160-AO).
8. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "2" FOR UNIT 2.
9. BORIC ACID TRANSFER PUMPS, 2CVE4 & 2CVE5 ARE NUCLEAR CLASS III. (RFE: S-C-CV-MEE-0680).
10. PIPING CLASS 530 WAS ORIGINALLY CLASSIFED AS NUCLEAR CLASS III. DCP 2EA-1022 RECLASSIFIES PIPING CLASS 530 TO BE NON-NUCLEAR. ANY MAINTENANCE, REPAIR AND/OR MODIFICATION HENCEFORTH SHALL COMPLY WITH THE REQUIREMENTS OF RECLASSIFIED PIPING CLASS.
11. TEMPORARY STRAINER TO BE PLACED IN SPOOL PIECE DURING FLUSHING OPERATION. CAPPED CONNECTION IS FOR A TEMPORARY PRESSURE GAUGE AT THIS TIME.

DESIGN				
BOUNDARY *	CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1548A	YES	I	II	YES
1548B	NO	II	II	NO
1548C	YES	I	II	YES
1548E	NO	II	II	NO
1548F	YES	I	II	YES
1548G	NO	II	II	NO
1548H	NO	II	II	NO
1548I	YES	I	II	YES
1548J	YES	I	II	YES
1548K	NO	II	II	NO
1548L	YES	I	II	YES
1548M	NO	II	II	NO
1548N	NO	II	II	NO
1548O	YES	I	II	YES
1548P	NO	II	III	NO
1548S	NO	II	II	NO
1544A	YES	I	I	YES
1544D	YES	I	II	YES
1551B	YES	I	II	YES
1549A	YES	I	III	YES
1549B	YES	I	II	YES
1553A	YES	I	III	YES
1553D	NO	III	NONE	NO
1553E	NO	III	III	NO
1553N	NO	III	III	NO
1556B	NO	II	III	NO
1556D	NO	II	NONE	A
1549C	YES	I	II	YES
1548D	NO	II	II	NO
SP553T	NO	II	NONE	A

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "25" (i.e. 2544A ETC.) UNLESS OTHERWISE NOTED.

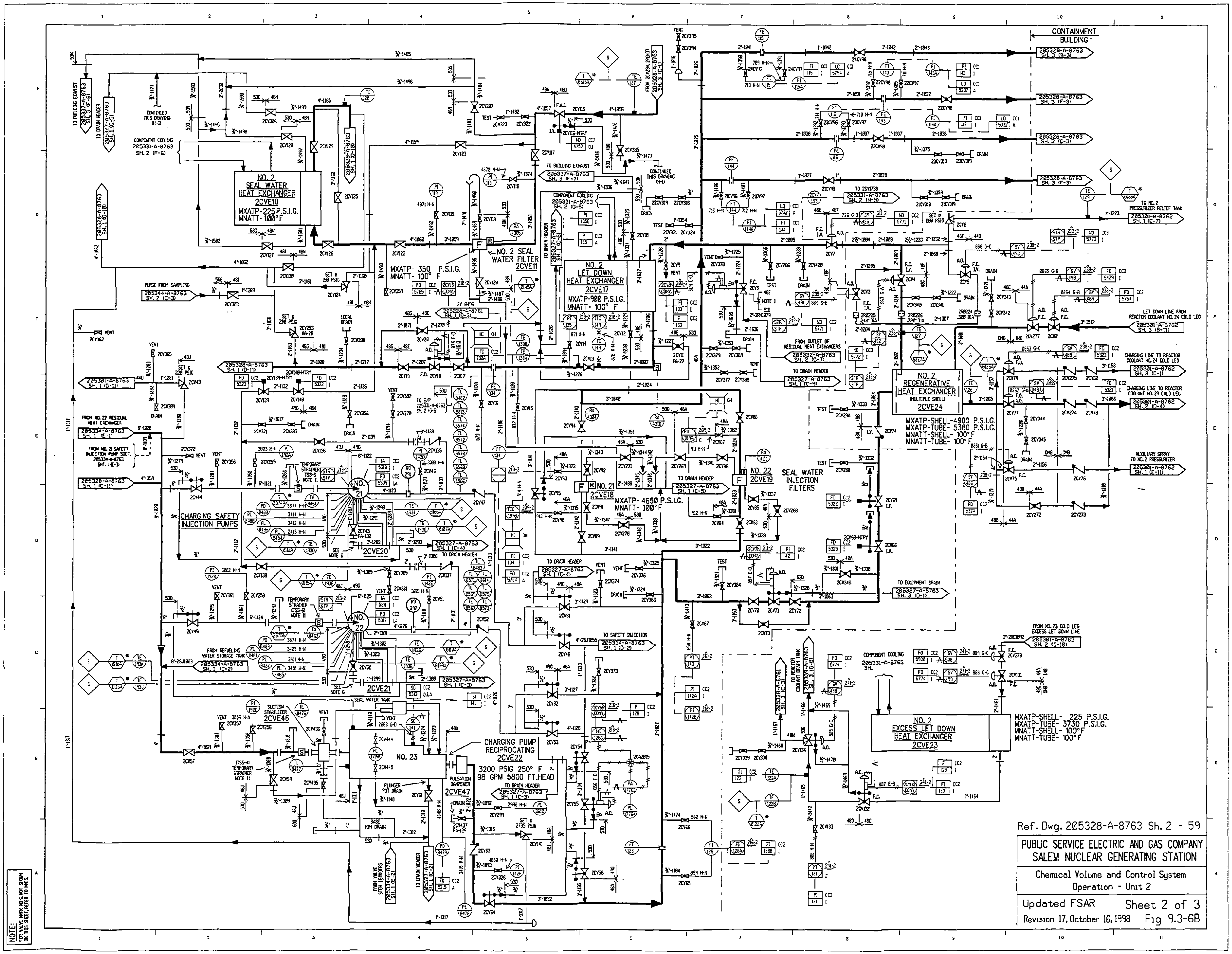
NOTE: FOR VALVE MARK NO'S NOT SHOWN ON THIS SHEET, REFER TO NAMES.

Ref. Dwg. 205328-A-8763 Sh. 1 - 48

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Chemical Volume and Control System
Operation - Unit 2

Updated FSAR — Sheet 1 of 3
Revision 17, October 16, 1998 — Fig 9.3-6B



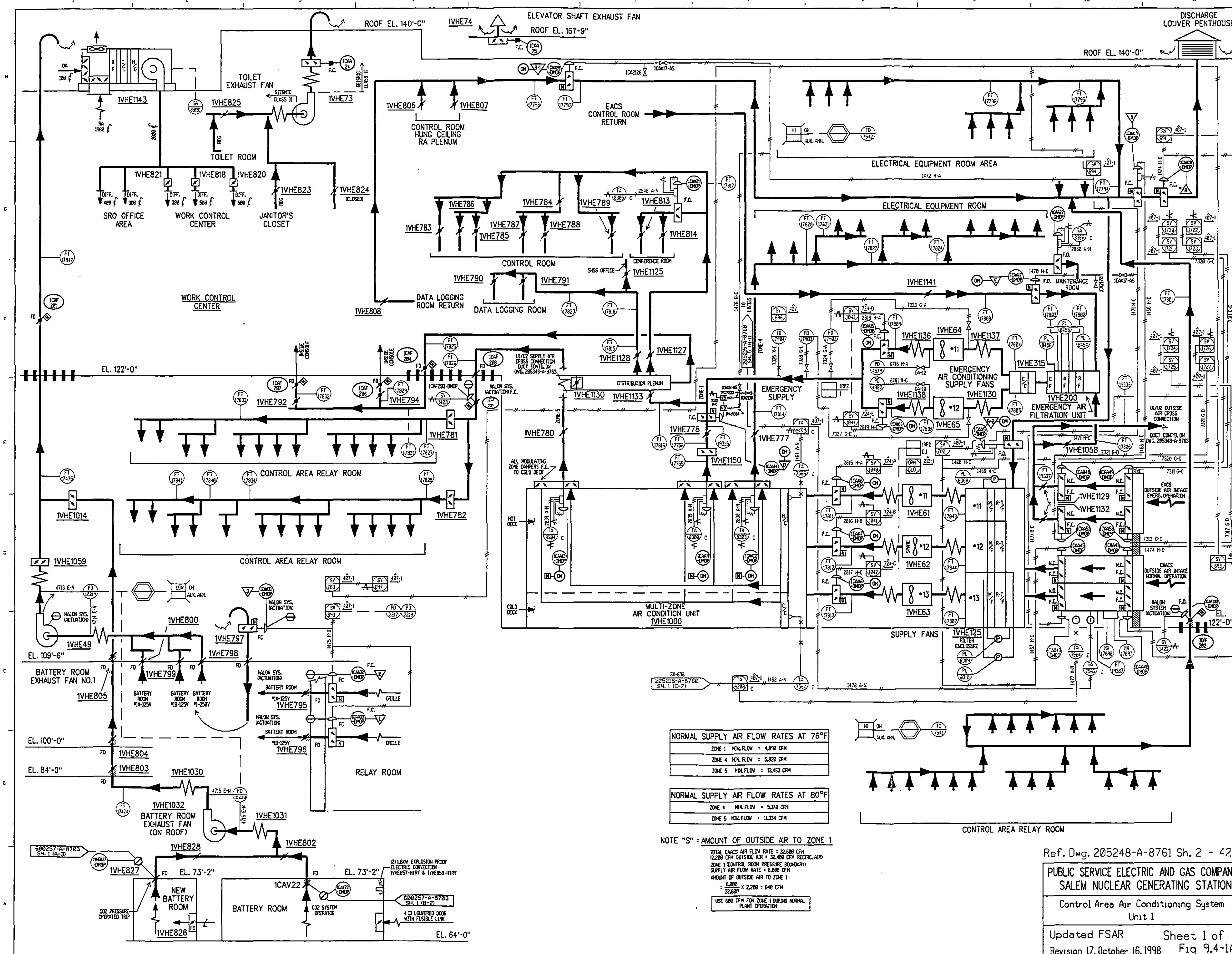
Ref. Dwg. 205328-A-8763 Sh. 2 - 59

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Chemical Volume and Control System
Operation - Unit 2

Updated FSAR Sheet 2 of 3

Revision 17, October 16, 1998 Fig 9.3-6B



NORMAL SUPPLY AIR FLOW RATES AT 76°F
ZONE 1 MIN.FLOW = 4,898 CFM
ZONE 4 MIN.FLOW = 5,820 CFM
ZONE 5 MIN.FLOW = 13,453 CFM

NORMAL SUPPLY AIR FLOW RATES AT 80°F
ZONE 4 MIN.FLOW = 5,378 CFM
ZONE 5 MIN.FLOW = 11,334 CFM

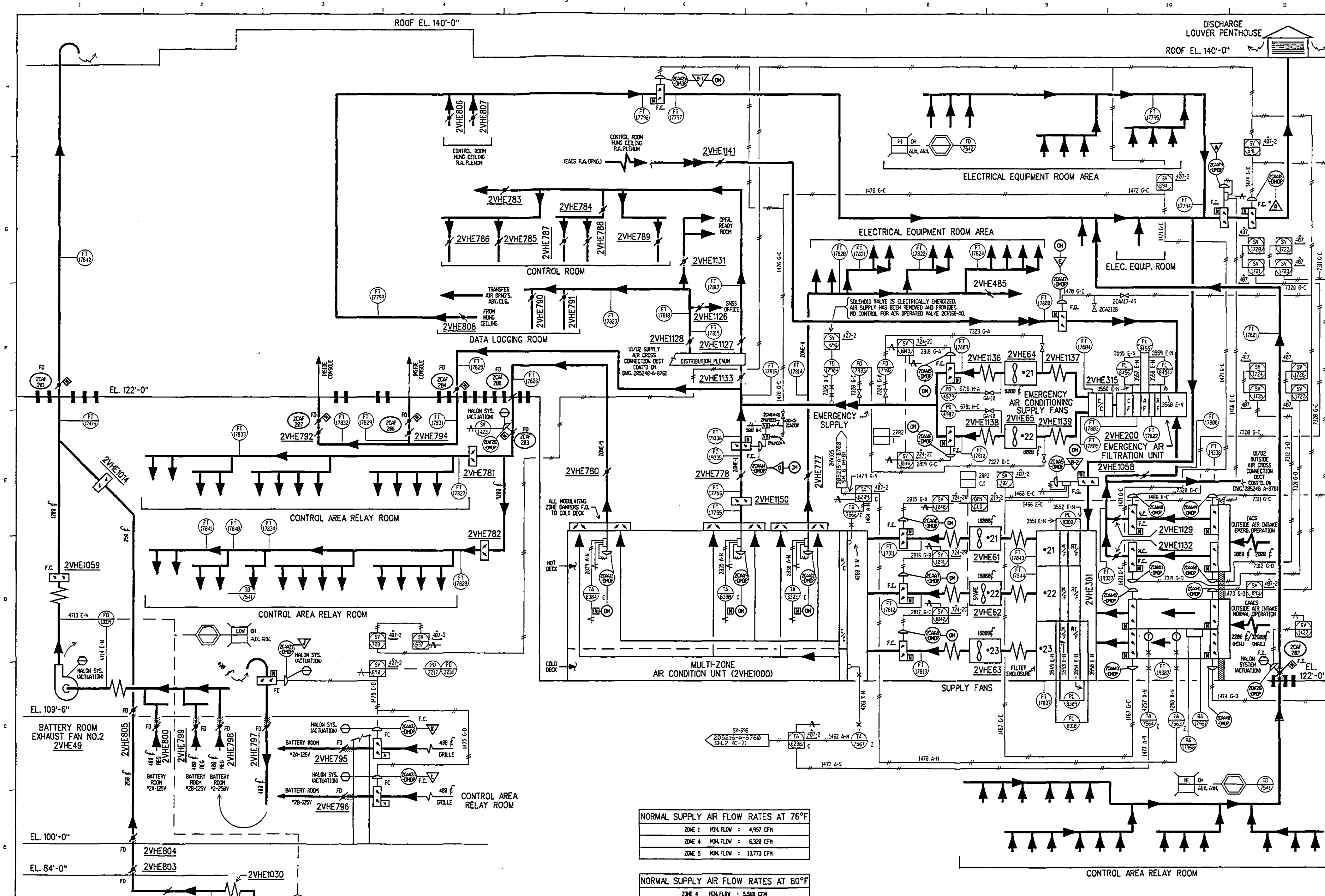
Ref. Dwg. 205248-A-8761 Sh. 2 - 42

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Control Area Air Conditioning System
Unit 1

Updated FSAR
Revision 17, October 16, 1998

Sheet 1 of 1
Fig 9.4-1A



NORMAL SUPPLY AIR FLOW RATES AT 76°F
ZONE 1 MIN. FLOW = 4,957 CFM
ZONE 4 MIN. FLOW = 6,320 CFM
ZONE 5 MIN. FLOW = 13,773 CFM

NORMAL SUPPLY AIR FLOW RATES AT 80°F
ZONE 4 MIN. FLOW = 5,580 CFM
ZONE 5 MIN. FLOW = 11,561 CFM

NOTE "S" : AMOUNT OF OUTSIDE AIR TO ZONE 1

TOTAL CAACS AIR FLOW RATE = 32,600 CFM
(2,200 CFM OUTSIDE AIR + 30,400 CFM RECIRC. AIR)

ZONE 1 (CONTROL ROOM PRESSURE BOUNDARY)
SUPPLY AIR FLOW RATE = 8,000 CFM

AMOUNT OF OUTSIDE AIR TO ZONE 1

$= \frac{8,000}{32,600} \times 2,200 = 540$ CFM

USE 600 CFM FOR ZONE 1 DURING NORMAL PLANT OPERATION

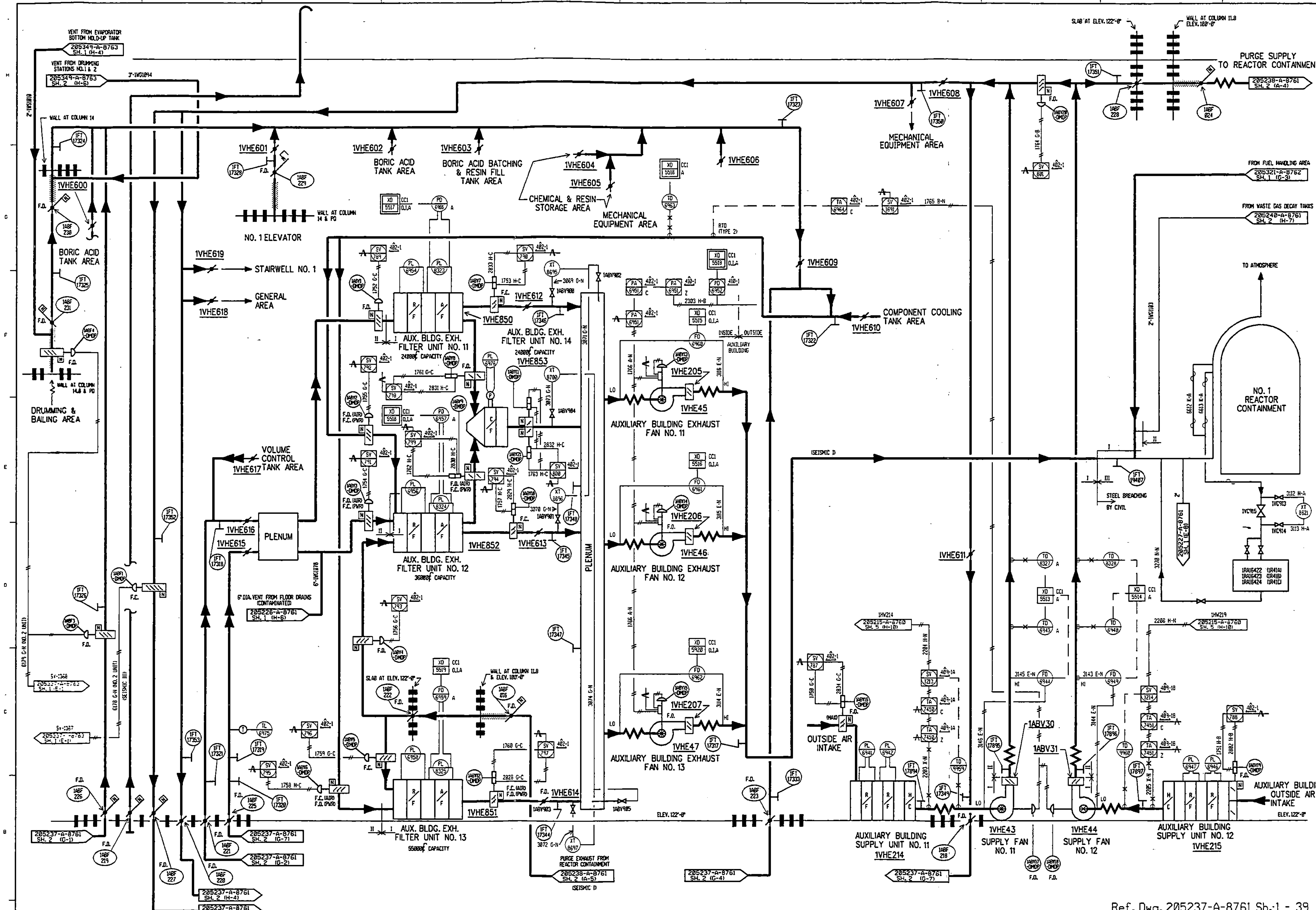
Ref. Dwg. 205348-A-8763 Sh. 2 - 32

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Control Area Air Conditioning System
Unit 2

Updated FSAR — Sheet 1 of 1

Revision 17, October 16, 1998 — Fig 9.4-1B



NOTES:

1. ALL DAMPERS ARE IDENTIFIED WITH A NUMBER (EX. 1ABF4), EXCEPT FAN AND FILTER UNIT DAMPERS WHICH ARE INCLUDED WITH THE UNIT I.D. NUMBER (EX. 1VHE215).
   ALL DAMPER OPERATORS (DMOP) ARE IDENTIFIED WITH A DAMPER NUMBER-DMOP (EX. 1ABF4-DMOP).
2. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "1" FOR UNIT 1.
3. PIPING CLASS 530 WAS ORIGINALLY CLASSIFED AS NUCLEAR CLASS III. DCP 1EA-1028 RECLASSIFIES PIPING CLASS 530 TO BE NON-NUCLEAR. ANY MAINTENANCE, REPAIR AND/OR MODIFICATION HENCEFORTH SHALL COMPLY WITH THE REQUIREMENTS OF RECLASSIFIED PIPING CLASS.

NOTE: FOR VALVE MARK NOS. NOT SHOWN ON THIS SHEET, REFER TO MMIS.

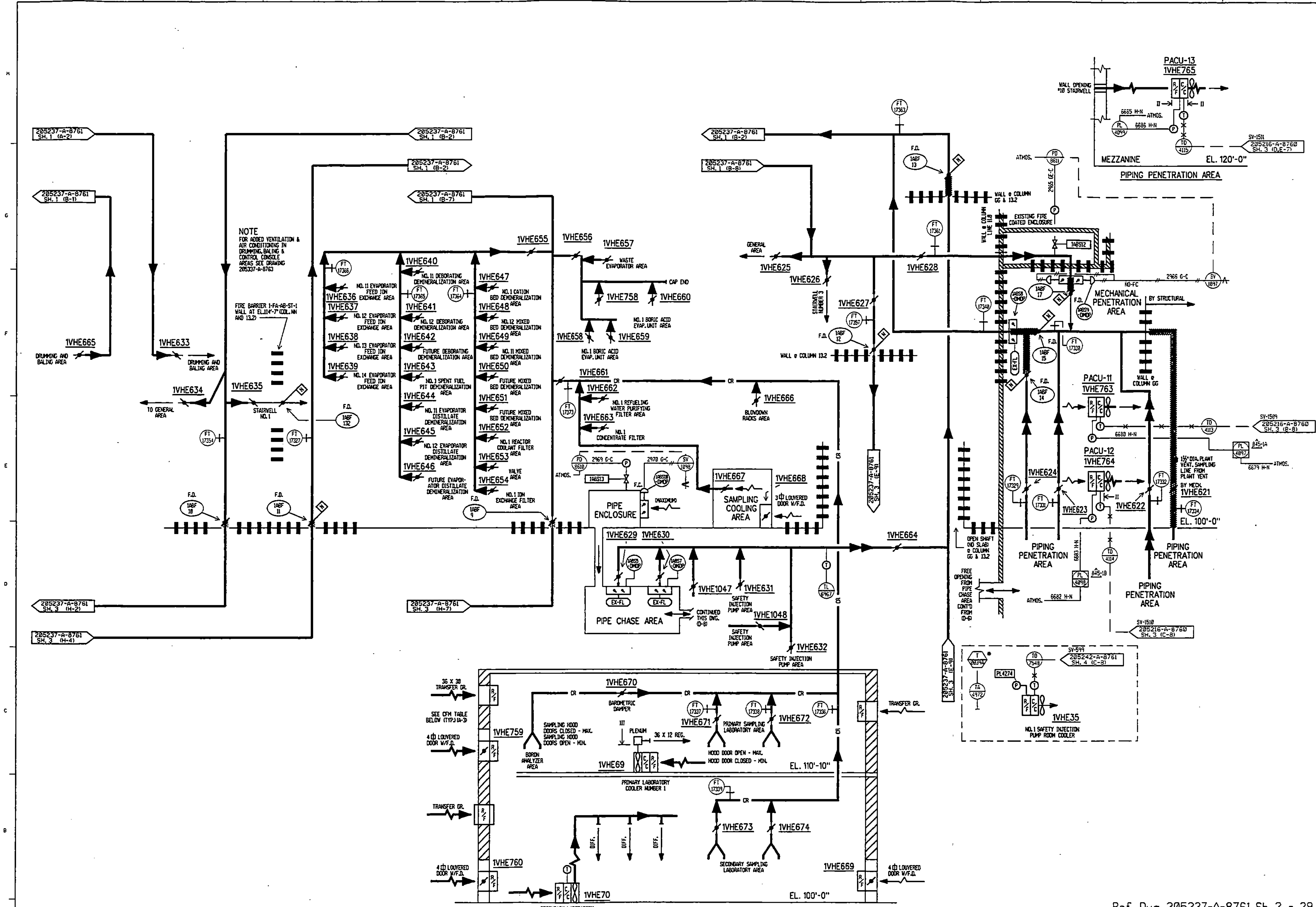
Ref. Dwg. 205237-A-8761 Sh. 1 - 39

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Auxiliary Building Ventilation System
Unit 1

Updated FSAR — Sheet 1 of 3

Revision 17, October 16, 1998 — Fig 9.4-2A



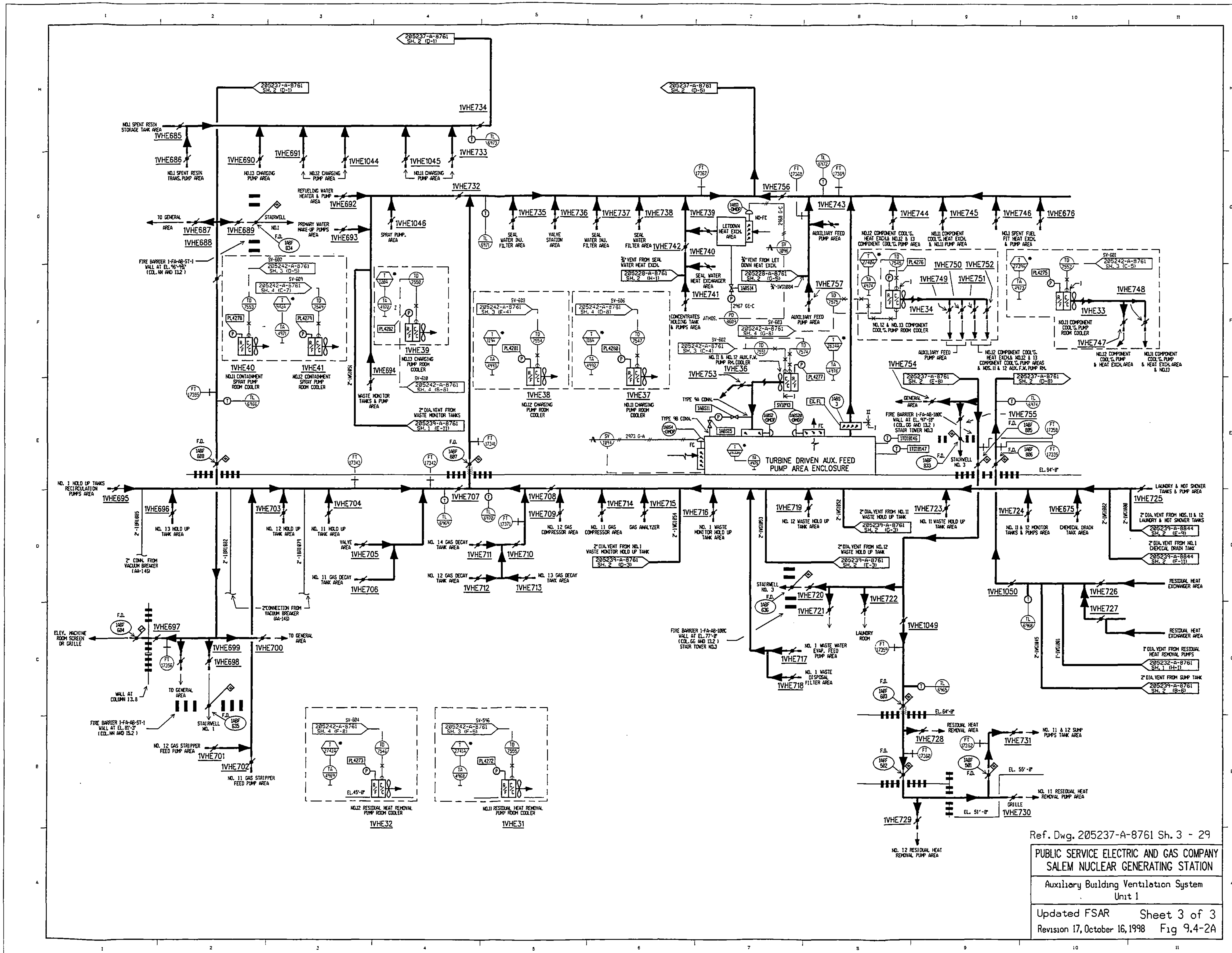
Ref. Dwg. 205237-A-8761 Sh. 2 - 29

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Auxiliary Building Ventilation System
Unit 1

Updated FSAR
Sheet 2 of 3

Revision 17, October 16, 1998
Fig 9.4-2A



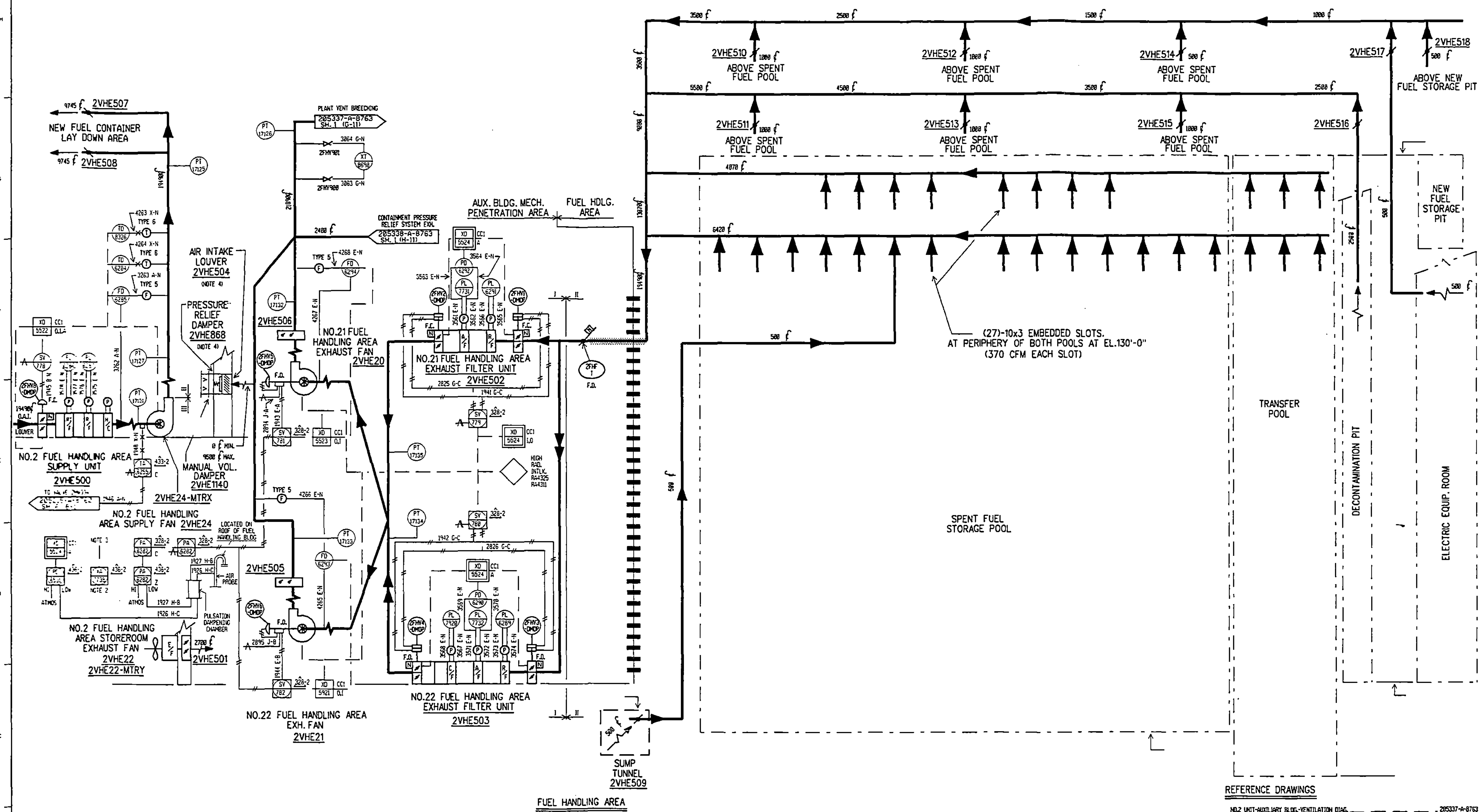
Ref. Dwg. 205237-A-8761 Sh. 3 - 29

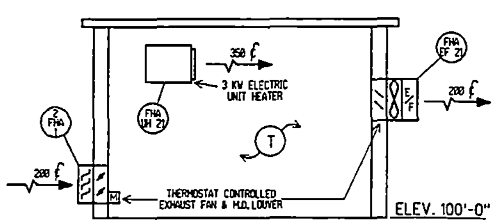
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Auxiliary Building Ventilation System
Unit 1

Updated FSAR — Sheet 3 of 3

Revision 17, October 16, 1998 — Fig 9.4-2A





VENT SAMPLING ENCLOSURE
(SEISMIC CLASS III)

NOTE:

1. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "2" FOR UNIT 2.
2. INSTRUMENT ABANDONED IN PLACE.
3. CABLE TO 2XL7739 (NOT INSTALLED) WAS SPARED.
4. LOCATED IN FUEL HANDLING TRUCK BAY, ELEV. 100'-0".

REFERENCE DRAWINGS

NO.2 UNIT-AUXILIARY BLDG.-VENTILATION DIAG.		205337-A-8763
NO.2 UNIT-REACTOR CONT.-VENTILATION DIAG.		205338-A-8763
FUEL HANDLING AREA VENTILATION SYSTEM	INSTR. SCH.	240679-B-9657-6
HEATING WATER-BUILDING HEATING & PLUMBING	INSTR. SCH.	232315-B-9608-10
AUX. BUILDING-DIESEL GENERATOR AREA VENTILATION	INSTR. SCH.	240705-B-9658-3
LEGEND SHEET		600658-A-8727
205322-A-8762 SH.1		NO.2 UNIT AUXILIARY BUILDING FUEL HANDLING AREA VENTILATION VENT SAMPLING ENCLOSURE EL.100'-0"
205322-A-8762 SH.2	(VOIDED)	NO.2 UNIT AUXILIARY BUILDING DIESEL GENERATOR AREA VENTILATION
205322-A-8762 SH.3		NO.2 UNIT AUXILIARY BUILDING DIESEL GENERATOR AREA VENTILATION

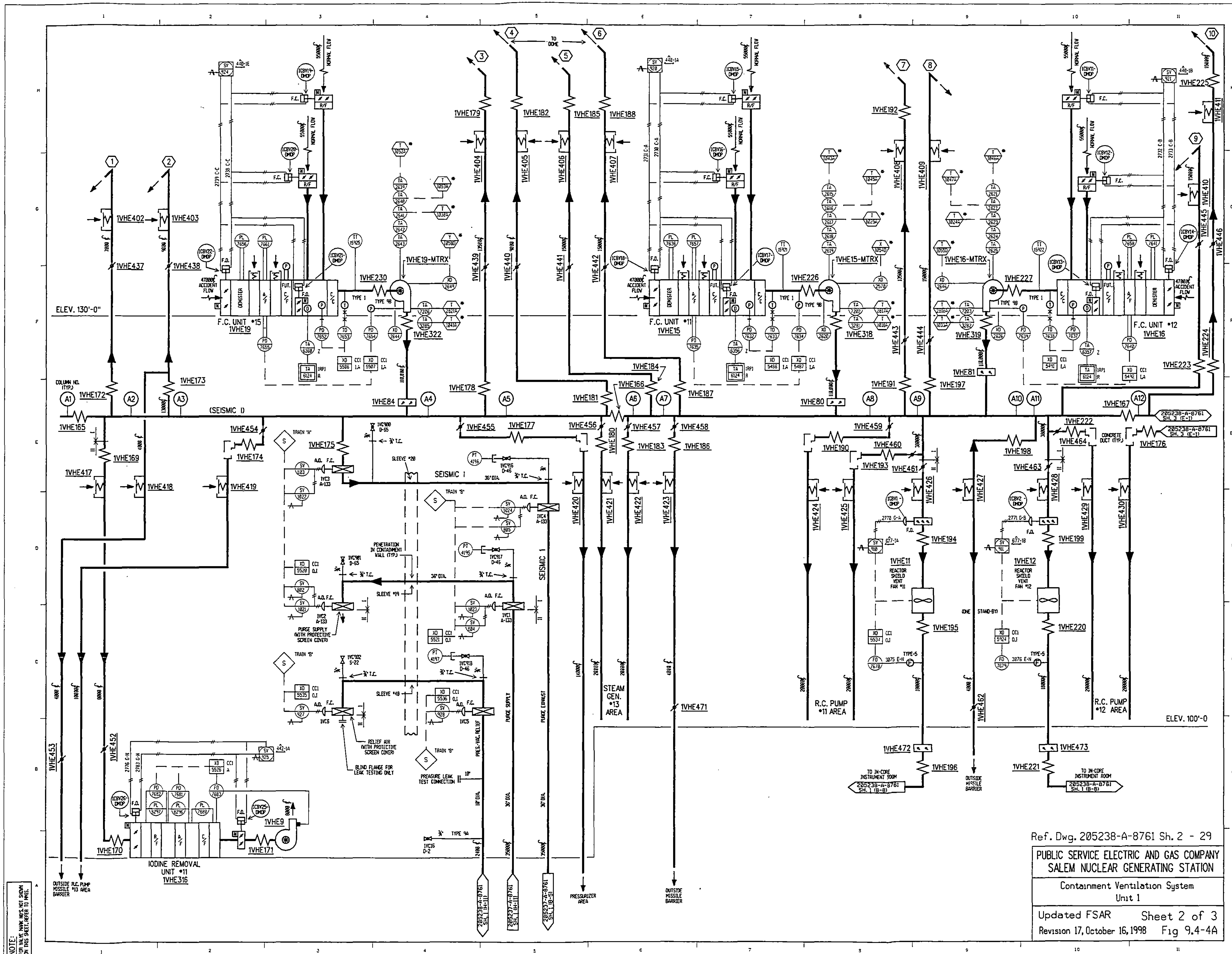
Ref. Dwg. 205322-A-8763 Sh. 1 - 20

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Fuel Handling Area Ventilation System
Unit 2

Updated FSAR — Sheet 1 of 1

Revision 17, October 16, 1998 — Fig 9.4-3B



Ref. Dwg. 205238-A-8761 Sh. 2 - 29

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Containment Ventilation System
Unit 1

Updated FSAR
Sheet 2 of 3

Revision 17, October 16, 1998
Fig 9.4-4A

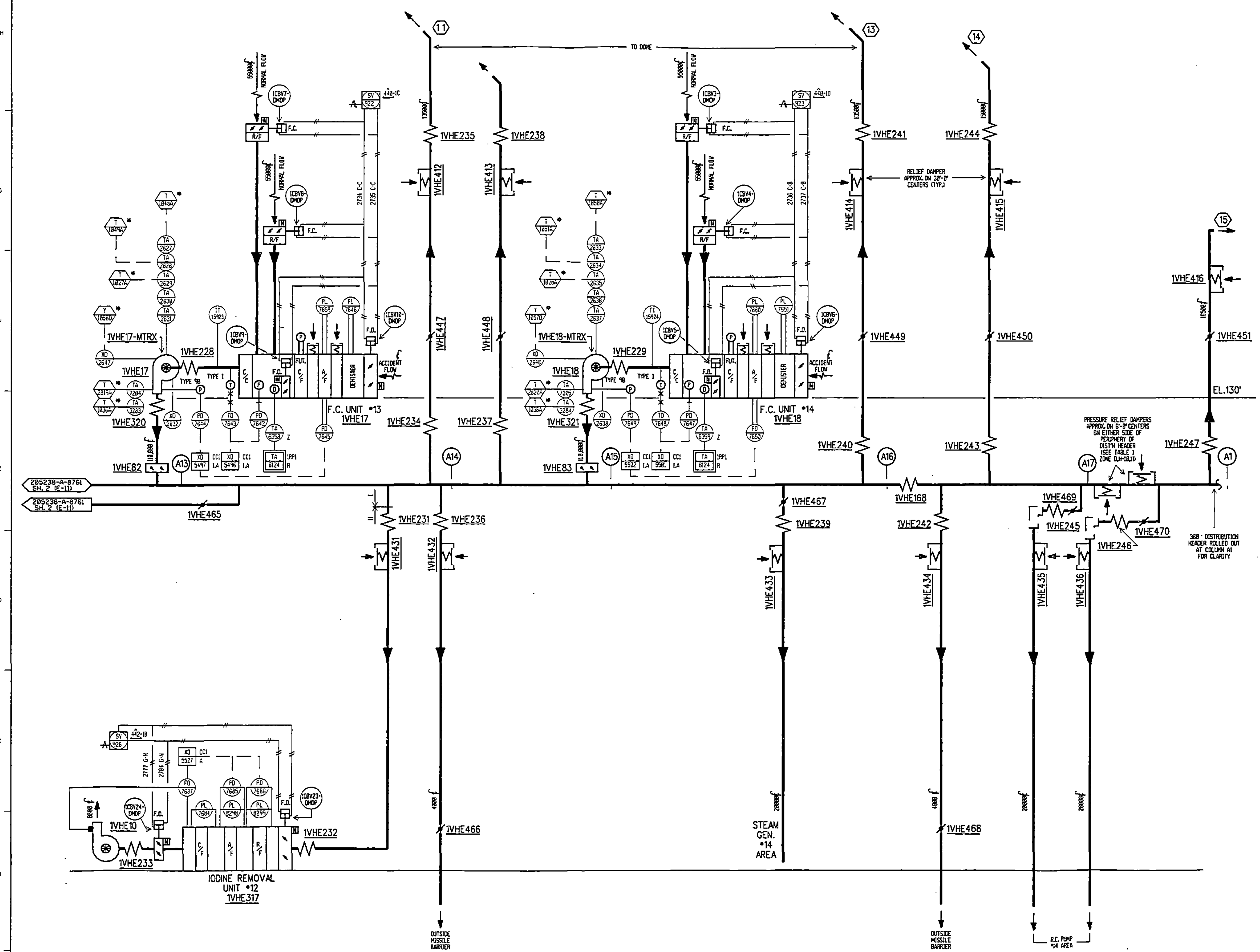


TABLE 1

CONTAINMENT VENTILATION 360-DEG DISTRIBUTION HEADER PRESSURE RELIEF DAMPERS

COMPONENT ID	AZIMUTH LOCATION	LOCATION DRAWING	FLOW DIRECTION
1VHE-1060	A1-A2	252226	IN
1VHE-1061	A1-A2	252226	OUT
1VHE-1062	A1-A2	252226	IN
1VHE-1063	A2	252226	OUT
1VHE-1064	A2-A3	252226	IN
1VHE-1065	A2-A3	252226	OUT
1VHE-1066	A3-A4	252226	IN
1VHE-1067	A3-A4	252226	OUT
1VHE-1068	A3-A4	252226	IN
1VHE-1069	A3-A4	252226	OUT
1VHE-1070	A4-A5	252226	IN
1VHE-1071	A4-A5	252226	IN
1VHE-1072	A4-A5	252226	OUT
1VHE-1073	A4-A5	252226	OUT
1VHE-1074	A5-A6	252226	IN
1VHE-1075	A5-A6	252223	OUT
1VHE-1076	A6-A7	252223	IN
1VHE-1077	A6-A7	252223	OUT
1VHE-1078	A6-A7	252223	IN
1VHE-1079	A6-A7	252223	OUT
1VHE-1080	A7-A8	252223	IN
1VHE-1081	A7-A8	252223	OUT
1VHE-1082	A7-A8	252223	IN
1VHE-1083	A8-A9	252223	OUT
1VHE-1084	A8-A9	252223	IN
1VHE-1085	A8-A9	252223	OUT
1VHE-1086	A8-A9	252223	IN
1VHE-1087	A9-A10	252223	OUT
1VHE-1088	A9-A10	252223	IN
1VHE-1089	A10-A11	252223	OUT
1VHE-1090	A10-A11	252223	IN
1VHE-1091	A10-A11	252223	OUT
1VHE-1092	A10-A11	252224	IN
1VHE-1093	A11-A12	252224	IN
1VHE-1094	A11-A12	252224	OUT
1VHE-1095	A11-A12	252224	OUT
1VHE-1096	A11-A12	252224	IN
1VHE-1097	A11-A12	252224	IN
1VHE-1098	A12-A13	252224	OUT
1VHE-1099	A12-A13	252224	IN
1VHE-1100	A12-A13	252224	OUT
1VHE-1101	A13-A14	252224	OUT
1VHE-1102	A13-A14	252224	IN
1VHE-1103	A13-A14	252224	OUT
1VHE-1104	A13-A14	252224	IN
1VHE-1105	A14-A15	252224	OUT
1VHE-1106	A14-A15	252224	OUT
1VHE-1107	A14-A15	252224	IN
1VHE-1108	A15-A16	252225	OUT
1VHE-1109	A15-A16	252225	IN
1VHE-1110	A15-A16	252225	OUT
1VHE-1111	A15-A16	252225	IN
1VHE-1112	A16-A17	252225	IN
1VHE-1113	A16-A17	252225	IN
1VHE-1114	A16-A17	252225	IN
1VHE-1115	A17	252225	OUT
1VHE-1116	A17-A18	252225	IN
1VHE-1117	A17-A18	252225	OUT
1VHE-1118	A17-A18	252225	OUT
1VHE-1119	A17-A18	252225	IN
1VHE-1120	A18-A1	252225	OUT
1VHE-1121	A18-A1	252225	OUT
1VHE-1122	A18-A1	252225	OUT
1VHE-1123	A18-A1	252225	IN

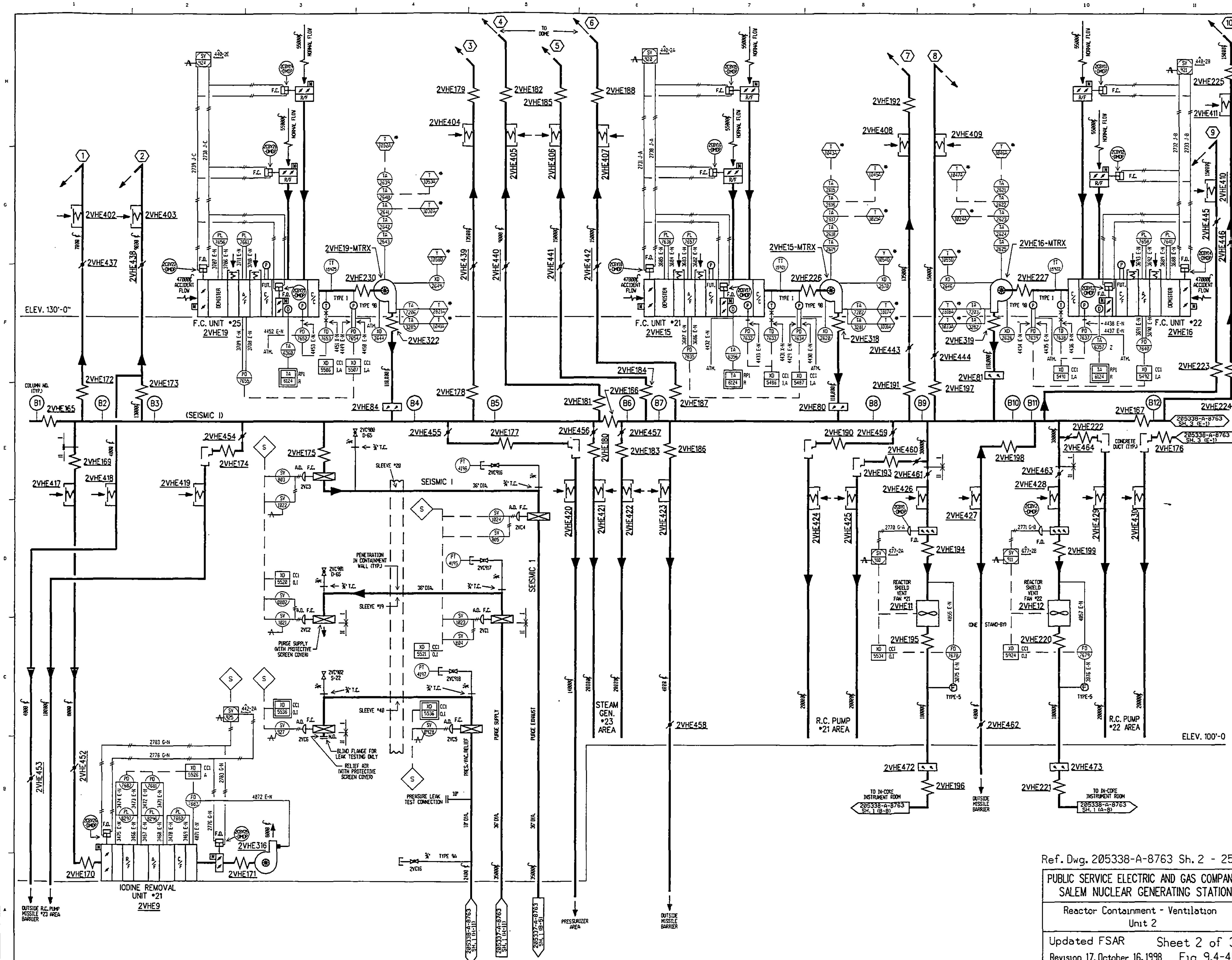
NOTE "B" - REV. 28
REVISED DWG. TO SHOW CORRECT TAP LOCATIONS
FOR PRESSURE SWITCHES PD-7644 (F-2) AND PD-7649 (F-5)
REVISION SUPERSEDES AND INCORPORATES
1EZ-6884 DWG. CHANGE ONLY

Ref. Dwg. 205238-A-8761 Sh. 3 - 28

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Containment Ventilation System
Unit 1

Updated FSAR Sheet 3 of 3
Revision 17, October 16, 1998 Fig 9.4-4A



NOTE:
FOR VALVE MARK NO'S NOT SHOWN ON THIS SHEET, REFER TO MANS.

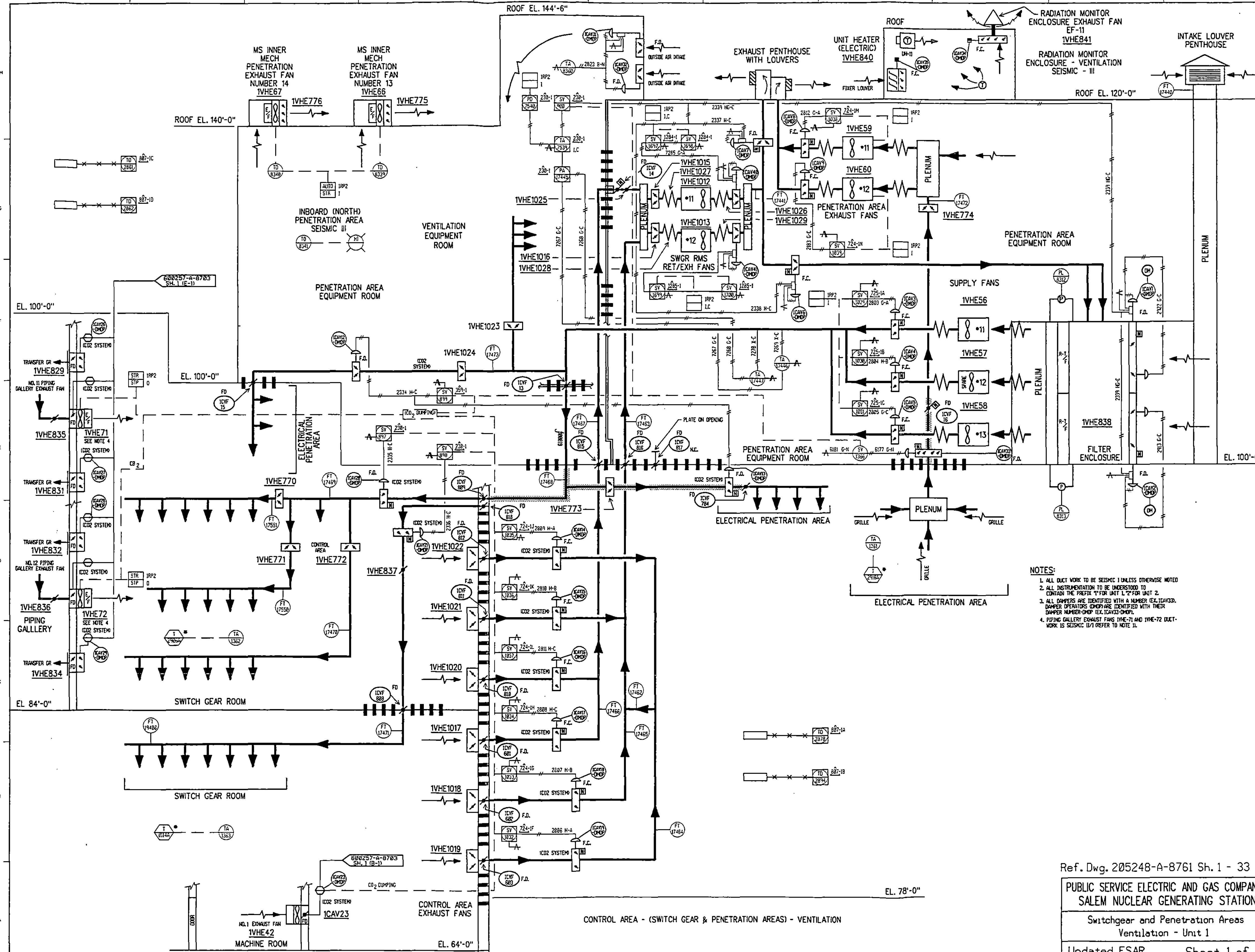
Ref. Dwg. 205338-A-8763 Sh. 2 - 25

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Reactor Containment - Ventilation
Unit 2

Updated FSAR
Sheet 2 of 3

Revision 17, October 16, 1998
Fig 9.4-4B



NOTES:

1. ALL DUCT WORK TO BE SEISMIC I UNLESS OTHERWISE NOTED
2. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "1" FOR UNIT 1, "2" FOR UNIT 2.
3. ALL DAMPERS ARE IDENTIFIED WITH A NUMBER (EX. 1CAV33). DAMPER OPERATORS (DMOP) ARE IDENTIFIED WITH THEIR DAMPER NUMBER-DMOP (EX. 1CAV33-DMOP).
4. PIPING GALLERY EXHAUST FANS 1VHE-71 AND 1VHE-72 DUCT-WORK IS SEISMIC II/I (REFER TO NOTE 1).

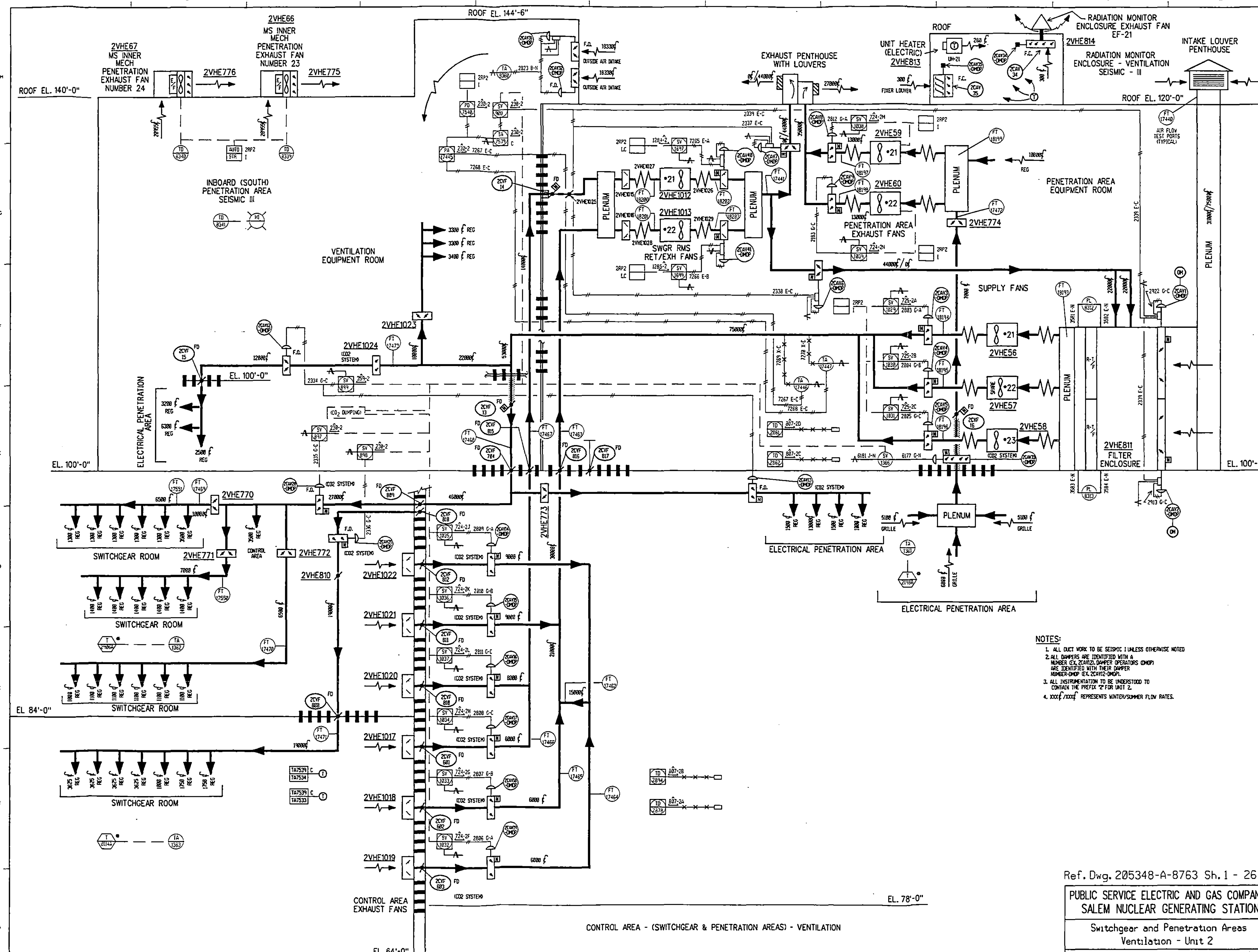
Ref. Dwg. 205248-A-8761 Sh. 1 - 33

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Switchgear and Penetration Areas Ventilation - Unit 1

Updated FSAR — Sheet 1 of 1

Revision 17, October 16, 1998 — Fig 9.4-6A



NOTES:
1. ALL DUCT WORK TO BE SEISMIC I UNLESS OTHERWISE NOTED
2. ALL DAMPERS ARE IDENTIFIED WITH A NUMBER (EX. 2CAV12). DAMPER OPERATORS (DMOP) ARE IDENTIFIED WITH THEIR DAMPER NUMBER-DMOP (EX. 2CAV12-DMOP).
3. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "2" FOR UNIT 2.
4. xxxf/xxxf REPRESENTS WINTER/SUMMER FLOW RATES.

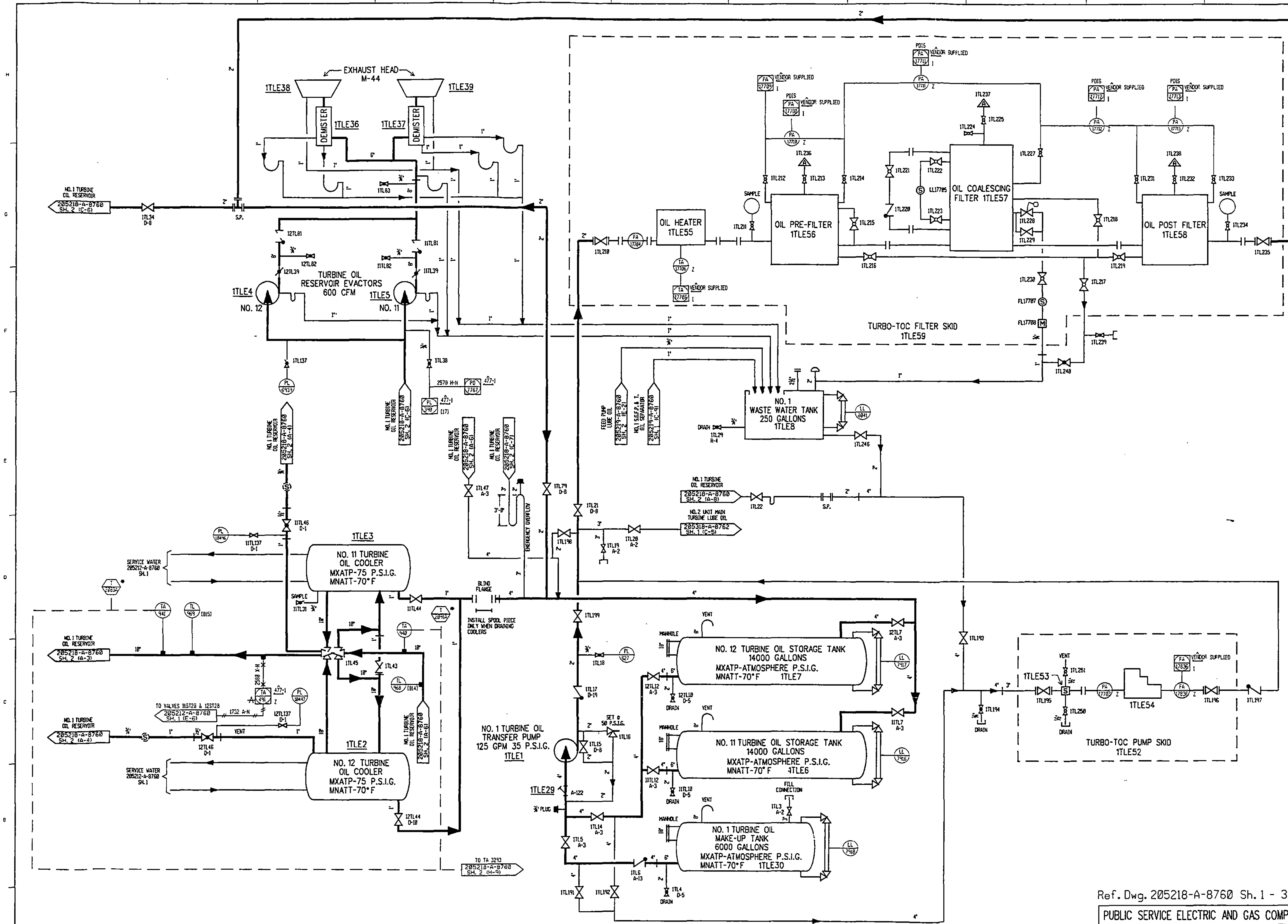
CONTROL AREA - (SWITCHGEAR & PENETRATION AREAS) - VENTILATION

Ref. Dwg. 205348-A-8763 Sh. 1 - 26

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Switchgear and Penetration Areas
Ventilation - Unit 2

Updated FSAR | Sheet 1 of 1
Revision 17, October 16, 1998 | Fig 9.4-6B



NOTE:

1. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051
2. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "1" FOR UNIT 1.

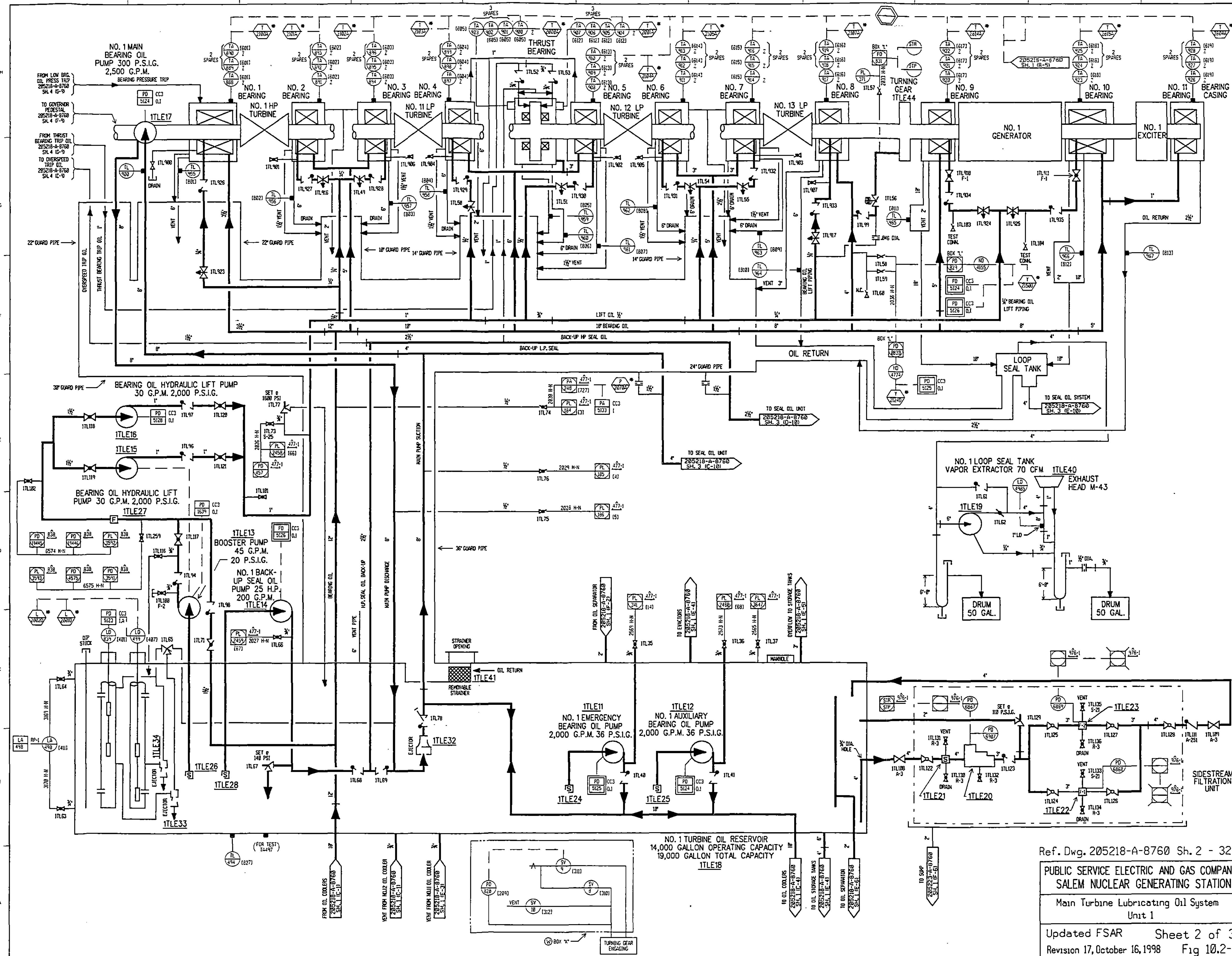
NOTE: FOR VALVE MARK NO'S. NOT SHOWN ON THIS SHEET, REFER TO M&IS.

Ref. Dwg. 205218-A-8760 Sh. 1 - 38

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Main Turbine Lubricating Oil System
Unit 1

Updated FSAR
Sheet 1 of 3
Revision 17, October 16, 1998
Fig 10.2-1



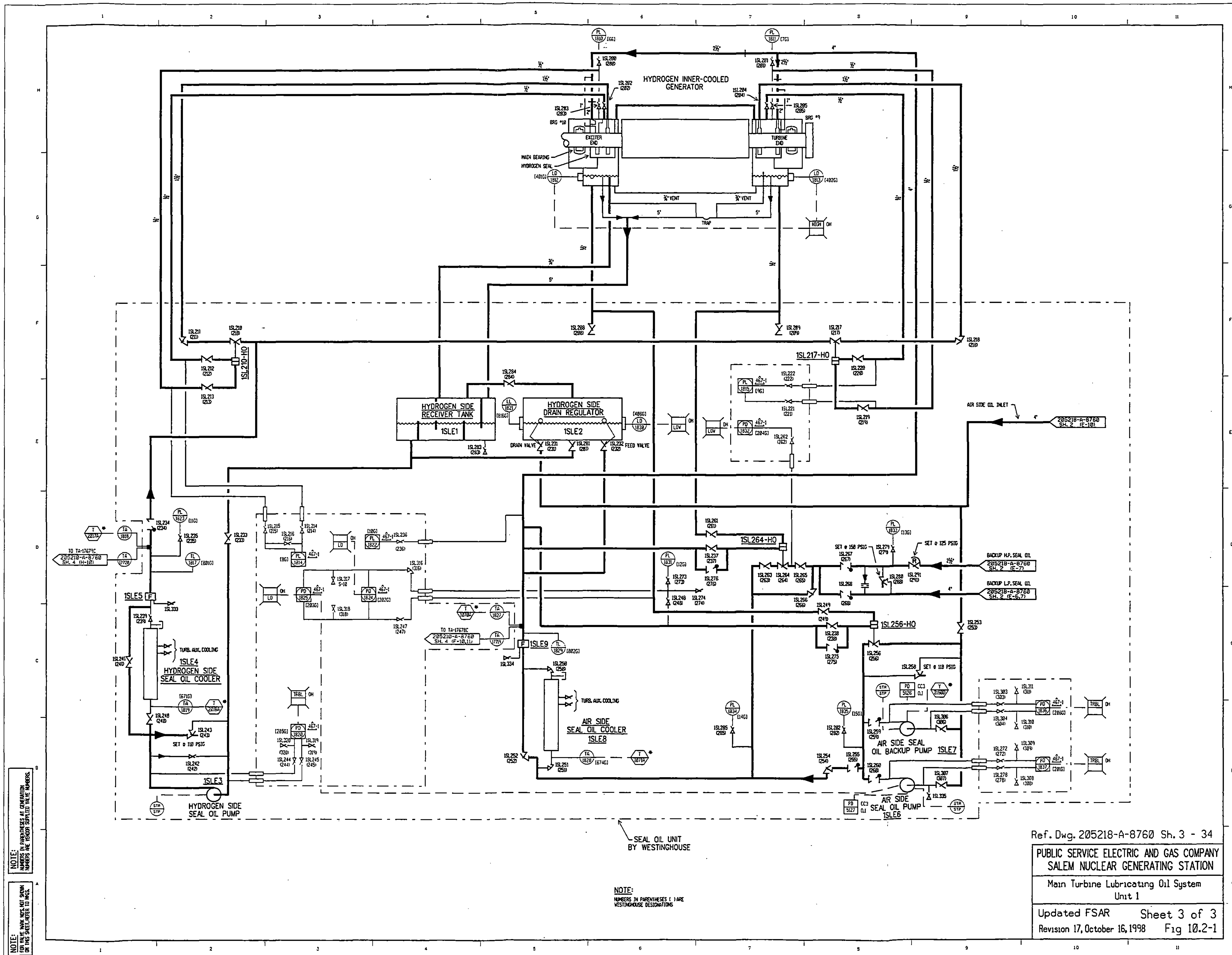
Ref. Dwg. 205218-A-8760 Sh. 2 - 32

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Main Turbine Lubricating Oil System
Unit 1

Updated FSAR Sheet 2 of 3
Revision 17, October 16, 1998 Fig 10.2-1

NOTE: FOR VALVE MARK NO'S NOT SHOWN ON THIS SHEET, REFER TO NMDS.



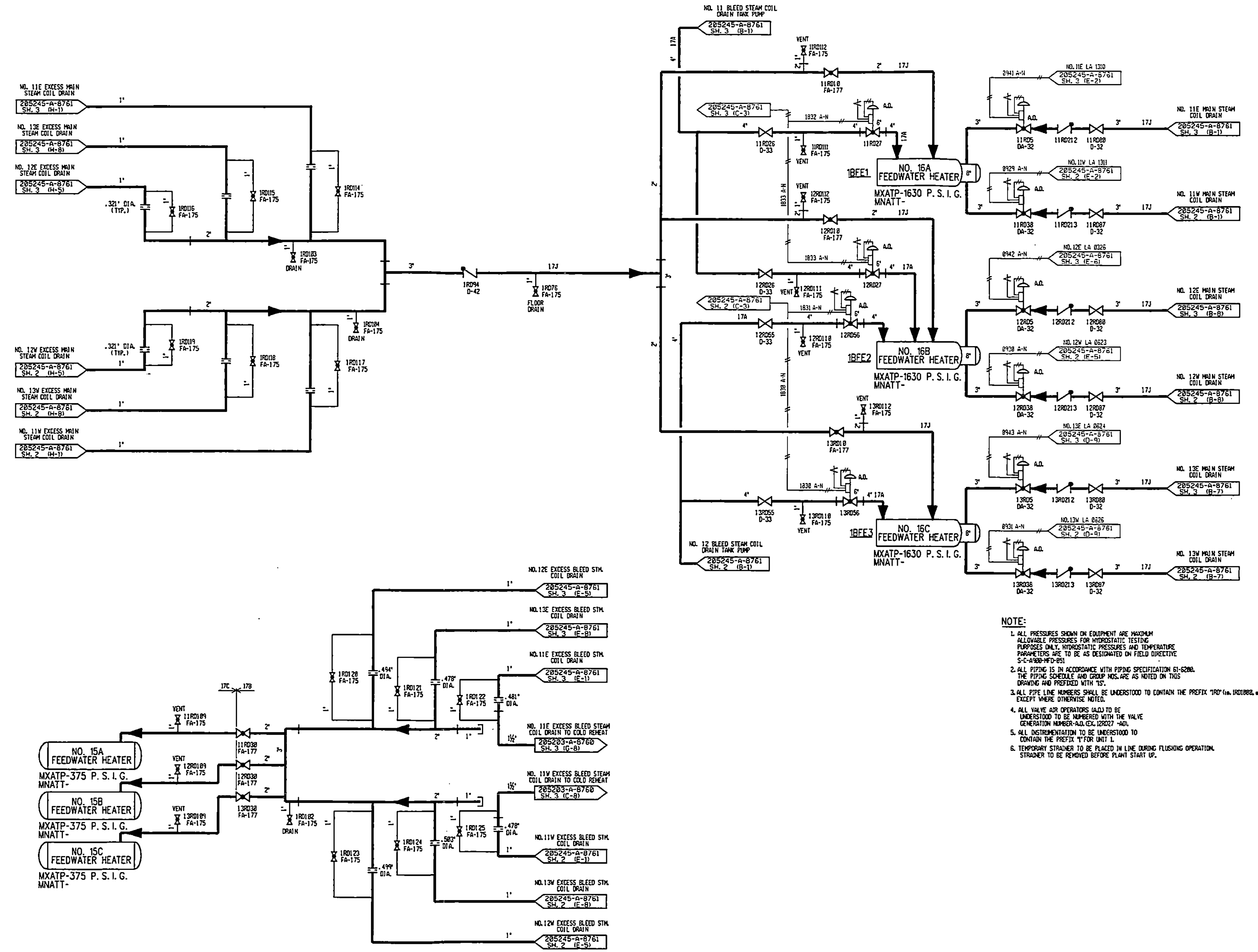
Ref. Dwg. 205218-A-8760 Sh. 3 - 34

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Main Turbine Lubricating Oil System
Unit 1

Updated FSAR — Sheet 3 of 3

Revision 17, October 16, 1998 — Fig 10.2-1



NOTE:

1. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051
2. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6200. THE PIPING SCHEDULE AND GROUP NOS. ARE AS NOTED ON THIS DRAWING AND PREFIXED WITH "1S".
3. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1RO" (ie. 1RO1000, etc.) EXCEPT WHERE OTHERWISE NOTED.
4. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 12R027 -AO).
5. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "1" FOR UNIT 1.
6. TEMPORARY STRAINER TO BE PLACED IN LINE DURING FLUSHING OPERATION. STRAINER TO BE REMOVED BEFORE PLANT START UP.

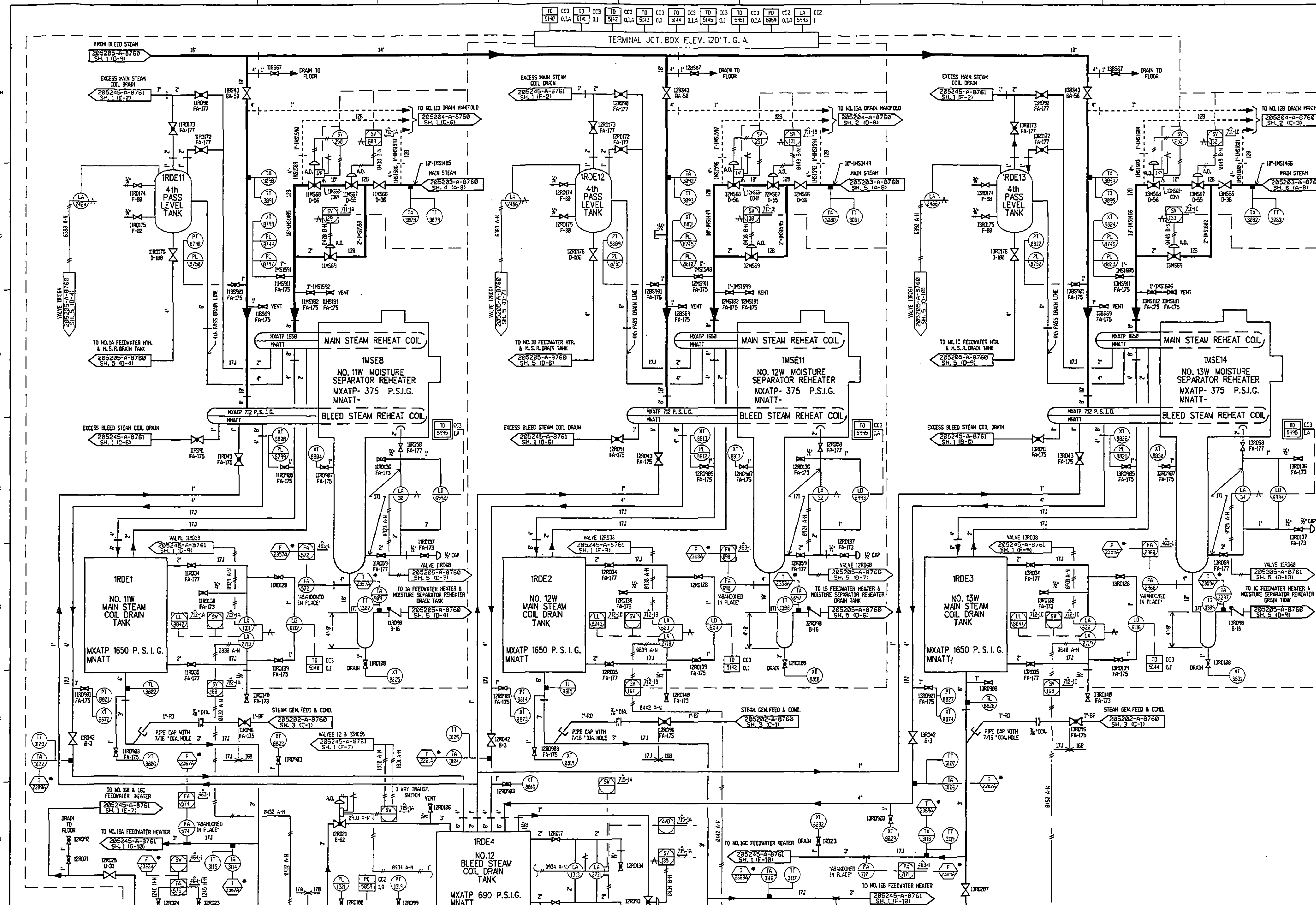
NOTE:
FOR VALVE MARK NOS. NOT SHOWN ON THIS SHEET, REFER TO MMIS.

Ref. Dwg. 205245-A-8761 Sh. 1 - 34

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Moisture Separator Reheaters, Steam and Drains - Unit 1

Updated FSAR | Sheet 1 of 3
Revision 17, October 16, 1998 | Fig 10.2-2A



Ref. Dwg. 205245-A-8761 Sh. 2 - 38

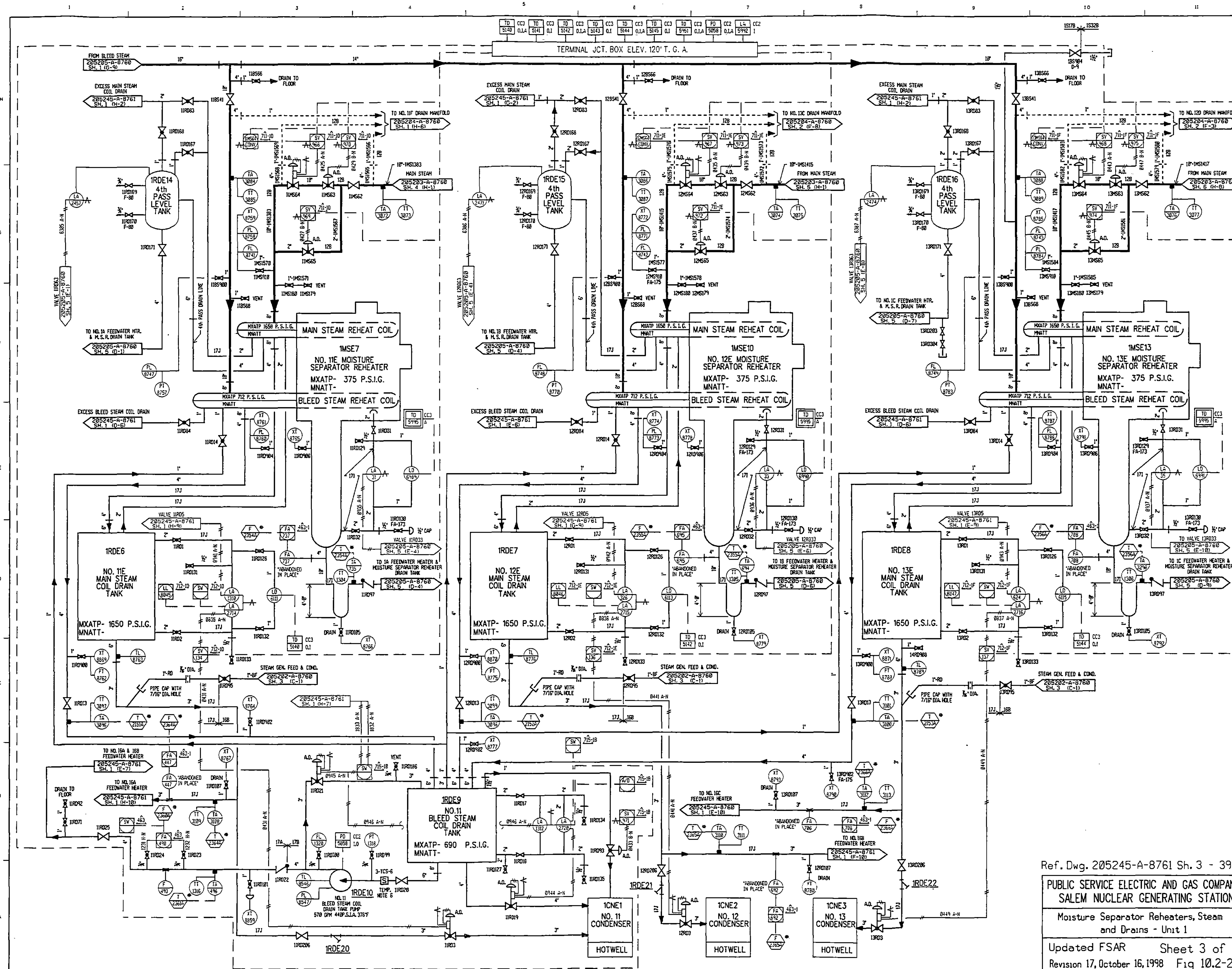
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Moisture Separator Reheaters, Steam and Drains - Unit 1

Updated FSAR — Sheet 2 of 3

Revision 17, October 16, 1998 — Fig 10.2-2A

NOTE: FOR VALVE MARK NOS. NOT SHOWN ON THIS SHEET, REFER TO MMIS.



NOTE:
FOR VALVE MARK NO'S. NOT SHOWN ON THIS SHEET, REFER TO HMIS.

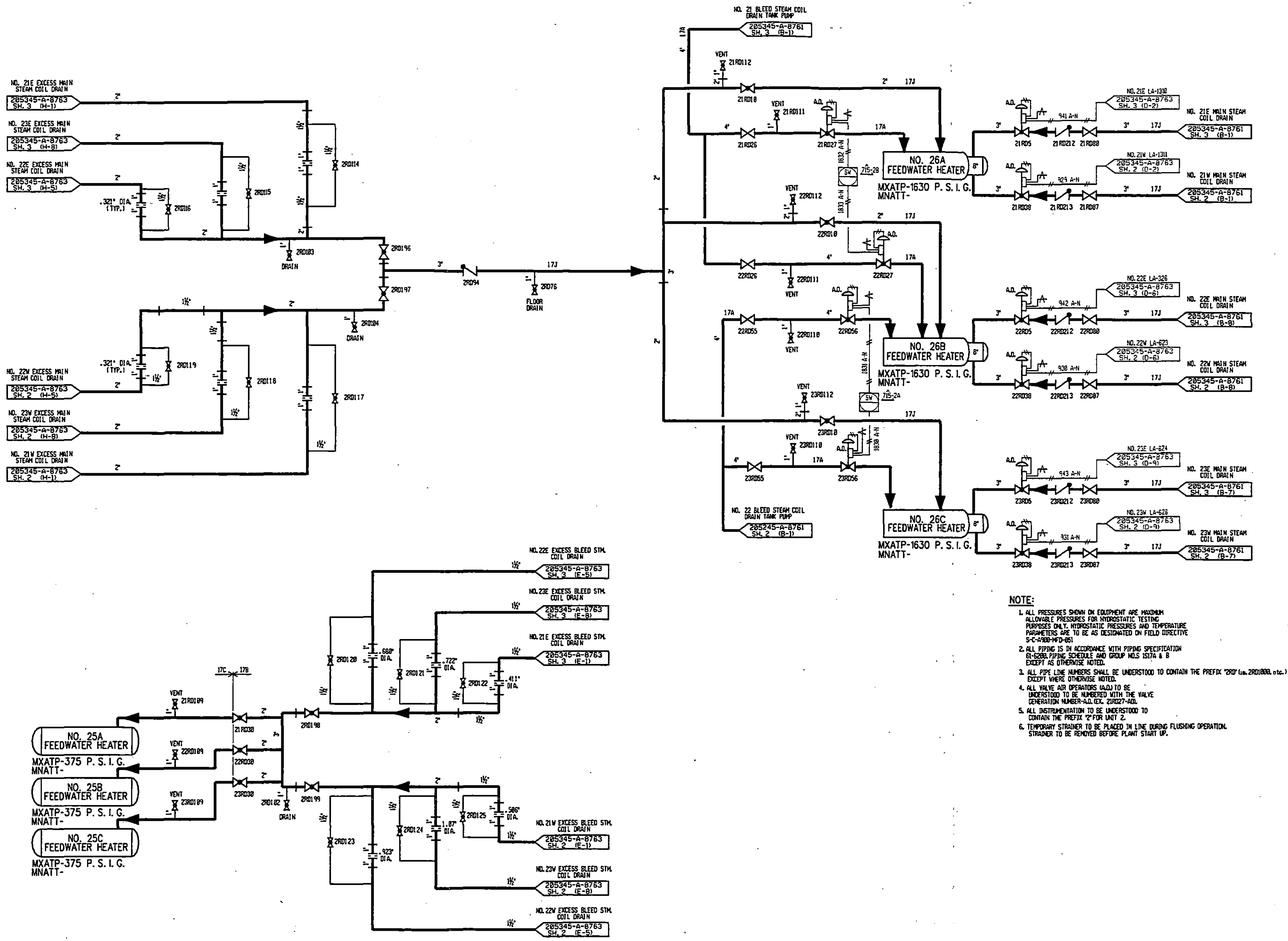
Ref. Dwg. 205245-A-8761 Sh. 3 - 39

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Moisture Separator Reheaters, Steam and Drains - Unit 1

Updated FSAR — Sheet 3 of 3

Revision 17, October 16, 1998 — Fig 10.2-2A



NOTE:

1. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051
2. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6200, PIPING SCHEDULE AND GROUP NO.S 1517A & B EXCEPT AS OTHERWISE NOTED.
3. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "2RD" (i.e. 2RD1000, etc.) EXCEPT WHERE OTHERWISE NOTED.
4. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 21RD27-AO).
5. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "2" FOR UNIT 2.
6. TEMPORARY STRAINER TO BE PLACED IN LINE DURING FLUSHING OPERATION. STRAINER TO BE REMOVED BEFORE PLANT START UP.

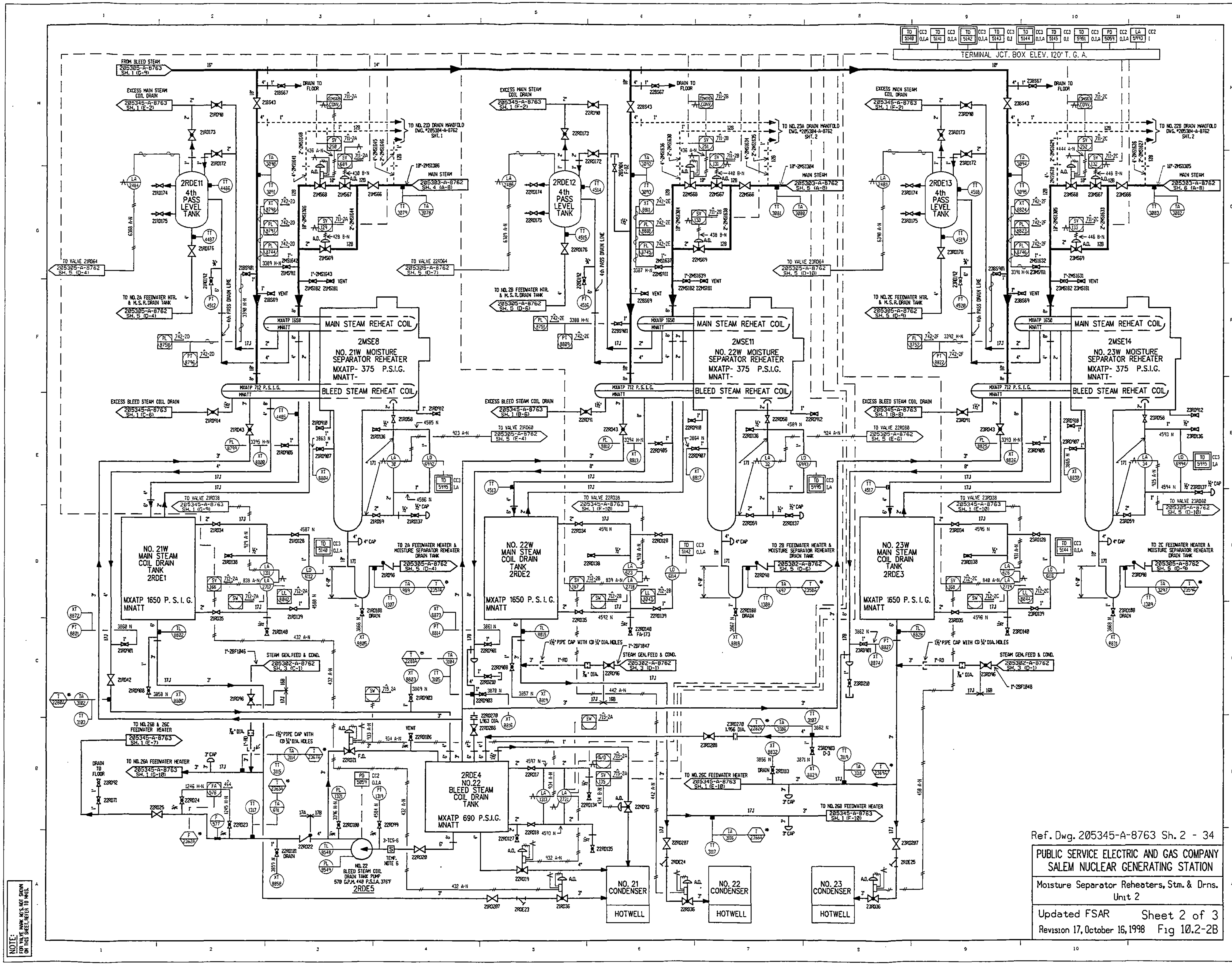
Ref. Dwg. 205345-A-8763 Sh. 1 - 31

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Moisture Separator Reheaters, Stm. & Drns.
Unit 2

Updated FSAR — Sheet 1 of 3
Revision 17, October 16, 1998 — Fig 10.2-2B

NOTE: FOR VALVE MARK NO'S NOT SHOWN ON THIS SHEET, REFER TO MMIS.



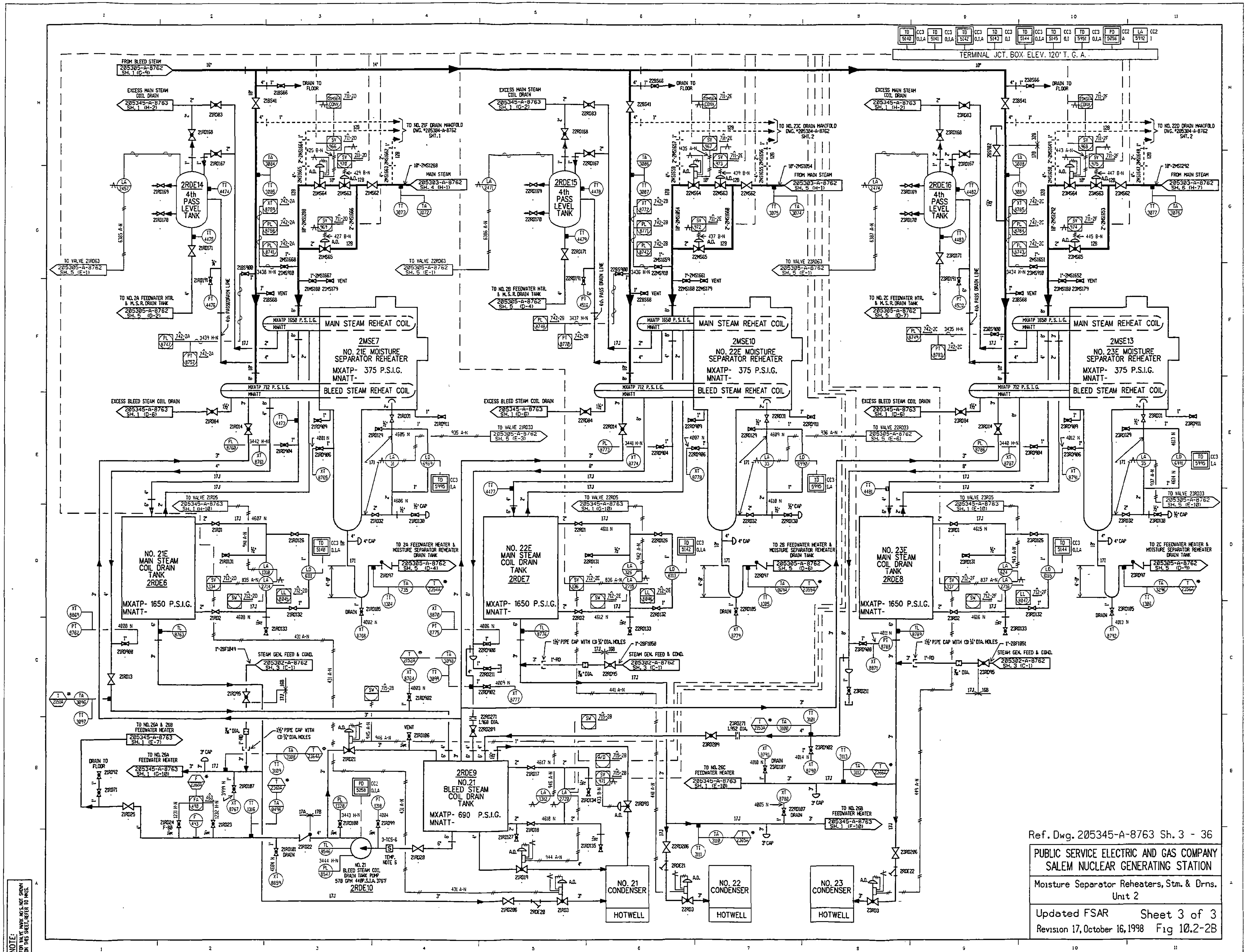
Ref. Dwg. 205345-A-8763 Sh. 2 - 34

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

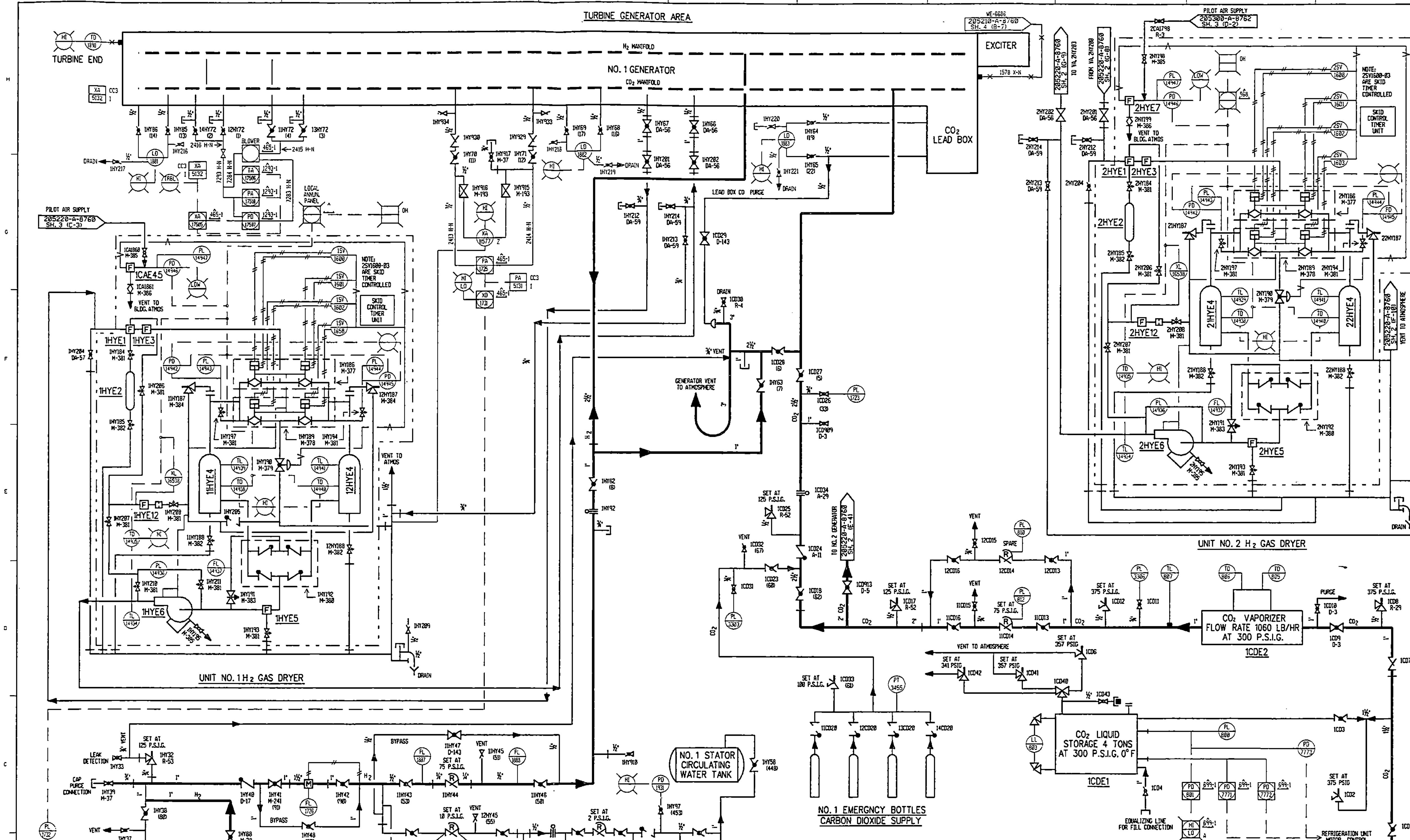
Moisture Separator Reheaters, Stm. & Drns.
Unit 2

Updated FSAR — Sheet 2 of 3

Revision 17, October 16, 1998 — Fig 10.2-2B



TERMINAL JCT. BOX ELEV. 120' T. G. A.
MAIN STEAM REHEAT COIL
2MSE7
NO. 21E MOISTURE SEPARATOR REHEATER
BLEED STEAM REHEAT COIL
2MSE10
NO. 22E MOISTURE SEPARATOR REHEATER
2MSE13
NO. 23E MOISTURE SEPARATOR REHEATER
2RDE14 4th PASS LEVEL TANK
2RDE15 4th PASS LEVEL TANK
2RDE16 4th PASS LEVEL TANK
NO. 21E MAIN STEAM COIL DRAIN TANK 2RDE6
NO. 22E MAIN STEAM COIL DRAIN TANK 2RDE7
NO. 23E MAIN STEAM COIL DRAIN TANK 2RDE8
2RDE9 NO. 21 BLEED STEAM COIL DRAIN TANK
NO. 21 CONDENSER
NO. 22 CONDENSER
NO. 23 CONDENSER
HOTWELL
Ref. Dwg. 205345-A-8763 Sh. 3 - 36
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION
Moisture Separator Reheaters, Stm. & Drns.
Unit 2
Updated FSAR
Sheet 3 of 3
Revision 17, October 16, 1998
Fig 10.2-2B



NOTES:

1. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6200/1520.
2. DESIGNATIONS IN PARENTHESES AT GENERATION NUMBERS ARE WESTINGHOUSE VALVE NUMBERS.
3. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 11HY73-AO).
4. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "1" FOR UNIT 1, & "2" FOR UNIT 2.

NOTE: NUMBERS IN PARENTHESES AT GENERATION NUMBERS ARE VENDOR SUPPLIED VALVE NUMBERS.

NOTE: FOR VALVE MARK NOS. NOT SHOWN ON THIS SHEET, REFER TO PANS.

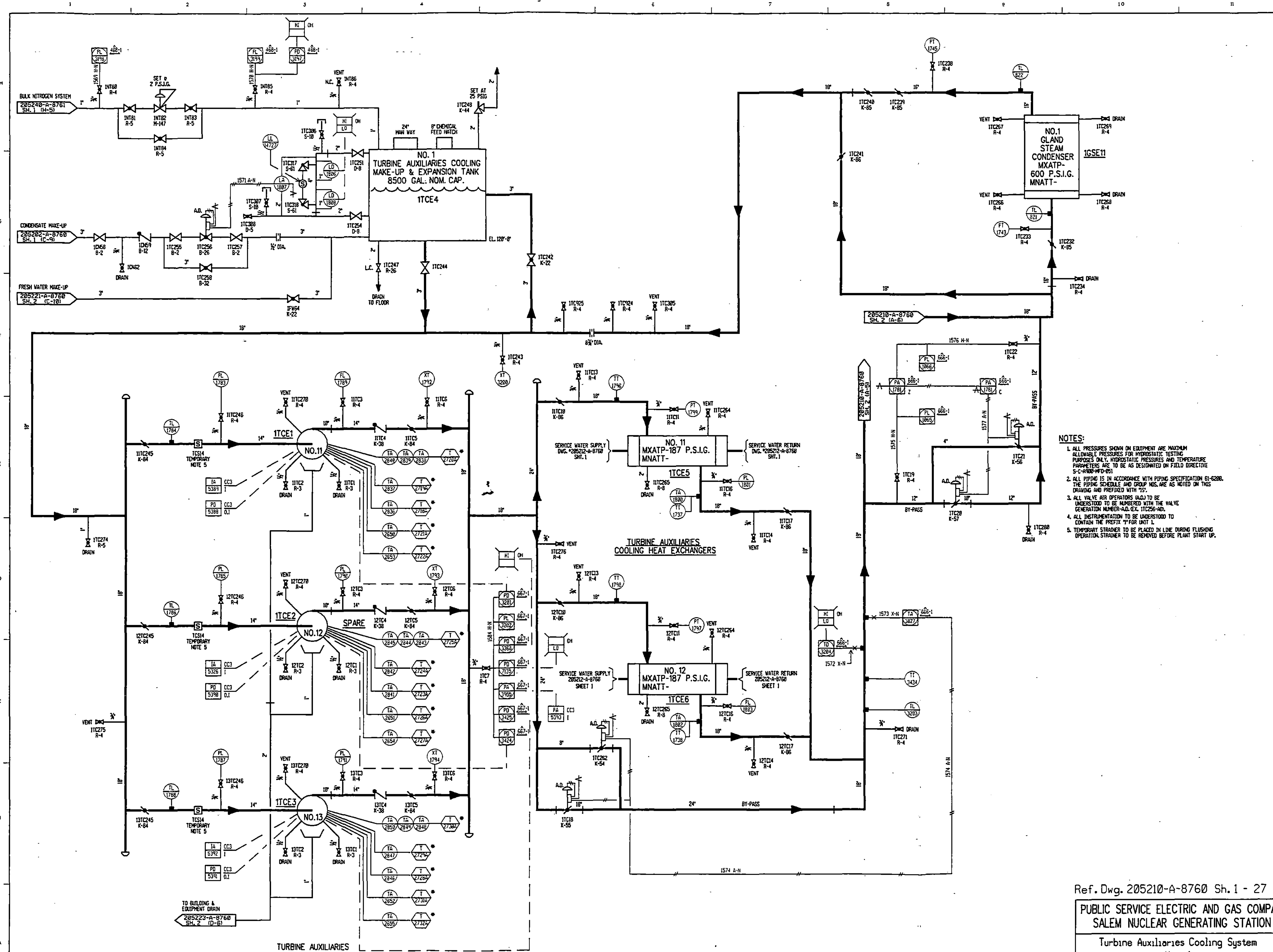
Ref. Dwg. 205220-A-8760 Sh. 1 - 44

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Hydrogen and Carbon Dioxide Systems
Unit 1 & 2

Updated FSAR — Sheet 1 of 2

Revision 17, October 16, 1998 — Fig 10.2-3



NOTES:

1. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE 5-C-A900-MFD-051
2. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6200. THE PIPING SCHEDULE AND GROUP NOS. ARE AS NOTED ON THIS DRAWING AND PREFIXED WITH "15".
3. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 1TC256-AO).
4. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "1" FOR UNIT 1.
5. TEMPORARY STRAINER TO BE PLACED IN LINE DURING FLUSHING OPERATION. STRAINER TO BE REMOVED BEFORE PLANT START UP.

NOTE:
FOR VALVE MARK NO'S NOT SHOWN ON THIS SHEET, REFER TO MMIS.

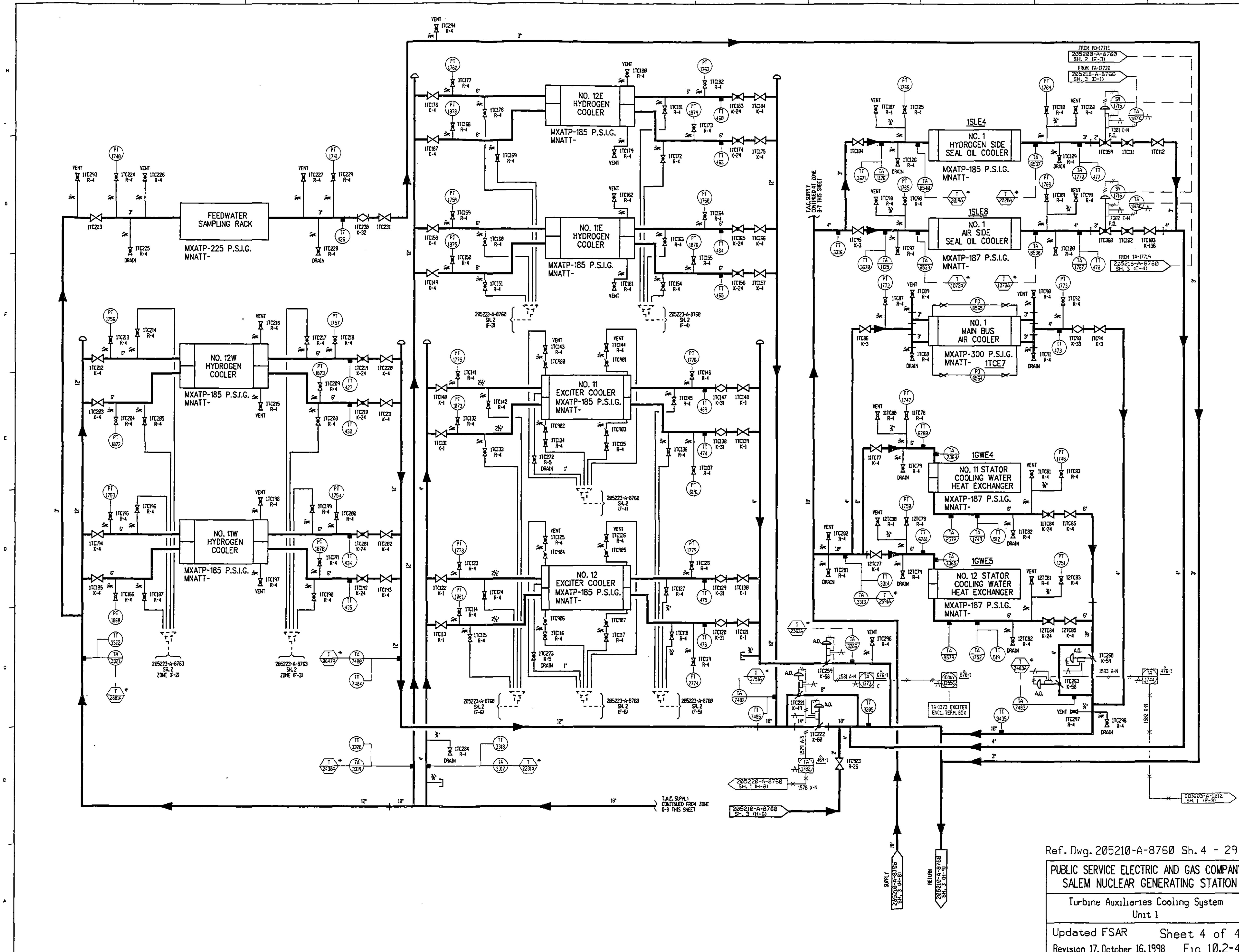
Ref. Dwg. 205210-A-8760 Sh. 1 - 27

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Turbine Auxiliaries Cooling System
Unit 1

Updated FSAR — Sheet 1 of 4

Revision 17, October 16, 1998 — Fig 10.2-4



Ref. Dwg. 205210-A-8760 Sh. 4 - 29

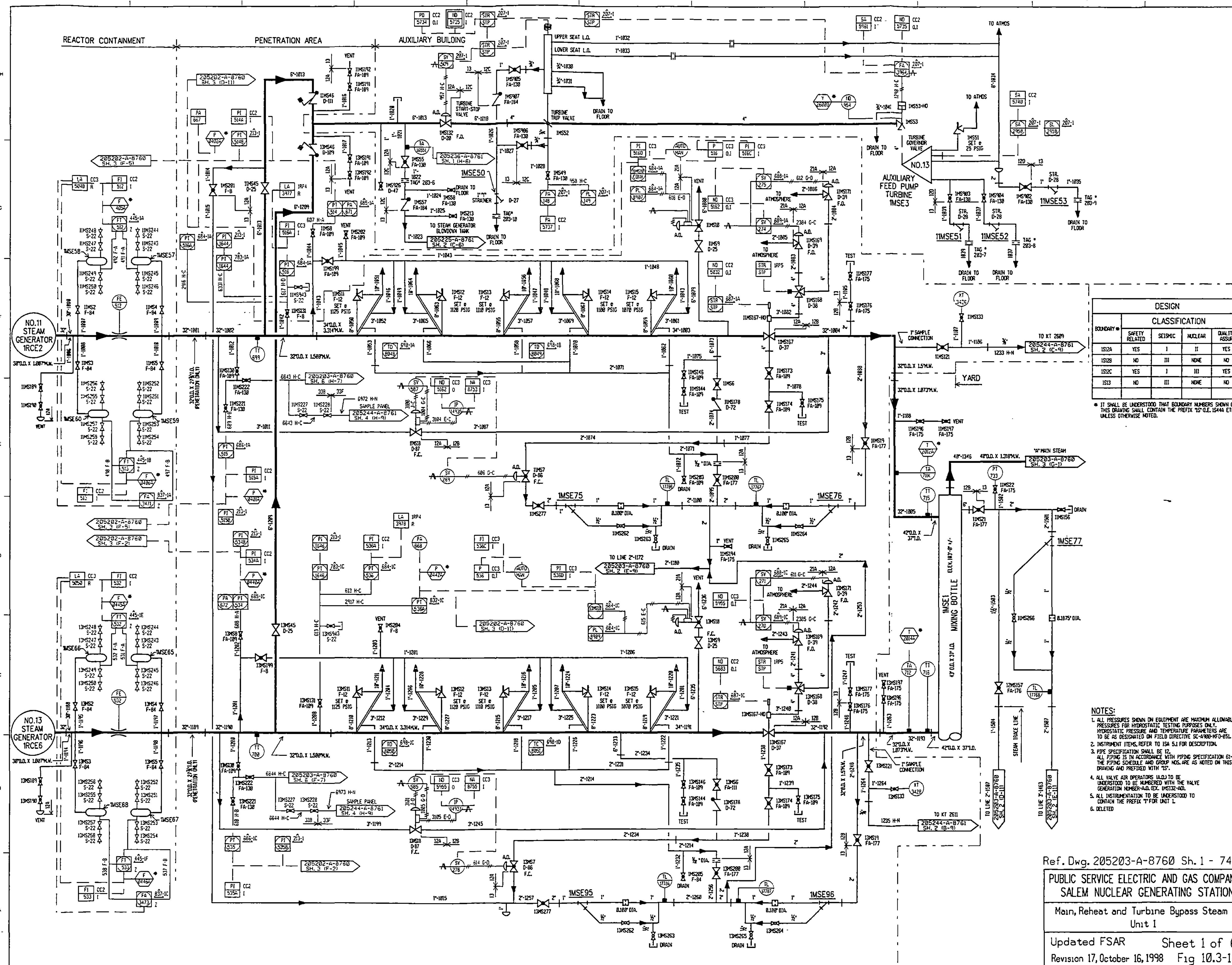
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Turbine Auxiliaries Cooling System
Unit 1

Updated FSAR — Sheet 4 of 4

Revision 17, October 16, 1998 — Fig 10.2-4

NOTE: FOR VALVE MARK NO'S NOT SHOWN ON THIS SHEET, REFER TO MAS.



BOUNDARY *	DESIGN CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR
1S12A	YES	I	II	YES
1S12B	NO	III	NONE	NO
1S12C	YES	I	III	YES
1S13	NO	III	NONE	NO

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (I.E. 1S44A ETC.) UNLESS OTHERWISE NOTED.

NOTES:

1. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE SC-A900-MFD-05L.
2. INSTRUMENT ITEMS, REFER TO ISA 5.1 FOR DESCRIPTION.
3. PIPE SPECIFICATION SHALL BE 12. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6200. THE PIPING SCHEDULE AND GROUP NOS. ARE AS NOTED ON THIS DRAWING AND PREFIXED WITH "1S".
4. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 1MS132-AO).
5. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "1" FOR UNIT 1.
6. DELETED

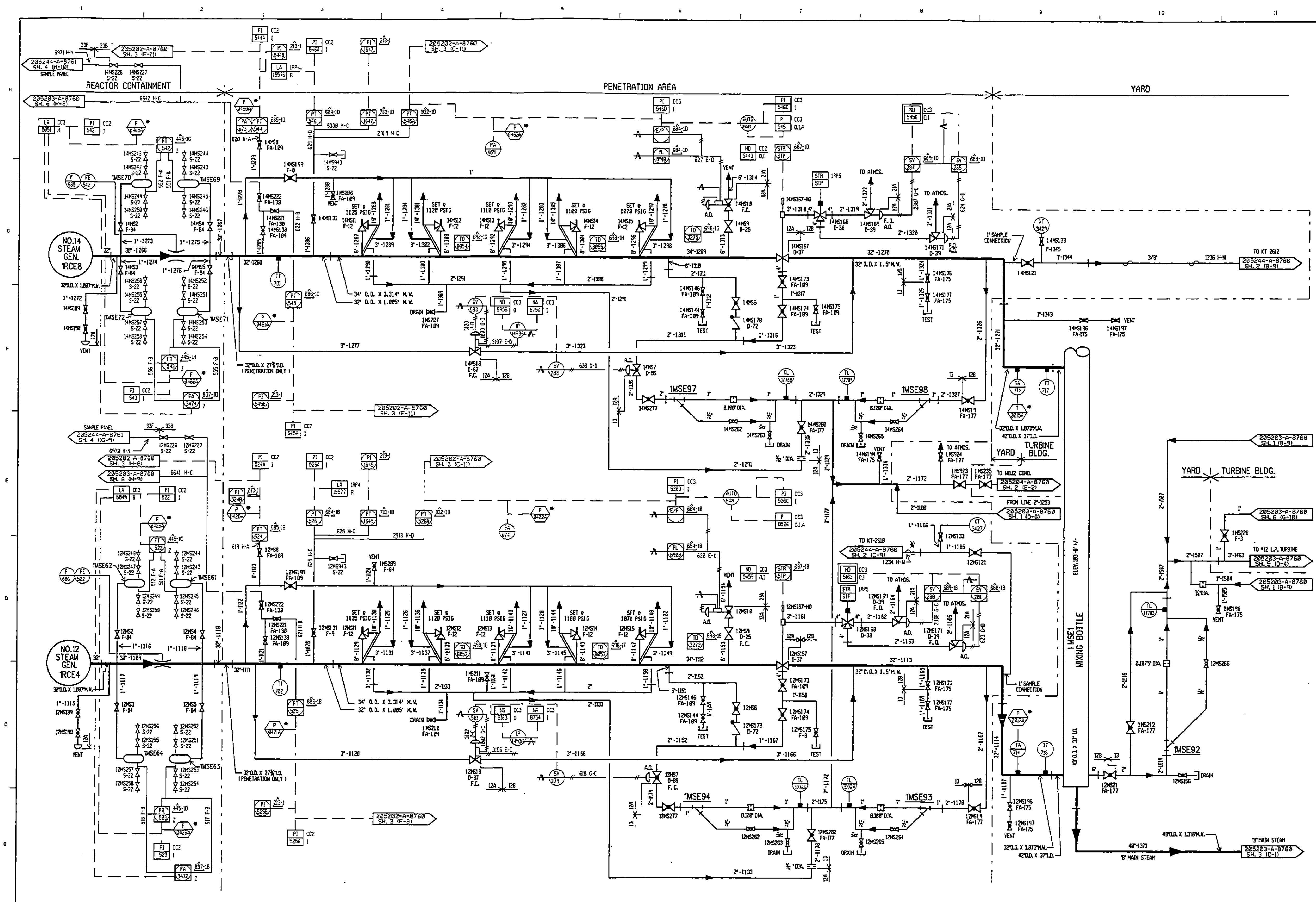
NOTE: FOR VALVE MARK NO'S. NOT SHOWN ON THIS SHEET, REFER TO MMIS.

Ref. Dwg. 205203-A-8760 Sh. 1 - 74

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Main, Reheat and Turbine Bypass Steam
Unit 1

Updated FSAR — Sheet 1 of 6
Revision 17, October 16, 1998 — Fig 10.3-1A



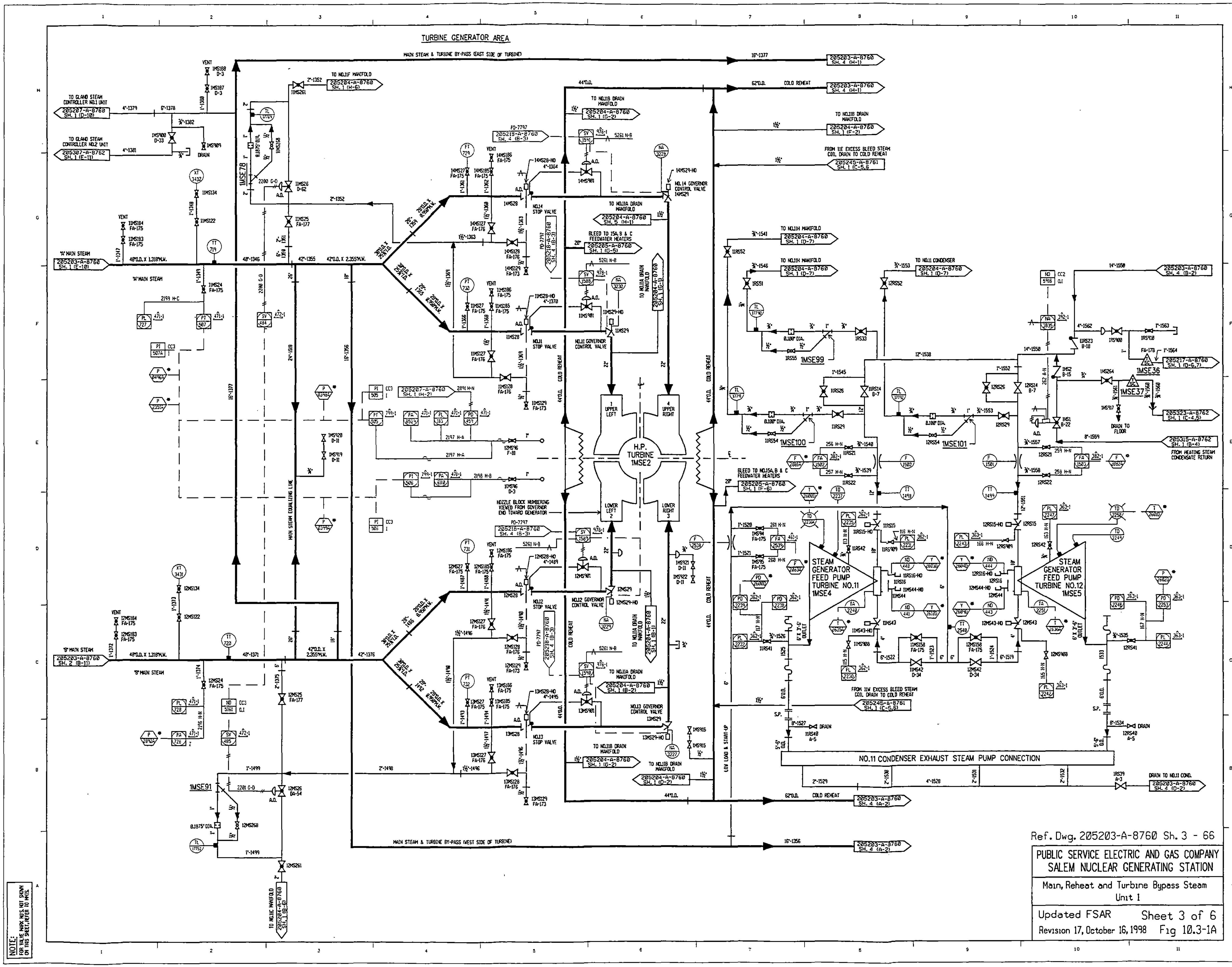
Ref. Dwg. 205203-A-8760 Sh. 2 - 72

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Main, Reheat and Turbine Bypass Steam
Unit 1

Updated FSAR Sheet 2 of 6
Revision 17, October 16, 1998 Fig 10.3-1A

NOTE:
FOR VALVE MARK NO'S. NOT SHOWN ON THIS SHEET, REFER TO MNIS.

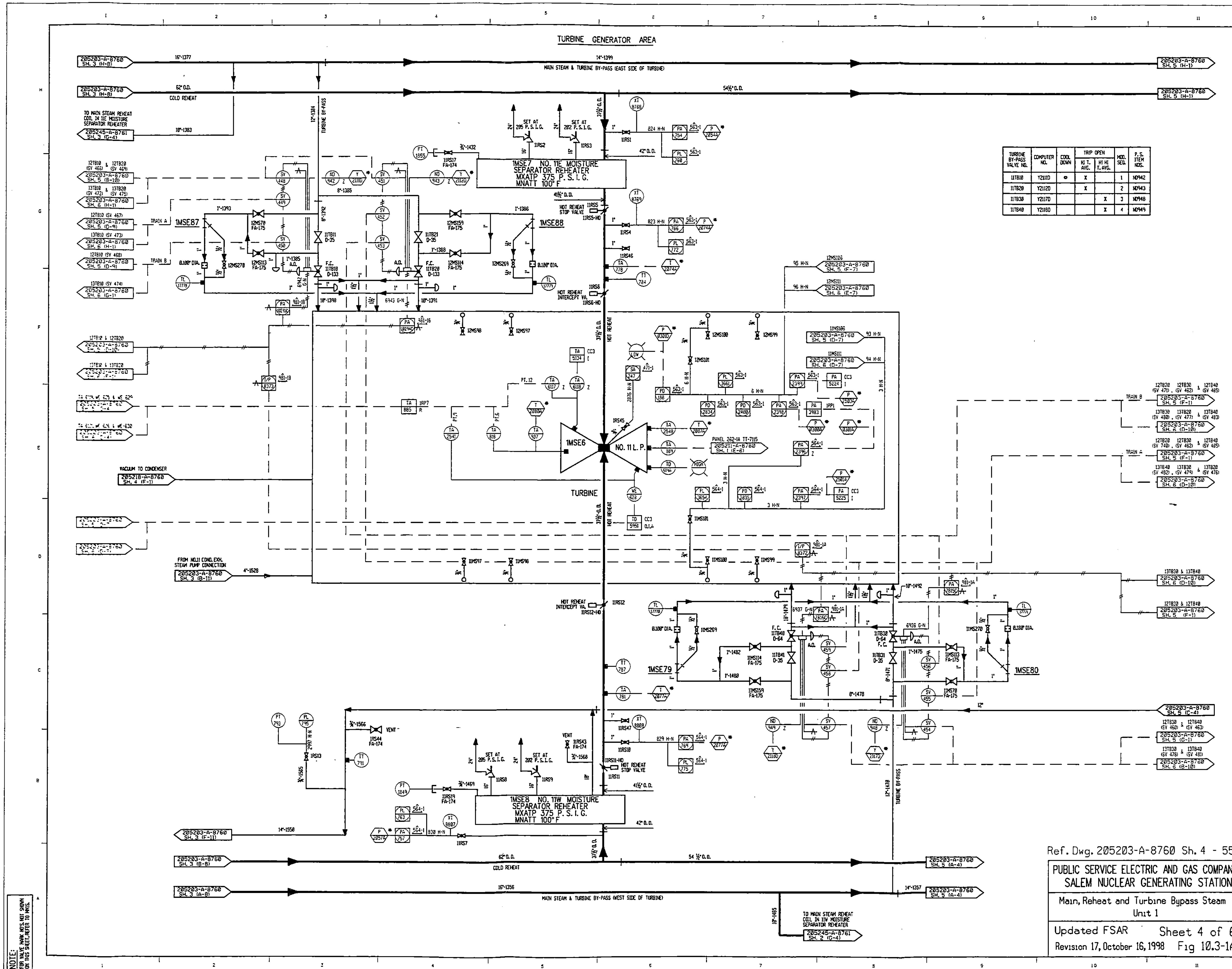


Ref. Dwg. 205203-A-8760 Sh. 3 - 66

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Main, Reheat and Turbine Bypass Steam
Unit 1

Updated FSAR Sheet 3 of 6
Revision 17, October 16, 1998 Fig 10.3-1A



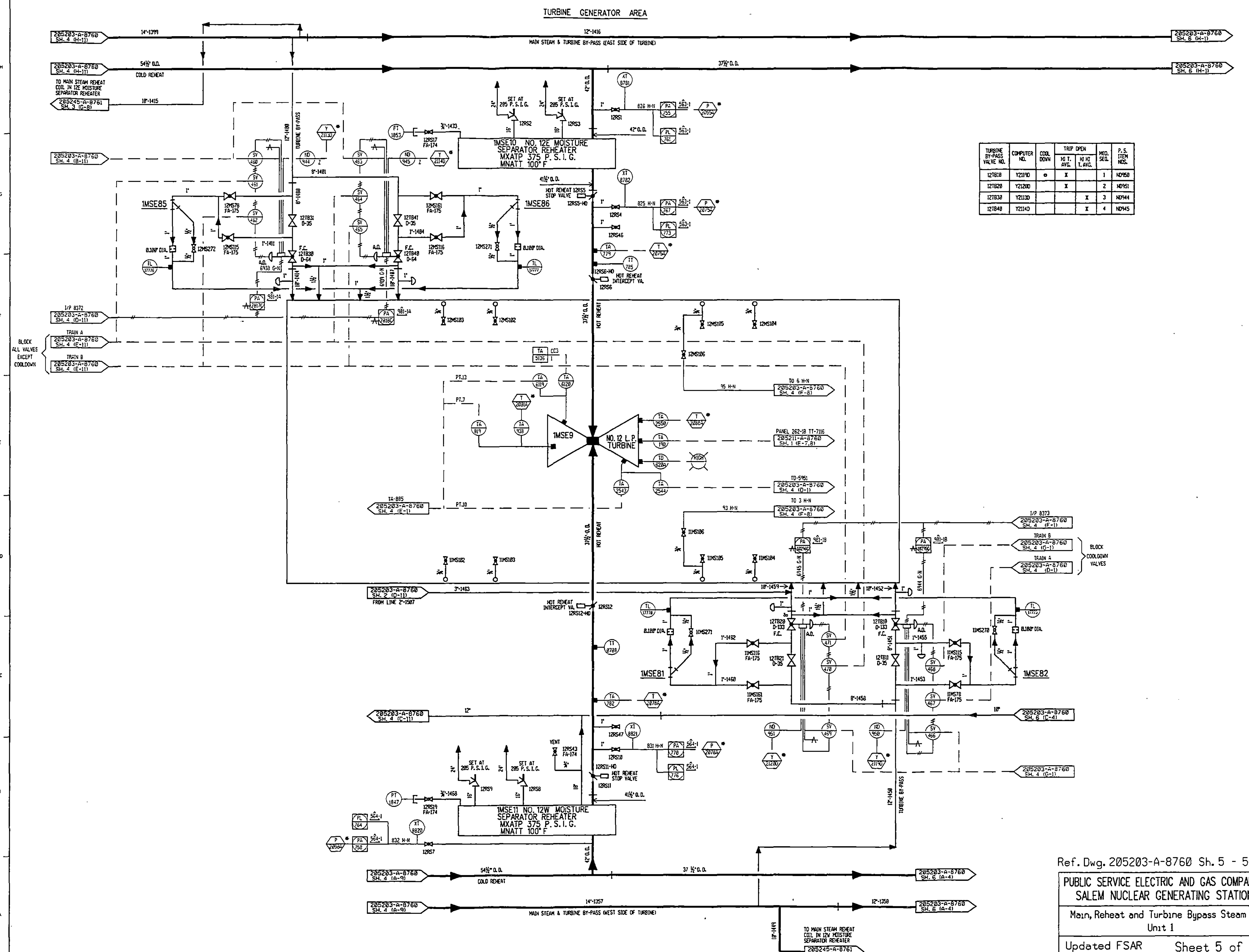
TURBINE BY-PASS VALVE NO.	COMPUTER NO.	COOL DOWN	TRIP OPEN		MOD. SEQ.	P.S. ITEM NOS.
			HI T. AVG.	HI HI T. AVG.		
11TB10	Y2111D	•	X		1	ND942
11TB20	Y2112D		X		2	ND943
11TB30	Y2117D			X	3	ND948
11TB40	Y2118D			X	4	ND949

Ref. Dwg. 205203-A-8760 Sh. 4 - 55

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Main, Reheat and Turbine Bypass Steam
Unit 1

Updated FSAR Sheet 4 of 6
Revision 17, October 16, 1998 Fig 10.3-1A



TURBINE BY-PASS VALVE NO.	COMPUTER NO.	COOL DOWN	TRIP OPEN		MOD. SEQ.	P.S. ITEM NOS.
			HI T. AVG.	HI HI T. AVG.		
12TB10	Y2119D	o	X		1	ND950
12TB20	Y2120D		X		2	ND951
12TB30	Y2113D			X	3	ND944
12TB40	Y2114D			X	4	ND945

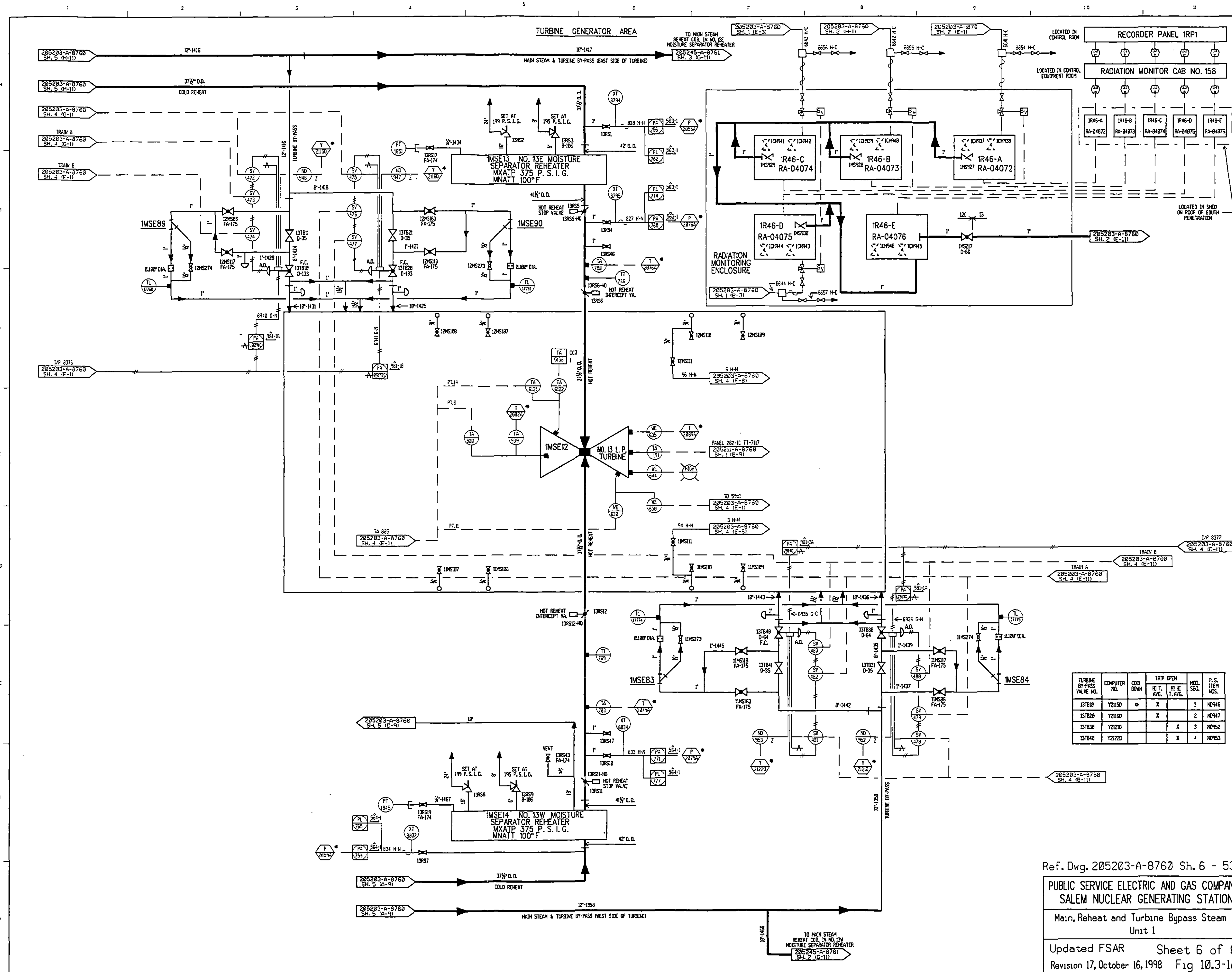
Ref. Dwg. 205203-A-8760 Sh. 5 - 52

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Main, Reheat and Turbine Bypass Steam
Unit 1

Updated FSAR Sheet 5 of 6

Revision 17, October 16, 1998 Fig 10.3-1A



TURBINE BY-PASS VALVE NO.	COMPUTER NO.	COOL DOWN	TRIP OPEN		MOD. SEQ.	P.S. ITEM NOS.
			HI T. AVG.	HI HI T. AVG.		
13TB10	Y21150	o	X		1	ND946
13TB20	Y21160		X		2	ND947
13TB30	Y21210			X	3	ND952
13TB40	Y21220			X	4	ND953

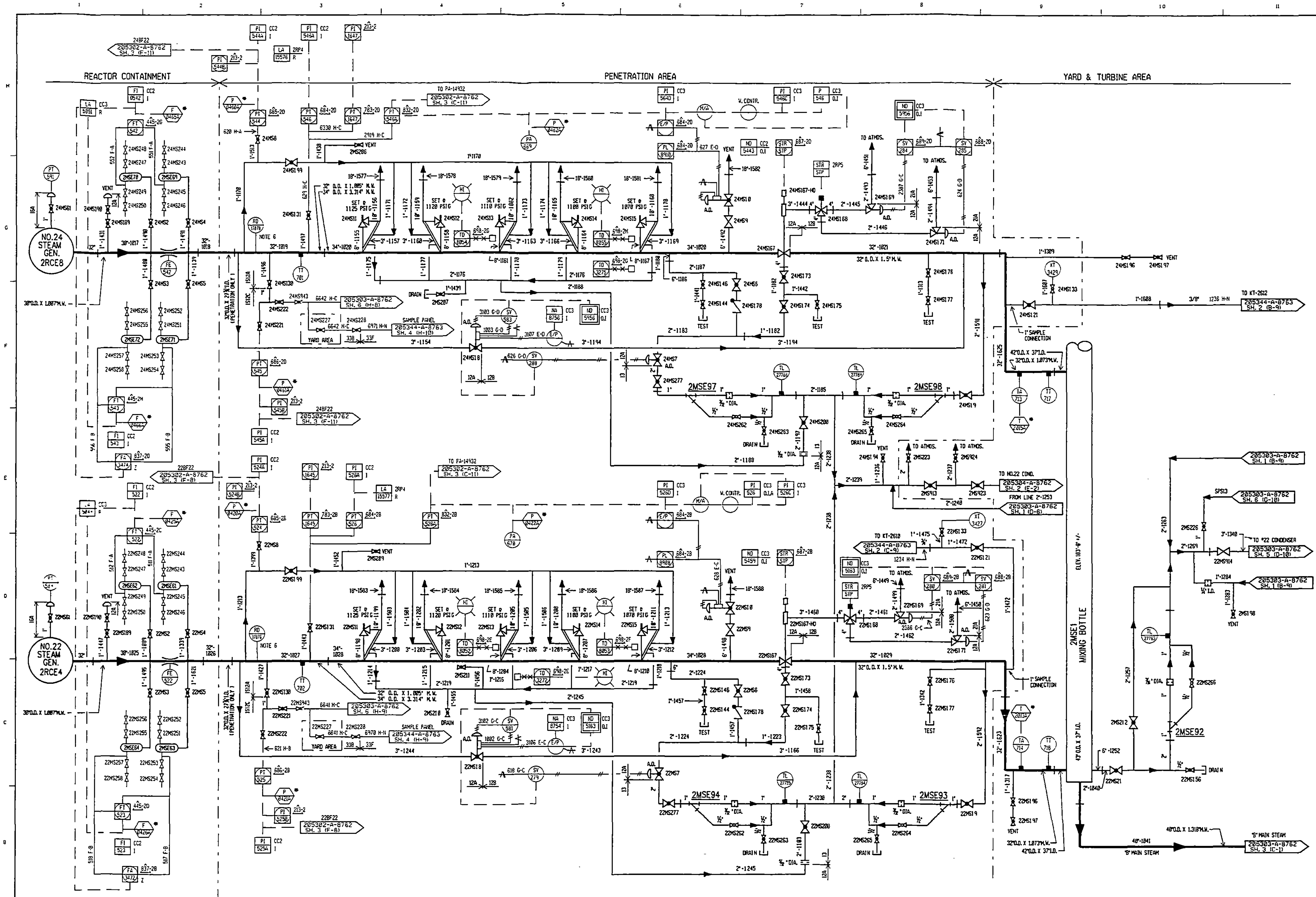
NOTE: FOR VALVE MARK NO'S. NOT SHOWN ON THIS SHEET, REFER TO MMIS.

Ref. Dwg. 205203-A-8760 Sh. 6 - 53

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Main, Reheat and Turbine Bypass Steam
Unit 1

Updated FSAR
Sheet 6 of 6
Revision 17, October 16, 1998
Fig 10.3-1A

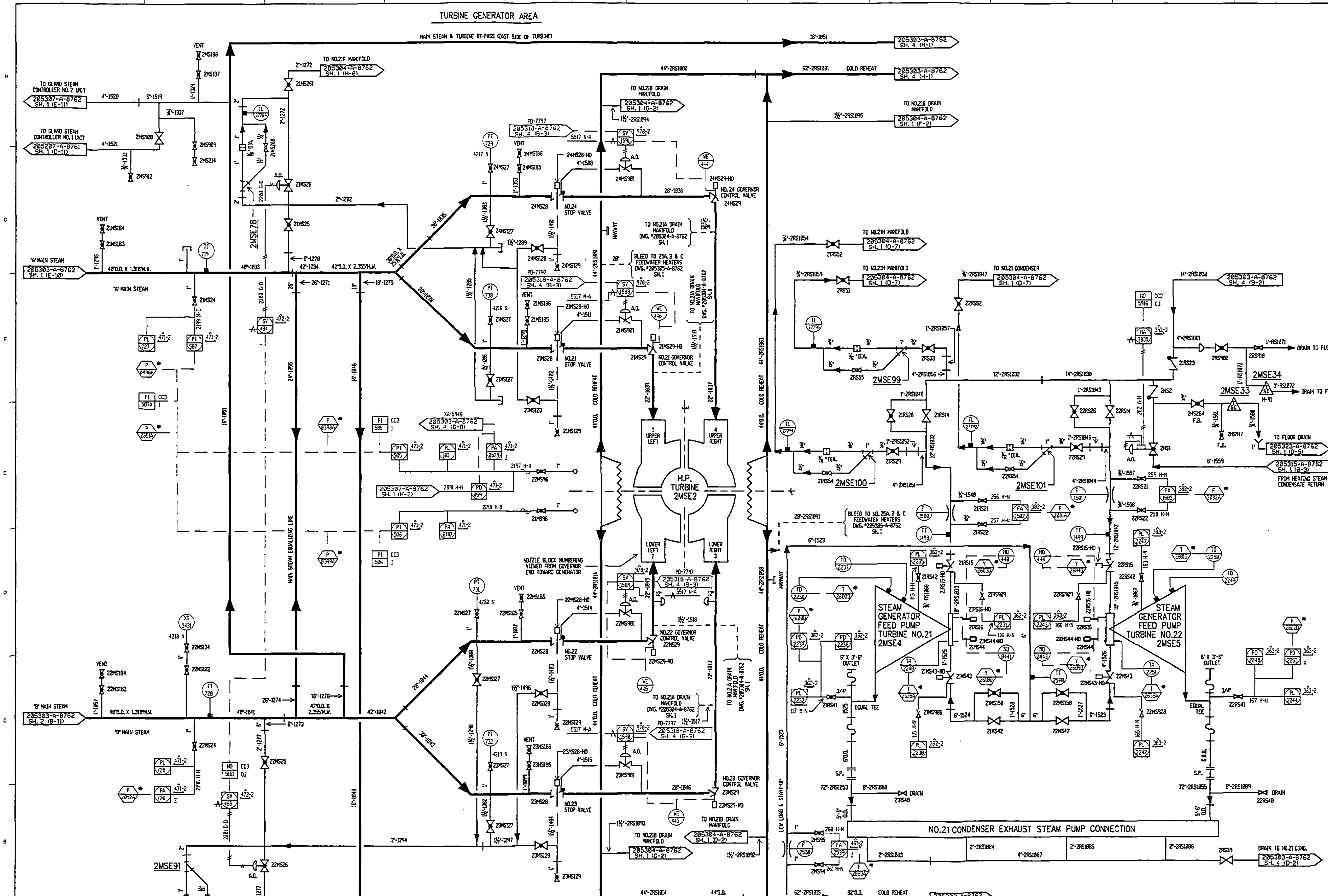


Ref. Dwg. 205303-A-8762 Sh. 2 - 55

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Main, Reheat and Turbine Bypass Steam
Unit 2

Updated FSAR | Sheet 2 of 6
Revision 17, October 16, 1998 | Fig 10.3-1B



Ref. Dwg. 205303-A-8762 Sh. 3 - 48

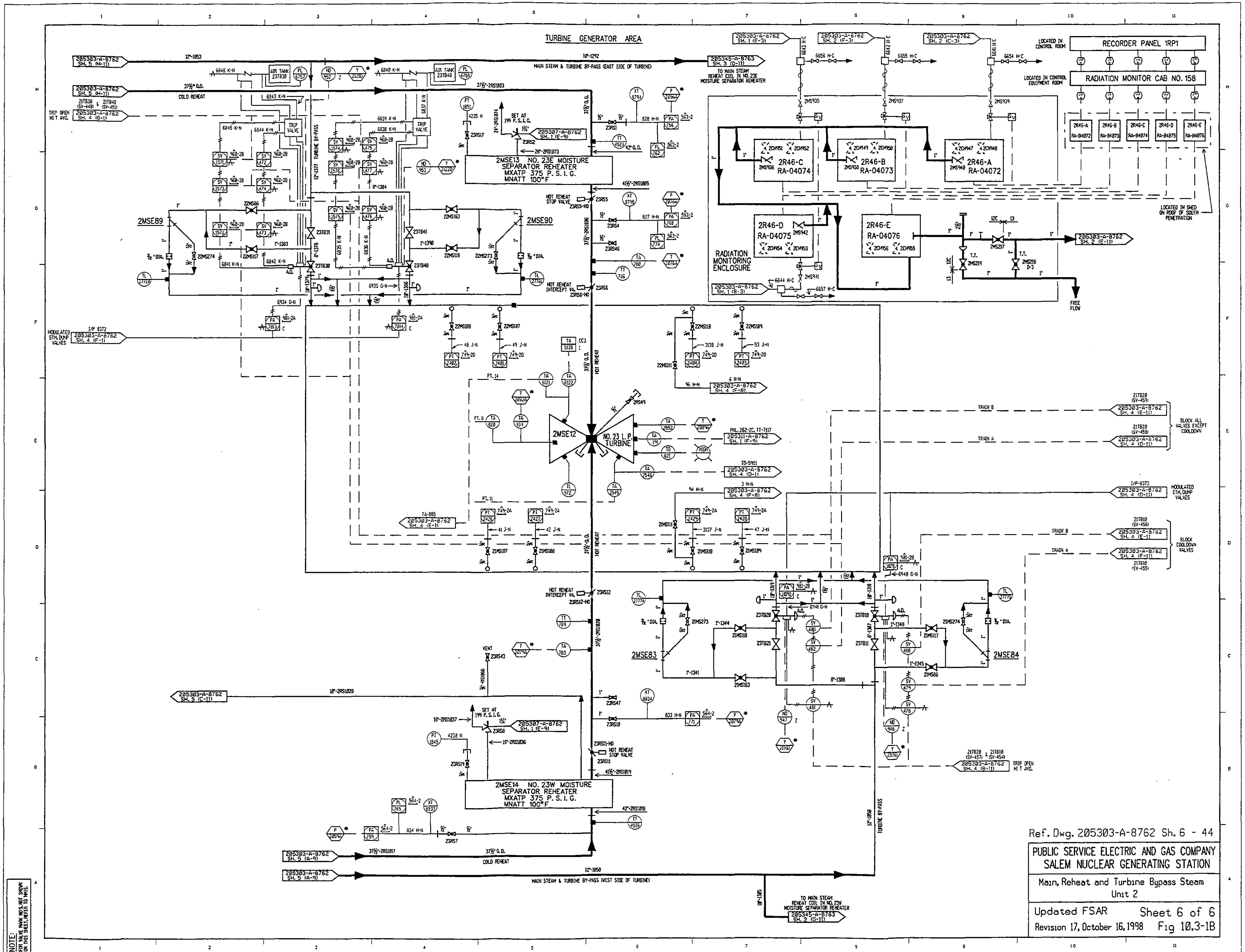
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Main, Reheat and Turbine Bypass Steam
Unit 2

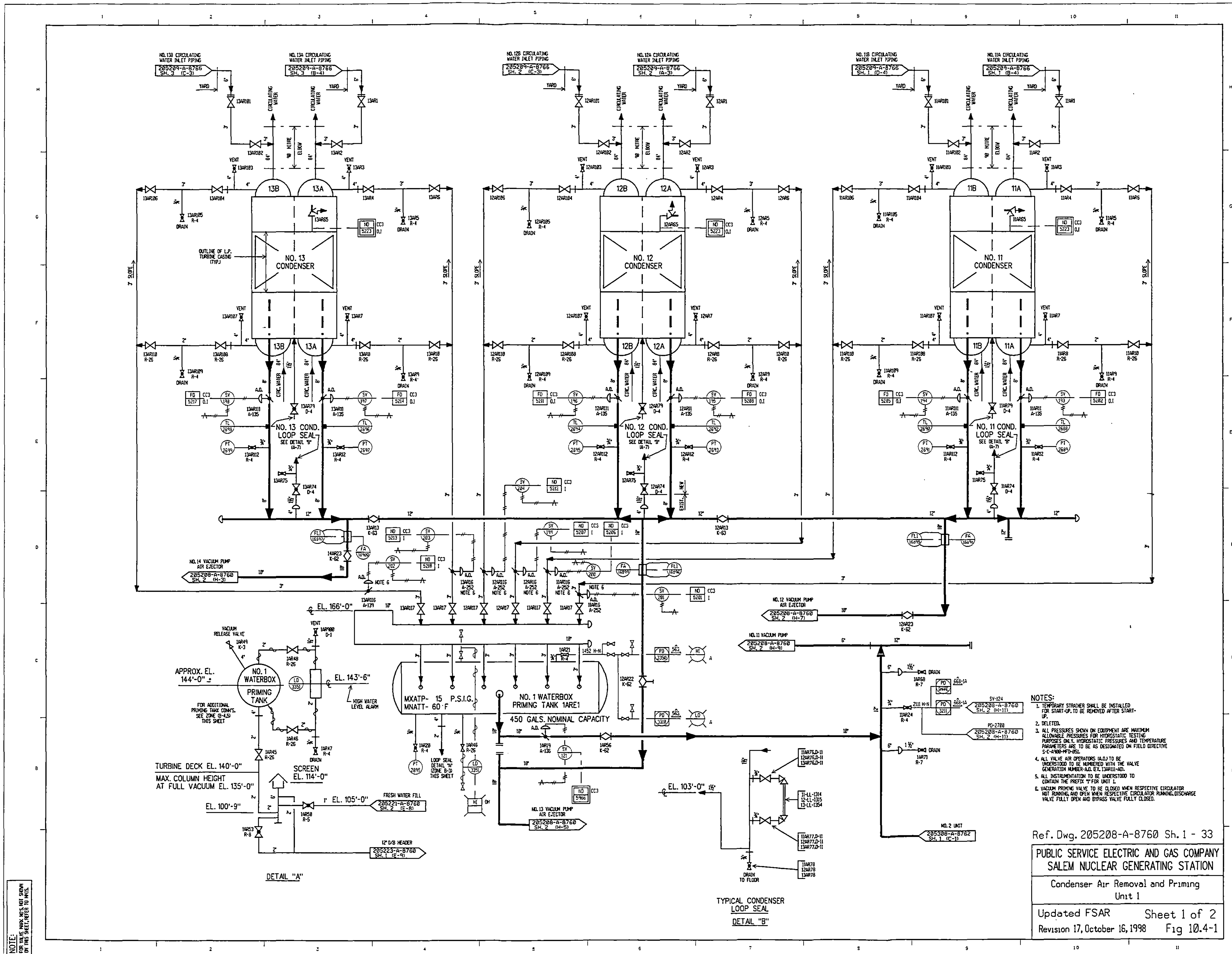
Updated FSAR — Sheet 3 of 6

Revision 17, October 16, 1998 — Fig 10.3-1B

NOTE: FOR VALVE MARK NO'S NOT SHOWN ON THIS SHEET, REFER TO P&IDs.



TURBINE GENERATOR AREA
MAIN STEAM & TURBINE BY-PASS (EAST SIDE OF TURBINE)
COLD REHEAT
2MSE13 NO. 23E MOISTURE SEPARATOR REHEATER MXATP 375 P.S.I.G. MNATT 100°F
2MSE89
2MSE90
2MSE12
NO. 23 L.P. TURBINE
RECORDER PANEL 1RP1
RADIATION MONITOR CAB NO. 158
2R46-C RA-04074
2R46-B RA-04073
2R46-A RA-04072
2R46-D RA-04075
2R46-E RA-04076
RADIATION MONITORING ENCLOSURE
FREE FLOW
2MSE83
2MSE84
2MSE14 NO. 23W MOISTURE SEPARATOR REHEATER MXATP 375 P.S.I.G. MNATT 100°F
MAIN STEAM & TURBINE BY-PASS (WEST SIDE OF TURBINE)
HOT REHEAT
TURBINE BY-PASS
NOTE: FOR VALVE MARK NOS. NOT SHOWN ON THIS SHEET, REFER TO MMIS.
Ref. Dwg. 205303-A-8762 Sh. 6 - 44
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION
Main, Reheat and Turbine Bypass Steam
Unit 2
Updated FSAR
Sheet 6 of 6
Revision 17, October 16, 1998
Fig 10.3-1B



NOTES:

1. TEMPORARY STRAINER SHALL BE INSTALLED FOR START-UP. TO BE REMOVED AFTER START-UP.
2. DELETED.
3. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051.
4. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 13AR111-AO).
5. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "1" FOR UNIT 1.
6. VACUUM PRIMING VALVE TO BE CLOSED WHEN RESPECTIVE CIRCULATOR NOT RUNNING, AND OPEN WHEN RESPECTIVE CIRCULATOR RUNNING, DISCHARGE VALVE FULLY OPEN AND BYPASS VALVE FULLY CLOSED.

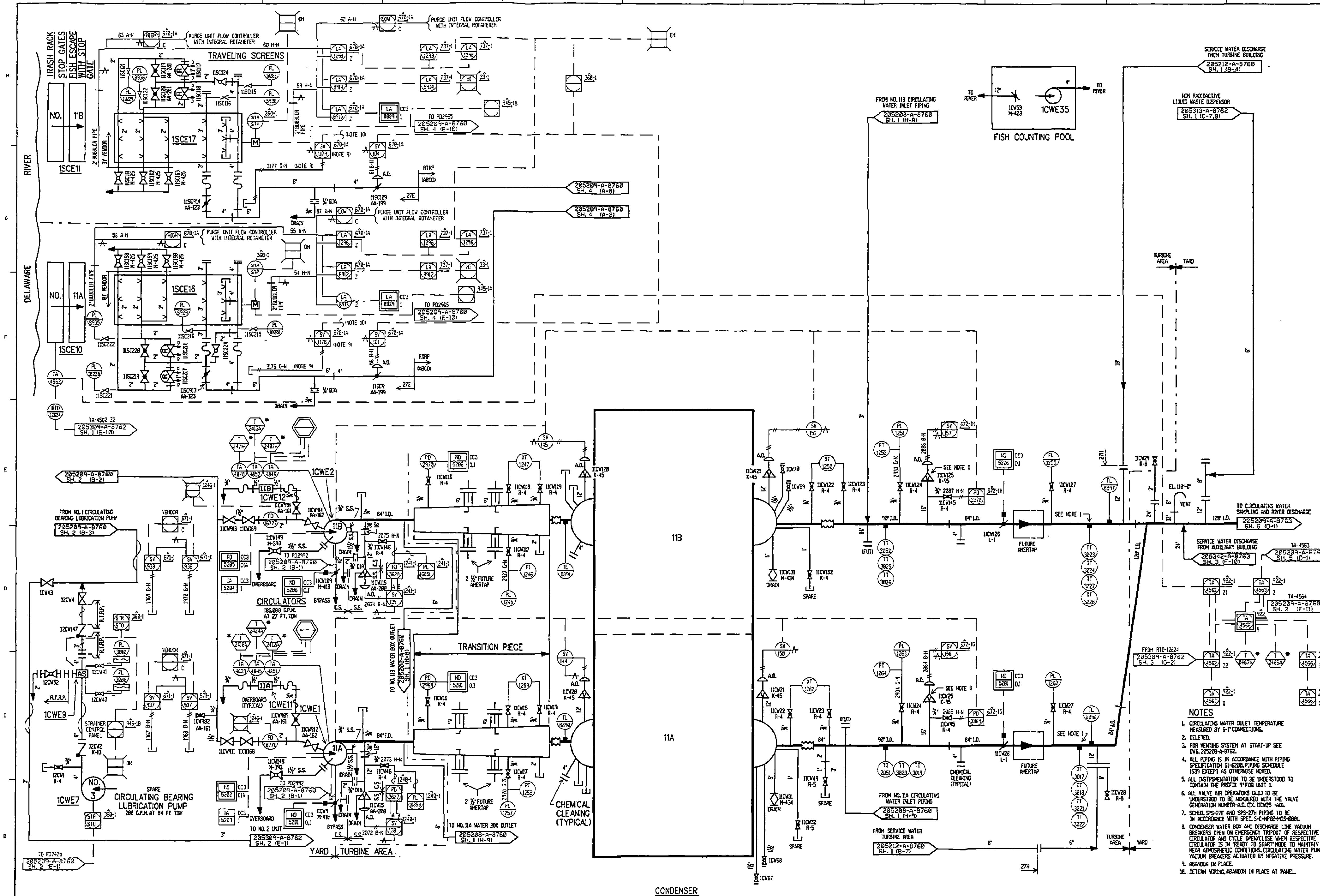
Ref. Dwg. 205208-A-8760 Sh. 1 - 33

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Condenser Air Removal and Priming
Unit 1

Updated FSAR
Revision 17, October 16, 1998

Sheet 1 of 2
Fig 10.4-1



NOTES

1. CIRCULATING WATER OULET TEMPERATURE MEASURED BY 6-1" CONNECTIONS.
2. DELETED.
3. FOR VENTING SYSTEM AT START-UP SEE DWG. 205208-A-8760.
4. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6200, PIPING SCHEDULE 1539 EXCEPT AS OTHERWISE NOTED.
5. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "1" FOR UNIT 1.
6. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 11CW25 -AO).
7. SCHED. SPS-27E AND SPS-27H PIPING TO BE IN ACCORDANCE WITH SPEC. S-C-MP00-MGS-0001.
8. CONDENSER WATER BOX AND DISCHARGE LINE VACUUM BREAKERS OPEN ON EMERGENCY TRIPOUT OF RESPECTIVE CIRCULATOR AND CYCLE OPEN/CLOSE WHEN RESPECTIVE CIRCULATOR IS IN "READY TO START" MODE TO MAINTAIN NEAR ATMOSPHERIC CONDITIONS. CIRCULATING WATER PUMP VACUUM BREAKERS ACTUATED BY NEGATIVE PRESSURE.
9. ABANDON IN PLACE.
10. DETERM WIRING, ABANDON IN PLACE AT PANEL.

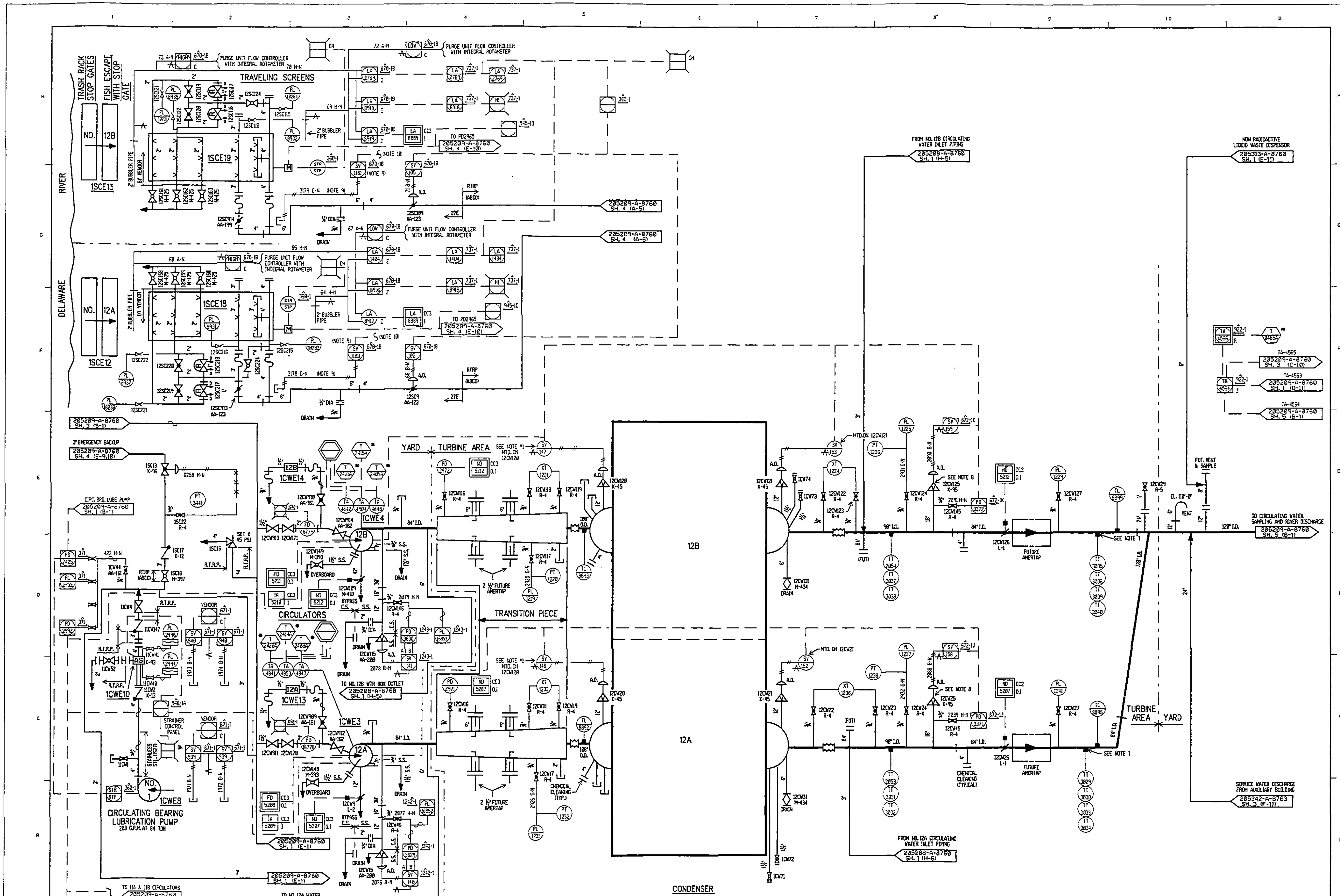
NOTE: FOR VALVE MARK NO'S. NOT SHOWN ON THIS SHEET, REFER TO MMIS.

Ref. Dwg. 205209-A-8760 Sh. 1 - 66

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Circulating Water System
Unit 1

Updated FSAR — Sheet 1 of 5
Revision 17, October 16, 1998 — Fig 10.4-3A



GENERAL NOTES

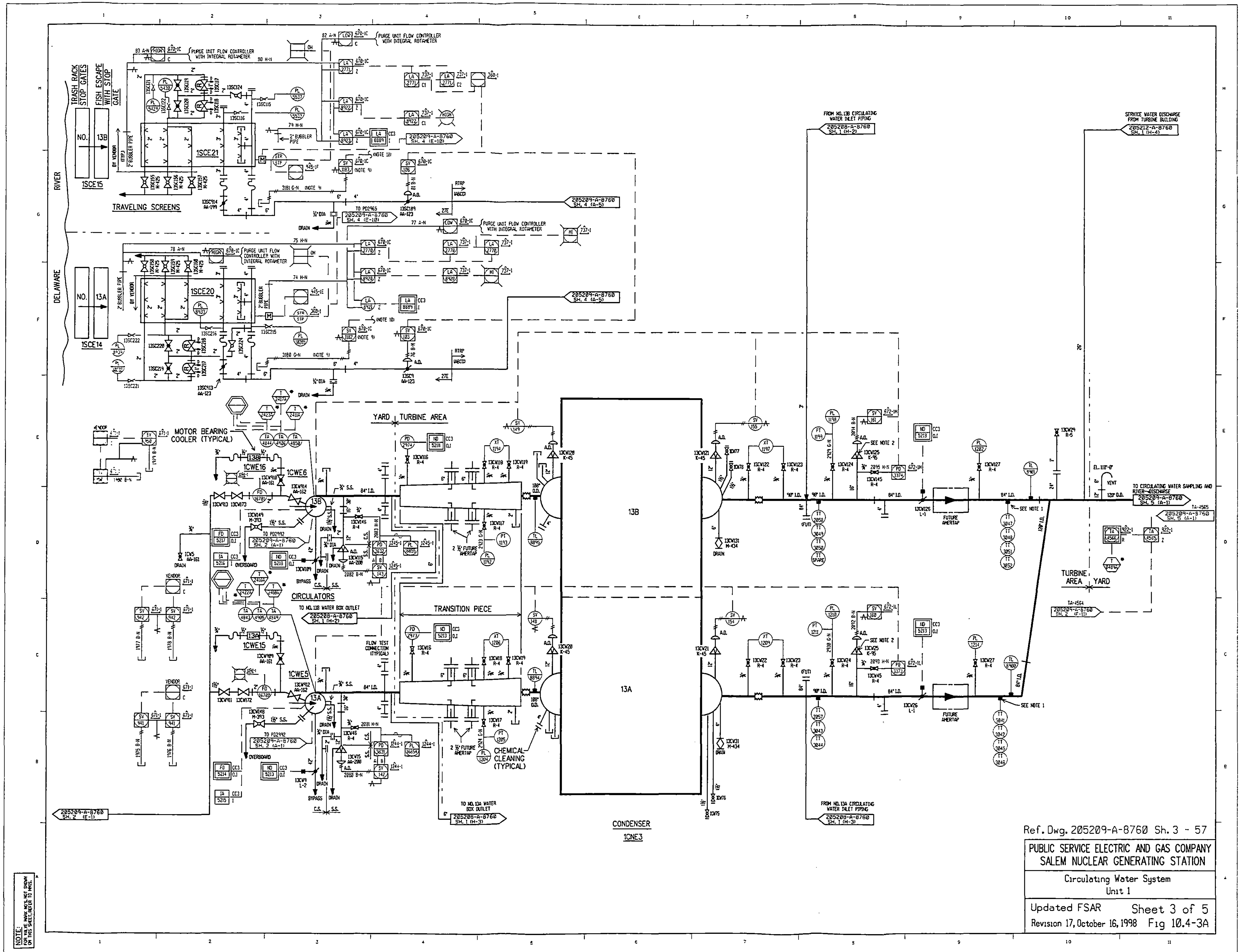
1.- SWITCH "S-1 TO ENERGIZE TO OPEN VENT WHEN PUMP STOPS.
2.- SWITCH "S-2 TO ENERGIZE TO CLOSE VENT WHEN PUMP STARTS.

Ref. Dwg. 205209-A-8760 Sh. 2 - 65

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Circulating Water System
Unit 1

Updated FSAR Sheet 2 of 5
Revision 17, October 16, 1998 Fig 10.4-3A

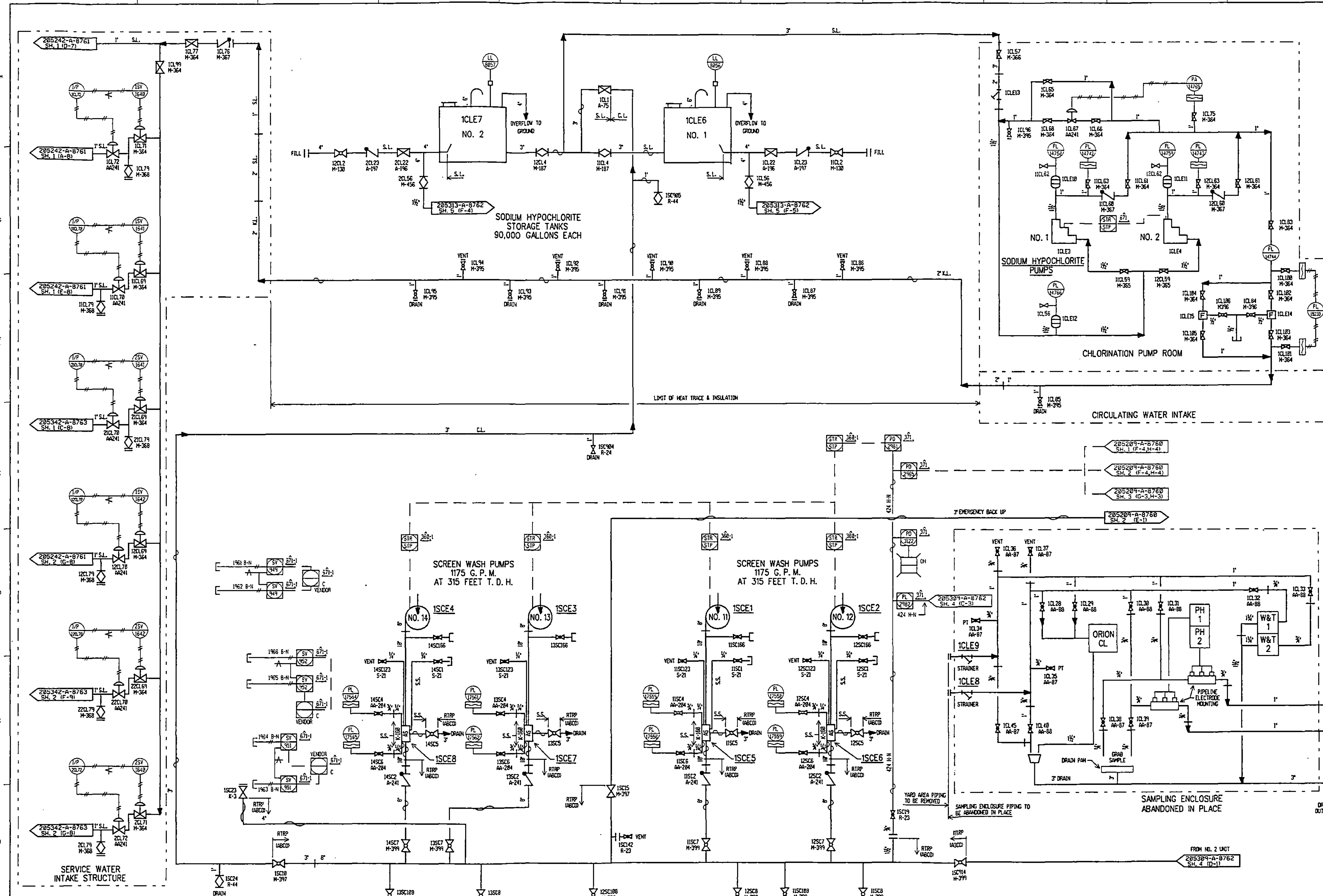


Ref. Dwg. 205209-A-8760 Sh. 3 - 57

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Circulating Water System
Unit 1

Updated FSAR Sheet 3 of 5
Revision 17, October 16, 1998 Fig 10.4-3A



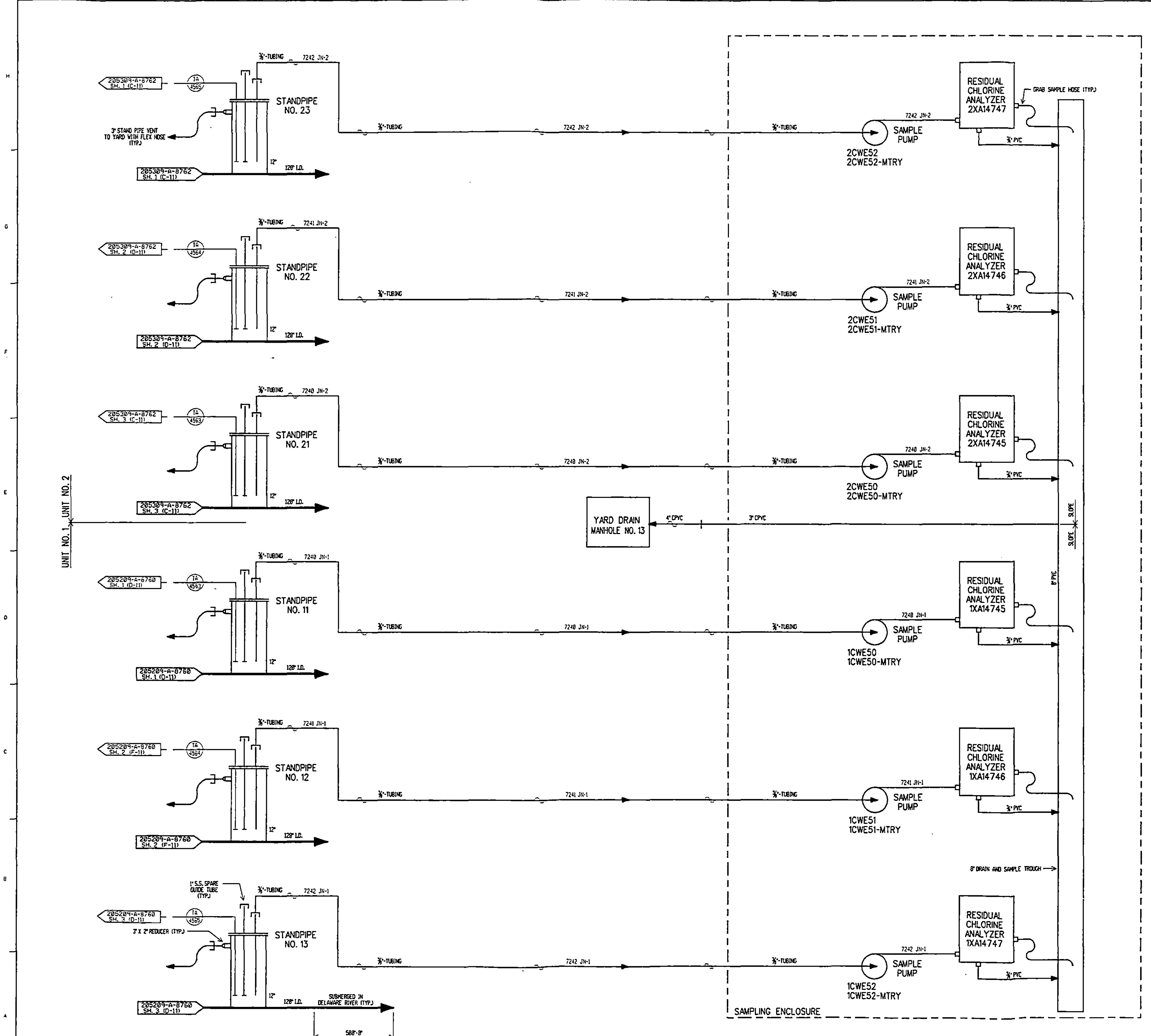
Ref. Dwg. 205209-A-8760 Sh. 4 - 51

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Circulating Water System
Unit 1

Updated FSAR — Sheet 4 of 5

Revision 17, October 16, 1998 — Fig 10.4-3A



GENERAL NOTES

1. FOR STANDARD P&ID SYMBOLS AND LEGEND SEE DRAWING NO. 600658-A-8727
2. ALL VALVES ARE SHOWN NORMALLY OPEN UNLESS INDICATED OTHERWISE

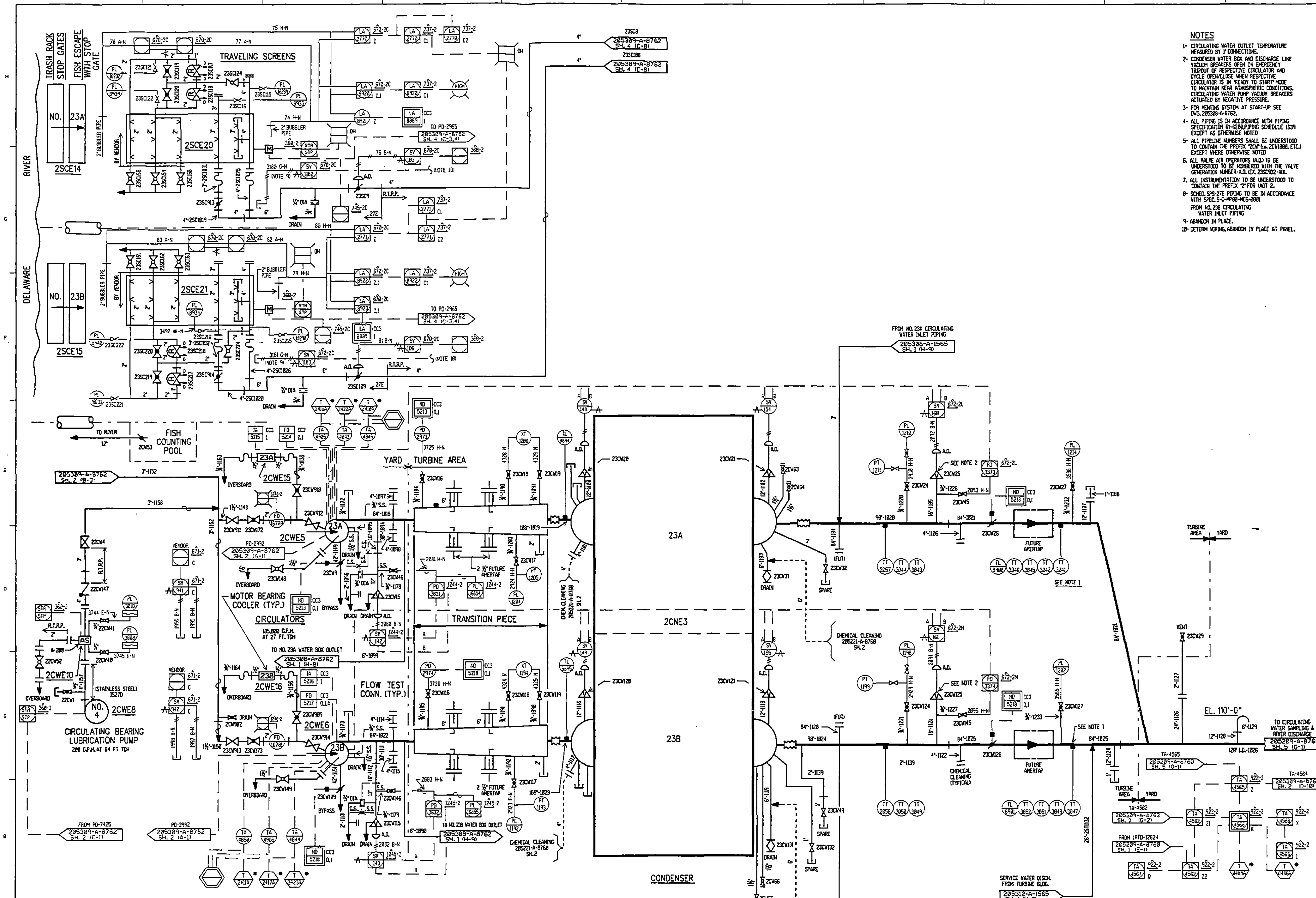
Ref. Dwg. 205209-A-8760 Sh. 5 - 08

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Circulating Water System
Unit 1

Updated FSAR — Sheet 5 of 5

Revision 17, October 16, 1998 — Fig 10.4-3A



NOTES

1- CIRCULATING WATER OUTLET TEMPERATURE MEASURED BY 1" CONNECTIONS.
2- CONDENSER WATER BOX AND DISCHARGE LINE VACUUM BREAKERS OPEN ON EMERGENCY TRIPOUT OF RESPECTIVE CIRCULATOR AND CYCLE OPEN/CLOSE WHEN RESPECTIVE CIRCULATOR IS IN "READY TO START" MODE TO MAINTAIN NEAR ATMOSPHERIC CONDITIONS. CIRCULATING WATER PUMP VACUUM BREAKERS ACTUATED BY NEGATIVE PRESSURE.
3- FOR VENTING SYSTEM AT START-UP SEE DWG. 205308-A-8762.
4- ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6200, PIPING SCHEDULE 1539 EXCEPT AS OTHERWISE NOTED
5- ALL PIPELINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "2CW" (i.e. 2CW1000, ETC.) EXCEPT WHERE OTHERWISE NOTED
6. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 23SC932-AO).
7. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "2" FOR UNIT 2.
8- SCHED. SPS-27E PIPING TO BE IN ACCORDANCE WITH SPEC. S-C-MP00-MGS-0001
FROM NO. 23B CIRCULATING WATER INLET PIPING
9- ABANDON IN PLACE.
10- DETERM WIRING, ABANDON IN PLACE AT PANEL.

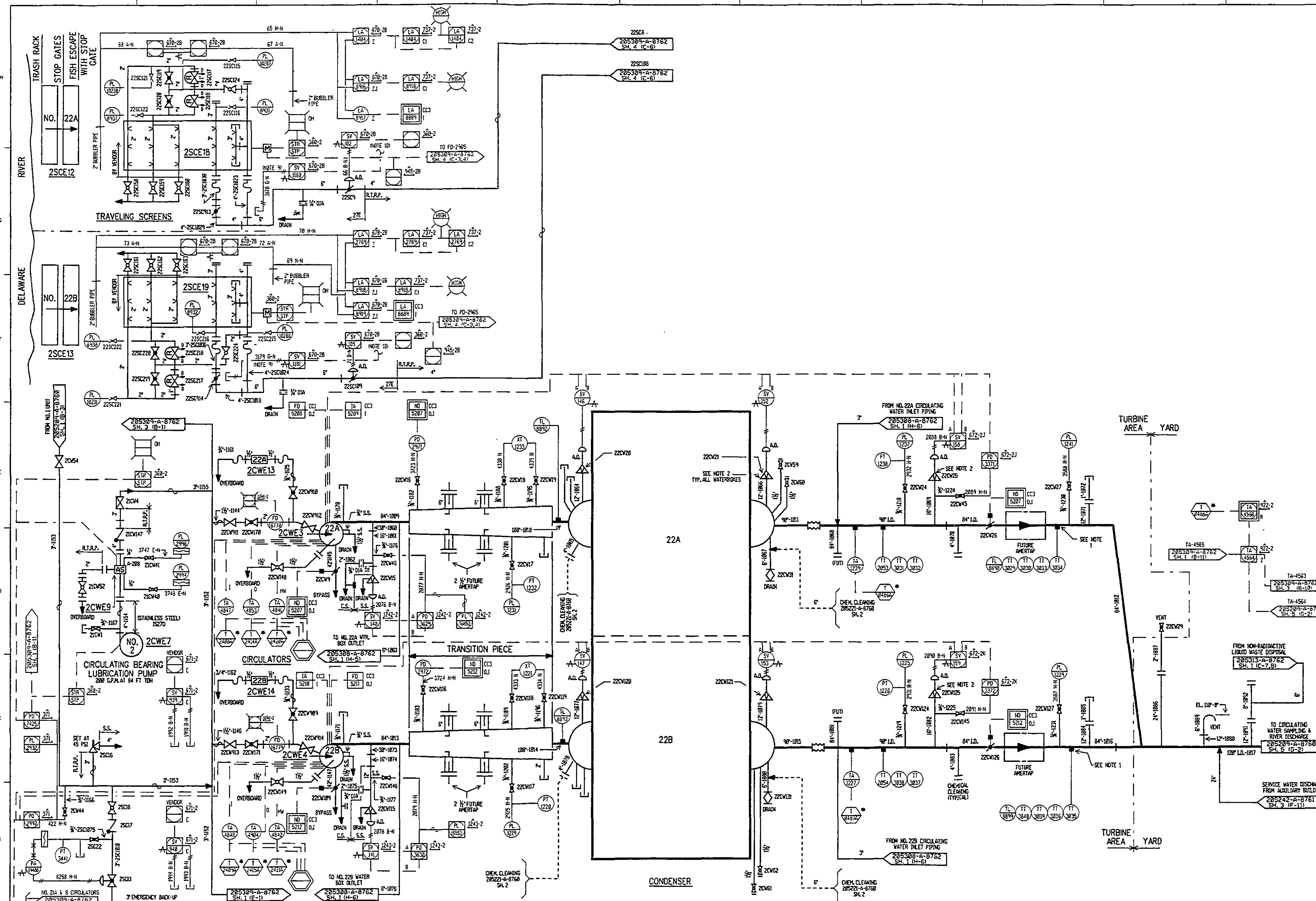
NOTE: FOR TRUE MARK NOS NOT SHOWN ON THIS SHEET, REFER TO MMIS.

Ref. Dwg. 205309-A-8762 Sh. 1 - 62

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Circulating Water System
Unit 2

Updated FSAR Sheet 1 of 4
Revision 17, October 16, 1998 Fig 10.4-3B

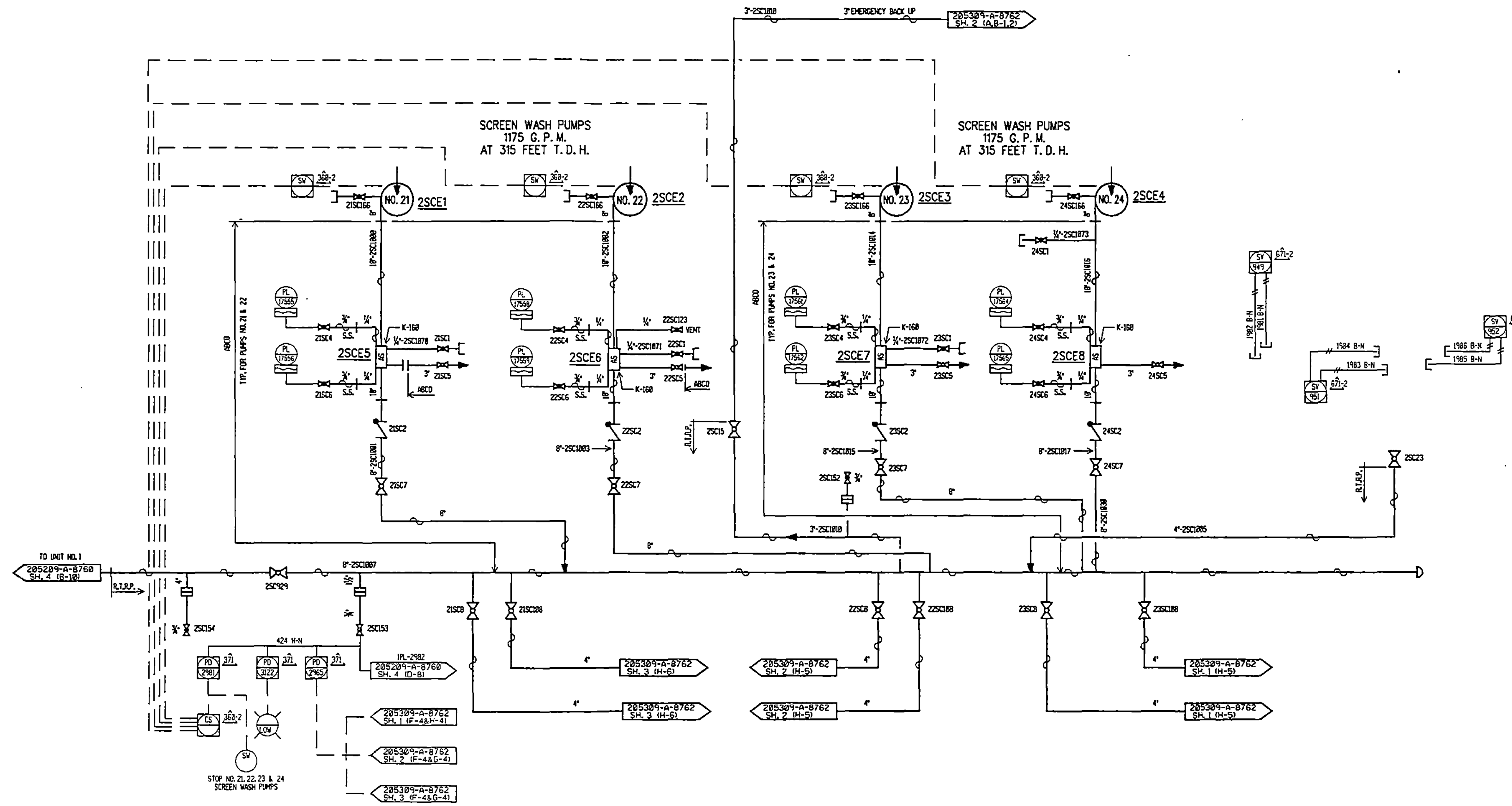


Ref. Dwg. 205309-A-8762 Sh. 2 - 64

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Circulating Water System
Unit 2

Updated FSAR Sheet 2 of 4
Revision 17, October 16, 1998 Fig 10.4-3B



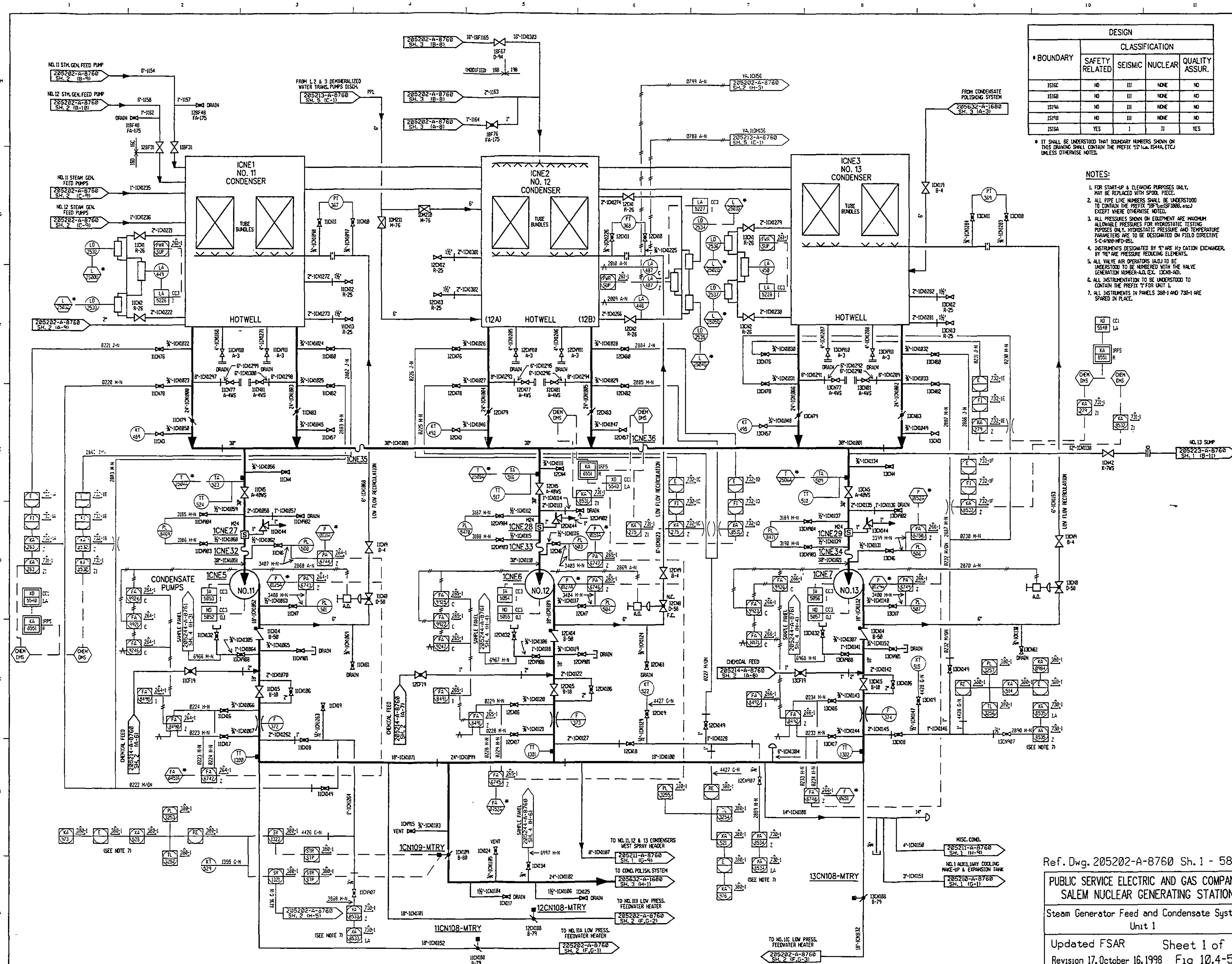
NOTE: FOR VALVE MARK NOS. NOT SHOWN ON THIS SHEET, REFER TO ANCS.

Ref. Dwg. 205309-A-8762 Sh. 4 - 34

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Circulating Water System
Unit 2

Updated FSAR Sheet 4 of 4
Revision 17, October 16, 1998 Fig 10.4-3B



* BOUNDARY	DESIGN CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S16C	NO	III	NONE	NO
1S16B	NO	III	NONE	NO
1S19A	NO	III	NONE	NO
1S19B	NO	III	NONE	NO
1S16A	YES	I	II	YES

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (i.e. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

NOTES:

1. FOR START-UP & CLEANING PURPOSES ONLY, MAY BE REPLACED WITH SPOOL PIECE.
2. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1BF" (i.e.:1BF1000, etc.) EXCEPT WHERE OTHERWISE NOTED.
3. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PUPOSES ONLY. HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO BE DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051.
4. INSTRUMENTS DESIGNATED BY "E" ARE H_2 CATION EXCHANGER, BY "RE" ARE PRESSURE REDUCING ELEMENTS.
5. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 13CN8-AO).
6. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "1" FOR UNIT 1.
7. ALL INSTRUMENTS IN PANELS 380-1 AND 730-1 ARE SPARED IN PLACE.

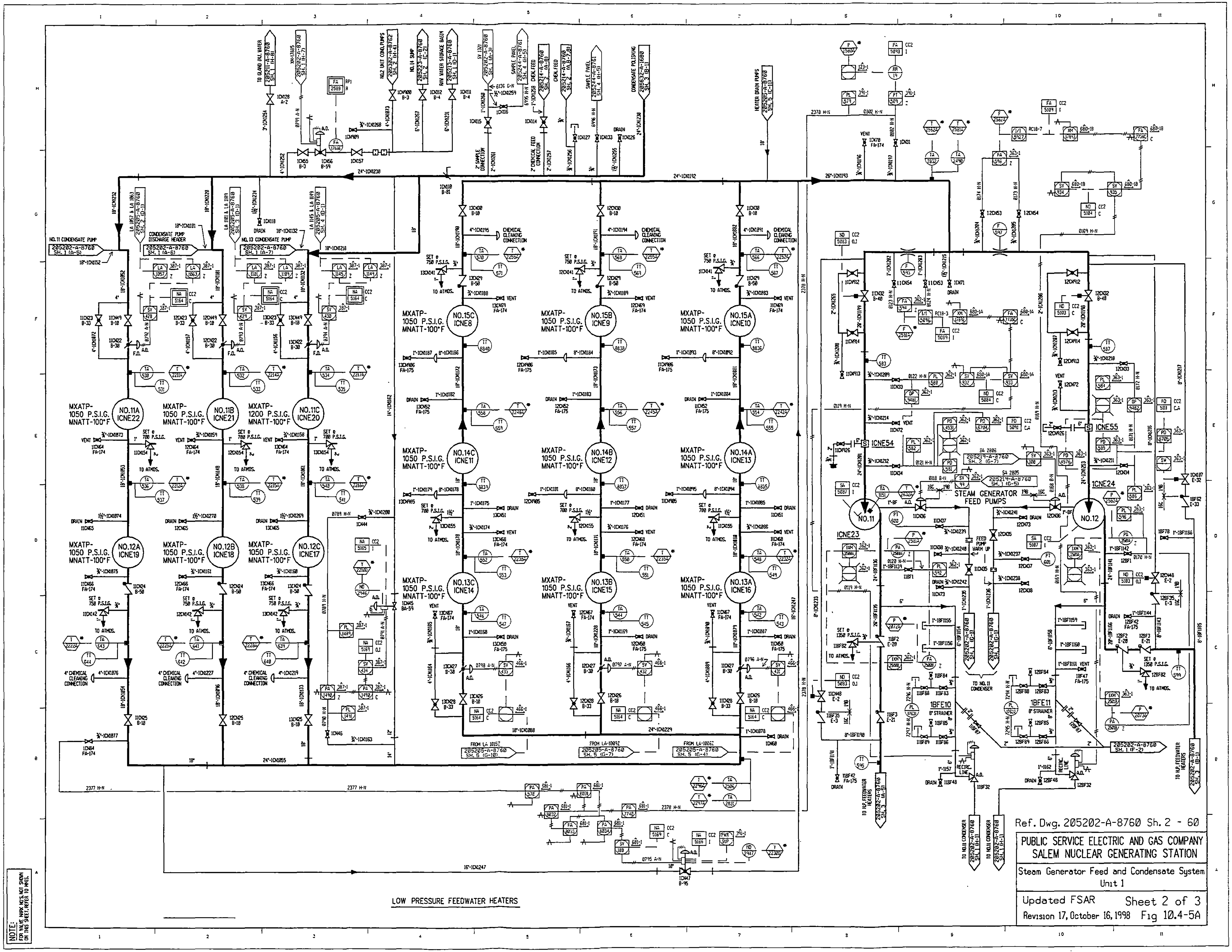
NOTE: FOR VALVE MARK NO'S. NOT SHOWN ON THIS SHEET, REFER TO MMIS.

Ref. Dwg. 205202-A-8760 Sh. 1 - 58

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Steam Generator Feed and Condensate System
Unit 1

Updated FSAR Sheet 1 of 3
Revision 17, October 16, 1998 Fig 10.4-5A



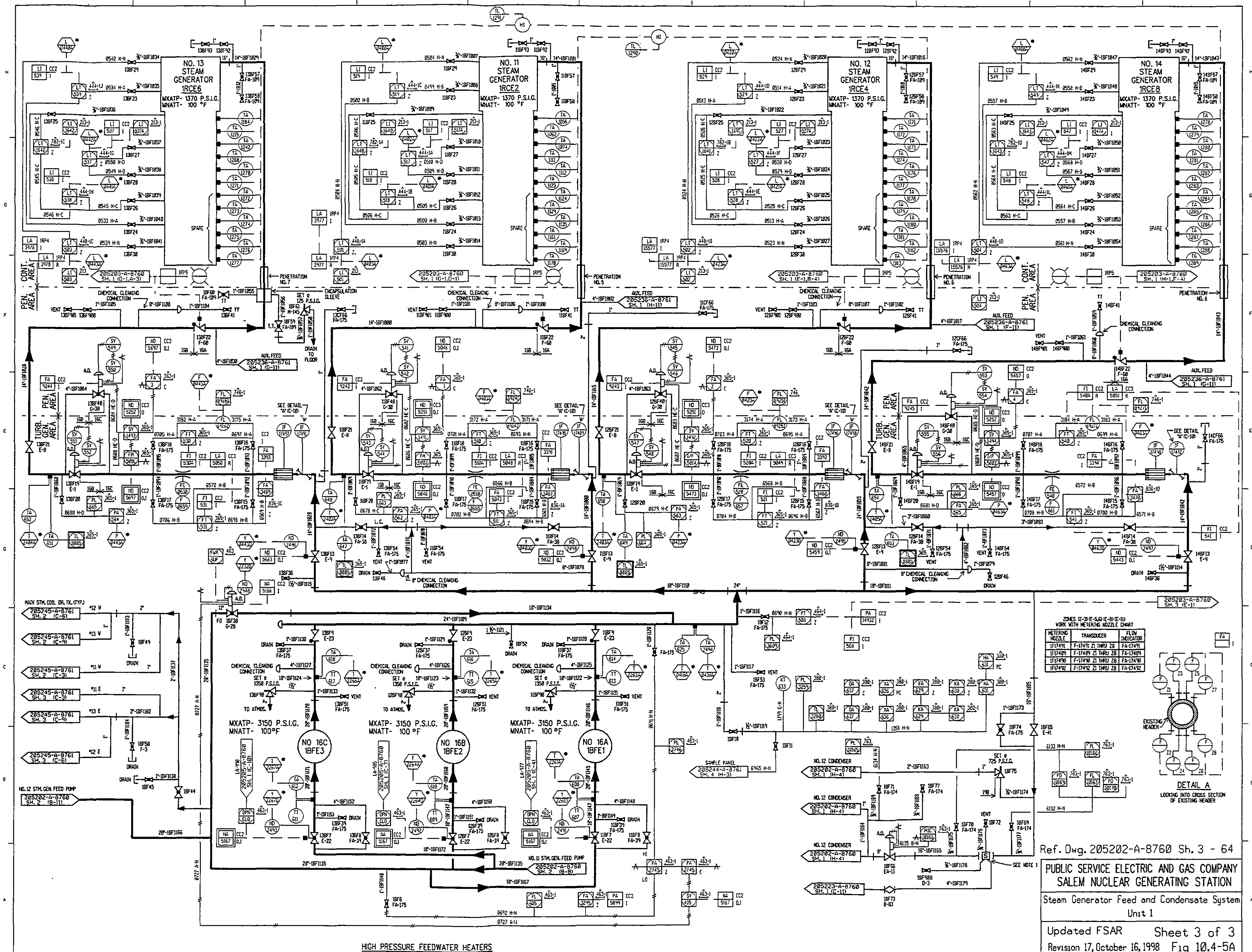
Ref. Dwg. 205202-A-8760 Sh. 2 - 60

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Steam Generator Feed and Condensate System
Unit 1

Updated FSAR — Sheet 2 of 3

Revision 17, October 16, 1998 — Fig 10.4-5A



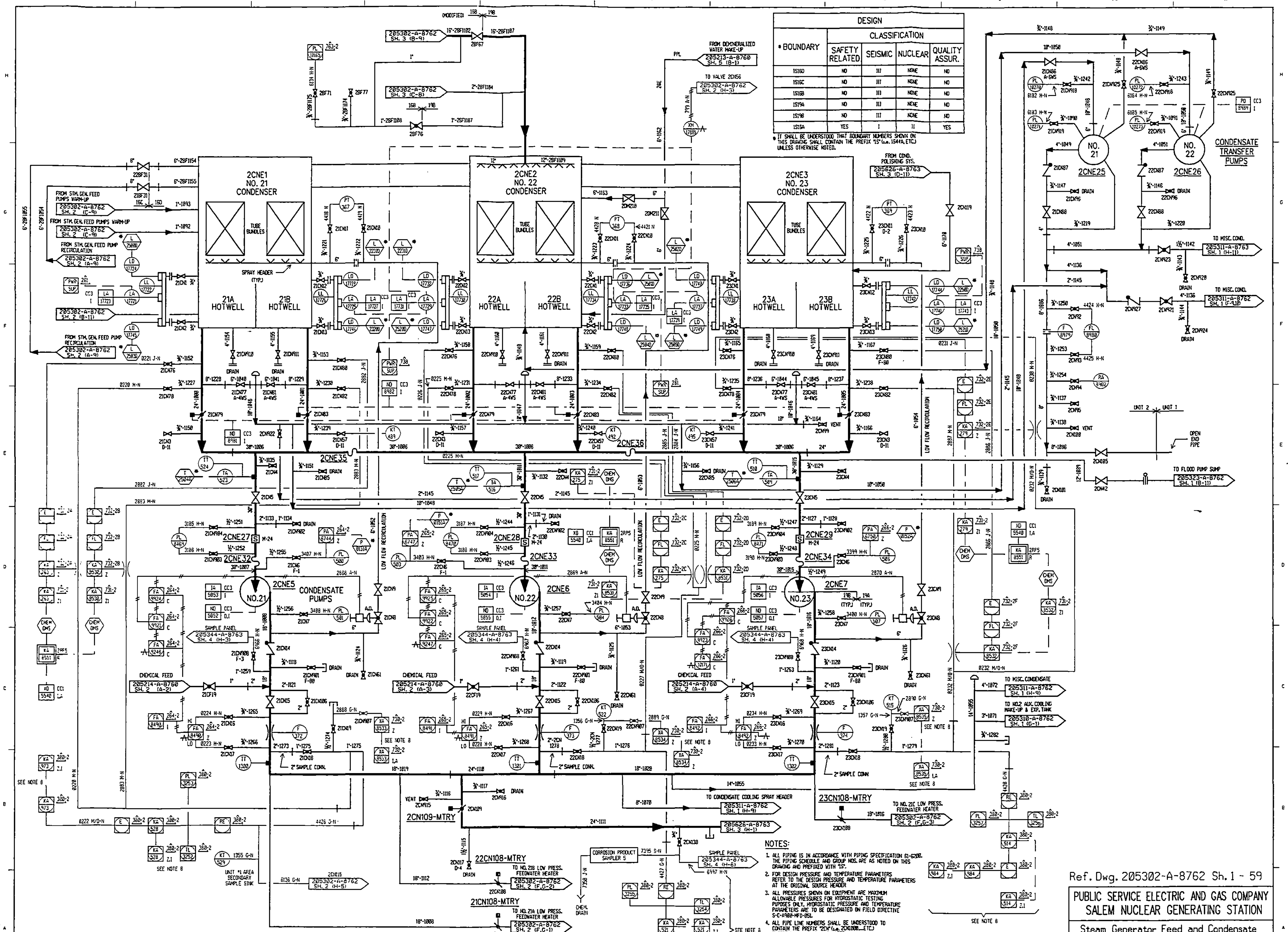
Ref. Dwg. 205202-A-8760 Sh. 3 - 64

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Steam Generator Feed and Condensate System
Unit 1

Updated FSAR
Sheet 3 of 3

Revision 17, October 16, 1998
Fig 10.4-5A



• BOUNDARY	DESIGN CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S16D	NO	III	NONE	NO
1S16C	NO	III	NONE	NO
1S16B	NO	III	NONE	NO
1S19A	NO	III	NONE	NO
1S19B	NO	III	NONE	NO
1S16A	YES	I	II	YES

• IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (i.e. 1S44A, ETC.) UNLESS OTHERWISE NOTED.

NOTES:

1. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6200. THE PIPING SCHEDULE AND GROUP NOS. ARE AS NOTED ON THIS DRAWING AND PREFIXED WITH "1S".
2. FOR DESIGN PRESSURE AND TEMPERATURE PARAMETERS REFER TO THE DESIGN PRESSURE AND TEMPERATURE PARAMETERS AT THE ORIGINAL SOURCE HEADER.
3. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PUPOSES ONLY. HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO BE DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051.
4. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "2CN" (i.e. 2CN1000...ETC.) EXCEPT WHERE OTHERWISE NOTED.
5. INSTRUMENT ITEMS IN PARENTHSIS ( ) ARE WESTINGHOUSE INSTRUMENT ITEMS. REFER TO ISA5.1 FOR DESCRIPTION.
6. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 21CN8-AO).
7. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "2" FOR UNIT 2.

NOTES: (CONT)

8. ALL INSTRUMENTS IN PANELS 380-2 AND 730-2 ARE SPARED IN PLACE.
9. FOR START-UP AND CLEANING PURPOSES ONLY 20 MESH STRAINER W/ SS HOUSING MAY BE REMOVED AS DETERMINED BY OPERATIONS.

NOTES: (CONT)

10. FOR JUSTIFICATION OF RELIEF VALVES CN141 AND CN142 SET POINT OF 750 P.S.I.G. SEE ENGINEERING EVALUATION S-C-CN-MEE-1073.

NOTE:
FOR VALVE MARK NO'S. NOT SHOWN ON THIS SHEET, REFER TO MMIS.

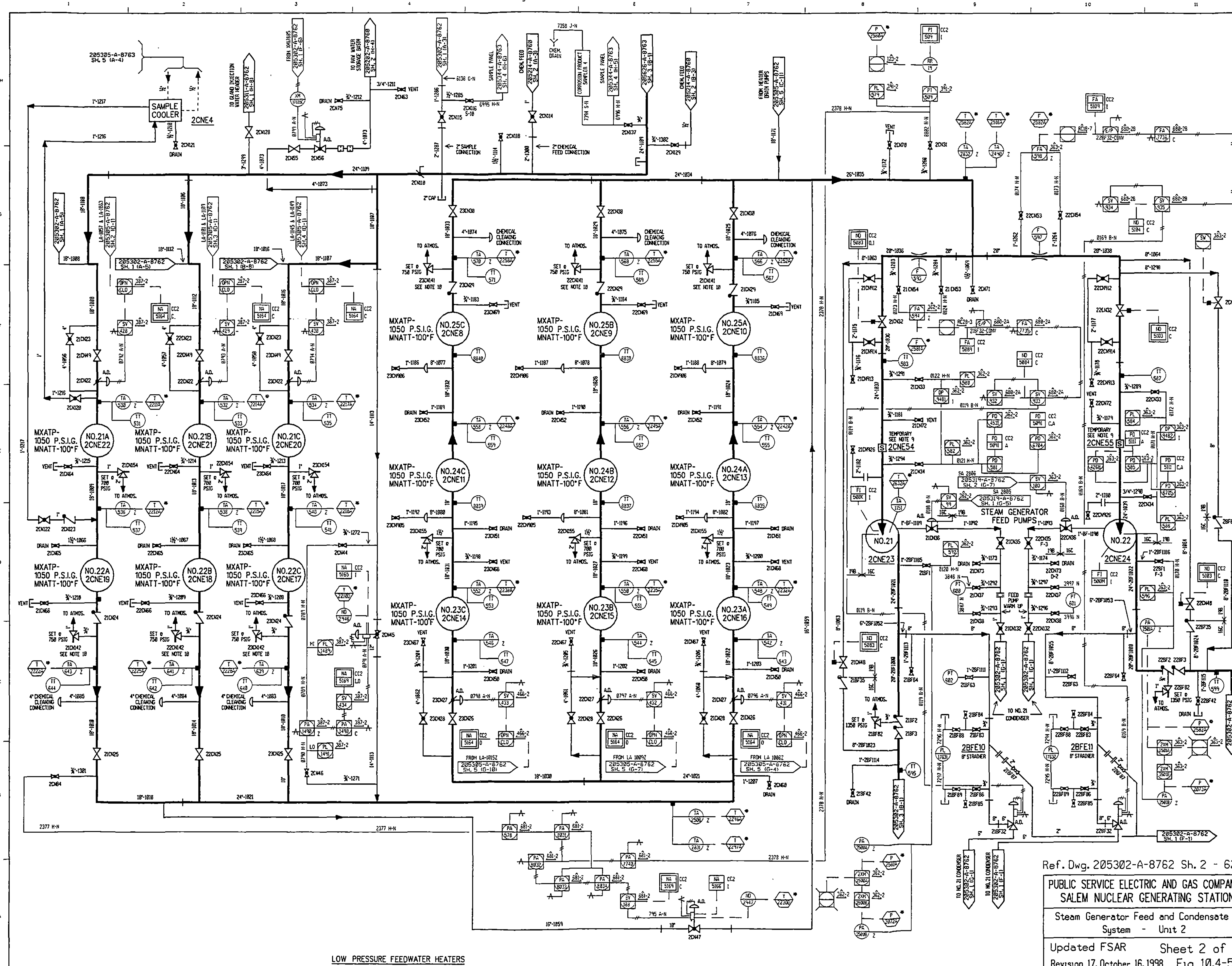
Ref. Dwg. 205302-A-8762 Sh. 1 - 59

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Steam Generator Feed and Condensate System - Unit 2

Updated FSAR
Revision 17, October 16, 1998

Sheet 1 of 3
Fig 10.4-5B



NOTE:
FOR VALVE MARK NO'S NOT SHOWN ON THIS SHEET, REFER TO M405.

Ref. Dwg. 205302-A-8762 Sh. 2 - 62

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

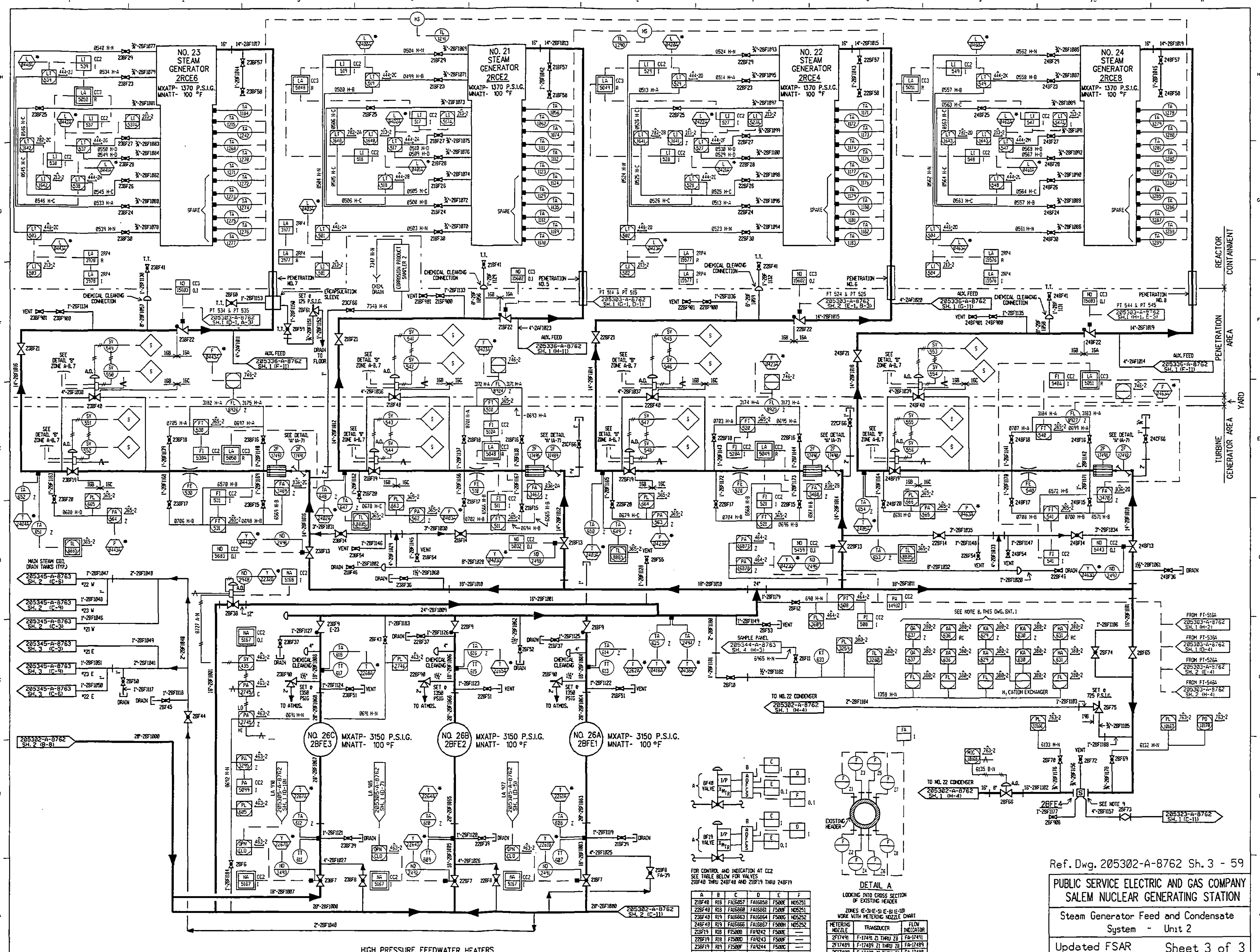
Steam Generator Feed and Condensate System - Unit 2

Updated FSAR

Sheet 2 of 3

Revision 17, October 16, 1998

Fig 10.4-5B



A	B	C	D	E	F
21BF40	R18	FA16857	FA16858	F500E	ND5251
22BF40	R18	FA16860	FA16861	F500F	ND5251
23BF40	R19	FA16863	FA16864	F500G	ND5252
24BF40	R19	FA16866	FA16867	F500H	ND5252
21BF19	R18	FI5008	FA9242	F500E	—
22BF19	R18	FI500D	FA9243	F500F	—
23BF19	R19	FI500F	FA9244	F500G	—
24BF19	R19	FI5001	FA9245	F500H	—

DETAIL B

DETAIL A

LOOKING INTO CROSS SECTION OF EXISTING HEADER

ZONES (E-3) (E-5) (E-8) (E-10) WORK WITH METERING NOZZLE CHART

METERING NOZZLE	TRANSDUCER	FLOW INDICATOR
2F17491	F-17491 Z1 THRU Z8	FA-17491
2F17489	F-17489 Z1 THRU Z8	FA-17489
2F17490	F-17490 Z1 THRU Z8	FA-17490
2F17492	F-17492 Z1 THRU Z8	FA-17492

NOTE:
FOR VALVE MARK NO'S NOT SHOWN ON THIS SHEET, REFER TO MMIS.

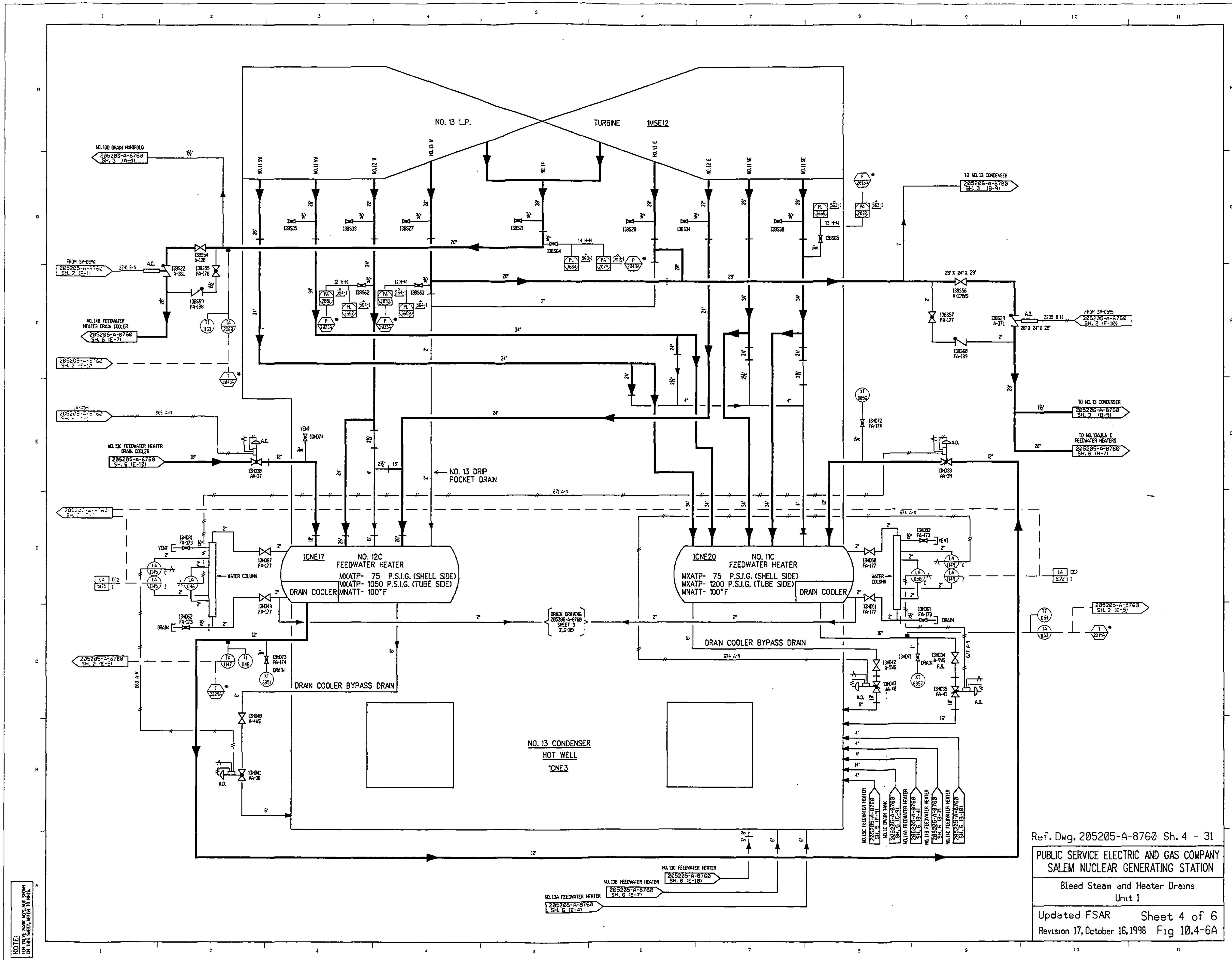
Ref. Dwg. 205302-A-8762 Sh. 3 - 59

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Steam Generator Feed and Condensate System - Unit 2

Updated FSAR — Sheet 3 of 3

Revision 17, October 16, 1998 — Fig 10.4-5B



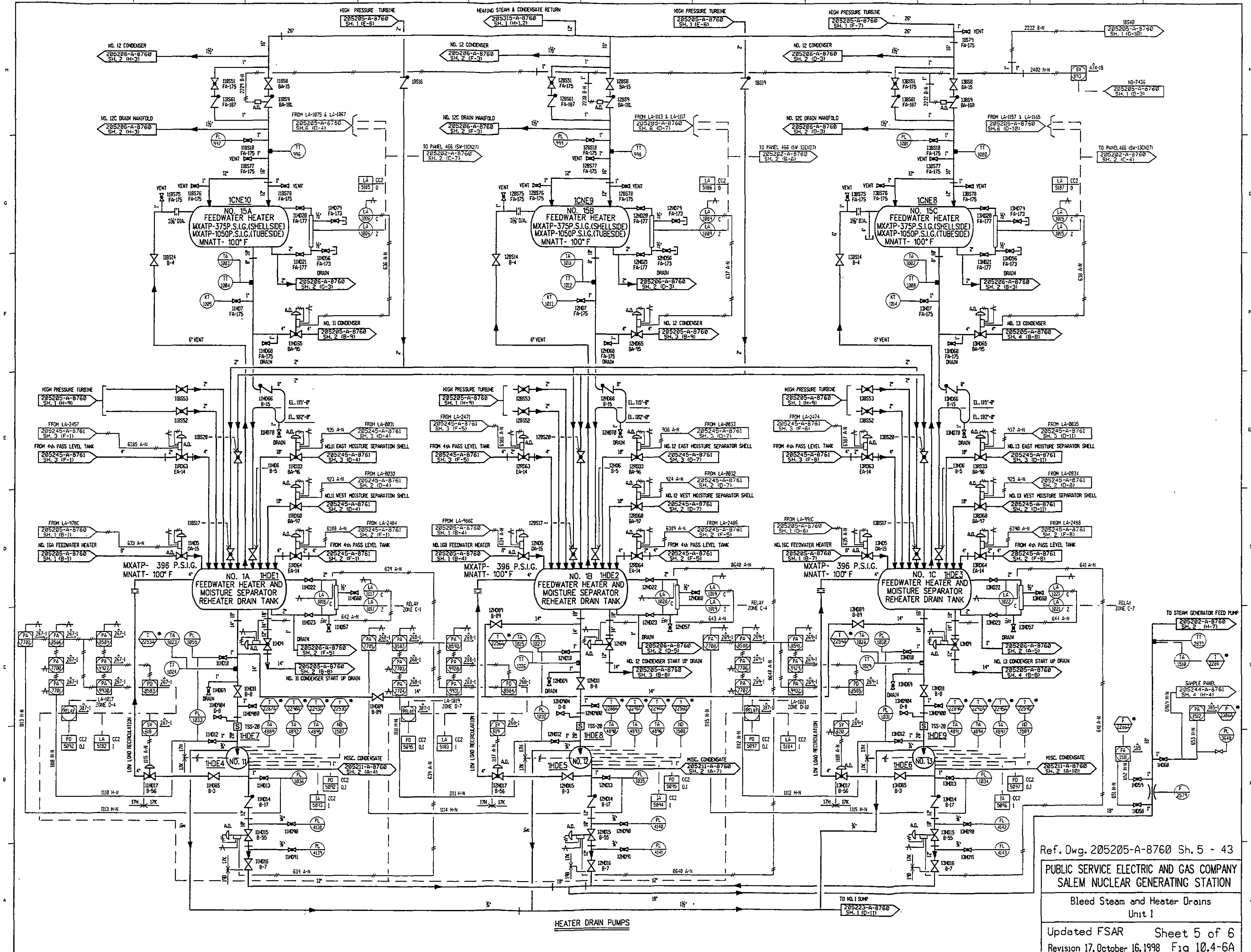
Ref. Dwg. 205205-A-8760 Sh. 4 - 31

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Bleed Steam and Heater Drains
Unit 1

Updated FSAR — Sheet 4 of 6

Revision 17, October 16, 1998 — Fig 10.4-6A



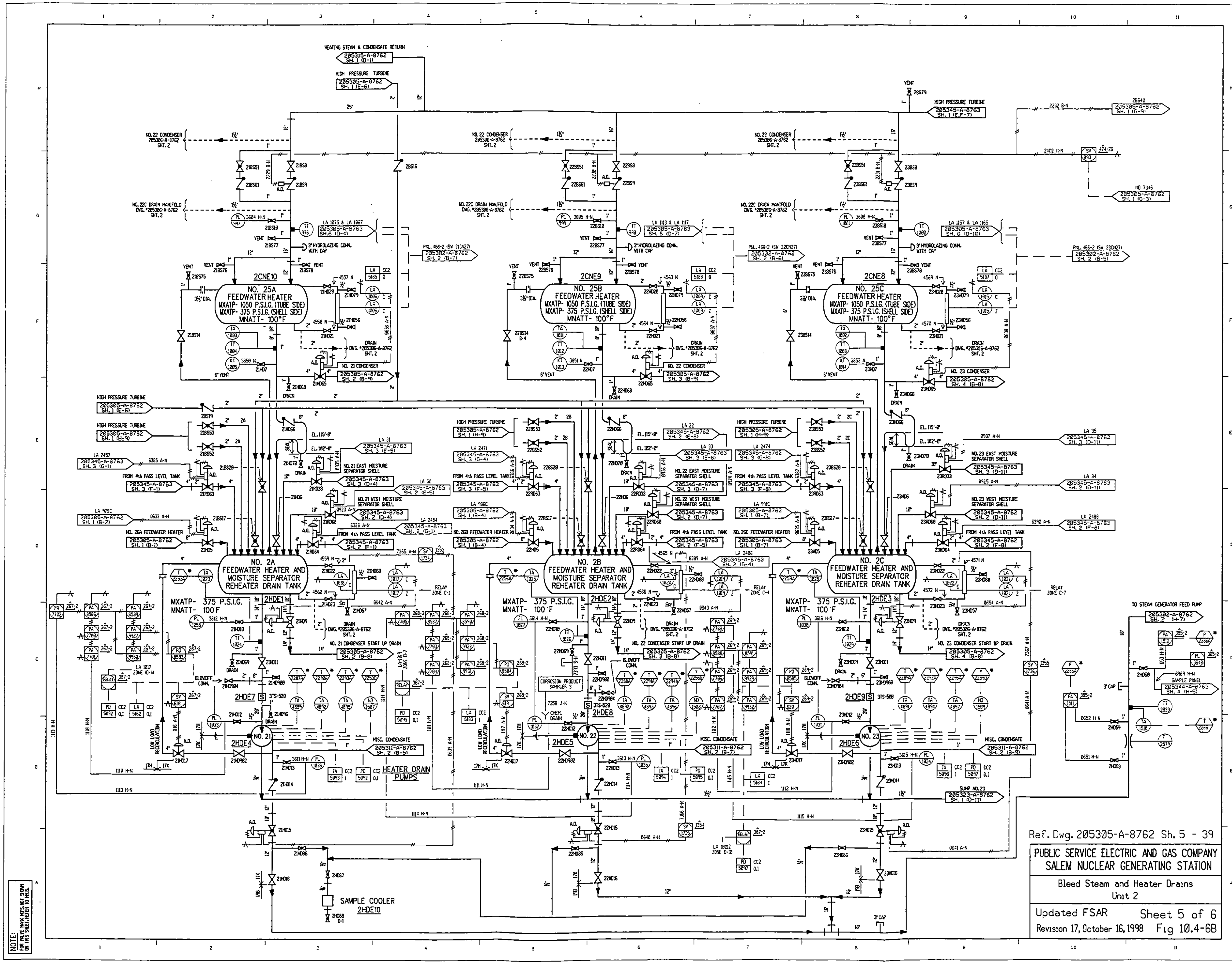
Ref. Dwg. 205205-A-8760 Sh. 5 - 43

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Bleed Steam and Heater Drains
Unit 1

Updated FSAR Sheet 5 of 6

Revision 17, October 16, 1998 Fig 10.4-6A

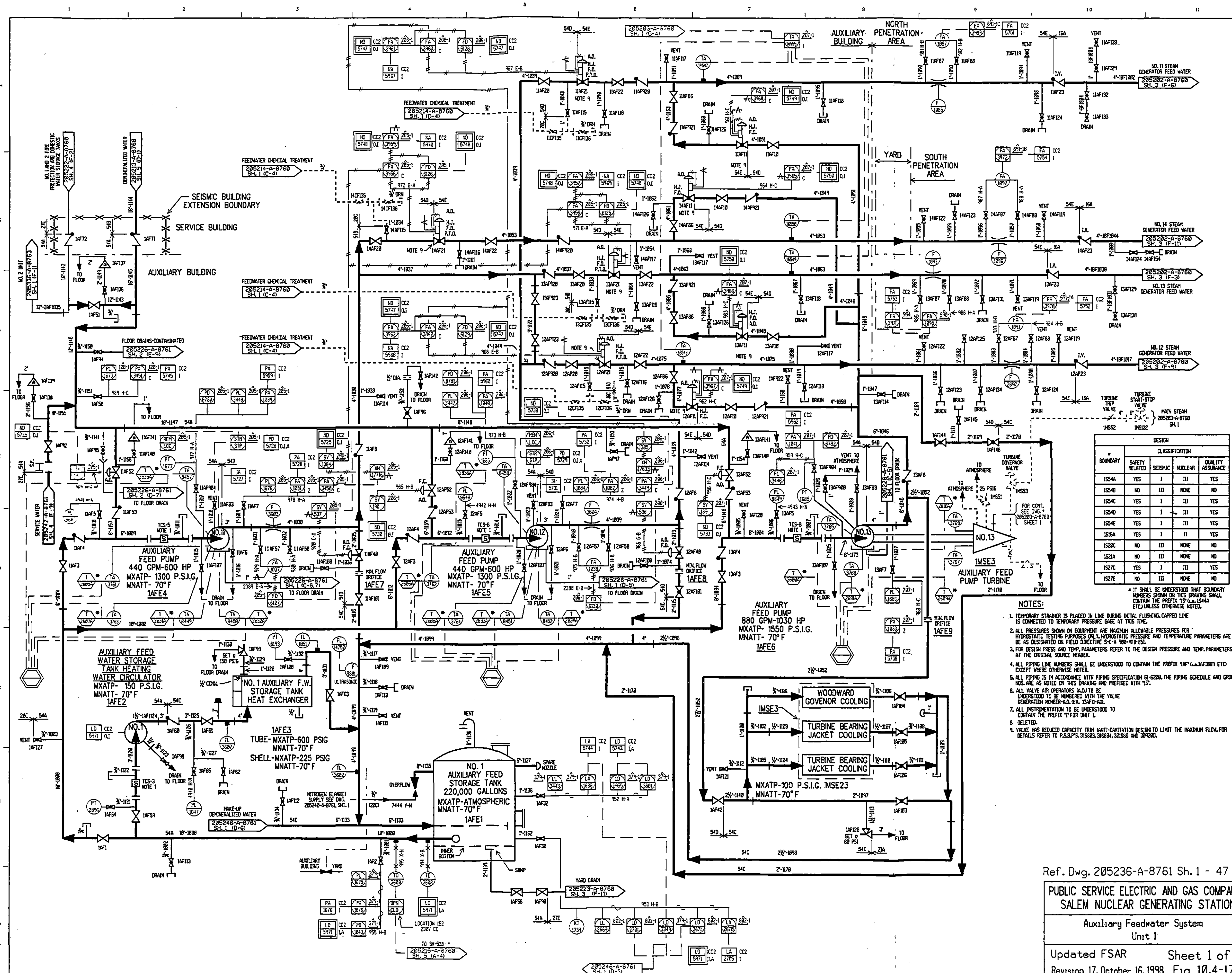


Ref. Dwg. 205305-A-8762 Sh. 5 - 39

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Bleed Steam and Heater Drains
Unit 2

Updated FSAR — Sheet 5 of 6
Revision 17, October 16, 1998 — Fig 10.4-6B



* BOUNDARY	DESIGN CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSURANCE
1S54A	YES	I	III	YES
1S54B	NO	III	NONE	NO
1S54C	YES	I	III	YES
1S54D	YES	I	III	YES
1S54E	YES	I	III	YES
1S16A	YES	I	II	YES
1S20C	NO	III	NONE	NO
1S21A	NO	III	NONE	NO
1S27C	YES	I	III	YES
1S27E	NO	III	NONE	NO

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (i.e. 1S44A ETC.) UNLESS OTHERWISE NOTED.

NOTES:

1. TEMPORARY STRAINER IS PLACED IN LINE DURING INITAL FLUSHING. CAPPED LINE IS CONNECTED TO TEMPORARY PRESSURE GAGE AT THIS TIME.
2. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A 900-MFD-051.
3. FOR DESIGN PRESS AND TEMP. PARAMETERS REFER TO THE DESIGN PRESSURE AND TEMP. PARAMETERS AT THE ORIGINAL SOURCE HEADER.
4. ALL PIPING LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1AF" (i.e. 1AF1889 ETC) EXCEPT WHERE OTHERWISE NOTED.
5. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6200. THE PIPING SCHEDULE AND GROUP NOS. ARE AS NOTED ON THIS DRAWING AND PREFIXED WITH "1S".
6. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 13AF11-AO).
7. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "1" FOR UNIT 1.
8. DELETED.
9. VALVE HAS REDUCED CAPACITY TRIM (ANTI-CAVITATION DESIGN) TO LIMIT THE MAXIMUM FLOW. FOR DETAILS REFER TO P.S.B.P'S. 316803, 316804, 301686 AND 309200.

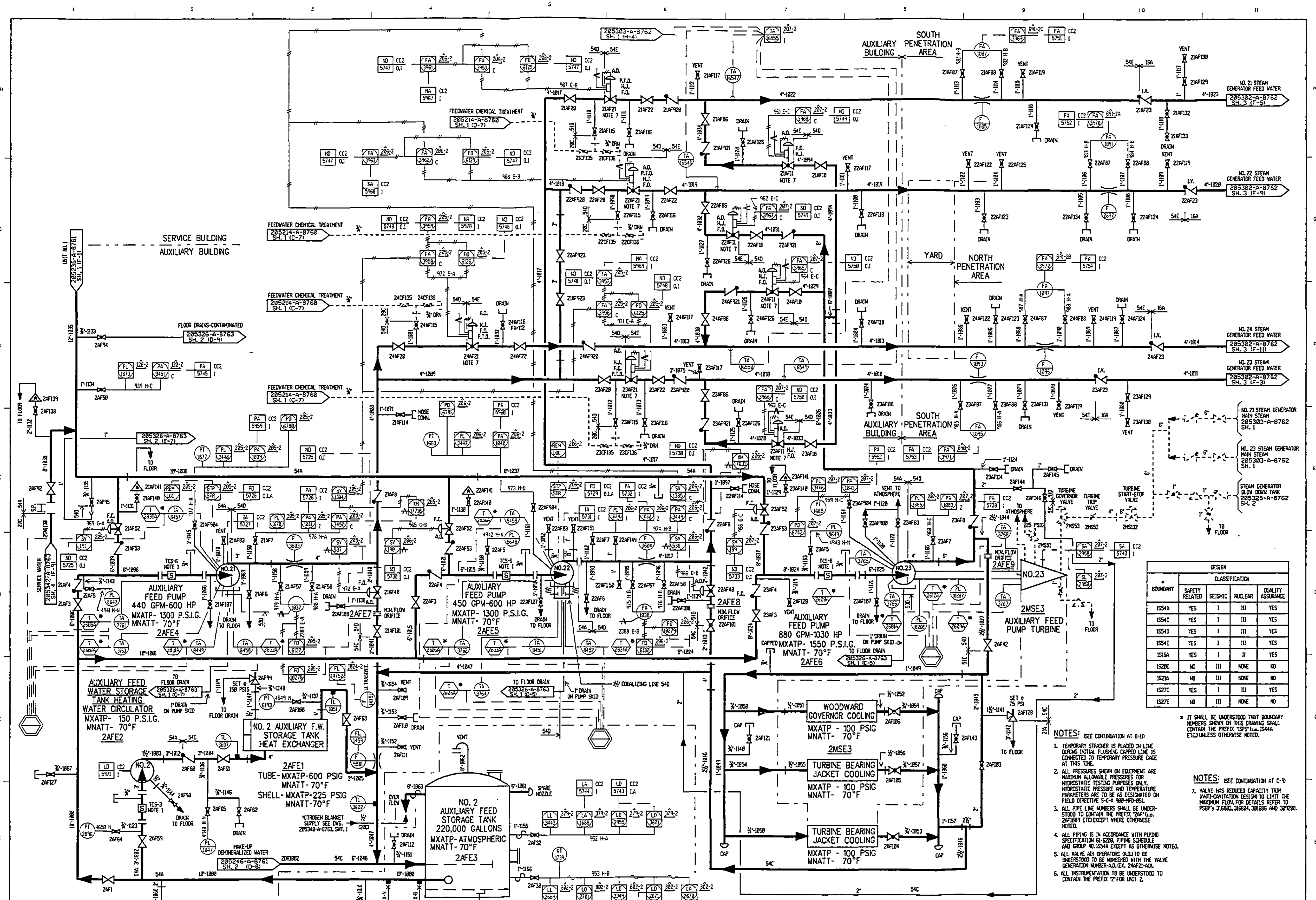
NOTE:
FOR VALVE MARK NO'S. NOT SHOWN ON THIS SHEET, REFER TO MMIS.

Ref. Dwg. 205236-A-8761 Sh. 1 - 47

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Auxiliary Feedwater System
Unit 1

Updated FSAR — Sheet 1 of 1
Revision 17, October 16, 1998 — Fig 10.4-17A



* BOUNDARY	DESIGN CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSURANCE
1S54A	YES	I	III	YES
1S54C	YES	I	III	YES
1S54D	YES	I	III	YES
1S54E	YES	I	III	YES
1S16A	YES	I	II	YES
1S20C	NO	III	NONE	NO
1S21A	NO	III	NONE	NO
1S27C	YES	I	III	YES
1S27E	NO	III	NONE	NO

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1SPS" (i.e. 1S44A ETC.) UNLESS OTHERWISE NOTED.

NOTES: (SEE CONTINUATION AT B-10)

1. TEMPORARY STRAINER IS PLACED IN LINE DURING INITIAL FLUSHING CAPPED LINE IS CONNECTED TO TEMPORARY PRESSURE GAGE AT THIS TIME.
2. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURE AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A 900-MFD-051.
3. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "2AF" (i.e. 2AF1009 ETC) EXCEPT WHERE OTHERWISE NOTED.
4. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6200, PIPING SCHEDULE AND GROUP NO. 1S54A EXCEPT AS OTHERWISE NOTED.
5. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 24AF21-AO).
6. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "2" FOR UNIT 2.

NOTES: (SEE CONTINUATION AT C-9)

7. VALVE HAS REDUCED CAPACITY TRIM (ANTI-CAVITATION DESIGN) TO LIMIT THE MAXIMUM FLOW. FOR DETAILS REFER TO PSBP's 316803, 316804, 301685 AND 309200.

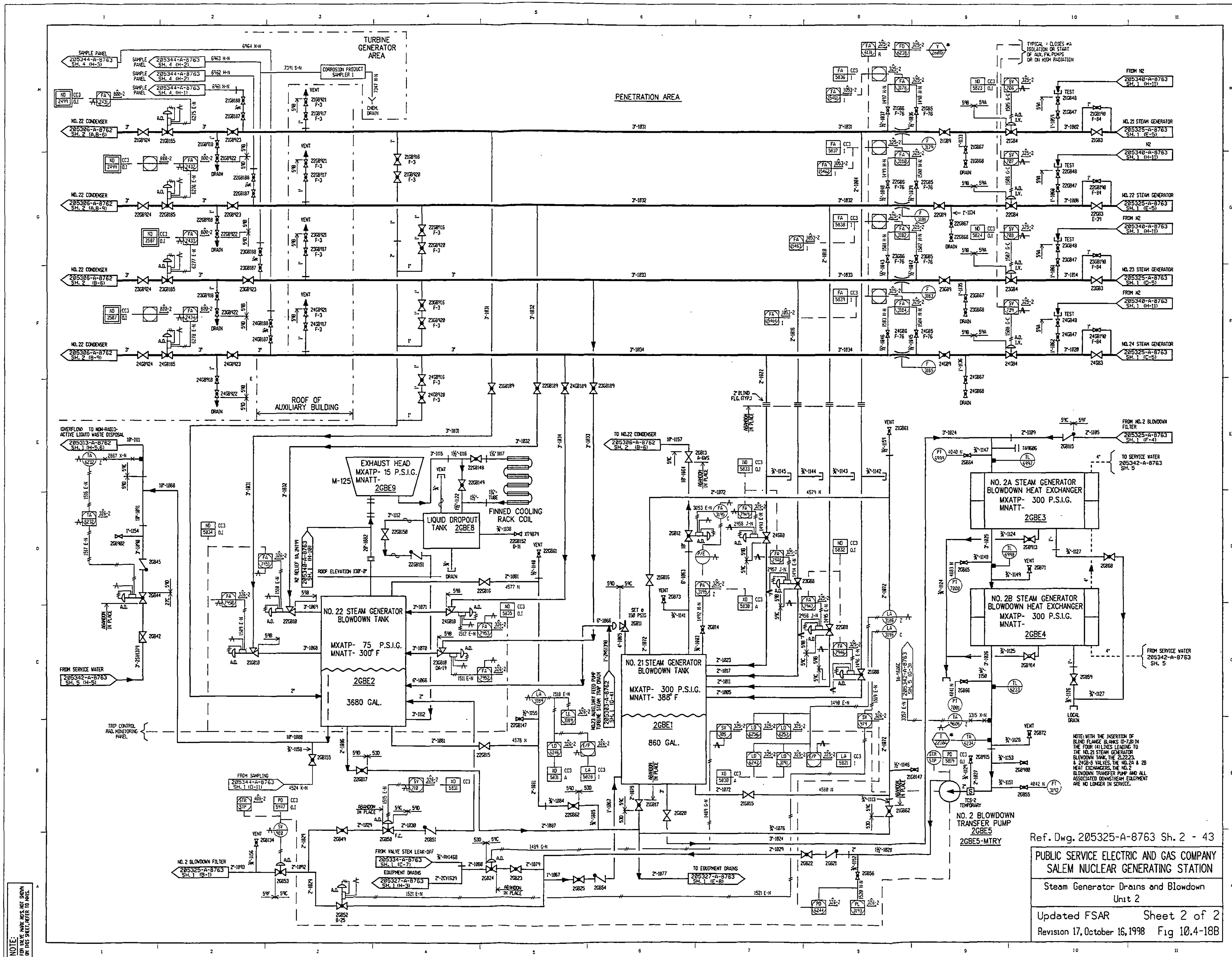
Ref. Dwg. 205336-A-8763 Sh. 1 - 43

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Auxiliary Feedwater System
Unit 2

Updated FSAR — Sheet 1 of 1
Revision 17, October 16, 1998 — Fig 10.4-17B

NOTE: FOR VALVE MARK NO'S. NOT SHOWN ON THIS SHEET, REFER TO MMIS.



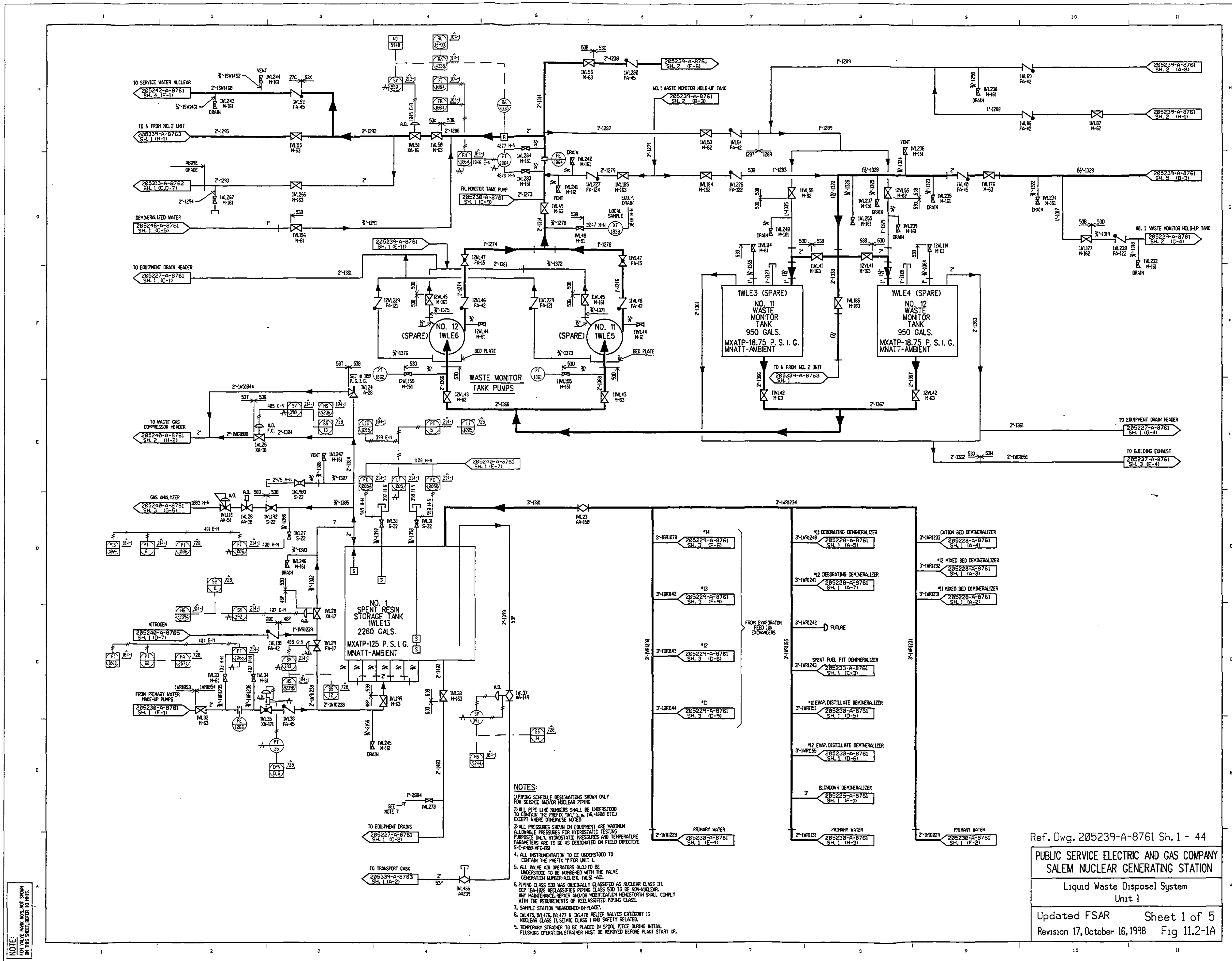
Ref. Dwg. 205325-A-8763 Sh. 2 - 43

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Steam Generator Drains and Blowdown
Unit 2

Updated FSAR — Sheet 2 of 2

Revision 17, October 16, 1998 — Fig 10.4-18B



NOTES:

1) PIPING SCHEDULE DESIGNATIONS SHOWN ONLY FOR SEISMIC AND/OR NUCLEAR PIPING

2) ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1WL" (i. e. 1WL-1000 ETC.) EXCEPT WHERE OTHERWISE NOTED

3) ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051

4. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "1" FOR UNIT 1.

5. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 1WL51 -AO).

6. PIPING CLASS 530 WAS ORIGINALLY CLASSIFED AS NUCLEAR CLASS III. DCP 1EA-1028 RECLASSIFIES PIPING CLASS 530 TO BE NON-NUCLEAR. ANY MAINTENANCE, REPAIR AND/OR MODIFICATION HENCEFORTH SHALL COMPLY WITH THE REQUIREMENTS OF RECLASSIFIED PIPING CLASS.

7. SAMPLE STATION "ABANDONED-IN-PLACE".

8. 1WL475, 1WL476, 1WL477 & 1WL478 RELIEF VALVES CATEGORY IS NUCLEAR CLASS II, SEIMIC CLASS I AND SAFETY RELATED.

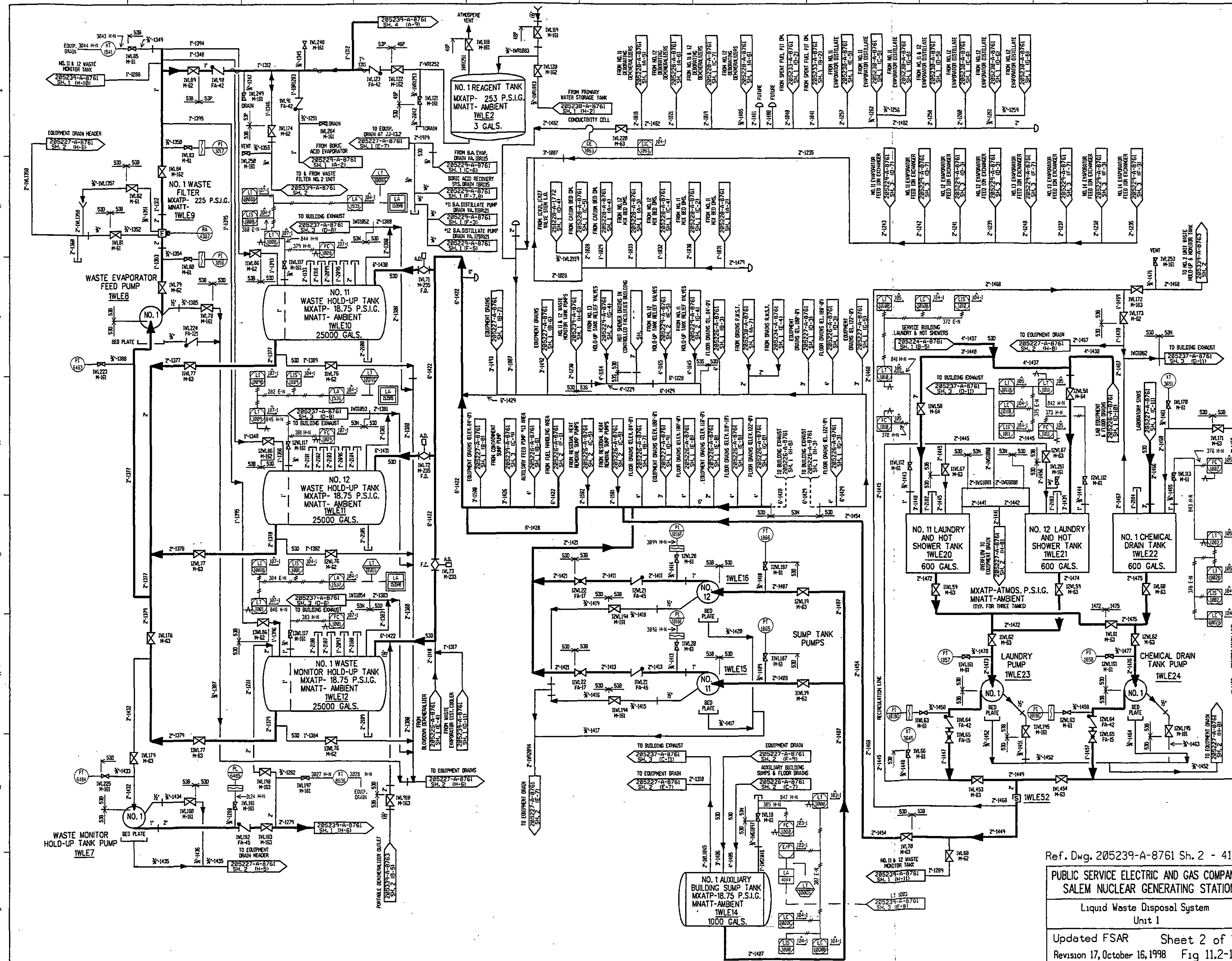
9. TEMPORARY STRAINER TO BE PLACED IN SPOOL PIECE DURING INITIAL FLUSHING OPERATION. STRAINER MUST BE REMOVED BEFORE PLANT START UP.

Ref. Dwg. 205239-A-8761 Sh. 1 - 44

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Liquid Waste Disposal System
Unit 1

Updated FSAR — Sheet 1 of 5
Revision 17, October 16, 1998 — Fig 11.2-1A



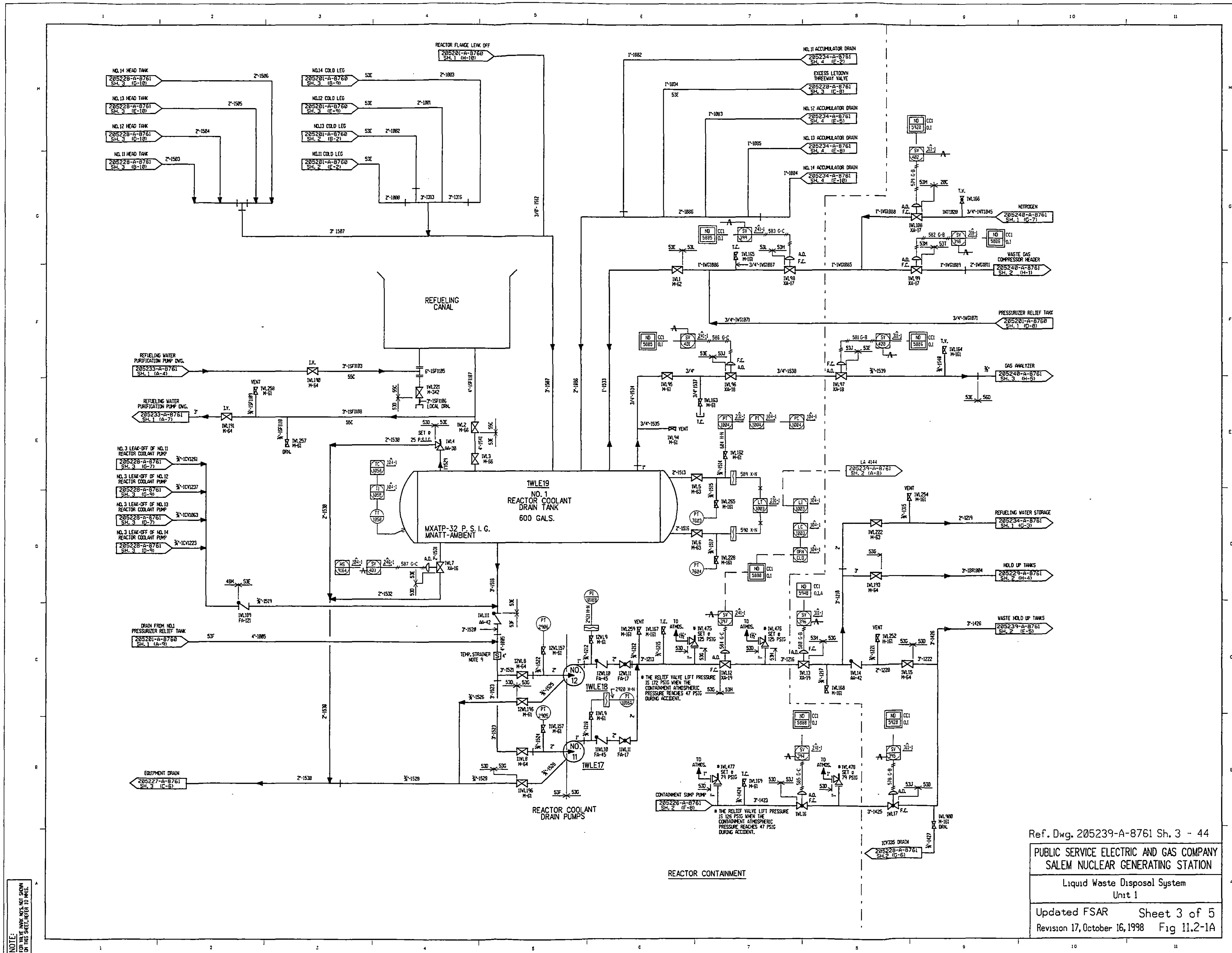
Ref. Dwg. 205239-A-8761 Sh. 2 - 41

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Liquid Waste Disposal System
Unit 1

Updated FSAR — Sheet 2 of 5

Revision 17, October 16, 1998 — Fig 11.2-1A



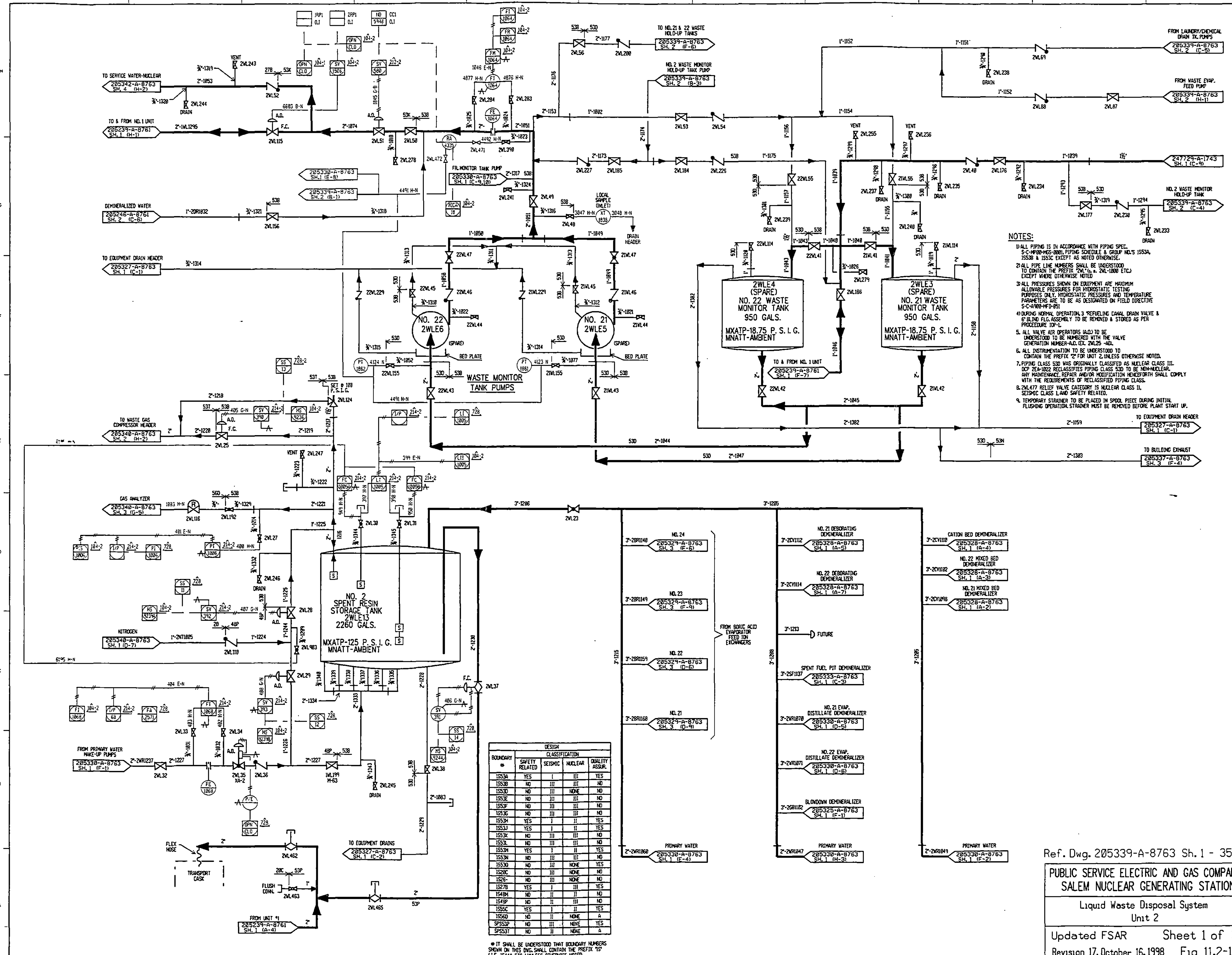
Ref. Dwg. 205239-A-8761 Sh. 3 - 44

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Liquid Waste Disposal System
Unit 1

Updated FSAR — Sheet 3 of 5

Revision 17, October 16, 1998 — Fig 11.2-1A



NOTES:

1) ALL PIPING IS IN ACCORDANCE WITH PIPING SPEC. S-C-MP00-MGS-0001, PIPING SCHEDULE & GROUP NO.'S 1553A, 1553B & 1553C EXCEPT AS NOTED OTHERWISE.

2) ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "2WL" (i. e. 2WL-1000 ETC.) EXCEPT WHERE OTHERWISE NOTED

3) ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051

4) DURING NORMAL OPERATION, 3" REFUELING CANAL DRAIN VALVE & 6" BLIND FLG. ASSEMBLY TO BE REMOVED & STORED AS PER PROCEEDURE IOP-1.

5. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 2WL25 -AO).

6. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "2" FOR UNIT 2, UNLESS OTHERWISE NOTED.

7. PIPING CLASS 530 WAS ORIGINALLY CLASSIFED AS NUCLEAR CLASS III. DCP 2EA-1022 RECLASSIFIES PIPING CLASS 530 TO BE NON-NUCLEAR. ANY MAINTENANCE, REPAIR AND/OR MODIFICATION HENCEFORTH SHALL COMPLY WITH THE REQUIREMENTS OF RECLASSIFIED PIPING CLASS.

8. 2WL477 RELIEF VALVE CATEGORY IS NUCLEAR CLASS II, SEISMIC CLASS I, AND SAFETY RELATED.

9. TEMPORARY STRAINER TO BE PLACED IN SPOOL PIECE DURING INITIAL FLUSHING OPERATION. STRAINER MUST BE REMOVED BEFORE PLANT START UP.

BOUNDARY *	DESIGN CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1553A	YES	I	III	YES
1553B	NO	III	III	NO
1553D	NO	III	NONE	NO
1553E	NO	III	III	NO
1553F	NO	III	III	NO
1553G	NO	III	III	NO
1553H	YES	I	II	YES
1553J	YES	I	II	YES
1553K	NO	III	III	NO
1553L	NO	III	III	NO
1553M	YES	I	II	YES
1553N	NO	III	III	NO
1553O	NO	III	NONE	YES
1520C	NO	III	NONE	NO
1526-	NO	III	NONE	NO
1527B	YES	I	III	YES
1548M	NO	II	II	NO
1548P	NO	II	III	NO
1555C	YES	I	II	YES
1556D	NO	II	NONE	A
SPS53P	NO	III	NONE	YES
SPS53T	NO	II	NONE	A

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DWG. SHALL CONTAIN THE PREFIX "1S" (I.E., 1S44A, ETC.) UNLESS OTHERWISE NOTED.

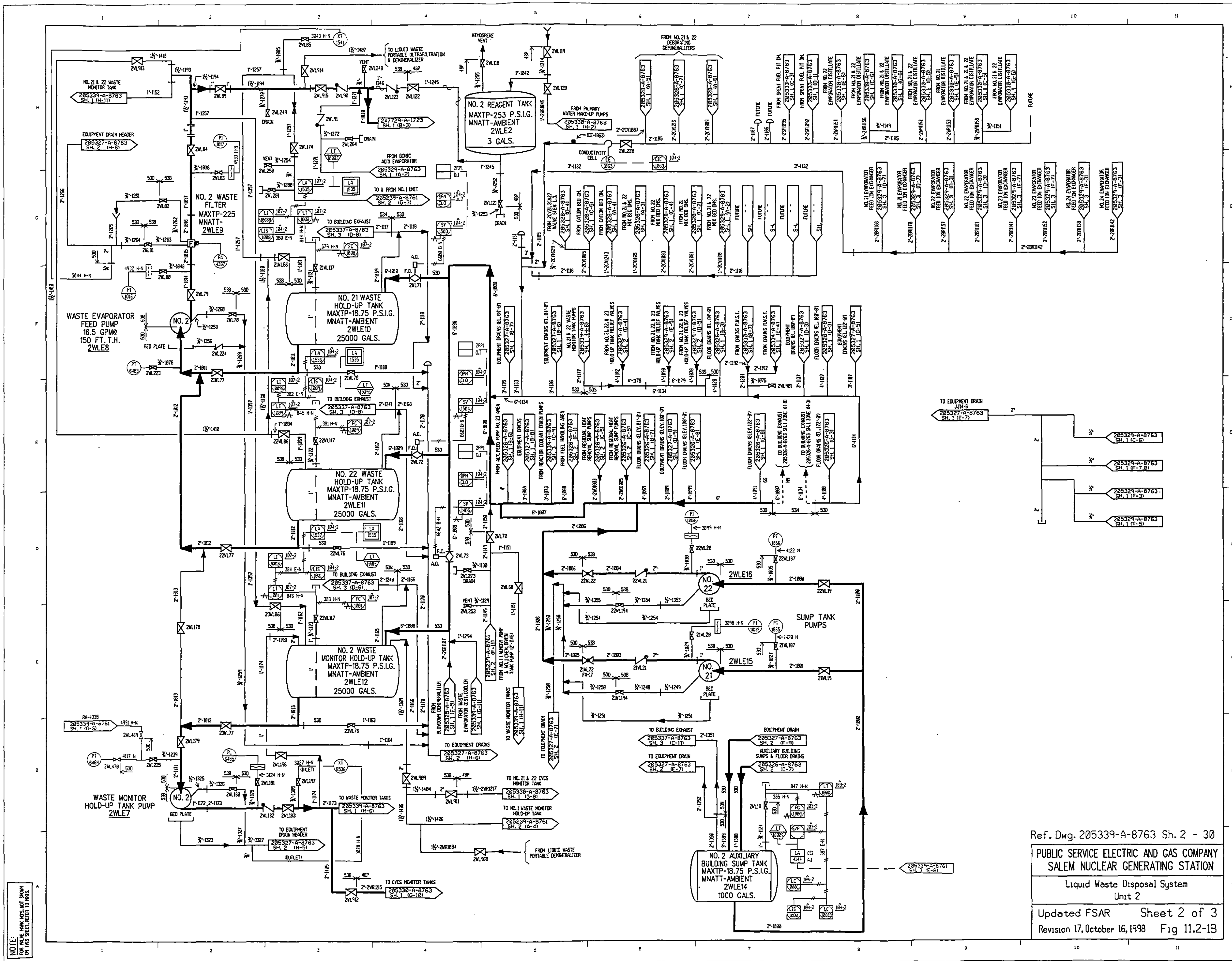
NOTE: FOR VALVE MARK NO'S NOT SHOWN ON THIS SHEET, REFER TO MMIS.

Ref. Dwg. 205339-A-8763 Sh. 1 - 35

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Liquid Waste Disposal System
Unit 2

Updated FSAR Sheet 1 of 3
Revision 17, October 16, 1998 Fig 11.2-1B



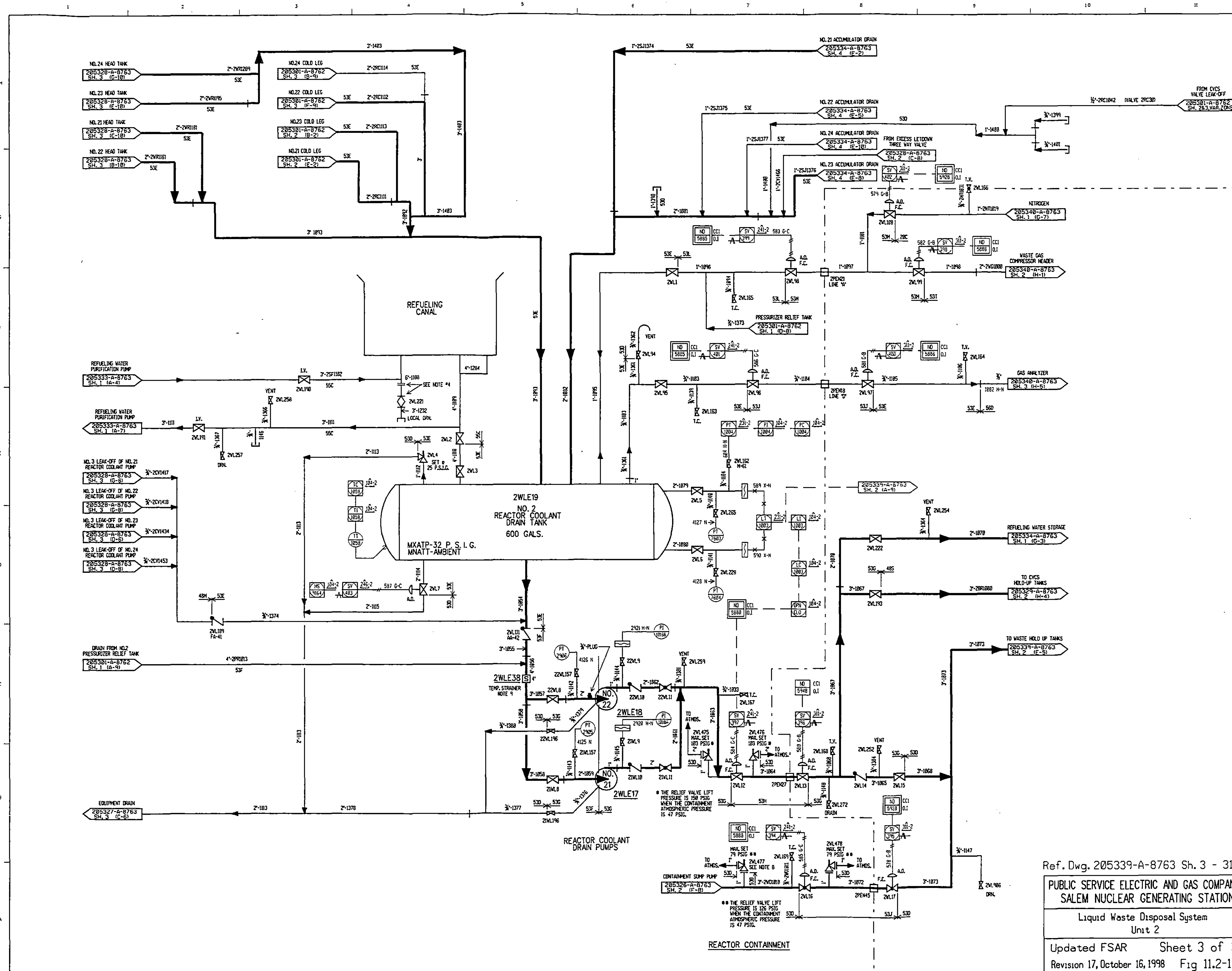
Ref. Dwg. 205339-A-8763 Sh. 2 - 30

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Liquid Waste Disposal System
Unit 2

Updated FSAR Sheet 2 of 3

Revision 17, October 16, 1998 Fig 11.2-1B

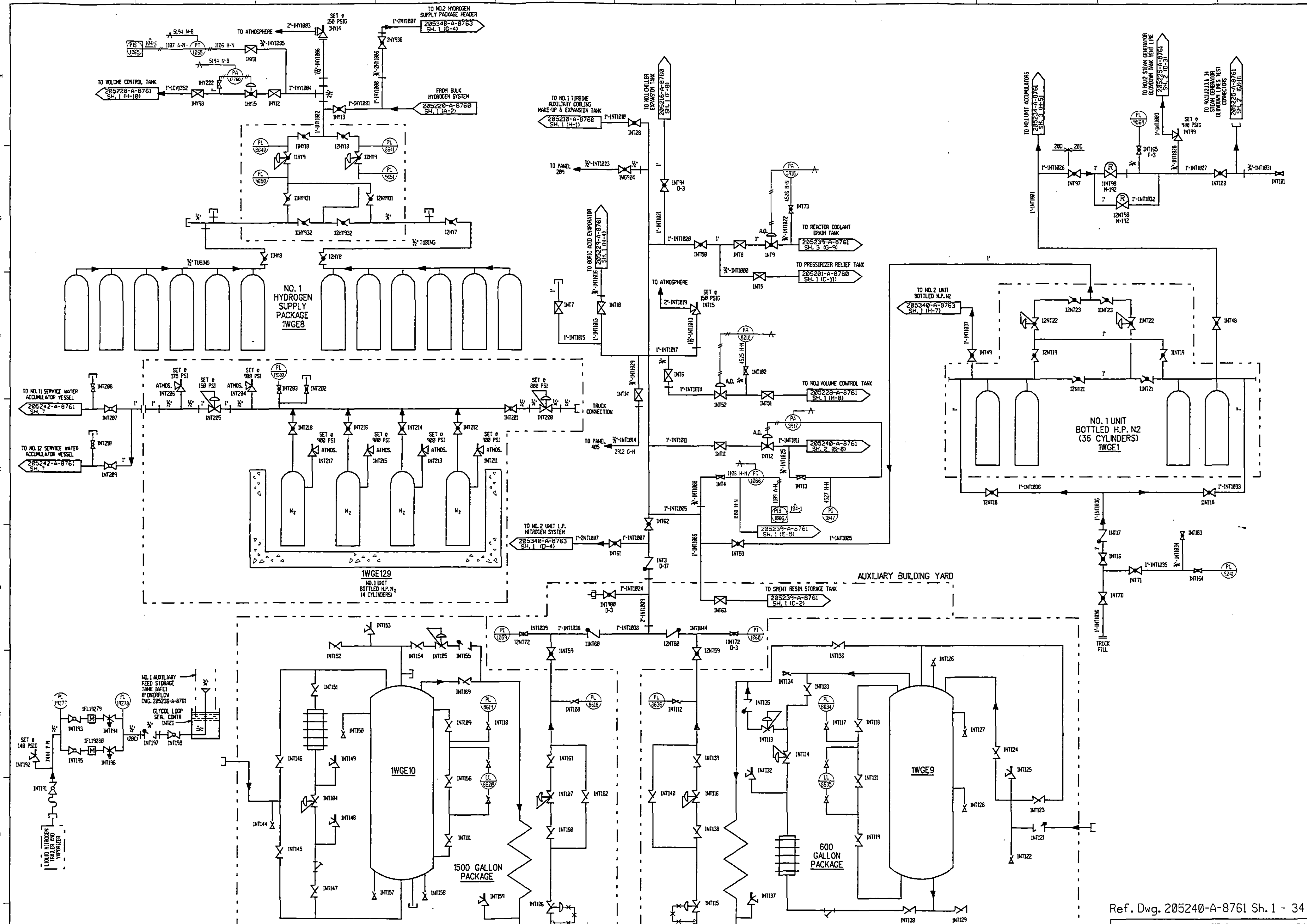


Ref. Dwg. 205339-A-8763 Sh. 3 - 31

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Liquid Waste Disposal System
Unit 2

Updated FSAR Sheet 3 of 3
Revision 17, October 16, 1998 Fig 11.2-1B



Ref. Dwg. 205240-A-8761 Sh. 1 - 34

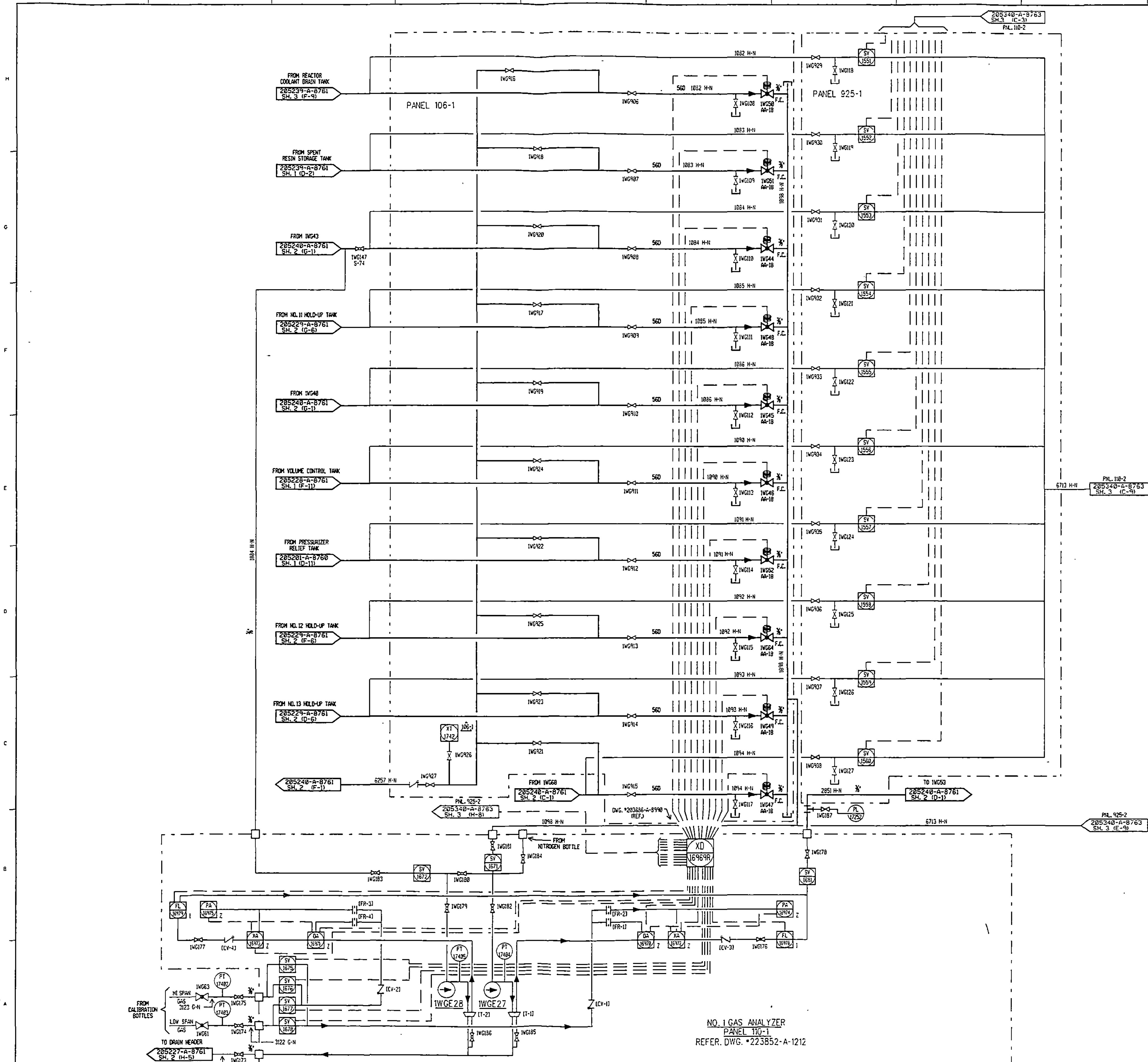
NOTES:

1. PIPING SCHEDULE DESIGNATIONS SHOWN ONLY FOR SEISMIC AND/OR NUCLEAR PIPING.
2. FOR DESIGN PRESSURE & TEMPURATURE PARAMETERS REFER TO THE DESIGN PRESSURE & TEMPERATURE PARAMETERS AT THE ORIGINAL SOURCE HEADER.
3. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051
4. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "1WG"(ie:1WG1000, etc.) EXCEPT WHERE OTHERWISE NOTED.
5. ALL PIPING IS IN ACCORDANCE WITH PIPING SPECIFICATION 61-6200. THE PIPING SCHEDULE AND GROUP NOS. ARE AS NOTED ON THIS DRAWING AND PREFIXED WITH "1S".
6. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 1NT12 -AO).
7. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "1" FOR UNIT 1.
8. PIPING CLASS 530 WAS ORIGINALLY CLASSIFED AS NUCLEAR CLASS III. DCP 1EA-1828 RECLASSIFIES PIPING CLASS 530 TO BE NON-NUCLEAR. ANY MAINTENANCE, REPAIR AND/OR MODIFICATION HENCEFORTH SHALL COMPLY WITH THE REQUIREMENTS OF RECLASSIFIED PIPING CLASS.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Gaseous Waste Disposal System
Unit 1

Updated FSAR — Sheet 1 of 3
Revision 17, October 16, 1998 — Fig 11.3-1A



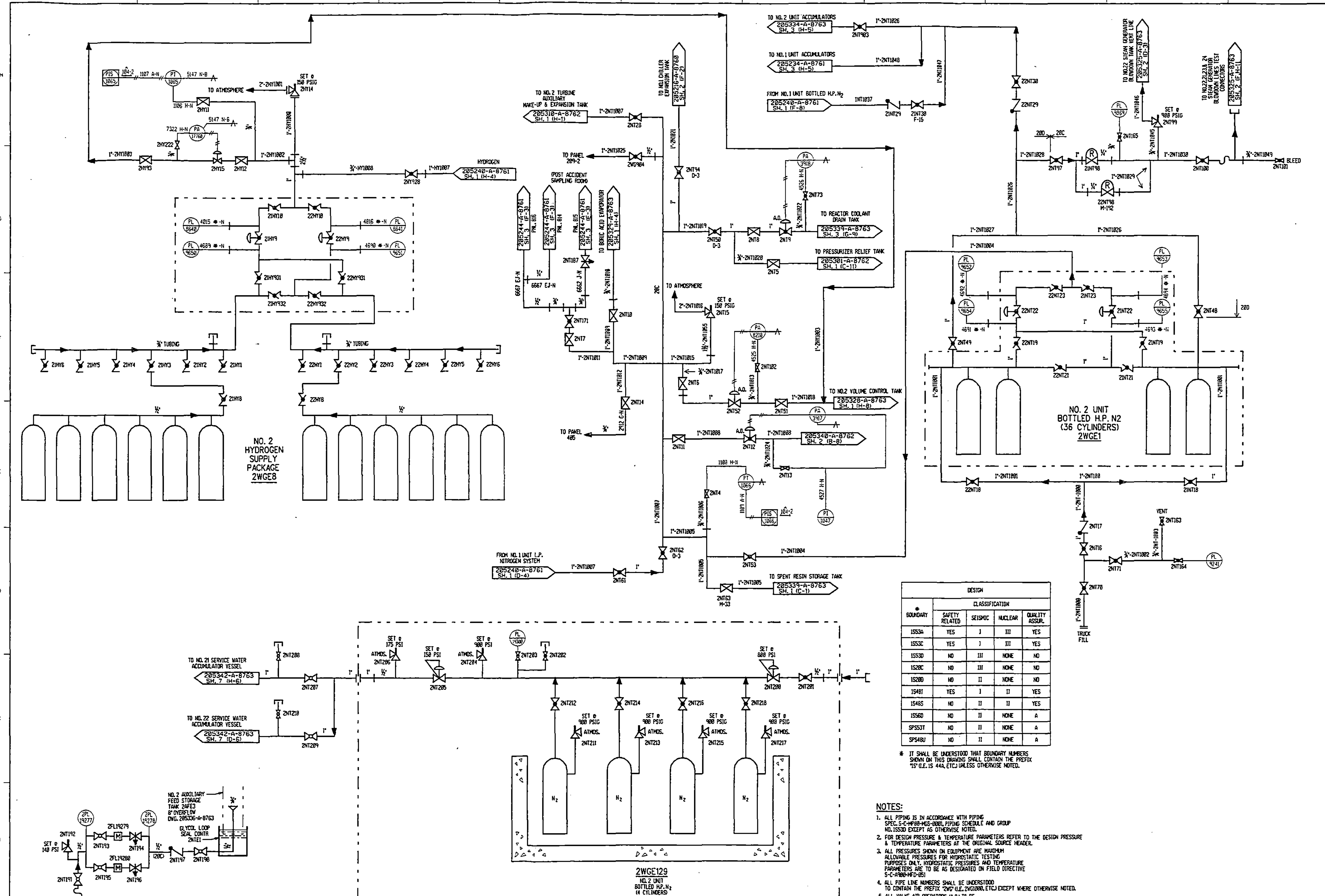
Ref. Dwg. 205240-A-8761 Sh. 3 - 29

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Gaseous Waste Disposal System
Unit 1

Updated FSAR — Sheet 3 of 3

Revision 17, October 16, 1998 — Fig 11.3-1A



DESIGN				
* BOUNDARY	CLASSIFICATION			
	SAFETY RELATED	SEISMIC	NUCLEAR	QUALITY ASSUR.
1S53A	YES	I	III	YES
1S53C	YES	I	III	YES
1S53D	NO	III	NONE	NO
1S20C	NO	III	NONE	NO
1S20D	NO	II	NONE	NO
1S48I	YES	I	II	YES
1S48S	NO	II	II	YES
1S56D	NO	II	NONE	A
SPS53T	NO	II	NONE	A
SPS48U	NO	II	NONE	A

* IT SHALL BE UNDERSTOOD THAT BOUNDARY NUMBERS SHOWN ON THIS DRAWING SHALL CONTAIN THE PREFIX "1S" (I.E. 1S 44A, ETC.) UNLESS OTHERWISE NOTED.

NOTES:

1. ALL PIPING IS IN ACCORDANCE WITH PIPING SPEC. S-C-MP00-MGS-0001, PIPING SCHEDULE AND GROUP NO. 1S53D EXCEPT AS OTHERWISE NOTED.
2. FOR DESIGN PRESSURE & TEMPERATURE PARAMETERS REFER TO THE DESIGN PRESSURE & TEMPERATURE PARAMETERS AT THE ORIGINAL SOURCE HEADER.
3. ALL PRESSURES SHOWN ON EQUIPMENT ARE MAXIMUM ALLOWABLE PRESSURES FOR HYDROSTATIC TESTING PURPOSES ONLY. HYDROSTATIC PRESSURES AND TEMPERATURE PARAMETERS ARE TO BE AS DESIGNATED ON FIELD DIRECTIVE S-C-A900-MFD-051
4. ALL PIPE LINE NUMBERS SHALL BE UNDERSTOOD TO CONTAIN THE PREFIX "2WG" (I.E. 2WG1000, ETC.) EXCEPT WHERE OTHERWISE NOTED.
5. ALL VALVE AIR OPERATORS (A.O.) TO BE UNDERSTOOD TO BE NUMBERED WITH THE VALVE GENERATION NUMBER-A.O. (EX. 2NT9 -AO).
6. ALL INSTRUMENTATION TO BE UNDERSTOOD TO CONTAIN THE PREFIX "2" FOR UNIT 2.
7. PIPING CLASS 530 WAS ORIGINALLY CLASSIFED AS NUCLEAR CLASS III. DCP 2EA-1022 RECLASSIFIES PIPING CLASS 530 TO BE NON-NUCLEAR. ANY MAINTENANCE, REPAIR AND/OR MODIFICATION HENCEFORTH SHALL COMPLY WITH THE REQUIREMENTS OF RECLASSIFIED PIPING CLASS.

Ref. Dwg. 205340-A-8763 Sh. 1 - 30

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM NUCLEAR GENERATING STATION

Gaseous Waste Disposal System
Unit 2

Updated FSAR — Sheet 1 of 3

Revision 17, October 16, 1998 — Fig 11.3-1B