Commonwealth Edison Company
Dresden Generating Station
6500 North Dresden Road
Morris, IL 60450
Tel 815-942-2920

ComEd

June 30, 1997

JSPLTR: # 97-0117

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

Subject: Dresden Nuclear Power Station Units 2 and 3
UFSAR Update Revision 2
NRC Docket Numbers 50-237 and 50-249

This letter transmits the Revision 2 update to the Dresden UFSAR, in accordance with 10 CFR 50.71(e). Revision 2 includes changes to the facility and its procedures through December 31, 1996.

The attached change log summarizes the changes and provides instructions for entering the revised pages. Revision 2 is submitted on a replacement page basis, please discard the replaced pages and insert the Revision 2 pages as directed in the attached instructions.

Pursuant to 10 CFR 50.4(b)(6), one (1) signed original and ten (10) copies are being provided to the Document Control Desk, plus one (1) copy to the NRC region III office and one (1) copy to the Dresden Senior Resident Inspector Office.

To the best of my knowledge and belief, the statements contained in the above are true and correct. In some respect these statements are not based on my personal knowledge, but obtained information furnished by other ComEd employees, contractor employees, and consultants. Such information has been reviewed in accordance with Company practice, and I believe it to be reliable.

Please address any questions or comments regarding this submittal to Mr. Frank Spangenberg, Regulatory Assurance Manager, at (815) 942-2920, extension 3800.

Sincerely,

J. Stephen Perry
Site Vice President
Dresden Station

A053

010001

1/11

Enclosure

cc: A. Bill Beach, Regional Administrator, Region III (W/ enclosure)
W. J. Kropp, Branch Chief, DRP, Region III (W/O enclosure
J. F. Stang, Project Manager, NRR (W/O enclosure)
Senior Resident Inspector, Dresden (W / enclosure)
Office of Nuclear Facility Safety - IDNS (W/ enclosure)

LIST OF EFFECTIVE PAGES
CURRENT THROUGH REVISION 2

This List of Effective Pages identifies those text pages, tables and figures that are currently effective in the FSAR.

Page/Table/Figure No.	Revision	Page/Table/Figure No.	Revision
1-i	2	T 1.2-1 Sheet 1	0
1-ii	2	T 1.2-1 Sheet 2	0
1-iii	0	T 1.2-1 Sheet 3	0
1-iv	0	T 1.2-1 Sheet 4	0
		T 1.2-1 Sheet 5	0
1.1-1	0	T 1.2-1 Sheet 6	0
1.1-2	0	T 1.2-1 Sheet 7	0
1.1-3	0		
		F 1.2-1	A
T 1.1-1 Sheet 1	0	F 1.2-2	H
T 1.1-1 Sheet 2	0	F 1.2-3	H
T 1.1-1 Sheet 3	2	F 1.2-4	Q
		F 1.2-5	H
1.2-1	0	F 1.2-6	H
1.2-2	0	F 1.2-7	D
1.2-3	2	F 1.2-8	C
1.2-3a	2	F 1.2-9	D
1.2-4	2	F 1.2-10	D
1.2-5	2	F 1.2-11	0
1.2-6	2	F 1.2-12	A
1.2-6a	2	F 1.2-13	B
1.2-7	0	F 1.2-14	C
1.2-8	0	F 1.2-15	C
1.2-9	0	F 1.2-16	B
1.2-10	2	F 1.2-17	B
1.2-11	0	F 1.2-18	A
1.2-12	0	F 1.2-19	C
1.2-13	2		
1.2-14	2	1.3-1	0
1.2-15	0		
1.2-16	0	1.4-1	0
1.2-17	01A		
1.2-18	0	1.5-1	0
1.2-19	01A		
1.2-20	0	1.6-1	0
1.2-20a	2		
1.2-21	2	1.7-1	0
1.2-21a	2		
1.2-22	2	F 1.7-1	H
1.2-23	0	F 1.7-2	R
1.2-24	0		
1.2-25	0	1.8-1	0

LIST OF EFFECTIVE PAGES
CURRENT THROUGH REVISION 2
(Continued)

LIST OF EFFECTIVE PAGES
CURRENT THROUGH REVISION 2
(Continued)

Page/Table/Figure No.	Revision	Page/Table/Figure No.	Revision
F 2.4-1	0	3.1-25	0
F 2.4-2	0	3.1-26	0
F 2.4-3	0	3.1-27	0
		3.1-28	0
2.5-1	0	3.1-29	0
2.5-2	0	3.1-30	0
2.5-3	0	3.1-31	0
2.5-4	0	3.1-32	0
		3.1-33	0
Appendix 2A	0	3.1-34	0
		3.1-35	0
3-i	0	3.1-36	0
3-ii	0	3.1-37	0
3-iii	2	3.1-38	0
3-iv	2	3.1-39	0
3-v	0	3.1-40	0
3-vi	2	3.1-41	0
3-vii	2	3.1-42	0
3-viii	2	3.1-43	2
3-ix	2	3.1-44	2
		3.1-45	0
3.1-1	01A	3.1-46	0
3.1-2	0	3.1-47	0
3.1-3	0	3.1-48	0
3.1-4	0	3.1-49	0
3.1-5	0	3.1-50	0
3.1-6	0	3.1-51	0
3.1-7	0	3.1-52	0
3.1-8	0	3.1-53	0
3.1-9	0	3.1-54	0
3.1-10	0	3.1-55	0
3.1-11	0	3.1-56	0
3.1-12	0	3.1-57	0
3.1-13	0	3.1-58	0
3.1-14	0	3.1-59	0
3.1-15	0	3.1-60	0
3.1-16	0	3.1-61	0
3.1-17	0	3.1-62	0
3.1-18	0	3.1-63	0
3.1-19	0	3.1-64	0
3.1-20	0	3.1-65	0
3.1-21	0	3.1-66	0
3.1-22	0	3.1-67	0
3.1-23	0	3.1-68	0
3.1-24	0	3.1-69	0

LIST OF EFFECTIVE PAGES
CURRENT THROUGH REVISION 2
(Continued)

Page/Table/Figure No.	Revision	Page/Table/Figure No.	Revision
3.2-1	0	3.5-13	0
3.2-2	0	3.5-14	0
3.2-3	0	3.5-15	0
3.2-4	0	3.5-16	0
3.2-5	0		
3.2-6	0	T 3.5-1 Sheet 1	0
3.2-7	2	T 3.5-1 Sheet 2	0
3.2-8	2	T 3.5-2	0
3.2-9	0	T 3.5-3	0
		T 3.5-4	0
3.3-1	0	T 3.5-5	0
3.3-2	0	T 3.5-6	0
3.3-3	0		
3.3-4	0	F 3.5-1	0
3.3-5	0	F 3.5-2	0
3.3-6	0		
3.3-7	0	3.6-1	0
3.3-8	01A	3.6-2	0
3.3-9	0	3.6-3	0
3.3-10	0	3.6-4	0
		3.6-5	0
F 3.3-1	0	3.6-6	0
F 3.3-2	0	3.6-7	0
		3.6-8	0
3.4-1	0	3.6-9	0
3.4-2	0	3.6-10	0
3.4-3	0	3.6-11	0
		3.6-12	0
3.4-4	0	3.6-13	0
3.4-5	0	3.6-14	0
3.4-6	0		
3.4-7	2	3.7-1	2
		3.7-2	2
3.5-1	0	3.7-3	01A
3.5-2	0	3.7-4	0
3.5-3	0	3.7-5	2
3.5-4	0	3.7-5a	2
3.5-5	0	3.7-6	2
3.5-6	0	3.7-7	0
3.5-7	0	3.7-8	0
3.5-8	0	3.7-9	0
3.5-9	2	3.7-10	0
3.5-10	0	3.7-11	0
3.5-11	0	3.7-12	0
3.5-12	0	3.7-13	0

LIST OF EFFECTIVE PAGES
CURRENT THROUGH REVISION 2
(Continued)

Page/Table/Figure No.	Revision	Page/Table/Figure No.	Revision
3.7-14	0	3.8-10	0
3.7-15	0	3.8-11	0
3.7-16	0	3.8-12	0
3.7-17	0	3.8-13	0
3.7-18	0	3.8-14	0
3.7-19	0	3.8-15	0
3.7-20	0	3.8-16	0
3.7-21	0	3.8-17	0
3.7-22	2	3.8-18	0
3.7-23	0	3.8-19	0
3.7-24	0	3.8-20	0
3.7-25	2	3.8-21	0
		3.8-22	2
T 3.7-1	2	3.8-23	0
T 3.7-2	0	3.8-24	0
T 3.7-3	0	3.8-25	0
T 3.7-4	0	3.8-26	0
T 3.7-5	0	3.8-27	0
T 3.7-6	0	3.8-28	0
		3.8-29	0
F 3.7-1	0	3.8-30	0
F 3.7-2	0		
F 3.7-3	0	T 3.8-1	2
F 3.7-4	0	T 3.8-2	01A
F 3.7-5	0	T 3.8-3	2
F 3.7-6	2	T 3.8-4 Sheet 1	0
F 3.7-7	0	T 3.8-4 Sheet 2	0
F 3.7-8	0	T 3.8-4 Sheet 3	01A
F 3.7-9	0	T 3.8-5 Sheet 1	0
F 3.7-10	0	T 3.8-5 Sheet 2	0
F 3.7-11	0	T 3.8-5 Sheet 3	0
F 3.7-12	0	T 3.8-6	0
F 3.7-13	0	T 3.8-7 Sheet 1	0
F 3.7-14	0	T 3.8-7 Sheet 2	0
		T 3.8-8	0
3.8-1	0	T 3.8-9 Sheet 1	0
3.8-2	2	T 3.8-9 Sheet 2	0
3.8-3	0	T 3.8-10 Sheet 1	0
3.8-4	0	T 3.8-10 Sheet 2	0
3.8-5	2	T 3.8-11	0
3.8-6	2	T 3.8-12	0
3.8-7	2		
3.8-7-a	2	F 3.8-1	0
3.8-8	2	F 3.8-2	0
3.8-9	0	F 3.8-3	0

LIST OF EFFECTIVE PAGES
CURRENT THROUGH REVISION 2
(Continued)

LIST OF EFFECTIVE PAGES
CURRENT THROUGH REVISION 2
(Continued)

Page/Table/Figure No.	Revision
3.9-37a	2
3.9-37b	2
3.9-38	2
3.9-39	2
3.9-40	0
3.9-41	0
3.9-42	2
3.9-43	2
T 3.9-1 Sheet 1	0
T 3.9-1 Sheet 2	0
T 3.9-2 Sheet 1	0
T 3.9-2 Sheet 2	0
T 3.9-2 Sheet 3	0
T 3.9-3	2
T 3.9-4	2
T 3.9-5 Sheet 1	0
T 3.9-5 Sheet 2	0
T 3.9-5 Sheet 3	0
T 3.9-6	0
T 3.9-7 Sheet 1	2
T 3.9-7 Sheet 2	2
T 3.9-8	0
T 3.9-9	2
T 3.9-10 Sheet 1	0
T 3.9-10 Sheet 2	0
T 3.9-11	0
T 3.9-12	0
T 3.9-13	0
T 3.9-14 Sheet 1	0
T 3.9-14 Sheet 2	0
T 3.9-15	0
T 3.9-16	0
T 3.9-17 Sheet 1	0
T 3.9-17 Sheet 2	0
T 3.9-18	2
T 3.9-19	2
T 3.9-20	2
T 3.9-21	2
F 3.9-1	0
F 3.9-2	0
F 3.9-3	0
F 3.9-4	0
F 3.9-5	0
F 3.9-6	0
F 3.9-7	0
F 3.9-8	0
F 3.9-9	0
F 3.9-10	0
F 3.9-11	2
F 3.9-12	2
3.10-1	0
3.10-2	0
3.10-3	2
3.10-4	2
3.11-1	0
3.11-2	0
3.11-3	2
3.11-4	0
3.11-5	2
3.11-6	0
3.11-7	0
3.11-8	0
3.11-9	2
3.11-10	0
3.11-11	0
T 3.11-1 Sheet 1	2
T 3.11-1 Sheet 2	2
T 3.11-2 Sheet 1	2
T 3.11-2 Sheet 2	2
T 3.11-2 Sheet 3	2
T 3.11-2 Sheet 4	2
T 3.11-2 Sheet 5	2
T 3.11-3 Sheet 1	2
T 3.11-3 Sheet 2	2
T 3.11-3 Sheet 3	2
F 3.11-1	6
F 3.11-2	6
F 3.11-3	6
F 3.11-4	6
F 3.11-5	6
Appendix 3A	0

LIST OF EFFECTIVE PAGES
CURRENT THROUGH REVISION 2
(Continued)

Page/Table/Figure No.	Revision	Page/Table/Figure No.	Revision
Appendix 3B	0	4.3-4	2
		4.3-4a	2
Appendix 3C	0	4.3-5	0
		4.3-6	0
4i	0	4.3-7	0
4ii	2	4.3-8	0
4iii	0	4.3-9	0
4iv	0	4.3-10	0
4v	0	4.3-11	2
		4.3-12	0
4.1-1	0	4.3-13	0
4.1-2	0	4.3-14	0
		4.3-15	0
T 4.1- Sheet 1	0	4.3-16	0
T 4.1- Sheet 2	0	4.3-17	0
T 4.1-2	2	4.3-18	0
T 4.1-3	2	4.3-19	0
		4.3-20	0
4.2-1	0	4.3-21	0
4.2-2	0	4.3-22	0
4.2-3	0	4.3-23	0
4.2-4	0	4.3-24	0
4.2-5	0	4.3-25	2
4.2-6	0	4.3-26	2
4.2-7	0		
4.2-8	0	T 4.3-1	0
4.2-9	0	T 4.3-2	0
4.2-10	0	T 4.3-3	0
4.2-11	0	T 4.3-4	0
4.2-12	2	T 4.3-5	0
4.2-12a	2	T 4.3-6	0
4.2-13	0		
4.2-14	0	F 4.3-1	0
4.2-15	0	F 4.3-2	0
		F 4.3-3	0
T 4.2-1	0	F 4.3-4	0
T 4.2-2	0	F 4.3-5	0
		F 4.3-6	0
F 4.2-1	0	F 4.3-7	0
F 4.2-2	0	F 4.3-8	0
F 4.2-3	0	F 4.3-9	0
		F 4.3-10	0
4.3-1	2	F 4.3-11	0
4.3-2	0	F 4.3-12	0
4.3-3	0	F 4.3-13	0

LIST OF EFFECTIVE PAGES
CURRENT THROUGH REVISION 2
(Continued)

LIST OF EFFECTIVE PAGES
CURRENT THROUGH REVISION 2
(Continued)

Page/Table/Figure No.	Revision	Page/Table/Figure No.	Revision
F 4.6-3	0	5.2-13	0
F 4.6-4	BE	5.2-14	2
F 4.6-5	F	5.2-14a	2
F 4.6-6	0	5.2-15	2
F 4.6-7	0	5.2-16	0
F 4.6-8	0	5.2-17	0
F 4.6-9	0	5.2-18	0
F 4.6-10	0	5.2-18a	2
F 4.6-11	0	5.2-19	2
F 4.6-12	0	5.2-20	2
F 4.6-13	0	5.2-21	2
F 4.6-14	0	5.2-22	2
		5.2-23	0
5i	2	5.2-24	2
5ii	2	5.2-25	0
5iii	2	5.2-26	0
5iv	0	5.2-27	0
5v	0		
5vi	0	T 5.2-1	0
5vii	0	T 5.2-2	2
		T 5.2-3 Sheet 1	0
5.1-1	0	T 5.2-3 Sheet 2	0
5.1-2	2	T 5.2-4	0
		T 5.2-5	0
T 5.1-1 Sheet 1	0	T 5.2-6 Sheet 1	0
T 5.1-1 Sheet 2	2	T 5.2-6 Sheet 2	0
T 5.1-1 Sheet 3	2	T 5.2-6 Sheet 3	0
T 5.1-2	0	T 5.2-7	0
T 5.1-3	2	T 5.2-8	0
F 5.1-1	0	F 5.2-1	0
		F 5.2-2	0
5.2-1	0	F 5.2-3	0
5.2-2	01A	F 5.2-4	0
5.2-2-a	01A	F 5.2-5	0
5.2-3	0	F 5.2-6	0
5.2-4	0	F 5.2-7	0
5.2-5	0	F 5.2-8	0
5.2-6	2	F 5.2-9	cp
5.2-7	2		
5.2-8	0	5.3-1	0
5.2-9	0	5.3-2	0
5.2-10	0	5.3-3	0
5.2-11	0	5.3-4	0
5.2-12	0	5.3-5	0

LIST OF EFFECTIVE PAGES
CURRENT THROUGH REVISION 2
(Continued)

Page/Table/Figure No.	Revision	Page/Table/Figure No.	Revision
5.3-6	0	5.4-26	2
5.3-7	0	5.4-27	2
5.3-8	0	5.4-28	01A
5.3-9	0	5.4-29	2
5.3-10	0	5.4-29a	2
5.3-11	0	5.4-30	2
5.3-12	2	5.4-31	01A
5.3-13	0	5.4-32	2
5.3-14	0	5.4-33	2
5.3-15	0	5.4-34	2
		5.4-34a	2
T 5.3-1	0	5.4-35	2
		5.4-36	01A
F 5.3-1	0	5.4-36a	2
F 5.3-2	0	5.4-37	2
F 5.3-3	0	5.4-38	2
		5.4-39	0
5.4-1	2	5.4-39a	2
5.4-2	2	5.4-40	2
5.4-3	0	5.4-41	0
5.4-4	2	5.4-42	0
5.4-5	2		
5.4-6	0	T 5.4-1	0
5.4-7	0	T 5.4-2	0
5.4-8	2		
5.4-9	0	F 5.4-1	BA
5.4-10	0	F 5.4-2	JF
5.4-11	0	F 5.4-3	BD
5.4-12	0	F 5.4-4	AS
5.4-13	0	F 5.4-5	2
5.4-14	0	F 5.4-6	0
5.4-15	0	F 5.4-7	0
5.4-16	0	F 5.4-8	0
5.4-17	0	F 5.4-9	0
5.4-18	0	F 5.4-10	0
5.4-18a	2	F 5.4-11	0
5.4-19	2	F 5.4-12	0
5.4-20	2	F 5.4-13	0
5.4-21	0	F 5.4-14	0
5.4-22	0	F 5.4-15	E
5.4-23	2	F 5.4-16	E
5.4-23a	2	F 5.4-17	0
5.4-24	0	F 5.4-18	LB
5.4-25	0	F 5.4-19	AU
5.4-25a	2	F 5.4-20	AR

LIST OF EFFECTIVE PAGES
CURRENT THROUGH REVISION 2
(Continued)

Page/Table/Figure No.	Revision	Page/Table/Figure No.	Revision
F 5.4-21	AL	T 6.1-1 Sheet 7	2
F 5.4-22	0		
F 5.4-23	ZL	6.2-1	0
F 5.4-24	AY	6.2-2	0
F 5.4-25	0	6.2-3	0
F 5.4-26	AD	6.2-4	01A
F 5.4-27	U	6.2-5	0
F 5.4-28	0	6.2-6	0
F 5.4-29	0	6.2-7	0
		6.2-8	0
Appendix 5A	0	6.2-9	0
		6.2-10	2
Appendix 5B	0	6.2-11	0
		6.2-12	0
Appendix 5C	0	6.2-13	0
		6.2-14	01A
6-i	2	6.2-15	0
6-ii	2	6.2-16	0
6-iii	0	6.2-17	01A
6-iv	2	6.2-18	0
6-v	2	6.2-19	2
6-vi	2	6.2-19a	2
6-vii	2	6.2-20	0
6-viii	2	6.2-21	0
6-ix	2	6.2-22	0
		6.2-23	0
6.0-1	0	6.2-24	0
6.0-2	0	6.2-24a	2
6.0-3	0	6.2-25	2
6.0-4	0	6.2-26	2
		6.2-27	2
6.1-1	0	6.2-28	2
6.1-2	2	6.2-28a	2
6.1-3	2	6.2-29	0
6.1-4	2	6.2-30	0
6.1-5	0	6.2-31	0
6.1-6	0	6.2-32	0
6.1-7	0	6.2-33	0
		6.2-34	0
T 6.1-1 Sheet 1	2	6.2-35	0
T 6.1-1 Sheet 2	2	6.2-36	0
T 6.1-1 Sheet 3	2	6.2-37	0
T 6.1-1 Sheet 4	2	6.2-38	0
T 6.1-1 Sheet 5	2	6.2-39	0
T 6.1-1 Sheet 6	2	6.2-40	0

LIST OF EFFECTIVE PAGES
CURRENT THROUGH REVISION 2
(Continued)

Page/Table/Figure No.	Revision	Page/Table/Figure No.	Revision
6.2-41	0	6.2-80	2
6.2-42	0	6.2-81	2
6.2-43	0	6.2-82	2
6.2-44	0	6.2-82a	2
6.2-45	0	6.2-83	2
6.2-46	0	6.2-84	2
6.2-47	0	6.2-85	2
6.2-48	2	6.2-85a	2
6.2-49	2	6.2-86	0
6.2-50	2	6.2-87	0
6.2-51	0	6.2-88	2
6.2-52	0	6.2-89	0
6.2-53	0	6.2-90	0
6.2-53a	2	6.2-91	2
6.2-54	2	6.2-92	0
6.2-55	0	6.2-92a	2
6.2-56	0	6.2-93	2
6.2-57	2	6.2-94	2
6.2-58	0	6.2-95	2
6.2-59	2	6.2-95a	2
6.2-60	2	6.2-96	2
6.2-60a	2	6.2-97	2
6.2-61	2	6.2-98	2
6.2-62	0	6.2-99	2
6.2-63	2	6.2-100	0
6.2-64	2	6.2-101	0
6.2-65	0	6.2-102	0
6.2-66	0	6.2-103	0
6.2-67	2	6.2-104	0
6.2-67a	2		
6.2-68	2	T 6.2-1 Sheet 1	0
6.2-69	2	T 6.2-1 Sheet 2	0
6.2-69a	2	T 6.2-1 Sheet 3	0
6.2-70	01A	T 6.2-2 Sheet 1	0
6.2-71	0	T 6.2-2 Sheet 2	0
6.2-72	0	T 6.2-3 Sheet 1	2
6.2-73	0	T 6.2-3 Sheet 2	2
6.2-74	01A	T 6.2-3a Sheet 1	2
6.2-74-a	01A	T 6.2-3b Sheet 1	2
6.2-75	0	T 6.2-4 Sheet 1	0
6.2-75a	2	T 6.2-4 Sheet 2	0
6.2-76	2	T 6.2-5	0
6.2-77	0	T 6.2-6 Sheet 1	2
6.2-78	2	T 6.2-7 Sheet 1	2
6.2-79	2	T 6.2-7 Sheet 2	0

LIST OF EFFECTIVE PAGES
CURRENT THROUGH REVISION 2
(Continued)

Page/Table/Figure No.	Revision	Page/Table/Figure No.	Revision
T 6.2-8	0	F 6.2-20B	2
T 6.2-9 Sheet 1	2	F 6.2-20C	2
T 6.2-9 Sheet 2	2	F 6.2-20D	2
T 6.2-9 Sheet 3	2	F 6.2-21	0
T 6.2-9 Sheet 4	2	F 6.2-22	0
T 6.2-9 Sheet 5	2	F 6.2-23	0
T 6.2-9 Sheet 6	2	F 6.2-24	0
T 6.2-9 Sheet 7	2	F 6.2-25	0
T 6.2-9 Sheet 8	2	F 6.2-26	0
T 6.2-9 Sheet 9	2	F 6.2-27	0
T 6.2-9 Sheet 10	2	F 6.2-28	0
T 6.2-9 Sheet 11	2	F 6.2-29	0
T 6.2-9 Sheet 12	2	F 6.2-30	0
T 6.2-9 Sheet 13	2	F 6.2-31	0
T 6.2-9 Sheet 14	2	F 6.2-32	0
T 6.2-9 Sheet 15	2	F 6.2-33	0
T 6.2-10 Sheet 1	2	F 6.2-34	0
T 6.2-10 Sheet 2	2	F 6.2-35	0
T 6.2-10 Sheet 3	2	F 6.2-36	0
T 6.2-11 Sheet 1	2	F 6.2-37	0
T 6.2-11 Sheet 2	2	F 6.2-38	0
T 6.2-11 Sheet 3	2	F 6.2-39	0
T 6.2-12	0	F 6.2-40	0
		F 6.2-41	0
F 6.2-1	0	F 6.2-42	0
F 6.2-2	0	F 6.2-43	0
F 6.2-3	0	F 6.2-44	0
F 6.2-4	0	F 6.2-45	0
F 6.2-5	0	F 6.2-46	0
F 6.2-6	0	F 6.2-47	0
F 6.2-7	0	F 6.2-48	AC
F 6.2-8	0	F 6.2-49	X
F 6.2-9	0	F 6.2-50	AH
F 6.2-10	0	F 6.2-51	AD
F 6.2-11	0	F 6.2-52	0
F 6.2-12	CP	F 6.2-53	0
F 6.2-13	BL	F 6.2-54	0
F 6.2-14	0	F 6.2-55	0
F 6.2-15	0	F 6.2-56	0
F 6.2-16	0	F 6.2-57	0
F 6.2-17	0	F 6.2-58	0
F 6.2-18	0	F 6.2-59	0
F 6.2-19A	2	F 6.2-60	0
F 6.2-19B	2		
F 6.2-20A	2	6.3-1	0

LIST OF EFFECTIVE PAGES
CURRENT THROUGH REVISION 2
(Continued)

Page/Table/Figure No.	Revision	Page/Table/Figure No.	Revision
6.3-2	0	6.3-44	0
6.3-3	2	6.3-45	0
6.3-4	2	6.3-46	0
6.3-5	0	6.3-47	2
6.3-6	0	6.3-48	2
6.3-7	2	6.3-48a	2
6.3-8	0	6.3-49	2
6.3-9	2	6.3-50	0
6.3-10	2	6.3-51	0
6.3-11	2	6.3-52	0
6.3-11a	2	6.3-53	0
6.3-12	0	6.3-54	0
6.3-13	2	6.3-55	2
6.3-14	2	6.3-55a	2
6.3-15	2	6.3-56	2
6.3-16	2	6.3-57	0
6.3-17	2	6.3-58	0
6.3-18	2	6.3-59	0
6.3-19	2	6.3-60	0
6.3-20	2	6.3-61	2
6.3-20a	2	6.3-61a	2
6.3-21	2	6.3-62	2
6.3-21a	2	6.3-63	0
6.3-22	2	6.3-64	0
6.3-23	0	6.3-65	0
6.3-24	0	6.3-66	0
6.3-25	2	6.3-67	0
6.3-26	2	6.3-68	0
6.3-27	2	6.3-69	0
6.3-28	0	6.3-70	0
6.3-29	0	6.3-71	2
6.3-30	0	6.3-72	2
6.3-31	0	6.3-73	2
6.3-32	0	6.3-74	2
6.3-33	0	6.3-75	2
6.3-34	0	6.3-76	2
6.3-35	0	6.3-77	2
6.3-36	2	6.3-78	2
6.3-37	0	6.3-79	2
6.3-38	0	6.3-80	0
6.3-39	0	6.3-81	2
6.3-40	0	6.3-82	0
6.3-41	0	6.3-83	2
6.3-42	0	6.3-84	0
6.3-43	0	6.3-85	0

LIST OF EFFECTIVE PAGES
CURRENT THROUGH REVISION 2
(Continued)

Page/Table/Figure No.	Revision	Page/Table/Figure No.	Revision
6.3-86	0	F 6.3-17	0
6.3-87	2	F 6.3-18	0
		F 6.3-19	0
T 6.3-1	2	F 6.3-20	0
T 6.3-2	0	F 6.3-21	0
T 6.3-3 Sheet 1	0	F 6.3-22	0
T 6.3-3 Sheet 2	0	F 6.3-23	0
T 6.3-4	2	F 6.3-24	0
T 6.3-5 Sheet 1	0	F 6.3-25	0
T 6.3-5 Sheet 2	0	F 6.3-26	0
T 6.3-6	0	F 6.3-27	0
T 6.3-7 Sheet 1	0	F 6.3-28	0
T 6.3-7 Sheet 2	0	F 6.3-29	0
T 6.3-8	0	F 6.3-30	0
T 6.3-9	0	F 6.3-31	0
T 6.3-10	0	F 6.3-32	0
T 6.3-11	0	F 6.3-33	0
T 6.3-12	2	F 6.3-34	0
T 6.3-13	2	F 6.3-35	0
T 6.3-14	2	F 6.3-36	0
T 6.3-15	2	F 6.3-37	0
T 6.3-16	2	F 6.3-38	0
T 6.3-17	2	F 6.3-39	0
T 6.3-18	2	F 6.3-40	0
T 6.3-19	2	F 6.3-41	0
		F 6.3-42	0
F 6.3-1	0	F 6.3-43	0
F 6.3-2A	YT	F 6.3-44	0
F 6.3-2B	BQ	F 6.3-45	0
F 6.3-3	0	F 6.3-46	0
F 6.3-4	0	F 6.3-47	0
F 6.3-5	0	F 6.3-48	0
F 6.3-6	0	F 6.3-49	0
F 6.3-7A	BQ	F 6.3-50	0
F 6.3-7B	UX	F 6.3-51	0
F 6.3-8	0	F 6.3-52	0
F 6.3-9A	BF	F 6.3-53	0
F 6.3-9B	BP	F 6.3-54	0
F 6.3-10	0	F 6.3-55	0
F 6.3-11	0	F 6.3-56	0
F 6.3-12	0	F 6.3-57	0
F 6.3-13	0	F 6.3-58	0
F 6.3-14	0	F 6.3-59	0
F 6.3-15	0	F 6.3-60	0
F 6.3-16	0	F 6.3-61	0

LIST OF EFFECTIVE PAGES
CURRENT THROUGH REVISION 2
(Continued)

Page/Table/Figure No.	Revision	Page/Table/Figure No.	Revision
F 6.3-62	0	6.5-4	0
F 6.3-63	0	6.5-5	2
F 6.3-64	0		
F 6.3-65	0	T 6.5-1	01A
F 6.3-66	0		
F 6.3-67	0	F 6.5-1	QG
F 6.3-68	0	F 6.5-2	01A
F 6.3-69	0	F 6.5-3	01A
F 6.3-70	0		
F 6.3-71	0	6.6-1	0
F 6.3-72	0	6.6-2	0
F 6.3-73	0	6.6-3	0
F 6.3-74	0		
F 6.3-75	0	7i	0
F 6.3-76	0	7ii	2
F 6.3-77	2	7iii	2
F 6.3-78	2	7iv	0
F 6.3-79	0	7v	0
F 6.3-80	2	7vi	2
F 6.3-81	0	7vii	0
F 6.3-82	0		
F 6.3-83	2	7.1-1	0
F 6.3-84	2	7.1-2	0
		7.1-3	0
6.4-1	0	7.1-4	0
6.4-2	2		
6.4-3	2	7.2-1	0
6.4-4	01A	7.2-2	0
6.4-5	01A	7.2-3	0
6.4-6	2	7.2-4	0
6.4-7	0	7.2-5	0
6.4-8	0	7.2-6	0
6.4-9	0	7.2-7	0
6.4-10	2	7.2-7a	2
6.4-11	0	7.2-8	2
		7.2-9	2
T 6.4-1	0	7.2-9a	2
		7.2-10	2
F 6.4-1	0	7.2-11	0
F 6.4-2	0	7.2-12	0
F 6.4-3	0	7.2-13	0
		7.2-14	0
6.5-1	2	7.2-15	0
6.5-2	2	7.2-16	0
6.5-3	2	7.2-17	0

LIST OF EFFECTIVE PAGES
CURRENT THROUGH REVISION 2
(Continued)

Page/Table/Figure No.	Revision	Page/Table/Figure No.	Revision
7.2-18	0	7.3-28	0
7.2-19	0	7.3-29	0
7.2-20	0	7.3-30	0
7.2-21	0	7.3-31	0
7.2-22	0	7.3-32	2
7.2-23	0	7.3-33	0
7.2-24	0	7.3-33a	2
7.2-25	0	7.3-34	2
7.2-26	0	7.3-35	0
7.2-27	0	7.3-36	0
		7.3-37	0
T 7.2-1	2	7.3-38	2
		7.3-39	0
F 7.2-1	0	7.3-40	2
F 7.2-2	0	7.3-41	2
F 7.2-3	0	7.3-42	0
F 7.2-4	0	7.3-43	2
		7.3-44	2
7.3-1	0	7.3-45	0
7.3-2	2	7.3-46	0
7.3-3	0	7.3-47	2
7.3-4	2	7.3-48	0
7.3-5	2	7.3-48a	2
7.3-6	2	7.3-49	2
7.3-7	2	7.3-50	0
7.3-8	0		
7.3-9	2	T 7.3-1	2
7.3-10	2		
7.3-11	0	F 7.3-1	2
7.3-12	0	F 7.3-2A	2
7.3-13	0	F 7.3-2B	0
7.3-14	0	F 7.3-3	0
7.3-15	0	F 7.3-4	0
7.3-16	2	F 7.3-5	0
7.3-17	2	F 7.3-6	0
7.3-18	2	F 7.3-7	0
7.3-19	2	F 7.3-8A	2
7.3-20	2	F 7.3-8B	0
7.3-21	0	F 7.3-8C	0
7.3-22	2	F 7.3-9	2
7.3-23	0	F 7.3-10	2
7.3-24	0	F 7.3-11	0
7.3-25	0		
7.3-26	2	7.4-1	2
7.3-27	0	7.4-2	0

LIST OF EFFECTIVE PAGES
CURRENT THROUGH REVISION 2
(Continued)

Page/Table/Figure No.	Revision	Page/Table/Figure No.	Revision
7.4-3	0	F 7.6-1	0
		F 7.6-2	0
7.5-1	0	F 7.6-3	0
7.5-2	0	F 7.6-4	0
7.5-3	0	F 7.6-5	0
7.5-4	2	F 7.6-6	0
7.5-5	0	F 7.6-7	0
7.5-6	2	F 7.6-8	0
7.5-7	0	F 7.6-9	0
7.5-8	0	F 7.6-10	0
7.5-9	0	F 7.6-11	0
7.5-10	0	F 7.6-12	0
7.5-11	0	F 7.6-13	0
7.5-12	0	F 7.6-14	0
		F 7.6-15	0
F 7.5-1	0	F 7.6-16	0
		F 7.6-17	2
7.6-1	0		
7.6-2	0	7.7-1	0
7.6-3	0	7.7-2	0
7.6-4	2	7.7-3	0
7.6-5	0	7.7-4	0
7.6-6	0	7.7-5	0
7.6-7	0	7.7-6	0
7.6-8	0	7.7-7	0
7.6-9	0	7.7-7a	2
7.6-10	0	7.7-8	2
7.6-11	0	7.7-9	0
7.6-12	0	7.7-10	0
7.6-13	2	7.7-11	2
7.6-14	0	7.7-12	0
7.6-15	2	7.7-13	0
7.6-16	0	7.7-14	0
7.6-17	0	7.7-15	0
7.6-18	0	7.7-16	0
7.6-18a	2	7.7-17	0
7.6-19	2	7.7-18	0
7.6-20	01A	7.7-19	2
7.6-21	2	7.7-19a	2
7.6-22	2	7.7-20	2
7.6-22a	2	7.7-21	0
7.6-23	0	7.7-22	0
7.6-24	2	7.7-23	0
7.6-24a	2	7.7-24	0
7.6-25	0	7.7-25	0

LIST OF EFFECTIVE PAGES
CURRENT THROUGH REVISION 2
(Continued)

Page/Table/Figure No.	Revision	Page/Table/Figure No.	Revision
7.7-26	0	8.2-2	2
7.7-27	0	8.2-2a	2
7.7-28	0	8.2-3	0
7.7-29	0	8.2-4	0
7.7-30	0	8.2-5	0
7.7-31	0	8.2-6	0
7.7-31a	2	8.2-7	0
7.7-32	2		
7.7-33	2	T 8.2-1	0
7.7-34	2		
7.7-34a	2	F 8.2-1	2
7.7-35	2	F 8.2-2	0
7.7-36	2	F 8.2-3	C
7.7-37	2	F 8.2-4	0
		F 8.2-5A	0
T 7.7-1	0	F 8.2-5B	0
T 7.7-2	0	F 8.2-6	0
		F 8.2-7A	0
F 7.7-1	0	F 8.2-7B	0
F 7.7-2	0	F 8.2-8	0
F 7.7-3	0	F 8.2-9A	0
F 7.7-4	0	F 8.2-9B	0
F 7.7-5	0		
F 7.7-6	0	8.3-1	0
F 7.7-7	0	8.3-2	0
F 7.7-8	0	8.3-3	0
F 7.7-9	0	8.3-4	01A
		8.3-5	01A
7.8-1	0	8.3-6	0
7.8-2	2	8.3-7	0
7.8-3	2	8.3-8	01A
7.8-4	0	8.3-9	2
7.8-5	0	8.3-10	0
7.8-6	0	8.3-11	0
		8.3-12	0
F 7.8-1	0	8.3-13	0
		8.3-14	0
8-i	2	8.3-15	0
8-ii	0	8.3-16	0
8-iii	0	8.3-17	0
		8.3-18	2
8.1-1	0	8.3-18a	2
8.1-2	2	8.3-19	2
		8.3-20	2
8.2-1	0	8.3-20a	2

LIST OF EFFECTIVE PAGES
CURRENT THROUGH REVISION 2
(Continued)

Page/Table/Figure No.	Revision	Page/Table/Figure No.	Revision
8.3-21	01A	9-viii	2
8.3-21-a	01A		
8.3-22	2	9.1-1	2
8.3-23	2	9.1-2	2
8.3-24	2	9.1-2a	2
8.3-24a	2	9.1-3	01A
8.3-25	2	9.1-4	2
8.3-25a	2	9.1-5	01A
8.3-26	01A	9.1-5a	01A
8.3-27	01A	9.1-6	0
		9.1-7	2
T 8.3-1 Sheet 1	2	9.1-7a	2
T 8.3-1 Sheet 2	2	9.1-8	0
T 8.3-1 Sheet 3	2	9.1-9	2
T 8.3-1 Sheet 4	2	9.1-9a	2
T 8.3-1 Sheet 5	2	9.1-10	2
T 8.3-1 Sheet 6	2	9.1-11	2
T 8.3-1 Sheet 7	2	9.1-11a	2
T 8.3-2	0	9.1-12	2
T 8.3-3	0	9.1-13	2
T 8.3-4	0	9.1-13a	2
T 8.3-5	0	9.1-14	2
T 8.3-6	0	9.1-15	2
T 8.3-7	2	9.1-16	2
T 8.3-8	01A	9.1-17	2
		9.1-18	2
F 8.3-1	L	9.1-19	2
F 8.3-2	AH	9.1-20	2
F 8.3-3	0	9.1-21	2
F 8.3-4	0	9.1-22	2
F 8.3-5	0	9.1-23	2
F 8.3-6	0	9.1-24	0
F 8.3-7	0	9.1-25	2
F 8.3-8	0	9.1-26	2
F 8.3-9	D		
F 8.3-10	C	T 9.1-1	2
F 8.3-11	R	T 9.1-2	2
		T 9.1-3 Sheet 1	0
9-i	2	T 9.1-3 Sheet 2	0
9-ii	2	T 9.1-3 Sheet 3	0
9-iii	2	T 9.1-3 Sheet 4	0
9-iv	2	T 9.1-4 Sheet 1	2
9-v	2	T 9.1-4 Sheet 2	2
9-vi	2		
9-vii	01A	F 9.1-1	0

LIST OF EFFECTIVE PAGES
CURRENT THROUGH REVISION 2
(Continued)

LIST OF EFFECTIVE PAGES
CURRENT THROUGH REVISION 2
(Continued)

Page/Table/Figure No.	Revision	Page/Table/Figure No.	Revision
9.3-9	01A	9.4-1	2
9.3-10	01A	9.4-2	0
9.3-11	01A	9.4-3	0
9.3-12	01A	9.4-4	2
9.3-13	01A	9.4-5	0
9.3-14	01A	9.4-6	01A
9.3-15	01A	9.4-7	2
9.3-16	01A	9.4-8	2
9.3-17	01A	9.4-9	2
9.3-18	01A	9.4-9a	2
9.3-19	01A	9.4-10	0
9.3-20	01A	9.4-11	0
9.3-21	01A		
9.3-22	2	F 9.4-1	E
9.3-23	01A	F 9.4-2	F
9.3-24	01A	F 9.4-3	13
9.3-25	01A	F 9.4-4	AD
9.3-26	01A	F 9.4-5	L
9.3-27	01A	F 9.4-6	B
9.3-28	2	F 9.4-7	F
9.3-28a	2	F 9.4-8	F
9.3-29	2	F 9.4-9	P
9.3-30	2	F 9.4-10A	B
9.3-31	01A	F 9.4-10B	A
9.3-32	01A	F 9.4-11	H
9.3-33	2	F 9.4-12	F
9.3-34	01A	F 9.4-13	E
9.3-35	01A	F 9.4-14	E
9.3-36	01A	F 9.4-15	Q
		F 9.4-16	Q
T 9.3-1	0	F 9.4-17	F
T 9.3-2 Sheet 1	0	F 9.4-18	C
T 9.3-2 Sheet 2	0	F 9.4-19	A
T 9.3-2 Sheet 3	0		
T 9.3-3	2	9.5-1	01A
		9.5-2	0
F 9.3-1	E	9.5-3	2
F 9.3-2	E	9.5-3-a	01A
F 9.3-3	AV	9.5-4	01A
F 9.3-4	J	9.5-5	0
F 9.3-5	01A	9.5-6	2
F 9.3-6	0	9.5-7	2
F 9.3-7	0	9.5-8	01A
F 9.3-8	HS	9.5-9	2
F 9.3-9	0	9.5-10	0

LIST OF EFFECTIVE PAGES
CURRENT THROUGH REVISION 2
(Continued)

Page/Table/Figure No.	Revision
9.5-11	0
9.5-12	0
9.5-13	2
9.5-14	2
9.5-15	2
9.5-16	2
9.5-17	2
9.5-18	2
9.5-19	2
9.5-20	2
9.5-21	2
T 9.5-1	0
T 9.5-2	0
F 9.5-1	X
F 9.5-2	0
F 9.5-3	0
F 9.5-4	0
F 9.5-5	0
F 9.5-6	F
F 9.5-7	F
F 9.5-8	E
F 9.5-9	0
F 9.5-10	AN
F 9.5-11	G
F 9.5-12	G
F 9.5-13	F
F 9.5-14	2
10-i	2
10-ii	0
10-iii	0
10-iv	2
10.1-1	0
T 10.1-1	0
10.2-1	2
10.2-2	2
10.2-3	0
10.2-4	0
10.2-5	2
10.2-6	0

Page/Table/Figure No.	Revision
F 10.2-1	0
10.3-1	0
10.3-2	2
10.3-3	0
T 10.3-1	2
F 10.3-1	NW
F 10.3-2	AAP
F 10.3-3	AP
F 10.3-4	PD
10.4-1	0
10.4-2	0
10.4-3	2
10.4-4	2
10.4-5	2
10.4-6	2
10.4-7	2
10.4-8	2
10.4-9	0
10.4-10	0
10.4-11	2
10.4-11a	2
10.4-12	0
10.4-13	2
10.4-14	2
10.4-15	2
10.4-16	2
10.4-17	2
10.4-18	2
10.4-19	0
T 10.4-1 Sheet 1	0
T 10.4-1 Sheet 2	2
T 10.4-2	2
T 10.4-3	2
T 10.4-4	0
T 10.4-5	0
F 10.4-1	KC
F 10.4-2	0
F 10.4-3	PW
F 10.4-4	PV

LIST OF EFFECTIVE PAGES
CURRENT THROUGH REVISION 2
(Continued)

Page/Table/Figure No.	Revision	Page/Table/Figure No.	Revision
F 10.4-5	VB	11.2-11	0
F 10.4-6	XA	11.2-12	2
F 10.4-7	AE	11.2-13	0
F 10.4-8	LB	11.2-14	0
F 10.4-9	AZ	11.2-15	2
F 10.4-10	AB	11.2-16	0
F 10.4-11	AD	11.2-17	2
F 10.4-12	S	11.2-18	2
F 10.4-13	2	11.2-19	2
		11.2-20	2
11-i	0	11.2-21	0
11-ii	0	11.2-22	0
11-iii	0		
11-iv	0	T 11.2-1	0
11-v	0	T 11.2-2	0
11-vi	0	T 11.2-3	0
		T 11.2-4 Sheet 1	0
11.1-1	0	T 11.2-4 Sheet 2	0
11.1-2	2	T 11.2-5	0
11.1-2a	2	T 11.2-6	0
11.1-3	01A	T 11.2-7 Sheet 1	0
11.1-4	0	T 11.2-7 Sheet 2	0
11.1-5	0	T 11.2-8	0
11.1-6	0	T 11.2-9	0
11.1-7	0		
11.1-8	0	F 11.2-1	CH
11.1-9	0	F 11.2-2	VE
11.1-10	01A	F 11.2-3	YN
11.1-11	0	F 11.2-4	MZ
		F 11.2-5	AC
T 11.1-1	0	F 11.2-6	N
T 11.1-2	0	F 11.2-7	AA
T 11.1-3 Sheet 1	2	F 11.2-8	AA
T 11.1-3 Sheet 2	2	F 11.2-9	R
		F 11.2-10	AP
11.2-1	0	F 11.2-11	AF
11.2-2	2	F 11.2-12	X
11.2-3	2	F 11.2-13	X
11.2-4	2	F 11.2-14	X
11.2-5	2	F 11.2-15	K
11.2-6	2	F 11.2-16	E
11.2-7	2	F 11.2-17	I
11.2-8	2	F 11.2-18	E
11.2-9	2	F 11.2-19	K
11.2-10	2	F 11.2-20	K

LIST OF EFFECTIVE PAGES
CURRENT THROUGH REVISION 2
(Continued)

Page/Table/Figure No.	Revision	Page/Table/Figure No.	Revision
F 11.2-21	01A	F 11.3-13	AN
		F 11.3-14	S
11.3-1	2	F 11.3-15	Z
11.3-2	2	F 11.3-16	G
11.3-3	2	F 11.3-17	2
11.3-4	2	F 11.3-18	D
11.3-5	2	F 11.3-19	N
11.3-6	2		
11.3-6a	2	11.4-1	2
11.3-7	2	11.4-2	0
11.3-8	2	11.4-3	2
11.3-9	2	11.4-4	2
11.3-10	2	11.4-5	0
11.3-11	2	11.4-6	2
11.3-12	2	11.4-7	0
11.3-13	2	11.4-8	0
11.3-14	2		
11.3-15	0	T 11.4-1	0
11.3-16	2	T 11.4-2	0
11.3-17	0		
11.3-18	0	F 11.4-1	AN
		F 11.4-2	0
T 11.3-1	0	F 11.4-3	2
T 11.3-2	2		
T 11.3-3	0	11.5-1	0
T 11.3-4	2	11.5-2	0
T 11.3-5	2	11.5-3	0
T 11.3-6 Sheet 1	0	11.5-4	0
T 11.3-6 Sheet 2	0	11.5-5	0
T 11.3-7	0	11.5-6	0
T 11.3-8 Sheet 1	0	11.5-7	0
T 11.3-8 Sheet 2	0	11.5-8	2
		11.5-9	01A
F 11.3-1	BP	11.5-10	01A
F 11.3-2	AA	11.5-11	0
F 11.3-3	AC	11.5-12	0
F 11.3-4	HS	11.5-13	2
F 11.3-5	AB	11.5-14	01A
F 11.3-6	Y	11.5-14-a	01A
F 11.3-7	AAP	11.5-15	0
F 11.3-8	PD	11.5-16	2
F 11.3-9	2	11.5-17	0
F 11.3-10	0	11.5-18	2
F 11.3-11	7	11.5-19	0
F 11.3-12	7	11.5-20	0

LIST OF EFFECTIVE PAGES
CURRENT THROUGH REVISION 2
(Continued)

Page/Table/Figure No.	Revision	Page/Table/Figure No.	Revision
T 11.5-1 Sheet 1	2	F 12.3-1	0
T 11.5-1 Sheet 2	2	F 12.3-2	0
T 11.5-1 Sheet 3	2	F 12.3-3	0
T 11.5-1 Sheet 4	2	F 12.3-4	0
T 11.5-2	0	F 12.3-5	0
F 11.5-1	0	12.4-1	0
F 11.5-2	0		
F 11.5-3	0	12.5-1	2
F 11.5-4	0	12.5-2	2
F 11.5-5	0	12.5-3	2
F 11.5-6	0	12.5-4	2
F 11.5-7	0	12.5-5	0
12-i	2	T 12.5-1	2
12-ii	0	T 12.5-2	2
12-iii	0		
12-iv	0	Appendix 12A	0
12.1-1	2	T 12A-1	0
12.1-2	2	T 12A-2	0
12.1-3	2	T 12A-3	0
		T 12A-4	0
12.2-1	2		
		F 12A-1 — 12A-7	0
12.3-1	2	F 12A-1A — 12A-7A	0
12.3-2	2	F 12A-1B — 12A-7B	0
12.3-3	0	F 12A-1C — 12A-7C	0
12.3-4	2	F 12A-1D — 12A-7D	0
12.3-5	2	F 12A-1E — 12A-7E	0
12.3-6	2	F 12A-1F — 12A-7F	0
12.3-7	2		
12.3-8	2	13-i	01A
12.3-9	2	13-ii	01A
12.3-10	2	13-iii	01A
12.3-11	0	13-iv	01A
T 12.3-1	2	13.1-1	2
T 12.3-2	0	13.1-2	01A
T 12.3-3	0		
T 12.3-4 Sheet 1	0	13.2-1	2
T 12.3-4 Sheet 2	2	13.2-2	2
T 12.3-5 Sheet 1	0	13.2-3	0
T 12.3-5 Sheet 2	0	13.2-4	0
		13.2-5	0

LIST OF EFFECTIVE PAGES
CURRENT THROUGH REVISION 2
(Continued)

Page/Table/Figure No.	Revision	Page/Table/Figure No.	Revision
13.2-6	0	14.2-2	0
13.2-7	0	14.2-3	0
13.2-8	0	14.2-4	0
13.2-9	0	14.2-5	0
13.2-10	0	14.2-6	0
13.2-11	0	14.2-7	0
		14.2-8	0
T 13.2-1	0	14.2-9	0
		14.2-10	0
13.3-1	01A	14.2-11	0
		14.2-12	0
13.4-1	2	14.2-13	0
		14.2-14	0
13.5-1	2	14.2-15	0
13.5-2	2	14.2-16	0
13.5-2a	2	14.2-17	0
13.5-3	2	14.2-18	0
13.5-4	0	14.2-19	0
13.5-5	2	14.2-20	0
13.5-6	2	14.2-21	0
13.5-7	0	14.2-22	0
13.5-7a	2	14.2-23	0
13.5-8	2	14.2-24	0
13.5-9	0	14.2-25	0
13.5-10	0	14.2-26	0
		14.2-27	0
T 13.5-1 Sheet 1	0	14.2-28	0
T 13.5-1 Sheet 2	0	14.2-29	0
		14.2-30	0
13.6-1	2	14.2-31	0
13.6-2	2	14.2-32	0
		14.2-33	0
13.7-1	2	14.2-34	0
13.7-2	0	14.2-35	0
		14.2-36	0
T 13.7-1 Sheet 1	2	14.2-37	0
T 13.7-1 Sheet 2	2	14.2-38	0
		14.2-39	0
14-i	0	14.2-40	0
14-ii	0	14.2-41	0
14-iii	0	14.2-42	0
		14.2-43	0
14.1-1	0	14.2-44	0
		14.2-45	0
14.2-1	0	14.2-46	0

LIST OF EFFECTIVE PAGES
CURRENT THROUGH REVISION 2
(Continued)

Page/Table/Figure No.	Revision	Page/Table/Figure No.	Revision
14.2-47	0	15.1-3	0
14.2-48	0	15.1-4	0
14.2-49	0	15.1-5	0
14.2-50	0	15.1-6	2
14.2-51	0	15.1-7	0
14.2-52	0	15.1-8	0
14.2-53	0		
14.2-54	0	F 15.1-1	0
14.2-55	0	F 15.1-2	0
14.2-56	0	F 15.1-3	0
14.2-57	0	F 15.1-4	0
14.2-58	0	F 15.1-5	0
14.2-59	0	F 15.1-6	0
14.2-60	0	F 15.1-7	0
14.2-61	0	F 15.1-8	0
14.2-62	0		
14.2-63	0	15.2-1	0
14.2-64	0	15.2-2	0
14.2-65	0	15.2-3	0
		15.2-4	2
T 14.2-1 Sheet 1	0	15.2-5	2
T 14.2-1 Sheet 2	0	15.2-6	0
T 14.2-2	0	15.2-7	0
T 14.2-3	0	15.2-8	2
T 14.2-4	0	15.2-8a	2
		15.2-8b	2
F 14.2-1	0	15.2-9	2
F 14.2-2	0	15.2-10	01A
		15.2-11	2
15-i	0	15.2-12	2
15-ii	0		
15-iii	0	F 15.2-1	0
15-iv	0	F 15.2-2	0
15-v	0	F 15.2-3	0
15-vi	0	F 15.2-4	0
15-vii	0	F 15.2-5	0
15-viii	0	F 15.2-6	0
		F 15.2-7	0
15.0-1	2	F 15.2-8	0
15.0-2	0	F 15.2-9	0
15.0-3	2	F 15.2-10	0
15.0-4	2		
		15.3-1	0
15.1-1	0	15.3-2	0
15.1-2	0	15.3-3	0

LIST OF EFFECTIVE PAGES
CURRENT THROUGH REVISION 2
(Continued)

Page/Table/Figure No.	Revision	Page/Table/Figure No.	Revision
15.3-4	0	15.6-3	2
15.3-5	0	15.6-4	2
15.3-6	0	15.6-5	0
15.3-7	0	15.6-6	0
15.3-8	0	15.6-7	0
		15.6-8	0
F 15.3-1	0	15.6-9	0
F 15.3-2	0	15.6-10	0
F 15.3-3	0	15.6-11	0
F 15.3-4	0	15.6-12	0
F 15.3-5	0	15.6-13	2
F 15.3-6	0	15.6-14	0
F 15.3-7	0	15.6-15	0
F 15.3-8	0	15.6-16	2
F 15.3-9	0	15.6-17	2
		15.6-18	2
15.4-1	2	15.6-19	0
15.4-2	0	15.6-20	0
15.4-3	2	15.6-21	0
15.4-4	2	15.6-22	0
15.4-5	0	15.6-23	0
15.4-6	0	15.6-24	0
15.4-7	0		
15.4-8	0	T 15.6-1	0
15.4-9	0	T 15.6-2	0
15.4-10	0	T 15.6-3	0
15.4-11	0	T 15.6-4	0
15.4-12	0	T 15.6-5	0
15.4-13	0	T 15.6-6	2
15.4-14	01A	T 15.6-7	2
15.4-15	0	T 15.6-8 Sheet 1	0
15.4-16	0	T 15.6-8 Sheet 2	0
		T 15.6-9 Sheet 1	2
T 15.4-1	0	T 15.6-9 Sheet 2	2
T 15.4-2	0	T 15.6-10	2
T 15.4-3	0		
		F 15.6-1	0
F 15.4-1	0	F 15.6-2	0
F 15.4-2	0	F 15.6-3	0
		F 15.6-4	0
15.5-1	0		
15.5-2	0	15.7-1	0
		15.7-2	0
15.6-1	0	15.7-3	0
15.6-2	0	15.7-4	2

LIST OF EFFECTIVE PAGES
CURRENT THROUGH REVISION 2
(Continued)

Page/Table/Figure No.	Revision
15.7-5	0
15.7-6	0
15.7-7	0
15.7-8	0
15.7-9	0
15.7-10	2
15.7-11	0
15.7-12	0
15.7-13	0
15.7-14	0
15.7-15	0
15.7-16	0
15.7-17	0
15.7-18	0
15.7-19	2
15.7-20	0
T 15.7-1 Sheet 1	0
T 15.7-1 Sheet 2	0
T 15.7-1 Sheet 3	0
T 15.7-1 Sheet 4	0
T 15.7-1 Sheet 5	0
T 15.7-1 Sheet 6	0
T 15.7-1 Sheet 7	0
T 15.7-1 Sheet 8	0
T 15.7-2	2
T 15.7-3	0
T 15.7-4	0
T 15.7-5	0
15.8-1	0
15.8-2	0
15.8-3	0
15.8-4	0
15.8-5	0
15.8-6	0
15.8-7	0
15.8-8	0
15.8-9	0
15.8-10	0
15.8-11	0
F 15.8-1	0
F 15.8-2	0
F 15.8-3	0

Page/Table/Figure No.	Revision
F 15.8-4	0
F 15.8-5	0
16-i	0
16.0-1	0
16.0-2	0
17-i	0
17.1-1	0
17.2-1	0
17.2-2	0

Dresden UFSAR Update Instructions

Identification of Page(s)	Remove	Insert	Notes
list of effective Pages	All Revision 1A	Revision 2	List of effective Pages showing Revision 2 changes
Page 1-i	Revision 0	Revision 2	Update to Table of Contents
Page 1-ii	Revision 0	Revision 2	Update to Table of Contents
Table 1.1-1 (sheet 3 of 3)	Revision 1A	Revision 2	update to table
Page 1.2-3	Revision 0	Revision 2	Change to clarify text
Page 1.2-3a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 1.2-4	Revision 0	Revision 2	Change related to Technical Specification upgrade
Page 1.2-5	Revision 0	Revision 2	Change to correct the vertical acceleration component of the ground motion
Page 1.2-6	Revision 0	Revision 2	Text Clarification
Page 1.2-6a	N/A new Page	Revision 2	New Page, text flow
Page 1.2-10	Revision 0	Revision 2	Text Clarification
Page 1.2-13	Revision 0	Revision 2	Text Clarification

Identification of Page(s)	Remove	Insert	Notes
Page 1.2-14	Revision 1A	Revision 2	Change to reflect the addition of the Station blackout Diesels M 12-0-91-019C
Page 1.2-20a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 1.2-21	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Page 1.2-21a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 1.2-22	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Figure 1.2-3	Revision G	Revision H	Drawing update
Figure 1.2-4	Revision L	Revision Q	Drawing update
Figure 1.2-5	Revision F	Revision H	Drawing update
Figure 1.2-6	Revision G	Revision H	Drawing update
Figure 1.2-9	Revision B	Revision D	Drawing update
Figure 1.2-11	Figure dated 12/21/87	Revision O	Drawing update
Figure 1.2-16	Figure dated 7/21/75	Revision B	Drawing update
Figure 1.2-17	Figure dated 7/21/97	Revision B	Drawing update
Table 1.8-1 sheet 1 of 4	Revision 0	Revision 2 sheet 1 of 4	Change related to Technical Specification upgrade

Identification of Page(s)	**Remove**	**Insert**	**Notes**
Table 1.8-1 sheet 2 of 4	Revision 0	Revision 2 sheet 2 of 4	Change related to Technical Specification upgrade
Table 1.8-1 sheet 3 of 4	Revision 0	Revision 2 sheet 3 of 4	Change related to Technical Specification upgrade
Table 1.8-1 sheet 4 of 4	Revision 0	Revision 2 sheet 4 of 4	Change related to Technical Specification upgrade
Page 2.3-2	Revision 0	Revision 2	Text Clarification
Page 3-iii	Revision 0	Revision 2	Update to Table of Contents
Page 3-iv	Revision 0	Revision 2	Update to Table of Contents
Page 3-vi	Revision 0	Revision 2	Update to List of Tables
Page 3-vii	Revision 0	Revision 2	Update to List of Tables
Page 3-viii	Revision 0	Revision 2	Update to List of Tables
Page 3-ix	Revision 0	Revision 2	Update to List of Tables
Page 3.1-43	Revision 0	Revision 2	Text Clarification
Page 3.1-44	Revision 0	Revision 2	Text Clarification
Page 3.2-7	Revision 0	Revision 2	Update to reflect U-2 ASME classification and to correct a typographical error
Page 3.2-8	Revision 0	Revision 2	Correction of Typographical error

Identification of Page(s)	<u>Remove</u>	<u>Insert</u>	<u>Notes</u>
Page 3.4-7	Revision 0	Revision 2	Update to reactor building floor drain text and submarine door verification
Page 3.5-9	Revision 0	Revision 2	Text clarification
Page 3.7-1	Revision 0	Revision 2	Update to reflect core shroud repair M12-2(3)-94-004
Page 3.7-2	Revision 0	Revision 2	Update to reflect core shroud repair M12-2(3)-94-004
Page 3.7-5	Revision 0	Revision 2	Text flow Page No text changes
Page 3.7-5a	N/A new page	Revision 2	Text flow Page No text changes
Page 3.7-6	Revision 0	Revision 2	Update to reflect core shroud repair M12-2(3)-94-004
Page 3.7-22	Revision 0	Revision 2	Update to reflect core shroud repair M12-2(3)-94-004
Page 3.7-25	Revision 0	Revision 2	Update to reflect core shroud repair M12-2(3)-94-004
Table 3.7-1	Revision 0	Revision 2	added note 1 to Table
Figure 3.7-6	Revision 0	Revision 2	Update to reflect core shroud repair M12-2(3)-94-004
Page 3.8-2	Revision 0	Revision 2	Text clarification

Identification of Page(s)	**Remove**	**Insert**	**Notes**
Page 3.8-5	Revision 0	Revision 2	Update to reference new Figures 3.8-9A and 3.8-9B
Page 3.8-6	Revision 0	Revision 2	Text clarification
Page 3.8-7	Revision 0	Revision 2	Text clarification
Page 3.8-7a	Revision 1a	Revision 2	Text Clarification
Page 3.8-8	Revision 0	Revision 2	Update to reflect the design of the Reactor Recirculation Pump Seal Purge Lines and added check valves (E12-2-96-208)
Page 3.8-22	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Table 3.8-1 sheet 1 of 1	Revision 0	Revision 2	Change to reflect bellows replacement (P12-2-94-208 and P12-2-94-209)
Table 3.8-3 sheet 1 of 1	Revision 0	Table deleted	Revision to state that the containment, containment penetration and seals, and containment isolation valves are tested in accordance with the Primary Containment Leakage Rate Testing Program.
Figure 3.8-9	Revision 0	Revision 2	Deleted Figure replaced with Figure 3.8-9A
Figure 3.8-9A	N/A New Figure	Revision 2	New Figure
Figure 3.8-9B	N/A New Figure	Revision 2	New Figure
Page 3.9-2a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability

Identification of Page(s)	**Remove**	**Insert**	**Notes**
Page 3.9-3	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Page 3.9-4a	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Page 3.9-5	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Page 3.9-6	Revision 0	Revision 2	Update to reflect core shroud repair M12-2(3)-94-004
Page 3.9-7	Revision 0	Revision 2	Update to reflect core shroud repair M12-2(3)-94-004
Page 3.9-8	Revision 0	Revision 2	Update to reflect core shroud repair M12-2(3)-94-004
Page 3.9-8a	N/A new Page	Revision 2	Update to reflect core shroud repair M12-2(3)-94-004
Page 3.9-9	Revision 0	Revision 2	Update to reflect core shroud repair M12-2(3)-94-004
Page 3.9-10	Revision 0	Revision 2	Repagination due to text deletion
Page 3.9-23a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability

Identification of Page(s)	Remove	Insert	Notes
Page 3.9-24	Revision 0	Revision 2	Update to reflect core shroud repair M12-2(3)-94-004
Page 3.9-25	Revision 0	Revision 2	Update to reflect core shroud repair M12-2(3)-94-004
Page 3.9-25a	N/A new Page	Revision 2	Text flow Page
Page 3.9-30	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Page 3.9-30a	N/A new Page	Revision 2	Update to reflect core shroud repair M12-2(3)-94-004
Page 3.9-31	Revision 0	Revision 2	Update to reflect core shroud repair M12-2(3)-94-004
Page 3.9-31a	N/A new Page	Revision 2	Update to reflect core shroud repair M12-2(3)-94-004
Page 3.9-33	Revision 0	Revision 2	Update to reflect core shroud repair M12-2(3)-94-004
Page 3.9-33a	N/A new Page	Revision 2	Update to reflect core shroud repair M12-2(3)-94-004
Page 3.9-37	Revision 0	Revision 2	Update to reflect core shroud repair M12-2(3)-94-004

Identification of Page(s)	Remove	Insert	Notes
Page 3.9-37a	N/A new Page	Revision 2	Text flow Page, no text changes
Page 3.9-37b	N/A new Page	Revision 2	Update to reflect core shroud repair M12-2(3)-94-004
Page 3.9-38	Revision 0	Revision 2	Update to reflect current IST program
Page 3.9-39	Revision 0	Revision 2	Update to reflect current IST program
Page 3.9-42	Revision 0	Revision 2	Update to reflect core shroud repair M12-2(3)-94-004
Page 3.9-43	N/A new Page	Revision 2	Update to reflect core shroud repair M12-2(3)-94-004
Table 3.9-3	Revision 0	Revision 2	Table deleted
Table 3.9-4	Revision 0	Revision 2	Table deleted
Table 3.9-7 sheet 1	Revision 0	Revision 2	Update to reflect general work specification K-4080 Revision
Table 3.9-7 sheet 2	Revision 0	Revision 2	Update to reflect general work specification K-4080 Revision
Table 3.9-9	Revision 0	Revision 2	Update to reflect general work specification K-4080 Revision
Table 3.9-18	Revision 0	Revision 2	Update to reflect core shroud repair M12-2(3)-94-004
Table 3.9-19	Revision 0	Revision 2	Update to reflect core shroud repair (M12-2(3)-94-004)

Identification of Page(s)	**Remove**	**Insert**	**Notes**
Table 3.9-20	Revision 0	Revision 2	Update to reflect core shroud repair M12-2(3)-94-004
Table 3.9-21	N/A new Table	Revision 2	Update to reflect core shroud repair M12-2(3)-94-004
Figure 3.9-11	N/A new Figure	Revision 2	Update to reflect core shroud repair M12-2(3)-94-004
Figure 3.9-12	N/A new Figure	Revision 2	Update to reflect core shroud repair M12-2(3)-94-004
Page 3.10-3	Revision 0	Revision 2	Text Clarification
Page 3.10-4	Revision 0	Revision 2	Text Clarification
Page 3.11-3	Revision 0	Revision 2	Text Clarification
Page 3.11-5	Revision 0	Revision 2	EQ change to reflect new zone parameters per Bechtel Spec. 13524-068-N102, Revision 6
Page 3.11-9	Revision 0	Revision 2	Revised to correct references
Table 3.11-1	Revision 0	Revision 2	EQ change to reflect new zone parameters per Bechtel Spec. 13524-068-N102, Revision 6
Table 3.11-2	Revision 0	Revision 2	EQ change to reflect new zone parameters per Bechtel Spec. 13524-068-N102, Revision 6
Table 3.11-3	Revision 0	Revision 2	EQ change to reflect new zone parameters per Bechtel Spec. 13524-068-N102, Revision 6

Identification of Page(s)	Remove	Insert	Notes
Figure 3.11-1	Revision 3	Revision 6	EQ change to reflect new zone parameters per Bechtel Spec. 13524-068-N102, Revision 6
Figure 3.11-2	Revision 3	Revision 6	EQ change to reflect new zone parameters per Bechtel Spec. 13524-068-N102, Revision 6
Figure 3.11-3	Revision 3	Revision 6	EQ change to reflect new zone parameters per Bechtel Spec. 13524-068-N102, Revision 6
Figure 3.11-4	Revision 3	Revision 6	EQ change to reflect new zone parameters per Bechtel Spec. 13524-068-N102, Revision 6
Figure 3.11-5	Revision 3	Revision 6	EQ change to reflect new zone parameters per Bechtel Spec. 13524-068-N102, Revision 6
Appendix 3B	Remove all Revision 0	replace with new appendix	Corrected Appendix to replace pages missing from Revision 0
Page 4-ii	Revision 0	Revision 2	Update to Table of Contents
Table 4.1-2 sheet 1 of 1	Revision 0	Revision 2	Revision to SBLC shutdown Keff
Table 4.1-3 sheet 1 of 1	Revision 0	Revision 2	update to reflect SPC 9x9-2 fuel bundles
Page 4.2-12	Revision 0	Revision 2	Update to reflect ATRIUM 9B fuel
Page 4.2-12a	N/A new Page	Revision 2	Update to reflect ATRIUM 9B fuel (flow Page)

Identification of Page(s)	Remove	Insert	Notes
Page 4.3-1	Revision 0	Revision 2	Change related to Technical Specification upgrade
Page 4.3-4	Revision 0	Revision 2	Change related to Technical Specification upgrade
Page 4.3-4a	N/A new Page	Revision 2	Change related to Technical Specification upgrade (text flow)
Page 4.3-11	Revision 0	Revision 2	Update to reactor stability discussion
Page 4.3-25	Revision 0	Revision 2	Update to reactor stability discussion
Page 4.3-26	Revision 0	Revision 2	Update to reactor stability discussion
Page 4.4-3	Revision 0	Revision 2	Update to reflect 1/FDLRC rather than FRP/MFLPD
Page 4.4-15	Revision 0	Revision 2	Text editorial corrections
Page 4.4-17	Revision 0	Revision 2	Update to reference section
Page 4.5-1	Revision 0	Revision 2	Update to reflect core shroud repair M12-2(3)-94-004
Page 4.6-3	Revision 0	Revision 2	Corrected section reference
Page 4.6-5	Revision 0	Revision 2	Update to discussion of Control Blade life
Page 4.6-5a	N/A new Page	Revision 2	Text flow Page, No text changes

Identification of Page(s)	Remove	Insert	Notes
Page 4.6-6	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Page 4.6-8	Revision 1A	Revision 2	Update to CRD hydraulic system operating pressures
Page 4.6-9	Revision 1A	Revision 2	Update to CRD hydraulic system operating pressures
Page 4.6-10	Revision 0	Revision 2	Text clarification
Page 4.6-11	Revision 0	Revision 2	update to CRD hydraulic system operating pressures
Page 4.6-12	Revision 0	Revision 2	Text clarification
Page 4.6-13	Revision 0	Revision 2	Text clarification
Page 4.6-14	Revision 0	Revision 2	Text clarification
Page 4.6-16	Revision 0	Revision 2	Text clarification
Page 4.6-20a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 4.6-21	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Page 4.6-24a	N/A new Page	Revision 2	Update to reflect the design of the Reactor Recirculation Pump Seal Purge Lines and added check valves (E12-3-96-212)
Page 4.6-25	Revision 0	Revision 2	Text Change to state that CRD scram timing will be done as required by Technical Specifications

Identification of Page(s)	**Remove**	**Insert**	**Notes**
Page 4.6-26	Revision 0	Revision 2	Deletion of discussion on Scram solenoid valve diaphragm material
Page 4.6-27	Revision 0	Revision 2	Added additional references related to the Control rod life discussion
Figure 4.6-5	Revision AAU	Revision F sheets 1 and 2	Drawing update
Page 5-i	Revision 0	Revision 2	Update to Table of Contents
Page 5-ii	Revision 0	Revision 2	Update to Table of Contents
Page 5-iii	Revision 0	Revision 2	Update to Table of Contents
Page 5.1-2	Revision 0	Revision 2	Added reference to Table 5.1-3 which lists coolant volumes
Table 5.1-1 sheet 2 of 3	Revision 0	Revision 2	Updated numbers of Recirculation valves (M12-2-91-005)
Table 5.1-1 sheet 3 of 3	Revision 0	Revision 2	Deleted Isolation Condenser level statement
Table 5.1-3 sheet 1 of 1	N/A new Table	Revision 2	New Table for Coolant Volumes
Page 5.2-6	Revision 0	Revision 2	Corrected reference to IST update frequency
Page 5.2-7	Revision 0	Revision 2	Change related to Technical Specification upgrade

Identification of Page(s)	Remove	Insert	Notes
Page 5.2-14	Revision 1A	Revision 2	Update to reflect current status of the IGSCC susceptible piping in the Non-safety Related portions of the RWCU system
Page 5.2-14a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 5.2-15	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Page 5.2-18a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 5.2-19	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Page 5.2-20	Revision 0	Revision 2	Change related to Technical Specification upgrade
Page 5.2-21	Revision 0	Revision 2	Removal of the first paragraph under 5.2.5.5 which was redundant to paragraph 5.2.5.1
Page 5.2-22	Revision 1A	Revision 2	Text clarification/correction
Page 5.2-24	Revision 0	Revision 2	Update to reflect current IST program and ASME code /standard references.

Identification of Page(s)	Remove	Insert	Notes
Table 5.2-2	Revision 0	Revision 2	Update to reflect general work specification K-4080 Revision
Figure 5.2-9	Revision BU	Revision CP	Drawing update
Page 5.3-12	Revision 0	Revision 2	Text clarification
Page 5.4-1	Revision 0	Revision 2	Text clarification
Page 5.4-2	Revision 0	Revision 2	Text clarification related to Recirculation bypass valving
Page 5.4-4	Revision 0	Revision 2	Removal of electrical controls for MO 2-7503. Delete remote for MO 2-0202-6/9 A and B. (M12-2-90-066)
Page 5.4-5	Revision 0	Revision 2	Update to Recirculation pump flow control and to address the manual control during maintenance in accordance with station procedures
Page 5.4-8	Revision 0	Revision 2	Section update to reflect the Removal of Unit 2 Recirculation Discharge Valve Bypass Line (M12-2-91-005)
Page 5.4-18a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 5.4-19	Revision 0	Revision 2	No text changes, pagination to improve computer search capability

Identification of Page(s)	Remove	Insert	Notes
Page 5.4-20	Revision 1A	Revision 2	Update to hydrogen addition and added new section addressing Feedwater Oxygen addition per station procedures
Page 5.4-23	Revision 0	Revision 2	Reflect the Installation of a passive depleted Zinc Oxide Injection System to the Feedwater to control Drywell dose rates. (M12-2-94-007)
Page 5.4-23a	N/A new Page	Revision 2	Reflect the Installation of a passive depleted Zinc Oxide Injection System to the Feedwater to control Drywell dose rates. (M12-2-94-007) text flow Page
Page 5.4-25a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 5.4-26	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Page 5.4-27	Revision 1A	Revision 2	Delete reference to "1070 psig" as the value for high reactor pressure initiation of the Isolation Condenser, insert reference to Technical Specification value

Identification of Page(s)	Remove	Insert	Notes
Page 5.4-29	Revision 1A	Revision 2	Delete reference to 11,300 gallons of shell side water as a correct criteria for operability
Page 5.4-29a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 5.4-30	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Page 5.4-32	Revision 1A	Revision 2	Correction to the TDH of the SDCS pumps, editorial standardization of the term mrem /hr
Page 5.4-33	Revision 0	Revision 2	Update to RWCU 1) remove filters from description 2). Clarify cleanup Recirculation pump function (M12-2-86-037; P12-3-90-644, M12-2-91-018)
Page 5.4-34	Revision 0	Revision 2	Update to RWCU 1) remove filters from description 2). Clarify cleanup Recirculation pump function (M12-2-86-037; P12-3-90-644, M12-2-91-018)
Page 5.4-34a	N/A new Page	Revision 2	Update to RWCU 1) remove filters from description 2). Clarify cleanup Recirculation pump function (M12-2-86-037; P12-3-90-644, M12-2-91-018)
Page 5.4-35	Revision 0	Revision 2	Repagination, due to text flow

Identification of Page(s)	Remove	Insert	Notes
Page 5.4-36a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 5.4-37	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Page 5.4-38	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Page 5.4-39a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 5.4-40	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Figure 5.4-1	Revision AS	Revision BA	Drawing update
Figure 5.4-2	Revision HT	Revision JF	Drawing update
Figure 5.4-3	Revision AZ	Revision BD	Drawing update
Figure 5.4-4	Revision AM	Revision AS	Drawing update
Figure 5.4-5	Revision 0	Revision 2	Update to Figure to reflect removal of bypass lines
Figure 5.4-15	Revision D	Revision E	Drawing update
Figure 5.4-16	Revision D	Revision E	Drawing update
Figure 5.4-18	Revision KW	Revision LB	Drawing update
Figure 5.4-19	Revision AS	Revision AU	Drawing update
Figure 5.4-20	Revision AL	Revision AR	Drawing update
Figure 5.4-21	Revision AH	Revision AL	Drawing update

Identification of Page(s)	Remove	Insert	Notes
Figure 5.4-23	Revision ZL	Revision ZS	Drawing update
Figure 5.4-24	Revision AV	Revision AY	Drawing update
Figure 5.4-26	Revision AA	Revision AD	Drawing update
Figure 5.4-27	Revision T	Revision U	Drawing update
Page 6-i	Revision 0	Revision 2	Update to Table of Contents
Page 6.ii	Revision 0	Revision 2	Update to Table of Contents
Page 6-iv	Revision 0	Revision 2	Update to List of Tables
Page 6-v	Revision 0	Revision 2	Update to List of Figures
Page 6-vi	Revision 0	Revision 2	Update to List of Figures
Page 6-vii	Revision 0	Revision 2	Update to List of Figures
Page 6-viii	Revision 0	Revision 2	Update to List of Figures
Page 6-ix	N/A new page	Revision 2	Update to List of Figures
Page 6.1-2	Revision 0	Revision 2	Containment and Drywell piping insulation clarification Removes statement that all piping in Drywell is covered by mirror insulation adds statement that other insulation inside containment meets the requirements in section 5.2.3.2.3 of the UFSAR
Page 6.1-3	Revision 0	Revision 2	Change related to Technical Specification upgrade
Page 6.1-4	Revision 0	Revision 2	Text clarification

Identification of Page(s)	Remove	Insert	Notes
Table 6.1-1 sheets 1-7	Revision 0	Revision 2	Clarification of wording in Table 6.1-1 reflecting material type and grade required for pipes and material required for fittings and valves.
Page 6.2-10	Revision 0	Revision 2	Text clarification
Page 6.2-19	Revision 0	Revision 2	Added Description to identify short term and long term containment response to LOCA
Page 6.2-19a	N/A new Page	Revision 2	Text flow Page
Page 6.2-24a	N/A new Page	Revision 2	New subsection to address the new evaluation for containment short term response to DBA LOCA for minimum NPSH available
Page 6.2-25	Revision 0	Revision 2	Added description to identify short term and long term containment response to LOCA
Page 6.2-26	Revision 0	Revision 2	Subsection and references to original licensing basis for long term cooling were removed / replaced to reflect the current licensing basis

Identification of Page(s)	Remove	Insert	Notes
Page 6.2-27	Revision 0	Revision 2	Subsection and references to original licensing basis for long term cooling were removed / replaced to reflect the current licensing basis
Page 6.2-28	Revision 0	Revision 2	Subsection and references to original licensing basis for long term cooling were removed / replaced to reflect the current licensing basis
Page 6.2-28a	N/A new Page	Revision 2	Text flow Page
Page 6.2-48	Revision 0	Revision 2	Subsection and references to original licensing basis for long term cooling were removed / replaced to reflect the current licensing basis
Page 6.2-49	N/A new Page	Revision 2	Subsection and references to original licensing basis for long term cooling were removed / replaced to reflect the current licensing basis

Identification of Page(s)	Remove	Insert	Notes
Page 6.2-50	Revision 0	Revision 2	Subsection and references to original licensing basis for long term cooling were removed / replaced to reflect the current licensing basis
Page 6.2-53a	N/A new Page	Revision 2	Text flow and clarification
Page 6.2-54	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Page 6.2-57	Revision 0	Revision 2	Subsection and references to original licensing basis for long term cooling were removed / replaced to reflect the current licensing basis
Page 6.2-59	Revision 0	Revision 2	Subsection and references to original licensing basis for long term cooling were removed / replaced to reflect the current licensing basis
Page 6.2-60	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Page 6.2-60a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability

Identification of Page(s)	Remove	Insert	Notes
Page 6.2-61	Revision 0	Revision 2	Change to secondary containment volume and air changes,
Page 6.2-63	Revision 0	Revision 2	Text clarification
Page 6.2-64	Revision 0	Revision 2	Correction to section reference
Page 6.2-67	Revision 0	Revision 2	Change related to Technical Specification upgrade
Page 6.2-67a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 6.2-68	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Page 6.2-69	Revision 0	Revision 2	Replacement of text related to SEP Topic VI-4 administrative controls of manual valves on process piping which penetrates Primary Containment with a Technical Position which describes the administrative controls of these manual valves.
Page 6.2-69a	N/A new Page	Revision 2	Replacement of text related to SEP Topic VI-4 administrative controls of manual valves on process piping which penetrates Primary Containment with a Technical Position which describes the administrative controls of these manual valves.

Identification of Page(s)	Remove	Insert	Notes
Page 6.2-75a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 6.2-76	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Page 6.2-78	Revision 0	Revision 2	Replacement Page due to text flow
Page 6.2-79	Revision 1A	Revision 2	Revision to reflect ACAD / NCAD configuration
Page 6.2-80	Revision 1A	Revision 2	Revision to reflect ACAD / NCAD configuration
Page 6.2-81	Revision 1A	Revision 2	Revision to reflect ACAD / NCAD configuration
Page 6.2-82	Revision 0	Revision 2	Revision to reflect ACAD / NCAD configuration
Page 6.2-82a	N/A new Page	Revision 2	Revision to reflect ACAD / NCAD configuration
Page 6.2-83	Revision 0	Revision 2	Revision to reflect ACAD / NCAD configuration
Page 6.2-84	Revision 0	Revision 2	Revision to reflect ACAD / NCAD configuration
Page 6.2-85	Revision 0	Revision 2	Revision to reflect ACAD / NCAD configuration
Page 6.2-85a	N/A new Page	Revision 2	Revision to reflect ACAD / NCAD configuration
Page 6.2-88	Revision 1A	Revision 2	Revision to reflect ACAD / NCAD configuration

Identification of Page(s)	Remove	Insert	Notes
Page 6.2-91	Revision 0	Revision 2	Eliminate reference to Drywell radiation monitoring sensors. (E12-2-95-217), clarification of discussion Radiation Monitoring Initiating Circuits
Page 6.2-92a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 6.2-93	Revision 0	Revision 2	Revision to state that the containment, containment penetration and seals, and containment isolation valves are tested in accordance with the Primary Containment Leakage Rate Testing Program.
Page 6.2-94	Revision 0	Revision 2	Revision to state that the containment, containment penetration and seals, and containment isolation valves are tested in accordance with the Primary Containment Leakage Rate Testing Program.
Page 6.2-95	Revision 1A	Revision 2	Revision to state that the containment, containment penetration and seals, and containment isolation valves are tested in accordance with the Primary Containment Leakage Rate Testing Program.
Page 6.2-95a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability

Identification of Page(s)	Remove	Insert	Notes
Page 6.2-96	Revision 0	Revision 2	DEOP 500-04 rev 07 Revision to permit use of APCVS for combustible gas control.
Page 6.2-97	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Page 6.2-98	Revision 0	Revision 2	Update to APCVS discussion
Page 6.2-99	Revision 0	Revision 2	Update to APCVS discussion
Table 6.2-3 sheet 1 of 2	Revision 0	Revision 2	Table revised to provide a summary of limiting Containment analysis results
Table 6.2-3 sheet 2 of 2	N/A New sheet	Revision 2	Table revised to provide a summary of limiting Containment analysis results
Table 6.2-3a	N/A new Table	Revision 2	New Table providing key parameters for Containment analysis
Table 6.2-3b	N/A new Table	Revision 2	New Table providing new LPCI/CCSW heat exchanger heat transfer rate

Identification of Page(s)	Remove	Insert	Notes
Table 6.2-6 sheet 1 of 4	Revision 0	Revision 2	Table deleted, references to original licensing basis for long term cooling were removed to reflect the current licensing basis
Table 6.2-6 sheet 2 of 4	Revision 0	N/A Table deleted	Table deleted, references to original licensing basis for long term cooling were removed to reflect the current licensing basis
Table 6.2-6 sheet 3 of 4	Revision 0	N/A Table deleted	Table deleted, references to original licensing basis for long term cooling were removed to reflect the current licensing basis
Table 6.2-6 sheet 4 of 4	Revision 0	N/A Table deleted	Table deleted, references to original licensing basis for long term cooling were removed to reflect the current licensing basis
Table 6.2-7 sheet 1 of 2	Revision 0	Revision 2	Updated to show new design specification
Table 6.2-9	Revision 1A sheets 1-10	Revision 2 sheets 1-15	Table replaced
Table 6.2-10 sheet 1 of 3	Revision 0	Revision 2	Table Revision
Table 6.2-10 sheet 2 of 3	Revision 0	Revision 2	Table Revision
Table 6.2-10 sheet 3 of 3	Revision 0	Revision 2	Table Revision
Table 6.2-11 sheet 1 of 3	Revision 0	Revision 2	Table Revision
Table 6.2-11 sheet 2 of 3	Revision 0	Revision 2	Table Revision

Identification of Page(s)	**Remove**	**Insert**	**Notes**
Table 6.2-11 sheet 3 of 3	Revision 0	Revision 2	Table Revision
Figure 6.2-12	Revision CC	Revision CP	Drawing update
Figure 6.2-13	Revision BE	Revision BL	Drawing update
Figure 6.2-19A	N/A New Figure	Revision 2	Subsection and references to original licensing basis for long term cooling were removed / replaced to reflect the current licensing basis
Figure 6.2-19B	N/A New Figure	Revision 2	Subsection and references to original licensing basis for long term cooling were removed / replaced to reflect the current licensing basis
Figure 6.2-20A	N/A New Figure	Revision 2	Subsection and references to original licensing basis for long term cooling were removed / replaced to reflect the current licensing basis
Figure 6.2-20B	N/A New Figure	Revision 2	Subsection and references to original licensing basis for long term cooling were removed / replaced to reflect the current licensing basis

Identification of Page(s)	Remove	Insert	Notes
Figure 6.2-20C	N/A New Figure	Revision 2	Subsection and references to original licensing basis for long term cooling were removed / replaced to reflect the current licensing basis
Figure 6.2-20D	N/A New Figure	Revision 2	Subsection and references to original licensing basis for long term cooling were removed / replaced to reflect the current licensing basis
Figure 6.2-48	Revision Z	Revision AC	Drawing update
Figure 6.2-49	Revision V	Revision X	Drawing update
Figure 6.2-50	Revision AF	Revision AH	Drawing update
Figure 6.2-51	Revision AB	Revision AD	Drawing update
Page 6.3-3	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Page 6.3-4	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Page 6.3-7	Revision 0	Revision 2	Update to LOCA analysis assumptions to section 6.3 including appropriate core spray flows and leakage's

Identification of Page(s)	Remove	Insert	Notes
Page 6.3-9	Revision 0	Revision 2	Added reference to Dresden Units 2 &3 principal LOCA analysis parameters for maximum valve opening time.
Page 6.3-10	Revision 0	Revision 2	Text clarification addressing differential pressure between the Reactor vessel dome and the Drywell.
Page 6.3-11	Revision 0	Revision 2	Text clarification
Page 6.3-11a	N/A new Page	Revision 2	Text flow Page
Page 6.3-13	Revision 0	Revision 2	Correction to the type of valves on the LPCI pump discharge lines. Deletion of the locked closed manual valve for LPCI subsystem isolation.
Page 6.3-14	Revision 0	Revision 2	Text clarification, added statement that the Condensate Transfer system can be used as an alternate fill system for the Jockey pump
Page 6.3-15	Revision 0	Revision 2	Text clarification

Identification of Page(s)	Remove	Insert	Notes
Page 6.3-16	Revision 0	Revision 2	Text clarification, added statement that AC power is required for the HPCI room cooler fans.
Page 6.3-17	Revision 0	Revision 2	Text clarification
Page 6.3-18	Revision 1A	Revision 2	Text Clarification and the Deletion of the statement on override HPCI operation is allowed by DEOPs.
Page 6.3-19	Revision 0	Revision 2	Text clarification
Page 6.3-20	Revision 0	Revision 2	Text clarification
Page 6.3-20a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 6.3-21	Revision 0	Revision 2	Added statement discussing the 100 psig isolation point.
Page 6.3-21a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 6.3-22	Revision 0	Revision 2	Update to LOCA analysis assumptions
Page 6.3-25	Revision 0	Revision 2	Text clarification
Page 6.3-26	Revision 0	Revision 2	Update to LOCA analysis assumptions

Identification of Page(s)	Remove	Insert	Notes
Page 6.3-27	Revision 0	Revision 2	Added clarifying statements to section 6.3.3.1.3.2 to distinguish the analysis associated with the design basis accident scenarios from analysis that demonstrate subsystem performance
Page 6.3-36	Revision 0	Revision 2	Update to new reference 64
Page 6.3-47	Revision 0	Revision 2	Repagination to ensure equation fidelity - no text changes
Page 6.3-48	Revision 0	Revision 2	Repagination to ensure equation fidelity - no text changes
Page 6.3-48a	N/A new Page	Revision 2	Repagination to ensure equation fidelity - no text changes
Page 6.3-49	N/A new Page	Revision 2	Repagination to ensure equation fidelity - no text changes
Page 6.3-55	Revision 0	Revision 2	Repagination to ensure equation fidelity - no text changes
Page 6.3-55a	N/A new Page	Revision 2	Repagination to ensure equation fidelity - no text changes
Page 6.3-56	Revision 0	Revision 2	Repagination to ensure equation fidelity - no text changes
Page 6.3-61	Revision 0	Revision 2	Update to LOCA analysis assumptions including appropriate core spray flows and leakage's
Page 6.3-61a	N/A new Page	Revision 2	Text flow Page
Page 6.3-62	Revision 0	Revision 2	Text clarification discussing Recirculation bypass valving configuration.

Identification of Page(s)	Remove	Insert	Notes
Page 6.3-71	Revision 0	Revision 2	Deleted Pages contain inconsistent and incorrect information. This information is outdated and was included as a historical reference.
Page 6.3-72 Page deleted	Revision 0	Revision 2	Deleted Pages contain inconsistent and incorrect information. This information is outdated and was included as a historical reference.
Page 6.3-73 Page deleted	Revision 0	Revision 2	Deleted Pages contain inconsistent and incorrect information. This information is outdated and was included as a historical reference.
Page 6.3-74	Revision 0	Revision 2	Subsection and references to original licensing basis for long term cooling were removed / replaced to reflect the current licensing basis
Page 6.3-75	Revision 0	Revision 2	Subsection and references to original licensing basis for long term cooling were removed / replaced to reflect the current licensing basis

Identification of Page(s)	Remove	Insert	Notes
Page 6.3-76	Revision 0	Revision 2	Subsection and references to original licensing basis for long term cooling were removed / replaced to reflect the current licensing basis
Page 6.3-77	Revision 0	Revision 2	Subsection and references to original licensing basis for long term cooling were removed / replaced to reflect the current licensing basis
Page 6.3-78	Revision 0	Revision 2	Subsection and references to original licensing basis for long term cooling were removed / replaced to reflect the current licensing basis
Page 6.3-79	Revision 0	Revision 2	Subsection and references to original licensing basis for long term cooling were removed / replaced to reflect the current licensing basis
Page 6.3-79a	N/A new page	Revision 2	text flow page
Page 6.3-81	Revision 0	Revision 2	Text clarification for LPCI pump testing

Identification of Page(s)	Remove	Insert	Notes
Page 6.3-83	Revision 0	Revision 2	Added statement that the remote Valve indication for the HPCI 2301-7 checkvalve is not used to verify valve stroke.
Page 6.3-87	Revision 0	Revision 2	Added new reference 64.
Table 6.3-1 sheet 1 of 1	Revision 0	Revision 2	Table unit clarification and additional statement that AC power is required for the HPCI room cooler fans.
Table 6.3-4 sheet 1 of 1	Revision 0	Revision 2	Correction to LPCI and Core Spray pump nomenclature.
Table 6.3-12 (replace with single sheet Table 6.3-12a and 6.3-12b)	Revision 0	Revision 2	Update to LOCA analysis for ANF 9X9 reload fuel
Table 6.3-13	Revision 0	Revision 2	Update to LOCA analysis for ANF 9X9 reload fuel
Table 6.3-14	Revision 0	Revision 2	Table contained historical data, Table deleted
Table 6.3-15	Revision 0	Revision 2	Table contained historical data, Table deleted
Table 6.3-16	Revision 0	Revision 2	Table contained historical data, Table deleted
Table 6.3-17	Revision 0	Revision 2	Table deleted, reflected original design information
Table 6.3-18	Revision 0	Revision 2	Table replaced to show long term NPSH margin

Identification of Page(s)	Remove	Insert	Notes
Table 6.3-19	N/A New Table	Revision 2	Update to LOCA analysis assumptions including appropriate core spray flows and leakage's
Figure 6.3-2A	Revision YL	Revision YT	Drawing update
Figure 6.3-2B	Revision BG	Revision BQ	Drawing update
Figure 6.3-7A	Revision BB	Revision BQ	Drawing update
Figure 6.3-7B	Revision UR	Revision UX	Drawing update
Figure 6.3-9A	Revision AX	Revision BF	Drawing update
Figure 6.3-9B	Revision BH	Revision BP	Drawing update
Figure 6.3-77 deleted	Revision 0	Revision 2	Subsection and references to original licensing basis for long term cooling were removed / replaced to reflect the current licensing basis
Figure 6.3-78 deleted	Revision 0	Revision 2	Subsection and references to original licensing basis for long term cooling were removed / replaced to reflect the current licensing basis
Figure 6.3-80	Revision 0	Revision 2	Subsection and references to original licensing basis for long term cooling were removed / replaced to reflect the current licensing basis

Identification of Page(s)	Remove	Insert	Notes
Figure 6.3-83	N/A new Figure	Revision 2	Subsection and references to original licensing basis for long term cooling were removed / replaced to reflect the current licensing basis
Figure 6.3-84	N/A new Figure	Revision 2	Subsection and references to original licensing basis for long term cooling were removed / replaced to reflect the current licensing basis
Page 6.4-2	Revision 0	Revision 2	Remove statement that HVAC system are capable of both automatic and manual transfer from the normal operating mode to the smoke purge mode to state only that manual transfer to the smoke purge mode is available.
Page 6.4-3	Revision 0	Revision 2	Documents an exception to the charcoal efficiency testing limits as set forth in Reg. Guide 1.52 as approved by SER for TSUP

Identification of Page(s)	**Remove**	**Insert**	**Notes**
Page 6.4-6	Revision 0	Revision 2	Change to state exhaust damper rather that exhaust fan. Included a statement discussing additional operator actions include disabling toxic gas protection interlocks to activate the Air Filtration Unit., during a LOOP/ LOCA
Page 6.4-10	Revision 0	Revision 2	Remove statement that HVAC system are capable of both automatic and manual transfer from the normal operating mode to the smoke purge mode to state only that manual transfer to the smoke purge mode is available.
Page 6.5-1	Revision 0	Revision 1	Change to secondary containment volume and air changes, change to SBGTS efficiency,
Page 6.5-2	Revision 0	Revision 2	Revision to reflect plant configuration of SBGTS demister drain; correction to the temperature capacity of the charcoal to reflect specifications; change to SBGTS efficiency,
Page 6.5-3	Revision 0	Revision 2	Revision to reflect current operation configuration of MO 2-7503

Identification of Page(s)	Remove	Insert	Notes
Page 6.5-5	Revision 0	Revision 2	Added statement that system flowrate is monitored in the Control Room.
Figure 6.5-1	Revision PY	Revision QG	Drawing update
Page 7-ii	Revision 0	Revision 2	Update to Table of Contents
Page 7-iii	Revision 0	Revision 2	Update to Table of Contents
Page 7-vi	Revision 0	Revision 2	Update to List of Figures
Page 7.2-7a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 7.2-8	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Page 7.2-9	Revision 0	Revision 2	Relocation of reactor Protection System Response times from Technical Specification 3.1.A.1
Page 7.2-9a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 7.2-10	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Table 7.2-1 sheet 1 of 1	Revision 0	Revision 2	Change related to Technical Specification upgrade

Identification of Page(s)	Remove	Insert	Notes
Page 7.3-2	Revision 0	Revision 2	Replace Reactor Low-Low Level Yarway Switches with existing Rosemont ATWS Transmitters (M12-2-94-002)
Page 7.3-4	Revision 0	Revision 2	Replace Reactor Low-Low Level Yarway Switches with existing Rosemont ATWS Transmitters (M12-2-94-002)
Page 7.3-5	Revision 0	Revision 2	Replace Reactor Low-Low Level Yarway Switches with existing Rosemont ATWS Transmitters (M12-2-94-002)
Page 7.3-6	Revision 0	Revision 2	Text clarification
Page 7.3-7	Revision 0	Revision 2	Replace Reactor Low-Low Level Yarway Switches with existing Rosemont ATWS Transmitters (M12-2-94-002) Revision to commitments to locked or lockable instrument valves and breakers for Core Spray, LPCI, and ADS.
Page 7.3-9	Revision 0	Revision 2	Replace Reactor Low-Low Level Yarway Switches with existing Rosemont ATWS Transmitters (M12-2-94-002)
Page 7.3-10	Revision 0	Revision 2	Text clarification
Page 7.3-16	Revision 0	Revision 2	Text clarification
Page 7.3-17	Revision 0	Revision 2	Replace Reactor Low-Low Level Yarway Switches with existing Rosemont ATWS Transmitters (M12-2-94-002) Added reference to two additional Figures.

Identification of Page(s)	Remove	Insert	Notes
Page 7.3-18	Revision 0	Revision 2	Text clarification
Page 7.3-19	Revision 0	Revision 2	Removal of discussion of MSC block
Page 7.3-20	Revision 0	Revision 2	Text clarification
Page 7.3-22	Revision 0	Revision 2	Text clarification
Page 7.3-26	Revision 0	Revision 2	Replace Reactor Low-Low Level Yarway Switches with existing Rosemont ATWS Transmitters (M12-2-94-002)
Page 7.3-32	Revision 0	Revision 2	Revision of commitments to locked or lockable instrument valves and breakers for Core Spray, LPCI, and ADS.
Page 7.3-33a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 7.3-34	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Page 7.3-38	Revision 0	Revision 2	Change related to Technical Specification upgrade
Page 7.3-40	Revision 0	Revision 2	Text clarification
Page 7.3-41	Revision 0	Revision 2	Text clarification
Page 7.3-43	Revision 0	Revision 2	Text clarification, change to High temperature trip setting, and change to HPCI high water level trip setting.

Identification of Page(s)	Remove	Insert	Notes
Page 7.3-44	Revision 0	Revision 2	Text clarification
Page 7.3-47	Revision 0	Revision 2	Text clarification
Page 7.3-48a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 7.3-49	Revision 0	Revision 2	Added reference to Technical Specifications for the Isolation Condenser initiation signal value.
Table 7.3-1 sheet 1 of 1	Revision 0	Revision 2	Change related to Technical Specification upgrade
Figure 7.3-1	Revision 0	Revision 2	Replace Reactor Low-Low Level Yarway Switches with existing Rosemont ATWS Transmitters (M12-2-94-002)
Figure 7.3-2A	Revision 0	Revision 2	Replace Reactor Low-Low Level Yarway Switches with existing Rosemont ATWS Transmitters (M12-2-94-002)
Figure 7.3-8A	Revision 0	Revision 2	Replace Reactor Low-Low Level Yarway Switches with existing Rosemont ATWS Transmitters (M12-2-94-002)
Figure 7.3-9	Revision 0	Revision 2	Replace Reactor Low-Low Level Yarway Switches with existing Rosemont ATWS Transmitters (M12-2-94-002)

Identification of Page(s)	Remove	Insert	Notes
Figure 7.3-10	Revision 0	Revision 2	Replace Reactor Low-Low Level Yarway Switches with existing Rosemont ATWS Transmitters (M12-2-94-002)
Page 7.4-1	Revision 0	Revision 2	Text clarification
Page 7.5-4	Revision 0	Revision 2	Changed wording from prime computer to minicomputer
Page 7.5-6	Revision 0	Revision 2	Changed wording from prime computer to minicomputer
Page 7.6-4	Revision 0	Revision 2	Change to the section 7.6.1.3.2 to reflect the philosophy of longer period during startup
Page 7.6-13	Revision 0	Revision 2	Revision to reflect procedural requirement to verify APRM calibration at greater that 25% of rated power
Page 7.6-15	Revision 0	Revision 2	Text clarification, Change to reflect that a rod block will occur if the reading falls below the RBM down scale trip setpoint.
Page 7.6-18a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 7.6-19	Revision 0	Revision 2	No text changes, pagination to improve computer search capability

Identification of Page(s)	**Remove**	**Insert**	**Notes**
Page 7.6-21	Revision 1A	Revision 2	No text changes, pagination to improve computer search capability
Page 7.6-22	Revision 1A	Revision 2	No text changes, pagination to improve computer search capability
Page 7.6-22a	Revision 1A	Revision 2	Text flow
Page 7.6-24	Revision 0	Revision 2	Changes associated with the Feedwater control modification (M12-2-88-013C)
Page 7.6-24a	N/A new Page	Revision 2	Replace Reactor Low-Low Level Yarway Switches with existing Rosemont ATWS Transmitters (M12-2-94-002)
Figure 7.6-17	Revision 0	Revision 2	Change to note to state that RBM high flux trip vs. Recirculation flow is specified in the COLR and values shown in the Figure are typical values
Page 7.7-7a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 7.7-8	Revision 0	Revision 2	Text clarification related to RBM Rodblock
Page 7.7-11	Revision 0	Revision 2	Text clarification replace core average power to core thermal power.

Identification of Page(s)	Remove	Insert	Notes
Page 7.7-19	Revision 0	Revision 2	Change related to Technical Specification upgrade
Page 7.7-19a	N/A new Page	Revision 2	Change related to Technical Specification upgrade
Page 7.7-20	Revision 0	Revision 2	No text changes Repagination to reflect the addition of the preceding 7.7-19a Page
Page 7.7-31a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 7.7-32	Revision 0	Revision 2	Text clarification
Page 7.7-33	Revision 0	Revision 2	Text clarification
Page 7.7-34	Revision 0	Revision 2	Corrected section references
Page 7.7-34a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 7.7-35	Revision 0	Revision 2	Changes associated with the Feedwater control modification (M12-2-88-013C)
Page 7.7-36	Revision 0	Revision 2	Changes associated with the Feedwater control modification (M12-2-88-013C)
Page 7.7-37	Revision 0	Revision 2	Changes associated with the Feedwater control modification (M12-2-88-013C)

Identification of Page(s)	Remove	Insert	Notes
Page 7.8-2	Revision 0	Revision 2	Replace Reactor Low-Low Level Yarway Switches with existing Rosemont ATWS Transmitters (M12-2-94-002)
Page 7.8-3	Revision 0	Revision 2	Replace Reactor Low-Low Level Yarway Switches with existing Rosemont ATWS Transmitters (M12-2-94-002)
Page 8-i	Revision 0	Revision 2	Update to Table of Contents
Page 8.1-2	Revision 0	Revision 2	Change to reflect the installation of the Station Blackout system (M12-0-91-019C)
Page 8.2-2	Revision 0	Revision 2	A second manual crosstie connection between safety buses 23-1 and 33-1 in addition to buses 24-1 and 34-1 has been installed. (M12-0-91-018-B)
Page 8.2-2a	N/A new Page	Revision 2	Text flow Page
Figure 8.2-1	Revision 0	Revision 2	A second manual crosstie connection between safety buses 23-1 and 33-1 in addition to buses 24-1 and 34-1 has been installed. (M12-0-91-018-B) Change to reflect the installation of the Station Blackout system (M12-0-91-019C)
Figure 8.2-3	Revision B	Revision C	Drawing update
Page 8.3-9	Revision 1A	Revision 2	Eliminate "Safety Related" from the description of the 250 VDC Computer UPS battery.

Identification of Page(s)	Remove	Insert	Notes
Page 8.3-18	Revision 0	Revision 2	Revision to reflect the current methodology used to derate power cables.
Page 8.3-18a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 8.3-19	Revision 1A	Revision 2	No text changes, pagination to improve computer search capability
Page 8.3-20	Revision 1A	Revision 2	Change to 250v Battery Charger Float and Equalizing voltages (DOP 6900-01 rev.)
Page 8.3-20a	N/A new Page	Revision 2	Correction of typographical error
Page 8.3-22	Revision 0	Revision 2	Add description of the 125 VDC battery qualified life. Clarification of wording for the 125 VDC Battery System ground detection
Page 8.3-23	Revision 0	Revision 2	Clarification of wording for the 125 VDC Battery System 1) ground detection. Change to reflect the installation of the Station Blackout system (M12-0-91-019C)
Page 8.3-24	Revision 1A	Revision 2	Replacement of 24/48 VDC Batteries and Chargers and repowering of ATS loads.
Page 8.3-24a	N/A new Page	Revision 2	Replacement of 24/48 VDC Batteries and Chargers and repowering of ATS loads.

Identification of Page(s)	Remove	Insert	Notes
Page 8.3-25	Revision 1A	Revision 2	Replacement of 24/48 VDC Batteries and Chargers and repowering of ATS loads.
Page 8.3-25a	N/A new Page	Revision 2	Clarification of wording for the 125 VDC Battery System for the transfer the DC control power to alternate.
Table 8.3-1 sheet 1 of 7	Revision 1A	Revision 2	Update to Table
Table 8.3-1 sheet 2 of 7	Revision 0	Revision 2	Update to Table
Table 8.3-1 sheet 3 of 7	Revision 0	Revision 2	Update to Table
Table 8.3-1 sheet 4 of 7	Revision 1A	Revision 2	Update to Table
Table 8.3-1 sheet 5 of 7	Revision 0	Revision 2	Update to Table
Table 8.3-1 sheet 6 of 7	Revision 0	Revision 2	Update to Table
Table 8.3-1 sheet 7 of 7	Revision 1A	Revision 2	Update to Table
Table 8.3-7 sheet 1 of 1	Revision 0	Revision 2	Update to Table
Page 9-i	Revision 0	Revision 2	Update to Table of Contents
Page 9-ii	Revision 0	Revision 2	Update to Table of Contents
Page 9-iii	Revision 0	Revision 2	Update to Table of Contents
Page 9-iv	Revision 0	Revision 2	Update to Table of Contents
Page 9-v	Revision 0	Revision 2	Update to Table of Contents
Page 9-vi	Revision 1A	Revision 2	Update to Table of Contents
Page 9-viii	Revision 0	Revision 2	Update to List of Figures

Identification of Page(s)	Remove	Insert	Notes
Page 9.1-1	Revision 0	Revision 2	Change to reflect refueling practice
Page 9.1-2	Revision 0	Revision 2	Update to UFSAR to reflect the Atrium 9B fuel type for fuel storage.
Page 9.1-2a	N/A new Page	Revision 2	Update to UFSAR to reflect the Atrium 9B fuel type for fuel storage.
Page 9.1-4	Revision 0	Revision 2	Text clarification
Page 9.1-7	Revision 0	Revision 2	Update to UFSAR to reflect the Atrium 9B fuel type for fuel storage.
Page 9.1-7a	N/A new Page	Revision 2	Update to UFSAR to reflect the Atrium 9B fuel type for fuel storage.
Page 9.1-9	Revision 0	Revision 2	Incorporated information pertaining to bundle drop height above the fuel racks
Page 9.1-9a	N/A new Page	Revision 2	Change to correct deviation of description for spent fuel pool high density fuel rack corrosion sampling program Clarified assumptions used in heat load calculations for a partial core offload and full core offload.. Changed partial core off-load Maximum temperature to 145 degrees F to equal full core off-load limit. Corrected SDC flowrate in fuel pool cooling mode

Identification of Page(s)	Remove	Insert	Notes
Page 9.1-10	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Page 9.1-11	Revision 1A	Revision 2	Clarified assumptions used in heat load calculations for a partial core offload and full core offload. Changed partial core off-load Maximum temperature to 145 degrees F to equal full core off-load limit.
Page 9.1-11a	Revision 1A	Revision 2	No text changes, pagination to improve computer search capability
Page 9.1-12	Revision 0	Revision 2	Added the heat capacity of the fuel pool cooling heat exchangers based on pool temperature of 125 degrees F. added discussion related to the flow rate and heat removal capability of the SDC cross connect

Identification of Page(s)	**Remove**	**Insert**	**Notes**
Page 9.1-13	Revision 0	Revision 2	Corrected RBCCW flow rate through the FPC heat exchangers based on performance calculations and the specification sheet for the heat exchangers. Standardization to the term mrem /hr, Added statement that fuel pool cooling and cleanup systems are tested per the augmented IST program.
Page 9.1-13a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 9.1-14	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Page 9.1-15	Revision 1A	Revision 2	Text clarification
Page 9.1-16	Revision 1A	Revision 2	Correction to height for auxiliary hoist upward block
Page 9.1-17	Revision 1A	Revision 2	Added discussion of X-Y coordinate backup system
Page 9.1-18	Revision 0	Revision 2	Addition of statement qualifying procedural monitoring as an alternative to the digital weight indicator load limiter

Identification of Page(s)	Remove	Insert	Notes
Page 9.1-19	Revision 0	Revision 2	Standardization to the term mrem /hr.
Page 9.1-20	Revision 0	Revision 2	Text clarification
Page 9.1-21	Revision 1A	Revision 2	Added the dryer/separator pit is pumped down to the raised step at the bottom of the pit when refueling is completed.. Added statement that direct communication is maintained between the refueling bridge and the control room during core alterations,
Page 9.1-22	Revision 1A	Revision 2	Text clarification to expand the discussion of the telescoping grapple, Standardization to the term mrem /hr.
Page 9.1-23	Revision 0	Revision 2	Revision to clarify that the statement about "single element components within the load path" having a safety factor of 7.5 does not apply to all crane components in Table 9.1-3. Only a subset of the components listed in the Table are considered to be within the load path of the crane and, therefore, subject to this requirement.. Additional change related to Technical Specification upgrade

Identification of Page(s)	Remove	Insert	Notes
Page 9.1-25	Revision 0	Revision 2	Text clarification added the term transport vehicle to discussion in 9.1.4.4.2
Page 9.1-26	Revision 0	Revision 2	Update to reference section
Table 9.1-1	Revision 01A	Revision 2	Update to Table
Table 9.1-2 sheet 1 of 1	Revision 0	Revision 2	Standardization of the term mrem /hr
Table 9.1-4 sheets 1 and 2	N/A new table	Revision 2	Table added to detail Spent Fuel Pool Cooling Capability and listing of assumptions used in the calculations
Figure 9.1-3	Revision AT	Revision BD	Drawing update
Figure 9.1-4	Revision AG	Revision AN	Drawing update
Figure 9.1-8	Revision 0	Revision 2	Figure Deleted
Figure 9.1-11	Revision 0	Revision 2	Figure Deleted
Figure 9.1-12	Revision 0	Revision 2	Figure Deleted
Figure 9.1-13	Revision AE	Revision AF	Drawing update
Figure 9.1-14	Revision X	Revision Y	Drawing update
Page 9.2-2	Revision 0	Revision 2	Subsection and references to original licensing basis for long term cooling were removed / replaced to reflect the current licensing basis
Page 9.2-3a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability

Identification of Page(s)	Remove	Insert	Notes
Page 9.2-4	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Page 9.2-7a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 9.2-8	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Page 9.2-11a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 9.2-12	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Page 9.2-12a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 9.2-13	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Page 9.2-15	Revision 0	Revision 2	Text clarification
Page 9.2-16	Revision 0	Revision 2	Deleted word wooden in discussion on stop logs.
Page 9.2-16a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability

Identification of Page(s)	Remove	Insert	Notes
Page 9.2-17	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Page 9.2-18	Revision 1A	Revision 2	This change describes these controls that are in place to reserve 90,000 gal. on either CCST.
Page 9.2-19	Revision 1A	Revision 2	Clarification on CCST discussion for HPCI supply.
Page 9.2-19a	N/A new Page	Revision 2	Change to the power supply for the U2 Isolation condenser clean demineralizer fill valve from AC to DC. (M12-2-90-057D)
Page 9.2-20	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Page 9.2-21	Revision 1A	Revision 2	No text changes, pagination to improve computer search capability
Page 9.2-21a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 9.2-22	Revision 0	Revision 2	No text changes, pagination to improve computer search capability

Identification of Page(s)	Remove	Insert	Notes
Table 9.2-1	Revision 0	Revision 2	Subsection and references to original licensing basis for long term cooling were removed / replaced to reflect the current licensing basis
Figure 9.2-1	Revision Y	Revision AC	Drawing update
Figure 9.2-2	Revision W	Revision AA	Drawing update
Figure 9.2-3	Revision BY	Revision CG	Drawing update
Figure 9.2-4	Revision PC	Revision PJ	Drawing update
Figure 9.2-8	Revision KS	Revision KX	Drawing update
Figure 9.2-9	Revision AH	Revision AK	Drawing update
Figure 9.2-10	Revision CH	Revision CR	Drawing update
Figure 9.2-11	Revision B	Revision C	Drawing update
Figure 9.2-12	Revision B	Revision C	Drawing update
Figure 9.2-19	Revision AN	Revision AT	Drawing update
Figure 9.2-20	Revision LX	Revision MA	Drawing update
Figure 9.2-22	Revision AL	Revision AM	Drawing update
Page 9.3-2	Revision 1A	Revision 2	Update FSAR description to reflect the replacement of the 2B instrument air compressor (E12-2-96-207)
Page 9.3-3	Revision 1A	Revision 2	Deletion of reference to unit 1 air system backup
Page 9.3-5a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability

Identification of Page(s)	Remove	Insert	Notes
Page 9.3-6	Revision 1A	Revision 2	No text changes, pagination to improve computer search capability
Page 9.3-22	Revision 1A	Revision 2	Update to reflect the as- built configuration of the radiation monitors associated with the Off- Gas sampling
Page 9.3-28	Revision 1A	Revision 2	Text clarification
Page 9.3-28a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 9.3-29	Revision 1A	Revision 2	No text changes, pagination to improve computer search capability
Page 9.3-30	Revision 1A	Revision 2	Text clarification
Page 9.3-33	Revision 1A	Revision 2	Change related to Technical Specification upgrade
Table 9.3-3 sheet 1 of 1	Revision 0	Revision 2	Update to design negative reactivity value
Figure 9.3-1	Revision B	Revision E	Drawing update
Figure 9.3-2	Revision A	Revision E	Drawing update
Figure 9.3-3	Revision AQ	Revision AV	Drawing update
Figure 9.3-4	Revision G	Revision J	Drawing update
Figure 9.3-8	Revision HQ	Revision HS	Drawing update
Page 9.4-1	Revision 0	Revision 2	Revision to address potential for air flow from points of higher contamination to areas of lower contamination

Identification of Page(s)	Remove	Insert	Notes
Page 9.4-4	Revision 0	Revision 2	Revision to address potential for air flow from points of higher contamination to areas of lower contamination
Page 9.4-7	Revision 1A	Revision 2	Change to state that the east Turbine Room Ventilation System will maintain the east Turbine Building at a slight positive pressure relative to atmosphere.
Page 9.4-8	Revision 0	Revision 2	Revise section 9.4.5 to clarify reactor building ventilation temperature requirements and include EQ temperature requirement from Table 3.11-1 Revision to address potential for air flow from points of higher contamination to areas of lower contamination.
Page 9.4-9	Revision 0	Revision 2	Installation of a chilled water system for the U-2 Reactor Building Ventilation Supply Fan System. (M12-2-94-008)
Page 9.4-9a	N/A new Page	Revision 2	Correction to discussion on Corner Room coolers to clarify the HPCI room cooler fan is required for proper operation of the HPCI system
Figure 9.4-1	Revision C	Revision E	Drawing update
Figure 9.4-2	Revision E	Revision F	Drawing update
Figure 9.4-3	Revision 10	Revision 13	Drawing update

Identification of Page(s)	Remove	Insert	Notes
Figure 9.4-4	Revision AC	Revision AD	Drawing update
Figure 9.4-7	Revision E	Revision F	Drawing update
Figure 9.4-11	Revision G	Revision H	Drawing update
Page 9.5-3	Revision 1A	Revision 2	Removed wording that the plant P.A. system can be accessed from the station PBX system
Page 9.5-6	Revision 0	Revision 2	Text clarification
Page 9.5-7	Revision 0	Revision 2	Include word "nominal" after 32 inches. in discussion of fuel oil transfer pumps
Page 9.5-9	Revision 0	Revision 2	Correct ion to the operating pressure for the diesel generator air receivers
Page 9.5-13	Revision 0	Revision 2	New sections to be added to reflect the installation of the Station Blackout system (M12-0-91-019C)
Page 9.5-14	N/A new Page	Revision 2	New sections to be added to reflect the installation of the Station Blackout system (M12-0-91-019C)
Page 9.5-15	N/A new Page	Revision 2	New sections to be added to reflect the installation of the Station Blackout system (M12-0-91-019C)
Page 9.5-16	N/A new Page	Revision 2	New sections to be added to reflect the installation of the Station Blackout system (M12-0-91-019C)
Page 9.5-17	N/A new Page	Revision 2	New sections to be added to reflect the installation of the Station Blackout system (M12-0-91-019C)

Identification of Page(s)	Remove	Insert	Notes
Page 9.5-18	N/A new Page	Revision 2	New sections to be added to reflect the installation of the Station Blackout system (M12-0-91-019C)
Page 9.5-19	N/A new Page	Revision 2	New sections to be added to reflect the installation of the Station Blackout system (M12-0-91-019C)
Page 9.5-20	N/A new Page	Revision 2	New sections to be added to reflect the installation of the Station Blackout system (M12-0-91-019C)
Page 9.5-21	N/A new Page	Revision 2	No text changes, section 9.5.10 moved to accommodate new section 9.5.9
Figure 9.5-1	Revision o	Revision X	Drawing update
Figure 9.5-6	Revision E	Revision F	Drawing update
Figure 9.5-7	Revision E	Revision F	Drawing update
Figure 9.5-10	Revision AF	Revision AN	Drawing update
Figure 9.5-11	Revision F	Revision G	Drawing update
Figure 9.5-12	Revision F	Revision G	Drawing update
Figure 9.5-14	N/A new Figure	Revision 2	New Figure to be added to reflect the installation of the Station Blackout system (M12-0-91-019C)
Page 10-i	Revision 0	Revision 2	Update to Table of Contents
Page 10-iv	Revision 0	Revision 2	Update to List of Figures

Identification of Page(s)	Remove	Insert	Notes
Page 10.2-1	Revision 0	Revision 2	Removal of KW rating for main turbine
Page 10.2-2	Revision 1A	Revision 2	Change related to Technical Specification upgrade. FAS subsystem change (P12-2-94-288)
Page 10.2-2a	Revision 1A	N/A Page deleted	Page deleted, change to Page 10.2 allowed all text from 10.2a to be included on the previous Page
Page 10.2-5	Revision 0	Revision 2	Change related to Technical Specification upgrade
Page 10.3-2	Revision 0	Revision 2	Change to define main turbine bypass valve opening time testing
Table 10.3-1	Revision 0	Revision 2	Update to reflect general work specification K-4080 Revision
Figure 10.3-1	Revision NS	Revision NW	Drawing update
Figure 10.3-2	Revision AAH	Revision AAP	Drawing update
Figure 10.3-3	Revision AJ	Revision AP	Drawing update
Figure 10.3-4	Revision NX	Revision PD	Drawing update
Page 10.4-3	Revision 1A	Revision 2	Change related to Technical Specification upgrade
Page 10.4-4	Revision 0	Revision 2	Text update following system review

Identification of Page(s)	Remove	Insert	Notes
Page 10.4-5	Revision 0	Revision 2	Change related to Technical Specification upgrade. Text update following system review
Page 10.4-6	Revision 0	Revision 2	Text update following system review
Page 10.4-7	Revision 0	Revision 2	No text changes, pagination to improve computer search capability
Page 10.4-8	Revision 0	Revision 2	Text clarification
Page 10.4-11	Revision 0	Revision 2	Update for Condensate demineralizer flowrate
Page 10.4-11a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 10.4-13	Revision 0	Revision 2	Changes associated with the Feedwater control modification (M12-2-88-013C) Install a passive depleted Zinc Oxide Injection System to the Feedwater to control Drywell dose rates.(M12-2-94-007)
Page 10.4-14	Revision 0	Revision 2	Changes associated with the Feedwater control modification (M12-2-88-013C) Deletion of text references to Tables 10.4-2 & 10.4-3
Page 10.4-15	Revision 0	Revision 2	Changes associated with the Feedwater control modification (M12-2-88-013C)

Identification of Page(s)	Remove	Insert	Notes
Page 10.4-16	Revision 0	Revision 2	Changes associated with the Feedwater control modification (M12-2-88-013C)
Page 10.4-17	Revision 0	Revision 2	Correction to ASME code reference. text addition to state that erosion / corrosion inspections are conducted per NSAC 202L
Page 10.4-18	Revision 0	Revision 2	Page reissued due to text flow
Table 10.4-1 sheet 2	Revision 0	Revision 2	Correction of typographical error in header
Table 10.4-2	Revision 0	Revision 2	Table deleted
Table 10.4-3	Revision 0	Revision 2	Table deleted
Figure 10.4-1	Revision JY	Revision KC	Drawing update
Figure 10.4-3	Revision PT	Revision PW	Drawing update
Figure 10.4-4	Revision PU	Revision PV	Drawing update
Figure 10..4-5	Revision UZ	Revision VB	Drawing update
Figure 10.4-6	Revision WZ	Revision XA	Drawing update
Figure 10.4-7	Revision AB	Revision AE	Drawing update
Figure 10.4-8	Revision KV	Revision LB	Drawing update
Figure 10.4-9	Revision AX	Revision AZ	Drawing update
Figure 10.4-11	Revision AC	Revision AD	Drawing update
Figure 10.4-13	Revision 0	Revision 2	Changes associated with the Feedwater control modification (M12-2-88-013C)

Identification of Page(s)	**Remove**	**Insert**	**Notes**
Page 11.1-2	Revision 0	Revision 2	Clarification that the activity level for gaseous effluents that isolate secondary containment equates to a calculated dose rate as annotated in the Technical specifications and not the revised 10 CFR part 20 as stated.. Changes to bring UFSAR in compliance with 1/94 Revision of 10CFR20.
Page 11.1-2a	N/A new Page	Revision 2	Text flow Page
Table 11.1-3 sheet 1 of 2	Revision 0	Revision 2	Added note to Table
Table 11.1-3 sheet 2 of 2	Revision 0	Revision 2	Added note to Table
Page 11.2-2	Revision 0	Revision 2	Provides for use of portable Waste Treatment Systems as another type of system that can utilize to process liquid radwaste. (E-12-0-95-206) Changes to bring UFSAR in compliance with 1/94 Revision of 10CFR20.
Page 11.2-3	Revision 0	Revision 2	Revision to reflect the retirement of U-1 radwaste tanks T-114 and T-129A, B, C. Change reflect the direct transfer of U-1 liquids to U-2/3 Radwaste for processing. (E12-1-95-212)

Identification of Page(s)	Remove	Insert	Notes
Page 11.2-4	Revision 0	Revision 2	Added statement that water in the floor drain sample tank can be discharged directly to the river if required.
Page 11.2-5	Revision 0	Revision 2	Added statement that water in the floor drain sample tank can be discharged directly to the river if required. Provides for use of portable Waste Treatment Systems as another type of system that can utilize to process liquid radwaste. (E-12-0-95-206)
Page 11.2-6	Revision 0	Revision 2	Clarification on the waste demineralizer flow rate
Page 11.2-7	Revision 0	Revision 2	Text clarification
Page 11.2-8	Revision 0	Revision 2	Correction to the Floor drain collector tank pump flow rate
Page 11.2-9	Revision 0	Revision 2	Change to section 11.2.2.2.13 to reflect the U-1 chemical surge tank (E12-1-95-212)
Page 11.2-10	Revision 0	Revision 2	Revised to reflect the as built configuration of the SBGTS loop seal drains as an input to the Waste Neutralizer. Tank in Rad Waste.

Identification of Page(s)	Remove	Insert	Notes
Page 11.2-12	Revision 0	Revision 2	Added clarifying statement that antifoam can be added directly into the concentrator vapor heads, Corrected flow rate of the Floor Drain neutralizer tank mixing pumps
Page 11.2-15	Revision 0	Revision 2	Removal of statements addressing required dilution flow for river discharges.
Page 11.2-17	Revision 0	Revision 2	Change related to Technical Specification upgrade
Page 11.2-18	Revision 1A	Revision 2	Added statement that water in the floor drain sample tank can be discharged directly to the river if required
Page 11.2-19	Revision 0	Revision 2	Changes to bring UFSAR in compliance with 1/94 Revision of 10CFR20.
Page 11.2-20	Revision 1A	Revision 2	Change related to Technical Specification upgrade, Added floor drain sample tank to description, and Removal of statements addressing required dilution flow for river discharges.

Identification of Page(s)	Remove	Insert	Notes
Figure 11.2-1	Revision BU	Revision CH	Drawing update
Figure 11.2-2	Revision UW	Revision VE	Drawing update
Figure 11.2-3	Revision YJ	Revision YN	Drawing update
Figure 11.2-4	Revision MX	Revision MZ	Drawing update
Figure 11.2-5	Revision Z	Revision AC	Drawing update
Figure 11.2-6	Revision L	Revision N	Drawing update
Figure 11.2-7	Revision W	Revision AA	Drawing update
Figure 11.2-8	Revision X	Revision AA	Drawing update
Figure 11.2-9	Revision N	Revision R	Drawing update
Figure 11.2-10	Revision AM	Revision AP	Drawing update
Figure 11.2-11	Revision AE	Revision AF	Drawing update
Figure 11.2-13	Revision V	Revision X	Drawing update
Figure 11.2-17	Revision I	Revision A	Drawing update
Figure 11.2-14	Revision W	Revision X	Drawing update
Page 11.3-1	Revision 0	Revision 2	Text update following review, deleted statement reflecting oxygen addition to off-gas recombiners
Page 11.3-2	Revision 0	Revision 2	Changes to bring UFSAR in compliance with 1/94 Revision of 10CFR20., Text clarification gland seal exhaust system section
Page 11.3-3	Revision 0	Revision 2	Text clarification
Page 11.3-4	Revision 0	Revision 2	Text clarification
Page 11.3-5	Revision 0	Revision 2	Text clarification Changes to bring UFSAR in compliance with 1/94 Revision of 10CFR20

Identification of Page(s)	Remove	Insert	Notes
Page 11.3-6	Revision 0	Revision 2	Text clarification
Page 11.3-6a	N/A new Page	Revision 2	Text clarification
Page 11.3-7	Revision 0	Revision 2	Text clarification
Page 11.3-8	Revision 0	Revision 2	Text clarification
Page 11.3-9	Revision 0	Revision 2	Text clarification
Page 11.3-10	Revision 0	Revision 2	Text clarification
Page 11.3-11	Revision 0	Revision 2	Text clarification, Change related to Technical Specification upgrade, updated testing of Offgas AO valves to reflect current testing requirements.
Page 11.3-12	Revision 0	Revision 2	Text clarification
Page 11.3-13	Revision 0	Revision 2	Change related to Technical Specification upgrade, Revise the air flow rates to reflect the design flow rates.
Page 11.3-14	Revision 0	Revision 2	Text clarification
Page 11.3-16	Revision 0	Revision 2	Standardization of the term mrem /hr
Table 11.3-2	Revision 0	Revision 2	Revise the air flow rates to reflect the design flow rates.
Table 11.3-4 sheet 1 of 1	Revision 0	Revision 2	Table Revision
Table 11.3-5	Revision 0	Revision 2	Table Revision
Figure 11.3-1	Revision BM	Revision BP	Drawing update
Figure 11.3-2	Revision W	Revision AA	Drawing update

Identification of Page(s)	Remove	Insert	Notes
Figure 11.3-3	Revision Z	Revision AC	Drawing update
Figure 11.3-4	Revision HN	Revision HS	Drawing update
Figure 11.3-5	Revision Y	Revision AB	Drawing update
Figure 11.3-6	Revision X	Revision Y	Drawing update
Figure 11.3-7	Revision AAH	Revision AAP	Drawing update
Figure 11.3-8	Revision NX	Revision PD	Drawing update
Figure 11.3-11	Revision 6	Revision 7	Drawing update
Figure 11.3-12	Revision 6	Revision 7	Drawing update
Figure 11.3-13	Revision AJ	Revision AN	Drawing update
Figure 11.3-14	Revision R	Revision S	Drawing update
Figure 11.3-15	Revision X	Revision Z	Drawing update
Figure 11.3-17	Revision 0	Revision 2	Figure Revision
Figure 11.3-19	Revision M	Revision N	Drawing update
Page 11.4-1	Revision 0	Revision 2	Change related to Technical Specification upgrade
Page 11.4-3	Revision 0	Revision 2	Update to section on contractor supplied solidification and dewatering systems
Page 11.4-4	Revision 0	Revision 2	Text flow Page
Page 11.4-6	Revision 0	Revision 2	Changes wording from controlled area to protected area in location of IRSF facility.
Figure 11.4-1	Revision AJ	Revision AN	Drawing update
Figure 11.4-3	Revision 0	Revision 2	Update to Figure

Identification of Page(s)	Remove	Insert	Notes
Page 11.5-8	Revision 0	Revision 2	Change related to Technical Specification upgrade, Revise the air flow rates to reflect the design flow rates.
Page 11.5-13	Revision 0	Revision 2	Change related to Technical Specification upgrade
Page 11.5-16	Revision 0	Revision 2	Standardization of the term mrem /hr
Page 11.5-18	Revision 0	Revision 2	Change related to Technical Specification upgrade
Table 11.5-1 sheet 1 of 4	Revision 0	Revision 2	Standardization of the term mrem /hr
Table 11.5-1 sheet 2 of 4	Revision 0	Revision 2	Standardization of the term mrem /hr
Table 11.5-1 sheet 3 of 4	Revision 0	Revision 2	Standardization of the term mrem /hr
Table 11.5-1 sheet 4 of 4	Revision 1A	Revision 2	Standardization of the term mrem /hr
Page 12-i	Revision 0	Revision 2	Update to Table of Contents
Page 12.1-1	Revision 1A	Revision 2	Update to reflect current management philosophy
Page 12.1-2	Revision 1A	Revision 2	Update to reflect current management philosophy

Identification of Page(s)	Remove	Insert	Notes
Page 12.1-3	Revision 0	Revision 2	Update to reflect current management philosophy
Page 12.2-1	Revision 0	Revision 2	Added clarifying statement to radioactive sources inventoried
Page 12.3-1	Revision 0	Revision 2	Text clarification
Page 12.3-2	Revision 0	Revision 2	Text clarification
Page 12.3-4	Revision 0	Revision 2	Text clarification
Page 12.3-5	Revision 0	Revision 2	Change the term Biological Shield wall to Reactor shield wall of Containment shield wall to make UFSAR terminology consistent in all sections
Page 12.3-6	Revision 0	Revision 2	Text clarification
Page 12.3-7	Revision 0	Revision 2	Text clarification
Page 12.3-8	Revision 0	Revision 2	Change term Biological Shield wall to Reactor shield wall of Containment shield wall to make UFSAR terminology consistent in all sections and Elimination of the statement that concrete aging shield surveys are conducted on an annual basis. Revision to address potential for air flow from points of higher contamination to areas of lower contamination
Page 12.3-9	Revision 0	Revision 2	Correction to number of area Radiation Monitors for unit 3
Page 12.3-10	Revision 0	Revision 2	Text clarification

Identification of Page(s)	Remove	Insert	Notes
Table 12.3-1 sheet 1 of 1	Revision 0	Revision 2	Text clarification
Table 12.3-4 sheet 2 of 2	Revision 0	Revision 2	Range change for Rad waste pump room
Page 12.5-1	Revision 0	Revision 2	Text clarification
Page 12.5-2	Revision 0	Revision 2	Text clarification
Page 12.5-3	Revision 0	Revision 2	Update to reflect current management philosophy
Page 12.5-4	Revision 0	Revision 2	Text clarification
Table 12.5-1 sheet 1 of 1	Revision 0	Revision 2	Table updated
Table 12.5-2 sheet 1 of 1	Revision 0	Revision 2	Table updated
Page 13.1-1	Revision 1A	Revision 2	Change related to Technical Specification upgrade
Page 13.2-1	Revision 0	Revision 2	Change to reflect current terminology used in the N-GET program
Page 13.2-2	Revision 1A	Revision 2	Change to reflect current terminology used in the N-GET program
Page 13.4-1	Revision 0	Revision 2	Change related to Technical Specification upgrade
Page 13.5-1	Revision 0	Revision 2	Change from TJM to current EWCS work management system
Page 13.5-2	Revision 0	Revision 2	Change related to Technical Specification upgrade

Identification of Page(s)	Remove	Insert	Notes
Page 13.5-2a	N/A new Page	Revision 2	Text flow Page
Page 13.5-3	Revision 0	Revision 2	Change to reflect the elimination of Temporary Procedures
Page 13.5-5	Revision 0	Revision 2	Change to reflect the elimination of Temporary Procedures
Page 13.5-6	Revision 0	Revision 2	Deleted reference to the TJM work management system
Page 13.5-7a	N/A new Page	Revision 2	No text changes, pagination to improve computer search capability
Page 13.5-8	Revision 1A	Revision 2	No text changes, pagination to improve computer search capability
Page 13.6-1	Revision 0	Revision 2	Text clarification
Page 13.6-2	Revision 0	Revision 2	Installation of biometrics hand geometry Readers to allow for automatic access to the station (E12-0-95-212)
Page 13.7-1	Revision 0	Revision 2	Change related to Technical Specification upgrade
Table 13.7-1 sheet 1 of 2	Revision 0	Revision 2	Added note to Table
Table 13.7-1 sheet 2 of 2	Revision 0	Revision 2	Added note to Table
Page 15.0-1	Revision 0	Revision 2	Added clarification for ATWS

Identification of Page(s)	**Remove**	**Insert**	**Notes**
Page 15.0-3	Revision 0	Revision 2	Text clarification
Page 15.0-4	Revision 0	Revision 2	Added section reference, added wording to reflect ASME overpressure event, added statement that transients A, B, and D are reanalyzed each cycle to confirm that maximum pressure is within 110% of Reactor coolant system design pressure.
Page 15.1-6	Revision 0	Revision 2	Change related to Technical Specification upgrade
Page 15.2-4	Revision 0	Revision 2	Change related to Technical Specification upgrade
Page 15.2-5	Revision 0	Revision 2	Change related to Technical Specification upgrade
Page 15.2-8	Revision 0	Revision 2	Text clarification, added reference to Section III of ASME Code
Page 15.2-8a	N/A new Page	Revision 2	Update to section 15.2.4.2.1 "Identification of Causes and Frequency Classification"

Identification of Page(s)	Remove	Insert	Notes
Page 15.2-8b	N/A new Page	Revision 2	Update to section 15.2.4.2.1 "Identification of Causes and Frequency Classification"
Page 15.2-9	Revision 0	Revision 2	Updated to discuss containment overpressure event.
Page 15.2-11	Revision 0	Revision 2	Added statement on 15 second time delay, added discussion on Scoop tube positioners, corrected Figure references.
Page 15.2-12	Revision 0	Revision 2	Repagination due to text flow
Page 15.4-1	Revision 0	Revision 2	Section 15.4.1 was reworded for clarification, added reference to section 7.6.1.4.3
Page 15.4-3	Revision 0	Revision 2	Rewrite of section 15.4.3 to reference sections 15.4.1 and 15.4.2 Deletion of statement referencing Technical Specification limit to pump speed for startup of idle loop
Page 15.4-4	Revision 0	Revision 2	Update to reflect the removal of Unit 2 Recirculation Discharge Valve Bypass Line (M12-2-91-005)

Identification of Page(s)	Remove	Insert	Notes
Page 15.6-3	Revision 0	Revision 2	Change related to Technical Specification upgrade
Page 15.6-4	Revision 0	Revision 2	Changes to bring UFSAR in compliance with 1/94 Revision of 10CFR20
Page 15.6-13	Revision 0	Revision 2	Text clarification
Page 15.6-16	Revision 0	Revision 2	Change to SBGTS efficiency, Change to control room dose
Page 15.6-17	Revision 0	Revision 2	Change to SBGTS efficiency, Change to control room dose
Page 15.6-18	Revision 0	Revision 2	Change to SBGTS efficiency, Change to control room dose
Table 15.6-6	Revision 0	Revision 2	Added note that table is maintained for historical purposes only
Table 15.6-7	Revision 0	Revision 2	Added note that table is maintained for historical purposes only
Table 15.6-9 sheet 1	Revision 0	Revision 2	Change to SBGTS efficiency,
Table 15.6-9 sheet 2	Revision 0	Revision 2	Change to Control room volume and Control Room intake flow
Table 15.6-10	Revision 0	Revision 2	Change to control room dose
Page 15.7-4	Revision 0	Revision 2	Changes to bring UFSAR in compliance with 1/94 Revision of 10CFR20
Page 15.7-10	Revision 0	Revision 2	Rewrite of section to link 5 minute Reactor Bldg. damper closure time to SBGTS 90% filter efficiency

Identification of Page(s)	Remove	Insert	Notes
Page 15.7-19	Revision 0	Revision 2	Correction to the capacity of the Condensate transfer pumps
Table 15.7-2	Revision 0	Revision 2	Added note 1 to Table

1.0 INTRODUCTION AND GENERAL DESCRIPTION OF PLANT

Page

1.0 INTRODUCTION AND GENERAL DESCRIPTION OF PLANT Page

Table 1.1-1 (Continued)

ACRONYMS AND INITIALISMS

POL	provisional operating license
ppm	parts per million
psi	pounds per square inch
psia	pounds per square inch, absolute
psid	pounds per square inch, differential
psig	pounds per square inch, gauge
PWR	pressurized water reactor
RBCCW	reactor building closed cooling water
RCPB	reactor coolant pressure boundary
RETS	Radiological Effluent Technical Specifications
RHRS	residual heat removal system
RPS	reactor protection system
RPV	reactor pressure vessel
RWCU	reactor water cleanup
RVWLIS	reactor vessel water level instrumentation system
SAR	safety analysis report
SBGTS	standby gas treatment system
SEP	systematic evaluation program
SER	safety evaluation report
SLC	standby liquid control
SNP	Siemens Nuclear Power (formerly ANF)
SRP	Standard Review Plan
SRV	safety relief valve
SWS	service water system
TBCCW	turbine building closed cooling water
TIP	traversing incore probe
TLD	thermoluminescent dosimeter
TMI	Three Mile Island
TSC	technical support center
UHS	ultimate heat sink
USI	unresolved safety issue
ZIP	zinc injection process

E. The integrity of the complete containment system and other associated engineered safeguards, as may be necessary, are designed and maintained so that offsite doses resulting from postulated accidents will be below the requirements presented in 10 CFR 100.

1.2.1.4 Control and Instrumentation

A. The station is provided with a control room having adequate shielding and air conditioning facilities to permit occupancy during and after all design basis accident situations.

B. Interlocks or other protective devices are provided in addition to procedural controls to prevent serious accidents.

C. A reliable reactor protection system (RPS), independent from the reactor process control system, is provided to automatically initiate appropriate action whenever plant conditions approach pre-established limits. Periodic testing capability is provided. Sufficient redundancy is provided so that failure or removal from service of any one component or portion of the system does not preclude appropriate actuation of the RPS when required.

1.2.1.5 Electrical Power

Sufficient normal and standby auxiliary sources of electrical power are provided to attain prompt shutdown and continued maintenance of the plant in a safe condition under all credible circumstances. The capacity of the power sources is adequate to accomplish all required safeguards functions under postulated accident conditions for which the plant is designed.

1.2.1.6 Radioactive Waste Disposal

A. Gaseous, liquid, and solid waste disposal facilities are designed so that discharge of effluents and offsite shipments are in accordance with 10 CFR 20 and within the requirements of the Interstate Commerce Commission or other regulatory agencies having jurisdiction.

B. Process and discharge streams are appropriately monitored and such features incorporated as may be necessary to maintain releases below the permissible limits of 10 CFR 20. Automatic off-gas monitors located downstream of the main condenser air ejector, at the inlet to the holdup line, are installed and are subject to manual override.

1.2.1.7 Shielding and Access Control

Radiation shielding and station access control are such that the personnel doses are less than the limits in 10 CFR 20.

1.2.1.8 Fuel Handling and Storage

Appropriate fuel handling and storage facilities are provided to preclude accidental criticality and to provide cooling for spent fuel.

1.2.2 Summary Design Description and Safety Analysis

1.2.2.1 Design Bases Dependent On Site and Environmental Characteristics

Information relating to the Dresden site and environment is summarized in Chapter 2 and was used in the design of Dresden Units 2 and 3.

1.2.2.1.1 Gaseous Waste Effluents

The off-gas systems for Units 2 and 3 are designed to use a 310-foot chimney for release of the treated, radioactive, gaseous effluents. Unit 1 continues to use its 300-foot chimney. The radioactivity release rate limits are as described in the Offsite Dose Calculation Manual (ODCM).

1.2.2.1.2 Liquid Waste Effluents

Units 2 and 3 use common intake and discharge canals, adjacent to the Unit 1 intake and discharge canals. Radioactive liquid releases are made on a batch basis (not continuously) and comply with 10 CFR 20.

1.2.2.1.3 Wind Loading Design

All structures are designed to withstand the maximum potential loadings resulting from a wind velocity of 110 mph. The design is in accordance with standard codes and normal engineering practice.

Structures whose failure could affect the operation and functions of the primary containment and process systems are designed to assure that safe shutdown of the reactor can be achieved considering the effects of possible damage when subjected to the forces of tornado loading.

1.2.2.1.4 Geology

The geology of the area indicates that bedrock loading capability ranges from 2000 to 15,000 psi. These values are well above normal high-load footing design values. Consequently, no problems or restrictions beyond normal design practice are anticipated.

1.2.2.1.5 Seismic Design

The following design criteria apply only to seismic Class I items. Class I items are defined as structures (building and equipment) which are vital to the safe shutdown of the unit and the removal of decay heat.

The seismic design for Class I structures and equipment for Dresden Station are based on dynamic analyses using acceleration or velocity response spectrum curves which are based on a horizontal ground motion of 0.1 g; a vertical acceleration equal to two-thirds of the horizontal, or 0.067 g, was assumed to occur simultaneously.

The natural periods of vibration are calculated for buildings and equipment which are vital to the safety of the plant. Damping factors are based upon the materials and the methods of construction used.

Earthquake design is based on ordinary allowable stress as set forth in the applicable codes, but is more conservative because the usual one-third increase in allowable working stresses due to earthquake loadings is not used. As an additional requirement, the design is such that a safe shutdown can be made during a horizontal ground motion of 0.2 g with a simultaneous vertical acceleration of 0.133 g.

1.2.2.1.6 Conclusions with Respect to the Site and Environment

The Dresden site meets the reactor site criteria described in 10 CFR 100 for the following reasons:

A. Commonwealth Edison's ownership of the large, 953-acre tract provides the requisite exclusion area for power reactors such as Units 2 and 3.

B. There are no residences on the site or within a radius of 0.5 miles of the units.

C. Units 2 and 3 are independent of each other to the extent that an accident in one would not initiate an accident in the other. The simultaneous operation of both units does not result in total radioactive effluent releases beyond allowable limits.

D. The calculated total radiation doses to an individual at the boundary of the exclusion area or at the outer boundary of the low population zone (LPZ) under postulated hypothetical accident conditions are within the limits prescribed by 10 CFR 100.

E. Activities which are permitted on the site, but are unrelated to the operation of any unit, do not present any hazards to the public.

F. There are numerous access roads, including Interstate Routes 55 and 80, within the LPZ permitting rapid evacuation.

G. The population density and use characteristics of the site environment in the LPZ are compatible with the combined operation of both units.

H. As discussed in Chapter 2, the geological, hydrological, meteorological, and seismological characteristics of the site and environment are suitable for the location of Units 2 and 3.

1.2.2.2 Station Arrangements

The arrangement of buildings at Dresden Station is shown in Figure 1.2-1 (Drawing M-1).

A single turbine building completely encloses turbine-generators for both units and their control room. The building is a reinforced concrete structure from its foundation at elevation 513'-6" to the main floor at elevation 561'-6". A steel-framed superstructure is used from the main floor to the roof. The roof is of precast concrete deck units with insulation and a tar-and-felt roofing membrane. The sidewalls are of insulated metal construction. The frame also supports a runway for the 175-ton and 125-ton traveling bridge cranes. The turbine building is connected to the reactor building by its main floor at elevation 561'-6" and its steel-framed roof at elevation 622'-6".

The Unit 2 turbine-generator, exciter, condenser, feedwater heaters, feedwater and condensate pumps, demineralizer system, condenser circulating system and electrical switch gear are located in the east half of the turbine building. Duplicate equipment and systems for Unit 3 are located in the west half of the building.

Access to the turbine building is through the access control building and connecting corridors of Unit 1. The turbine building has a common supply and exhaust ventilation system for Units 2 and 3.

The main generators are supported centrally at the top of the concrete portion of the building with the control room at one end of the building on the next lower level. The equipment arrangement and principal dimensions are shown in Figures 1.2-2 through 1.2-9 (Drawings M-2 through M-9).

A common reactor building for Units 2 and 3 is constructed abutting the south wall of the turbine building. The east half of the reactor building houses the Unit 2 reactor vessel, recirculation system, primary containment, reactor auxiliary systems, refueling equipment and spent fuel storage, as well as the common fuel storage vault used for both Units 2 and 3. Except as noted, duplicate equipment

1.2.2.4.1 Primary Containment System

The primary containment is designed to accommodate the pressures and temperatures which would result from, or occur subsequent to, a circumferential rupture of a major recirculation line within the primary containment. This failure would produce a loss of reactor cooling water at the maximum rate for a line break scenario. The pressure suppression chamber is a steel, torus-shaped pressure vessel approximately half-filled with water and is located below and encircles the drywell. The vent system from the drywell terminates below the water level of the pressure suppression chamber so that, in the event of a pipe failure in the drywell, the released steam would pass directly to the water where it would be condensed. This transfer of energy to the water pool would rapidly reduce (within 30 seconds) the residual pressure in the drywell and substantially reduce the potential for subsequent leakage from the primary containment.

Isolation valves are provided on piping penetrating the drywell and the suppression chamber to provide integrity of the containment when required. These primary containment isolation system (PCIS) valves are actuated automatically. The isolation valves on the auxiliary systems are left open or are closed, depending upon the functional requirements of the system, without reducing the integrity of the primary containment system.

Two features are included in the primary containment design to aid in maintaining the integrity of the primary containment system indefinitely in the event of a LOCA. Two independent, full capacity containment cooling systems are included for the removal of heat within the drywell and the pressure suppression chamber. Capability is provided in the containment structure design to inert or control the composition of the containment atmosphere during operation.

Following construction of the drywell and suppression chamber, the penetrations were sealed with welded end caps and each vessel tested to 1.15 times the design pressure of 62 psig. Following the strength test each vessel was tested for leakage at design pressure and met the criteria of less than 0.5% leakage per day. The torus was half-filled with water during this test to simulate operating conditions.

After complete installation of all penetrations in the drywell and suppression chamber, these vessels were pressurized to the calculated maximum peak accident pressure of 48 psig and measurements taken to verify that the integrated leakage rate from the vessels did not exceed 0.5% per day of the combined volumes. An integrated leakage rate test is performed periodically on the primary containment at 48 psig.

Electrical penetrations are also provided with double seals and are separately testable at 48 psig. The test taps and the seals are located so that the tests can be conducted without entering or pressurizing the drywell or suppression chamber.

Those pipe penetrations which must accommodate thermal movement are provided with expansion bellows. The bellows expansion joints are designed for the containment system design pressure and can be checked for leaktightness when the containment system is pressurized. In addition, these joints are provided with a second seal and test tap so that the space between the seals can be pressurized to

A bypass system having a capacity of approximately 40% steam flow at rated load is supplied with the turbine to restrict overpressure transients resulting from sudden turbine control valve or stop valve closure.

The bypass valves are operated on an overpressure signal from the initial pressure regulator. Rapid partial load rejection can be accommodated with the bypass system.

The reactor protection system overrides the above controls to initiate any required safety action. A standby liquid control system is provided to inject a borated solution into the reactor and shut it down in the remote event that the control rod system becomes inoperative.

1.2.2.6.2 Reactor Protection System

A reactor protection system is provided which automatically initiates appropriate action whenever the plant conditions monitored by the system approach pre-established limits. The reactor protection system acts to shut down the reactor.

The reactor protection system consists of two buses of relay contacts that are actuated by sensors from the parameters being monitored. The buses are energized during normal operation, and deenergization of both buses in the reactor scram circuit results in the opening of the scram valves in the control rod hydraulic system causing rapid insertion (scram) of the control rods. Each bus has at least two independent devices for each measured variable which initiates a scram, but only one device must operate to trip the bus in which it is connected. Both buses must be deenergized to produce a scram. The reactor protection system initiates a scram on loss of power to the protection system.

Components of the reactor protection system can be removed from service for testing and maintenance without interrupting plant operations and without negating the ability of the protection system to perform its protective functions upon receipt of appropriate signals.

1.2.2.7 Radiation Monitoring Systems

Instrumentation is provided for continuous monitoring of the radioactivity of certain processes. Processes significantly high in radioactivity are monitored for variation from normal. Certain nonradioactive processes are monitored to provide alarm in the event of contamination.

1.2.2.8 Fuel Handling and Storage

The refueling procedure is generally referred to as "wet" refueling since irradiated fuel is always kept under water. The facility's design allows visual control of operations at all times. This feature is instrumental in producing a safe, efficient refueling sequence.

The steam dryer and separator assemblies are transferred to a special storage pit. Water is added to the storage pit prior to transferring the assemblies to provide shielding from the parts of the separator which have been adjacent to the top of the core and which have been the most heavily irradiated.

Spent fuel discharged from the reactor is transferred under water into racks provided in the storage pool. The storage pool is designed to accommodate the channel stripping operation and the many other fuel maintenance operations that are required. Storage space is also provided in the pool for irradiated fuel assembly channels and control rods and for small internal components of the reactor.

New fuel is brought in through the equipment entrance of the reactor building and hoisted to the upper floor utilizing the reactor building crane. The new fuel for both Units 2 and 3 is stored in the new fuel vault located adjacent to the Unit 2 refueling pool area within the reactor building.

1.2.2.9 Turbine System

The saturated steam leaving the reactor vessel flows through four carbon steel steam lines to the turbine located in the turbine building. After passing through the turbine, the low pressure steam is condensed, the noncondensible gases are removed, and the condensate is demineralized before being returned to the reactor through the feedwater heaters.

1.2.2.10 Electrical System

The electrical output of the units is fed into a 345-kV switchyard and from the yard to CECo's network grid system via six 345-kV transmission lines and six 138-kV transmission lines. The 138-kV transmission lines receive power from the Dresden units through 345-kV to 138-kV transformers via a 138-kV switchyard. Auxiliary power is supplied from the respective units themselves, from the 345-kV switchyard (for Unit 3), or from the 138-kV switchyard (for Unit 2). A diesel-generator (DG) system provides emergency power. An additional diesel-generator system is provided for power in the event of a station black-out.

Batteries are used for all controls which are vital to unit and station safety, for emergency lighting, and as a power supply for certain functions required for unit shutdown, such as closing of isolation valves, driving motors, and opening valves for ECCS. A separate battery supplies the neutron monitoring equipment to monitor the core during shutdown.

1.2.2.11 Shielding, Access Control, and Radiation Protection Procedures

Control of radiation exposure of plant personnel and people external to the plant is accomplished by a combination of radiation shielding, control of access into certain areas, plant ventilation systems, and administrative procedures. The requirements of 10 CFR 20 are used for establishing the basic criteria and objectives.

1.2.4.5 Inter-Plant Effects of Accidents

An accident in either of the units, up to and including the maximum postulated accident, will not prohibit control room access or prevent safe operation or shutdown of the other.

1.2.5 New Features

The design of Units 2 and 3 includes certain features which were developed by GE for use in the corresponding generation of nuclear power plants but are not found on previously constructed GE BWRs. These features are summarized below, with further detailed discussion presented in other sections of this report.

1.2.5.1 Features Which Reduce the Probability and Magnitude of Potential Reactivity Insertion Accidents

The design of Dresden Station includes features to limit the maximum control rod worth and to prevent rapid insertion of reactivity, thereby limiting the probability of occurrence and magnitude of postulated reactivity excursion accidents.

These features include the following:

A. Control rod worth minimizer,

B. Rod velocity limiter, and

C. Control rod drive housing support.

The control rod worth minimizer is a device which limits control rod withdrawal sequences and patterns to preselected programs. The rod drop velocity limiter restricts the free-fall velocity of a control rod to a maximum of 5 ft/s. The CRD housing support prevents the ejection of a control rod if the control rod drive housing were to fail.

1.2.5.2 Features Which Mitigate Effects of Postulated LOCAs

The reactor vessel internal components, the ECCS, and the main steam piping have been designed to assure continuity of cooling to the core and containment during and following postulated LOCAs.

The following components or design features are included in this category:

A. Flow restrictors in the main steam lines;

B. Jet pumps and arrangement of reactor vessel internal structure; and

C. Emergency core cooling system, including two core spray systems, a LPCI/containment cooling system, a HPCI, and an automatic depressurization system (ADS).

The flow restrictors are venturi nozzles which are installed in the main steam lines to limit the maximum steam flowrate in the line if the line were to break.

The jet pumps are an improved mechanism for providing reactor coolant flow. The jet pumps and attendant reactor vessel internal configuration allow reflooding of the core following a LOCA. The ECCS, which provides the cooling water necessary to cool and reflood the core following LOCA, includes the HPCI system, core spray system, LPCI system, and ADS system.

1.2.5.3 Features Which Improve Operability of the Units

The recirculation flow control system and the incore neutron monitoring system contribute to operational control.

The recirculation flow control system provides a method for adjusting the output of the units over a power range of approximately 30%. The incore monitors provide operational input data for core performance evaluation and for signals in the reactor protection system.

1.2.6 Drywell Post-Accident Recovery Provisions

Accidents which could occur within the drywell are normally thought to be LOCAs. A LOCA could be a break in any line connected to the primary system from a small line break to a line break equivalent to the double-ended break of a recirculation line. Each break of a given size can be postulated to occur in any one of the primary system pumps or valves or along any point in the varied primary system pipes. In addition to the numerous combinations of break sizes and locations, an almost unlimited set of various conditions within the primary containment, secondary containment, and site area can be postulated.

The primary concerns during an accident situation are identification of the accident, automatic and manual protection following the accident, available information related to the accident, and the ability to take corrective action based on the data. Analyses presented to date have emphasized the automatic protective features provided in the plant design. These automatic features limit and terminate the transient condition associated with the accident situation and enable the plant to be maintained in a safe condition thereafter. Those plant design features which could provide information following the accident and the ability to take action which is deemed proper based on this information are discussed below:

A. Reactor control system: The general status of the neutron flux is available. The control rod positions are indicated by position lights and by rod-notch position. The standby liquid control system is monitored for pump outlet flow and pressure, as well as solution volume and temperature.

Table 1.8-1

REGULATORY GUIDE REFERENCE SECTIONS

Commitment to or conformance with the identified Regulatory or Safety Guides is to the extent identified in the referenced UFSAR sections.

Regulatory Guide	Title	UFSAR Section(s)
1.3	Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Boiling Water Reactors	15.6
1.7	Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident	6.2
1.8 (Safety Guide 8, March 1971)	Qualification and Training of Personnel for Nuclear Power Plants	T.S. 6.3 (1)
1.21	Measuring, Evaluating, and Reporting Radioactivity in Solid Wastes, Releases of Radioactive Materials in Liquid, and Gaseous Effluents from Light-Water-Cooled Nuclear Power Plants	11.2 T.S. 6.8.D.9
1.23	Onsite Meteorological Programs	2.3
1.26	Quality Group Classifications and Standards for Water, Steam, and Radioactive Waste Containing Components of Nuclear Power Plants (for Comment)	5.2, 6.6
1.28, Rev. 3, August 1985	Quality Assurance Program Requirements — Design and Construction	(1)

Table 1.8-1 (Continued)

REGULATORY GUIDE REFERENCE SECTIONS

Regulatory Guide	Title	UFSAR Section(s)
1.30 (Safety Guide 30, August 1972)	Quality Assurance Program Requirements for the Installation, Inspection, and Testing of Instrumentation and Electrical Equipment	(1)
1.33 (Safety Guide 33, November 1972)	Quality Assurance Program Requirements — Operation	13.5
1.34	Control of Electroslag Weld Properties	5.2, 5.3
1.36	Nonmetallic Thermal Insulation for Austenitic Stainless Steel	6.1
1.37, March 1973	Quality Assurance Requirements for Cleaning Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants	(1)
1.38, March 1973	Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants	(1)
1.39, March 1973	Housekeeping Requirements for Water-Cooled Nuclear Power Plants	(1)
1.44	Control of the Use of Sensitized Stainless Steel	5.3
1.45	Reactor Coolant Pressure Boundary Leakage Detection Systems	5.2
1.49	Power Levels of Nuclear Power Plants	T.S. 1.1/2.1 bases

Table 1.8-1 (Continued)

REGULATORY GUIDE REFERENCE SECTIONS

Regulatory Guide	Title	UFSAR Section(s)
1.50	Control of Preheat Temperature for Welding of Low-Allow Steel	5.3
1.52	Design, Testing, and Maintenance Criteria for Post-Accident Engineered Safety Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants	6.5 6.4
1.54, June 1973	Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants	(1)
1.61	Damping Values for Seismic Design of Nuclear Power Plants	3.9, 3.7
1.70, Rev 3, November 1978	Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants, LWR Edition	1.1, 5.2, 5.3, 9.5, 12.2, 15.5
1.75	Physical Independence of Electric Systems	7.5
1.77, May 1974	Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors	3.2, 4.3
1.78	Assumptions for Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release	6.4, 2.2
1.91	Evaluation of Explosions Postulated to Occur on Transportation Routes Near Nuclear Power Plants	2.2
1.97	Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident	7.1, 7.5, 9.1, 3.11

Table 1.8-1 (Continued)

REGULATORY GUIDE REFERENCE SECTIONS

Regulatory Guide	Title	UFSAR Section(s)
1.99, Rev. 2, May 1988	Effects of Residual Elements on Predicted Radiation Damage to Reactor Vessel Materials	5.2, 5.3
1.100	Seismic Qualification of Electric Equipment for Nuclear Power Plants	3.10
1.101, Rev. 2, October 1981	Emergency Planning and Preparedness for Nuclear Power Reactors	13.3
1.109	Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I	11.3 ODCM
1.111	Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light-Water-Cooled Reactors	11.3 ODCM
1.113	Estimating Aquatic Dispersion of Effluent from Accidental and Routine Reactor Releases for the Purpose of Implementing, Appendix I	ODCM
4.8 Table 1, December 1975	Environmental Technical Specifications for Nuclear Power Plants	T.S. 6.6 bases

Notes:

1. These items are committed to in Topical Report CE-1-A for Dresden Station, but not specifically referenced in the text of the rebaselined UFSAR. Exceptions or alternatives identified in the UFSAR take precedence over commitments in the Topical Report.

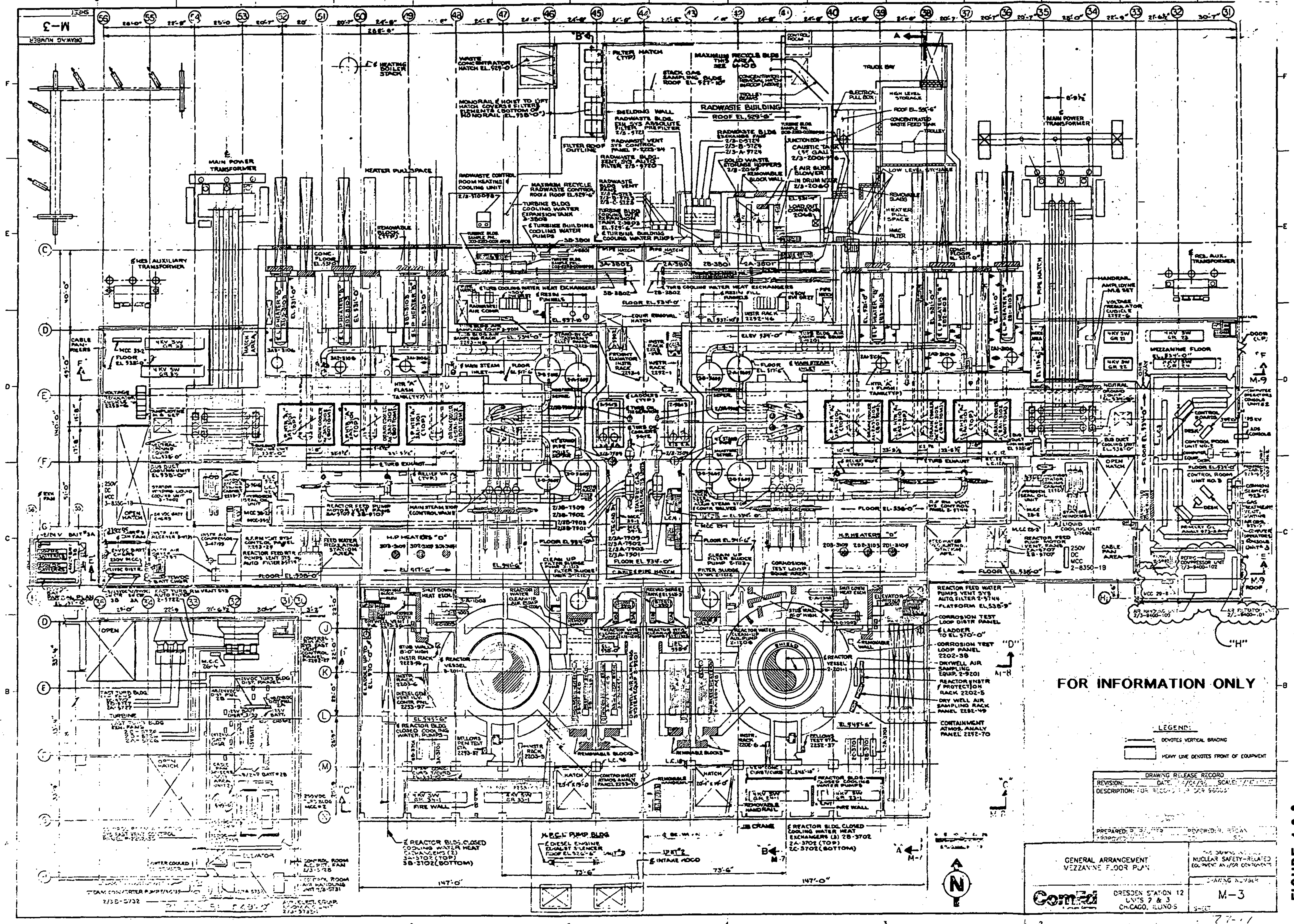
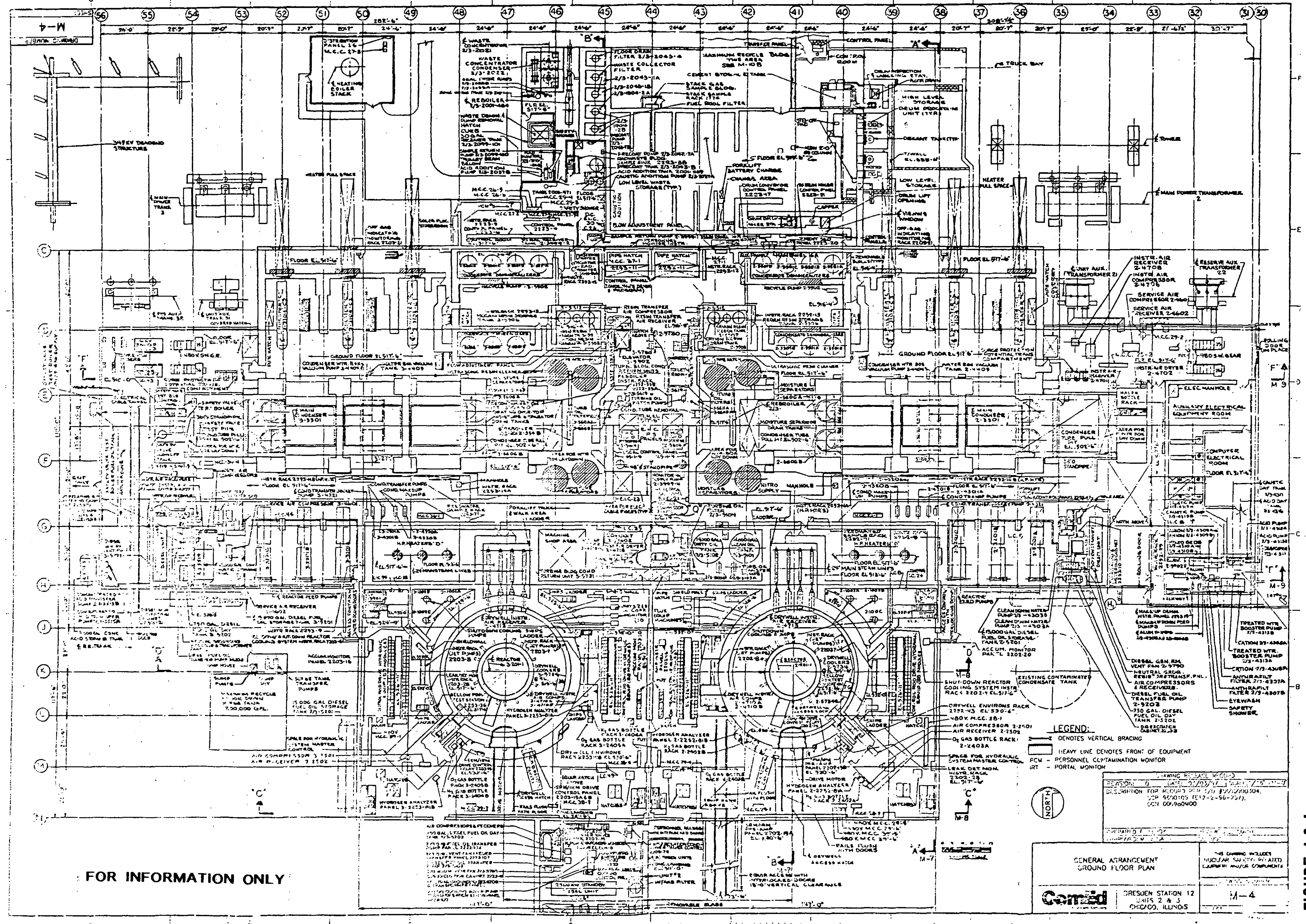


FIGURE 1.2-3 REV. 02 / JUNE 1997

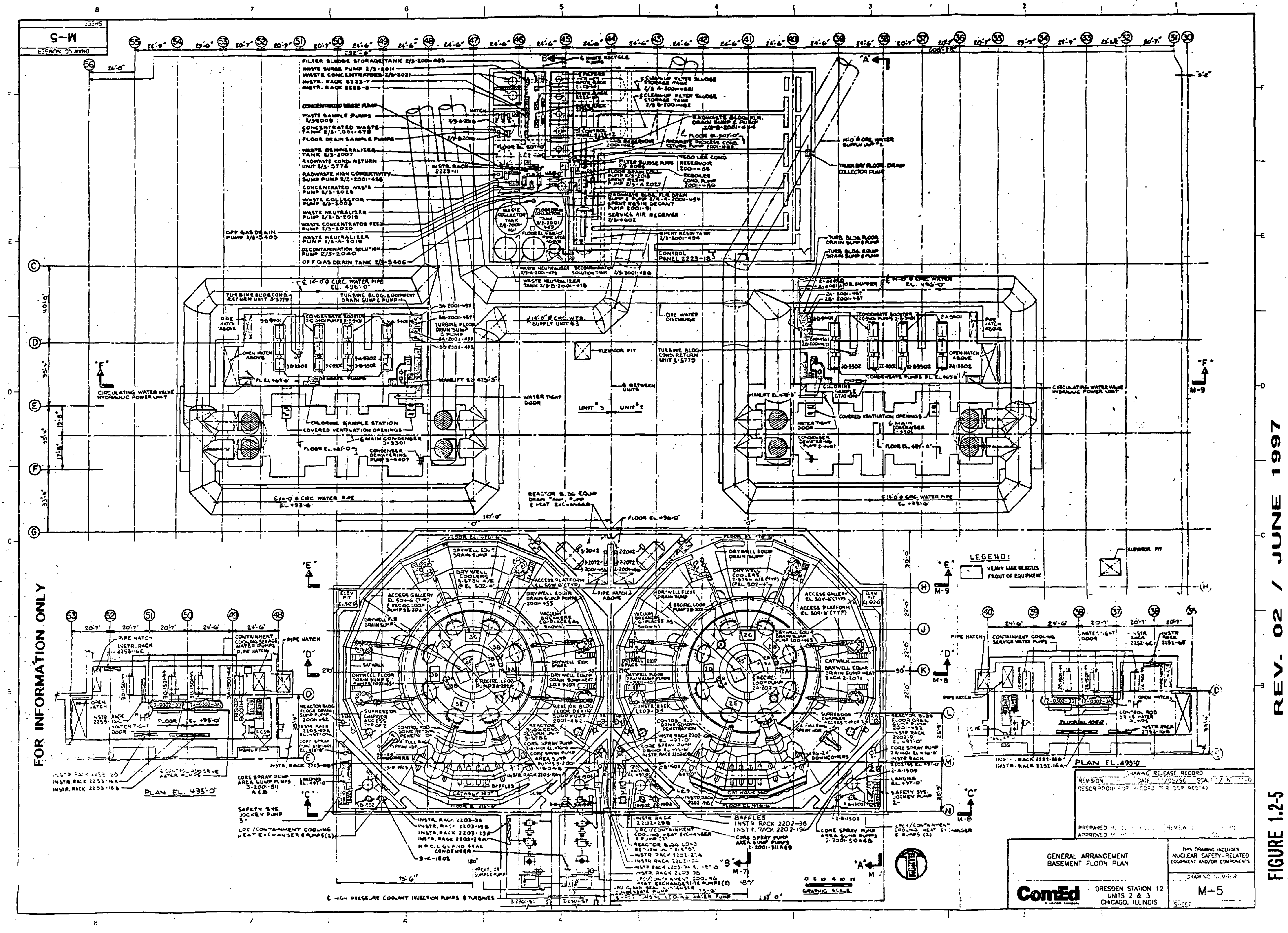
CENTRAL DRAWING FACILITY

30 X



REV. 02 / JUNE 1997

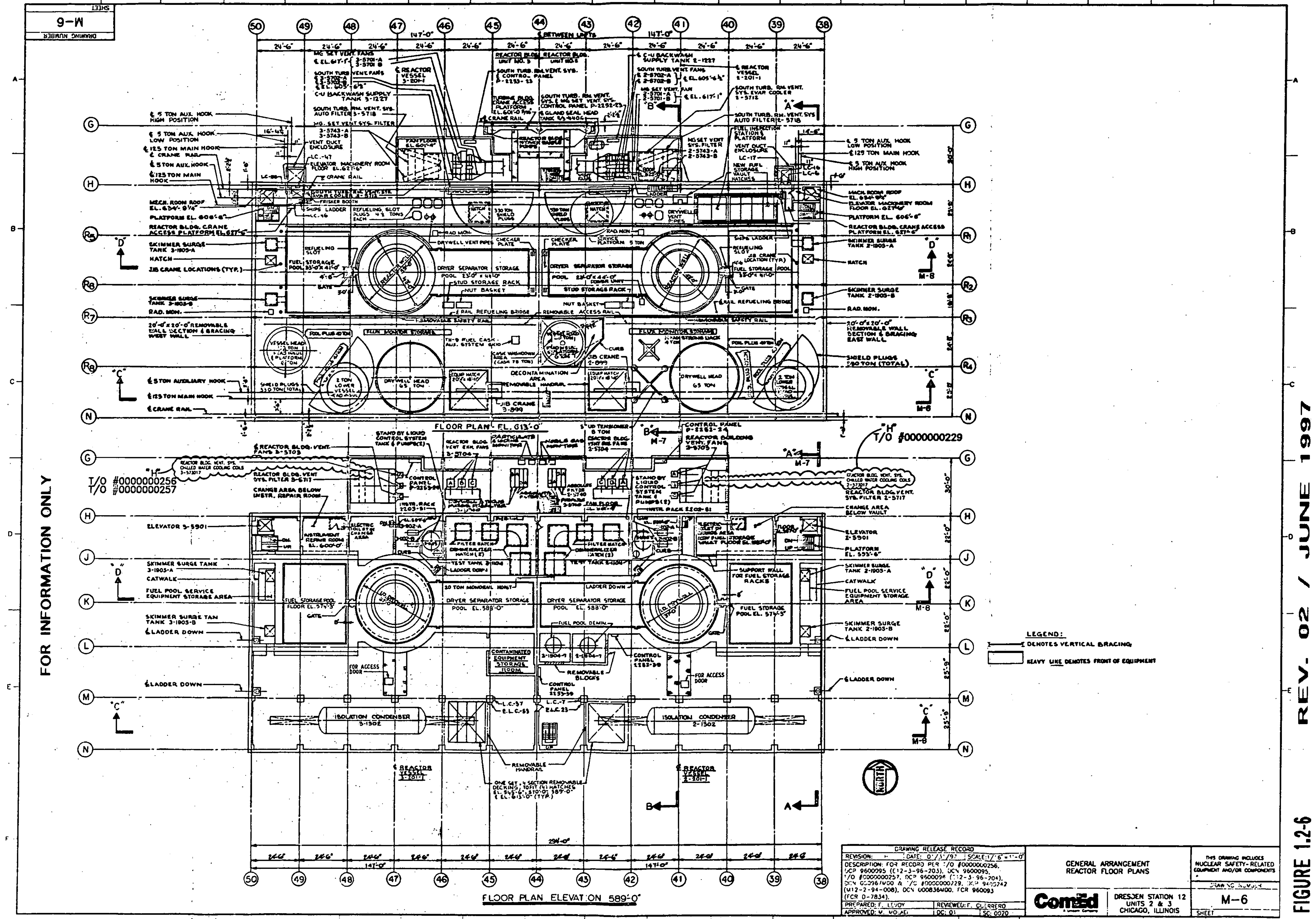
FIGURE 1.2-4



REV. 02 / JUNE 1997

FIGURE 1.2-5

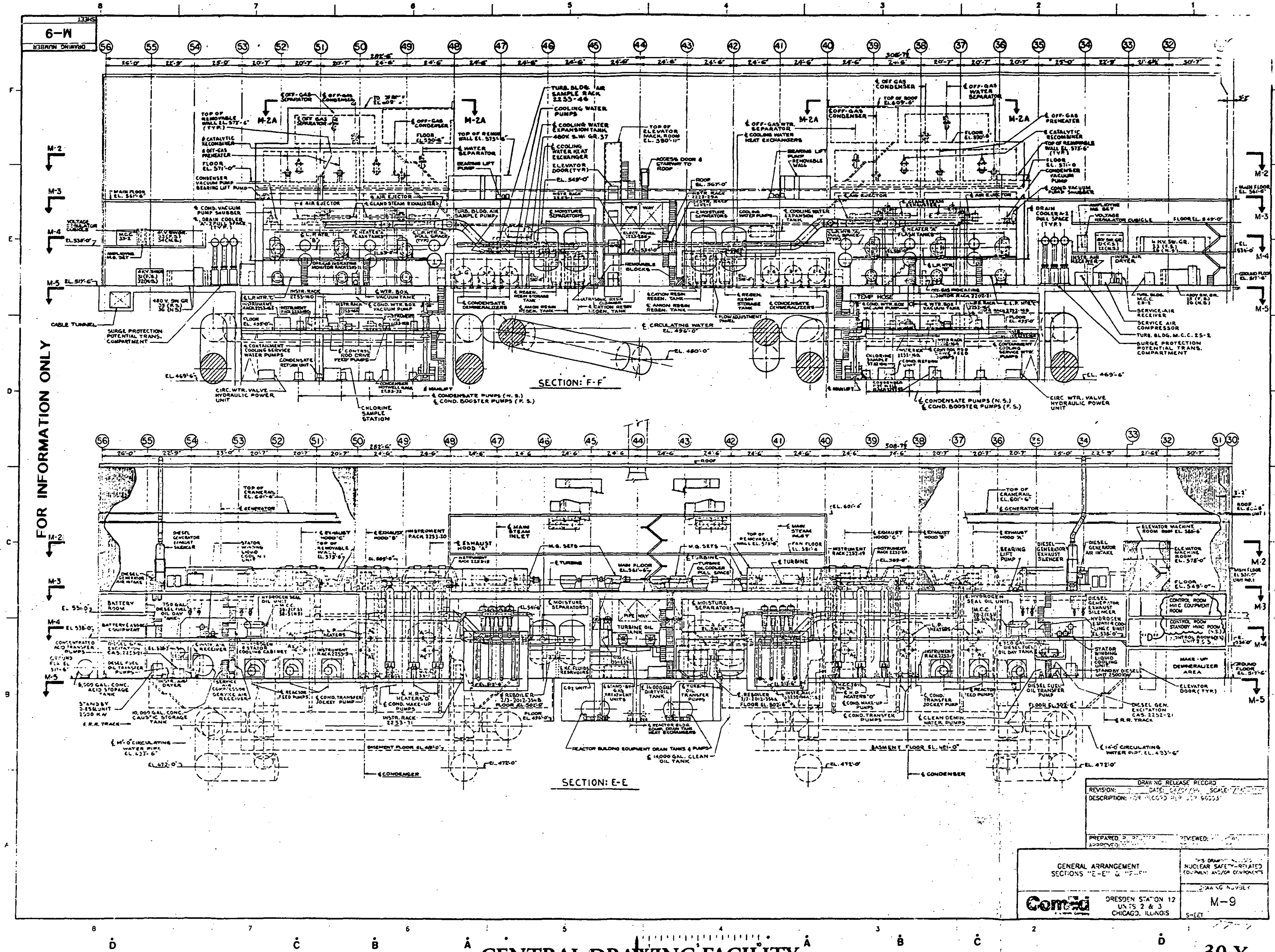
FOR INFORMATION ONLY



REV. 02 / JUNE 1997

FIGURE 1.2-6

CENTRAL DRAWING FACILITY 30 X

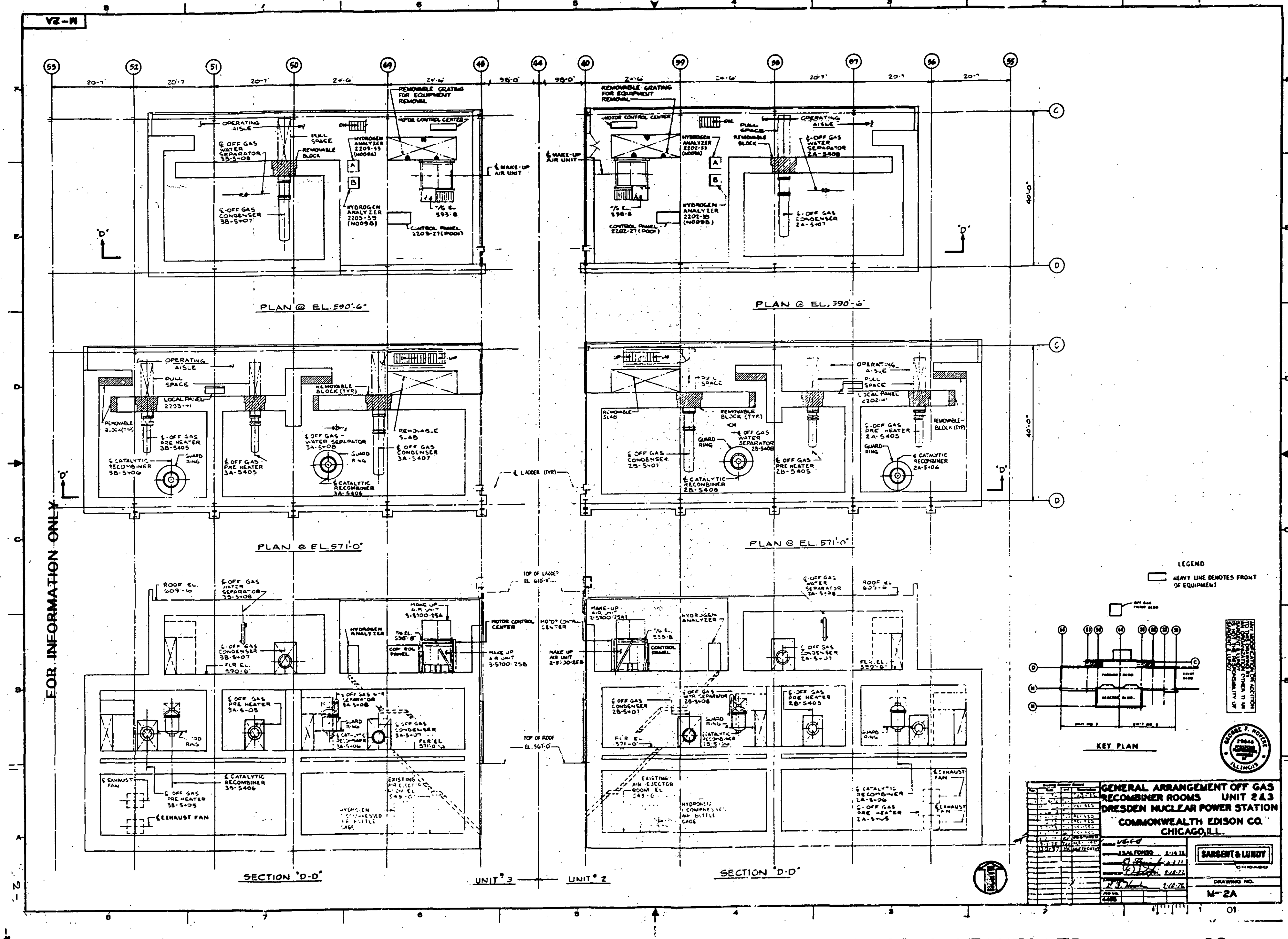


REV. 02 / JUNE 1997

FIGURE 1.2-9

CENTRAL DRAWING FACILITY

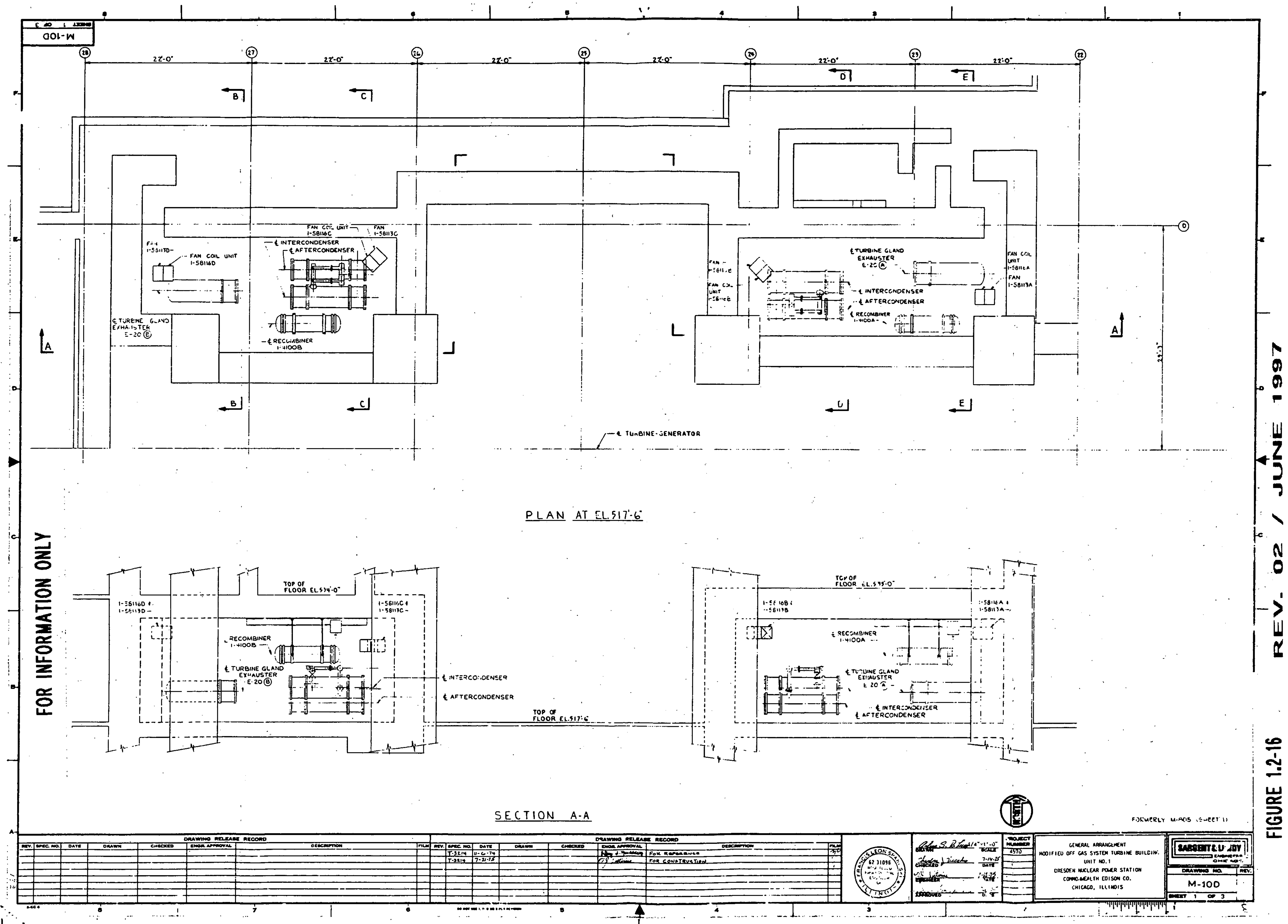
30 X



REV. 02 / JUNE 1997

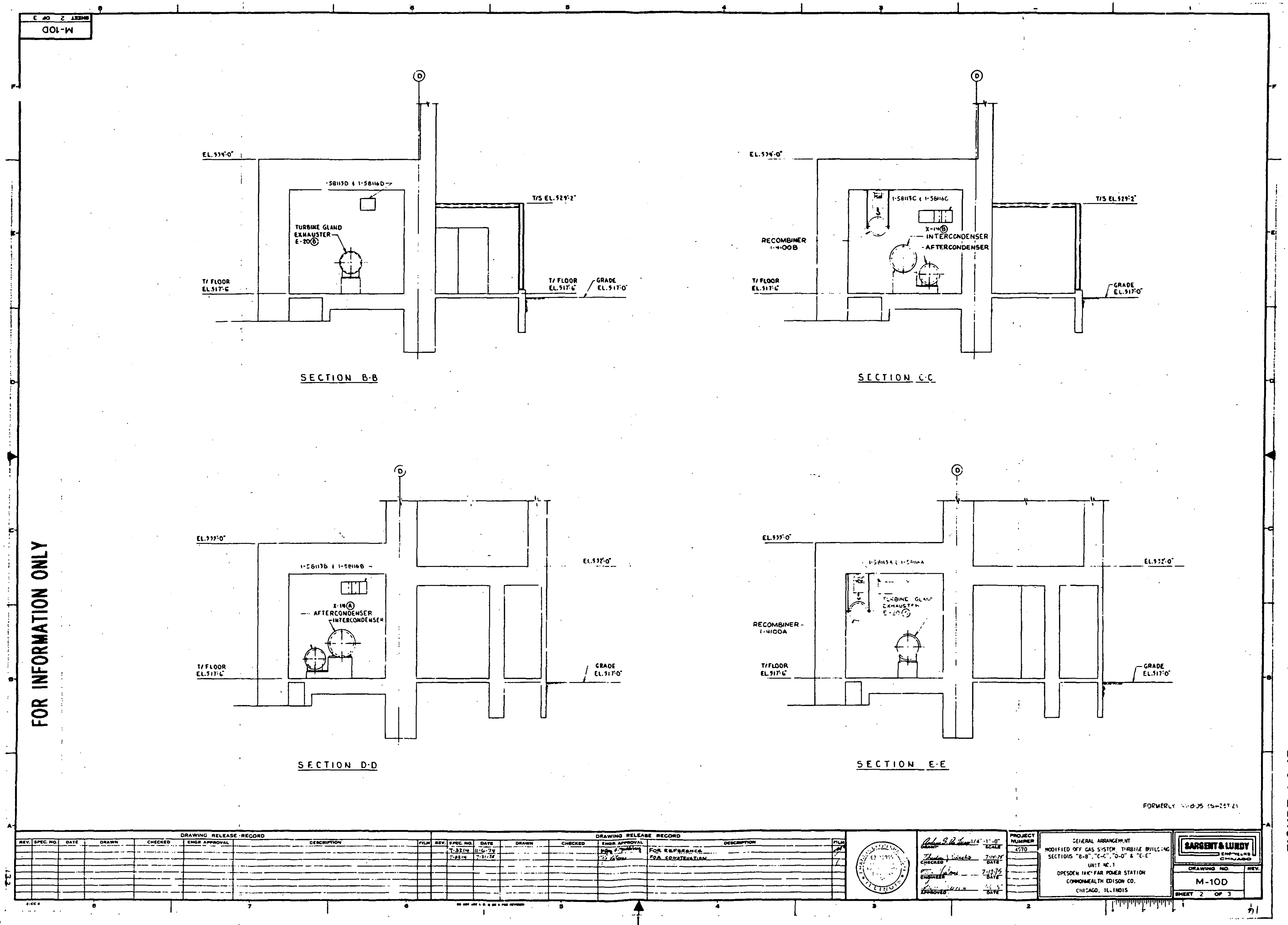
FIGURE 1.2-11

FOR INFORMATION ONLY



REV. 02 / JUNE 1997

FIGURE 1.2-16



FOR INFORMATION ONLY

FIGURE 1.2-17

REV. 02 / JUNE 1997

2.3.2 Local Meteorology

At the time of original plant licensing, the normal annual precipitation in the area was 33.18 inches. A 24-hour maximum rainfall of 6.24 inches had been recorded. The average annual snowfall since 1929 was 37.1 inches. The maximum snowfall from 1929 through mid-1967 was 66.4 inches, recorded in the winter of 1951-1952.

Thunderstorms occur an average of 49 days per year in the site region. Based on the annual number of thunderstorm days, the calculated annual flash density of ground lightning strikes is five flashes per square kilometer. A structure with the approximate dimensions of the Dresden reactor buildings can be expected to be subjected to an average of one strike every 5 years.

On the average, hail storms occur about 2 days per year, and freezing rain occurs approximately 12 days per year. The maximum radial thickness of ice expected in the site region is about 1 inch.

Fogging and icing from the Dresden cooling lake are not expected to adversely affect the surrounding area except for an increased hazard on County Line and Dresden roads. Warning signs with flashing lights are installed to alert traffic to fog conditions. Additionally, a fog fence and a lighted, covered bridge were constructed on County Line Road to further assure traffic safety.

In SEP Topic II-2.A, the NRC concluded that the extreme maximum and minimum temperatures appropriate at the Dresden site for general plant design (i.e., HVAC systems) are 94°F (equalled or exceeded 1% of the time), and -5°F (equalled or exceeded 99% of the time).

Annual wind frequencies show a rather uniform distribution of wind direction which is typical of mid-continent locations. The most frequent wind directions are from the west and south sectors. (A sector is defined as 22½°.) The highest velocity of wind officially reported at various locations around the site area is 87 mph at Chicago and 75 mph at Peoria. Higher gusts are reported unofficially, up to 109 mph during heavy thunderstorms and scattered tornadic activity. Thus, the design criterion that structures be capable of withstanding wind loadings of 110 mph is considered appropriate for withstanding the anticipated sustained winds.

Hourly wind direction variability at the site shows that an average direction range (angular change in direction) is 120° in a 1-hour period, for all wind speed conditions combined. During 0 — 3 mph wind speeds, the average range in direction is 100°. Approximately 87% of the time when the wind speed is 0 — 3 mph (or 98.3% of all wind speeds) the wind direction range is 60° or more, which corresponds to a value of the diffusion parameter of 20 degree-mph or 0.16 radian-m/s.

2.3.3 Onsite Meteorological Measurements Program

The meteorological measurements program at the Dresden site consists of monitoring wind direction, wind speed, temperature, and precipitation. Two methods of determining atmospheric stability are used: delta T (vertical

3.0 DESIGN OF STRUCTURES, COMPONENTS, EQUIPMENT, AND SYSTEMS

TABLE OF CONTENTS

3.0 DESIGN OF STRUCTURES, COMPONENTS, EQUIPMENT, AND SYSTEMS

TABLE OF CONTENTS

Page

3.0 DESIGN OF STRUCTURES, COMPONENTS, EQUIPMENT, AND SYSTEMS
LIST OF TABLES

Table

3.0 DESIGN OF STRUCTURES, COMPONENTS, EQUIPMENT, AND SYSTEMS
LIST OF TABLES

Table

3.0 DESIGN OF STRUCTURES, COMPONENTS, EQUIPMENT, AND SYSTEMS
LIST OF FIGURES

3.0 DESIGN OF STRUCTURES, COMPONENTS, EQUIPMENT, AND SYSTEMS
LIST OF FIGURES

Figure

The onsite electric power supplies,including the batteries, and the onsite electric distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure.

Electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits (not necessarily on separate rights-of-way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both circuits is acceptable. Each of these circuits shall be designed to be available in sufficient time following a loss of all onsite alternating current power supplies and the other offsite electric power circuit, to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. One of these circuits shall be designed to be available within a few seconds following a LOCA to assure that core cooling, containment integrity and other vital safety functions are maintained.

Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electric power supplies.

<u>Response</u>

Electric power from Units 2 and 3 is transmitted through a 345 kV system. Auxiliary power can be supplied from five separate and independent sources: Units 2 and 3, the 138 and 345 kV transmission system, and diesel generators.

The auxiliary power supply from the 138 and 345 kV transmission system is protected against the effect of unplanned outages by the diversity of five separate 345 kV circuits and six 138 kV circuits and three major generating units feeding into the two switchyards at the Dresden site.

Each unit has adequate auxiliary power supplied from either the 138 or 345 kV switchyard.

One auxiliary power supply for Unit 2 is from a unit auxiliary transformer connected to its generator leads. The reserve auxiliary power supply is from a transformer connected to the 138 kV bus at Dresden by means of duplicate conductors permitting connection to either of two bus sections. The two connections are separated by two bus sectionizing circuit breakers. A failure in a single bus section or of a single circuit breaker will affect only one of the auxiliary power transformer connections.

Each connection is equipped with two disconnecting switches in series so that failure of any one disconnecting switch can involve not more than one 138 kV bus section. The switching sequence will be protected by electrical interlocks so that one connection must be opened before the other can be closed.

The auxiliary power supply for Unit 3 is split between the unit auxiliary power transformer which is connected to the generator leads an the reserve auxiliary power transformer which is connected to the 345 kV bus at Dresden.

It is impossible for the failure of any one component of either the 138 or 345 kV transmission systems to cause a simultaneous outage of both buses at Dresden.

Two of the 345 kV circuits leave the Dresden bus on double circuited towers in a southerly direction for a distance of approximately one mile, then turn east for a distance of 2¾ miles and then turn north easterly to Gooding's Grove Transmission Substation.

One of the 345 kV circuits leaves the Dresden bus on single circuited towers in a southwesterly direction to Pontiac Midpoint Transmission Substation.

The auxiliary power system provides adequate power to operate all the station auxiliary loads necessary for station operation. The station auxiliary bus is also connected by appropriate switching sequences to diesel generators which will provide standby power in the event of total loss of auxiliary power from offsite sources. This power source is physically independent from any normal power system and each power source, up to the point of its connection to the auxiliary power bus, is capable of complete and rapid electrical isolation from any other sources.

Provisions are made for supplying a source of electrical power which is self contained within the plant and not dependent on normal sources of supply. The diesel generator system produces ac power at a voltage and frequency compatible with normal bus requirements. The diesel generators are sized so that one can carry the ECCS power requirements on one unit within the rating of the diesel or that power necessary for safe shutdown of the unit. The second diesel generator is shared by both Units 2 and 3. In addition, the system is of sufficient capacity to start all initial loads it is expected to drive.

A total of three (250-volt, 125-volt, and 24/48-volt) station battery systems are provided for each unit. One 250-volt "power" battery is provided to serve the larger loads such as dc motor driven pumps, valves, etc. One 125-volt "control" battery is provided to supply the power required for exit lighting and all dc control functions such as that required for control of the 4 kV breakers, 480-volt breakers, various control relays, annunciators, etc. Two 24/48-volt batteries are provided to supply the neutron monitoring system.

The 250-volt, 125-volt, and 24/48-volt batteries are located in a ventilated battery room having concrete block walls. Each battery is further protected by a chain link fence enclosure.

The 250-volt station battery is sized with a capacity suitable to supply emergency power for a time deemed adequate to safeguard the plant until normal sources of power are restored. The battery chargers are sized with a capacity suitable for restoring the battery to full charge under normal (not emergency) load in a time commensurate with the recommendations of the battery manufacturer.

The 125 volt station battery is sized with a capacity suitable to supply emergency power for a time deemed adequate to safeguard the plant until normal sources of power are restored. The battery chargers are sized with a capacity suitable for restoring the battery to full charge under normal (not emergency) load in a time commensurate with the recommendations of the battery manufacturer.

LPCI piping	ASME Section III, Class C
Main steam piping	USAS B-31.1; ASME Section I and III
Off-gas piping	USAS ASA B-31.1
Off-gas recombiner/adsorber	ASME Section III, Subsection ND, Class 3
Oxygen injection	ASME Section VIII, Division I
RBCCW heat exchangers	ASME Section VIII
Reactor protection system	IEEE 279-1966
Reactor water cleanup vessels	ASME Section III Class C, 1965 (Unit 2 purchased to ASME Section VIII, reconciled to ASME Section III, Class C, 1965)
Shutdown cooling system	ASME III, Class C)
Suppression pool temperature monitoring system	IEEE 279-1971, 323-1974, 344-1971, 344-1975
Traversing incore probe guide tubes	ASME Section VIII

3.2.10 Control of Purchased Material, Equipment, and Services

The purpose of this section is to discuss the requirements for procurement, fabrication, and material documentation of component replacements and piping installation at the Dresden Station.

For replacements of components that were originally constructed to ASME Code Section III, Classes 1, 2 or 3 or to other standards within the scope of the current edition of Section XI, Division 1 of the code, Article IWA 7000 of Section XI specifies general requirements. Paragraph IWA 7210 requires replacements of components to meet the requirements of the original construction code used or those of a later code edition and/or addenda approved in the codes and standards rule 10 CFR 50.55a. The material documentation and the non-destructive examination (NDE) requirements for piping installation and valve/pump fabrication are also provided in detail in ASME Code Section III and Section XI, ANSI B31.1, and ANSI B16.34. These requirements can be applied to the procurement of the replacement parts for existing valve disks and removable seats. These requirements, however, do not apply to other replacement valve internals.

If the replacement components available are found not to be in full compliance of the original code, it should be ensured that the level of quality of a replacement component is at least equivalent to the original code, as recommended in Generic Letter 89-09.

Currently at Dresden, repair/replacement materials for components that were originally constructed to ASME Section III, Classes 1, 2, or 3 or to other standards within the scope of Section XI of the code, are ordered in accordance wth code requirements, i.e., the materials shall meet the requirements of the original construction code used or those of a later code edition and/or addenda approved in 10 CFR 50.55a. This requirement has been noted in the Dresden administrative procedure.[1] In the event of conflict between the existing procurement specifications for replacement components/parts and the codes, the codes shall take precedence.

equipment. Because of the above design considerations, rupture of this low pressure system is not considered credible.

In order to remove postulated water leakage from valve stems, flanges, etc., the reactor building has been equipped with two floor drain sump pumps each with a capacity of 50 gal/min for a total removal capacity of 100 gal/min. Leakage of 100 gal/min corresponds to a system rupture equivalent to a 1-inch diameter hole. Two additional submersible pumps were installed by a modification to provide redundancy in the system. Excess operation of the sump pumps would also be noted in the radwaste facility. In addition, torus water level is constantly monitored in the control room and alarmed for departure from normal water level.

Additionally, submarine-type doors have been installed between the low pressure coolant injection (LPCI) rooms and the torus basement to provide a leaktight barrier in the event of flooding in the torus basement. Should the torus basement become flooded, it will be necessary to pump the water out of it. This is accomplished via a 2-inch pipe that has been installed in one of the submarine doors. These submarine-type doors are verified to be properly closed daily.

Due to the design of the drywell and torus, it is not possible to accumulate any large quantity of water under the reactor vessel. During a loss-of-coolant accident (LOCA) or similar event, the design permits the area under the vessel to drain into the torus via the downcomers. Without pumping, the sumps would overflow to the drywell floor, and once the water level reached the downcomers, water would flow into the torus. Since the torus level is monitored, this increase would be noted and investigated. Even under this scenario, the water would not reach a level where it could adversely affect any critical system.

3.4.2 Analytical Procedures

This section describes the analytical procedures by which the static and dynamic effects of the flood conditions are applied to safety-related structures, systems, and components.

3.4.2.1 Drywell

The drywell was analyzed to determine the additional effects due to seismic loads when it is in a flooded condition. From the analysis it was concluded that the natural period of vibration of the drywell is about 0.07 seconds for the empty condition and 0.12 seconds for the flooded condition. Thus, the resulting effect of hydrodynamics is to reduce the total seismic forces. Because of this, the effects of the dynamic response of the fluid in the drywell were conservatively neglected in the dynamic analysis employed for the drywell design. Refer to Sections 3.7 and 3.8 for more detailed information concerning the seismic analyses performed for the drywell.

The NRC concluded that the total turbine missile risk from high and low trajectory missiles for Dresden Station Unit 2 design is acceptably low so that plant structures, systems, and components important to safety are adequately protected against potential turbine missiles. This conclusion was drawn in conjunction with an agreement between CECo and the NRC for higher frequency turbine maintenance and inspections.

3.5.4 Missiles Generated by Natural Phenomena

An analysis of Dresden Unit 2 was performed by the NRC, as a part of the SEP, to determine the ability of certain structures to adequately protect the systems contained within them from postulated tornado missiles. Two types of missiles were considered:

A. A steel rod, 1 inch in diameter, 3 feet long, and weighing 8 pounds, with a horizontal velocity equal to 317 ft/s, and

B. A utility pole, 13.5 inches in diameter, 35 feet long, and weighing 1490 pounds, with a horizontal velocity equal to 211 ft/s.

These missiles were considered to be capable of striking in all directions with vertical speeds equal to 80% of the horizontal speeds listed above.

The structures that were evaluated included:

A. The reactor building;

B. The turbine building;

C. The control room structure;

D. The radwaste buildings;

E. The diesel-generator buildings; and

F. The crib house (intake structure).

In order to assess the adequacy of tornado missile protection of these structures, the NRC compared the wall and roof thicknesses of the structures to the current NRC requirements for the two postulated missiles using the Region I design basis tornado (360 mph). For a concrete strength of 4000 psi, the required concrete thicknesses are as stated below:

Missile Type	Required Wall Thickness (inches)	Required Roof Thickness (inches)
Telephone pole	12	12
Steel rod (1 inch)	8	8

3.7 SEISMIC DESIGN

This section summarizes the seismic design bases for Dresden Station. Section 3.7.1 describes the seismic input motion applied in the analysis of structures, systems, and components at the Dresden site. Analytical methods are provided in Section 3.7.2 along with a description of the analyses performed for major plant structures. Section 3.7.3 summarizes seismic analysis methods and criteria applicable to piping systems, including alternatives implemented since the implementation of the original methods and criteria. Instrumentation used to measure and record seismic events at the Dresden site is addressed in Section 3.7.4.

It should be noted that seismic design of Dresden Unit 2 was examined by the NRC under systematic evaluation program (SEP), Topic III-6. The NRC evaluated the capability of Dresden Unit 2 to withstand a safe shutdown earthquake (SSE) by sampling review and confirmatory analysis. The NRC concluded that the majority of "safety related structures and structural elements of the Dresden 2 facility are adequately designed to resist the postulated seismic event." The remaining SEP Topic III-6 reviews have been closed out by the NRC (reference 36).

3.7.1 Seismic Input

The seismic design of structures and equipment at Dresden Units 2 and 3 was based upon the recommendations of seismologist Perry Byerly. John A. Blume and Associates, engineering consultants, reviewed the seismology, geology, and other pertinent data of the site and recommended the seismic design criteria. They also performed a dynamic analysis of the Class I structures.

Based upon the seismology report (in Volume III, Section 4 of the Dresden Unit 2 PDAR), an earthquake having an intensity of VII on the Modified Mercalli Scale is the maximum anticipated for the site.

The input for the seismic analysis of Class I equipment and structures was the north-south component of the El Centro earthquake of May 18, 1940, normalized to a maximum operating basis earthquake (OBE) ground acceleration of 0.10 g. The length of the earthquake record employed was 10 seconds. The maximum response occurred within the first 4 to 6 seconds. Longer intervals of motion have been used on similar structures, and the maximum response always occurred within 4 to 6 seconds regardless of the length of record used.

Figure 3.7-1 shows an unsmoothed response spectrum curve for the El Centro earthquake normalized to 0.10 g maximum OBE ground acceleration at 2% damping. The unsmoothed response spectrum was calculated from the El Centro record using the usual analytical methods. Also shown is the design OBE response spectrum curve for Dresden (Housner) at 2% damping which was applied to equipment and structures analyzed by the response spectrum method rather than the time-history method.

The actual El Centro response spectrum has not been used for any of the analyses. All OBE response spectrum calculations employed the smooth Housner response acceleration spectrum shown in Figure 3.7-2. When an OBE time-history analysis was made, the El Centro earthquake record was employed, normalized to a ground acceleration of 0.10 g.

The time-history method of analysis was used for the reactor-turbine building, the reactor pressure vessel, the chimney, and the drywell.

The response spectrum method of analysis was used for the following structures or systems:

A. Recirculation loop piping,

B. Suppression chamber ring header (suction),

C. Feedwater lines,

D. Main steam lines,

E. Isolation condenser,

F. Control room, and

G. Suppression chamber.

The actual El Centro unsmoothed spectrum (Figure 3.7-1, upper curve) was not used for response analyses in either of the methods (time-history or smooth response spectrum) above. It was used, however, to verify that when using the time-history method the maximum OBE loadings did not occur in valleys of the unsmoothed spectrum.

Since the unsmoothed curve is generated from the time-history record and the smooth response spectrum curve has lower accelerations for nearly all periods, it is concluded that the time-history method tends to overestimate the response when compared to the design criteria (smooth response spectrum).

The seismic consultant prepared the OBE acceleration response spectrum curves shown in Figures 3.7-2 and 3.7-3 based upon a ground acceleration of 0.10 g and the Housner response spectra shape. The seismic design of Class I structures and equipment was based upon a dynamic analysis using these curves. The natural periods of vibration were calculated for buildings which are vital to the proper shutdown of the plant. The damping factors given in Table 3.7-1 were used for strong vibrations within the elastic limit.

For the design of Class I structures and equipment the maximum horizontal acceleration and the maximum vertical acceleration were considered to act simultaneously. Where applicable the resulting seismic stresses for the two motions were combined linearly. The vertical OBE acceleration assumed was equal to 0.067 g, two-thirds the horizontal ground acceleration.

concrete walls between adjacent floors. The top story masses are similarly developed but include the tributary mass of the walls, frame, and the mechanical equipment of the story. The average area and moment of inertia of the concrete between floors was used to determine the stiffness characteristics between masses. The steel-framed top portion was investigated separately; however, an equivalent frame stiffness was developed for each direction. A value of 3×10^6 psi was assigned as the elastic modulus of concrete, and 3×10^7 psi was assigned as the elastic modulus of the steel structure.

The design modulus of 3×10^6 psi is in accordance with the ACI "Building Code Requirements for Reinforced Concrete" (ACI 318-63, Section 1102), which is standard design practice. However, it is recognized that the modulus of elasticity of concrete increases with age following the 28-day period, but it is difficult to evaluate the amount of increase. The following factors affect the strength of concrete:

A. Curing temperature,

B. Initial temperature,

C. Variations in mixes, and

D. Amount of hydration.

The elastic modulus is not directly proportional to the strength of concrete; nevertheless, the effect of increasing the strength causes an increase in the modulus. However, the increase in the modulus due to age is not believed to be significant in light of all the uncertainties affecting the modulus of concrete. Whatever the small change in the modulus may be, this effect is partially accounted for by cracks in the concrete structure due to shrinkage and temperature. Such cracks tend to make the structure more flexible, which tends to compensate for the increased modulus. Also the percentage change in the modulus is small compared to other inputs in the analysis such as dimensions, areas, cross sections, mass grouping, etc. Hence the effect of an unknown modulus change on the validity of the dynamic analysis is considered to be negligible.

The mathematical model of the reactor turbine building (Figures 3.7-4 and 3.7-5) includes the mass of the drywell. In the analysis of the drywell, discussed in Section 3.7.2.2.1.1, the mass and properties of the drywell are taken out of the reactor turbine building model. The drywell lumped mass model was considered fixed at elevation 500'-0-⅝" and laterally supported at elevation 572'-2".

The mathematical model of the reactor pressure vessel (Figure 3.7-6) gives the support conditions which are fixed at the base of the pedestal, lateral support at the stabilizer elevation connecting the reactor pressure vessel to the sacrificial shield, and a horizontal pipe truss system connecting the sacrificial shield to the building. The reactor pressure vessel seismic analysis is affected by seismic motions at the support points only. Therefore, the reactor pressure vessel could be decoupled from the rest of the building and analyzed separately, taking into consideration the effects of input motion at all supports and conservatively combining the individual effects.

A rebaselined seismic model of the RPV, internals and interrelated portions of the main plant structures was developed in 1994 to address issues associated with the seismic analysis of the core shroud repair as well as other RPV internals component repair designs. This model was modified to incorporate the core shroud repair hardware and was used to perform the seismic analysis for the repair design. The revised seismic analysis of the RPV was performed using a combined RPV and main power block model to directly account for the affects of the coupling. The El Centro and Housner spectrum compatible time histories were used to perform the seismic analysis for the core shroud repair design. The enveloping values (accelerations displacements, shears and moments) from the two time histories were used for the evaluations and design of the repair hardware. A core shroud repair designed to structurally replace circumferential core shroud welds H1 through H7 was installed in Unit 2 during D2R14.

The ground motion utilized in determining the dynamic response of the reactor building has a maximum base OBE acceleration of 0.10 g. A constant vertical OBE acceleration of 0.067 g was assumed to act simultaneously with the horizontal OBE design acceleration.

The computer program used in this analysis was specially designed to solve the dynamic response of structures subjected to arbitrary ground motions. Since the program was written to cover as many structural configurations as possible, the structural member input data for the program is in the form of member moments of inertia, areas, and effective shear areas. The effects of axial and shear deformation are included in the calculation of the stiffness matrix. The input and output data are shown in Tables 3.7-2 and 3.7-3. A simplified block diagram of the computer program is shown in Figure 3.7-7.

Section 3.8.4 presents the results of the reactor building seismic analysis. In the north-south direction, the coupled periods of vibration determined for the subject structure were 0.39, 0.23, 0.20, 0.17, and 0.14 seconds for the first five modes respectively. In the east-west direction coupled periods of vibration determined for the subject structure were 0.37, 0.34, 0.25, 0.15 and 0.12 seconds for the first five modes respectively.

The structure has been designed to resist the OBE shears and moments presented without any increase in stress for short-term loadings. In addition, the structure was reviewed to assure that it would resist a safe shutdown earthquake (SSE), equal to twice the OBE seismic shears and moments presented without hindering the ability of the plant to be shut down safely.

Calculations were performed with the aid of a digital computer and five modes were considered in the analysis. Since the predominant response of the building is due to the first mode of vibration while the fifth mode has a period of vibration approaching that of a rigid system, the fifth mode has a negligible participation on the overall response.

3.7.2.2.1 Primary Containment Seismic Analysis

The seismic study of the drywell conducted by John A. Blume and Associates is summarized in this section.

3.7.2.2.1.1 Drywell Seismic Analysis

For seismic purposes, the drywell containment structure is considered to be a bulb-shaped steel structure free to move except where it is attached to the concrete around it at two points: at the bottom fixed in the reactor building at elevation 500'-0-⅝" and supported laterally by the reactor building at elevation 575'-2".

A 2-inch gap for thermal expansion between the steel drywell and the concrete containment shield wall was ensured by cementing elastic polyurethane sheets to the steel drywell and to the sleeves for the drywell penetrations prior to pouring the containment shield concrete wall. This process is described more fully in Section 6.2.1.2.3.6. Since the foam against the supporting structural members. The center of the wall cracks due to tension stresses, and a three-hinged arch is formed to resist the loads through compression stresses only.

Design seismic loads generated by the safe shutdown earthquake are based on the peak acceleration of the applicable response criteria and a damping factor of 10% of critical.

The stiffnesses of the supporting structural elements are accounted for in the analysis. Also, the deflection at the center hinge must be less than or equal to one third of the wall thickness. If an arching wall meets the above requirement, it is considered acceptable when the compression stress developed in the arch is less than or equal to the allowable flexural compression stress.

3.7.4 Seismic Instrumentation

A strong motion seismograph is installed at Dresden (a Model SSA-1 manufactured by Kinemetrics). The unit is self-contained and is battery-operated from rechargeable batteries.

The seismograph is located in the auxiliary electric equipment computer room on elevation 516'-0". The unit is mounted directly onto the floor and is placed out of the way of normal traffic.

31. ASME Boiler & Pressure Vessel Code, Code Case N-47, "Class 1 Component in Elevated Temperature Service," dated December 11, 1981.

32. "Proposed Code Change to Place Seismic Loading in the Fatigue Category," PVRC Technical Committee on Piping Systems, dated July 11, 1984.

33. Galambos, T.V. and Ravindra, M.K., "Properties of Steel for Use in the LRFD," Journal of the Structural Division, ASCE, September 1978.

34. "Final Report on Bar Tests for the Committee of Reinforcing Bar Producers, AISI," by Wiff, Janney, Elstner and Associates, April 1970.

35. "Comparative Tests of Physical Properties of No. 18 Reinforcing Bars, AISI," by Wiff, Janney, Elstner and Associates, January 1971.

36. U. S. Nuclear Regulatory Commission (NRC) Letter from Mr. J. F. Stang, To Mr D. L. Farrar - Commonwealth Edison, Subject - "Systematic Evaluation Program, Topic lll-6, Structural Integrity of Reactor Pressure Vessel - Dresden Nuclear Power Station, Unit 2", (TAC NO. M72906), dated September 10, 1993.

37. NUREG/CR-0891, "Seismic Review of Dresden Unit 2 For the Systematic Evaluation Program", April 1980.

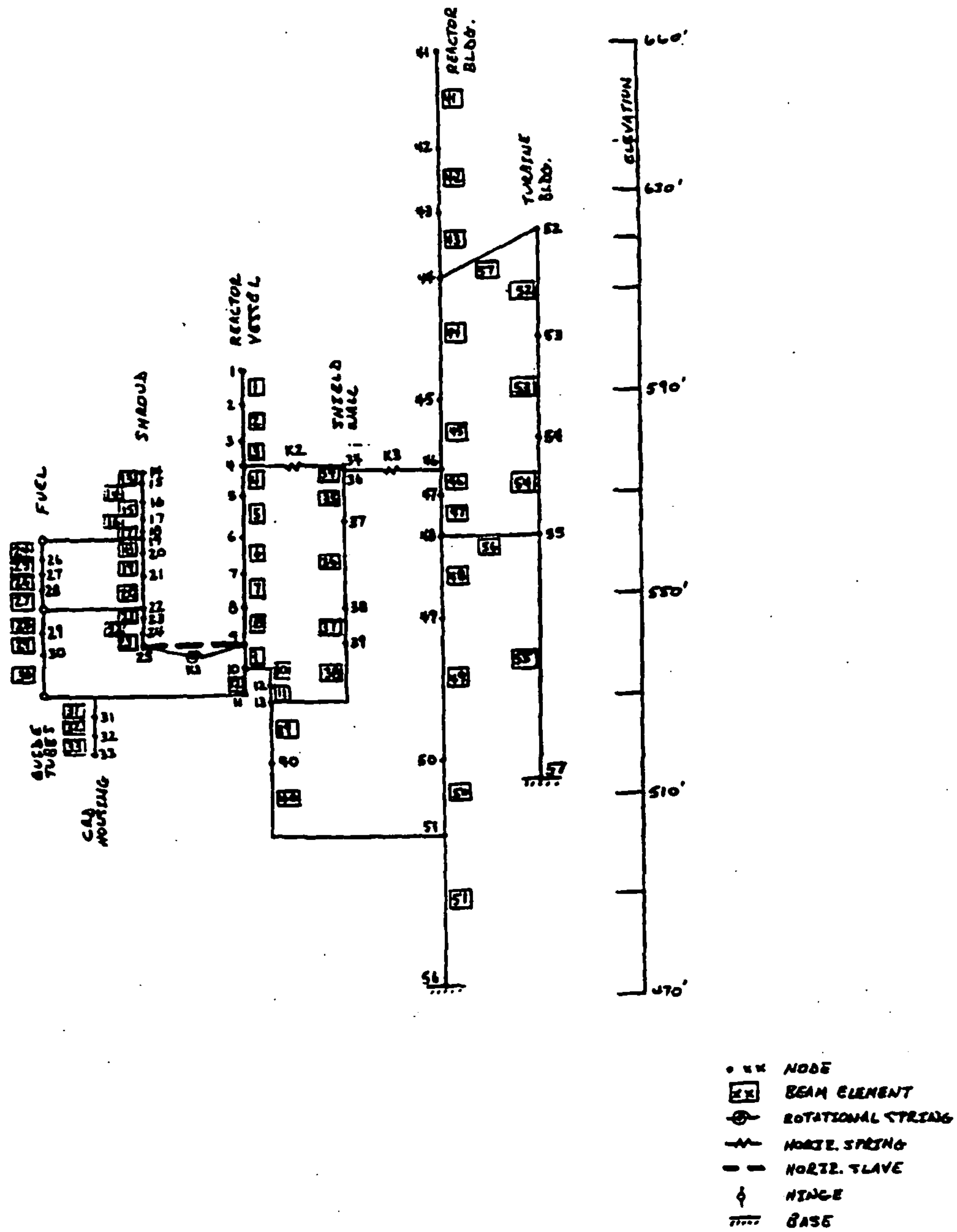
Table 3.7-1

DAMPING FACTORS FOR STRONG VIBRATIONS WITHIN THE ELASTIC LIMIT

Item (Note 1)	Percentage of Critical Damping
Reinforced Concrete Structures	5.0
Steel Frame Structures	2.0
Welded Assemblies	1.0
Bolted and Riveted Assemblies	2.0
Vital Piping Systems	0.5

Notes

1. The damping factors for the core shroud, guide tubes, CRD housing and RPV stabilizer are considered proprietary information and are provided in GENE-771-84-1194, Revision 2, "Dresden Units 2 and 3, Shroud Repair Seismic Analysis".



Notes:

1. The details of the modeling of the core shroud repair hardware is considered proprietary information (see GENE 771-84-1194 and section 3.9.5.3.4).

UFSAR REVISION 2, JUNE 1997

DRESDEN STATION
UNITS 2 & 3

MATHEMATICAL MODEL, REACTOR PRESSURE VESSEL & INTERNALS

FIGURE 3.7-6

The drywell and suppression chamber are interconnected by a vent system. Eight main vents connect the drywell to a vent ring header, which is located within the suppression chamber airspace. A bellows assembly is located at the junction where each main vent penetrates the suppression chamber shell to permit differential movement of the suppression chamber and drywell/vent system. Projecting downward from the vent ring header are downcomer pipes, arranged in 48 pairs around the vent header circumference, terminating below the surface of the suppression chamber water volume (Figure 6.2-4).

The original design of the Mark I containment system considered various postulated accident loads associated with the containment design as input into the analysis (see Section 6.2 for a functional description of the containment system). These included pressure and temperature loads resulting from a LOCA, seismic loads, dead loads, jet impingement loads, hydrostatic loads due to water in the suppression chamber, and pressure test loads. Subsequently, while performing large-scale testing for the Mark III containment system and in-plant testing for Mark I primary containment system, new suppression chamber hydrodynamic loads were identified. These hydrodynamic loads are related to the postulated LOCA and safety relief valve (SRV) actuation.

The additional loads result from dynamic effects of drywell atmosphere and steam being rapidly forced into the suppression pool during a postulated LOCA and from suppression pool response to SRV operation generally associated with plant transient operating conditions. Additional details regarding the origin and nature of these hydrodynamic loads are presented in Section 6.2.1. Because these hydrodynamic loads had not been considered in the original design of the containment, a detailed reevaluation was undertaken. This reevaluation, referred to as the Mark I Program, involved tasks performed to restore the originally intended design safety margins for the Dresden plant. The Mark I Program culminated in the issuance of the Plant Unique Analysis Report (PUAR)[1] for Dresden, followed by review and acceptance by the NRC.[2]

The following subsections address structural design of the drywell (Section 3.8.2.1), vent system (Section 3.8.2.2), and suppression chamber (Section 3.8.2.3).

3.8.2.1 Drywell

Due to the physical layout of the drywell, in which the main vent junctions are immediately above the drywell's concrete embedment (see Figure 6.2-2), the main vents are anchored to the drywell shell. With the exception of the main vent junctions, the drywell was not reevaluated under the Mark I Program. The following subsections thus describe original drywell structural design.

3.8.2.1.1 Description of Structure

Drywell dimensions were dictated by the need to enclose the reactor vessel and associated auxiliary equipment. The governing thermal-hydraulic aspects for containment sizing are addressed in Section 6.2.1.

diameter as the drywell skirt. The shear in the two ⅜-inch fillet welds attaching this shear plate to the drywell under the OBE is 3550 psi. The bearing on the concrete for this condition is 315 psi. These values are within the allowable of 15,800 psi for the weld metal and 935 psi for the concrete. For the SSE, the stress in the weld is 7000 psi and in bearing on the concrete 615 psi. The weld stress and the concrete allowable bearing stress for the SSE is still below the working stress allowables.

Absolute seismic acceleration curves were developed to give an envelope of the maximum absolute accelerations with respect to height. Moment, shear, and displacement curves were also developed. Instead of directly using the absolute acceleration curves, the moment, shear, and displacement curves were used in the seismic design of the drywell. Figures 3.8-2 through 3.8-7, present the maximum displacements, shears, and moments in both the east-west and north-south directions.

In the drywell/reactor building/turbine building analysis, some minor discrepancies in the displacements of the interconnecting elements resulted due to:

A. The plotting procedures, whereby a displacement is calculated for each mass point and a continuous curve drawn through these points, and

B. The deflection of the spring connections shown between the reactor and turbine buildings.

The NRC performed an independent review, under Systematic Evaluation Program Topic III-7.B, of the Dresden Unit 2 drywell and concluded that the drywell will perform its intended function when subjected to combined seismic-LOCA loads.

3.8.2.1.6 Testing and Inservice Inspection Requirements

Pressure and leakage rate testing of the containment system are addressed in Section 6.2.6.

3.8.2.1.7 Flued Head Penetrations

Fluid pipe penetrations are of two general types; i.e., those which accommodate thermal movement and those which experience relatively little thermal stress. Fluid piping penetrations for which movement provisions are made are high-temperature lines such as the main steam line and certain other reactor auxiliary and cooling system lines. Typical penetrations of this type are shown in Figures 3.8-8, 3.8-9A and 3.8-9B. These penetrations have a guard pipe between the hot line and the penetration nozzle and a two-ply expansion bellows between the penetration nozzle and the flued head. This configuration permits the penetration to be vented to the drywell should a rupture of the hot line occur within the penetration.

The guard pipes are designed to the same pressure and temperature as the fluid line and are attached to a multiple flued head fitting, a forging with integral flues or nozzles. This fitting was designed to conform to ASME Section VIII. The penetration sleeve is welded to the steel drywell and extends through the concrete containment shield wall where it is welded to a bellows, which in turn is welded to the guard pipe. The bellows accommodates the thermal expansion of the steam pipe and steel drywell relative to the steam pipe. A double bellows arrangement permits remote leakage testing of the penetration seal. The lines are anchored at one end of the penetration assembly to limit the movement of the line relative to the containment yet permit pipe movement parallel to the penetration.

The only lines which connect to a high-pressure system which do not have a double seal penetration sleeve are the hydraulic lines to the control rod drives. These comprise 354 small, stainless steel lines, shop-welded to three sections of the drywell plate. The mechanical problems involved with this number of small penetrations in a relatively small area make it impractical to provide individual penetration sleeves. The pipes are designed to deflect with the drywell shell. They are not individually testable but are tested as part of the overall containment leakage rate test.

Penetration details of cold piping lines are shown on Figure 3.8-10. The pipe sleeve which attaches to the drywell is designed for 62 psig but can withstand a substantially higher pressure due to the use of heavy wall pipe. No bellows are required, since thermal expansion is minimal. A tabulation of the type of penetration used for each service is shown in Tables 3.8-1 and 3.8-2 for Unit 2 and 3, respectively.

Lines which open directly to the containment do not have a separate penetration sleeve and are welded directly to the containment shell.

Modifications have been made to replace flued head anchors for containment penetrations X-113, X-108A, and X-109A with new flued head anchor structures with increased load capacity. The new anchor structures resist pipe loads due to pipe breaks or seismic events.

3.8.2.1.8 Electrical Penetrations

Electrical penetration seals were designed to accommodate the electrical requirements of the plant. These are functionally grouped into low-voltage power and control cable penetration assemblies, high-voltage power cable penetration assemblies, and shielded cable penetration assemblies. Each penetration seal has the same basic configuration shown in Figure 3.8-11. An assembly is sized to be inserted in the 12-inch Schedule 80 penetration nozzles which are furnished as part of the containment structure. Installation of the penetration assembly is accomplished by inserting it from either side of the containment into the penetration nozzle. Three field welds are required to complete the installation of the assembly in the penetration nozzle.

Headerplates conforming to the inner diameter of the penetration nozzle are provided at each end of the penetration assembly, forming a double pressure barrier. Radiation shielding is attached to the penetrations on the drywell side to provide external access to the electrical connections during plant operation.

The design and fabrication of each type of penetration assembly is in accordance with the requirements of ASME Section III, Class B, and materials of construction are self-extinguishing in accordance with ASTM-D635. The electrical penetrations were designed to withstand environmental conditions present during a postulated LOCA, as well as to maintain containment integrity for extended periods of time with a post-accident environment. These conditions, including the normal operating environmental conditions, are shown in Table 3.8-3.

The installed assemblies are designed to withstand a continuous internal pressure of 125 psi during normal environmental conditions and to meet a leakage rate of 1.16 x 10^{-6} cc/s when pressurized to 63 psig with dry helium at an ambient temperature of 175°F. The latter condition is verified prior to installation in the primary containment.

The low-voltage assembly is suitable for voltages 600V or less and is designed for conductors varying in size from 18 to 4/0 AWG. The cables are grouped and passed through openings in the headerplates as shown in Figure 3.8-12. A potting compound is applied at each end of the penetration to seal the assemblies. A cable lead is terminated at either a splice or an environment-resistant connector. The maximum wire density is restricted to 42% of the end flange cross-sectional area.

Shielded signal cables are provided to interconnect low-noise circuits between the reactor and the control room; in particular, the reactor neutron monitoring channels. Figure 3.8-13 shows a cutaway view of the containment penetration assembly for shielded signal cables. One type of circuit uses coax connectors mounted directly on the headerplates and isolated from ground. Another type of circuit uses connectors mounted on the penetration assembly auxiliary structure. The cable density is restricted to one circuit per three square inches of headerplate surface for the first type and approximately 80 circuits of the latter type for each 12-inch penetration nozzle.

A sectional view of the high-voltage power cable penetration assembly is shown on Figure 3.8-14. The penetration assembly accommodates voltages up to 5 kV and cables as large as 1000 MCM and is designed to maintain low gas leakage rates and high insulation resistance. The high-voltage cables are passed through openings in the headerplates, and potting compound is applied to both sides of the headerplates to effect a pressure seal. The headerplates are constructed of stainless steel, a nonmagnetic material, in order to eliminate the possibility of eddy current heating.

3.8.2.1.9 Instrument Line Penetrations

Instrument line penetrations for the drywell are shown in Table 3.8-4. The following discussion, including descriptions and quantities, is applicable to Unit 3; the descriptions are generally applicable to Unit 2 also.

Dresden Unit 3 contains 16 penetration assemblies which are used for primary system instrumentation. Each of these assemblies is configured to carry six instrument pipes through the concrete containment shield wall. Of the total of 96 penetrating pipes, 77 are active lines and 19 are spares. Each of the active penetrating pipes are equipped with stop valves and excess flow check valves located outside the containment as indicated in Table 3.8-4.

"In addition to the stop and excess flow check valves on the Reactor Vessel Water Level A-Loop and B-Loop (penetrations X-209 and X-108B respectively), these lines have Reactor Vessel Water Level Instrumentation System (RVWLIS) Backfill interfaces upstream of the stop valves. Each of the RVWLIS Backfill lines has two simple 3/8-inch tubing, Type 316 stainless steel check valves in series acting as primary containment isolation valves."

The penetrating lines are 1-inch Schedule 80, Type 304 stainless steel pipe. Each of the lines is welded to a stainless steel pipe which is welded to the drywell penetration housing. A detail of a typical multiple pipe instrument penetration is shown in Figure 3.8-15.

Within the secondary containment are 1-inch process stop valves, flow check valves, and ½-inch Schedule 80, Type 304 stainless steel piping to the instrument rack. Piping or stainless steel tubing is used within the rack to the sensor. All welds have been dye-penetrant tested. Analyses have been performed to assure that the installation from the penetration to the instrument rack meet seismic Class I requirements.

The two reactor recirculation pump No. 1 seal cavity instrument lines are interconnected with the reactor recirculation pump seal purge lines between the excess flow check valves and the instruments. Redundant, safety related check valves are installed in each seal purge line in close proximity to the containment penetrations. The piping between the excess flow check valves and the safety related seal purge line check valves is seismically designed, consistent with the design of the piping to the instruments. See Section 4.6.4.6. for further discussion of the seal purge line check valves.

Each process stop valve and excess flow check valve is Type 304 or Type 316 stainless steel. The excess flow check valves permit a maximum flow of 2 gal/min. A detail of a typical penetrating pipe installation is shown in Figure 3.8-16. There are three exceptions where the process stop valves are more than 12 inches from the penetration. These are for penetrations X-130, X-131, and X-135, all of which are located below grade.

No special protection has been provided for any of the instrument lines within the secondary containment. An analysis has been performed of the consequences of a 1-inch instrument line break in the Dresden Unit 3 plant. The break was assumed to occur outside the primary containment but upstream of the excess flow check valve in the line. A manually operated stop valve located outside the containment wall upstream of the break was not assumed to be closed until after the reactor was shut down and depressurized. The reactor was assumed to be shut down manually by the operator upon detection of the break, i.e., by audible disclosure or by detection of increased radiation level in the reactor building or water level increase in the reactor building sumps. The results of this analysis, including secondary containment integrity and radiological consequences, are addressed in Section 15.6.2.

The instrumentation required to either shutdown the reactor or initiate core cooling functions are separated so that a single event cannot jeopardize these functions, as discussed in Section 7.6.2.

3.8.2.2 Vent System

3.8.2.2.1 Description of Structure

The vent systems for Units 2 and 3 are constructed from cylindrical shell segments joined together to form a manifold-like structure connecting the drywell to the suppression chamber. Figures 3.8-1, 6.2-2, and 6.2-3 show the configuration of the vent system. The major components of the vent system include the vent lines, vent line/vent header spherical junctions, vent header, and downcomers. Figures 3.8-17, 3.8-18, 6.2-4 and 6.2-5 show the proximity of the vent systems to other containment components.

The eight vent lines connect the drywell to the vent header in alternate mitered cylinders or bays of the suppression chamber. The vent lines are nominally ¼ inch thick and have an inside diameter (ID) of 6 feet, 9 inches. The upper ends of the

3.8.2.3.5 Structural Evaluation

The NUREG-0661[3] acceptance criteria on which the suppression chamber analyses are based follow the ASME Code, Section III, 1977 Edition, including the Summer 1977 Addenda for Class MC components and component supports. The corresponding service level assignments, jurisdictional boundaries, allowable stresses, and fatigue requirements are consistent with those contained in the applicable subsections of the ASME Code and the PUAAG.[5]

The items examined in the analysis of the suppression chamber include the suppression chamber shell, the ring girder, and the suppression chamber horizontal and vertical support systems.

The suppression chamber shell and ring girder were evaluated in accordance with the requirements for Class MC components contained in Subsection NE of the ASME Code. Fillet welds and partial penetration welds in which one or both of the joined parts includes the suppression chamber shell and the ring girder were also evaluated in accordance with the requirements for Class MC component attachment welds contained in Subsection NE of the ASME Code.

The allowable stresses for each suppression chamber component and vertical support system component were determined at 165°F. The allowable stresses for the vertical support system base plate assemblies were determined at 100°F. Table 3.8-9 shows the resulting allowable stresses for the load combinations with ASME Code Service Level B, C, and D limits.

Table 3.8-10 summarizes the maximum stresses and associated design margins for the major suppression chamber components and welds for the controlling load combinations.

The components of the suppression chamber, which are specifically designed for the loads and load combinations used in this evaluation, exhibit the margins of safety inherent in the original design of the primary containment after completion of the modifications described in Section 6.2. The intent of the NUREG-0661[3] requirements is therefore considered to be met.

3.8.2.3.6 Testing and Inservice Inspection Requirements

Pressure and leakage rate testing of the containment system is addressed in Section 6.2.6.

3.8.3 Internal Structures of Steel Containment

Class I structures located within the primary containment include the reactor concrete pedestal and the concrete reactor shield wall. Structural evaluation for the reactor pedestal and reactor shield wall are addressed in Section 3.9.3.

Table 3.8-1

DRYWELL MAJOR PENETRATION CLASSIFICATION
UNIT 2

Penetration	Quantity	Service	Type[1]	Size (in.)
X-105A, B, C, D	4	Main steam	1	20
X-106	1	Main steam drain	1	2
X-107A, B	2	Feedwater	1	18
X-108A	1	Isolation condenser steam supply	1	14
X-109B	1	Isolation condenser return	1	12
X-111A, B	2	Shutdown cooling supply	1	8
X-113	1	Cleanup system supply	1A	8
X-115	1	HPCI steam supply	1	10
X-116A	1	LPCI pump discharge	1B	16
X-116B	1	LPCI pump discharge	1	16
X-117	1	Drywell floor drain sump discharge	2	3
X-118	1	Drywell equipment drain sump discharge	2	3
X-119	1	Demineralized water supply	2	3
X-120	1	Service air supply	2	1
X-121	1	Instrument air supply	2	1
X-123	1	Reactor building closed cooling water supply	1	6
X-124	1	Reactor building closed cooling water return	1	6
X-130	1	Standby liquid control	1	1½
X-144[2]	1	CRD system return[2]	1[2]	4
X-145, X-150	2	Containment spray	2	10
X-147	1	Reactor head cooling	1	2½
X-149A, B	2	Core spray	1A	10

Notes:

1. Penetration types are illustrated in Figures 3.8-8 (Type 1), 3.8-9 A (Type 1A), 3.8-9B (Type 1B), and 3.8-10 (Type 2).
2. The Unit 2 CRD return line was removed inside the drywell in 1993. The penetration and the CRD return line were both capped on the inboard side of the penetration.

Table 3.8-3

ELECTRICAL PENETRATIONS ENVIRONMENTAL DESIGN CONDITIONS

Normal Operating Environment — Each penetration assembly shall be capable of continuous operation at the environmental conditions listed below:

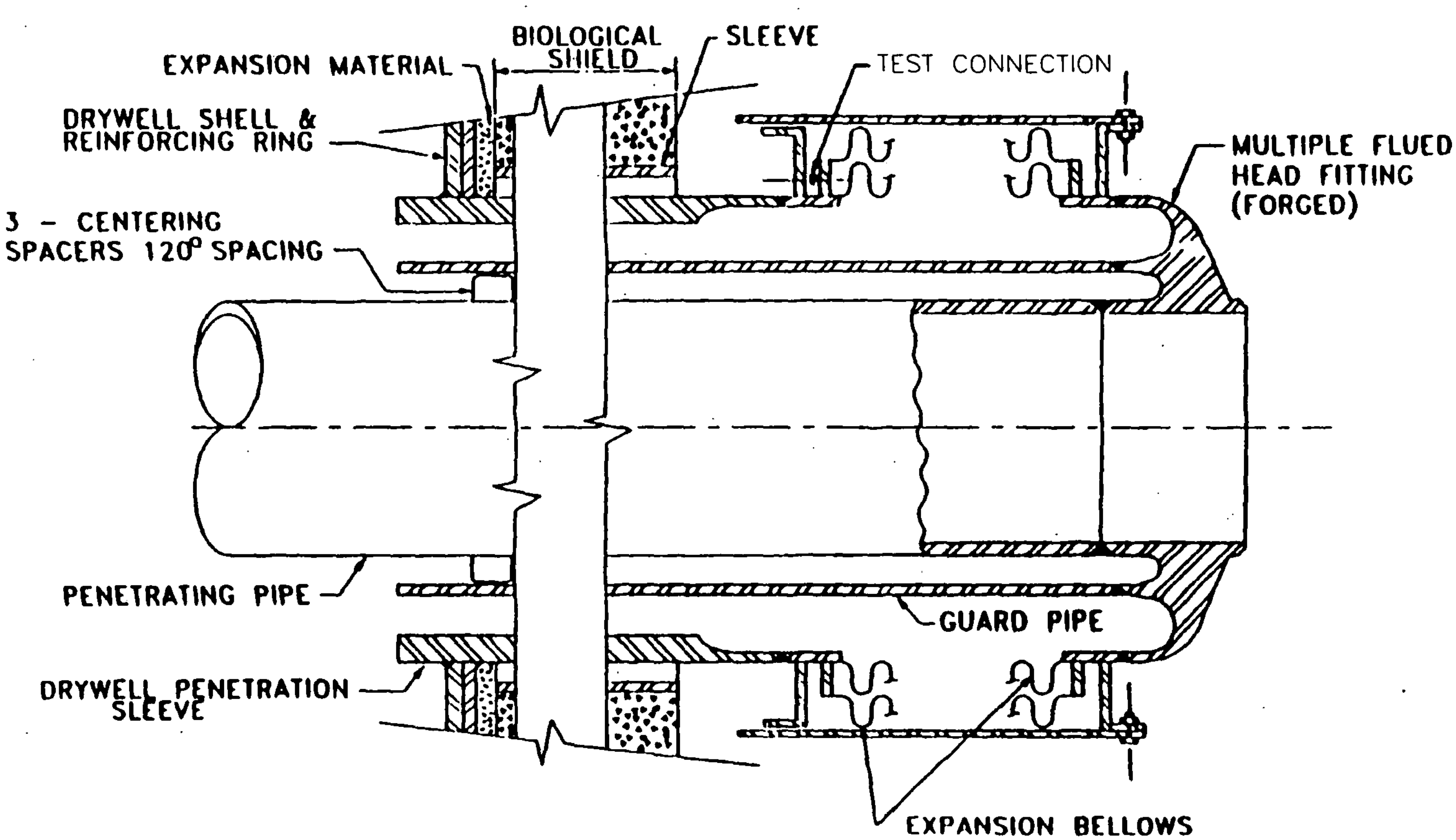
Parameter	Inside Primary Containment	Outside Primary Containment
Temperature	150°F	125°F
Pressure	-2 to +2 psig	0 psig
Relative Humidity (RH)	20% to 100%	20% to 100%
Limits of RH vs. Lifetime	50% RH < 2% time 70% RH < 1% time 90% RH < 0.5% time	50% RH < 2% time 70% RH < 1% time 90% RH < 0.5% time
Radiation Dose (without shielding)	10 R/hr	Less than 0.1 R/hr

Maximum Emergency Environment — Each penetration assembly shall be capable of maintaining containment integrity for not less than 2 hours when subjected to the environmental conditions listed below. The canister leakage rate limits are established by the Primary Containment Leakage Rate Testing Program.

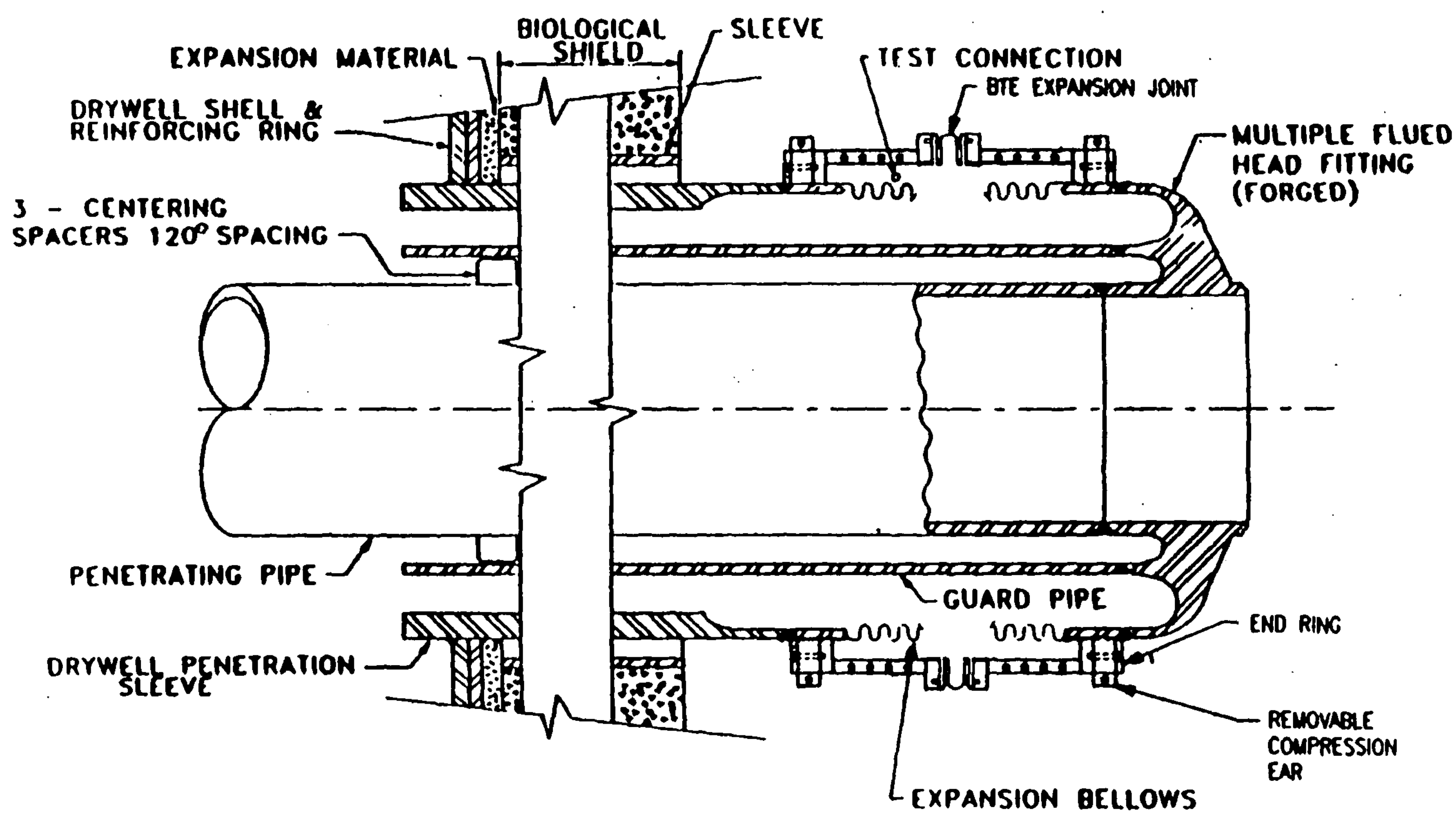
Parameter	Inside Primary Containment
Temperature	320°F
Pressure	125 psig
Relative Humidity	100% RH

Maximum Long-Term Emergency Environment — Each penetration assembly shall be capable of maintaining containment integrity for at least 10 days when subjected to the environmental conditions listed below. The canister leakage rate limits are established by the Primary Containment Leakage Rate Testing Program.

Parameter	Inside Containment
Temperature	281°F
Pressure	62 psig
Relative Humidity	100% RH



UFSAR REVISION 2, JUNE 1997
DRESDEN STATION UNITS 2 & 3
TYPE "1A" PIPING PENETRATION ASSEMBLY
FIGURE 3.8-9A



UFSAR REVISION 2, JUNE 1997
DRESDEN STATION UNITS 2 & 3
TYPE "1B" PIPING PENETRATION ASSEMBLY
FIGURE 3.8-9B

With the allowables discussed above, all vessel components have acceptable fatigue usage for 40 years except the closure studs. For Unit 2, the usage reaches 1.0 in 1997, and for Unit 3 in 2000. The closure studs may need to be replaced prior to reaching a usage factor of 1.0; however, it is not necessary to replace all studs, because fatigue-related cracks may not develop until usage is as high as 2.0.

3.9.1.2 Considerations for the Evaluation of the Faulted Condition

For a discussion of dynamic analysis methods applicable to seismic evaluation of piping, see Section 3.7.

3.9.2 Dynamic Testing and Analysis

The following subsections discuss testing performed to evaluate the effects of piping vibration and the type of analysis performed to qualify safety-related mechanical equipment.

3.9.2.1 Piping Vibration, Thermal Expansion, and Dynamic Effects

The reactor vessel internals have undergone vibration testing, as discussed in Section 3.9.2.4.

3.9.2.2 Seismic Qualification of Safety-Related Mechanical Equipment

Safety-related mechanical equipment is qualified by either dynamic or static analysis methods.

Where a dynamic analysis was not performed, the horizontal seismic coefficients for rigid equipment in the reactor-turbine building were considered to be equal to or greater than the building acceleration at the installed elevation. The vertical seismic coefficient was considered as two-thirds of ground acceleration, i.e., 0.067 g. The input motion to the equipment was assumed to be the absolute acceleration of the structure at the points of support of the equipment.

A reassessment of the seismic adequacy of mechanical and electrical equipment at Dresden Unit 2 was performed under the systematic evaluation program (SEP), Topic III-6, titled, "Seismic Design Considerations." In addition, Generic Letter (GL) 87-02, "Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors, Unresolved Safety Issue (USI) A-46," requires verification of seismic adequacy. Section 3.10.1 addresses the methods which will be used to respond to Generic Letter 87-02.

mass-flow. Only those points whose motion would be affected by two-phase (water and steam) flow were measured during power operation.

The vibratory motion of the incore guide tubes could be measured without the fuel in place. The instrumented control rod guide tubes required, as a minimum, the fuel to be in place on these tubes for them to give correct vibration response readings. In both cases, however, the orifice plates had to be in place so that flow patterns would be close to normal.

The sensors used were accelerometers, strain gauges, and linear differential transducers, and were of such design as to withstand the environment to which they were subjected.

In all vibration tests, the coolant was maintained at ±20°F of starting temperature as much as practical. To maintain this temperature with the recirculation pumps operating, shutdown cooling was needed.

APED-5453[3] and GEAP-22274[4] provide a generalized discussion of the vibration analysis and testing of the reactor internals.

Extensive vibration monitoring was done on Dresden Unit 2. The results of the vibration monitoring conducted on Dresden Unit 2 show all values to be within the design specified limit. Since the design and construction of Dresden Unit 3 is identical to Dresden Unit 2, vibration monitoring is not necessary on Dresden Unit 3.

No study is being made to monitor for the presence of loose parts within the primary coolant system. Loose parts within the primary coolant system can be detected by anomalies in the flow instrumentation available on the reactor coolant system.

3.9.3 ASME Code Class 1, 2, and 3 Components, Component Supports, and Core Support Structures

This subsection provides a description of the loads and acceptance criteria applicable to mechanical systems and components.

3.9.3.1 Load Combinations, Design Transients, and Stress Limits

The following subsections provide a discussion of the design of the reactor vessel and vessel supports (Section 3.9.3.1.1), mechanical equipment (Section 3.9.3.1.2) and piping (Section 3.9.3.1.3). Fatigue evaluation of the reactor vessel was discussed previously in Section 3.9.1.1.1.

As defined in Section 3.2, mechanical systems and components which are designated as safety Class I are either components vital to safe plant shutdown and removal of decay heat or are systems or components whose failure could cause significant release of radioactivity. Throughout this section use of the term "Class I" refers to this classification basis and not to ASME Code classifications. See Section 3.2 for definition of all safety classifications.

3.9.3.1.1 Reactor Pressure Vessel and Supports

The reactor vessel is described in Section 5.3. The reactor vessel is supported by a steel skirt. The top of the skirt is welded to the bottom of the vessel. The base of the skirt is continuously supported by a ring girder fastened to a concrete foundation, which carries the load through the drywell to the reactor building foundation slab.

Stabilizer brackets, located below the vessel flange, are connected to tension bars with flexible couplings (see Figure 3.9-1). The bars are then connected through the drywell to the concrete structure outside the drywell to limit horizontal vibration and to resist seismic and jet reaction forces. The bars are designed to permit axial expansion.

3.9.3.1.1.1 Acceptance Criteria

The Dresden reactor pressure vessels were designed according to ASME Section III, 1963 Edition, including the Summer 1964 Addenda, plus code case interpretations pertaining to primary nuclear reactor vessels applicable on February 8, 1965 (see Appendix 5A). Applicable code cases and exceptions are described in Section 3.2.

Design of the primary reactor vessel supports was governed by the ASME Code, the American Institute for Steel Construction (AISC) Structural Steel Code, the American Concrete Institute (ACI) Code.

A re-evaluation of the RPV and RPV support system was performed in 1995 as part of the core shroud modification project. All affected components were demonstrated to satisfy the applicable code requirements.

3.9.3.1.1.2 Design Loadings

Information regarding the design transients and fatigue evaluation of the reactor pressure vessel is presented in Section 3.9.1.1.

This subsection describes the loads and load combinations applicable to the design of the reactor pressure vessel internals and supports.

The applicable loads for the reactor vessel internals and supports, and for the emergency core cooling system equipment and piping covered in Section 3.9.3.1.2.2, are defined as follows:

D = Dead load of structure and equipment plus any other permanent loads contributing stress, such as soil or hydrostatic loads or operating pressures, and live loads expected to be present when the plant is operating.

P = Pressure due to loss-of-coolant accident (LOCA).

R = Jet force or pressure on structure due to rupture of any one pipe.

H = Force on structure due to thermal expansion of pipes under operating conditions.

E = Operating basis earthquake (OBE) load, ground horizontal g = 0.10. vertical g = 0.067.

T = Thermal loads on containment due to LOCA.

E′ = Design basis earthquake (DBE) load, ground horizontal g = 0.20, vertical g = 0.13.

Following are the load combinations used for the reactor vessel and vessel supports.

Reactor Primary Internals

D + E	Stresses which occur as a result of the maximum possible combination of loadings encountered in operational conditions; they are within the stress criteria of ASME Section III, Class A Vessel.
D + E′	The primary stresses and primary plus secondary stresses are examined on a rational basis taking into account elastic and plastic strains. These strains are limited to preclude failure by deformation which would compromise any of the engineered safeguards or prevent safe shutdown of the reactor.
P + D	Primary stresses are within the stress criteria of ASME Section III, Class A. The primary stresses and primary plus secondary stresses are examined on a rational basis taking into account elastic and plastic strains. These strains are limited to preclude failure by deformation which would compromise any of the engineered safeguards or prevent safe shutdown of the reactor.

Reactor Primary Vessel Supports

D + H + E	Stresses remain within Code allowables without the usual increase for earthquake loadings (AISC for structural steel; ACI for reinforced concrete).
D + H + R + E	Stresses do not exceed: • 150% of AISC allowables for structural steel • 90% of yield stress for reinforcing bars • 85% of ultimate stress for concrete
D + H + E′	No functional failure — usually stresses do not exceed the yield point of the material for steel or the ultimate strength of the concrete. If these limits are exceeded energy absorption capacity is determined and compared to the energy input from the earthquake. The design is such that energy absorption capacity exceeds energy input.

3.9.3.1.1.3 Design Evaluation

When Dresden was originally designed, two independent calculations were made for the seismic analysis of the reactor and reactor building. The first analysis was performed by J.A. Blume and Associates Engineers in January of 1967 (Appendix 5.A, Exhibit H). Seismic loads on the RPV support skirt and shroud support were extracted from the Blume report and used in the stress analysis performed by Babcock & Wilcox (B&W). Later, in December 1968, General Electric Company (GE) performed a more detailed seismic analysis of the RPV and internals (Reference 16). General Electric Company's calculations showed that the seismic loads on the vessel skirt and shroud support were less than the seismic loads calculated by J.A. Blume and Associates and, therefore, the stress analysis by B&W is conservative.

As part of the core shroud repair project, new horizontal seismic analysis of Dresden Units 2 and 3 were performed. The seismic model includes the RPV, internals and supporting structures. Prior to use for the core shroud repair, the model was benchmarked against the design basis model used for the original seismic analysis. The revised seismic model included updates to incorporate the current fuel as well as the core shroud repair hardware in the form of three horizontal and one rotational springs. The horizontal springs are located at the elevation of the core support plate, the jet pump riser braces and the top guide. The rotational spring represents the tie rod assemblies. At the time of this UFSAR update only Unit 2 has the core shroud repair hardware installed.

The seismic analyses were performed using the time history method. The input motions included the north-south component of the May 18, 1940 El Centro earthquake record and a synthetic time history record enveloping the Housner spectra. Both time histories were normalized to a peak ground motion of 0.20 g for the Design Basis Earthquake (DBE). Bounding DBE and Operation Basis Earthquake (OBE) loads were obtained. All relevant modes of vibration of the coupled system were considered. The damping factors utilized are defined in Table 3.7-1. The resulting shears, moments, displacements and accelerations were determined and used to reevaluate the adequacy of the reactor pressure vessel support system.

3.9.3.1.1.3.1 Original Evaluation

The RPV was analyzed as a single-mode system fixed at the base of the concrete pedestal, with lateral support at the stabilizer elevation connecting the RPV to the sacrificial shield and a horizontal pipe truss system connecting the sacrificial shield to the building.

The RPV seismic analysis is affected by seismic motions at the support points only. Therefore, the RPV can be decoupled from the rest of the building and analyzed separately taking into consideration the effects of input motion at all supports and conservatively combining the individual effects.

Although two different methods of analysis were used in the design of the reactor vessel and the reactor building (response-spectrum method and time-history method, respectively), the inputs to the separate analyses were consistent. Only the damping coefficients for the two analyses differed.

A critical damping factor of 2% was used in the analysis of the RPV and the concrete supports. This resulted in conservative interaction forces between the reactor and supports.

3.9.3.1.1.3.2 1995 Evaluation

As part of the core shroud repair project, new evaluations and stress reports were prepared to determine the effect of the revised loads and displacements on the core shroud, RPV and RPV internals. Evaluations of the core shroud, core shroud repair hardware, RPV, RPV stabilizer system, core plate wedges and RPV support system were performed, demonstrating that the code requirements were satisfied.

3.9.3.1.1.3.3 Support System Evaluation

Vertical loads from the RPV are transmitted to the foundation through the RPV skirt, RPV support girder, and RPV support pedestal. Lateral loads are transmitted to the building through RPV stabilizers. The RPV stabilizers are attached near the top third of the RPV and are connected to the top of the concrete and steel shield wall. The shield wall in turn is anchored at the base to the top of the RPV pedestal and restrained at the top by a horizontal tubular truss system. The lateral loads are transmitted through the truss system to the drywell shear lug mechanism. This shear lug mechanism permits vertical movement of the drywell but restricts rotational movement. However, lateral loads are transmitted through the shear lug mechanism to the heavy concrete envelope around the drywell which is part of the reactor building. A portion of the lateral loads are transmitted from the reactor pressure vessel to the RPV pedestal and then on to the foundation.

Following is a discussion of the critical stresses in all parts of the supporting structure (reactor skirt, steel ring girder, bolts, concrete pedestal, including thermal, seismic, and jet stresses) which may arise during an earthquake. Figures 3.9-1, 3.9-2, and 3.9-3 are sketches of the supporting structure and the vessel stabilizers.

For the RPV to ring girder, the horizontal shear at the bottom of the RPV skirt flange is transferred to the top flange of the ring girder through the high-strength, bolt-friction-type connection. Friction between the connecting parts exists under all load conditions because the bolt-proof load is greater than the maximum tension any bolt will be subject to. Hence, the skirt ring and the girder will always be in contact and the friction is of such magnitude to withstand the shear forces due to earthquake.

The horizontal reactor shears are carried through the anchor bolts into the reactor support pedestal concrete. The 120 anchor bolts are not considered to have oversized hole connections; the clearances have normal construction tolerances which must be available in order to assemble the structure. The resulting low stresses, coupled with the fact that bolt friction and sole plate bearing allowance for the transfer of shear loads was neglected, are standard practice and result in a conservative design.

The reactor vessel skirt analyses resulted in primary membrane and primary shear stresses that are within the code allowables. Shear is carried through the skirt that acts as a large membrane or shear ring.

The allowable stresses for the various steel RPV support components and the RPV concrete pedestal are within the code allowables. See references 17, 24, 25, 26, 27 and 28 for the details of the re-evaluation of these components that was performed as part of the core shroud modification project.

The concrete structure inside the drywell that supports the reactor pedestal is prevented from sliding by a 6-in. x 1-in. continuous shear plate that stands vertically, is welded to the inside of the drywell, and is located on the same diameter as the drywell skirt. The shear in the two ⅝-inch fillet welds attaching this shear plate to the drywell under the OBE is 3550 psi. The bearing on the concrete for this condition is 315 psi. These values are within the allowable of 15,800 psi for the weld metal and 935 psi for the concrete. For the SSE the stress in the weld is 7000 psi and in bearing on the concrete is 615 psi. The weld stress and the concrete allowable bearing stress for the SSE are still below the working stress allowable.

There is free movement of air between the inside and outside of the reactor pedestal; therefore, no temperature gradient through the concrete wall need be considered.

The vessel does not rock under earthquake conditions because the tension force due to the earthquake does not exceed the clamping force of the bolts. Thus the plates cannot separate and there can be no stretch of the bolts or increase in the tensile load.

The anchor bolts connecting the ring girder to the concrete pedestal will stretch under seismic loading. The effect of this stretch in the anchor bolts is to cause a rotation of the RPV about its base, resulting in a horizontal deflection of the RPV above its base. Evaluations of the effect of this phenomena have concluded that due to the very small relative elongation of the anchor bolts, the corresponding increase in the lateral displacement of the RPV is also small, and therefore its influence on rocking response is considered negligible.

The thermal expansion effects between the ring girder and concrete pedestal on the anchor bolts were conservatively evaluated by assuming that the operating temperature at the bottom flange of the ring girder (maximum 150°F) is attained while the concrete pedestal is at 70°F. This results in a differential temperature of 80°F, and the ring girder will try to expand radially.

To restrain this expansion requires a force of 4280 lb/in. inward on the circumference of the ring girder. It was assumed that this force is shared by the ring girder anchor bolts and the shield wall anchor bolts in proportion to their cross sectional areas. Under these conditions the resulting shear stress in both the ring girder anchor bolts and the shield wall anchor bolts is 2400 psi. To develop this shear in the ring girder anchor bolts, the space in the oversize holes of the ring girder bottom flange was filled. To transfer the force from the ring girder to the shield wall an additional depth of concrete of 4 inches was placed between the ring girder and the shield wall. The allowable shearing stress is 10,000 psi.

3.9.3.1.2 Mechanical Equipment

The following section describes the acceptance criteria, loading conditions, and evaluations applicable to mechanical equipment at Dresden Station.

3.9.3.1.2.1 Acceptance Criteria

Applicable codes, addenda and code cases for the design of Class I pumps and valves of the reactor coolant pressure boundary are described in Section 3.2.

Class II defines all equipment which are not designated Class I. Class II pumps and valves have been designed in accordance with normal practices for design of power plants in the State of Illinois, including local building codes.

3.9.3.1.2.2 Loading Conditions

Using the nomenclature defined in Section 3.9.3.1.1.2, following are the load combinations applicable to the emergency core cooling system equipment and piping for original design.

In summary, the design of the TAP supports is adequate for the loads, load combinations, and acceptance criteria limits specified in NUREG-0661[5] and substantiates the piping analysis results.

3.9.4 Control Rod Drive Systems

The design of the CRD system is discussed in Section 4.6. Control rod drive materials are addressed in Section 4.5.

3.9.5 Reactor Pressure Vessel Internals

The following sections provide descriptions of the physical layout of the reactor pressure vessel internals (Section 3.9.5.1), of loading conditions applicable to their structural and functional integrity (Section 3.9.5.2), and of their design evaluation (Section 3.9.5.3). Design of the control rods is described in Section 4.6. Information on the reactor internals materials is provided in Section 4.5.2.

3.9.5.1 Design Arrangements

In addition to the fuel and control rods, reactor vessel internals include the following components:

A. Shroud, including the tie rods with spring stabilizers,

B. Baffle plate (shroud support plate),

C. Baffle plate supports,

D. Fuel support piece,

E. Control rod guide tubes,

F. Core top grid,

G. Core bottom grid,

H. Jet pumps,

I. Feedwater sparger,

J. Core spray spargers,

K. Standby liquid control system sparger,

L. Steam separator assembly,

M. Steam dryer assembly, and

N. Incore nuclear instrumentation tubes.

The shroud is a stainless steel cylinder which surrounds the reactor core and provides a barrier to separate the upward flow of the coolant through the reactor core from the downward recirculation flow. In-vessel inspections found linear indications in the horizonal core shroud welds. Metallurgical evaluation determined intergranular stress corrosion cracking to be the root cause of the linear indications. A core shroud repair designed to structurally replace the core shroud's horizontal welds H1 though H7 (also accounts for potential flaws on horizontal weld H8) and provide vertical clamping forces on the shroud, was installed on Unit 2 during the refueling outage in 1995. The core shroud repair design includes low tension tie rods with spring stabilizers connected between the separator head support ring and the jet pump support plate. Four tie rods were evenly distributed in the annulus region of the reactor pressure vessel. Spring stabilizers were mounted at top guide support ring and the core plate support ring in the annulus area between the core shroud and the reactor pressure vessel wall. A middle spring stabilizer is mounted on the tie rod at the same elevation as the jet pump riser braces. The shroud repair upper and lower springs transmit seismic loads from the nuclear core directly to the RPV via the core plate support ring and the top guide support ring. Four symmetrically spaced core plate wedges were installed to provide a redundant load transfer path between the core plate and the core shroud. The function of the shroud repair is to ensure the intent of the original design is maintained (i.e. to ensure core geometry and a refloodable volume are maintained).

Bolted on top of the shroud is the steam separator assembly which forms the top of the core discharge plenum. This provides a mixing chamber before the steam-water mixture enters the steam separator. Refer to figure 3.9-4 for the reactor vessel cut away isometric for illustration of the component arrangement.

The recirculation outlet and inlet plenum are separated by the baffle plate joining the bottom of the shroud to the vessel wall. The jet pump diffuser sits on and is welded to the baffle plate, making the jet pump diffuser section an integral part of the baffle plate.

The baffle plate and inner rim are made of Inconel to allow for welding to the ferritic base metal of the reactor vessel. The bottom of the shroud is welded on top of the rim, which provides for the differential expansion between the ferritic, Inconel, and stainless steel components. Inconel legs welded at intervals around the baffle plate support it from the vessel bottom head.

The baffle plate supports carry all the vertical weight of the shroud, steam separator and dryer assembly, top and bottom core grids, peripheral fuel assemblies, core plugs not carried on guide tubes, and jet pump components carried on the shroud. In addition, the supports must withstand the differential pressures of normal operations and blowdown accidents (either upward or downward), and for the vertical and horizontal thrust of the seismic design.

The reactor fuel supports are the 4-lobed, Type 304 stainless steel fuel support pieces mounted on top of the control rod guide tubes. Each support piece holds four fuel assemblies and is designed to hold the orifice plates used for core flow distribution. There are two types of orifices, one for peripheral assemblies and one for nonperipheral assemblies. The control rods pass through slots in the center of the support piece. Each fuel support piece is removed to take out the control rod with attached velocity limiter.

The control rod guide tubes extend up from the control rod drive housing through holes in the core bottom grid. Each tube is designed as a lateral guide for the control rod and as the vertical support for the fuel support piece which holds the four fuel assemblies surrounding the control rod. The guide tubes are fabricated from stainless steel with 0.165-inch nominal and 0.134-inch minimum wall thickness which results in a safety factor of 4 during the maximum applied loading. This maximum loading occurs at the end of control rod insertion so that even if the tube were to buckle the control rod would remain inserted. The bottom of the guide tube is inserted and locked into a sleeve in the control rod drive housing.

The core top grid appears as a series of beams at right angles forming square openings, each for four fuel assemblies. The grid provides lateral support and guidance for the assemblies. Holes in the beams are provided to receive the top hooks of the temporary control curtains, which are then prevented from unhooking by the adjacent fuel assemblies. The top grid is attached to the reactor core shroud.

Based on analyses of the reactor internals during both normal and accident conditions, it was determined that stresses in the individual components are limiting, except in the following areas where deformation is the controlling parameter:

A. Deflection of the fuel channels under accident pressure conditions is limited to an amount substantially less than that which would prevent control rod drive insertion. The maximum frictional force exerted on the fuel channel by the control rod (as a result of interference), during a design basis accident, is less than 100 pounds. The minimum force exerted by the control rod drive on a control blade is 3000 pounds. Therefore, control blades can be fully inserted against the forces of fuel channel deflection under the most severe accident conditions. Under the above control rod insert conditions, the fuel bundles which weigh about 700 pounds will not be lifted due to the resisting insertion forces of 100 pounds friction from the deflection of its members.

B. Horizontal deflection of the control rod drive housings is limited to a value which through test has been demonstrated not to impede control rod insertion.

C. Deflection of the core plate and lower grid assembly is limited under normal operation to preclude taking up vertical clearance between the core plate and control rod guide tubes so that the core bypass leakage flow can be predicted. This results in stresses that are below yield even during accident conditions. The maximum deflection of the core plate under accident conditions is limited to 0.125 inches, which represents a considerable factor of safety below the deflection at which the core plate and guide tube could come into contact.

The maximum value of primary stress in reactor internal components generally results from the large pressure difference created when either the recirculation line or the steam line are completely severed. A discussion of these two accidents is given in Sections 3.9.5.3.1.2 and 3.9.5.3.1.3, respectively.

The sensitive point within the reactor pressure vessel which is most affected by operation of the emergency core cooling systems (HPCI and LPCI) is in the area of the jet pump to baffle plate joint. The stress and fatigue evaluation of this location is discussed in Section 3.9.5.3.2.

3.9.5.3.1 Pressure Loadings

Values of calculated pressure difference versus design pressure capability for major reactor internal components are included in Tables 3.9-18 and 3.9-19 to show the margin of safety that exists below ASME Section III limits. The margin of safety for these components which actually exist, based upon the GE Atomic Power Equipment Department (APED) design criteria for reactor internals, is equal to or greater than the margin specified in the tables. The loading combinations, and stress and deformation limits for reactor internal components are also discussed in these criteria.

A "best estimate" thermal-hydraulic analysis of a main steam line break was performed in 1994 as part of the core shroud flaw evaluations for Dresden Unit 3 and Quad Cities Unit 1. The results of this analysis provide differential pressures for use in performing structural flaw evaluations of the core shroud and internals (Reference 19). A detailed thermal-hydraulic analysis of a recirculation suction line break was performed in 1994 as part of the core shroud flaw evaluations for Dresden Unit 3 and Quad Cities Unit 1. The results of this analysis provide a detailed definition of the asymmetric blowdown loads that are applied to the core shroud under the bounding conditions of a recirculation suction line break (References 20 and 21).

3.9.5.3.1.1 Thermal-Hydraulic Model

In this section, the internal pressure forces which would be imposed across the internal reactor components during rapid depressurizations associated with pipe breaks are discussed in detail.

Internal reactor pressure forces are calculated for two postulated break conditions, a steam line rupture and recirculation line rupture. The steam line break is assumed to be a guillotine line severance which is located upstream of the flow limiter. This break gives the maximum break steam flow and maximum pressure forces. The conclusion of the event is complete blowdown to the drywell. The recirculation line break is assumed to be a guillotine line severance at the pressure vessel outlet. This places the break in the downcomer and the conclusion of this event is again to have a complete blowdown to the drywell. In both cases, reflooding of the reactor is accomplished by the emergency core cooling system. The break is assumed, in each case, to occur while the plant is operating at 2527 MWt with 98 x 10^6 lb/hr core recirculation flow.

When calculating internal pressure loading due to a blowdown accident, an analytical model is employed in which the pressure vessel is divided into major chambers or nodes.

The original design basis thermal-hydraulic model was prepared to calculate the various design basis input parameters required to support the design of the RPV and RPV internals. In the original design basis thermal-hydraulic models each node was connected to the adjoining nodes by a flow resistance as shown in Figure 3.9-5. The five nodes modeled are:

1. Sub-cooled lower plenum,

2. Saturated core,

3. Saturated upper plenum,

4. Saturated mixing plenum, and

5. Saturated steam dome.

The lower plenum to core resistance includes the inlet orifice, acceleration, local, and flow losses to the core midplane. The core to upper plenum resistance consists of the remaining core local losses and flow losses. The separator resistance is between the upper plenum and mixing plenum and steam dome. In the recirculation line break, one additional resistance is included — the resistance between the downcomer and the lower plenum through the open jet pumps of the broken line. Jet pumps are described in Section 5.4.1.

Referring to Figure 3.9-5, the pressure forces acting on major components are as shown in Table 3.9-20. The two design basis breaks will be discussed individually.

In 1994 additional thermal-hydraulic models were developed as part of the core shroud repair program. Separate thermal hydraulic models and analyses were performed for the steam line and recirculation line break conditions. The following sections provide a description of the analyses performed and the results obtained.

3.9.5.3.1.2 Recirculation Line Rupture

The instantaneous recirculation line rupture (double-ended) causes high flowrate from the downcomer and plenum regions. Initially, supercritical flow (high-single-phase flow) exists in the blowdown lines prior to flashing of the water. After bubbles form in the lines, two-phase critical flow is established and the blowdown rate is reduced from the supercritical flow value. No credit is taken for friction losses in the broken line.

Although the flowrate from the downcomer is high, the pressure change rate in the mixing plenum is only about 20 psi/s assuming no turbine control valve action to maintain pressure. Because large amounts of saturated water are present in the mixing plenum, the depressurization rate is low due to the accompanying flashing.

is expected that at least 100 milliseconds would be realistically required for a crack to propagate into a large break.

As discussed above, large asymmetric loads are not expected for a realistic break opening time. However, a hypothetical case has been analyzed in which the break opening was conservatively assumed to be instantaneous. It is assumed that the fluid pressure at the break drops instantaneously from rated pressure to saturation pressure and generates a step change in pressure which propagates toward the vessel. The analysis was performed for a break just outside the pressure vessel nozzle.

A detailed thermal-hydraulic analyses of a double-ended guillotine break of the reactor recirculation suction line was performed in 1994 to obtain a more accurate definition of the asymmetrical lateral blowdown loads that are applied to the core shroud (Reference 20). The TRACG computer code was used to calculate a detailed pressure distribution in the downcommer annulus during the blowdown period as a function of time. The resulting pressure distribution was then used to compute the resultant lateral forces applied to the core shroud.

The TRACG model included detailed nodalization that was developed as a result of a sensitivity study regarding the effect of azimuthal and axial nodalization on the resulting blowdown load. Proportional simulation of the jet pumps, feedwater flow and frictional effects were included in the model. Other RPV components such as the steam separators, guidetubes and external recirculation loops were also modeled. Additional sensitivity studies were performed to determine the effect of nodalization, time step size, friction loss coefficient, and break flow area on the resulting blowdown load. The bounding case was determined to include a 120% safe end break area and a 100% friction loss coefficient. The lowest feed water temperature was used in the analysis to account for the subcooling in the reactor downcommer annulus, resulting in the bounding blowdown load.

The blowdown force and corresponding core shroud moment were calculated in a plane parallel to the break (0° - 180°) and orthogonal to the plane of the break (90° - 270°). The evaluation of the orthogonal plane was performed to account for the nonsymmetrical operation of the jet pumps during the transient. The results of the two orthogonal components were combined to provide a bounding estimate of the total applied lateral load. The resulting forces and core shroud movements from this analyses are summarized in Table 3.9-21 and Figures 3.9-11 and 3.9-12. For the determination of the maximum force and moment, the critical time period is within the first five seconds when subcooled blowdown occurs and the highest load is applied to the core shroud. Once two-phase blowdown begins the loads decrease significantly. This analysis was performed to determine the bounding blowdown loads and thus does not include the acoustic wave response within the initial 50 milliseconds.

The acoustic phenomena associated with an instantaneous break of a reactor recirculation suction line results in a short duration asymmetric lateral load that is applied to the core shroud. This asymmetric load is generated as a result of the finite time that the shock wave takes to travel from the broken reactor recirculation suction line to the other side of the annulus. The results of the original design basis analysis is provided in figure 3.9-6. This figure is a graphical representation of the applied core shroud lateral force as a function of time (milliseconds) after the line break occurs. A reassessment of the acoustic lateral load was performed as part of the core shroud evaluations and repairs. Based on the available industry information (Reference 21), an equivalent static load of 60 kips was established. This bounding lateral load was calculated using the envelope of several different load time histories and the applicable dynamic load factors (Reference 23).

A finite element analysis of the core shroud was prepared to verify that the stresses are within the ASME section III limits. This analysis and corresponding stress evaluation (References 29, 30, 31, 32 and 33) included all of the applied loading cases including recirculation line breaks and seismic.

3.9.5.3.1.3 Steam Line Rupture

Following the instantaneous, double-ended, steam line rupture, critical flow is established in each broken line. Since the break is postulated to be upstream of the flow restrictor, the break area is the sum of one open steam line area plus one steam flow restrictor area. As shown in Figure 3.9-7, this break causes the system to depressurize at about 35 psi/s, during initial steam blowdown. About 4 seconds later the depressurization rate is reduced to about zero when the two-phase mixture at about 7 % quality enters the steam line. In comparison, for a steam line break downstream of a flow limiter the initial depressurization rate is 25 psi/s as reported in Section 15.6.4.6.

The design break is assumed to have a constant break area of 2.33 square feet. Actually the effective break area will diminish with time since the isolation valves are closing in one end of the break. When the isolation valves have been closed, the effective break area is reduced to only one steam line.

Rapid decompression of the subcooled lower plenum does not occur because the decompression rate is limited by the saturated upper core regions.

The shroud receives the maximum irradiation at the inside surface opposite the midpoint of the core where the total integrated neutron flux at end of life is 2.7 x 10^{20} nvt (greater than 1 MeV). The maximum thermal shock stress in this region is 155,700 psi or 0.57% strain. All reactor internal structural members located in high-flux regions, including the shroud, are constructed of 304 stainless steel which does not suffer from irradiation embrittlement. It does experience hardening and an apparent loss in uniform elongation but its reduction in area is not changed. Since the reduction in area is the property which relates to tolerable local strain, it can be concluded that irradiation can generally be ignored. However, even on the basis of changes in the total elongation, one would conclude that this material at 2.7 x 10^{20} nvt integrated flux would be capable of about 15 — 20% elongation.

The strain range of 0.57% was calculated at the midpoint of the shroud which is the zone of highest neutron irradiation. The value of 0.57% strain range was determined by dividing the calculated stress range of 155,700 psi (peak surface stress) by the modulus of elasticity for Type 304 stainless steel which was assumed to be 27.5 x 10^6 psi. The calculated strain range of 0.57% represents a considerable margin of safety below measured values of percent reduction in area (which is the property that relates to tolerable local strain) for annealed Type 304 stainless steel irradiated to 1 x 10^{21} nvt (greater than 1 MeV). The value of percent reduction in area for Type 304 stainless steel reported in Reference 14 is a minimum of approximately 38% for a temperature of 550°F and neutron flux of 1 x 10^{21} nvt (greater than 1 MeV) and in Reference 15 a reduction in area of 52.5% is reported for a temperature of 750°F and neutron flux of 6.9 x 10^{21} nvt (greater than 1 MeV). At lower values of temperature or neutron flux, the percent reduction in area is generally even higher. Therefore, thermal shock effects on the shroud at the point of highest irradiation level will not jeopardize the proper functioning of the shroud following the design basis accident (DBA).

A "best estimate" thermal-hydraulic analysis of a main steam line break was performed in 1994 to support the core shroud safety assessments and flaw evaluations (Reference 19). Since this analysis was performed utilizing "best estimate" techniques it is not a design basis main steam line break analysis. The differential pressures calculated in this analysis are applicable only for use in structural flaw assessments and safety consequences evaluations.

3.9.5.3.3 Thermal Shock Effects on Reactor Vessel Components

Several high stress points on the reactor vessel have been analyzed approximately and conservatively to determine the effects of LPCI cold water injection. The points examined are as follows:

1. Recirculation inlet nozzle,

2. Midcore inside of vessel, and

3. Control rod drive penetration.

The results on the recirculation nozzle are as follows:

	Sleeve	Nozzle
Amplitude of alternating stress	595,000 psi	215,000 psi
Allowable ASME Section III cycles	12	130
Maximum strain range	4.5%	1.6%

The results at midcore inside of vessel are 67,500 psi peak stress. More than 1000 such cycles would be imposed under ASME Section III fatigue criteria. The total maximum vessel irradiation (greater than 1 MeV) at this point has been found to be 2.4 x 10^{17} nvt which is below the threshold level of any nil ductility temperature (NDT) shift for the vessel material. Therefore, irradiation effects can be ignored at all locations on the vessel.

The results on the control rod drive penetration are:

Amplitude of alternating stress	560,000 psi
Allowable ASME Section III cycles	14
Maximum strain range	3.7%

3.9.5.3.4 Seismic Loading

An initial dynamic analysis was performed which determined the seismic responses of the Dresden Unit 2 reactor internals (See sections 3.9.3.1.1.3.1). The methods, approximations, and computer programs used in this analysis are detailed in a report by GE Atomic Power Equipment Department.[16]

The nuclear steam supply system of Dresden Unit 2 was modeled with lumped mass configurations. The internals model included the following components: shroud, CRD housing, top guide and core plate, fuel, guide tubes, separators, dryer, and vessel head in addition to the flanges, vessel skirt, standpipes, pedestal, shield wall, building, foundation, and the vessel itself. Not included in the mathematical model were light components such as jet pumps, incore guide tube and housing, spargers and their supply headers. Representative damping values used were reinforced concrete structure, 5%; reinforced or prestressed concrete primary containment structure, 2%; vessel and skirt, 1%; shroud, 1%; fuel, 7%; guide tubes, 1%; and control rod drive, 1%. The maximum seismic shears and moments of reactor internals due to their respective SSEs were determined. These were used to determine the adequacy of the original component design.

As part of the core shroud repair project new horizontal seismic analyses of the RPV and RPV internals was performed. A description of the modeling and analyses performed is provided in section 3.9.3.1.1.3. The core shroud repair was designed to structurally replace the core shroud's horizontal welds H1 through H7 and provide vertical clamping forces on the shroud. The repair hardware was installed on Unit 2 during the D2R14 refueling outage. The shroud repair upper and lower springs transmit seismic loads from the nuclear core directly to the RPV via the core plate support ring and the top guide support ring. A new rebaselined seismic model including the RPV and the RPV internals was generated with the core shroud repair hardware installed. In these analyses all relevant modes of vibration of the coupled system were considered. The damping factors utilized are defined in Table 3.7-1.

3.9.6 Inservice Testing of Pumps and Valves

Presently, inservice testing (IST) of pumps and valves is governed by the Third 10-Year Interval IST Program which will remain in effect through February 28, 2002. The IST program was developed in response to the requirements of 10 CFR 50.55a.

In accordance with 10 CFR 50.55a, IST programs are updated at 10-year intervals to incorporate the provisions of newer editions of ASME Section XI. Specifically, the regulation requires that IST program revisions meet the requirements (to the extent practical) of the latest ASME Code edition and addenda incorporated by reference in Paragraph (b) of 10 CFR 50.55a 12 months prior to the start of the 10-year inspection interval. The current IST program is based upon the requirements of the 1986 Edition of Section XI, subsection IWV, and ANSI/ASME OMa-1988 Part 6, consistent with the requirements of 10 CFR 50.55a.

The construction permits for Dresden Units 2 and 3 were issued on January 10, 1966, and October 14, 1966, respectively. At that time the ASME Code covered only nuclear reactor vessels and associated piping up to and including the first isolation or check valve. Piping, pumps, and valves were built primarily to the Power Piping Code rules of USAS B31.1. Consequently, the Dresden IST program contains no ASME Code Class 1, 2, or 3 designed systems. The system classifications used as a basis for the IST program are based on the requirements given in 10 CFR 50.55a(g) and Regulatory Guide 1.26, and were developed for the sole purpose of assigning the appropriate IST requirements. Components within the reactor coolant pressure boundary (RCPB), as defined in 10 CFR 50.2, are designated as Inservice Inspection (ISI) Class 1 while other safety-related components are designated as ISI Class 2 and 3 in accordance with the guidelines of Regulatory Guide 1.26. Pursuant to 10 CFR 50.55a(a)(1), IST requirements of Section XI of the ASME Code are then assigned to these components, within the constraints of existing plant design.

The extent of the Class 1, 2, and 3 designations for systems or portions of systems subject to the IST requirements are identified on the Dresden Piping and Instrumentation Diagrams (P&ID). In accordance with Regulatory Guide 1.26, the IST boundaries on the P&ID are limited to safety-related systems which contain water, steam, or radioactive materials.

Inservice inspection and testing of the reactor coolant pressure boundary is addressed in Section 5.2.4. Table 5.2-3 provides a listing of the ISI classification for various plant systems. Inservice inspection for Class 2 and 3 components is discussed in Section 6.6. Preservice inspection and testing of pumps and valves is discussed in Chapter 14.

3.9.6.1 Inservice Testing of Pumps

The inservice testing program for ISI Class 1, 2, and 3 pumps meets the requirements of ASME Operations and Maintenance Standard OMa 1988, Part 6. Where these requirements were determined to be impractical, specific requests for relief have been approved by the NRC.

The IST program establishes the requirements for inservice testing to assess the operational readiness of certain centrifugal and positive displacement pumps used in nuclear power plants. The pumps covered are those that are provided with an emergency power source, which are required in shutting down the reactor to the cold shutdown condition, maintaining the cold shutdown condition, or mitigating the consequences of an accident. In addition to ISI Class 1, 2, and 3 pumps, some safety-related pumps and some nonsafety-related pumps have been included in the IST program at the request of the NRC.

3.9.6.2 Inservice Testing of Valves

The IST program for ISI Class 1, 2 and 3 valves meets the requirements of ASME Operations and Maintenance Standard OM-1-1981. Where these requirements were determined to be impractical, specific requests for relief have been approved by the NRC.

14. "The Effects of Radiation on Structural Materials," ASTM Special Technical Publication No. 426, ASTM, Philadelphia, Pa., 1966, pages 278-327.

15. L.A. Waldman and M. Doumas, "Fatigue and Burst Tests on Irradiated In-Pile Stainless Steel Pressure Tubes," Nuclear Applications, Vol. 1, October 1965.

16. "Seismic Analysis of Reactor Internals for the Dresden II Plant," General Electric Company Atomic Power Equipment Department, December 1968.

17. DBD-DR-037, "Design Basis Document Dresden Station - Units 2 and 3, Seismic Topical Report", Chapter 8.

18. GENE-523-A100-0995, DRF 137-0010-8, "Analyses of the Dresden and Quad Cities Shroud Repair Hardware Seismic Design with Improved Tie Rod and Shroud Weld Crack Equivalent Rotational Stiffness", Appendix B.

19. GENE-523-A163-1194, "Quad Cities and Dresden Main Steam Line Break Analysis with TRACG Model", November 9, 1994.

20. GENE-L12-00819-05, "Core Shroud Blowdown Load Calculation During Recirculation Suction Line Break by TRACG Analysis for Dresden Nuclear Power Station, Units 2 and 3, and Quad Cities Nuclear Power Station, Units 1 and 2.

21. BWR-VIP Report No. SL-4942, " BWR Core Shroud Evaluation Load Definition Guideline".

22. U. S. Nuclear Regulatory Commission (NRC) Letter, To Mr D. L. Farrar-Commonwealth Edison, Subject - Dresden Nuclear Power Station, Units 2 and 3, Safety Evaluation Regarding Core Shroud Repair (TAC NOS. M91301, M91302 and M93584), dated December 6, 1995.

23. SL-4971, Revision 1, "Final Evaluation of the Core Shroud Flaws at the H5 Horizontal Weld for Dresden Unit 3", Chapter 3.0.

24. GE Stress Report 25A5691, Revision 2, "Dresden Units 2 & 3 RPV Stress Report".

25. GENE-771-77-1194, Revision 2, "Shroud Repairs Program for Dresden Units 2 and 3 - Back-up Calculations for RPV Stress Report No. 25A5691", (Proprietary Information).

26. GENE-771-95-0195, Revision 1, "Dresden Units 2 and 3, Top Ring Plate and Star Truss Stress Analysis", (Proprietary Information).

27. GENE-771-96-0196, Revision 1, "Dresden Units 2 and 3, Top Ring Plate and Star Truss Analysis Back-up Calculations", (Proprietary Information).

28. GENE-771-92-0195, Revision 1, "Shroud Repair Program for Dresden Units 2 and 3 RPV Skirt Ring Girder Stress Analysis", (Proprietary Information).

29. GENE-771-81-1194, Revision 2, "Commonwealth Edison Dresden Nuclear Power Station Units 2 and 3, Shroud and Shroud Repair Hardware Analysis, Volume l, Shroud Repair Hardware".

30. GENE-771-81-1194, Revision 1, "Commonwealth Edison Dresden Nuclear Power Station Units 2 and 3, Shroud Repair Hardware Analysis, Volume ll, Shroud".

31. GENE-771-81-1194 Supplement A to Revision 1 of Volume ll, Shroud Mechanical Repair Program Dresden Nuclear Power Station - Supplement A to Shroud and Shroud Repair Hardware Stress Analysis, June 1995, (Proprietary Information).

32. GENE-771-82-1194, Revision 1, "Backup Calculations for Dresden Shroud Repair Shroud Stress Report for Commonwealth Edison Dresden Nuclear Power Station Units 2 and 3", (Proprietary Information).

33. GENE-771-83-1194, Revision 2, "Commonwealth Edison Dresden Nuclear Power Station Units 2 and 3, Shroud and Shroud Repair Hardware Analysis, Shroud Repair Hardware Backup Calculation", (Proprietary Information).

Table 3.9-3

Intentionally Deleted

Table 3.9-4

Intentionally Deleted

Table 3.9-7

MAXIUMUM STRESSES FOR ORIGINAL CLASS I STATICALLY ANALYZED PIPING
SAFE SHUTDOWN EARTHQUAKE

Item	System	Point No.	Material	O.D. (inches)	Thickness (inches)	Intensification Factor	Horizontal Static Coefficient K	Weight Stress (psi)	Pressure Stress (psi)	Total DBE Seismic Stress (psi)	Combined Stress Sigma (psi)	Yield Stress (psi)
1	HPCI Turbine Exhaust	105 Bend	ASTM A106 GR.B	24.000	.375	4.27	1.4	74	1529	7,576	9,179	30,000
2	HPCI Pump Suction	55 TGNT	ASTM A106 GR.B	16.000	.375	3.17	1.4	3935	744	5,612	31,008	35,000
3	Core Spray Pump Suction	125 TGNTR	ASTM A106 GR.B	16.000	.375	4.97	1.4	1314	744	5,068	32,463	35,000
4	Core Spray Pump Discharge	30 Bend	ASTM A106 GR.B	10.750	.593	1.83	1.4	534	1329	24,086	25,949	35,000
5	LPCI Pump Suction	145 TGNT BP	ASTM A106 GR.B	14.000	.375	4.57	1.4	1335	601	7,324	40,173	35,000
6	LPCI Pump Discharge to Containment Cooling Heat Exchanger	70 TGNT BP	ASTM A106 GR.B	12.750	.375	4.51	1.4	263	2327	5,462	28,147	35,000
7	LPCI Pump Discharge from Containment Cooling Heat Exchanger to Drywell	330 TGNT BP	ASTM A106 GR.B	18.000	.438	3.38	1.4	416	2859	8,818	34,070	35,000
8	Containment Cooling to Heat Exchanger	50 TGNT	ASTM A106 GR.B	16.000	.375	2.30	1.4	7168	2977	5,634	32,422	35,000

Table 3.9-7 (Continued)

MAXIUMUM STRESSES FOR ORIGINAL CLASS I STATICALLY ANALYZED PIPING
DESIGN BASIS EARTHQUAKE

Item	System	Point No.	Material	O.D. (inches)	Thickness (inches)	Intensification Factor	Horizontal Static Coefficient K	Weight Stress (psi)	Pressure Stress (psi)	Total DBE Seismic Stress (psi)	Combined Stress Sigma (psi)	Yield Stress (psi)
9	Containment Cooling from Heat Exchanger to 48-inch Stand Pipe	220 Bend	ASTM A106 GR.B	14.000	.375	2.94	1.4	706	601	33,422	34,729	35,000
10	Isolation Condenser Supply	60 Anchor	ASTM A358 TP 304	14.000	.638	1.00	2.50	2694	5935	3,211	11,840	17,000
11	Isolation Condenser Return	90 Anchor	ASTM A358 TP 304	13.170	.585	1.00	2.50	2272	6112	5,476	13,860	17,000
12	HPCI Pump Discharge	305 Bend	ASTM A106 GR.B	14.000	1.093	3.34	1.4	2402	3710	21,608	27,720	35,000

Notes:

1. For piping 2" and under, ASTM A335 Grade P11 or P22 may be substituted for ASTM A106 Grade B material for the same schedule. For fittings and valves 2" and under, ASTM A132 Grade F11 or F22 may be substituted for ASTM A105 for the same rating. Substitutions are allowed up to a maximum temperature of 450°F (operating or design).

DRESDEN — UFSAR

Table 3.9-9

APPLICABLE ASME CODE EQUATIONS AND
ALLOWABLE STRESSES FOR MARK I TORUS ATTACHED PIPING

Stress Type	ASME Code Equation Number	Service Level	Stress Limit(1)	Allowable Value (ksi) (2), (3)	Governing Load Combination Number(4)
Primary	8	A	1.0 S_h	15.0	A-1, T-1
Primary	9	B	1.2 S_h	18.0	B-1, B-2
Primary	9	B	1.8 S_h	27.0	C-1 Through C-3
Primary	9	B	2.4 S_h	36.0	D-1 Through D-5
Secondary	10	B	1.0 S_a	22.5	A-2 Through A-9
Primary and Secondary	11	B	$S_h + S_a$	37.5	(1)

Notes:

1. See ASME Section III, Subsection NC-3650.

2. Increased allowables as defined in NUREG-0661 have been utilized for piping systems which have been classified as nonessential.

3. Allowable stress values are for ASTM A106, Grade B material since this material is used for most of the TAP systems.

4. Governing load combination numbers are listed in Table 3.9-5.

5. For piping 2" and under, ASTM A335 Grade P11 or P22 may be substituted for ASTM A106 Grade B material for the same schedule. For fittings and valves 2" and under, ASTM A132 Grade F11 or F22 may be substituted for ASTM A105 for the same rating. Substitutions are allowed up to a maximum temperature of 450°F (operating or design).

Table 3.9-18

RPV INTERNALS PRESSURE DIFFERENTIAL
DUE TO RECIRCULATION LINE RUPTURE

Major Component	Maximum dP (psi)[3]	Design Capability dP (psi)[1]
Shroud Support[2]	25 (initial)	100
Guide Tube	17 (initial)	68
Lower Shroud[2]	25 (initial)	185
Upper Shroud[2]	7 (initial)	185
Core Plate	17 (initial)	50
Shroud Head Assembly	9	25

Notes:

1. This is the pressure differential consistent with ASME Code allowable stresses. For primary loading, considerably higher differentials can be sustained before failure.

2. Core cooling dependent.

3. An additional thermal-hydraulic analysis was performed in 1994, for the results see reference 20.

Table 3.9-19

RPV INTERNALS PRESSURE DIFFERENTIAL DUE TO STEAM LINE BREAK

Major Component	Maximum Delta-P (psi)[2]	Design Capability Delta-P (psi)[1]
Shroud Support	30	100
Guide Tube	20	68
Lower Shroud	30	185
Upper Shroud	12	185
Core Plate	20	50
Shroud Head Assembly	12	25

Notes:

1. Capability within ASME Code allowable stresses. For primary loading, considerably higher differentials can be sustained before failure.

2. An additional thermal-hydraulic analysis was performed in 1994, for the results see references 19 and 20.

Table 3.9-20

RPV INTERNALS PRESSURE FORCES

Major Component	Pressure Force	Initial Value (psi)
Shroud Support	P_1-P_4	25
Guide Tube	P_1-P_3	17
Core Plate	P_1-P_3	17
Lower Shroud	P_1-P_4	25
Upper Shroud	P_3-P_4	7
Shroud Head Assembly	P_3-P_4	7
Jet Pump Diffuser	P_1-P_4	25

Notes:

1. Refer to Figure 3.9-5 (BWR Internal Configuration) for location of pressure nodes.
2. An additional thermal-hydraulic analysis was performed in 1994, for the results see references 19 and 20.

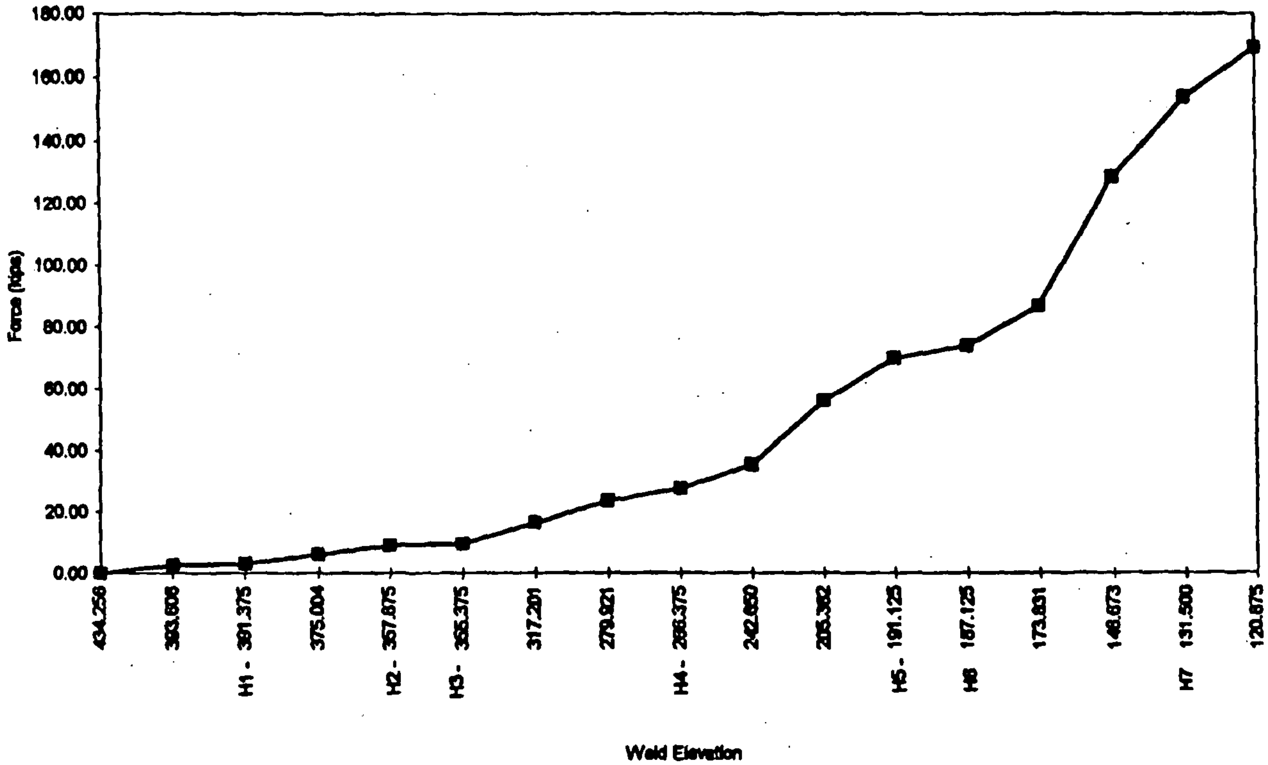
Table 3.9-21

RESULTANT CORE SHROUD LATERAL LOADS
FOR A RECIRCULATION SUCTION LINE BREAK

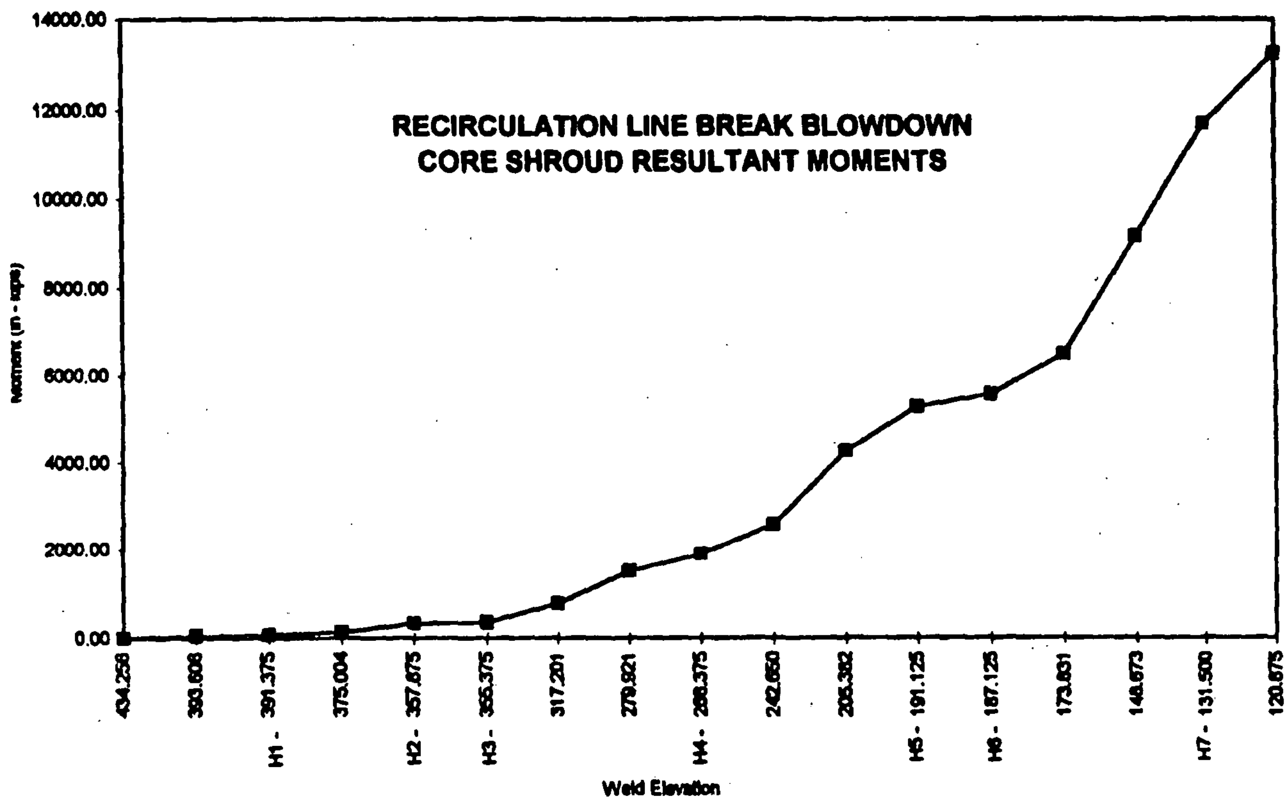
Shroud Weld Designation	Shroud Weld Elevation (Inches)	Maximum Force (Kips)	Maximum Moment (Inch-Kips)
	434.26	0.00	0.00
	393.61	2.50	50.80
H1	391.38	2.90	60.05
	375.00	5.83	128.01
H2	357.88	8.88	315.74
H3	355.38	9.33	343.16
	317.20	16.12	761.94
	279.92	23.26	1494.91
H4	266.38	27.54	1887.56
	242.65	35.11	2576.91
	205.38	55.79	4255.01
H5	191.13	69.62	5255.30
H6	187.13	73.52	5536.79
	173.83	86.49	6474.08
	148.67	128.20	9146.43
H7	131.50	153.44	11674.81
	120.88	169.07	13243.75

Notes:

1. Determined from the TRACG recirculation line break analysis (Reference 20).



UFSAR REVISION 2, JUNE 1997
DRESDEN STATION UNITS 2 & 3
RECIRCULATION LINE BREAK BLOWDOWN CORE SHROUD RESULTANT FORES
FIGURE 3.9-11



UFSAR REVISION 2, JUNE 1997
DRESDEN STATION UNITS 2 & 3
RECIRCULATION LINE BREAK BLOWDOWN CORE SHROUD RESULTANT MOMENTS
FIGURE 3.9-12

3.10.2.1 Qualification by Analysis

Equipment is qualified by analysis if the equipment is not too complex and can be represented in a mathematical model for performing static analysis and/or dynamic analysis.

3.10.2.1.1 Static Analysis

Static analysis is performed for equipment which is determined to be rigid. The seismic forces on each component of the equipment are obtained by concentrating the total mass at the equipment's center of gravity and multiplying the values of the mass and the appropriate floor acceleration from the seismic response spectra. The resulting stresses are added to the other equipment stresses, as per the design criteria, to determine if the equipment is adequate to withstand this load.

3.10.2.1.2 Dynamic Analysis

Dynamic analysis is performed for flexible equipment. The equipment is analyzed using the response spectrum or time-history methods. Both of these methods have been used to qualify equipment for Dresden.

3.10.2.2 Qualification by Test

If the equipment is flexible and too complex to be represented properly by an analytical model, then the equipment is qualified by test. Testing is also performed where the equipment is required to operate during or after a seismic event but this cannot be established analytically. Seismic tests are performed by subjecting the equipment to vibratory motion which conservatively simulates the motion postulated at the equipment mounting during an OBE, followed by the vibratory motion associated with a safe shutdown earthquake (SSE).

The components of the instrumentation and electrical systems of the reactor protection system and engineered safety features of Dresden are capable of performing their required safety functions while withstanding the forces generated by a 0.2 g earthquake. Test results of components that were qualified by test were reported to the NRC. A detailed review of the equipment in the test program showed that the results of these tests are applicable to Dresden.

3.10.2.3 Qualification by Combination of Test and Analysis

Some electrical equipment and instrumentation are qualified by a combination of test and analysis. This qualification can be achieved through various methods such as extrapolation for similar equipment and extrapolation for similar seismic conditions.

3.10.3 Methods and Procedures of Analysis or Testing of Supports of Electrical Equipment and Instrumentation

Supports of Class I electrical equipment and instrumentation have been qualified using the same methods as described in Section 3.10.2. Examples of these supports include: battery racks, control consoles, cabinets, instrument racks, panels, motor control centers, and switchgears.

In response to IEN 80-21 and the SEP Positive Anchorage Verification Program, anchorage for safety-related electrical equipment was verified through plant walkdowns, and modifications were performed on the anchorage of some equipment to provide adequate support to withstand all postulated seismic loading.

3.10.4 Qualification Results

The protective system instrumentation and supporting panels or cabinets located in the control room were analyzed, tested, or investigated to confirm that they can perform their safety related functions under all required seismic loads at their respective locations.

The seismic qualification of new and replacement components for Regulatory Guide 1.97 components (that require seismic qualification) is performed to the requirements of IEEE 344-1975.

D. Plant areas with environmental parameters (pressure, temperature, humidity, radiation level, submergence level, etc.) which increase significantly above normal ambient conditions as a result of a design basis event were defined as harsh post-accident areas. Containment spray and radiation dose from recirculating radioactive fluids were included in these considerations.

E. A review of the location of the equipment was performed. Equipment required to function but not located within a harsh post-accident area was judged outside the scope of 10 CFR 50.49. In addition, certain equipment items are not exposed to a harsh environment at the same time or prior to when they are required to perform a safety function; these items were also judged outside the scope of 10 CFR 50.49.

F. For 10 CFR 50.49 electrical equipment, the required post-design basis event operating time was determined. This is the time period following occurrence of the design basis event for which the equipment must remain functional in order to accomplish safety or display functions or must not fail in an adverse manner. Subsequent failure of the equipment would not be detrimental to plant safety.

Based on the above methodology, a safety-related systems listing and an EQ Equipment List (including display instruments) were developed. These lists, together with other plant listings, were inputs to the development of the Master Equipment List (MEL). The MEL identifies the set of electrical equipment requiring environmental qualification. It is revised and updated on a continuing basis to reflect plant design changes and new information.

The methodology used in the MEL to identify safety-related electrical equipment requiring environmental qualification is in full compliance with the requirements of IE Bulletin 79-01B, Supplements 1 and 2, and 10 CFR 50.49. Therefore, the MEL is judged to address all electrical equipment within the scope of 10 CFR 50.49(b)(1).

3.11.1.2 Identification of Nonsafety-Related Electrical Equipment Requiring Environmental Qualification

Paragraph (b)(2) of 10 CFR 50.49 includes in its scope nonsafety-related electrical equipment whose failure under postulated environmental conditions could prevent satisfactory accomplishment of safety functions by the safety-related equipment. Environmental qualification is not required for nonsafety-related electrical equipment whose failure under postulated environmental conditions does not affect the accomplishment of safety functions. An evaluation of the possibility of failure of nonsafety-related equipment in a manner detrimental to safety-related equipment used a combination of methods which are summarized below:

A. A list of safety-related electric equipment, as defined in Paragraph (b)(1) of 10 CFR 50.49, that are required to remain functional during or following design basis events such as LOCAs, MSLBs inside containment, and HELBs outside containment was generated (described in Section 3.11.1.1).

The plant is divided into 47 distinct zones. Each of these is assigned a unique zone number. Figures 3.11-1 through 3.11-5 depict the location and boundaries of these zones within the plant. Tables 3.11-1 and 3.11-2 list separately the temperature, pressure, and radiation parameters for each zone under normal conditions and conditions due to a HELB and a LOCA. Table 3.11-3 lists the relative humidity conditions for each zone under normal, spurious, and accident conditions.

3.11.1.4.1 Harsh Post-Accident Areas

By definition, a harsh environment meets one or more of the following conditions:

A. Temperatures above 120°F;

B. Total radiation exposure greater than 5 x 10^4 rads; or

C. Pressure transient in excess of atmospheric pressure resulting from a LOCA or HELB inside the drywell, the pressure suppression pool, and the main steam tunnel.

Qualification for humid environments is required only when the humidity is in conjunction with harsh temperatures. Humidity aging is not required.

The IE Bulletin 79-01B requirement restricts design basis events that must be considered to the LOCA/HELB inside containment and HELB outside containment. In this context, the HELB includes the MSLB.

10 CFR 50.49 is more generally worded, requiring consideration of all postulated design basis events; however, the difference is not significant. A nonpipe break design basis event (such as a refueling accident, dropped fuel assembly during refueling) or a rod drop accident (reactivity excursion following sudden uncontrolled control rod withdrawal) produces less severe service conditions than a LOCA or HELB. The postulated nonpipe break design basis events are described in detail in Chapter 15.

The LOCA is postulated only in the drywell. A full range of LOCAs was analyzed, from a small rupture, where the makeup flow is greater than the coolant rate, to the largest LOCA, a double-ended rupture of the 28-inch recirculation line. The analysis showed that the full double-ended recirculation line break results in maximum drywell pressure. Therefore, this postulated LOCA defines the post-LOCA environment for environmental qualification.

Although smaller breaks may produce somewhat more severe long-term environments and longer operability time requirements for equipment, the most severe environmental conditions were used to perform environmental qualification. Major assumptions used in the LOCA analysis are discussed in Sections 6.2 and 15.6.

The only non-LOCA pipe break in the drywell that can produce a harsh environment comparable to the LOCA is the MSLB. Therefore, no other HELBs in the drywell are analyzed. The analysis of postulated MSLBs in the drywell considers postulated break sizes ranging from 0.01 to 0.75 square feet. A steam break larger than 0.75 square feet will result in rapid reactor vessel

B. Standby diesel generator rooms (see Section 9.4 for further discussion).

HVAC systems are also provided for the high pressure coolant injection (HPCI) and low pressure coolant injection (LPCI)/core spray pump rooms. See Section 9.4. However, analysis has been performed which justifies operability of the ECCS when the associated room coolers are unavailable. This analysis includes consideration of equipment within the scope of 10 CFR 50.49 which is located in the ECCS rooms and reactor building and is affected by the elevated temperatures resulting from a LOCA concurrent with a loss of room coolers (LOCA/LORC). This analysis established that effected equipment will perform required safety functions at the LOCA/LORC elevated temperatures. These elevated temperatures are reflected in the data provided in Table 3.11-2.

In determining the normal temperature parameters for environmental zones (shown in Table 3.11-1), the evaluation includes the effects of normal plant operation, loss of HVAC, or operation of equipment required for post-design basis event plant recovery. Where comparatively high values for normal temperature appear, these result from conditions other than direct exposure to a LOCA or HELB.

3.11.5 Estimated Chemical and Radiation Environment

No special chemical environments that warrant investigation for their effects on safety-related equipment are present at Dresden. Demineralized water is used for containment spray, and its effect on safety-related equipment has been evaluated.

A radiation study was performed to establish integrated doses to equipment following a postulated LOCA. The core fission product inventory was based on the GE document, "Radiation Source Information for NUREG-0578 Implementation Computer Run."[2]

The fission products were diluted into the appropriate fluid media as follows:

Fluid	Noble Gases (%)	Halogens (%)	Other (%)
Suppression pool liquid	---	50	1
Reactor coolant liquid	100	50	1
Containment atmosphere	100	25	---
Reactor steam	100	25	---

Dilution of the fission products was considered using the fluid volume as the dilution media.

For components located inside the drywell, only gamma doses were considered if the component was enclosed in an inorganic material (e.g., valve motor actuators in metal enclosures). The gamma dose was established based on immersion of the component in the gaseous drywell atmosphere for the time that the component must remain functional. For components enclosed in organic material (e.g., cable), beta radiation doses were also calculated. Where components enclosed in organic materials are installed in metal enclosures (e.g., cable in conduit or flex-conduit), beta radiation is neglected. The effects of the beta dose have been considered by analysis. The analysis demonstrates that the combined gamma and beta dose is

Table 3.11-1

ENVIRONMENTAL ZONE PARAMETERS FOR NORMAL SERVICE CONDITIONS

Zone	Temperature (°F)	Pressure (psia)	40-Year Dose (rads)
1	150	14.7	8.8×10^6
2	104	14.7	3.5×10^4
3	104	14.7	$<1.0 \times 10^4$
4	104(1)	14.7	$<1.0 \times 10^4$
5	104(1)	14.7	$<1.0 \times 10^4$
6	104(1)	14.7	$<1.0 \times 10^4$
7	120	14.7	1.8×10^6
7a	120	14.7	$<1.0 \times 10^4$
7b	120	14.7	1.0×10^7
8	150	14.7	8.8×10^6
9	150	14.7	1.8×10^6
9a	125	14.7	1.8×10^6
10	104	14.7	$<1.0 \times 10^4$
11	104	14.7	$<1.0 \times 10^4$
12	104	14.7	$<1.0 \times 10^4$
13	104	14.7	$<1.0 \times 10^4$
14	104	14.7	$<1.0 \times 10^4$
15(2)	104	14.7	$<1.0 \times 10^4$
16	104	14.7	$<1.0 \times 10^4$
17	104	14.7	$<1.0 \times 10^4$
18	104	14.7	$<1.0 \times 10^4$
19	120	14.7	$<1.0 \times 10^4$
19a	80	14.7	$<1.0 \times 10^4$
20	120	14.7	$<1.0 \times 10^4$
20a	120	14.7	1.8×10^6
21	150	14.7	1.8×10^7
22(4)	104	14.7	5.4×10^6
23	104	14.7	1.8×10^4
24	104	14.7	$<1.0 \times 10^4$
25	150	14.7	$<1.8 \times 10^6$
26	104	14.7	$<1.0 \times 10^4$
27	104	14.7	$<1.0 \times 10^4$
28	104	14.7	$<1.0 \times 10^4$

(Sheet 1 of 2)

Table 3.11-1 (Continued)

ENVIRONMENTAL ZONE PARAMETERS FOR NORMAL SERVICE CONDITION

Zone	Temperature (°F)	Pressure (psia)	40-Year Dose (rads)
1	150	14.7	8.8×10^6
29	120	14.7	1.8×10^6
30	120	14.7	$<1.0 \times 10^4$
30a	80	14.7	$<1.0 \times 10^4$
31	125	14.7	1.8×10^6
31a	120	14.7	$<1.0 \times 10^4$
32	150	14.7	1.8×10^7
33	150	14.7	1.8×10^6
34	104	14.7	3.6×10^6
35	104	14.7	$<1.0 \times 10^4$
36	104	14.7	$<1.0 \times 10^4$
37	104	14.7	$<1.0 \times 10^4$
38(5)	120	14.7	$<1.0 \times 10^4$
39(3)	120	14.7	$<1.0 \times 10^4$
40	104	14.7	$<1.0 \times 10^4$
41	150	14.7	8.8×10^6
42	104	14.7	$<1.0 \times 10^4$
43	104	14.7	$<1.0 \times 10^4$
44	104	14.7	$<1.0 \times 10^4$
45	104	14.7	$<1.0 \times 10^4$
46	104	14.7	$<1.0 \times 10^4$
47	120	14.7	$<1.0 \times 10^4$

Notes:

1. When the ECCS pump in the room is operating, the normal service temperature is 150°F.
2. Zone 15 is a 5-foot zone around 18-inch line 1603-18".
3. Zone 39 is a 5-foot zone around 18-inch line 7504-18".
4. Pump rooms are seperate from the HX bay and experience lower doses per NEDO-24218; however, the area is currently included as part of Zone 22 (1.8×10^4 rads).
5. The normal 40-year dose in the area around the steam jet air ejectors is 5.3×10^6 rads per NEDO-2418.

Table 3.11-2

ENVIRONMENTAL ZONE PARAMETERS FOR POST-ACCIDENT CONDITIONS

	HELB		LOCA			
Zone	Temperature (°F)	Pressure (psia)	Temperature (°F)	Pressure (psia)	1-Hour Dose (rads)	30-Day Dose (rads)
1	334	40.0	281	63.0	2.0×10^{7}	1.0×10^{8}
2	242	15.1	135	14.7	1.42×10^{6}	1.0×10^{7}
3	221	14.9	104	14.7	$<1.0 \times 10^{4}$	$<1.0 \times 10^{4}$
4	228[5]	15.0[5]	150[6]	14.7	2.1×10^{5}	4.1×10^{6}
5	228[7]	15.0[7]	150[6]	14.7	2.1×10^{5}	4.1×10^{6}
6	298[6]	16.6	150	14.7	1.8×10^{5} [2]	3.5×10^{6} [2]
7	120	14.7	120	14.7	$<1.0 \times 10^{4}$	$<1.0 \times 10^{4}$
7a	120	14.7	120	14.7	$<1.0 \times 10^{4}$	$<1.0 \times 10^{4}$
7b	120	14.7	120	14.7	$<1.0 \times 10^{4}$	$<1.0 \times 10^{4}$
8	334	40.0	281	63.0	2.0×10^{7}	1.0×10^{8}
9	304	27.5	150	14.7	1.1×10^{5}	2.0×10^{6}
9a	304	27.5	125	14.7	1.1×10^{5}	2.0×10^{6}
10	201	14.8	104	14.7	2.6×10^{5}	1.4×10^{6}
11	201	14.8	104	14.7	1.1×10^{5}	2.0×10^{6}
12	201	14.8	104	14.7	$<1.0 \times 10^{4}$	1.1×10^{5}
13	201	14.8	104	14.7	1.1×10^{5}	2.0×10^{6}
14	201	14.8	104	14.7	6.5×10^{4}	2.8×10^{5}

Table 3.11-2 (Continued)

ENVIRONMENTAL ZONE PARAMETERS FOR POST-ACCIDENT CONDITIONS

	HELB		LOCA			
Zone	Temperature (°F)	Pressure (psia)	Temperature (°F)	Pressure (psia)	1-Hour Dose (rads)	30-Day Dose (rads)
15[3]	201	14.8	104	14.7	2.6×10^5	1.4×10^6
16	201	14.8	104	14.7	1.6×10^5	5.8×10^5
17	104	14.7	104	14.7	1.5×10^5	5.8×10^5
18	104	14.7	104	14.7	1.2×10^5	2.0×10^6
19	120	14.7	120	14.7	$<1.0 \times 10^4$	$<1.0 \times 10^4$
19a	80	14.7	80	14.7	$<1.0 \times 10^4$	$<1.0 \times 10^4$
20	120	14.7	120	14.7	$<1.0 \times 10^4$	$<1.0 \times 10^4$
20a	120	14.7	120	14.7	$<1.0 \times 10^4$	$<1.0 \times 10^4$
21	334	40.0	281	63.0	2.0×10^7	1.0×10^8
22	275	45.0	104	14.7	1.5×10^5	5.8×10^5
23	212	14.8	104	14.7	$<1.0 \times 10^4$	$<1.0 \times 10^4$
24	212	14.8	104	14.7	1.0×10^5	2.0×10^6
25	299	15.1	150	14.7	4.4×10^6	3.5×10^7
26	212	14.8	104	14.7	1.1×10^5	2.0×10^6
27	212	14.8	104	14.7	2.6×10^5	1.3×10^6
28	179	14.8	104	14.7	9.6×10^4	1.9×10^6

Table 3.11-2 (Continued)

ENVIRONMENTAL ZONE PARAMETERS FOR POST-ACCIDENT CONDITIONS

	HELB		LOCA			
Zone	Temperature (°F)	Pressure (psia)	Temperature (°F)	Pressure (psia)	1-Hour Dose (rads)	30-Day Dose (rads)
29	200	16.5	120	14.7	$<1.0 \times 10^4$	$<1.0 \times 10^4$
30	120	14.7	120	14.7	$<1.0 \times 10^4$	9.6×10^6
30a	80	14.7	80	14.7	$<1.0 \times 10^4$	$<1.0 \times 10^4$
31	200	16.5	125	14.7	1.1×10^5	2.0×10^6
31a	120	14.7	120	14.7	$<1.0 \times 10^4$ (9)	$<1.0 \times 10^4$ (9)
32	334	40.0	281	63.0	2.0×10^7	1.0×10^8
33	299	15.1	150	14.7	4.8×10^5	2.5×10^6
34	210	14.7	104	14.7	$<1.0 \times 10^4$	$<1.0 \times 10^4$
35	210	14.7	104	14.7	$<1.0 \times 10^4$	$<1.0 \times 10^4$
36	210	14.7	104	14.7	5.2×10^5	2.8×10^6
37	210	14.7	104	14.7	5.5×10^5	2.9×10^6
38	120	14.7	120	14.7	$<1.0 \times 10^4$	$<1.0 \times 10^4$
39(4)	120	14.7	120	14.7	2.6×10^5	1.4×10^6
40	104	14.7	104	14.7	$<1.0 \times 10^4$	$<1.0 \times 10^4$
41	334	40.0	281	63.0	2.0×10^7	1.0×10^8
42	292	14.8	104	14.7	4.6×10^6	3.5×10^7

Table 3.11-2 (Continued)

ENVIRONMENTAL ZONE PARAMETERS FOR POST-ACCIDENT CONDITIONS

	HELB		LOCA			
Zone	Temperature (°F)	Pressure (psia)	Temperature (°F)	Pressure (psia)	1-Hour Dose (rads)	30-Day Dose (rads)
43	104	14.7	104	14.7	$<1.0 \times 10^4$	$<1.0 \times 10^4$
44	104	14.7	104	14.7	$<1.0 \times 10^4$	$<1.0 \times 10^4$
45	104	14.7	104	14.7	$<1.0 \times 10^4$	$<1.0 \times 10^4$
46	104	14.7	104	14.7	$<1.0 \times 10^4$	$<1.0 \times 10^4$
47	291	16.0	120	14.7	$<1.0 X 10^4$	$<1.0 X 10^4$

Note:

1. NFS calculation RSA-D-92-06, Rev. 0 predicted worst case 24 hour temperature of 185°F in the HPCI room with loss of room cooling.
2. For components in HPCI system, dose is $<1.0 \times 10^4$ rads because HPCI operates following design basis events not associated with rapid depressurization and fuel failure.
3. Zone 15 is a 5-foot zone around 18-inch line 1603-18".
4. Zone 39 is a 5-foot zone around 18-inch line 7504-18".
5. Values shown are based on worst case corner room conditions following a torus compartment break. The Unit 2 zone can experience higher temperatures and pressure due to a HPCI steam line break in the HPCI room (270°F, 14.8 psia) per Bechtel Calc. DR-055-M-001 with LOOP.
6. NFS calculation RSA-D-92-07, Rev. 0 predicted a peak post LOCA temperature of 178.6°F in this room without room coolers.
7. Values shown are based on worst case corner room conditions following a torus compartment break. The Unit 3 Zone 5 can experience higher temperatures and pressures due to a HPCI steam line break in the HPCI room (270 °F, 14.8 psia) per Bechtel Calculation DR-055-M-001 with LOOP.

Table 3.11-2 (Continued)

ENVIRONMENTAL ZONE PARAMETERS FOR POST-ACCIDENT CONDITIONS

8. Temperature of the adjacent HPCI room of the other Unit will be 176 °F. A LOOP is considered concurrent with a HPCI line break in the HPCI room.
9. The portion of the zone on the north side of the turbine building considers a post accident radiation source (2/3-7509-24" containment air pipe) and could see higher doses than other parts of Zone 31A.

Table 3.11-3

RELATIVE HUMIDITY BY ENVIRONMENTAL ZONE

Zone	Relative Humidity (%) Normal	Spurious	Accident
1	20.90	5.100	100(C)
2(2)	20.90	5.100	100(C)
3	20.90	5.100	100(C)
4	20.90	5.100	100(C)
5	20.90	5.100	100(C)
6	20.90	5.100	100(C)
7(1)	20.90	5.100	100(NC)
7a(1)	20.90	5.100	100(NC)
7b(1)	20.90	5.100	100(NC)
8	20.90	5.100	100(C)
9	20.90	5.100	100(C)
9a	20.90	5.100	100(C)
10(2)	20.90	5.100	100(C)
11(2)	20.90	5.100	100(C)
12(2)	20.90	5.100	100(C)
13(2)	20.90	5.100	100(C)
14(2)	20.90	5.100	100(C)
15(2)	20.90	5.100	100(C)
16(2)	20.90	5.100	100(C)
17(1)	20.90	5.100	100(NC)
18(1)	20.90	5.100	100(NC)
19(1)	20.90	5.100	100(NC)
19a	40.70	20.90	90
20(1)	20.90	5.100	100(NC)
20a(1)	20.90	5.100	100(NC)
21	20.90	5.100	100(C)

(Sheet 1 of 3)

Table 3.11-3 (Continued)

RELATIVE HUMIDITY BY ENVIRONMENTAL ZONE

	Relative Humidity (%)		
Zone	Normal	Spurious	Accident
22	20.90	5.100	100(C)
23	20.90	5.100	100(C)
24(1)	20.90	5.100	100(NC)
25	20.90	5.100	100(C)
26(1)	20.90	5.100	100(NC)
27(1)	20.90	5.100	100(NC)
28	20.90	5.100	100(C)
29	20.90	5.100	100(C)
30(1)	20.90	5.100	100(NC)
30a	40.70	20.90	90
31	20.90	5.100	100(C)
31a(1)	20.90	5.100	100(NC)
32	20.90	5.100	100(C)
33	20.90	5.100	100(C)
34(1)	20.90	5.100	100(NC)
35(1)	20.90	5.100	100(NC)
36(1)	20.90	5.100	100(NC)
37(1)	20.90	5.100	100(NC)
38(1)	20.90	5.100	100(NC)
39(1)	20.90	5.100	100(NC)
40(1)	20.90	5.100	100(NC)
41	20.90	5.100	100(C)
42	20.90	5.100	100(C)

Table 3.11-3 (Continued)

RELATIVE HUMIDITY BY ENVIRONMENTAL ZONE

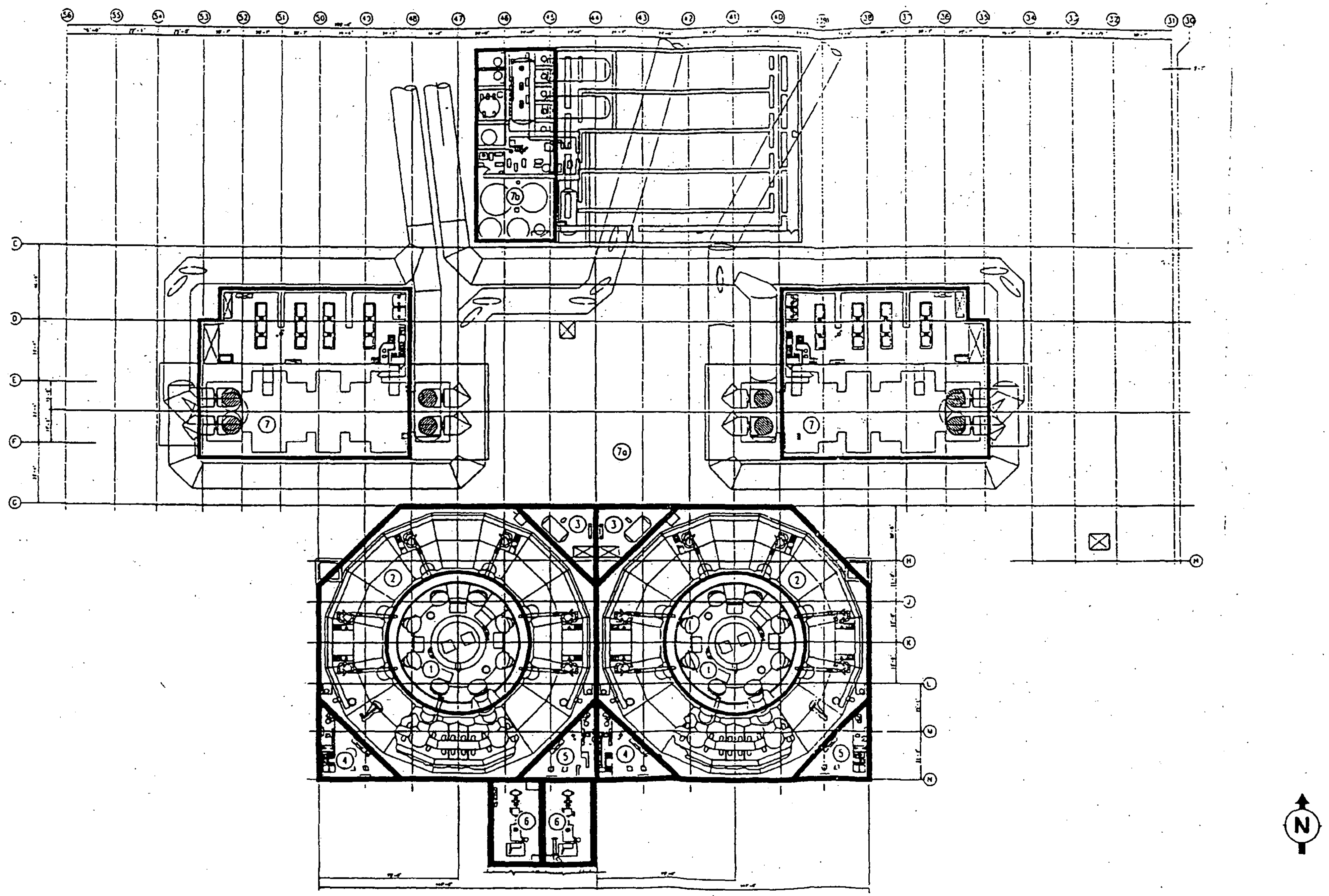
Zone	Relative Humidity (%) Normal	Spurious	Accident
43[1]	20.90	5.100	100(NC)
44[1]	20.90	5.100	100(NC)
45[1]	20.90	5.100	100(NC)
46[1]	20.90	5.100	100(NC)
47	20.90	5.100	100(C)

Notes:

(C) = Condensing (NC) = Noncondensing

1. Maximum relative humidity for individual components containing an equipment heat source is 95%. Maximum relative humidity for area without a moisture source is 95%.

2. Maximum relative humidity for motor control centers and bus ducts in this zone is 95%.



BECHTEL
CHICAGO PROJECTS OFFICE

DRESDEN UNITS 2 AND 3
COMMONWEALTH EDISON CO.

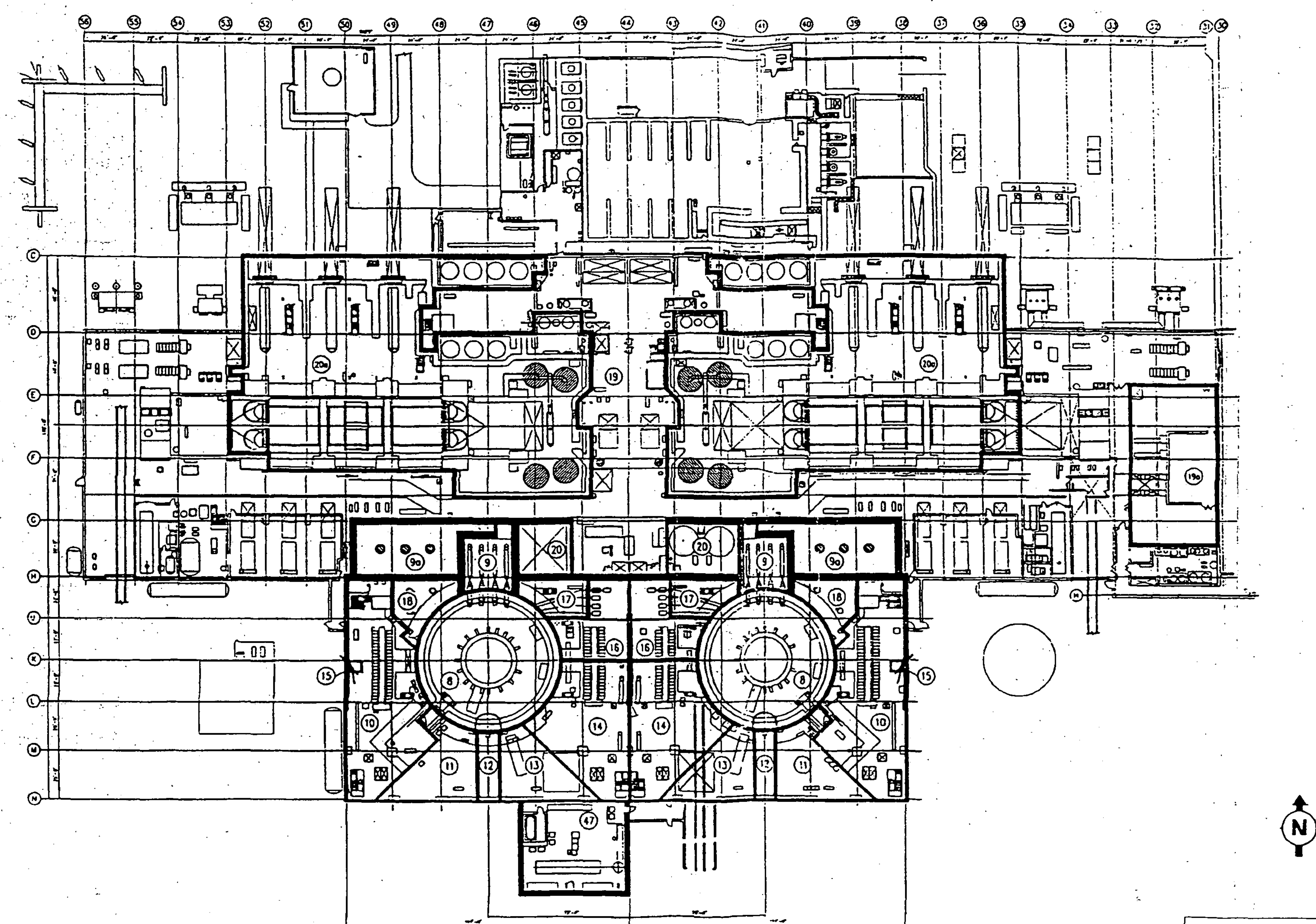
ENVIRONMENTAL ZONE MAP
(BASEMENT FLOOR PLAN) ELEV. 476'-6"
FIGURE 1

13524	13524-06I-N102	6

DRESDEN STATION
UNITS 2 & 3

ENVIRONMENTAL ZONE MAP
BASEMENT FLOOR PLAN
ELEVATION 476'-6"

FIGURE 3.11-1



BECHTEL
CHICAGO PROJECTS OFFICE

DRESDEN UNITS 2 AND 3
COMMONWEALTH EDISON CO.

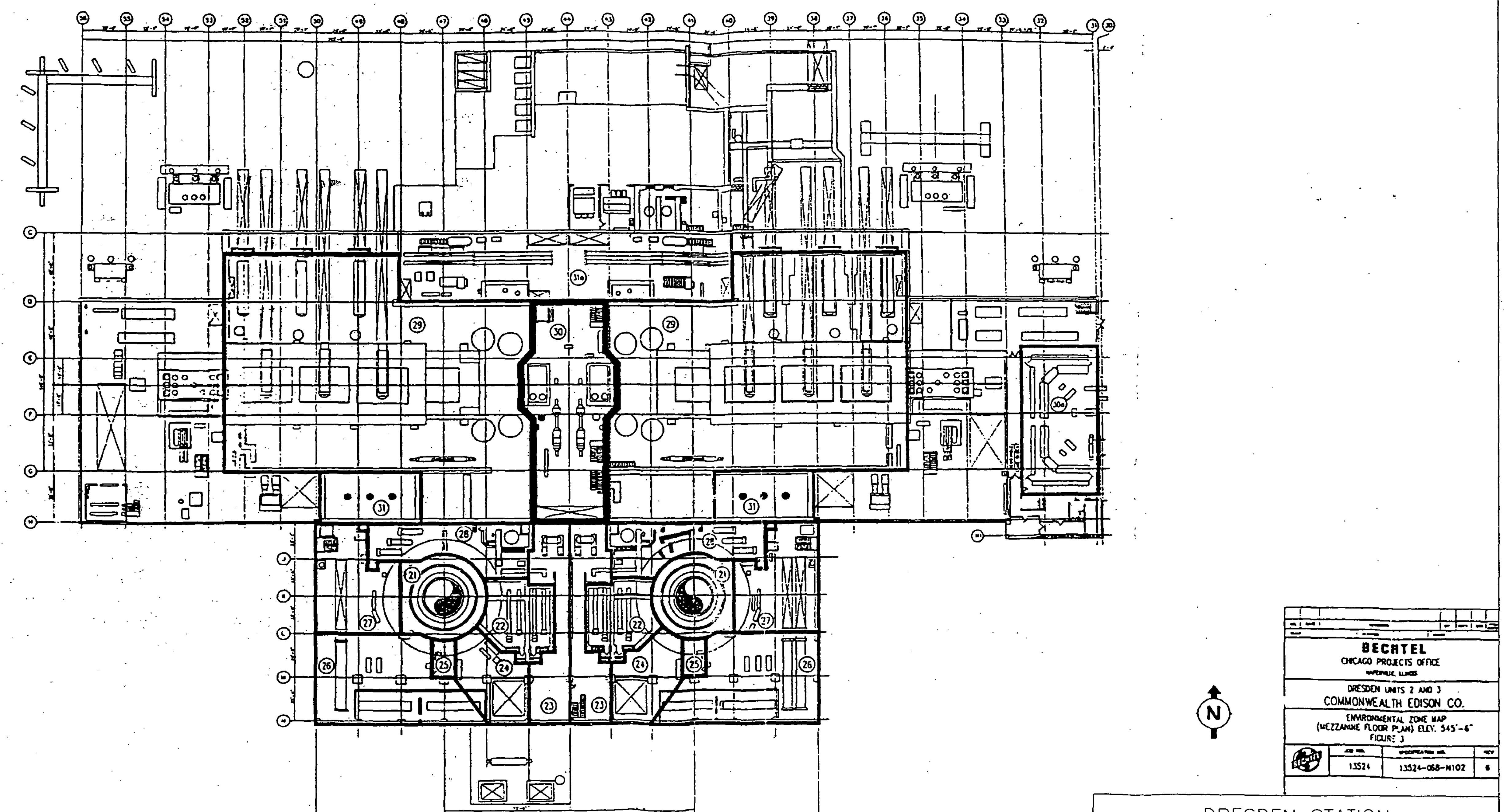
ENVIRONMENTAL ZONE MAP
(GROUND FLOOR PLAN) ELEV. 517'-6"
FIGURE 2

13524	13524-068-M102	6

DRESDEN STATION
UNITS 2 & 3

ENVIRONMENTAL ZONE MAP
GROUND FLOOR PLAN
ELEVATION 517'-6"

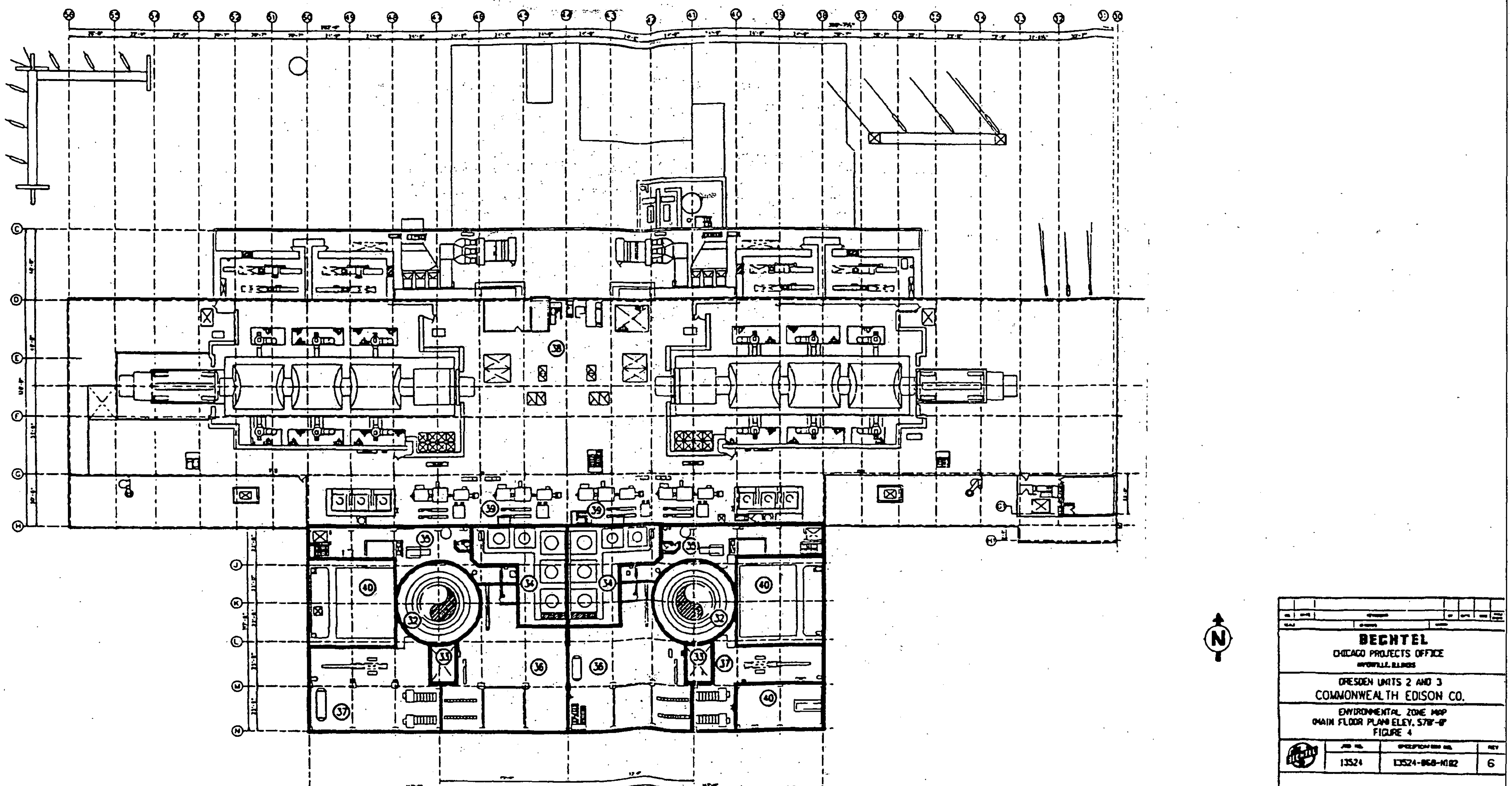
FIGURE 3.11-2



DRESDEN STATION
UNITS 2 & 3

ENVIRONMENTAL ZONE MAP
MEZZANNE FLOOR PLAN
ELEVATION 545'-6"

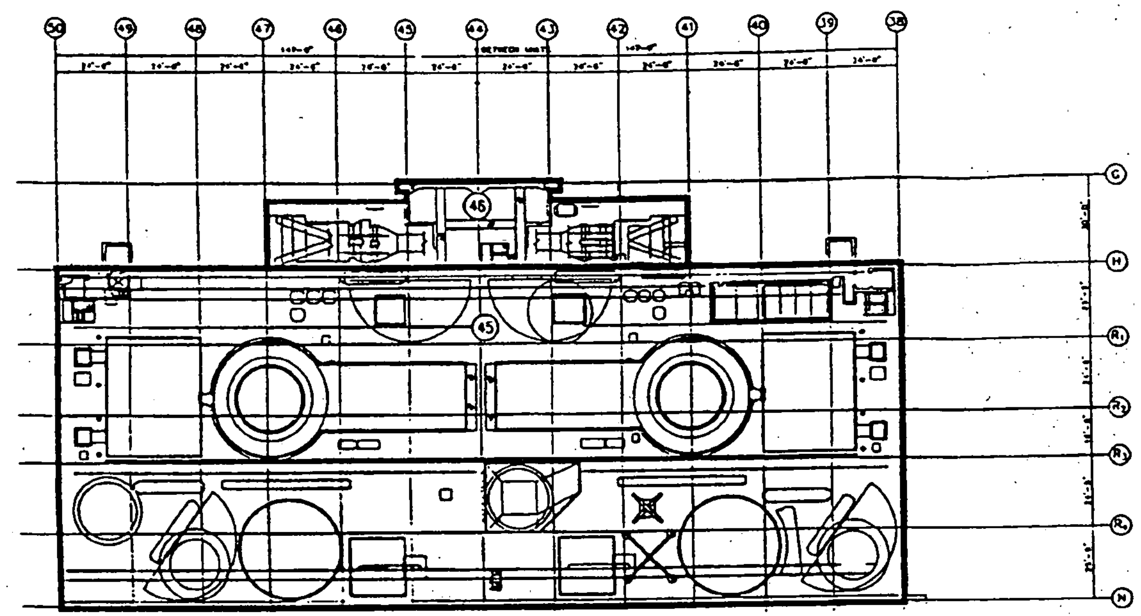
FIGURE 3.11-3



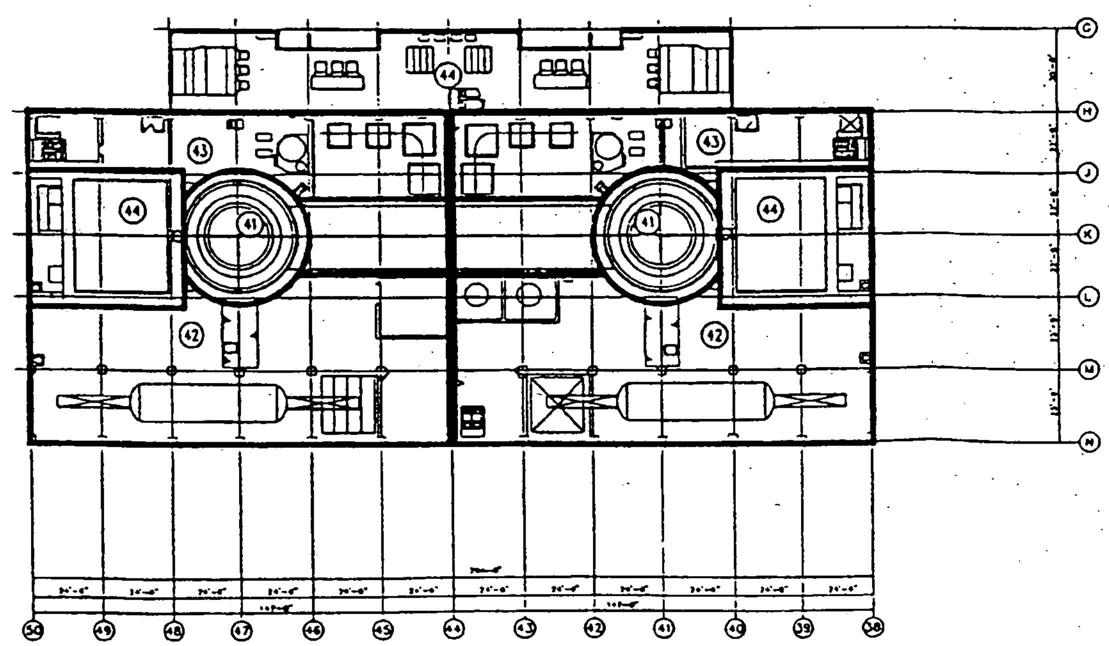
DRESDEN STATION
UNITS 2 & 3

ENVIRONMENTAL ZONE MAP
MAIN FLOOR PLAN
ELEVATION 570'-0"

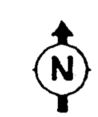
FIGURE 3.11-4



FLOOR PLAN ELEVATION 613'-0"



FLOOR PLAN ELEVATION 589'-0"



BECHTEL
CHICAGO PROJECTS OFFICE

DRESDEN UNITS 2 AND 3
COMMONWEALTH EDISON CO.

ENVIRONMENTAL ZONE MAP
(REACTOR FLOOR PLAN) ELEV. 589'-0" & 613'-0"
FIGURE 5

13524	13524-068-N102	6

DRESDEN STATION
UNITS 2 & 3

ENVIRONMENTAL ZONE MAP
REACTOR FLOOR PLAN
ELEVATION 589'-0" & 613'-0"

FIGURE 3.11-5

APPENDIX 3B

Dresden 2

SEP Topic: III-5.A, High Energy Line Break
Inside Containment

Commonwealth Edison
One First National Plaza, Chicago, Illinois
Address Reply to: Post Office Box 767
Chicago, Illinois 60690

November 17, 1982

Mr. Paul O'Connor
Project Manager
Operating Reactors Branch No. 5
Division of Licensing
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Subject: Dresden 2
SEP Topic: III-5.A, High Energy Line Break
Inside Containment

NRC Docket 50-237

Dear Mr. O'Connor:

Enclosed is the final report on Effects of Pipe Break on Systems, Structures and Components Inside Containment. This report adequately addresses all of the concerns of Chapter 4 of the Integrated Assessment.

Please address any questions you may have concerning this matter to this office.

One (1) signed original, thirty-nine (39) copies of this transmittal letter and due to the volume only twenty (20) copies of the report have been provided for your use.

Very truly yours,

for Thomas J. Rausch
Nuclear Licensing Administrator
Boiling Water Reactors

SPP/ji
2500D
cc: RIII Resident Inspector, Dresden
Gregg Cwalina, SEP Integrated Assessment
Project Manager

TARGET TECHNOLOGY LTD.

DRESDEN UNIT 2
SEP TOPIC III-5.A
EFFECTS OF PIPE BREAKS ON SYSTEMS
STRUCTURES AND COMPONENTS INSIDE CONTAINMENT

TTL FINAL REPORT

1105 CECO-01

Approved by: John Dainora
J. Dainora

Date: October 8, 1982

TABLE OF CONTENTS

Table of Contents (Cont'd)

* Appendices A & B are part of Dresden Unit 2 & 3 Docketed Information (ref Nov. 12, 1982 letter from T.S. Raush of Commonwealth Edison to Mr. P. O'Conner of the NRC concerning SEP Topic III-5.A) but are not included in the UFSAR.

Note that page 6-1 through 8-1 were retyped from a the best avaiilable microfilm copy. Not all characters were clear, and some contextual interpretation was necessary.

LIST OF TABLES

LIST OF FIGURES

LIST OF FIGURES (Cont'd)

1.0 INTRODUCTION

The safety objective of SEP Topic III-5.A, for high and moderate energy piping systems inside the containment, has been evaluated by Target Technology for the Dresden 2 Nuclear Power Station. The program plan developed by Commonwealth Edison for resolution of this SEP Topic consisted of the following six major tasks:

(1) Finalize Program Plan

(2) Define Mechanistic Break Locations

(3) Develop Target Evaluation Criteria

(4) Perform Interaction Evaluation

(5) Perform Cost/Benefit Analysis

(6) Perform Additional Analysis (as required)

a) Fracture Mechanics Evaluation

b) Rigorous Jet Impingement and Pipe Whip Analysis

c) Rigorous Containment and Structure Damage Analysis

d) Piping Stress Analysis

e) Restraint Feasibility Study

The evaluation was performed to ensure that pipe breaks would not cause the loss of needed functions of safety related systems, structures, and components, and to ensure that the plant can be safely shut down in the event of such breaks.

This report describes the methods used for postulating pipe break locations, the formulations required for the development of generic target evaluation criteria, and the procedures utilized to evaluate target interactions from postulated pipe breaks.

In addition, the report identifies the possible alternatives considered to perform a cost/benefit analysis of the design analysis options available to reduce the number of unresolved break interactions. Finally, a description of the approaches utilized to evaluate and qualify the remaining unresolved interactions is presented.

2.0 EXECUTIVE SUMMARY

2.1 Summary of Pipe Break Evaluation

The utilization of the mechanistic approach for postulating break locations in high and moderate energy piping systems inside the containment resulted in the determination of 85 and 20 break locations for high and moderate energy piping systems, respectively.

Evaluation of interactions from the above breaks, utilizing the generic target evaluation criteria described in Section 4.0, resulted in the qualification of 58 breaks in the high energy piping system, and all of the 20 breaks in the moderate energy systems.

The remaining 27 unresolved break interactions after the completion of Task 4 were all qualified on the basis of one of the following approaches:

i) Further system evaluation of electrical interactions.

ii) A sophisticated non-linear, dynamic (time history) finite element analysis for pipe whip interactions with containment liner, RPV pedestal and piping components.

iii) Rigorous and more refined development of jet pressure loading for jet interaction.

2.2 Tabulation of Findings

The status of pipe breaks throughout the evaluation process for high and moderate energy systems is summarized in Tables 2-1 and 2-2.

2.3 Results

The evaluation indicates that the effects of pipe breaks inside the containment do not affect the ability of the Dresden 2 Nuclear Power Station to:

i) maintain a coolable core geometry following any postulated break,

ii) maintain the capability of safe plant shutdown,

iii) maintain containment integrity.

The evaluation identified no potentially unacceptable break locations and therefore the fracture mechanics alternative and the guidance provided by the NRC staff for a "leak-before-break" approach for resolution of open items was not utilized.

TABLE 2-1 QUALIFICATION SUMMARY OF BREAK LOCATIONS IN HIGH ENERGY LINES

Break No.	Qualified in Task	Break No.	Qualified in Task	Break No.	Qualified in Task
A2-1403-01G	4	I2-1303-01G	6	L2-0201-12G	6
B2-1404-01G	4	I2-1303-02G	4	L2-0202-01G	4
C2-0308-01G	4	I2-1303-03S	6	L2-0202-02G	6
C2-0308-02G	4	I2-1303-04G	4	M2-1201-01G	4
C2-0308-03G	4	I2-1303-05S	6	M2-1201-02G	6
C2-0308-04G	4	I2-1303-06G	4	M2-1201-03G	6
D2-3204-01G	6	I2-1303-07G	6	M2-1201-04S	4
D2-3204-02G	6	J2-1506-01G	4	M2-1001-01G	4
D2-3204-03G	6	J2-1506-02G	4	M2-1001-02G	6
D2-3204-04G	6	J2-1506-03S	6	Ø2-3001-01G	6
D2-3204-05G	4	J2-1506-04G	4	Ø2-3001-02G	6
E2-3204-01G	4	J2-1506-05G	4	Ø2-3001-03G	4
E2-3204-02G	6	J2-1506-06G	4	Ø2-3001-04G	6
E2-3204-03G	6	K2-1519-01G	4	P2-3001-01G	4
E2-3204-04G	4	K2-1519-02G	4	P2-3001-02G	6
E2-3204-05G	4	K2-1519-03S	4	P2-3001-03G	6
G2-2305-01G	4	K2-1519-04G	4	P2-3001-04G	4
G2-2305-02G	4	K2-1519-05S	6	Q2-3001-01G	4
G2-2305-03G	4	K2-1519-06G	4	Q2-3001-02G	6
G2-2305-04G	4	L2-0201-01G	4	Q2-3001-03G	4
H2-1302-01G	4	L2-0201-02G	4	Q2-3001-04G	4
H2-1302-02G	4	L2-0201-03G	4	R2-3001-01G	6
H2-1302-03S	4	L2-0201-04G	4	R2-3001-02G	6
H2-1302-04G	4	L2-0201-05G	4	R2-3001-03G	4
H2-1302-05S	4	L2-0201-06G	4	R2-3001-04G	4
H2-1302-06G	4	L2-0201-07G	4		
H2-1302-07S	4	L2-0201-08G	4		
H2-1302-08G	4	L2-0201-09G	4		
H2-1302-09S	4	L2-0201-10G	4		
H2-1302-10G	6	L2-0201-11G	6		

TABLE 2-2 QUALIFICATION SUMMARY OF LEAKAGE CRACKS IN MODERATE ENERGY LINES IN TASK 4.

Lines in Which Cracks are Postulated	Lines in Which Cracks are Postulated
2-2001-3"-LX	2-3746B-3
2-2005-3"-LX	2-3746C-3
2-3715A-3	2-3746D-3
2-3715B-3	2-3746E-3
2-3715C-3	2-3746F-3
2-3715D-3	2-3746G-3
2-3715E-3	2-3747A-6
2-3715F-3	2-3747B-6
2-3715G-3	2-3769A-6
2-3746A-3	2-3769B-6

3.0 MECHANISTIC BREAK LOCATIONS (TASK 2)

3.1 Criteria for Break Locations

The procedure for postulating break locations on a mechanistic basis in high and moderate energy piping systems inside the drywell is presented in this section. The approach reflects the guidance provided by the NRC Branch Technical Position MEB 3-1, "Postulated Rupture Locations in Fluid Systems Inside and Outside Containment," Rev. 1 - July, 1981.

3.1.1 Definitions

High Energy Piping System -- Any system, or portion of system, where the maximum operating pressure exceeds 275 psig, or the maximum operating temperature exceeds 200°F, during normal plant operating conditions. Those piping systems that operate above these limits for only a relatively short portion (less than approximately two percent) of the period of time to perform their intended function, are excluded from evaluation.

Moderate Energy Piping System -- Any system, or portion of a system, where neither the maximum operating pressure exceeds 275 psig nor the maximum operating temperature exceeds 200°F during normal plant operating conditions.

Branch Run -- A pipe run that originates as a branch of the main run and ends at a terminal end, another main run, another branch run or is free ended, with the exception of the following:

(a) free-ended branch lines throughout which there is no significant restraint to thermal expansion may be considered part of the main run;

(b) branch lines which are included with the main run piping in the stress analysis computer mathematical model, may be considered part of the main run.

Main Run -- A pipe run that interconnects terminal ends.

Terminal End -- That section of piping originating at a structure or component (such as a vessel or component nozzle or structural piping anchor) that acts as an essentially rigid constraint to the piping thermal expansion. Typically, an anchor assumed for the piping code stress analysis would be a terminal end.

3.1.2 Postulated Rupture Locations

3.1.2.1 Break Configurations

Circumferential Break -- A circumferential break shall be assumed to result in pipe severance with full separation of the two severed pipe ends. The extent of separation can be limited by structural design features or pipe stiffness. The break shall be assumed perpendicular to the longitudinal axis of the pipe, and the break area on each side assumed to be the cross-sectional flow area of the pipe at the break location, except when limited by structural design features.

Longitudinal Break -- A longitudinal break shall be assumed to result in a split of the pipe wall along the pipe longitudinal axis, but without severance. Splits should be oriented (but not concurrently) at two diametrically opposed points on the piping circumference such that the jet reactions cause out-of-plane bending of the piping configuration.

Alternatively, a single split may be assumed at the section of highest tensile stress as determined by detailed stress analysis. For the purpose of pipe whip analysis, the longitudinal break shall be assumed to be rectangular in shape, with an area equal to the largest piping cross-sectional flow area at the point of the break, with its length parallel to the pipe axis and equal to twice the piping internal diameter at that cross section.

3.1.2.2 Break Locations

Breaks in piping systems inside the containment were to be postulated at the following locations in each piping (main or branch) run:

(a) At terminal ends.

(b) At intermediate locations selected by one of the following criteria:

(i) At each pipe fitting (e.g., elbow, tee, cross, flange, and nonstandard fitting), welded attachment, and valve. Where the piping contains no fittings, welded attachments, or valves, at one location.

(ii) At each location where the stresses exceed 0.8 $(1.2S_h + S_A)$ but at not less than two separated locations chosen on the basis of highest stress. Where the piping consists of a straight run without fittings, welded attachment, or valves, and all stresses are below 0.8 $(1.2S_h + S_A)$, at a minimum of one location chosen on the basis of highest stress. Select two locations with at least ten percent difference in stress, or if stresses differ by less than ten percent, two locations separated by a change of direction of the pipe run.

3.1.2.3 Break Types

Circumferential Pipe Breaks -- The following circumferential breaks should be postulated individually in high energy fluid system piping at the locations specified in Section 3.1.2.2.

(a) Circumferential breaks should be postulated in fluid system and branch runs exceeding a nominal pipe size of 2½ inches except where the maximum stress range exceeds the limit of 0.8 $(1.2S_h + S_A)$, but the circumferential stress range is at least 1.5 times the axial stress range.

(b) Where break locations are selected without the benefit of stress calculations, breaks should be postulated at the piping welds to each fitting, valve, or welded attachment. Alternatively, a single break location at the section of maximum stress range may be selected as determined by detailed stress analyses or tests on a pipe fitting.

Longitudinal Pipe Breaks -- The following longitudinal breaks should be postulated in high energy fluid system piping at the locations of the circumferential breaks specified in Section 3.1.2.3 (a).

(a) Longitudinal breaks in fluid system piping and branch runs should be postulated in nominal pipe sizes 4-inch and larger, except where the maximum stress range exceeds the limit 0.8 $(1.2S_h + S_A)$, but the axial stress range is at least 1.5 times the circumferential stress range.

(b) Longitudinal breaks need not be postulated at:

- Terminal ends
- At intermediate locations where the criterion for a minimum number of break locations must be satisfied.

3.1.3 Postulated Crack Locations

The effects of moderate-energy fluid systems were evaluated using the following criteria:

1. For piping systems that by plant arrangement and layout are isolated and physically separated and remotely located from systems and components important to safety, through-wall leakage cracks need not be postulated.

2. For piping systems that are located in the same areas as high-energy fluid systems which, by the criteria of Section 3.1.2 have postulated pipe break locations, through-wall leakage cracks need not be postulated.

3. For piping systems that are located in areas containing systems and components important to safety, but where no high-energy fluid systems are present, through-wall leakage cracks should be postulated at the most adverse location to evaluate the effects of the resulting water spray and flooding.

4. Leakage cracks are postulated in those portions of piping from containment wall to and including the inboard or outboard isolation valves.

Fluid flow from a crack is based on a circular opening or area equal to that of a rectangle one-half pipe-diameter in length and one-half pipe wall thickness in width.

The environmental effects of pressure, temperature, humidity and flooding are evaluated under SEP Topic III-12, "Environmental Qualification of Safety-Related Equipment" and were not considered in this evaluation. Structural loading effects resulting from fluid flow through the crack, will be considered on safety-related systems, structures and components.

3.2 High Energy Piping Systems

Piping systems inside the drywell that have an operating temperature of 200°F or greater and/or an operating pressure of 275 psig or greater are considered to be high energy systems.

High energy lines inside the containment greater than 2½ inches in diameter are as follows:

Core Spray	2-1403-10" ECCS 2-1404-10" ECCS
Control Rod Drive	2-0308-3" 2-0308-4"
Feedwater	2-3204-A-18"C 2-3204-C-12"C 2-3204-D-12"C 2-3204-B-18"C 2-3204-E-12"C 2-3204-F-12"C
High Pressure Coolant Injection	2-2305-10"B
Isolation Condenser	2-1303-12" 2-1302-14"
Low Pressure Coolant Injection	2-1506-16"A 2-1519-16"
Reactor Recirculation	2-0201-B-22"A 2-0201-A-28"A 2-0201-B-28"A 2-0201-C-12"A 2-0201-D-12"A 2-0201-E-12"A 2-0201-F-12"A 2-0201-G-12"A

Reactor Recirculation (Cont.)	2-0201-H-12"A 2-0201-J-12"A 2-0201-K-12"A 2-0201-L-12"A 2-0201-M-12"A 2-0203-A-4"A 2-0203-B-4"A 2-0202-A-28"A 2-0202-B-28"A
Reactor Water Cleanup	2-1201-8"
Shutdown Cooling	2-1001-A-16" 2-1001-B-16"
Main Steam	2-3001-A-20"B 2-3001-B-20"B 2-3001-C-20"C 2-3001-D-20"B

The following lines have been excluded from consideration of postulated pipe break locations per Section 3.1.

<u>Operating Less than 2 Percent of the Time</u>

SRV Lines 2-3019A-8, 2-3019B-8, 2-3019C-8, 2-3019D-8, 2-3019E-8, Segments of Core Spray System beyond closed valves during normal operation.

3.3 Moderate Energy Piping Systems

Moderate energy systems inside the containment greater than 2½ inches in diameter are as follows:

Drywell Equipment and Floor Drain Discharge
2-2001-3"-LX 2-2005-3" LX

Reactor Building Closed Cooling Water System
2-3715A-3" through 2-3715G-3"
2-3746A-3" through 2-3746G-3"
2-3747A-6", 2-3747B-6",
2-3769A-6", and 2-3769B-6"

3.4 Break Postulation

Pipe stress analysis of fourteen pipe stress problems were performed by EDS Nuclear as part of the IE Bulletin 79-14 reanalysis activity. The pipe stress analysis was performed by a version of SUPERPIPE which did not generate computer output in a format which was suitable for postulating pipe break locations based on points of highest stress.

A computer program identified as PBREAK was developed to create the required pipe stress data base. The program combines stresses due to thermal, deadweight and seismic effects and compares the total stress with a limiting value used in the postulation of pipe break locations.

The seismic stresses calculated in the IE Bulletin 79-14 reanalysis activity were based on the original amplified response spectra curves for the plant. As part of the SEP evaluation effort, new amplified response spectra curves with lower "g" values have been generated. Seismic forces and moments were reduced by a scaling factor to reflect the new SEP seismic data.

The Main Steam Line and associated SRV Discharge Lines were stress analyzed by Sargent & Lundy. The pipe stress data were received in a summary form consistent with ASME Section III Subsection NC analysis. The stress summary output could be used with minimal stress combinations in postulating pipe break locations. Because the overall stress results were low, no scaling of seismic forces and moments was performed.

The type and location of postulated breaks are identified on the isometrics which are presented in Appendix A.

The relationships between Target Line Identification scheme and the pipe stress analysis problems are as follows:

TTL Identifier	Pipe Stress Problem Number
A.	D2-COSP-01B(C)
B.	D2-COSP-02B(C)
C.	D2-CRDS-02B(C)
D.	D2-FW-01C
E.	D2-FW-02C
G.	D2-HPCI-09B(C)
H.	D2-ISCO-03C
I.	D2-ISCO-04C
J.	D2-LPCI-09C
K.	D2-LPCI-10C
L.	D2-RRCI-01C
M.	D2-RWCU-02B(C)
O.	MS-A
P.	MS-B
Q.	MS-C
R.	MS-D

Postulated pipe break location and type identifier are as follows:

D2-3204-01G

Guillotine Type Break

Postulated Break Location Number

Line Number

Unit Number

Corresponds to stress problem and associated isometric as found in EDS Nuclear Problem No. D2-FW-01C.

D2-3204-02S

Longitudinal

Longitudinal Split Type Break

Same as above

The number of postulated breaks identified in Appendix A on a system basis is as follows:

Core Spray	2
Control Rod Drive	4
Feedwater	10
High Pressure Coolant Injection	4
Isolation Condenser	17
Low Pressure Coolant Injection	12
Reactor Recirculation	14
Reactor Water Cleanup	6
Main Steam	16
Total Number of Breaks	85

4.0 TARGET EVALUATION (TASK 3)

4.1 Load Formulation

4.1.1 Pipe Whip

After a postulated circumferential rupture, the broken pipe is accelerated by the unbalanced pressure and momentum of escaping fluid. A pipe whip interaction is assumed to occur if a sufficient fluid force is applied so that the ruptured pipe either forms a plastic hinge and whips about this plastic region, or moves elastically and impacts targets within its reach.

The initial decision in the determination of the load and/or energy imparted to the target from a whipping pipe is the assumption of the location of the pivot point about which the broken pipe whips. This point dictates the length of span to be considered in kinetic energy and velocity calculations, and is determined from inspection of the piping isometric drawings. The piping configuration in the region of the postulated break is examined and the pivot point selected based upon considerations of pipe bend locations and adjacent supports.

As the pipe whip phenomenon is considered to be the uncontrollable whipping of a pipe, two cases are considered. Depending upon the length of the whipping pipe and the distance from the break point to the target, the whipping pipe may either form a plastic hinge, thus dissipating some of its energy prior to impact, or it may remain as an elastic system.

An equivalent static load is determined through consideration of the whipping pipe's kinetic energy, and the strain energy of deformation of both the impacting pipe and the target, including their local crushing characteristics. The crushing stiffness of a pipe is based upon the superimposed results from considering the ring crush in the localized region and the effect of the continuity of the pipe (indentor crush) (Reference 1).

4.1.2 Jet Impingement

Calculations of jet impingement loads on various targets are based on the methodology presented in ANSI/ANS 58.2-1980 (Reference 2). The basic assumptions that are used in modeling the jet characteristics are given below:

- For flashing fluids the jet area expands uniformly at a half-angle not exceeding ten degrees. It remains equal to the break area for saturated water and sub-cooled fluids.

- The impingement force is uniformly distributed across the cross-sectional area of the jet, and only the portion intercepted by the target is considered.

- o The total jet impingement force across any cross-sectional area of the jet is time and distance invariant.

- o For longitudinal breaks, circular jet shapes identical to those for circumferential breaks are assumed. The jet issues from the break opening with its centerline normal to the opening area and the pipe centerline.

- o The flow across the cross-section of the jet is parallel to the axis of the jet.

The jet impingement load will be calculated by calculating the momentum change of the jet caused by the target.

The applied load on the target for static stress analysis will be determined by using a dynamic load factor as follows (Reference 2):

$$F_S = DLF\ (F_{imp.\ max}) \qquad (4\text{-}1)$$

where:

F_S = Equivalent static impingement force

DLF = Dynamic load factor (conservatively assumed equal to 2.0)

$F_{imp.\ max}$ = Maximum value of the jet impingement force.

The impingement force, $F_{imp.max}$, can be conservatively calculated as:

$$F_{imp.max} = K\ K_\emptyset\ (P_e - P_a)\ A\ (A_t/A_j) \qquad (4\text{-}2)$$

where,

K = Thrust factor (1.26 for flashing and partially flashing fluids and 2.0 for sub-cooled, non-flashing fluids)

$K_\emptyset$ = Shape factor (defined in Sec. 4.1.2.1)

P_e = Fluid pressure in the pipe

P_a = Ambient pressure around the target

A = Area of the jet at the break

A_j = Full jet impingement area (as defined in Sec. 4.1.2.2)

A_t = Target area (as defined in Sec. 4.1.2.3)

4.1.2.1 <u>Shape Factors</u> ($K_\emptyset$):

The shape factor is a measure of the target's potential for changing the momentum of the jet. The shape factors for four distinct cases that are identified as relevant in the present study are given below.

A. Plane surface whose normal is inclined at an angle $\emptyset$ with respect to the jet center line (Fig. A).

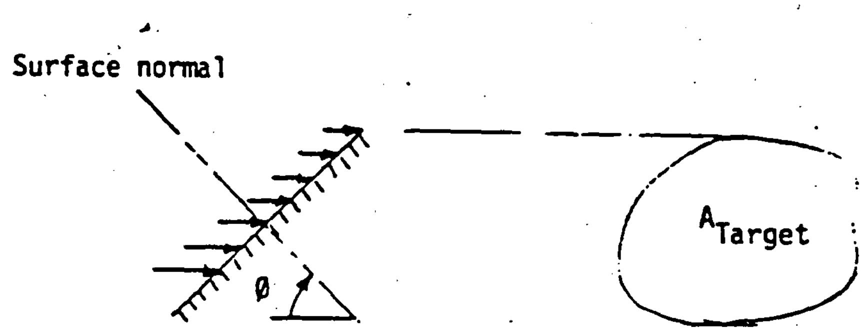


Figure A

$$K_\emptyset = \cos \emptyset \tag{4-3}$$

B. Circular jet impinging on pipe or conduit with jet diameter less than pipe diameter (Fig. B).

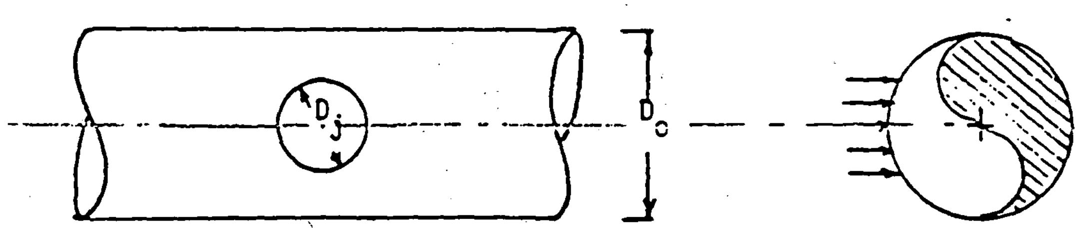


Figure B

$$K_\emptyset = 1 - 0.424\, D_j/D_o \tag{4-4}$$

where, D_j = Diameter of the jet at the impingement plane, and

D_o = Diameter of the target pipe.

Equation 4-4 can be conservatively used in cases where the entire jet is impinging on the target pipe and the jet center line is not intersecting the pipe axis.

If the jet center line is inclined at an angle β (Fig. C), then the shape factor for a circular jet impinging on pipe or conduit with jet diameter less than pipe diameter can be calculated as:

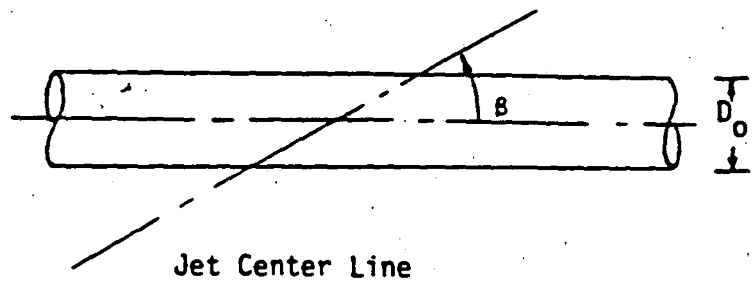


Figure C

$$K_\phi = (1 - 0.424\ D_j/D_o)\ \text{Sin}\ \beta \qquad (4\text{-}5)$$

C. Circular jet impinging on pipe or conduit, jet diameter greater than pipe diameter (Fig. D).

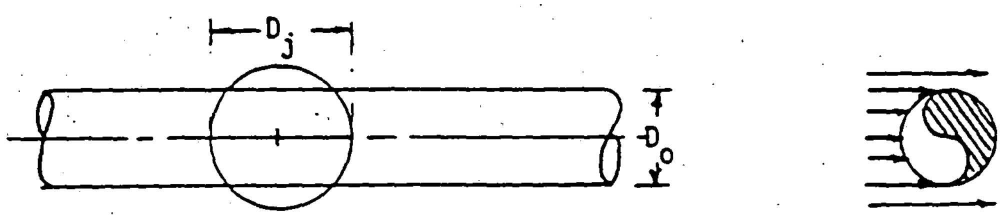


Figure D

$$K_\phi = 0.576 \qquad (4\text{-}6)$$

The value of K_ϕ given in Eqn. 4-6 can be conservatively used when the jet center line does not intersect the pipe axis and the pipe cross-section is completely submerged in the jet.

If the jet center line is inclined at an angle, β, (Fig. E) to the axis of the pipe, then the shape factor for a circular jet impinging on pipe or conduit with jet diameter greater than pipe diameter.

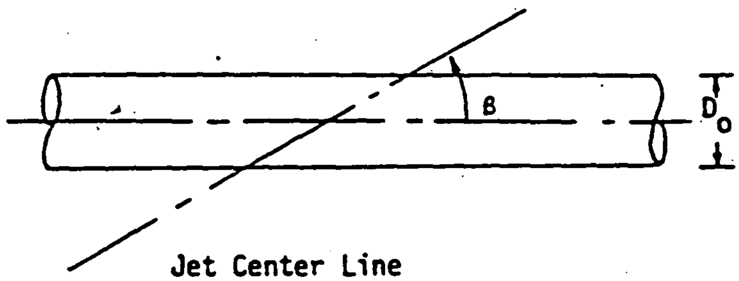


Figure E

$$K_{\emptyset} = 0.576 \text{ Sin } \beta \tag{4-7}$$

D. Circular jet impinging on pipe or conduit with pipe partially submerged in the jet (Fig. F).

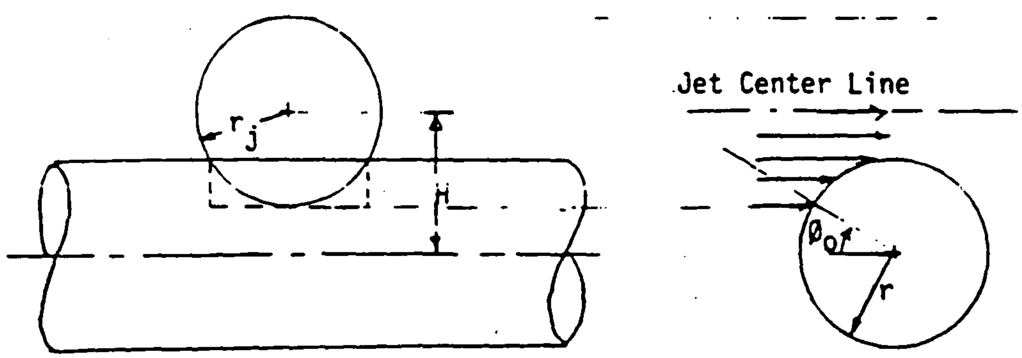


Figure F

In this case the impingement area can be conservatively approximated by the area shown in dotted lines. The shape factor for this case is given by:

$$K_\emptyset = \left(\frac{\pi}{4} - \frac{\emptyset_o}{2} - \frac{1}{4}\sin 2\emptyset_o\right)/(1 - \sin \emptyset_o) \qquad (4\text{-}8)$$

where, $\sin \emptyset_o = (H - r_j)/r$

H = Distance between the jet centerline and the axis of the pipe

r_j = Radius of the jet at the impingement plane

r = Radius of the pipe

Note that $\emptyset_o$ should be expressed in radians.

4.1.2.2 Full Jet Impingement Area

Full jet impingement area, A_j is the cross-sectional area of the jet perpendicular to jet center line at the impingement plane. For jets issuing from circumferential and longitudinal breaks, A_j can be calculated as follows.

Circumferential Break

A. Unrestrained Pipes: Circumferential breaks are perpendicular to the longitudinal axis of the pipe. Total separation of the pipe at the postulated break point is assumed. For unrestrained pipes the break area is therefore equal to internal cross-sectional area of the pipe (Ref. 3)

The following equation gives the full jet impingement area (Fig. 4-1)

$$A_j = 0.25\pi(D + 2L \tan\emptyset)^2 \qquad (4\text{-}9)$$

where: D = inside diameter of the pipe

L = distance of the target from the jet opening

$\emptyset$ = expansion angle of the jet (=10°)

B. Restrained Pipes: Full jet impingement area of the fan jet due to a postulated circumferential break in a restrained pipe (Fig. 4-2) is given by:

$$A_j = 2\pi(L + 0.5D)(B + 2L \tan\emptyset) \quad (4\text{-}10)$$

where: B = distance between the broken ends of the pipe

Longitudinal Break

Longitudinal breaks are parallel to the axis of the pipe and are oriented at any point around the circumference (Ref. 3). The jet axis is therefore perpendicular to the pipe axis. The break area is assumed to be equal to the internal cross-sectional area of the pipe and the shape of the break is assumed to be circular.

Full jet impingement area on a target plane (Fig. 4-3) is given by:

$$A_j = 0.25\,\pi(D + 2L \tan\emptyset)^2 \quad (4\text{-}11)$$

4.1.2.3 Target Area

Target area, A_t is the impinged upon portion of the target cross-sectional projected area perpendicular to jet center line at the impingement plane. Target areas for various targets that would be encountered in this study are discussed below.

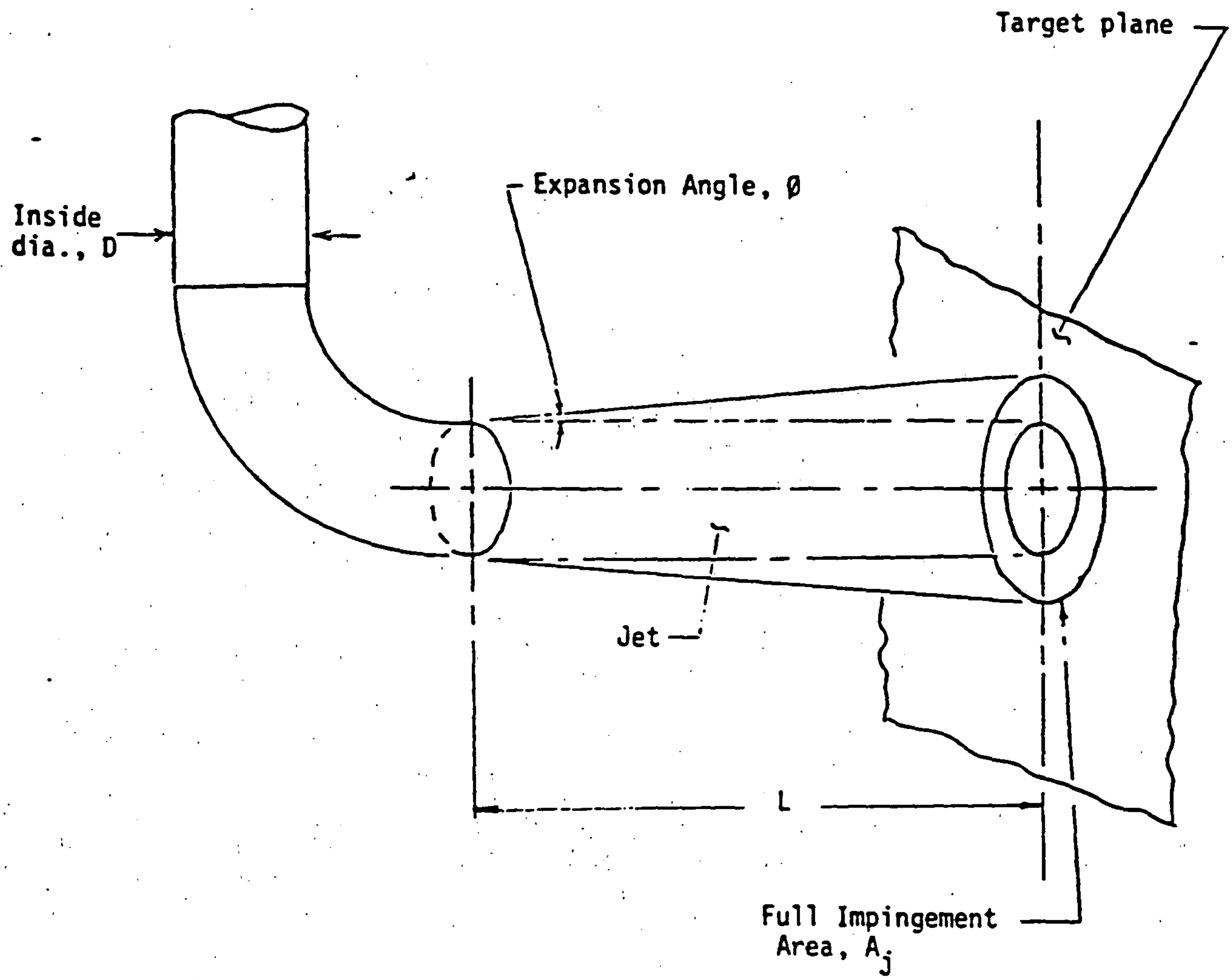


Figure 4-1 - Full Impingement Area - Circumferential Break
Unrestrained Pipe

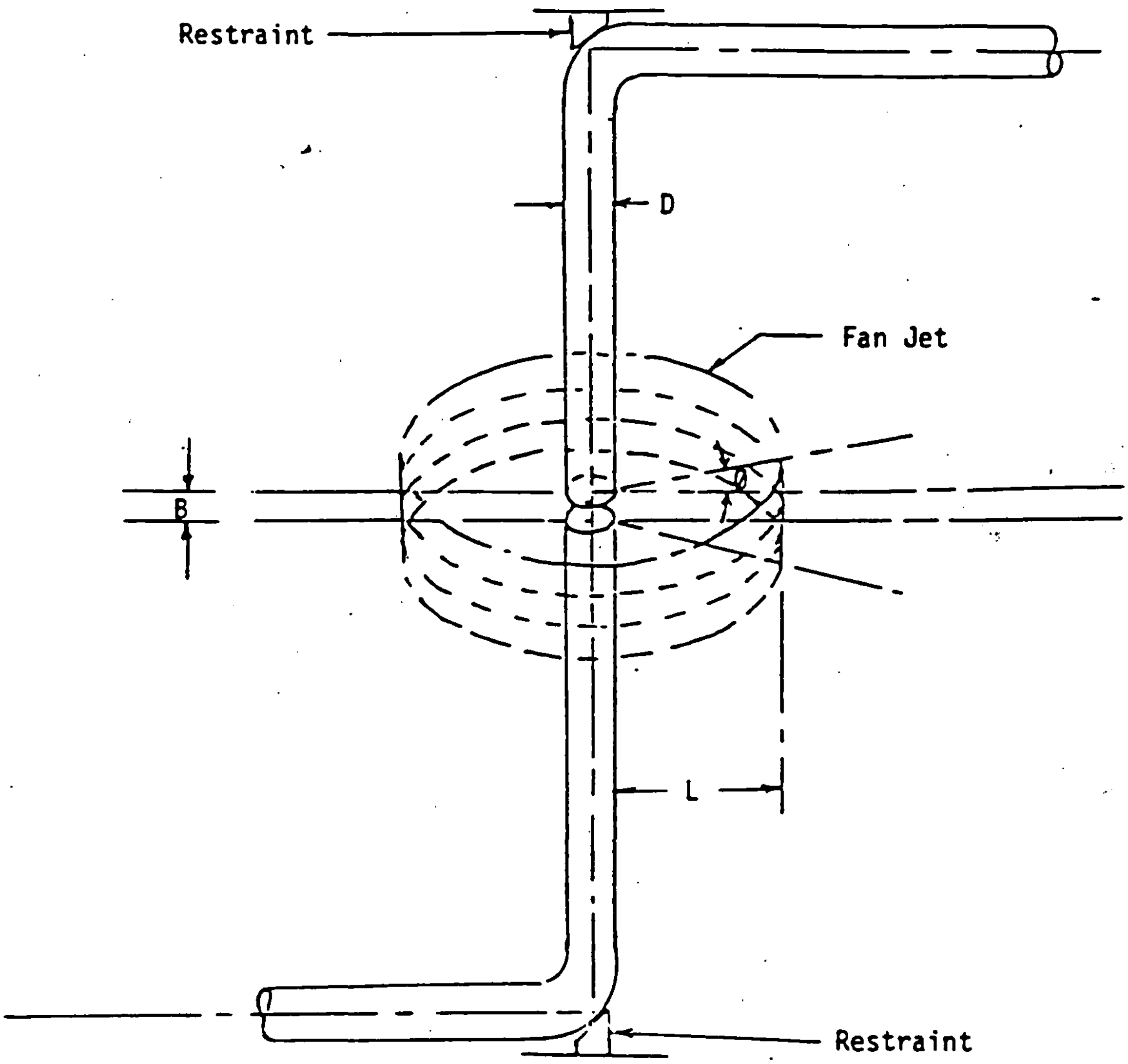


Figure 4-2 - Full Impingement Area - Circumferential Break Restrained Pipe

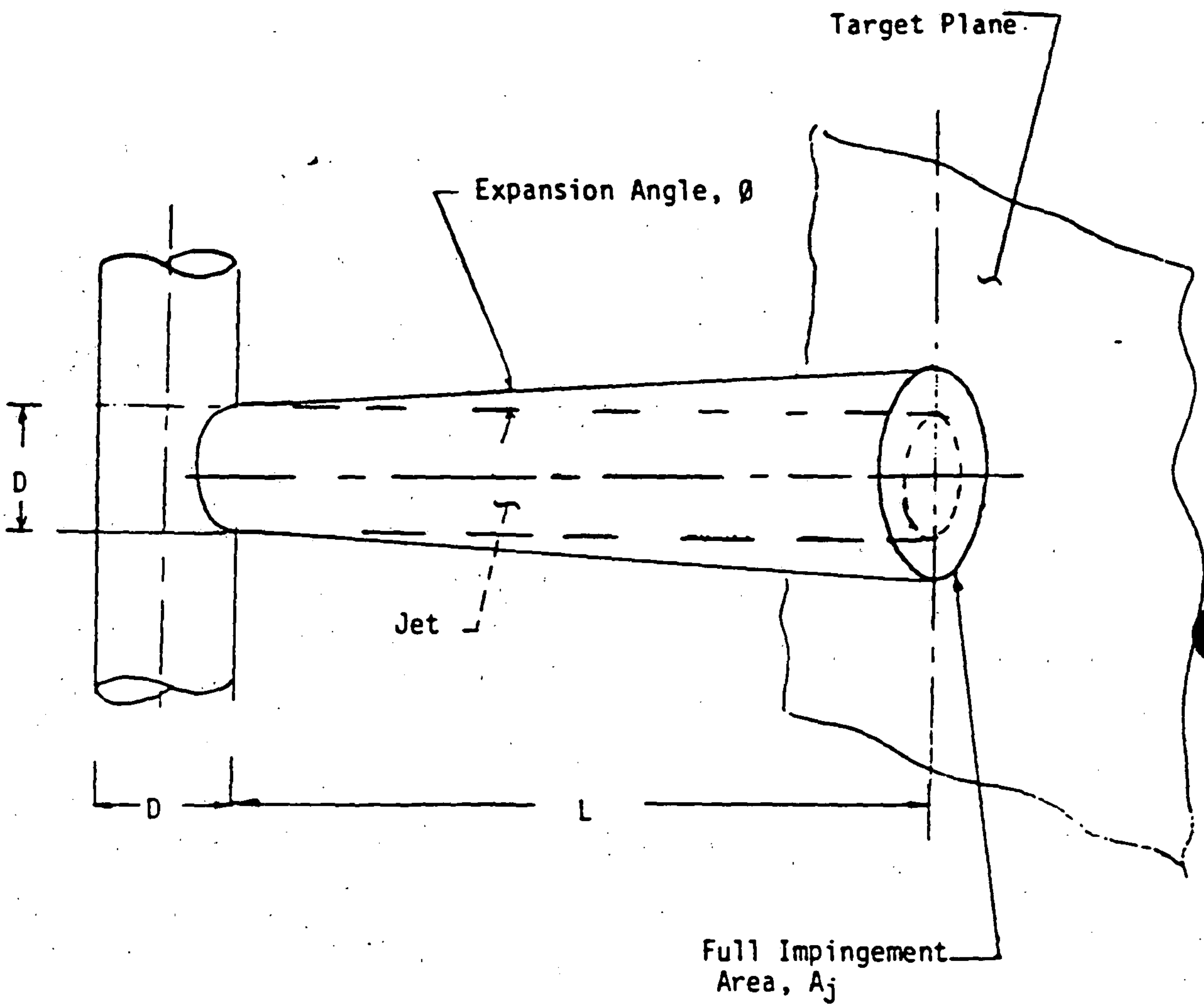


Figure 4-3 - Full Impingement Area - Longitudinal Break

Case A If the jet is completely intercepted by the target, then

$$A_t = A_j \tag{4-12}$$

where: A_j is the jet area as defined in Sec. 4.1.2.2.

Case B If the jet is partly intercepted and the target cross-section is completely submerged, then

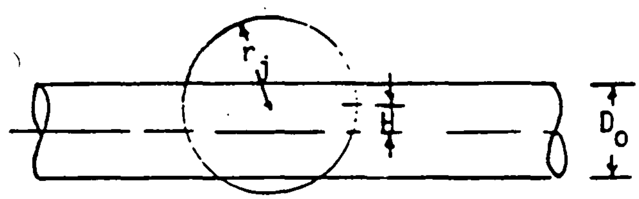


Figure G

$$A_t = \pi r_j^2 + r_j r(\sin \beta_2) + r_j H(\sin \beta_1 - \sin \beta_2) - r_j^2(\beta_1 + \beta_2) \tag{4-13}$$

where :

r_j = radius of the jet at the impingement

r = radius of the target pipe

H = distance between the jet centerline and the axis of the pipe

$$\beta_1 = \cos^{-1} \frac{r + H}{r_j}$$

$$\beta_2 = \cos^{-1} \frac{r - H}{r_j}$$

Note that β_1 and β_2 should be expressed in radians.

Case C   If the jet is partly intercepted and the target cross-section is partly submerged in the jet, Fig. H, then,

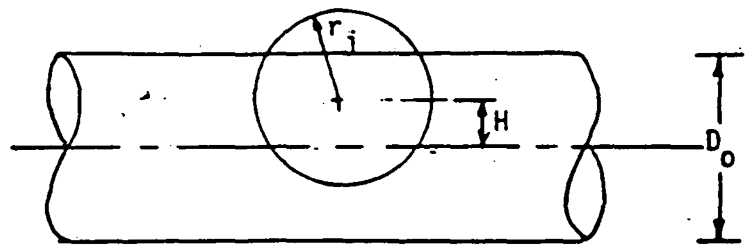


Figure H

$$A_t = (\pi - \beta)\, r_j^2 + r_j(r - H) \sin \beta \qquad (4\text{-}14)$$

where: $\beta = \cos^{-1} (r - H)/r_j$ and r, r_j and H are as defined before.
(Note: β should be expressed in radians)

Case D   If the jet impinging on the target has constant width, Fig. I, then,

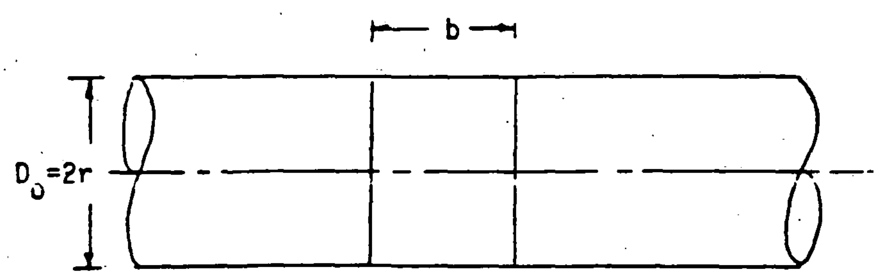


Figure I

$$A_t = 2rb \qquad (4\text{-}15)$$

where: b = width of the target area.

The diameter of the jet, D_j at the impingement plane can be computed as:

$$D_j = D + 2L\tan\emptyset \tag{4-16}$$

where: D = inside diameter of the pipe

L = distance of the impingement plane from the jet opening

$\emptyset$ = expansion angle of the jet (=10°)

4.2 Containment Analysis Criteria

The integrity of the drywell liner must be maintained as a result of either pipe whip or jet impingement loading conditions. Test results performed by Chicago Bridge & Iron Company (Reference 4) indicate that when the drywell liner is loaded over a large enough area, deformation of over three inches can occur without failure of the liner plate. Based on these test results, it has been concluded that for breaks occurring in piping greater than 14 inches in diameter, even if contact occurred with the drywell liner, the liner could deform without failure until deformation was limited by the concrete shield wall. No unacceptable interactions are considered to result with the drywell as a consequence of breaks postulated in piping greater than 14 inches in diameter.

The effects of postulated break locations in lines greater than 14 inches in diameter have been reviewed. Eleven break locations were identified as having interactions with the containment liner. Scaled drawings depicting the movement of the whipping pipe into the containment liner have been prepared. The velocity component normal to the liner at impact is in the range of 10 to 236 feet per second for the above eleven interactions. The lower bound of the normal velocity range results from postulated pipe break locations in lines which have a relatively small gap initially between the piping and the liner with the result that the velocity buildup prior to impact is relatively low.

References 5 and 6 present empirical formulations and test results of missile impact on steel plates. One of the test configurations included a Schedule 40, 12-inch diameter steel pipe weighing 743 lbs. impacting the target panel (3/4 inch thick) end-on at 210 feet per second. In the region of plate impact, the rectangular area unsupported by stiffeners was approximately 3'-6" by 6'-1". Although the test configuration appears to be stiffer than the free standing drywell liner at Dresden 2, the test target place displacement was greater than 3 inches. As the drywell liner at Dresden 2 is backed up by concrete after a 3 inch displacement of the liner, the pipe test results can be considered to be an upper bound on postulated pipe whip impact on the Dresden 2 liner.

The test velocity of the 12 inch pipe at impact was 210 feet per second. A review of the normal velocities for the eleven postulated pipe whip/liner interactions indicates that ten of the interactions have velocities 114 feet per second or less. The only interaction which is greater than the test velocity of 210 feet per second is for a postulated break location in the feedwater line. The feedwater line appears to make contact with the liner at an 18" x 12" reducer in the feedwater line, and the impact for this interaction is considered not to be as severe as the 12 inch pipe end-on impact in Reference 6.

The acceptability of pipe whip effects on the containment liner resulting from breaks ranging in size from 2 to 14 inches in diameter was determined using the approach outlined in Reference 6. It has been conservatively assumed that 80 percent penetration through the drywell liner thickness constitutes liner failure. A plot of kinetic energy as a function of pipe diameter is shown in Figure 4-4. A comparison of the actual impact energy of a whipping pipe with the energy capacity shown in Figure 4-4 is used for evaluating the pipe whip effects on the liner. If the calculated impact energy is less than the energy capacity, the interaction is acceptable.

The modified SRI formula, as presented in References 5 & 6, is used in determining the energy absorption capacity of the containment liner. The formula is given below:

$$\frac{\Delta E}{K_t \sigma_u D T^2} = 4.128 + 0.0967 \frac{W_e}{T} \qquad \text{(Eq. 4-17)}$$

where: $\Delta E = E_1 = E_r$ = Kinetic energy required for perforation.

E_1 = Initial kinetic energy of the missile.

E_r = Residual kinetic energy of the missile after penetration (0 in our usage).

K_t = Target energy absorption capacity reduction factor with respect to its ductile fracture temperature - 1.0 at room temperature.

σ_u = Ultimate tensile strength of the target material (70,000 psi for containment liner).

D = Outer diameter of missile.

T = Target plate thickness

$W_e = \frac{1}{4}(r_1 + r_2 + r_3 + r_4)C$ = Effective window size.

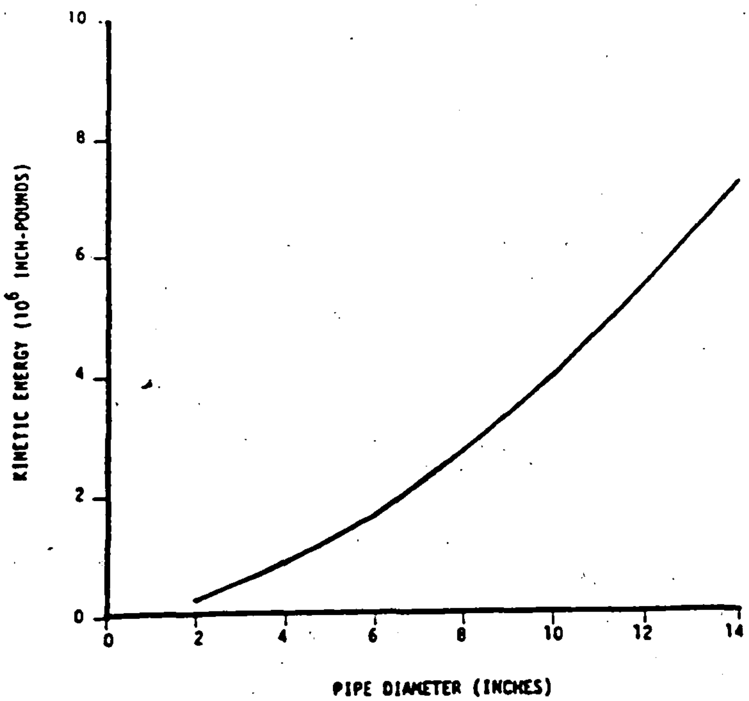


FIGURE 4-4. ENERGY ABSORPTION CAPACITY OF CONTAINMENT LINER (BASED ON 80 PERCENT PENETRATION)

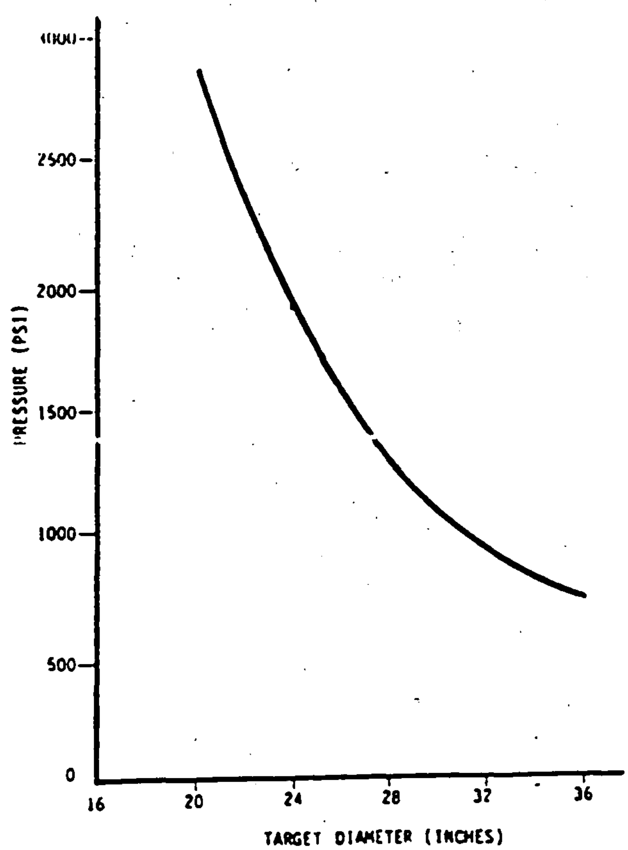


FIGURE 4-5. INTERACTION EVALUATION CURVE

r_i = Effective crater radius measured from the center of impact along one of the four approximately orthogonal directions; i - 1, 2, 3, 4.

r_c = Full effective crater radius, = 3.6 D if no edge or stiffener is less than this distance from center of impact.

$$C = 1/3 \{4 - (\frac{T}{T_o})^2\} \quad \frac{T_o}{T} = 1.0 \text{ if } T = T_o$$

T_o = Actual or calculated thickness for which the missile is just stopped, i.e., E_r = 0 (incipient perforation).

This formula was used to calculate the energy absorption capacity of the containment liner for 80% penetration. A plot of the energy capacity for pipe diameters of 2" to 14" is presented as Figure 4-4.

Finite element analyses using the ANSYS computer program were used to evaluate the jet impingement effects on the drywell liner. Analyses corresponding to jet impingement loading areas with diameters of 4, 12, 24 and 36 inches were performed.

In order to arrive at a conservative analysis, the following assumptions were made:

- The thickness of the liner is 3/4" throughout
- The loading area is circular
- The impingement pressure is uniform over the loading area and is normal to the surface
- The inner surface temperature of the liner in the impingement area is uniform and is equal to 575°F.
- The inner surface temperature outside the impingement area is 165°F.
- The outer surface temperature of the drywell is 100°F.

This study was intended to determine the maximum allowable pressure loading on the liner. The pressure loading on the liner was increased until one of the following conditions was reached:

1. The maximum deflection of the liner is three inches.
2. The maximum strain in the liner is one-half the ultimate strain of the liner material.
3. The maximum pressure reached is 2500 psi which is considered to be an upper bound from jet impingement loading on the liner.

The results of the finite element analyses are presented in Figure 4-5. If the actual jet impingement pressure and associated impingement area diameter result in a data point that falls below the curve in Figure 4-5, the interaction is considered to be acceptable.

The use of 2500 psi as an upper bound in the nonlinear finite element analysis is based on engineering judgment in order to limit excessive computational expense. An examination of Figure 4-5 indicates that even for a circular loading area equivalent to 20 inches in diameter the curve is already tending toward being asymptotic at a pressure of 2800 psi. The analysis was performed for circular loading areas as small as 4 inches in diameter in order to cover a full spectrum of target areas. The 2500 psi calculational limit does not imply that actual jet impingement pressures are limited to this value.

The mathematical model (shown in Fig. 4-6) represents a segment of the spherical portion of the containment liner. The center of the loading area is located at the center of the plate. The edges are assumed to be fixed. The dimensions of the model are chosen such that the boundaries are sufficiently far away from the edge of the loading area. Based on small deflection theory, Reference 7 gives the following formula for calculating the minimum distance of the boundary from the edge of the load, for neglecting the boundary conditions.

$$a = R \, \mathrm{Sin}^{-1} \left(1.65 \sqrt{t/R}\right) \qquad \text{(Eq. 4-18)}$$

where R = Radius of curvature of the spherical shell

t = thickness of the shell

For $R = 396"$ and $t = 3/4"$,

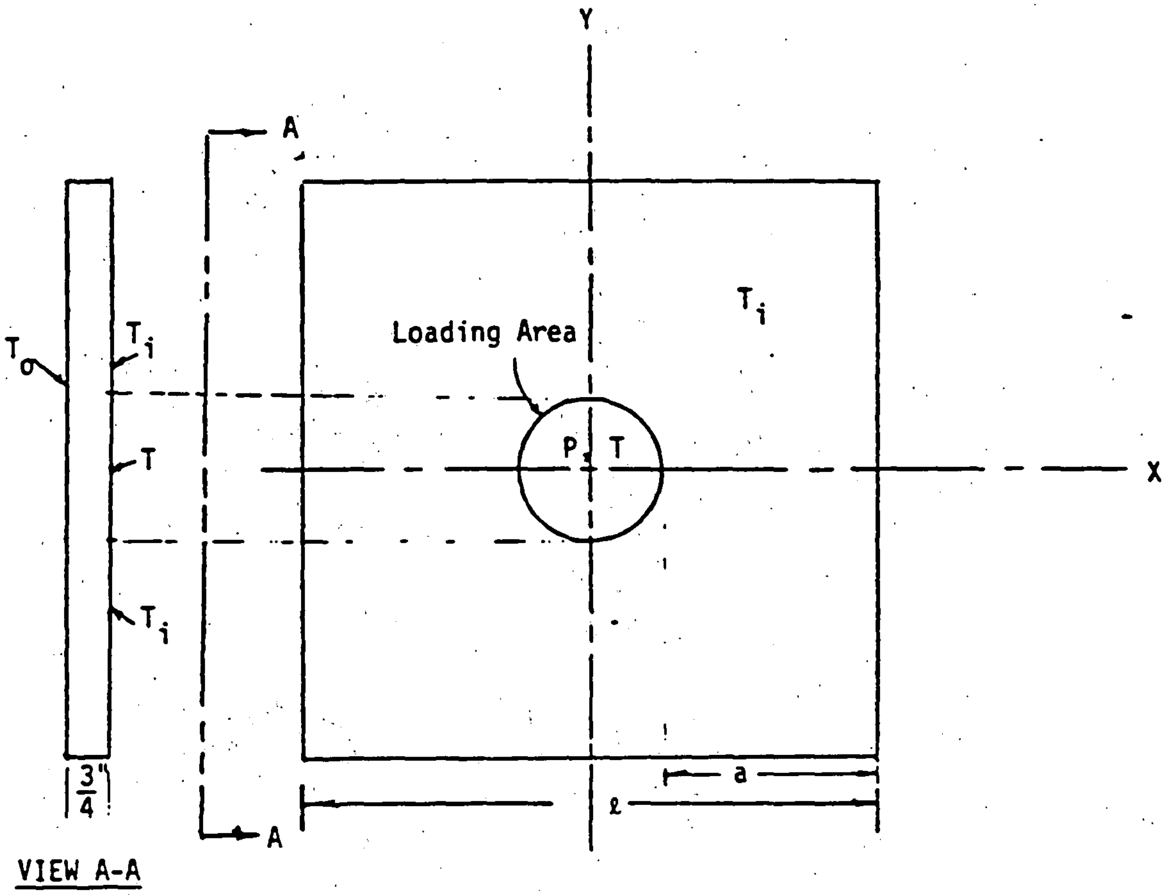
$a = 28.46"$

for boundary condition effects to be small.

The value of a as calculated from Equation 4-18 is used to determine the size of the generic model.

For the loading areas corresponding to 4", 12", 24" and 36" diameters considered here, the dimensions of the plate used in the finite element model are as follows:

Loading area diameter (inches)	Size of the model (1 in x 1 in)
4	72 x 72
12	96 x 96
24	144 x 144
36	144 x 144



T = Temperature inside impingement area

T_i = Temperature outside impingement area

T_o = Temperature outside drywell

P = Pressure

FIGURE 4-6. MATHEMATICAL MODEL OF THE CONTAINMENT LINER - EVALUATION OF JET IMPINGEMENT EFFECTS

Since the structure, the loading, and the boundary conditions are symmetrical about both x-axis and y-axis (Figure 4-6), symmetrical distribution of the stresses and deflections is expected about x and y-axes. Hence, for the ANSYS finite element analysis, only one-quarter portion of the model located in the first quadrant is considered (Figures 4-7 through 4-10). The following boundary conditions are assumed in the ANSYS model:

- The displacement parallel to y-axis, ie., U_y is zero along the boundary y = 0.
- The slope, $\theta_x = \frac{\partial U_2}{\partial y}$ is zero at the boundary, y = 0.
- The displacement parallel to x-axis, U_x is zero along the boundary x = 0.
- The slope, $\theta_y = \frac{\partial U_z}{\partial_x}$ is zero along x = 0.
- The liner is fixed at the remaining two boundaries.

The plastic triangle shell element (STIF 48) in the ANSYS element library has been used in the finite element model of the liner. By using this element, both the membrane stiffness and the bending stiffness in the liner are considered in the analysis. In addition, this element is suitable for analyzing the structure in the plastic domain.

The following loading conditions on the liner were considered in the analysis:

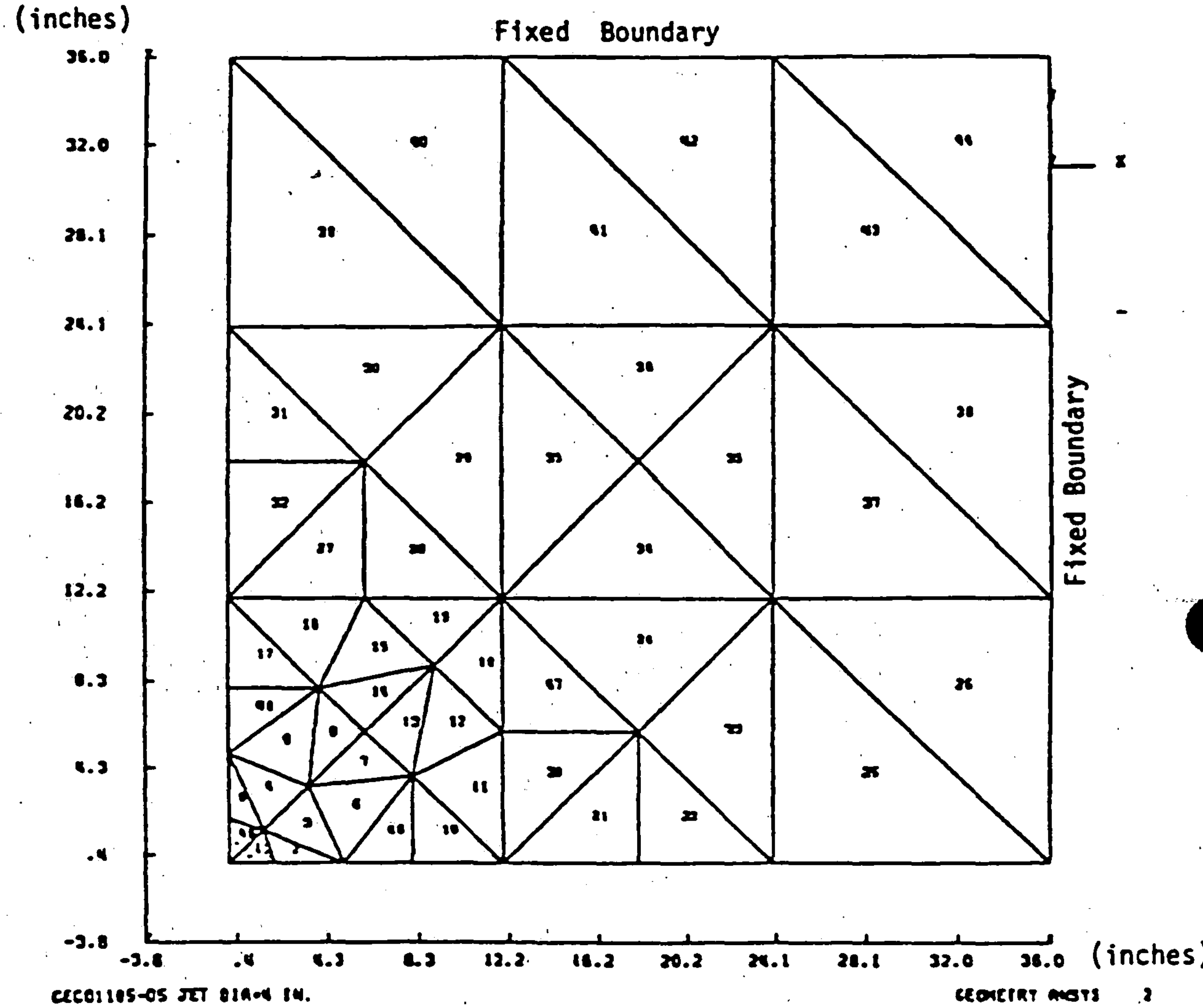
A. Thermal Loads:

In the jet impingement area, the temperature of the liner surface is 575°F. Outside the impingement area, the liner surface is at 165°F. The temperature on the outside surface of the drywell is 100°F.

B. Pressure Loading:

A uniform pressure loading is applied in the jet impingement area. The magnitude of the pressure is gradually increased in steps until either the pressure reached 2500 psi (calculational limit), or the deflection of the liner is about 3".

From ANSYS computer runs, the maximum allowable pressure loadings on the liner for 4", 12", 24" and 36" diameter loading areas were determined. For loading areas corresponding to other diameters, the allowable pressures were computed by interpolation.



L = Elements in the loading area

FIGURE 4-7: FINITE ELEMENT MODEL OF THE LINER FOR 4 IN. DIAMETER LOADING AREA

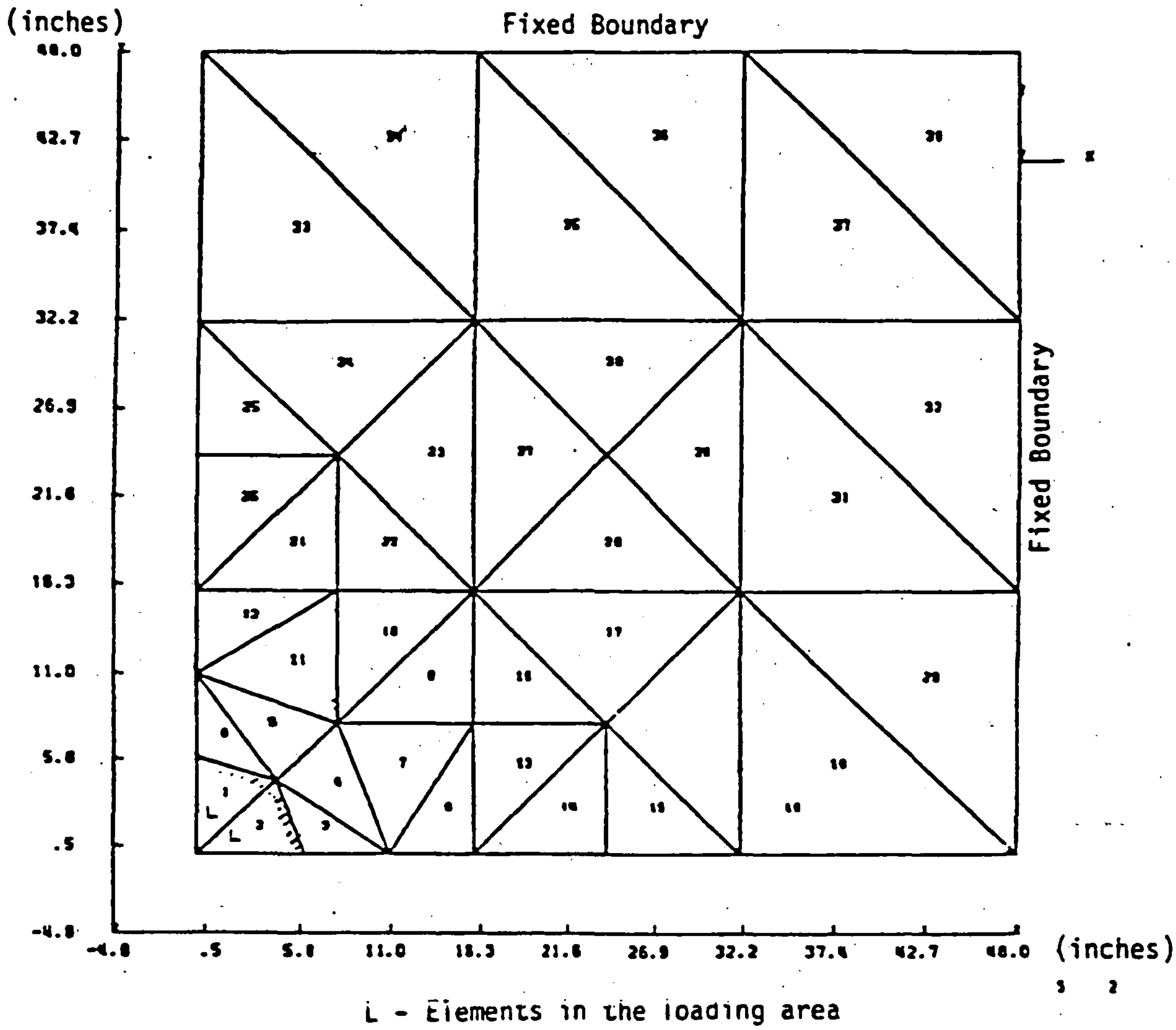
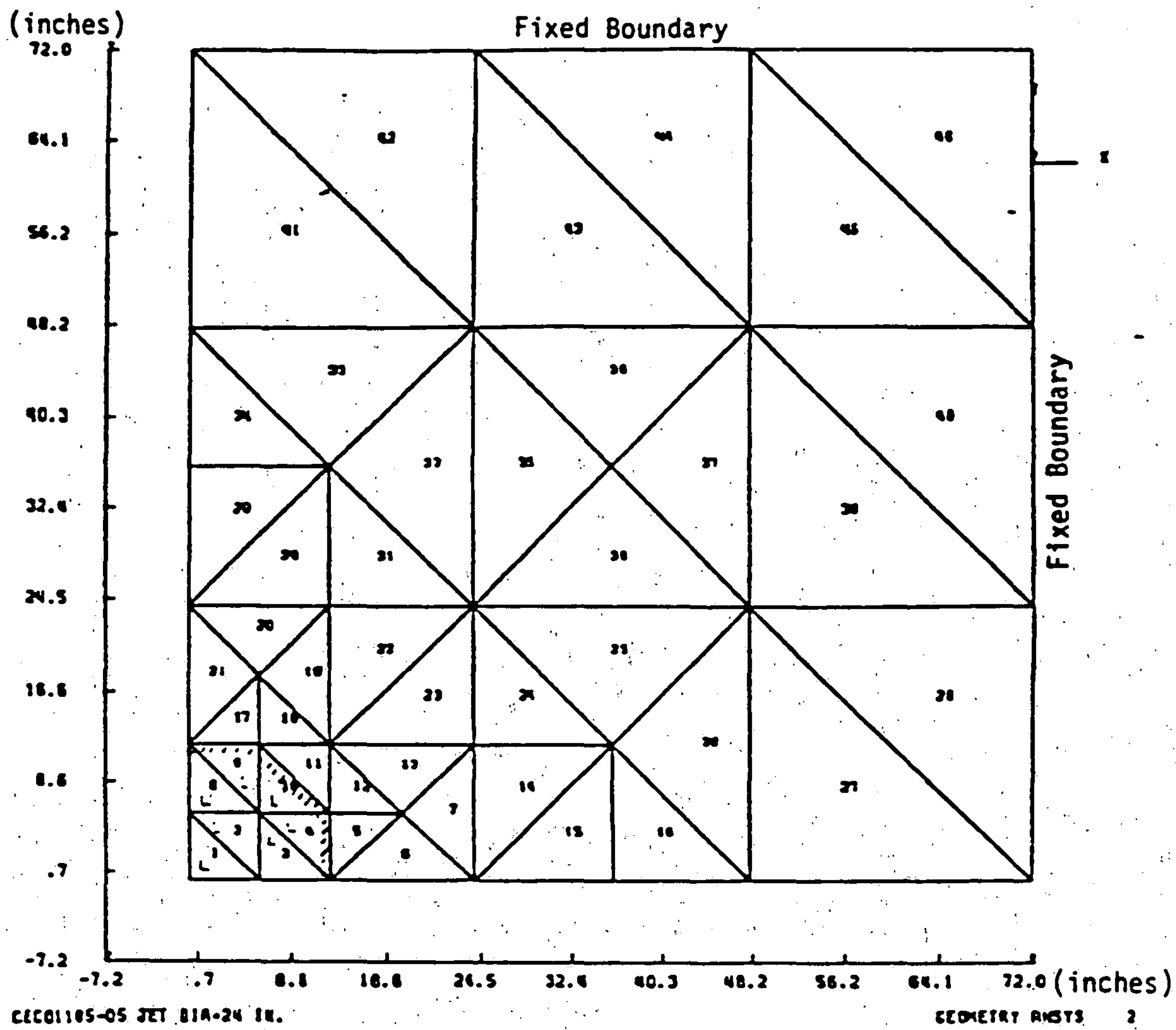
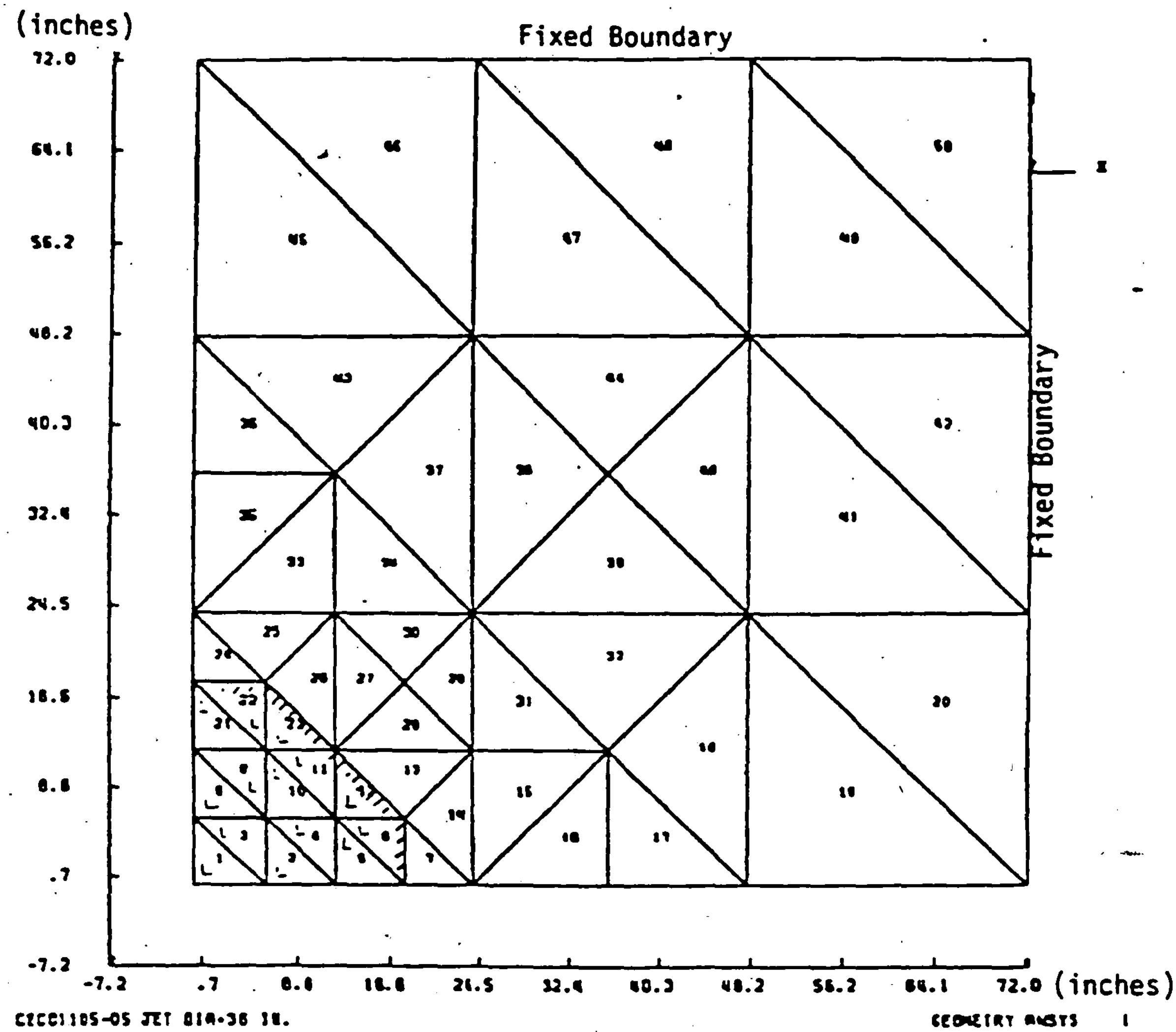


FIGURE 4-8: FINITE ELEMENT MODEL OF THE LINER FOR 12 IN. DIAMETER LOADING AREA



L - Elements in the loading area

FIGURE 4-9: FINITE ELEMENT MODEL OF THE LINER FOR 24 IN. DIAMETER LOADING AREA



L - Elements in the loading area

FIGURE 4-10: FINITE ELEMENT MODEL OF THE LINER

FOR 36 IN. DIAMETER LOADING AREA

4.3 Target Pipe Analysis Criteria

4.3.1 Analytical Procedure

Each target pipe is analyzed as a beam with variable end conditions to determine the deflection, plastic hinge formation, and tensile stress resulting from a load at the postulated target point. It is assumed that plastic hinges form successively at all points of maximum resisting moments under appropriate support conditions. Once all plastic hinges are formed and moments are eliminated, it is assumed that additional strain will occur until the total strain reaches the allowable strain limit. The load applied on the given beam configuration that creates this limit strain combination is calculated and designated as the limiting load (W). The load (W) is then compared to the previously calculated applied load (F) resulting from pipe whip or jet impingement.

The beam configuration for which the limiting load is derived is a straight beam fixed at one end and spring-supported at the other. The spring stiffness may be varied from $k=0$ (cantilever) to $k=\infty$ (fixed-simple support). A simplified expression for the deflection required to determine the limiting load is presented for the special case of $k=\infty$. Given an actual target pipe configuration, simplifying assumptions are made to determine the spring stiffness to represent the remaining segment of piping, as well as the span length of target pipe to be analyzed.

4.3.2 Stress Criteria

The first consideration of the criteria is to avoid cascading pipe breaks. The criteria are established to prevent the rupture of the target pipe. The limiting loads derived in Section 4.3.3, expressed in terms of pipe material properties, pipe geometry, and point of load application, ensure that the strain limits specified below are not exceeded and the potential for rupture of the target pipe is eliminated.

The limiting factor for an applied equivalent static load (F), is the resulting strain in the target pipe material. This strain is not to exceed 45 percent of the minimum ultimate uniform strain of the material at the appropriate temperature. The ultimate strain value is based on test data under slowly applied loads. The allowable strain limit is based on correlations between the results from this simplified procedure and the results obtained from finite element analyses using the ANSYS computer program.

4.3.3 Determination of Limit Loads

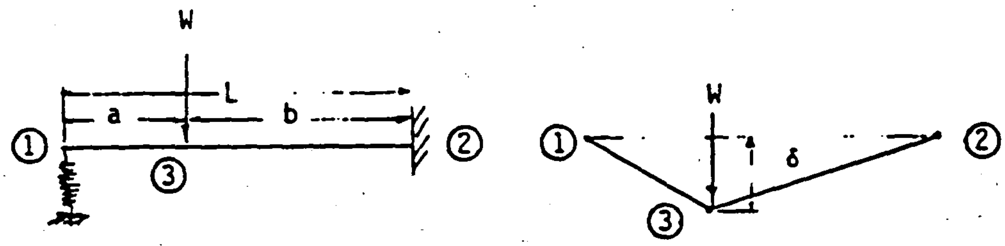
In order to evaluate the acceptability of certain target pipe interactions, limit loads are established. However, pipe whip induced interactions which meet the conditions of Equation 4-19 are immediately judged to be acceptable and the applied load and limit load calculation and comparison need not be performed. The requirements for these interactions are as follows:

$$d_T \geq d_W \quad \text{and} \quad t_T \geq t_W \tag{4-19}$$

where:

d_T = diameter of target pipe
d_W = diameter of whipping pipe
t_T = wall thickness of target pipe
t_W = wall thickness of whipping pipe

For pipe whip load interactions which do not satisfy Equation 4-19, the following procedure for evaluating acceptability applies. Strain is induced in the target pipe during the formation of the successive plastic hinges required to produce the failure mechanism. Additional elastic strain may occur after the hinges have formed and the beam behaves as a truss. The figure below depicts the original target configuration, as well as the truss resulting from the formation of plastic hinges at points ② and ③ .



Original Configuration — After Hinge Formation

The expression for the tension in the two truss segments is:

$$T = W \left[\frac{a^2 b + a\delta^2 + \delta^2 (a+b)}{\delta(a+b)\ (a^2 + \delta^2)^{\frac{1}{2}}} \right] \tag{4-20}$$

where:
W = load on target
a,b = dimensions as shown
δ = deflection under load at collapse

Comparing the total strain to the strain limit previously established gives:

$$\frac{T}{AE_1} + \frac{M_y}{SE_1} + \frac{(M_y - M_p)}{Z\ E_2} \leqslant .45\ \dot{\varepsilon}_{uu} \tag{4-21}$$

where:
ε_{uu} = minimum ultimate uniform strength
Z = plastic modulus
E_1 = elastic modulus
E_2 = slope of line connecting yield point to point of ultimate uniform strain on stress strain curve.
M_y, M_p = elastic, plastic moments, respectively

The limit load W is found by substituting the expression for T from Equation 4-20 into 4-21, and rearranging terms,

$$W = \frac{\delta A E_1 \ (a+b) \ (b^2+\delta^2)^{1/2}}{ab^2 + b\delta^2 + \delta^2 \ (a+b)} \left[.45\varepsilon_{uu} - \frac{M_y}{SE_1} - \frac{(M_p - M_y)}{ZE_2} \right] \qquad (4\text{-}22)$$

To solve Equation 4-22 explicitly for (W), the value of δ must be established. The two possible sequences of hinge formation include hinge formation first at the point of load (3), or hinge formation first at the fixed end (point 2).

Conservative expressions for the deflection δ have been derived for the above two possible sequences, and the lower value of δ is conservatively used. Equation 4-23 for hinge formation first at point of load, yields conservative results and is generally used. However, for springs with low or zero-stiffness (i.e., cantilever), Equation 4-24 is used for determining δ. Simplified expressions for δ have been derived for the special case when $k=\infty$ (simple support).

FIRST HINGE AT POINT OF LOAD:

$$\delta = \frac{M_p \ (3EI + kL^3)}{6EI \ a \ k} \left[\frac{4b}{(3a+2b)} - \frac{k(2L^3 - 3L^2 \ a + a^3)}{3EI + k \ L^3} \right] \qquad (4\text{-}23)$$

Special Case of Fixed-Simple Support:

$$\delta = \frac{M_p ab}{6EI} \left[\frac{4a + 3b}{3a + 2b} \right] \qquad (4\text{-}24)$$

FIRST HINGE AT FIXED END:

$$\delta = \frac{M_p(2a + b)}{abL} \left[\frac{a^2 b^2}{3EI} + \frac{b^2}{kL} \right] - \frac{M_p}{L} \left[\frac{(L^2 a - a^3)}{6EI} + \frac{b}{kL} \right] \qquad (4\text{-}25)$$

Special Case of Fixed-Simple Support:

$$\delta = \frac{M_p ab}{6EIL} \ (2a + b) \qquad (4\text{-}26)$$

The value of (W) calculated from Equation 4-22 is compared to the actual applied jet or pipe whip loads (F). The interaction is judged to be:

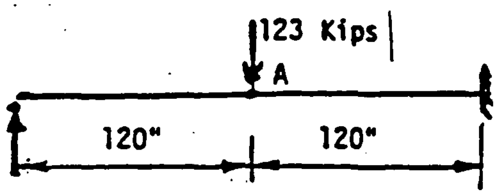
Acceptable, if $W \geq F$

Unacceptable, if $W < F$.

Jet impingement evaluations were performed for all ratios of whipping pipe to target pipe diameters.

Plastic hinge formation of the target pipe is of a localized nature and the zone of plasticity is limited to the region of the hinge location. It is therefore possible to achieve strain levels approaching 45 percent of the minimum uniform ultimate strain of the material in a localized region without affecting significantly the overall deformation or functionality of the target pipe.

A parametric study covering a range of geometric and load parameters was performed using the ANSYS finite element program. The nonlinear dynamic analysis results indicated the coexistence of large localized strain levels and small global deformations. The above conclusion is illustrated by the following numerical results from the ANSYS computer program:



Target pipe properties used were as follows:

Pipe = 16 inch diameter - Schedule 40
Wall Thickness = 0.5 inches
σ_y = 35,000 psi

The plastic hinge which formed at point A (point of load application) reached a strain level of approximately 3% of the uniform ultimate strain of the material at time t = 0.088 seconds. The downward displacement of point A was 1.814 inches with an angle of rotation at the support of 0.866 degrees.

A more detailed shell model of the above target pipe was analyzed using ANSYS to further substantiate the conclusions drawn. The realistic assumption of internal pressurization of the target was introduced, and by virtue of using a shell model, the phenomenon of crushing in both the target and whipping pipes was accounted for.

At time t = 0.088 seconds, the shell model reached an equivalent strain of approximately 21% of the ultimate uniform strain. The corresponding meridional strain at this time was approximately 14% of ultimate uniform strain. The downward deflection of the center of the target pipe at midspan was 4.503 inches, with an angle of rotation at the support of approximately 2.15 degrees. At the termination of the analysis of the shell model at time t = 0.132 seconds, the maximum equivalent strain reached was 25% of the ultimate uniform strain.

Based upon the simplified formulation presented in Section 4.3.2, the subject target pipe experiencing 45% of ultimate strain would have a limit load w of 123^k. Neither the beam nor shell model of the target pipe reached 45% uniform ultimate strain under the applied load of 123^k. Consequently, the actual limit load for the problem is higher than 123^k, and Equation 4-22 is shown to predict a conservative value for the limit load.

The mathematical model of the target pipe and whipping pipe segment is shown in Figure 4-11. The target pipe is comprised of 480 ANSYS STIF 48 plastic triangular shell elements. Twelve elements are modeled around the circumference, and the meridional mesh is finest at the midspan where the load applied to the whipping pipe is transmitted to the target. A 6' long segment of an equally sized pipe (16" Ø, 0.5" thickness) is modeled as initially resting on the target. This shell is comprised of 192 ANSYS STIF 48 shell elements, and is oriented with its longitudinal axis perpendicular to the longitudinal axis of the target pipe, as shown in Figure 4-11.

The load is applied at two nodes on the top of the whipping pipe segment, and is transmitted to the target pipe through a grid of 25 STIF 40 combination elements. The STIF 40 spring-gap elements each act in the vertical (global y) direction and have an initial gap size associated with them. The specified gap sizes are based on the original y-coordinate differences between the connecting nodes on the target and whipping pipes. As the whipping pipe is loaded, it tends to flatten out at the bottom, causing the closure of certain gaps. When a gap closes, the STIF 40 element behaves like a rigid spring and transmits force to the attached node on the target pipe. As the target also begins to flatten and bend, more gaps may close, and others tend to open. Thus, the applied load of 123^k gets continuously redistributed over the target pipe.

An internal pressure of 1020 psi in the target pipe was assumed, and the same 123^k step forcing function as applied to the previously discussed beam model of the target pipe, was considered. The maximum load of 123^k was attained after a rise time of 8.5 milliseconds.

During the course of application of the load to the whipping pipe segment, displacements, stresses and strains in the target pipe were examined. The analysis continued until the strain rate in the most highly stressed region of the target pipe ("top" elements under the transmitted load) stabilizes. This occurred during the time from approximately 0.112 seconds to 0.132 seconds.

The maximum strain experienced by the target pipe was 5.6%, or approximately 25% of the minimum uniform ultimate strain of the material. Although plasticity had spread through much of the target pipe (most noticeably at midspan under the load and at the supported ends), the target cross-sections maintained their integrity, and sustained strains well below the ultimate strain level. A plot of strain vs. time for the most highly strained element is given in Figure 4-12.

The corresponding maximum deflection of the upper surface of the target pipe was 7.18" downward. Figure 4-13 shows the deflections vs. time for nodes at the top and bottom midspan cross-section of the target pipe.

The shell analysis shows that the functionality of the target pipe is not significantly affected. As Figure 4-14 illustrates, although the shape of the cross section was altered, the flow area decreased by approximately 8.7%.

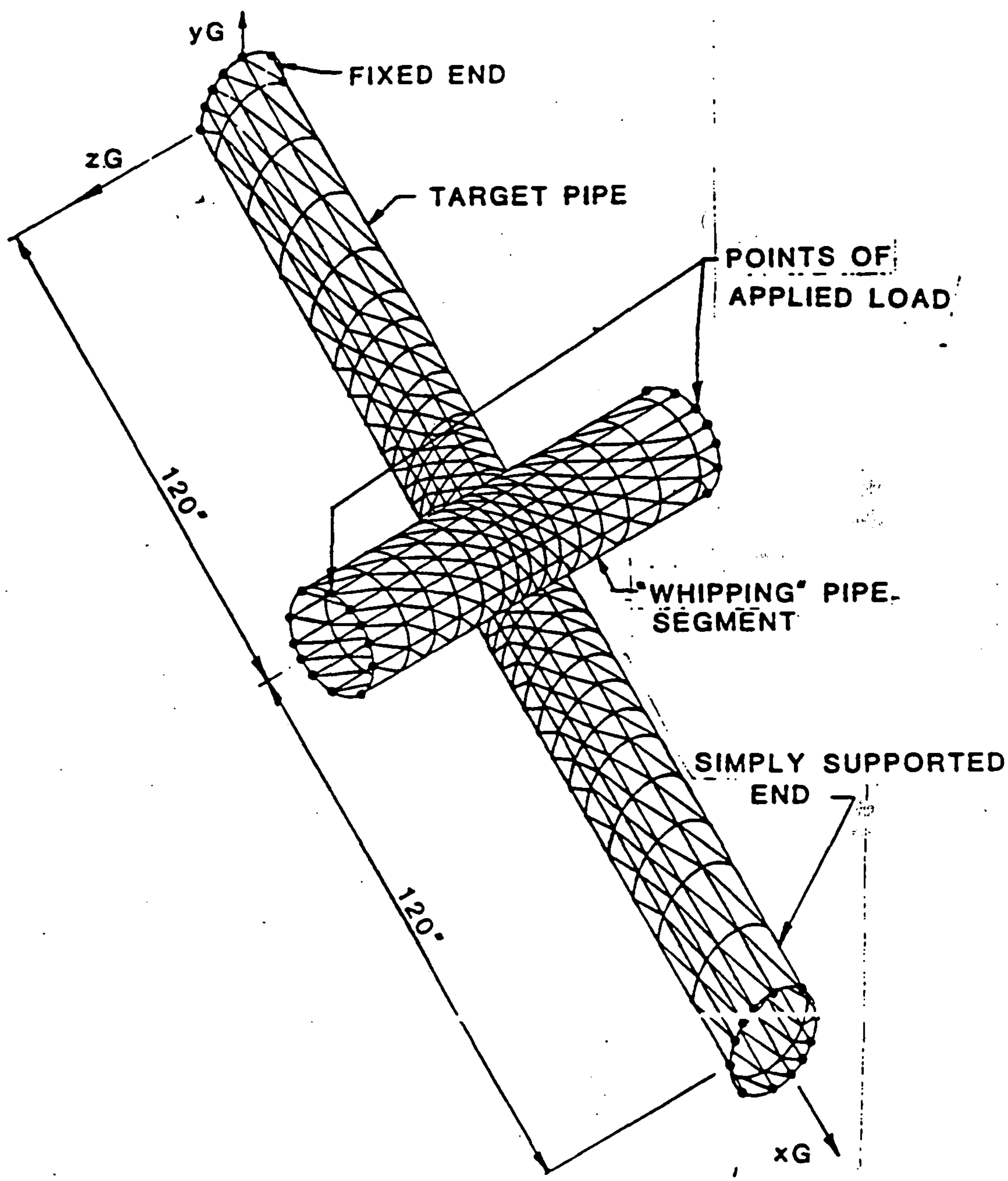


FIGURE: 4-11
MATHEMATICAL SHELL MODEL OF TARGET PIPE

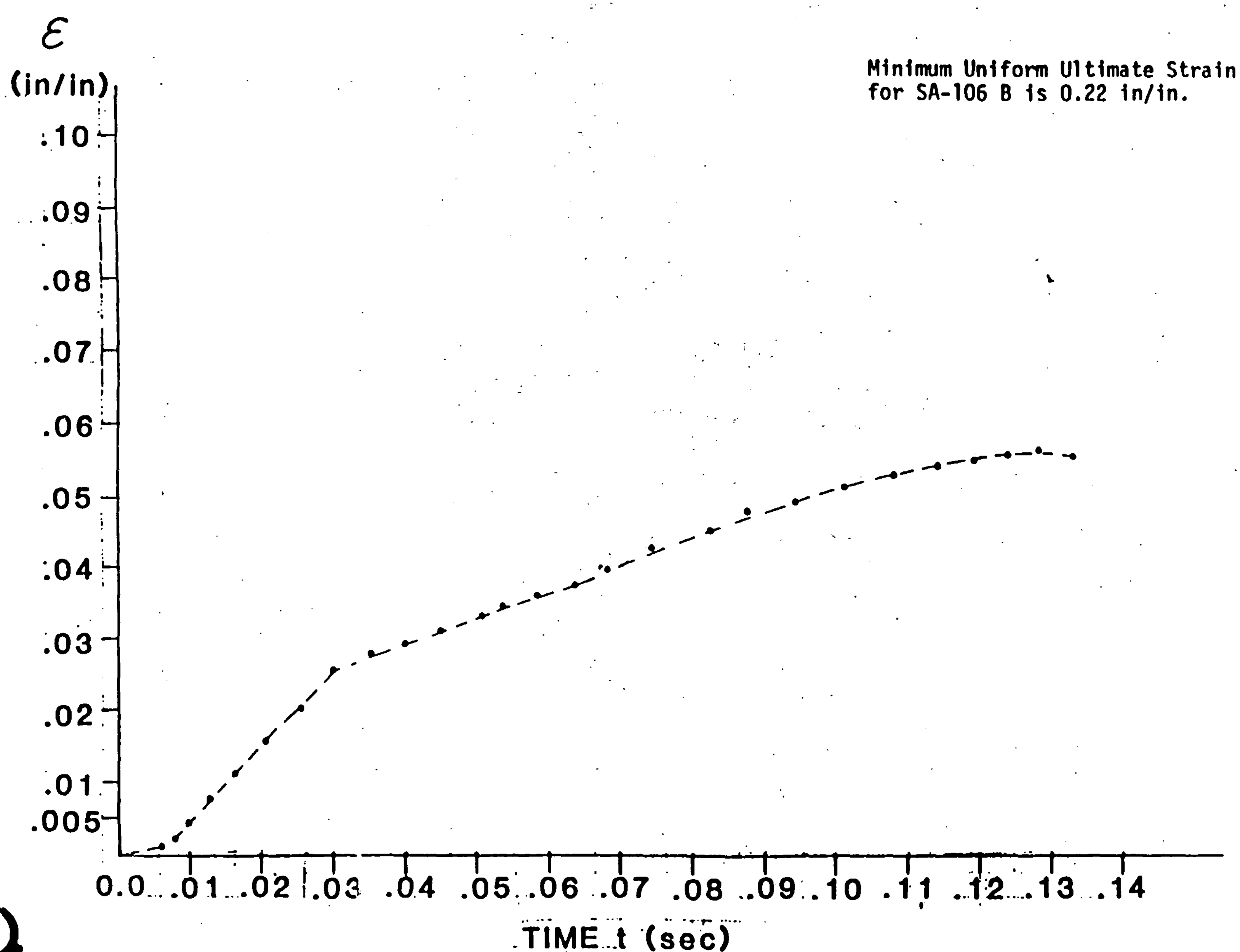
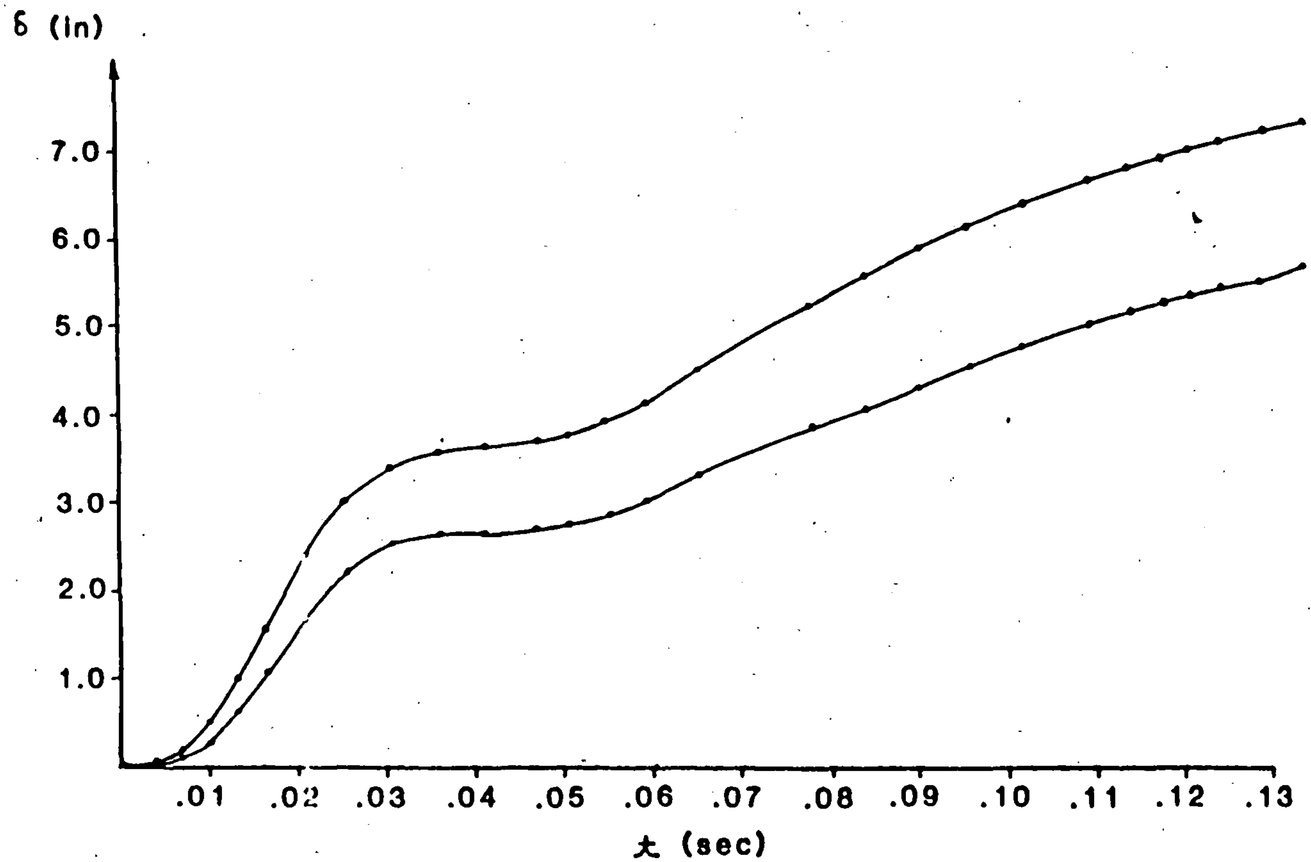


FIGURE: 4-12 STRAIN VS TIME (TARGET PIPE)

TARGET TECHNOLOGY LTD.



UPPER CURVE-VERTICAL DISPLACEMENTS OF NODE 97
(TOP OF TARGET PIPE UNDER LOAD)

LOWER CURVE-VERTICAL DISPLACEMENTS OF NODE 103
(BOTTOM OF TARGET PIPE UNDER LOAD)

FIGURE: 4-13 DISPLACEMENT VS TIME

As the whipping pipe segment became plastic, its lower surface tended to flatten out, as did the upper surface of the target pipe. As these two surfaces flattened out, an increasing number of connecting spring-gap elements closed and the load transmitted to the target pipe became distributed over a larger surface. Thus, as the time progressed, the flattening of the upper surface of the target became more pronounced. Figures 4-14 and 4-15 show the deformation of the midspan cross-sections of the target and whipping pipes, respectively, at the final step considered in the analysis. The final deformation of the upper and lower surfaces of the target is shown in Figure 4-16.

4.4 RPV Pedestal and Biological Shield Wall Analysis Criteria

The methodology used in arriving at evaluation criteria for postulated pipe break interactions with the RPV pedestal and the sacrificial shield was based on finite element analyses using the ANSYS computer program. Various magnitudes of pipe whip and jet impingement loads were applied to the above structural systems to establish the allowable load envelopes.

The evaluation curve for use in pipe whip interactions with the RPV pedestal is presented in Figure 4-17 where maximum allowable load "F_{eq}" is plotted as a function of the nominal pipe diameter. The evaluation curve for use in jet impingement interactions is given in Figure 4-18. The maximum allowable pressure is plotted as a function of the target diameter. Similar curves for the biological shield wall are presented in Figure 4-19 and 4-20.

Postulated break characteristics of pressure, pipe diameter, distance from target, angle of impingement and type of break are needed prior to using the evaluations curves. Pipe whip interactions are evaluated by determining the pipe diameter corresponding to the postulated break and comparing the maximum allowable load or kinetic energy level from Figures 4-17 and 4-19 to the actual pipe whip load results. All interactions resulting in a greater allowable load or allowable kinetic energy level are considered satisfactory and not requiring further investigation.

Similar evaluations are performed for jet impingement interactions where target areas are first computed and the corresponding allowable pressure from Figures 4-18 or 4-20 is compared to the actual load. All interactions permitting a greater pressure than existing in actuality are considered satisfactory. All interactions that fail either the pipe whip or jet impingement evaluation are investigated further using other available analytical/design approaches (see Figure 5-1, Nodes 9 through 16).

The methodology used in arriving at evaluation criteria for postulated pipe break interactions with the RPV pedestal is explained below. The criteria is basically intended to be in the form of curves relating the maximum static equivalent whip loads and jet impingement pressures to the various pipe diameters expected.

Various factors were considered in determining the location of the load. The horizontal load was applied on the outer surface of the pedestal at the location of the haunch in order to include the effects of geometrical discontinuity as well as to be conservative in most cases for overturning stability considerations. Three different loading diameters were considered, i.e., 36"Ø, 24"Ø, 12"Ø, along with vertical loads from the Biological Shield Wall and the Reactor Pressure Vessel.

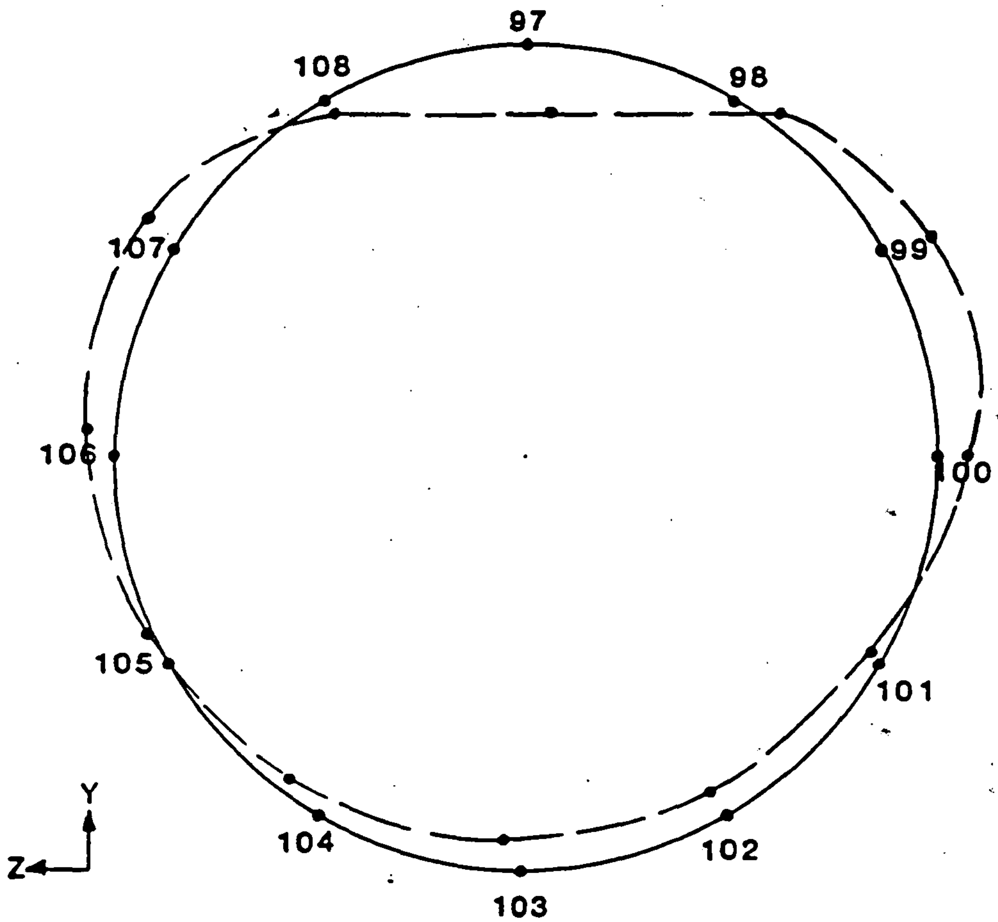


FIGURE: 4-14
MIDSPAN CROSS SECTION OF TARGET PIPE AT T=.132 SEC.

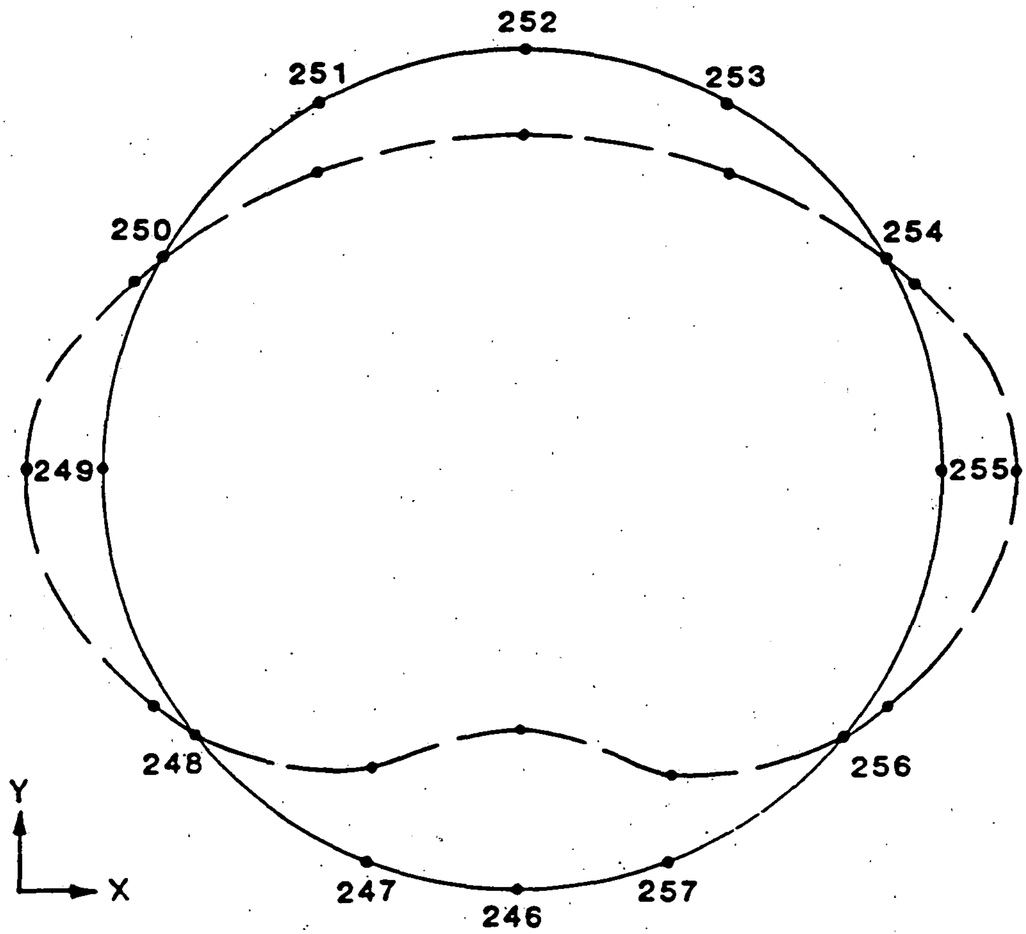
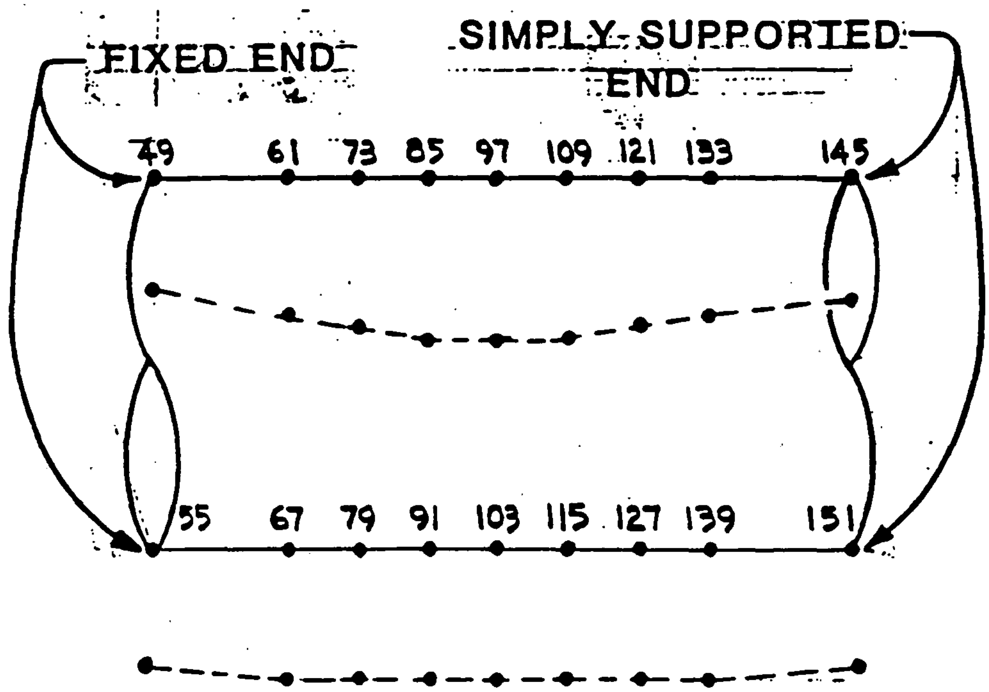


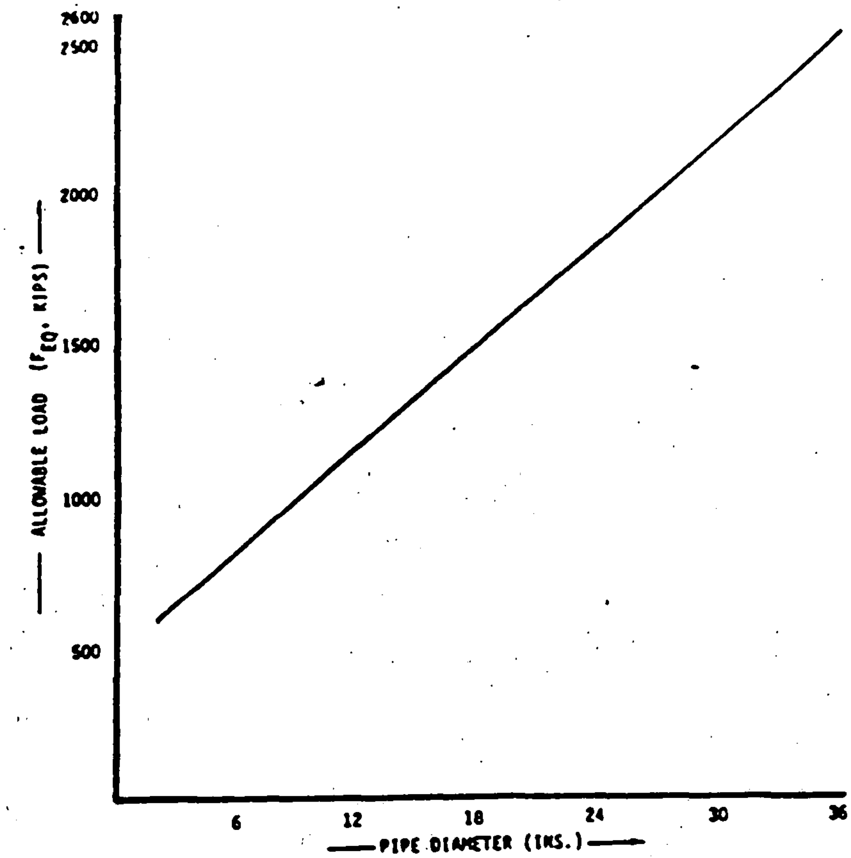
FIGURE: 4-15
MIDSPAN CROSS SECTION OF WHIPPING PIPE AT T=.132 SEC.



NOTE: The 2 solid lines showing node numbers represent the original position of upper and lower meridians.

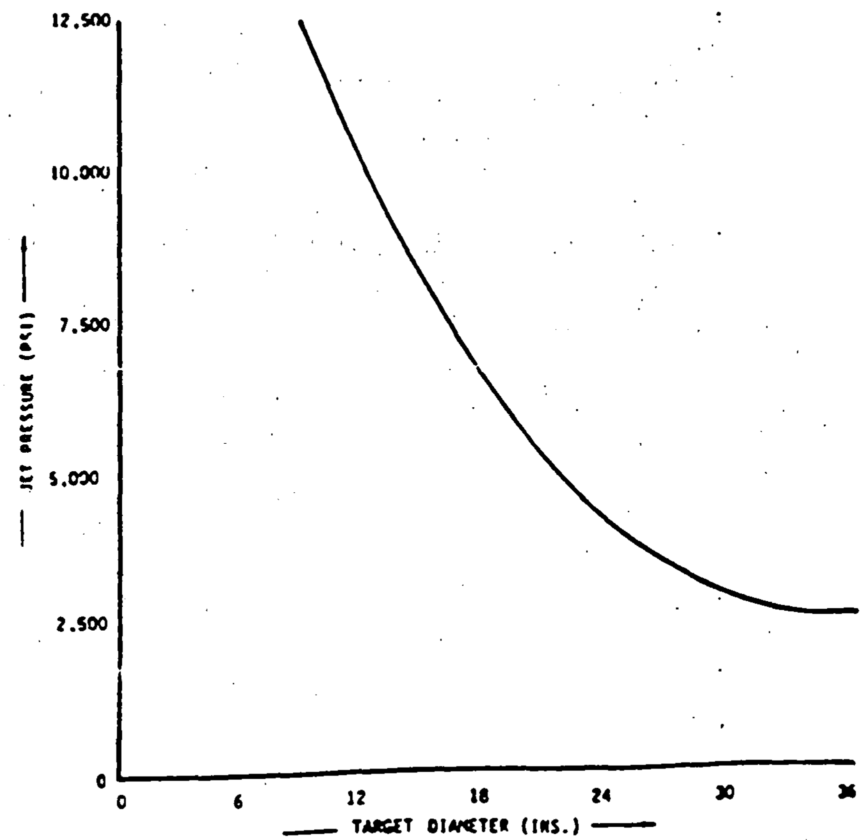
The 2 dotted lines represent the deflected shape of the upper and lower meridians.

FIGURE: 4-16
DISPLACEMENTS OF TARGET PIPE
UPPER AND LOWER SURFACE MERIDIANS
AT T= 132 SEC.



RPV PEDESTAL SCREENING CRITERIA-PIPE WHIP

Figure 4-17



RPV PEDESTAL SCREENING CRITERIA
JET IMPINGEMENT

Figure 4-18

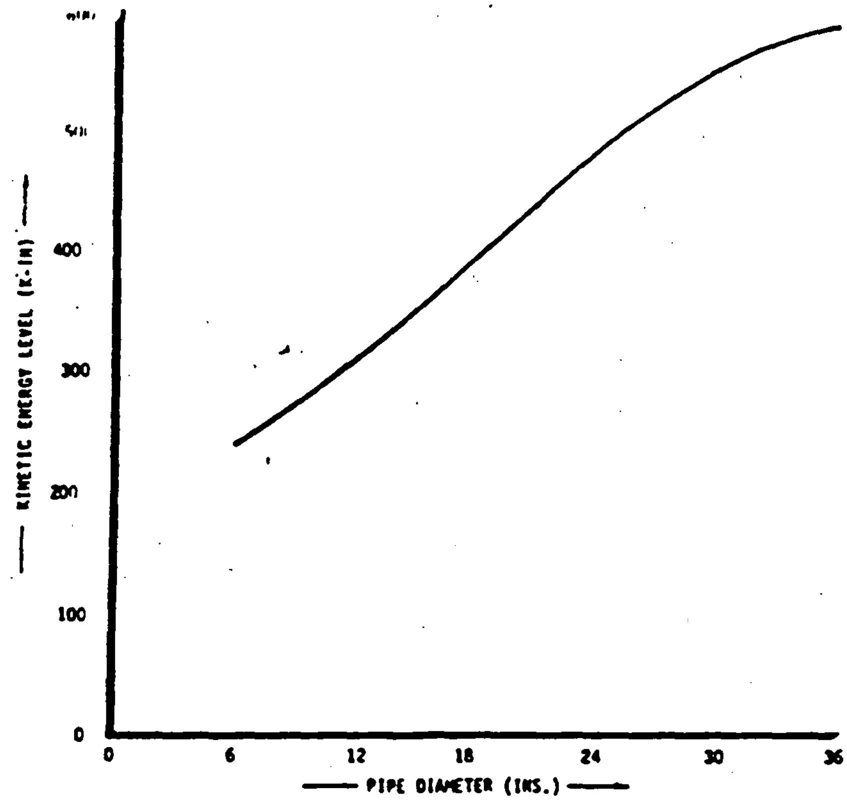


Figure 4-19.

BIOLOGICAL SHIELD WALL SCREENING CRITERIA
PIPE WHIP

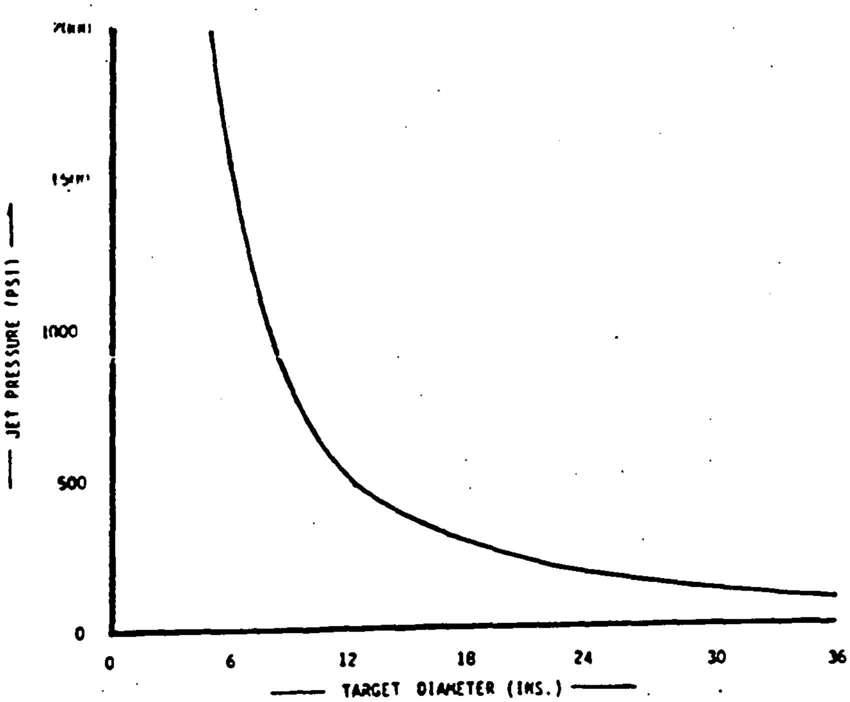


Figure 4-20.

BIOLOGICAL SHIELD WALL SCREENING CRITERIA
JET IMPINGEMENT

In conformance with the requirements for an initial screening criteria the following conservative assumptions were made:

- o All impulsive and impactive loads can be equated to an equivalent static force and the transient nature of the force does not result in adverse dynamic effects.

- o Due to the short duration of the jet impingement load the transient temperature effects on concrete can be neglected.

- o Pipe diameters less than 2½"Ø will not be considered to affect the RPV pedestal.

Bending stresses were based on the requirements of Chapter 10 of the ACI Code (Ref. 8). The pedestal wall was analyzed in both the hoop and meridional directions. Balanced section conditions were determined using the following equation (Ref. 9).

$$P_b = 0.85\, f_c'\ \beta_1 x_b b + A_s'\ (f_y - .85\, f_c') - A_s f_y$$

and $$M_b = 0.85\, f_c'\ b\beta_1\, x_b (d - 0.5\beta_1 x_b - d'')$$

$$+ A_s'\ (f_y - .85\, f_c')(d - d' - d'') + A_s f_y d''$$

where:

P_b, M_b = balanced section axial load and bending capacities

A_s = area of tension steel

A_s' = area of compression steel

d = section depth

b = section width

f_c' = compressive strength of concrete

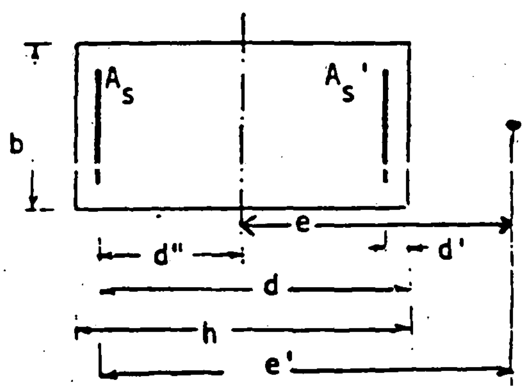
f_y = yield strength of steel

β_1 = .85

x_b = $\dfrac{87000d}{f_y + 87000}$

e' = eccentricity of axial load

Plastic Centroid



and the rest of the terms are shown in the sketch.

For a section whose capacity is controlled by compression the following equation was used to evaluate the axial load capacity:

$$P_n = bhf_c' \Big/ \left(\frac{3he}{d^2} + \frac{3(d - d')h}{2d^2}\right) + A_s' \, f_y \Big/ \left(\frac{e}{d-d'} + 0.5\right)$$

For a section whose capacity is controlled by tension the following equation was used to evaluate the axial load capacity:

$$P_n = 0.85 \, f_c' \, bd \left\{ -\rho + 1 - \frac{e'}{d} + \sqrt{\left(1 - \frac{e'}{d}\right)^2 + 2\rho \left[(m-1)\left(1 - \frac{d'}{d}\right) + \frac{e'}{d}\right]} \right\}$$

where

P_n = nominal axial load capacity

$\rho = A_s/bd$

and $m = f_y/.85 \, f_c'$

Shear strength was based on the requirements of Chapter 11 of ACI Code. Stresses were conservatively considered at a section a distance less than 'd' from the face of the load or reaction, where 'd' is the distance from the extreme compression fibre to the centroid of the tension steel. For sections under axial compression (hoop or meridional) the following equation was used to determine shear strength:

$$V_c = \left[1.9\sqrt{f_c'} + 2500 \, \rho_w \frac{V_u d}{M_m}\right] b_w d$$

where

$$M_m = M_u - \frac{N_u(4h - d)}{8}$$

V_c = Nominal shear strength provided by concrete

$\rho_w = A_s/bd$

V_u = Factored shear force at section

$b_w = b$ = section width

M_u = moment corresponding to V_u

and N_u = Factored axial load at section (+ve for compression -ve for tension)

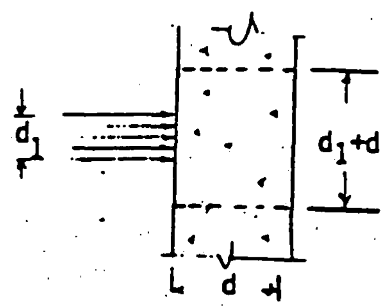
For cases where M_m was negative the following equation was used to determine V_c:

$$V_c = 3.5\sqrt{f_c'}\, b_w d \sqrt{1 + \frac{N_u}{500A_g}}$$

where

A_g = gross concrete area

Punching shear evaluation was also based on the requirements of Chapter 11 of ACI Code. The allowable load was calculated using the following formula:



$$P_n = 4\sqrt{f_c'} \quad \{\pi(d_1 + d)d\}$$

where P_n = nominal horizontal load

d_1 = diameter of loaded area

and d = depth of concrete section

Overturning stability was based on treating the pedestal as a hollow cylinder. A static analysis was performed to determine the maximum load that the pedestal cross section could allow before developing tension.

Cracked concrete section properties were computed for various cross-sections of the pedestal in both the hoop and meridional directions. These properties were utilized to determine equivalent Young's moduli in these directions.

The RPV pedestal was represented mathematically as an elastic shell. An ANSYS computer model using Element (STIF 25) was developed. The full Pedestal height was required in modelling based on the calculation for decay length from the following equation (Ref. 10):

$$L_c = \pi \left[\frac{a^2 h^2}{3(1 - \gamma_{xs}\gamma_{sx})} \; \frac{E_x}{E_s} \right]^{\frac{1}{4}}$$

where

L_c = required decay length

a = radius of cylinder

h = thickness of wall

γ_{xs}, γ_{sx} = poisson's ratio in meridional and hoop directions

E_x, E_s = Young's Modulus in meridional and hoop directions

Horizontal loads were applied on these models in the form of a harmonic series of the form:

$$f(\theta) = a_o \sum_{n+1}^{\infty} (a_n \cos n\theta + b_n \sin n\theta)$$

where

$$a_o = \frac{1}{2\pi} \int_{-\pi}^{\pi} f(\theta)\, d\theta$$

$$a_n = \frac{1}{\pi} \int_{\pi}^{\pi} f(\theta) \cos n\theta d\theta$$

b_n = 0 for an even function

The analytical result for the effects of pipe whip and jet impingement on the RPV pedestal were summarized and presented as Figures 4-17 and 4-18.

The biological shield wall's structural response to pipe whip and jet impingement loads were evaluated using finite element analysis. The magnitude of the applied loading corresponded to the range of expected pipe diameters or jet impingement target areas.

In conformance with the requirements for an initial screening criteria the following conservative assumptions are made:

- o All impulsive and impactive loads can be equated to an equivalent static force.

- o Due to the short duration of the jet impingement, only the loaded area experiences a thermal load, and variations of temperature through thickness and along the surface can be neglected.

- o Shielding concrete is capable of transmitting compressive loads from the loaded face to the rear face.

The shield wall was modelled as two thin cylindrical shells connected by axial springs which represented the shielding concrete. It was assumed that the concrete was not capable of transmitting vertical shears between the two plates and hence the choice of a spring-gap element.

The ANSYS elements chosen to model the shield wall are shown schematically in Figure 4-21. The elements were chosen from the ANSYS element library and a list of elements along with their salient features is given in Table 4-1.

Evaluations were based on the more conservative of the following criteria:

(1) An average deflection under the loaded area of 4".
(2) A maximum strain of up to 50 percent of ultimate strain.

An examination of the results indicated that the strains under applied loads were much lower than the limitation, and the deflection criteria governed in all cases. Overall stability computations were performed to determine the capacity of anchoring mechanisms at the bases into the RPV Pedestal.

The analytical results for the effects of pipe whip and jet impingement on the sacrificial shield wall are summarized and presented as Figures 4-19 and 4-20. These figures are used in screening interactions with the sacrificial shield wall as part of the Task 4 activity.

TARGET TECHNOLOGY LTD.

FIGURE 4-21- SCHEMATIC SKETCH OF ANSYS ELEMENTS

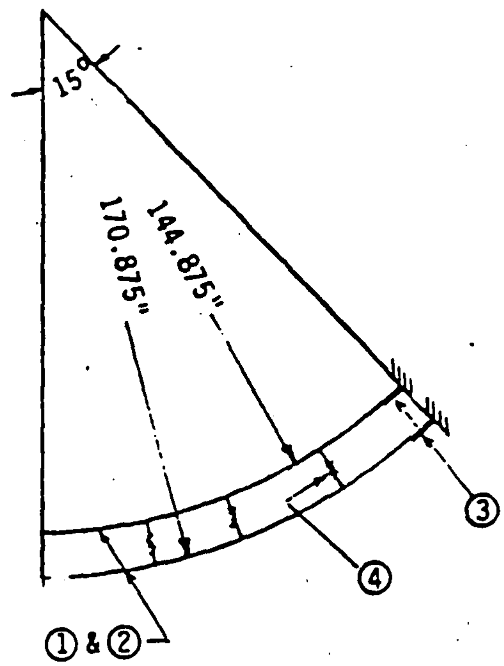


TABLE 4-1. ANSYS ELEMENTS FOR SHIELD WALL MODELLING

ELEMENT NO.	ANSYS ELEMENT NO.	DESCRIPTION	ANSYS FEATURES
1	STIF 43	1/4" plate, front & rear	Rectangular Shell Element. Capabilities in the Elastic range of material properties only. Six DOF's at each node.
2	STIF 48	1/4" plate, front & rear	Triangular Shell Element. Permits properties in the Plastic range. Six DOF's at each node. This element enables the use of nonlinear isotropic material.
3	STIF 43	Flange of W27x177	See Element No. 1
4	STIF 40	Concrete in compression only	Combination element with a gap. This element enables the use of only compression loading with no shear transfer, for modeling the concrete fill.

4.5 Damage Criteria

The following criteria are used to evaluate the significance of mechanical damage to piping, components, electrical power cables, and instrumentation as a result of pipe failure effects, including:

a. Impact of whipping pipe
b. Jet impingement

Exceptions to these criteria will be justified on a case-by-case basis.

1. All whip and jet interactions with the drywell liner, RPV pedestal and biological shield wall will be investigated to determine if the interactions are acceptable using the criteria presented in Sections 4.2 and 4.4.

2. The pressure integrity of piping is assumed to be maintained following pipe or jet impingement damage to a valve operator, provided criterion 3 is satisfied.

3. A whipping pipe will be assumed to inflict no damage on other pipes of equal or greater size and equal or greater thickness. All jets and whipping pipes impacting smaller or thinner pipes are to be evaluated using the criteria presented in Section 4.3.

4. For purposes of evaluating the mechanical integrity effects of the impact of a jet or whipping pipe on piping components, piping component pressure boundaries will be considered to be pipe of the same size and wall thickness as the main process piping to which the components are attached.

5. An active component or instrument will be assumed to be incapable of performing its active function following impact by a whipping pipe or immersion in a jet unless proved otherwise by detailed analysis.

6. Electrical and instrument cables will be assumed severed upon impact by a jet or whipping pipe, unless it can be demonstrated otherwise.

7. Where piping components are mechanically breached by a jet or a whipping pipe, the break size will be assumed to be equal to the largest cross-sectional area of any pipe directly connected to the upstream side of the piping component, or to a downstream side if applicable.

8. Valves in pipe lines which are allowed to whip are assumed to be inoperative. If the line is restrained to prevent accelerations or loads greater than the design values, the valve is assumed to be operable.

9. Valves which are normally closed and are not signalled to open, are not assumed to fail open. Valves normally open shall remain open during and after loss of power or impact.

10. Whipping pipes are not assumed to become missiles; i.e., the structural integrity of the pipe at the point where the plastic hinge forms remains intact.

11. Pipe anchors are considered to be capable of continuing to perform their intended functions. Terminal end points which are outside the drywell boundary are evaluated only for their effects on the drywell boundary.

12. Minimum engineered safety features performance shall be provided for each type of break.

13. Pipe break effects shall not preclude the ability of instrumentation, electric power supplies and components, and controls to initiate, actuate, and complete a safety action. In this regard, a loss of redundancy is permissible but the loss of function is not, considering a single active failure.

14. The effects of pipe break must not affect the capability of the plant to achieve and maintain a safe shutdown condition, assuming any single active failure or the loss of off-site power when a turbine trip is the direct consequence of a pipe rupture.

15. LOCA breaks (References 11 and 12) require:

a) -Full operability of the Automatic Depressurization System
-HPCI
-2 Core Spray
(Limiting single active failure is LPCI Injection Failure)

or

b) -Full operability of the Automatic Depressurization System
-HPCI
-1 Core Spray
-2 LPCI
(Limiting single active failure is Diesel Generator)

or

c) -Full operability of the Automatic Depressurization System
-2 Core Spray

-4 LPCI (cross-tie Unit 2 to Unit 3)
(Limiting single active failure is HPCI)

or

d) -80 percent operability of the Automatic Depressurization System
-HPCI
-2 Core Spray
-4 LPCI (cross-tie Unit 2 to Unit 3)
(Limiting single active failure is 1 ADS Valve)

16) Total break area cannot exceed 4.18 $ft.^2$

17) Active components, electrical cabling, and instrument wiring are assumed environmentally qualified for the worst case pipe rupture in accordance with the Dresden 2 safety analysis report, as supplemented by lists of environmental qualification information submitted to the NRC by Commonwealth Edison.

It should be noted that Section 4.0 was developed as a conservative screening criteria for application in the Task 4 activity. Interactions which are determined not to satisfy this conservative criteria are evaluated in Task 6 using sophisticated analytical methods as appropriate on a case-by-case basis.

5.0 INTERACTION EVALUATION (TASK 4)

5.1 High Energy Piping Systems

The primary objective of this task was to perform an interaction analysis using the criteria defined in Section 4.0 to evaluate pipe whip and jet impingement interactions with structural and mechanical components, for the design conditions given in Table 5-1. The end product was a set of interaction matrices which are presented in Appendix A. These matrices indicate the remaining unresolved pipe break locations after completion of Task 4 and which are to be resolved on the basis of the most favorable cost/benefit approach.

In order to establish the boundaries of the interaction evaluation activity, the overall logic for the pipe rupture evaluation at the start of the activity is presented in Figure 5-1. An explanation of major steps in the logic diagram is presented below:

Node (1) The postulated break locations are defined in accordance with Criteria of Section 3.1.

Node (2) Each rupture is postulated separately as a single event and is traced through the logic diagram (Figure 5-1) until a satisfactory resolution is obtained.

Node (3) Break locations which can be determined a priori to have no adverse consequences are eliminated at this point from further consideration.

Node (7) Determine target loading resulting from pipe whip and jet impingement effects.

Node (8) Does loading of target exceed the acceptance criteria defined in Sections 4.1 through 4.4? The established target loading and acceptance criteria are utilized to screen break locations which have no potential adverse consequences.

Node (9) Is target necessary for achieving safe shutdown? The damage criteria defined in Section 4.5 are used to evaluate the potential for adverse consequences and the ability to accomplish and maintain safe shutdown.

Node (11) Perform cost/benefit analysis. The objective of this task is to evaluate which of the remaining design/analysis options appears to be most promising in resolving the consequences of the postulated break location. The analysis/design options which were considered are presented in Section 7.0.

Table 5-1. HIGH ENERGY PIPING SYSTEM DESIGN CONDITIONS

System	Mean Diam., in.	Wall Thickness, in.	Material	Design Pressure, psig.	Design Temp., °F
Core Spray	10.157	0.593	S/S A312-TP304	350	165
Control Rd.	3.969	0.531	C/S A106-GRB	1250	575
Control Rd.	4.163	0.337	S/S A312-TP304	1250	575
Control Rd.	3.284	0.216	S/S A312-TP304	1250	575
Feedwater	16.625	1.375	C/S A106-GRB	1850	350
Feedwater	11.750	1.000	C/S A106-GRB	1850	350
H.P.C.I.	10.157	0.593	C/S A106-GRB	1275	560
Isol. Cond.	13.362	0.638	S/S A358-TP304	1250	550
Isol. Cond.	12.081	0.669	S/S A358-TP304	1250	550
Isol. Cond.	15.175	0.825	S/S A358-TP304	1250	550
Isol. Cond.	15.156	0.844	C/S A106-GRB	1250	550
L.P.C.I.	15.278	0.722	S/S A358-TP304	1250	575
R.R.C.I.	26.797	1.203	S/S A358-TP304	1250	575
R.R.C.I.	20.907	1.093	S/S A358-TP304	1250	575
R.R.C.I.	12.063	0.687	S/S A358-TP304	1250	575
R.R.C.I.	26.641	1.359	S/S A358-TP304	1250	575
R.R.C.I.	4.163	0.337	S/S A312-TP304	1250	575
R.R.C.I.	3.200	0.300	S/S A312-TP304	1250	575
R.W.C.U.	8.125	0.500	S/S A312-TP304	1250	575
R.W.C.U.	15.278	0.722	S/S A358-TP304	1250	575
R.W.C.U.	15.158	0.842	C/S A106-GRB	1250	575
Main Stm.	18.969	1.031	C/S A106-GRB	1125	550
Main Stm.	6.312	1.688	C/S A106-GRB	1125	550
Main Stm.	5.625	1.000	C/S A106-GRB	1125	550
Main Stm.	10.157	0.593	C/S A106-GRB	500	380
Main Stm.	8.125	0.500	C/S A106-GRB	500	380
Main Stm.	22.781	1.219	C/S A106-GRB	1125	550

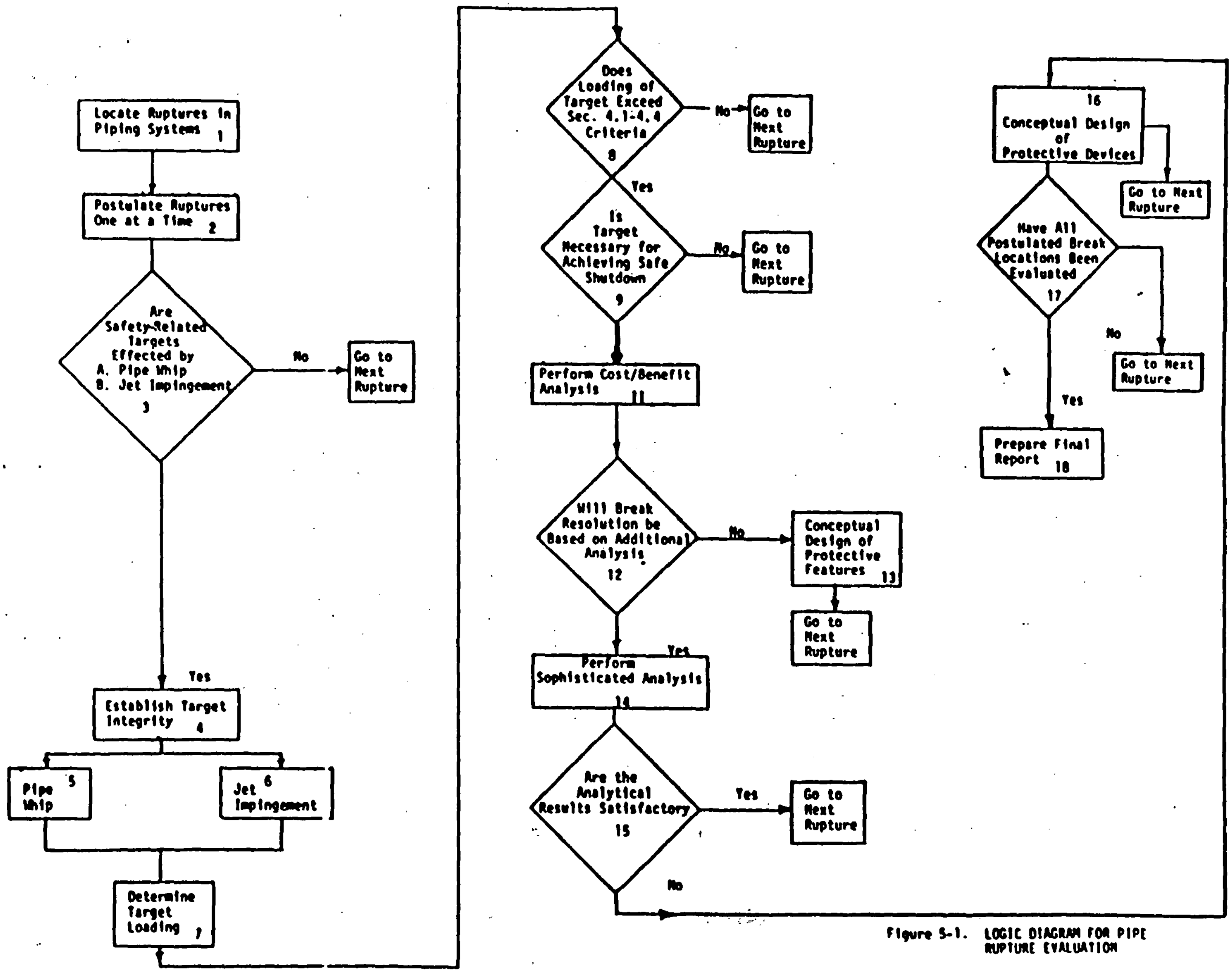


Figure 5-1. LOGIC DIAGRAM FOR PIPE RUPTURE EVALUATION

The results of the evaluation activity of Figure 5-1 are summarized on interaction matrices Appendix A (Table A-1). The matrices are prepared on a system basis showing the potential interactions between the source, for each postulated break point as identified in Appendix B and the selected target. Interactions are defined as follows:

(N) - Interaction physically not possible.

(A) - Interaction causes no damage or extent of damage does not preclude safe shutdown.

(U) - Interaction exists, damage is possible, further evaluation is required for unresolved break location.

It should be noted that each interaction falling within the (U) category was evaluated individually using the alternatives available (Nodes 11 through 16 of Figure 5-1).

The pipe break locations which remained unresolved at the completion of Task 4 are indicated in Table 5-2.

5.2 Moderate Energy Systems

An evaluation of the moderate energy piping systems inside the containment was performed using the criteria outlined in Sub-section 3.1.3 and section 4.1. In the evaluation process, the potential targets in the vicinity of each moderate energy line were identified. The most adverse break location was determined by selecting the most critical of the targets previously identified. The particular target was assumed to be impacted by a jet impingement load resulting from a through-wall leakage crack in the line.

The acceptability of interactions was determined on the basis of structural and/or system evaluation.

None of the interactions from the moderate energy lines were found to impact the safe shutdown of the plant. Hence, they were considered to be acceptable.

5.3 Interactions Requiring Additional Evaluation

Listed below are the break numbers and the corresponding number of interactions which remained unresolved at the completion of Task 4:

Table 5.2 SUMMARY OF UNRESOLVED PIPE BREAK INTERACTIONS AFTER COMPLETION OF TASK 4 ACTIVITY

System	Break Number	No. of Interactions
Main Steam	Ø2-3001-01G	3
	Ø2-3001-02G	1
	Ø2-3001-04G	2
	R2-3001-01G	2
	R2-3001-02G	1
	P2-3001-02G	1
	P2-3001-03G	2
	Q2-3001-02G	1
Reactor Recirculation	L2-0201-11G	1
	L2-0201-12G	1
	L2-0202-02G	3
Isolation Condenser	H2-1302-10G	1
	I2-1303-01G	2
	I2-1303-03S	1
	I2-1303-05S	1
	I2-1303-07G	1
Low Pressure Coolant Injection	J2-1506-03S	1
	K2-1519-05S	1
Reactor Water Cleanup	M2-1201-02G	2
	M2-1201-03G	1
	M2-1001-02G	1
Feedwater	D2-3204-01G	1
	D2-3204-02G	1
	D2-3204-03G	2
	D2-3204-04G	2
	E2-3204-02G	1
	E2-3204-03G	3
Number of Affected Systems = 6	Unresolved Break Locations = 27	Unresolved Interactions = 40

6.0 COST BENEFIT ANALYSIS (TASK 5)

The objective of this task was to perform a cost/benefit analysis of the design and analysis options which are available to eliminate the remaining unacceptable interactions after the preliminary screening was performed in Task 4 (Section 5.0.).

The following six approaches were identified as potential solutions:

(1) Fracture Mechanics Evaluation

(2) Rigorous Jet Impingement and Pipe Whip Analysis

A more rigorous analysis of unacceptable interactions can be performed to demonstrate that targets will not fail. This analysis eliminates some of the conservative assumptions in the following areas:

- Axial jet/decay momentum losses
- Actual jet parameters
- Target orientation
- Pipe loading limits
- Support configurations
- Source pipe motion

The analysis is performed at the level of detail deemed necessary to qualify the target or remove the interaction. Sophisticated finite elements analysis techniques using nonlinear time history methods are applied as necessary to solve the problem.

(3) Rigorous Containment and Structure Damage Analysis

A more rigorous analysis of pipe whip and jet impingement interactions with the containment and other structural targets can be performed. This analysis reduces the conservatism of the source pipe motion, jet parameter, target yield strength and deformation parameter assumptions. The analysis is performed at the level of detail deemed necessary to qualify the unacceptable interaction.

(4) Further System Evaluation

(5) Piping Stress Analysis

(6) Restraint Feasibility Study

The cost/benefit analysis indicated that the most promising approaches were options (2), (3) and (4) to complete the evaluation of the unresolved break locations.

7.0 ADDITIONAL ANALYSIS (TASK 6)

The unresolved pipe break interactions after completion of Task 4 activity were resolved as follows:

02-3001-01G

3 Interactions - Whip on electrical
- Jet on electrical
- Jet on electrical

Further system evaluation indicated that the above electrical components were not required for safe-shutdown of the plant.

02-3001-02G

1 Interaction - Impact on penetration/liner.

A finite element model of the main steam line from the reactor to the break location at the penetration was generated using pipe and shell elements. The Containment penetration and a 12 ft. diameter section of the liner in the penetration area were included in the model. The ANSYS computer program was used to perform a non-linear dynamic transient analysis.

The results indicate that the penetration sleeve did not become plastic. The maximum plastic strain in the containment liner within a 4 foot radius of the penetration centerline was less than 1.2 percent.

02-3001-04G

2 Interactions - Potential impact with Motor Operated Valve (M.O. 2-0202-4B) in the Reactor Recirculation Line.

- Whip on electrical

For the first interaction a finite element model of the main steam line from the reactor to the postulated break location was developed using pipe elements. The ANSYS computer program was used to perform a non-linear dynamic transient analysis. Results from the above analysis indicate that the trajectory of the whipping pipe does not contact the motor operated valve and therefore no interaction exists.

The second interaction was found to be acceptable as a result of further system evaluation which showed that the interaction did not affect safe-shutdown.

TARGET TECHNOLOGY LTD.

R2-3001-01G

2 Interactions - Whip on electrical
- Jet on electrical

Further system evaluation indicated that the above electrical components were not required for safe-shutdown of the plant.

R2-3001-02G

1 Interaction - Impact on penetration/liner.

The results from 02-3001-02G were used to qualify this break location.

P2-3001-02G

1 Interaction - Impact on penetration/liner.

The results from 02-3001-02G were used to qualify this break location.

P2-3001-03G

2 Interactions - Whip on electrical
- Impact on RPV pedestal

Further system evaluation indicated that the above electrical components were not required for safe-shutdown of the plant.

Consideration of line pressure drop losses and maximum normal operation pressure instead of the design pressure reduced the thrust loading at the break location such that the impact force was less the allowable loading envelope of figure 4-17. The interaction was determined to be acceptable.

Q2-3001-02G

1 Interaction - Impact on penetration/liner

The results from 02-3001-02G were used to qualify this break location.

L2-0202-02G

3 Interactions - Jet on electrical

Further system evaluation indicated that the above electrical components were not required for safe-shutdown of the plant.

L2-0201-11G

1 Interaction -Whip on electrical

Further system evaluation indicated that the above electrical components were not required for safe-shutdown of the plant.

L2-0201-12G

1 Interaction - Whip on electrical

Further system evaluation indicated that the above electrical components were not required for safe-shutdown of the plant.

M2-1302-10G

1 Interaction - Impact on penetration/liner

A finite element model of the isolation condenser line from the reactor to the postulated break location was developed using pipe and shell elements. The containment penetration and a section of the liner in the penetration area were also modeled.

The results of an ANSYS analysis indicate the penetration sleeve did not become elastic and the maximum plastic strain in the containment liner in the vicinity of the penetration was approximately 1.11%.

I2-1303-01G

2 Interactions - Impact on penetration/liner.
- Potential whip on biological shield wall

The first interaction was shown to be acceptable based upon an ANSYS finite element analysis similar to those performed for the previously discussed liner/penetration interactions. The maximum strain of 0.65% occurred at the sleeve/liner junction.

It was shown that the whip on the shield wall was not possible since the liner would be impacted first and can withstand the impact.

L2-1303-03S

1 Interaction - Jet on biological shield wall

This interaction was found to be acceptable based upon a more refined development of jet pressure loads. Consideration of maximum normal operating pressure instead of the design pressure resulted in a reduced jet impingement load.

TARGET TECHNOLOGY LTD.

I2-1303-05S

1 Interaction - Jet on electrical

Further system evaluation indicated that the electrical components were not required for safe-shutdown of the plant.

I2-1303-07G

1 Interaction - Impact on penetration/liner

An ANSYS finite element analysis similar to those previously discussed for penetration/liner interactions was performed. The maximum strain on the liner was 1.54% which is well below the ultimate strain level.

J2-1506-03S

1 Interaction - Jet biological shield wall

This interaction was found to be acceptable based on the redefinition of jet pressure load as indicated for break # I2-1303-03S.

K2-1519-05G

1 Interaction -Jet on biological shield wall

Calculation of the jet impingement load on the basis of the maximum normal operating pressure instead of the design pressure indicated that the interaction was acceptable.

M2-1201-02G

2 Interactions -Whip on liner
-Whip on electrical

In the first interaction, the whipping pipe from liner penetration number X-111A to the postulated break location was modeled using ANSYS plastic pipe elements. A transient non-linear dynamic analysis was performed and the motion and velocity of the whipping pipe were determined prior to impact against the containment liner.

The kinetic energy of the pipe at impact was calculated using the effective mass and velocity as established by the ANSYS analysis. The value of kinetic energy was below the energy absorption capacity of the liner as established in the Task 3 criteria, and hence the interaction is acceptable.

Further system evaluation indicated that the electrical components were not required for safe-shutdown of the plant.

M2-1201-03G

1 Interaction - Jet on electrical

System evaluation indicated that the subject component was not necessary for the safe-shutdown of the plant.

M2-1001-02G

1 Interaction - Impact on penetration liner

This interaction was deemed acceptable based on review of results from the analysis of break number I2-1303-07G. The pipe and liner geometries were similar and the dynamic forcing function for this break was lower than that of break I2-1303-07G, due to higher friction losses in the piping system.

D2-3204-01G

1 Interaction - Whip on liner

The interaction was found to be acceptable on the basis of a reduced thrust forcing function based on maximum operating pressure and temperature. The Task 4 evaluation used design pressure and temperature values.

D2-3204-02G

1 Interaction - Jet on electrical

Further system evaluation indicated that the above electrical component was not required for safe-shutdown of the plant.

D2-3204-03G

2 Interactions - Whip on liner
- Jet on electrical

The results from break number D2-3204-01G were used to qualify the first interaction.

The second interaction was qualified on the basis of further system evaluation which indicated that the above electrical component was not required for safe-shutdown of the plant.

TARGET TECHNOLOGY LTD.

D2-3204-04G

2 Interactions - Whip on SRV line 2-3019E-8
- Whip on SRV line 2-3019A-8

Both interactions were found to be acceptable on the basis of the reduced thrust force considering maximum normal operating pressure and temperature of the whipping pipe.

E2-3204-02G

1 Interaction - Whip on liner

The results of break number D2-3204-01G were used to qualify this interaction.

E2-3204-03G

3 Interactions - Whip on SRV line 2-3019C-8
- Whip in SRV line 2-3019D-8

The first interaction was qualified on the basis of results from break number D2-3204-01G.

The other two interactions were deemed acceptable based on results from break number D2-3204-04G

8.0 BIBLIOGRAPHY

1. Enis, R.O., Bernal, D.B., and Burdette, E. G., "A Design Guide for Evaluation of Barriers for Impact from Whipping Pipes"- Paper from Second ASCE Conference on Civil Engineering and Nuclear Power, September, 1980.

2. "Design Basis for Protection of Light Water Nuclear Power Plants Against Effects of Postulated Pipe Rupture," ANSI/ANS-58.2-1980, published by the American Nuclear Society, December 31, 1980.

3. "Protection Against Pipe Whip Inside Containment," Regulatory Guide 1.46, Directorate of Regulatory Standards, U.S. Atomic Energy Commission.

4. Thullen, P., "Loads in Spherical Shells," Oak Brook Engineering Department, Chicago Bridge and Iron Company, August, 1964.

5. "Report of the ASCE Committee on Impactive and Impulsive Loads" - Civil Engineering and Nuclear Power, Volume V, September, 1980.

6. "Special Criteria Developed for the Design and Analysis of Floating Nuclear Plant Containment Structures," Tsai, J.C., Orr, R.S., Transactions of the 4th International Conference on Structural Mechanics in Reactor Technology, Vol. J(a), August 19, 1977.

7. Roark, R.J., and Young, W.C., Formulas for Stress and Strain, 5th Edition, McGraw-Hill, 1975.

8. "Code Requirements for Nuclear Safety Related Concrete Structures" ACI 349-80.

9. Salmon and Wong, Reinforced Concrete Design, Intext Press, Inc., 1973.

10. Kraus, H., Thin Elastic Shells, John Wiley, June, 1967.

11. "Loss-of-Coolant Accident Analysis Report" for Duane Arnold Energy Center, NEDO-21032-02-2A, Class I, July 1977, Appendix A, Revision 1.

12. "Loss-of-Coolant Accident Analysis Report" for Dresden Units 2, 3 and Quad Cities Units 1, 2 Nuclear Power Stations, NEDO-241146A, 79NED273, Class 1, April 1979, Revision 1.

4.0 REACTOR
TABLE OF CONTENTS

Table 4.1-2

NUCLEAR DESIGN LIMITS, TARGETS, AND TYPICAL VALUES

Reactivity Control			
Cold shutdown k_{eff}, rod of maximum worth stuck out fully — design target	0.99		
Standby liquid control shutdown Δk_{eff}	0.03		
Approximate Reactivity Coefficients			
	Cold	Hot (no voids)	Operating
Moderator temperature coefficient, $(\Delta k/k)/°F$	-8×10^{-5}	-17.0×10^{-5}	
Moderator void coefficient, $(\Delta k/k)$/% void	$< -0.6 \times 10^{-3}$	-1.0×10^{-3}	-1.4×10^{-3}
Fuel temperature (Doppler) coefficient, $(\Delta k/k)/°F$	-1.2×10^{-5}	-1.2×10^{-5}	-1.2×10^{-5}
Power coefficient for xenon stability	More negative than -0.01 $(\Delta k/k)/(\Delta P/P)$		
Typical Excursion Parameter Values			
Prompt neutron lifetime (ℓ^*)	48.9 μs		
Effective delayed neutron fraction ($\bar{\beta}$) — at 0 MWd/t — at 10,000 MWd/t	 0.0072 0.0056		

Table 4.1-3

THERMAL AND HYDRAULIC DESIGN

Design thermal output, MWt	2527
Reactor pressure (dome), psia	1020
Steam flowrate, lb/hr	9.765×10^6
Recirculation flowrate, lb/hr	98×10^6
Fraction of power appearing as heat flux	0.965
Core subcooling, Btu/lb	22.4
Core average void fraction, active coolant	0.299
Core average exit quality	0.101
Fuel Type	SPC 9x9-2
Power density*, kW/ℓ	40.74
Average heat flux, Btu/(hr-ft^2)	108,000
Maximum heat flux, Btu/(hr-ft^2)	325,000
Maximum UO_2 temperature, °F	4115
Safety Limit Minimum Critical Power Ratio (SLMCPR)	1.08
Maximum steady state LHGR (beginning of bundle life), kW/ft	14.5

* This parameter is a function of rated core thermal power (2527 MWt), active fuel length, number of fuel assemblies (724) and fuel assembly pitch (6 inches). The active fuel length for an SPC 9x9-2 assembly is 145.24 inches.

4.2.3.3.3 Transients and Excursions

Results of transients and excursions remain unchanged with the replacement of absorber curtains by the gadolinia burnable absorber. Of primary importance in the rapid excursions is the presence of a strong Doppler effect to compensate for the excess reactivity input. For slower transients, the moderator void coefficient assumes a major role. None of the reactivity coefficients associated with the fuel lattice are materially affected by the change in control augmentation method from absorber curtains to gadolinia absorber.

Gadolinia is held in solid solution by the UO_2. The initially chemically uniform gadolinia-bearing pellets remain so at all exposures, because neutron absorption in Gd-155 and Gd-157 produces stable isotopes Gd-156 and Gd-158, respectively. Initially, the gadolinia is highly self-shielded. During irradiation, the isotopic distribution varies radially in the pellet, nearly as a step function with an essentially zero concentration of Gd-155 and Gd-157 outside a certain radius and a natural percentage of these isotopes inside that radius. Because no chemical concentration gradients exist in the pellet, net migration of gadolinia in normal temperature gradients has not been detected in any of the postirradiation examinations to date. Either the migration does not occur, or it is limited to amounts below the detection threshold. Any dispersal of the solid solution into the moderator caused by an excursion would only reduce the self-shielding, causing an increase in the local neutron absorption and producing a loss in reactivity. There seems to be no mechanism which could cause the control effectiveness of the gadolinia to vary in such a way as to compromise safety.

4.2.3.3.4 Absorber Omission and Fuel Loading Errors

The safety effect of the omission of gadolinia during fuel fabrication and the consequences of fuel assembly misorientation or mislocation during fuel loading are considered.

Quality contol procedures assure production of fuel in conformance with design. For initial cores, even if gadolinia were omitted from all fuel assemblies, no safety problem would result. The fuel storage facilities were designed for fuel reactivity in excess of that which would exist in the initial fuel designs with gadolinia omitted. For the SPC 9x9-2 and ATRIUM-9B fuel assemblies, residual gadolinia is credited in the fuel storage criticality analyses. Extensive experience with the use of gadolinia has justified the confidence in crediting the presence of the gadolinia. This confidence is based upon precise quality control measures which are utilized during the manufacture of gadolinia bearing UO_2 pellets and during the assembly of these fuel pellets into fuel rods. Special fuel fabrication procedures also assure accurate placement of gadolinia bearing fuel rods.

Core loading procedures also provide control in the event that the fuel reactivity was higher than expected. For initial cores, frequent shutdown margin checks would expose the abnormal condition before sufficient fuel could be loaded to exceed the capability of the control rod system. After extensive experience with the construction of gadolinia bearing fuel bundles and the computer modeling of the depletion of the gadolinia during power operation, the shutdown margin checks during the core loading process have been replaced with close monitoring of the Source Range Monitor (SRM) count rates.

SPC has analyzed the effects of fuel misloading errors for Dresden Units 2 and 3. Misloading errors include both misrotation error and mislocation error. Results show that the lowest MCPR resulting from operation with a misloaded fuel assembly is well above the Fuel Cladding Integrity Safety Limit MCPR (defined in Section 4.4). The highest LHGR resulting from a misloaded fuel assembly is found to exceed the operating limit LHGR beginning at low exposure and exceed the fuel damage limit LHGR at high exposures. The potential resulting offsite dose has been calculated to be a small fraction (less than 10%) of the 10 CFR 100 offsite dose limit.

4.3 NUCLEAR DESIGN

This section discusses the nuclear design bases (Section 4.3.1), steady-state and dynamic nuclear characteristics of the core (Sections 4.3.2.1 and 4.3.2.2, respectively), stability (Section 4.3.2.3), nuclear design analytical methods (Section 4.3.3), and new changes in stability criteria (Section 4.3.4).

4.3.1 Design Bases

The bases for nuclear design include the nuclear design basis for the reactor and the design basis for system stability, which are discussed in Section 4.3.1.1 and 4.3.1.2, respectively.

4.3.1.1 Reactor

A summary of the nuclear design bases is presented below:

A. The neutronic design shall be compatible with all reactivity control requirements specified in the Technical Specifications.

B. The average enrichment of the reload fuel design shall be selected so as to achieve the target equilibrium batch average discharge exposure.

C. The enrichment distribution within an assembly shall be designed with consideration of the following:

1. Fuel performance criteria, i.e., limits on plastic strain;
2. Fuel assembly thermal limits, i.e., limits on minimum critical power ratio (MCPR); and
3. Operating limits associated with the postulated loss-of-coolant accident (LOCA), i.e., limits on maximum average planar linear heat generation rate (MAPLHGR).

D. The core shall be capable of being made subcritical at any time or at any core condition with the highest worth control rod fully withdrawn. A cold shutdown margin of 1% Δk is used as a design target in the core loading plan.

E. A value of 1% Δk is used as a design objective for hot excess reactivity at the beginning of cycle (BOC). The minimum value considers the existence of an equilibrium-xenon core at BOC and provides a balance of reactivity attributed to gadolinia and control blades to allow fixing of acceptable margins to operating limits.

F. The moderator void coefficient is negative over the entire operating range.

power peak is expected to occur. The Siemens Power Corporation (SPC) fuel is designed to balance the performance of the fuel relative to thermal limits.

4.3.2.1.3 Reactivity Control

The excess reactivity designed into the core is controlled by a control rod system supplemented by gadolinia in the fuel. Control rod design is discussed in Section 4.6. The use of gadolinia as a burnable neutron absorber is discussed in Section 4.2.

The control rod system is designed to provide adequate control of the maximum excess reactivity anticipated during the fuel cycle operation. Shutdown capability is evaluated assuming a xenon-free core at ambient temperature, which represents the condition of maximum fuel reactivity.

The basic design criterion for reactivity control is that the core, in its maximum reactivity condition, be subcritical with the control rod of highest worth fully withdrawn and all other rods fully inserted. The criterion provides a substantial shutdown margin with all rods in.

In accordance with this basic design criterion, the core loading is limited to that which can be made subcritical (i.e., effective neutron multiplication factor k_{eff} less than 1) in the most reactive condition during the operating cycle with the highest worth operable control rod in its full-out position and all other operable rods fully inserted.

According to the Technical Specification Limiting Conditions for Operation the shutdown margin (SDM) shall be equal to or greater than:

1. 0.38% $\Delta k/k$ with the highest worth control rod analytically determined, or

2. 0.28% $\Delta k/k$ with the highest worth control rod determined by test.

The shutdown margin is defined as the amount of reactivity by which the reactor is subcritical or would be subcritical assuming all control rods are fully inserted except for the single control rod of highest reactivity worth which is assumed to be fully withdrawn and the reactor is in the shutdown condition; cold; i.e. 68 °F and xenon free.

Since satisfaction of the limitation is demonstrated at the time of core loading and applied to the entire fuel cycle, the generalized requirement is that the reactivity of the loaded core be limited so the core can be made subcritical by at least R + 0.38% $\Delta k/k$ or R + 0.28% $\Delta k/k$, as appropriate, with the strongest control rod fully withdrawn and all others fully inserted. The quantity R is the difference between the calculated shutdown margin at the beginning of the cycle and the minimum calculated shutdown margin at any time later in the cycle when it would be less than at the beginning. The value of R is always positive or zero, and it includes the potential shutdown margin loss assuming full settling of boron carbide (B_4C) in all inverted control rod poison tubes in the core. A new value of R is determined for each fuel cycle.

In order to assure that the basic design criterion and the LCO (k_{eff} less than 1) are always satisfied, a 0.01 Δk design margin was adopted as the design goal. Thus, the design target is calculated k_{eff} less than or equal to 0.99, with the rod of highest worth fully withdrawn. This design target assures that the unit can be shut down slightly positive moderator reactivity effect. If, however, the transient accelerates so that steam voids are produced inside the channel, an immediate negative k_{∞} contribution would result such that the total moderator coefficient would be negative. There are no potentially severe transients in which a positive moderator reactivity effect plays a major role.

In summary, in those regions of the core where rapid moderator density changes can occur, moderator temperature and moderator void coefficients are designed to be always negative.

Figures 4.3-6 and 4.3-7 show typical moderator temperature and moderator void coefficients for beginning of life and at 10,000 MWD/t fuel exposure. Because refueling is done utilizing symmetrical loadings which avoid concentrations of the most exposed fuel, the 10,000 MWD/t points are representative of the maximum exposure effects. As shown in Figure 4.3-7, the moderator void coefficient satisfies the design basis that it remains negative throughout core life.

4.3.2.3 Stability

The following discussions on stability are based on the original design basis of no inherent tendency toward oscillations (see Section 4.3.1.2) and are presented here for historical perspective. The new design and operating criteria since IE Bulletin 88-07 are based on detection and suppression of oscillations as addressed in 10 CFR 50, Appendix A, GDC 12 (see Section 4.3.1.2). In the near term, satisfaction of this GDC is by compliance with IE Bulletin 88-07, 88-07, Supplement 1 and as described in the ComEd Response to Generic Letter 94-02. In the long term, satisfaction of this GDC is expected by implementing the option III long-term solution options discussed in NEDO-31960 (see Section 4.3.4).

The new stability concerns resulting from the LaSalle Unit 2 instability event of March 9, 1988, are addressed in Section 4.3.4.

4.3.2.3.1 Design Basis

The design basis for stability is contained in Section 4.3.1.2.

4.3.2.3.2 Description and Design Evaluation

4.3.2.3.2.1 Introduction

A BWR unit consists of many interacting processes and associated control systems. A process is self-regulating if it exhibits a negative feedback effect. In a BWR, MICROBURN-B is a three-dimensional, two-group, course-mesh diffusion theory reactor simulator program for the analysis of BWR cores. The simulator code models the reactor core in three-dimensional geometry, and the reactor calculations can be performed in one-quarter, one-half, or full core geometry. The code calculates the reactor core reactivity, core flow distribution, nodal power distribution, reactor thermal limit values, and incore detector responses.

The code includes special treatment of moderator void and control rod history and a more accurate treatment of plutonium production and depletion.

4.3.4 Changes in Stability Criteria

On March 9, 1988, LaSalle County Station Unit 2 experienced a dual recirculation pump trip event. After the pump trip, while on natural circulation, the unit experienced an excessive neutron flux oscillation. The event was described in NRC Information Notice No. 88-39, "LaSalle Unit 2 Loss of Recirculation Pumps With Power Oscillation Event," dated June 15, 1988.

The NRC has been concerned with generic questions that this event raised and has issued IE Bulletin No. 88-07 which requests that holders of operating licenses for BWRs ensure that adequate operating procedures and instrumentation are available and adequate operator training is provided to prevent the occurrence of uncontrolled power oscillations during all modes of operation.

In IE Bulletin No 88-07, Supplement 1, the NRC provides additional information concerning power oscillations in BWRs and requests that addressees take action to ensure that the safety limit for the plant minimum critical power ratio is not violated.

In Generic Letter 94-02 actions 1.a and 1.b, the NRC requested licensees to implement the proposed upgrade to BWROG Interim Corrective actions (ICAs) to better address startup and low power maneuvering conditions.

ComEd performed the actions requested by IE Bulletin 88-07, 88-07 Supplement 1 and actions 1.a and 1.b of Generic Letter 94-02 for Dresden Units 2 and 3.[11]

ComEd Participated in the BWR Owners' Group (BWROG) program which is developing generic long-term solutions to the stability issue. The BWROG program developed a design and evaluation methodology to analyze thermal-hydraulic stability and identified several viable approaches to the long-term resolution of the stability issue. Details of this methodology and examples of the Option III solution concept ComEd will be implementing are discussed in NEDO-31960.[10]

4.3.5 References

1. Dunnivant, et al., "Dresden Unit 2 ANF-5 Design Report — Mechanical, Thermal, and Neutronic Design for ANF 9x9 Fuel Assemblies," ANF-90-057(P), Rev. 0, April 26, 1990.

2. Ackermann, et al., "High Temperature Vapor Pressure of UO_2," Journal of Chemical Physics, Vol. 25, No. 6, December 1956.

3. Pettus, W.G., and Baldwin, M.N., "Resonance Absorption in U-238 Metal and Oxide Rods", BAW-1244.

4. Hellstrand, E., Nuclear Science and Engineering, No. 8, p. 497, 1960.

5. Engesser, F.C., et al., "PCTR Measurements of the EGCR Fuel Temperature Coefficient," HW-67766, February 1960.

6. Neal, L.G., and Zivi, S.M., "The Stability of Boiling-Water Reactors and Loops," Nuclear Science and Engineering, Vol. 30, p. 25, 1967.

7. "Exxon Nuclear Methodology for Boiling Water Reactors," XN-NF-80-19 (P)(A), Volume 1, Supplement 3, November 1990.

8. "Exxon Nuclear Methodology for Boiling Water Reactors," XN-NF-80-19(P)(A), Volume 1, Supplements 1 and 2, March 1983.

9. "Stability Evaluation of Boiling Water Reactor Cores — Sensitivity Analysis and Benchmark Analysis," XN-NF-691(P)(A), Volume 1, and Supplements 1 and 2, March 1983.

10. "BWR Owner's Group Long-Term Stability Solutions Licensing Methodology," General Electric Company, NEDO-31960, May 1991.

11. John C. Brons to William T. Russell, "Dresden Stations 2 and 3, Quad Cities Station Units 1 and 2, LaSalle County Station Units 1 and 2, Response to Generic Letter 94-02 (BWR Stability), NRC Dockets 50-237 and 50-249, NRC Dockets 50-254 and 50-265, NRC Dockets 50-373 and 50-374," Commonwealth Edison Company, September 9,1994.

Even if transition boiling were to occur, cladding perforation would not be expected. Significant test data accumulated by the NRC and private organizations indicate that BWR fuel can survive for an extended period in an environment of transition boiling.

If reactor pressure during normal power operation should ever exceed the limit of applicability of the critical power correlation, it would be assumed that the fuel cladding integrity safety limit MCPR was violated. This applicability pressure limit is higher than the pressure safety limit specified in the Technical Specifications.

4.4.1.3.1.3 Maximum Linear Heat Generation Rate

In addition to the boiling transition limit (MCPR limit), operation is constrained to a maximum linear heat generation rate (MLHGR) stated in Section 4.2.3.1.2 (detailed curves are specified in the Core Operating Limits Report). This constraint is established to provide adequate safety margin to plastic strain and centerline melt considerations for AOOs initiated from high-power conditions. Equivalent safety margin for transients initiated from lower power conditions is provided by decreasing the average power range monitor (APRM) flow-biased scram setting by the ratio of the fuel design limiting ratio for centerline melt (1/FDLRC) or by increasing the APRM gain setting by the fuel design limiting ratio for centerline melt (FDLRC), when the FDLRC is greater than 1.0.

4.4.1.3.2 Operating Basis

Based on the preceding design criteria, the operating basis for the thermal and hydraulic characteristics of the core design is to control the local power density to levels such that the fuel assembly powers are maintained within the critical power limits.

The basis of the steady-state MCPR and MLHGR limits is to provide sufficient margin to accommodate uncertainties and to ensure that the fuel damage limits would not be exceeded during transients caused by any reasonably expected single operator error or single equipment malfunction.

4.4.1.3.3 Operating Limits

The following operating limits are used during normal steady-state operation: the MCPR is maintained no less than the Technical Specification limiting condition for operation (LCO) value, and the linear heat generation rate (LHGR) is maintained no higher than the MLHGR for each fuel type stated in Section 4.2.3.1.2 (detailed curves are specified in the Core Operating Limits Report). Note that the above statement does not specify the operating power nor does it specify peaking factors; these parameters are controlled by the operator subject to a number of constraints, including the thermal limits given above.

4.4.4.2.3 Power Transient

During an operating transient, the heat flux lags behind the neutron flux due to the inherent heat transfer time constant of the fuel, which is 8 to 9 seconds. Also, the LSSSs are at values which do not allow the reactor to be operated above the safety limit during normal operation or during analyzed abnormal operating situations. For normal operating transients, the neutron flux transient is terminated by scram before a significant increase in surface heat flux occurs. Control rod scram times are checked as required by the Technical Specifications.

Analyses of normal turbine or generator trips, which are among the most severe normal operating transients expected, show that if a flux scram occurs such that the period of time when the neutron flux stays above the LSSS is less than 1.7 seconds, the safety limit will not be exceeded. These analyses show that even if the bypass system fails to operate, the design limit of MCPR equal to the fuel cladding integrity safety limit MCPR would not be exceeded.

During periods when the reactor is shut down, consideration must be given to water level requirements due to the effect of decay heat. If the reactor water level should drop below the top of the active fuel during this time, the ability to cool the core would be reduced, which could lead to excessive cladding temperatures and cladding perforation. The core would be cooled sufficiently to prevent clad melting should the water level be reduced to two-thirds the core height. Establishment of the safety limit at 12 inches above the top of the fuel provides adequate margin. This level is continuously monitored whenever the recirculation pumps are not operating.

During rapid power increases, the neutron flux may exceed the scram level by a considerable amount, but the resulting scram would be sufficiently fast that the heat flux would either decrease or exceed the initial value by only a small amount.

The potential transient events of BWRs have been reviewed by SPC to determine the extent of analyses necessary for licensing the use of SPC fuel. These events are described in Chapter 15 of the NRC Standard Review Plan (NUREG-0800) and have been dispositioned as described in XN-NF-79-71(P).[2] The events were dispositioned as not applicable, consequences of an event bounded by a different event, or analysis necessary for reload licensing.

The transients most likely to limit operation because of MCPR considerations are:

A. Turbine trips or generator load rejection without bypass (Section 15.2);

B. Loss of feedwater heating (Section 15.1.1) or inadvertent HPCI startup (Section 15.5.1);

C. Feedwater controller failure (to maximum demand) (Section 15.1.2); and

D. Control rod withdrawal error (Section 15.4)

4.4.7 References

1. "Dresden Unit 2, Cycle 14, Plant Transient Analysis," Siemens Power Corporation, EMF-92-126, October 1992.

2. "Exxon Nuclear Plant Transient Methodology for Boiling Water Reactors," Exxon Nuclear Company Inc, XN-NF-79-71(P).

4.5 REACTOR MATERIALS

4.5.1 Control Rod Drive System Materials

Control rod drive system materials are discussed in Section 4.6.

4.5.2 Reactor Internals Materials

The major internal components of the reactor include the control rod guide tubes; incore neutron monitors; shroud and other internal core support structures; steam separators; steam dryers; jet pumps; and the feedwater, core spray, and standby liquid control spargers and nozzles. This section does not cover the fuel assemblies, control rods, or incore neutron monitors; these components are discussed in Section 4.2, 4.6, and 7.6, respectively.

The following subsections describe the materials and welding methods used for reactor internals. A further description of reactor internals, including steam separators and steam dryers, is included in Section 3.9.5 and Section 6.1.

4.5.2.1 Structural Components

The materials used for the structural members of the reactor internals are listed below:

A. Shroud — Type 304 stainless steel
Shroud tie rod with spring stabilizers — 316/316L, XM-19 stainless steel and X-750 nickel base alloy,

B. Core top grid — Type 304 stainless steel,

C. Core bottom grid — Type 304 stainless steel,

D. Fuel support piece — Type 304 stainless steel,

E. Baffle plate — Inconel,

F. Baffle plate supports — Inconel,

G. Control rod guide tubes — stainless steel, and

H. Incore nuclear instrumentation tubes — stainless steel.

All reactor internal structural members located in high flux regions are constructed of Type 304 stainless steel.

The baffle plate and inner rim are made of Inconel to permit welding to the ferritic base metal of the reactor vessel. The welded joints that attach the baffle plate to the vessel wall were made in the vessel fabrication shop in a highly controlled operation. The bottom of the shroud is welded on top of the rim, which provides for the differential expansion between the ferritic, Inconel, and stainless steel

The hafnium rods have a diameter of 0.188 inches and a length of 143 inches. The dimensions of the B_4C encapsulating tubes are similar to the tubes in the standard GE control blade. Since hafnium is a heaver material than B_4C, the sheath wall thickness is reduced from 0.056 inches to 0.045 inches to maintain the same weight as the standard GE control blade, approximately 218 pounds. Also, the overall blade width is reduced by 0.022 inches and, in turn, results in an increase in clearance. These factors ensure similar insertion times as the standard GE control blades during a scram. In addition, the roller and pin assemblies at the top and bottom end of the blades are made of noncobalt alloys. Therefore, the roller-and-pin assembly is less of an activation and radioactive waste concern than the standard GE control blades.

The Advanced Longer Life Control Rod design (ALLCR) (also known as the Duralife 190 control rod) is an extension of the HICR design. It is designed to increase control rod assembly life and to eliminate cracking of absorber tubes containing B_4C. This design is also compatible with reactor internals and existing site equipment. The ALLCR design differs from the HICR only in the following areas:

A. There is a 6-inch long hafnium plate in the top portion of each blade wing. The hafnium plate increases blade lifetime since the blade tip generally experiences the highest neutron flux.

B. There is a modified velocity limiter which weighs approximately 20 pounds less than the original design to compensate for the additional weight of the hafnium absorber plates. Scram and withdrawal performance, however, is maintained.

C. The overall weight is slightly less than the weight of either the standard GE blade or the HICR design due to the lighter velocity limiter. The reduction in weight does not adversely affect rod drop velocity or scram times. The new design results in average drop velocities of less than 2.78 ft/s at operating conditions which is bounded by the design basis value of 3.11 ft/s. Both velocities are bounded by the 5-ft/s drop velocity assumed in the rod drop accident analysis (see Section 15.4.10).

All other features of the HICR are retained, such as the high-purity, Type 304 stainless steel B_4C absorber rod tubing, the full-length hafnium rods in each wing, and the noncobalt pin-and-roller material.

A further advancement of the Duralife 190 control rod is the Duralife 230 control rod. These control rods are the same except the volume of absorber material (B_4C and Hafnium) is greater in the Duralife 230 control rod, extending the control rod life.

4.6.2.1.3 ASEA-ATOM Control Blade

The ASEA-ATOM manufactured control blades are very similar to standard GE control blades (Figure 4.6-3). The cruciform absorber section is formed by four solid stainless steel sheets intermittently welded together at the center. The intermittent center weld-joint ensures straightness and required stiffness while permitting 28 cutout sections which result in significant weight savings. The blade

The tubes in the HICR- and ALLCR-type control blades are made of a high-purity, Type 304 stainless steel, resulting in these control blades being less susceptible to intergranular stress corrosion cracking than the standard GE control blades. These control blades experience lower gas pressure buildup since there is no gaseous release from the hafnium.

Operating experience shows that the materials used in the control blades are not susceptible to dimensional distortion in service.

Control blade absorber tubing is supported within the control blade assembly and can withstand external pressures far in excess of those experienced under accident conditions.

The design internal pressure and design external pressure for the ASEA-ATOM blades were set at 2175 psi and 1375 psi, respectively. Results from a stress analysis indicated that a maximum internal pressure and maximum external pressure of 2030 psi and 3190 psi, respectively, would not exceed ASME Section III criteria. The design internal pressure (2175 psi) was achieved by tightening manufacturing tolerances in order to increase minimum wall thickness. These control blades are expected to withstand external pressures that may be experienced under accident conditions.

4.6.2.1.5 Control Blade Life

The end of control blade life is defined as either the exposure when any quarter segment of a control blade reaches a 10% reduction in worth relative to a new original equipment control blade, or a mechanical (structural) limit. The reduction in control blade worth is due to a combination of B-10 depletion, transmutation of hafnium isotopes and the B_4C loss resulting from the cracking of the absorber tubes, commonly known as wash-out. B-10 depletion occurs when a B-10 atom captures a neutron to form helium and lithium (i.e., $^{10}B + {}^{1}n \rightarrow {}^{7}Li + {}^{4}He$). Thus, for each B-10 neutron capture, the number of B-10 atoms is reduced. In control blades utilizing hafnium, hafnium transmutation is expressed in terms of B-10 equivalent depletion. Washout has been observed in original equipment control blades irradiated to exposures greater than 50% of the B-10 depletion lifetime criteria. The B_4C in original equipment control blades is in a powder form packed in stainless steel tubes. At high exposures in the reactor, these tubes have been observed to crack thereby allowing the reactor coolant to wash-out the local B_4C. Therefore, an acceleration term is used in determining the recommended lifetime for original equipment control blades. The end of control blade life (i.e., 10% reduction in relative worth) for the different control rod designs is provided in the appropriate lifetime documents.[4,5]

The on-line core monitoring code, POWERPLEX, calculates control blade exposure in snvts (nvt* 10^{21}) on both a nodal and quarter segment basis. These control blade exposures are then compared to appropriate lifetime limits for the various control blade types in the core.

4.6.2.2 Burnable Neutron Absorbers

See Section 4.2 for information on the use of gadolinium in the fuel.

4.6.2.3 Recirculation Flow Control

The recirculation flow control system is discussed in Section 7.7.

4.6.2.4 Standby Liquid Control

The standby liquid control system is described in Section 9.3.5.

4.6.3 Information for Control Rod Drive System

4.6.3.1 Control Rod Drive System Design

The reactivity control system provides the means to regulate core excess reactivity under normal operating conditions. Moveable control rods are used to control the fission rate and fission density. The control rods are capable of being positioned in 6-inch steps,more commonly called notches, corresponding to the CRD index tube, to control neutron flux distribution in the reactor core. They can be moved only individually at an average rate of approximately 3 in./s once system differential pressures and flows have been established. The movement of control rods does not perturb the reactor beyond the capability of an operator to respond to the disturbance. This requirement prevents unnecessary operation of the reactor protection system. The maximum rate at which the rods can be moved and the incremental distance between control drive notches is such that under normal operating conditions a single notch increment of control rod withdrawn at the maximum withdrawal rate results in a reactor period of not less than 20 seconds.

The following list of BWR/6-type CRD components vary from the original BWR/3-type CRD:

A. Piston tube,

B. Index tube,

C. Buffer assembly,

D. Spud and cylinder,

E. Inner filter,

F. Uncoupling rod,

G. Cooling water orifice ,

H. Nut, and

I. Drive piston assembly.

The BWR/6 CRD design, which incorporates a new hydraulic buffer configuration, utilizes the higher strength material and implements the latest design improvements. These BWR/6-type features provide improved operating availability and reduced maintenance. The BWR/6-type design was previously installed in a BWR/4-type plant at a different utility. This installation was for one operating cycle and served as part of the demonstration/verification test for this new design. The design has been recommended and reviewed by General Electric Company. General Electric has also provided a safety evaluation report and a stress analysis report.[2]

4.6.3.3 Control Rod Drive Hydraulic System

4.6.3.3.1 Design Bases

The control rod drive hydraulic system is designed to achieve the following objectives:

A. Provide a water source at a pressure of nominally 1380-1510 psig for charging the scram accumulators;

B. Provide a water source at a constant pressure of nominally 250-280 psi above reactor pressure to supply water for normal drive operation;

C. Provide a water source at a constant pressure of about 20 psi above reactor pressure to supply cooling water for each control rod drive mechanism, and

D. Provide a source of clean high pressure reactor recirculating pump seal purge flow.

E. Provide a continuous source of water to backfill the reference-leg piping of the Reactor Vessel Water Level Instrumentation System.

4.6.3.3.2 System Description

Under normal operation, the hydraulic control system uses condensate as the working fluid to accomplish hydraulic positioning of the control rod drives and their attached control rods. Drive water pressure is set to achieve the desired control rod velocity during control rod positioning. The desired rate of control rod motion is obtained by supplying a set quantity of water to the drive which moves the drive by displacing water on the other side of the drive piston. Manual valves are set to provide the desired water flowrate at the established drive water pressure thereby controlling the control rod speed. Pressure and flow for fast insertion (scram) of the control rods is supplied by stored energy in the scram accumulators or by reactor pressure.

The system, shown in Figures 4.6-4 and 4.6-5, is made up of supply pumps, filters, strainers, control valves and associated instrumentation and controllers. The CRD system normally draws suction from the condensate reject line which is downstream of the condensate demineralizers. This system can also draw suction from the condensate storage tank. The CRD system provides water for the reactor recirculation pump seals, CRD accumulator charging, drive water for normal CRD insert/withdraw operations, CRD drive cooling water and the RVWLIS Backfill System. Flow control and drive water pressure control stations are connected in series and provide pressure regulation for the various requirements. The highest pressure, nominally 1500 psig, is provided to the scram subsystem for charging the scram accumulators and to purge the reactor recirculation pump seals. The next highest pressure is regulated to maintain 250-280 psi above reactor pressure and supplies water for normal CRD drive operations. The third water source is regulated to maintain 20 psi above reactor pressure and provides cooling water to the drive mechanisms. These pressures vary directly with reactor pressure changes, and are controlled by using valves which develop constant pressure drops due to the constant flow from the flow control station. These three water supplies plus the exhaust water header are the four operating pressures of the control rod drive hydraulic system. A crosstie of the Unit 2 and Unit 3 CRD hydraulic systems is provided on the discharges of the CRD pumps.

The CRD hydraulic system is also identified as an alternate reactor coolant supply during an accident as directed by the Emergency Operating Procedures.

4.6.3.3.2.1 Supply Pump

The supply pump pressurizes the system. The spare pump is a 100% capacity standby unit. Changeover from one unit to the other is manual. Each pump is installed with a suction strainer and appropriate isolation valves to permit pump maintenance. The pump is designed to operate at the required pressure. The pump discharge pressure is indicated at the pump by a pressure gauge. A minimum-flow bypass connection between the discharge of the pump and the condensate storage tanks prevents the pump from overheating if the pump discharge valve is inadvertently closed. The CRD piping is routed from the CRD pumps in the turbine building through the feedwater heater bay to the reactor building and the drive water filters. A line taps off to provide water to the reactor recirculation pump seals.

The CRD pump discharge valves are motor-operated stop-check valves. The power source for each motor operator is the same as that of the associated CRD pump. The power and control cables for the motor operators are routed as balance-of-plant cables with separate routings provided to enhance the reliability of the design.

Two parallel filters are provided on the suction side of the pump to remove foreign material larger than 25 microns from the hydraulic system water. Discharge filters utilize a 50 micron material. Either filter can be drained, cleaned, and vented for reuse while the other is in service. A differential pressure indicator and an alarm monitor the discharge filter elements as they collect foreign material. StraTiners in the filter discharge lines guard the hydraulic system in the event of a filter element failure.

4.6.3.3.2.2 Accumulator Charging Pressure

The accumulator charging pressure is established by pump head and the flow control station and is independent of reactor pressure. The accumulator charging header taps off the outlet of the drive water filters downstream of the system flow-sensing element but before the flow control station. The CRD accumulator charging water pressure is considered the first stage pressure in a three-stage pressure control system. On a scram, the scram inlet valves open causing the accumulators to discharge to the area below the drive pistons. The scram outlet valves allow water above the pistons to discharge to the scram discharge headers. The accumulators automatically recharge by CRD system flow when the scram signal is cleared and the inlet and outlet scram valves close.

Since the accumulators discharge during a scram, the CRD supply pumps provide maximum flow to try to recharge the accumulators. The high charging line flow is sensed by the flow element closing the flow control valve during a scram to force the water to the accumulators. Once the accumulators are recharged, the flow control station is restored to its normal flow control operation.

The accumulator charging pressure in the header is monitored in the control room with a pressure indicator and low pressure alarm.

4.6.3.3.2.3 Flow Control Station

Downstream of the accumulator charging line is a flow control station which consists of air-operated flow control valves. Two parallel valves are provided, one being a spare to permit valve maintenance. The CRD flow-indicating programmable controller works in conjunction with the flow sensor located upstream of the accumulator charging line to maintain a constant flow through the flow control valves. The pressure in the charging line header is monitored in the control room with a pressure indicator and a low pressure alarm. (See Section 4.6.3.3.2.2 for a description of the flow control station during a scram.)

4.6.3.3.2.4 Drive Water Pressure Control Station

The second stage pressure is maintained at approximately 250-280 psi above the reactor vessel pressure. A motor-operated drive water pressure control valve, which is remotely adjusted from the main control room, is used in conjunction with the CRD stabilizing valves to adjust CRD drive water flow. Two stabilizing valve stations are provided, each containing one insert and one withdraw stabilizing valve. These normally open valves provide bypass flow around the drive water pressure control valves to the cooling water header. This flow helps maintain constant CRD drive pressure when making CRD position changes by compensating for the flow needed to reposition the CRD. Whenever an insert signal is given, the insert stabilizing valve closes to provide the required CRD insert flow (approximately 4 gal/min). Whenever a withdraw signal is given, the withdraw stabilizing valve closes to provide the required CRD withdraw flow (approximately 2 gal/min). The variation in flow requirements between drives is small enough that the corresponding pressure variation is within acceptable limits.

Filters are installed before the stabilizing bypass valves to prevent fouling. Isolation valves are provided for maintenance. A flow element and an indicator are installed for measuring the flow through the stabilizing bypass valves so that they can be adjusted to provide the required flow for normal drive operation.

The drive water header flow element and indicator are used to measure flow to the drives for adjustment and testing. Differential pressure indication in the main control room and in the reactor building shows the differential pressure between the reactor vessel and the drive water header. This pressure indicator is used when adjusting the second stage pressure with the motor-operated drive pressure control valve.

The CRD drive water pressure control valve control switch is a spring-return-to-center-position-type switch and is located in the main control room on the 902(3)-5 panel.

4.6.3.3.2.5 Cooling Water Header

The CRD cooling water header pressure is maintained at 20 psi above reactor pressure. The CRD cooling water supplies the CRD drives. This pressure is controlled from the control room and maintained by the combination of the upstream flow control station and the drive water pressure control station.

The CRD cooling water system is made up of the cooling water header, an individual line for each drive and a ball check valve at the CRD. This system admits water to the underside of the drive piston. Although the drive can function without cooling water, the life of the graphitar seals and elastomer O-rings is shortened by exposure to reactor temperatures; therefore, cooling water is provided to protect these components. The ball check valve opens to admit cooling water when the drive is stationary. When a drive is in motion, the pressure under the piston is higher than the cooling water pressure, and the ball check valve closes.

The cooling water is monitored by a flow indicator located in the main control room. A differential pressure indicator indicates the difference between reactor pressure and cooling water pressure. Control rod drive temperatures are recorded in the control room.

4.6.3.3.2.6 Exhaust Header

The exhaust header receives water discharged by the drives during repositioning and returns this water to the reactor through the CRDs by way of the cooling water header and back lifting of other "121" valves. The piping is sized to maintain a low differential (approximately 5 psi) above reactor pressure in this header. A check valve prevents backflow through the exhaust header.

4.6.3.3.2.7 Hydraulic Control Unit

One hydraulic control unit (HCU) serves each individual CRD and contains all actuating valves and other components required for the normal or scram operation of that CRD. Figures 4.6-9 and 4.6-10 provide an overall view of an HCU. The 177 HCUs are installed in roughly equal numbers in eight rows divided into two banks, one bank on the east side and one bank on the west side of the reactor building at ground level, as shown on Figure 1.2-4 (Drawing M-4). Each bank consists of four rows of HCUs arranged back-to-back forming two row-pairs. Principal components of the HCUs are described below.

4.6.3.3.2.7.1 Accumulator

The accumulator in each HCU is an independent source of stored energy for the scram function of the associated drive.

To assure that it is always capable of producing a scram, the accumulator is continuously monitored for water leakage and for nitrogen pressure. A float-type level switch actuates an alarm if water leaks past the nitrogen-water barrier and collects in the bottom of the HCU instrument block. A pressure indicator and a pressure switch are connected to the accumulator to monitor nitrogen pressure. A decrease in nitrogen pressure actuates the pressure switch and sounds an alarm in the control room. An isolation valve allows the accumulator instruments to be isolated and serviced.

4.6.3.3.2.7.2 Scram Pilot Valves

During normal operation, each of the two parallel branches of the RPS energizes one of the two 3-way solenoid scram pilot valves associated with each HCU. During normal operation, these pilot valves are energized and supply instrument air to the operators of both the scram inlet valve and the scram outlet valve, holding both scram valves closed. During a full scram, both of the RPS branches are deenergized and both pilot valves open, venting the scram valve operators and allowing the scram valves to open. To protect against spurious scrams, the pilot valves are interconnected so that both pilot valves must be deenergized to vent the scram valve operators. On the other hand, either loss of electric power to both solenoids or loss of instrument air produces a scram. The pilot valves are selected based on simplicity of design, a minimum of moving parts, fast opening time (approximately 0.050 seconds) and satisfactory statistical operating history on similar units.

For added protection, the instrument air header to all the pilot valves has a pair of backup scram valves. When energized, the backup scram valves isolate and vent the instrument air header to the scram valves and insert all drives should any of the scram pilot valves fail to vent.

4.6.3.3.2.7.3 Inlet/Outlet Scram Valves

The scram inlet valve is a globe valve which opens by the force of an internal spring and closes when air pressure is applied to the top of the diaphragm operator. The opening force of the spring is approximately 700 pounds. Each valve has a position indicator switch. The inlet and outlet scram valve position indicator switches energize a light in the control room as soon as both valves start to open. The scram inlet valve was selected based on high operating force, fast opening time (approximately 0.1 seconds) and satisfactory operating history on similar units.

The scram outlet valve is identical to the scram inlet valve. By design it must open first to prevent damage to the CRD, therefore the scram outlet valve spring is set at a higher tension.

4.6.3.3.2.7.4 Directional Control Valves

Four solenoid directional control valves are used for switching the drive water header and the exhaust header to the two drive ports of the CRD. By energizing and opening two valves at a time, the drive water header can be connected under or over the control rod drive piston while the exhaust header is connected to the opposite side. Two of these directional control valves, which include speed control valves, are connected so that they always pass the flow to or from the underside of the piston. The normal drive speed is 3 in./s.

The balance of forces in the drive mechanism is such that the differential pressure under the piston is approximately 80 psi whenever the drive is either inserting or withdrawing.

Proper speed for control rod insertion is obtained when the speed control valve is set so that a flow of 4 gal/min through the valve produces a pressure drop of 200 psi (from 280 psi in the drive water header to 80 psi under the piston). Similarly, for control rod withdrawal, the speed control valve is set so that 3 gal/min produces a pressure drop of 75 psi (from 80 psi under the drive piston to 5 psi in the exhaust header). The directional control valves are protected from dirt by filters.

The cooling, control, and scram flow paths for each drive use common piping to the drive. The two directional control valves connected to the drive water header could be caused to open when subjected to this higher pressure during a scram on their outlet ports. The check valve prevents significant loss of water to the drive water header during scram.

4.6.3.3.2.8 Scram Discharge Volume

The scram discharge volume (SDV) is used to limit the loss of, and contain, the reactor vessel water from all the drives during a scram. During normal operation, the SDV is empty, with its drain and vent valves open. These valves operate very much like the HCU scram valves. With a scram signal, the RPS is deenergized and the two SDV pilot valves vent the discharge volume valve operators, causing them to close. Position indicator switches on the main valves indicate the position of the vent and drain valves.

The SDV consists of a separate, nonconnected volume for each of the two banks of CRDs. For each bank of CRDs, the SDV consists of four 4-inch and two 8-inch diameter pipes mounted horizontally over the CRD HCUs, a 20-inch diameter tank located nearby, and a 6-inch header connecting the pipes and tank. Each tank on Unit 3 is instrumented with 4 float-type level switches and 2 dP-type level switches. Each tank on Unit 2 has 4 moisture detection switches and 2 dP-type switches. One level switch provides a high-level alarm, and one a rod block. The other four level switches provide a scram function in the RPS. These level switches also guard against the SDV being filled such that it cannot accommodate the water discharge during a scram. Should the SDV start to fill with water, an alarm would sound, a rod block would be activated, and if filling were to continue, the reactor would automatically scram. Each tank is also provided with a vent and drain. The Unit 2 vent goes to a vent header routed to the RBEDT, while the drain goes to the equipment drain header. The Unit 3 vent goes to a floor drain while the drain is piped directly to the RBEDT.

During a scram, the SDV partly fills with the water from above the drives. While scrammed, the control rod drive seal leakage continues to flow to the SDV until the SDV pressure equals reactor vessel pressure or until the scram valves are reset. When scram signals are no longer present, the scram logic can be reset to allow the scram valves to reclose. This allows the SDV isolation valves to reopen and allow the SDV to be drained. A control system interlock does not allow the drives to be withdrawn until the SDV is emptied to below the rod block point.

A test pilot valve allows the SDV valves to be tested without disturbing the RPS.

pressure to drop below this value, a condition necessary for higher withdrawal speeds, results in collet locking.

During reactor shutdown and with fuel loaded into the core all control rods are normally inserted. Interlocks are provided which prevent the inadvertent withdrawal of more than one control rod with the mode switch in the refuel position.

4.6.3.4.1.1 Operational Reliability

Each drive mechanism has its own complete set of electrically operated directional control valves, which are closed when deenergized. The correct operation of all four valves in the correct sequence is required to cause the drive to withdraw. Consequently, the probability of multiple simultaneous independent valve failures that could cause accidental multiple rod withdrawal is extremely small. The electrical system which actuates the directional control valves is designed to prevent any credible failure from producing accidental movement of more than one control rod.

High operational reliability contributes generally to overall safety by minimizing the occasions when abnormal operating conditions are encountered. High operational reliability is the objective of the following features of the CRD hydraulic system:

A. Components in the hydraulic system are picked based on established reliability. A spare pump and control valves are provided for reliability. Operating valves are accessible for maintenance while the reactor is in operation.

B. Provisions are made to operate with a reasonable amount of foreign material in the reactor water and in the water supplied to the hydraulic system. Filters and strainers are incorporated in the drive mechanism in passages through which water is drawn into the drive mechanism.

C. The CRD housing has the capacity to resist buckling under the design loads and reduces the potential consequences in the event that it did buckle. Using conservative assumptions (housing at outer edge of pattern, full length of housing thin wall, extreme tolerances, and no support by housing support structure) the housing can support a load of 66,500 pounds. The maximum applied load occurs when the control rod is scrammed and is reaching its fully inserted position. The maximum column loading on the CRD housing during this instant is 17,100 pounds. A safety factor of nearly 4 exists. This maximum loading occurs at the end of the control rod insertion; therefore, if the control rod housing were to buckle, the control rod would remain inserted and could not be withdrawn.

Instrumentation and alarms monitor operation of flow and pressure regulation to assure availability of drive water and cooling water. Operation of drive control, scram, and scram pilot valves are observed during periodic testing of CRD operation and during scram tests.

The guide tubes are 10-inch, Schedule 10, Type 304 stainless steel pipe. Each guide tube has a backseat on the lower end which rests on the control rod drive thimble. This seat restricts water flow out of the tube during a velocity limiter free fall; the seat also restricts water flow into the interior of the guide tube during normal reactor operation to prevent coolant bypass of the fuel elements.

4.6.3.6.3 Design Evaluation

During the development of the original GE velocity limiter, sensitivity tests were performed to assess the effect of manufacturing tolerances in the following items on the velocity limiter performance: limiter and guide tube diametral tolerance; nozzle (interfacial gap between cones) gap; top cone thickness; limiter/guide tube eccentricity; and surface finish. These tests and the optimization of the velocity limiter design are described in detail in APED-5446, "Control Rod Velocity Limiter."[1] The results of these tests are summarized as follows:

A. Dropout Velocities

1. Cold reactor 2.46 ft/s
2. Hot reactor 2.86 ft/s

B. Scram Times

1. 10% of full insertion 0.33 s
2. 90% of full insertion 3.05 s

Since the new velocity limiter is interchangeable with the original GE velocity limiter, the operational characteristics are bounded by the original velocity limiter design. This was confirmed by extensive testing performed at both room and operating temperatures and pressures to confirm that drop velocities and scram performance are within the design bases of the original velocity limiters. During these tests, the velocity limiter and control rod were subjected to the worst case scram loads, including failed CRD buffer conditions, with no degradation of structural integrity.

4.6.4 Evaluation of the Control Rod Drive System

4.6.4.1 Scram Effect

The rod position versus time curve used in the transient analyses lies on the conservative side of the data, i.e., on the slow side of the data spread but faster than specifications given above. In addition, in making the analyses, the standard S-shaped curve of reactivity versus position is used. Analysis of the limiting excursions (Section 15.4.9) has shown that negative reactivity insertion rates of 3% $\Delta k/s$ for the first 10% of rod travel and 5% $\Delta k/s$ to the 90% insertion point, with a 0.2-second instrument and valve actuation delay, provide the required protection. Figure 4.6-14 shows the scram system response used in the analyses of Section be capable of expelling any conceivable line restrictions. The system is designed to accommodate such pressures.

Also, because of the unique design of the locking-piston drive, an automatic scram occurs if both drive lines or only the outlet line is severed at any point with the reactor at pressure.

4.6.4.6 Potential Release Path Through the CRD Hydraulic System

An issue raised by the NRC identified the CRD system as a potential containment bypass pathway. This pathway combines a loss-of-coolant accident with either a postulated seismic event which results in a CRD line rupture in the turbine building or backleakage through the CRD piping to the condensate storage tank. An evaluation was performed on the Dresden design to assess the risk to the public and the plant operators during such an event. The effects of the event were found to be limited in scope and to result in exposure below the 10 CFR 100 limits.

The two reactor recirculating pump seal purge lines were identified as an additional potential release pathway. These lines are equipped with redundant, safety related check valves between the containment penetration and the CRD drive water header. In the event of loss of the operating CRD pump, either during normal operation or after an accident, these check valves close and isolate the potential pathway. These check valves are leak rate tested as part of the IST program.

4.6.5 Testing and Verification of the CRD System

4.6.5.1 Control Rods and Control Rod Drives

Testing and inspecting of the control rod velocity limiter is not required following installation of the control rod assembly. In addition to close surveillance during the fabrication of the rod velocity limiter and control rod assembly manufacture, random control rod assemblies were shop-tested (which included rod drop tests). Each velocity limiter was visually inspected and gauged prior to assembly. Preoperational tests confirm the operation of the individual control rod assemblies for normal operation and scram conditions.

During production, control rods are statistically tested for dimensions. After installation, all rods and drive mechanisms are tested full stroke for operability.

During reactor operation, individual drive mechanisms can be actuated to demonstrate functional performance. Each time a control rod is withdrawn a notch, the operator observes the incore monitors' indications to verify that the control rod is following the drive mechanism.

When the operator withdraws a control rod fully out of the core, the coupling integrity is tested by trying to withdraw the rod drive mechanism to the overtravel position. Failure of the drive to overtravel demonstrates rod-to-drive coupling integrity.

During reactor shutdown, the shutdown margin can be verified by withdrawing a maximum worth rod and demonstrating that the reactor is substantially subcritical. During a refueling outage, each control rod is fully withdrawn and inserted to test for operability. The scram time for each control rod is tested as required by the technical specifications.

During normal rebuilding of drive mechanisms, a pull test is performed on the inner filter to insure proper installation. Loose inner filters had been identified as contributing to control rod to drive uncoupling events. The pull test is performed to significantly reduce the potential for a loose inner filter to cause control rod uncoupling.

4.6.5.2 Control Rod Drive Housing Supports

Sections of the CRD housing support may be removed to permit maintenance on control rods. Any time maintenance or other work on the CRD system has been performed, the support structure is inspected to assure proper installation before the reactor is returned to operation.

4.6.6 References

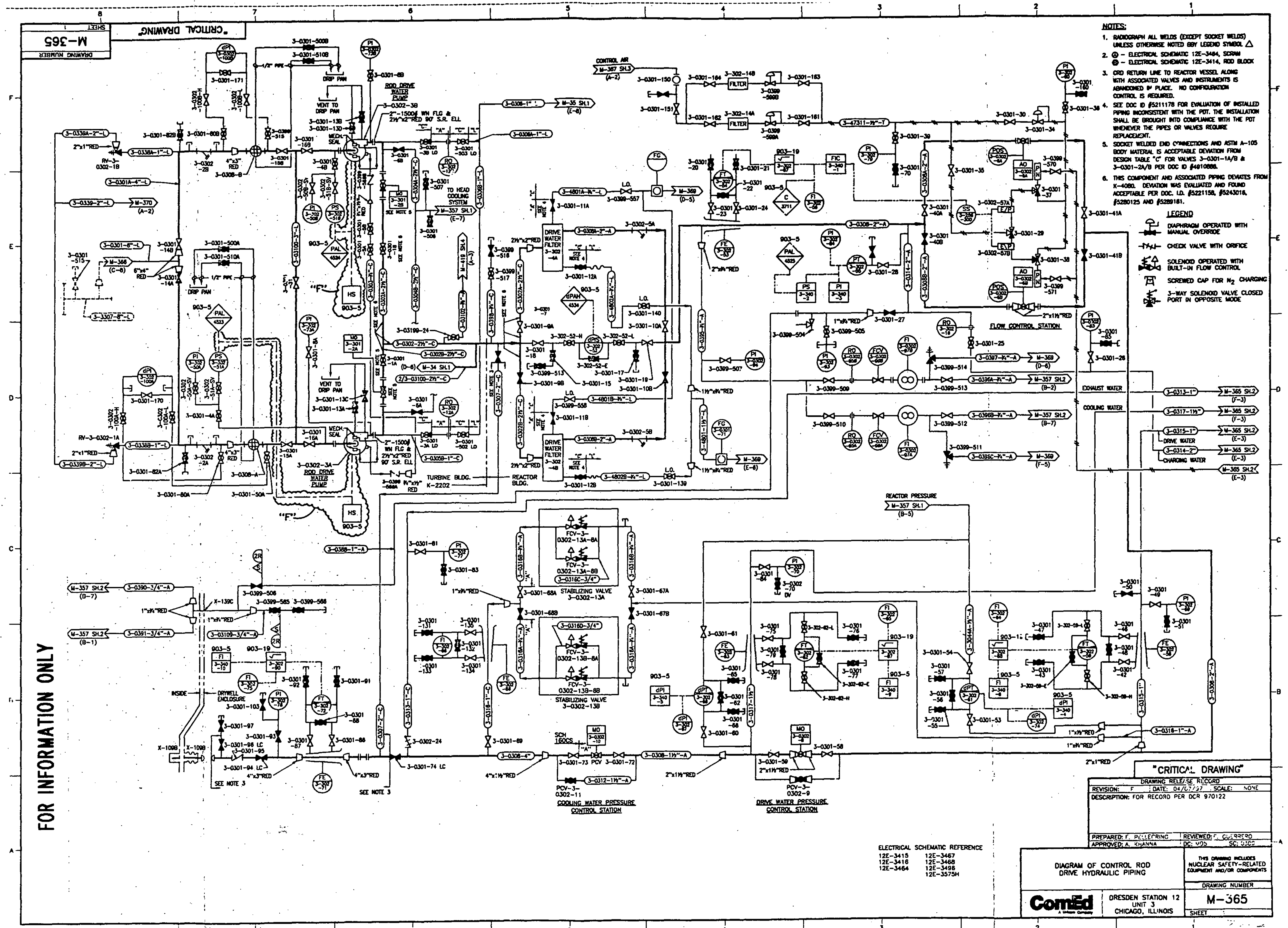
1. Nuclear Regulatory Commission, "Control Rod Velocity Limiter," APED-5446.

2. General Electric letter to E.D. Eenigenburg, G-EBO-7-18, dated January 9, 1987.

3. "GE Evaluation in Response to NRC Request Regarding BWR Scram System Pipe Breaks," NEDO-24342, April 1981.

4. "GE BWR Control Rod Lifetime," NEDE-30931.

5. "ABB-ATOM Control Rods for BWR 2/3/4/5/6 Service Life Limits Recommendations," UR 87-102, Revision 1, April 15, 1987.



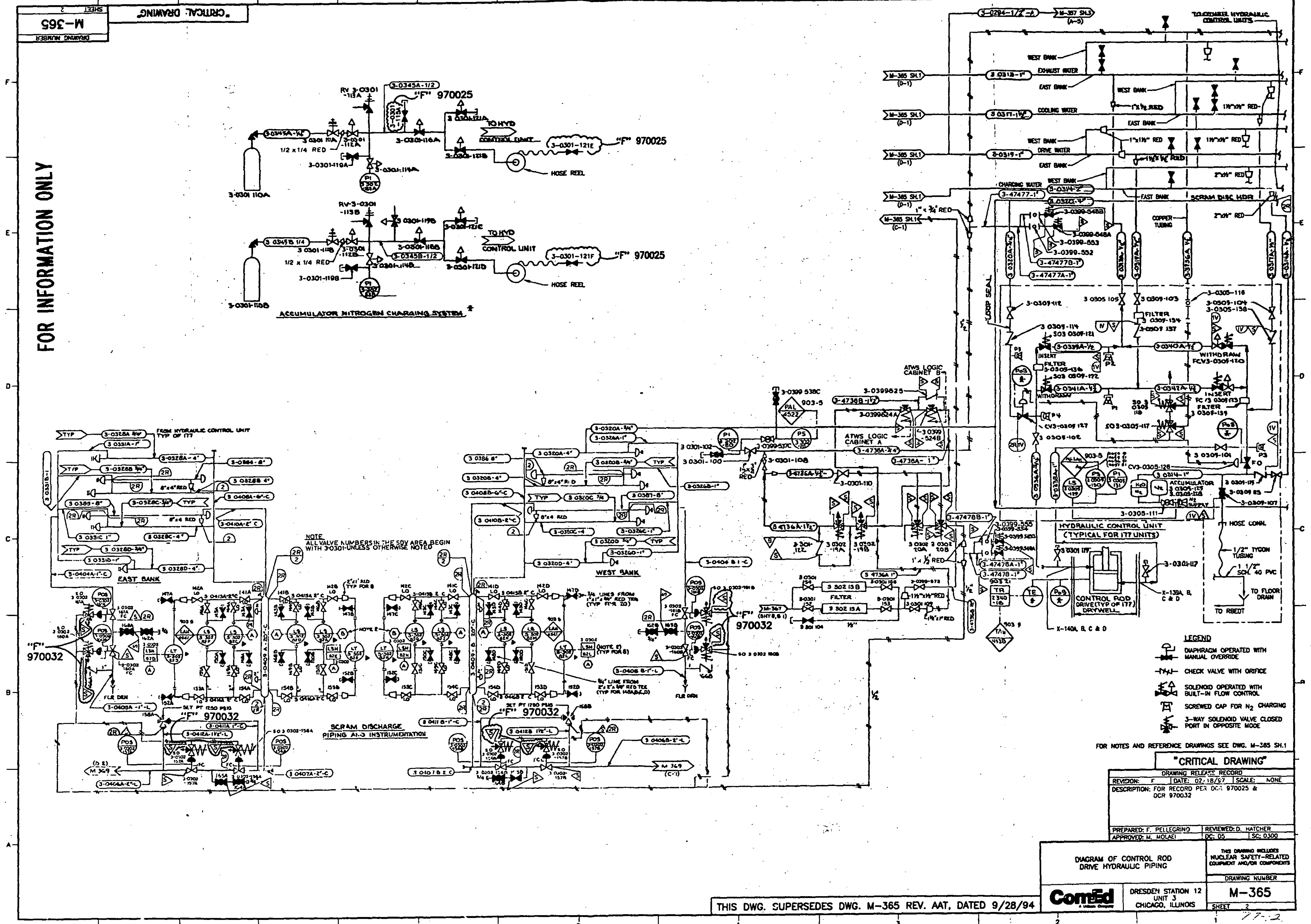
CENTRAL DRAWING FACILITY

30X

REV. 02 / JUNE 1997

FIGURE 4.6-5

FOR INFORMATION ONLY



REV. 02 / JUNE 1997

FIGURE 4.6-5

CENTRAL DRAWING FACILITY

30 X

5.0 REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS
TABLE OF CONTENTS

5.0 REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS
TABLE OF CONTENTS

5.0 REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS
TABLE OF CONTENTS

Page

Table 5.1-1 (Continued)

REACTOR COOLANT SYSTEM DATA

Speed	variable
Flowrate	45,000 gal/min
Design pressure and temperature	1450 psig at 575°F
Developed head	570 ft
Design code	ASME Section III, Class C

Recirculation Valves

Number	
Unit 2	8
Unit 3	4
Type	Motor-operated gate
Design code	ASME Section I and USAS B 31.1.0

Jet Pumps

Number	20
Material	Stainless steel
Overall height (top of nozzle to diffuser discharge)	18 ft, 7 in.
Diffuser diameter	20¾ in.
Design	APED-5460 (General Electric)

Main Steam Lines

Number	4
Diameter	20 in.
Material	Carbon steel
Design code	ASME Section I and USAS B 31.1.0

Table 5.1-1 (Continued)

REACTOR COOLANT SYSTEM DATA

<u>Electromatic Relief Valves</u>	
Number	4
Capacity (each)	540,000 lb/hr
Pressure setting	1101 or 1124 psig
Design code	USAS B 31.1.0
<u>Target Rock Safety Relief Valve</u>	
Number	1
Capacity	622,000 lb/hr
Pressure setting, relief	1124 psig
Pressure setting, safety	1135 psig
Design code	ASME Section III, 1971
<u>Safety Valves</u>	
Number	8
Capacity (each)	Varies with setpoint — see Table 5.2-1
Pressure setting	Varies 1240 to 1260 psig
Design code	ASME Section III and USAS B 31.1.0
<u>ISOLATION CONDENSER</u>	
Number	1
Number of tube bundles	2
Design pressure	
Shell	25 psig at 300°F
Tubing	1250 psig at 575°F
Design code	
Shell	ASME Section VIII
Tubing	ASME Section III, Class A

Table 5.1-3

Coolant Volumes (ft^3)

	Unit 2	Unit 3
Lower Plenum	2196	2211
Upper Plenum	1216	1626
Steam Dome	6672	6642
Steam Line Piping (up to MSIVs)	1759	1759

The reactor vessel and its appurtenances are addressed in Section 5.3. Items of discussion include the vessel materials of construction, compliance with fabrication codes and regulatory guides, and methods of fabrication. Sensitized stainless steel and intergranular stress corrosion cracking (IGSCC) associated with the safe ends and vessel internal brackets are addressed in Section 5.3; the reactor vessel materials surveillance program for the shift in the nil ductility transition (NDT) temperature is also covered in Section 5.3. The NDT temperature effect on the pressure-temperature operating curves is also addressed. Compliance with the intent of 10 CFR 50, Appendices G and H is also addressed.

The associated systems interfacing with or acting as a part of the RCS are addressed in Section 5.4. The systems and/or components discussed are the reactor recirculation system, the hydrogen water chemistry system, the isolation condenser, the main steam line isolation system and flow restrictors, the reactor shutdown cooling system, the reactor water cleanup system, and the main steam line and feedwater piping up to and including the outermost isolation valves. The main steam system, feedwater system, and condensate system are addressed in more detail in Chapter 10.

5.1.1 Schematic Flow Diagram

The typical reactor coolant system is shown in Figure 5.1-1. Nominal flowrates, temperatures, and pressures for both units are listed. Coolant volumes are listed in Table 5.1-3.

5.1.2 Piping and Instrumentation Diagrams

The P&IDs applicable to the RCS and connected systems are identified in Table 5.1-2. This table is organized according to the drawing topic first and then the applicable unit.

5.1.3 Elevation Drawings

The elevation drawings and plan view section drawings for the RCS and other associated equipment are addressed in Figures 1.2-2 through 1.2-19

Each of the four relief valves and the dual-function safety relief valve discharge to the torus via dedicated (one per valve) relief valve discharge lines (RVDLs). Analyses have shown that upon valve closure, steam remaining in the RVDL can condense, thereby creating a vacuum which draws suppression pool water up into the discharge line. This "elevated water leg" condition is quickly alleviated by operation of the vacuum breakers on the RVDLs; however, the condition is of concern since a subsequent actuation in the presence of an elevated water leg can result in unacceptably high thrust loads on the discharge piping.

To prevent these unacceptable loads, the setpoints, control logic, and administrative controls for the relief and the safety relief valves have been designed to ensure that each valve which closes remains closed until the normal water level in the RVDL is restored. Prevention of these unacceptable loads is accomplished by first establishing opening and closing setpoints such that all pressure-induced subsequent actuations (after the first actuation) are limited to the two lowest set valves (203-3B and 203-3C). These two valves which are on separate steam lines are equipped with additional logic which functions in conjunction with the setpoints to inhibit valve reopening (via reactor repressurization or the automatic depressurization system) for at least 8 seconds following each closure. (This time delay compares with a calculated worst-case elevated water leg duration time of 6.3 seconds.) Administrative controls ensure an operator does not operate the valve manually. This combination of setpoint selection, control logic design, and administrative controls is sufficient to ensure that no credible scenario can result in actuation of a relief or safety relief valve in the presence of an elevated water leg.

The reactor safety valves are located on the steam lines inside the primary containment. They are balanced, spring-loaded-type safety valves which discharge directly to the drywell atmosphere. The safety valves are the final protection against overpressurizing the vessel and are sized to prevent the reactor pressure from exceeding the pressure limitations specified in the ASME Code. Sizing of the safety valves (see Section 5.2.2.2.3) assumed credit for either a flux or pressure scram of the reactor from full power but took no credit for the electromatic relief valves following closure of the MSIVs. The number of valves with their setpoints and capacities are listed in Table 5.2-1.

5.2.2.5 Mounting of Pressure Relief Devices

The relief valves, the safety valves, and the safety relief valve are mounted on the steam lines upstream of the isolation valves inside containment. These valves are flange mounted for ease of compliance with the testing requirements specified in the Technical Specifications. Distribution of these valves among the four steam lines on each unit is shown in Figures 10.3-1 and 10.3-3.

5.2.2.6 Applicable Codes to Maintain Reactor Coolant Pressure Boundary Structural Integrity

The structural integrity of the RCPB is maintained at the level required by ASME Section XI. The component inservice inspection (ISI) program, updated every 120 months, is performed in accordance with ASME Section XI rules as required by 10

CFR 50.55a(g), except where specific written relief is approved by the NRC pursuant to 10 CFR 50.55a(g)(6)(i).

5.2.2.7 Material Specification

Reactor coolant pressure boundary materials, including materials for the overpressurization protection system, are addressed in Subsection 5.2.3.

5.2.2.8 Process Instrumentation

The process instrumentation for the safety valves, the relief valves, and the safety relief valve is shown in Drawings M-12 (Figures 10.3-1, 10.3-2, 10.3-3, and 10.3-4). Acoustic monitors provide position indication and leakage detection (see Section 5.2.5.7) for all relief and safety valves. Temperature monitors with a range of 0 to 600°F provide additional backup information on all relief and safety valves.

5.2.2.9 System Reliability

Safety valve and relief valve sizing uses very conservative assumptions. The safety valve sizing relies on relief valve availability, turbine bypass valves, and the method of reactor scram. Further discussion about failures and their effects are addressed in Section 15.2.

5.2.2.10 Environmental Equipment Qualification

Environmental equipment qualification (EQ) testing was performed to verify the operability of the electromatic main steam relief valves actuators under accident conditions. See Section 3.11 for additional details on equipment qualification.

5.2.2.11 Inspection and Testing

Dresden Station has a preventive maintenance program for the relief valves. The Technical Specifications delineate the requirements such that one-half of the safety valves shall be bench-checked each refueling outage, and all relief valves shall be checked for set pressure each refueling outage. Inservice inspection is performed as required by ASME Section XI and the station's inservice inspection program. Additional details of the station's inservice inspection program is discussed in Section 5.2.4.

5.2.3.4.1.1 Avoidance of Significant Sensitization

Solution-annealing of stainless steel, whether the low carbon grades of Type 304L or normal Type 304, eliminates sensitization. Solution annealing of assembly welds or the use of Type 308L corrosion resistant cladding on the interior weld and heat-affected zone surface minimizes the effects observed from sensitization.

5.2.3.4.1.2 Electroslag Welds

The reactor vessel fabrication report on electroslag welding (compared to Regulatory Guide 1.34) is contained in Appendix 5B.

5.2.3.5 Intergranular Stress Corrosion Cracking

The Unit 2 reactor vessel entered service with furnace-sensitized material exposed to the reactor coolant (see Table 5.2-3). The Unit 3 reactor vessel underwent several modifications to the furnace-sensitized material such as replacement of the safe ends (see Table 5.2-6) to mitigate IGSCC before entering service. Generic Letter 88-01, "NRC Position on IGSCC in BWR Austenitic Steel Piping," dated January 25, 1988, provides the NRC staff position and guidelines concerning the piping materials used for the RCPB such as the Unit 3 reactor recirculation system piping which was replaced in the 1980's.

5.2.3.5.1 Program to Mitigate Intergranular Stress Corrosion Cracking

Commonwealth Edison Company is pursuing an integrated program to mitigate IGSCC. This program is in compliance with the requirements of Generic Letter 88-01; Generic Letter 88-01, Supplement 1; and NUREG-0313, Revision 2. Additionally, Dresden Station has committed to replacing IGSCC susceptible piping in the non-safety related portion of the RWCU system. The Unit 2 replacement was completed during D2R14. The Unit 3 replacement will be performed during D3R14.

5.2.3.5.2 Augmented Inspection Programs

Commonwealth Edison Company's augmented inspection program for IGSCC conforms basically to the NRC positions on inspection schedules, methods, personnel, and sample expansion delineated in Generic Letter 88-01. Any variances from the NRC staff positions are reviewed and approved by the NRC.

Commonwealth Edison Company has an inspection program in place to monitor carbon steel piping systems for wall thinning in response to the NRC Generic Letter 89-08, "Erosion/Corrosion - Induced Pipe Wall Thinning."[3,4] The feedwater system piping is examined in accordance with NSAC-202L. See Section 10.4 for further coverage of the feedwater system. The main steam line is exempted because it operates with dry or saturated steam and has little to no susceptibility to erosion/corrosion.

5.2.3.5.3 Technical Specification Amendment

The inservice inspection (ISI) program, in lieu of the Technical Specifications, contains a statement of CECo's conformance with Generic Letter 88-01 and NUREG-0313, Revision 2.[5]

5.2.3.5.4 Improved Leak Detection

Leakage detection limits and time periods were changed to reflect that the reactor coolant system leakage shall be limited to a 2-gal/min increase in unidentified leakage within any 24-hour period. The leakage shall be monitored and recorded at least once per shift, not to exceed 12 hours. If this leakage limit is exceeded, the unit shall start an orderly shutdown within the next 12 hours for inspection and corrective action. At least one primary containment sump collection and flow monitoring system shall be operable. With the primary sump collection and flow monitoring system inoperable, the inoperable system must be restored to operable status with 24 hours or the unit must immediately initiate an orderly shutdown.

5.2.3.5.5 NRC Notification

The NRC will be notified of the following conditions identified during examinations in accordance with Generic Letter 88-01:

A. Flaw indications exceeding the acceptance criteria of applicable ASME Section XI, Subsection IWB-3500;

B. A change found in the condition of the welds previously known to have flaw indications; and

C. The evaluation by the CECo Engineering Department for the above conditions for continued operation and/or the necessary corrective action to be taken.

5.2.4 Inservice Inspection of Reactor Coolant Pressure Boundary

The inservice inspection program for the third 10-year interval became effective March 1, 1992, and continues through February 28, 2002.[5] The ISI Program delineates and implements the requirements of 10 CFR 50.55a, July 31, 1991, and the ASME Section XI, 1989 Edition. Certain requirements are impractical to perform because of the design, component geometry, and materials of construction. Relief from such requirements is granted in accordance with 10 CFR 50.55a(g)(6)(i) following an NRC review of the request.

5.2.4.8 System Leakage and Hydrostatic Pressure Tests

System leakage and hydrostatic pressure tests are conducted in accordance with ASME Section XI and the relief requests granted as a part of the ISI program.[5]

5.2.5 Detection of Leakage Through Reactor Coolant Pressure Boundary

In the operation of any power plant, fossil fuel or nuclear, the ability to detect leaks and mitigate possible serious incidents is necessary for safe power plant operation. For a nuclear fuel plant, the detection and location of leakage is important due to the possible consequences to the public. However, there is a major difference between the "detection" of a leak and the "location" of a leak. The ability to detect a very small leak, e.g., in the cubic centimeters per minute range, is of no value unless the source of leakage can be found.

Ideally, frequent visual inspection by operating personnel of the main steam and feedwater lines would provide the means for detection of small leaks. Due to the steam lines being high sources of radiation and the proximity of the feedwater lines to the steam lines, visual inspection is possible only at low reactor power for those lines outside the drywell and with the reactor subcritical for those lines inside the drywell.

With the use of an unmanned containment for both units, remote means of leak location must be employed. However, at some point in the sequence of locating a leak, the visual inspection is necessary. For this visual inspection to be meaningful, the primary system has to be at or near operating conditions of pressure and temperature.

Once a leak has been determined to exist in the primary system within the primary containment, the magnitude of the leakage has to be determined.

If the leakage is within the allowable limit set by Technical Specifications, unit operation can continue unless the leakage is determined to be due to a through-wall RCPB pipe crack.

Since the primary containments for both units are unmanned systems, it is necessary that the operator be provided with remote means for the detection of leakage from the primary system. A number of systems are provided for the purpose of leak detection. Through the use of instrumentation on other operating systems and the systems to be discussed below, it is possible to determine the source and magnitude of the leakage.

The description of the systems contained in this section would be used by the operator to determine that leakage does exist within the drywell. These various systems operating together or singly provide information to the operator that a possible problem has developed within the drywell.

5.2.5.1 Drywell Sumps

The drywell floor drain sump (with a volume of 1000 gallons) and the equipment drain sump (with a volume of 1000 gallons) systems provide a reliable means of determining leakage trends in the drywell. These sumps are periodically pumped and, based on flow integrator readings at the pumping times, leakage rates are determined and compared. The sump isolation valves are normally closed and are opened manually (after receiving a high-level alarm) prior to pumping either the drywell floor drain sump or the equipment drain sump. The sump pumps then start automatically on high sump levels. Sudden increases in leakage causing a high sump level are alarmed in the control room and are evaluated based on flow integrator readings. The leakage collected in the drywell equipment drain sump is identified leakage and the leakage collected in the drywell floor drain sump is unidentified leakage.

Technical Specifications impose the following limits for reactor coolant leakeage:

1. No Pressure Boundary Leakage
2. ≤ 25 gpm total leakage averaged over any 24 hour surveillance period
3. ≤ 5 gpm unidentified leakage
4. ≤ 2 gpm increase in unidentified leakage within any period of 24 hours or less during power operations.

The leakage limits addressed here do not conflict with those addressed in Sections 5.2.5.6.4 and 5.2.5.8.

5.2.5.2 Continuous Air Monitor

Each drywell is equipped with one continuous air monitor (CAM) sampling point which takes an air sample from a selected point within the drywell. The air sample is drawn through the tubing, out through a drywell penetration and auto-isolation valves (Group II), and then to a continuous air monitor. This air monitor will count gross activity which is recorded and alarm on an increase. The alarm provides an indication that a radioactive leak has occurred. A charcoal and particulate sample cartridge is also provided in the CAM. The air sample is returned to the drywell via Group II auto-isolation valves.

5.2.5.3 Thermocouple Leak Detection

Thermocouples are located throughout the drywell. Selected points are provided to indicate, record, and alarm containment temperatures in the control room. Additional drywell temperature information is available to the operators locally at a instrument rack in the reactor building.

The main steam safety and electromatic relief valves are equipped with leak-off lines. Leakage is vented off through a closed piping system. The leakage from each main steam safety valve is routed past its own thermocouple and then to the drywell equipment drain sump. The leakage from each electromatic relief valve is routed past its thermocouple and then to its discharge line to the torus. The leakage from the Target Rock safety relief valve is monitored by a thermocouple in the valve discharge line to the torus. An increase in temperature on any of the thermocouples will sound an alarm in the control room.

5.2.5.4 Flow and Pressure Switches

Each of the reactor recirculating pumps is equipped with flow switches which will actuate an alarm in the control room on excessive seal leakage.

A pressure switch will alarm if failure of the inner O-ring takes place on the reactor vessel. Normal pressure between inner and outer O-ring is drywell pressure. Both the flow switch alarms and the pressure switch alarm are leak location systems.

5.2.5.5 Floor and Equipment Drains

In the case of a steam leak, essentially all of the leak will be routed to the floor drain sump as condensate from the drywell coolers. In the case of a liquid leak, about 60% will leak directly into the floor drain, and 40% will flash to steam and be routed to the floor drain sump as described above for steam leaks. Any significant increase can be detected in a few hours.

5.2.5.6 Location of Leakage in the Drywell

Once a leak is detected within the drywell by any of the methods covered above, it becomes necessary to determine its magnitude and rate of change with time. The smaller the leak, the more difficult it becomes to locate its source. However, through the use of the continuous air monitoring system, it is possible to detect changes in radioactive nuclides from one 24-hour period to the next. Very small leaks are thus possible to detect.

The systems described below would be used to find the source of leakage. The systems are remote in nature and provide a method of cross checking to locate the source of leakage or the area in the drywell in which the leak has developed. Chemical analysis of the reactor building sump contents aids in determining whether the leakage is from the reactor, the reactor building closed cooling water system, or the feedwater system.

5.2.5.6.1 Air Sample Manifold System

There are 24 air sampling points for the drywell and one for the torus which provide a means of taking air samples from specific areas of the drywell. Four of these sample points (three drywell, one torus) have automatic Group II containment isolation valves upstream. The remaining 21 drywell sample points have their inboard manual isolation valves locked closed. One of the three drywell sample points which have automatic containment isolation capability is equipped for a portable air sampler to obtain routine drywell atmosphere samples. A charcoal cartridge and particulate sample cartridge are included in the sampling system. Samples may not be taken from the 21 manual isolation points unless a person is in continuous communication with the control room and in attendance to manually close the isolation valves from the drywell in the event of a Group II isolation condition. If sampling from these points is necessary, only one sample point may be open at a time. Refer to Section 9.3.2.7 for additional system details. The points sampled are as follows:

A. Air return from reactor head area;

B. Airspace around reactor vessel;

C. Area over each recirculation system valve;

D. Drywell cooler outlet;

E. Area of recirculation pump seal (each pump)

F. Area of main steam and feedwater line penetrations;

G. Area under reactor vessel control rods;

H. Openings to control rod area; and

I. Torus sample.

The area between the two reactor vessel head O-rings is drained, vented, and monitored to provide an indication of leakage from the inner O-ring seal.

5.2.5.6.2 Deleted.

5.2.5.6.3 Flow or Pressure Switches

Each of the reactor recirculation system pumps is equipped with flow switches which actuate an alarm in the control room on excessive pump seal leakage. A

5.2.5.8 Leakage Rate Limits

The limiting leakage rates are presented in the Technical Specifications. With irradiated fuel in the reactor and coolant temperature greater than 212°F, the maximum unidentified leakage is less than or equal to 5 gal/min and the total leakage is restricted to less than or equal to 25 gal/min. If either of these leakage rates is exceeded, the operational action to be followed is stated in the Technical Specifications. These identified and unidentified leakages do not conflict with the leakage addressed in Section 5.2.5.1.

5.2.5.9 High/Low Pressure Interface

The core spray system, low pressure coolant injection system, and the shutdown reactor cooling system are all monitored for reactor coolant system leakage into the system by pressure switches located in the pumps discharge lines. These switches activate a high-pressure alarm in the main control room when the line pressure exceeds the alarm setpoint. The core spray system and low pressure coolant injection system lines are protected by relief valves which are tested in accordance with ASME Section XI. The Shutdown reactor cooling system lines beyond the double isolation valves are protected by relief valves (tubeside of the heat exchangers) which are tested in accordance with the state of Illinois pressure vessel inspections.

5.2.5.10 Compliance with Regulatory Guide 1.45

The various leak detection systems and capabilities, as described herein, detect RCPB leakage, both identified and unidentified. These sensitive and diverse systems meet the acceptance criteria of Regulatory Guide 1.45.

5.2.6 Detection of Leakage Beyond the Reactor Coolant Pressure Boundary

This section addresses only those portions of the steam and feedwater lines external to the drywell.

The area of concern for the steam lines is between the drywell penetration and the turbine stop valves and for feedwater lines between the drywell penetration and the outlet valve of the D feedwater heaters. This piping of concern is contained in a compartment called the steam tunnel and other portions are located in the turbine building.

Various remote leak detection and leak location systems have been provided so the operator has the necessary information to determine that a leak has developed and its possible source. A backup system is also provided which automatically takes action if a serious leak were to occur.

A temperature monitoring system is employed in the steam tunnel. There are four thermocouples located in the vicinity of the main steam isolation pilot valves; any one of the four will alarm in the main control room on high temperature.

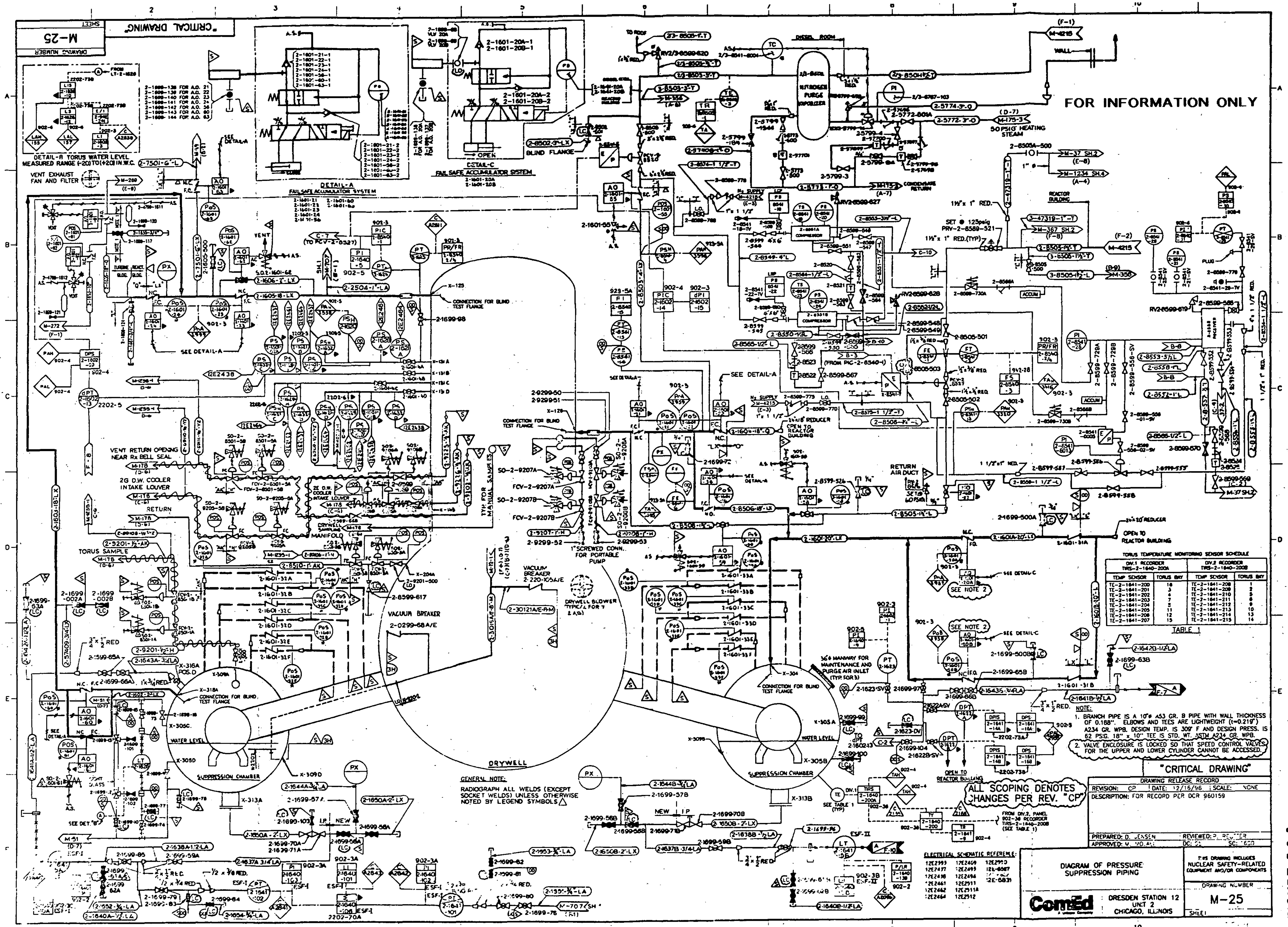
Table 5.2-2

TYPICAL REACTOR COOLANT PRESSURE BOUNDARY
MATERIAL SPECIFICATIONS

Reactor vessel	A 302 B Modified (Code Case 1335)
Reactor vessel closure head studs (6-inch diameter, 65-inch length)	SA 320 Gr L43 (Code Case 1335) (Material similar to 4340)
Reactor vessel bottom head	SA 302 B Modified (Code Case 1335)
Control rod housing material penetrating bottom head	SA 376 Type 304 or SA 312 Type 304
Stub material welded to reactor vessel and to housing	SB 167 Inconel 600 or SB 166
Weld filler metal	
Shop weld	ASTM B-295 (ENiCrFe-3 Group F-45)
Field weld	Inconel 182 or Inconel 82
Main steam	
Piping	A 106 Gr B
Fittings	A 105 Gr B
Feedwater piping	A 106 Gr B
HPCI	
Piping	A 106 Gr B
Fittings	A 105 Gr B
Pumps	A 216 Gr WCB
LPCI	
Heat exchanger shell	A 212 Gr B
Pumps	A 216 Gr WCB
Core spray pumps	A 216 Gr WCB
Recirculation pumps	AISI Type 304 and 316 stainless steel

Notes;

1. For piping 2" and under, ASTM A335 Grade P11 or P22 may be substituted for ASTM A106 Grade B material for the same schedule. For fittings and valves 2" and under, ASTM A132 Grade F11 or F22 may be substituted for ASTM A105 for the same rating. Substitutions are allowed up to a maximum temperature of 450°F (operating or design).



REV. 02 / JUNE 1997

FIGURE 5.2-9

CENTRAL DRAWING FACILITY 30 X

Stabilizer brackets, located below the vessel flange, are connected with flexible couplings to tension bars mounted on the top of the reactor shield wall. The reactor shield wall is laterally supported by stabilizers which are attached to gibs passing through the drywell wall and embedded in the concrete structure outside the drywell. The lateral supports limit horizontal vibration and resist seismic and jet reaction forces, yet the tension bars will permit radial and axial expansion.

Vertical loads from the reactor vessel are transmitted to the foundation through the vessel skirt, support girder, and support pedestal. Lateral loads are transmitted to the building through vessel stabilizers. The vessel stabilizers are attached near the top third of the vessel and are connected to the top of the concrete and steel reactor shield wall. The reactor shield wall in turn is anchored at the base to the top of the vessel pedestal and restrained at the top by a horizontal tubular truss system. The lateral loads are transmitted through the truss system to the drywell shear lug mechanism. This shear lug mechanism permits vertical movement of the steel drywell, but restricts rotational movement. However, lateral loads are transmitted through the shear lug mechanism to the heavy concrete envelope around the drywell which is part of the reactor building. A portion of the lateral loads are transmitted from the reactor vessel to the vessel pedestal and then to the foundation. Additional details of the loadings and supports are addressed in Section 3.9.

5.3.3.2 Materials of Construction

The materials of construction for the reactor vessels are addressed in Sections 5.2.3.1 and 5.3.1.1 and in the purchase order and vessel design report contained in Appendix 5A.

5.3.3.3 Fabrication Methods

The methods used in fabricating the reactor vessels are addressed in Sections 5.2.3.3 and 5.2.3.4, Section 5.3.1, and Appendices 5A and 5B. The major fabrication processes involved are electroslag welding, submerged arc welding, hot rolling of thick vessel plate, forging of nozzles and vessel closure flanges, and stress-relieving heat treatments. A summary of the reactor vessel fabrication history is presented for both units in References 7 through 9.

5.3.3.4 Inspection and Testing Requirements

The reactor vessel was stamped with an ASME Code N-symbol verifying that a hydrostatic test was satisfactorily made and all other required inspection and testing was satisfactorily completed. Such application of the ASME Code N-symbol together with final certification confirms that all applicable ASME Code requirements have been complied with.

The reactor coolant system was given a system hydrostatic test in accordance with code requirements prior to initial reactor startup. Before pressurization, the system was heated to 60°F above the NDT temperature. Piping and support

5.4 COMPONENT AND SUBSYSTEM DESIGN

5.4.1 Reactor Recirculation System

5.4.1.1 Design Bases

The performance objective of the recirculation system is to provide forced convection cooling of the reactor core to permit operation at rated power. This forced convection increases the power output of the core above the capability of a natural convection system. To achieve this objective, the recirculation system was designed using the following bases:

A. The reactor recirculation system provides adequate fuel barrier thermal margin during postulated transients. That is, all transients due to normal operation and to single operator error or equipment malfunction result in a minimum critical power ratio (MCPR) greater than the safety limit MCPR.

B. The design suction pressure is 1175 psig. The suction pressure was selected relative to the reactor vessel design pressure.

C. The design discharge pressure is 1325 psig. The discharge pressure was established at a nominal 150 psi above the suction pressure to accommodate the pressure output of the recirculation pumps.

D. The recirculation piping system (pipes and valves) design codes are ASME Section I (1965 Edition with Winter 1966 Addenda) and USAS B31.1 (1967). In addition, nuclear code cases N-1, N-2, N-3, N-4, N-7, N-8, N-9, N-10, and N-11 apply. ASME Section I also permits an increase of 20% in allowable stress. The intent of using USAS B31.1 and ASME Section I for the recirculation piping system is to provide a piping system of such quality as to be equivalent to the reactor vessel to which it is attached.

   Stresses for replacement piping in the Unit 3 recirculation system have been analyzed to show compliance with the original design codes (see Section 3.9.3.1.3.4).

   Recirculation system valve sizes were selected to match piping sizes, which were determined based upon flowrate and velocity requirements. The recirculation loop flowrates through the suction and discharge valves were determined based upon heat balance and jet pump hydraulic requirements. The maximum differential pressures for opening the discharge valves were based on the assumption that the recirculation pumps are running at the speed required for minimum flow when the valves are opened. The maximum differential pressure ratings for closing valves were based upon low pressure coolant injection (LPCI) requirements under loss-of-coolant accident (LOCA) conditions for the discharge and upon maintenance considerations for the suction valves.

E. The recirculation pump casing design code is ASME Section III, Class C. The recirculation pumps are classified as machinery and as such are specifically exempt from the jurisdiction of any section of the ASME Code or of the USASI Code for pressure piping. The Standards of the Hydraulic Institute are the only applicable standards; however, they are more cogent to the testing and performance of the pump and consequently provide little or no guidance in the areas of casing quality and structural integrity. Therefore, to assure that the pump casing will contain pressure which is at least equivalent to the reactor vessel pressure, the pump casing was designed in accordance with ASME Section III, Class C. This class is used because the pump casings do not experience the pressure and temperature transients that the reactor vessel and certain piping connections experience and so do not need the cyclic analysis required by Class A of ASME Section III.

5.4.1.2 Description

5.4.1.2.1 General System Description

The reactor recirculation system consists of 2 external recirculation pump loops and 20 jet pumps internal to the reactor vessel. Each external loop consists of a 28-inch diameter line, a motor-driven recirculation pump, two motor-operated gate valves for pump isolation, and required recirculation flow measurement devices.

The recirculation system piping is shown in Figures 5.4-1 and 5.4-2 (Drawing M-26) for Unit 2 and Figures 5.4-3 and 5.4-4 (Drawing M-357) for Unit 3.

The recirculated fluid consists of saturated water, rejected from the dryers and steam separators, which has been mixed with subcooled feedwater. This flow mixture passes down the annulus area between the vessel and the core shroud. About 35% of this flow exits the vessel and goes through the two outside driving loops. The other 65% of the flow is the driven flow of the jet pumps. This flow enters the jet pumps at the suction inlet and is accelerated by the driving flow from the jet pump nozzles.

Each external recirculation loop discharges high-pressure flow into an external manifold from which connections lead to the jet pump nozzles. The driving and driven flows are mixed in the pump throat section, resulting in partial pressure recovery. The balance of pressure recovery occurs in the jet pump diffusing section.

The operating instrumentation on the recirculation system includes:

A. Recirculation pump differential pressure and flow instruments;

Both recirculation pumps are driven by variable speed induction motors, which receive electrical power from variable frequency motor-generator sets. Recirculation flow control is described in Section 5.4.1.2.4.

The recirculation pumps are vertical and are arranged within the drywell to facilitate inspection, maintenance, and/or removal during unit shutdown conditions. The recirculation pumps and motors are located below the reactor vessel in order to take advantage of the elevation head for net positive suction head (NPSH) requirements.

The Unit 2 equalizer line connecting the two recirculation loops is a stainless steel pipe with two manual main isolation valves. A 2-inch line with a manual operated valve is provided to bypass each of the equalizer line main isolation valves. During operation, one bypass valve is normally open to prevent hydrostatic pressurization of the section of equalizer line between the isolation valves due to heatup. In the event that one recirculation pump fails or is shut off, the discharge valve in the inoperative driving loop is closed. In this case, the original plant design required the equalizer line valves to be opened, which would provide positive pressure to all jet pumps thus preventing backflow through any jet pump. This equalizer line usage was found to lead to unstable flow, causing the operative recirculation pump to overspeed and trip. Currently, licensing conditions prohibit use of the equalizer line during reactor power operation. The Unit 3 equalizer line and associated valves were removed. The Unit 2 equalizer line is used for system decontamination only. Single loop operation is discussed in Section 4.4.

The recirculation lines have been provided with a system of pipe restraints to limit pipe motion so that any reaction forces associated with a pipe split or circumferential break will not jeopardize containment integrity. These restraints allow for unrestricted movement of the piping due to pressure and temperature expansion. Design pressures range from 0 psig to 1250 psig. Design temperatures range from 70°F to 575°F. Positioning of the restraints assumes that the strength of the pipe is maintained on both sides of the circumferential break and over the entire length of the split pipe.

5.4.1.2.3 Jet Pumps

The jet pumps, which have no moving parts, are located between the core shroud and the reactor vessel wall, as shown in Figure 5.4-5. Each pair of jet pumps is supplied driving flow from a single riser pipe. The risers have individual vessel penetrations and receive flow from one of two external manifolds.

Each jet pump consists of a diffuser, a throat section, and a nozzle section as illustrated in Figure 5.4-6. The jet pump diffuser is a gradual conical section terminating in a straight cylindrical section at the lower end which is rigidly attached to the shroud support. The throat section is a straight section of tubing with a short diffuser entrance section at the lower end. The throat section and the nozzle section are clamped together and are attached to the riser and diffuser with brackets. These brackets provide structural rigidity and yet permit differential expansion between the carbon steel vessel and the stainless steel jet pump.

The overall height from the top of the inlet nozzle to the diffuser discharge is 18 feet, 7 inches; each diffuser has an outside diameter of 20.75 inches. Replacement of the throat and nozzle sections of the jet pump is possible.

5.4.1.2.4 Recirculation Flow Control

A typical power-flow map is shown schematically in Figure 4.4-1. This figure illustrates the concept of recirculation flow control, but may not be accurate for the current cycle.

Recirculation pump speed is controlled by varying the frequency (speed) of the recirculation pump motor power supply. Frequency variation is accomplished with a synchronous motor-generator set coupled by a variable slip hydraulic coupling. The hydraulic coupling limits the minimum generator output frequency to approximately 20% of rated frequency. The minimum pump speed is limited to 27% of rated speed when in master control. When feedwater flow is below 20% of rated, the recirculation flow controller is limited to a maximum pump speed of 28% as specified by operating procedures. This speed typically results in a core flow of about 28% rated flow at zero power or about 40% rated flow at the average power range monitor (APRM) rod block power of about 68% (exact values are cycle dependent).

In the event of a loss of power to both driving loops, the inertia of the motor-generator sets sustains reactor recirculation sufficiently to prevent exceeding reactor thermal limits. Proper design of the power connection from the motor-generator sets makes simultaneous faulting of these buses unlikely.

For testing and maintenance, the motor-generator set scoop tube positioner can be locked out and controlled manually using appropriate operating procedures.

5.4.1.3 System Operation

Steady-state operation of the BWR unit with jet pumps has been investigated; the conclusion of this study was that unit operation is highly satisfactory. The operational characteristics are presented in Sections 5.4.1.3.1 through 5.4.1.3.3.

5.4.1.3.1 Principles of Jet Pump Operation

The principle of operation of the jet pump is the conversion of momentum to pressure. The fluid emerging from the driving nozzle, called the driving or motive flow, has a high velocity and a high momentum. By a process of momentum exchange, suction fluid is entrained. The combined flow enters the mixing section or throat where the velocity profile is converted by mixing such that the momentum decreases with a resultant pressure increase. For optimum operation, the velocity profile at the exit of the throat should be as flat as possible; i.e., the boundary layer should be as thin as possible. The flat velocity profile gives the minimum momentum with the resultant highest pressure increase in the throat. In the diffuser, the relatively high velocity of the combined stream is converted to a still higher pressure. The combined stream flows out of the diffuser at the pressure required to provide the necessary recirculation flow for the core.

5.4.1.3.2 Recirculation Pump Startup

The recirculation pumps are located approximately 60 feet below the normal water level. This static head alone does not provide sufficient NPSH during power operation with recirculation pump speeds greater than minimum speed (specified in Section 5.4.1.2.4). However, during normal operation, the feedwater subcools the inlet flow to the recirculation pumps more than enough to prevent cavitation.

During plant startup, when the reactor is being pressurized, there is no feedwater flow. Under these conditions, the recirculation pumps are started in the following manner:

1. First, establish recirculation pump operation at minimum speed as described below.

   The recirculation pumps are started and brought up to minimum speed with the discharge valves closed. When minimum speed is established, the discharge valves are jogged open. (An automatic jogging circuit with a separate control switch provides discrete ½-second and 1-second OPEN signals to the valve to facilitate pump startup.)

2. With the pumps at minimum speed, control rods are withdrawn to heat the system, establish steam production, and increase system pressure. As soon as steam flow is established, feedwater flow begins and the downcomer flow is subcooled. When the feedwater flow reaches a minimum value (and the recirculation pump discharge valves are fully open), the recirculation flow limiters (see Section 7.7) are bypassed for the respective loops. The recirculation pumps may then be safely operated at speeds up to rated speed.

5.4.1.5.3 Inspections

Inspection of the recirculation system is governed by ASME Section XI, 1989 Edition.

Dresden Station has implemented actions to address NRC concerns stated in IE Bulletin 80-07 as a result of a jet pump failure in Dresden Unit 3 in February 1980. Visual inspection of the uppermost jet pump components, including holddown beams, is performed each refueling outage using underwater television equipment. Procedures have been established for a daily surveillance of jet pump parameters; this surveillance assures proper jet pump performance. The procedures utilize established operating databases, which, in conjunction with the daily surveillance program, provide an early indication of an impending jet pump failure. Based on the established procedures and surveillance program, significant cracking of a jet pump beam will be detected at least 7 days prior to beam failure and jet pump disassembly.

5.4.2. Steam Generators

This section is not applicable to Dresden Station.

5.4.3 Hydrogen Water Chemistry System

The hydrogen water chemistry (HWC) system was installed in Unit 2 as part of a pilot program to demonstrate that intergranular stress corrosion cracking (IGSCC) in sensitized austenitic stainless steel BWR recirculation piping can be controlled by injection of hydrogen into the reactor feedwater system. In the reactor coolant, hydrogen combines with the oxygen that is produced from the radiolytic decomposition of water. Reducing oxygen concentration in the recirculation system drops the electrochemical potential of the stainless steel recirculation piping to a level which arrests the growth of IGSCC and prevents initiation of new IGSCC. A general discussion of the HWC control program is contained in Section 5.2.3.2.1.

The HWC system consists of a hydrogen injection system for adding hydrogen to the condensate system and an oxygen injection system for controlling excess hydrogen in the off-gas stream. The following subsections address the HWC system in Unit 2. The hydrogen water chemistry verification system is addressed in Section 5.2.3.2.1.

Implementation of an HWC program in Unit 3 is under consideration.

5.4.3.1 <u>Hydrogen Injection System</u>

5.4.3.1.1 <u>Design Basis</u>

The hydrogen injection system piping was fabricated, installed, and tested in accordance with ANSI B31.1, 1967 Edition. Storage containers were designed, constructed, and tested in accordance with the appropriate requirements of ASME Section VIII.

5.4.3.1.2 <u>Description</u>

The hydrogen injection system is shown in Figure 5.4-15 (Drawing M-3658, Sheet 1).

Hydrogen gas supplied from high-pressure transportable tubes is delivered through a manifold distribution system. A ½-inch carbon steel pipe with socket weld fittings delivers the hydrogen through an instrumentation station which controls the pressure and flow. Hydrogen can be injected into the bowl drains of four condensate booster pumps. Typically two or three injection points are used at any one time for adding hydrogen.

The hydrogen injection system has automatic flow control capability, with the hydrogen flowrate controlled as a function of the feedwater flowrate. Injection rate is controlled by Dresden Operating Procedures and is commensurate with industry practice.

5.4.3.1.3 <u>Feedwater Oxygen Injection</u>

To maintain the Feedwater dissolved oxygen concentration within the specifications as required by NOD CY.2 BWR water chemistry controls, Oxygen may be injected into the Feedwater through the Turbine Sample Panel Drainline. This evolution is procedurally controlled under a Dresden Chemistry Procedure which provides for the controlled addition of small amounts of oxygen via the drain of the sample panel as needed to maintain the Feedwater Oxygen Concentration within the specifications of NOD CY.2.

5.4.3.2 <u>Off Gas Oxygen Injection System</u>

5.4.3.2.1 <u>Design Basis</u>

The oxygen injection system is designed to add oxygen to the off-gas system to ensure that the excess hydrogen in the off-gas stream is recombined so as to prevent a fire in the charcoal adsorbers due to a combustible mixture of hydrogen and oxygen.

The inner vessel of the liquid oxygen tank (see Section 5.4.3.2.2) is designed, fabricated, tested, and stamped in accordance with ASME Section VIII, Division 1. The outer vessel is constructed of carbon steel and does not require ASME certification.

The oxygen injection copper piping (see Section 5.4.3.2.2) is fabricated, installed, and tested in accordance with ANSI B31.1, 1980 Edition.

Testing and inspection of the HWC system are performed in accordance with the requirements of ANSI B31.1. The liquid oxygen storage tank was tested in accordance with ASME Section VIII, Division 1, 1977.

5.4.3.7 Zinc Injection Process System

The zinc injection process (ZIP) system was installed to passively inject depleted zinc oxide to the feedwater to limit and control drywell dose rates. The technique was adapted from the observation that plants with naturally occurring zinc in the reactor water (about 10 ppb) had low shutdown dose rates. Subsequent laboratory tests showed that ionic zinc provided a thinner, more stable corrosion film on stainless steels, thus allowing less incorporation of Co-60. Zinc ions have the additional benefit of lowering the overall Co-60 concentration of the reactor water, as shown in most plants which have observed from 30 -50 % in dose rates on reactor coolant system piping surfaces.

5.4.3.7.1 Design Basis

The ZIP system has been fabricated, installed, and tested in accordance with ANSI B31.1, 1967 Edition. The zinc vessel has been designed, constructed, and tested in accordance with the appropriate requirements of ASME Section VIII.

5.4.3.7.2 Description

The zinc system consists of a skid containing a vessel to hold the zinc oxide and a flow control valve and associated piping and instrumentation to monitor flow. The system will use the feedwater pump discharge to inject the zinc ion into the feedwater system. A tap location has been located on the feedwater header to supply water at a pressure above the suction pressure of the feedwater pumps. The return line from the zinc skid has been located so that its injection point will be in the flow stream when any of the three feedwater pumps are in service. Flow control through the zinc skid will be controlled at the zinc skid by using a manual flow control valve and a local flow indicator mounted on the skid.

The zinc skid shall be capable of providing from 4 gpm to 100 gpm through the skid into the feedwater system at the design pressure conditions. Normal flow conditions shall be about 50 gpm, with the 100 gpm reached when the zinc is about to be depleted.

5.4.3.7.3 Performance Analysis

The zinc water chemistry verification will be taken from the reactor water chemistry sample panel.

5.4.4 Main Steam Line Flow Restrictors

5.4.4.1 Design Bases

The performance objective of the steam flow restrictors is to limit the quantity of steam which would be discharged from the reactor vessel in the event of a steam line break.

To achieve the above objective, the design basis of the steam flow restrictors is to limit steam flow through a ruptured steam line to 175% of rated flow.

Limiting the steam flow in a severed steam line would:

A. Limit the loss of coolant inventory from the reactor vessel;

B. Minimize the amount of moisture carryover before the main steam isolation valves (MSIVs) are closed; and

C. Minimize the probability of forming high-velocity water slugs in the steam line.

5.4.4.2 System Description

The main steam line flow restrictors are simple venturis; one is welded into each steam line between the reactor vessel and the first MSIV. The restrictors have no moving parts and are located as close to the reactor vessel as practical. The restrictors also serve as flow nozzles to provide flow monitoring. The main steam line flow restrictor is shown in Figure 5.4-17.

Each main steam line flow restrictor in Unit 2 is supported by six axial pins. These pins were installed to prevent the restrictor cone from moving downstream in the event that the weld were to fail. The design precludes pin failure since one pin alone can withstand the stresses. Unit 3 did not require the axial pin addition since the Unit 3 restrictors are of a different design.

5.4.4.3 Design Evaluation

5.4.4.3.1 Functional Evaluation

The accident for which the main steam line flow restrictors are evaluated is the postulated complete severance of a main steam line outside of the primary containment. This event would lead to rapid depressurization and the flow of a

D. Fabrication — The welding of the steam flow restrictors to the main steam line piping sections was performed by M.W. Kellog Company with code-qualified welders. The radiographs for these welds were reviewed by qualified inspectors and found to be satisfactory.

Therefore, it is concluded that these steam flow restrictors are acceptable from an engineering design standpoint and that the requirements of ASME Section I and USAS B31.1 have been met.

5.4.4.4 Tests and Inspections

Initial differential pressure measurements were obtained over the range of flows expected. These measurements are repeated periodically and the results compared with the initial readings to assure that no significant erosion or crudding has occurred in the nozzles.

5.4.5 Main Steam Line Isolation System

The main steam line isolation system is described in Sections 6.2.4 and 7.3.2.

5.4.6 Isolation Condenser

5.4.6.1 Design Bases

The performance objective of the isolation condenser is to provide reactor core cooling in the event that the reactor becomes isolated from the turbine and the main condenser by closure of the main steam isolation valves. To achieve this objective, the isolation condenser was designed for a cooling rate of 252.5 x 10^6 Btu/hr.

The isolation condenser system is capable of operation without ac electrical power.

5.4.6.2 Description

The isolation condenser consists of two tube bundles immersed in a large water storage tank. The tubes are Type 304 stainless steel U-tubes. The shell is carbon steel. Figures 5.4-18 (Drawing M-28) and 5.4-19 (Drawing M-359) show the isolation condenser system for Unit 2 and Unit 3, respectively. The isolation condenser system operates by natural circulation. During isolation condenser system operation, steam flows from the reactor, condenses in the tubes of the heat exchanger, and returns by gravity to the reactor via the A recirculation loop. The differential water head, created when the steam is condensed, serves as the driving force.

The tube side of the isolation condenser system is equipped with high point vent valves which are used during normal operation to prevent the long-term buildup of noncondensible gases. These gases are vented to the main steam line.

The isolation condenser tube sheets were designed to the same code as the reactor vessel, ASME Section III, Class A. Refer to Section 5.2 for a discussion of the reactor coolant pressure boundary requirements for the isolation condenser system.

Makeup water for the isolation condenser can be supplied from several sources. The preferred source is from the clean demineralized water storage tank via two diesel driven isolation condenser makeup water pumps, located in the Isolation Condenser Pumphouse. Alternately, water can be supplied from the clean demineralized water storage tank via two clean demineralized water transfer pumps. If clean demineralized water is unavailable, the fire protection system is the preferred source. The fire protection system has access to an inexhaustible supply of river water supplied either by the service water pumps or the diesel-driven fire pump. When condensate was used as the primary makeup, low levels of radioactive contamination in the condensate tended to concentrate in the isolation condenser shell; under high steaming conditions, carryover would slightly contaminate the area below the isolation condenser vent to atmosphere. Therefore, the least desirable source of makeup water for the isolation condenser is from the contaminated condensate storage tanks via two condensate transfer pumps or the condensate jockey pump. Contaminated water will be used for makeup only if absolutely necessary. Refer to Section 9.2 for a description of the condensate and demineralized water makeup facilities.

The valves on the steam inlet line to the condenser are normally open; thus the tube bundles are at reactor pressure. Normally, the outboard containment isolation valve for the condensate return line is closed and the inboard valve is open. The isolation condenser is placed in operation by opening the outboard condensate return valve to the reactor system. The isolation condenser is initiated automatically on a sustained high reactor pressure signal as defined in the Technical Specifications. Manual initiation is also possible from the control room. Refer to Section 7.3.4 for a description of the isolation condenser initiation logic.

The outboard steam supply valve and the outboard condensate return are powered by a safety related 250-Vdc bus. Therefore, the outboard condensate return valve can be opened to initiate isolation condenser operation without the availability of ac power. The inboard steam supply and condensate return valves are powered by a 480-Vac electrical bus which can be powered by the emergency diesel generators. These inboard valves are also equipped with a safe shutdown feature; that is, the Unit 2 valves can be powered from Unit 3, and the Unit 3 valves can be powered from Unit 2.

The outboard steam supply valve operator motors were sized to meet the design requirement of full torque capability of 70% of rated dc voltage.

During isolation condenser operation, the water on the shell side of the condenser boils and vents to atmosphere. Two radiation monitors are provided on the shell vent. In the event of excessive radiation levels, the tube side of the heat exchanger can be isolated from the reactor. Refer to Section 11.5 for a description of the radiation monitoring system.

The fire protection system supplies water to the isolation condenser via a 4-inch line, drawing from an inexhaustible supply of river water. The fire protection system is normally pressurized by the service water system. All service water pumps can be supplied with emergency power by manual operation limited only by the diesel generator capacity as discussed in Section 8.3. The Unit 2/3 diesel-driven fire pump or the Unit 1 diesel-driven fire pump automatically provide a backup supply of river water to the fire protection system on low system pressure.

Isolation condenser makeup water availability subsequent to a seismic event has been considered. Assuming loss of offsite power as a consequence of the seismic event, the fire protection system would still be available since the diesel-driven fire pump automatically starts if the service water system fails to maintain pressure in the fire protection system header. The fire water makeup isolation valves are powered from a safety related 250-Vdc bus. The condensate transfer pumps and jockey pump require only the closing of one circuit breaker to put emergency diesel ac power to their bus, and the pumps can then be started. It is emphasized that these two supplies are designed to meet the State of Illinois code which accounts for earthquake loadings. Hence, it is highly probable that at least one of these supplies would be available. Assuming the loss of off-site power is a consequence of any credible event other than a seismic event, the makeup supply from the clean demineralized water storage tank via the diesel driven isolation condenser makeup water pumps would be available.

In the event that makeup supply from the clean demineralized water system is not available, the Class I high pressure coolant injection (HPCI) system in the pressure control mode is the next preferred method to provide core cooling water to the vessel. Fire water as makeup to the isolation condenser is the next, followed by the automatic depressurization, core spray, and LPCI systems. Contaminated demineralized water will be used only if absolutely necessary.

Leakage of reactor water through the heat exchanger tubes can be detected by the two radiation monitors on the vent to atmosphere and by changes in water level or water temperature in the isolation condenser.

The isolation condenser requires a minimum level of water to meet its design basis heat load prior to makeup. Level indication and level alarms are provided in the main control room. The level indication transmitter, which is located in the vicinity of the isolation condenser level sight glass, is qualified for the expected station blackout temperature profile. The power supply for the level transmitter is supplied from the essential service uninterruptible power supply (UPS).

Leaks and line breaks in the isolation condenser system are detected by differential pressure indication. Unit 2 utilizes elbow taps located in the first elbow of the steam line leaving the reactor vessel and in the condensate return line at the elbow closest to the reactor vessel. Unit 3 utilizes elbow taps located in the first elbow of the steam line leaving the reactor vessel and an annubar flow element in the condensate return line vertical section closest to the reactor vessel. All differential pressure switches for the isolation condenser leak detection logic network are located outside the primary containment. Local temperature detectors are located in all compartments external to the primary containment containing system equipment and piping. The temperature detectors have remote readouts with adjustable setpoints and alarm switches which fail safe in the event of power loss.

The isolation condenser control logic for the inboard and outboard steam inlet and inboard condensate return isolation valves prevents automatic valve opening when the Group V isolation signal is reset. The containment isolation logic for the isolation condenser is described in Section 7.3.2.

The controls for the outboard condensate return isolation valve are designed to reduce the possibility of inadvertent override of an automatic initiation signal, yet permit deliberate remote manual valve closure.

5.4.6.4 Tests and Inspections

The isolation condenser shell was constructed and tested in accordance with ASME Section VIII. It has a joint efficiency of 85%. Spot radiography was performed.

The functional operability of the isolation condenser system was tested at the time of system installation and plant startup. A design heat removal test is also conducted every 5 years. Isolation valve operation can be tested by remote manual actuation from the control room. All automatic devices in the isolation condenser system are tested for proper operation during each scheduled refueling outage. The radiation monitors for the isolation condenser vent to atmosphere are calibrated periodically. Refer to Section 11.5 for a description of the radiation monitoring system.

5.4.7 Reactor Shutdown Cooling System

5.4.7.1 Design Bases

The design objective of the reactor shutdown cooling system (SDCS) is to cool the reactor water when the temperature and pressure in the reactor fall below the point at which the main condenser can no longer be used as a heat sink following reactor shutdown.

Following reactor cooldown using the main condenser, the SDCS is designed for initiation once the reactor water has been cooled to below 350°F. The SDCS is capable of cooling reactor water to 125°F within 24 hours after reactor shutdown and maintaining it at this temperature by removing fission product decay heat from the reactor water. To achieve this objective the system was designed on the following bases:

Design code	ASME Section III, Class C
Design pressure	1250 psig
Design temperature	350°F

Power to the ac isolation valves and to the pumps can be supplied from the emergency diesel generators. Power to the three branch suction isolation valves and the branch discharge isolation valves is obtained from safety related 250-Vdc buses. The diversity of power supplies to active components can assure system isolation to protect equipment from overheating.

The vertically mounted centrifugal SDCS pumps with mechanical seals are designed to deliver 6750 gal/min each at total developed head of 225 feet.

The SDCS heat exchangers are cooled by water from the reactor building closed cooling water (RBCCW) system and are each designed to remove 27 x 10^6 Btu/hr. The removable U-tube heat exchangers are designed for horizontal mounting.

The SDCS is also used to help cool the fuel pool during refueling outages and to heat reactor water with steam from the heating boiler during startup from cold shutdown. When used to augment fuel pool cooling, only one of the loops is required.

All components in the shutdown cooling system are located in a common concrete shielded compartment designed to attenuate radiation levels to 5 mrem/hr outside the compartment.

5.4.7.3 Performance Evaluation

Since the shutdown cooling system is designed for reactor design pressure, the reactor vessel code safety valves provide adequate overpressure protection. Pump permissive instrumentation will prevent the pumps from operating unless the suction pressure is above 4 psig and the reactor water temperature below 350°F.

Area temperature detectors are installed at appropriate locations to initiate an alarm in the control room in case of a line break.

Samples may be taken and analyzed for tube leaks from a sample point on the outlet side of the cooling water from the heat exchanger.

5.4.7.4 Tests and Inspections

The tube side of the SDCS heat exchangers was constructed and tested in accordance with ASME Section III, Class C. The shell side of the heat exchangers was constructed and tested in accordance with ASME Section VIII. The shell joint efficiency is 85% and spot radiography was performed.

Isolation valves are tested periodically to verify operability and leak-tightness.

5.4.8 Reactor Water Cleanup System

5.4.8.1 Design Bases

The design objectives of the reactor water cleanup (RWCU) system are to maintain high reactor water purity to minimize deposition on fuel surfaces; and, to reduce the secondary sources of beta and gamma radiation resulting from the deposition of corrosion products, fission products, and impurities in the primary system. To achieve these objectives, the system is designed as follows:

	Unit 2	Unit 3
Nominal flow capacity	3.25×10^5 lb/hr	6.5×10^5 lb/hr
Design pressure	1250 psig	1250 psig
Vessel Design code	ASME Section VIII, reconciled to Section III, Class C	ASME Section III, Class C

5.4.8.2 System Description

The RWCU system provides a continuous purification of a portion of the recirculation flow with a minimum of heat loss and water loss from the cycle. It can be operated during startup, shutdown, refueling operations, and during normal operation.

As can be seen in Figures 5.4-23 (Drawing M-30) and 5.4-24 (Drawing M-361) or in Figure 5.4-25, the major components of the RWCU system are the regenerative heat exchangers, non-regenerative heat exchangers, demineralizers, a surge tank, pumps, and necessary control and support equipment.

Water is normally removed at reactor pressure from one of the reactor recirculation loops and from the reactor vessel bottom drain connection, and is routed through a drywell penetration. Containment isolation capability is provided by four motor-operated containment isolation valves; one 8-inch valve with a normally closed, 2-inch bypass valve inside containment, and two 8-inch valves in parallel outside containment. The 2-inch bypass valve provides a means of gradually equalizing pressure around the inboard isolation valve, thereby reducing the possibility of water hammer during system startup. All four valves are required as containment isolation valves.

Downstream of the containment isolation valves the reactor water is cooled in regenerative and non-regenerative heat exchangers. Reactor pressure provides the motive force through the heat exchangers tube side during normal system operation. With low reactor pressure an auxiliary cleanup recirculation pump is used.

On Unit 3, two trains of heat exchangers are arranged in parallel. Each train contains two regenerative and two non-regenerative heat exchangers arranged in series. Each train is rated for a flowrate of 3.25×10^5 lb/hr which is 50% of the system nominal flow capacity. Unit 2 contains a single train of heat exchangers rated for a flowrate of 3.25×10^5 lb/hr which now represents 100% of the system nominal flow. This was performed under modification M12-2-91-018.

The regenerative heat exchangers transfer heat from the water leaving the reactor to the water which returns to the reactor via the feedwater system. The non-regenerative heat exchangers cool the water further to approximately 120°F (140°F maximum) by transferring heat to the RBCCW system. The non-regenerative heat exchangers are capable of maintaining this low temperature and not exceeding a maximum of 140°F even during a blowdown of a portion of the cleanup flow, when effectiveness of the regenerative heat exchangers is reduced.

Downstream of the heat exchangers the reactor water enters a pressure reducing valve (PRV) which controls system pressure downstream to a maximum of 150 psig. The PRV is a stacked disk valve with a design pressure drop of 950 psi in the full open position. Therefore, if the valve failed open, reactor pressure must be greater than 1100 psig before downstream pressure would exceed the 150 psig design pressure for the piping. The downstream piping is further protected against overpressurization by relief valves as described in Section 5.4.8.3.

From the pressure reducing valve, the system flow is routed directly to the cleanup demineralizers, bypassing the cleanup filters which have been abandoned in place on Units 2 and 3. There are three cleanup demineralizers arranged in parallel. Demineralizer effluent flows to the suction of the two cleanup recirculation pumps which raise system pressure sufficiently to return the flow to the reactor.

A surge tank is provided at the suction of the cleanup recirculation pumps to prevent pump trips during small system transients. The tank is sized to provide a water supply to the cleanup recirculation pumps for a minimum of 15 seconds (assuming flow blockage) before the pumps trip. The surge tank is pressurized by nitrogen to maintain suction pressure to the cleanup recirculation pumps.

A bypass line with a motor-operated isolation valve is provided around the cleanup recirculation pumps for low-pressure operation when the cleanup auxiliary pump is providing system flow.

From the suction of the cleanup recirculation pumps, a blowdown line directs the cleanup system flow to a manually controlled blowdown control valve to either the main condenser or radwaste.

The cleanup recirculation pumps provide motive force through the shell side of the recirculation heat exchangers to the feedwater system.

Each cleanup recirculation pump discharges through a motor-operated discharge valve into a common header. Pump minimum flow requirements are assured by minimum flow lines which recirculate a portion of the pump discharge to the surge tank. Flow through the minimum flow lines can be isolated by air-operated valves which are kept open at all times except when the cleanup recirculation pumps are shutdown.

Cleanup system flow then passes through another flow control valve to the shell side of the regenerative heat exchangers where the system water temperature is increased to 440°F while cooling the tube-side water from the reactor. From the regenerative heat exchangers, the demineralized water passes through a motor-operated isolation valve and is returned to the reactor via the feedwater system.

Blowdown is used during hot standby and startup operation to maintain reactor water chemistry and vessel level. It can also be used during normal operation if the RWCU system is not functioning. Blowdown water is normally routed to the condenser, but it can also be transferred to the radwaste system for reprocessing and returned to storage. Replacement water for blowdown is supplied by normal plant makeup.

Three, mixed-bed demineralizers are provided to permit continuous operation. The demineralizers can be operated individually or in parallel. Normal operation consists of operating one demineralizer for each reactor water cleanup recirculating pump in operation. The unused demineralizer(s) will typically be kept in a standby condition; this allows maintenance on standby demineralizers during full flow operation of the system.

Each demineralizer is equipped with instrumentation, in the form of a differential pressure indicating switch, to measure the pressure differential between the inlet and outlet piping. The indicating switches are located at a local panel. In addition to providing local pressure data, the switches will also activate control room annunciators, automatically alerting the control room operators in the event that a high-differential-pressure condition exists.

Spent cleanup resins are not normally regenerated because of the radioactivity of the impurities removed from the reactor coolant. The resins are sluiced from the demineralizer vessels directly to the spent resin tank in the radwaste disposal system for processing, storage, and eventual offsite disposal.

Y-type post-strainers on the outlet of each of the three demineralizers prevent resins from entering the reactor system in the event of a resin support failure. Each post-strainer is equipped with differential pressure indicating switches, similar to the ones provided for the demineralizers. These indicating switches are also located at a local panel, and also activate control room annunciators, automatically alerting the control room operators in the event that a high-differential-pressure condition exists.

The reactor water cleanup pumps may be operated individually or in parallel. The cleanup pumps are horizontal, electric-motor-driven, multistage, centrifugal pumps with mechanical seals. Each of the cleanup recirculation pumps have a design capacity of 685 gal/min which is approximately 50% of the system nominal flow capacity for Unit 3 (for Unit 2 this flow represents 100% of the system nominal flow capacity as a result of the single train configuration provided in modification M12-2-91-018). If reactor pressure does not provide sufficient suction pressure, an auxiliary pump is used. The design capacity of the single cleanup auxiliary pump is 1310 gal/min for Unit 3. (The Unit 2 auxiliary pump installed under modification M12-2-91-018 has a design capacity of 675 gpm).

The 2-inch bypass line for the inboard containment isolation valve was designed, constructed, and tested in accordance with ANSI B31.1-1980, IEEE 323-1974, IEEE 344-1975, applicable portions of ANSI N45.2, as well as other ANSI and ASTM specifications per Sargent & Lundy Specification K-2202 piping design Table A.

Operation of the cleanup system is controlled from the main control room. Resin sluicing operations are controlled from a local panel.

5.4.8.3 System Evaluation

As shown in Figures 5.4-26 (Drawing M-48) and 5.4-27 (Drawing M-372), system leakage is monitored by three sets of temperature detectors. The first set of eight area temperature detectors provides a high-temperature alarm and displays area temperature in the control room. These temperature elements cause no automatic plant response except for the control room alarms. Since these elements are resistance temperature devices (RTDs), failure would most likely result in an open circuit or high resistance, which would conservatively actuate a high temperature alarm. These temperature elements are not environmentally qualified.

Supplementing the originally installed leak detection monitors, two sets of five RTDs provide an environmentally qualified, dual train leak detection system. Each train of five RTDs provides input to a temperature switch which alarms in the control room.

A sensitivity evaluation of the area leak detection system in the vicinity of the IGSCC-susceptible RWCU piping confirmed that the temperature sensors will detect a leak prior to a crack reaching a critical crack size. The temperature sensors in the vicinity of the RWCU outboard piping will detect leakage in sufficient time to allow for system isolation prior to a crack reaching critical size.

Therefore, the RWCU system design provides sufficient relief capacity to assure pressure boundary integrity in case of PRV failure and concurrent interlock failure, in compliance with General Design Criterion 15.

Sample points are provided before and after the RWCU demineralizers to assure the satisfactory performance of equipment. The demineralizer influent sample point is also the source of samples of reactor water during normal operation. A sample point on the cooling water side of the non-regenerative heat exchanger permits analysis for tube leaks.

5.4.8.4 Tests and Inspections

Isolation valves can be tested periodically to verify operability and leak-tightness.

5.4.9 Main Steam Line and Feedwater Piping

5.4.9.1 Description

A diagram of the main steam piping is shown in Figures 10.3-1 (Drawing M-12, Sheet 1) and 10.3-2 (Drawing M-12, Sheet 2) for Unit 2 and in Figures 10.3-3 (Drawing M-345, Sheet 1) and 10.3-4 (Drawing M-345, Sheet 2) for Unit 3. The main steam system is described in Section 10.3. The feedwater piping is described in Section 10.4.7 and shown in Figures 10.4-8 (Drawing M-14) and 10.4-9 (Drawing M-347).

The materials used in the main steam and feedwater piping comply with the design codes and supplementary requirements described in Sections 3.2 and 10.3. The general requirements of the feedwater system are described in Sections 7.7 and 10.4.

5.4.9.2 Performance Evaluation

Steam flow from the reactor under the assumed accident condition of a ruptured steam line is limited by a flow restrictor in each of four main steam lines. Refer to Section 5.4.4 for a description of the main steam line flow restrictors.

5.4.9.3 Inspection and Testing

Inservice inspection of Class I piping is discussed in Section 5.2.4. Inservice inspection of Class II and III piping is discussed in Section 6.6. Inspection and testing of the main steam and feedwater piping are carried out as described in Sections 10.3 and 10.4.

5.4.10 Pressurizer

This section is not applicable to Dresden Station.

5.4.11 Pressurizer Relief Discharge System

This section is not applicable to Dresden Station.

5.4.12 Valves

This section describes performance objectives and design features of valves within the reactor coolant system and subsystems interfacing with the reactor coolant system. Additional information on containment isolation valves is provided in Section 6.2.4. Specific details of valves utilized at Dresden can be found in the subsection describing the system in which the valves are installed.

5.4.12.1 Design Bases

The criteria for valves are described in Section 3.9. Compliance with ASME Codes is discussed in Sections 3.2 and 3.9. Design bases for containment isolation valves are addressed in Section 6.2.

5.4.12.2 Description

Valves utilized for the nuclear boiler and other systems which may become contaminated have been designed to ensure the integrity of the piping systems and generally conform to the following guidelines:

A. All lines connected to the nuclear boiler, not subjected to nuclear system pressure and temperature during normal operation, should have check and isolation valves or two isolation valves located as close as possible to the nuclear system lines.

B. Valves for non-radioactive systems should be located outside of inaccessible areas.

C. Except for resin outlet transfer valves, no valve should be located in the same room housing the condensate demineralizers or in cells containing cleanup or waste demineralizers or filters.

D. Valves used for high temperature and pressure service, 4 inches and larger in size, should be provided with drains in the valve bonnet, or in the bottom of the valve body, if controlled packing leakoff is desired. An alternate packing scheme may be used in lieu of a valve packing design that requires leakoff.

5.4.13.1 Design Description

Pressure relief valves are designed and constructed in accordance with the same code classes as those of the line valves in the system. Section 3.2 lists the applicable code classes for valves. The design criteria, design loading, and design procedure are described in Section 3.9.

5.4.13.2 Performance Evaluation

Refer to Section 5.2.2 for a detailed evaluation of the reactor vessel safety and relief valves.

5.4.13.3 Tests and Inspections

Refer to Section 5.2.2 for a description of the tests and inspections for the safety and relief valves.

5.4.14 Component Supports

Refer to Section 3.9 for a description of component support design.

5.4.15 Reactor Vessel Head Cooling System

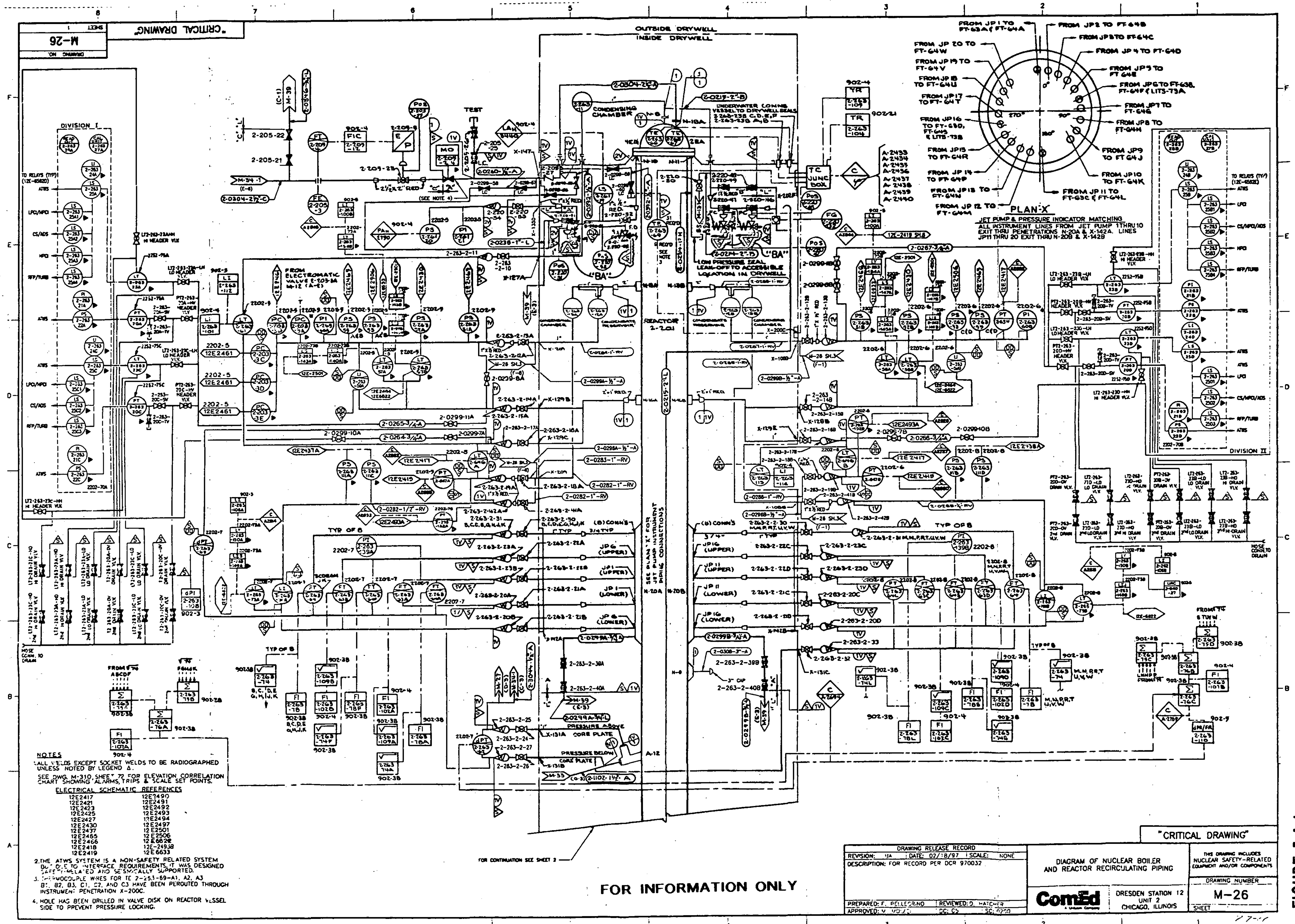
5.4.15.1 Design Bases

The objectives of the reactor vessel head cooling system are to collapse the steam bubble during vessel flooding, to cool the reactor vessel head, and to condense the steam in the vessel while the reactor is in the shutdown mode of operation. To achieve these objectives, the following design bases have been used:

Design flow	170 gal/min
Design pressure of carbon steel piping	1750 psig
Design pressure of stainless steel piping	1250 psig

5.4.15.2 System Design

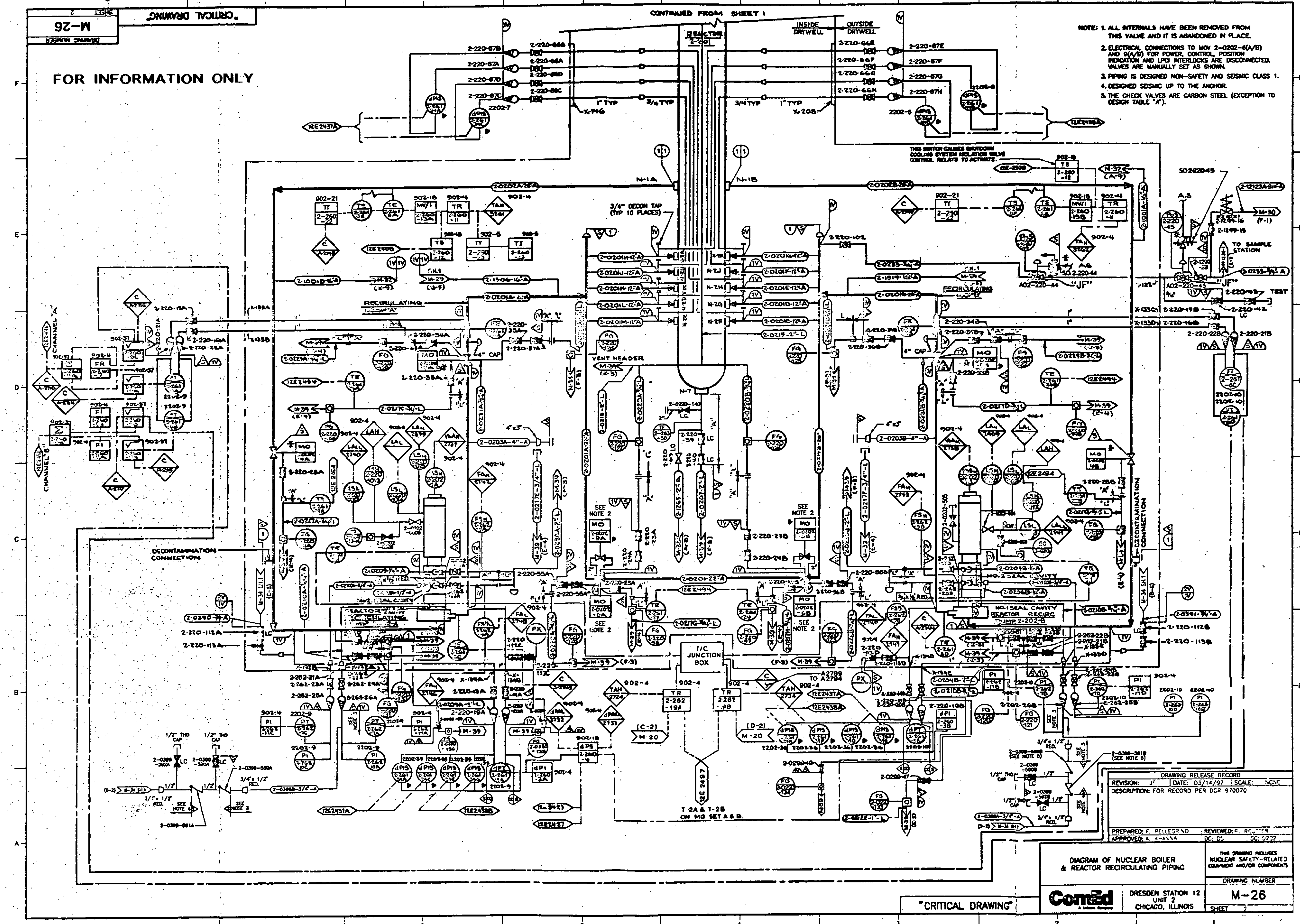
The reactor vessel head cooling system consists of selected components from the control rod drive (CRD) system, the head spray line and associated valves, and the head spray element.



CENTRAL DRAWING FACILITY

30 X

FIGURE 5.4-1 REV. 02 / JUNE 1997



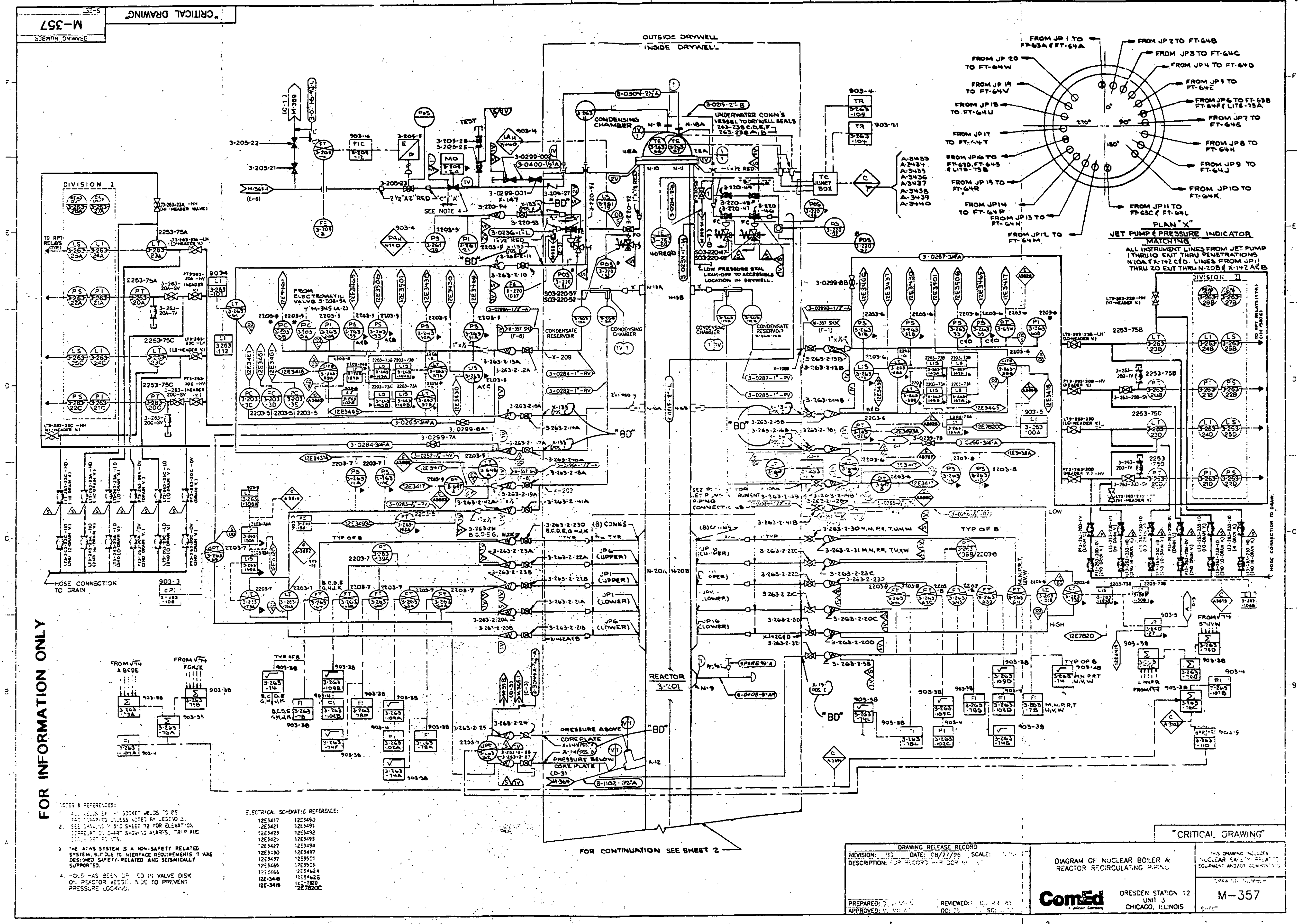
CENTRAL DRAWING FACILITY

30X

REV. 02 / JUNE 1997

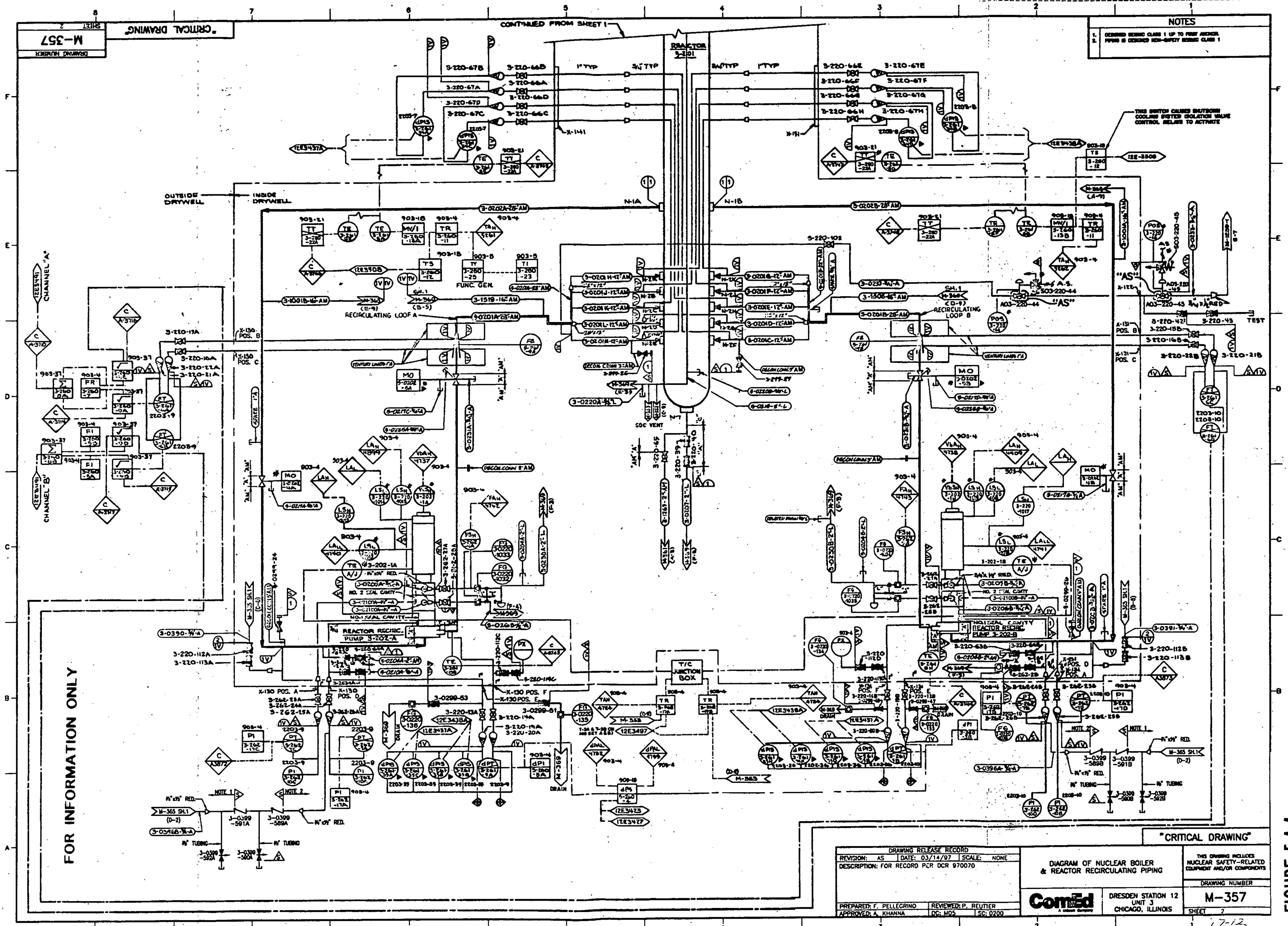
FIGURE 5.4-2

FOR INFORMATION ONLY



REV. 02 / JUNE 1997

FIGURE 5.4-3

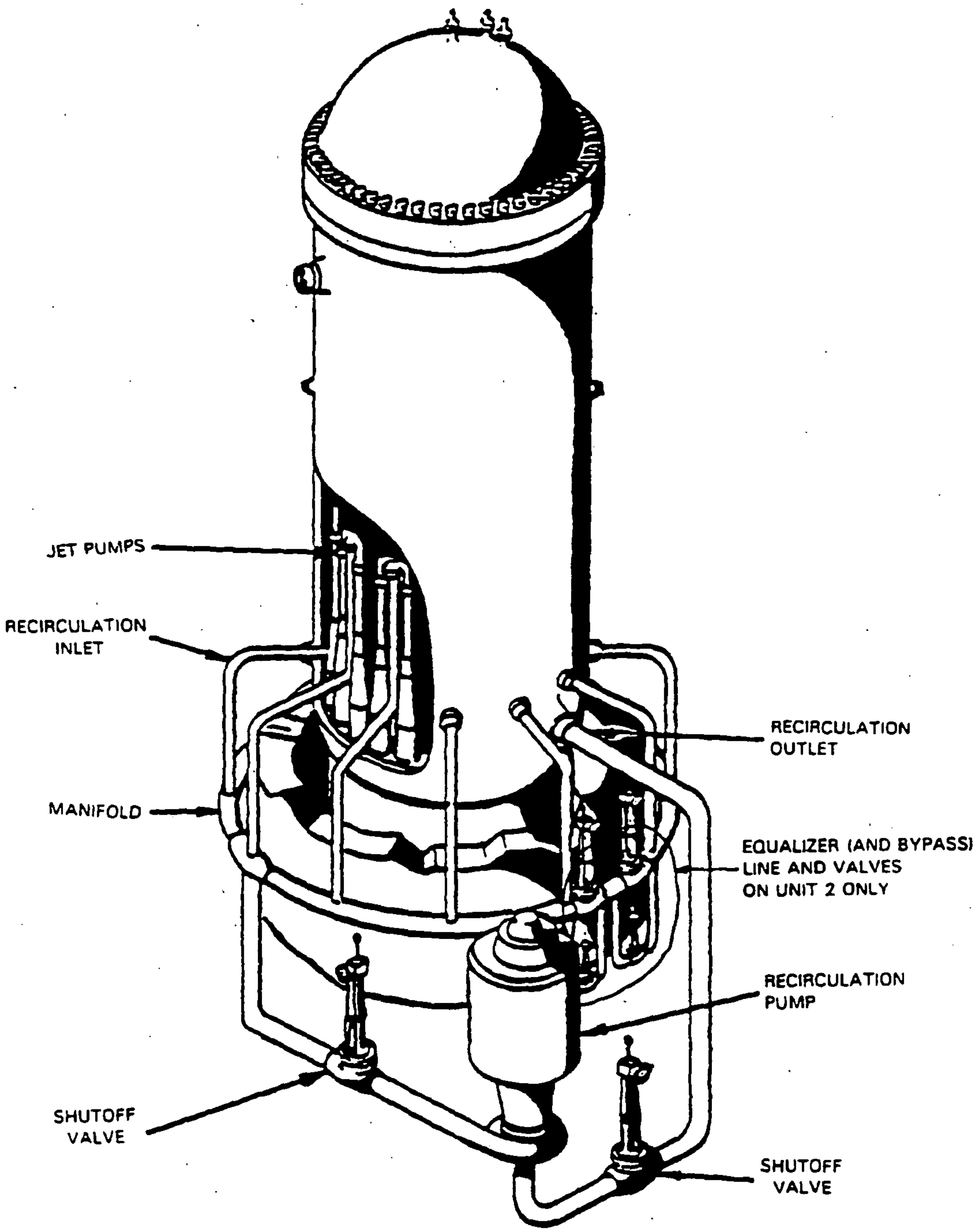


CENTRAL DRAWING FACILITY

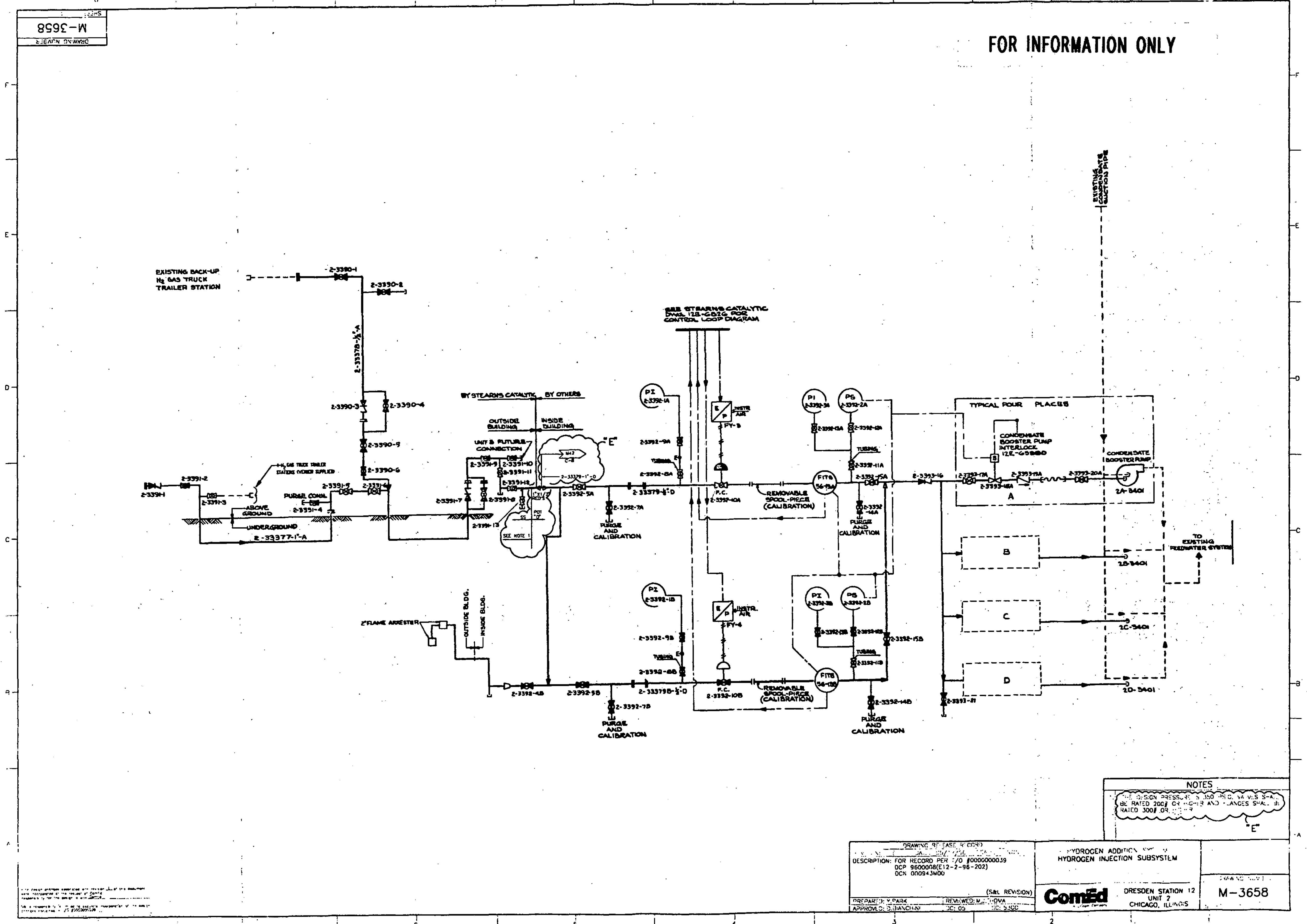
30X

FIGURE 5.4-4

REV. 02 / JUNE 1997



UFSAR REVISION 2, JUNE 1997
DRESDEN STATION UNITS 2 & 3
REACTOR VESSEL ISOMETRIC
FIGURE 5.4-5

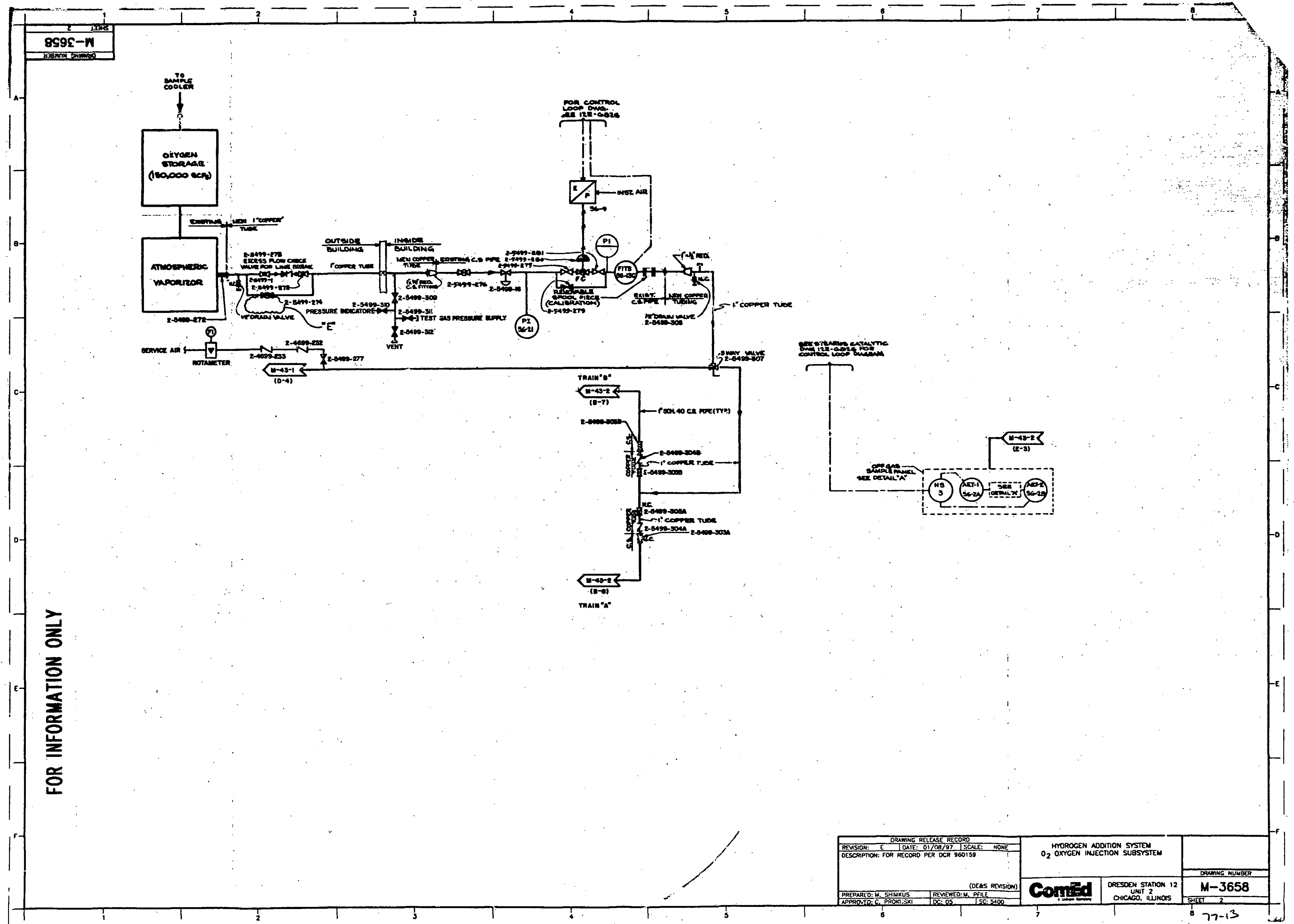


REV. 02 / JUNE 1997

FIGURE 5.4-15

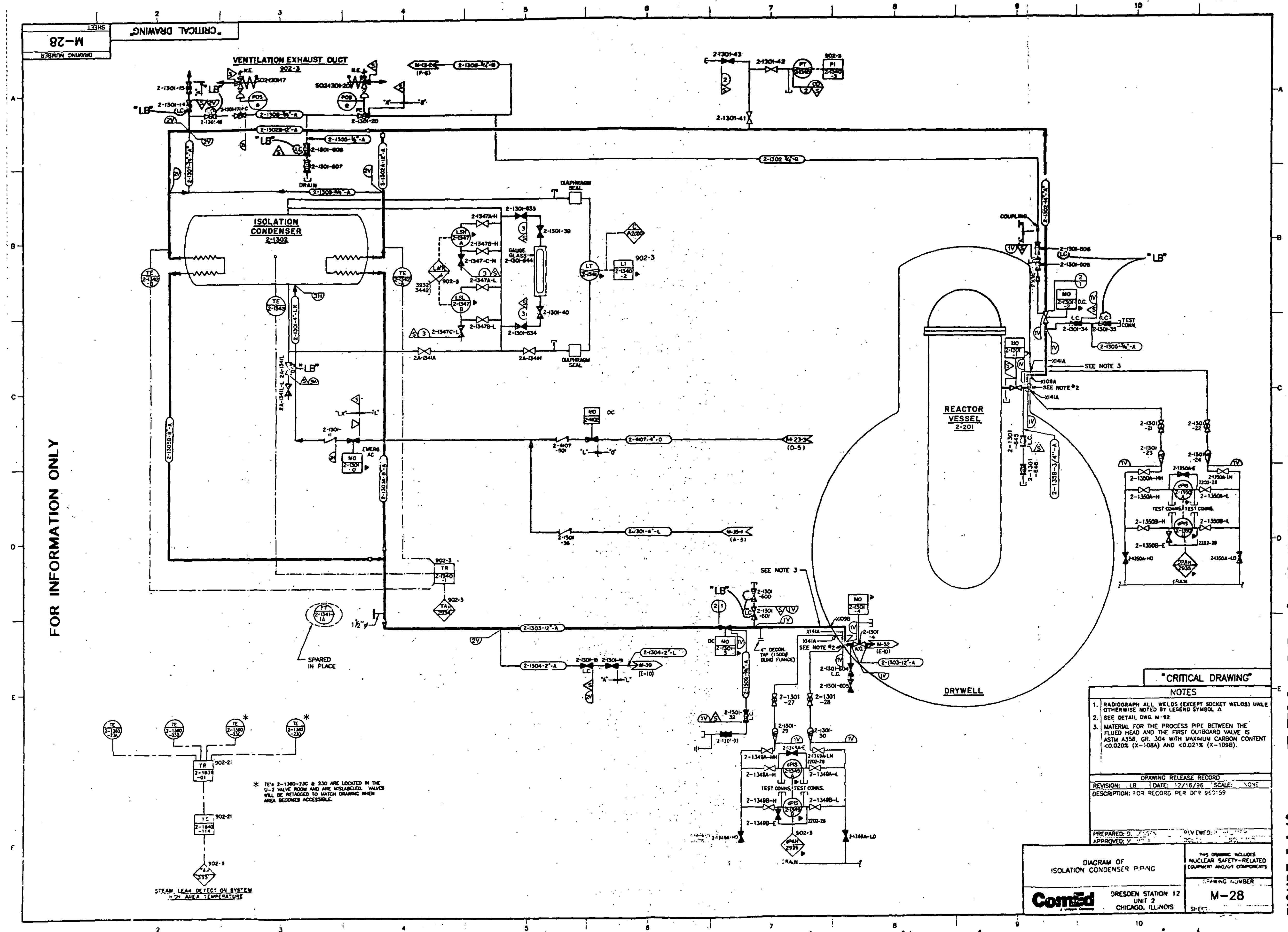
CENTRAL DRAWING FACILITY

30 X



REV. 02 / JUNE 1997

FIGURE 5.4-16



REV. 02 / JUNE 1997

FIGURE 5.4-18

CENTRAL DRAWING FACILITY 30 X

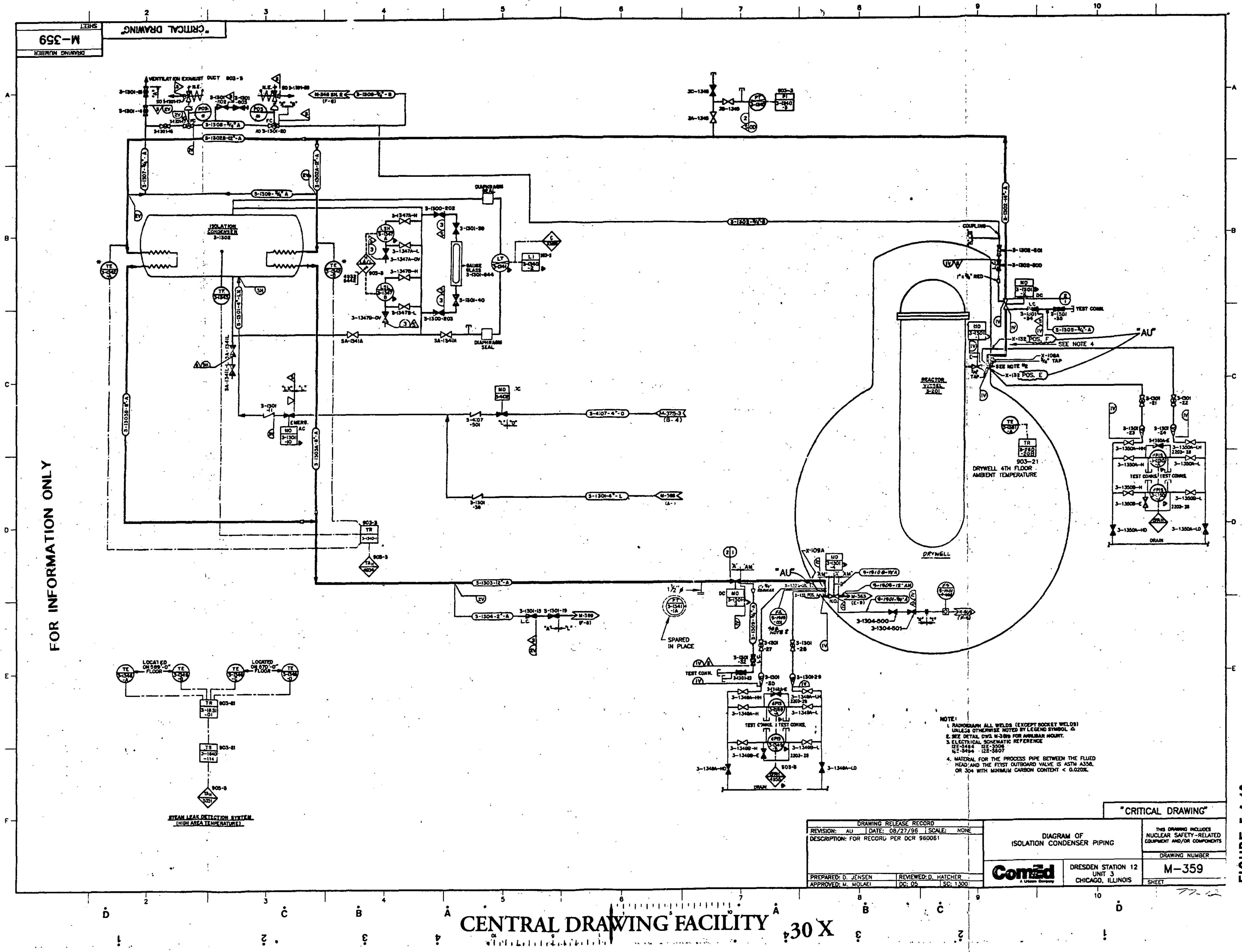
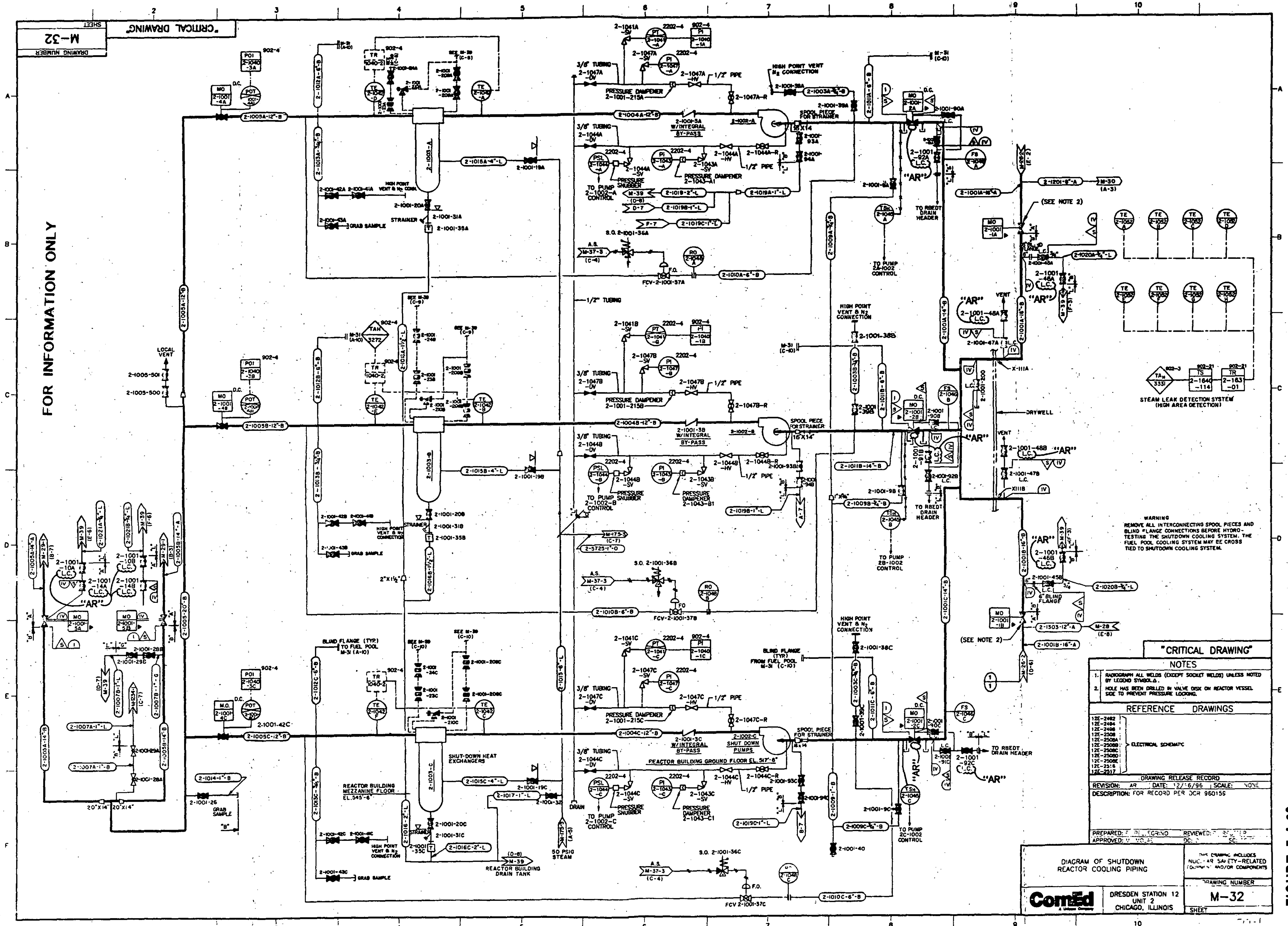


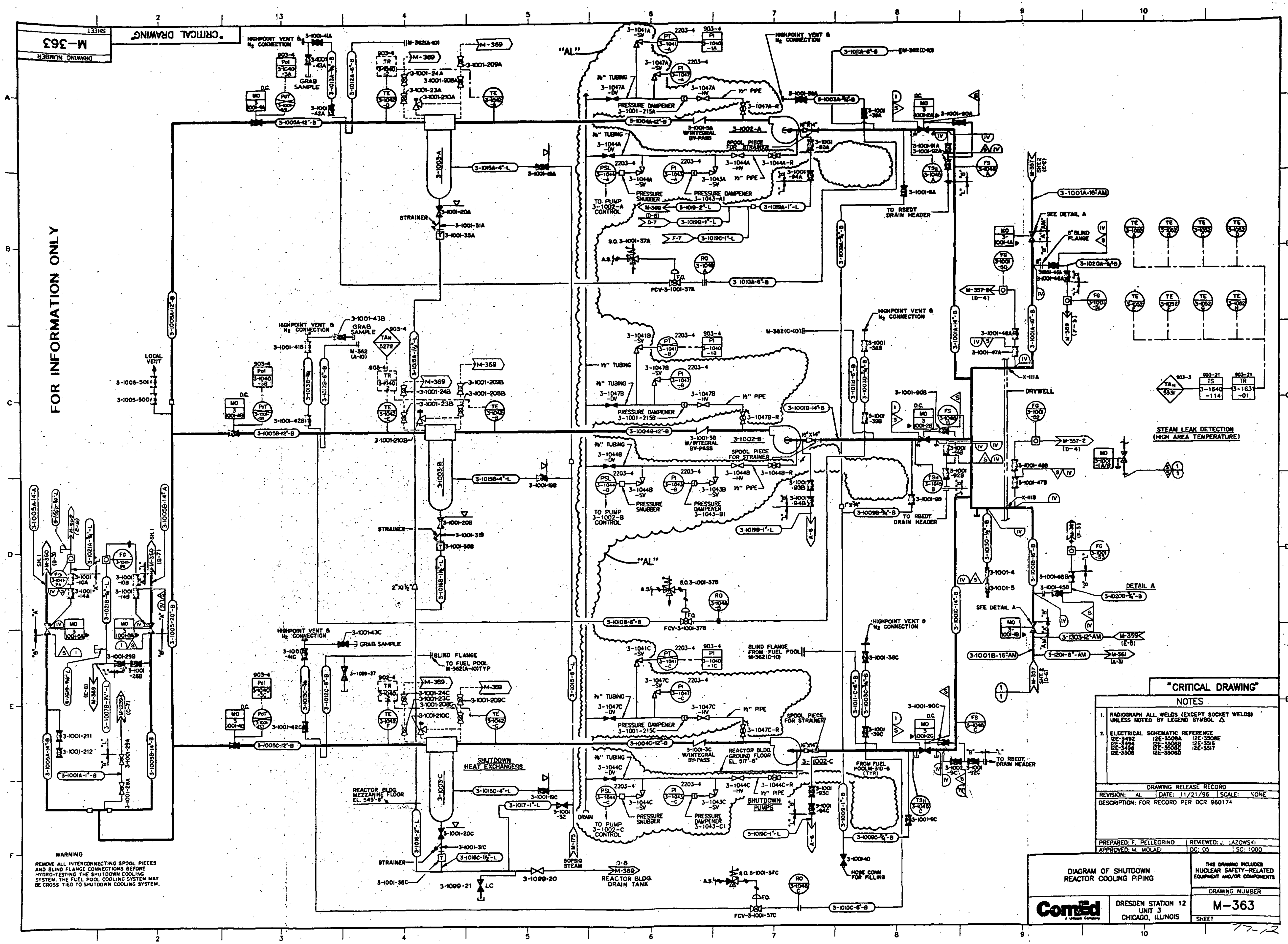
FIGURE 5.4-19 REV. 02 / JUNE 1997



CENTRAL DRAWING FACILITY 30 X

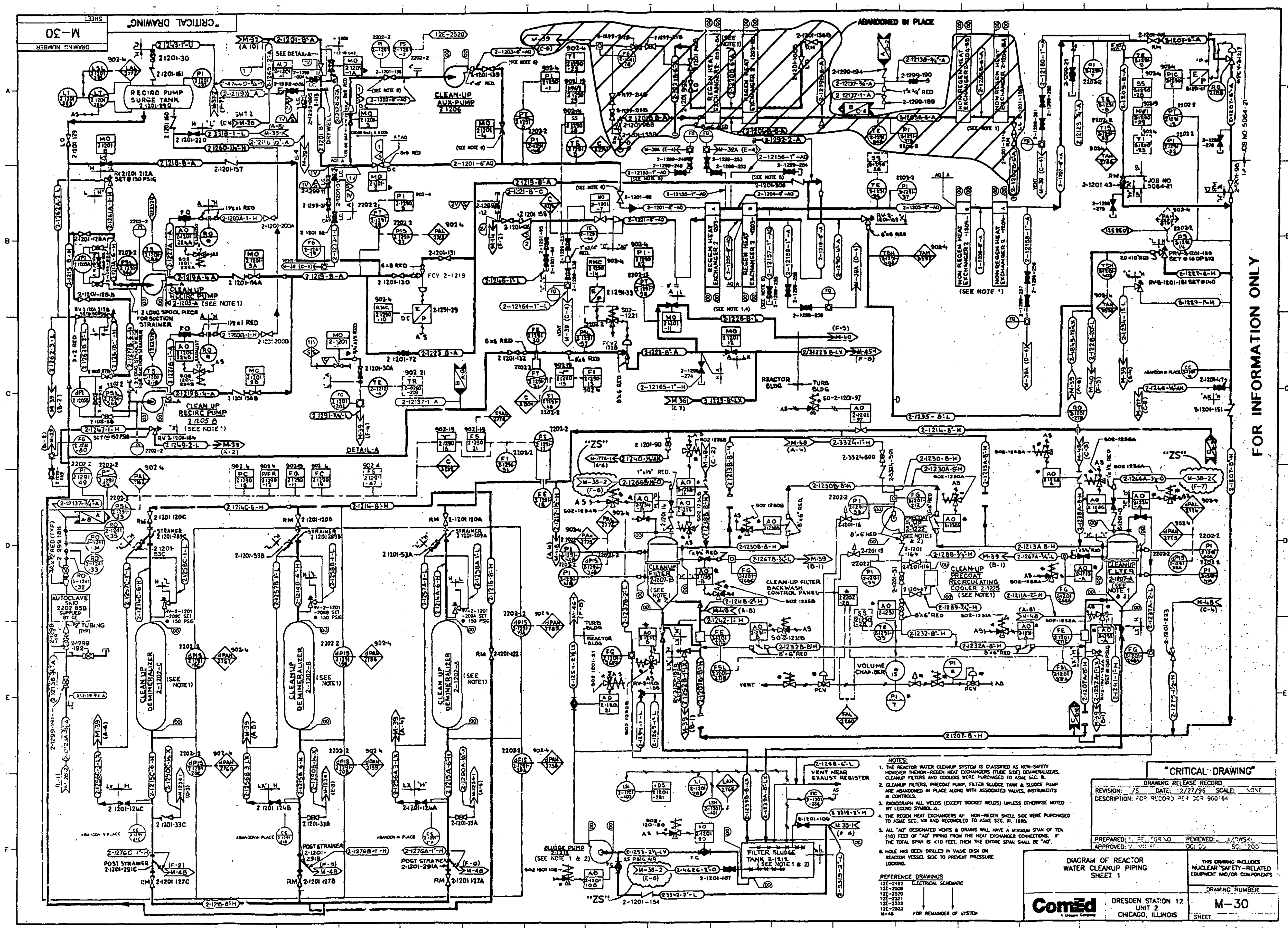
REV. 02 / JUNE 1997

FIGURE 5.4-20



REV. 02 / JUNE 1997

FIGURE 5.4-21

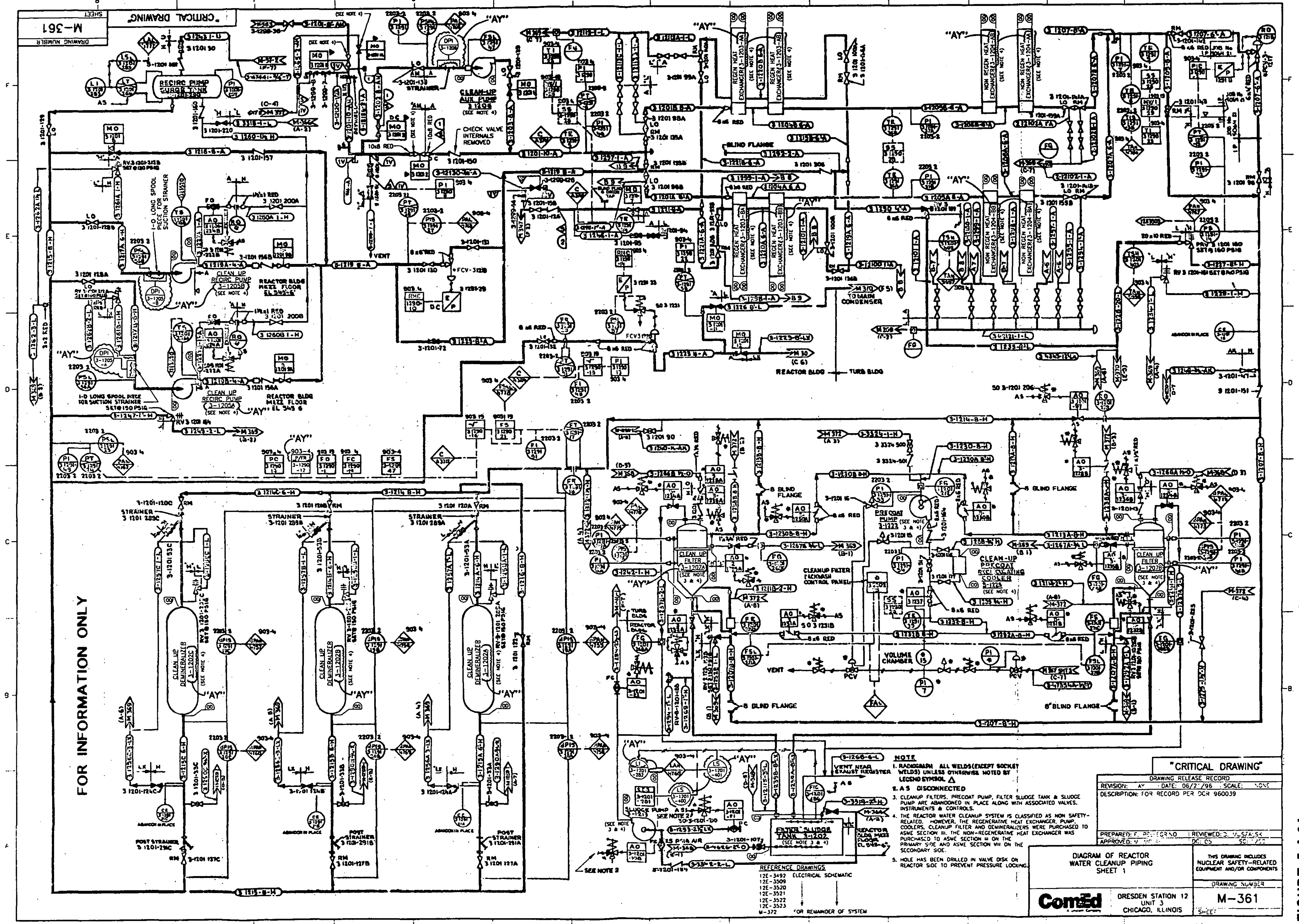


FOR INFORMATION ONLY

REV. 02 / JUNE 1997

FIGURE 5.4-23

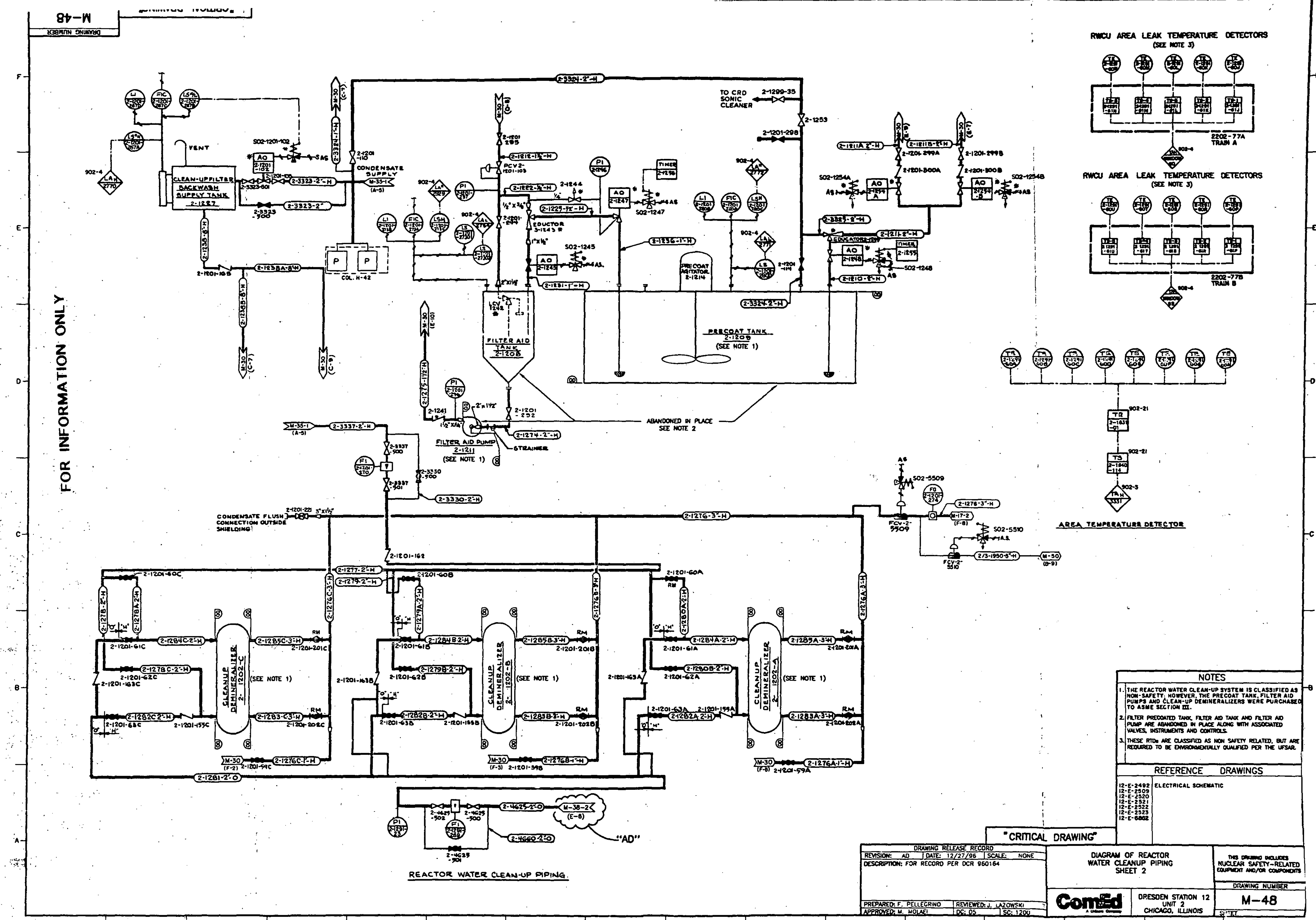
CENTRAL DRAWING FACILITY 30 X



REV. 02 / JUNE 1997

FIGURE 5.4-24

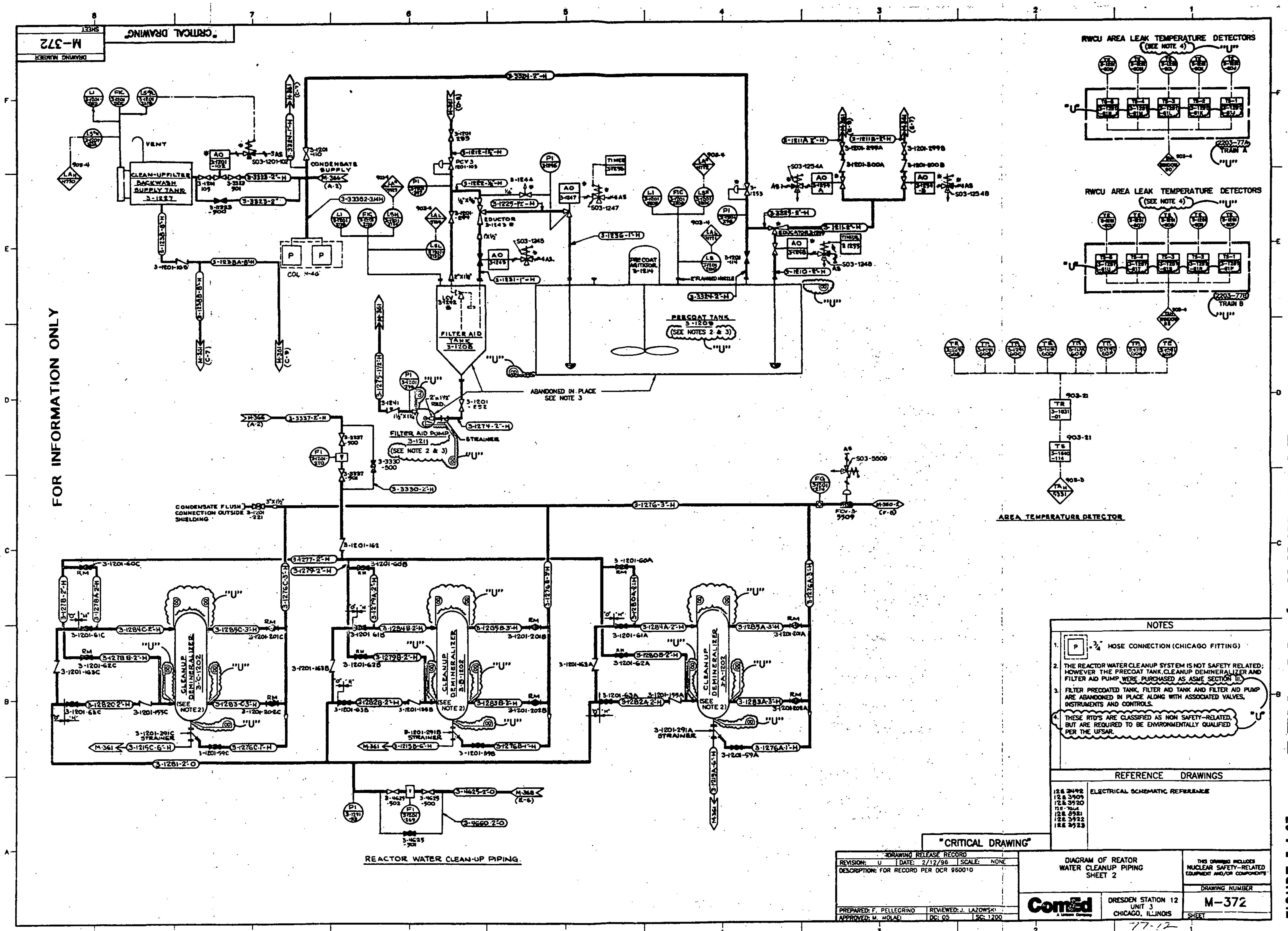
CENTRAL DRAWING FACILITY 30 X



CENTRAL DRAWING FACILITY 30 X

FIGURE 5.4-26

REV. 02 / JUNE 1997



REV. 02 / JUNE 1997

FIGURE 5.4-27

6.0 ENGINEERED SAFETY FEATURES
TABLE OF CONTENTS

Page

6.0 ENGINEERED SAFETY FEATURES
TABLE OF CONTENTS

6.0 ENGINEERED SAFETY FEATURES
LIST OF TABLES

Table

6.0 ENGINEERED SAFETY FEATURES
LIST OF FIGURES

6.0 ENGINEERED SAFETY FEATURES
LIST OF FIGURES

6.0 ENGINEERED SAFETY FEATURES
LIST OF FIGURES

6.0 ENGINEERED SAFETY FEATURES
LIST OF FIGURES

6.0 ENGINEERED SAFETY FEATURES
LIST OF FIGURES

temperature around 95°F. Brittle fracture is not a problem in this moderate temperature range.

The original specification indicates that the LPCI heat exchangers (shell side) were built to ASME Section III, Class C. The 1965 edition of the code requires impact testing. Material specification A212 has been discontinued and replaced by A515, Grade 70. Fracture toughness at the minimum heat exchanger service temperature of 51°F has been analyzed and shown to be adequate. Refer to Section 6.2.2.3.3 for additional details of this evaluation.

The HPCI drain and condensate line piping, fittings, and valves have ⅝-inch minimum wall thickness and are exempt from impact testing. The steam piping is over 6 inches in diameter and has a ⅝-inch wall thickness with the lowest operating temperature exceeding 150°F. This further exempts this system from impact testing according to ASME Section III, NC 2311a9.

Note that ASME Section III, 1965 edition, provided minimum construction requirements for vessels used in nuclear power plants. It classified pressure vessels as A, B, or C. Class A vessels are equivalent to Class 1 vessels of the current code. Class B is concerned with containment vessels, and Class C is concerned with vessels used in a nuclear power system not covered under Classes A or B. System classification is addressed in the Dresden Station third interval Inservice Inspection (ISI) Plan. As noted in the plan, piping, pumps and valves were built primarily to the rules of USAS B31.1.1.0-1967, Power Piping. Consequently, the Dresden Station ISI Program does not contain any ASME Section III, Code Class 1, 2, or 3 systems. The ISI Program system classifications are based on Regulatory Guide 1.26, Revision 3, and were developed for the sole purpose of assigning appropriate ISI requirements. The ISI Program is discussed further in Sections 5.2 and 6.6.

The LPCI and core spray pumps for Dresden are Class 2 components, as described in Regulatory Guide 1.26 under Group B quality standards. The code of construction and current classification of the pumps were verified by GE.

Confirmation that the atmospheric storage tanks meet current compressive stress requirements was requested by the NRC. In response to this request, it was found that the standby liquid control tank was designed and analyzed based on the methodology outlined in API-650 Code specifications. However, in 1982 the tank was requalified per the then current ASME Section III, Subsection ND. It was determined that the standby liquid control tank roof cover, vessel shell, base plate, roof ring, weldment, and U-bolts met the ASME Code requirements current in 1982. The analysis also showed that the actual stresses in these components subjected to specified seismic excitations are well within the ASME Section III allowables at the design temperature of 150°F.

Reflective Metal insulation (mirror type) or nonmetallic insulation (Nukon Blanket, foam glass or closed cell foam plastic) installed on piping inside the containment meets the requirements as defined in Section 5.2.3.2.3, "Compatibility of Construction Materials with External Insulation and Reactor Coolant". Therefore, the potential for stress corrosion cracking due to the presence of leachable chlorides in nonmetallic thermal insulation is not a concern.

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

Dresden Station uses high-purity demineralized water in the reactor vessel and for post-accident containment spray and core spray. The torus also contains demineralized water.

All carbon steel surfaces in the torus are painted to prevent corrosion (see Section 6.1.2). Even without protective coatings, the expected corrosion rate for carbon steel, used structurally in air-saturated demineralized water, is less than 10 mils per year. Such a corrosion rate following an accident is of negligible significance.

In the unlikely event that the standby liquid control system were actuated after a loss-of-coolant accident (LOCA), sodium pentaborate solution would be introduced into the reactor vessel. If the vessel were refilled to the elevation of the break, the sodium pentaborate solution in the vessel would spill into the torus.

When sodium pentaborate dissolves in water, it produces a mildly basic solution. The pH of the solution varies with concentration. For the range of concentrations expected, the pH is between 7.4 and 7.8.[1] At the maximum expected sodium pentaborate concentration during recirculation, carbon steel would corrode at a uniform rate of about 11 mils per year, and stainless steel at a rate of less than 0.1 mils per year. Again, these rates are insignificant following an accident. Thus, no additional provisions are required to control corrosion of steel following an accident.

Dresden relies primarily on inerting the containment atmosphere for post-accident hydrogen control. Control of post-accident chemistry to minimize the evolution of hydrogen from aluminum corrosion is therefore not a consideration in the Dresden design. Post-accident iodine control is accomplished through containment integrity, and operation of the standby gas treatment system. Containment spray additives, such as sodium hydroxide, are not used to remove radio-iodines from the containment atmosphere. Therefore, post-accident chemistry control to ensure the retention of iodines in sump water is not required.

Reactor water is sampled and analyzed for conductivity and chloride concentration every 72 hours during normal operation, to ensure that the conductivity and chloride concentration do not exceed 5 μmho/cm and 0.5 ppm, respectively. Water in the condensate storage tank is sampled 3 times a week, to ensure that the conductivity and chloride concentration do not exceed 1 μmho/cm and 0.1 ppm, respectively, and that the pH is between 5.6 and 8.6. The torus water is sampled monthly.

The NRC has determined that the use of demineralized water in the reactor vessel, post-accident containment spray, and core spray, in conjunction with the established periodic water sampling programs, provide reasonable assurance that the conductivity, pH, and chloride concentration of the water would be within the normal plant operating limits such that proper water chemistry can be maintained during the recirculation phase following a DBA consistent with the acceptance criteria of Standard Review Plan Section 6.1.1 for boiling water reactors.

6.1.2 Organic Materials

Identified coatings cover approximately 180,500 square feet of the interior of the Dresden containment. Approximately 58,950 square feet of this is in the drywell, and 121,550 square feet is in the torus.

The drywell shell, reactor shield wall, and vessel supports were originally coated with Dupont #67-4-746 Dulux Zinc Chromate Primer. This layer was covered with Carboline Rustbond Primer 6C Modified Vinyl. It was finished with Carboline Polyclad #933-1 Vinyl Copolymer. These two vinyls are described as a polyvinyl chloride. Failure of this type of material is at an exposure of 8.7×10^8 rads.[2] The total integrated dose for coatings within a typical BWR containment ranges from 5×10^6 to 3×10^9 rads, with most surfaces seeing less than 10^7 rads.[3] The normal integrated 40-year dose for Dresden is between 1.5×10^6 to 1.9×10^6 rads;[4] add this to a 1-year post-accident dose of 1.1×10^8 rad[5] and the total dose inside drywell would be 1.11×10^8 rads. It is, therefore, evident that this coating system would not fail due to radiation effects following an accident.

Other components of the drywell, which are coated with different materials, would not fail due to radiation effects following an accident. The concrete surfaces are coated with Carboline 195 Surfacer, a modified epoxy-polyamide, and Carboline Phenoline 368 WG Finish, a modified phenolic. The maximum gamma radiation resistance of an epoxy is approximately 4×10^8 to 9×10^8 rads, while that of phenolic coatings is 4.4×10^9 rads. The structural steel framing and lateral bracing are covered with the above named Dupont primer, an intermediate coating of alkyd enamel, and a finish of Detroit Graphite Red Lead 501 Alkyd Enamel. The grating areas are covered with the Dupont Zinc Chromate and finished with the Alkyd Enamel. The maximum gamma radiation resistance for an Alkyd Enamel is 5.7×10^9 rads. As compared to the values listed in Section 6.1.3, Reference 3, it may be deduced that this system would not fail following an accident.

The design temperature for the Dresden containment is 281°F for a design basis accident (DBA) and 135°F during normal power operation (see Section 6.2.1). The manufacturer's data lists the vinyls' main temperature resistance at approximately 150°F and the phenolics at 200°F — 250°F. This low temperature resistance in the vinyl materials is causing some peeling in the upper level of the drywell. The material has never dropped off, and the peelings are smaller than 1 square inch. Also, pull tests show pulls were greater than 200 pounds, as stated in the ANSI N5.12 report. This problem is controlled by scraping, blasting, and touching up the peeling areas with Carboline Carbo Zinc 11 during each outage. This product rates very good to excellent in chemical resistance and its temperature resistance is 750 — 800°F. Peeling is not expected with this material since the most extreme temperature encountered would cause the material to fall in a fine powder form, rather than large segments. The CZ-11 is also used to touch up the torus, and according to Carboline product data, meets stringent performance requirements of ANSI N101.2-1972 and ANSI N5.12-1974.

Since the ESF fluids are not taken from the sump in the Mark I design, it is unlikely that any peeling of the vinyl paint on drywell surfaces would lead to significant safety problems. The sump at the bottom of the drywell acts as a drain which is valved off during the DBA. The containment and core sprays during a DBA take suction from the bottom of the suppression pool. Any peeling vinyl paint flakes would collect in the bottom of the drywell where they would not interfere

Table 6.1-1

FRACTURE TOUGHNESS REQUIREMENTS

Structures, Systems, and Components	Quality Group Classification[1]	Material	Impact Test Required?	Reason for Exemption[2]	Remarks
Recirculation System					
Recirculation system piping	Class A	Type 304 stainless steel	No	8e	
Recirculation system valves	Class A	ASTM A351, Gr. CF8M stainless steel	No	8e	
Recirculation system pumps	Class A	Type 304, 316 stainless steel	No	8e	
Emergency Systems					
Isolation Condenser					
Shell side	Class C	ASTM A106, Gr. B carbon steel	No	8a	
Tube side	Class B	Type 304, 316 stainless steel	No	8e	
All stainless steel piping, valves, fittings	Class B	Type 304	No	8e	
All carbon steel piping	Class B	ASTM A106, Gr. B	No	8a	
Fittings and Valves	Class B	carbon and steel	No	8a	
Standby Liquid Control System					
Pump casing	Class B	Carbon steel	No	8d	
Tank	Class B	Type 304 stainless steel	No	8e	
Piping and casing	Class B	Type 304 stainless steel	No	8d, e	

Table 6.1-1 (Continued)

FRACTURE TOUGHNESS REQUIREMENTS

Structures, Systems, and Components	Quality Group Classification(1)	Material	Impact Test Required?	Reason for Exemption(2)	Remarks
Core Spray System					
Pump casing	Class B	ASTM A216, Gr. WCB carbon steel	Yes		Thickness up to 13/16 in.
All carbon steel piping	Class B	ASTM A106, Gr. B	No	8a	
Valves and fittings	Class B	carbon steel	No	8a	
All stainless steel piping, fittings, valves	Class B	Type 304	No	8a, e	
Spray spargers and spray nozzles	Class B	Type 304 stainless steel	No	8e	
Low Pressure Coolant Injection/ Containment Coolant Subsystem					
Pump casing	Class B	ASTM A216, Gr. WCB carbon steel	Yes		Thickness up to 13/16 in.
All Stainless steel piping, fittings, valves	Class B	Type 304	No	8e	
All carbon steel piping	Class B	ASTM A106, Gr. B	No	8a	
Valves and fittings	Class B	carbon steel	No	8a	

Table 6.1-1 (Continued)

FRACTURE TOUGHNESS REQUIREMENTS

Structures, Systems, and Components	Quality Group Classification[1]	Material	Impact Test Required?	Reason for Exemption[2]	Remarks
Heat exchangers:					
tube side	Class B	70/30 CuNi	No	8f	
shell side	Class C	ASTM A212, Gr. B carbon steel	Yes		Portions have 1-in. thickness
High Pressure Coolant Injection					
Pump casing	Class B	ASTM A216, Gr. WCB carbon steel	Yes		Thickness up to 1 1/2 in.
Piping	Class B	ASTM A106, Gr. B carbon steel	No	(8a, d)[3]	Impact test on all piping with nominal pipe diameter greater than 6 in.
Fittings, and valves	Class B	carbon steel	No	8a	
Spargers (feedwater spargers used)	Class B	Type 304 stainless steel	No	8e	
Standby Coolant Supply System (condenser hotwell to service water line)					
Pipings, fittings, and valves	Not safety-related				Deleted

Table 6.1-1 (Continued)

FRACTURE TOUGHNESS REQUIREMENTS

Structures, Systems, and Components	Quality Group Classification[1]	Material	Impact Test Required?	Reason for Exemption[2]	Remarks
Standby Gas Treatment System					
Pipings	Class B	ASTM A106, Gr. B, ASTM A211	No	8a	
fittings, and valves	Class B	Carbon steel,	No	8a	
Primary Containment					
Safety valves	Class A	Carbon steel	No	8d	
Relief valves	Class A	Carbon steel	No	8d	
Containment Penetrations					
Hydraulic lines to the control rod drives	Class B	Stainless steel	No	8d	
Valves	Class B		No	8d	
Containment Isolation Valves Not Listed with Major System	Class A		No	8d	
Control Rod Drive Housing	Class A		No	8d	

Table 6.1-1 (Continued)

FRACTURE TOUGHNESS REQUIREMENTS

Structures, Systems, and Components	Quality Group Classification[1]	Material	Impact Test Required?	Reason for Exemption[2]	Remarks
Control Rod Drive System					
Velocity limiter	Class B	Stainless steel casting	No	8d	
Guide tubes	Class B	Type 304 stainless steel	No	8e	
Spent Fuel Storage Facilities					
Spent fuel pool	Class C	Stainless steel lining (3/16-in. thick)	No	8a	
Reactor Vessel Head Cooling System					
Piping, fittings, and valves	Class C	Stainless steel	No	8d, e	

Table 6.1-1 (Continued)

FRACTURE TOUGHNESS REQUIREMENTS

Structures, Systems, and Components	Quality Group Classification(1)	Material	Impact Test Required?	Reason for Exemption(2)	Remarks
Condensate Feedwater System					
Piping from reactor vessel to outermost containment isolation valve	Class A	ASTM A106, Gr. B carbon steel	Yes		Thickness varies from .718 — 1.093 in.
Valves and fittings	Class A	Carbon steel	Yes		
Main Steam System					
Piping	Class A	ASTM A106, Gr. B	Yes		Thickness 1.031 in.
Valves and fittings	Class A	Carbon steel	Yes		
Condensate Storage Tank	Class C	Aluminum	No	8f	
Compressed Air System					
Piping, fittings, and valves	Class D		No	8d	

Table 6.1-1 (Continued)

FRACTURE TOUGHNESS REQUIREMENTS

Structures, Systems, and Components	Quality Group Classification[1]	Material	Impact Test Required?	Reason for Exemption[2]	Remarks
Standby Diesel-Generator System					
Service water piping	Class C	ASTM A106, Gr. B	No	8a	
Valves and fittings	Class C	Carbon steel	No	8a	
Fuel oil piping	Class C	ASTM A53, Gr. B	No	8a	
Valves and fittings	Class C	Carbon steel	No	8a	

Notes:

1. The quality group classification given here is the Regulatory Guide 1.26 classification to determine fracture toughness testing requirements and should not be confused with safety classification. Refer to Section 3.2 for a discussion of the seismic and quality group classifications.
2. Refer to Tables A4-4 — A4-6 of Appendix A in Franklin Research Center report on quality group classification of components and systems for explanation of exemptions.
3. Applies to drain and condensate piping.
4. For piping 2" and under, ASTM A335 Grade P11 or P22 may be substituted for ASTM A106 Grade B material for the same schedule. For fittings and valves 2" and under, ASTM A132 Grade F11 or F22 may be substituted for ASTM A105 for the same rating. Substitutions are allowed up to a maximum temperature of 450°F (operating or design).

transferred to the vent system by the penetration assembly and internal supports on the vent line.

6.2.1.2.3 Pressure Suppression Chamber

As shown in Figures 6.2-3, 6.2-4, 6.2-5, and 3.8-18, the pressure suppression chamber is a steel pressure vessel in the general shape of a torus, symmetrically encircling the drywell. The circular path around its major axis is formed by 16 cylindrical segments or bays. Alternate bays (eight in all) are connected to vent lines leading from the drywell. The horizontal centerline of the suppression chamber is located slightly below the bottom of the drywell. The inside diameter of the mitered cylinders, which make up the suppression chamber, is 30 feet 0 inches. A reinforcing ring with two column supports and a "saddle" is provided at each miter joint (Mark I Containment Long-Term Program) to transmit dead loads and seismic loads to the reinforced concrete foundation slab of the reactor building.

The reinforcing ring at each miter joint is in the form of a T-shaped ring girder. The ring girder is braced laterally with stiffeners connecting the ring girder web to the suppression chamber shell.

The suppression chamber shell thickness is typically 0.585 inches above and 0.653 inches below the horizontal centerline, except at penetration locations where it is thicker.

The suppression chamber is anchored to the basemat by a system of base plates, stiffeners, and anchor bolts. Space is provided outside of the chamber for inspection and maintenance.

Two manholes with double-gasketed bolted covers provide access from the reactor building to the pressure suppression chamber. These access ports are bolted closed when primary containment integrity is required. They are opened only when the primary coolant temperature is below 212°F and the pressure suppression system is not required to be operational. A test connection between the double gaskets on each cover permits checking gasket leak-tightness without pressurizing the containment.

Original plant design included baffles in the suppression pool intended to aid in thermal mixing of the suppression pool water. As a result of a reevaluation of the necessity for these baffles and a concern for their continued structural integrity in a blowdown event, the baffles have been removed.

The suppression chamber can be drained using the low pressure coolant injection (LPCI) pumps discharging via the LPCI heat exchanger to either radwaste or the condenser hotwell until the LPCI pumps lose suction. However, the path to the condenser hotwell is the preferred route to minimize the volume of water to be processed by radwaste. Complete suppression pool draining can be accomplished even with the LPCI pumps out of service by use of specially installed piping and isolation valves.

analyses to restore the margin of safety required in the original containment design.

After completion of the Mark I Containment Program, it was determined that the water volumes specified in the plant unique load definition [8] and the plant unique analysis[7] actually correspond to a downcomer submergence of 3.21 to 3.54 feet at zero differential pressure. An evaluation concluded that affected components were still within the allowables established for the Mark I Containment Program[9]. This evaluation concluded that the present volume, corrected for the 1.0 psid overpressure in the drywell, does not adversely affect the existing analyses, and that the maximum component stresses reported in the plant unique analysis are still valid and meet the criteria of NUREG-0661. See Section 6.2.1.3.6.2 for additional discussion of the Mark I acceptance criteria. Refer to Section 6.2.1.3.6.4.2 for a description of the details of the reevaluation.

6.2.1.3.2 Containment Response to a Loss-of-Coolant Accident

In order to identify containment response to a loss of coolant (LOCA) accident, several analyses were performed. These analyses were performed to evaluate the containment short-term and long-term pressure and temperature response following the Design Basis Accident (DBA) LOCA. Short-term is defined as a time period from the beginning of the DBA LOCA to 600 seconds. There is no credit taken for operator actions during this short-term interval. Long-term is defined as a time period after short-term, namely from 600 seconds into the event, at which time the operator takes actions to initiate containment cooling or to control pump flows.

6.2.1.3.2.1 Containment Short-Term Response to a Design Basis Accident

The spectrum of postulated break sizes with respect to reactor core response is discussed in Section 6.3.3.2. The following information covers the effects of a LOCA on the containment, with particular emphasis on the most severe break: the doubled-ended rupture of one of the 28-inch-diameter recirculation pump suction lines. For the purpose of sizing the primary containment, an instantaneous, circumferential break of this line was hypothesized. The LOCA involving the recirculation pump suction line would occur upstream of point 1 on Figure 6.2-14.

For the vessel blowdown, the reactor was assumed to be operating at a full power of 2527 MWt with the equalizer line valves between the recirculation loops open, even though these valves will be closed during power operation. Note that the equalizer line and valves were removed from the Unit 3 recirculation loops as described in Section 5.4.1.

Assuming the equalizer line valves are open, the flow area through the equalizer line must be considered in determining the total blowdown flow area. The total blowdown flow area is equal to the sum of all parallel flow areas and is given by:

$$A_B = A_R + A_E + NA_N \tag{1}$$

where:

A_B = Total equivalent break area (or blowdown flow area)

A_R = Flow area of recirculation line = 3.57 ft^2

A_E = Flow area of equalizer line valve port = 1.48 ft^2

N = Number of jet pumps on one header = 10

A_N = Flow area of a single jet pump nozzle = 0.057 ft2

6.2.1.3.2.2 Containment Short-Term Response to a (DBA) LOCA for Minimum NPSH Available

Various cases involving different pump combination, pump flow rates, initial conditions and assumptions were analyzed as shown in Tables 6.2-3, 6.2-3a and 6.2-3b. The short-term scenarios (0-600 seconds) that resulted in the minimum net positive suction head (NPSH) are described as follows:

- Four (4) LPCI pumps and two (2) core spray (CS) pumps for vessel makeup and no containment cooling up to 600 seconds following the DBA-LOCA with no operator actions required (short term case in Tables 6.2-3, 6.2-3a and 6.2-3b). This analysis was performed to determine the short-term (0-600 seconds) suppression pool temperature and suppression chamber pressure response for a postulated break in the recirculation discharge line with all 4 LPCI pumps and 2 core spray pumps available for vessel injection and with the assumed single failure of the loop selection logic which allows all the LPCI flow to be directed to the containment from the broken loop. It was assumed that all LPCI flow was injected directly into the drywell

- Two (2) LPCI pumps and one (1) core spray pump for vessel makeup and no containment cooling up to 600 seconds following the DBA-LOCA with no operator action required (long term case with 100% thermal mixing in Tables 6.2-3, 6.2-3a and 6.2-3b). This scenario provides the minimum conditions for NPSH with the single failure of an Emergency Diesel Generator.

The GE computer model SHEX-04 with decay heat based on the ANS 5.1, 1979 decay heat model (without adders) was used in each analyses. Analyses performed to benchmark analyses with the SHEX-04 code to the Dresden FSAR analyses were performed. The benchmarking analyses included sensitivity studies to quantify the effect on peak suppression pool temperature due to differences between the updated analyses and the FSAR original analysis.

Various assumptions were used in the analyses. These assumptions are included in Section 6.2.1.3.2.3. Additional assumptions for the short-term response are as follows:

- With an ECCS signal, all 4 LPCI pumps start vessel injection mode and inject directly into the drywell (no flow to the vessel) at a flow rate of 5,150 gpm per pump for the short term case and 5,000 gpm per pump for the long term case during the first ten minutes of this event.

- After receiving a signal for CS initiation, the 2 CS pumps start injecting into the vessel at a flow rate of 5,800 gpm per pump for the first ten minutes of this event.

- There is 60% thermal mixing efficiency of the break liquid with the drywell atmosphere for the short term case (<600 sec.) and 100% thermal mixing efficiency of the break liquid with the drywell atmosphere for the long term case (>600 sec.). These thermal mixings were chosen as appropriate for the conditions represented.

As a result of the large LPCI injection directly into the drywell during the first ten minutes, a significant reduction in drywell pressure and temperature produced a reduction of pressure in the suppression chamber. The results of this analysis are summarized in the short term case of Table 6.2-3 and include the suppression pool temperature and suppression chamber pressure at 600 seconds (at initiation of operator actions). Figures 6.2-19a, 6.2-19b, 6.2-20a and 6.2-20b show the suppression pool temperature and suppression chamber pressure responses. The results of these are also listed in Table 6.2-3. The results of the short term case, 60% thermal mixing and the long term case, 100% thermal mixing analyses, which provide the minimum NPSH in the short term, are input to the 0-600 second short-term position of the NPSH analysis in Section 6.3.3.4.3.1.

6.2.1.3.2.3 Containment Long-Term Response to a Design Basis Accident

The original DBA analyses showed that after the blowdown immediately following a postulated recirculation line break, the temperature of the suppression chamber water would approach 130°F, and the primary containment system pressure would equalize at about 27 psig as discussed in Section 6.2.1.3.2. Most of the noncondensible gases would be transported to the suppression chamber during blowdown and during LPCI and core spray injection for the first ten minutes. However, soon after initiation of the containment spray, the gases would redistribute between the drywell and the suppression chamber via the vacuum-breaker system as the spray reduces drywell pressure.

The core spray system would remove decay heat and stored heat from the core, thereby minimizing core heatup and any metal-water reaction. The core heat is removed from the reactor vessel through the broken recirculation line in the form of hot liquid. This hot liquid combines with liquid from the containment spray and flows into the suppression chamber via the drywell-to-suppression-chamber connecting vent pipes. Steam flow would be negligible. The energy transported to the suppression chamber water would ultimately be removed from the primary containment system by the containment cooling heat exchangers.

To assess the long-term pressure and temperature response of the primary containment after the postulated blowdown, and to demonstrate the adequacy and redundancy of the core and containment cooling systems, an analysis was made of the recirculation line break under various conditions of core and primary containment cooling. The current licensing basis long-term pressure and temperature response of the primary containment was analyzed for various flow rates and mixing conditions.

For containment cooling after 600 seconds, two CCSW pumps providing flows evaluated at 5,000 gal/min were assumed to be in service for the limiting scenario at a cooling water temperature of less than or equal to 95°F. LPCI and CS pump flow rates were also evaluated for different values. Analyses were performed at these LPCI, CS and CCSW pump flows by GE using the SHEX computer code with current standard assumptions for containment cooling analyses, including the use of the ANS 5.1 decay head model. Long term temperature is maximized and NPSHA minimized with a thermal mixing efficiency of 20%.

All analyses cases (except for the long term case as described in Section 6.2.1.3.2.2) were performed assuming that during the first 10 minutes, two LPCI pumps and one CS pump are conservatively used for vessel makeup to provide the initial conditions for the long term cooling analysis. This assumes a single failure of an emergency diesel generator. At 10 minutes into the event, the operator shuts down one LPCI pump and aligns the other LPCI pump from the vessel injection mode to the containment cooling mode. At the same time, two CCSW pumps and one LPCI heat exchanger are lined up for long term cooling. The resulting long-term containment cooling configuration consists of 1 LPCI pump, two CCSW pumps and one LPCI heat exchanger. The various analyses used different pump flow rates and heat exchanger performance values which were also evaluated for the various flows. The evaluated heat exchanger performance values are identified in Table 6.2-3b.

Different initial containment conditions were used for each combination of pump flow rates. Sensitivity cases were also analyzed to minimize the suppression chamber pressure response. The sensitivity parameters include heat sinks and the efficiency of thermal mixing between liquid break flow and drywell atmosphere. Additionally, the input assumptions were chosen to conservatively minimize the suppression chamber pressure and minimize the available NPSH.

Assumptions

1. The reactor is assumed to be operating at 102% of the rated thermal power.

2. Vessel blowdown flow rates are based on the Homogeneous Equilibrium Model.

3. The core decay heat is based on ANSI/ANS-5.1-1979 decay heat.

4. Feedwater flow into the RPV continues until all the feedwater above 180°F is injected into the vessel.

5. Thermodynamic equilibrium exists between the liquids and gases in the drywell.

6. The heat Transfer to the drywell airspace from the liquid flow from the break which does not flash is assumed to be partial (20%) or full (100%), depending upon cases to minimize the containment pressure. Thermal equilibrium conditions are imposed between the held-up liquid and the

fluids in the drywell as described in Assumption 5 above. The liquid not held up is assumed to flow directly to the suppression pool without heat transfer to the drywell fluids.

7. The vent system flow to the suppression pool consists of a homogenous mixture of the fluid in the drywell.

8. The initial suppression pool volume is at the minimum to maximize the calculated suppression pool temperature.

9. The initial drywell and suppression chamber pressure are at the minimum expected operating values to minimize the containment pressure.

10. The maximum operating value of the drywell temperature of 150°F and a relative humidity of 100% are used to minimize the initial non-condensable gas mass and minimize the long-term containment pressure for the NPSH evaluation.

11. The initial suppression pool temperature is at the maximum TS value (95°F) to maximize the calculated suppression pool temperature.

12. Consistent with the UFSAR analysis, containment sprays are available to cool the containment. Once initiated at 600 seconds, it is assumed that containment sprays are operated continuously with no throttling of the LPCI pumps below rated flow.

13. Passive heat sinks in the drywell, suppression chamber air space and suppression pool are conservatively neglected to maximize the suppression pool temperature. Heat sink inputs were developed based on the Dresden drywell geometry parameters which were compiled and used during the Mark I Containment Long Term Program and which are documented in GE Document 22A5743 and GE Document 22A5744, Containment Data, September, 1982. The drywell and torus shell condensation heat transfer coefficient is based on the Uchida correlation with a 1.2 multiplier. The inclusion of the heat sinks conservatively minimizes suppression chamber pressure.

14. All core spray and LPCI system pumps have 100% of their horsepower rating converted to a pump heat input which is added either to the RPV liquid or suppression pool water.

15. Heat transfer from the primary containment to the reactor building is neglected.

16. The effect of containment leakage is negligible considering that conservative input assumptions are used to minimize containment pressure.

The design parameters determined by the evaluations for the various LPCI, CS and CCSW flow rates, including the sensitivity cases are shown in Table 6.2-3. The table includes the suppression pool temperature and suppression chamber pressure at 600 seconds (at initiation of operator actions), the minimum suppression chamber pressure following initiation of containment (drywell and suppression chamber) sprays and the suppression pool temperature and suppression chamber pressure at the time of peak suppression pool temperature.

A comparison of the results show that the heat sinks have a negligible effect on the suppression pool temperature. As for the impact of the suppression chamber pressure, the inclusion of the heat sinks resulted in a reduction of approximately 0.8 psi at 600 seconds, and a reduction of approximately 0.2 psi in the minimum suppression chamber pressure following initiation of suppression chamber sprays. However, the heat sink effect on the suppression chamber pressure is negligible at the time of peak suppression chamber temperature. The results demonstrate that once containment sprays are initiated, the effects of heat sinks become insignificant.

The parameters identified in the evaluation (see Table 6.2-3) performed for the long term case (Above nominal pump flow rate for LPCI pump [5,800 gpm] and CS [5,800 gpm] for first 10 minutes and nominal pump flow for LPCI [5,000 gpm] and CS [4,500] rate after 10 minutes / Containment initial conditions to minimize containment pressure / Drywell and torus shell heat sinks modeled) provides the minimum NPSH. Figures 6.2-20a, 6.2-20b, 6.2-20c and 6.2-20d shows the suppression pool temperature and suppression chamber pressure responses. This case provides the limiting condition for evaluating available NPSH after initiation of containment sprays including available NPSH at the time of the peak suppression pool temperature. The analysis performed and identified in Table 6.2-3 provides the maximum suppression temperature to be 176°F. These design and operating parameters are such that they ensure that plant safety margins are met.

The results of the new analysis indicate that the heat removal capability of the containment heat removal system remains sufficient to maintain containment integrity following DBA's with a peak suppression pool temperature of 176°F. The consequences of this higher peak temperature have been analyzed and found to be acceptable. The results of the long term case analysis, which provides the minimum NPSH in the long term, are input to the greater than 600 second long-term position of the NPSH analysis in Section 6.3.3.4.3.2.

Containment spray itself does not significantly affect the peak post-accident pressure rise. It does, however, result in a somewhat faster depressurization immediately following the completion of the blowdown. The controlling parameter affecting the post-accident secondary pressure peak is the heat removal capability of the containment cooling heat exchanger relative to the core decay heat production.

Additional analyses of the short-term containment pressure and temperature response to a SBA, IBA, and DBA have been conducted as part of the Mark I Program. Refer to Section 6.2.1.3.6.4 for a description of these analyses.

6.2.1.3.3 Containment Long-Term Response to a Design Basis Accident

This section was revised and moved to Section 6.2.1.3.2.3.

6.2.1.3.4 Mark I Program Description for Reevaluation of Containment Response to Hydrodynamic Loads

This subsection describes the analysis performed to resolve new loadings identified after the original design of the primary containment.[13]

The first generations of GE BWR nuclear steam supply systems are housed in a containment structure designated as the Mark I containment system. Dresden Units 2 and 3 utilize Mark I Containments.

The original design of the Mark I containment system considered postulated accident loads previously associated with containment design. These included pressure and temperature loads associated with a LOCA, seismic loads, dead weight loads, jet impingement loads, hydrostatic loads due to water in the suppression chamber, overload pressure test loads, and construction loads.

In the course of performing large-scale testing of an advanced design pressure-suppression containment (Mark III), and during in-plant testing of Mark I containments, new suppression pool hydrodynamic loads, which had not been explicitly included in the original Mark I containment design basis, were identified. These additional loads result from dynamic effects of drywell air and steam being rapidly forced into the suppression pool (torus) during a postulated LOCA and from mass after drywell air carryover. The larger initial torus water mass has only approximately a 1°F effect on peak pool temperature. These effects result in a calculated increase in peak torus pressure of about 0.6 psi. For the IBA and SBA the peak drywell pressure increases by an equal amount. For the DBA, the increase in containment pressure increases the density of the vent flow which reduces the vent system pressure drop. This partially offsets the torus pressure increase and results in only a 0.3 psi increase in the peak drywell pressure.

6.2.1.3.6.4.3 Safety Relief Valve Discharge Device Limitations

Dresden Station is equipped with safety/relief valves (SRVs) to protect the reactor from overpressurization during operating transients. When the SRVs open, steam released from the reactor vessel is routed through SRV discharge lines to the suppression pool where it is condensed. Extended steam blowdown into the suppression pool, however, can create temperature conditions near the discharge location that can lead to instability of the condensation process. These instabilities can, in turn, lead to severe vibratory loading on containment structures. This effect is termed condensation oscillation. This is mitigated at Dresden Station by the usage of quenchers at the end of the SRV discharge lines, as well as restrictions on the allowable bulk suppression pool water temperature, in order to ensure that the local pool temperature stays within acceptable ranges. Technical Specifications Section 3/4.7.K provides limiting conditions for operation and action requirements, regarding the suppression chamber temperature.

By letter dated March 21, 1995, the BWR Owners' Group (BWROG) requested the NRC staff review and approve GE report, NEDO-30832 entitled, "Elimination of Limit on BWR Suppression Pool Temperature." NEDO-30832 presented a discussion of test data and analysis that supports deletion of the requirement to maintain the local suppression pool temperature 20°F below the saturation temperature of the pool during SRV discharge.

Dresden has eliminated the local suppression pool temperature limits. The test data and analysis presented within NEDO-30832 is applicable to Dresden Station. The NRC staff Safety Evaluation Report (SER) approval of NEDO-30832, dated August 29, 1994, concluded that the elimination of the local suppression pool temperature limit is acceptable if the plant has emergency safety features pump inlet located below the elevation of the quencher. Because Dresden Station's pump inlet is below the elevation of the quencher, NEDO-30832 is applicable to Dresden Station (see UFSAR figures 1.2-7 and 3.8-17). The NRC staff found that the quencher device is effective in maintaining the unstable condensation oscillation load to benign levels when the suppression pool is operated at temperatures nearing saturation.

6.2.1.3.7 Containment Capability

6.2.1.3.7.1 Potential For Hydrogen Generation

If, as a result of a severe accident, Zircaloy in the reactor core was to be heated above about 2000°F in the presence of steam, an exothermic chemical reaction would occur in which zirconium oxide and hydrogen would be formed. The corresponding energy release of about 2800 Btu per pound of zirconium reacted, would be absorbed in the suppression pool. The hydrogen formed, however, would result in an increased pressure due simply to the added moles of gas in the fixed volume. Although very small quantities of hydrogen would be produced during a DBA, the containment has the inherent ability to accommodate much larger amounts.

The Dresden containment is normally provided with an inerted atmosphere to preclude the possibility of a hydrogen combustion event within the containment. The oxygen deficient atmosphere assures that hydrogen build-up due to metal-water reaction is not a concern.

The generation of significant quantities of hydrogen due to a metal-water reaction from high fuel cladding temperatures is prevented by assurance of adequate core cooling. During normal operation, there are several systems, including feedwater and control rod drive (CRD), which add water directly to the reactor pressure vessel. A reliable, automatic means of cooling the core is provided by ECCS. This system is designed to provide adequate cooling in accordance with 10 CFR 50.46 limits assuming any single failure in addition to loss of offsite power. Refer to Section 6.3 for an evaluation of the ECCS performance.

Following a postulated LOCA, both oxygen and hydrogen may be produced by the radiolytic decomposition of primary coolant and suppression pool water. Decomposition would occur due to the absorption of gamma and beta energy released by fission products into reactor coolant and suppression pool water. Radiolysis is the only significant reaction mechanism whereby oxygen, the limiting combustion reactant, is produced within the containment. Therefore, radiolysis is the primary focus relative to combustible gas control for containments with inerted

LOCA. The initial portion of the curves on Figure 6.2-40 covers the time span during which the uniform energy release rate is high enough to generate steam within the drywell. All gases are thus transferred to the suppression chamber. When the duration is sufficiently long, the containment spray is sufficient to absorb all the energy without steam generation. The containment capability then increases with time as energy is removed from the system.

Even without containment spray, the pressure suppression system can tolerate a significant amount of metal-water reaction significantly greater than that actually calculated across the break spectrum consistent with the core cooling systems provided.

Therefore, that even without containment spray or inerting, the capability of the containment to tolerate postulated metal-water reactions following a LOCA is several orders of magnitude above that which is conservatively estimated to occur consistent with the case cooling provisions incorporated..

6.2.1.3.8 Containment Subcompartments — Pipe Break in the Subcompartment Between the Reactor Shield Wall and the Reactor

Section 3.6.2 provides a discussion of the jet impingement forces which are postulated to act on the concrete reactor shield wall surrounding the reactor.

6.2.1.3.9 Seismic Analysis

Seismic studies of the drywell and the pressure suppression chamber were conducted by John A. Blume and Associates of San Francisco, California. The results of this study are summarized in Section 3.7.2.2.1. The suppression chamber seismic analysis was updated in the Mark I Plant Unique Analysis Report to incorporate the effect of the Mark I modification.[7]

6.2.2 Containment Heat Removal System

Containment cooling is the operating mode of the low pressure coolant injection (LPCI) subsystem initiated to cool the containment in the event of a LOCA. This section describes the primary components and major functions of the containment cooling subsystem including: suppression pool cooling, drywell spray, and suppression chamber spray. The term containment spray, as used within this section, refers to drywell spray and suppression chamber spray collectively. A description of LPCI system pumps and related piping and valves is provided in Section 6.3.

During normal operation, containment cooling is provided by air handling units located in the drywell. Normal drywell cooling is addressed in Section 9.4.

The containment cooling heat exchangers are sized on the basis of their required duty to meet the containment capability. Refer to Section 6.2.1 for a description of the suppression pool cooling requirements. The heat exchangers are designed to withstand the maximum pressures corresponding to the shutoff heads of the CCSW and LPCI pumps. When service water is flowing, the pressure on the tube side of the heat exchanger is maintained 20 psi above the pressure on the shell side to prevent shell side water leakage into the service water and subsequent discharge to the river. Local instrumentation is provided to monitor the ΔP between the LPCI heat exchanger tube side and shell side. Additional containment cooling heat exchanger design information is provided in Table 6.2-7.

Since the LPCI flow passes through the containment cooling heat exchangers, containment heat may be rejected during post-LOCA LPCI mode operation by starting the CCSW pumps (when sufficient electrical power is available) to provide cooling to the heat exchangers. This results in the transfer of heat from the suppression pool to the CCSW system. During this mode of operation, suction is taken from the suppression pool, pumped through the containment cooling heat exchangers to the reactor vessel, and back to the drywell via the postulated break. When the drywell water level reaches the level of the containment vent pipes, the water flows through the vent pipes to the suppression pool.

Stagnant water conditions in the containment cooling heat exchangers (EPNs 2(3)-1503-A&B) during standby conditions cause both pitting and corrosion of the 70-30 CuNi tubes.[34] This has resulted in heat exchanger tube leaks and excessive equipment outage durations. Various materials were evaluated for better corrosion resistance and AL-6XN was selected as the replacement tube material. A limited number of tubes will be replaced with AL-6XN tubes as tubes fail. (AL-6XN has been accepted by ASME under Code Case N-438).

To ensure that other design basis evaluations are not invalidated by replacement of these tubes, the number of tubes plugged or replaced in each heat exchanger will be limited such that the total reduction in heat removal capability will not exceed that which would result from plugging 6% of the 70-30 CuNi heat exchanger tubes. The 6% limit is based on the number of excess tubes provided in the containment cooling heat exchanger design. The 6% replacement limitation will ensure that the design basis heat exchanger capability will not be reduced. The relationship between plugging tubes and replacing 70-30 CuNi tubes with AL-6XN tubes is shown in Figure 6.2-42.

Fibrous insulation is a molded insulation used only on parts of the recirculation system and the 4-inch and smaller lines. The total amount of such material used in the drywell is only 0.16% by volume or 0.05% by weight of the suppression pool water. Any postulated accident would dislodge only a fraction of this material.

Miscellaneous items are expected to contribute a negligible volume of contaminates in comparison to the suppression pool water volume. Any particles contributed are expected either to be stopped by strainers if they reach that position or to be colloidal rust type particles which would have little or no effect on ECCS pump seals or bearings.

As well as having limited contaminate sources, minimal probability of problems exist because of the circuitous path from the drywell to ECCS pump suctions. Particles first must pass through 1 x 1 ½-foot openings from the drywell to the 8-foot suppression pool downcomers. The downcomers are connected to large spherical shells which are interconnected by 4-foot diameter pipes forming the inner suppression pool ring header. From this header, the path to the suppression pool is through 96 circumferentially spaced 24-inch diameter pipes which extend below the suppression pool water line. The path then proceeds through four suppression pool suction strainers located about ⅓ of the suppression pool water level height above the suppression pool bottom. From the strainers the path leads into a 24 inch suction ring header and then to the pump suctions. This path is quite circuitous, providing many places to trap foreign objects and also spreading the particles that do get through uniformly throughout the suppression pool volume. Larger pieces of metal will settle to the bottom of the suppression pool, and lighter materials such as unibestos will float rather than be drawn into the ECCS pump inlets.

The average water velocity in the suppression pool during ECCS equipment operation is less than 0.1 ft/s and is not sufficient to transport particles (except for the smaller pieces in colloidal suspension). However, during a postulated blowdown from the drywell to the suppression pool, there will be a less idealized situation. The suppression pool water will be disturbed and a certain portion of materials will be near the suction strainers. The strainers are stainless steel perforated plates with ³⁄₃₂ inch diameter openings. Larger pieces and part of longer pieces (of smaller diameter) will be stopped and the strainer effective area will be somewhat reduced. To account for this possibility, hydraulic performance of the ECCS pump system is based on 100% plugging of one of the four strainers with 5.8-feet head loss at 10,000 gpm assumed across each of the remaining strainers. Therefore, more than a 33% extra strainer capacity is available. This conclusion is conservatively based on simultaneous operation of all ECCS equipment at full rated flow.

Extended operation of all ECCS pumps is not required in order to satisfy long term decay heat removal requirements. Short term DBA-LOCA cooling analyses assume the use of two LPCI pumps and one core spray pump, or two core spray pumps, to provide adequate core cooling. However, on a long-term basis, only one LPCI and one core spray pump are necessary to provide required cooling to the containment and the core. This flow would require only one-eighth of the total screen area. Also, the suppression pool water is demineralized and does not contain special additives. Therefore, the pH is expected to remain essentially neutral so that neither alkaline nor acidic corrosive actions are anticipated to affect ECCS pump seals or bearings.

In summary, the potentially damaging material sources are small, the volume is low in comparison to the suppression pool water volume, it is difficult for contaminates to reach the suction strainers and even more difficult to reach the pump. In addition, pump flow requirements for long term operation are low. These factors, in conjunction with a low probability of occurrence of a major accident, lead to the conclusion that the probability of suppression pool contamination creating a safety problem is extremely remote, to the point of being negligible. This position is further enhanced by the normal feedwater supplies which would be available when considering the long term operating requirements.

6.2.2.3.3 LPCI Heat Exchanger

A fracture toughness analysis was performed to determine adequacy of the shell material on the LPCI heat exchanger secondary side. The heat exchanger shells were designed as Quality Group Class C and were constructed of carbon steel A-212, Grade B material. They were built to requirements of ASME Section III, 1965 edition. The fracture toughness was calculated at the minimum heat exchanger service temperature of 51°F. The analysis indicates that approximately 1.5×10^6 heatup and cooldown cycles would be required to propagate an initial crack of 0.010 inches (the maximum crack size that could go undetected by inspection) to a critical crack size of 5.25 inches. The NRC evaluated these results and after performing their own confirmatory analyses concluded that the shell material on the secondary side of the LPCI heat exchangers has adequate fracture toughness.

6.2.2.4 Tests and Inspections

Because containment cooling is an operating mode of the LPCI system, LPCI system testing partially verifies that the containment cooling subsystem is functional. Additional tests are periodically performed to verify that containment spray is operable. The containment spray header discharge valves are tested by individually operating the header isolation valves. Control system logic provides for automatic return of the valves from the test mode to the operating mode if LPCI initiation is required during testing. An air test of the drywell spray headers and nozzles is performed periodically to verify operability of the drywell spray function.

Eddy current testing is performed during inspection of replacement containment cooling heat exchanger tubes.

6.2.3 Secondary Containment Functional Design

The description presented in this section is applicable to Units 2 and 3, since the secondary containment is common to both units. This description includes the design basis and design features of the secondary containment (reactor building) structure and all interfacing structures and systems needed to ensure its integrity. A design evaluation is provided which addresses performance characteristics. Tests and inspections needed to verify that secondary containment is operable and the instrumentation required to monitor and operate secondary containment are also described.

6.2.3.1 Design Basis

From a safety consideration, the primary purpose of the secondary containment is to minimize the ground level release of airborne radioactive materials and to provide for a controlled, elevated release of the building atmosphere under accident conditions. The reactor building serves as the secondary containment structure. It provides secondary containment when the primary containment is required to be in service and provides primary containment during reactor refueling and maintenance operations when the primary containment system is open. The building meets any combination of the above as may be required by the operation of Units 2 and 3. Specific design bases of secondary containment are as follows:

A. The reactor building is designed so that under neutral wind conditions the building is maintained at an internal negative pressure of $\geq$¼ in.H_2O.

B. Exfiltration from the building does not exceed 100 % of the building volume per day for wind speeds on the order of 40 mph.

C. The reactor building is capable of withstanding an external wind loading equivalent to a wind velocity of about 110 mph.

D. The seismic design and tornado analysis of the reactor building are in accordance with Chapter 3.

E. The reactor building is designed to withstand an internal pressure of 7 in.H_2O without structural failure and without pressure relief. Provisions are made to relieve reactor building pressure in excess of the design pressure in the unlikely event of a rupture of the high energy piping within the building. Relief devices (blowoff panels) are provided to assure that building structural integrity will not be impaired.

F. Means are provided for exhausting treated air from the reactor building using the standby gas treatment system (SBGTS).

G. Means are provided for periodically monitoring the leak-tightness of the reactor building as described in Section 6.2.3.4.

operating floor with the bridge crane. The reactor building houses the Unit 2 and 3 refueling and reactor servicing equipment; new and spent fuel storage facilities; and other reactor auxiliary or service equipment, including the emergency core cooling systems (ECCS), isolation condenser systems, demineralizers, standby liquid control systems, control rod hydraulic system equipment, and components of electrical equipment. The general arrangement of the reactor building and the principal equipment is shown on Figures 1.2-6 (Drawing M-6) and 1.2-8 (Drawing M-8).

The structural and shielding design of the reactor building are discussed in Chapter 3 and Section 12.3, respectively.

Special sealing methods were used throughout the construction of the reactor building. The sheet metal siding panels have interlocking joints sealed with vinyl plastic gaskets and special caulking compounds as shown in Figure 6.2-43. Other joints are sealed with such materials as rubber strips, two-sided adhesive tapes, and special caulking. Screw holes are caulked. The reactor building parapet is sealed with urethane foam.

The reactor building roofing is made of a vapor barrier overlaid by 1-inch thick (minimum) loose-laid board insulation, covered with 10-year, single-ply, elastomeric-membrane fabric, and ballasted with paver blocks. Steel holddown clips on the corners of the roof slabs are welded to the roof purlins. Longitudinal and transverse joints are filled with mastic sealer, and the corner recesses are filled with grout.

6.2.3.2.2 Reactor Building Airlock Doors

Reactor building airlock doors have weather-strip-type rubber compression seals. The design basis leakage limit is 25 ft^3/min per door at ¼ in.H_2O pressure. Each pair of personnel access control doors is electrically interlocked so that only one of the pair may be open at a given time.

There are two personnel air locks between the turbine and reactor buildings at grade elevation. There is one equipment airlock and one equipment access door from the outdoors into the reactor building on the ground floor. In addition, there is one personnel air lock into the reactor building from the turbine building main floor. The equipment access door is enclosed on the outside by a material interlock structure, however this structure is not considered to provide secondary containment. There are personnel airlocks from the Unit 2/3 diesel generator room to the high pressure coolant injection (HPCI) pipeway, the Unit 2 and Unit 3 HPCI rooms, and the Unit 2 reactor building. There are other personnel airlocks from the turbine building to the Unit 2 and Unit 3 MSIV rooms (X-areas).

Inside the reactor building between Units 2 and 3 there are ordinary single doors at three floor levels.

6.2.3.2.3 Reactor Building Pipe and Electrical Penetrations

Reactor building pipe and electrical penetrations are sealed as necessary to minimize air leakage and meet the infiltration specification. Leakage through minor apertures is acceptable. Electrical penetrations may be caulked with oakum and a soft setting compound, for example. Airflow through pipeways may be blocked sufficiently with sheet metal curtains or collars. Larger annuli may be blocked with appropriate fabric sleeves (e.g., insulation for hot pipes). Small annuli between pipes and the concrete opening may be left open.

6.2.3.2.4 Secondary Containment Isolation System

Secondary containment isolation consists of closing the reactor building ventilation system isolation dampers, shutting down the ventilation fans, and activating SBGTS. The reactor building ventilation system is described in Section 9.4, and SBGTS is described in Section 6.5.

Secondary containment isolation of both units is automatically initiated in response to airborne contamination or a refueling accident (both detected by the reactor building air monitoring system) or by a Group 2 primary containment isolation signal in either unit. The reactor building air monitoring system is described in Section 11.5.2.4, and the primary containment isolation signals are described in Section 7.3. The refueling accident is analyzed in Section 15.7.3.

Following isolation, the SBGTS will restore the negative pressure inside the reactor building and will remove radioactive contamination from the reactor building air before discharging it through the 310-foot chimney.

The reactor building ventilation isolation dampers for each unit are located adjacent to the reactor building in the turbine building, on the supply and exhaust fan deck at elevation 581'-0". There are two dampers in series in both the supply and exhaust ducts.

6.2.3.3 Design Evaluation

The containment system provides the principal mechanism for mitigation of accident consequences with the reactor building atmosphere being filtered and discharged through the 310-foot chimney for elevated release. The offsite accident consequences are relatively insensitive to the reactor building inleakage rate as long as the SBGTS can maintain the building at a negative gauge pressure and prevent exfiltration at low wind speeds.

Exfiltration from the secondary containment would be minimized by construction to the specified leakage limit of 1600 ft^3/min. at internal negative pressure of ¼-in.H_2O (gauge), with 40 mph winds. If high wind exfiltration were to occur, dilution of any released radioactive material would be large so that potential exposures are inherently minimized. Such exfiltration is not postulated since the design and operation of the reactor building ventilation system and SBGTS

Analysis shows that the secondary containment will sustain about 7 in.H_2O (36.5 lb/ft^2) positive pressure, due to accident conditions such as escape of primary containment pressure or leakage from a steam or hot water line, without exceeding specified leakage limits and without structural failure. Tests show the blowoff panels would relieve at 70 lb/ft^2 without other damage to the superstructure. The blowoff panels and other tornado protection measures are described in Section 3.3.

Four dP sensors, one on each side of the building, are used to compare the pressure external to the reactor building with the internal pressure on the 613 ft elevation operating floor. The points selected for external measurement are on the exterior of the siding above the operating floor level. The signal from each dP transmitter is then sent to a circuit which selects the lowest differential pressure to control the position of the reactor building ventilation system exhaust fan dampers. The controller is set to maintain a negative pressure difference of at least ¼ in.H_2O relative to the pressure on the side of the building with the lowest atmospheric pressure. Fan mass flow varies as a function of wind direction and velocity.

6.2.3.4 Inspection and Testing

The reactor building leakage rate is tested by isolating the building and operating the SBGTS. The SBGTS flow control valve is adjusted to obtain 4000 ft^3/min, and the building ΔP is measured. The building is required to hold at least ¼ in.H_2O vacuum to pass the test.

The reactor building inleakage is tested prior to refueling, when an operation or event brings the reactor building leakage integrity into question, or at least every 18 months.

Secondary Containment is maintained as defined in Technical Specification 3.7.N in operational modes 1, 2, 3 and when handling irradiated fuel in the secondary containment, during core alteration(s) and operations with a potential for draining the reactor vessel.

Double interlock doors on equipment and personnel access airlocks prevent the breaching of containment integrity. Possible deterioration of airlock door seals and penetration seals is detected during periodic inspections and tests. Corrective maintenance is performed as necessary.

6.2.3.5 Instrumentation Requirements

The instruments required to support the secondary containment are those instruments necessary to control reactor building pressure and to initiate secondary containment isolation. These include the reactor building pressure sensors, process radiation monitors in the reactor building exhaust ducts and refueling floor, drywell pressure sensors, and reactor water level monitors.

6.2.4 Containment Isolation System

6.2.4.1 Design Bases

The primary containment system performance objective and design bases are stated in Section 6.2.1.1. The containment isolation system is required for the primary containment system to meet its performance objective to provide a barrier which, in the event of a loss-of-coolant accident (LOCA), will control the release of fission products to the secondary containment.

6.2.4.2 System Design

6.2.4.2.1 Isolation Valves

Isolation valves are provided on lines penetrating the drywell and pressure suppression chamber to ensure containment integrity when required during emergency and post-accident periods. Isolation valves which must be closed to ensure containment integrity immediately after a major accident are automatically controlled. Section 7.3.2.4 describes changes which have been made to primary containment isolation valves to preclude automatic opening when the isolation signal is reset so that manual opening by an operator is required, thus avoiding accidental automatic opening. The control logic for the containment isolation valves is described in Section 7.3.2. Refer to Table 6.2-9 for a tabulation of the principal containment penetrations and the automatic isolation valves provided to maintain containment integrity. This table does not list instrument or electrical penetrations or the test, vent, or drain valves on piping between isolation valves.

Pipes which penetrate the containment and connect to the nuclear steam supply system (NSSS) are equipped with two isolation valves in series. Pipes that penetrate the containment and are open ended into the free space of the containment are also equipped with two isolation valves in series. As a general rule, one of each pair of isolation valves in series is located inside the containment, and the other is located outside and as close to the containment as practical.

Lines which open to the free space of the containment and which have two valves normally closed have the valves located outside the containment (e.g., containment spray spargers). Lines forming a closed loop inside the containment but which, as a result of pipe failure inside the contained area, may carry radioactive fluids out of the containment are generally provided with either a self-actuating check valve or a remote manually controlled motor-operated valve outside the containment.

Systems which connect to the NSSS and which may be required to have flow into the NSSS after an accident are provided with either of two valves arrangements. Either both isolation valves in series are self-actuated check valves (one inside and one outside the containment) or one is a check valve and the other is a power-operated valve (electric motor or air) that can be remotely controlled. These systems include the feedwater, low pressure coolant injection (LPCI), and standby liquid control systems. On lines where flow may be in either direction, both valves are power-operated.

In general, the closure time of all isolation valves is such that the release of fission products to the environment is minimized. The closure times of all valves on lines in systems connecting to the nuclear steam supply system are based on preventing fuel damage due to overheating with no feedwater makeup following a line break in the particular system. The valve closure time for the main steam line is based on the main steam line break accident discussed in Section 6.3. By keeping the valve closure time less than approximately 10 seconds, sufficient coolant remains in the reactor vessel to provide adequate core cooling. The valves are designed to close and to be essentially leaktight during the worst conditions of pressure, temperature, and steam flow following a break in the main steam line outside the containment.

Motive power for each of a pair of power-operated isolation valves in series is from physically independent sources to preclude the possibility of a single malfunction interrupting power to both valves. Air-operated valves which close for the normal containment isolation mode, fail closed on loss of motive power with the exception of the reactor building to containment vacuum relief valves discussed in Section 6.2.1.2.4.1. Electric motor-operated valves fail as is.

Typically, power operators on valves inside the containment are supplied with ac power and those outside the containment are supplied with dc power.

The following is the guidance used for determining which manually-operated valves are primary containment isolation valves (PCIVs) and which valves are required to be locked. Typically these valves are on vent lines, drain lines, capped branch lines, or test connections. When the principal inboard PCIV is located inside containment and the principal outboard PCIV is located outside of containment:

Valves in line, as well as test valves, located inboard of the principal inboard PCIV are not considered PCIVs.

The inboard test valve, when located between the principal inboard and outboard PCIVs, is considered a PCIV. This test valve must be locked closed when not in use.

Valves in line between the principal inboard and outboard PCIVs are considered PCIVs. These Valves will be administratively controlled on a case by case basis.

When both the principal inboard and outboard PCIVs are located outside of containment:

Valves in line, as well as test valves, located inside containment are not considered PCIVs.

Valves in line between containment and the principal inboard PCIV are considered PCIVs. These valves will be administratively controlled on a case by case basis.

Both the inboard and outboard test valves, when located between containment and the principal inboard PCIV, are considered PCIVs. Both of these test valves must be locked closed when not in use.

The inboard test valve, when located between the principal inboard and outboard PCIVs, is considered a PCIV. This test valve must be locked closed when not in use.

Valves in line between the principal inboard and outboard PCIVs are considered PCIVs. These valves will be administratively controlled on a case by case basis.

In addition, numerous principal PCIVs are manually-operated. Since these valves do not get an automatic closure signal, nor can they be remotely closed, they must be locked closed when not in use.

Instrument lines are exempt from Type C testing provided they are not isolated from containment during the performance of a Type A ILRT. Although instrument lines are exempt, Dresden Station chooses to be more conservative in regards to locking instrument line test, vent and drain valves. Therefore, test valves on instrument lines without excess flow check valves are considered equivalent to test valves on process lines penetrating containment.

The inboard test valve on an instrument line without an excess flow check valve is considered a PCIV. When not in use, this test valve must be locked closed.

Tables 6.2-10 and 6.2-11 list the Unit 2 and 3 valves which are required to be locked closed.

Locked-closed, manual, containment isolation valves required to be opened to conduct sampling, may be opened one line at a time provided the following conditions are met:

A. An operator is dedicated to attend to the valves;

A program for periodic testing and examination of the excess flow check valves in instrument lines penetrating the containment has also been established.

Refer to Section 6.2.6 for a discussion of the local leakage rate tests.

6.2.5 Combustible Gas Control in Containment

The primary means of containment combustible gas control is the nitrogen inerted containment. The inerted containment is sufficient to ensure peak combustible gas concentrations are below acceptable limits without the need to purge or repressurize the containment. In addition, the following criteria are met:

A. Drywell oxygen is limited to less than 4% (per Technical Specifications);

B. Only nitrogen or recycled containment atmosphere is used for pneumatic control within containment; and

C. There are no potential sources of oxygen into containment other than radiolysis of the reactor coolant.

As such, reliance on a purge/repressurization system is not necessary.

In addition, various containment atmosphere control systems are installed which are capable of providing venting and nitrogen makeup during normal operation and post-loss-of-coolant accident (LOCA) conditions. In the event of a post-LOCA combustible gas mixture, the existing purge systems can be used to vent this mixture out of the containment through the charcoal beds and high efficiency particulate air (HEPA) filters of the standby gas treatment system (SBGTS). The nitrogen makeup system and nitrogen inerting system are capable of adding nitrogen to the containment, thus reducing the combustible gas concentration. This section describes the systems available for combustible gas control at Dresden.

Refer to Section 6.2.1.3.7 for a discussion of the sources of hydrogen in the containment and the containment capability to handle the hydrogen generated.

6.2.5.1 Historical Basis for Combustible Gas Control System Design

The potential generation and control of hydrogen within the containment following a LOCA has been a concern since the first nuclear power plant was constructed. However, it was not until 1971 that the AEC documented its acceptance criteria for combustible gas control in Safety Guide 7, "Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident." One of the criteria stated in the guide was the amount of zirconium metal-water reaction that was to be considered as part of the hydrogen production analysis; specifically 5% by weight of the zirconium within the reactor core was

The NRC indicated that the models were appropriate for the major segment of accidents under consideration. For degraded core accidents where significant amounts of metal-water reaction hydrogen are produced, the hydrogen acts as an inerting component with respect to oxygen. As a result, neither set of models showed a need for an active combustible control system.

However, the NRC found that there were a small number of accidents, both within the DBA envelope and slightly beyond, where the assumptions used in NEDO-22155 were at least questionable. The NRC staff has found the models contained in NEDO-22155, which several licensees generically used to support the position of not requiring an active combustible gas control system, unacceptable for DBA applications. Safety Guide 7 guidelines have been and continue to be the basis of acceptance for the DBA events. The NRC weighed the benefits to be gained for this small number of accidents to the costs of providing recombiner capability. The NRC concluded that the costs outweighed the benefits for this limited situation. To reflect this position, the NRC issued Generic Letter 84-09. In the Generic Letter, the NRC specified that Mark I BWR plants do not need to rely on a purge/repressurization system as the primary means of combustible gas control provided that three technical criteria are met. The NRC staff, however, also indicated in the Generic Letter that if the licensee has a safety-related purge/repressurization system, which was installed to meet 10 CFR 50.44(g), the licensee must maintain that system. The intent of the Generic Letter was to provide relief from the recombiner capability.

The three criteria which must be satisfied to meet the requirements of Generic Letter 84-09 are:

A. Technical Specifications must require the containment atmosphere to be less than 4% oxygen when the containment is required to be inerted;

B. Nitrogen or recycled containment atmosphere must be used for all pneumatic applications within containment; and

C. No potential sources of air and oxygen may be present other than radiolysis of reactor coolant.

The amount of oxygen that could be expected to be introduced into the containment shall not cause the containment to become deinerted within the first 30 days after an accident.

Since the atmospheric containment atmosphere dilution (ACAD) system uses standard air to repressurize the containment and thereby reduce the hydrogen concentration, it represents an oxygen source contrary to the guidelines of Generic Letter 84-09 and a threat in dealing with accidents beyond the DBA. As a result, ACAD systems can no longer be considered as an effective safety system for all accidents.

The primary means for combustible gas control is the inerted containment. On Unit 2 the NCAD system has been installed to provide a redundant path, single failure proof means of reinerting the containment following a LOCA. On Unit 3, until NCAD is installed, administrative controls have been implemented to prevent the inadvertent actuation of the ACAD system. The ACAD system is normally isolated and deenergized and requires station director's approval for initiation, thereby the intent of the criterion is met. The modification to install NCAD for Unit 3 is currently scheduled for D3R14.

6.2.5.2 Design Bases

The combustible gas control systems are designed to prevent the formation of a combustible gas mixture in the primary containment. This is a redundant safety measure since the highly reliable emergency core cooling system (ECCS) provides sufficient cooling during a LOCA to inhibit formation of hydrogen by a metal-water reaction, the primary containment can accommodate an energy addition equivalent to the combustion of hydrogen formed during postulated accidents, and the containment is inerted.

The design bases for combustible gas control are as follows:

A. To maintain the drywell in a nitrogen inerted condition as a means of inhibiting the formation of a combustible gas mixture under LOCA conditions;

B. To monitor radiation and hydrogen levels within the primary containment; and

C. To provide a means to dilute the primary containment atmosphere under LOCA conditions if a potentially combustible gas mixture were to develop.

Since NCAD is now installed on Unit 2, Unit 2 ACAD has been removed as a potential post-accident oxygen source in order to satisfy the criteria of Generic letter 84-09. In order to satisfy this requirement, the instrument air to open valves 2-2599-1A and 1B has been removed and manual valves 2-2599-6A, 6B, 2-2599-7A, B have been closed and locked. This places two valves in series both closed and out of service which prevents ACAD from adding air to Unit 2. The Unit 2 and Unit 3 ACAD air compressors provide redundant air supplies to both Units. Therefore the Unit 2 ACAD air compressor is maintained in service Until Unit 3 NCAD is operational.

The Unit 2 and Unit 3 ACAD compressors are left to load and unload to ensure operability of the compressors. This prevents moisture damage to the compressors. The Unit 3 pilot solenoid valves are normally deenergized. These solenoid valves can not be energized to open the Unit 3 feed and bleed air operated valves without approval of a Station Director. The Station Director is a GSEP position and is filled only after an accident or transient event.

Following are the criteria used to design the atmospheric containment atmosphere dilution (ACAD)/containment atmosphere monitoring (CAM) system:

A. The system was designed in accordance with guidelines contained in Branch Technical Position CSB 6-2, "Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident."[38] This system was also designed in accordance with General Design Criteria 41, 42, 43, 54, and 56 of 10 CFR 50, Appendix A.[39]

B. In postulating the occurrence of metal-water reaction, a penetration of the oxide layer 0.00023 inches into the cladding was assumed, and the core was assumed to consist of 8x8 fuel assemblies. This assumption is representative of the 7x7 configuration or any combination between the 7x7 and 8x8 assemblies. The generation of hydrogen from metal-water reaction was assumed to evolve over a 2-minute period at a constant reaction rate. he resulting hydrogen was assumed to be uniformly distributed in the drywell, as recommended by Branch Technical Position CSB 6-2.[38]

C. The system has the capability of sampling and measuring the hydrogen concentration throughout the drywell or torus during all modes of operation.

D. The system has the capability of controlling combustible gas concentrations in the drywell and torus atmospheres without reliance on purging and with a minimum release of radioactive material to the environment.

E. The system will not introduce safety problems that affect containment integrity.

F. As a backup to the combustible gas control system, capability is provided to control gas concentrations by purging the drywell and torus atmospheres via the existing purge system.

G. An appropriate margin between the hydrogen concentration limit and the hydrogen concentration at which the equipment actuation occurs is provided. This margin is based on the simplicity of the system and the start-up procedure.

Following are design bases for post accident design of the NCAD System (Unit 2 only):

A. The NCAD system is to provide a redundant path, single failure proof means of reinerting the containment following a LOCA.

B. The NCAD system must be capable of being initiated 15 hours after the accident, and provide a maximum required flow rate of approximately 29 scfm of nitrogen against a maximum containment backpressure of 31 psig.

C. The nitrogen supply system including the inerting pathways upstream of the Containment Isolation Valves are not required to be safety related.

D. Accessibility for operator action to initiate the NCAD system post LOCA must be assured.

6.2.5.3 System Design

6.2.5.3.1 Vent, Purge, and Inerting System

Containment isolation criteria are met by isolation valves in each system which close on isolation signals from the primary containment isolation system discussed in Section 7.3.

The oxygen sampling system automatically draws samples of the containment atmosphere at various elevations, analyzes the sample oxygen content, and indicates and records the results continuously in the control room. Oxygen sample concentration is also indicated at the drywell personnel airlock entrance. Low-purge supply temperature, high-supply line pressure, high-makeup flow, high-oxygen content, and low-sample flow alarms are annunciated in the control room.

Primary containment venting to reduce drywell pressure and purging to reduce containment oxygen concentration are conducted in accordance with established operating procedures. During startup, shutdown and normal operation venting and purging are accomplished via either the standby gas treatment system and plant chimney, or the reactor building ventilation stack, depending upon sample analysis results.

Containment venting is also discussed in Section 6.2.1.2.7. Venting through the augmented primary containment vent system (APCVS) is discussed in Section 6.2.7.

6.2.5.3.2 Atmospheric Containment Atmosphere Dilution (Unit 3); Nitrogen Containment Atmospheric Dilution (Unit2)/Containment Atmosphere Monitoring System

In the event of a major LOCA, generation of hydrogen and oxygen gases may take place at such rates that a combustible gas mixture could be produced. To assure containment integrity is not endangered due to the possible ignition and combustion of the gas mixture, the ACAD (Unit 3) or NCAD (Unit 2) system and the containment atmosphere monitoring (CAM) system are provided for controlling the relative concentrations of hydrogen and oxygen to below combustible mixture levels. The control of gas concentrations following a LOCA is accomplished by diluting the evolved hydrogen with air. The resulting pressure increase in the containment is controlled to well below the design pressure by intermittent bleeding of the containment atmosphere into the SBGTS. As a backup means of control, the containment atmosphere can be purged.

This protection supplements that provided by the emergency core cooling systems and nitrogen inerting system.

The concentration of combustible gases in the containment following a LOCA is monitored by the CAM system and controlled by an ACAD/NCAD system. The CAM and ACAD systems are safety-related and are designed such that all components are Seismic Category I and all active components are redundant. Separate power buses are used for the redundant channels of the CAM and ACAD systems. All equipment associated with the CAM and ACAD systems is located within the reactor building, which is a Seismic Category I structure. The NCAD system is redundant path and single failure proof.

The CAM system consists of redundant hydrogen, oxygen, and radiation monitoring subsystems. The entire monitoring system is automatically activated upon the occurrence of a LOCA through core spray system initiation logic (-59 inches reactor water level or +2 psig drywell pressure). The system may also be manually initiated from the control room using a keylock switch. The system remains on at all times after initiation, unless turned off with a keyswitch.

Hydrogen and oxygen concentrations within containment are determined by taking gas samples from the torus and drywell, routing the sample to the gas monitors, and returning the sample to the drywell thereby forming a closed loop system. The system is seismically Category I and environmentally qualified. The CAM system is designed in accordance with NRC Standard Review Plan 6.2.4.II.3.e. It is safety-related and built to ASME Section III, Class 2 code requirements. The system is qualified to IEEE 323-1974 and IEEE 344-1975.

The philosophy for the design of the system is to continuously return the gas samples to the containment rather than to isolate the system from containment under LOCA conditions. Therefore, this system is designed as an extension of the containment during an accident.

As shown in Figure 6.2-48 (Drawing M-706, Sheet 1) and Figure 6.2-49 (Drawing M-706, Sheet 2), the system is completely redundant and separated into engineered safety features (ESF) Divisions I and II. There are four intake ports on each of the two headers in containment. The intake ports on each header are located at four elevations (three in the drywell, one in the torus) approximately equidistant from each other. The headers are on opposite sides of the reactor. A globe valve is installed on each intake port to allow throttling. These valves are set to provide approximately equal flow into each intake port. There are no obstructions which would prevent hydrogen from reaching the intake ports quickly.

Since there are two monitors per unit, a single active failure of the hydrogen monitoring system can be accommodated.

The CAM system is designed to operate under the conditions described below:

A. Mixture of nitrogen, oxygen, hydrogen, noble gases, and saturated steam;

B. Radiation levels of 10^0 to 10^8 R/hr.

C. Temperature: 340°F for 3 hours
250°F for 1 day
60°F to 200°F for 100 days

D. Pressure: 45 psig for 9 hours
25 psig for 1 day
0 to 20 psig for 100 days

E. Relative Humidity: 40 to 100%

The ACAD system consists of dilution air injection subsystem and pressure bleed subsystems. A piping and instrument diagram of the ACAD is shown in Figures 6.2-50 (Drawing M-707, Sheet 1) and 6.2-51 (Drawing M-707, Sheet 2).

The ACAD (Unit 3 only) system operation is based on the following:

A. Following a LOCA, the combustible gas concentration in both the torus and drywell atmospheres is postulated to increase due to radiolysis and water-metal reactions. This buildup of hydrogen gas is observed by the control room operator via hydrogen monitoring instrumentation.

B. The hydrogen concentration in both the drywell and torus continues to increase due to radiolysis and, if allowed to do so, would eventually approach the 4% by volume control limit. Introduction of dilution air prevents the concentration of combustible gases from reaching 4% by volume; however, the introduction of dilution air also increases the containment internal pressure. The introduction of dilution air continues intermittently as necessary to keep hydrogen concentration below the control limit, until the containment high-pressure operating limit is reached. At this time, the pressure bleed subsystem is manually activated and the dilution air is stopped (if in operation) by the control room operator. The containment atmosphere is bled off through the selected redundant loop and is routed to the standby gas treatment system thereby reducing the containment pressure. The pumping of dilution air into the containment and bleeding off to reduce the internal pressure continues until the generation of combustible gases has ceased or been reduced to an insignificant level.

C. As a backup to the system, the existing purge system can be used to force the hydrogen-air mixture out of the containment through charcoal beds and HEPA filters. The air thus removed is replaced with hydrogen-free air, thus reducing the overall hydrogen concentration.

The dilution air injection subsystem includes two compressors, each of which is capable of supplying dilution air through piping systems to the drywell and suppression chamber of Unit 3.

The ACAD system is initiated manually from the main control room when the hydrogen concentration in the containment reaches 3.5% by volume. An alarm is annunciated by the CAM system once the high-hydrogen setpoint is reached. The maximum flowrate requirement for the drywell and suppression chamber is 100 scfm with the flow splitting such that the drywell and suppression chamber pressures equalize. Containment dilution continues until hydrogen concentration falls below 3.3%.

The containment dilution flow path starts from the air compressor. The compressor is sized at 100 scfm and 50 psig, capable of diluting both the drywell and suppression chamber simultaneously. The compressor discharges air to the air receiver, which is full at all times. The start-stop of the compressor is controlled via the pressure switches located at the air receiver or manually from the control panel. Upon initiation of the dilution air injection subsystem the inlet flow control valve and isolation valves open. Pressure loss in the air receiver activates the compressor and controls the start-stop of the compressor as required.

The pressure bleed subsystem consists of two parallel and redundant valving and piping systems which are piped into a header to the standby gas treatment system. The pressure bleed subsystem is initiated manually when pressure in the containment reaches 27 psig (the containment design pressure is 62 psig). An alarm annunciates on the main control panel, and automatic isolation of the inlet flow valve of the air dilution line occurs when the containment pressure exceeds 28 psig. Each of the redundant legs of the containment vent outlet flow path contains an automatic shutoff valve, a flow control valve, a pressure reducing valve, flow element for flow control and indication, and pressure indicator. The vent flowrate is 25 scfm maximum. The venting continues until the pressure in the containment decreases to 26 psig. Section 6.2.5.4 presents a detailed evaluation of the system as described above.

6.2.5.3.3 Nitrogen Containment Atmospheric Dilution (NCAD) System (Post LOCA Operation - Unit 2 Only)

In the event of a LOCA, combustible gas concentrations may require the addition of nitrogen to the containment. The NCAD system is designed to be initiated at 15 hours after a LOCA, when the oxygen concentration may reach 5 percent by volume (see section 6.2.5.4.2.2.).

In addition to the normal inerting and makeup pathways, two bypass lines are provided for Unit 2 only. These bypass lines are routed from the discharge of the makeup line atmospheric vaporizer, located outside, to the downstream side of the pressure regulating stations in the normal inerting and makeup pathways, located within the reactor building. These lines provide the capability of inerting the containment post-LOCA.

The NCAD nitrogen flow is initiated through either or both of the bypass lines by opening the manual isolation valve located outside in the vicinity of the nitrogen supply system equipment, and opening the containment isolation valves from the control room.

The NCAD system is designed to inject a maximum required flowrate of approximately 29 scfm of nitrogen to the containment, considering a maximum backpressure of 1/2 of the containment design pressure, or 31 psig.

6.2.5.4 Design Evaluation

In evaluating the combustible gas control system design, it was necessary to consider the following:

A. The production and accumulation of combustible gases within the drywell and torus following the postulated LOCA;

B. The capability of the system to reduce combustible gas concentrations within containment;

C. The radiological impact of ACAD operation; and

D. The capability to mix the combustible gases within the containment atmosphere and prevent high concentrations of combustible gases in local areas.

6.2.5.4.1 Short- and Long-Term Hydrogen Generation

In the period immediately after LOCA, hydrogen would be generated by both radiolysis and metal-water reaction. However, in evaluating short-term hydrogen generation, the contribution from radiolysis is small in comparison with the hydrogen generated by a postulated metal-water reaction. Refer to Section 6.2.1.3.7 for a detailed discussion of the sources of hydrogen in the containment.

In accordance with the provisions of the Branch Technical Position CSB 6-2,[38] the amount of hydrogen assumed to be generated by metal-water reaction in establishing combustible gas control system performance requirements was based on the amount calculated in demonstrating compliance with 10 CFR 50.46.[40]

As described in NEDO-20566[41] GE submitted two alternate methods for the calculation of core-wide metal-water reaction.

The first method of analysis for core-wide hydrogen generation utilizes the heatup code CHASTE in a series of calculations. The calculations for planar segments are made with varying values of segment power to represent all feasible segment powers for a particular core. The calculated temperature responses are used to predict the amount of cladding reacted locally for each planar segment. The local cladding reactions are weighted by a conservative core axial power distribution and summed to calculate the total core-wide cladding reacted. The core axial power distribution is based upon fine noding of operating reactor data and is conservative since it is relatively flat. The total cladding reacted is divided by the total cladding surrounding the active fuel. The quotient is the percentage of core-wide hydrogen generation.

The second method of analysis, documented in NEDO-11013-77,[42] develops a relationship between core-wide metal-water reaction and peak clad temperature, based on a core model which has power and temperature distributions which conservatively bound those calculated for BWRs.

Both of the methods described above have been found acceptable by the NRC staff; however, the second method has been used in Appendix K submittals. The metal-water reaction fraction calculated utilizing the second method, because of the simplifications made in formulating that model, renders a number which is higher by a factor of approximately 4 than the result of the preliminary calculations utilizing the first method.

The result obtained from this core-wide metal-water reaction calculation is 0.21%. In accordance with the provision of Branch Technical Position CSB 6-2, the core-wide metal-water reaction calculated, in compliance with 10 CFR 50.46 (0.21%), is multiplied by a factor of 5. This results in a metal-water reaction fraction of 1.05%. This metal-water reaction fraction is greater than the metal-water reaction fraction which results from postulating a reaction of all the metal in the outside surface of the cladding cylinders surrounding the fuel (excluding the cladding surrounding the plenum volume) to a depth of 0.00023 inches. This calculated metal-water reaction fraction, 1.05%, was therefore used as input into the computer program CONCEN. The computer program CONCEN is described in Reference 6.

The 0.21% metal-water reaction was calculated based on an all 7x7 core and, therefore, the zirconium inventory was based on a 7x7 core. The 8x8 core was not used because a 7x7 core rendered a more restrictive core-wide metal-water reaction.

It has been shown that the amount of 9x9 fuel element cladding which reacts chemically with water or steam does not exceed 1.0% of the total amount of zircaloy in the reactor. Refer to Section 6.3 for a complete description of the current LOCA analyses. Refer to Section 6.2.1.3.7 for a description of the containment's capability with respect to hydrogen generation.

The generation of hydrogen due to radiolysis begins immediately after the LOCA. The guidelines contained in Branch Technical Position CSB 6-2[38] have been followed to determine hydrogen generation rates. The details of modeling and the input variables used are described in Section A.2.1.2. and Section A.3 of Reference 6.

6.2.5.4.2 Reduction of Containment Combustible Gas Concentrations

6.2.5.4.2.1 Combustible Gas Control Using ACAD (Unit 3 only)

Drywell oxygen concentration	4% by vol
Suppression chamber temperature	95°F
Suppression chamber pressure	14.7 psia
Suppression chamber relative humidity	100%
Suppression chamber oxygen concentration	4% by vol

The amount of pre-accident gases in the containment increases with increasing initial containment pressure and decreases with increasing initial containment temperature. The containment initial conditions selected for the analysis were selected to minimize the calculated initial gas amount and the time to reach a flammable concentration and maximize the calculated initial gas amount and the time to reach a flammable concentration and maximize the calculated nitrogen addition.

The analysis led to the following conclusions:

A. The containment would reach 5% oxygen by volume about 15 hours after the postulated LOCA.

B. To maintain the oxygen concentration at exactly 5% by volume up to 7 days after the LOCA, 378 lb. moles of nitrogen (135,700 standard ft^3) would have to be added at a time-dependent rate starting at 29 scfm at 15 hours after the accident, reducing to 10.6 scfm at 7 days, and further reducing to 5.2 scfm at 32 days when the pressure is calculated to reach the regulatory limit of 31 psig.

C. If nitrogen were added to the containment at a rate that just maintains the oxygen at 5% by volume, the containment pressure would reach the 10 CFR 50.44 limit (one-half of the design pressure or 31 psig) in about 32 days using Regulatory Guide 1.7 assumptions and assuming zero leakage.

D. At 32 days, nitrogen would have to be added at a rate of 5.2 scfm to maintain oxygen concentration at 5% by volume and the containment would have to be vented at a rate of 6.1 scfm to maintain the pressure equal to 31 psig.

E. At 32 days, a total of 474,600 standard ft^3 of nitrogen would have been added.

F. Nitrogen dilution can control the containment combustible gas composition without venting for at least 30 days if the conservative generation rates of Regulatory Guide 1.7 are used. If more realistic rates are assumed, nitrogen dilution would not be needed.

6.2.5.4.3 Radiological Impact of ACAD System Operation (Unit 3 only) gamma radiation levels in the containment following a LOCA. The gross gamma monitoring subsystem monitors the dose rate resulting from gross release of fission products from the fuel. The hydrogen and gross gamma monitoring subsystems consist of duplicate channels; each channel provides a local measurement in both areas and transmits the signal to the control room where a permanent record is provided on recorders.

6.2.5.5.1 Hydrogen Monitoring Initiating Circuits

This system consists of a hydrogen sensor, an electronics assembly and a recorder. The monitors are located in the reactor building on the first floor.

The hydrogen sensor provides a signal proportional to the hydrogen partial pressure of the drywell and torus. This signal is then divided by a signal equal to the containment pressure. A signal is produced that is proportional to the volume percent of a hydrogen in the containment, thus:

$$\frac{H_2 \text{ Partial Pressure}}{\text{Total Pressure}} = \% \; H_2$$

The sensor output is directed to control room panels 902(3)-55 and 902(3)-56, and is indicated on SPAN meters and a recorder. A range of 0 — 10% is provided.

6.2.5.5.2 Radiation Monitoring Initiating Circuits

The radioactivity monitoring subsystem employs two sensors, mounted within the drywell.

Each instrument channel consists of a gamma-sensitive ion chamber high range radiation monitor. One upscale trip circuit is used to initiate an alarm on high radiation. The second circuit is a downscale trip that actuates an instrument trouble alarm in the control room. The output from each high range radiation monitor is displayed on an eight-decade meter in the control room. The detector covers the range of 10^0 to 10^8 R/hr. Two 2-pen strip chart recorders are also located in the control room. One channel of each strip chart has been abandoned in place. When activated, the trip circuit for each monitoring channel is energized. When power to monitoring components is interrupted, a trip signal results.

6.2.5.6 Tests and Inspections

6.2.5.6.1 Hydrogen/Oxygen Monitor Tests

Since the CAM is activated during an accident, the entire closed loop of the CAM is subjected to drywell pressure. Thus, leak rate testing of the CAM includes all piping outside the containment isolation valves, the analyzer cabinet, and the CAM drywell return line check valve.

6.2.6 Containment Leakage Testing

The Primary Containment Leakage Rate Testing Program was developed to provide assurance that the primary containment, including those systems and components which penetrate the primary containment, does not exceed the allowable leakage rate values specified in the Technical Specifications and bases. The allowable leakage rate is determined so that the leakage rate assumed in the safety analysis is not exceeded. This program meets the requirements of Regulatory Guide 1.163, Performance-Bases Containment Leak-Test Program and 10 CFR 50, Appendix J.

The program for testing the primary containment system includes an integrated leak rate test (ILRT) of the containment and local leakage rate tests (LLRTs) of containment penetrations and containment isolation valves.

6.2.6.1 Containment Integrated Leakage Rate Test

Following construction of the drywell and suppression chamber, each was pressure tested at 1.15 times its design pressure. Penetrations were sealed with welded end caps. Following the strength test, the drywell and suppression chamber were tested for leakage rate at design pressure; each met the leakage criterion for that stage of construction of less than 0.5% per day at design pressure. The suppression chamber was also tested while half-filled with water to simulate operating conditions.

After complete installation of all penetrations, an integrated leakage rate test of the drywell, suppression chamber, and associated penetrations was conducted. The tests were conducted at several test pressures to establish a leakage rate curve. The necessary temporary instrumentation was installed in the containment systems to provide the data to calculate the leakage rate.

The design basis accident (DBA) used for determination of allowable containment leakage rates was the loss-of-coolant accident (LOCA) as discussed in Section 6.2.1.3.5.1 and Section 15.6.5. The initial containment conditions, containment pressure transient, percent metal-water reaction, and fission product release to the containment assumed for the double-ended recirculation line break were used in this analysis. In addition, the emergency ventilation system was assumed operative such that any fission products which leaked from the primary containment would pass through filters prior to discharge to the environment via the chimney.

Containment leakage rate tests, including Types A, B, and C tests as defined in 10 CFR 50, Appendix J, are performed in accordance with the requirements of the Technical Specifications. These requirements conform to the requirements of 10 CFR 50, Appendix J, with the exception of several NRC-authorized exemptions.

An exemption from Appendix J requirements for containment isolation valve leakage rate tests (Type C tests) permits Type C tests to be performed prior to the ILRT (Type A test) and the results of the Type A test to be back-corrected to simulate the as-found conditions using the results of the Type C tests provided that:

A. When performing Type C tests, the conservative assumption that all measured leakage is in a direction out of the containment is applied, unless the test is performed by pressurizing between the isolation valves; and

B. When performing Type C tests by pressurizing between the isolation valves, the conservative assumption that two valves leak equally is applied (and therefore one-half of the measured leakage is in a direction out of the containment), when the isolation valves are shut by normal operation without preliminary exercising or adjustment.

Type C tests for instrument line manual isolation valves installed in accordance with Regulatory Guide 1.11, "Instrument Lines Penetrating Primary Containment," are not required provided that the subject instrument lines are not isolated from the containment atmosphere during performance of a Type A test.

Due to the design of the two-ply containment penetration expansion bellows, it has been determined that the bellows cannot be properly tested to satisfy Appendix J, Type B testing requirements. Accordingly, a testing and replacement program for the bellows assemblies has been accepted by the NRC as an acceptable alternative to the testing requirement, and an exemption from Appendix J has been granted for these assemblies. Each assembly is individually exempted until it is replaced by a testable bellows assembly at which time the testable assembly will be tested in accordance with the normal Type B test program. Similarly, if a method is developed which ensures a valid Type B test on one or more assemblies, those bellows will also be excluded from the exemption and will be required to be tested in accordance with the normal Type B test program.

The periodic ILRT is conducted at a test pressure of 48 psig which corresponds to the calculated maximum peak accident pressure. The test is conducted in accordance with the provisions of ANSI /ANS-56.8-1994. During testing, the initial pressure is maintained much longer than the few seconds for which the peak accident pressure is expected to be sustained (see Figure 6.2-14). Testing with the peak accident pressure is also conservative because the airborne fission product inventory is negligible for the short time (after the initial blowdown) during which the peak pressure occurs.

The ILRT is performed at a frequency specified in the Technical Specifications, based on maintaining the primary containment leakage rate below the permissible leakage rate limit. An integrated test with a leakage rate above the permissible leakage rate limit requires identification of the cause of unacceptable performance and determination of corrective action. Once computed, the test interval shall be at a frequency specified in NEI 94-01, Rev.0.

6.2.6.2 Containment Penetration Leakage Rate Test

The pre- and post-operational testing of the penetrations include testing of the piping and electrical penetrations, access openings, and flanged openings.

Containment penetrations and seals are tested in accordance with the Primary Containment Leakage Rate Testing Program. Testing is conducted using either of two methods: measuring the decay rate of a given volume with no replacement gas, or, more commonly, measuring the flowrate of replacement gas at a constant pressure. The testing is conducted at a pressure not less than 48 psig which is sufficient to verify the ability of the penetrations to withstand the peak containment pressure as a result of a LOCA, as well as to verify the ability of the penetrations to maintain overall containment leakage within acceptable limits. These tests were performed prior to initial startup and subsequent tests are performed on a regular basis.

The personnel access lock is provided with double doors, which open inward, toward the drywell and are designed to withstand a large outward force due to a high drywell internal pressure. The doors are not designed to withstand a large inward force due to a differential pressure in the reverse direction. Therefore, the leakage rate testing for the access lock requires placing a strongback on the inner door prior to pressurizing the space between the doors to 48 psig. Testing is conducted on a regular basis.

Type B tests of the containment airlocks are performed at pressures and intervals specified in the Technical Specifications. In addition, a 48-psig test is performed when primary containment is required following an airlock opening. The intent of the requirement is to ensure that the airlock door seal integrity is maintained and that no degradation has occurred as a result of opening the airlock.

Flanged openings are provided with double seals and test ports so that the space between the seals can be pressurized to test for leakage. Testing is conducted on a regular basis, or after seal maintenance. If a flange is to be opened thereby breaking the seal, the seal is tested first in the as found condition before the flange is opened, in accordance with (10 CFR 50, Appendix J, and then again when the flange is closed, in accordance with the Technical Specifications.

The major portion of leakage from the containment has been shown at Humboldt Bay and other nuclear power stations[55-58] to come primarily from valves and penetrations. Little or no leakage is attributable to the containment shell.

Shell leakage (including leakage through nonisolatable lines and seals) can be determined by conducting both an ILRT and LLRTs and subtracting the results of the LLRTs from that of the ILRT. (For valves in a series, only the LLRT result of the valve with the lowest leakage rate is subtracted.) A calculated value for integrated leakage can be subsequently obtained by adding the results of later LLRTs (performed more frequently than the ILRT) to the most recent value for shell leakage.

6.2.6.3 Containment Isolation Valve Leakage Rate Test

The pre- and post-operational testing of the primary containment isolation valves includes pressure testing, leakage testing, and operability testing. Isolation valves tested include those valves in lines connecting to the open space within the containment vessels and valves in lines connected to the reactor coolant system. Local leakage rate testing of the volume between containment isolation valves (Type C test) is conducted at the calculated maximum peak accident pressure of 48 psig with one exception: the volume between the main steam isolation valves (MSIVs) is tested at 25 psig. Testing is conducted on a regular basis.

Type C testing of the MSIVs at the reduced pressure of 25 psig instead of the 48 psig required by 10 CFR 50, Appendix J has been authorized by the NRC. The leakage rate acceptance criterion for the MSIVs at 25 psig test pressure is 11.5 scfh. The leakage rate measured at 25 psig is corrected mathematically to a leakage rate at 48 psig. The reason for the reduced test pressure is that the inboard MSIV is tested with pressure acting in the reverse direction to that encountered in a LOCA situation. The MSIV is designed such that it is held closed by a combination of the spring force, air cylinder closing force, and upstream line pressure. During the leakage rate test there is no upstream pressure. Any downstream pressure greater than 25 psig would tend to lift the MSIV disk off the seat, giving an inaccurate leakage rate measurement. Refer to Section 6.2.4.2.2 for a description of the MSIVs.

Test taps are located between the MSIVs to permit leakage testing while the reactor is in a cold shutdown condition by pressurizing the enclosed space between the valves.

The sum of the leakage rates determined from the individual tests of those isolation valves in lines open to the free space of the containment is added to the total leakage rate of the penetrations and access openings alone.

Isolation valves in lines which form a closed loop, either within the containment vessels or outside the containment, were not required to be separately leak tested, but their performance was carefully observed during initial system acceptance tests. At each major refueling, these systems are operated at normal operating pressure and their leakage observed.

6.2.7 Augmented Primary Containment Vent System

The purpose of the augmented primary containment vent system (APCVS) is to vent the primary containment only as directed by the Dresden Emergency Operating Procedures (DEOPs).

The APCVS is designed to prevent containment pressure from exceeding the Primary Containment Pressure Limit (PCPL), as defined in the DEOPs, in the highly unlikely event of a transient requiring reactor shutdown followed by a complete and sustained failure of decay heat removal capability. This scenario has been labeled the TW sequence in the station probabilistic risk assessment (PRA). The APCVS provides a direct vent path from the pressure suppression chamber or from the pressure suppression chamber and the drywell to the chimney. This containment emergency vent path will prevent a containment breach with the subsequent uncontrolled radioactivity release.

The APCVS may also be utilitized for venting primary containment, as directed by the DEOPs, for combustible gas control. Use of the APCVS for combustible gas control is authorized only after the primary containment hydrogen and oxygen concentrations have exceeded the deflagration limits as defined in the DEOPs. The APCVS is utilized to reduce the primary containment pressure below the operational pressure limit of the SBGT system. The APCVS could also be utilized to rapidly vent and purge the primary containment with air, but only if nitrogen makeup and NCAD are unable to reduce the concentration of one or both of the explosive constituents, either hydrogen or oxygen, below the respective deflagration limits.

6.2.7.1 Design Basis

The APCVS is designed to prevent containment pressure from exceeding the PCPL. The system is nonsafety-related but seismically supported.

The design assumes a maximum pressure of 62 psig, measured at the bottom of the pressure suppression chamber coincident with a maximum water level in the pressure suppression chamber.

The vent is sized such that, under conditions of constant heat input at a rate equal to 1% of rated thermal power and containment pressure equal to the PCPL, the exhaust flow through the vent (78,910 lb/hr) is sufficient to prevent the containment pressure from increasing. This vent is capable of operating up to the PCPL.

The APCVS piping, also referred to as the hardened vent path, is capable of withstanding, without loss of functional capability, expected venting conditions associated with the TW sequence. The design is such that the APCVS will not create a combustible gas mixture through introduction of air.

6.2.7.2 System Description

The APCVS is comprised of piping, round duct, square duct, air-operated valves, and the associated electrical components for operation and indication. The air-operated valves each have an accumulator for storage of compressed air in the event of a loss of instrument air. The system piping is shown in Figures 6.2-59 and 6.2-60.

The piping interfaces with the suppression chamber main exhaust and the drywell main exhaust lines. It is routed through the reactor building into the turbine building via an 18-inch diameter vent and purge duct. The APCVS vent valve, AO-1601-92, is located in a 10-inch diameter branch line connected upstream of the vent and purge system prefilters. This 10-inch line is routed below the turbine building roof above the Unit 3 turbine, passes through the turbine building wall below the radwaste building roof, is routed under the radwaste building roof, penetrates the exterior wall, and ties into the radwaste ventilation exhaust duct which flows to the chimney. A description of normal containment venting is included in Section 6.2.1.2.7. Refer to Section 6.2.5.3.1 for a description of the vent, purge, and inerting system.

The APCVS controls are located in the main control room. The APCVS mode switch, three keylock containment isolation valve (CIV) override switches, and valve control switches are located on the 902(3)-3 panel. Annunciation for the APCVS mode switch position and CIV override is also on the 902(3)-3 panel.

Initiation of the APCVS requires multiple, deliberate operator actions. The APCVS mode switch is a two-position switch which is administratively controlled. In the APCV position this switch's only active function is to close valves AO-1601-91 and AO-1601-63 (if they are not already in the closed position). These valves isolate the vent and purge system prefilters and standby gas treatment system. The APCVS mode switch also provides a permissive for valve AO-1601-92 to be opened and a permissive to override the Group 2 primary containment isolation signal for valves AO-1601-60, -23, and -24 in conjunction with their respective keylock switches. The primary containment isolation logic system is discussed in Section 7.3.2. A description of the primary containment isolation valves is included in Section 6.2.4.

6.2.7.3 Safety Evaluation

Operation of the APCVS will be required as directed by the DEOPs only in the event of a TW sequence or other event such that primary containment pressure might exceed the PCPL or for combustible gas control. These postulated events are beyond the design basis of the plant.

The APCVS has no active functions during normal plant operation or design basis events. The only required function under normal operating conditions is that the valves, except for the normally open 18-inch vent and purge prefilter isolation valve, remain in their closed position to allow reactor building ventilation operation and provide chimney isolation.

The APCVS was installed in response to Generic Letter 89-16. Although not a part of the commitment, the APCVS also provides the capability to vent the drywell if conditions such as high suppression chamber water level prevent suppression chamber venting. To take advantage of the scrubbing effect of the suppression pool, the selected vent path will normally be from the pressure suppression chamber only.

Existing radiation monitoring capability in the chimney will alert control room operators of radioactivity release during venting.

Because Dresden is a dual unit station, the Unit 2 and Unit 3 APCVSs are crosstied, and a common line directs the effluent of both units to the chimney. It is not postulated that simultaneous TW sequences and/or LOCAs in both units would require simultaneous venting of both units. Although extremely unlikely, simultaneous venting of both units is precluded administratively, through procedures and communication between units. Venting from one unit does not compromise the safety of the other unit. System design precludes backflow from the venting unit to the other unit.

Subsequent venting sequences are controlled by closing and opening the APCVS vent valve until decay heat removal capability is reestablished or until it is assured that primary containment pressure will not exceed PCPL. In the event that both units were to require venting at the same time, both units could be vented by alternating the vent path from one unit to the second unit and back again as necessary.

Table 6.2-3

CONTAINMENT PRESSURE AND PEAK TORUS TEMPERATURE FOR VARIOUS COMBINATIONS OF CONTAINMENT SPRAY AND CORE SPRAY PUMP OPERATION

Summary of Limiting Dresden Containment Analyses Results

CASE**	Long Term (>600 seconds) Containment Pressure Case	Long Term Suppression Pool Heatup Case	Short Term (<600 seconds) Containment Pressure Case
Thermal Mixing Efficiency (%)	100	20	60
Heat Sinks	yes	yes	yes
Suppression Pool Temperature at 600 sec (°F) (At initiation of operator actions).	149	148	149
Suppression Chamber Airspace Pressure at 600 sec (psig) (At initiation of operator actions).	5.5	10.9	3.1
Minimum Suppression Chamber Pressure following initiation of containment spray (psig)	3.6	2.0	N/A
Peak Long Term Suppression Pool Temperature (°F)	172	176	N/A
Pressure at time of Peak Suppression Pool Temperature (psig).	4.8	3.5	N/A

** The limiting containment overpressure curve is a combination of the Short Term Case and the Long Term Case. The Short Term Case was used from accident initiation until 600 seconds. The Long Term Case was used from 600 seconds until termination of the accident scenario. A description of the containment analyses case specific assumptions are as follows:

Table 6.2-3 (continued)

Long Term (>600 seconds) Containment Pressure
Above nominal pump flow rate for LPCI and core spray pumps for the first 10 minutes and nominal pump flow rate after 10 minutes. Containment initial conditions to minimize containment pressure, drywell and torus shell heat sinks modeled. This case was analyzed with 100% thermal mixing efficiency.

Long Term Suppression Pool Heatup
Above nominal pump flow rate for LPCI and core spray pumps for the first 10 minutes and nominal pump flow rate after 10 minutes. Containment initial conditions to minimize containment pressure, drywell and torus shell heat sinks modeled. This case was analyzed with 20% thermal mixing efficiency.

Short Term (<600 seconds) Containment Pressure
With ECCS initiation all LPCI pumps start vessel injection mode and inject directly into the drywell (no flow to vessel) at a flow rate of 5150 gpm per pump during the first 10 minutes of this event. After receiving a signal for CS initiation, the two CS pumps are injecting into the vessel at a flow rate of 5800 gpm per pump for the first 10 minutes of the event. This case was analyzed with a 60% thermal mixing efficiency.

Table 6.2-3a

KEY PARAMETERS FOR CONTAINMENT ANALYSIS

	Long Term (>600 seconds) Containment Pressure Case	Long Term Suppression Pool Heatup Case	Short Term (<600 seconds) Containment Pressure Case
Decay Heat Model	ANS 5.1	ANS 5.1	ANS 5.1
Initial Suppression Pool Temperature (°F)	95	95	95
Feedwater Added	yes	yes	yes
Pump Heat Added	yes	yes	yes
Heat Exchanger K Value (BTU/sec-°F)	307.4	281.7	N/A
Initial Drywell Pressure (psia)	15.70	15.70	15.70
Initial Suppression Chamber Pressure (psia)	14.70	14.70	14.70
Initial Drywell Temperature	150	150	N/A
Initial Drywell Relative Humidity (%)	100	100	N/A
Initial Suppression Chamber Relative Humidity (%)	100	100	N/A
Mixing Efficiency Between Break Liquid and Drywell Fluid (%)	100	20	60

Table 6.2-3b

HEAT EXCHANGER HEAT TRANSFER RATE

Case	Shell Side Flow Rate (LPCI Pump) GPM	Tube Side Flow Rate (CCSW Pump) GPM	K-Value BTU/sec-°F	Heat Transfer Rate (165°F Shell Side Temperature, 95 °F Tube Side Temperature) Million BTU/hr
Long Term Suppression Pool Heatup	5000	5000	281.7	71.0

The heat exchanger parameters identified in this table reflect the new basis for system capability.

Table 6.2-6

Intentionally Deleted

Table 6.2-7

CONTAINMENT COOLING EQUIPMENT SPECIFICATIONS

Containment Cooling Heat Exchangers

Number	2
dP - river water to containment water	20 psi
Primary (shell) design pressure	375 psi
Secondary (tube) design pressure	375 psi

Containment Cooling Heat Exchanger Capability

Basis	LPCI Flow (gal/min)	LPCI Temp. °F Note 1	CCSW Flow (gal/min)	CCSW Temp. °F Note 2	Heat Load (Btu/hr)
Heat exchanger design specification (original)	10,700	165	7000	95	98.6×10^6
Heat exchanger design specification (new)	5000	165	5000	95	71.0×10^6

Heat Exchanger Codes

Shell Side	Carbon Steel A212, Grade B
Code	ASME Section III (1965, Class C) Requirements per manufacturer's specification sheet. Certificate of Shop Inspection indicates construction per applicable code. Berlin Chapman Specification Sheet specifies heat exchanger built to ASME Section III.
Radiography requirements	Tested in accordance with GE Specification 21A5451, Section 4.0 which states testing per ASME Section III, Class C. Manufacturer's data sheet specified joint efficiency of 100% and radiography as complete.

Table 6.2-9

PRINCIPAL PENETRATIONS OF PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

Containment Penetration Number[1]	Valve Number	Line Isolated	Valve Type[2]	Location Relative to Containment[3]	Normal Status[4]	Actuation on PCIS Signal[5]	PCIS Signal[6]	Power Supply	Line Size (in.)	Maximum Isolation Time (sec)[9]	Reference Drawings[11]
X-101	9207A	Drywell Sample	AO Gate	O	O	GC	Group 2[7]	AC Solenoid[8]	1	5	25 (356)
X-101	9207B	Drywell Sample	AO Gate	O	O	GC	Group 2[7]	AC Solenoid[8]	1	5	25 (356)
X-101	9208A	Drywell Sample	AO Gate	O	O	GC	Group 2[7]	AC Solenoid[8]	1	5	25 (356)
X-101	9208B	Drywell Sample	AO Gate	O	O	GC	Group 2[7]	AC Solenoid[8]	1	5	25 (356)
X-105A	203-1A	Main Steam	AO Globe	I	O	GC	Group 1	AC/DC Solenoid/Air Pilot Spring Closed [8]	20	3-5	12-1 (345-1)
X-105A	203-2A	Main Steam	AO Globe	O	O	GC	Group 1		20	3-5	12-2 (345-2)
X-105B	203-1B	Main Steam	AO Globe	I	O	GC	Group 1		20	3-5	12-1 (345-1)
X-105B	203-2B	Main Steam	AO Globe	O	O	GC	Group 1		20	3-5	12-2 (345-2)
X-105C	203-1C	Main Steam	AO Globe	I	O	GC	Group 1		20	3-5	12-1 (345-1)
X-105C	203-2C	Main Steam	AO Globe	O	O	GC	Group 1		20	3-5	12-2 (345-2)
X-105D	203-1D	Main Steam	AO Globe	I	O	GC	Group 1		20	3-5	12-1 (345-1)
X-105D	203-2D	Main Steam	AO Globe	O	O	GC	Group 1		20	3-5	12-2 (345-2)
X-106	220-1	Main Steam Line Drains	MO Globe [13]	I	C	SC	Group 1	AC	2	35	12-1 (345-1)
X-106	220-2	Main Steam Line Drains	MO Globe [13]	O	C	SC	Group 1	DC	2	35	12-2 (345-2)

Table 6.2-9 (Continued)

PRINCIPAL PENETRATIONS OF PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

Containment Penetration Number[1]	Valve Number	Line Isolated	Valve Type[2]	Location Relative to Containment[3]	Normal Status[4]	Actuation on PCIS Signal[5]	PCIS Signal[6]	Power Supply	Line Size (in.)	Maximum Isolation Time (sec)[9]	Reference Drawings[11]
X-107A (B)	220-58A	Feedwater	Check	I	O	N/A	N/A	Self	18	N/A	14 (347)
X-107A (B)	220-62A	Feedwater	Check	O	O	N/A	N/A	Self	18	N/A	14 (347)
X-107B (A)	220-58B	Feedwater	Check	I	O	N/A	N/A	Self	18	N/A	14 (347)
X-107B (A)	220-62B	Feedwater	Check	O	O	N/A	N/A	Self	18	N/A	14 (347)
X-108A	1301-1	Isolation Condenser Steam Supply	MO Gate	I	O	GC	Group 5	AC	14	40	28 (359)
X-108A	1301-2	Isolation Condenser Steam Supply	MO Gate	O	O	GC	Group 5	DC	14	40	28 (359)
X-108A	1301-17	Isolation Condenser Vent	AO Globe	O	O	GC	Group 1	AC Solenoid[8]	3/4	10	28 (359)
X-108A	1301-20	Isolation Condenser Vent	AO Globe	O	O	GC	Group 1	AC Solenoid[8]	3/4	10	28 (359)
X-108B	0299-97B	RVWLIS Backfill	Check	O	O	N/A	N/A	Self	3/8	N/A	26-3(357-3)
X-108B	0299-98B	RVWLIS Backfill	Check	O	O	N/A	N/A	Self	3/8	N/A	26-3(357-3)
X-108B	0299-99B	RVWLIS Backfill	Check	O	O	N/A	N/A	Self	3/8	N/A	26-3(357-3)
X-108B	0299-100B	RVWLIS Backfill	Check	O	O	N/A	N/A	Self	3/8	N/A	26-3(357-3)
X-109B(A)	1301-3	Isolation Condenser Condensate Return	MO Gate	O	C	SC	Group 5	DC	12	40	28 (359)
X-109B(A)	1301-4	Isolation Condenser Condensate Return	MO Gate	I	O	GC	Group 5	AC	12	40	28 (359)

Table 6.2-9 (Continued)

PRINCIPAL PENETRATIONS OF PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

Containment Penetration Number[1]	Valve Number	Line Isolated	Valve Type[2]	Location Relative to Containment[3]	Normal Status[4]	Actuation on PCIS Signal[5]	PCIS Signal[6]	Power Supply	Line Size (in.)	Maximum Isolation Time (sec)[9]	Reference Drawings[11]
X-111A	1001-1A	Shutdown Cooling Supply	MO Gate	I	C	SC	Group 3	AC	16	40	32 (363)
X-111A/B	1001-2A	Shutdown Cooling Supply	MO Gate	O	C	SC	Group 3	DC	14	40	32 (363)
X-111B	1001-1B	Shutdown Cooling Supply	MO Gate	I	C	SC	Group 3	AC	16	40	32 (363)
X-111A/B	1001-2B	Shutdown Cooling Supply	MO Gate	O	C	SC	Group 3	DC	14	40	32 (363)
X-111A/B	1001-2C	Shutdown Cooling Supply	MO Gate	O	C	SC	Group 3	DC	14	40	32 (363)
X-113	1201-1	Cleanup System Supply	MO Gate	I	O	GC	Group 3	AC	8	30	30 (361)
X-113	1201-1A	Cleanup System Supply	MO Globe (13)	I	C	SC	Group 3	AC	2	30	30 (361)
X-113	1201-2	Cleanup System Supply	MO Gate	O	O	GC	Group 3	DC	8	30	30 (361)
X-113	1201-3	Cleanup System Supply	MO Gate	O	C	SC	Group 3	DC	8	30	30 (361)
X-115A (128)	2301-4	HPCI Steam Supply	MO Gate	I	O	GC	Group 4	AC	10	50	51 (374)
X-115A (128)	2301-5	HPCI Steam Supply	MO Gate	O	O	GC	Group 4	DC	10	50	51 (374)

Table 6.2-9 (Continued)

PRINCIPAL PENETRATIONS OF PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

Containment Penetration Number[1]	Valve Number	Line Isolated	Valve Type[2]	Location Relative to Containment[3]	Normal Status[4]	Actuation on PCIS Signal[5]	PCIS Signal[6]	Power Supply	Line Size (in.)	Maximum Isolation Time (sec)[9]	Reference Drawings[11]
X-116A	1001-5A	Shutdown Cooling Return	MO Gate	O	C	SC	Group 3	AC	14	50	32 (363)
X-116A	1501-22A	LPCI Core Flooding	MO Gate	O	C	N/A	RM	AC	16	N/A	29-1 (360-1)
X-116A	1501-25A	LPCI Core Flooding	AO Check	I	C	N/A	N/A	AC, Self	16	N/A	29-1 (360-1)
X-116B	1001-5B	Shutdown Cooling Return	MO Gate	O	C	SC	Group 3	AC	14	50	32 (363)
X-116B	1501-22B	LPCI Core Flooding	MO Gate	O	C	N/A	RM	AC	16	N/A	29-1 (360-1)
X-116B	1501-25B	LPCI Core Flooding	AO Check	I	C	N/A	N/A	AC, Self	16	N/A	29-1 (360-1)
X-117	2001-105	DW Floor Drain Sump Discharge	AO Diaphragm	O	C	SC	Group 2	AC Solenoid[8]	3	20	39 (369)
X-117	2001-106	DW Floor Drain Sump Discharge	AO Diaphragm	O	C	SC	Group 2	AC Solenoid[8]	3	20	39 (369)
X-118	2001-5	DW Equipment Drain Sump Discharge	AO Diaphragm	O	C	SC	Group 2	AC Solenoid[8]	3	20	39 (369)
X-118	2001-6	DW Equipment Drain Sump Discharge	AO Diaphragm	O	C	SC	Group 2	AC Solenoid[8]	3	20	39 (369)
X-119	4327-500	Demineralized Water Supply	Hand Gate	O	LC	N/A	N/A	Hand	3	N/A	35-1 (366)
X-119	4327-502	Demineralized Water Supply	Hand Globe	I	LC	N/A	N/A	Hand	3	N/A	35-1 (366)
X-119	1916-500	Demineralized Water Supply	Hand Globe	I	LC	N/A	N/A	Hand	2	N/A	31 (362)
X-120	4640-500	Service Air Supply	Hand Globe	O	LC	N/A	N/A	Hand	1	N/A	38 (368)
X-120	Various	Service Air Supply	Hand Gate, Plug	I	C	N/A	N/A	Hand	1	N/A	38 (368)

Table 6.2-9 (Continued)

PRINCIPAL PENETRATIONS OF PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

Containment Penetration Number(1)	Valve Number	Line Isolated	Valve Type(2)	Location Relative to Containment(3)	Normal Status(4)	Actuation on PCIS Signal(5)	PCIS Signal(6)	Power Supply	Line Size (in.)	Maximum Isolation Time (sec)(9)	Reference Drawings(11)
X-121	4722	Instrument Air Supply	AO Globe	O	O	N/A	RM	AC Solenoid	2	N/A	37-2 (367-2)
X-121	4799-530	Instrument Air Supply	Check	O	O	N/A	N/A	Self	2	N/A	37-2 (367-2)
X-122	220-44	Rx Water Sample	AO Globe	I	O	GC	Group 1(7)	AC Solenoid	3/4	5	26-2 (357-2)
X-122	220-45	Rx Water Sample	AO Globe	O	O	GC	Group 1(7)	AC Solenoid	3/4	5	26-2 (357-2)
X-123	3702	RBCCW Supply	MO Gate	O	O	N/A	RM	AC	6	60(14)	20 (353)
X-123	3769-500	RBCCW Supply	Check	I	O	N/A	N/A	Self	6	Standard	20 (353)
X-124	3703	RBCCW Return	MO Gate	O	O	N/A	RM	AC	6	60(14)	20 (353)
X-124	3706	RBCCW Return	MO Gate	I	O	N/A	RM	AC	6	60(14)	20 (353)
X-125	1601-23	DW Vent	AO Butterfly	O	C	SC	Group 2	AC Solenoid(8)	18	10	25 (356)
X-125/318A	1601-24	DW and Torus Vent	AO Butterfly	O	C	SC	Group 2	AC Solenoid(8)	18	10	25 (356)
X-125	1601-62	DW Vent Relief	AO Globe	O	C	SC	Group 2	AC Solenoid	2	15	25 (356)
X-125/318A	1601-63	DW and Torus Vent to SBGT	AO Butterfly	O	C	SC	Group 2	AC Solenoid(8)	6	10	25 (356)
X-125	2599-4A	ACAD Air Exhaust from DW	AO Globe	O	C	N/A	RM	AC Solenoid	1	N/A	707-1 (707-2)
X-125	2599-5A	ACAD Air Exhaust from DW	AO Globe	O	C	N/A	RM	AC Solenoid	1	N/A	707-1 (707-2)
X-125	2599-4B	ACAD Air Exhaust from DW	AO Globe	O	C	N/A	RM	AC Solenoid	1	N/A	707-1 (707-2)
X-125	2599-5B	ACAD Air Exhaust from DW	AO Globe	O	C	N/A	RM	AC Solenoid	1	N/A	707-1 (707-2)

Table 6.2-9 (Continued)

PRINCIPAL PENETRATIONS OF PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

Containment Penetration Number[1]	Valve Number	Line Isolated	Valve Type[2]	Location Relative to Containment[3]	Normal Status[4]	Actuation on PCIS Signal[5]	PCIS Signal[6]	Power Supply	Line Size (in.)	Maximum Isolation Time (sec)[9]	Reference Drawings[11]
X-126	1601-21	DW Inert and Purge	AO Butterfly	O	C	SC	Group 2	AC Solenoid[8]	18	10	25 (356)
X-126/304	1601-22	DW and Torus Vent from Rx Building	AO Butterfly	O	C	SC	Group 2	AC Solenoid[8]	18	10	25 (356)
X-126/304	1601-55	DW and Torus Inerting	AO Butterfly	O	O	GC	Group 2	AC Solenoid[8]	4	15	25 (356)
X-304	1601-56	Torus Inerting and Purge	AO Butterfly	O	O	GC	Group 2	AC Solenoid[8]	18	10	25 (356)
X-126/304	1601-57	DW and Torus N_2 Makeup	MO Globe	O	O	GC	Group 2	AC	1½	15	25 (356)
X-304	1601-58	Torus Nitrogen Makeup	AO Butterfly	O	C	GC	Group 2	AC Solenoid	1½	15	25 (356)
X-126	1601-59	DW Nitrogen Makeup	AO Butterfly	O	O	GC	Group 2	AC Solenoid[8]	1½	15	25 (356)
X-130 (138)	1101-15	Standby Liquid Control	Check	I	C	N/A	N/A	Self	1½	N/A	33 (364)
X-130 (138)	1101-16	Standby Liquid Control	Check	O	C	N/A	N/A	Self	1½	N/A	33 (364)

Table 6.2-9 (Continued)

PRINCIPAL PENETRATIONS OF PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

Containment Penetration Number(1)	Valve Number	Line Isolated	Valve Type(2)	Location Relative to Containment(3)	Normal Status(4)	Actuation on PCIS Signal(5)	PCIS Signal(6)	Power Supply	Line Size (in.)	Maximum Isolation Time (sec)(9)	Reference Drawings(11)
X-136J (X-136C)	0733A	TIP Ball	Ball	O	C	SC	Group 2	AC Solenoid	1/2	5	37-2 (367-2)
X-136J (X-136C)	0736-1	TIP Shear	Explosive	O	O	N/A	N/A	DC	1/2	N/A	37-2 (367-2)
X-136F (X-136B)	0733B	TIP Ball	Ball	O	C	SC	Group 2	AC Solenoid	1/2	5	37-2 (367-2)
X-136F (X-136B)	0736-2	TIP Shear	Explosive	O	O	N/A	N/A	DC	1/2	N/A	37-2 (367-2)
X-136E (X-136D)	0733C	TIP Ball	Ball	O	C	SC	Group 2	AC Solenoid	1/2	5	37-2 (367-2)
X-136E (X-136D)	0736-3	TIP Shear	Explosive	O	O	N/A	N/A	DC	1/2	N/A	37-2 (367-2)
X-136H (X-136F)	0733D	TIP Ball	Ball	O	C	SC	Group 2	AC Solenoid	1/2	5	37-2 (367-2)
X-136H (X-136F)	0736-4	TIP Shear	Explosive	O	O	N/A	N/A	DC	1/2	N/A	37-2 (367-2)
X-136G (X-136E)	0733E	TIP Ball	Ball	O	C	SC	Group 2	AC Solenoid	1/2	5	37-2 (367-2)
X-136G (X-136E)	0736-5	TIP Shear	Explosive	O	O	N/A	N/A	DC	1/2	N/A	37-2 (367-2)
X-136E (X-136F)	4799-514	TIP Nitrogen Purge	Check	O	C	N/A	N/A	Self	1/2	N/A	37-2 (367-2)
X-139B (139C)	220-112A	CRD to Reactor Recirculation Loop	Hand Globe	I	C	N/A	N/A	Hand	3/4	N/A	26-2 (357-2)
X-139B (139C)	220-112B	CRD to Reactor Recirculation Loop	Hand Globe	I	C	N/A	N/A	Hand	3/4	N/A	26-2 (357-2)
X-139B (139C)	399-506	CRD to Reactor Recirculation Loop	Hand Gate	O	C	N/A	N/A	Hand	1	N/A	34 (365)
X-139D	4720	DW Pneumatic Supply	AO Gate	O	C	GC	Group 2	AC Solenoid(8)	1	N/A	37-2 (367-2)
X-139D	4721	DW Pneumatic Supply	AO Gate	O	C	GC	Group 2	AC Solenoid(8)	1	N/A	37-2 (367-2)

Table 6.2-9 (Continued)

PRINCIPAL PENETRATIONS OF PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

Containment Penetration Number(1)	Valve Number	Line Isolated	Valve Type(2)	Location Relative to Containment(3)	Normal Status(4)	Actuation on PCIS Signal(5)	PCIS Signal(6)	Power Supply	Line Size (in.)	Maximum Isolation Time (sec)(9)	Reference Drawings(11)
X-143 (X-144)	9205A	Drywell Air Sample	AO Globe	O	O	GC	Group 2(7)	AC Solenoid(8)	½	5	25 (356)
X-143 (X-144)	9205B	Drywell Air Sample	AO Globe	O	O	GC	Group 2(7)	AC Solenoid(8)	½	5	25 (356)
X-143 (X-144)	9206A	Drywell Air Sample	AO Globe	O	O	GC	Group 2(7)	AC Solenoid(8)	½	5	25 (356)
X-143 (X-144)	9206B	Drywell Air Sample	AO Globe	O	O	GC	Group 2(7)	AC Solenoid(8)	½	5	25 (356)
X-143 (X-144)	8507-500, 502-521 (8507-501-521)	Drywell Manifold Samples	Hand Globe	O	C	N/A	N/A	Hand	½	N/A	178 (421)
X-143 (X-144)	8501-5A	Drywell Air Sample	AO Globe	O	O	GC	Group 2(7)	AC Solenoid(8)	½	5	25 (356)
X-143 (X-144)	8501-5B	Drywell Air Sample	AO Globe	O	O	GC	Group 2(7)	AC Solenoid(8)	½	5	25 (356)
X-143 (X-144)	8599-629, 631-650 (8599-630-650)	Drywell Manifold Samples	Hand Globe	O	C	N/A	N/A	Hand	½	N/A	178 (421)
X-145 (150A)	1501-27B	Containment Spray	MO Gate	O	C	N/A	RM	AC	10	N/A	29-1 (360-1)
X-145 (150A)	1501-28B	Containment Spray	MO Gate	O	C	N/A	RM	AC	10	N/A	29-1 (360-1)

Table 6.2-9 (Continued)

PRINCIPAL PENETRATIONS OF PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

Containment Penetration Number(1)	Valve Number	Line Isolated	Valve Type(2)	Location Relative to Containment(3)	Normal Status(4)	Actuation on PCIS Signal(5)	PCIS Signal(6)	Power Supply	Line Size (in.)	Maximum Isolation Time (sec)(9)	Reference Drawings(11)
X-147	3-205-24	Reactor Head Cooling	MO Gate	O	C	SC	Group 2	AC	2½	45	357-1
X-147	2-205-24	Reactor Head Cooling	MO Gate	O	C	SC	Group 2	AC	2½	60	26-1
X-147	205-27	Reactor Head Cooling	Check	I	C	N/A	N/A	Self	2½	N/A	26-1 (357-1)
X-149A (B)	1402-25A	Core Spray to Reactor	MO Gate	O	C	N/A	RM	AC	10	N/A	27 (358)
X-149B (A)	1402-25B	Core Spray to Reactor	MO Gate	O	C	N/A	RM	AC	10	N/A	27 (358)
X-149A (B)	1402-24A	Core Spray to Reactor	MO Gate	O	O	N/A	RM	AC	10	N/A	27 (358)
X-149B (A)	1402-24B	Core Spray to Reactor	MO Gate	O	O	N/A	RM	AC	10	N/A	27 (358)
X-150A (145)	1501-27A	Containment Spray	MO Gate	O	C	N/A	RM	AC	10	N/A	29-1 (360-1)
X-150A (145)	1501-28A	Containment Spray	MO Gate	O	C	N/A	RM	AC	10	N/A	29-1 (360-1)
X-202V (146)	2499-1A	DW H_2/O_2 Monitor	Solenoid	O	C	N/A	RM	AC Solenoid	1/2	N/A	706-1 (706-2)
X-202V (146)	2499-2A	DW H_2/O_2 Monitor	Solenoid	O	C	N/A	RM	AC Solenoid	1/2	N/A	706-1 (706-2)
X-202V (146)	2499-28A	Containment H_2/O_2 Monitor Return	Check	O	C	N/A	N/A	Self	1/2	N/A	706-1 (706-2)
X-202V (140B)	2599-2A	ACAD Dilution Air Supply to DW	AO Globe	O	C	N/A	RM	AC Solenoid	1	N/A	707-1 (707-2)
X-202V (140B)	2599-23A	ACAD Dilution Air Supply to DW	Check	O	C	N/A	N/A	Self	1	N/A	707-1 (707-2)

Table 6.2-9 (Continued)

PRINCIPAL PENETRATIONS OF PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

Containment Penetration Number[1]	Valve Number	Line Isolated	Valve Type[2]	Location Relative to Containment[3]	Normal Status[4]	Actuation on PCIS Signal[5]	PCIS Signal[6]	Power Supply	Line Size (in.)	Maximum Isolation Time (sec)[9]	Reference Drawings[11]
X-204A (X-115)	8501-3A	DW Air Sample Return	AO Globe	O	O	GC	Group 2[7]	AC Solenoid[8]	1	5	25 (356)
X-204A (X-115)	8501-3B	DW Air Sample Return	AO Globe	O	O	GC	Group 2[7]	AC Solenoid[8]	1	5	25 (356)
X-204B (127)	2499-1B	DW H_2/O_2 Monitor	Solenoid	O	C	N/A	RM	AC Solenoid	1/2	N/A	706-1 (706-2)
X-204B (127)	2499-2B	DW H_2/O_2 Monitor	Solenoid	O	C	N/A	RM	AC Solenoid	1/2	N/A	706-1 (706-2)
X-204B (127)	2499-28B	Containment H_2/O_2 Monitor Return	Check	O	C	N/A	N/A	Self	1/2	N/A	706-1 (706-2)
X-204B (127)	2599-2B	ACAD Dilution Air Supply to DW	AO Globe	O	C	N/A	RM	AC Solenoid	1	N/A	707-1 (707-2)
X-204B (127)	2599-23B	ACAD Dilution Air Supply to DW	Check	O	C	N/A	N/A	Self	1	N/A	707-1 (707-2)
X-209	0299-97A	RVWLIS Backfill	Check	O	C	N/A	N/A	Self	3/8	N/A	26-3(357-3)
X-209	0299-98A	RVWLIS Backfill	Check	O	C	N/A	N/A	Self	3/8	N/A	26-3(357-3)
X-209	0299-99A	RVWLIS Backfill	Check	O	C	N/A	N/A	Self	3/8	N/A	26-3(357-3)
X-209	0299-100A	RVWLIS Backfill	Check	O	C	N/A	N/A	Self	3/8	N/A	26-3(357-3)

Table 6.2-9 (Continued)

PRINCIPAL PENETRATIONS OF PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

Containment Penetration Number[1]	Valve Number	Line Isolated	Valve Type[2]	Location Relative to Containment[3]	Normal Status[4]	Actuation on PCIS Signal[5]	PCIS Signal[6]	Power Supply	Line Size (in.)	Maximum Isolation Time (sec)[9]	Reference Drawings[11]
X-303A-D	1501-5A	LPCI Suction Pump A	MO Gate	O	O	N/A	RM	AC	14	N/A	29-1 (360-1)
X-303A-D	1501-5B	LPCI Suction Pump B	MO Gate	O	O	N/A	RM	AC	14	N/A	29-1 (360-1)
X-303A-D	1501-5C	LPCI Suction Pump C	MO Gate	O	O	N/A	RM	AC	14	N/A	29-1 (360-1)
X-303A-D	1501-5D	LPCI Suction Pump D	MO Gate	O	O	N/A	RM	AC	14	N/A	29-1 (360-1)
X-303A-D	1599-13A (1501-13A)	LPCI Suction Relief	Relief	O	C	N/A	N/A	Self	2	N/A	29-1 (360-1)
X-303A-D	1599-13B (1501-13B)	LPCI Suction Relief	Relief	O	C	N/A	N/A	Self	2	N/A	29-1 (360-1)
X-303A-D	1599-13C (1501-13C)	LPCI Suction Relief	Relief	O	C	N/A	N/A	Self	2	N/A	29-1 (360-1)
X-303A-D	1599-13D (1501-13D)	LPCI Suction Relief	Relief	O	C	N/A	N/A	Self	2	N/A	29-1 (360-1)
X-303A-D	1402-3A	Core Spray Pump Suction	MO Gate	O	O	N/A	RM	AC	16	N/A	27 (358)
X-303A-D	1402-3B	Core Spray Pump Suction	MO Gate	O	O	N/A	RM	AC	16	N/A	27 (358)
X-303A-D	2301-35	HPCI Pump Suction from Torus	MO Gate	O	C	SC	Group 4	DC	16	80	51 (374)
X-303A-D	2301-36	HPCI Pump Suction from Torus	MO Gate	O	C	SC	Group 4	DC	16	80	51 (374)

Table 6.2-9 (Continued)

PRINCIPAL PENETRATIONS OF PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

Containment Penetration Number(1)	Valve Number	Line Isolated	Valve Type(2)	Location Relative to Containment(3)	Normal Status(4)	Actuation on PCIS Signal(5)	PCIS Signal(6)	Power Supply	Line Size (in.)	Maximum Isolation Time (sec)(9)	Reference Drawings(11)
X-303A-D	1599-61	Torus to Condenser Drain	AO Gate	O	C	SC	Group 2	AC Solenoid	3	10	29-1 (360-1)
X-303A-D	1599-62	Torus to Condenser Drain	AO Gate	O	C	SC	Group 2	AC Solenoid	3	10	29-1 (360-1)
X-304	1601-20A	Torus Vacuum Relief	AO Butterfly	O	C	N/A	RM	AC Solenoid(10)	20	5	25 (356)
X-304	1601-20B	Torus Vacuum Relief	AO Butterfly	O	C	N/A	RM	AC Solenoid(10)	20	5	25 (356)
X-304	1601-31A	Torus Vacuum Relief	Check	O	C	N/A	N/A	Self	20	N/A	25 (356)
X-304	1601-31B	Torus Vacuum Relief	Check	O	C	N/A	N/A	Self	20	N/A	25 (356)
X-309A	8501-1A	Torus Air Sample	AO Globe	O	O	GC	Group 2(7)	AC Solenoid(8)	½	5	25 (356)
X-309A	8501-1B	Torus Air Sample	AO Globe	O	O	GC	Group 2(7)	AC Solenoid(8)	½	5	25 (356)
X-310A	1402-4A	Core Spray Test Return	MO Globe	O	C	N/A	RM	AC	8	N/A	27 (358)
X-310A	1402-38A	Core Spray Pump Minimum Flow	MO Gate	O	O	N/A	RM	AC	1½	N/A	27 (358)
X-310A	1501-13A	LPCI Pump Minimum Flow	MO Gate	O	O	N/A	RM	AC	3	Standard	29-1 (360-1)
X-310A	1501-20A	LPCI Test	MO Gate	O	C	N/A	RM	AC	14	N/A	29-1 (360-1)
X-310A	1501-38A	LPCI Test	MO Globe	O	C	N/A	RM	AC	14	N/A	29-1 (360-1)
X-310B(A)	2301-14	HPCI Pump Minimum Flow	MO Globe	O	C	N/A	RM	DC	4	N/A	51 (374)
X-310B(A)	2301-40	HPCI Pump Minimum Flow	Check	O	C	N/A	N/A	Self	4	N/A	51 (374)
X-310B(A)	2301-53	HPCI Pump Minimum Flow	Relief	O	C	N/A	N/A	N/A	4	N/A	51 (374)

Table 6.2-9 (Continued)

PRINCIPAL PENETRATIONS OF PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

Containment Penetration Number(1)	Valve Number	Line Isolated	Valve Type(2)	Location Relative to Containment(3)	Normal Status(4)	Actuation on PCIS Signal(5)	PCIS Signal(6)	Power Supply	Line Size (in.)	Maximum Isolation Time (sec)(9)	Reference Drawings(11)
X-310B	1402-4B	Core Spray Test Return	MO Globe	O	C	N/A	RM	AC	8	N/A	27 (358)
X-310B	1402-38B	Core Spray Pump Minimum Flow	MO Gate	O	O	N/A	RM	AC	1½	N/A	27 (358)
X-310B	1501-13B	LPCI Pump Minimum Flow	MO Gate	O	O	N/A	RM	AC	3	Standard	29-1 (360-1)
X-310B	1501-20B	LPCI Test	MO Gate	O	C	N/A	RM	AC	14	N/A	29-1 (360-1)
X-310B	1501-38B	LPCI Test	MO Globe	O	C	N/A	RM	AC	14	N/A	29-1 (360-1)
X-311A	1501-18A	LPCI Suppression Pool Spray	MO Globe	O	C	N/A	RM	AC	6	N/A	29-1 (360-1)
X-311A	1501-19A	LPCI Suppression Pool Spray	MO Gate	O	C	N/A	RM	AC	6	N/A	29-1 (360-1)
X-311B	1501-18B	LPCI Suppression Pool Spray	MO Globe	O	C	N/A	RM	AC	6	N/A	29-1 (360-1)
X-311B	1501-19B	LPCI Suppression Pool Spray	MO Gate	O	C	N/A	RM	AC	6	N/A	29-1 (360-1)
X-312	2301-34	HPCI Condensate Drain	Check	O	C	N/A	N/A	Self	2	N/A	51 (374)
X-312	2301-71	HPCI Condensate Drain	Stop Check	O	C(12)	N/A	N/A	Self	2	N/A	51 (374)

Table 6.2-9 (Continued)

PRINCIPAL PENETRATIONS OF PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

Containment Penetration Number[1]	Valve Number	Line Isolated	Valve Type[2]	Location Relative to Containment[3]	Normal Status[4]	Actuation on PCIS Signal[5]	PCIS Signal[6]	Power Supply	Line Size (in.)	Maximum Isolation Time (sec)[9]	Reference Drawings[11]
X-316A	2499-3A	Torus H_2/O_2 Monitor	Solenoid	O	C	N/A	RM	AC Solenoid	1/2	N/A	706-1 (706-2)
X-316A	2499-4A	Torus H_2/O_2 Monitor	Solenoid	O	C	N/A	RM	AC Solenoid	1/2	N/A	706-1 (706-2)
X-316A	2599-3A	ACAD Dilution Air Supply to Torus	AO Globe	O	C	N/A	RM	AC Solenoid	1	N/A	707-1 (707-2)
X-316A	2599-24A	ACAD Dilution Air Supply to Torus	Check	O	C	N/A	N/A	Self	1	N/A	707-1 (707-2)
X-316B	2499-3B	Torus H_2/O_2 Monitor	Solenoid	O	C	N/A	RM	AC Solenoid	1/2	N/A	706-1 (706-2)
X-316B	2499-4B	Torus H_2/O_2 Monitor	Solenoid	O	C	N/A	RM	AC Solenoid	1/2	N/A	706-1 (706-2)
X-316B	2599-3B	ACAD Dilution Air Supply to Torus	AO Globe	O	C	N/A	RM	AC Solenoid	1	N/A	707-1 (707-2)
X-316B	2599-24B	ACAD Dilution Air Supply to Torus	Check	O	C	N/A	N/A	Self	1	N/A	707-1 (707-2)
X-317A	2301-45	HPCI Turbine Exhaust	Check	O	C	N/A	N/A	Self	24	N/A	51 (374)
X-317A	2301-74	HPCI Turbine Exhaust	Stop Check	O	C[12]	N/A	N/A	Self	12	N/A	51 (374)
X-318A	1601-60	Torus Vent	AO Butterfly	O	C	SC	Group 2	AC Solenoid[8]	18	10	25 (356)
X-318A	1601-61	Torus Vent Relief	AO Globe	O	C	SC	Group 2	AC Solenoid[8]	2	15	25 (356)

Table 6.2-9 (Continued)

PRINCIPAL PENETRATIONS OF PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

NOTES TO TABLE 6.2-9

1. 100- and 200-series penetration numbers are typically drywell penetrations
   300-series penetration numbers are suppression chamber penetrations
   Penetration numbers shown are for Unit 2. Unit 3 penetration numbers, if different, are shown in parentheses.

2. AO — Air-operated
   MO — Motor-operated

3. I — Inside primary containment
   O — Outside primary containment

4. O — Normally open
   C — Normally closed

5. GC — Goes closed
   SC — Stays closed

6. PCIS — Primary Containment Isolation System Group Isolation Designations - refer to Section 7.7 for a definition of the group isolations.
   RM — Remote manual
   N/A — Not applicable

7. Valve can be reopened after isolation for sampling

8. Fails closed on loss of air

9. Standard closing rate for MO Globe valves is 4 in./min. Standard closing rate for MO Gate valves is 12 in./min.

10. Fails open on loss of air

11. Drawing numbers are Unit 2 P&ID numbers. Unit 3 P&ID numbers are shown in parentheses.

12. The valve position indicated relates to the valve disk position.

13. The Unit 3 Primary Containment Isolation Valves were replaced with Anchor-Darling double-disk gate valves during D3R13.

14. This is a clarification, a maximum closure time of 60 seconds is still considered "Standard" per NUREG-0800.

Table 6.2-10
LOCKED CLOSED CONTAINMENT ISOLATION VALVES - UNIT 2

System	Penetration No.	Valve No.
Main Steam	X-105A, B, C, D	2-220-10A, 10B, 10C, 10D 2-3099-87, 88, 89, 90
Main Steam	X-106	2-220-5
Feedwater	X-107A	2-220-103A 2-3299-52
Feedwater	X-107B	2-220-103B 2-3299-50
Isolation Condenser	X-108A	2-1301-34, 505, 606, 645
RVWLIS Backfill	X-108B	2-0299-108B, 110B, 112B, 113B, 114B, 115B
Isolation Condenser	X-109B	2-1301-32, 601, 604
Shutdown Cooling	X-111A, B	2-1001-200, 90A, 90B, 90C, 91A, 91B, 91C
Shutdown Cooling	X-111A	2-1001-45A, 47A
Shutdown Cooling	X-111B	2-1001-45B, 47B
Cleanup	X-113	2-1201-31 2-1299-11, 004
HPCI	X-115A	2-2301-16
LPCI	X-116A	2-1501-23A ,92A, 2-1599-2A
Shutdown Cooling	X-116A	2-1001-14A
LPCI	X-116B	2-1501-23B, 92B, 2-1599-2B
Shutdown Cooling	X-116B	2-1001-14B
Drywell Floor Drains	X-117	2-2099-871
Drywell Equipment Drains	X-118	2-2099-552
Clean Demin Water	X-119	2-1916-500 2-4327-500, 502
Service Air	X-120	2-4640-500
Instrument Air	X-121	2-4799-533
Recirculation Sample	X-122	2-220-42
RBCCW	X-123	2-3799-30,132
RBCCW	X-124	2-3799-29
Primary Containment Vent, ACAD	X-125	2-1605-500, 2-1699-81 2-2599-16A, 16B

Table 6.2-10
LOCKED CLOSED CONTAINMENT ISOLATION VALVES - UNIT 2
(Continued)

System	Penetration No.	Valve No.
Primary Containment Vent	X-126	2-1699-72 2-8599-526
Standby Liquid Control	X-130	2-1199-107
CRD Hydraulics	X-139B	2-220-112A, 112B 2-0399-585, 506
Instrument Air	X-139D	2-4799-565
Sample System	X-143	2-8507-500, 502 through 521 2-8599-629, 631 through 650
Containment Spray	X-145	2-1501-30B 2-1599-124B, 125B
Reactor Head Spray	X-147	2-205-25 2-0299-57
Core Spray	X-149A	2-1402-32A, 33A, 5A 2-1403-A-500 2-1404-A-500
Core Spray	X-149B	2-1402-32B, 33B, 5B 2-1403-B-500 2-1404-B-500
Containment Spray	X-150A	2-1501-30A 2-1599-124A, 125A
CAM	X-202V	2-2499-7A, 31A, 32A
ACAD	X-202V	2-2599-11A
Sample System	X-204A	2-8599-617
ACAD	X-204B	2-2599-11B
CAM	X-204B	2-2499-7B, 31B, 32B
RVWLIS Backfill	X-209	2-0299-108A, 110A, 112A, 113A, 114A, 115A
HPCI	X-303A, B, C, D	2-2301-37, 93, 94 2-2399-15,
Core Spray	X-303A, B, C, D	2-1402-10A, 10B 2-1499-37A, 37B
LPCI	X-303A, B, C, D	2-1501-57A, 57B, 70A, 70B, 72A, 72B, 73A, 73B 2-1599-27A, 27B, 75A, 75B, 68

Table 6.2-10
LOCKED CLOSED CONTAINMENT ISOLATION VALVES - UNIT 2
(Continued)

System	Penetration No.	Valve No.
Pressure Suppression	X-304	2-1699- 500A, 500B, 63B 2-1623-DV
Pressure Suppression	X-305A	2-1699-99
Pressure Suppression	X-305B	2-1699-100
Pressure Suppression	X-305D	2-1699-75, 77, 65, 66
LPCI	X-310A	2-1501-87A, 2-1599-31A
LPCI	X-310B	2-1501-87B, 2-1599-31B
LPCI	X-311A	2-1501-40A
LPCI	X-311B	2-1501-40B
HPCI	X-312	2-2301-41B
Pressure Suppression	X-313A	2-1699-58A, 61A, 83, 103
Pressure Suppression	X-313B	2-1699-58B, 61B
ACAD	X-316A	2-2599-14A
CAM	X-316A	2-2499-9A
Pressure Suppression	X-316A	2-1699-63A
ACAD	X-316B	2-2599-14B
CAM	X-316B	2-2499-9B
HPCI	X-317A	2-2301-41A, 2-2306-500
Pressure Suppression	X-318A	2-1699-002A

Table 6.2-11
LOCKED CLOSED CONTAINMENT ISOLATION VALVES - UNIT 3

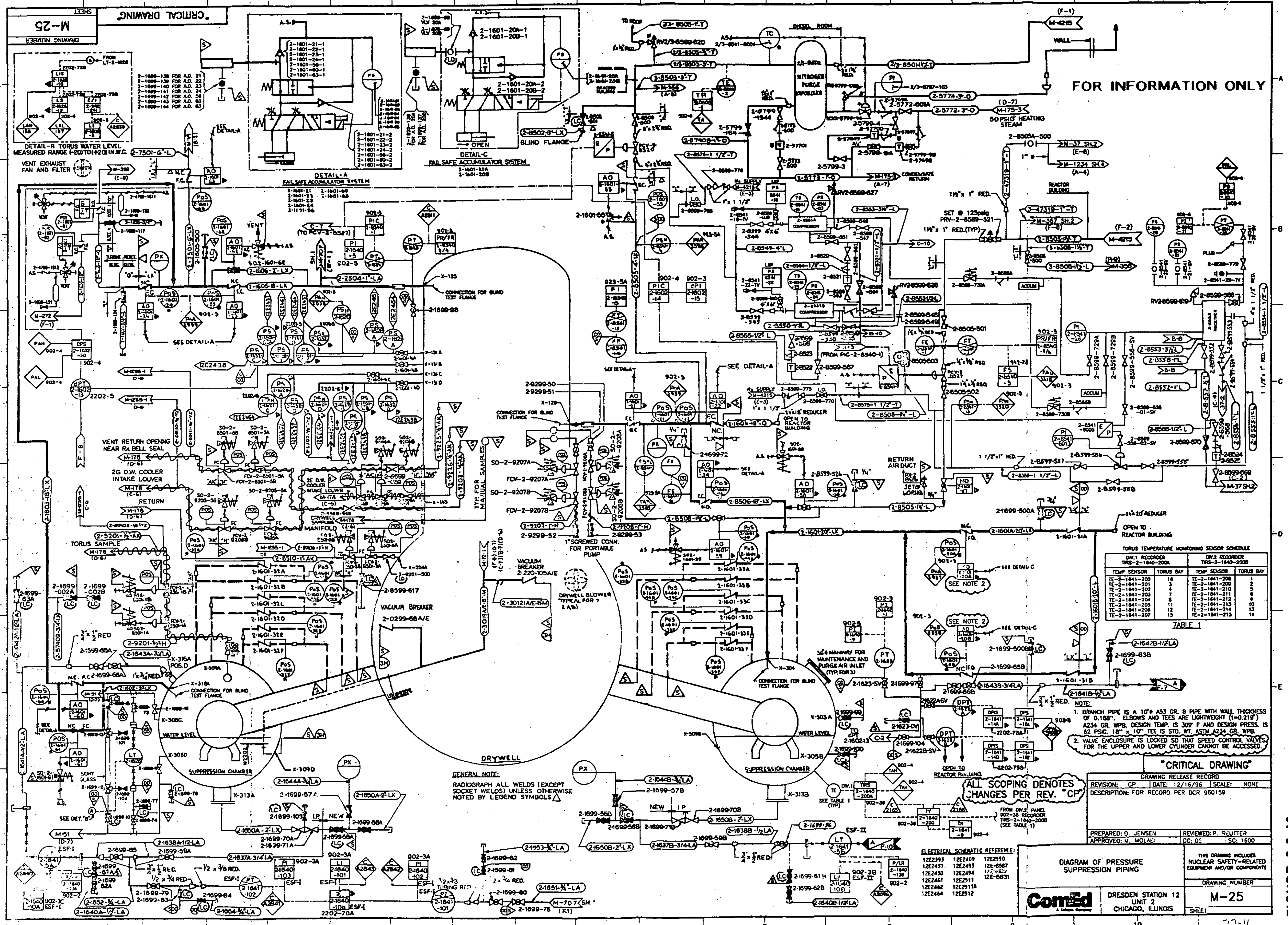
System	Penetration No.	Valve No.
Main Steam	X-105A, B, C, D	3-220-10A, 10B, 10C, 10D 3-3099-91, 92, 93, 94
Main Steam	X-106	3-220-5
Feedwater	X-107A	3-220-103B 3-3299-53
Feedwater	X-107B	3-220-103A 3-3299-55
Isolation Condenser	X-108A	3-1301-34, 602 3-1302-500
RVWLIS Backfill	X-108B	3-0299-108B, 110B, 112B, 113B, 114B, 115B
Isolation Condenser	X-109A	3-1301-32, 3-1304-500
Shutdown Cooling	X-111A, B	3-1001-90A, 90B, 90C, 91A, 91B, 91C, 4
Shutdown Cooling	X-111A	3-1001-45A, 47A
Shutdown Cooling	X-111B	3-1001- 45B, 47B
Cleanup	X-113	3-1201-32 3-1299-7
Sample System	X-115	3-8599-617
LPCI	X-116A	3-1501-23A, 92A
Shutdown Cooling	X-116A	3-1001-14A
LPCI	X-116B	3-1501-23B, 92B
Shutdown Cooling	X-116B	3-1001-14B
Drywell Floor Drains	X-117	3-2099-871
Drywell Equipment Drains	X-118	3-2099-552
Clean Demin Water	X-119	3-4327-500, 502, 3-1916-500
Service Air	X-120	3-4640-500
Instrument Air	X-121	3-4799-533
Recirculation Sample	X-122	3-220-42
RBCCW	X-123	3-3799-137, 139
RBCCW	X 124	3-3799-181
Primary Containment Vent, ACAD	X-125	3-1605-500, 3-1699-81 3-2599-16A, 16B

Table 6.2-11
LOCKED CLOSED CONTAINMENT ISOLATION VALVES - UNIT 3
(Continued)

System	Penetration No.	Valve No.
Primary Containment Vent	X-126	3-1604-500 3-1699-72 3-8502-500 3-8599-527
CAM	X-127	3-2499-7B, 31B, 32B
ACAD	X-127	3-2599-11B
HPCI	X-128	3-2301-16
Standby Liquid Control	X-138	3-1199-003
Instrument Air	X-139A	3-4799-565
CAM	X-139B	3-2499-31A, 32A
CRD Hydraulics	X-139C	3-0399-585, 506 3-220-112A, 112B
ACAD	X-140B	3-2599-11A
Sample System	X-144	3-8507-501 through 521 3-8599-630 through 650
Containment Spray	X-145	3-1501-30A
CAM	X-146	3-2499-7A
Reactor Head Spray	X-147	3-205-25
Core Spray	X-149A	3-1402-32B, 33B, 5B, 508, 510
Core Spray	X-149B	3-1402-32A, 33A 5A, 504, 507
Containment Spray	X-150A	3-1501-30B
RVWLIS Backfill	X-209	3-0299-108A, 110A, 112A, 113A, 114A, 115A
HPCI	X-303A, B, C, D	3-2301-37, 93, 94 3-2399-15
Core Spray	X-303A, B, C, D	3-1402-10A, 10B 3-1499-38, 39 3-1418B-500
LPCI	X-303A, B, C, D	3-1501-70A, 70B, 72A, 72B, 73A, 73B 3-1599-76, 77, 68

Table 6.2-11
LOCKED CLOSED CONTAINMENT ISOLATION VALVES - UNIT 3
(Continued)

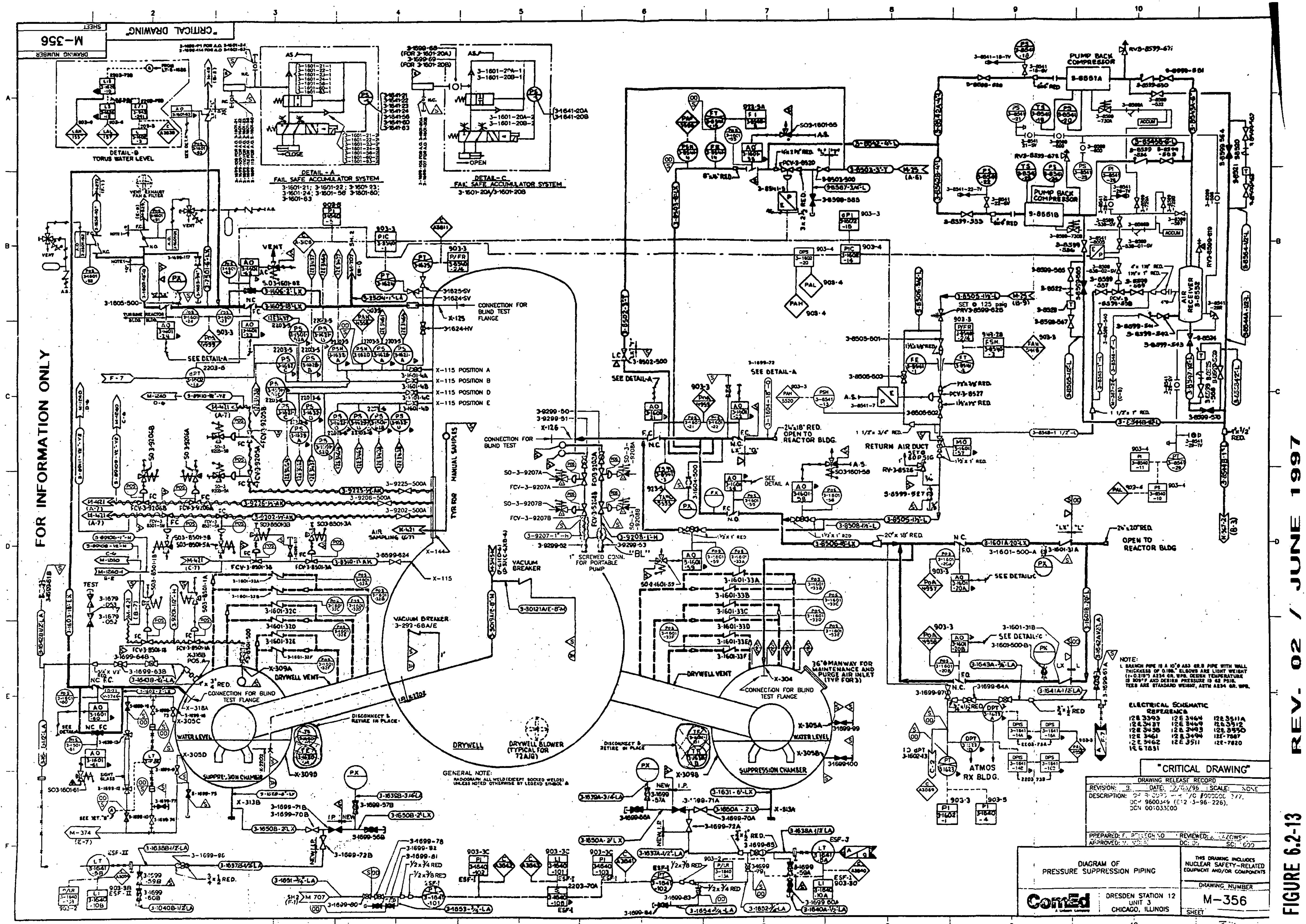
System	Penetration No.	Valve No.
Pressure Suppression	X-304	3-1601-A-500 3-1601-B-500 3-1699-61A, 3-1623-DV
Pressure Suppression	X-305A	3-1699-99
Pressure Suppression	X-305B	3-1699-100
Pressure Suppression	X-305D	3-1699-75, 77 3-2351A-DV, 3-2351B-DV
LPCI	X-310A	3-1501-87A
LPCI	X-310B	3-1501-87B
LPCI	X-311A	3-1501-40A
LPCI	X-311B	3-1501-40B
HPCI	X-312	3-2301-41B
Pressure Suppression	X-313A	3-1699-59A, 71A, 83
Pressure Suppression	X-313B	3-1699-59B, 71B
CAM	X-316A	3-2499-9A
ACAD	X-316A	3-2599-14A
CAM	X-316B	3-2499-9B
ACAD	X-316B	3-2599-14B
HPCI	X-317A	3-2301-41A
Pressure Suppression	X-316B	3-1699-61B
Pressure Suppression	X-318A	3-1679-52



CENTRAL DRAWING FACILITY 30 X

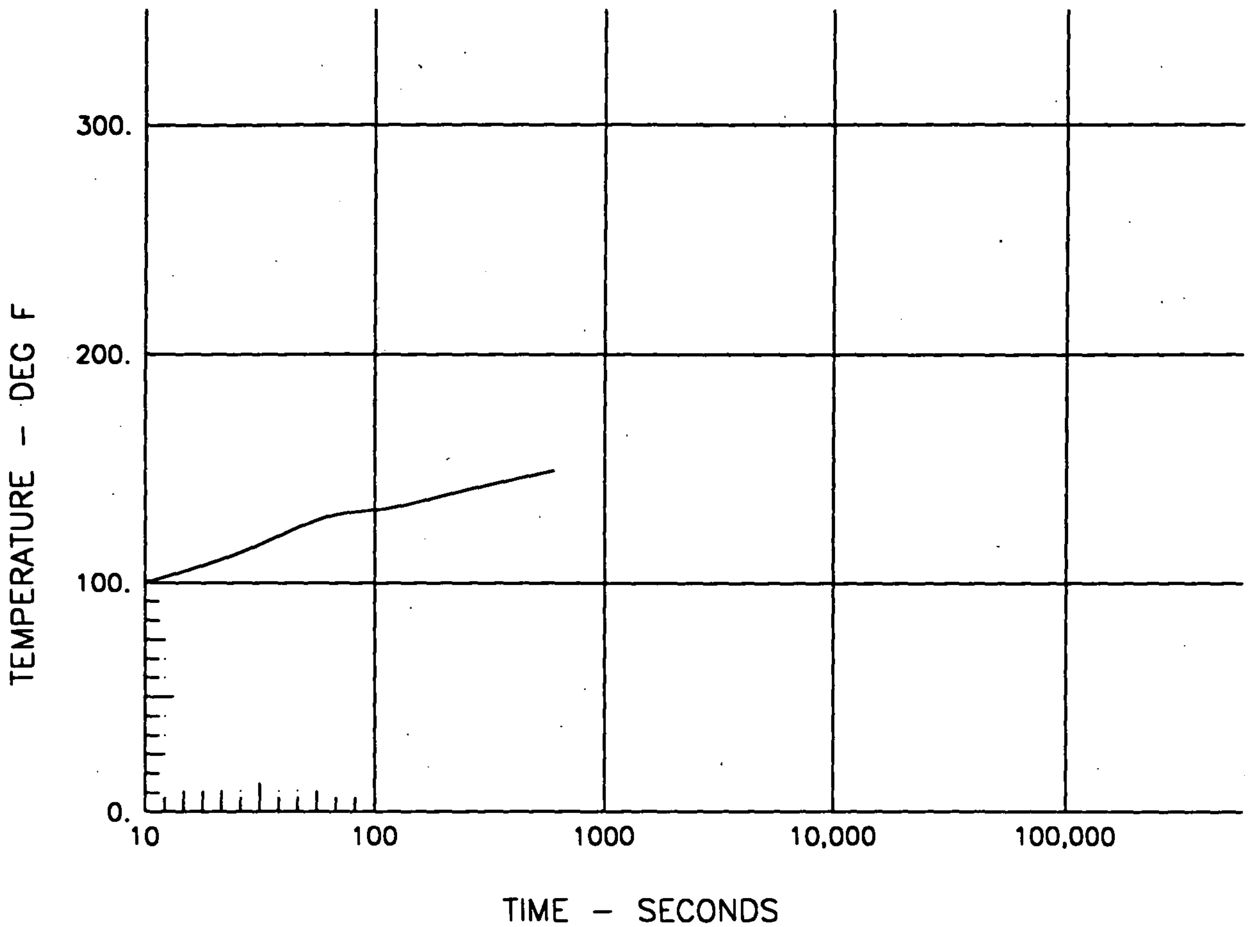
REV. 02 / JUNE 1997

FIGURE 6.2-12



REV. 02 / JUNE 1997

FIGURE 6.2-13

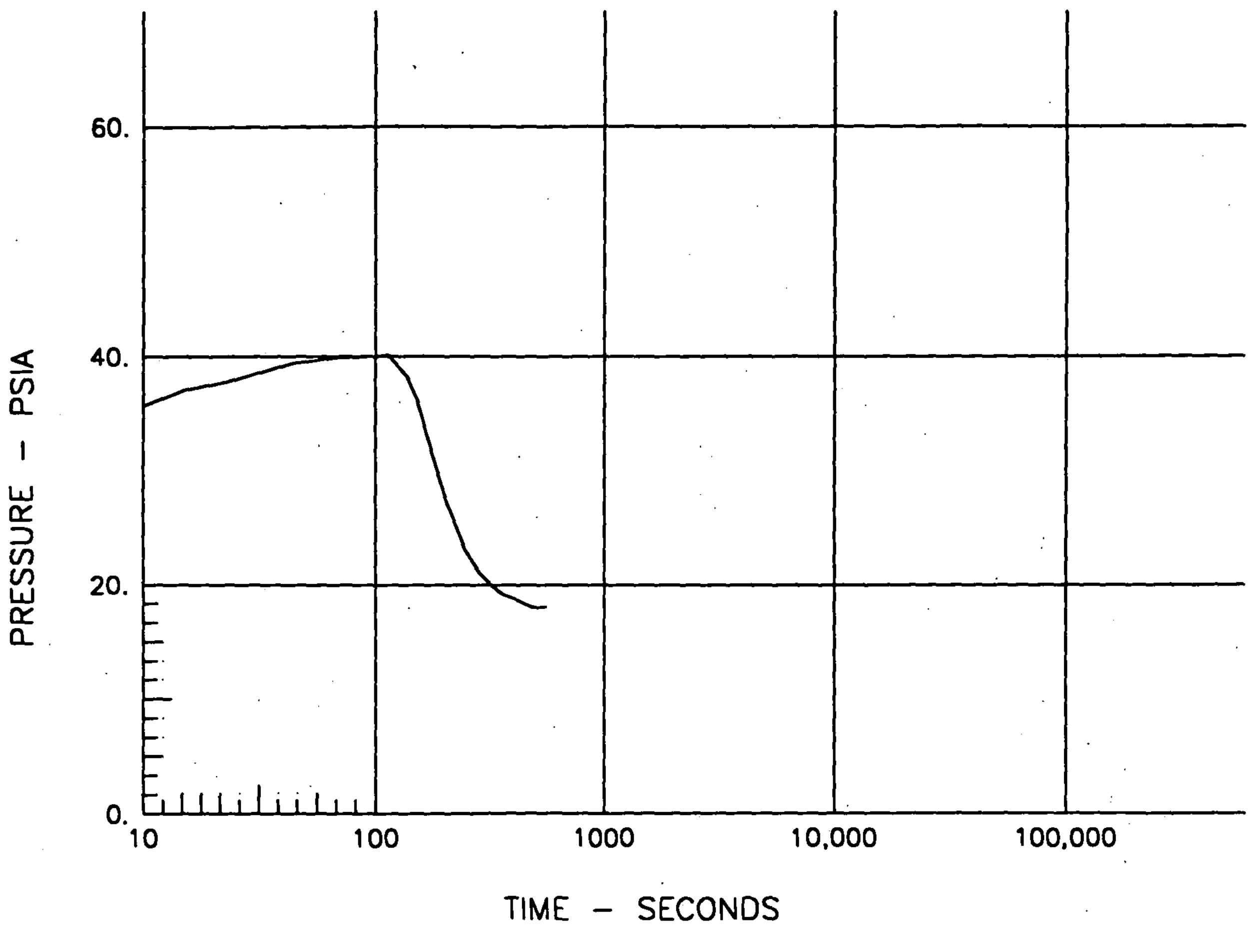


UFSAR REVISION 2, JUNE 1997

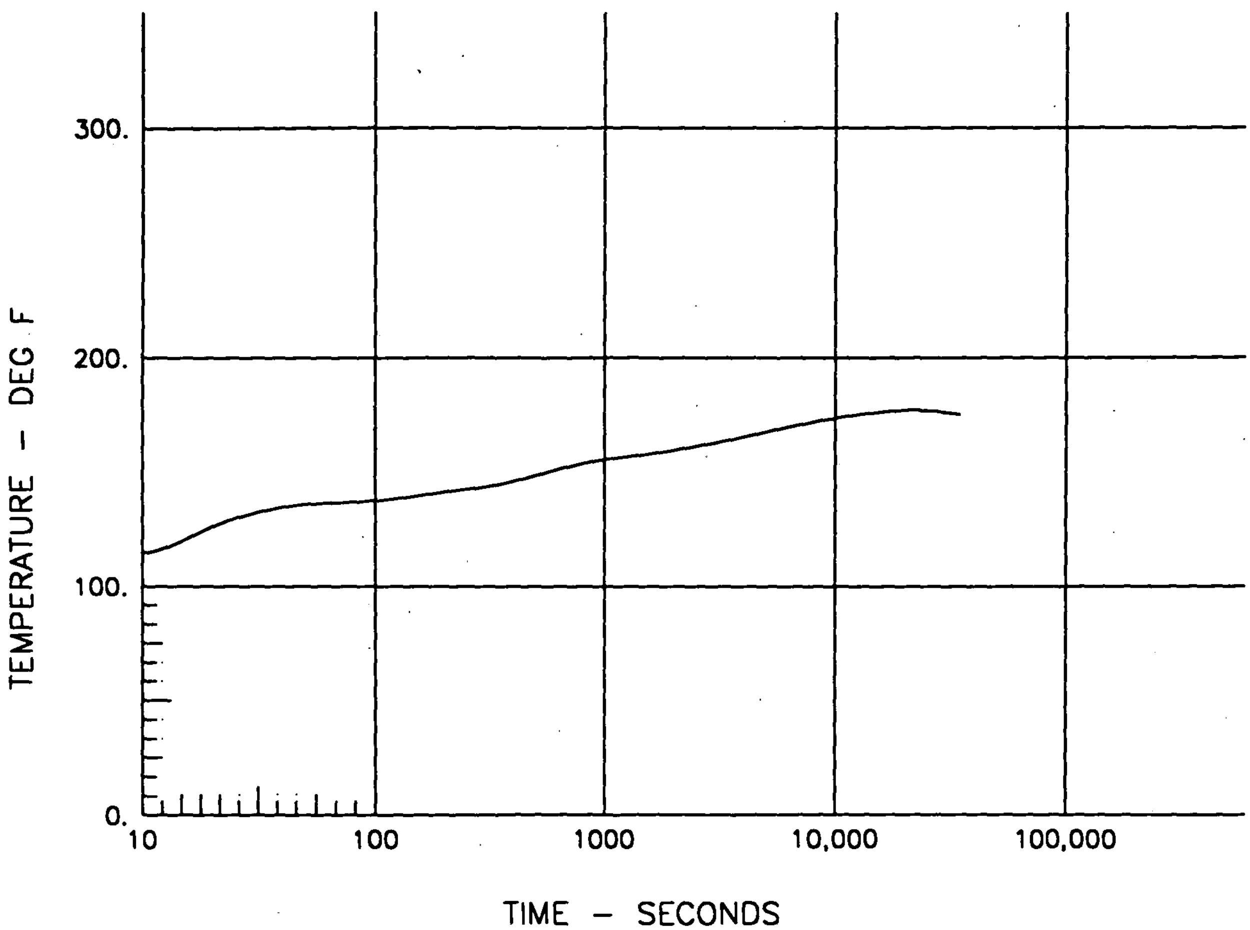
DRESDEN STATION
UNITS 2 & 3

SHORT TERM SUPPRESSION POOL
TEMPERATURE RESPONSE
CASE 6A2 - (60%) MIXING EFFICIENCY

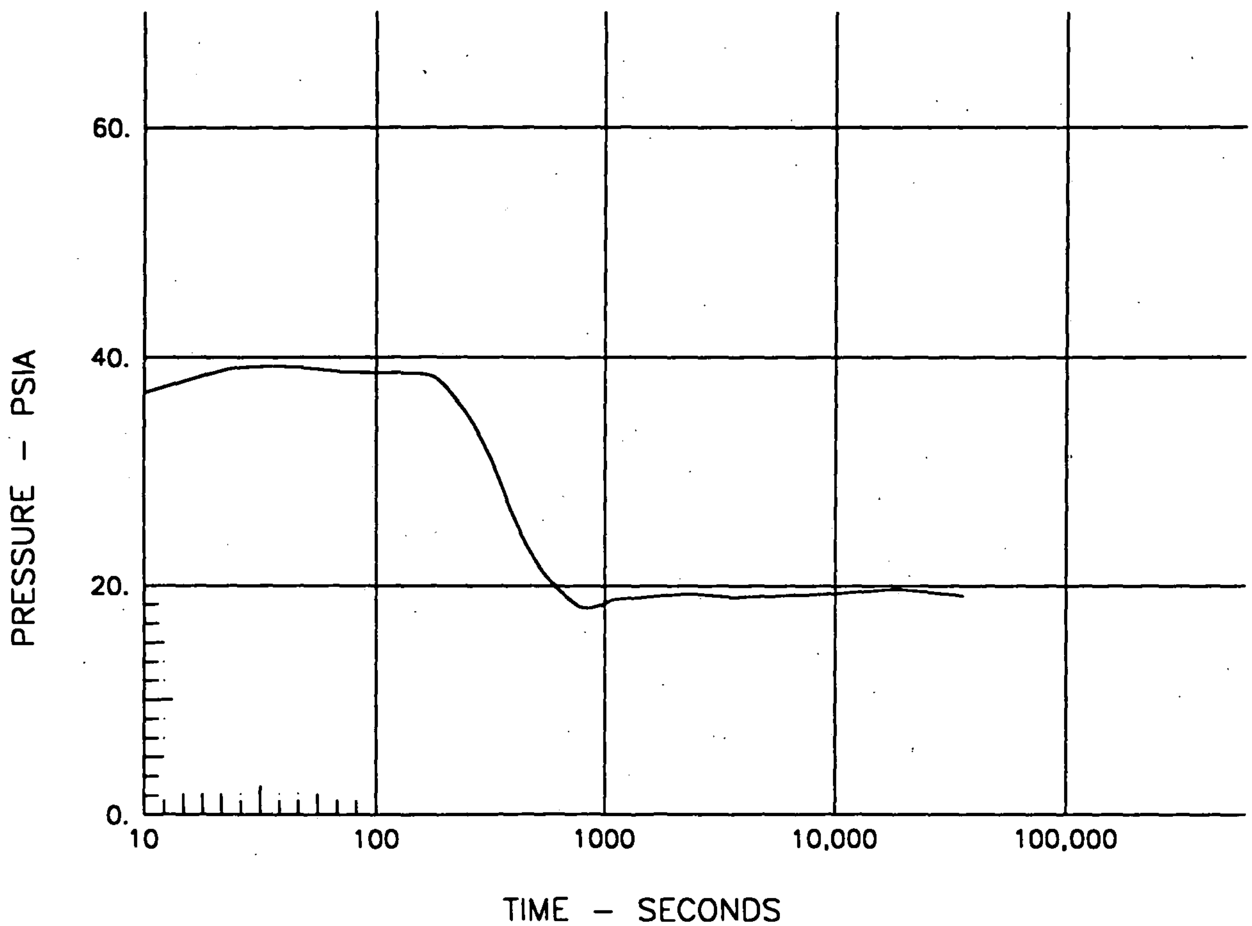
FIGURE 6.2-19A



UFSAR REVISION 2, JUNE 1997
DRESDEN STATION UNITS 2 & 3
SHORT TERM SUPPRESSION CHAMBER PRESSURE RESPONSE CASE 6A2 - (60%) MIXING EFFICIENCY
FIGURE 6.2-19B



UFSAR REVISION 2, JUNE 1997
DRESDEN STATION UNITS 2 & 3
LONG TERM SUPPRESSION POOL TEMPERATURE RESPONSE CASE 2A1-HIGH (100%) MIXING EFFICIENCY
FIGURE 6.2-20A

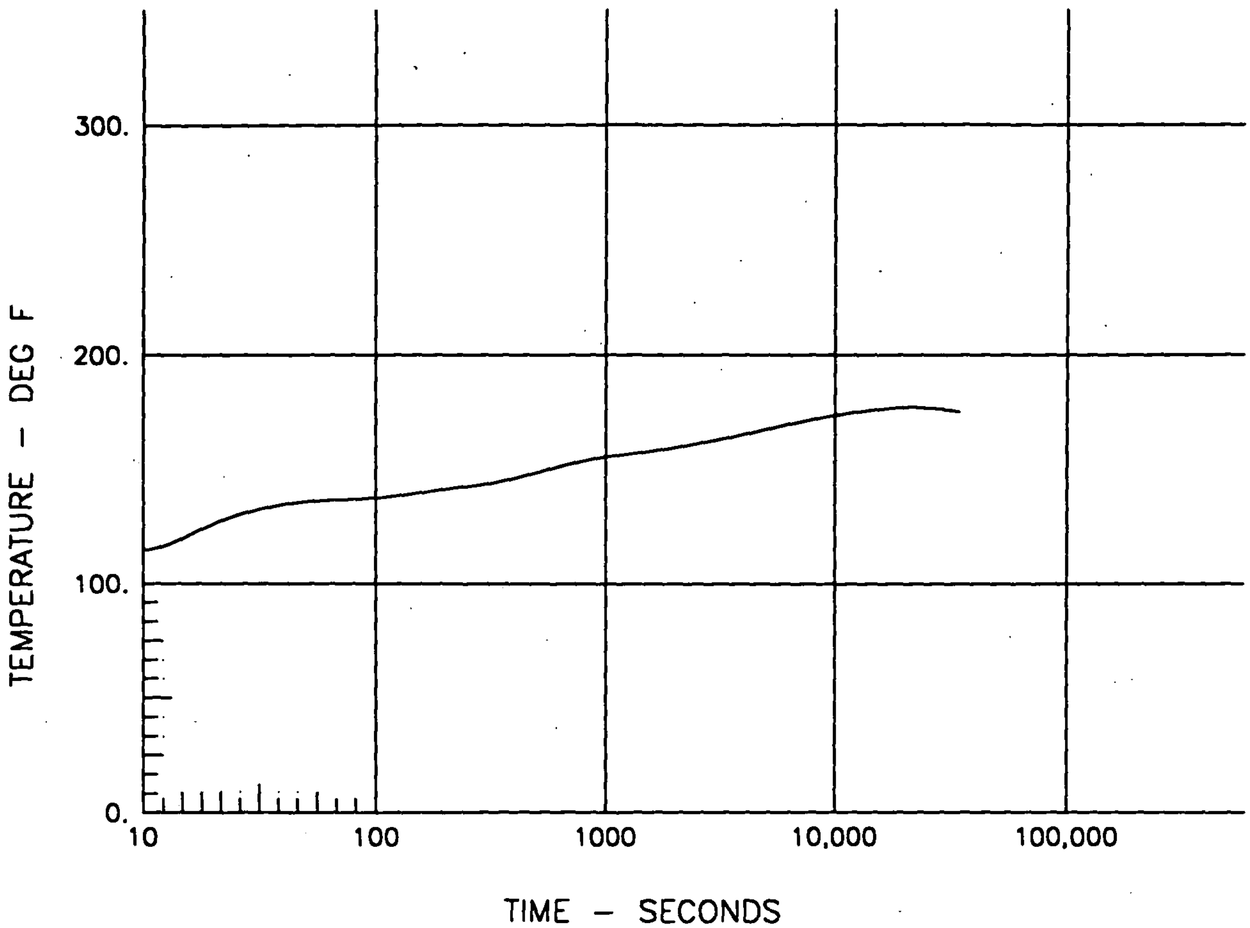


UFSAR REVISION 2, JUNE 1997

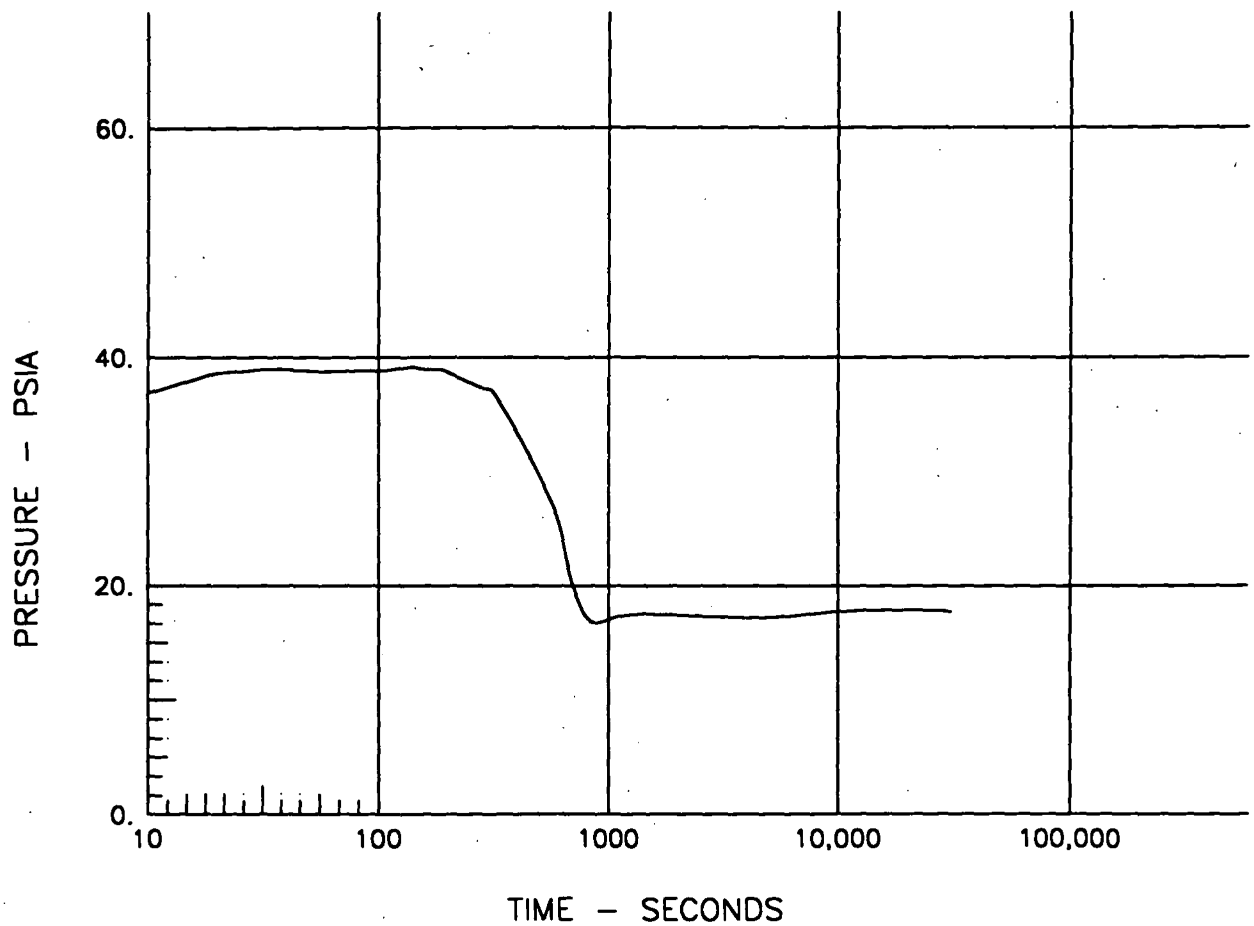
DRESDEN STATION
UNITS 2 & 3

LONG TERM SUPPRESSION CHAMBER
PRESSURE RESPONSE
CASE 2A1-HIGH (100%) MIXING EFFICIENCY

FIGURE 6.2-20B



UFSAR REVISION 2, JUNE 1997
DRESDEN STATION UNITS 2 & 3
LONG TERM SUPPRESSION POOL TEMPERATURE RESPONSE CASE 2A1-LOW (20%) MIXING EFFICIENCY
FIGURE 6.2-20C



UFSAR REVISION 2, JUNE 1997

DRESDEN STATION
UNITS 2 & 3

LONG TERM SUPPRESSION CHAMBER
PRESSURE RESPONSE
CASE 2A1-LOW (20%) MIXING EFFICIENCY

FIGURE 6.2-20D

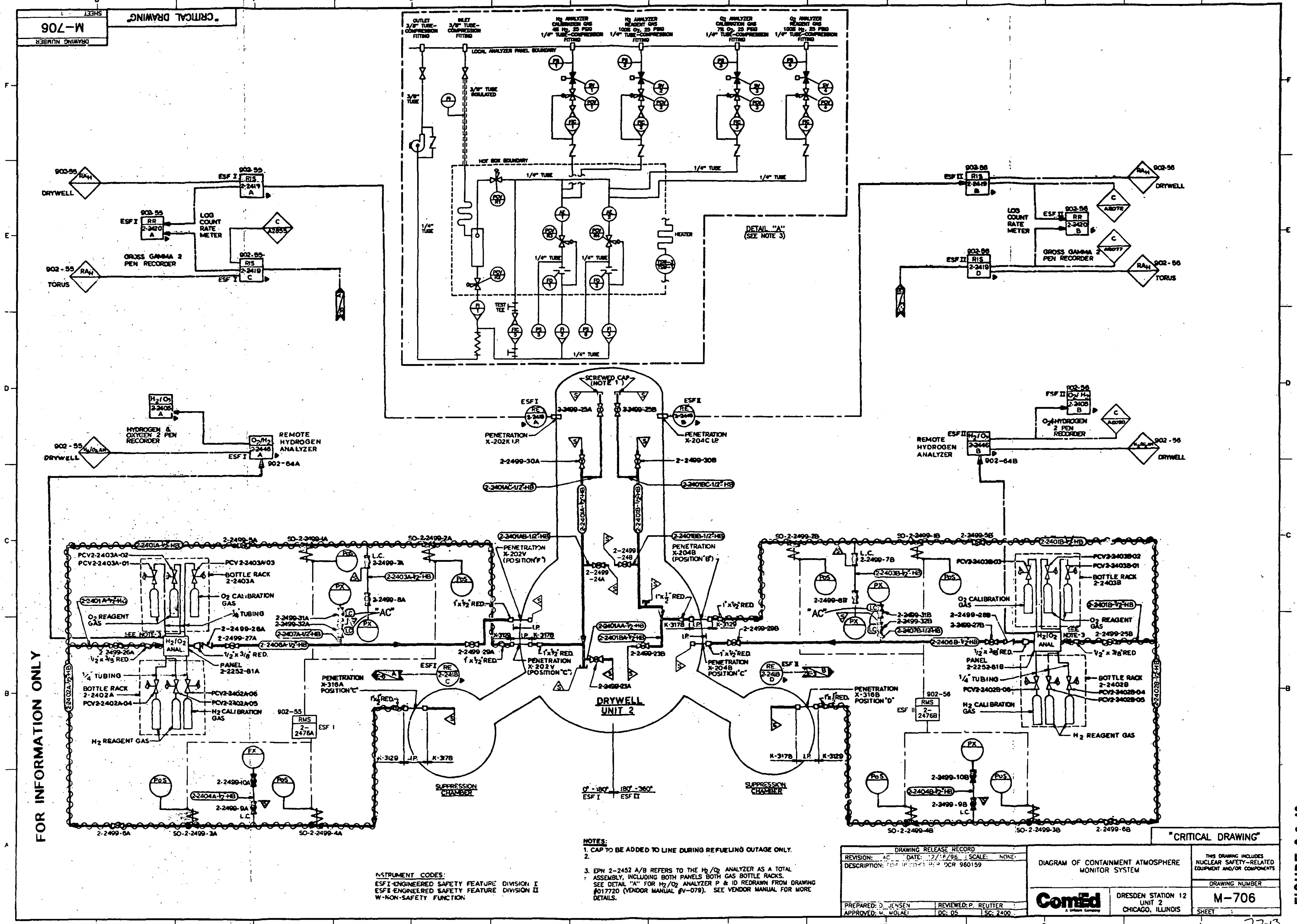
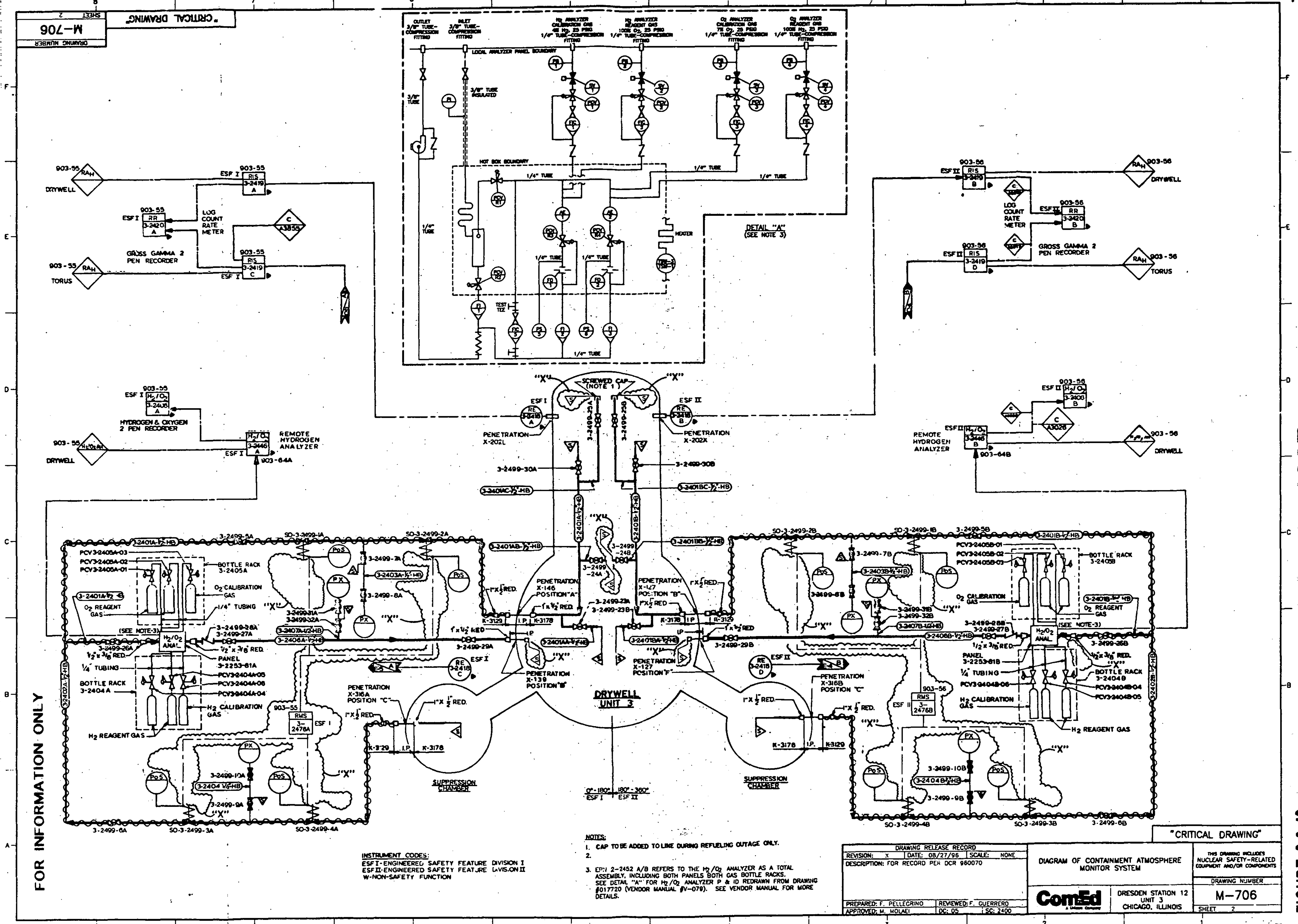


FIGURE 6.2-48

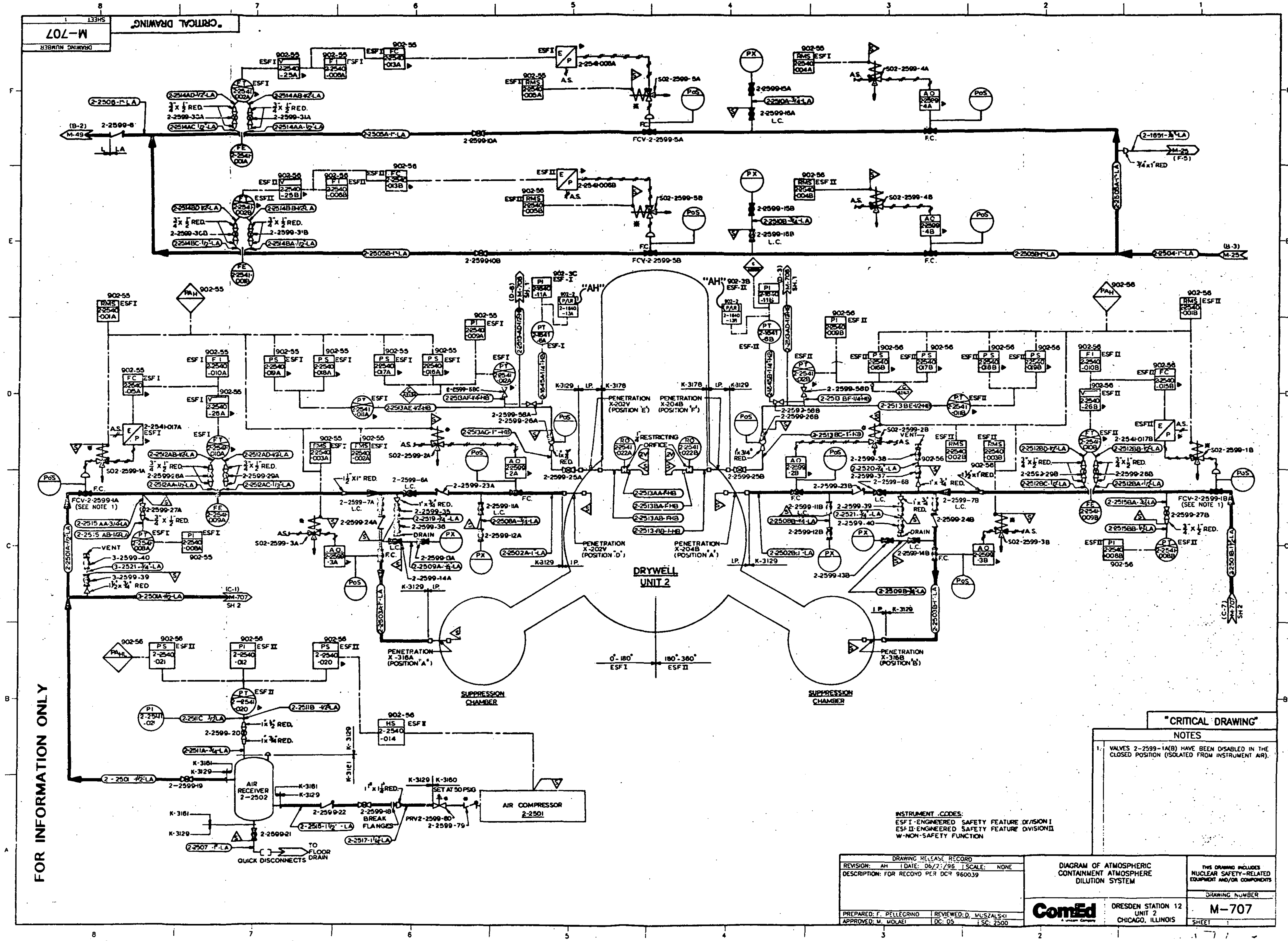
REV. 02 / JUNE 1997



CENTRAL DRAWING FACILITY 30X

REV. 02 / JUNE 1997

FIGURE 6.2-49



REV. 02 / JUNE 1997

FIGURE 6.2-50

CENTRAL DRAWING FACILITY 30 X

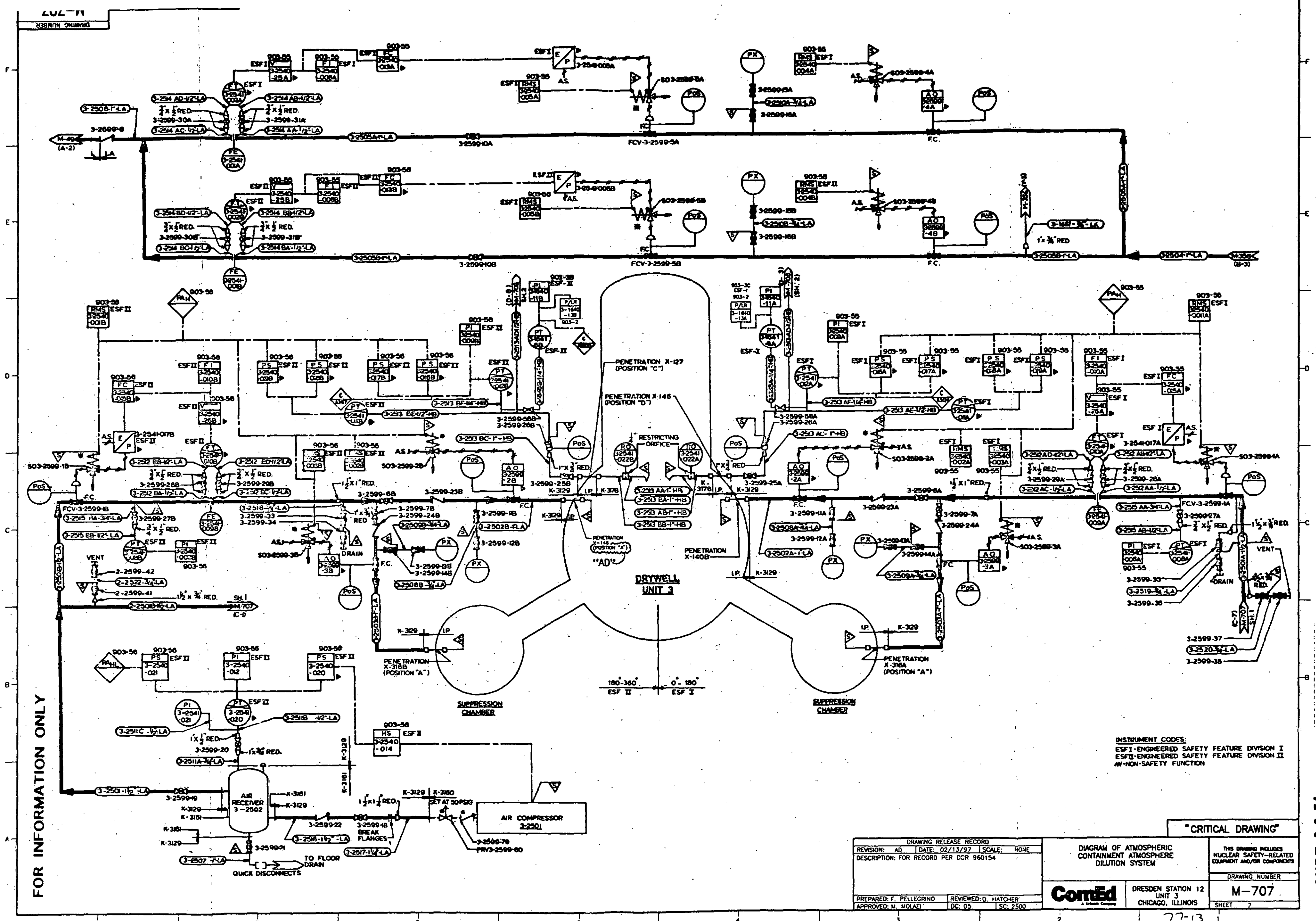


FIGURE 6.2-51

REV. 02 / JUNE 1997

CENTRAL DRAWING FACILITY

30 X

C. The LPCI subsystem is provided with redundancy in critical components to meet reliability requirements.

D. The LPCI subsystem operates without reliance upon external sources of power.

E. The LPCI subsystem is designed so that each component can be tested and inspected periodically to demonstrate availability of the subsystem.

In addition to its ECCS design bases, the LPCI subsystem also provides the capability to achieve cold shutdown — during the Systematic Evaluation Program (SEP) review of SEP topic VII-3, the NRC determined that General Design Criteria 19 and 34 require the capability of achieving cold shutdown from normal operating conditions using safety grade systems. The containment cooling service water (CCSW) system and pressure relief system are used in conjunction with the LPCI subsystem to provide this capability.

6.3.1.3 High Pressure Coolant Injection Subsystem

The following design basis was adopted for the HPCI subsystem and served as the basis for evaluating the adequacy of the system:

A. The HPCI subsystem is provided to ensure adequate core cooling for all break sizes smaller than those sizes for which the low pressure core cooling subsystems can adequately protect the core without assistance from other safeguards systems.

B. The HPCI subsystem shall meet the above design basis requirement without reliance on an external power source. Thus, condenser hotwell inventory is considered unavailable.

C. The HPCI subsystem is designed so that each component of the subsystem can be periodically tested.

6.3.1.4 Automatic Depressurization Subsystem

The automatic depressurization subsystem is provided as a backup to the HPCI subsystem and performs the function of vessel depressurization for all small breaks thereby enabling the low pressure core cooling subsystems to provide adequate core cooling. Applicable design bases are the same as for the HPCI subsystem (refer to Section 6.3.1.3). The ADS is provided with power from two separate divisional dc power supplies.

6.3.2 System Design

The following sections discuss the design of the ECCS subsystems.

6.3.2.1 Core Spray Subsystem

6.3.2.1.1 Core Spray Subsystem Interface with Other Emergency Core Cooling Subsystems

Each core spray subsystem is designed to operate in conjunction with the LPCI subsystem and either the ADS or HPCI subsystems to provide adequate core cooling over the entire spectrum of liquid or steam pipe break sizes. Thus, the ADS size and core spray subsystem head and flow requirements are related.

For small breaks without either feedwater or HPCI availability, the core would uncover while reactor pressure remains above the core spray pump shutoff head. Hence, ADS is actuated to reduce reactor pressure to permit core spray and LPCI to reach rated flow in time to ensure adequate core cooling. Two core spray subsystems or one core spray subsystem and two LPCI pumps, with the assistance of the ADS, provide adequate cooling for all break sizes.

If feedwater or HPCI is available, the necessary depressurization occurs through the addition of cold feedwater to the vessel. Hence, in combination with feedwater or HPCI, two core spray subsystems or one core spray subsystem and two LPCI pumps provide adequate core cooling for all break sizes.

The core spray flow requirement was established by heat transfer and flow distribution tests on simulated prototype fuel assemblies. These tests are described in detail in References 1 and 2. The head requirements of the core spray subsystem were determined by a series of analyses of the core spray subsystem in conjunction with either the ADS or HPCI subsystem over the small break size spectrum, since small breaks depressurize the reactor at the slowest rates and, therefore, require the largest core spray head. The size of the ADS or HPCI subsystem plays an important role here also, particularly for the small breaks for which core spray subsystem requires depressurization assistance. As ADS or HPCI capacity is increased, core spray head requirements decrease since the larger the capacity, the faster the vessel will depressurize.

The determination of the flowrate was based on refined prototype testing of a full scale fuel assembly under actual power and spray distribution conditions. To ensure that the test situations resulted in a limiting case, the test fuel rods were allowed to overheat (1600°F) prior to core spray activation, and the channel boxes were allowed to stay at high temperature. The core spray subsystems were sized to provide the minimum required flowrate to each assembly in the core. Flow distribution in the upper plenum and leakage flow available to fuel rods were also taken into account in establishing the core spray flow requirements.

6.3.2.1.2 Subsystem Characteristics

Each of the two independent core spray loops consists of a pump, valves, piping, and an independent circular sparger ring inside the core shroud just above the core. The normal water source for the pump suction is the suppression pool. Condensate storage tank water is used for initial flushing and for system testing when using suppression pool water is either undesirable or not feasible. The core spray

6.3.2.1.3.2 Piping

Core spray piping internal to the reactor which connects each spray sparger to its reactor pressure vessel penetration is designed and routed to meet the necessary flexibility requirements for thermal expansion and also to accommodate postulated vessel movement even though such movement is not considered credible.

The core spray nozzle arrangement consists of sixty-five 1HH12 full jet nozzles and sixty-five 1-inch open elbows. The spray outlets are equally spaced with the full jets and open elbows alternating around the sparger. The core spray sparger ring is actually two 180° sections with flow entering each section 15° from the midpoint. Uniform distribution of flow around the sparger was obtained by the use of orifices placed in the entrance of the spray branches around the sparger. The effect of inclination angle is shown in Figure 6.3-5 for the open elbows of the lower header. Variation of the full jet inclination angle has even less effect and is not shown. The effect of azimuth setting is shown in Figure 6.3-6. The design value for azimuth for all nozzles is 0°. As a result of these sensitivity tests, an allowable tolerance of ±1° has been set for all angle settings.

Concern over possible oxygen accumulation in the core spray piping and nozzles was addressed by making an opening at the top of the core spray line divider end plate. The opening is sized to provide a flow in the line of approximately 5 gal/min with the normal pressure differential between the shroud head and the region outside the core spray lines.

Design of the piping system external to the reactor vessel reflects considerations for potential damage to the piping. The piping runs of each subsystem are physically separated and located to take maximum advantage of protection afforded by structural beams and columns. A sketch of pipe protection provisions is shown on Figure 6.3-3. Drywell penetrations for the core spray pipes are located to achieve minimum length pipe runs within the drywell and to provide maximum circumferential distance between main steam and feedwater lines.

6.3.2.1.3.3 Instrumentation

Leaks in the core spray lines in the annulus region between the vessel wall and the core shroud are detected by continuous monitoring of the pressure differential between the core spray header and a point in the fuel bundle bypass leakage path above the core plate. During normal reactor operation, the pressure differential is the static head of water in the leakage path between the core plate and the core upper plenum. This pressure differential is monitored continuously, and a rise in the reading of approximately 0.5 psid alarms in the control room. This provides leak detection coverage for core flows from 33% to full core flow. Thus, a leak in the core spray line of approximately 6 gal/min during normal reactor operation would initiate the alarm. Such a leak would not significantly affect core spray cooling capability were it to be activated. The operator can isolate the faulty core spray loop until the reactor can be normally shut down. The leakages evaluated for Units 2 and 3 are shown in Table 6.3-19

Other local instrumentation provided for monitoring core spray subsystem operation include core spray pump suction pressure, core spray pump discharge pressure, and core spray loop flow (% rated flow).

C. Time required for reactor pressure to decay below the pump discharge pressure, plus a 3-second allowance for the injection valves to allow measurable flow;

D. Eighteen seconds for injection valves to reach full opening after opening signal is received. Reference latest "Dresden Units 2 and 3 Principal LOCA Analysis Parameters" for maximum valve opening time.

6.3.2.1.4.2 Operating Sequence with Diesel Generator

Upon receipt of an initiation signal coincident with a loss of normal ac power, the following sequence occurs:

A. Diesel generators start (see Table 6.3-4 and Section 8.3.1.5.3 for the ECCS loading sequence)

B. Permissive available to activate pumps and valves of both subsystems;

C. Pump suction valves open (if closed) in both subsystems;

D. Test bypass valves close (if open) in both subsystems;

E. Ten seconds after power is available on the respective bus, both core spray subsystem pumps receive start permissives.

Separate timers are used to start each core spray subsystem to improve system reliability.

The injection valves in both core spray loops will remain closed until the reactor pressure decays to approximately the design discharge pressure of the pumps, at which time the valves will open to admit flow into the reactor vessel. The pumps are operated on minimum flow bypass which discharges back to the suppression pool during the period they are running with the injection valves closed.

6.3.2.2 Low Pressure Coolant Injection Subsystem

The LPCI subsystem includes the equipment for coolant injection and containment cooling. Refer to Section 6.2.2 for a description of the containment cooling subsystem. Refer also to Section 9.2.1 for a description of the containment cooling service water pumps. The LPCI subsystem is further subdivided into two functional loops. The LPCI subsystem equipment includes two heat exchangers, four containment cooling service water pumps, four LPCI pumps, two drywell spray headers, and a suppression chamber spray header. The LPCI subsystem is shown in Figures 6.3-7A and 6.3-7B (Drawings M-29, Sheet 1 and M-360, Sheet 1).

6.3.2.2.1 Low Pressure Coolant Injection Subsystem Interface with Other ECCS Subsystems

The LPCI subsystem operates in conjunction with the HPCI and core spray subsystems to achieve its core cooling function. During a loss-of-coolant accident, coolant is lost from the core with a corresponding decrease in reactor vessel pressure. The HPCI subsystem operates initially during the high-pressure phase of the accident to supply a small amount of coolant at high pressure.

As the pressure in the reactor vessel decreases, the HPCI subsystem flow ceases and the core spray and LPCI subsystems automatically begin operation to take over the core cooling function. When the pressure in the reactor vessel equals the pressure in the suppression chamber, the LPCI subsystem is capable of delivering maximum capacity. LPCI delivers rated flow with reactor pressure equal to 20 psid (differential pressure between the reactor vessel dome and the drywell). After the core has been flooded to two-thirds height, only one LPCI pump is required to maintain this level.

6.3.2.2.2 Subsystem Characteristics

The LPCI subsystem is required to inject sufficient makeup water to reflood the vessel to the appropriate core height to provide adequate core cooling and is later required to maintain the level at two-thirds core height. Although redundancy is provided in that only three of the four LPCI pumps are required to deliver full capacity LPCI flow, the DBA LOCA analyses take credit for a maximum of two operable LPCI pumps. These analyses also require operation of at least one core spray subsystem to ensure adequate core cooling. The pump head characteristic was selected such that sufficient but less than rated flow is provided before the HPCI turbine is tripped by low vessel pressure. This approach provides core cooling over the complete spectrum of breaks up to the design basis break. The specifications for these pumps are shown in Table 6.3-5 and the performance curve for the LPCI subsystem is shown in Figure 6.3-8.

The two LPCI pumps for each LPCI subsystem are located on the basement floor in shielded rooms in each of two corners of the reactor building. Each LPCI pump room has the necessary piping and instrumentation to perform in any LPCI or containment cooling mode of operation (refer to Section 6.2.2 for a description of containment cooling functions by the LPCI subsystem). A crosstie header between the otherwise separate subsystems makes it possible for the LPCI pumps in one room to deliver their flow through the second loop's piping. This crosstie is located in a well-protected basement floor area and has two normally keylocked open, motor-operated valves. The valves may be closed from the control room if loop isolation is necessary. Separation of the piping provides protection against missiles in the vicinity of the reactor in that only one of the two flow paths must be assumed to be incapacitated by missiles. Missile protection shielding is provided by routing piping along the reactor building structure walls as much as possible.

Each of the two LPCI pump rooms contains its own room cooler and associated fan. Cooling water is normally provided by the service water system as described in Section 9.2.

The LPCI room cooler fan motors are seismically supported from rod hangers in a pendulum fashion from the ceiling of the reactor building at elevation 517'-6".

The LPCI subsystem is protected from plugging (due to the presence of foreign material which may find its way into the suppression chamber) by the use of multiple suction header connections with strainers. An evaluation of the strainers is provided in Section 6.2.2.

The LPCI pump motors are cooled by use of the LPCI pump discharge water which is routed through a 1-inch line to the pump motor oil coolers and returned to the suction side of the pump. The pump discharge water cools the oil that in turn lubricates and cools the motor. Hence, no external power source is required other than that used to power the pump motors.

During post-accident operation one or more of the LPCI pumps may be used for containment spray mode. The containment long-term response analysis for a DBA LOCA assumes that a minimum of 5000 gal/min is provided by LPCI to cool the containment (refer to Section 6.2.1.3.3). Additionally, to meet two-thirds core coverage requirements, continued post-LOCA ECCS flow is required to make up shroud leakage as described by Section 6.3.2.2.3.1. Therefore, post-DBA LOCA operation of the ECCS system must address both core coverage and containment spray requirements. The long term post-LOCA analysis employed the containment spray mode in order to yield the lowest containment pressure over the long term. Note that containment spray mode is not the preferred method of long term cooling, but was assumed in the analysis since it yields the lowest containment pressures and is therefore conservative in determining ECCS pump NPSH requirements.

After a period not exceeding 2 hours, the operator can manually stop one LPCI pump and start the two containment cooling service water pumps (460 bhp each) powered by the same diesel generator (assuming offsite power is not available). Operating procedures have the operator start the two CCSW pumps in less than this period of time. This pump sequencing serves to limit the load imposed on a diesel generator. Utilization of the LPCI subsystem in conjunction with containment cooling service water would achieve the containment cooling capability as specified in Section 6.2.1.3.3.

During LPCI subsystem operation, water is normally taken from the suppression pool and is pumped into the core region of the reactor vessel via one of the two recirculation loops. There is also a connection to the condensate storage tanks to make condensate available as a backup supply. In the event of a recirculation line break, instrumentation is provided to select the undamaged flow path for injection of the required LPCI flow into the reactor vessel. This instrumentation also causes appropriate valves to close which could otherwise result in spillage of the LPCI flow from the shroud region. The sensing circuit for break detection and loop selection is arranged so that failure of a single device or circuit to function on demand will not prevent correct selection of the loop for injection. All components of the loop selection network are operated from dc power sources so that loop selection can take place irrespective of the availability of ac power. LPCI loop selection logic and instrumentation is described in Section 7.3.

6.3.2.2.3 Equipment Characteristics

6.3.2.2.3.1 Low Pressure Coolant Injection Pumps

The LPCI pumps were sized on the basis of the flow requirements for the LPCI subsystem. These are the maximum subsystem flow requirements and were

The LPCI pump motors utilize normal auxiliary ac power when it is available and are also connected to the diesel generators to ensure availability in the event normal ac power is lost. Each pump has a 700 hp rating at a service factor of 1.0. The LPCI pump motors are rated at 700 hp each with a service factor of 1.0. All of a unit's four LPCI pumps will be used when operating in the accident mode. However, as discussed in Section 6.3.2.2.2, the DBA LOCA analysis takes credit for only two LPCI pumps. If normal power is not available, two pumps will receive power from the unit diesel generator and two from the 2/3 diesel generator.

6.3.2.2.3.2 Valves

Isolation valves are located on the LPCI subsystem piping since this system penetrates the primary system. There are two separate injection points in the primary recirculation loop for the LPCI subsystem flow, and since the core spray subsystem is concurrently placed in operation, no special valving redundancy is provided. The isolation valves provide protection against core uncoverage if the LPCI piping were to break. The isolation valves also serve to protect the LPCI subsystem against high reactor pressure in case of a component malfunction. The isolation valves are designed and constructed to achieve the highest possible reliability and to withstand maximum reactor vessel temperature and pressure. The speed and response of the LPCI injection valves and primary recirculation loop isolation valves are compatible with LPCI subsystem objectives.

The crosstie line between the two LPCI loops contains two motor-operated valves. Gate and check valves are located on the pump discharge lines, and flow control valves are provided on the lines where flow adjustment is necessary. Check valves located in the containment are equipped with operators to permit exercising and testing during normal plant operation.

When the HPCI system is operated, the suppression chamber water level rises. The normal level can be restored by opening LPCI subsystem valves (two control-room-operated automatic isolation valves) and discharging water to the condenser hotwell or to the floor drain collection tank.

Gate and butterfly valves are located where necessary to permit maintenance on the system. These are normally locked open.

6.3.2.2.3.3 Piping and Fittings

Two independent pipe lines are each sized for full LPCI subsystem flow, thereby providing redundancy in flow paths for LPCI operation. These lines are physically separated and protected as much as practical.

The piping is carbon steel, except for the stainless steel piping from the isolation valves to the reactor system. All LPCI subsystem components are designed in accordance with applicable codes for reactor auxiliary systems.

Leaks in the LPCI injection lines inside the drywell would be identified by the LPCI break detection logic as a loss-of-coolant accident if the LPCI line leak were between the LPCI injection line check valve and the recirculation loop. Leaks greater than 2500 gal/min at rated pressure would cause a noticeable pressure differential to develop across the recirculation line riser pipes. Leaks up to this size can be handled by LPCI without violating core cooling criteria regardless of which loop LPCI injection occurs in. Larger leaks are large enough to allow the logic to determine in which loop the leak exists. For leaks smaller than those described above, the drywell sump pump method is capable of detecting leakage of only a few gallons per minute. Such unidentified leakage in excess of 5 gal/min would result in plant shutdown within 24 hours to determine the cause of the leak. However, for leaks of up to about 2500 gal/min, the LPCI subsystem is effective.

Because the low pressure ECCS piping outside the drywell up to the first outside isolation valve is considered an extension of the primary containment, the LPCI subsystem piping must meet the same design, surveillance, and testing criteria as the primary containment. Rupture of this low pressure piping is, therefore, extremely unlikely. The location and identification of such leaks would be through room temperature alarms, reactor building floor drain sump activity, and visual inspection (since these lines are accessible).

All leakage in the ECCS outside the primary containment can be isolated from the suppression chamber and the primary system itself.

The discharge piping of the LPCI subsystem is required to be filled and vented in order for the subsystem to be considered operable. The vent pathway for LPCI is through vent valves and a sight glass to the reactor building equipment drain tank. The fill system is used to ensure that the LPCI discharge lines remain pressurized. This fill system consists of a core spray jockey pump described in Section 6.3.2.1.2. If the jockey pump is removed from service for maintenance, the condensate transfer system can be used as an alternate fill system.

6.3.2.2.3.4 Instrumentation

The LPCI subsystem is initiated on any of the following signals as discussed in Section 7.3:

A. High drywell pressure;

B. Low-low reactor water level coincident with low reactor pressure; or

C. Low-low reactor water level coincident with timeout of the ADS high drywell pressure bypass timer.

Logic is provided to ensure the LPCI flow is injected into the unbroken recirculation loop. A detailed description of LPCI subsystem loop selection instrumentation, logic, and minimum flow valve operation is provided in Section 7.3.

Interlocks are provided to prevent LPCI flow from being diverted to the containment cooling subsystem piping unless the core is flooded to at least two-thirds of its height. Sections 6.2.2 and 7.4 provide a more detailed description of containment cooling interlocks.

Instrumentation provided for monitoring LPCI subsystem operation includes LPCI pump suction and discharge pressure, LPCI flow to recirculation loop pressure, LPCI minimum flow (% rated flow), and LPCI loop select logic jet pump riser differential pressure.

6.3.2.2.4 LPCI Operating Sequence

6.3.2.2.4.1 LPCI Operating Sequence with Plant on Normal Auxiliary AC Power

Upon receipt of an initiation signal with normal ac power available, the following sequence automatically occurs:

A. Diesel generators start;

B. Permissive available to activate pumps and valve;

C. All four LPCI pumps start without delay;

D. Pump suction valves open (if closed). The pump suction valve opening signal can be overridden such that the valves can be closed if necessary to isolate a leak; and

E. Containment cooling service water pumps stop (if running).

When the reactor primary system pressure drops to the shutoff head of the LPCI pumps, a check valve in the LPCI injection line opens. Prior to this time, the LPCI control system would have sensed the loop in which the break has occurred, closed the recirculation line pump discharge valve in the unbroken loop, and opened the LPCI injection valve to the unbroken recirculation line.

6.3.2.2.4.2 LPCI Operating Sequence with Diesel Generator

Upon receipt of an initiation signal coincident with a loss of normal ac power, the following sequence occurs:

A. Diesel generators start;

B. Permissive available to activate pumps and valves;

C. Pump suction valves open (if closed);

D. After the diesel generators restore power to their respective buses, LPCI pumps A and C receive a start signal;

E. Five seconds after the diesel generators restore power to their respective buses, LPCI pumps B and D receive a start signal. (See Table 6.3-4.)

LPCI flow to the vessel is established as previously described in Section 6.3.2.2.4.1.

6.3.2.3 High Pressure Coolant Injection Subsystem

The HPCI subsystem is designed to pump water into the reactor vessel under those LOCA conditions which do not result in rapid depressurization of the reactor pressure vessel. The loss-of-coolant might be due to a loss of reactor feedwater or to a small line break which does not cause immediate depressurization of the reactor vessel.

The HPCI subsystem includes a steam turbine driving a two-stage high pressure pump and a gear-driven, single-stage booster pump, valves, high pressure piping, water sources, and instrumentation. The HPCI subsystem is shown in Figures 6.3-9A and 6.3-9B (Drawings M-51 and M-374). The HPCI equipment specifications are shown in Table 6.3-7.

The subsystem piping was designed to USAS B31.1 and ASME Section I. The pumps were designed to ASME Section VIII. The piping arrangement includes considerations for potential damage, and open piping runs are protected by structural steel. Fabrication, testing, and inspection of this piping was equal to that required for the primary containment system.

Operation of the HPCI system in the emergency mode is completely independent of ac power with the exception of the HPCI room cooler fans, and requires only dc power from the station battery to operate the controls.

Operation of the HPCI subsystem is dependent upon reactor water level signals (Figures 7.3-8A, 8B, and 8C). Either low-low water level or high drywell pressure starts the subsystem and high water level stops it.

6.3.2.3.1 High Pressure Coolant Injection Interface with Other Emergency Core Cooling Subsystems

The sizing of the HPCI subsystem is based upon providing adequate core cooling during the time that the pressure in the reactor vessel decreases to a value where the core spray subsystem and/or the LPCI subsystem become effective.

6.3.2.3.2 Subsystem Characteristics

Suction for the HPCI pump is normally taken from a condensate storage tank, where 90,000 gallons of water are reserved for HPCI. On low-low level in the condensate storage tank or high level in the torus, the HPCI suction will automatically switch to the suppression pool.

The discharge piping of the HPCI subsystem is required to be filled and vented for the subsystem to be considered operable. With HPCI suction aligned to a condensate storage tank (CST), keep fill is provided by the head of the CST. If HPCI suction is aligned to the torus, ECCS keep fill must be aligned to the HPCI discharge line.

The water from either source is pumped into the reactor vessel through the feedwater sparger to obtain mixing with the hot water in the reactor pressure vessel. Water leaving the vessel through a line break drains by gravity to the suppression pool. The LPCI subsystem in conjunction with the containment cooling service water system is required for cooling of the suppression pool after several hours of HPCI subsystem operation.

The HPCI subsystem is designed to pump 5600 gal/min into the reactor vessel within a reactor pressure range of about 1135 psia to 165 psia. However, the HPCI flow assumed in the LOCA analysis is 5000 gal/min. The turbine is driven with steam from the reactor vessel. As reactor pressure decreases, the control valves throttle to pass the required steam flow to maintain the set pump flowrate. Turbine speed is controlled by the motor speed changer (MSC) and the motor gear unit (MGU) described in Section 7.3.1.3.2.

The HPCI flowrate is measured in the pump discharge line. A conventional flow controller compares this measured flowrate with a preset flow requirement of 5600 gal/min. The output of the flow controller will vary from 4 to 20 milliamps, depending on where (i.e., at what speed) the flow demand is satisfied. The controller output is fed to the turbine control (MGU) logic for turbine-pump speed control and, therefore, ultimate flow control.

The controlling design condition for the turbine steam path is the low pressure operation point, i.e., developing the required horsepower (1000 hp at 2250 rpm) with 155 psia inlet steam pressure and 65 psia exhaust pressure. This operating condition (maximum volume flow) dictates the required turbine stage areas. All other operating conditions require less volume flow and, therefore, result in throttling the turbine control valves. This control function is no different than that encountered in boiler feed pump drive systems.

Exhaust steam from the unit is discharged to the suppression pool. The turbine exhaust line is provided with a vacuum breaker system. The vacuum breakers were added to improve turbine low-load operation, to minimize pressure fluctuations, and to prevent suppression pool water rise in the exhaust line which would result in unacceptable back pressure during the turbine startup transient.

The turbine gland seals are vented to the gland seal condenser, and water from the HPCI booster pump discharge is routed through the gland seal condenser for cooling purposes. Noncondensible gases from the gland seal condenser are ducted to the standby gas treatment system.

Moisture removal systems are provided both in the steam supply line near the turbine, in the turbine exhaust line, and in the turbine casing. The systems use conventional equipment consisting of collection drain pots and steam traps.

Moisture removal from the HPCI turbine steam supply eliminates water slug buildup, thereby permitting rapid start of the unit without warmup. The steam supply line up to the steam shutoff valve located directly upstream of the turbine stop valve is maintained at reactor pressure and temperature. A water collection pot is located upstream of the steam shutoff valve and is drained through a choke trap to the main condenser during normal plant operation. Upon receipt of a HPCI initiation signal, the condensate drain to the main condenser is automatically isolated and diverted to the suppression pool.

Provisions have been made to provide protection against possible failure of the choke trap. An automatic bypass is provided around the trap, actuated by a level sensing switch in the drain pot. Should the choke trap fail to pass water, condensate will collect in the drain pot. The level switch will automatically open the steam bypass valve prior to the condensate level reaching the bottom of the steam line.

A conventional drain collection pot is used to drain the turbine exhaust line, turbine casing drains and moisture collecting downstream of the stop valve. This pot is normally drained to the suppression pool. An automatic level controlled bypass provides gravity draining to the gland seal condenser.

Steam line valve closure logic, as described in Section 7.3, is provided to initiate isolation of the HPCI steam line should abnormally high steam line flow, low steam line pressure, or high HPCI area temperature conditions be experienced. The turbine is rated for a reactor vessel steam flow of 145,000 lb/hr 1135 psia and 102,500 lb/hr of steam at 165 psia.

The HPCI steam supply inboard containment isolation valve, 2(3)-2301-4, is provided with throttle open capability which allows a gradual pressure increase in the steam inlet line to the HPCI turbine. The valve control switch and relay provide a throttle open, seal-in on close, spring return to AUTO feature, with a PULL-TO-LOCK function 90° from center. The PULL-TO-LOCK function of the 2301-4 valve switch is capable of closing the valve during subsystem operation and defeating the automatic mode of the HPCI subsystem. The primary sensors to automatic initiation of HPCI (2 psig drywell high pressure and -59 inches reactor low-low water level) are not affected by this change.

The HPCI system can be tested for operability (see Section 6.3.4.3.3) by returning the pump discharge flow to the condensate storage tank (CST) via the safety related 250-Vdc-powered full flow test valve 2301-10. The test bypass valve (2301-10) is a high-pressure, multi-stage valve designed to avoid cavitation. To ensure non-coincident motor initiation of the test bypass valve with the HPCI injection valve (2301-8), an auxiliary relay is included in the full flow test valve circuitry. This limits the load on the safety related 250-Vdc battery system.

The lube oil for the HPCI pumps and turbine is cooled by water taken from the HPCI booster pump discharge line. The HPCI pump is turbine driven and, hence, no external power is needed for cooling water under accident conditions.

However, for preoperational warmup in the test mode using a controlled startup procedure rather than an emergency auto startup, the subsystem has a cooling water pump which can be used only when normal ac power is available.

A minimum flow bypass system returns a portion of the pump discharge flow back to the suppression chamber for pump protection. The bypass valve is automatically opened on low pump flow and closed on high flow whenever the steam supply valve to the turbine is open.

The HPCI pump suction valves are interlocked to prevent opening the valve from the condensate storage tank whenever both valves from the suppression chamber are fully open. The test return valves to the condensate storage tank are also interlocked closed when either suction valve from the suppression chamber is not fully closed.

Instrumentation provided for monitoring HPCI operation includes main pump discharge temperature, turbine oil temperature, booster pump suction pressure, main pump discharge pressure, turbine inlet and outlet pressure, gland seal pump discharge pressure, turbine lube oil and hydraulic oil pressures, steam supply pressure, HPCI flow (% rated water flow), and HPCI steam line flow.

6.3.2.3.3 High Pressure Coolant Injection Operational Sequence

6.3.2.3.3.1 High Pressure Coolant Injection Automatic Initiation

Initiation of the high pressure coolant injection subsystem occurs on signals indicating reactor low-low water level or high drywell pressure. These signals and their associated logic are discussed in detail in Section 7.3.

Upon receipt of the initiation signal, the HPCI turbine and its required auxiliary equipment such as the auxiliary oil pump and gland seal leakoff blower, automatically start. The automatic HPCI turbine trip due to low booster pump suction pressure is bypassed if an initiation signal is present. In addition, the following valves assume or maintain the following positions:

A. Steam supply line containment isolation valves open, if closed (these are normally open valves);

B. Turbine steam supply and stop valves open;

C. Pump suction valve from the condensate storage tank opens if closed (normally open);

D. Pump discharge valves open (one valve is normally open);

E. Cooling water return valve to the HPCI booster pump suction opens;

F. Steam line drain valves to the main condenser close and the steam line drain valve to the suppression chamber opens;

G. Turbine stop valve drain valves close;

H. Cooling water return valve to condensate storage tank closes; and

I. Test return valves to condensate storage tank close (if open). Note: the 2301-10 test bypass valve closing logic includes an interposing relay which delays the closing of the valve by approximately 40 milliseconds to limit loading on the battery system.

6.3.2.3.3.2 High Pressure Coolant Injection Automatic Isolation and Shutdown

Shutdown of the HPCI subsystem may occur in either of two ways: isolation of the steam supply to the turbine or tripping the turbine stop valve closed. It should be noted that with the turbine stop valve leaving the full open position, the turbine control valves close automatically. A description of the HPCI subsystem shutdown signals and logic is provided in Section 7.3.

The steam supply isolation will occur upon receipt of a high steam line flow, high area temperature, or low steam line pressure. Turbine stop valve closure will occur upon receipt of a turbine overspeed trip, low booster pump suction pressure, high turbine exhaust pressure, or reactor vessel high water level.

A steam leak from the HPCI line, outside the primary containment, in the HPCI room would result in high room temperature which would then result in HPCI isolation and an alarm in the control room. A steam leak of sufficient magnitude would result in a high HPCI steam flow isolation and annunciation. If HPCI does not automatically isolate due to high steam flow then, upon detection of the leak, the operator may close the HPCI steam line isolation valves to terminate the leak.

Leakage from the HPCI subsystem discharge line which leads to the feedwater line would be condensate storage tank water and, as such, the leakage does not constitute a hazard.

Since the ADS provides a backup to the HPCI subsystem and would automatically be actuated if HPCI could not maintain core cooling, a complete loss of HPCI flow could be tolerated.

6.3.2.3.3.3 High Pressure Coolant Injection — Continuous Operation

Operation of the HPCI turbine continues as long as reactor pressure is above 165 psia. Components are designed to maintain constant speed as the pressure is reduced. The HPCI subsystem automatically maintains reactor water level between low-low level and high level if the break size is within the capacity of the pump and the reactor is not depressurized below 165 psia.

6.3.2.3.3.4 High Pressure Coolant Injection — Termination of Operation

When the reactor pressure falls below 165 psia, the speed of the turbine-pump unit will begin to decrease and will gradually be slowed to a stop by friction and windage losses at a reactor pressure of about 65 psia; however, HPCI isolation will automatically occur on low reactor pressure of 100 psig. This isolation setpoint occurs at or above the pressure at which the turbine would stop due to friction and windage losses.

Core cooling at this time will be accomplished by the core spray subsystem and the LPCI subsystem. For a small break, core cooling will be maintained by the control rod drive pumps if ac power is available.

6.3.2.4 Automatic Depressurization System

6.3.2.4.1 Automatic Depressurization Subsystem Interface with Other Emergency Core Cooling Systems

The ADS is an ECCS subsystem which is employed as a backup to the HPCI subsystem to depressurize the reactor pressure vessel for small area breaks. The HPCI subsystem provides primary depressurization and core cooling for small breaks. In the event that HPCI is not effective, the ADS reduces pressure by blowdown through automatic opening of the relief valves to vent steam to the suppression pool. For small breaks the vessel is depressurized in sufficient time to allow core spray or LPCI to provide adequate core cooling. For large breaks the vessel depressurizes through the break without assistance. Pressure relief of the reactor vessel may be accomplished manually by the operator or without operator action by the ADS circuitry. Additional ADS logic information is provided in Section 7.3.

6.3.2.4.2 Subsystem Characteristics

The ADS is designed to automatically actuate to depressurize the reactor vessel if the following conditions A and B and C are met for 120 seconds or if conditions C and D are met:

A. Low-low reactor water level,

B. High drywell pressure,

C. At least one LPCI or one core spray pump with discharge pressure exceeding 100 psig.

D. Low-low reactor water level (continuous for 8.5 minutes), in conjunction with Condition C.

The 120-second ADS time delay prevents unnecessary blowdowns resulting from transient conditions and provides an opportunity for HPCI to restore reactor water level. The ADS timer logic is discussed in Section 7.3.

The time delay also provides surveillance time in which the operator can evaluate possible spurious activation signals. A permissive signal from the time delay circuit serves as the confirming signal to activate the relief valves when the control station switch is in the automatic position. The delay time setting before the ADS is actuated is chosen to be long enough so that the HPCI has time to start, yet not so long that the core spray and LPCI are unable to adequately cool the fuel if the HPCI fails to start. All of the five relief valves (four electromatic relief valves and one Target Rock safety/relief valve) normally open simultaneously; however, two of the electromatic relief valves are equipped with additional control logic and are subjected to an additional 10-second valve reopening delay to preclude immediate automatic reopening of valves that were previously opened. This delay will prevent excessive loading as a result of an elevated water leg in the relief valve discharge piping (see Section 5.2.2.2). An ADS inhibit switch is provided to prevent ADS actuation during an anticipated transient without scram (ATWS) event or whenever the emergency operating procedures require an ADS override. Manual blowdown of the reactor vessel is accomplished independently of the automatic circuitry.

Excessive vessel pressure is automatically relieved by circuitry which supplies a direct signal to the auxiliary relay to actuate the relief valves (Section 5.2 provides a description of the relief valves and associated reactor vessel high pressure relief controls). The vessel high pressure relief function is not performed by the ADS subsystem.

Based upon an ADS spurious actuation study which was initiated to meet the NRC's circuit failure mode interpretation of 10 CFR 50, Appendix R requirements, further separation of ADS cabling was mandated. The study revealed that certain combinations of short circuits would result in the spurious operations of the five relief valves. To reduce the probability of spurious actuation, the control cable of concern was replaced by two cables to provide separation such that multiple shorts within cables associated with ADS would not cause spurious operation of multiple valves.

6.3.3 Performance Evaluation

6.3.3.1 Emergency Core Cooling Subsystem Performance Evaluation

This section provides a performance evaluation of each ECCS subsystem followed by a description of the integrated performance of the ECCS.

6.3.3.1.1 Core Spray Subsystem

Each core spray subsystem is designed to maintain continuity of reactor core cooling for a large spectrum of loss-of-coolant accidents. Each subsystem provides adequate cooling for intermediate and large line break sizes; however, either two core spray subsystems or one core spray subsystem and two LPCI pumps are required to ensure adequate core cooling following a DBA LOCA. The integrated performance of a core spray subsystem in conjunction with other emergency core cooling subsystems is provided in Section 6.3.3.3.

As indicated previously, there exists a break size below which the core spray subsystem alone cannot protect the core (see Figure 6.3-1). Vessel pressure does not drop rapidly enough to allow sufficient core spray injection to occur before the fuel cladding reaches an excessively high temperature. Below this break size either HPCI or ADS extends the range of the core spray subsystem to breaks of insignificant magnitude.

The core spray heat transfer tests were completed and are reported in Reference 2. These tests covered fuel bundles having an initial power level of 6.5 MWt, well in excess of the peak bundle power for the units. The test fuel rods were allowed to overheat (1600°F) prior to core spray activation. Actual core spray operating temperatures of 2350°F were tested, well in excess of the maximum 2030°F

The maximum vessel pressure against which the LPCI pumps must deliver some flow is determined by the required overlap with HPCI which has a low pressure cutoff for the HPCI subsystem turbine at about 150 psig. The LPCI subsystem can pump about 8000 gal/min (about half of the maximum flowrate) at a differential pressure between the suppression pool and the reactor pressure vessel of 200 psid and, in conjunction with the HPCI subsystem, LPCI can provide adequate coverage for the intermediate and smaller breaks over the entire pressure range. The required LPCI pump head characteristic for a range of conditions is shown on Figure 6.3-8.

The performance analysis of the LPCI subsystem for a typical break size within the capability of the unassisted LPCI subsystem is shown in Figure 6.3-13. Note that this analysis is for a three LPCI pump operation even though all four LPCI pumps normally start in response to an initiation signal. The phenomena during the first phases of the transient before the LPCI subsystem becomes effective are seen in Figure 6.3-13 to be the same as for the core spray subsystem performance analysis discussed in Section 6.3.3.1.1. The analytical model is described in detail in Section 6.3.3.2.2.

Operation of the LPCI pumps, closure of the recirculation line pump discharge valve in the unbroken loop, and opening the check valve and LPCI injection valve to the unbroken recirculation line provides an integral flow path for the injection of the LPCI flow into the bottom plenum of the reactor vessel. As the LPCI flow accumulates, the level rises inside the shroud. When the level reaches the top of the jet pumps, spillover occurs for a time raising the level outside the shroud. As the subcooled LPCI flow begins spilling into the region outside the shroud, the depressurization effect of the break is reduced since the subcooled water is now flowing out the break.

As the pressure begins to rise, the LPCI flow is reduced until a quasi-equilibrium pressure is reached. At this point the break is partially covered by subcooled water which has spilled over the top of the jet pumps and the equivalent area of the break available for steam blowdown is thus reduced. The size of the break available for steam blowdown is maintained at the required equilibrium value by the LPCI spillage. If pressure were to rise, the LPCI flow would be reduced, the equivalent break size for steam blowdown would increase, and the pressure would drop. Complete equilibrium is reached when the rate of saturating the LPCI water becomes equal to the boiloff rate.

It is noted that this condition will not actually be attained due to the HPCI and ADS effects on the transient. Also, no credit is taken for the pressure reduction affect of the cold LPCI water in the reactor vessel.

There exists a break size below which the LPCI subsystem requires depressurization assistance to maintain core cooling. For these small breaks, the HPCI and ADS subsystems provide the necessary depressurization to allow LPCI to provide adequate core cooling.

During LPCI injection, the minimum flow valve in the non-selected loop will remain open to ensure a pump flow path. The valve remains open because the "A" loop flow sensor controls only the "A" loop valve, and similarly, the "B" loop sensor controls only the "B" loop valve. This logic permits one of the LPCI pump minimum flow bypass lines to remain open, during a LOCA. As a result, there is a reduction in LPCI flowrate to the core by an amount equivalent to the flowrate through the minimum flow line. The 10 CFR 50 Appendix K analysis assumes a two pump LPCI flowrate of 9000 gal/min for the DBA LOCA with a diesel generator failure. However, the peak clad temperature (PCT) of 2030°F for LPCI injection valve failure, which remains the limiting case, is well within the 2200°F 10 CFR 50.46 fuel clad temperature limit. Based on actual station test data obtained with the minimum flow valves open, the minimum LPCI flowrate assumed by the current accident analysis was verified.

6.3.3.1.3 High Pressure Coolant Injection Subsystem

The high pressure coolant injection subsystem has been evaluated to assure that the design bases are met. This evaluation considers the structural integrity of the HPCI subsystem to withstand the effects of an accident for which the subsystem must be available. The suitability of valves, pump and turbine sequencing, speed of operation, capacity, and the depressurization efficiency for HPCI flow were also evaluated.

6.3.3.1.3.1 High Pressure Coolant Injection Subsystem Availability

To inject water at a high pressure, three major active components must operate. A motor-operated valve must open to admit steam to the turbine driving the pump, a motor-operated valve must open to admit the discharge flow from the pump into the reactor feedwater line, and the turbine driven pump itself must operate. Section 6.3.2.3.3.1 identifies additional HPCI components required to ensure proper HPCI system operation.

The turbine driving the pump is designed especially for this type of service. It operates over a wide range of inlet and exhaust pressures and the construction is such that it can start cold and come to full power operation almost instantaneously. The HPCI turbine is essentially identical to numerous units in service as boiler feed pump drives. Steam pressure is available to drive this pump whenever high pressure injection is needed. The HPCI subsystem can be tested frequently so that any operating deficiencies can be detected early.

Operation of the HPCI subsystem is automatic and requires no manual intervention.

The HPCI subsystem and core spray subsystem in conjunction with the LPCI subsystem complement one another. The HPCI subsystem provides protection against small breaks and the core spray subsystem and the LPCI subsystem provide protection against large breaks and automatically take over from the high pressure injection subsystem when the steam pressure falls below the minimum level required to operate HPCI.

There are many actions the operator can take to prevent core damage for moderate size breaks. If normal sources of power are available, the operator can continue to operate the regular feedwater pumps to provide makeup. The operator can transfer water from the condensate system to the hotwell so that this type of cooling can be continued indefinitely. Whether or not normal sources of power are available, the operator can manually depressurize the vessel using the electromatic relief valves so that core spray and LPCI will provide adequate core cooling.

6.3.3.1.3.2 Evaluation of HPCI Subsystem Performance

The HPCI subsystem is designed to provide adequate reactor core cooling for small breaks and to depressurize the reactor primary system to enable cooling water injection by the LPCI and core spray subsystems. A detailed discussion of the performance of the HPCI subsystem in conjunction with the LPCI and core spray subsystems is given in Section 6.3.3.3.

Performance analyses of the HPCI subsystem were conducted in the same manner and with the same basic assumptions as for the core spray subsystem described previously. The detailed model is described in Section 6.3.3.2.2.

The results of a performance analysis of the HPCI subsystem for a typical small break within the protection range of the unassisted HPCI subsystem are shown in the Figure 6.3-14. During the initial phase of the transient before the HPCI subsystem begins operation, the reactor primary system pressure does not change significantly due to the release of the core stored energy and the action of the main turbine pressure regulator. The small liquid break cannot remove enough energy from the system to cause a rapid pressure decrease. When the HPCI subsystem begins operation, a significant change in the vessel depressurization rate occurs due to the condensation of steam by the cold fluid pumped into the reactor vessel by the HPCI subsystem. The effect of the mass addition by HPCI is also reflected in the changing slope of the liquid inventory trace.

As the reactor vessel pressure continues to decrease, the HPCI flow momentarily reaches equilibrium with the flow through the break. Continued depressurization causes the break flow to decrease below the HPCI flow and the liquid inventory begins to rise. This type of response is typical of the small breaks. The core never uncovers and is continuously cooled throughout the transient so that no core damage of any kind occurs for breaks that lie within the range of the HPCI.

The HPCI subsystem is designed to deliver full rated flow down to a reactor pressure of 165 psia. For lower pressures, the estimated flow decreases linearly to zero at 65 psia reactor pressure. If reactor pressure drops below the low pressure isolation setpoint, a later pressure buildup above the setpoint would automatically restart the turbine if a HPCI initiation signal were present. Thus, slow pressure changes may occur depending on the level in the core and the fraction of decay heat released to the fluid. If the HPCI subsystem decreases reactor pressure below the low pressure isolation and shuts off while the level is below the top of the core, subsequent level rise would cause enough energy to be added from core heat to raise the pressure which would reactuate the HPCI turbine. However, this discussion is focused on the operation of HPCI acting alone, a scenario that is not in the design basis. The integrated operation of all ECCS subsystems is discussed in Section 6.3.3.4.

An evaluation was made to evaluate the combined performance of the HPCI and LPCI subsystems, considering a 0.3 square foot break area, a 100 psig low reactor pressure HPCI isolation, and a HPCI restart (with a delay of 30 seconds) after reactor pressure rises above 100 psig. It should be noted that the evaluation was intended to address the performance capabilities of the HPCI and LPCI subsystems under one specific break size. However, this evaluation was not intended to establish the design basis for either system. Refer to Section 6.3.3.4 for a discussion of integrated system operating sequences, under various design basis accident scenarios.

6.3.3.2 Integrated Emergency Core Cooling System Performance Evaluation

6.3.3.2.1 Analytical Methods and Models for LOCA Analysis

6.3.3.2.1.1 Description of ANF LOCA Analysis

The Advanced Nuclear Fuels (ANF) (now Siemens Power Corporation) ECCS evaluation model for the analysis of LOCAs in jet-pump-type BWRs (EXEM)[8] is based upon ANF's methodology previously approved[9]) by the NRC. Reference 8 provides a full discussion of the model as well as the verification for the various computer codes. The latest versions of the approved codes were used for the Dresden reactor 9x9 analysis,[64] which considered jet pump plant configuration effects on the blowdown and reflood phases of LOCA transients. The EXEM model addresses the various phases of a LOCA, and methods have been developed to analyze the system response during the blowdown and refill/reflood phases as well as the fuel response during all phases of the LOCA. A schematic of the model is shown in Figure 6.3-19.

6.3.3.2.1.1.1 Blowdown Model Description

The changes previously made to ANF's approved model[9] are retained by the latest code versions. These changes included the addition of a slip flow model, a mechanistic jet pump mode, and three heat transfer regimes. The slip flow model was added to obtain more representative two-phase flow phenomena than was possible with the previous homogeneous model and thereby obtain more realistic heat transfer and energy predictions during the blowdown phase of a LOCA. Addition of the jet pump model was required to account for the hydrodynamic effects of the jet pump on the reactor system. The addition of heat transfer regimes was made to allow modeling of condensation heat transfer when isolation condensers are modeled, natural convection heat transfer when dual cycle BWR steam generators are modeled, and pool film boiling heat transfer to provide improved heat transfer predictions during low flow/low quality fluid conditions in the core.

The slip flow model used by ANF is based on the familiar Zuber-Findley[11] drift flux relation to determine relative liquid and vapor velocities in two-phase mixtures. However, the relationship has been modified to give a more detailed but consistent correlation over a more detailed flow regime map. Determination of the drift velocity, as modified, covers the bubbly flow, churn-turbulent bubbly flow, and slug flow regimes in the flow regime map. For annular flow, the relationships of Ishii[12] and Ishii, Chawla, and Zuber[13] are used.

Transitions between flow regimes are handled by linear weighing using the methods described for the TRAC computer code.[14] The effects of pressure are introduced through the density term in the correlation.

The jet pump model is based on a mechanistic multi-control volume mode using two-dimensional equations of motion to determine the jet pump pressure changes due to momentum and friction effects. The resulting jet pump pressure gradient

The bubble sweep time, T, is approximately

$$T = t - \tau \approx \frac{M_f}{W_{fr}} \qquad (23)$$

The distance traveled by a bubble from time τ when the bubble leaves elevation y = 0 until time t when it breaks through the mixture surface is:

$$y = \int_{\tau}^{t} V_B dt = \int_{o}^{T} V_B d(t - \tau) \qquad (24)$$

The choice of y = 0 at t = τ leads to the initial condition

$$M_f(y, \tau)_{y=0} = 0 \qquad (25)$$

in Equation 21. Substituting for V_B from Equation 21 into Equation 24 and expressing T from Equation 23 leads to

$$y = \frac{M_f(t)}{A_v}\left[v_g - v_{fg}\frac{W_{fr}}{W}\left(1 - e^{-\frac{W}{W_{fr}}}\right)\right] \qquad (26)$$

Since

$$e^{-W/W_{fr}} = 1 - W/W_{fr} + \frac{1}{2}\left(\frac{W}{W_{fr}}\right)^2 + \ldots \qquad (27)$$

Equation 26 can be written as:

$$y_L \approx \frac{M_f v_g}{A_v}\left(1 + 0.5\,\frac{W v_{fg}}{U A_v}\right) \qquad (28)$$

Since core heat is not added uniformly, a modification to Equation 28 is required. It can be shown that the flashing rate below the mixture level W is given by:

$$W = \frac{\dot{q}}{h_{fg}} - \left[M_f F_1(P) + M_g F_2(P)\right]\frac{dP}{dt} \qquad (29)$$

where:

$$F_1(P) = \frac{1}{h_{fg}}\left(\frac{dh_f}{dP} - v_f\right)$$

$$F_2(P) = \frac{1}{h_{fg}}\left(\frac{dh_g}{dP} - v_g\right)$$

Thus mixture level is given by:

$$y_L = \frac{M_f v_f}{A_v} \left\{ 1 + 0.5 \frac{v_{fg}}{UA_v} \left[\frac{q}{h_{fg}} - M_f F_1(P) \frac{dP}{dt} + M_g F_2(P) \frac{dP}{dt} \right] \right\} \tag{30}$$

Equation 30 consists of three basic terms, i.e.:

$$y_L = y_{L_c} + \Delta y_{L_P} + \Delta y_{L_H} \tag{31}$$

These terms are the collapsed level:

$$y_{L_c} = \frac{M_f v_f}{A_v} \tag{32}$$

The increase in level due to depressurization:

$$\Delta y_{L_P} = \frac{M_f v_f}{A_v} \left\{ 0.5 \frac{v_{fg}}{UA_v} \left[-M_f F_1 (p) \frac{dP}{dt} + M_g F_2(p) \frac{dP}{dt} \right] \right\} \tag{33}$$

and the increase in level due to the uniform addition of heat:

$$\Delta y_{L_H} = \frac{M_f v_f}{A_v} \left(0.5 \frac{v_{fg}}{UA_v} \right) \frac{\dot{q}}{h_{fg}} \tag{34}$$

If heat is added non-uniformly, the total liquid mass, M_f, is not affected by the heat but is rather just a part of the mass, say M_{fl}.

Thus the increase in level due to non-uniform heat addition may be written as:

$$\Delta y_{L_H} = \frac{M_{fl}}{M_f} \Delta y_{L_H} \tag{35}$$

In this case M_{fl} is the saturated liquid mass above the bottom of the active core region, $q = F_{sat} (q/q_0) Q_0$, and M_f is the total saturated liquid mass inside the shroud.

Thus the level is obtained from Equations 31, 32, 33, and 35.

$$y_L = y_{L_C} + \Delta y_{L_P} + \Delta y_{L_H} \tag{36}$$

$$y_L = \frac{M_f v_f}{A} \left[\left[1 + 0.5 \frac{v_{fg}}{UA} \left\{ \frac{M_{fl}}{M_f} \left[F_{sat}(q/q_o) \frac{Q_o}{h_{fg}} \right] - M_f F_1(p) \frac{dP}{dt} + M_g F_2(p) \frac{dP}{dt} \right\} \right]\right] \tag{37}$$

The bubble rise velocity used in this analysis is obtained from experimental data taken with a variety of fluids and corrected to fit the pressure and geometric conditions in the reactor. Zuber and Hench[37] used 0.83 ft/s in their correlation, which showed excellent agreement between analysis and experimental air-water data. Haberman and Morton[38] present bubble rise velocity from several different sources, from different countries. These data indicate that for a bubble diameter of 1 inch, the bubble rise velocity is slightly less than 1 ft/s and for smaller bubbles, the bubble rise velocity is less. The expected bubble size should be of the order of magnitude of the space between fuel rods, about ½ inch. At ½ inch, the bubble rise velocity is 0.8 ft/s. Hence, a bubble rise velocity of 1 ft/s was used as the basis for evaluating the level swell in this analysis.

6.3.3.2.3 Historical Analysis of Recirculation Flow Coastdown During Blowdown

It has been determined that during recirculation pump coastdown immediately following a line rupture, all flow from the unaffected recirculation loop goes through the core and that there is a 50%-50% flow split between the core and the jet pumps during the period of flashing in the lower plenum. Flow will not bypass the core through the jet pumps of the broken loop. Flow reversal will not occur in the broken side jet pumps. Thus, all the flow injected into the bottom plenum must go through the core. This flow split is based upon the predictions of a computerized model of the entire reactor recirculation system. The model includes a momentum exchange simulation of the jet pumps that can analyze their performance under all operating conditions. Figure 6.3-26 represents the model used in the analysis of transient jet pump performance. Momentum exchange between the drive and suction flows is assumed to occur in a mixing region in the jet pump throat. The suction and drive flows enter the mixing region with different velocities but at a common static pressure ($P_d = P_s$). At the exit of the mixing length, a homogeneous velocity is established and momentum exchange between the two flows results in an increased static pressure.

The conservation of momentum law states that the rate of change of momentum of a body is equal to the summation of all the forces acting on the body[39] and the summation of forces equals the change in momentum as given by:

$$\sum \text{Forces} = \frac{d}{dt}(MV) = \frac{\partial}{\partial t}(w\,V) + \int V dw_{out} - \int V dw_{in} \qquad (38)$$

For this application, the above equation can be solved in terms of the change of fluid momentum from inlet to exit of the mixing region.

For the linear loss-less mixing region, the only forces acting on the fluid are the static pressure at the inlet and outlet sections. Elevation terms have been neglected; this implies that the momentum exchange occurs over a short distance. Hence,

$$\sum Fdt = (P_s A_s + P_d A_d - P_t A_t)\,dt \qquad (39)$$

Combining the equations yields:

$$P_t = \left(P_s A_s + P_d A_d + \frac{W_d^2}{\rho_d A_d g} + \frac{w_s^2}{\rho_s A_s g} - \frac{W_t^2}{\rho_t A_t g} \right) \cdot \frac{1}{A_t} \qquad (40)$$

Where V is bubble rise velocity relative to the vessel, u is bubble rise velocity in stationary liquid, and v is local mixture specific volume based on X, which is local instantaneous vapor mass fraction. Equations 46 through 52 can be combined to give:

$$\frac{A_B}{A_v u} = \frac{1}{G_c v_f} \quad \frac{X}{X - X_F} \quad = f\,(P_o, X, X_F) \tag{53}$$

Equation 53 relates P_o, X, and X_F to the property $A_B/A_v u$. If flowing quality X_F is zero, then stagnation enthalpy is $h_f(P_o)$, and bottom blowdown of saturated liquid occurs; i.e., the condition for $A_B/A_v u$ to be satisfied for bottom liquid blowdown is that:

$$\left.\frac{A_B}{A_v u}\right|_{LIQ} \leq \frac{1}{G_c\left[P_o, h_f(P_o)\right] \cdot v_f\,(P_o)} \tag{54}$$

However, if the above inequality is not satisfied, vapor bubbles will be entrained in the blowdown flow, and Equation 53 must be used to determine X_F. Bottom liquid or mixture blowdowns from 1000 psig characteristically produce X in the range 0 to 0.10. The corresponding effect on blowdown rate is small. It follows from Equation 53, therefore, that:

$$\frac{X_F}{X} \approx 1 - \frac{1}{G_c v_f \dfrac{A_B}{A_v u}} \tag{55}$$

Equation 55 can be used to help select test data for comparisons which can be closely approximated by liquid blowdown until the mixture level reaches the break.

6.3.3.2.6.2 <u>Historical Analysis of Blowdown Rates and Pressure Traces</u>

Calculated graphs already are available for liquid blowdown from 1000, 1250, and 2000 psia initial stagnation pressures.[45,46]

The graphs include a variable time scale with break area A_B as a parameter. Proper selection of an equivalent A_B* to bring theoretical and measured blowdown pressure traces into agreement will enable a better evaluation of the mixture level model.

6.3.3.2.6.3 Historical Analysis of Mixture Level Prediction

Mixture level has been calculated for vessel bottom blowdown from 1000 psia initial pressure with initial liquid level equal to 75% of the vessel overall height.

Where necessary, mixture level calculations can be made from the following equations[36] whenever X_F is greater than 0 from Equation 55:

$$\frac{Y_L^{(t^*)}}{H} = \frac{A_v u}{A_B} \frac{v_g^{(t^*)}}{v(o)} I_1(t^*) + \frac{Y_{Lo}}{H} \frac{M_f^{(t^*)}}{M_{fo}} \left[v_g(t^*) \frac{S_{fg}(t^*)}{S_y(t^*) - S_{f(o)}} - v_{fg}(t^*) \right] \frac{1}{v_{fo}}$$

$$I_1(t^*) = -\int_o^{t^*} \frac{S_{f(o)} - S_f(t^*)}{S_g(t^*)} - S_{f(o)} \, dt^* \tag{57}$$

The time t* is given by:

$$t^* = \frac{A_B}{M_o} t \tag{58}$$

6.3.3.2.6.4 Historical Evaluation of Selected Tests for Comparison

Three tests were selected for this comparison from CSE,[43] Bodega,[47] and Humboldt[48] blowdowns. Pertinent experimental quantities are listed in Table 6.3-10.

Bodega and Humboldt vessels were cylindrical without internal mechanical components to obstruct internal flows. The CSE vessel contained a dummy core plate.

The equivalent break areas were determined so that theoretical and measured pressure-time curves were closely aligned up to the pressure trace knee. The quantity $A_B^*/A_v u$ was based on u = 1.0 ft/s bubble rise velocity, which seems to be more characteristic of small vessels. All three cases show that $A_B^*/A_v u$ is larger than the term $1/(G_{fc}U_f)$ initially so that mixture blowdown is ensured. (G_{fc} decreases as pressure drops so that mixture blowdown is ensured throughout the blowdown.) It follows that Equations 56 and 57 can be applied for necessary calculations.

Rather than calculate level curves for Bodega 30 and Humboldt 17, it was decided to make an approximate comparison with calculations already available from initial vessel pressures of 1000 psia. The tests begin at 1250 psia. Figures 6.3-29 and 6.3-30 show true vessel pressure traces with attention called to the knee. The lower half of each graph gives mixture level calculations based on 1000 psia and 75% initial water level. A dotted curve also is shown, based on the appropriate $A_B^*/A_v u$. When mixture level reaches zero, the pressure "knee" should occur. Even though the calculation is based on 1000 psia and the tests were run from 1250 psia, mixture level disappearance was predicted within 12.5% using the model described (this is a direct index of its accuracy).

The CSE data in Figure 6.3-31 include both pressure, mass remaining, and level for comparison with the mixture level model. Comparing only the level data in Figure 6.3-31, it is seen that a bubble rise velocity between 0.5 ft/s and 1.0 ft/s brackets the CSE-measured level. Note that the level swell model is not applied to the test data until the system is saturated. Note also that the 0.5-ft/s curve shows liquid vanishing at about the right time as indicated by the knee in the experimental curve. Thus reasonable agreement is also shown with the CSE data.

Additional comparison with the only other available data is addressed by Moody in Reference 11 in which the level rise data from EVESR[42] are given.

The LOCA-ECCS analyses taken from XN-NF-85-63 and contained in this section were performed for the ANF 9x9 fuel design for the identified limiting LOCA break without taking credit for the ADS. The analyses were performed at the expected worst points bounding the operating power-flow map for a Dresden reactor.

For normal operation, limiting LOCA break calculations were performed with the Dresden reactor system parameters with a full core of ANF 9x9 fuel. Two calculations were performed, one for full power/full flow (100/100) and the other at full power and 87% of rated flow (100/87), which is the minimum flow for allowed operation at full power from the current Dresden Unit 2/3 operating power-flow map. Both operating conditions were found to result in essentially identical LOCA transients. The power/flow of 100/87 resulted in the highest PCT and was used to verify the LOCA-ECCS maximum average planar linear heat generation rate (MAPLHGR) limits.

The limiting break with single failure of the LPCI injection valve takes into account ECCS leakages, a conservative ECCS fluid temperature of 170 °F as well as the leakages associated with the core shroud weld repairs, access hole cover and the bottom head drain. The leakages assumed in the LOCA analysis are given in Table 6.3-19. The values assumed for these leakages were based on calculated values, but chosen such that both unit's leakages would be bounded by the leakages used in the analysis. This provides a peak cladding temperature (PCT) applicable to both units.

Calculated event time results and LOCA-ECCS results for the limiting break and worst case conditions are given in Tables 6.3-12 and 6.3-13. The results shown in Table 6.3-12 (metal-water reaction and peak clad temperature) are from the low flow case, since these are bounding. The full flow case done at the same MAPLHGR limits resulted in lower PCTs and, therefore, these limits apply to both cases. System blowdown results are presented in Figures 6.3-33 through 6.3-51.

System refill and reflood results are given in Figures 6.3-52 through 6.3-54. These system conditions are used as boundary conditions for a series of exposure-dependent maximum power assembly heatup calculations. Calculation results are given in Figures 6.3-55 through 6.3-57. Typical calculated temperatures are shown in Figure 6.3-58.

The MAPLHGR limits for 9x9 fuel during normal operation as a function of exposure were determined based on the limiting operating conditions for the identified limiting LOCA break. The ANF MAPLHGR limits also protect against exceeding fuel design limits for 9x9 fuel. When the fuel design limit is more restrictive than LOCA-ECCS criteria, the LOCA-ECCS results will be significantly below the 2200°F criteria at higher exposures. This is the case for Dresden Units 2 and 3 with ANF 9x9 fuel. The exposure-dependent MAPLHGR limits are shown in Figure 6.3-59, and the computed points used to determine this curve are given in Table 6.3-12. The MAPLHGR limits apply to ANF 9x9 fuel in the Dresden reactors during normal operation for both the initial and subsequent reloads of the current 9x9 fuel design.

All calculations were performed with the NRC-approved EXEM/BWR ECCS Evaluation Model in accordance with 10 CFR 50, Appendix K. Operation of the Dresden reactors with ANF 9x9 fuel at or below the MAPLHGR limits of Figure 6.3-59 satisfies the criteria specified by 10 CFR 50.46, and assures that the emergency core cooling system for the Dresden reactors will meet the NRC acceptance criteria for LOCA breaks up to and including the double-ended severance of a reactor coolant pipe. The acceptable criteria are as follows:

A. The calculated peak fuel element clad temperature does not exceed the 2200°F limit.

B. The amount of fuel element cladding which reacts chemically with water or steam does not exceed 1% of the total amount of Zircaloy in the reactor.

C. The cladding temperature transient is terminated at the time when the core is still amenable to cooling. The hot fuel rod cladding oxidation limit of 17% is not exceeding during or after quenching.

D. The system long-term cooling capabilities provided for the initial core and subsequent reloads remains applicable to ANF fuel.

6.3.3.3.3 Historical Large Break Analysis — Recirculation Line

The double-ended recirculation line break is one of the bases for the design of the emergency core cooling system and the containment response calculations. The containment response is discussed in Section 6.2.1.

This accident is analyzed with a nine-node reactor simulation model. The nine nodes are the lower plenum, the core, the upper plenum, the leakage region, the separation zone, the steam dome, the downcomer, and the two recirculation loops. The jet pump modeling assumes that conservation of momentum and drive pump trip can be included. The core and leakage regions each have 10 common pressure subnodes. Included in the model is a method of calculating the movements of the liquid level in the separation region. A vapor to liquid relative velocity of 1 ft/s is assumed in these calculations.[36,54]

It is assumed that the reactor is operating at 2527 MWt when a complete circumferential rupture instantaneously occurs in one of the two recirculation system suction lines. An interlock ensured that the valve in the equalizer line between the jet pump headers will be closed when both recirculation pumps are operating (see Section 7.3); thus, the area available for coolant discharge from the reactor vessel would be the sum of 10 jet pump nozzle areas and the cross-sectional area of the main recirculation line. On Unit 3, the equalizing line has been removed. On Unit 2, both of the equalizing valves and one of the equalizer bypass valves are closed and de-energized. The other equalizer bypass valve is maintained open and de-energized.

Immediately after the break, critical flow would be established at the breaks, and the total flow would be approximately 35,000 lb/s. The large increase in core void fraction that would be caused by the decreasing vessel pressure would be sufficient to render the core subcritical. High drywell pressure would initiate a mechanical scram of the control rod system in less than 1 second. In 6 seconds the liquid inventory in the downcomer and the separator region of the vessel would be depleted, and the break flow would switch from liquid to vapor. This would result in a large increase in the vessel depressurization rate.

Core inlet flow and vessel pressure are shown in Figure 6.3-60. For this accident, it is assumed the normal ac power supply to the recirculation pumps fails at the time of the accident. The drive flow in the 10 jet pumps of the broken loop very rapidly reverses to critical flow at the nozzles. However, the rapid flow from the downcomer region to these nozzles inhibits reverse flow in the associated jet pump throats and diffusers. In the meantime, the rotating energy stored in the pump and motor-generator set of the other recirculation system is used to provide continuing flow into the lower plenum. This flow is assumed to cease when the falling level in the downcomer reaches the jet pump suction level. It is also assumed (conservatively) that feedwater flow ceases at the time of the accident due to loss of electrical power, without any coastdown time.

6.3.3.4 Integrated System Operating Sequence

6.3.3.4.1 Design Basis Accident

Since the emergency core cooling system is composed of several subsystems that are designed to perform under specific conditions, the operating sequence must be described for alternate operating conditions.

With normal ac power available all systems are actuated and there is no preferential sequencing. However, when power is supplied by the diesel generators, the pump motor starting loads must be sequenced to prevent overloading each diesel. The design basis accident (complete severance of the largest coolant pipe) represents the most severe time/load conditions. Therefore, the event sequence shown in Table 6.3-13 is based on this accident condition.

Upon receipt of the accident initiation signal, the LPCI subsystem is initiated first to start the flooding effort as soon as possible (see Section 6.3.2.2 for the description of operation). The LPCI pumps are started with 3% bypass flow since the admission valves are still closed.

Both core spray subsystems are timed to start after sufficient time has been allowed for starting all LPCI pumps. The core spray subsystems are started with 3% bypass flow to minimize the diesel starting load. The detailed operating sequence for the core spray subsystem is discussed in Section 6.3.2.1.

The LPCI injection valve and each core spray subsystem opens as soon as the reactor low pressure permissive is cleared.

After a period not greater than 2 hours, two of the four LPCI pumps can be shut down and two containment cooling service water pumps would be placed in service to cool the suppression pool. One LPCI pump or one core spray pump is adequate to maintain two-thirds core coverage, and at least one LPCI pump must operate to provide containment spray cooling. The loads on the diesel under these conditions can be carried indefinitely. Diesel generator 2/3 can then be made available to the non-accident unit.

This page is intentionally blank.

This page is intentionally blank.

6.3.3.4.3 Net Positive Suction Head for ECCS Pumps

The evaluation of post LOCA NPSH for core spray and LPCI pumps was divided into two portions:

1. Short Term (less than 600 seconds - no operator action credited-vessel injection phase)

2. Long Term (greater than 600 seconds - operator action credited-containment cooling phase)

It should be noted that the 600 second mark for operator action was established per UFSAR Sections 6.2.1.3.2.3 as the time in which credit for manual initiation of containment cooling can be taken.

6.3.3.4.3.1 CS/LPCI PUMP Post-LOCA Short Term Evaluation

A calculation was performed to evaluate LPCI and core spray NPSH requirements in the short-term post-DBA LOCA. Short-term is considered the time period from initiation of the design basis LOCA until 10 minutes post-accident when operator action is credited.

The most limiting failures relating to Peak Clad temperature (PCT) were considered:

1. SF-LPCI: Failure of a LPCI injection valve

   This case results in two (2) core spray pumps injecting at maximum flow with four (4) LPCI pumps running on minimum flow only.

2. SF-DG: Loss of Diesel Generator

   This case results in two (2) LPCI pumps and one (1) core spray pump injecting at maximum flow.

The most limiting failure with regards to LPCI/CS pump NPSH, however, is failure of the LPCI Loop Select Logic (SF-LSL). This scenario involves the LPCI pumps injecting into a broken reactor recirculation loop and is discussed in detail in GE SIL 151. From a PCT perspective, this case is identical to the SF-LPCI case since the net result of each scenario is two core spray pumps injecting into the core with no contribution from the LPCI pumps. SF-LSL is the NPSH limiting scenario due to the LPCI/CS pumps operating at the highest achievable flow rates, resulting in the maximum pump suction losses and NPSH requirements. Additionally, the LPCI water escaping to the containment results in reduced containment and suppression pool pressures, which limit the available NPSH, see Section 6.2.1.3.2.2. Both the SP-LSL and SF-DG single failure cases were evaluated in the calculation. The SF-LPCI case is bounded by the SF-LSL case.

The calculations use the following inputs:

1. Maximum LPCI and core spray pump flow conditions (un-throttled system, reactor pressure at 0 psid), maximizing suction friction losses and NPSH required.

    a. Maximum LPCI and core spray pump flows-case SF-LSL

CS	1-Pump Maximum Injection Flow:	5800 gpm
LPCI	3-Pump Maximum Injection Flow:	16,750 gpm [5,610/11,140]
LPCI	4-Pump Maximum Injection Flow:	20,600 gpm

    b. Maximum LPCI and core spray pump flows-case SF-DG

CS	1-Pump Maximum Injection Flow:	5800 gpm
LPCI	2-Pump Maximum Injection Flow:	11,600 gpm

2. Increased clean, commercial steel suction piping friction losses by 15% to account for potential aging effects, thus maximizing suction losses.

3. To account for strainer plugging, the most limiting of the four torus strainers is assumed 100% blocked, while the remaining three strainers are assumed clean.

4. Containment conditions used in the analysis are given in UFSAR Section 6.2.1.3.2.3 which minimize the NPSH available.

5. Initial suppression pool temperature is 95°F which is the maximum allowable pool temperature under normal operating conditions. This value is used as the initial pool temperature to maximize pool peak temperature, and is used as a minimum temperature during the LOCA to maximize piping friction losses (maximum viscosity).

6. The minimum suppression pool level elevation using a maximum drawdown of 2.1 ft. is 491'5", (491.4 ft). LPCI and core spray pump centerline elevation is 478.1 ft.

7. The suppression pool strainers have a 100% clean head loss of 5.8 ft. @ 10,000 gpm.

8. NPSHR values at various LPCI/CS pump flows are taken from the vendor pump curves.

The minimum suppression pool pressure required to meet LPCI/CS pump NPSH requirements was determined for both the SF-LSL and SF-DG single failure cases. The minimum pool pressure required was compared to the minimum pool pressure available post-LOCA for two cases:

- Case 6a2 with 60% thermal mixing used for SF-LSL containment conditions.

- Case 2a1 with 100% thermal mixing used for the SF-DG containment conditions.

If the pressure available is greater than the pressure required, then adequate NPSH exists. If the available pressure is less than the pressure required, then the potential exists for the pumps to cavitate, resulting in reduced flows.

For the SF-LSL case, no cavitation is expected to occur for the first 290 seconds post-LOCA. During this time, the LPCI and CS pumps will deliver maximum flow of 5800 gpm per pump. Since PCT occurs at about 170 seconds, the CS pumps will deliver adequate flow to ensure no impact on PCT. After 290 seconds, the LPCI and CS pumps may cavitate, resulting in reduced flows. The CS pump NPSH deficit reaches a maximum of 10.0 feet at 533 seconds. Under these conditions for NPSH, core spray pump flow will reduce from 11,600 gpm (5800 gpm per pump) at 290 seconds to about 10,200 gpm (5100 gpm per pump). This represents the minimum expected flow from the core spray pump for the 290 to 600 second interval.

As stated above, a potential exists for the LPCI and CS pumps to cavitate after the first 290 seconds post-LOCA. However, as part of the original design of the plant, the pump vendor performed a cavitation test on a LPCI pump (a Quad Cities (RHR) pump was actually used). The Cavitation Test Report for Bingham 12x14x14x1/2 CVDS pump demonstrated no evidence of any damage to the pump components from cavitation with up to one hour of operation at the cavitating condition.

This analysis was reviewed with respect to the core spray pump and the results determined to be applicable. The rationale for this determination is the following:

- Core spray and LPCI are the same make and model pump (only impeller diameter is different).

- LPCI and core spray utilize the same impeller pattern, and therefore the same overall characteristics.

- All LPCI and core spray pumps have tested NPSHR curves that are essentially identical (within 1%).

For the SF-DG case, adequate suppression pool pressure is available to satisfy LPCI/CS pump NPSH requirements for the entire 10 minute period. That is, no LPCI/CS pump cavitation will occur, nor will any reduction take place from 5800 gpm for core spray and 11,600 gpm for LPCI (5800 gpm per pump).

LPCI/CS pump flow requirements are as follows:

- For the SF-LSL and SF-LPCI cases, a two-pump core spray flow of ≥ 11,300 gpm up to the 200 second mark results in a PCT of ≤ 2030 °F.

- For the SF-DG case, a two-pump LPCI flow of at least 9000 gpm and a single core spray pump flow of at least 5650 gpm are required for PCT considerations.

- Only a constant nominal total pump flow of 9000 gpm is required to achieve 2/3 core reflood in less than 5 minutes.

Therefore, under the most limiting single failures, the ECCS will still perform its function in the short term with no credit for operator action.

6.3.3.4.3.2 CS/LPCI Pump Post-LOCA Long Term Evaluation

The evaluation examined the net positive suction head (NPSH) available to the Dresden LPCI and core spray (CS) pumps after the first 600 seconds following a DBA LOCA for several pump combinations.

If the suppression pool pressure available is greater than the pressure required for adequate NPSH to the LPCI and CS pumps, then these pumps have adequate NPSH for operation. If the suppression pool pressure available is less than the pressure required by the pumps, then there is inadequate NPSH for operation and there is a potential for pump cavitation. In these situations, LPCI pump flows were reduced below nominal values and new cases were run to establish the ability of the operator to throttle the pumps to an acceptable condition.

A spectrum of pump combinations was explored to determine the bounding NPSH case for the LPCI and core spray pumps. It will be shown that the 4 LPCI/2 CS pump case is bounding for NPSH.

The calculation uses the following inputs:

1. Various LPCI and core spray pump flow conditions are evaluated (See Table 6.3-18).

2. Increased clean, commercial steel suction piping friction losses by 15% to account for potential aging effects, thus maximizing suction losses.

3. It is assumed that at 10 minutes into the accident, operator action will be taken to ensure that the LPCI/CS pumps have been throttled to their rated flows (5000 and 4500 gpm respectively). Therefore, the pumps are at their rated flows at the time of peak suppression pool temperature (~20,000 seconds).

4. To account for strainer plugging, the most limiting of the four torus strainers is assumed 100% blocked, while the remaining three strainers are assumed clean.

5. Initial suppression pool temperature is 95 °F. This is the maximum allowable suppression pool temperature under normal operating conditions.

6. The containment pressure and pressure responses provided in case 2a1 with 20% mixing as shown in UFSAR Section 6.2.1.3.2.3 are used. These responses result in the bounding NPSH case.

7. The minimum torus level elevation with a maximum drawdown of 2.1 ft is 491.4 ft. At the time of peak suppression pool temperature, a recovery of 1.1 ft occurs, resulting in a net drawdown of 1 ft.

8. The torus strainers have a head loss of 5.8 ft @ 10,000 gpm clean.

9. LPCI and core spray pump centerline elevation is 478.1 ft.

The calculation determined the minimum suppression pool pressure required to meet pump NPSH requirements for several ECCS pump combinations. The calculation shows that adequate NPSH exists to meet core spray pump requirements post-LOCA for all ECCS pump combinations. However, potential exists for the LPCI pumps to cavitate at rated flows in the 4 LPCI/2 CS and 3 LPCI/2 CS pump scenarios. For these cases, throttling of the LPCI pumps to below rated flows may be required to ensure NPSH requirements are met. A minimum of 5000 gpm total LPCI flow is required for containment cooling. Table 6.3-18 provides NPSH margin for throttled LPCI cases.

The containment analysis used to determine minimum containment pressures was performed with containment sprays on from 600 seconds through accident termination. In order to more closely tie containment pressure to NPSH requirements, the Emergency Operating Procedures provide guidance to the operators to terminate sprays at pressures up to 6 psig when required to ensure adequate NPSH for the LPCI and core spray pumps. NPSH calculations show that 5 psig containment overpressure is required for no cavitation during long term post-LOCA conditions with 4 LPCI and 2 core spray pumps operating at rated flows. The value of 6 psig for consideration of containment sprays provides an additional 1 psig margin. Operating procedures provide directions for operating sprays so that containment pressure will be maintained within the pressure required for adequate NPSH and the spray initiation pressure of 9 psig.

Operators have been trained to recognize cavitation conditions and to protect their equipment by throttling flow if evidence of cavitation should occur due to inadequate NPSH. The control room has indication of both discharge pressure and flow on each division of core spray and LPCI. The Emergency Operating Procedures (EOPs) also provided guidance to maintain adequate NPSH for the core spray and LPCI pumps. The NPSH curves provided in the EOPs utilize torus bulk temperature and torus bottom pressure to allow the operator to determine maximum pump or system flow with adequate NPSH. These curves are utilized as long as the core is adequately flooded.

6.3.3.4.3.3 NPSH Margin

Figure 6.3-80 gives a graphical representation of the minimum required containment pressure to meet NPSH requirements for both LPCI and core spray pumps. The chart covers both the short-term (≤ 600 seconds) and long-term (> 600 seconds) periods.

The containment pressure response shown on the chart, and covered in UFSAR Section 6.2.1.3.2.3, is for the following pump combinations over the short and long-term periods:

≤ 600 sec 4 LPCI pumps/2 CS pumps Case 6a1-60% thermal mixing
> 600 sec 1 LPCI pump/1 CS pump Case 2a1-20% thermal mixing

The LPCI and core spray required containment pressure on the chart is for the following limiting pump combinations and flows over the short and long-term periods:

≤ 600 sec 4 LPCI pumps @ 5150 gpm each /2 CS pumps @ 5800 gpm each
> 600 sec 2 LPCI pumps @ 2500 gpm and 1 LPCI pump @ 5000 gpm/2 CS pumps @ 4500 gpm each

At runout flows, the core spray pumps have the potential to cavitate for a short period of time (290 sec - 600 sec) during the ≤ 600 second period. This is acceptable per the discussion in UFSAR Section 6.3.3.4.3.1. Figure 6.3-80 also shows the ability to throttle the core spray and LPCI pumps to an acceptable long term operating condition as discussed in UFSAR Section 6.3.3.4.3.2.

6.3.3.4.3.4 Containment Overpressure

Adequate net positive suction head for the low pressure ECCS pumps is credited as follows:

Time Period (seconds)	Containment Overpressure (psig)
0 - 240	9.5
240 - 480	2.9
480 - 6000	1.9
6000 - accident termination	2.5

This is graphically shown in Figures 6.3-83 and 6.3-84.

During a LOCA, the operator's concern will be restoration of the vessel water level. The LPCI flow will be among the parameters closely monitored in the minutes immediately after the LOCA. The operator has several motor-operated valves available to him in the main control room to adjust flowrates or even isolate flow paths. It is, therefore, concluded that operator observation and response to flow conditions will be completed shortly after the LOCA.

Because of the falling head characteristics of these pumps, the brake horsepower requirements are nearly constant from 4000 to 6000 gal/min. It is thus concluded that no overload will occur for either the LPCI pumps or for the emergency diesel generators powering them in the event of a loss of offsite power.

It is, therefore, concluded that for the conditions evaluated, no threat to the long-term cooling capability exists.

Hence, adequate NPSH is ensured at all times to allow continuous operation of the LPCI and core spray pumps.

6.3.3.4.3.5 HPCI NPSH

The HPCI subsystem takes suction from the condensate storage tank which remains cold throughout the plant cooldown so that the NPSH available is unaffected by torus heatup. If suction were taken from the torus, the maximum torus water temperature would be less than 140°F and the minimum NPSH available would be 30 feet compared to the 25 feet required by the HPCI pump.

6.3.4 Tests and Inspections

6.3.4.1 Core Spray Subsystem

Provisions have been designed into the core spray subsystem to test the performance of its various components. These provisions and tests are summarized as follows:

A. Instrumentation

- Operational test of entire subsystem.
- Periodic subsystem tests using test lines.

B. Valves

- Preoperational test of entire subsystem.
- Periodic subsystem tests using test lines.
- Test leak-off lines between isolation valves.
- Test drainline on pump side of outboard isolation valves.
- Motor-operated valves can be exercised independently.

C. Pumps

- Preoperational test of entire subsystem.
- Periodic subsystem tests using test lines.
- Monitoring pump seal leakage.

All necessary experimental programs to confirm the performance of the core spray subsystem were performed and are described in Section 6.3.3.1.1.

6.3.4.2 Low Pressure Coolant Injection Subsystem

To assure that the LPCI subsystem will function properly if required, specific provisions have been made for testing the operability and performance of the several components of the subsystem. Testing is performed periodically. In addition, surveillance features provide continuous monitoring of the integrity of vital portions of the subsystem.

A design flow functional test of the LPCI pumps is performed for each combination of three pumps during normal plant operation by taking suction from the suppression pool and discharging through the test lines back to the suppression pool. The injection valves to the reactor recirculation loops remain closed during this test and reactor operation is undisturbed. An operational test of the LPCI injection valves is performed by shutting the downstream valve after it has been satisfactorily tested and then operating the upstream injection valve. The discharge valves to the containment spray headers are checked in a similar manner by operating the upstream and downstream valves individually. All of these valves can be actuated from the control room using remote manual switches. Control system design provides automatic return from test to operating mode if LPCI initiation is required during testing.

Testing of LPCI subsystem sequencing is performed after the reactor is shut down. Testing the operation of the valves required for the remaining modes of operation of the subsystem is performed at that time.

Periodic inspection and maintenance of the LPCI pumps, pump motors, and heat exchangers is carried out in accordance with the manufacturer's instructions.

6.3.4.3 High Pressure Coolant Injection Subsystem

To ensure that the HPCI subsystem will function properly if it is needed, specific provisions have been made for testing the operability and performance of the various parts of the subsystem. This testing can be done at a frequency that will ensure availability of the subsystem. In addition, surveillance features will provide continuous monitoring of vital portions of the HPCI subsystem.

The performance of the pump assembly was certified by the vendor over its operating range based on the following test data:

A. Head/flow tests of the booster pump running at 2155 rpm;

B. NPSH requirement of the booster pump running at 2155 rpm determined at 6500 gal/min and 5000 gal/min;

C. Head/flow tests of the main pump running at 3584 rpm;

Testing is accomplished as follows:

A. The pump suction valve from the condensate storage tank is opened (if shut) and the minimum flow bypass valve to the suppression pool is opened;

B. The turbine steam supply valve is opened with the remote manual switch to start the pump and establish minimum flow;

C. The test bypass valve is then opened to establish full rated flow from the pump through the bypass line to the condensate storage tank;

D. With the pump off and the maintenance block valve upstream of the pump discharge valve closed, the pump discharge valve may be tested by stroking the valve open and closed with the remote manual switch.

The HPCI check valve is tested by opening the equalizing line and then manually stroking the valve. The check valve is only testable when the unit is shutdown. Remote valve disc position indication is not used to verify valve stroke for the 2(3)-2301-7 check valves.

6.3.4.3.4 <u>An Accident Signal Simultaneous with Test</u>

In the event that an accident signal occurs while the HPCI subsystem is being tested, the subsystem is automatically restored to the automatic startup status and will begin operation.

6.3.4.4 <u>Automatic Depressurization Subsystem</u>

Testing of the ADS valves is described in Section 5.2.2. Operability testing of the ADS subsystem is discussed in Section 7.3.

51. "Loss-of-Coolant Accident Analysis Report for Duane Arnold Energy Center (Lead Plant)," NEDO-21082-02-1A, Appendix A, Revision 1, July 1977.

52. "Generic Jet-Pump BWR 3 LOCA Analysis Using the ENC EXEM Evaluation Model," XN-NF-81-71(P)(A) and Supplement 1 (P)(A), Exxon Nuclear Company, Richland, Washington, September 1982.

53. "Dresden Units 2 and 3 LOCA—ECCS Analysis, Single Failure Diesel Generator," ANF-89-131, Advanced Nuclear Fuels Corporation, August 29, 1989.

54. J.F. Wilson, et.al., "The Velocity of Rising Steam in a Bubbling Two Phase Mixture", ANS Transactions, Vol. 5, No. 1, p. 151, 1962.

55. APED 5529, Core Spray and Core Flooding Heat Transfer Effectiveness in a Full Scale Boiling Water Reactor Bundle.

56. Docket 50-249, Dresden Unit 3, Amendment 5, Appendix IIE.

57. Reliability Analysis of Nuclear Power Plant Protective system, B.J. Garrick et al., HN-190, May 1967.

58. Availability Analysis, A Useful Tool for Improving system Designs, I.M. Jacobs and A.H. Klose, APED-5496, Class II, April 1967.

59. Failure Rate Data Handbook, Bureau of Naval Weapons, U.S. Naval Ordnance Laboratory, Corona, California.

60. Apollo Reliability Prediction and Evaluation Guidelines, National Aeronautics and Space Administration; ASK-R-05-64-1 (R-11).

61. Reliability Application and Analysis Guide, D.R. Earles.

62. UKAEC Atomic Power Plant Failure Rate Data (Received from Rodney Fordham, UKAEC, England).

63. NUREG 0823, Section 4.2.3.1, February 1983 SEP Topic VI-10.8 Shared Engineering Safety Features/Sharing of DC systems.

64. Dresden Units 2 and 3 LOCA-ECCS Analysis, MAPLHGR Results for ANF 9x9 Fuel, ANF-88-191, Supplement 4, dated November 1996

Table 6.3-1

EMERGENCY CORE COOLING SYSTEM SUMMARY

Function	Number of Operating Pumps	Design Coolant Flow (gal/min)	Delivery Pressure Range	Required Electrical Power	Additional Backup Systems
Core Spray[1]	1	4500 at 90 psid[4]	<260 psid	Normal auxiliary power or emergency diesel generator	Second core spray subsystem and LPCI subsystem
LPCI[1]	3	8000 at 200 psid[4] 14,500 at 20 psid[4]	<275 psid	Normal auxiliary power or emergency diesel generator	Core spray subsystems and fourth LPCI pump
HPCI[2]	1	5600 constant	1135 to 165 psia	DC battery system for control and AC power for room cooler fan[3]	Automatic depressurization plus core spray and LPCI

Notes:

1. Automatic startup of the core spray and LPCI systems is initiated by: reactor low-low water level and reactor low pressure, drywell high pressure, or reactor low-low water level continuing for 8.5 minutes.
2. Automatic startup of the HPCI system is initiated by: reactor low-low water level, or drywell high pressure.
3. Reactor steam-driven pump.
4. Differential pressure between the reactor and primary containment.

Table 6.3-4

ECCS LOADING SEQUENCE

Sequence	Elapsed Time (seconds)	Event	Condition
1	0	Design basis accident	
2	3	High drywell pressure; diesel generator start signal	
3	16	Start and run isolation valves	
4	20	Start LPCI pump A and C[1]	3% bypass flow
5	25	Start LPCI pump B and D[1]	3% bypass flow
6	30	Start core spray pump A and B[1]	3% bypass flow to 70% speed; 100% flow at speed

Note:

1. One pump on each diesel generator.

Table 6.3-12a

HISTORICAL DRESDEN LOCA ANLAYSIS RESULTS FOR ANF 9x9 RELOAD FUEL

Assembly Average Burnup (GWd/MTU)	MAPLHGR (kW/ft)	Local Metal-Water Reaction (%)	Peak Clad Temperature (°F)
0	11.40	2.20	2006
5	11.75	2.44	2045
10	11.40	0.91	1893
15	10.55	0.63	1805
20	9.70	0.44	1710
25	8.85	0.29	1623
30	8.00	0.18	1529
35	7.15	0.12	1421
40	6.30	0.08	1309

Table 6.3-12b

DRESDEN LOCA ANLAYSIS RESULTS FOR ANF 9x9 RELOAD FUEL

Assembly Average Burnup (GWd/MTU)	MAPLHGR (kW/ft)	Local Metal-Water Reaction (%)	Peak Clad Temperature (°F)
0	11.40		
5*	11.75	1.96	2030
10	11.40		
15	10.55		
20	9.70		
25	8.85		
30	8.00		
35	7.15		
40	6.30		

Table 6.3-13

DRESDEN LIMITING BREAK EVENT TIMES

Event	Time (seconds)
Initiate Break	0.05
Feedwater Flow Stops	0.55
Low-Low Water Mixture Level Trip	4.50
MSIV Fully Closed	5.05
Jet Pump Uncovers	7.60
Recirculation Suction Uncovers	10.8
Lower Plenum Flashing	12.0
HPCI Flow Starts	14.5
LPCS Starts	37.3
End Blowdown (Rated Spray)	59.7
Depressurization Ends	144.6
Start of Core Reflood	160.6
Core Reflood (High Power Node)	165.4
Peak Clad Temperature Reached	165.4

Table 6.3-14

Table deleted

Table 6.3-15

Table deleted

Table 6.3-16

Table deleted

Table 6.3-17

Intentionally Deleted

Table 6.3-18

LONG-TERM NPSH MARGIN

NPSH margins at flow rates of 5000 gpm LPCI and 4500 gpm CS:

LPCI/CS Pumps	Minimum LPCI Margin (ft)	Minimum CS Margin (ft)
4/2	-5.8	-0.1
3/2	-2.8	3.1
2/2	-0.4	5.7
1/2	2.8	7.5

NPSH margins with throttled LPCI flows:

LPCI/CS Pumps (LPCI flow rates per pump) With all CS flow rates @ 4500 gpm per pump	Minimum LPCI Margin (ft)	Minimum CS Margin (ft)
4/2 (2500)	9.6	5.6
3/2 (2500/5000)*	1.0	5.6
2/2 (2500)	11.4	7.6
1/2 (5000)	2.8	7.5

* Two pumps @ 2500, one pump @ 5000

Table 6.3-19

LEAKAGE CURRENTLY CALCULATED AND ANALYZED
FOR LOSS-OF-COOLANT ACCIDENTS

Source	Current Unit 2 Calculated Leakage (gpm)	Current Unit 3 Calculated Leakage (gpm)	Currently Analyzed Leakage (gpm)
RPV penetration assembly Design leakage (2-loop)	2 x 190 380 total	2 x 115 230 total	400 [1]
Upper T-box vent hole leakage (2-loop)	2 x 8 16 total	2 x 8 16 total	0 [1]
Core spray piping weld cracks End-of-Cycle leakage [4] (2-loop)	2 2 total	3 + 17 20 total	0 [1]
Core shroud weld cracks	184	0[2]	184
Access hole cover	78 [3]	0[2]	78 [3]
Bottom head drain line	225 [3]	225 [3]	286

1. The 400 gpm of RPV assembly penetration leakage listed in the table is equivalent to 400 gpm of total leakage for the RPV assembly leakage, Upper T-box vent hole leakage, and the CS line postulated crack leakage. Since all of these leakages occur in the CS line between its entry into the vessel and the penetration of the core shroud, the distribution of these leakages is insignificant. Conservatively, none of the core spray leakage flow is credited to enter the vessel.

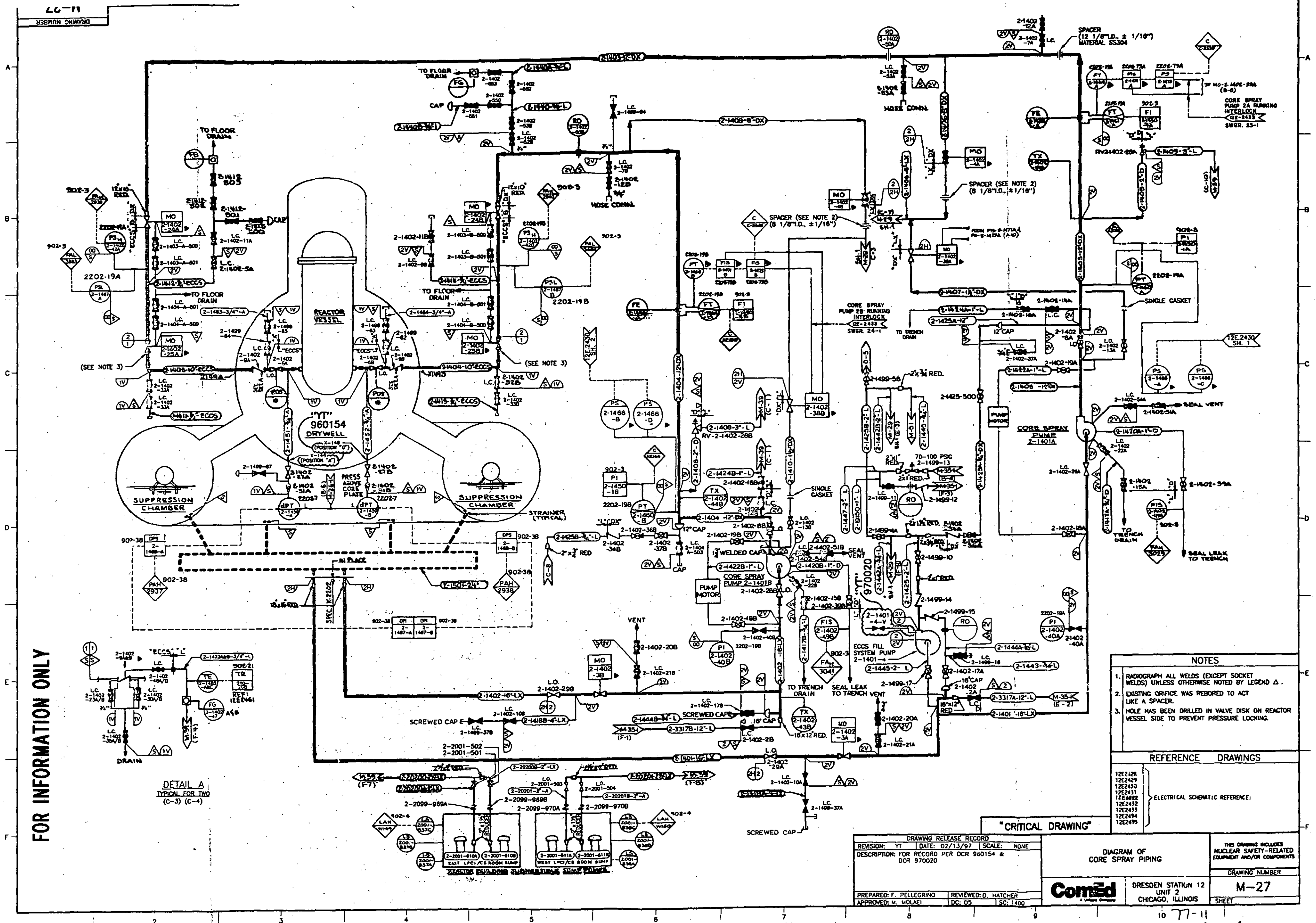
2. The access hole cover and core shroud repair leakage are not present at Unit 3. The ANF-88-191, Supplement 4[64] analysis conservatively assumes that these leakages are present for both units. Rather than performing a Unit 3 specific analysis, this additional leakage is assumed in order to provide additional conservatism.

3. The bottom head drain was recalculated by Siemens Power Corporation and determined to be 61 gpm less than the 286 gpm of leakage assumed in the previous analyses. It should be noted that this decrease in bottom head drain leakage was not used in the current analysis [64] in order to provide additional conservatism.

4. The end-of cycle crack lengths (including unit specific projected crack growth) were used to calculate the leakages.

5. The leakage through the access hole cover is a function of reactor water level as described in Section 6.3.2.2.3.1, but for LOCA analysis purposes, this value is assumed to be constant at the maximum predicted value.

FOR INFORMATION ONLY



CENTRAL DRAWING FACILITY

30 X

REV. 02 / JUNE 1997

FIGURE 6.3-2A

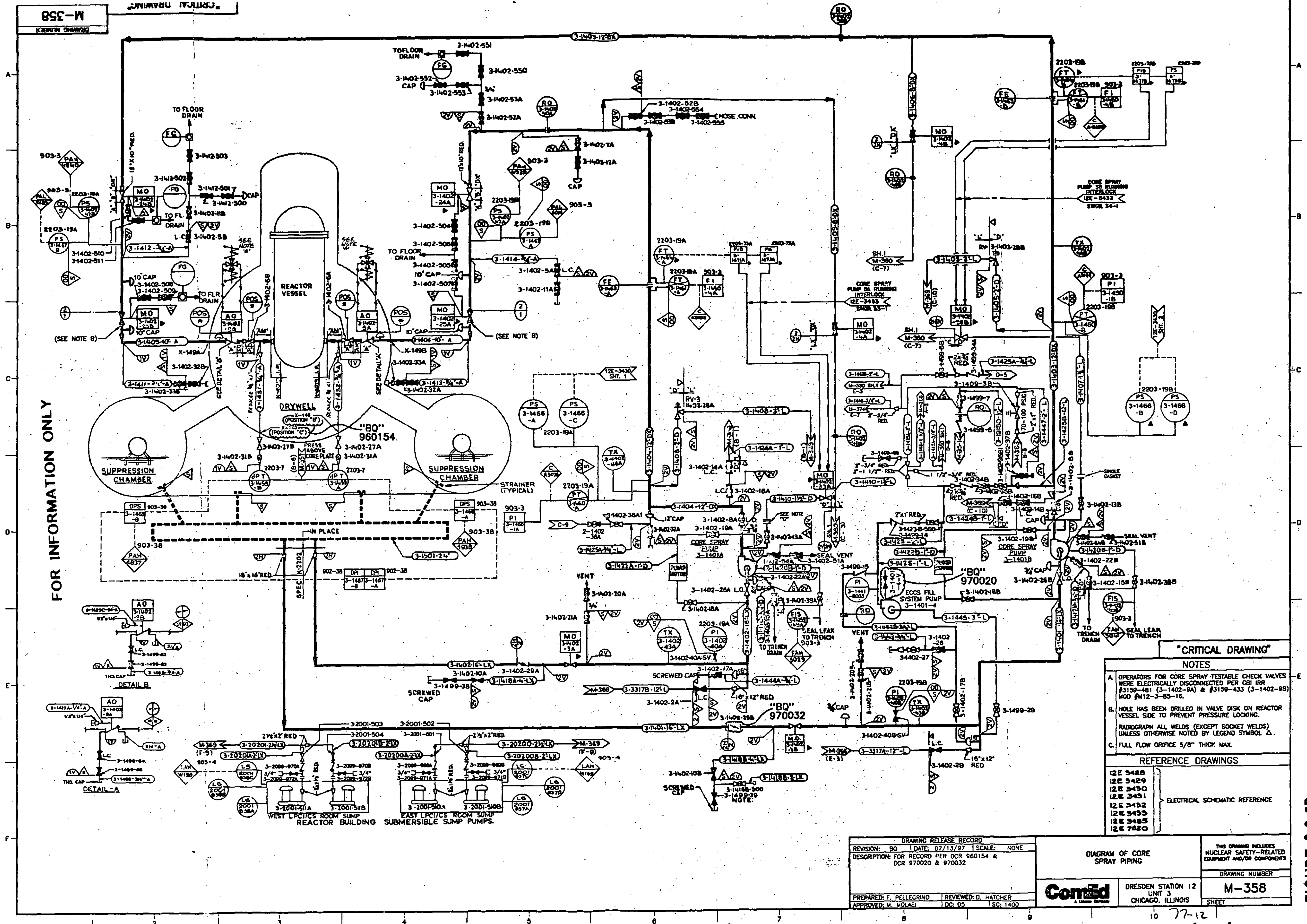


FIGURE 6.3-2B REV. 02 / JUNE 1997

CENTRAL DRAWING FACILITY

30 X

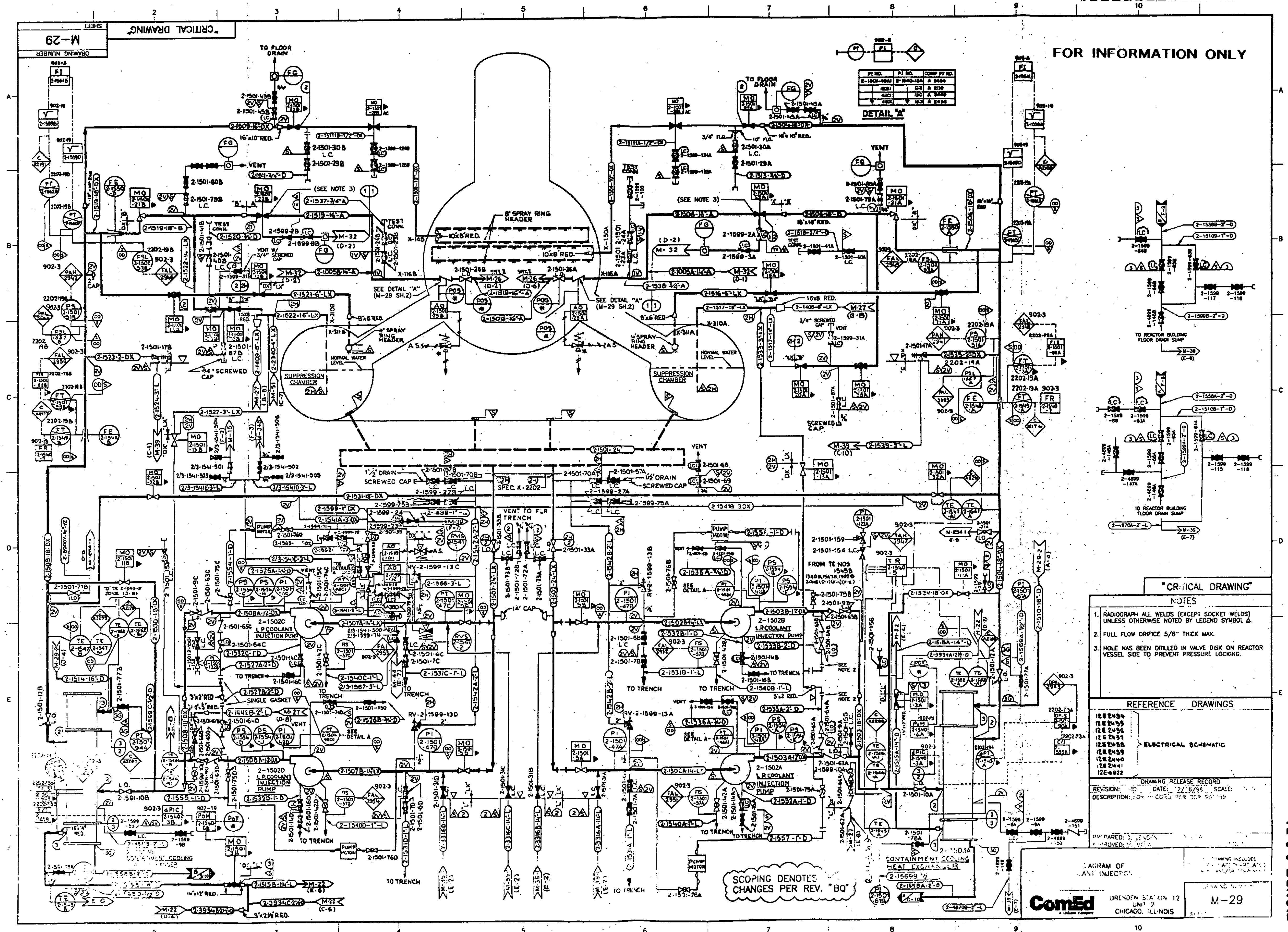


FIGURE 6.3-7A

REV. 02 / JUNE 1997

CENTRAL DRAWING FACILITY 30 X

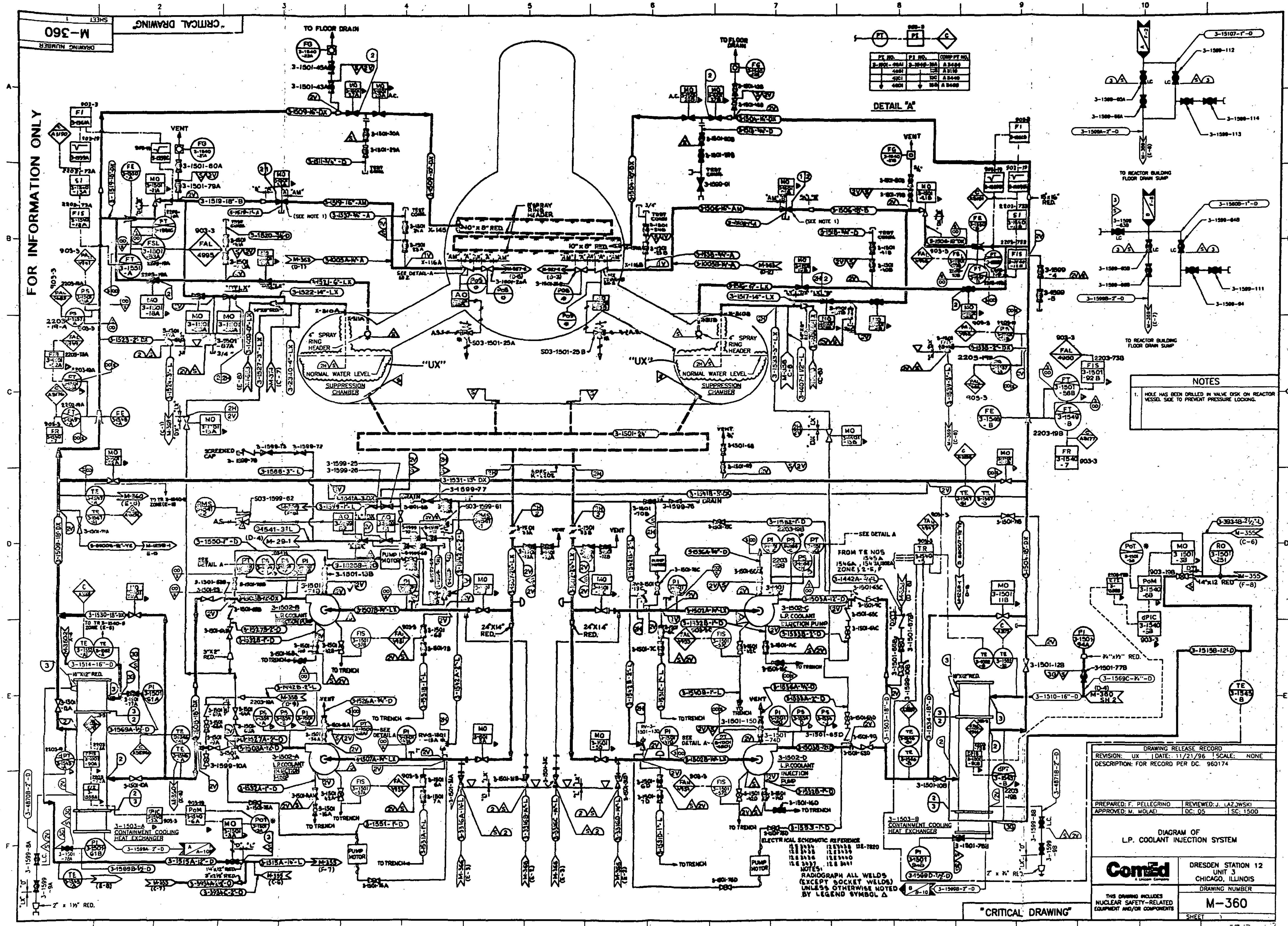


FIGURE 6.3-7B REV. 02 / JUNE 1997

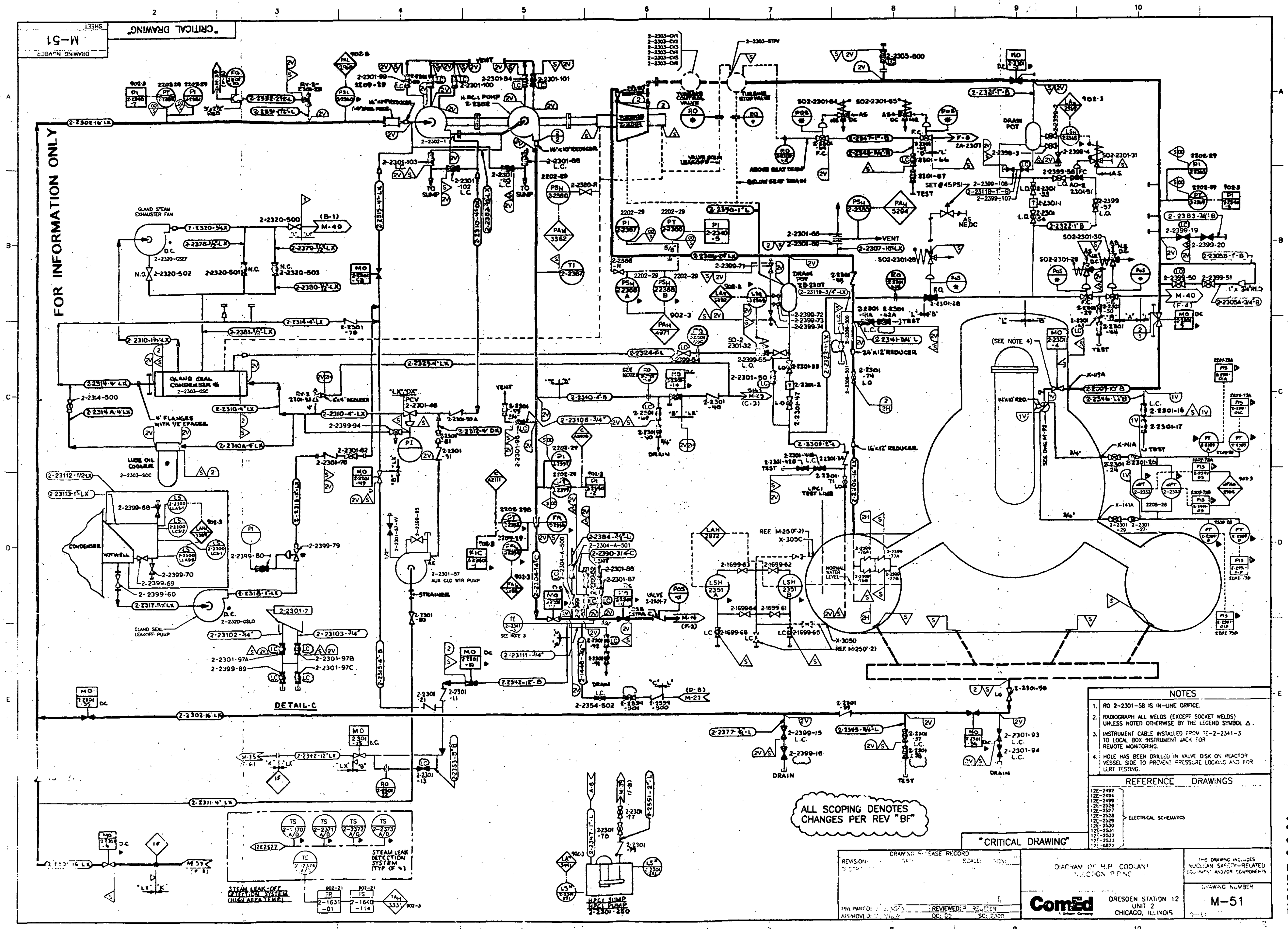
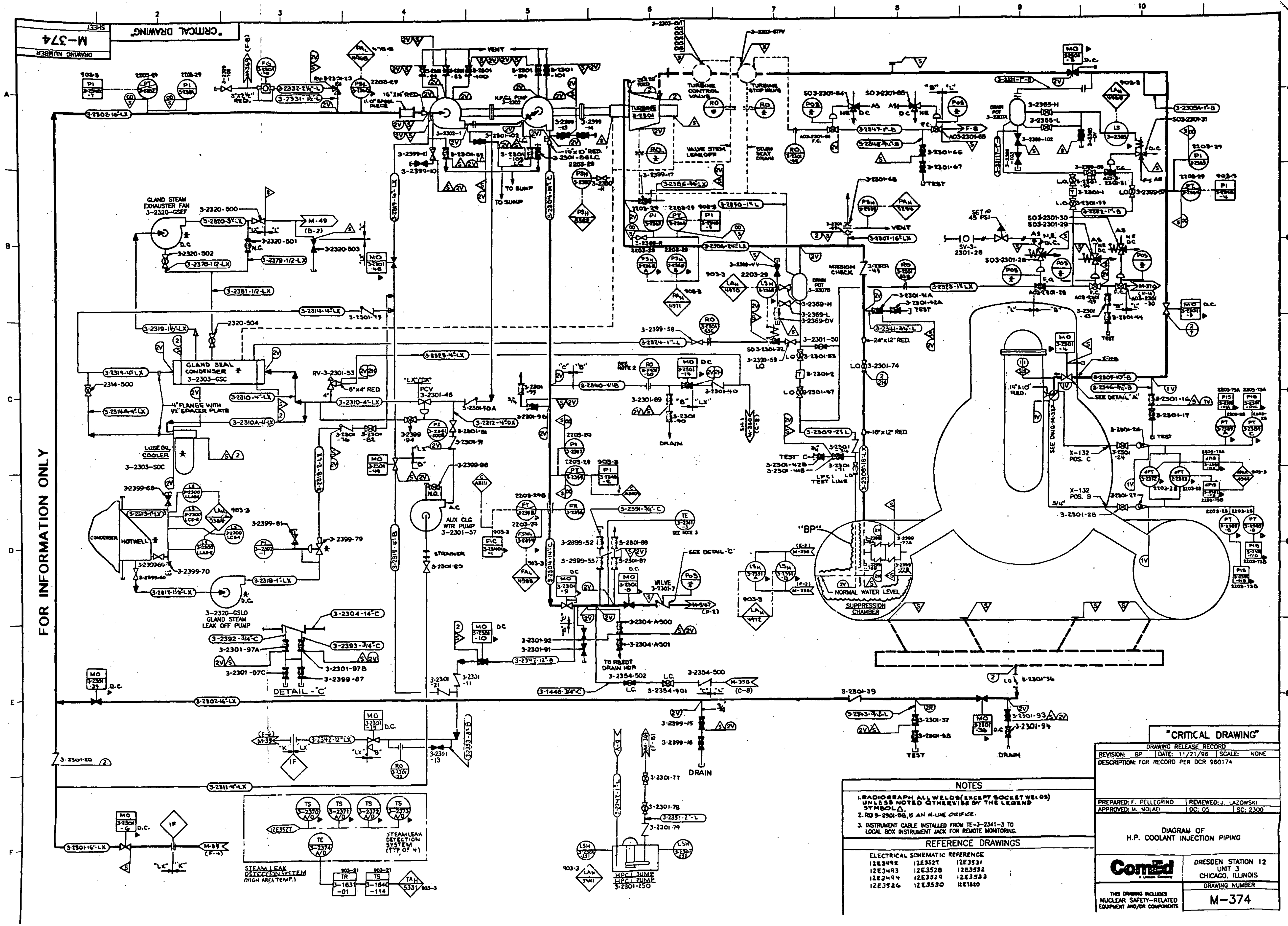


FIGURE 6.3-9A REV. 02 / JUNE 1997



REV. 02 / JUNE 1997

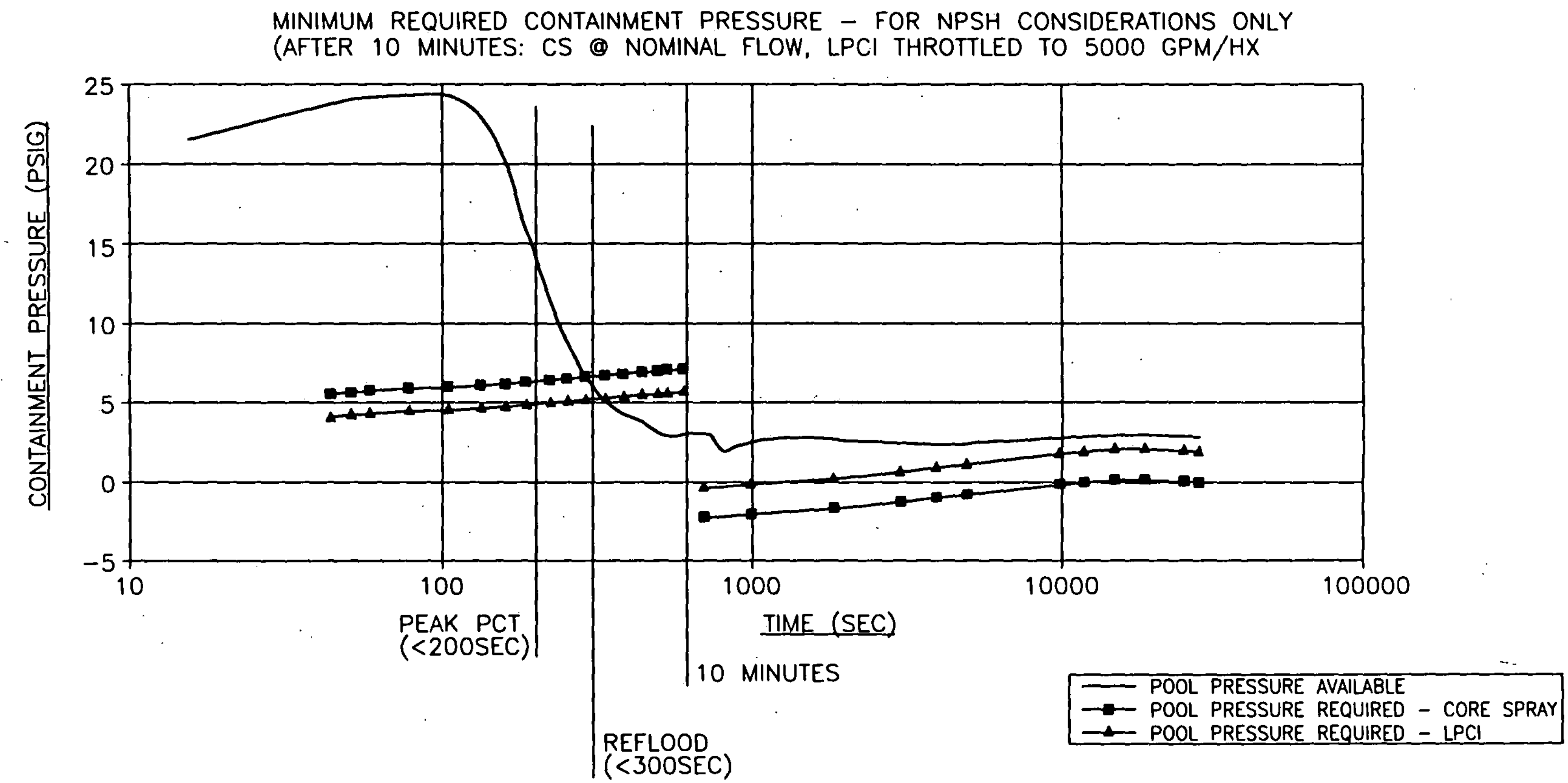
FIGURE 6.3-9B

FIGURE DELETED

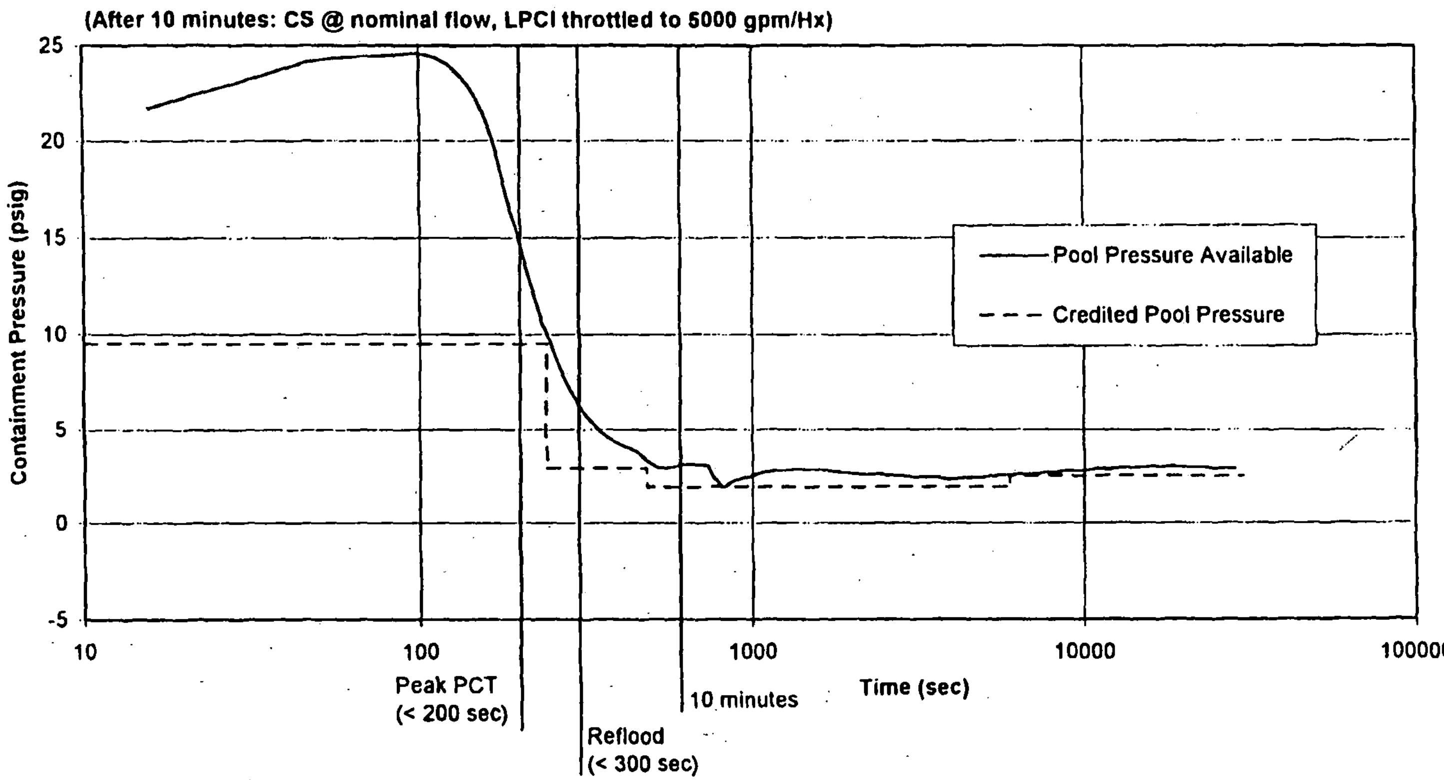
UFSAR REVISION 2, JUNE 1997
DRESDEN STATION UNITS 2 & 3
AVAILABILITY ANALYSIS – SMALL LINE BREAK
FIGURE 6.3-77

FIGURE DELETED

UFSAR REVISION 2, JUNE 1997
DRESDEN STATION UNITS 2 & 3
AVAILABILITY ANALYSIS – LARGE LINE BREAK
FIGURE 6.3–78



UFSAR REVISION 2, JUNE 1997
DRESDEN STATION UNITS 2 & 3
MINIMUM CONTAINMENT PRESSURE AVAILABLE AND CONTAINMENT PRESSURE REQUIRED FOR PUMP NPSH
FIGURE 6.3-80

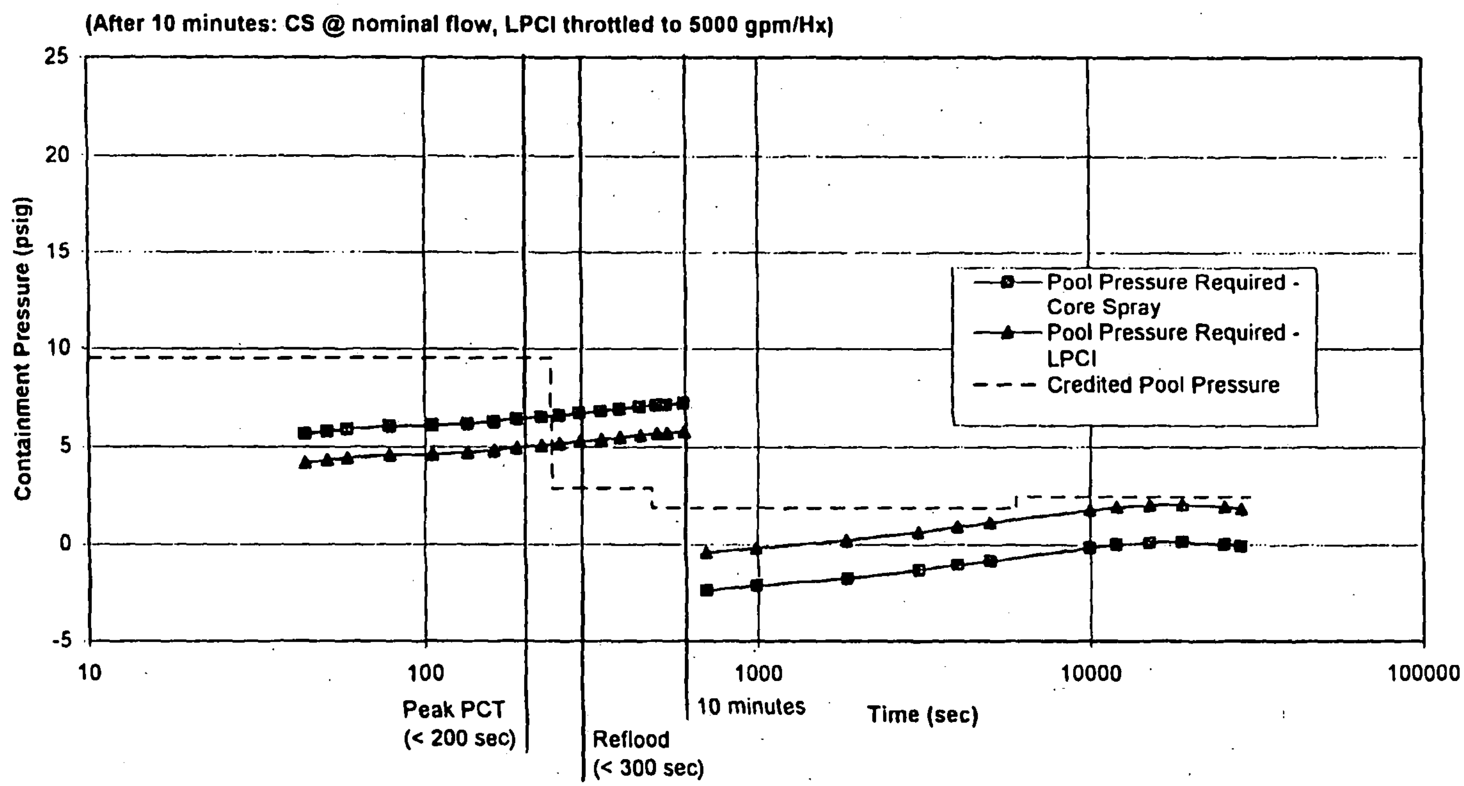


UFSAR REVISION 2, JUNE 1997

DRESDEN STATION
UNITS 2 & 3

MINIMUM CONTAINMENT PRESSURE AVAILABLE AND CREDITED CONTAINMENT PRESSURE FOR PUMP NPSH

FIGURE 6.3-83



UFSAR REVISION 2, JUNE 1997
DRESDEN STATION UNITS 2 & 3
CREDITED CONTAINMENT PRESSURE FOR PUMP NPSH
FIGURE 6.3-84

C. The HVAC systems are capable of detecting and protecting control room personnel from radioactive contamination, smoke, or toxic gas released to the atmosphere.

D. Emergency breathing air, supplied by a bottled air reservoir or by self-contained air packs, is provided to protect control room personnel from exposure to contaminated air.

E. The HVAC system Train A is capable of manual transfer from the normal operating mode to the smoke purge mode. The HVAC systems are capable of manual transfer from the normal operating mode to the isolation/pressurization or isolation/recirculation modes. Emergency monitors and control room equipment are provided as necessary to ensure this capability, as described in Sections 6.4.4.1, 6.4.4.2, and 6.4.4.3.

The control room is a Class I structure. Seismic design is addressed in Section 3.7.2. Seismic qualification of instruments and electrical equipment is addressed in Section 3.10. Missile protection is addressed in Section 3.5.2.

6.4.2.1 Definition of Control Room Emergency Zone

SRP 6.4 provides guidance for defining the boundaries for a control room emergency zone. Within this zone, the plant operators are adequately protected against the effects of accidental radioactive gas releases. This zone also allows the control room to be maintained as the center from which emergency teams can safely operate during a design basis radiological release. To accomplish this, the following areas are included in the emergency zone:

A. Main control room for Units 1, 2, and 3, which includes kitchen, toilet, and locker rooms;

B. Auxiliary computer room for Units 2 and 3; and

C. Train B HVAC equipment room.

Areas outside the emergency zone are isolated in emergency conditions. Support rooms such as the Shift Supervisor's office are accessible to operators with the aid of breathing equipment. The Train A HVAC equipment room and the auxiliary electrical equipment room are not included in the emergency zone. The boundaries of the control room emergency zone envelope are shown on Figure 6.4-1. A simplified diagram of the control room HVAC system is included in this figure.

Figure 6.4-2 shows the arrangement of equipment in the control room and points of entry. Figure 6.4-3 is a plan view showing the location of radioactive material release points and control room air inlets.

6.4.2.2 Ventilation System Design

The HVAC equipment described in this section is also discussed in Section 9.4.1, which explains normal use of the equipment. This section addresses emergency service requirements and the response and operation of control room HVAC equipment under emergency conditions. The control room HVAC system is shown in the control room HVAC P&IDs: Figures 9.4-1 (Drawing M-273, Sheet 1), 9.4-2 (Drawing M-273, Sheet 2), and 9.4-3 (Drawing M-3121).

The control room HVAC system consists of a Train A HVAC system, a Train B HVAC system, an air filtration unit, and a smoke detection system. The multizone Train A system is the primary train for the control room emergency zone. Since Train A is used primarily during normal operations, it is described in Section 9.4.

The Train B HVAC system is a single zone system which provides the necessary cooling required in case of failure of the Train A system. The discharge air from the air handling unit (AHU) is divided into three branches which tie into the zone distribution system of Train A. The air distribution from each train is aligned through the use of air-operated isolation dampers. These dampers fail to the Train B mode since this train is powered from the emergency bus during a loss of offsite power (LOOP). The Train B AHU contains a centrifugal supply air fan, a direct-expansion cooling coil, and a medium-efficiency filter bank.

Train B provides cooling through the use of a 90-ton reciprocating compressor and direct-expansion cooling coil. The condensing unit is normally cooled with the service water system. However, upon loss of service water, the condenser may be cooled with the containment cooling service water (CCSW) system. The CCSW supply to the refrigerant condenser can be drawn from either loop of the Unit 2 CCSW system.

The air filtration unit (AFU) maintains control room pressure when the HVAC system is in the isolation/pressurization mode by supplying 2000 ft^3/min of filtered makeup air from the outside. The AFU can be used in conjunction with either the A or B HVAC trains. This component consists of an inlet damper, prefilter, electric heating coils, High Efficiency Particulate Air (HEPA) prefilter, fire protection line, activated charcoal adsorber, HEPA afterfilter, and two full-capacity fans and outlet dampers. The AFU complies with Regulatory Guide 1.52 and is located in the Train B HVAC equipment room. An exception to NRC Regulatory Guide 1.52 allows the laboratory testing of the AFU charcoal efficiency to have a methyl iodide penetration of less than 0.50% in lieu of the Regulatory Guide Value of less than 0.175%

The makeup air intake and exhaust dampers are bubbletight, with an area of 25 square feet each and a leakage factor of zero. The exhaust dampers for the kitchen and locker room/toilet exhaust ducts are leaktight. Isolation of the normal makeup air intake takes approximately 20 seconds.

6.4.2.3 Leak-Tightness

The infiltration of unfiltered air into the control room emergency zone occurs through three different paths:

A. Through the emergency zone boundary;

6.4.4 Design Evaluations

This section evaluates the effectiveness of the HVAC system design in protecting the control room personnel from the postulated hazards of radioactive material, toxic gases, and smoke contaminating the control room atmosphere.

6.4.4.1 Radiation Protection

The control room HVAC system provides radiation protection by pressurizing the control room emergency zone with filtered air, isolating the normal outdoor air intakes, and isolating the kitchen and locker room exhaust fan dampers. This zone isolation with a filtered pressurization air-type system provides radiation protection by minimizing the infiltration of unfiltered air into the control room emergency zone. A positive pressure of ⅛-in.H_2O with respect to adjacent areas is maintained by passing 2000 ft^3/min of outdoor air through a HEPA filter unit with an iodine removal efficiency of 99%. The filter unit, booster fans, and associated controls are powered from the emergency bus.

Radiation protection is provided to allow control room access and occupancy for the duration of a DBA. Satisfactory protection is provided based on isolating and pressurizing the control room emergency zone with filtered outdoor air no later than 40 minutes after radiation has been detected in the reactor building ventilation manifolds. The control room operator doses are within the limits of GDC-19 and SRP 6.4, as analyzed in Section 15.6.5.3.

Operator action is required within the time limit specified above to isolate the control room emergency zone and to activate the air filter unit. In the event of LOOP and LOCA condition, the additional operator actions include disabling toxic gas protection interlocks to activate the Air Filtration Unit. Isolation consists of closing the outdoor air intakes for both the Train A and B systems and closing the kitchen and locker room exhaust isolation dampers. Additionally, the exhaust fans are tripped from limit switches on the isolation dampers, thereby preventing the induction of unfiltered air into the control room via the exhaust duct.

In the event of a LOOP or loss of instrument air, the isolation dampers fail to the isolation/pressurization mode. However, the pneumatic AFU booster fan discharge dampers also fail closed, thereby requiring manual operation prior to activating the booster fans during loss of instrument air. This failure mode is required to protect the emergency zone from a toxic chemical release during a loss of instrument air.

Section 15.6 contains an evaluation of the maximum expected dose to the control room during a DBA.

6.4.4.2 Toxic Gas Protection

The control room HVAC system provides toxic gas protection to the control room emergency zone in case of either an onsite or offsite toxic chemical accident. The results of the toxic chemical survey are provided in Section 2.2.3. An analysis of survey results was carried out to conform to Regulatory Guide 1.78, which discusses the requirements and guidelines to be used for determining the toxicity of chemicals in the control room following a postulated accident. The guidelines for

The estimated probabilities of control room uninhabitability due to release of ammonia or ethylene oxide are an order of magnitude below the SRP 2.2.3 criterion for realistic estimates. Therefore, the proposed risk is acceptable and monitoring is not required.

6.4.4.3 Fire and Smoke Protection

The control room HVAC system is designed to isolate and maintain the design conditions within the control room during fires in either the control room or the auxiliary computer room, or outside the emergency zone.

Smoke detectors, located in the control room and auxiliary computer room return air ducts, will annuciate in the control room and the Train A HVAC system will be switched manually to the smoke purge mode. During this mode, the system supplies 100% outdoor air. This will prevent the recirculation of smoke into any of the occupied areas in the event of fire while exhausting 100% of the return air to the outdoors. The smoke purge capability is only available on Train A.

SCBA units are located in the control room. In addition, a bank of emergency air bottles is located in the Unit 2 battery room, and can be connected to the SCBAs by 50-foot hoses stored in the control room. The control room emergency air system can be used during release of radioactivity, toxic gas, or smoke.

6.4.5 Testing and Inspection

The AFU is periodically operated and tested. At least once per month the unit is operated at design flow with the heaters operating to prevent the buildup of moisture on the charcoal adsorbers. The HEPA filters are tested periodically to demonstrate a removal efficiency of 99% of 0.3-μm dioctylphthalate (DOP) aerosol. The charcoal adsorbers are tested periodically by performing a laboratory analysis on a test canister of each bank to demonstrate an overall methyl iodide removal efficiency of at least 99%. The charcoal adsorber system is leak tested using an in-place halogenated hydrocarbon test. The pressure drop across the AFU filters is periodically checked to determine the need for filter maintenance.

6.4.6 Instrumentation Requirements

The AFU has instrumentation installed to support the testing outlined in Section 6.4.5. Differential pressure is monitored across the rough prefilter, the HEPA prefilter, the HEPA afterfilter, and the complete unit. Temperature is monitored at the inlet, after the electric heater, and after the activated carbon adsorber bed. An additional readout is provided as part of the electric heater temperature control circuit. The temperature element after the activated carbon adsorber provides an interlock to allow the fire protection deluge to be activated.

6.5 FISSION PRODUCT REMOVAL AND CONTROL SYSTEMS

6.5.1 Engineered Safety Feature Filter Systems

The secondary containment system is the only engineered safety feature (ESF) which uses a filter system to control fission product releases. This filter system is the standby gas treatment system (SBGTS) described in Section 6.5.3. The ESFs are described in Section 6.0.

6.5.2 Containment Spray Systems

The containment spray system is part of the containment cooling system described in Section 6.2.2.

6.5.3 Fission Product Control Systems

The SBGTS is provided to maintain a small negative pressure in the reactor building under isolation conditions, in order to prevent ground level escape of airborne radioactivity. Filters are provided to remove radioactive particulates, and charcoal adsorbers are provided to remove radioactive halogens which may be present in concentrations significant to environmental dose criteria. Any radioactive noble gases passing through the filter/adsorbers are diluted with air and dispersed into the atmosphere from the 310-foot chimney. The system is also used to dispose of purge and vent gases from the primary containment, and to assist with containment inerting/deinerting. The exhaust duct radiation monitor provides a continuous indication of radioactivity entering the system, and the chimney monitor samples the effluent. The SBGTS is shown in Figure 6.5-1. The primary containment vent, purge, and inerting systems are discussed in Section 6.2.5. The radiation monitoring system is discussed in Section 11.5.

6.5.3.1 Design Objectives

The system is sized to maintain the reactor building at a negative pressure of ¼ in.H_2O relative to the atmosphere under neutral wind conditions. The nominal flowrate is 4000 ft^3/min to achieve these objectives. Two separate filter/ adsorber/ fan units are provided. One train is selected as primary and the other train is placed in standby. If the primary train fan or heater fails to start, the standby train will be started automatically. Both units receive power from the emergency electrical supply. The system is designed for Class I seismic conditions. The equipment is located in the shielded center tunnel between the two main condenser rooms. The exhaust pipe runs through the radwaste building and up into the 310-foot chimney.

6.5.3.2 System Description

In the direction of airflow, each standby gas treatment unit has the following major components:

A. Inlet valve — This is a motor-operated butterfly valve which is normally closed. It opens automatically upon system initiation.

B. Cooling air supply line — This line draws 300 ft^3/min of cooling air from the turbine building to remove decay heat from the standby SBGTS train, or can be used to purge contaminated air from the SBGTS area. Upon initiation of the primary train, a normally open motor-operated butterfly valve closes to isolate this train from the line. Cooling air is drawn via the supply line through another normally open valve into the standby train.

C. Demister — The demister reduces the moisture content of the steam-air mixture routed through SBGTS. It consists of a woven nylon mesh which traps water droplets. Water removed from the steam-air mixture is routed through a loop seal arrangement to the "A" waste neutralizer tank in the radwaste building.

D. Electric heater — The electric heater raises the temperature of the entering air by at least 14°F to ensure a relative humidity of less than 70%. The heater energizes automatically upon adequate system flow. A downstream temperature switch can deenergize the heater to ensure that the activated charcoal bed is not damaged by excessive heat. The heater is powered from the emergency bus.

E. Rough prefilter — The rough prefilter removes dust and other debris which may enter the system. This filter increases the usable life of the downstream high efficiency particulate air (HEPA) prefilter. The prefilter is capable of withstanding a temperature of 500°F.

F. HEPA prefilter — Radioactive particulates entering the SBGTS are removed by the HEPA prefilters. The HEPA filters are designed to have a removal efficiency of not less than 99% for 0.3-μm particles and were factory-tested with thermally generated dioctylphthalate (DOP) aerosol to verify this capability. The HEPA prefilter is designed to withstand 500°F temperatures.

G. Activated charcoal adsorber — Filtered air is passed through an activated charcoal adsorber bed capable of removing 95% of fission product iodine. Flowrates above the design range lower air retention time and lower the bed's efficiency. Carbon bed capacity is approximately 200 grams of iodine. Samples of the carbon are placed in the adsorber inlet for periodic removal and analysis. High temperature charcoal (626°F ignition temperature), framing, and sealing materials are specified. The bed consists of charcoal adsorbent contained in twelve cells. Each cell contains at least 45 pounds of activated charcoal for a total bed weight of at least 540 pounds. The design charcoal adsorption requirement is 95% methyl iodide removal at a relative humidity of 70% and a temperature of 30°C (86°F). The geometry of the SBGTS charcoal cells is shown on

Figure 6.5-2. Replacement charcoal shall be qualified according to the guidelines of Regulatory Guide 1.52.

H. Test orifice — A test orifice is installed downstream of the charcoal adsorber bed during system testing. The orifice produces turbulent gas flow for more complete mixing, ensuring that the sample taken is a representative one. This orifice also serves as a flow element to automatically start the standby train on low flow in the primary train.

I. HEPA afterfilter — The HEPA afterfilters are similar to the HEPA prefilters (see Item F) and are provided to remove any activated charcoal particles that may be released from the activated charcoal adsorber.

J. Crosstie line — A crosstie line, with restricting orifice and manual butterfly valve (which is normally locked open), interconnects the two trains so that the operating train fan can provide filter decay heat cooling air at the proper flowrate through the idle train. The valve allows isolation of the two trains when required for test purposes or when one train is down for maintenance.

K. Flow control valve — This is an air-operated butterfly valve which maintains the flowrate through the train at 4000 ft^3/min ±10% (4300 ft^3/min through the system when cooling the standby train). This valve is normally open and is controlled by the flow element in the discharge line to the 310-foot chimney.

L. Fan — The fans operate in parallel from a common system inlet plenum to provide flow through the two separate parallel trains. They are located downstream of the filters to minimize contamination during maintenance. Fan performance is discussed in Section 6.5.3.3. The fan performance curve is shown on Figure 6.5-3.

M. Backdraft damper — A backdraft damper is provided to ensure that reverse flow through the SBGTS filter train, which could spread contamination, will not occur. This damper acts as a check valve and closes whenever airflow into the exhaust fan occurs.

N. Outlet valve — This is a motor-operated butterfly valve which is normally closed. It opens automatically upon system initiation.

The SBGTS intake ducts can take suction from the reactor building ventilation system exhaust duct, the HPCI gland seal condenser exhaust, the ACAD system, the cooling air supply line, or from primary containment. The discharges from the two SBGTS trains are joined together and the discharge from the system is routed to the 310-foot chimney through a common line. Note: valve MO 2-7503 is retained open with remote control removed.

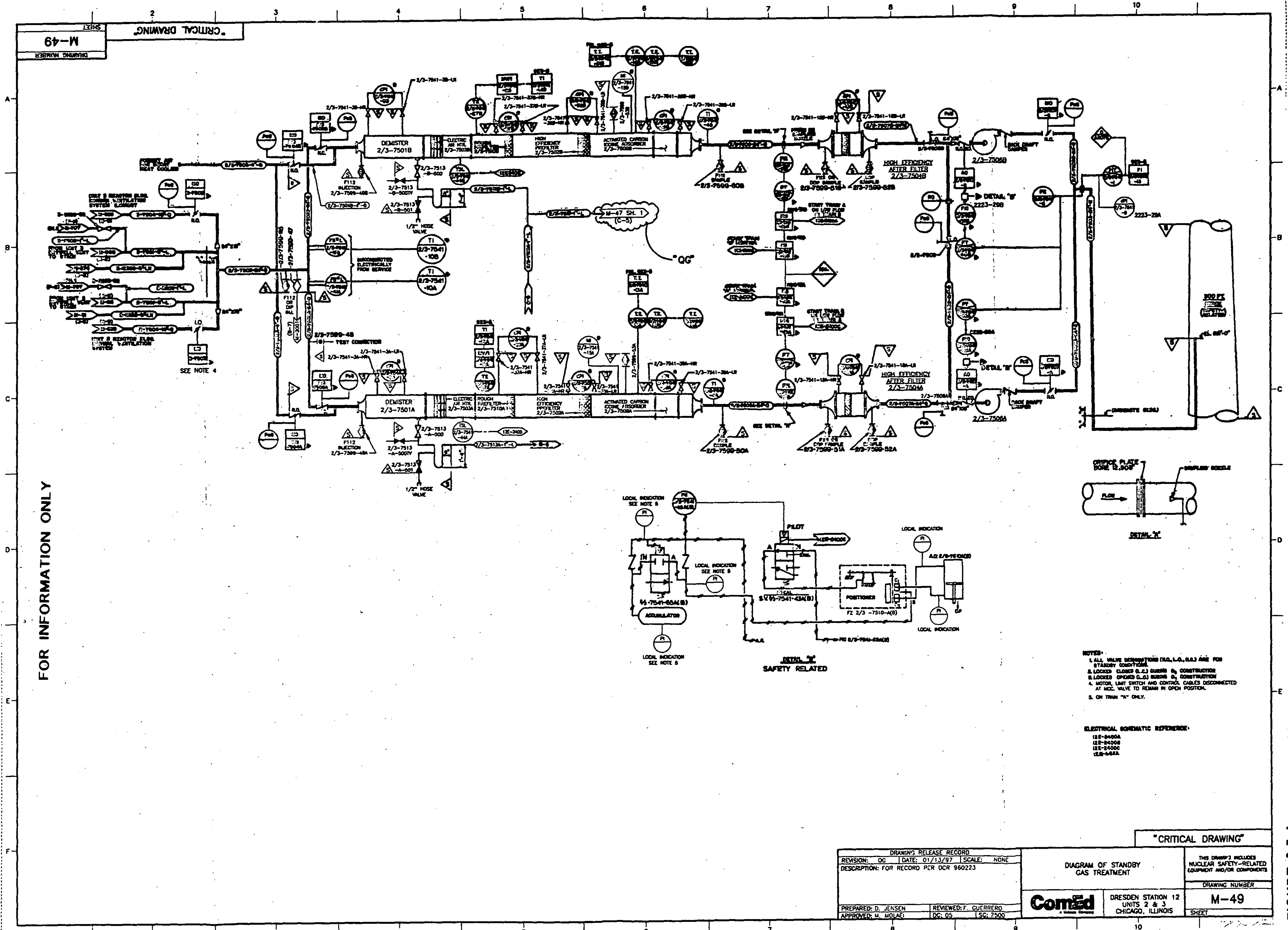
SBGTS can be started manually, but is automatically initiated by a secondary containment isolation signal (as described in Section 6.2.3).

maintenance. Testing for clogging or leakage is performed periodically, as directed by the Technical Specifications.

The in-place efficiency of each HEPA filter is tested periodically with the DOP portable instrumentation. The testing must demonstrate at least 99% efficiency. Iodine removal efficiency of the charcoal adsorber is tested periodically by laboratory analysis of a test canister removed from the adsorber.

6.5.3.5 Instrumentation Requirements

The SBGTS system has instrumentation installed to support the testing outlined in Section 6.5.3.4. Differential pressure is monitored across the demister, rough prefilter, HEPA prefilter, activated charcoal bed, and HEPA afterfilter. Temperature is monitored before and after the electric heater, and before and after the activated charcoal adsorber bed. Humidity is locally indicated at the adsorber bed inlet. System flowrate is monitored at the flow control valves, at a flow element in the common discharge line and in the control room. Parameters which cause automatic initiation of the SBGTS, along with damper positions and fan operation, are monitored in the control room.



CENTRAL DRAWING FACILITY 16 X

FIGURE 6.5-1

REV. 02 / JUNE 1997

7.0 INSTRUMENTATION AND CONTROLS
TABLE OF CONTENTS

Page

7.0 INSTRUMENTATION AND CONTROLS
TABLE OF CONTENTS

Page

7.0 INSTRUMENTATION AND CONTROLS
LIST OF FIGURES

E. The turbine control valve fast closure inputs to the RPS are from pressure switches on each of the four fast-acting solenoid valves which initiate fast closure of the control valve.

F. Turbine stop valve closure inputs to the protection system are from valve stem position switches located on each of the four turbine stop valves. Each switch provides an independent signal to an RPS logic subchannel. The logic is such that partial closure of any three stop valves initiates a scram.

G. Sensors which monitor reactor pressure vessel parameters are discussed in Section 7.6.

H. Nuclear instrumentation is described in Section 7.6. Nuclear instrumentation channel assignments to RPS trip logics are as follows:

1. A1 — IRM 11, 13; APRM 1, 3

2. A2 — IRM 12, 14; APRM 2, 3

3. B1 — IRM 15, 17; APRM 4, 5

4. B2 — IRM 16, 18; APRM 4, 6

I. The main steam line radiation monitors which provide RPS inputs are from four sensors, each of which monitors all four main steam lines. They are further described in Section 11.5.

7.2.3 Design Evaluation

In terms of protection system nomenclature, the dual logic channel reactor protection system is a one-out-of-two-twice system. Theoretically, its reliability is slightly lower than a one-out-of-two system. However, since the reliability differences are slight, they can be neglected. The advantage of the dual logic channel reactor protection system is that it can be tested completely during full-power operation. This capability for a thorough testing program, which contributes significantly to increasing reliability, is not possible on a one-out-of-two system. Topical Report APED-5179[1] presents a full discussion of the reliability of the dual logic channel system.

A failure of any one RPS input or component produces a trip in just one subchannel of one logic channel, a condition insufficient to produce a reactor scram. This resistance to spurious scrams contributes to plant safety since unnecessary cycling of the reactor through its operating modes would increase the probability of error or actual failure. The circuits are isolated to preclude a fault in one circuit from propagating to another and to reduce the likelihood that severe environmental influence, which might adversely affect reliability, will affect more than one circuit. The sensors are dispersed; both sensors in one logic channel are not allowed to occupy the same general region or to be connected to a common header or point. The wiring is dispersed so that a single fire or accident would probably not affect more than one input to the protection system. The relays associated with the contacts feeding one subchannel scram relay are isolated from corresponding circuits in the other scram relay subchannel.

Since each control rod is scrammed as an independent unit, the failure of any one rod to scram does not affect the ability of the other rods to scram.

Additional scram reliability is provided by the backup scram valves, which energize from dc power when both logic channels are tripped. The backup scram valves relieve instrument air pressure from the scram valves when the solenoids are energized, resulting in a scram.

The response of the RPS is sufficiently rapid to prevent the release of radioactive material in excess of the limitations of 10 CFR 100 following the design basis accidents. The system response times from the opening of the sensor contacts up to and including the opening of the trip actuator contacts shall not exceed 50 milliseconds.

The RPS response to single component malfunctions or single operator errors is sufficient to prevent fuel damage. Single component malfunctions have been evaluated in Section 7.2.5.2.

The primary sensors for subchannels A1 and B1 share the same set of sensing lines. Those for subchannels A2 and B2 share a different set of sensing lines. The two sets of sensing lines servicing the two trip systems are geometrically separated by approximately 180° in azimuth and pass through drywell penetrations that are greater than 50 feet apart and are in separate rooms, in accordance with the separation criterion.

The wiring to the independent sensors for trip system A run in different conduits or trays from those of trip system B. The system is connected such that the channels of each trip system are electrically isolated from each other so that a failure of one channel cannot prevent a valid trip of the second channel of the trip system. The system thus meets the single-failure criterion and channel separation criterion. The highest quality materials and components were used in the design of the system.

The RPS meets IEEE 279 in that single failures in the system do not prevent the system from producing valid scrams, while the system design provides for maximum system availability by preventing or reducing the number of spurious scrams. The system is arranged to provide for physical separation of components and electrical isolation.

The design of the dual logic channel RPS facilitates maintenance and troubleshooting. Most faults annunciate themselves, and those that do not are easily located, without ambiguity, by testing.

The component parts used in the dual logic channel reactor protection system have been used in volume for many years in critical industrial applications. The parts are suitably derated to prolong life and increase the margin of safety.

The power supply for the RPS consists of two independent electrical buses (Figure 7.2-4). The components, wiring, and relays are seismically qualified as Class 1E at the interface of the power supply and the RPS.

The RPS bus breakers are equipped with mechanical interlocks to prevent both an M-G set and the reserve power source from simultaneously supplying power to an RPS bus. The normal feed for RPS bus A (M-G set B) is MCC 28-2(38-2). The normal feed for RPS bus B (M-G set A) is MCC 29-2(39-2). Either bus may be fed from the reserve feed from MCC 25-2(35-2).

A key interlock system, consisting of two locking devices on the reserve power supply breakers that require the same key, prevents reserve power from supplying more than one RPS bus at a time. It prevents cross-connecting the independent buses and overloading the reserve power instrument transformer.

During a power loss to the M-G set, the high-inertia flywheel is designed to maintain generator output within 5% of rated values for at least one second to keep the RPS bus energized. The non-Class 1E RPS M-G sets are provided with relaying to trip on undervoltage and underfrequency conditions.

In addition, two Class 1E electrical protection assemblies (EPAs) are in series between each RPS power supply and its RPS bus breaker (see Figure 7.2-4). The EPAs protect the Class 1E components powered by the RPS buses from abnormal voltage and frequency conditions resulting from failures of the non-Class 1E power supplies (RPS M-G sets or reserve power supply). Each EPA includes a breaker and associated monitoring module consisting of overvoltage, undervoltage, and underfrequency relays which trip the EPA breaker.

7.2.4 Surveillance and Testing

The trip circuitry is arranged to facilitate testing. A test signal can be applied to one input at a time. If the test signal exceeds the limit, a single logic channel trip occurs. Switches are installed in series with each pilot scram valve solenoid to facilitate scramming a single rod so that rod travel time can be measured. A single rod scram proves that each rod tested can be inserted by means of the scram valves within the time specified for rod travel.

Pressure switches are on/off devices. The signal used to test these devices is an actual pressure. Other on/off devices are tested similarly with basic signals.

Analog devices, notably the flux monitoring channels, are tested in two phases. First, the device must show reasonable agreement with similar devices and must respond normally to power level changes and control rod movements. Second, a dummy electrical signal may be introduced using the amplifier already tested. This dummy signal is adjusted until the setpoint limit is exceeded in order to initiate a single logic channel trip.

The reactor protection system is designed to fail safe. In every case a failure is annunciated so that the location of the failure can be ascertained without ambiguity.

A routine testing schedule is arranged to assure that a system failure can be identified and corrected. The testing prevents system degradation over time. Surveillance frequency is specified in Technical Specifications.

Table 7.2-1

TYPICAL PROTECTION SYSTEMS SETPOINTS

Signal	Scram Setpoint[3]
Reactor High Pressure	1060 psig
Reactor Low Level	1 in.[1]
Reactor High Neutron Flux	
APRM	(See Technical Specifications)
IRM	120%/125% of full scale
Main Steam Line High Radiation[2]	3 times normal background
Primary Containment High Pressure	2.0 psig
Condenser Low Vacuum	21 in.Hg vacuum
Scram Discharge Volume High Level	Unit 2: ≤ 40.4 gallons Unit 3: ≤ 41 gallons
Turbine-Generator Load Rejection	460 psig oil pressure at the control valve
Main Steam Line Isolation Valve Closure	10% closure
Turbine Stop Valve Closure	10% closure
Loss of Turbine Control Oil Pressure	900 psig

Notes:

1. One-inch instrument level = 504 inches above vessel zero.

2. (Unit 2 only) Due to addition of hydrogen to the primary coolant, the main steam line radiation monitor setting will be less than or equal to 3 times full power background without hydrogen addition for all conditions except for greater than 20% power with hydrogen being injected during which the main steam line radiation trip setting will be less than or equal to 3 times full power background with hydrogen addition. Required changes in main steam line radiation monitor trip setting will be made within 24 hours except during controlled power reduction at which time the setpoint change will be made prior to going below 20% power. If, due to a recirculation pump trip or other unanticipated power reduction event, the reactor is below 20% power without the setpoint change, control rod motion will be suspended until the necessary trip setpoint adjustment is made.

3. Data on alarm setpoints can be obtained from Technical Specifications Table 2.2.A-1.

B. Four independent low-low reactor water level transmitters and trip units; and

C. Two independent low reactor pressure switches.

The core spray initiation signal requires one of the following logic combinations:

A. High drywell pressure (one-out-of-two-twice);

B. Low-low reactor water level (one-out-of-two-twice) coincident with low reactor pressure (one-out-of-two); or

C. Low-low reactor level (one-out-of-two-twice) sustained for 8.5 minutes (one-out-of-one). This signal is generated by the ADS system logic.

The core spray initiation signal starts the core spray pumps, opens the suction valves (if closed) and closes the test bypass valves (if open). The operator can, in the event of a system line break, override the automatic opening of the suction valves and close them.

Opening of the admission valves is accomplished only after the reactor pressure decays to approximately the design discharge pressure of the pump. The reactor low pressure is detected by two pressure switches connected in a one-out-of-two logic array. The permissive signal which opens the core spray admission (discharge) valves requires this low reactor pressure signal and voltage at the applicable 4160-V ESF bus in addition to the core spray initiation signal.

With normal auxiliary ac power available, the actions described above occur automatically and without delay. A diesel generator start signal is generated by either a low-low reactor water level signal or high drywell pressure signal (both one-out-of-two-twice logic). If normal power is not available, the pumps are started sequentially as described in Sections 6.3 and 8.3.

While the pump is running but prior to the admission valve opening, flow is through minimum flow valves which automatically close when flow to the reactor vessel is established. The minimum flow valves are interlocked with the pump breakers such that stopping the core spray pump or placing the pump control switch in the PULL-TO-LOCK position allows the minimum flow valve to be positioned in either the open or closed position using its control switch. The minimum flow valves are provided with logic which allows the operator to close the valves from the control room even with a core spray initiation signal present. This logic allows the minimum flow valves to be closed to perform their closed loop isolation function as required by General Design Criteria (GDC) 57.[1]

7.3.1.1.1 Conformance to IEEE 279-1968

The following subsections present a point-by-point comparison of the core spray system with the requirements of proposed IEEE 279-1968 which has been summarized from GE Topical Report, NEDO-10139.[2] For more detailed information, refer to the topical report.

relays are of the same types used in the reactor protection system (RPS) described in Section 7.2. Ratings have been selected with sufficient conservatism to insure against significant deterioration during anticipated duty over the lifetime of the plant (IEEE 279-1968, Paragraph 4.3).

7.3.1.1.1.4 Equipment Qualification

No components of the core spray or LPCI control system are required to operate in the drywell environment with the exception of the temperature compensating columns for the vessel level transmitters. These columns are calibrated for a specific normal ambient temperature and can introduce nominal errors under steam leak (high drywell temperature) conditions. Dresden emergency operating procedures provide guidance and limitations on the level instrumentation during elevated drywell temperature. All other sensory equipment is located in the reactor building outside the drywell and is capable of accurate operation even with wider swings in ambient temperature than those which result from normal or abnormal conditions (loss of ventilation and loss-of-coolant accident [LOCA]). The reactor vessel level sensors also provide input to the ATWS and are environmentally qualified.

All components used in the core spray control system have demonstrated reliable operation in similar nuclear power plant protection systems or industrial applications (IEEE 279-1968, Paragraph 4.4).

7.3.1.1.1.5 Channel Integrity

The core spray control system is designed to tolerate the spectrum of failures listed under general requirements (Section 7.3.1.1.1.1) and the single-failure criterion (Section 7.3.1.1.1.2); therefore, it satisfies the channel integrity objectives (IEEE 279-1968, Paragraph 4.5). Each of the two core spray loop sensors are backed up by sensors from the other loop so that neither system loses its integrity due to a failure or failures in its sensory equipment.

The core spray system control backup has been achieved without compromising the integrity of the channel being backed up. Analysis shows that complete destruction of a wireway (conduit) carrying wires between the two relay cabinets cannot prevent operation of both core spray loops. During a design basis accident, the control system environment does not differ significantly from normal.

7.3.1.1.1.6 Channel Independence

Channel independence of the sensors for each variable is provided by electrical isolation and mechanical separation (IEEE 279-1968, Paragraph 4.6). The A and C sensors for reactor vessel level are located on one local instrument rack (identified as Division I equipment), and the B and D sensors are located on a second instrument rack (identified as Division II equipment), widely separated from the first. The A and C sensors have a common process tap which is widely separated from the corresponding tap for sensors B and D. Disabling of one or both sensors at one location does not disable the control for either of the two core spray loops or two separate divisions of LPCI.

Relay cabinets for core spray system A are in a separate physical division from those for core spray system B. Likewise, relay cabinets for LPCI Division I are in a separate physical division from those for LPCI Division II. Each division is complete in itself, having its own station battery control, power distribution buses, and motor control centers. The divisional split is carried all the way from the process taps to the final control element. The split includes both control and motive power supplies.

7.3.1.1.1.7 Control and Protection Interaction

The core spray and LPCI systems are strictly on/off systems, and no signal whose failure could cause a need for core spray or LPCI can also prevent them from starting (IEEE 279-1968, Paragraph 4.7). Annunciator circuits using contacts of sensor relays and logic relays cannot impair the operability of system control due to the electrical separation between controls of the two core spray loops or the two LPCI divisions.

7.3.1.1.1.8 Derivation of System Inputs

The inputs which start the core spray and LPCI systems are direct measures of the variables that indicate the need for low pressure core cooling; reactor vessel low water, high drywell pressure, and reactor low pressure (IEEE 279-1968, Paragraph 4.8). Reactor vessel level is sensed by vessel water level transmitters. Drywell high pressure is sensed by nonindicating pressure switches on four separate sensing lines connected to two separate penetrations. Each sensing line has its own root valve, and each pressure switch has its own instrument valve. Four reactor vessel pressure switches for the low-pressure injection valve opening permissive are on four separate instrument lines going through the drywell at two different general locations (the A and C lines in one location and the B and D lines in a separate location). These switches operate relays whose contacts are connected in A-or-B and C-or-D logic for the core spray and LPCI valve opening permissives.

7.3.1.1.1.9 Capability for Sensor Checks

All sensors are pressure-sensing-type sensors and are installed with calibration taps and instrument valves to permit testing during normal plant operation or during shutdown (IEEE 279-1968, Paragraph 4.9). This discussion also applies to the LPCI system.

7.3.1.1.1.10 Capability for Test and Calibration

The core spray and LPCI control systems are capable of being completely tested during normal plant operation to verify that each element of the system, active or passive, is capable of performing its intended function (IEEE 279-1968, Paragraph 4.10).

7.3.1.1.1.11 Channel Bypass or Removal from Operation

Calibration of any sensor introduces a single instrument channel trip. This trip does not cause a protective function without coincident operation of a second channel. Removal of an instrument channel from service during calibration is brief and in compliance with a special provision of IEEE 279-1968, Paragraph 4.11, for one-out-of-two-twice systems. This discussion also applies to the LPCI system.

7.3.1.1.1.12 Operating Bypasses

There are no operating bypasses for the core spray system.

7.3.1.1.1.13 Indication of Bypasses

There are no automatic bypasses of any part of the core spray or LPCI control systems, but manual bypassing of high drywell pressure inputs is permitted in order to purge the drywell as required. This bypass is annunciated (IEEE 279-1968, Paragraph 4.13). Deliberate opening of a valve motor breaker gives indication in the control room because both valve position lights would be deenergized.

7.3.1.1.1.14 Access to Means for Bypassing

Access to switchgear, motor control centers, and instrument valves is procedurally controlled. This discussion also applies to the LPCI system.

7.3.1.1.1.15 Multiple Trip Settings

Paragraph 4.15 of IEEE 279-1968, which deals with multiple trip settings, is not applicable because all setpoints are unique.

7.3.1.1.1.16 Completion of Protection Action Once Initiated

The final control elements for the core spray system are essentially bistable; that is, pump breakers stay closed without control power, and motor-operated valves stay open once they have reached their open position, even though the motor starter drops out when the valve open limit switch is reached. In the event of an interruption in ac power, the control system will reset itself and recycle on restoration of power. Thus, protective action once initiated must go to completion or continue until terminated by deliberate operator action (IEEE 279-1968, Paragraph 4.16). This discussion also applies to the LPCI system.

7.3.1.1.1.17 Manual Actuation

Each piece of core spray actuation equipment (pump, valve, breaker, or starter) is capable of individual manual initiation, electrically from the control panel in the main control room and locally, if desired, by use of physical mechanisms (IEEE 279-1968, Paragraph 4.17). The valves have handwheels for manual operation, and the switchgear is capable of having the closing springs charged manually and the breaker closed by mechanical linkages on the switchgear.

In no event can failure of an automatic control circuit for one core spray loop disable the manual electrical control circuit for the other core spray loop. Single electrical failures cannot disable manual electric control of the core spray function.

7.3.1.1.1.18 Access to Setpoint Adjustments

Setpoint adjustments for the core spray and LPCI system sensors are located on the slave trip units in the ATWS cabinets. A card file locking bar prevents unauthorized access to the setpoint adjustments. Test points are incorporated into the control relay cabinets which are located in limited access areas. The range of the drywell and reactor vessel pressure switches is not adjustable. The reactor vessel level transmitters have zero and span adjustments that are external to the transmitters but require removal of the nameplate. Because of these restrictions, compliance with the access requirements of IEEE 279-1968, Paragraph 4.18, is considered complete.

7.3.1.1.1.19 Identification of Protective Actions

Protective actions (here interpreted to mean pickup of a single sensor relay) are directly indicated and identified by action of the sensor relay, which has an identification tag and a clear glass front window permitting convenient, visible verification of the relay position. Any one of the sensor relays actuates an annunciator, so no single-channel trip (relay pickup) can go unnoticed. Either indication should be adequate, so this combination of annunciation and visible verification of relay actuation fulfills the requirements of IEEE 279-1968, Paragraph 4.19. In addition, indicator lights are provided to show pickup of sensor relays. This discussion also applies to the LPCI system.

7.3.1.1.1.20 Information Readout

The core spray and LPCI control systems are designed to provide the operator with accurate and timely information pertinent to its status. It does not introduce signals into other systems that could cause anomalous indications confusing to the

The LPCI system is automatically actuated by the same signals and trip logic as described for the core spray system. These signals are generated by the following sensors:

A. Four independent high drywell pressure switches;

B. Four independent low-low reactor water level transmitters and trip units; and

C. Two independent low reactor pressure switches.

The LPCI initiation signal requires one of the following logic conditions:

A. High drywell pressure (one-out-of-two-twice). This trip is at 2 psig;

B. Low-low reactor level (one-out-of-two-twice) coincident with low reactor pressure (one-out-of-two); or

C. Low-low reactor level (one-out-of-two-twice) sustained for 8.5 minutes (one-out-of-one). This signal is generated by the ADS system logic.

Figures 7.3-2A and 7.3-2B are functional control diagrams that show various interlocks in the LPCI subsystem.

Upon receipt of an initiation signal with normal ac power available, the following actions occur:

A. Diesel generators start;

B. Permissives become available to activate pumps and valves;

C. All four LPCI pumps start and run on minimum flow until loop selection is made;

D. Pump suction valves open (if closed), valves interlock in the open position;

E. Containment cooling service water pumps stop (if running) and containment cooling heat exchanger service water outlet valves close; and

F. Necessary valves close or open (as needed) to establish the full LPCI flow. (Injection valves do not open until reactor low pressure interlock has cleared.)

The operator can, in the event of a system line break, override the automatic opening of the suction valves and close them.

If normal ac power is not available, pumps are started sequentially once the diesel generators accelerate to operating speed. See Sections 6.3 and 8.3 for additional information.

The injection valves are opened on a preset reactor low-pressure signal. The valve operation is similar to that of the valving on the core spray system.

Each LPCI loop has a minimum flow valve that opens (if closed) on pump start but prior to injection valve opening and automatically closes when sufficient cooling flow is established. The valve control is based on flow through its associated loop. The LPCI minimum flow valves are interlocked with the LPCI pump breakers. By stopping or placing the LPCI pump control switch for a given loop in the PULL-TO-LOCK position, the associated minimum flow valve may be positioned in either the open or closed position by operation of its control switch even with an accident signal present. If the LPCI pump starts, the minimum flow valve will operate properly to provide a minimum flow path as required. Logic is provided which allows the LPCI pump minimum flow valves to be maintained closed from the control room to perform their closed loop isolation function as required by General Design Criteria (GDC) 57.[1] Figure 7.3-4 is a functional control diagram for the minimum flow valve.

Interlocks are provided to prevent the diversion of LPCI injection flow, if any initiating signal is present, to ensure the flooding of the core (see Section 7.4).

7.3.1.2.2 Loop Selection Logic

On Unit 2 only, the loop selection logic is capable of generating an equalizer valve closure signal, however, the actuator motors of the two equalizer valves and the two equalizer bypass valves, are disconnected at the MCCs. These signals will not be discussed elsewhere in the loop selection logic. On Unit 3, the equalizing line has been removed.

The loop selection logic ensures that LPCI injection flow is directed to an unbroken recirculation pump loop. The operation of the logic depends on the number of operating recirculation pumps and the break location. The basic loop selection logic sequence initiated by either high drywell pressure or low-low water level is as follows (see Figure 7.3-5):

A. If either or both recirculation pump is not running, the pumping mode selector section of the logic trips both recirculation pumps and waits for reactor pressure to decrease to 900 psig to ensure a meaningful differential pressure measurement.

B. A time delay imposes a 2 second wait for momentum effects to establish the maximum differential pressure for loop selection.

C. Four differential pressure detectors compare the pressure between riser pipes in loop A and the corresponding riser pipes in loop B. The loop selection instrumentation is shown in Figures 7.3-6 (Unit 2) and 7.3-7 (Unit 3).

D. If the loop A pressure is greater than the loop B pressure, the logic selects loop A for injection.

E. If the loop A pressure is not greater than the loop B pressure (recirculation loop A is broken or neither recirculation loop is broken), a ½-second timer runs out causing loop B to be selected for injection.

7.3.1.2.3.13 Indication of Bypasses

The discussion of indication of bypasses for the core spray system (Section 7.3.1.1.1.13) also applies to the LPCI system.

7.3.1.2.3.14 Access to Means for Bypassing

Access to switchgear, motor control centers, and instrument valves is controlled as discussed in Section 7.3.1.1.1.14. Access to other means of bypassing (i.e., closure of pump suction valves by means of a control switch) are located in the main control room and, therefore, under the administrative control of the operator (IEEE 279-1968, Paragraph 4.14).

7.3.1.2.3.15 Multiple Trip Settings

IEEE 279-1968, Paragraph 4.15, which deals with multiple trip settings, is not applicable because all setpoints are unique.

7.3.1.2.3.16 Completion of Protection Action Once Initiated

The discussion of completion of protective action for the core spray system (Section 7.3.1.1.1.16) also applies to the LPCI system.

7.3.1.2.3.17 Manual Actuation

Each piece of LPCI actuation equipment required to operate (pumps and valves) is capable of manual initiation electrically from the control panel in the main control room (IEEE 279-1968, Paragraph 4.17).

7.3.1.2.3.18 Access to Setpoint Adjustments

The discussion of setpoint adjustments for the core spray system (Section 7.3.1.1.1.18) also applies to the LPCI system.

7.3.1.2.3.19 Identification of Protective Actions

The discussion of identification of protective actions for the core spray (Section 7.3.1.1.1.19) also applies to the LPCI system.

7.3.1.2.3.20 Information Readout

Sufficient information is provided on a continuous basis so that the operator can have a high degree of confidence that the LPCI function is available and/or operating properly (IEEE 279-1968, paragraph 4.20).

7.3.1.2.3.21 System Repair

The discussion of system repair for the core spray system (Section 7.3.1.1.1.21) also applies to the LPCI system.

7.3.1.2.4 Failure Mode and Effects Summary

Since the LPCI system is by itself a single system and, as such, vulnerable to single failures in common components, a detailed failure mode and effects analysis is not presented here. No single component, cable, wireway, or cabinet failure can disable the LPCI injection function of the system except the injection valves and specific portions of the loop selection circuitry. Those single failures that could possibly disable the LPCI system will not directly affect the core spray system. The low-pressure core cooling system is designed such that for any single failure the availability of two core spray loops or one core spray loop and two LPCI pumps will be maintained.

7.3.1.3 High Pressure Coolant Injection System Instrumentation and Control

7.3.1.3.1 Initiation and Interlocks

The HPCI subsystem is designed to pump water into the reactor under LOCA conditions which do not result in rapid depressurization of the pressure vessel. The loss of coolant might be due to a loss of reactor feedwater or to a small line break which does not cause immediate depressurization of the reactor vessel.

Automatic initiation of the HPCI system occurs on low-low reactor water level or high drywell pressure. Low-low reactor water level and high drywell pressure are detected by four independent level transmitters and pressure switches connected in one-out-of-two-twice logic arrays. When the initiation signal is received, the HPCI turbine and its required auxiliary equipment starts automatically and the required valves reposition automatically. A HPCI system initiation pushbutton is provided in the control room for rapid single action manual system initiation. Figures 7.3-8A, 7.3-8B and 7.3-8C are functional control diagrams of the HPCI system.

A minimum flow bypass valve which is provided for pump protection is automatically opened on low pump flow and closed on high flow whenever the steam supply valve to the turbine is open. Placing the minimum flow valve control switch in the PULL-TO-LOCK position closes the minimum flow valve under any system condition. The position of the minimum flow valve PULL-TO-LOCK switch is administratively controlled by station procedures.

In the event of low water level in the condensate storage tank or high water level in the suppression pool, whichever comes first, the pump suction valves from the suppression chamber open and the suction valves from the condensate storage tank close. The valves are interlocked to prevent opening the valves from the condensate storage tank whenever both valves from the suppression chamber are not fully closed.

Automatic isolation of the HPCI system is discussed in Section 7.3.2.

HPCI turbine stop valve closure will occur upon receipt of any of the following signals:

A. Turbine overspeed trip — A spring-loaded mechanical-type plunger, located in a housing threaded to the high pressure end of the turbine shaft. In the event the turbine overspeeds, the overspeed trip operates to actuate the emergency tripping mechanism closing the stop valve to shut off steam flow to the turbine. The plunger's center of gravity is off the axis of rotation in a direction which results in centrifugal forces tending to unseat the plunger. A retaining spring is factory-adjusted to hold the plunger on its seat up to the desired tripping speed when the centrifugal force will overcome the spring force and unseat the plunger. This occurs in a small fraction of a revolution. The plunger strikes the emergency trip mechanism actuating trigger thereby tripping the turbine. The device automatically resets when shaft speed has reduced approximately 20% from the trip setpoint.

B. Low pump suction pressure — A single pressure switch is used to detect excessive vacuum conditions at the pump suction, i.e., provide pump protection in the event of lost suction. (This trip is bypassed during automatic initiation of HPCI.)

C. High turbine exhaust pressure — Two pressure switches, connected in one-out-of-two logic, protect the turbine casing from overpressure without relying on the pressure relief system logic. This trip is initiated at a pressure of 100 psig (assuming flashing steam flow through the turbine with a locked rotor, it would be possible to obtain this high pressure condition).

D. Reactor vessel high water level — Two level sensors, connected in series logic, shutdown the HPCI subsystem when water inventory is normal.

There are no provisions for overriding any signals which shut down the HPCI subsystem. For those signals which have seal-in logic, the operator may reset the logic at any time after the signal clears. If the shutdown signal is no longer present, the HPCI subsystem is capable of auto-restart upon receipt of an initiation signal.

Numerous combinations of instrumentation logic have been used for the automatic signals and the turbine trip signals for the HPCI system. The justification for the differences in logic used follows:

A. The design is such that no single failure will result in a breach of the primary containment pressure integrity.

B. Where there is a high probability of spurious signals (e.g., for the steam leak detection system), the full complement of instrumentation has been selected and connected in one-out-of-two-twice logic.

C. Where trip signals are employed for equipment protection, single or double instrumentation has been used for simplicity and economics. In these instances, there is a low probability that the instrument failure would prevent system operation.

D. Finally, it must be noted that the single-failure criterion has not been used as a design basis for the HPCI system. The ADS is its backup.

7.3.1.3.2 HPCI Turbine Control Logic

The HPCI turbine control logic consists of three major components for speed control:

A. Speed governor — A mechanical flyball device which positions the valve portion of a primary pilot valve and bushing assembly. The speed governor serves a twofold function: speed setting in response to the other components of the turbine control logic and speed limiting by providing physical stops on the allowable movement of the primary pilot valve bushing. The speed governor is capable of limiting turbine speed to 4000 rpm.

B. Motor speed changer (MSC) — A remote manual speed control device covering a speed range from 0 to 4000 rpm. The MSC is automatically returned to its low speed stop (LSS) whenever the turbine stop valve is tripped. The function of the MSC is twofold: to prevent opening the turbine control valves until the stop valve is fully open and to provide for controlled startup of the turbine.

C. Motor gear unit (MGU) — An automatic speed control device covering a speed range from 2000 to 4000 rpm, the required range for HPCI system operation. The MGU is automatically positioned by the output signal from the flow controller. This control logic is essentially identical to that used for control of turbine-driven feed pump systems.

When the HPCI turbine is in the standby condition, the MGU is above the MSC speed, preferably at its high-speed stop (4000 rpm), receiving a maximum demand signal from the flow controller since flow is zero. The MSC is at its low-speed stop (0 rpm) since the stop valve is closed. The turbine control valves are closed since the MSC is at its low-speed stop. The turbine stop valve is closed, with no hydraulic pressure.

When an initiation signal is received, the following actions occur:

A. The auxiliary oil pump is automatically started, and the stop valve reset solenoid is automatically energized.

B. Hydraulic oil pressure develops, opening the turbine stop valve with closed control valves. The MSC is at the (LSS).

C. Once the stop valve is fully open, the MSC automatically runs to the high speed stop at high speed.

D. The turbine control valves open at their maximum rate (MGU at its high-speed stop), accelerating the turbine.

E. The turbine speed is initially limited to slightly higher than 4000 rpm by the turbine speed governor. The MSC controls the rate of turbine acceleration.

F. Once pump discharge flow reaches its preset value, the output from the flow controller diminishes, and the MGU is ultimately reset below the limiting value of the speed governor, thereby controlling turbine speed. The pump discharge flow controller continues to adjust the MGU, changing the turbine speed setpoint as required to maintain the preset flow requirement over the range of HPCI operation (i.e., 4000 rpm down to approximately 2000 rpm). HPCI flowrate is dependent on steam flow available from the reactor.

Under normal operation, the turbine control valves are operated by the MGU to automatically maintain an injection flowrate determined by a flow indicating controller (FIC). The signal generated by the FIC is compared to the actual HPCI flow as determined by a flow transmitter. The resulting signal is applied to the signal converter which drives the MGU to properly position the turbine control valve through a series of mechanical and hydraulic linkages. A position signal corresponding to the MGU speed setting is also applied to the signal converter to stabilize its output. The MGU is also operable from a control room manual RAISE-LOWER control switch. In addition, a local handwheel provides manual speed control in the event of control circuit failure or burned-out MGU motor.

The MGU can be operated automatically or manually. Each mode has its own power source.

The HPCI MGU electrical controls transfer the dc power from the manual mode (control switch) to the automatic flow control mode (HPCI pump flow control signal converter) without electrically connecting the two sources. This prevents any ground in the automatic controls from being connected to the ungrounded battery systems.

The turbine speed is controlled by the lowest setting of the preceding components:

A. Limited to 4000 rpm by the speed governor (with MSC at the high speed stop).

B. Automatically controlled between 2000 and 4000 rpm by the MGU.

7.3.1.3.3.2 Single-Failure Criterion

The HPCI system, by itself, is not required to meet the single-failure criterion (IEEE 279-1968, Paragraph 4.2). The control logic circuits for the HPCI system initiation and control are housed in a single relay cabinet, and the power supply for most HPCI equipment is from a single dc power source. However, the relay cabinet and normal power source for ADS are independent of the HPCI system.

The HPCI initiation sensors and wiring up to the HPCI relay logic cabinet do, however, meet the single-failure criterion. Physical separation of instrument lines is provided so that no single instrument rack destruction or single instrument line (pipe) failure can prevent HPCI initiation. Wiring separation between divisions also provides tolerance to single wireway destruction (including shorts, opens, and grounds) in the accident detection portion of the control logic. This single-failure criterion is not applied to logic relay cabinet or to other equipment required to function for HPCI operation.

7.3.1.3.3.3 Quality of Components

The discussion of equipment qualification for the core spray system (Section 7.3.1.1.1.3) also applies generally to the HPCI system.

7.3.1.3.3.4 Equipment Qualification

No components of the HPCI control system are required to operate in the drywell environment except for the temperature compensation columns of the vessel level switches. Errors introduced under steam leak (high drywell temperature and reactor depressurization) for HPCI initiation are negligible as discussed in Section 7.3.1.3.3.1. The HPCI steam line isolation valve located inside the drywell is a normally open valve and is therefore not required to operate except under normal surveillance testing.

Other process sensor equipment for HPCI initiation is located in the reactor building and is capable of accurate operation in ambient temperature conditions that result from abnormal conditions (loss of ventilation and LOCA), IEEE 279-1968, Paragraph 4.4.

7.3.1.3.3.5 Channel Integrity

The HPCI system instrument initiation channels meet the single-failure criterion (as discussed in Section 7.3.1.3.3.2). Therefore, they satisfy the channel integrity objective of IEEE 279-1968, Paragraph 4.5.

annunciation and visible relay actuation is considered to fulfill the requirements of IEEE 279-1968, Paragraph 4.19.

7.3.1.3.3.20 Information Readout

The HPCI control system is designed to provide the operator with accurate and timely information pertinent to its status. It does not introduce signals into other systems that could cause anomalous indications confusing to the operator. There are many elements of this energize-to-operate system, both active and passive, which are not continuously monitored for operability. Two examples are: 1) relay circuits which are normally open and are not monitored for continuity on a continuous basis, and 2) pressure and level sensors, which although continuously active are not continuously exercised and verified operable. Verifying the operability of these components is accomplished by periodic testing and by proper selection of test periods to be compatible with the historically established reliability of the components tested. Complete and timely indications are made available. Sufficient information is provided on a continuous basis so that the operator can have a high degree of confidence that the HPCI function is available and/or operating properly (IEEE 279-1968, Paragraph 4.20).

7.3.1.3.3.21 System Repair

The discussion of system repair for the core spray system (Section 7.3.1.1.1.21) applies equally to the HPCI system.

In addition to the recognition of failed components during test, components which fail so as to produce a trip condition are continuously monitored by alarm (IEEE 279-1968, Paragraph 4.21.

7.3.1.3.4 Failure Mode and Effects Summary

Since the HPCI system is by itself a single system, and as it is recognized that there are single failures that could disable the system, a detailed failure mode and effects analysis is not warranted.

No single failure in the initiation instrumentation can prevent HPCI operation if required. Again, those single failures that could possibly disable the HPCI system will in no way affect the ADS system and vice versa.

The only instrumentation and equipment common to the ADS and HPCI systems are the reactor vessel water level transmitters. Separate trip units on the shared transmitters are used for the two systems. Both physical and electrical separation are maintained so that no single failure of the level-sensing equipment or wiring (shorts or opens) can disable either HPCI or ADS.

Therefore, it is concluded that no single failure can disable both the HPCI and the ADS systems.

brief and does not significantly increase the probability of system failure. There are no channel bypasses as such in ADS. Removal of a sensor from operation during calibration does not prevent the redundant trip circuit from functioning if accident conditions occur because they will be sensed by the redundant sensors (IEEE 279-1968, paragraph 4.11). The manual reset button can interrupt the automatic depressurization for a limited time. However, releasing either one of the two reset buttons will allow automatic timing and action to resume. The ADS inhibit switch will prevent blowdown if placed in the INHIBIT position. This switch is keylocked and administratively controlled.

7.3.1.4.1.12 Operating Bypasses

The discussion of operating bypasses for the core spray system (Section 7.3.1.1.1.12) also generally applies to the ADS. Disabling two selected sensors would also disable the auto-depressurization action. Disabling of the sensors would result from selective closing of one or more sensor instrument valves for each of the two sets of four sensors. This mechanism of disabling the system is not considered to be an operating bypass, so no exception to IEEE 279-1968, Paragraph 4.12, is taken.

7.3.1.4.1.13 Indication of Bypasses

The ADS inhibit switch, as well as the manual opening of the control power breakers, can disable the automatic depressurization function. Placing the ADS inhibit switch in the INHIBIT position or losing control power, is annunciated. Disabling the sensors by deliberately closing instrument valves is not indicated (IEEE 279-1968, Paragraph 4.13).

7.3.1.4.1.14 Access to Means for Bypassing

Instrument valves are maintained in their normal operating positions and cannot be operated without permission of responsible authorized personnel. Reset buttons are on the control panel in the main control room. Control power breakers are in dc distribution cabinets which are located in limited access areas. (IEEE 279-1968, Paragraph 4.14).

7.3.1.4.1.15 Multiple Trip Settings

IEEE 279-1968, Paragraph 4.15, which deals with multiple trip settings, is not applicable because all trip points are unique.

built-in rather than approached by accelerated maintenance. All devices in the system are designed for a 40-year lifetime under the imposed duty cycles. Since this duty cycle is composed completely of testing at infrequent intervals, the durability of active components other than sensors is more a matter of shelf life than active life. However, all components are selected for continuous duty plus thousands of cycles of operation (far beyond anticipated usage in actual service). Recognition and location of a failed component is accomplished during periodic testing (IEEE 279-1968, Paragraph 4.21).

7.3.2 Primary Containment Isolation System

7.3.2.1 Design Basis

The primary containment isolation system (PCIS) provides automatic isolation of appropriate pipelines which penetrate the primary containment whenever certain monitored variables exceed their preselected operational limits. To achieve this objective, PCIS was designed using the following criteria:

A. Prevent the release of radioactive materials in excess of the limits in 10 CFR 100 as a result of the design basis accidents;

B. Function safely following any single component malfunction; and

C. Function independently of other plant controls and instrumentation.

7.3.2.2 Isolation Logic Description

The PCIS logic is arranged as a dual logic channel system, similar to the reactor protection system logic (Section 7.2). Sensor relays in the PCIS receive their power either from one of the reactor protection system channel buses or from the essential service ac bus. The sensor relays are normally energized, as in the reactor protection system. Deenergization of the sensor relays causes operation of contacts in trip channel logic circuits. Trip channel logic circuit relays cause a single logic channel trip. In most cases both logic channels must trip to initiate isolation.

Isolation valves use various methods of operation: ac motor, dc motor, solenoid, or pilot solenoid and instrument air pressure. For those valves closed by ac or dc motor operation, deenergizing the trip channel isolation logic relays closes contacts in the valve motor control circuitry. Solenoid-operated valves normally have their solenoids energized when open; isolation logic relays open contacts in the solenoid power supply. Air-operated isolation valves are actuated through solenoid-controlled pilot air valves.

Primary containment isolation functions are initiated by groups, according to the trip channel logic associated with each group. Additionally, manual switches on the control room panel are available to back up all trip signals. In addition to providing isolation, the system initiates other actions designed to limit radioactive release. Nominal setpoints are listed in Table 7.3-1. Figure 7.3-11 identifies the

7.3.2.2.3 Main Steam Line Space High Temperature

Temperature monitoring instrumentation is provided in the main steam line tunnel to detect leaks in this area. Trips are provided by this instrumentation which cause closure of Group 1 isolation valves. The setting of less than or equal to 200°F is low enough to detect leaks of the order of 5 to 10 gal/min; thus, this trip is capable of covering the entire spectrum of breaks. For large breaks, it is a backup to high steam flow instrumentation discussed below. For small breaks with the resultant small release of radioactivity, it provides isolation before the guidelines of 10 CFR 100 are exceeded.

7.3.2.2.4 Main Steam Line High Flow

Venturis are provided in the main steam lines as a means of measuring steam flow and also limiting the loss of mass inventory from the vessel during a steam line break accident. In addition to monitoring steam flow, instrumentation is provided which causes a trip of Group 1 isolation valves. The primary function of the instrumentation is to detect a break in the main steam line outside the drywell; thus only Group 1 valves are closed. For the worst case accident, main steam line break outside the drywell, the trip setting of 120% of rated steam flow, in conjunction with the flow limiters and main steam line valve closure, would limit the mass inventory loss such that fuel is not uncovered, fuel temperatures remain less that 1500°F, and release of radioactivity to the environs is well below 10 CFR 100 guidelines.

7.3.2.2.5 Low Steam Line Pressure

Pressure instrumentation trips when main steam line pressure drops below 825 psig. A trip of this instrumentation results in closure of Group 1 isolation valves. In the REFUEL, SHUTDOWN, and STARTUP/HOT STANDBY modes, this trip function is bypassed. This function provides protection against a pressure regulator malfunction which would cause the control and/or bypass valves to go full open. With the trip set at greater than or equal to 825 psig, inventory loss is limited so that fuel is not uncovered and peak clad temperatures are much less than 1500°F; thus, there are no fission products available for release other than those in the reactor water.

7.3.2.2.6 Primary Containment (Drywell) High Pressure

The high drywell pressure instrumentation is a backup to the water level instrumentation, and, in addition to initiating ECCS, it causes isolation of Group 2 isolation valves. For the breaks discussed above, this instrumentation will initiate ECCS operation about the same time as the low-low water level instrumentation. Thus the results given above are applicable here. Also, Group 2 isolation valves include the drywell vent, purge and sump isolation valves. High drywell pressure activates only these valves because high drywell pressure could occur as the result of nonsafety-related causes such as not purging the drywell air during startup.

sensors and instrumentation are required to be operable. The trip settings as defined in the technical specifications and valve closure time prevent uncovering the core or exceeding site limits. The Unit 3 high-flow isolation logic has a time delay of 2 ± 0.5 seconds to eliminate spurious isolation. The sensors will actuate due to high flow in either direction.

7.3.2.3 Primary Containment Isolation System Instrumentation

The sensors for the PCIS are described in the following paragraphs.

A. Reactor water level pressure sensors are identical to those utilized in the reactor protection system and are described in Section 7.2.

B. Main steam line high radiation monitors are described in Section 11.5.2.

C. Steam line tunnel temperatures are sensed by 16 temperature switches. Four switches are used in each instrumentation trip channel. High temperature is indicative of a steam line break.

D. High main steam line flow is sensed by 16 indicating differential pressure switches operating from flow restrictor devices. Each main steam line has one flow restrictor: four separate differential pressure switches operate across each flow restrictor, providing an input from each flow restrictor into each logic trip channel. A trip is actuated by a high differential pressure, indicating high flow.

E. Main steam line low pressure is sensed by four bourdon-tube-operated pressure switches, sensing pressure directly downstream of the main steam equalizing header. Each pressure switch provides an input to one instrumentation trip channel. These switches are mounted on shock absorbing isolators to prevent spurious actuation of the switches.

   A bypass is provided for the main steam line low pressure trip. The bypass is effective when the mode switch is in any position other than RUN.

F. High drywell pressure is sensed by four diaphragm-operated pressure switches. Each switch provides an input to one instrumentation subchannel.

G. High drywell radiation is detected by two radiation monitors in the drywell. This isolation has a two-out-of-two-once logic.

H. There are two HPCI differential-pressure-type flow switches, both connected in one-out-of-two logic, across a single set of sensing lines across the steam line elbow within the primary containment vessel (drywell). The flow sensors are electrically connected to the isolation system such that a trip in either one or both sensors will initiate isolation. A failure of one sensor in the nontrip mode will neither initiate isolation nor prevent the other sensor from initiating isolation on high flow. Therefore, failure of any single component will not result in violation of primary containment isolation criteria. The isolation signal is sealed-in upon receipt, and in addition to closing the HPCI steam isolation valves, the signal blocks the auto-initiation of the HPCI subsystem.

The differential pressure (ΔP) across the elbow taps at reactor vessel rated flow of 145,000 lb/hr of steam at 1135 psia and 102,500 lb/hr of steam at 165 psia is below the isolation trip setting.

The HPCI steam line isolates by high-flow indicative of an HPCI steam line break. The high steam flow trip setting is selected high enough to avoid spurious isolation yet low enough to provide timely detection of an HPCI steam line break. The isolation trip setpoint is 3 times maximum rated flow or 435,000 lb/hr of steam at the reactor vessel maximum operating pressure of 1135 psia, corresponding to a break size of approximately 0.05 square feet. The switches trip for flow in either direction, which protects against breaks on either side of the transducers. The HPCI high steam flow isolation incorporates a time delay setting of 3 to 9 seconds which prevents inadvertent isolation on high steam flow after the subsystem automatically initiates.

Analysis shows that only 3000 gal/min of saturated water is required to produce the isolation trip differential pressure. The sensor is designed to produce a signal indicative of steam flow. As such, it does not give a reliable indication of moisture carryover. However, should a water slug occur and pass down the HPCI steam line at a velocity near that of rated steam flow, an isolation signal would definitely be generated.

I. Four sets of temperature switches are used to detect high temperature in the vicinity of the HPCI turbine. Each set consists of four temperature switches connected in one-out-of-two-twice logic. The setpoint for the switches is 200°F. The one-out-of-two-twice logic was selected to avoid spurious trips since the area temperature closely approaches the setpoint (within 50°F). This high temperature is indicative of steam leakage including that from the turbine shaft seals. This isolation signal is also sealed-in upon receipt, and blocks the auto-initiation logic of the HPCI subsystem.

J. Four pressure switches which are used to initiate low steam line pressure isolation are connected in a one-out-of-two-twice logic. The pressure switches initiate the trip when the reactor pressure decreases to 100 psig. The low-pressure signal provides automatic isolation of the turbine loop prior to stalling the turbine on low available energy. With the steam supply open to the turbine in the stalled condition, the reserve coolant in the gland seal condenser would ultimately rise in temperature, resulting in possible external steam leakage from the shaft seals. This isolation signal is not sealed-in. With the low-pressure condition present, the isolation signal will block the automatic initiation logic of the HPCI subsystem. If reactor pressure should rise above the pressure switch setpoint, the isolation signal will auto-reset, and the HPCI subsystem will auto-restart upon receipt of an initiation signal.

switches on the other three lines. Electrical circuit separation is maintained from the flow switches to the protection panels.

The arrangement of the high-flow isolation logic for the HPCI and isolation condenser systems is such that any one signal can cause isolation of the system. Any single component failure will not prevent isolation.

The HPCI isolation control function includes the sensors, trip channels, switches, and remotely activated valve closing mechanisms associated with the valves in the HPCI steam line, which when closed, effect isolation of the primary containment or reactor vessel, or both.

A failure of the low-pressure (reference) flow sensing line will appear as high flow to both sensors and initiate isolation. A failure of the high-pressure flow sensing line will drive both flow sensors downscale appearing as instrument failure (below zero reading on one or both sensors) and initiate isolation. Both flow sensors will read zero in event of failure of both flow sensing lines and neither will initiate isolation, however backup is provided by the pressure sensors described in the next paragraph.

The differential pressure (ΔP) across the elbow taps at reactor vessel rated flow of 145,000 lb/hr of steam at 1135 psia, and at reactor vessel rated flow of 102,500 lb/hr of steam at 165 psia, is below the isolation trip setting.

The isolation trip is set for 3 times the rated flow, or 435,000 lb/hr of steam at 1135 psia. Analysis shows that only 3000 gal/min of saturated water would be required to produce the isolation trip differential pressure. The sensor is designed to produce a signal indicative of steam flow. As such, it does not give a reliable indication of moisture carryover. However, should a water slug occur and pass down the HPCI steam line at a velocity near that of rated steam flow, an isolation signal would definitely be generated.

There are four static pressure sensors piped to the same sensing lines as the flow sensors and connected in a one-out-of-two-twice logic that will initiate isolation in event of simultaneous failure of both sensing lines or upon low steam line static pressure. It is clear that no mode of failure of pressure or flow sensing devices will prevent isolation; although, inadvertent isolation will be initiated for some modes of failure.

The HPCI steam line isolation valves are also closed by high space temperature in the HPCI equipment compartment. Sixteen temperature switches are used for this function. The sixteen sensors are grouped, four to a group, and each group is connected in a one out of two twice logic to provide the isolation trip. The trip setting is 200°F to automatically close the valves. This setting is well above the expected ambient condition but low enough to detect steam line leakage. Failure of any one sensor or group of sensors does not prevent isolation by the other sensors.

The HPCI turbine stop valve that closes off the steam line for system control purposes is not safety-related but does offer a secondary means of isolating the steam lines. The turbine stop valve closes as follows:

A. Reactor high water level trips the HPCI turbine stop valve upon an increase in normal operating level of approximately 18 inches of water.

This trip point is about 14 inches below the HPCI steam center-line outlet from the reactor. The stop valve is designed to close within 5 seconds following trip signal. The turbine control valves also close as a result of stop valve closure so that a double valve closure of the line is effective under trip conditions.

B. Pressure switches in the turbine exhaust line trip the stop valve upon high exhaust line pressure. In the event of two-phase mixture carryover with enough moisture to cause failure of the turbine thrust bearing, the turbine exhaust pressure would increase and initiate closure of the turbine stop valve to isolate the turbine.

7.3.2.5 Surveillance and Testing

Since electrical components used in the primary containment isolation system are normally energized, most failures result in the deenergization of the component involved. Such failures initiate an alarm and/or a trip of one of the two channels. Surveillance is attained by this self-annunciation upon failure. Any failures which are not self-annunciating will be identified by a testing schedule; the schedule assures that such failures are found and corrected on a routine basis. Valves within the system may be tested periodically to verify operational capability.

7.3.2.6 Conformance to IEEE 279-1968

The following subsections present a point-by-point comparison of the containment isolation control system with the requirements of IEEE 279-1968 which has been summarized from GE Topical Report, NEDO-10139.[2] For more detailed information, refer to the topical report.

7.3.2.6.1 General Functional Requirements

A. Auto-Initiation of Appropriate Action — The control system action from sensor to final control signal to the valve actuator is capable of initiating appropriate action within a time commensurate with the need for valve closure. Total time, from the point where a process out-of-limits condition is sensed to the energizing or deenergizing of appropriate valve actuators, is less than 500 milliseconds. The closure time of valves ranges upward from a minimum of 3 seconds for the main steam isolation valves, depending upon the urgency for isolation considering possible release of radioactivity. Thus, it can be seen that the control initiation time is at least an order of magnitude lower than the minimum required valve closure time.

B. Precision — Accuracies of each of the sensing elements are sufficient to accomplish the isolation initiation within required limits without interfering with normal plant operation.

7.3.2.6.11 Channel Bypass or Removal from Operation

Calibration of any sensor introduces a single instrument channel trip. This trip does not cause a protective function without the coincident trip of at least one other instrument channel, except for the HPCI system where leak detection flow sensors have a one-out-of-two logic (IEEE 279-1968, Paragraph 4.11).

7.3.2.6.12 Operating Bypasses

The only bypass in PCIS is the main steam line low-pressure bypass which is imposed by the mode switch when the switch is not in the run mode. The mode switch cannot be left in other than RUN with neutron flux measuring power above 15% of rated power without imposing a scram. Therefore the bypass is considered to be removed in accordance with the intent of IEEE 279-1968, Paragraph 4.12; although manual action removes the bypass, rather than an automatic one. In the case of the motor-operated valves, automatic or manual closure can be prevented by shutting off electric power.

7.3.2.6.13 Indication of Bypasses

The bypass of the main steam line low-pressure isolation signal is not indicated directly in the control room except by the position of the mode switch. This switch is under strict operator control. Its specific bypass functions are a matter of operator training. Therefore, no bypass indication is required when the mode switch is not in RUN. Since the bypass is not removed by any automatic action, it is positively in effect any time the mode switch is in position to impose it (IEEE 279-1968, Paragraph 4.13).

7.3.2.6.14 Access to Means for Bypassing

The mode switch is the only bypass switch affecting PCIS, and it is centrally located on the main control console (IEEE 279-1968, Paragraph 4.14).

7.3.2.6.15 Multiple Trip Settings

IEEE 279-1968, Paragraph 4.15, which deals with multiple trip settings, is not applicable because all setpoints are unique.

7.3.2.6.16 Completion of Protection Action Once Initiated

All isolation decisions are sealed-in downstream of the decision-making logic, so valves go to the closed position, which ends protective action (IEEE 279-1968, 7.3.2.6.21 System Repair

Those components which are expected to have a moderate need for replacement (including the temperature amplifier units and thermocouples in the ventilation ducts) are designed for convenient removal. The amplifier units employ a circuit card or replaceable module construction and the thermocouples or resistance temperature detectors are replaceable units with disconnectable heads. Pressure sensors, vessel level sensors, etc., can be replaced in a reasonable length of time, but are considered to be permanently installed. They have nonwelded connections at the instrument which allow replacement.

7.3.3 Secondary Containment Isolation System

The secondary containment isolation system is described in Section 6.2.3.

7.3.4 Isolation Condenser Instrumentation and Control

The isolation condenser provides reactor core cooling in the event that the reactor becomes isolated from the main condenser by closure of the main steam isolation valves. The isolation condenser is described in Section 5.4.6. The PCIS description relating to the isolation condenser is in Section 7.3.2.

The isolation condenser is automatically placed in service on a sustained high reactor pressure signal as defined in the Technical Specifications in a one-out-of-two-twice logic. This initiation signal will close the vent line valves and open the outboard condensate return valve, completing the flow path through the isolation condenser.

The isolation condenser steam supply lines have a vent line which returns steam and noncondensibles to the "A" main steam line. The two valves in the vent line automatically close on one of the following signals:

A. Isolation condenser initiation (one-out-of-two logic);

B. Isolation condenser line break (PCIS signal) (one-out-of-two logic); and

C. Main steam line isolation signal (one-out-of-two twice logic).

The isolation condenser return valve control switch has PULL-TO-LOCK, CLOSE, AUTO, and OPEN positions, with spring return to AUTO from the CLOSE position to avoid the inadvertent override of an initiation signal. The AUTO and OPEN positions are maintained contact. The PULL-TO-LOCK position overrides the automatic signals to reopen and permits valve isolation with deliberate operator action.

Table 7.3-1

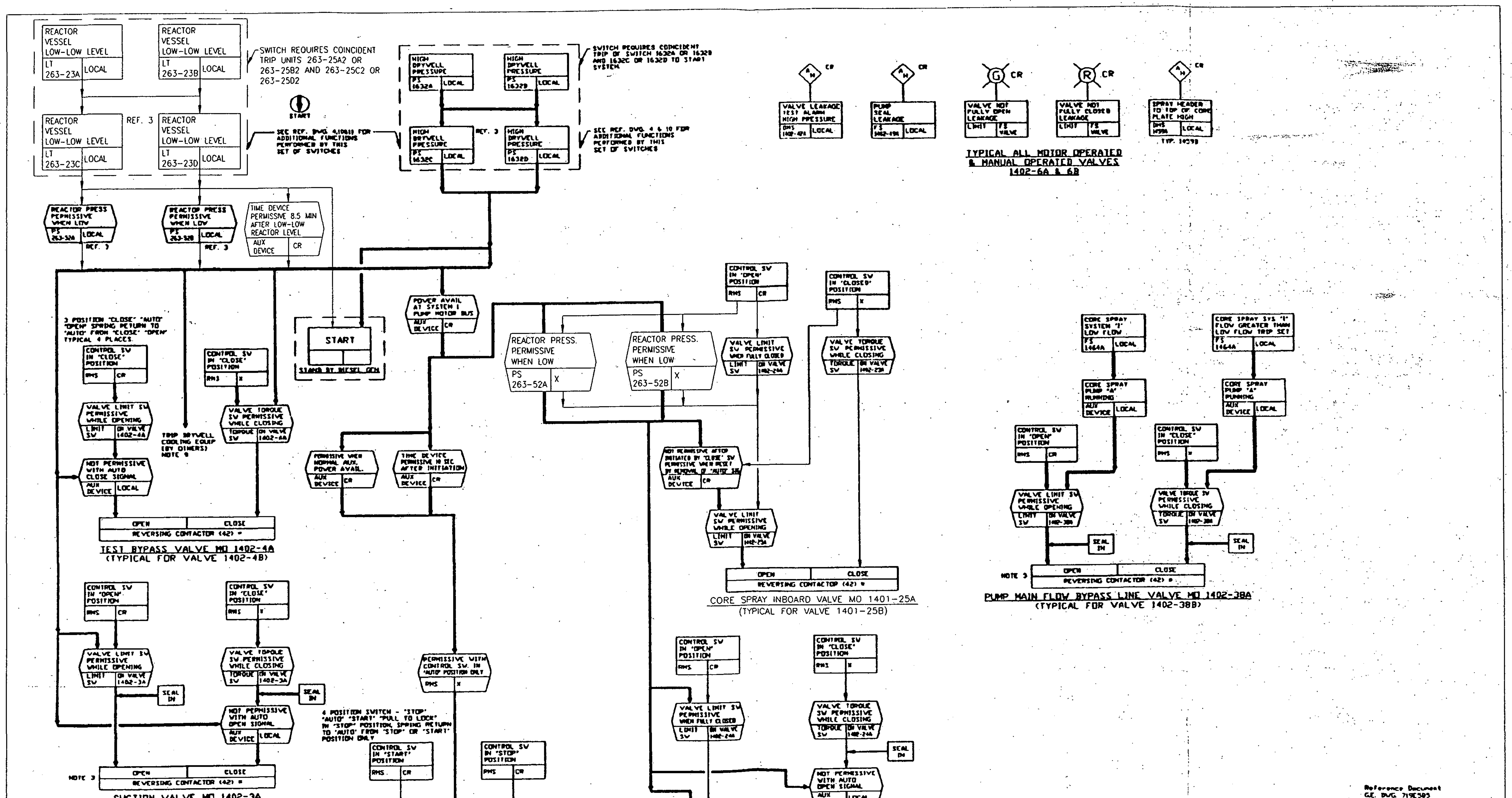
GROUP ISOLATION SIGNALS AND SETPOINTS

Valve Isolation Group	Isolation Signal	Nominal Setpoint
Group 1	Reactor low-low water level	-59 in.
	Main steam line high radiation	3 times normal full power background[1]
	Main steam line high flow	120% of rated flow
	Main steam line tunnel high temperature	200°F
	Main steam line low pressure	825 psig
Group 2	Reactor low water level	+8 in.
	High drywell pressure	2 psig
	High drywell radiation level	100 R/hr
Group 3	Reactor low water level	+8 in.
Group 4	HPCI steam line high flow	≤ 300% rated steamflow
	HPCI vicinity high temperature	200°F
	Low reactor pressure	100 psig
Group 5	High flow isolation condenser steam supply	20 psid
	High flow isolation condenser condensate return	32 in.H_2O differential (Unit 2) 14.8 in.H_2O differential (Unit 3)

Note:

(Unit 2 only)

1. Due to addition of hydrogen to the primary coolant, the main steam line radiation monitor setting will be less than or equal to 3 times full power background without hydrogen addition for all conditions except for greater than 20% power with hydrogen being injected during which the main steam line radiation trip setting will be less than or equal to 3 times full power background with hydrogen addition. Required changes in main steam line radiation monitor trip setting will be made within 24 hours except during controlled power reduction at which time the setpoint change will be made prior to going below 20% power. If, due to a recirculation pump trip or other unanticipated power reduction event, the reactor is below 20% power without the setpoint change, control rod motion will be suspended until the necessary trip setpoint adjustment is made.

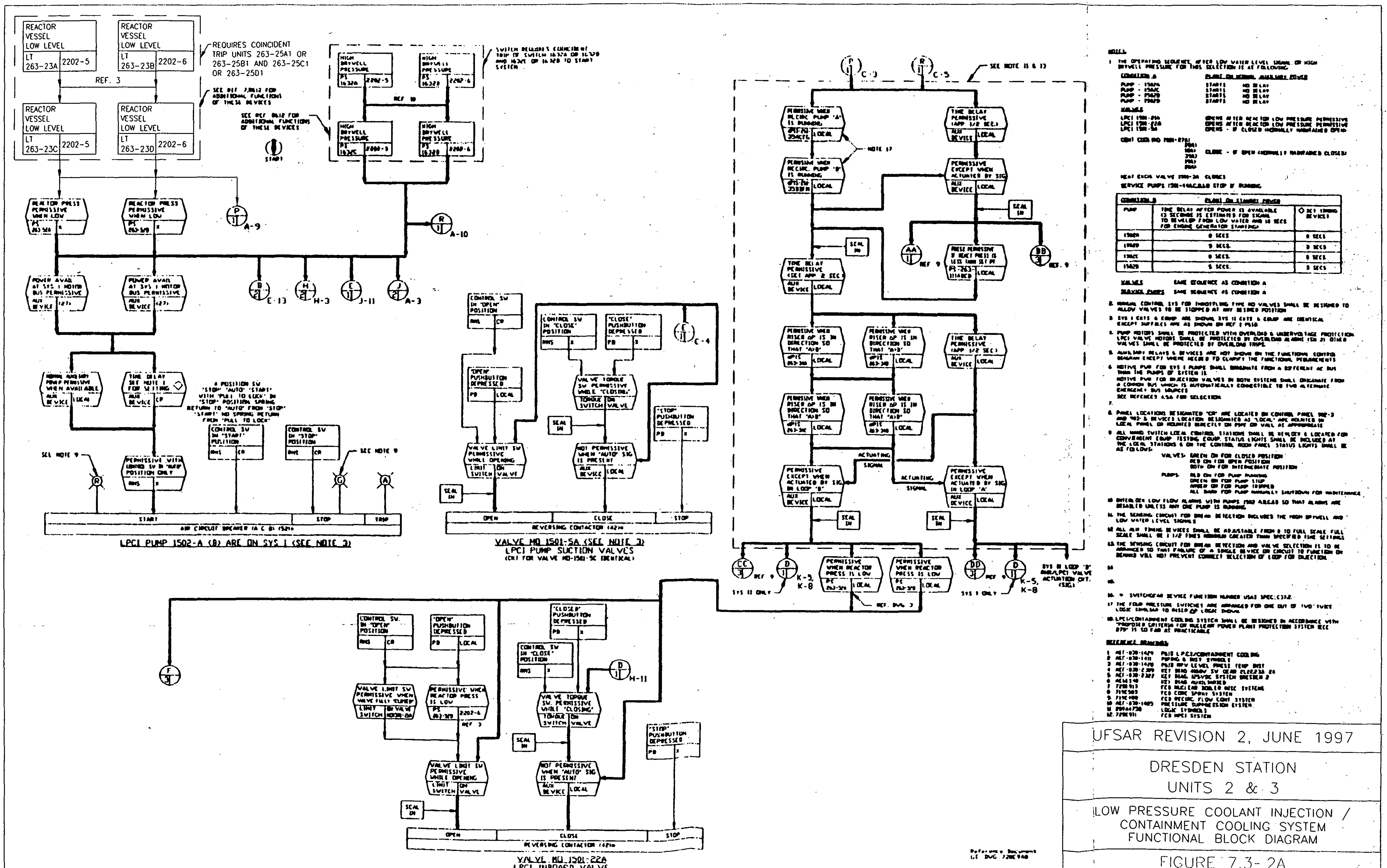


UFSAR REVISION 2, JUNE 1997

DRESDEN STATION
UNITS 2 & 3

CORE SPRAY SYSTEM
FUNCTIONAL CONTROL DIAGAM

FIGURE 7.3-1

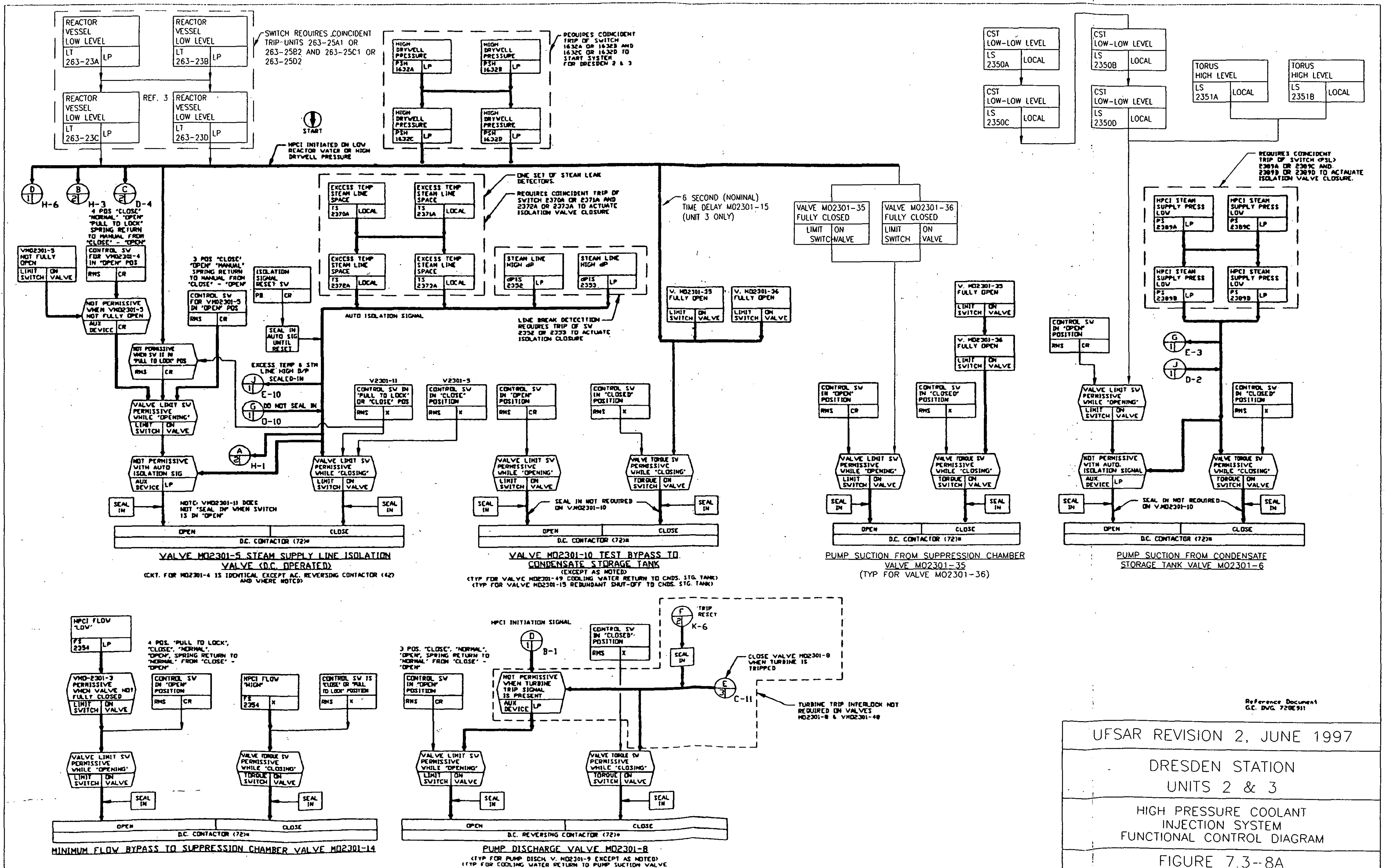


UFSAR REVISION 2, JUNE 1997

DRESDEN STATION
UNITS 2 & 3

LOW PRESSURE COOLANT INJECTION / CONTAINMENT COOLING SYSTEM FUNCTIONAL BLOCK DIAGRAM

FIGURE 7.3-2A



UFSAR REVISION 2, JUNE 1997

DRESDEN STATION
UNITS 2 & 3

HIGH PRESSURE COOLANT INJECTION SYSTEM
FUNCTIONAL CONTROL DIAGRAM

FIGURE 7.3-8A

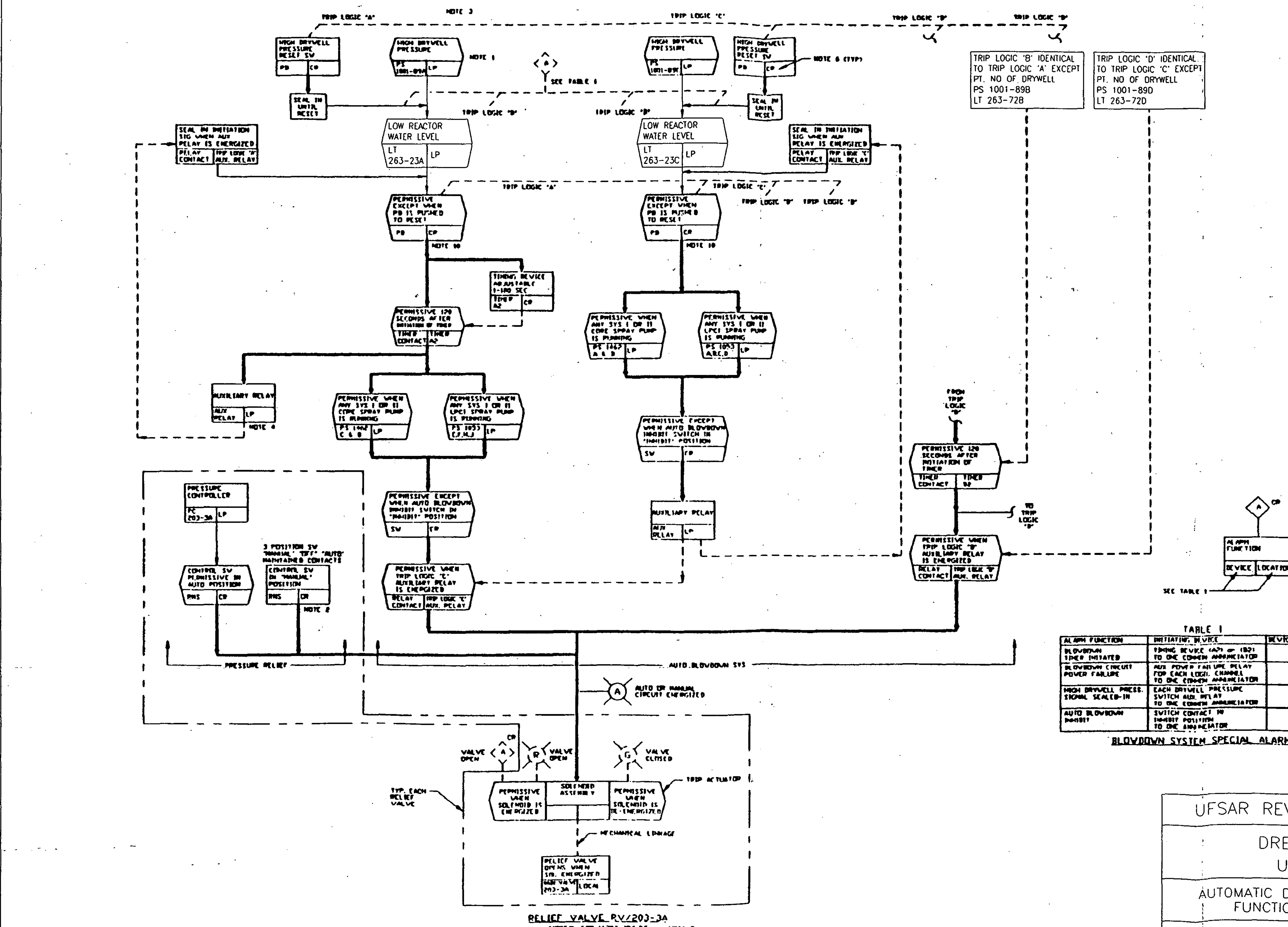


TABLE 1

ALARM FUNCTION	INITIATING DEVICE	DEVICE LOCATION
BLOWDOWN TIMER INITIATED	TIMING DEVICE (A2) or (B2) TO ONE COMMON ANNUNCIATOR	CR
BLOWDOWN CIRCUIT POWER FAILURE	AUX POWER FAILURE RELAY FOR EACH LOGIC CHANNEL TO ONE COMMON ANNUNCIATOR	CR
HIGH DRYWELL PRESS. SIGNAL SEALED-IN	EACH DRYWELL PRESSURE SWITCH AUX. RELAY TO ONE COMMON ANNUNCIATOR	CR
AUTO BLOWDOWN INHIBIT	SWITCH CONTACT IN INHIBIT POSITION TO ONE ANNUNCIATOR	CR

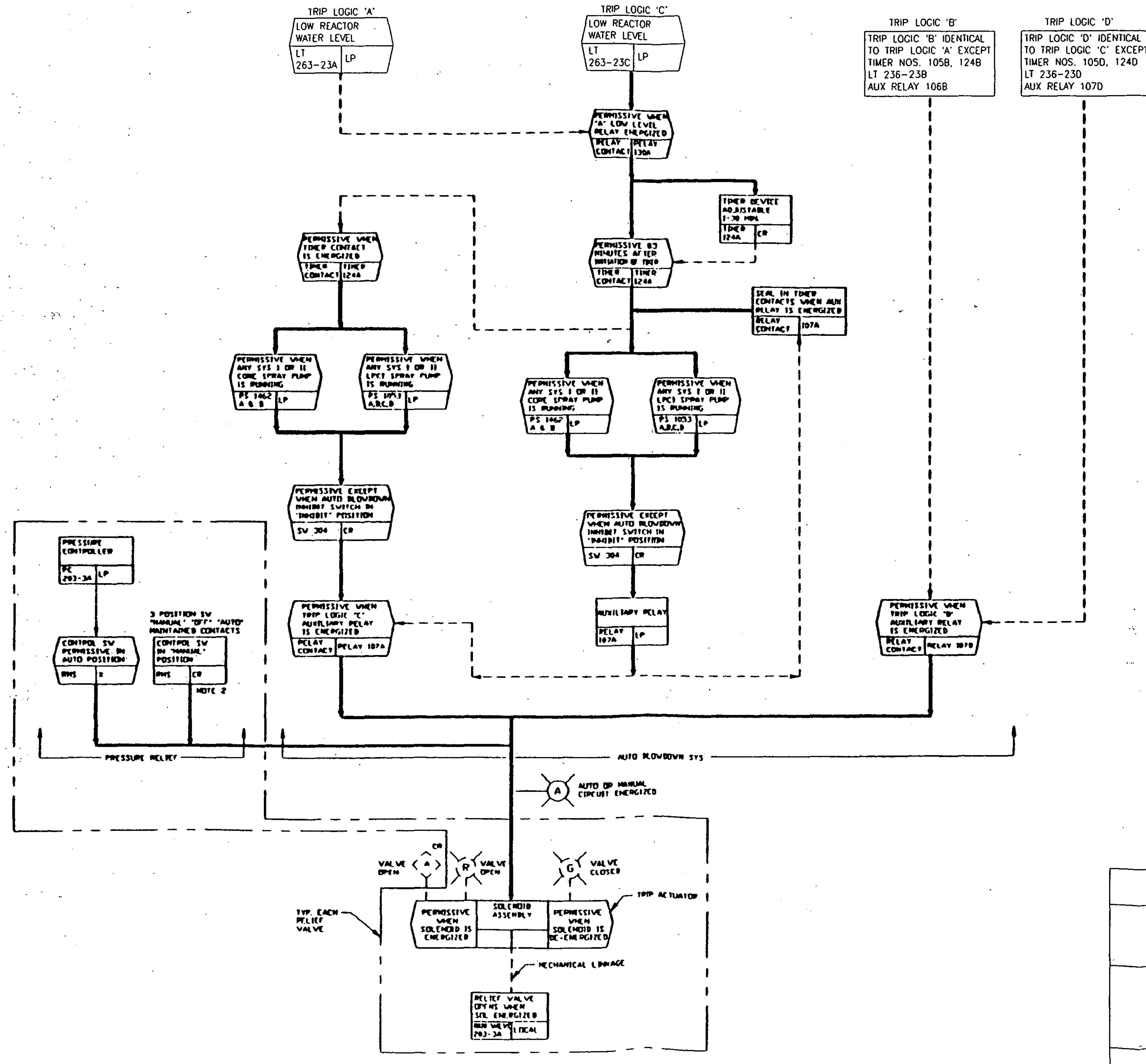
BLOWDOWN SYSTEM SPECIAL ALARMS

UFSAR REVISION 2, JUNE 1997

DRESDEN STATION
UNITS 2 & 3

AUTOMATIC DEPRESSURIZATION SYSTEM
FUNCTIONAL BLOCK DIAGRAM

FIGURE 7.3-9



UFSAR REVISION 2, JUNE 1997

DRESDEN STATION
UNITS 2 & 3

AUTOMATIC DEPRESSURIZATION SYSTEM
AUTO BLOWDOWN WITHOUT HIGH
DRYWELL PRESSURE
FUNCTIONAL BLOCK DIAGRAM

FIGURE 7.3-10

7.4 SAFE SHUTDOWN

The following section describes the instrumentation and control system aspects of the containment cooling mode of the low pressure coolant injection (LPCI) system. This section also provides a description of shutdown outside the control room.

7.4.1 Containment Cooling

The containment cooling function is provided by the low pressure coolant injection system after the core is flooded. Suppression pool water can be recirculated through the heat exchangers for cooling. The cooled water can also be used to spray the drywell and/or torus. For a complete description of the design basis, system functions and components, refer to Section 6.2.

The containment cooling mode of LPCI is initiated manually from the control room by alignment of the proper combination of valves, pumps, and heat exchangers. No automatic start function is provided.

A LPCI initiation signal actuates interlocks which close valves to prevent flow to the suppression pool and containment sprays, thus directing all LPCI flow to the core. With a LPCI initiation signal present, the containment spray normal manual keylock switch must be placed in the MANUAL position to permit alignment of flow for suppression pool cooling or for containment sprays. Placing this switch in MANUAL also permits opening the outboard injection valve in the loop not selected by the LPCI loop selection logic. This provides capability for suppression pool cooling through one loop while injecting through the other.

A LPCI initiation signal also trips any running containment cooling service water (CCSW) pumps and prevents starting CCSW pumps unless the containment cooling service pumps permissive keylock switch is placed in the MANUAL OVERRIDE position.

Two level transmitters are used to monitor water level inside the core shroud. If the water level drops below ⅔ core height, interlocks close valves in the flow paths for suppression pool cooling and containment sprays. The ⅔ core height permissive keylock switch in conjunction with the containment spray permissive keylock switch allows these valves to be opened, if necessary, when placed in the MANUAL OVERRIDE position. The ⅔ core height interlock uses a one-out-of-one logic.

To initiate or maintain drywell and/or torus spray, drywell pressure must be above the low limit setpoint. This parameter is measured by two pressure switches per division arranged in one-out-of-two-twice logic. This condition does not have a bypass switch.

Once containment cooling has been placed in operation, if any of the preceding requirements do not continue to be either met or bypassed, the associated valves will close to allow full LPCI injection flow.

Neither Category 2 nor Category 3 instrumentation requires redundant monitoring channels. Therefore, only one power source for these categories of monitoring instrumentation is required. Even though this station received its construction permit prior to the categorization of power sources as Class 1E or non-1E, the power sources and the reserve sources provide the required reliability to meet the intent of R.G. 1.97.

This station was licensed before R.G. 1.75 established the requirements for physical independence of electrical systems. Existing instrumentation used for post-accident monitoring does not follow these separation requirements. To fulfill a Category 1 requirement, new instrument loops added after August 1, 1985, will comply with the requirements of R.G. 1.75 whenever possible.

7.5.2 Process Computer

This section contains information on the process computer programs, the function of the process computer, the operation of its major components, and the different kinds of programs comprising the computer software. Section 8.3.1.4.4 describes the computer UPS in more detail. Section 7.5.2.2 describes in more detail the computer equipment (excluding rod worth minimizer hardware) with which the plant operator is primarily concerned and provides functional and operating descriptions for the Nuclear Steam Supply System (NSSS), Balance of Plant (BOP), and Scan, Log and Alarm (SLA) programs.

7.5.2.1 System Description

The Honeywell 4500 is a distributed process computer system that provides on-line monitoring of over 1500 input points (digital, pulse, and analog) representing significant plant process variables. The system scans digital and analog inputs at specified intervals and issues appropriate alarm indications and messages if monitored analog values exceed predefined limits or if digital trip signals occur. It performs calculations with selected input data to provide the operator with essential core performance information through a variety of logs, trends, displays, summaries, and other typewritten data. Computer outputs also include various front panel displays (digital lights, trend recorders and color graphic displays). By making a wide range of plant performance data immediately available, in a summary format, the computer greatly increases the speed with which operating personnel can respond to changing plant conditions. It thereby contributes significantly to the maintenance of optimum core power distribution, economical utilization of nuclear fuel, and overall plant operating efficiency.

In general, the Honeywell process computer system drives all peripherals that display or log real-time data, while the minicomputer drives all devices which edit nuclear program output (e.g., Siemens Power Corporation [SPC] Powerplex codes) and which display or log historical operating data and performs the thermo-hydraulic calculations. Typical peripherals include: request CRTs, typers, output CRTs and color graphic displays.

7.5.2.2 Equipment Operation

placed in computer memory as a discrete entity to be called for as needed by an operating program. A function is a still more circumscribed set of instructions defining a single calculation which can be called from memory and used by an operating program or subroutine. The Honeywell 4500 software can be divided into the following functional categories.

7.5.2.3.1 Real-Time Multiprogramming Operating System Programs

Real-time multiprogramming operating system (RTMOS) programs are covered in the applicable programming manuals provided by the computer hardware supplier. Their basic purpose is to achieve operating efficiency through time-sharing of computer hardware by concurrently operating programs. The RTMOS programs perform the following specific functions:

A. Real-time priority assignment and scheduling of functional programs via the executive control program (ECP);

B. Signal processing, error detection and alarming, and corrective action routines required for support of process input/output functions;

C. Input/output request scheduling and peripheral equipment allocations for operating functional programs; and

D. Performance of diagnostic routines and alarming of hardware or software failures.

7.5.2.3.2 Nuclear Steam System Supply Programs

The current NSSS programs perform the calculations required to provide present (and past) reactor core performance information. The POWERPLEX core monitoring software system supplied by SPC is run on a minicomputer. Powerplex is the heart of the NSSS programs (installed for Unit 2 during fuel cycle 9 and for Unit 3 during fuel cycle 8). POWERPLEX runs periodically at specified intervals and is triggered based on specified plant conditions, calculating fuel assembly power, flows, void distributions, peak heat fluxes, critical power ratios, and reactor operating thermal limits. This information is output on periodic, daily, and monthly core performance logs supplying operating personnel with the current status of significant nuclear system parameters. This information is stored to provide a historical record of these important nuclear parameters. Another useful feature of POWERPLEX is the predictive mode which can assist the nuclear engineer in deciding operating strategy by predicting future core conditions based on present or past power and exposure distributions.

The minicomputer is interfaced with the process computer (Honeywell 4500, installed October, 1983) which supplies POWERPLEX with the appropriate plant operating data. The process computer also provides various on-demand (OD) programs used by operating personnel to calculate and/or edit a variety of nuclear systems data arrays including local power range monitor and average power range monitor (LPRM/APRM) readings, APRM gain adjust factors, operating thermal power and flow control line, control rod positions, etc. Furthermore, specific plant not plugged in, or the channel is not in its OPERATE mode. A rod block signal from any one of the four channels prevents rod withdrawal.

Any one of the four SRM channels may be bypassed by operation of a bypass switch on the control panel. An automatic bypass of the SRM channel detector position rod block occurs when the count rate is greater than 100 cps.

Reactor startup is begun with the unbypassed SRM chambers fully inserted. At least two of the SRM chambers are required for startup. (One of the four may be bypassed and another downscale, for example.) Withdrawal of control rods increases the reactivity of the reactor core and hence, the multiplication of source neutrons. Although the withdrawal of an individual control rod may not show as a measurable increase on all chambers, the approach to criticality through distributed control rod withdrawal will be indicated by an appreciable increase in the count rate. Both the log count rate meters and the period meters provide a predictable indication as the reactor approaches criticality, becomes critical, and, with further withdrawal of control rods, becomes supercritical. After sufficient rod withdrawal to obtain a useful reactor period (on the order of 60 to 300 seconds), the reactor power is allowed to increase exponentially.

The SRM chambers may be withdrawn from the fully inserted position when the count rate is greater than 100 cps on the chamber to be withdrawn. To continue the reactor startup, withdrawal of the SRM detectors must be gradual, maintaining the SRM count rates between the low level (100 cps) and high level (10^5 cps) rod block set points. Each SRM chamber can be withdrawn individually and may be stopped at any intermediate point in its travel.

The useful range of the SRM channels is from 10^{-1} cps to 10^6 cps, which corresponds to a flux range of 10^4 nv to 5×10^8 nv.

7.6.1.3.3 Design Evaluation

The number and location of the SRM detectors and neutron-emitting sources have been analytically and experimentally determined to be sufficient to result in a count rate of 3 cps with all rods inserted in the cold, xenon-free condition prior to initial power operation. Verification of conformance to the minimum count rate was made at the time of fuel loading. The sources are not necessary following extended power operation. The detector sensitivity and monitor electronic characteristics have been chosen to guarantee a minimum signal to noise ratio of 3:1.

The primary safety function of the SRM subsystem is to verify that an adequate neutron flux background exists during an approach to criticality. The number of SRM channels and sources was selected to permit positive detection of an approach to criticality performed by withdrawing control rods in the region most remote from the chambers. In this worst case, the nearest unbypassed SRM channel would show a factor of 1.1 signal increase at the time criticality is achieved.

Since the SRM detectors can be retracted as reactor startup is continued, a large overlap of indication is possible during transition from the SRM to the IRM. Figure 7.6-1 depicts the possible overlap between the two monitoring subsystems. Even with the SRM detectors fully inserted, an overlap of approximately one affect the output signals of the LPRM amplifiers which are averaged in the APRM channel.

If an LPRM used to provide input to an APRM channel fails, the operator can manually bypass this invalid input. The APRM channel then properly averages the inputs from the remaining LPRM channels. If the number of bypassed LPRMs used as inputs to an APRM channel exceeds a preset number, the APRM instrument inoperative alarm is actuated. This feature assures that the APRM system will adequately perform its safety function of terminating average neutron flux level transients through scram initiation. In addition to the automatic input monitoring, administrative controls require at least 50% of all LPRMs and at least 2 LPRMs per level for an APRM to be operable. The "too few input trip" feature also automatically provides a high degree of assurance that the APRM system will be capable of preventing fuel damage due to rod withdrawal errors.

7.6.1.5.2.3 Design Evaluation

As shown in Figures 7.6-10 and 7.6-11, the LPRM inputs to the APRM channels provide a wide sampling of local flux levels on which to base an average power level measurement. The fact that three APRM channels are provided for each RPS logic channel assures that at least two independent average power measurements will be available under the worst permitted bypass or failure conditions. The six APRM channels provide continuous indications of core average power level based on different samplings of local flux levels. Figures 7.6-14 and 7.6-15, which are the results of analysis, show that the APRM provides valid average power measurements during typical rod- or flow-induced power level maneuvering.

Using a plant heat balance technique, the APRM measurements are calculated such that the meter indications are within ±2% of the bulk thermal power when the power level is greater than 25% of rated; this calibration is maintained by procedure.

The effectiveness of the APRM high-flux scram signals in preventing fuel damage following single component failures or single operational errors is shown in each section of this report where system failures are analyzed; in all such failures, no fuel damage occurs. Since only two APRM channels in each RPS logic channel are required for effective detection of bulk power level transients, the same effectiveness is attained even under the worst permitted bypass conditions.

The APRM rod block setpoint is set lower than the scram setpoint; thus, reactivity insertions due to rod withdrawal errors are terminated well before fuel damage limits are approached.

To account for the decreasing margin to fuel damage at a given power level with reduced recirculation flow, the APRM rod block setpoint is varied with flow.

Average power range monitor component failures which result in upscale, downscale, or instrument inoperative conditions are annunciated, and the reduction of LPRM inputs for any APRM channel below a preset number gives an alarm, rod block, and a logic channel trip. These features warn of loss of APRM capability.

B. RBM channel inoperative, or

C. Channel reading below RBM downscale trip setpoint.

The RBM system is equipped with an automatic bypass feature so that both RBMs are bypassed in the event that the power level is below a level where local damage is possible (30% power; this signal is derived from the reference APRMs) or if a peripheral rod is selected; i.e., a rod in the outer region of the core, which cannot be instrumental in causing local fuel damage. A manual bypass switch allows the operator to manually bypass either RBM for maintenance or calibration.

Since all APRMs are measuring the core average flux with the same precision, any APRM may be selected for use as the primary reference APRM. The channels which were selected are APRM channel 3 for RBM channel 7, and APRM channel 4 for RBM channel 8. The alternate reference APRMs are channels 2 and 5 for RBMs 7 and 8, respectively. These reference signals are routed to the RBMs via contacts associated with the APRM bypass switches, arranged so that if the primary reference APRM is bypassed, the alternate reference APRM signal is automatically routed to the RBM. Note that the primary reference APRM and the alternate reference APRM cannot be bypassed at the same time because they are both assigned to the same RPS trip system.

An inoperative APRM will cause a rod block; therefore, no rod can be withdrawn until either the inoperative condition is corrected or the inoperative APRM is bypassed (in which case the alternate APRM reference is used). In any event, the RBM will be operable when it is needed.

RBM gain adjustment can be expressed as follows:

If $P_L \geq P_A$, then gain = 1.0

If $P_L < P_A$, then gain = P_A/P_L

where:

P_L = average power in vicinity of rod selected for withdrawal. (This is the power seen by the RBM.)

P_A = core average (bulk) power

Upon selection of a rod, signals directed to the LPRM Input/Rod Selected Matrix which routes the appropriate LPRM signals to the RBM inputs. An operational amplifier in each of the RBMs averages these LPRM signals and the result is compared with the reference APRM signal as the amplifier gain factor is adjusted upward in small steps from a value of 1.0. The comparator terminates the gain adjustment sequence when the average is equal to or slightly greater than the reference signal value. If the gain cannot be properly adjusted, a "failure to null" inoperative trip will be generated.

The RBM trip varies linearly with recirculation flow along one of three possible power-flow lines (see Figure 7.6-17); the appropriate trip setpoint (HIGH, INTERMEDIATE, or LOW) is automatically selected by the RBM when a new rod is selected. For increases in power, the operator can transfer to the next higher block by pushing a set-up button. The system alerts the operator when local power

An additional manual ball valve is installed between the automatic ball valve and the drywell penetration.

A guide tube ball valve is normally de-energized and in the closed position. When the TIP starts forward the valve is energized and opens. As it opens it actuates a set of contacts which gives a signal light indication at the TIP control panel and bypasses an inhibit limit which automatically stops TIP motion if the ball valve does not open on command. A Group 2 containment isolation signal initiates TIP drive withdrawal and closes the ball valve when the TIP is retracted.

7.6.1.5.5 Surveillance and Testing

Power range nuclear instrumentation failures are annunciated. Monitor circuitry is arranged to facilitate testing with simulated signals. The TIP system provides information used to periodically calibrate the system.

7.6.2 Reactor Vessel Instrumentation

The following section describes instrumentation associated with the reactor pressure vessel. This includes those instruments which measure vessel water level, reactor pressure, vessel metal temperature, and head flange leakage.

7.6.2.1 Design Bases and Design Features

A. Design Bases

The reactor vessel instrumentation is designed to fulfill a number of requirements pertaining to the vessel itself or the reactor core. The instrumentation must:

1. Provide the operator with sufficient information in the control room to protect the vessel from undue stresses;

2. Provide information which can be used to assure that the reactor core remains covered with water and that the separators are not flooded. (Inputs to ESF systems are discussed in Section 7.3.);

3. Provide redundant, reliable inputs to the reactor protection system to shut the reactor down when fuel damage limits are approached. (Also see Section 7.2.); and

4. Provide a method of detecting leakage from the reactor vessel head flange.

B. Design Features

1. Provide inputs to ECCS and ATWS to assure initiating and interlocking signals occur as required; and

sensors. Additionally, reactor pressure is monitored to provide control signals for the RPS high pressure trip, the core spray and low pressure coolant injection (LPCI) low pressure emergency core cooling system (ECCS) injection permissive and LPCI loop select logic, automatic relief valve operation, anticipated transient without scram (ATWS) system operation, and reactor level control signal density compensation.

The reactor pressure inputs to the RPS are from local non-indicating type pressure switches. The pressure is tapped off the vessel through two sensor lines on opposite sides of the reactor vessel. The sensor lines are extended outside the drywell to separate instrument racks. The RPS pressure switches on the two independent sensing lines are grouped so that a single event cannot jeopardize the ability of the RPS to initiate a scram.

Core spray and LPCI reactor vessel low pressure ECCS injection permissive pressure switches, isolation condenser initiation pressure switches, and ATWS pressure transmitters are grouped into separate divisions and connected to the same two sensing lines used for the RPS pressure switches.

The logic and sequencing, bypasses and interlocks, actuated devices, and system design bases of the systems to which these instruments connect, are discussed in their respective UFSAR instrumentation and control or system functional description sections:

A. Emergency core cooling systems (HPCI, LPCI, ADS, and core spray)	7.3, 6.3
B. Reactor protection system	7.2, 4.6
C. Anticipated transient without scram	7.8
D. Safety relief valve	5.4
E. Isolation condenser	7.3, 5.4

7.6.2.2.3 Reactor Vessel Water Level

Two sets of sensing lines on opposite sides of the reactor vessel are extended outside the drywell to separate instrument racks. The switches and transmitters are grouped so that a single event cannot jeopardize the ability of the RPS to initiate a scram. Each set of sensing lines comprising one division provides level measurement to the FW control system, primary containment isolation system (PCIS), the ECCS, containment cooling ⅔ core height interlock, and the analog trip system (ATS).

Two temperature-equalizing reference columns are used to increase the accuracy at the scram setpoint of the level measurements and are also located on opposite sides of the reactor vessel. This temperature compensation is used for the ECCS and ATS sensor for RPS and PCIS.

Reactor vessel water level is indicated and recorded in the control room. Level is measured to provide ECCS initiation signals by non-indicating differential pressure transitters which also provide trip functions in the anticipated transient without scram (ATWS) system. The water level is also monitored by level transmitters coupled to the same sensing lines to provide (ATS) signals for the RPS and PCIS.

The reactor water level is controlled by the reactor feedwater control system which receives inputs from water level, steam flow, and feedwater flow instrumentation when operated in three-element control. (See Section 7.7). The water level measurement is corrected to compensate for water density changes due to temperature.

"The Reactor Vessel Water Level Instrumentation System (RVWLIS) Backfill System (installed in response to NRC Bulletin 93-03) provides a continuous low flow backfill from the CRD drive header through a flow control station to the RVWLIS reference legs to prevent noncondensible gases from forming in the reference legs over time during normal operation. These gases, when exposed to a normal or rapid depressurization event, could exit solution causing a change to the reference leg head, impacting water level measurement. The backfill system reduces the possibility of these level discrepancies."

Level instruments provide inputs to other systems and are described in sections listed below:

A. Reactor protection system	7.2
B. Anticipated transient without scram	7.8
C. Emergency core cooling system	7.3.1, 6.3
D. Diesel start	8.3
E. Primary containment isolation system	7.3.2
F. Feed pump and turbine trip	7.7, 10.2, 10.4
G. Containment cooling ⅔ core height	7.4

Complete testing of this level instrumentation is possible during any mode of reactor operation. If an accident were to occur during a test, the core water level could still be detected by the redundant differential pressure instrumentation.

7.6.2.2.3.1 Reactor Water Level Instrumentation Replacement

The original reactor level switches have been replaced in response to environmental qualification of electrical equipment program, I.E. Bulletin 79-01B.

The replacement system is an analog transmitter-trip unit system and is installed as a seismic category I divisionalized system. This includes conduit routing from the transmitter location to a new divisionalized cable tray system which runs from the reactor building to the mezzanine level of the Unit 2 turbine building where the trip unit cabinets are located. Pressure, flow, differential pressure and reactor water level switches have been replaced with an analog system which consists of transmitters and trip units.

The function of the present transmitter/trip unit remains unchanged. The interfaces required for installation are within their design capabilities. The present instruments operate throughout the design ranges of the existing switches. The present instruments are not prone to the same failure mechanisms of the original switches and have demonstrated greater reliability.

These instruments are qualified and maintained in accordance with the station environmental qualification program (see Section 3.11).

Functional Testing Requirements

The functional testing requirements are found in the Licensing Topical Report NEDO-21617-A (December, 1978), "Analog Transmitter/Trip Unit System for Engineered Safeguard Sensor Trip Units."

either the proper level is maintained, or that the reactor will be shut down automatically.

Tests have been conducted to determine the stability of the vessel level instrumentation in the presence of rapidly decaying pressures. These tests were conducted at 1500 psig on a standard temperature compensated head chamber. A series of test runs, starting at 1500 psig, verified that the level instrumentation assembly would withstand a depressurization rate of 200 psi/s for the first 3 seconds. At this point, the surface of the water started simmering. Thereafter, the rate was 100 psi/s. Thus, the pressure was dropped rapidly without interfering with the stability of the constant head chamber level and the accuracy of the connected level instrumentation.

Redundant level indicating switches and transmitters are provided, and there are a sufficient number of sensing lines so that plugging of a line will not cause a failure to scram. The arrangement provides assurance that vital protection functions will occur, if necessary, in spite of a failure in the system.

The feedwater control system level sensors are independent of the RPS level sensors with the exception of an isolated input to the feedwater control system from one medium range reactor water level instrument for Unit 2. A failure in the level control which causes the water level to exceed limits will in no way influence the level signals feeding the RPS. Feedwater control system failures are discussed in Sections 7.7, 15.1, and 15.6..

Reactor pressure is also sensed for core protection purposes. A damaging core power transient resulting from a reactor vessel pressure rise is prevented through the control actions initiated by the reactor pressure signal. The four pressure sensors used by the RPS are arranged so that a plugged line or any other single failure will not prevent a reactor scram initiated by high pressure.

The reactor vessel flange leak detection system gives immediate qualitative information about a leak by sensing a pressure buildup. The sensitivity of the reactor vessel flange leak detection system is such that degradation of the seal is noted long before excessive leakage occurs.

7.6.2.4 Surveillance and Testing

All reactor vessel instrumentation inputs to the RPS and ECCS are derived from pressure or differential pressure measurements. The sensing devices are piped so that they may be individually actuated with a known signal during shutdown to initiate a protection system single logic channel trip. The master trip units have indicators so that the readings can be compared to check for nonconformity.

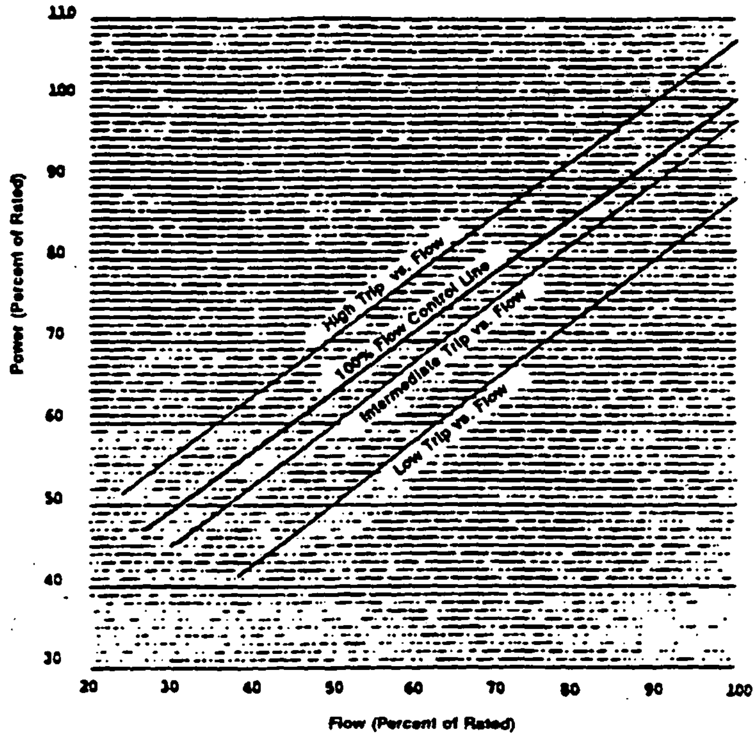
During equilibrium conditions, either hot or cold, thermocouples monitor an approximately uniform temperature; this information is used to detect abnormalities.

The reactor feedwater system control scheme is a dynamic system and malfunctions become self-evident. The system can at all times be cross compared with the other level measurements.

In considering the various failure modes of the rod block circuitry, it is important to note the standby nature of the interlocks. A rod block interlock failure, by itself, cannot result in any fuel damage. A failure of the rod block interlocks combined with a rod withdrawal error is required before even a chance of local fuel damage can occur. The design performance and safety margins provided by the reactor protection system are not affected by any rod block interlock failure. The details of this analysis are presented in Hatch Nuclear Plant, Docket 50-321, Amendment 6. Section 7.2 describes the scram setpoints.

7.7.1.4 Inspection and Testing

Plant Technical Specifications specify required rod block testing (a particular rod block must be periodically tested during any plant condition when it is required to be operable). This testing includes specified functional tests, instrument checks, and calibration.



NOTE:
THE SETPOINT FOR THE HIGH TRIP VS. FLOW IS SPECIFIED IN THE COLR (CORE OPERATIING LIMITS REPORT).
TYPICAL LOW, MEDIUM & HIGH TRIP SETPOINTS ARE SHOWN BELOW:

LOW	$0.65W_D + 32\%$
MEDIUM	$0.65W_D + 40\%$
HIGH	$0.65W_D + 48\%$

UFSAR REVISION 2, JUNE 1997

DRESDEN STATION
UNITS 2 & 3

RBM HIGH FLUX TRIP VS. RECIRCULATION FLOW

FIGURE 7.6-17

7.7.2 Rod Worth Minimizer

7.7.2.1 Design Basis

The design basis of the RWM is to serve as a backup to procedural control during startup and low-power operation to limit control rod worth and the reactivity addition rate resulting from a control rod drop and thus assure that peak fuel enthalpy would be less than 280 cal/g. Operating procedures are the primary defense against high-worth control rod patterns. Preplanned, normal rod patterns result in low individual control rod worths. The RWM is not designed to replace a Qualified Nuclear Engineer's selection of control rod patterns but is intended to monitor and partially enforce approved control rod movements. The RWM will produce a rod block below the low power setpoint (LPSP). The RWM's function is performed with minimal interference with normal operation and is designed for continuous operation at all power levels.

7.7.2.2 Definitions

7.7.2.2.1 Operator Interface

The color graphics terminal is located within the 902(3)-5 panel in the control room. The computer-driven color-coded screen provides all the information necessary for the control room operator to monitor the system's response. Operator informational requests and implementation of special functions are performed by touching screen areas associated with specific actions.

The control rod positions are color coded as follows:

A. Red — Withdraw error,

7.7.2.2.9 Insertion Error

An insertion error is defined as the insertion of a control rod inconsistent with the latched operation sequence. For example, if the operator is withdrawing control rods exactly according to procedures and has withdrawn several of the rods which are defined to be in Group 4, the insertion of any withdrawn rod of Group 4 at that time is not considered an insertion error even though it may be a deviation from planned procedures. However, if he were to insert a rod from another group which was withdrawn previously in the sequence, that action is inconsistent with the operating sequence and is an insertion error. This definition is independent of how far the rod is inserted.

An insertion error occurs when:

A. A control rod in the array of the currently latched step (Step i) is inserted past the insert limit at that step; or

B. A control rod is inserted past the withdraw limit of the closest lower step (Step i - 1 down to Step 1) containing that control rod.

7.7.2.2.10 Withdrawal Error

A withdrawal error is defined similarly to an insertion error. For example, if several rods in Group 4 are not withdrawn, the withdrawal of a rod from a different group which should be withdrawn later in the sequence is a withdrawal error regardless of how far the rod is moved.

A withdrawal error occurs when:

A. A control rod in the array of the currently latched step (Step i) is withdrawn past the withdraw limit at that step; or

B. A control rod is withdrawn past the withdraw limit of the closest lower step (Step i - 1 down to Step 1) containing that rod.

7.7.2.2.11 Low Power Setpoint

The low power setpoint (LPSP) is the core thermal power level below which alarms and rod movement blocks are enabled if generated due to sequence violations. Above the LPSP, sequence violations are alarmed but rod movement blocks may be disabled by the Nuclear Station Operator (NSO). Rod blocks are normally left in effect to enforce sequences to full power. Sequence violations with rod blocks in effect require movement of a mispositioned rod before constraints are removed from other rod movements. The LPSP is determined by steam flow and feed flow measurements and is output from the feedwater control system instrumentation to the RWM computer as a digital signal (reset = below LPSP). The LPSP signal is set to about 20% of rated core thermal power and may be raised or lowered by adjustment of the field sensors.

C. Enable/disable a control rod alternate limit — An alternate limit is defined as one notch position in from the target rod position. Since missing positions frequently occur from the RPIS system, the alternate positions allow the operator to insert a control rod one notch from the target position and continue with control rod movements. There is a limit of two alternate limits corresponding to any of the defined banking limits (except for control rods at positions 00 and 48); they will be displayed in cyan on the color graphics monitor.

Along with the secondary functions touch box, there are other touch boxes on the main screen which enable the operator to perform other RWM functions. The touch boxes are as follows:

A. POWER REDUCTION — used when the operator needs to quickly reduce power. Cram arrays are provided for this task.

B. MAIN MENU — includes toggle switches for various functions and allows edits to be printed.

C. REVIEW SCREENS — allows operator review of the sequence, events, system status, and Cram arrays.

D. SPECIAL MODES — includes the rod test, rod exercise, scram timing, and scram mode functions.

Control rod movements are tracked and verified against the loaded sequence at all reactor power levels. When errors are encountered, control rod blocks are always issued when below 20% power (BPWS range). The control rod blocks can be selectively enabled above 20% power by enabling the function through the main menu.

The RWM function is inhibited when the mode switch is placed to BYPASS or SEQUENCE position. The RWM can be placed in the SEQUENCE position whenever an updated sequence is to be loaded by the Qualified Nuclear Engineer.

7.7.2.7 Surveillance and Testing

Detailed on-demand system diagnostic routines are provided to test the computer and the control rod interlock networks.

Technical Specifications require the following RWM surveillance tests:

A. Verify that the control rod patterns and sequence input to the RWM computer are correctly loaded following any loading of the program into the computer.

B. In operational mode 2 prior to withdrawal of control rods for the purpose of making the reactor critical
   a. Verify the proper indication of the selection error of at least one out-of-sequence control rod.

   b. Verify the rod block function.

C. In operational mode 1 prior to reducing power to below 20% of rated thermal power.
   a. Verify the proper indication of the selection error of at least one out-of-sequence control rod.
   b. Verify the rod block function.

7.7.3 Load Control Design

Load control of a BWR power plant differs from a conventional fossil fuel power plant due primarily to the sensitivity of boiling to pressure variations. In a conventional plant, the turbine control valves are controlled by the speed/load governor responding directly to system frequency and load demand via the governor setpoint. The resulting pressure changes in the boiler cause a pressure regulator to adjust the firing rate of the boiler furnace to match the steaming rate with the turbine steam flow.

In a nuclear boiler, power (and hence steaming rate) is directly affected by the steam volume in the reactor core. In turn, the steam volume is sensitive to pressure variations. If a BWR turbine were controlled as in a conventional plant, opening the control valves would cause decreasing reactor pressure, which would cause the steam volume in the core to increase, which in turn would cause the neutron flux (fission power) to decrease; exactly the opposite of the effect desired. Conversely, closing the control valves would cause the reactor power to increase rather than decrease. The greater the rate of change of pressure, the greater the short-term change in neutron flux. However, the difference in the neutron flux between two steady-state pressure levels (e.g., 1000 and 1020 psia) is small, provided only the operating pressure is changed.

The heat addition rate of a BWR boiler can be changed much faster than that of a conventional boiler, but even so, it cannot be changed fast enough to cope with the effect of a rapid pressure change on reactor power. A control scheme was adopted which placed the turbine control valves under control of a high performance pressure regulator (refer to Section 7.7.4). To get the load response, the speed/load signal from the turbine governing system controls the reactor recirculation flow which directly and strongly affects the reactor power. Therefore, the steam generation rate in the reactor must first be changed before the pressure regulator will react to change the turbine steam flow.

This load control scheme is made up of two control systems, a turbine control system which is supplied with the turbine, and a recirculation flow control system which is supplied with the reactor. Figure 7.7-3 a diagram of the plant load control scheme, shows the basic features in the power operating mode. Reactor pressure and turbine-generator controls are addressed in Section 7.7.4. Additional turbine controls are addressed in Section 10.2.

In addition to the two control systems named above, an economic generation control (EGC) system interfaces with the "load set" controller shown in Figure 7.7-4.

capable of accepting demand rates in excess of these values with no safety consequences for the reactor.

7.7.3.3 Other Reactivity Control Systems

The standby liquid control system is described and evaluated in Section 9.3.

7.7.4 Pressure Regulator and Turbine-Generator Controls

7.7.4.1 Design Basis

The pressure regulator and turbine-generator controls are integrally connected to accomplish the functions of controlling reactor pressure and turbine speed. Specifically, reactor pressure must be prevented from increasing too high during load maneuvers, and turbine speed must be maintained below design limits. The system response must be stable for all anticipated maneuvering rates.

7.7.4.2 System Description

Control and supervisory equipment for the turbine generator are conventional and are arranged for remote operation from the turbine-generator control panel board or console in the control room. In addition, turbine oil pressure and steam extraction pressure are transmitted to receivers on the panel board. Normally, the pressure regulator controls turbine control valve position to maintain constant reactor pressure. The ability of the plant to follow system load is accomplished by adjusting the reactor power level, either by regulating the reactor coolant recirculation system flow or by moving control rods.

However, the turbine speed governor can override the pressure regulator, and the turbine control valves will close when an increase in system frequency or a loss of generator load causes the speed of the turbine to exceed the setpoint. In the event that the reactor is delivering more steam than the turbine control valves will pass, the excess steam will be bypassed directly to the main condenser automatically by pressure-controlled bypass valves.

The total capacity of the bypass valves is equal to 40% of the rated reactor flow. Load rejection in excess of the bypass valves' capacity, which occurs due to generator or tie-line breaker trips, will cause the reactor to scram.

A single pressure regulator, with a backup regulator, is used to position both the turbine control valves and the turbine bypass system valves. The operation of the two groups of valves are coordinated to satisfy the system control requirements. Normally, the bypass system valves are held closed and the pressure regulator controls the turbine control valves utilizing all the steam production to make electrical power.

The second, or backup, pressure regulator is provided to control pressure in the event that the operating regulator should fail.

The setpoint of the backup pressure regulator is normally biased about 10 psi above the setpoint of the operating pressure regulator.

A maximum combined flow limit device is provided to limit the total steam flow through the turbine control valves and bypass valves to a combined value about 105% of the rated reactor steam flow.

As seen in Figure 7.7-4, the pressure regulator with the higher value controls through the low value gate because the other input to the gate, the speed/load signal, is normally set to be larger by about the equivalent of 10% steam flow (or 0.5% speed for 5% speed regulation). A bias signal of this amount is subtracted from the speed/load signal resulting in the load demand signal. The difference between this signal and the output signal from the high-pressure regulator (which represents the steam flow required to satisfy the pressure control requirement), is the load demand error signal. This load demand error signal is the control signal for the recirculation flow control system which adjusts the core recirculation flow until the load demand error signal is zero. This same signal is used to add the equivalent of a setpoint adjustment, at a controlled rate and magnitude, to the pressure regulator to cause the control valves to respond immediately. This effect is temporary since the load demand error signal returns to zero as the load demand is satisfied (see Section 7.7.3).

The speed/load signal will take over control of the turbine control valves should the speed increase over 0.5% (due to overspeed caused by load rejection or system frequency rise due to an upset) or should the load set signal be decreased greater than 10% and faster than the recirculation flow control system can change the reactor steaming rate. In such event of takeover, the steam flow required signal will exceed the control valve flow demand signal. When this difference exceeds a small bias signal (equivalent to about 1 psi), the bypass valves will open and control the pressure if the rejected load does not exceed the bypass capacity. If the bypass capacity is exceeded, the reactor will scram.

The reactor steaming rate can keep up with normal load maneuvering (EGC or otherwise) and, therefore, bypassing of steam is not normally required.

Typical pressure/steam flow relationships are shown in Figure 7.7-9. The pressure regulator setpoint is fixed and both turbine and reactor pressures vary with steam flow — the turbine due to the regulation of the pressure controller and the reactor due to this same regulation plus the variable steam line pressure drop. There appears to be no penalty to this mode of operation (which is recommended for a BWR plant).

The turbine stop valves are equipped with limit switches which open when the valve has moved from its fully opened position. These switches provide a scram signal to the reactor protection system, anticipating the resulting reactor high pressure condition. The turbine stop valve scram signal is discussed in Section 7.2.

To protect the turbine, closure of the four turbine stop valves is initiated for various abnormal conditions as listed in Section 10.2.

7.7.4.3 Design Evaluation

The pressure regulator and turbine-generator design is such that the system provides a stable response to normal maneuvering transients. Section 4.3 evaluates the stability of the overall boiling water reactor cycle, including the pressure and turbine control. Section 15.5 analyzes transients due to turbine trips.

The bypass valves are capable of responding to the maximum closure rate of the turbine control valves such that reactor steam flow is not significantly affected until the magnitude of the load rejection exceeds the capacity of the bypass valves. Load rejections in excess of bypass valve capacity may cause the reactor to scram due to high pressure, high neutron flux, or rapid electrical load reduction. When first stage turbine pressure is above that corresponding to 45% power, any condition causing the turbine stop valves to close will directly initiate a scram before reactor pressure or neutron flux have risen to the trip level.

The pressure regulator can be assumed to fail in either of two ways: opening the turbine control valves or the bypass valves or closing them. These malfunctions are discussed below and in Sections 15.1 and 15.2; fuel damage does not occur in either case. The backup pressure regulator reduces the probability that pressure regulator malfunction will cause operational problems.

The failure modes analyzed are:

A. Controlling pressure regulator failing as is;

B. Controlling pressure regulator failing such that the turbine control valves open; and

C. Controlling pressure regulator failing such that the turbine control valves close.

If the controlling pressure regulator fails as is, the effect upon the plant is dependent upon how the plant pressure behaves. The controlling regulator would be the regulator with the highest value steam flow demand. If system pressure rises, the backup pressure regulator output would rise until it takes over control of the turbine control valves, and the plant response could be similar to a 10-psi setpoint change depending upon the rate of pressure increase experienced. If reactor pressure drops, the reactor power will decrease, further dropping reactor pressure until the reactor vessel is isolated upon a low steam line pressure signal. Reactor recirculation flow will probably be increasing under the influence of the EGC system sensing reduced plant power output.

If the controlling pressure regulator fails in the direction to open the control valves, reactor pressure and power will be decreased and the transient will finally be terminated by the closing of the main steam isolation valves.

If the controlling pressure regulator fails in the direction to close the control valves the effect would be quite similar to a 10-psi positive pressure setpoint change as the backup pressure regulator would than take over control of reactor pressure.

7.7.5 Feedwater Control System

7.7.5.1 Design Basis

The feedwater control system (FCS) is designed to regulate the feedwater flow to the reactor vessel such that proper reactor vessel water level is maintained.

7.7.5.2 System Description

During steady-state operation, feedwater flow closely matches steam flow and the water level is maintained by the microprocessor-based, digital control system.

The level of the water in the reactor is controlled by the digital feedwater controller which receives inputs in one of two ways as selected by the operator: from reactor vessel water level, steam flow, and feedwater flow transmitters (three-element control) or from reactor vessel water level only (single-element control). In three-element control, signals from feedwater flow, steam flow, and reactor vessel level are used to provide a quick response to power changes by reacting to feedwater and steam flow changes before a level change could be detected by level instrumentation. In single-element control a change in water level is immediately sensed and the system adjusts the opening of the feedwater control valves to maintain level. The water level is monitored by level transmitters coupled to two separate sensing lines from the proper elevations on the vessel shell. Level sensors are described in Section 7.6.

Feedwater flow is monitored by flow transmitters coupled to flow nozzles in the feedwater lines. The total feedwater flow is the summation of the signals from the three feedwater lines.

Steam flow is monitored by four flow transmitters coupled to four flow restrictors in the steam lines. The total steam flow is the summation of the signals from the four steam lines.

Reactor vessel water level, feedwater flow, and steam flow are recorded in the control room. High and low reactor vessel water levels are annunciated in the control room.

Each reactor feedwater pump has recirculation controls which pass feedwater back to the condenser when individual feed pump flow is below minimum flow required to cool the pumps. Each feed pump is shutdown automatically on low suction pressure (see Sections 10.4).

In the control room, a microprocessor-based digital control system is installed. The microprocessor-based system provides improved reliability of operation.

7.7.5.3 Design Evaluation

Key feedwater system parameters are recorded and, upon abnormal conditions, annunciated in the control room; the operator can monitor system operation continuously.

Feedwater level control signals are redundant, providing assurance that malfunctions will not result in operational difficulties.

Feedwater control system malfunctions could result in maximum or zero feedwater flow. These malfunctions are discussed in Sections 15.1.2, 15.2.7 and 15.8.3. In all cases, fuel damage does not occur.

7.7.6 Main Condenser, Condensate, and Condensate Demineralizer Systems' Control

7.7.6.1 Design Basis

The main condenser, condensate, and condensate demineralizer systems' control is designed to provide indications of system trouble. Main condenser sensors must provide inputs to the reactor protection system to anticipate loss of the main heat sink and to protect against condenser overpressure. The condensate system controls must ensure adequate cooling to the condensate pumps.

7.7.6.2 System Description

The condensate/condensate booster pumps discharge without throttling to the suction of the reactor feedwater pumps. See Section 10.4.7 for a description of the condensate system.

Discharge pressure of the condensate pumps is indicated. A condensate/condensate booster pump is usually kept on standby and low pressure on the discharge header starts the additional pump. In addition, if any of the running pumps trip, the standby pump will auto start. A modulating control valve, located downstream of the condensate booster pumps, recirculates condensate back to the main condenser on low loads. Recirculation maintains a minimum cooling flow through the condensate/condensate booster pumps, steam jet air ejector condensers, gland seal steam condenser, and off-gas condenser.

Conductivity of condensate both upstream and downstream of the demineralizer is measured, recorded, and actuates an alarm on high conductivity.

Main condenser hotwell level is indicated in the control room and is automatically controlled by either making up or returning condensate from the condensate storage tank. Vacuum switches monitoring condenser vacuum provide scram signals to protect the reactor from loss of the main heat sink; protection for the condenser itself is assured by closure of the turbine stop and bypass valves as vacuum decreases below a preset low level.

7.7.6.3 Design Evaluation

Indication of key parameters from the main condenser, condensate system, and condensate demineralizer system are provided in the control room. The operator is kept fully cognizant of the conditions of the systems. Abnormal conditions are annunciated so that the operator may take appropriate action. The reactor is protected from loss of the main heat sink by main condenser low vacuum scram signals; the vacuum sensors meet the design requirements established for all reactor protection system functions (Section 7.2). To protect the condenser from overpressure, continued decrease of condenser vacuum below the scram setpoint will initiate closure of the turbine stop valves and bypass valves.

7.8.2 Design Requirements

The ATWS rule (10 CFR 50.62) requires the following three elements to mitigate ATWS events:

A. Recirculation pump automatic trip equipment;

B. An alternate rod insertion system, diverse from RPS, with redundant scram air header exhaust valves; and

C. A standby liquid control system that meets minimum flow and concentration requirements.

The RPT portion of the ATWS mitigation system is designed to perform its function in a reliable manner and to conform to the NRC-approved Monticello design.[1]

The overall requirements for the ARI portion of the ATWS mitigation system are as follows:

A. The system should be diverse from RPS;

B. The system shall be designed so that any component whose single failure can cause insertion of all control rods shall be highly reliable;

C. The system should be testable in service;

D. The system should be designed so that, as much as possible, no single component failure can prevent total mitigation action; and

E. All hardware should be of high quality and environmentally qualified.

For an ATWS (per 10 CFR 50.62), the standby liquid control system must be capable of injecting into the reactor pressure vessel a borated water solution equivalent in reactivity control to injecting 86 gal/min of 13 wt% sodium pentaborate at natural B-10 concentration into a 251-inch inside diameter reactor vessel for a given core design. The specific requirements of flowrate and concentration for Dresden Station are addressed in Section 9.3.5.

7.8.3 Mitigation System Description

All of the anticipated transients which require mitigation in the unlikely event of an ATWS quickly reach at least one of two conditions which are readily sensed and from which mitigating actions may be initiated. These conditions are high reactor vessel pressure and low-low reactor water level.

The ATWS mitigation system consists of reactor pressure and reactor water level sensors and trip units, logic, power supplies, and instrumentation to automatically initiate RPT and ARI. The reactor dome pressure automatic actuation setpoint (1240 psig) was chosen to be slightly above the relief valve setpoint. (The value used in analysis was 1250 psig.) The nominal low-low reactor water level automatic actuation setpoint (-59 inches) is that level at which the recirculation pumps trip (ATWS mitigation function) and low and high pressure coolant injection and core spray (ECCS mitigation function) are initiated. For each division, both mitigation functions are initiated by two independent level transmitters which feed reactor water level signals to a set of dedicated master and slave trip units.

Certain manual actions are required of the operator. Suppression pool cooling and standby liquid control must be initiated manually as required by the Emergency Operating Procedures (EOPs). The following subsections describe the capability and requirements for manual initiation of RPT and ARI. Alarms and indications are available to the operator to allow performance of manual actions within the time limits. In addition to the alarms and indications which are initiated by RPS scram logic, other annunciator windows actuate when the reactor water level or reactor pressure reach the ATWS setpoints. Therefore, during an ATWS event, the operator is alerted that an ATWS event has occurred and then has sufficient time to perform the required manual actions. Figure 7.8-1 shows the ATWS mitigation system block diagram.

7.8.3.1 Recirculation Pump Trip

The ATWS mitigation system automatically initiates a RPT of both recirculation pump M-G set field breakers on a two-out-of-two trip logic in either of two channels upon either continuous low-low reactor water level for 9 seconds or high reactor pressure. The performance characteristics are as follows:

A. Logic delay for trip (seconds) (Including dynamic response of the sensors, logic action of the breakers and collapse of generator field.) < 0.53

B. Pump inertial constant (JN/ft, seconds) < 3.0

Manual RPT is achieved by a manual trip of the recirculation pump drive motor breakers. Drive motor breaker control switches are located at panel 902(3)-4 and at the switchgear breakers. Manual RPT should be performed following receipt of alarms indicating an ATWS has occurred if automatic RPT does not occur:

A.	High torus water average temperature alarm setpoint	≤110°F
B.	High reactor dome pressure alarm setpoint	1240 psig nominal
C.	Reactor low water level alarm setpoint	Low-low (-59 inches)

7.8.3.2 Alternate Rod Insertion

The ATWS mitigation system logic automatically energizes the ARI valves when the ATWS reactor vessel high pressure trip setpoint is reached, the ATWS low-low reactor water level trip setpoint is reached, or the manual switches are actuated.

Two manual initiation pushbutton switches are provided in the control room at panel 902(3) for each division of ARI logic. Failure of automatic initiation cannot prevent manual initiation. In order to avoid an inadvertent manual initiation of ARI, the two initiation switches per division must first be armed by rotating a

8.0 ELECTRICAL POWER
TABLE OF CONTENTS

Auxiliary power for each unit is also supplied from the unit auxiliary power transformer (UAT), which is connected to the generator leads (see Figure 8.2-1).

Each auxiliary transformer (UAT or RAT) was originally designed to handle the auxiliary power requirements of one unit plus the emergency power requirements of the other unit. When necessary, an auxiliary transformer of one unit can be connected to the Division II emergency auxiliary equipment of the other unit via circuit breaker switching. Thus, the auxiliary transformers of one unit can serve as a redundant source of offsite power for the other unit.

8.1.3 Onsite Power Systems — Summary Description

The onsite ac distribution system has nominal ratings of 4160-V, 480-V, and 208/120-V. The station auxiliary power system is designed to provide reliable power to those auxiliaries necessary for power generation and to those auxiliary systems important to safety. In the event of total loss of auxiliary power, the auxiliary power required for safe shutdown is supplied from three standby diesel generators located onsite. There is one dedicated diesel generator for each unit plus a swing generator that can be utilized by either unit. For further information about onsite ac distribution refer to Section 8.3.1. For specific ac loads refer to Tables 8.3-1, 8.3-2, and 8.3-3.

Startup auxiliary power is provided through the RATs via any one or combination of the 345-kV and 138-kV transmission lines which connect the station to the offsite system.

In addition to the ac power system, each unit has four dc power systems, each with separate batteries (nominally safety related 250-Vdc, non safety related 250-Vdc, 125-Vdc, and 24/48-Vdc), that provide power to dc loads such as motor-driven pumps and valves, control power for equipment such as relays and circuit breakers, and power to the nuclear monitoring systems. Section 8.3.2 describes the dc distribution system.

An alternate AC power source, with a voltage rating of 4160-V, is provided by the Station Blackout diesel generator system. This system is described in Section 9.5.9. This system is non-safety-related.

8.2.1.1.2 138-kV System

The 138-kV system is comprised of four bus sections. The four bus sections are connected by two normally closed circuit breakers and one normally open circuit breaker, as shown in Figure 8.2-1. The system receives power from the 345-kV system and supplies six 138-kV transmission circuits via autotransformers TR81 and TR83 (see Figure 8.2-1). The six 138-kV transmission lines leave the station on four different rights-of-way, as shown on Figure 8.2-2. Two lines to Joliet Station and two lines to Mazon Station are on double-circuited towers.

8.2.1.2 Transmission Interconnections

Commonwealth Edison Company is a member of the Mid-America Interconnected Network (MAIN). In general, all electric utilities in Illinois, northern and eastern Missouri, Upper Michigan, and the eastern half of Wisconsin are members of MAIN. The transmission system within MAIN consists of one hundred and fifty-nine 345-kV lines totaling approximately 5387 miles and three 765-kV lines totaling approximately 152 miles as of December 31, 1990. These interconnections permit economical exchanges of power and energy with neighboring utilities and provide for emergency assistance.

8.2.1.3 Switchyards

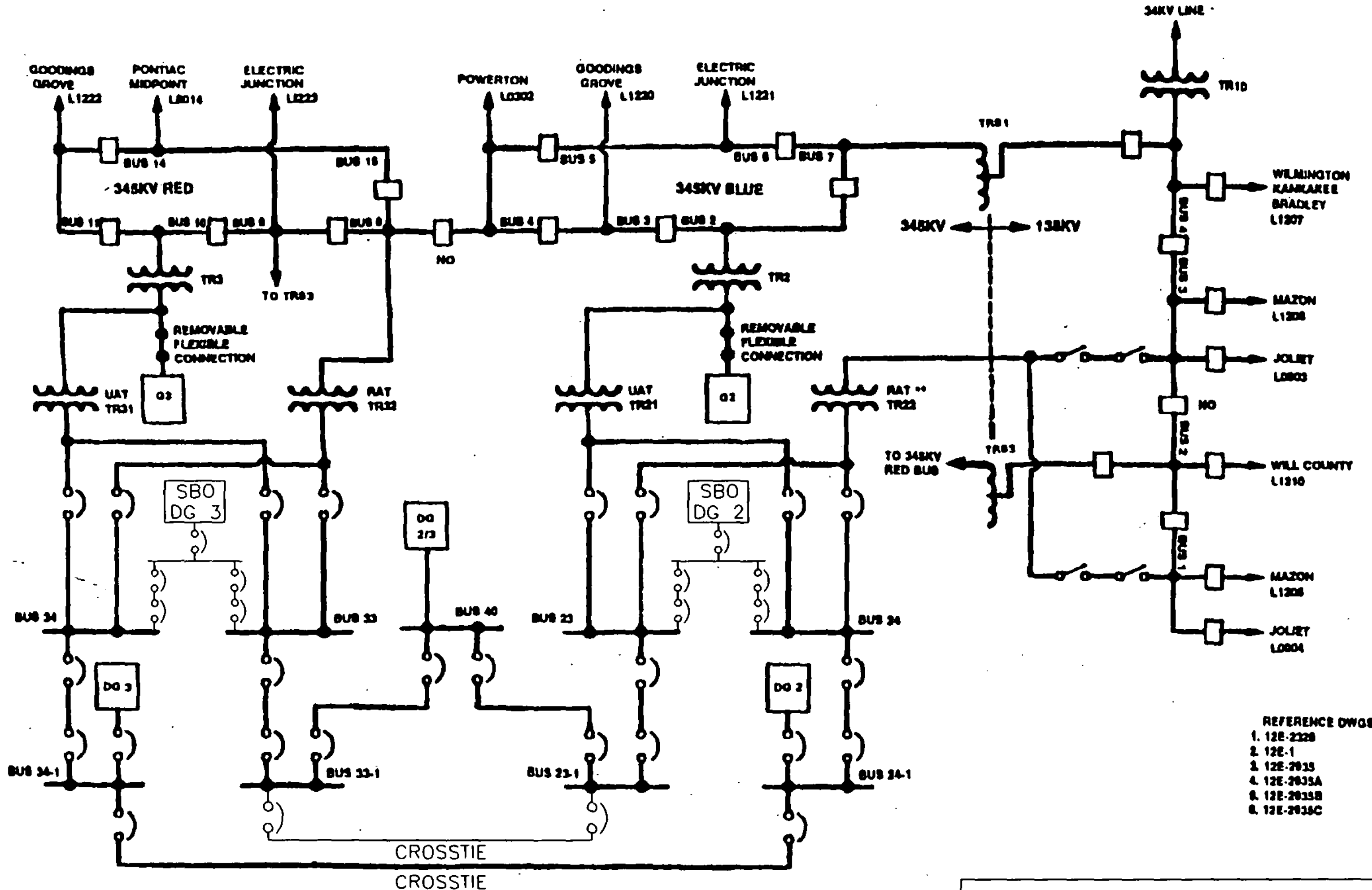
Units 2 and 3 each have two independent sources of offsite power available. The normal source of offsite power for Unit 3 is supplied by the 345-kV switchyard through reserve auxiliary transformer (RAT) 32. The alternate source of offsite power for Unit 3 is supplied by the 138-kV switchyard through the 4-kV crosstie between safety buses 34-1 and 24-1 or safety buses 23-1 and 33-1. The normal source of offsite power for Unit 2 is supplied by the 138-kV switchyard through RAT 22. The alternate source of offsite power for Unit 2 is supplied by the 345-kV switchyard through the 4-kV crosstie between safety buses 24-1 and 34-1 or safety buses 23-1 and 33-1. No single bus fault or accidental opening of one breaker will directly result in a complete loss of power to one unit.

An additional source of off-site power is available when the main generator is off-line by backfeeding through the main power/unit auxiliary transformers. The backfeed operation must be manually performed and involves removal of flexible link connections between the main generator and main power/ unit auxiliary transformer. Minor control and protective relay changes are controlled by procedure.

It is significant that the RAT for Unit 2 is supplied from the 138-kV switchyard while the RAT for Unit 3 is supplied from the 345-kV switchyard. The 138-kV lines connect to different remote terminals than the 345-kV lines, thereby providing diversity of supply to the Dresden RATs.

The 138-kV and 345-kV switchyards are interconnected by two 138-kV — 345-kV autotransformers (TR81 and TR83), which are connected to separate sections of the 138-kV bus. A 40-MVA 138-kV — 34-kV transformer also connects to a section of the bus. There are also transformers between the 138-kV and 345-kV systems at Electric Junction, Lombard, and Goodings Grove.

The output from the 138-kV — 34-kV transformer (TR10) is sent to one 34-kV bus. The three 34-kV lines connected to this bus supply power for towns and rural areas near Dresden Station. A tap off one of these 34-kV lines also feeds a standby transformer for Unit 1 (TR13).



**-AUXILARY POWER TRANSFORMER #22 POWER SOURCE MAY BE EITHER BUS 1 OR 3 DEPENDING ON AVAILABILITY OF EQUIPMENT, GENERATING UNITS AND TRANSMISSION LINES (REFERENCE LETTER TO H. DENTON FROM M. TURBAK DATED 12-31-85).

NO - NORMALLY OPEN

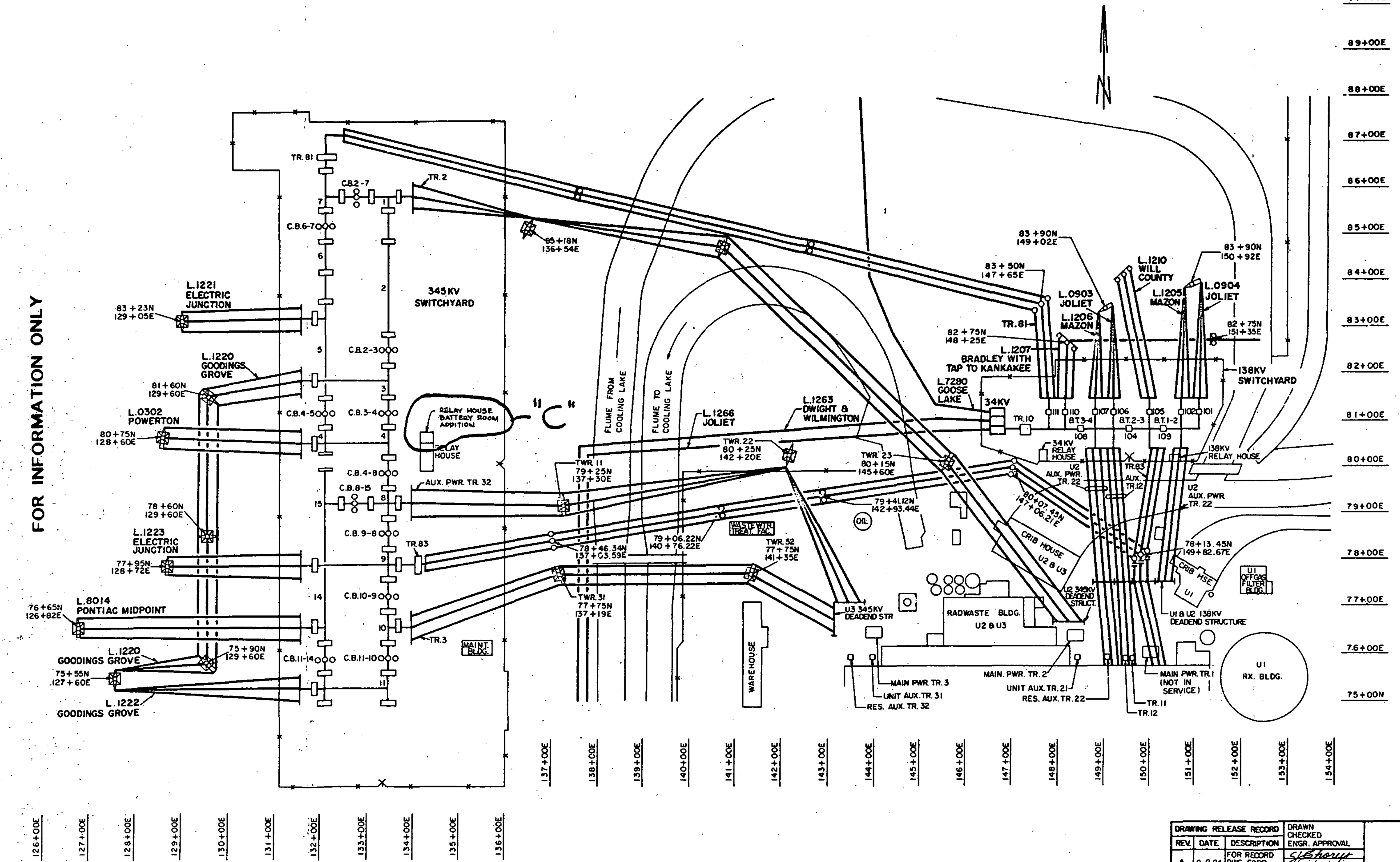
UFSAR REVISION 2, JUNE 1997

DRESDEN STATION
UNITS 2 & 3

SINGLE LINE DIAGRAM
SWITCHYARDS TO EMERGENCY POWER SYSTEM
(4kV LEVEL)

FIGURE 8.2-1

FOR INFORMATION ONLY



REFERENCE DRAWINGS:

PLAN OF PROPERTY & BLDGS.	12E-2
138KV SWYD. PLAN & ELEV.	-93
TR. 1, 14.4KV & 4KV BUS DUCT	-123
PLAN & ELEV. 138KV BUS 4 STRUCT.	-582
PLAN 34.5KV STRUCT.	-583
U1 & U2, 138KV DEADEND ELEV.	-717
PLAN 345KV SWYD.	12E-2176, -2177, -2194
U3, 345KV DEADEND	-2182A
U1 & U2, 138KV DEADEND PLAN	-3189

REV. 02 / JUNE 1997

DRAWING RELEASE RECORD			DRAWN / CHECKED / ENGR. APPROVAL
REV.	DATE	DESCRIPTION	
A	8-8-84	FOR RECORD DWG. CORR. C.E.CO. REV.	
B	11-22-89	FOR RECORD DCR 12-89-51 C.E.CO. REV.	MES / RPZ
C	9-21-95	ADD RELAY HSE. BATTERY RM. ADDITION W.R. 111442A	AAP/JIM / JIM / LJF

"C" →

PLAN VIEW OF TRANSMISSION LINES 34KV, 138KV & 345KV SWITCHYARDS

STATION 12 DRESDEN

SCALE 1" = 100'

CHECKED 8-7-84

ENGINEER

APPROVED

COMMONWEALTH EDISON CO.
CHICAGO ILLINOIS
STATION NUCLEAR ENGR DEPT.

12E-2C

FIGURE 8.2-3

CENTRAL DRAWING FACILITY

24X

H. A manual transfer switch for bypassing the static switch and selecting either the inverter or the reserve source; and

I. Related devices such as instruments, meters, alarms, relays, switches, and fuses.

A malfunction of the static UPS system will have no adverse affects on the bus because it is physically separated and electrically isolated, by the use of circuit breakers, from the Class 1E bus.

8.3.1.4.4 Computer Bus

The computer bus supplies electrical power to the process computer, the main computer, the rod worth minimizer computers, and the fire protection system computer. This bus is normally fed from 480-V switchgear 36 through a 100-kVA UPS. The alternate supply is from 480-V switchgear 25 with backup from a dedicated 250-Vdc battery should the normal and alternate sources fail.

8.3.1.5 Standby Diesel Generator System

The standby diesel generator system produces ac power at a voltage and frequency compatible with normal bus requirements. Each unit has its own DG sized to carry the ECCS power requirements on one unit or supply that power necessary for safe shutdown of the unit. Another DG is shared by Units 2 and 3. In addition, the system is of sufficient capacity to start all initial loads it is expected to drive.

The primary basis for using a standby diesel generator system is to provide an independent source of onsite electric power for the station auxiliaries. Actually, normal sources of power are very reliable and the probability of truly random coincident failures of all sources of power into the station is very low. If the failures were random, standby power would probably not be necessary. However, all the external sources of power entering the plant are carried on overhead lines with a certain vulnerability to storms of wind, lightning, and ice. The standby diesel generator system is provided to guard against the contingency of the concurrent forced outage of all normal sources of power. As a consequence, it is imperative that the diesel generator system not be influenced by the same environments that affect the normal sources of power. For these reasons, the DG air starting capability is completely self-contained and, aside from fuel and the 125-Vdc control power, no outside power source is required for it to start.

8.3.1.5.1 System Components

The physical locations, in relation to each other, of the DGs and emergency buses for the present design provides a great degree of independence. Each DG is housed in its own concrete block cell with an independent fuel supply serving each diesel engine (refer to Section 9.5.4 for a description of the DG fuel oil system). Two of the DGs are housed in reinforced concrete block cells in the turbine building, and the third DG is located in a concrete vault next to the reactor building. Equipment

8.3.1.6.5.2 Derating of Current-Carrying Capacity of Cable in Pans

The current carrying capacity of cable is limited by the continuous temperature rating of the insulation. The ambient temperature, the heat generated in the conductor and the heat transfer from the conductor to ambient all affect the current carrying capacity. The quantity and type of cables in cable pans affect the heat transfer. Record is kept of the quantity and type of cable at each section of the cable pan system. Allowable ampacity is established for every cable at a given cable pan section to assure that no cable will have a continuous conductor temperature in excess of the temperature rating of the cable insulation. Cable size or the different routing paths that can be taken by the new cables are used to meet the allowable criteria.

8.3.1.7 Analysis of Station Voltages

A study and a transient analysis were conducted at the original plant design stage to confirm the ability of the DG to start and accelerate the emergency cooling pumps. The major focus of this effort was to determine the effect of the voltage dips on the running motors. Should the running motors fail to develop sufficient torque to overcome the load torques, they will decelerate toward a stall condition. If they decelerate below the breakdown-torque speed, they will draw high currents (inrush current reduced proportionately with the voltage) and compound the voltage dip problem. The manufacturer's design performance data was used for the pumps, drive motor, and diesel characteristics to conduct the transient studies. The results of these studies are reflected in the designed starting sequence and have been used in determining if the undervoltage relay setpoints are adequate from a motor-starting and voltage dip standpoint. The analysis of the undervoltage relays is described in the following paragraphs.

In addition to the first level "loss of voltage" relays which protect against a LOOP condition by initiating the sequence of events discussed in Section 8.3.1.5.4, a second level of undervoltage relays has been added to each of the 4160-V buses 23-1 (33-1) and 24-1 (34-1) to protect against a degraded voltage condition. As noted above, a degraded voltage condition causes induction motors to draw more current and results in the motor windings becoming overheated. These relays are typically set as indicated in Table 8.3-7. If the degraded voltage condition persists for 7-seconds, an annunciator alerts the operator and a 5-minute timer is initiated. After 5-minutes have passed, the DG is started, the incoming line breakers are tripped, load shedding is initiated, and the DG breakers close when the existing permissives are satisfied. The 7-second time delay prevents circuit initiation due to grid disturbances and motor starting transients, whereas the 5-minute time allows the operator to attempt restoration of normal bus voltage. The 5-minute timer is bypassed on high drywell pressure/low-low reactor water level conditions.

An evaluation of system voltages determined that the critical voltage for the 4160-V buses was above the setpoint of the second level "degraded voltage," undervoltage relays. To remedy this situation, CECo raised the setpoint to the values indicated in Table 8.3-7 and implemented modifications which reduced the voltage drop to those 480-V MCCs that supply critical safety-related loads. These modifications involved the installation of larger feed cables to the 480-V MCCs that supply the DG cooling water pumps; and an automatic trip of the nonessential loads from the 480-V switchgear upon a LOCA start signal for the DG (high drywell pressure or low-low reactor water level). Analyses were performed to ensure that the new setpoints would not have deleterious effects on operation of low voltage equipment fed from the 480-V MCCs. Thus, the setpoints listed in Table 8.3-7 are adequate.

The second level of protection can cause the possibility of a non-synchronous closure of the DG breakers. This could happen when a high drywell pressure/low-low reactor water level signal starts the DGs and there is a subsequent degradation of offsite voltage. Non-synchronous closure is avoided by the presence of a time delay relay in the close circuitry that ensures bus voltage is sufficiently low before closing to the DG. Note that the original undervoltage scheme (first level loss of voltage) does not have this possibility of causing a non-synchronous closure, because the relays are set for a very low voltage (approximately 70% of normal). A fault on the feed to the essential service buses after an ESF signal has started the DGs is another potential for non-synchronous closure. Both undervoltage schemes are susceptible to this failure because opening the feed breaker will immediately close the DG breaker regardless of bus voltage. Note that a fault will not cause a common mode failure; whereas, a degraded voltage induced trip will.

8.3.2 DC Power Systems

Station batteries are provided as a final source of power for specific vital loads. A total of four (250-V safety related, 250-V non safety related, 125-V and 24/48-V) station battery systems are provided for each unit. One safety related 250-V "power" battery is provided to serve the larger loads, such as dc motor-driven pumps and valves. One 125-V "control" battery is provided to supply the power required for exit lighting and all dc control functions; e.g., that required for control of the 4160-V breakers, 480-V breakers, various control relays and annunciators. Two 24/48-V batteries are provided to supply the neutron monitoring system and the stack gas, radwaste discharge, off-gas and process radiation monitors.

An alternate 125-V battery is provided to allow rated discharge testing of the unit 125-V battery while both units remain at power. The alternate 125-V battery is also available, in accordance with the Technical Specifications, if the unit 125-V battery is inoperable.

The unit safety related 250-V, 125-V and 24/48-V batteries are located in a ventilated battery room having concrete block walls. The Unit 2 alternate 125-V battery is located in the former Unit 1 high pressure coolant injection (HPCI) building east battery room. The Unit 3 alternate 125-V battery is located on the Unit 3 turbine building mezzanine floor outside the Unit 3 battery charger room.

The reliability of the dc systems has been improved by the installation of dc battery and bus voltage indication, undervoltage alarms, battery high discharge current alarms, dc ground alarms (safety related 250-V and 125-V systems only), and battery charger trouble alarms on the safety related 250-V, 125-V, and 24/48-V systems. This assures that an adequate state of charge exists on the station batteries at all times and meets IEEE 308-1974, Regulatory Guide 1.97, and Criterion 13 of Appendix A to 10 CFR 50.

8.3.2.1 250-V System

8.3.2.1.1 Safety Related 250-V System

The safety related 250-V battery system is sized to start and carry the normal dc loads plus all dc loads required for safe shutdown on one unit, and the operational loads required to limit the consequences of a design-basis event on the other unit for a period of four hours following loss of all ac sources. These loads are summarized in the load tracking database. This time period is deemed adequate to safeguard the plant until normal sources of power are restored.

The three battery chargers (one per unit plus a swing charger) have a capacity suitable for restoring the battery to full charge under normal load conditions. The chargers are powered from separate ac buses. These buses are arranged so that they can be connected to any source of ac power available in the plant, including the DG. The battery chargers are supplied from MCC 28-2 for Unit 2, MCC 38-2 for Unit 3, and either MCC 29-2 or 39-2 for the swing charger.

The 250-V MCCs are normally fed from their primary source (charger) and their secondary source (battery) operating in a float charger configuration. The battery charger and the battery each have sufficient capacity to supply normal bus loads. The voltage is raised periodically for equalization of the charge on the battery cells. The normal float voltage should remain between 262.8-V and 265.2-V, (2.19-V and 2.21-V per cell). The equalizing voltage must remain between 2.25-V and 2.26-V, per cell or between 270.0-V and 271.2-Vdc while the load is connected to the battery.

The ampere-hour capacity of each unit's battery is adequate to supply expected essential loads following station trip and loss of all ac power without battery terminal voltage falling below the minimal discharge level (i.e., 210-Vdc).

The Unit 2 and 3 safety related 250-V batteries are lead calcium batteries which utilize 120 GNB type NCX-21 and NCX-1500 cells for a total 8-hour battery rating of 1495 ampere-hours based on a minimum terminal voltage of 210-V (1.75-V per cell). This rating is based on the lowest expected electrolyte temperature of 65°F.Below this temperature, the battery may not have sufficient capacity to meet the load profile. The battery racks are seismically qualified and the breakers and buswork are of sufficient capacity for the new batteries.

A design margin exists for aging and load growth (it was 11% in 1988) that is reported by a load tracking database.

The battery room is classified as a mild environment. Therefore, the batteries do not specifically require environmental qualification. However, the batteries have a qualified life of 10 years after which they are required to be replaced.

Units 2 and 3 each have two 125-V battery chargers; one of each pair is a backup. The battery chargers have a capacity suitable for restoring the battery to full charge under normal load. The chargers are powered from separate ac buses. These buses are arranged so that they can be connected to any valid source of ac power available in the plant, including the DG. The battery chargers are supplied from MCC 29-2 for the Unit 2 normal charger, MCC 28-2 for the Unit 2 backup charger, MCC 39-2 for the Unit 3 normal charger, and MCC 38-2 for Unit 3 backup charger.

The 125-V buses and distribution panels are normally fed from their primary source (charger) and their secondary source (battery) operating in a float charger configuration. Loss of either source does not interrupt power flow to the bus. The voltage is raised when required for equalization of the charge on the battery cells.

The ampere-hour capacity of each unit battery is adequate to supply expected essential loads following station trip and loss of all ac power, without the battery terminal voltage falling below the minimal discharge level (i.e., 105-Vdc).

The Units 2 and 3 125-V batteries are lead calcium batteries which utilize 58 Type NCX-21 (NCX-1500) cells with a nominal 8-hour, 77°F electrolyte temperature rating of 1495 amp hours.

The areas of the plant housing the 125-V dc batteries are mild environments. Therefore, the batteries do not require environmental qualification. However the batteries have a qualified life of 10 years after which they are required to be replaced.

The 125-V system is arranged so that more than one failure is required before normal plant needs are not served. All of the loads normally connected to the 125-V dc system can be supplied by either charger. Buses are arranged to allow for alternate paths to other systems throughout the plant where redundancy is employed. The aggregate system is so arranged and powered that the probability of system failure due to a loss of 125-V dc power is very low. All of the systems either self-annunciate upon failure or can be periodically tested in service to discover faults.

The 125-V battery system operates ungrounded with an alarm located in the main control room and a recording ground-detection device to annunciate the first ground. In addition, the ground fault resistance and the time at which a ground fault occurs is recorded by a ground detection device. Thus grounds of a magnitude that could effect equipment operability, the only reasonable mode of failure, are extremely unlikely. The normal mode of battery failure is a single cell deterioration which is signaled well in advance by the tests that are performed regularly on the battery.

When a ground is identified, the action that is taken is determined by the ground's level. If it is a Level I ground (indicated voltage is less than the alarm setpoint voltage that corresponds to 125,000 ohms), then it is recorded and tracked each shift. If it is a Level II ground (between the alarm setpoint of 125,000 ohms and 20,000 ohms) or a Level III ground (20,000 ohms or less), then station procedures are implemented immediately to locate and remove the ground. If a Level III ground cannot be eliminated within 14 days, then a JCO is prepared. If an intermittent ground occurs, then it is logged with the time, date, and coincident activities. Table 8.3-8 provides the voltage-resistance correlation for the action response levels described above.

Each unit has been provided with an alternate 125-V battery in order to allow the unit 125-V battery to undergo rated discharge testing while both units remain at power. The alternate battery is available to supply system loads upon a failure of the unit 125-V battery. The alternate battery is of a similar type as the unit battery, though of a different size, and has been sized to support the same loads. The alternate battery is normally disconnected from the system and is kept on a float charge.

Each 125-Vdc system provides Division I dc power to its unit and Division II dc power to the other unit. The system's battery is tested in accordance with the latest revision of IEEE-450. However, due to crossties between units, the unit battery test requires that the alternate battery be declared operable.

The Unit 1 Charger 1C provides an equalizing charge to the alternate battery. After the equalizing charge, the Unit 1 Charger 1C is disconnected, and the battery is connected to the 125-Vdc system by momentarily paralleling with the Unit 2 battery and charger. The alternate battery is then declared operational.

Because of the physical distance between the Unit 2 alternate battery and the dc distribution panel, the associated voltage drop was considered when sizing the alternate battery. The alternate battery is larger in size (NCX-27) than the permanent battery (NCX-21) and uses more cells (60 versus 58).

The Unit 2 alternate battery is located in the Station Blackout Building (former Unit 1 HPCI Building) east battery room. This location was originally designed to house a battery and as such provides adequate seismic and tornado missile protection.

MCC 65-1 provides power to the heating/cooling units and exhaust fans in the alternate battery room, and smoke detection and lighting of the Station Blackout Building. A safety-related ac feed for MCC 65-1 is available from MCC 29-2 if the normal feed for MCC 65-1 is out-of-service.

The Unit 3 alternate battery is located on the turbine building mezzanine floor outside the Unit 3 battery charger room. This location provides adequate seismic protection but does not provide the required tornado missile protection. To address this concern, a risk analysis was performed to determine the probability of a tornado missile striking the alternate battery. From the analysis, it was determined that the probability of a tornado missile strike is less than 1×10^{-7} for an entire calendar year. Therefore, the current location of the alternate battery maintains the probability of the tornado missile event below a threshold level where the event is not a concern.

The station battery is an integral part of the 125-V dc system which includes the battery chargers, breakers, buses, and other auxiliaries (Figures 8.3-9 and 8.3-10). The 125-V distribution system is divided into three buses as follows:

A. The turbine building main bus,

B. The turbine building reserve bus, and

C. The reactor building bus.

The following description for Unit 2 is typical for Unit 3.

The Unit 2 turbine building main buses 2, 2A-1, and 2A-2 are supplied by the Unit 2 battery and are the normal sources of control power to 4160-Vac switchgear 21 and 23 and 480-Vac switchgear 25, the Unit 2 main control room panels, relay panels and control room, turbine and radwaste building escape lighting. The Unit 2 main buses also supply reactor building bus 2 and the Unit 3 turbine building reserve buses 3B, 3B-1 and 3B-2. The main buses are the reserve power supply to the Unit 2 reserve buses 2B, 2B-1 and 2B-2.

The Unit 2 reactor building bus 2 is normally supplied from the Unit 2 turbine building main bus 2A-1 (as described above) and is the normal source of control power for the Unit 2 4160-Vac switchgear 23-1, 480-Vac switchgear No. 28, and reactor building escape lighting, etc. It is the reserve source of control power to Unit 2 4160 -Vac switchgear 24-1 and 480-Vac switchgear 29.

The Unit 2 turbine building reserve bus 2 is normally supplied from the Unit 3 turbine building main bus 3 and is the normal source of control power for 4160-Vac switchgear 22, 24, and 24-1 and 480-Vac switchgear 26, 27 and 29.

Note that the control power for one set of reactor building 4160-Vac and 480-Vac switchgear is completely independent (including the battery) from the control power to the other set of switchgear in the reactor building.

The unit battery is sized to carry its loads for specific time periods as indicated by the load tracking database.

Control power to the 138-kV switchyard is supplied from the Unit 1 125-V battery and has been replaced with a new battery and seismic rack. The ratings on the new battery are within the ratings of the existing equipment.

8.3.2.3 24/48-V System

Unit 2

The electrical supply for the source range monitor (SRM) and IRM systems, the analog trip systems (Division I only), the dP type scram discharge volume level switches, the signal isolators and the stack gas, radwaste discharge, and off-gas radiation monitors consists of two duplicate 24/48-V three-wire, grounded neutral systems (Figure 8.3-11).

Each system (2A, 2B)consists of two 12 cell, Gould Type 2-MCX-190, 24-V, 190-ampere hour (8-hour rated), lead calcium batteries in series and connected to a dc distribution panel. There are two silicon rectifier-type 25-ampere battery chargers on each system, one of which is connected to each of the 24-V batteries. The source of power for the battery chargers is the 120-Vac instrument bus. Each 24/48-V system is equipped with undervoltage and overvoltage alarms, as well as battery discharge and open bus alarms. The battery chargers are capable of completely recharging the battery in approximately 8.5 hours while simultaneously supplying the normal continuous load, estimated at 15 amperes. The batteries are mounted in seismically qualified racks.

Unit 3

The electrical supply for the source range monitor (SRM) and IRM systems, the dP type scram discharge volume level switches, the signal isolators and the stack gas, radwaste discharge, and off-gas radiation monitors consists of two duplicate 24/48-V three-wire, grounded neutral systems (Figure 8.3-11). Each system (3A & 3B) consists of two 11-cell, C & D type KCR-7, 24-V, 250-ampere hour (8- hour rated), lead calcium batteries in series and connected to a dc distribution panel. There are two silicon rectifier-type 25-ampere battery chargers on each system, one of which is connected to each of the 24-V batteries. The source of power for the battery chargers is the 120-Vac instrument bus. Each 24/48-V system is equipped with undervoltage and overvoltage alarms, as well as battery discharge and open bus alarms. The battery chargers are capable of completely recharging the battery in approximately 8.5 hours while simultaneously supplying the normal continuous load, estimated at 15 amperes. The batteries are mounted in seismically qualified racks.

8.3.2.4 Test and Inspection

The station batteries and other equipment associated with the 24/48-V, 125-V, and safety related 250-V dc systems are easily accessible for inspection and testing. Service and testing is accomplished on a routine basis in accordance with recommendations of the manufacturer. Typical inspections include visual inspections for leaks and corrosion, and checking all batteries for voltage, specific gravity, and level of electrolyte.

8.3.3 Evaluation of AC and DC Emergency Power Systems

The emergency power systems, starting with the batteries and DGs, and continuing through the control equipment to the driven equipment, are designed (and/or located) to be completely operable regardless of seismic or tornadic events. To accomplish this design, the DGs and battery racks are Class I equipment and are separated by the length of the reactor building. The cable pans and cables were routed in Class I areas of the plant and are physically separated where redundancy is involved. The switchgear for critical components is also located within Class I structures.

Redundancy and separation are employed in all critical systems and equipment essential to safe plant shutdown and/or control of the design basis accident.

An exhaustive study has been made to determine if any single component failure could negate operation of the emergency power system's redundant counterpart or of any other component which could possibly prevent meeting the onsite power requirements. No failures were found which could prevent the receipt of electrical power to the required core cooling equipment. The most degraded cases found were: the loss of one DG through failure of a diesel auto-start relay which limits the core cooling capabilities to one core spray subsystem and two LPCI subsystem pumps, and the failure of the MCCs that provide power to the LPCI admission valves, which limit the core cooling capabilities to two core spray subsystems.

Despite the degraded cases stated above the LPCI Swing MCC (28/29-7, 38/39-7) has special features which are represented in Figure 8.3-1 and are discussed in Section 8.3.1.5.4.

The safety related 250-Vdc power supply is used as a source of power for some of the containment isolation valves. Each dc-powered isolation valve is backed up by an ac-operated isolation valve. For example the HPCI steam line isolation valves; the in-board valve is ac, and the outboard valve is dc supplied from the safety related 250-V battery. Should the safety related 250-V battery fail, the ac-operated valve would still isolate the system. Manual switchover to the other safety related 250-V battery is possible and is represented in Figure 8.3-8 of the FSAR.

The 125-V power supply is used to supply control power to the switchgear that is required during a LOCA. Both the Unit 2 and the Unit 3 125-V battery systems are shown in Figure 8.3-9. Control power (125-V) to all of the 4160-V and 480-V switchgear is monitored. The loss of this control power to any one bus actuates an alarm in the control room. The operator acknowledges the alarm and can take manual action to transfer DC control power for the bus to the alternate dc power supply. Feeder breakers to all dc distribution panel buses have trip alarms to alert the operator of the loss of power to any dc bus. Loss of either battery or any one bus in its entirety will interrupt control power to only one of the two redundant power systems.

For example, loss of turbine building main bus 2 or the Unit 2 battery will result in the loss of control power to Switchgear 23, 23-1, and 28 and the normal supply to DG 2/3, HPCI, and automatic depressurization system (ADS). The DG control circuit, HPCI, and ADS, will automatically switch over to their alternate power source. Buses 24, 24-1, and 29 are unaffected. The operator will be alerted and can transfer the control power feeds for buses 23, 23-1, and 28 to their alternate sources. Should the core cooling systems be required before the alternate source is

Table 8.3-1

AUXILIARY ELECTRICAL SYSTEM EQUIPMENT LISTING[1]

TRANSFORMER		
TR2 Main	850-MVA (55°), 17.1 — 345 kV, 1050 kVBIL, 3ϕ, 60Hz, FOA, 55°/65° Rise	
TR20	1000 kVA, 4160 — 480-V, 3ϕ, 60Hz.	
TR21 Unit Auxiliary Power	27.6/36.8/46-MVA, 17.1 — 4.16 — 4.16 kV 150 kVBIL, 3ϕ, 60Hz, OA/FA/FOA, 55°/65° Rise	
	Impedance:	H - X = 26% (on a 46-MVA base) H - Y = 20.5% (on a 46-MVA base) X - Y = 55% (on a 46-MVA base)
	Winding Ratings:	H - 27.6/36.8/46-MVA (55° rise) X - 11.4/15.2/19-MVA (55° rise) Y - 16.2/21.6/27-MVA (55° rise)
TR22 Reserve Auxiliary Power	27.6/36.8/46-MVA, 138 — 4.16 — 4.16 kV 550 kVBIL, 3ϕ, 60Hz, OA/FA/FOA, 55°/65° Rise	
	Impedance:	H - X = 6.4% (on an 11.4-MVA base) H - Y = 7.5% (on a 16.2-MVA base) X - Y = 11.6% (on an 11.4-MVA base)
	Winding Ratings:	H - 27.6/36.8/46-MVA (55° rise) X - 11.4/15.2/19-MVA (55° rise) Y - 16.2/21.6/27-MVA (55° rise)
TR25, TR26, TR27, TR28 and TR29	1500 kVA, 4160 — 480-V, 3ϕ, 60Hz, OA, 55° Rise Impedance 9.7%	
CIRCUIT BREAKERS		
4160 V Bus 40		
Incoming	None	
Feeders	2 - AM 4.16 — 250-MVA, 1200 A	
4160 V Buses 21 and 22		
Incoming	4 - AM 4.16 — 350-MVA, 3000 A	
Feeders	6 - AM 4.16 — 350-MVA, 1200 A	
4160 V Buses 23 and 24		
Incoming	4 - AMHG 4.16 — 350-MVA, 2000 A	
Feeders	20 - AMHG 4.16 — 350-MVA, 1200 A	
Bus Tie	4 - AMHG 4.16 — 350-MVA, 1200 A	
Spares	2 - AMHG 4.16 — 350-MVA, 1200 A	
4160 V Buses 23-1 and 24-1		
Incoming	4 - AMH 4.16 — 250-MVA, 1200 A	
Feeders	19 - AMH 4.16 — 350-MVA, 1200 A	
Bus Tie	4 - AMH 4.16 — 250-MVA, 1200 A	

Table 8.3-1 (Continued)

AUXILIARY ELECTRICAL SYSTEM EQUIPMENT LISTING[1]

480-V Switchgear 25, 26 and 27	
Incoming	3 - AK - 75
Feeders	40 - AK - 25
Bus Tie	2 - AK - 50
480-V Switchgear 28 and 29	
Incoming	2 - AK - 75
Feeders	33 - AK - 25
Bus Tie	1 - AK - 50

BUS DUCT

Main Generator Leads (isolated phase bus)	Isolated-phase 33,000 A
Unit and Reserve Secondary Feeders	Winding "X" to switchgear — non-segregated, 3000 A Winding "Y" to switchgear — non-segregated, 4000 A

GENERATORS

G2	920-MVA, 0.90 PF, 0.58 SCR, 18 kV 1800 rpm, 3ϕ, 60Hz.
DG 2 and DG 2/3	Diesel-driven, 3250 kVA, 2600 kW, 0.80 PF, 4160-V, 3ϕ, 60Hz
SBO DG2	Diesel-driven, 5437 kVA, 4350kW, 0.80 PF, 4160-V, 3ϕ, 60Hz

EQUIPMENT DATA SHEET
ELECTRICAL BUS LOADS

4160-V Bus 21	1 - Reactor feed pump 2A	9000 hp
	1 - Reactor recirculation pump M-G set 2A	7000 hp
	1 - Feeder to reserve reactor feed pump 2C	9000 hp[2]
4160-V Bus 22	1 - Reactor feed pump 2B	9000 hp
	1 - Reactor recirculation pump M-G set 2B	7000 hp
	1 - Feeder to reserve reactor feed pump 2C	9000 hp[2]

Table 8.3-1 (Continued)

AUXILIARY ELECTRICAL SYSTEM EQUIPMENT LISTING[1]

4160-V Bus 23	1 - 480-V switchgear 25	1500 kVA[3]
	2 - Circulating water pumps	1750 hp each
	2 - Condensate and booster pumps	1750 hp each
	1 - Service water pump 2A	1000 hp
	2 - Containment cooling service water pumps	500 hp each
	1 - 4160-V bus 23-1	
	1 - Control rod drive (CRD) feed pump 2A	250 hp
	1 - Tie to SBO Bus 61	
	1 - Spare	
4160-V Bus 23-1	2 - Shutdown cooling pumps	500 hp each
	1 - Reactor building closed cooling water (RBCCW) pump	300 hp
	2 - LPCI pumps	700 hp each
	1 - Reactor cleanup recirculation pump 2A	600 hp
	1 - 480-V switchgear 28	1500 kVA[3]
	1 - Core spray pump 2A	800 hp
4160-V Bus 24	1 - CRD feed pump 2B	250 hp
	2 - Condensate and booster pumps	1750 hp each
	1 - 4160-V bus 24-1	
	2 - 480-V switchgear 26, and 27	1500 kVA each[3]
	1 - 480-V switchgear 20	1000 kVA[3]
	2 - Service water pumps	1000 hp each
	1 - Circulating water pump 2C	1750 hp
	2 - Containment cooling service water pumps	500 hp each
	1 - Tie to SBO Bus 61	
	1 - Spare	

Table 8.3-1 (Continued)

AUXILIARY ELECTRICAL SYSTEM EQUIPMENT LISTING[1]

4160-V Bus 24-1	2 - RBCCW pumps	300 hp each
	2 - LPCI pumps	700 hp each
	1 - 480-V switchgear 29	1500 kVA[3]
	1 - Shutdown cooling pump 2B	500 hp
	1 - Core spray pump 2B	800 hp
	1 - Reactor cleanup recirculation pump 2B	600 hp
<u>ESS Switchgear Loads</u>		
480-V Switchgear 28, 28-1, 28-2, 28-3, 28-7, 29, 29-1, 29-2, 29-3, 29-4, 29-5, 29-6, 29-7, 29-8, and 29-9	1 - Essential service uninterruptible power supply	35 kVA
	1 - Unassigned ACB	
	5 - 120/208- and 240-V distribution transformers	9, 10, and 15 kVA each
	68 - Motor-operated valves	
	1 - Standby liquid control pump	50 hp
	7 - Drywell cooling blowers	75 hp each
	3 - Diesel engine starting compressors	5 hp each
	1 - Reactor building emergency lighting	8 kW
	2 - Diesel oil transfer pumps	1.5 hp each
	2 - Safety related 250-V battery chargers	52 kW each
	1 - Standby gas treatment fan	20 hp
	2 - Condensate transfer pumps	30 hp each
	2 - Reactor protection system M-G sets	25 hp each
	6 - Standby gas treatment motor-operated dampers (valves)	
	1 - Main hydrogen seal oil pump	15 hp
	2 - 125-V battery chargers	26 kW each
	1 - Hydrogen seal oil vacuum pump	2 hp

Table 8.3-1 (Continued)

AUXILIARY ELECTRICAL SYSTEM EQUIPMENT LISTING[1]

2 - Diesel standby circulating lube oil pumps	1 hp each
2 - Diesel standby turbo circulating lube oil pumps	0.75 hp each
1 - Condensate transfer jockey pump	7.5 hp
1 - Turbine and radwaste buildings emergency lighting	22 kW
2 - Diesel cooling water pumps	87 kW each or 105 hp each
1 - Turbine turning gear oil pump	50 hp
1 - Turbine turning gear	60 hp
5 - Turbine bearing lift pumps	10 hp each
2 - Standby gas treatment air heaters	30 kW each
2 - Diesel circulating water heaters	15 kW each
1 - Drywell and torus purge exhaust fan	30 hp
2 - LPCI sump pumps	1.5 hp each
2 - Drywell floor drain sump pumps	5 hp each
4 - Reactor building sump pumps	7.5 hp each
2 - Drywell equipment drain sump pumps	3 hp each
1 - Reactor building elevator	25 hp
1 - Refueling platform feeder	
1 - Fuel pool receptacle feeder	
1 - Reactor building equipment drain tank pump	5 hp
1 - Reactor building evaporative coolant recirculation pump	20 hp
1 - Cleanup precoat tank mixer	0.75 hp
1 - Cleanup precoat pump	15 hp
1 - Cleanup filter sludge pump	2 hp
1 - Cleanup filter aid pump	7.5 hp
1 - Safety system jockey pump	7.5 hp
2 - Diesel generator vent fans	30 hp each

Table 8.3-1 (Continued)

AUXILIARY ELECTRICAL SYSTEM EQUIPMENT LISTING[1]

2 - LPCI/core spray pump area cooling units	5 hp each
1 - HPCI pump area cooling unit	3 hp each
1 - Computer room transformer	10 kW
1 - Turbine deck vertical milling machine	36 hp
2 - Reactor building condensate return pumps	7.5 hp each
1 - Drywell air sampling compressor motor and pump	7.5 hp
1 - Control room standby HVAC air handling unit	50 hp
1 - Control room standby HVAC cooling/ condensing unit	150 hp
2 - Control room standby HVAC booster fans	7.5 hp each
1 - Control room standby HVAC air filter unit heater	9 kW
1 - 120/208-Vac distribution panel	15 kVA
1 - Fuel storage vault and equipment hatch jib crane	7.5 hp
1 - Drywell equipment patch shield door	0.5 hp
3 - Reactor building vent fans	100 hp each
1 - Reactor cleanup demineralization auxiliary pump	100 hp
2 - Fuel pool cooling water pumps	100 hp each
3 - Reactor building exhaust fans	100 hp each
2 - South turbine room ventilation Fans	60 hp each
1 - Post-LOCA monitor and sample pump	1 hp
1 - High velocity air distribution fan	30 hp
1 - Torus/drywell air compressor	40 hp
2 - Instrument bus transformer feeds	25 kVA each
8 - Component cooling service water (CCSW) cooling water pumps	3 hp each
1 - Submersible sewage pump	1 hp

Table 8.3-1 (Continued)

AUXILIARY ELECTRICAL SYSTEM EQUIPMENT LISTING[1]

1 - HPCI auxiliary coolant pump	15 hp
1 - HPCI oil tank heater	9 kW
9 - Contaminated condensate tank heaters	36 kW each

Notes:

1. Listing is for Unit 2 but also applies to Unit 3 except for 480-V MCC 39-9, which does not exist and for Bus 34 which is rated 250 MVA. In general the load values listed are the nameplate values. See engineering to obtain the calculation of record for design values. The number of spare circuit breakers and cubicles is different between units.
2. Pump 2C is a reserve which may be fed from either Bus 21 or Bus 22.
3. For a detailed list of equipment on 480-V buses, see Dresden Station Electrical Distribution Manual.

Table 8.3-7

TYPICAL PROTECTIVE RELAY SETPOINTS

	Protective Relay Type	Setpoint	Time Delay
4 kV Buses 23-1, 24-1, 33-1, and 34-1	Undervoltage		
	(loss of voltage)	2930 V (±5%)	Inductive device time delay is inversely proportional to voltage
	(degraded voltage)	3872 V (±7V) bus 23-1	5 min. and 7 sec. (±20%)
		3872 V (±7V) bus 24-1	5 min. and 7 sec. (±20%)
		3884 V (±7V) bus 33-1	5 min. and 7 sec. (±20%)
		3870 V (±7V) bus 34-1	5 min. and 7 sec. (±20%)
480 V MCC	Overvoltage	133.0 V, (±2%)	10.0 seconds, (±10%)
28-7/29-7	Undervoltage	106.5 V, (±2%)	5.0 seconds
	Under/Overfrequency	57.0 Hz, (±0.008 Hz)	99 cycles, (+3, -2)
		63.0 Hz, (±0.008Hz)	99 cycles, (+3, -2)

9.0 AUXILIARY SYSTEMS
TABLE OF CONTENTS

9.0 AUXILIARY SYSTEMS
TABLE OF CONTENTS

Page

9.0 AUXILIARY SYSTEMS
TABLE OF CONTENTS

Page

9.0 AUXILIARY SYSTEMS
TABLE OF CONTENTS

9.0 AUXILIARY SYSTEMS
LIST OF TABLES

Table

9.0 AUXILIARY SYSTEMS
LIST OF FIGURES

Figure

9.0 AUXILIARY SYSTEMS
LIST OF FIGURES

Figure

9.0 AUXILIARY SYSTEMS

9.1 FUEL STORAGE AND HANDLING

The equipment and evaluation presented in this section are applicable to either unit unless noted otherwise.

The major components of this system are the new fuel storage vault, spent fuel pool, dryer/separator storage pit, spent fuel pool cooling pumps and heat exchangers, reactor building overhead crane, and the refueling platform. Refer to Section 1.2 for drawings showing the complete layout of the operating floor.

9.1.1 New Fuel Storage

9.1.1.1 Design Bases

The design objective of the new fuel storage system is to provide a clean, dry storage vault for new fuel. To achieve this objective, the new fuel storage system is designed using the following bases:

A. New fuel is stored in a manner which precludes inadvertent criticality.

B. Normal reactor refueling involves replacement of 25% to 35% of the core.

C. New or undamaged used flow channels are installed on new fuel bundles. Present channel management strategy is to only use new flow channels on new fuel.

D. The new fuel storage vault is designed to withstand earthquake loading of a Class I structure.

E. There will be no release of contamination or exposure of personnel to radiation in excess of 10 CFR 20 limits.

9.1.1.2 Facilities Description

The new fuel dry storage vault is common for Unit 2 and 3 fuel. The vault contains aluminum, unpoisoned, full length, top entry storage racks. The vault can store a maximum of 320 new fuel bundles in an upright position. The minimum center-to-center spacing of fuel bundles within a given row is 6.5 inches and the minimum spacing between fuel bundles in adjacent rows is 10 inches. Racks in the vault are designed to prevent an accidental critical array, even in the event that the vault becomes flooded. Vault drainage is provided by an open drain in the vault bottom to prevent possible water collection. A lip around the top of the vault prevents water on the refueling floor from draining into the vault.

The new fuel storage vault is a reinforced concrete Class I structure, accessible only through top hatches. All entrances to the vault, including hatches and personnel openings, are capable of being locked. An area radiation monitor is located in the vault.

9.1.1.3 Safety Evaluation

The spacing of fuel bundles in the new fuel storage vault maintains k_{eff} less than or equal to 0.90 dry and k_{eff} less than or equal to 0.95 flooded. ATRIUM-9B fuel assemblies can be safely stored in the Dresden Unit 2/3 new fuel storage vault and meet the above criteria of K_{eff} less than 0.90 dry and 0.95 fully flooded. These conditions will be met, if for any enriched lattice in the assembly, the maximum enrichment is less than or equal to 5.0 w/o U-235 and the minimum gadolinia loading is greater than or equal to 6 gadolinia rods at 2 w/o GD_2O_3 (natural uranium blankets are excluded). If the above criteria is not met, CASMO-3G lattice physics calculations must be performed to demonstrate that the k_∞ with in-core geometry for any axial lattice in the assembly is less than 1.310 at BOL. The CASMO-3G calculations should be performed at 20°C fuel temperature, 100°C moderator temperature, and xenon free conditions.[4]

In addition, controls have been implemented to further reduce the probability of a criticality occurrence, i.e., the storage array will be in a moderation controlled area. A moderation control area limits the amount of hydrogenous material in the area. Administrative controls as generally defined in SIL 152[6] have been incorporated for the area. The vault floor drain prevents flooding. A radiation monitor in the new fuel storage vault provides warning of any radiation level increase.

9.1.2 Spent Fuel Storage

9.1.2.1 Design Bases

The design objectives of the station spent fuel storage system are as follows:

A. To provide a maximum underwater storage capability for 7074 fuel assemblies;

B. To provide for underwater storage of reactor vessel internals; and

C. To provide adequate protection against the loss of water from the fuel pools.

To achieve these objectives, the spent fuel storage system is designed using the following bases:

A. There will be no release of contamination or exposure of personnel to radiation in excess of 10 CFR 20 limits;

B. The storage space in each of the Unit 2 and Unit 3 spent fuel pools is designed for a maximum of 3537 irradiated fuel assemblies;

C. It is possible, at any time, to perform limited work on irradiated components; and

D. Space is provided for used control rods, flow channels, and other reactor components.

E. The spent fuel pool is designed to withstand earthquake loadings of a Class I structure.

F. The spent fuel assembly racks are designed to ensure subcriticality in the storage pool. A maximum K_{eff} of 0.95 is maintained with the racks fully loaded with fuel of the highest anticipated reactivity and flooded with unborated water at a temperature corresponding to the highest reactivity.

The reactor-vessel-to-drywell seal accommodates the differential expansion that occurs between the reactor vessel and the drywell during reactor heatup and cooldown (Figure 9.1-2). The seal is a cylindrical, one-piece, stainless steel bellows. One end is welded to a special skirt on the reactor vessel, while the other end is welded to the refueling bulkhead. It seals the opening between the reactor vessel head flange and the drywell to allow flooding the reactor cavity above. To facilitate leak detection, a flow switch is provided to monitor leakage to a drain line located at the low point on the outside of the seal. The drain line is piped to the drywell equipment drain sump.

9.1.2.2.3 Spent Fuel Pool

The spent fuel pool has been designed to withstand the anticipated earthquake loadings as a Class I structure. Each unit has its own spent fuel pool measuring 33 ft x 41 ft. Each pool is a reinforced concrete structure, completely lined with seam-welded stainless steel plates welded to reinforcing members (channels, I beams, etc.) embedded in concrete. The $\frac{3}{16}$-inch stainless steel liner will prevent leakage even in the unlikely event that the concrete develops cracks. To avoid unintentional draining of the spent fuel pool, there are no penetrations that would permit the spent fuel pool to be drained below a safe storage level, and all lines extending below this level are equipped with suitable valving to prevent backflow. As shown in Figure 9.1-3 (Drawing M-31) and Figure 9.1-4 (Drawing M-362), the passage between the spent fuel pool and the refueling cavity above the reactor vessel is provided with two double-sealed gates with a monitored drain between the gates. This arrangement permits detection of leaks from the passage and repair of a gate in the event of such leakage. The normal depth of water in the spent fuel pool is 37 feet, 9 inches and the depth of water in the transfer canal during refueling is 22 feet, 9 inches. A reinforced area is provided in one corner of each spent fuel pool for loading the spent fuel shipping cask. The liner is 1-inch thick at this location to ensure liner integrity. The cask set down pad is sized to accommodate the 100-ton NL 10/24 spent fuel shipping cask. The pad is reinforced above the pool liner by stainless steel plates welded in place. The water in the spent fuel pool is continuously filtered and cooled by the spent fuel pool cooling and cleanup system described in Section 9.1.3.

In addition to the current capacity for fuel assemblies, the spent fuel pool holds discarded local power range monitors (LPRMs), control blades (also control blades to be reinserted in the core), small reactor vessel components, and miscellaneous tools and equipment as necessary. Additional storage for large components, e.g. steam dryer and separator, is provided in the dryer/separator pit (see Section 9.1.2.2.1) adjacent to the reactor cavity.

9.1.2.2.3.1 Spent Fuel Pool Liner and Sumps

The spent fuel pool system incorporates design features to compensate for damage to the spent fuel pool liner. In addition to the system design capabilities, there are procedural controls to prevent damage from occurring.

The system design provides for minor cracks in the stainless steel liner. Beneath each liner seam weld is a drainage trough which directs leakage to the spent fuel pool liner drain network. These drains lead from beneath the liner to the reactor

H. The fact that B_4C in the Boral core is not mixed with aluminum homogeneously; and

I. The effect of missing absorber plates.

For conditions D and E, rack size was conservatively assumed to be 7x9. This gives a greater reactivity than the actual 9x11 or 9x13 arrays.

The most significant nuclear-related effect was determined to be the effect of missing absorber plates. Analysis has shown that the rack design is able to maintain k_{eff} less than 0.95 for approximately 1 out of every 32 absorber plates missing, even if conditions D and E and other uncertainties from fabrication are applied at the same time. The Quality Assurance Program for the manufacture of the Boral plates and the fabrication of the absorber tubes ensured that each absorber tube included absorber plates of the required boron content.

The 8x8 fuel designs modeled were bounding enrichments [3.01(G.E.) — 3.02 (Exxon) wt.%] and conservatively assumed no gadolinia in the fuel. An analysis of storage of Exxon Nuclear Corporation (now Siemens Power Corporation) 9x9 fuel in the HDFRs has been performed.[1] This analysis modeled a 3.5 wt.% U-235 9x9 assembly at peak reactivity (6000 MWd/MT) with credit taken for residual gadolinia. Abnormal conditions analyzed assumed the spacing between the racks was reduced to zero, the absence of 1 Boral absorber plate per 25 plates, and the spent fuel pool temperature at 40°F. Each of these assumptions would have to occur simultaneously to violate the 0.95 limit on spent fuel pool k_{eff}. This is not considered credible.

The acceptance criterion for fuel storage in the HDFRs is dependent on the fuel design. To ensure k_{eff} for fuel stored in the spent fuel pool is maintained below 0.95, a limit has been set on peak reactor lattice k_∞. This limit factors in the effects of U-235 loading, gadolinia loading, and other minor perturbations. The maximum k_∞ value for each type of fuel stored in the spent fuel pool is listed below. Each value is calculated using the XFYRE code and includes the effect of residual gadolinia and fission products.

The peak reactor lattice k_∞ for the specified stored fuel assemblies is limited to less than or equal to the following values:

Fuel Assembly Type	Peak Reactor Lattice k_∞
GE 7x7	1.26
GE 8x8	1.32
ANF 8x8	1.33
ANF 9x9	1.27

The ATRIUM-9B can be safely stored in any Dresden Unit 2(3) spent fuel rack, if for any enriched lattice in the assembly, the maximum enrichment is less than or equal to 4.30 w/o U-235 and the minimum gadolinia loading is greater than or equal to 6 gadolinia rods at 2 w/o Gd_2O_3 (natural uranium blankets are excluded). If the above criteria is not met, CASMO-3G lattice physics calculations must be performed to demonstrate that with in-rack geometry for any axial lattice in the assembly the k_∞ is less than 0.895 at any point in its lifetime. The CASMO-3G calculations should be performed at 4°C (39.2°F) fuel and moderator temperature, and xenon free conditions.[3]

Before any HDFR was placed in the spent fuel pools, each storage location was checked with a mandrel to confirm that the minimum dimension between the lead-in clips which provide the intertube connection at the top of each storage location was at least 5.758 inches. The storage clips were ground down as necessary to ensure this dimension was achieved.

The maximum combined stress calculations show that the racks meet all stress acceptance criteria.

From the stability analyses of the loaded racks, the safety factor against overturning was found to be 18.9. This is far in excess of the minimum required value of 1.5. Thus, the racks are safe against overturning.

The top corners of the racks were found to be the most critical locations for evaluating the consequence of dropping a fuel bundle. When the fuel bundle drops on the rack, the cross-sectional area of the cell walls absorbing the impact energy increases as the load is transmitted downward. Since the cross-sectional area is smallest when the fuel bundle drops on a corner, the top corner constituted the most critical location.

For evaluating the consequences of fuel bundle drop from 12 inches, the bundle configuration was assumed to be vertical at impact.

In the event that a fuel bundle drops straight through a tube, it will impact on the fuel support plate inside the tube. Each fuel support plate is a thin rectangular plate with a circular hole at the center. This is attached to the inside of the tube with fillet welds. The energy required to cause the plate to yield is small compared to the energy with which the bundle will impact the fuel support plate. Hence, the plate will yield under the impacting bundle. However, the fuel support plates can be dispensed with since these are not essential for the structural integrity of the rack. The stress analysis was performed without considering the stiffening effect of the fuel support plates.

The elasto-plastic analyses of the racks for the accidental fuel bundle drop showed that the maximum length of the rack, measured from the top, which might be stressed beyond elastic limits is 2.1 inches; whereas, the available length of the racks above the active fuel length is about 13 inches.

An Additional evaluation was performed showing that a potential energy of 30240 in-lbs will result in a deformation length of 4 inches. If an assembly weight of 1000 lbs is assumed (which bounds the actual weight of a channeled fuel bundle), a drop height of 30 inches would result in the same potential energy and deformed length. After accounting for a deformed length of 4 inches, the undamaged rack length containing neutron absorbing material is about 9 inches above active fuel. However, a deformation length of 4 inches or more is not expected since the equipment and operating procedures used to handle the fuel bundles limit the maximum height of fuel bundle drop while over the fuel racks to approximately 15 inches.

To ensure the HDFRs are utilized in accordance with the safety analysis assumptions, no loads heavier than the weight of a single spent fuel assembly and handling tool will be carried over fuel stored in the spent fuel pool.

A corrosion sampling program to verify the integrity of the neutron absorber material employed in the HDFRs in the long-term environment has been implemented. The test conditions represent the vented conditions of the spent fuel tubes. Samples are located adjacent to the fuel racks and suspended from the spent fuel pool wall. Eighteen test samples were installed in the Unit 3 pool. Two samples are tested each testing interval in accordance with a predefined schedule. If corrosion is determined to have caused adverse conditions, the samples may be subjected to a B-10 loading analysis.

Additionally, two full length vented fuel storage tubes are suspended in the Unit 2 and 3 spent fuel pools and will be examined should the sample program indicate any reduction of neutron absorber material to below 0.02 g/cm^2, B-10.

This corrosion surveillance program for the HDFRs ensures that any loss of neutron absorber material and/or swelling of the storage tubes will be detected.

The effects of the additional loading on the storage pool structure due to the HDFR and equipment have been analyzed. The spent fuel pool structures including the two stainless steel grid structures spanning the trench were evaluated as Seismic Category I structures in accordance with Regulatory Guide 1.29. Their structural adequacy was verified in accordance with Standard Review Plan Section 3.8.4.

Results of spent fuel pool structural analyses and analyses of grid structures spanning the floor trench show adequacy of the pool structures to withstand the added loads resulting from increased spent fuel pool storage capacity. The stresses in the two grid structures over the trench are within the permissible limits.

The additional thermal loading on the spent fuel pool cooling system was evaluated assuming decay heat energy release rates specified in ANS 5.1, Standard Decay Heat Curve. The calculated maximum heat loads for a partial core offload and a full core offload from 18 month fuel cycles were based on discharging fuel bundles to the spent fuel pool after a 100-hour cooling period and completing the offload after 10 days from shutdown. The decay heat released in the spent fuel pool from 18 month fuel cycles with a conservatively high batch fraction bounds 24 month fuel cycles at high/low batch fractions independent of fuel type. Various combinations of operating equipment were evaluated. The results are shown in Figures 9.1-9 and 9.1-10 for a partial core offload situation. In addition, heat exchanger performance calculations demonstrate that one shutdown cooling heat exchanger operating at 1500 gal/min in parallel with the spent fuel pool cooling system can maintain the pool water temperature below 145 °F for the full core offload condition. For the partial offload condition with the cooling systems operating, and assuming a loss of one of the three cooling trains, the temperature of the pool will be kept below 145 °F.[7] The results are shown in Table 9.1-4.

In the event of a complete loss of spent fuel pool cooling capability, the pool temperature would reach the boiling point after 9.6 hours. This conclusion assumes the following:

A. A 100-hour cooling time following reactor shutdown, prior to discharging fuel to the spent fuel pool;

B. Full core discharge completed 10 days after shutdown;

C. Initial fuel pool temperature of 150°F; and

D. Complete mixing of the water.

The NRC has evaluated the HDFRs and determined that with respect to structural and mechanical design, the HDFRs satisfy the applicable requirements of General Design Criteria 2, 4, 61, and 62 of 10 CFR 50, Appendix A.

The refueling floor is monitored for abnormal radiation levels. Refer to Section 12.3 for a description of the radiation monitoring system.

9.1.2.3.2 Storage of Unit 1 Spent Fuel in the Unit 2 and 3 Spent Fuel Storage Racks

The structural, criticality, and thermal hydraulic effects of storing Unit 1 spent fuel in the Unit 2 and 3 high-density spent fuel racks has been evaluated.[2] Storing Unit 1 spent fuel in Units 2 and 3 spent fuel pools will not increase k_{eff} above 0.95 because Unit 1 fuel is less reactive than Unit 2 and 3 fuel. Since a Unit 1 fuel assembly is dimensionally smaller than a Unit 2 and 3 fuel assembly, it is necessary to insert an adapter in the Unit 2 and 3 spent fuel rack.

It was concluded that Unit 1 fuel assemblies can be safely stored provided an adapter is used and the prescribed storage pattern is followed. The storage pattern requires that Unit 1 fuel assemblies be stored symmetrically starting in the center of the rack and be limited to 63 fuel assemblies per 9x13 rack array and 49 fuel assemblies per 9x11 rack array. The calculations show that the HDFRs are safe and meet the original design requirements when Unit 1 fuel is stored in the limiting pattern.

9.1.2.3.3 Spent Fuel Pool Blade Guide Racks

Design of the control blade guide racks has been carried out in accordance with the applicable portions of Appendix D to the USNRC Standard Review Plan Section 3.8.4, "Technical Position on Spent Fuel Racks." The detailed seismic analyses were performed which demonstrate that rack stresses and displacements meet the acceptance criteria. Although the racks are not classified as safety related, they have been ruggedly designed and carefully analyzed similar to a seismic Category I structure. The rack lifting lugs and lifting sling have been designed with a safety factor of ten with respect to ultimate strength for the maximum combined concurrent static and dynamic load in accordance with the guidelines of NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants." The malfunction of these racks under normal and abnormal loading is, therefore, not anticipated. Additionally, the safe load path for the racks will avoid movement of the racks over the spent fuel being stored in the pool.

9.1.3 Spent Fuel Pool Cooling and Cleanup System

9.1.3.1 Design Bases

The design objectives of the spent fuel pool cooling and cleanup system are to handle the spent fuel cooling load and to maintain pool water clarity. To achieve these objectives the system has been designed as follows:

A. To remove the decay heat from a partial or full core discharge of fuel and maintain the spent fuel pool water temperature at or below 145 °F with one shutdown cooling heat exchanger operating in parallel with the spent fuel pool cooling system.

B. To provide enough filtering capacity to filter the spent fuel pool water volume every 12 hours.

The results of the HDFR licensing report show the spent fuel pool water temperatures for both refueling cases will remain below the above limits with one shutdown cooling heat exchanger in parallel with the spent fuel pool cooling system. The calculated maximum heat load for both refueling cases is based on discharging fuel bundles to the spent fuel pool after 100-hour cooling period and completing the off-load after 10 days from shutdown.

The maximum fuel pool temperature has been chosen to maintain a comfortable working environment in the pool area, to keep the filtering system at an operable temperature, and to maintain clarity of the air above the pool. The filtration flow may be varied to maintain spent fuel pool water clarity and purity. The system has been designed using the following bases:

Design flowrate (maximum)	1400 gal/min
Pump design code	ASME Section VIII
Heat exchanger design code	ASME Section III, Class C
Minimum size of particles filtered	25 microns

9.1.3.2 System Description

The spent fuel pool cooling and cleanup system consists of two circulating pumps; two heat exchangers; a filter; a deep-bed demineralizer; and the required piping, valves, and instrumentation.

The pumps, heat exchangers, and demineralizer are located in the reactor building near the spent fuel pool. The fuel pool filter, which may become radioactive as it collects corrosion products, is located in the radwaste building.

The spent fuel pool cooling and cleanup system is shown in Figures 9.1-3 (Drawing M-31), 9.1-13 (Drawing M-50), 9.1-4 (Drawing M-362), and 9.1-14 (Drawing M-373). Water from the spent fuel pool overflows via scuppers and an adjustable weir into a pair of crosstied skimmer surge tanks. Foreign material entering the spent fuel pool will either sink to the bottom (where it may be removed by a portable vacuum cleaner) or float about in the pool and eventually enter the skimmers, surge tanks, and filtering loop. The pumps take suction from the skimmer surge tanks (located at the top of the spent fuel pool); continuously skim the water from the surface; and circulate the water to the heat exchanger, filter, and demineralizer before discharging the water through two lines back to the spent fuel pool. During refueling operations, the spent fuel pool cooling system may be aligned to discharge into the reactor refueling cavity via manual isolation valves.

The precoat-type filter in each unit uses stainless steel wire-wound elements. Precoat material is Solka-Floc, a powdered cellulose material which is virtually inert. One precoat mix tank and pump serves all radwaste building filters. The slurry is circulated through the filter vessel until a uniform coating of precoat material covers all the elements. The filter is then placed in service until differential pressure signals the need for backwashing. The backwashing process consists mainly of first valving off and draining the dome of the filter, then filling the filter with high-pressure air. All vents are closed during this filling, and air is trapped in the filter dome above the elements. When the pressure in the filter dome reaches approximately 100 psig, the drain valve is quickly opened, and the filter cake, together with trapped impurities, washes into the filter sludge tank. From the sludge tank, the suspension of impurities and water is processed through the radwaste system.

The deep-bed demineralizer consists of a mixture of cation and anion resins. When the resins are depleted they are either sluiced out and regenerated or disposed of as solid radioactive wastes.

Aside from its normal function of cooling and purifying the spent fuel pool water, the system can be used after reactor refueling to drain the dryer/separator storage pit and reactor cavity. Drain lines allow transport of the water to either the condensate storage tanks or to the radwaste disposal system for processing, depending upon water condition. Usually water from the dryer/separator storage pit and reactor cavity is drained to the torus via the shutdown cooling system.

The system maximum heat load capacity is approximately 7.25×10^6 Btu/hr at a pool temperature of 125 °F. Each pump and heat exchanger is rated at 700 gal/min and will handle the heat load imposed on the system during normal spent fuel storage, which is approximately 3.65×10^6 Btu/hr. In the event that a pump or heat exchanger should become inoperative, the cooling load can be handled by the remaining pump and/or heat exchanger until such time as the failed equipment can be repaired. Either one or both loops may be used, dependent upon the spent fuel heat load in the pool, for a total design flowrate of 1400 gal/min.

The shutdown cooling system may be connected in parallel with the spent fuel pool cooling system to assist in cooling the pool during periods of extremely high heat loads, such as immediately after refueling or a full core discharge. The shutdown cooling system consists of three pumps and heat exchangers. Each heat exchanger is rated at 27×10^6 Btu/hr. Refer to Section 5.4.7 for a description of the shutdown cooling system.

The two spent fuel pool heat exchangers, with one shutdown cooling heat exchanger, are capable of handling the decay heat load of a full core discharge plus the two most recently discharged batches of fuel. The cross connection is designed for 1500 gal/min flow from the spent fuel pool to the shutdown cooling system. This provides approximately 12.7×10^6 BTU/hr of decay heat removal at a pool temperature of 145 °F.

Refer to Section 9.1.2.3 for an evaluation of the spent fuel pool temperature response to a complete loss of spent fuel pool cooling and maximum spent fuel pool temperature for various combinations of operating pumps and heat exchangers.

Weekly surveillances are performed to insure the following chemistry is maintained in the spent fuel pool:

A. Conductivity less than 5.0 μmho/cm;

B. pH between 5.6 and 8.6;

C. Silicas less than 0.5 ppm; and

D. Chlorides less than 0.1 ppm.

9.1.4 Fuel Handling System

9.1.4.1 Design Bases

The design objectives of the fuel handling system are to receive and transfer nuclear fuel in a way that precludes inadvertent criticality and to provide equipment for handling both new and irradiated fuel. To achieve these objectives the fuel handling equipment is designed to handle fuel assemblies and other reactor components described in Chapter 4. There will be no release of contamination or exposure of personnel to radiation in excess of 10 CFR 20 limits.

The reactor building overhead cranes were designed such that all crane parts meet or exceed design criteria as established by Crane Manufacturers Association of America (CMAA) Specification 70 and are compatible with the requirements of the Occupational Safety and Health Act of 1970, as amended in 1971, as well as ANSI B30.2.0.

9.1.4.2 System Description

The major components of this system are the refueling platform and the reactor building overhead crane.

Underwater vacuum cleaning equipment is available for removal of dirt and small particles from sections of the spent fuel pool floor not obstructed by racks or other equipment. A variety of special tools is provided for remote handling of fuel and reactor internals and for exchanging fuel channels. Refer to Section 1.2 for drawings showing a complete layout of the operating floor.

9.1.4.2.1 Refueling Platform

Each unit is provided with a refueling platform equipped with a refueling grapple, two ½-ton auxiliary hoists, and associated equipment. Either of these hoists can be positioned for servicing the reactor cavity or the spent fuel pool.

The refueling platform equipment assembly provides a rigid superstructure which moves on parallel tracks to the location of components either in the spent fuel pool or in the reactor well. Using the fuel grapple or designated accessories, a component can be grappled and transported to a storage or installation position.

The refueling platform consists of a track-mounted bridge which includes an electric motor drive manual and optional semiautomatic controls, instrumentation, and service facilities required to support the operation of the fuel grapple or the handling equipment used at the auxiliary hoists. The refueling platform bridge includes a walkway; railings; a trolley-mounted control cab located on the forward (fuel pool) side; a main grapple hoist; the adjacent frame-mounted auxiliary hoist; a reverse-mounted (reactor side) monorail auxiliary hoist; a hinged jib arm power winch; and the reels, drives, pulleys, and sheaves required for the hoist cables and the service air lines from the self-contained, refueling-platform-mounted air compressor. Service connections include power, service air, and communication receptacles. Bridge motion is in the "X" (east-west) direction. Trolley motion is in the "Y" (north-south) direction. The Hoist motion is in the "Z" (up-down) direction. Bridge and trolley motion controls are provided for fixed speed operation and variable speed operation. The fixed speed control (creep speed) is preset at 10 ft/min. The variable speed control permits operation up to 30 ft/min for the trolley and 50ft/min for the Bridge.

9.1.4.2.1.1 Main Hoist

The main hoist is attached to the trolley and is positioned horizontally by the bridge and trolley motion controls. The fuel grapple consists of a mast and head assembly and accessories. The sectional, telescopic mast is gimbal-mounted to a bearing and hanger assembly installed in the upper floor of the control cab trolley and suspended through the slot, thus providing for lateral (Y-axis) movement. The primary equipment controls, except for the monorail auxiliary hoist, are mounted to the tower section in the operator's cab and optional semiautomatic controls from the touch screen. The position of the main fuel grapple with respect to the core grid may be measured by machine-mounted transducers and displayed to the operator on the digital display. To prevent raising the mast to an overhoist position, prohibitive interlocks are established on the mast. Two limit switches are installed on the upper mast section. One of these switches is the normal-up limit and the other the overhoist limit. The grapple normal-up limit may be overridden to allow raising the hoist to the overhoist limit. A mechanical stop at the top of the mast provides a hard-stop capability. The mast is powered from the main hoist motor assembly. Grapple vertical movement is controlled by a variable speed circuit. The variable speed controller permits operation up to 40 ft/min.

The main hoist drive is mounted on a base located above the operator cab but below the main trolley upper deck. In addition to the motor brake, a second safety brake is provided.

The hook assembly at the end of the telescoping mast includes counteracting primary and secondary hooks integrated to double latch the fuel bundle bail from both sides (Figure 9.1-16). The two hooks are pinned between the parallel side plates which are provided at the lower, or grappling, end with a head guide. Two switches for the engaged positions of the hook are located inside the parallel side plates, just above each hook shank. These series connected switches signal the closed condition (air valve solenoid deenergized) through the instrumentation circuitry to the control logic and indicator on the operator's console. Each hook is provided with an eye-lug on its spine for manual operation by means of the actuator pole and J-hook attachment.

9.1.4.2.1.2 Auxiliary Hoists

There are two auxiliary hoists on the refueling platform. The first, known as the frame-mounted hoist, is mounted on the main trolley along with the main fuel hoist. The second, known as the monorail auxiliary hoist, is mounted on its own trolley which travels the length of the platform and works over the side of the platform opposite the main and frame-mounted hoists.

The frame-mounted hoist cable allows travel of approximately 85 feet. The end points of travel are from an elevation approximately at the upper portion of the personnel walkway deck handrails to approximately 85 feet below that point. The hoist has a 1000-pound load interlock on raising. Control is a dual-speed, momentary-contact control at 10 and 30 ft/min. The raising motion of the hoist is blocked by a drum revolution counter switch at a point about 14 feet below the personnel walkway deck. Raising the hoist above that point can be accomplished only by simultaneously pushing the HOIST RAISE and the RAISE OVERRIDE pushbuttons.

The frame-mounted hoist raising motion is also blocked by an adjustable jamming button, a cylinder-shaped weight with tapered ends which is bolted onto the hoist cable. It is designed to lift a hairpin limit switch mounted alongside the cable on the underside of the trolley upper deckplate. In the event the hairpin limit switch does not block the raising of the hoist electrically, the jamming button will mechanically jam the hoist and stall the motor.

The frame-mounted hoist lowering motion is blocked at a point about 85 feet below the personnel walkway deck by the drum revolution counter switch. The hoist is also supplied with dual air hoses with a spring motor take-up reel to follow the hoist cable up and down under tension.

The monorail hoist is mounted on the monorail trolley which travels on a rail attached to the backside of the upper walkway. It is operated from the personnel walkway by means of a control pendant suspended from the monorail hoist trolley. Its line of travel is parallel to the personnel walkway, opposite the operator's cab.

The monorail hoist moves parallel to the personnel walkway at 30 ft/min controlled from the monorail hoist controller. The other functions and controls are identical to those of the frame-mounted hoist.

9.1.4.2.1.3 Instrumentation and Control

All control of the refueling bridge is PLC bused. Control can be from one of the three control stations but at only one Station at a time for the Bridge and Trolley motion. Which station is controlling is selected at the main hoist operator's console. Platform control can be from either the main console, the frame-mounted auxiliary control pendant, or the monorail auxiliary control pendant. Optional semiautomatic control is also provided for positioning of the bridge and main hoist.

The main hoist, monorail hoist, and frame-mounted hoist use a load cell in conjunction with the PLC. The load cell is an electric system which provides a hoist load readout anytime a load is applied to the grapple. All three hoists can operate independently.

The main hoist utilizes a load cell which provides slack cable indication. The force switch provides a rod block interlock for the hoist-loaded indication and another provides the hoist jam indication.

The load cell switch arrangement for the auxiliary monorail and frame-mounted hoists is the same as the arrangement for the main hoist. The load cell is also used to provide hoist-loaded indication, rod blocks and hoist jam indication.

The main hoist grapple position in the horizontal and vertical planes are displayed on digital readouts and swing arm display as follows:

A. Bridge position — Provides X (east-west) position; and

B. Trolley position — Provides Y (north-south) position; and

C. Hoist position — Provides Z (up-down) position; and

The bridge and trolley digital readouts are designed to provide reactor core coordinates to the platform operator. A backup system of X and Y position indication may be provided along the bridge tracks and the trolley cab by lighted or fixed pointers.

9.1.4.2.2 Reactor Building Overhead Crane

The operating floor is serviced by the reactor building overhead crane, which is equipped with a 125-ton main hoist and a 9-ton auxiliary hoist. These hoists can reach any equipment storage area on the operating floor. The main hoist is operated by a main motor or a slow speed (inching) motor. A third motor operates the auxiliary hoist.

The reactor building overhead crane handling system consists of an overhead, bridge-type crane, spent fuel cask lifting devices, and controls (Figures 9.1-17 and 9.1-18). The overhead crane handling system is used for lifting and transporting the spent fuel shipping cask between the spent fuel pool and the cask decontamination/shipping area. It is also used to lift and move other equipment and reactor components accessible from the refueling floor. The overhead crane is located in a controlled environment in the reactor building. The crane main hoist system consists of a dual load path through the hoist gear train, the reeving system, and the hoist load block along with restraints at critical points to provide load retention and minimization of uncontrolled motions of the load in the event of failure of any single hoist component. Redundancy has also been designed into the main hoist and trolley brakes, the spent fuel cask lifting devices, and crane control components. The system will prevent all postulated credible single component failures over the entire supporting load path.

Both the bridge and trolley meet the CMAA fatigue loading requirements. These requirements are stated in Table 3.3.3.1.3-1 of CMAA Specification No. 70. The service classification for the reactor building overhead crane is Class A1 which is designed for 100,000 loading cycles. The weldments fall into categories B and C which permit a stress range of 28,000 — 33,000 psi.

The reactor building overhead crane is classified as Safety Class II equipment and is not seismically qualified.

The main and auxiliary hoists have power control braking as well as two holding brakes. The brakes provided are dc-magnet-operated, electric-shoe-type with a maximum torque rating of 200% of motor torque. The brakes are applied whenever the dc solenoids are deenergized. One dc brake is provided to stop the bridge when deenergized. A manually operated hydraulic brake is also capable of stopping the bridge.

Spring bumpers effective for both directions of travel are provided on the outboard ends of the bridge truck. Crane runway stops with four spring-type trolley bumpers are mounted on runway girders at the ends of the runway rails. The reactor building overhead crane has stops which hook under both the bridge and trolley rails to prevent derailment. The stops also would prevent the reactor building overhead crane trolley from falling into the spent fuel pool.

The reactor building overhead crane is provided with three emergency shutdown switches located on the reactor building walls (elevation 613'-0").

A cable train equalizer feature guards against lifting loads that are not positioned directly beneath the main hook or when the load is off balance. If, during crane operation, the respective lengths of the redundant cable trains become excessively different, the equalizer circuit will disable all crane functions and activate a rotating red light. Following such a trip, all crane functions except raising and lowering may be restored by operating the EQUALIZER BYPASS keyswitch located in the cab.

The main hoist and auxiliary hoist each have two upper limit switches for the lifting circuit and one limit switch for the lowering circuit which inhibit the operation of the hoist in either direction when the upper or lower limit is reached. One set of the main hoist limit switch contacts is used for the main hoist motor control and a second set is used for the main hoist slow speed motor control. These switches are used to restrict lifting to a predetermined limit in the crane's restricted mode.

A digital-type weight indicator for the main hoist is provided. High- and low-load limits can be set manually on the unit with contact closures available for the set weight limits. The contacts operate the slow speed motor for the main hoist. When the weight to be lifted is above the setpoint on the weight indicator, the control circuit for the slow speed motor will prevent its operation and the main hoist brakes will set. As an alternative to the digital load limiter, station procedures require supervising personnel to ensure load hangups do not occur during reactor building crane operation.

A radiation monitor is mounted on the crane bottom and is interlocked with the crane controls. A radiation monitor reading of less than 0.1 mrem/hr will give a low-radiation alarm indicating equipment malfunction. This will actuate an interlock which prevents further upward movement of either hoist. A radiation monitor reading of 30 mrem/hr or greater will give a high-radiation alarm and actuates an interlock which also prevents further upward movement of either hoist. This interlock prevents upward hoisting movement when a highly radioactive component is lifted too close to the surface of the pool water, although lowering or lateral movements are still permitted.

The high-radiation interlock may be bypassed in the crane cab. In the bypass position, movement of a high-radiation load is permitted after the high-radiation interlock has stopped the crane.

The crane can be operated in either a NORMAL or RESTRICTED mode. In the RESTRICTED mode, the crane bridge and trolley movement is restricted to ensure the crane remains within a predefined pathway. Limit switches are provided for both bridge and trolley forward and reverse directions of travel. When the limits are reached, the limit switches deenergize the control circuits. In the NORMAL mode the pathway limit switches are bypassed.

Fuel cask handling above the 545-foot level of the reactor building is considered a "restricted load" and must be performed in the restricted mode. Fuel cask handling in other than restricted mode is permitted only in emergency or equipment failure situations and only to the extent necessary to move the cask to the closest acceptable and stable location.

A RESTRICTED MODE/NORMAL MODE key selector switch activates the restricted pathway limit switches and the main hoist restricted mode upper limit switches. The main hoist must be centered over the pathway when the RESTRICTED MODE is selected. Once on the pathway, the main hoist must also be raised to engage the restricted mode upper limit switches before the bridge or trolley will move. Either one of the two limit switches failing to function properly will prevent movement of the bridge or trolley. The restricted mode upper limit switches must be adjusted so that the restricted load (spent fuel cask) will be lifted a maximum of 6 inches above the refuel floor. This adjustment will depend on the height of the spent fuel cask to be lifted.

For carrying a restricted load, the RESTRICTED MODE/NORMAL MODE selector switch RESTRICTED MODE is selected. The hoist FAST/SLOW switch SLOW position is selected to disable the main hoist fast speed circuitry.

Limit switches on the hoist equalizer bar will shut off power to the bridge, trolley, and the hoist when they open. Either one of the two limit switches will open the power circuit for the crane.

Administrative control is exercised by the key-operated restricted mode switch and the key-operated bypass switch for the equalizer bar limit switches.

The brakes for the hoist will set for any one of the following conditions and keep the load in a safe position:

A. AC power supply failure;

B. Either one of the two limit switches on the equalizer bar open;

C. Main hoist restricted area upper and final upper limit switches open after reaching the set limit;

D. Main hoist weight upper limit switch;

E. Main hoist area upper limit switch;

F. High load contact of the digital indicator control panel;

G. Slow speed motor overload trip;

H. Slow speed motor overspeed trip;

I. Slow speed motor up/down pushbuttons open; and

J. Overload on hoist GE maximum speed control ac motor.

The circuitry is designed such that only the bridge or trolley can be operated at one time. The bridge and trolley brakes will set for any one of the following conditions and keep the restricted load in a safe position:

A. AC power supply failure;

B. Either one of the two limit switches on the equalizer bar open;

C. Main hoist restricted area upper and final upper limit switches open after reaching the set limit;

D. Field loss relay trip;

E. Instantaneous overcurrent relay trip;

F. Bridge or trolley forward/reverse limit switch open; and

G. Overload on GE maximum speed ac motor.

9.1.4.2.3 Fuel Handling Operations

A variety of specialized tools and servicing equipment are utilized for fuel handling. Table 9.1-1 is a list of equipment typically (not all inclusive) used. Use of this equipment for fuel handling is outlined below.

New fuel is brought into the reactor building through the equipment entrance. A rail crane is provided in the equipment access area for removal of new fuel from trucks and, if necessary, for movement of the multiassembly transfer basket. The new fuel is hoisted to the upper floor for storage utilizing the reactor building overhead crane.

Prior to refueling, the new fuel is transferred to the spent fuel pool using the reactor building overhead crane or new fuel transfer crane for Unit 2 and the reactor building overhead crane for Unit 3. If new fuel channels are to be used, the fuel is channeled on the new fuel inspection stand before being placed in the spent fuel pool. If previously irradiated channels are to be used, the fuel is placed into the pool, then channeled under water with special tools. Present channel management strategy is to only use new flow channels on new fuel.

Prior to initial reactor fueling, the spent fuel pool, reactor head cavity, and reactor internals storage pit were filled with water and checked for leakage. Dummy fuel assemblies were run through a complete cycle from the new fuel storage vault to the spent fuel pool. Prior to fuel handling, all hoists, cranes, and tools are inspected and tested to assure safe operation.

In preparation for refueling, the concrete shield plugs in the reactor cavity and the transfer canal are removed using the reactor building overhead crane. The drywell head, head insulation, and reactor vessel head are removed, using the same crane. The steam dryer assembly may be moved to the dryer/separator storage pit either before or after flooding of the storage pit. The steam separator assembly is unbolted from the core structure using a special hand tool. Contaminated demineralized water from any of several sources, as convenient, is pumped into the reactor until the reactor cavity and the dryer/separator storage pit are flooded to the normal level of the spent fuel pool. The steam separator assembly is then transferred to the dryer/separator storage pit.

The reactor water cleanup system (see Section 5.4.8) may be operated to assure sufficient water clarity for fuel movement, then the spent fuel pool gates are removed. Spent fuel is removed from the reactor using the main fuel grapple and placed in racks in the spent fuel pool. The same equipment is used to transfer the new fuel and exposed fuel to be reloaded from the spent fuel pool to the reactor. The racks in which fuel assemblies are placed are designed and arranged to ensure subcriticality in the pool.

When reactor refueling is complete, the spent fuel pool gates are set back in place. The steam separator assembly is returned to the reactor. The steam separator assembly is bolted down and the steam dryer assembly is replaced. The water in the dryer/separator storage pit is pumped down to the raised step at the bottom of the pit, and reactor cavity is pumped down to the reactor vessel flange. The reactor vessel head, insulation, drywell head, and concrete shield blocks are replaced.

During core alterations, direct communication is maintained between the control room and refueling platform personnel.

During and after refueling operations, some fuel channels may be removed from the fuel using the underwater channeling equipment. Fuel channels on spent fuel may be taken off and put onto new fuel or may be swapped with those on partially spent fuel, if they are relatively undeformed (i.e., not bowed, bulging, or twisted past certain limits). However, present channel management strategy is to only use new channels on new fuel. Channels which can no longer be used are temporarily stored in the spent fuel pool and eventually disposed of offsite as solid radwaste.

When the spent fuel is to be moved offsite, a spent fuel shipping cask is used. After confirmation of the operational acceptability of the reactor building overhead crane as described in Section 9.1.4.4.2, the fuel cask will be hoisted to the refueling floor and moved over a controlled path to the decontamination pad and then to its position in the spent fuel pool. The spent fuel is loaded into the cask under water. The cask is closed and removed from the pool. After decontamination, the spent fuel shipping cask is lowered by the reactor building overhead crane to a truck or railway car in the equipment access area.

9.1.4.3 Safety Evaluation

This section discusses the safety aspects of the refueling platform, reactor building overhead crane, and associated equipment design. The analyses of the radiological consequences for fuel handling accidents and spent fuel cask drop accidents are discussed in Section 15.7.

9.1.4.3.1 Refueling Platform

Protective interlocks prevent handling of fuel over the reactor when a control rod is withdrawn, and another set of interlocks prevents control rod withdrawal when fuel is being handled over the reactor. Optional boundary zones generated by the PLC prevent moving the bridge outside of the fuel pool area or reactor cavity without additional operator action. The telescoping fuel grapple in the normal up position cannot lift any load, including fuel assemblies, which would result in less than seven feet of water coverage at normal fuel pool water level. For a fuel assembly, the top of active fuel (pellets) is about 18 inches below the bale handle. This results in about 8.5 feet of water coverage over fuel in the normal up position.

Fuel stored in the spent fuel pool is covered with sufficient water for radiation shielding, and fuel being moved is at all times covered by a minimum depth of 8 feet of water. Spent fuel will not be handled with an inadequate depth of water shielding. However, the geometry of the TN9.1 fuel transfer cask requires that less than 8 feet of water be above a spent fuel bundle during transfer to the cask.

An evaluation of the dose rates at the spent fuel pool surface as a function of fuel bundle age for a 5-foot water shield above a spent fuel assembly has been completed. For calculational purposes, zero age was taken to be reactor shutdown. The active fuel length is 12 feet. The plenum above the fuel was assumed to be filled with normal density water. The assembly was assumed to be 5 inches on a side and to have an average power of 3.54 MWt. This was based on an equilibrium exposure of a 2561 MWt core containing 724 assemblies. A peaking factor of 1.5 was used to consider dose rates associated with a highly activated assembly. The water shield was placed 5 feet above the assembly, not above the active fuel. The neutron activation contribution to the dose rate was based on 1000 grams of Zircaloy-2 (wt.%: 97.89 Zr, 0.06 Ni, 0.15 Cr, 0.20 Fe, and 1.7 Sn) located 5 feet below the surface of the fuel pool.

The self-shielding properties of UO_2 were not considered in calculating the dose rates given in Table 9.1-2 and shown in Figure 9.1-19. With self-shielding considered, the fuel geometry is such that the dose rate calculations would yield a lower dose rate along the axis of the assembly. However, some points on the fuel pool surface are essentially unaffected by the UO_2 self-shielding effect. The calculation assumed the fuel assembly was filled with fission products associated with a 3.54 MWt fuel bundle but with normal density water as the self-shielding material.

If operations dictate that the assemblies be moved in 90 days, the dose rates at the surface of the spent fuel pool for the average and the highly activated assembly would be approximately 14 and 21 mrem/hr respectively.

During actual fuel transfer to/from the cask, the actual water shield thickness is 5 feet, 10⅜ inches. The expected radiation dose will then be decreased by approximately a factor of 10.

9.1.4.3.2 Reactor Building Overhead Crane

The reactor building overhead crane main hoist is single failure proof. Within the dual load path, the design criteria are such that all dual elements comply with the CMAA Specification No. 70 for allowable stresses, except for the hoisting rope which is governed by more stringent job specification criteria. With several approved exceptions, single element components within the load path (i.e. the crane hoisting system) have been designed to a minimum safety factor of 7.5, based on the ultimate strength of the material. Components critical to crane operation, other than the hoisting system, have been designed to a minimum safety factor of 4.5, based on the ultimate strength of the material. Table 9.1-3 lists the results of the crane component failure analysis.

The reactor building overhead crane and spent fuel cask yoke assemblies meet the intent of NUREG-0554.

All analyses performed relative to the overhead crane handling system loads have been based on the NL 10/24 spent fuel shipping cask which weighs 100 tons (Figure 9.1-18). If larger casks are used, additional analyses will be required to assure safety margins are maintained.

Administrative controls and installed limit switches restrict the path of travel of the crane to a specific controlled area when moving the spent fuel cask. The controls are intended to assure that a controlled path is followed in moving a cask between the shipping area and the spent fuel pool. Administrative controls also ensure movement of other heavy loads such as the drywell head, reactor vessel head, and dryer separator assembly is over preapproved pathways.

Technical Specification 3.10/4.10 states refueling requirements. Station procedures prohibit movement of heavy loads over the spent fuel pools or open reactor cavity except under special procedures that have been reviewed and approved by an onsite designated committee.

The crane reeving system does not meet the recommended criteria of Branch Technical Position APCSB 9-1 (now incorporated into NUREG-0554) for wire rope safety factors and fleet angles. The purpose of these criteria is to assure a design which minimizes wire rope stress wear and thereby provides maximum assurance of crane safety under all operating and maintenance conditions. Because the crane reeving system does not meet these recommended criteria, there is a possibility of an accelerated rate of wire rope wear occurring. Accordingly, to compensate in these design areas, a specific program of wire rope inspection and replacement is in place.

The inspection and replacement program assures that the entire length of the wire rope will be maintained as close as practical to original design safety factors at all times. This inspection and replacement program provides an equivalent level of protection to the methods suggested in wire rope safety and crane fleet angle criteria and will assure that accelerated wire rope wear will be detected before crane use.

"Two blocking" is an inadvertently continued hoist which brings the load and head block assemblies into physical contact, thereby preventing further movement of the load block and creating shock loads to the rope and reeving system. A mechanically operated power limit switch in the main hoist motor power circuit on the load side of all hoist motor power circuit controls provides adequate protection

9.1.4.4 Inspection and Testing Requirements

Surveillance requirements are stated in Technical Specification 3.10/4.10. These are summarized below.

9.1.4.4.1 Refueling Platform

The refueling platform interlocks are functionally tested prior to any fuel handling with the head off the reactor vessel. They are tested at weekly intervals thereafter until these interlocks are no longer required. The refueling platform interlocks are tested following any repair work or maintenance associated with the interlocks.

9.1.4.4.2 Reactor Building Overhead Crane

To minimize the potential of a cask dropping into the spent fuel pool, a detailed procedure of inspection and load testing of the reactor building overhead crane is performed at the time of a fuel cask transfer or at a minimum of every 6 months. In addition, the fuel cask travel path will never be over the reactor vessel or the fuel racks in the spent fuel pool. Travel over the spent fuel pool is limited to that small area allocated for cask storage.

Prior to cask lifting operations, a detailed visual inspection is made of all mechanical and electrical components of the crane. Following the visual inspection, an operational test is conducted with no load on the hook. This test verifies that all controls are operating correctly. Following these tests, a load test is conducted by raising the fuel cask approximately 1 foot off its transport vehicle or rail car. The prime purpose of this test is to verify that there is no load movement after a fixed period of time. Hoisting and lowering rates are then determined to ensure that they comply with the vendor's recommendations.

9.1.5 References

1. Exxon Nuclear Criticality Analysis for 9x9 Fuel, XN-NF-84-115, Revision 1.

2. Quadrex Corporation, Qualification Report, QUAD-3-83-002, Revision 1.

3. EMF-94-098(P) Revision 1, "Criticality Safety Analysis for ATRIUM-9B Fuel: Dresden Units 2 and 3 Spent Fuel Storage Pool,"NFS NDIT #960095, dated January 1996.

4. EMF-96-148(P) Revision 1, "Criticality Safety Analysis for ATRIUM-9B Fuel: Dresden and Quad Cities New Fuel Storage Vaults,"NFS NDIT #960127, dated September 1996.

5. Letter, J. A. Zwolinski (NRC) to D. L. Farrar (ComEd), "Technical Specifications Relating to Storage of New and Spent Fuel in the High Density Fuel Storage Racks," dated December 12, 1985. Transmitted Amendment No. 91 to DPR-19 and Amendment No. 85. to DPR-25.

6. GE SIL No. 152, "Criticality Margins For Storage Of New Fuel," dated March 31, 1976.

7. Fuel Pool Cooling Heat Removal Capability, DRE 97-0096, Revision 0.

Table 9.1-1

TOOLS AND SERVICING EQUIPMENT

Fuel Servicing Equipment

Fuel preparation machines
New fuel inspection stand
Channel bolt wrenches
Channel handling tool
Fuel pool sipper
Channel gauging fixture
General purpose grapples
Fuel inspection fixture
Channel transfer grapple
Channel storage adapter
New fuel transfer stand

Servicing Aids

Pool tool accessories
Actuating poles
General area underwater lights
Local area underwater lights
Drop lights
Underwater TV monitor
Underwater vacuum cleaner
Viewing aids
Light support brackets
Incore detector cutter
Incore manipulator
Underwater viewing tube
Pole Handling System
Mast Mounted Camera

Refueling Equipment

Refueling equipment servicing tools
Refueling platform equipment

In-Vessel Servicing Equipment

Instrument strongback
Control rod grapple
Control rod guide tube grapple
Fuel support grapple
Grid guide
Control rod latch tool
Instrument handling tool
Control rod guide tube seal
Incore guide tube seals
Blade guides
Fuel bundle sampler
Peripheral orifice grapple
Jet pump service tools
Peripheral fuel support plug
Peripheral orifice holder

Storage Equipment

Spent fuel pool high density storage racks
Spent fuel pool blade guide storage racks
Channel storage racks
Storage racks (control rod/defective fuel)
In-vessel racks
New fuel storage rack
Defective fuel storage containers
Spent fuel rack adapter lifting tool
Unit 1 canister lid tool
Unit 1 canister handling tool
Unit 1 fuel assembly tool

Table 9.1-2

DOSE RATE AT FUEL POOL SURFACE (mrem/hr)

Time Post-Shutdown (days)	Average Fuel Bundle	Zircaloy-2	TOTAL	Hot Fuel Bundle	Zircaloy-2	TOTAL
30	34.1	12.5	46.6	51.2	18.8	70.0
60	10.6	10.0	20.6	15.9	15.0	30.9
120	3.90	5.90	9.80	5.88	8.90	14.8
180	2.83			4.25		
210	2.51	2.50	5.01	3.77	3.80	7.57
240	2.24	1.90	4.14	3.36	2.85	6.21
300	1.82	1.03	2.85	2.73	1.55	4.28
360	1.52	0.58	2.10	2.28	0.87	3.15

Table 9.1-4
SPENT FUEL POOL COOLING CAPABILITY

Spent Fuel Pool Equipment Configuration	Heat Removal Capability (Btu/hr) (Note 1)	Partial Core Offload (Note 2)		Full Core Offload (Note 3)	
		Decay Heat Released (Btu/hr)	Pool Water Temperature < 145F	Decay Heat Released (Btu/hr)	Pool Water Temperature < 145F
1 FPC Train	7.384E6	11.283E6	No	22.572E6	No
2 FPC Trains	14.768E6	11.283E6	Yes	22.572E6	No
1 SDC Train	12.740E6	11.283E6	Yes	22.572E6	No
1 FPC Train & 1 SDC Train	20.124E6	11.283E6	Yes	22.572E6	No
2 FPC Trains & 1 SDC Train	27.508E6	11.283E6	Yes	22.572E6	Yes

Notes:

1. Calculation DRE97-0096 assumes the following:

    a. FPC pump flow rate is 700 gpm per pump.
    b. SDC pump flow rate is 1500 gpm to the spent fuel pool.
    c. RBCCW temperature is 105 °F.
    d. RBCCW flow rate through the FPC heat exchanger is 1600 gpm.
    e. RBCCW flow rate through the SDC heat exchanger is 3300 gpm.
    f. Spent fuel pool water temperature is 145 °F.

Table 9.1-4
SPENT FUEL POOL COOLING CAPABILITY

Notes:

2. For the calculated heat load from a partial core discharge, licensing report QUAD-1-79-234 assumes the following:

   a. A maximum discharge of 42% of the core (306 fuel assemblies).
   b. Fuel assemblies are discharged to the spent fuel pool after a 100-hour cooling period.
   c. The offload is completed 10 days from shutdown.
   d. A margin of 15% to 25% is added for uncertainties in fission product decay.

3. For the calculated heat load from a full core discharge, licensing report QUAD-1-79-234 assumes the following:

   a. The spent fuel pool is completely filled with a full core discharge of 724 fuel assemblies (total of 3780 assemblies).
   b. Fuel assemblies are discharged to the spent fuel pool after a 100-hour cooling period.
   c. The offload is completed 10 days from shutdown.
   d. A margin of 15% to 25% is added for uncertainties in fission product decay.

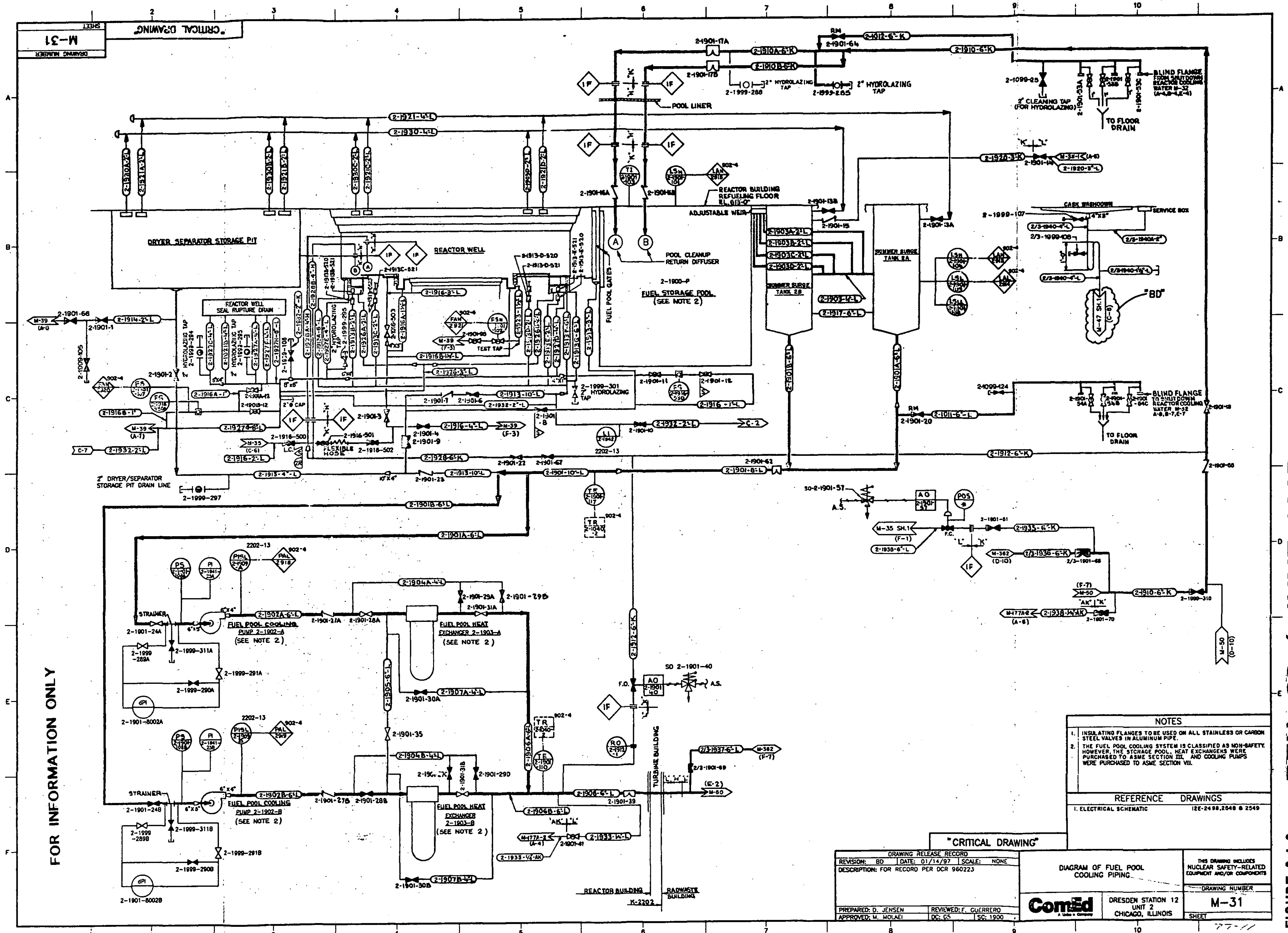
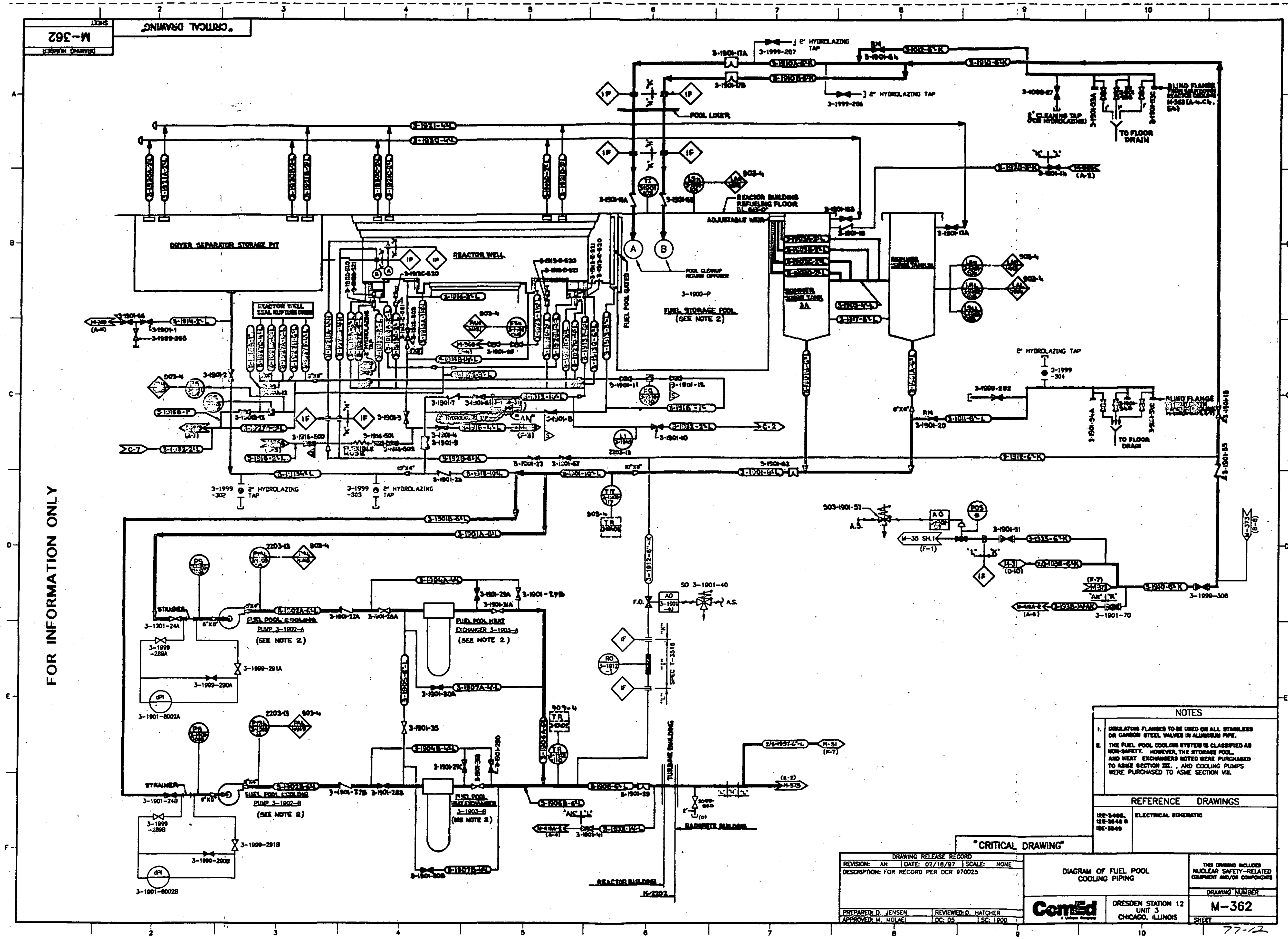


FIGURE 9.1-3

REV. 02 / JUNE 1997

CENTRAL DRAWING FACILITY 16X



CENTRAL DRAWING FACILITY

30 X

REV. 02 / JUNE 1997

FIGURE 9.1-4

UFSAR Revision 2
DRESDEN STATION UNITS 2 & 3
Intentionally Deleted Figure
FIGURE 9.1-8

UFSAR Revision 2
DRESDEN STATION UNITS 2 & 3
Intentionally Deleted Figure
FIGURE 9.1-11

UFSAR Revision 2

DRESDEN STATION
UNITS 2 & 3

Intentionally Deleted Figure

FIGURE 9.1-12

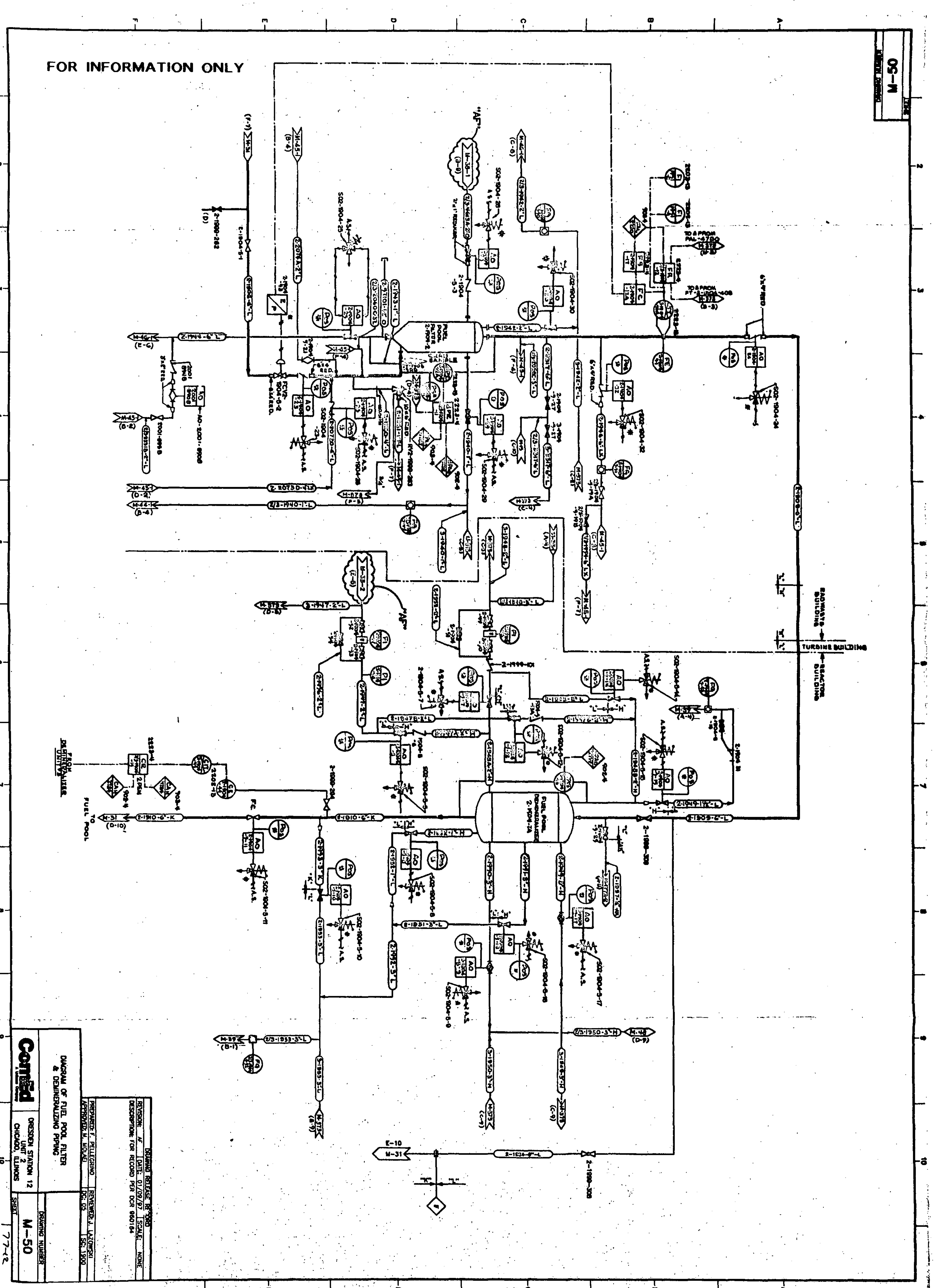
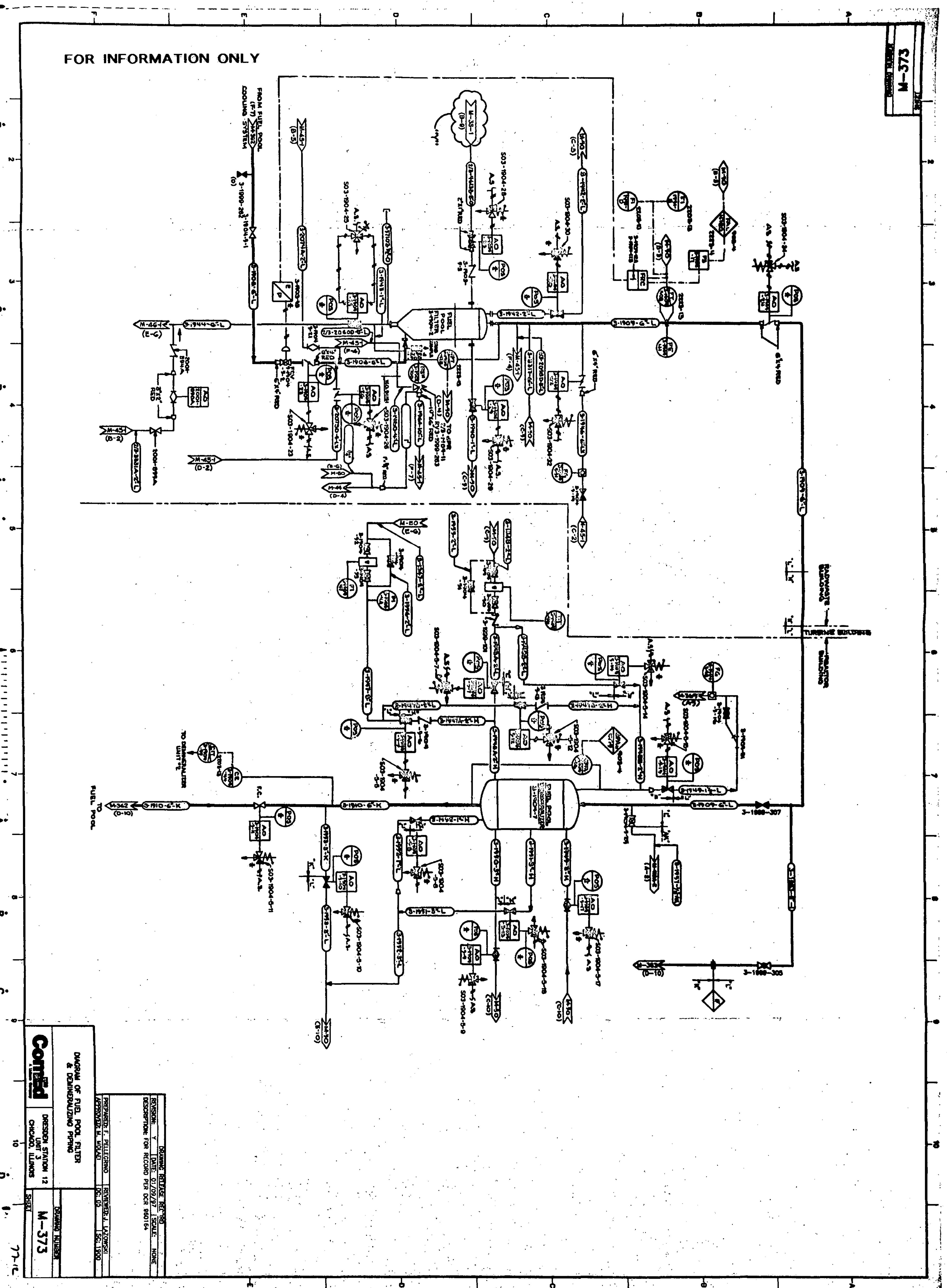


FIGURE 9.1-13

REV. 02 / JUNE 1997

FOR INFORMATION ONLY



CENTRAL DRAWING FACILITY 30 X

FIGURE 9.1-14

REV. 02 / JUNE 1997

diagrams of the CCSW systems for Units 2 and 3 are shown in Figures 9.2-1 (Drawing M-29, Sheet 2) and 9.2-2 (Drawing M-360, Sheet 2), respectively.

The CCSW system provides cooling water for the containment cooling heat exchangers during both accident and nonaccident conditions, as described in Section 6.2.2. System piping is arranged to form two separate, two pump, flow networks (loops). Each pair of CCSW pumps takes a suction from the crib house via separate supply piping. Two CCSW pumps discharge into a common header which routes the cooling water to that loop's associated heat exchanger. At the heat exchanger, heat is transferred from the low pressure coolant injection (LPCI) subsystem to the CCSW system, and subsequently to the river.

During normal plant operation, the CCSW system is not operating. Following an accident or other plant evolution which requires containment heat removal, the CCSW system is manually started. Each CCSW pump is rated at 500 hp with a service factor of 1.15. The CCSW pumps are powered by normal ac or diesel generator ac power. Additional CCSW pump information is provided in Table 9.2-1.

The CCSW pumps develop sufficient head to maintain the cooling water heat exchanger tube side outlet pressure 20 psi greater than the LPCI subsystem pressure on the shell side. The ΔP is maintained by the manual operation of a differential pressure control valve in the CCSW outlet piping from the LPCI heat exchanger. Maintaining this pressure differential prevents reactor water leakage into the service water and thereby into the river. A minimum of 5000 gpm is necessary to maintain containment cooling.

The four CCSW pumps are located in the turbine building. Two of the four CCSW pumps (pumps B and C) are located in a single, common watertight vault for flood protection. To prevent the CCSW pump motors from overheating, the vault has two vault coolers. The cooling water for each cooler is provided from its respective CCSW pump discharge line through a four-way valve. This valve also permits flow reversal of the cooling water through these coolers to help clean the tubes. Refer to Section 3.4 for a discussion of the flood protection features at Dresden.

A continuous fill of the CCSW system is provided by the service water system or, in the case of a loss of power to the service water pumps, the diesel generator cooling water system may be aligned to provide the continuous fill. This eliminates the potential for water hammer upon CCSW system startup. The diesel generator cooling water system is discussed in Section 9.5.5.

The Unit 2 CCSW loops also provide a safety-related source of service water to the control room air conditioning condensers. Refer to Sections 6.4 and 9.4.1 for a description of the control room ventilation system.

9.2.1.3 Safety Evaluation

Containment cooling is not immediately required following a design basis loss-of-coolant accident (LOCA). The required timing of the initiation of containment cooling functions by CCSW is described in Section 6.2.2. One of the two heat exchangers, two CCSW pumps, and one LPCI pump all in the same loop are the minimum requirements for containment cooling.

exchanger to monitor for blockage. Pressure gauges are provided on the CCSW pump vault coolers to monitor for flow blockage and to determine the need for heat exchanger cleaning.

The CCSW pumps and the CCSW heat exchanger discharge motor-operated valves are controlled from the main control room.

Radiation monitoring of the CCSW system is provided to detect leakage of radioactive water from the containment cooling heat exchanger. This radiation monitor is located in the service water system at the discharge of the CCSW system. Radiation monitoring information is provided in Section 11.5.

9.2.2 Service Water System

9.2.2.1 Design Bases

The design objective of the service water system is to provide strained river water of suitable quantity and quality for plant equipment cooling requirements. To achieve this objective, the service water system was designed to:

A. Cool the RBCCW system under all operating conditions;

B. Meet cooling water requirements during the reactor shutdown mode, which represents the most severe condition and is used as the design basis;

C. Operate at a higher pressure than any of the loads which it serves; and

D. Provide an inexhaustible supply of water to the condenser hotwell, via the standby coolant supply valves, so that feedwater flow can be maintained to the reactor in the event of a LOCA. A description of the standby coolant supply system is provided in Section 9.2.8.

9.2.2.2 System Description

The service water system is shared by Units 2 and 3. The purpose of the system is to provide strained river water for various plant equipment. The components and systems which are cooled by or receive water from the service water system are listed in Table 9.2-2. The service water systems for Units 2 and 3 are shown in Figures 9.2-3 (Drawing M-22) and 9.2-4 (Drawing M-355), respectively. As shown in these figures, the system consists of five pumps, three strainers, and a common distribution header. Two service water pumps are provided per unit and the fifth shared pump is used as a backup. A chemical treatment system and the necessary control and support equipment are also provided.

Normally two pumps and one strainer for each unit are in operation while the fifth pump and one strainer are in standby. The system is cross-tied between Units 2 and 3. The pumps take their suction from a flooded pit in the common intake structure (crib house) for Units 2 and 3. The water supply from the river and/or

Pressure and temperature instrumentation is provided on selected heat exchangers cooled by the service water system.

Principal measurements such as service water header pressure, supply pressure, and pump motor current are indicated in the control room. Local pressure and temperature gauges are provided for flow balancing and equipment cooling control by manual valve adjustment. For that equipment which requires a controlled temperature, local automatic temperature controllers are provided to control service water flow through the equipment. As shown in Figures 9.2-3 (Drawing M-22) and 9.2-4 (Drawing M-355), temperature control valves are included for the following:

A. The TBCCW heat exchanger common service water discharge;

B. Turbine oil coolers common service water discharge;

C. Main generator hydrogen coolers common service water discharge;

D. Reactor recirculation pump M-G set oil coolers common service water discharge;

E. The RBCCW individual heat exchanger service water discharge; and

F. Each control room air conditioner condenser service water discharge.

Abnormal conditions, such as low service water pressure, a service water pump trip, or an X-area cooler trip are annunciated in the main control room. This provides the operator with information to assess the abnormal condition and initiate corrective actions.

Instrumentation is provided for the operation of the automatic backflush of the service water strainers on high differential pressure.

Radiation monitoring instrumentation is provided at the outlet of the service water system to monitor the radioactive discharges to the environment. Process radiation monitoring information is provided in Section 11.5.

9.2.3 Reactor Building Closed Cooling Water System

9.2.3.1 Design Bases

The performance objectives of the RBCCW system are to provide cooling for equipment and systems in the reactor and radwaste buildings and to minimize the release of radioactive material from the reactor equipment to the service water. To achieve these objectives, the system has been designed with the following specifications:

A. Design flowrate (maximum) of 8800 gal/min per pump and

B. Design code for the heat exchangers — ASME Section VIII.

room. Leakage into and out of the RBCCW system, beyond the control capability of the level control valve, is detected by these high- and low-level switches.

Leakage from equipment into the RBCCW system can be detected by the radiation monitor located at the inlet to the RBCCW heat exchangers. This monitor records and alarms in the control room. The outlet of each major component of the RBCCW system is also provided with a grab sample station which can be used to locate the source of a leak.

9.2.4 Demineralized Water Makeup System

The demineralized water makeup system consists of all equipment required to transfer water from the well water storage tank, through the makeup demineralizers, and into the various water storage tanks onsite.

9.2.4.1 Design Bases

The design objective of the demineralized water makeup system is to provide the desired quantity of reactor quality water for pre-operation and normal operation of the power plant. The system provides makeup water to the clean demineralized water storage tanks and the contaminated condensate storage tanks.

9.2.4.2 System Description

The demineralized water makeup system is common to both Units 2 and 3 and consists of pumps, storage tanks, demineralizers, and the necessary control and support equipment. The system pumps are of adequate size to provide the maximum expected flowrates. Figures 9.2-10 (Drawing M-35, Sheet 1) and 9.2-11 through 9.2-15 (Drawings M-423, Sheets 1 through 5, respectively) depict the demineralized water makeup system.

The system takes well water from the existing 200,000-gallon Unit 1 well water storage tank. This tank is filled from two deep wells. Well water is pumped from the well water storage tank, by any of the three well water transfer pumps, to the makeup demineralizer system. As shown in Figures 9.2-11 through 9.2-15, the makeup demineralizer system consists of three 33⅓% capacity dual media filters whose combined effluent is routed to either of two parallel cation demineralizer beds which discharge to a decarbonator. Two decarbonator booster pumps are provided to transfer the water from the decarbonator through either of two parallel anion demineralizers. From the anion beds the effluent is routed through either of two mixed bed demineralizers. The combined demineralizer effluent is routed through a direct acting pressure control valve to the 200,000-gallon clean demineralized water storage tank. Water may also be routed to any of the contaminated condensate storage tanks.

As shown in Figures 9.2-16 through 9.2-18 (Drawings M-423, Sheets 6 through 8, respectively), the demineralizer system is provided with necessary storage tanks and pumps to regenerate the demineralizer resin beds in place.

The demineralized water makeup system operates on demand at infrequent intervals to replenish demineralized water in the storage tanks.

9.2.4.3 Safety Evaluation

The demineralized water makeup system has been evaluated by the NRC under Systematic Evaluation Program (SEP) Topic VI-10.B, Shared Systems. This evaluation determined that this system is not required to function for any safety-related purpose.

9.2.4.4 Testing and Inspection Requirements

The makeup water system operates intermittently during operation of the plant and no testing of the system is required.

9.2.4.5 System Instrumentation

As shown in Figure 9.2-10 (Drawing M-35, Sheet 1), and 9.2-11 through 18 (Drawing M-423, Sheets 1 through 8), the well water storage tank and clean demineralized water storage tank levels are indicated locally. Pumps and valves for the demineralized water makeup system are controlled from the makeup demineralizer building. The demineralizer trains are fully instrumented with flow, level, pressure, temperature, conductivity, and pH indicators located as necessary throughout the process.

9.2.5 Ultimate Heat Sink

9.2.5.1 Design Bases

The design objective of the ultimate heat sink is to provide sufficient cooling water to the station to permit operation of the CCSW system when the normal heat sink (the river) is unavailable. The CCSW system is described in Section 9.2.1.

In addition to supplying the CCSW system, the ultimate heat sink may also be used for cooling other plant equipment if desired.

9.2.5.2 System Description

The ultimate heat sink consists of water sources for the cooling water systems, necessary retaining structures, and the canals connecting the water sources with the intake structures.

During this sequence of events, the operator is required to trip the circulating and service water pumps to prevent pump damage. Other equipment, which either adds heat to the primary system or which is cooled directly or indirectly by river water, would be removed from service.

Following the reactor scram on Units 2 and 3, the relief valves from the primary system to the suppression chamber would open to prevent overpressurizing the reactor vessel. Level in the reactor would be maintained by reactor feed pumps; control rod drive pumps; or, in the case of loss of auxiliary power, the HPCI system. With the initiation of the isolation condenser, depressurization of the primary system would start.

Each of the reactors could be depressurized at a controlled rate using the isolation condensers. The primary system temperature could be reduced to 212°F in 8 — 12 hours and be maintained at this condition with the isolation condensers. Generally, the temperature could not be reduced below this point since the system depends on steam flow to remove the core decay heat.

Preferred makeup water to the isolation condenser is from the clean demineralized water storage tank via two diesel driven makeup pumps or the clean demineralized water pumps, the latter of which are discussed in Section 9.2.6. With this water source unavailable, river water would be pumped to the isolation condensers by diesel-driven fire pumps or by the service water pumps pumping into the fire system. Contaminated condensate water is also available to provide makeup water to the isolation condensers; however, the use of this water source is less desirable than the other sources.

The fire protection system is considered a Class II system; however, parts of this system can meet the requirements of a Class I system. Using existing valves, it is possible to sectionalize the system to isolate the failed parts.

The suctions of the service water pumps for Units 2 and 3 are below elevation 495'-0"; therefore, a service water pump could be valved to supply cooling water to the RBCCW system which, in turn, could be valved to cool the shutdown cooling heat exchangers. The heated service water would be discharged to the discharge flume to dissipate its heat to the environs. The water in the discharge flume could then be recirculated either through the lake or back to the intake flume through the deicing line.

Operation of the diesel generators is assured since the diesel generator cooling water pumps' suction lines are at elevation 487'-8". The diesel fire pump of Units 2 and 3 has its suction at elevation 492'-0".

Analysis has shown that the amount of water required by each unit to remove decay heat through the isolation condenser over a 30-day period is 2.5 million gallons. This water would not be returned to the intake structure since it will be boiled off. This analysis assumed the cooling water entering the isolation condenser is at 100°F.

An additional small amount of cooling water for diesel generator cooling is also required but could be recirculated to the intake structure after dissipating its heat to the environment.

Loss of impounded river water, due to evaporation, could be made up by a portable, low-head, high-volume, engine-driven pump. CECo has six 1500-gal/min engine-driven pumps on standby at various fossil fuel generating stations. These pumps could be moved to Dresden within 6 hours. Pumps are also available from large contractors in the northern Illinois area.

Depending upon the season of the year, using the process described above, it will be possible to maintain the reactor primary system well below 212°F.

9.2.5.3.2 Dam Failure Coincident with a LOCA

If, at the time of the catastrophic failure of the dam, either Unit 2 or Unit 3 were to have a LOCA, it would still be possible to handle the LOCA and safely shut down the unaffected unit. Safe shutdown is still possible with coincident failure of offsite electrical power and Class II systems.

For a postulated LOCA on Unit 2, Unit 3 would be forced to shut down and depressurize due to the loss of circulating water, as previously described in Section 9.2.5.3.1. For Unit 2, depressurization would be to its suppression chamber. None of the core cooling systems would be affected by the loss of river water except the LPCI containment cooling mode. The LPCI containment cooling mode would be affected because the CCSW pumps take suction from the Unit 2 and 3 intake structure via two lines at elevations 499'-0" and 498'-0" (see Section 9.2.1.). As indicated in Figure 2.4-1, a dam failure places the CCSW suction piping above the water level in the intake canal, which would be at elevation 495'-0".

In order to operate a CCSW pump to reduce containment pressure and cool the water in the suppression chamber, it would be necessary to raise the water level in the area of these suction pipes. The drywell pressure and temperature would rise due to the transfer of core decay energy to the containment system. In about ½ hour, containment system pressure would start to increase and, after a period of 2 hours, cooling of the suppression chamber would be needed. During this period of time, measures would be undertaken in the intake structure to restore suction to the CCSW pumps.

Reference should be made to Figure 1.2-10 (Drawing M-10). The suction lines for the CCSW pumps take suction from a compartment between column row B and C with its center line on column line 4. The diesel fire pump also takes suction from this compartment. River water enters this compartment through two screened openings to the left and right of column line 4. The floor of this compartment is at elevation 493'-8" and the ceiling is at elevation 509'-6". The two openings extend between these two elevations. The wire mesh screens from each of these openings would be lifted out of place and replaced with stop logs. The stop logs are stored in the crib house at a location which would minimize the time required for their installation by station operators should a dam failure occur.

Dewatering valves, located at elevation 480'-0", would be opened to permit river water to flow from the compartments under the circulating water pumps and intake piping to the trash rake refuse pit located between column row C and D and column line 7 and 8. The floor of this pit is at elevation 477'-0". Thus, the water in this pit would rise to elevation 495'-0", the level in the intake canal.

Two refuse pumps take suction from this pit. The pumps are located in a compartment adjacent to the pit with their suction at elevation 479'-0". Each pump has a discharge capacity of 2400 gal/min. A lightweight, flanged spool piece of pipe is bolted in place in a permanent pipe line between the discharge line of these pumps and the compartment with the CCSW pumps. By proper electrical switching, the refuse pumps can be operated off the diesel generator.

A CCSW pump would be placed in service discharging to the containment cooling heat exchanger of Unit 2 and then to the discharge canal. River water in the discharge canal would be recirculated by way of the deicing line back to the crib house forebay. In this manner, containment pressure would be reduced and the suppression chamber water cooled.

If necessary, the Unit 2 containment may be completely flooded by using the service water pumps. As was indicated previously, the suctions of these pumps are below the surface of the water impounded in the circulating water system. Flooding of the containment would be through the feedwater system.

In discussions with the Army Corps of Engineers, they indicated that a number of measures would be undertaken if damage were to occur to the dam. The use of increased diversion from Lake Michigan (with approval of the U.S. Supreme Court) would be one method if the dam were partially damaged. This method would be used to maintain pool level. Another method would be the sinking of stone-loaded barges directly above the dam as a base for a temporary rock-filled dam. Both of these methods would help to hold levels in the Dresden flumes to permit maintaining the Dresden units in a safe condition.

9.2.5.4 Testing and Inspection Requirements

A surveillance is performed every third refueling outage to verify the ability of the system to accomplish its intended purpose of providing a source of water for post-LOCA containment cooling and also verify that the required manual operations described in Section 9.2.5.3.2 can be performed in a reasonable time.

9.2.6 Condensate Storage Facilities

The condensate storage facilities include all equipment necessary to store potentially contaminated demineralized water and condensate and to transfer water from the clean and contaminated water storage tanks throughout the plant for various uses.

9.2.6.1 Design Bases

The design objective of the condensate storage facilities is to provide water of a quality and quantity required for preoperation and operation of the power plant.

The system is designed to ensure a minimum of 90,000 gallons of water is available from each contaminated condensate storage tank (CCST) for use by HPCI.

9.2.6.2 System Description

As shown in Figures 9.2-10 (Drawing M-35, Sheet 1) and 9.2-19 (Drawing M-366), the condensate storage facilities consist of two 250,000-gallon capacity CCSTs (CCST 2/3A and 2/3B), one 200,000-gallon capacity contaminated demineralized water storage tank (T-105A), and two clean demineralized water pumps shared between Units 2 and 3. Two of the tanks, CCST 2/3 A and 2/3 B, are restricted to a minimum level of 90,000 gallons each because of the HPCI system makeup water requirements during a LOCA. For the CCST 2/3B, this is accomplished by the design of the discharge lines from the tanks; all taps into the tank for nonemergency use are at higher elevations on the tank than the 90,000-gallon level. For the CCST 2/3A, this is accomplished by administrative control. The low level will be annunciated before levels are reduced below 90,000 gallons. A minimum combined water volume in CCST 1, CCST 2/3A, and CCST 2/3 B of 130,000 gallons (single plant operation) and 260,000 gallons (dual plant operation) is required for safe shutdown. Refer to Section 6.3 for a discussion of the HPCI system. Each unit has two condensate makeup pumps, two condensate transfer pumps, and one condensate transfer jockey pump with associated piping and valving to transfer condensate throughout the plant.

Two clean demineralized water pumps, each rated at 250 gal/min, take suction from the clean demineralized water storage tank and discharge into a common header. The clean demineralized water transfer system provides water for multiple uses including the following:

A. Decontamination;

B. Floor washdown in areas containing radioactive drain systems;

C. Laboratories;

D. Filling of cooling water systems;

E. Purposes requiring demineralized water where radioactive contamination is not desired;

F. Makeup water to the isolation condenser.

All three of the contaminated water tanks are capable of being crosstied and the two CCSTs are normally connected. Either CCST 2/3A or CCST 2/3B may supply water to HPCI subsystems for emergency core cooling systems (ECCS) for Unit 2 and Unit 3. The safety related water supply for HPCI is the suppression pool.

The two CCSTs provide a source of condensate for use by the following systems of both units:

A. Main condenser hotwell,

B. Control rod drive hydraulic system,

C. HPCI,

D. Core spray, and

E. LPCI.

The condensate makeup pumps take suction from the CCSTs and provide the driving force to transport makeup water to the main condenser hotwell whenever there is no condenser vacuum.

The two redundant condensate transfer pumps, each rated at 500 gal/min, and the 70-gal/min condensate jockey pump take suction from the CCSTs and provide the motive force to supply the following systems with condensate:

A. Isolation condenser alternate makeup,

B. Fuel pool cooling and cleanup,

C. Reactor water cleanup,

D. Radwaste, and

E. ECCS fill header alternate supply.

9.2.6.3 Safety Evaluation

The entire clean demineralized water system piping arrangement to the isolation condenser utilizes normally open, manually operated valves, with the exception of the final power-operated isolation valve at the isolation condenser shell side inlet. Power to this valve is supplied from 250-Vdc motor control center (MCC) 2A (Unit 2), or 250-Vdc MCC 3A (Unit 3). The isolation valve is also accessible for manual operation in case its power supply or motor malfunctions.

The clean demineralized water system includes two pumps, neither of which are on buses supplied by emergency power (they are both on MCC 25-2). However, emergency power can be aligned to MCC 25-2 by the plant operators, diesel load permitting.

Both condensate transfer pumps are provided power from buses which are fed from the emergency diesel generators upon loss of ac power. The pumps can be locally controlled in the event the control room and the auxiliary electric equipment room are inaccessible. All valves in the supply system to the isolation condenser are manually operated, with the exception of the final isolation valve, which is supplied from 250-Vdc power. This valve is accessible should its motor or power supply fail, thus requiring manual operation.

Sufficient pure water is stored onsite to perform a plant cooldown in a reasonable amount of time in accordance with Branch Technical Position RSB 5-1.

The potential for the ECCS condensate supply lines to freeze has been evaluated. The majority of the CCST piping to ECCS is buried 5 to 6 feet below surface grade. To prevent freezing, the ECCS lines entering the CCSTs above ground are well insulated, heat traced, and contained in an insulated permanent enclosure. All other safety-related process instrument and sampling lines are indoors and not exposed to subfreezing temperatures.

9.2.6.4 Testing and Inspection Requirements

Water quality in the clean and contaminated condensate storage tanks is periodically analyzed in accordance with station chemistry procedures.

9.2.6.5 System Instrumentation

As shown in Figure 9.2-10 (Drawing M-35, Sheet 1), each CCST level is indicated in the control room and low-level alarms alert the operator to excessive use of condensate or when normal makeup is required. High-level alarms are provided for each tank to indicate the filled condition. Each storage tank is electrically heated and thermostatically controlled locally.

The condensate makeup pumps, condensate transfer pumps, and the condensate transfer jockey pumps are remotely operated from the control room. Each is provided with circuitry to annunciate a tripped condition in the control room. The condensate makeup pumps will automatically start due to a low hotwell level.

Condensate transfer pump discharge header pressure and demineralized water pump discharge header pressure are indicated in the control room. Low condensate transfer header pressure and low demineralized water header pressure signals actuate alarms in the control room.

9.2.7 Turbine Building Closed Cooling Water System

9.2.7.1 Design Bases

The purpose of the TBCCW system is to provide a means of heat rejection from systems located in the turbine building and crib house.

9.2.7.2 System Description

The TBCCW is a closed loop system which consists of pumps, heat exchangers, an expansion tank, a chemical feeder, and associated control and support equipment. Separate, independent systems are provided for Units 2 and 3. The TBCCW system is shown in Figures 9.2-20 (Drawing M-21), 9.2-21 (Drawing M-354, Sheet 1), and 9.2-22 (M-354, Sheet 2).

The TBCCW system consists of two pumps which circulate the cooling water throughout the unit. An expansion tank piped to the TBCCW pump suction line is located on the turbine building ventilation fan floor (elevation 549'-0"). Its elevation above the TBCCW pumps ensures adequate NPSH for the pumps. It also provides a surge volume for the system as the cooling water density varies. Expansion tank level is maintained by an automatic level control valve which supplies demineralized water to the tank as level decreases. An internal overflow for the tank is routed to the 48-inch service water discharge header.

The TBCCW pumps discharge to a common header which supplies cooling water to the various equipment listed in Table 9.2-4.

The electrohydraulic control (EHC) fluid coolers have a temperature control valve on the common cooling water outlet of the heat exchangers which automatically controls the cooling water flow in response to EHC fluid effluent temperature.

The sparging air compressor aftercoolers, the instrument air compressors, service air compressors, and reactor feedwater pump oil coolers have temperature control valves on the cooling water inlet lines which automatically control the cooling water flow through the heat exchangers.

Other loads have no automatic temperature control, but flow through them may be manually throttled.

Return flow from the various loads enters a common header which is routed to one of two TBCCW heat exchangers. The cooling water flows through the shell side of the selected heat exchanger and the effluent is routed to the TBCCW pump suction. Service water provides the cooling medium on the tube side of the heat exchanger. An air-operated temperature control valve, common to both heat exchangers, throttles the service water in response to the temperature of the cooling water effluent. Refer to Section 9.2.2 for a description of the service water system. A chemical feeder at the suction to the pumps provides a mechanism to add a corrosion inhibitor to the system.

9.2.7.3 Safety Evaluation

The equipment cooled by the TBCCW system is not considered essential. It is important to note that loss of TBCCW cooling to the control rod drive pumps does not affect the function of the control rod scram function. Service water backs up the TBCCW supply to the CRD pumps.

9.2.7.4 Testing and Inspection Requirements

The TBCCW system operates continually and requires no operability checks. The cooling water is sampled periodically in accordance with station chemistry procedures. A corrosion-inhibitor is added via the chemical feeder when required, as determined by the sample analysis.

9.2.7.5 System Instrumentation

As shown in Figures 9.2-20 (Drawing M-21), 9.2-21 (Drawing M-354, Sheet 1), and 9.2-22 (Drawing M-354, Sheet 2), a level switch is provided to automatically open the demineralized water makeup valve to fill the TBCCW expansion tank. A second level switch actuates a common high or low expansion tank level annunciator in the control room.

The TBCCW pumps are remotely controlled from the main control room. Discharge header pressure is indicated and low header pressure is annunciated in the control room. Discharge header temperature is also indicated and high temperature is annunciated in the control room.

The TBCCW pumps are powered by normal ac power supplies (480-V MCCs) and are protected by thermal overload trips. A trip of a TBCCW pump annunciates in the control room. There are no automatic start features for the pumps; thus, if only one TBCCW pump is operating, the idle TBCCW pump will not automatically start if the originally operating pump trips.

Local temperature and pressure indicators are provided throughout the system to allow for flow balancing and determination of individual heat exchanger performance.

9.2.8 Standby Coolant Supply System

9.2.8.1 Design Bases

The purpose of the standby coolant supply system is to provide an inexhaustible supply of water to the condenser hotwell so that feedwater flow to the reactor can be maintained in the event it is needed for core flooding and/or containment flooding following a postulated LOCA.

9.2.8.2 System Description

The system consists of piping between the service water system and the condenser hotwell (see Figures 9.2-3 and 9.2-4), as well as associated valves, and instrumentation. The service water system is described in detail in Section 9.2.2. This equipment supplies approximately 15,000 gal/min of screened and strained river water to the hotwell. Two motor-operated isolation valves are used in the interconnected piping to provide the capability for testing the valves and to prevent leakage of river water to the condenser. The volume between the valves is provided with a tell-tale drain with a flow sightglass.

A hydrostop flange has been added upstream of standby coolant supply isolation valve, MO-3-3901, to permit valve maintenance. The hydrostop plug that remains in the system is in the tee out of the main flow stream. The line water pressure acts on the plug to force it into the tee. This ensures the plug will not enter the main flow stream.

Table 9.2-1

CONTAINMENT COOLING SERVICE WATER EQUIPMENT SPECIFICATIONS

Containment Cooling Service Water Pumps

Number	4 (2 needed to provide required cooling capacity)
Type	Horizontal, centrifugal
Power source	Auxiliary transformer or emergency diesel
Capacity	3,500 gal/min each — 5,000 gal/min total
Head (approximately)	435 feet

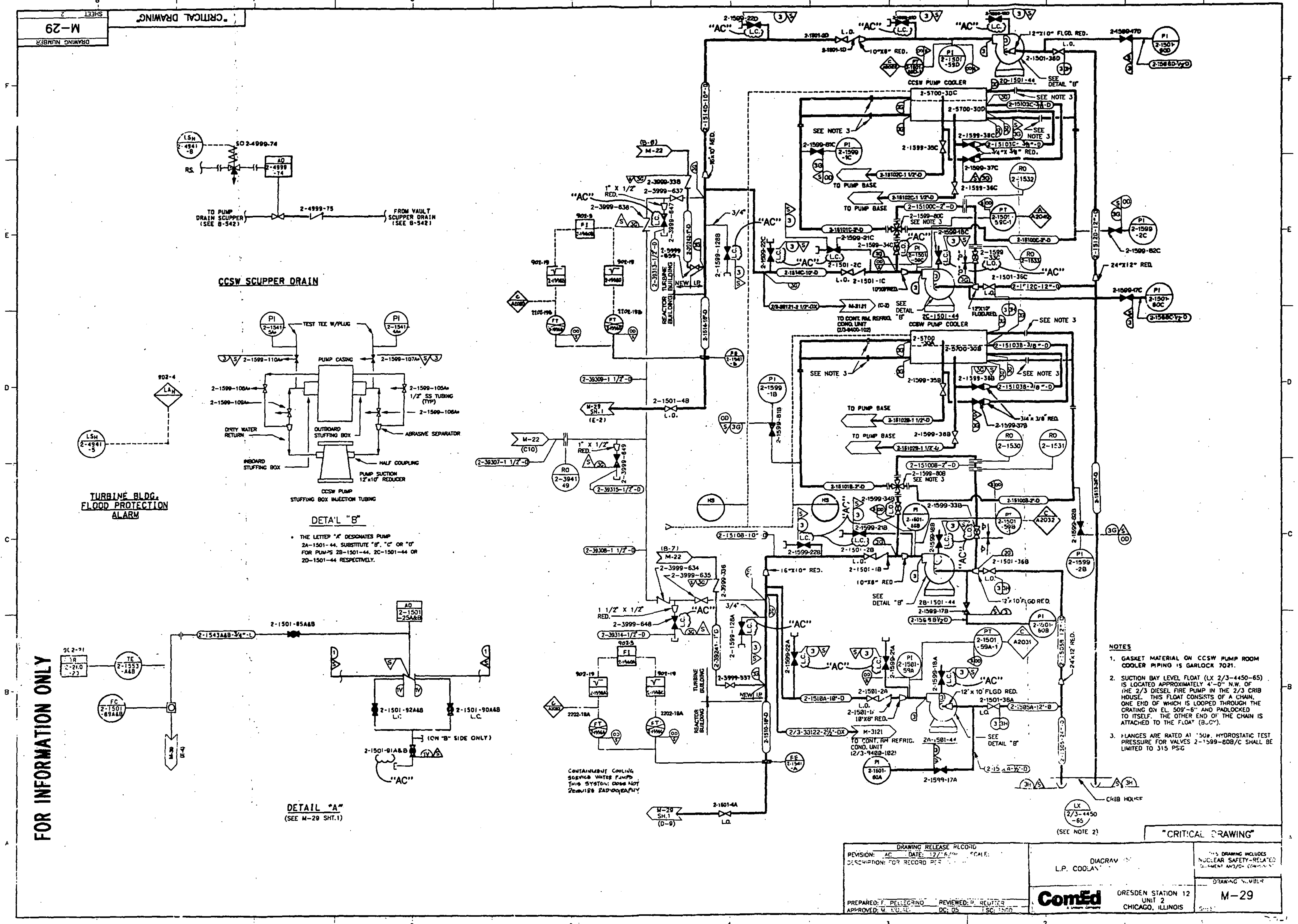
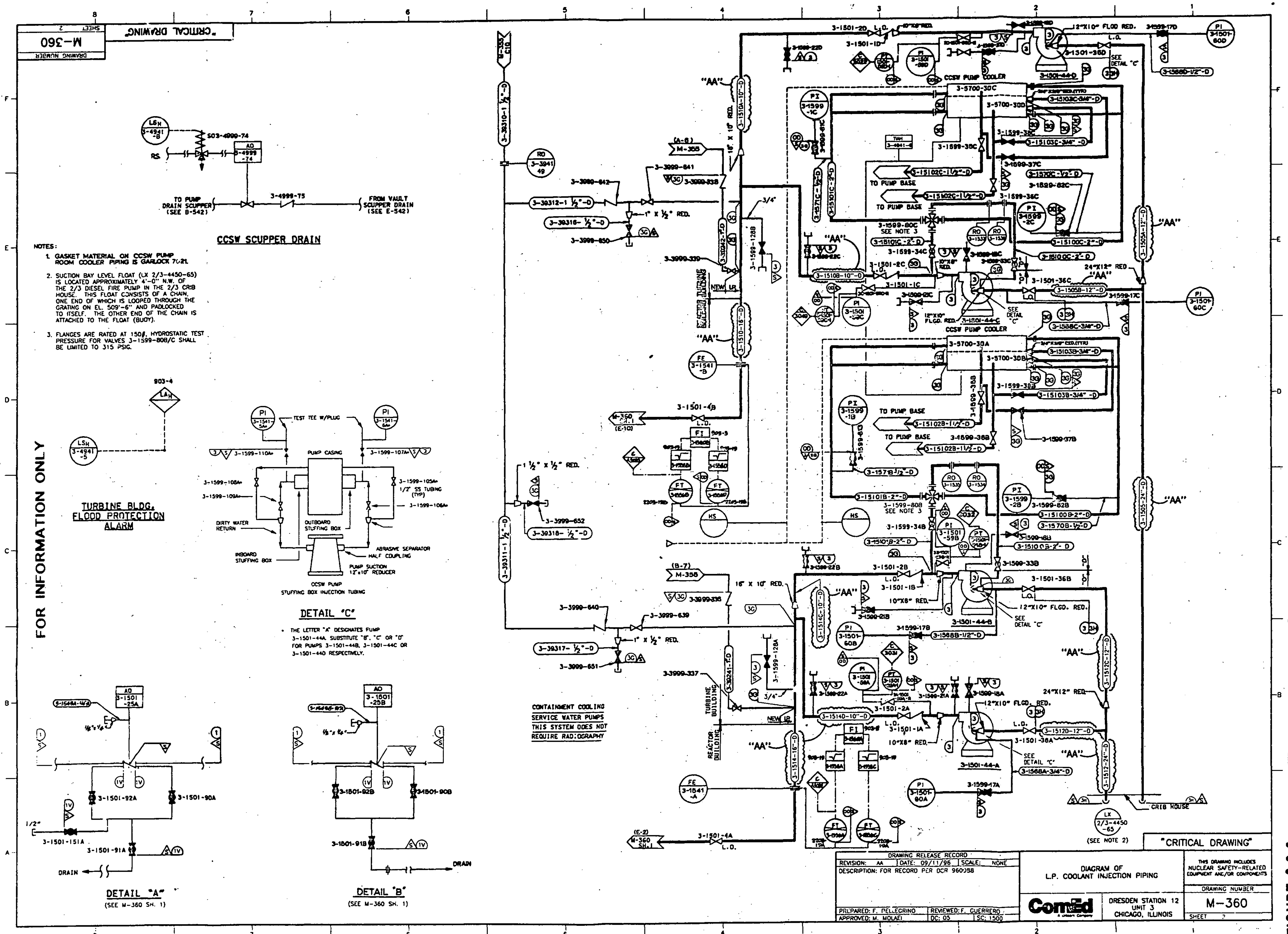


FIGURE 9.2-1

REV. 02 / JUNE 1997

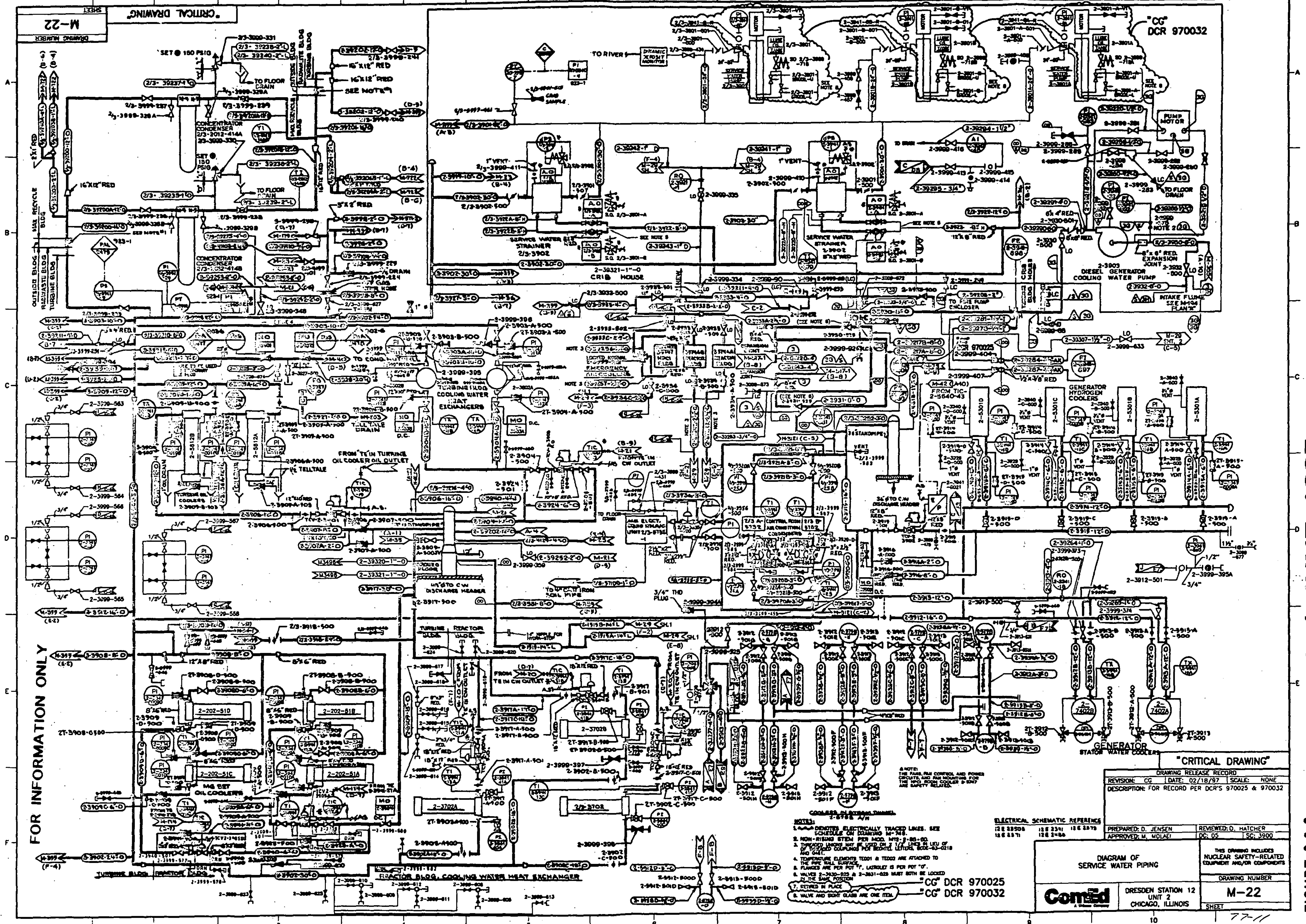
CENTRAL DRAWING FACILITY 30 X



CENTRAL DRAWING FACILITY 30 X

REV. 02 / JUNE 1997

FIGURE 9.2-2

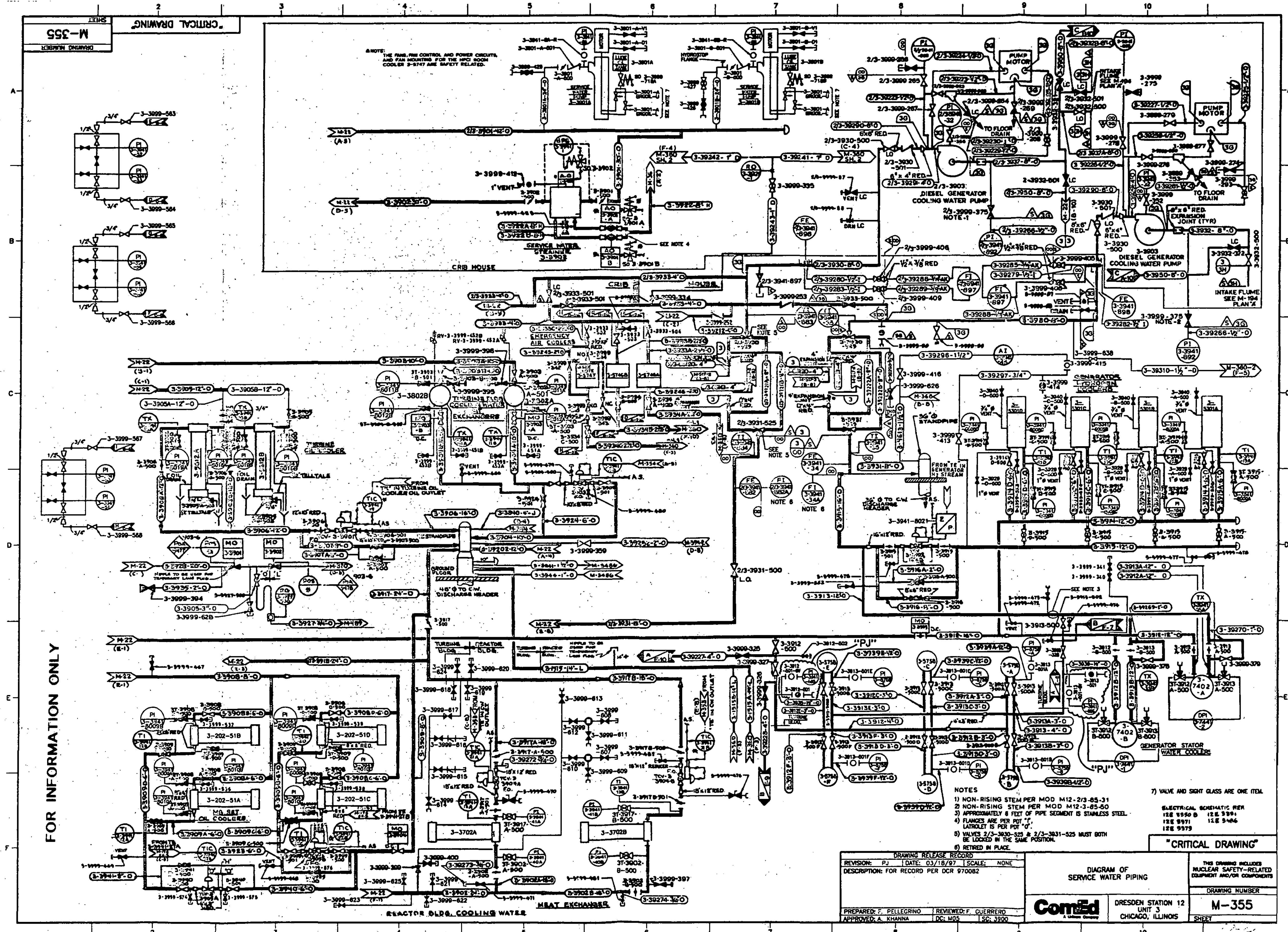


REV. 02 / JUNE 1997

FIGURE 9.2-3

CENTRAL DRAWING FACILITY

30 X



REV. 02 / JUNE 1997

FIGURE 9.2-4

CENTRAL DRAWING FACILITY

30 X

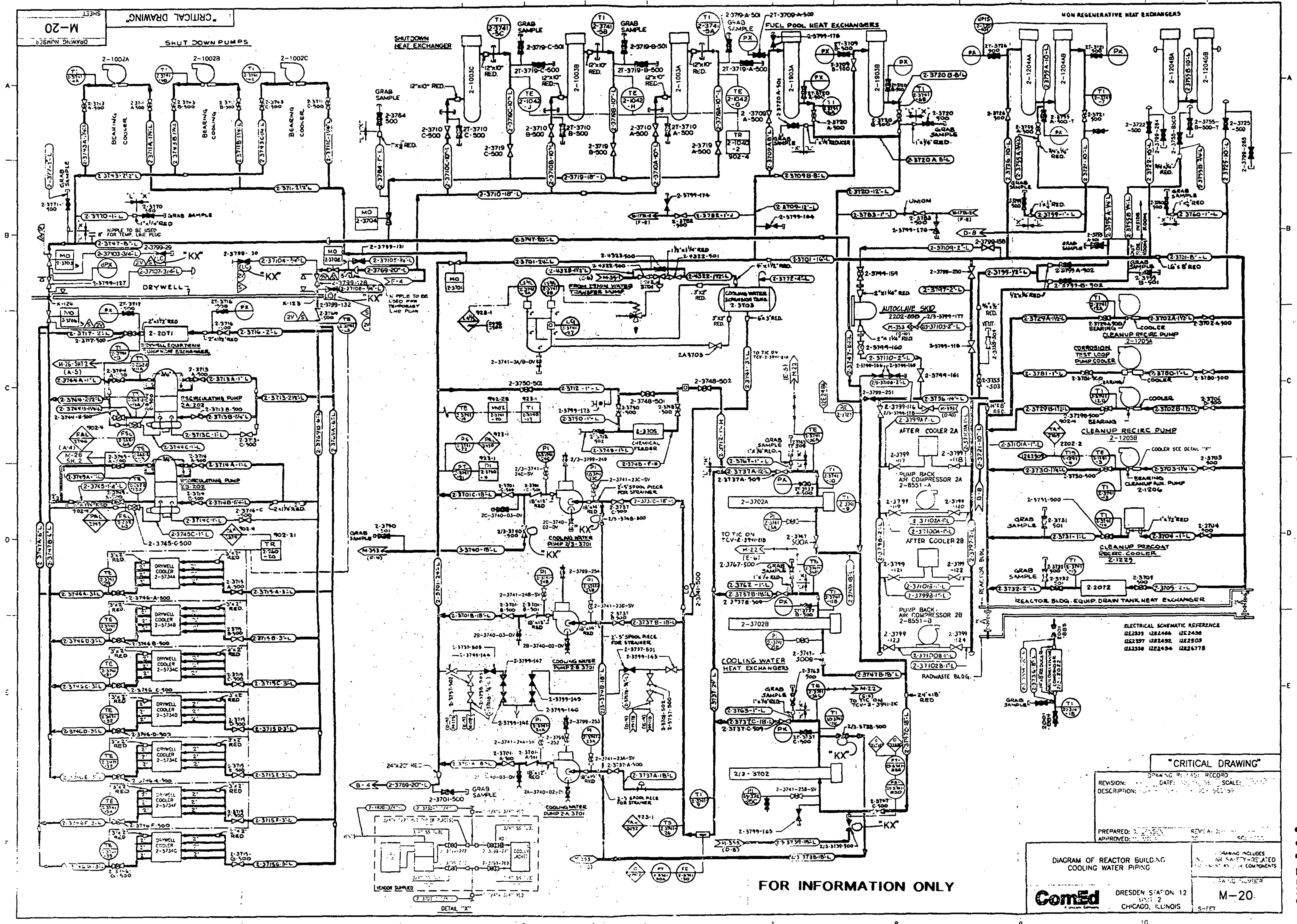
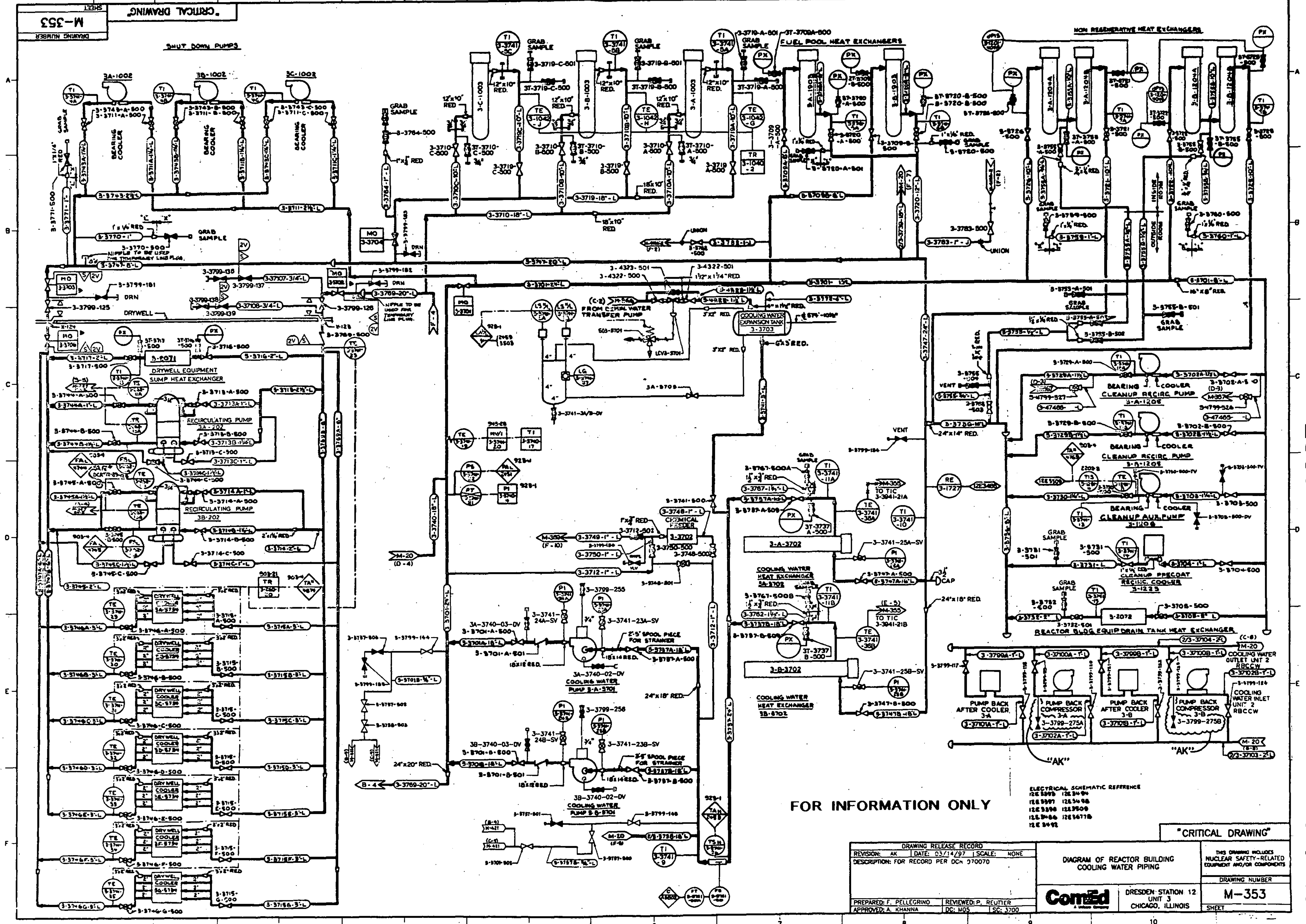


FIGURE 9.2-8 REV. 02 / JUNE 1997

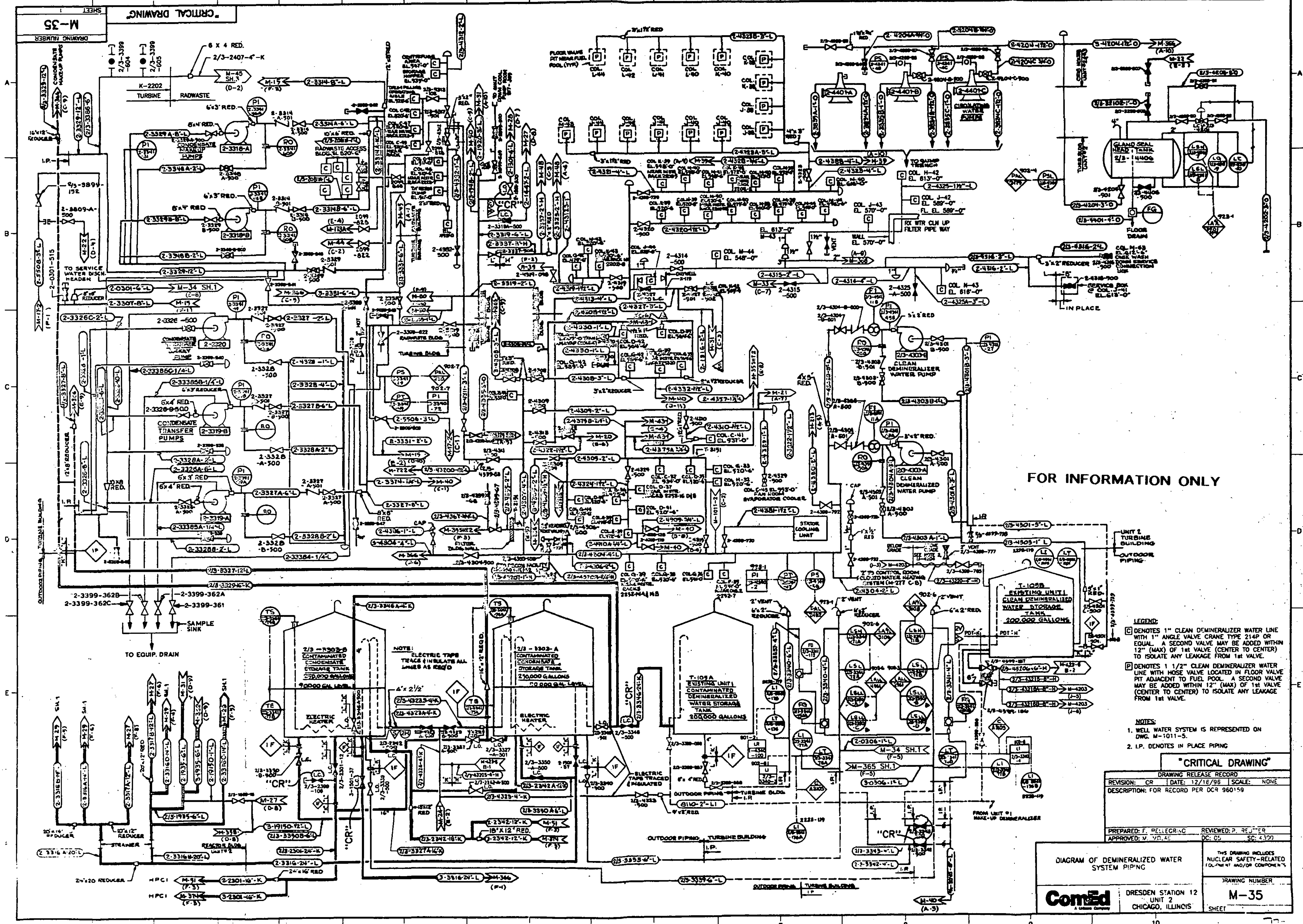


REV. 02 / JUNE 1997

FIGURE 9.2-9

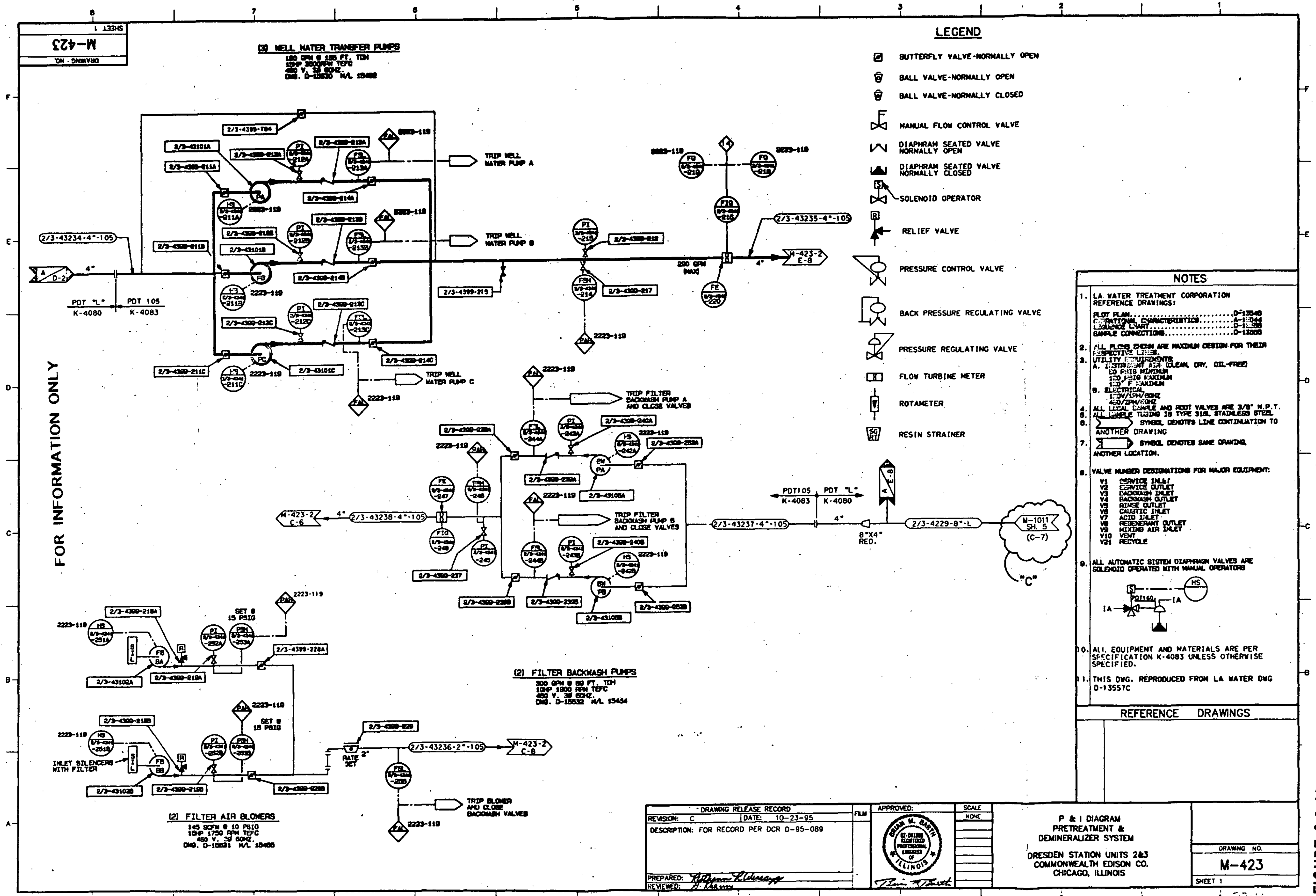
CENTRAL DRAWING FACILITY

30X



REV. 02 / JUNE 1997

FIGURE 9.2-10

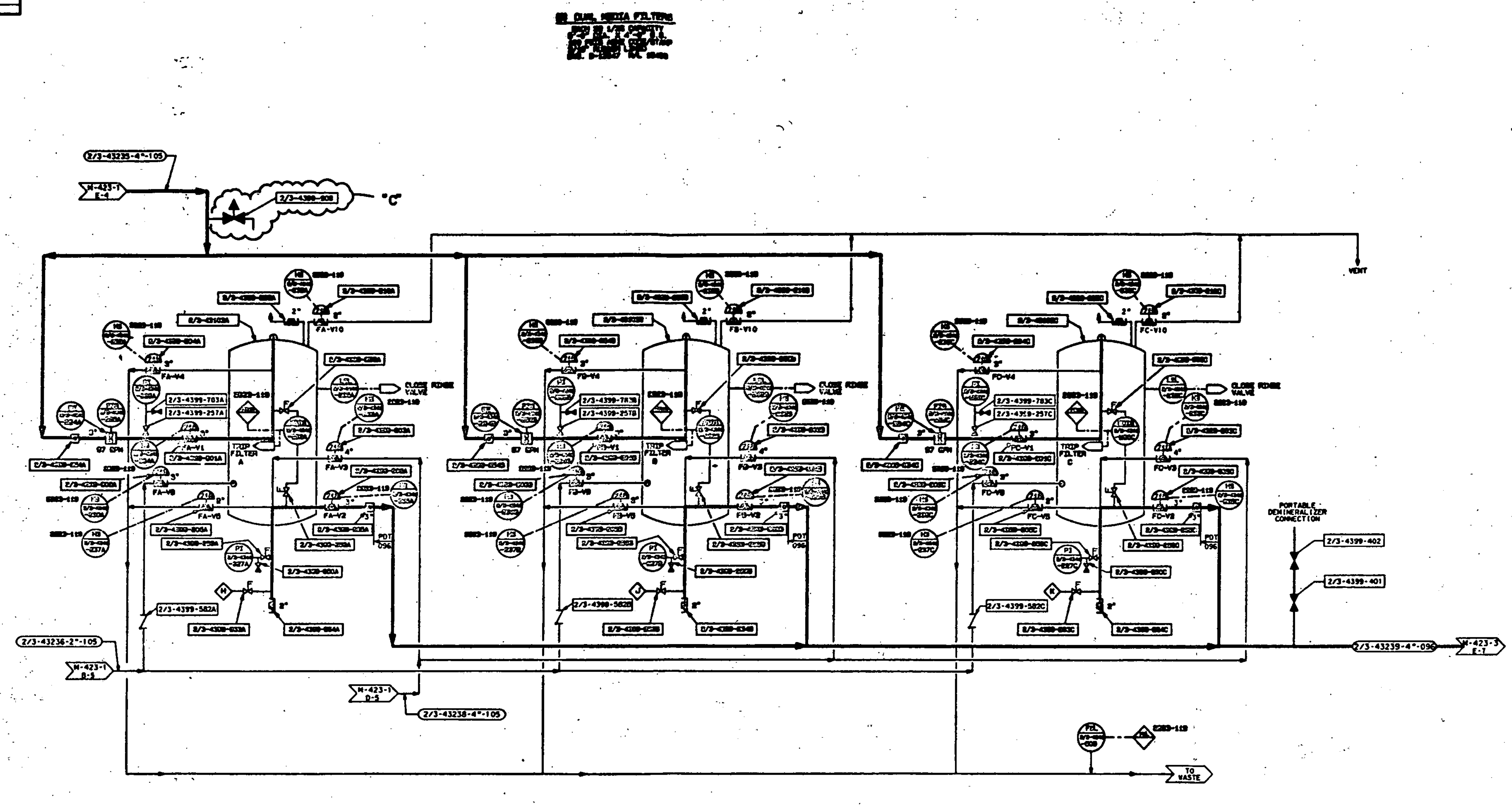


REV. 02 / JUNE 1997

FIGURE 9.2-11

CENTRAL DRAWING FACILITY

30 X



FOR INFORMATION ONLY

NOTES	
1.	SEE DRAWING M-423, SH.1 FOR NOTES AND LEGEND
2.	THIS DRAWING REPRODUCED FROM LA WATER DWG. D-13557C

DRAWING RELEASE RECORD		
REVISION: C	DATE: 03/05/97	SCALE: NONE
DESCRIPTION: FOR RECORD PER DCR 980195		
PREPARED: S. DWORNICZEK	REVIEWED: D. HATCHER	
APPROVED: A. KHANNA	DC: M05	SC: 4300

P & I DIAGRAM
PRETREATMENT &
DEMINERALIZER SYSTEM

ComEd

DRESDEN STATION 12
UNIT 2 & 3
CHICAGO, ILLINOIS

DRAWING NUMBER
M-423
SHEET 2

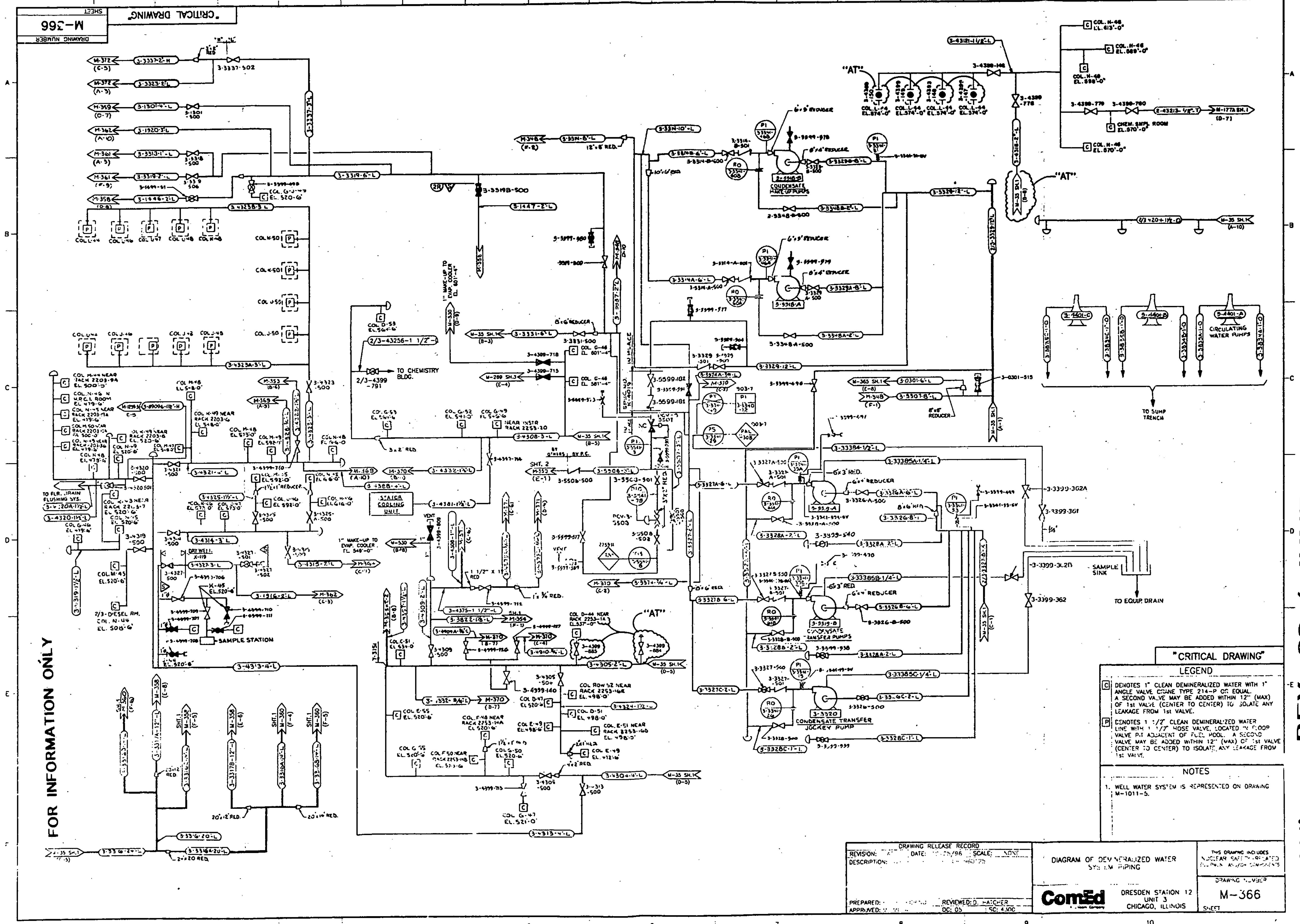
77-13

REV. 02 / JUNE 1997

FIGURE 9.2-12

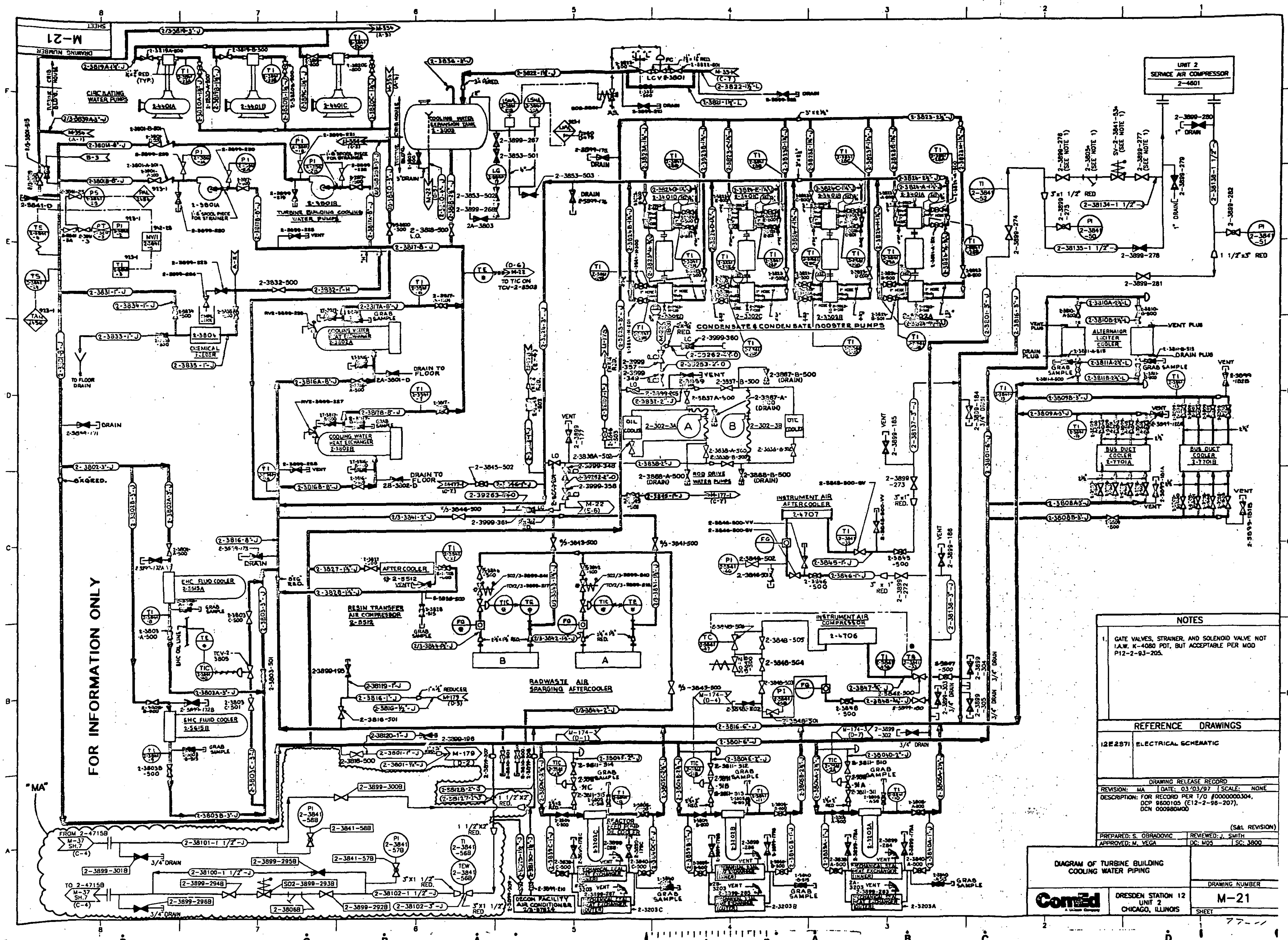
CENTRAL DRAWING FACILITY

30X



REV. 02 / JUNE 1997

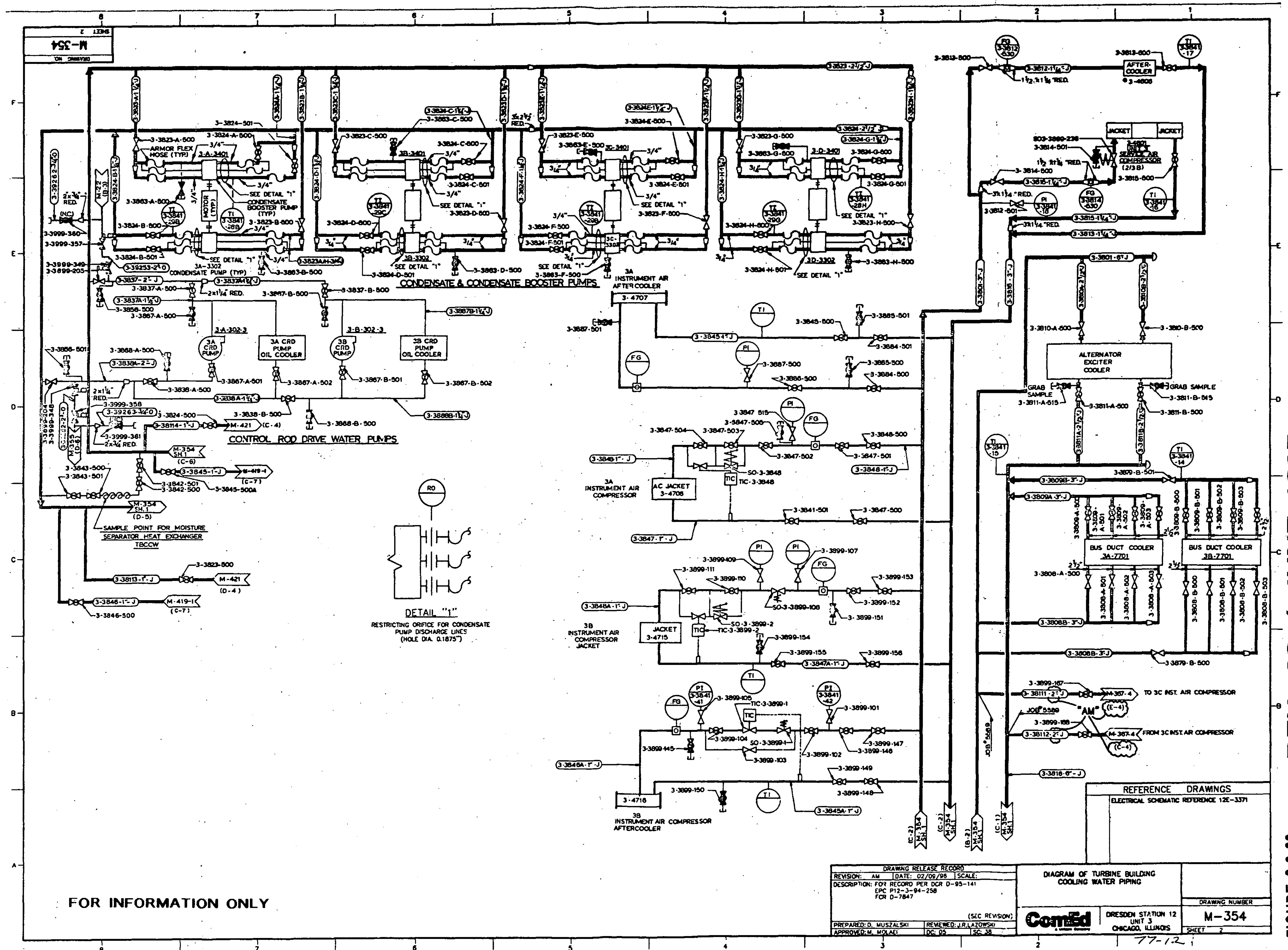
FIGURE 9.2-19



REV. 02 / JUNE 1997

FIGURE 9.2-20

CENTRAL DRAWING FACILITY



REV. 02 / JUNE 1997

FIGURE 9.2-22

CENTRAL DRAWING FACILITY

30 X

All major instrument air system components except those associated with the 3C compressor train are located at elevation 517'-6" in the turbine building. The 3C compressor train is located on the Unit 3 538'-0" elevation. Unit 2 has two compressor trains, 2A and 2B; Unit 3 has three, 3A, 3B, and 3C. Each train consists of a compressor, an aftercooler, air receiver tanks, dryers, prefilters, afterfilters and the necessary control and support equipment (see Figures 9.3-1 through 9.3-4).

The instrument air system supplies air to:

A. Turbine building loads,

B. Reactor building loads,

C. Radwaste building loads,

D. Crib house loads, and

E. Off-gas filter building loads.

The 2A and 3A compressors are single-stage reciprocating air compressors powered by 60-hp electric motors. Each compressor is rated for 200 ft^3/min at 125-psig discharge pressure.

The 2B instrument air compressor is a two-stage, water cooled, 100-hp electric motor driven screw compressor, which delivers oil-free, pulsation-free air. This compressor is rated at 460 ft^3/min at 100-psig discharge pressure. The compressor will operate on the compressor pressure switch to load and unload and has no interlock with the Unit 2 instrument air main receiver pressure.

The 3B instrument air compressor is a two-stage reciprocating air compressor powered by a 100-hp electric motor. The 3B compressor is rated at 400 ft^3/min at 125-psig discharge pressure.

The 3C instrument air compressor is a rotary screw compressor capable of providing 460 ft^3/min at 100-psig discharge pressure to Units 2 and 3.

Cooling for all compressors is provided by the turbine building closed cooling water (TBCCW) system.

The instrument air supply system is operable at all times during plant operations. With the compressor in NORMAL mode and set to RUN, the following sequence occurs:

A. The instrument air compressor starts and runs unloaded (magnetic unloader deenergized);

B. If after a predetermined time the main receiver pressure is less than a predetermined setpoint, the magnetic unloader energizes and loads the compressor;

C. The instrument air compressor runs loaded until the proper main receiver pressure is established. At that time the magnetic unloader deenergizes and the compressor unloads; and

Instrument air receivers are used as buffers between compressor discharge and the rest of the system. In this configuration, they dampen pressure pulses from the compressor and provide a smooth flow of air to the system. They also provide storage capacity to accommodate intervals when demand exceeds the capacity of the compressors.

Relief valves are set as follows:

A. Compressor discharge — 135 psig,

B. Local air receivers — 135 psig, and

C. Main air receivers — 125 psig.

The service air crosstie provides instrument air backup from the service air header. It operates automatically when instrument air pressure falls below 85 psig. Once operated, it must be manually reset when the air pressure is again greater than 85 psig. A control room alarm is provided to indicate low instrument air pressure.

9.3.1.2.2 Safety Evaluation

The postulated worst-case scenario for instrument air failure was identified as an event that would cause a total loss of instrument air as a result of a nonsafety-related system failure. Total loss of instrument air would cause a forced power reduction or plant shutdown, but all safety-related devices requiring instrument air would perform as designed.

Safety-related equipment design considers properly sized air accumulators as an effective means to supply residual air, pressurized nitrogen as an alternate motive force, and selection of appropriate component fail-safe positions to demonstrate acceptable consequences of the loss of air. The instrument air system provides high-quality air (i.e., free of moisture, particulates, and oil), thereby minimizing the potential for safety-related valve failure resulting from a lack of air due to blocked air supply lines. The station's air quality monitoring and preventative maintenance programs ensure that consistently high-quality instrument air is supplied.

In addition to these design features and administrative controls, the Unit 2 and 3 instrument air systems can be cross-connected during those rare occasions when one air compressor becomes unavailable and there is an unusually high and sudden demand on the instrument air system. Under normal circumstances one unit's air system is isolated from the other unit's with the exception of the 3C compressor, which may be aligned with either unit's system for additional support. Typically, the 3C compressor is aligned to Unit 2 to support the additional house loads on that system. This dedicated configuration isolates failure events and prevents them from affecting another dedicated system.

9.3.1.6 Radwaste Air Sparging System

The radwaste air sparging system is an independent air system. The system contains its own air compressors, coolers, and filters. The system is designed for a pressure of 13 psig and a capacity of 1300 ft^3/min.

The radwaste disposal system uses large amounts of low-pressure compressed air for agitating materials in waste tanks. Materials are agitated to prevent packing or solidification in the tanks.

The system is also connected with the off-gas system upstream of the booster air ejectors and can provide air for the dilution of the off-gas.

9.3.2 Process Sampling Systems

9.3.2.1 High Radiation Sampling System

The High Radiation Sampling System (HRSS) or Post-Accident Sampling System (PASS) is provided to meet the requirements of NUREG 0737[2] and the recommendations of Regulatory Guide 1.97[3] for the following:

- provide the capability to determine the degree of core damage under degraded core accident conditions through the collection and analysis of reactor coolant and containment atmosphere samples,

- provide for the analysis of reactor coolant to verify the injection of standby liquid control into the reactor system, and

- to assess the corrosion potential of post-accident reactor coolant on components and materials in contact with the coolant.

These requirements/recommendations are met through the installation of the HRSS, and the establishment of a program for the collection and analysis of reactor coolant and containment atmosphere samples and development of a core damage assessment procedure.

9.3.2.1.1 Design Bases

The Post-Accident Sampling (PAS) program provides the capability to sample, transport, and/or analyze reactor coolant and/or containment atmosphere samples from either unit under degraded core accident conditions. The criteria of NUREG 0737, II.B.3 and the recommendations of Regulatory Guide 1.97 were considered in the development of the program. The criteria used for the design and construction of systems to collect post-accident reactor coolant and containment atmosphere samples include the following[4]:

- the capability to promptly obtain for analysis a reactor coolant sample representative of the core area following an accident, water recirculation, reactor water cleanup filter inlet, and reactor water cleanup demineralizer can be routed to the chromatograph for additional analyses.

The reactor building sampling system is equipped with the necessary auxiliary components to support the sampling process, such as coolers, pressure and flow indicators, pressure and flow controllers, and supplies of demineralized water and instrument air. Additional sampling taps are provided on each sampling line (except for the reactor water cleanup filter inlet) for the installation of any additional measuring devices in the future.

9.3.2.4 Off-Gas Sampling System

Each unit's off-gas sampling system is constructed in two parts: a vial sampler and the sampling rack. The vial sampler provides the ability to extract a sample of effluent from the following:

A. Absorber train bypass line;

B. Inlet to A charcoal absorber;

C. Inlet to B charcoal absorber;

D. Inlet to C charcoal absorber;

E. Inlet to F charcoal absorber;

F. Inlet to J charcoal absorber;

G. Inlet to buried shielded filters; and

H. Absorbers recirculation line.

The vial sampler is equipped with a remotely operated pump, a grab sample vial, and an in-line filter.

The sampling rack provides the ability to extract a sample of effluent from only the inlet to the off-gas system's buried and shielded filters (which is also the discharge of the third and final absorber train; all three trains are connected in series). The rack is equipped with two remotely operated pumps, in-line suction-side and discharge-side particulate filters, flow and pressure indicators and pressure switches.

Samples from the vial sampler and the sampling rack are discharged into a common sample return header, which directs samples back to the outlet of the off-gas system's prefilter.

9.3.2.5 Off-Gas Filter Building Air Particulate Sampling System

Each unit has one reactor building equipment drain tank (RBEDT) located in the reactor building basement:

A. Unit 2 RBEDT is located in the northwest corner room and

B. Unit 3 RBEDT is located in the northeast corner room

The single pump on each tank starts automatically on a high tank level signal or a high tank temperature signal and trips on a low tank level signal or a low tank temperature signal. Tank level is indicated on an RBEDT level recorder.

A heat exchanger cooled by RBCCW water provides temperature control of the RBEDT fluid by automatically opening a heat exchanger recirculation valve on the discharge of the pump and closing the discharge valve to radwaste when the high temperature setpoint is reached. The temperature switch also starts the pump if it is not running. Once the temperature of the water in the tank is reduced to acceptable level, flow is rerouted to radwaste, unless the pump had been started by the temperature switch, in which case the pump trips. The high-temperature setpoint for the automatic recirculation valve is adjustable in the main control room. The discharge valve fails open on loss of air while the recirculation valve fails closed. The RBEDT pump is interlocked off when a Group II primary containment isolation signal is received.

The reactor building equipment drain liquid is pumped to the waste collector tank through a common line with the drywell equipment drains. A run time meter is provided to monitor the flow to the collector tank. A collector tank high-temperature alarm is provided in the main control room.

9.3.3.4 Reactor Building Floor Drains and Sumps

Each unit has two reactor building floor drain (RBFD) sumps with two pumps in each sump. Both sumps are located in the reactor building basement with RBFD sump A being on the east side and RBFD sump B on the west.

The reactor building floor drain liquid is pumped to the floor drain collector tank through a common line with the drywell floor drains. A run time meter is provided to monitor the flow to the floor drain collector tank. In each sump, the pump starts on a high sump level signal and trips on a low sump level signal. The pumps also trip when a Group II primary containment isolation signal is received. A high sump level alarm is provided in the main control room.

The sump pumps from the southeast and southwest (low pressure core injection [LPCI] and core spray) corner room sumps discharge sump fluid to the RBFD sumps. Individual sump high-level alarms annunciate on a control room panel.

9.3.3.5 Turbine Building Equipment Drains and Sumps

Each unit has one equipment drain sump with two pumps located in the condensate pump pits (elevation 469'-6"). Sump pumps are started automatically by a mechanical alternator level switch. One sump pump starts on a sump high-level signal and the second pump starts on a sump high-high level signal. A high-high sump level alarm is provided in the main control room. Both pumps trip on sump low level. Run time indication is provided in the radwaste control room.

9.3.3.6 Turbine Building Floor Drains and Sumps

Each unit has one floor drain sump with two pumps located in the condensate pump pit. Sump pumps are started automatically by a mechanical alternator level switch. One pump starts on a high sump level signal and the second pump starts on a high-high sump level signal. A high-high sump level alarm is provided in the main control room. Both pumps trip on sump low level. Run time indication is provided in the radwaste control room.

9.3.3.7 Radwaste Floor Drains and Sumps

Two sumps, each with one pump, are located in the radwaste basement near the west wall. Each pump is started automatically by a level float switch on a high sump level signal and trips on a low sump level signal. Run time indication is provided in the radwaste control room. A high sump level alarm is also provided in the radwaste control room.

9.3.3.8 High-Pressure Coolant Injection Room Floor Drains and Sumps

Each unit has one sump and sump pump located in their respective high-pressure coolant injection (HPCI) rooms. Each sump pump is started automatically by a float switch on a high-level signal and the pump trips on a low-level signal. Run time indication is provided in the radwaste control room. Normal flow is directed to the reactor building floor drain sump; however, flow can also be directed to the floor drain collector tank. A high sump level alarm is also provided in the main control room.

9.3.4 Chemical and Volume Control System

This section is not applicable to Dresden Station.

9.3.5 Standby Liquid Control System

9.3.5.1 Design Bases

The performance objective of the standby liquid control (SBLC) system is to bring the reactor to a shutdown condition at any time during core life independent of control rod system capabilities. To accomplish this objective the SBLC system is designed to inject sufficient sodium pentaborate solution into the reactor to shutdown from full power to a subcritical condition, with a reactor core boron concentration of 600 ppm.

The quantity of liquid control is determined by the negative reactivity required to render and maintain the reactor subcritical with the control rods withdrawn to their full power position. Allowance for nonuniform mixing of the liquid poison injected into the reactor coolant has been provided.

The design of the SBLC system assumes certain conditions as the bases. It is assumed that the reactor is operating at maximum power, 2527 MWt, at xenon equilibrium with the control rods in a normal operation pattern. Further, it is assumed that the operator is unable to insert control rods either by scram or by the normal mode of insertion. The SBLC design results in a core boron concentration which produces k_{eff} of 0.97 in the cold, xenon-free core with the control rods in the configuration defined above. This assures existence of a shutdown margin of 3% Δk which is adequate to account for uncertainties and off-standard initial conditions.

Control rod drive malfunctions sufficiently severe to prevent insertion of a single rod are highly unlikely, and the coincidental occurrence of such malfunctions in all fully or partially withdrawn drives is more unlikely. Therefore, the assumption that no control rods can be inserted is extremely conservative, as is the design shutdown margin imposed, 3% Δk. In view of this inherent conservatism, an additional assumption of peak xenon conditions is not warranted.

The maximum licensed reactor power for the units is 2527 MWt. Raising power to the average power range monitor (APRM) rod block line at 100% flow would be in violation of the operating license; therefore, operation at the rod block line would not occur. The present analysis is valid whether or not the local peak power approaches rod block monitor (RBM) limits. Only large changes in total initial power would materially affect the boron concentration determinations.

The basis assumed for the reactor water level is the normal operating level. This water level is assumed because there is no loss of feedwater or vessel level control during insertion of the liquid control solution.

The original design provided for injection of 3478 gallons of 13.4% sodium pentaborate solution.

An additional operational criterion imposed by 10 CFR 50.62 (Reference 9.3.6.7) requires the system to deliver 86 gal/min of 13% (minimum) sodium pentaborate solution or equivalent. To satisfy this requirement, an additional performance objective is to provide a system flowrate (using both pumps) of 80 gal/min of 14% sodium pentaborate solution, which is equivalent to 86 gal/min of 13% solution. Using the 14% concentration, 3329 gallons of solution provide an equivalent of the original design of 3478 gallons of 13.4% solution.

9.3.5.2 System Description

The equipment for the SBLC system is located in the reactor building and consists of an unpressurized tank for low-temperature sodium pentaborate solution storage; a storage tank heater; two positive displacement pumps; two explosion-actuated removal of 4.5% of reactor coolant boron before the demineralizers became saturated to the extent that no more boron could be removed. This small amount is easily accounted for by the 25% nonuniform mixing factor present in the original amount of boron solution.

The SBLC system is not designed to respond at a rate which would shut down the reactor during a transient situation. The simultaneous failure of 177 individual control rod assemblies and the loss of the main condenser vacuum would cause a power transient which is beyond the design capabilities of the nuclear system.

In the event that the reactor was critical with the reactor open and flooded to the normal water level during refueling, as is possible during low-power tests (power level less than 0.5 MWt) and insertion of the control rods was found to be impossible, the SBLC system would be started. The additional volume of water would diminish the boron concentration to 250 ppm which would produce a k_{eff} less than 0.95 in the cold, xenon-free core.

Since the SBLC system is to be operable in the event of an auxiliary power failure, it can be powered from the diesel generator. When fuel is in the reactor, the SBLC system is operable in all operating modes except hot and cold shutdown with all control rods fully inserted. At least one pump and one explosion-actuated shear valve must be operable for the system to be considered operable.

The availability of the SBLC system is assured by the continual monitoring of the system key parameters, the system's testability, and the two independent sets of active components (pumps and explosion-actuated injection valves and their actuation circuits) provided to inject boron into the system.

9.3.5.4 Tests and Inspections

The system must be tested periodically to establish the operability of all components. To avoid introducing boron to the reactor, the test is done in two parts. With the injection valves closed, each pump may be started locally and the solution may be pumped from the storage tank and returned to the tank. This demonstrates the ability of the pumps to remove solution from the tank at the required flowrate. By valving out the liquid poison supply and valving in demineralized water, the system can be flushed to prevent any boron precipitation in the pumps and lines.

The system can be tested for complete continuity during a shutdown when demineralized water can be pumped from the test tank into the reactor vessel. Testing necessitates replacement of the explosive charges in the shear plug valves.

The SBLC tank solution temperature is monitored periodically to ensure that boron (in the form of sodium pentaborate) does not precipitate out of solution and occlude pump supply lines. Ensuring adequate solution temperature also verifies the operability of tank heaters.

The containment isolation valves, two check valves located in series near the drywell penetration, are tested in accordance with 10 CFR 50, Appendix J.

Table 9.3-3

STANDBY LIQUID CONTROL SYSTEM PRINCIPAL DESIGN PARAMETERS

System	
Design negative reactivity (% Δk/k)	3.0
Required reactor boron concentration	750 ppm
Poison injection rate per pump	40 gal/min
Poison compound	$Na_2B_{10}O_{16} \cdot 10H_2O$
Minimum solution volume	3329 gal
Standby liquid control tank capacity	5250 gal
Pumps	
Type of pump (postitive displacemnt)	Triplex plunger
Number	2 (two required)
Normal Operating Conditions (each pump)	
Capacity	40 gal/min
Total developed head	1500 psi
Suction pressure	Atmospheric
Pumping temperature	70°F
Available net positive suction head	25 feet
Type of drive	Electric motor
Rating	50 hp
Power Sources	
Pumping and control	Unit Auxiliary Transformer 21 (31), Reserve Auxiliary Transformer 22 (32) or diesel-generator [MCC 28-1(38-1) for 2A(3A) standby liquid control pump; MCC 29-1(39-1) for 2B(3B) standby liquid control pump]

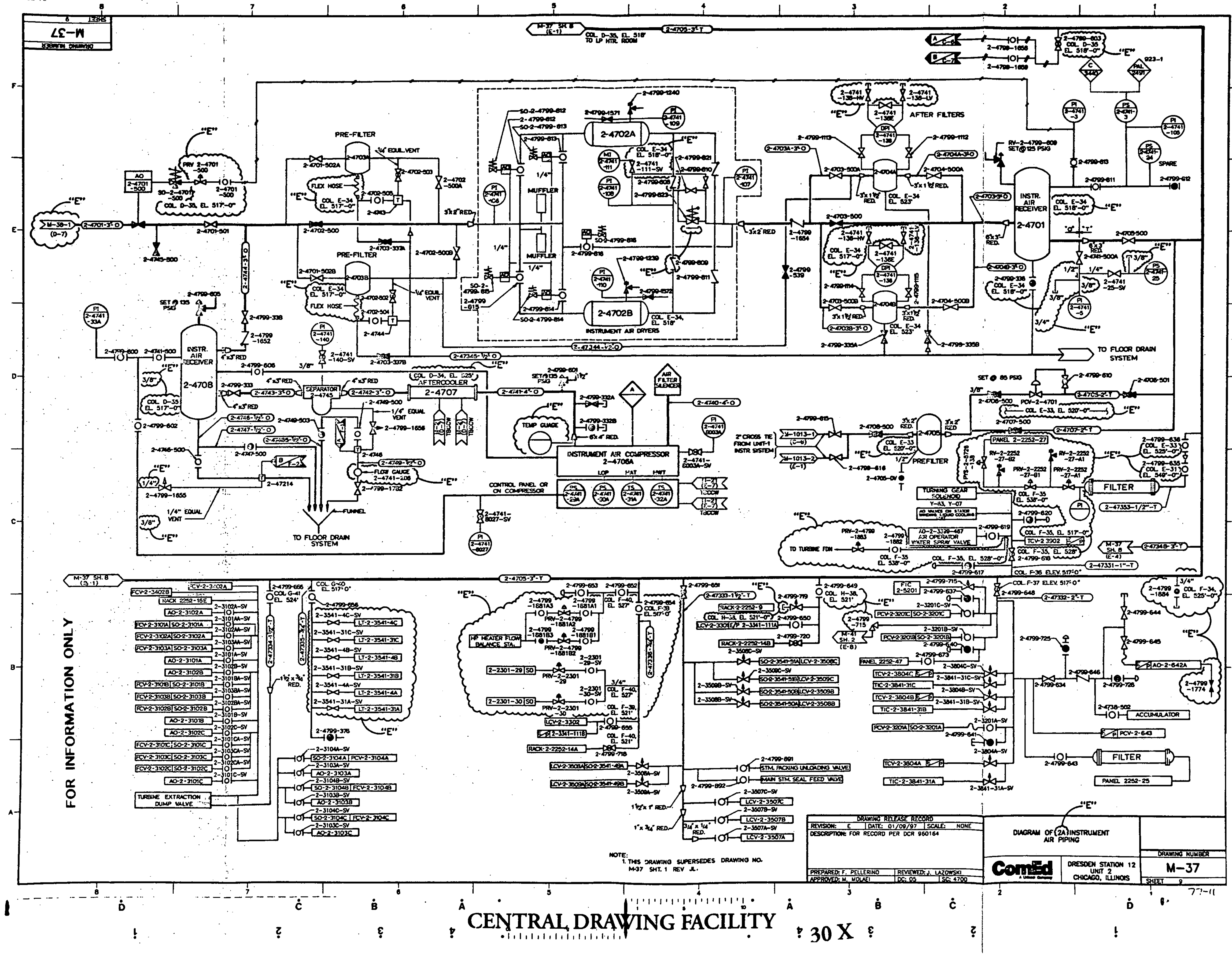


FIGURE 9.3-1

REV. 02 / JUNE 1997

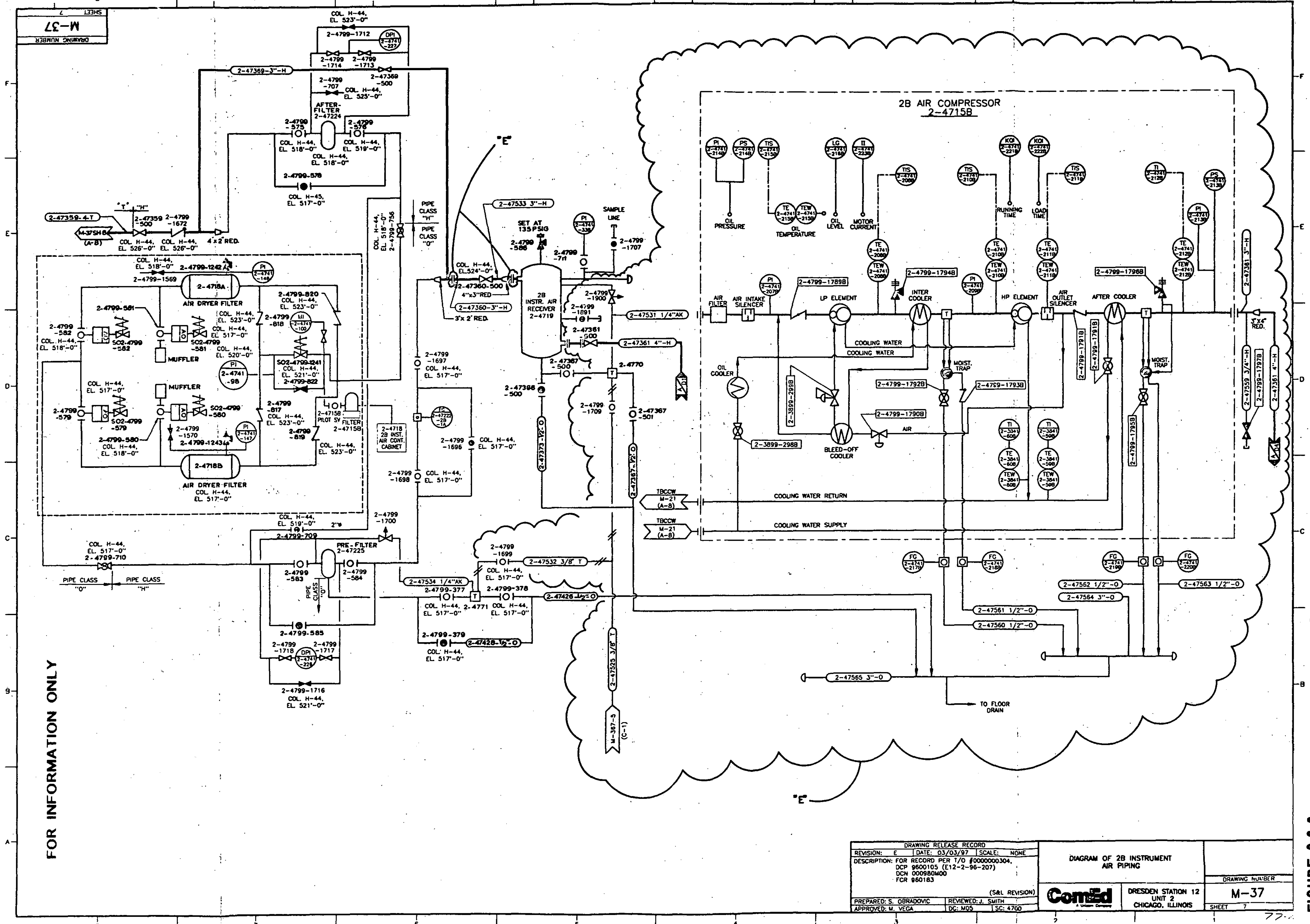


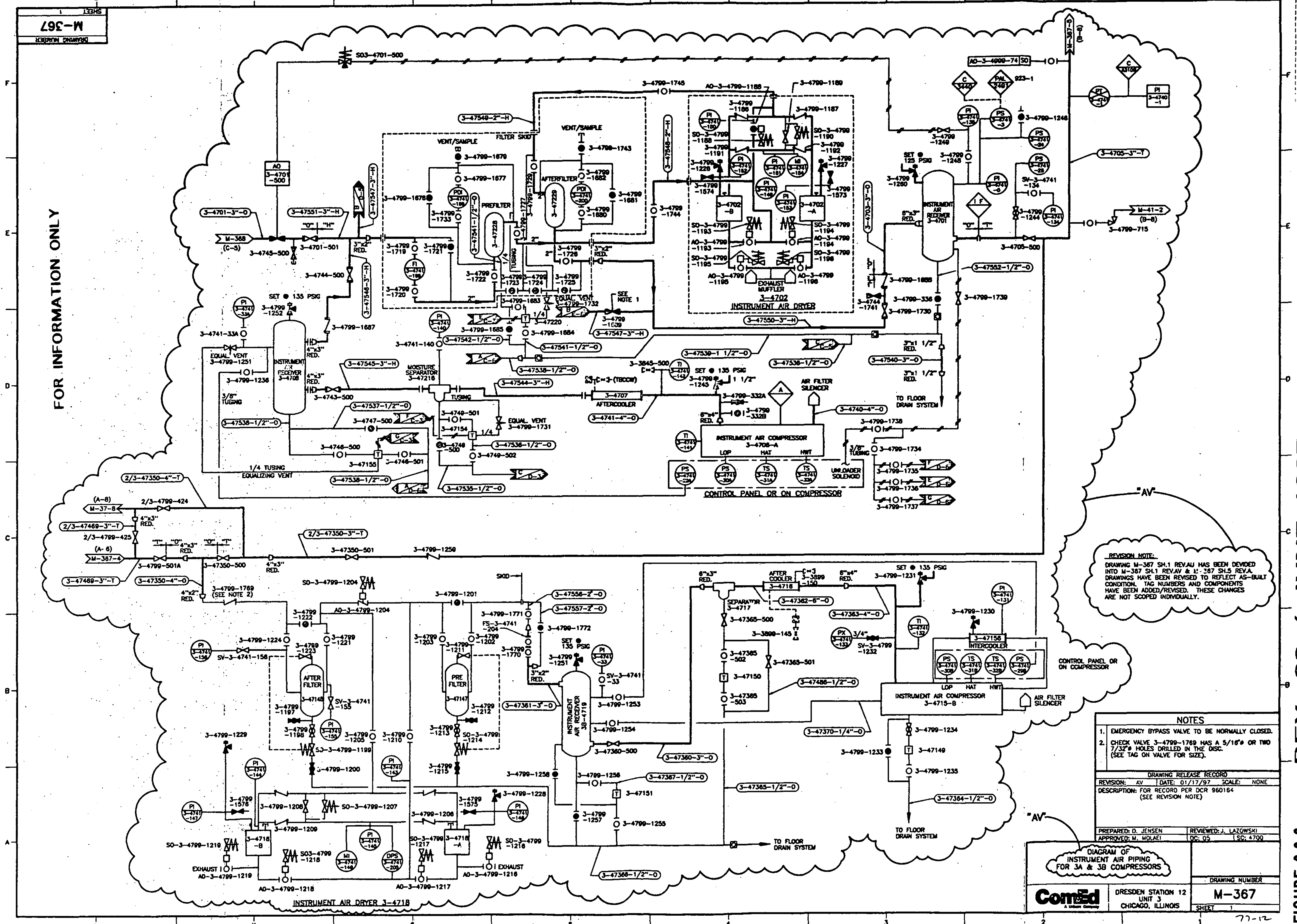
FIGURE 9.3-2

REV. 02 / JUNE 1997

CENTRAL DRAWING FACILITY

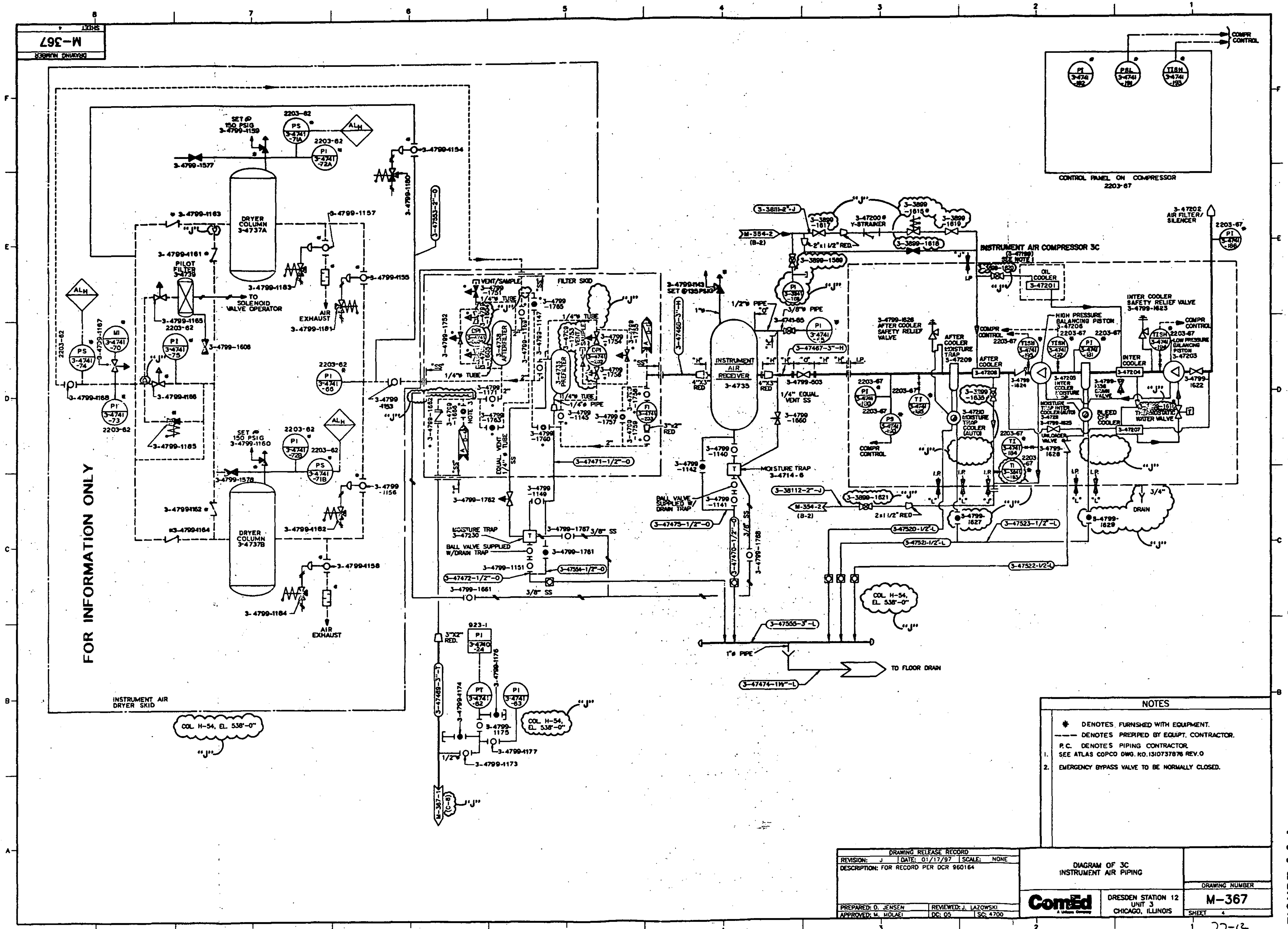
30 X

FOR INFORMATION ONLY



REV. 02 / JUNE 1997

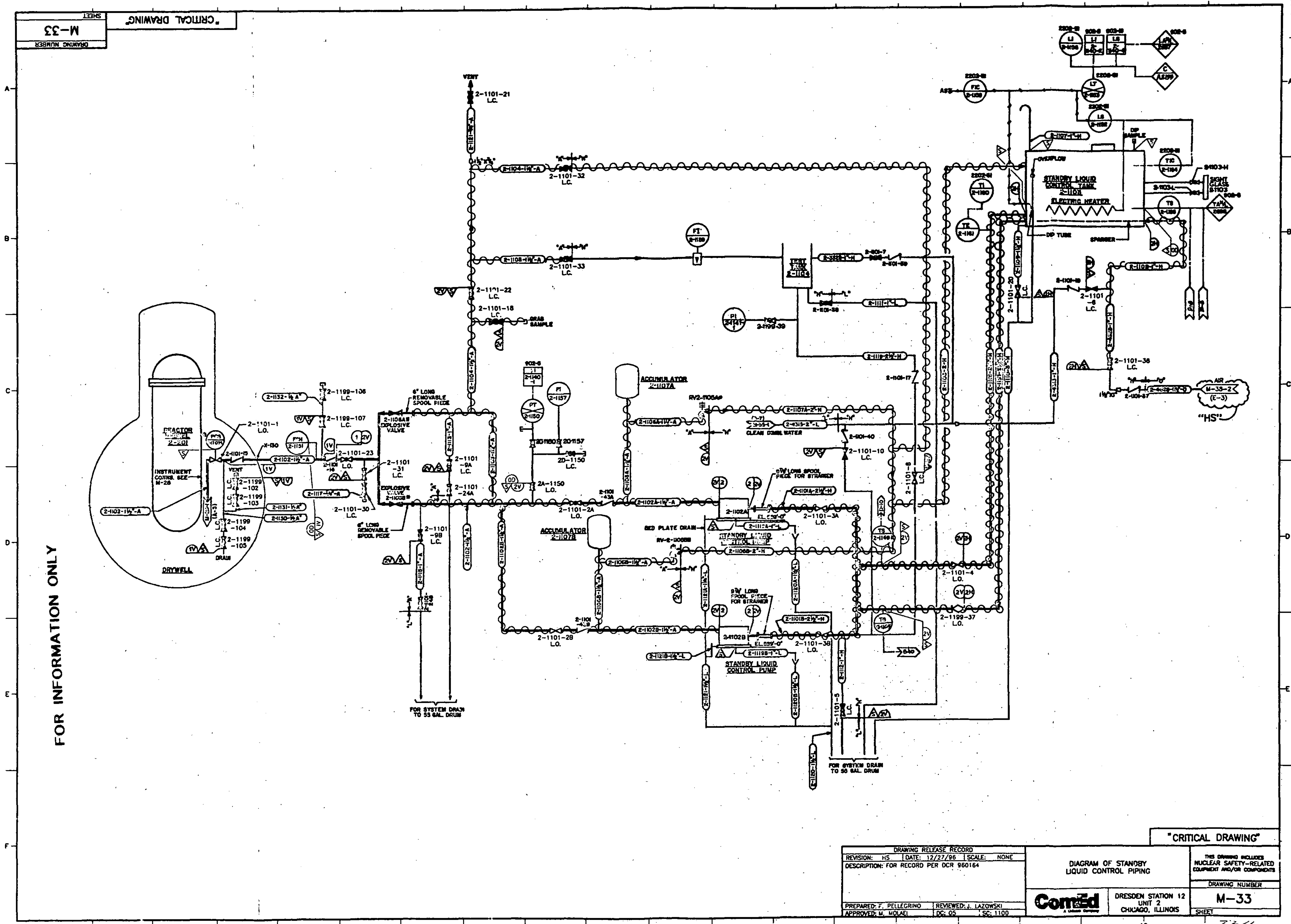
FIGURE 9.3-3



CENTRAL DRAWING FACILITY

FIGURE 9.3-4

REV. 02 / JUNE 1997



REV. 02 / JUNE 1997

FIGURE 9.3-8

CENTRAL DRAWING FACILITY 30 X

9.4 AIR CONDITIONING, HEATING, COOLING, AND VENTILATION SYSTEMS

The design objectives of the station heating, ventilation, and air conditioning (HVAC) systems are to provide protection to plant personnel and equipment from extreme thermal environmental conditions and to provide personnel protection from airborne radioactive contaminants. To achieve these objectives, the following design bases were used:

A. The design of equipment and components complies with the requirements of the applicable codes and standards of the major regulatory organizations, such as:

   1. Underwriters Laboratory;

   2. National Bureau of Standards; and

   3. American Society of Heating, Refrigerating and Air Conditioning Engineers.

B. A minimum of ¼-in.H_2O pressure differential is maintained at all times during plant operation between those areas which are clean and normally accessible and those areas designated as having the greatest contamination potential. This requirement does not necessitate "cascading" of several successive differential pressures of this magnitude. In many cases flow control can be maintained satisfactorily by individual differentials of considerably less than ¼-in.H_2O. The HVAC systems are designed to maintain differentials smaller than ¼-in.H_2O between adjacent areas where several steps in series are present before the area of greatest contamination potential is reached.

Normal plant HVAC equipment will be in continuous operation and will not need periodic testing.

It is normal practice to flow air from points of less contamination to points of greater contamination. This practice has been used throughout the design of the ventilation system. In some cases proper air flow direction cannot be maintained. Regardless of air flow direction, station radiological programs (e.g., radiological surveys, plant decontamination) are in place to monitor and limit the spread of contamination. Radioactive airborne activity is monitored continuously. Redundancy of equipment and recorders are used for reliable sampling and to provide a record of the reactor building ventilation stack release. The fuel pool area is also monitored to allow for trend indication and a permanent record of condition. The area radiation monitoring system is described in Section 12.3.

9.4.1 Control Room Area Ventilation System

The control room HVAC system provides conditioned air for personnel comfort, safety, and equipment reliability. In addition, the control room ventilation system provides habitability during toxic gas or radioactive gas releases, as described in Section 6.4. This section discusses operation of the control room HVAC system under non-emergency conditions. The control room HVAC system is shown in

9.4.3.1 Radwaste Building Ventilation

The radwaste building ventilation system has been designed to maintain the following conditions with outside temperatures varying between -6°F and +93°F:

A. Occupied areas	Minimum 50°F Maximum 103°F
B. Cells and collector tank room	Minimum 50°F Maximum 120°F
C. Concentrator and concentrator waste tank cells	Minimum 50°F Maximum 150°F

The radwaste building HVAC system is shown in Figure 9.4-4 (Drawing M-272).

The outside air for the radwaste building system is drawn into the building through stationary louvers, filtered, heated as necessary, and distributed by supply air ducts and registers throughout the building. Normally the airflow sequence starts from the clean areas and moves progressively to the areas of greater potential contamination. The system includes three 50% capacity supply fans and three 50% capacity exhaust fans. Normally, the system operates on one supply fan and two exhaust fans. The other fans are on standby. The standby supply and exhaust fans will start automatically on low airflow or auto trip of a running fan. The system is balanced to maintain a slight negative pressure in the general areas of the building, with certain areas of highest contamination potential maintained at ¼-in.H_2O negative pressure. All supply fans trip on building overpressure, and all exhaust fans trip on excessive building vacuum.

The system exhausts air out of the building to the 310-foot chimney. The exhaust fans draw building air into the exhaust vents located throughout the building and through two parallel filter trains, each composed of a prefilter followed by a high efficiency particulate air (HEPA) filter before discharging the air to the 310-foot chimney. Each supply and discharge fan is equipped with backdraft dampers that open when the fan is in operation.

9.4.3.2 Radwaste Control Room HVAC

The radwaste control room is cooled by a dedicated refrigeration unit which rejects heat to the outside atmosphere. The unit is equipped with an electric heater coil for use in cold weather. Control room air is recirculated through a filter and supply fan, and air lost by exfiltration is made up by outside air. The radwaste control room HVAC system is shown in Figure 9.4-5 (Drawing M-760).

9.4.3.3 Radwaste Solidification Building HVAC

A fan in each of the two trains of the radwaste solidification building ventilation system draws outside air into the building through a rough prefilter, a heat

The reactor feedwater pump room ventilation system is shown in Figures 9.4-9 (Drawing M-270) and 9.4-10A (Drawing M-530, Sheet 1 and 9.4-10B (Drawing M-530, Sheet 2).

9.4.4.3 Motor-Generator Room Ventilation System

The recirculation pump M-G room ventilation system removes heat generated by the M-G sets and control cabinets. This is a separate ventilation system within the turbine building. Two full capacity supply fans draw outside air through parallel air filters and duct it to the M-G set equipment. Temperature-controlled dampers are provided to allow the air to be recirculated back to the inlet of the supply fans or replaced with up to 100% outside air. Air that is not recirculated is discharged directly to the atmosphere separately from the main turbine room exhaust system. This system is not essential for safe shutdown.

The M-G room ventilation system is shown in Figures 9.4-9 (Drawing M-270), 9.4-10A (Drawing M-530, Sheet 1) and 9.4-10B (Drawing M-530, Sheet 2).

9.4.4.4 East Turbine Room Ventilation System

The east turbine room ventilation system draws outside air into the building through fixed louvers. This air is filtered, heated as necessary, and distributed through plenums and ducts by three 50% capacity supply and exhaust fans. Two fans are normally in operation and one on standby. Air is directed to the north and south HVAC equipment rooms, the switchgear room, the Unit 2 battery room, the auxiliary electrical equipment room, the demineralizer room, and other areas in this part of the turbine building. The supply and exhaust systems are balanced to provide a slight positive differential pressure relative to the atmosphere. Depending on the temperature of the return air, it is either recirculated or fully exhausted to the atmosphere. The demineralizer area discharges to the atmosphere through a separate fan.

The east turbine room ventilation system is shown in Figure 9.4-11 (Drawing M-936).

9.4.4.5 Battery Room Ventilation System

The Unit 2 battery room, located above the main control room, is served by the east turbine room ventilation system. Air is ducted into the battery room and exhausted to the north HVAC equipment room through an opening in the wall.

The Unit 3 battery and battery charger rooms are located in the southwest corner at the mezzanine level. Air is ducted into the charger room by the south turbine building ventilation system and discharged into the turbine room by an exhaust fan. The battery room has its own dedicated air conditioning system to maintain the room temperature between 70°F and 85°F for reliable battery operation. Air is discharged into the turbine room by a fan installed in an opening in the wall.

Following a loss of offsite power, ventilation to the battery rooms will be lost. Hydrogen gas emitted from the batteries as they are recharged by the diesel generators will accumulate in the rooms, but the hydrogen concentration will not reach the lower flammability limit.

The battery room ventilation systems for both units are shown in Figure 9.4-12 (Drawing M-973).

9.4.4.6 Off-Gas Recombiner Rooms

The off-gas recombiner area ventilation system for each unit draws outside air into the system through stationary louvers. This air is filtered, heated as necessary, and discharged to the upper level operating aisle ("penthouse"). The system consists of two parallel supply and exhaust trains, one supply and exhaust train in operation and one in standby. The parallel exhaust fans draw from the recombiner rooms, condenser rooms, and the off-gas instrument and control panel. This air is discharged without further filtering to the 310-foot chimney. The system is isolated by dampers in each parallel inlet and exhaust duct, with one set of exhaust dampers normally closed. The off-gas instrument and control panel is ventilated with a separate exhaust blower. Additional heating is supplied by steam area heaters.

The off-gas recombiner room ventilation system is shown in Figures 9.4-13 (Drawing M-625) and 9.4-14 (Drawing M-633).

9.4.5 Reactor Building Ventilation System

The reactor building ventilation system is designed to maintain the reactor building area temperatures between 65 °F and 103 °F based on outside temperatures varying between -6 °F and +93 °F.

The reactor building is also divided into distinct zones based on environmental conditions. Refer to Table 3.11-1, Environmental Zone Parameters for Normal Service Conditions.

Special ventilating and ducting systems are used on the refueling floor to continually exhaust air from the spent fuel storage pool area, dryer/separator storage pit, and drywell head cavity. See Section 9.4.2.

The normal ventilation system provides at least one free-volume change of air per hour in the reactor building. Normally the air flows from the filtered supply through ducts to the uncontaminated areas, through potentially contaminated areas, and then is returned and exhausted through the exhaust fans to the reactor building ventilation stack. Cooling and heating units in various rooms of the reactor building provide for personnel comfort and equipment protection.

The reactor building ventilation system is designed to supply filtered, tempered outside air and distribute it through all working areas and equipment rooms in the reactor building. The system maintains a negative pressure of at least ¼-in.H_2O within the building. The system also maintains a differential pressure of at least ¼-in.H_2O between clean and potentially contaminated areas. The system is designed to trip automatically on a secondary containment isolation signal, as described in Section 6.2.3.

The Unit 3 air supply system tempers the filtered outside air by means of a non-freezing-type steam heating coil or by an evaporative cooler, the Unit 2 air supply system tempers the filtered outside air by means of a non-freezing type steam heating coil or by chilled water cooling coils. Cooling water for the chilled water coils is provided by a piping system from air-cooled chiller units located outside the reactor building (M-269, Sht.2). Tempered air is directed by three 50% capacity fans through a redundant pair of pneumatically operated isolation butterfly valves to the building's duct system. Each of these three 50% capacity supply fans is equipped with a pneumatically actuated backdraft damper to isolate each fan when the fan is not in operation. Power to the fans is supplied by electrical buses which may be connected to the emergency diesel power in the event of an offsite power failure.

The conditioned supply air is then directed to all working areas and equipment rooms of the reactor building as shown in Figures 9.4-15 (Drawing M-269, Sht. 1) and 9.4-16 (Drawing M-529). Flow to and within these areas is indicated and controlled by means of differential pressure indicators and pneumatically operated dampers.

Exhaust air is collected by a network of ducts throughout the reactor building and is returned to the exhaust fan plenum through a pair of pneumatically operated isolation dampers. The air exhaust system consists of a set of three 50% capacity fans which exhaust to the reactor building vent stack. The drywell purge system is also ducted to these exhaust fans so that drywell effluent is exhausted by this system when the drywell is inerted, purged, or opened for access. The three exhaust fans are powered by emergency diesel-powered electric buses. Reactor building infiltration is discussed in Section 6.2.3.

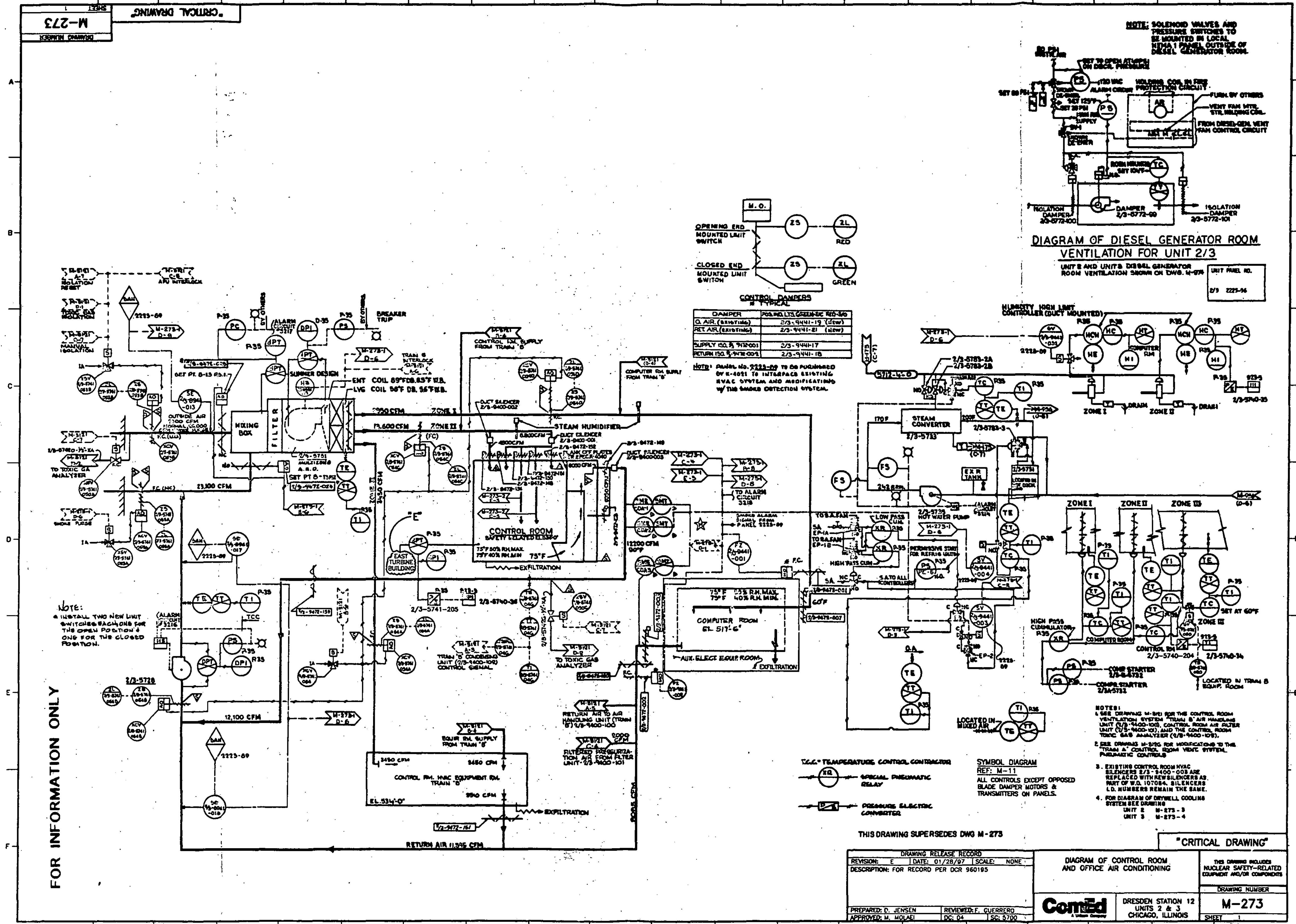
9.4.6 Emergency Core Cooling System Ventilation System

The emergency core cooling system (ECCS) rooms consist of two low pressure coolant injection (LPCI)/core spray pump rooms and one high pressure coolant injection (HPCI) pump room per unit, all of which are served by the reactor building ventilation system. Each of the rooms has a water-cooled heat exchanger/fan unit which functions as a room cooler. The fans for these units are powered by the emergency bus and are capable of operating following a LOOP. The LPCI/core spray rooms are normally maintained at less than 104°F. The HPCI rooms are normally maintained less than 140°F. These temperatures are below the qualification temperatures of the mechanical and electrical components in the rooms that are required for safe shutdown of the plant. Section 3.11 contains a further discussion of equipment qualification.

The LPCI/core spray pump room cooler fan motors are supported from rod hangers in a seismically qualified pendulum fashion from the room ceiling.[1]

During normal plant operating conditions, the cooling water for the ECCS room coolers is provided by the service water system. The service water system is discussed in Section 9.2.1.

If the reactor building ventilation system is shut down due to secondary containment isolation or LOOP, the equipment in the ECCS rooms are cooled solely by the room coolers. Loss of the room coolers will not prevent proper operation of the LPCI and core spray systems. The HPCI room cooler fan is necessary for proper operation of the HPCI system.

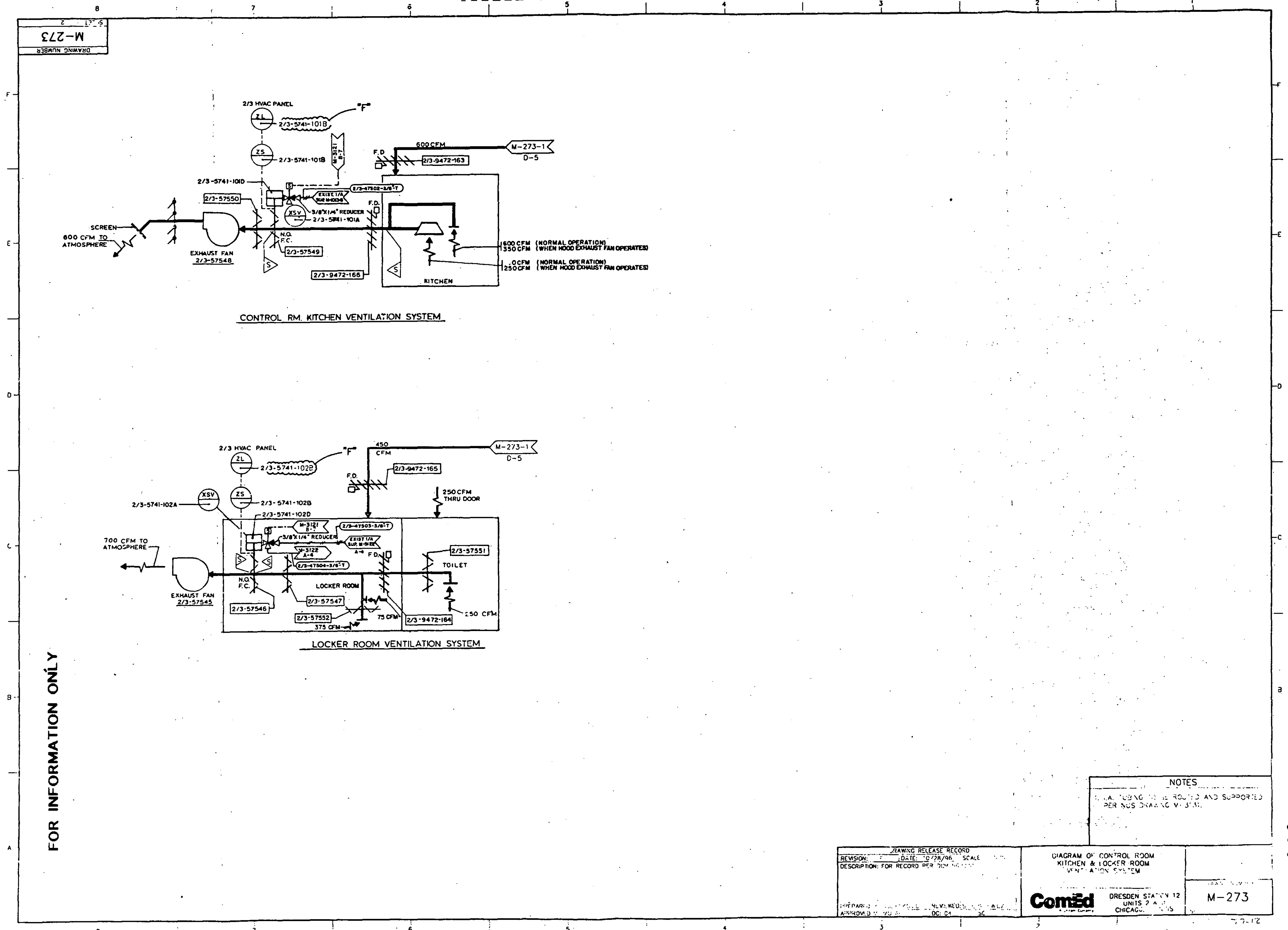


REV. 02 / JUNE 1997

FIGURE 9.4-1

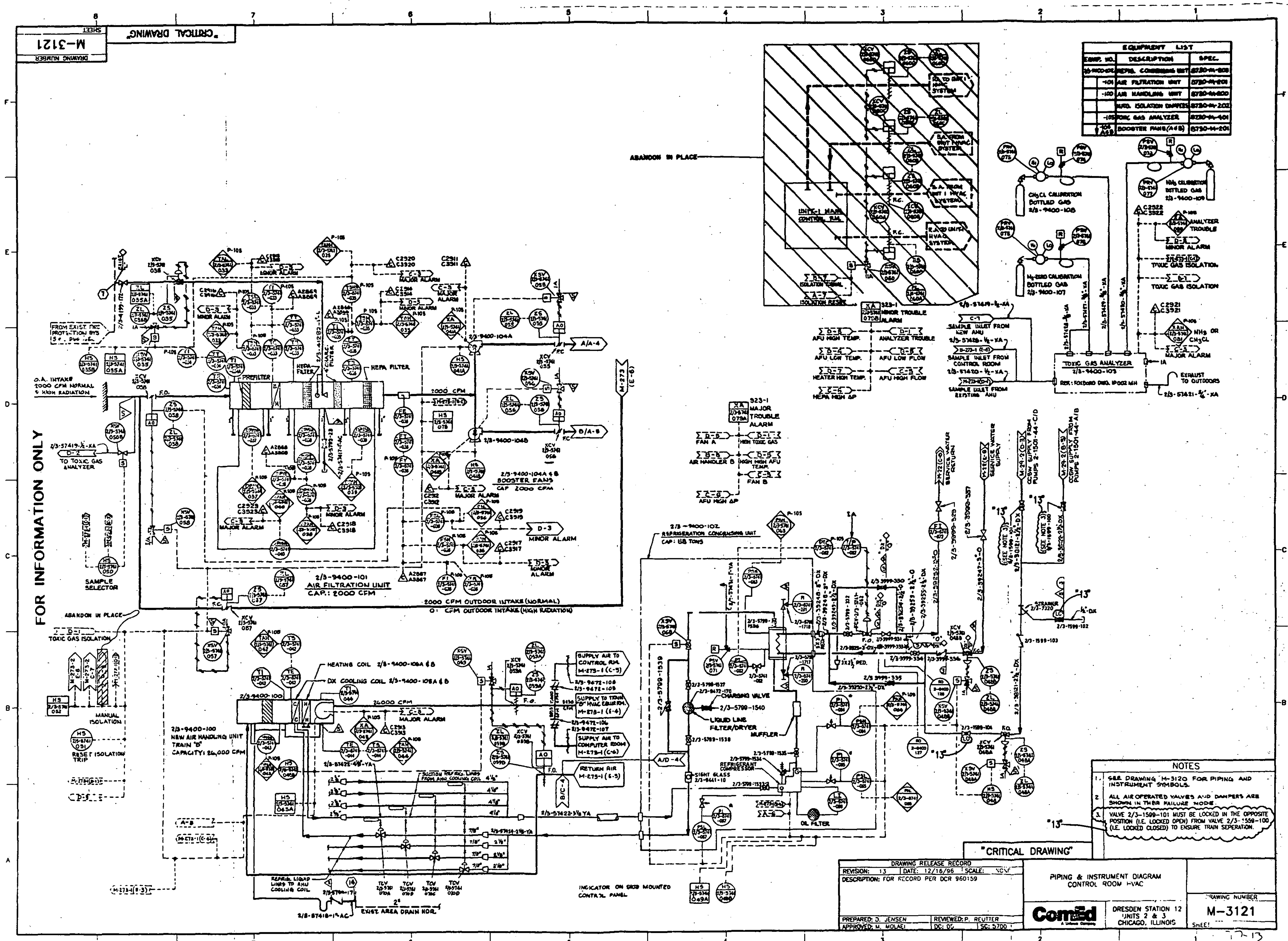
CENTRAL DRAWING FACILITY

30 X



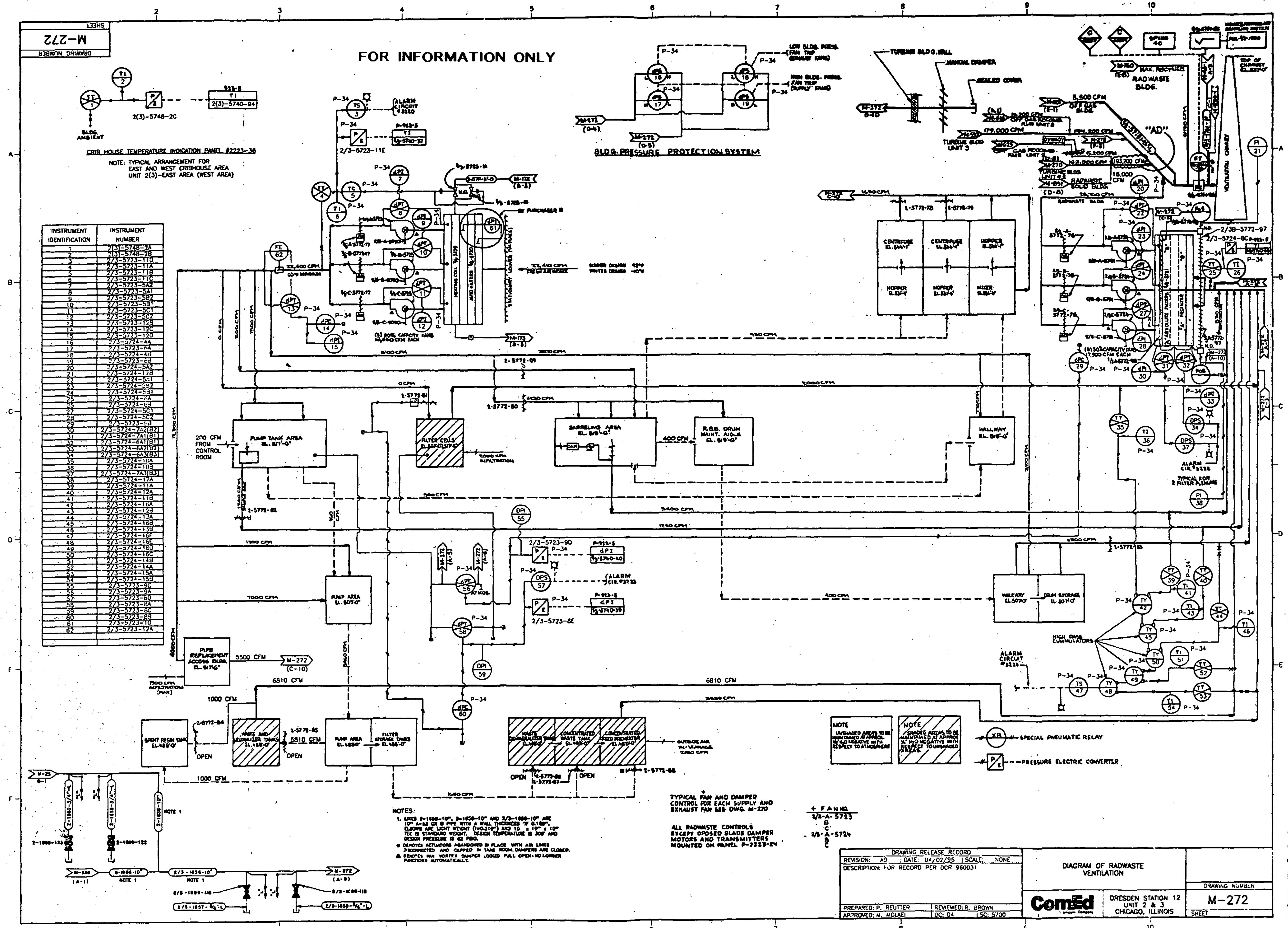
REV. 02 / JUNE 1997

FIGURE 9.4-2



REV. 02 / JUNE 1997

FIGURE 9.4-3

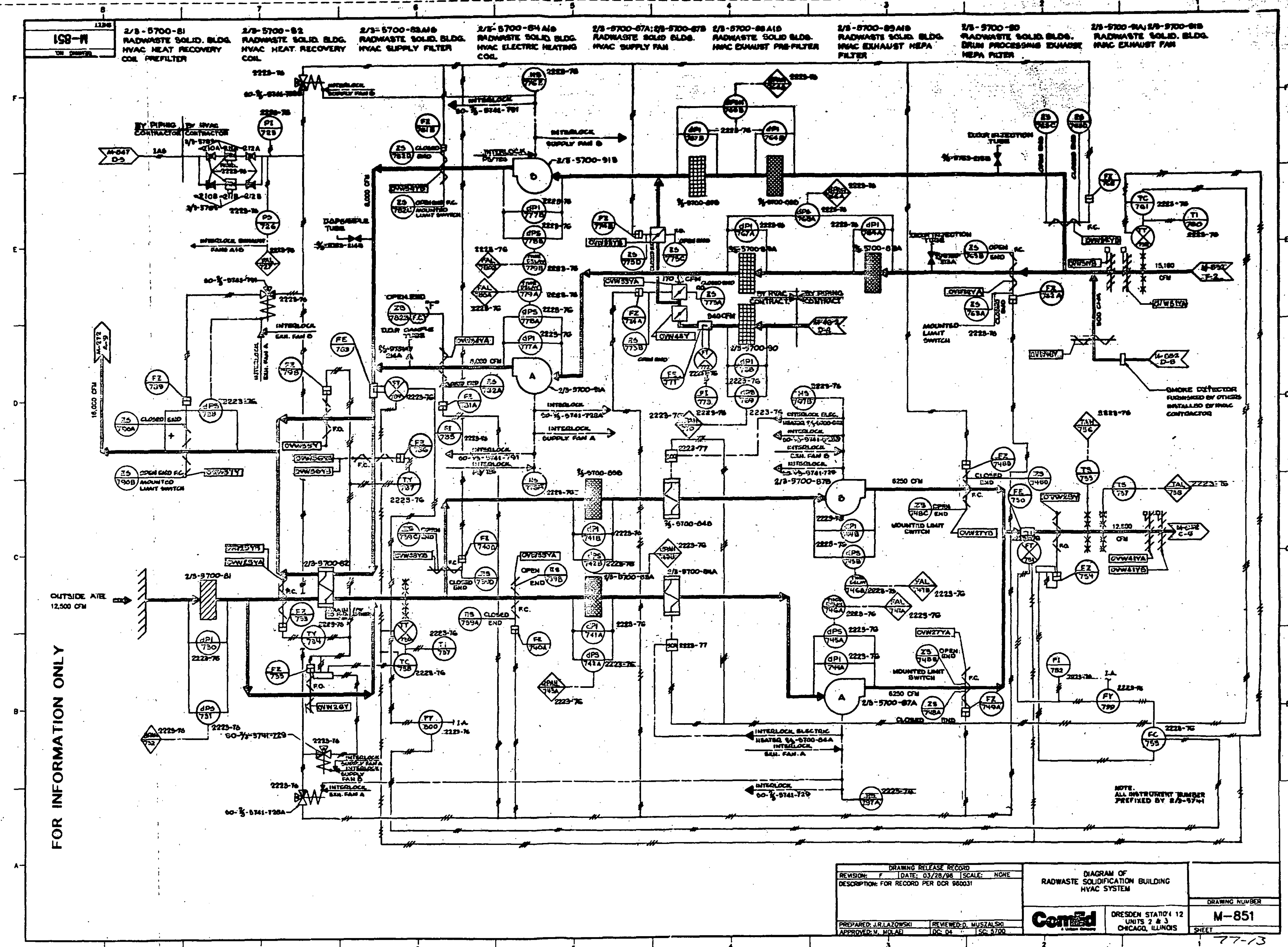


REV. 02 / JUNE 1997

FIGURE 9.4-4

CENTRAL DRAWING FACILITY

30 X

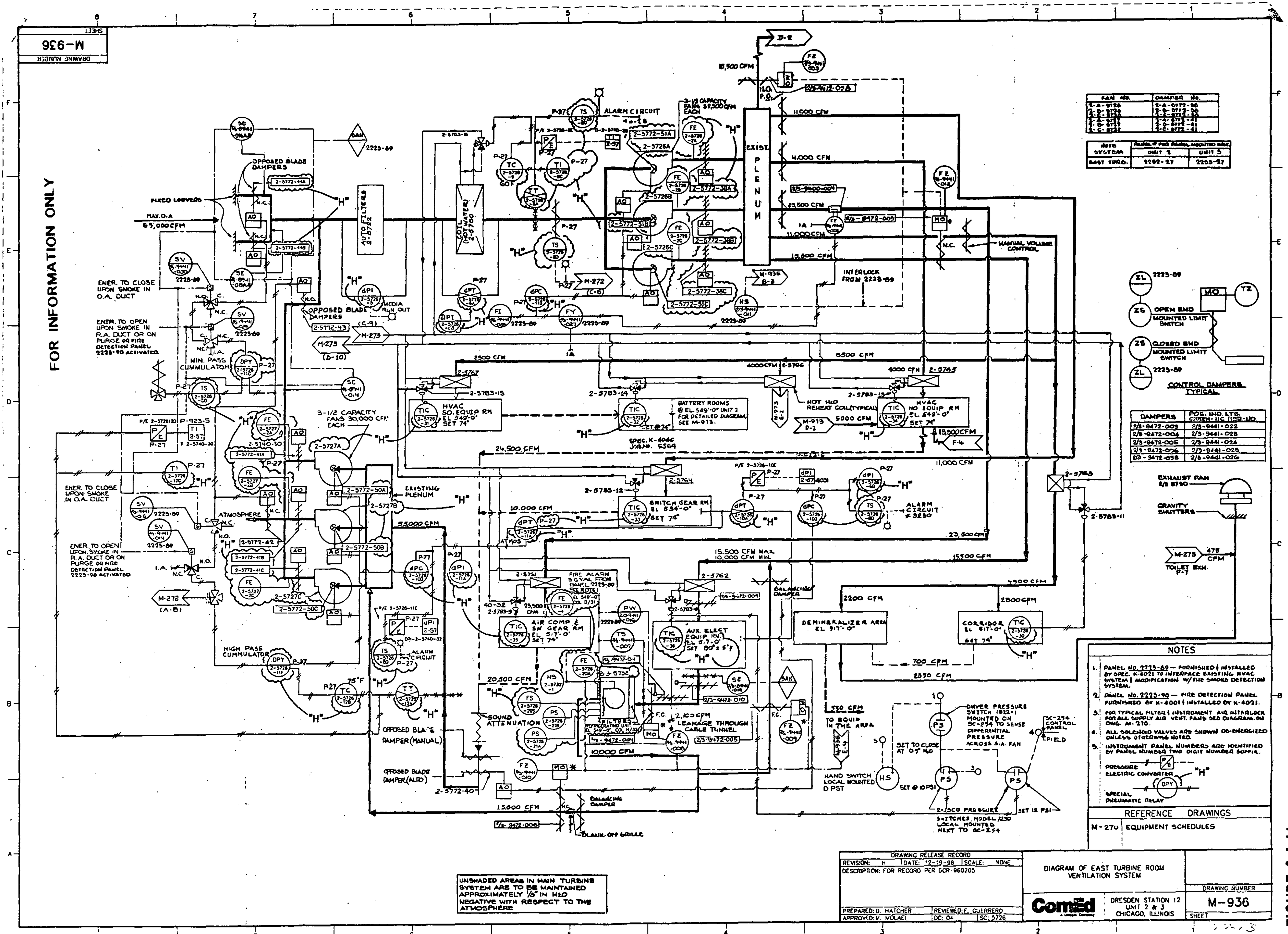


CENTRAL DRAWING FACILITY

24 X

REV. 02 / JUNE 1997

FIGURE 9.4-7



REV. 02 / JUNE 1997

FIGURE 9.4-11

CENTRAL DRAWING FACILITY

H. A microwave voice channel, which is a CECo environmental party line, allows communication between the following (PL-2, blue phone):

1. All EOFs,
2. Corporate EOF,
3. Zion Station,
4. LaSalle Station,
5. Dresden Station,
6. Braidwood Station,
7. Byron Station, and
8. Quad Cities Station.

I. A microwave voice channel, which is a CECo technical support party line, allows communication between the following (PL-3, blue phone):

1. All EOFs,
2. Corporate EOF,
3. Zion Station,
4. LaSalle Station,
5. Dresden Station,
6. Braidwood Station,
7. Byron Station, and
8. Quad Cities Station.

An intercom phone and loud speaker system is also provided within the Unit 2, and 3 areas. This system is independent of the PBX system, and can be accessed from the paging phones. This system provides voice communication between the control room and selected areas in the plant. The power source for this system is from the emergency ac system.

An independent sound power phone system is also provided in the plant. Phone jacks are located throughout the two-unit area to permit instrument calibration between control room and local sensors. Under emergency conditions sound power phones can be used to maintain communications between the control room and the affected area.

A new intraplant 900 MHz. radio communication system has replaced the 150 MHz. system. The new trunked system consists of five repeater transmitters that are computer controlled. One channel continuously monitors the system and enables the controller to efficiently assign transmissions to an available frequency.

Fuel is transferred from the 15,000-gallon diesel fuel oil storage tank to the 750-gallon diesel oil day tank with the diesel oil transfer pump. Transfer is accomplished automatically by level switches on the day tank. Diagrams of the Unit 2, Unit 3, and the Unit 2/3 DG fuel oil storage and transfer system are shown on Figures 9.5-1 (Drawing M-41, Sheet 2), and 9.5-2.

Each day tank contains sufficient fuel to sustain emergency diesel generator operation for 1 hour of operation at rated load. The configuration of the system is such that the minimum normal operating level in the day tank is above the low level alarm setpoint. The low level alarm setpoint is maintained above the minimum required 1 hour fuel storage level. This ensures that the day tank provides a minimum 1 hour of fuel for operation of the diesel generator at 10% above rated load (205 gallons). The fuel oil transfer system, which is safety-related and seismically qualified, ensures the delivery of fuel for diesel generator operation beyond the 1-hour supply of the day tank. Each diesel fuel oil storage tank has a capacity adequate to sustain system operation pending normal commercial deliveries of fuel. The diesel generator uses a fuel which is readily available.

The Technical Specifications require a minimum of 10,000 gallons of diesel fuel to be kept on site for each DG. Figure 9.5-3 shows diesel fuel consumption versus load. At the 10% overload condition (2860 kW) each DG will consume 205 gallons of fuel per hour; at a rated load of 2600 kW, each DG will consume 192 gal/hr, and at 50% rated load, 105 gal/hr. An original FSAR analysis, using original diesel loads, postulated that two DGs are connected to the emergency buses in a unit which has experienced a design basis accident concurrent with a loss of offsite power and that a third DG is connected to the non-accident unit which is being shut down after having also experienced a loss of offsite power. This analysis conservatively estimated a total fuel consumption of 340 gallons for the first hour. After the first hour the reactor will probably have been sufficiently cooled such that some emergency core cooling system (ECCS) pumps can be shut off and the loads diminished on the diesels, resulting in a fuel consumption of about 250 gal/hr. The analysis estimated that the maximum onsite diesel fuel supply (47,250 gallons total) would last 7.9 days and that the minimum onsite diesel fuel supply, as required by Technical Specifications, would last 5.2 days.

To provide an adequate margin of safety beyond the anticipated 8-hour delivery time for fuel oil, the actual basis for the minimum onsite fuel supply specification is a two-day supply to each diesel with the diesel operating at a 10% overload condition. This basis resulted in the specified 10,000 gallon minimum supply for each diesel.

The diesel oil day tank level is sensed by a level switch, which initiates a signal to automatically start or stop the fuel oil transfer pump. The fuel oil transfer pump starts automatically when its respective day tank level drops below a predetermined level.

Upon initiation of a DG start signal, fuel from the fuel oil day tank is supplied through a strainer via an electrically-driven fuel oil priming pump and a duplex filter to the injectors. Any excess fuel is returned to the fuel oil day tank. At an engine speed of approximately 200 rpm, the priming pump deenergizes and the engine-driven fuel oil pump continues to supply fuel oil.

The Unit 3, diesel oil transfer system also supplies fuel oil to the Unit 2/3 diesel fire pump. Technical Specifications require that the fire pump diesel engine fuel day tank contain sufficient fuel for 20 hours of fire pump operation. This is considered to be sufficient for any postulated fire fighting needs. There is also sufficient fuel oil stored onsite to support the simultaneous operation of the fire pump and the Unit 3 DG.

The connection of the diesel fuel oil transfer pumps to the emergency buses is automatic. Each diesel generator has one fuel oil transfer pump which starts automatically when its respective day tank level drops to 32 inches nominal (two-thirds full). Figure 9.5-4 shows the electrical schematic and control from each DG to its respective fuel oil transfer pump.

A three-position switch (Unit 2, Normal, and Unit 3) on the 2/3 DG auxiliary control panel isolates, controls, and protects the 2/3 DG fuel oil transfer pump in the event of a fire. With the switch in the normal position, the 2/3 DG fuel oil transfer pump receives power from MCC 28-1. If the power is unavailable from MCC 28-1, the power automatically transfers to MCC 38-1. If the switch is in either the Unit 2 or Unit 3 position, the opposite unit's power source is electrically isolated. This would be performed if a fault has occurred or is anticipated on MCC 28-1 or MCC 38-1 such as if a major fire is located at the MCC or near the cabling of the fuel oil transfer pump.

A curb around the 2/3 DG fuel oil day tank provides a means of containing oil and water leaks or fires, and facilitates leak disposal. For additional information regarding fire protection, see Section 9.5.1. Also, as shown in Figure 9.5-2, an emergency fuel cutoff valve is provided for each fuel oil day tank in the event of a fire or other emergency.

Operability of the DG fuel oil transfer pumps is verified during DG testing. Diesel fuel oil additives are used to maintain fuel oil quality. Diesel fuel oil is sampled and tested once a month to verify quality.

9.5.5 Diesel Generator Cooling Water System

The diesel generator cooling water (DGCW) system provides cooling water to each of the three DGs. In addition, the system provides an alternate water supply for the containment cooling service water (CCSW) keep fill system. Refer to Figure 9.5-9.

The closed loop portion of the DGCW system circulates cooling water through cored passages in the diesel's cylinder liners, cylinder heads, turbocharger aftercoolers, and lube oil cooler. Diesel engine cooling water temperature is maintained relatively constant by the temperature regulating valve which controls the flow of engine water through the DGCW heat exchangers. A bypass line provides fast engine warmup and a constant flow of diesel engine cooling water. The heat exchanger cooling water is provided by the open loop portion of the DGCW system. A water expansion tank provides a surge volume and makeup capability. The motive force for this cooling water is provided by two gear-driven centrifugal pumps. During diesel standby readiness, a 15-kW immersion heater is provided to warm the diesel lube oil. Natural circulation forces the cooling water through the immersion heater. The oil cooler then becomes an oil "heater" and the flow of oil pump trip alarms in the control room, and remotely, on the generator relay and metering panel. A restriction orfice-type flow indicator is also provided in the DGCW pump discharge line in accordance with Regulatory Guide 1.97.

The Unit 2 pump receives electrical power from 480-V motor control center (MCC) 29-2. The Unit 3 pump receives electrical power from MCC 39-2. The 2/3 DGCW pump normally receives power from MCC 28-3, but an automatic device connects the pump to MCC 38-3 (Unit 3) if MCC 28-3 is deenergized. The pumps can be operated in manual mode or in automatic start mode. In the event of a loss of offsite power, the pumps are connected to the DG bus.

Each DG can operate without cooling water for 3 minutes at full load with a speed of 900 rpm assuming an initial cooling water temperature of 100°F prior to engine start. The DG operating time increases to 10 minutes with no load on the generator (at 900 rpm). At its idling speed each diesel generator can run for 42 minutes without cooling water, again assuming an initial water temperature of 100°F.

9.5.6 Diesel Generator Starting Air System

The purpose of the diesel generator (DG) starting air system is to store and deliver sufficient air to start the diesel under all conditions. The safety function of the air start piping is to provide a means to start the diesel engine in case of a loss of offsite power.

The DGs are started by air-driven starting motors. A separate starting air system is provided for each DG. Each DG starting air system has two starting air compressors and two air-driven starting motors. If the starting solenoid valve is energized, two air-driven starting motors engage a flywheel ring gear. After the two air-driven starting motors engage, the air start relay valve opens and four air receiver units supply the air which cranks the starting motors. Two air compressors maintain the air receiver pressure at greater than or equal to 220 psig. At an engine speed greater than 200 rpm, the starting solenoid valve deenergizes, interrupting the air to the starting motors and venting off the pressure which causes the air motors to stop and disengage. If the air receiver pressure is reduced to 175 psig, sufficient pressure would remain to start the DG once with no air compressor action. A diagram of diesel starting air piping is shown on Figure 9.5-10 (Drawing M-173). The safety-related portion of the system is shown on Figure 9.5-10.

Some minor modifications to the DG starting air system resulted from design concerns raised by the Dresden Safety System Functional Inspection (SSFI). These concerns have been addressed in the "Operability Assessment of SSFI Report Concerns".[2] The modifications have enhanced the DG starting air system, and have been implemented on the Unit 2 and Unit 3 DGs and the Unit 2/3 swing diesel generator. These modifications included the following:

A. Addition of a single 1½-inch check valve to the combined discharge header of both air receiver units in each starting air train;

9.5.9 Station Blackout System

Note: This change has been written to update the UFSAR reflecting the installation of the station blackout diesels (M12-0-01-019). The Unit 2 diesel has been Op Authorized and is fully operational. The Unit 3 diesel installation is complete and all auxiliary systems are operational; however, the Unit 3 diesel has not been Op Authorized pending testing which requires that the unit be in a refueling outage. This testing is currently scheduled for D3R14.

9.5.9.1 Station Blackout System Description

The station blackout system is a non-safety-related, independent source of additional on-site emergency ac power. The System consists of 2 diesel-driven generator sets, each set having a continuous rated output of 4350 kw at 4160 volts ac and a 0.8 power factor. Each generator is connectable, but not normally connected, to the safe shutdown equipment on one nuclear unit, but can also be connected to the opposite unit via the safety-related 4kv cross-ties. The station blackout diesel generators (SBO DGs) must be manually started and manually connected to the appropriate safe shutdown loads. The start and load function of the SBO DG can be performed from the main control room.

The SBO diesel generators and auxiliaries are located in the station blackout building, which also houses the Unit 2 safety-related 125 Vdc alternate battery. For this reason, the SBO Building is a Category 1, safety-related structure. The SBO building protects against weather-related events which could initiate an SBO event and provides physical isolation from safety related components. The SBO Building is physically separated from emergency systems, thus avoiding the consequences of multiple failures of on-site diesel generator systems due to severe weather-related events. The 4 kV power cables between the SBO and safety-related switchgear are located in underground cable ducts.

The SBO DG auxiliaries include: a fuel oil system, starting air system, engine lubrication system, engines cooling system, engine combustion air and exhaust, a distributed control system (DCS), local engine control panels, dc battery and switchboard, uninterruptible power supply and panel, 4kv switchgear, synchronizing equipment, 480 volt motor control center, HVAC, building drain and sump system, and fire detection/protection system.

9.5.9.1.1 Engine/Generator Set

The configuration of engines is a tandem DG set with a 12-cylinder and 16-cylinder engine on a common shaft with the generator in the middle.

The synchronous generator is rated at 4350 kw, 4160 volts, 60 hertz, 0.8 power factor. Its maximum output current is 755 amps. The rotor has an 8-pole field rotating at the synchronous speed of 900 rpm. The exciter is a brushless design. A permanent magnet generator provides a source of power to the voltage regulator and exciter and obviates the need for dc field flashing circuitry.

9.5.9.1.2 Fuel Oil System

The purpose of the fuel oil system is to provide for storage and transfer of fuel oil from the storage tank to day tank and from the day tank to the engines. The fuel oil system for the SBO DGs is entirely independent of any other fuel oil systems at Dresden.

The two SBO DGs share a common 15,000 gallon underground storage tank and short sections of common suction and return piping. Each SBO DG has its own fuel oil transfer pump which takes suction on the storage tank and discharges to a 1095-gallon day tank. The transfer pump is an ac-driven, positive-displacement pump. The discharge piping of each transfer pump can be cross-tied to allow for filling the opposite unit's day tank. The storage tank and each of the day tanks is equipped with a vent line to atmosphere through a flame arrestor to prevent overpressurization of the tanks. Overfilling of the storage tank will initiate in alarm, locally and in the control room. An overflow line from each of the day tanks back to the storage tank mitigates the consequences of overfilling of the day tanks.

Fuel oil is transferred from the day tanks to the engines using an engine-driven pump. In parallel with the engine-driven fuel pump is an ac-powered fuel oil backup pump and a manual priming pump.

The following fuel oil consumption data for the Unit 2 SBO DG, using No. 2 diesel fuel oil, was obtained during factory testing. The data for Unit 3 SBO DG is similar to these values.

50% load:Observed consumption 154 gallons/hr
75% load:Observed consumption 207 gallons/hr
100% load:Observed consumption 271 gallons/hr
110% load:Observed consumption 307 gallons/hr

Thus, the day tank contains enough fuel for about 4 hours of single-unit operation at 100% load without refilling. The filled storage tank, accounting for the unfilled head space, has enough fuel to operate both SBO DGs at 100% load for about 24 hours.

Manual and automatic operation of the fuel oil transfer pump is available. In the automatic mode, the pump will operate upon a signal from the distributed control system (DCS), indicating a low-normal level in the day tank. The DCS also starts the pump upon an engine shutdown. The pump stop signals are received from the DCS upon sensed high-normal level. The ac-powered fuel oil backup pump will operate upon sensed low fuel oil pressure while at rated speed. This pump will sustain engine-operation in case the engine-driven pump fails.

The fuel oil transfer pump and the ac backup pump are powered from MCC 65-1 (75-1).

9.5.9.1.3 Starting air system

The SBO starting air system, consisting of two independent trains, provides full redundancy in both components and connections to supply air to the engine starting motors. Each redundant train can provide, at a minimum, five (5) full cranking cycles without recharging its air receivers. Therefore, each DG set can receive 10 cranking cycles, independent of ac power.

Operation of the starting air system to start the SBO DG is accomplished either locally or from the main control room. A local control switch is used to select the lead starting air train. Starting air logic is as follows. The engines will crank using the selected lead train by energizing the two (2) dc-operated solenoid pilot valves for that train. If after 4 seconds, the controller does not sense at least 80 rpm engine speed, it will automatically swap over to the opposite train. This swapping will continue for a total cranking time of 10 seconds, after which the start controls will lock out and provide an overcrank alarm both locally and in the control room. Swapping is inhibited as long as the sensed engine speed is above 80 rpm. The starting motors will continue to crank until 200 rpm engine speed or the 10 second overcrank alarm and lock out is enabled. Above 200 rpm, the starting motors disengage by de-energizing the solenoid pilot valve, venting off the pressure which causes the air motors to stop and the pinion gear to retract.

All ac- power components of the starting air system are fed from MCC 65-1 (75-1).

9.5.9.1.4 Engine Lubrication System

A separate lubrication oil system is provided for each diesel engine, with all components on either the main skid or the engine accessory rack. During operation, the engine drives three oil pumps: the scavenging oil pump, the piston cooling oil pump, and the main bearing oil pump.

The scavenging oil pump takes a suction from the diesel engine oil sump, pumps the oil through a filter and cooler, and provides a suction to the piston cooling oil pump and main bearing oil pump.

The piston cooling oil pump supplies oil for the cooling of the piston and lubrication of the piston pin bearing surfaces.

The main bearing oil pump supplies oil for the other moving engine parts such as the main bearings, gear train, cam shaft, and rocker arms. This supply stream exits the engine and is filtered through an engine-mounted turbo lube oil filter and supplies the turbocharger bearings.

During standby conditions, the engine lubricating oil is kept warm by heat transferred from the jacket water system via the engine oil coolers which, in standby, heat circulating oil. The circulating oil is driven by a 1 hp, ac lube oil circulating pump.

Unlike the emergency diesel engine, the SBO engine does not provide lubrication of the crankshaft bearings during standby conditions, only the turbocharger bearings. However, each engine is equipped with a pre-lube function which can be used prior to non-emergency engine starts to lubricate crankshaft bearings, camshaft bearings and rocker arms.

The ac lube oil circulating pumps are fed from MCC 65-1 (75-1) and the dc lube oil circulating pumps are fed from Panel 6A-1 (7A-1). Low lube oil pressure during operation will annunciate both locally and in the control room and will trip the engines if in non-emergency conditions.

9.5.9.1.5 Engine cooling system

Heat rejection from the engine jacket water cooling system is provided by dedicated radiators. Each engine has its own independent flow path and radiator. Included in this flow path is a hotwell tank which serves as a source of cooling water so that the engine can operate without ac-driven radiator fans for a short time.

The engine-driven jacket water pumps provide the only forced circulation in the jacket water system. There are two pumps per engine with each pump supplying loads on its half of the engine.

An engine trip will automatically be initiated on jacket water low pressure at rated speed or on jacket water high-high temperature while at rated or idled speed. These trips are accompanied by alarms both locally and in the control room. During emergencies, these trips are automatically bypassed. A high temperature alarm and low expansion tank level will alarm at any time, regardless of engine operating status, locally and in the control room.

During standby, a 15-kw immersion heater heats the jacket water directly and the lube oil indirectly for more reliable starts.

The immersion heaters and radiator fans are powered form MCC 65-1 (75-1).

9.5.9.1.6 Local engine control panels

The main engine control panels (2202 (3)-104, 105, 106, 107) are housed in a common structure. These panels contain engine and generator control, monitoring, and status functions. Local operation of the generator set can be performed from the -105 panel. This panel also contains the local annunciator board and a programmable logic controller (PLC), in which many of the control and monitoring functions are embedded. The -107 panel contains the generator protective relays and the neutral grounding transformer.

9.5.9.1.7 DC battery and switchboard

An independent 125 volt dc battery system for each generator unit will provide the necessary power for 4 kV switchgear control and indications, diesel generator control and indications, lube oil standby circulation, and the uninterruptible power supply (UPS) inverter.

The battery is a 125 Vdc lead-acid battery, rated at 1220 amp-hours, and is contained in its own bermed, ventilated room. The battery, its 300 A stationary battery charger, and a shared maintenance charger connect to dc Switchboard 6A(7A). The switchboards provide feeds to the various dc loads.

The ac source for the stationary battery chargers is MCC 65-1 (75-1).

9.5.9.1.8 Uninterruptible Power Supply (UPS) and panel

The UPS is an independent system which will provide 15 kva single phase power to the local DG control panel and the Distributed Control System (DCS) in the event of loss of normal ac power. The normal source for the UPS panelboard is a 15 kva inverter and dc switchboard. A bypass source is available through a 15 kva single-phase isolimiter transformer whose primary side is fed from MCC 65-1 (75-1).

9.5.9.1.9 4 kv switchgear

Figure 9.5-14 is a single-line diagram showing the 4kv connections between the SBO DGs and the plant safe shutdown buses for both Units 2 and 3.

Dedicated 4 kv switchgear centers 61 (71) are provided for 4 kv connections from the SBO diesel generator to the safety-related 4 kv buses. Bus 61 can be connected to either Bus 23 or 24, but not both simultaneously. Bus 71 can be connected to either Bus 33 or 34, but not both simultaneously. These connections to the safety-related buses are isolated via 2 breakers, one safety-related (located at the safety-related bus) and one non-safety-related (located at Bus 61 (71)), controllable from the main control room.

The safety-related feed breakers from SBO at Bus 23 (33) and 24 (34) all operate similarly. These breakers must be closed manually from control room panel 923-74 before the associated breaker at Bus 61 (71) can be closed. The breakers are tripped manually from control room panel 923-74. The breakers will also trip upon Bus 23 (33) or 24 (34) undervoltage or upon unit LOCA signal being generated, if the SBO mode switch is in the normal mode, as it would be during surveillance test conditions.

The tie breakers at Bus 61 (71) to Buses 23 (33) and 24 (34) all operate similarly. When Bus 23 (33) is deenergized and the SBO mode switch at panel 923 - 74 is in the SBO mode, the feed breaker can be "dead bus " closed. The tie to Bus 24 (34) works similarly. These breakers can be manually tripped under all conditions and will trip automatically should the diesel generator feed breaker trip.

The SBO DG 2(3) generator is connectable to Bus 61 (71) from the main control room. When Bus 61 (71) is deenergized, the SBO mode switch at panel 923-74 can be placed in the SBO mode and the feed breaker can be "dead bus" closed. Once the breaker is closed in this mode, and the diesel generator running in emergency mode, only a manual trip, a bus fault or a select few diesel generator faults will trip this breaker. If the diesel generator is secured from the emergency mode at panel 923-74, a manual trip or any diesel generator trip or normal stop of the diesel generator will trip the breaker.

The normal SBO building power source is supplied from Unit 1 Bus 11 to Bus 61 and 71, when the SBO DG is in standby. This feed is tripped on undervoltage of the respective bus or when the respective mode switch at panel 923-74 is placed in SBO mode.

Buses 61 and 71 can be cross-tied to prevent blacking out half of the SBO Building when normal feed breaker for that half is out-of-service. Interlocks prevent completing the cross-tie if any of the Bus 61 or 71 feed breaker to the safety buses are closed or the SBO DG output breaker is closed. These breakers trip if the respective SBO mode switch is placed in SBO mode or if an undervoltage condition exists on either Bus 61 or 71.

9.5.9.1.10 480 Volt Motor Control Center (MCC)

Dedicated 480 Vac motor control centers (MCC 65-1(75-1)) are provided for distribution of station blackout auxiliary power. The MCC is fed from Bus 61 (71) through 4 kv/480 v transformer 65 (75). Load distribution is provided for the diesel auxiliaries, heating, ventilation and air conditioning, battery chargers, lighting, and welding receptacles.

9.5.9.1.11 Distributed Control System (DCS)

The DCS provides remote operation of some SBO systems, primarily the diesel generator and switchgear control, from the main control room. The DCS receives analog signals and contact open/close signals for monitoring of the SBO systems status. The DCS sends digital outputs for system control via contact open/close changes.

The DCS central processing unit, touch screen control console, and other controls are located in main control room panel 923-74.

9.5.9.1.12 Fire protection system

The SBO Building and equipment are protected from fire by fire hoses in the main rooms of the building and a wet pipe sprinkler system in each of the diesel rooms and day tank rooms. The source of water is the main fire ring header. Alarms are generated when these water systems are actuated.

A smoke and heat detection system is installed in the rest of the SBO building and supervised by the plant XL-3 Pyrotronics system. The power for this function comes from MCC 75-1.

9.5.9.2 Capacity of SBO Diesel Generators

Two SBO diesel generators are installed at Dresden. The capacity of each of these generators is 4350 kw continuous, with a 2000-hour rating of 4785 kw. This capacity is sufficient to power one division of safe shutdown loads needed in dealing with a station blackout event. The SBO event loading scenario was developed on a per station per division basis with the aid of station operators and considered a reactor initially a full power and an indefinite SBO event duration (except for refilling the fuel oil storage tank). The worst-case divisional load requirements at either Dresden or Quad Cities was then used as the design basis for the minimum generator capacity. This capacity easily envelopes the load requirements for a LOOP or LOCA event as defined in the UFSAR Tables 8.3-2 and 8.3-3. Additional capacity to reduce the need for operator manual load-shedding and provide a contingency margin of 10% was added to this minimum capacity.

Initial system tests have demonstrated that the capacity of 4785 kw is achievable. In addition, a more rigorous initial test of the Unit 2 generator capacity was performed by picking up plant loads on isolated plant buses in a stepwise fashion, more accurately simulating emergency conditions. During this test, the following loads were successfully accelerated to rated speed without violating the criteria for allowable voltage and speed drop during the transient.

2 CCSW pumps,
2 LPCI pumps,
1 Core spray pump,
1 Service water pump,
3 Drywell coolers,
2 RB exhaust fans,
1 RB vent fan, and
Various other 480 volt loads - for a total loading of 3650 kw (2200 kvar).

The Unit 3 generator response and capacity is similar. Actual loading of the SBO generators, during a station blackout event or a less severe event, will be done manually by the operators under the guidance of procedure DGA-12 and the Dresden Emergency Operating Procedures (DEOPs).

9.5.9.3 Connectability to Safety-Related 4 KV Buses

Although not normally connected to any bus, the configuration of the SBO 4 kv distribution system allows connection of each SBO DG to any of the four safety-related emergency buses. Figure 9.5-14 shows that the Unit 2(3) SBO DG feed, Bus 61(71) in the SBO Building which then connects to either Bus 23(33) or 24 (34). These connections will be isolatable via a two breaker system, that is, one safety-related and one non-safety related breaker in each line-up. During emergency conditions, Bus 23-1(33-1) or 24-1(34-1) will then be connected to the SBO DG. If conditions require, the safety-related cross-tie between Bus 23-1 and 33-1 or between 24-1 and 34-1 can be utilized so that the Unit 2 SBO DG can supply power to Unit 3 loads and vice versa.

9.5.9.4 Modes of Operation

The control logic for starting and loading the emergency diesel generators is not affected by any of the station blackout controls.

Under conditions of total or partial loss of offsite power, the SBO DGs can either be remotely or locally started in the emergency mode in which the engine will immediately accelerate to rated speed and almost all trips are bypassed. Dead bus connections can be made to allow the SBO DGs to provide power to safe shutdown plant loads. Emergency operation is designed to utilize the programmable logic controller (PLC) in panel 2202(3)-105. If a failure is detected in the PLC, the generator set can still be started and controlled locally in the PLC Bypass mode; however, the emergency start pushbutton must be depressed which provides for a fast start and bypassed trips. The trips which are not bypassed during emergency condition, are:

Engine overspeed
Generator ground fault (59G)
Generator differential (87)

The generator trips require resetting a lockout relay at the SBO switchgear and the overspeed trip requires resetting an engine latch.

Prior to starting the engines for surveillance tests (i.e. non-emergency conditions), the lube oil valves can be manually configured to provide prelubrication of the engine bearings and rocker arm assemblies while the engine is barred over. The engines can then be remotely started in the normal mode in which the engine heatup for 5 minutes at idle speed prior to going to rated speed with all trips enabled. Synchronized breaker closings connect the generator set to the plant safety buses and off-site power for loading. A local normal (non-emergency) start is also possible; however, synchronized breaker closings must still be performed remotely. In addition to the trips enabled in the emergency mode, the following trips are enabled in the normal mode:

Engine A/B Lube Oil Pressure LO-LO
Engine A/B Jacket Water Pressure LO
Engine A/B Jacket Water Temperature HI-HI
Engine A/B Crankcase Pressure HI
Generator Overcurrent
Generator Negative Sequence
Generator Loss of Field
Generator Neutral Overvoltage
Generator Reverse Power

A local or remote emergency stop is provided which will immediately stop the engine and trip the output breaker. A local or remote normal stop can also be performed, if the diesel generator is in the normal mode, which will trip the generator feed breaker and run the engine at idle speed for a 10 minute cooldown before stopping.

A four-position control switch ("LOCKOUT/REMOTE/LOCAL/PLC BY-PASS") at panel 2202(3)-105 controls some of the generator set functions. In the LOCKOUT position, the engine starting air solenoids are prevented from being energized. This switch position is used when taking the generator set out-of-service. In the REMOTE position, normal starting and stopping of the generator set can only be done from the main control room. In the LOCAL position, normal starting and stopping can only be done from the SBO Building. Emergency starting or stopping can be done either remotely or locally regardless of the switch position in LOCAL or REMOTE. In the PLC BYPASS position, critical engine controls (starting, stopping, non-bypassed trips) which otherwise are provided by the PLC, are bypassed in favor of hard-wired control circuitry. Only a local emergency start is possible and the start pushbutton must be depressed continually until the starters disengage automatically above 200 rpm.

Control of generator loading via voltage and speed controls can be done remotely or locally regardless of the REMOTE/LOCAL switch position.

9.5.9.5 Remote Control of SBO Diesel Generators

The SBO system is designed to provide remote operations from the main control room. These operations include start and control of the diesel generators and auxiliaries, manipulation of the 4 kv connections, and loading of the diesel generators. This remote operation is accomplished via a Distributed Control System (DCS). The diesel generators can be manually started and manually loaded from the DCS and main control room panels.

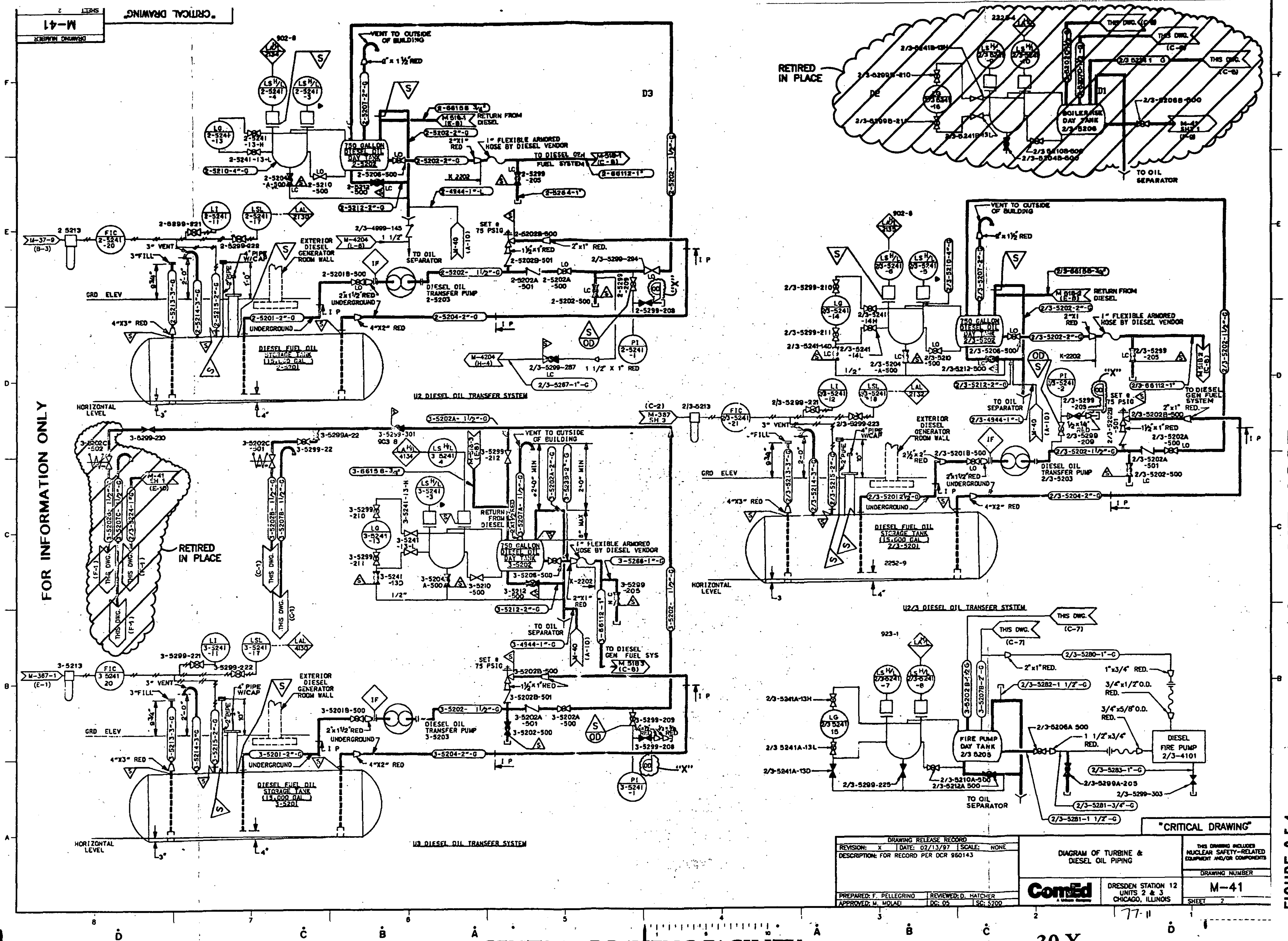
9.5.10 References

1. Commonwealth Edison Company, "Dresden Units 2 and 3 Fire Protection Reports, Volumes 1 through 5, and Fire Protection Program Documentation Package, Volumes 1 through 13," Current Amendment.

2. QAL 12-87-197 Quality Assurance, Dresden Station, August 28, 1987.

3. Sargent & Lundy Specification K-2183, "Specification for Generator Sets."

4. Integrated Plant Safety Assessment Final Report, Systematic Evaluation Program, Dresden Nuclear Power Station, Unit 2, NUREG-0823, Supplement No. 1, October 1989, Section 2.3.2.



CENTRAL DRAWING FACILITY

30 X

FIGURE 9.5-1

REV. 02 / JUNE 1997

FOR INFORMATION ONLY

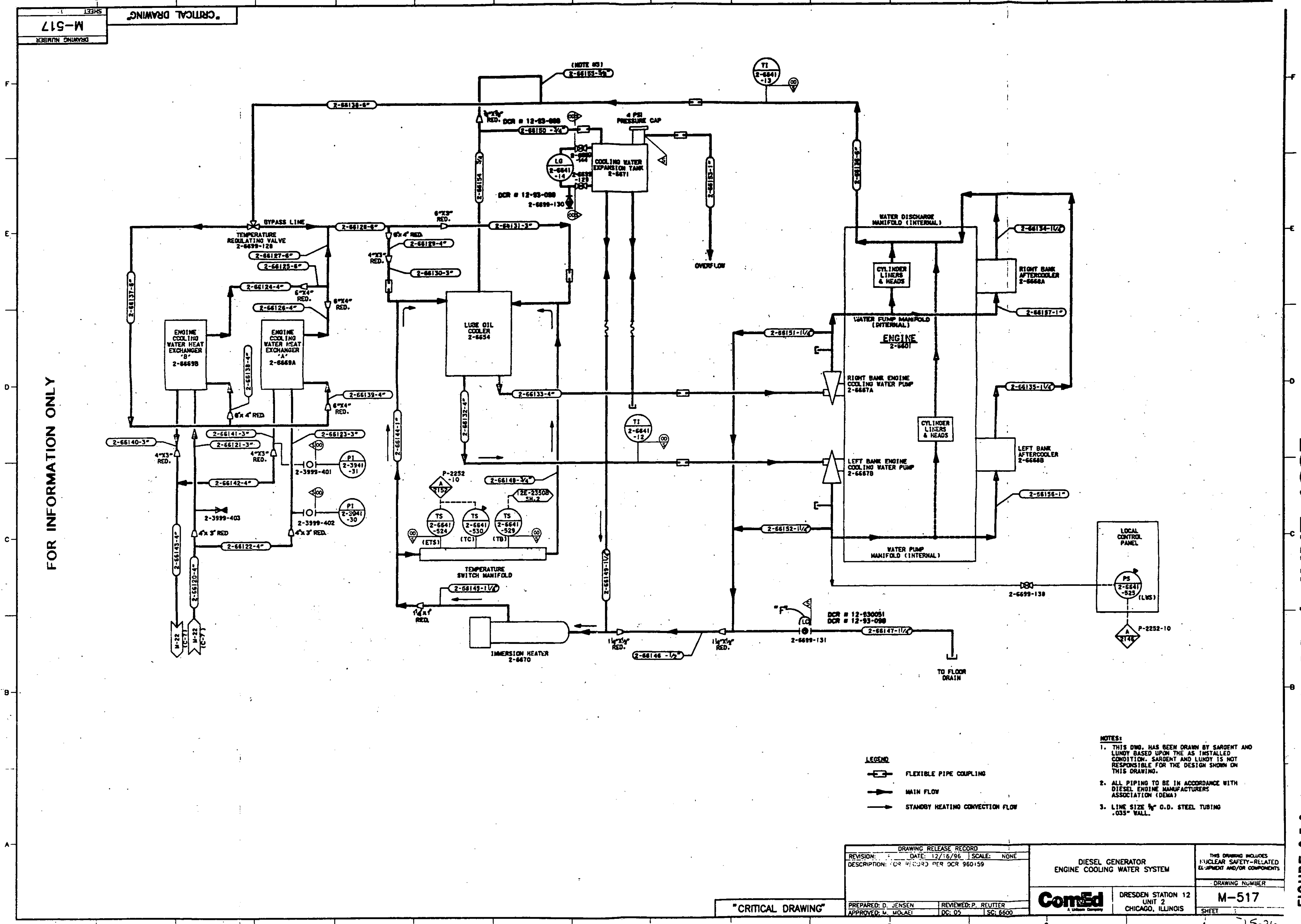
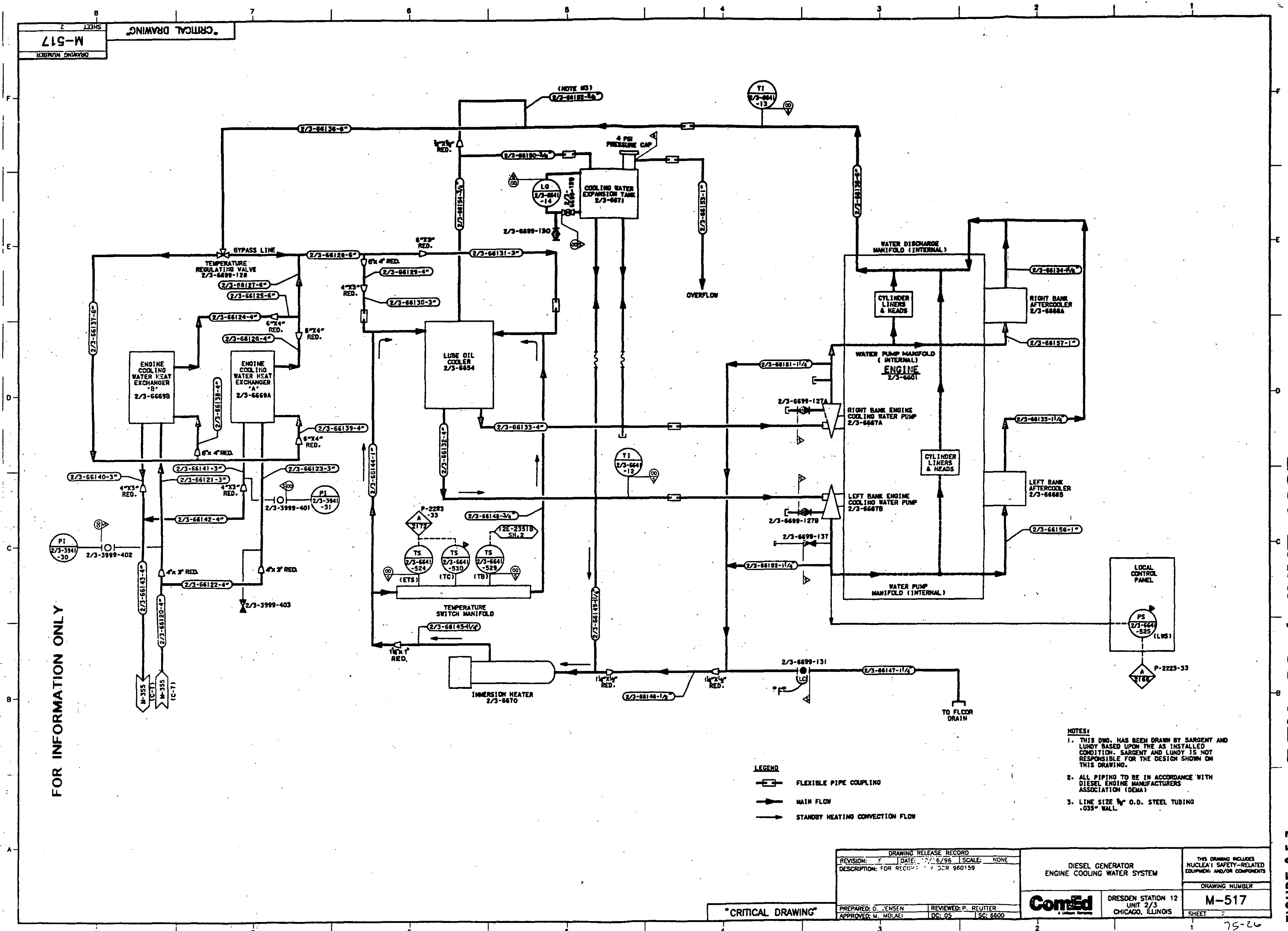


FIGURE 9.5-6

REV. 02 / JUNE 1997

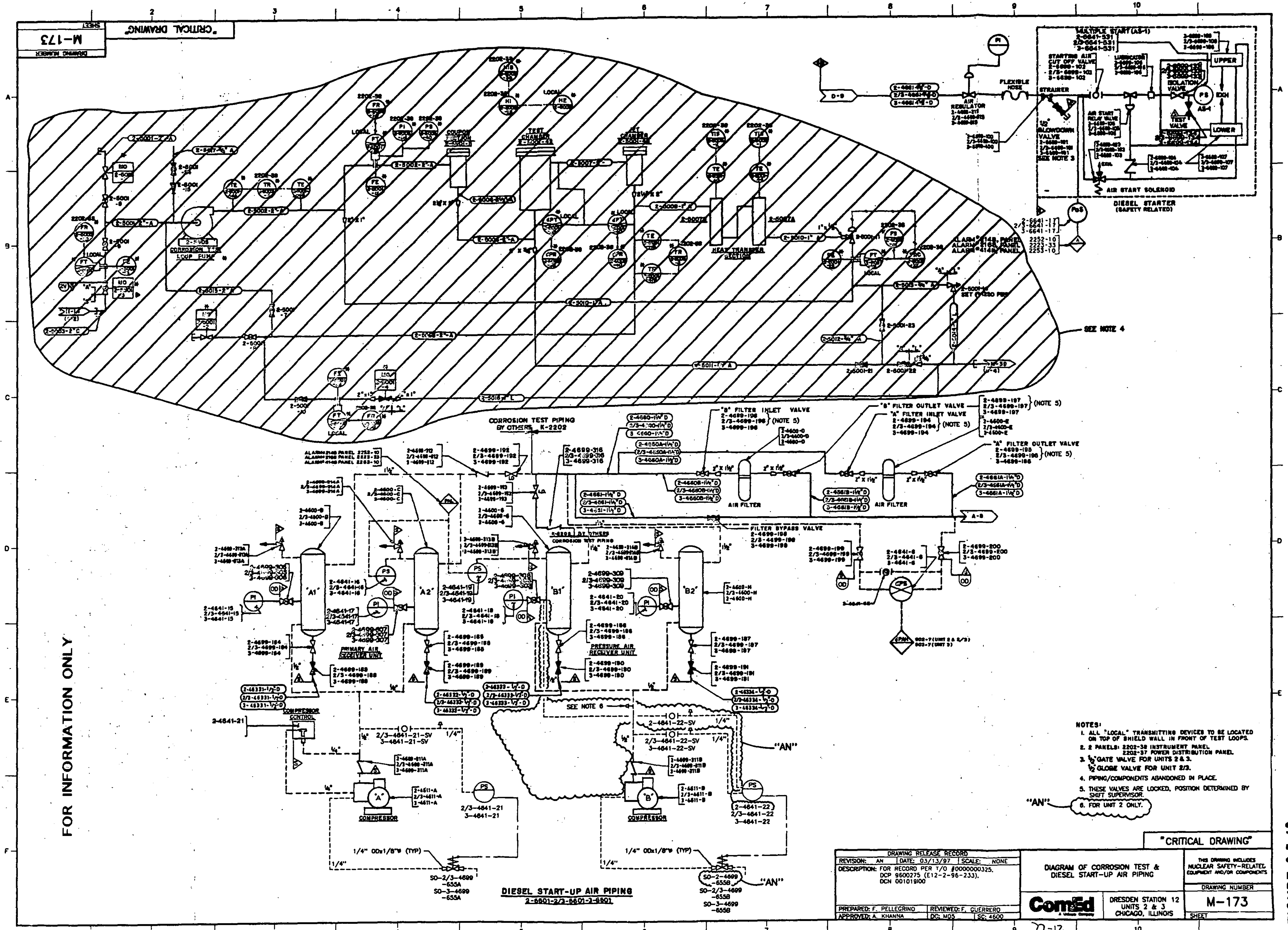
CENTRAL DRAWING FACILITY 30 X



REV. 02 / JUNE 1997

FIGURE 9.5-7

CENTRAL DRAWING FACILITY 30 X



CENTRAL DRAWING FACILITY

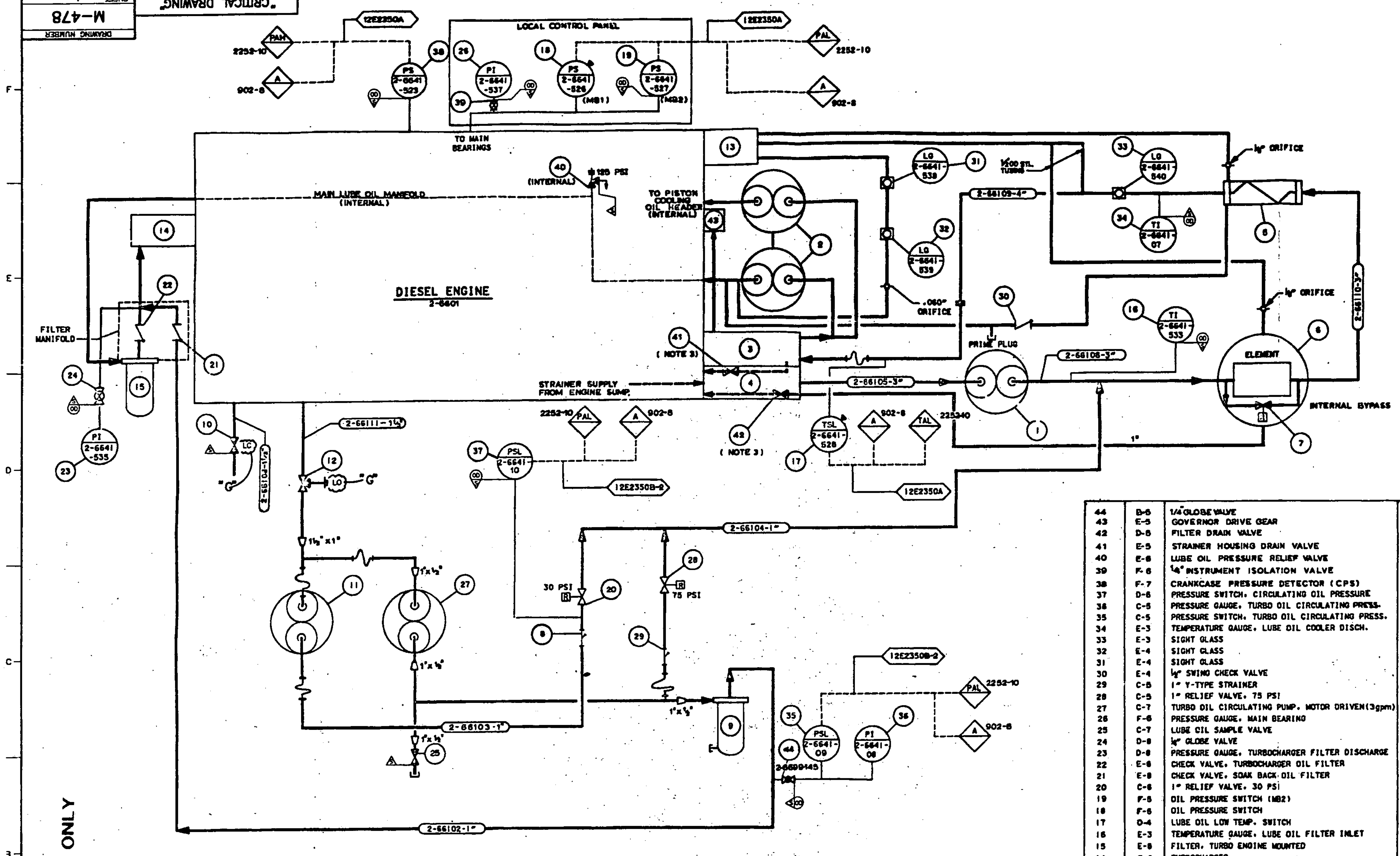
30 X

REV. 02 / JUNE 1997

FIGURE 9.5-10

"CRITICAL DRAWING"

DRAWING NUMBER M-478 SHEET 1



FOR INFORMATION ONLY

NOTES:

1. THIS DWG. HAS BEEN DRAWN BY SARGENT & LUNDY BASED UPON THE AS INSTALLED CONDITION. SARGENT & LUNDY IS NOT RESPONSIBLE FOR THE DESIGN SHOWN ON THIS DRAWING. ALL PIPING SHOWN SUPPLIED BY VENDOR.
2. ALL PIPING TO BE IN ACCORDANCE WITH DIESEL ENGINE MANUFACTURER'S ASSOCIATION (DEMA).
3. VALVE INTERNAL TO SCAVENGING PUMP STRAINER.

ITEM NO.	ZONE	NOMENCLATURE OR DESCRIPTION	EQUIPMENT IDENTIFICATION NUMBER	PART OR IDENTIFYING NO.	QTY.
44	D-6	1/4" GLOBE VALVE	2-6699-145		1
43	E-5	GOVERNOR DRIVE GEAR			1
42	D-6	FILTER DRAIN VALVE	2-6699-140		1
41	E-5	STRAINER HOUSING DRAIN VALVE	2-6699-141		1
40	E-6	LUBE OIL PRESSURE RELIEF VALVE	2-6699-143		1
39	F-6	1/4" INSTRUMENT ISOLATION VALVE	2-6699-142		1
38	F-7	CRANKCASE PRESSURE DETECTOR (CPS)	2-6641-523		1
37	D-6	PRESSURE SWITCH, CIRCULATING OIL PRESSURE	2-6641-10	8342487 (EMD)	1
36	C-5	PRESSURE GAUGE, TURBO OIL CIRCULATING PRESS.	2-6641-08	TYPE 213 (WIKA)	1
35	C-5	PRESSURE SWITCH, TURBO OIL CIRCULATING PRESS.	2-6641-09	8341873 (EMD)	1
34	E-3	TEMPERATURE GAUGE, LUBE OIL COOLER DISCH.	2-6641-07	9088874 (EMD)	1
33	E-3	SIGHT GLASS	2-6641-540	9327526 (EMD)	1
32	E-4	SIGHT GLASS	2-6641-539	9327526 (EMD)	1
31	E-4	SIGHT GLASS	2-6641-538	9327526 (EMD)	1
30	E-4	1/2" SWING CHECK VALVE	2-6699-114	92-A (JENKINS)	1
29	C-5	1" Y-TYPE STRAINER	2-6661	352 (MUELLER)	1
28	C-5	1" RELIEF VALVE, 75 PSI	2-6699-113	416-C-1-75 (KEPNER)	1
27	C-7	TURBO OIL CIRCULATING PUMP, MOTOR DRIVEN(3gpm)	2-6660	ILE (TUTHILL)	1
26	F-6	PRESSURE GAUGE, MAIN BEARING	2-6641-537		1
25	C-7	LUBE OIL SAMPLE VALVE	2-6699-117		1
24	D-8	1/2" GLOBE VALVE	2-6699-118		1
23	D-8	PRESSURE GAUGE, TURBOCHARGER FILTER DISCHARGE	2-6641-535		1
22	E-8	CHECK VALVE, TURBOCHARGER OIL FILTER	2-6699-120		1
21	E-8	CHECK VALVE, SOAK BACK OIL FILTER	2-6699-119		1
20	C-6	1" RELIEF VALVE, 30 PSI	2-6699-110		1
19	F-5	OIL PRESSURE SWITCH (MB2)	2-6641-527		1
18	F-6	OIL PRESSURE SWITCH	2-6641-526		1
17	D-4	LUBE OIL LOW TEMP. SWITCH	2-6641-528		1
16	E-3	TEMPERATURE GAUGE, LUBE OIL FILTER INLET	2-6641-533		1
15	E-8	FILTER, TURBO ENGINE MOUNTED	2-6659		1
14	E-8	TURBOCHARGER	2-6658		1
13	F-5	CAMSHAFT COUNTER-WEIGHT HOUSING			1
12	D-7	1 1/2" 3-WAY VALVE	2-6699-112		1
11	C-7	LUBE OIL CIRCULATING PUMP, MOTOR DRIVEN(6gpm)	2-6657	8274509 (EMD)	1
10	D-8	1 1/2" DRAIN VALVE	2-6699-111		1
9	C-5	AUX.TURBOCHARGER LUBE OIL FILTER	2-6656	8379120 (EMD)	1
8	C-6	1"-"Y" TYPE STRAINER	2-6672		1
7	D-2	RELIEF VALVE, 40 PSI	2-6699-109		1
6	D-2	LUBE OIL FILTER	2-6655	8362640 (EMD)	1
5	E-2	LUBE OIL COOLER	2-6654	8271246 (EMD)	1
4	D-5	SCAVENGING PUMP STRAINER	2-6653		1
3	E-5	LUBE OIL STRAINER	2-6652	8186637 (EMD)	1
2	E-5	MAIN LUBE & PISTON COOLING PUMP, ENGINE DRIVEN	2-6651A & B	8360537 (EMD)	2
1	D-3	SCAVENGING PUMP, ENGINE DRIVEN	2-6650	8252720B (EMD)	1

DRAWING RELEASE RECORD
REVISION: G | DATE: 12/16/96 | SCALE: NONE
DESCRIPTION: FOR RECORD PER DCR 960159

PREPARED: D. JENSEN | REVIEWED: P. REUTTER
APPROVED: M. MOLAEI | DC: 05 | SC: 5200

"CRITICAL DRAWING"

DIAGRAM OF DIESEL GENERATOR LUBE OIL PIPING

ComEd A Unicom Company

DRESDEN STATION 12 UNIT 2 CHICAGO, ILLINOIS

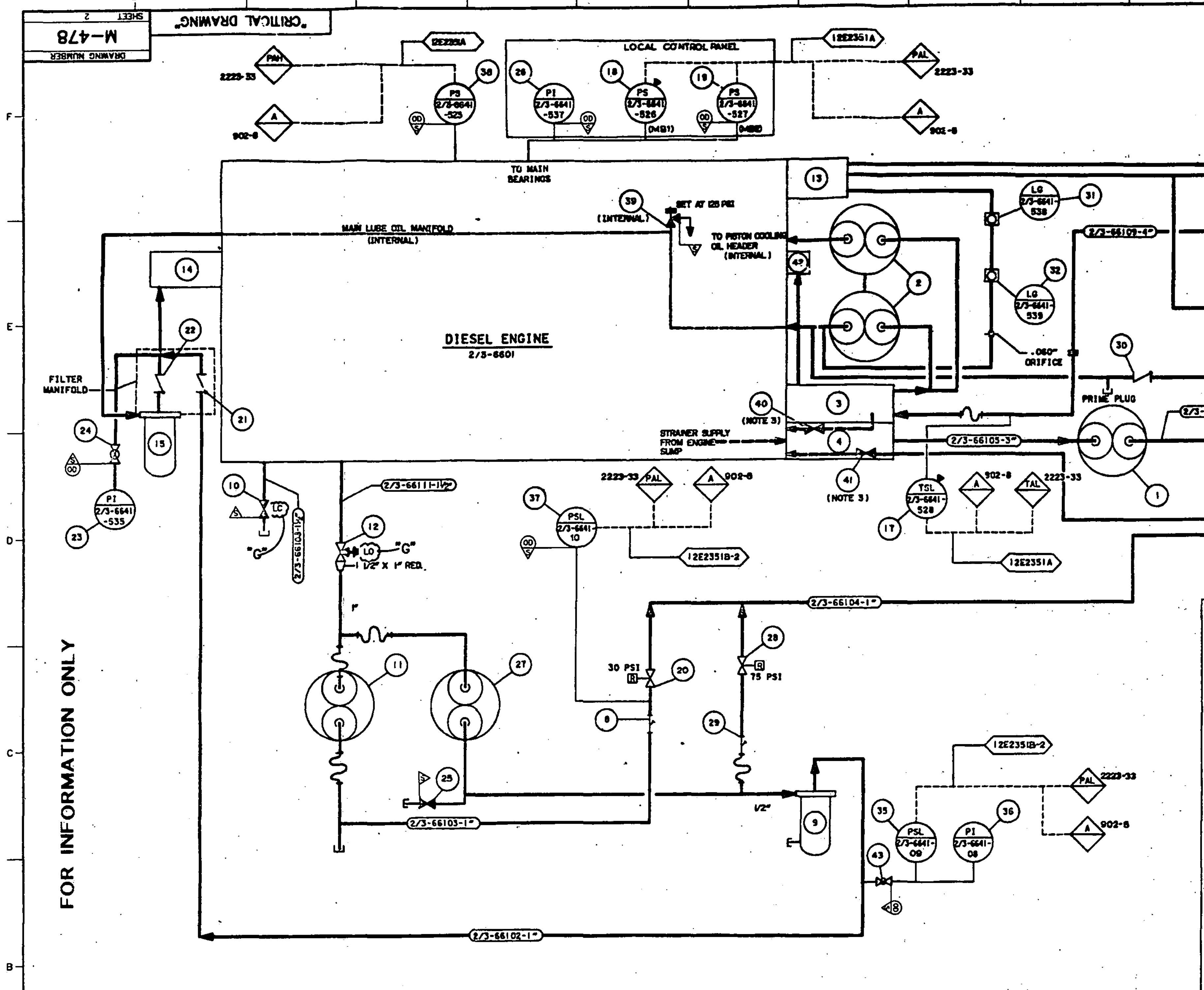
THIS DRAWING INCLUDES NUCLEAR SAFETY-RELATED EQUIPMENT AND/OR COMPONENTS

DRAWING NUMBER M-478 SHEET

FIGURE 9.5-11

REV. 02 / JUNE 1997

FOR INFORMATION ONLY



NOTES:

1. THIS DWG. HAS BEEN DRAWN BY SARGENT & LUNDY BASED UPON THE AS INSTALLED CONDITION. SARGENT & LUNDY IS NOT RESPONSIBLE FOR THE DESIGN SHOWN ON THIS DRAWING. ALL PIPING SHOWN SUPPLIED BY VENDOR.
2. ALL PIPING TO BE IN ACCORDANCE WITH DIESEL ENGINE MANUFACTURER'S ASSOCIATION (DEMA).
3. VALVE INTERNAL TO SCAVENGING PUMP STRAINER.

ITEM NO.	ZONE	NOMENCLATURE OR DESCRIPTION	EQUIPMENT IDENTIFICATION NUMBER	PART OR IDENTIFYING NO.	QTY.
43	B-6	1/4 GLOBE VALVE	2/3-6699-145		1
42	E-5	GOVERNOR DRIVE GEAR			1
41	D-5	FILTER DRAIN VALVE	2/3-6699-140		1
40	E-5	STRAINER HOUSING DRAIN VALVE	2/3-6699-141		1
39	E-6	LUBE OIL PRESSURE RELIEF VALVE	2/3-6699-143		1
38	F-7	CRANKCASE PRESSURE DETECTOR (CPS)	2/3-6641-523		1
37	D-6	PRESSURE SWITCH, CIRCULATING OIL PRESSURE	2/3-6641-10	8342487 (EMD)	1
36	C-5	PRESSURE GAUGE, TURBO OIL CIRCULATING PRESS.	2/3-6641-08	TYPE 213 (WIKA)	1
35	C-5	PRESSURE SWITCH, TURBO OIL CIRCULATING PRESS.	2/3-6641-09	8341873 (EMD)	1
34	E-3	TEMPERATURE GAUGE, LUBE OIL COOLER DISCH.	2/3-6641-07	9086874 (EMD)	1
33	E-3	SIGHT GLASS	2/3-6641-540	9327526 (EMD)	1
32	E-4	SIGHT GLASS	2/3-6641-539	9327526 (EMD)	1
31	E-4	SIGHT GLASS	2/3-6641-538	9327526 (EMD)	1
30	E-4	1/2" SWING CHECK VALVE	2/3-6699-114	92-A (JENKINS)	1
29	C-6	1" Y-TYPE STRAINER	2/3-6661	552 (MUELLER)	1
28	C-5	1" RELIEF VALVE, 75 PSI	2/3-6699-113	416-C-1-75 (KEPNER)	1
27	C-7	TURBO OIL CIRCULATING PUMP, MOTOR DRIVEN(3gpm)	2/3-6660	ILE (TUTHILL)	1
26	F-6	PRESSURE GAUGE, MAIN BEARING	2/3-6641-537		1
25	C-7	LUBE OIL SAMPLE VALVE	2/3-6699-117		1
24	D-8	1/2" GLOBE VALVE	2/3-6699-118		1
23	D-8	PRESSURE GAUGE, TURBOCHARGER FILTER DISCHARGE	2/3-6641-535		1
22	E-8	CHECK VALVE, TURBOCHARGER OIL FILTER	2/3-6699-120		1
21	E-8	CHECK VALVE, SOAK BACK OIL FILTER	2/3-6699-119		1
20	C-6	1" RELIEF VALVE, 30 PSI	2/3-6699-110		1
19	F-6	OIL PRESSURE SWITCH (MB2)	2/3-6641-527		1
18	F-6	OIL PRESSURE SWITCH	2/3-6641-526		1
17	D-4	LUBE OIL LOW TEMP. SWITCH	2/3-6641-528		1
16	E-3	TEMPERATURE GAUGE, LUBE OIL FILTER INLET	2/3-6641-533		1
15	E-8	FILTER, TURBO ENGINE MOUNTED	2/3-6659		1
14	E-8	TURBOCHARGER	2/3-6658		1
13	F-5	CAMSHAFT COUNTER-WEIGHT HOUSING			1
12	D-7	1 1/2" 3-WAY VALVE	2/3-6699-112		1
11	C-7	LUBE OIL CIRCULATING PUMP, MOTOR DRIVEN(6gpm)	2/3-6657	8274509 (EMD)	1
10	D-8	1 1/2" DRAIN VALVE	2/3-6699-111		1
9	C-5	AUX.TURBOCHARGER LUBE OIL FILTER	2/3-6656	8379120 (EMD)	1
8	C-6	1"-"Y" TYPE STRAINER	2/3-6672		1
7	D-2	RELIEF VALVE, 40 PSI	2/3-6699-109		1
6	D-2	LUBE OIL FILTER	2/3-6655	8362640 (EMD)	1
5	E-2	LUBE OIL COOLER	2/3-6654	8271246 (EMD)	1
4	D-5	SCAVENGING PUMP STRAINER	2/3-6653		1
3	E-6	LUBE OIL STRAINER	2/3-6652	8186637 (EMD)	1
2	E-5	MAIN LUBE & PISTON COOLING PUMP, ENGINE DRIVEN	2/3-6651A & B	8360537 (EMD)	2
1	D-3	SCAVENGING PUMP, ENGINE DRIVEN	2/3-6650	82527208 (EMD)	1

DRAWING RELEASE RECORD
REVISION: C DATE: 12/16/96 SCALE: NONE
DESCRIPTION: FCR RECORD PER DCR 960159

PREPARED: D. JENSEN REVIEWED: P. REUTTER
APPROVED: M. MOLAEI DC: 05 SC: 5200

"CRITICAL DRAWING"

DIAGRAM OF DIESEL GENERATOR LUBE OIL PIPING

ComEd A Unicom Company

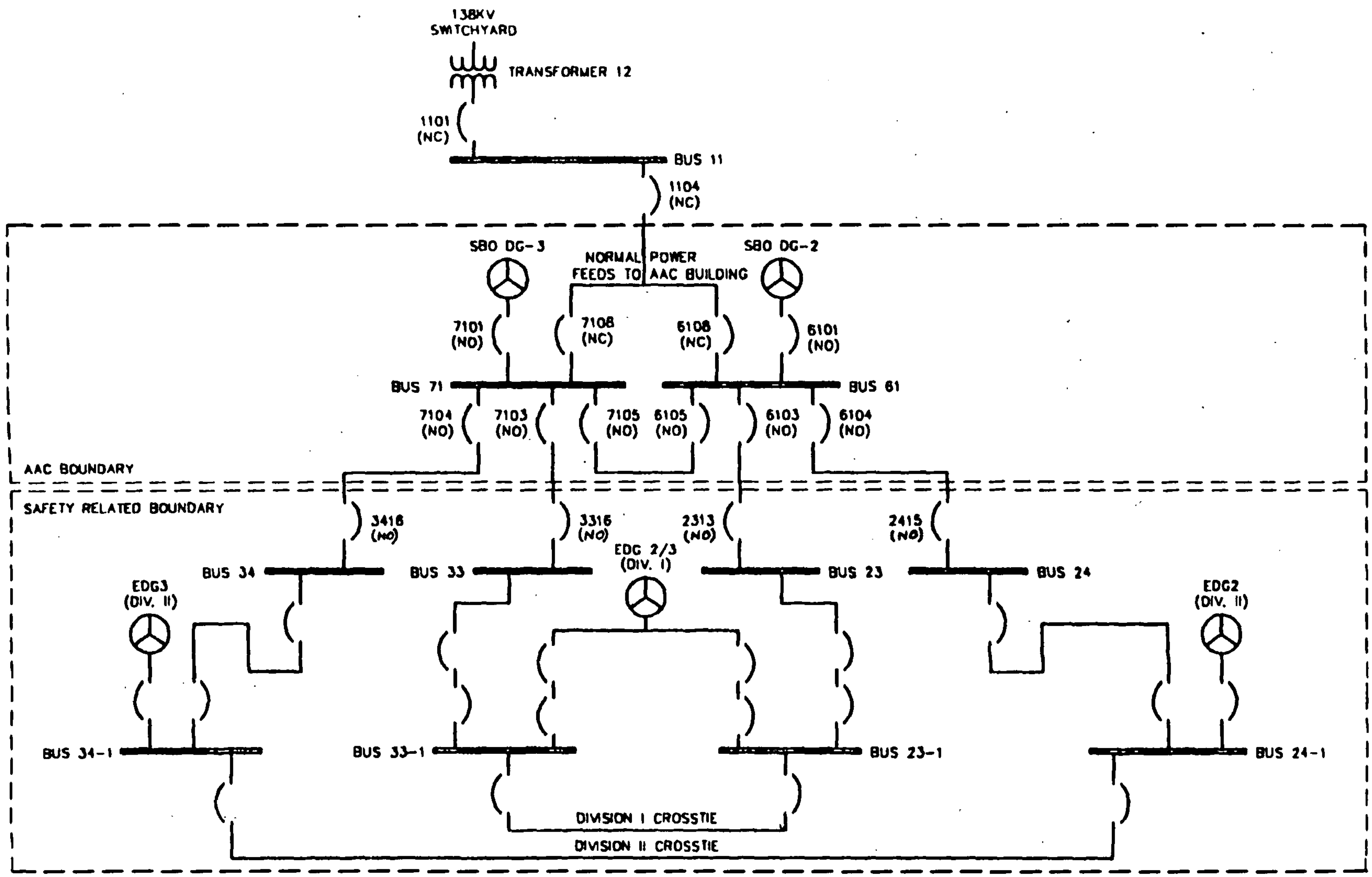
DRESDEN STATION 12
UNIT 2/3
CHICAGO, ILLINOIS

THIS DRAWING INCLUDES NUCLEAR SAFETY-RELATED EQUIPMENT AND/OR COMPONENTS

DRAWING NUMBER
M-478
SHEET 2

75-26

FIGURE 9.5-12 REV. 02 / JUNE 1997



DRESDEN STATION
UNITS 2 & 3

SINGLE-LINE ELECTRICAL DIAGRAM OF STATION BLACKOUT GENERATOR TIES TO PLANT AUXILIARY ELECTRIC SYSTEM

FIGURE 9.5-14

10.0 STEAM AND POWER CONVERSION SYSTEM
TABLE OF CONTENTS

10.0 STEAM AND POWER CONVERSION SYSTEM
LIST OF FIGURES

10.2 TURBINE-GENERATOR

10.2.1 Design Bases

The turbine-generator system converts the thermodynamic energy of steam into electrical energy. The turbine-generator was designed to the following specifications:

Steam Conditions:	
Throttle Pressure	950 psig
Quality	Saturated with 0.28% moisture
Exhaust Pressure	1.5 in.Hg abs.

The inlet pressure of the turbine is dictated by the choice of the optimum reactor pressure. As limited by the interfacing equipment, saturated steam quality is maintained as high as possible to minimize blade erosion, and exhaust pressure is maintained as low as possible for maximum turbine efficiency.

There are no industry codes related to the design, manufacture, or installation of the turbine rotor. The turbine and all components, including the turbine rotor, were designed in accordance with the manufacturer's standards.[1]

10.2.2 Description

The turbine-generator system consists of the turbine, generator, exciter, controls, and required subsystems.

The turbine is an 1800 rpm, tandem-compound, six-flow, nonreheat steam turbine. The turbine is designed for saturated steam conditions of 950 psig with 0.28% moisture, 1.5 inches mercury absolute exhaust pressure, and 0.5% makeup while extracting steam for four stages of feedwater heating (see Figure 10.3-2 [Drawing M-12, Sheet 2], and Figure 10.4-10 [Drawing M-13]). The turbine unit consists of one double-flow, high-pressure element, and three double-flow, low-pressure elements. Exhaust steam from the high-pressure element passes through moisture separators before entering the three low-pressure elements. The low-pressure elements have 38-inch last stage buckets. The separators reduce the moisture content of the steam to less than 1% by weight.

The generator is directly driven from the turbine shaft and is rated at 920,350 kVA at a 0.9 power factor and 0.58 short circuit ratio. It is a synchronous generator with a 60-Hz, 18,000 V output at 1800 rpm. The generator armature and stator are cooled by hydrogen. The design operating pressure for the generator hydrogen system is 60 psig. Stator internals are water cooled. Generator-excitation is provided by an Alterrex exciter rated at 1910 kVA at a 0.95 power factor and 375 Vac. The ac output of the exciter is rectified to dc before feeding the main generator field. The main generator field is rated at 3592 A and 500 Vdc.

Turbine steam flow is controlled by a set of four hydraulically operated turbine control valves on the high-pressure element main steam supply as shown in Figure 10.3-2. Four hydraulically operated main steam stop valves provide isolation of the main steam supply to the turbine. High-pressure element exhaust steam is routed to four moisture separators prior to entering the low-pressure elements. Steam flow from the moisture separators to the low-pressure elements is controlled by the combined intermediate valves (CIVs). Each CIV includes an intercept valve and an intermediate stop valve. The intercept valves throttle to control flow from the moisture separators during turbine overspeed conditions and the intermediate stop valves provide isolation between the moisture separators and the low-pressure elements (similar to the turbine control valves and main steam stop valves on the main steam supply).

Turbine controls include a speed control unit, a load control unit, a bypass control unit, a flow control unit, and a pressure control unit. An electrohydraulic control (EHC) system integrates the electronic control circuits with the hydraulic system. The EHC system positions the turbine control and bypass valves to control reactor pressure and consequently generator load and turbine speed and is driven by a pair of pressure regulators. Refer to Section 7.7 for a description of the turbine control system.

The unit follows system load by adjusting the reactor power level. Power level can be adjusted by regulating the reactor recirculating flow or by moving control rods. The economic generation control (EGC) system, together with the turbine control system, provides an automatic load control feature which can be used with automatic recirculation flow control in the 65 — 100% range of rated core flow with reactor power at or above 20%, per Technical Specification 3.3/4.3.N. The EGC system is discussed in Section 7.7.

The turbine speed governor can override the pressure regulator and close the turbine control valves and intercept valves when an increase in system frequency or a loss of generator load causes the speed of the turbine to increase. In the event that the reactor is delivering more steam than the turbine control valves will pass, up to 40% of rated steam flow can be routed directly to the main condenser via a set of nine bypass valves. The bypass valves are controlled by the EHC system as part of the overall reactor pressure control scheme. The turbine-generator load controls are designed for a 20 MWe gross per second maximum rate of change of power demand.

The EHC system oil is supplied through numerous interconnected or interacting subsystems. Some of these are the fluid actuator supply (FAS), fluid actuator supply trip controlled (FASTC), and fluid jet supply (FJS) subsystems.

The FAS subsystem supplies the actuators for the main and intermediate stop valves, and the actuators for the bypass valves. FAS supplies the servo unit for No. 2 main steam stop valve via a ported manifold block between the servo unit and the control pac on the valve. FAS also supplies the FASTC subsystem through an orifice and relay trip valve. The FASTC subsystem supplies the actuators for the intercept and control valves. In addition, FASTC supplies the FJS to the servo units on the turbine control valves and No. 1, No. 3, and No. 5 intercept valves via a ported manifold block between the servo unit and the control pac. The FJS subsystem supplies the servo units for the bypass valves directly from the hydraulic power unit.

10.2.3.2 Inservice Inspection and Testing

Tests and inspections are conducted to ensure adequate functional performance as required for continued safe operation and to provide maximum protection for operating personnel. One of these tests is periodic exercising of the main steam stop valves and the bypass valves. Each main steam stop valve is tested individually to full closure. The valves will close only 10% when multiple valves are tested simultaneously. The test procedure requires individual valve testing using individual test buttons to minimize the possibility of a transient. Other control valves not normally in motion are also periodically exercised. Mechanical and electrical overspeed trips are tested periodically.

During operation, prior to entering the EGC load control scheme, the EGC operating parameters are reviewed for acceptability in accordance with Technical Specification 3.3/4.3.N. The turbine, including rotors, is inspected periodically at intervals recommended by the vendor to preclude the probability of turbine missiles due to stress corrosion cracking of the turbine disk.[1]

Acceptance testing and operability verification of the new rotors have been performed using manufacturer's procedures, station start-up procedures, and engineering department procedures.

10.2.4 Evaluation

The effects of component failures in this system have been evaluated in detail. The turbine system component failure events having the most significant effects on the plant are as follows:

A. Generator load rejection without bypass;

B. Turbine trip, coincident with failure of the turbine bypass system;

C. Inadvertent closure of main steam isolation valves;

D. Turbine trip (main steam stop valve closure);

E. Loss of EHC system oil pressure;

F. Loss of condenser vacuum; and

G. Steam pressure regulator malfunction or failure.

Descriptions of these failures is contained in Chapter 15 and Section 5.2.2.

Commonwealth Edison Company's experience with turbines in its nuclear power plants has not shown significant radioactive contaminants during maintenance. A radiological evaluation of the turbine system is provided in Chapters 11 and 12.

manifold. From the turbine bypass manifold, nine 8-inch lines connect to the turbine bypass valves, which discharge to the main condenser through horizontal perforated pipes located immediately below the tube bundles. The perforations are directed downward onto the condensate in the collecting trays. A maximum of 40% of rated steam flow can be bypassed to the main condenser.

From the main steam equalizing header, each of the four main steam lines passes through main steam stop valves and turbine control valves, then discharges to the high-pressure turbine.

Drains are provided at several locations along the main steam system to drain condensate from the line and return it to the condenser.

The main steam stop valves are described in Section 10.2. Steam pressure and flow measuring devices are described in Chapter 7.

10.3.3 Evaluation

Leakage from the MSS into the steam tunnel is evaluated in Section 15.6.

Evaluations of the MSS response to seismic and pipe break events is contained in Chapter 3.

10.3.4 Inspection and Testing Requirements

Inspection and testing for the main steam piping are essentially the same as those described in Section 5.2 for the primary process piping in general.

Portions of the main steam system within the primary containment are provided with removable thermal insulation to enable periodic inspection in accordance with the Technical Specifications.

Components and piping for the MSS were originally hydrostatically tested in accordance with ASA B-31.1. Inspection and acceptance standards were in accordance with ASME Code, Section VIII. All circumferential butt welds for 2½-inch diameter piping and larger were specified to be 100% radiographed in compliance with paragraph UW51 of ASME Code, Section VIII.

Inservice inspection (ISI) of the MSS is outlined in Section 6.6. Testing of the main steam stop valves is addressed in Section 10.2. Testing of the MSIVs is addressed in Section 6.2.

The opening times of the main turbine bypass valves are measured after any maintenance is performed that may affect the operation of the bypass system but at least once per refuel outage prior to unit startup. The results are used to confirm that the appropriate bypass valve opening times were used to establish the OLMCPR, which is presented in the Core Operating Limits Report (COLR).

10.3.5 Water Chemistry Pressurized Water Reactor (PWR)

This section is not applicable to Dresden Station.

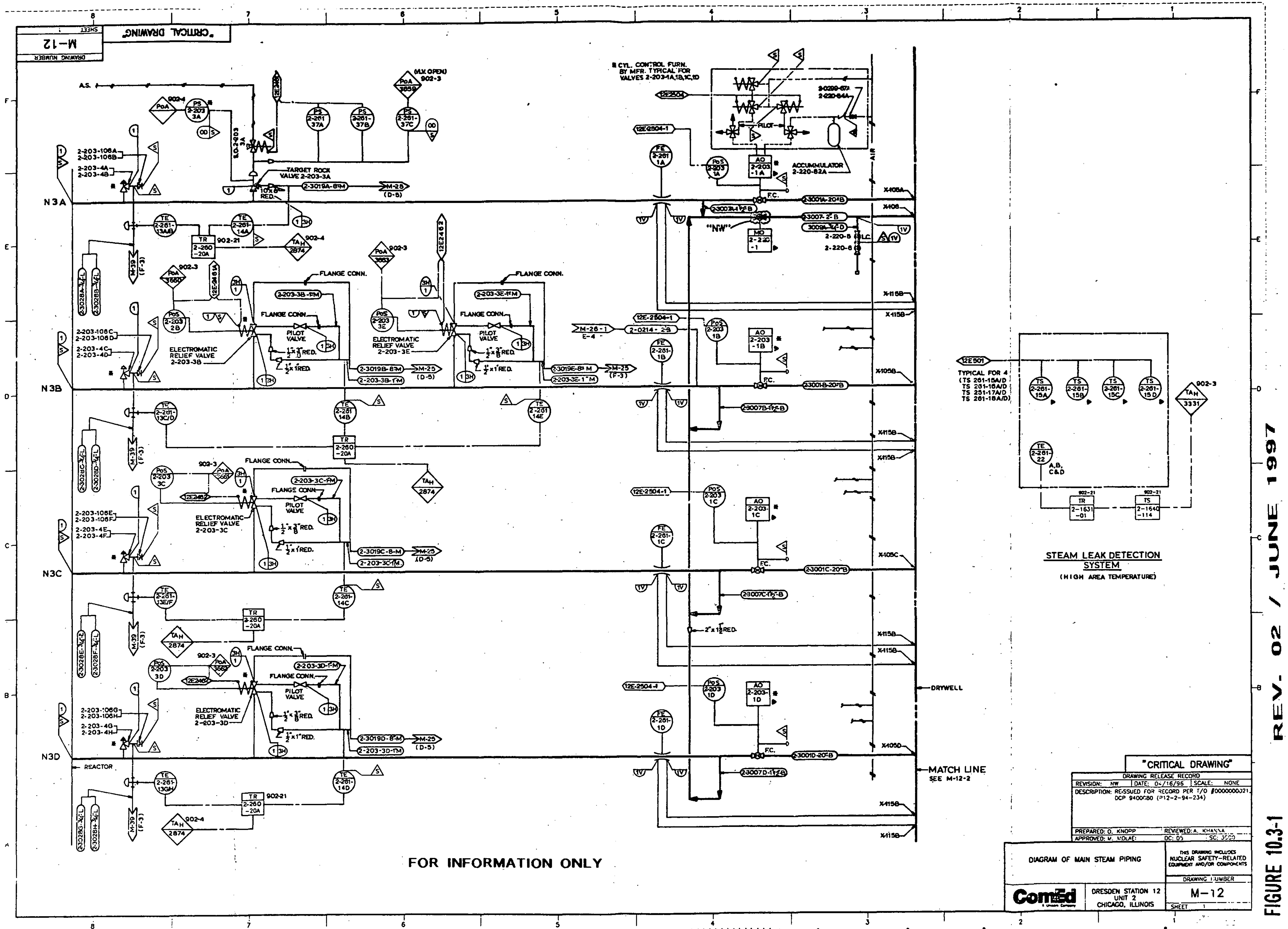
Table 10.3-1

DESIGN, FABRICATION, AND INSTALLATION OF THE MAIN STEAM PIPING

Pipe	
Size	20 in. and 24 in.
Type	Seamless
ASTM Specification	A 106 Grade B
Schedule	80 (Maximum wall thickness 1.031 in.)
Weld Joint	
Root pass	Gas tungsten arc (TiG)
Second pass	Gas tungsten arc (TiG)
Remainder	Shielded metal arc (SMA)
Fittings	
Type	Butt weld
ASTM Specification	B 16.9
ASTM Specification	A 234 grade WPB
Schedule	80

Notes

1. For piping 2" and under, ASTM A335 Grade P11 or P22 may be substituted for ASTM A106 Grade B material for the same schedule. For fittings and valves 2" and under, ASTM A132 Grade F11 or F22 may be substituted for ASTM A105 for the same rating. Substitutions are allowed up to a maximum temperature of 450°F (operating or design).



REV. 02 / JUNE 1997

FIGURE 10.3-1

CENTRAL DRAWING FACILITY

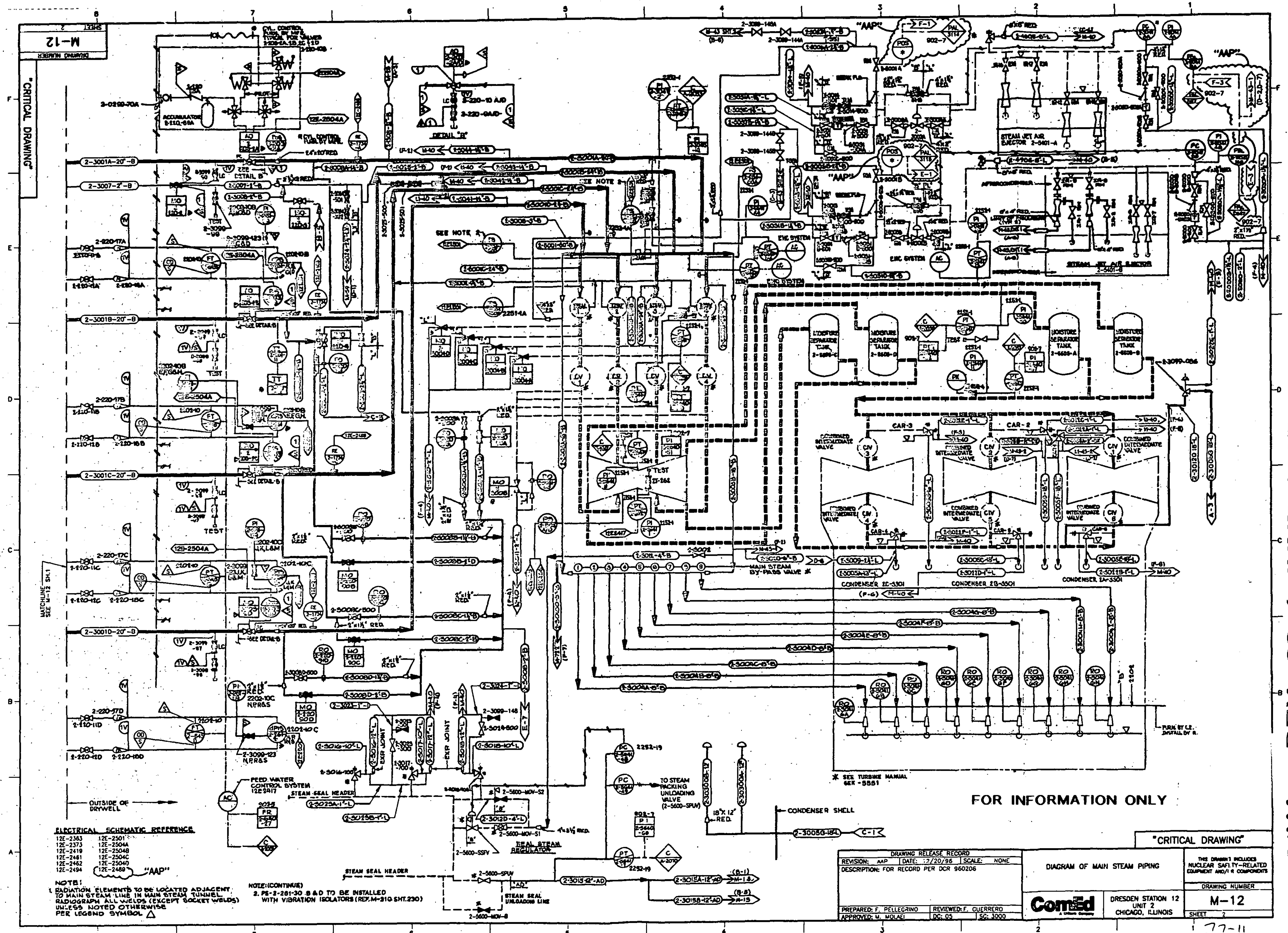


FIGURE 10.3-2 REV. 02 / JUNE 1997

CENTRAL DRAWING FACILITY

30 X

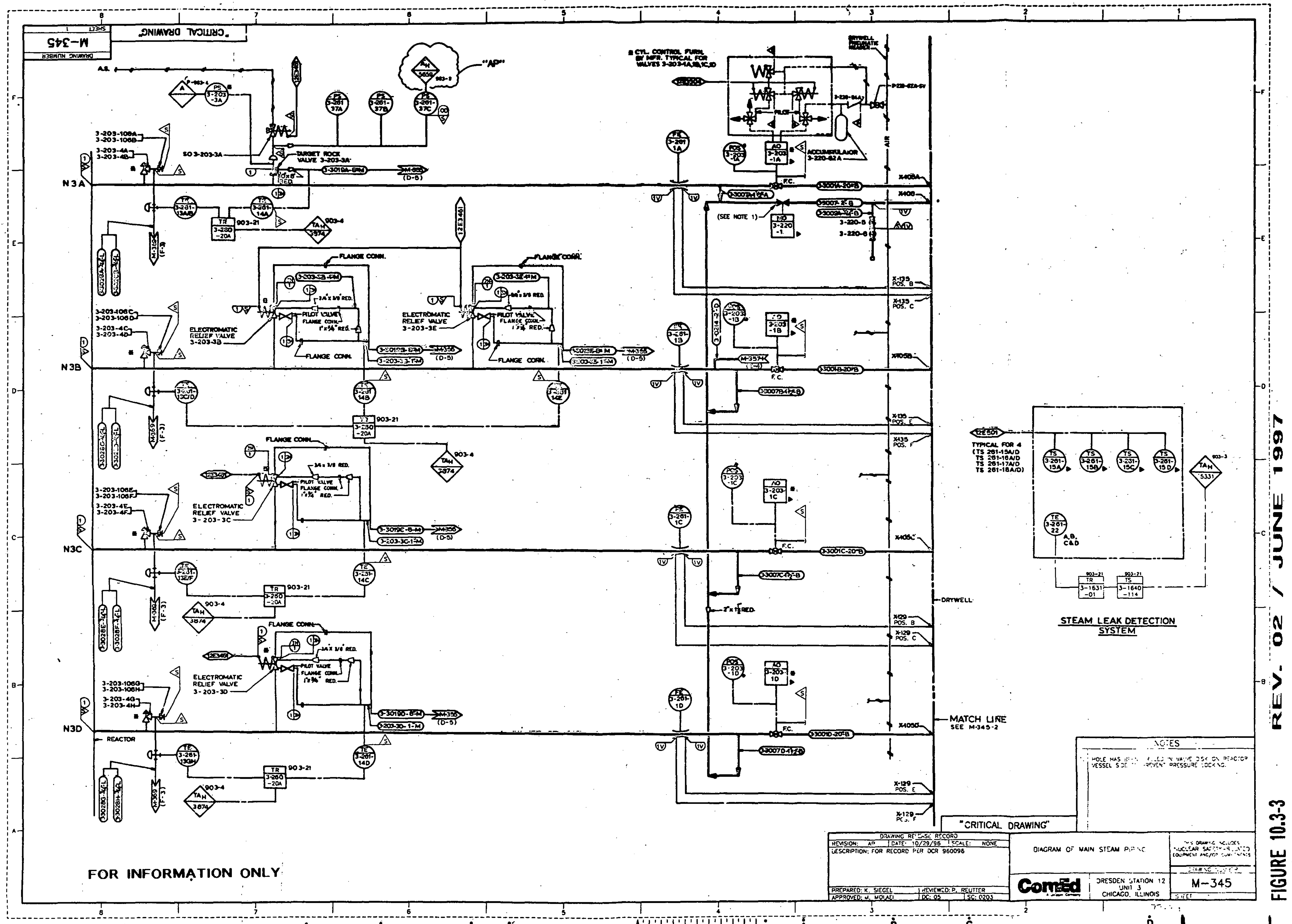
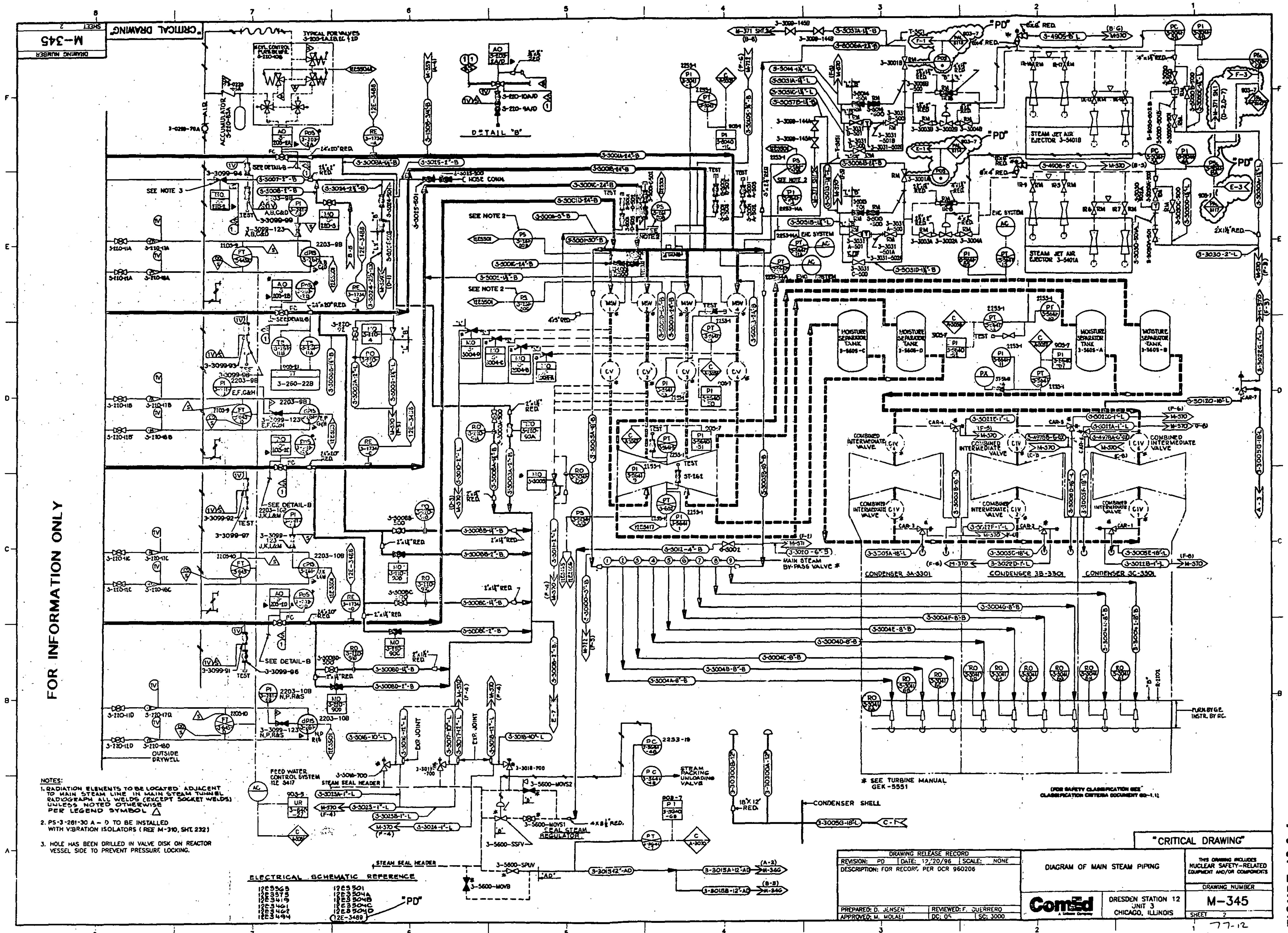


FIGURE 10.3-3

REV. 02 / JUNE 1997

CENTRAL DRAWING FACILITY 30 X



REV. 02 / JUNE 1997

FIGURE 10.3-4

CENTRAL DRAWING FACILITY

30 X

10.4.1.4 Tests and Inspections

The condenser is monitored for vacuum, circulating water pressure drop, and temperature rise. The condensate conductivity is measured at the condensate demineralizer inlet. All tests and inspections of the condenser are in accordance with station inspection and maintenance procedures.

10.4.1.5 Instrumentation Applications

Indication of condenser level and pressure is provided in the control room. The condensate level in the condenser hotwell is maintained within proper limits by automatic controls that provide makeup or transfer of condensate to or from the condensate storage tanks. Turbine exhaust hood temperature is monitored and controlled with water sprays which provide protection from exhaust hood overheating.

Loss of condenser vacuum is an indication of loss of normal heat sink. Therefore, loss of condenser vacuum initiates a closure of the main steam stop valves and turbine bypass valves which eliminates heat input to the condenser. Per Technical Specification reactor scram occurs in the RUN mode at 21 in.Hg vacuum, stop valve closure occurs at 20 in.Hg vacuum, and bypass valve closure occurs at 7 in.Hg vacuum. The reactor protection system, which initiates the scram, is addressed in Section 7.2.

The condenser pit underneath the hotwell is monitored for flooding due to circulating water system leakage. The condenser pit level alarms are set at the 1-foot level and the 3-foot level. The circulating water pump trip is set at 5 feet from the condenser pit floor. For flood protection, the condenser pit has a watertight submarine-type door as described in Section 3.4.

10.4.2 Main Condenser Evacuation System

The purpose of the main condenser evacuation system is to evacuate air leaking into the condenser and noncondensible gases (such as fission gases, activation gases, and hydrogen and oxygen from water dissociation) and to discharge them to the off-gas system.

10.4.2.1 Design Bases

The main condenser evacuation system is not credited to support safe shutdown of the reactor or to perform any reactor safety function.

The main condenser evacuation system is designed to evacuate the main condenser during startup and normal operation. The off-gas piping is designed in accordance with ASA B-31.1 Code for the original system; the recombiner and charcoal adsorber system is designed to ASME Section III, Subsection ND, Class 3.

10.4.2.2 System Description

The main condenser evacuation system is shown in Figures 11.3-1 (Drawing M-43, Sheet 1) and 11.3-4 (Drawing M-371, Sheet 1).

The main condenser evacuation system for each unit consists of steam jet air ejectors (SJAEs) for normal plant operation and a mechanical vacuum pump for startup.

The SJAEs discharge through the off gas system. In the off gas system, hydrogen and oxygen are recombined to reduce volume and eliminate the explosive hazard. Off gas is filtered and passed through a charcoal adsorber. See Section 11.3 for details.

The air ejector and off gas condensers are cooled by the condensate system. Moisture extracted from off-gas flow is drained back to the main condenser.

The steam jet driving flow is from the main steam supply through pressure regulating valves set at approximately 125 psig.

The mechanical vacuum pump system provides the initial vacuum in the condenser during unit startup. The gases from the turbine and condenser system are discharged from the pump to the stack via the gland seal exhaust piping system. The mechanical vacuum pump detail is discussed in Section 11.3.2.

10.4.2.3 Safety Evaluation

The off-gas flow from the main condenser is one source of radioactive gas in the station. An inventory of radioactive contaminants in the effluent from the SJAEs is evaluated in Section 11.3. The main steam flow to the ejectors dilutes the off-gas to less than 4% hydrogen by volume to minimize the possibility of hydrogen detonation. The entire system is designed to maintain its integrity in the event of hydrogen detonation.

The SJAE suction valves close when the supply steam pressure is low and decreasing. Main steam line radiation monitors isolate the mechanical pump and close the SJAE suction valves on high fission product radioactivity. The hydrogen water chemistry system is addressed in Section 5.4.3.

10.4.2.4 Tests and Inspections

The off-gas systems are used on a routine basis and do not require specific testing to assure operability. Monitoring equipment is calibrated and maintained on a specific schedule and on indication of malfunction. Tests and inspections of the main condenser evacuation system equipment are performed in accordance with normal station practices and procedures.

10.4.2.5 Instrumentation Applications

The off-gas system is continuously monitored for radiation within the 36-inch holdup pipe by dual radiation monitors. A high-radiation alarm is provided in the control room. If the radioactivity exceeds the limits of the off-site dose calculation manual, the holdup line of the off-gas system is automatically isolated after a 15-minute delay. The holdup of the off-gas provides sufficient time between detection and isolation to prevent release. Off-gas instrumentation is discussed in Section 11.3.2.1.

10.4.3 Turbine Gland Sealing System

The purpose of the turbine gland sealing system is to prevent air leakage into, or radioactive steam leakage out of, the turbine shaft packings and turbine admission valve stem packings. See Section 11.3.2.2 for a description of the turbine gland seal exhaust system.

10.4.3.1 Design Bases

The turbine gland sealing system is not credited to support safe shutdown of the reactor or required to perform any reactor safety function. The turbine gland sealing system is designed in accordance with ASA B-31.1 Code.

10.4.3.2 System Description

The turbine gland sealing system is designed to provide turbine shaft sealing, prevent steam leakage to the atmosphere, prevent air inleakage, and prevent leakage between turbine sections. The system also provides sealing to the valve stem packing of the main steam stop valves, turbine control valves, combined intermediate valves, and bypass valves. The steam-air mixture from the gland seal system is removed by the turbine gland seal exhaust system.

The turbine gland seal exhaust system is shown in Figures 10.4-2 and 11.3-1 through 11.3-4. The turbine gland sealing system consists of a steam-seal feed valve with bypass, a steam unloading valve with bypass, a steam-seal header, exhaust headers, valves, piping, and instrumentation. The turbine steam is sealed against leakage along the shaft to the atmosphere by the labyrinth pressure packing. Air inleakage to the turbine is controlled by the labyrinth vacuum packing. These packings limit the leakage by a series of throttling seals from the high-pressure space to the low-pressure space. Sealing steam is supplied to the pressure packing at low load and to the vacuum packing at all loads.

At low load, sealing steam is supplied from main steam via an air-operated control valve, which reduces the pressure to 2.5—4.5 psig. The sealing steam is supplied to the high-pressure element shaft seals, low-pressure element shaft seals, valve stem packings of the main steam stop valves, turbine control valves, combined intermediate valves, and bypass valves. A mixture of steam, moisture, and air is routed to the exhaust header. At full load, the steam from the high-pressure element packing provides enough pressure for the low-pressure element vacuum packing. The feed control valve completely closes and the unloading valve opens to maintain pressure. The steam unloading valve discharges to the extraction lines of low-pressure heater A. The exhaust header need only be maintained at sufficient vacuum to prevent steam from coming out of the seals.

10.4.3.3 Safety Evaluation

The system is designed to provide low-pressure sealing steam to the turbine shaft glands.

The relief valve will maintain the system at a safe pressure if the control valves fail. Manual pressure control is possible using bypass valves. Section 11.3 discusses radiation issues.

10.4.3.4 Tests and Inspections

Tests and inspections of the turbine gland sealing system equipment are performed in accordance with station practices and procedures.

10.4.3.5 Instrumentation Applications

The steam seal header pressure and the exhaust header vacuum are indicated by instruments in the control room. The steam seal header is provided with a low-pressure alarm, as well as a thermocouple.

10.4.4 Turbine Bypass System

The purpose of the turbine bypass system is to bypass up to 40% of the turbine-generator throttle steam flow to the condenser.

Although the bypass valves are not credited for safe shutdown, evaluation of the accidents and transients for which the plant is designed considered the bypass valves. The main accidents and transients that the bypass valves affect are turbine trip, load reject, and feedwater controller failure. The description of the bypass valve function during accidents and transients can be found in Sections 15.2 and 15.8.

10.4.4.1 Design Basis

The turbine bypass system is not credited to support safe shutdown of the reactor or to perform any reactor safety function.

The turbine bypass system is designed in accordance with ASA B-31.1 Code.

10.4.4.2 System Description

The turbine bypass valves discharge reactor steam directly to the main condenser. They are used during unit startup and shutdown to regulate the steam pressure in the reactor vessel and are designed to pass up to 40% of the turbine-generator throttle steam flow. The capacities of the bypass valves and relief valves are sufficient to keep the reactor safety valves from opening in the event of a sudden loss of full load on the turbine-generator; thus, the turbine bypass system provides protection against reactor vessel overpressure. The relief valves alone would be sufficient if a reactor scram were assumed to occur simultaneously with turbine trip and bypass system failure (see Section 5.2.2.3).

The turbine bypass system is shown in Figure 10.3-1 (Drawing M-12, Sheet 2). Two 18-inch diameter pipes extend from the 30-inch main steam equalizing header to the turbine bypass manifold. Nine turbine bypass valves are situated on the bypass manifold and are sequentially operated by hydraulic pressure of the turbine electrohydraulic control (EHC) system. Nine 8-inch diameter bypass lines are piped directly to the main condenser via pressure reducing orifices. The turbine bypass system is used during normal startup and shutdown to pass partial main steam flow to the condenser.

The bypass valves are automatically controlled by reactor pressure. Two independent pressure regulators are provided; one is used as a backup or standby regulator. The setpoint of the pressure regulators is adjusted manually from the control room. The bypass valves may be manually controlled from the control room by the bypass valve jack.

10.4.4.3 Safety Evaluation

The bypass valves close automatically on low-condenser vacuum of 7 in.Hg. In the event of the loss of EHC hydraulic pressure, the check valve in the hydraulic system allows the accumulator to keep the turbine bypass valves open for approximately 1 minute to discharge steam to the condenser. The turbine bypass valves then fail closed on loss of EHC hydraulic pressure. On turbine trip or generator load reject, the turbine bypass valves open. The evaluation of all Anticipated Operational Occurrences (AOOs), including turbine trip coincident with the failure of the bypass system, may be found in Chapter 15.

10.4.4.4 Tests and Inspections

The opening and closing of the turbine bypass valves are performed during startup and shutdown in accordance with station practices and procedures.

The tests and inspection requirements of the turbine bypass system are addressed with the main steam system in Section 10.3.4.

10.4.4.5 Instrumentation Applications

The turbine bypass system is controlled by the EHC system as addressed in Section 7.7.4.

10.4.5 Circulating Water System

The purpose of the circulating water system is to remove the heat rejected from the main condenser.

surges of 19,100 gal/min. The system can maintain effluent impurity levels at or below the following concentration limits:

Total dissolved solids	— 25 ppb
Total iron as Fe	— 8 ppb
Total copper as Cu	— 8 ppb
Total nickel as Ni	— 5 ppb
Total silica as SiO_2	— 10 ppb
Total chloride as Cl	— 10 ppb
Specific conductivity at 77°F	— 0.1 μmho/cm
pH at 77°F	— 7

The condensate pumps take suction from the condensers and discharge through the SJAE condensers, gland seal condensers, and off-gas condenser to a full-flow condensate demineralizer system to ensure the supply of high-purity water to the reactor. The condensate enters the mix-bed demineralizer vessel at the top and passes through the cation and anion resins. The resins remove dissolved cations and anions. The treated condensate exits the bottom of the vessel to the condensate booster pumps.

The system and auxiliaries, as shown in Figures 10.4-4 (Drawing M-17, Sheet 1), 10.4-5 (Drawing M-17, Sheet 2), and 10.4-6 (Drawing M-17, Sheet 3), include resin transfer, cation regeneration, anion regeneration, ultrasonic resin cleaner, backwash, recycle pump, resin trap, and instrumentation and control for proper operation. The condensate demineralizer system can be used during refueling operation to treat suppression pool water.

The condensate demineralizer system is composed of seven mixed-bed demineralizer units (one of which is a spare) and the required tanks, piping and valving for regeneration of the demineralizers. The demineralizer tanks are of the rubber-lined, carbon-steel-type and are rated by the manufacturer for a design flow rate of 3270 gal/min per tank to achieve proper performance within design parameters as related to ion exchange performance. Demineralizer flow rates that exceed 3270 gpm are acceptable with no anticipated mechanical damage to the demineralizer; however, higher flow rates will result in poorer effluent quality and shorter ion service times. Station water chemistry quality will determine the need to reduce demineralizer flow rates.

Exhausted resins are sluiced from a demineralizer unit to the resin separation tank. The resins are then hydraulically classified and separated, followed by removal of the lower density anion resin to the anion tank for regeneration. The primary resin separation tank is then used for subsequent backwashing and regeneration of the cation resin. The resins are separately backwashed to remove insoluble material. After rinsing, the regenerated resins are sluiced to the resin storage tank for remixing of the resins and eventual reuse.

Any radioactive material removed from the exhausted resins by the rinse solutions is transferred to the radioactive waste system for analysis and treatment as required. Wastes from the regeneration process are segregated on the basis of conductivity. Low-conductivity water is diverted to the waste collector tank, and high-conductivity water is routed to the waste neutralizer tank.

The condensate demineralizer and associated regeneration systems are manually controlled from a local panel. Integrated flow and conductivity monitors are provided for each demineralizer to indicate when regeneration or backwash is required. Alarms and pressure drop recorders are provided in the control room.

10.4.7 Condensate and Feedwater Systems

The purpose of the condensate and feedwater systems is to deliver condensate from the condenser to the reactor. The portion of condensate and feedwater systems addressed in this section is from the outlet of the condenser up to the outboard feedwater check valve. The feedwater system from the outboard feedwater check valve to the reactor is addressed in Section 5.2. The condenser is addressed in Section 10.4.1. Feedwater system controls are addressed in Section 7.7.

10.4.7.1 Design Basis

The condensate and feedwater systems are not credited to support safe shutdown or to perform any reactor safety function. The feedwater system performance is, however, modeled in some of the Chapter 15.0 transients.

The objective of the condensate and feedwater systems is to supply the reactor vessel with demineralized water equivalent to the rate of water which is being generated into steam by boiloff. To achieve this objective, the condensate feedwater system was designed to supply 9,725,000 lb/hr of water at 1100 psia.

The condensate and feedwater systems are designed in accordance with ASA B-31.1 Codes.

10.4.7.2 System Description

The condensate and feedwater systems consist of condensate pumps, condensate booster pumps, a demineralizer system, feedwater heaters (high- and low-pressure), feed pumps, feedwater regulating valves, piping, controls and instrumentation, and subsystems that supply the reactor with regenerative feedwater heating in a closed steam cycle.

The condensate system is shown in Figure 10.4-1 (Drawing M-15). The condensate booster system is shown in Figure 10.4-7 (Drawing M-16). The feedwater system is shown in Figures 10.4-8 (Drawing M-14) and 10.4-9 (Drawing M-347).

The Zinc injection process system is addressed in Section 5.4.

The extraction steam system is shown in Figure 10.4-10 (Drawing M-13). The heater drain system is shown in Figure 10.4-11 (Drawing M-18). The heater vent and drain piping is shown in Figure 10.4-12 (Drawing M-19).

The hydrogen water chemistry system is addressed in Section 5.4.

Four condensate pumping units are located next to the condenser pit. Each unit consists of one condensate pump and one condensate booster pump driven by one common motor. The pumps are horizontal, single-stage, centrifugal-type with a capacity of 6825 gal/min, sized so that only 3 pumping units are required for normal full-load operation. The fourth unit serves as a backup and auto starts on an operating unit trip or on low-discharge pressure sensed at the condensate booster pump discharge header. The drive motors are 1750-hp, 3-phase, 60-Hz, 4160-V induction motors with a speed of 1800 rpm.

The four condensate pumps take their suction from both sides of the main condenser hotwell through a common 48-inch header that reduces to 24-inch piping. The condensate pumps then discharge throughout the cooling side of the SJAEs, gland steam condensers, and off-gas condenser to the condensate demineralizers. The condensate booster pumps take their suction from the full-flow condensate demineralizers and are used to raise pressure immediately before the condensate passes through the low-pressure heaters and on to the feed pump suction. Minimum flow is maintained by circulation to the condenser.

The condensate demineralizer system is addressed in Section 10.4.6.

The feedwater heaters are divided into three parallel strings. There are three low-pressure feedwater heaters, A, B, and C, and one high-pressure feedwater heater D in each string. Separate drain coolers are provided for each A heater, while the other heaters have integral drain coolers.

Separation of water in the extraction steam is accomplished in the heaters. All drains flow by pressure differential from the heater through the drain cooler to the next lower pressure heater. All heaters have stainless steel tubes welded to the tube sheets. Stainless steel baffles are provided at entering steam and drain connections.

Each feedwater heater shell receives quantities of steam and/or water under the conditions in the amounts listed in Table 10.4-4. The listed quantities are for one heater string only.

Valving and a bypass line permit bypassing each string of low-pressure heaters in the event of failure of any component in the string. Any of the three high-pressure heaters can be similarly bypassed.

The reactor feed pumps take suction from the low-pressure feedwater heater C and discharge through the feedwater regulating valves to high-pressure feedwater heater D. Three 2-stage horizontal feed pumps are provided, each with a capacity of 5,105,000 lb/hr. They are sized so that only two need to be in service during normal full load operation; the third pump serves as a standby. Each pump is driven by a 9000-hp, 4160-V, 3-phase, 60-Hz induction motor through a speed increasing gear unit with a rating of 10,350 hp. At an input speed of 1800 rpm, this unit drives the pump at a speed of 4500 rpm. Each pump has the design characteristics shown in Table 10.4-5.

A minimum flow of 900 gal/min is required from each reactor feed pump. When reactor feed requirements fall below this minimum, an air-operated flow control valve opens and allows feedwater recirculation back into the condenser hotwell. Loss of the running reactor feed pump starts the pump on standby. The feed pump trips on reduced suction pressure.

Feedwater to the reactor is controlled by throttling the feedwater regulating valves (FWRVs). Two 18-inch full-flow FWRVs are provided for power operation and are normally set to automatically maintain reactor water level. One low-flow regulating valve is used for lower power operation. The feedwater control valves provide stable reactor water level control.

Piping supports and restraints were installed to mitigate flow-induced transient loads. A description of the feedwater system materials, particularly fracture toughness characteristics, is provided in Section 10.3.6.

Condensate storage and transfer systems, as described in Section 9.2.7, are provided for both units to fill the system during startup and to serve as a reservoir. Two 250,000-gallon contaminated condensate tanks are provided. The condensate hotwell level is the controlled variable for setting the rejection or addition rate of the condensate storage system.

10.4.7.2.1 Feedwater Regulating Valves and Low-Flow Feedwater Regulating Valve

The normal feedwater flow path from the reactor feed pumps is through the FWRVs. Each unit has two FWRVs, whose positions are determined by the feedwater level control system. The positions of these valves may be manipulated manually or automatically from the control room through the feedwater master controller.

The FWRVs are configured as follows:

- FWRV 2A is a globe valve with drag type trim and an air cylinder actuator.
- FWRV 2B is a drag valve with an air cylinder actuator
- FWRV 3A is a drag valve with an electrohydraulic actuator.
- FWRV 3B is a hush trim valve with an electrohydraulic actuator.

The stroke time for the FWRVs ≥ 5 seconds, from full closed to full open. This time has been reviewed and accepted by Siemens Power Corporation, the fuel vender for Units 2 and 3.

The flow coefficient of the FWRV 3A is 1670. This flow coefficient allows nearly 100% feedwater flow through the FWRV 3A. However, 100% flow through a single FWRV is not recommended since flow-induced vibrations increase to unacceptable levels above 700 MWe. The vibrations are believed to be caused by the irregular piping configurations throughout the feedwater system that cause feedwater velocity changes at elbows and other piping bends.

The flow coefficient of the FWRV 3B is 1500.

There is one air operated low-flow feedwater regulating valve dedicated to each unit. The capacity of the Unit 2 and 3 low-flow valves differ. The Unit 2 valve is approximately a 13% capacity drag valve. The Unit 3 valve is approximately a 22% capacity drag valve. The difference in capacity is due to the line sizes. The Unit 2 line is a 6-inch line and the Unit 3 line is a 10-inch line designed to provide a larger flow capacity during unit start-up.

10.4.7.3 Safety Evaluation

During operation, radioactive steam and condensate are present in the feedwater heating portion of the system, which includes the extraction steam piping, feedwater heater shells, feedwater heater drains, and vent piping. Radioactivity may also be present in the condensate and feedwater. Shielding and controlled access are provided, as addressed in Section 12.3. The condensate is retained in the hotwell for approximately 2 minutes to allow for N-16 and O-19 radioactivity decay.

A multistring arrangement provides the ability to isolate and bypass condensate and feedwater systems' equipment and remove it from service.

Loss of feedwater heating resulting from a loss of a feedwater heater can occur through either the malfunction of its level controller or inadvertent valve closure. The probability of simultaneous loss of more than one heater is very remote. Loss of feedwater heating will result in a gradual increase in subcooling and consequently a gradual rise in reactor power. The operator first will be warned by control room annunciation that indicates loss of feedwater heating and will take prompt action to reduce reactor power in accordance with station procedures. The average power range monitor high-flux alarm will warn the operator of the reactor power increase. Thus, there is sufficient time to take corrective action. Even if operator actions were assumed not to occur, the reactor would scram from high flux.

Failure of the feedwater control system is analyzed in Chapter 15. A description of the feedwater control system is contained in Section 7.7.

10.4.7.4 Tests and Inspections

Tests and inspections are conducted to assure functional performance as required for continued safe operation and to provide maximum protection for operating personnel. During normal operating periods, operational readiness of duplicate equipment is verified whenever equipment operation is rotated.

After installation, components and piping of the condensate and feedwater systems were hydrostatically tested in accordance with ASA B-31.1 Code. Inspection and acceptance standards were in accordance with ASME Code, Section VIII. All circumferential butt welds for 2½-inch diameter and larger piping were specified to be 100% radiographed as indicated in paragraph UW51 of ASME Code, Section VIII.

Inservice inspection of the feedwater system is performed in accordance with the Dresden Inservice Inspection Plan, Third Interval.

An erosion/corrosion inspection program is in place to monitor carbon steel piping systems for wall thinning in response to the NRC Generic Letter 89-08, "Erosion/Corrosion - Induced Pipe Wall Thinning." This program is conducted per NSAC 202L. Additional discussions of the erosion/corrosion program can be found in Section 5.2.3.5.2.

10.4.7.5 Instrumentation Applications

Feedwater flow control instrumentation measures the feedwater flowrate from the condensate and feedwater systems. This measurement is used by the feedwater control system which regulates the feedwater flow to the reactor to meet system demands. The feedwater control system is described in Section 7.7.

Instrumentation and controls regulate pump recirculation flowrates for the condensate pumps, condensate booster pumps, and reactor feedwater pumps. Measurements of pump suction and discharge pressures are provided where appropriate. Sampling means are provided for monitoring the quality of the final feedwater. Temperature measurements are provided for each stage of feedwater heating; these include measurements at the inlet and outlet on both the steam and water sides of the heaters. Steam pressure measurements are provided at each feedwater heater. Instrumentation and controls are provided for regulating the heater drain flowrate to maintain the proper condensate level in each feedwater heater. A high-level alarm and an automatic dump-to-condenser action on high level are provided as well.

Table 10.4-1 (continued)

	Cold Compartment	Intermediate Compartment	Warm Compartment
BTU rejected per hour (x 10^6)	1,757	1,757	1,757
Absolute pressure	1.170 in.Hg	1.432 in.Hg	1.762 in.Hg
Circulating water temperature	60°F	67.47°F	74.95°F

The other steam and water loads are as follows:

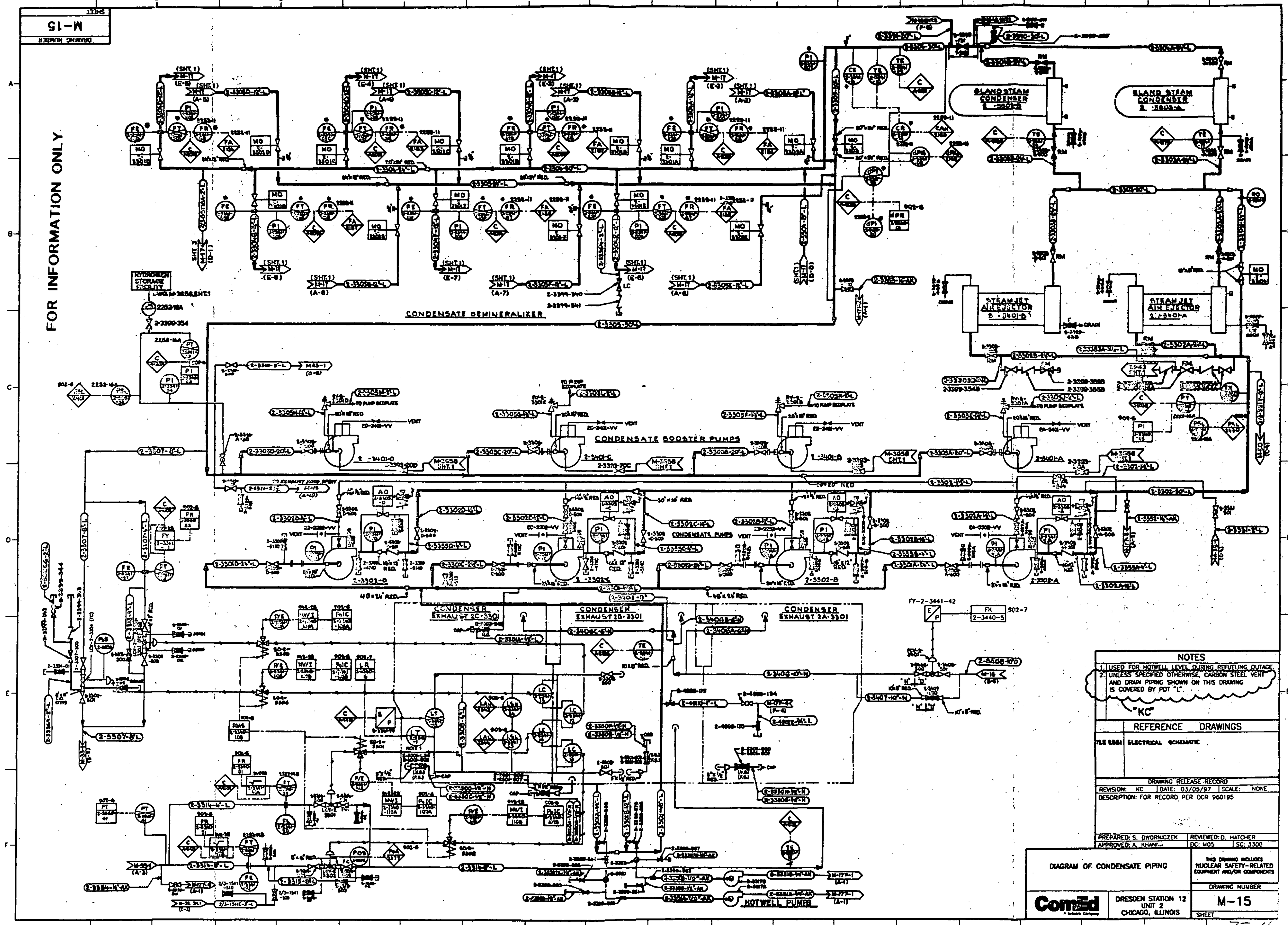
Steam from moisture removal stage	9,920 lb/hr
Drains from moisture removal stage	51,630 lb/hr
Steam from gland seal regulator	2,000 lb/hr
Drains from low pressure heater	1,013,280 lb/hr
Drains from gland seal exhausters (total)	9,000 lb/hr
Steam from steam jet air ejectors (total)	7,500 lb/hr
Water from makeup system (total)	45,020 lb/hr

Table 10.4-2

Intentionally Deleted

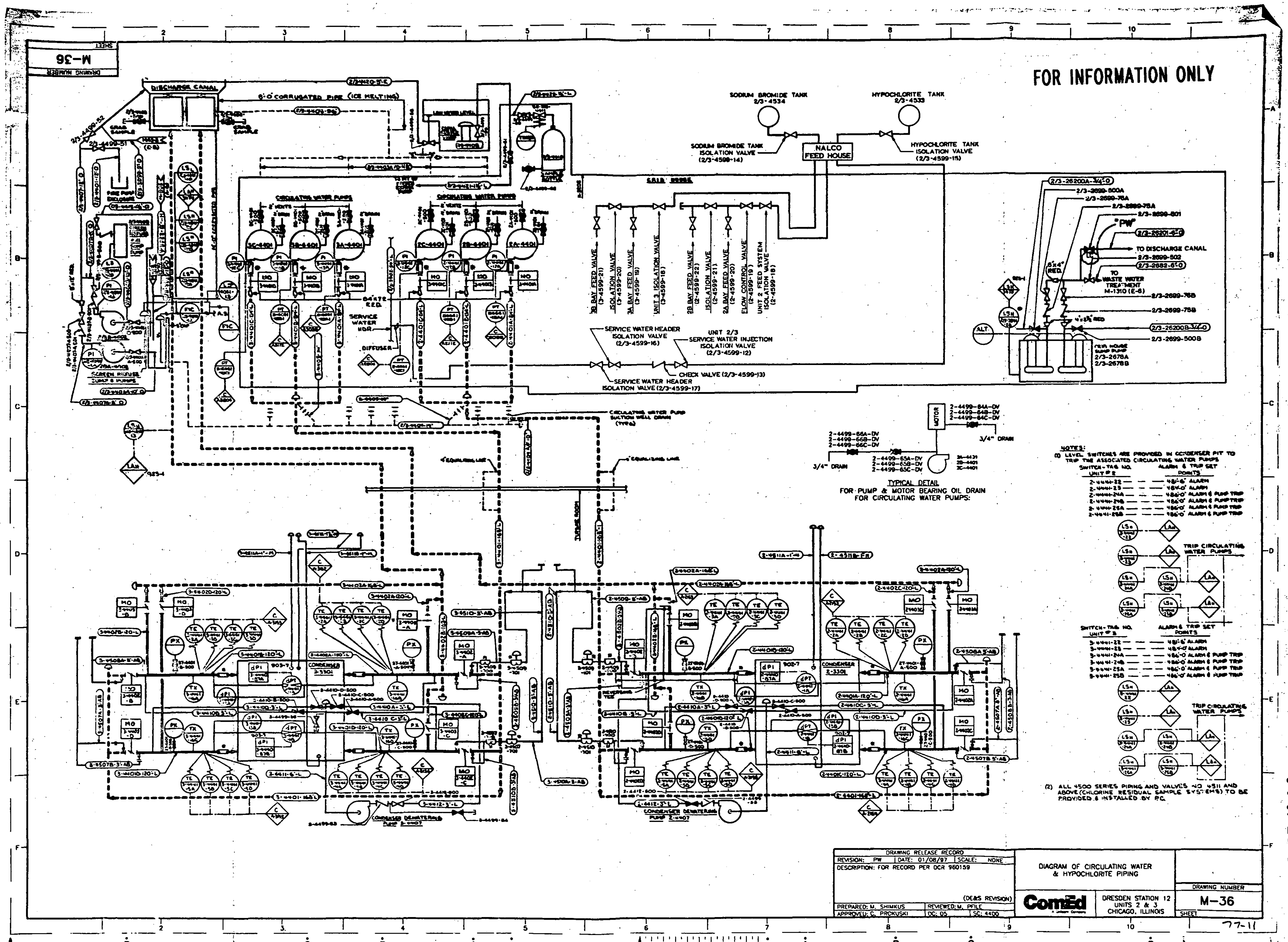
Table 10.4-3

Intentionally Deleted



REV. 02 / JUNE 1997

FIGURE 10.4-1



REV. 02 / JUNE 1997

FIGURE 10.4-3

CENTRAL DRAWING FACILITY

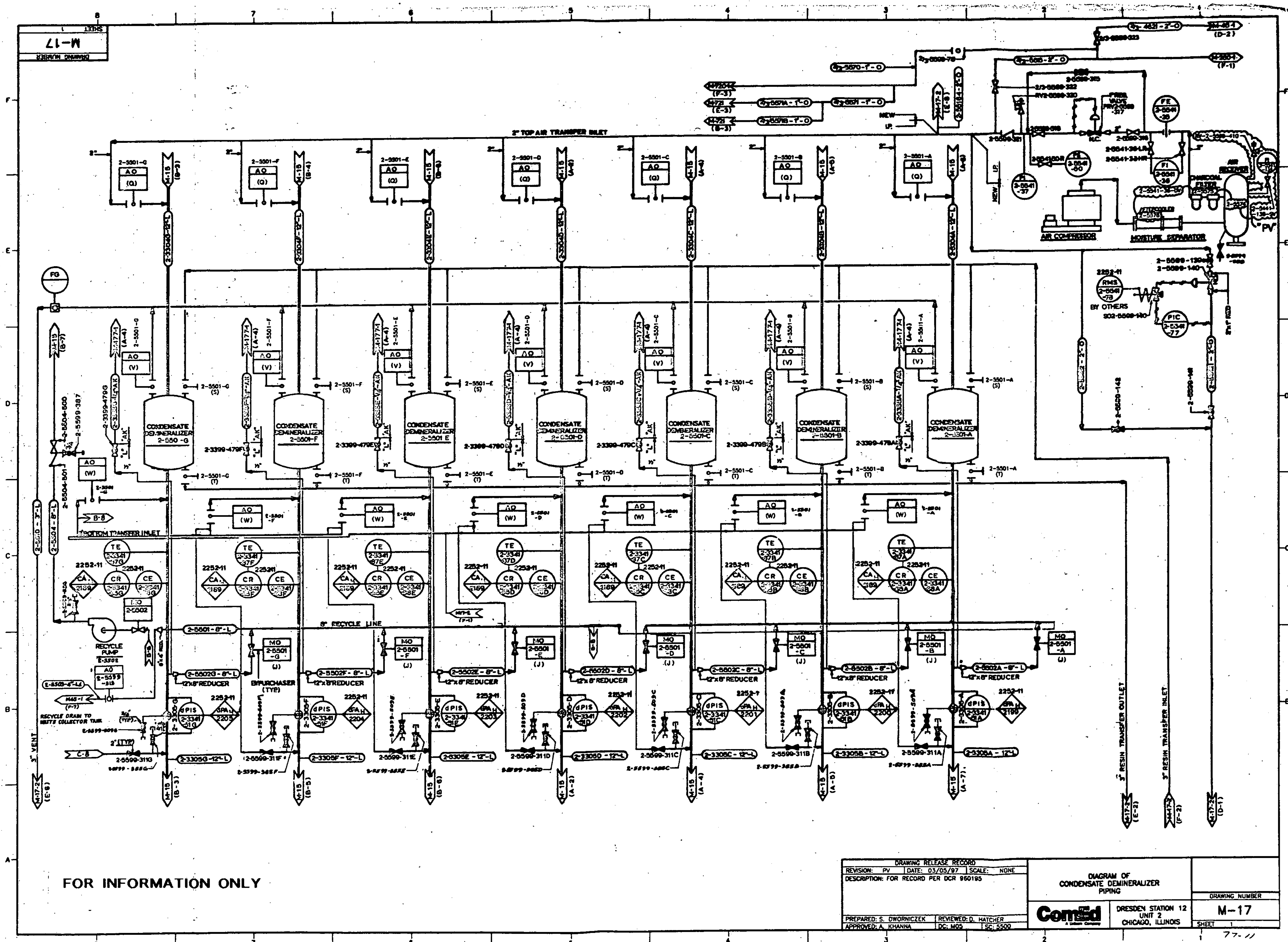
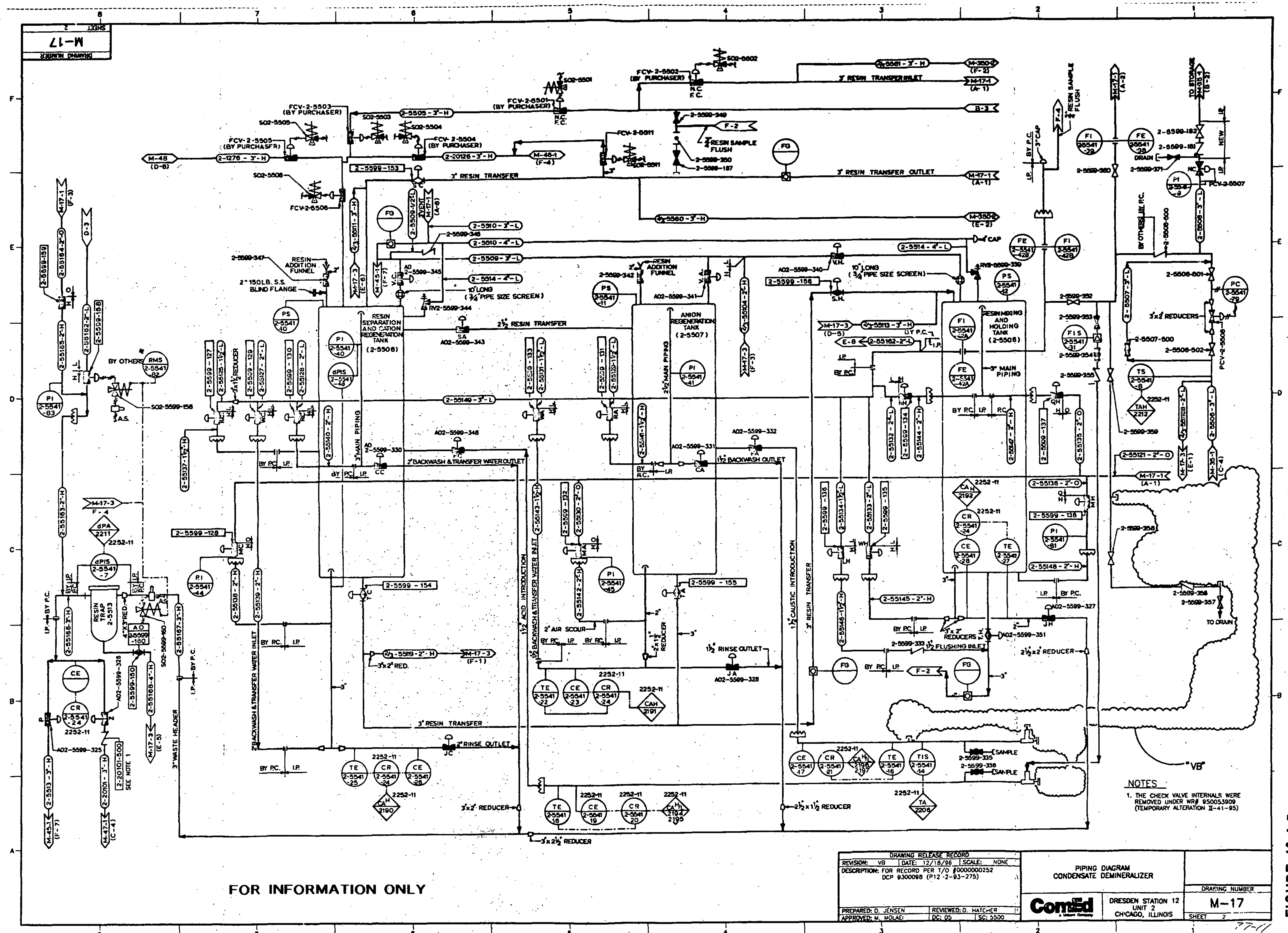


FIGURE 10.4-4

REV. 02 / JUNE 1997

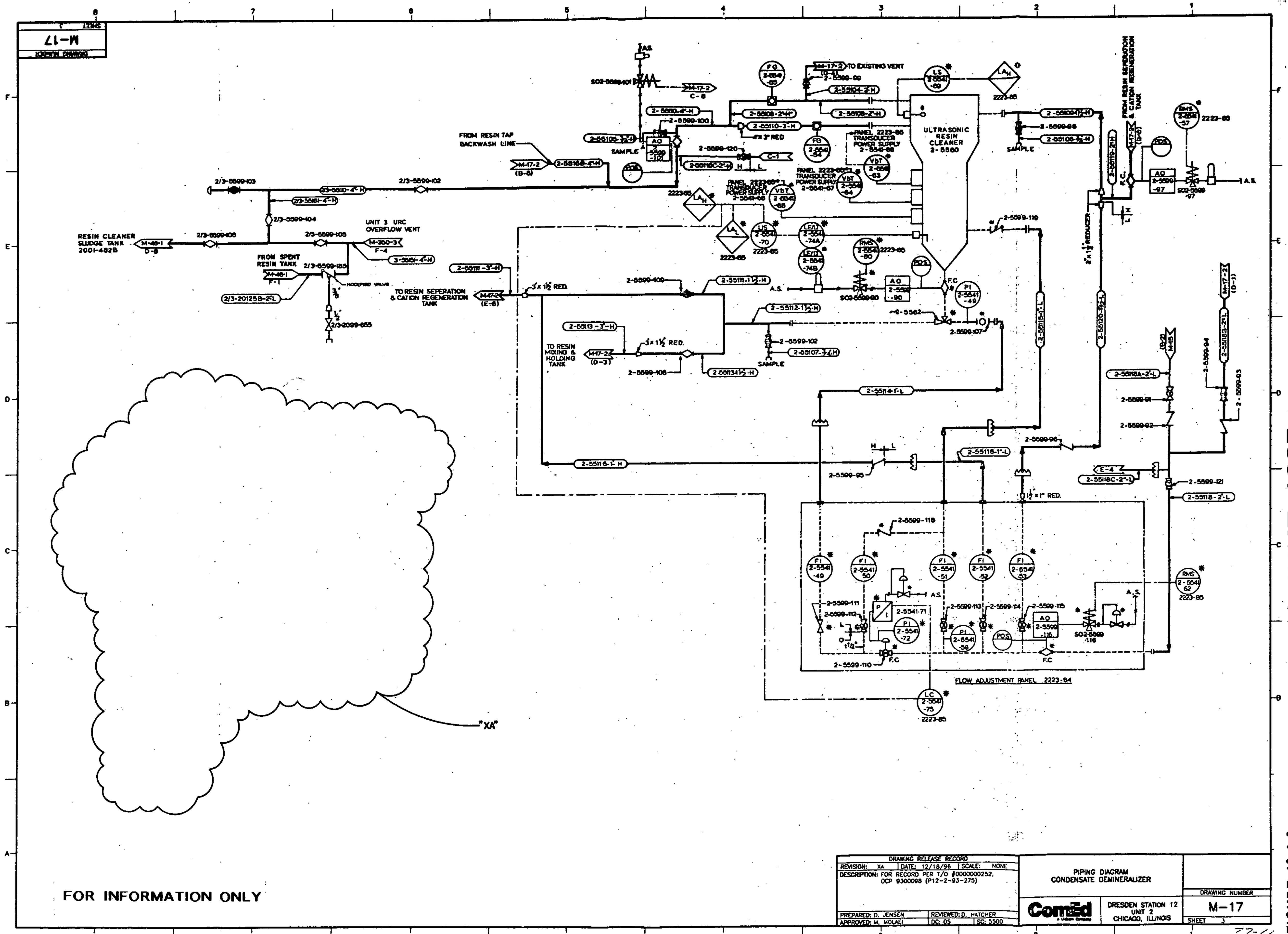


REV. 02 / JUNE 1997

FIGURE 10.4-5

CENTRAL DRAWING FACILITY

30X

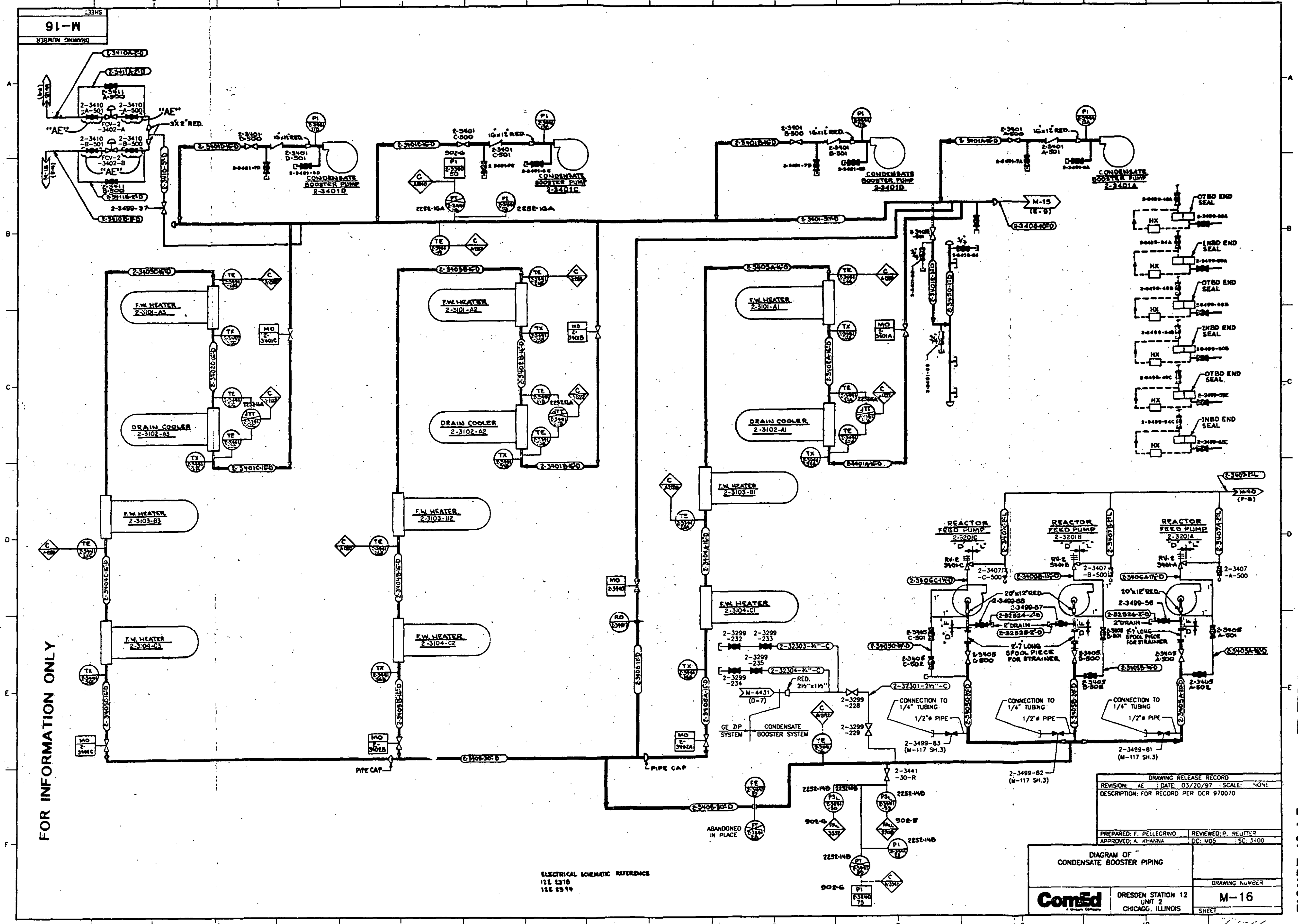


REV. 02 / JUNE 1997

FIGURE 10.4-6

CENTRAL DRAWING FACILITY

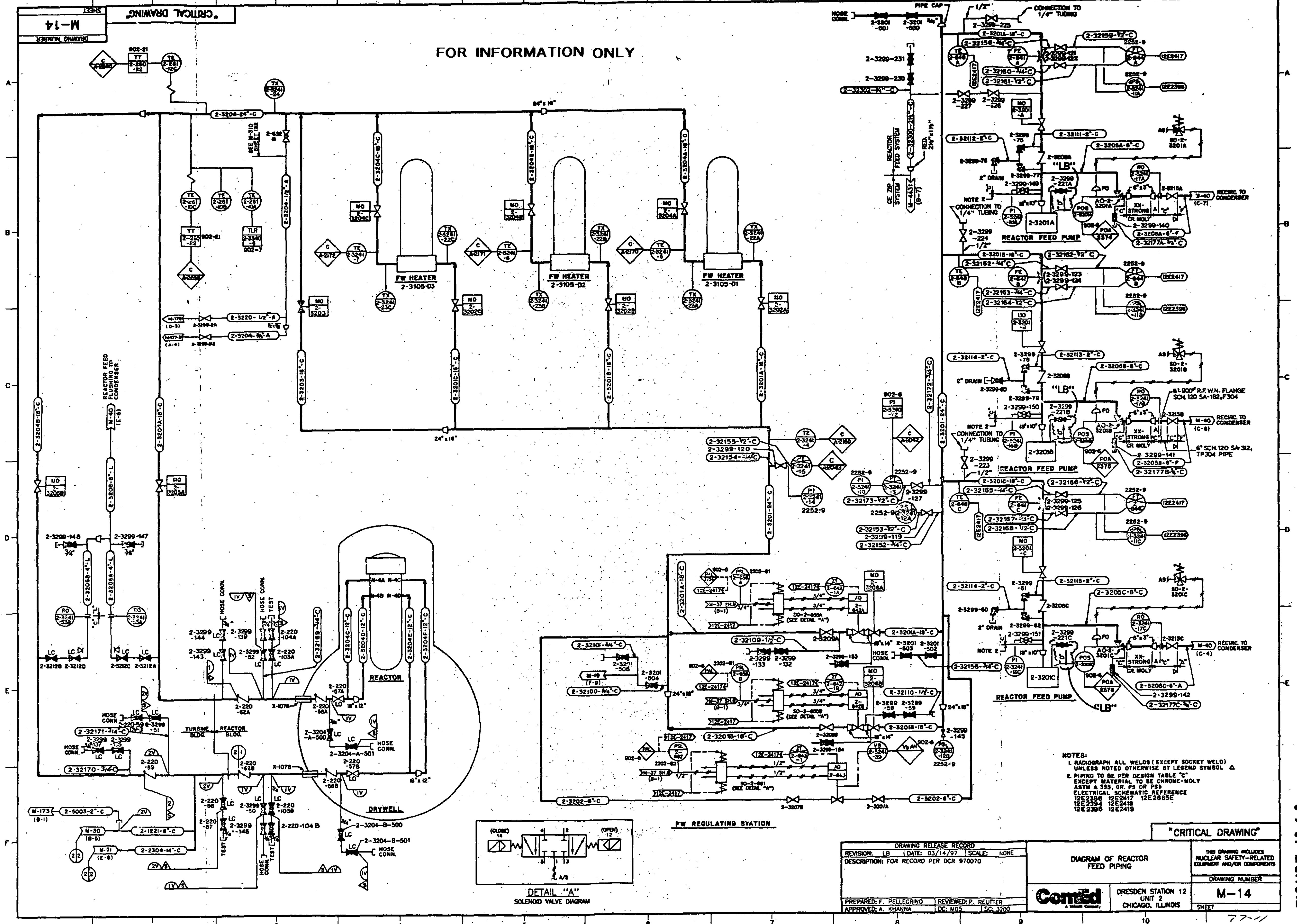
30X



REV. 02 / JUNE 1997

FIGURE 10.4-7

CENTRAL DRAWING FACILITY 30X



CENTRAL DRAWING FACILITY

30X

REV. 02 / JUNE 1997

FIGURE 10.4-8

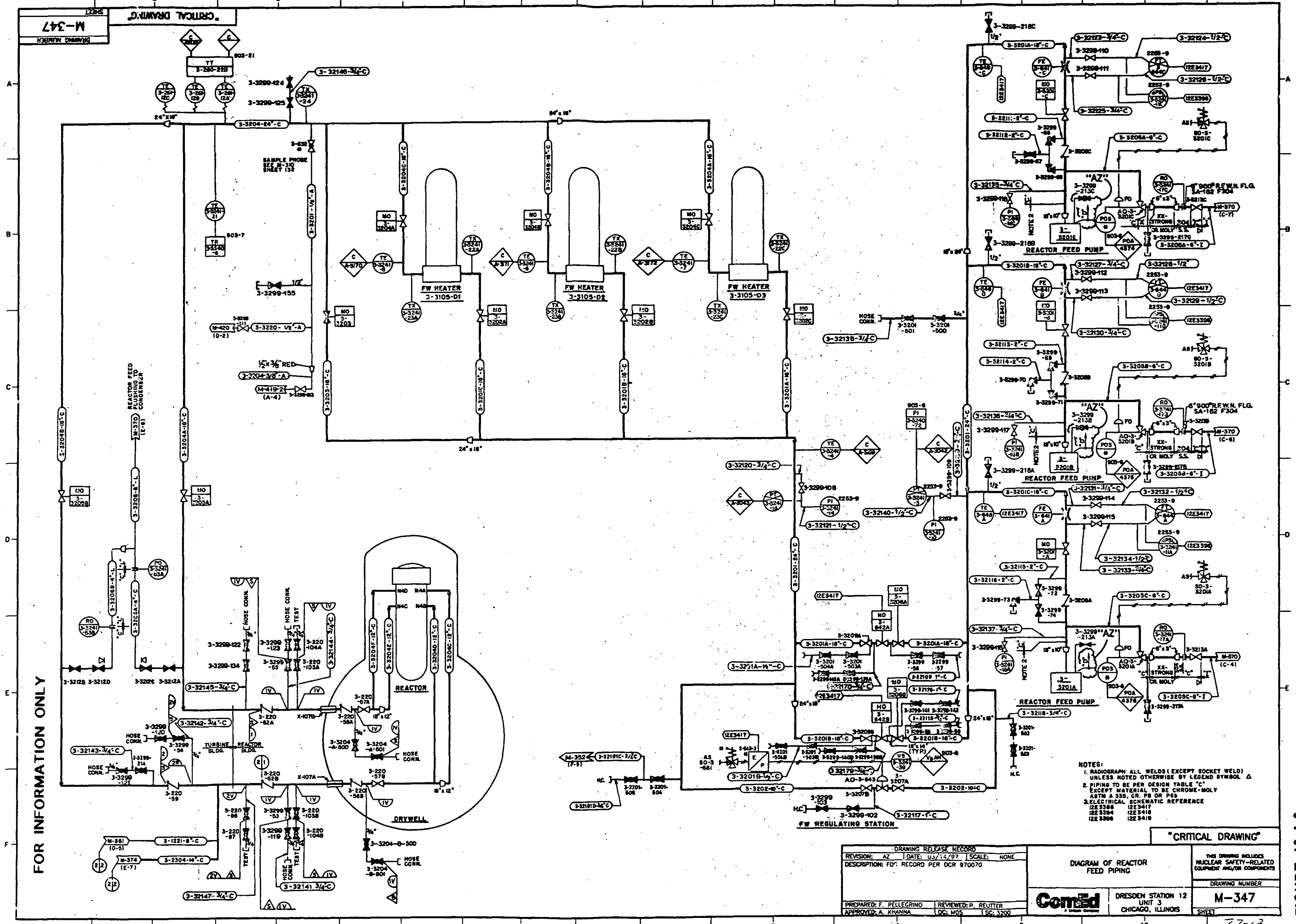


FIGURE 10.4-9

REV. 02 / JUNE 1997

CENTRAL DRAWING FACILITY

30X

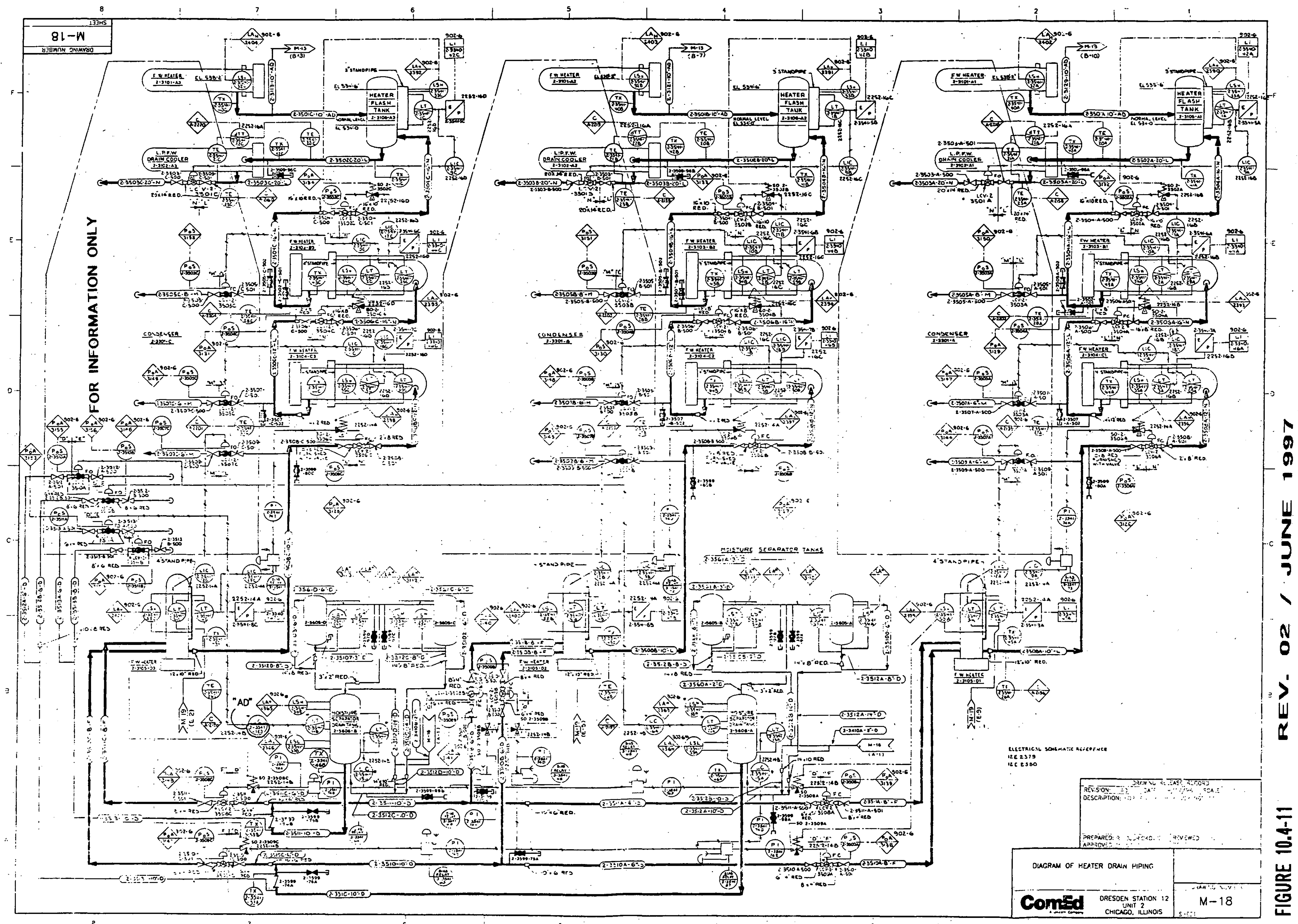


FIGURE 10.4-11

REV. 02 / JUNE 1997

FIGURE DELETED

UFSAR REVISION 2, JUNE 1997
DRESDEN STATION UNITS 2 & 3
FEEDWATER REGULATING VALVE 2A ACTUATOR
FIGURE 10.4-13

The components of the system are designed and operated in such a manner as to minimize radiation exposure of personnel and significantly reduce the radioactivity levels below those limits set forth in 10 CFR 20; 10 CFR 50, Appendix I; and the regulations of the State of Illinois.

Discharge paths for the release of radioactive materials are monitored by the following systems.

A. Off-gas radiation monitor — The off-gas monitoring system actuates an alarm in the control room in the event that the gaseous discharge from the main turbine condenser significantly exceeds the normal emission rate. The monitoring system isolates the off-gas system after a time delay in the event that the release rate limit is exceeded. As a result of the action initiated by this system, the resultant doses will be below the guidelines set forth in 10 CFR 20 and 10 CFR 50, Appendix I.

B. Chimney effluent radiation monitor — The gaseous effluent discharged to the environment via the chimney is monitored for particulate, iodine, and noble gas activity. An alarm annunciates in the control room if the release rate limit is exceeded. Appropriate action, such as power reduction, etc., will be taken upon indication of the limits being exceeded.

C. Reactor building ventilation exhaust radiation monitor — In the event of high radiation levels in the reactor building ventilation exhaust duct or on the refueling floor, the monitors isolate the secondary containment and initiate the standby gas treatment system. The activity level necessary to isolate the secondary containment equates to a calculated dose rate less than the instantaneous effluent release limit of 500 mrem/year whole body and 3000 mrem/year skin.

D. Before any batch of liquid waste is discharged to the environment from the liquid waste treatment facility, the tank is isolated so that no additional water can be added to it. The batch of liquid waste is mixed by recirculation to assure that the sample obtained is representative. After mixing, the batch of liquid waste is sampled and analyzed for gamma isotopic activity. Based upon this analysis, a discharge rate for the batch is determined so that when the batch is discharged and diluted by the plant circulating water discharge, the radioactivity level in the circulating water leaving the plant site will be less than the applicable effluent concentration limit (ECL), as stated in 10 CFR 20, Appendix B, Table 2. This ensures that the level of activity at the outlet of the discharge canal will be within the NRC limit for non-occupational use. Normally, the waste is a small percentage of the ECL, and at no time will waste discharge water leaving the discharge canal and entering the river exceed average ECL values over the course of a calender year.

An offline radiation detector monitors the radioactive system discharge line that feeds the circulating water discharge canal whenever a discharge is made. If an abnormal radioactivity level is detected, a grab sample is automatically collected, an alarm annunciates in the radwaste control room, and the operator terminates the discharge. As final verification, the circulating water discharge is continuously sampled, and a 24-hour composite sample is analyzed on a daily basis for gamma

Table 11.1-3

REACTOR AND RECIRCULATION SYSTEM PARAMETERS USED FOR FISSION PRODUCT ESTIMATES

Parameter	Reactor Nominal Design		Turbine Maximum Design	
Reactor power (MWt)	2255		2467	
Core — Active fuel length (in.)	144		144	
Equivalent diameter (in.)	182.2		186.2	
Circumscribed diameter (in.)	189.7		198.6	
Number of fuel assemblies	724		756	
Overall average core power density* (w/cc)	36.65		38.4	
Total coolant flowrate through the core (lb/hr)	9.8×10^7		9.8×10^7	
Primary steam flowrate (lb/hr)	8.62×10^6		9.43×10^6	
Core power peaking factors:	Max. at Core ℄	At Core Boundary	Max. at Core ℄	At Core Boundary
$\left.\frac{P_{max}}{P_{ave}}\right]_Z$ (axial)	1.57	0.7	1.57	0.7
$\left.\frac{P_{max}}{P_{ave}}\right]_R$ (radial)	1.5	0.7	1.5	0.7

Core Volume Fractions:

Material	Density (g/cc)	Volume Fraction	Volume Fraction
UO_2	10.4	0.254	0.254
Zr	6.4	0.130	0.130
H_2O	1.0	0.296	0.296
Void	0	0.320	0.320

Table 11.1-3 (Continued)

REACTOR AND RECIRCULATION SYSTEM PARAMETERS
USED FOR FISSION PRODUCT ESTIMATES

Parameter	Reactor Nominal Design	Turbine Maximum Design
Reactor operating pressure (psia)	1015	1015
Average water density between core and vessel (g/cc)	0.73	0.73
Average water density below core (g/cc)	0.74	0.74
Average water-steam density above core		
In the plenum region (g/cc)	0.27	
Above the plenum (homogenized) (g/cc)	0.52	
Average steam density (g/cc)	0.036	0.036
Vessel inside radius (in.)	125.5	125.5
Vessel wall thickness (base material) (in.)	6⅛ min	6⅛ min
Vessel clad thickness (stainless steel) (in.)	⅛	⅛
Core shroud thickness (in.)	2	2
Nitrogen-16 activity of steam leaving the vessel (average gamma energy of 6.2 MEV/γ)	95 Ci/s	109 Ci/s

* This parameter is a function of a rated core thermal power (2255 or 2467 MWt), active fuel length (144 inches), number of fuel assemblies (724) and fuel assembly pitch (6 inches). This number does not represent the current licensed rated core thermal power nor active fuel length currently in use; it is only useful in the presented context.

released to the discharge canal. Evaporators, demineralizers, filters or a portable waste treatment system may be utilized to remove contaminants.

Liquid radwaste is divided into three categories:

A. Low conductivity;

B. Moderate conductivity; or

C. High conductivity.

The four systems utilized to process the liquid radwaste are, respectively:

A. Equipment drain system;

B. Floor drain system ; or

C. Maximum recycle system (which is part of the floor drain system).

D. Portable waste treatment system;

Filter sludges and spent resins are treated as solid radwaste — decanted, placed in appropriate containers, and dewatered or solidified. This is described in Section 11.4.

Overall control of the radwaste system is exercised from a local control room situated in the radwaste building. A main panel in this room contains the instruments, controls, and alarms for the operation of the system. Various radwaste system alarm signals are received in the radwaste control room.

Table 11.2-2 shows the locations and capacities of the radwaste tanks. The total allowed activity in the six tanks in the tank farm outside the radwaste building is 3 curies; the allowed activity in any one tank is 0.7 curies.

In accordance with the Systematic Evaluation Program (SEP) Topic III-4.A, the liquid radioactive waste systems and tanks in the radwaste building are adequately protected from tornado generated missiles. See Section 3.3.2.3.2 for additional discussion.

Seismic damage was evaluated for the liquid radwaste system. The tanks of radioactive waste of concern were those at grade outside the radwaste building. Assuming failure of all outside tanks and structures, the evaluation showed that the Effluent Concentration Limits (ECL) were not exceeded. Although the activities resulting from a tank failure condition that are released to the river indicate the applicability of 10 CFR 100 limits, the actual expected concentrations are sufficiently low to allow 10 CFR 20 limits to be applied (see Section 15.7.4 for details of accident considerations).

The general arrangement figures in Section 1.2 show the general building layout of various pieces of equipment comprising the liquid radwaste system. Figure 11.2-1 (Drawing M-39) and Figure 11.2-2 (Drawing M-369) show the reactor building equipment drains and the drywell equipment drains which are the sources of liquid radwaste collected for normal processing in the equipment drain system. Figure 11.2-1 and Figure 11.2-2 also show the floor drain system in the reactor building that collects liquid radwaste for normal processing in the floor drain system. The drywell drain systems shown in these figures are normally routed to the equipment drain system. Figure 11.2-3 (Drawing M-40) and Figure 11.2-4 (Drawing M-370) show the turbine building equipment drain system which collects liquid radwaste from the turbine building area for treatment in the equipment drain system. Figure 11.2-3 and Figure 11.2-4 also show the turbine building floor drain system which collects liquid radwaste for normal processing in the floor drain system. Figure 11.2-5 (Drawing M-45, Sheet 1), Figure 11.2-6 (Drawing M-45, Sheet 2), and Figure 11.2-7 (Drawing M-45, Sheet 3) show the equipment drain liquid radwaste process piping, tanks, pumps, and instrumentation. Figure 11.2-8 (Drawing M-44) shows the floor drain liquid radwaste processing system piping, pumps, tanks, and instrumentation. Figure 11.2-9 (Drawing M-47, Sheet 1) shows the piping and instrumentation for the waste neutralizer tanks and pumps. Figure 11.2-10 (Drawing M-720, Sheet 1), Figure 11.2-11 (Drawing M-720, Sheet 2), Figure 11.2-12 (Drawing M-721), Figure 11.2-13 (Drawing M-722), Figure 11.2-14 (Drawing M-723), and Figure 11.2-15 (Drawing M-724) show the process piping equipment and instrumentation for the maximum recycle system. These figures also show the interfaces between this system and other liquid radwaste systems. The liquid radwaste process sampling is shown in Figure 11.2-16 (Drawing M-178A) and Figure 11.2-17 (Drawing M-720A). Figure 11.2-18 (Drawing M-3478) shows the liquid radwaste radiation monitor. Figure 11.2-19 (Drawing M-3486) and Figure 11.2-20 (Drawing M-3496) show the liquid radiation monitors for the service water systems. Figure 11.2-21 (Offsite Dose Calculation Manual [ODCM] Figure 10-3) shows a simplified liquid radwaste processing diagram and also shows the liquid radwaste discharge points leading to the river.

Cross-connection of the equipment and floor drain systems allows processing of wastes in various modes depending upon the water quality and/or equipment availability.

The liquid radwaste system is piped such that transfer of liquid wastes can be made directly from Dresden Unit 1 to Dresden Unit 2/3 radwaste system. Dresden Unit 1 is in a safe storage (SAFSTOR) condition, although some portions of the Unit 1 radioactive waste system remain operable.

11.2.2.1 Process Description

11.2.2.1.1 Equipment Drain System

Input for the equipment drain system, also known as the waste collector system, includes seal leakage from pump and valve glands which is collected in equipment drain sumps in the drywells, reactor building, and turbine building (Figures 11.2-1, 11.2-2, 11.2-3, and 11.2-4). The wastes handled by this system typically have a low conductivity (on the order of 10 µmho or less) and a low-solids content, but may have a low or high activity.

Where appropriate, sources of waste water are provided with heat exchangers and/or multiple sumps and sump pumps. The drywell equipment drain sump, for example, has a heat exchanger which operates intermittently, and one sump, which has two sump pumps. The drywell floor drain sump also has two sump pumps. The drywell floor drain sump is normally pumped to the radwaste waste collector tank. During a refueling outage it may be aligned to the floor drain collection tank. Also during normal operation the drywell floor drain sump may be aligned to the floor drain collection tank, depending on the water conductivity. The reactor building equipment drain tanks, drywell equipment drain sump, and the drywell floor drain sump are prevented from automatic pumping of the sump and/or tank contents to the radwaste waste collector tank during an accident. This is discussed further in Section 11.2.3.4.

In the processing (see Figures 11.2-5, 11.2-6, and 11.2-7) of the liquid radwaste from the equipment drain system, the normal process path for the low-conductivity wastes are as follows. These low-conductivity wastes are collected in the waste collector tank. The waste is pumped through a filter and then to the demineralizer unit. The normal process flow is to the waste sample tanks where the processed water is sampled. If the processed liquid radwaste in the waste sample tank meets certain specifications (typical criteria are listed in Table 11.2-3), the processed water is pumped to the condensate storage tanks. Dependent upon the station water inventory, the water may be discharged to the river through the discharge canal. In the flow path for discharge to the river, the water from the waste sample tanks or floor drain sample tanks can be transferred to the waste surge tank for discharge to the river. Water processed into the floor drain sample tanks can be discharged directly to the river if required. Other processing flow paths exist in this processing system and are addressed in Section 11.2.2.4.

11.2.2.1.2 Floor Drain System

Input for the floor drain system (shown in Figure 11.2-8) includes water from the floor drain sumps in the reactor buildings, turbine building, and radwaste building, the maximum recycle drains and vents, and the heating boiler (Figures 11.2-1, 11.2-2, 11.2-3, and 11.2-4). The wastes handled by this system are those having a higher conductivity than the water in the equipment drain system.

The liquid radwaste collected in the floor drain collector tank is transferred into the waste neutralizer tanks, which are sampled and batched to the maximum recycle neutralizer tanks, and then processed through the maximum recycle system to remove as much radioactive contamination as possible. The liquid from the floor drain collector tank can also be transferred to the floor drain surge tank or to the floor drain neutralizer tanks for processing through the maximum recycle system.

Drywell floor drains are routed to the equipment drain system because that waste is expected to have a low conductivity (leakage from reactor coolant system), and this routing removes a potential source of activity from the floor drain system.

Sample sink drains are segregated to minimize activity input to the floor drain system. The sample system is addressed in Subsection 11.2.2.6.

Curbs are placed around certain equipment drain sumps to prevent activity and high conductivity from entering these sumps in the event of floor drain sump overflow.

Input to the floor drain system collected in the floor drain collector tank (in the radwaste building basement) are those liquid wastes having a higher conductivity than the wastes in the equipment drain system. These liquid wastes are processed through the maximum recycle system.

11.2.2.1.3 Maximum Recycle System

The maximum recycle system (Figures 11.2-10, 11.2-11, 11.2-12, 11.2-13, 11.2-14, and 11.2-15) consists of two identical trains of components. Normally one train is used at a time, and the other is in standby. The maximum recycle trains can be used in parallel. The maximum recycle demineralizers can be operated in series as well as in parallel.

Waste water to be processed by the maximum recycle system is sampled and the pH adjusted if necessary. The solids or sludge, commonly called concentrated waste, are solidified or further processed as solid radwaste by contract services (Section 11.4). The distillate is demineralized, then sent to a sample tank. After being sent to a floor drain sample tank or waste sample tank for sampling, the water may be reused as condensate, or it may be discharged to the river by way of the floor drain sample tanks or waste surge tank, processed through the waste filter and demineralizer, or recycled for further distillation/demineralization.

Heat for the maximum recycle concentrators is supplied by steam from one of the three closed loop reboilers. The maximum recycle reboilers are shell and tube heat exchangers which are heated by steam from the nuclear steam supply system. The radwaste reboiler is also a shell and tube heat exchanger which is heated by steam from the auxiliary heating steam boiler.

11.2.2.1.4 Waste Concentrator System

The waste concentrator system, excluding the closed loop radioactive waste reboiler system, has been partly removed and partly abandoned in-place. Although this system was a part of the initial licensing basis of the plant, liquid radwaste treatment methods have been improved such that this system is no longer efficient in treating the waste for discharge and/or solidification for shipment for burial.

11.2.2.1.5. Portable Waste Treatment System

System taps are provided to allow connection to portable waste treatment systems that are capable of processing liquid radwaste. A portable waste treatment system is any system that enables efficient processing of liquid radwaste. Portable waste treatment systems can either be connected to plant installed radwaste equipment to augment processing capabilities or may be self contained, skid mounted equipment, capable of all liquid radwaste processing needs and requirements.

11.2.2.2 Description of Major Components

The components addressed in this subsection comprise the liquid radioactive waste systems described in Subsection 11.2.2.1.

11.2.2.2.1 Waste Collector Tank

The waste collector tank (2001-461) provides a storage volume of 33,000 gallons for liquid radioactive waste. The waste collector tank is a closed tank. Input to the tank comes from the sources (shown in Table 11.2-4) which are considered low-conductivity sources.

11.2.2.2.2 Waste Collector Pumps

The waste collector pumps (2005A and 2005B) perform the following functions:

A. Mix the contents of the waste collector tank;

B. Transfer tank contents to the floor drain collector tank;

C. Transfer tank contents to the waste sample tanks by way of the waste collector filters and demineralizer;

D. Provide redundant pump capability in the event that one of the pumps is not available;

E. Blowdown to the waste filter sludge tank;

F. Transfer to the maximum recycle system;

G. Supply the eductor driving force to decant the waste filter sludge tank ("A" cleanup filter sludge storage tank); and

H. Supply the eductor driving force to decant the resin cleaner sludge tanks ("B" cleanup filter sludge storage tank).

The pumps are designed for a 200-gal/min flow. The design temperature is 200°F and the design pressure is 150 psig. The pumps are provided with a seal water system to minimize maintenance requirements.

11.2.2.2.3 Waste Collector Filters

The waste collector filters (2043-1A and 2043-1B) remove fine particulates from the liquid waste. The filters use a filter aid (or precoat material) which, along with the filter sludge, is backwashed to the filter sludge tank where the sludge and filter media are processed further as solid waste. The filters have 400 square feet of filtering area each. The flow through these filters is normally 200 gal/min.

11.2.2.2.4 Waste Demineralizer

The waste demineralizer (2007) is used to purify the liquid radioactive waste to the water specifications for the condensate storage tanks. The demineralizer vessel typically contains a bed of mixed resin (H-OH) polishing type. When the resins are depleted they are normally transferred to the spent resin tank for disposal as radioactive waste. The demineralizer normal flowrate is 200 gal/min.

11.2.2.2.5 Waste Surge Tank

The waste surge tank (2001-463) is used for liquid radioactive waste discharge from the station to the river, or the water may be reprocessed. Excess low-conductivity water can also be stored in the water surge tank temporarily until it can be processed through the waste filter and waste demineralizer to the waste sample tanks. Normally the waste surge tank contents are processed through filters and demineralizers to the waste sample tanks and to storage in the condensate storage tanks however, if the total organic carbon content is high, or condensate storage tank is not available, the contents may be discharged to the river or reprocessed. Inputs to waste surge tank are from the following sources:

A. The floor drain sample tanks and

B. The waste sample tanks.

The 77,000-gallon capacity tank is normally the single source for discharge of liquid radioactive waste, however floor drain sample tanks can also be discharged, if required.

11.2.2.2.6 Waste Surge Tank Pump

The waste surge tank pump (2011) transfers the liquid waste either to the waste collection system for further processing or to the discharge canal to the river. The pump can also transfer the waste surge tank contents to the Unit 1 radwaste storage, to the "B" waste neutralizer tank, and to the maximum recycle system. The waste surge tank pump is also used to recirculate the waste surge tank contents for mixing. The pump capacity is 400 gal/min.

11.2.2.2.7 Waste Sample Tanks

The waste sample tanks (2001-468A, 2001-468B, and 2001-468C) collect the processed liquid radioactive waste from either the waste collector system or the floor drain system. The three tanks have a capacity of 33,000 gallons each. The redundancy allows one tank to be isolated for sampling and pumping of the liquid waste while the other tanks are available to receive processed liquid effluent. The waste sample tank contents are normally transferred to the condensate storage tanks. The tank contents can be transferred to the floor drain surge tank if required.

11.2.2.2.8 Waste Sample Tank Pumps

The waste sample tank pumps (2001-80A, 2001-80B, and 2001-80C) recirculate the tank contents for mixing prior to sampling and then transfer the processed liquid contents of the waste sample tanks to any of the following places:

A. The condensate storage tanks;

B. The waste collector tank;

C. The waste surge tank; and

D. The floor drain surge tank.

The design capacity for each pump is 400 gal/min.

11.2.2.2.9 Floor Drain Collector Tank

The floor drain collector tank (2001-459) provides a storage volume of 22,000 gallons for liquid radwaste. The floor drain collector tank is a closed tank. The input sources come from the areas shown in Table 11.2-5.

11.2.2.2.10 Floor Drain Collector Tank Pumps

The floor drain collector tank pumps (2/3-2013A and 2/3-2013B) provide the following functions:

A. Mix the contents of the floor drain collector tank by recirculation;

B. Transfer tank contents to the floor drain surge tank;

C. Transfer tank contents to the maximum recycle floor drain neutralizer tanks;

D. Transfer tank contents to waste neutralizer tanks A or B;

E. Transfer tank contents to "A" waste collector filter;

F. Transfer blowdown tank contents to floor drain filter sludge tank;

G. Supply the eductor driving force to decant the waste filter sludge tank ("A" cleanup filter sludge storage tank);

H. Supply the eductor driving force to decant the resin cleaner sludge tank ("B" cleanup filter sludge storage tank); and

I. Supply the eductor driving force to decant the floor drain filter sludge tank (filter sludge storage tank).

The pumps are designed for a 400-gal/min flowrate with a design temperature of 200°F and a design pressure of 150 psig. The pumps are provided with a seal water system to minimize maintenance requirements.

11.2.2.2.11 Floor Drain Filter

The floor drain filter was provided to remove fine particulate from the liquid radwaste stream, however this filter is no longer used. The equipment is bypassed.

11.2.2.2.12 Floor Drain Sample Tanks

The floor drain sample tanks (2001-484A and 2001-484B) collect the processed liquid radioactive waste from the maximum recycle system. The floor drain sample tanks have a capacity of 22,000 gallons each. The redundancy allows one tank to be isolated for sampling and pumping of the liquid waste while the other tank is available to receive processed liquid effluent. The contents of these tanks may be transferred to the condensate storage tank, reprocessed for additional cleanup, or discharged to the river as needed.

11.2.2.2.13 Floor Drain Sample Tank Pumps

The floor drain sample tank pumps (2016A and 2016B) recirculate the tank contents for mixing prior to sampling and then transfer the processed liquid contents from the floor drain sample tanks to any of the following places:

A. The maximum recycle floor drain neutralizer tanks;

B. The "B" waste neutralizer tank;

C. The waste collector tank;

D. The waste surge tank;

E. The floor drain surge tank;

F. The condensate storage tanks; and

G. The Unit 1 chemical cleaning storage tanks.

11.2.2.2.14 Waste Neutralizer Tanks

The waste neutralizer tanks (2001-473A and 2001-473B) provide a 16,500-gallon capacity each for the storage, sampling, and processing of floor drain liquid wastes. Input to the waste neutralizer tanks are from the following sources:

A. Floor drain sample tanks;

B. Cask washdown;

C. Detergent drain from main turbine floor decontamination pit;

D. Floor drain collector tank/waste neutralizer tank A header;

E. Waste demineralizer area;

F. Unit 2 mechanical vacuum pump;

G. Unit 3 mechanical vacuum pump;

H. Drain from the 613' decontamination pit; and

I. Unit 1 radioactive waste system.

J. SBGT loop seal drains;

The redundancy allows one tank to be isolated for sampling and pumping of the neutralized liquid waste while the other tank is available to receive high- conductivity waste for neutralization.

11.2.2.2.15 Waste Neutralizer Pumps

The waste neutralizer pumps (2019A, 2019B, and 2019C) provide the following functions:

A. Recirculation of the tank liquid contents for mixing;

B. Transfer tank contents between the waste neutralizer tanks;

C. Transfer the tank contents to the maximum recycle floor drain neutralizer tanks;

D. Transfer the tank contents through the floor drain filter to the floor drain sample tanks;

E. Transfer the tank contents to the floor drain surge tank; and

F. Provide redundant pump capability in the event that one of the pumps is not available.

The design capacity of these waste neutralizer pumps is 400 gal/min with a design temperature of 200°F and a design pressure of 150 psig. These pumps are provided with seal water to minimize maintenance and replacement of these pumps seals due to wear from the chemical solutions.

11.2.2.2.16 Floor Drain Surge Tank

The floor drain surge tank (2/3-2012-359) provides the necessary surge volume (200,000 gallons) for the floor drain system. The tank is located outside the Unit 3 turbine building near the southwest corner. The tank is equipped with electric heaters to prevent freezing during cold weather. The tank bottom is sloped to reduce sludge buildup. The floor drain surge tank is considered a Class I Structure and is, therefore, not considered an above-ground tank for the purpose of the curies content requirements of the Technical Specifications. The following sources provide input to the floor drain surge tank:

11.2.2.2.19 Chemical Addition Tank

The chemical addition tank (2/3-2012-406) with its integral mixer provides sufficient volume for a 1-week supply of chemical solution of disodium phosphate which neutralizes the liquid waste. A sufficient amount of the chemical solution is added to the neutralizer tanks to maintain a pH range of 7.5 to 8.0.

11.2.2.2.20 Chemical Feed Pumps

The positive displacement chemical feed pumps (2/3-2012-408A and 2/3-2012-408B) transfers the required amount of chemical solution to the floor drain neutralizer tanks. The pump capacity is 7.5 gal/min.

11.2.2.2.21 Antifoam Addition Tank

The antifoam addition tank (2/3-2012-366) chemical solution is added to minimize the foaming and sudsing from detergents in the floor drain wastes. Antifoam chemical addition also minimizes liquid carryover from sudsing in the concentrator. The chemicals are gravity fed to the mixing pump suction line of the floor drain neutralizer tanks. Antifoam may also be added by using the vapor head spray and chemical feeder (2/3-3323) directly into the concentrator vapor heads.

11.2.2.2.22 Floor Drain Neutralizer Tank Mixing Pumps

The floor drain neutralizer tank mixing pumps (2/3-2012-401A and 2/3-2012-401B) are used to recirculate the liquid contents of the floor drain neutralizer tank as a means of mixing. These pumps can also transfer the waste solution from one floor drain neutralizer tank to the other floor drain neutralizer tank; they can also transfer the waste solution to the floor drain surge tank. The pumps have a design flow capacity of 200 gal/min each. The pumps also provide sample flow for grab sampling and mixing for chemical additions and for antifoam additions made to the tank contents.

11.2.2.2.23 Maximum Recycle Concentrator Feed Pumps

The maximum recycle concentrator feed pumps (2/3-2012-403A and 2/3-2012-403B) normally transfer the liquid waste to the maximum recycle concentrator vapor head. The pumps may also be used to recirculate the floor drain neutralizer tank contents. The pumps may transfer the floor drain neutralizer tank contents to the distillate tank without transfer to the maximum recycle concentrator. The maximum recycle concentrator feed pumps can transfer the floor drain neutralizer tank contents to either maximum recycle concentrator train.

11.2.2.2.34 Floor Drain Demineralizers

The floor drain demineralizers (2/3-2012-418A and 2/3-2012-418B) are typically mixed deep bed (H-OH) polishing type resin. When the resins are depleted they are normally transferred to the spent resin tank for disposal of radioactive waste. Flow through the resin bed is 200 gal/min to ensure proper ion exchange. The liquid flow from the system is about 25 gal/min with a recirculation flow of about 175 gal/min back to the liquid feed tank from the demineralizer outlet.

11.2.2.2.35 Discharge Flow to the Discharge Canal

The tank contents to be discharged are sampled and must have a minimal radioactivity content so that the calculated discharge flowrate is greater than the pump capacity with dilution flow from the main condenser circulating water flow to the discharge canal. An effluent radiation monitor is located off-stream to warn of high-activity water being discharged.

11.2.2.2.36 Discharge Line to the Discharge Canal

The discharge line (2/3-2019-3"L) outside the restricted area is fiberglass- reinforced, epoxy resin pipe.

11.2.2.2.37 Liquid Radwaste System Piping

A major upgrade of the radwaste system piping (about 7000 feet) replaced approximately 2500 feet of piping and permanently removed approximately 1500 feet of piping. About 3000 feet of the piping remains in place. The replacement piping, fittings, and valves are stainless steel. The original piping is carbon steel.

11.2.2.3 Redundancy of Major Equipment

Redundancy of the major pieces of equipment discussed in Section 11.2.2.2 facilitates operation of the systems while a pump is down for maintenance; a filter is being backwashed; or an ion-exchange resin is being cleaned or sluiced to the spent resin tank. The redundancy in tanks provides for an available process tank while the contents of one tank are being recirculated, sampled, or transferred.

11.2.2.4 Alternate Process Pathways

There are several process pathways within the liquid radwaste system. The normal flow path for liquids collected in the waste collector tank is through the

F. Floor drain filter outlet (range 0 to 100 µmho); and

G. Waste demineralizer outlet (range 0 to 10 µmho).

The sample sources for the maximum recycle sample sink are listed below:

A. Maximum recycle floor drain neutralizer tank "A";

B. Maximum recycle floor drain neutralizer tank "B";

C. Concentrator condenser "A" outlet; and

D. Concentrator condenser "B" outlet.

These sample points provide means to obtain liquid grab samples at a centralized location for radioisotopic analysis in the chemical laboratory. The analytical results determine the water quality and system operation.

The sample sources for the maximum recycle demineralizer sample sink are listed below:

A. Floor drain demineralizer inlet "A";

B. Floor drain demineralizer outlet "A";

C. Floor drain demineralizer inlet "B"; and

D. Floor drain demineralizer outlet "B."

These sample points provide means to obtain liquid grab samples at a centralized location for radioisotopic analysis in the chemical laboratory. The analytical results determine water quality and demineralizer efficiency.

11.2.2.7 Inspection And Testing

Testing of this system is precluded by its normal day-to-day operation. Inspection is performed per equipment requirements and normal maintenance procedures. Effluent monitor calibration is performed periodically as required by procedure and the Offsite Dose Calculation Manual (ODCM)

11.2.2.8 Protection Against Accidental Discharge

Protection against accidental discharge is provided by design redundancy, instrumentation for detection and alarm of abnormal conditions, and procedural controls. The arrangement of the radwaste building and the methods of waste processing provide a substantial degree of immobility of the wastes within the station. This arrangement assures that in the event of a failure of any of the liquid waste equipment or errors in operation of the system, the potential for inadvertent release of liquids is small. For example, the waste collector tanks, filter and demineralizers, and other equipment within the radwaste building are contained within rooms so that leakage is contained within the building.

All Potentially Radioactive and Radioactive liquid waste discharges to the environment are routed through a single line to the discharge canal. This line has flowmeters, an offline radiation monitor, and double valves which are kept locked closed except when in use. The normal flow of liquid waste to the river is from the waste surge tank. The floor drain sample tank(s) can be discharged if necessary. Locked closed valves (2/3-2001-91, 2/3-2018A-504, and 2/3-2018B-501) prevent transfer to the discharge canal when transferring waste sample tank contents and floor drain sample tank contents to the waste surge tank. Procedurally, the waste surge tank must be sampled, analyzed, and a discharge rate determined prior to allowing discharge to the canal. The discharge procedure also requires the valve lineup for discharge to be independently verified and the discharge rate calculation to be independently verified. Once a transfer is initiated, the operator checks the flowmeter, the effluent radiation monitor, and the level recorder for the waste surge tank. Thus, the operator has a number of means of confirming the correct routing.

The only error that could cause inadvertent waste discharge from the radioactive waste management system to the canal would be leaving the canal discharge valves open so subsequent tank filling could result in flow to the canal. Most tank contents transferred to the waste surge tank are to be discharged. Since averaging over a period of a year is permitted by 10 CFR 20, the consequences of inadvertent discharge would be nil.

It should be noted that procedural controls require the discharge valves to be locked closed at the end of a discharge. Also the discharge valves must be verified locked closed when transferring a tank of liquid to the waste surge tank.

11.2.2.9 Leakage Detection Systems

Provisions are made in the design of the station to detect leakage from vital fluid carrying systems at and beyond the reactor coolant pressure boundary. These leakage detection methods are discussed in detail in Section 5.2.

11.2.2.10 Ultrasonic Resin Cleaners

The ultrasonic resin cleaner is a device for cleaning the ion-exchange resins in the deep bed condensate treatment system. Ultrasonic resin cleaners are installed in the Unit 2 and 3 condensate demineralizer regeneration systems. Ultrasonic resin cleaners are cross-connected to permit use with either unit. The accumulated crud (principally iron oxides) is removed as a thin water slurry to the waste collector subsystem of radwaste. The use of the ultrasonic resin cleaner reduces the amount of regenerative chemicals required to maintain ion exchange capacity. Since ion-exchange capacity is principally used when and if condenser tube leaks occur, the use of regenerant chemicals and the resulting liquid waste is substantially reduced. A potential waste stream to the discharge canal is thus substantially minimized. Potential solid waste quantities (concentrated waste) are also reduced.

11.2.3 Radioactive Releases

11.2.3.1 Release Concentrations

Activity released with the liquid wastes is difficult to characterize since liquid wastes come from a number of sources and the quantity of activity is a strong function of plant operation, including holdup time. The total amount of activity and the relative quantities of each isotope will vary significantly from day to day with varying power levels and leakage from fuel elements.

Table 11.2-7 shows the typical isotopic content which may be present in the radioactive liquid waste discharged to the river. Table 11.2-8 shows the typical tritium content in the liquid waste discharged from the station. Table 11.2-9 shows the typical isotopic content discharged in the containment cooling service water.[1—10]

When discharged to the river, the liquid radioactive wastes from Units 2 and 3 are diluted in the condenser cooling water discharge canal. This dilution of the liquid radioactive wastes lowers the concentration at the time of discharge to a level which is in accord with the limits prescribed by 10 CFR 20 and State of Illinois regulations. The expected average annual activity discharge is significantly less than that permissible under 10 CFR 20. Since this estimate assumes that the activity discharged consists only of radioisotopes Sr-90 and Pb-210, the estimate overstates the actual contribution to the environment radioactivity.

Since additional dilution of wastes by the normal river flow further reduces radioactivity, concentrations of waste activity actually in the river are of the order of one-hundredth of the ECL per 10 CFR 20 for the mixtures generally discharged.

On the basis that the tritium activity in the liquid waste originates in the reactor and is essentially associated with the water molecule, tritium concentrations in liquid wastes will be about the same as in reactor water. Because of the infrequent need to discharge wastes to the river, and the large dilution factor which results in a tritium concentration several orders of magnitude below the ECL, the radiological consequences of tritium activity in the liquid wastes are nil.

11.2.3.2 Effluent Monitoring and Sampling

The radwaste discharge monitor is an offline sampling type monitor (see Figure 11.2-18). When a discharge occurs, the radwaste operator valves-in the monitor and energizes the instrumentation. The water sample is taken from the discharge to river line and is fed through the process detector, a grab sample valve, and into a receiver tank. Failure by any of several means provides audible annunciation in the radwaste control room. The high-activity alarm annunciates in both the radwaste control room and the main control room. The monitor is addressed in more detail in Section 11.5.

The liquid contents of the waste surge tank or floor drain sample tank are sampled and analyzed before being discharged to the river. The discharge rate is determined based on the chemical analysis and the dilution flow in the discharge canal. A composite sample is collected during the discharge of the waste surge tank contents by taking hourly samples and filling a container from which other analyses can be made. If the radiation monitor high-radiation alarm sounds, an automatic sample is taken in the monitor cabinet for chemical analysis by the laboratory.

The service water system discharge stream for both Unit 2 and Unit 3 is monitored for radioactivity and is sampled for chemical analysis periodically as required by the ODCM (see Figures 11.2-19 and 11.2-20).

11.2.3.3 Liquid Waste Release Points

There are three liquid Potentially Radioactive and Radioactive waste release points from the station to the discharge canal. The following release points (see Figure 11.2-21) are shown in the ODCM:[11]

A. The Unit 2/3 liquid radwaste discharge point;

B. The Unit 2 service water system discharge point; and

C. The Unit 3 service water system discharge point.

The typical isotopic quantities of activity found in these streams are given in Tables 11.2-7 and 11.2-9.

There are radiation monitors on each of these three discharge streams.

11.2.3.4 Liquid Waste Discharge from Containment During Accident Conditions

Following the Three Mile Island accident, the NRC requested that each licensee evaluate the possibility of an inadvertent transfer of potentially highly radioactive liquids from inside containment to the liquid radwaste area. The evaluation was conducted and the appropriate modifications were completed.

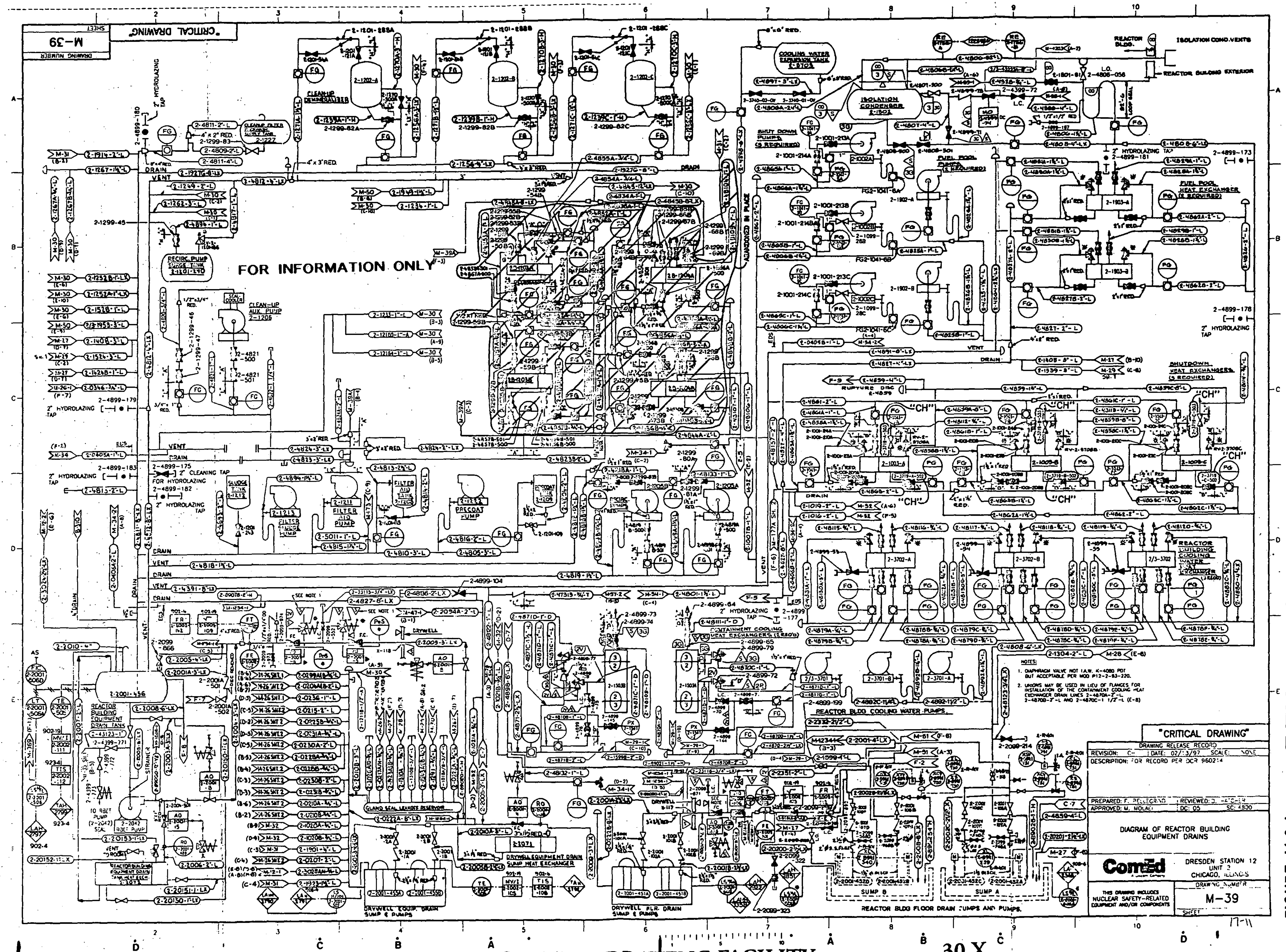
Plant design ensures that highly radioactive fluids are confined to the reactor building during a loss-of-coolant accident. Transfer of radioactive water from the following systems and components is prevented during an accident:

A. Reactor building equipment drain tank (RBEDT) pump;

B. East reactor building floor drain sump (RBFDS) pump;

C. West reactor building floor drain sump (RBFDS) pump;

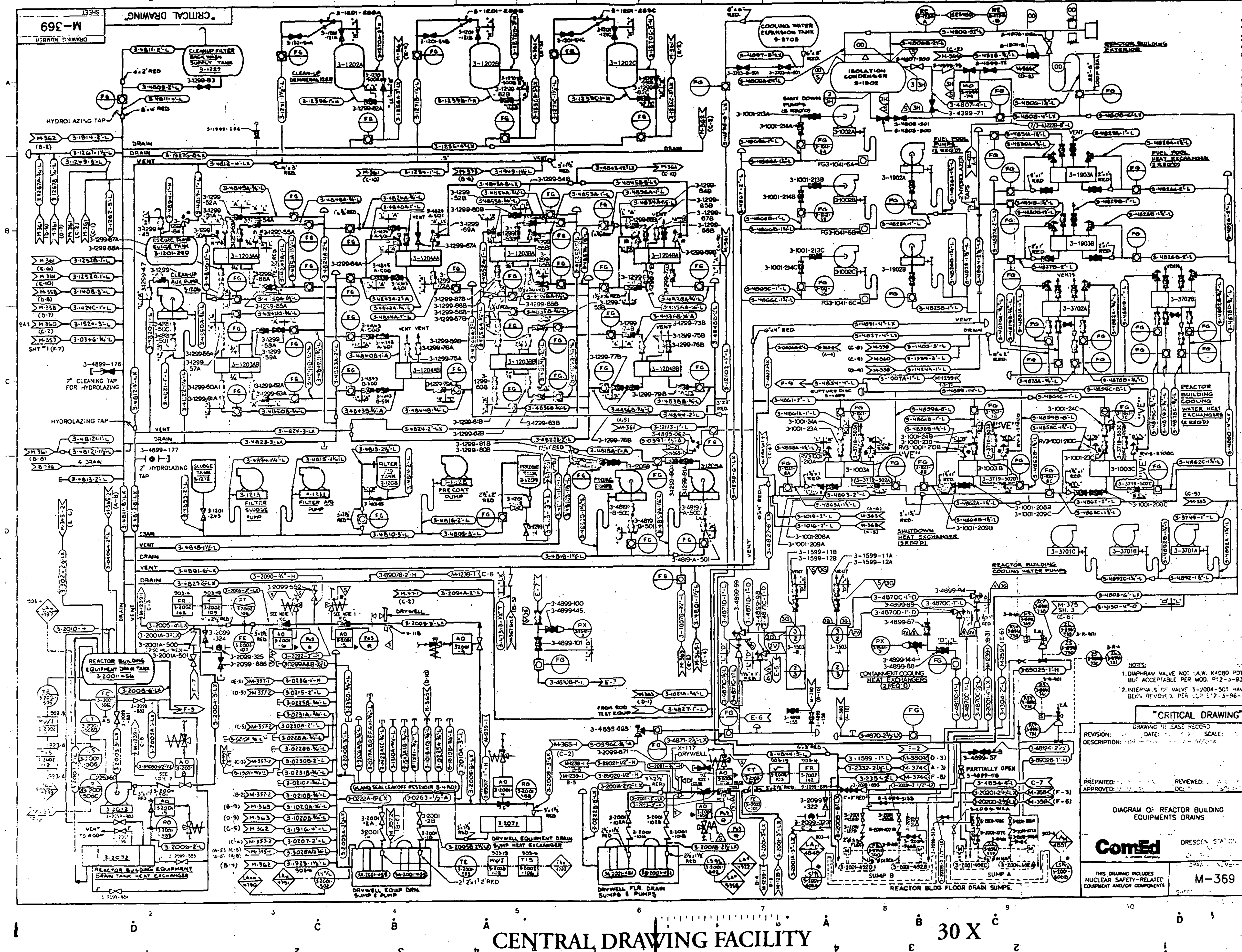
D. Southeast core spray/LPCI corner room sump pump;



CENTRAL DRAWING FACILITY 30 X

REV. 02 / JUNE 1997

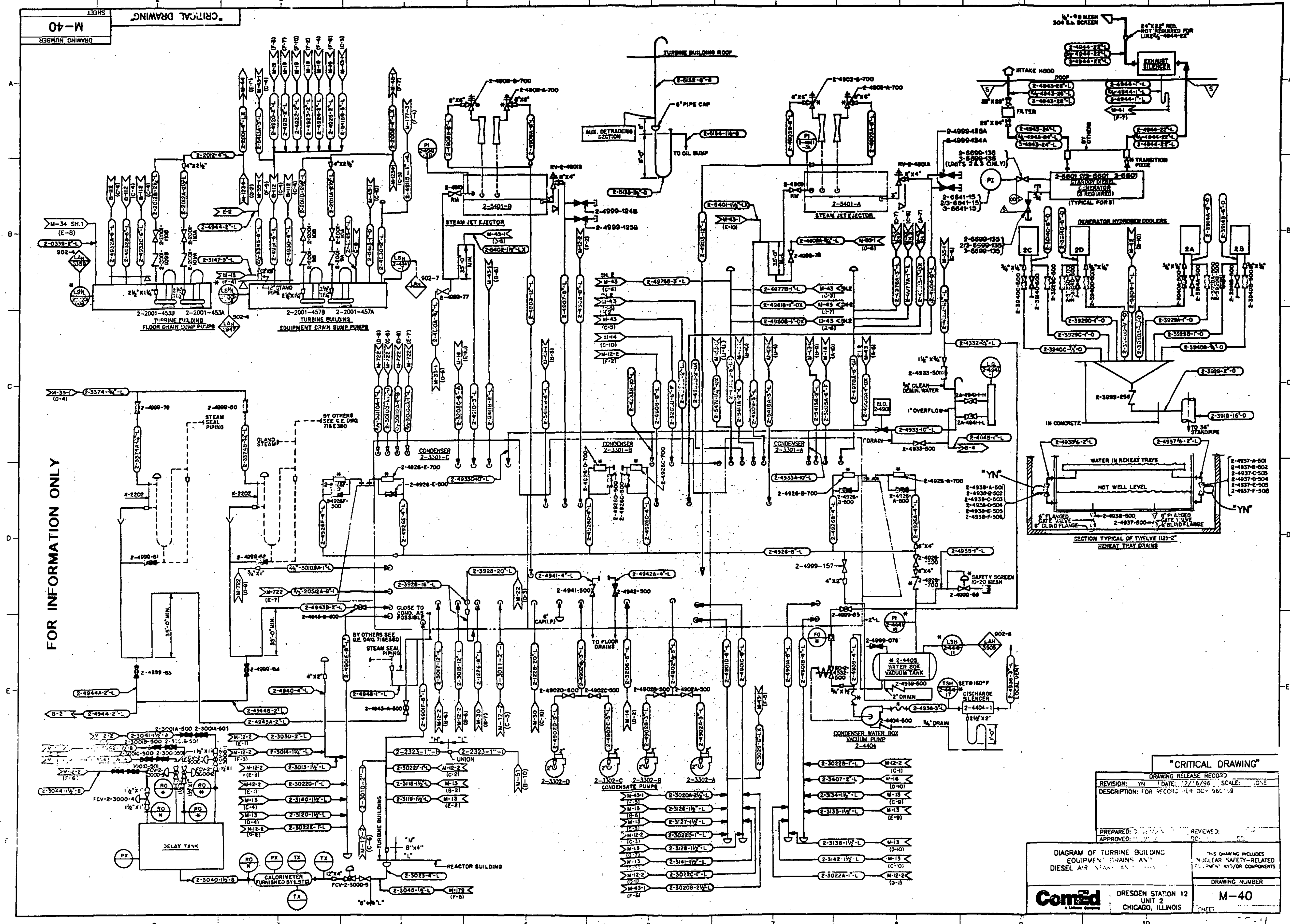
FIGURE 11.2-1



FOR INFORMATION ONLY

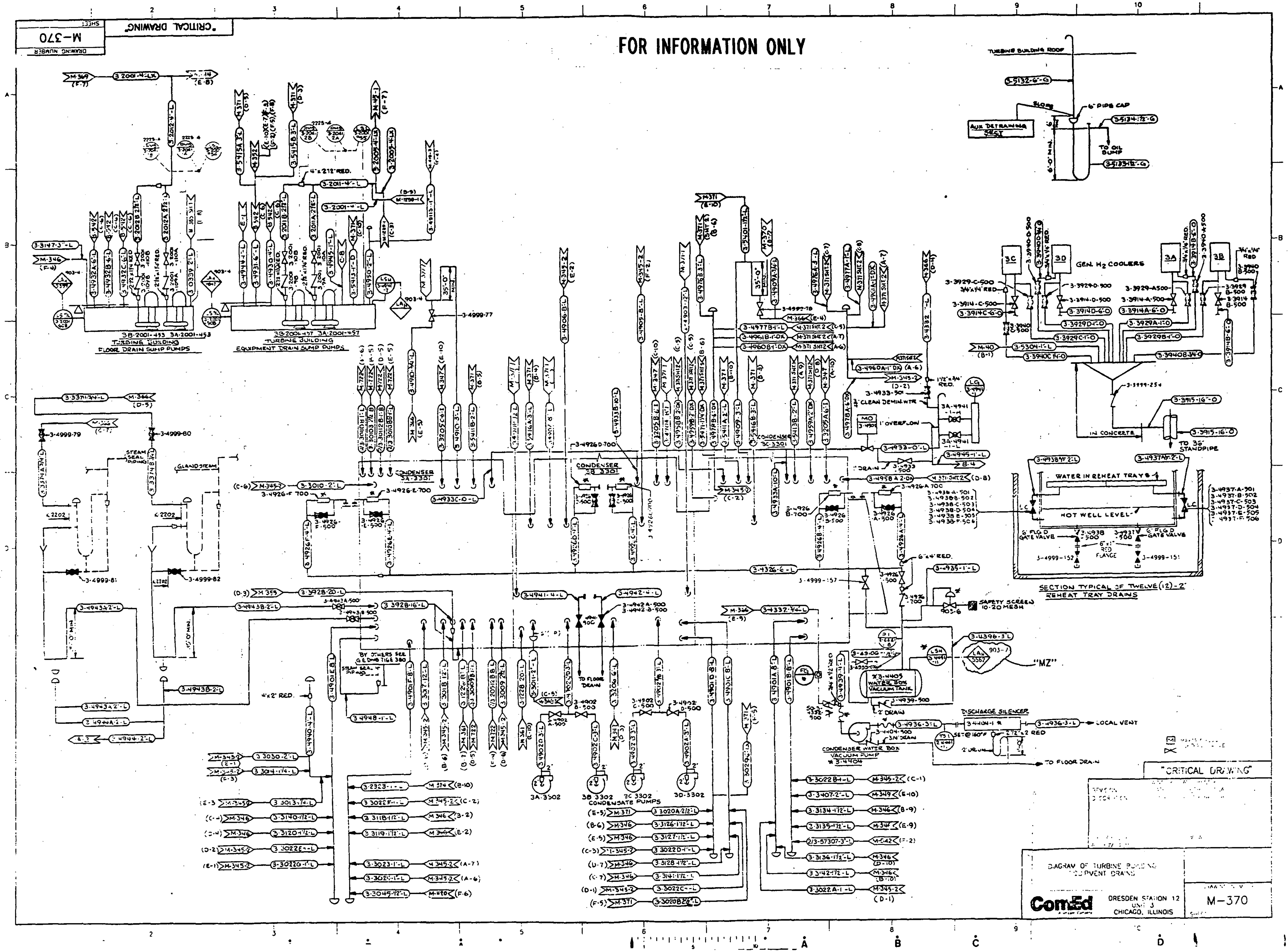
REV. 02 / JUNE 1997

FIGURE 11.2-2



REV. 02 / JUNE 1997

FIGURE 11.2-3



REV. 02 / JUNE 97

FIGURE 11.2-4

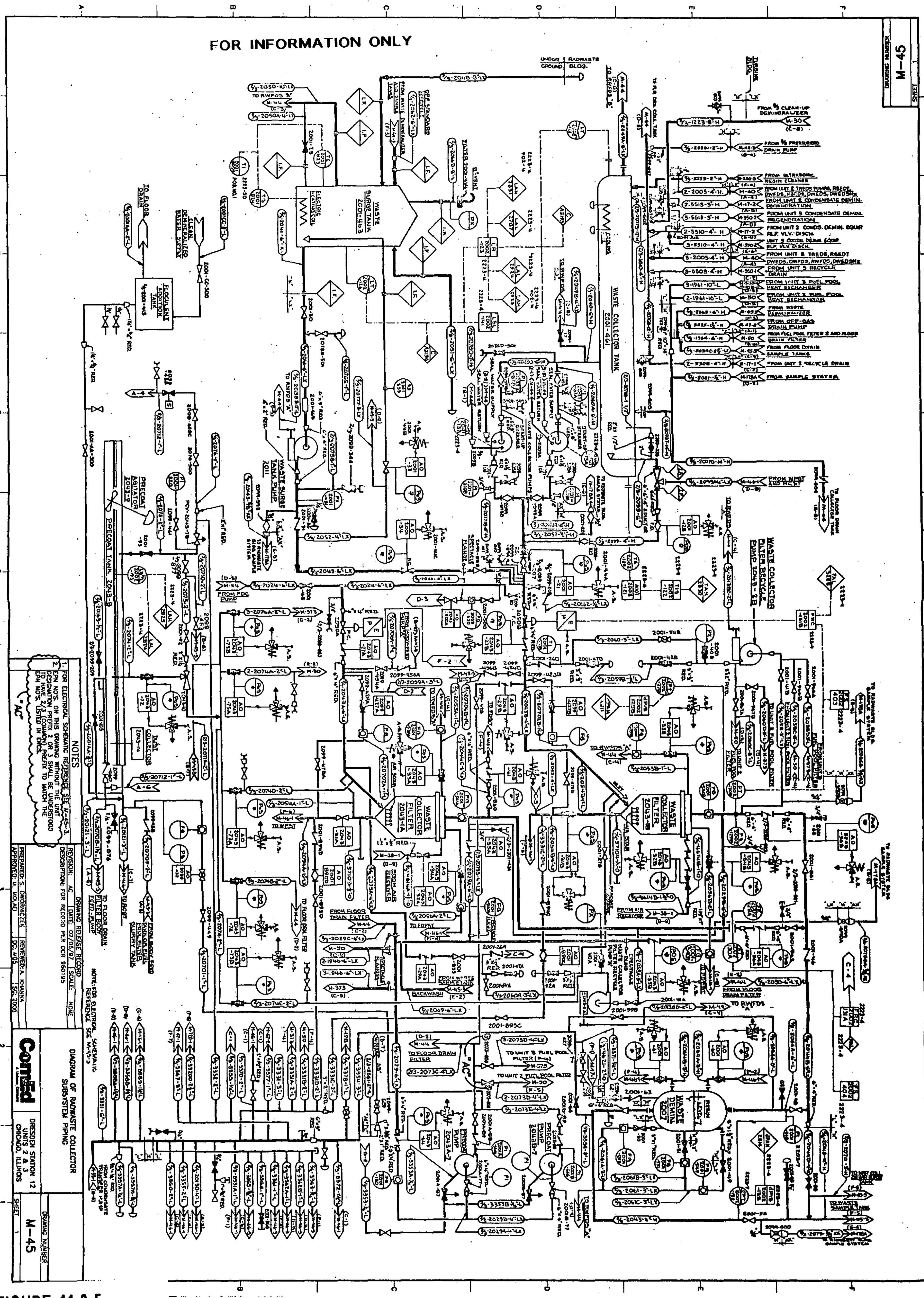


FIGURE 11.2-5

REV. 02 / JUNE 1997

CENTRAL DRAWING FACILITY

30 X

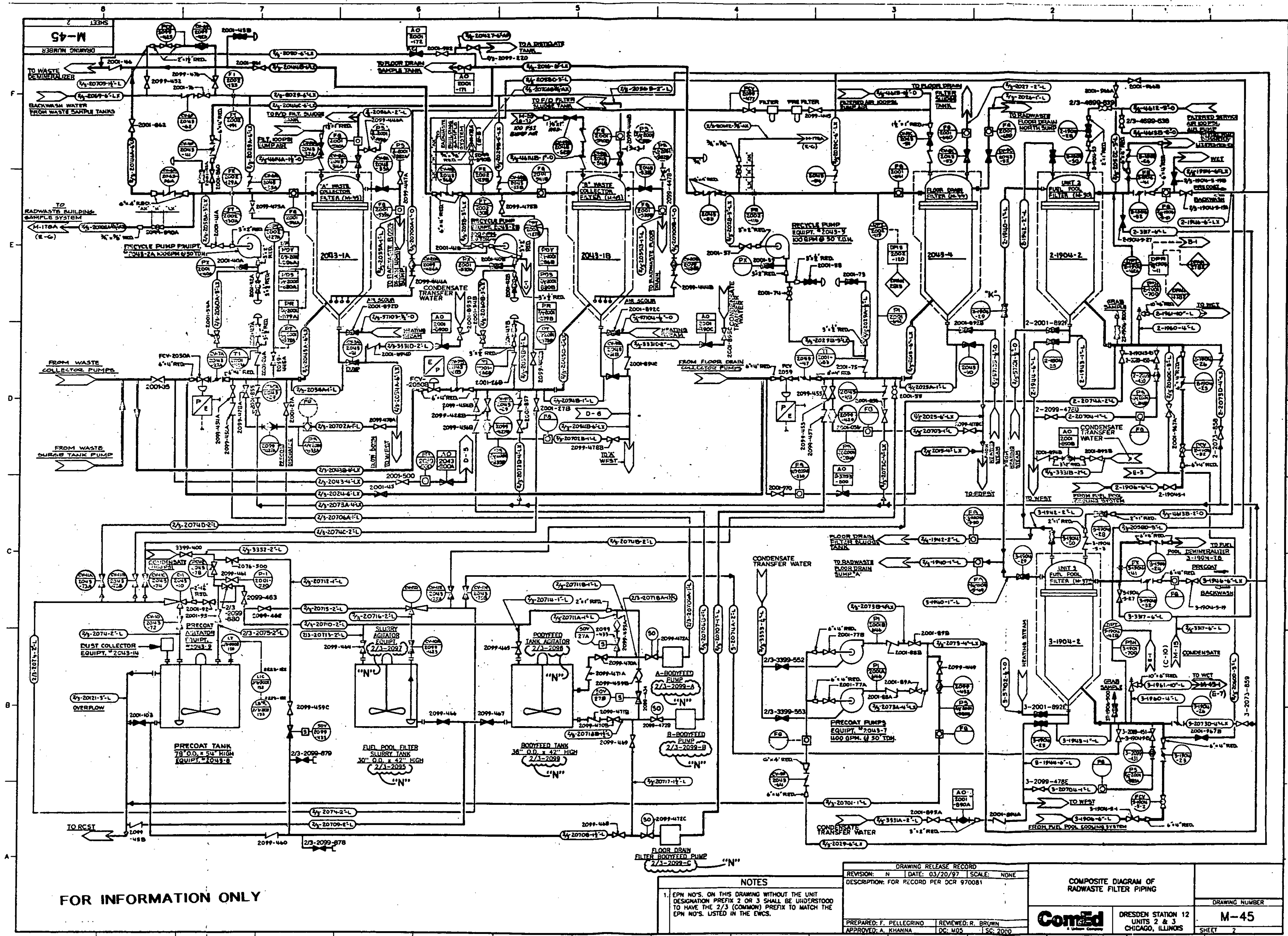


FIGURE 11.2-6

REV. 02 / JUNE 1997

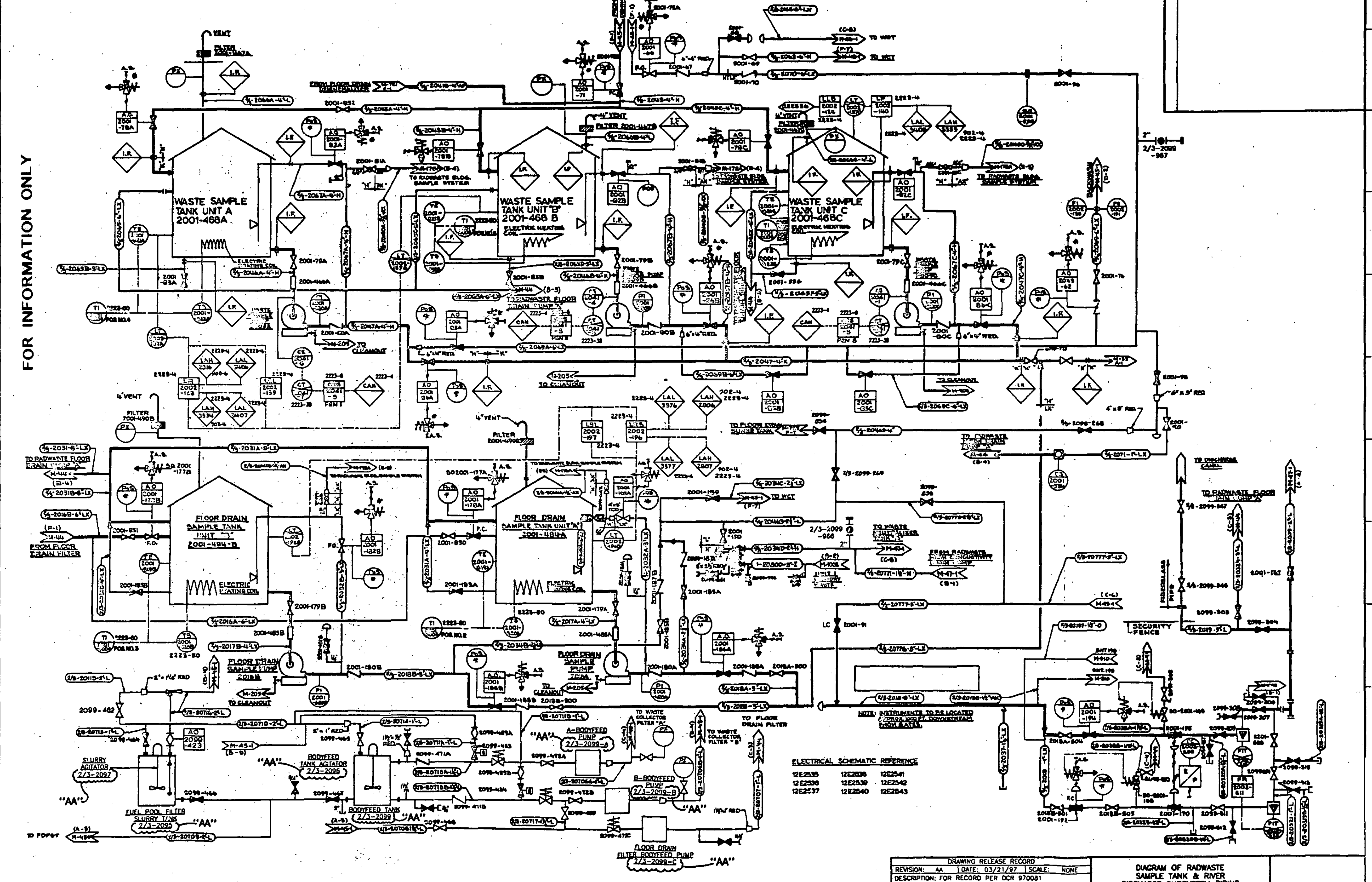
CENTRAL DRAWING FACILITY

30X

FOR INFORMATION ONLY

NOTES

1. EPN NO'S. ON THIS DRAWING WITHOUT THE UNIT DESIGNATION PREFIX 2 OR 3 SHALL BE UNDERSTOOD TO HAVE THE 2/3 (COMMON) PREFIX TO MATCH THE EPN NO'S. LISTED IN EWCS.



DRAWING RELEASE RECORD		
REVISION: AA	DATE: 03/21/97	SCALE: NONE
DESCRIPTION: FOR RECORD PER DCR 970081		
PREPARED: F. PELLEGRINO	REVIEWED: R. BROWN	
APPROVED: A. KHANNA	DC: M05	SC: 2000

DIAGRAM OF RADWASTE SAMPLE TANK & RIVER DISCHARGE SUBSYSTEM PIPING

ComEd A Unicom Company

DRESDEN STATION 12
UNITS 2 & 3
CHICAGO, ILLINOIS

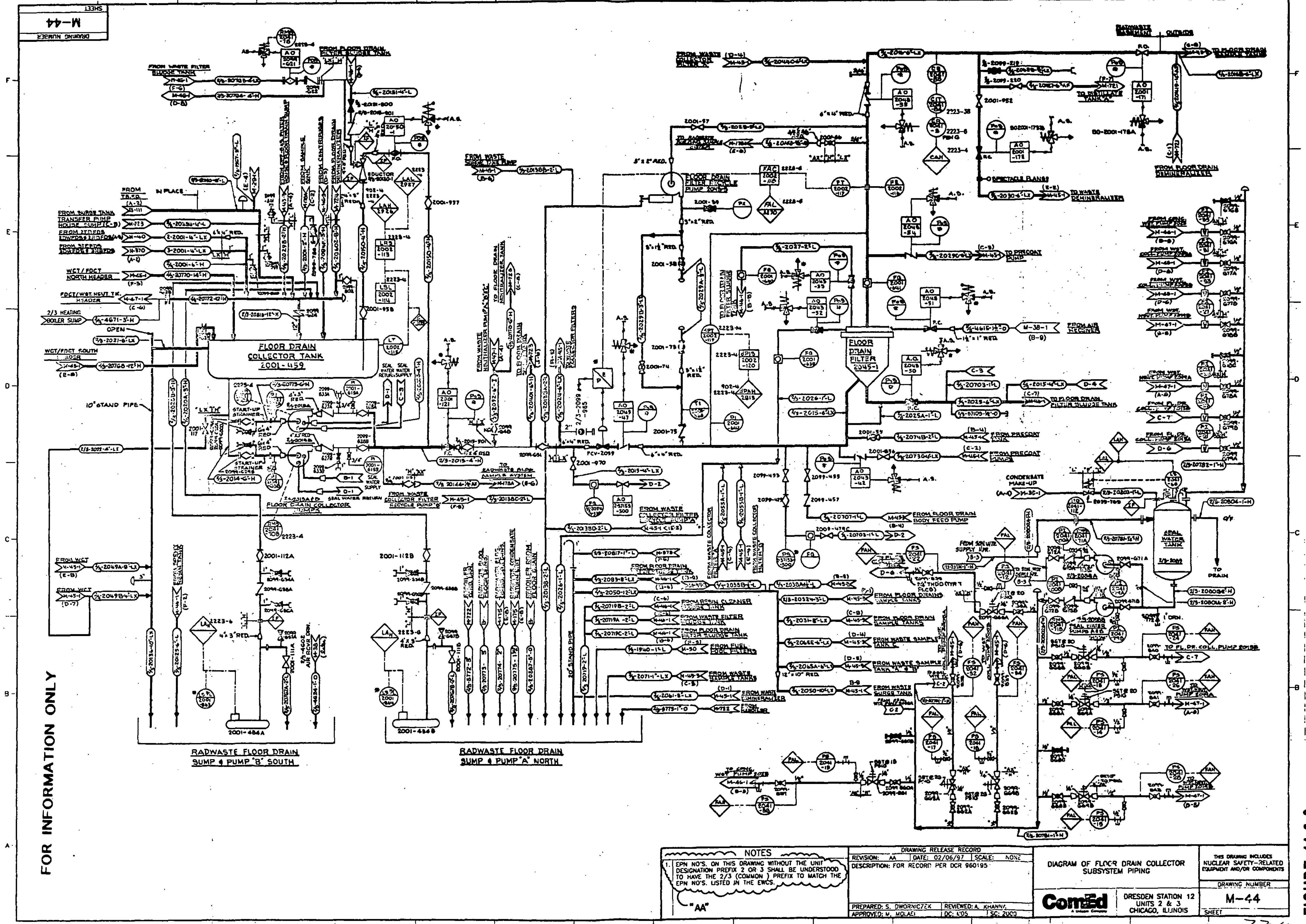
DRAWING NUMBER M-45
SHEET 3

CENTRAL DRAWING FACILITY

30X

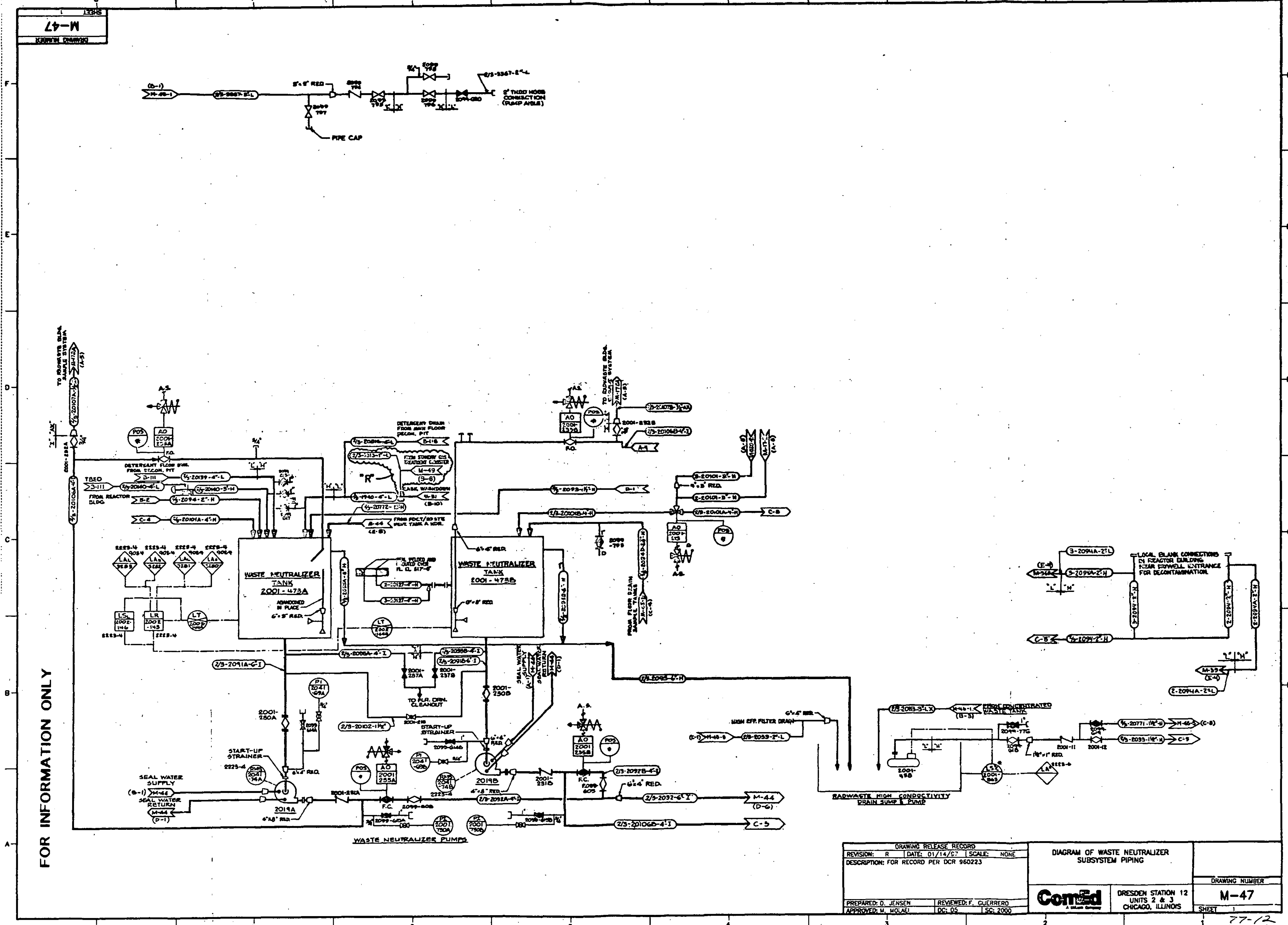
REV. 02 / JUNE 1997

FIGURE 11.2-7



REV. 02 / JUNE 1997

FIGURE 11.2-8



REV. 02 / JUNE 1997

FIGURE 11.2-9

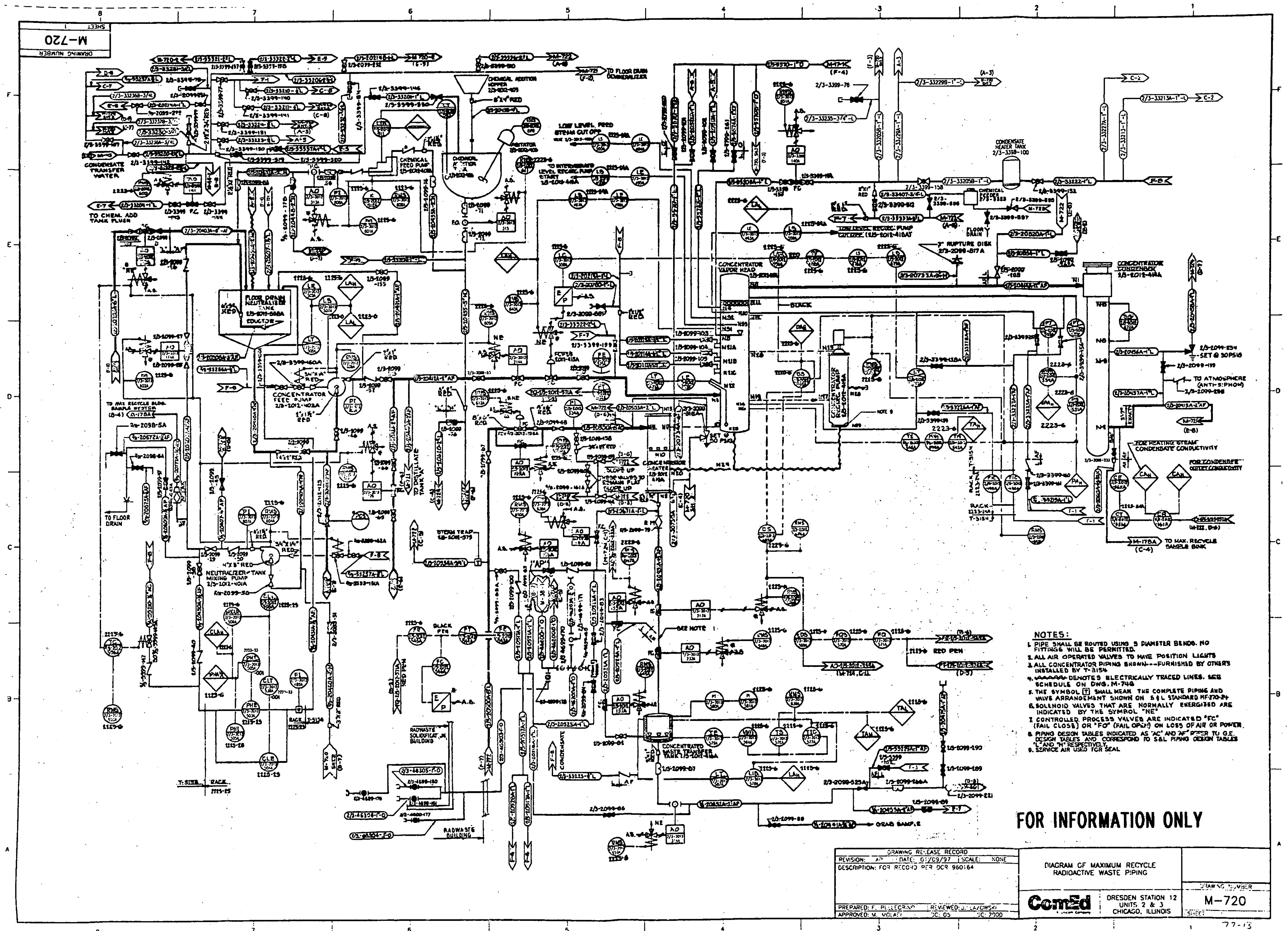
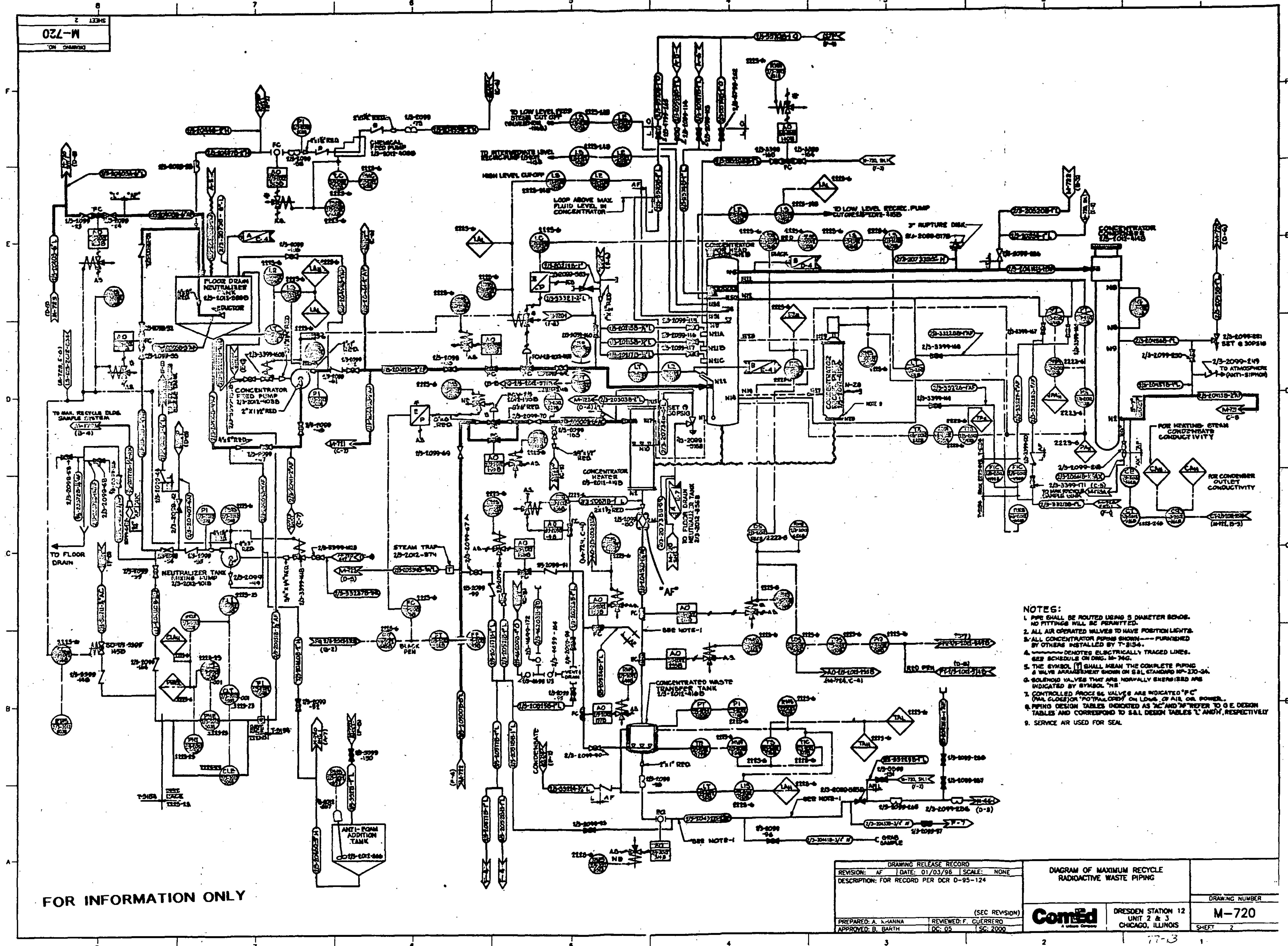


FIGURE 11.2-10

REV. 02 / JUNE 97

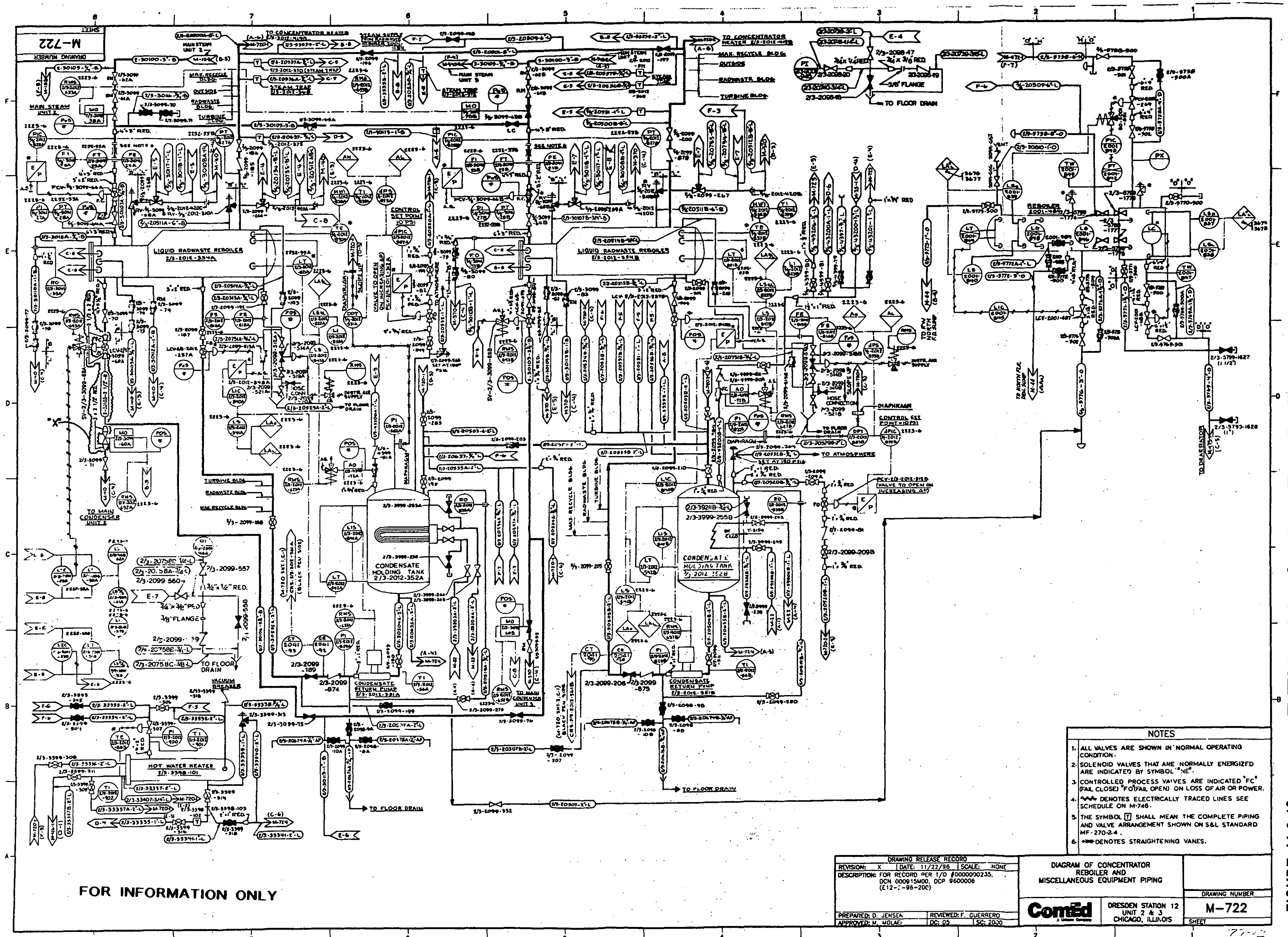
30 X



REV. 02 / JUNE 1997

FIGURE 11.2-11

CENTRAL DRAWING FACILITY 30 X



REV. 02 / JUNE 1997

FIGURE 11.2-13

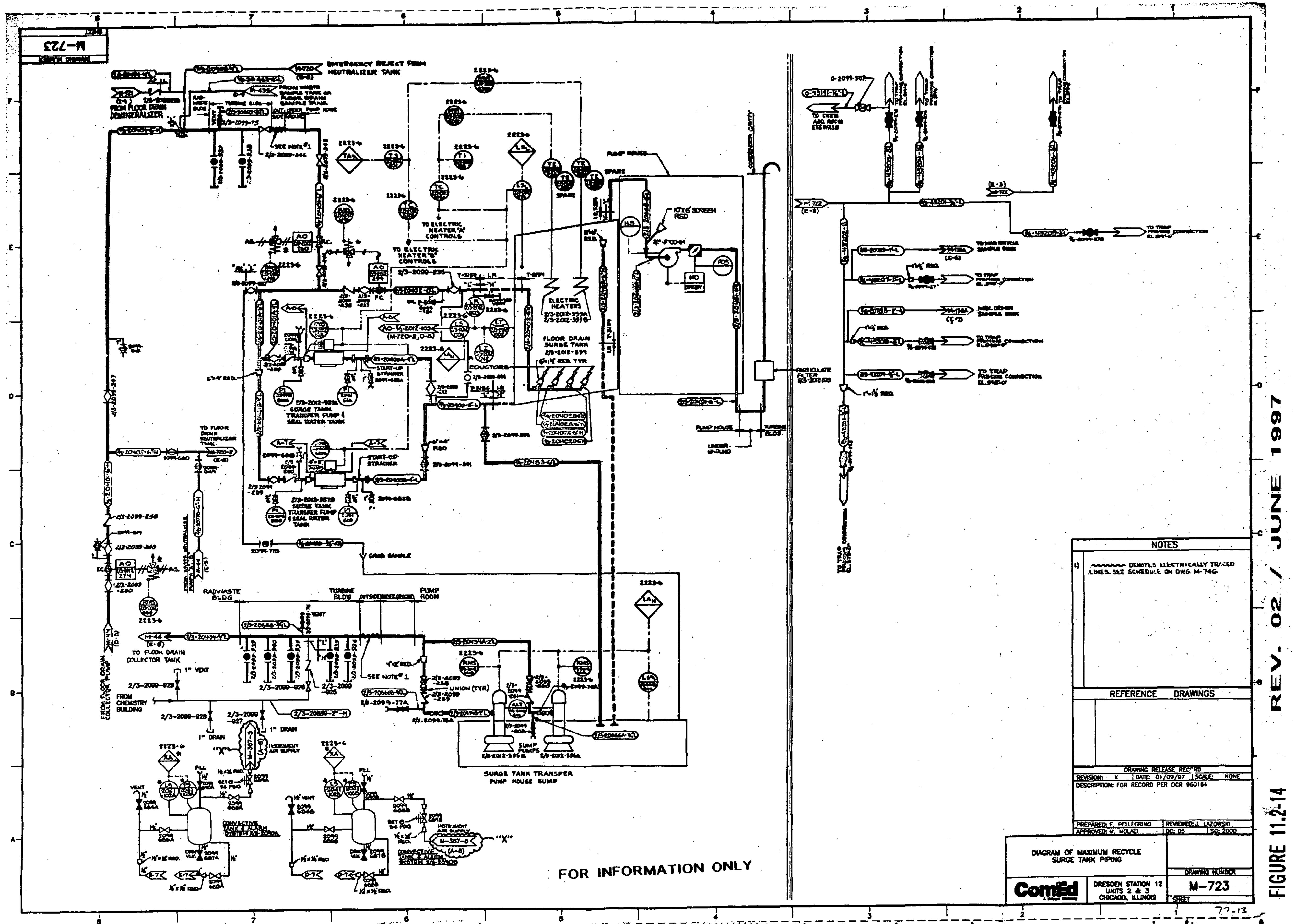


FIGURE 11.2-14

REV. 02 / JUNE 1997

11.3 GASEOUS WASTE MANAGEMENT SYSTEMS

This section describes the capabilities to control, collect, process, handle, and dispose of the gaseous radioactive waste generated as a result of normal operation and anticipated operational occurrences.

The systems addressed in this section are the off-gas system, the turbine gland seal exhaust system, and the mechanical vacuum pump system. The effects of hydrogen addition for hydrogen water chemistry are also addressed in this section.

The off-gas system collects, contains, and processes the radioactive gases extracted from the steam condenser. The gases are exhausted by the steam jet air ejectors and flow through a preheater to a catalytic recombiner where all of the hydrogen is recombined with oxygen to form steam. All steam, from recombination booster jets and dilution is condensed for return as condensate and the noncondensible gases flow to a holdup pipe. The gas flow continues through a cooler condenser, a moisture separator, electric reheaters, a prefilter, activated charcoal adsorber vessels, high efficiency particulate air (HEPA) filters, and then to the 310-foot chimney for discharge to the environment. An alternate off-gas system flow path allows flow to bypass the catalytic recombiners, the activated charcoal adsorber vessels, (bypass lines around 2A, 3A and 3B recombiners exist but their use is not permitted by TSUP.)

The gland seal exhaust system removes steam,air and radioactive gases from the turbine gland sealing system(see section 10.4.3) exhaust header. The steam is condensed and the condensate returned to the main condenser. The gases are discharged to the chimney via a holdup volume in the base of the stack shared by Units 2 and 3

The mechanical vacuum pump system rapidly establishes main condenser vacuum during startup. The vacuum pump effluent is discharged to the gland seal exhaust system line to the holdup volume in the stack base. If the mechanical vacuum pump is not available, the SJAES can establish vacuum.

The hydrogen water chemistry (HWC) system, including the hydrogen addition and oxygen addition systems, is described in Section 5.4.

The gaseous waste treatment facilities, including the 310-foot chimney (see Section 3.3 for additional details), were evaluated under the Systematic Evaluation Program (SEP) Topic III-4.A with respect to tornado-generated missiles. Two cases were evaluated, and it was determined that the Dresden Station Unit 2 gaseous waste treatment facilities were adequately protected from the effects of tornado missiles. In Topic III-2 the reactor building ventilation stack was evaluated. It was determined that the loss of the reactor building ventilation stack would not result in an inability to achieve safe shutdown or in an adverse offsite radiological impact. Upgrading of the reactor building ventilation stack to withstand the design basis tornado was not recommended.[1]

11.3.1 Design Objectives

11.3.1.1 Off-Gas System

The design objectives of the off-gas system are as follows:

A. To provide effective control of process off-gases with capability for preventing releases over limits prescribed in 10 CFR 20;

B. To minimize radioactive particle release to the atmosphere;

C. To provide sufficient time for operator decision and action when continuous monitoring indicates development of abnormal conditions;

D. To minimize the release of the normally occurring activated radioactive gases by suitable short-term decay; and

E. To minimize the hazard of explosion of hydrogen and oxygen gas in the off-gas system. The off-gas system is also designed to contain a possible explosion resulting from hydrogen and oxygen present as a result of radiolytic decomposition of reactor water, by isolating on high pressure or temperature.

To achieve these objectives, the off-gas system is designed using the following bases:

A. Design pressure	300 psi
B. Original equipment capability	300 psi
C. Recombiner/activated charcoal adsorber vessels	350 psi
D. Operating pressure	6 psig
E. Off-gas system design flowrate	250 ft^3/min
F. Minimum size of particulates filtered	0.3 μm
G. Release point above ground	310-foot (chimney)
H. Piping design code	ASA B31.1

The equipment containing process off-gas is designed per ASME Section III, Subsection ND, Class 3, Nuclear Power Plant Components, and is Class II. The off-gas system is not safety-related.

The original off-gas system design was modified in 1972 to reduce the radioactive gaseous effluent discharged from the chimney. For the off-gas system with the recombiner and activated charcoal adsorber vessel addition, the design objectives for offsite doses were 10 mrem/yr for noble gases and 1.0 x 10^{-5} times the old (prior to January 1994)10 CFR 20 limits for iodines during normal operations.

11.3.1.2 Turbine Gland Seal Exhaust System

The design objective and description for the turbine gland seal exhaust system are given in Section 11.3.2.2.

11.3.1.3 Mechanical Vacuum Pump System

The design objective and description for the mechanical vacuum pump system are given in Section 11.3.2.3.

11.3.1.4 Plant Features Which Minimize the Amounts of Radioactive Effluents

The plant design includes several specific features or effects which minimize the amounts of radioactive materials released to the environment. These are summarized below:

A. Use of high-integrity Zircaloy-clad fuel rods to contain fission products within the fuel.

B. Use of water-to-steam partition to retain halogens in the coolant.

C. Holdup of off-gas to allow decay of short half-lived activities before discharge. The nominal holdup with the recombiner bypassed reduces the potential radiation effects on the order of a factor of 10 as compared to no holdup.

D. Monitoring of the air ejector off-gas stream and initiating automatic isolation of the holdup piping when the radioactivity release rate exceeds limits. The holdup provides ample time to prevent release of fission product gases in excess of the limits.

E. Use of HEPA filters at the end of the holdup piping to remove particulate radioisotopes formed by the decay of the noble gas radioisotopes in the holdup pipe.

F. Elevated release from the 310-foot chimney, which is approximately 1½ times the height of nearby structures, to reduce direct radiation dose rates on the ground, and to maximize the atmospheric dispersion of the gas plume before it reaches ground level.

G. Continuous monitoring of the chimney effluent with appropriate alarms in addition to the air ejector monitors. A separate high-range noble gas monitor (SPING) and grab sampling point for monitoring accident effluents has also been installed (see Section 11.5).

H. Use of activated charcoal adsorber beds to delay the discharge of noble gases in the effluent and for the adsorption of any radioactive iodine. The activated charcoal adsorber vessels and beds are designed such that the temperature increase from radioactive isotopic decay is limited well below the activated charcoal ignition temperature, thus precluding overheating of the activated charcoal bed and the vessel or a fire in the activated charcoal bed and consequent escape of radioactive materials. Although the iodine input into the off-gas system is small by virtue of its retention in the reactor coolant and steam condensate, the activated charcoal bed effectively removes it by adsorption and prevents its release.

I. Monitoring of the air ejector and dilution steam supply pressure with alarms and trips on low pressure to protect the recombiner. The recombiner temperatures are monitored and alarmed to indicate any deterioration of performance. The preheaters are heated with steam rather than electrically to eliminate the presence of potential ignition sources and to limit the temperature of the gases in event of cessation of gas flow.

11.3.2 System Description

There are 16 sources of radioactive gaseous effluent, all of which exhaust through the 310-foot chimney. These sources are listed in Table 11.3-1.

Major sources of gaseous waste radioactivity are the off-gas system and the turbine gland seal system.

The off-gas system is discussed in Section 11.3.2.1. The ventilation systems for the off-gas recombiner rooms for Units 2 and 3, the turbine building for Units 2 and 3, the radwaste building, the maximum recycle building, and the solidification building are discussed in detail in Section 9.4. The potentially radioactive ventilation air from these systems is discharged to the environment through the 310-foot chimney. The SBGTS discharges treated radioactive gases to the environment through the 310-foot chimney. The SBGTS is discussed in more detail in Section 6.5. The turbine gland seal system for Units 2 and 3 and the mechanical vacuum pump system for Units 2 and 3 are discussed in Sections 11.3.2.2 and 11.3.2.3 respectively.

11.3.2.1 Off-Gas System

11.3.2.1.1 Process Description

The off-gas system is shown in Figure 11.3-1 (Drawing M-43, Sheet 1), Figure 11.3-2 (Drawing M-43, Sheet 2), Figure 11.3-3 (Drawing M-43, Sheet 3), Figure 11.3-4 (Drawing M-371, Sheet 1), Figure 11.3-5 (Drawing M-371, Sheet 2) and Figure 11.3-6 (Drawing M-371, Sheet 3). The general arrangement figures in Section 1.2 show the elevation and plan views for the off-gas systems. Figure 11.3-7 (Drawing M-12, Sheet 2) and Figure 11.3-8 (Drawing M-345, Sheet 2) show more detail of the piping for the steam jet air ejectors. In brief, the condenser off-gas, or air ejector effluent, passes through a recombiner for radiolytically produced H_2, and O_2, followed by moisture separators, a shielded holdup line, a treatment system including additional moisture separation, a bed of activated charcoal filters, and through final particulate filters. It is then discharged at a height of about 40 feet inside of the chimney from a line that enters at the base. The effluents are diluted by a large volume of ventilation exhaust from several buildings (Table 11.3-2); the ventilation exhaust enters the side of the chimney at a height of about 40 feet and contains little activity by comparison.

The off-gas system operates at a pressure of approximately 6 psig or less, so the differential pressure that could cause leakage is small. To preclude leakage of radioactive gases, the system is welded wherever possible, and bellows seal valve stems or equivalent are used. The entire system is designed to maintain its integrity in the event of a hydrogen-oxygen detonation.

The fission gases, activation gases, radiolytic hydrogen and oxygen, and air inleakage are removed from the main condenser by the air ejectors and/or the main vacuum pump when in use. The mixture is diluted with steam during the process and passes through condensers for moisture removal. The mixture is then routed through a preheater to the catalytic recombiner. Preheating the mixture is necessary to ensure optimum recombiner performance.

In the recombiner, the radiolytic hydrogen and oxygen are catalytically converted to water in the form of superheated steam. This steam (along with steam used for the air ejector driving flow, trace quantities of unreacted hydrogen and oxygen, air, and radioactive gases) exits the recombiner to a condenser where the steam is condensed to liquid and returned to the main condenser.

The noncondensible effluent is then routed to the holdup piping. In the holdup piping, the shorter lived radioactive isotopes (principally N-13, N-16, O-19 and certain isotopes of xenon and krypton) decay either to nonradioactive isotopes or radioactive particulate daughter products.

A sustained high radiation level in the off-gas holdup line (which would be expected to occur in the event of a significant fuel failure, for example) will first cause annunciation of an alarm in the main control room, then after a time delay, will cause isolation of the off-gas system. Isolation of the off-gas system results in a loss of condenser vacuum and a scram. The time delay gives the operator time to take action to reduce the radiation level in the off-gas system below the trip point (by reducing power, for example) to avoid a scram of the unit.

After leaving the holdup pipe, the effluent is cooled again for removal of water, reprocessed through a moisture separator for further drying, and then heated in a reheater for humidity control.

Before entering the activated charcoal adsorber vessels, the effluent is filtered by prefilters to remove the previously noted particulate daughter products.

The 12 activated charcoal adsorption beds permit selective adsorption and delay of the xenons and kryptons from the carrier gas (principally air). Following the activated charcoal adsorber vessels, the effluent is filtered again by afterfilters to remove particulate daughter products and then is discharged through the 310-foot concrete chimney.

The afterfilter system, which is located just before the chimney, consists of two parallel sets of full-flow HEPA filters. The spare set of filters provides backup and assures availability of filtration. These filters are designed to remove 99% of the particulates in the off-gas based on a dioctylphthalate (DOP) test.

Shielding is provided for the off-gas system equipment to maintain safe radiation exposure levels for plant personnel.

The off-gas system startup and process operational limitations and requirements are covered in the ODCM and operating procedures.

11.3.2.1.2 Description of Major Components

11.3.2.1.2.1 Steam Jet Air Ejectors

The 2A, 3A and 3B trains have a two stage air ejector unit with an inter and after condenser, which discharges to a booster jet. Dilution steam is added to the discharge flow to the preheater. Either or both first stage jets may be used depending on the capacity needed and condensate temperature, but both second stage jets must be used at all times. (This arrangement resulted from a modification made to the original system when the plant was modified for closed cycle circulating water system operation.) Fig. 11.3-1, 11.3-2, 11.3-4 and 11.3-5.

The 2B train has two first stage jets whose use is the same as in 2A, 3A and 3B trains. There are two second stage jets whose discharge bypasses the after condenser. There is no booster jet, but dilution steam is also added to the flow path. (This arrangement resulted from a modification made to prevent Off Gas fires, by maintaining the gas mixture diluted.) Steam is never condensed out of the flow stream by the after condenser, so there is never a combustible mixture present in the 2B train. Figures 11.1-2, 11.1-9 and 11.1-10.

Steam for the jets is from the turbine throttle header via 125 psig pressure control valves.

11.3.2.1.2.2 Preheaters

The preheaters are U-tube heat exchangers using steam on the tube side to superheat the off-gas mixture of steam and gases on the shell side. The off-gas mixture is heated to ensure recombination. The preheaters are heated with steam rather than electricity to eliminate the presence of potential ignition sources and to limit the temperature of the gases in the event of cessation of gas flow. The steam source is the turbine throttle steam, and the steam passes through a pressure-reducing valve set at 250 psig. This limits the steam temperature at or below 410°F in case of loss of off-gas flow.

11.3.2.1.2.3 Catalytic Recombiners

The gaseous hydrogen and oxygen are combined catalytically into superheated steam at a variable temperature (nominally 800°F) based on the hydrogen and oxygen volume. The inlet temperature to the recombiner is nominally 350°F. Water will quench the catalytic reaction, but drying restores capability (temporary poison). Freon gases, oil and halogens act as permanent poisons to the catalyst.

A source for oxygen addition is provided to ensure that proportionate amounts of hydrogen and oxygen are available for recombination when the hydrogen water chemistry system is used. See Section 5.4 for a detailed discussion of the hydrogen and oxygen addition systems.

11.3.2.1.2.4 Off-Gas Condensers

The off-gas condensers are U-tube heat exchangers which use condensate to cool the gases and condense the steam in the off-gas piping. The effluent temperature is approximately 130°F. The condensed water drains to the main condenser.

The gas flow exiting the off-gas condenser consists mainly of air inleakage and fission product gases.

11.3.2.1.2.5 Water Separators

The water separator removes any entrained moisture from the gaseous mixture exiting the off-gas condenser. The water separator drains to the off-gas condenser.

11.3.2.1.2.6 Holdup Pipe

The radioactivity of the gaseous stream is reduced in the off-gas system holdup pipe. The holdup allows the shorter-lived xenons and kryptons to decay to particulate daughter products, which are removed by the prefilters downstream. The holdup pipe is 36 inches in diameter and 965 feet long. With the recombiner bypassed and a design flowrate of 250 ft^3/min (the normal flowrate is about 150 ft^3/min — see Table 11.3-3), the pipe provides a holdup time of about 30 minutes. The traverse time is increased from 30 minutes to approximately 6 hours by removal of the hydrogen and oxygen as water from the gaseous stream.

11.3.2.1.2.7 Cooler Condensers

The cooler condenser, is a shell and tube heat exchanger where the gas makes multiple shell side passes, it further cools the gas to remove as much moisture as possible. The gas stream is cooled by a chilled ethylene glycol-water mixture to a temperature of 45°F. This results in a moisture content of the off-gas of less than 1%.

11.3.2.1.2.8 Moisture Separators

The moisture separator removes any entrained moisture from the gas stream exiting the cooler condenser. Removal of condensible water vapor and entrained moisture is essential because the activated charcoal efficiency is a function of moisture content.

11.3.2.1.2.9 Reheaters

The electric reheater heats the off-gas stream to the optimal temperature for activated charcoal adsorption of iodine. Heating of the off-gas stream to approximately 70°F assures that any residual water vapor does not interfere with the charcoal adsorption process. Heating of the gas to approximately 70°F also increases the efficiency of the prefilters downstream.

11.3.2.1.2.10 Prefilters

The prefilters consist of full-flow HEPA filters designed to remove 99.97% of the radioactive and non-radioactive particulates that are greater than 0.3 μm in size from the gas stream. There is a high differential pressure alarm which annunciates in the control room on a high differential pressure across the HEPA filter unit.

11.3.2.1.2.11 Charcoal Adsorbers

The activated charcoal adsorber beds provide for radioactive decay of the major activation gases and fission gases in the main condenser off-gas. The activated charcoal adsorber beds provide a retention time of 14.6 days for xenon holdup and 19.4 hours for krypton holdup. There are 12 activated charcoal adsorption beds. Each bed of activated charcoal is contained in a steel vessel which is 4 feet in diameter with an overall height of 21 feet. The 12 activated charcoal adsorption vessels contain approximately 74,000 pounds of activated charcoal, and are designed for 350 psig. The absorbers may be operated with 12 beds in series or 3 parallel trains of 4 beds in series.

Although iodine input into the off-gas system is small by virtue of its retention in reactor water and condensate, the activated charcoal will effectively remove it by adsorption and prevent its release.

The activated charcoal adsorber beds and vessels are designed to limit the temperature of the activated charcoal bed to well below the ignition temperature, thus precluding overheating or fire and consequent escape of radioactive materials. The activated charcoal adsorber vessels and beds are located in a shielded room, maintained at a constant temperature by an air conditioning system designed to remove the decay heat generated in the adsorber vessels. The maximum centerline temperature of each of the activated charcoal adsorber beds is less than 10°F above room temperature when the flow is stopped. The decay heat of 50 Btu/hr is sufficiently small compared to the thermal mass of the activated charcoal adsorber vessels in the vault. Even if the vault cooling is lost, the temperature rise is not sufficient to cause activated charcoal ignition. The activated charcoal adsorber beds are maintained at 77°F by the vault air conditioning system. Due to the thermal capacitance of the activated charcoal adsorber beds and the massive concrete vault walls, temperature changes caused by failure of the vault air conditioning system will be sufficiently slow so that the resulting changes in the activated charcoal adsorption coefficient will not produce a rapid release of adsorbed radioactive nuclides. In order to maintain consistent system operation, a redundant vault air conditioning system is supplied to allow for maintenance and operational convenience. During a plant outage when the condenser is not maintained at vacuum, there is no gas flow through the activated charcoal adsorber beds and the holdup is very high, even if the activated charcoal reaches ambient temperatures. High radiation level in the activated charcoal adsorber bed vault will cause an alarm in the control room.

11.3.2.1.2.12 Afterfilters

Afterfilters provide the final filtration of the off-gas before its release to the 310-foot chimney.

The filters, located just before the chimney, consist of two 100% capacity HEPA filtering units. The second filter (spare) provides backup and assures availability of filtration. These filters are designed to remove from the off-gas 99.97% of the particulates greater than 0.3 μm in size. Static grounding wires are installed on the filter to minimize the potential for an off-gas explosion at this point. A loop seal is installed on the drain line from the filters to eliminate a leakage point for the radioactive gaseous effluent. The maximum operating differential pressure across these filter units is 4 in.H_2O. Pressure switches alarm in the control room on high differential pressure across the filter unit.

11.3.2.1.3 Redundancy of Equipment

Redundancy of the air ejector, preheater, recombiner, off-gas condenser, water separator, cooler-condenser systems, moisture separator, particulate filters, and activated charcoal adsorber vessel vault air conditioning units is provided for operating convenience and maintenance. Valving is provided for selecting one or both ejectors, preheaters, recombiners, off-gas condensers, or water separators. Provision is made for the two hydrogen analyzers to sample the effluent from either or both recombiner trains. Either or both cooler condenser trains (cooler condenser, moisture separator, reheater, and prefilter) may be selected for operation. The activated charcoal adsorber beds can be operated in one of three modes: all 12 activated charcoal adsorber beds in series; three parallel strings of four activated charcoal adsorber beds or bypassing of all 12 activated charcoal adsorber beds.

11.3.2.1.4 Alternate Off-Gas Discharge Pathway

Alternate pathways for the radioactive gases, as shown in Figure 11.3-1 (Drawing M-43, Sheet 1), Figure 11.3-3 (Drawing M-43, Sheet 3), Figure 11.3-4 (Drawing M-371, Sheet 1), and 11.3-6 (Drawing M-371, Sheet 3), exist from the SJAE to the main chimney for discharge to the environment. These alternate pathways can bypass the recombiner train and the activated charcoal adsorber vessels and establish the original design pathway with only the holdup pipe and discharge filters to account for nuclide decay and for capturing particulates in the gas stream. Valving is provided to bypass and isolate the off-gas treatment system (recombiner and/or activated charcoal adsorber beds) and to operate with just the holdup line. Using this alternate pathway, the radioactive gases entering the off-gas system are held up to allow decay of the short-lived isotopes before being discharged to the environment through the 310-foot chimney. The radioactive gases from the main condenser air ejectors are delayed a minimum of 30 minutes in shielded piping before entering the activated charcoal and HEPA filter system.

A more desirable alternate pathway is to bypass only the activated charcoal adsorber system. Use of the recombiners in the off-gas system would allow up to 6 hours holdup due to the removal of the hydrogen and oxygen content as water. Due to the high moisture content of the off-gas stream the activated charcoal adsorber beds cannot be employed in the system if the recombiners are bypassed.

The 2B recombiner can not be bypassed due to the fire prevention modification, and the others may no longer be bypassed per TSUP.

11.3.2.1.5 Instrumentation and Control

The off-gas system is monitored by flow, humidity, and temperature instrumentation and by hydrogen analyzers for operation and control. Table 11.3-4 lists process instruments that cause alarms and notes whether the parameters are indicated or recorded in the main control room.

Figure 11.3-11 (Drawing M-43, Sheet 5) and Figure 11.3-12 (Drawing M-371, Sheet 5) show the hydrogen analyzer and oxygen analyzers for the off-gas system.

11.3.2.1.6 Process Monitoring and Sampling

The activity of the effluent entering and leaving the off-gas treatment system is continuously monitored.

The off-gas sampling system sample racks are shown in Figure 11.3-13 (Drawing M-178), Figure 11.3-14 (Drawing M-179), Figure 11.3-15 (Drawing M-421), and Figure 11.3-16 (Drawing M-420).

The process radiation monitoring includes the air ejector off-gas monitoring system and the area radiation monitors for the activated charcoal adsorber vessel vault. The air ejector off-gas monitoring system is discussed in Section 11.5, and the activated charcoal adsorber vessel vault area radiation monitor is discussed in Section 12.3. The activated charcoal adsorber vessel vault radiation monitor provides a local high-radiation alarm. A low alarm indicates malfunction of this monitoring system.

A manual sample of the process treated off-gas flow stream is taken downstream of the activated charcoal adsorber beds, see Figure 11.3-14 (Drawing M-179) and Figure 11.3-15 (Drawing M-421). At other sample points shown in Figure 11.3-3 (Drawing M-43, Sheet 3), Figure 11.3-6 (Drawing M-371, Sheet 3), Figure 11.3-2 (Drawing M-43, Sheet 2) and Figure 11.3-5 (Drawing M-371, Sheet 2), sample vials of gas are collected manually from the off-gas sampling system at a common point located in the off-gas filter building.

11.3.2.1.7 Inspection and Testing

The off-gas and exhaust ventilation filters are replaced when the pressure drop across the filter exceeds the normal operating range. Test connections are available for checking the efficiency of the installed filters. Adequate tests to determine filter efficiency are conducted as necessary. They are only of importance when fission gas release rates are significant. The off-gas system prefilters are also included in the testing requirements.

The gaseous waste disposal systems are used on a routine basis and do not require specific testing to assure operability.

Monitoring equipment and process instrumentation are calibrated and maintained on a specific schedule or when indication of malfunction occurs. The systems were functionally tested to verify their initial operability prior to placing them in service. The radioactive gaseous radiation monitoring instruments listed in the ODCM are demonstrated operable by performance of an instrument check on a daily basis. The offgas system air operated valves are tested every refuel outage in conjunction with the offgas radiation monitor calibration and main steam line high radiation offgas valves logic testing.

11.3.2.2 Turbine Gland Seal Exhaust System

11.3.2.2.1 System Description

The turbine gland seal exhaust system (see Figures 11.3-1, 11.3-4 and 10.4-2) consists of the gland steam condenser and the gland steam condenser exhauster. There are two turbine gland seal exhaust systems for each unit.

The turbine gland sealing steam, along with substantial quantities of air (which is drawn through the outer seals), is drawn to the gland steam condenser by the exhauster. Approximately 95% of the steam used in the turbine gland seals is condensed in the gland steam condenser and returned to the main condenser.

The remaining steam, air and noncondensibles (including any radioactive gases) present in the gland seal off-gas is discharged to the Unit 2/3 common hold-up volume for gland seal exhaust/main vacuum pumps in the base of the chimney. The small quantity of radioactive gases released by way of the gland seal off-gas system does not require a long decay time. A minimum holdup time of 1.75 minutes in the hold up volume is used for decay of the major activation gases (N-16 and O-19), which have half-lives on the order of seconds.

The gland seal steam condenser exhauster maintains a vacuum on the gland seal steam condenser and the sealing steam exhaust header. The effluents from the gland seal system cannot be routed to the air ejector recombiner or charcoal beds. The relative absence of hydrogen renders a recombiner useless for reducing the effluents from this system. In using charcoal to delay radioactive noble gases, the volume required for a given delay time is directly proportional to the gas flow. The noncondensible air and gas flow from the gland seals is about 30 to 50 times larger than the flow of noncondensibles exiting a recombiner in the off-gas system. Therefore, dynamic charcoal adsorption is not practical for treatment of the gland seal effluent discharged to the chimney. The shorter holdup time is adequate because the activity present in this system is three orders of magnitude less than that from the condenser air ejector.

11.3.2.2.2 Description of Major Components

11.3.2.2.2.1 Turbine Gland Seal Exhaust System Condenser

The turbine gland seal exhaust system condenser, using main condensate water through double-pass tubes, condenses about 95% of the steam in the gas stream. A bypass flapper in the water box causes most of the main condensate to bypass the tubes except at low flow. Level is maintained by a control valve. There are high and low level alarms.

11.3.2.2.2.2 Turbine Gland Seal Steam Condenser Exhauster

The turbine gland seal steam condenser exhauster maintains a vacuum on the turbine gland seal steam condenser and thereby on the gland sealing steam exhaust. The exhauster vents to the 1.75-minute holdup volume.

11.3.2.3 Mechanical Vacuum Pump System

The mechanical vacuum pump system (see Figures 11.3-1 and 11.3-4) rapidly establishes the main condenser vacuum at 20 to 25 in.Hg in preparation for condenser operation. This system is used only during startup. It exhausts through a discharge silencing tank at about 2320 scfm of gas (air) at 15 in.Hg. The pump discharges this flow of contaminated gaseous effluent to the base of the 310-foot chimney via the gland seal exhaust system piping. There is one condenser vacuum pump and silencer for each unit. If it is not available, the SJAEs can draw vacuum, but this takes considerably longer.

11.3.2.4 Hydrogen Ignition Control

Because the off-gas system contains mixtures of hydrogen and oxygen, it contains a potentially explosive and burnable gas stream. Some of the precautions taken to minimize the potential for these explosions, pre-ignitions, and fires are as follows:

A. The off-gas afterfilters are grounded to prevent static build-up and sparks;

B. Operating procedures exist for controlling and extinguishing an off-gas system fire. Normally an explosive mixture exists only between the second stage air ejector discharge and the booster jet in 2A, 3A and 3B strains. 2B train was modified to always have a diluted, non combustible mixture, to prevent off gas fires.

11.3.3 Radioactive Releases

11.3.3.1 Plant Release Points

There are three release points to the atmosphere for gaseous effluent and ventilation exhaust — the reactor building vent stack, the 310-foot chimney, and the Unit 1 chimney.

11.3.3.1.1 Reactor Building Ventilation Stack

The physical and process characteristics of the two principal gaseous release points are shown in Table 11.3-5. The limitations for release of gaseous effluents from the station are set in the ODCM. Table 11.3-6[2—11] presents the typical radioactive isotopes and quantities discharged from Units 2 and 3.

Air from the reactor building ventilation exhaust (approximately 110,000 ft^3/min per unit) is normally released through the reactor building vent stack, which is common to Units 2 and 3 (see Figure 9.4-16 and Figure 9.4-15). If activity is present in any significant quantity, secondary containment is isolated and normal ventilation flow to the vent stack is automatically terminated as discussed in Section 6.2.3. Flow from the standby gas treatment system (SBGTS) (4000 ft^3/min) is directed to the base of the chimney. The SBGTS has its own particulate and charcoal filters.

Air or nitrogen from inerting or deinerting the drywell is normally discharged with the reactor building ventilation exhaust from the vent stack. If radioactivity is present in any significant quantity (because of activation products such as Argon-41 for example) the purge air can be discharged separately through the SBGTS to avoid a high-radiation trip of the reactor building ventilation.

11.3.3.1.2 Plant 310-Foot Chimney

The ventilation system air flow through the chimney is approximately 430,910 ft^3/min during normal operation of both units. The radioactive gaseous flow from the off-gas systems, the turbine gland seal systems, and the SBGTS is estimated to be 12,000 ft^3/min during operation of both units. The radioactive gaseous system flows for the main chimney are shown on Figure 11.3-17 (Figure 10-2 from the Offsite Dose Calculation Manual [ODCM]).[12] The chimney dilution flow of ventilation air is shown on Figure 9.4-4.

Natural dispersion of gases into the atmosphere is achieved in an efficient manner by discharge through the chimney. The combination of the height of the chimney, the exit velocity of the effluent, and the buoyancy of the exit gases promotes favorable plume behavior for efficient dispersal. The height of the chimney assures that diffusion of the plume will not be influenced by the eddy currents occurring around the station structures. Based upon diffusion characteristics of the gases and considering the meteorological characteristics of the site and surroundings, it is calculated that release from the top of the 310-foot chimney contributes to a reduction in offsite dose by a factor of approximately 100 as compared with release of the gaseous wastes at ground level.

Air ejector off-gases are normally expected to have the composition shown in Table 11.3-3.

The activation gases listed in Table 11.3-7 (principally N-13) are released from the chimney at the rate of approximately 250 µCi/s per unit during operation at 2527 MWt. The rate of release of these gases is proportional to the thermal output of the reactor and the holdup time in the system before release at the chimney. For Units 2 and 3, the combined release rate is approximately 500 µCi/s.

The fission product gases may arise from minor amounts of tramp uranium on the surface of the fuel cladding, from imperfections, or from perforations which might develop in the fuel cladding. The principal gaseous isotopes from fissionable material sources discharged from the chimney are shown in Table 11.3-8. Typical quantities, including the isotopic analysis, of the radioisotopes discharged from the 310-foot chimney are presented in Table 11.3-8.[2—11]

In the absence of fuel rod leaks, N-13 from the air ejector off-gases and the N-16 and O-19 from the gland seal system are the principal contributors to the environs radiation dose. The aggregate of these three corresponds to a radiation dose of less than 0.1 mrem/yr. If fuel rod leaks do occur, the noble radioactive gases xenon and krypton become the principal contributors. The solid daughter products of the noble gases are removed in the filter of the off-gas system before release of the gases to the 310-foot chimney.
The holdup of the condenser air ejector off-gas provides sufficient time between detection of high-radiation levels and isolation of the holdup line to prevent release of fission product gases in excess of the release limits. When such a release rate is detected, the holdup line is automatically isolated after a 15-minute delay. This time interval is provided to permit corrective action to be taken to obviate plant shutdown. The holdup time is established to provide for decay of short half-lived noble gases to reduce chimney release.

Similarly the 1.75-minute holdup time for the gland seal off-gas system is chosen to provide sufficient decay of the activation gases. The holdup time is shorter because the activity present in this system is three orders of magnitude less than that from the condenser air ejector. The short holdup time allows decay of N-16 and O-19, which have half-lives of 7 and 27 seconds, respectively. The 1.75 minute holdup time is provided by a five chamber holdup volume in the base of the chimney. This holdup volume is common to Units 2 and 3.

A. Units 2 and 3 without HWC	0.13 mrem/year
B. Unit 2 with HWC and Unit 3 without	0.36 mrem/year
C. Units 2 and 3 with HWC	0.64 mrem/year

During the first HWC test (performed in May and June of 1982) it was determined that injecting hydrogen into the feedwater increases the carry-over of N-16 with the steam. This phenomenon results in higher than normal radiation levels in all areas of the plant that contain steam piping. This effect raised concerns about an increase in offsite dose due to the "sky-shine" of the turbine.

During operation of Unit 2 with Cycle 9 reload, an assessment of the effects of hydrogen injection on dose rate was made. In order to assess the effects of hydrogen injection, dose rate measurements were taken under the following conditions:

A. With hydrogen injection;

B. Without hydrogen injection; and

C. With Unit 2 shutdown.

Units 1 and 3 were shut down during this operating period.

The data indicate that the three plant areas most significantly influenced by hydrogen injection are the main turbine floor, the area above the main turbine floor, and the condensate pump room area. The largest average increase is seen on the turbine deck where dose rates rise by 450%. Additional decay time in the condenser and hotwell lessen the N-16 contribution in the condenser pump room so the dose rates increase by only 340%.

The area that shows the most significant increase is the turbine crane cab. The radiation shine off the top of the turbine increases the dose rate to the crane operator to as much as 100 mrem/hr. This dose rate is a function of positioning over the turbine as well as the amount of hydrogen being injected into the feedwater.

Other areas surveyed in the turbine building realize an insignificant increase in dose rates. All of these areas are well-shielded from reactor steam and condensate lines.

To assess the HWC impact on the environmental dose, thirty locations were selected to be surveyed based on their positions relative to one reference point. The reference point, the intersection of the turbine axis and center line between the D-2 low pressure turbines B and C, was assumed to be the center of the N-16 source for the environs. Measurements were taken for 5 to 30 minutes using a multiplying ion chamber.

Based on the data obtained, the contributions from HWC to the environment dose rate is a function of measurement location. Significant variation exists in the dose rate contributions at similar distances. This is a result of the shielding effect of various onsite structures and the dose contributed from radioactive onsite storage (such as holding tanks).

Table 11.3-2

CHIMNEY DILUTION AIR

Source	Flowrate (ft^3/min)
U2 turbine building and recombiner rooms ventilation exhaust	177,200
U3 turbine building and recombiner rooms ventilation exhaust	194,200
Radwaste building ventilation exhaust	28,760
Radwaste solidification building ventilation exhaust	16,000
Maximum recycle building ventilation exhaust	6,750
Off-gas filter building ventilation exhaust	5,500
* U2 turbine gland seal exhaust	4,000
* U3 turbine gland seal exhaust	4,000
Standby gas treatment system exhaust	4,000
U2 high-radiation sampling system building ventilation exhaust	1,000
U3 high-radiation sampling system building ventilation exhaust	1,000
TOTAL(1)	442,910

Notes:

1. In addition, 250 ft^3/min of off-gas per unit (total 500 ft^3/min) is exhausted through the 310-ft chimney.

* Figure reference value per FSAR - not located on drawing.

Table 11.3-4

PROCESS INSTRUMENT ALARMS FOR OFF-GAS TREATMENT SYSTEM

	Main Control Room	
Parameter	Indicated	Recorded
Preheater discharge temperature — low	X	
Recombiner catalyst temperature — high/low		X
Off-gas condenser drain well (dual) level — high/low (alarm only)		
Off-gas condenser gas discharge temperature — high (alarm only)		
H_2 analyzer (off-gas condenser discharge) (dual) — high		X
Cooler-condenser discharge temperature — high/low		X
Glycol solution temperature — high/low		X
Glycol storage tank level — low (alarm only)		
Prefilter pressure — high	X	
Charcoal bed inlet humidity — high		X
Charcoal bed temperature — high		X
Charcoal vault temperature — high/low		X
After filter inlet gas flow — high/low		X
After filter differential pressure — high (alarm only)		

Table 11.3-5

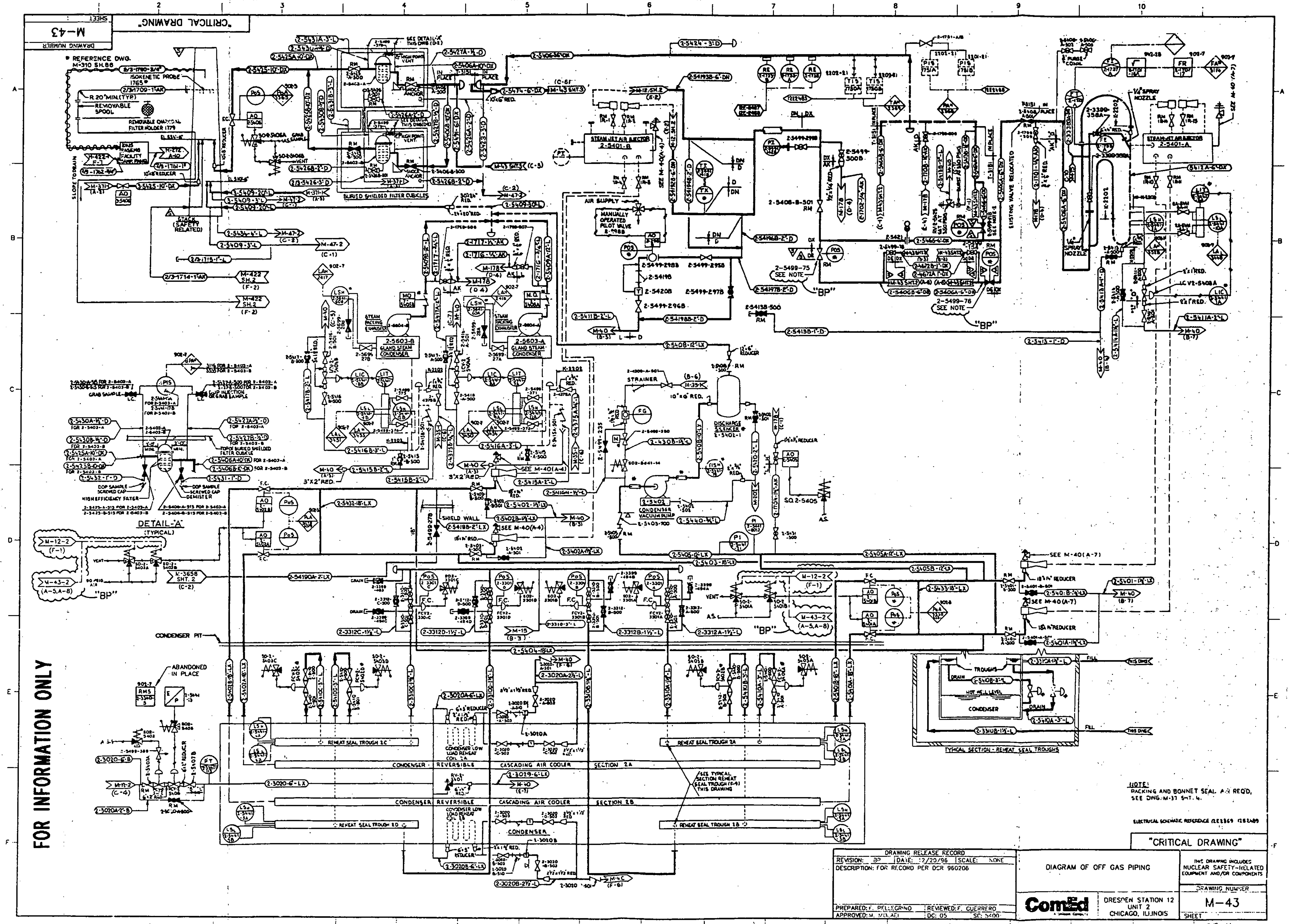
PHYSICAL AND PROCESS CHARACTERISTICS
OF PRINCIPAL GASEOUS RELASE POINTS

Characteristics	Gaseous Release Point	
	Chimney	Reactor Building Ventilation Stack[1]
Height (above grade)	310 ft (95 m)	160 ft (48 m)
Inside diameter, exit	11 ft (3.36 m)	9 ft (3 m)
Exit velocity	77.7 ft/s (23.7 m/s)	52 ft/s (16 m/s)
Discharge volume	Variable: can range from 200,000 to 442,910 ft^3/min	Variable: can range from 220,000 to 223,000 ft^3/min
Heat rate control	4 x 10^6 calories/s at 375,000 ft^3/min and is proportional to flow	—

Note:

1. The reactor building ventilation stack itself is 55 feet tall and is mounted on the turbine building.

FOR INFORMATION ONLY

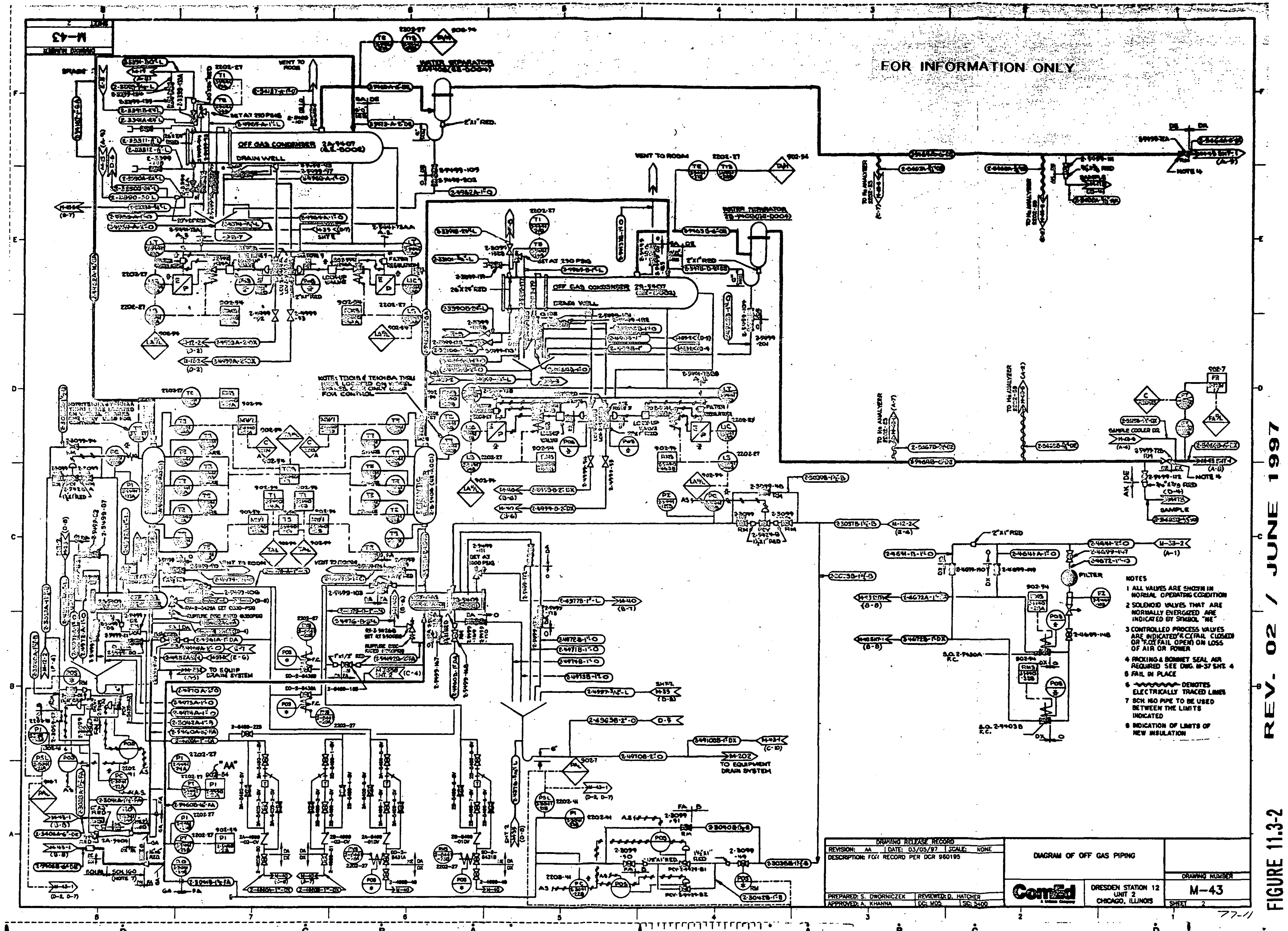


CENTRAL DRAWING FACILITY

30 X

REV. 02 / JUNE 1997

FIGURE 11.3-1



CENTRAL DRAWING FACILITY

30X

REV. 02 / JUNE 1997

FIGURE 11.3-2

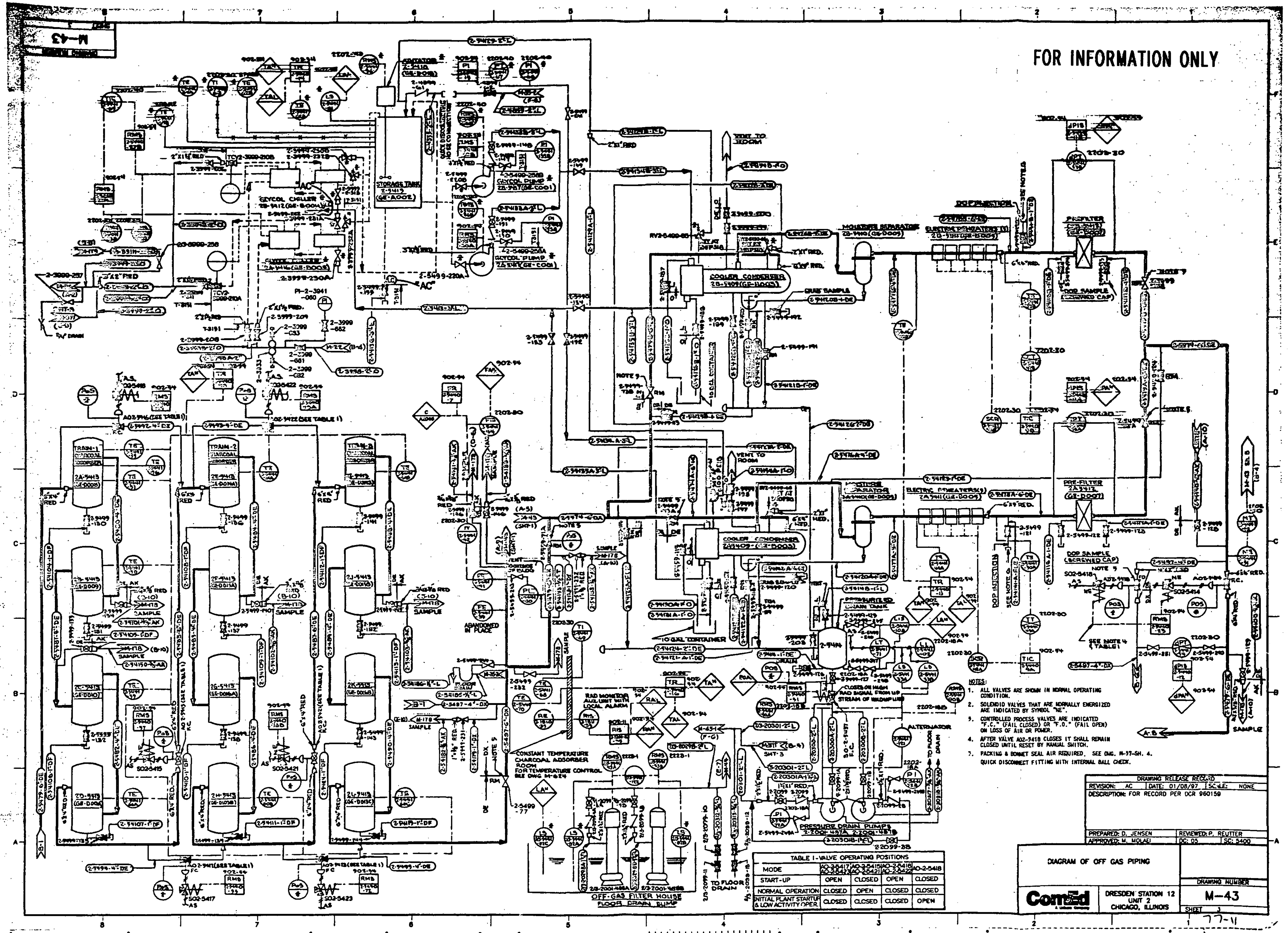
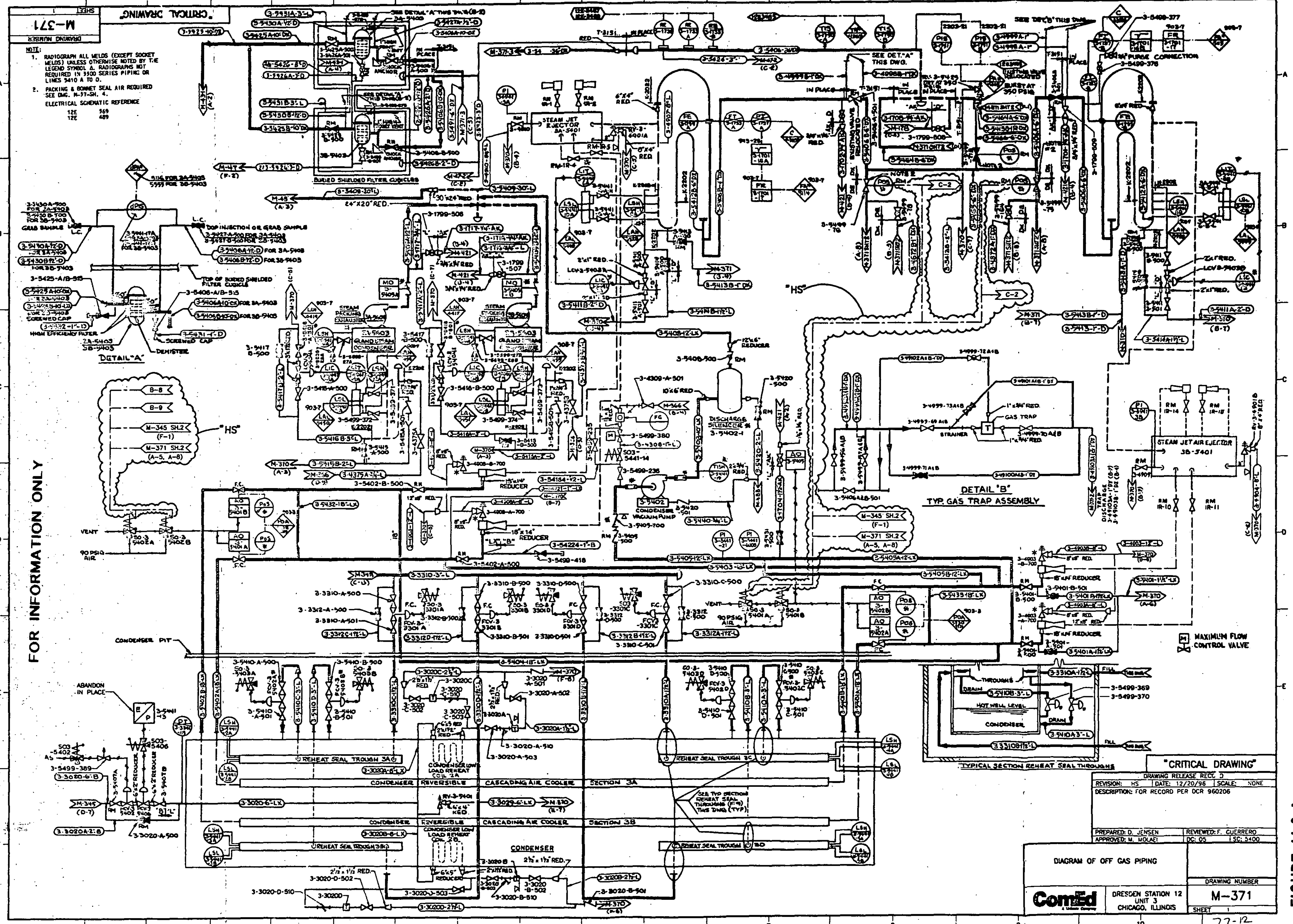


TABLE I - VALVE OPERATING POSITIONS

MODE	AO-2-5417 AO-2-5423	AO-2-5415 AO-2-5421	AO-2-5416 AO-2-5422	AO-2-5418
START-UP	OPEN	CLOSED	OPEN	CLOSED
NORMAL OPERATION	CLOSED	OPEN	CLOSED	CLOSED
INITIAL PLANT STARTUP & LOW ACTIVITY OPER.	CLOSED	CLOSED	CLOSED	OPEN

FIGURE 11.3-3

REV. 02/ JUNE 97

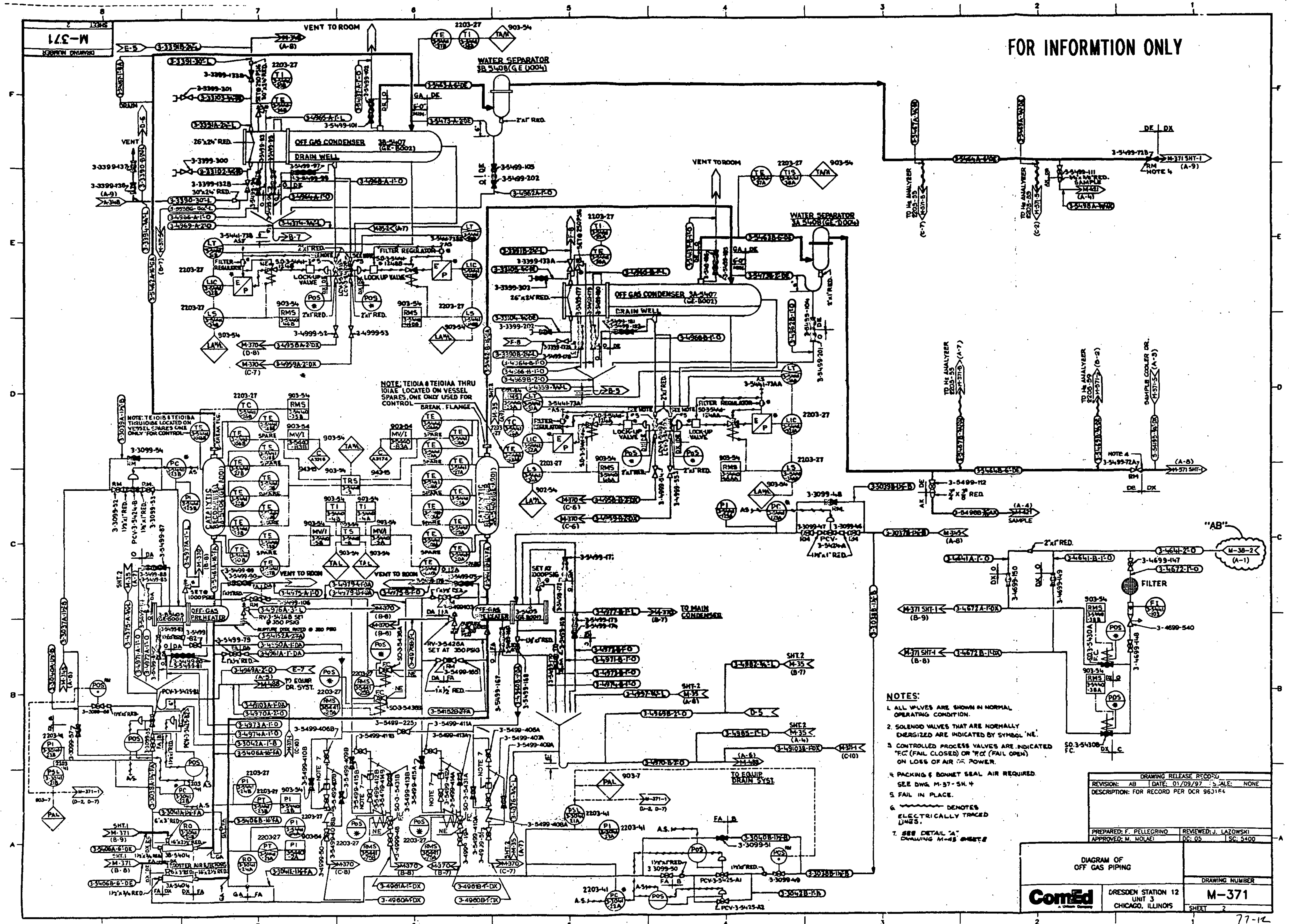


REV. 02 / JUNE 1997

FIGURE 11.3-4

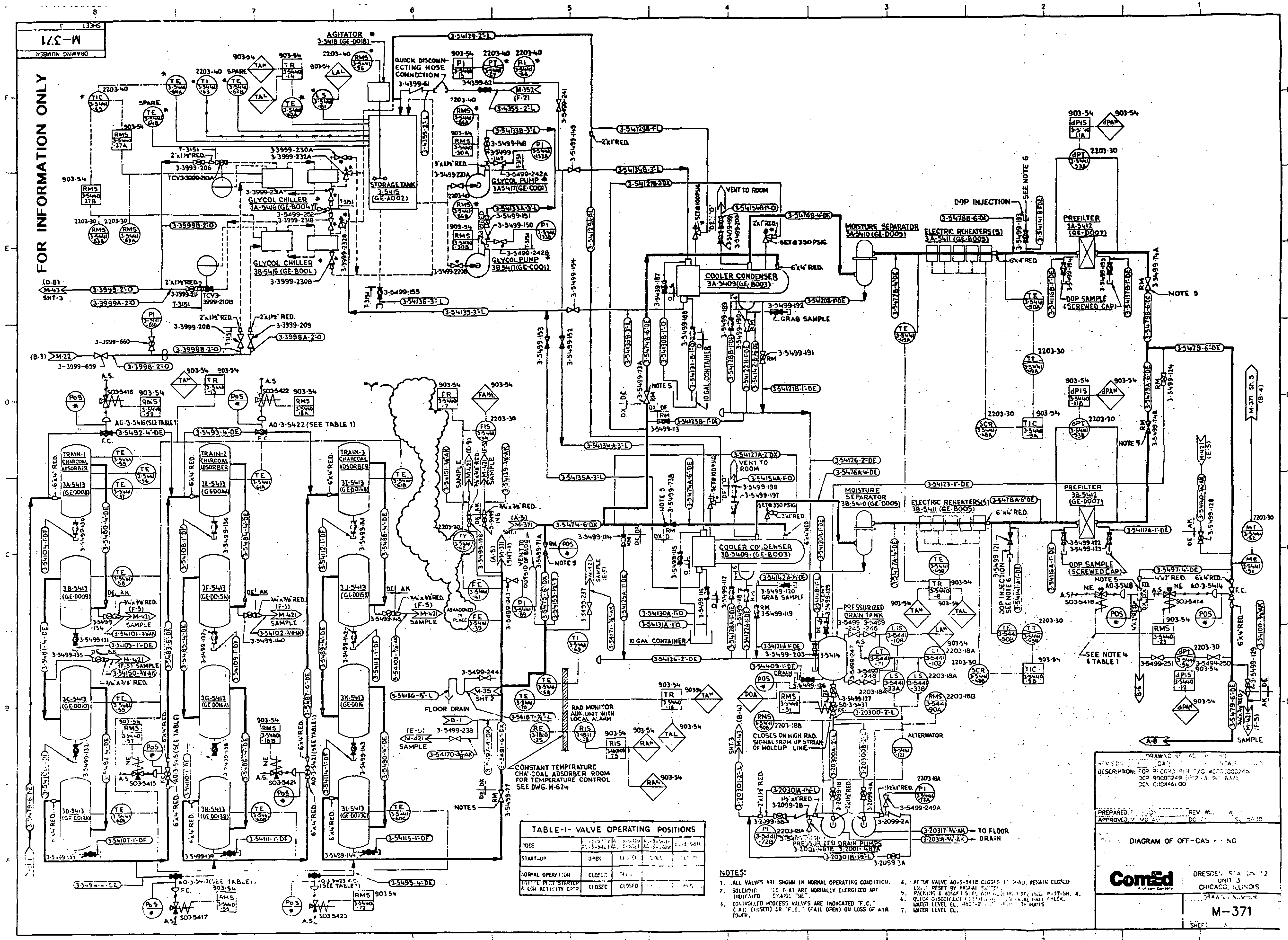
CENTRAL DRAWING FACILITY

30 X



REV. 02 / JUNE 1997

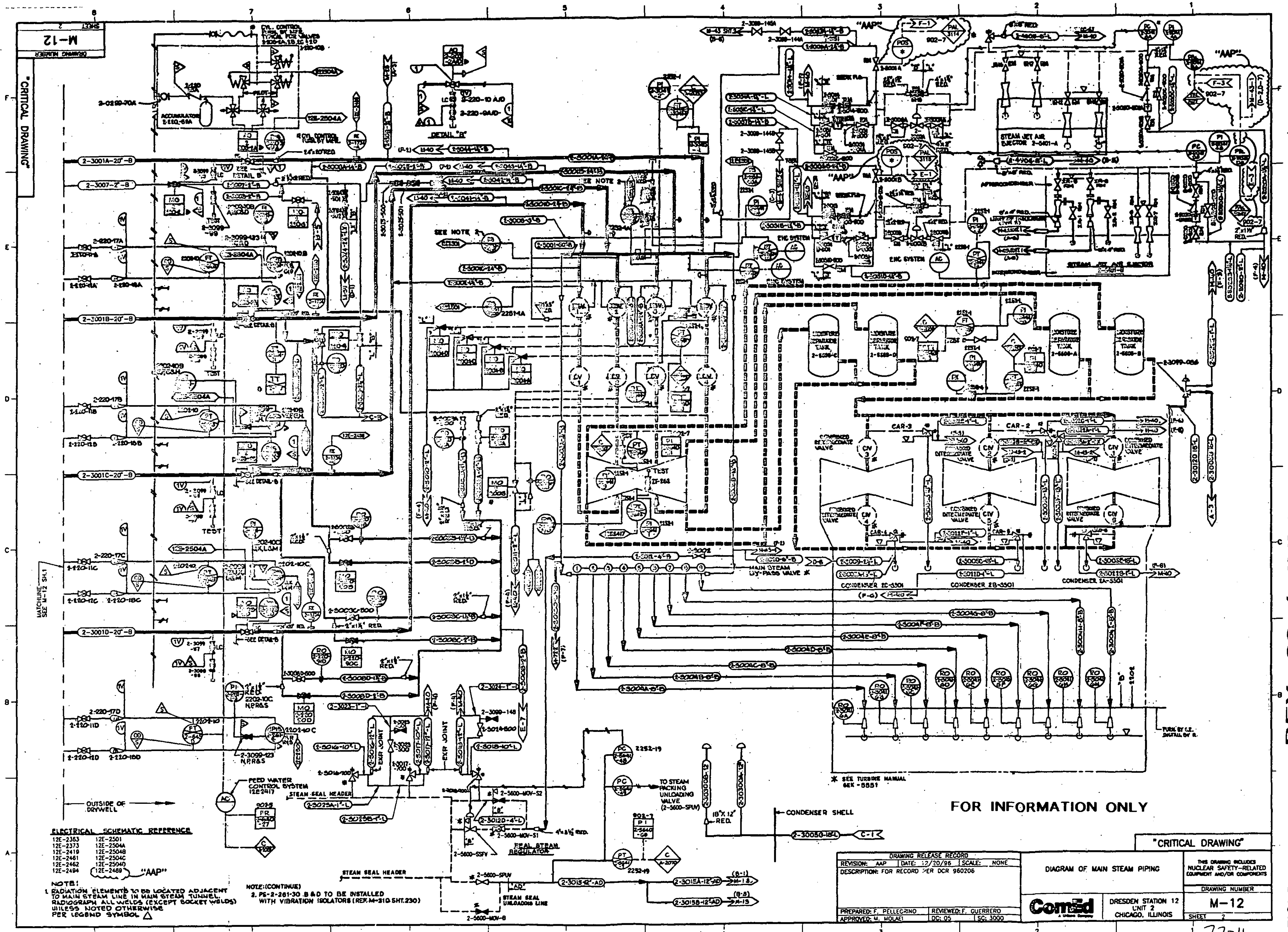
FIGURE 11.3-5



REV. 02 / JUNE 1997

FIGURE 11.3-6

CENTRAL DRAWING FACILITY



REV. 02 / JUNE 1997

FIGURE 11.3-7

CENTRAL DRAWING FACILITY

30 X

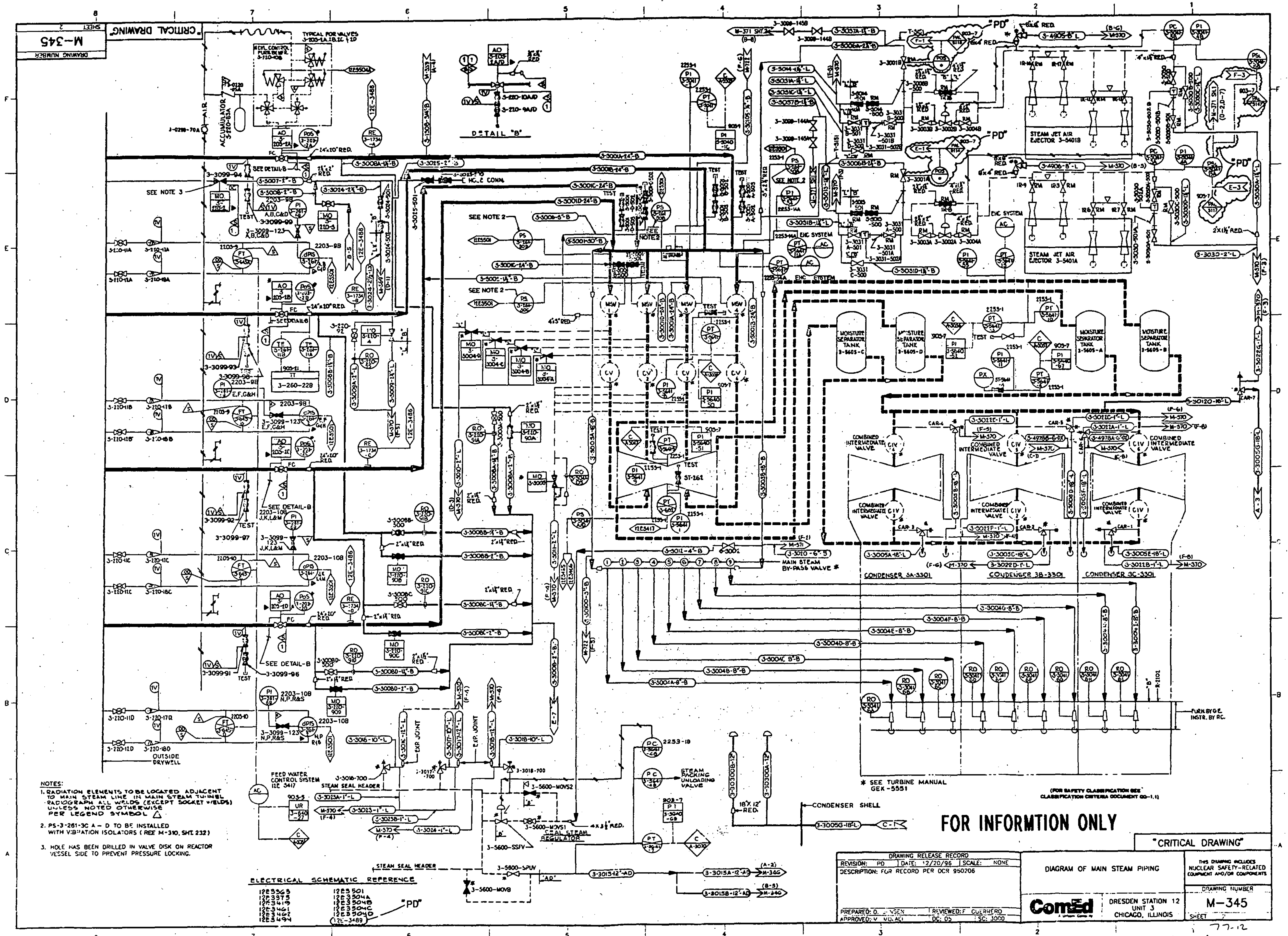
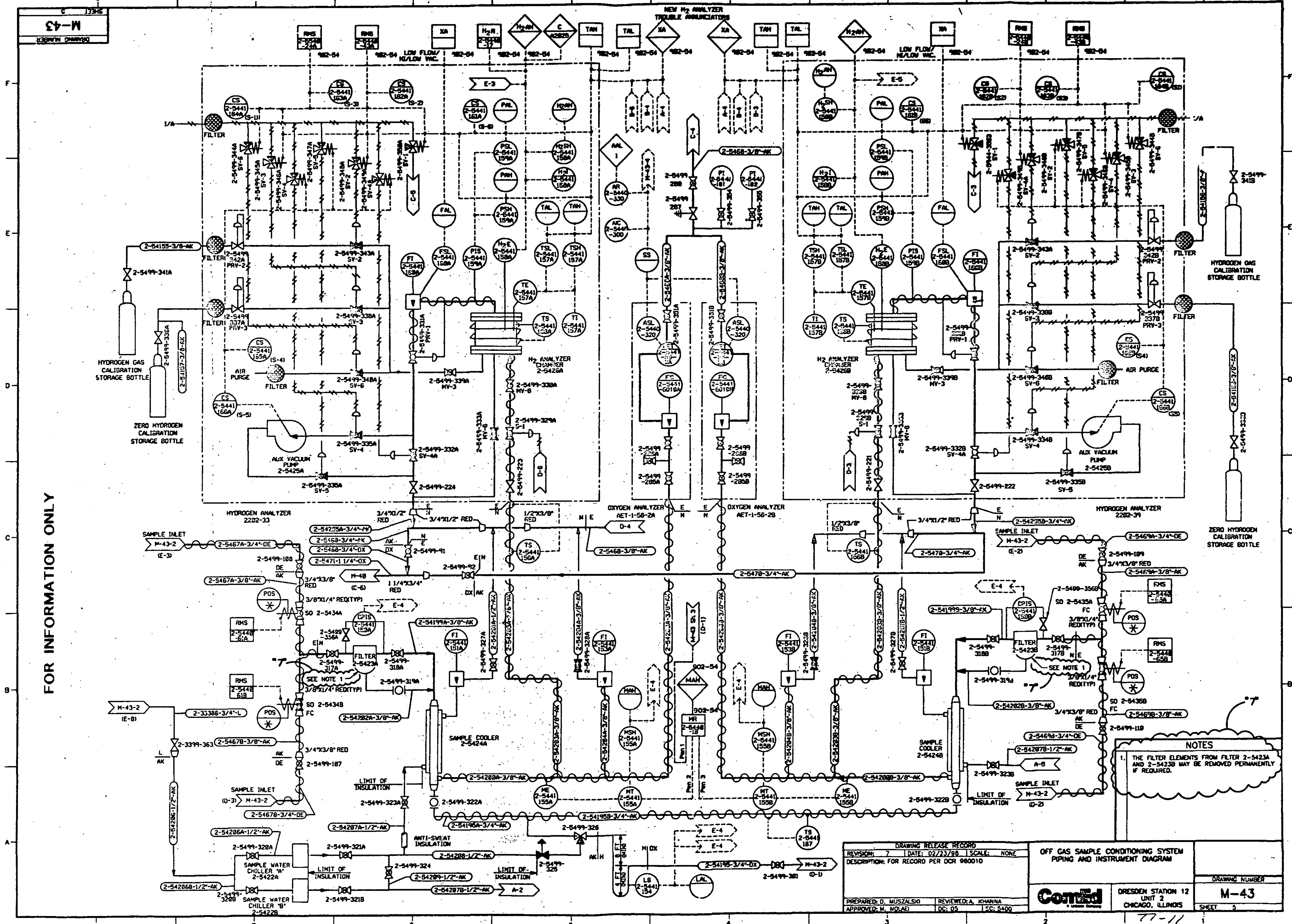


FIGURE 11.3-8

REV. 02 / JUNE 1997

CENTRAL DRAWING FACILITY

30 X

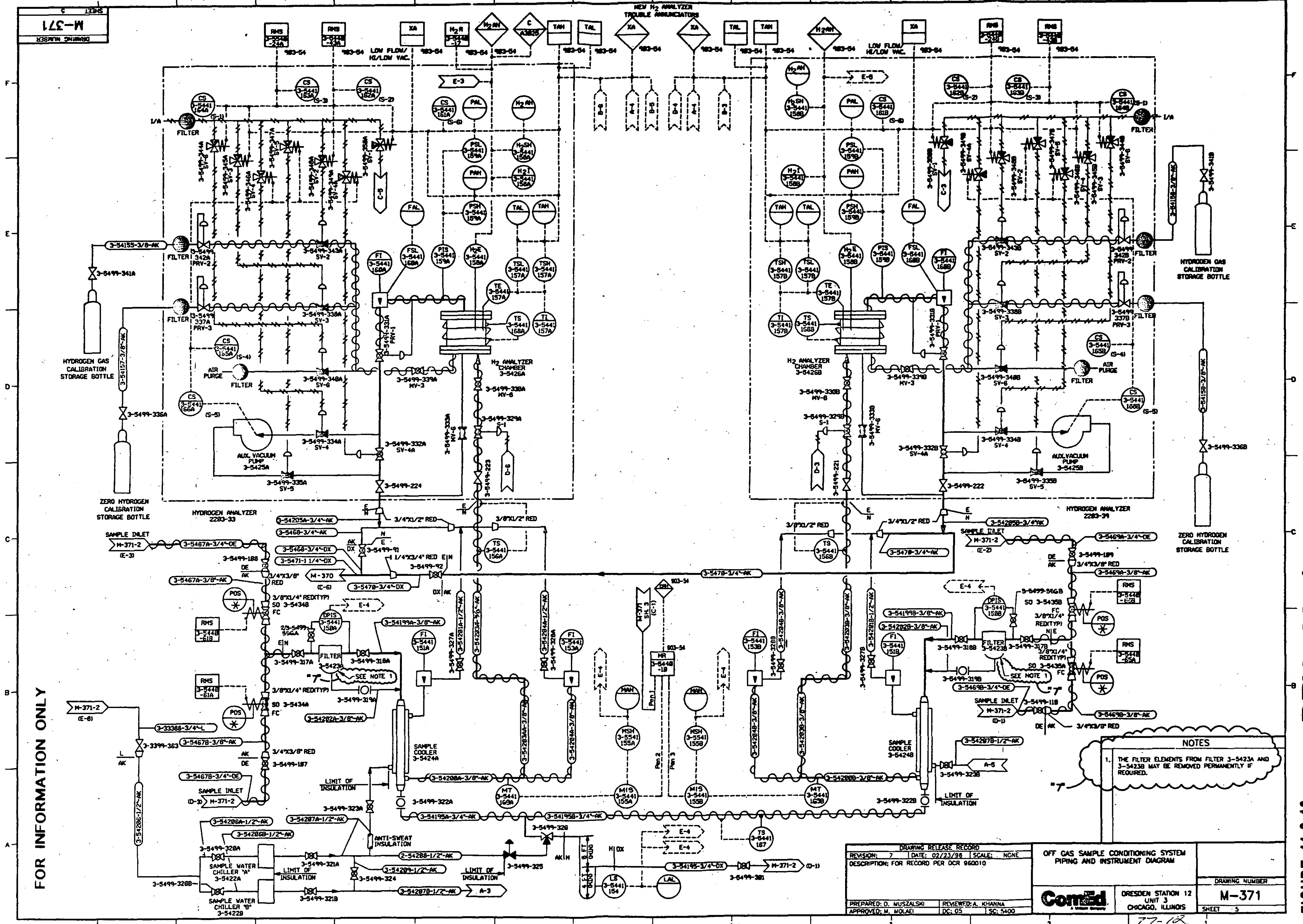


REV. 02 / JUNE 1997

FIGURE 11.3-11

CENTRAL DRAWING FACILITY

30 X

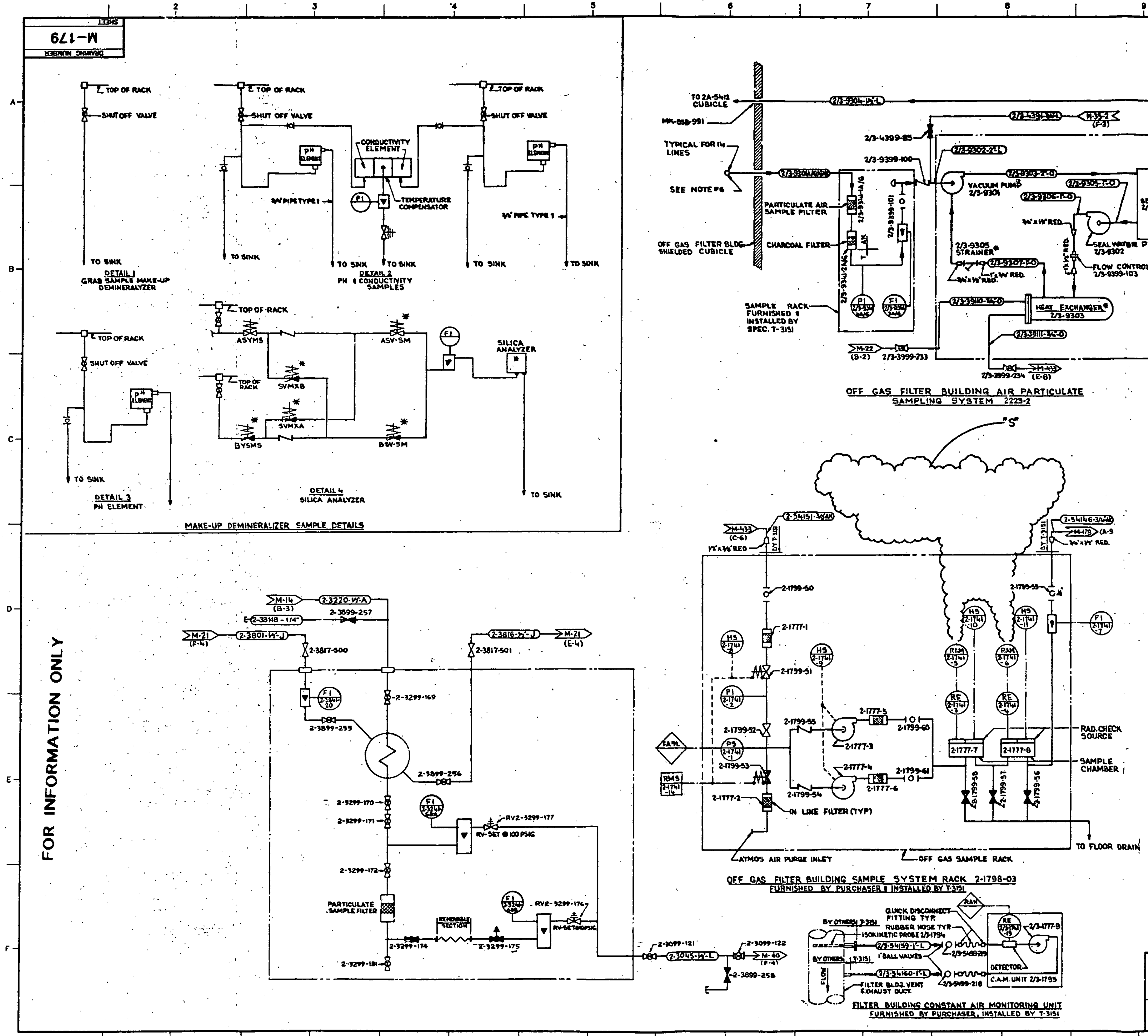


REV. 02 / JUNE 1997

FIGURE 11.3-12

CENTRAL DRAWING FACILITY

30 X



FOR INFORMATION ONLY

OFF GAS FILTER BUILDING — UNITS 2 & 3

SAMPLE POINT NO	LINE NO.	LOCATION	APPROX. ELEV.
1	2-9301A-1/2"AK	OFF GAS PREFILTER 2A CUBICLE	512'-6"
2	2-9301B-1/2"AK	OFF GAS PREFILTER 2B CUBICLE	512'-6"
3	2-9301C-1/2"AK	CHARCOAL ADSORBER CUBICLE	512'-6"
4	2-9301D-1/2"AK	CHARCOAL ADSORBER VALVE AISLE	493'-0"
5	2-9301E-1/2"AK	COOLER CONDENSER 2A CUBICLE	493'-0"
6	2-9301F-1/2"AK	COOLER CONDENSER 2B CUBICLE	493'-0"
7	2-9301G-1/2"AK	PRESSURIZED DRAIN TANK CUBICLE	493'-0"
8	3-9301A-1/2"AK	OFF GAS PREFILTER 3A CUBICLE	512'-6"
9	3-9301B-1/2"AK	OFF GAS PREFILTER 3B CUBICLE	512'-6"
10	3-9301C-1/2"AK	CHARCOAL ADSORBER CUBICLE	512'-6"
11	3-9301D-1/2"AK	CHARCOAL ADSORBER VALVE AISLE	493'-0"
12	3-9301E-1/2"AK	COOLER CONDENSER 3A CUBICLE	493'-0"
13	3-9301F-1/2"AK	COOLER CONDENSER 3B CUBICLE	493'-0"
14	3-9301G-1/2"AK	PRESSURIZED DRAIN TANK CUBICLE	493'-0"
15		SPARE	
16		SPARE	

NOTES

1. ALL FILTERS TO BE NUPRO SS-FR-60.
2. ALL NEEDLE VALVES TO BE WHITEY 2RS4 & ALL SHUT OFF VALVES TO BE WHITEY 2VS4.
3. BALL VALVES TO BE WHITEY 43S4-316.
4. FLOW INDICATORS TO BE F & P 0-580 CC/MIN RANGE.
5. TUBING AND FITTINGS PER TABLE X.
6. SAMPLING TUBE INLET TO BE PLACED LOCALLY TO THE BULK OF EQUIPMENT AND/OR IN THE EFFLUENT VENTILATION STREAM OF EACH CUBICLE, CLEAR OF HATCH OPENINGS AND OBSTRUCTIONS.

DRAWING RELEASE RECORD

REVISION: S | DATE: 03/11/97 | SCALE: NONE

DESCRIPTION: FOR RECORD PER DCR 970038

PREPARED: D. JENSEN | REVIEWED: D. HATCHER

APPROVED: A. KHANNA | DC: VOS | SC:

DIAGRAM OF PROCESS SAMPLING
PART 3

ComEd

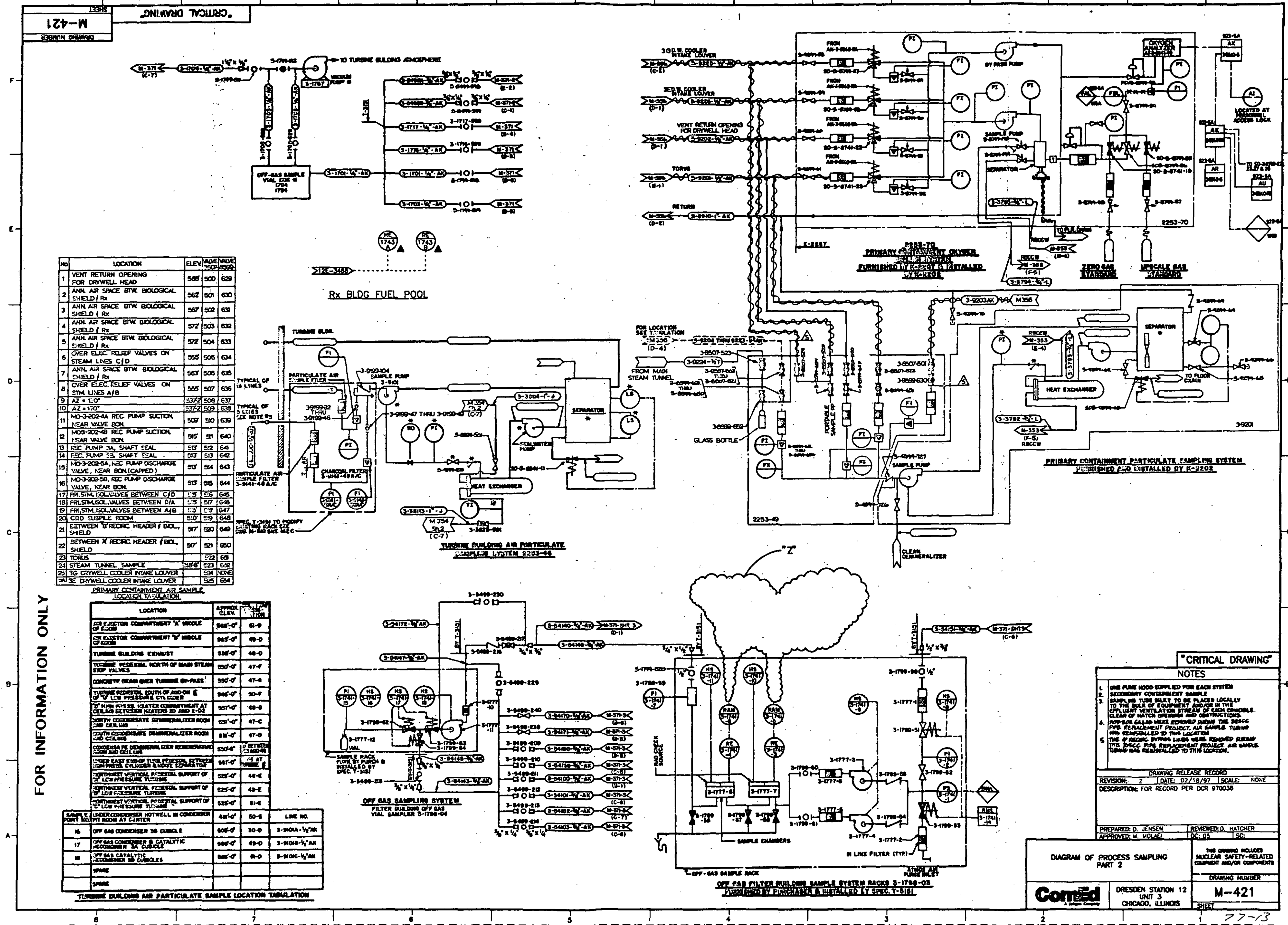
DRESDEN STATION 12
UNIT 2 & 3
CHICAGO, ILLINOIS

DRAWING NUMBER: M-179

SHEET

REV. 02 / JUNE 1997

FIGURE 11.3-14



FOR INFORMATION ONLY

No	LOCATION	ELEV	VALVE 2507	VALVE 8599
1	VENT RETURN OPENING FOR DRYWELL HEAD	588'	500	629
2	ANN. AIR SPACE BTW. BIOLOGICAL SHIELD / Rx	562'	501	630
3	ANN. AIR SPACE BTW. BIOLOGICAL SHIELD / Rx	567'	502	631
4	ANN. AIR SPACE BTW. BIOLOGICAL SHIELD / Rx	572'	503	632
5	ANN. AIR SPACE BTW. BIOLOGICAL SHIELD / Rx	572'	504	633
6	OVER ELEC. RELIEF VALVES ON STEAM LINES C/D	555'	505	634
7	ANN. AIR SPACE BTW. BIOLOGICAL SHIELD / Rx	563'	506	635
8	OVER ELEC. RELIEF VALVES ON STM. LINES A/B	555'	507	636
9	AZ = 10°	537-2	508	637
10	AZ = 170°	537-2	509	638
11	MO-3-202-4A REC. PUMP SUCTION, NEAR VALVE BON.	509'	510	639
12	MO3-202-4B REC. PUMP SUCTION, NEAR VALVE BON.	515'	511	640
13	REC. PUMP 3A, SHAFT SEAL	513'	512	641
14	REC. PUMP 3B, SHAFT SEAL	513'	513	642
15	MO-3-202-5A, REC. PUMP DISCHARGE VALVE, NEAR BON.(CAPPED)	513'	514	643
16	MO-3-202-5B, REC. PUMP DISCHARGE VALVE, NEAR BON.	513'	515	644
17	PRI. STM. ISOL. VALVES BETWEEN C/D	515'	516	645
18	PRI. STM. ISOL. VALVES BETWEEN D/A	515'	517	646
19	PRI. STM. ISOL. VALVES BETWEEN A/B	515'	518	647
20	CRD SUBPILE ROOM	510'	519	648
21	BETWEEN 'B' RECIRC. HEADER / BIOL. SHIELD	517'	520	649
22	BETWEEN 'A' RECIRC. HEADER / BIOL. SHIELD	517'	521	650
23	TORUS		522	651
24	STEAM TUNNEL SAMPLE	538'-6"	523	652
25	3G DRYWELL COOLER INTAKE LOUVER		524	NONE
26	3E DRYWELL COOLER INTAKE LOUVER		525	654

PRIMARY CONTAINMENT AIR SAMPLE LOCATION TABULATION

SAMPLE POINT NO.	LOCATION	APPROX. ELEV.	[illegible]	LINE NO.
	AIR EJECTOR COMPARTMENT "A" MIDDLE OF ROOM	565'-0"	51-9	
	AIR EJECTOR COMPARTMENT "B" MIDDLE OF ROOM	565'-0"	49-0	
	TURBINE BUILDING EXHAUST	538'-0"	48-D	
	TURBINE PEDESTAL NORTH OF MAIN STEAM STOP VALVES	550'-0"	47-F	
	CONCRETE BEAM OVER TURBINE BY-PASS	550'-0"	47-8	
	TURBINE PEDESTAL SOUTH OF AND ON ℄ OF "B" LOW PRESSURE CYLINDER	546'-0"	50-F	
	"D" HIGH PRESS. HEATER COMPARTMENT AT CEILING BETWEEN HEATERS 2D AND 2-D2	557'-0"	48-6	
	NORTH CONDENSATE DEMINERALIZER ROOM AND CEILING	531'-0"	47-C	
	SOUTH CONDENSATE DEMINERALIZER ROOM AND CEILING	531'-0"	47-D	
	CONDENSATE DEMINERALIZER REGENERATIVE ROOM AND CEILING	530'-6"	D BETWEEN 43 AND 48	
	UNDER EAST END OF TURB. PEDESTAL BETWEEN HIGH PRESS. CYLINDER & MOIST. SEPARATOR	551'-0"	45 AT TURBINE ℄	
	NORTHWEST VERTICAL PEDESTAL SUPPORT OF "A" LOW PRESSURE TURBINE	525'-0"	48-E	
	NORTHWEST VERTICAL PEDESTAL SUPPORT OF "B" LOW PRESSURE TURBINE	525'-0"	49-E	
	NORTHWEST VERTICAL PEDESTAL SUPPORT OF "C" LOW PRESSURE TURBINE	525'-0"	51-E	
	UNDER CONDENSER HOTWELL IN CONDENSER PIT ROOM AT CENTER	481'-0"	50-E	
16	OFF GAS CONDENSER 3B CUBICLE	605'-0"	50-D	3-9101A-½"AK
17	OFF GAS CONDENSER & CATALYTIC RECOMBINER 3A CUBICLE	566'-0"	49-D	3-9101B-½"AK
18	OFF GAS CATALYTIC RECOMBINER 3B CUBICLES	566'-0"	51-D	3-9101C-½"AK
	SPARE			
	SPARE			

TURBINE BUILDING AIR PARTICULATE SAMPLE LOCATION TABULATION

"CRITICAL DRAWING"

NOTES

1. ONE FUME HOOD SUPPLIED FOR EACH SYSTEM
2. SECONDARY CONTAINMENT SAMPLE
3. SAMPLING TUBE INLET TO BE PLACED LOCALLY TO THE BULK OF EQUIPMENT AND/OR IN THE EFFLUENT VENTILATION STREAM OF EACH CRUCIBLE. CLEAR OF HATCH OPENINGS AND OBSTRUCTIONS.
4. AO9-202 GALAD WERE REMOVED DURING THE IGSCC PIPE REPLACEMENT PROJECT. AIR SAMPLE TUBING WAS REINSTALLED TO THIS LOCATION
5. THE 4" RECIRC BYPASS LINES WERE REMOVED DURING THE IGSCC PIPE REPLACEMENT PROJECT. AIR SAMPLE TUBING WAS REINSTALLED TO THIS LOCATION.

DRAWING RELEASE RECORD

REVISION: Z | DATE: 02/18/97 | SCALE: NONE

DESCRIPTION: FOR RECORD PER DCR 970038

PREPARED: D. JENSEN | REVIEWED: D. HATCHER

APPROVED: M. MOLAEI | DC: 05 | SC:

DIAGRAM OF PROCESS SAMPLING PART 2

THIS DRAWING INCLUDES NUCLEAR SAFETY-RELATED EQUIPMENT AND/OR COMPONENTS

ComEd A Unicom Company

DRESDEN STATION 12 UNIT 3 CHICAGO, ILLINOIS

DRAWING NUMBER M-421

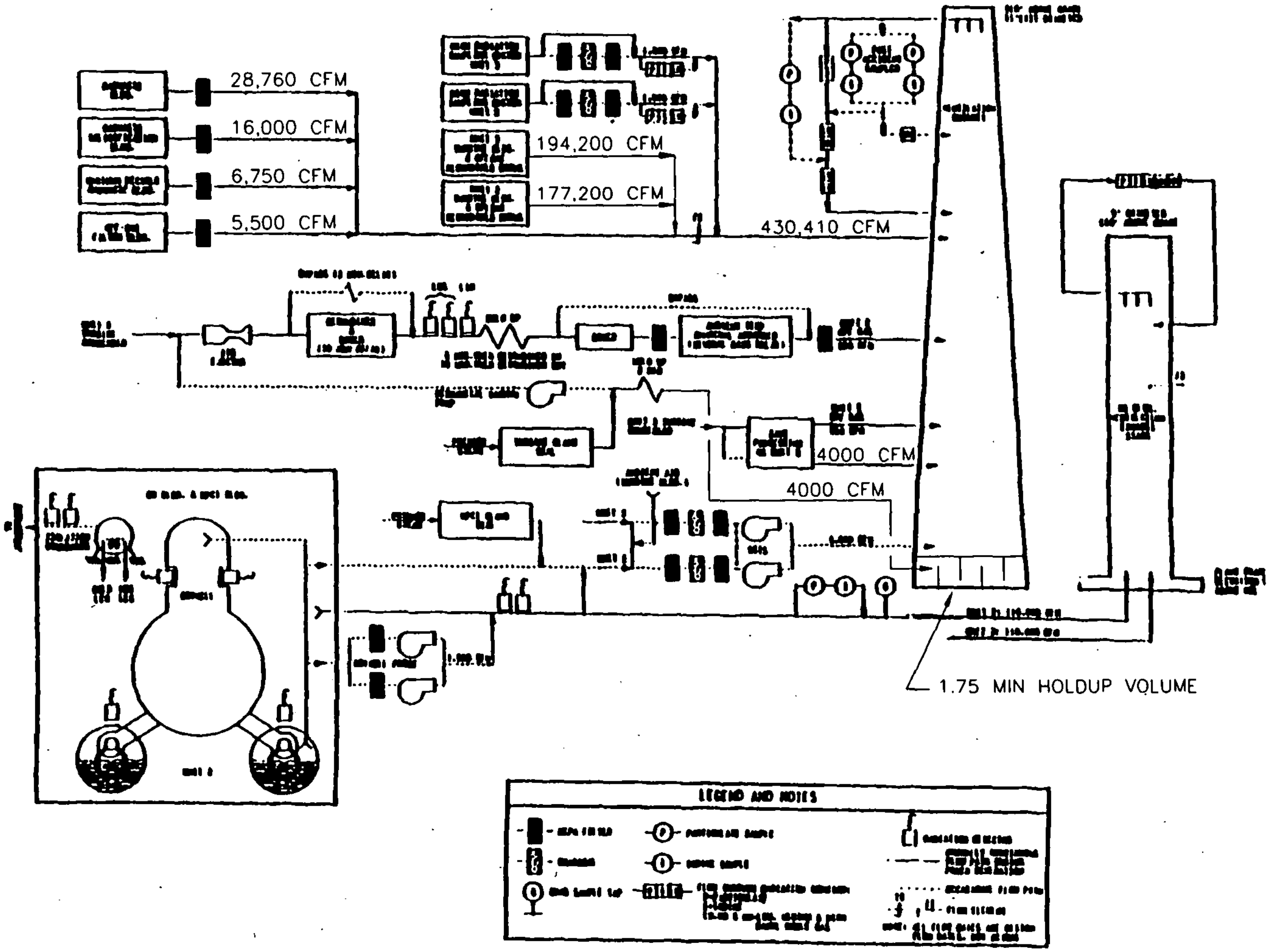
SHEET

77-13

REV. 02 / JUNE 1997

FIGURE 11.3-15

30 X



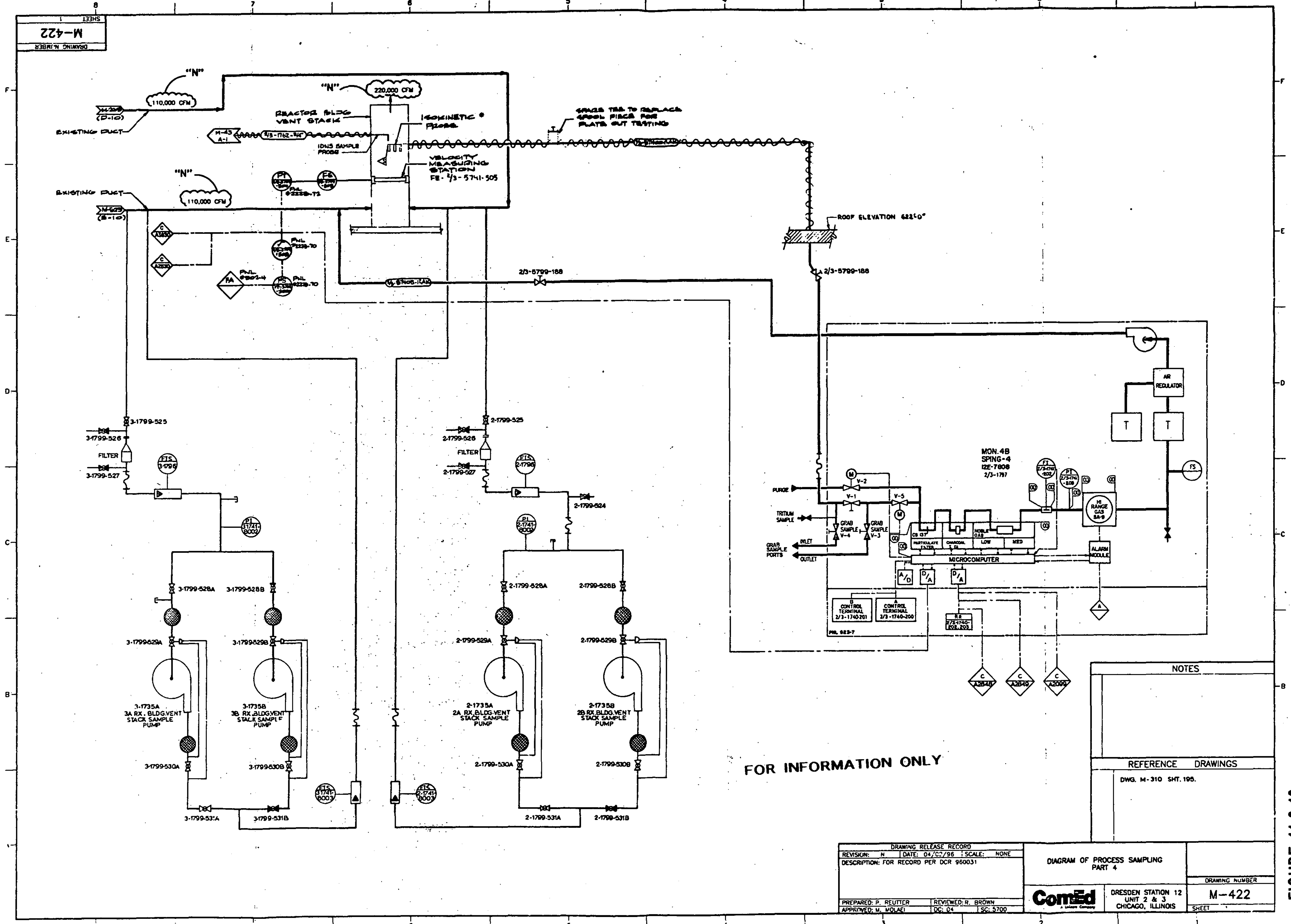
UFSAR REVISION 2, JUNE 1997

DRESDEN STATION

UNITS 2 & 3

SIMPLIFIED GASEOUS RADWASTE AND GASEOUS EFFLUENT FLOW DIAGRAM

FIGURE 11.3-17



REV. 02 / JUNE 1997

FIGURE 11.3-19

CENTRAL DRAWING FACILITY

30 X

11.4 SOLID WASTE MANAGEMENT SYSTEM

This section describes the capabilities of the station for collecting, processing, and packaging wet and dry solid radioactive waste generated as a result of normal operation, including anticipated operational occurrences, for shipment offsite or storage onsite.

11.4-1 Contract services are used for processing Class A unstable waste and waste which requires stability for burial offsite due to the requirements of 10 CFR 61. The process control program (PCP)[1] is used, as applicable, to process all low-level radioactive wet wastes that are solidified or dewatered to meet the applicable federal, state, and burial site requirements.

The solid radwaste area is shown in the general arrangement figures in Section 1.2. The treatment and flow of wet solid waste is shown in Figure 11.4-1 (Drawing M-46, Sheet 1).

11.4.1 Design Objectives

The design objectives of the solid radioactive waste control system are to process, package, and provide shielded facilities for solid wastes and to allow for radioactive decay and/or temporary storage prior to shipment from the station for offsite disposal. These solid radioactive wastes are prepared for shipment via common or contract carriers on vehicles having suitable shielding, in compliance with the United States Department of Transportation (DOT) regulations (49 CFR) and 10 CFR 20, 10 CFR 61, and 10 CFR 71 as applicable.

11.4.2 System Description

The solid radioactive waste control system is a series of mechanical operations that are designed to process the solid wastes remotely with a minimum of personnel handling and exposure. The equipment supplied to accomplish this handling is designed to be remotely operated in order to accomplish the functions described below. The handling and processing are capable of being performed without exceeding established exposure limits. Automatic instrumentation is used to measure the level of activity of each container.

The following are typical solid radioactive wastes:

A. Filter sludges and spent resins;

B. Concentrated wastes;

C. Air filters from off-gas and radioactive ventilation systems;

D. Contaminated clothing, tools, and small pieces of equipment which cannot be economically decontaminated;

11.4.2.1 Contractor-Supplied Solidification System

Contractor solidification services are currently used at the station. Radioactive wastes requiring solidification or dewatering include concentrator waste, certain sludges, and ion exchange resins.

The following paragraphs describe the preparation of solid radioactive waste for the contractor's system.

Filter sludges and spent resins are decanted in their respective storage tanks (additional details are given in Section 11.2 and the PCP[1]).

The excess water removed is returned to either the waste collector tank or the floor drain collector tank.

Concentrated waste is treated similarly except that no decanting is performed.

The waste tanks contents are pumped to the contractor's shipping container either by the station's permanently installed pump or by the contractor supplied equipment. The low level radioactive waste (LLRW) is preconditioned and dewatered within the shipping container in accordance with the requirements of the contractor's PCP.

Prior to or during transfer, a sample of the waste is obtained and processed to ensure that a solidified product can be obtained using the contractor's process in accordance with the contractor's PCP.

A fillhead and extension skirt assembly which seals onto the opening provides means to control the spread of contamination and dust during the solidification operation.

The system is designed with interlocks and safeguards to ensure troublefree operation. The control panel is designed to be easily understood and simple to operate. Interlocks and alarms are provided to preclude unsafe operation or operator error. A more in-depth operating description can be obtained from the contractor's PCP as referenced in the station's PCP.[1]

11.4.2.2 Contractor-Supplied Dewatering System

Contractor dewatering services may be used at the station in lieu of solidification for stable and unstable waste forms. The wastes considered for dewatering are ion exchange resins and filter media. Generally the ion exchange resins and filter media (sludge) are dewatered or solidified in a liner or a high integrity container (HIC).

The liner or HIC is normally shipped to the plant in a suitable transportation cask. The contractor's fillhead is positioned on the liner or HIC, and the transfer and dewatering process is started. The contractor receives waste from the station radwaste mixing tank via a radwaste pump or contractor supplied equipment.

After the radwaste has been transferred to the liner or HIC, the balance of the dewatering process is completed by the contractor. The liquid waste resulting from this process is returned to the liquid radwaste system. Upon completion of the dewatering process, the fillhead is removed and the container full of waste is inspected to verify that the remaining liquid content is acceptable for shipment and burial. Samples are obtained, and the container is capped, secured, surveyed, and shipped for offsite burial or stored onsite to be shipped for burial at a later date. The container may be stored in the interim radwaste storage facility until shipment to the burial site.

11.4.2.3 Contractor Encapsulation of Waste

Contractor encapsulation services may be utilized for wastes which require classification as stable wastes per 10 CFR 61 and/or burial site licenses. The contractor-supplied procedures or other documents which support the encapsulation process are used by the station to prepare specific station procedures for review, prior to use, to assure compatibility with the station systems, procedures, and Technical Specifications.

11.4.2.4 Dry Active Waste

Dry active waste (DAW) occurs from many sources:

A. Air filters from the off-gas systems, the various plant ventilation systems, and the standby gas treatment systems;

B. Contaminated clothing, tools, and small equipment;

C. Miscellaneous contaminated paper, rags, plastic, metal, wood, etc.;

D. Contaminated concrete chippings and dirt;

E. Cartridge/sock filters from liquid radwaste processing; and

F. Activated plant components; i.e., control blades, local power range monitors (LPRMs), fuel channels, etc.

The dry active wastes are collected in containers located in appropriate zones around the plant, as dictated by the volume of wastes generated during plant operation and maintenance. The containers are then collected and moved to a controlled-access location where the wastes are packaged in suitable containers. Compressible wastes are typically compacted into drums by a hydraulic press to reduce their volume. They are packaged and stored until shipped offsite for burial or to a waste-processing facility. Ventilation is provided to maintain control of contaminated particles when operating packaging equipment or during equipment maintenance and cleanup.

building container storage areas. DAW may also be stored at an interim storage location which is away from the processing area while awaiting shipment to the burial site.

11.4.4.2 Contractor Solidified, Dewatered, or Encapsulated Waste

The contractor solidified waste and the container are normally shipped when solidification is completed. The contractor dewatered waste and the container are normally shipped when dewatering is completed. Contractor encapsulated waste is generally shipped when encapsulation is completed. If storage is required for any of these types of wastes, the containers of waste may be temporarily stored onsite at an interim storage location.

11.4.4.3 Interim Radwaste Storage Facility

The interim radwaste storage facility (IRSF) was constructed to facilitate continued nuclear power station operation should the existing burial facilities shut down.

The IRSF is located inside the protected area. Figure 11.4-2 shows the location of the facility. Figure 11.4-3 shows the general arrangement of the IRSF.

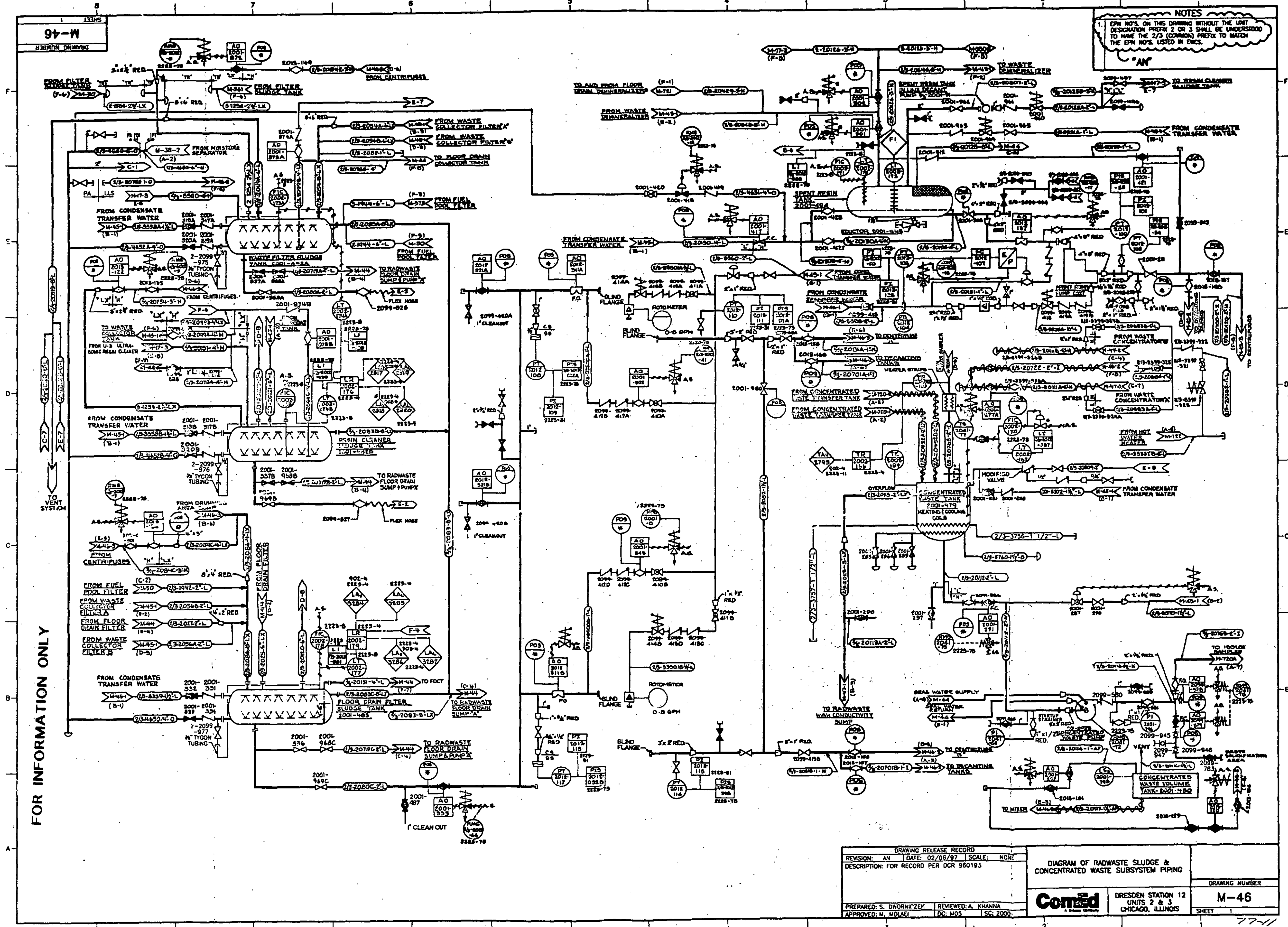
A portion of the existing chemical cleaning facility was used in the construction of the IRSF. The major IRSF areas are the truck bay, control room, equipment room, and storage bay. The truck and storage bays are serviced by a 10-ton crane.

Six closed-circuit television (CCTV) cameras are located on the crane; two of them are permanently fixed to observe the grid system coordinates for proper placement of the low level water (LLW) containers. The other four CCTV cameras can be moved to several orientations to facilitate container placement and remote container surveillances.

Storage bay access is limited to access through the normally locked container decontamination area or via the crane through the storage bay/truck bay interface notch.

The IRSF truck bay is used for receiving LLW material for storage. It is also used as a truck loading area for LLW material being shipped to the burial site.

The control room contains the IRSF crane control panel and CCTV monitors. The control room and the equipment room are located adjacent to the IRSF but in the chemical cleaning building. The ventilation system for the IRSF is an extension of the chemical cleaning building ventilation system. The ventilation system exhausts through a prefilter/HEPA filter arrangement and then through the chemical cleaning building exhaust stack. The exhaust discharge is monitored for radioactivity.

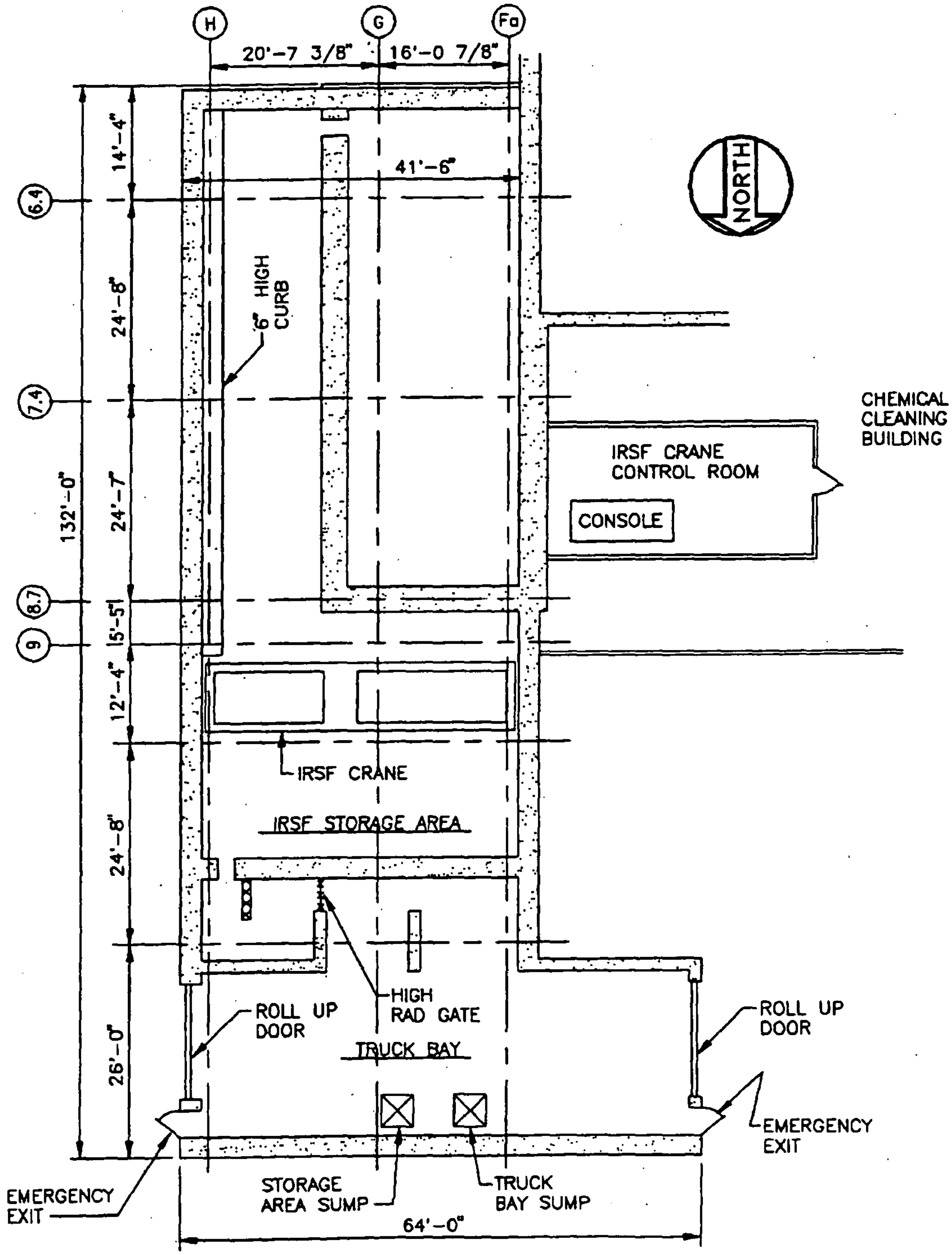


REV. 02 / JUNE 1997

FIGURE 11.4-1

CENTRAL DRAWING FACILITY

30 X



UFSAR REVISION 2, JUNE 1997
DRESDEN STATION UNITS 2 & 3
IRSF PLAN OF DRIVE THRU TRUCK BAY
FIGURE 11.4-3

The redundancy incorporated into the monitoring system provides assurance that abnormal releases of radioactive material are detected, annunciated, and isolated.

To calibrate the monitors, the results of analysis of a grab sample are compared to the monitor indications at the time of sampling. Since the radioactivity levels of N-16 and O-19 in the main steam are normally relatively high, the transportation time delay to the air ejector off-gas monitor location allows for the rapid decay of the short-lived gases. The delay permits a more accurate indication of the activity levels of the longer-lived gases of interest.

11.5.2.3 Chimney Effluent Gas Monitoring System

The chimney effluent monitor (see Figure 11.5-4 and Figure 11.3-24) consists of a single multiple-range system particulate, iodine, and noble gas (SPING) monitor and a backup system which incorporates two channels of instrumentation.

The release rates (µCi/s) from the 310-foot chimney and the reactor building ventilation stack are calculated from the instrument readouts (counts per second) and totalled by the operator to assure compliance with gaseous release rate limits for the plant. The isotopic quantities are reported as required by the ODCM.

The chimney flow consists of air ejector off-gas (approximately 20 ft^3/min with the recombiner operating; 150 ft^3/min without the recombiner operating) mixed with ventilation air (approximately 430,910 ft^3/min)(see Section 11.3.3.1.2 for additional information). A representative sample is drawn continuously from the chimney through an isokinetic sample probe located at two-thirds of the chimney height. The placement of the probe is in accordance with good engineering design practice, i.e., probe height is at least 10 times the chimney diameter. The SPING monitor and its backup system use the same isokinetic probe.

11.5.2.3.1 SPING Monitoring Instrumentation

The SPING monitor is computerized instrumentation (see Figure 11.5-4 and Figure 11.3-24) with sufficient range to accurately monitor the chimney effluent for the worst postulated accident releases as well as for normal operating conditions. The installation of the SPING monitor is a result of the events occurring at Three Mile Island (TMI) on March 28, 1979.

The SPING monitor is a microprocessor-based radiation detection system. The programs (software) which control the system are stored in read-only memory (ROM) and therefore are fixed. Only the parameters of the system can be varied. The microcomputer performs the tasks of data acquisition, history file management, operational status check, and alarm determination. The microcomputer communicates with the operator through a terminal in the control room.

each unit. Secondary containment isolation (see Section 6.2.3) is manually initiated by the operator if the automatic functions of the reactor building ventilation duct monitoring system fail. Adequate backup is also provided for the SPING monitor by the reactor building ventilation exhaust samplers. These samples are routinely removed and counted in the chemistry lab area. The results of SPING monitor and sample testing are reported as required by the ODCM.[1]

11.5.2.6 Reactor Building Closed Cooling Water System Monitoring System

The reactor building closed cooling water system is primarily utilized to provide cooling for potentially contaminated systems such as the reactor water cleanup (RWCU) system, reactor concrete shielding, non-regenerative heat exchangers, and recirculation pumps. The system contains activity due to design inleakage from heat exchangers or other components which contain radioactive water. Changes in the normal radiation level signify an increase in activity concentration in the system.

The process liquid monitor (see Figure 11.5-5) incorporates one channel of instrumentation consisting of the following components:

A. A scintillation crystal-photomultiplier counter;

B. A linear count rate meter;

C. A continuous strip chart recorder;

D. Trip auxiliaries; and

E. A control room alarm.

At the mounting installation, a scintillation detector is located in a shielded sampler which is positioned on a vertical section of the process liquid piping. A vertical section of piping is used to minimize background radiation due to plate out.

Trip circuits are also included to indicate abnormal concentrations of fission and radioactive corrosion products so that action can be taken to prevent the accidental transfer of highly radioactive materials. The readout consists of a seven decade meter display. This system shares a common two-pen strip chart recorder with the service water radiation monitoring system.

The reactor building closed cooling water system radiation monitor provides seven-decade monitoring with the lowest decade established below the normal background of the system. The high-radiation alarm setpoint is based upon the normal, full power, operating background but is considerably less than the operating limit. Table 11.5-1 lists the specific data pertaining to the sensitivities and accuracies of the monitoring equipment.

provides local indication and alarms and radwaste control room panel annunciation. Both the discharge pump and the grab sample valve have local, manual control.

The system, which has been designed to maintain a constant flow and a preset band of tank level, provides annunciation in the radwaste control room to alert the operator of any deviations from the normal operating status. A low-level annunciation is received if the discharge pump continues to run below the low setpoint. Low-flow annunciation will be received if the sample flow drops below the prescribed setpoint. If the high-radiation setpoint is exceeded, annunciation is received and a grab sample is automatically obtained by a solenoid valve which opens for a set period of time to allow part of the sample flow leaving the detector to flow into a container. In addition, a loss of monitor power, loss of a monitor radiation signal, or loss of a high-radiation signal results in a monitor failure annunciation.

The procedures for liquid radioactive waste discharge to the river, along with the monitor failure, low flow, high and low receiver-tank level, and high-radiation annunciation in the radwaste control room, will assure that the liquid radioactive waste discharges are monitored properly. This assures that the activity in the water leaving the discharge canal and entering the river is within federal limits for nonoccupational use.

The use of applicable procedures assures that the valve lineup for the discharge of liquid radwaste is correct. After initiating the discharge the lineup can be further verified by the noting level drop in the waste surge tank.

11.5.2.9 Isolation Condenser Vent Monitoring System

Monitoring of gross radiation is provided at the isolation condenser vent line by two channels of instrumentation. Each channel is powered from one of the RPS buses. The amplifiers associated with the detectors are logarithmic and have ranges of 10^{-2} to 10^{3} mrem/hr and 1 to 10^{5} mrem/hr, respectively. The detectors are identical to those used for the area radiation monitoring system addressed in Section 12.3. The output of each monitor is indicated and recorded in the control room. When the gross activity in the condenser vent line reaches a preset level (indicating tube leaks in the isolation condenser) an alarm is sounded. Failure of the monitoring equipment, either upscale or downscale, is annunciated.

The isolation condenser vent monitor is of sufficient range and sensitivity to detect radiation increases in the condenser which indicate a tube leak. The alarm level is set sufficiently above background to be representative of a leak. Since the background is continuously recorded, any abnormal increase is noted by the operator. Following an alarm, the operator may isolate the condenser.

11.5.2.10 Process Liquid Sampling System

The process liquid sampling system is provided in three parts at three locations. The process liquid sampling system is addressed in more detail in Section 11.2.

ODCM defines sampling and sampling frequency dependent on operation of the discharge monitor.

11.5.3.2 Gaseous Effluent Monitoring and Sampling

The three continuous gaseous release points (the Unit 1 chimney, the Unit 2 and 3 chimney, and the Unit 2 and 3 reactor building ventilation stack) are monitored continuously by SPING radiation monitors. The monitors for Units 2 and 3 are addressed in more detail in Section 11.5.2. Additional details of sampling are addressed in Section 11.3. The requirements for sampling and laboratory analysis are addressed in the plant Technical Specifications. The SPING monitors provide activity information and provide an alarm when a preset activity level is reached.

11.5.3.3 Environmental Radiation Monitoring and Radiological Sampling Program

The environmental radiation monitoring and radiological sampling program is conducted in accordance with the requirements of the ODCM. Analyses of the results are determined as required by the ODCM. The results are reported annually to the NRC in the Annual Radiological Environmental Operating Report.

11.5.3.4 Response to Draft of the AEC-Proposed General Design Criteria

For the details of the response to AEC-Proposed General Design Criteria, see Section 3.1. In addition to the discussion in Section 3.1, the gaseous and liquid release paths are monitored during normal operation including any anticipated operational occurrences.

11.5.4 Process Monitoring and Sampling

11.5.4.1 Process Liquid Monitoring and Sampling

The liquid process monitoring and sampling system is addressed in Section 11.2 for the liquid radwaste system, the service water system, and the reactor building closed cooling water system.

11.5.4.2 Process Gaseous Monitoring and Sampling

The crossties between the reactor building ventilation system, the SBGTS system, and the refueling floor monitors is addressed in Sections 11.3, 11.5.2.4, and 6.2.3. The MSL monitors and/or the steam jet air ejector radiation monitors provide the

Table 11.5-1

RADIATION MONITORING SYSTEMS EQUIPMENT PARAMETERS

Radiation Monitoring System	General Monitor Type	Number of Channels	Detector Type	Range	Indicator and Alarm Location	Radiation Alarm Types	Equipment Alarm Types	Recorder		Sampling	Logic
								Type	Location		
Main Steam	Area	4	Ionization chamber	0 to 10^6 mrem/hr	Main control room	High and high-high	Downscale	Dual pen	Main control room	In-line	Scram and Group I isolation; off-gas isolation; mechanical vacuum pump trip
Air-Ejector (Off-Gas)	Radioactive gas	2	Ionization chamber	0 to 10^6 mrem/hr	Main control room	High and high-high	Downscale	Dual pen	Main control room	In-line	Off-gas isolation (after 15-min delay)
					Radwaste control room	High and high-high					

Table 11.5-1 (continued)

RADIATION MONITORING SYSTEM EQUIPMENT PARAMETERS

Radiation Monitoring System	General Monitor Type	Number of Channels	Detector Type	Range	Indicator and Alarm Location	Radiation Alarm Types	Equipment Alarm Types	Recorder		Sampling	Logic
								Type	Location		
Effluent Gas (SPING)	Air particulate	1	Solid-state alpha and	Up to 10^5 μCi/cc for high noble gas	Main control room and locally	High, high-high, and trend	Fail	Computer memory to strip chart type for noble gases	Local and main control room	Offline	
		1	Scintillation								
(one for main chimney, one for reactor building ventilation stack)	Iodine	1	Scintillation								
	Noble gas	1	Scintillation (low)								
		1	G-M tube (medium)								
		1	G-M tube (high)								
	Area	1	G-M tube								

Table 11.5-1 (continued)

RADIATION MONITORING SYSTEM EQUIPMENT PARAMETERS

Radiation Monitoring System	General Monitor Type	Number of Channels	Detector Type	Range	Indicator and Alarm Location	Radiation Alarm Types	Equipment Alarm Types	Recorder		Sampling	Logic
								Type	Location		
Effluent Gas (Chimney GE System)	Noble gas	2	Scintillation	10^{-1} to 10^{6} cps	Main control room	High	Downscale	Dual pen	Main control room	Offline	
	Air particulate	1	None								
	Iodine	1	None								
Reactor Building Ventilation Exhaust Plenum	Area	2	G-M tube	10^{-2} to 10^{2} mrem/hr	Main control room	High and high-high	Downscale	Dual pen	Main control room	In-line	SBGTS initiation and reactor building ventilation isolation
Refueling Floor	Area	2	G-M tube	1 to 10^{6} mrem/hr	Main control room	High	Downscale	Multi-point (with ARMs)	Main control room	Offline	SBGTS initiation and reactor building ventilation isolation
Reactor Building Closed Cooling Water System	Liquid effluent	1	Scintillation	10^{-1} to 10^{6} cps	Main control room	High and high-high	Downscale	Strip chart	Main control room	In-line	

Table 11.5-1 (continued)

RADIATION MONITORING SYSTEM EQUIPMENT PARAMETERS

Radiation Monitoring System	General Monitor Type	Number of Channels	Detector Type	Range	Indicator and Alarm Location	Radiation Alarm Types	Equipment Alarm Types	Recorder		Sampling	Logic
								Type	Location		
Service Water Effluent	Liquid effluent	1	Scintillation	10^1 to 10^6 cps (10^{-6} to 10^{-2} μCi/cc)	Main control room	High and high-high	Monitor failure, receiver tank low level,(1) return pump failure(1)	Strip chart	Main control room	Offline	
Radwaste Liquid	Liquid effluent	1	Scintillation	10^1 to 10^6 cps	Main control room	High and high-high	Downscale, loss of power	Dual pen strip chart	Main control room	Offline	
					Radwaste control room	High and high-high			Radwaste control room		
Isolation condenser	Area	2	G-M tube	10^{-2} to 10^3 and 1 to 10^5 mrem/hr	Main control room	High	Downscale	Multi-point (with ARMs)	Main control room	In-line	

Notes:

1. Receiver tank low level and return pump failure alarms for Unit 3 only. Unit 2 has a low service water sample flow alarm.

12.0 RADIATION PROTECTION
TABLE OF CONTENTS

Page

12.0 RADIATION PROTECTION

The protection of operating personnel from radiation emanating from process equipment, from radioactive materials present on equipment externals in work areas, or from airborne radioactive material particles and gases is accomplished by a combination of the design of the facility's shielding structures, selection and use of appropriate radiation monitoring instrumentation, and the development and implementation of control standards and procedures. The purpose of the following sections is to provide a brief summary of these radiation protection aspects of these units. The shielding and instrumentation are described in greater detail in Sections 11.5, 12.3, and 12.5. A study contained in Appendix 12A details dose rates throughout the plant following a postulated accident.

12.1 ENSURING THAT OCCUPATIONAL RADIATION EXPOSURES ARE AS LOW AS REASONABLY ACHIEVABLE

12.1.1 Policy Considerations

This subsection addresses the management policy and organizational structure related to implementation of the "as low as reasonably achievable" (ALARA) program to ensure that occupational exposure for station personnel are maintained ALARA. The ALARA program is part of the station radiation protection program.

12.1.1.1 Management Policy

It is the policy of ComEd to maintain the occupational dose equivalents to the individual and the sum of dose equivalents received by all exposed workers to levels that are as low as reasonably achievable (ALARA). This ALARA philosophy is implemented in a manner consistent with station operating, maintenance, and modification requirements, taking into account the state of technology, the economics of improvements in relation to the state of technology, the economics of improvements in relation to benefits to the public health and safety, and other societal and socioeconomic considerations, and in relation to utilization of nuclear energy and licensed materials in the public interest.

Commonwealth Edison's commitment to this policy is reflected in the ComEd ALARA program, in station design, in careful preparation and review of station radiation protection operating and maintenance procedures, and in review of equipment design to incorporate the results of operating experience.

It is the policy of ComEd to have all levels of management strongly committed to radiation protection and, specifically, to maintain occupational radiation exposures ALARA. Also, it is recognized that each worker must take personal responsibility for actions necessary to implement successful dose reduction measures.

12.1.1.2 Organizational Structure

The Station ALARA Committee functions as the executive body for the station's ALARA program. The committee is responsible for developing the ALARA goals for the station. The committee provides guidance and recommendations on aspects of radiological protection operations thus ensuring that effective radiation dose reduction measures are applied.

12.1.2 Design Considerations

The initial licensing of Dresden Station predated issuance of 10 CFR 50, Appendix I. Therefore, specific ALARA design considerations were not developed as part of the PSAR or FSAR. The purpose of these considerations is to ensure that design of the plant facilities contributes to keeping occupational exposures ALARA. The ALARA design considerations for plant modifications are addressed at an early stage of the modification planning process as part of the ongoing ALARA program.

The design of modifications is reviewed for their exposure impact. A preliminary review of the exposure impact of the modification to be performed at the station is completed by the responsible engineer in the planning phase shortly after a request to do the modification is submitted. This review is required by engineering procedures. Additional guidance is provided by the ALARA design guide, which includes a detailed compilation of ALARA considerations. The design guide is not a requirement for approval of the modification. Some items covered in the design guide include the following:

A. Layout and radiological boundaries;

B. Activation product concerns;

C. Contamination control;

D. Operability and maintenance concerns;

E. Shielding;

F. Equipment types; and

G. Possible use of robots to minimize personnel exposure.

Station ALARA personnel attend a series of meetings during the planning phases of the modifications to provide information on the exposure impact of the modification. This meeting is the first review of the modification and offers the opportunity to address all ALARA concerns before the procedural process for approval of the modification begins. Written ALARA Action Reviews are required when performing radiation work which has the potential for high cumulative exposures. The ALARA personnel also participate in the walkdown phase of modification planning and in the post-job review process.

12.1.3 Operational Considerations

Plant procedures are required to comply with the ALARA program. Procedures provide the necessary guidance for assuring the radiation protection program addresses ALARA considerations. Aside from procedures which directly implement the ALARA program such as ALARA Action Reviews, other procedures are also associated with the ALARA program. Examples are procedures for exposure review and authorization; respiratory protection; high radiation area control; contamination control; and radiation protection training. The radiation work permit (RWP) procedure also contributes significantly to ALARA. The ALARA actions are determined based on the RWP information and station work activities.

12.2 RADIATION SOURCES

The initial licensing of Dresden Station predated issuance of Regulatory Guide 1.70, Revision 3. Therefore, the identification of radiation sources (beyond those in radioactive waste management systems) was not developed as part of the PSAR or FSAR. The purpose of identifying radiation sources is to permit evaluation of radiation protection design features (described in Section 12.3) in order to provide reasonable assurance that radiation exposure of plant personnel will be within allowable limits. Radiation surveys within the plant are made and evaluated as part of the ongoing as low as reasonably achievable (ALARA) program at Dresden.

Radiation sources generated in the reactor core and transported by the reactor coolant system are described in Section 11.1. Radiation sources from components of the radioactive waste management systems are described in Sections 11.2, 11.3, and 11.4.

Radioactivity is also present in the fuel pool cooling and cleanup systems described in Section 9.1.3, the reactor water cleanup system described in Section 5.4.8, and the condensate cleanup system described in Section 10.4.6.

A complete and current inventory of radioactive sources (i.e., instrument calibration sources, etc.) at the station is maintained. Sealed radiation sources are tested for removable contamination according to Technical Specification requirements. Storage, handling, and use of sealed sources are controlled by plant procedures.

12.3 RADIATION PROTECTION DESIGN FEATURES

This section describes plant design features used to ensure that occupational radiation exposures resulting from the radiation sources within the plant meet the "as low as reasonably achievable" (ALARA) program objectives described in Section 12.1. These features include shielding, ventilation systems, and radiation monitoring instruments.

12.3.1 Facility Design Features

When Dresden Units 2 and 3 were designed, the structures were shaped and arranged on the site to conform to the locations of the previously existing plant (Unit 1), water supply, roads, and railroad. The structures were also arranged to provide the best layout for the equipment. Safety requirements also were met with respect to circulation of contaminants and protection from radiation. Figure 1.2-1 (Drawing M-1) is a plot plan showing the arrangements of the structures.

Additional information on the design features of Dresden Station that protect personnel from radiation exposure and minimize radiation damage to plant equipment can be found in the following:

A. Sections 11.1 through 11.4 describe radioactive waste processing;

B. Section 11.5 addresses process and effluent radiation monitoring;

C. Section 12.5.3.4 addresses control of access to radiation areas; and

D. Section 12.5.2 describes the radiochemical laboratory facilities.

12.3.2 Shielding

Normal operating conditions determine the major portion of the shielding requirements. Two notable exceptions are the control room, where shielding is determined by the radiation levels produced during the loss-of-coolant accident (LOCA), and the shutdown cooling system, where shielding is determined by shutdown conditions.

12.3.2.1 Design Basis

The basis for the design of the radiation shielding is in compliance with the requirements of 10 CFR 20, which describes the limits of occupational radiation exposures. Compliance with these regulations is achieved in part through shield design, which is based upon occupancy requirements in various areas. A list of generalized occupancy requirements and attendant radiation dose rates are presented in Table 12.3-1. The duration of expected operating personnel occupancy in various areas of each unit was obtained from experience during operation of Dresden Unit 1 and other similar nuclear-powered units.

Radiation areas with dose rates in excess of those listed in Table 12.3-1 were designed to be entered on a controlled time basis. Radiation areas with dose rates in excess of 100 mrem/hr at 30cm from the radiation source are equipped with barriers and administrative controls which prohibit unauthorized entry.

The primary objective of the radiation shielding is to protect personnel against radiation emanating from the reactor, turbine, and their auxiliary systems. Supplemental procedures to control access to radiation areas (see Section 12.5) and to control personnel exposure serve to limit radiation exposure to acceptable levels.

The secondary objective of the radiation shielding is to limit radiation damage to operating equipment. Specific fabrication materials are given individual consideration. Of principal concern are organic materials used in the equipment, such as insulation, rubber tank linings, and gaskets.

In general, it is sufficient to limit the radiation exposure to 10^6 rads for materials of concern over the expected service life of the equipment or of individual parts. For certain materials the exposure must be less or can be greater without significantly affecting serviceability: e.g., a limit of 10^4 rads for teflon and about 10^8 rads for polyurethane.

The shielding materials required to meet the preceding objectives are primarily concrete, water, and steel. High-density concrete, lead, and neutron absorption material may be used as alternates in special applications. The original estimated design dose rate in most areas outside of the drywell in the reactor building was 1 mrem/hr. Consequently, the drywell and its contents are shielded so that most areas outside the drywell and outside the pressure suppression chamber are accessible. Actual dose rate increases resulting from buildup of activated erosion and corrosion products ("crud") are evaluated as part of the station radiation protection program.

12.3.2.1.1 Control Room

The dose in the control room is limited to 0.5 rem in any 8-hour period following a design basis accident in either Unit 2 or Unit 3. During normal operation of either Unit 2 or Unit 3, the total shielding provided for the control room is sufficient to limit the transmission of radiation from the reactor building to less than 0.1% of the above limit. A discussion of control room habitability is contained in Section 6.4.

12.3.2.1.2 Reactor Building

The following regions within the reactor building but outside the primary containment have design dose rates exceeding 1 mrem/hr:

A. Fuel storage pool;

12.3.2.1.4 Off-Gas System

The shielding for the off-gas air ejector is based upon N-16 and the noble gases as principal radiation sources. The noble gas component of the combined radiation source is based upon an average annual release rate of 0.7 Ci/s. Shielding for the off-gas filters is based upon the accumulation of particulate radionuclides that are produced by the decay of the noble gases during a 30-minute holdup time. The off-gas system is described in Section 11.3.

Actual holdup time is closer to 7 hours following installation of the modified off-gas system. The amount of off-gas flow leaving the steam jet air ejectors is reduced significantly after passing through a catalytic recombiner which recombines free H_2 and O_2 produced by the radiolytic decomposition of water inside the reactor, therefore taking longer to traverse the holdup volume.

12.3.2.1.5 Radwaste Building

The radwaste building shielding is designed to limit the dose rate in the building control room to approximately 1 mrem/hr. Regions where pumps and valves are located have design radiation levels of 6 to 12 mrem/hr. The solid waste preparation area is shielded to a design dose rate of 1 mrem/hr.

Ample shielding has been provided in the radioactive waste control systems design to maintain personnel exposure well below established limits. Sumps, tanks and other high-activity vessels are housed in limited-access areas or concrete cells. Piping which would contribute significantly to radiation dose rates is shielded or not run in normally frequented areas.

12.3.2.2 Description

This subsection describes the radiation shielding for the reactor vessel, the drywell, the shutdown cooling system components, the control room, the turbine and main steam system, the condensate demineralizers, and the radwaste systems.

12.3.2.2.1 Reactor Shield Wall

Within the drywell, an annular shield wall of concrete is provided between the reactor vessel and the drywell walls to limit gamma heating in the drywell concrete, provide shielding for access in the drywell during shutdown, and limit activation of drywell materials by neutrons from the core.

The reactor shield wall consists of a hollow cylinder of ordinary concrete having a 2-foot thick wall and circumscribing the reactor vessel. The inside and outside surfaces of the reactor shield wall concrete are formed with steel plate which is increased in thickness for extra shielding at the elevation of the core. Reinforcing steel is used in the concrete to give structural strength. The cylinder is supported on the same structural concrete that supports the reactor vessel. This shield is cooled on both surfaces by circulating air from the drywell cooling system.

The pipes leaving the vessel at elevations below the top of the shield wall penetrate the wall. The penetrations in the vicinity of the core utilize removable shield plugs which fit around the penetrating pipe. The plugs are provided in order to allow access to the pipe welds for purposes of inservice inspections. The Dresden plugs are two 9-inch thick steel plates attached to the shield wall by two 1-7/16-inch diameter vertical hinges, with both halves locked in place by a 1-7/8-inch diameter locking pin. The remaining plug shielding is made of Permali blocks that are stacked into the shield wall penetration inside the steel plates. Recirculation piping penetrates this annular shield wall around the reactor vessel. Streaming through these penetrations by radiation from the core is limited by shielding located within the reactor vessel. These penetrations are also provided with removable shielding sections at the annular shield so that access is available for inspection of the connections of recirculation piping to the reactor vessel. The region that houses the control rod drives is shielded against radiation from the recirculation piping. This piping constitutes a radiation source during shutdown as a result of crud buildup.

During reactor operation, the reactor shield wall serves as a thermal shield to protect the containment shield wall outside the drywell from thermal damage. During shutdown, this shield also serves to protect personnel in the drywell from the gamma radiation from the core and the reactor vessel.

12.3.2.2.2 Containment Shield Wall

The primary containment vessel for each reactor is enclosed completely in a reinforced concrete structure (an integral part of the reactor building) having a variable thickness of from 4 to 6 feet. This structure is called the containment shield wall. See Figures 1.2-6 (Drawing M-7) and 1.2-7 (Drawing M-8). In addition to serving as the basic biological shielding for the containment system, this concrete structure also provides a major mechanical barrier for the protection of the containment vessel and the reactor system against potential missiles generated external to the primary containment. It also serves as a backup for the steel drywell wall in resisting jet forces. Additional information on missile protection is contained in Section 3.5. Jet forces and other effects of pipe breaks are described in Section 3.6.

Bedrock is used as the main support for the concrete containment shield wall which is structurally designed to handle the loads of floors, equipment, and the higher elevations of the shield itself. Reinforcing steel is used to maintain structural integrity under the design basis accident and seismic loading.

Penetrations through the concrete containment shield wall are designed so that they are not aimed directly at the core or major items of equipment in the drywell. In addition, they are either terminated in shielded cubicles or are shielded with steel flanges to reduce radiation levels in accessible areas.

12.3.2.2.3 Shutdown Cooling System

The heat exchangers and pumps of the shutdown cooling system are located in separate shielded cubicles. Gamma radiation from the equipment in these cubicles is reduced by the shield walls to a design dose rate of about 2 mrem/hr or less in the adjacent accessible areas at the time the system is placed in operation.

12.3.2.2.4 Control Room

The shielding for the control room consists of poured-in-place reinforced concrete. The floor and ceiling slabs are 6-inch thick ordinary concrete; whereas, the walls range in thickness from 18 inches of ordinary concrete to 27 inches of magnetite concrete which was used because of space limitations.

Advantage is taken of the shadow shielding offered by other structures to reduce shielding thicknesses and to locate penetrations (see Figures 12.3-1 through 12.3-5). Ordinary concrete shielding for the battery and computer rooms complements the floor and ceiling slabs of the control room.

The shielding factor is based on the expected attenuation of the concrete walls. The control room is designed to provide a minimum of 3 feet of effective concrete shielding. This shielding includes an 18-inch concrete control room wall and an 18- to 36-inch concrete reactor building wall. In addition, the angle of shine is oblique to the control room walls, thus providing greater than 3 feet of effective concrete shielding. Using an average energy of 1.0 MeV, the attenuation through 3 feet of concrete, including buildup, is 3.1×10^{-5}. The peak radiation level in the control room following a LOCA in Unit 2 or 3 is 23 to 30 mrem/hr. This peak value occurs 3 days after the design basis accident.

12.3.2.2.5 Turbine Steam Handling Equipment

The steam handling equipment associated with the turbine-generator unit is shielded with concrete to reduce the radiation levels in accessible areas, (design radiation levels for steam handling equipment are shown in Table 12.3-2). When the hydrogen injection system is operated, the resulting increase in N-16 activity can cause the radiation levels in the turbine building to increase beyond these design levels. Removable shield walls are used where existing shielding is inadequate. As an example, at the end of the Unit 2 high-pressure turbine, a gap between the 3-inch steel shield and the 30-inch concrete wall permits a 60-mrem/hr field to exist. A water shield reduces the dose rate to 10 mrem/hr. Lead blankets are also used to shield steam sample lines, where appropriate.

12.3.2.2.6 Condensate Demineralizer System

For each reactor the demineralizer vessels are located in two cubicles, four service units in one cubicle and three service units in the other cubicle, separated by an operating aisle. The regeneration tanks are located in one adjoining cubicle.

The radiation penetrating the concrete shielding of these cubicles is designed to be less than 1 mrem/hr, exclusive of radiation streaming. Recycle pumps, valves, some piping, and instrumentation associated with the demineralizer vessels are located in the operating aisle. Piping carrying condensate or demineralized condensate does not require shielding.

12.3.2.2.7 Reactor Water Cleanup System

Most of the reactor water cleanup equipment is shielded with concrete. The bases for shielding design were determined by the estimated frequency of operating, inspecting and maintaining the various equipment and its devices. The shielding is designed to reduce the radiation levels in the valve corridors to 30 mrem/hr or less and the levels in the access corridors around the cleanup system complex to 5 mrem/hr or less. The unshielded equipment is located in controlled access areas.

12.3.2.3 Performance Analysis

The design basis accidents for Units 2 and 3 are defined in the Preliminary Design and Analysis Report (PDAR), Volume I, Section XI.5. The accidents which are significant for control room design are the fuel loading accident, described in PDAR Section XI.5.2, and the LOCA inside the drywell, described in PDAR Section XI.5.4. The radiation sources for control room shielding are the reactor building airborne fission product inventories. The maximum airborne activity for the fuel loading accident is cited as occurring within 1 minute of the accident yielding 1.1×10^4 curies of noble gases and 3.2×10^3 curies of halogens. The maximum reactor building airborne activity for the LOCA is cited as occurring 1 day after the accident, yielding 4980 curies of noble gases, 350 curies of halogens, 86 curies of volatile solids, and 15 curies of other solids. The airborne activities in the reactor building were arrived at using a 10% leak rate from the primary containment, radioactive decay, fallout and plateout, and a reactor building air change rate of 100% building volume per day.

The analysis of the shield design was performed by applying the source as a point source. The point source was located at the nearest approach to the control room that did not require the radiation to penetrate the concrete walls of the reactor building. This point was determined to be a point at columns 39 and K at elevation 636'. The control room point nearest the source point is the southwest corner of the Unit 3 control room 178 feet from the point source. The source was assumed to be 1 gamma ray per disintegration with an average energy of 1.5 MeV. The source was reduced to 12% of the total source to reflect the fractional part of the reactor building volume visible to the control room.

The least shielding path from the point source to the control room requires penetration through a 6-inch floor at elevation 561'-6", the 18-inch west wall of the control room complex, and the 6-inch floor of the battery room. Shielding paths from the refueling floor to the control room which do not pass through the battery room floor must pass through the 3-foot turbine building room floor. The exception is paths through the turbine building floor hatch. In this area, the control room west wall has been constructed of magnetite concrete yielding an effective thickness of 34.8 inches for shielding paths from the refueling floor to the control room.

Shielding paths which do not penetrate this west wall must penetrate the 24-inch battery room ceiling. Shielding paths from the refueling floor along column line 38 must penetrate the 18-inch turbine building wall along column line H and the 20-inch west guard wall to the control room entrance, or penetrate the south wall of the control room, or penetrate the west magnetite wall of the control room.

For shielding paths below the refueling floor, the radiation reaching the control room must penetrate the walls of the reactor building in addition to penetrating the walls of the control room. The reactor building north wall is 4 feet thick up to elevation 621', and the east wall is 2 feet thick up to elevation 613'.

Table 12.3-3 shows the shielding path thicknesses and the calculated dose rates for several conditions.

12.3.2.4 Inspection and Testing

Visual inspections of the shielding were conducted during the construction phase. The value of those inspections, however, was limited to locating major defects because of the massive nature of the shielding. Thus upon initiation of reactor operation, radiation surveys were performed at various power levels. The purpose of these surveys was to assure that:

A. There were no defects or inadequacies in the shielding, equipment, or operating procedures that might, as a result of reactor operation during initial and subsequent testing up to full power, cause unacceptable levels of radiation or exposure to the public, the operators, or the equipment.

B. Radiation areas were posted, and in addition to posting, high radiation areas were provided with access control provisions in compliance with 10 CFR 20 requirements that were in effect at the time. Current access control practices are described in Section 12.5.3.4.

The surveys consisted of both gamma and neutron monitoring with appropriate portable instrumentation. Gamma surveys were performed on all shielding, while neutron surveys were conducted around the concrete containment shield wall and associated penetrations. Further information about startup testing is contained in Chapter 14.

Surveys of dose rates are routinely conducted throughout the plant. Any significant changes in shielding integrity such as concrete aging may be detected in routine radiation surveys, as described in Section 12.5.3.5.

12.3.3 Ventilation

It is normal practice to flow air from points of less contamination to points of greater contamination. This practice has been used throughout the design of the ventilation systems and is a requirement for design basis as described in Section 15.7.3. In some cases proper air flow direction cannot be maintained. Regardless of air flow direction, station radiological programs (e.g., radiological surveys, plant decontamination) are in place to monitor and limit the spread of contamination. Pressure differentials are maintained to prevent backflow of potentially contaminated air. Additionally, the control room ventilation system is capable of isolation from the outside air during a radioactivity release.

The plant ventilation systems are addressed in Section 9.4. Control room habitability is addressed in Section 6.4.

12.3.4 Area Radiation Monitoring Instrumentation

The area radiation monitoring system detects, measures, and records the radiation level in various areas of each unit. There are 35 detectors for Unit 2 and 42 detectors for Unit 3. The system actuates alarms if the radiation level exceeds a preset level for each monitor. A description of the use of the area radiation monitors to detect radioactive water leakage is presented in Section 5.2.6.2.

12.3.4.1 Design Objectives

The design objectives of the area radiation monitoring system are to monitor the radiation level in areas where personnel may be required to work, to alarm on a radiation level that exceeds a preset level, and to provide a record of the radiation level as a function of time at the location.

12.3.4.2 System Description

The area radiation monitoring system provides operating personnel with a record of gamma radiation levels at detector locations within the various structures or buildings. All monitors provide continuous indication and intermittent recording of radiation levels and alarm in the control room when radiation levels exceed preselected values or when the monitor has experienced an operational failure. Some monitors also alarm at the detector location. Tables 12.3-4 and 12.3-5 list detector locations. Emergency power is supplied by the safety-related instrument bus.

Each monitor has one channel of instrumentation consisting of a gamma sensitive Geiger-Mueller tube and a dc log radiation monitor, complete with fail-safe operational alarm, electrical test circuitry, appropriate high- and low-voltage power supplies, and control and trip contacts. All channels share a calibration unit and a strip chart recorder. The monitor readout is logarithmic and covers four decades, except for one 5-decade channel provided for the refueling floor.

Each channel has a high- and low-trip alarm adjustable over the entire scale. These trip functions operate indicator lights that "seal in" on trip and require a manual reset.

Other monitors on the refueling floor are part of the reactor building ventilation monitoring subsystem described in Section 11.5.2.4 and have the capability of isolating the secondary containment in the event of a refueling accident. These monitors are also used for detection of criticality in the new fuel storage pool.

12.3.4.3 Design Evaluation

Area radiation monitor detectors are distributed (Tables 12.3-4 and 12.3-5) in such a way that radiation detection coverage is provided in most areas where personnel may be required to work for extended periods. Increases in radiation above some preselected level annunciate an alarm. The ranges and sensitivities of the equipment are sufficient to detect increases in radiation level above background level.

It has been determined from shielding calculations and from operating experience on other BWR plants that four ranges of monitoring instrumentation sensitivity are adequate for the radiation areas selected for location of area monitors. These ranges are as follows:

A. 10 to 10^6 mrem/hr (low-low sensitivity);

B. 1.0 to 10^4 mrem/hr (low sensitivity);

C. 0.1 to 10^3 mrem/hr (medium sensitivity); and

D. 0.01 to 10^2 mrem/hr (high sensitivity).

A low-low sensitivity monitor is used for one of the monitors on the refueling floor area (station 2). This instrument is intended for post-accident (refueling accident) radiation measurements for use in recovery. Since radiation levels could potentially be very high, a low-low sensitivity instrument is used. More sensitive instruments are also located on the refueling floor (stations 1 and 3) to provide capability to ascertain that expected low background radiation does exist.

The other three ranges of instruments are utilized in various areas to assure detection capability as low as expected background radiation levels and up to unlikely maximum levels. Most instruments are high sensitivity monitors since they are located in areas with very low background but with potential for moderate radiation levels. Several instruments are medium sensitivity monitors located in low background areas. A few are low sensitivity monitors in higher background areas (TIP cubicle, torus area, HPCI cubicle).

Local alarms at the detector locations were selected on the basis of personnel safety. In areas normally occupied by personnel, local alarms are installed.

12.3.4.4 Reactor Building Crane Monitor

The reactor building crane monitor is designed to enable the crane operator to monitor refueling floor radiation levels from the crane cab. A sensor/converter unit (Geiger-Mueller tube) is mounted on the overhead crane. An indicator/trip unit is mounted in the crane cab. The monitor has a range of 0.1 to 1000 mrem/hr. High radiation and downscale alarms are provided to the crane operator. The downscale alarm function alerts the crane operator of monitor failure. The upscale alarm function serves to alert the crane operator of elevated dose readings on the refueling floor.

Table 12.3-1

OCCUPANCY REQUIREMENTS AND ATTENDANT RADIATION DOSE RATES

Degree of Access Required	Design Radiation Dose Rate at Shield Wall (mrem/hr)
Continuous Occupancy	
Outside controlled areas	0.5
Inside controlled area	1
Occupancy up to 10 hours per week	6
Occupancy up to 5 hours per week	12

Radiation areas with dose rates higher than those listed above were designed to be entered on a time limit basis.

Table 12.3-4

AREA RADIATION MONITORS — DETECTOR LOCATION AND RANGE

UNIT 2

Station Number	Detector Location	Range (mrem/hr)	Auxiliary Unit and Local Alarm
24	Feedwater Pump Area	0.01—100	Yes
25	Auxiliary Electrical Equipment Area	0.01—100	
26	Access Control Area	0.01—100	
27	CRD Pump Area	0.1—1000	
28	Main Condenser Area	0.01—100	
29	Radwaste Conveyor Operating Area	0.01—100	Yes
30	Radwaste Pump Room	0.1—1000	
31	Radwaste Control Room	0.01—100	Yes
32	Radwaste Storage and Shipping	0.01—100	Yes
33	Not Used		
34	Not Used		
35	Charcoal Adsorber Vault	1.0—10^6	Yes
36	Recombiner Area Level 1	0.01—100	
37	Recombiner Area Level 2	0.01—100	

12.5 HEALTH PHYSICS PROGRAM

This section describes the organization, equipment, and procedures utilized by the radiation protection program, which includes the health physics program.

12.5.1 Organization

A portion of the administrative organization of the health physics program is described in Section 12.1, which describes the "as low as reasonably achievable" (ALARA) program. The health physics program at Dresden Station is administered by the Radiation Protection Manager. The experience and qualification requirements of the Radiation Protection Manager are provided in Section 13.1.3.8.

12.5.2 Equipment, Instrumentation, and Facilities

Section 12.3 contains a discussion of plant design features which ensure that occupational exposures are maintained ALARA.

12.5.2.1 Decontamination and Change Room Facilities

All changing into or out of protective clothing or equipment is performed at various designated locations within the station perimeter or security fenced area. Provisions are made for collection, transfer, cleaning, and monitoring of all potentially contaminated protective equipment.

The general arrangement of the plant is designed to provide adequate change areas and a personnel decontamination area. The service building is provided with a special shower facility and sink for the decontamination of personnel. Local change areas are provided for control of radioactive contamination at the work areas. Radiation monitors are provided so that personnel may check for contamination.

12.5.2.2 Laboratories

The facilities provided for processing chemical and radiochemical samples, measuring radioactivity, and for other related health physics activities were originally provided for Unit 1 and are further augmented to meet the requirements of Units 2 and 3. The original facilities have been described in detail previously as part of the application for Dresden Station Byproduct Material License Number 12-05650-01, issued September 1959. Laboratory instrumentation is listed in Table 12.5-1.

12.5.2.3 Portable Instrumentation

Battery-powered portable radiation instrumentation is provided for use by all qualified personnel.

12.5.2.3.1 Design Basis

Portable radiation survey instruments are available for the measurement of the alpha, beta, gamma, and neutron radiations expected in normal operation and emergencies. Appropriate instruments and auxiliary equipment are available to detect and measure radioactive contamination on surfaces, in air, and in liquids.

12.5.2.3.2 Description

A list of the instrumentation is given in Table 12.5-2. Friskers and/or personnel contamination monitors (PCMs) are provided at exits from radiologically posted areas.

Personnel dosimetry is provided to be worn by persons in areas where monitoring is required by 10 CFR 20 regulations or station radiation protection program procedures.

Laboratory radiation measuring instruments are provided for alpha, beta, and gamma radiations and for gaseous, liquid, and solid samples.

Secondary calibration sources and check-test sources for the various instruments are provided.

12.5.2.3.3 Inspection and Testing

Proper operation of survey and laboratory instruments is checked frequently by built-in testing circuits and/or radiation sources. Measuring instruments are periodically calibrated with secondary calibration sources.

12.5.2.4 Personnel Protective Equipment

Special protective equipment is provided to minimize the possibility of transfer of radioactive materials to the hands, head and face, or personal clothing of any individual. This equipment includes coveralls, shoe covers, gloves, glove liners, waterproof clothing, boots, and head covers. When engineering controls are not feasible, or cannot be applied, respiratory protective equipment is used to limit the intake of airborne radioactive materials, consistent with the principle of minimizing the total effective dose equivalent. Commonwealth Edison's authority to use these respirators was granted in February 1965. The nature of the work to be done and the contamination levels present are the governing factors in the selection of protective clothing to be worn. In all cases, radiation protection personnel shall evaluate the radiological conditions and specify the required items of protective clothing.

12.5.3 Procedures

The radiation protection procedures and policies are designed to provide protection of personnel against exposure to radiation and radioactive materials in a manner consistent with applicable regulations. It is the policy of ComEd to maintain personnel radiation exposure within the regulations, and further, to reduce such exposure to as low as reasonably achievable via the ALARA program. Individuals are trained to minimize their exposure consistent with discharging their duties and are responsible for observing rules adopted for their safety and that of others.

Radiation protection personnel evaluate radiological conditions and establish the procedures to be followed by all personnel. They ensure that all RP program elements are in compliance with all applicable regulations and that the required radiation protection records are adequately maintained.

Training of operations, maintenance, support, and technical personnel, as well as contractors, in radiation protection principles and procedures is completed before the beginning of their work assignments.

Section 12.1.3 addresses radiation protection provisions of other station procedures.

12.5.3.1 Personnel Monitoring

The official and permanent record of accumulated external radiation exposure received by each individual is normally obtained from the interpretation of the thermoluminescent dosimeter (TLD). Secondary dosimeters provide day-by-day indication of external radiation exposure.

All employees, contractors, and visitors are issued and required to wear appropriate dosimetry when entering, working in, or visiting radiation areas. In accordance with station procedures.

Under normal conditions each person leaving the plant is required to pass through a portal monitor in the main access facility. Multiple portal monitors are installed to facilitate egress during times of high traffic, such as end of normal workday.

12.5.3.2 Visitors Monitoring

All visitors to the station who enter a radiation area are monitored by appropriate dosimetry or are provided with an escort having such monitoring devices.

12.5.3.3 Bioassay and Medical Examination Program

Commonwealth Edison provides whole body radiation counting service for employees and contractors at Dresden Station in compliance with 10 CFR 20 requirements and in accordance with station procedure.

Special medical examinations are given for authorization to use respiratory equipment (e.g., face masks for areas with airborne radioactive contamination). These examinations (or medical physicals) are performed to meet the requirements of 10 CFR 20.

12.5.3.4 Access Control

Plant areas can be classified as radiation areas, high radiation areas, airborne radioactivity areas, or radioactive materials areas. Areas so classified are posted to warn personnel approaching the area from any direction. Access to posted areas for all work is controlled by plant procedures and by the use of the station radiation work permit (RWP) program.

Control of access to radiation areas is provided through the detailed design of equipment location, shielding, access doors, and passageways. In addition, procedural control is achieved through administrative control of radiation exposures and the control of the concentrations of radioactive material concentration present in various areas of each unit structure. Commonwealth Edison has extensive experience in the application of access control principles.

Accessible areas in which the radiation levels could result in dose rates greater than 100 mrem in 1 hour (at 30 cm from the radiation source) are posted as high radiation areas. Access to these areas is controlled with barriers which prohibit unauthorized entry. Administrative controls are in the Technical Specifications.

12.5.3.5 Radiological Surveys

Radiation surveys of plant areas are performed for a number of reasons, including:

A. Establishment of representative radiation levels;

B. Identification and characterization of contaminated areas;

C. Verification of clean areas;

D. Evaluation of airborne radioactivity concentrations; and

E. Providing pre-job and post-job data as part of the ALARA program.

F. Identification of localized "hot spots" and areas where radiation streaming may occur.

Routine survey frequencies for a given plant area are based on considerations such as area occupancy, the potential for dose rate change due to potential contamination, and the extent of these considerations. Survey schedules are

Table 12.5-1

LABORATORY INSTRUMENTATION

Radiation Type	General Monitor Type	Detector Type
Alpha	Gross Activity	Ionization or Scintillation
Beta	Gross Activity	Ionization or Scintillation
Gamma	Specific Activity	Hp Ge Ionization
Tritium	Specific Activity	Scintillation

Notes:

The above instrument list is intended to be typical of in-service instrumentation.

Table 12.5-2

HEALTH PHYSICS MONITORING INSTRUMENTS

Radiation Monitoring System	General Monitor Type	Detector Type	Approximate Ranges	Radiation Alarm Types
Alpha	Survey meter	Scintillation or Ionization	0 — 500,000 cpm	None
Beta/Gamma	Survey meter	Ionization chamber	0 — 5 rem/hr 0 — 50 rem/hr	None
Beta/Gamma	Survey meter	G-M tube	0 — 100,000 cpm	None
Beta/Gamma	Extendable survey meter	G-M tube	0 — 999 rem/hr	None
Neutron	Survey meter	BF_3 tube	0 — 5 rem/hr	None
Air Particulate	High/low volume sampler	G-M tube	NA	Local
Gamma	Portal monitor	Plastic scintillator	50 — 200 nCi	Contaminated
Beta/Gamma	Personnel contamination monitor	Gas proportional	2 — 200 nCi	Contaminated

Notes:

The above instrument list is intended to be typical of in-service instrumentation.

13.0 CONDUCT OF OPERATIONS

13.1 ORGANIZATIONAL STRUCTURE

13.1.1 Corporate Management and Technical Support Organization

CECo's corporate organization and its functions and responsibilities are described in Section 1.0 of CECo Topical Report CE-1-A,[1] as revised and filed with the NRC. Organizational charts within this report reflect the current corporate structure and the departments which provide technical support for operation and backup support. Where appropriate, these services are provided by outside groups through contractual agreements.

13.1.2 Plant Operating Organization

The overall organization of Dresden Station is in accordance with the CECo Quality Assurance (QA) Manual (Quality Requirement 1.0).[2] Exhibit 1 of CECo Topical Report CE-1-A[1] shows the line of responsibility from the Chairman and Chief Executive Officer down through the station staff.

13.1.3 Plant Personnel Responsibility and Authority

The basic job functions of Plant positions are described in QA Topical Report CE-1-A and Station Administrative Procedures.

13.1.4 Deleted

13.1.5 Deleted

13.1.6 Deleted

13.1.7 Operating Shift Crews

Minimum shift manning requirements are listed in Technical Specification Section 6.2 and in the GSEP, Section 4.4.

13.2 TRAINING

13.2.1 Plant Training Programs

Dresden Station provides training programs which are necessary and prudent for assuring the safety of personnel, preventing the degradation of safety-related systems, structures, and components, and increasing the efficiency of operation through improved human performance.

The Station Manager has overall responsibility for personnel training. The Training Supervisor (see Section 13.1.2.2.4.4) and other personnel assigned training responsibilities administer the training function under the general direction of the Station Manager.

13.2.1.1 General Training Programs

Training for Dresden Station personnel is developed using a systematic approach to ensure that they receive training appropriate to their positions or tasks at the station. Training is normally divided into three types:

A. Initial training is intended to provide training on safety and job skills commensurate with an individual's position;

B. Retraining, including continuing training, is intended to refresh and reinforce information received during initial training; and

C. Specialized or task-related training is intended to acquaint personnel with information related to complex processes, procedures, and equipment which are not used on a routine basis.

The training needs of non-Dresden Station personnel granted unescorted access to the station are also considered in order to protect them from excessive or unnecessary radiation exposure and to acquaint them with security procedures and various safety concerns.

Selected training programs are described in the following subsections.

13.2.1.1.1 Nuclear General Employee Training

The Nuclear General Employee Training (N-GET) is designed to train personnel in the regulations and hazards associated with the nuclear power industry. The N-GET program consists of a number of separate modules which are based on CECo practices, procedures, and radiation protection standards, INPO guidelines, and regulatory agency requirements.

Initial N-GET consists of two sequential levels, "PAT" and "RWT." Plant Access Training "PAT" is required for all personnel who require unescorted access to the protected area. Course content for PAT N-GET typically includes the following modules:

A. Fitness for duty training;

B. Security training;

C. Industrial safety training;

D. Hazardous material training;

E. Quality assurance (QA)/quality control training; and

F. Radiation protection training (selected topics).

Personnel requiring unescorted access to a radiologically posted area must have received Radiation Worker Training (RWT) in addition to "PAT" training. The RWT N-GET typically consists of these modules:

A. Additional radiation protection training;

B. Donning and removing protective clothing; and

C. Computerized dose accountability system.

13.2.1.1.2 New Employee Orientation Training

Dresden's New Employee Orientation Training is intended to acquaint all incoming Dresden employees (new or transferred) in the unique features associated with a nuclear power plant. The course content typically includes:

A. Station organization overview;

B. Industrial safety;

C. General station policy information;

D. Corrective action items;

E. Out-of-service (OOS) and Hold Card program; and

F. Generic overview of specific Dresden Administration Procedures (DAPs).

13.2.1.1.3 Emergency Preparedness Training

Emergency Preparedness (EP) Training is required for all designated response personnel who may be called upon to assist in an emergency. Station personnel who could be affected by an emergency are provided with training on the Generating Station Emergency Plan (GSEP) in order to provide for the health and safety of the public, including CECo employees, and to limit damage to the facility and property. Emergency Preparedness Training typically consists of the following topics:

13.4 REVIEW AND AUDIT

Review and Investigative Functions (committees) are established in accordance with the ComEd Quality Assurance Program. These functions include the Onsite Review and Investigative Function and the Offsite Review and Investigative Function. Station Audits are performed as specified in the Quality Assurance Program described in Chapter 17.

In the event that a safety limit is exceeded, the reactor is shut down in accordance with the Technical Specifications and the conditions of shutdown are promptly reported to the Dresden Station Site Vice President or his designated alternate. Reactor operation is not resumed until authorized by the NRC. The incident receives onsite and offsite investigations and reviews pursuant to the Technical Specifications. For each occurrence, a separate report is submitted to the NRC as required by Technical Specifications and 10 CFR 50.73.

Any reportable occurrence is promptly reported to the Site Vice President or his designated alternate. Personnel performing the onsite review and investigative function will review investigation results and prepare a report covering the evaluation and recommendations to prevent recurrence. A separate report for each reportable occurrence is submitted to the NRC as required by Technical Specifications and 10 CFR 50.73.

13.4.1 Onsite Review and Investigative Function

Personnel performing the onsite review and investigative function are responsible for reviewing a variety of activities and documents as specified in the ComEd Quality Assurance Program. In accordance with ComEd Quality Assurance Program, certain of these reviews are forwarded to the Offsite Review and Investigative Function for concurrence.

13.4.2 Offsite Review and Investigative Function

Personnel performing the offsite review and investigative function are responsible for reviewing a variety of documents as specified in the ComEd Quality Assurance Program.

13.5 PLANT PROCEDURES

The procedure manuals for Dresden Units 2 and 3 provide procedures and surveillances for administration, operation, and maintenance of the facility. Procedures and surveillances are reviewed periodically and revised as necessary in light of operating experience and plant modifications. Station procedure designations and categories are shown in Table 13.5-1.

Station procedures are identified by discipline and by departmental responsibility. Descriptions of the types of departmental procedures and the purposes for which they are implemented are described in this section.

Procedures call for suspension of any potentially unsafe operation and for investigation by station management of any incident resulting in unsafe operation. Appropriate authorities will be notified, and existing procedures will be changed or new procedures added to prevent a recurrence of the incident or occurrence of similar incidents.

With only a few exceptions, acronyms for procedure identification normally begin with the letter "D" for Dresden Station.

13.5.1 Administrative Procedures

Administrative Procedures (DAPs) describe the station organization and position responsibilities, establish station policy, supplement the requirements and procedures of the CECo Quality Assurance Manual, implement the requirements of the Technical Specifications, and supplement the electronic work control system (EWCS).

Administrative controls and managerial procedures assure that required record keeping, review of unit operation, and appropriate reporting are performed.

The administrative controls specify the administrative organizations and functions which provide for proper operation of the unit, including actions to be taken in the event prescribed limits are exceeded.

13.5.1.1 Conformance with Federal Guidelines

Dresden Station procedures are written to conform to applicable federal guidelines. The contents of the procedure manuals follow Appendix A of Regulatory Guide 1.33 (Revision 2) and ANSI N18.7-1972 requirements.

13.5.1.2 Preparation of Procedures

Detailed station procedures (i.e., plant procedures), administrative procedures, and safety-related operating procedures are prepared by members of the station management staff or by personnel whom they designate. The Technical

Specification 6.8A provides a list of items for which written procedures are required to be established, implemented, and maintained. Planned safety-related operations are conducted in accordance with detailed station procedures.

The station Onsite Review and Investigative Function reviews applicable administrative procedures and emergency operating procedures, as required by the ComEd Quality Assurance Program.

Technical review and approval of procedures which affect nuclear safety (and changes thereto) are carried out per the requirements of the ComEd Quality Assurance Program.

All procedures described in this section are authorized by appropriate station management personnel before being implemented.

13.5.1.3 Procedures

Brief descriptions of selected station administrative procedures which control specific tasks are provided in the following subsections. The descriptions of station positions, responsibilities, and qualification requirements are given in Section 13.1.

13.5.1.3.1 Daily Orders and Operating Orders

Written orders are issued by the station to promulgate instructions and information to the operation and maintenance crews. These orders are issued as Daily Orders and Operating Orders. Operating Orders contain primarily administrative direction and are not a substitute of permanent or special procedures. A Daily Order cannot supersede any approved Operating Order or procedure.

13.5.1.3.2 Equipment Control

Equipment control procedures provide for the necessary control of equipment to maintain plant equipment and personnel safety and to avoid unauthorized operation of equipment. These procedures provide a method to control and maintain labeling to secure and identify equipment. They also describe the criteria for the selection of Operations Department-controlled equipment and valves which are to be locked. The locking of equipment and valves provides assurance that the components will be operated only by authorized personnel performing required activities.

13.5.1.3.3 Control of Maintenance and Modifications

Control of maintenance and modifications is provided for in the CECo Quality Assurance Manual. Station administrative procedures have also been developed to control plant maintenance and modification activities.

13.5.1.3.4 Master Surveillance Testing Schedule

A surveillance schedule prescribes the surveillance to be performed, the performance frequency as outlined in the Technical Specifications, and the departments assigned to perform the surveillance. This schedule is produced as part of the station surveillance and periodic task scheduling program. A computerized system for tracking surveillance tasks has also been developed to augment the existing system.

13.5.1.3.5 Logbook Usage and Control

Procedures for logbook usage and control ensure that adequate documentation of various unit operations and conditions is maintained. The procedure provides detailed instructions for maintenance of records and narrative logbooks to ensure that day-to-day shift activities are properly documented.

13.5.1.3.6 Temporary Changes to Procedures

The use of temporary procedure changes (TPC) was discontinued in August 1996. As a part of the TPC discontinuation process a review was made of all active TPCs. As a result of this review, the active TPCs were either canceled or incorporated into permanent procedures.

13.5.2 Operating and Maintenance Procedures

The various operating and maintenance procedures that have been developed for Dresden Station are described in the following subsections.

13.5.2.1 Operating Procedures

The procedures described in this section are performed primarily by or with the knowledge of licensed operators.

13.5.2.1.1 System Operating Procedures

System Operating Procedures (DOPs) detail steps necessary for startup, operation, and shutdown of individual systems or subsystems as well as steps necessary to troubleshoot system problems. These procedures also detail actions required to correct abnormal conditions for which time is not an element of concern and for

13.5.2.1.7 Temporary Changes to Operating Procedures

The use of temporary procedure changes (TPC) was discontinued in August 1996. As a part of the TPC discontinuation process a review was made of all active TPCs. As a result of this review, the active TPCs were either canceled or incorporated into permanent procedures.

13.5.2.2 Other Procedures

This section describes certain other operating and maintenance procedures, including the general objectives and characteristics of each class of procedure.

13.5.2.2.1 Radiation Protection Procedures

Radiation Protection Procedures (DRPs) detail steps necessary to comply with policies established by the Radiation Protection Department, operation and surveillance of radiation protection instrumentation, methods of conducting surveys and collecting samples, and steps necessary to meet Technical Specification and Code of Federal Regulation requirements.

13.5.2.2.2 Emergency Plan Implementing Procedures

Emergency Plan Implementing Procedures (EPIPs) detail the steps necessary to implement the Generating Station Emergency Plan.

13.5.2.2.3 Instrument Procedures

Instrument Procedures (DIPs) detail control of instrument surveillance, steps for calibrations and checks performed only on an as-needed basis, instrument maintenance performed during refueling outages, control of test equipment, and control of instrument records.

13.5.2.2.4 Chemistry Procedures

Chemistry Procedures (DCPs) supplement the Central Computer Procedures and the Central Chemistry Procedures. They detail analyses performed at the station, specifications and limitations for such analyses, and actions required of radiation chemistry personnel if the conditions are found to be outside specifications.

13.5.2.2.5 Radiological Control Procedures

Radiological Control Procedures prescribe the methods and modes of operation and guidance for proper handling, transfer, storage, and packaging of radioactive waste materials resulting from plant operations.

13.5.2.2.6 Maintenance Procedures

13.5.2.2.6.1 Mechanical Maintenance Procedures

Mechanical maintenance Procedures (DMPs) govern maintenance of safety-related components, detail steps for complex mechanical maintenance activities, and detail steps for mechanical maintenance activities that are not performed at a fixed frequency.

Maintenance Procedures provide guidance for both electrical and mechanical repair personnel. Maintenance Procedures differ from Repair Manuals in that the repair manuals contain rigging suggestions, tool lists and supplementary information to vendor manuals. Repair manuals do not contain detailed step-by-step sequences. Consequently, repair manuals are not procedures, do not require review by the Onsite Review and Investigative Function, and are administratively controlled within the Maintenance Department.

13.5.2.2.6.2 Electrical Maintenance Procedures

Electrical Maintenance Procedures (DEPs) govern electrical maintenance of safety-related components and detail steps for electrical maintenance activities not performed on a fixed frequency.

13.5.2.2.6.3 Emergency Plan Maintenance Procedures

Emergency Plan Maintenance Procedures (EPMPs) detail the steps necessary for station personnel to perform surveillance and maintenance activities on station Emergency Response Facilities to assure they are available to implement the Generating Station Emergency Plan.

13.5.2.2.7 Warehouse Procedures

Warehouse Procedures (DWPs) control packaging, receiving, handling, and storage of items in the storeroom. They also control storage of safety-related and ASME-related materials, provide for preventive maintenance for items in storage, and provide for proper documentation.

13.5.2.2.15 Special Procedures

Special Procedures are temporary in nature. They serve one or more of the following purposes:

A. To detail operation during specific and/or unique circumstances;

B. To detail steps required to accomplish a task not immediately covered by permanently approved procedures;

C. To verify steps or conditions such that a permanent procedure can be developed;

D. To detail steps necessary to accomplish a specific and/or unique task;

E. To detail steps necessary to accomplish an infrequently performed task or a task that is not expected to be repeated;

F. To detail steps for troubleshooting a specific problem; and

G. To detail steps necessary to accomplish preoperational testing and/or initial calibration of systems and/or equipment when not covered by a modification procedure, work package instruction, or a permanently approved procedure.

H. To detail steps necessary to perform a test, experiment, modification test, or operability test.

Special Procedures that affect Nuclear Safety receive the same onsite and offsite review that permanent procedures receive. Although the procedure or steps of the procedure may be repeated as necessary to accomplish the task or purpose of the procedure, the Special Procedure may not be reused once the intent of the procedure has been achieved without subsequent review and approval under a new Special Procedure number. Except for outage-related procedures, a Special Procedure is not used for a time period in excess of 6 months. The level of detail should be consistent with the complexity, skill level, and acceptance criteria of the task to be performed.

13.5.3 Surveillance Procedures

Surveillance procedures provide station surveillance and periodic task scheduling required for each department.

13.5.3.1 Chemistry Surveillances

Chemistry Surveillances (DCSs) provide for scheduling of periodic checks, inspections, tests, analyses, periodic calibrations, preventive maintenance tasks that are expected to prevent malfunctioning of equipment, and tasks that satisfy commitments to documents (e.g., the Technical Specifications).

13.6 SECURITY

Commonwealth Edison Company implements and maintains in effect all provisions of the NRC-approved physical security, guard training and qualification, and safeguards contingency plans for Dresden Station in accordance with the operating licenses. The plans are specified in the following documents, as revised and filed with the NRC:

A. "Dresden Nuclear Power Station Security Plan,"

B. "Dresden Nuclear Power Station Security Personnel Training and Qualification Plan," and

C. "Dresden Nuclear Power Station Safeguards Contingency Plan."

These plans meet the requirements of 10 CFR 73.55 and Part 73, Appendices B and C.

The security plan documents contain safeguards information protected under 10 CFR 73.21 and are, therefore, withheld from public disclosure. Some general information relating to security is presented in the following paragraphs.

The Dresden Station Site Vice President has ultimate responsibility and authority for security at the station. Authority for security administration is delegated through the Support Services Director to the Station Security Administrator (see Section 13.1). The Station Security Administrator administers the station security program and assures that commitments set forth by the station security plan are met.

Station access is controlled by station security in accordance with the Dresden security plan and Dresden administrative procedures.

The following area designations are used at the station:

A. Unrestricted area: that area beyond the site property line.

B. Owner Controlled Area: that area between the station security fence and the property boundary line.

C. Unposted area: that area within the station security fence that is not part of a radiologically posted area.

D. Radiologically posted areas: those areas posted as radiation areas, high radiation areas, radioactive materials areas, airborne radioactivity areas, or combinations thereof. Access to radiologically posted areas for all work is controlled in accordance with station radiation protection procedures.

E. Protected area: that area within the owner-controlled area enclosed by a station security fence in which the main buildings are located. Access to the protected area is controlled.

F. Vital area: any area within the protected area which contains vital equipment. Vital equipment is any plant equipment, system, or device whose failure or destruction could directly or indirectly endanger public health and safety by a release of radioactivity which could result in a total radiation dose in excess of the limits established by 10 CFR 100.11. Equipment or systems which would be required to function to protect public health and safety following such failure or destruction are also considered vital equipment. Security equipment is not considered vital equipment. All vital equipment is contained in vital areas.

Normal access to the protected area is through the gatehouse. Personnel entering the gatehouse are screened by security systems, e.g., explosive and firearms detectors. When necessary, personnel are given a pat-down search in accordance with the requirements of the Dresden security plan.

Final entry to the protected area is controlled by a computerized card reader in conjuntion with a hand geometry reader system at the Main Access Facility (MAF). Movement within the protected area is controlled by a computerized card reader system.

Security personnel coordinate with Training and Radiation Protection Department personnel to ensure that applicable entry requirements are met.

13.7 RECORDS

Quality assurance records are retained to furnish evidence of activities affecting quality. These records are stored from the time of their creation or receipt until their ultimate disposal in a manner which meets the requirements of applicable standards, codes, and regulatory agencies with regard to maintenance, preservation, and protection of files.

Records may be in various forms such as logs, reports, drawings, or meeting minutes.

Records are kept in a manner convenient for review and retained for the period of time specified in Table 13.7-1. It also describes specific records within each type and specifies the minimum required retention period. Record types are briefly discussed in the following subsections.

Other records are retained in accordance with schedules established by NRC orders, Federal Power Commission regulations, and Illinois Commerce Commission regulations. The retention periods for these records are specified in Dresden's Records Retention Schedule.

13.7.1 Control Room Records

Ledger-type log books are kept in the control room and in the radioactive waste facility to record unit operations and conditions. Personnel on each shift record sequentially in these log books such items as status of unit equipment, malfunctions, scrams (including the reasons therefor), changes in operating conditions, tests and measurements performed by the operators, and any other information of a significant nature noted by the operators. In addition to the log books, separate log sheets are maintained for significant routine data and special tests or measurements.

The Shift Engineer keeps records of operating and testing data on log books and log sheets similar to those described above.

13.7.2 Plant Operation Records

Plant operation records provide pertinent information on the history of unit power production, operational excursions, operational testing, and other quality activities. For example, records of normal plant operation include notation of power levels and periods of operation at each power level.

13.7.3 Procedure Changes

Records of changes to procedures required by the Technical Specifications, as well as other procedures which affect nuclear safety, are retained.

Table 13.7-1
REQUIREMENTS FOR RECORD RETENTION[a]

Record Type	Record Description	Minimum Retention Period
Control room records	Shift Engineers' logs	5 years
Plant operation records	Normal plant operation	5 years
	Reportable events	5 years
	Safety limit events	5 years
	Reactor coolant system inservice inspections	Life of plant
	Transient or operational cycling of life-limited components	Life of plant
	Physics tests and other tests pertaining to nuclear safety	5 years
Procedure changes	Changes to procedures as required by Technical Specifications	5 years
Review committee transactions	Reviews by Onsite Review Function	Life of plant
	Reviews by Offsite Review Function	Life of plant
Radiological records	Personnel exposure records	Life of plant
	Radioactivity in liquid and gaseous wastes released to the environment	Life of plant
	Plant radiation and contamination surveys	Life of plant
	Offsite environmental monitoring surveys	Life of plant

Table 13.7-1
REQUIREMENTS FOR RECORD RETENTION[a]

Record Type	Record Description	Minimum Retention Period
	Radioactive material shipments	5 years
	Byproduct material inventory	5 years
	Source leak test results	5 years
	New and spent fuel inventory	Life of plant
	New and spent fuel assembly histories	Life of plant
Maintenance records	Substitution or replacement of principal equipment pertaining to nuclear safety	Life of plant
	Maintenance of principal equipment pertaining to nuclear safety	5 years
	Periodic checks and calibrations to meet Technical Specification surveillance requirements	5 years
Records of facility description and evaluation	Equipment changes or reviews of tests and experiments to comply with 10 CFR 50.59	5 years
	Changes to the plant as it is described in the SAR	Life of plant
	Plant drawings (updated, corrected, and as-built)	Life of plant
	Environmental qualification	Life of plant
Personnel records	Staff member qualifications, experience, training, and retraining	Life of plant

[a] Changes to this table must be made via the provisions of 10 CFR 50.54(a) until the record retention requirements are listed in the ComEd QA Topical Report CE-1.

15.0 ACCIDENT AND TRANSIENT ANALYSIS

The evaluation of the safety of a nuclear power plant includes analyses of the plant's response to postulated disturbances in process variables and to postulated malfunctions or failures of equipment. These safety analyses provide a significant contribution to the design and operation of components and systems from the standpoint of public health and safety.

In previous chapters, the important structures, systems, and components are discussed. In this chapter, the effects of anticipated process disturbances and postulated component failures are examined to determine their consequences and to evaluate the capability built into the plant to control or accommodate such failures and situations (or to identify the limitations of expected performance).

15.0.1 Frequency Classification

The effects of various postulated anticipated operational occurrences and incident events are investigated for a variety of plant conditions. With the exceptions of Anticipated Transients Without Scram (ATWS) and the ASME overpressure event, transients and accidents are categorized into the following three groups according to frequency of occurrence:

A. Incidents of moderate frequency — incidents that may occur with a frequency greater than once in 20 years for a particular plant. These events are referred to as anticipated (expected) operational occurrences.

B. Infrequent incidents — incidents that may occur during the life of the particular plant (spanning once in 20 years to once in 100 years). These events are referred to as abnormal (unexpected) operational occurrences. For conservatism, infrequent events can be analyzed as if they were moderate frequency events.

C. Limiting faults — incidents that are not expected to occur but are postulated because their consequences may result in the release of significant amounts of radioactive material. These events are referred to as design basis (postulated) accidents.

Treatment of ATWS events and the ASME overpressure protection analysis are discussed in Sections 15.8 and 15.2.4.2, respectively.

15.0.2 Transients and Accidents Analyzed

Events analyzed in this chapter are categorized as either transients (anticipated and abnormal operational occurrences) or accidents, depending on the frequency classifications described in Section 15.0.1. Transients and accidents have different acceptance criteria for their analyses. Listings of transients and accidents, a summary of analysis methods, and a description of specific transients which are reanalyzed for each fuel cycle are provided in the following subsections.

CC.	Failure of one diesel generator to start	8.3.1.6.4

In addition to the above transients, the following events have been analyzed as transients although they are not anticipated operational occurrences when considered without scram:

A.	Closure of main steam isolation valves without scram	15.8.1
B.	Loss of normal ac power without scram	15.8.2
C.	Loss of normal feedwater flow without scram	15.8.3
D.	Turbine-Generator trip without scram	15.8.4
E.	Loss of condenser vacuum without scram	15.8.5

15.0.2.2 Design Basis Accidents

In order to evaluate the ability of the plant safety features to protect the public, a number of accidents are analyzed herein. These accidents are of very low probability; they are considered in order to include the far end of the spectrum of challenges to the safeguards and the containment system. The accidents evaluated are discussed in the following sections:

Analysis		Section
A.	Control rod drop	15.4.10
B.	Loss of coolant	15.6.2 and 15.6.5
C.	Main steam line break	15.6.4
D.	Recirculation pump shaft seizure	15.3.3
E.	Recirculation pump shaft seizure while in single loop operation	15.3.4
F.	Fuel assembly drop during refueling	15.7.3
G.	Mislocated fuel assembly	15.4.7
H.	Misoriented fuel assembly	15.4.8
I.	Spent fuel cask drop	15.7.4

15.0.2.3 Method of Analysis

Sections 15.1 through 15.8 provide analyses for each transient and accident given above, from the initiating event to the propagation of the event including effects on other systems. Generally, for each transient or accident analysis there are subsections which delineate the cause identification, frequency classification, sequence of events and system operation, core and system performance, barrier performance, and radiological consequences.

15.0.2.4 Transients Reanalyzed for each Fuel Cycle

Some of the transients listed above in Section 15.0.2.1, are reanalyzed for each fuel cycle to account for the characteristics specific to the fuel type and configuration for that cycle. The results of these transient analyses are used to set reactor thermal limits for that cycle in order to prevent fuel damage or reactor coolant pressure boundary (RCPB) overpressurization.

The remaining transients are not reanalyzed for each fuel cycle since they have been found to be always bounded by (i.e., less severe than) those transients that are reanalyzed.

The transients currently reanalyzed for each cycle are as follows:

A. Generator load rejection without bypass;

B. Feedwater controller failure;

C. Loss of feedwater heating; and

D. Main steam line isolation valve closure without direct scram or credit for relief valves (ASME overpressure event).

Transients A through C are reanalyzed for each cycle to determine thermal margins, and transient A, B, and D are reanalyzed to confirm that maximum pressure is within 110% of the reactor coolant system design pressure. Generator load rejection without bypass is usually the most limiting transient for determining thermal limits to prevent fuel damage. Closure of the turbine control valves following load rejection is considered more severe than turbine trip and/or stop valve closure because of the longer scram delay associated with the load rejection without bypass transient.. A more detailed description of these transients is given in Sections 15.1 and 15.2.

15.1.3.1 Identification of Causes and Frequency Classification

The event postulated is the failure of either turbine pressure regulator in the valve-open direction.

An increase in steam flow is classified as a moderate frequency event.

15.1.3.2 Sequence of Events and System Operation

It is postulated that the pressure regulator malfunction would occur at reactor rated thermal power. If either regulator fails in a wide open direction, the maximum control valve plus bypass valve demand would be limited by the control system to 105%. The vessel pressure, due to the excess steam flow to the turbine, would drop 100 psi in the first 10 seconds. Core flux is decreased significantly as the pressure drop increases the moderator void fraction of the core. When the steam line pressure decreases by about 100 psi, closure of the main steam isolation valves (MSIVs) is initiated by a Group 1 isolation signal, which occurs on reactor pressure less than 825 psig. In order to prevent unnecessary MSIV closure from spurious main steam line low-pressure signals, the logic actuation is delayed by 270 ± 5 milliseconds for Unit 2 and 220 ± 5 milliseconds for Unit 3 by a time delay relay in the circuit. The total channel response time, from the time the main steam line pressure reaches 825 psig until power is removed from the MSIV solenoid, is less than or equal to 500 milliseconds. The scram occurs when the MSIVs reach 10% closed. The depressurization is stopped as soon as the isolation becomes effective. After the reactor is shut down and isolated, the pressure would rise slowly. The isolation condenser can dissipate the decay heat for long-term shutdown. A typical pressure regulator failure is shown in Figures 15.1-7 and 15.1-8 (based on Group I isolation at 850 psig main steam line pressure).

The above analysis depends on the Group 1 isolation signal (with consequent MSIV closure and scram) occurring approximately 10 seconds into the event. If the pressure regulator failure event were to occur when the initial RPV water level was just below the high-level alarm point, the resultant level swell would reach the alarm point in approximately 5 seconds. This alarm would trip the feedwater pumps and main turbine, causing a reactor scram. The bypass valves would open fully and depressurize the RPV.

The Dresden scram procedure directs the operator to turn the mode switch to the shutdown position immediately following a scram signal. If the operator were to shift the mode switch within 4 to 5 seconds after the high-level trip occurred, the Group 1 signal would be bypassed. The scram procedure further directs the operator to the normal shutdown procedure, which maintains vessel cooldown rate below the Technical Specification limit of 100°F per hour.

If the operator does not enter the shutdown procedure after turning the mode switch and does not manually close the MSIVs, then the vessel will blow down through the bypass valves and the water level will drop to the low-low level isolation point of -59 inches. The MSIVs would then automatically close and the high pressure coolant injection (HPCI) system would inject water into the vessel until the water level reached the high-level HPCI shutoff point. The introduction of relatively cold water from the condensate storage tank will cause cooldown of the

15.2.2.1.5 Radiological Consequences

Since the fuel cladding integrity safety limit would not be violated, a radiological consequence analysis was not performed.

15.2.2.2 Load Rejection with Bypass

15.2.2.2.1 Identification of Cause and Frequency Classification

The cause and frequency classification of the load rejection with bypass transient are the same as that for load rejection without bypass discussed in Section 15.2.2.1.

15.2.2.2.2 Sequence of Events and System Operation

A loss of generator load would cause a load rejection trip of the turbine generator. The control valves would fully close in about 0.15 seconds. The bypass system would be actuated simultaneously. The automatic load rejection scram signal is bypassed when the first stage turbine pressure is less than that corresponding to 45% rated core thermal power. Because steam flow is assumed to exceed the capacity of the bypass system, 40% of turbine design steam flow, an anticipatory load rejection scram would occur. Scram is initiated by pressure switches on the control valve solenoids which indicate fast control valve closure.

15.2.2.2.3 Core and System Performance

The pressure rise due to the valve closure would cause voids in the moderator to collapse and result in a spike in neutron flux before the scram shuts down the reactor. The pressure rise also would result in an increase in coolant saturation temperature and a momentary decrease in nucleate boiling and heat transfer from the fuel cladding.

15.2.2.2.4 Barrier Performance

This transient is not analyzed for reload cores since the fuel-specific operating limit MCPR is determined for each reload core based on bounding events for the cycle. The operating limit MCPR is established to preclude violation of the fuel cladding integrity safety limit.

15.2.2.2.5 Radiological Consequences

Since the fuel cladding integrity safety limit would not be violated, a radiological consequence analysis was not performed.

15.2.3 Turbine Trip (Stop Valve Closure)

The analysis of a turbine trip coincident with failure of the turbine bypass system which was used to establish the design basis for the required capacity of the electromatic relief valves is discussed in Section 5.2.2.2.2. MSIV closure without direct scram failure was used to establish the design basis for the required capacity of the safety valves. In addition to failure of the turbine bypass system, these analyses did not take credit for turbine trip scram.

The turbine trip analyses without bypass and with bypass, presented in Sections 15.2.3.1 and 15.2.3.2, respectively, assume a reactor scram due to turbine trip (stop valve closure).

15.2.3.1 Turbine Trip Without Bypass

15.2.3.1.1 Identification of Causes and Frequency Classification

A variety of turbine or nuclear system malfunctions will initiate a turbine stop valve closure and turbine trip. Some examples are moisture separator high levels, large vibrations, loss of control fluid pressure, low condenser vacuum, and reactor high water level. A turbine stop valve closure would cause a sudden reduction in steam flow which would result in a nuclear system pressure increase and the shutdown of the reactor.

This event is classified as a moderate frequency event.

15.2.3.1.2 Sequence of Events and System Operation

The plant operating conditions and assumptions are identical to those of the generator load rejection.

The sequence of events for a turbine trip would be similar to that for a generator load rejection. Stop valve closure occurs over a period of 0.10 second. Position switches at the stop valves sense the stop valve closure and initiate reactor scram signal when the stop valves are less than 90% open.

As in the case with the load rejection scram, this scram signal would be bypassed if first stage turbine pressure were less than that corresponding to 45% of rated core thermal power. If the pressure were to rise to the pressure relief setpoints at 1101 and 1124 psig, the relief valves would open and discharge steam to the suppression pool.

15.2.4.1.3 Core and System Performance

A typical transient response to inadvertent closure of these valves from 2527 MWt is shown in Figures 15.2-4 and 15.2-5. No significant neutron flux or surface heat flux peaks would be encountered since the first 10% of the valve stroke (i.e., when the scram is initiated) does not reduce valve flow area. The relief valves would open to remove excess stored heat; safety valves, other than the Target Rock safety relief valve, would not actuate since the pressure would peak at 1144 psig well below the safety valve lowest setpoint of 1240 psig. The isolation condenser could be actuated to handle long-term decay heat removal.

15.2.4.1.4 Barrier Performance

The inadvertent MSIV closure with direct scram was not reanalyzed for reload cycle since it has been identified by SPC to be bounded by the inadvertent MSIV closure without direct scram event. The ASME vessel pressure limit of 1375 psig in the lower plenum would not be exceeded during this transient.

15.2.4.1.5 Radiological Consequences

Since the fuel cladding integrity safety limit would not be violated, a radiological consequence analysis was not performed.

15.2.4.2 Inadvertent MSIV Closure Without Direct Scram

Closure of the MSIVs without direct scram and without credit for the relief valves is analysed to assure compliance with the ASME Pressure Vessel Code, Section III.

15.2.4.2.1 Identification of Causes and Frequency Classification

Various steam line and nuclear system malfunctions, or operator actions, can initiate MSIV closure. Some examples are low steam line pressure, high steam line flow, high steam line radiation, low water level, and manual action.

The Summer 1968 Addenda to the 1968 Edition of Section III to the ASME code revised the conditions to be considered when performing pressure vessel stress analyses. Loads were to be considered from four categories of conditions:

1. Normal;
2. Upset;
3. Emergency; and
4. Faulted.

The Addenda defines an upset condition as any deviation from normal operating conditions caused by any single error, malfunction or a transient which does not result in a forced outage. These events are anticipated to occur frequently enough that design should include the capability to withstand the upsets without operational impairment. Emergency conditions are stated as having "...a low probability of occurrence..." and require shutdown for correction but cause no gross damage to the system. Additionally, faulted conditions are "...those combinations of conditions associated with extremely low probability postulated events..." which may impair the integrity and operability of the nuclear system to the point where public safety is involved.

As described in the Summer 1968 Addenda of Section III, the following pressure limits are applied to the operating limit category:

1. Under upset conditions, the code requires that reactor pressures are not to exceed 110% of design pressure (1.1 x1250 = 1375 psig).
2. For emergency conditions, it allows up to 120% of design pressure (1.2 x 1250 = 1500 psig).
3. For faulted conditions, it allows up to 150% of design pressure (1.5 x 1250 = 1875 psig).

As documented in later FSARs and accepted by the NRC, GE defined an upset event as one which has a 40-year encounter probability of occurrence of 10^{-1} through 1; an emergency event has a 40-year encounter probability of 10^{-3} through $<10^{-1}$; and a faulted event has a 40-year encounter probability of 10^{-6} through $<10^{-3}$.

GE analyses have determined the probability of occurrence of MSIV closure is 1 event/plant-year. Failure probability of the direct MSIV position switch scram failure, such that the scram occurs on neutron monitoring system signal, is 1 x 10^{-3}/demand. Using the above probabilities, this event should be considered an "emergency" condition. Therefore, application of the "emergency" limit under these assumed failure conditions would be considered appropriate. However, in addition to conservatively assuming failure of the direct safety grade position scram signals in its licensing analysis, and conservatively relying upon indirectly derived signals (high neutron flux) from the Reactor Protection System, GE further conservatively applied the upset code requirements, and required pressure safety limits, rather than the more appropriate emergency limits.

The assumption of concurrent failure of the relief valves reduces the probability of occurrence even further thus adding additional conservatism to the application of the pressure limit for upset conditions(1375 psig).

Siemens (SPC) applies the same conservative criterion (110% of vessel design pressure) for cycle-specific analyses of the MSIV with indirect (flux) scram. Historically, SPC assumes the relief function of the Target Rock S/RV be inoperable (in addition to not crediting the Electromatic RVs) when performing this analysis. Beginning with Dresden 3 Cycle 15, both the safety and relief functions of the Target Rock valve are assumed inoperable for consistency with reload analyses performed for Quad Cities.

In addition to assuring that the lower vessel pressure is below the conservatively applied ASME code limit of 1375 psig, the peak pressure calculated in the vessel steam dome is verified to be less than the Technical Specification Safety Limit for Reactor Coolant system Pressure (1345 psig as measured by the steam space sensor).

15.2.4.2.2 <u>Sequence of Events and System Operation</u>

Though the closure rate of the MSIVs is substantially slower than that of the turbine stop or control valves, the compressibility of the fluid in the steam lines would provide significant damping of the compression wave associated with the turbine trip events to the point that the slower MSIV closure without direct scram results in nearly as severe a compression wave. Once the containment was isolated, the subsequent core power production would need to be contained within a smaller system volume than that associated with the turbine trip events. Comparative analyses have demonstrated that the containment isolation event under these conservative assumptions would result in a higher overpressure than either the turbine trip or the generator load rejection without bypass.

15.2.4.2.3 Core and System Performance

Due to valve characteristics and steam compressibility, the vessel pressure response would not be noted until about 3 seconds after the beginning of the valve stroke. Since credit is not taken for the MSIV closure scram in this analysis, effective power shutdown would be delayed until after 5 seconds following initiation of the MSIV stroke. Assuming a delay of the scram until the high flux trip setpoint is reached results in a more severe transient. The power operated relief valves (including the relief mode of the Target Rock valve) are assumed to fail, preventing that mechanism from assisting in the shutdown. The recirculation pump trip was assumed to occur at 1250 psig.

A typical transient response is shown in Figures 15.2-6, 15.2-7, and 15.2-8. Pressure in the steam lines was calculated to peak at 1307 psig at approximately 7.2 seconds. The maximum vessel pressure was calculated to be 1329 psig in the lower plenum occurring at 6.6 seconds.

15.2.4.2.4 Barrier Performance

The ASME overpressure event (as described in 15.2.4.2) is analyzed for every reload cycle to assure that this low probability, multiple failure event will not result in peak reactor pressure greater than that associated with the most conservative classification in ASME Section III (upset conditions). In addition, other potentially limiting pressurization events (e.g.; Load Reject with Bypass Failure and Feedwater Controller Failure) are also verified to result in peak reactor pressure less than 1375 psig in the lower vessel plenum.

15.2.4.2.5 Radiological Consequences

Since the reactor pressure safety limit would not be violated, a radiological consequence analysis was not performed.

15.2.5 Loss of Condenser Vacuum

15.2.5.1 Identification of Causes and Frequency Classification

The main condenser vacuum is assumed to be suddenly lost while the unit is operating at 2527 MWt.

This event is classified as a moderate frequency event.

15.2.7 Loss of Normal Feedwater Flow

15.2.7.1 Identification of Causes and Frequency Classification

A loss of feedwater transient is assumed to occur due to a feedwater controller malfunction demanding closure of the feedwater control valves.

This event is classified as a moderate frequency event.

15.2.7.2 Sequence of Events and System Operation

With an initial power level of 2527 MWt, the feedwater control valves are assumed to close at their maximum rate. The unit response to simultaneous tripping of all feedwater pumps would be very similar to the transient analyzed. The reactor water level would decrease rapidly due to the mismatch between the steam flow out of the vessel and the shut off feedwater flow. Low water level scram would occur after about 7.4 seconds. The recirculation loop motor-generator (M-G) set flow controllers would run down to 28 % speed demand when the feedwater flow drops below 20 % and a 15 second time delay expires. This interlock is used to protect the recirculation drive pumps from steady-state net positive suction head (NPSH) problems and the jet pumps from inefficiency due to cavitation.

If the scoop tube positioner(s) for one or both recirculation loops are electrically locked out for testing or maintenance when a low feedwater condition occurs, the operator has the capability to remotely reset the scoop tube(s) from the control room and assure that the recirc. pump(s) are runback to minimum pump speed. For most loss of feedwater events, a reactor scram would be likely on low water level. The reactor scram recovery procedure directs the operator to verify runback of both pumps or to reset the scoop tube and assure runback. If needed, the operator also has the option to trip the recirculation pumps, (e.g.; if the scoop tubes are locally locked out).

15.2.7.3 Core and System Performance

The transient response to this event is shown in Figures 15.2-9 and 15.2-10.

The decrease in moderator subcooling would slightly decrease the neutron flux until scram occurs and completely shuts down the reactor. Vessel steam flow would closely follow the decay of fuel surface heat flux.

Analysis of the transient was discontinued at 16 seconds since the model was not programmed to handle the situation when core inlet subcooling becomes negative. Subsequent events would be complete drive motor trip, main steam isolation valve closure, and high pressure coolant injection (HPCI) initiation, all occurring when the water level drops to the low-low level setpoint. The time when this would occur, estimating from the established rate of level decrease, is about 33.5 seconds. Pressure would rise following the isolation and would eventually actuate the isolation condenser to handle the long-term shutdown heat removal.

Water inventory loss from 16 seconds until 36.5 seconds (the time the isolation valves would be closed) was conservatively estimated to be less than 550 cubic feet of saturated water. (At 16 seconds, vessel steam flow was 45 % of rated. For extreme conservatism, this rate was considered to exist until 36.5 seconds.)

Accounting for the above conservative inventory loss after 16 seconds and assuming the recirculation pumps would trip, an estimate of the final water level was made. All steam existing as carry-under and as voids in the core, upper plenum, standpipes and separators at 16 seconds was allowed to condense. The volume of water discharged to the scram discharge volume was assumed to be removed from the vessel. Even neglecting the inventory makeup from the HPCI system, the calculations showed that greater than 5 feet of water would remain above the core.

15.2.7.4 Barrier Performance

No thermal limits would be violated since the transient would be less severe than the turbine or generator trips. The fuel-specific operating limit MCPR is determined for each reload core based on bounding events for the cycle. The operating limit MCPR is calculated to preclude violation of the fuel cladding integrity safety limit.

15.2.7.5 Radiological Consequences

Since the fuel cladding integrity safety limit would not be violated, a radiological consequence analysis was not performed.

15.4 REACTIVITY AND POWER DISTRIBUTION ANOMALIES

Some events described in this section have not been reanalyzed for the current fuel cycle because these events continue to be bounded by generic analyses or analyses for previous fuel cycles. Although not reanalyzed, these events, including the associated assumptions and conclusions, continue to be part of the plant's licensing basis. The conclusions of these analyses are still valid; however, specific details contained in the descriptions and associated figures should be used only to understand the analysis and its conclusions. These specific details should not be used as sources of current fuel cycle design information.

15.4.1 Uncontrolled Control Rod Assembly Withdrawal — Subcritical or Startup Condition

This transient was analyzed for the most severe initial condition, a reactor core just subcritical and the IRM subsystem not yet on-scale. The full withdrawal of the worst-case control rod was evaluated. The power at the peak was demonstrated to be within thermal limits. A detailed description of this evaluation may be found in section 7.6.1.4.3.

15.4.2 Rod Withdrawal Error — At Power

See the introduction to Section 15.4 for information regarding use of details from this analysis description which may not be applicable to the current fuel cycle.

15.4.2.1 Identification of Causes and Frequency Classification

The rod withdrawal error (RWE) transient evaluation assumes the reactor is operating at a power level above 75% of rated power at the time the control rod withdrawal error occurs; that the reactor operator has followed procedures; and, up to the point of the withdrawal error, the reactor is in a normal mode of operation (i.e., the control rod pattern, flow setpoints, etc., are all within normal operating limits). For these conditions, it is assumed that the withdrawal error occurs with the maximum worth control rod. Therefore, the maximum positive reactivity insertion would occur.

While operating in the power range in a normal mode of operation, the reactor operator is assumed to make a procedural error by withdrawing the maximum worth control rod to its fully withdrawn position. Due to the positive reactivity insertion, the core average power would increase. More importantly, the local power in the vicinity of the withdrawn control rod would increase and could cause cladding damage either by overheating, which may accompany the occurrence of boiling transition, or by exceeding the 1% plastic strain limit imposed on the cladding.

The rod withdrawal error is considered a moderate frequency event.

15.4.2.4 Barrier Performance

The fuel-specific operating limit MCPR is determined for each reload core based on bounding events for the cycle. The operating limit MCPR is established to preclude violation of the fuel cladding integrity safety limit.

15.4.2.5 Radiological Consequences

Since the fuel cladding integrity safety limit would not be violated, a radiological consequence analysis has not been performed.

15.4.3 Control Rod Misoperation

The limiting control rod misoperation events have been analyzed as discussed in Sections 15.4.1 and 15.4.2.

15.4.4 Startup of Inactive Recirculation Loop at Incorrect Temperature

See the introduction to Section 15.4 for information regarding use of details from this analysis description which may not be applicable to the current fuel cycle.

15.4.4.1 Identification of Causes

Startup of an inactive recirculation loop at incorrect temperature would require multiple operator errors and failure of the recirculation pump speed mismatch interlock. The initial conditions given below assume startup of the idle recirculation pump with the operating pump at 90% rated drive flow. Procedures require warming the idle loop and running back the operating recirculation pump to 28% (minimum speed) before starting the idle loop (as well as meeting the differential temperature limit). Also, the recirculation pump speed mismatch interlock would trip the idle pump on a 10% mismatch after a 20-second time delay if an attempt were made to start it with the operating pump at greater than 38% speed. The trip would occur because the idle pump is automatically restricted to 28% speed for startup regardless of controller position and operating pump speeds greater than 38% would exceed the 10% mismatch.

The startup of an inactive recirculation loop at incorrect temperature has been classified as a moderate frequency event.

15.4.4.2 Sequence of Events and System Operation

The initial conditions assumed for the startup of an inactive recirculation loop at incorrect temperature are as follows:

A. One drive loop is shutdown and filled with cold water (110°F). (Normal procedure requires warming this loop to prevent thermal shock to the pumps and piping.)

B. The active recirculation loop is operating at about 90% of rated drive flow and 130% of normal rated diffuser flow in the 10 active jet pumps.

C. The core is receiving 50% of its normal flow, while the remainder of the flow is reversed up the 10 inactive jet pumps.

D. Reactor power is 30% of 2527 MWt.

E. The drive pump suction valve is open and the discharge valve is shut until minimum pump speed is established, then the discharge valve is jogged open. The equalizer line valves are closed on Unit 2. There are no equalizer line valves on Unit 3.

F. The fluid coupler scoop tube in the idle loop is at a position corresponding to approximately 50% of generator speed demand.

The startup transient sequence used is as follows:

A. The drive motor breaker is closed at event initiation (t = 0).

B. The drive motor reaches near synchronous speed quickly, while the generator approaches full speed in about 5 seconds.

C. At 5 seconds, the generator field breaker is closed, loading the generator and starting the pump. (The current value for elapsed time from drive motor breaker closing to generator excitor field breaker closing is 7 seconds). Pump acceleration and then controlled speed is shown in Figures 15.4-1 and 15.4-2. The coupler demand is programmed back to 20% speed as shown by the transient traces.

D. The pump discharge valve is opened as soon as its interlock clears when the drive motor breaker is closed. (Normal procedure would delay valve opening to separate the two portions of the flow transient and make sure the drive loop is properly mixed with vessel temperature water.) A nonlinear 30-second valve opening characteristic was used.

15.4.4.3 Core and System Performance

The transient response of the plant to the starting of an idle recirculation loop without warming the drive loop water is shown in Figures 15.4-1 and 15.4-2.

established ODCM limits; therefore, this event, at the worst, would result in an insignificant increase in the yearly integrated exposure level.

15.6.2 Break in Reactor Coolant Pressure Boundary Instrument Line Outside Containment

See the introduction to Section 15.6 for information regarding use of details from this analysis description which may not be applicable to the current fuel cycle.

A rupture of a reactor coolant pressure boundary instrument line outside containment could allow primary coolant and radioactivity contained therein to escape to the environment. The following section describes an instrument line break analysis performed by CECo during the initial licensing phase, the potential radiological consequences, and a subsequent analysis performed by the NRC for the SEP.

15.6.2.1 Identification of Causes

A postulated 1-inch reactor coolant pressure boundary instrument line break has been analyzed for the Dresden Unit 3 plant. Dresden Unit 3 is virtually identical to the Dresden Unit 2 design.

15.6.2.2 Sequences of Events and System Operation

The break in the reactor coolant pressure boundary instrument line was assumed to occur outside the primary containment but upstream of the flow check valve in a 1-inch pipe. A manually operated stop valve located outside the containment wall upstream of the break was not assumed to be closed until after the reactor was shut down and depressurized. The reactor was assumed to be shut down manually by the operator upon detection of the break.

Radiation levels in the reactor building ventilation duct would not be high enough to start the standby gas treatment system (SBGTS), so all of the radioactive materials escaping to the atmosphere would do so via the reactor building ventilation stack. The analysis showed that 70,000 pounds of water and 30,000 pounds of steam would be released to the reactor building. Air in the building would be exhausted to make room for the expanding steam, then all the steam not condensed in the reactor building would be transported out via the stack.

The leak is non-isolable (between the primary containment and first isolation valve outside the containment) within the first 4 hours until the reactor is manually shut down and depressurized. Then the manual valve can be closed and the ruptured line can be repaired.

Routine surveillance on the part of the operator (as described in the following list A through H) has been a sufficient program for the periodic testing and examination of the valves in these small diameter instrument lines.

Such leaks would be detected by one or a combination of the following:

A. Comparison of readings among several instruments monitoring the same process variable, such as reactor level, jet pump flow, steam flow, and steam pressure;

B. Annunciation of the failure of the affected control function, either high or low, in the control room;

C. Annunciation of a half-channel scram if the rupture occurred on a reactor protection system instrument line;

D. A general increase in the area radiation monitor readings throughout the reactor building;

E. Noise from the leakage audible either inside the turbine building or outside the reactor building on a normal tour;

F. Unexplained increase in floor drain collector tank water level as well as alarms on the corner room floor sumps;

G. Detection of the leak as soon as an access door to the reactor building is opened; and

H. Increases in area temperature monitor readings in the reactor building.

15.6.2.3 Barrier Performance

No core uncovering would occur and no fuel cladding perforations would occur.

15.6.2.4 Radiological Consequences

Calculations of doses due to the released radioactive materials included the following assumptions. Coolant activity consistent with a plant off-gas release rate of 100,000 μCi/s was assumed to be released to the environment. Although the release would occur at the top of the reactor building, it was assumed that downwash would result in an effective release height of 0 meters. Since no core uncovering or fuel cladding perforations would occur, only coolant activity would be released. Iodine in the 30,000 pounds of water that flashed to steam was assumed to be transported with the steam.

The iodine activity associated with the released liquid was 0.04 μCi/cc of I-131 and 0.3 μCi/cc of I-133. No further release of iodine from the water was assumed. Very stable (1 m/s) meteorological conditions were assumed, since these conditions represent the worst case for an equivalent ground level release. Calculated lifetime dose for the duration of the release is 0.3 rem, which is well below the reference doses of 10 CFR 100 and is in fact less than the annual dose permitted in the old 10 CFR 20 prior to January 1, 1994.

15.6.5.2 Sequence of Events and Systems Operation

The postulated LOCA results from a rupture of primary system piping. The loss of inventory produces core depressurization and decreasing water level in the vessel.

The HPCI, automatic depressurization system (ADS), LPCI, and core spray systems would act to cool the core following the accident.

Reactor scram occurs on low water level or high drywell pressure. The ECCS is automatically actuated on either low-low water level or high-drywell pressure. A simultaneous loss of offsite power is assumed with the break together with the worst single failure in the ECCS. The assumed simultaneous loss of offsite power causes the recirculation pumps to coast down and delays initiation of ECCS until the diesel generators attain speed and are loaded.

The course of the accident depends on the break size and location.

For a small break, failure of HPCI is the worst single failure, and core cooling is provided by the ADS, LPCI, and the core spray systems. For these breaks, the vessel depressurizes relatively slowly due to the small break size. The ADS automatically actuates to reduce pressure so that the low pressure cooling system can function.

For larger breaks, failure of the LPCI injection valve is the most severe single failure since the vessel depressurizes faster and the HPCI system is not available due to the low-system pressure. The core uncovers as coolant inventory is lost through the break. After several minutes, injection flow from the core spray refloods the core.

The coolant lost through the rupture is condensed by the pressure suppression pool, thus reducing primary containment pressure. Energy is removed from the pressure suppression pool by the containment cooling system.

15.6.5.3 Core and System Performance

The analyses for loss-of-coolant accidents were originally performed using calculational models and techniques different from those that are currently used.

Siemens Power Corporation (SPC) has performed the LOCA analyses for SPC 9x9 fuel in the Dresden reactors. The calculations have been performed with the generically approved Exxon Nuclear Company EXEM/BWR ECCS Evaluation model according to 10 CFR 50, Appendix K, and the results comply with the NRC 10 CFR 50.46 criteria.

Section 6.3.3 discusses the fuel thermal response, the ECCS performance, and the current analysis models.

Section 6.2.1 discusses the containment and coolant blowdown responses.

If fission products leak from the drywell, drywell high pressure or reactor building high-radiation signals would isolate secondary containment as described in Section 6.2.3. The analysis assumed all the noble gases and halogens released into the reactor building remain airborne.

The airborne fission product inventory in the reactor building, which was evaluated considering the leakage from the drywell to the reactor building, radioactive decay, fallout and plateout, and an air change rate of 100% of the reactor building volume per day, is shown in Table 15.6-6.

15.6.5.4.4 Fission Product Release from Reactor Building to Atmosphere

THIS SECTION IS MAINTAINED FOR HISTORICAL INFORMATION ONLY.

The halogens which leak from the pressure suppression containment into the reactor building are exhausted by the SBGTS through a high efficiency filter and an activated charcoal adsorber. The reactor building exhaust air is treated to reduce the humidity so that the activated charcoal adsorber is effective for removal of organic halogens. Tests on adsorber efficiencies have shown that inorganic halogens are removed by charcoal filters with efficiencies greater than 99.99%.[20,21] These tests have also shown that organic halogens are removed at a relative humidity less than 30% with adsorber efficiencies from 99.9% to 99.9999%.[21–25] The activated charcoal adsorber on the EVESR at Vallecitos Atomic Power Laboratory retained organic halogens produced at power operation with efficiency from 99.8% to 99.9% at a relative humidity of 10 to 15%. The experimental results were used as the basis of the original SBGTS design. The system is designed to provide the necessary residence time in the adsorbers. Thus, the analysis assumption of 99% efficiency for the removal of inorganic and organic halogens in the SBGTS is conservative by approximately 4 orders of magnitude.

The compounding of conservative assumptions used in the LOCA analysis results in calculated doses from halogens that are 20 to 1000 times higher than the doses which would actually be expected. LOCA discharge rates to the chimney (stack) are shown in Table 15.6-7.

15.6.5.5 Radiological Consequences

The discussion in this subsection represents various evaluations performed to estimate the radiological consequences for 7x7 fuel arrays.

15.6.5.5.1 Offsite Dose Rates

The radiological effects of a design basis LOCA, as estimated by CECo for the initial core (7x7 arrays) licensing, are shown in Table 15.6-8. These doses are far below the guideline radiation doses listed in 10 CFR 100.

Subsequent to the CECo's original analysis, the AEC evaluated the radiological consequences for the design basis LOCA inside containment using conservative assumptions in the SER. The AEC assumed the Technical Information Document (TID) 14844 source term with 100% of the noble gases, 50% of the halogens released from the core. In addition, 50% of the halogen released from the core was assumed to plate out onto internal surfaces of the containment building or onto internal components. The primary containment was assumed to leak at a constant rate of 2.0% of the containment volume per day for the duration of the accident. A 90% halogen removal efficiency of charcoal absorbers of the SBGTS was assumed. It was also conservatively assumed that leakage from the drywell goes directly to the standby gas treatment system without mixing in the reactor building and then to the environment via the 310-foot chimney. Fumigation conditions were assumed for the first half-hour exposure at the site boundary, followed by the most conservative unstable condition. The resultant 2-hour dose at the site was calculated by the AEC to be 185 rem to the thyroid. This value is less than the 10 CFR 100 guideline dose of 300 rem for the thyroid. The current accident analyses are based on a 95% SBGTS efficiency.

In addition to the AEC's SER analysis, the NRC also performed an independent evaluation of the offsite radiological consequences following a postulated LOCA with conservative assumptions as part of the SEP. In this evaluation, the NRC assumed that an outboard MSIV is leaking at 11.5 scfh, which is the Technical Specification limit. The NRC also estimated a 30-hour delay time for the MSIV portion of the leakage, based on at least an 80-foot length of seismically qualified main steam line downstream of the leaking MSIV. The NRC assumed the leakage to occur at ground level at the turbine stop valve in the turbine building. The total offsite radiological consequences of the LOCA, including containment leakage, were calculated by the NRC to be 36 rem to the thyroid and 2 rem to the whole body at the EAB and 230 rem to the thyroid and less than 1 rem to the whole body in the LPZ. These are also within the offsite radiological consequence guidelines of 10 CFR 100.

Another independent evaluation has been performed by the NRC to estimate radiological consequences of a LOCA while purging the containment. The NRC estimated that the steam released through the purge line prior to post-LOCA closure would result in an incremental dose of 0.76 rem to the thyroid at the EAB and 0.1 rem to the thyroid at the LPZ. These doses when added to the above mentioned SEP review of LOCA doses meet the applicable guidelines of 10 CFR 100.

Thus, there is adequate margin in the design of the reactor and containment to limit the consequences of large postulated accidents and protect the public.

15.6.5.5.2 Radiological Consequences — Control Room Dose Rates

A control room dose analysis was performed in accordance with the guidance of NUREG-0737,[26] Item III.D.3.4 to determine compliance with the radiological requirements of General Design Criterion (GDC) 19 and SRP 6.4.[27] The analysis considered the LOCA to be the radiological design basis accident (DBA) and assumed simultaneous main steam isolation valve leakage. Furthermore, MSIV leakage at the Technical Specification limit was assumed for the analysis. The results of this analysis are considered conservative. Several natural mechanisms would reduce or delay the radioactivity prior to release to the environment. However, credit was taken only for iodine plateout on surfaces of the steam lines and condenser and radioactive decay prior to release.

Subsequently, the original analysis was revised due to two major deficiencies. One deficiency involved the assumption that only 10 ft^3/min of unfiltered air entered the control room habitable zone. The results of a walkdown revealed that the habitable zone boundary could leak in excess of the 10 ft^3/min assumed in the original analysis. This leakage was actually calculated to be 263 ft^3/min. The second deficiency involved crediting a SBGTS efficiency of 99%; whereas, the Technical Specification limit is only 95%. The resultant dose calculation with these revised input parameters was reduced to within its acceptance limits by requiring initiation of the control room emergency filtration system within 40 minutes after an accident.

The infiltration to the control room HVAC system ductwork has been discussed in Section 6.4.

15.6.5.5.2.1 Methodology

The guidelines given in SRP 6.4[27] and Regulatory Guide 1.3[28] have been used with the exceptions of the X/Q for the control room, the treatment of the secondary containment, and plateout of iodines during transportation within pipes. Realistically, the components of the main steam lines and the turbine-condenser complex would remain intact following a design basis LOCA. Therefore, plateout of iodines on surfaces of the main steam lines and the turbine-condenser complex would be expected.

Figure 15.6-4 shows the radiological control room model used for activity released through the SBGTS and through the MSIVs. The total control room 30-day integrated dose would be equal to the sum of the two dose models. The input parameters used to develop the activity levels in the control room are shown on Table 15.6-9.

15.6.5.5.2.2 Assumptions and Bases

Regulatory Guide 1.3[28] has been used to determine activity levels in the containment following a design basis LOCA. Activity releases are based on a containment leakage rate of 1.6% per day. Table 15.6-9 lists the assumptions and parameters used in the analysis and dose point locations. The majority of the containment leakage would be collected in the reactor building and exhausted to the atmosphere through the SBGTS as an elevated release from the main stack. Any SBGTS bypass leakage has been quantified by assuming that all MSIVs leak at the Technical Specification limit of 11.5 scfh per main steam line when tested at 25 psig. The leak rate was corrected to the containment design pressure using the laminar flow extrapolation factors from ORNL NSIC.[29]

Leakage past the isolation valves could be released through the outboard MSIV stems into the steam tunnel, or it could continue down the steam lines to the stop valves and into the turbine-condenser complex. The steam tunnel is exhausted by the SBGTS filtration system, thus eliminating it as a bypass pathway. The MSIV leakage down the steam piping travels to the turbine-condenser complex where it is released as a ground level release at a rate of 1% of the turbine-condenser volume

Table 15.6-6

POST-LOCA REACTOR BUILDING AIRBORNE FISSION PRODUCT INVENTORY

This table (15.6-6) is maintained for historical information only. The bases for this table are described in Section 15.6.5.4.3.

Time After Accident	Noble Gases (Ci)	Halogens (Ci)
30 minutes	1.4×10^{2}	7.0×10^{0}
1 hour	2.3×10^{2}	1.3×10^{1}
3 hours	6.3×10^{2}	3.2×10^{1}
10 hours	1.4×10^{3}	5.7×10^{1}
1 day	1.9×10^{3}	7.1×10^{1}
3 days	1.8×10^{3}	6.6×10^{1}
10 days	3.1×10^{0}	9.0×10^{-2}
25 days	less than 10^{-10}	8.0×10^{-9}

Table 15.6-7

POST-LOCA DISCHARGE RATES TO CHIMNEY

This table (15.6-7) is maintained for historical information only. The bases for this table are described in Section 15.6.5.4.4.

Time After Accident	Noble Gases (Ci/s)	Halogens (Ci/s)
30 minutes	1.5×10^{-3}	8.1×10^{-7}
1 hour	2.7×10^{-3}	1.5×10^{-6}
3 hours	7.3×10^{-3}	3.7×10^{-6}
10 hours	1.7×10^{-2}	6.6×10^{-6}
1 day	2.2×10^{-2}	8.2×10^{-6}
3 days	2.1×10^{-2}	7.8×10^{-6}
10 days	3.7×10^{-5}	1.1×10^{-8}
25 days	less than 10^{-12}	less than 10^{-14}

Table 15.6-10

30-DAY POST-LOCA CONTROL ROOM DOSES (INTEGRATED)

	Doses (rem)		
	Thyroid	Wholebody	Beta
MSIV Leakage			
Activity inside control room	6.76	1.21×10^{-2}	0.47
Plume shine	–	2.03×10^{-3}	–
Direct shine	–	1.01×10^{-1}	–
Stack Release			
Activity inside control room	15.88	7.28×10^{-2}	1.67
Plume shine	–	1.98×10^{-2}	–
Total control room doses	22.64	0.208	2.14
SRP 6.4 Guidelines	30	5	30

Table 15.6-9

LOSS-OF-COOLANT ACCIDENT INPUT PARAMETERS FOR CONTROL ROOM DOSE ANALYSIS

A.	Data and Assumptions used to Estimate Radioactive Source from Postulated Accidents:		
	1.	Power level (MWt)	2527
	2.	Burnup	N/A
	3.	Fission products released from damaged fuel	100%
	4.	Iodine fractions:	
		a. Organic	0.04
		b. Elemental	0.91
		c. Particulate	0.05
B.	Data and Assumptions used to Estimate Activity Released:		
	1.	Primary containment leak rate (total), percent per day	1.6
	2.	Leak rate through each MSIV, ft^3/hr (standard) at 25 psig	11.5
	3.	Number of MSIVs	4
	4.	Total leak rate through MSIVs, ft^3/h (standard) at 25 psig	46.0
	5.	Extrapolation factor for 48 psig design pressure	1.58
	6.	Total leak rate through MSIVs, ft^3/h (standard) at 48 psig	72.7
	7.	Volume of primary containment (mixed volume), (ft^3)	286,234
	8.	Primary containment leak rate which goes to secondary (percent per day)	1.45
	9.	Primary containment leak rate which goes through MSIV (percent per day)	0.15
	10.	SBGTS adsorption and filtration efficiencies (percent)	
		a. Organic iodines	95
		b. Elemental iodines	95
		c. Particulate iodines	95
	11.	Secondary containment leak rate (percent per day)	140.5
	12.	Leak rate from turbine-condenser complex (percent per day)	1
	13.	Plateout removal constant (MSIV leak rate only), 1/second	
		a. Elemental iodine	1.503×10^{-3}
		b. Particulate iodine	1.503×10^{-3}
		c. Organic iodine	0

The Effluent Concentration Limit (ECL) for an unidentified mixture is 10^{-6} µCi/cc. Thus, in the worst case of all tanks being full, at maximum activity concentration, and failing simultaneously, river concentration over an hour would be greater than the ECL for the mixture. However since the release period and subsequent human intake are for periods much shorter than a year, the doses attendant with maximum releases expected for the seismic event can be reduced by the ratio of the release period to a year. The 10 CFR 20 ECL for an unidentified mixture of 1 x 10^{-6} µCi/cc is equivalent to 50 mrem/yr dose limit assuming a human intake of 2200 mℓ/day for a year.

$$\text{dose potential} = \frac{(1 \times 10^{-6}\ \mu\text{Ci/cc})\ (1\ \text{hour})}{(1 \times 10^{-6}\ \mu\text{Ci/cc})\ (8760\ \text{hr/yr})}$$

$$= 0.0011 \text{ of yearly dose rate}$$

The pool of the Dresden dam would provide some additional volume for mixing with the river water. Tritium content at a maximum could be 4 curies to give a maximum river concentration of 1.3 x 10^{-5} µCi/cc. This would still be 2 orders of magnitude below its ECL of 1 x 10^{-3} µCi/cc.

Therefore the actual maximum dose expected from this event would be 2 orders of magnitude less than the 50 mrem/yr allowed by 10 CFR 20 even with no consideration for downstream dilution factors, decay times, or unidentified versus identified mixtures.

Thus, the dose associated with the postulated seismic events described above is not considered to be at a level to cause concern.

The remaining waste tankage is located below grade in the radwaste building. The building is a concrete structure located in rock. Although seismic occurrences may cause tank damage, radwaste liquids will accumulate in the basement of the radwaste building. Escape of the radwaste liquids from the basement would have to be through cracks and fissures in concrete walls and surrounding rock. Passage through the rock would be accompanied by some degree of filtration and ion exchange. Maximum activity possibly present in basement tanks is 530 curies. If the liquids escaped, they would take a substantial period of time to get through the rock. Assuming this time to be 100 hours would make the consequence similar to the case above.

In both of the above cases, river activity would accumulate in a discrete time interval, very short when compared to the year interval upon which 10 CFR 20 ECL limits are based.

Further it may be pointed out that, although the activities released to the river would result from a tank failure condition indicating applicability of 10 CFR 100 limits, the actual expected concentrations are sufficiently low to allow 10 CFR 20 limits to be applied. This total failure analysis also eliminates the requirement for a retention sump/curbing around the radwaste tanks.

Based on the preceding assumptions and a discharge rate of 100% of building volume per day through the standby gas treatment system (SBGTS), the calculated building fission product inventory as a function of time following the accident is shown in Table 15.7-3.

15.7.3.4.3.4 Chimney Release Rate

After a fuel handling accident, releases of fission products to the atmosphere will occur through the normal reactor building ventilation system prior to the automatic initiation of the SBGTS and closure of the Reactor Building isolation damper by high radiation monitors located near the fuel pool and in the reactor building ventilation exhaust duct.

The accident release rate, given in Table 15.7-4, was originally calculated assuming an efficiency of 99% for the SBGTS filters. Using the more conservative SBGTS filter efficiency of 90% (correlates to the technical specification limit of <10% penetration) for calculations, the releases are will within the 10CFR100 limits at the exclusion area boundary and the control room exposure is less than the GDC-19 limits with the SBGTS initiation time and the isolation damper automatic closure time of 5 minutes or less.

15.7.3.4.3.5 Meteorology and Dose Rates

Table 15.7-5 summarizes the calculated radiological effects for the following six meteorological conditions:

A. Very stable conditions with a 2-mph wind speed (VS-2);

B. Moderately stable conditions with a 2-mph wind speed (MS-2);

C. Neutral stability conditions with 2-mph wind speeds (N-2),

D. Neutral stability conditions with a 10-mph wind speed (N-10);

E. Unstable stability conditions with 2-mph wind speed (U-2), and

F. Unstable stability conditions with a 10-mph wind speed (U-10).

The largest of these radiation exposures is well below the limits of 10 CFR 100. For the failure of 445 rods, the calculated upper bound, the doses are at most only 6.4×10^{-4} of 10 CFR 100 guideline dose limits.

As a part of the Systematic Evaluation Program (SEP), the NRC reviewed two analyses to evaluate the radiological consequences of fuel damaging accidents: the 7x7 refueling accident analysis described above and an AEC prepared analysis presented in the Safety Evaluation Report for Dresden Unit 2. On the basis of the results and a comparison of the assumptions used in these studies to the assumptions suggested in Regulatory Guide 1.254, the NRC concluded that the radiological consequences would be appropriately within the guidelines of 10 CFR 100.

Therefore,

$$q = 0.25 \times \frac{1.25}{144} \sqrt{(2)\ (32.2)\ (38)}$$

$$q = 0.11 \text{ ft}^3/\text{s} = 50 \text{ gal/min}$$

The choice of a discharge coefficient is a matter of judgement. The cracks are assumed to pass uniformly through the slab. It should be noted that there is no mechanism to provide gross cracking completely through the floor. This mode of cracking would be inconsistent with structural conditions existing in the slab and would be overly conservative; the paths would be rough and distorted. Under these conditions, 0.25 is believed to be adequately conservative. However, even if a coefficient of 1.0 were chosen, the estimated leakage would be 200 gal/min, still well within the capacity (500 gal/min each) of one of four condensate transfer pumps available.

In summary, the analysis results in an estimate on the order of 10 to 80 gal/min leakage rate through crack paths that could develop as a result of the above postulated accident. The water would leak onto the floor beneath the pool and subsequently to the reactor building floor drain sumps. The sump capacity and the normal makeup capability are both greater than this calculated leakage. Depending upon the plant operating conditions at the time a leak is postulated to develop, there are various methods of supplying makeup water to the pool to prevent the pool level from decreasing to an unsafe level above the fuel. The condensate transfer system is normally used to supply makeup water to the pool. There are two condensate transfer pumps in each unit; under normal conditions, one pump can supply all the necessary unit makeup requirements. Should a circumstance occur which requires more than the capacity of one pump (500 gal/min), the other pumps can be started. Since the pumps of the two units are crosstied, the capacity for makeup can be increased to above 1000 gal/min. This is in excess of any leakage that could conceivably occur.

In conclusion, the energy absorption capability of the cask housing, fins, and concrete fuel pool is such that the expected damage to the floor would not result in a leakage rate greater than the pool makeup capability. Therefore, no energy absorbing system is necessary.

Table 15.7-2

RADIOLOGICAL EXPOSURE DUE TO OFF-GAS TREATMENT SYSTEM COMPONENT FAILURE

Component Failed	Primary Activity Released	Percentage Released	Resultant Exposure (800 meters)	Regulatory Limits	
				10 CFR 20	10 CFR 100
First Activated Carbon Bed	Iodine	1%	12.4 mrem	* Note 1	300,000 mrem
12 Activated Carbon Beds	Noble Gas	10%	1.0 mrem	* Note 1	25,000 mrem
Prefilter	Particulates	1%	18.5 mrem	* Note 1	25,000 mrem
Holdup Pipe	Particulates	20%	20.3 mrem	* Note 1	25,000 mrem

* Note 1 - The total limit for annual exposure of all types of radiations (noble gases, particulates, iodines) is 100 mrem/year TEDE. The 100 mrem TEDE is the annual 10 CFR 20 limit for dose to the public.