Entergy

Entergy Nuclear Northeast
Entergy Nuclear Operations, Inc.
James A. FitzPatrick NPP
P.O. Box 110
Lycoming, NY 13093
Tel 315-349-6024 Fax 315-349-6480

Brain R. Sullivan
Site Vice President - JAF

JAFP-15-0047
April 8, 2015

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555-0001

Subject: 2015 Updated Final Safety Analysis Report, Technical Specification Bases and Technical Requirements Manual Changes Transmittal

James A. FitzPatrick Nuclear Power Plant
Docket No. 50-333
License No. DPR-059

Dear Sir or Madam:

The changes to the Final Safety Analysis Report (FSAR) for the James A. FitzPatrick Nuclear Power Plant (JAF) are being submitted as required by 10 CFR 50.71(e).

This submittal also includes the changes made to the JAF Technical Specifications Bases and the Technical Requirements Manual, which are controlled under 10 CFR 50.59, and submitted to the NRC biennially with the changes to the UFSAR.

The changes and their bases are summarized in Attachment 1, 2, and 3. The changed pages are included in Enclosures 1, 2, and 3 respectively. A component of the Technical Requirements Manual contains proprietary information. Enclosure 3A contains the proprietary version of the Core Operating Limits Report (COLR), Revision 28, with an affidavit.

There are no commitments contained in this letter. If you have any questions, please contact Mr. Chris M. Adner, Regulatory Assurance Manager, at 315-349-6766.

I declare under penalty of perjury that the foregoing is true and correct. Executed on this 8th day of April 2015.

Very truly yours,

Brian R. Sullivan

AD53
NRR

BS/CA/mh

Enclosure 3A to this letter contains ~~Proprietary Information that should be withheld from public disclosure per 10 CFR 2.390.~~ When separated from Enclosure 3A there are no withholding criteria.

Attachments 1: Table of Final Safety Analysis Report (FSAR) 2015 Changes
2: Table of Technical Specification (TS) Bases 2015 Changes
3: Table of Technical Requirements Manual (TRM) 2015 Changes

Enclosures 1: Final Safety Analysis Report (FSAR) 2015 Change Pages
2: Technical Specification (TS) Bases 2015 Change Pages
3: Technical Requirements Manual (TRM) 2015 Change Pages
3A: TRM Appendix G, Core Operating Limits Report (COLR), Revision 28 (Proprietary Version /w Affidavit)

cc: Regional Administrator, Region 1
U. S. Nuclear Regulatory Commission
2100 Renaissance Boulevard, Suite 100
King of Prussia, PA 19406-2713

Resident Inspector's Office
U.S. Nuclear Regulatory Commission
James A. FitzPatrick Nuclear Power Plant
P.O. Box 136
Lycoming, NY 13093 (without enclosures)

Mr. Douglas Pickett, Senior Project Manager
Plant Licensing Branch I-1
Division of Operating Reactor Licensing,
U.S. Nuclear Regulatory Commission,
Mail Stop: O-8-C2A
Washington, DC 20555-0001

Ms. Bridget Frymire
New York State Department
of Public Service
3 Empire State Plaza, 10th Floor
Albany, NY 12223-6399

Mr. John B. Rhodes
President and CEO
NYSERDA
17 Columbia Circle
Albany, NY 12223-1350

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ATTACHMENT 1

Table of Final Safety Analysis Report (FSAR) 2015 Changes
(3 Pages)

Table of Final Safety Analysis Report (FSAR) 2015 Changes

FSAR Page / Table / Figure	Description of Change	Justification for Change
P4.2-11, P16.10-10, P16.10-14	Update FSAR with reference to current BWRVIP-86 Rev 1 Integrated Surveillance Program.	PAD and SEP-FTP-JAF
T4.2-3	Change "all other scrams" value used in reactor pressure vessel thermal cyclic/transients from 64 to 75.	Engineering Change EC 43136
F9.9-6	Correct discrepancy for distribution panel number from RRAC88 to ABAC1 for 72FN-20, 72FN-21, and from RRACA8 to ABAC1 for 72FN-35.	Editorial Change
F10.8-2 Sh1	Remove obsolete information for 34RV-104A. Delete Note 5 and reference to Note 5	UFSAR only – Removing Obsolete Information
P16.10-17	Change to address Core Plate Bolt inspections	NRC SER per ML14198A152
P13.2-1 thru 13.2-12; F13.2-1 thru 13.2-4 F13.2-6, F13.2-7	Organizational report structure and organization charts to reflect the current reporting structure due to HCM position changes	PAD and UFSAR only - Reformatting
P1.1-2	Remove reference to White Plains Office	UFSAR only- Removing obsolete Information
P2.6-2	Seismic monitoring system instrumentation upgrade	Engineering Change EC 37682
P2.4-1 thru 2.4-11 P2.5-1 thru 2.5-4 P10.9-2	Revise Hydrology and Geology sections of the USFAR based on the latest site hydrogeological study and correct a drain path	PAD
P11.4-5	Add Temp Mod Annotation to off-gas dryer regeneration interval	UFSAR only- Referencing other documents
P9.12-1, P9.22-1 F9.10-4, F9.22-1 Sh 2	Reinstall Demin Water to DHR secondary side to provide makeup water	Engineering Change EC 48461
T7.19-1 Sh 10	Correct EPIC point typo	Editorial Change
TOC Chapter 9 P9-iii	Correct TOC typo for 9.7.3.6	Editorial Change
P16.10-3	Update Renewed License BWR Vessel Internals Program for top guide inspections	NUREG-1905
P16.10-1 thru 16.10-19	Update Renewed License commitments status to identify implemented state	UFSAR only – Removing Obsolete Information

Table of Final Safety Analysis Report (FSAR) 2015 Changes

FSAR Page / Table / Figure	Description of Change	Justification for Change
P16.10-8	Remove Main Steam Line flow restrictors from the One-Time Inspections	PAD
P16.10-4	Update Fire Protection Program for Renewed License for seal inspections	NUREG-1905 Letter JAFP-07-0048
P16.10-18	Add Renewed License section for 115KV underground cable testing	NUREG-1905
P7.8-3, P14.5-22 F7.8-2	New Reactor Water level transmitter (02-3LT-95) to Remote Shutdown Panel (25RSP)	Engineering Change EC 43148
P11.5-4	Neutron shielding thickness change for doors at N-16A and N-16B	Engineering Change EC 53156
F9.11-1 Sh 1	Correction of Figure for Air System configuration	Editorial Change
P16.10-5	Fire Water System Program for Renewed License will not require wall thickness inspections during PEO	PAD
P8.3-1, F8.2-1, F8.3-1, F8.3-3, F8.5-1	Main Transformer 71T-1A replacement	Engineering Change EC 41864
F12.3-19 F12.3-20	6th Point Feedwater Heater replacement	Engineering Change EC 45460
F4.9-1 Sh. 1 F4.9-2 Sh 1	Remove 12MOV-68, Reactor Water Cleanup Return Outboard Isolation Valve	Engineering Change EC 49465
F4.9-1 Sh 1	Remove relief valve 12RV-210	Engineering Change EC 52929
P10.3-2 F9.10-2	Sodium Hypochlorite Injection System upgrade	Engineering Change EC 49654
P10.3.1, P10.3-2, P10.6-1, F10.4-1 Sh. 2, F10.6-1	Main Condenser Retube	Engineering Change EC 40597
P8.4-4 F8.3-1	Added generator backup distance relay (11G-UPRN05) since 21-UPRN05 was removed by Temp Mod EC-39145	Engineering Change EC 42313
P9.10-1	Clarify Demineralized Water and Transfer System design	Editorial Change
F9.10-2	Clarify connection as valve 46	Engineering Change EC 50290
P 7-xvii F7.5-2	Replace and retitle Figure for Dry Tubes Replacement	Engineering Change EC 50656 UFSAR-only removing excessive detail

Table of Final Safety Analysis Report (FSAR) 2015 Changes

FSAR Page / Table / Figure	Description of Change	Justification for Change
F8.10-1	Correct 71INV-3A inaccuracies	PAD and Editorial Change
P7.18-1	Update changes to meteorological monitoring system data access.	PAD
P13.8-7	Add Cyber Security Milestone 8 extension / TSA-308	TSA-308
P8.6-4 / F8.2-1, F8.3-3, F8.5-1	Note temporary jumpering of 71MOD-10001	Temp Mod EC 45213
F7.4-3 sh 1 F7.4-3 sh 2 F7.4-3 sh 3	Updated Functional Control Diagrams (FCDs) for HPCI	Engineering Change EC 47983
F4.7-2 sh 1 F4.7-2 sh 2 F4.7-2 sh 3 F4.7-2 sh 4 F7.4-6 F7.4-9 sh 1 F7.4-9 sh 2 F7.4-9 sh 3 F7.10-1	Updated Functional Control Diagrams (FCDs) for RCIC, Core Spray, Reactor Recirculation and IED drawing for Feedwater Control	Engineering Changes EC 52770, EC 47900, EC 47981, EC 47148, EC 47147
P14.5-17 P14.5-18	Clarify reference to Decay Heat Removal in FSAR Section 14.5.8.1	Safety evaluation JAF-SE-96-042 revision
P3.3-20 P3.4-1 thru 3.4-8 P3.10-5 P14.6-3 F3.4-6	Control Rod Blade Replacement	Engineering Change EC 50609
T3.2-1 P3.2-2 P3.2-3 P3.2-4 P3.2-5 P3.2-6 P3.2-10 P3.7-2 P3.7-7 P3.10-5 P14.5-4 P14.5-15 P14.5-18 F14.5-10 F14.5-16 F14.5-17 F14.5-18 P14.9-6	Cycle 22 Reload	Engineering Change EC 45913

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ATTACHMENT 2

Table of Technical Specification (TS) Bases 2015 Changes
(1 Page)

Table of Technical Specification (TS) Bases 2015 Changes

TS Bases Page	Description of Change	Justification for Change
B 2.1.1-2 B 2.1.1-4	Reduce reactor pressure associated with Low Pressure Safety Limit	Rev.32 LBDCR BASES-15-001 and NRC SER for Tech Spec Amendment 309, LBDCR TSA-309, JAFP-14-0123

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ATTACHMENT 3

Table of Technical Requirements Manual (TRM) 2015 Changes
(1 Page)

TRM Page / Table	Description of Change	Justification for Change
B 3.4.A-1	Revise Bases B 3.4.A to update the reference of the JAF ISI Program	Rev. 56 TRM-13-002 and ENN /SEP-ISI-007
Appendix I Page I-2	Update NUREG 1022 revision from Rev. 2 to Rev. 3	Rev. 56 TRM-13-003
5.0-7	Revise TRO 5.5.C to remove reference to specific procedures and training documents	Rev. 56 TRM-13-004
Page D-7 of Table D-1	New Reactor Water Level Instrument (02-3LI-95) to Remote Shutdown Panel (25RSP) (Pages D-1 thru D-7)	Rev. 57 TRM-14-002
Appendix G	Core Operating Limits Report (COLR) Rev. 28 for Cycle 22 update to reflect TSA-307 (Contains Proprietary information. Enclosure 3 contains non-proprietary version. See Enclosure 3A for full version) (Page G-1 and 25 pages of COLR)	Rev. 57 TRM-14-003
3.3.A-2	Corrected error in allowable valve for TRS 3.3.A.1	Rev. 58 TRM-14-004
5.0-10 5.0-11 5.0-18 5.0-19	Revise Program 5.5.F responsibility from Programs & Components to Design & Programs Eng. Revise Program 5.5.G responsibility from Programs & Components to Design & Programs Eng. Revise Program 5.5.N responsibility from System Eng. to Systems & Components Eng. Revise Program 5.5.O responsibility from System Eng. to Systems & Components Eng.	Rev. 58 TRM-15-001 for HCM Changes
3.4.B-1 B 3.4.B-2	Revise TRO 3.4.B, Required Action A.2, and Bases TRO 3.4.B to reflect change in BWRVIP-190 revisions and replaced Chemistry sampling procedure reference from SP-01.02 with new procedure SP-05.02	Rev. 58 TRM-15-002
5.0-9 5.0-15	Revise Program 5.5.E responsibility from Systems Engineering to Operations Department (Reactor Engineering). Revise Program 5.5.K responsibility from Regulatory Compliance to Regulatory Assurance	Rev. 58 TRM-15-003 for HCM Changes

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ENCLOSURE 1

Final Safety Analysis Report (FSAR) 2015 Change Pages

STATUS OF FSAR PAGES, TABLES AND FIGURES

Page No.	Rev. No.	Date
CHAPTER 1		
1-i	3	4/15
1-ii	1	1/92
1-iii	1	1/92
1-iv	3	5/97
1-v	1	5/03
1-vi	1	4/13
1-vii	1	7/90
1.1-1	6	4/15
1.1-2	6	4/15
1.1-3	6	4/15
1.2-1	0	7/82
1.2-2	0	7/82
1.2-3	0	7/82
1.2-4	0	7/82
1.2-5	0	7/82
1.2-6	0	7/82
1.2-6A	3	5/07
1.2-7	0	7/82
1.2-8	0	7/82
1.2-9	1	5/97
1.2-10	1	5/97
1.2-11	0	7/82
1.2-12	0	7/82
1.2-13	4	5/99
1.2-14	3	4/13
1.2-15	1	7/90
1.2-16	1	7/90
F1.2-1	0	7/82
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F1.2-3	2	2/07
1.3-1	1	7/83
1.3-2	1	7/83
1.4-1	0	7/82
1.4-2	0	7/82
1.5-1	0	7/82
1.5-2	0	7/82
1.5-3	0	7/82
1.5-4	0	7/82
1.5-5	1	7/83
1.6-1	3	4/13
1.6-2	0	7/82
1.6-3	1	7/83
1.6-4	2	5/01
1.6-5	4	4/13
1.6-6	0	7/82
1.6-7	2	7/84
1.6-8	0	7/82
1.6-9	1	5/06
1.6-10	0	7/82
1.6-11	2	7/95
1.6-12	5	5/01
1.6-13	0	7/82
1.6-14	2	5/01
1.6-15	1	7/83
1.6-16	3	5/03
1.6-17	3	4/11
1.6-18	5	4/13
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F1.6-1	1	5/97
1.7-1	0	7/82
1.8-1	2	5/03
1.9-1	4	5/01
1.10-1	3	5/01
1.11-1	0	7/82
1.12-1	0	5/03
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2.1-1	1	5/03
2.1-2	4	4/11
2.1-3	2	5/01
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T2.1-2	0	7/82
T2.1-3	0	7/82
T2.1-4, Sh. 1	2	8/03
T2.1-4, Sh. 2	3	8/03
T2.1-5, Sh. 1	2	5/01
T2.1-5, Sh. 2	0	5/97
T2.1-6	0	7/82
T2.1-7	0	7/82
T2-1-8	1	7/95
F2.1-1	0	7/82
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T2.2-4	0	7/82	2.3-13	0	7/82
T2.2-5	0	7/82	2.3-14	0	7/82
T2.2-6	0	7/82	2.3-15	0	7/82
F2.2-1	0	7/82	2.3-16	0	7/82
F2.2-2	0	7/82	2.3-17	0	7/82
F2.2-3	0	7/82	2.3-18	0	7/82
F2.2-4	0	7/82	2.3-19	0	7/82
F2.2-5	0	7/82	2.3-20	0	7/82
F2.2-6	0	7/82	2.3-21	0	7/82
F2.2-7	0	7/82	2.3-22	1	7/95
F2.2-8	0	7/82	2.3-23	1	7/95
F2.2-9	0	7/82	2.3-24	1	7/95
F2.2-10	0	7/82	2.3-25	2	4/09
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F2.2-12	0	7/82	F2.3-2	0	7/82
F2.2-13	0	7/82	F2.3-3	0	7/82
F2.2-14	0	7/82	2.4-1	3	4/15
F2.2-15	0	7/82	2.4-2	3	4/15
F2.2-16	0	7/82	2.4-3	3	4/15
F2.2-17	0	7/82	2.4-4	3	4/15
F2.2-18	0	7/82	2.4-5	3	4/15
F2.2-19	0	7/82	2.4-6	3	4/15
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F2.2-24	0	7/82			
F2.2-25	0	7/82	T2.4-1	0	7/82
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2.5-2	1	4/15	3.2-9	6	4/09
2.5-3	1	4/15	3.2-10	9	4/15
			3.2-11	7	5/03
2.6-1	2	4/15	3.2-12	7	5/03
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2.7-4	4	5/05	3.3-4	1	7/95
2.7-5	3	5/05	3.3-5	3	4/09
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T2.7-2	1	5/05	3.3-7	2	4/09
T2.7-3	1	5/05	3.3-8	1	7/83
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F3.3-15	0	7/82	F3.5-1	0	7/82
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F3.3-17	0	7/82	F3.5-3	0	7/82
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3.4-3	10	4/15	3.6-1	0	7/82
3.4-4	10	4/15	3.6-2	0	7/82
3.4-5	10	4/15	3.6-3	1	5/99
			3.6-4	1	5/99
			3.6-5	1	5/99
			3.6-6	0	7/82
			3.6-7	1	5/99
F3.4-1	2	5/01	3.6-8	1	5/97
F3.4-2	3	5/01	3.6-9	0	7/82
F3.4-3	1	7/88	3.6-10	1	5/01
F3.4-4	0	7/93	3.6-11	0	7/82
F3.4-5	1	5/97	3.6-12	1	5/99
F3.4-6	10	4/15	3.6-13	0	7/82
F3.4-7	0	5/01	3.6-14	1	5/01
3.5-1	0	7/82	3.6-15	2	5/01
3.5-2	3	5/01	3.6-16	1	5/01
3.5-3	1	5/01	F3.6-1	0	7/82
3.5-4	1	5/01	F3.6-2	0	7/82
3.5-5	1	5/03	F3.6-3	1	5/01
3.5-6	0	7/82	F3.6-4	0	7/82
3.5-7	3	5/01	F3.6-5	0	7/82
3.5-8	7	5/01	F3.6-6	0	7/82
3.5-9	6	5/01	F3.6-7	0	7/82
3.5-10	6	5/01	F3.6-8	0	7/82
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CHAPTER 1

INTRODUCTION AND SUMMARY

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INTRODUCTION AND SUMMARY

1.1 PROJECT IDENTIFICATION

The New York Power Authority (NYPA) (also referred to as "the Authority" or "the Power Authority") constructed a nuclear power plant for the purpose of supplying energy to high load factor industries, municipal and rural electric cooperatives, and to other members of the New York Power Pool. This project is authorized by Article V, Title 1 of the New York Public Authorities Law as amended by Chapter 294 of the Laws of New York of 1968.

By an amended application the Authority did seek a facility license to operate such a nuclear power plant under the Atomic Energy Act of 1954 as amended and the Regulations of the Atomic Energy Commission set forth in Title 10, Part 50 of the Code of Federal Regulations (10 CFR 50). The Final Safety Analysis Report was originally submitted in support of that application. The facility operating license was transferred to Entergy on November 21, 2000.

Entergy's plant is known as the James A. FitzPatrick (JAF) Nuclear Power Plant. The FitzPatrick Plant is located about 3,000 ft east of Constellation Energy's Nine Mile Point Nuclear Station Unit I situated on the southeast shore of Lake Ontario, Oswego County, New York, approximately seven miles northeast of the City of Oswego. The rated gross electric output of the plant is approximately 881 MWe when operating at approximately 2536 MWt. The FitzPatrick Plant commenced commercial operation on July 28, 1975.

1.1.1 Identification of Contractors During Design, Construction and Operation

The New York Power Authority assumed complete responsibility for the overall project. The Authority retained the Stone & Webster Engineering Corporation of Boston, Massachusetts to perform the architectural and engineering work and supervise construction. The S. M. Stoller Corporation of New York, N. Y. was retained to act as nuclear consultant.

The General Electric Company designed, fabricated and delivered the nuclear steam supply system, turbine-generator unit and auxiliaries, other major components and systems, and nuclear fuel.

The architectural and engineering work was performed by the Stone & Webster Engineering Corporation including the preparation of engineering specifications and design of systems not supplied by the General Electric Company. Stone & Webster assisted in the preparation of license documents, permits, and other engineering work associated with the plant. Stone & Webster was also retained to manage the plant construction, erection, and overall site coordination.

As nuclear consultant, the S. M. Stoller Corporation provided advice and technical assistance with respect to the nuclear core and the procurement, utilization and disposal of nuclear fuel.

The Power Authority had contracted with the Niagara Mohawk Power Corporation (NMPC) to operate the plant. NMPC reviewed all aspects of the plant design during the design phases as they related to safety and operability. In this manner, the project received the benefits of the expertise developed at the adjacent Nine Mile Point Nuclear Station owned and operated by NMPC. By amendment to its Facility Operating License the Authority took over the plant o operations on June 4, 1977. On November 21, 2000 the operating license was transferred to Entergy.

1.1.1.1 Licensee

Entergy

The headquarters for Entergy Nuclear is located in Jackson, MS. The company has expanded into the competitive power market in the Northeast by purchasing the Pilgrim Nuclear Power Station in Plymouth, Massachusetts in 1999 and the Indian Point 3 plant in Westchester County, New York, and the James A. FitzPatrick plant in Oswego County, New York, in 2000. Entergy is also managing decommissioning activities at Maine Yankee in Wiscassett, Maine, and Millstone Unit 1 in Waterford, Connecticut.

In addition to the services of technical consultants, Entergy maintains an engineering staff to supervise, operate, maintain and review the design and construction of all projects.

Entergy's Staff includes personnel with experience in the nuclear power field to ensure an overall review of work being carried on by contractors, suppliers, consultants and plant staff.

1.1.1.2 Architect-Engineer

Stone & Webster Engineering Corporation is an engineering-construction firm serving the electric utility industry in the design and construction of all types of power stations. Stone & Webster has provided engineering services in connection with generating capacity in excess of 21,000,000 kw, which represents approximately 20 percent of the investor-owned utility generating capacity of the United States.

Stone & Webster began its early association with the nuclear industry in 1942 with the Metallurgical Laboratory at the University of Chicago. The Company has performed varied design and construction services. Stone & Webster was retained for the Shippingport Atomic Power Station to provide engineering design for the nuclear portion of the plant, including containment, shielding, waste disposal system, and fuel handling system, and to provide inspection services during plant construction.

Subsequently, Stone & Webster has had major responsibility for engineering and construction on the Yankee Rowe Atomic Electric Plant; the Connecticut Yankee Atomic Power Plant; the Maine Yankee Atomic Power Plant; the Surry Power Station Unit 1 and 2; the Beaver Valley Power Station Units 1 and 2; the Shoreham Nuclear Power Station; the North Anna Power Station Units 1 and 2; Nine Mile Point Unit 2 and construction management for the Nine Mile Point Unit I.

1.1.1.3 Nuclear Steam Supply System Supplier

The General Electric Company has been engaged in the development, design, construction and operation of boiling water reactors since 1955. Operating boiling water reactors designed and supplied by General Electric include the Dresden Units 1, 2 and 3, Humboldt Bay, Big Rock Point, KRB (Germany), KAHL (Germany), JPDR (Japan), SENN (Italy), Oyster Creek Unit 1, Nine Mile Point Unit 1, Millstone Point Unit No. 1, Quad Cities Unit 1 and 2, Monticello, Vermont Yankee Unit 1, Peach Bottom Units 2 and 3, Edwin I. Hatch Nuclear Plant Unit No. 1, Cooper Station, Pilgrim Station and Browns Ferry Units 1, 2 and 3.

Also adding to General Electric's total nuclear capability is the experience gained from the design and construction of test and research reactors and the management and conduct of numerous nuclear research and development programs for the utility industry, the Nuclear Regulatory Commission, and overseas customers. Significant from the standpoint of expanding the limits of knowledge applicable to power reactors is the work that was conducted by General Electric with the 12,500 kwt Empire State Atomic Development Associates (ESADA) experimental superheat reactor and the 20,000 kwt Southwest Experimental Fast Oxide Reactor (SEFOR).

Thus, General Electric was found to be technically qualified to design, fabricate, deliver, and provide technical direction for the installation and start-up of the nuclear steam supply system and nuclear fuel.

1.1.1.4 Turbine-Generator Supplier

The General Electric Company designed, fabricated and delivered the turbine-generator and provided technical assistance for the installation and start up thereof. General Electric has a long history in the application of turbine-generators in nuclear power stations which goes back to inception of nuclear facilities for the production of electrical power. General Electric has furnished the turbine-generator unit for most of its BWR nuclear plants. General Electric has supplied many turbine- generator units for use in nuclear facilities similar to the JAFNPP facility and also many non-nuclear turbine units. Thus, General Electric was found to be technically qualified to design, fabricate and deliver the turbine-generator and to provide technical assistance for the installation and start-up of the turbine-generator.

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2.4 HYDROLOGY

2.4.1 Surface and Ground Water

Prior to plant construction, the study of the hydrology of the JAF site included a review of the available pertinent hydrologic literature, interviews with representatives of government agencies and individuals possessing knowledge of the local area, and a study of the hydrologic features of the site and surrounding area.

The plant buildings were constructed on a slight topographic high; however, a few swamps and bogs are present in other portions of the site. There are no naturally-occurring, perennial streams located on the site, but drainage ditches were constructed parallel to the western and eastern boundaries of the power block. Storm water runoff at the plant discharges to Lake Ontario via overland flow, intermittent streams, the drainage ditches, and/or the plant's storm drain system.

Prior to plant construction, regional groundwater in the vicinity of the plant likely flowed in a generally northerly direction towards Lake Ontario. Based on regional water well information provided by the New York State Department of Environmental Conservation (DEC), the natural overburden consisted of a thin layer of predominantly glacial till, which typically remained unsaturated. Therefore, groundwater generally flowed within the underlying Oswego sandstone-bedrock, primarily along bedrock fractures and joints. Hydraulic conductivity data collected during multiple hydrogeologic investigations indicate that the permeability of the bedrock is relatively low, which is consistent with rock core sample descriptions. Pumping tests conducted during the investigation of the Nine Mile Point Nuclear Station and experience during the construction of the James A. FitzPatrick Nuclear Power Plant are in agreement with this overall low permeability. The pre-construction groundwater at the site generally migrated along the regional flow paths towards Lake Ontario, at an average horizontal gradient of approximately 37 feet per mile. Vertically upward gradients would have been anticipated within the bedrock consistent with groundwater discharge into the lake.

During plant construction, bedrock was excavated to depths of up to 50 feet below the original bedrock surface, with the buildings in the power block founded directly on bedrock. As part of foundation construction, two drains were placed immediately adjacent to the perimeter of the power block buildings to control post-construction groundwater levels around the foundations. Structural fill was generally used to backfill the excavations between the outer foundation walls and the blasted bedrock face, thus providing connection between the drains and the bedrock fractures. The deeper of the two drains surrounds the Reactor Building, and the shallower drain encompasses the Turbine Building, Electric Bay, Pump House Screenwell Building, Water Treatment Building, Radioactive Waste Building, and the Heater Bay. These two drains are referred to as the Reactor Building Perimeter Drain (RBPD) and the Turbine Building Perimeter Drain (TBPD), respectively.

The post-construction groundwater elevations suggest that the majority of groundwater flowing through shallow bedrock in the power block area likely discharges into either the RBPD or the TBPD, rather than Lake Ontario. However, a groundwater divide located between Lake Ontario and the power block results in divergence of shallow groundwater flow in this localized area; while the flow to the south of the divide is directed southwards, towards the TBPD, the flow north of the divide is moving northwards into the lake. Within the deeper bedrock, the groundwater elevation in the central portion of the power block is below the invert elevation of the TBPD, suggesting enhanced communication with the deeper RBPD. However, northeast of the Reactor Building, the deeper bedrock groundwater is below even the invert of the RBPD, which indicates a groundwater discharge point with an elevation less than the RBPD.

The post-construction hydraulic gradients are steeper than the inferred pre-construction gradients due to the localized influence of the RBPD and TBPD. The shallow bedrock water table within the

central portion of the power block generally slopes toward the RBPD and TBPD at a local horizontal gradient of between approximately 50 feet and 300 feet per mile, with the steeper gradients located in the vicinity of the perimeter drains. The vertical gradients within the power block have been shifted from the original pre-construction upward orientation to the current post-construction downward direction due to the influence of the TBPD and RBPD.

2.4.2 Water Use

There are 17 public water supplies within a 50 mile area of the plant site. These 17 public water supplies obtain water from Lake Ontario. No groundwater supplies are located hydraulically down-gradient from the site. The two nearest public water supplies are located approximately eight and one-half miles from the site and both use surface water from Lake Ontario.

Private water supplies in the area utilize groundwater; however, according to the DEC's database, the nearest producing well is located approximately 3,500 feet to the east of the plant. All known water wells are located either hydraulically up-gradient or cross-gradient from the site and would not likely be affected by the localized changes in the groundwater flow directions at the site.

The possibility of adversely affecting the groundwater resources of existing wells in the area by the operation of a nuclear facility is remote.

2.4.3 Lake Water Levels

2.4.3.1 Reference Datum

The reference datum on which the design water level elevations are based is the U.S. Lake Survey 1935 Datum which is 1.23 ft higher than the International Great Lakes Datum of 1955.

2.4.3.2 Maximum Probable Flood Level at Screenwell

The probable maximum setup of Lake Ontario at the JAF site was determined to be 4.1 ft above mean lake water level based on a two dimensional time dependent mathematical model.

According to the storm study for the R. E. Ginna Plant (Docket No. 50-244- 5), the maximum probable rainfall on Lake Ontario as a whole is 0.35 ft.

The original design basis maximum flood level in the screenwell was, therefore, obtained by adding the maximum probable short term rise in lake level, 4.1 ft, and maximum probable rainfall on the lake, 0.35 ft, to the maximum controlled water level of el. 248.0 ft (Ref. 6), resulting in a screenwell flood level of el. 252.5 ft. A later evaluation (Ref. 40 and 41) considered a maximum lake level el. 250. This evaluation assessed the effects of a ten thousand year storm and resulted in a revised design basis screenwell flood level of el. 255 ft.

2.4.3.3 Computing Maximum and Minimum Water Level Variations

General

A brief discussion of the methods used to compute the wind-driven setup of Lake Ontario and the probable maximum and minimum water elevations which could occur at the JAF site is presented below. The effects of the maximum and minimum lake levels on the JAF site are also addressed.

A two-dimensional time dependent mathematical model was developed to simulate the water elevation variations on all portions of Lake Ontario due to a wind storm passing over the lake.

The results of the mathematical model using an actual wind storm as input agreed very favorably with the observed water elevations at several gaging stations located along the shores of Lake Ontario.

The model was then used to predict the behavior of the lake at JAF site due to the maximum probable wind storm which is postulated to occur over the lake area.

In addition, a one-dimensional steady-state model was used to predict the maximum probable setup at the JAF site using the maximum probable wind storm as input.

Comparisons were made to Lake Erie, Lake Michigan, and Lake Ontario based on the results of the one-dimensional model.

Two-dimensional Time Dependent Model

a. Description of the Model

During winter or during a large wind storm, Lake Ontario is in a barotropic or "homogeneous fluid" condition (Ref. 10). Therefore, the hydrodynamics of the lake can be represented by a two-dimensional barotropic mathematical model in a vertically integrated form. The complete momentum equations in two horizontal directions, including the pressure term vertically integrated, and the continuity equation, are solved for the water level fluctuation using an imposed time variable wind field as input on the surface of the lake. Effects of bottom friction, bottom topography and lateral boundary configuration are included in the model. The effect of the rotation of the earth is represented by a constant coriolis parameter.

The wind driven circulation patterns of the lake were first determined by the development of the vorticity equation from the governing equations (Refs. 11,12). The velocity field of the lake, the continuity equation, and the divergence of the vector form of the momentum equations were then used to obtain the water level fluctuation in the lake. A square grid of 5 km was used to form the basis for the circulation and setup model of Lake Ontario. Figure 2.4-1 shows the depth and rectangular step approximation of the outline of Lake Ontario. The important parameters which appear to have strong influence on the magnitude of the setup of the lake are wind stress, bottom stress, depth of water, and bottom configuration

b. Validation of the Model

The wind storm used to validate the model occurred on January 25, 1972. The storm generated a considerable surge in the eastern end of Lake Ontario. The storm was selected on the basis of easy access to the wind data and water level records.

The lowest pressure of the storm was located about 300 miles north of Lake Ontario at 7 a.m., January 25, 1972, with a minimum central pressure of 982 mb. The center of the low moved toward the northeast with a speed of approximately 40 miles per hour. During the period of high wind speed, the direction of wind over the lake was persistently toward east, which coincides with the long axis of Lake Ontario. The wind field over the lake was compiled from ten weather stations located along the shorelines of the lake in the United States and Canada. At the eastern end of the lake, wind speeds as high as 52 miles per hour for about three hours were recorded at Kingston, Ontario. A complete spacial time dependent wind field over the lake for the period of the storm was used to compute the wind stress at each grid point on the lake surface. A typical wind speed and direction at the JAF site, grid index of the mathematical model - (55, 5), is shown in Figure 2.4-2

The water level fluctuation over the entire extent of Lake Ontario was generated by the mathematical model using the prescribed wind field as input data. Figure 2.4-3 depicts the predicted and observed water levels at Toronto, Rochester, and Oswego, which represent the western, middle, and eastern sections of Lake Ontario, respectively. It can be seen that at all three locations the predicted and observed water levels compare reasonably well.

Since the wind was blowing toward the east, the water level at the western end of the lake was depressed while the eastern end of the lake was higher and the

mid-section of the lake experienced minimal fluctuations. Figure 2.4-4 shows the water level variation over the entire lake at the hour of maximum setup at the eastern end.

Prediction of the Maximum and Minimum Probable Setup - Two-dimensional Time Dependent Model

The maximum probable wind storm which will occur in the lake area was based on a modification of the storm of January 25, 1972. The duration and wind directions of the January 25, 1972 storm were retained; however, the wind speeds were increased by a statistical technique developed by Gumbel (Ref. 13) to reflect a storm with a recurrence interval of 10,000 years. The resulting storm, Figure 2.4-5, has a maximum sustained wind speed of 88 mph, lasting for 3 hours. The mathematical model was used to simulate the circulation and water level fluctuations of Lake Ontario under the influence of the probable maximum wind storm. Figure 2.4-6 is the result of the numerical simulation showing the water level variations on the entire lake at the hour of maximum setup at the eastern end. A vertical profile across the axis of the lake is also shown in Figure 2.4-6. Due to the combination of on-shore and along-shore currents resulting from the bottom and boundary configurations, the setup along the shore is relatively higher than that at some distance off-shore. At JAF site, the maximum setup was calculated to be 4.1 feet. With west wind the maximum water level of Lake Ontario occurs at the east shore and the minimum water level occurs at the west shore. The maximum instantaneous water variations occurred at both the west shore and the east shore with a magnitude of 4.6 ft.

The probable maximum decrease in lake level at JAF site when the wind blows from the opposite direction was assumed to be the same as the probable maximum setup as described above, namely 4.1 ft. Since the fetch and flow resistance in the lake would be the same for both east wind or west wind, the nodal point or the pivot point of the lake water surface would also remain essentially unchanged.

The hydrograph of water level versus time near JAF site during the storm period is shown in Figure 2.4-7. According to the prediction, the maximum setup of 4.1 ft above mean water level will last for about one hour.

Steady State - One-dimensional Model

The steady state one-dimensional model was used to calculate the maximum setup for comparison. The stress coefficient of the one-dimensional model was adjusted by using the observed wind and water level data for the January 25, 1972 storm. Water levels over Lake Ontario were then calculated using the maximum probable windstorm described in the above paragraph as input to the adjusted one-dimensional model. The water level profile along the long axis of the lake is shown in Figure 2.4-8. The maximum setup at JAF site was calculated to be 3.5 ft and that at the eastern end of the lake was calculated to be 4.5 ft. These values compare reasonably well with those calculated by the two-dimensional model.

Comparison of Setup in Lakes Ontario, Michigan, and Erie - One-dimensional Model

Since the one-dimensional model can estimate setup of Lake Ontario reasonably well as compared to the observed setup and because it is a simple model, it was used to calculate the setup values on Lake Michigan and Erie for the purpose of comparing the setup values of these three lakes.

Setup values for each lake are calculated using the one-dimensional model with the same wind speed and stress coefficient. These values are shown in Table 2.4-1. The greater setup (and setdown) values calculated for Lake Erie and Michigan, reflect the major influences of the shallower depth of Lake Erie and longer fetch of Lake Michigan, as compared to Lake Ontario.

Since the magnitude of wind surges depends primarily on the wind speed, the fetch length over which the wind blows, and the depth of the lake, it is possible to make an estimate of the magnitude

of wind setups on the Great Lakes for a given wind speed with the wind direction along the longest fetch. Such an estimate serves as an index for relative magnitude of wind driven surges in the lakes. Table 2.4-2 shows the mean depth, fetch, and the relative setup index of the Great Lakes. The relative setup index is the relative magnitudes of wind surge among the five Great Lakes. Assuming maximum wind setup on Lake Erie as 100 percent, the percentages in the index column show the relative maximum setups on the other lakes for any given wind speed. For example, if for a given wind speed the maximum setup on Lake Erie were 10.0 ft, for the same wind speed, the maximum setup on Lake Ontario would be 18 percent of 10.0 ft, or 1.8 ft. The values shown on

Table 2.4-2 agree well with the results of the one- dimensional model as indicated on Table 2.4-1.

2.4.3.4 Computing Maximum Wave Runup

The maximum probable wind storm was used in conjunction with deep water wave forecasting curves of the Bretschneider-revised Sverdrup-Munk method (Ref. 15) to determine the "significant" deep water wave height and period. The significant deep water wave produced by the maximum probable storm had a height of 35 ft (trough to crest) and a period of 13.5 sec.

The portion of the storm with average hourly winds greater than 50 mph was taken to be the critical portion of the storm for wave formation. The duration of winds 50 mph and greater is 23 hrs. Using the significant wave period of 13.5 sec, approximately 6,100 consecutive waves reached the shore during the critical portion of the storm. The probability that a single wave with the highest combination of height and period will occur during this period is 1/6100 or 0.16 per 1,000 consecutive waves. Using the data from Bretschneider (Ref. 15) as to the joint distribution of height and period per 1,000 consecutive waves, this probability corresponds to a deep water wave 50 ft in height with a period of 20 sec.

Standard orthogonal refraction techniques were used to determine the variation in wave height as the waves approached the shoreline. All waves were assumed to break when the ratio of wave height to water depth was 0.78. This criterion is derived from solitary wave theory and is consistent with data on the breaking of oscillatory waves (Ref. 16).

The magnitude of the wave runup was determined according to the composite slope method of Saville (Ref. 17). This technique, based on model test data, considers the following parameters:

a. The location and water depth at which the wave breaks
b. The wave period and breaking height
c. The lake bottom topography
d. The shore topography.

A maximum wave runup of 7.5 ft was estimated.

2.4.3.5 Monthly Mean High Water Level of Record

The all-time monthly mean high water level (el. 249.3) occurred in June, 1952 when Lake Ontario was unregulated and subject to changes in levels produced by natural inflows and outflows.

Regulation of Lake Ontario was implemented in April, 1960 at the direction of the International Joint Commission (IJC). One of the primary objectives of the plan of regulation is that the monthly mean level of Lake Ontario shall not exceed el. 248. The agreement states that lake level is regulated within a range of elevations from "244 feet (navigation season) to 248 feet as nearly as may be..."

The regulation of Lake Ontario is carried out under the general supervision of the International St. Lawrence River Board of Control, composed of ten members representing Canada and the United States. The Board has appointed regulation representatives who oversee the day-to-day operations conducted under the regulation plan. In addition, the Board formed a five member operations advisory group whose members include NYPA, Ontario Hydro, Hydro Quebec, the St. Lawrence Seaway Development Corporation, and the Canadian Coast Guard. This group, together with the

regulation representatives, meets at weekly intervals to consider Lake Ontario and St. Lawrence River conditions as they affect regulation. Regulation is physically implemented through the control of the flows through the St. Lawrence Project. To this end, Ontario Hydro and the Authority receive advice each Thursday as to the flow to be released during the following week which meets the IJC's objectives insofar as Lake Ontario regulation is concerned.

In view of the strict surveillance exercised by the IJC, through the St. Lawrence River Board of Control and the Board's operations advisory group, with respect to the levels of Lake Ontario, lake level will not be regulated in excess of el. 248 through operator error or unilateral action on the part of the Authority or Ontario Hydro. Furthermore, there is no likelihood that the International Joint Commission will allow the level of Lake Ontario to be regulated in excess of el. 248 due to the adverse effect of such action on development along the lake shorefront.

The plan of regulation is based upon historic norms for the period 1860 to 1954. Since regulation began, transient conditions in excess of historic norms have caused monthly mean lake level to exceed el. 248 on a few separate occasions, each of three to four months duration. In each case, levels were lower than would have been experienced under natural control. The highest monthly mean lake level experienced since regulation began was el. 249.1 in May 1973.

The original FSAR concluded that the all-time monthly mean high water level, or any other level above el. 248 would be experienced only if regulation were suspended and Lake Ontario were to revert to natural control; and that it was proper to assume that the maximum storm occurs when the lake stage is at el. 248, the maximum controlled still water level. Since it has been shown that input in excess of historic norms can occur and can cause lake level to exceed el. 248 on rare occasions, an additional evaluation was performed (Ref. 40). This evaluation concluded that no condition adverse to safety exists with a maximum lake level at or below el. 250.

2.4.3.6 Design Minimum Low Water

The design minimum low water level of Lake Ontario for the FitzPatrick Plant is el. 236.5. This elevation is based on superposition of the following effects:

1.	Minimum still water level of Lake Ontario	el. 240.6
2.	Instantaneous lowering of the still water level due to the maximum probable seiche on Lake Ontario	4.1 ft

It should be noted that the actual minimum still water levels of Lake Ontario, observed during a period of record beginning in 1860 and continuing through the present time, were:

1.	Lowest monthly mean water surface level recorded prior to construction of the St. Lawrence Power Project (November, 1934)	el. 242.7
2.	Lowest mean water surface level for a quarter-month recorded prior to construction of the St. Lawrence Power Project (third quarter of December, 1934)	el. 242.6
3.	Lowest monthly mean water surface level recorded subsequent to the commencement of regulation of Lake Ontario by the St. Lawrence Power Project (January, 1965)	el. 243.0

The Effect of Failure of the St. Lawrence Power Project on Low Lake Levels

The St. Lawrence Power Project constructed jointly by the Authority and Ontario Hydro consists of two dams and a hydroelectric power plant in the St. Lawrence River. Iroquois Dam is a gated gravity-type structure located 78 miles below the outlet of the lake. Long Sault Dam, a second gated

gravity type structure, is located 102 miles below the outlet of the lake and serves as the spillway for the power dam. The central element of the St. Lawrence Power Project is the Robert Moses-Robert H. Saunders Power Dam, a massive gravity-type structure located 106 miles below the outlet of the lake. Iroquois Dam and the Moses-Saunders Power Dam ordinarily pass the full flow of the St. Lawrence River, less relatively small diversions, including the quantity of water needed to operate the locks of the St. Lawrence Seaway which, in the aggregate, amount to much less than 1 percent of the river's total flow. Long Sault Dam is operated infrequently and customarily discharges no water at all.

In the course of normal operation, Lake Ontario is regulated at the Power Dam pursuant to a plan of regulation approved by the IJC. Actual operation has demonstrated that the lake also can be regulated by manipulating the gates at Iroquois Dam. The Power Project, therefore, provides a redundant safeguard against any loss of capability to regulate Lake Ontario.

The failure of any part of the St. Lawrence Power Project is beyond reasonable expectations. The three gravity dams are massive structures which were conservatively designed to withstand all static and dynamic forces by wide margins. For example, the design criteria applicable to these dams provided factors of safety of at least 2.0 against overturning and at least 3.0 against sliding. Gravity structures were designed to resist seismic forces equivalent to 0.05 g in both the horizontal and vertical directions, while the seismic design of slender structures was based on dynamic analysis. All phases of construction which had any bearing on the ultimate safety of any structure were continuously inspected, during performance of the work, by qualified engineers and subjected to rigorous quality control requirements.

Since completion of the project, all structures have been under continuous surveillance by the Authority and Ontario Hydro. Both Ontario Hydro and the Authority conduct rigorous programs of inspection and preventive maintenance with respect to all elements of the project under their jurisdiction. Once every five years, or more often if necessary, a complete safety inspection of the project is performed by independent consultants who report to the Federal Power Commission with respect to the condition of dams and other structures. The integrity of the dams which comprise the St. Lawrence Power Project and regulate the levels of Lake Ontario is, therefore, ensured by the combination of conservative design, rigorous quality control during construction, and continuous surveillance following completion of the project.

In November, 1968, the St. Lawrence Study Office at the Canadian Department of Energy, Mines and Resources analyzed possible upstream and downstream effects resulting from failure of the St. Lawrence Power Project structures. Under the adverse assumptions of this study, which postulated the sudden destruction of the above mentioned dams and the lowest supply sequence on record, it was determined that the lake level would decline gradually and, approximately one year following the assumed failure, be no more than 2.1 ft below the lowest level attained during regulation, i.e., the lake level would decline from el. 242.7 to el. 240.6. The study concluded that once the lake level had declined to about el. 240.6, natural controls, such as existed before the project, would be re-established and the lake levels would rise and fall thereafter in accordance with natural supplies delivered to Lake Ontario from the Great Lakes watershed.

Lake Ontario is the source of the St. Lawrence River and the last in the chain of five Great Lakes. These lakes drain an area of approximately 300,000 sq miles in the United States and Canada. Taken together, they makeup the largest body of fresh water in the world. Each lake acts as an enormous natural regulating reservoir which smooths out variations in inflow and tends to equalize outflows from season to season.

Lake Ontario obtains its principal supply of water from the Niagara River which drains the four upper lakes (Erie, Huron, Michigan and Superior) and discharges 200,000 cu ft per sec on an annual average basis. Other inflows are received from precipitation and springs within the Lake Ontario watershed.

The outflow from Lake Ontario, which corresponds to the flow in the St. Lawrence River, is equal to the quantity of water supplied from the Niagara River and all other sources, less the change in the quantity of water stored in the lake. Although storage in Lake Ontario is now governed by artificial controls, the lake was self-regulating in its natural state.

Flow in the St. Lawrence River is characterized by its extreme regularity. The maximum flow (350,000 cu ft per sec) is about twice the minimum flow (170,000 cu ft per sec). This condition existed before construction of the St. Lawrence Power Project, and would continue today if the project did not exist. In the improbable event of the simultaneous failure of the Iroquois Dam and the Moses-Saunders Power Dam or Long Sault Dam, the actual level to which Lake Ontario could fall would be governed by supplies of water to the lake during the period following such failure and the natural resistance of the lakes to sudden changes in levels and flows. These effects would guarantee that the actual minimum still water level of the lake would be well above the design minimum water level elevation of the FitzPatrick Plant during any period necessary to re-establish control of the lake.

It is concluded that the simultaneous failure of the dams which regulate the levels of Lake Ontario is beyond any reasonable probability of occurrence. In the event of any such catastrophe, the levels of Lake Ontario would decline gradually. The full effect should be experienced about a year following the failure, by which time the still water level might fall to a minimum at el. 240.6. Superposition of the maximum probable seiche would produce a further lowering of 4.1 ft. to el. 236.5 over a short term.

2.4.3.7 Implication of the Maximum and Minimum Lake Levels on Power Station

The cross-sectional profiles through the intake and discharge screenhouses and tunnels are shown in Figure 2.4-9. The average ground elevation outside the screenhouse is 272.0 ft. Concerning the flooding of the exterior access of the power plant, the maximum wave runup of 7.5 ft, the maximum wind setup of 4.1 ft, and the maximum rainfall of 0.35 ft were added to the maximum controlled still water level of 248 ft resulting in a maximum probable flood level of el. 260 at the JAF site. The grade elevation of the power plant, 272.0 ft, is well above the probable coincident maximum flood level of 260 ft at the power plant site with a freeboard of 12 ft. Consideration of a maximum lake level of el. 250 would still result in approximately 10 ft. of freeboard.

The original design basis maximum flood level in the screenhouse was determined as el. 252.5. Since the intake screenhouse top deck ceiling is at el. 253.0, which is 0.5 ft above maximum probable flood level in the screenhouse, no damage from flooding would be expected. The revised design basis flood level of el. 255 coincides with the floor level in the screenwell. Any uplift forces on the floor slab resulting from this higher floor level are more than offset by the weight of the slab (Ref. 40). Again, no damage from flooding is expected. All seismic Class I equipment in the screenwell area is mounted at or above el. 255.

The effect of waves in the lake on the performance of the circulating water system is negligible and no loss of cooling water resulting from surging in the intake conduit could occur.

A mathematical model of the circulating water system was developed. The model uses the equation of continuity and momentum and solves for the flow system and the pumps characteristics simultaneously.

The maximum wave height that can exist without breaking at the location of the intake with a maximum probable lake elevation of el. 252.5 is 22 ft. Different wave periods of 8 sec, 13.9 sec, and 27.8 sec, representing a range of possible occurrences, were considered. The variations in the circulating water system due to the action of the above mentioned waves under the evaluated conditions is summarized below:

Wave Hgt ft	Wave Period sec	Pump Flow Fluctuation cfs	Intake Tunnel Flow Fluctuation cfs	Screenwell Water Level Fluctuation inch
22	8	-1.0	±85.0	+0.1,-0.4
22	13.9	-2.0	±148.0	+0.5,-1.2
22	27.8	-6.0	±300.0	+2.3,-5.4

Figure 2.4-10 shows the effects of a 22 ft wave having a period of 13.9 sec., which represents the most probable occurrence of a 22 ft wave over the lake structure.

It can be seen from Figure 2.4-10 that although the circulating water system is subjected to a continuous train of 22 ft high waves over the intake structure, the screenwell water level experiences only about two inches of fluctuation and the variation in the circulating water pump flow is negligible. Because of the energy damping effects of the long intake and discharge tunnels, the resonance period of the circulating water system is much longer than the periods of waves acting over the intake and discharge structures.

2.5 GEOLOGY

The plant lies within the Erie-Ontario Lowland physiographic province. This province is bounded on the south by the Appalachian Uplands, on the east by the Tug Hill Upland and Adirondack Highlands, and on the north by the Canadian Shield. Strata of the Erie-Ontario Lowland are Paleozoic sediments which are essentially undeformed. Regional dip is to the south or southwest at an average slope of less than 2 degrees. No folds or faults of any consequence are known in the general site area. The area surrounding the plant is generally poorly drained because of its very low relief resulting in the presence of a number of small swampy areas in shallow, localized depressions.

Prior to plant construction, the site was generally level with very minor irregularities in surface. The surface overburden consisted of a very shallow thickness of ablation till underlain by a shallow thickness of basal till, directly overlaying Oswego sandstone. The tills consisted of mixtures of silts, sands, gravels, cobbles and some clay material. Total thickness of the till layer varied from about 0 to as much as 10 or 12 ft.

During construction of the plant, the overburden materials were removed in the power block area and bedrock was excavated to a depth of up to 50 feet below the original bedrock surface. All structures of the plant were founded directly on the bedrock. Structural backfill was placed between the outer foundation walls and the face of the rock excavations. The blast rock removed during the bedrock excavation was used across the plant as backfill to bring the grade to an elevation of approximately 272 feet.

The Oswego sandstone is a hard, thin to medium bedded fine grained sandstone with laminations and lenticular beds of dark grey shale. The shale content increases with depth, and at approximately 130 feet below surface, the Oswego sandstones grade into the underlying Lorraine group, which is predominantly shale with some sandstone members. The sandstones are a hard, competent material, well suited to the foundations of the plant. The Oswego sandstone is moderately jointed, the joints being the most common in the upper 5 to 10 feet. Below that depth, the joints are much more widely spaced and are tight. Master joint sets strike north 70 to 80 degrees east, with a secondary set striking north 40 to 50 degrees east. Joints basically are moderately to widely spaced. The shale members are well cemented, durable shales which show no slaking when exposed to the weather over a period of several years. They also are sound, competent foundation materials for the plant.

The sandstone in this area is almost flat lying, showing a general regional dip to the south to southwest of about 1 1/2 degrees. It shows no evidence of disturbance or orogenic activity. It is of mid-Paleozoic Age. Regionally, the area is known to be very quiet seismically. The nearest fault known prior to the start of the work on this project was approximately 40 miles southeast near Syracuse where it was exposed in a quarry. This is a minor, local fault striking north 75 degrees west. The nearest significant fault is the Clarendon-Linden Fault, which is located 90 miles west and which has a north-south trend tangent to the site. Displacement on this fault is approximately 100 feet.

During the course of the excavation of the plant, two minor geologic features were disclosed. The first is a compression buckle or teepee fold which was found crossing the axis of the turbine-generator. This fold has a strike of north 78 degrees west. The axis of the fold dips to the north at about 70 degrees. A detailed investigation was made of it and, the findings may be summarized as follows:

1. The feature is not a fault. Rather, it is a near surface compression failure or buckle of quite limited extent.

2. It is a single, small feature which does not derive from nor is it related to regional tectonics, nor is it of orogenic origin.
3. It is old and inactive. In origin, it predates the last advance of continental ice, Wisconsin glaciation (50,000 yr), and there has been no motion on it since the retreat of the ice approximately 10,000 years ago.
4. The forces which caused it no longer exist. Stress measurements made showed that no measurable stresses exist in the rock adjacent to the fold. Thus, residual stresses of a character which would exist if the rock were still under strain or compression loadings are absent or negligible. There is no probability of renewed activity.
5. This feature is not affected by seismic activity. Accordingly, it has no effect on project safety, on seismic design requirements or on structural design.

The second geologic feature which was disclosed was a minor normal (tension) fault which was found crossing the intake and discharge tunnels at a point approximately 1,000 feet north of the center line of the reactor. This minor fault strikes north 78 degrees west and dips approximately 60 to 64 degrees to the south. It is a very small fault. Total displacement is approximately 17 in. ±1 in. The gouge zone associated with it varies from approximately one half inches in sandstone members to possibly 3 or 4 inches in shale members. In addition, there is some subsidiary jointing of the rock adjacent to it which extends through a width of a foot or two on either side. The fault was projected up to the surface and then along a strike to the southeast to intercept the shoreline approximately at the barge slip some 1,500 ft east of the plant. A detailed examination was made where it crosses the barge slip and in a test trench at a point approximately 300 ft further east. At both locations, the fault could not be definitely established. There is no evidence of offsetting of any of the beds. There were, however, at the theoretical location of the fault, or very close to it:, several minor joints which trended in a north 75 to 78 degrees west direction. It is noted that this joint direction is anomalous to the normal jointing of the area. This indicates that in the short distance of approximately 1,500 feet, the fault motion has died out and resolved itself simply into a set of joints. The joints show no displacement where the bedding is exposed in the cut for the barge slip. A detailed examination of the fault was made by Dr. Don U. Deere of the University of Illinois, Urbana, Illinois. His report is included in Section 16.1.1. At Dr. Deere's request, an X-ray diffraction analysis was made of material obtained from the shale adjoining the fault and of the fault gouge itself. These showed essentially identical clay materials present consisting primarily of chlorites and illites, and some alpha quartz. The absence of montmorillonite or halloysite strongly indicates there has been no hydrothermal alteration as would be expected if the fault were associated with deep seated tectonic activity. There is some secondary calcite deposited in joints immediately along the fault, and probably associated with it, which indicates the fault is relatively old.

It is concluded that the fault is a minor local feature that has most probably developed from differential loading by overlying material at some time in the geologic history of the area, and that it is not associated with orogenic movements nor regional tectonics. The conditions which created the fault no longer exist and, therefore, renewed motion on this small fault is not a matter of concern. It does not affect the safety or design of the plant. Corrective measures were taken by drainage and guniting of the surface of the fault zone in each tunnel after cleaning it out a shallow distance, in accordance with good engineering practice.

Some bedrocks which were concealed before, were subsequently exposed along the shoreline, east of the barge slip, and a small normal fault was encountered in these shoreline out crops in 1977. The fault was striking about N 73 W and dipping 68 SW and occurred about 70 ft north of

the surface projection of the tunnel fault described above. Because of the close proximity to the projected trace of the tunnel fault and of similarity in strike, dip and the amount of apparent offset (15 in ±) it was believed that the barge slip structure might be a continuation of the tunnel fault.

A detailed investigation was performed by excavating and mapping two trenches, excavating two rock pits perpendicular to fault traces in the bottom of the trenches and mapping the shoreline exposure near the barge slip. The investigation was performed by the Stone & Webster Engineering Corp., Boston, Massachusetts and is included in Section 16.1.1. The investigation revealed that:

1. Individual faults within the zone are quite short and not related to regional tectonics. No buckling or reverse shear was noted in the trenching investigation or in the outcrop at the barge slip.
2. The last movement along the normal faults occurred before the last advance of the Wisconsin ice sheet or before about 22,000 B.P.
3. Fluid inclusion analysis reveals that the normal faulting is Early to Middle Paleozoic in age and is due to minor adjustments within the sedimentary basin.
4. The faults are minor geologic features - old and inactive and may not be called capable fault as defined by Appendix A, (10 CFR 100.)
5. These faults do not constitute any geologic, seismic or engineering safety hazard to the plant.

In summary, the plant is founded upon strong, competent bedrock of mid- Paleozoic Age, the Oswego formation. The rock is well suited to the foundations of a nuclear power plant. The minor geologic features which were found during construction and also after construction have no effect on the design or safety of the plant.

2.6 ENGINEERING SEISMOLOGY

The engineering seismology phase of the environmental study included a literature research to compile a record of the seismicity of the area, evaluation of the geologic structure and tectonic history of the region, and field geophysical measurements to evaluate the in-situ physical properties of the foundation materials.

The JAF site is located in a region which can be considered seismically inactive. Earthquake activity within 50 miles of the site has been infrequent and minor and no earthquake damage has resulted. Most of the reported earthquakes in the region are associated with well defined structural zones. The St. Lawrence River Valley, located well to the northeast of the site beyond the Thousand Islands, is extensively faulted and has experienced considerable earthquake activity. The larger St. Lawrence Valley shocks were felt throughout New York State, including the site area. There has been some earthquake activity near Attica, New York, approximately 110 miles southwest of the site. The earthquake of 1929 (Intensity low VIII -Modified Mercalli Scale) damaged some structures at the epicenter, near Attica, and may have been perceptible in the vicinity of the site. Some minor earthquake activity, which has not been related to known geologic structures, has occurred in the vicinity of Buffalo, New York, to the west of the site. It is likely that these earth-quakes result from crustal readjustment in areas of local stress concentrations. The closest earthquake (1853 Intensity VI) which caused any structural damage at its epicenter occurred near Lowville, New York, approximately 50 miles east-northeast of the site. Several minor shocks (Intensity generally less than III) have been reported within about 30 miles of the site. These shocks were relatively insignificant and it is not probable that any were felt in the site area.

The regional study of seismicity and tectonics indicates that significant earthquake ground motion is not expected at the site during the design life of the plant. This historical record indicated that the Seismic Class I structures of the plant could be designed for an Operating Basis Earthquake of .05g horizontal ground acceleration, and a Design Basis Earthquake of .10g horizontal ground acceleration as all structures are founded on or within competent bedrock.

The acceleration given above for the Operating Basis Earthquake is probably equal to or greater than ground accelerations which might have been experienced at the site during any historical event and therefore is appropriately conservative.

However, to be conservative, the Operating Basis Earthquake was assumed to have a horizontal ground acceleration of .08g, and the Design Basis Earthquake is assumed to have a horizontal ground acceleration of .15g. The vertical acceleration is taken as two-thirds the horizontal acceleration for each earthquake.

Structural design is based upon modal response techniques, outlined in Section 12.5, using smoothed response spectra normalized to "zero period" ground accelerations of 0.08 g and 0.15 g for the OBE and DBE, respectively, as shown in Fig. 2.6-1 and 2.6-2. The use of modal response based on smoothed response spectra is considered a conservative and appropriate technique for dynamic analysis of structures in that it gives consistent and uniform results over a wide range of frequencies.

Three field seismic recorders and three field triaxial (X,Y,Z) sensors are installed. A data acquisition device and computer are located in the Relay Room for processing seismic event data. Three recorder and sensor packages are located near the top of the Reactor Building structure, near the reactor within the containment, and in a remote area representative of free field ground acceleration at the plant site. The sensors are equipped with seismic triggers set to initiate recording at an acceleration equal to or exceeding 0.01 g. The Control Room Operator is

notified of the seismic event by the plant EPIC.

The seismic monitoring system has the ability to calculate the cumulative absolute velocity (CAV) provided that the free field sensor is functional. The determination if the OBE has been exceeded can be based on the threshold response spectrum ordinate check and a CAV check. If both the response spectrum check and CAV check are exceeded, the OBE is exceeded. If either check does not exceed the criterion, the earthquake motion did not exceed the OBE. If only one check can be performed, the other check is assumed to be exceeded. The CAV limit is 0.16 g-seconds.

If accelerations exceeding the OBE were recorded on the ground acceleration sensor, an analysis would be made to evaluate base shears and maximum stresses at critical points as compared to the design. These studies would be used to evaluate possible areas of damage for critical examination.

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3.2 FUEL MECHANICAL DESIGN

3.2.1 Power Generation Objectives

The objective of the nuclear fuel is to provide a high integrity assembly of fissionable material which can be arranged in a critical array. The assembly must be capable of efficiently transferring the generated fission heat to the circulating coolant water while maintaining structural integrity and containing the fission products.

3.2.2 Power Generation Design Basis

The nuclear fuel is designed to ensure (in conjunction with the core nuclear characteristics, the core thermal and hydraulic characteristics, the plant equipment characteristics, and the capability of the nuclear instrumentation and Reactor Protection System) that the fuel centerline temperature limit and fuel cladding damage limit are not exceeded during either planned operation or abnormal operational transients caused by any single equipment malfunction or single operator error.

3.2.3 Safety Design Basis

In meeting the power generation objectives, the nuclear fuel is utilized as the initial barrier to the release of fission products. The fission product retention capability of the nuclear fuel is substantial during normal modes of reactor operation so that significant amounts of radioactivity are not released from the reactor fuel barrier.

3.2.4 Fuel Description

A core cell is defined as a control rod and four fuel assemblies which immediately surround it. Each core cell is associated with a four-lobed fuel support piece. Around the outer edge of the core, certain fuel assemblies are not immediately adjacent to a control rod and are supported by individual peripheral fuel support pieces.

A fuel assembly consists of a fuel bundle and the channel which surrounds it (Fig. 3.2-5 and 3.2-6). The fuel assemblies are arranged in the reactor core to approximate a right circular cylinder inside the core shroud. Each fuel assembly is supported vertically by a fuel support piece and laterally by the top guide (Section 3.3). With the four fuel assemblies lowered into the core cell and, seated in place, channel fasteners (spring-clips), which are mounted at the tops of the channels, attach the channels to the fuel bundle. The fasteners force the channels into the corners of the cell such that the sides of the channel may contact the grid beams for stability.

See Table 3.2-1 for design information of fuel in current cycle.

The fuel assemblies presently in use are GNF2 Barrier.

Each fuel assembly contains fuel rods and water rods.

Each fuel rod consists of fuel pellets stacked within Zircaloy-2 cladding, which was evacuated, backfilled with helium and sealed with Zircaloy end plugs welded in each end. The helium backfill pressure is specific to the fuel design; 10 atmospheres for current designs.

The fuel pellets are manufactured by compacting and sintering uranium dioxide powder into right cylindrical pellets with flat ends and chamfered edges. The average pellet immersion density is 97.0% of the theoretical density of UO2. Ceramic uranium dioxide is chemically inert to the cladding at operating temperatures and is resistant to attack by water. Several U-235 enrichments are used in the fuel assemblies to reduce the local peak-to-average fuel rod power ratios. Selected fuel rods within each reload bundle also incorporate small amounts of gadolinium as burnable poison which is uniformly distributed in the UO2 pellet and is in the form of a solid solution. The pellets with gadolinium are described in Section 3.4.5.1.

All fuel bundles in the reactor have natural uranium blankets on the top and bottom ends to increase the nuclear efficiency of their assemblies. The bottom six inches of each rod contains natural, unenriched pellets; the top blanket varies in length from 6-12 inches.

The fuel rod cladding thickness is adequate to be essentially freestanding. Adequate free volume is provided within each fuel rod in the form of a pellet-to-cladding gap and a plenum region at the top of the fuel rod to accommodate thermal and irradiation expansion of the UO2 and the internal pressures resulting from the helium gas, impurities, and gaseous fission products liberated over the design life of the fuel.

A plenum spring, or retainer, is provided in the plenum space to minimize movement of the fuel column inside the fuel rod during fuel shipping and handling. Adequate protection against primary hydride failure is assured by hydrogen control during fabrication. Requirements for hydrogen content are specified in Reference 1.

Fuel designs use barrier cladding on all fuel rods. Barrier cladding is a duplex tube comprised of an outer layer of Zircaloy and an inner layer of zirconium which is metallurgically bonded to the Zircaloy. The use of barrier cladding provides greater protection against cladding failure due to pellet-clad interaction during normal operation and operational transients.

Three types of fuel rods are used in a fuel bundle: tie rods, standard rods, and part length rods (PLR). The eight tie rods in each bundle have lower end plugs which thread into the lower tie plate casting and threaded upper end plugs which extend through the upper tie plate casting. A stainless steel hexagonal nut and locking tab are installed on the upper end plug to hold the fuel bundle together. These tie rods support the weight of the bundle only during fuel handling operations when the assembly hangs by the handle. During operation, the fuel assembly is supported by the lower tie plate.

The end plugs of the standard rods have shanks which fit into bosses in the tie plates. An Inconel-X expansion spring is located over the upper end plug shank of each full length rod in the assembly to keep the rods seated in the lower tie plate while allowing independent axial expansion by sliding within the holes of the upper tie plate. Part-length fuel rods are threaded into the lower tie plate. GNF2 uses two PLR lengths, one approximately 1/3 and the other approximately 2/3 the length of a normal rod. The upper end of the PLR's is fixed laterally by the spacer only.

Fuel bundles contain 92 fuel rods and two water rods. The water rods for all fuel types are hollow Zircaloy tubes with several holes located around the circumference near each end, to allow coolant to flow into the water rod and then to flow upward.

One water rod in each bundle positions fuel spacers axially. This spacer-positioning water rod is equipped with a square bottom end plug and with tabs which are welded to the exterior. The water rods in GNF2 fuel are threaded into the lower tie plate, and prevented from rotating by a keyed upper end plug fitting into a matching hole in the upper tie plate. The rod and spacers are assembled by sliding the rod through the appropriate spacer cell with the welded tabs oriented in the direction of the corner of the spacer cell. It is then rotated so that the tabs are above and below the spacer structure. Once in position the water rod is prevented from rotating by the engagement of its square lower end plug with the lower tie plate hole. The spacer-positioning water rod on all fuel types are designed to avoid differential growth problems due to higher expected discharge exposure. The length of water rod lower end plug is increased to allow for a greater upward displacement of the water rod before disengagement from the lower tie plate can occur.

The rods of all bundle types are spaced and supported in a square (10 x 10) array by the upper and lower type 304 stainless steel tie plates and eight spacers. The lower tie plate has a nose piece which has the function of vertically supporting the fuel assembly in the reactor and providing a flow path entry point for coolant. The upper tie plate has a handle for transferring the fuel bundle from one location to another location. The individual bundle identifying serial number is engraved on the top of the handle and a boss projects from one side of the handle to aid in ensuring proper fuel assembly orientation.

The primary function of the fuel spacer is to provide lateral support and spacing of the fuel rods, with consideration of thermal-hydraulic performance, fretting wear, strength, neutron economy, and productivity. The spacer design is unique to the fuel design, although there are similarities in materials and construction among the designs. The GNF2 spacer is all Inconel made up of individual cells for each fuel rod welded in a square array.

The upper and lower tie plates serve the functions of supporting the weight of the fuel and positioning the rod ends during all phases of operation and handling. The fuel bundles also have two alternate path bypass flow holes located in the lower tie plate. These holes are drilled to augment flow in the bypass region.

The BWR Zircaloy fuel channel performs the following functions:

a. Forms the fuel bundle flow path outer periphery for bundle coolant flow

b. Provides surfaces for control rod guidance in the reactor core

c. Provides structural stiffness to the fuel bundle during lateral readings applied from fuel rods through the fuel spacers

d. Minimizes coolant bypass flow at the channel-lower tie plate interface

e. Transmits fuel assembly seismic loadings to the top guide and fuel support of the core internal structures

f. Provides a heat sink during Loss-of-Coolant Accidents (LOCA)

g. Provides a stagnation envelope for in-core fuel sipping.

The channel is open at the bottom and makes a sliding seal fit on the lower tie plate surface. The upper ends of the fuel assemblies in a four-bundle cell are positioned in the corners of the cell against the top guide beams by the channel fastener springs. At the top of the channel, two diagonally opposite corners have welded tabs, one of which supports the weight of the channel from a threaded raised post on the upper tie plate. One of these raised posts has a threaded hole. The channel is attached using the threaded channel fastener assembly, which also includes the fuel assembly positioning spring. Channel-to-channel spacing is provided for by means of spacer buttons located on the upper portion of the channel adjacent to the control rod passage area.

"Interactive" channels with thick corners and thin walls are used in place of the standard 80 mil channel on all fuel assemblies. The channel contains pairs of vertical grooves machined into the outside of each wall over the bottom two-thirds of the channel. The average wall thickness is 70 mil, but it retains the structural strength of the 80 mil design.

The GNF2 channel is slightly longer than in GE14, and the lower tie plate flow holes in GNF2 fuel are smaller to balance the increased bypass flow from the channel to tie plate path which is a function of both elastic and inelastic (creep) channel wall deflection. GNF2 fuel channel does not use finger springs.

The fresh fuel assemblies loaded in Cycles 13 - 15 are designated by GE as GE12, with a 10x10 fuel rod array. These assemblies have a unique mechanical design that differs from other assembly types used at FitzPatrick principally by the 10x10 fuel rod array. The following is a list of the significant design changes between the GE12 and those previously used in the reactor.

1. 10x10 fuel rod lattice replaces 8x8 or 9x9 in previous fuel assemblies. The number of fuel rods is increased to 14 part length rods and 78 full length rods. The fuel rod diameter is decreased to 0.404".

2. Eight fuel rod spacers are used; one more than in any of the other GE fuel designs. The smaller diameter of GE12 fuel rods makes them less stiff and require more lateral support. All previous fuel designs used spacers positioned at the same axial heights.

3. The GE12 design uses eight spacers, and the pitch of the spacers in the lower two-thirds of the assembly is different than all other designs. The lower part of the bundle is most sensitive to flow induced vibration; thus the need for additional lateral support in that area. See References 24 and 25 for lead test assembly performance.

4. The spacer design has been modified; all previous spacer designs incorporated a Zircaloy structure with Inconel springs. The GE12 spacer is all Inconel. The spacer design incorporated into Reload 12 has been tested for mechanical performance and corrosion behavior. Fuel bundles using this spacer design have operated as LTAs in several reactors, see References 24 and 25 for a summary.

5. Fuel upper end shanks are not sized differently. Earlier fuel designs used upper end plug diameter variation to prevent misloading of fuel rods into the assembly during fabrication. New fuel bundle assembly equipment that uses fuel rod serial numbers, from bar code markings on the rods, or serial numbers stamped on the end plugs, are now used to perform the same function.

The fresh fuel assemblies, initially loaded in Cycles 16 - 18, are designated by GE as GE14. There are three significant differences between the GE12 and GE14 designs. First, the Partial Length Fuel Rods (PLR) are shorter in the GE14 design than in the GE12 design. Second, Zircaloy ferrule spacers are used in GE14 assemblies, while GE12 assemblies use all Inconel spacers. Finally, GE12 fuel channels have flow trippers and GE14 fuel channel design does not include flow trippers.

The flow holes in the lower tie plate (LTP) that allow the passage to water into the fuel bundle are smaller for GE12 and GE14 compared with previously used designs. The GE12 fuel initially loaded in Cycles 14 and 15, and GE14 fuel have a debris filter lower tieplate (DFLTP). Flow holes in both GE12 and GE14 with the DFLTP are 0.112 inch in diameter (non-DFLTP flow holes are 0.265 in), see Reference 32 for a description of the DFLTP. This feature will provide increased protection against introduction of debris into the bundle, but not impose an added risk due to flow blockage. The LTP holes are larger than the holes in the torus suction strainers (<0.1 in.), therefore, debris small enough to pass through the torus strainers is not capable of blocking fuel assembly flow.

The fuel assemblies loaded beginning in Cycle 19, are designated GNF2. Only GNF2 assembly types are used at FitzPatrick starting with Cycle 21 core. This design uses a different part length rod configuration compared with earlier designs, and the part length rods are of different heights depending on the position in the bundle lattice. GNF2 uses Inconel spacers. GNF2 uses a modified debris filter (Defender) that improves resistance against debris introduction. The LTP holes are larger than the holes in the torus strainers as noted above for the DFLTP. Design details are given in Reference 44.

3.2.5 Safety Features

Fuel damage is defined as perforation of the fuel rod cladding which would permit the release of fission products to the reactor coolant. The mechanisms which could cause fuel damage in reactor operational transients are: (a) severe overheating of the fuel rod cladding caused by inadequate cooling, and (b) rupture of the fuel rod cladding due to strain caused by relative expansion of the UO2 pellet. Cladding failure due to overpressure from vaporization of UO2 following a rapid reactivity transient is not considered to be an operational transient and is discussed in Section 3.6. Margin against the mechanism of severe overheating is discussed in greater detail in Section 3.7.

Fuel rod safety analysis requirements are in Reference 1. Application of those requirements for individual fuel designs are provided in Reference 44 (GNF2).

The fuel assembly and its components are designed to withstand:

a. The predicted thermal, pressure, and mechanical interaction loadings occurring during startup testing, normal operation, and abnormal operational transients, without impairment of operational capability

b. Loading predicted to occur during handling without impairment of operational capability

c. In core loading predicted to occur from an Operating Basis Earthquake (OBE), occurring during normal operating conditions, without impairment of operational capability.

The strength theory, terminology, and stress categories presented in the ASME Boiler and Pressure Vessel Code, Section III, are used as a guide for determining these elastic stress limits. There are different stress intensity limits for normal and abnormal conditions. Each stress intensity limit is based on both yield strength and ultimate tensile strength, and the lower value is always applied.

The fuel assembly and its component parts are analyzed to ensure mechanical integrity after exposure to normal and transient operational loadings. The evaluations performed for the fuel rod, water rod, spacer, and upper and lower tie plate are given below. Fuel rod evaluations are performed for dimensional stability, creep collapse, stress, deflection, fatigue, water log rupture, and flow induced vibrations.

The fuel assembly and fuel components are designed to assure dimensional stability in service. The fuel cladding and channel specifications include provisions to preclude dimensional changes due to residual stresses. In addition, the fuel assembly is designed to accommodate dimensional changes that occur in service due to thermal differential expansion and irradiation effects.

Flow induced fuel rod vibrations depend primarily on flow velocity and fuel rod geometry. For the range of flow rates and geometrical variations for the plant, vibrations do not exceed an amplitude of 0.0006 in at frequencies characteristic for a given fuel rod and fuel bundle design, approximately 80 Hz for GE12. The maximum vibrational amplitude occurs midway between spacers due to the constraint of the spacer contact points. The stress levels resulting from the vibrations are negligibly low and well below the endurance limit of all affected components. GNF2 flow-induced vibration is similar to GE12.

The fatigue life analysis is based on the estimated number of temperature, pressure, and power cycles. During fuel life, less than 25 percent of the expected fatigue life is consumed.

A detailed analysis of the reload fuel is included in References 1 and 2.

3.2.6 Inspection and Testing

Rigid quality control requirements are enforced at every stage of fuel manufacturing to ensure that the design specifications are met. Written manufacturing procedures and quality control plans define the steps in the manufacturing process. Fuel cladding is subjected to 100 percent dimensional inspection and ultrasonic inspection to reveal defects in the cladding wall. Destructive tests are performed on representative samples from each lot of tubing, including chemical analysis, tensile tests, and corrosion tests. Integrity of end plug welds is assured by standardization of weld processes based on ultrasonic, radiographic and metallographic inspection of welds. Completed fuel rods are helium leak tested to detect the escape of helium through the tubes and end plugs or welded regions. UO_2 powder characteristics and pellet densities, composition, and surface finish are controlled by regular sampling inspections. UO2 weights

Table 3.2-1
FUEL DATA

Core Data	Initial Core	Cycle 22
Fuel Cell Spacing (Control Rod Pitch), in	12	12
Number of Fuel Assemblies	560	560
Total Number of Fuel Rods	27,440	51,520
Total Weight of UO2, lb	264,886	260,439
Total Weight of U, lb	233,492	229,577
Core Power Density (rated power), kW/liter	51.2	51.18
Specific Power (rated power), kW/kg. U	23.0	24.35
Average Linear Rod Power (rated power), kW/ft	7.102	4.232
Total Heat Transfer Area, ft2	48535.2	63,359.9
Core Average Heat Flux, Btu/hr-ft2	164,410	136,687

Fuel Assembly Data	Initial Core	GNF2 (R19, R20, R21)
Overall Length, in	175.98	176.16
Nominal Active Fuel Length, in	144	150
Fuel Rod Pitch, in	0.738	0.5098
Space Between Fuel Rods, in	0.175	0.1059
Fuel Channel Wall Thickness[1], in	0.08	0.07
Fuel Bundle Heat Transfer Area, ft2	86.67	113.14
Number of Fuel Rods	49	92
Ave # Gd Rods		14.09
Number of Part Length Fuel Rods(PLR)	0	14
Fueled Length of PLRs, in	NA	54(6)/102(8)
Total Fueled Length, in	7056.0	12,840.0
Number of Bundles in Core	560	560

	Initial Core Fuel		
Fuel Rod Data	Type II & III	Type I	GNF2 (R18, R19, R20)
Outside Diameter, in	0.563	0.563	0.4039
Cladding Thickness, in	0.037	0.032	0.0236
Pellet Outside Diameter, in	0.477	0.487	0.3496
Fission Gas Plenum Length, in	16	16	9.78
Pellet Immersion Density, gm/cc or %TD	10.42	10.42	97

Notes:

1. Average Channel Thickness for Reload Fuel

	Case 1	Case 2
Core Power (MWt)	2587	571
Core Recirculation Flow (lb/hr)	80.85×10^6	80.85×10^6

A steam line break at low reactor power would impose less severe requirements on the ECCS, because there would be less stored heat in the core. If a Steam Line Break Accident occurred during a reactor startup (at low power and natural recirculation flow) the resulting loads would be similar but less severe.

The maximum differential pressures across the reactor assembly internals resulting from the postulated accidents are shown in Table 3.3-2. Figure 3.3-8 and 3.3-9 show the differential pressures for various internals as a function of time.

Response of Reactor Internals to Pressure Differences

The maximum differential pressures are used, in combination with other structural loads, to determine the total loading on the various reactor vessel internals. The internals are then evaluated to assess the extent of deformation and collapse, if any. Of particular interest are: (a) the responses of the guide tubes and the metal channels around the fuel bundles, and (b) the potential leakage around the jet pump joints.

The guide tube is evaluated for collapse caused by externally applied pressure. A number of formulae are used to calculate the collapse pressure of the lower shroud and core support assembly. Unfortunately, the Winderberg test does not apply, because the geometry of the guide tube is outside the test range. Use of ASME curves indicates extreme sensitivity to wall thickness. For the minimum wall thickness of 10 in Schedule 10 pipe, the ASME curves give a collapse load of 45 psi. Using the average wall thickness, the collapse pressure is increased to more than 70 psi. Using empirical relations for tubes over the critical length, the calculated collapse pressure is more than 100 psi. The ASME curves indicate that the collapse pressure is reached at 54 psi for a wall thickness of 1.150 in, which is 6 mils over the minimum for 10 in Schedule 10 pipe. The calculated total loading for the guide tubes is considerably below the collapse loading, and it can be concluded that no failure occurs. The analysis also indicates that the control rods are 70 to 80 percent inserted at the time when the maximum external pressure is applied to the guide tubes.

A historical analysis of fuel channel load resulting from an internally applied pressure utilized a fixed-beam analytical model under a uniform load. Tests to verify the applicability of the analytical model indicated that the model is conservative. The fuel channels may deform sufficiently outward to cause some interference with movement of the control rod blades. There are approximately 15 factors, such as fuel channel deformation, core support

hole tolerance, and top fuel guide beam location, that determine the clearance between the control rod blades and the fuel channels. If each tolerance factor is assumed to be at the worst extreme of the tolerance range, then a slight interference would develop under an 18 psi pressure difference across the channel wall. However, the maximum calculated pressure differential is only 13 psi. In the analysis, a roller at the top of the control rod guides the blade as it is inserted. The clearance between channels is 70 mils less than the diameter of the roller, causing it to slide or skid instead of roll. As the rod is inserted approximately halfway, the control rod sheath tends to push inward on the channel and cause the control rod surface to contact the channel surface. A "worst case" study indicates the possibility of a 50 mil interference.

The possibility of a worst case developing is extremely remote. A statistical analysis utilizing a normal distribution for each of the 15 variables indicates that no interference occurs within 3 σ limits, where σ is the standard deviation in a point distribution of events (3 σ lies in the 0.995 percentile of probability of nonoccurrence). However, even if interference occurs, the result is negligible. About 1 lb of lateral force is required to deflect the channel inboard 1 mil. The friction force developed is an extremely small percentage of the total force available to the control rod drives.

The previous discussion presupposes that the control rod has not moved when the fuel channel experiences the largest magnitude of pressure drop. Analysis indicates that the rod is about 70 to 90 percent inserted. If the rod is beyond 70 percent inserted, then no interference is likely to develop because all the channel deformation is in the lower portion of the fuel channel, whereas the roller is at the top of the rod. It is concluded that the Main Steam Line Break Accident can pose no significant interference to the movement of control rods.

The effect of Reactor Internal Pressure Differences on fuel channel performance has been evaluated for operation in the Maximum Extended Operating Domain (MEOD) with acceptable results.

<u>Jet Pump Joints</u>: An analysis has been performed to evaluate the potential leakage from within the floodable inner volume of the reactor vessel during the recirculation line break and subsequent LPCI reflooding. The three possible sources of leakage are:

a. Jet pump throat to diffuser joint
b. Jet pump nozzle to riser joint
c. Jet pump to shroud support welding joint (indications)

The jet pump to shroud support joint is welded and therefore typically not a potential source of leakage. However, indications discovered during jet pump ultrasonic test (UT) inspection have been evaluated to determine a bounding potential leakage of 200 gpm per recirculation loop. The slip joints for all jet pumps leak not more than a total of 225 gpm. The jet pump bolted joint, by analysis, is shown to leak no more than 582 gpm for the pumps through which the reactor vessel is being flooded.

The summary of maximum leakage is:

Total leakage through all throat to diffuser joints	225 gpm
Total leakage through all nozzle to riser joints	582 gpm
<u>Total leakage for indications at jet pump to shroud support welds</u>	<u>400 gpm</u>
Total maximum rate	1207 gpm

3.4 REACTIVITY CONTROL MECHANICAL DESIGN

3.4.1 Power Generation Objective

The power generation objective of the reactivity control mechanical design is to provide a means to control power generation in the fuel.

3.4.2 Power Generation Design Basis

The reactivity control design includes reactivity control mechanical devices (control rods) that contain and position the material that controls just the excess reactivity in the core in conjunction with the gadolinia burnable poison which is located in selected fuel rods within the fuel assemblies.

3.4.3 Safety Objective

The safety objectives of the reactivity control mechanical design is to provide a means to quickly terminate the nuclear fission process in the core so that damage to the fuel barrier is prevented or limited.

3.4.4 Safety Design Bases

The reactivity control mechanical design includes control rods and gadolinia burnable poison in selected fuel rods within fuel assemblies. Safety design bases are as follows:

1. The control rods and gadolinia-urania fuel rods have sufficient mechanical strength to prevent displacement of their reactivity control material.
2. The control rods have sufficient strength and are so designed as to prevent deformation that could inhibit their motion.
3. Each control rod has a device to limit its free-fall velocity sufficiently to avoid damage to the Reactor Coolant Pressure Boundary by the rapid reactivity increase resulting from a free fall of one control rod from its fully inserted position to the position where the drive was withdrawn.

3.4.5 Description

3.4.5.1 Gadolinia-Urania Fuel Rods

In the gadolinia-urania fuel rods, gadolinium (Gd_2O_3) is uniformly distributed in the UO_2 pellets and form a solid solution. The description of the UO_2 - Gd_2O_3 fuel is given in Reference 1 and the description of the core configuration is provided in the current reload licensing submittal.

3.4.5.2 Control Rods

The control rods perform the dual function of power shaping and reactivity control (Fig. 3.4-1). Power distribution in the core is controlled during operation of the reactor by establishing selected patterns of control rods. Control rod displacement tends to counterbalance steam void effects at the top of the core and results in significant power flattening.

The control rod consists of a cruciform array of neutron absorbing material. The control rods are approximately 9.88 in. in maximum span and are distributed uniformly throughout the core on a 12 in. pitch. Each control rod is surrounded by four fuel assemblies. The neutron absorbing material is either boron carbide powder (B_4C) or hafnium in the form of plates or rods. The neutron absorbing material may be located in stainless steel tubes filled with B_4C power and in some cases hafnium

plates or rods contained within a sheath; as B_4C filled stainless steel tubes and hafnium rods within a welded array of stainless steel tubes; or as B_4C powder or hafnium contained within holes drilled in stainless steel wings.

3.4.5.2.1 Original Equipment Control Rods

The main structural member of a control rod is made of Type 304 stainless steel and consists of a top handle, a bottom casting with a velocity limiter and control rod drive coupling, a vertical cruciform center post, and four U-shaped absorber tube sheaths. The top handle, bottom casting, and center post are welded into a single skeletal structure. The U-shaped sheaths are welded to the center post, handle, and castings to form a rigid housing to contain the B_4C filled absorber rods. Rollers at the top and bottom of the control rod guide the control rod as it is inserted and withdrawn from the core. The control rods are cooled by the core bypass flow. The U-shaped sheaths are perforated to allow the coolant to circulate freely about the absorber tubes. Operating experience has shown that control rods constructed as described above are not susceptible to dimensional distortions.

The B_4C powder in the absorber tubes is compacted to about 70 percent of its theoretical density. Absorber tubes are made of Type 304 stainless steel. Absorber tubes are sealed by a plug welded into each end. The B_4C is longitudinally separated into individual compartments by stainless steel balls at approximately 16 in. intervals. The steel balls are held in place by a slight crimp of the tube. Should B_4C tend to compact further in service, the steel balls will distribute the resulting voids over the length of the absorber tube. The operating lifetime of the B_4C Control Blades is governed by either nuclear reactivity or mechanical stress considerations, whichever proves most limiting.

1. The nuclear lifetime limit is reached when the peak boron depletion results in a 10 percent loss in relative control worth of any 3-foot axial section of the blade, and
2. The mechanical lifetime limit is reached when stresses in any absorber tube of the control rod reaches the most restrictive design limit. The stress is caused by the internal helium pressure resulting from the boron-10 (B-10) (neutron, alpha) reaction.

The actual replacement (or relocation within the reactor core) of control rods based on these criteria will depend on the service history of individual control blades and operating experience gained with blades of similar design. Figure 3.4-6 summarizes the control blade change-out activity at FitzPatrick; it shows the location of replacement control blades in the FitzPatrick core, and includes all relocations.

All original equipment control rods were discharged from the reactor prior to operation in cycle 22. However, original equipment control rod operating characteristics (particularly control rod worth) remain a standard against which replacement control rod performance is judged.

3.4.5.2.2 Replacement Control Rods

Control rod blades that have reached their neutronic or mechanical life have been replaced by control rods of the following designs. All of these control rods have similar worth to original equipment control rods and their velocity limiter performance continues to provide satisfactory performance in the event of a control rod drop accident. The replacement rod designs incorporate changes to improve control rod lifetime and to enhance performance compared to the original equipment design.

Duralfe-190

New features of the Duralife-190 control rods (licensed as Advanced Longer Life Control Rods)

manufactured by General Electric (GE) are:

1. Use of solid hafnium rodlets and plates in the highest fluence regions of the rod to replace stainless steel clad B_4C. Hafnium in the geometry used provides equivalent worth to the B_4C rodlets. Specifically, the top six inches of all B_4C rodlets is replaced with a hafnium plate of equivalent thickness and the outer three B_4C rodlets in each wing are replaced with hafnium rods of equivalent diameter. The reactivity worth of the Duralife-190 control rod is equivalent to the original equipment control rod to within the uncertainty in the calculations of rod worth.
2. Use of high purity 304 stainless steel to replace commercial grade 304 stainless steel for B_4C rodlets to prevent stress corrosion cracking and loss of B_4C material.
3. A new velocity limiter design is welded rather than cast as in original equipment. This change effectively reduces the weight of the velocity limiter and allows addition of heavier hafnium absorber without increasing overall control rod weight. The weight of the replacement control rods is approximately 210 pounds compared to approximately 235 pounds for original equipment. The new velocity limiter meets or exceeds all performance criteria established for original equipment.
4. Pin and roller material has been changed from HAYNES 25 and Stellite 3 respectively to PH13-8 Mo and Inconel X-750 respectively to reduce the amount of cobalt activation produced in the control rods and released to reactor coolant. The replacement material does not contain cobalt.
5. Structural spot welds between the absorber sheath and handle, tie rod and velocity limiter have been replaced with fusion welds to eliminate crevices at these interfaces which are known to cause crevice corrosion cracking.

Duralife-230

Two versions of control rods manufactured by GE and given the commercial name Duralife-230 are utilized in the reactor. Both designs are functionally equivalent to the original equipment control rods and have the following features:

1. The three full length hafnium absorber rods at the edge of each wing have been replaced with a hafnium strip. This change results in a small increase in the amount of hafnium added in the region of the wing.
2. Certain interface dimensions have been changed primarily due to changes in component assembly. None of these changes will affect the fit of the control rods.
3. There is a small increase in the cold reactivity worth of the Duralife-230 control rod when compared to the original equipment control rods. However, the hot reactivity worth is within the uncertainty of the calculations. The small increase in cold reactivitiy requires no change in how the control rod is treated in nuclear calculations and is within the bounds of analyses of control rod drop accidents.

GE Marathon

Similar to the Duralife-230 control rod, the GE control rods given the commercial designation "Marathon" have evolved over time with several detailed designs in use at JAF. New characteristics of Marathon control rods are as follows:

1. Marathon control rods do not use a sheath enclosing the poison rodlets (and bars

and plates of hafnium). The wings of the GE Marathon blades are longitudinally welded square tubes. Thus the structure containing the poison is also the structure for the CRB. This design change allows greater flexibility in poison loading to obtain higher control strength or longer life. The solid cruciform spine, to which the sheath was attached, has been replaced by an intermittent cruciform to provide overall structural integrity.

2. The absorber configuration for GE Marathon CRB's is similar to that used in other replacements at FitzPatrick except that the hafnium plate at the top of each wing has been replaced by hafnium rodlets or B_4C capsules in each tube. Within the structural tube GE uses a thin walled capsule as the poison container. These capsules are sealed by crimping the ends over plugs; the capsules allow the flow of the evolved helium but hold the B_4C in place. By maintaining a gap between the capsule and the tube ID, the tube is protected against stress corrosion cracking due to B_4C swelling until significant B-10 burnup is reached. There are empty capsules at the bottom of two tubes to allow for helium buildup in the highest burnup tubes, and an empty tube (with a short hafnium rod at the top of the column in some cases) at the inside of each wing to provide the proper worth of the rod.

3. Marathon control rods use high-purity stainless steel to contain the absorbing material. The improved stainless steel cladding materials can resist cracking to higher fluence levels than original equipment materials.

4. Marathon control rods use either cast or fabricated velocity limiters. In either case, the performance is similar to the original equipment device and the rod drop velocity satisfies the requirements of the control rod drop accident.

5. Marathon control rods use either an upper pin and roller to provide the means for the control rod to stand off from the fuel channels, or alternatively, wear pads. Either configuration locates the blade in the gap between fuel channels and has adequate performance with regard to control rod insertion.

6. Marathon control rods have reactivity worth within +/-5% of original equipment control rods (matched worth criterion) and therefore do not require special treatment in plant core analyses.

ABB Atom CR-82M

Compared to original equipment control rods, ABB Atom CR-82M control blades have the following new features:

1. The wings of ABB CR-82M blades are made of solid stainless steel plate with drilled horizontal holes to contain the neutron absorbing material. Therefore the structure containing the poison is also the structure for the CRB. This design change allows greater flexibility in poison loading to obtain higher control strength or longer life. The solid cruciform spine, to which the sheath was attached, has been replaced by welds joining the plates to provide overall structural integrity.

2. ABB CR-82M control rod blades use high-purity stainless steel to contain the absorbing material. The improved stainless steel cladding materials can resist cracking to higher fluence levels than original equipment materials.

3. The ABB guide buttons or pads (used in place of upper rollers), lower rollers, and pins are Inconel X-750.

4. ABB CR-82M control rods satisfy the matched worth criterion for reactivity and do not require special treatment in core analyses.

GE Marathon-Ultra HD

Also known commercially as Ultra HD, GE Marathon-Ultra HD control rod blades meet the same form, fit and functional requirements as previous Marathon control rod designs used at JAF with no significant differences with respect to the UFSAR description of control rod blades.

3.4.5.3 Control Rod Velocity Limiter

The control rod velocity limiter (Figure 3.4-2) is an integral part of the bottom assembly of each control rod. This engineered safeguard protects against a high reactivity insertion rate by limiting the control rod velocity in the event of a control-rod-drop accident. It is a one-way device in that the control rod scram velocity is not significantly affected but the control rod dropout velocity is reduced to a permissible limit.

The velocity limiter is in the form of two nearly mated conical elements that act as a large clearance piston inside the control rod guide tube.

The geometry of the elements provides a large resistance to flow when the control rod is moving in the withdrawal direction with significantly less resistance to control rod insertion. The hydraulic drag forces on a control rod are proportional to approximately the square of the rod velocity and are negligible at normal rod withdrawal or rod insertion speeds. However, during the scram stroke the rod reaches high velocity, and the drag forces must be overcome by the drive mechanism.

To limit control rod velocity during dropout but not during scram, the velocity limiter is provided with a streamlined profile in the scram (upward) direction. Thus, when the control rod is scrammed, water flows over the smooth surface of the upper conical element into the annulus between the guide tube and the limiter. In the dropout direction, however, water is trapped by the lower conical element and discharged through the annulus between the two conical sections. Because this water is jetted in a partially reversed direction into water flowing upward in the annulus, a severe turbulence is created, thereby slowing the descent of the control rod assembly to less than 3.11 ft per sec at reactor operating conditions.[1]

3.4.6 Safety Evaluation

3.4.6.1 Evaluation of Control Rods and Gadolinia Urania Fuel Rods

The description shows that the control rods and gadolinia urania fuel rods meet the safety and power generation design bases.

3.4.6.2 Evaluation of Control Rod Velocity Limiter

The control rod velocity limiter limits the free fall velocity of the control rod to a value that cannot result in Reactor Coolant Pressure Boundary damage. This velocity is evaluated by the rod drop accident analysis described in Section 14.6 and in Reference 1.

3.4.7 Inspection and Testing

The quality assurance program for fuel manufacturing is described in detail in Reference 1. Some of the quality control tests performed on control rods are (historical information):

a. Material integrity of the tubing and end plug is verified by ultrasonic inspection and/or eddy current inspection of all tubes.

b. Boron 10 fraction of the boron content of each lot of boron carbide is verified.

c. Integrity of the finished absorber tubes and welds is verified by helium leak testing.

Cycle 22 Control Rod Map

	02	06	10	14	18	22	26	30	34	38	42	46	50
51					7 14-35 (16)	9 22-39(18)	7 34-31 (20) SFP (21)	7 30-43 (17)	7 34-39(19)				
47			7 10-23(19)	7 18-39(19)	12 18-35 (21)	15	13	15	12 34-35 (21)	7 34-15(15)	7 42-31(19)		
43		9 30-35 (20) SFP (21)	8	14	12	17	10G 26-47(12)	17	12	14	8	9 30-19 (20) SFP (21)	
39		7 10-31(19)	13 14-27 (21)	9	19	18	16	18	19	9	13 38-27 (21)	9 38-31(18)	
35	8 10-19 (12,13)	12 26-35 (20) SFP (21)	12	16	21	20	20	20	21	16	10G 26-23(12)	12 26-19 (20) SFP (21)	10A 38-27(13)
31	9 14-23(18)	15	19	18	20	13	13	14	20	18	19	15	7 38-35 (16)
27	7 14-19 (16)	13	12	21	17	13	12	13	17	21	12	13	8 42-35 (12,13)
23	9 22-15(18)	15	19	18	20	13	13	14	20	18	19	15	7 42-23(19)
19	7 38-19 (16)	12 18-19 (21)	12	16	21	20	20	20	21	16	12	10G 34-19 (21)	8 34-11(12) 38-11 (20)
15		10A 14-27(13)	9 30-15(18)	9	19	18	13	18	15	9	7 22-11(19)	8 42-19 (12,13)	
11		7 22-43 (17)	8	14	12	19	10G 26-07(12)	15	12	7 30-11(15) 50-19 (20)	8	10A 26-39(13)	
07			9 18-27 (12,17)	9 22-19 (20) SFP (21)	9 38-23(18)	15	13	15	8 26-19(12)	7 18-23 (20) SFP (21)	9 22-35 (20) SFP (21)		
03					7 18-15(19)	7 18-31 (20) SFP (21)	7 34-23 (20) SFP(21)	9 34-27 (12,17)	10A 26-15(13)				

Notes for Figure

1. First number in cell represents the Refueling Outage when Control Blade was introduced to the core:

RFO#	Blade Type	Number In Core at BOC22
7	Duralife-190	20
8	Duralife-230	9
9	Duralife-230	16
10A	ABB CR-82M	4
10G	MARATHON	4
12	MARATHON	15
13	MARATHON	13
14	MARATHON	5
15	MARATHON	10
16	MARATHON	5
17	MARATHON	4
18	MARATHON	8
19	MARATHON	8
20	MARATHON	10
21	MARATHON ULTRA HD	6

2. Second number in a cell represents the location of a control blade prior to shuffling.
3. The number in parenthesis is the refueling outage when the control blade was shuffled.

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MAP OF CONTROL BLADES IN THE CORE

REV. 10 APRIL 2015 FIGURE NO. 3.4-6

3.7 THERMAL AND HYDRAULIC DESIGN

3.7.1 Power Generation Objectives

The objective of the thermal and hydraulic design of the core is to achieve power operation of the fuel over the life of the core without sustaining fuel damage.

3.7.2 Power Generation Design Bases

The thermal hydraulic design of the core provides the following characteristics:

a. The ability to achieve rated core power output throughout the design lifetime of the fuel without sustaining fuel damage.

b. The flexibility to adjust core power output over the range of plant load and load maneuvering requirements without sustaining fuel damage.

3.7.3 Safety Design Bases

1. The thermal hydraulic design of the core establishes limits as discussed in Section 3.7.4 so that no fuel damage occurs as a result of abnormal operational transients.

2. The thermal hydraulic design of the core establishes a thermal hydraulic safety limit for use in evaluating the safety margin relating the consequences of fuel barrier failure to public safety.

3. The thermal hydraulic design of the core in conjunction with the APRM flow referenced trip provide protection for the MCPR safety limit from the effects of thermal-hydraulic instability.

3.7.4 Thermal and Hydraulic Limits

Limits on plant operation are established to assure that the plant can be safely operated and not pose any undue risk to the health and safety of the public. This is accomplished by demonstrating that radioactive release from plants for normal operation, abnormal operational transients, and postulated accidents meet applicable regulations in which conservative limits are documented. This conservatism is augmented by using conservative evaluation models and by observing limits which are more restrictive than those documented in the applicable regulations.

3.7.4.1 Steady-State Limits

The objective for normal operation and transient events is to maintain nucleate boiling and thus avoid a transition to film boiling. Operating limits are specified to maintain adequate margin before the onset of boiling transition. The figure of merit utilized for plant operation is the critical power ratio (CPR). This is defined as the ratio of the critical

power (bundle power at which some point within the fuel assembly experiences onset of boiling transition) to the operating bundle power. The critical power is determined at the same mass flux, inlet temperature, and pressure which exists at the specified reactor condition. Thermal margin is stated in terms of the minimum value of the critical power ratio, (MCPR) which corresponds to the most limiting fuel assembly in the core. To ensure that adequate margin is maintained, a design requirement based on a statistical analysis was selected as follows:

> Moderate frequency transients caused by a single operator error or equipment malfunction shall be limited such that, considering uncertainties in manufacturing and monitoring the core operating state, more than 99.9% of the fuel rods would be expected to avoid boiling transition[1].

Both the transient (safety) and normal operating thermal limits in terms of MCPR are derived from this basis. A discussion of these limits is given in Reference 1.

The fuel cladding integrity safety limit is given in the Technical Specifications.

The Safety Limit MCPR is calculated for each operating cycle based on the method described in Reference 1. Standard statistical uncertainties, as approved by the NRC, actual core loading, actual fuel bundle peaking parameters, and the full cycle exposure range are analyzed to determine the Safety Limit MCPR.

3.7.4.2 Transient Limits

Fuel damage is defined for design purposes as perforation of the cladding which permits release of fission products (See Section 3.2). The mechanisms which could cause fuel damage in reactor transients are:

a. Severe overheating of the fuel cladding caused by inadequate cooling. Fuel damage due to local overheating of the cladding is conservatively defined as the onset of the transition from nucleate to film boiling, although fuel damage is not expected to occur until well into the film boiling regime. If MCPR remains above the safety limit given in the Technical Specifications, more than 99.9% of the fuel rods would be expected to avoid boiling transition.

b. Rupture of the fuel cladding due to strain caused by relative expansion of the uranium dioxide pellet and the fuel cladding.

c. A value of one percent plastic strain of Zircaloy cladding has traditionally been defined as the limit below which fuel damage due to overstraining of the fuel cladding is not expected to occur. Available data indicate that the threshold for damage is in excess of this value. The linear heat generation rate required to cause this amount of cladding strain for different fuel types and exposures is discussed in Section 3 of Reference 1.

Load following is accomplished by varying the recirculation flow to the reactor. This method of power level control takes advantage of the reactor negative void coefficient. To increase reactor power, it is necessary only to increase the recirculation flow rate which sweeps some of the voids from the moderator, causing an increase in core reactivity. As the reactor power increases, more steam is formed and the reactor stabilizes at a new power level with the transient excess reactivity balanced by the new void formation. No control rods are moved to accomplish this power level change. Conversely, when a power reduction is required, it is necessary only to reduce the recirculation flow rate. When this is done, more voids are formed in the moderator, and the reactor power output automatically decreases to a new power level commensurate with the new recirculation flow rate. No control rods are moved to accomplish the power reduction.

Load following through the use of variations in the recirculation flow rate (flow control) is advantageous relative to load following by control rod positioning. Flow variations perturb the reactor uniformly in the horizontal planes, and thus allow operation with flatter power distribution and reduced transient allowances. As the flow is varied, the power and void distributions remain approximately constant at the steady-state end points for a wide range of flow variations. These constant distributions provide the important advantage that the operator can adjust the power distribution at a reduced power and flow by movement of control rods and then bring the reactor to rated conditions by increasing flow, with the assurance that the power distribution remains approximately constant. Section 7.9 describes the means by which recirculation flow is varied.

The capability of operating at reduced power with a single recirculation loop in service is desirable from a plant availability/outage planning standpoint, in the event one loop is inoperative. The analyses reported in Reference 4 demonstrate that reactor operation with only a single recirculation loop will not decrease overall plant safety. During periods of single-loop operation, the MCPR (Minimum Critical Power Ratio) safety limit is increased to account for core flow measurement greater than actual flow and Traversing Incore Probe (TIP) reading uncertainties. The MCPR increase preserves the margin to boiling transition established in the Technical Specification Bases. The MCPR Safety Limit for single loop operation (SLO) increase is evaluated each time the Safety Limit is changed, and the current increase is given in the Core Operating Limit Report.

SLO is limited to 81.47% of rated thermal power and 58.05% of rated core flow based on the assumptions in the LOCA analysis (Reference 45 and 46 [note: this is the GNF LOCA report]).

Single-loop operation results in a maximum power output of approximately 30 percent less than that attainable during two-loop operation. Because of this reduction in maximum power, the consequences of core-wide, abnormal operational transients will be less severe. The reload analysis results establish an upper limit on the thermal and over-pressure consequences for single-loop operation. Flow-biased RBM (Rod Block Monitor) setpoints assure that the thermal consequences of a rod withdrawal error during single-loop operation will be bounded by the two-loop analyses. A reduction factor is applied to LHGR and MAPLHGR (Maximum Average Planar Linear Heat Generation Rate) as a result of differences in loss-of-coolant accident (LOCA) for single-loop versus two-loop operation. These reduction factors assure that peak clad temperature limits are not exceeded during a LOCA. The most significant contribution to a decreased LHGR and MAPLHGR during single-loop operation is the very short time to boiling transition assumed (0.1 second versus approximately 10 seconds assumed in the two-loop analysis). This conservative assumption accounts for decreased forced circulation during recirculation pump coastdown in the early stages of a LOCA.

3.7.5.5 Core Power Distribution

Thermal design of the reactor including the selection of the core size and effective heat transfer area, the design steam quality, the total recirculation flow, the inlet subcooling, and the specification of internal flow distribution is based on the concept and application of a design power distribution.

A description of analyses and core power distribution can be found in Reference 1.

3.7.6 Thermal and Hydraulic Evaluation

There are three different types of boiling heat transfer to water in a forced convection system - nucleate boiling, transition boiling, and film boiling. Nucleate boiling, at lower heat fluxes, is an extremely efficient mode of heat transfer, allowing large quantities of heat to be transferred with a very small temperature rise at the heated wall. As power is increased, the boiling heat transfer surface alternates between film and nucleate boiling, leading to fluctuations in heated wall temperatures. The bundle power at the point of departure from the nucleate boiling region into the transition boiling region anywhere in the bundle is called the critical power. Transition boiling begins at the critical power, and is characterized by fluctuations in cladding surface temperature. Film boiling occurs a the highest heat fluxes; it begins as transition boiling comes to an end. Film boiling heat transfer is characterized by stable wall temperatures which are higher than those experienced during nucleate boiling. The parameter used for core design and monitoring is the critical power ratio as described in Reference 1.

3.7.6.1 Fuel Damage Mechanisms

Fuel damage is defined as perforation of the fuel cladding. Defects in the fuel cladding should be minimized for two reasons:

a. Defects permit the release of fission products to the reactor coolant. This release involves a portion of those fission products that have diffused out of the uranium dioxide matrix.

b. Water which enters the fuel rods through defects can cause progressive clad corrosion and further deterioration of the cladding in the fuel rod leading eventually to water and steam leaching of fission products and uranium from the fuel pellets. If this progressive failure persists, the reactor coolant activity level increases, and it becomes necessary to remove the fuel assembly from the core.

A discussion of potential fuel damage mechanisms is given in Reference 1.

3.7.6.2 Fuel Damage Experiences

A description of experiences with BWR fuel can be found in Reference 2.

3.7.7 Inspection and Testing

The detailed core power and MCPR distribution is calculated periodically. The plant is operated as necessary to maintain MCPR and the linear heat generation rates within the applicable Technical Specifications values.

44. Global Nuclear Fuel, "GNF2 Advantage Generic Compliance with NEDE-24011-P-A (GESTAR II)," NEDC-33270P, Class III (Proprietary), Revision 5, May 2013.

45. GE Hitachi Nuclear Energy, "Correction of the Single Loop Operation Power Percentage Reported in the GNF2 ECCS-LOCA Evaluation," 001N9141-R0, Revision 0, September 2014.

46. GE Hitachi Nuclear Energy, "James A. FitzPatrick Nuclear Power Plant GNF2 ECCS-LOCA Evaluation," 0000-0076-4111-R0, Class III (Proprietary), Revision 0, August 2008.

47. NEDE-33213P-A, DRF 0000-0041-6653, April 2009, GEH Licensing Topical Report, ODYSY Application for Stability Licensing Calculations Including Option I-D and II Long Term Solutions.

48. GE Report, GE Marathon Control Rod Assembly, NEDE-31758P-A, October 1991.

49 GE Report, Marathon-Ultra Control Rod Assembly, NEDE-33284 Supplement 1P-A, March 2012.

The reactor vessel and Reactor Coolant System were hydrostatically tested in accordance with code requirements at 125 percent design pressure. Vessel temperature is maintained at a minimum of the temperature shown in the Pressure Temperature Limits Report (PTLR). In accordance with the ISI program, hydrostatic or leakage testing follows each removal and replacement of the reactor vessel head. Other preoperational tests included the calibration and testing of reactor vessel flange, seal ring leakage detection and instrumentation, the adjustment of reactor vessel stabilizers, a check of all vessel thermocouples, and an operational check of the vessel flange stud tensioner.

4.2.7 Inspection and Testing

Accessibility for inservice inspection was considered during the design of the reactor vessel and insulation to ensure adequate working space and access for inspection. The selection of the components and locations to be inspected meet the intent of the ASME Boiler and Pressure Vessel Code, Section XI, "Inservice Inspection of Nuclear Reactor Coolant Systems", dated January 1, 1970. The details of the Inservice Inspection Program for JAF plant are specified in Section 16.4.

The original material surveillance test program for the reactor vessel provides for the preparation of a series of Charpy V-Notch impact specimens and tensile specimens from the base metal of the reactor vessel, weld heat affected zone metal, and weld metal from a reactor steel joint which simulates a welded joint in the reactor vessel. The specimens (two capsules with 12 impact specimens each) and neutron monitor wires (iron, nickel and copper) were placed near core mid-height, adjacent to the reactor vessel wall where neutron exposure is similar to that of the vessel wall. The specimens were installed at startup or just prior to full-power operation. Selected groups of specimens are removed at intervals over the lifetime of the reactor and tested to compare mechanical properties with the properties of control specimens which are not irradiated. This material surveillance test program is based on 10 CFR 50 Appendix H. The first capsule was removed at 5.98 effective full power years (EFPY) of operation and the second capsule was removed at 13.4 EFPY of operation. An Integrated Surveillance Program (ISP) was established by the BWRVIP to replace individual plant vessel surveillance programs. This was originally documented in BWRVIP-86-A, "BWR Vessel and Internals Project, Updated BWR Integrated Surveillance Program (ISP) Implementation Plan," Final Report, October 2002. The ISP matches the vessel chemistry of an individual plant to a representative plant and the capsule results (i.e., changes in fracture toughness with neutron exposure from the representative plant) are applied at the individual plant. The NRC approved the BWRVIP program in an SER, dated February 1, 2002, and determined the approved ISP adequately addresses the requirements of 10 CFR 50 Appendix H. A condition of the NRC SER requires that individual plant vessel fluence calculations be performed using methods in accordance with the recommendations of Regulatory Guide 1.190. This methodology was used to support replacing the P-T Limit Curves in the Technical Specifications with the PTLR. The capsule withdrawal schedule at the representative plant is controlled by the BWRVIP. JAF is a member of the BWRVIP and replaced its individual plant surveillance program with the ISP. The ISP criteria are now documented in BWRVIP-86. JAF has enhanced its program to reflect the revised BWRVIP-86 criteria. The balance of the JAF specimen capsules will remain in place to serve as backup for the BWRVIP program, or as otherwise needed.

No weak direction specimens were included in the reactor vessel material surveillance program. All Charpy V-Notch specimens were taken parallel to the direction of rolling. The majority of development work on radiation effects has been with longitudinal specimens. This is considered the best specimen to be used for determination of changes in transition temperature.

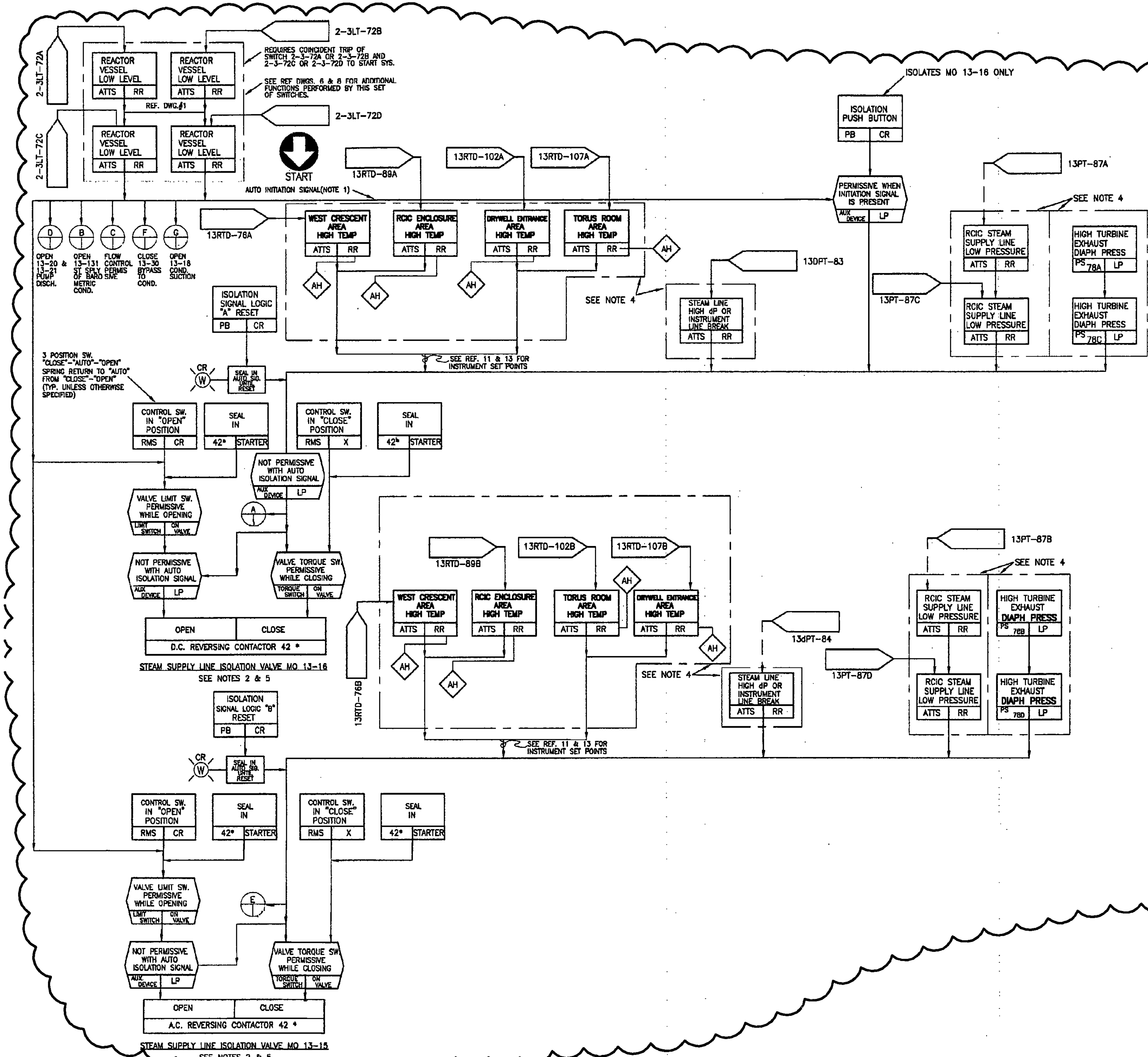
At the low neutron fluence levels of plants no change in transverse shelf level is expected and transition temperature changes are minimal.

NRC Regulatory Guide 1.99, "Radiation Embrittlement of Reactor Vessel Materials", Revision 2, May 1988, provides the basis for the reactor vessel material surveillance analysis which accounts for irradiation embrittlement effects in the reactor vessel core region, or beltline. The best estimate fluence for the peak locations in the lower shell and the lower intermediate shell after 54 effective full power years (EFPY), which includes the period of extended operation at 90% capacity factor are expected to be 2.5 x 10^{18} n/cm^2 and 3.1 x 10^{18} n/cm^2 respectively at the vessel ID.

The limiting beltline material, from the perspective of brittle fracture, is the material with the highest adjusted reference temperature (ART) at a given time. For the remainder of the FitzPatrick plant's lifetime, the limiting beltline material will be longitudinal weld 2-233 in the lower shell. Pressure-temperature limits are located in the PTLR, which is Appendix F of the Technical Requirements Manual (TRM).

TABLE 4.2-3
Reactor Pressure Vessel Thermal Cyclic/Transient Limits

Event number	Description	Number Allowed
1	Bolt Up (70°F)	36
2	Design Hydro Test (1250 psig, 100°F)	36
	START UPS	
3	Start-up (100 °F/hr to 546 °F)	233
4	Turbine Roll and Increase to Rated Power	221
5	Daily Reduction to 75% Power	7566
6	Weekly reduction to 50% Power	1685
7,8	Rod Worth Test (Sequence Exchange)	357
	LOSS OF FEEDWATER HEATER	
9	Turbine Trip at 25% Power	7
10	Feedwater Heater Bypass	34
	SCRAMS	
11	Loss of Feedwater Pumps, Isolation Valves Close	12
12	Turbine Generator Trip, Feedwater On, Isolation Valves Stay	12
13	Reactor Overpressure with Delayed Scram, Feedwater Stays On, Isolation Valves Stay Open	1
14	Single Relief Valve Blowdown	2
15	All Other Scrams	75
16	Normal Operation	------
17	Improper Start of Cold Recirculation Loop	5
18	Sudden Start of Pump in Cold Recirculation Loop	5
	SHUTDOWNS	233 Total
19	Reduction to 0% Power	
20	Hot Standby	
21	Cooldown (100 °F/hr to 375 °F)	
22	Vessel Flooding (375 °F to 330 °F in 10 min.)	
23	Cooldown (100 °F/hr to 100 °F)	
24	Hydrostatic Test (1563 psig)	1
25	Unbolt	35
26	Refueling (70 °F)	-------



FCF: 239X357BA 13-112

NOTES:

1. THE RCIC SYS IS ARRANGED FOR TEST OF PUMP AT FULL FLOW AND ALL VALVES FOR OPEN AND CLOSE CAPABILITY AT ANY TIME EXCEPT WHEN INITIATION SIGNAL OR AUTO ISOLATION SIGNAL IS ACTIVATED. IN THE EVENT THE INITIATION SIGNAL OCCURS WHILE TEST IS UNDER WAY, THE SYS AUTOMATICALLY RETURNS TO STARTUP MODE.
2. ALL POWER FOR OPERATION OF D.C. VALVE MOTORS SHALL ORIGINATE FROM A PLANT D.C. BUS. POWER FOR AC OPERATED VALVES SHALL ORIGINATE FROM AN EMERGENCY A.C. BUS.
3. ALL PART NO'S. ARE PREFIXED BY 13 EXCEPT WHERE OTHERWISE SHOWN.
4. ISOLATION SIGNAL DEVICES SHALL BE OF THE TYPE THAT CLOSE CONTACTS FOR THE SPECIFIED ISOLATION EVENT. WHERE AUX RELAYS ARE USED IN THE ISOLATION CHANNELS, THEY SHALL BE POWERED FROM THE STATION BATTERIES.(REF. 10).
5. AUXILLARY RELAYS & DEVICES NOT SHOWN ON FUNCTIONAL CONTROL DIAGRAMS EXCEPT WHERE REQUIRED TO CLARIFY FUNCTION.
6.
7. FOR LOCATION AND IDENTIFICATION OF INSTRUMENTS SEE MPL ITEM NO. 9-61.
8. THE RCIC SYSTEM SHALL BE DESIGNED IN ACCORDANCE WITH REF. 10.

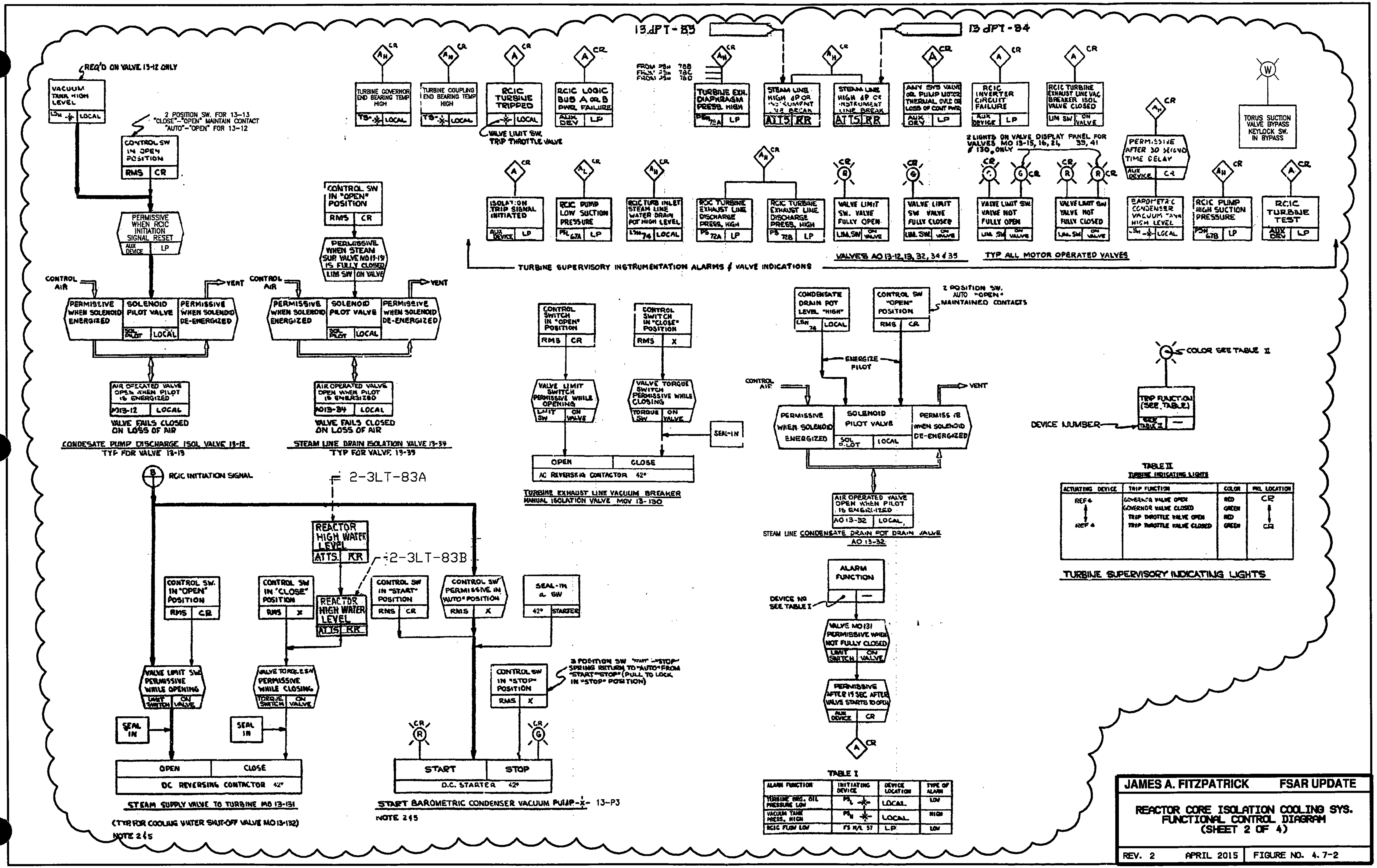
LEGEND:

* = SWITCHGEAR DEVICE FUNCTION NUMBERS USAS SPEC. C37.2.
✦ = FURNISHED WITH TURBINE. SEE REF. DWGS. 4.

REFERENCE DRAWINGS:

1. P&ID RCIC
2. NUCLEAR BOILER VESSEL INSTRUMENT, P&ID
3. LOGIC SYMBOLS
4. TURBINE CONTROL SYSTEM
5. FUNCTIONAL CONTROL DIAG NUCLEAR BOILER MISC. SYSTEM
6. FUNCTIONAL CONT DIAG RHR SYSTEM
7. FUNCTIONAL CONT DIAG CORE SPRAY SYS
8. FCD HPCI SYSTEM
9. P&ID REACTOR WATER CLEANUP SYSTEM
10. ELECTRICAL EQUIPMENT SEPERATION FOR SAFEGUARDS SYSTEM DESIGN SPEC.
11. NUCLEAR BOILER LEAK DETECTION SYSTEM DESIGN SPEC.
12. TESTABLE CHECK VALVE WIRING DIAGRAM
13. EDB

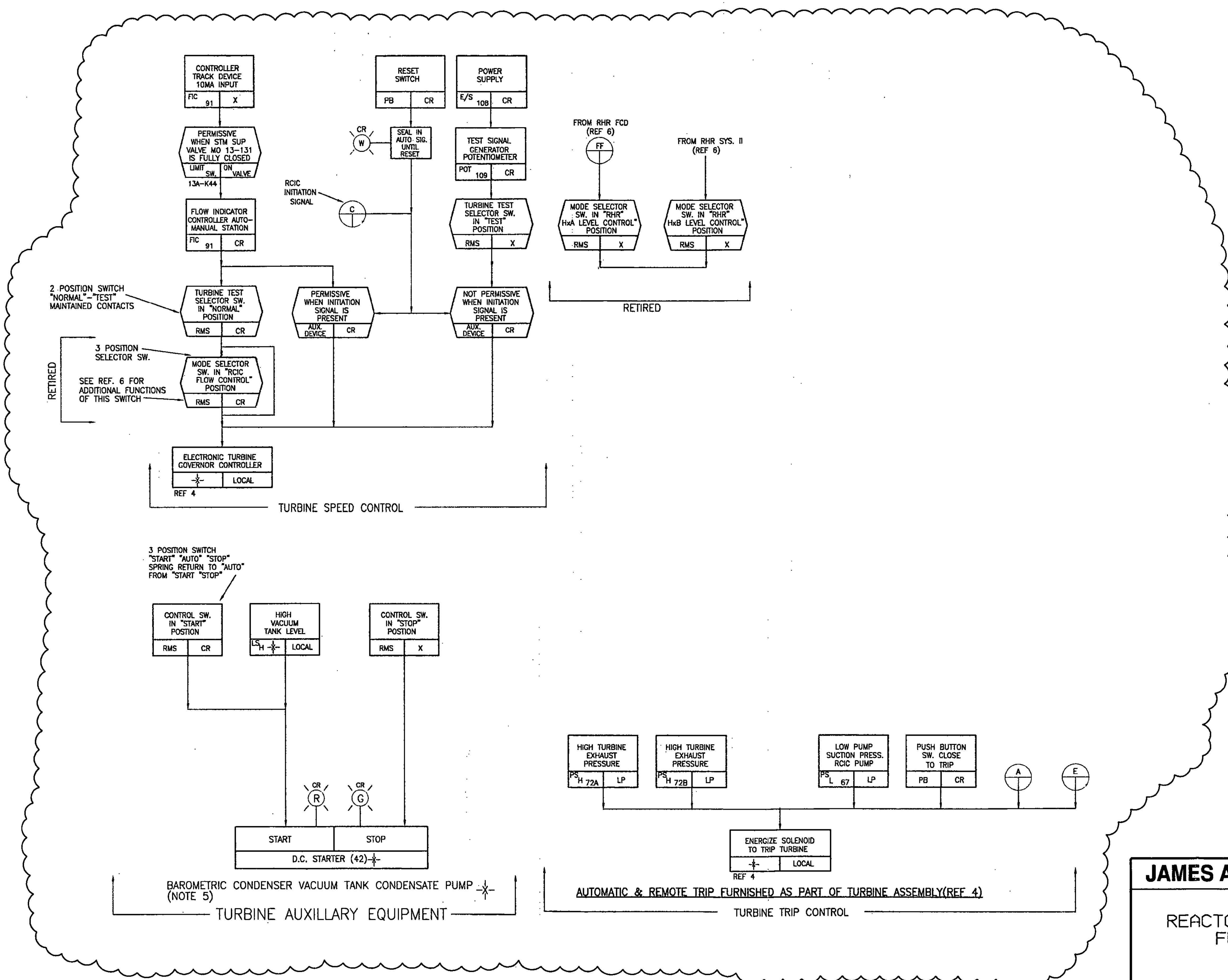
JAMES A. FITZPATRICK	FSAR UPDATE
REACTOR CORE ISOLATION COOLING SYS. FUNCTIONAL CONTROL DIAGRAM (SHEET 1 OF 4)	
REV. 4 APRIL 2015	FIGURE NO. 4.7-2



JAMES A. FITZPATRICK FSAR UPDATE

REACTOR CORE ISOLATION COOLING SYS. FUNCTIONAL CONTROL DIAGRAM (SHEET 2 OF 4)

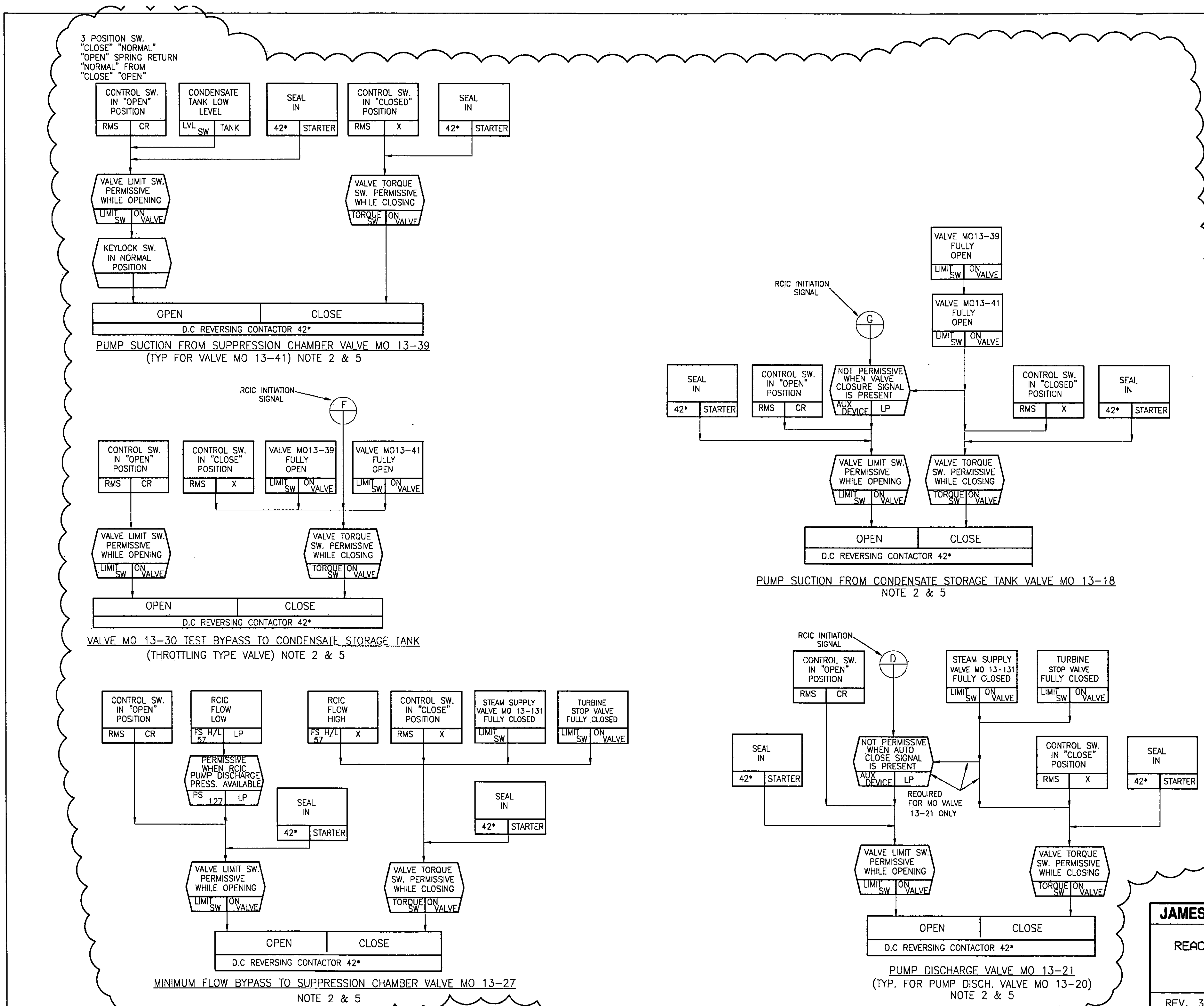
REV. 2 | APRIL 2015 | FIGURE NO. 4.7-2



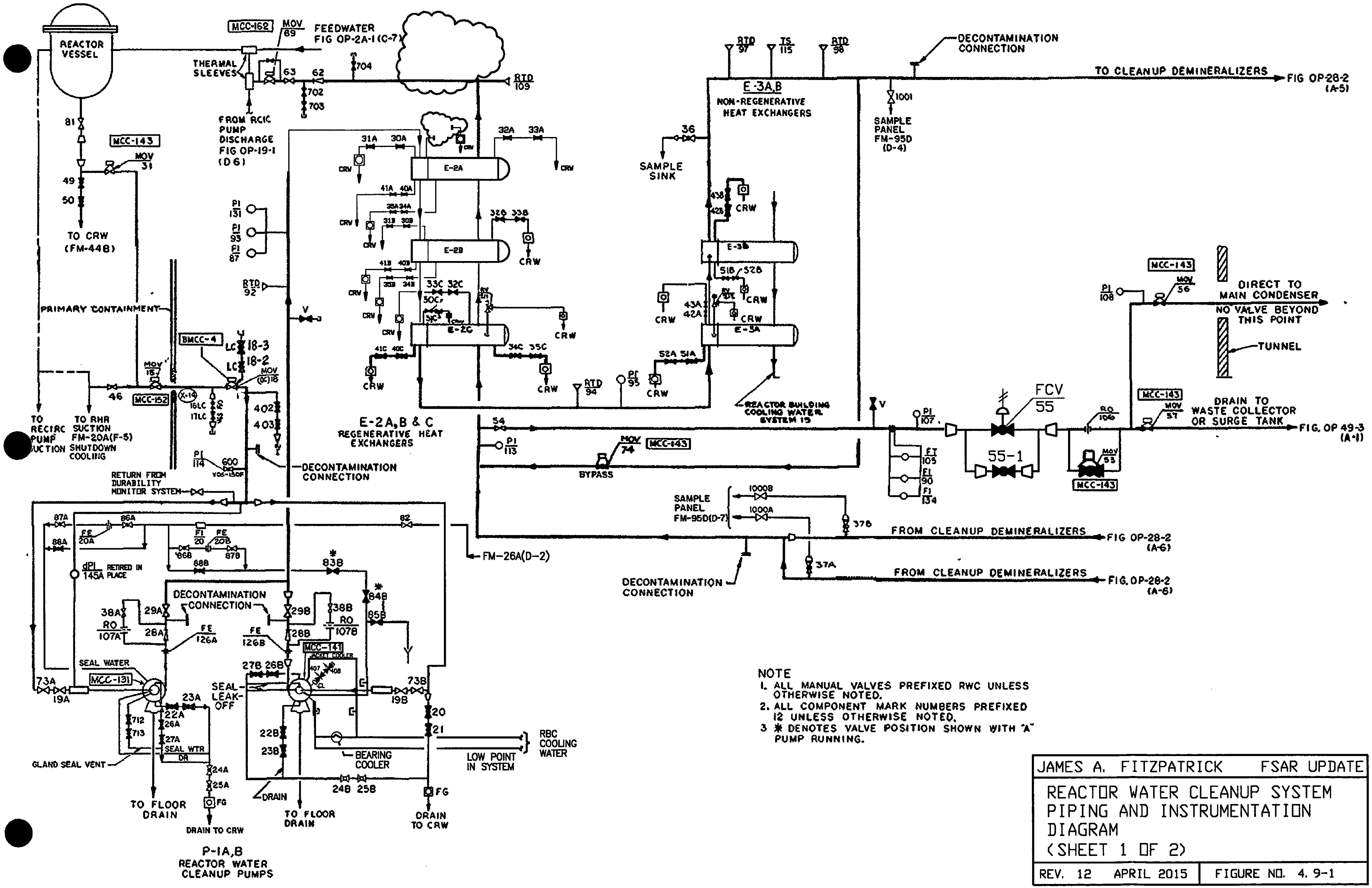
JAMES A. FITZPATRICK **FSAR UPDATE**

REACTOR CORE ISOLATION COOLING SYS.
FUNCTIONAL CONTROL DIAGRAM
(SHEET 3 OF 4)

REV. 2	APRIL 2015	FIGURE NO. 4.7-2



JAMES A. FITZPATRICK		FSAR UPDATE
REACTOR CORE ISOLATION COOLING SYS. FUNCTIONAL CONTROL DIAGRAM (SHEET 4 OF 4)		
REV. 3	APRIL 2015	FIGURE NO. 4.7-2



NOTE

1. ALL MANUAL VALVES PREFIXED RWC UNLESS OTHERWISE NOTED.
2. ALL COMPONENT MARK NUMBERS PREFIXED 12 UNLESS OTHERWISE NOTED.
3. * DENOTES VALVE POSITION SHOWN WITH "A" PUMP RUNNING.

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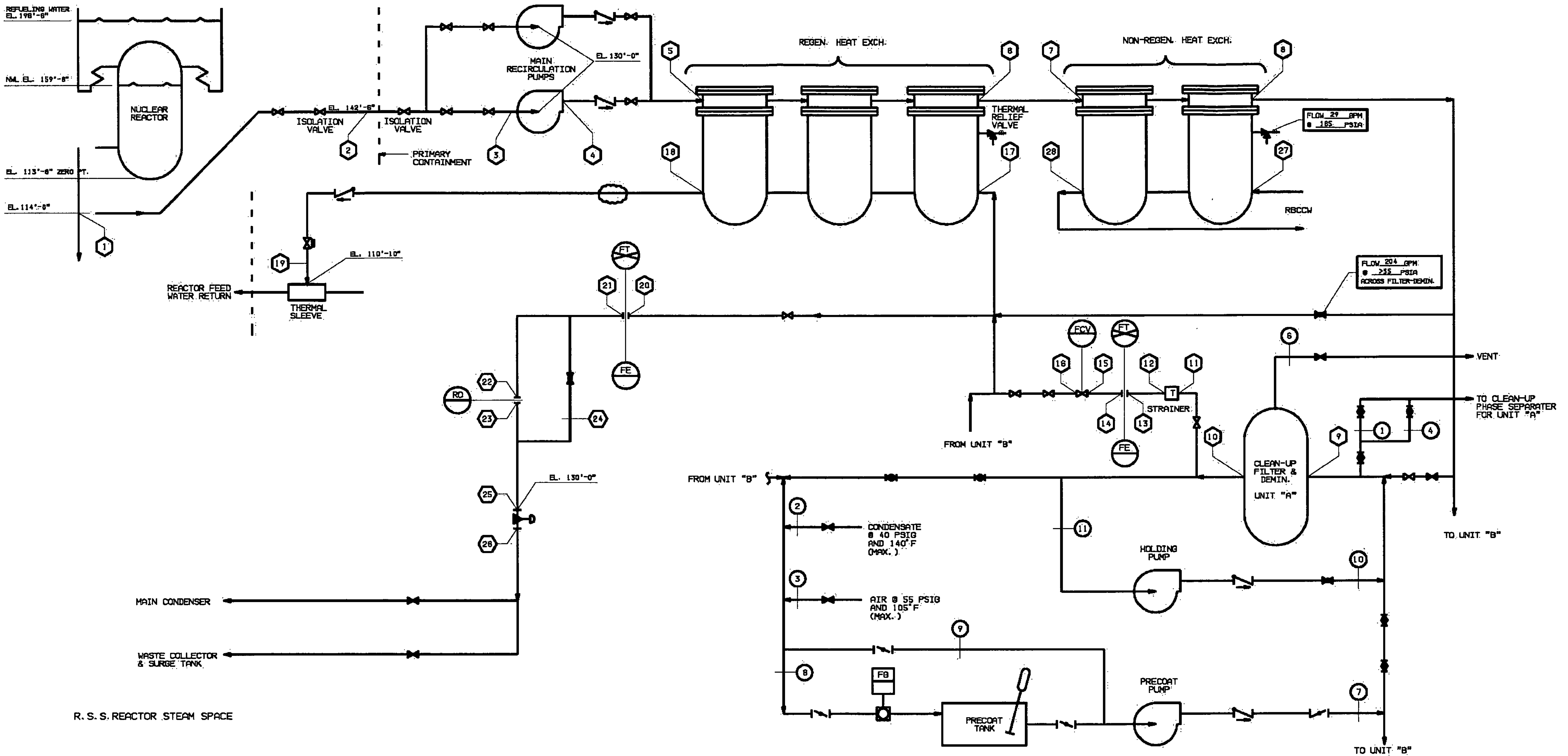
REACTOR WATER CLEANUP SYSTEM PIPING AND INSTRUMENTATION DIAGRAM (SHEET 1 OF 2)	
REV. 12 APRIL 2015	FIGURE NO. 4.9-1



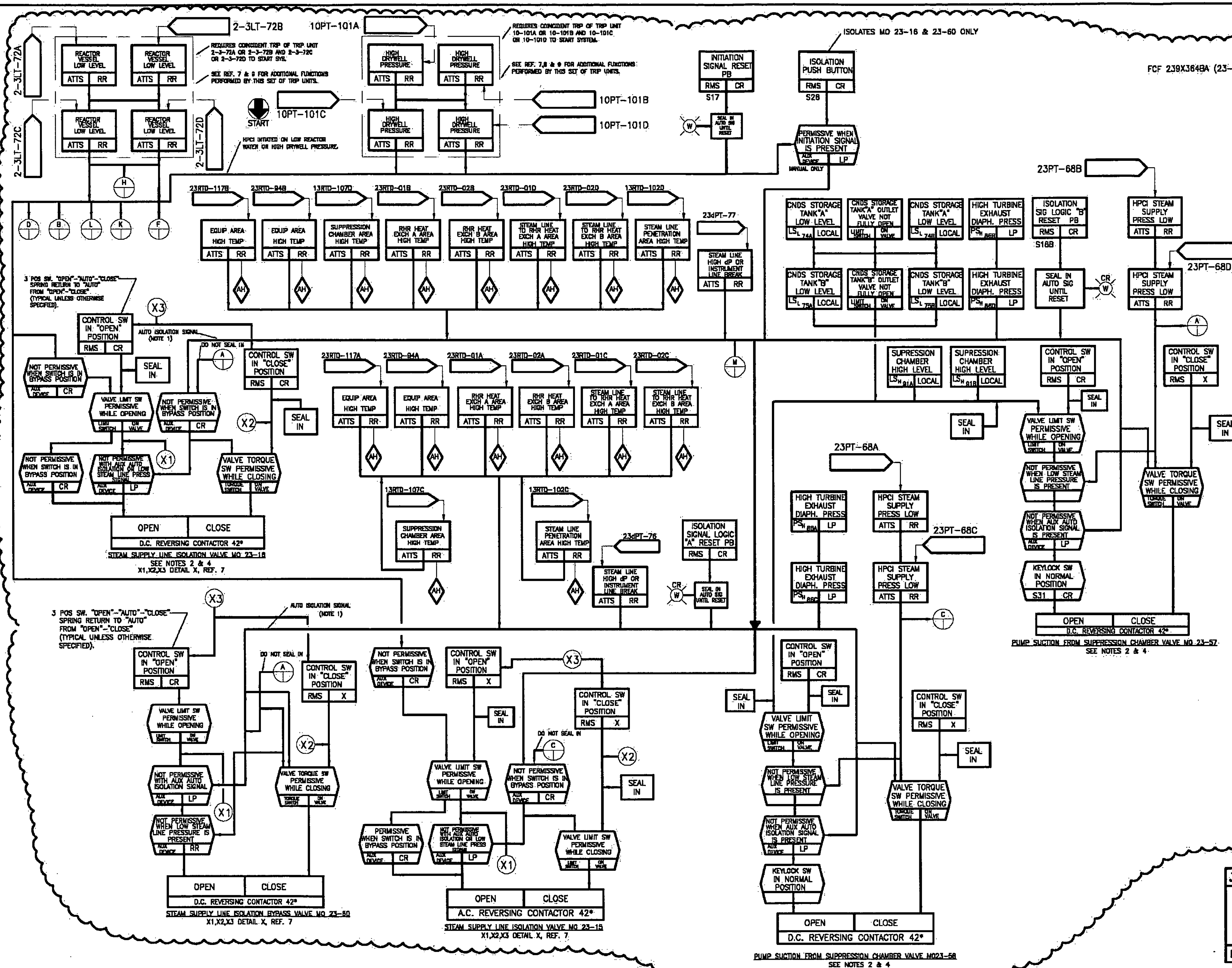
NOTES

1. FOR NOTES, REF. DWGS., MODE OF OPERATIONS, FILTER DEMINERALIZER BACKWASH & PRECOAT SEQUENCE, SEE FIG. NO. 4.9-2, SHT. 2

JAMES A. FITZPATRICK	FSAR UPDATE
REACTOR WATER CLEANUP SYSTEM-PROCESS DIAGRAM SHEET 1 OF 2	
REV. 4 APRIL 2015	FIGURE NO. 4.9-2

LIST OF FIGURES

LIST OF FIGURES



NOTES:

1. THE HPCI SYS IS ARRANGED FOR TEST OF PUMP AT FULL FLOW & ALL VALVES FOR OPEN AND CLOSE CAPACITY AT ANY TIME EXCEPT WHEN INITIATION SIGNAL OR AUTO ISOLATION SIGNAL IS ACTIVATED. IN EVENT THE INITIATION SIGNAL OCCURS WHILE TEST IS UNDERWAY THE SYS AUTOMATICALLY RETURNS TO STARTUP MODE.
2. ALL POWER FOR OPERATION OF D.C. VALVE MOTORS SHALL ORIGINATE FROM A PLANT D.C. BUS. POWER FOR A.C. OPERATED VALVES SHALL ORIGINATE FROM AN EMERGENCY A.C. BUS.
3. ALL PART NO'S PREFIXED BY 23 EXCEPT WHERE OTHERWISE SHOWN.
4. AUXILIARY RELAYS & DEVICES NOT SHOWN ON FUNCTIONAL CONTROL DIAGRAMS EXCEPT WHERE REQUIRED TO CLARIFY FUNCTION.
5.
6. ISOLATION SIGNAL SWITCHES SHALL BE OF THE TYPE THAT CLOSE CONTACTS FOR SPECIFIED ISOLATION EVENT. WHERE AUX. RELAYS ARE USED IN THE ISOLATION CHANNELS, THEY SHALL BE POWERED FROM THE STATION BATTERIES. (REF.13).
7.
8. AN ALTERNATE SOURCE OF EMERGENCY A.C. POWER SHALL BE PROVIDED TO THE INSIDE ISOLATION VALVE MO23-16.
9. THE HPCI SYSTEM SHALL BE DESIGNED IN ACCORDANCE WITH "PROPOSED CRITERIA FOR NUCLEAR POWER PLANT PROTECTION SYSTEM IEEE-279" INSOFAR AS PRACTICABLE.
10. THE HPCI SYSTEM SHALL BE DESIGNED IN ACCORDANCE WITH REF.14.

REFERENCE DOCUMENTS:

1. P&ID HIGH PRESSURE COOLANT INJECTION SYSTEM
2. P&ID NUCLEAR BOILER VESSEL INSTRUMENTATION
3. LOGIC SYMBOLS
4. HPCI TURBINE CONTROL SYSTEM DWG.
5.
6. FCD NUCLEAR BOILER MISC. SYSTEM
7. FCD RHR SYSTEM
8. FCD CORE SPRAY SYSTEM
9. FCD RCIC SYSTEM
10. P&ID RHR SYSTEM
11.
12. P&ID REACTOR WATER CLEANUP SYSTEM
13. P&ID RCIC SYSTEM
14. ELECTRICAL EQUIP. SEPARATION FOR SAFEGUARDS SYS.
15. TESTABLE CHECK VALVE WIRING DIAGRAM

LEGEND:

* - SWITCHGEAR DEVICE FUNCTION NO. USAS SPEC. C37.2
‡ - FURNISHED WITH TURBINE (SEE REF. DRAWING 4)

JAMES A. FITZPATRICK	FSAR UPDATE
HIGH PRESSURE COOLANT INJECTION SYSTEM (FCD) (SHEET 1 OF 3)	
REV. 9 APRIL 2015	FIGURE NO. 7.4-3

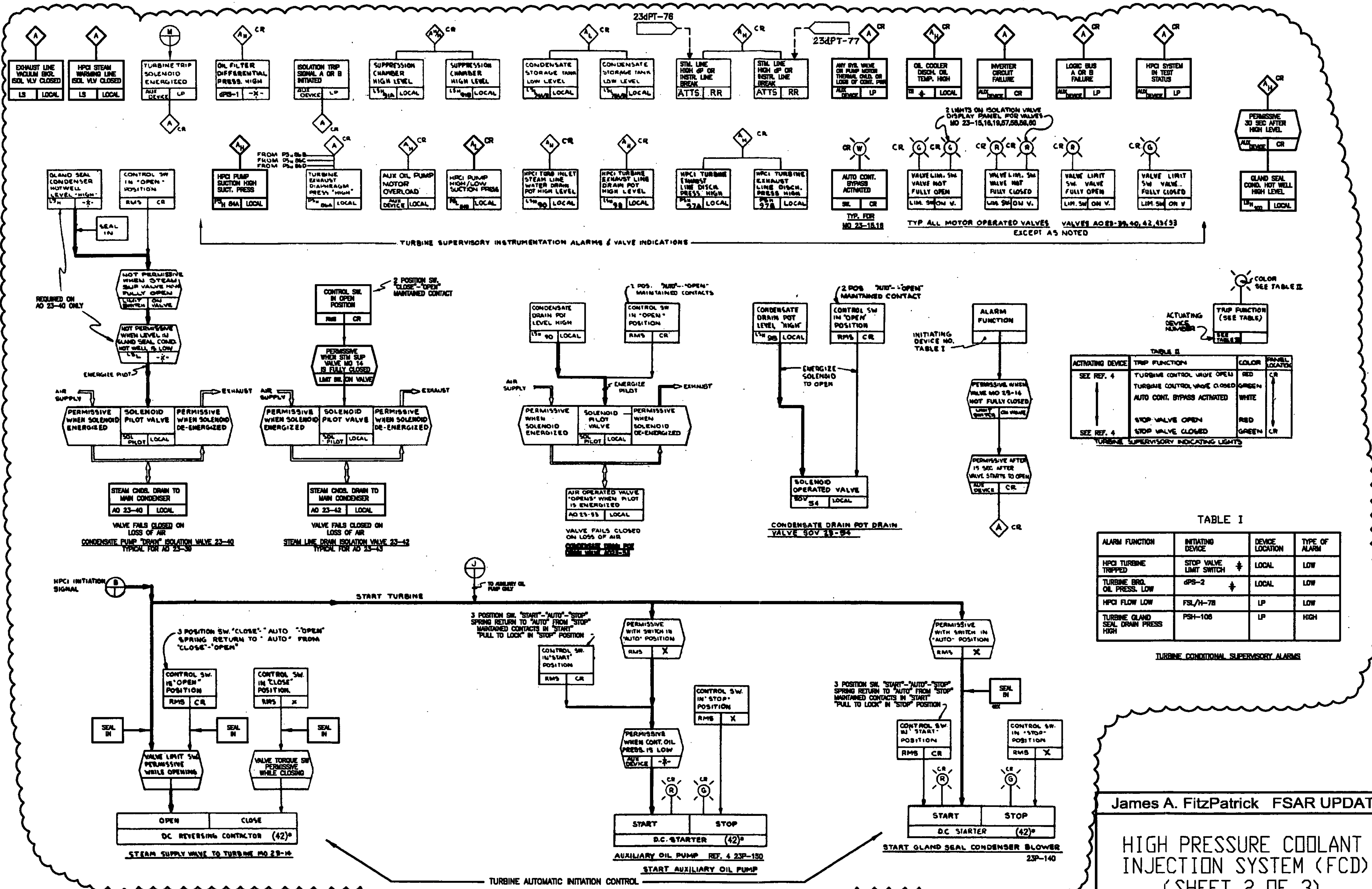


TABLE II

ACTIVATING DEVICE	TRIP FUNCTION	COLOR	PANEL LOCATION
SEE REF. 4	TURBINE CONTROL VALVE OPEN	RED	CR
	TURBINE CONTROL VALVE CLOSED	GREEN	
	AUTO CONT. BYPASS ACTIVATED	WHITE	
	STOP VALVE OPEN	RED	
SEE REF. 4	STOP VALVE CLOSED	GREEN	CR

TURBINE SUPERVISORY INDICATING LIGHTS

TABLE I

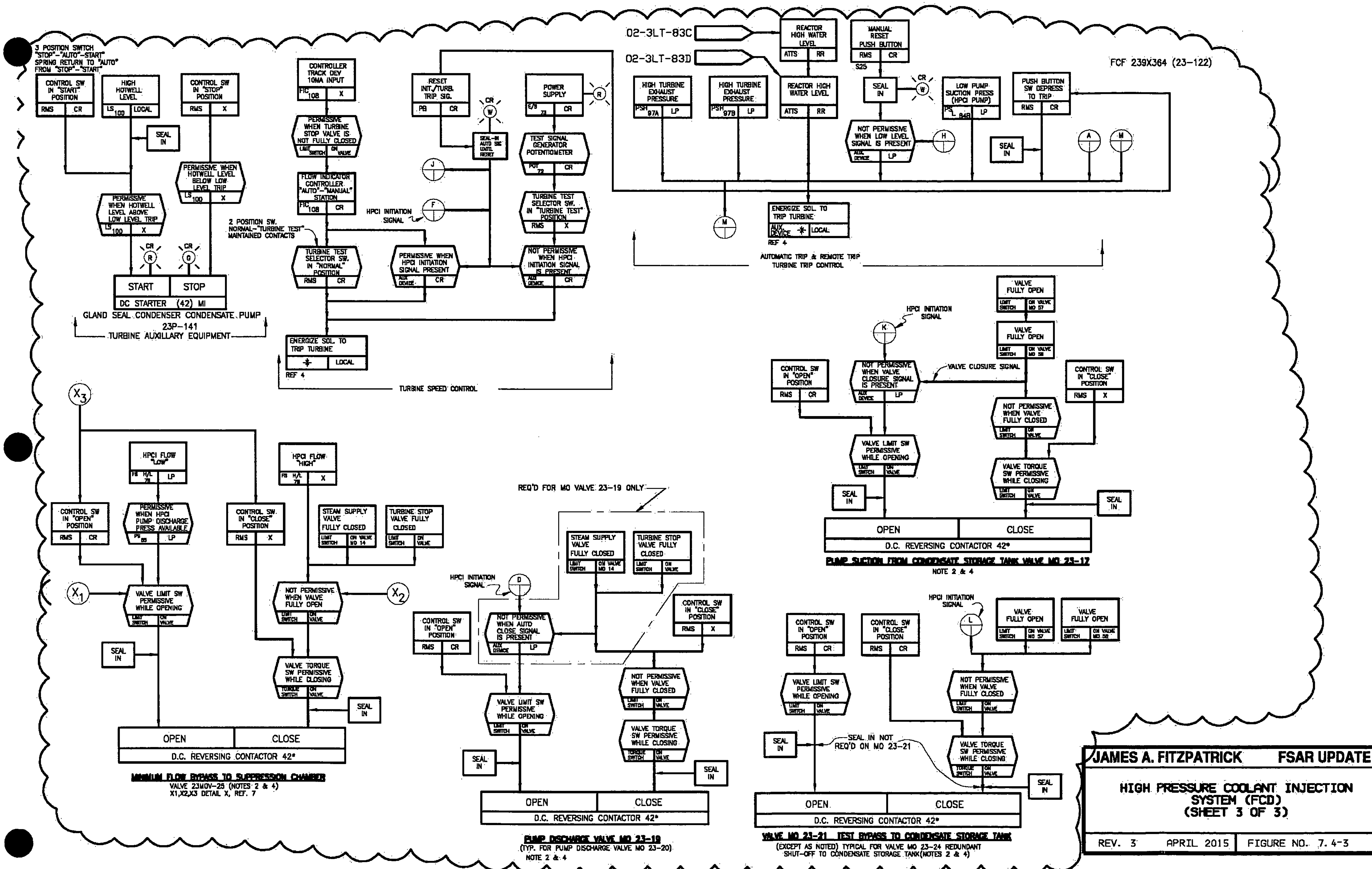
ALARM FUNCTION	INITIATING DEVICE	DEVICE LOCATION	TYPE OF ALARM
HPCI TURBINE TRIPPED	STOP VALVE LIMIT SWITCH	LOCAL	LOW
TURBINE BRG. OIL PRESS. LOW	dPS-2	LOCAL	LOW
HPCI FLOW LOW	FSL/H-78	LP	LOW
TURBINE GLAND SEAL DRAIN PRESS HIGH	PSH-106	LP	HIGH

TURBINE CONDITIONAL SUPERVISORY ALARMS

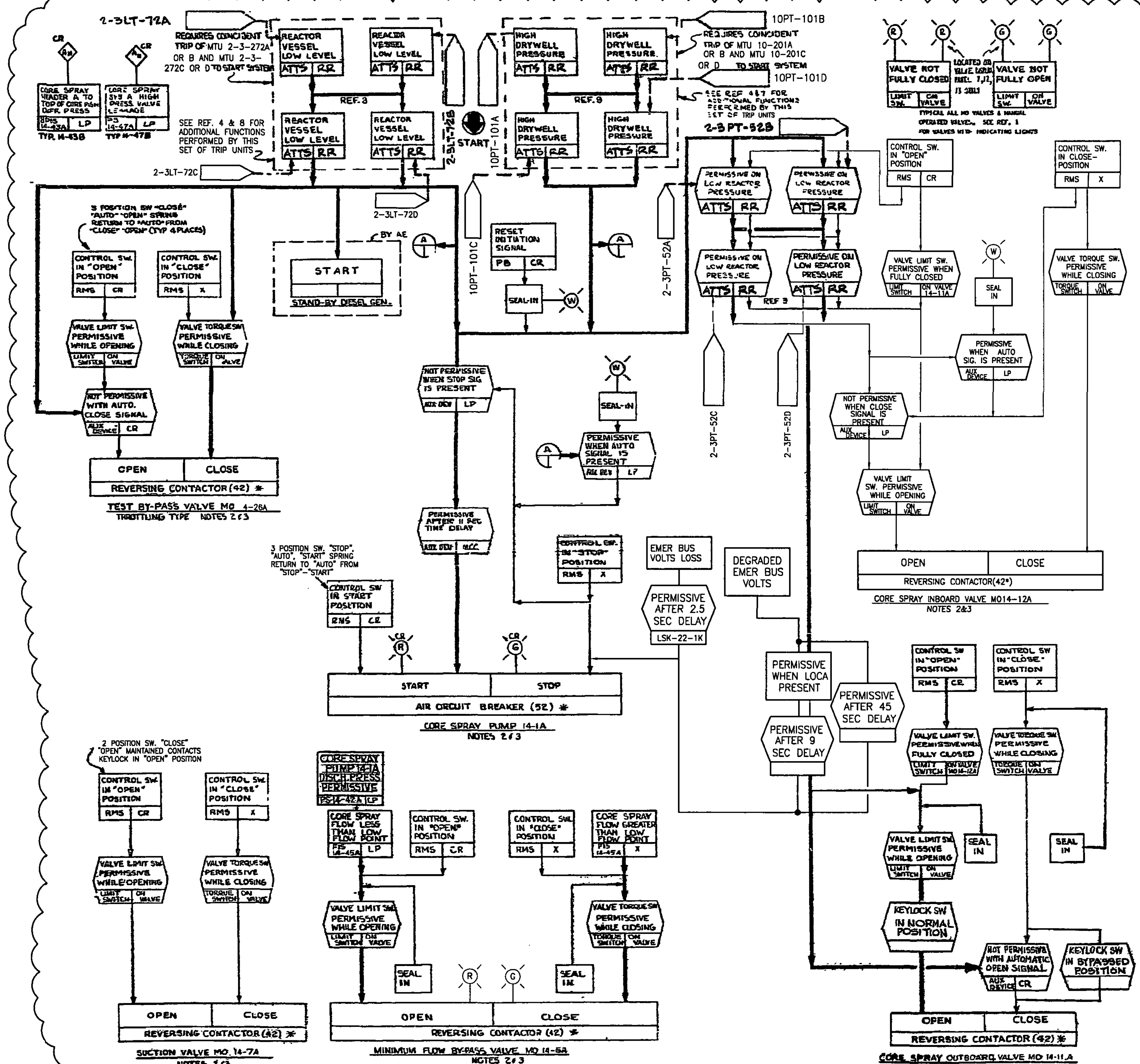
James A. FitzPatrick FSAR UPDATE

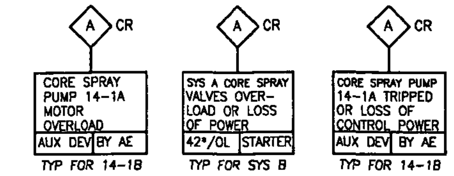
HIGH PRESSURE COOLANT INJECTION SYSTEM (FCD) (SHEET 2 OF 3)

REV. 4 | APRIL 2015 | FIGURE NO. 7.4-3



JAMES A. FITZPATRICK		FSAR UPDATE
HIGH PRESSURE COOLANT INJECTION SYSTEM (FCD) (SHEET 3 OF 3)		
REV. 3	APRIL 2015	FIGURE NO. 7.4-3





NOTES:

1. THE CONTROL SYSTEM AS DRAWN SHOWS SYSTEM I, OPERATING SEQUENCE AFTER LOW WATER LEVEL OR HIGH DRYWELL PRESSURE SIGNAL IS AS FOLLOWS.

CONDITION A — WITH PLANT ON NORMAL AUXILLARY POWER

ACTIVE PUMPS:	TIME DELAY ON PUMPS
14-1A	11 SEC
14-1B	11 SEC

VALVES:

14-11A	SYSTEM I - OPENS AFTER REAC LOW PRESS. PERM. IF CLOSED
14-11B	SYSTEM II- " " " " " " " "
14-12A	SYSTEM I - " " " " " " " "
14-12B	SYSTEM II- " " " " " " " "
14-26A	SYSTEM I - CLOSES IF OPEN-NO DELAY
14-26B	SYSTEM II- CLOSES IF OPEN-NO DELAY
14-5A	SYSTEM I - CLOSES AFTER FLOW ESTABLISHED
14-5B	SYSTEM II- CLOSES AFTER FLOW ESTABLISHED

CONDITION B — WITH PLANT ON STANDBY DIESEL POWER

ACTIVE PUMPS	TIME DELAY
14-1A	11 SEC
14-1B	11 SEC

VALVES: SAME SEQUENCE AS CONDITION A

2. SYSTEM II CIRCUIT IDENTICAL TO CIRCUIT FOR SYSTEM I EXCEPT COMPONENT PARTS ARE IDENTIFIED AS FOLLOWS:

	SYSTEM I	SYSTEM II
PUMP	14-1A	14-1B
MIN. FLOW BYPASS VALVE	14-5A	14-5B
OUTBOARD ISOL. VALVE	14-11A	14-11B
INBOARD ISOL. VALVES	14-12A	14-12B
TESTABLE CHECK VALVES	14-13A	14-13B
PUMP SUCTION VALVE	14-7A	14-7B
TEST BYPASS VALVE	14-26A	14-26B

3. PUMP MOTOR CIRCUITS SHALL PROVIDE FOR OVERLOAD PROTECTION. OVERLOAD RELAYS TO BE APPLIED SO AS TO MAINTAIN POWER AS LONG AS POSSIBLE WITHOUT IMMEDIATE DAMAGE TO MOTOR OR HARM TO ENERGIZED POWER SYSTEM. VALVE MOTORS SHALL BE PROVIDED WITH OVERLOAD PROTECTION.
4. MOTIVE POWER FOR SYSTEM I PUMPS SHALL ORIGINATE FROM A DIFFERENT EMERGENCY AC BUS THAN POWER FOR SYSTEM II PUMPS.

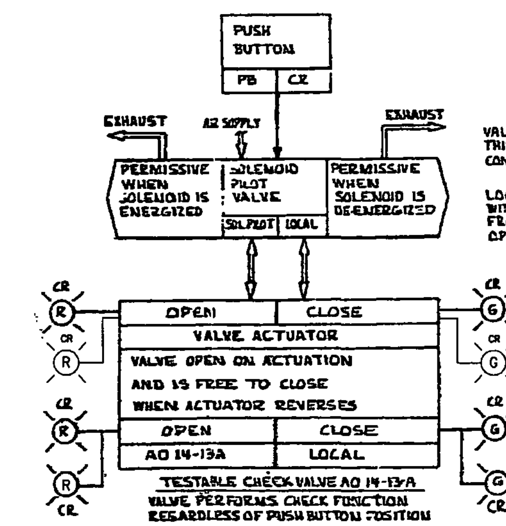
   POWER FOR VALVES IN EACH SYSTEM SHALL ORIGINATE FROM THE SAME BUS SUPPLYING PUMP POWER. CONTROL POWER FOR PUMPS & VALVES OF SYSTEM I SHALL BE FROM A DIFFERENT SOURCE THAN CONTROL POWER FOR SYSTEM II.
5. THE CORE SPRAY SYSTEM SHALL BE DESIGNED IN ACCORDANCE WITH "PROPOSED CRITERIA FOR NUCLEAR POWER PLANT PROTECTIVE SYSTEM IEEE 279" IN-SOFAR AS PRACTICABLE.
6. THE CORE SPRAY SYSTEM SHALL BE DESIGNED IN ACCORDANCE WITH REF. 10.

REFERENCES:

1. P&ID CORE SPRAY SYSTEM
2. LOGIC SYMBOLS
3. P&ID NUCLEAR BOILER VESSEL INSTR.
4. FCD RESIDUAL HEAT REMOVAL SYSTEM
5. DESIGN SPEC. CORE SPRAY SYSTEM
6. FCD RCIC SYSTEM
7. FCD HPCI SYSTEM
8. FCD NUCLEAR BOILER MISC. SYSTEM
9. P&ID RHR SYSTEM
10. ELECTRICAL EQUIP SEPARATION FOR SAFEGUARD SYS.

LEGEND:

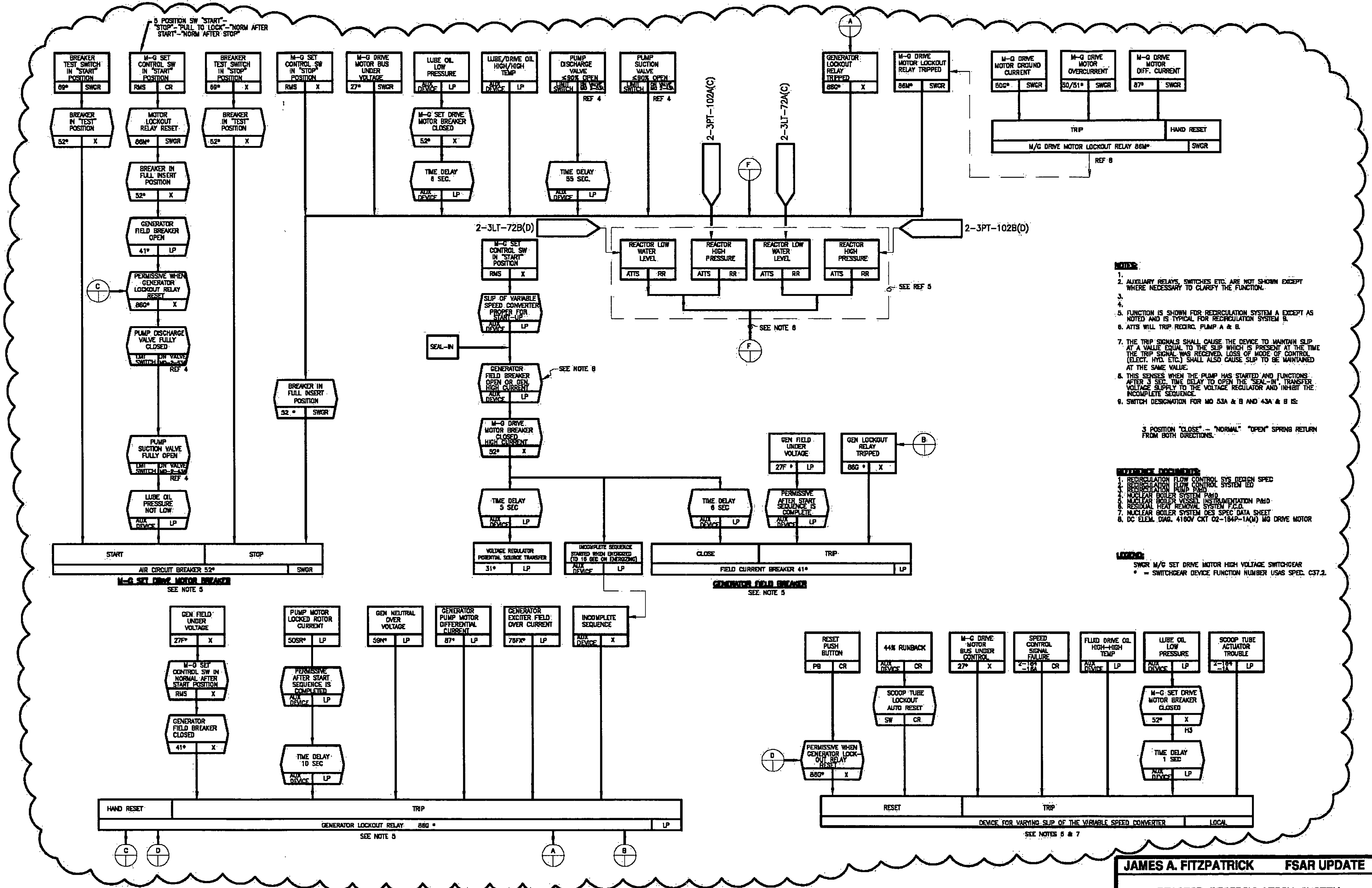
* = SWITCHGEAR DEVICE FUNCTION NUMBERS USAS SPEC. C37.2.



VALVE SUPPLIERS TO CONFIRM THIS METHOD OF CONTROL. VALVE CONTROL IS TYP OF ROCKWELL

LOCAL CONTROL SW FURNISHED WITH SOLENOID TO BE REMOVED FROM SERVICE DURING PLANT OPERATION

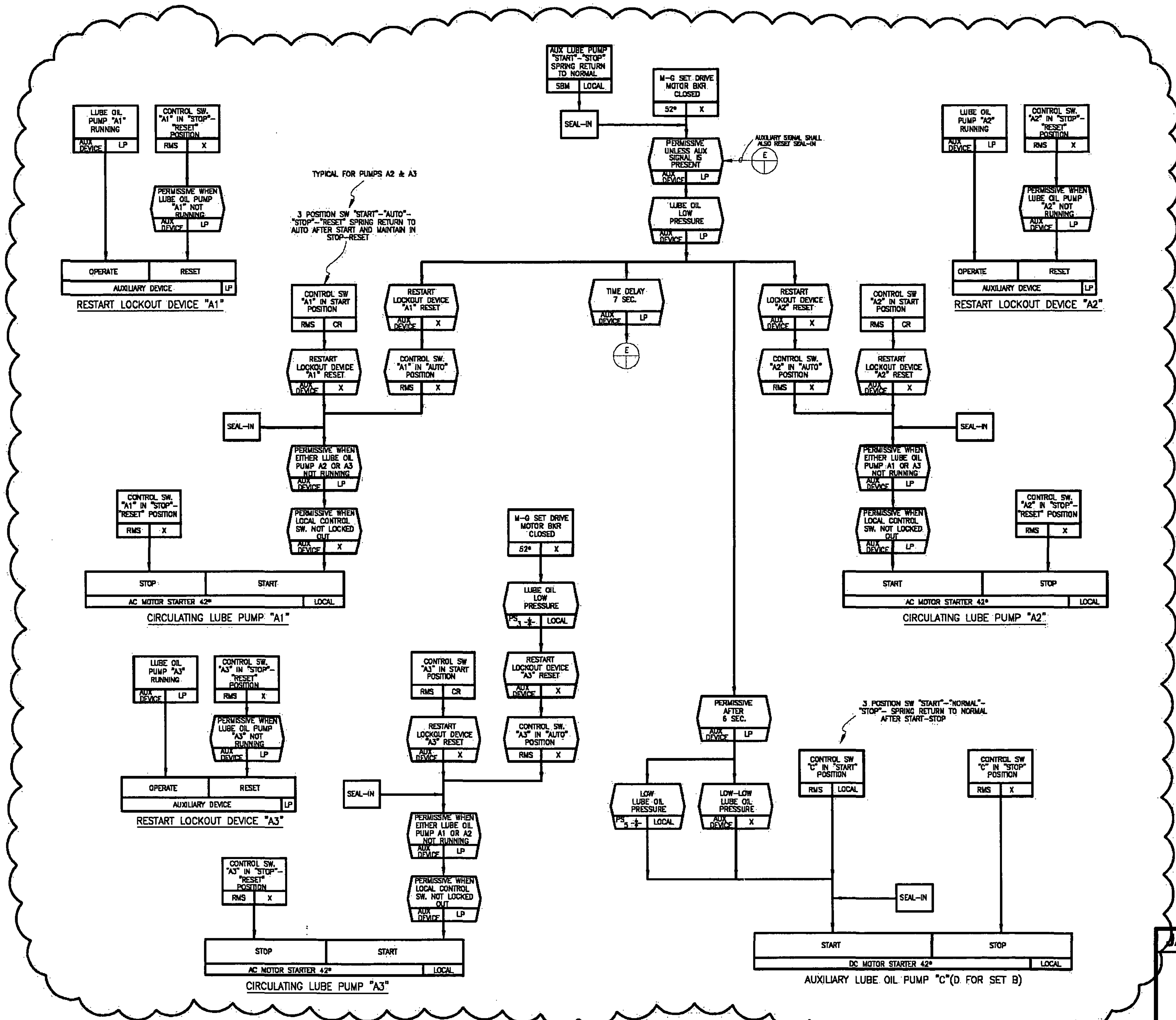
JAMES A. FITZPATRICK	FSAR UPDATE
CORE SPRAY SYSTEM FUNCTIONAL CONTROL DIAGRAM	
REV. 4 APRIL 2015	FIGURE NO. 7.4-6



JAMES A. FITZPATRICK FSAR UPDATE

REACTOR RECIRCULATION SYSTEM FUNCTIONAL CONTROL DIAGRAM (SHEET 1 OF 3)

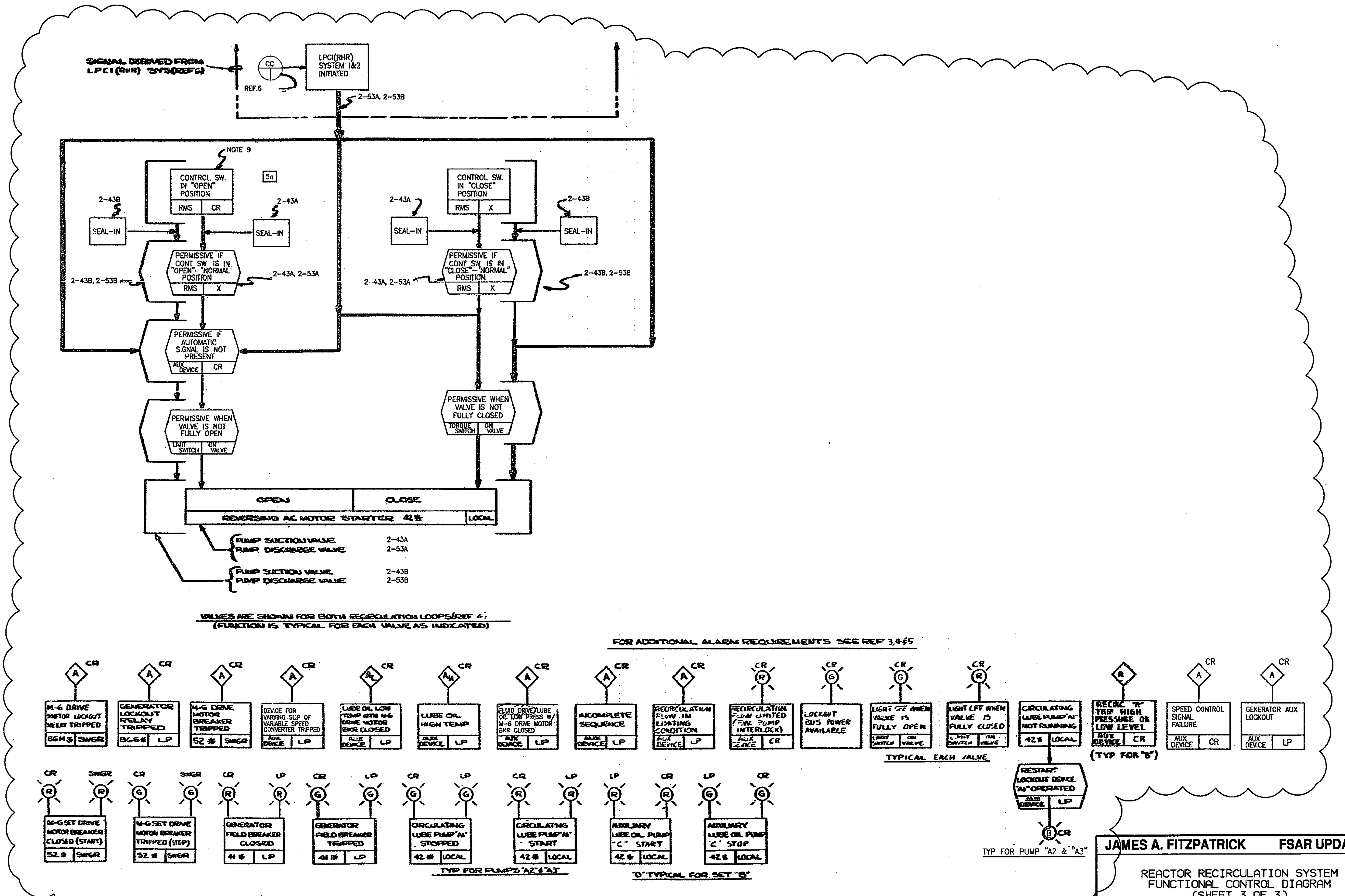
REV. 3 | APRIL 2015 | FIGURE NO. 7.4-9



JAMES A. FITZPATRICK FSAR UPDATE

REACTOR RECIRCULATION SYSTEM (FCD) (SHEET 2 OF 3)

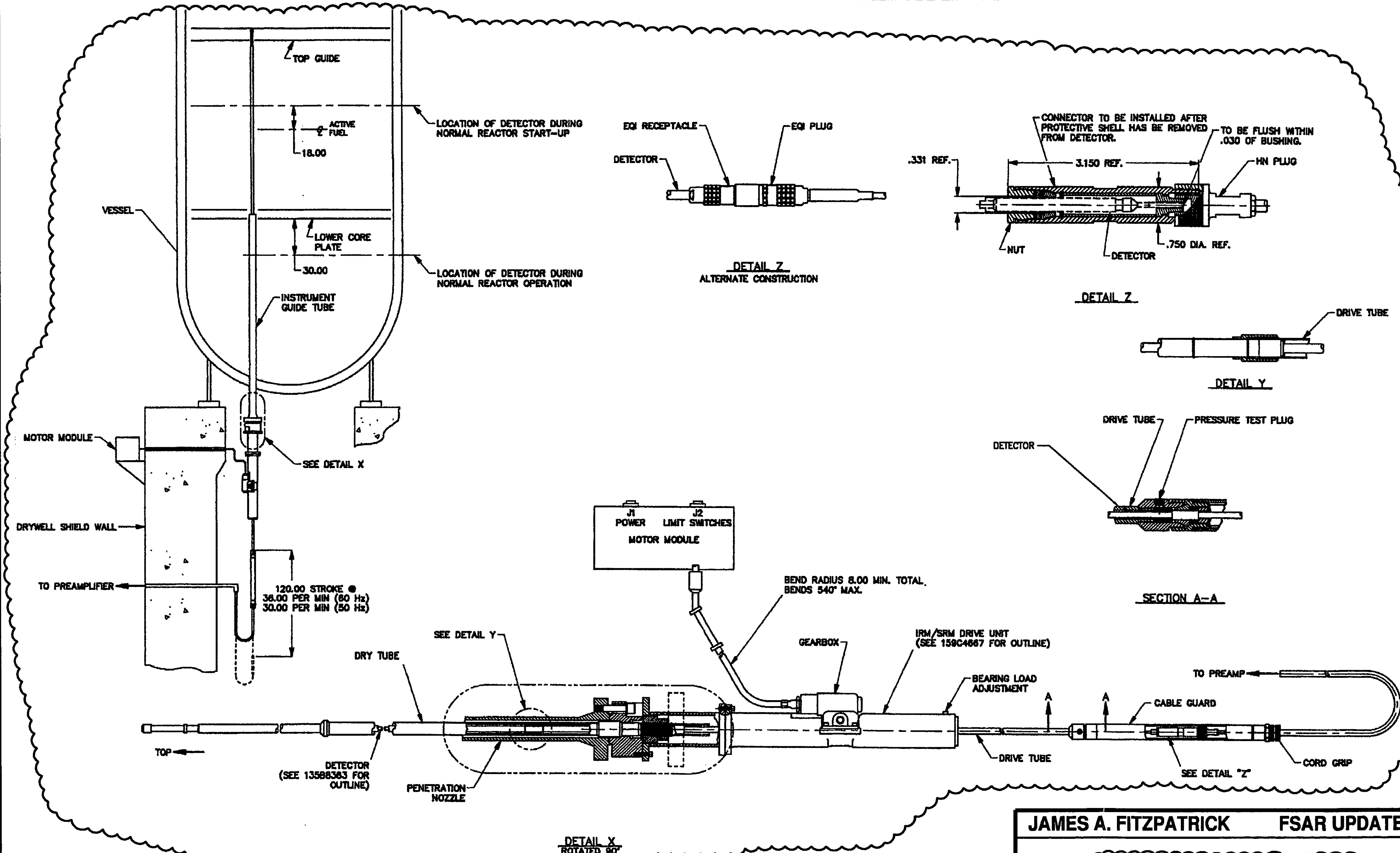
REV. 1	APRIL 2015	FIGURE NO. 7.4-9



JAMES A. FITZPATRICK FSAR UPDATE

REACTOR RECIRCULATION SYSTEM
FUNCTIONAL CONTROL DIAGRAM
(SHEET 3 OF 3)

REV. 1 APRIL 2015 FIGURE NO. 7.4-9



JAMES A. FITZPATRICK **FSAR UPDATE**

INCORE STARTUP CHAMBER
RETRACT MECHANISM

REV. 1	APRIL 2015	FIGURE NO. 7.5-2

Each of the instrument lines is fitted with a manual isolation (root) valve, excess flow check valve, and a flow restricting orifice. The valves are located directly outside the drywell in the reactor building. The orifice is located inside the drywell. The continuous back-fill connections are made outside of the primary containment, on the instrument rack side of the manual isolation and excess flow check valves. The primary containment manual isolation valves are locked open to prevent unintended pressurization of the water level and pressure indicating instrumentation by the back-fill system. The instrument lines slope downward at a minimum slope of 1/8 inch per foot from the reference legs toward the instrument racks. The slope is designed to prevent false indications caused by trapped air or gasses. Pressure and differential pressure measuring instruments use the same instrument lines, as indicated in Figure 7.8-2.

Reactor vessel water level indications provide continuous displays in the control room. One indication is derived from the wide range level transmitters. Three indicators come from the narrow range level transmitters provided for the Feedwater Control System. Two level indicators come from the fuel zone instruments used to measure the water level inside the core shroud. These instruments read full scale during jet pump operation and are also used for containment spray lockout. One refuel zone water level indicator is provided by an instrument which uses a dedicated reference column to indicate level beyond the top of the vessel during refueling.

Three strip chart recorders are provided for reactor water level. Normal operating range levels are recorded from signals from the narrow range level transmitters in the Feedwater Control System. This same recorder provides high and low level alarms. Continuous monitoring of vessel level is provided by a recorder connected to a level transmitter which measures the fuel zone water level inside the core shroud. A third level recorder provides, wide range level recording. Table 7.8-1 lists the specifications for level instruments not previously described with other systems.

Local pressure and level indication is provided in the reactor building on instrument racks 25-6 and 25-51 and on panel 25RSP. These indicators comply with 10 CFR 50 Appendix R requirements for providing local indication for safe shutdown of the reactor from a location outside of the main control room.

Figure 7.8-2 shows the indicated pressure and level instruments which initiate automatic alarms and safety actions. The following list identifies the FSAR sections where various level measuring components and their set points are discussed:

Level Sensor Instrumentation Function	Discussed in Section
Scram initiation	7.2
Reactor vessel isolation	7.3
HPCI, LPCI, Core Spray, Automatic Depressurization operation	7.4
Feedwater level control transmitters and recorders	7.10
High Water Level Trips for Main, HPCI, RCIC Turbine	7.4
RCIC initiation	4.7

The multiplicity of reactor vessel water level indications provides the control room operator with the information required to determine the coolant inventory necessary to cool the fuel. The approach of water level to abnormal conditions is indicated to the control room operator by audible and visual alarms. The high reactor water level turbine trip instruments provide additional assurance to the operator that the turbines will not be damaged by water carryover into the steam lines.

7.8.5.3 Reactor Vessel Coolant Flow Rates and Differential Pressures

Figure 7.8-1 shows the flow instruments, differential pressure instruments, recorders and EPIC points provided for determining the core coolant flow rates and the hydraulic performance of reactor vessel internals.

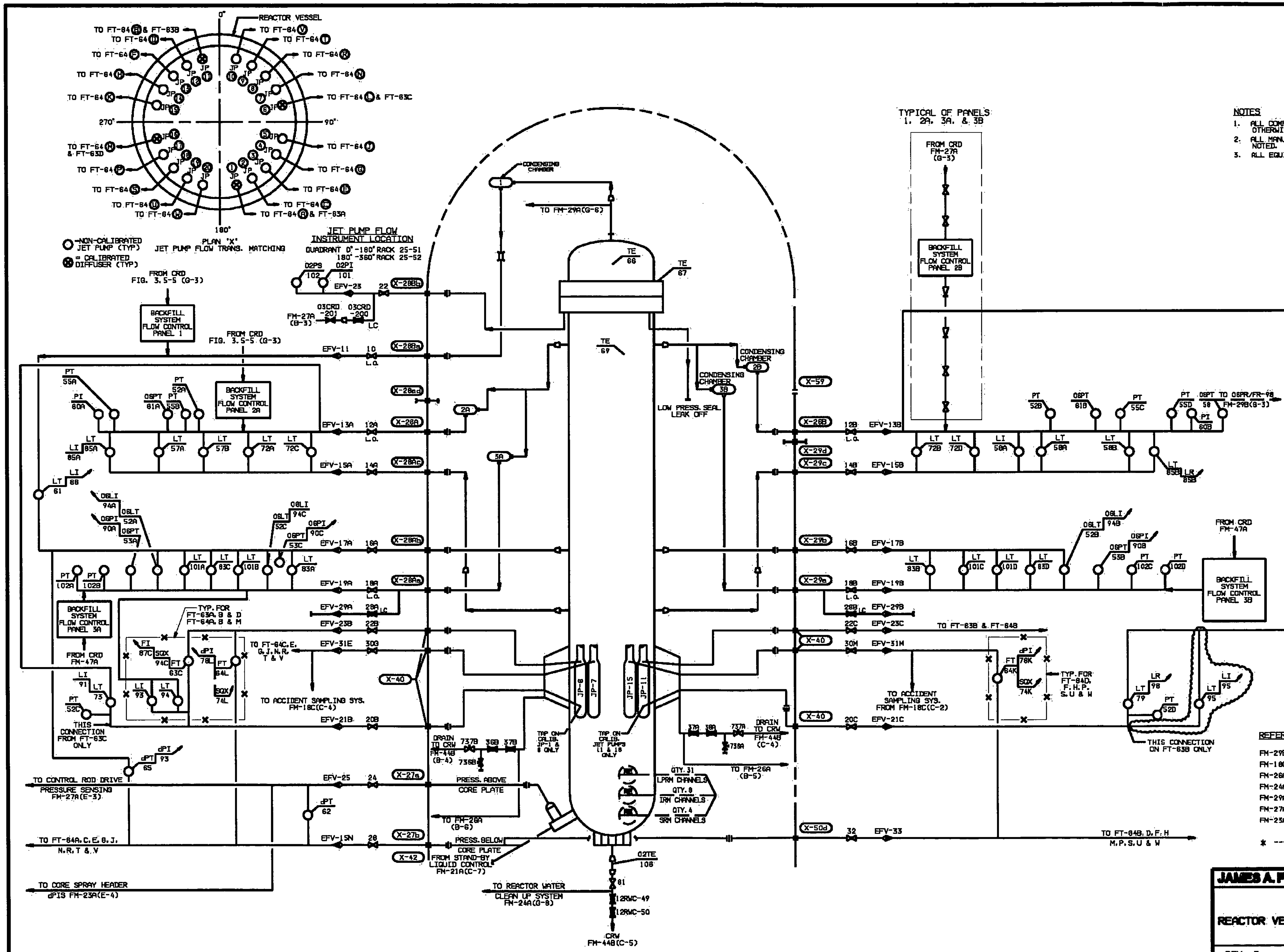
The differential pressure between the throat of each of the jet pumps and the core inlet plenum is measured and indicated in the control room. Two jet pumps per recirculation loop are specially calibrated and are provided with special pressure taps in the diffuser sections. The differential pressure measured between the special taps and the throat allows precise flow calibration, using jet pump prototype test performance data. The flow rates through the remaining jet pumps are calculated from the flows shown by the calibrated jet pumps. The flow rates through the jet pumps associated with each recirculation loop are summed to provide control room indication of the core flow rate associated with each recirculation loop. The total flows for both recirculation loops are again summed to provide a recorded control room indication of the total flow through the core.

Total core flow indication (derived from the measured flow in the jet pumps) is provided during the operation of a single recirculation loop by subtracting the reverse flow signal from the forward flow signal of the active jet pumps. This indication is provided automatically any time a single recirculation pump is in operation, or a recirculation pump discharge valve is shut, by the pump and valve circuitry.

A differential pressure transmitter and indicator are provided to measure the pressure difference between the reactor vessel above the core assembly and the core inlet plenum. This indication can be used to determine the overall hydraulic performance of the jet pump group and to check the total core flow rate. These indications are available in the Control Room.

A differential pressure transmitter is provided to indicate core pressure drop by measuring the pressure difference between the core inlet plenum and the space just above the core support assembly. The line used to determine the pressure in the core inlet plenum is the same line provided for the Standby Liquid Control System. A separate line is provided for the pressure measurement above the core support assembly. The differential pressure is both indicated and recorded in the Control Room.

Instrument lines leading from the reactor vessel to locations outside the drywell are provided with one manual isolation valve, one excess flow check valve, and a flow restricting orifice. All of the flow and differential pressure instruments are located outside the Primary Containment.



NOTES

1. ALL COMPONENT MARK NUMBERS PREFIXED 02-3 UNLESS OTHERWISE NOTED.
2. ALL MANUAL VALVES PREFIXED NBI UNLESS OTHERWISE NOTED.
3. ALL EQUIPMENT INSIDE RX VESSEL IS SYSTEM 02-1.

REFERENCE DWGS:

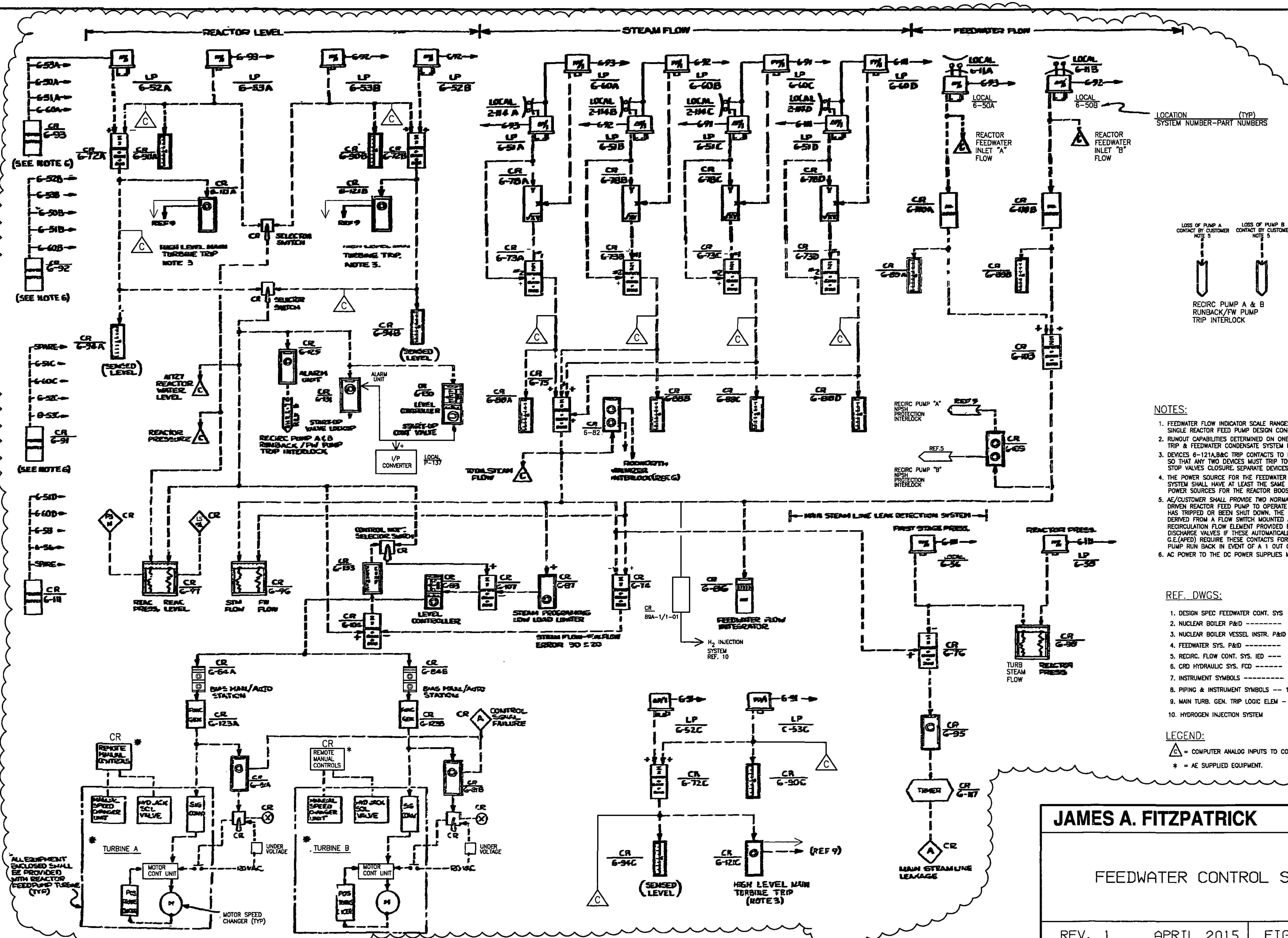
FM-29B	FIG. 4.11-1 SH. 2
FM-18C	FIG. 5.2-9 SH. 5
FM-26A	FIG. 4.3-2
FM-24A	FIG. 4.9-1 SH. 1
FM-29A	FIG. 4.11-1 SH. 3
FM-27A	FIG. 3.5-5 SH. 1
FM-23A	FIG. 7.4-5

* NO FSAR CROSS REFERENCE

JAMES A. FITZPATRICK FSAR UPDATE

FLOW DIAGRAM
REACTOR VESSEL INSTRUMENTATION (P & ID)

REV. 7 | APRIL 2015 | FIGURE NO. 7.8-2



NOTES:

1. FEEDWATER FLOW INDICATOR SCALE RANGES DEPENDANT ON CUSTOMER/AE SINGLE REACTOR FEED PUMP DESIGN CONDITION.
2. RUNOUT CAPABILITIES DETERMINED ON ONE OUT OF TWO REACTOR FEED PUMP TRIP & FEEDWATER CONDENSATE SYSTEM P&ID OR FLOW DIAGRAM.
3. DEVICES 6-121A,B&C TRIP CONTACTS TO BE WIRED IN A 2 OUT OF 3 TRIP SO THAT ANY TWO DEVICES MUST TRIP TO INITIATE MAIN & R.F.P. TURBINE STOP VALVES CLOSURE. SEPARATE DEVICES PROVIDES THE REQUIRED LOGIC.
4. THE POWER SOURCE FOR THE FEEDWATER INSTRUMENTATION AND CONTROL SYSTEM SHALL HAVE AT LEAST THE SAME DEGREE OF RELIABILITY AS THE POWER SOURCES FOR THE REACTOR BOOSTER/CONDENSATE PUMPS.
5. *AE/CUSTOMER SHALL PROVIDE TWO NORMALLY OPEN CONTACTS PER TURBINE* DRIVEN REACTOR FEED PUMP TO OPERATE WHEN TURBINE FEED PUMP UNIT HAS TRIPPED OR BEEN SHUT DOWN. THE CONTACTS SHALL PREFERABLY BE DERIVED FROM A FLOW SWITCH MOUNTED ACROSS THE R.F.P. LOW FLOW RECIRCULATION FLOW ELEMENT PROVIDED BY THE AE/CUSTOMER OR R.F.P. DISCHARGE VALVES IF THESE AUTOMATICALLY RUN CLOSED ON R.F.P. TRIP G.E.(APED) REQUIRE THESE CONTACTS FOR INITIATION OF REACTOR RECIRCULATION PUMP RUN BACK IN EVENT OF A 1 OUT OF 2 R.F.P. TRIP AT HIGH LOADS.
6. AC POWER TO THE DC POWER SUPPLIES MUST BE FROM INDEPENDENT SOURCES.

REF. DWGS:

1. DESIGN SPEC FEEDWATER CONT. SYS 6-1
2. NUCLEAR BOILER P&ID --------- 2-0
3. NUCLEAR BOILER VESSEL INSTR. P&ID 2-3
4. FEEDWATER SYS. P&ID --------- BY A.E.
5. RECIRC. FLOW CONT. SYS. IED --- 2-184
6. CRD HYDRAULIC SYS. FCD ------- 3-7
7. INSTRUMENT SYMBOLS ---------- 921D280
8. PIPING & INSTRUMENT SYMBOLS -- 104R900
9. MAIN TURB. GEN. TRIP LOGIC ELEM - BY A.E.
10. HYDROGEN INJECTION SYSTEM

LEGEND:

(C) = COMPUTER ANALOG INPUTS TO COMPUTER.

* = AE SUPPLIED EQUIPMENT.

JAMES A. FITZPATRICK		FSAR UPDATE
FEEDWATER CONTROL SYSTEM (IED)		
REV. 1	APRIL 2015	FIGURE NO. 7.10-1

7.18 DOSE ASSESSMENT COMPUTER SYSTEM

The FitzPatrick plant is equipped with a dose assessment computer system. This computer system, separate and distinct from the SPDS/EPIC system, is used to evaluate the magnitude and effects of actual or potential radioactive material releases from the plant to determine dose projections. The dose assessment computer system utilizes site-specific meteorological data to support calculations. The meteorological data may be accessed via networked portable computers in the Control Room and/or Technical Support Center (TSC) and the Emergency Operating Facility (EOF). The Control Room and Technical Support Center are provided with recorders for recording wind speed and direction for each tower location.

The system consists of data collection hardware and three meteorological towers. Meteorological instruments located on each tower are interrogated by data collection equipment also located at each tower.

One of the towers has been designated the main tower and is located at the Nine Mile Nuclear Power Plant site. A second, backup tower has been installed on the FitzPatrick site, the third, inland tower is located approximately thirteen miles inland from Lake Ontario at the Oswego County Airport near Fulton, New York.

Microcomputers compute averages and sample counts for all meteorological data at fifteen minute intervals.

Desktop computers at various locations can then access this data to perform calculations.

The system meets the major criteria for Class A atmospheric dispersion model as described in NUREG-0654 ("Criteria for Preparation and Evaluation of Radiological Emergency Response Plans for Preparedness in Support of Nuclear Power Plants"). The model uses fifteen minute averaged meteorological data, is capable of defining source characteristics, definable release modes, and includes the effects of complex wakes in dispersion calculations. Atmospheric transport and diffusion calculations are specific to the Nine Mile Point / JA FitzPatrick Site. The system provides projected dose as defined in EPA-400 and can track a plume in both the Plume Exposure and Ingestion Exposure Pathways.

Graphic displays of plume dimensions and position are available in addition to displaying the location, magnitude and arrival time of the point of peak relative concentration.

POSITION SUMMARY TABLE

(10 of 24)

(See Notes on Page 24)

ITEM	VARIABLE		CAT.	QA	INSTRUMENT RANGE	ENV. QUAL. NOTE 1	SEIS. QUAL. NOTE 2	REDUNDANT	POWER SUPPLY	CONTROL ROOM INDICATION	TSC	EOF	COMMENTS	EPIC POINT #
C14	RADIATION	-	-	-	-	-	-	-	-	-	-	-	DELETED R.G.-1.97, REV 3	-
	EXPOSURE RATE	-	-	-	-	-	-	-	-	-	-	-	SEE E2	-
C15	EFFLUENT RADIOACTIVITY – NOBLE GASES	R.G. 1.97	2	NSR	10^{-6} TO 10^{3} uCi/cc	YES	NO	NO	NON-1-E	RECORDED	-	-	COMPLIES F1-80-014	1194 1195 1196
		JAF	2	QP	10-10^{6} CPM & 10^{-1} TO 10^{7} MR/HR	YES	NO	IND-YES REC-NO	UPS AND NON-1E	17RM-434A, B 17RM-431, 432** 17RM-458A, B** 17RM-463A, B 17RR-434 17RR-433** 17RR-458** 17RR-463	EPIC	EPIC		1197 1200 1201
D1	MAIN FEEDWATER FLOW	R.G. 1.97	3	-	0-110% DESIGN PRESSURE	NO	NO	NO	NON-1E	CONTINUOUS OR ON DEMAND	-	-	COMPLIES	435 436
		JAF	3	QP	0-12X10^{6} LB/HR	NO	NO	NO	UPS	INDICATORS 06FI-89A, B RECORDER O6FR-96	EPIC	EPIC		
D2	CONDENSATE STORAGE TANK LEVEL	R.G. 1.97	3	-	BOTTOM TO TOP	NO	NO	NO	NON-1E	CONTINUOUS OR ON DEMAND	-	-	COMPLIES	1371
		JAF	3	NSR	0-360 IN.	NO	YES	NO	NON-1E	INDICATOR 33LI-101A	EPIC	EPIC		

GENERATORS

G1-981.4 MVA, 0.9 PF, 0.58 SCR 24 KV, 1800 RPM,
3 PH, 60 CY, 60 PSI H.
EDGA, EDGB, EDGC, EDGD DIESEL DRIVEN

TRANSFORMERS

T1A & T1B 525MVA, 24KV–345KV, 60CY, OFAF, 65°C RISE

T4 - 24/32/40 MVA (55C), 22.8 - 4.16 - 4.16 KV, 3 PH, 60 CY,
OA/FA/FOA, 55/65 C RISE, LTC
H WINDING - 24/32/40 MVA
X WINDING - 8/10.7/13.3 MVA
Y WINDING - 16/21.3/26.7 MVA

T2 & T3 - 15/20/25 MVA (65°C), 115–4.16–4.16KV, 3PH,
60 CY, ONAN/ONAF1/ONAF2, 65° RISE
H WINDING - 15/20/25 MVA
X WINDING - 5/6.66/8.33 MVA
Y WINDING - 10/13.33/16.66 MVA

T-5 & T-13 - 1000KVA, 4160-600V, 3PH, 60CY
T-6 THRU T-12, T-14, T-15, T-16 - 1000/1333 KVA, 4160-600V, 3PH, 60CY

BUS'

GENERATOR LEADS - ISOLATED PHASE 24000 AMP FORCED COOLED
STATION SERVICE TRANSFORMERS SECONDARY LEADS NON-
SEGREGATED PHASE, 5 KV, 1200, 2000 & 4000 AMP.

AUXILIARIES

4.16 KV BUS 10100
- 1 REACTOR CIRCULATION PUMP A

4.16 KV BUS 10200
- 1 REACTOR CIRCULATION PUMP B

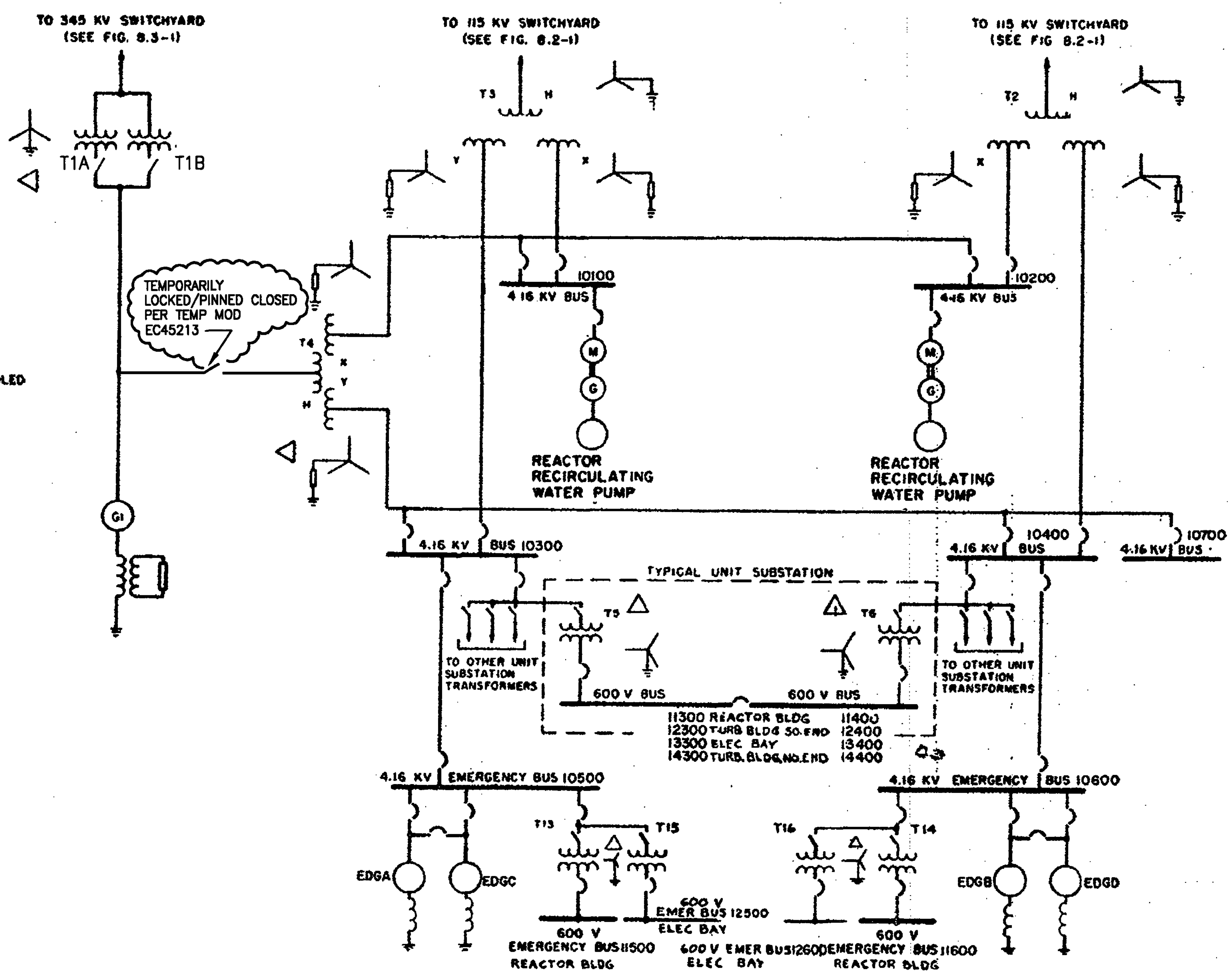
4.16 KV BUS 10300
- 1 CIRCULATING WATER PUMP A
- 1 CONDENSATE PUMP A
- 1 CONDENSATE BOOSTER PUMP A
- 1 SERVICE WATER PUMP A
- 1 TURBINE CLOSED LOOP COOL WATER PUMP A
- 4 600 V UNIT SUBSTATIONS
- 1 AIR REMOVAL VAC PUMP A

4.16 KV BUS 10400
- 1 CIRCULATING WATER PUMP B
- 1 CONDENSATE PUMP B
- 1 CONDENSATE BOOSTER PUMP B
- 1 SERVICE WATER PUMP B
- 1 TURBINE CLOSED LOOP COOL WATER PUMP B
- 4-600V UNIT SUBSTATIONS
- 1 AIR REMOVAL VAC PUMP B

4.16 KV BUS 10500
- 1 CORE SPRAY PUMP A
- 2 RHR SERVICE WATER PUMPS A & C
- 2 RHR PUMPS A & C
- 2 600 V UNIT SUBSTATIONS

4.16 KV BUS 10600
- 1 CORE SPRAY PUMP B
- 2 RHR SERVICE WATER PUMPS B & D
- 2 RHR PUMPS B & D
- 2 600 V UNIT SUBSTATIONS

4.16 KV BUS 10700
- 1 CONDENSATE PUMP C
- 1 CONDENSATE BOOSTER PUMP C
- 1 SERVICE WATER PUMP C
- 1 CIRCULATING WATER PUMP C
- 1 TURBINE CLOSED LOOP COOL WATER PUMP C



JAMES A. FITZPATRICK FSAR UPDATE

PLANT ELECTRICAL DIAGRAM

REV. 6 APRIL 2015 FIGURE NO. 8.2-1

8.3 TRANSMISSION SYSTEM CONNECTIONS

8.3.1 345 kV System Connections

8.3.1.1 Power Generation Objective

The power generation objective is to deliver power generated within the plant to offsite terminal stations.

8.3.1.2 Description

The main generator provides power through isolated phase bus duct at 24 kV to each of two main transformers, connected in parallel as shown in Figure 8.3-1. The generator voltage is stepped up by each main transformer to 345 kV and power flows to the bus in the switchyard.

The oil-forced and air-forced cooled main transformers are rated at 525 MVA, 65 C temperature rise, three phase, 60 Hz. The high voltage winding is rated at 345 kV, 1050 kV BIL and is connected in grounded wye. The low voltage winding is rated 24 kV, 150 kV BIL and is connected in delta.

Two single circuit 345 kV transmission lines, as shown in Figure 8.3-2, deliver power to the New York Power Pool transmission grid.

One line, 68.3 miles in length, runs south easterly from the plant switchyard to National Grid's Edic Substation where it connects to the existing 345 kV transmission system. The other line, approximately 4900 feet in length, runs southward from the plant switchyard to National Grid's Scriba Substation where it connects to the 345 kV transmission system. The two 345 kV lines from the JAF Plant exceed the requirements of the National Electric Safety Code for heavy loading districts, Grade B.

The 345 kV line between the JAF Plant and the Scriba Substation is protected by 345 kV air blast circuit breakers at JAF and oil circuit breakers at Scriba. The 345 kV line to Edic substation is protected by an SF6 circuit breaker at JAF and an air blast circuit breakers at Edic. Either line has transmission capacity in excess of the capability of the generating unit. With this arrangement, either line can be out of service without curtailing the output from the JAF Plant.

During normal operation all breakers in both switchyards are closed and all lines energized. Duplicate protective relays systems and backup functions provide a high degree of reliability in line operation.

While it is highly improbable that both transmission lines could be out of service simultaneously, such an event would not jeopardize the safe shutdown of the plant. If the load rejected is within the range where opening of the Turbine Bypass System valves permits continued operation of the reactor, the turbine generator continues to run and carry the plant auxiliaries; if the load rejected is greater than the capacity of the Turbine Bypass System valves, reactor trip results and the plant auxiliaries are automatically transferred to the 115 kV reserve power source.

Figure 8.3-5 is a station layout which illustrates the degree of independence of transmission and underground power lines at this station and the Nine Mile Point Stations.

8.3.1.3 Inspection and Testing

Inspection and testing at vendor facilities and initial system tests at the plant site were conducted to ensure that all components are operational within their design ratings.

The system and its components are tested throughout plant life in accordance with plant operating procedures.

8.3.2 115 kV System Connections

8.3.2.1 Safety Objective

The safety objective is to provide a supply of offsite electrical power of sufficient capacity for the engineered safeguard loads.

8.3.2.2 Safety Design Basis

The offsite power supply is capable of supplying all engineered safeguard loads.

8.3.2.3 Power Generation Objective

The power generation objective is to provide two sources of offsite AC power to the Plant Service AC Power Distribution System for plant startup, operating and shutdown power including adequate power to the emergency service buses for the safe shutdown of the reactor.

8.3.2.4 Description

The 115 kV bus at the plant is energized from two 115 kV transmission lines as shown in Figure 8.3-2.

One of the transmission lines, approximately 26 miles long, is connected to the National Grid transmission system at the Lighthouse Hill Hydroelectric Station. In addition to being a hydroelectric generating station and an integral part of the National Grid 115 kV system, this station also serves as the switchyard for National Grid's Bennetts Bridge Hydroelectric Station, which is less than a mile away from Lighthouse Hill. Other nearby hydroelectric generating stations are also connected to the Lighthouse Hill 115 kV bus.

The other line, approximately 3700 ft long, is connected to the 115 kV bus at Nine Mile Point Nuclear Station Unit 1 which in turn is directly connected to National Grid's South Oswego Substation approximately 12 miles away.

Under normal operation, the sectionalizing disconnect switches and all breakers at both JAF Plant and NMPNS Unit 1 are operated in the closed position, thereby providing two sources of 115 kV power for the JAF Plant.

Each line from the JAF Plant is protected by a 115 kV, 1200 amp, 3 phase, oil circuit breaker. Two complete sets of protective relays are provided for automatic tripping of the circuit breakers under fault conditions. Recognizing that most line faults are transient in nature, automatic reclosing equipment and circuitry is provided to re energize the lines after the extremely short interruption required to clear a temporary fault.

In the event of a fault on either section of the 115 kV bus, the associated breakers will de energize the bus and the 115 kV bus disconnect switch will open automatically to isolate the faulted bus section.

8.3.2.5 Safety Evaluation

The 115 kV lines to the Lighthouse Hill Station and to National Grid's South Oswego Substation are the same lines used at the Nine Mile Point Nuclear Station Unit 1. The 115 kV tie line between the JAF Plant and the NMPNS Unit 1 is designed to equal or exceed the requirements of the incoming lines.

Under normal system conditions, both National Grid's South Oswego Substation and Lighthouse Hill buses have multiple connections to the National Grid 115 kV transmission system in addition to local generation input. To stay within the motor starting capability of the 115 kV and 4 kV station systems, certain loads, whether energized automatically or manually,

are sequentially started. With this consideration there is more than adequate capacity to supply power to the NMPNS Unit 1 and the JAF Plant concurrently from either Lighthouse Hill or National Grid's South Oswego Substation for any possible combination of normal, shutdown or engineered safeguard loads.

With degraded supply voltage, the 4 kV undervoltage protection scheme will operate, and after a designated time delay, will start the Emergency Diesel Generators (EDGs) and open the supply breakers to the 10500 and 10600 buses.

In the design base LOCA, the 115 kV transmission lines must maintain adequate voltage after a generator trip to allow the Reserve Station Service Transformers (RSSTs) connected to the 115 kV system to power all connected loads, including ECCS loads and those plant loads that would be energized from the RSSTs, without the emergency buses separating and being energized from the EDGs. This post-contingency voltage is monitored frequently by the 115 kV system operator, using a predictive model to confirm that, after a generator trip with the expected emergency loads started and supplied from the RSSTs, the voltage will not decrease sufficiently to cause the 10500 or 10600 bus to separate from the RSSTs. If the post-contingency voltage drops below this level, the 115 kV system operator receives an alarm,

notifies the JAF Control Room, and takes whatever actions are available to attempt to raise this post-contingency voltage back above the alarm setpoint. The 115 kV system operator also notifies the Control Room when the post-contingency voltage alarm clears.

In case of a system blackout, the JAF Plant has access to hydroelectric generation from the Lighthouse Hill Station, with permission from Nine Mile Point Nuclear Station Unit 1.

8.3.2.6 Inspection and Testing

Inspection and testing at vendor facilities and initial system testing was conducted to ensure all components were operational within design ratings.

The system and its components are tested throughout plant life in accordance with plant operating procedures.

8.3.3 115 kV and 345 kV Switchyard Control Circuits

345 kV Switchyard

As described in Section 8.3.1.2 and shown on Figure 8.3-3, the 345 kV switchyard consists of facilities for connecting the generating unit, the 345 kV transmission line to National Grid's Edic Substation and the 345 kV tie line to National Grid's 345 KV Scriba Substation.

The Edic 345 kV line is protected by an SF6 circuit breaker at JAF and the Scriba line is protected by an air blast breaker at JAF. At the terminating switchyards, the lines are protected by air blast breakers at Edic and oil circuit breakers at Scriba. During normal operation all circuit breakers and disconnect switches are closed and each transmission line is energized. Duplicate protective relay systems and backup functions, provide a high degree of reliability in line operation.

Each circuit breaker has two trip coils, either of which can trip the breaker. The wiring for one breaker trip coil and its associated relaying is physically separated from the wiring for the other trip coil and its associated relaying. Physical separation is accomplished by using separate tray and conduit systems in the plant, and separate duct lines, cable trenches, and conduit systems in the switchyard.

Separate 125 V DC power sources are used for each trip coil and its associated tripping contacts. Branch circuit protective and isolation devices are used as required to protect and isolate the control circuits.

Disconnect switches in the 345 kV switchyard include motor operated breaker isolation switches located on each side of the 345 kV circuit breaker, and one motor operated switch which is located in the tie between the main step up transformers and the 345 kV bus. These switches are supplied from two separate 125 V DC power sources which are judiciously distributed and physically separated to ensure a high degree of reliability and operability. Physical separation of wiring is accomplished for these switches by the same means as described previously for the circuit breakers.

All breakers and disconnect switches have control switches and status indicating lights in the Control Room. In addition, alarms are displayed in the Control Room to furnish the control room operator with complete information on the switchyard and the transmission lines. Each

345 kV circuit breaker and disconnect switch can be operated by the control room operator. Circuit interlocks are included to prevent the accidental misoperation of a circuit breaker or disconnect switch. These interlocks ensure that all prior actions have been performed before the manual operation of any switch or breaker can be executed.

During normal operation all circuit breakers and disconnect switches are closed. However, should an emergency condition arise which, in the judgment of the Site Executive Officer, Plant Manager, or Shift Manager, requires that a circuit breaker and disconnect switch be opened, then this action will be executed.

The JAF Plant may be uncoupled from the 345 kV transmission system by means of disconnect switch 10031 shown on Figure 8.3 3 if conditions require this be done. Circuit breakers 10042 and 10052 must be opened or the generator must be off line before switch 10031 can be opened to uncouple the plant.

115 kV Switchyard

As described in Section 8.3.2.4 and shown in Figures 8.3 2 and 8.3 4, the 115 kV switchyard consists of facilities connecting a 115 kV transmission line from Lighthouse Hill, a 115 kV tie line to Constellation Energy's Nine Mile Point Nuclear Station and two reserve station service transformers which supply station service power to the JAF Plant.

Each of the two 115 kV transmission lines to the plant is protected by a 115 kV oil circuit breaker. During normal operations both circuit breakers and all disconnect switches are closed and each transmission line is energized. Two complete sets of relaying are provided for tripping each circuit breaker. Automatic reclosing relaying is also provided to re energize the lines after a short interruption required to clear a temporary fault.

Each circuit breaker has two trip coils either of which can trip the breaker. The wiring for one breaker trip coil and its associated tripping contacts is physically separated from the wiring for the other trip coil and its associated tripping contacts. Physical separation is accomplished by using separate tray and conduit systems in the plant and separate duct lines and conduit systems in the switchyard.

Separate 125 V DC power sources are used for each trip coil and its associated tripping contacts. Branch circuit protective and isolation devices are used as required to protect and isolate the control circuits.

Electrically operated disconnect switches in the 115 kV switchyard include a bus sectionalizing switch and a disconnect switch between the bus and each reserve station service transformer. Again two separate 125 V DC sources are used to control the switches, and each source is judiciously distributed and physically separated to ensure a high degree of reliability and operability.

Physical separation of wiring is accomplished for these switches by the same means as indicated previously for the circuit breakers.

Each circuit breaker and electrically operated disconnect switch has control switches and status indicating lights in the Control Room. In addition, alarms are displayed in the Control Room to furnish the operator with information on the switchyard and its transmission lines. Each circuit breaker and electrically operated disconnect switch can be operated by the control room operator. Curcuit interlocks are included to prevent accidental misoperation of a circuit breaker or disconnect switch.

During normal operation all circuit breakers and disconnect switches are closed. However, should a situation arise which, in the judgement of the Site Executive Officer, Plant Manager, or Shift Manager, requires that a circuit breaker and disconnect switch be opened, then this action will be executed.

The JAF Plant equipment is not normally powered from the 115 kV system because the 4 kV circuit breakers 10212, 10412, 10112, and 10312, which are connected to the low voltage side of each reserve station service transformer are normally open. In addition, disconnect switches 10025 and 10015 shown in Figure 8.3-4, can be opened to completely uncouple the JAF Plant from the 115 kV transmission system. However, switches 10025 and 10015 cannot be opened unless either the above listed 4 kV circuit breakers or 115 kV circuit breakers 10022 and 10012 are open.

The operation of both the JAF Plant and the Nine Mile Point Nuclear Station is coordinated with National Grid and the New York Power Pool so that reliability of one station is not jeopardized by operations in the other station.

8.3.4 Transient Stability Performance at the FitzPatrick Plant

Extensive transient stability studies were carried out on the digital computer to examine the performance of the interconnected transmission system for various contingency conditions in the vicinity of the JAF Plant. These studies assessed system performance for 1985 conditions with the FitzPatrick-Nine Mile Point #1 345 kV line connected to the Scriba substation. The most critical faults were recently re-examined for 1995 conditions with the addition of the 1080 MW Sithe Energies generating facility near Oswego connected to the grid via new 345 kV lines to National Grid's Scriba and Clay substations. The tests were performed in conformance with the criteria outlined in the NPCC document entitled "Basic Criteria For Design and Operation of Interconnected Power Systems." The pertinent conclusions of JAF-area studies follow:

a. For faults on the local JAF - Nine Mile Point - Scriba 345 kV transmission system, the two 115 kV sources from Lighthouse Hill and Oswego would not be interrupted. Also, the FitzPatrick and Nine Mile Point units, as well as other generator units in the interconnected system, remain stable.

b. If a fault occurs on the 115 kV transmission system in either the Lighthouse Hill or Oswego area, the JAF unit remains stable and its associated 345 kV transmission will not be affected.

c. Direct tripping of the JAF Plant, whether or not due to a fault on the 345 kV system, will not open the two 115 kV auxiliary power lines nor disrupt the 4 kV station service bus.

d. For loss of the most critical unit, which is Nine Mile Point #2, the FitzPatrick unit remains stable and its associated 345 kV transmission and the two 115 kV sources of auxiliary power supply will not be affected.

8.3.5 Historical Questions on Electrical System

The following text delineates previous AEC Questions and subsequent responses. Specifically, AEC Question 7.3.g.3, dated January 12, 1972 and response and follow-up AEC Question 8.5,

dated August 11, 1972, and response are provided. This information is considered historical FSAR information. Note that references made to FSAR Figures, pages, etc. are references to the original FSAR.

Question 7.3: Provide the information requested in the Commission's Information Guide 2, "Instrumentation and Electrical Systems" (10/27/71). If the requested information is presently contained in the FSAR, the response should identify its specific location.

g. A partial response to Item 13 of Information Guide 2 is presented in Appendix K of the FSAR. Provide the following additional information in your response: (3) the changes made to the 115 kV power system and a comparison of the adequacy of the new design with that of the design approved for the construction permit.

Response:

Item 3 (Q.7.3-g) - As stated in item 8 of Appendix K, the 115 kv Reserve A-C Power source has been rearranged to increase the reliability of the system. The former and the present arrangements of this system are shown on Figure 8.3-7, and a comparison of the salient features of the two arrangements is given below. The criteria to which the system is designed are given in the safety objective, the safety design basis, and the power generation objective on Page 8.3-2 of the FSAR. These criteria have not changed since the issuance of the FitzPatrick construction permit.

1. <u>Operation</u>

PSAR Arrangement

The buses at both stations were to have been operated with the sectionalizing disconnects and all breakers closed. The system in effect was composed of two three-terminal lines.

FSAR Arrangement

The buses at both stations are operated with the sectionalizing disconnects and all breakers closed. All lines are of the two-terminal type, and are independent of each other.

2. <u>Electrical Faults</u>

On Line:

PSAR Arrangement

Since lines leave each station with one reserve supply from the other station, a line fault required tripping of breakers at three terminals. Should one of the local breakers have failed to clear, it would have jeopardized the 115 kv bus at the associated station, and could have affected the supplies to the other station.

FSAR Arrangement

Since lines leave each station with one independent reserve supply, a line fault requires tripping of breakers at two terminals. Should a breaker on the faulted line fail to clear, backup, in-series breakers are available to clear the other station from the faulted line.

On Station Bus:

PSAR Arrangement

A fault on either bus section at either station would have been cleared by tripping the appropriate breakers and bus sectionalizing switch. Upon reclosing of the breaker associated with the unaffected bus section, a single reserve supply would have been provided to the plant with the faulted bus, and two supplied to the other station. If either breaker failed to open, the reserve power supply to both stations would have been interrupted.

FSAR Arrangement

A fault on the outboard (point 1) section of either bus is cleared by opening the appropriate supply and tie breakers and the bus sectionalizing switch. Upon reclosing the tie breaker associated with the unaffected bus section, and leaving the bus sectionalizing switch open, a single reserve supply is provided for both stations.

A fault on the inboard section (point 2) of either bus is cleared by tripping the appropriate supply and tie breakers, and the sectionalizing switch on the faulted bus. Upon reclosing the supply breaker and leaving the bus sectionalizing switch open, the affected station is provided an independent reserve power supply. The reserve power supply to the other station is not interrupted by the occurrence of a fault in the other bus.

If either breaker fails to open, the remote tie breaker will be opened, and there will be no interruption of power to the unaffected station.

At Transformer:

PSAR Arrangement

A fault at any transformer would be cleared by tripping the appropriate bus supply breakers, opening the appropriate transformer isolating switch and reclosing the supply breakers. If either breaker failed to open, the reserve power supply to both stations would have been interrupted.

FSAR Arrangement

A fault at any transformer will be cleared by tripping the appropriate supply and tie breaker and the appropriate transformer isolating switch, and then reclosing the supply and tie breakers. If either breaker fails to open, the remote tie breaker will be opened, and there will be no interruption of power to the unaffected station.

3. Protection

PSAR Arrangement

With the three terminal system, the relay protection scheme would be more complex and increase the interaction between plants.

FSAR Arrangement

With the two-terminal system, the relay protection scheme is simplified. Since it is achieved basically on an in-plant basis, plant interaction is minimized.

Conclusions

1. A two-terminal system is more reliable because the number of elements that can affect any circuit and circuit interaction is reduced.

2. Because of greater separation between lines and less exposures to other lines, the two-terminal system is less vulnerable to physical hazards.

3. The two-terminal system is less vulnerable to operator error, and to maintenance error, both manual and automatic.

4. The two-terminal system provides greater assurance of power to both systems in the event of faults on either reserve power supply.

Question 8.5: The responses to Questions 7.3 (Item 13-3), 8.1, and 8.3 are incomplete and lack the information discussed with your representatives at a recent meeting. The following items are required for our review:

a. Our preliminary review of your post-construction permit change to the arrangement of the transmission lines for off site power determined that the change could be acceptable if the

final design and installation were implemented in accordance with the General Design Criteria and IEEE-308. Our present review of this change has determined that it does not conform to the requirements of General Design Criterion 17.

Provide for our evaluation: (1) A discussion of the 115 kv off site power system, identifying conformance to General Design Criterion 17, with justification of the acceptability of areas of nonconformance, since your comparison of the salient features of the former and present arrangements with the design criteria does not include this. (2) A detailed description and failure analysis of the circuitry which automatically disconnects both off site power supplies from the Fitzpatrick plant as a result of conditions in the adjoining Nine Mile Point Station, or any other conditions. (3) Justification and analysis showing that adequate separation of the transmission lines on your station is provided to prevent any physical event from causing simultaneous failure to both off site power supplies. The distance between the 115 kv off site power lines routed to the switchyard and the 345 kv transmission line that crosses over both off site power lines are of concern. Your response should include the examples and assure that no others exist.

b. Figure Q.8.1-1 (UFSAR Fig. 8.3-8) does not include the locations of the Reserve and Normal Station Service Transformers. Modify the figure to include these locations. This figure also indicates that an underground duct line (control) is installed between the Nine Mile Point Station and the FitzPatrick switchyard. Provide a description of the circuitry and control systems to which the cabling in this duct line is connected. Also include the equipment served and their power supply requirements.

Response: The FitzPatrick plant has two independent sources of offsite power. One is a line from Lighthouse Hill; the other a line from the Nine Mile Point Unit 1 switchyard, which is in turn fed from the Oswego steam station. The two lines are connected to the 115 kv bus in the Fitzpatrick plant 115 kv switchyard. A motor-operated bus sectionalizing disconnect switch is incorporated in the bus.

Two feeds, one from each end of the 115 kv bus, feed the reserve station service transformers through motor operated disconnect switches. Each of these transformers feeds its own pair of 4 kv station service buses through electrically operated air circuit breakers (one breaker in each of four independent switchgear assemblies).

The switchgear breakers involved in supplying off site power to 4 kv bus 10500 (emergency bus "A") are independent of those supplying bus 10600 (emergency bus "B"). In the first case, breaker closing control power is supplied from station battery "A," in the second case from battery "B." Likewise, closing power for the 115 kv breaker in the line to the Nine Mile Point Station and for the 115 kv disconnect for Reserve Station Service Transformer T3 is supplied from battery "A" and closing power for the Lighthouse Hill line breaker and the 115 kv disconnect for Reserve Station Service Transformer T2 is supplied from battery "B." Power for the 115 kv bus motor-operated disconnect is supplied from battery "B."

Each of the 115 kv line breakers has two separate tripping circuits. Either trip circuit is capable of tripping the breaker. In each breaker, one trip circuit is fed from battery "A" and the other from battery "B." For each line there is a primary and a secondary protective relaying scheme. The tripping relays for each scheme are on a separate DC circuit (a total of four circuits). Both primary relaying circuits are supplied from battery "A," both secondary schemes from battery "B." For the two trip coils in each breaker and for the primary and secondary relaying schemes, the "A" and "B" wiring is run in separate raceways and is also separated ("A" from "B") by barriers in the switchyard compartments. Both breaker trip circuits for a line breaker are actuated by both the primary and secondary relaying for the associated 115 kv line.

Additional 115 kv relaying includes 115 kv bus differential relaying, a 115 kv breaker failure scheme, and a lockout scheme which trips and locks out the four 4 kv breakers on the

secondaries of both reserve station service transformers in the event of a system blackout. The lockout scheme is actuated on a simultaneous loss of potential at four points, one on the line side of each 115 kv breaker (points A and B on Fig. Q8.5-1 (UFSAR Fig. 8.3-6)) and one on each section of the 115 kv bus (points C and D on Fig. Q8.5-1 (UFSAR Fig. 8.3-6)). At each of these points, there are two undervoltage relays. The simplified electrical schematics on Fig. Q8.5-1 (UFSAR Fig. 8.3-6)) show how one set of four contacts, one from the undervoltage relay at each point, is connected in series with Auxiliary Relay AA and how the contacts of the other set of four under voltage relays are connected in series with Auxiliary Relay BB. It is also shown how "normally closed" contacts from Auxiliary Relays AA and BB are connected in the closing circuits of the 4 kv breakers and "normally open" contacts are connected in the trip circuits of these breakers. On loss of potential at points A, B, C and D, the "normally closed" contacts of Auxiliary Relays AA and BB will all be open, thus preventing the closing circuits of the four 4 kv breakers from being energized so that the breakers cannot be closed; the "normally open" contacts will be closed, thus energizing the trip circuits of these breakers so that they will be tripped open if they have been previously closed. A single failure to either Auxiliary Relay AA or BB will not trip any of the breakers nor will it prevent their closure.

Auxiliary Relays AA and BB can be manually reset, but only after word has been received from Nine Mile Point Station that adequate power is available for both that station as well as the FitzPatrick Plant. It is thus possible, if adequate power is available, for FitzPatrick Plant to have off-site power even during blackout.

Other contacts from each of the Auxiliary Relays are used for annunciation in the main control room of the Fitzpatrick Plant. Two main objectives are accomplished by the above undervoltage tripping and lockout scheme; (1) during a system blackout, the 115 kv line from Lighthouse Hill switchyard is reserved for use by the Nine Mile Point Station until such time as adequate offsite power is available for the Fitzpatrick Plant also; (2) no single failure of the tripping and lockout scheme can inadvertently cause a loss of off-site power to the FitzPatrick Plant.

Each reserve transformer has two protective relaying schemes. For each transformer, the trip relays of one scheme are fed from battery "A" and the trip relays of the other scheme from battery "B." If the transformer and bus 115 kv disconnects are closed, a fault on either transformer will cause a trip and lockout the 4 kv breakers for the faulted transformer and a trip of both 115 kv line breakers and the other transformers 4 kv breakers. The 115 kv disconnect of the faulted transformer will automatically open and both 115 kv line breakers will automatically reclose in turn after an approximate 10 second delay and permissives will be established to allow closure of the 4 kv breakers from the control room for the unfaulted transformer.

Normally the 4 kv buses are supplied through the Normal Station Service Transformer and the 4 kv breakers from the Reserve Station Service Transformers are open. The following describes the operation of the 4 kv breakers at buses 10100, 10200, 10300, and 10400.

Upon automatic trip of the Normal Station Service Transformer 4 kv breaker the Reserve Station Service Transformer 4 kv breaker will automatically close if all of the following permissives are satisfied: the Reserve Station Service Transformer is not locked out, the control switch for that 4 kv breaker is in the after trip position, the control switch for the Normal Station Service 4 kv breaker is in the after close position, the Normal Station Service Transformer the 4 kv breaker is proved open and not electrically locked out, greater than 90 percent voltage is present at the low side terminals of the Reserve Station Service Transformer, the 4 kv bus voltage is greater than 75 percent or less than 25 percent, and that 4 kv breaker is not electrically locked out.

The Reserve Station Service Transformer 4 kv breakers must be closed manually by control switch in the control room if all the above permissives are not satisfied.

Whenever both 115 kv breakers are tripped, the time for reclosing the first 115 kv circuit breaker is approximately ten seconds. If 4 kv Emergency Bus 10500 is being supplied through breakers

10514 and 10304 from bus 10300, both of these breakers will be tripped when the bus voltage is less than 80 percent of normal for longer than approximately 5 seconds. The Emergency Diesel Generators associated with this 4 kv bus will get a start signal immediately upon detection of bus voltage less than 80 percent of nominal. Safety related equipment supplied from this emergency 4 kv bus 10500 will therefore have power available from the Emergency Diesel Generators in accordance with the Emergency Diesel Generator loading program. The same events apply to the breakers and diesel generators associated with emergency 4 kv bus 10600.

Upon operation of the 115 kv bus differential or breaker failure scheme, 115 kv line breakers and the 4 kv breakers of both transformers will be tripped.

An automatic reclosure of the first line breaker will then be initiated after a time delay of about 10 seconds. If the breaker remains closed the bus disconnect will not open and the other line breaker will reclose automatically when the line is proven in synchronism with the bus.

A failure of the first line breaker to reclose successfully will be followed by automatic opening of the 115 kv bus disconnect and then by an automatic reclosure of the second line breaker followed by a second reclosure of the first line breaker. Whichever of the line breakers is connected to the unfaulted section of the bus will remain closed. If necessary, power will be restored to the 4 kv system manually from the control room.

There is no protective relay action which will not be followed by automatic attempts to reclose both line breakers. After any single fault at least one line will be reconnected to the 115 kv bus.

If the operator has no indication of the successful reclosure of at least one line breaker within a short time (less than 5 mm) after a trip, a failure will be assumed. At this time the operator will, from the control room, manually attempt to reclose one 115 kv breaker. If the reclosure attempt is unsuccessful, he will manually from the control room open the 115 kv bus disconnect and again attempt to close one 115 kv breaker. If it does not stay closed he will then attempt to close the other 115 kv breaker. If the failure was an active device failure (such as a false relay operation) at least one line breaker will successfully close. If the failure was an improbable fault in the control wiring, both breakers may trip again but there is sufficient diversity of relaying and trip circuits to allow control power to be removed from the affected circuit. The lines can be put back in service once the fault in the control wiring is isolated.

Based on the above, the possibility of simultaneous loss of both sources of off site power has been minimized to the extent practical.

There is no circuitry which automatically disconnects both offsite power supplies from the Fitzpatrick Plant as a result of conditions in the adjoining Nine Mile Point Station or conditions at any other station.

The two 115 kv transmission lines leaving the Fitzpatrick site as shown on Figure Q8.1-1 (UFSAR Fig. 8.3-8) are 76 ft apart at the switchyard portal structure and diverge from that point.

Fig. Q8.1-1 (UFSAR Fig. 8.3-8) shows two tangent (suspension) towers, numbers 2 and 3, supporting the 595 foot 345 kv span that crosses the 115 kv tie from FitzPatrick Plant to Nine Mile Point Station. Structurally, these towers are designed to support a span of identical 345 kv conductors and insulators that supports a 1,000 foot horizontal wind span and a 1,400 ft vertical weight span. In either case, the tower design is predicated on 1-1/2 inch radial ice load on each conductor or 100 mph wind load. (Experience has shown, that heavy ice load never occurs simultaneously with high wind load. This is documented National Electric Code (NESC) 6th Edition National Bureau of Standards Handbook No. 81, where the heavy ice loading condition is given as 1/2 inch of radial ice plus a 40 mph wind). Transverse wind loading is the governing factor in transmission tower design. For this span, towers 2 and 3 are consequently nearly twice as strong as required for normal line design. The vertical distance from the 345 kv line to the 115 kv line is 40 ft at 60 degrees F.

Towers 3 and 4 support the 578 foot 345 kv span that crosses the 115 kv line from Fitzpatrick Plant to Lighthouse Hill Station. Tower 4 is a dead-end (strain angle) tower. Structurally, tower 4 is designed to support a span of identical 345 kv conductors and insulators that supports a 1,000 ft horizontal wind span and a 1,500 ft vertical weight span upon with the same ice and wind loads as described above. For a dead-end tower, the line tension is the governing factor in transmission tower design. Tower 4 is designed for a line tension of 11,500 lb per conductor but the design tension used for each conductor in this span is 8,000 lb, including 1/2 inch radial ice load and a simultaneous 40 mph wind. For this span, tower 4 is nearly 1-1/2 times as strong as required for normal line design. The minimum vertical distance from the 345 kv line to the 115 kv line underneath it is 23-1/2 ft at 60 degrees F.

Towers 1 and 2 support a 776 foot 345 kv span west of the span that crosses the 115 kv line from Fitzpatrick Plant to Nine Mile Point Station. Tower 1 is a dead-end (Strain) tower. Structurally, tower 1 is designed to support a span of identical 345 kv conductors and insulators that supports a 1,000 ft horizontal wind span and a 1,500 ft vertical weight span with the same ice and wind loads as described above. Tower 1, being a dead-end tower, has its design governed by line tension. It, too, is designed for a line tension of 11,500 lb per conductor, but the design tension used in each conductor is 8,000 lb, including 1/2 inch radial ice and a simultaneous 140 mph wind. For this span, tower 1 is nearly 1-1/2 times as strong as required for normal line design.

Towers 1, 2, 3 and 4 will withstand the breaking of any one phase or all three phases in any one of the above spans without collapsing the tower structures. There is no other instance where lines of both off site power sources are crossed by another line.

Insofar as insulator strength is concerned, the insulator design is based on a single string of 30,000 lb units in suspension in towers 2 and 3 and a double string of 40,000 lb units in strain towers 1 and 4. With the previously mentioned 1-1/2 radial ice load criterion, this design results in a loading of 37 percent of the suspension insulators' rated strength and 39 percent of the strain insulators' rated strength, so that a consistent design is obtained. This 37-39 percent loading is extremely conservative in that it considers 1-1/2 inch radial ice loading. The <u>heavy</u> ice loading criterion in the NESC was given above as 1/2 inch of radial ice load, a much less severe criterion for insulator loading than 1-1/2 inch radial ice. The line tensions are such that for the 1-1/2 inch radial ice load, both conductors in the bundle constituting a single phase will be supported by only one of the dual 40,000 lb, strain insulators without exceeding the insulator rated strength.

Towers 1 and 4 are both dead-end (strain) structures with two sets of dual strain insulators per phase. Tower 1 has dual insulators both on the side facing tower 2 and on the side facing the Nine Mile Point Nuclear station; tower 4 has dual insulators on the side facing tower 3 and also on the side facing the portal structure of the JAFNPP 345 kv switchyard. Continuity of the phase conductors around the strain insulators sets is maintained by securely anchored jumper loops. Failure or breakage of the insulators will not result in phase conductors falling into the 115 kv line because the jumper loops maintain the integrity of the 345 kv phase conductors.

In order to provide an extra margin of reliability in case of breakage of the suspension insulators at towers 2 and 3, due to vandalism or similar incidents, a dual string of insulators is provided at both these towers. Should failure of the dual string of insulators occur at suspension towers 2 and 3 or at strain tower 4, the conductors will not fall into the 115 kv line but may come as close as 6 ft; under worst ambient conditions, to the two shield wires above the 115 kv lines. Such an event could result in a trip of the 345 kv line but will not affect the 115 kv line concerned.

We believe that, based on our interpretation of General Design Criterion 17, this arrangement meets the requirements of this criterion. Where conflicts exist between applicable portions of IEEE-308 and General Design Criterion 17 exist, the latter governs.

<u>Control Duct Line</u>

The control duct line which runs between the Fitzpatrick plant and Nine Mile Point Station switchyards contains cabling for the protective relaying on the 345 kv tie line and 115 kv line between the switchyards.

115 kv System Cable

Only one cable in this duct line is for the 115 kv system and this cable is for the pilot wire differential current transformer circuit used to trip breaker 10012. This cable is connected to the Nine Mile Point Station current transformer of this relay circuit. All pilot wire relays for tripping breaker 10012 are located in the Fitzpatrick Plant, and all wiring except the cable in the duct line is described in the response to Question 8.2.

The pilot wire relaying is connected to the power supply in the Fitzpatrick Plant which contains all the "primary" relaying for the Fitzpatrick - Nine Mile Point 115 kv Transmission Line.

345 kv System Cables

All other cables in this duct line are for relaying and metering circuits associated with the 345 kv system and more specifically with the 345 kv transmission line from the Fitzpatrick Plant to the Nine Mile Point Station.

These cables fall into the following grouping:

a. Alternate 1 relaying current transformer circuits.

b. Relaying potential transformer circuits.

c. Alternate 2 relaying current transformer circuits.

d. Metering current transformer circuits.

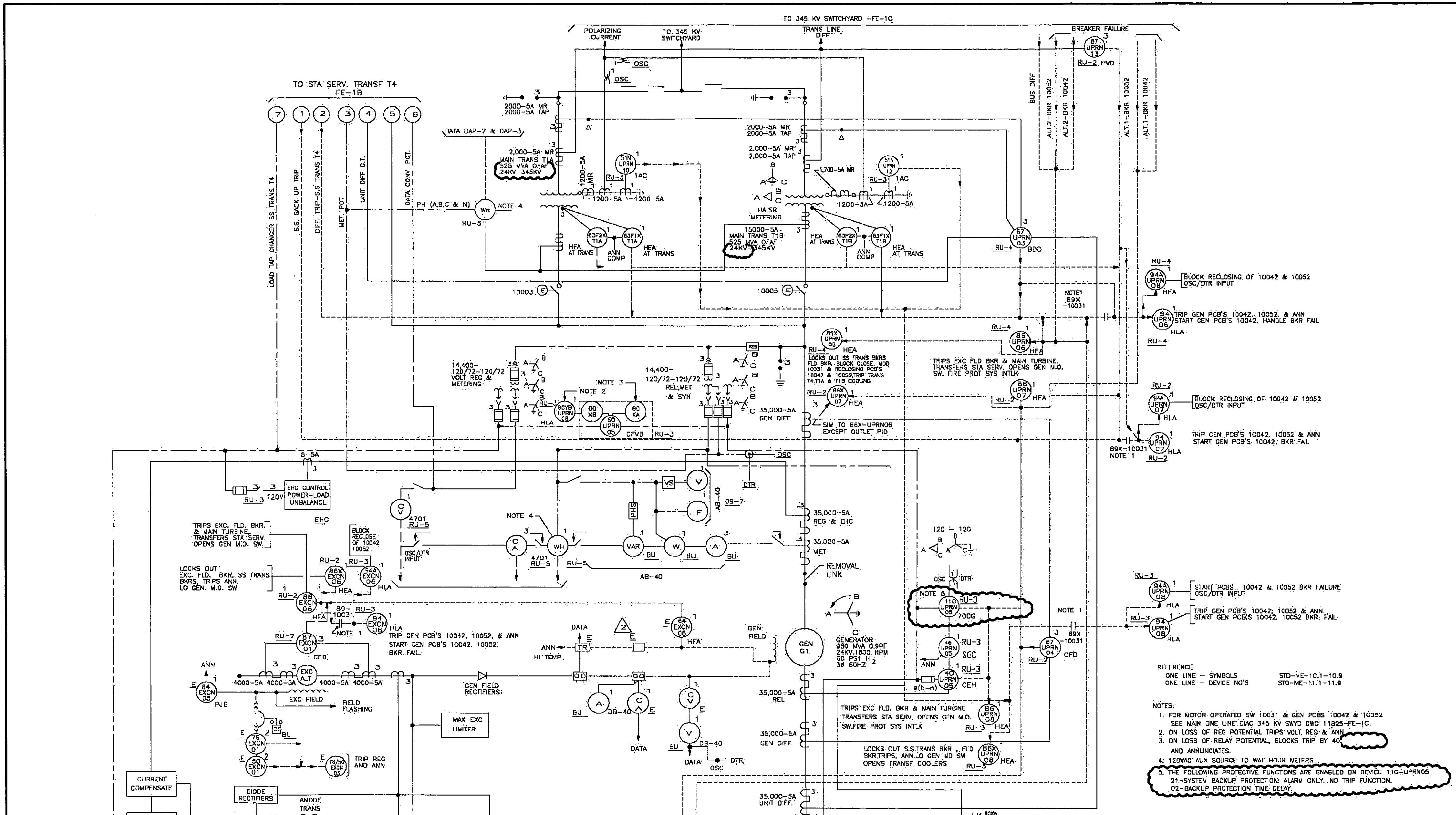
e. Relaying control circuits, for differential relaying and transfer trip.

Alternate 1 and Alternate 2 are designations for two separate relay schemes and are shown in Figure 8.3-1 of the FSAR.

Power supplies to which this relaying is connected are located at both the Fitzpatrick and Nine Mile Point Stations and do not run in the control duct. Circuits from these power supplies are not safety related, and all cabling in the duct line is not safety related.

Separation of cabling is accomplished in the Fitzpatrick Plant and switchyard as described in the response to Q.8.2. Separation for Alternates 1 and 2 is maintained in the duct line by use of separate ducts and manholes for each relaying scheme.

For the arrangement of the normal and reserve station service transformers in relation to the main transformers please refer to FSAR Figure 9.8-1.



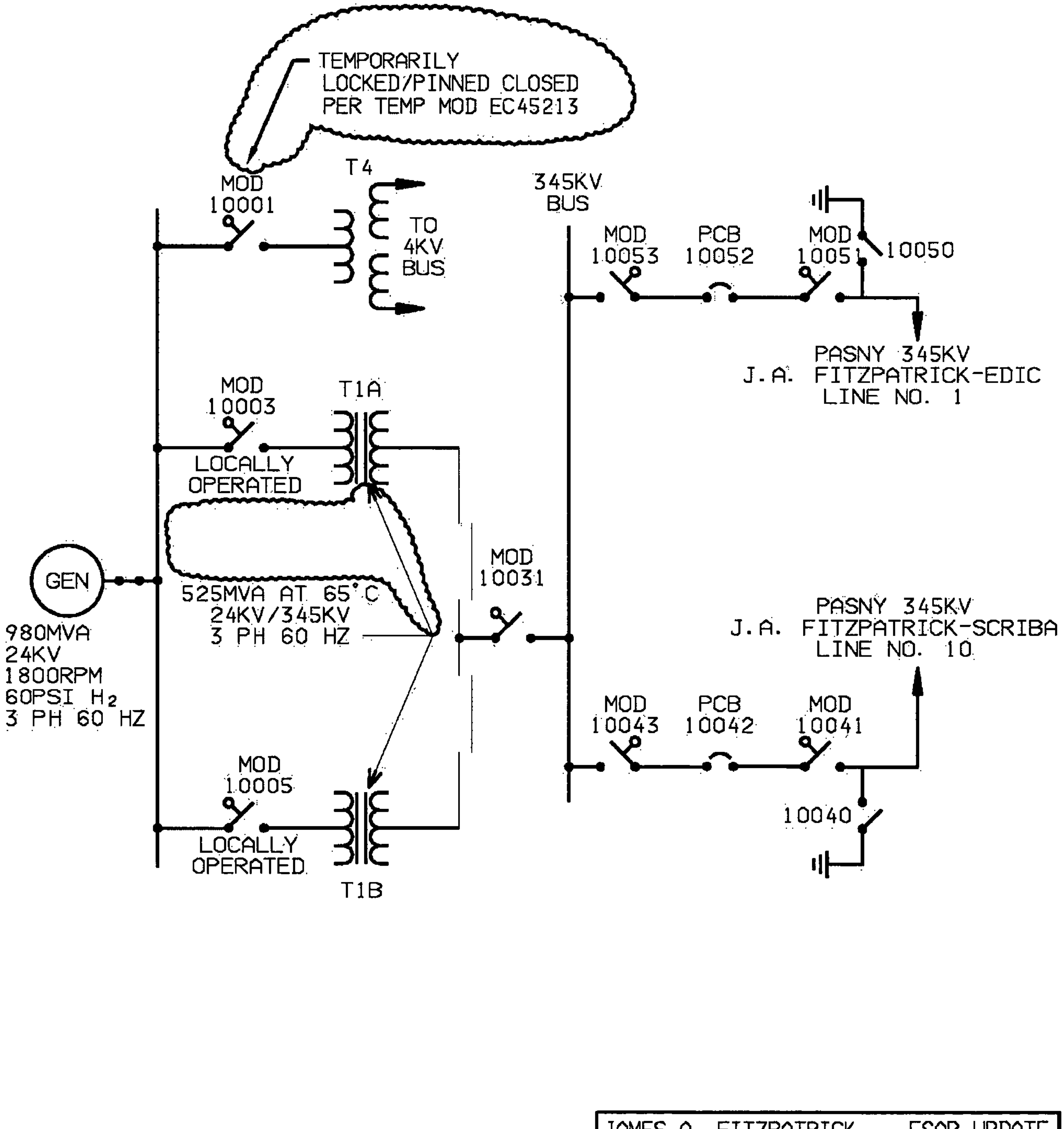
REFERENCE
ONE LINE - SYMBOLS STD-ME-10.1-10.9
ONE LINE - DEVICE NO'S STD-ME-11.1-11.9

NOTES:
1. FOR MOTOR OPERATED SW 10031 & GEN PCBS 10042 & 10052 SEE MAIN ONE LINE DIAG 345 KV SWYD DWG 11825-FE-1C.
2. ON LOSS OF REG POTENTIAL TRIPS VOLT. REG & ANN.
3. ON LOSS OF RELAY POTENTIAL, BLOCKS TRIP BY 40 AND ANNUNCIATES.
4. 120VAC AUX SOURCE TO WAT HOUR METERS.
5. THE FOLLOWING PROTECTIVE FUNCTIONS ARE ENABLED ON DEVICE 11G-UPRN05
21-SYSTEM BACKUP PROTECTION: ALARM ONLY, NO TRIP FUNCTION.
02-BACKUP PROTECTION TIME DELAY.

James A. FitzPatrick FSAR UPDATE

MAIN ONE LINE DIAGRAM

REV. 7 APRIL 2015 | FIGURE NO. 8.3-1



JAMES A. FITZPATRICK	FSAR UPDATE
MAIN ONE LINE DIAGRAM 345KV SWITCHYARD	
REV. 6 APRIL 2015	FIGURE NO. 8.3-3

Reserve station service transformer T2 high voltage winding is connected to the 115 kV bus through an underground low pressure oil filled cable; reserve station service transformer T3 high voltage winding is connected to the 115 kV bus through an overhead transmission line.

Each of the oil natural air natural/oil natural air forced/oil natural air forced cooled reserve station service transformers is rated at 15/20/25 MVA, 65 C temperature rise. The high voltage windings are rated 115 kV, 450 kV BIL and are wye connected with solidly grounded neutrals; the two low voltage windings, X or Y, are each rated at 4160 V 100 kV BIL and are wye connected with resistance grounded neutrals; the low voltage Y winding is equipped with a load tap changer.

The low voltage windings of the reserve transformers supply 4160 V reserve power through an enclosed non-segregated bus duct to the plant service AC distribution buses as follows:

TransformerT2	AC Distribution Bus
"X"winding	10200
"Y"winding	10400

TransformerT3	AC Distribution Bus
"X"winding	10100
"Y"winding	10300

8.4.2.5 Safety Evaluation

The lines connecting the reserve station service transformers to the 115 kV bus are arranged so that a failure of either line does not result in the loss of the other line. The overhead line to reserve station service transformer T3 is designed to equal or exceed the requirements of the 115 kV incoming transmission lines. The line to reserve station service transformer T2 is underground. The underground line is not subjected to the surface conditions which affect the overhead line.

The overhead and underground lines are each capable of continuously carrying full capacity of their respective reserve station service transformers.

The transformers are located approximately 153 ft apart and are further protected by fire walls.

The secondary leads from each transformer consist of a non-segregated phase bus duct.

Each transformer and its high and low voltage connections are capable of starting and supplying all loads on its associated emergency service bus of the Plant Service AC Power Distribution System.

In the event that the normal AC power source is lost, the reserve AC power sources are automatically connected to the Plant Service AC Power Distribution System as described in Section 8.5.

Monitoring and indicating devices are provided in the Control Room to permit supervision of the operational status of the reserve AC power source.

8.4.2.6 Inspection and Testing

Inspection and testing at vendor facilities and initial system tests were conducted to ensure that all components are operational within their design ratings.

The system and its components are tested throughout plant life in accordance with plant operating procedures.

8.4.3 345kV Backfeed During Outages

8.4.3.1 Power Generation Objective

The power generation objective is to provide an alternate source of offsite AC power to the Plant Service AC Power Distribution System during plant outages.

8.4.3.2 Safety Objective

The safety objective is to provide an alternate source of offsite AC power to the redundant emergency buses of the Plant Service AC Power Distribution System to maintain the reactor in the safe shutdown condition.

8.4.3.3 Safety Design Bases

The 345kV system is capable of supplying all loads on the emergency buses to maintain the plant in the shutdown condition. As the 345kV backfeed power will be used only during plant outages, a LOCA is not postulated.

8.4.3.4 Description

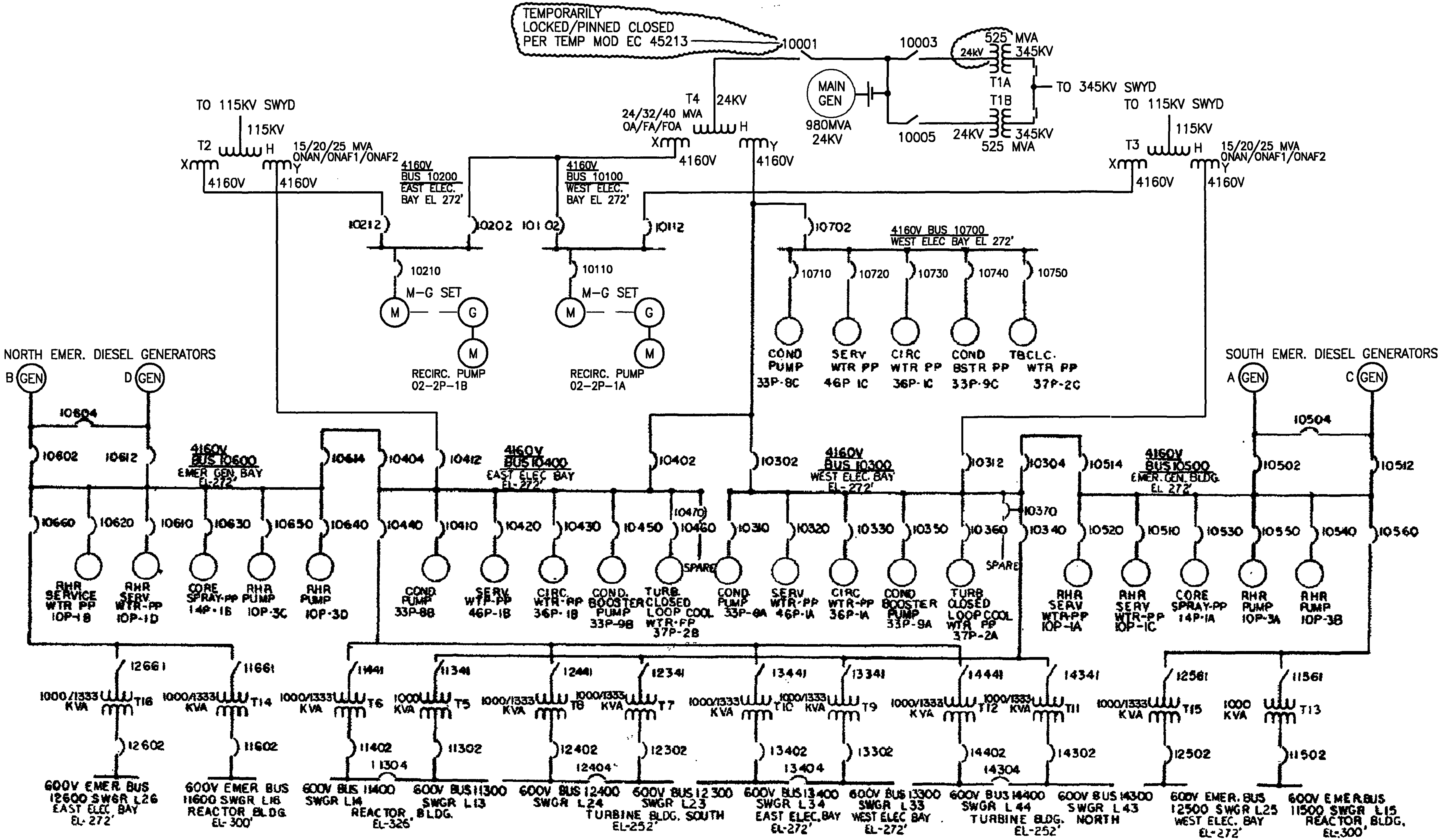
The 345kV system description is provided in Section 8.3.1.

The 345kV backfeed operation is used only during plant outages. The power is supplied from the 345kV bus to the Plant Service AC Power Distribution System Buses via main transformer 71T-1A and/or 71T-1B and normal station service transformer 71T-4. Prior to start of the backfeed, the plant is supplied from the 115kV switchyard. The 345kV bus is de-energized and the isolated phase bus duct disconnect links are removed. Then the 345kV bus is energized and the plant load is manually transferred from the 115kV system to the 345kV system.

The 24kV isolated phase bus duct system operates ungrounded during backfeeding as the main generator is isolated. A ground overvoltage relay connected across wye-broken delta potential transformer, is made operational during backfeeding to provide ground fault protection of the 24kV isolated phase bus duct system. The 345kV breakers 10042 and 10052 dead bus interlock is overridden and generator protective relays (Relays 11G, 40 and 46) are disabled during this mode of operation. The 11G multifunctional relay performs the 21 distance relay function for alarm only, no trip function.

The automatic bus fast transfer scheme will operate as designed except that the fast transfer will also be blocked, should there be a fault on the isophase bus system. The residual bus transfer scheme will operate as designed. The protective schemes for 4.16kV buses, normal station service transformer T4, isolated phase bus duct, main transformers T1A and T1B, and 345kV lines are adequate for the backfeed mode of operation.

The operation of the emergency buses of the Plant service AC Distribution System is the same as that when supplied from the main generator via normal station service transformer. The voltages on the 4.16kV and 600V emergency buses will be maintained by use of the load tap changer on the normal station service transformer.



JAMES A. FITZPATRICK	FSAR UPDATE

ONE LINE DIAGRAM PLANT SERVICE A-C POWER DISTRIBUTION

REV. 5	APRIL 2015	FIGURE NO. 8.5-1

The switchgear associated with each of the redundant emergency AC power sources is described under Section 8.5 and contains an individual output breaker for each of the diesel generator units and a common tie breaker. The arrangement of these breakers which are part of the emergency service portion of the Plant Service AC Power Distribution System is shown in Figures 8.5-5 and 8.5-6.

The generators are connected to their associated switchgear by cables. All power and control cabling for the emergency AC power sources is installed as described in Section 8.5.

8.6.4 Description of Operation

Under normal operating conditions, the normal AC service power source and the offsite reserve AC power source are available to supply each emergency bus. The loss of the normal plant service power source results in automatic fast or residual transfer to the offsite reserve AC power source.

The redundant safety buses are neither cross-tied, nor transferable, and any one reserve station service transformer does not supply loads on both safety trains for any mode of JAF Plant operation; i.e., full load, startup, standby or shutdown.

1. The total auxiliary load of the JAF Plant at 100% generation conditions is approximately 25 MW and at shutdown conditions, approximately 10 MW.

2. During normal operation, the normal station service transformer T4 supplies all plant loads, while reserve transformers T2 and T3, although energized at the 115 kV level, are disconnected from the 4.16 kV plant buses.

3. During shutdown, transformer T4 is de-energized and its 4.16 kV breakers are open. The 4.16 kV breakers of the two reserve transformers T2 and T3 are closed, and these transformers supply the plant loads which are approximately divided evenly between the two. From the transformer ratings shown in Figure 8.2-1 and the actual loads indicated above, transformers T2, T3 and T4 are conservatively rated and are more than adequate to carry their respective loads.

   The transfer of loads from transformer T4 to transformers T2 and T3 occurs automatically if the unit trips for any reason, or is accomplished manually during the normal shutdown procedures. In the reverse direction, the transfer is always manual. Regardless of how or in which direction it is accomplished, after a transfer, either only T4 or both T2 and T3 are connected to their respective buses. Please note that 4.16 kV bus 10700 is not transferred to T2 or T3, since it is tied only to T4.

Under these conditions, with a total plant load of only about 10 MW, both T2 and T3 are loaded to approximately 5 MW each and no ties will be closed at any plant voltage level.

4. Maintenance of transformers T2 or T3 or of the 115kV or 4.16kV breakers serving them requires that one of these transformers be taken out of service. This maintenance is normally done under shutdown conditions. In this case, it is possible to transfer some of the non-essential loads from one transformer to the other. As can be seen in Figure 8.2-1, such partial transfer of loads is possible by various configurations of breaker positions, including transfer through transformer T4 after isolating its primary connection to the generator bus (as made necessary due to Temp Mod EC 45213).

   If maintenance of transformers T2 or T3 or of the 115 kV offsite supply breakers must, for any reason, be performed during normal plant operation, either T2 or T3 may be taken out of service for the time and under the conditions stated in the Technical Specifications. No transfer of plant loads is required in this case since reserve transformers T2 and T3 do not supply loads during normal operation.

From the above, it is evident that transformers T2 and T3 are always operated well within their ratings regardless of any load transfer.

5. During shutdown, an alternate source of AC power from the 345kV system is available to supply plant buses. Refer to Section 8.4.3 for the description.

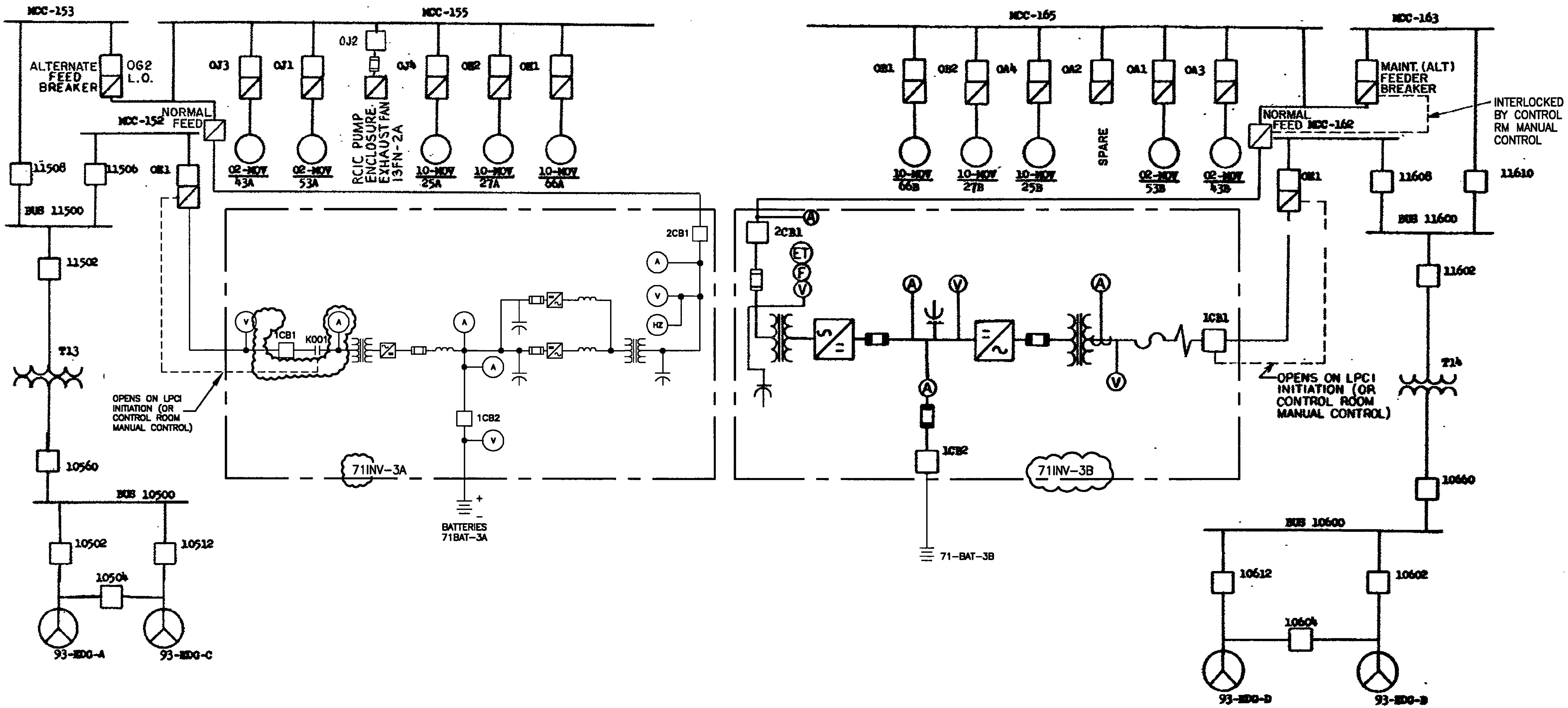
The loss of voltage or degraded voltage coincident with triple low reactor water level, high drywell pressure or extended degraded voltage of both normal and offsite reserve AC power sources, initiates automatic starting of both redundant emergency AC power sources. As soon as the diesels have reached rated speed and voltage (less than 10 seconds), the emergency diesel generator output breakers close to connect the generators to the appropriate dead emergency AC bus. The closing of the emergency diesel generator output breakers blocks any automated load shedding while the diesel generator breakers are supplying the bus.

The following events occur under loss of coolant accident conditions in the order indicated:

1. If either or both of the reserve AC power sources are available, the appropriate engineered safeguard loads are started in the same sequence as shown in Table 8.6-1.

2. All four diesel generators are automatically started whether or not the reserve AC power source is available.

3. When both diesel units of either emergency AC power source have reached approximately 25 percent of rated speed the diesel generator tie breaker is closed. At approximately 45 percent speed, the fields of both associated generators are automatically energized from the 125 V plant DC power sources. The paralleled pair of diesel generator units of each emergency AC power source continue accelerating to full speed, by which time the static excitation system assumes the duty of supplying the generator fields.



JAMES A. FITZPATRICK	FSAR UPDATE
LPCI MOTOR OPERATED VALVES INDEPENDENT POWER SUPPLY SYSTEM	
REV. 6 APRIL 2015	FIGURE NO. 8.10-1

CHAPTER 9

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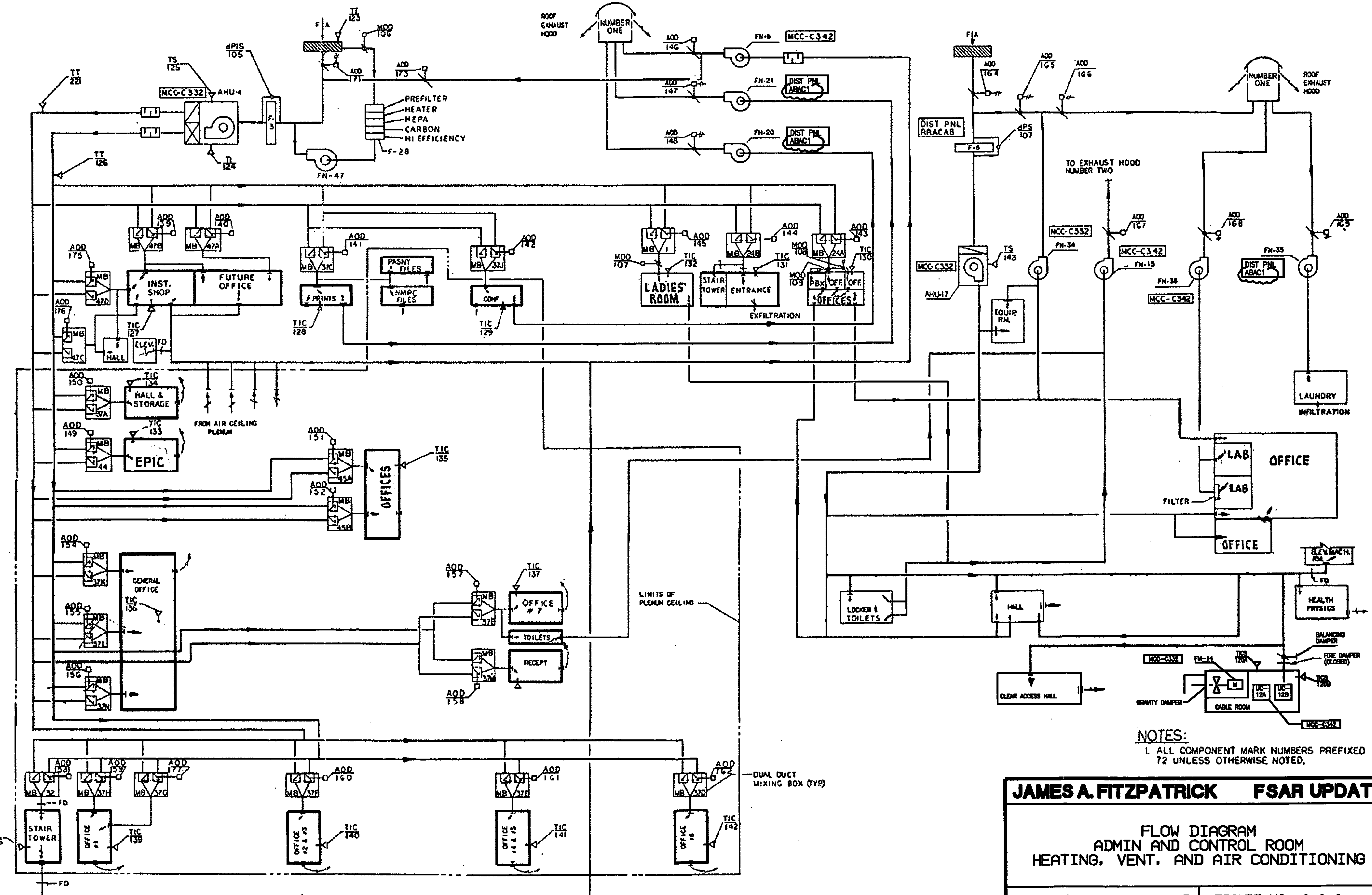


NOTES:

1. ALL COMPONENT MARK NUMBERS PREFIXED 72 UNLESS OTHERWISE NOTED.

JAMES A. FITZPATRICK	FSAR UPDATE
FLOW DIAGRAM ADMIN AND CONTROL ROOM HEATING, VENT, AND AIR CONDITIONING	
REV. 4 APRIL 2015	FIGURE NO. 9.9-6

9.10 MAKEUP WATER TREATMENT SYSTEM

9.10.1 Power Generation Objective

The power generation objective of the Makeup Water Treatment System is to provide a supply of treated water suitable for plant makeup and other demineralized water requirements.

9.10.2 Power Generation Design Bases

The Makeup Water Treatment System is designed to:

A. Provide makeup water of reactor coolant quality.

B. Provide an adequate supply of treated water for all plant operating requirements.

9.10.3 Description

9.10.3.1 General

The Makeup Water Treatment System equipment is located in the screenwell area. It is composed of two major groupings of equipment. The front end of the system consists of a standard clarification and filtration train. The latter part of the system includes absorption by activated carbon and deionization in a train of ion exchange beds. The deionization train includes a unit for dissolved gas removal. A reverse osmosis system is normally used upstream of the deionization train.

Input water for the makeup water treatment system may be either service water from Lake Ontario or city water from the Oswego municipal system.

The Demineralized Water Storage and Transfer system is designed to supply 150 gpm of 0.1 uS/cm water with <100 ppb dissolved oxygen, negligible CO_2 and <25 ppb silica. System design allows short term flow rates of up to 200 gpm, however maximum demineralized water production is limited by the RO system capacity of 60 gpm. Normal throughput is approximately 200,000 gallons per month (equivalent to 5 gpm).

The equipment listed in process sequence includes the service water prefilters, a clarifier, three parallel anthracite filters, a clearwell holdup tank, an activated carbon filter, a reverse osmosis (RO) system, a cation exchanger, a vacuum deaerator, an anion exchanger and a mixed bed exchanger. System effluent passes to three 25,000 gallon fiberglass polyester resin demineralizer water storage tanks, from which it is pumped by two demineralized water transfer pumps (one standby) to supply the plant requirements.

In addition to the demineralized water storage tanks, two 200,000 gallon condensate storage tanks are provided to store the necessary volume of high purity water for initial testing and cleaning and to provide the required volume for refueling and emergency requirements (ECCS, HPCI, RCIC, condensate makeup and reject), and to provide storage for liquid radioactive water that has been processed for reuse.

Also, as a source of seal water, 200 gpm of filtered water from the discharge of the anthracite filter treated water pumps, is provided for

non-safety related pump seals such as the circulating water and service water pumps, and other plant uses.

See Fig. 9.10-1 for the clarification and filtration systems, and Fig. 9.10-2 for the deionization system of the Makeup Water Treatment System.

The makeup system is operated manually when water is needed. The effluent from the reverse osmosis skid, cation and anion exchangers and the mixed bed exchanger is continuously monitored for quality by conductivity analyzers and a recorder with associated high conductivity alarms. The exchangers are automatically isolated from the demineralized water storage tanks upon detection of high effluent conductivity. The reverse osmosis skid will alarm locally and in the Radwaste Control Room and can be programmed to shutdown upon detection of high permeate (product water) conductivity.

The piping and associated equipment are fabricated from corrosion resistant materials which prevent contamination of the makeup water.

To centralize the water treatment operations, the control panel for the makeup water treatment is in the same control room as the radioactive waste and condensate demineralizer control panels. This control room is located in the southwest corner of the radioactive water treatment building. See Fig. 11.1-4.

The RO system has a local control panel mounted directly on the RO skid and a RO trouble annunciator in the Radwaste Control Room.

When the normal plant equipment for producing demin water fails and cannot be restored as quickly as desired, a portable water treatment skid is brought on site to provide demin water. This skid can be parked outside the screenwell area or inside as desired. This equipment produces the same high purity, low conductivity water to the Demin Water Storage Tanks The skid also contains protective instrumentation similar to that described above including a conductivity analyzer that continuously monitors the skid effluent and isolates the skid from the Demin Water Storage Tanks in the event that high conductivity is measured by the analyzer. Water for the skid may come from city water, or from the treated water pumps of the demin system, or from the service water system.

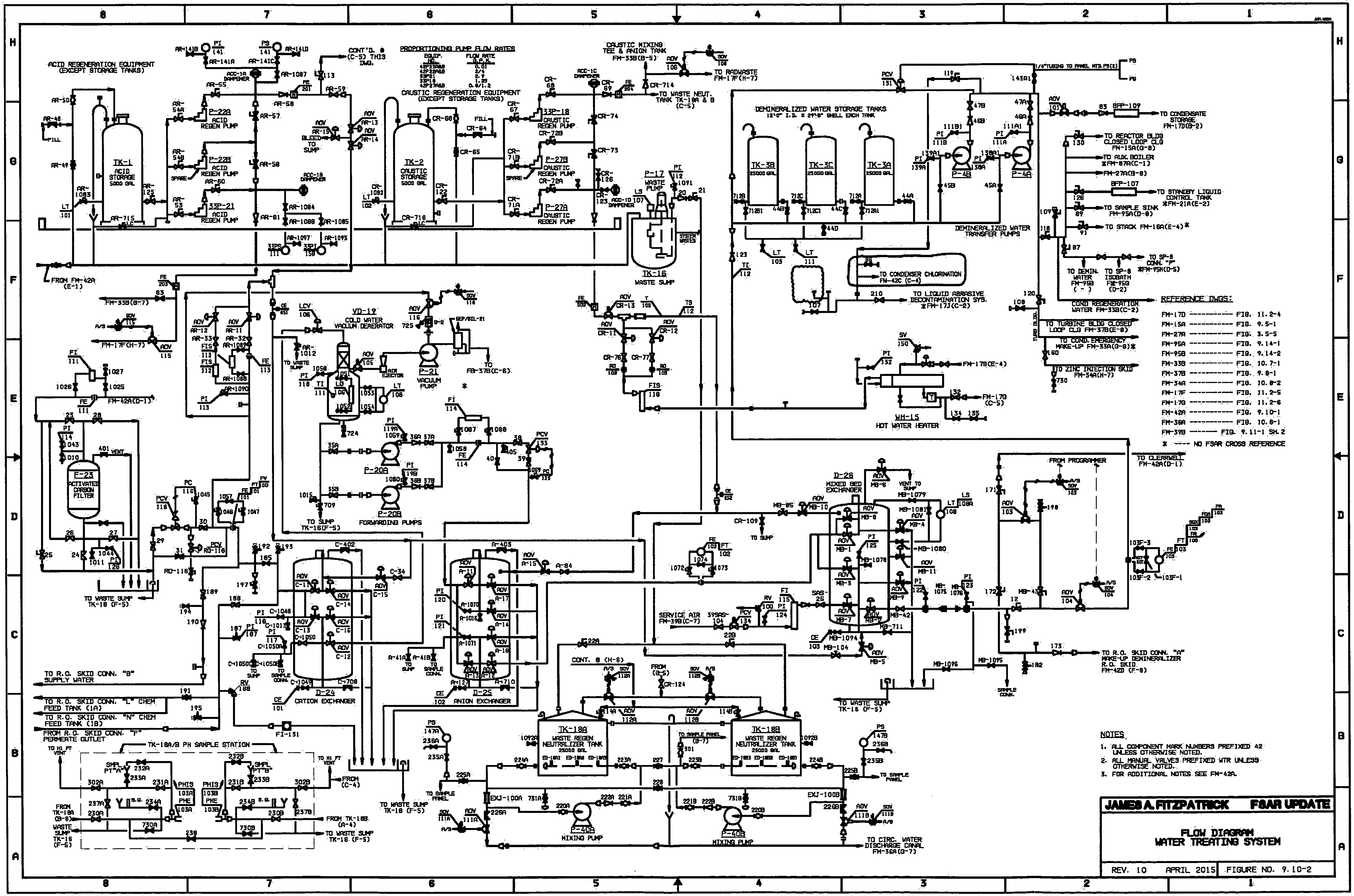
9.10.3.2 Prefilter for Service Water Feed to the Clarifier

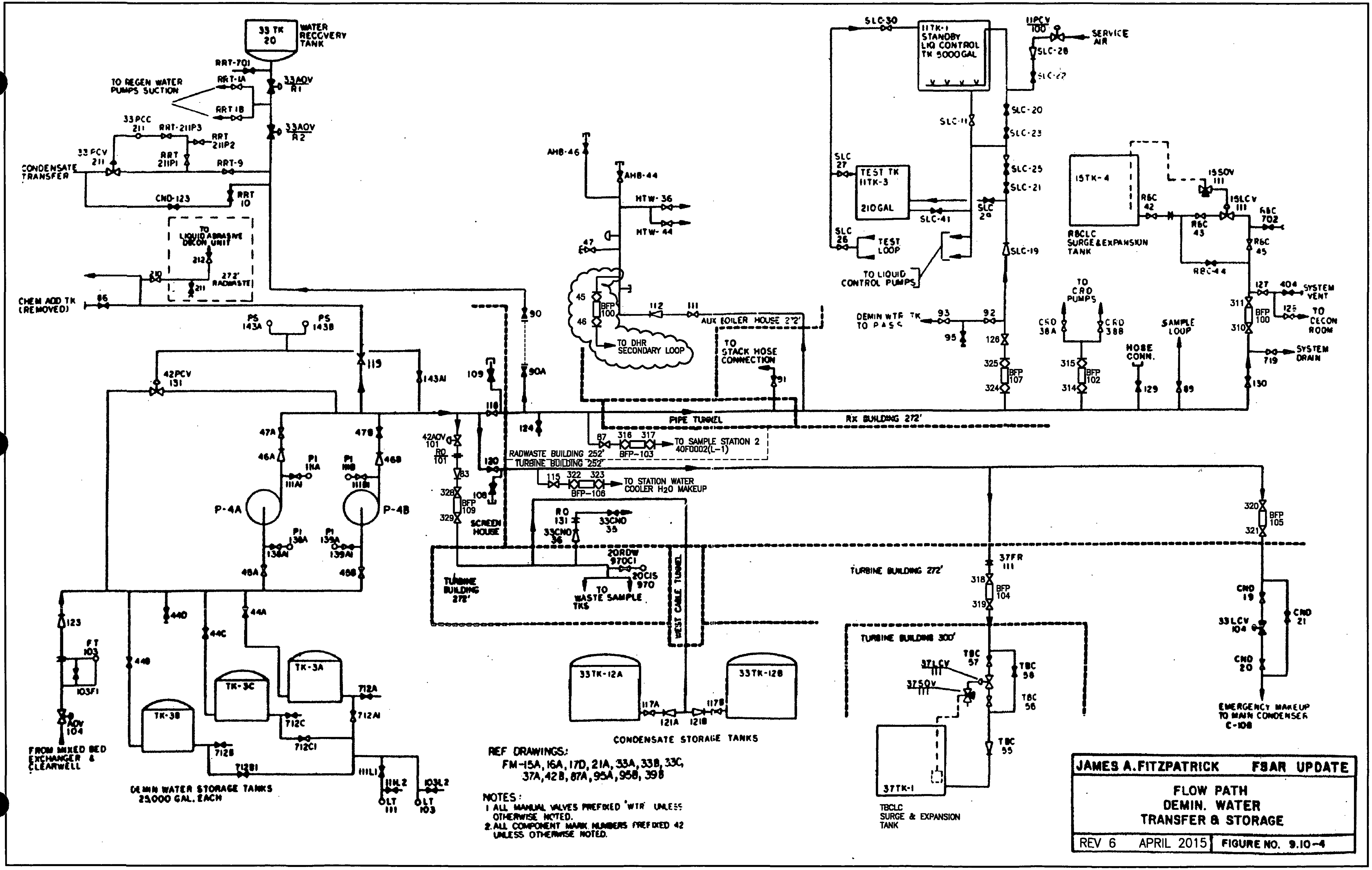
As of December 31, 1988, the limit imposed by a revision to the State Pollution Discharge Elimination System (SPDES) Permit no longer allowed the FitzPatrick plant to discharge silt removed from raw service water by the Makeup Water Treatment System. Consequently, a prefilter (42F-1) was added to the service water feed to the clarifier to control discharge of silt removed from lake water back to lake Ontario. The new filter will discharge silt to the Sewage Treatment Plant for processing.

The Service Water Prefilter, 42F-1, consists of a Durion tabular skid assembly with four independent filters with removable cartridges, automatic valves, and a differential pressure switch. The filters are designed and fabricated in accordance with the ASME Code Section VIII Division, 1, and are rated at 150 psig and capable of processing 350 gpm. The filter can process an average concentration of 32 mg/l suspended solids regularly; concentration of 90 mg/l during any two month period; and maximum concentrations of 192 mg/l on rare occasions.

9.10.3.3 Cold Lime Softener-Clarifier

The clarifier subsystem was designed to remove suspended matter from the raw water. The clarifier supporting equipment includes mixing tanks and metering pumps for flocculent, lime and disinfectant additions. Flocculent (coagulant) is added to remove silica, colloidal matter and

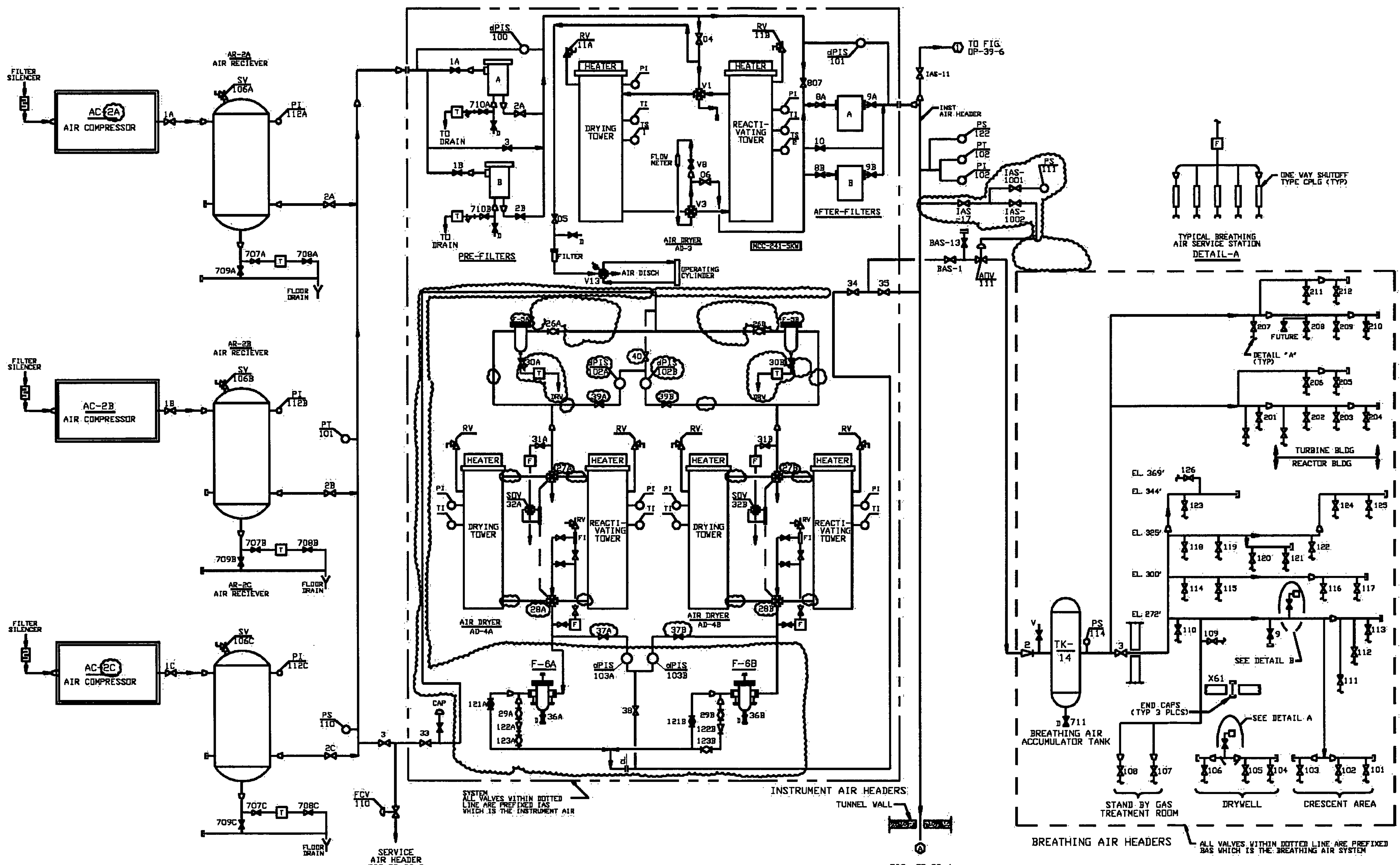

ACID REGENERATION EQUIPMENT (EXCEPT STORAGE TANKS)
TK-1 ACID STORAGE 5000 GAL
P-22A ACID REGEN PUMP
P-22B ACID REGEN PUMP
33P-21 ACID REGEN PUMP
PROPORTIONING PUMP FLOW RATES
CAUSTIC REGENERATION EQUIPMENT (EXCEPT STORAGE TANKS)
TK-2 CAUSTIC STORAGE 5000 GAL
33P-18 CAUSTIC REGEN PUMP
P-27B CAUSTIC REGEN PUMP
P-27A CAUSTIC REGEN PUMP
CAUSTIC MIXING TEE & ANION TANK FM-33B(B-5)
TO RADWASTE FM-17F(H-7)
TO WASTE NEUT. TANK TK-18A & B (C-5)
P-17 WASTE PUMP
TK-16 WASTE SUMP
DEMINERALIZED WATER STORAGE TANKS 12'-0" I.D. X 27'-8" SHELL EACH TANK
TK-3B 25000 GAL
TK-3C 25000 GAL
TK-3A 25000 GAL
DEMINERALIZED WATER TRANSFER PUMPS
P-4B
P-4A
TO CONDENSATE STORAGE FM-17D(G-2)
TO REACTOR BLDG CLOSED LOOP CLG FM-15A(G-8)
TO AUX. BOILER *FM-87A(C-1)
FM-27A(B-8)
TO STANDBY LIQUID CONTROL TANK *FM-21A(E-2)
TO SAMPLE SINK FM-95A(D-8)
TO STACK FM-16A(E-4)*
TO CONDENSER CHLORINATION FM-42C (C-4)
TO LIQUID ABRASIVE DECONTAMINATION SYS. *FM-17J(C-2)
COND REGENERATION WATER FM-33B(C-2)
TO TURBINE BLDG CLOSED LOOP CLG FM-37B(E-8)
TO COND. EMERGENCY MAKE-UP FM-33A(G-8)*
TO ZINC INJECTION SKID FM-34A(H-7)
WH-15 HOT WATER HEATER
VD-19 COLD WATER VACUUM DEAERATOR
P-21 VACUUM PUMP
P-20A
P-20B
FORWARDING PUMPS
F-23 ACTIVATED CARBON FILTER
FROM FM-42A (E-1)
D-24 CATION EXCHANGER
D-25 ANION EXCHANGER
D-26 MIXED BED EXCHANGER
TO CLEARWELL FM-42A(D-1)
FROM PROGRAMMER
SERVICE AIR FM-39B(C-7)
TO R.O. SKID CONN. "A" MAKE-UP DEMINERALIZER R.O. SKID FM-42D (F-8)
TO R.O. SKID CONN. "B" SUPPLY WATER
TO R.O. SKID CONN. "L" CHEM FEED TANK (1A)
TO R.O. SKID CONN. "N" CHEM FEED TANK (1B)
FROM R.O. SKID CONN. "F" PERMEATE OUTLET
TK-18A/B PH SAMPLE STATION
TK-18A WASTE REGEN NEUTRALIZER TANK 25000 GAL
TK-18B WASTE REGEN NEUTRALIZER TANK 25000 GAL
P-40A MIXING PUMP
P-40B MIXING PUMP
TO CIRC. WATER DISCHARGE CANAL FM-36A(G-7)
TO WASTE SUMP TK-16 (F-5)
REFERENCE DWGS:
FM-17D ---------- FIG. 11.2-4
FM-15A ---------- FIG. 9.5-1
FM-27A ---------- FIG. 3.5-5
FM-95A ---------- FIG. 9.14-1
FM-95B ---------- FIG. 9.14-2
FM-33B ---------- FIG. 10.7-1
FM-37B ---------- FIG. 9.8-1
FM-34A ---------- FIG. 10.8-2
FM-17F ---------- FIG. 11.2-5
FM-17G ---------- FIG. 11.2-6
FM-42A ---------- FIG. 9.10-1
FM-36A ---------- FIG. 10.8-1
FM-39B ------- FIG. 9.11-1 SH. 2
* ---- NO FSAR CROSS REFERENCE
NOTES
1. ALL COMPONENT MARK NUMBERS PREFIXED 42 UNLESS OTHERWISE NOTED.
2. ALL MANUAL VALVES PREFIXED WTR UNLESS OTHERWISE NOTED.
3. FOR ADDITIONAL NOTES SEE FM-42A.
JAMES A. FITZPATRICK
FSAR UPDATE
FLOW DIAGRAM WATER TREATING SYSTEM
REV. 10
APRIL 2015
FIGURE NO. 9.10-2

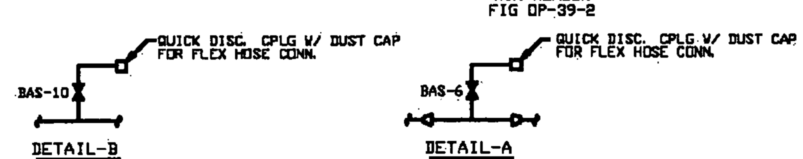


JAMES A. FITZPATRICK FSAR UPDATE

FLOW PATH
DEMIN. WATER
TRANSFER & STORAGE

REV 6 APRIL 2015 FIGURE NO. 9.10-4





NOTES:
1. ALL COMPONENT MARK NUMBERS PREFIXED 39 UNLESS OTHERWISE NOTED.
2. ALL MANUAL VALVES PREFIXED SAS UNLESS OTHERWISE NOTED.

JAMES A. FITZPATRICK FSAR UPDATE

BREATHING INSTRUMENT AND SERVICE AIR SYSTEM (SHEET 1 OF 3)

REV. 7 APRIL 2015 FIGURE NO. 9.11-1

9.12 POTABLE WATER AND SANITARY WASTE DISPOSAL SYSTEMS

9.12.1 Power Generation Objective

The power generation objective of the Potable Water and Sanitary Waste Disposal Systems is to provide drinking water supplies and disposal of sanitary wastes during normal plant operation.

9.12.2 Power Generation Design Basis

The Potable Water System supplies water in sufficient quantities to satisfy normal plant demand for potable water. The Sanitary Waste Treatment and Disposal System provides for the disposal of sanitary wastes in accordance with the design requirements established in "Standards for Waste Treatment Works" for institutional and commercial sewage facilities, 1980 by the New York State Department of Environmental Conservation (NYSDEC).

9.12.3 Description

Oswego city water is extended to the plant for domestic use and distributed throughout the Potable Water System at city water pressure. A hot water heating and storage unit together with a circulating pump distributes hot water to all required locations.

A 15,000 gal potable Oswego city water storage tank with pump is installed in the screenwell building for standby domestic water supply should the regular Oswego city water supply be temporarily disrupted.

The sewage treatment plant is located in the northeast corner of the site protected area; just north of the interim waste storage facility. This on-site plant and corresponding sanitary sewer system provides for the treatment and disposal of sewage and wastewater from all plant facilities. The treatment plant is designed for flows ranging from 25,000 gal/day, under usual effluent loading, to 60,000 gal/day peak loading. The sanitary treatment plant is an extended aeration secondary treatment facility, with flow equalization and chlorination to disinfect the effluent prior to discharge to Lake Ontario through an outfall to the drainage ditch along the east side of the site.

The Plant Potable Water Supply and Sanitary Waste Disposal Systems are independent of plant process systems, and no cross connections exist between these systems and any process systems which could contain radioactive material.

9.12.4 Inspection and Testing

The system was initially tested prior to placing it in service and is in continuous use. Routine chemical tests are performed by the Radiation Protection and Chemistry Department.

9.22 DECAY HEAT REMOVAL SYSTEM

9.22.1 Power Generation Objective

The power generation objectives of the Decay Heat Removal (DHR) System are to provide an alternate means of removing decay heat from the spent fuel pool (SFP) and from the reactor core via the SFP when the reactor pressure vessel head has been removed, the reactor cavity flooded, and the fuel transfer gates removed. In this capacity, the DHR System may be placed in service to supplement or substitute for the functions provided by the Fuel Pool Cooling and Cleanup (FPCC) System and the Residual Heat Removal (RHR) System in its shutdown cooling mode or its fuel pool assist mode.

9.22.2 Power Generation Design Basis

The DHR System provides a design maximum heat removal capability of approximately 45 x 10^6 BTU/hr while operating at the design condition. The DHR System operating configuration for maximum heat removal consists of one primary loop pump, two primary loop heat exchangers, two secondary loop pumps, and two sets of secondary loop cooling towers operating with a wet bulb temperature of 73°F. The DHR System is designed such that a heat removal capacity of approximately 30 x 10^6 BTU/hr is maintained following an operational (active) failure of one major primary loop or secondary loop component for a wet bulb temperature of 73°F. Actual capacity varies slightly from 30 x 10^6 BTU/hr depending on wet bulb temperature. The DHR System provides operational flexibility by supplementing or substituting for the heat removal capabilities of the FPCC and RHR Systems. The DHR System has been shown by analysis and test to be unaffected by RWCU or CRD operation.

9.22.3 Description

The DHR System, shown in Figure 9.22-1, may be placed in service in order to provide an independent means of cooling the water contained in the SFP. The DHR System, being an alternate means of decay heat removal, is normally out-of-service; however, it may be used to supplement the FPCC System. The DHR System may also be placed in service to supplement, or substitute for the RHR System in its shutdown cooling mode or its fuel pool assist mode.

In support of the RHR System, the DHR System can cool the reactor core due to the natural convection currents established between the SFP and the reactor cavity when the reactor pressure vessel head has been removed, the reactor cavity flooded, and the fuel transfer gates removed. Use of the DHR System during refueling would allow one or both trains of RHR shutdown cooling to be removed from service at the same time for the purpose of repairs, surveillance testing or modifications. In this operational configuration, a postulated active failure of a DHR component can be accommodated since decay heat removal can be re-established through operation of redundant DHR equipment. However, at least one train of RHR shutdown cooling (including an associated RHRSW pump) and one train of the Core Spray System must remain available with any irradiated fuel in the core and the Torus unavailable/open to the Crescents. The Technical Specifications allow the DHR System to be an alternate to the required RHR shutdown cooling subsystem as described in the Bases for Technical Specification 3.9.7 Required Action A.1.

The DHR System is not nuclear safety related and is designed to Class II requirements in accordance with UFSAR Section 12.2. The DHR System does not involve physical interfaces with any safety-related systems and interfaces with other plant systems are limited. The DHR System utilizes primary and secondary cooling loops. Permanent connections to the Condensate Transfer System and the Demineralized Water System are provided to fill the primary and secondary loops, respectively.

The primary loop is contained within the Reactor Building. Water is drawn from the SFP via one of the two primary loop pumps which are arranged in parallel. The pump discharge is then directed through a 100 micron, full-flow, strainer to the plate and frame heat exchangers before returning to the SFP.

Siphon breaking holes in both the support and return spargers ensure that the required SFP water inventory is maintained. The water level in the SFP is further assured by a low level alarm, which is annunciated in the Control Room. SFP makeup water can be provided from the condensate storage tanks.

The two plate and frame heat exchangers are the interface between the DHR System primary and secondary cooling loops. These heat exchangers are designed to minimize the potential for leakage. Any leakage is expected to be confined within the Reactor Building. Leakage to the secondary loop is prevented since the secondary loop is operated at a higher pressure than the primary loop.

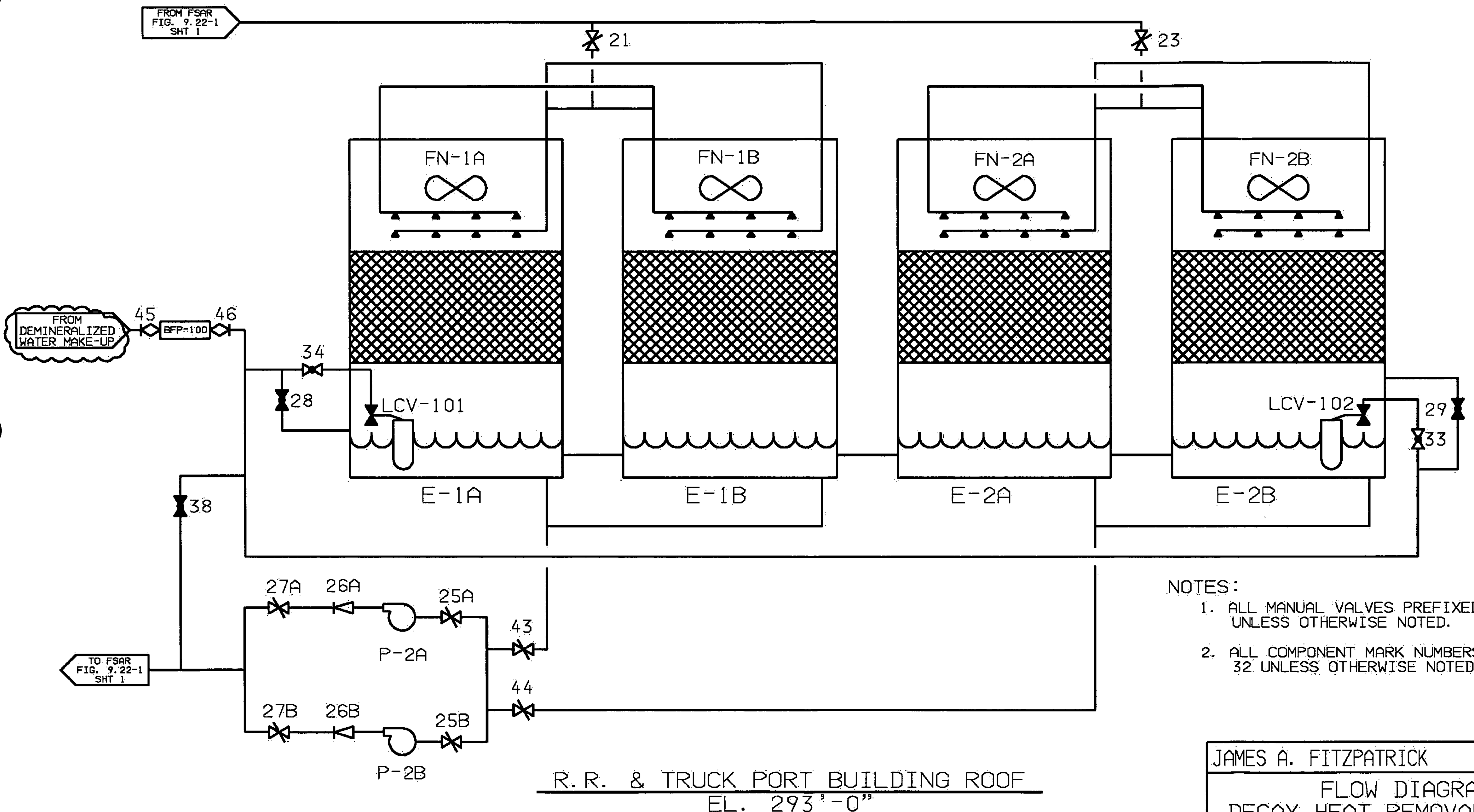
The secondary loop is composed of two secondary loop pumps, two sets of two-cell cooling towers located on the roof of the Standby Gas Treatment Building/Railroad and Truck Port Building, interconnecting piping and valves. A pressure control valve is located in the secondary cooling water loop downstream of the heat exchangers to maintain a secondary side heat exchanger exit pressure greater than the primary side heat exchanger inlet pressure.

DHR System components installed within the Reactor Building, including the primary loop pumps, strainer, plate heat exchangers, and control panel are seismically anchored. Piping located inside the Reactor Building is seismically designed. DHR System power and control cable within the Reactor Building are physically separated and routed in seismically supported cable tray and conduit. Each secondary loop supply and return line which penetrates the secondary containment boundary includes a manual isolation valve located inside the Reactor Building. The Reactor Building penetrations are QA Category SR and are protected against tornado-generated missiles.

The two sets of two-cell secondary loop cooling towers, the two secondary loop pumps, local control panels, piping, and raceways are installed on the roof of the Standby Gas Treatment Building/Railroad and Truck Port Building. These buildings are capable of accommodating the additional loads imposed by the DHR System. Roof-mounted DHR System equipment is designed to withstand the design basis wind loading and piping that is installed outside of the Reactor Building is heat-traced and insulated.

The DHR System is powered from a reliable off-site 13.2 kV source. To further enhance system reliability, a truck-mounted diesel generator can be made available on-site to provide back-up power supply whenever the DHR System is in operation. Conditions under which the back-up power supply must be provided are specified.

Local control panels are provided to monitor and control system operation. Local and Control Room alarms are provided as appropriate. Local pressure and temperature indicators in the primary and secondary loops are provided to monitor component performance.



NOTES:

1. ALL MANUAL VALVES PREFIXED DHR UNLESS OTHERWISE NOTED.
2. ALL COMPONENT MARK NUMBERS PREFIXED 32 UNLESS OTHERWISE NOTED.

JAMES A. FITZPATRICK	FSAR UPDATE
FLOW DIAGRAM DECAY HEAT REMOVAL SYSTEM (SHEET 2)	
REV. 3 APRIL 2015	FIGURE NO. 9.22-1

10.3 MAIN CONDENSER

10.3.1 Power Generation Objective

The objective of the main condenser is to provide a heat sink for the turbine exhaust steam, turbine bypass steam and other flows. It also provides deaeration and holdup capacity for the condensate which is reused after a period of radioactive decay.

10.3.2 Power Generation Design Bases

The main condenser was originally designed for the following conditions:

1.	Condenser Duty	5.714 x 109 Btu/hr
2.	Circulating Water Inlet Temperature	77°F (Maximum)
	Circulating Water Temperature at Condenser Outlet	109.4°F
3.	Cleanliness Factor	85% (Minimum)
4.	Number of Passes	1
5.	Circulating Water Velocity	6.48 ft per sec
6.	Pressure	3.711 in. Hg abs (Maximum)

The operating condenser duty under uprated power conditions is less than the original designed duty.

Analyses of the retubed condenser performance show that theoretically operation with lake temperatures up to 83.2°F is possible without power reduction. At lake temperatures higher than 83.2°F, power reduction may be required to keep discharge temperature within the limits imposed by the State Pollutant Discharge Elimination System discharge permit.

10.3.3 Description

During normal operation, steam from the low-pressure turbines is exhausted directly downward through exhaust openings in the bottom of the turbine casings into the condenser shells. The condenser serves as a heat sink for several other flows such as reactor feed pump turbine exhaust, cascading heater drains, air ejector intercondenser drain, gland seal condenser drain, feedwater heater shell operating vents, condensate pump suction vents, etc.

During abnormal conditions, the main condenser is designed to receive, but not all simultaneously, flow from the Turbine Bypass System, feedwater heater high level dump(s), relief valve discharges (crossover steam line, feedwater heater shells, steam seal regulator, various steam supply lines).

There are also other intermittent flows into the main condenser, such as condensate booster and reactor feed pump minimum recirculation flow, feedwater line pre-startup cleaning and recirculation, turbine equipment low-conductivity drains, extraction steam line drains, low-conductivity sample drains, and condensate makeup. During shutdown, drainage of reactor water through the main steam line drains to the main condenser provides an alternate method for removing water and/or decay heat. No credit for the removal of decay heat is taken in the accident analysis.

The main condenser is a twin-shell, horizontal tube, lake water cooled unit. It has an effective condensing surface area of 370,000 sq ft, utilizing 7/8 in. O.D., 18 BWG and 22 BWG titanium tubes, 44 ft long.

The design lake water circulating water flow rate through the condenser is 399,000 gpm.

Each condenser shell has divided waterboxes which permit isolation of one-half of the shell while

the other half remains in operation. Fish screens are provided at each water box inlet. The arrangement of this system allows gravity drain of the condenser by sections to remove possible debris accumulated on the inlet tube sheets.

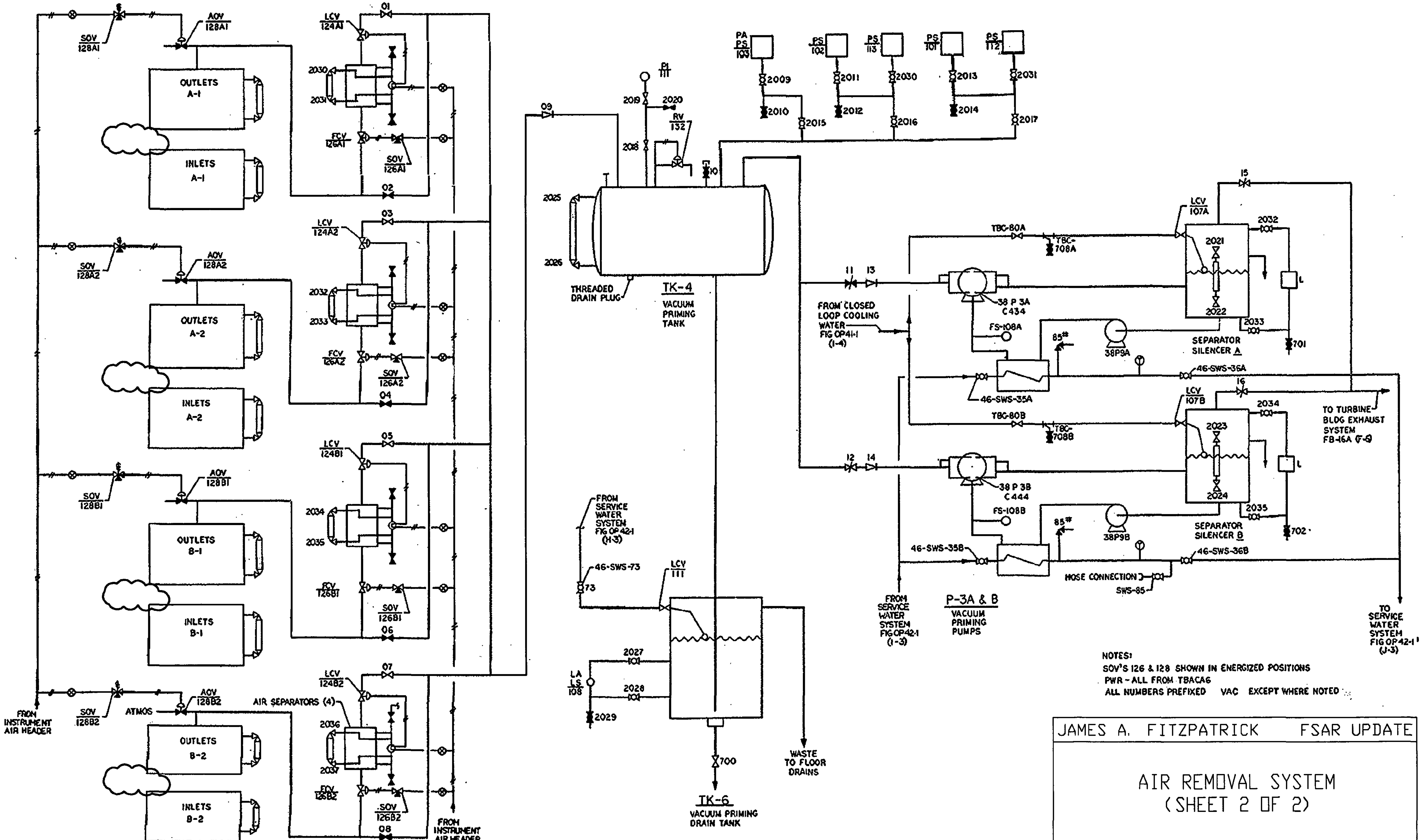
A sodium hypochlorite injection system is used to mitigate the detrimental effects of microbiological fouling in the condenser tubes. Sodium hypochlorite stored in a tank located on the north side of the Screenwell Building, is injected into each individual water-box via metering pumps on a skid located on the morth end of the 260 elevation of the Screenwell Building. A sodium hypochlorite solution is injected intermittently through nozzles in the Circulating Water riser into each condenser water box between the water-box inlet isolation valves and the de-fishing screen valves. The injection flow rate and duration are controlled to ensure State Pollutant Discharge Elimination System (SPDES) permit discharge limits are not exceeded.

The hotwell storage capacity is 110,000 gal. The condenser is located beneath the low-pressure cylinders of the main turbine. Condenser tubes are located transversely to the turbine-generator axis.

To accommodate thermal expansion, a rubber belt expansion joint is provided for each condenser neck. Equalizing connections between the two condenser shells are provided for both the steam space and hotwell. Condenser tubes are titanium (18 and 22 BWG). The 18 BWG titanium tubes are located in the peripheral region of the bundles.

The main condenser is designed to maintain an oxygen content of 0.005 cc per liter or less. The noncondensable gases are concentrated in the air-removal sections of the condenser, and removed by the air ejectors. To permit a 5 min decay period for the radioactivity in the condensed steam, the condenser hotwells are equipped with a baffling arrangement to form labyrinths.

The most significant condenser isolation valves heat leakage paths are monitored by a performance monitoring system, to help the plant staff maintain a heat balance of the plant.



NOTES:
SOV'S 126 & 128 SHOWN IN ENERGIZED POSITIONS
PWR - ALL FROM TBACA6
ALL NUMBERS PREFIXED VAC EXCEPT WHERE NOTED

JAMES A. FITZPATRICK		FSAR UPDATE
AIR REMOVAL SYSTEM (SHEET 2 OF 2)		
REV. 2	APRIL 2015	FIGURE NO. 10.4-1

10.6 CIRCULATING WATER SYSTEM

10.6.1 Power Generation Objective

The objective of the Circulating Water System is to provide the main condenser with a continuous supply of cooling water for removing the heat rejected by the turbine exhaust and turbine bypass steam as well as from other exhausts (Section 10.3) over the full range of operating loads.

10.6.2 Power Generation Design Bases

1. Provide the required lake water flow to the condenser.
2. Provide debris removal from lake water.

10.6.3 Description

The Circulating Water System uses water taken from Lake Ontario. Water passes through trash racks and then through traveling water screens. A major portion (approx. 91 percent) of the flow is directed to the circulating water pumps which deliver water to the main condenser. A small portion (approx. 9 percent) of the water is used by the service water pumps. The discharge from the main condenser and from the Service Water System (Section 9.7) is returned via the discharge tunnel and Diffuser System to the lake (Figure 10.6-1).

The trash rack installed in front of the traveling water screens retains pieces of debris larger than 3 1/8 in. The traveling water screens retain particles 1/2 in. and larger.

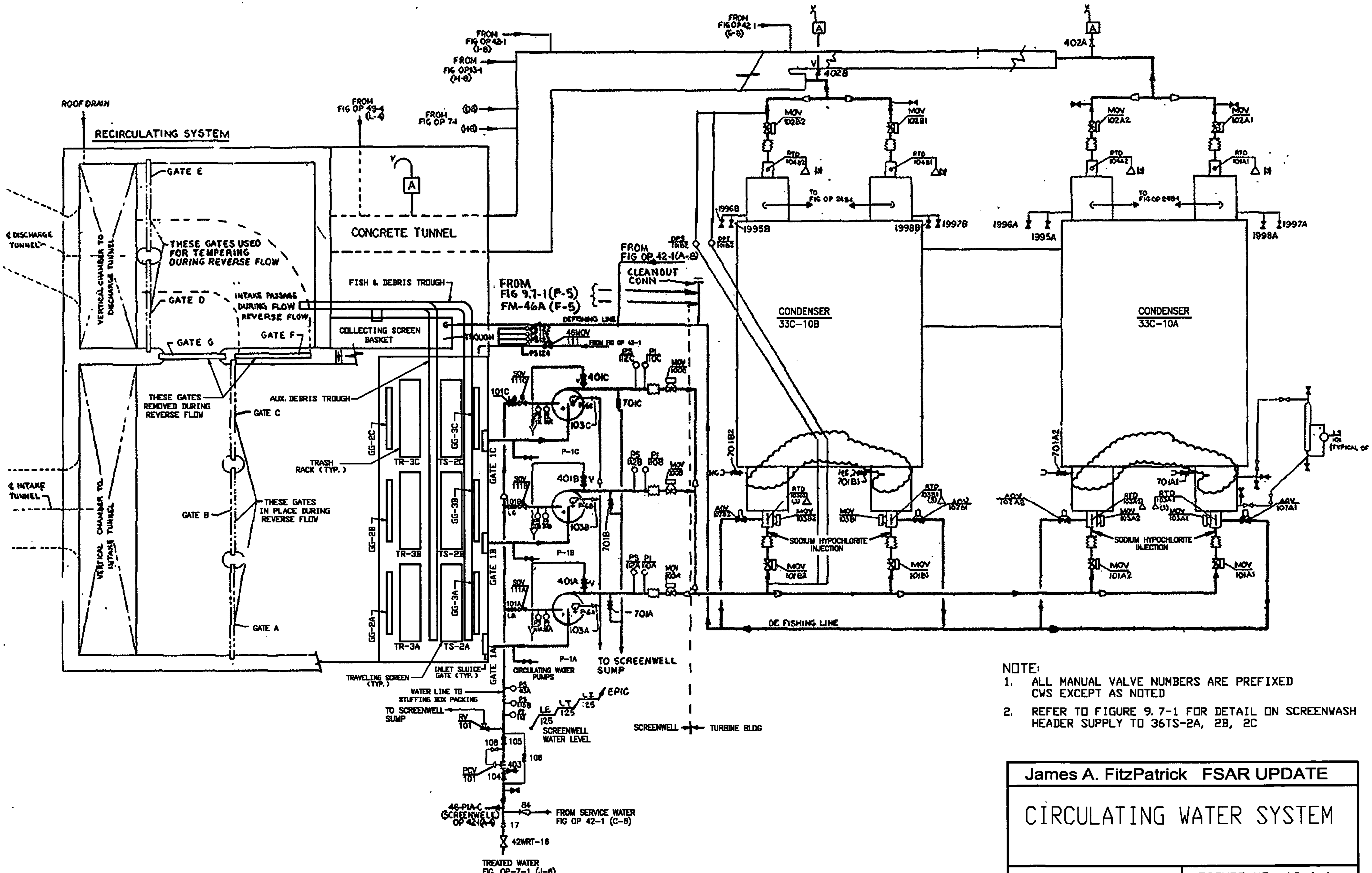
The screenwell (Fig. 12.3-23) houses three circulating water pumps, each having a rated head of 27 ft. TDH and a rated flow of 120,000 gpm. The pumps are vertical, mixed flow, dry pit type. The pump drivers are open, drip-proof, induction motors rated at 1,000 hp, 257 rpm, 4160V, 3 phase, 60 Hz.

Following retubing of the main condensers with titanium tubes, the circulating water flow has an estimated increase to 399,000 gpm through the condensers. At design power conditions of the turbine generator, the temperature rise through the condenser is approximately 28.8 °F.

The original design effluent flow rate to the discharge tunnel is 388,600 gpm, including the design service water pumps discharge of 36,000 gpm.

Original design effluent is 3.886×10^5 gpm (total)
Original design circulating water flow is 3.526×10^5 gpm (through condenser)
Original design circulating water pumps flow: 3 at 1.2×10^5 gpm (pump design)

Nine integrated projector housings are installed on top of the intake structure roof symmetrically located at elevation 232'-8" to provide for fish deterrence of the Alewives fish species. This system will not reduce or change the flow rates as described. The projectors can be removed for the winter months due to the ice packs possibly defacing the projector face.



NOTE:

1. ALL MANUAL VALVE NUMBERS ARE PREFIXED CWS EXCEPT AS NOTED
2. REFER TO FIGURE 9. 7-1 FOR DETAIL ON SCREENWASH HEADER SUPPLY TO 36TS-2A, 2B, 2C

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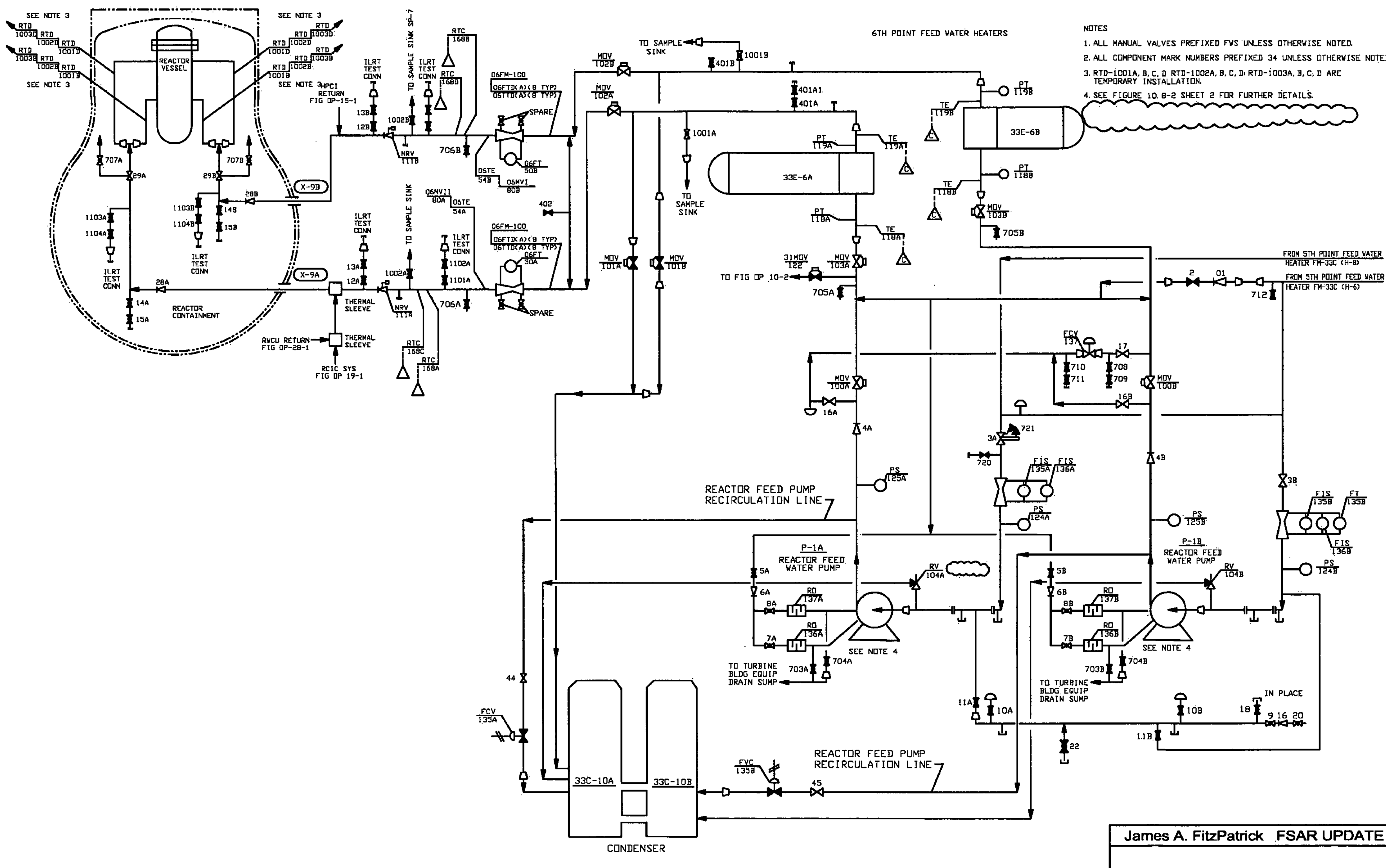
CIRCULATING WATER SYSTEM

REV. 7 | APRIL 2015 | FIGURE NO. 10. 6-1



James A. FitzPatrick FSAR UPDATE

FEEDWATER SYSTEM

REV. 11 APRIL 2015 | FIGURE NO. 10.8-2 SH 1 OF 2

10.9 CONDENSATE STORAGE SYSTEM

10.9.1 Power Generation Objective

The power generation objective is to provide initial suction feedwater to the Reactor Core Isolation Cooling and High Pressure Core Injection Systems to cover the nuclear fuel in the reactor during postulated accidents. In addition, the Condensate Storage System provides system makeup and "reject" during condenser hotwell surges.

10.9.2 Power Generation Design Bases

The Condensate Storage System provides plant system makeup, receives system reject flow and provides condensate for any continuous service needs and intermittent batch type services. The design total stored quantity of condensate is based on the demand requirements during refueling for filling the reactor internals storage pit and the reactor head cavity. The system design also takes into account the minimum reserve capacity for providing suction to the high pressure injection pumps (HPCI and RCIC) during postulated small pipe breaks.

Two tanks are used for reasons of operational flexibility so that a plant shutdown is not required when one tank is being maintained.

10.9.3 Description

The two 200,000 gallon condensate storage tanks supply the various plant requirements as shown in Figure 10.9-1. The tanks are constructed of stainless steel and have their lower half located below ground level for tornado and seismic protection of their 100,000 gallon reserve storage capacity (Section 6.2).

The condensate storage tanks are cross connected so that during normal operations their levels are the same.

Two thermosiphon heat exchangers (one per tank) were provided to maintain the contents of the storage tanks at a minimum temperature of 40°F. Steam was supplied to the heat exchangers from either the Reboiler System or the Auxiliary Boiler System. The steam supply to the two thermosiphon heat exchangers has been permanently isolated. The two thermosiphon heat exchangers have been retired in place.

The Condensate Storage System also includes two full size condensate transfer pumps which supply condensate to core spray flush, RHR flush, Reactor Building (Figure 10.9-1), radioactive waste system precoat filters and pump seals, backwash water for reactor cleanup and fuel pool filter demineralizers and condensate demineralizer regeneration.

The condensate tanks provide the preferred supply of water to the HPCI and RCIC Systems (Section 6.4). The torus water storage provides the backup HPCI and RCIC Systems supply. Suction connections are located above the HPCI and RCIC suctions to provide a 100,000 gallon reserve in each tank for the ECCS.

The failure of the above ground portion of the condensate storage tanks has been postulated and the release of the contents onto the ground is assumed to occur, however both the storage tank valve pits have sump pumps that discharge directly into the CST overflow drain line.

A CST shield wall, building structures, curbing and elevated grade surround the entire area (see Figure 12.1-2) in which the condensate storage tanks are located. These would effectively force accidental spillage to be routed to the lake by means of the West Storm Drain piping. The discharge from the 24 inch pipe into the lake would occur over a period of about 1 hour and would be diluted by a factor of 4000 as the material travels from JAF to the Oswego water intake. The dilution factor of 4000 for this discharge compared to the dilution factor of 165 for the circulating water discharge structure is due to the great difference in the volume of these two discharges. The small volume of the accidental discharge can be treated as a point source for dilution purpose rather than a line source which is applicable to larger volumes. A shield wall was built around the condensate storage tanks to minimize the radiation exposure during times of high activity from the stored water.

The basis and factors considered in the determination of the potential accident exposure are as follows:

1. The plant limit on specific activity for any one tank that can be discharged directly to the lake is 10 curies total activity. For the condensate storage tank this limit corresponds to a specific activity of 1.32×10^{-2} µCi/ml.

2. Decontamination occurs due to radioactive decay, settling, and processing in the Oswego Water Treatment System resulting in an additional concentration reduction factor of 10.

3. Resulting concentration in the City of Oswego water is 3.3×10^{-7} µCi/ml.

4. The isotopic mix is such that the 10 x EC = 5.70×10^{-5} µCi/ml (based on the isotopic mix provided in Table 11.2-2).

5. It is assumed that the contaminated water takes 2 hours to pass by the city water system intake.

The resulting exposures based on these data are as follows:

1. Resulting whole body dose to an average individual who consumes 1/12 of his daily average 2.2 liter of water during the 2 hours is 0.0132 mrem.

2. The population dose is 0.317 man-rem based on a population of 23,800.

3. The maximum whole body dose to an individual assuming that the individual consumes 2.2 liters of water in the 2 hour period is 0.158 mrem.

The off-gas dryers reduce the moisture content of the mixture to less than +10°C (50°F) dewpoint to ensure proper operation of the activated charcoal beds. The off-gas dryer consists of two drying towers. One tower is in service, while the other tower is regenerating or in a standby status. During regeneration, the tower is heated to remove moisture absorbed by the dryer desiccant. When regeneration is complete, the tower is in standby until cycled automatically at 8 hour intervals (temporarily reduced from a standard 12 hour interval per Temp Mod EC 40258).

The off-gas drying towers are contained within an enclosure designed to capture off-gas leakage. Air flow through the enclosure removes the heat generated during desiccant regeneration.

During start-up or in the intermediate mode when the charcoal vessels cannot be used (due to either high hydrogen concentration, high moisture content at the recombiner dryer exit or high charcoal temperature), the off-gas mixture is discharged via the 24" holdup pipe to the stack.

In the start-up mode, the holdup piping and system provide approximately 22 minutes of holdup time (at a flow rate of 269 cfm) for all nuclides prior to being released through HEPA filters 01-107F-1A & B.

During the intermediate mode (recombiner in use; charcoal tanks bypassed), the system and holdup piping provides approximately 1.63 hours of holdup time for all nuclides prior to being released through the HEPA filters and exiting through the stack. The holdup pipe is buried five feet below grade to provide shielding and protection of the holdup pipe (See Table 11.4-2).

During normal operating mode, the 24" holdup pipe is bypassed. Holdup time for activation gases is one minute based on 60 scfm flow through the 2 inch discharge line to the charcoal tanks. Holdup times with the use of activated charcoal beds for Kr and Xe are 4.6 hours and 106.7 hours, respectively.

The recombiner system is located in an open area in the West Condenser Bay. This unshielded high radiation area has a radiation level greater than 100 mrem/hr while the equipment is operating and has controlled access in accordance with 10 CFR 20, paragraph 20.203(c). The adjacent accessible area, the electrical switchgear area, is shielded by a 4-foot wall where the radiation level is about 5 mrem/hr while the plant is operating. The areas above and below the recombiner are also high radiation areas and therefore are not shielded from the recombiner.

The recombiner system is located adjacent to the steam jet air ejectors to reduce the hydrogen as soon as possible, and minimize the length of pipe run. The recombiner 2-inch discharge piping runs along the B column line wall shown on Figure 11.4-2 for approximately 50 ft. before entering either the 24-inch diameter underground holdup pipe or the 2 inch bypass line to the charcoal filters depending on the mode of operation.

In the Turbine Building area, the off-gas lines are completely in the high radiation area. The lines are run so that they are not in the normal personnel passage area, so that the effects of accidental rupture would be minimized.

The recombiner system has several alarm conditions that can be used to warn the control room operator that the line from the steam jet air ejectors to the recombiner has ruptured.

If the line upstream of the recombiner should rupture, the hydrogen concentration to the recombiner would be reduced, thus lowering the recombiner effluent temperature which is alarmed.

Following rupture of the recombiner intake piping, the recombiner is automatically isolated on a signal from either the recombiner effluent temperature or the steam flow to the recombiner, thus routing the steam jet air ejector off-gas through a bypass line directly to the 24 inch underground pipe.

The probability of a pipe break in the 24 inch underground line is slight, and if it does occur, the leak would not be detectable at ground level. The pipe is coated and wrapped to protect it from external corrosion. Since the pressure in the holdup pipe is normally at atmospheric pressure, the pressure from the five feet of soil would restrict the gas flow to the surface to an undetectable amount.

The off-gas holdup piping meets the requirements of ANSI B31.1.0 and the additional quality requirements of Class Q2 piping (Section 16.5). The off-gas holdup pipewall is designed for pressures per NACA-TN-3935. The holdup piping and valves were designed prior to inclusion of the recombiner and were designed to remain intact in the unlikely event of a hydrogen explosion in the Off-Gas System. The recombiner bypass and underground pipe have been designed to withstand a hydrogen explosion such as that described in the National Advisory Committee for Aeronautics Technical Note 3935, "Hydrogen Oxygen Explosions in Exhaust Ducting." Even though the system is designed to withstand a hydrogen explosion, precautions are taken to eliminate all sources of heat, spark and static electricity in the condenser off-gas piping system.

If, in spite of the precautions described, a hydrogen explosion were to occur, pressure sensors in the 24 inch off-gas line would cause both Vacuum SJAE Valves 38AOV-113 A and B to close, thereby preventing further combustion in the piping. Pressure and temperature alarms are provided in the Control Room to indicate the occurrence of an explosion.

An Automatic Purge System is also provided to purge the system. The off-gas holdup pipe air purge is provided from the Service Air System. The air purge occurs automatically when both Vacuum SJAE Off-Gas Trip Suction Air Operated Valves 38AOV-113A and B are closed and the off-gas line high pressure/high temperature matrix is not actuated.

There is a short section of 2 inch and 6 inch off-gas piping located upstream of the 24 inch diameter underground holdup pipe whose rupture would not be detected until the main stack or turbine building ventilation alarm is actuated. This piping is not used during normal operation mode.

In the normal operating mode with the recombiner in use, the hydrogen concentration in the off-gas line is reduced by more than 95%. Hence the potential for a hydrogen explosion is remote. Therefore, the piping downstream of the recombiner was not constructed to be explosion proof. Recombiner steam dilution flow and inlet/outlet temperatures are monitored, and the system is automatically isolated if not operating within established design limits.

Shielding requirements for facilities to the east of the Turbine Building and Installation of the shield wall shown in Figure 12.2-5 are based on N-16 levels in the Turbine Building corresponding to hydrogen injection rates of 48 scfm.

Radiation source activities in the Radioactive Waste Building are based on concentrations and quantities developed in the design of the Radioactive Waste System as indicated in Figure 11.1-1. Included in Figure 11.1-2 are data tables and explanatory notes for Figure 11.1-1.

Radiation sources during accident conditions are as specified in Chapter 14.

11.5.3.1 Control Room

Shielding requirements for the Control Room are governed by the conditions during a Loss-of-Coolant Accident as defined in Chapter 14. Continued occupancy of the Control Room during this accident, however, is ultimately governed by the ventilation air intake and recirculation rates as defined in Section 9.9 With these rates, Control Room occupancy can be continuously maintained throughout the 31 day duration of the accident without exceeding the regulatory limits.

11.5.3.2 Reactor Building

The Reactor Building contains four major shielding structures; the sacrificial shield, the drywell biological shield, the spent fuel pool and the main steam pipe chase.

The sacrificial shield, shown in Figure 12.3-7, protects major portions of the drywell space from excessive radiation during operation, provides decay gamma shielding during shutdown, and contributes to the protection of reactor building areas external to the drywell biological shield. The sacrificial shield consists of a structure having steel skin plates of 1/2 inch or more thickness filled with approximately 27 inches of concrete. Access for inspection of the vessel and piping penetrations is provided by 9 inch thick hinged steel inspection doors. Removable high density neutron shielding material is installed inside inspection doors in the region of the active core to minimize neutron streaming.

Ten inches of removable, seismically supported, high density neutron shielding material is restrained behind the inspection doors between the 321 and 305 ft. elevation. (Nozzle N-16A and N-16B have a minimum of 9 ¼" of neutron shielding behind the inspection doors). Six inspection openings at the 325 ft. elevation have the doors removed providing the required venting of the sacrificial shield wall cavity.

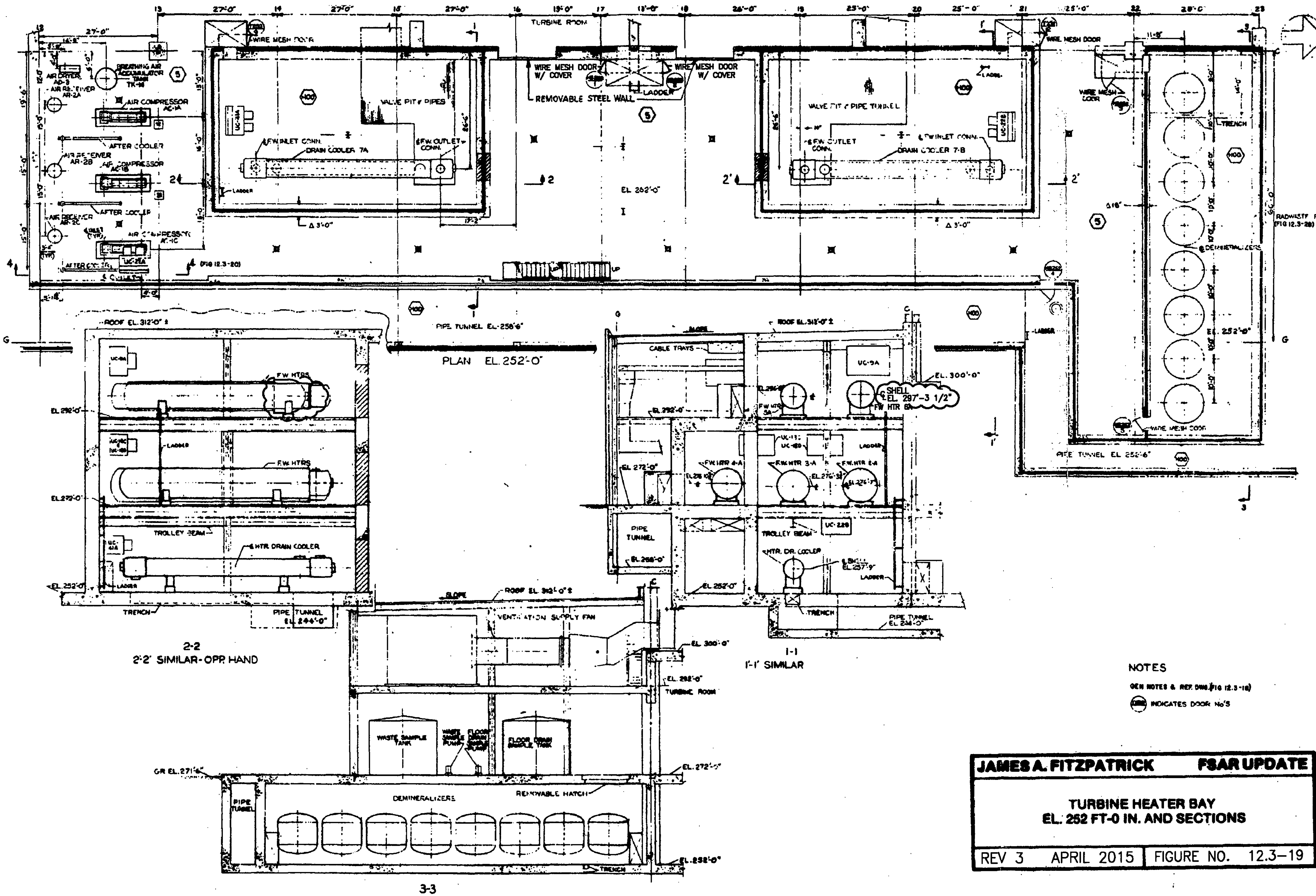
The drywell biological shield, shown in Figure 12.3-7, provides the main protection for spaces external to the drywell. It consists of poured concrete varying in thickness from about 5 to 9 ft.

The spent fuel pool shielding provides protection to other areas of the Reactor Building from the radioactive fuel elements which have been removed from the core. A minimum of 10 ft. of water is maintained above the spent fuel assemblies for protection of personnel during fuel storage, and a minimum of 9 ft. during transfer operations. For dry fuel storage (ISFSI) in-pool cask operations, a minimum of 7 ft. of water is maintained above active fuel. Refueling platform hoist travel limits will not be adjusted when the 360 degree work platform is used in the reactor cavity. This may result in reduced water shielding when the refuel mast is at its closest approach to the platform. Radiation exposure will be controlled in accordance with 10 CFR 20.

The main steam pipe chase which connects the Reactor and Turbine Buildings is constructed with a minimum concrete thickness of 4 ft. on both sides and roof to protect plant personnel from the high energy N-16 gammas from the main steam lines.

Numerous additional shielded areas are provided for components of the Reactor Water Cleanup System and Fuel Pool Systems, incore flux monitoring equipment, reactor internals, and Radioactive Waste System components in order to permit the remaining areas to be occupied on a 20 hr. per week basis if required.

Major entrances to the drywell are protected by a suitable thickness of layed-up concrete block walls and water shield walls to facilitate removal when required.



NOTES

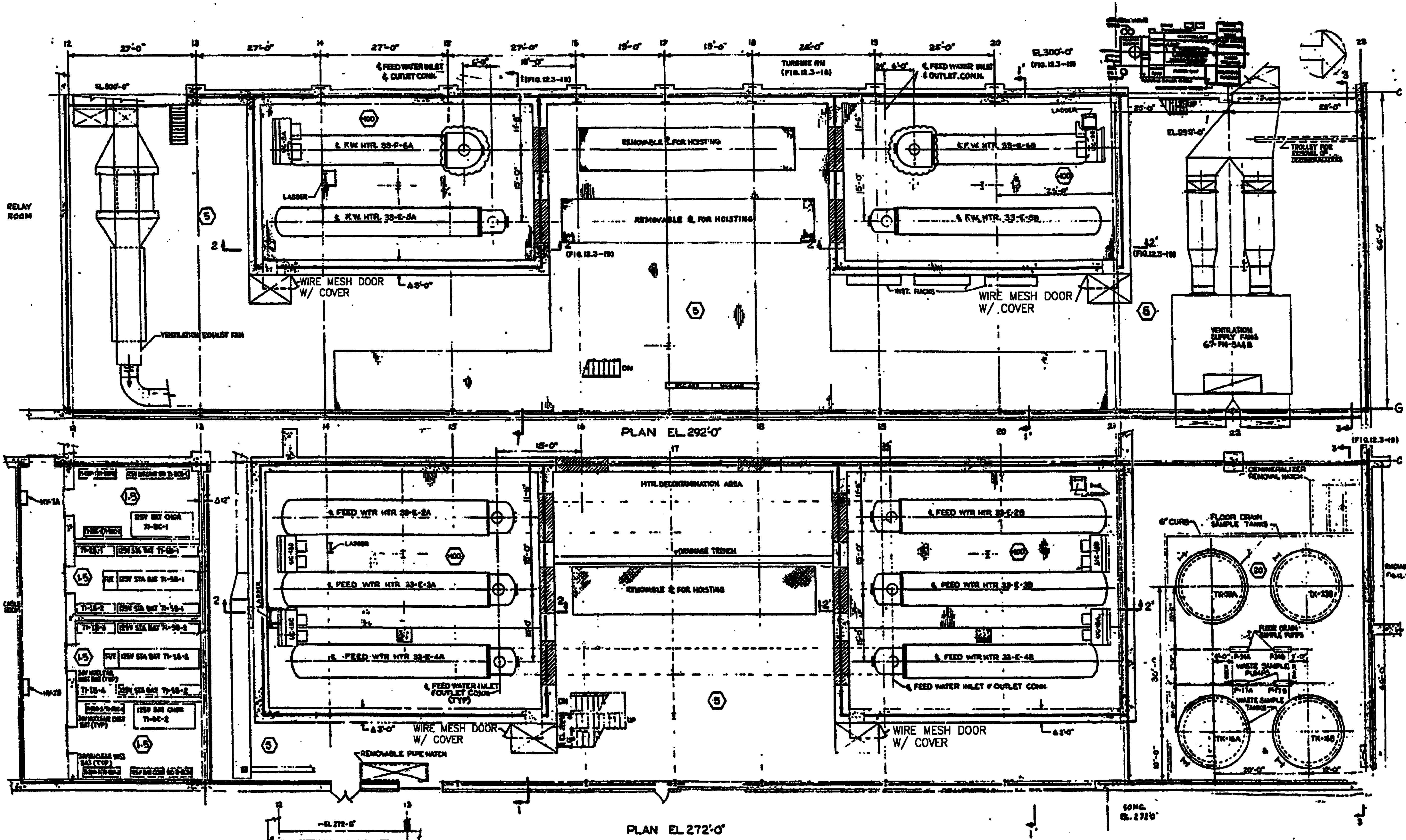
GEN NOTES & REF. DWG. (FIG 12.3-18)

INDICATES DOOR No'S

JAMES A. FITZPATRICK **FSAR UPDATE**

TURBINE HEATER BAY
EL. 252 FT-0 IN. AND SECTIONS

REV 3 APRIL 2015 FIGURE NO. 12.3–19



JAMES A. FITZPATRICK **FSAR UPDATE**

TURBINE HEATER BAY
EL. 272 FT-0 IN. AND 292 FT-0 IN.

REV 3	APRIL 2015	FIGURE NO. 12.3-20

CHAPTER 13

CONDUCT OF OPERATIONS

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13.2 ORGANIZATIONAL STRUCTURE AND RESPONSIBILITIES

13.2.1 Management Organization

13.2.1.1 Entergy Nuclear Operations

Figure 13.2-1 depicts the organizational structure for Entergy Nuclear Operations management.

Chief Nuclear Officer
The Chief Nuclear Officer Entergy Nuclear Operations (CNO) has overall responsibility for the entire administration of Entergy Nuclear.

Chief Operating Officer
The Chief Operating Officers (COO) are responsible to the CNO for the overall safe, efficient, and reliable operation of nuclear power plants. Each COO is responsible for the executive direction of operations and support activities at each of Entergy's Nuclear generating facilities under their management.

Vice President Oversight
The Vice President of Oversight has overall responsibility for the administration of the Quality Assurance Program and the QAPM at Entergy's Nuclear generating facilities.

The Quality Assurance Program and procedures are implemented by the Nuclear Oversight Manager (NOS) at James A. FitzPatrick Nuclear Power Plant (JAF). The NOS Manager reports to the Director of Oversight who reports to the Vice President of Oversight.

Employee Concerns Coordinator
The Employee Concerns Coordinator located at JAF reports to the Manager of Employee Concerns at Entergy Nuclear Operations. They are responsible for investigations or providing oversight, as appropriate, for investigations that result from concerns or allegations received from internal or external sources.

13.2.1.2 Maintenance Program

JAF is maintained in accordance with the fleet and plant approved Administrative Procedures. Work procedures to maintain the plant in a safe and operable condition are prepared and approved, prior to the time they are required, in accordance with the Administrative Procedures. Non-routine or emergency maintenance is accomplished in accordance with maintenance procedures. Maintenance requests are made using properly approved forms provided for that purpose. Work does not commence until the equipment is placed in such condition as to safely protect personnel, equipment and other plant components from harm or damage. Administrative Procedures define the mechanics of the protective controls.

A preventive maintenance program is conducted on equipment for which experience has demonstrated a need for periodic servicing. Testing is regularly scheduled on equipment and systems in order to detect degradation from original operating parameters. Historical records of maintenance activities on all principal equipment are preserved.

13.2.1.3 Technical Services

Figure 13.2-2 depicts the organizational structure related to Entergy's Technical Services.

Entergy maintains a high degree of technical expertise on plant staff. Technical support of the various activities associated with overall plant operation is provided by Entergy headquarters and site personnel.

Entergy Nuclear Operations has prime responsibility for all planned and systematic activities necessary to assure the safe, reliable and efficient operation of Entergy's nuclear power plants.

The expertise in this unit includes nuclear, mechanical, electrical, and civil/structural engineering disciplines as well as operations, maintenance, training, core physics and fuel management. The original plant architect-engineer, the NSSS vendor and other qualified consultants are used to provide additional support and expertise. This unit is responsible for assisting in recovery efforts after Emergency Plan events.

The unit also provides technical expertise in the areas of thermo-hydraulic and transient analysis, metallurgy, process control, piping, materials, chemistry, nuclear and environmental matters.

13.2.2 Plant Management Organization

Entergy has staffed and operates the facility in conformance with Figure 13.2-3. The Site Vice President reporting to the Chief Operating Officer (COO) has complete responsibility for the safe and efficient operation of the plant.

The Site Vice President administers an organization of Entergy supervisory employees skilled in the various disciplines of nuclear power plant operation. Supervisory employees in turn direct the actions and supervise the performance of physical forces at the plant, some of which may be contracted personnel. Plant personnel that perform duties described in ANSI N18.1-1971 meet or exceed the minimum qualifications of Section 13.4, or justifications will be provided to the NRC prior to an individual's filling one of these positions.

13.2.2.1 Site Vice President

The Site Vice President (S-VP) is responsible for the safe, efficient and dependable operation of the plant. The General Manager of Plant Operations, the Director of Engineering, and the Director of Regulatory and Performance Improvement, report to the S-VP.

13.2.2.2 General Manager, Plant Operations

The General Manager, Plant Operations (GMPO) is responsible for the safe and efficient operation, maintenance and radiation protection by managing all station activities in Operations, Maintenance, Production, Radiation Protection, Chemistry, and Site Projects & Maintenance Services.

Manager, Chemistry
The Chemistry Manager is responsible for assuring that the plant's operational chemistry and radiochemistry programs are conducted in compliance with administrative and regulatory requirements, including monitoring the environmental program and all other functions having to do with the radiological and ecological effects of the plant.

Manager, Radiation Protection
The Radiation Protection (RP) Manager is responsible for the radiological control and protection of personnel and the general public from radiological hazards. The RP Manager has overall responsibility for radiation protection areas, custodianship of source material used for equipment, and radiological aspects of nuclear shipments leaving the plant.

If, in the opinion of the RP Manager, radiological conditions threaten a radiation hazard to plant personnel or the general public, the RP Manager may recommend cessation of work or that the plant be shut down. If necessary, the RP Manager has recourse to the S-VP or the COO.

Sr. Manager, Maintenance
The Sr. Maintenance Manager is responsible for maintenance of mechanical, electrical, instrumentation and controls systems by controlling activities in mechanical, electrical, building and grounds, instrumentation and control maintenance, modification and construction activities.

Sr. Manager, Operations
The Sr. Operations Manager is responsible for direction of the functional conduct of shift operations, assurance that the plant is operated in accordance with approved procedures by qualified personnel, assurance that maintenance requests are properly transmitted, thus assuring that plant equipment is in a state of high reliability and readiness, providing the liaison between the shift and plant staff organizations, and assurance that plant operation is conducted in full compliance with the Technical Specifications and all other regulatory requirements.

The Sr. Operations Manager shall maintain a Senior Reactor Operator License.

Sr. Manager, Production
The Sr. Production Manager is responsible for the entire Work Management Process and the Outage Readiness and Execution Process by setting and reinforcing station productivity and schedule performance standards. Responsible for ensuring all station System Outages, Plant Downpowers and Plant Outages are executed with the highest level of Risk Mitigation, Safety and Efficiency. Serves as the process owner and sets the direction for Online Risk Management, the T Process, all Online and Outage Planning, Scheduling Process, and Work Management Critique Process.

Sr. Manager, Site Projects & Maintenance Services
The Sr. Site Projects & Maintenance Services Manager is responsible for scoping, funding, design, planning and implementation of major projects.

13.2.2.3 Director, Engineering

The Engineering Director is responsible for the delivery of safe, reliable and timely engineering support by developing and maintaining engineering and design standards, designing and implementing plant modifications, and controlling changes to the design basis.

Manager, Design & Programs Engineering
The Design & Programs Engineering Manager is responsible for engineering design and programs by maintaining Design basis control, Design Modifications, Configuration Management, ASME Code Program, Procurement Engineering, Mechanical Component Maintenance, and Predictive Maintenance Programs.

Manager, Systems & Components Engineering
The Systems & Components Engineering Manager is responsible for engineering support of major plant systems by monitoring plant performance and reliability and overseeing and implementing engineering projects.

13.2.2.4 Director, Regulatory & Performance Improvement

The Regulatory & Performance Improvement Director is responsible for managing the emergency planning, licensing, corrective action program, human performance/industrial safety and performance improvement.

Manager, Emergency Planning
The Emergency Planning Manager is responsible for the development and administration of the emergency preparedness program by maintaining the Emergency Response Organization (ERO). Oversees the training of ERO Team members, local government representatives and the media. Ensures emergency program meets all federal, state and local regulations and requirements. Oversees Emergency Response Teams, ERO team drills and evaluated exercises. Maintains ERO in a state of readiness. Ensures functionality of all plant emergency alert and communications systems. Maintains and revise the Emergency Plan and procedures.

Manager, Performance Improvement
The Performance Improvement Manager is responsible the corrective action program, including human performance, industrial safety, and performance improvement.

Manager, Regulatory Assurance
The Regulatory Assurance Manager is responsible for the operating license and related licensing basis documents. Supports NRC regulation compliance, interfaces with NRC Resident and inspectors, submits NRC correspondence and reports, and implements record retention requirements.

Manager, Security
The Security Manager is responsible for overall security by maintaining security intrusion, detection, and access control systems, training and exercise of the plant's guard force, and implementing the Security Plan.

Manager, Training
The Training Manager is responsible for the training of all classifications of personnel within the plant by developing and implementing training programs that meet or exceed industry standards and regulatory requirements. Manages the achievement and maintenance of National Academy for Nuclear Training accreditation. Also, maintains the training program for NRC licensed operators pursuant to NRC requirements.

13.2.2.5 Lines of Communication

Major communications on plant operation, availability, scheduling and maintenance generally are between the S-VP, and the President, CEO, and CNO. However, should consultation on performance, anomalies or modifications be required, the S-VP has at his disposal, for direct communications, the entire headquarters staff. Likewise, any of the managers at the plant having specific responsibilities may have direct communication with the engineer at headquarters assigned to that discipline or with the staff person most cognizant of the area of concern.

Should the S-VP be absent from the site, he shall delegate in writing the succession to his responsibilities during his absence.

Managers of major departments within the plant organization are responsible to General Manager of Plant Operations on an overall performance basis. The Managers of Maintenance, Site Projects & Maintenance Services, Operations, Radiation Protection, Chemistry, and Production report directly to the General Manager of Plant Operations for the functional performance of the plant. A Shift Manager, competent to supervise all shift operations, is on duty at all times, and has the authority to control all operating, maintenance and testing on his shift. Each Shift Manager on duty has direct authority to shut down the plant if, in his opinion, it is required because of radiation or any other hazard.

Administrative procedures originate from the General Manager - Plant Operations or his authorized representative. Safety related procedures are reviewed in accordance with section 13.8.

13.2.2.6 Operations Department Organization

The Operations department operates the plant in accordance with approved procedures with qualified personnel, performs maintenance requests properly thus assuring that plant equipment is in a state of high reliability and readiness, and assures that plant operation is conducted in full compliance with the Technical Specifications and all other regulatory requirements. The Sr. Operations Manager is responsible for the direction of the Operations Department.

Support Manager
The Operations Support Manager(s) assists the Sr. Operations Manager in the exercise of his responsibilities by providing day to day management of shift operation. In this capacity the Operations Manager(s) monitors and directs the activities of operating shift personnel, as directed by the Sr. Operations Manager.

The Operations Manager(s) shall assume the responsibility and authority of the Sr. Operations Manager when the Sr. Operations Manager is absent.

The Operations Manager(s) shall maintain a Senior Reactor Operator License, if a Senior Reactor Operator's license is not maintained by the Sr. Operations Manager.

Shift Manager
The Shift Manager reports to the Operations Manager(s) and is responsible for the operation of the plant on his shift. On off-shifts, weekends, and holidays, the Shift Manager represents plant management unless the Sr. Operations Manager, Operations Manager(s), General Manager of Plant Operations, or S-VP is onsite. The Shift Manager is responsible for:

- operation of the plant, in accordance with requirements of the NRC and other regulatory agencies,
- assuring that all operations on his shift are performed in accordance with approved procedures and are in compliance with the limits of the Technical Specifications,
- originating maintenance requests, as problems may arise,
- administrative implementation of plant security on off-shifts,
- maintaining an NRC Senior Reactor Operator License.

In case of radiation or any other hazard which, in the opinion of the Shift Manager, requires plant shutdown, the Shift Manager can order the plant shut down.

Control Room Supervisor
The Control Room Supervisor reports to the Shift Manager and directs and coordinates the activities of Operations Department shift personnel. The Control Room Supervisor has Control Room Command unless relieved by the Shift Manager.

The Control Room Supervisor shall assume the responsibilities and authority of the Shift Manager if the Shift Manager becomes incapacitated.

The Control Room Supervisor may initiate a reactor shutdown when it is determined that the safety of the reactor is in jeopardy, or when operating parameters exceed any of the reactor protection setpoints and an automatic shutdown does not occur.

The Control Room Supervisor shall maintain an active Senior Reactor Operator License.

Shift Technical Advisor*
The Shift Technical Advisor (STA) is directed in his activities by the Operations Shift Manager. The primary function of the STA is to provide accident assessment advice to the Shift Manager.

The STA must:

- possess a bachelor's degree in a scientific or engineering discipline or have completed the Advanced Technical Training Program and be functioning in a dual role as SRO and STA and
- have received specific training in the response and analysis of the plant for transients and accidents

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* The Shift Technical Advisor position may be a dual role (SRO/STA) who also is performing the duties of Shift Manager or Control Room Supervisor.

Field Support Supervisor
The Field Support Supervisor (FSS) is responsible to the SM for the supervision and coordination of operational activities outside the Control Room in accordance with approved Operations Department directives and station procedures.

Coordinate, in conjunction with the SM and CRS, the implementation of work activities affecting station equipment, including corrective and preventive maintenance, modifications, and protective tagging.

Senior Nuclear Operators
The Senior Nuclear Operators (SNO) are responsible to the Shift Manager for plant starting, stopping, operational adjustment, and testing and for recording of these events either personally or by the direction of others. In this capacity, the SNOs normally takes direction from the Control Room Supervisor. The major portion of the SNO's time is spent in the control room. The SNO is accorded the responsibility for:

- coordinating the activities of other Licensed Reactor Operators,
- directing the Nuclear Plant Operators,
- maintaining an NRC Reactor Operator License

The SNOs on duty has direct authority to shut down the plant, if, in the SNO's opinion, it is required because of radiation or any other hazard.

Nuclear Plant Operator
The Nuclear Plant Operator takes direction from the Senior Nuclear Operators, Control Room Supervisor and Shift Manager. The Nuclear Plant Operators are responsible for:

- operation of all auxiliary equipment throughout the plant,
- providing clearance operations prior to maintenance,
- restoring equipment to service following maintenance,
- knowledge of radiation control and protection requirements.

Reactor Engineering
Reactor Engineering provides technical leadership for reactor core performance and monitoring, advocates nuclear fuel reliability, maintains and revises fuel and special nuclear material management accountability and configuration, and provides technical assistance to Operations that establish conservative reactivity management and conservative decision making.

- Supports Operations for maneuvers / core analysis / operating limits considerations. Supports Operations in Reactivity Control and Management.
- Manages reactor core related surveillances and startup testing.
- Supports dry fuel storage related activities and irradiated core component disposal. Implements fuel storage and handling requirements. Supports core reload design analysis and batch reload implementation.

Operating Shift Crews
The minimum shift crew requirements, in Technical Specifications Section 5.2.2, shall be met.

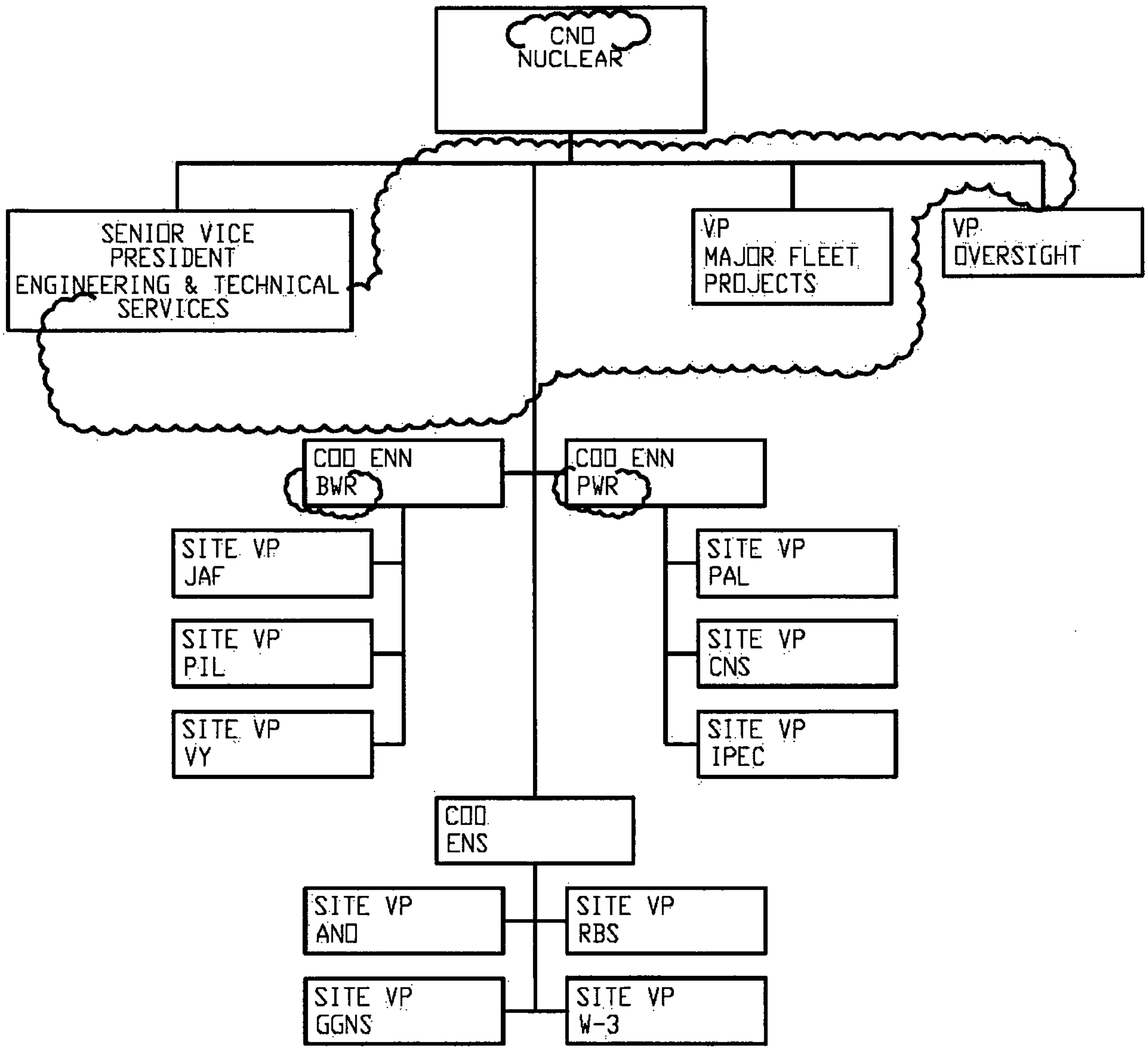
A Licensed Senior Reactor Operator (SRO) shall be onsite during refueling and cold shutdown conditions. During startup, hot shutdown, and run modes two SROs must be onsite and one should be in the Control Room.

A Licensed Reactor Operator (RO) shall be in the Control Room during refueling and cold shutdown conditions. During startup, hot shutdown, and run modes two ROs must be onsite and one should be in the Control Room. During a startup or planned shutdown; both ROs must be in the Control Room.

13.2.3 Qualification of Nuclear Plant Personnel

The minimum qualifications with regard to educational background and experience for plant staff positions shown in Figure 13.2-3 will meet or exceed the minimum qualifications of ANSI 18.1-1971 for comparable positions except for: (1) the Radiation Protection Manager who shall meet the qualifications of Regulatory Guide 1.8, September 1975, and (2) the Shift Technical Advisor who shall meet or exceed the minimum requirements of either Option 1 (combined SRO/STA position) or Option 2 (continued use of STA position), as defined in the Commission Policy Statement on Engineering Expertise on Shift, published in the October 28, 1985 Federal Register (50FR43621). The 13 individuals who hold SRO licensees, and have completed the FitzPatrick Advanced Training Program prior to the issuance of License Amendment III, shall be considered qualified as dual-role SRO/STAs. Any deviations to the STA's qualification shall be justified to the NRC prior to an individual's filling of position.

In general, the minimum qualifications with respect to education and experience for those headquarters personnel directly involved with providing technical support for JAF are consistent with ANSI/ANS 3.1, 1978.



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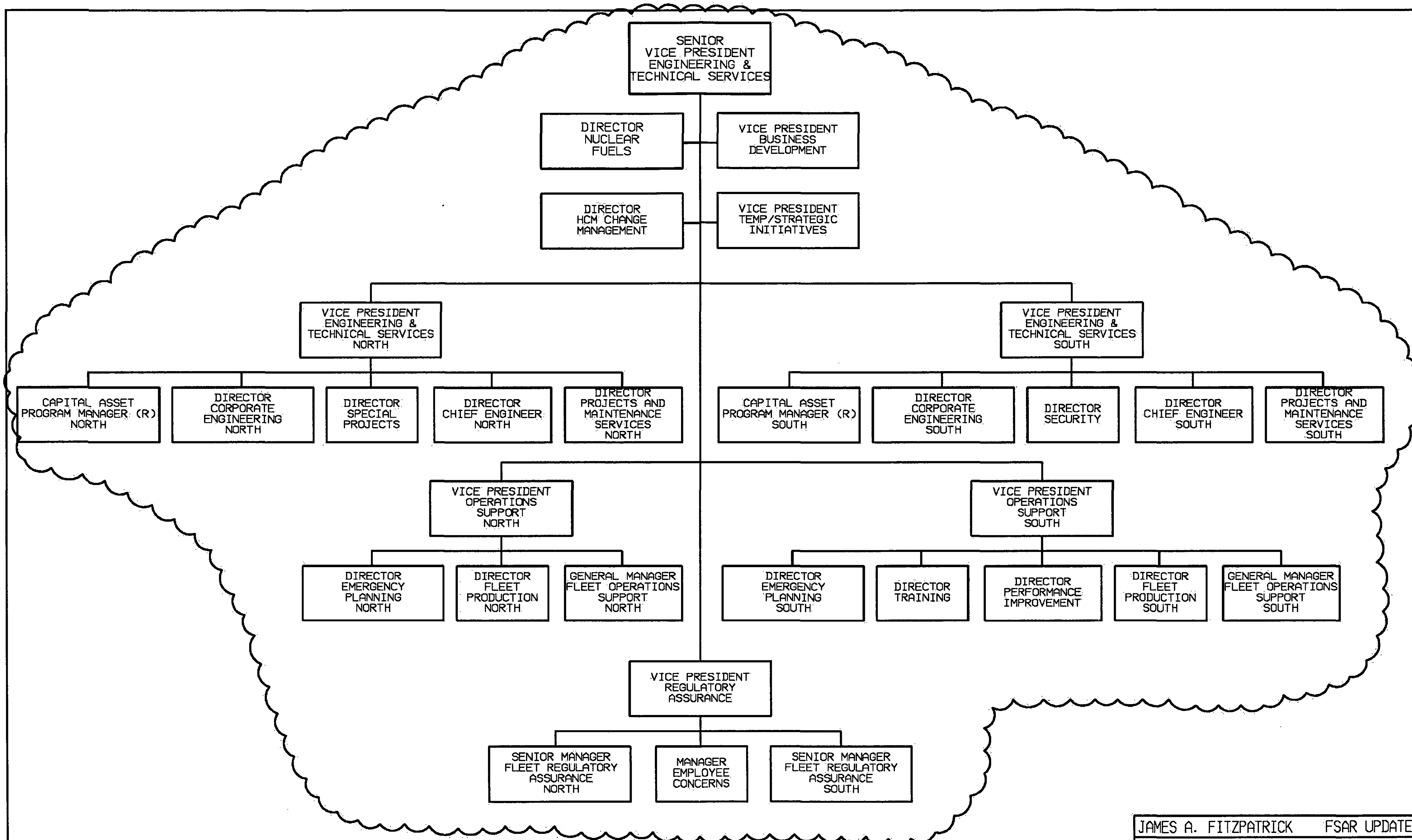
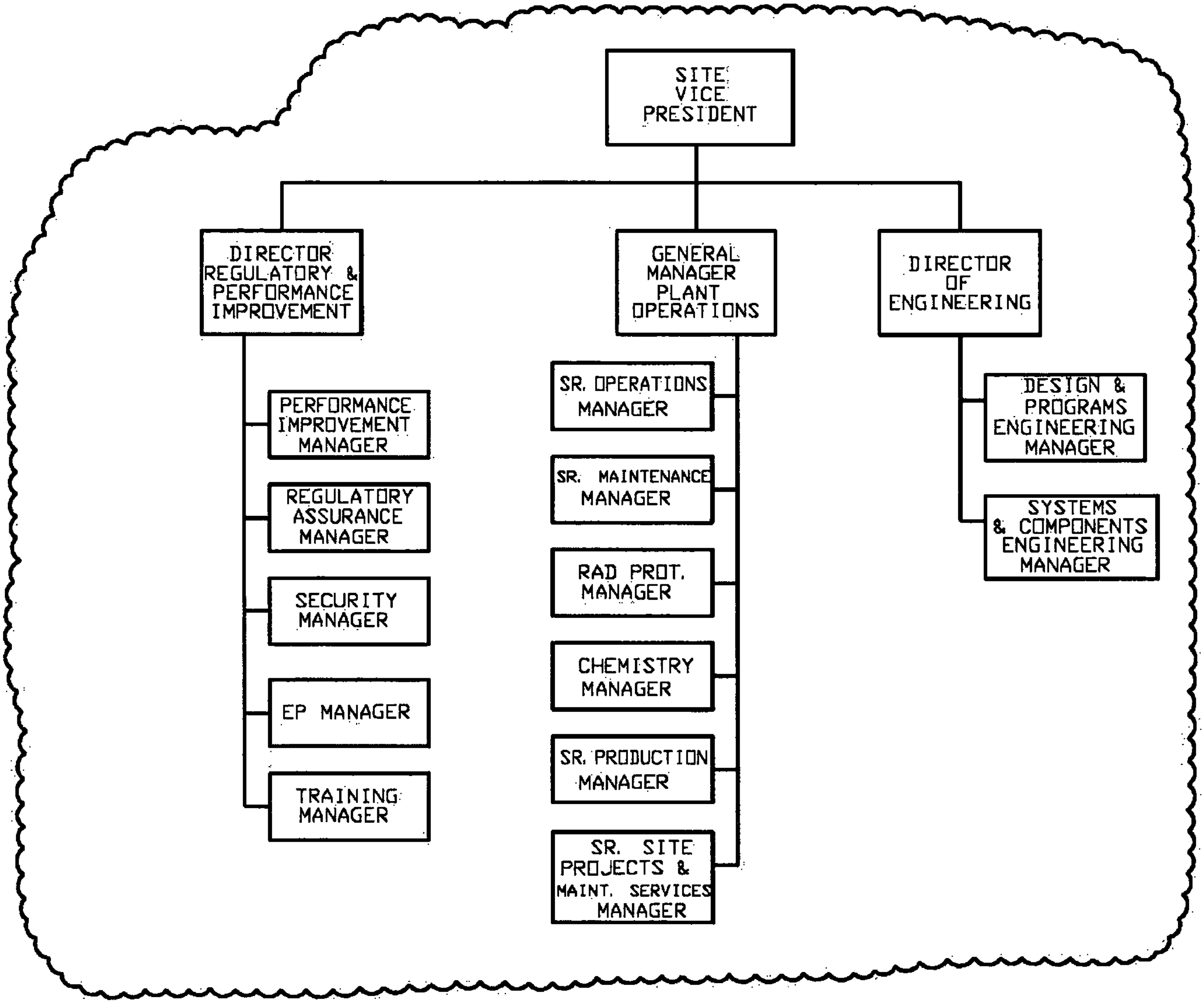
ENTERGY NUCLEAR OPERATIONS (ENO) MANAGEMENT ORGANIZATION

REV. 13 APRIL 2015 | FIGURE NO. 13.2-1



JAMES A. FITZPATRICK	FSAR UPDATE
TECHNICAL SERVICES	
REV. 11 APRIL 2015	FIGURE NO. 13.2-2



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13.8.5 Emergency Plans and Procedures

Entergy in cooperation with state and local governments has developed emergency plans and procedures. These plans and procedures are as follows:

a. On site response; JAFNPP Emergency Plan and Procedures.

b. State Response; New York Radiological Emergency Preparedness Plan and Procedures.

c. Local Response; Oswego County Radiological Emergency Response Plan and Procedures and Onondaga County Radiological Emergency Response Host Plan.

13.8.6 Security Plan

13.8.6.1 General

A Security Plan is maintained throughout the life of the Plant. It is comprised of procedures and measures to be taken to thwart attempted sabotage. Means to accomplish this purpose include: controlling entry to the plant site or portions of the facility; deterring or discouraging penetration by unauthorized persons; detecting such penetrations in the event they occur; apprehending in a timely manner unauthorized persons, or authorized persons acting in a manner constituting a threat of sabotage; and, providing for appropriate authorities to take custody of violators. The provisions relating to Security are described the "Physical Security, Training and Qualification, and Safeguards Contingency Plan". JAF adopted a standard "Security, Training and Qualification, and Safeguards Contingency Plan" consistent with NEI-03-012, as required by order EA-03-086.

The above noted document is referenced in Facility Operating License Section 2.D. This document has been revised under the authority of 10 CFR 50.54(p). These revisions did not decrease the safeguards effectiveness of the plan. As such, a 10 CFR 50.90 submittal and NRC prior approval was not required. The revised provisions relating to security submitted to the NRC under 10 CFR 50.54(p)(2) are described in documents entitled: "Revision to the James A. FitzPatrick Physical Security, Training and Qualification, and Safeguards Contingency Plan". Revisions 1 through 12 were submitted to the NRC with summaries documenting the revision as required by 10 CFR 50.54(p)(2).

13.8.6.2 Cyber Security

A Cyber Security Program protects digital computer and communications systems and networks performing the following categories of functions from those cyber attacks that would act to modify, destroy, or compromise the integrity of confidentiality of data and/or software; deny access to systems, services, and/or data, and; impact the operation of systems, networks, and associated equipment: (i) Safety-related and important-to safety functions; (ii) Security functions; (iii) Emergency preparedness functions, including offsite communications; and (iv) Support systems and equipment which, if compromised, would adversely impact safety, security, or emergency preparedness functions.

JAF Adopted a Cyber Security Plan (CSP) consistent with NEI 08-09 Revision 6 in order to implement the provisions of 10 CFR 73.54, "Protection of Digital Computer and Communication Systems and Networks." ENO shall fully implement and maintain in effect all provisions of the Commission approved CSP, including changes made pursuant to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). ENO CSP was approved by License Amendment No. 300, as supplemented by License Amendment No. 303 and No. 308.

13.8.7 Radiation Protection Program

13.8.7.1 General

Plant radiation protection procedures are designed to minimize the exposure of personnel to radiation and contamination. They contain guides and limits for radiation protection and contamination control as well as detailed procedures to ensure that these limits are not exceeded.

Procedures for personnel radiation protection shall be prepared and adhered to for all plant operations. These procedures shall be formulated to maintain radiation exposures received during operation and maintenance as far below the limits specified in 10 CFR 20 as practicable. The procedures shall include planning, preparation, and training for operation and maintenance activities. They shall also include exposure allocation, radiation and contamination control techniques, and final debriefing.

13.8.7.2 Personnel Monitoring

Sections of the radiation protection procedures describe the equipment used and the practices followed by plant personnel to monitor their individual radiation exposure.

13.8.7.3 Personnel Protective Equipment

This section deals with the proper use of such items as protective clothing (coveralls, shoe covers, gloves, etc.) and respiratory equipment. The equipment is described in detail along with its protective qualities and limitations.

13.8.7.4 Area Control

This section of the plant radiation protection procedures describes each of the various classes of access areas (Restricted Area, Radiologically Controlled Area, Radiation Area, High Radiation Area, Very High Radiation Area), along with the procedures for entry and exit from each area.

13.8.8 Fire Fighting

The fire fighting plan provides for prompt and efficient handling of fire, regardless of the size or presence of radioactivity. The first line of defense for fires is the plant fire brigade. Fire fighting assistance can be obtained from The Oswego County Fire Control Center. Plant personnel are trained in fire fighting techniques.

13.8.9 References

1. Nuclear Safety Evaluation, JAF-SE-98-053, Revision 0, dated December 11, 1998.
2. Nuclear Safety Evaluation, JAF-SE-90-068, dated June 17, 1990.

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CHAPTER 14

SAFETY ANALYSIS

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A consideration of the last two varieties of events shows that turbine bypass valve failure and loss of condenser vacuum are specific cases of the first three event types. A failure of the turbine bypass valves to open when required is analyzed as the most severe form of a turbine trip or generator load rejection. The most conservative transient (instantaneous loss of condenser vacuum) is a nearly identical transient with scram from the turbine stop valve position indicating signals. For the loss of condenser vacuum, the reactor feedpump turbines would also be tripped. However, the parameters of main concern, fuel thermal margin and margin to vessel overpressure, are not significantly different from the analysis performed for the turbine trip (no bypass) transient (see Section 14.5.2.2). Thus, all of the effects of these events are included in the effects described for the generator and turbine trip.

14.5.2.1 Control Valve Fast Closure - Generator Load Rejection

A loss of generator load causes the turbine-generator to overspeed. The turbine speed and acceleration protection systems and the power load unbalance circuitry in the Electrohydraulic Control (EHC) System quickly close the turbine control valves to shut off the steam supply to the turbine in order to avoid excessive turbine overspeed. As these transients are essentially the same as the turbine trip transients described later, they are included for completeness of this section.

Generator Load Rejection From High Power With 25 Percent Bypass

A loss of generator electrical load from high power conditions produces the following transient sequence:

a. The power load unbalance circuitry energizes fast-acting solenoid operated valves which open disc dump valves on the turbine control valves such that the control valves close rapidly (about 0.15 sec).

b. Reactor scram is initiated immediately from pressure switches mounted on the hydraulic oil lines to the control valves (at initial power levels greater than or equal to 29 percent rated thermal power).

c. The turbine bypass valves are opened simultaneously with the turbine control valves closure when the load demand is stepped to zero and reactor pressure control is transferred from the control valves to the bypass valves.

d. Reactor vessel pressure rises to the relief valve set points causing them to open and discharging some of the stored energy into the suppression pool.

e. The turbine bypass system controls the Reactor Coolant System pressure after the relief valves close.

Below about 25 percent of rated power, the Turbine Bypass System transfers steam to the condenser and avoids reactor scram. Between about 25 and 30 percent power, high pressure scram results unless operator action can reduce power to within the bypass capacity.

Generator Load Rejection from Low Power with 25 Percent Bypass

The mismatch between steaming rate and bypass capacity is small for a generator trip from an initial power level between 25 and 30 percent of rated power and the effects of the transient are not severe. A high pressure scram will not occur for approximately 35 seconds and the neutron flux will not rise above approximately 45 percent of rated. The transient resulting from turbine trip from low power without bypass is more significant and is presented in Section 14.5.2.2.

Generator Load Rejection Without Bypass

The worst single failure generator load rejection case occurs if the Turbine Bypass System fails to open. This event may establish the MCPR operating limit as the most limiting transient for reload cores. Details of the analysis of this event are given in Reference 22. The results of the analysis of this event are given in Reference 28 and in Figure 14.5-17.

Peak neutron flux reaches approximately 557 percent of rated power; however, the fuel surface heat flux peaks at about 134 percent of its initial value (Reference 28). The relief valves open to limit the pressure rise, then reclose as the stored energy is dissipated. The peak pressure rise in the reactor is approximately 205 psig. The overpressure transient is clearly below the Reactor Coolant Pressure Boundary design pressure limit.

14.5.2.2 Stop Valve Closure-Turbine Trip

A turbine trip is the primary turbine protection mechanism and is initiated whenever various turbine or reactor system malfunctions occur which may threaten turbine operation. The turbine trip initiates fast closure (about 0.1 sec) of the turbine stop valves. This event represents the fastest possible steam flow shutoff and a severe Reactor Coolant System pressure increase. Several variations in the turbine trip transient are possible according to the assumptions made concerning the initial power level and the Turbine Bypass System. These cases are discussed individually.

Normal Turbine Trip (With Bypass)

The sequence of events for a turbine trip is very similar to that for a generator load rejection. However, the valve closure is somewhat faster occurring over a period of about 0.1 sec. The turbine trip, besides initiating the stop valves closure, also sets back the load demand to zero such that reactor pressure control is quickly transferred to the bypass valves. Reactor scram is initiated immediately from position switches mounted on the turbine stop valves. The relief valves open to help relieve the pressure transient and then close, allowing the bypass system to control pressure during the reactor shutdown. The neutron flux peak is about 195 percent of rated power. Peak pressure at the bottom of the vessel is well below the ASME Code limit of 1375 psig. The bypass valves start to close at about 24 seconds and are fully closed at about 31.5 seconds. Turbine trips, from lower initial power levels decrease in severity to the point where scram may even be avoided within the 25 percent Turbine Bypass

more than its normal rated flow. This total flow, however, is limited due to the maximum pump speed of approximately 1660 rpm. As the pump trip transient settles out, symmetrical, natural circulation operation is approached with positive flow in both loops as shown by diffuser flow plots on Figure 14.5-7.

Trip Of Both Driven Motors

This two-loop trip provides the evaluation of the fuel thermal margins maintained by the rotating inertia of the recirculation drive equipment. No single operator act or plant protection action can produce simultaneous trip of the generator field breakers in both loops. Plant protection action can, however, simultaneously trip the power supplying the MG set drive motors.

Figure 14.5-8 graphically shows the transient with the nominal design rotating inertia. No damage to the fuel barrier occurs. No scram is initiated directly by the simultaneous pump trip and the power settles out at part-load, natural circulation conditions. Reactor Coolant System pressure decreases throughout the transients such that the Reactor Coolant Pressure Boundary is not threatened by overpressure.

14.5.6.3 Recirculation Pump Seizure

This case represents the instantaneous stoppage of one pump motor shaft. It produces the most rapid decrease of core flow. The reactor is assumed to be operating at maximum power conditions.

Figure 14.5-9 shows the calculated transient. Note the fast decrease in drive flow in the seized loop due to the large loss introduced by the stopped rotor. Core flow reaches the minimum value near 1.1 sec. Nucleate boiling is maintained and no damage occurs to the fuel clad barrier. The initial pressure regulator maintains pressure control as the reactor settles out at the final lower power condition. No scram occurs. Because the Reactor Coolant System pressure decreases throughout the transient, the Reactor Coolant Pressure Boundary is not threatened by overpressure.

Single Recirculation Loop Operation-Pump Seizure

Figure 14.5-10 shows the pump seizure transient for a transition core with GE14 and GNF2 fuel. As the pump seizure transient settles out, symmetrical, natural circulation operation is approached as shown by the diffuser flow.

The Reactor Recirculation Pump Seizure (RRPS) event analysis for Single Loop Operation (SLO) was performed at 2066 Mwt (81.47% CTP) and 44.7 Mlb/hr (58% WT), which bounds the SLO operating domain. Although the analysis used a transition core of GE14 and GNF2, application of a conservative multiplier is intended to bound alternate cycles exposures and other core designs of GNF2 through equilibrium. The results GNF2 fuel bound all other fuel types.

Results of the RRPS event analysis for SLO shows that a SLO Operating Limit Minimum Critical Power Ratio (OLMCPR) of 1.42 for GE14 and 1.53 for GNF2 ensure that the Minimum Critical Power (MCPR) remains greater than a reference SLO SLMCPR of 1.09. When operating in SLO, the SLO OLMCPR may be adjusted such that the rated operating limit multiplied by the power dependent multiplier at 81.47% power bounds the respective GE14 and GNF2 OLMCPRs. If the SLO SLMCPR is greater than 1.09, then the SLO OLMCPR must be adjusted by the ratio of SLMCPR/1.09. If the SLO SLMCPR is less than 1.09, then the SLO OLMCPR limits of 1.42 for GE14 and 1.53 for GNF2 are conservative. However, the SLO OLMCPR may still be adjusted by SLMCPR/1.09 if desired.

Cycle specific RRPS event SLO OLMCPR validation is documented in Reference 28.

14.5.7 Events Resulting In A Core Coolant Flow Increase

Events that result directly in a core coolant flow increase are those that affect the Reactor Recirculation System. The following events result in the most significant transients in this category:

a. Recirculation flow control failure - increasing flow.

b. Startup of idle recirculation pump.

14.5.7.1 Recirculation Flow Controller Failure - Increasing Flow

Several possibilities exist for an unplanned increase in core coolant flow resulting from a recirculation flow control system malfunction. Failure of the master controller can result in a speed increase for both recirculation pumps. However, both individual speed controllers are provided with input rate limits which are adjusted in such a way that a master controller failure is less severe than the failure of one of the MG set speed controllers. The most severe case of increasing coolant flow results when the MG set fluid coupler for one recirculation pump attempts to force full speed at maximum acceleration. The maximum coupler positioner rate of change for this failure is assumed to be 25 percent per sec. This forces a maximum pump speed change of about 37 percent of rated speed per sec. The most severe transient results when the reactor is initially at 65 percent of rated power and recirculation flow is at the lower end of the automatic flow control range. These conditions correspond to the lowest power and flow conditions on the automatic flow control characteristic curve for the reactor.

Figure 14.5-11 illustrates the results of the transient. The changes in the Reactor Coolant System pressure are not significant with regard to overpressure. The pressure decreases over most of the transient. The rapid increase in core coolant flow causes an increase in neutron flux, which initiates a reactor scram in about 2.7 sec. The transient fuel surface heat flux reaches about 84 percent of rated value, but it barely exceeds the steady state 105 percent power-flow control characteristic curve. The fuel center temperature increases only 301°F. No fuel damage occurs.

14.5.7.2 Startup Of Idle Recirculation Pump

The transient response to the starting of an idle recirculation loop without warming the drive loop water is shown in Figure 14.5-12. The initial conditions which were assumed are:

a. One drive loop is shut down and filled with water 50°F cooler than RPV coolant temperature. (Normal procedure requires warming this loop).

b. The active recirculation pump is operating at a speed producing about 67 percent of normal rated diffuser flow in the active jet pumps.

c. The core is receiving 50 percent of its normal rated flow, while the remainder of the flow is reversed up the inactive jet pumps.

d. Reactor power is 65 percent of design conditions. (Normal procedures require startup of an idle loop at a lower power.)

e. The idle recirculation pump suction valve is open, but the pump discharge valve is closed.

f. The idle pump fluid coupler is at a setting which approximates 50 percent generator speed demand.

The loop startup transient sequence is:

a. The drive motor breaker is closed at t = 0.

b. The drive motor reaches near synchronous speed quickly, while the generator approaches full speed near 5 sec.

c. Next, the generator field breaker is closed, loading the generator and applying starting torque to the pump motor. Generator speed is drawn down as it tries to start the stopped rotor of the pump. Pump break away is modeled to start pumping coolant at 8 seconds. Speed demand is sequentially programmed back to approximately 26 percent of rated speed.

d. The pump discharge valve may be manually opened after the pump has been started. (Normal procedure would delay valve opening to separate the two portions of the flow transient and make sure the water in the idle loop is properly mixed with the hot water in the reactor vessel). A non-linear 30 sec valve opening characteristic is used.

   Shortly after the pump begins to move, a surge in flow from the activated jet pump diffusers gives the core inlet flow a sharp rise. A short-duration neutron flux peak of about 90 percent of rated is produced (no scram occurs as flow reference scram is neglected), however, surface heat flux follows the slower response of the fuel as the reactor settles out at its new steady state condition. No damage occurs to the fuel barrier. No significant changes in Reactor Coolant System pressure result from the transient.

Throughout the transient, diffuser flow in the startup loop jet pumps is reversed. For this reason, the cold loop water does not significantly affect the transient.

14.5.8 <u>Event Resulting In A Core Coolant Temperature Increase</u>

An event which can directly cause a reactor vessel water temperature increase is one in which hotter water is returned to the reactor vessel without changing the coolant flow rate. This event is loss of RHR shutdown cooling.

14.5.8.1 <u>Loss Of RHR Shutdown Cooling</u>

The loss of RHR shutdown cooling can only occur during the low pressure portion of a normal reactor shutdown and cooldown and during refueling condition. At this time the RHR System is operating in the shutdown cooling mode. For most single failures which could result in loss of shutdown cooling no unique safety actions are required; in these cases, shutdown cooling is simply re-established using other normal shutdown cooling equipment. In the cases where the RHR shutdown cooling suction line becomes inoperative, a unique requirement for cooling arises. In operating states A and B, in which the reactor vessel head is off, either half of the RHR Systems LPCI mode can be used to maintain water level to ensure continued core cooling.

While not credited in the loss of RHR shutdown cooling analysis, the Decay Heat Removal System may also be available to supplement decay heat removal via the Spent Fuel Pool when the reactor vessel head is removed, the reactor cavity is flooded, and the fuel transfer gates are removed.

In operating states C and D, in which the reactor vessel head is on and the system can be pressurized, the low pressure cooling systems, relief valves (manually operated), and RHR System suppression pool cooling mode can be used to maintain water level and remove decay heat.

14.5.9 Event Resulting In Excess Of Coolant Inventory

An event which can directly cause an excess of coolant inventory is one in which makeup water flow is increased without changing other core parameters. This event is feedwater controller failure - maximum demand.

Feedwater Controller Failure - Maximum Demand

The transient response of the plant to a failure of the feedwater controller which demanded maximum flow is shown in Figure 14.5-16. This transient is postulated on the basis of a single failure of the feedwater controller to maximum flow demand that can directly cause an increase in coolant inventory by increasing the feedwater flow. This event may establish the MCPR operating limits as the most limiting transient for a reload core.

The feedwater controller is forced to its upper limit at the beginning of the event. The starting conditions and assumptions considered in this analysis are as follows:

a. Feedwater controller fails during maximum flow demand
b. Maximum feedwater pump runout is assumed
c. The reactor is operating in a manual flow control mode at rated power, which provides for the most severe transient.

A feedwater controller failure during maximum demand produces the following sequence of events:

a. The reactor vessel receives an excess of feedwater flow
b. This excess flow results in an increase in core subcooling, which results in a rise in both core power and reactor vessel water level.
c. The rise in the reactor vessel water level eventually leads to high water level turbine trip, feedwater pump trip and reactor scram trip.

Under most conditions, no operator action will be required. The reactor will scram as a result of main turbine trip due to high water level which will end the transient.

The influx of excess feedwater flow results in an increase in core subcooling that reduces the void fraction and thus induces an increase in reactor power. The excess feedwater flow also results in a rise in the reactor water level, which eventually leads to high RPV water level, main and feedwater pump turbine trip, reactor scram and turbine bypass valve opening. Relief valves open as steamline pressures reach relief valve setpoints.

The limiting core wide Abnormal Operating Occurrences (AOOs) throughout the operating cycle for normal operating conditions are the Generator Load Reject without bypass (LR w/o BP) and Feedwater

Controller Failure (FWCF) because the events have similar Operating Limit Minimum Critical Power Ratio (OLMCPR) considering the range of exposure dependent calculations. In order to support plant operation flexibility and Out of Service (OOS) equipment, the analysis includes results for transients with FWCF in combination with Turbine Bypass Valve Out of Service (TBVOOS) and/or Feed Water Temperature Reduction (FWTR). Under the TBVOOS condition the FWCF event is more limiting than the LR w/o BP because this event normally assumes 3 of 4 bypass valves operate to mitigate the effect of the high-level turbine trip. FWCF is more limiting under FWTR conditions because of the added reactivity of the colder water and consequently higher power at the time of the turbine trip. Finally, FWCF is slightly more limiting than the later event under both TBVOOS and FWTR conditions.

14.5.10 Plant Shutdown From Outside The Control Room

This special event is presented to demonstrate the capability to perform the operations required to maintain the plant in a safe condition from outside the Control Room.

14.5.10.1 Criteria For Plant Shutdown From Outside The Control Room

It is possible to bring the reactor to a cold shutdown condition by using controls and equipment outside the Control Room. This will be accomplished by performing an RPV depressurization using the available safety relief valves and flooding the RPV with water from the Torus using B residual heat removal system.

A maximum of 30 minutes has been established for completion of operator actions outside the control room which initiate RPV injection.

14.5.10.2 Plant Shutdown Procedure

The plant shutdown procedure will contain the appropriate steps to ensure the reactor is shutdown, depressurized and subsequently reflooded to ensure the reactor is placed in a safe condition. In order to achieve the desired goal, the plant abnormal operating procedure for plant shutdown outside the control room will contain the following steps as a minimum:

The following steps will be performed by the control room operators prior to exiting the control room if possible:

A. The Control Room Operators will notify the shift personnel of the need to evacuate the Control Room and to man their respective auxiliary shutdown panels

B. Manually scram the reactor

C. Trip the main turbine

D. Close the MSIV's

E. Trip the RWR pumps

The following steps will be conducted by the operators outside the control room.

A. As backup steps, operators will be dispatched into the plant to carry out steps at the various power sources and panels to ensure the following:

1. RPS System is de-energized
2. Scram Air System is isolated and vented
3. MSIV's are closed
4. RWR System is shutdown

B. An operator will be dispatched to the Emergency Switchgear Room to take the necessary steps to ensure that the 10600 volt bus is being supplied from the B and D emergency diesel generators only.

C. When the Shift Manager has determined that the control room cannot be reentered, the SM will then verify the required systems are available and direct the following:

Note: The SM should complete the following steps prior to reactor level reaching TAF or torus temperature reaching 110 degrees.

1. Start RHRSW Pump and establish RHRSW flow.
2. Start RHR Pump.
3. Open seven SRV's.
4. When RPV pressure is within RHR capabilities, then inject into the reactor vessel.
5. Establish conditions such that the reactor vessel is flooded to the steam lines and water is being directed to the torus through open SRV's.

14.5.11 Reactor Shutdown Without Control Rods

This special event is presented to demonstrate the capability of the Standby Liquid Control System to shut down the reactor. The Standby Liquid Control System is manually initiated and controlled and is not intended to replace control rods for fast scram of the reactor.

Two cases are postulated to evaluate the capability of the Standby Liquid Control System to shut down the reactor:

1. The reactor is scrammed, and it is postulated that some of the control rods malfunction and are not fully inserted.
2. The reactor is operating normally and it is postulated that all control rods malfunction and remain fixed at their present position.

The maximum number of control rods are withdrawn when the reactor is at full power with equilibrium xenon poisoning. This condition establishes the maximum total reactivity control requirement for the Standby Liquid Control System. The bases are set upon the reactivity control required to achieve the cold shutdown condition from the initial conditions assumed in Case 2 above. The Standby Liquid Control System, as designed, has sufficient capacity to control the reactivity difference between the steady state full power operating condition of the reactor with voids and the cold shutdown condition including shutdown margin to ensure complete shutdown from the most reactive condition at any time in the core life.

The maximum rate of core reactivity increase for Case 1 conditions would result if the reactor was scrammed from full power, held at the hot standby condition for about one day until the rate of xenon decay was maximum and then depressurized at the maximum allowable cooldown rate of 100° F per hr. Following scram, the available shutdown margin would actually increase as xenon poisoning in the core increases. The maximum xenon decay rate occurs after xenon poisoning has decreased again to values below those present at equilibrium xenon conditions at full power. The combined reactivity effects of maximum xenon decay rate and maximum reactor cooldown rate (with control rods partially withdrawn from the core) result in a maximum rate of change of core reactivity which is approximately one fifth of the rate of change of core reactivity using the Standby Liquid Control System.

The maximum rate of core reactivity increase for Case 2 conditions would result if the reactor was scrammed, held at the hot standby conditions until the xenon concentration is maximum, and then returned to the full power condition. This sequence maximizes the rate of xenon depletion (burnup) after return to power and results in the maximum rate of increase of core reactivity from inherent nuclear processes. This sequence results in a maximum rate of core reactivity change which is approximately one fifteenth of the rate of change of core reactivity using the Standby Liquid Control System.

14.5.12 Plant Shutdown From Outside the Control Room

In the unlikely event that a fire in the Control Room (CR), the Relay Room, the Cable Spreading Room, the Battery Room Corridor or the North Cable Run Room prevents a reactor shutdown from the Control Room, the operators will shutdown the reactor from outside the Control Room in accordance with the JAFNPP abnormal operating procedures. While some shutdown actions take place at various MCCs, breaker panels or valve stations; the majority of the shutdown functions take place at the panels and racks listed below:

PANEL	LOCATION	CONTROL
02ADS-071	Reactor Building El 300' North (W-6)	Local control of ADS relief valves
25-6	Reactor Building El 300' North (YW-5.5) (Rack)	RPV water level
25-51	Reactor Building El 272' West (P-4) (Rack)	RPV water level
25ASP-1	Reactor Building El 272' South (W-1)	Isolates Control Room circuitry and local control of RHR and RHRSW
25ASP-2	East Crescent Stairway El 243.5' (D-1.5)	Isolates Control Room circuitry and local control of LPCI and RHR

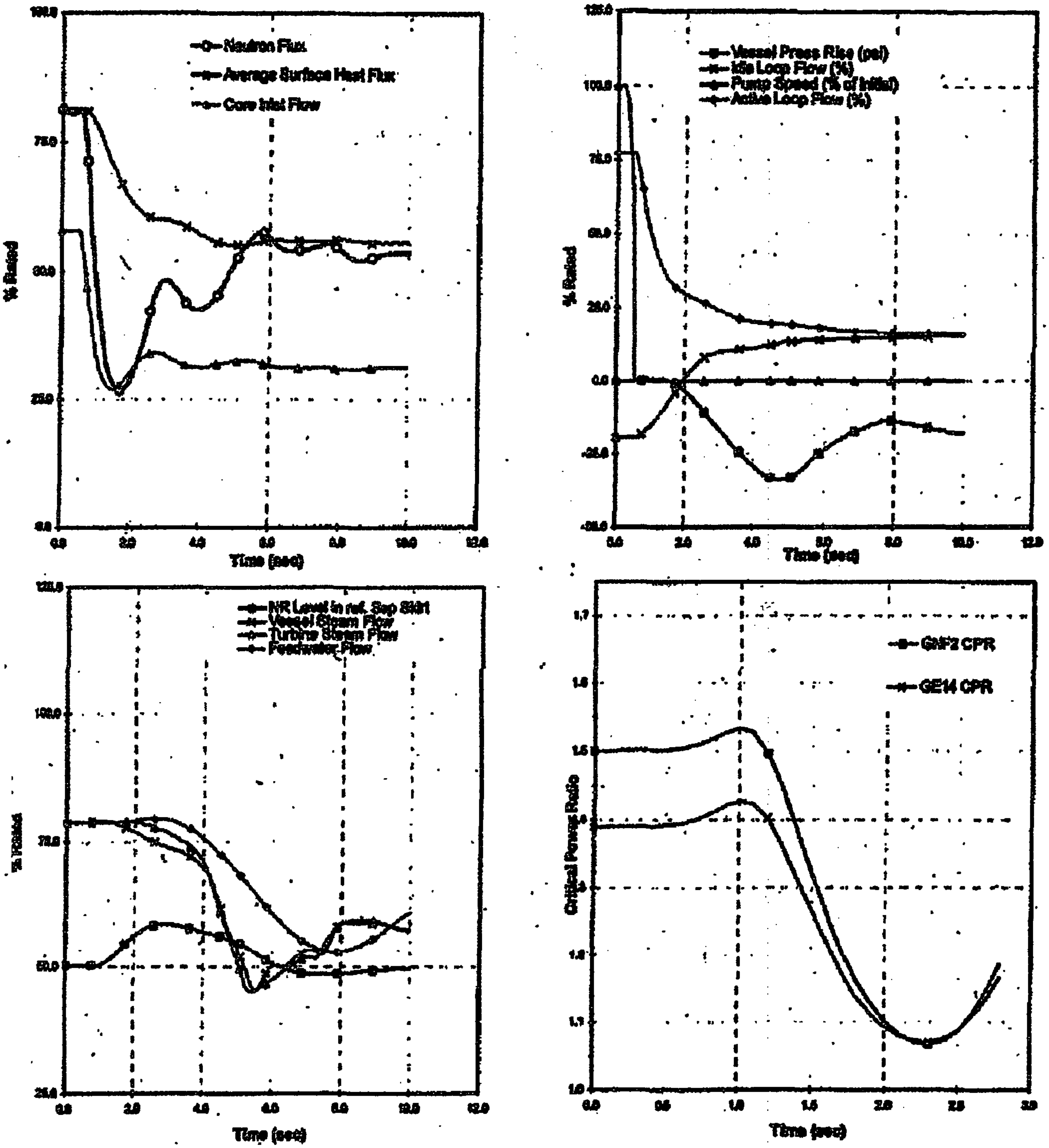
PANEL	LOCATION	CONTROL
25ASP-3	North Emergency Switchgear Room El 272' (A-26.5)	Isolates Control Room circuitry local control of Emergency Switchgear and ESW
25ASP-4	Administrative Building Hallway El 300' (Z-11)	Isolates Control Room MSIV circuitry
25ASP-5	Administrative Building Hallway El 300' (Z-11)	Isolates Control Room ADS circuitry
25RSP	Reactor Building El 300' North (Y-6)	RPV water level, isolates Control Room circuitry and local control of LPCI, RHR, and RHRSW
66HV-3B	Reactor Building El 272' South (A-2)	Isolates Control Room circuitry
93ECP-B	North Emergency Switch-gear Room El 272' (A3-26)	Local control of B Emergency Diesel Generator
93ECP-D	North Emergency Switch-gear Room El 272' (A1-27)	Local control of D Emergency Diesel Generator
93EGP-B	North Emergency Switch-gear Room El 272' (A1-26)	Local control of B Emergency Diesel Generator
93EGP-D	North Emergency Switch-gear Room El 272' (A1-27)	Local control of D Emergency Diesel Generator

Except for 02ADS-071, which is QA Category QP, these panels and racks are QA Category SR.

Refer to FSAR Section 9.15 for the plant Shutdown Communication System which provides uninterrupted communication between Control Room Panel 09-3, Remote/Alternate Shutdown Panels 25RSP, 25ASP-1, 25ASP-2, 25ASP-3, and Instrument Rack 25-51.

14.5.13 Anticipated Transients Without Scram (ATWS)

ATWS is a beyond design basis event that is analyzed to demonstrate conformance with the licensing requirements of 10 CFR 50.62. The regulation includes requirements for an ATWS Recirculation Pump Trip (RPT), and Alternate Rod Insertion (ARI) system and an adequate Standby Liquid Control System (SLCS) injection rate.



James A. FitzPatrick FSAR UPDATE

SINGLE LOOP OPERATION
RECIRCULATION PUMP SEIZURE RESULTS

REV. 3 APRIL 2015	FIGURE NO. 14.5-10

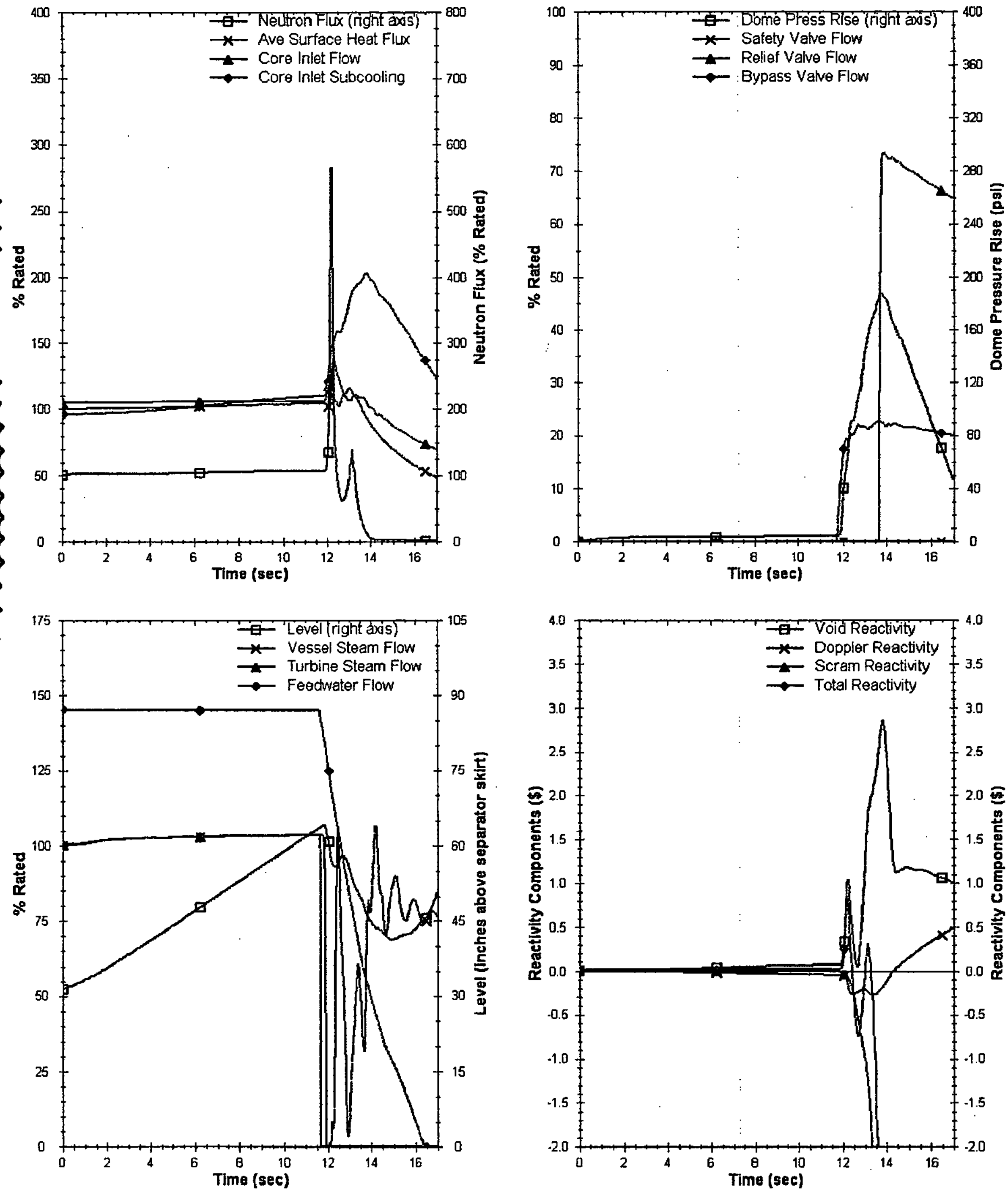


Figure 4 Plant Response to FW Controller Failure (EOC ICF (HBB))

JAMES A. FITZPATRICK	FSAR UPDATE
PLANT RESPONSE TO FW CONTROLLER FAILURE EOC22 ICF	
REV. 10 APRIL 2015	FIGURE NO. 14.5-16

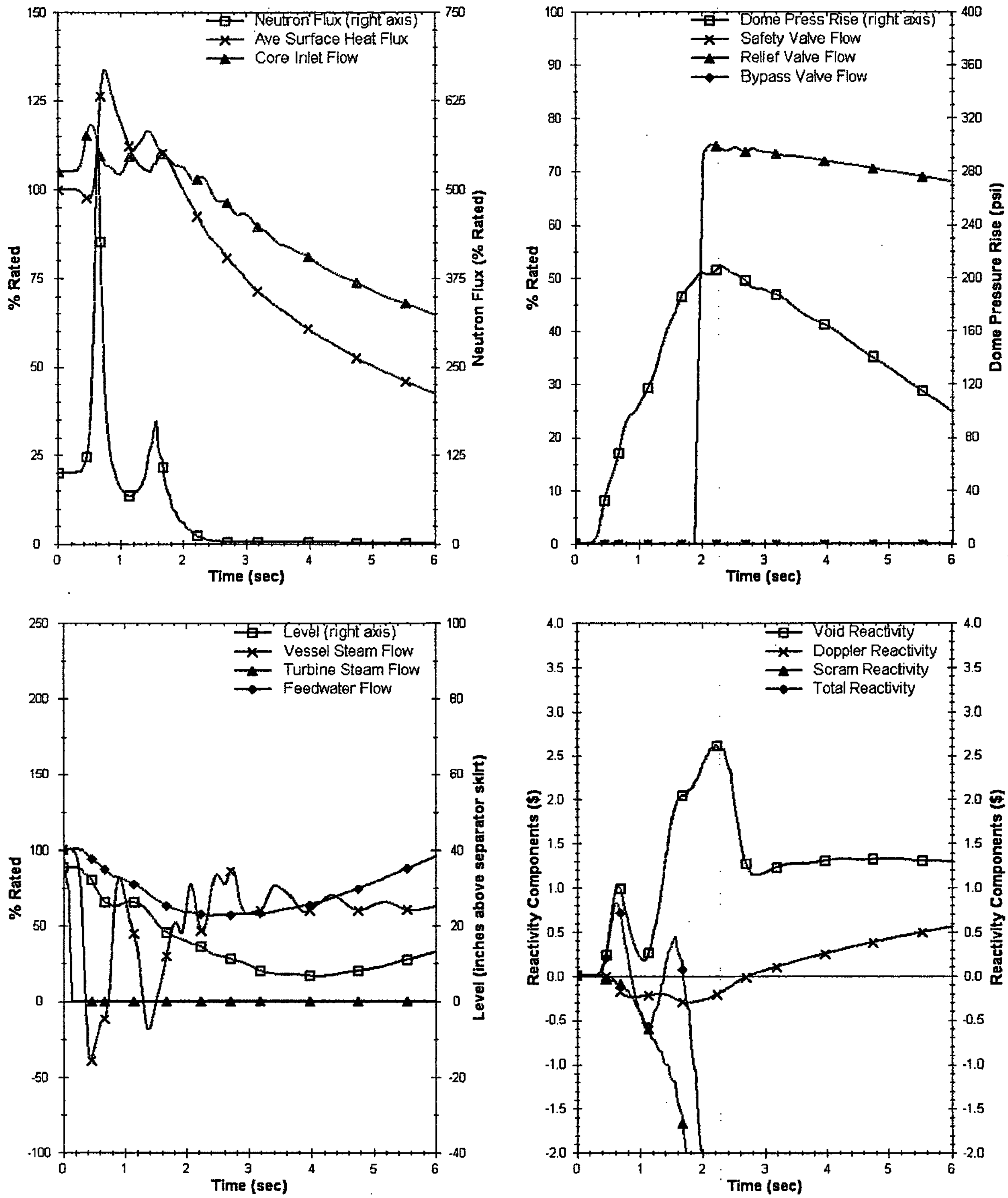


Figure 5 Plant Response to Load Rejection w/o Bypass (EOC ICF (HBB))

JAMES A. FITZPATRICK	FSAR UPDATE
PLANT RESPONSE TO LOAD REJECT W/O BYPASS EOC22 ICF	
REV. 10 APRIL 2015	FIGURE NO. 14.5-17

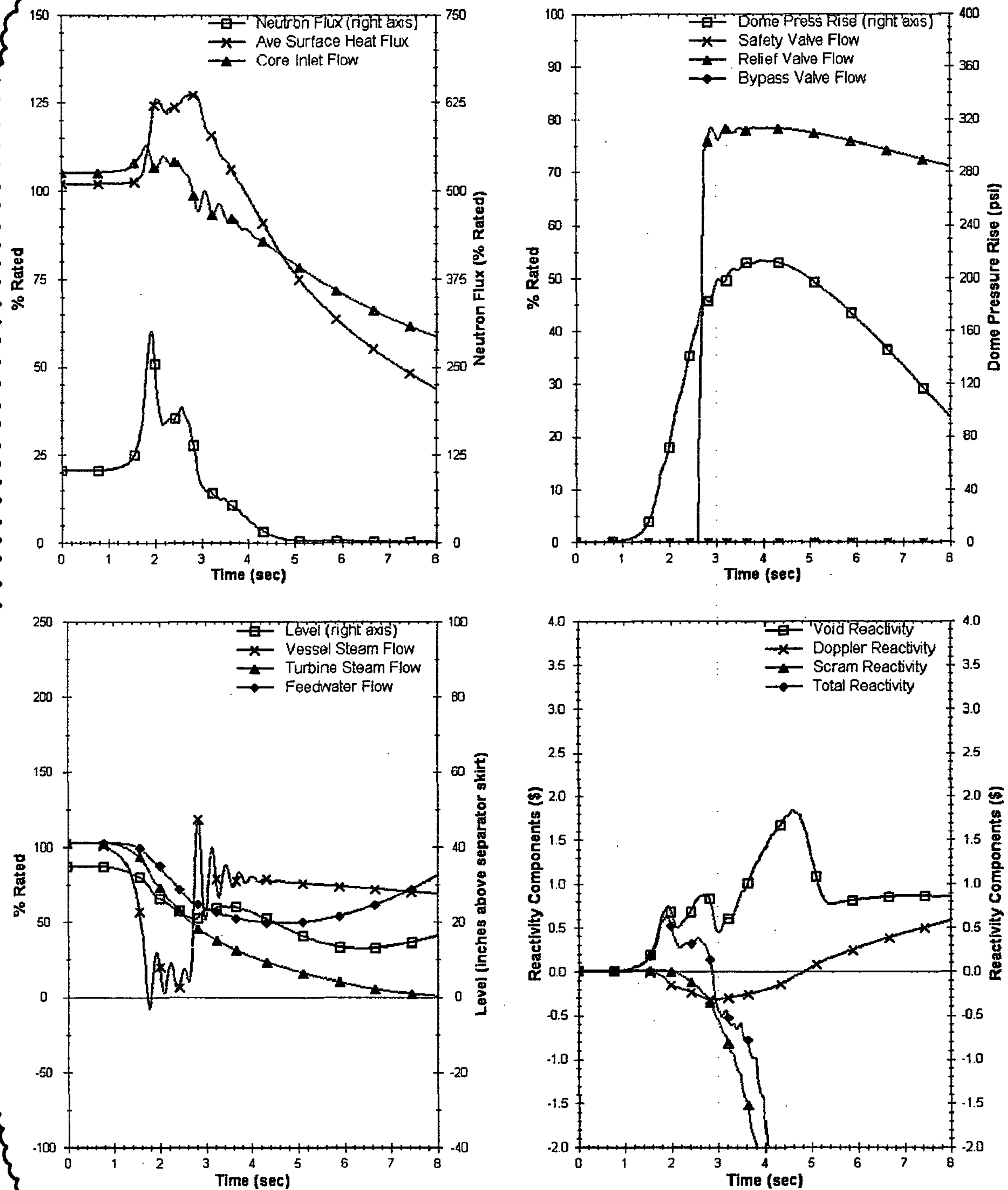


Figure 26 Plant Response to MSIV Closure (Flux Scram) - ICF (HBB)

James A. FitzPatrick FSAR UPDATE

PLANT RESPONSE TO MSIV CLOSURE (FLUX SCRAM)

CYCLE 22

REV. 10 APRIL 2015 | FIGURE NO. 14.5-18

b. Sticking of the control rod in its full inserted position as the drive is withdrawn. The control rods are designed to minimize the probability of sticking in the core. The control rod blades, which are equipped with rollers or wear pads that make contact with the channel walls, travel in gaps between the fuel assemblies with approximately 1/2 inch total clearance. Control rods of similar design, in operating reactors, have shown no tendency to stick in the core due to distortion or swelling of the blade.

c. Full withdrawal of the control rod drive.

d. Failure of the control room operator to notice the lack of response of neutron monitoring channels as the rod drive is withdrawn.

e. Failure of the control room operator to verify rod coupling. The control rod locks on a seal, preventing the control rod drive from being withdrawn to the overtravel position. Attempting to withdraw a control rod drive to the overtravel position provides a method for verifying rod coupling: this verification is required whenever neutron monitoring equipment response does not indicate that the rod is following the drive.

The accident is analyzed over the full spectrum of power conditions. Nuclear excursion results are presented for three points in this range: (1) the cold (68 F) critical condition for moderator and fuel, (2) a hot (547 F) critical condition, and (3) the 10 percent of rated power condition. The results of the rod drop accident initiated from higher than 10 percent power are less severe than the 10 percent power case due to the faster Doppler response. Only the radiological results of the most severe case are presented.

14.6.1.2.1 Initial Conditions

The following initial conditions are assumed for the three cases presented:

Case A (cold)	Reactor critical Moderator and fuel at 68 F Power level 10^{-8} x rated Rod worth (for dropped rod) .025 Δk
Case B (hot)	Reactor critical Moderator and fuel at 547 F Power level 10^{-6} x rated Rod worth (for dropped rod) .025 Δk

Case C (power)

Reactor critical
Moderator and fuel at 547°F
Power level 10^{-1} x rated
Rod worth (for dropped rod) .038 Δk

In considering the possibilities of a control rod drop accident, only the rod worths of the lower curve of Figure14.6-1 are pertinent at less than 10 percent power. These are the rods which are normally allowed to be moved by operating procedures and the rod worth minimizer. The nonscheduled rods, those within the central envelope, do not have a withdrawal permissive during the time their worths are greater than the lower curve, so they are held full in by the control rod drive and cannot drop from the core. If a nonscheduled rod were selected, the rod worth minimizer blocks rod movement. Therefore, the worth of the strongest rod which could be stuck is limited to about 0.01 Δk. The 0.025 Δk worth assumed for cases A and B is considerably above the rod worth values available for stuck rods under the assumed reactor conditions. At power ranges greater than 10 percent the maximum rod worth is determined by FLARE[1] and WANDA[2] computer codes shown in Figure14.6-2. Thus, in case C, the rod worth is assumed to be .038 Δk.

14.6.1.2.2 Excursion Analysis Assumptions

The following assumptions are used in the analysis of the nuclear excursion for each case:

a. The velocity at which the control rod falls out of the core is assumed to be 5 ft per sec. The control rod velocity limiter,[3] an engineered safeguard, limits the rod drop velocity to less than this value.

b. Control rod scram motion is assumed to start at about 290 msec after the neutron flux has attained 120 percent of rated flux. This assumption allows the power transient to be terminated initially by the Doppler reactivity effect of the fuel. This assumption is particularly conservative for cases A and B because a high neutron flux scram would be initiated earlier by the intermediate range neutron monitoring (IRM) channels.

c. No credit is taken for the negative reactivity effect resulting from the increased temperature of or void formation in the moderator. Since the time constant for heat transfer between the fuel and the moderator is long compared with the time required for control rod motion, this effect would be small.

57. JAF Procedure AOP-3, "High Activity in Reactor Coolant or Offgas"

58. US NRC Regulatory Guide 1.49, "Power Levels for Nuclear Power Plants" (Rev. 1, December 1973)

59. US NRC Regulatory Guide 1.77, "Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors" (May 1974)

60. US NRC Regulatory Guide 1.25, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident in the Fuel Handling and Storage Facility for Boiling and Pressurized Water Reactors" (3/23/72)

61. CRE Calculation JAF-CALC-RAD-00048, Rev.3, "Power Uprate Project - Radiological Impact at Onsite and Offsite Outdoor Receptors Following Design-Basis Accidents" (2/28/00)

62. CRE Calculation JAF-CALC-RAD-00023, Rev. 1, "Power Uprate Program - TSC Post-Accident Radiological Habitability Study" (9/24/99)

63. Design Basis Document DBD-072, "Administration Building Heating Ventilation and Air Conditioning Systems" (Rev. 0, 12/14/94)

64. Stone & Webster Engineering Calculation No. 12966-PE(N)-019-0, "High Energy Line Break Analysis in the Turbine Building for Class 1E Electrical Equipment Qualification in Response to IE Bulletin 79-01B," 6/9/81

65. GPU Nuclear Corporation Letter 5450-95-0006, addressed to M. Karasulu, from N. G. Trikouros, "FitzPatrick Nuclear Power Plant Turbine Building HELB Analysis Results," dated 2/7/95

66. DELETED

67. International Commission on Radiological Protection (ICRP) 30, "Limits for Intake by Workers" (Various parts and supplements, 1979 - 1982)

68. DELETED

69. GE Report, Transient Analysis For FitzPatrick FSAR EOC1 Prepared April, 1973, NEDM-11071-54, January 1974

70. GE Report NEDO-20533, "The General Electric Mark III Pressure Suppression Containment System Analytical Model," June 1974

71. US NRC Regulatory Guide 1.109, "Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR 50, Appendix" (Rev. 1, October 1977)

72. General Electric Report DRF T23-00670, "Extended Post-LOCA Calculation", July 1992.

73. General Electric Report GE-NE-T23-00737-01, August 1996, "James A. FitzPatrick Nuclear Power Plant Higher Service Water Temperature Analysis."

74. General Electric Report GE-NE-T23-00725-01, DRF T23-00725 dated March 1995, "James A. FitzPatrick Nuclear Power Plant LOCA Drywell Temperature Analysis at Power Uprate Conditions."

75. General Electric Report GE-NE-T23-00766-00-01, dated October 1999, "James A. FitzPatrick Nuclear Power Plant Containment Analysis."

76. GE Letter R.E. Engel to USNRC, Control Rod Drop Accident, February 24, 1982.

77. Calculation JAF-CALC-MISC-04428, Rev. 1, "Number of failed fuel rods caused by Spent Fuel Pool Refueling Accident." (04/12/02).

78. NUREG/CR-5009 "Assessment of the Use of Extended Burnup Fuel in Light Water Power Reactors," February 1988.

79. USNRC Regulatory Guide, 1.183 "Alternate Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Plants," July 2000.

80. JAF Calculation No. JAF-CALC-RAD-04409, Rev. 0, "CR X/Qs Using ARCON 96 Code for Post FHA Releases from RB Track Bay Doors and RB Vent."

81. JAF Calculation No. JAF-CALC-RAD-04410, Rev. 1, "Fuel Handling Accident-AST Analysis for Relaxation of Secondary Containment Operability."

82. S.L. Humphreys, et.al., "RAD TRAD: A Simplified Model for Radionuclide Transport and Removal and Dose Estimation", NUREG/CR-6604, USNRC APRIL 1998.

83. J.V. Ramsdell, Jr and C.A. Simonen, "Atmospheric Relative Concentration in Building Wakes," NUREG/CR-6331, Revision 1, USNRC, May 1997.

84. DELETED

85. GE NEDC-31984P, "Generic Evaluations of GE BWR Power Uprate", Volume 1, July 1991, and Supplement 1 (October 1991) and Supplement 2 (October 1992).

86. JAF Calculation No. JAF-CALC-RCIC-04472, Rev. 0, "RCIC Response Time Sensitivity Analysis For J. A. FitzPatrick During LOFW Event," September 2003.

87. GE Nuclear Energy, "J. A. FitzPatrick Nuclear Power Plant APRM/RBM/Technical Specifications/Maximum Extended Operating Domain (ARTS/MEOD)," NEDC-33087P, Class III (Proprietary), Revision 1, September 2005.

88. GE Hitachi Nuclear Energy, "GNF2 Fuel Design Cycle-Independent Analysis for Entergy FitzPatrick," GEH-0000-0074-2662, Revision 1, June 2010.

89. GE Hitachi Nuclear Energy, BWROG-TP-08-032, "Evaluation of Steam Flow Induced Error (SFIE) Impact on the L3 Set-point Analytic Limit," GEH-NE-0000-0077-4603-R1, Revision 1, October 2008.

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16.10 SUPPLEMENT FOR RENEWED OPERATING LICENSE

The James A. FitzPatrick Nuclear Power Plant license renewal application (Reference 16.10-1) and information in subsequent related correspondence provided sufficient basis for the NRC to make the findings required by 10 CFR 54.29 (Final Safety Evaluation Report) (Reference 16.10-2). As required by 10 CFR 54.21(d), this UFSAR supplement contains a summary description of the programs and activities for managing the effects of aging (Section 16.10.1) and a description of the evaluation of time-limited aging analyses for the period of extended operation (Section 16.10.2). The period of extended operation is the 20 years after the expiration date of the original operating license.

16.10.1 Aging Management Programs and Activities

The integrated plant assessment for license renewal identified aging management programs necessary to provide reasonable assurance that components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis (CLB) for the period of extended operation. This section describes the aging management programs and activities required during the period of extended operation. All aging management programs were implemented prior to entering the period of extended operation.

JAFNPP quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR 50, Appendix B. The Entergy Quality Assurance Program applies to safety-related structures and components. Corrective actions and administrative (document) control for both safety-related and nonsafety-related structures and components are accomplished per the existing JAFNPP corrective action program and document control program and are applicable to all aging management programs and activities that will be required during the period of extended operation. The confirmation process is part of the corrective action program and includes reviews to assure that proposed actions are adequate, tracking and reporting of open corrective actions, and review of corrective action effectiveness. Any follow-up inspection required by the confirmation process is documented in accordance with the corrective action program.

The corrective action, confirmation process, and administrative controls of the Entergy (10 CFR 50, Appendix B) Quality Assurance Program are applicable to all aging management programs and activities required during the period of extended operation.

16.10.1.1 Buried Piping and Tanks Inspection Program

The Buried Piping and Tanks Inspection Program includes (a) preventive measures to mitigate corrosion and (b) inspections to manage the effects of corrosion on the pressure-retaining capability of buried carbon steel, copper alloy, gray cast iron, and stainless steel components. Preventive measures are in accordance with standard industry practice for maintaining external coatings and wrappings. Buried components are inspected when excavated during maintenance. If trending within the corrective action program identifies susceptible locations, the areas with a history of corrosion problems are evaluated for the need for additional inspection, alternate coating, or replacement.

Prior to entering the period of extended operation, a review was performed to verify that an inspection occurred within the past 10 years. If an inspection did not occur, a focused inspection was performed.

16.10.1.2 BWR CRD Return Line Nozzle Program

Under the BWR CRD Return Line Nozzle Program, JAFNPP has cut and capped the CRD return line nozzle to mitigate cracking and continues inservice inspection (ISI) examinations to monitor the effects of crack initiation and growth on the intended function of the control rod drive return line nozzle and cap. ISI examinations include ultrasonic inspections of the nozzle-to-vessel weld, nozzle inside radius section, and the dissimilar metal weld overlay at the nozzle.

This program examines the CRDRL nozzle-to-vessel weld and the CRDRL nozzle inside radius section per Section XI Table IWB-2500-1 category B-D items B3.90 and B3.100.

16.10.1.3 BWR Feedwater Nozzle Program

Under the BWR Feedwater Nozzle Program, JAFNPP has removed all identified feedwater blend radii flaws, removed feedwater nozzle cladding, and installed a double piston ring, triple thermal sleeve sparger to mitigate cracking. This program continues enhanced inservice inspection (ISI) of the feedwater nozzles in accordance with the requirements of ASME Section XI, Subsection IWB and the recommendation of General Electric (GE) NE-523-A71-0594 to monitor the effects of cracking on the intended function of the feedwater nozzles.

16.10.1.4 BWR Penetrations Program

The BWR Penetrations Program includes (a) inspection and flaw evaluation in conformance with the guidelines of staff-approved boiling water reactor vessel and internals project (BWRVIP) documents BWRVIP-27-A and BWRVIP-49-A, and (b) monitoring and control of reactor coolant water chemistry in accordance with the guidelines of BWRVIP-190 to ensure the long-term integrity of vessel penetrations and nozzles.

16.10.1.5 BWR Stress Corrosion Cracking Program

The BWR Stress Corrosion Cracking Program includes (a) preventive measures to mitigate intergranular stress corrosion cracking (IGSCC), and (b) inspection and flaw evaluation to monitor IGSCC and its effects on reactor coolant pressure boundary components made of stainless steel or CASS.

JAFNPP has taken actions to prevent IGSCC and will continue to use materials resistant to IGSCC for component replacements and repairs following the recommendations delineated in NUREG-0313, Generic Letter (GL) 88-01, and the staff-approved BWRVIP-75-A report. Inspection of piping identified in NRC GL 88-01 to detect and size cracks is performed in accordance with the staff positions on schedule, method, personnel qualification and sample expansion included in the generic letter and the staff-approved BWRVIP-75-A report.

16.10.1.6 BWR Vessel ID Attachment Welds Program

The BWR Vessel ID Attachment Welds Program includes (a) inspection and flaw evaluation in accordance with the guidelines of staff-approved BWR Vessel and Internals Project (BWRVIP) BWRVIP-48-A, and (b) monitoring and control of reactor coolant water chemistry in accordance with the guidelines of BWRVIP-190 to ensure the long-term integrity and safe operation of reactor vessel inside diameter (ID) attachment welds and support pads.

16.10.1.7 BWR Vessel Internals Program

The BWR Vessel Internals Program includes (a) inspection, flaw evaluation, and repair in conformance with the applicable, staff-approved BWR Vessel and Internals Project (BWRVIP)

documents, and (b) monitoring and control of reactor coolant water chemistry in accordance with the guidelines of BWRVIP-190 to ensure the long-term integrity of vessel internals components.

In addition to the scope described in NUREG-1801, JAFNPP scope also includes the steam dryer. BWRVIP-139 and GE Service Information Letter (SIL) 644 Rev. 1 provide guidelines for inspection and evaluation. JAFNPP follows BWRVIP-139 and GE SIL 644 Rev. 1 guidelines.

JAFNPP will perform inspections of the core plate rim hold down bolts in accordance with ASME Section XI Table IWB-2500-1, Examination Category B-N-2 or in accordance with a future NRC-approved revision of BWRVIP-25 that provides a feasible method of inspection.

This program includes inspection of fifteen (15) percent of the top guide locations using enhanced visual inspection technique, EVT-1, within the first 18 years of the period of extended operation, with at least one-third of the inspections to be completed within the first six (6) years and at least two-thirds within the first 12 years of the period of extended operation. Locations selected for examination will be areas that have exceeded the neutron fluence threshold.

16.10.1.8 Containment Leak Rate Program

As described in 10 CFR 50, Appendix J, containment leak rate tests are required to assure that (a) leakage through primary reactor containment and systems and components penetrating primary containment shall not exceed allowable values specified in technical specifications or associated bases, and (b) periodic surveillance of reactor containment penetrations and isolation valves is performed so that proper maintenance and repairs are made during the service life of containment, and systems and components penetrating primary containment. Corrective actions are taken if leakage rates exceed acceptance criteria.

16.10.1.9 Diesel Fuel Monitoring Program

The Diesel Fuel Monitoring Program entails sampling to ensure that adequate diesel fuel quality is maintained to prevent loss of material in fuel systems. Exposure to fuel oil contaminants such as water and microbiological organisms is minimized by periodic sampling and analysis, draining and cleaning of tanks, and by verifying the quality of new oil before its introduction into the storage tanks.

This program includes periodic draining, cleaning, visual inspections, and ultrasonic measurement of the bottom surfaces of the fire pump diesel fuel oil tanks, EDG day tanks, and EDG fuel oil storage tanks. Also, this program specifies acceptance criteria for UT measurements of diesel generator fuel storage tanks within the scope of this program.

16.10.1.10 Environmental Qualification (EQ) of Electric Components Program

The JAFNPP EQ of Electric Components Program manages the effects of thermal, radiation, and cyclic aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. As required by 10 CFR 50.49, EQ components exceeding their qualification are refurbished, replaced, or their qualification extended prior to reaching the aging limits established in the evaluations. Aging evaluations for EQ components are considered time-limited aging analyses (TLAAs) for license renewal.

16.10.1.11 External Surfaces Monitoring Program

The External Surfaces Monitoring Program entails inspections of external surfaces of components subject to aging management review. The program is also credited with managing

loss of material from internal surfaces, for situations in which internal and external material and environment combinations are the same such that external surface condition is representative of internal surface condition.

Surfaces that are inaccessible during plant operations are inspected during refueling outages. Surfaces are inspected at frequencies to provide reasonable assurance that effect of aging will be managed such that applicable components will perform their intended function during the period of extended operation.

This program includes periodic inspections of systems in scope and subject to aging management review in accordance with 10 CFR 54.4(a)(1) and (a)(3). Inspections shall include areas surrounding the subject systems to identify hazards to those systems. Inspections of nearby systems that could impact the subject systems will include SSCs that are in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(2).

16.10.1.12 Fatigue Monitoring Program

In order not to exceed design limits on fatigue usage, the Fatigue Monitoring Program tracks the number of critical transients for selected reactor coolant system components. The program ensures the validity of analyses that explicitly assumed a fixed number of fatigue transients by assuring that the actual effective number of transients do not exceed the assumed limit.

The transient cycles tracked by this program are referenced in Section 4.3.

16.10.1.13 Fire Protection Program

The Fire Protection Program includes a fire barrier inspection and a diesel-driven fire pump inspection. The fire barrier inspection requires periodic visual inspection of fire barrier penetration seals, fire dampers and frames, fire barrier walls, ceilings, and floors, and periodic visual inspection and functional tests of fire rated doors to ensure that their operability is maintained. The diesel-driven fire pump inspection requires that the pump and its driver be periodically tested and inspected to ensure that diesel engine sub-systems, including the fuel supply line, can perform their intended functions.

This program inspects fire barrier walls, ceilings, and floors at least once every refueling outage. Inspection results will be acceptable if there are no indications of degradation such as cracks, holes, spalling, or gouges. This program inspects each seal type in a 10% sample every 24 months.

16.10.1.14 Fire Water System Program

The Fire Water System Program applies to water-based fire protection systems that consist of sprinklers, nozzles, fittings, valves, hydrants, hose stations, standpipes, and aboveground and underground piping and components that are tested in accordance with applicable National Fire Protection Association (NFPA) codes and standards. Such testing assures functionality of systems. Also, many of these systems are normally maintained at required operating pressure and monitored such that leakage resulting in loss of system pressure is immediately detected and corrective actions initiated.

In addition, wall thickness evaluations of fire protection piping were performed on system components using non-intrusive techniques (e.g., volumetric testing) to identify evidence of loss of material due to corrosion. Analysis of the inspections performed determined that the fire water piping had a remaining service life greater than 30 years.

A sample of sprinkler heads will be inspected using the guidance of NFPA 25 (2002 Edition) Section 5.3.1.1.1, which states, "Where sprinklers have been in place for 50 years, they shall be replaced or representative samples from one or more sample areas shall be submitted to a recognized testing laboratory for field service testing." This sampling will be repeated every 10 years after initial field service testing.

This program includes inspection of hose reels and spray and sprinkler systems internals for evidence of corrosion. The acceptance criteria verifies no unacceptable signs of degradation. A sample of sprinkler heads will be inspected using guidance of NFPA 25 (2002 Edition) Section 5.3.1.1.1. This program also includes wall thickness evaluations of fire protection piping using non-intrusive techniques (e.g., volumetric testing) to identify evidence of loss of material due to corrosion. Results of the initial wall thickness evaluations concluded that the fire water piping had a remaining service life greater than 30 years.

16.10.1.15 Flow-Accelerated Corrosion Program

The Flow-Accelerated Corrosion Program applies to safety-related and nonsafety-related carbon steel components in systems containing high-energy fluids carrying two-phase or single-phase high-energy fluid > 2% of plant operating time.

The program, based on EPRI recommendations for an effective flow-accelerated corrosion program, predicts, detects, and monitors FAC in plant piping and other pressure retaining components. This program includes (a) an evaluation to determine critical locations, (b) initial operational inspections to determine the extent of thinning at these locations, and (c) follow-up inspections to confirm predictions. The program specifies repair or replacement of components as necessary.

16.10.1.16 Heat Exchanger Monitoring Program

The Heat Exchanger Monitoring Program inspects heat exchangers for degradation. If degradation is found, then an evaluation is performed to evaluate its effects on the heat exchanger's design functions including its ability to withstand a seismic event.

Representative tubes within the population of heat exchangers are eddy current tested at a frequency determined by internal and external operating experience to ensure that effects of aging are identified prior to loss of intended function. Along with each eddy current test, visual inspections are performed on accessible heat exchanger heads, covers and tube sheets to monitor surface condition for indications of loss of material. The population of heat exchangers includes the HPCI turbine lube oil coolers and gland seal condensers, and EDG lube oil heat exchangers.

16.10.1.17 Inservice Inspection - Containment Inservice Inspection (CII) Program

The Containment Inservice Inspection Program outlines the requirements for the inspection of Class MC pressure-retaining components (primary containment) and their integral attachments in accordance with the requirements of 10 CFR 50.55a and the ASME Boiler and Pressure Vessel Code, 2001 Edition through the 2003 Addenda, Section XI, Subsection IWE.

The primary inspection method for the primary containment and its integral attachments is visual examination. Visual examinations are performed either directly or remotely with illumination and resolution suitable for the local environment to assess general conditions that may affect either the containment structural integrity or leak tightness of the pressure retaining component. The

program includes augmented ultrasonic exams to measure wall thickness of the containment drywell structure.

16.10.1.18 Inservice Inspection - Inservice Inspection (ISI) Program

The ISI Program is based on ASME Inspection Program B (Section XI, IWA-2432), which has 10-year inspection intervals. Every 10 years the program is updated to the latest ASME Section XI code edition and addendum approved in 10 CFR 50.55a. On February 27, 2007, JAFNPP entered the fourth ISI interval. The code edition and addenda used for the fourth interval is the 2001 Edition through the 2003 Addenda.

The program consists of periodic volumetric, surface, and visual examination of components and their supports for assessment, signs of degradation, flaw evaluation, and corrective actions.

16.10.1.19 Metal-Enclosed Bus Inspection Program

Under the Metal-Enclosed Bus Inspection Program, internal portions of the non-segregated phase bus T2Y and T3Y components are inspected for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion. Bus insulation is inspected for signs of embrittlement, cracking, melting, swelling, or discoloration, which may indicate overheating or aging degradation. Internal bus supports are inspected for structural integrity and signs of cracks. Since bolted connections are covered with heat shrink tape or insulating boots per manufacturer's recommendations, a sample of accessible bolted connections is visually inspected for insulation material surface anomalies. Enclosure assemblies are visually inspected for evidence of loss of material and, where applicable, enclosure assembly elastomers are visually inspected and manually flexed to manage cracking and change in material properties.

These inspections are performed at least once every five years.

16.10.1.20 Non-EQ Instrumentation Circuits Test Review Program

Under the non-EQ Instrumentation Circuits Test Review Program, calibration or surveillance results for non-EQ electrical cables in circuits with sensitive, high voltage, low-level signals; (i.e., neutron flux monitoring instrumentation); are reviewed. Most neutron flux monitoring system cables and connections are calibrated as part of the instrumentation loop calibration at the normal calibration frequency, which provides sufficient indication of the need for corrective actions based on acceptance criteria related to instrumentation loop performance. The review of calibration results is performed once every 10 years.

For neutron flux monitoring system cables that are disconnected during instrument calibrations, testing is performed at least once every 10 years using a proven method for detecting deterioration for the insulation system (such as insulation resistance tests, or time domain reflectometry).

16.10.1.21 Non-EQ Insulated Cables and Connections Program

The non-EQ Insulated Cables and Connections Program provides reasonable assurance that intended functions of insulated cables and connections exposed to adverse localized environments caused by heat, radiation and moisture can be maintained consistent with the current licensing basis through the period of extended operation. An adverse localized environment is significantly more severe than the specified service condition for the insulated cable or connection.

A representative sample of accessible insulated cables and connections in adverse localized environments is visually inspected at least once every 10 years for cable and connection jacket surface anomalies such as embrittlement, discoloration, cracking or surface contamination.

16.10.1.22 Oil Analysis Program

The Oil Analysis Program maintains oil systems free of contaminants (primarily water and particulates) thereby preserving an environment that is not conducive to loss of material, cracking, or fouling. Activities include sampling and analysis of lubricating oil for detrimental contaminants, water, and particulates.

Sampling frequencies are based on vendor recommendations, accessibility during plant operation, equipment importance to plant operation, and previous test results.

This program periodically samples oil in the oil-filled cable system, the security generator, and the fire pump diesel. This program includes viscosity and neutralization number determination of oil samples from components that do not have regular oil changes. This program includes determinations of particulate and water content for oil replaced periodically.

16.10.1.23 One-Time Inspection Program

The elements of the One-Time Inspection Program include (a) determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience; (b) identification of the inspection locations in the system or component based on the aging effect; (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined; and (d) evaluation of the need for follow-up examinations to monitor the progression of any aging degradation.

A one-time inspection activity is used to verify the effectiveness of the water chemistry control programs by confirming that unacceptable cracking, loss of material, and fouling is not occurring on components within systems covered by water chemistry control programs [Sections 16.10.1.32, 16.10.1.33, and 16.10.1.34].

One-time inspection activities on

- internal surfaces of HPCI system components containing untreated air,
- carbon steel and cast iron plant drain components exposed to indoor air,
- internal surfaces of carbon steel components in the EDG system containing untreated air,
- internal surfaces of stainless steel and aluminum components in the radioactive waste system containing raw water,
- internal surfaces of stainless steel and copper alloy components in the raw water treatment system containing raw water,
- internal surfaces of copper alloy components in the plumbing, sanitary and lab system and the city water system containing raw water,
- small bore piping in the reactor coolant system and associated systems that form the reactor coolant pressure boundary,
- internal surfaces of carbon steel scram accumulators, and
- reactor vessel flange leakoff line

are used to confirm that loss of material, cracking, and reduction of fracture toughness, as applicable, are not occurring or are so insignificant that an aging management program is not warranted.

One-Time Inspection Program has been completed.

16.10.1.24 Periodic Surveillance and Preventive Maintenance Program

The Periodic Surveillance and Preventive Maintenance Program includes periodic inspections and tests that manage aging effects not managed by other aging management programs. The preventive maintenance and surveillance testing activities are generally implemented through repetitive tasks or routine monitoring of plant operations.

Periodic inspections using visual or other non-destructive examination techniques verify that the following components are capable of performing their intended function.

- battery racks "A" & "B" carbon steel framing
- reactor building cranes, crane rails and girders
- equipment access lock doors
- refueling platform carbon steel components
- reactor track bay inner & outer doors carbon steel components
- drywell equipment hatch (16X-1A, 16X-1B) and drywell personnel hatch (16X-2A) carbon steel components
- elastomer seals for equipment lock doors at reactor track bay inner & outer doors
- main steam relief valve tailpipes in the waterline region of the torus
- carbon steel portion of T quenchers in the waterline region of the torus
- HPCI, RCIC, and core spray piping listed as susceptible to erosion
- loop seal piping and valves on demister drain piping off each filter train and at drain piping downstream of the SGT fans
- piping (including loop seals) and valves in the vent piping and from the stack analyzer sample chambers (including loop seal)
- piping downstream of the SGT fans between the drain and the outlet of the stack sump
- piping, valves and flow elements in the discharge piping from the steam packing exhauster and the condenser air removal pumps to the SGT discharge piping to the stack
- external surfaces of coils for CAD heat exchangers 27E-1A/B, 27NV-A/B, 27PBC-1A/B
- internal surfaces of EDG air intake components – after-coolers (fins), flexible duct connection
- internal surfaces of EDG exhaust and air start subsystem components
- HVAC duct flexible connections
- air handling units 70AHU-3A & B, 70AHU-12A & B, 70AHU-19A, B
- heat exchanger portions of the control and relay room chillers 70RWC-2A and 70RWC-2B

- floor drain components that provide a drain path for fire suppression water from floor drains to the floor drain collection tank or to the yard drain system
- internal surfaces of security generator exhaust gas components
- external surfaces of security generator radiator heat exchanger coils
- internal surfaces of carbon steel components in the radwaste system
- internal surfaces of carbon steel and copper alloy components in the circulating water system
- internal surfaces of carbon steel components in the turbine building closed loop cooling system
- internal surfaces of carbon steel components in the raw water treatment system
- internal surfaces of carbon steel components in the contaminated equipment drain system
- internal surfaces of carbon steel and stainless steel components used in chemical treatment in the service water system
- internal surfaces of carbon steel pump casings in the turbine building ventilation system
- external surfaces of copper alloy tube for administration building ventilation and cooling system unit coolers 72UC-12A & B, 72UC-25, 72UC-26, 72UC-35
- internal surfaces of carbon steel components BFP-255, WSC-250 - 260, STR-253 in the plumbing, sanitary and lab system
- internal surfaces of carbon steel components WSC-7A - 7C, WSC-8, WSC-37, WSC-40 in the city water system
- Internal surfaces of carbon steel components in the floor and roof drainage system

This program assures that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis.

16.10.1.25 Reactor Head Closure Studs Program

The Reactor Head Closure Studs Program includes inservice inspection (ISI) in conformance with the requirements of the ASME Code, Section XI, Subsection IWB, and preventive measures (e.g. rust inhibitors, stable lubricants, appropriate materials) to mitigate cracking and loss of material of reactor head closure studs, nuts, washers, and bushings.

16.10.1.26 Reactor Vessel Surveillance Program

JAFNPP is a participant in the BWR vessel and internals project (BWRVIP) Integrated Surveillance Program (ISP). The Reactor Vessel Surveillance Program monitors changes in the fracture toughness properties of ferritic materials in the reactor pressure vessel (RPV) beltline region. As BWRVIP-ISP capsule test reports become available for RPV materials representative of JAFNPP, the actual shift in the reference temperature for nil-ductility transition of the vessel material may be updated. In accordance with 10 CFR 50 Appendices G and H, JAFNPP reviews relevant test reports to assure compliance with fracture toughness requirements and P-T limits.

BWRVIP-116, "BWR Vessel and Internals Project Integrated Surveillance Program (ISP) Implementation for License Renewal," described the design and implementation of the ISP during the period of extended operation. BWRVIP-116 identified additional capsules, their withdrawal schedule, and contingencies to ensure that the requirements of 10 CFR 50 Appendix H are met for the period of extended operation. BWRVIP-86, Revision 1 merged BWRVIP-86-A and BWRVIP-116 into a single, updated implementation plan for the ISP.

This program proceduralizes the data analysis, acceptance criteria, and corrective actions to meet the requirements of the ISP as found in BWRVIP-86 and 135.

The BWRVIP-116 report which was approved by the staff will be implemented at JAFNPP with the conditions documented in Sections 3 and 4 of the staff's final SE dated March 1, 2006, for the BWRVIP-116 report.

If the JAFNPP standby capsule is removed from the reactor vessel without the intent to test it, the capsule will be stored in a manner which would permit its future use.

16.10.1.27 Selective Leaching Program

The Selective Leaching Program ensures the integrity of components made of cast iron, bronze, brass, and other alloys exposed to raw water, treated water, soil, or other environments that may lead to selective leaching. The program includes a one-time visual inspection and hardness measurement of selected components that may be susceptible to selective leaching to determine whether loss of material due to selective leaching is occurring, and whether the process will affect the ability of the components to perform their intended function for the period of extended operation.

16.10.1.28 Service Water Integrity Program

The Service Water Integrity Program relies on implementation of the recommendations of NRC GL 89-13 to ensure that the effects of aging on the service water systems (SWS) will be managed for the period of extended operation. The SWS includes the normal service water (NSW), emergency service water (ESW), and residual heat removal service water (RHRSW). The program includes component inspections for erosion, corrosion, and blockage and performance monitoring to verify the heat transfer capability of the safety-related heat exchangers cooled by SW. Chemical treatment using biocides and chlorine and periodic cleaning and flushing of redundant or infrequently used loops are the methods used to control or prevent fouling within the heat exchangers and loss of material in SW components.

16.10.1.29 Structures Monitoring - Masonry Wall Program

The objective of the Masonry Wall Program is to manage aging effects so that the evaluation basis established for each masonry wall within the scope of license renewal remains valid through the period of extended operation.

The program includes all masonry walls identified as performing intended functions in accordance with 10 CFR 54.4. Included components are the 10 CFR 50.48-required masonry walls, radiation shielding masonry walls, and masonry walls with the potential to affect safety-related components.

Masonry walls are visually examined at a frequency selected to ensure there is no loss of intended function between inspections.

16.10.1.30 Structures Monitoring - Structures Monitoring Program

Structures monitoring is in accordance with 10 CFR 50.65 (Maintenance Rule) as addressed in Regulatory Guide (RG) 1.160 and NUMARC 93-01. Periodic inspections are used to monitor the condition of structures and structural components to ensure there is no loss of structure or structural component intended function.

This program specifies that manholes, duct banks, underground fuel oil tank foundations, manway seals and gaskets, hatch seals and gaskets, underwater concrete in the intake structure, and crane rails and girders are included.

This program provides guidance for performing structural examinations of elastomers and rubber components to identify cracking and change in material properties.

This program provides guidance for performing periodic inspections to confirm the absence of aging effects for lubrite surfaces in the torus radial beam seats and for lubrite surfaces in the torus support saddles.

This program performs an engineering evaluation on a periodic basis of groundwater samples to assess aggressiveness of groundwater to concrete. This program inspects any inaccessible concrete areas that may be exposed by excavation for any reason, or any inaccessible area where observed conditions in accessible areas, which are exposed to the same environment, show that significant concrete degradation is occurring.

16.10.1.31 Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel

The purpose of the Thermal Aging and Neutron Irradiation Embrittlement of CASS Program is to assure that reduction of fracture toughness due to thermal aging and reduction of fracture toughness due to radiation embrittlement will not result in loss of intended function during the period of extended operation. This program evaluates CASS components in the reactor vessel internals and requires non-destructive examinations as appropriate.

16.10.1.32 Water Chemistry Control – Auxiliary Systems Program

The purpose of the Water Chemistry Control – Auxiliary Systems Program is to manage loss of material for components exposed to treated water.

Program activities include sampling, analysis, and replacement of coolant for control room and relay room chilled water system, security generator jacket cooling water, auxiliary boiler heating water, decay heat removal cooling water, and the stator cooling water system to minimize component exposure to aggressive environments.

The One-Time Inspection Program for Water Chemistry utilizes inspections or non-destructive evaluations of representative samples to verify that the Water Chemistry Control - Auxiliary Systems Program has been effective at managing loss of material.

This program provides guidance for sampling the control room and relay room chilled water, decay heat removal cooling water, and security generator jacket cooling water.

16.10.1.33 Water Chemistry Control – BWR Program

The objective of the Water Chemistry Control – BWR Program is to manage aging effects caused by corrosion and cracking mechanisms. The program relies on monitoring and control of water chemistry based on EPRI Report 1016579 (BWRVIP-190). BWRVIP-190 has three sets of guidelines: one for primary water, one for condensate and feedwater, and one for control rod

drive (CRD) mechanism cooling water. EPRI guidelines in BWRVIP-190 also include recommendations for controlling water chemistry in the torus, condensate storage tank, demineralized water storage tanks, and spent fuel pool.

The Water Chemistry Control – BWR Program optimizes primary water chemistry to minimize the potential for loss of material and cracking. This is accomplished by limiting the levels of contaminants in the RCS that could cause loss of material and cracking. Additionally, JAFNPP has instituted hydrogen water chemistry (HWC) and noble metal chemical addition (NMCA) to limit the potential for intergranular SCC (IGSCC) through the reduction of dissolved oxygen in the treated water.

The One-Time Inspection Program for Water Chemistry utilizes inspections or non-destructive evaluations of representative samples to verify that the Water Chemistry Control – BWR Program has been effective at managing loss of material.

16.10.1.34 Water Chemistry Control – Closed Cooling Water Program

The Water Chemistry Control – Closed Cooling Water Program includes preventive measures that manage loss of material, cracking, and fouling for components in closed cooling water systems (jacket cooling water subsystem for the emergency diesel generator, reactor building closed loop cooling, and turbine building closed loop cooling). These chemistry activities provide for monitoring and controlling closed cooling water chemistry using JAFNPP procedures and processes based on EPRI guidance for closed cooling water chemistry.

The One-Time Inspection Program for Water Chemistry utilizes inspections or non-destructive evaluations of representative samples to verify that the Water Chemistry Control - Closed Cooling Water Program has been effective at managing loss of material.

16.10.1.35 Bolting Integrity Program

The Bolting Integrity Program relies on recommendations for a comprehensive bolting integrity program, as delineated in NUREG-1339, and industry recommendations, as delineated in the Electric Power Research Institute (EPRI) NP-5769, with the exceptions noted in NUREG-1339 for safety-related bolting. The program relies on industry recommendations for comprehensive bolting maintenance, as delineated in EPRI TR-104213 for pressure retaining bolting and structural bolting.

This program includes guidance from EPRI NP-5769 and EPRI TR-104213. This program clarifies that actual yield strength is used in selecting materials for low susceptibility to SCC and to clarify the prohibition on use of lubricants containing MoS2 for bolting.

16.10.1.36 Bolted Cable Connections Program

The Bolted Cable Connections Program will focus on the metallic parts of the cable connections. This sampling program provides a one-time inspection to verify that the loosening of bolted connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation is not an aging issue that requires a periodic aging management program. A representative sample of the electrical cable connection population subject to aging management review will be inspected or tested. Connections covered under the EQ program, or connections inspected or tested as part of a preventative maintenance program are excluded from aging management review. The factors considered for sample selection will be application (medium and low voltage), circuit loading (high loading),

and location (high temperature, high humidity, vibration, etc.). The technical basis for the sample selection will be documented.

16.10.2 Evaluation of Time-Limited Aging Analyses

In accordance with 10 CFR 54.21(c), an application for a renewed license requires an evaluation of time-limited aging analyses (TLAA), for the period of extended operation. The following TLAA have been identified and evaluated to meet this requirement.

16.10.2.1 Reactor Vessel Neutron Embrittlement

The reactor vessel neutron embrittlement TLAA has been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii). Fifty-four EFPY will be the effective full power years at the end of the period of extended operation assuming an average capacity factor of 90% for 60 years.

16.10.2.1.1 Reactor Vessel Fluence

Calculated fluence is based on a time-limited assumption defined by the operating term. As such, fluence is the time-limited assumption for the time-limited aging analyses that evaluate reactor vessel embrittlement.

The existing 32 EFPY fluence is based on a General Electric analysis of measured fluence from the JAFNPP surveillance flux wires (Reference 16.10-8).

Neutron fluence was projected to the end of the period of extended operation (54 EFPY) using the RAMA fluence model.

16.10.2.1.2 Pressure-Temperature Limits

The P-T limits were derived from calculations made in accordance with the guidance of ASME Appendix G, as modified by Code Cases N-588 and N-640, ASTM Standards, 10 CFR 50 Appendices G and H, RG 1.99 Revision 2, and GL 88-11.

Pressure-temperature limits are valid through 32 EFPY. The fact that the projected maximum RTNDT is well below the 200°F suggested in Section 3 of RG 1.99, gives confidence that P-T curves will provide acceptable operating area through 54 EFPY. The BWRVIP Integrated Surveillance Program (BWRVIP Reports 86 and 135) will be used to adjust projected RTNDT values as additional surveillance capsule results are collected. JAFNPP will submit additional P-T curves prior to the period of extended operation.

16.10.2.1.3 Charpy Upper-Shelf Energy

The predictions for percent drop in C_VUSE at 54 EFPY are based on chemistry data and unirradiated C_VUSE data submitted to the NRC in the JAFNPP response to GL 92-01, and 1/4 T fluence values.

The 54 EFPY C_VUSE values were calculated using RG 1.99, Position 1, Figure 2; specifically, the formula for the lines was used to calculate the percent drop in C_VUSE.

All C_VUSE values are predicted to remain well above the requirement of 50 ft-lbs during the period of extended operation. As such, this TLAA has been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

16.10.2.1.4 Adjusted Reference Temperature

JAFNPP has projected values for RTNDT and adjusted reference temperature (ART) at 54 EFPY using the methodology of RG 1.99. These values were calculated using the chemistry

data, margin values, initial RNDT values, and chemistry factors (CFs) contained in the JAFNPP response to GL 92-01 and other licensing correspondence (Reference 16.10-6). New fluence factors (FFs) were calculated using the expression in RG 1.99, Revision 2, Equation 2 using 54 EFPY fluence values.

The RTNDT TLAA has been projected through the period of extended operation, with acceptable results, in accordance with 10 CFR 54.21(c)(1)(ii).

16.10.2.1.5 Reactor Vessel Circumferential Weld Inspection Exemption

Exemption from reactor vessel circumferential weld examination requirements under GL 98-05 is based on assessments indicating an acceptable probability of failure per reactor operating year. The analysis is based on reactor vessel metallurgical conditions as well as flaw indication sizes and frequencies of occurrence that are expected at the end of a licensed operating period.

JAFNPP received NRC approval for this exemption for the remainder of the original 40-year license term (Reference 16.10-3). The basis for this exemption is an analysis that satisfied the limiting conditional failure probability for the circumferential welds at the expiration of the current license, based on the NRC SERs for BWRVIP-05 (Reference 16.10-5) and BWRVIP-74 (Reference 16.10-7) and the extent of neutron embrittlement.

The JAFNPP reactor pressure vessel circumferential weld parameters at 54 EFPY will remain within the NRC's (64 EFPY) bounding CEOG parameters from the BWRVIP-05 SER. Although a conditional failure probability has not been calculated, the fact that the JAFNPP values at the end of license are less than the 64 EFPY value provided by the NRC leads to the conclusion that the JAFNPP RPV conditional failure probability is bounded by the NRC analysis. As such, the conditional probability of failure for circumferential welds remains below that stated in the NRC's Final Safety Evaluation of BWRVIP-05. Therefore, this analysis has been projected through the period of extended operation per 10 CFR 54.21(c)(1)(ii).

16.10.2.1.6 Reactor Vessel Axial Weld Failure Probability

The BWRVIP recommendations for inspection of reactor vessel shell welds are based on generic analyses supporting an NRC SER (References 16.10-4, 16.10-5). The generic-plant axial weld failure rate is no more than 5×10^{-6} per reactor year as calculated in the BWRVIP-74 SER (Reference 16.10-7). BWRVIP-05 showed that this axial weld failure rate is orders of magnitude greater than the 40 year end-of-life circumferential weld failure probability, and used this analysis to justify exemption from inspection of the circumferential welds as described above.

The BWRVIP-74 SER states it is acceptable to show that the mean RTNDT of the limiting beltline axial weld at the end of the period of extended operation is less than the limiting value (114°F) given in Table 1 of the BWRVIP-74 SER. This value supports the axial weld failure probability and is based on the assumption of essentially 100% (> 90%) inspection of the axial welds in the beltline region. Due to various obstructions within the reactor vessel, JAFNPP is able to inspect approximately 88% of the axial welds in the beltline region. The NRC granted a relief request for less than 90% coverage. The projected 54 EFPY mean RTNDT values for JAFNPP are less than the limiting mean RTNDT of 114°F. The 2% difference in the amount of inspected weld will not offset the 21.6°F margin between the 92.4°F mean RTNDT for JAFNPP and the 114°F mean RTNDT used in the NRC SER for BWRVIP-74. Therefore, the axial weld failure probability will not exceed 5×10^{-6} per reactor operating year during the period of extended operation. As such, this TLAA has been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

16.10.2.2 Metal Fatigue

16.10.2.2.1 Class 1 Metal Fatigue

Class 1 components evaluated for fatigue and flaw growth include the reactor pressure vessel (RPV) and appurtenances, certain reactor vessel internals, the reactor recirculation system (RRS), and the reactor coolant system (RCS) pressure boundary. The JAFNPP Class 1 systems include components within the ASME Section XI, IWB inspection boundary.

The design of the reactor vessel internals is in accordance with the intent of ASME Section III. A review of the design basis documents reveals that fatigue analyses were performed and determined the most significant fatigue loading occurs in the jet pump-shroud-shroud support area of the internals. The location of the maximum fatigue usage is at the ID of the jet pump diffuser adapter at the thin end of the tapered transition section. Additionally, a fatigue evaluation was performed on the tie rod assemblies installed as part of the core shroud repair. The maximum CUF values identified have been projected to the end of the period of extended operation and remain less than 1.0.

The JAFNPP fatigue monitoring program will assure that the allowed number of transient cycles is not exceeded. The program requires corrective action if transient cycle limits are approached. Consequently, the TLAA (fatigue analyses) is based on those transients that are projected through the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii), or the aging effect is managed per 10 CFR 54.21(c)(1)(iii).

16.10.2.2.2 Non-Class 1 Metal Fatigue

For non-Class 1 components identified as subject to cracking due to fatigue, a review of system operating characteristics was conducted to determine the approximate frequency of any significant thermal cycling. If the number of equivalent full temperature cycles is below the limit used for the original design (usually 7000 cycles), the component is suitable for extended operation. If the number of equivalent full temperature cycles exceeds the limit, evaluation of the individual stress calculations require evaluation. No components were identified with projected cycles exceeding 7000. Therefore, the TLAA for non-Class 1 piping and components remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(i).

16.10.2.2.3 Environmental Effects on Fatigue

The effects of reactor water environment on fatigue were evaluated for license renewal. Projected cumulative usage factors (CUFs) were calculated for the limiting locations identified in NUREG/CR-6260. Several locations may exceed a CUF of 1.0 with consideration of environmental effects during the period of extended operation. For these locations, prior to the period of extended operation, JAFNPP will implement one or more of the following: (1) refine the fatigue analysis to lower the predicted CUF to less than 1.0; (2) manage fatigue at the affected locations with an inspection program that has been reviewed and approved by the NRC (e.g., periodic non-destructive examination of the affected locations at inspection intervals to be determined by a method acceptable to the NRC); or (3) repair or replace the affected locations.

JAFNPP has refined the fatigue analysis to lower the predicted CUF to less than 1.0, including the effects of environmental fatigue for the period of extended operation at the limiting locations identified in NUREG/CR-6260. The effects of environmentally assisted fatigue will be managed per 10 CFR 54.21(c)(1)(iii).

16.10.2.3 Environmental Qualification of Electrical Components

The JAFNPP EQ Program implements the requirements of 10 CFR 50.49 (as further defined by the Division of Operating Reactors Guidelines, NUREG-0588, and Reg. Guide 1.89). The program requires action before individual components exceed their qualified life. In accordance with 10 CFR 54.21(c)(1)(iii), implementation of the EQ Program provides reasonable assurance that the effects of aging on components associated with EQ TLAAs will be adequately managed such that the intended functions can be maintained for the period of extended operation.

16.10.2.4 Fatigue of Primary Containment, Attached Piping, and Components

In conjunction with the Mark I Containment Long-Term Program, the torus and attached piping systems were analyzed for fatigue due to mechanical loadings as well as thermal and anchor motion. This analysis was based on assumptions of the number of SRV actuations, operating basis earthquakes, and accident conditions during the life of the plant.

The analysis considered all BWR plants which utilize the Mark I containment design. The analysis concluded that for all plants and piping systems considered, the fatigue usage factor for an assumed 40-year plant life was less than 0.5. Extending plant life by an additional 20 years would produce a usage factor below 0.75. Since this is less than 1.0, the fatigue criteria are satisfied. This TLAA has been projected through the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

16.10.2.5 Recirculation Valve Fatigue Evaluation

The recirculation isolation valves are evaluated for 30 cycles of normal pressurization followed by blowdown and 270 cycles of normal pressurization followed by normal depressurization.

This number of cycles evaluated exceeds the value allowed as part of the Fatigue Monitoring Program, so the transients suggested will not be exceeded. Thus this TLAA will remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

16.10.2.6 Fatigue Crack Growth Analysis for UFSAR Section 16.3.2.2

UFSAR Section 16.3.2.2 concludes that for cyclic stress equal to the design yield strength with defect sizes permitted by the Code, the fatigue life of each pipe line is greater than 100,000 transient cycles. Since transient cycles will not exceed 100,000 in 60 years of operation, the existing fatigue crack growth analysis presented in UFSAR Section 16.3.2.2 remains valid for the period of extended operation in accordance with 10 CFR 54.21(C)(1)(i).

16.10.2.7 Core Plate

The loss of preload and cracking of the core plate rim hold-down bolts is a TLAA per the NRC SER for BWRVIP-25. As part of the License Renewal Commitment, analysis performed to develop an Inspection Protocol for the Core Plate Bolts calculated the bolts will retain 66% of their preload through the period of extended operation. Preload of the core plate holddown bolts is required to prevent lateral motion of the core plate for those plants that have not installed core plate wedges (including JAFNPP). A plant-specific calculation is required to determine minimum bolting requirements to prevent core plate motion. Thus the loss of core plate hold down bolt preload will be projected for the period of extended operation.

JAF will inspect 50% of the core plate hold down bolts every other refueling outage, commencing with RFO 22, using the VT-3 method in accordance with the JAF Reactor Vessel

Internals Inspection Program until BWRVIP-25 is revised. JAF will implement the revised BWRVIP-25 inspection guidance for the core plate bolts.

16.10.2.8 Shroud Support

The fatigue analysis of the shroud support is considered TLAA. The shroud support is included in the 60-year fatigue analysis and shows a CUF of 0.37. This analysis remains valid for the period of extended operation per 10 CFR 54.21(c)(1)(i).

16.10.2.9 Lower Plenum

The fatigue analysis of the lower plenum pressure boundary components is considered a TLAA. The bottom head, shroud support, and CRD penetrations in the lower plenum are included in the 60-year fatigue analysis. Values of CUF (including effects of environmental fatigue) are 0.17, 0.37, and 0.23 respectively. This analysis remains valid for the period of extended operation per 10 CFR 54.21(c)(1)(i).

16.10.2.10 115kV Underground Oil-Filled Cable

The aging management program includes a power factor or partial discharge test every 10 years in accordance with industry standards. The initial test was performed prior to the period of extended operation with satisfactory results. This test is controlled by PMID 50054325-16 "LR-PM – OIL FILLED CABLES POWER FACTOR & PARTIAL DISCH TEST."

16.10.3 References

16.10-1 JAFNPP License Renewal Application, JAFP-06-0109, dated July 31, 2006

16.10-2 NRC SER for JAFNPP License Renewal, NUREG-1905

16.10-3 USNRC letter, Gamberoni, M. K. (NRC), to J. Knubel (PASNY), "Relief Request No. 17 - Request for Relief from the Requirements of 10CFR50.55a(g)(6)(ii)(A)(2) for Augmented Inspection of the Circumferential Welds in the Reactor Vessel of the James A. Fitzpatrick Nuclear Power Plant (TAC No. MA6215)," February 22, 2000.

16.10-4 USNRC letter, Lainas, G. C. (NRC), to C. Terry (Niagara Mohawk Power Company, BWRVIP Chairman), "BWRVIP-05 SER (Final), Final Safety Evaluation of the BWRVIP Vessel and Internals Project BWRVIP-05 Report (TAC No. M93925)," July 28, 1998.

16.10-5 USNRC letter, Lainas, G. C. (NRC), to C. Terry (BWRVIP), "Final Safety Evaluation of the BWR Vessel and Internals Project BWRVIP-05 Report (TAC No. M93925)," July 28, 1998.

16.10-6 Josiger, W. A. (NYPA), to USNRC Document Control Desk, "James A. Fitzpatrick Nuclear Power Plant, Docket No. 50-333, Generic Letter 92-01, Revision 1, Reactor Vessel Structural Integrity," letter JPN-94-041 dated August 10, 1994.

16.10-7 USNRC letter, Grimes, C. I. (NRC), to C. Terry (BWRVIP Chairman), "Acceptance for referencing of EPRI Proprietary Report TR-113596, BWR Vessel and Internals Project, BWR Reactor Vessel Inspection and Flaw Evaluation Guidelines (BWRVIP-74) and Appendix A, Demonstration of Compliance with the Technical Information requirements of the License Renewal Rule (10 CFR 54.21)," October 18, 2001.

16.10-8 GE Nuclear Energy, "Plant Fitzpatrick RPV Surveillance Materials Testing and Analysis of 120° Capsule at 13.4 EFPY," GE-NE-B1100732-01, Revision 1, February 1998.

JAFP-15-0047

ENCLOSURE 2

Technical Specification (TS) Bases 2015 Change Pages

B 2.0 SAFETY LIMITS (SLs)
B 2.1.1 Reactor Core SLs

BASES

BACKGROUND

JAFNPP design criteria (Ref. 1) requires. and SLs ensure, that specified acceptable fuel design limits are not exceeded during steady state operation, normal operational transients, and abnormal operational transients.

The fuel cladding integrity SL is set such that no significant fuel damage is calculated to occur if the limit is not violated. Because fuel damage is not directly observable, a stepback approach is used to establish an SL, such that the MCPR is not less than the limit specified in Specification 2.1.1.2. MCPR greater than the specified limit represents a conservative margin relative to the conditions required to maintain fuel cladding integrity.

The fuel cladding is one of the physical barriers that separate the radioactive materials from the environs. The integrity of this cladding barrier is related to its relative freedom from perforations or cracking. Although some corrosion or use related cracking may occur during the life of the cladding, fission product migration from this source is incrementally cumulative and continuously measurable. Fuel cladding perforations, however, can result from thermal stresses, which occur from reactor operation significantly above design conditions.

While fission product migration from cladding perforation is just as measurable as that from use related cracking, the thermally caused cladding perforations signal a threshold beyond which still greater thermal stresses may cause gross, rather than incremental, cladding deterioration. Therefore, the fuel cladding SL is defined with a margin to the conditions that would produce onset of transition boiling (i.e., MCPR = 1.00). These conditions represent a significant departure from the condition intended by design for planned operation. The MCPR fuel cladding integrity SL ensures that during normal operation and during abnormal operational transients, at least 99.9% of the fuel rods in the core do not experience transition boiling.

Operation above the boundary of the nucleate boiling regime could result in excessive cladding temperature because of the onset of transition boiling and the resultant sharp reduction in heat transfer coefficient. Inside the steam film, high cladding temperatures are reached, and a cladding water (zirconium water) reaction may take place. This chemical reaction results in oxidation of the fuel cladding

(continued)

BASES

BACKGROUND (continued)

to a structurally weaker form. This weaker form may lose its integrity, resulting in an uncontrolled release of fission products to the reactor coolant.

The reactor vessel water level SL ensures that adequate core cooling capability is maintained during all MODES of reactor operation. Establishment of Emergency Core Cooling System initiation setpoints higher than this safety limit provides margin such that the safety limit will not be reached or exceeded.

APPLICABLE SAFETY ANALYSIS

The fuel cladding must not sustain damage as a result of normal operation and abnormal operational transients. The reactor core SLs are established to preclude violation of the fuel design criterion that a MCPR limit is to be established, such that at least 99.9% of the fuel rods in the core would not be expected to experience the onset of transition boiling.

The Reactor Protection System setpoints (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"). In combination with the other LCOs, are designed to prevent any anticipated combination of transient conditions for Reactor Coolant System water level, pressure, and THERMAL POWER level that would result in reaching the MCPR limit.

2.1.1.1 Fuel Cladding Integrity

The GEXL17 critical power correlation is applicable for all critical power calculations at pressure $\geq$ 685 psig and core flows $\geq$10% of rated flow (References 5 and 6). For operation at low pressures or low flows, another basis is used, as follows:

> Since the pressure drop in the bypass region is essentially all elevation head, the core pressure drop at low power and flows will always be > 4.5 psi. Analyses (Ref. 2) show that with a bundle flow of 28 x 10^3 lb/hr. bundle pressure drop is nearly independent of bundle power and has a value of 3.5 psi. Thus, the bundle flow with a 4.5 psi driving head will be > 28 x 10^3 lb/hr. Full scale ATLAS test data taken at pressures from 14.7 psia to 800 psia indicate that the fuel assembly critical power at this flow is approximately 3.35 MWt. With the design peaking factors, this corresponds to a THERMAL POWER> 50% RTP. Thus, a THERMAL POWER limit of 25% RTP for reactor pressure < 785 psig (including the GEXL17 correlation lower limit of 685 psig) is conservative.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

2.1.1.2 MCPR

The fuel cladding integrity SL is set such that no significant fuel damage is calculated to occur if the limit is not violated. Since the parameters that result in fuel damage are not directly observable during reactor operation, the thermal and hydraulic conditions that result in the onset of transition boiling have been used to mark the beginning of the region in which fuel damage could occur. Although it is recognized that the onset of transition boiling would not result in damage to BWR fuel rods, the critical power at which boiling transition is calculated to occur has been adopted as a convenient limit. However, the uncertainties in monitoring the core operating state and in the procedures used to calculate the critical power result in an uncertainty in the value of the critical power. Therefore, the fuel cladding integrity SL is defined as the critical power ratio in the limiting fuel assembly for which more than 99.9% of the fuel rods in the core are expected to avoid boiling transition, considering the power distribution within the core and all uncertainties.

The MCPR SL is determined using a statistical model that combines all the uncertainties in operating parameters and the procedures used to calculate critical power. The probability of the occurrence of boiling transition is determined using the approved General Electric Critical Power correlations. Details of the fuel cladding integrity SL calculation are given in Reference 2. Reference 2 also includes a tabulation of the uncertainties used in the determination of the MCPR SL and of the nominal values of the parameters used in the MCPR SL statistical analysis.

2.1.1.3 Reactor Vessel Water Level

The reactor vessel water level is required to be above the top of the active irradiated fuel. The top of the active irradiated fuel is the top of a 150 inch fuel column which includes both the enriched and the natural uranium. During MODES 1 and 2 the reactor vessel water level is required to be above the top of the active irradiated fuel to provide core cooling capability. With fuel in the reactor vessel 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 water level should drop below the top of the active irradiated fuel during this period, the ability to remove decay heat is reduced. This reduction in cooling capability could lead to elevated cladding temperatures and clad perforation in the event that the water level becomes < 2/3 of the core height (Ref. 3). The reactor vessel water level SL has been established at the top of the active irradiated fuel to provide a point that can be monitored and to also provide adequate margin for effective action.

(continued)

BASES (continued)

SAFETY LIMITS	The reactor core SLs are established to protect the integrity of the fuel clad barrier to prevent the release of radioactive materials to the environs. SL 2.1.1.1 and SL 2.1.1.2 ensure that the core operates within the fuel design criteria. SL 2.1.1.3 ensures that the reactor vessel water level is greater than the top of the active irradiated fuel in order to prevent elevated clad temperatures and resultant clad perforations.
APPRLICABILITY	SLs 2.1.1.1, 2.1.1.2, and 2.1.1.3 are applicable in all MODES.
SAFETY LIMIT VIOLATIONS	Exceeding a SL may cause fuel damage and create a potential for radioactive releases in excess of 10 CFR 100, "Reactor Site Criteria," limits (Ref. 4). Therefore, it is required to insert all insertable control rods and restore compliance with the SLs within 2 hours. The 2 hour Completion Time ensures that the operators take prompt remedial action and also ensures that the probability of an accident occurring during this period is minimal.

REFERENCES

1 UFSAR, Section 16.6.

2 NEDE-24011-P-A, General Electric Standard Application for Reactor Fuel, (Revision specified in the COLR).

3 NEDC-31317P, Revision 2, James A. FitzPatrick Nuclear Power Plant SAFER/GESTR-LOCA, Loss-of-Coolant Accident Analysis, April 1993.

4 10 CFR 100.

5 NEDC-33292P, Rev 3, "GEXL17 Correlation for GNF2 Fuel", dated June 2009.

6 NEDC-33270P, Rev. 4, "GNF2 Advantage Generic Compliance with NEDE-24011-P-A (GESTAR II)", dated October 2011.

7 NRC Letter, Issuance of Amendment RE: Application to Revise Technical Specifications for Technical Specification Low Pressure Safety Limit (TAC No. MF2897), ML15014A277 dated February 9, 2015.

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ENCLOSURE 3

Technical Requirements Manual (TRM) 2015 Change Pages

**Note: TRM Appendix G, Non-propriety version included in this Enclosure.
Enclosure 3A contains full proprietary version of TRM Appendix G.**

SURVEILLANCE REQUIREMENTS

-----------------------------------NOTE-----------------------------------
When a channel is placed in an inoperable status solely for performance of the required Surveillance, entry into the associated Conditions and Required Actions may be delayed for up to 6 hours.

SURVEILLANCE		FREQUENCY
TRS 3.3.A.1	Perform CHANNEL CALIBRATION. The allowable value is $\geq$ 41 psig and $\leq$ 74 psig.	24 months
TRS 3.3.A.2	Perform CHANNEL CHECK	12 hours
TRS 3.3.A.3	Perform CHANNEL FUNCTIONAL TEST	92 days
TRS 3.3.A.2	CALIBRATE the Trip Units	184 days

3.4 REACTOR COOLANT SYSTEMS (RCS)

3.4.B Reactor Coolant System (RCS) Chemistry

TRO 3.4.B The chemistry of the RCS shall be maintained within the limits specified in SP-05.02.

APPLICABILITY: At all times

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Conductivity, sulfate, or chloride outside limits.	A.1	Initiate a Condition Report.	Immediately
	AND		
	A.2	Evaluate the condition and commence taking actions per SP-05.02.	1 Hour

5.0 ADMINISTRATIVE CONTROLS

5.5 Programs

5.5.C Post Accident Sampling

Plant commitments associated with NRC approval of TS Amendment 278 require controls be provided to ensure the capability to obtain and analyze reactor coolant, radioactive gases and particulates in plant gaseous effluents, and containment atmosphere samples under accident conditions. This program is implemented as follows:

a. Training of personnel:

b. Procedures for sampling and analysis:

c. Provisions for maintenance of sampling and analysis equipment:

Chemistry Department is responsible for this program.

5.0 ADMINISTRATIVE CONTROLS

5.5 Programs

5.5.E Component Cyclic or Transient Limit

Technical Specification 5.5.5, "Component Cyclic or Transient Limit," requires controls be provided to track the UFSAR Table 4.2-3, cyclic and transient occurrences to ensure that components are maintained within design limits. This program is implemented by RAP-7.4.10, "Component Cyclic or Transient Limit Program."

Operations Department (Reactor Engineering) is responsible for this program.

5.0 ADMINISTRATIVE CONTROLS

5.5 Programs

5.5.F Primary Containment Leakage Rate Testing Program

Technical Specification 5.5.6, "Primary Containment Leakage Rate Testing Program," requires implementation of leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50 Appendix J, Option B as modified by approved exemptions. This program is implemented by:

- SEP-APJ-007, "Primary Containment Leakage Rate Testing (Appendix J) Program" and
- EN-DC-334, "Primary Containment Leakage Rate Testing (Appendix J)"

Design & Programs Engineering is responsible for this program.

5.0 ADMINISTRATIVE CONTROLS

5.5 Programs

5.5.G Inservice Testing Program

Technical Specification 5.5.7, "Inservice Testing Program," requires controls be established for inservice testing of certain ASME Code Class 1, 2, and 3 components. This program is implemented by:

- SEP-IST-007, James A. FitzPatrick Inservice Testing for Pumps and Valves, Fourth Ten-Year Interval Program Section

Design & Programs Engineering is responsible for this program.

5.0 ADMINISTRATIVE CONTROLS

5.5 Programs

5.5.K Technical Specifications (TS) Bases Control Program

Technical Specification 5.5.11, "Technical Specifications (TS) Bases Control Program," requires means be provided for processing changes to the Bases of Technical Specifications. This program is implemented by EN-LI-113, "Licensing Basis Document Change Process."

Regulatory Assurance Department is responsible for this program.

5.0 ADMINISTRATIVE CONTROLS

5.5 Programs

5.5.N Control Room Envelope Habitability Program

Technical Specification 5.5.14, "Control Room Envelope Habitability Program" requires means be provided to ensure the Control Room Envelope (CRE) Habitability is maintained such that, with an OPERABLE Control Room Emergency Ventilation Air Supply (CREVAS) System, CRE occupants can control the reactor safely under normal conditions and maintain it in a safe condition following a radiological event, hazardous chemical release, or a smoke challenge. This program is implemented by:

- AP-19.18, "Control Room Envelope Habitability Program" and
- EN-DC-177, "Control Room Habitability Program."

Systems & Components Engineering is responsible for this program.

5.0 ADMINISTRATIVE CONTROLS

5.5 Programs

5.5.O Surveillance Frequency Control Program

Technical Specification 5.5.15, "Surveillance Frequency Control Program" provides controls for Surveillance Frequencies. The program ensures that Surveillance Requirements specified in the Technical Specifications are performed at intervals sufficient to assure the associated Limiting Conditions for Operation are met.

a. The Surveillance Frequency Control Program shall contain a list of Frequencies of the Technical Specification Surveillance Requirements for which the Frequency is controlled.

b. Changes to the Frequencies listed in the Surveillance Frequency Control Program shall be made in accordance with NEI 04-10, "Risk-Informed Method for Control of Surveillance Frequencies," Revision 1.

c. The provisions of Technical Specification Surveillance Requirements 3.0.2 and 3.0.3 are applicable to the Frequencies established in the Surveillance Frequency Control Program.

This program is implemented by:

- EN-DC-354, "Risk Assessment of Surveillance Test Frequency Changes,"
- EN-DC-355, "Implementation of the Technical Specification Surveillance Frequency Control Program,"
- EN-DC-355-01, "Selecting a Candidate To Be Evaluated For A Proposed Surveillance Test Interval (STI) Change,"
- EN-DC-355-02, "Surveillance Test Interval (STI) Evaluation Form,"
- EN-DC-355-03, "Engineering Evaluation of Proposed Surveillance Test Interval Changes,"
- EN-DC-355-04, "Surveillance Frequency Control Program Integrated Decision-Making Panel (IDP) Roles and Responsibilities,"
- EN-DC-355-05, "Implementing an Approved Surveillance Frequency Change," and
- EN-DC-355-06, "Monitoring the Effects of Changes to the Surveillance Frequency Control Program (SFCP)."

Systems & Components Engineering is responsible for this program.

APPENDIX D
REMOTE SHUTDOWN INSTRUMENTATION AND CONTROLS

Table D-1 (page 1 of 6)
Remote Shutdown Instrumentation and Controls

	INSTRUMENT OR CONTROL	PANEL OR LOCATION
1.	ADS & Safety Relief Valve A Control (02RV-71A)	02ADS-71
2.	ADS & Safety Relief Valve B Control (02RV-71B)	02ADS-71
3.	ADS & Safety Relief Valve C Control (02RV-71C)	02ADS-71
4.	ADS & Safety Relief Valve D Control (02RV-71D)	02ADS-71
5.	ADS & Safety Relief Valve E Control (02RV-71E)	02ADS-71
6.	Safety Relief Valve F Control (02RV-71F)	02ADS-71
7.	ADS & Safety Relief Valve G Control (02RV-71G)	02ADS-71
8.	ADS & Safety Relief Valve H Control (02RV-71H)	02ADS-71
9.	Safety Relief Valve J Control (02RV-71J)	02ADS-71
10.	Safety Relief Valve K Control (02RV-71K)	02ADS-71
11.	Safety Relief Valve L Control (02RV-71L)	02ADS-71
12.	RHR Heat Exchanger Outlet Valve Control (10MOV-12B)	25ASP-1
13.	Deleted	
14.	RHR Service Water to RHR Cross-Tie Valve Control (10MOV-148B)	25ASP-1
15.	RHR Service Water to RHR Cross-Tie Valve Control (10MOV-149B)	25ASP-1
16.	RHR Heat Exchanger Vent Valve Control (10MOV-166B)	25ASP-1

(continued)

Table D-1 (page 2 of 6)
Remote Shutdown Instrumentation and Controls

	INSTRUMENT OR CONTROL	PANEL OR LOCATION
17.	RHR Pump D Torus Suction Valve Control (10MOV-13D)	25ASP-2
18.	RHR Pump D Shutdown Cooling Suction Valve Control (10MOV-15D)	25ASP-2
19.	RHR Pump B Minimum Flow Valve Control (10MOV-16B)	25ASP-2
20.	Deleted	
21.	RHR Outboard Injection Valve Control (10MOV-27B)	25ASP-2
22.	Torus Cooling Isolation Valve Control (10MOV-39B)	25ASP-2
23.	RHR Heat Exchanger Inlet Valve Control (10MOV-65B)	25ASP-2
24.	Reactor Water Cleanup Outboard Isolation Valve Control (12MOV-18)	25ASP-2
25.	HPCI Minimum Flow Valve Control (23MOV-25)	25ASP-2
26.	HPCI Outboard Isolation Bypass Valve Control (23MOV-60)	25ASP-2
27.	Main Steam Line Drain Outboard Isolation Valve Control (29MOV-77)	25ASP-2
28.	DW Spray Outboard Valve Control (10MOV-26B)	25ASP-3
29.	ESW Loop B Supply Header Isolation Valve Control (46MOV-101B)	25ASP-3
30.	ESW Pump B Test Valve Control (46MOV-102B)	25ASP-3
31.	Emergency Service Water Pump B Control (46P-2B)	25ASP-3
32.	EDG B & EDG D Tie Breaker Control (71-10604)	25ASP-3

(continued)

Table D-1 (page 3 of 6)
Remote Shutdown Instrumentation and Controls

	INSTRUMENT OR CONTROL	PANEL OR LOCATION
33.	Bus 10400-10600 Tie Breaker Control (71-10614)	25ASP-3
34.	Unit Substation L16 & L26 Feeder Breaker Control (71-10660)	25ASP-3
35.	BUS 12600 Supply Breaker Control (71-12602)	25ASP-3
36.	Breaker 71-10614 Synchronizing Check Control	25ASP-3
37.	EDG B Control Room Metering Check Control	25ASP-3
38.	EDG B Engine Start/Stop Control	25ASP-3
39.	EDG D Control Room Metering Check Control	25ASP-3
40.	EDG D Engine Start/Stop Control	25ASP-3
41.	Outboard MSIV A Isolation Switch (29AOV-86A)	25ASP-4
42.	Outboard MSIV B Isolation Switch (29AOV-86B)	25ASP-4
43.	Outboard MSIV C Isolation Switch (29AOV-86C)	25ASP-4
44.	Outboard MSIV D Isolation Switch (29AOV-86D)	25ASP-4
45.	ADS & Safety Relief Valve A Isolation Switch (02RV-71A)	25ASP-5
46.	ADS & Safety Relief Valve B Isolation Switch (02RV-71B)	25ASP-5
47.	ADS & Safety Relief Valve C Isolation Switch (02RV-71C)	25ASP-5
48.	ADS & Safety Relief Valve D Isolation Switch (02RV-71D)	25ASP-5
49.	ADS & Safety Relief Valve E Isolation Switch (02RV-71E)	25ASP-5

(continued)

Table D-1 (page 4 of 6)
Remote Shutdown Instrumentation and Controls

	INSTRUMENT OR CONTROL	PANEL OR LOCATION
50.	Safety Relief Valve F Isolation Switch (02RV-71F)	25ASP-5
51.	ADS & Safety Relief Valve G Isolation Switch (02RV-71G)	25ASP-5
52.	ADS & Safety Relief Valve H Isolation Switch (02RV-71H)	25ASP-5
53.	Safety Relief Valve J Isolation Switch (02RV-71J)	25ASP-5
54.	Safety Relief Valve K Isolation Switch (02RV-71K)	25ASP-5
55.	Safety Relief Valve L Isolation Switch (02RV-71L)	25ASP-5
56.	Reactor Head Vent Isolation Switch (02AOV-17)	25RSP
57.	RHR Flow (Loop B) (10FI-133)	25RSP
58.	RHR Service Water Flow (Loop B) (10FI-134)	25RSP
59.	RHR Service Water Pump Control (10P-1B)	25RSP
60.	RHR Pump Control (10P-3D)	25RSP
61.	RHR Discharge Pressure (Pump D) (10PI-279)	25RSP
62.	RHR Inboard Injection Valve Control (10MOV-25B)	25RSP
63.	RHR Heat Exchanger Bypass Valve Control (10MOV-66B)	25RSP
64.	RHR Service Water Heat Exchanger Outlet Valve Control (10MOV-89B)	25RSP
65.	Torus Water Level (23LI-204)	25RSP

(continued)

Table D-1 (page 5 of 6)
Remote Shutdown Instrumentation and Controls

	INSTRUMENT OR CONTROL	PANEL OR LOCATION
66.	HPCI Steam Supply Outboard Isolation Valve Control (23MOV-16)	25RSP
67.	CAD B Train Inlet Valve Control (27AOV-126B)	25RSP
68.	Nitrogen Instrument Header Isolation Valve Control (27AOV-129B)	25RSP
69.	Torus Water Temperature (27TI-101)	25RSP
70.	Drywell Temperature (68TI-115)	25RSP
71.	Bus 11600 Supply Breaker Control (71-11602)	25RSP
72.	East Crescent Area Unit Cooler B, D, F Isolation Switch (66UC-22B, 22D, 22F)	66HV-3B
73.	East Crescent Area Unit Cooler H, K Isolation Switch (66UC-22H, 22K)	66HV-3B
74.	EDG B Load Breaker Control (71-10602)	93EGP-B
75.	EDG B Emergency Bus Meter (71VM-600-1B)	93EGP-B
76.	EDG B Frequency Meter (93FM-1B)	93EGP-B
77.	EDG B Running Bus Meter (93VM-11B)	93EGP-B
78.	EDG B Incoming Bus Meter (93VM-12B)	93EGP-B
79.	EDG B Governor Switch	93EGP-B
80.	EDG B Motor Control	93EGP-B
81.	EDG B Synchronizing Switch	93EGP-B
82.	EDG B Voltage Control	93EGP-B

(continued)

Table D-1 (page 6 of 6)
Remote Shutdown Instrumentation and Controls

	INSTRUMENT OR CONTROL	PANEL OR LOCATION
83.	EDG D Load Breaker Control (71-10612)	93EGP-D
84.	EDG D Emergency Bus Meter (71VM-600-1D)	93EGP-D
85.	EDG D Frequency Meter (93FM-1D)	93EGP-D
86.	EDG D Running Bus Meter (93VM-11D)	93EGP-D
87.	EDG D Incoming Bus Meter (93VM-12D)	93EGP-D
88.	EDG D Governor Switch	93EGP-D
89.	EDG D Motor Control	93EGP-D
90.	EDG D Synchronizing Switch	93EGP-D
91.	EDG D Voltage Control	93EGP-D
92.	Reactor Vessel Water Level (02-3LI-58A)	Rack 25-6
93.	Reactor Vessel Pressure (02-3PI-60B)	Rack 25-6
94.	Reactor Vessel Water Level (02-3LI-93)	Rack 25-51
95.	Reactor Vessel Water Level (02-3LI-95)	25RSP

APPENDIX G
CORE OPERATING LIMITS REPORT