

TABLE 1.6-1

REFERENCED REPORTS

## A. General Electric Company Reports

<u>Report Number</u>	<u>Title</u>	<u>Referenced in FSAR Section</u>
APED-4824	Maximum Two-Phase Blowdown from (April 1965)	6.2
APED-4986	Consequences of Operating Zircaloy-2 Clad Fuel Rods Above the Critical Heat Flux (October 1965)	4.2
APED-5286	Design Basis for Critical Heat Flux Condition in BWRs (September 1966)	1.5
APED-5458	Effectiveness of Core Standby Cooling Systems for General Electric Boiling Water Reactors (March 1968)	5.4
APED-5460	Design and Performance of General Electric BWR Jet Pumps (July 1968)	3.9
APED-5555	Impact Testing on Collet Assembly for Control Rod Drive Mechanism 7RDB144A (November 1967)	4.6
APED-5640	Xenon Considerations in Design of Large Boiling Water Reactors (June 1968)	4.1, 4.3
APED-5652	Stability and Dynamic Performance of the General Electric Boiling Water Reactor	4.1
APED-5706	In-Core Neutron Monitoring System for General Electric Boiling Water Reactors (November 1968, Revised April 1969)	7.6, 7.7, 7.6.2a.5
APED-5736	Guidelines for Determining Safe Test Intervals and Repair Times for Engineered Safeguards (April 1969)	Appendix
APED-5750	Design and Performance of General Electric Boiling Water Reactor Main Steam Line Isolation Valves (March 1969)	5.4

TABLE 1.6-1 CONTINUED

<u>Report Number</u>	<u>Title</u>	<u>Referenced in FSAR Section</u>
APED-5756	Analytical Methods for Evaluating the Radiological Aspects of the General Electric Boiling Water Reactor (March 1969)	15.4
GEAP-10546	Theory Report for Creep-Plast Computer Program (January 1972)	4.1
GEAP-13112	Thermal Response and Cladding Performance of an Internally Pressurized, Zircaloy-Clad, Simulated BWR Bundle Cooled by Spray Under Loss-of-Coolant Conditions (April 1971)	4.2
NEDE-10313	PDA-Pipe Dynamic Analysis Program for Pipe Rupture Movement (Proprietary Filing)	3.6
NEDE-11146	Design Basis for New Gas System (July 1971) (Company Proprietary)	11.3
NEDE-20386	Fuel Channel Deflections	4.2
NEDE-21156	Supplemental Information for Plant Modification to Eliminate Significant In-Core Vibration (January 1976)	4.4
NEDE-21175-P	BWR/6 Fuel Assembly Evaluation of Combined Safe Shutdown Earthquake (SSE) and Loss-of-Coolant Accident (LOCA) Loadings (November 1976)	3.9
NEDE-21354-P	BWR Fuel Channel Mechanical Design and Deflection (September 1976)	3.9
NEDE-23014	HEX 01 User's Manual (July 1976)	15.2
NEDM-10735	Densification Considerations in BWR Fuel Design and Performance (December 1972)	4.2
NEDO-10173	Current State of Knowledge, High Performance BWR Zircaloy-Clad UO <sub>2</sub> Fuel (May 1970)	4.2, 11.1



TABLE 1.6-1 CONTINUED

<u>Report Number</u>	<u>Title</u>	<u>Referenced in FSAR Section</u>
NEDO-10174	Consequences of a Postulated Fuel Blockage Incident in a Boiling Water Reactor (May 1970)	4.2
NEDO-10299	Core Flow Distribution in a Modern Boiling Water Reactor as Measured in Monticello (January 1971)	4.4
NEDO-10320	The General Electric Pressure Suppression Containment Analytical Model (April 1971) Supplement 1 (May 1971)	6.2
NEDO-10329	Loss-of-Coolant Accident and Emergency Core Cooling Models for General Electric Boiling Water Reactors (April 1971) Supplement 1 (April 1971) Addenda (May 1971)	4.3
NEDO-10349	Analysis of Anticipated Transients Without Scram (March 1971)	15.8
NEDO-10466	Power Generation Control Complex Design Criteria and Safety Evaluation (February 1972)	3.12.3.4.2.1(f)
NEDO-10505	Experience with BWR Fuel Through September 1971 (May 1972)	4.2, 11.1
NEDO-10527	Rod Drop Accident Analysis for Large Boiling Water Reactors (March 1972) Supplement 1 (July 1972) Supplement 2 (January 1973)	4.3, 15.4
NEDO-10585	Behavior of Iodine in Reactor Water During Plant Shutdown and Startup (August 1972)	15.6
NEDO-10602	Testing of Improved Jet Pumps for the BWR/6 Nuclear System (June 1972)	3.9
NEDO-10734	A General Justification for Classification of Effluent Treatment System Equipment as Group D (February 1973)	11.3



TABLE 1.6-1 CONTINUED

<u>Report Number</u>	<u>Title</u>	<u>Referenced in FSAR Section</u>
NEDO-10739	Methods for Calculating Safe Test Intervals and Allowable Repair Times for Engineered Safeguard Systems (January 1973)	6.3
NEDO-10751	Experimental and Operational Confirmation of Offgas System Design Parameters (January 1973) (Company Proprietary)	11.3
NEDO-10801	Modeling the BWR/6 Loss-of-Coolant Accident: Core Spray and Bottom Flooding Heat Transfer Effectiveness (March 1973)	1.5
NEDO-10802	Analytical Methods of Plant Transient Evaluations for General Electric Boiling Water Reactor (February 1973)	4.4, 5.2, 15.1
NEDO-10846	BWR Core Spray Distribution (April 1973)	1.5
NEDO-10899	Chloride Control in BWR Coolants (June 1973)	5.2
NEDO-10958	General Electric BWR Thermal Analysis Basis (GETAB): Data, Correlation, and Design Application (November 1973)	4.3, 4.4, 15.0
NEDO-10958-A	General Electric BWR Thermal Analysis Basis (GETAB): Data, Correlation, and Design Application (January 1977)	1.5, 15.4, 16.1
NEDO-10959	General Electric BWR Thermal Analysis Basis (GETAB): Data, Correlation, and Design Application (November 1973)	15.0
NEDO-20231	Emergency Core Cooling Tests of an Internally Pressurized, Zircaloy-Clad, 8x8 Simulated BWR Fuel Bundle (December 1973)	1.5

TABLE 1.6-1 CONTINUED

<u>Report Number</u>	<u>Title</u>	<u>Referenced in FSAR Section</u>
NEDO-20340	Process Computer Performance Evaluation Accuracy (June 1974)	4.3
NEDO-20360	General Electric Boiling Water Reactor Generic Reload Application for 8x8 Fuel (May 1975)	4.2, 15.4
NEDO-20360-IP	General Electric Boiling Water Reactor Generic Reload Application for 8x8 Fuel (March 1976)	4.2
NEDO-20533	The General Electric Mark III Pressure Suppression Containment System Analytical Model (June 1974)	1.5
NEDO-20566	General Electric Company Model for Loss-of-Coolant Accident Analysis in Accordance with 10 CFR 50, Appendix K (January 1976)	3.9, 4.3, 6.3
NEDO-20605 and NEDO-20606	Creep Collapse Analysis of BWR Fuel Using Safe Collapse Model (August 1974)	4.2
NEDO-20626	Studies of BWR Designs for Mitigation of Anticipated Transients without Scrams (October 1974)	15.8
NEDO-20626-1	Studies of BWR Designs for Mitigation of Anticipated Transients without Scrams (June 1975)	15.8
NEDO-20626-2	Studies of BWR Designs for Mitigation of Anticipated Transients without Scrams (July 1975)	15.8
NEDO-20631	Mechanical Property Surveillance of Reactor Pressure Vessels for General Electric BWR/6 Plants (March 1975)	5.3
NEDO-20913	Lattice Physics Methods (June 1975)	4.3
NEDO-20922	Experience with BWR Fuel Through September 1974 (June 1975)	4.2, 11.1
NEDO-20939	Lattice Physics Methods Verification	4.3

TABLE 1.6-1 CONTINUED

<u>Report Number</u>	<u>Title</u>	<u>Referenced in FSAR Section</u>
	(August 1975)	
NEDO-20943	Urania-Gadolinia Nuclear Fuel Physical and Material Properties (January 1977)	4.2
NEDO-20944 and NEDE-20944P	BWR/4 and BWR/5 Fuel Design (October 1976)	4.1, 4.3
NEDO-20946	BWR Simulator Methods Verification (May 1976)	4.3
NEDE-20944-1P	BWR/4 and BWR/5 Fuel Design (January 1977)	4.2
NEDO-20948-P	BWR/6 Fuel Design (June 1976)	4.2
NEDO-20953	Three-Dimensional Boiling Water Reactor Core Simulator (May 1976)	15.4
NEDO-20964	Generation of Void and Doppler Reactivity Feedback for Application to BWR Plant Transient Analysis (August 1975)	4.3
NEDO-21142	Realistic Accident Analysis for General Electric Boiling Water Reactor - The RELAC Code and User's Guide, to be issued (December 1977)	15.4, 15.6, 15.7
NEDO-21143	Conservative Radiological Accident Evaluation.- The CONAC01 Code (March 1976)	15.4, 15.6, 15.7
NEDO-21159	Airborne Release from BWRs for Environment Impact Evaluations (March 1976)	11.1
NEDO-21174	BWR Fuel Channel Deflections	4.2
NEDO-21231	Banked Position Withdrawal Sequence (September 1976)	4.3
NEDO-21291	Group Notch Mode of the RSCS for	15.4

TABLE 1.6-1 CONTINUED

<u>Report Number</u>	<u>Title</u>	<u>Referenced in FSAR Section</u>
	Cooper (June 1976)	
NEDO-26453	3D BWR Core Simulator (May 1976)	4.3
	Oyster Creek Station, FSAR Amendment 10	1.5
	"Summary Memorandum on Excursion Analysis Uncertainties," Dresden Nuclear Power Station, Unit 3, Plant Design Analysis Report Amendment 3	4.3, 15.0
	Hatch Nuclear Plant, Unit 1, PSAR Amendment 10, Appendix L	15.5
	Millstone Nuclear Power Station, PSAR Amendment 14	6.3
	Pilgrim Nuclear Power Station, PSAR Amendment 14	6.3
	Quad Cities Station, Units 1 and 2, PSAR, Amendment 9	4.3

This listing to be updated for each requisition plant.

#### B. Other Referenced Reports

AE-RTL-788	Void Measurements in the Region of Subcooled and Low Quality Boiling (April 1966)	4.4
ANL-5621	Boiling Density in Vertical Rectangular Multichannel Sections with Natural Circulation (November 1956)	4.4
ANL-6385	Power-to-Void Transfer Functions (July 1961)	4.4
AGN-TM-407	AGN-GAM, an IBM 7090 Code to Calculate Spectra and Multigroup Constants (April 1965)	4.3
ANL-7460	Reactor Development Program Progress Report, p. 121-122 (June 1968)	4.3

TABLE 1.6-1 CONTINUED

<u>Report Number</u>	<u>Title</u>	<u>Referenced in FSAR Section</u>
ANL-7527	Reactor Development Program Progress Report, p. 132 (December 1968)	4.3
BNL-5826	THERMOS-A Thermalization Transport Code for Reactor Design (June 1961)	4.3
BNWL-340	"Computer Code Abstracts, Computer Code--HRG," Reactor Physics Dept., Technical Activities Quarterly Report, July, August, September, 1966 (October 15, 1966)	4.3
BHR/DER 70-1	Radiological Surveillance Studies at a Boiling Water Nuclear Power Reactor (March 1970)	11.1
BMI-1163	Vapor Formation and Behavior in Boiling Heat Transfer (February 1957)	4.4
CF 59-6-47 (ORNL)	Removal of Fission Product Gases From Reactor Off-Gas Streams by Adsorption (June 11, 1959)	11.3
IDO-ITR-105	The Response of Waterlogged UO <sub>2</sub> Fuel Rods to Power Bursts (April 1969)	4.2
IN-ITR-111	The Effects of Cladding Material and Heat Treatment on the Response of Waterlogged UO <sub>2</sub> Fuel Rods to Power Bursts (January 1970)	4.2
STI-372-38	Kinetic Studies of Heterogeneous Water Reactors (April 1966)	4.4
TID-4500	Relap 3 - A Computer Program for Reactor Blowdown Analysis IN-1321 (June 1970)	3.6
UCRL-50451	Improving Availability and Readiness of Field Equipment Through Periodic Inspection, p. 10 (July 16, 1968)	16.3
WACP-6065	Melting Point of Irradiated Uranium Dioxide (February 1965)	4.2

TABLE 1.6-1 CONTINUED

<u>Report Number</u>	<u>Title</u>	<u>Referenced in FSAR Section</u>
WAPD-BT-19	A Method of Predicting Steady-Boiling Vapor Fractions in Reactor Coolant Channels (June 1960)	4.4
WAPD-TM-283	Effects of High Burnup on Zircaloy-clad, Bulk UO <sub>2</sub> Plate Fuel Element Samples (September 1962)	4.2
WAPD-TM-416	WIGLE - A Program for the Solution of the Two-Group Space-Time Diffusion Equations in Slab Geometry (1964)	4.3
WAPD-TM-629	Irradiation Behavior of Zircaloy-Clad Fuel Rods Containing Dished End UO <sub>2</sub> Pellets (July 1967)	4.2



Design Conformance

The primary containment system, which includes the drywell and suppression chamber, is designed, fabricated, and erected to accommodate, without failure, the pressures and temperatures resulting from the double-ended rupture or equivalent failure of any coolant pipe within the primary containment. The reactor building encompassing the primary containment provides secondary containment. The two containment systems and their associated safety systems are designed and maintained so that offsite doses, which could result from postulated design basis accidents, remain below the guideline values stated in 10CFR100 when calculated by the methods of Regulatory Guide 1.3 (Rev. 2, 6/74). Sections 6.2 and 15.1 have detailed information which demonstrates compliance with Criterion 16.

3.1.2.2.8 Electric Power Systems (Criterion 17)Criterion

An onsite electric power system and an offsite electric power system shall be provided to permit functioning of structures, systems, and components important to safety. The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.

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

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

following a loss-of-coolant accident to assure that core cooling, containment integrity, and other vital safety functions are maintained.

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

#### Design Conformance

Two offsite power transmission systems and four onsite standby diesel generators with their associated battery systems are provided. Either of the two offsite transmission power systems or any three of the four onsite standby diesel generator systems have sufficient capability to operate safety related equipment for cooling the reactor core and maintaining primary containment integrity and other vital functions in the event of a postulated accident in one unit with a safe shutdown of the other unit.

The two independent offsite power systems supply electric power to the onsite power distribution system via the 230 kV transmission grid. Each of the offsite power sources is supplied from a transmission line which terminates in switchyards (or Substations) not common to the other transmission line. The two transmission lines are on separate rights-of-way. These two transmission circuits are physically independent and are designed to minimize the possibility of their simultaneous failure under operating and postulated accident and environment conditions.

Each offsite power source can supply all Engineered Safety Feature (ESF) buses through its associated transformer. Power is available to the ESF buses from their preferred offsite power source during normal operation and from the alternate offsite power source if the preferred power is unavailable. Each diesel generator supplies standby power to one of the four ESF buses in each unit. Loss of both offsite power sources to an ESF bus results in automatic starting and connection of the associated diesel generator within 10 seconds. Loads are progressively and sequentially added to avoid generator instabilities.

There are four independent ac load groups provided to assure independence and redundancy of equipment function. These meet the safety requirements assuming a single failure since any three of the four load groups have sufficient capacity to supply the minimum loads required to safely shut down the unit. Independent routing of the preferred and alternate offsite power source circuits to the ESF buses are provided to meet the single failure safety requirements.

### 3.4- WATER LEVEL (FLOOD) DESIGN

As discussed in Section 2.4, all Seismic Category I structures are secure against flooding due to probable maximum flood (PMF) of the Susquehanna River or probable maximum precipitation (PMP) on the area surrounding the plant. Therefore, special flood protection measures are unnecessary. The Seismic Category I structures have, however, been designed for hydrostatic loads resulting from groundwater, as discussed in Section 3.8. The groundwater table is at elevation 665 MSL in the main plant area.

A postulated break in the cooling tower basins or of the water delivery pipes to the basin could result in a build-up of water against the walls of either or both of the ESSW pumphouse and the turbine building. In the event of such water build-up breaching the turbine building wall, water that would not be intercepted by the floor drains or grilles and thus would flow through the turbine building to the reactor building would be prevented from endangering equipment in the latter by means of watertight doors. Flood water building up against the ESSW pumphouse would also be prevented from entering the building by means of watertight doors. Impact forces and water pressure due to flood water will not endanger the integrity of the ESSW pumphouse.

All safety-related systems are located in the Reactor Building, Diesel Generator Building, Control Structure and the Engineered Safeguard Service Water (ESSW) Pumphouse.

Sufficient physical separation between these buildings is provided to prevent internal spreading of any floods from one building to another.

Redundant Engineered Safety Features, pumps and drives, heat exchangers and associated pipes, valves and instrumentation in the reactor building subject to potential flooding, are housed in separate watertight rooms. Seismic Category I level detectors trip alarms in the main control room when the water level in any room exceeds the set point. Isolation of the floor drainage lines from these rooms is provided by outside manual valves.

All other rooms in the reactor building and control structure containing safety related equipment which are subject to potential flooding by process fluid leakage or fire protection water are provided with at least one open floor drain.

Floods in excess of the approximately 80 gpm floor drain capacity increase the water level in the affected area and are released through the door-to-floor clearance of these rooms.

Refer to Subsection 9.3.3 for a detailed description of the reactor building and control structure drainage system.

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The four diesel generator sets are housed in individual water tight compartments within the diesel generator building. Floor drain line branches from each of these compartments are equipped with check valves to prevent backflooding from the common sump.

The ESSW pumphouse is divided into two redundant compartments. Flooding from internal leakage would, therefore, only affect one of the redundant pump sets. The control and electrical panels are mounted on minimum 4 inch high concrete pads or structural supports. Operating floor openings allow drainage of any leakage to the ESSW pump suction space below or to a reserve sump space that could be emptied with a portable pump.

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### APPENDIX 3.6A

#### PIPE BREAK OUTSIDE CONTAINMENT SUMMARY OF ANALYSIS AND RESULTS

##### PART I - ANALYSIS FOR SPACES OTHER THAN MAIN STEAM TUNNEL

In addition to the analysis provided in Table 3.6-3, compartments containing high energy lines were analyzed to determine the peak pressures that might result from breaks in these lines. The analysis was done mainly to verify structural integrity. Duration of the blowdown was not a factor in the analysis since adequate vent area was provided, and pressure peaked quickly then declined to a lower steady state value. The structures are adequate to withstand the peak pressures indicated by the analysis.

The valves which would be used to terminate the blowdown are indicated. In general, however, it is unnecessary to qualify equipment for the pipe break environment because the safeguards systems are separated into compartments which are vented directly to the atmosphere and high energy breaks affect only a single space. The plant can be safely shutdown using equipment not affected by the high energy line break.

The following information for each compartment was utilized with the analytical techniques described in Appendix 6B of the PSAR to determine the pressures and temperatures resulting from high energy line breaks outside containment.

##### ANALYSIS FOR HPCI PENETRATION ROOM (UNIT 1)

###### Pipe Break Data

Location: HPCI Penetration Room  
Line Identification/Size: DBB-114/10"

Isolation Valve Designation and Location: HV E41-1F003 located in  
the HPCI Penetration  
Room

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## Blowdown Data:

<u>t(sec)</u>	<u>m(lbm/sec)</u>	<u>h(BTU/lbm)</u>
0.0	1892	1192.2
0.1	1892	1192.2
0.1	1353	1192.2
0.2	1353	1192.2
0.2	738	1192.2
0.882	738	1192.2
0.882	407	1192.2
51.0	0	1192.2

Compartment Volume: 87,680 cu ft

Vent Area: 67.0 sq ft

Vent Coefficient: .574  
L/A 0.0022 Ft<sup>-1</sup>

Results: Peak Pressure: 2.12 psig  
Peak Temperature: 288.4 F

## ANALYSIS FOR HPCI PUMP ROOM (UNIT 1)

### Pipe Break Data

Location: HPCI Pump Room  
Line Identification/Size: DBB-114/10"

Isolation Valve Designation and Location: HV E41-1F003 located in the HPCI Penetration Room

## Blowdown Data:

<u>t(sec)</u>	<u>m(lbm/sec)</u>	<u>h(BTU/lbm)</u>
0.0	1892	1192.2
.088	1892	1192.2
.088	1402	1192.2
.164	1402	1192.2
.164	946	1192.2
.218	946	1192.2
.218	283	1192.2
50.0	0	1192.2

Compartment Volume: 27,883 cu ft

Vent Area: 60 sq ft

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Vent Coefficient: .575  
L/A 0.0172Ft<sup>-1</sup>

Results: Peak Pressure: 4.11 psig  
Peak Temperature: 298.6 F

ANALYSIS FOR RCIC PUMP ROOM (UNIT 1)

Pipe Break Data

Location: RCIC Pump Room  
Line Identification/Size: DBB-109/4"

Isolation Valve Designation and Location: HV-E51-1F008 Located in  
the HPCI Penetration  
Room

Blowdown Data:

<u>t(sec)</u>	<u>m(lbm/sec)</u>	<u>h(BTU/lbm)</u>
0.0	286.6	1192.2
0.024	286.6	1192.2
0.024	218.5	1192.2
0.042	218.5	1192.2
0.042	143.3	1192.2
0.278	143.3	1192.2
0.278	29	1192.2
7.6	29	1192.2
28.0	0	1192.2

Compartment Volume: 18,129 cu ft

Vent Area: 46.0 sq ft

Vent Coefficient: .575  
L/A 0.0426 Ft<sup>-1</sup>

Results: Peak Pressure: 0.52 psig  
Peak Temperature: 238.3 F

ANALYSIS FOR RHR ROOM A (UNIT 1)

Pipe Break Data

Location: RHR Room A  
Line Identification/Size: OBB-115/10"

Isolation Valve Designation and Location: HV E41-1F003 located in  
the HPCI Penetration  
Room

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## Blowdown Data:

<u>t(sec)</u>	<u>m(lbm/sec)</u>	<u>h(BTU/lbm)</u>
0.0	1892	1192.2
.092	1892	1192.2
.092	1336	1192.2
.151	1336	1192.2
.151	738	1192.2
.261	738	1192.2
.261	348	1192.2
1.7	348	1192.2
52.0	0	1192.2

Compartment Volume: 48,554 cu ft

Vent Area: 85 sq ft

Vent Coefficient: .575  
L/A 0.0098 Ft<sup>-1</sup>

Results: Peak Pressure: 2.16 psig  
Peak Temperature: 297.1 F

## ANALYSIS FOR RHR ROOM B (UNIT 1)

### Pipe Break Data

Location: RHR Room B  
Line Identification/Size: OBB-115/8"

Isolation Valve Designation and Location: HV E41-1F003 located in the HPCI Penetration Room

## Blowdown Data:

<u>t(sec)</u>	<u>m(lbm/sec)</u>	<u>h(BTU/lbm)</u>
0.0	1892	1192.2
0.023	1892	1192.2
0.023	946	1192.2
0.222	946	1192.2
0.222	255	1192.2
2.6	255	1192.2
53.0	0	1192.2

Compartment Volume: 60,000 cu ft

Vent Area: 85 sq ft



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Vent Coefficient: .575  
L/A 0.0076 Ft<sup>-1</sup>

Results: Peak Pressure: 1.33 psig  
Peak Temperature: 287.4 F

## ANALYSIS FOR REACTOR WATER CLEANUP SYSTEM (RWCS) PENETRATION ROOM

### Pipe Break Data

Location: RWCS Penetration Room  
Line Identification/Size: DBC-101/6"

Isolation Valve Designation and Location: HV G33-1F004 in RWCS  
Penetration Room

### Blowdown Data:

<u>t(sec)</u>	<u>m(lbm/sec)</u>	<u>h(BTU/lbm)</u>
0.0	3630	513
0.063	3630	513
0.063	2450	513
.11	2450	513
.11	1085	513
.843	1085	513
.843	450	513
30.0	0	513

### Compartment Volumes:

<u>Arch. Room No.</u>	<u>Volume (Cu. Ft.)</u>
I-501	5552
I-502	2540
I-503	2540
I-504	4933
I-505	4850

<u>Flow Path</u>	<u>Area (Ft<sup>2</sup>)</u>	<u>Flow Coefficient</u>	<u>L/A (Ft<sup>-1</sup>)</u>
I-501 to ATM	45	0.575	0.0426
I-501 to I-503	64	0.711	0.0327
I-503 to I-504	64	0.682	0.0580
I-504 to I-505	150	0.709	0.0169
I-503 to I-502	53	0.745	0.0854

### Results:

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<u>Arch. Room No.</u>	<u>Peak Pressure</u>	<u>Peak Temp.</u>
I-501	2.14 PSIG	211.7°F
I-502	2.07 PSIG	113.9°F
I-503	2.14 PSIG	154.4°F
I-504	2.27 PSIG	113.3°F
I-505	2.31 PSIG	132.3°F

Note: The RWCS penetration room I-501, communicates with the two RWCS Pump Rooms; I-502 and I-503 (vol. 2,540 cu ft each), the Regenerative Heat Exchanger Room, I-504 (vol. 4,933 cu ft), and the Non-regenerative Heat Exchanger Room, I-505, (vol. 4,850 cu ft). A break in the RWCS penetration room results in a more severe environment than a break in any other room; therefore, only results for this break are presented.

Analysis for Compartment Pressurization in Unit 2 is identical to Unit 1, with the exception of breaks in the HPCI and RCIC Rooms. These analyses are presented below.

## ANALYSIS FOR RCIC PUMP ROOM (UNIT 2)

### Pipe Break Data

Location: RCIC Pump Room  
Line Identification/Size: DBB-209/4"

Isolation Valve Designation and Location: HV-E51-2F008 located in HPCI Penetration Room

### Blowdown Data:

<u>t(sec)</u>	<u>m(lbm/sec)</u>	<u>h(BTU/lbm)</u>
0	286	1192.2
.024	286	1192.2
.024	215	1192.2
.045	215	1192.2
.045	143	1192.2
.278	143	1192.2
.278	29.2	1192.2
7.6	29.2	1192.2
58	0	1192.2

### Compartment Volumes:

RCIC 18129 Cu. Ft.  
HPCI 27883 Cu. Ft.

# SSES-PSAR

Tunnel 2650 Cu. Ft.

<u>Flow Path</u>	<u>Area (Ft<sup>2</sup>)</u>	<u>Flow Coefficient</u>	<u>L/A (Ft<sup>-1</sup>)</u>
RCIC to Tunnel	25	0.677	0.341
Tunnel to HPCI	72	0.711	0.355
Tunnel to ATM	45	0.679	0.319

## Results:

<u>Room</u>	<u>Peak Pressure (PSIG)</u>	<u>Peak Temp. (°F)</u>
RCIC	0.57	238.5
HPCI	0.74	108.1
Tunnel	0.74	220.2

## Notes:

A break in the RCIC pump room results in a change in environment to the HPCI pump room via connection of the tunnel to both rooms. Therefore, peak pressures are shown for all three compartments.

## ANALYSIS FOR HPCI PUMP ROOM (UNIT 2)

### Pipe Break Data

Location: HPCI Pump Room  
Line Identification/Size: DBB-214/10"

Isolation Valve Designation and Location: HV-E41-2F003 located in the HPCI Penetration Room

### Blowdown Data:

<u>t(sec)</u>	<u>m(lbm/sec)</u>	<u>h(BTU/lbm)</u>
0	1892	1192.2
.07	1892	1192.2
.07	1412	1192.2
.127	1412	1192.2
.127	946	1192.2
.223	946	1192.2
.223	284	1192.2
.500	0	1192.2

### Compartment Volumes:

HPCI	27883 Cu. Ft.
RCIC	18129 Cu. Ft.
Tunnel	2650 Cu. Ft.

# SSSES-FSAR

<u>Flow_Path</u>	<u>Area (FT<sup>2</sup>)</u>	<u>Flow Coefficient</u>	<u>L/A (Ft<sup>1</sup>)</u>
HPCI to Tunnel	72	0.842	0.355
Tunnel to RCIC	25	0.626	0.341
Tunnel to ATM	45	0.679	0.319

## Results:

<u>Room</u>	<u>Peak Pressure</u>	<u>Peak Temp. (°F)</u>
HPCI	3.69	298.7
RCIC	2.98	143.5
Tunnel	3.07	294.7

## Notes:

A break in the HPCI pump room results in a change in environment to the RCIC pump room via connection of the tunnel to both rooms. Therefore, peak pressures are shown for all three compartments.

## PART II - ANALYSIS OF MAIN STEAM LINE BREAKS IN THE MAIN STEAM LINE TUNNEL

Subcompartment differential pressure analysis were performed for the main steamline tunnel. Two break locations were chosen to render the design of each portion of the tunnel (viz. - Reactor and Burbine Building sides) conservative. They are:

Case A. MSLB in the Reactor Building.  
(24" DBB-103 at El. 719'-8", 1st elbow)

Case B. MSLB in the Turbine Building.  
(24" DBB-103 at El. 719'-8", 2nd elbow)

The pressure and temperature response of these areas to the postulated pipe breaks are predicted using the analytical model described in Appendix 6B with the changes described below. The Appendix 6B model ignores "momentum effects" within a subcompartment. For most cases considered, this is justified as the momentum effects are insignificant relative to the absolute pressure peaks. However, momentum effects are important to

conservatively predicting pressures resulting from the main steam tunnel case. Therefore, for this study, the momentum equation

$$\frac{\partial}{\partial \tau} (\rho \vec{u}) + \vec{\nabla} \cdot (\rho \vec{u} \vec{u}) = -\vec{\nabla} p - \vec{\nabla} \cdot \vec{\tau} + \rho \vec{g}$$

is "one-dimensionalized" and solved in the following manner:

$$\begin{aligned} \frac{1}{g_c A(x)} \frac{\partial}{\partial \tau} [A(x) \dot{m}(x,t)] = & - \frac{1}{g_c A(x)} \frac{\partial}{\partial x} \left[ \frac{A(x) \dot{m}^2(x,t)}{\rho(x,t)} \right] \\ & - \frac{\partial p(x,t)}{\partial x} - \frac{1}{A(x)} \frac{\partial F(x,t)}{\partial x} \end{aligned} \quad (1)$$

Where the  $F(x,t)$  term includes shear forces and non-one-dimensional momentum change effects. Its integral over a flow path is evaluated by means of empirically determined flow coefficients (see Appendix 6B).

Equation (1) is now integrated from midpoint to midpoint of two adjoining compartments assuming incompressible flow, but with a uniquely determined fluid density. The density of the flow mixture is evaluated in a way which assures that, as flow approaches steady state conditions, the density and the computed mass flux approach the values obtained from the compressible steady state equations in Appendix 6B.

Using this assumption and integrating term by term, we obtain:

First term:

$$\begin{aligned} \frac{1}{g_c} \int_{x_1}^{x_2} \frac{1}{A(x)} \frac{\partial}{\partial \tau} [A(x) \dot{m}(x,t)] dx &= \frac{1}{g_c} \frac{\partial}{\partial t} W(t) \int_{x_1}^{x_2} \frac{dx}{A(x)} \\ &= \frac{1}{g_c} \frac{dW(t)}{dt} \sum_i \left( \frac{L_i}{A_i} \right) \end{aligned} \quad (1a)$$

Where the integral of  $(dx/A(x))$  is evaluated sequentially for constant area segments between  $x_1$  and  $x_2$ .  $L_i$  thus represents the length of segment  $i$ .

Second term:

$$\begin{aligned}
 - \frac{1}{gc} \int_{x_1}^{x_2} \frac{1}{A(x)} \frac{\partial}{\partial x} \left[ \frac{A(x) \dot{m}^2(x,t)}{\rho(x,t)} \right] dx &= - \frac{W^2(t)}{gc\rho} \int_{x_1}^{x_2} \left( \frac{1}{A(x)} \right) \frac{d}{dx} \left( \frac{1}{A(x)} \right) dx \quad (1b) \\
 &= - \frac{W^2(t)}{2gc\rho} \left[ \frac{1}{A_2^2} - \frac{1}{A_1^2} \right]
 \end{aligned}$$

Where the  $\rho$  in the above expression remains to be defined.

Third term:

$$- \int_{x_1}^{x_2} \frac{\partial \rho(x,t)}{\partial x} dx = - [P_2 - P_1] \quad (1c)$$

It should be noted that the above pressures are static values and to match the units of Equation (1) are, at this point, given in terms of lb /ft<sup>2</sup>.

Fourth term:

$$- \int_{x_1}^{x_2} \frac{1}{A(x)} \frac{\partial F(x,t)}{\partial x} dx = - K_i \frac{V_T^2}{2gc} \rho \quad (1d)$$

Where  $i = +1$  if  $W \geq 0$  and  $i = -1$  if  $W < 0$ .

The above equation is not really a proper integration, but just a replacement of this integral by the appropriate empirical correlation. The coefficient  $K$  is a properly summed coefficient for the flow path from  $x_1$  to  $x_2$  and can include friction terms. The velocity  $V_T$  depends on the empirical correlation used, but is usually taken as the "throat" velocity. This is assumed to be the case, then Equation (1d) becomes:

$$- \frac{K_i V_T^2 \rho}{2gc} \left( \frac{\rho A_T^2}{\rho A_T^2} \right) = - K_i \frac{W^2(t)}{2gc A_T^2} \quad (1e)$$

Where  $A_T$  is the junction flow area.

Before collecting all the integrated terms, it is preferable to convert the static pressures of Equation 1c into stagnation pressures.

$$P_{stat}(i) = P_{stag}^*(i) - \frac{\rho V(i)^2}{2gc} = P_{stag}^*(i) - \frac{W^2(t)}{2gc\rho A_1} \quad (1f)$$

Summing the expressions obtained by Equations (1b) to (1e) and using (1f) we get:

$$\frac{1}{gc} \frac{dW(t)}{dt} \sum_i \left( \frac{L_i}{A_i} \right) = P_1^* - P_2^* - \frac{K_1 W^2(t)}{2gc\rho A_T^2} \quad (1g)$$

Where the starred pressures imply stagnation values.

Now the flow rate of the previous time step is used to evaluate a finite-difference approximation of the time derivative:

$$\frac{dW(t)}{dt} = \frac{W(t) - W(t-\Delta t)}{\Delta t} \quad (2)$$

In a given time interval,  $W(t-\Delta t)$  is known, thus Equation (1g) is a quadratic in  $W(t)$ . Writing it in the customary quadratic form we have:

$$\begin{aligned} & \frac{K_1}{2gc\rho A_T^2} W^2(t) + \frac{\sum_i \left( \frac{L_i}{A_i} \right)}{\Delta t gc} W(t) \\ & - \left\{ \frac{\sum_i \left( \frac{L_i}{A_i} \right)}{\Delta t gc} W(t-\Delta t) + P_1^* - P_2^* \right\} = 0 \end{aligned} \quad (3)$$

and substituting the compressible flow equation for  $W$ . The resulting ratio is:

$$\frac{\rho}{\rho_2} = \left( \frac{k}{k-1} \right) \left[ \frac{1}{1 - \frac{P_2}{P_1}} \right] \left[ \left( \frac{P_2}{P_1} \right)^{1/k} - \left( \frac{P_2}{P_1} \right) \right] \quad (5)$$

In the limit as  $(P_2/P_1) \rightarrow 1$ , Equation 5 approaches a value of one as required and the  $P_2/P_1$  ratio stays below one for all other values of  $P_2/P_1$  and for all positive  $k$ .  $\rho$  is thus smaller than the arithmetic mean of the densities and smaller than the downstream density itself. This assures a conservatively minimized flow rate for a given pressure gradient. This also holds true when the inertial effects (time dependent momentum equation) are included. Table 3.6A-1 shows representative mass flux values calculated by density  $\rho_2$ , and the proper compressible flow compatible density  $\rho$  is used. As seen for all cases, the use of  $\rho$  results in minimum and thus conservative flow rates.

The calculational sequence can now be summarized.

- (1) After compartment state functions have been obtained, a first estimate of  $W(t)$  is evaluated using the compressible flow equation.
- (2) The estimate of  $W(t)$  is used in Equation 3b to evaluate the fluid density.
- (3) Utilizing the flow rate from the previous time step and the calculated  $\rho$ , Equation (3) is solved to obtain  $W(t)$ .

During each time step, the junction flow rate is chosen as the smaller of the flow rate resulting from the one-dimensional momentum equation or the flow rate resulting from the selected steady state compressible flow correlation. (Appendix 6B).

Schematic drawings showing the nodalization of the steam tunnel for Case A and Case B are given in Figures 3.6A-1 and 3.6A-5, respectively. Blow out panel locations are shown in Figure 3.6A-2. Volumes, flow areas, flow coefficients, and  $L/A$ 's for the models are presented in Tables 3.6A-2 through 3.6A-5. As indicated in Figure 3.6A-1, the main steam tunnel is subdivided into a total of eighteen volumes to model the effect of obstructions such as pipe restraints and blowout panels. For Case B, in Figure 3.6A-5, a ten volume model is used since the one-way blowout panels completely block the flow path to reactor building side, leaving it unpressurized. The overall flow diagrams for both Cases A & B are presented in Figures 3.6A-3 and 3.6A-6.

The blowdown data for the postulated double end guillotine mainsteam line break is shown in Table 3.6A-4. This blowdown is done in a way similar to ANS 176 standard (draft), as discussed below, but system friction is accounted for to reduce the calculated mass and energy releases to reasonable levels while maintaining a degree of conservatism. Other criteria are addressed as follows:



1. Full double-end break area Moody flow for steam blowdown immediately after pipe break.
2. Choking Moody flow occurs first at the break, then moves up to choke at flow restrictors.
3. Frictional loss of valves is not included.
4. Level swell (4% quality blowdown) occurs at 1 sec.
5. Steam isolation valves close in 5 seconds with a 0.6 second instrument and signal delay time. A linear ramp in flow area is used to model this closure.

The computational method of this double-end guillotine mainsteam line break is shown in Fig. 3.6A-8.

In Figure 3.6A-8, flow from the RPV to the break location is "forward flow," while the flow from the turbine to the break location is "reverse flow."

Let  $L_1$  = The distance from flow restrictors to break location.

$L_2$  = The distance from reactor pressure vessel nozzle to the flow restrictors.

$L_3$  = The distance from flow restrictor to the turbine crosstie.

$L_4$  = The shortest distance from the MSL crosstie back to the break location.

(A) Calculation of mass and energy release rates from the forward direction.

Let  $A_p$  = The cross-sectional flow area of the break,  $\text{ft}^2$ .

$A_v$  = The throat area of the flow restrictor,  $\text{ft}^2$ .

$P_o$  = No-load system pressure, PSIA.

$X$  = Steam quality.

$h$  = Enthalpy of fluid, BTU/lbm

$N$  = Number of lines.

$c$  = Sonic speed for steam.

$f$  = Frictional factor.

$D$  = Diameter of the pipe system.

- (1) At  $0 \leq T \leq L_1/C$  sec.

$$\dot{W}_{1F} = (G_{M1} A_P - \dot{W}_{2F}) (1 - T/(L_1/C)) + \dot{W}_{2F}$$

Where  $G_{M1}$  = Moody specific flowrate (LBM/sec\*ft<sup>2</sup>) based on  $P_0 = 1050$  PSIA and  $h = 1190.0$  BTU/IBM.

This ramp-down in flow rate simulates the increasing system resistance downstream of the decompression wave front

- (2) At  $L_1/C \leq T \leq \frac{2 * (1.1 * L_1)}{0.9 * C}$  sec (Time for choking at flow restrictor)

$$\dot{W}_{2F} = G_{M2} * A_P$$

Where  $G_{M2}$  = Moody specific flow rate based on  $p = 1050$  psia and  $h = 1190.0$  BTU/IBM with

- (3) At  $\frac{2 * (1.1 * L_1)}{(0.9 * C)} \leq T \leq 1.0$  sec (Time for level swell)

$$\dot{W}_{3f} = G_{M3} * A_V$$

Where  $G_{M3}$  = Moody specific flow rate based on  $p = 1050$  psia and  $h = 1190$  BTU/IBM with

- (B) Calculation of mass and energy release rates from the reverse direction.

- (1) At  $0 \leq T \leq \frac{L_4}{C}$  sec

$$\dot{W}_{1R} = (G_{M1} * A_P - \dot{W}_{2R}) (1 - T/L_4/C)) + \dot{W}_{2R}$$

This ramp-down in flow rate simulates the increasing system resistance downstream of the decompression wave front.

- (2) At  $L_4/C \leq T \leq \frac{2 * (L_3 + L_4)}{C}$  sec (Time for choking at the flow restrictors)

$$\dot{W}_{2R} = G_{M2R} * A_V * N$$

Where  $G_{M2R}$  = Moody specific flow rate based on  $h = 1190$  BTU/IBM with  $f \left( \frac{L_3 + L_4}{D} \right)$

- (3) At  $\frac{2 * (L_3 + L_4)}{C} \leq T \leq 1.00$  sec (Time for level swell)

$$\dot{W}_{3R} = \dot{W}_{3R} (A \text{ LINE}) + \dot{W}_{3R} (B \text{ LINE}) + \dot{W}_{3R} (C \text{ LINE})$$

$$= A_v [G_{M3R} (A) + G_{M3R} (B) + G_{M3R} (C)]$$

Where  $G_{M3R} (A)$ ,  $G_{M3R} (B)$  and  $G_{M3R} (C)$  are the Moody specific flow rates for lines A, B, C based on  $P_0 = 1050$  PSIA and  $H = 1190$  BTU/IBM with  $f L_2/D$  for each line.

(C) Calculation of mass and energy release rates from the swell phenomenon.

(1) At  $1.0 \leq T \leq 4.35$  sec. (Time for choking at the valve)

$$\dot{W}_S = \dot{W}_S (A) + \dot{W}_S (B) + \dot{W}_S (C) + \dot{W}_S (D)$$

$$= A_v [G_{MA} (A) + G_{MS} (B) + G_{MS} (C) + G_{MS} (D)]$$

Where  $G_{M2} (A)$ ,  $G_{M2} (B)$ ,  $G_{M2} (C)$ ,  $G_{M2} (D)$  are the Moody specific flow rates for lines A, B, C, D based on  $h = 572$  BTU/IBM (4% quality) and  $f L_2/D$  for each line.

(2) At  $T = 5.6$  sec. (Time for valve completely closed)

$$\dot{W}_S = 0.0 \text{ LBM/sec}$$

(D) Calculation of the total mass and energy release rates.

The total flow rate is obtained by adding up the forward flow and reverse flow at each time sequence by superpositioning of the two curves (forward and reverse). Then after 1.0 second, the total flow rate will be just the flow rate calculated from swell on section (C).

The pressure transients of this analysis for Cases A and B are plotted in Figures 3.6A-4 and 3.6A-7. It can be seen that the maximum pressure for Case A in the Reactor Building is 22.9 PSIA and for Case B in the Turbine Building is 37.1 PSIA. The peak temperature for Case A is 300.0°F and for Case B is 325.0°F.

The following essential equipment is located with the steam tunnels on Susquehanna SES:

Main Steam Isolation Valves (MSIV's) and Piping  
Feedwater Check Valves and Piping  
HPCI Piping  
RCIC Piping  
Leak Detection Instrumentation

Pipe breaks in the remaining portion of the main steam piping between the reactor building and the turbine building will not

impact essential equipment since breaks in these areas are completely vented to the turbine building.

Waterflooding in either the turbine building or reactor building portion of the tunnel will drain to the turbine building without damage to the structure.

All of the terms in the coefficients of Equation 3 can be evaluated except for the as yet undefined fluid density,  $\rho$ . As stated in the assumptions,  $\rho$  will be evaluated in such a way that, under steady state conditions, Equation (3) and the compressible flow equations of Appendix 6B will yield identical results for  $W(t)$ . Under steady state conditions  $W(t) = W(t-\Delta t)$  and Equation (3) reduces to:

$$\frac{K}{2gc\rho A_T^2} W^2 - \Delta\rho^* = 0 \quad (3a)$$

which yields

$$\rho = \frac{W^2 K}{2gc A_T^2 \Delta\rho^*} \quad (3b)$$

where the  $W^2$  can be obtained from the steady state compressible flow equations in Appendix 6B.

Under steady state conditions, the above value of  $\rho$  which is used in the momentum equation has a straightforward definition -- it is the density which has to be used in the steady state incompressible flow equation in order to reproduce correct steady state compressible flow rates. To achieve this, the density includes an implied correction factor which compensates for the energy required in compressible flow to accelerate the expanding fluid. Because of this correction,  $\rho$  will, in fact, be smaller than the downstream density,  $\rho_2$ , calculated by the isentropic expansion relationship. This can be shown by dividing Equation (3b) by

$$\rho_2 = \rho_1 \left( \frac{P_2}{P_1} \right)^{1/k} \quad (4)$$

#### 3.9.1.4.10 Fuel Assembly (Including Channels)

GE BWR fuel assembly design bases and analytical methods including those applicable to the faulted conditions, are contained in References 3.9-4 and 3.9-5. Reference 3.9-5 is written primarily for BWR/6 plants; however, the methodology is applicable to BWR/4 plants.

#### 3.9.1.4.11 Refueling Equipment

Refueling and servicing equipment that is important to safety is classified as essential equipment per the requirements of 10 CFR 50, Appendix A. This equipment and other equipment whose failure would degrade an essential component is defined in Section 9.1 and is classified as Seismic Category I. These components are subjected to an elastic dynamic finite element analysis to generate loadings. This analysis utilizes appropriate seismic floor response spectra and combines loads at frequencies up to 33 Hz for seismic and up to 60 Hz for the hydrodynamic loads in three directions. Imposed stresses are generated and combined for normal, upset, and faulted conditions. Stresses are compared, depending on the specific safety class of the equipment, to Industrial Codes, ASME, ANSI or Industrial Standards, AISC, allowables. The calculated stresses and allowable limits for the faulted loads for the fuel preparation machine are provided in Table 3.9-2(s). The refueling platform has also been examined; it can withstand the faulted loads due to seismic hydrodynamic events.

#### 3.9.1.4.12 Seismic Category I Items Other than NSSS

For statically applied loads, the stress allowables of Appendix F of the ASME Code, Section III, Winter 1972 were used for code components. For noncode components, allowables were based on tests or accepted standards consistent with those in Appendix F of the code.

Dynamic loads for components loaded in the elastic range were calculated using dynamic load factors, time history analysis, or any other method that assumes elastic behavior of the component.

The limits of the elastic range are defined in Paragraph 1323 of Appendix F for the code components. The local yielding due to stress concentration is assumed not to affect the validity of the assumptions of elastic behavior. The stress allowables of Appendix F for elastically analyzed components were used for code components. For noncode components, allowables were based on

tests or accepted material standards consistent with those in Appendix F for elastically analyzed components.

The methods used in evaluating the pipe break effects are discussed in Section 3.6.

### 3.9.2 DYNAMIC TESTING AND ANALYSIS

#### 3.9.2.1a Preoperational Vibration and Dynamic Effects Testing on NSSS Piping

The test program is divided into three phases: preoperational vibration, startup vibration, and operational transients.

##### 3.9.2.1a.1 Preoperational Vibration Testing

The purpose of the preoperational vibration test phase is to verify that operating vibrations in the recirculation piping are acceptable. This phase of the test uses visual observation.

##### 3.9.2.1a.2 Small Attached Piping

There is no small attached piping in the NSSS scope of supply.

##### 3.9.2.1a.3 Startup Vibration

The purpose of this phase of the program is to verify that the main steam and recirculation piping vibration are within acceptable limits. Because of limited access due to high radiation levels, no visual observation is made during this phase of the test. Remote measurements shall be made during the following steady state conditions:

- (a) Main steam flow at 25% of rated;
- (b) Main steam flow at 50% of rated;
- (c) Main steam flow at 75% of rated;
- (d) Main steam flow at 100% of rated.

3.9.7 REFERENCES

- 3.9-1 "Design and Performance of G.E. BWR Jet Pumps," General Electric Company, Atomic Power Equipment Department, APED-5460, July 1968.
- 3.9-2 Moen, H.H., "Testing of Improved Jet Pumps for the BWR/6 Nuclear System," General Electric Company, Atomic Power Equipment Department, NEDO-10602, June 1972.
- 3.9-3 General Electric Company, "Analytical Model for Loss-of-Coolant Analysis in Accordance with 10 CFR 50, Appendix K," Proprietary Document, General Electric Company, NEDE-20566.
- 3.9-4 "BWR Fuel Channel Mechanical Design and Deflection," NEDE-21354-P, September, 1976.
- 3.9-5 "BWR/6 Fuel Assembly Evaluation of Combined Safe Shutdown Earthquake (SSE) and Loss-of-Coolant Accident (LOCA) Loadings," NEDE-21175-P, November, 1976.
- 3.9-6 Seismic Analysis of Piping Systems, BP-TOP-1, Bechtel Power Corporation, San Francisco, California, Rev. 2, January, 1975.
- 3.9-7 "Assessment of Reactor Internals Vibration in BWR/4 and BWR/5 Plants", NEDE-24057-P (Class III) and NEDO-24057 (Class I), November, 1977.
- 3.9-8 "Functional Capability Criteria for Essential Mark II Piping", NEDO-21985, 78 NED174 (Class I), September, 1978.

TABLE 3.9-2 INDEXTABLE      CONTENTS

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3.9-2o	RESIDUAL HEAT REMOVAL (RHR) HEAT EXCHANGER



of this portion of the system is specifically exempted from the requirement for volumetric inspection by paragraph IWB-1220(a) of Section XI of the ASME Boiler and Pressure Vessel Code (Summer 1975 Addenda).

Regulatory Guide 1.97 - INSTRUMENTATION FOR LIGHT WATER  
COOLED NUCLEAR POWER PLANTS TO  
ASSESS PLANT CONDITIONS DURING  
AND FOLLOWING AN ACCIDENT  
(December 1975)-----

The accident monitoring instrumentation was designed prior to this Regulatory Guide being issued. The instrumentation for accident monitoring is not specifically identified on the control panels and has not been evaluated against Regulatory Guide 1.97, Revision 1.

Safety related display instrumentation and seismic qualification will be addressed following issue and project resolution of Reg. Guide 1.97 (Rev. 2).

Regulatory Guide 1.98 - ASSUMPTIONS USED FOR EVALUATING  
THE POTENTIAL RADIOLOGICAL  
CONSEQUENCES OF A RADIOACTIVE  
OFFGAS SYSTEM FAILURE IN A  
BOILING WATER REACTOR  
(March 1976)-----

Subject to the clarifications or exceptions indicated below, the assumptions of Regulatory Guide 1.98 are followed in the analyses of the offgas system failure in Subsection 15.7.1.

(1) Reference: Position C.4.a. Dose conversion factors are taken from the most recent data available. The average beta and gamma energies used are given in Section 15.8.

(2) Reference: Position C.4.a. External whole-body gamma doses and beta-skin doses are presented separately, inasmuch as the dose from beta radiation to the whole body is negligible. The total dose to the skin is the sum of the beta-skin dose and whole-body dose.

Regulatory Guide 1.99 - EFFECTS OF RESIDUAL ELEMENTS  
ON PREDICTED RADIATION DAMAGE  
TO REACTOR VESSEL MATERIALS  
(Revision 1, April 1977)-----

GE is responding to this guide under the Appendix G program Fracture Toughness Requirements.

Regulatory Guide 1.100 - SEISMIC QUALIFICATION OF  
ELECTRIC EQUIPMENT FOR  
NUCLEAR POWER PLANTS  
(March 1976)-----

The implementation paragraph of this regulatory guide states that the requirements of the position statements will only be applied to plants that received construction permits after November 16, 1976. The Construction Permit for Susquehanna SES was issued in November 1973 and therefore the guidelines of this regulatory guide have not been utilized in the design of this nuclear power station.

Seismic qualification of the safety related electric equipment (non-NSSS scope of supply) has been conducted in accordance with the IEEE Standard 344-1971. Section 3.10 describes the complete qualification methods and procedures that have been utilized.

The safety-related electric equipment (NSSS scope of supply) meets IEEE 323-1971 and IEEE 344-1971.

Regulatory Guide 1.101 - EMERGENCY PLANNING FOR  
NUCLEAR POWER PLANTS--

Withdrawn September 24, 1980.

Regulatory Guide 1.102 - FLOOD PROTECTION FOR NUCLEAR  
POWER PLANTS (Revision 1,  
September 1976)-----

The present design of the Susquehanna SES complies with the provisions of this regulatory guide.

Regulatory Guide 1.103 - POSTTENSIONED PRESTRESSING  
SYSTEMS FOR CONCRETE REACTOR  
VESSELS AND CONTAINMENTS  
(Revision 1, October 1976)---

Not Applicable.

Regulatory Guide 1.104 - OVERHEAD CRANE HANDLING SYSTEMS  
FOR NUCLEAR POWER PLANTS  
(February 1976)-----

Subject to the clarifications and exceptions indicated below, the safety related overhead crane handling systems of this station comply with the provisions of this regulatory guide.

(1) Reference: Position C.1.b(2). The nil-ductility transition temperature for the structural steel associated with the cranes was not determined as suggested by this position. Position

5.3.1.4.1.3 Regulatory Guide 1.43, (5/73) Control of  
Stainless Steel Weld Cladding of Low-Alloy  
Steel Components

Reactor pressure vessel specifications require that all low alloy steel be produced to fine grain practice. The requirements of this regulatory guide are not applicable to BWR vessels.

5.3.1.4.1.4 Regulatory Guide 1.44, (5/73) Control  
of the Use of Sensitized Stainless Steel

Controls to avoid severe sensitization are discussed in Subsection 5.2.3.4.1.1.

5.3.1.4.1.5 Regulatory Guide 1.50 (5/73), Control of Preheat  
Temperature for Welding Low-Alloy Steel

Preheat controls are discussed in Subsection 5.2.3.3.2.1.

5.3.1.4.1.6 Regulatory Guide 1.71, (12/73) Welder  
Qualification for Areas of Limited Accessibility

Qualification for areas of limited accessibility is discussed in Subsection 5.2.3.3.2.3.

5.3.1.4.1.7 Regulatory Guide 1.99, (Rev. 1) Effects of Residual  
Elements on Predicted Radiation Damage to  
Reactor Pressure Vessel Materials

Predictions for changes in transition temperature and upper shelf energy were made in accordance with the requirements of Regulatory Guide 1.99.

### 5.3.1.5 Fracture Toughness

#### 5.3.1.5.1 Compliance with 10CFR50 Appendix G

A major condition necessary for full compliance to Appendix G is satisfaction of the requirements of the Summer 1972 Addenda to Section III. This is not possible with components which were purchased to earlier Code requirements. For the extent of the compliance, see Tables 5.3-1a and 5.3-2a.

Ferritic material complying with 10 CFR 50, Appendix G, must have both drop weight tests and Charpy V-notch (CVN) tests with the CVN specimens oriented transverse to the principal material working direction to establish the  $RT_{NDT}$ . The CVN tests must be evaluated against both an absorbed energy and lateral expansion criteria. The maximum acceptable  $RT_{NDT}$  must be determined in accordance with the analytical procedures of ASME Code Section III, Appendix G. Appendix G of 10 CFR 50 requires a minimum of 75 ft-lb upper shelf CVN energy for beltline material. It also requires at least 45 ft-lb CVN energy and 25 mils lateral expansion for bolting material at the lower of the preload or lowest service temperature.

By comparison, material for the Susquehanna SES reactor vessels was qualified by either drop weight tests or longitudinally oriented CVN tests (both not required), confirming that the material nil-ductility transition temperature (NDTT) is at least 60°F below the lowest service temperature. When the CVN test was applied, a 30 ft-lb energy level was used in defining the NDTT. There was no upper shelf CVN energy requirement on the beltline material. The bolting material was qualified to a 30 ft-lb energy requirement at 60°F below the minimum preload temperature.

From the previous comparison it can be seen that the fracture toughness testing performed on the SSES reactor vessel material cannot be shown to comply with 10 CFR 50, Appendix G. However, to determine operating limits in accordance with 10 CFR 50, Appendix G, estimates of the beltline material  $RT_{NDT}$  and the highest  $RT_{NDT}$  of all other material were made, as explained in Subsection 5.3.1.5.1.2. The method for developing these operating limits is also described therein.

On the basis of the last paragraph on page 19013 of the July 17, 1973, Federal Register, the following is considered an appropriate method of compliance.

### 5.3.1.5.1.1 Intent of Proposed Approach

The intent of the proposed special method of compliance with Appendix G for this vessel is to provide operating limitations on pressure and temperature based on fracture toughness. These operating limits assure that a margin of safety against a nonductile failure of this vessel is nearly the same as that for a vessel built to the Summer 1972 Addenda.

The specific temperature limits for operation when the core is critical are based on a proposed modification to 10 CFR 50, Appendix G, Paragraph IV, A.2.C. The proposed modification and the justification for it are given in GE Licensing Topical Report, NEDO-21778-A.

### 5.3.1.5.1.2 Operating Limits Based on Fracture Toughness

Operating limits which define minimum reactor vessel metal temperatures vs reactor pressure during normal heatup and cooldown and, during in-service hydrostatic testing, were established using the methods of Appendix G of Section III of the ASME Boiler and Pressure Vessel Code, 1971 Edition, including the summer 1972 Addenda. The results are shown in Figure 5.3-4a for Unit 1 and 5.3-4b for Unit 2.

All the vessel shell and head areas remote from discontinuities plus the feedwater nozzles were evaluated, and the operating limit curves are based on the limiting location. The boltup limits for the flange and adjacent shell region are based on a minimum metal temperature of  $RT_{NDT} + 60^{\circ}$ . The maximum through-wall temperature gradient from continuous heating or cooling at  $100^{\circ}\text{F}$  per hour was considered. The safety factors applied were as specified in ASME Code, Appendix G, and GE Licensing Topical Report, NEDO-21778-A.

For the purpose of setting these operating limits, the reference temperature,  $RT_{NDT}$ , is determined from the toughness test data taken in accordance with requirements of the Code to which this vessel is designed and manufactured. This toughness test data, Charpy V-notch (CVN) and/or drop-weight nil-ductility transition temperature (NDT) is analyzed to permit compliance with the intent of 10 CFR 50, Appendix G. Because all toughness testing needed for strict compliance with Appendix G was not required at the time of vessel procurement, some toughness results are not available. For example, longitudinal CVN's, instead of transverse, were tested, usually at a single test temperature of  $+10^{\circ}\text{F}$  or  $+40^{\circ}\text{F}$ , for absorbed energy. Also, at the time either CVN or NDT testing was permitted; therefore, in many cases both

tests were not performed as is currently required. To substitute for this absence of certain data, toughness property correlations were derived for the vessel materials in order to operate upon the available data to give a conservative estimate of  $RT_{NDT}$ , compliant with the intent of Appendix G criteria.

These toughness correlations vary, depending upon the specific material analyzed, and were derived from the results of WRC Bulletin 217, "Properties of Heavy Section Nuclear Reactor Steels", and from toughness data from the Susquehanna SES vessels and other reactors. In the case of vessel plate material (SA-533 Grade B, Class 1), the predicted limiting toughness property is either NDT or transverse CVN 50 ft-lb temperature minus 60°F. CVN and NDT are available for all the beltline plates. Where NDT results are missing, NDT is estimated as the longitudinal CVN 35 ft-lb transition temperature. The transverse CVN 50 ft-lb transition temperature is estimated from longitudinal CVN data in the following manner. The lowest longitudinal CVN ft-lb value is adjusted to derive a longitudinal CVN 50 ft-lb transition temperature by adding 2°F per ft-lb to the test temperature. If the actual data equal or exceed 50 ft-lb, the test temperature is derived by interpolation. Once the longitudinal 50 ft-lb temperature is derived, an additional 30°F is added to account for orientation effects and to estimate the transverse CVN 50 ft-lb temperature minus 60°F, estimated in the preceding manner.

For forgings (SA-508 Class 2), the predicted limiting property is the same as for vessel plates. CVN and NDT values are available for the vessel flange, closure head flange, and feedwater nozzle materials for Susquehanna SES.  $RT_{NDT}$  is estimated in the same way as for vessel plates.

For the vessel weld metal, the predicted limiting property is the CVN 50 ft-lb transition temperature minus 60°F, as the NDT values are -50°F or lower for these materials. This temperature is derived in the same way as for the vessel plate material, except the 30°F addition for orientation effects is omitted since there is no principal working direction. When NDT values are available, they are also considered and the  $RT_{NDT}$  is taken as the higher of NDT or the 50 ft-lb temperature minus 60°F. When NDT is not available, the  $RT_{NDT}$  shall not be less than -50°F, since lower values are not supported by the correlation data.

For vessel weld heat affected zone (HAZ) material, the  $RT_{NDT}$  is assumed the same as for the base material as ASME Code weld procedure qualification test requirements, and post weld heat treatment indicates this assumption is valid.

Closure bolting material (SA-540 Grade B24) toughness test requirements for Units 1 and 2 were for 30 ft-lb at 60°F below the bolt-up temperature. Current Code requirements are for 45

ft-lb and 25 mils lateral expansion (MLE) at the preload or lowest service temperature, including bolt-up. Therefore, since CVN values as low as 40 ft-lb (with 25 mils lateral expansion) exist at the 10°F test temperature for Unit 1 closure bolts, 60°F is added to the test temperature in order to derive the bolt-up temperature of 70°F. All Unit 2 closure stud materials meet current requirements at 10°F.

Using the above general approach, an initial RT<sub>NDT</sub> of +18°F was established for the core beltline region for Unit 1 and +30°F for Unit 2.

The effect of the main closure discontinuity was considered by adding 60°F to the RT<sub>NDT</sub> to establish the minimum temperature for boltup and pressurization. The minimum bolt-up temperature of +70°F for Units 1 and 2, which is shown on Figures 5-3.4a and 5.3-4b, is based on an initial RT<sub>NDT</sub> of +10°F for the closure flange forgings.

The effect of the feedwater nozzle discontinuities was considered by adjusting the results of a BWR/6 reactor discontinuity analysis to the reactor. The adjustment was made by increasing the minimum temperatures required by the difference between the Susuehanna SES and BWR/6 feedwater nozzle forging RT<sub>NDT</sub>'s. The feedwater nozzle adjustment was based on an RT<sub>NDT</sub> of -16°F for Unit 1 and an RT<sub>NDT</sub> of -10°F for Unit 2.

The reactor vessel closure studs for Unit 1 have a minimum Charpy impact energy of 40 ft-lbs and a 25-mil lateral expansion at 10°F. The lowest service temperature for the closure studs is 70°F for Unit 1. For Unit 2, the closure studs have a minimum Charpy impact energy of 48 ft-lb and a 27-mil lateral expansion at 10°F; therefore, the lowest service temperature for the Unit 2 closure studs is +10°F.

#### 5.3.1.5.1.3 Operating Limits During Heatup, Cooldown and Core Operation

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The fracture toughness analysis was done for the normal heatup or cooldown rate of 100°F/hour. The temperature gradients and thermal stress effects corresponding to this rate were included. The results of the analyses are a set of operating limits for non-nuclear heatup or cooldown shown as curves labeled B on Figures 5.3-4a and 5.3-4b. Curves labeled C on these figures apply whenever the core is critical. The basis for the C Curves is described in GE BWR Licensing Topical Report NEDO-21778-A.

#### 5.3.1.5.1.4 Temperature Limits for Preoperational System Hydrostatic Tests and ISI Hydrostatic or Leak Pressure Tests

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Based on 10 CFR 50, Appendix G, IV, A.2.d, which allows a reduced safety factor for tests prior to fuel loading, the preoperational system hydrostatic test at 1563 psig may be performed at a minimum temperature of 117°F for Unit 1 and 129°F for Unit 2 which is established by the intermediate shell plate RT<sub>NDT</sub> of 20°F for Unit 1 and the core beltline plate RT<sub>NDT</sub> of 30°F for Unit 2.

The fracture toughness analysis for in-service inspection or leak pressure tests resulted in the curves labeled A shown in Figures 5.3-4a and 5.3-4b. The curves labeled "core beltline" are based on an initial RT<sub>NDT</sub> of +18°F for Unit 1 and +30°F for Unit 2. The predicted shift in the RT<sub>NDT</sub> from Figure 5.3-4c (based on the neutron fluence at 1/4 of the vessel wall thickness) must be added to the beltline curve to account for the effect of fast neutrons.

#### 5.3.1.5.1.5 Temperature Limits for Boltup

A minimum temperature of 70° for Unit 1 and of 10° for Unit 2 is required for closure studs. A sufficient number of studs may be tensioned at 70°F to seal the closure flange O-rings for the purpose of raising reactor water level above the closure flanges in order to assist in warming them. The flanges and adjacent shell are required to be warmed to a minimum temperature of 70°F before they are stressed by the full intended bolt preload. The fully preloaded bolt-up limits are shown on Figure 5.3-4a for Unit 1 and Figure 5.3-4b for Unit 2.

#### 5.3.1.5.1.6 Reactor Vessel Annealing

In-place annealing of the reactor vessel because of radiation embrittlement is unnecessary because the predicted end of life value of adjusted reference temperature will not exceed 200°F (see 10 CFR 50, Appendix G, Paragraph IV.C).



TABLE 5.3-2a

APPENDIX G MATRIX FOR SUSQUEHANNA SES UNIT 2

<u>Appendix G</u> <u>Par. No.</u>	<u>Topic</u>	<u>Comply</u> <u>Yes/No.</u> <u>Or N.A.</u>	<u>Alternate Actions</u> <u>Or Comments</u>
I, II	Introduction; Definitions	--	
III.A	Compliance With ASME Code, Section NB-2300	Yes	See Subsection 5.3.1.5.1.2 for discussion.
III.B.1	Location & Orientation of Impact Test Spec	Yes	See III.A, above.
III.B.2	Materials Used to Prepare Test Specimens	No	Compliance except for CVN orientation and CVN upper shelf.
III.B.3	Calibration of Temp. Inst. and Charpy Test Machines	No.	Paragraph NB-2360 of the ASME B&PV code, Section IV, was not in existence at the time of purchase of the Susquehanna SES Unit 2 reactor pressure vessel. However, the requirements of the 1971 edition of the ASME B&PV Section III Code, Summer 1971 addenda, were met. For the discussions of the GE interpretations of compliance and NRC acceptance see References 1 and 2. The temperature instruments and Charpy Test Machines cali- bration data are retained until the next recalibration. This is in accordance with Reg. Guide 1.88 Rev. 2, GE Alternative Position 1.88, and ANSI N45.2.9, 1974. Therefore, the instrument calibration data for Susquehanna SES Unit 2 would not be currently available.
III.B.4	Qualification of Testing Personnel	No	No written procedures were in existence as required by the Regulation; however, the individuals were qualified by on-the-job training and past experience. For the discussion of the GE interpretation of compliance and NRC acceptance see References 1 and 2.
III.B.5	Test Results Recording and Certification	Yes	See References 1 and 2.
III.C.1	Test Conditions	No	See III.A, III.B.2, above.
III.C.2	Materials Used to Prepare Test Specimens for Reactor Vessel Beltline	Yes	Compliance on base metal and weld metal tests. Test weld not made on same heat of base plate, necessarily.
IV.A.1	Acceptance Standard of Materials	--	--
IV.A.2.a	Calculated Stress Intensity Factor	Yes	
IV.A.2.b	Requirements for Nozzles, Flanges and Shell Region Near Geometric Discontinuities	No.	Plus 60°F was added to the RT <sub>NDT</sub> for the reactor vessel flanges. For feedwater <sub>E</sub> nozzles the results of the BWR/6 analysis were adjusted to Susquehanna Unit 2 RT <sub>NDT</sub> conditions.

TABLE 5.3-2a (continued)

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Appendix G Par. No.	Topic	Comply Yes/No Or N/A.	Alternate Actions ---Or Comments---
IV.A.2.c	RPV Metal Temperature Requirement When Core is Critical	No	Regulation change in process (See LTR NEDO-21778-A).
IV.A.2.d	Minimum Permissible Temp. During Hydro Test	Yes	
IV.A.3	Materials for Piping, Pumps and Valves	No	Main steamline piping is in compliance. See Subsection 5.2.3.3.1 for discussions on pumps and valves.
IV.A.4	Materials for Bolting and Other Fasteners	Yes	Current toughness requirements for closure head studs are met at 10°F.
IV.B	Minimum Upper Shelf Energy For RPV Beltline	No	No upper shelf tests run. However, recommend acceptance based upon lowest longitudinal CVN's for plates at +10°F of 45 ft-lb (50% shear) for heat C2421-3 (0.10% Cu), 50 ft-lb (50% shear) for heat C2929-1 (0.13% Cu), and 39 ft-lb (40% shear) for heat C2433-2 (0.10% Cu). Lowest CVN's for welds are 22, 30, 31, 43, 55 ft-lb (no % shear records) at -20°F with 0.06% Cu. The scatter in energy data at -20°F indicates transition behavior and the probability that upper shelf is in excess of 50 ft-lb (for 100% shear). End-of-life upper shelf values (100% shear) are predicted to be in excess of 50 ft-lb, based upon preceding data and Regulatory Guide 1.99.
IV.C	Requirement for Annealing When RT 200°F	N/A	
V.A	Requirements for Material Surveillance Program	See App. H	
V.B	Conditions for Continued Operation	Yes	See Sections 5.3.1.5.1.1, 5.3.1.5.1.2, 5.3.1.5.1.3, 5.3.1.5.1.4, 5.3.1.5.1.6, 5.3.1.6 and Table 5.3-2b
V.C.	Alternative If V.B Cannot Be Satisfied	--	--
V.D.	Requirement For RPV Thermal Annealing If V.C Cannot Be Met	N/A	
V.E	Reporting Requirement For V.C and V.D	N/A	

References

1. Letter MPN-414-77, G. G. Sherwood (GE) to Edson G. Case (NRC) dated October 17, 1977.

TABLE 5.3-2a (continued)

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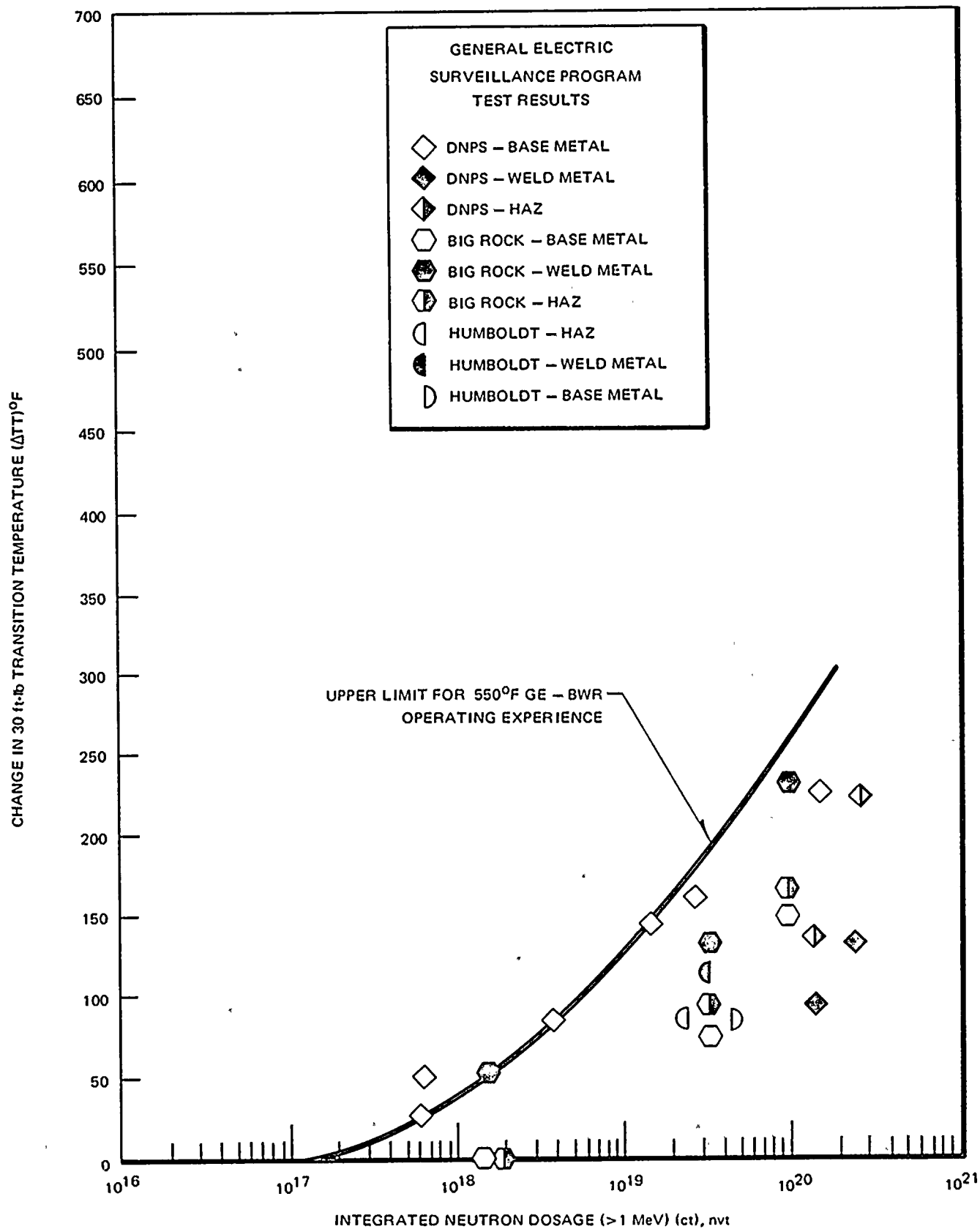
Appendix G  
Par. No.

Topic

Comply  
Yes/No  
Or N.A.

Alternate Actions  
Or Comments

2. Letter, Robert B. Minogue (NRC) to G. G. Sherwood (GE)  
dated February 14, 1978.



SUSQUEHANNA STEAM ELECTRIC STATION  
UNITS 1 AND 2  
FINAL SAFETY ANALYSIS REPORT

CHANGE IN CHARPY V TRANSITION  
TEMPERATURE VERSUS NEUTRON  
EXPOSURE

FIGURE 5.3-5



instrumentation and control systems and no discussion is provided.

- b) Non-NSSS - Refer to Subsection 3.11.2b.2 and Section 3.13.

7.1.2.6.9 Conformance to Regulatory Guide 1.47 (5/73)

- a) NSSS - The system of bypass indication is designed to satisfy the requirement of IEEE 279-1971 paragraph 4.13 and Regulatory Guide 1.47 and is discussed for each safety-related system under Sections 7.2, 7.3, 7.4, and 7.6. The design of the bypass indication system allows testing during normal operation and is used to supplement administrative procedures by providing indications of safety systems status.

The bypass indication system is designed and installed in a manner which precludes the possibility of adverse affects on the plant safety system. The bypass indication system is electrically isolated from the protection circuits such that the failure or bypass of a protective function is not a credible consequence of failures in the bypass indication system and the bypass indication system cannot reduce the independence between redundant safety systems.

- b) Non-NSSS - Refer to individual systems in Section 7.3 and discussion in Section 7.5

7.1.2.6.10 Conformance to Regulatory Guide 1.53 (6/73)

- a) NSSS - The safety-related system designs conform to the single failure criterion. The analysis portions of Sections 7.2, 7.3, 7.4 and 7.6 provide further discussion.
- b) Non-NSSS Refer to Section 3.13

7.1.2.6.11 Conformance to Regulatory Guide 1.62 (10/73)

- a) NSSS - Manual initiation of the protective action is provided at the system level in the Reactor Protection System, (primary) Containment and Reactor Vessel Isolation Control System and Emergency Core Cooling

Systems. The analysis portions of Sections 7.2 and 7.3 provide further discussion.

- b) Non-NSSS - Refer to Section 3.13.

7.1.2.6.12\_\_Conformance to Regulatory Guide 1.63 (10/73)

- a.) NSSS - Regulatory Guide 1.63 applies to electrical penetration assemblies which are not part of NSSS scope.
- b.) Non-NSSS - Refer to Section 3.13.

7.1.2.6.13\_\_Conformance to Regulatory Guide 1.68 (11/73)

Refer to Section 3.13.

7.1.2.6.14\_\_Conformance to Regulatory Guide 1.70 (Rev. 2)

The format and content of Chapter 7 conform to the requirements of Regulatory Guide 1.70.

7.1.2.6.15\_\_Conformance to Regulatory Guide 1.73 (1/74)

Refer to Section 3.13.

7.1.2.6.16\_\_Conformance to Regulatory Guide 1.75 (1/75)

- a) NSSS Regulatory Guide 1.75 is not applicable to Susquehanna SES; however, degree of compliance to separation criteria of IEEE 384 is discussed in Subsection 7.1.2.5.8.
- b) Non-NSSS - Refer to Section 3.13 and Subsection 8.1.6.1, Paragraph n.

7.1.2.6.17\_\_Conformance to Regulatory Guide 1.80 (6/74)

- a) NSSS - Regulatory Guide 1.80 applies to the testing of instrument air systems which are not part of the NSSS scope.

- b) Non-NSSS - Refer to Section 3.13.

#### 7.1.2.6.18 Conformance to Regulatory Guide 1.89 (11/74)

- a) NSSS - See the Susquehanna SES Environmental Equipment Qualification Program.
- b) Non-NSSS - Refer to Section 3.13.

#### 7.1.2.6.19 Conformance to Regulatory Guide 1.96 (5/75)

Main Steamline Isolation Valve Leakage Control System is designed to the requirements of Regulatory Guide 1.96. Further discussion is provided in Subsection 7.3.2a.3.

#### 7.1.2.7 Technical Design Bases

The technical design bases for RPS are in Subsection 7.2.1, for engineered safety features in Subsection 7.3.1, for systems required for safe shutdown in Subsection 7.4.1, and for other systems required for safety in Subsection 7.6.1.

#### 7.1.2.8 Safety System Settings

The safety system setpoints are listed in the Technical Specifications. The settings are determined based on operating experience and conservative analyses. The settings are high enough to preclude inadvertent initiation of the safety action, but low enough to assure that significant margin is maintained between the actual setting and the limiting safety system settings. Instrument drift, setability and repeatability are considered in the setpoint determination (see Subsections 7.1.2a.4 and 7.1.2b.4). The margin between the limiting safety system settings and the actual safety limits include consideration of the maximum credible transient in the process being measured.

The periodic test frequency for each variable is determined from experimental data on setpoint drift and from quantitative reliability requirements for each system and its components.



equipped for automatic depressurization are identical. Ten additional safety/relief valves providing only the SRV function are discussed in Subsection 7.7.1.12.

#### 7.3.1.1a.1.4.2---Equipment Design

The control system consists of drywell pressure and reactor water level sensors arranged in trip systems that control two solenoid-operated pilot air valves (one for each ADS system) for each safety relief valve. Each of these two air valves controls pneumatic pressure for safety relief valves actuation. (A third solenoid-operated pilot air valve with each safety relief valve is used for the Relief Valve function. See Subsection 7.7.1.12 for details of Relief Valve control.) An accumulator is included with the control equipment to store pneumatic energy for safety/relief valve operation. The accumulator is sized to provide air for five actuations of the ADS piston type pneumatic actuator via the solenoid valves following failure of the pneumatic supply to the accumulator. Cables from the sensors lead to the control structure where the logic arrangements are formed in cabinets. The electrical control circuitry is powered by dc from the plant batteries. The power supplies for the redundant control circuits are selected and arranged to maintain tripping ability in the event of an electrical power circuit failure. Electrical elements in the control system energized to cause opening of the safety/relief valve.

#### 7.3.1.1a.1.4.3---Initiating Circuits

The pressure and level switches used to initiate one ADS logic are separated from those used to initiate the other logic on the same ADS valve. Reactor vessel low water level is detected by six switches that measure differential pressure. Primary containment high pressure is detected by four pressure switches, which are located outside the primary containment and inside the reactor building. The level instruments are piped individually so that an instrument pipeline break will not inadvertently initiate auto blowdown. The primary containment high pressure signals are arranged to seal into the control circuitry; they must be manually reset to clear.

A timer is used in each ADS logic. The time delay setting before actuation of the ADS is long enough that the HPCI system has time to operate, yet not so long that the LPCI and CS systems are unable to adequately cool the fuel if the HPCI system fails to start. An alarm in the main control room is annunciated when either of the timers is timing. Resetting the ADS initiating signals recycles the timers.

7.3.1.1a.1.4.4 Logic and Sequencing

Three initiation signals are used for the ADS; namely, reactor vessel low water level, drywell high pressure, and RHR and/or CS pumps running. All signals must be present to cause the safety/relief valves to open, as shown in Figure 7.3-5. Reactor vessel low water level indicates that the fuel is in danger of becoming uncovered. The second (lower) low water level initiates the ADS. Primary containment high pressure indicates a breach in the RCPB inside the drywell. A permissive signal indicating LPCI or CS pump discharge pressure is also required. Discharge pressure on any one of the RHR pumps or either pair of the CS pumps (A&C) or (B&D) is sufficient to give the permissive signal, which permits automatic depressurization when the LPCI and CS systems are operable.

After receipt of the initiation signals and after a delay provided by timers, each of the pilot gas solenoid valves is energized. This allows pneumatic pressure from the accumulator to act on the gas cylinder operator. The gas cylinder operator holds the relief valve open. Lights in the main control room indicate when the solenoid-operated pilot valves are energized to open a safety/relief valve.

Manual reset circuits are provided for the ADS initiation signals. By manually resetting the initiation signal the delay timers are recycled. The operator can use the reset push buttons to delay or prevent automatic opening of the relief valves if such delay or prevention is prudent.

Control switches are available in the main control room for each safety/relief valve associated with the ADS. The OPEN position is for manual safety/relief valve operation.

Two ADS logics trains are provided as shown in Figure 7.3-8. Division I sensors for low reactor water level and high drywell pressure initiate ADS A (logics A & C), and Division II sensors initiate ADS B (logics B & D). One of the two solenoid-operated pilot air valves associated with each safety relief valves is controlled by ADS A and the other is controlled by ADS B.

The reactor vessel low water level initiation setting for the ADS is selected to depressurize the reactor vessel in time to allow adequate cooling of the fuel by the LPCI system or CS system following a LOCA in which the HPCI system fails to perform its function adequately. The primary containment high pressure setting is selected as low as possible without inducing spurious initiation of the automatic depressurization system. This provides timely depressurization of the reactor vessel if the HPCI system fails to start, or fails after it successfully starts following a LOCA.

7.3.1.1b.8.1.5 Supporting Systems

The ESSW pumphouse HVAC system described in Subsection 9.4.8 is a supporting system to the emergency service water system.

7.3.1.1b.8.1.6 ESW Instrumentation Not Required for Safety

Non-safety related instrumentation in the control room includes:

- a) ESW pump A/C discharge header temperature (loop A)
- b) ESW pump B/D discharge header temperature (loop B)
- c) Diesel generator A cooler outlet temperature
- d) Diesel generator B cooler outlet temperature
- e) Diesel generator C cooler outlet temperature
- f) Diesel generator D cooler outlet temperature
- g) ESW loop A (B) flow (recording)

Refer to Section 7.5 for instrument ranges, accuracy, and panel location for the above mentioned instruments.

Control room annunciators are not required for safety, but alert the operator of abnormal process conditions. The following alarms are in the main control room:

- a) Spray pond low level
- b) ESSW structure flooded
- c) ESW loop low flow
- d) Diesel generator coolers high outlet temperature
- e) Diesel generator rooms flooded

7.3.1.1b.8.2 RHR Service Water System - Instrumentation and Controls

The description, the design basis and the safety evaluation of the RHR service water system are in Subsection 9.2.6.

## SSSES-PSAR

The controls and instrumentation for the RHR service water system are designed to provide adequate information to the control room operator for control and monitoring of the system during system operating modes. Capability for test and calibration is provided as described in Subsection 7.3.2b.2-4.10.

### 7.3.1.1b.8.2.1 Initiation Circuits

The RHR service water system can be manually initiated from either the main control room or the remote shutdown panel.

### 7.3.1.1b.8.2.2 Logic, Bypasses, Interlocks, and Sequencing

The RHR service water system control logics are designed using electromechanical relays and control switch signals to actuate the equipment.

#### 7.3.1.1b.8.2.2.1 Logic Power Source

The RHR service water system logics are powered from two independent divisionalized 125 V dc Class 1E power sources. Refer to Section 8.3 for description.

#### 7.3.1.1b.8.2.2.2 Pump Control Logic

For documentation of the logic, refer to electrical schematic diagram E-150 which was submitted under separate cover.

Each RHRSW pump can be started from the main control room, or one can be started from the unit remote shutdown panel (1B/2A) and the other (1A/2B) from the unit switchgear. In order to start any RHRSW pump the following conditions must be satisfied:

- a) Power supply bus voltage is available
- b) Control switch is turned to pump run position

Any of the following conditions trip the circuit breaker to the pump motor:

- a) Manual stop by operator in main control room or at the remote shutdown panel (or local circuit breaker control switch at the switchgear)

- e) RHR service water radiation monitoring (refer to Section 11.5)
- f) Spray pond temperature
- g) Computer inputs for process monitoring
- h) Annunciator system

All instrument data and ranges for the RHR service water system are listed in Section 7.5.

#### 7.3.1.1b.8.3 Containment Instrument Gas System Instrumentation and Control

The containment instrument gas system is described in Subsection 9.3.1.5 and gives the design basis, system operation, and safety evaluation.

The two redundant sets of high pressure nitrogen storage bottles are designed as an ESF auxiliary supporting system to provide the necessary compressed gas for the operation of the main steam relief valves for auto depressurization (ADS).

Containment isolation of the instrument gas system is described in Subsection 7.3.1.1b.1. Capability for testing is provided when testing containment isolation and further described in Subsection 7.3.2b.2-4.10.

##### 7.3.1.1b.8.3.1 Initiating Logic and Interlocks

A pressure sensing transmitter is located in piping headers A&B leading to the ADS relief valves.

A signal from an electronic switch automatically opens the isolation valve of the nitrogen storage bottles if the normal supply pressure is not available from the gas compressors. A signal from containment isolation also initiates the automatic opening of the nitrogen storage isolation valve.

The manual control of the outboard isolation valves allows the operator, after determining that adequate supply pressure is available from the compressors, to open the normal supply line to the ADS relief valves. This operation will isolate the instrument gas storage bottles. However, low instrument gas header pressure will automatically override this interlock to ensure the necessary gas supply.

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Refer to electrical schematic diagram E-172 which was submitted under separate cover.

The logic power supply for containment isolation valves is divisionalized from a 125 V dc Class 1E bus.

The instrument panel supply is provided by a 120 V ac Class 1E source to 120 V ac/24 V dc power supply.

### 7.3.1.1b.8.3.2 Bypasses, Interlocks and Sequencing

The system is not designed with bypass capability.

Sequencing is not applicable for this system. This system is not interlocked with other systems.

### 7.3.1.1b.8.3.3 Redundancy

Instrumentation and controls are provided on a one-to-one basis with the mechanical equipment.

### 7.3.1.1b.8.3.4 Containment Instrument Gas Instrumentation Not Required for Safety

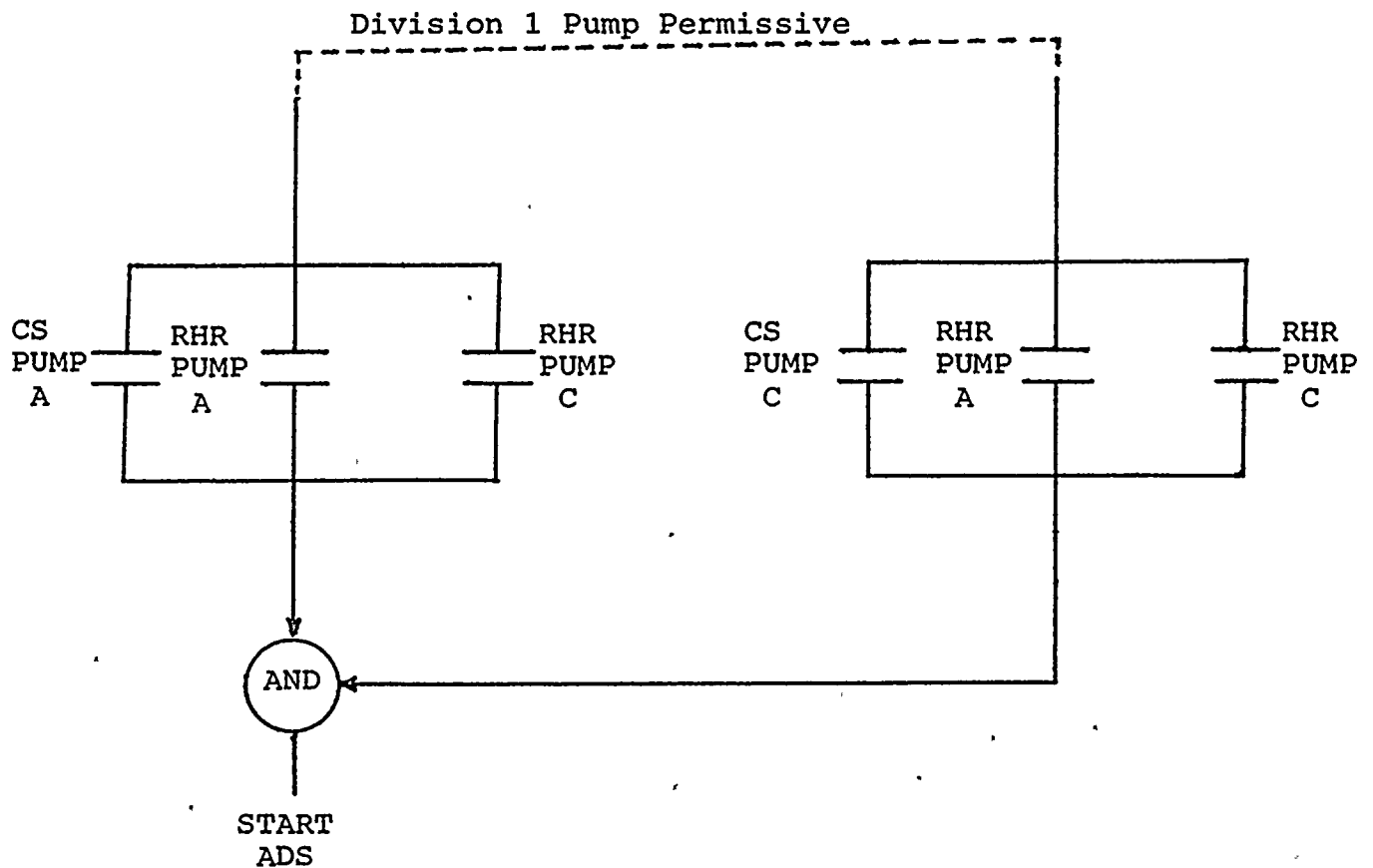
The instrumentation application discussed in Subsection 9.3.1.5.5 describes the monitoring instruments and controls for the gas compressors and its controls.

The monitoring instruments in the auxiliary support system are not safety-related. Each train of gas bottles has a low header pressure alarm in the main control room. The isolation valve position is indicated by status lights on the main control room panel. Refer to Table 7.5-7 for listing of instrumentation for the containment instrument gas system.

### 7.3.1.1b.8.4 Standby Power System

Descriptions of the standby power system and supporting system can be found in the following:

- a) Refer to Subsection 8.3.1 for description of the diesel generators. Refer to Section 7.6.1b.3 for NSSS to non-NSSS diesel initiation signal.



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(SHEET 2)

**FIGURE 7.3-5**

Indicating Lamps

- (1) Storage tank heaters A&B status

7.4.1.2.5.3 Set Points

The SLCS has set points for the various instruments as follows:

- (1) The injection valve position switches are adjusted to indicate the valve is fully open.
- (2) Loss of continuity activates the annunciator below the trickle current that is observed when both primers of an explosive valve are new.
- (3) The high and low standby liquid temperature switch is set to activate the annunciator at temperatures of 110° F and 70° F, respectively.
- (4) The high and low standby liquid storage tank level switch is set to activate the annunciator when the level is approximately 94% and 89% of the storage tank capacity respectively.
- (5) The thermostatic controller is set to turn on the operating heater when the standby liquid temperature drops to 75°F and to turn off the heater at 85°F.

7.4.1.3 RHRS/Reactor Shutdown Cooling Mode -  
-----Instrumentation and Controls-----

7.4.1.3.1 System Identification7.4.1.3.1.1 Function

The shutdown cooling mode of the RHR System (including the reactor vessel head spray) used during a normal reactor shutdown and cooldown is the non-safety portion of the RHRS. The shutdown cooling mode utilizes most of the safety classified portions of the RHRS.

The initial phase of a normal RCPB cooldown is accomplished by routing steam from the reactor vessel to the main condenser which serves as the heat sink.



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The Reactor Shutdown Cooling System consists of a set of pumps, valves, heat exchangers, and instrumentation designed to provide decay heat removal capability for the core. The system specifically accomplishes the following:

- (1) The reactor shutdown cooling system is capable of providing cooling for the reactor during shutdown operation after the vessel pressure is reduced to approximately 135 psia.
- (2) The system is capable of cooling the reactor water to a temperature at which reactor refueling and servicing can be accomplished.
- (3) The system is capable of diverting part of the shutdown flow to a nozzle in the reactor vessel head to condense the steam generated from the hot walls of the vessel while it is being flooded.

The system can accomplish its design objectives by a preferred means by directly extracting reactor vessel water from the vessel via the recirculation loop B and routing it to a heat exchanger and back to the vessel, or by an alternate means by indirectly extracting the water via relief valve discharge lines to the suppression pool and routing pool water to the heat exchanger and back to the vessel.

### 7.4.1.3.1.2 Classification

Electrical components for the Reactor Shutdown Cooling Mode of the Residual Heat Removal System are classified as Safety Class 2 and Seismic Category I.

### 7.4.1.3.2 Power Sources

This system utilizes standby power sources, since the RHRS has safety modes of operation (e.g., LPCI) connected to this equipment.

### 7.4.1.3.3 Equipment Design

#### 7.4.1.3.3.1 General

The reactor water is cooled by taking suction from one of the recirculation loops; the water is pumped through the system heat

7.5 SAFETY RELATED DISPLAY INSTRUMENTATION (SRDI)

Safety Related Display Instrumentation (SRDI) required for safe functioning of the plant during normal operating and accident conditions is incorporated in a control room complex named the Advanced Control Room (ACR). It is necessary to consider the ACR as a whole to verify conformance to the requirements.

The ACR is a complex of major components, provided with the NSSS, for monitoring and controlling two units and providing safety functions. The entire complex consists of the Power Generation Control Complex (PGCC) in the upper relay room at the 754 ft 0 in. level and the lower relay room at the 698 ft 0 in. level, the plant computer system at the 698 ft 0 in. level and the plant-operator interface at the 729 ft 0 in. level.

## a) PGCC

The PGCC provides support and interconnections to the systems panels of the upper and lower relay rooms and the computer room of the ACR complex. The plant-operator interface noted below is not mounted on PGCC, however, all other principles of the PGCC concept, eg, separation, are used.

## b) Plant-Operator Interface

Major components are in the main control room arranged as shown on Figure 7.5-1 and include the following:

Unit Operating Benchboard Panel (C651/H12-P680) - houses controls, hardwired displays, the control rod position display and process displays which are computer generated from the plant computer system described below and in Section 7.7. The combination of displays on this panel and panel (C652/H12-P678), Standby Information Panel, are arranged by system and are used for start up, normal operation, and shut down. See Section 7.7 for a description of the Display Control System (DCS).

Standby Information Panel (C652/H12-P678) - houses hardwired indicators and recorders required to start up, run, and shut down the plant. It is a hardwired backup to the DCS. See below and Section 7.7 for DCS description.

Reactor Core Cooling System Benchboard (C601/H12-P601) - houses hardwired indicators, recorders, manual controls, and annunciators for ESF systems including containment atmosphere systems.

Unit Services Benchboard (C668/H12-P870) - houses hardwired indicators, recorders, annunciators and controls for unit BOP system's functions which do not require the operator's immediate attention during normal operation of the power plant. Functions on this panel have been determined to be long time response functions.

Plant Operating (Common Plant) Benchboard (C653/H12-P853) - houses hardwired indicators, recorders, controls and annunciators for systems common to both units. Manual controls for the diesel generators are located here. It also houses two CRTs connected to the plant computer system.

Unit Monitoring Console (C684/C92-P628) - provides the unit operator with sit down surveillance of the unit operating benchboard and access to DCS and Performance Monitoring System CRT displays with the use of a selection keyboard.

Plant Monitoring Console (C683/C92-P627) - provides sit down surveillance of both units and keyboard access to computer functions of both units. There is also computer generated trend recording of variables from either unit.

Panels which support the primary plant-operator interface are mounted in back rows of the main control room and on PGCC floor modules on floors above and below the main control room.

The annunciator system is a hardwired system which provides the operator with the alarm information required for unit operation, startup, and shutdown. This system is independent of the plant computer system, is not part of the SRDI, and is not Class 1E.

#### c) Plant Computer System

The Plant Computer System is divided into the Display Control System (DCS) and the Performance Monitoring Systems (PMS). The DCS is the system primarily used for monitoring unit operation by generating graphic displays to optimize operator surveillance. The PMS is a supporting system capable of displays, NSSS and BOP calculations, historical recording, data logging and off-line capabilities. The PMS and DCS are not part of the SRDI and are not Class 1E.

The DCS makes use of redundant computers which are both updated with current information. Either computer may be automatically or manually switched into operation thus maximizing availability.

7.5.1b.7.1. System Description

The primary control method is administrative control which is exercised by the unit control room operator; however, these administrative controls are supplemented by an automated Bypass Indication System (BIS). Restricted access to various in-plant areas is also used to supplement the administrative control.

The BIS indicators annunciate on the Reactor Core Cooling System benchboard in the control room, automatically, at the system level, indicates the bypass or deliberately induced inoperability of a safety related system.

The BIS is provided with the capability for manual initiation of each system-level indicator. This manual-entry method is used to cover system components that have not been provided with automatic BIS input capability.

The Bypass Indication System for non-NSSS Systems consists of the following:

- a) Two indicator lamp boxes each consisting of 4x6 array of lights and located in the control room on the Reactor Core Cooling System benchboard. Each window, provided with dual lamps and an integral pushbutton for lamp test, will indicate a system-level bypass.
- b) Two annunciator windows, located above the lamp box assemblies, will alert the operator that a system-level bypass has occurred.
- c) The indication of the bypass status of components, systems, channels, and/or divisions is provided on a backrow panel in the main control room. This panel contains the hardware logic required to translate the combination of component bypasses that constitute system bypasses.

A manual control switch for each safety system enables the operator to indicate a system's inoperability whenever a component which is not included in the automatic indication system is deliberately bypassed.

The BIS and its logic can be tested by depressing test pushbuttons.

The following systems provide inputs to the Bypass Indication System:

- Emergency service water system
- Diesel generator control system

- Diesel generator output system
- Diesel generator auxiliary system
- Control room habitability system
- Standby gas treatment system
- Battery room exhaust system
- RHR service water system
- Remote shutdown panel
- Containment instrument gas system
- Containment hydrogen recombiner system
- Containment isolation system
- Drywell ventilation system
- Reactor building emergency switchgear and  
motor control center cooling

Table 7.5-8 identifies the system and components of the automatic Bypass Indication System.

#### 7.5.2a Analysis of NSSS Safety-Related Displays

##### 7.5.2a.1 General

The safety-related display instrumentation provides adequate information to allow the reactor operator to perform the necessary manual safety function.

All protective actions required under accident conditions for the NSSS equipment are automatic, redundant, and decisive such that immediate reactor operator information or intervention is unnecessary.

The ACR design improves the availability of the plant by providing the operator with more readily accessible information and control of the various plant operational parameters. This is accomplished by the logical organization of functional plant system indicators, displays, controls and a computer display system.

A complete description and analysis of design criteria applicable to the hard-wired indicators, displays and controls for the various safety-related systems are described elsewhere in Chapter 7 with the systems they serve. Redundancy and independence or diversity are provided in all of those information systems which are used as a basis for operator-controlled safeguards action.

A complete failure of the Display Control System which serves as an active part of the operator/plant interface does not degrade the quantity or quality of necessary information presented by hard-wired devices needed to determine the status or action of plant safety systems.

7.5.2h.5 Analysis of the Bypass Indication System

The Bypass Indication System (BIS) indicates on panel (C601/H12-P601) that any non-NSSS ESF or ESF supporting system is inoperable. That is indication of inoperability at a system level. Indication of component inoperability within the non-NSSS ESF systems is provided on panel C694. Both panels are located in the operator interface ring of panels.

Table 7.5-8 lists the systems and components included in the system.

Manual capability for testing operability of each indication is provided. The system design maintains the divisionalized structure of the ESF and signals to the BIS are mechanically and electrically isolated from the associated ESF system.

Regulatory Guide 1.47 and Branch Technical Position EICSB 21 are complied with in the design of BIS.

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Table 7.5-7

SAFETY RELATED DISPLAY INSTRUMENTATION  
CONTAINMENT INSTRUMENT GAS SYSTEM

Parameter Measured	No. of Channels	Range	Accuracy	Type of Readout	Location	Panel No.	Power IE Bus	RPS	ESF	AS	PPD	Remarks
Instrument Gas Pressure to Main Steam Relief Valve	1	0-180 psig	±2%	Ind	CR	C601	no			X		
Instrument Gas Supply Pressure	1	0-100 psig	±2%	Ind	CR	C601	no			X		
Instrument Gas Bottles Isol Vlv Status	2	---	---	LT	CR	C601	yes			X		*)
Instrument Gas Suction IB/OB Isol Vlv Status	2	---	---	LT	CR	C601	yes			X		*)
Instrument Gas Contain- ment IB/OB Isol Vlv Status	9	---	---	LT	CR	C601	yes			X		*)

Note: PAM = Post Accident Monitoring; RSP = Remote Shutdown Panel; RPS = Reactor Protection System;  
ESF = Engineered Safety Feature; AS = Auxiliary Support; PPD = Plant Process Display

pressure switches actuating on low pressure. Additionally, differential pressure of the common steamline (Figures 5.4-13, 6.3-1a and 6.3-1b) is monitored by differential pressure indicating switches to detect HPCI line break. Annunciation is provided in the main control room. These monitoring systems are described in Subsections 7.6.1a.4.3.9.3 and 7.6.1a.4.3.9.4.

#### 7.6.1a.4.3.6 Reactor Water Clean-Up System Leak Detection

See Subsection 7.3.1.1a.2.4.1.9.

#### 7.6.1a.4.3.7 Safety/Relief Valve Leak Detection

##### 7.6.1a.4.3.7.1 Subsystem Identification

Normally, the safety/relief valves are in the shut tight condition and are all at about the same temperature. Steam passage through the valve will elevate the sensed temperature at the exhaust, causing an "abnormal" temperature reading on the recorder. Switch contacts on the recorder, adjusted to actuate at a predetermined set point, close to complete an annunciator circuit. Safety valve operation usually occurs only after relief valve actuation. Leakage from a valve is usually characterized by a temperature increase on a single input. As discussed in Subsection 18.1.24.3, each of the sixteen safety/relief valves are provided with a safety grade acoustic monitoring system to detect flow through the valve.

##### 7.6.1a.4.3.7.2 Safety/Relief Valve Discharge Line Temperature Monitoring

##### 7.6.1a.4.3.7.2.1 Description

A temperature element (sensor) is placed in the discharge pipe of each of the sixteen (16) safety/relief valves for remote indication of leakage. The outputs of the temperature elements are sequentially sampled and recorded by one common temperature recorder. Each temperature element is compared against a set point valve which if exceeded will be annunciated by one common annunciator. Thus, when the annunciator sounds, it is possible to ascertain which specific valve(s) may be leaking by observing the recorder print-out.



7.6.1a.4.3.7.2.2 Logic and Sequencing

No action is initiated by the safety/relief valve temperature monitoring circuit.

7.6.1a.4.3.7.2.3 Bypasses and Interlocks

There are no bypasses or interlocks associated with this subsystem.

7.6.1a.4.3.7.2.4 Redundancy and Diversity

No redundancy or diversity is required for this system.

7.6.1a.4.3.8 Reactor Vessel Head Leak Detection

7.6.1a.4.3.8.1 Subsystem Identification

A pressure between the inner and outer head seal ring will be sensed by a pressure switch. If the inner seal leaks, the pressure indicating switch will monitor the pressure.

The plant will continue to operate with the outer seal as a backup and the inner seal can be repaired at the next outage when the head is removed. If both the inner and outer head seals leak, the leak will be detected by an increase in drywell temperature and pressure.

7.6.1a.4.3.8.2 Head Seal Integrity Pressure Monitoring

7.6.1a.4.3.8.2.1 Circuit Description

A pressure indicating switch will monitor the pressure between the inner and outer head seals.

Each system provides a continuous, isolated signal to the remote shutdown panel (RSP) which does not require any transfer action in the Control Room. Two indicators are provided at each RSP and are divisionalized.

The primary Containment and suppression pool temperature elements and temperature indicators will be qualified to operate following a DBA.

#### 7.6.1b.1.2.3 Power Sources

The safety related instrumentation is powered from divisionalized power sources. Division I Class IE bus (120 V ac) powers Loop A, Division II Class IE bus (120 V ac) powers Loop B.

#### 7.6.1b.1.2.4 Equipment Design

##### 7.6.1b.1.2.4.1 Equipment Design-Containment Temperature

Four dual element RTDs per redundant system are located in the primary containment to sense the temperature at the following elevations:

- a) Reactor pressure vessel head
- b) Upper platform
- c) Lower platform
- d) Drywell (below reactor pressure vessel).

Two redundant temperature elements monitor the suppression chamber air space temperature.

The selected location for the temperature sensors helps the operator to define the area of the heat source within the primary containment.

The signal from the RTD elements is amplified by electronic temperature transmitters to drive meters, recorder channels, and alarm switches in the control room.

Two redundant indicators, for the primary containment are located in the main control room. The initiating contacts for the high speed start of the drywell cooling fans (refer to system description in Section 9.4) are derived from the two redundant

temperature sensing elements located in the service area of the fans. If high temperature is detected the electronic switches will initiate the low speed operation of the drywell cooling fans.

Electronic signal converters with full electrical input-output isolation are placed between safety related instrumentation and the input channels to the recorders.

Two redundant multipoint recorders for the primary containment pool temperature monitoring system provide a permanent history of all RTD measurements to the operator in the control room.

Each temperature sensing circuit is equipped with alarm switches and initiate one control room alarm per redundant channel.

One temperature indicator for the primary containment is located on the remote shutdown panel. Refer to Subsection 7.4.1.4 for system description. Instrument ranges are defined in Section 7.5.

#### 7.6.1b.1.2.4.2 Equipment Design-Suppression Pool Temperature

The suppression pool temperature is monitored by two redundant systems, each of which performs as described below.

Eight RTD's per redundant system are located in the suppression pool approximately six inches below the minimum pool water level. These sensors are located around the pool in order to provide a good spatial distribution of pool temperature. Refer to Table 7.6-9 for the exact location of these sensors.

The signals from the sensors are processed by an electronic unit located on a main control room back panel. This electronic unit converts the RTD signals into degrees Fahrenheit and computes the average of the eight temperatures. If one of the RTD's fails, an error alarm is generated, and the failed RTD may be removed from the calculation of the average by operator action. The average value is displayed by digital indicators located both on the electronic unit, the main control board, and a vertical meter located on the RSP. A keyboard allows the operator to display any individual temperature input.

A high temperature alarm is generated by comparing the average temperature to several internally stored setpoints. The alarm condition is displayed by status lights located both on the electronic unit and on the main control board. Electrically isolated outputs interface with an annunciator located on the main control board.

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TABLE 7.6-5

APRM\_SYSTEM\_TRIPS<sup>(1)</sup>

TRIP_FUNCTION	TRIP_POINT_RANGE	ACTION
APRM downscale	2% to full scale	Rod block, annunciator white light display
APRM upscale (high)	Setpoint varied with flow, slope adjustable, intercepts separately adjustable	Rod block, annunciator amber light display
✓ APRM upscale (high-high)	2% to full scale	Scram, annunciator, red light display
APRM inoperative	Calibrate switch or too few inputs	Scram, rod block, annunciator, red light display
APRM Bypass	Manual Switch	White light

-----  
(1) See plant Technical Specifications for setpoints.

evaluation of core thermal limits with subsequent modification to the LPRM ATS based on the new reactor operating level. Execution of these rapid computations does not exceed 3 minutes and yields ATS values that are conservative with respect to the more accurate periodic power distribution calculation, which requires approximately 10 minutes to execute. This range of surveillance and the rapidity with which the computer responds to reactor changes permit more rapid power maneuvering with the assurance that thermal operating limits will not be exceeded.

Flux level and position data from the traversing in-core probe (TIP) equipment are read into the computer. The computer evaluates the data and determines gain adjustment factors by which the LPRM amplifier gains can be altered to compensate for exposure-induced sensitivity loss. The LPRM amplifier gains are not to be physically altered except immediately prior to a whole core calibration using the TIP system. The gain adjustment factor computations help to indicate to the operator when such a calibration procedure is necessary.

Using the power distribution data, a distribution of fuel exposure increments from the time of previous power distribution calculation is determined and is used to update the distribution of cumulative fuel exposure. Each fuel bundle is identified by batch and location, and its exposure is stored for each of the axial segments used in the power distribution calculation. These data are printed out on operator demand.

Exposure increments are determined periodically for each quarter-length section of each control rod. The corresponding cumulative exposure totals are periodically updated and printed out on operator demand.

The exposure increment of each local power range monitor is determined periodically and is used to update both the cumulative ion chamber exposures and the correction factors for exposure-dependent LPRM sensitivity loss. These data are printed out on operator demand.

The NSSS computer system provides on-line capability to determine monthly and on-demand isotopic composition for each one-quarter-length section of each fuel bundle in the core. This evaluation consists of computing the weight of one neptunium, three uranium, and five plutonium isotopes as well as the total uranium and total plutonium content. The isotopic composition is calculated for each one-quarter length of each fuel bundle and summed accordingly by bundles and batches. The method of analysis consists of relating the computed fuel exposure and average void fraction for the fuel to computer stored isotopic characteristics applicable to the specific fuel type.

### 7.7.1.7.5.2 -- Reactor Operator Information

Major components are arranged as shown in Figure 7.7-13. Functional description and operational arrangement is as follows:

Unit Operating Benchboard (H12-P680) (Panel C651) - houses controls, annunciators and displays, including the control rod position display. The primary process displays are computer generated CRT formats from the DCS and PMS computers. All variables in the DCS displays that are required for unit operation, startup and shutdown are displayed on hardwired indicators on either the Unit Operating Benchboard or the Standby Information Panel. These variables in both CRT and hardwired displays generally originate from the same source.

Standby Information Panel (H12-P678) (C652) - houses hardwired indicators and recorders required to startup, run, and shutdown the plant without the use of the Display Control System. It is a hardwired backup to the DCS.

Reactor Core Cooling System BB (H12-P601) (C601) - houses hardwired indicators, recorders, annunciators and controls for unit BOP system's functions which do not require the operator's immediate attention during normal operation of the power plant. Functions on this panel have been determined to be long time response functions.

Common Plant Benchboard (H12-P853) (C653) - houses hardwired indicators, recorders annunciators and controls for systems which are common to Units 1 and 2. It also houses two CRT's connected to the Performance Monitoring System (PMS).

Unit Monitoring Console (C92-P628) (C684) - provides the unit operator sit down surveillance of the Unit Operating Benchboard and access to DCS and PMS CRT displays with the use of a selection keyboard.

Plant Monitoring Console (C92-P626) (C683) - provides sit down surveillance of both units and keyboard access to computer functions of both units. There is also computer generated trend recording of variables from either unit.

The annunciator system is a hardwired system which provides the operator with the alarm information required for unit operation, startup, and shutdown. This system is independent of the Plant Computer System although the computer system does provide redundant and auxiliary alarm information as AID's through the DCS and the alarm status summary CRT display from the PMS.

The Display Control System collects unit process information and presents it on nine of the ten video displays (CRTs) on the Unit

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- a. Any average power range monitor (APRM) upscale rod block alarm. The purpose of this rod block function is to avoid conditions that would require reactor protection system action if allowed to proceed. The APRM upscale rod block alarm setting is selected to initiate a rod block before the APRM high neutron flux scram setting is reached.
- b. Any APRM inoperative alarm. This assures that no control rod is withdrawn unless the average power range neutron monitoring channels are either in service or correctly bypassed.
- c. Either recirculation flow converter upscale or inoperative alarm. This assures that no control rod is withdrawn unless the recirculation flow converters, which are necessary for the proper operation of the RBMs, are operable.
- d. Recirculation flow converter comparator alarm or inoperative. This assures that no control rod is withdrawn unless the difference between the outputs of the flow converters is within limits and the comparator is in service.
- e. Scram discharge volume high water level. This assures that no control rod is withdrawn unless enough capacity is available in the scram discharge volume to accommodate a scram. The setting is selected to initiate a rod block earlier than the scram that is initiated on scram discharge volume high water level.
- f. Scram discharge volume high water level scram trip bypassed. This assures that no control rod is withdrawn while the scram discharge volume high water level scram function is out of service.
- g. The rod worth minimizer (RWM) function of the process computer can initiate a rod insert block, a rod withdrawal block, and a rod select block. The purpose of this function is to reinforce procedural controls that limit the reactivity worth of control rods under lower power conditions. The rod block trip settings are based on the allowable control rod worth limits established for the design basis rod drop accident. Adherence to prescribed control rod patterns is the normal method by which this reactivity restriction is observed. Additional information on the rod worth minimizer function is available in Subsection 7.7.1.2.8.

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- h. Rod position information system malfunction. This assures that no control rod can be withdrawn unless the rod position information system is in service.
  - i. Rod movement timer malfunction during withdrawal. This assures no control rod can be withdrawn unless the timer is in service.
  - j. The Rod Sequence Control System initiates rod blocks, whenever out of sequence rods are selected. The RSCS is required to be in operation below 20% rated power to prevent the operator from establishing control rod patterns that are not consistent with a prestored rod sequence.
  - k. Either rod block monitor (RBM) upscale alarm. This function is provided to stop the erroneous withdrawal of a control rod so that local fuel damage does not result. Although local fuel damage poses no significant threat in terms of radioactive material released from the nuclear system, the trip setting is selected so that no local fuel damage results from a single control rod withdrawal error during power range operation.
  - l. Either RBM inoperative alarm. This assures that no control rod is withdrawn unless the RBM channels are in service or correctly bypassed.
- (3) With the mode switch in the RUN position, any of the following conditions initiates a rod block.
- a. Any APRM downscale alarm. This assures that no control rod will be withdrawn during power range operation unless the average power range neutron monitoring channels are operating correctly or are correctly bypassed. All unbypassed APRMs must be on scale during reactor operations in the RUN mode.
  - b. Either RBM downscale alarm. This assures that no control rod is withdrawn during power range operation unless the RBM channels are operating correctly or are correctly bypassed. Unbypassed RBMs must be on scale during reactor operations in the RUN mode.
- (4) With the mode switch in the STARTUP or REFUEL position, any of the following conditions initiates a rod block:
- a. Any source range monitor (SRM) detector not fully inserted into the core when the SRM count level is below the retract permit level and any IRM range switch on either of the two lowest ranges. This assures that



The interlocks from the refueling equipment to the Reactor Manual Control System actuate circuitry that provides a control rod block. The rod block prevents the operator from withdrawing any control rods.

#### 7.7.1.10.3.6 Separation

The refueling interlocks are not designed to nor required to meet the IEEE 279-1971 criteria for Nuclear Power Plant Protection Systems. However, a single interlock failure will not cause an accident. Refueling interlocks are used in conjunction with administration controls during planned refueling operations.

#### 7.7.1.10.3.7 Testability

Complete functional testing of all refueling interlocks before any refueling outage will positively indicate that the interlocks operate in the situations for which they were designed. The interlocks can be subjected to valid operational tests by loading each hoist with a dummy fuel assembly, positioning the refueling platform, and withdrawing control rods. Where redundancy is provided in the logic circuitry, tests are performed automatically, on a periodic basis, to assure that each redundant logic element can independently perform its function.

#### 7.7.1.10.4 Environmental Considerations

Equipment (refueling) will be subjected to the conditions listed in Table 3.11-1 during normal operation. The refueling interlocks are not required to operate under the conditions listed in Table 3.11-3.

Refueling components are capable of surviving design basis events such as earthquakes, accidents, and anticipated operational occurrences without consequential damage, but are not required to be functional during or after the event without repair.

#### 7.7.1.10.5 Operational Considerations

##### 7.7.1.10.5.1 General Information

The refueling interlocks system is required only during refueling operations.

7.7.1.10.5.2--Reactor Operator Information

In the refueling mode, the control room operator has an indicator light for "Select Permissive" whenever all control rods are fully inserted. He can compare this indication with control rod position data from the computer as well as control rod in-out status on the full core status display. Furthermore, whenever a control rod withdrawal block situation occurs, the operator receives annunciation and computer logs of the rod block. He can compare these outputs with the status of the variable providing the rod block condition. Both channels of the control rod withdrawal interlocks must agree that permissive conditions exist in order to move control rods; otherwise, a control rod withdrawal block is placed into effect. Failure of one channel may initiate a rod withdrawal block, and will not prevent application of a valid control rod withdrawal block from the remaining operable channel.

Core flux activity monitoring is provided during refueling by the SRM's and/or dunking chambers which are specified and controlled in Technical Specification 3/4.9.

In terms of refueling platform interlocks, the platform operator has analog type readout indicators for the platform x-y position relative to the reactor core.

The position of the grapple is shown on a digital indicator immediately below the platform position indicators. Analog load cell indications of hoist loads are given for each hoist by locally mounted indicators. Individual push button and rotary control switches are provided for local control of the platform and its hoists. The platform operator can immediately determine whether the platform and hoists are responding to his local instructions, and can, in conjunction with the control room operator, verify proper operation of each of the three categories of interlocks listed previously.

7.7.1.10.5.3--Set Points

There are no safety set points associated with this system.

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TABLE 8.1-2

AFFILIATED AND NON-CLASS 1E CIRCUITS  
THAT CONNECT TO CLASS 1E POWER SUPPLIES

<u>CIRCUIT NUMBER</u>	<u>NON CLASS 1E LOAD</u>	<u>CLASS 1E POWER SUPPLY</u>	<u>METHOD OF ISOLATION</u> (Ref.FSAR 8.1.6.ln.5)	23
1	Control Structure HVAC Chiller Condenser Water Pump OP170A	Control Structure H&V Room Div.I Engineered Safeguard MCC OB136	i	
2	Control Structure HVAC Chiller Condenser Water Pump OP170B	Control Structure H&V Room Div.II Engineered Safeguard MCC OB146	i	
3	Drywell Area Unit Cooler IV411A	Reactor Area Div.I Engineered Safeguard MCC 1B236	i	
4	Drywell Area Unit Cooler IV411B	Reactor Area Div.II Engineered Safeguard MCC 1B246	i	
5	Drywell Area Unit Cooler IV412A	Reactor Area Div.I Engineered Safeguard MCC 1B236	i	
6	Drywell Area Unit Cooler IV412B	Reactor Area Div.II Engineered Safeguard MCC 1B246	i	
7	Drywell Area Unit Cooler IV413A	Reactor Area Div.I Engineered Safeguard MCC 1B236	i	
8	Drywell Area Unit Cooler IV413B	Reactor Area Div. II Engineered Safeguard MCC 1B246	i	
9	Drywell Area Unit Cooler IV417A	Reactor Area Div.I Engineered Safeguard MCC 1B236	i	

CIRCUIT  
NUMBERNON CLASS 1E LOADCLASS 1E POWER SUPPLYMETHOD OF  
ISOLATION  
(Ref.FSAR  
8.1.6.1n.5)

23

10	Drywell Area Unit Cooler LV417B	Reactor Area Div.II Engineered Safeguard MCC 1B246	i
11	Drywell Area Unit Cooler 2V411A	Reactor Area Div.I Engineered Safeguard MCC 2B236	i
12	Drywell Area Unit Cooler 2V411B	Reactor Area Div.II Engineered Safeguard MCC 2B246	i
13	Drywell Area Unit Cooler 2V412A	Reactor Area Div.I Engineered Safeguard MCC 2B236	i
14	Drywell Area Unit Cooler 2V412B	Reactor Area Div.II Engineered Safeguard MCC 2B246	i
15	Drywell Area Unit Cooler 2V413A	Reactor Area Div.I Engineered Safeguard MCC 2B236	i
16	Drywell Area Unit Cooler 2V413B	Reactor Area Div.II Engineered Safeguard MCC 2B246	i
17	Drywell Area Unit Cooler 2V417A	Reactor Area Div.I Engineered Safeguard MCC 2B236	i
18	Drywell Area Unit Cooler 2V417B	Reactor Area Div.II Engineered Safeguard MCC 2B246	i
19	Instrument Air Compressor 'A' 1K107A	Channel B/Div II Engineered Safeguard Load Center 1B220	ii

CIRCUIT  
NUMBER

NON CLASS 1E LOAD

CLASS 1E POWER SUPPLY

METHOD OF  
ISOLATION  
(Ref. FSAR  
8.1.6.ln.5)

23

20	Instrument Air Compressor 'B' 1K107B	Channel D/Div II Engineered Safeguard Load Center 1B240	ii
21	Instrument Air Dryer Panel 'AB' 1C142A	Reactor Bldg. Div.II Engineered Safeguard MCC 1B247	ii
22	Instrument Air Dryer Panel 'B' 1C142B	Reactor Bldg. Div.II Engineered Safeguard MCC 1B226	ii
23	Instrument Gas Compressor 'A' 1K205A	Reactor Bldg. Div.I Engineered Safeguard MCC 1B217	ii
24	Instrument Gas Compressor 'B' 2K205B	Reactor Bldg. Div.I Engineered Safeguard MCC 1B236	ii
25	Instrument Air Compressor 'A' 2K107A	Channel A/Div.I Engineered Safeguard Load Center 2B210	ii
26	Instrument Air Compressor 'B' 2K107B	Channel C/Div. I Engineered Safeguard Load Center 2B230	ii
27	Instrument Air Dryer Panel 'A' 2C142A	Reactor Bldg. Div.I Engineered Safeguard MCC 2B237	ii
28	Instrument Air Dryer Panel 'B' 2C142B	Reactor Bldg. Div.I Engineered Safeguard MCC 2B216	ii
29	Instrument Gas Compressor 'A' 2K205A	Reactor Bldg. Div.I Engineered Safeguard MCC 2B217	ii

CIRCUIT  
NUMBERNON CLASS 1E LOADCLASS 1E POWER SUPPLYMETHOD OF  
ISOLATION  
(Ref.FSAR  
8.1.6.1n.5)

23

30	Instrument Gas Compressor 'B' 2K205B	Reactor Bldg. Div.I Engineered Safeguard MCC 2B236	ii
31	Turbine Area 480V MCC 1B116	Channel A/Div. I Engineered Safeguard Load Center 1B210	iii
32	Turbine Area 480V MCC 1B126	Channel B/Div. II Engineered Safeguard Load Center 1B220	iii
33	Auto Transfer Switch 1ATS21B	Reactor Area Div.I Engineered Safeguard MCC 1B216	iii
34	Auto Transfer Switch 1ATS218	Reactor Area Div.I Engineered Safeguard MCC 1B236	iii
35	Auto Transfer Switch 1ATS228	Reactor Area Div.II Engineered Safeguard MCC 1B226	iii
36	Auto Transfer Switch 1ATS228	Reactor Area Div.II Engineered Safeguard MCC 1B246	iii
37	Computer Power Supply inverter 1D656	Div. I 250V DC Load Center 1D652	iv
38	Vital Power Supply inverter 1D666	Div. II 250V DC Load Center 1D662	iv
39	Computer Power Supply inverter 1D656	Reactor Area Div. I Engineered Safeguard MCC 1B236	iii

23

CIRCUIT  
NUMBER

## NON CLASS 1E LOAD

## CLASS 1E POWER SUPPLY

METHOD OF  
ISOLATION  
(Ref.FSAR  
8.1.6.1n.5)

23

40	Vital Power Supply inverter 1D666	Reactor Area Div.II Engineered Safeguard MCC 1B246	iii
41	250V DC Turbine Building control center A	Div.I 250V DC Load Center 1D652 1D155	iii
42	250V DC Turbine Building control center B	Div.II 250 V DC Load Center 1D662 1D165	iii
43	125V DC Distribution Panel 1D615	Channel A/Div. I 125V DC Load Center 1D612	iii
44	125V DC Distribution Panel 1D625	Channel B/Div. II 125V DC Load Center 1D622	iii
45	125V DC Distribution Panel 1D635	Channel C 125V DC Load Center 1D632	iii
46	125V DC Distribution Panel 1D645	Channel D 125V DC Load Center 1D642	iii
47	480/277V Essential Lighting Panel	Reactor Area Div.I Engineered Safeguard MCC 1B217 1EP07	iii
48	480/277V Essential Lighting Panel 1EP08	Reactor Area Div.II Engineered Safeguard MCC 1B227	iii
49	480/277V Essential Lighting Panel 1EP03	Reactor Area Div. II Engineered Safeguard MCC 1B226	iii

23

23

CIRCUIT  
NUMBERNON CLASS 1E LOADCLASS 1E POWER SUPPLYMETHOD OF  
ISOLATION  
(Ref.FSAR  
8.1.6.1n.5)

50	480/277V Essential Lighting Panel 1EP04	Reactor Area Div.II Engineered Safeguard MCC 1B246	iii
51	Turbine Area 480V MCC 2B116	Channel A/Div. I Engineered Safeguard Load Center 2B210	iii
52	Turbine Area 480V MCC 2B126	Channel B/Div.II Engineered Safeguard Load Center 2B220	iii
53	Auto transfer switch 2ATS218	Reactor Area Div.I Engineered Safeguard MCC 2B216	iii
54	Auto transfer switch 2ATS218	Reactor Area Div.I Engineered Safeguard MCC 2B236	iii
55	Auto transfer switch 2ATS228	Reactor Area Div.II Engineered Safeguard MCC 2B226	iii
56	Auto transfer switch 2ATS228	Reactor Area Div.II Engineered Safeguard MCC 2B246	iii
57	Computer Power supply inverter 2D656	Div.I 250V DC Load Center 2D652	iii
58	Vital Power supply inverter 2D666	Div.II 250V DC Load Center 2D662	iii
59	Computer Power supply inverter 2D656	Reactor Area Div.I Engineered Safeguard MCC 2B236	iii
60	Vital Power supply inverter 2D666	Reactor Area Div.II Engineered Safeguard MCC 2B246	iii



Table 8.1-2 (cont.)

<u>CIRCUIT NUMBER</u>	<u>NON CLASS 1E LOAD</u>	<u>CLASS 1E POWER SUPPLY</u>	<u>METHOD OF ISOLATION</u> (Ref. FSAR 8.1.6.1n.5)
50	480/277V Essential Lighting Panel 1EP04	Reactor Area Div. II Engineered Safeguard MCC 1B246	iii
51	Turbine Area 480V MCC 2B116	Channel A/Div. I Engineered Safeguard Load Center 2B210	iii
52	Turbine Area 480V MCC 2B126	Channel B/Div. II Engineered Safeguard Load Center 2B220	iii
53	Auto transfer switch 2ATS218	Reactor Area Div. I Engineered Safeguard MCC 2B216	iii
54	Auto transfer switch 2ATS218	Reactor Area Div. I Engineered Safeguard MCC 2B236	iii
55	Auto transfer switch 2ATS228	Reactor Area Div. II Engineered Safeguard MCC 2B226	iii
56	Auto transfer switch 2ATS228	Reactor Area Div. II Engineered Safeguard MCC 2B246	iii
57	Computer Power supply inverter 2D656	Div. I 250V DC Load Center 2D652	iv
58	Vital Power supply inverter 2D666	Div. II 250V DC Load Center 2D662	iv
59	Computer Power supply inverter 2D656	Reactor Area Div. I Engineered Safeguard MCC 2B236	iii
60	Vital Power supply inverter 2D666	Reactor Area Div. II Engineered Safeguard MCC 2B246	iii

CIRCUIT  
NUMBER

## NON CLASS 1E LOAD

## CLASS 1E POWER SUPPLY

METHOD OF  
ISOLATION  
(Ref.FSAR  
8.1.6.ln.5)

23

61	250V DC Turbine Building Control Center A	Div.I 250V DC Load Center 2D652 2D155	iii
62	250V DC Turbine Building Control Center B	Div.II 250V DC Load Center 2D662 2D165	iii
63	125V DC Distribution Panel 2D615	Channel A/Div.I 125V DC Load Center 2D612	iii
64	125V DC Distribution Panel 2D625	Channel B/Div.II 125V DC Load Center 2D622	iii
65	125V DC Distribution Panel 2D635	Channel C 125V DC Load Center 2D632	iii
66	125V DC Distribution Panel 2D645	Channel D 125V DC Load Center 2D642	iii
67	480/277V Essential Lighting Panel 2EP07	Reactor Area Div.I Engineered Safeguard MCC 2B217	iii
68	480/277V Essential Lighting Panel 2EP08	Reactor Area Div.II Engineered Safeguard MCC 2B227	iii
69	480/277V Essential Lighting Panel 2EP03	Reactor Area Div.II Engineered Safeguard MCC 2B226	iii
70	480/277V Essential Lighting Panel 2EP04	Reactor Area Div.II Engineered Safeguard MCC 2B246	iii

23



<u>CIRCUIT NUMBER</u>	<u>NON CLASS 1E LOAD</u>	<u>CLASS 1E POWER SUPPLY</u>	<u>METHOD OF ISOLATION (Ref. FSAR 8.1.6.1n.5)</u>
71	480/277V Essential Lighting Panel OEP01	Control structure H&V Room Eng. Div.I Safeguard MCC OB136	iii
72	480V/277V Essential Lighting Panel OEP02	Control structure H&V Room Eng. Div.II Safeguard MCC OB146	iii
73	480V/277V Essential Lighting Panel 1EP05	Control structure H&V Room Eng. Div.II Safeguard MCC OB146	iii
74	Reactor Bldg. Chiller compressor 1K206A	Channel A/Div.I Emergency auxiliary Switchgear 1A201	iv
75	Control Rod Drive Water pump 1P132A	Channel A/Div.I Emergency auxiliary Switchgear 1A201	iv
76	Turbine Bldg. Chiller compressor 1K102A	Channel A/Div. I Emergency auxiliary Switchgear 1A201	iv
77	Reactor Bldg. Chiller compressor 1K206B	Channel B/Div.II Emergency auxiliary Switchgear 1A202	iv
78	Main condenser Mechanical vacuum pump 1P105	Channel B/Div.II Emergency auxiliary Switchgear 1A202	iv
79	Turbine Bldg. Chiller compressor 1K102B	Channel B/Div.II Emergency auxiliary Switchgear 1A202	iv
80	Control Rod Drive Water pump 1P132B	Channel D/Div.II Emergency auxiliary Switchgear 1A204	iv
81	Control Structure Passenger Elevator ODS108	Control Structure H&V Room Div.I Engineered Safeguard MCC OB136	iv
82	Engr. Safeguard Service Water Pumphouse OLP16	Div.I Engr. Safeguard Service Water Pump house MCC OB517	i



TABLE 8.1-2

<u>CIRCUIT NUMBER</u>	<u>NON CLASS 1E LOAD</u>	<u>CLASS 1E POWER SUPPLY</u>	<u>METHOD OF ISOLATION (Ref.FSAR 8.1.6.1n.5)</u>
83	Engr. Safeguard Service Water Pumphouse Distribution Panel OPP509A	Div.I Engr. Safeguard Service Water Pumphouse MCC OB517	i
84	Engr. Safeguard Service Water Pumphouse Distribution Panel OPP511	Div.II Engr. Safeguard Service Water Pumphouse MCC OB527	i
85	Spray Pond Piping Drain Pump OP513A	Div.I Engr. Safeguard Service Water Pumphouse MCC OB517	i
86	Spray Pond Piping Drain Pump OP513B	Div.II Engr. Safeguard Service Water Pumphouse MCC OB527	i
87	Reactor Bldg. Closed Cooling Water Pump 1P210A	Reactor Area Div. I Engineered Safeguard MCC 1B216	iv
88	Reactor Bldg. Closed Cooling Water Pump 1P210B	Reactor Area Div.I Engineered Safeguard MCC 1B237	iv
89	Reactor Bldg. Equip. Rm. H&V Supply Fan IV232	Reactor Area Div. II Engineered Safeguard MCC 1B227	iv
90	Reactor Bldg. Equip. Rm. H&V Supply Fan 2V232	Reactor Area Div. II Engineered Safeguard MCC 2B227	iv
91	Reactor Bldg. Service Elevator 1DS204	Reactor Area Div. II Engineered Safeguard MCC 1B246	iv
92	Process Radiation Monitoring Cabinet 1C604	Div. I 24VDC Distribution Panel 1D672	iv
93	Process Radiation Monitoring Cabinet 1C604	Div. II 24VDC Distribution Panel 1D682	iv

METHOD OF  
ISOLATION  
(Ref. FSAR  
8.1.6.1n.5)

<u>CIRCUIT NUMBER</u>	<u>NON CLASS 1E LOAD</u>	<u>CLASS 1E POWER SUPPLY</u>	
94	Control Rod Drive Water Pump 2P132A	Channel A/Div. I Emergency Auxiliary Switchgear 2A201	iv
95	Turbine Bldg. Chiller Compressor 2K102A	Channel A/Div. I Emergency Auxiliary Switchgear 2A201	iv
96	Reactor Bldg. Chiller Compressor 2K206B	Channel B/Div. II Emergency Auxiliary Switchgear 2A202	iv
97	Main Condenser Mechanical Vacuum Pump 2P105	Channel C/Div. I Emergency Auxiliary Switchgear 2A203	iv
98	Turbine Bldg. Chiller Compressor 2K206A	Channel C/Div. I Emergency Auxiliary Switchgear 2A203	iv
99	Control Rod Drive Water Pump 2P132B	Channel D/Div. II Emergency Auxiliary Switchgear 2A204	iv
100	Turbine Bldg. Chiller Compressor 2K102B	Channel D/Div. II Emergency Auxiliary Switchgear 2A204	iv
101	Reactor Bldg. Closed Cooling Water Pump 2P210A	Reactor Area Div. II Engineered Safeguard MCC 2B247	iv
102	Reactor Bldg. Closed Cooling Water Pump 2P210B	Reactor Area Div. II Engineered Safeguard MCC 2B226	iv
103			
104			
105	Process Radiation Monitoring Cabinet 2C604	Div. I 24VDC Distribution Panel 2D672	iv

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TABLE 8.1-2

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<u>CIRCUIT NUMBER</u>	<u>NON CLASS 1E LOAD</u>	<u>CLASS 1E POWER SUPPLY</u>	<u>METHOD OF ISOLATION (Ref.FSAR 8.1.6.1n.5)</u>
106	Process Radiation Monitoring Cabinet 2C604	Div. II 24VDC Distribution Panel 2D682	iv
107	Containment Vacuum Relief Valve PSV-15704A1	Div. I 120V Inst. AC 1Y216 PNL	iv
108	PSV-15704B1		iv
109	PSV-15704C1		iv
110	PSV-15704D1		iv
111	PSV-15704E1		
112	PSV-15704A2	Div. II 120V Inst. AC1Y226 PNL	iv
113	PSV-15704B2		iv
114	PSV-15704C2		iv
115	PSV-15704D2		iv
116	PSV-15704E2		iv
117	PSV-25704A1	Div. I 120V Inst. AC 2Y216 PNL	iv
118	PSV-25704B1		iv
119	PSV-25704C1		iv
120	PSV-25704D1		iv
121	PSV-25704E1		iv
122	PSV-25704A2	Div. II 120V Inst. AC 2Y226 PNL	iv
123	PSV-25704B2		iv
124	PSV-25704C2		iv
125	PSV-25704D2		iv
126	PSV-25704E2		iv
127	Reactor Protection System Transformer 2X201A	Reactor Area Div. II Engineered Safeguard MCC 1B227	iv
128	Reactor Protection System Transformer 2X201A	Reactor Area Div. II Engineered Safeguard MCC 2B227	iv
129	ES Transformer Cooling Fans and Control OX201	Diesel Generator Rm. Ch. A Engineered Safeguard MCC OB516	iv
130	ES Transformer Cooling Fans and Control OX203	Diesel Generator Rm. Ch. B Engineered Safeguard MCC OB526	iv
131	ES Transformer Cooling Fans and Control OX201	Diesel Generator Rm. Ch. C Engineered Safeguard MCC OB536	iv
132	ES Transformer Cooling Fans and Control OX203	Diesel Generator Rm. Ch. D Engineered Safeguard MCC OB546	iv



TABLE 8.1-2

<u>CIRCUIT NUMBER</u>	<u>NON CLASS 1E LOAD</u>	<u>CLASS 1E POWER SUPPLY</u>	<u>METHOD OF ISOLATION</u> (Ref.FSAR 8.1.6.1n.5)
133	HPCI Vacuum Tank Condensate Drain Pump 1P215	Div. II 250VDC Motor Control Center 1D264	iv
134	HPCI Barometric Condensate Vacuum Pump 1P216	Div. II 250VDC Motor Control Center 1D264	iv
135	RCIC Barometric Condensate Vacuum Pump 1P219	Div. I 250VDC Motor Control Center 1D254	iv
136	RCIC Vacuum Tank Condensate Drain Pump 1P220	Div. I 250VDC Motor Control Center 1D254	iv
137	SLC Storage Tank Electric Heater 'A' 1E219	Channel C 480V Motor Control Center 1B236	iv
138	SLC Storage Tank Electric Heater 'B' 1E220	Channel C 480V Motor Control Center 1B236	iv
139	HPCI Vacuum Tank Condensate Drain Pump 2P215	Div. II 250 VDC Motor Control Center 2D264	iv
140	HPCI Barometric Condensate Vacuum Pump 2P216	Div. II 250VDC Motor Control Center wD264	iv
141	RCIC Barometric Condensate Vacuum Pump 2P219	Div. I 250VDC Motor Control Center 2D254	iv
142	RCIC Vacuum Tank Condensate Drain Pump 2P220	Div. I 250VDC Motor Control Center 2D254	iv
143	SLC Storage Tank Electric Heater 'A' 2E219	Channel C 480V Motor Control Center 2B236	iv
144	SLC Storage Tank Electric Heater 'B' 2E220	Channel C 480V Motor Control Center 2B236	iv

## 8.2 OFFSITE POWER SYSTEM

### 8.2.1 DESCRIPTION

#### 8.2.1.1 Transmission System

The bulk power transmission system of PP&L operates at 230 KV and 500 KV. Unit #1 of the Susquehanna Steam Electric Station supplies power to the 230 KV system through a 230 KV switchyard and Unit #2 supplies power to the 500 KV system through a separate 500 KV switchyard. The offsite power system for the plant is supplied through the 230 KV portion of the bulk power system.

Figure 8.2-1 shows the Susquehanna 230 KV and 500 KV switchyards and the transmission lines associated with each yard and in the vicinity of the plant. The figure shows the line arrangement with both units in operation. The two switchyards are physically separate and are tied together by a 230 KV yard tie line with a 230-500 KV transformer in the 500 KV yard.

Two independent offsite power sources are supplied to the Susquehanna plant. One source is established by tapping the Montour-Mountain 230 KV line north of the plant and constructing 1300 ft. of 230 KV line on painted steel pole structures to startup transformer #10. The Montour-Mountain line shares double circuit steel pole structures with the Stanton-Susquehanna #2 230 KV line in the vicinity of the plant. The double circuit line extends to a point 1.5 miles east of the transformer #10 tap at which point the two circuits split as shown in Figure 8.2-1. The Montour-Mountain line extends 16.8 miles north on double circuit lattice towers with the Stanton-Susquehanna #1 230 KV line and terminates in the Mountain Substation. The Stanton-Susquehanna #2 circuit extends southward on double circuit towers with the Stanton-Susquehanna #1 circuit and terminates in the Susquehanna 230 KV Switchyard.

To the west of the tap into the Susquehanna plant the Montour-Mountain 230 KV circuit extends 1500 feet on double circuit steel pole structures at which point the Stanton-Susquehanna #2 circuit separates and extends northward to Stanton Substation. The Montour-Mountain 230 KV circuit then joins the Montour-Susquehanna 230 KV circuit on double circuit steel lattice towers and extends 29.0 miles to the Montour Switchyard. The total distance to Mountain Substation from the tap into the plant is 18.7 miles. The distance from Montour to the tap is 29.7 miles.

Several lines feed the Montour Switchyard and Mountain Substation, as can be readily seen in Figure 8.2-3. These lines

offer a multitude of possible supplies for the tap into Susquehanna startup transformer #10. Montour Switchyard is supplied directly by generation from the Montour Steam Electric Station. Other generating stations are indirectly linked by the bulk power grid system. The conductors for the transformer #10 tap and the Montour-Mountain line are 1590 kcmil 45/7 ACSR and are supported by single string insulator assemblies. Maximum conductor tension is limited to 16,000 pounds on steel pole line sections and 21,900 pounds on lattice tower sections under maximum anticipated loading conditions.

The second offsite power source is supplied at 230 KV from the yard tie circuit between the Susquehanna 500 kv and 230 kv Substations south of the Susquehanna Steam Electric Station. The source is provided by a single 400 ft. span tap from the 230 KV yard tie circuit to startup transformer #20.

The yard tie line consists of 230 KV double circuit tubular steel pole structures supporting two parallel circuits of 1590 kcmil 45/7 ACSR conductors on single string insulator assemblies. The circuits are tied together to form a two conductor per phase single circuit line. The 400 ft. tap to transformer #20 consists of one 1590 kcmil 45/7 ACSR conductor per phase. The distance from the tap point west to the 500 KV yard is 1500 ft. The distance from the tap point east to the 230 KV yard is 1.6 miles. Maximum conductor tension is limited to 16,000 pounds in the yard tie line under maximum loading conditions.

The second offsite power supply is furnished by the multiple sources throughout the bulk power grid system through the 230 KV and 500 KV lines emanating from the Susquehanna 230 KV and 500 KV switchyards. See Figure 8.2-3.

All transmission lines meet or exceed design requirements set forth by the National Electric Safety Code. One or two overhead ground wires are employed on the transmission lines above the phase conductors to provide adequate lightning flashover protection. All lines meet the Army Corps of Engineers requirements for clearance over flood levels. All bulk power transmission lines are designed to withstand 100 mph hurricane wind loads on bare conductors.

The Montour-Mountain 230 KV line is crossed by the Stanton-Susquehanna #2 230 KV line. No transmission lines cross over the Susquehanna 500 KV to 230 KV yard tie line or the two tap lines supplying transformers #10 and #20.

No single disturbance in the bulk power grid system will cause complete loss of offsite power to the Susquehanna SES. This is a basic system design criteria.

8.2.1.2 Transmission Interconnection

PP&L is a member of the Pennsylvania, New Jersey, and Maryland Interconnection which permits economical exchanges of power with neighboring utilities and provides emergency assistance. Direct bulk power ties are between PP&L and Philadelphia Electric, Luzerne Electric Division of UGI, Metropolitan Edison, Pennsylvania Electric, Jersey Central Power and Light, Public Service Electric and Gas, and Baltimore Gas and Electric Companies.

8.2.1.3 Switchyards8.2.1.3.1 Startup Transformers #10 and #20

The Montour-Mountain 230 KV line and the 230 KV yard tie line supply power to startup transformers #10 and #20, respectively, through motor operated air break switches. High speed positive ground switches are installed between the motor operated air break switches (MOABs) and the startup transformers. The startup transformers and low side bus connections are discussed in Section 8.3.1. The startup transformer yards are physically separated from each other, the Unit #1 and #2 main transformer yards and the 230 KV and 500 KV switchyards as can be seen on figure 8.2-1. 1590 kcmil 45/7 ACSR conductors connect the air switches to the startup transformers. 13.8 KV cables are installed in underground conduit between the startup transformers and the turbine building. Non-segregated phase bus ducts establish the tie to the 13.8 KV startup buses within the turbine building. See Figure 8.2-4 for a one line diagram of the offsite power system.

Line relay protection for the Montour-Mountain 230 KV line and the 230 KV yard tie circuit is provided by two independent directional comparison carrier blocking pilot relaying and two zone directional distance backup systems which ensure adequate line protection in the event of a malfunction. These relaying schemes detect faults on the transmission line and isolate the power sources to the transformers by tripping the power circuit breakers (PCBs) at the line terminals. Breaker failure relaying, applied at each line terminal, detects a failure to trip or failure to interrupt condition at the line terminal and trips all associated PCBs necessary to isolate the line. Power to the line relaying facilities is supplied from the local switchyard power sources.

Startup transformers #10 and #20 are protected by high speed percentage differential, sudden pressure and overcurrent

relaying. Direct transfer trip facilities are utilized as the primary relaying scheme to open the PCBs at the transmission line remote terminals in the event of transformer trouble. Backup protection is provided by the high speed ground switch on the 230 KV side of the startup transformer. This switch is closed to place a positive fault on the 230 KV transmission line which will be detected by the remote line terminal relaying systems if the primary direct transfer trip scheme fails to function correctly. The motor operated air switch automatically opens after the 230 KV system is de-energized to isolate the startup transformer from the transmission system and permit reclosing of the transmission line terminal PCBs.

A time delay undervoltage relay monitors the 13.8 KV startup bus voltage. On loss of offsite power the relay trips the startup bus incoming feeder breaker and initiates transfer of the bus loads to the other startup transformer through closure of the startup bus tie breaker. The time delay undervoltage relay also prevents unnecessary automatic trip of the incoming feeder breaker for short duration disturbances on the transmission line.

Power to transformer #10 and #20 switchgear, motor operated air break switches, and high speed ground switches is supplied from the station 125 V DC power supplies.

#### 8.2.1.3.2 Susquehanna Unit #1 230 KV Main Transformer Leads

Overhead 1590 kcmil 45/7 ACSR conductors, bundled two per phase, tie the Unit #1 main stepup transformers, through a high voltage Disconnect switch-Synchronizing PCB-Disconnect switch arrangement, to the 230 KV switchyard. The synchronizing breaker and disconnect switch arrangement is provided at the Susquehanna SES site to improve reliability in synchronization and flexibility of operating Unit 1. Steel pole structures support the strain bus and the 2.2 mile 230 KV tie with single string insulator assemblies. The tie line is capable of transmitting the full 1280 MVA output of the Unit #1 generator.

Relay protection between the Unit #1 transformer and the synchronizing breaker is provided by high speed percentage differential relays which trip Unit #1 and the synchronizing breaker by the unit master trip lockout relays. A second protection scheme is provided by the Unit #1 overall differential relaying which also detects fault conditions between Unit #1 transformer and the synchronizing breaker. Two directional comparison carrier blocking pilot and two zone directional distance backup relaying systems provide fault protection between the 230 KV synchronizing PCB and the Susquehanna 230 KV Switchyard. Breaker failure protection relaying is applied at

each terminal to detect a failure to trip or failure to interrupt condition and to electrically isolate the faulty component.

Control power to the synchronizing power circuit breaker and power to the onsite relaying equipment are provided by the plant 125 V DC power supplies.

#### 8.2.1.3.3 Susquehanna 230 KV Switchyard

The 230 KV switchyard is an outdoor steel structure, comprised of 6 bay positions containing 14-230 KV power circuit breakers arranged in a breaker and one half scheme. Terminating positions are provided for seven lines, one generator lead, and a yard tie to the 500 KV switchyard. The switchyard breakers can be operated by remote supervisory control from the PP&L System Operating Offices.

Service power to the 230 KV switchyard is provided by a local 12 KV distribution line with a backup diesel generator in the 230 KV switchyard. An automatic throwover scheme is employed in the event of one source failure. Line protection equipment power is provided by a single 125 V DC switchyard service battery equipped with two full capacity chargers.

#### 8.2.1.3.4 Susquehanna Unit #2 500 KV Main Transformer Leads-----

Unit #2 generator output is connected to the 500 KV switchyard by a 1400 ft. overhead 500 KV transmission line. 2493 kcmil 54/37 ACAR conductors bundled two per phase are supported by V-string insulator assemblies on steel pole H-frame structures. The tie is capable of transmitting the full 1280 MVA generator output of Unit #2 to the 500 KV switchyard.

Relay protection for the connection between the Unit #2 transformer and the Susquehanna 500 KV switchyard is provided by high speed bus differential relays which trip Unit #2 and the three 500 KV switchyard generator breakers by the master trip lockout relays for a fault in the connection. An overall differential protection scheme provides a second system to trip Unit #2 and the three PCBs connected to the generator in the 500 KV switchyard for a fault on the transformer leads. Breaker failure protection is applied at each terminal to detect a failure to trip or failure to interrupt condition and to electrically isolate the faulty component.

#### 8.2.1.3.5 Susquehanna 500 KV Switchyard

The 500 KV switchyard is an outdoor steel structure, comprised of three bays containing five 500 KV power circuit breakers arranged in a modified ring bus configuration. The switchyard provides for ultimate future expansion to 5 bays in a breaker and one half scheme. Terminating positions are provided for two lines, one 500 KV generator lead circuit and a circuit to a bank of three single phase 500-230 KV autotransformers. Manual operation of the 500 KV generator lead synchronizing circuit breakers is by the plant control room operator. The remaining PCBs can be operated by PP&L's remote supervisory control or by the plant supervisory control.

Service power to the 500 KV switchyard is provided by two sources: one from the generating station, and the second from the tertiary winding of the yard tie autotransformers with an automatic low voltage throwover scheme in the event of one source failure. Line protection equipment is powered by a single 125 V DC switchyard service battery equipped with two full capacity battery chargers.

#### 8.2.1.3.6 Montour and Mountain 230 kv Switchyards

Figure 8.2-5 shows a one line diagram of the off-site power system for Startup Transformer #10.

The Montour Switchyard is an outdoor steel structure comprised of four bay positions containing 11-230 kv power circuit breakers arranged in a breaker and one half scheme. Two generating leads from the Montour Steam Electric Station and five transmission lines are terminated in the yard. The switchyard breakers can be operated by remote control from the PP&L System Operating offices.

The Mountain Switchyard is owned and operated by UGI Corporation, Luzerne Electric Division. It is an outdoor steel structure with two bay positions each containing one 230 kv PCB. The two PCBs are arranged back to back between the Montour-Mountain and Mountain-Lackawanna Lines. Between the two PCBs is a normally open MOAB to the Susquehanna-Stanton #1 line. The PCBs and MOAB can be operated by remote supervisory control from the UGI Corporation System operator's office. PCB and MOAB status is monitored by PP&L's System Operating offices.

#### 8.2.1.4 Offsite Power System Monitoring

PP&L's transmission lines are patrolled approximately three times throughout a year to ensure that the physical and electrical integrity of the transmission line supports, hardware, insulators, and conductors is maintained for safe and reliable continuity of service.

The periodic transmission line patrol is conducted by helicopter. Less frequent foot patrols and selective structure inspections are performed depending on the age of the line.

Monitoring of the Unit #1 and Unit #2 offsite power sources in the plant control room is via a hardwired mimic bus arrangement which shows startup transformers #10 and #20, the transformer #10 and #20 motor operated air break switches, the 13.8 KV start-up buses, the 13.8 KV bus feeder breakers, and the 13.8 KV bus tie breaker. Annunciation signals abnormal tripping to the control room operator. Control and status indication are provided for the 230 KV MOAB switches and the 13.8 KV breakers. Potential indication for the PP&L grid and 13.8 KV bus and status indication of the 230 KV high speed ground switches are provided.

A cathode ray tube (CRT) display is provided by the plant computer system which provides the operator with additional information about the offsite power sources. The display is a mimic bus arrangement, similar to the hardwired mimic bus, and includes the status of the PCBs at the remote terminals of the transformer #10 and #20 supply lines.

Monitoring of the Unit #1 main generator output leads to the 230 KV switchyard is provided in the control room. A hardwired mimic bus arrangement provides control and status indication of the synchronizing PCB. Potential indication and monitoring of current, watts, vars, watt hours and voltage are provided. Annunciation signals an abnormal change in status of the synchronizing PCB. The computer CRT display system provides the operator with the status of all PCB's in the 230 KV switchyard and the synchronizing PCB via input from PP&L's supervisory control system. Annunciation accompanies a failure of the supervisory system. Manual control of the 230 KV switchyard is by a supervisory system from selected PP&L System Operating facilities.

Monitoring of the Unit #2 main generator output leads and the 500 KV switchyard is provided in the control room via a mimic bus arrangement. PCB open-close status indication and control are provided for all PCBs in the 500 KV switchyard. Except for the main generator synchronizing breakers which are hardwired directly to the control room along with potential indication, all 500 KV PCB control and status indication in the control room is



provided through a supervisory system. Digital displays monitor output current, watts, vars, watt hours, and voltage. Annunciation accompanies uncommanded PCB status changes, loss of potential, transformer trouble, fire protection system actuation, carrier equipment failure, and fault recorder failure. Control of the 500 KV switchyard fault recorder and tap change control on the 500-230 KV transformer are made available to the operator. Similar information is provided to the control room operator via the computer CRT mimic bus arrangement display through the supervisory system. Primary control of the 500 KV switchyard is via the System Operating supervisory control system except for the main generator synchronizing breakers which can be controlled only by the plant operator.

Preoperational and initial startup testing of all apparatus, equipment, relaying, and PCBs is conducted at transformers #10 and #20 and the 500 KV and 230 KV switchyards to ensure compliance with design criteria and standards.

PCB protective relay testing, maintenance, and calibration in the 230 KV and 500 KV switchyards, Montour switchyard and at transformers #10 and #20 will be conducted approximately once every two years. PCB protective relay testing, maintenance and calibration at Mountain switchyard is performed approximately every year.

#### 8.2.1.5 Industry Standards

The requirements, criteria and recommended practices set forth in the following documents are implemented in the design of the transmission system:

- A. National Electric Safety Code, 7th Addition.
- B. PJM Interconnection Protective Relaying Philosophy and Design Standards
- C. MAAC Group Reliability Principles and Standards for Planning Bulk Power Electric Supply System of MAAC Group, July 18, 1968 (Appendix 8.2A)
- D. In general, high voltage circuit breakers are manufactured and tested in accordance with the latest recommendations and rules of the ANSI, IEEE, NEMA, and AEIC.
- E. Pennsylvania Power & Light Company Substation and Relay and Control Engineering Instruction Manuals, Engineering and Construction Standards, Operating Principles and Practices; Relay and Control Facilities 3/3/76 and sound engineering principles. The design criteria include consideration of aesthetics, reliability, economics, and safety.

## 8.2.2 Analysis

### 8.2.2.1 Grid Availability

The offsite power sources provide adequate capacity and capability to start and operate safety related equipment. In addition, the sources provide both redundancy and electrical and physical independence such that no single event is likely to cause a simultaneous outage of both sources in such a way that neither can be returned to service in time to prevent fuel design limits and design conditions of the reactor coolant pressure boundary from being exceeded. Each of the circuits from the off-site transmission network to the safety related distribution buses has the capacity and capability to supply the assigned loads during normal and abnormal operating conditions, accident conditions and plant shutdown conditions.

The PP&L bulk power system is planned in accordance with established PP&L bulk power planning criteria. These criteria are based on the Reliability Principles and Standards of the Mid-Atlantic Area Council (MAAC). MAAC is a regional reliability council of the National Electric Reliability Council (NERC). MAAC is comprised of the electric utility companies of the Pennsylvania-New Jersey-Maryland (PJM) Interconnection, of which PP&L is a member. The primary objective of MAAC is to augment reliability through a continuing review of all planning in connection with additions or revisions to generating plant or bulk power transmission facilities. The PP&L bulk power system is designed to meet the MAAC Reliability Principles and Standards, which are included in Appendix 8.2A.

Digital power flow and transient stability studies were conducted to demonstrate that bulk power system is in compliance with the MAAC reliability criteria. The digital power flow studies included an evaluation of all practical single contingencies, including double circuit tower line, outage conditions and several abnormal system disturbance conditions.

Based on historical operating data for the PP&L transmission network, the annual forced outage rate per 100 circuit miles for 500 KV and 230 KV lines is 0.46 and 6.04 outages, respectively. The number of permanent faults per year per 100 circuit miles for 500 KV and 230 KV lines is 0.23 and 1.79 respectively. The duration of the individual outages varies greatly (from 3 minutes to in excess of 8 hours) depending on the cause of the outage. The major causes of forced outages and permanent faults are lightning and weather related phenomena, tree contacts, equipment failure or malfunction, and emergency maintenance.

8.2.2.2. Stability Analysis

Transient stability studies were conducted using a digital computer program. These studies show that for various 230 KV and 500 KV bus and line faults, system stability and satisfactory recovery voltages are maintained resulting in uninterrupted supply to the offsite power system. Specifically, the system is stable for any three phase fault cleared in normal clearing time and for any single phase to ground fault with delayed clearing. The system is also stable for any three phase fault applied to the 500 KV and 230 KV transmission associated with the Susquehanna plant and cleared with delay. A transient stability case list is included in Table 8.2-1.

The loss of either Susquehanna Unit #1 or Unit #2 represents the loss of the largest single supply to the network. For the loss of either Susquehanna unit, grid stability and the integrity of supply to the offsite power system are maintained. Grid stability and the integrity of supply to the offsite power system are also maintained for the loss of any other single generating unit in the network. Supply to at least one of the offsite power sources is also maintained for the following abnormal disturbances:

1. The sudden loss of all lines emanating from the Susquehanna 230 KV Switchyard,
2. The sudden loss of all lines emanating from the Susquehanna 500 KV Switchyard.

No single occurrence is likely to cause a simultaneous outage of all offsite sources during operating, accident, or adverse environmental conditions. While the loss of all offsite power is improbable, such an event would not prevent the safe shutdown of the station because the onsite batteries and standby diesel generators are able to supply the necessary power to systems required for safe shutdown.

## SSES-FSAR

TABLE 8.2-1

1982 50% OF SUMMER PEAK LOAD

SUSQUEHANNA UNIT #1 &amp; #2

STABILITY CASE LIST

<u>CASE</u>	<u>DESCRIPTION</u>	<u>RESULT</u>
1	3 phase fault at Susquehanna 500 KV on the Sunbury 500 KV line. Fault cleared in normal 3.5 cycle clearing time.	Stable
2	3 phase fault at Susquehanna 500 KV on the Sunbury 500 KV line with one breaker pole stuck at Sunbury. Clear Susquehanna in 3.5 cycles. Clear remote terminal in 7.5 cycles.	Stable
3	3 phase fault at Susquehanna 500 KV on Wescosville 500 KV line with one Susquehanna 500/230 KV transformer breaker pole stuck. Clear remote terminal in 3.5 cycles. Clear Susquehanna in 7.5 cycles.	Stable
4	3 phase fault at Susquehanna 500 KV on Sunbury 500 KV line with one Susquehanna 500/230 KV breaker pole stuck. Clear remote terminal in 3.5 cycles. Clear Susquehanna in 7.5 cycles.	Stable
5	Phase-ground fault at Susquehanna 500 KV on Sunbury 500 KV line with Susquehanna 500/230 KV breaker stuck. Clear remote terminal in 3.5 cycles. Clear Susquehanna in 12.0 cycles.	Stable
6	3 phase fault at Susquehanna 230 KV on the Susquehanna 500/230 KV transformer. Fault cleared in normal 4.0 cycle clearing time.	Stable
7	3 phase fault at Montour 230 KV on Susquehanna 230 KV line. Fault cleared in normal 4.0 cycle clearing time. (Reclosed after 10 seconds).	Stable
8	3 phase fault at Susquehanna 230 KV on Montour line with stuck west bus breaker. Clear remote terminal in 4.0 cycles, clear Susquehanna in 8.0 cycles (lose Stanton-Susquehanna #2 230 KV line).	Stable
9	3 phase fault at Susquehanna 230 KV on Jenkins line with stuck	Stable

## SSES-PSAR

TABLE 8.2-1 (Continued)

<u>CASE</u>	<u>DESCRIPTION</u>	<u>RESULT</u>
	east bus breaker. Clear remote terminal in 6.0 cycles, clear Susquehanna in 8.0 cycles.	
10	3 phase fault at Susquehanna 230 KV on the 500/230 KV transformer with one pole stuck on west bus breaker. Clear two poles in 4.0 cycles, clear fault in 8.0 cycles (lose Stanton-Susquehanna #2 230 KV line).	Stable
11	3 phase fault at Susquehanna 230 KV on Harwood line with stuck tie breaker pole. Clear two poles in 4.0 cycles. Clear stuck pole in 8.0 cycles (lose Sunbury-Susquehanna 230 KV line).	Stable
12	3 phase fault at Susquehanna 230 KV on E. Palmerton line with one pole stuck on west bus breaker. Clear two poles in 4.0 cycles. Clear stuck pole in 8.0 cycles (lose Stanton-Susquehanna #2 230 KV line).	Stable
13	Phase-ground fault at Susquehanna 500 KV on Wescosville 500 KV line with Susquehanna 500/230 KV breaker stuck. Clear remote terminal in 3.5 cycles. Clear Susquehanna in 12.0 cycles.	Stable
14	Susquehanna-Wescosville 500 KV and Susquehanna-Harwood (E. Palmerton) Double Circuit 230 KV crossing failure (3 phase fault on all circuits). Trip Susquehanna Unit #1 in 12 cycles. Clear Susquehanna-Wescosville 500 KV line in 3.5 cycles. Clear Susquehanna-Harwood and Susquehanna-E. Palmerton 230 KV lines in 4.0 cycles.	Stable
15	3 phase fault near E. Palmerton on all lines in E. Palmerton-Harwood R/W corridor. Clear Susquehanna-Wescosville 500 KV line in 3.5 cycles. Clear E. Palmerton-Susquehanna and Harwood-Siegfried 230 KV lines in 4.0 cycles.	Stable



SSSES-PSAR

TABLE 8.2-1 (Continued)

<u>CASE</u>	<u>DESCRIPTION</u>	<u>RESULT</u>
16	3 phase fault near Susquehanna on both lines in Sunbury-Susquehanna R/W corridor. Clear Sunbury-Susquehanna 500 KV line in 3.5 cycles. Clear Sunbury-Susquehanna 230 KV line in 4.0 cycles.	Stable
17	3 phase fault near Susquehanna 500 KV at Sunbury 230 KV line crossing. Trip Susquehanna-Wescosville 500 KV, Sunbury-Susquehanna 500 KV, and Unit #2 in 3.5 cycles. Trip Sunbury-Susquehanna 230 KV in 4.0 cycles.	Stable
18	3 phase fault at Susquehanna 230 KV on Harwood (E. Palmerton) Double Circuit. Trip Harwood and E. Palmerton breakers in 4.0 cycles.	Stable
19	3 phase fault at Columbia-Frackville 230 KV line crossing. Trip Sunbury-Susquehanna 500 KV line in 3.5 cycles. Trip Columbia-Frackville and Sunbury-Susquehanna 230 KV lines in 6.0 cycles.	Stable
20	3 phase fault on 230 KV side of Unit #1 main transformer. Trip Unit #1 main transformer. Trip Unit #1 and overtrip Unit #2 in 4.0 cycles (loss of entire station).	Stable
21	3 phase fault at Susquehanna 230 KV on Unit #1 generator leads with a stuck west bus breaker. Trip Unit #1 and Stanton #2 line in 12.0 cycles.	Stable

### 8.3 ON-SITE POWER SYSTEMS

#### 8.3.1 AC POWER SYSTEMS

##### 8.3.1.1 Description

The on-site ac power systems are divided into Class IE and non-Class IE systems. Figure 8.3-1 shows the single line of both systems with the Class IE system identified by a dotted line enclosure.

The on-site ac power systems consist of main generators, main step-up transformers, unit auxiliary transformers, and diesel generators. The distribution system has nominal ratings of 13.8 kV, 4.16 kV, 480 V, and 208/120 V.

The off-site ac power system supplies power to plant systems through two start-up transformers.

##### 8.3.1.2 Non-Class IE ac System

The non-Class IE portion of the on-site power systems provides ac power for non-nuclear safety related loads. A limited number of nonsafety related loads are important to the power generating equipment integrity and are fed from the Class IE distribution system through the isolation system as discussed in Subsection 8.1.6.1(n).

The non-Class IE ac power system distributes power at 13.8 kV, 4.16 kV, 480 V, and 208/120 V voltage levels. These distribution levels are grouped into two symmetrical distribution systems emanating from the 13.8 kV buses.

All non self-activated switchgears receive control power from the 125 Vdc control power sources. The 125 Vdc control power sources for the non-Class IE 13.8 kV and 4 kV switchgear breakers, and 480 V load center breakers are shown in Tables 8.3-17 and 8.3-18 respectively.



8.3.1.2.1 Operation

The unit auxiliary transformer supplies all the non-Class IE unit auxiliary loads except unit HVAC and Units 1 and 2 common loads, which are fed by the two startup transformers as shown on Figures 8.3-1 and 8.3-2.

The unit auxiliary transformer primary is connected to the main generator isolated phase bus duct tap (24 kV) while the secondary of the transformer is connected to two 13.8 kV unit auxiliary buses through a nonsegregated phase bus.

During plant startup, shutdown, and post shutdown, power is supplied from the off-site power sources through the two startup transformers. In addition, capability is provided to transfer the unit auxiliary buses to the startup power source to maintain continuity of power at the unit auxiliary distribution system.

In addition to the loading conditions mentioned in the above paragraph, the 13.8 kV startup buses also supply the preferred power supplies to the Class IE load groups through their respective 13.2 kV - 4.16 kV engineered safeguard transformers as discussed in Subsection 8.3.1.3 (Figure 8.3-1).

The auxiliary bus feeder breakers from the unit auxiliary transformers and the startup tie bus section are interlocked to prevent supplying power to the startup bus from the unit auxiliary transformer.

A 13.8 kV tie bus is provided for the two startup buses. A separate (not in switchgear line-up) bus tie breaker is located in the tie bus. In the event of a loss of startup power supply to the 13.8 kV startup bus, an alarm is initiated and, a time delay undervoltage relay initiates the tripping of the 13.8 kV incoming breaker and the closing of the tie breaker, resulting in a slow transfer. However, this transfer is prevented if either auxiliary 13.8 kV bus is being fed from the undervoltage tie bus section. This condition is sensed by the closure of two (2) auxiliary "b" contacts in series, one from each of the unit auxiliary bus to tie-bus circuit breakers connected to a common tie bus section. Manual initiation of the tie breaker is also provided. However, the use of this manual control is administratively limited as an overriding means only. Under automatic operating conditions of the tie breaker, auxiliary switch "b" contacts of the startup transformer incoming breakers are also utilized as a permissive to close the tie breaker to prevent tying of the two startup transformers.

At the 4 kV ESF power distribution subsystem a three-way transfer system is provided to enable the ESF loads to connect to either of the two off-site power sources or to the standby diesel

generators. Each ESF bus is normally connected to a preferred source which is one of two ES transformers connected respectively to the two startup buses. During loss of one off-site power source, that is, upstream of the startup bus, the startup bus undervoltage relay will trip the feeder breaker to the ES transformer, causing a transfer at the 4kV ESF bus. If power loss occurs between the 13kV startup bus and the 4kV ESF bus, a 4kV transfer will occur. The 4kV ESF bus transfer is initiated by the bus undervoltage relay, which trips the normal incoming breaker and subsequently closes the alternate incoming breaker. This is practically a dead bus transfer. If both off-site power sources are unavailable, the diesel generator breaker closes as soon as the diesel generator power is available.

The above transfer mechanism allows only one source breaker to be closed at any one time and to ensure this, breaker auxiliary switch contacts are used for interlocking. A manual live bus transfer is possible through a synchronizing device in which case an alternate source breaker is first closed and is followed by an automatic tripping of the preferred supply breaker. In this case the duration of the tie is merely a few cycles. Furthermore, the diesel generator can be tied with any one of the two off-site sources for an indefinite time under test condition but this does not in any way cause the two off site power systems to be tied together.

The plant security load center is double ended, each end being supplied from one of the 13 kV start-up buses through a stepdown transformer and is provided with a normally open tie breaker. Each bus is supplied from its own start-up source. Should one source be lost the undervoltage relay at the transformer secondary trips the bus incoming breaker. The bus undervoltage relay then initiates closure of the tie breaker provided the incoming breaker has successfully tripped. Upon return of the failed source the incoming breaker will not automatically close and can only be manually closed after the tie breaker has been tripped.

In all of the foregoing tie or transfer systems, there is no way that the two off-site power systems can be tied together at the on-site buses assuming loss of one off-site source.

The 13.8 kV switchgear provide power for large auxiliary loads and 480 V load centers. The 13.8 kV switchgear feed double-ended 480 V load centers. A manual tie breaker is provided for each set of load centers to intertie the two load centers in the event of failure of one load center transformer. Load centers generally supply power to 480 V loads larger than 100 hp and power for their respective motor control centers. The motor control centers supply 480 V loads smaller than 100 hp while 480 V, 480/277 V, 208/120 V panels provide miscellaneous loads such as unit heaters, space heaters, lighting systems, etc.

8.3.1.2.2 Non-Class IE Equipment Capacities

Refer to Figure 8.3-1 for interconnections of the following equipment. Physical locations of each of the following equipment can be found in Section 1.2.

## a) Unit Auxiliary Transformer

33/44/55 MVA, 3 $\phi$ , OA/FA/FOA, 55°C  
 37/49.3/61.6 MVA, OA/FA/FOA, 65°C  
 23.0-13.8 kV Grd. Y/7.96 kV  
 Z = 9.0% @ 33 MVA

## b) Startup Transformer

45/60/75 MVA 3 $\phi$ , OA/FOA/FOA, 65°C  
 225/129.9 -- 13.8/7.97 kV  
 Z = 15.0% @ 45 MVA  
 LTC  $\pm$  15% in 15/16% steps

## c) Engineered Safeguard Transformer

10.5/13.12 MVA, 3 $\phi$ , OA/FA, 55°C  
 11.76/14.7 MVA, OA/FA, 65°C  
 13.2-4.16 kV Grd. Y/2.4 kV  
 Z = 6.8% @ 10.5 MVA

## d) Unit Auxiliary 13.8 kV Switchgear

Buses	2000 A continuous rating, 750 MVA bracing
Incoming breakers	2000 A continuous rating, 750 MVA 3 $\phi$ Class 28,000 A sym interrupting rating
Feeder breakers	1200 A continuous rating, 750 MVA 3 $\phi$ Class 28,000 A sym interrupting rating

## e) Startup 13.8 kV Switchgear

Buses	3000 A continuous rating, 750 MVA bracing
Incoming breakers	3000 A continuous rating, 750 MVA 3 $\phi$ Class 28,000 A sym interrupting rating

Tie breaker	3000 A continuous rating, 750 MVA 3 $\phi$ Class 28,000 A sym interrupting rating
Feeder breakers	1200 A continuous rating, 750 MVA 3 $\phi$ Class 28,000 A sym interrupting rating
f) 4.16 kV Switchgear	
Buses	1200 A continuous rating, 250 MVA bracing
Incoming breakers	1200 A continuous rating, 250 MVA 3 $\phi$ Class 29,000 A sym interrupting rating
Feeder breakers	1200 A continuous rating, 250 MVA 3 $\phi$ Class 29,000 A sym interrupting rating
g) 480 V Load Centers	
Transformers	1500/2000 kVA, 3 $\phi$ , AA/FA, 13200-480 V Grd. Y/277 V
Control structure, Administration, Security and machine shop transformers only	1000/1333 kVA, 3 $\phi$ , AA/FA, 13200-480 V Grd. Y/277 V
Buses	3000 A continuous; 65,000 A bracing (1500/2000 kVA) 1600 A continuous; 50,000 A bracing (1000/1500 kVA)
Incoming breakers	3000 A continuous, 65,000 A sym interrupting rating (1500/2000 kVA) 1600 A continuous, 50,000 A sym interrupting rating (1000/1500 kVA)
Feeder breakers	600 A continuous, 30,000 A sym interrupting rating
Tie breakers	1600 A continuous, 50,000 A sym interrupting rating

## h) 480 V Motor Control Centers

Horizontal bus (main) 600 A continuous; 42,000 A bracing

Vertical bus 400 A continuous; 42,000 A bracing

Breakers (Molded Case)

150 A frame 25,000 A symmetrical interrupting rating

250 A frame 22,000 A symmetrical interrupting rating

## i) 480 V Distribution Panel

Bus 225 A rating, 14,000 A bracing

Branch breakers 100 A frame, 14,000 A interrupting rating

## j) 208/120 V ac Instrument ac Distribution Panels

Main breaker (molded case) 225 A continuous 22,000 A sym interrupting rating

Buses 225 A continuous

Branch breakers (molded case) 100 A frame size 10,000 A sym interrupting rating

### 8.3.1.3 Class IE ac Power System

The Class IE ac portion of the on-site power system is shown on Figure 8.3-1.

The Class IE ac system distributes power at 4.16 kV, 480 V, and 208/120 V to the safety related loads. The safety related loads are divided into four load groups per generating unit and are tabulated in Table 8.3-1. Each load group has its own distribution system and power supplies.

The 4.16 kV bus of each Class IE load group channel is provided with connections to two off-site power sources designated as preferred and alternate power supplies. Diesel generators are provided as a standby power supply in the event of total loss of

the preferred and alternate power supplies. Standby power supply is discussed in Subsection 8.3.1.4.

Preferred and alternate power supplies up to the 4.16 kV buses of the Class IE power system are considered as non-Class IE.

All non self-activated switchgears receive control power from the 125 Vdc control power sources. The 125 Vdc control power sources for the Class IE 4.16 kV switchgear breakers and 480 V load center breakers are shown in Tables 8.3-19 and 8.3-20 respectively.

In order to achieve adequate separation between channelized load group and divisionalized load group, two 125 Vdc control power supplies are provided for each 4.16 kV switchgear (refer to Table 8.3-19).

#### 8.3.1.3.1 Power Supply Feeders

Each Class IE 4.16 kV switchgear of a load group channel is provided with a preferred and an alternate (off-site) power supply feeder and one standby diesel generator feeder. Each bus is normally energized by the preferred power supply. If the preferred power source is not available at the 4.16 kV bus, automatic transfer is made to the alternate power source as described in Subsection 8.3.1.3.6. If both preferred and alternate power feeders become de-energized, the safety-related loads on each bus are picked up automatically by the standby diesel generator assigned to that bus as described in Subsection 8.3.1.4.

#### 8.3.1.3.2 Power Feeder Cables

Power feeder cables for the 4.16 kV system are aluminum conductor, and are rated 5 kV, 90°C conductor temperature with high temperature Kerite insulation. The cables are provided with an overall flame resistant Kerite jacket covering. For the 480 V system, cables of size #4/0 AWG and larger are aluminum conductor; cables less than #4/0 AWG are copper conductor. Both types of cables are rated 600 V, 90°C conductor temperature with ethylene-propylene insulation with a flame-resistant hypalon jacket covering. The conductors are sized to carry the maximum available short circuit current for the time required for the circuit breaker to clear the fault. All Class IE cables have been designed for operation as discussed in Section 3.11.

The 4.16 kV switchgear, D.C. load centers, and D.C. Control centers are equipped with aluminum buses and silver-plated bolted

connections. The 480 V load centers and motor control centers are equipped with copper/aluminum busses and the bolted connections are also silver-plated. All circuit breaker terminals are copper. For power cable terminations, Burndy compression aluminum terminals (HYLUG) are used. These terminals are of seamless tubular construction, tin-plated to resist corrosion, and factory filled with oxide inhibiting compound penetrox A. Compression adapters MAC ADAPT MPT series or equivalent are used for equipment/vendor supplied components having mechanical lugs which cannot be converted to accept a Burndy compression lug due to physical or practical limitations. A non-oxidizing lubricant such as D50H47 or equivalent will be applied on all contact surfaces at bolted joints to avoid damaging the silver-plated contact surfaces.

### 8.3.1.3.3 Bus Arrangements

The Class IE ac system is divided into four load group channels per unit (load group Channels A, B, C, and D). Power supplies for each load group are discussed in Subsection 8.3.1.3.1. All Class IE ac loads are divided among the four load groups so that any combination of three out of four load groups has the capability of supplying the minimum required safety loads.

The distribution system of each load group consists of one 4.16 kV bus, one 480 V load center, four or five motor control centers, and several low voltage distribution panels. The bus arrangements are shown on Figure 8.3-1, 8.3-3, 8.3-4, 8.3-7 and 8.3-8.

### 8.3.1.3.4 Loads Supplied from Each Bus

Table 8.3-1 provides a listing of all the loads supplied from each Class IE bus.

### 8.3.1.3.5 Class IE Isolated Swing Bus

Two redundant 480 V swing buses are provided for each unit for the RHR injection valve motor operators, recirculation loop bypass valve motor operators, and recirculation discharge valve motor operators. The single line of the swing bus is shown on Figure 8.3-9.

A Class IE 480 V load center of one load group channel supplies the preferred power to the swing bus through the electrical isolation of a motor-generator (M-G) set. The alternate power is

supplied directly from another redundant Class IE 480 V load center. The M-G set is used for electrically isolating two redundant load groups. Faults at the swing bus cannot be propagated onto more than one load group.

The swing buses are Class IE motor control center constructions. An automatic transfer switch is provided for transferring the swing bus from the preferred to the alternate power source upon reduction or loss of voltage at the swing bus. If the undervoltage is caused by a fault at the swing bus, the transfer will be prevented even if the alternate power is available. The swing bus will be retransferred back to preferred power when the voltage is restored within acceptable limits.

The swing bus and transfer switch are designed so that for a loss of off-site power and any single failure, the minimum required ECCS flow to meet 10CFR50 Appendix K criteria is always available.

The following is a common mode-common cause failure analysis (CMCCFA) for the automatic transfer switches:

Figure 8.3-13 depicts a simplified single line diagram for the swing bus system to facilitate the analysis.

Table 8.3-24 provides a step-by-step CMCCFA of the auto transfer switch by postulating the various major common causative factors (events).

Normal conservatism in design and manufacturing margins, mandatory requirements of QA/QC procedures, Initial Test Program, Preoperational Tests, applicable administrative procedures and maintenance programs as well as operator actions contribute to minimize the susceptibility of the auto transfer switch to the various common causative factors as analyzed in Table 8.3-24.

This analysis demonstrates that the transfer switch, as a component of the swing bus system design, will not degrade the independence and separation between the redundant Class IE channels (load center channels A and C or B and D).

The test program (Section 14.2 and Technical Specification 314.8) for the 480V swing bus system (Figure 8.3-13) consists of:

- a) Periodic inspection of wiring, insulation, and connections etc. to assess the continuity of the components and system.
- b) Periodic testing to verify the operability and functional performance of individual components in the system.
- c) Periodic testing of operational sequence and operability of the system as a whole.



### 8.3.1.3.6 Manual and Automatic Interconnections Between -----Buses, Buses and Loads, and Buses and Supplies-----

No provision exists for automatically or manually connecting one Class IE load group to the redundant Class IE load group or for automatically transferring loads between load groups except the swing buses as discussed in Subsection 8.3.1.3.5.

For each load group, one 4.16 kV feeder circuit breaker is provided for the normal incoming preferred power source, and another 4.16 kV feeder circuit breaker is connected to the alternate power source (see Subsection 8.3.1.3.1). The normal preferred power source to each bus is electrically interlocked with the alternate power source such that the bus can be connected to a single power source at any one time. In the event of loss of preferred power to the load group, undervoltage relays (less than or equal to 15 percent voltage) on the 4.16 kV switchgear will initiate an automatic transfer to the alternate power source if available. In the event of losing both preferred and alternate power supplies, the load group will be powered from the standby diesel generator.

Restoration of power from standby power to the preferred source of offsite power is manually initiated in the control room on panel QC653. When the standby power source is in synchronism with the offsite power source, the preferred offsite source incoming breaker is closed. Upon closing of this preferred source breaker, the standby source breaker will automatically trip. This tripping is initiated by the preferred offsite source breaker auxiliary switch contact interlock.

A similar procedure is used to restore power from standby to the alternate offsite power.

### 8.3.1.3.7 Interconnections Between Safety Related and Nonsafety Related Buses, Nonsafety Related -----Loads, and Safety Related Buses-----

Discussion of interconnections between safety related and non-safety related buses, nonsafety related loads, and safety related buses is presented in Subsections 3.12.2 and 8.1.6.1.

8.3.1.3.8 Redundant Bus Separation

The engineered safety features switchgear, load centers, and motor control centers for the redundant Class IE load groups are located in separate Seismic Category I rooms in the reactor building to ensure electrical and physical separation. Electrical equipment separation is discussed in Subsection 3.12.2 and Subsection 8.1.6.1. Equipment layout drawings can be found in Section 1.2.

8.3.1.3.9 Class IE Equipment Capacities

## a) 4.16 kV Switchgear

Buses	1200 A continuous rating, 250 MVA bracing
Incoming breakers	1200 A continuous rating, 250 MVA 3 $\phi$ Class 29,000 A sym interrupting rating
Feeder breakers	1200 A continuous rating, 250 MVA 3 $\phi$ Class 29,000 A sym interrupting rating

## b) 480 V Load Centers

Transformers (Unit 1)	750/1000 kVA, 3 $\phi$ , AA/FA, 13800-480 V Grd. Y/277 V
Transformer (Unit 2)	750 kVA, 3 $\phi$ , AA, 13800-480 V Grd. Y/277 V
Buses	1200 A continuous, 30,000 A bracing
Breakers	600 A frame size, 30,000 A sym interrupting rating

## c) 480 V Motor Control Centers

Buses	
Horizontal (main)	600 A continuous, 42,000 A bracing
Vertical	400 A continuous, 42,000 A bracing

## Breakers (molded case)

150 A frame	25,000 A sym interrupting rating
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250 A frame	22,000 A sym interrupting rating
-------------	----------------------------------

d) Automatic transfer switch	480 V, 3 $\phi$ , 400 A continuous 31,000 A sym withstand capability
------------------------------	--

e) 208/120 V ac Instrument ac Distribution Panels	
---	--

Buses	225 A continuous 10,000 A sym interrupting rating
-------	--

Branch breakers (molded case)	100 A frame size 10,000 A sym interrupting rating
-------------------------------	--

8.3.1.3.10 Automatic Loading and Load Shedding

If preferred off-site power is available to the Class 1E 4.16 kV bus following a LOCA signal, the required ESP loads will start as shown in Tables 8.3-1 and 8.3-1b.

In the event of loss of preferred and alternate off-site power supplies, the Class 1E 4.16 kV buses will shed all loads except the 480 V load centers and connect the standby diesel generator to the Class 1E bus. The loading sequence is shown on Table 8.3-1.

However, if a slow bus transfer (bus voltage on transfer is less than 15%) at the Class 1E 4.16 kV bus is initiated to the alternate off-site power as a result of a loss of preferred off-site power, all loads are shed except the 480 V load centers. Then the required ESP loads will start as shown on Tables 8.3-1 and 8.3-1b.

Emergency loads are also sequenced with off-site power because of the power system limitation (transformer capability). Load sequencing is designed to minimize system disturbance.

Tables 8.3-1 and 8.3-1b show the anticipated starting time of all ESP loads. Both Unit 1 and Unit 2 buses for a given diesel generator are normally supplied by the same off-site power supply. An individual timing unit is provided for each of the

ESF loads with automatic start function. Failure to start on one load will not affect the starting initiation of other loads.

The loading sequence for a simultaneous LOCA in one unit and a false LOCA in the other unit is shown in Table 8.3-1b. A false LOCA signal as used in this section refers to a non-mechanistic failure resulting in a LOCA signal in one reactor unit when a LOCA has not occurred in that unit.

The load starting transient on the diesel generators is reduced if the Unit 1, and Unit 2 load sequences do not start simultaneously.

If off-site power is available, the LOCA signal in one unit and false LOCA signal in the other will shed 2 RHR motors and 2 core spray motors of each unit and sequentially start 2 RHR and 2 core spray motors as shown in Table 8.3-1b. This is done in order not to exceed the loading limitations of the ES Transformers and to provide at least the minimum core cooling requirements of both units. Under the modified core cooling arrangement, 2 RHR pumps (one in each loop) and 2 core spray pumps (both in the same loop) will satisfy the minimum cooling requirements of each unit.

Approximately ten minutes after the above event the operator will be able to determine which is the false-LOCA unit and shutdown non-essential loads in the non-LOCA unit. In case off-site power is not available, the loading is the same as discussed above, but the sequencing is slightly altered as shown in Table 8.3-16.

Under all conditions discussed in Subsections 8.3.1.3.10.1 and 8.3.1.3.10.2, safety functions are met within the time limits shown in Table 6.3-1.

#### 8.3.1.3.11 Safety Related Equipment Identification

Subsection 8.3.1.11.3 provides information regarding the physical identification of Class IE equipment.

#### 8.3.1.3.12 Instrumentation and Control Systems for the Applicable Power Systems with the Assigned Power Supply Identified

The dc power supplies for the control of the redundant Class IE equipment are physically and electrically separate and independent. Refer to Subsection 8.3.2 for a detailed discussion of the dc system.

8.3.1.3.13 Electric Circuit Protection Systems

Protective relay schemes and direct-acting trip devices on primary and backup circuit breakers are provided throughout the on-site power system in order to:

- a) Isolate faulted equipment and/or circuits from unfaulted equipment and/or circuits
- b) Prevent damage to equipment
- c) Protect personnel
- d) Minimize system disturbances
- e) Maintain continuity of the power supply

Major types of protection measures employed include the following:

a) Bus Differential Relaying

A bus differential relay is provided for each Class IE 4.16 kV bus. This relay provides high speed disconnecting of bus supply breakers to prevent propagation of internal bus fault to another bus.

b) Overcurrent Relaying

Each Class IE 4.16 kV bus feeder circuit breaker is equipped with three extremely inverse-time overcurrent relays to sense and to protect the bus from an overcurrent condition.

The standby diesel generator feeder circuit breaker to the 4.16 kV bus is equipped with three voltage restrained overcurrent relays and one inverse-time ground fault relay for feeder circuit protection.

Each 4.16 kV motor feeder circuit breaker has three overcurrent relays, each with one long time and one instantaneous element for overload, locked rotor, and short-circuit protection. Each breaker is also equipped with an instantaneous ground current relay.

Each Class IE 4.16 kV supply circuit breaker to a 480 V load center transformer is protected by three overcurrent relays with long-time and instantaneous elements. An instantaneous overcurrent ground sensor relay provides sensitive ground fault protection.

c) Under/Overvoltage Relaying

Each 4.16 kV Class IE bus is equipped with undervoltage relays for diesel generator starting and undervoltage annunciation. Each 4kV bus is provided with degraded grid voltage protection. Each 480 V Class IE load center bus is equipped with under/overvoltage relays for annunciation.

d) Diesel Generator Differential Relaying

Each diesel generator is equipped with differential relaying protection. This circuitry provides high speed disconnection to prevent severe damage in case of diesel generator internal faults.

e) 480 V Load Center Protection

Each load center circuit breaker is equipped with integral, solid-state, dual magnetic, adjustable, direct-action trip devices providing inverse-time overcurrent protection. Motor feeders are equipped with long-time overcurrent and instantaneous short-circuit protection.

f) 480 V Motor Control Center Protection

Molded-case circuit breakers provide inverse-time overcurrent and/or instantaneous short circuit protection for all connected loads. For motor circuits, the molded-case circuit breakers are equipped with an adjustable instantaneous magnetic trip function only. Motor thermal overload protection is provided by the heater element trip unit in each phase of the motor feeder circuit. The molded-case breakers for nonmotor feeder circuits provide thermal inverse-time overcurrent protection and instantaneous short circuit protection. The thermal overload trip units for safety related motor-operated valves are normally bypassed except during maintenance tests.

The circuit protection system is designed so that fault isolation is secured with a minimum circuit interruption. The combination of devices and settings applied affords the selectivity necessary to isolate a faulted area quickly with a minimum of disturbance to the rest of the system.\* The protective devices are preoperationally tested in accordance with the requirements of Chapter 14. After the plant is in operation, periodic tests will be performed to verify the protective device calibration, set points, and correct operation in accordance with the requirements of Chapter 16.

8.3.1.3.14 Testing of the ac System During Power Operation

All Class IE circuit breakers and motor starters, except for the electric equipment associated with Class IE loads identified in Subsection 8.3.1.3.15, are testable during reactor operation. During periodic Class IE system tests, subsystems of the ESF system such as safety injection, containment spray, and containment isolation are actuated, thereby causing appropriate circuit breaker or contactor operation. The 4.16 kV and 480 V circuit breakers and control circuits can also be tested independently while individual equipment is shut down. The circuit breakers can be placed in the test position and exercised without operation of the related equipment.

8.3.1.3.15 Class IE Loads not Testable During Power Operations

## A. Feedwater Line Isolation Valves

The feedwater line isolation valves (HV-F032 A/B) are of the motor operated check valve type and are not testable with the feedwater flow present. Motor operation is not required for isolation. Only the outermost isolation valve is Class IE powered and would be motor operated for long term isolation after isolation of the feedwater line.

Conformance with Regulatory Guide 1.22 Section D.4:

1. The feedwater isolation is not designed for isolation with feedwater flow present as the loss of flow would adversely affect operability of the plant.
2. Motor operation is not required for isolation.
3. The motor operator of the outermost isolation valve is fully testable during shutdown.

## B. Main Steam Isolation Valves

The main steam isolation valves can be tested individually to the 90% open position at full power with the slow acting test solenoid valve. A fully closed test using the two fast acting main solenoids would require a reduction in reactor power.

Conformance with Regulatory Guide 1.22: See Subsections 7.3.2a.2.2.1.2 and 5.4.5.4.

## C. ADS System - Safety/Relief Valves

The active components of the ADS system except the safety/relief valves and their associated solenoid valves are designed so they may be tested during plant power operation. The relief valve and associated solenoid are not tested during reactor power operation.

Conformance with Regulatory Guide 1.22:

1. The safety/relief valves are not tested during power operation because of resulting adverse affect on plant operation.
2. Because of low failure rates of valve actuation, the probability of failure is acceptably low without testing.
3. The safety/relief valves and associated solenoid valves can be tested during startup following shutdown.

D. Recirculation Loop Isolation Valves

The recirculation pump isolation valves are not tested during reactor power operations.

Conformance with Regulatory Guide 1.22 Section D.4:

1. Operation of a recirculation loop isolation valve would result in a reduction of circulation which would adversely affect the safety and operability of the plant.
2. The probability of failure is acceptably low without testing the valve motor during operation.
3. The valve and motor are fully testable during reactor shutdown.

8.3.1.4 Standby Power Supply

The standby power supply for each safety related load group consists of one diesel generator complete with its accessories and fuel storage and transfer systems. Each diesel generator is rated 4000 kw at 0.8 pf for continuous operation and 4700 kw for 2000 hr operation. The ratings for each diesel generator are calculated in accordance with the recommendation of Regulatory Guide 1.9 (discussed in Subsection 8.1.6.1). The diesel-generators can operate at loads of from 50 to 100 percent for unlimited periods without harm. Any diesel generator continuously operated at loads of less than 50 percent will be loaded to 75-100 percent for 15-30 minutes approximately every



six hours and immediately prior to shutdown. Any diesel generator continuously operating at loads of less than 50 percent for less than six hours will be loaded to 75-100 percent for 15-30 minutes immediately prior to shutdown. Such operation will enhance engine performance and reliability.

The four diesel generators are shared by the two units. Each diesel generator is connected to the 4.16 kV bus of the assigned load group per unit. The capacity of the diesel generators (assuming one diesel fails) is sufficient to operate the engineered safety features loads of one unit and those systems required for concurrent safe shutdown of the second unit.

No provisions are provided for parallel operation of the diesel generator of one load group with the diesel generator of the redundant load group. The diesel generator circuit breaker and the off-site power incoming circuit breakers are interlocked to prevent feedback into the off-site power system. These interlocks are bypassed during diesel generator load tests; however, only one unit is tested at any one time. During the test period, the diesel generator under test is manually synchronized to the preferred off-site power system. Upon receipt of a LOCA signal under the test condition, the diesel generator breaker is tripped but the diesel generator continues to run.

The diesel generators are physically and electrically isolated from each other. Physical separation for fire and missile protection is provided between diesel generators by separate rooms within a Seismic Category I structure. Power and control cable for each of the diesel generators and associated switchgear are routed in separate raceways. Physical electrical equipment layout of the diesel generator rooms is shown on Figure 8.3-10.

Auxiliaries required for starting and continuous operation of each diesel generator are fed by the Class IE power load group associated with that diesel generator.

Control power for each diesel generator is provided by its corresponding 125 V dc systems from both Unit 1 and Unit 2. These two power feeders are not redundant, but have been provided for ease of maintenance. Indication of which unit is supplying the dc control power is not provided in the control room. Manual switches are installed at the local panel to select the preferred power feeder. Since each diesel generator is shared by both units, either source of DC control power is adequate. Loss of DC power to the Diesel Generator is indicated on the BIS panels as a group trouble alarm on panel 0C653 in the main control room.

Each diesel generator is provided with a local engine control panel, a generator-exciter control panel, a local 4.16 kV

distribution panel, and a 480 V motor control center in the diesel generator room.

- a) Local Engine Control Panel - consists of a local annunciator, engine control devices, gauges, and control for diesel generator auxiliary equipment such as fuel oil transfer pump, standby jacket water pump, etc.

The diesel generator control system is designed in such a manner that some control devices are mounted in the free standing control panel separate from the engine, while others are mounted directly on the engine, as required for reliable service. All devices that are essential to the start-up or power output of the diesel-generator set have been seismically qualified by analysis or test to acceleration levels consistent with their mounting location.

- b) Generator-Exciter Control Panel - consists of generator excitation control equipment, generator protective relays and devices, etc.
- c) 4.16 kV Distribution Panel - provides connections for diesel generator feeders to Unit 1 and 2. Also houses potential transformers and current transformer, etc.
- d) 480 V Motor Control Center - provides power to all 480 V auxiliary equipment related with that diesel generator. This MCC is equipped with an automatic transfer switch for connection to either Unit 1 or 2 480 V Class IE load center. These two load centers belong to the same load group channel as the diesel generator.

Physical separation of standby power system is discussed in Section 3.12.

#### 8.3.1.4.1 Automatic Starting Initiating Circuits

The diesel generators are automatically started by any of the following conditions:

- a) Total loss of power to the 4.16 kV Class IE bus of either unit to which the diesel generator is connected
- b) Safety injection signal - low water level in the reactor, high drywell pressure, or manual actuation.

Two redundant control/starting circuits are provided for each diesel generator. Failure of one circuit would not prevent the respective diesel generator from starting or from continuous operation.

The diesel generators are ready to accept loads within 10 sec after the initiation of the start circuit.

#### 8.3.1.4.2 Diesel Starting Mechanism and System

The diesel generator start system is described in Subsection 9.5.6. To ensure fast and reliable starting, each diesel engine is provided with immersion heaters in the engine jacket water and the lube oil system to maintain the engine coolant and lube oil temperature at an operable level. The electric jacket water immersion heater and the water circulating pump are interlocked for simultaneous operation when the jacket water temperature drops below the preset temperature. The electric lube oil immersion heater and the prelube circulating pump are interlocked for simultaneous operation when the engine is below 280 rpm. Refer to Subsections 9.5.5 and 9.5.7 for further description.

#### 8.3.1.4.3 Alarm and Tripping Device

The protective and alarm logic diagrams for the diesel generator and its associated breakers are shown on Figures 8.3-11 and 8.3-12.

While supplying loads following an automatic start, each diesel engine and related generator circuit breaker are tripped by protective devices under the following conditions only:

- a) Engine overspeed
- b) Lube oil low pressure
- c) Generator differential

To prevent spurious tripping of the diesel generator due to malfunction of the engine lube oil low pressure trip device, four independent sensors are provided and connected in a coincidence one-out-of-two taken twice tripping logic. An individual tripping alarm is provided by the annunciator at each local control panel.

The starting circuit is also equipped with a "fail to start" relay operator that interrupts the starting of the diesel

generator if a predetermined speed is not reached within a limited time following a start initiation.

In addition to the above-listed trips, each generator circuit breaker is tripped by the following protective relays to disconnect the generator from a faulty bus (the diesel generator continues to run):

- a) Voltage restrained overcurrent
- b) 4 kV bus differential.

Following a manual start, a diesel generator is in the test mode and ready for a load test. When so operated, in addition to the above-listed trips, each diesel engine and related generator circuit breaker are automatically tripped by the following protective devices:

- a) Generator loss of field
- b) Generator overexcitation
- c) Antimotoring
- d) Generator underfrequency
- e) Generator overvoltage
- f) Generator high bearing temperature
- g) High jacket water temperature
- h) Turbo lube oil pressure low
- i) Main and connecting rod bearing temperature high
- j) Engine vibration
- k) Turbo thrust bearing failure.

An individual alarm is also provided for each of these abnormal conditions at the local control panel. A group alarm is provided in the main control room as a high priority alarm.

Other relays and devices are provided to annunciate abnormal diesel engine and generator conditions at the local control panel as following. These conditions are annunciated in the main control room as a low priority alarm.

- a) Generator field ground
- b) Generator voltage unbalance

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- c) Generator neutral overvoltage
- d) Engine lube oil pressure high
- e) Crankcase pressure high
- f) Engine lube oil temp off normal
- g) Engine crankcase level low
- h) Auxiliary standby pump on
- i) Jacket water temperature off normal
- j) Jacket water low pressure
- k) Fuel oil pressure high
- l) Fuel oil pressure low
- m) Fuel strainer high differential pressure
- n) Fuel filter high differential pressure
- o) Lube oil filter high differential pressure
- p) Starting air system low pressure or malfunction
- q) Voltage regulator transfer to standby
- r) Jacket water standpipe level high
- s) Jacket water standpipe level low
- t) Fuel oil day tank level high
- u) Fuel oil day tank level low
- v) Fuel storage tank level high
- w) Fuel storage tank level low
- x) Motor control center not proper for automatic operation  
(actuated by blown control fuse, etc.)
- y) Control switches not proper for remote automatic  
operation (diesel generator auxiliaries)
- z) Lube oil circulating pump malfunction
- aa) Lube oil heater malfunction

- bb) Jacket water heater malfunction
- cc) Jacket water circulating pump malfunction

The following alarms are provided in the main control room annunciator:

- a) Diesel generator tripped
- b) High priority alarm (all trip conditions listed previously)
- c) Low priority alarm (all abnormal conditions listed previously)
- d) Diesel generator breaker tripped
- e) Diesel generator fails to start
- f) Diesel generator near full load
- g) Diesel generator not in automatic mode.

#### 8.3.1.4.4 Breaker Interlocks

Interlocks have been provided in the closing and tripping of the 4.16 kV Class IE circuit breakers to protect against the following conditions:

- a) Automatic energizing of electric devices or loads during maintenance
- b) Automatic closing of the diesel generator breaker to any energized or faulted bus
- c) Connecting two sources out of synchronism

#### 8.3.1.4.5 Control Permissive

A single key-operated switch at the local control panel is provided for each diesel generator to block automatic start signals when the diesel is out of service for maintenance. An annunciator alarm in the main control room and an indication at the bypass-indication-system panel indicate when the switch is not in automatic position.

A pushbutton in the control room and a local pushbutton at the local control panel in the diesel generator room are provided to allow manual start of the diesel when all protective systems are permissive. During periodic diesel generator tests, permissives and interlocks are designed to permit manual synchronizing and loading of the diesel generator with either off-site power source.

A key operated switch at the local control panel is provided for each diesel generator to regain speed and voltage control of the diesel generators following a loss of and subsequent restoration of offsite power. This permits the diesel generators to be synchronized to the offsite power source, while maintaining the diesel generator in the emergency mode of operation. An annunciator alarm in the main control room indicates when the switch is not in the normal position.

#### 8.3.1.4.6 Loading Circuits

Upon automatic starting of the diesel (emergency mode), connection of the diesel generator to the 4.16 kV bus is not made unless both off-site power sources are lost. As the generator reaches the predetermined voltage and frequency levels, control relays provide a permissive signal for the closing of the respective diesel generator breaker to the corresponding 4.16 kV bus. The diesel generator circuit breaker is closed within 10 sec. after the receipt of the starting signal. The required safety related loads are connected in sequential order to the Class IE buses as shown in Table 8.3-1. This prevents diesel generator instability and ensures voltage recovery thereby minimizing motor accelerating time. A fast-responding exciter and voltage regulator ensures voltage recovery of the diesel generator after each load step.

#### 8.3.1.4.7 Testing

##### Preoperational Test

Each diesel generator is tested at the site prior to reactor fuel loading in accordance with requirements of Chapter 14.

##### Periodic Testing

After being placed in service, the standby power system is tested periodically to demonstrate continued ability to perform its intended function, in accordance with the requirements of Chapter 16.

#### 8.3.1.4.8 Fuel Oil Storage and Transfer System

The diesel generator fuel oil system is described in Subsection 9.5.4.

#### 8.3.1.4.9 Diesel Generator Cooling and Heating

The diesel generator cooling system is described in Subsection 9.5.5.

#### 8.3.1.4.10 Instrumentation and Control Systems for ----- Standby Power Supply -----

The instrumentation and control circuit of each diesel generator is provided with a manual selector switch for connection to either Unit 1 or 2 125 V dc power supply. These two power supplies belong to the same load group channel to which the diesel generator is connected.

Control hardware is provided in the control room for each diesel generator for the following operations:

- a) Starting and stopping
- b) Synchronization
- c) Frequency and voltage adjustment
- d) Manual or automatic voltage regulator selection
- e) Isochronous and droop selection.



Control hardware is provided at each local control panel for the following operations:

- a) Starting and stopping
- b) Frequency and voltage adjustment
- c) Manual or automatic diesel generator mode (key lock selector switch)
- d) Automatic or manual voltage regulator selection
- e) Normal or standby voltage regulator selection
- f) Units 1 or 2 dc control power supply selection.

Electrical metering instruments are provided in the control room for surveillance of the diesel generator:

- a) Voltage
- b) Current
- c) Frequency
- d) Power output.

Electrical metering instruments are provided at the local control panel for surveillance of the diesel generator:

- a) Voltage
- b) Current
- c) Frequency
- d) Power (watt) output
- e) Reactive power (var) output.

8.3.1.4.11 Qualification Test Program

8.3.1.4.11.1 Class IE Equipment Identification

The diesel-generator sets are designated Class IE since they perform essential safety-related functions. Therefore, the equipment was qualified per IEEE 323-1971 and documented in Cooper Energy Services (CES) Report #CE-0188-1. The diesel engine, synchronous generator, and auxiliaries, such as heat exchangers, air receivers, and fuel tanks were qualified.

8.3.1.4.11.2 Qualification Techniques and Documentation

All testing conducted by CES for the Susquehanna SES diesel-generator sets provides the basis for data evaluation of future, ongoing, periodic, jobsite testing. Periodic exercising of the diesel-generator sets shows availability and reliability. Data taken during those tests will be compared to data taken under corresponding load conditions during factory testing. By comparison, trends which may indicate equipment degradation are developed and utilized to predict maintenance intervals.

Testing and analyses completed to verify equipment performance capability are as follows:

- a) Testing performed on the first generator of this contract included the following parameters, with testing procedures as outlined in IEEE 115. Refer to Electric Products test report for generator serial number 17402243-200 dated 5-20-76 for documentation of test results.
  - 1. Synchronous impedance curve.
  - 2. Zero power factor saturation curve.
  - 3. Losses (for efficiency calculation).
  - 4. Direct-axis synchronous reactance.
  - 5. Negative sequence reactance.
  - 6. Direct-axis transient reactance.
  - 7. Direct-axis transient open circuit time constant.
  - 8. Open circuit saturation curve.
  - 9. Start circuit test.

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- b) Testing performed on each generator furnished under this contract included the following parameters with testing procedure as outlined in IEEE 115. Refer to Electric Products test report for generator serial numbers 17402244/246-200 dated 6/22/76 for documentation of test results.
1. Insulation resistance.
  2. High potential tests.
  3. Winding resistance.
  4. Overspeed.
  5. Phase sequence rotation.
  6. Mechanical balance.
- c) Testing was performed on each assembled engine-generator set per IEEE 387 and included the following. Refer to CES test procedure T1-T5 and to CES reports for engine serial numbers 7157-60 for documentation of test results.
1. High potential testing of control wiring.
  2. Measurement of engine vibration.
  3. Fast start capability.
  4. Transient performance evaluation.
  5. Steady state load capability.
  6. Load rejection.
  7. Number of starts from a single air receiver.
  8. Performance evaluation of power factor discriminator and standby voltage regulator.
- d) Functional auxiliaries, such as lube oil pumps, jacket water pumps, heaters, and coolers were evaluated to ensure proper operation during the assembled engine-generator set testing described in c above. The functional capability of the auxiliaries is documented in the test log section of the CES reports for engine serial numbers 7157-60. The establishment of adequate pressures and temperatures in the lube oil, cooling water, and fuel oil systems confirms correct operation of auxiliaries.

- e) Engine and generator control panels were assembled and tested with their respective engine-generator sets and evaluated for proper control and monitoring. Refer to CES reports for engine serial numbers 7157-60 for test results. The achievement of engine-generator transient and steady state performance confirms correct operation of control panels.
- f) To evaluate the seismic effects on the safe shutdown capability some tests have been performed, but most evaluations were achieved by analysis. Both CES and vendor furnished equipment, which are essential to the power output capability of the generator, have been seismically evaluated and determined adequate to meet the specified response spectra with no loss of functional or structural integrity. Refer to CES seismic reports numbered CES-1 through CES-49 for documentation of seismic analyses and tests.

#### 8.3.1.4.11.3 Performance In Service Environment

Actual performance requirements and service conditions are achievable in the field installation only. Simulation of performance is attained through computer techniques which comparatively analyze motor starting data taken during factory testing with motor load starting characteristics predicted for the essential pumps-motors to be started at the jobsite. Simulation of service environments, such as the predicted diesel generator room ambient temperature, would require an environmental chamber large enough to store the entire engine-generator set. In order to ascertain the ability of this equipment to perform in the predicted environment, operating experience and design experience are used. The varied types of engines designed, the varied installation applications, and the resultant experience gained have determined the capabilities of this equipment to perform under different service conditions. This experience is augmented by previous and ongoing R&D testing of a similar CES Type KSV engine where specific data may be needed relative to particular performance requirements. However, much of this data is proprietary.

As a result of this experience and testing, it is concluded the service conditions described in Section 3.11 can be accommodated while fulfilling the performance requirements. For example, installation elevations of up to 1500 feet are accommodated without any derating or design modification. The 676 feet elevation for the Susquehanna SES diesel-generator sets falls well within this range. To accommodate variance in combustion air temperature, coolers/heaters are supplied which either add heat to or take heat from combustion air as needed to provide the

necessary manifold air temperature. The range of  $-19^{\circ}\text{F}$  to  $+105^{\circ}\text{F}$  air temperature is therefore accommodated.

In addition, all service water heat exchangers are designed with fouling factors incorporated permitting the buildup of specified amounts of dirt or sludge while maintaining the necessary heat transfer characteristics under the most adverse load and cooling water temperature conditions. Particles or minerals in the service water are therefore accommodated in heat exchanger design.

Seismic effects are taken into account analytically and by test for all essential components and systems of the diesel-generator sets.

#### 8.3.1.4.12\_\_Control\_and\_Alarm\_Logic

The control and alarm logic for the diesel generators is shown on Fig. 8.3-12. Conditions which render the diesel generator incapable of responding to an automatic emergency start are shown on Table 8.3-16. The following is an item by item analysis of each of these conditions:

##### General Note

The diesel generator will be tripped by (1) generator differential relay, (2) engine overspeed, and (3) low engine lube oil pressure (one-out-of-two taken twice logic) under emergency operation. For test operation, the diesel generator will be tripped by all conditions listed under "Diesel Generator High Priority" alarm as shown on Figure 8.3-12. Following a manual stop, no reset is necessary for subsequent emergency or test operation except the mode selector switch must be returned to "Remote" position. This condition is annunciated locally and in the control room. Following a trip, the control circuit must be reset. The diesel generator trip is also alarmed locally and in the control room.

There are two engine starting circuits for each diesel generator for added reliability. Each circuit is supplied from the same 125 V battery system but through separate circuit breakers. Only one circuit is required for starting and keeping the diesel generator in a running mode. Therefore, any single component failure (as listed in Column B of Table 8.3-16) cannot prevent the diesel generator from starting.

##### 1) ID-B.1 Generator Differential Relay activated

A generator differential relay is provided for each diesel generator for internal fault protection. This relay will

trip the diesel generator under any mode of operation. The diesel generator differential alarm is annunciated locally and repeated as a group alarm "Diesel Generator High Priority Trouble" in the main control room.

2) ID-B.2 Engine Overspeed Relay activated

An independent overspeed sensor is provided for each diesel generator starting circuit. Activation of any one sensor is alarmed, but will not prevent the diesel generator from starting or running.

3) ID-B.3 Engine Lube Oil Low Pressure Relay activated

Each of the control circuits have two independent engine lube oil low pressure switches arranged in a one out of two logic. Pressure switches are bypassed during engine starting. Therefore, alarm is initiated for any one pressure switch (or relay) activation. Disabling of the diesel generator can only be accomplished with one engine lube oil low pressure relay activated in each control circuit.

4) ID-B.4 Operating Mode Switch in "Local"

Operating mode switch (key locked) is put on "Local" for local testing and maintenance services only. "Local position" is annunciated in the main control room as "Diesel Generator not in Auto." Alarm is also indicated in the Bypass Indication System (BIS) on "Diesel Generator Switch in Local" (also in the main control room). Automatic bypass of the "Local" operating mode under emergency condition is not provided. Only one diesel generator will be tested or taken out for service at any one time.

5) ID-B.5 Loss of 125 VDC Engine Control Power

As discussed above, two separate control circuits are provided for each diesel generator. Alarm is indicated locally and annunciated in the main control room as "Diesel Generator High Priority." Indication is also provided at the BIS panel. Loss of either circuit will not prevent the diesel generator from starting or operating.

6) ID-B.6 Control Relay Malfunction

Control relays can fail in either contact open or closed state. Since there are two circuits provided assuming a single relay failure, the diesel generator will not be prevented from starting or operating.

7) ID-B.7 Engine & Generator Mechanical Trouble

Low priority and high priority trouble alarms are provided for engine and generator mechanical trouble as shown on Figure 8.3-12 and Table 8.3-16.

8) ID-B.8 Starting Air Control Solenoid Valve Failure

There are two starting air solenoid valves for each of the two starting circuits for each D/G. Loss of any three starting solenoids will not prevent the diesel generator from starting.

9) ID-B.9 Starting Air System Trouble

See (9) ID-B.9 and Section 9.5.6 for a complete starting air system discussion. The starting air pressure is monitored at all times with annunciation provided locally and in the main control room.

10) ID-B.10 Fuel Oil Control Solenoid Failure

One fuel oil control solenoid is provided in each of the two control circuits for each diesel-generator. A failure of either fuel oil control solenoid will not prevent the diesel generator from starting.

11) ID-B.11 Loss of 125 VDC Generator Control Power

Loss of the generator control power will prevent the operation of the excitation system. Indication is provided at the Bypass Indication System as "Excitation Control Power Loss" (Main Control Room).

12) ID-B.12 Disabling of Engine and Generator Mechanical Parts During Maintenance Services

Before the diesel generator is taken out of the automatic mode for maintenance services, the operating mode selector switch must be in "Local" position as required by maintenance procedures. This will result in an alarm in the main control room as "Diesel Generator not in Auto" ("Diesel Generator Control Switch in LOCAL" in BIS panel).

No alarms are specifically provided for monitoring of engine and generator mechanical parts under the subject condition.

Conclusion

No modifications are necessary as a result of this evaluation because adequate alarms and indications are provided in addition to the alarm redundancy of the control circuits.

### 8.3.1.5 Electrical Equipment Layout

Class IE switchgear, load centers, motor control centers, and distribution panels of redundant load groups are in separate rooms of the reactor building and the control structure.

Standby diesel generators and associated equipment are in separate rooms of the Seismic Category I diesel generator building. Each room is provided with a separate ventilation system.

Plant layout drawings are included in Section 1.2.

### 8.3.1.6 Reactor Protection System Power Supply

The reactor protection system (RPS) power supply is a non-Class IE system. The normal 120 V ac power to each of the two reactor protection systems is supplied, via a separate bus, by its own high inertia motor generator set. The drive motor is supplied from a 480 V Class IE motor control center. High inertia is provided by a flywheel. The inertia is sufficient to maintain voltage and frequency within 5 percent of rated values for at least 1.0 sec following a loss of power to the drive motor.

The alternate 120 V ac power for each of the reactor protection systems is supplied by a non-Class IE motor control center through a 480-120 V, 1Ø transformer. A selector switch is provided for the selection of the two power supplies. The switch also prevents paralleling the motor generator set with the alternate supply.

The electrical protective assembly (EPA), consisting of Class 1E protective circuitry is installed between the RPS and each of the power sources. The EPA provides redundant protection to the RPS and other systems which receive power from the RPS busses by acting to disconnect the RPS from the power source circuits.

The EPA consists of a circuit breaker with a trip coil driven by logic circuitry which senses line voltage and frequency and trips the circuit breaker open on the conditions of overvoltage, undervoltage and underfrequency. Provision is made for setpoint verification, calibration and adjustment under administrative control. After tripping, the circuit breaker must be reset manually. Trip setpoints are based on providing 115 VAC, 60 Hz power at the RPS logic cabinets. The protective circuit functional range is  $\pm 10\%$  of nominal AC voltage and  $-5\%$  of nominal frequency.



The EPA assemblies are packaged in an enclosure designed to be wall mounted. The enclosures are mounted on a seismic Category I structure separately from the motor generator sets and separate from each other. Two EPAs are installed in series between each of the two RPS motor-generator sets and the RPS busses and between the auxiliary power sources and the RPS busses. The block diagram in Figure 7.2-9 provides an overview of the EPA units and their connections between the power sources and the RPS busses. The EPA is designed as a Class IE electrical component to meet the qualification requirements of IEEE 323-1974 and IEEE 344-1975. It is designed and fabricated to meet the quality assurance requirements of 10CFR50, Appendix B.

The enclosures containing the EPA assemblies are located in an area where the ambient temperature is between 40°F and 122°F. The circuits within the enclosure are qualified to operate under accident conditions from 40°F to 137°F, at 10% to 95% relative humidity and survive a total integrated radiation dose of  $2 \times 10^5$  rads. The assemblies are seismically qualified per IEEE 344-1975, to the Safe Shutdown Earthquake (SSE) and Operating Base Earthquake acceleration response spectra and environmentally qualified to the requirement of IEEE 323-1974. The enclosure dimensions are approximately 16x24x8 inches and accommodate power cable sizes from 7 AWG to 250 MCM.

#### 8.3.1.7 Class IE 120 V ac Instrumentation and Control -----Power Supply-----

Four independent Class IE 120 V ac instrumentation and control power supplies are provided to supply the four channels of engineered safety features load groups. The four bus arrangement provides a separate single-phase electric power supply to each of the four protection channels that are electrically and physically isolated from the other protection channels. Each

power supply consists of a 480-120 V transformer and a distribution panel. The 480 V power supply is provided by the corresponding 480 V Class IE motor control center.

There is no manual or automatic transfer between the four 120 V ac Class IE panels.

There is no automatic loading or load shedding of the panels.

### 8.3.1.8 Non-Class IE Instrument and Vital ac Power Supply

#### Non-Class IE Instrument ac Power Supply

Two 208/120 V non-Class IE instrument ac power supplies per unit furnish reliable power to non-Class IE miscellaneous instrumentation systems.

The non-Class IE instrument ac power supply for each unit consists of two subsystems, each with a regulating transformer, an automatic transfer switch, and a 208/120 V distribution panel. Each distribution panel is supplied as an associated circuit from two Class IE motor control centers.

The transfer switch maintains separation between the two Class IE power supplies, and the redundant breakers act as an isolation system between the Class IE power supply and the non-Class IE load.

#### Vital ac Power Supply

Two 208/120 V non-Class IE vital ac power supplies (uninterruptible power supplies) per unit supply essential non-Class IE equipment such as the plant computer. Each vital ac power supply consists of one inverter, automatic transfer switch, manual bypass switch, and distribution panel(s). Normally, the distribution panel is supplied by the inverter.

Each inverter is supplied by a separate Class IE 250 V dc subsystem as described in Subsection 8.3.2. If the inverter is inoperable or is to be removed from service for maintenance or testing, a transfer to the backup supply is made through the manual bypass switch. The backup supply is a regulating type transformer from a 480 V Class IE motor control center. A transfer switch provides the automatic switch-over in case of inverter failure.

The supply from the Class IE 480 V MCC is an associated circuit. Redundant breakers act as an isolation system between the Class IE power supply and non-Class IE load.

### 8.3.1.9 Design Criteria for Class IE Equipment

The following design criteria are applied to the Class IE equipment.

**MOTOR SIZE** - Motor size (horsepower capability) is equal to or greater than the maximum horsepower required by the driven load under normal running, runout, or discharge valve (or damper) closed condition.

**MINIMUM MOTOR ACCELERATING VOLTAGE** - The electrical system is designed so that the total voltage drop on the Class IE motor circuits is less than 20 percent of the nominal motor voltage. The Class IE motors are specified with accelerating capability at 80 percent nominal voltage at their terminals.

**MOTOR STARTING TORQUE** - The motor starting torque is capable of starting and accelerating the connected load to normal speed within sufficient time to perform its safety function for all expected operating conditions, including the design minimum terminal voltage.

**MINIMUM MOTOR TORQUE MARGIN OVER PUMP TORQUE THROUGH ACCELERATING PERIOD** - The minimum motor torque margin over pump torque through the accelerating period is determined by using actual pump torque curve and calculated motor torque curves at 80 and 100 percent terminal voltage. The minimum torque margin (accelerating torque) is such that the pump-motor assembly reaches nominal speed in less than 6.5 seconds. This margin is usually not less than 10 percent of the pump torque.

**MOTOR INSULATION** - Insulation systems are selected on the basis of the ambient conditions to which the insulation is exposed. For Class I motors located within the containment, the insulation system is selected to withstand the postulated accident environment.

**TEMPERATURE MONITORING DEVICES PROVIDED IN LARGE HORSEPOWER MOTORS** - Six resistance temperature detectors (RTD) are provided in the motor stator slots, two per phase, for motors larger than 1500 hp. In normal operation, the RTD at the hottest location (selected by test) monitors the motor temperature and provides an alarm on high temperature. RTDs are provided for motors from 250 to 1500 hp. Each bearing that is not antifriction type has a chromel-constantan ISA Type E thermocouple bearing temperature device to alarm on high temperature.

**INTERRUPTING CAPACITIES** - The interrupting capacities of the protective equipment are determined as follows:

a) Switchgear

Switchgear interrupting capacities are greater than the maximum short circuit current available at the point of application. The magnitude of short circuit currents in medium voltage systems is determined in accordance with ANSI C37.010-1972. The off-site power system, a single operating diesel generator, and running motor contributions are considered in determining the fault level. High voltage power circuit breaker interrupting capacity ratings are selected in accordance with ANSI C37.06-1971.

b) Load Centers, Motor Control Centers, and Distribution Panels

Load center, motor control center, and distribution panel interrupting capacities are greater than the maximum short circuit current available at the point of application. The magnitude of short circuit currents in low-voltage systems is determined in accordance with ANSI C37.13-1973, and NEMA AB1. Low-voltage power circuit breaker interrupting capacity ratings are selected in accordance with ANSI C37.16-1970. Molded case circuit breaker interrupting capacities are determined in accordance with NEMA AB1.

ELECTRIC CIRCUIT PROTECTION - Electric circuit protection criteria are discussed in Subsection 8.3.1.3.13.

GROUNDING REQUIREMENTS - Equipment and system grounding are designed in accordance with IEEE 80-1961 and 142-1972.

8.3.1.10 Safety-related Logic and Schematic Diagrams

Safety-related logic and schematic diagrams are provided as listed in Section 1.7.

8.3.1.11 Analysis

A failure mode effects analysis for the ac power system is presented in Table 8.3-9.

### 8.3.1.11.1 General Design Criteria and Regulatory Guide ----- Compliance -----

The following paragraphs analyze compliance with General Design Criteria 17 and 18. All Regulatory Guides are discussed in Subsections 3.13 and 8.1.6.1.

#### GENERAL DESIGN CRITERION 17, ELECTRIC POWER SYSTEMS

An on-site electric power system is provided to permit functioning of structures, systems, and components important to safety. With total loss of off-site power, the on-site power system provides sufficient capacity and capability to ensure that:

- a) Specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences
- b) The core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.

Tables 8.3-1 to 8.3-5 list those loads important to safety under design conditions.

The on-site electric power system includes four load groups. The load groups are redundant in that three load groups are capable of ensuring (a) and (b) above. Sufficient independence is provided between redundant load groups to ensure that postulated single failures affect only a single load group and are limited to the extent of total loss of that load group. The redundant load groups remain intact to provide for the measures specified in (a) and (b) above.

During a loss of off-site power, the Class IE system is automatically isolated from the off-site power system. This minimizes the probability of losing electric power from the on-site power supplies as a result of the loss of power from the transmission system.

Protection, such as voltage restraint overcurrent and 4.16 kV bus differential relays, is provided to trip the diesel generator circuit breaker, if abnormal conditions occur. This protection prevents damage to or shutdown of the diesel generator.

The turbine generator is automatically isolated from the switchyard following a turbine or reactor trip. Therefore, its loss does not affect the ability of either the transmission network or the on-site power supplies to provide power to the

Class IE system. Transmission system stability studies indicate that the trip of the most critical fully loaded generating unit does not impair the ability of the system to supply plant station service. Further discussion is provided in Subsection 8.2.2.

#### GENERAL DESIGN CRITERION 18, INSPECTION AND TESTING OF ELECTRICAL POWER SYSTEMS-----

The Class IE system is designed to permit:

- a) Periodic inspection and testing, during equipment shutdown, of wiring, insulation, connections, and relays to assess the continuity of the systems and the condition of components
- b) During normal plant operation, periodic testing of the operability and functional performance of on-site power supplies, circuit breakers and associated control circuits, relays, and buses
- c) During plant shutdown, testing of the operability of the Class IE system as a whole, including the system's operational sequence, operation of signals of the engineered safety features actuation system and the transfer of power between the off-site and the on-site power system.

#### 8.3.1.11.2 Safety Related Equipment Exposed to Accident Environment-----

The detailed information on all Class IE equipment that must operate in an accident environment during and/or subsequent to an accident is furnished in Section 3.11.

#### 8.3.1.11.3 Physical Identification of Safety Related Equipment-----

Each circuit and raceway is given a unique alphanumeric identification, which distinguishes a circuit or raceway related to a particular voltage, function, channel, or load group. One alpha character of the identification is assigned to a load group on the basis of the following criteria:

SEPARATION GROUP CHANNEL A (Red Color Code) - Class IE instrumentation, controls, and power cables, raceways, and equipment related to Channel A loads, dc subsystem A, 120 V ac instrumentation and control channel A, Division I raceways.

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SEPARATION GROUP CHANNEL B (Green Color Code) - Class IE instrumentation, controls, and power cables, raceways, and equipment related to Channel B loads, dc subsystem B, 120 V ac instrumentation and control channel B, Division II raceways.

SEPARATION GROUP CHANNEL C (Orange Color Code) - Class IE instrumentation, controls, and power cables, raceways, and equipment related to Channel C loads, dc subsystem C, 120 V ac instrumentation and control channel C.

SEPARATION GROUP CHANNEL D (Blue Color Code) - Class IE instrumentation, controls, and power cables, raceways, and equipment related to Channel D loads, 120 V ac instrumentation and control channel D.

SEPARATION GROUP N (Black Color Code) - Non-Class IE instrumentation, controls, and power cables, raceways, and related equipment.

SEPARATION GROUP DIVISION I (Red/Brown Color Code) - Class IE instrumentation, control, and power cables.

SEPARATION GROUP DIVISION II (Green/Brown Color Code) - Class IE instrumentation, control, and power cables.

The affiliated cables are routed with the separation groups they are associated with. The affiliated cables are identified as follows:

- a) Red/Brown - associated with separation group channel A or division I.
- b) Green/Brown - associated with separation group channel B or division II.
- c) Orange/Brown - associated with separation group channel C.
- d) Blue/Brown - associated with separation group channel D.

Cable and raceway separation groups are summarized in Table 8.3-10.

For identification of raceways and Class IE cables refer to Section 3.12.

Design drawings provide distinct identification of Class IE equipment. The applicable separation group or load group designation is also identified.

Electrical component identification is discussed in Subsection 1.8.6.

#### 8.3.1.11.4 Independence of Redundant Systems

##### Separation Criteria

This subsection establishes the criteria and the bases for preserving the independence of redundant Class IE power systems. (For PGCC see Section 3.12).

##### Raceway and Cable Routing

Wherever possible, cable trays are arranged from top to bottom, with trays containing the highest voltage cables at the top. A raceway designated for one voltage category of cables contains only those cables. Voltage categories are:

- a) 480 V ac, 120 V ac, 125 V dc and 250 V dc power
- b) 120 V ac, 125 V dc, and 250 V dc control and digital signal
- c) Low level signal.

The 480 VAC power, 120 VAC control, and digital alarm signal cables originated from the same 480 VAC motor control center (MCC) are routed through a common shuttle tray and riser above the MCC. The shuttle tray covers the length of the MCC, and it is used to connect the MCC to the main raceway system via vertical tray risers. The cables are routed in accordance with the above raceway categories once they leave the shuttle tray and vertical tray risers.

15 kV and 5 kV class cables are routed in conduits only.

Cables corresponding with each separation group, as defined in Subsection 8.3.1.3, are run in separate conduits, cable trays, ducts, and penetrations.

Refer to Subsection 3.12.3.4.2 for description of physical separation of raceway and cable routing.



### 8.3.1.11.5 Administrative Responsibilities and Controls for -----Ensuring Separation Criteria-----

The separation group identification described in Subsection 8.3.1.11.3 facilitates and ensures the maintenance of separation in the routing of cables and the connections. At the time of the cable routing assignment during design, those persons responsible for cable and raceway scheduling ensure that the separation group designation on the scheme to be routed is compatible with a single-line-diagram load group designation and other schemes previously routed. Extensive use of computer facilities assists in ensuring separation correctness. Each cable and raceway is identified in the computer program, and the identification includes the applicable separation group designation. Auxiliary programs are made available specifically to ensure that cables of a particular separation group are routed through the appropriate raceways. The routing is also confirmed by quality control personnel during installation to be consistent with the design document. Color identification of equipment and cabling (discussed in Subsection 8.3.1.11.3 and Section 3.12) assists field personnel in this effort.

## 8.3.2\_\_DC POWER SYSTEMS

### 8.3.2.1\_\_Description

The dc power systems are divided into Class IE and non-Class IE systems.

#### 8.3.2.1.1\_\_Class IE dc Power System

The Class IE dc system is shown on Figures 8.3-5 and 8.3-6 . The dc system for each generating unit consists of four 125 V dc subsystems, two 250 V dc subsystems, and two  $\pm 24$  V dc subsystems.

##### 8.3.2.1.1.1\_\_125 V dc Subsystems

Four Class IE 125 V dc power subsystems provided for each unit are located in separate rooms in the control structure. These four subsystems are identified as channels A, B, C, and D. Each subsystem provides the control power for its associated Class IE ac power load group channel: 4.16 kV switchgear, 480 V load centers, and standby diesel generator as discussed in Subsection

8.3.1. Also these dc subsystems provide dc power to the engineered safety feature valve actuation, diesel generator auxiliaries, plant alarm and indication circuits, and emergency lighting system.

Each 125 V dc subsystem consists of one load center, one Class IE and one non-Class IE distribution panel, one 125 V battery bank, and one battery charger. The non-Class IE distribution panel is connected to the Class IE dc power supply through an isolation system. The isolation system is defined in Subsection 8.1.6.1(n). The battery charger of each system is supplied with 480 V Class IE ac power from the motor control center associated with the same load group channel. One spare 125 V battery charger is provided for both generating units.

The charger output voltage can be regulated at two different control points. One is a variable resistor located inside the cabinet and is used for rough voltage settings. The other is a screwdriver adjusted potentiometer located on the front of the cabinet, and is used for fine adjustments. By setting both controls at their maximum positions, the charger output voltage would be 145.2 volts. All equipment or devices connected to the 125 V DC supply are rated 105 V to 144 V DC. Maximum output voltage resulting from a failure of charger voltage control circuit is not available at the present time.

There are no overvoltage protection devices provided for the 125 V dc subsystem. "The 125 V dc power is distributed through circuit breaker type distribution panels. The 125 V dc loads are shown in Table 8.3-6."

The failure mode and effect analysis for the 125 V dc subsystem is shown in Table 8.3-21.

#### 8.3.2.1.1.2 250 V dc Subsystems

Two Class IE 250 V dc subsystems are provided for each unit and identified as Divisions I and II as shown on Figure 8.3-5. The 250 V dc subsystems are located in separate rooms in the control structure. The two subsystems supply the dc power required for larger loads such as dc motor driven pumps and valves, inverters for plant computer and vital 120 V ac power supplies. The 250 V dc loads are shown in Table 8.3-7.

A 2,000 amp fuse is provided at each pole of the 250 V dc battery output for short circuit protection. These fuses are also used to disconnect the load center from the battery during battery discharge and service tests.

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The Division I 250 V dc subsystem is provided with one 250 V battery bank, one load center, two equal capacity chargers, and motor control centers. The Division II 250 V dc subsystem is provided with one 250 V battery bank, one distribution load center, one battery charger, and motor control centers.

The 250 V dc battery chargers are supplied by 480 V Class IE ac motor control centers.

One spare 250 V battery charger is provided for both generating units.

There is no load shedding provided for any of these non-Class 1E loads.

All 250 V dc motor control centers (MCC), including non-Class 1E, are seismically qualified. However, the Class 1E MCC's are located in a seismic Category I structure while the non-Class 1E MCC's are located in a non-seismic Category I structure (Turbine Building).

The charger output voltage can be regulated at two different control points. One is a variable resistor located inside the cabinet and is used for rough voltage settings. The other is a screwdriver adjusted potentiometer located on the front of the cabinet, and is used for fine adjustments. By setting both controls at their maximum positions, the charger output voltage would be 290.4 volts. All equipment or devices connected to the 250 V dc supply are rated 210 V to 288 V dc. Maximum output voltage resulting from a failure of charger voltage control circuit is not available at the present time. There are no overvoltage protective devices provided for the 250 V dc subsystem.

The 250 V dc power is distributed through dc motor control centers except for the inverters, which are fed directly from the distribution load centers.

The non-Class IE 250 V dc loads are supplied by a non-Class IE dc motor control center. The non-Class IE dc motor control center is connected to the Class IE dc distribution load center through an isolation system as defined in Subsection 8.1.6.1(n). The non-Class IE 250 V dc loads consist mainly of emergency turbine generator auxiliaries.

The failure mode and effect analysis for the 250 V dc subsystem is shown in Table 8.3-22.

8.3.2.1.1.3  $\pm 24$  V dc Subsystems

Two  $\pm 24$  V dc subsystems are provided for each unit for radiation monitoring circuits. These two subsystems are located in separate rooms in the control structure and are identified as Divisions I and II. Each  $\pm 24$  V dc subsystem consists of two 24 V battery banks, two chargers, and a circuit breaker type distribution panel.

The 24 V dc chargers are supplied by 120 V Class IE instrument ac power panels. The  $\pm 24$  V dc loads are shown in Table 8.3-8.

One spare 24 V dc battery charger is provided for both generating units.

The 24 V dc subsystem is equipped with under/overvoltage relays for tripping of the chargers and annunciation. All 24 V dc equipment and devices in Susquehanna SES are rated for 20 to 28 V dc.

8.3.2.1.1.4 Class IE Station Batteries and Battery Chargers

Refer to Subsection 8.3.2.1.1.5 for all Class IE dc system equipment ratings.

The battery chargers are full wave, silicon controlled rectifiers. The housings are freestanding, NEMA Type I, and are ventilated. The chargers are suitable for equalizing the batteries. The chargers are in compliance with all applicable NEMA, and ANSI standards.

The capacity of each battery charger, or the combined capacity of both chargers in the case of Division I 250 V dc subsystem, is based on the largest combined demand of all the steady-state loads and the charger current required to restore the battery from the design minimum charged state to the fully charged state within 12 hr.

The battery chargers are constant voltage type with capability of operating as battery eliminators, and would function properly with battery disconnection being a normal condition. The battery eliminator feature is incorporated as a precautionary measure to protect against inadvertent disconnection of the battery. There are no planned modes of operation which would require battery disconnection. Variation of the charger output voltage has been determined by testing to be less than 1% with or without the battery connected. Maximum output ripple for the 24 V and 125 V dc chargers is 30 millivolts RMS with or without the battery, and 200 millivolts for the 250 V chargers.

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The failure mode and effect analysis for the  $\pm 24$  V dc subsystem is shown in Table 8.3-23.

Each 125 V, 250 V, and  $\pm 24$  V battery bank has sufficient capacity without its charger to independently supply the required loads for 4 hr as shown in Tables 8.3-6, 8.3-7, and 8.3-8 respectively.

In accordance with IEEE 450-1972 initial rated battery capacity is 25 percent greater than required. This margin allows replacement of the battery to be made when its capacity has decreased to 80 percent of its rated capacity (100 percent of design load).

### 8.3.2.1.1.5 Class 1E DC System Equipment Ratings

#### a) 125 V dc Subsystems

Battery	60 lead-calcium cells 720 amp-hr (8 hrs to 1.75 V per cell @ 77°F)
Charger	ac input - 480 V, 3Ø dc output - 100 A continuous rating
Load Center	
Main bus (horizontal)	1600 A continuous rating, 25,000 A short circuit bracing
Vertical bus	1200 A continuous rating, 25,000 A short circuit bracing
Breakers	600 A frame size, 2 poles 25,000 A interrupting rating
Distribution Panel	
Main bus	225 A continuous rating, 50,000 A short circuit bracing
Breakers (molded case)	100 A frame size, 2 poles 10,000 A interrupting rating

#### b) 250 V dc Subsystems

Battery	120 lead - calcium cells 1800 amp-hr (8 hrs to 1.75 V per cell @ 77°F)
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Chargers	ac input - 480 V, 3Ø dc output - 300 A continuous
Load Center	
Main bus (horizontal)	1600 A continuous rating 25,000 A short circuit bracing
Vertical bus	1,200 A continuous rating 25,000 A short circuit bracing
Breakers	600 A continuous rating 25,000 A interrupting rating
Control Center	
Main bus (horizontal)	600 A continuous rating 10,000 A short circuit bracing
Vertical bus	600 A continuous rating 10,000 A short circuit bracing
Breakers (molded case)	100 A, 225 A and 600 A frame rating sizes, 2 poles, 10,000 A interrupting

### c) ±24 Volt Subsystems.

Battery	2 groups of 12 lead-calcium cells. 75 amp-hr (8 hrs to 1.75 V per cell @ 77°F).
Chargers	ac input - 120 V, 1Ø dc output - 25 amp continuous
Distribution Panels	
Main bus	100 A continuous 5,000 A short circuit bracing
Breakers (molded case)	100 A frame size, 2 poles, 5,000 A interrupting rating

### 8.3.2.1.1.6 Inspection, Maintenance, and Testing

Testing of the dc power systems is performed prior to plant operation in accordance with the requirements of Chapter 14.

In-service tests and inspections of the dc power systems including batteries, chargers, and auxiliaries are specified in Chapter 16.

#### 8.3.2.1.1.7 Separation and Ventilation

For each Class IE dc subsystem, the battery bank, chargers, and dc switchgear are located in separate rooms of the Seismic Category I control structure. The battery rooms are ventilated by a system that is designed to preclude the possibility of hydrogen accumulation. Section 9.4 contains a description of the battery room ventilation system.

#### 8.3.2.1.1.8 Non-Class IE dc System

Generally, non-Class IE dc loads are connected to a Class IE dc system through a non-Class IE dc distribution panel. These cases are discussed in Subsections 8.3.2.1.1.1 and 8.3.2.1.1.2.

A non-Class IE 125 V dc system is provided for the remote river water intake pump house 4.16 kV switchgear control. This 125 V dc system consists of a distribution panel, two 25A chargers, 60 lead-calcium cells and is rated 50 Ah at 8 hr discharge rate based on a terminal voltage of 1.75 V per cell when discharged.

#### 8.3.2.2 Analysis

##### 8.3.2.2.1 Compliance with General Design Criteria, Regulatory Guides, and IEEE Standards

The following paragraphs analyze compliance of the Class IE dc power systems with General Design Criteria 17 and 18, Regulatory Guides 1.6, 1.32, 1.41, 1.81, and 1.93, and IEEE 308-1974 and 450-1972.

a) General Design Criterion 17, Electric Power Systems

Consideration of Criterion 17 leads to the inclusion of the following factors in the design of the dc power systems:

- 1) Separate Class IE 125 V dc subsystems supply control power for each of the Class IE ac load groups.
- 2) The ac power for the battery chargers in each of these dc subsystems is supplied from the same ac load group for which the dc subsystem supplies the control power.
- 3) Two independent 250 V dc subsystems are provided to ensure the availability of the dc power system for maintaining the reactor integrity during postulated accidents.
- 4) The Class IE dc subsystems including batteries, chargers, dc switchgear, and distribution equipment are physically separate and independent.
- 5) Sufficient capacity, capability, independence, redundancy, and testability are provided in the Class IE dc subsystems, ensuring the performance of safety functions assuming a single failure.

b) General Design Criterion 18, Inspection and Testing of Electric Power Systems-----

Each of the Class IE subsystem is designed to permit:

- 1) Inspection and testing of wiring, insulation, and connections during equipment shutdown to assess the continuity of the subsystem and the condition of its components.
- 2) Periodic testing of the operability and functional performance of the components of the subsystems during normal plant operation.

The Class IE dc subsystems are periodically inspected and tested to assess the condition of the battery cells, charger, and other components in accordance with Chapter 16. Preoperational testing is discussed below in assessment of compliance with Regulatory Guide 1.41.



c) Regulatory Guide 1.6 (1/71)

The design of the dc system complies with Regulatory Guide 1.6.

Separate Class IE 125 V dc subsystems supply control power for each of the four Class IE load groups. Loss of any one of the subsystems does not prevent the minimum safety function from being performed. The 125 V dc subsystem chargers are supplied from the same ac load group for which the dc subsystem supplies the control power. Each of the four 125 V dc subsystems, including battery bank, charger, and distribution system, is independent of other 125 V dc subsystems. Thus, sufficient independence and redundancy exist between the 125 V dc subsystems to ensure performance of minimum safety functions, assuming a single failure.

Two independent Class IE 250 V dc subsystems are provided. Each subsystem is independent of the other. Sufficient independence and redundancy exist in these subsystems so that a single failure in the 250 V dc subsystems does not prevent the performance of minimum safety functions.

Two independent Class IE  $\pm 24$  V dc subsystems are provided. Each subsystem is independent of the other. Sufficient independence and redundancy exist in these subsystems so that a single failure in the  $\pm 24$  V dc subsystems does not prevent the performance of minimum safety functions.

d) Regulatory Guide 1.32 (8/72)

The battery charger capacity for each of the Class IE dc subsystems complies with this Regulatory Guide.

Each Class IE battery charger has sufficient capacity to supply the largest combined demand of the various steady-state loads and the charging current required to restore the battery from the design minimum charge state to the fully charged state irrespective of the status of the plant during which these demands occur.

e) Regulatory Guide 1.41 (3/73)

The Class IE dc subsystems have been designed in accordance with Regulatory Guides 1.6 and 1.32 and testing capabilities are provided in accordance with the guidance of Regulatory Guide 1.41 and will be preoperationally tested as described in Chapter 14.

f) Regulatory Guide 1.81 (1/75)

The requirements of the Regulatory Guide are met. Each generating unit is provided with separate and independent on-site dc electric power systems capable of supplying power to the control systems of engineered safety features loads and loads such as valves, and actuators, required for attaining a safe and orderly cold shutdown of the unit, assuming a single failure.

g) Regulatory Guide 1.93 (12/74)

Compliance is discussed in Subsection 8.1.6.1 (g).

h) IEEE Standard 308-1974

The Class IE dc systems provide power to Class IE loads and for control and switching of Class IE systems. Physical separation and electrical isolation are provided to prevent the occurrence of common mode failures. The design of the Class IE dc systems includes the following:

- 1) The 125 V dc system is separated into four subsystems
- 2) The 250 V dc and  $\pm 24$  V dc systems are each separated into two subsystems
- 3) The safety action by each group of loads are independent of the safety actions provided by their redundant counterparts
- 4) Each dc subsystem includes power supplies that consist of one battery bank and one or two chargers as required for capacity as shown on Figures 8.3-5 and 8.3-6.
- 5) The batteries are not interconnected.

Each Class IE distribution circuit is capable of transmitting sufficient energy to start and operate all required loads in that circuit. Distribution circuits to redundant equipment are independent of each other. The distribution system is monitored to the extent that it is shown to be ready to perform its intended function. The dc auxiliary devices required to operate equipment of a specific ac load group are supplied from the same load group.

Each battery supply is continuously available during normal operations and following the loss of power from the ac system to start and operate all required loads.

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The 125 V dc and 250 V dc subsystems are ungrounded; thus, a single ground fault does not cause immediate loss of the faulted system. Ground detection and alarm is provided for each dc subsystem so that ground faults can be located and removed. The  $\pm 24$  V dc subsystem is grounded.

Equipment of the Class IE dc system is protected and isolated by fuses or circuit breakers for short circuit or overload protection. The following instrumentation is provided to monitor the status of each of the dc subsystems:

1) 125 V dc and 250 V dc subsystems:

System undervoltage

System ground

Battery availability

Battery charger trouble - ac undervoltage; charger failure; charger output breaker trip

Load center breaker trip (250 V dc subsystem only)

All above alarms are annunciated as a group alarm in the main control room.

2)  $\pm 24$  V dc subsystems:

Positive bus low voltage

Negative bus low voltage

Positive bus high voltage

Negative bus high voltage

Battery availability

Battery charger trouble - ac failure; charger failure; charger output breaker trip

All above alarms are annunciated in the main control room as  $\pm 24$  V dc system trouble, a group alarm for each battery bank and its associated system.

The batteries are maintained in a fully charged condition and have sufficient stored energy to operate all necessary circuit breakers and to provide an adequate amount of energy for all required emergency loads for four hours after loss of ac power.

Each battery charger has an input ac and output dc circuit breaker for isolation of the charger. Each battery charger power supply is designed to prevent the ac supply from becoming a load on the battery due to a power feedback as the result of the loss of ac power to the chargers.

The battery charger ac supply breaker can be periodically opened to verify the load carrying ability of the battery.

The batteries, battery chargers, and other components of the dc subsystems are housed in the control structure, which is a Seismic Category I structure.

The periodic testing and surveillance requirements for the Class IE batteries are detailed in Chapter 16.

i) IEEE Standard 450-1972

The recommended practices of IEEE 450 for maintenance, testing, and replacement of batteries are followed for the Class IE batteries and are discussed in Chapter 16.

8.3.2.2.2 Physical Identification of Safety Related Equipment

Physical identification of Class IE equipment is discussed in Subsection 8.3.1.3.

8.3.2.2.3 Independence of Redundant Systems

The general considerations for the independence of Class IE dc power subsystems are described in Subsection 8.1.6.1(n). The physical separation criterion is discussed in Section 3.12.

8.3.3 FIRE PROTECTION FOR CABLE SYSTEMS

8.3.3.1 Cable Derating and Cable Tray Fill

The power and control cable insulation is designed for a conductor temperature of 90°C. Allowable current carrying capacity of the cable is based on not exceeding the insulation design temperature while the surrounding air is at an ambient temperature of 65.5°C for the primary containment and 40°C for all other areas. The design operating conditions of all Class IE cables are discussed in Section 3.11.

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The power cable ampacities are established in accordance with IPCEA Publications P-54-440 and P-46-426 and are shown in Tables 8.3-11 through 8.3-15.

For control circuits, minimum #14 AWG conductors are generally used.

Instrumentation cable is also designed for a conductor temperature of 90°C. Operating currents of these cables are low (usually mA or mV) and will not cause the design temperature to be exceeded at maximum design ambient temperature.

In general, cable tray fill is limited to 30 percent fill by cross-sectional area. In cases where the limitation is exceeded, a review will be performed for each case for the adequacy of the design.

In general, conduit fill is in compliance with Tables I and II, Chapter 9, National Electrical Code, 1975. In cases where these values are exceeded, a review is performed for each case to insure the adequacy of the design.

Power cables, control cables, and instrumentation cables are defined as follows:

### Power Cables

Power cables are those cables that provide electrical energy for motive power or heating to all 13.8 kV ac, 4.16 kV ac, 480 V ac, 120 V ac, 250 V dc, and 125 V dc loads.

### Control Cables

Control cables, for the purpose of derating, are generally 120 V ac, 250 V dc, 125 V dc, and 24 V dc circuits between components responsible for the automatic or manual initiation of auxiliary electrical functions and the electrical indication of the state of auxiliary components.

### Instrumentation Cables

Instrumentation cables are those cables conducting low-level instrumentation and control signals. These signals can be analog or digital. Typically, these cables carry signals from thermocouples, resistance temperature detectors, transducers, neutron monitors, etc.

#### 8.3.3.2 Fire Detection for Cable Systems

Fire detection systems are discussed in Subsection 9.5.1.

#### 8.3.3.3 Fire Barriers and Separation Between Redundant Trays

Electrical equipment and cabling has been arranged to minimize the propagation of fire from one separation group to another. Physical separation of cabling systems is discussed in Subsection 3.12.2.

Where the minimum physical separation cannot be met as specified in Subsection 3.12.2, and a fire barrier is selected as the alternative, a 1/4 in. Haysite ETR-FR-C is installed. The bolts and hardware used to secure the Haysite panel to the tray support are coated after installation with 1/8 in. of fireproofing material Dynatherm's Flamemastic 71A compound.

#### 8.3.3.4 Fire Stops

Fire stops and seals are provided for cable penetrations in the floor for vertical runs of raceways, at each access opening in ceilings and at fire-rated wall penetrations. The fire stops are furnished to provide a method of sealing off air spaces around cable penetrations. The properties of materials and qualification tests are discussed in Subsection 9.5.1.

TABLE 8.3-9

## AC POWER FAILURE MODE EFFECTS ANALYSIS

ID No.	Component Name	Function	Failure Mode	Effect on Subsystem	Effect on Safety Function
1	Offsite power source through engineered safeguards transformer 101	Supplies preferred power to Units 1&2 load group channels A&C	Loss of power	Loss of preferred power to Units 1&2 load groups A&C	No effect - offsite power through engineered safeguards transformer 201 supplies backup
		Supplies alternate power to Units 1&2 load group channels B&D	Loss of power	Loss of backup power to Units 1&2 load groups B&D	No effect - diesel generators provide standby power
2	Offsite power source through engineered safeguards transformer 201	Supplies preferred power to Units 1&2 load group channels B&D	Loss of power	Loss of preferred power to Units 1&2 load groups B&D	No effect - offsite power through engineered safeguards transformer 101 supplies backup
		Supplies alternate power to Units 1&2 load group channels A&C	Loss of power	Loss of backup power to Units 1&2 load group A&C	No effect - diesel generators provide standby power
Load Group "A"					
3	4.16 kV Bus 1A201	Provide power to all loads belonging to load group "A"	Fault	Loss of power to all load group "A" loads	No effect - redundant equipment from load groups B,C,&D provide the required safety function
3A	Circuit breaker 52-20101	Provides preferred power to load group "A"	Fails open	Loss of preferred power to load group "A"	No effect - automatic transfer to alternate offsite power by closing breaker 52-20109 (See ID No. 11)
4	Circuit breaker 52-20102	Provides power to RHR pump 1P202A	Fails open	Loss of power to RHR pump 1P202A	No effect - three redundant RHR pumps from load groups B,C,&D provide the required safety function
5	Circuit breaker 52-20103	Provides power to reactor chiller 1K206A	Fails open	Loss of power to reactor chiller 1K206A	No effect - non-Class 1E equipment
6	Circuit breaker 52-20104	Provides standby power to bus 1A201	Fails to close	Failed to provide standby power to load group "A"	No effect - safety functions are provided by redundant equipment supplied by load groups B,C,&D

TABLE 8.3-9 (Continued)

ID No.	Component Name	Function	Failure Mode	Effect on Subsystem	Effect on Safety Function
7	Circuit breaker 52-20105	Provides power to core spray pump 1P206A	Fails open	Loss of power to core spray pump 1P206A	No effect - three redundant core spray pumps from load groups B,C,&D provide the required safety function
8	Circuit breaker 52-20106	Provides power to 480 V load center 1B210 (2B210)	Fails open	Loss of power to all load group "A" 480 V loads	No effect - safety functions are provided by redundant equipment supplied by load groups B,C,&D
9	Circuit breaker 52-20107	Provides power to CRD water pump 1P132A (2P132A)	Fails open	Loss of power to CRD water pump 1P132A (2P132A)	No effect - non-Class 1E equipment
10	Circuit breaker 52-20108	Provides power to the emergency service water pump 0P504A	Fails open	Loss of power to the emergency service water pump 0P504A	No effect - three redundant emergency service water pumps from load groups B,C,&D provide the required safety function
11	Circuit breaker 52-20109	Provides alternate preferred offsite power to bus 1A201	Fails to close	Loss of alternate preferred offsite power to load group "A"	No effect - diesel generator provides the standby power (see ID No. 6)
12	Circuit breaker 52-20110	Provides power to turbine building chiller 1K102A	Fails open	Loss of power to turbine building chiller 1K102A	No effect - non-Class 1E equipment
Load Group "C"					
13	4.16 kV bus 1A203	Provides power to all loads belonging to load group "C"	Fault	Loss of power to all load group "C" loads	No effect - redundant equipment from load groups A,B,&D provide the required safety function
13A	Circuit breaker 52-20301	Provides preferred power to load group "C"	Fails open	Loss of preferred power to load group "C"	No effect - automatic transfer to alternate offsite power by closing breaker 52-20309 (See ID #21)



TABLE 8.3-9 (Continued)

ID No.	Component Name	Function	Failure Mode	Effect on Subsystem	Effect on Safety Function
14	Circuit breaker 52-20302	Provides power to RHR pump 1P202C (2P202C)	Fails open	Loss of power to RHR pump 1P202C (2P202C)	No effect - three redundant RHR pumps from load groups A,B,&D provide the required safety function
15	Circuit breaker 52-20303	Provides emergency service water pump 0P504C	Fails open	Loss of power to emergency service water pump 0P504C	No effect - three redundant emergency service water pumps from load groups A,B,&D provide the required safety function
16	Circuit breaker 52-20304	Provides standby power to bus 1A203 (2A203)	Fails to close	Failure to provide standby power to load group "C"	No effect - safety functions are provided by redundant equipment supplied by load groups A,B,&D
17	Circuit breaker 52-20305	Provides power to core spray pump 1P206C	Fails open	Loss of power to core spray pump 1P206C	No effect - three redundant core spray pumps from load groups A,B,&D provide the required safety function
18	Circuit breaker 52-20306	Provides power to 480 V load center 1B230	Fails open	Loss of power to all load group "C" 480 V loads	No effect - safety functions are provided by redundant equipment supplied by load groups B,C,&D
19	Circuit breaker 52-20307	Spare			
20	Circuit breaker 52-20308	Provides power to the RHR service water pump 1P506A	Fails open	Loss of power to RHR service water pump 1P506A	No effect - redundant RHR service water pump 1P506B provides the required safety function
21	Circuit breaker 52-20309	Provides alternate preferred offsite power to bus 1A203	Fails to close	Loss of alternate preferred offsite power to load group "C"	No effect - diesel generator provides the standby power (see ID No. 16)
22	Circuit breaker 52-20310	Provides power to control structure chiller 0K112A	Fails open	Loss of power to the control structure chiller 0K112A	No effect - the redundant control structure chiller 0K112B provides the required safety function

TABLE 8.3-9 (Continued)

ID No.	Component Name	Function	Failure Mode	Effect on Subsystem	Effect on Safety Function
Load Group "B"					
23	4.16 kV bus 1A202	Provides power to all loads belonging to load group "B"	Fault	Loss of power to all load group "B" loads	No effect - redundant equipment from load groups A,C,&D provides the required safety function
23A	Circuit breaker 52-20201	Provides preferred power to load group "B"	Fails open	Loss of preferred power to load group "B"	No effect - automatic transfer to alternate offsite power by closing breaker 52-20209 (ID No. 31)
24	Circuit breaker 52-20202	Provides power to RHR pump 1P202B	Fails open	Loss of power to RHR pump 1P202B	No effect - three redundant RHR pumps from load groups A,C,&D provide the required safety function
25	Circuit breaker 52-20203	Provides power to reactor building chiller 1K206B	Fails open	Loss of power to reactor building chiller 1K206B	No effect - non-Class IE equipment
26	Circuit breaker 52-20204	Provides standby power to bus 1A202	Fails to close	Failure to provide standby power to load group "B"	No effect - safety functions are provided by redundant equipment supplied by load groups A,C,&D
27	Circuit breaker 52-20205	Provides power to core spray pump 1P206B	Fails open	Loss of power to core spray pump 1P206B	No effect - three redundant core spray pumps from load groups A,C,&D provide the required safety function
28	Circuit breaker 52-20206	Provides power to 480 V load center 1B220	Fails open	Loss of power to all load group "B" 480 V loads	No effect - safety functions are provided by redundant equipment supplied by load groups A,C,&D
29	Circuit breaker 52-20207	Spare			



TABLE 8.3-9 (Continued)

ID No.	Component Name	Function	Failure Mode	Effect on Subsystem	Effect on Safety Function
30	Circuit breaker 52-20208	Provides power to emergency service water pump 0P504B	Fails open	Loss of power to emergency service water pump 0P504B	No effect - three redundant service water pumps from load groups A,C,&D provide the required safety function
31	Circuit breaker 52-20209	Provides alternate preferred offsite power to bus 1A202	Fails to close	Loss of alternate preferred offsite power to load group "B"	No effect - diesel generator provides the standby power (See ID No. 26)
32	Circuit breaker 52-20210	Provides power to condensate vacuum pump 1P105	Fails open	Loss of power to condensate vacuum pump 1P105	No effect - non-Class 1E equipment
33	Circuit breaker 52-20211	Provides power to turbine building chiller 1K102B	Fails open	Loss of power to turbine building chiller 1K102B	No effect - non-Class 1E equipment
	Load Group "D"				
34	4.16 kV bus 1A204	Provides power to all loads belong to load group "D"	Fault	Loss of power to all load group "D" loads	No effect - redundant equipment from load groups A,B,&C provide the required safety function
35	Circuit breaker 52-20401	Provides preferred power to load group "D"	Fails open	Loss of preferred power to load group "D"	No effect - automatic transfer to alternate offsite power by closing breaker 52-20409 (See ID No. 43)
36	Circuit breaker 52-20402	Provides power to RHR pump 1P202D	Fails open	Loss of power to RHR pump 1P202D	No effect - three redundant RHR pumps from load groups A,B,&C provide the required safety function
37	Circuit breaker 52-20403	Provides power to emergency service water pump 0P504D	Fails open	Loss of power to emergency service water pump 0P504D	No effect - three redundant emergency service water pumps from load groups A,B,&C provide the required safety function

TABLE 8.3-9 (Continued)

ID No.	Component Name	Function	Failure Mode	Effect on Subsystem	Effect on Safety Function
38	Circuit breaker 52-20404	Provides standby power to bus 1A204	Fail to close	Failure to provide standby power to load group "C"	No effect - safety functions are provided by redundant equipment supplied by load groups A,B,&C
39	Circuit breaker 52-20405	Provides power to core spray pump 1P206D	Fails open	Loss of power to core spray pump 1P206D	No effect - three redundant core spray pumps from load groups A,B,&C provide the required safety function
40	Circuit breaker 52-20406	Provides power to 480 V load center 1B240	Fails open	Loss of power to all load group "D" 480 V loads	No effect - safety functions are provided by redundant equipment supplied by load groups A,B,&C
41	Circuit breaker 52-20407	Provides power to CRD pump 1P132B	Fails open	Loss of power to CRD pump 1P132B	No effect - non-Class 1E equipment
42	Circuit breaker 52-20408	Provides power to RHR service water pump 1P506B	Fails open	Loss of power to RHR service water pump 1P506B	No effect - redundant RHR service water pump 1P506A provides the required safety function
43	Circuit breaker 52-20409	Provides alternate preferred power supplies to bus 1A204	Fail to close	Loss of alternate preferred offsite power to load group "D"	No effect - diesel generator provides the standby power (See ID No. 38)
44	Circuit breaker 52-20410	Provides power to control structure chiller 0K112B	Fails open	Loss of power to control structure chiller 0K112B	No effect - redundant control structure chiller 0K112A provides the required safety function
45	Circuit breaker 52-20411	Spare	-	-	-



TABLE 8.3-11

## CABLE CAPACITIES - 15 kV CABLES (ALUMINUM)

Conductor Size	Amps in Duct and Embedded Conduit		Amps in Conduit in Air	
	40°C Ambient	40°C Ambient	65.5°C Ambient	
3-1/c *	1/c	1/c	1/c	
#4/0 AWG	195	232	162	
350 KCMIL	258	313	219	
500 KCMIL	313	387	271	
750 KCMIL	386	486	340	
1000 KCMIL	444	574	402	
6-1/c	2/c	2/c	2/c	
#4/0 AWG	353	427	299	
350 KCMIL	463	576	403	
500 KCMIL	559	712	498	
750 KCMIL	686	894	626	
1000 KCMIL	786	1056	739	
9-1/c	3/c	3/c	3/c	
#4/0 AWG	472	592	414	
350 KCMIL	616	798	559	
500 KCMIL	738	987	691	
750 KCMIL	900	1239	867	
1000 KCMIL	1024	1463	1024	

\* 3-1/c indicates single conductor per phase, and  
6-1/c indicates two conductors per phase, etc.





TABLE 8.3-12CABLE AMPACITIES - 5 kV CABLES (ALUMINUM)

Conductor Size	Amps in Duct and Embedded Conduit		Amps in Conduit in Air	
	40°C Ambient	40°C Ambient	65.5°C Ambient	
3-1/c	1/c	1/c	1/c	
#4/0 AWG	194	226	158	
350 KCMIL	257	307	215	
500 KCMIL	312	381	267	
750 KCMIL	386	479	335	
1000 KCMIL	445	560	392	
6-1/c	2/c	2/c	2/c	
#4/0 AWG	333	416	291	
350 KCMIL	438	565	396	
500 KCMIL	527	701	491	
750 KCMIL	647	881	617	
1000 KCMIL	741	1030	721	
9-1/c	3/c	3/c	3/c	
#4/0 AWG	471	576	403	
350 KCMIL	618	783	548	
500 KCMIL	743	972	680	
750 KCMIL	907	1221	855	
1000 KCMIL	1037	1428	1000	

cooling system alone. It is therefore necessary to connect the RHR system to the spent fuel pool. When this is done the pool temperature can be maintained well below 125°F.

All piping and equipment shared with or connecting to the RHR intertie loop are Seismic Category I, Quality Group C, and can be isolated from any piping associated with the non-Seismic Category I Quality Group C fuel pool cooling system.

Provisions to minimize and monitor leakage from the fuel pool are described in Subsection 9.1.2.3.

Makeup for evaporative and small leakage losses from the fuel pool is normally supplied from the demineralized water system to the skimmer surge tanks of each unit. The intermittent flow rate is approximately 50 gpm to each surge tank.

A Seismic Category I makeup of 60 gpm is provided by a 2 in. line from each emergency service water (ESW) loop to the RHR fuel pool diffusers, thus providing redundant flow paths from a reliable source of water. The design makeup rate from each ESW loop is based on replenishing the boil-off from the MNHL in each fuel pool for 30 days following the loss of the FPCCS capacity. The time required to reach boiling after loss of loading is approximately 25 hours.

The water level in the spent fuel storage pool is maintained at a height which is sufficient to provide shielding for required building occupancy. Radioactive particulates removed from the fuel pool are collected in filter demineralizer units in shielded cells. For these reasons, the exposure of station personnel to radiation from the spent fuel pool cooling and cleanup system is normally minimal. Further details of radiological considerations are described in Chapter 12.

An evaluation of the radiological effect of a boiling fuel pool is presented in Appendix 9A.

#### 9.1.3.4 Inspection and Testing Requirements

No special tests are required because at least one pump, heat exchanger, and filter demineralizer are continuously in operation while fuel is stored in the pool. The remaining components are periodically operated to handle increased heat loads during refueling.

The pool liner leak detection drain valves are periodically opened and the leak rate estimated by the volumetric method. Gas or dye pressure testing from behind the liner plate may be performed to locate a liner plate leak.

Routine visual inspection of the system components, instrumentation, and trouble alarms is provided to verify system operability. Components and piping of the PPCCS designed per ASME Boiler and Pressure Vessel Code, Section III, Class 3 are in-service inspected as described in Section 6.6.

The system will be preoperationally tested in accordance with the requirements of Chapter 14.

#### 9.1.4 FUEL HANDLING SYSTEM.

##### 9.1.4.1 Design Bases

The fuel-handling system is designed to provide a safe and effective means for transporting and handling fuel from the time it reaches the plant until it leaves the plant after post-irradiation cooling. Safe handling of fuel includes design considerations for maintaining occupational radiation exposures as low as practicable during transportation and handling.

Design criteria for major fuel handling system equipment is provided in Tables 9.1-2 through 9.1-4 which list the safety class, quality group, and seismic category. Where applicable, the appropriate ASME, ANSI, Industrial and Electrical Codes are identified. Additional design criteria is shown below and expanded further in Subsection 9.1.4.2.

The transfer of new fuel assemblies between the uncrating area and the new fuel inspection stand and/or the new fuel storage vault is accomplished using the reactor building crane or the refueling floor jib cranes equipped with a general purpose grapple.

The reactor building crane auxiliary hoist or a refueling floor jib crane is used with a general purpose grapple to transfer new fuel from the fuel inspection stand or the new fuel vault to the fuel storage pool. From this point on, the fuel will be handled by the telescoping grapple on the refueling platform.

The refueling platform including refueling platform rails, clamps, and clips are Safety Class 2 and Seismic Class 1 from a structural standpoint in accordance with 10CFR50, Appendix A and B. Allowable stress due to safe shutdown earthquake loading is 120 percent of yield or 70 percent of ultimate, whichever is least. A dynamic analysis is performed on the structures using the response spectrum method with load contributions resulting from each of three earthquakes being combined by the RMS procedure.

#### 9.1.4.2.10 Fuel Transfer Description

##### 9.1.4.2.10.1 Arrival of Fuel on Site

New fuel arrives in the railway bay of the reactor building Unit 1 either by railcar or truck. The access doors are closed to maintain the secondary containment as required by Technical Specifications. Unloading of the metal shipping containers is done by the auxiliary hoist of the reactor building crane.

##### 9.1.4.2.10.2 Refueling Procedure

The plant refueling and servicing sequence diagram is shown in Figure 9.1-15. Fuel handling procedures are described below and shown visually in Figure 9.1-16 through Figure 9.1-19.

The Refueling Floor Layout is shown in Figure 9.1-4 and component drawings of the principal fuel handling equipment are shown in Figures 9.1-7 through 9.1-14 and Figure 9.1-20.

The fuel handling process takes place primarily on the refueling floor above the reactor. The principal locations and equipment are shown on Figure 9.1-16. The reactor, fuel pool, and shipping cask pool are connected to each other by slots, as shown at (A) and (B). Slot (A) is open during reactor refueling, and slot (B) is open during spent fuel shipping. At other times the slots are closed by means of blocks and gates, which make water-tight barriers.

The handling of new fuel on the refueling floor is illustrated in Figure 9.1-17. The transfer of the bundles between the crate (C) and the new fuel inspection stand (D) and/or the new fuel storage vault (E) is accomplished using 5-ton auxiliary hoist of the reactor building crane or a half-ton floor mounted refueling jib crane equipped with a general-purpose grapple. The fuel bundle cannot be handled horizontally without support, so the crate is placed in an almost vertical position before being opened. The top and front of the crate are opened, and the bundles removed in a vertical position.

The auxiliary hoist of the reactor building crane or the jib crane are also used with a general-purpose grapple to transfer new fuel from the new fuel vault or inspection stand to a storage rack position in the fuel pool. From this point on, the fuel is handled by the telescoping grapple on the refueling platform.

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The storage racks in both the vault and the fuel pool hold the fuel bundles or assemblies vertical, in an array which is subcritical under all possible conditions.

The new fuel inspection stand holds one or two bundles in vertical position. The Inspector(s) ride up and down on a platform, and the bundles are manually rotated on their axes. Thus the inspectors can see all visible surfaces on the bundles.

The general-purpose grapples and the fuel grapple of the refueling platform have redundant hooks, and an indicator which confirms positive grapple engagement.

The refueling platform uses a grapple on a telescoping mast for lifting and transporting fuel bundles or assemblies. The telescoping mast can extend to the proper work level; and, in its normal up position state, maintains adequate water shielding over the fuel being handled.

The reactor refueling procedure is shown schematically in Figure 9.1-18. The refueling platform (G) moves over the fuel pool, lowers the grapple on the telescoping mast (H), and engages the bail on a new fuel assembly which is in the fuel storage rack. The assembly is lifted clear of the rack, and moved through slot (A) and over the appropriate empty fuel location in the core (J). The mast then lowers the assembly into the location, and the grapple releases the bail.

The operator then moves the platform until the grapple is over a spent fuel assembly which is to be discharged from the core. The assembly is grappled, lifted, and moved through slot (A) to the fuel pool. Here it is placed in one of the fuel prep machines (K).

An operator, using a long-handled wrench, removes the screws and springs from the top of the channel. The channel is then held, while a carriage lowers the fuel bundle out of the channel. The channel is then moved aside, and the refueling platform grapple carries the bundle and places it in a storage rack. The channel handling boom hoist, (L), moves the channel to storage, if appropriate.

In actual practice, channeling and dechanneling may be performed in many sequences, depending on whether a new channel is to be used, or a used channel is to be installed on a new bundle and returned to the core. A channel rack is conveniently located near to the fuel prep machines, for temporary storage of channels which are to be reused.

To preclude the possibility of raising radioactive material out of the water, redundant electrical limit switches are incorporated in the auxiliary hoists of the refueling platform

and the jib crane hoist, and interlocked to prevent hoisting above the preset limit. In addition, the cables on the hoists incorporate adjustable stops that will jam the hoist cable against the hoist structure, which prevents hoisting if the limit switch interlock system should fail.

When spent fuel is to be shipped, it is placed in a cask, as shown in Figure 9.1-19. The refueling platform grapples a fuel bundle from the storage rack in the fuel pools, lifts it, carries it through slot (B) into the shipping cask pool, and lowers it into the cask, (M). When the cask is loaded, the reactor building crane sets the cask cover (N) on the cask. After draining the shipping cask pool, the cask is decontaminated and lowered through the open hatchways, (P), onto the truck or railcar in the railway bay at grade level.

Provision of a separate cask loading pool, capable of being isolated from the fuel storage pool, eliminates the potential accident of dropping the cask and rupturing the fuel storage pool.

Additional detailed information is provided below.

#### 9.1.4.2.10.2.1 New Fuel Preparation

##### 9.1.4.2.10.2.1.1 Receipt and Inspection of New Fuel

The incoming new fuel will be delivered to a receiving station. The crates should be unloaded from the transport vehicle and examined for damage during shipment. The crate dimensions are approximately 32" x 32" x 18 feet long. Each crate contains two fuel bundles supported by an inner metal container. Shipping weight of each unit is approximately 3000 pounds. The receiving station includes a separate area where the crate covers can be removed. The crates are then moved to the reactor building where the metal inner containers are removed and lifted to the refueling floor. Both inner and outer shipping containers are reusable. Handling during uncrating is to be accomplished by use of the reactor building crane extending down from the refueling floor through the equipment hatch.

9.1.4.2.10.2.1.2 Channeling New Fuel

The initial core for both units will be channeled as each new fuel bundle is inspected in the fuel inspection stand. This process will be repeated whenever new fuel channels are to be placed on new fuel bundles. Usually channeling new fuel is done concurrently with de-channeling spent fuel. Two fuel preparation machines are located in the fuel pool; one used for de-channeling spent fuel and the other to channel new fuel. The procedure is as follows: Using a jib crane and the general purpose grapple, a new fuel bundle is transported to one the fuel prep machine if it had been residing in the fuel storage vault. Otherwise it is moved from a spent fuel pool storage rack to the fuel preparation machine using the refueling bridge. A spent fuel bundle is moved from a spent fuel pool storage rack to the other fuel prep machine. The channel is unbolted from the spent fuel bundle using the channel bolt wrench. The channel handling tool is fastened to the top of the channel and the fuel prep machine carriage is lowered removing the fuel from the channel. The channel is then positioned over a new fuel bundle located in the first fuel prep machine #2 and the process reversed. The channeled new fuel is then stored in the pool storage racks ready for insertion into the reactor.

9.1.4.2.10.2.1.3 Equipment Preparation

Prior to the plant shutdown for refueling, all equipment must be placed in readiness. All tools, grapples, slings, strongbacks, stud tensioners, etc. should be given a thorough check and any defective (or well worn) parts should be replaced. Air hoses on grapples should be routinely leak tested. Crane cables should be routinely inspected. All necessary maintenance and interlock checks should be performed to assure no extended outage due to equipment failure.

The in-core flux monitors, in their shipping container, should be on the refueling floor. The channeled new fuel and the replacement control rods should be ready in the storage pool.

9.1.4.2.10.2.2 Reactor Shutdown

The reactor is shut down according to a prescribed procedure. During cool down the reactor pressure vessel is vented and filled to above flange level to equalize cooling. The drywell and suppression chamber are de-inerted. The eight reactor well shield plugs can be removed. This is accomplished with the reactor building crane and the supplied slings.

This operation can be immediately followed by removal of the three canal plugs and the three slot plugs. Thus, a total of 14 separate plugs must be removed and placed on the refueling floor. A "Refueling Equipment Storage and Crane Clearance" arrangement drawing is issued to locate placement of these plugs on the refueling floor. The outer fuel pool gate is also removed at this time. The gate sling is attached to the gate lifting lugs and the reactor building crane lifts the gate and places it on the fuel pool gate storage lugs.

#### 9.1.4.2.10.2.2.1 Drywell Head Removal

Immediately after removal of the reactor well shield plugs, the work to unbolt the drywell head can begin. The drywell head is attached by removable bolts protruding from the lower drywell flange. The nuts on top are merely loosened and the bolt heads swing outward. The bolts are then pulled upwards and supported with the nuts on a slotted lip of the head.

The sister hook of the reactor building crane is attached to the hook box on top of the unbolted drywell head and lifted to its appointed storage space on the refueling floor. The drywell seal surface protector is installed before any other activity proceeds in the reactor well area.

#### 9.1.4.2.10.2.2.2 Reactor Well Servicing

When the drywell head has been removed, an array of piping is exposed that must be serviced. Various vent piping penetrations through the reactor well must be removed and the penetrations made water tight. Vessel head piping and head insulation must be removed and transported to storage on the refueling floor.

Water level in the vessel is now brought to flange level in preparation for head removal.

#### 9.1.4.2.10.2.3 Reactor Vessel Opening

##### 9.1.4.2.10.2.3.1 Vessel Head Removal

The stud tensioner is transported by the reactor building crane and positioned on the reactor vessel head. Each stud is tensioned and its nut loosened in a series of 2-3 passes. When the nuts are loose, they are backed off using a nut runner until only a few threads engage. The vessel nut handling tool is



engaged in the upper part of the nut and the nut is rotated free from the stud. The nuts and washers are placed in the racks provided for them and transported to the refueling floor for storage. With the nuts and washers removed, the vessel stud protectors and vessel head guide caps are installed.

The head strongback, transported by the reactor building crane, is attached to the vessel head and the head transported to the head holding pedestals on the refueling floor. The head holding pedestals keep the vessel head elevated to facilitate inspection and "O" ring replacement.

The six studs in line with the fuel transfer canal are removed from the vessel flange and placed in the rack provided. The loaded rack is transported to the refueling floor for storage.

#### 9.1.4.2.10.2.3.2 Dryer Removal

The dryer-separator sling is lowered by the reactor building crane and attached to the dryer lifting lugs. The dryer is lifted from the reactor vessel and transported to its storage location in the dryer-separator storage pool adjacent to the reactor well. The dryer is transported in air. However, if the dryer should become highly contaminated, the reactor well and storage pool can be flooded and a wet transfer effected.

#### 9.1.4.2.10.2.3.3 Separator Removal

In preparation for separator removal, the service platform and service platform support are installed on the vessel flange. From the service platform work area, the four main steam lines are plugged from inside the vessel using the furnished plugs for this duty. Servicing of the safety and relief valves can thus be accomplished without adding to the critical refueling path time. Working from the service platform, the separator is unbolted using the shroud head bolt wrenches furnished.

When the unbolting is accomplished, the service platform is removed and stored on the refueling floor. The service platform support remains on the vessel flange during the remainder of the refueling outage and acts as the flange seal surface protector.

The dryer-separator sling is lowered into the vessel and attached to the separator lifting lugs. The water in the reactor well and in the dryer-separator storage is raised to fuel pool water level and the separator is transferred underwater to its allotted storage place in the adjacent pool.

9.1.4.2.10.2.3.4 Fuel Bundle Sampling

During reactor operation, the core off-gas radiation level is monitored. If a rise in off-gas activity has been noted, the reactor core will be sampled during shutdown to locate any leaking fuel assemblies. The fuel sampler or sipper rests on the channels of a four bundle array in the core. An air bubble is pumped into the top of the 4 fuel bundles and allowed to stay about 10 minutes. This stops water circulation through the bundles and allows fission products to concentrate if a bundle is defective. After 10 minutes, a water sample is taken for fission product analysis. If a defective bundle is found, it is taken to the fuel pool and if required, may be stored in a special defective fuel storage container to prevent the spread of contamination in the pool.

9.1.4.2.10.2.4 Refueling and Reactor Servicing

The remaining gate isolating the fuel pool from the reactor well is now removed thereby interconnecting the fuel pool, the reactor well, and the dryer-separator storage pool. The actual refueling of the reactor can now begin.

9.1.4.2.10.2.4.1 Refueling

During a normal equilibrium outage, approximately 25% of the fuel is removed from the reactor vessel, 25% of the fuel is shuffled in the core (generally from peripheral to center locations) and 25% new fuel is installed. The actual fuel handling is done with the fuel grapple which is an integral part of the refueling platform. The platform runs on rails over the fuel pool and the reactor well. In addition to the fuel grapple, the refueling platform is equipped with two auxiliary hoists which can be used with various grapples to service other reactor internals.

To move fuel, the fuel grapple is aligned over the fuel assembly, lowered and attached to the fuel bundle bail. The fuel bundle is raised out of the core, moved through the refueling slot to the fuel pool, positioned over the storage rack and lowered to storage. Fuel is shuffled and new fuel is moved from the storage pool to the reactor vessel in the same manner.

9.1.4.2.10.2.5 Vessel Closure

The following steps, when performed, will return the reactor to operating condition. The procedures are the reverse of those described in the proceeding sections: Many steps are performed in parallel and not as listed.

- a) Install inner fuel pool gate.
- b) Core verification. The core position of each fuel assembly must be verified to assure the desired core configuration has been attained.
- c) Control rod drive tests. The control rod drive timing, friction and scram tests are performed.
- d) Replace separator.
- e) Drain dryer-separator storage pool and reactor well.
- f) Decontaminate reactor well.
- g) Install service platform, bolt separator, and remove the four steam line plugs. Return the service platform and platform support to storage on refueling floor.
- h) Remove drywell seal surface covering.
- i) Open drywell vents, install vent piping.
- j) Replace fuel pool outer gate.
- k) Replace steam dryer.
- l) Decontaminate dryer-separator storage pool.
- m) Replace vessel studs.
- n) Replace slot plugs.
- o) Install reactor vessel head.
- p) Install vessel head piping and insulation.
- q) Replace dryer-separator canal plugs.
- r) Hydro-test vessel, if necessary.
- s) Install drywell head.
- t) Inert reactor drywell and suppression chamber.

- u) Install reactor well shield plugs.
- v) Startup tests. The reactor is returned to full power operation. Power is increased gradually in a series of steps until the reactor is operating at rated power. At specific steps during the approach to power, the in-core flux monitors are calibrated.

#### 9.1.4.2.10.3 Departure of Spent Fuel from Site

The spent fuel shipping cask arrives by railcar or truck in the railway bay of the reactor building Unit 1. It is lifted from there by the 125 ton hook of a reactor building crane through the floor hatches to the refueling floor and placed into the empty shipping cask pit between the fuel pools of Units 1 and 2.

The cask outside is decontaminated from road dirt and the lid removed by the reactor building crane. One of the inner gates of the shipping cask pit is removed. After filling of the shipping cask pool, the second gate to one of the fuel pools is removed and loading of the cask with irradiated fuel commences. The refueling platform is used to transfer fuel bundles of sufficiently low decay heat level from the spent fuel storage racks underwater into the shipping cask.

Following replacement of the cask lid, the gates to the fuel pool are inserted, the shipping cask pit drained and the cask outside decontaminated. The reactor building crane then transfers the cask from the storage pit onto the shipping vehicle where a cooling system dissipates the remaining decay heat of the fuel during transport.

#### 9.1.4.3 Safety Evaluation

##### 9.1.4.3.1 Spent Fuel Cask

The spent fuel cask is equipped with dual sets of lifting lugs and yokes compatible with the reactor building crane main hook, thus preventing a cask drop due to a single failure. An analysis of the spent fuel cask drop is therefore not required.

#### 9.1.4.3.2 -Reactor Building Crane

See Subsection 9.1.5.3 for the reactor building crane safety evaluation.

#### 9.1.4.3.3 Fuel Servicing Equipment

Failure of any fuel servicing equipment listed in Table 9.1-2 poses no hazard beyond the effect of the refueling accident analyzed in Chapter 15.

Safety aspects (evaluation) of the fuel servicing equipment are discussed in Subsection 9.1.4.2.3.

#### 9.1.4.3.4 Servicing Aids

The small manual devices listed in Table 9.1-5 facilitate underwater viewing and handling of fuel. Failure of any servicing aid does not pose any hazard beyond the effect of the refueling accident.

#### 9.1.4.3.5 Reactor Vessel Servicing Equipment

The dryer-separator sling and the reactor vessel head strongback are both of a cruciform design providing two redundant sets of lifting points compatible with the single failure proof reactor building crane main hoist and hook. Therefore accident analysis is not required.

#### 9.1.4.3.6 In-Vessel Servicing Equipment

Failure of any in-vessel servicing equipment listed in Table 9.1-5 poses no hazard beyond the effect of the refueling accident analyzed in Chapter 15.

#### 9.1.4.5.4 Radiation Monitoring

The area radiation monitoring equipment for the refueling area is described in Subsection 12.3.4.

#### 9.1.5 REACTOR BUILDING CRANES

Two reactor building cranes are provided for the Susquehanna SES. Unit 1 crane is a single failure-proof crane and is designed to handle the spent fuel cask. The Unit 2 crane is not single failure-proof and is designed to handle construction loads and all normal plant operation loads except the spent fuel cask.

The Unit 2 reactor building crane, rated 125 tons (main hoist), 5 tons (auxiliary hoist), is potentially capable of carrying any loads within its rated capacity, but not over or within restricted areas of the refueling floor. Limits of the restricted areas are shown on Figures 9.1-16 A & B.

Administrative controls are used to preclude the Unit 2 reactor building crane from being used for handling the spent fuel cask when stored in the spent fuel shipping cask storage pit.

The following description will address the Unit 1 crane only, which will be referred to as the reactor building crane or the crane.

##### 9.1.5.1 Design Bases

The main purpose of the reactor building crane is to handle the spent fuel cask between the cask transport vehicle, the cask storage pit, and the wash-down area in the reactor building. Secondary purposes of the reactor building crane include:

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- a) Handling loads related to maintenance and replacement of equipment from the reactor building which are received or shipped through the railroad access doors
- b) Handling of shield plugs, reactor vessel and drywell heads, steam dryer and separator, etc, during refueling operations.

The reactor building crane is designed for the following ratings:

Main hoist capacity	125 tons
Auxiliary hoist capacity	5 tons
Speed of main hoist (at rated load)	5 fpm (see Note 1)
Speed of auxiliary hoist (at rated load)	20 fpm (see Note 1)
Speed of trolley (using main hoist)	30 fpm
Speed of trolley (using aux hoist)	50 fpm
Speed of bridge	50 fpm
Lift of main hook (see Note 2)	173 ft
Lift of auxiliary hook	173 ft
Crane span	130 ft
Length of runway (between stops)	323 ft
Uncontrolled drop	
Main hoist	0.5 in. (max.)
Auxiliary hoist	8.55 in. (max.)

Note 1: Minimum speed at rated load is less than 2 percent of rated speed

Note 2: Unit 2 reactor building crane ratings are identical to those of the Unit 1 crane, except for the main hook lift, which is 68 ft. This, in addition to administrative controls, precludes inadvertent use of the Unit 2 crane for spent fuel cask handling, since the main hook does not reach the spent fuel cask plant entry level.

The auxiliary hooks of both cranes are designed for use underwater, up to 50 ft. depth.

#### 9.1.5.2 Equipment Design

##### a) General

The reactor building crane is designed, fabricated, installed, and tested in accordance with ANSI B30.2.0, CMMA-70, and OSHA regulations.

##### b) Structural

The structural portions of the crane bridge and trolley are designed for (1) dead load plus rated lift load plus impact load of 15 percent of the total dead plus rated live loads, not to exceed allowable stresses; (2) dead load plus rated lift load plus a lateral load of 10 percent of the total dead plus rated live loads, not to exceed allowable stresses; (3) the operating basis earthquake (OBE) while lifting the rated load, the working stresses not to exceed 125 percent of the allowable stress; (4) the design basis earthquake (DBE) while lifting the rated load, the allowable stresses to be less than 90 percent in bending, 85 percent in axial tension, and 50 percent in shear of the material minimum yield stresses; (5) a tornado loading of 300 psf, without live load, the allowable stresses to be the same as for (4) above.

The structure of the crane bridge consists of welded box type girders with truck saddles and truck frames of welded steel construction. The trolley side frames, sheave frames, and truck frames are of structural steel welded construction.

##### c) Mechanical

The crane is of a single trolley top running electric overhead travelling bridge design. The general arrangement of the crane in the reactor building is shown on Figure 9.1-4.

The main hoist is provided with the following dual components preventing a single failure to result in a drop of the spent fuel shipping cask:



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- 1) Dual sister hook (hook within a hook)
- 2) Dual reeving systems complete with redundant wire ropes, upper, lower, and equalizing sheaves
- 3) Dual main hoist gear boxes with individual braking systems.

Each wire rope has a safety factor of five against breaking while lifting the rated capacity. In case of failure of one of the two reeving systems, the dynamic load transfer to the other system will not cause the rope load to exceed one-third of the rope breaking strength.

The following holding brakes are provided:

Main hoist	Three, rated for 150 percent of the motor torque, with provision for manual operation to allow lowering of the load after a power failure
Trolley	Two, rated for 50 percent of motor torque
Bridge	One, rated for 100 percent of motor torque.

All holding brakes are ac magnet operated. In addition, the bridge is provided with a hydraulic foot operated brake.

### d) Controls

Bridge and trolley	ac static stepless speed control with reversing plugging control
Hoists	dc static reversing stepless speed control including regenerative braking, with a minimum speed of less than 2 percent of the rated speed.

Operation of the crane is from the bridge mounted cab or floor. The floor operation is by pendant or radio control. Control at any one time is from one point only.

### 9.1.5.3 Safety Evaluation

As described in Subsection 9.1.5.2, the main hoist is provided with dual main hoist components capable of holding the load in the event of a single failure.

The reactor building crane is provided with limit switches to prevent overtravel of the bridge and trolley and stop the main and auxiliary hooks in their highest and lowest safe positions.

Two limit switches, each of different design, are provided to limit the upward movement of the main and auxiliary hoist.

Two geared limit switches are provided for the main hoist, and one for the auxiliary hoist to limit the downward movement of the respective hoists.

When the 125-ton hook is not in the parked upper position, movement of the crane bridge and/or trolley will be stopped when entering the restricted areas shown on Figures 9.1-16A & B. The following means are provided to accomplish the above:

- a) A series of proximity switches mounted on the crane, adjacent to the crane and trolley runways.
- b) A series of trip bars mounted on the bridge and trolley runways are positioned to trip respective proximity switches.
- c) Relays and logic systems to trip power supplies to affected drive motors, when a proximity switch is tripped. This will result in the setting of respective holding brakes and cessation of bridge or trolley movement. "Memory logic" will then allow the bridge or trolley to move in the opposite direction away from the restricted area.
- d.) Administrative controls.

A key locked bypass switch is provided in the cab and the pendant to allow the use of the main hoist over the RPV area for handling shield plugs, RPV and drywell heads, steam dryer/separator, etc.

Crane overload protection is provided by an electrical cut-out on the hoist drive motor. In addition, a loud cell is provided on the equalizer to prevent the crane from lifting loads in excess of its rated capacity.

An overspeed switch activating all spring set motor brakes in the lowering direction holds the load in suspension.

See Section 3.13 for discussion of compliance with Regulatory Guides 1.104 and 1.13.

See Appendix 9B for a discussion of compliance with BTP ASB9-1.

The results of a failure mode and effect analysis are presented in Table 9.1-6.

The crane is safety related and a quality assurance program has been established and implemented in the design, fabrication, erection, and testing.

The crane is designed to remain on the runway in a parked and restrained position (by tornado locks) with no load attached under the following tornado wind loadings:

- a) 300 psf on the windward crane girder
- b) ±200 psf on the leeward crane girder.

The crane mechanical and structural components are qualified to Seismic Category I requirements. The crane, however, may become and remain inoperational after the operating basis earthquake, but no parts or the load will dislodge or fall. Manual towering of the main hoist load is provided.

#### 9.1.5.4 Inspection and Testing Requirements

Crane components tests are performed during the crane fabrication as follows:

- a) Each hook:                      Ultrasonic tests  
    200 percent load test followed  
    by dimensional check  
    Dry powder magnetic particle  
    test
- b) Wire rope:                      Rope sample destructive  
    breaking test
- c) Gears, gear pinions,  
     swivels, load block  
     frames, hook  
     trunnions, seismic  
     restraints, and  
     tornado locks:                      Magnetic particle tests
- d) Major structural

welds: 100 percent magnetic  
particle testing.

The crane hoists, trolley, and bridge drives are operated in the shop to demonstrate their operability and the trolley tracking.

After the crane is erected, it is thoroughly tested, including the crane rating test in accordance with ANSI B30.2.0.

The crane periodic operational tests are in accordance with applicable OSHA regulations, local codes, and ANSI B30.2.0.

#### 9.1.5.5 Instrumentation Requirements

The crane is furnished with dual devices and controls, as described in Subsection 9.1.5.3, to prevent or detect a single crane failure and thus preclude dropping of the spent fuel cask.

#### 9.1.6 REFERENCES

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- 9.1-4 "CORC-BLADE Manual, LEAHS Nuclear Fuel Management and Analysis Package," Control Data Corporation, Publication Number 84005400, Minneapolis, Minnesota (1974).
- 9.1-5 W. R. Cadwell, "PDQ-7 Reference Manual", WAPD-TM-678, January, 1967.
- 9.1-6 L. M. Petrie and N. F. Cross, "KENO-IV - An Improved Monte Carlo Criticality Program," ORNL-4938, November, 1975.
- 9.1-7 N. M. Greene, J. L. Lucius, W. E. Ford, III, J. E. White, R. Q. Wright, and L. M. Petrie, "AMPX - A Modular Code System for Generating Coupled Multigroup Neutron-Gamma Libraries from ENDF/B", ORNL-TM-3706, 1974.

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- 9.1-8 Design and Fabrication Criteria for Susquehanna FSAR.
- 9.1-9 PARSP/3157, P. 7-1 and Appendix I.
- 9.1-10 Summary Report, Nuclear Criticality Analysis for the Spent Fuel Racks of the Susquehanna Power Plant; Nuclear Associates International, DR-3157-3, Report NAI78-15, May 15, 1979.

the header start their respective compressor if the compressor is in standby mode.

A pressure transmitter on the header transmits to a pressure indicator in the main control room. Two local pressure gages indicate the pressure in the manifold of each safety related instrument gas supply bottle header. A pressure switch on each header annunciates safety related header low pressure in the main control room.

Reduced pressure instrument gas is provided via a pressure reducing valve. Local and control room indication of this pressure is provided, as well as local pressure indication on the instrument gas accumulator.

### 9.3.2 PROCESS SAMPLING SYSTEM

The process sampling system is provided to monitor the operation of plant equipment and to provide information needed to make operational decisions.

The process sampling system provides remote sampling facilities and the capability for sampling fluids of various process systems during normal plant power operation and shutdown conditions.

The monitoring of gaseous and liquid process streams for nuclear radiation is covered separately in Section 11.5.

#### 9.3.2.1 Design Bases

The portion of the process sampling system running from the reactor coolant system to the first isolation valve outside the containment is constructed in accordance with ASME Boiler and Pressure Vessel Code, Section III, Class 1. Other sample piping, from the point where it connects to the process system and including the first process shutoff valve (root valve), will be the same classification as the system piping to which it connects. For ASME III, Class 1, 2, and 3 systems the sampling piping downstream from the root valve will be ASME III, Class 3 up to and including the isolation valve above the sample station.

All ASME Section III Class 1, 2 and 3 sample piping and valves are designed to Seismic Category I requirements.

Lines connected to reactor water or main steam systems are of sufficient length to permit decay of short lived nuclides so that sampling personnel will not be unnecessarily exposed to radiation. Additionally, shielding is installed at points on sampling piping to further curtail exposures (as described in

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Chapter 12) and ensure that they be kept below the limits of 10CFR20.

The process sampling system is designed to ensure that representative samples of all appropriate process fluids will be obtained.

Process sampling system piping is large enough to avoid being clogged by anticipated solids. Piping size is minimized to permit effective line purging with a minimum loss of fluid volume.

The process sampling system is designed so that the sample stations will not affect plant safety.

The process sampling system is designed to provide the capability to conduct continuous analysis as well as analysis of discrete samples (grab samples).

The process sampling system is designed to prevent hazards to operating personnel from high pressure, temperature, or radiation levels of the process fluid during all modes of operation.

The process sampling systems for each unit is designed to be functionally similar but operationally independent.

### 9.3.2.2\_\_System Description

The process sampling system is illustrated schematically by Figures 9.3-6 thru 9.3-9. Locations of sample points are shown on the appropriate system piping and instrumentation diagrams for the systems to be sampled. The process sampling system consists of sampling lines, heat exchangers, sample vessels, sample sinks, and analysis equipment and instrumentation.

Sampling stations are located in the reactor, turbine, and radwaste buildings. The liquid radwaste collection sample station and the auxiliary boiler sample station are common for Units 1 and 2. The reactor and turbine building sample stations are operationally independent systems with the following exception: the spare fuel pool filter demineralizer effluent sample and the common offgas recombiner closed loop cooling water sample are located in Unit 1 stations.

Local grab samples rather than permanently installed sample lines to a control sampling station are provided for process points that require weekly sampling and are in zones where radioactivity is less than 15 mrem/hr (radiation Zones I, II, or III).

Samples of reactor feedwater, reactor recirculation water, main steam, and fuel pool water are routed to the reactor building

9.3.3.5 Instrumentation Application

High and low level switches are provided in each sump. For sumps having two pumps, the level switch will actuate the second pump at a higher level. The first pump to start is alternated on each pumping cycle to equalize run times. Table 9.3-10 shows the usage factors resulting from this provision.

The drywell equipment drain tank drains by gravity. The drain tank's discharge valves automatically open when a predetermined high level in the tank is reached. The discharge valves close at a predetermined low level.

Oil sumps are equipped with level switches and high level alarms in the main control room.

To detect leaks, a level alarm will be provided in the main control room for each ECCS equipment room.

The drywell floor drain sump and the drywell equipment drain tank temperatures are indicated, and a high alarm is annunciated on a local panel in the reactor building of each unit.

The levels in the drywell floor drain sumps and drywell equipment drain tanks are recorded, and a high-high level alarm is annunciated in the main control room. Refer to Subsection 5.2.5 and Section 7.6 for further details of the Leak Detection System.

9.3.4 CHEMICAL AND VOLUME CONTROL SYSTEM

Not applicable to BWR's.

9.3.5 STANDBY LIQUID CONTROL SYSTEM9.3.5.1 Design Bases

The standby liquid control system is a special safety system and is designed in accordance with Seismic Category I requirements. It shall meet the following safety design bases:

- (a) Backup capability for reactivity control shall be provided, independent of normal reactivity control provisions in the nuclear reactor, to be able to shut down the reactor if the normal control ever becomes inoperative.



- (b) The backup system shall have the capacity for controlling the reactivity difference between the steady-state rated operating condition of the reactor with voids and the cold shutdown condition, including shutdown margin, to assure complete shutdown from the most reactive condition at any time in core life.
- (c) The time required for actuation and effectiveness of the backup control shall be consistent with the nuclear reactivity rate of change predicted between rated operating and cold shutdown conditions. A fast scram of the reactor or operational control of fast reactivity transients is not specified to be accomplished by this system.
- (d) Means shall be provided by which the functional performance capability of the backup control system components can be verified periodically under conditions approaching actual use requirements. Demineralized water, rather than the actual neutron absorber solution, can be injected into the reactor to test the operation of all components of the redundant control system.
- (e) The neutron absorber shall be dispersed within the reactor core in sufficient quantity to provide a reasonable margin for leakage or imperfect mixing.
- (f) The system shall be reliable to a degree consistent with its role as a special safety system; the possibility of unintentional or accidental shutdown of the reactor by this system shall be minimized.

#### 9.3.5.2\_\_System Description

The standby liquid control system (see Figure 9.3-13) is manually initiated through a single keylock switch in the main control room to pump a boron neutron absorber solution into the reactor if the operator determines the reactor cannot be shut down or kept shut down with the control rods. The keylocked control room switch is provided to assure positive action from the main control room should the need arise. Procedural controls are applied to the operation of the keylocked control room switch.

The boron solution tank, the test water tank, the two positive displacement pumps, the two explosive valves, the two pump suction valves, and associated local valves and controls are located in the reactor building. The liquid is piped into the reactor vessel and discharged near the bottom of the core shroud so it mixes with the cooling water rising through the core (see Section 5.3).

## SSER-FSAR

The specified neutron absorber solution is sodium pentaborate ( $\text{Na}_2\text{B}_{10}\text{O}_{16}\cdot 10\text{H}_2\text{O}$ ). It is prepared by dissolving stoichiometric quantities of borax and boric acid in demineralized water. An air sparger is provided in the tank for mixing. To prevent system plugging, the tank outlet is raised above the bottom of the tank.

The SLC system is sized to deliver enough sodium pentaborate solution into the reactor (see Figure 9.3-14) to assure reactor shutdown.

The saturation temperature of the recommended solution is  $59^\circ\text{F}$  at the low level alarm volume and approximately  $49^\circ\text{F}$  at the tank overflow volume (see Figure 9.3-15). The equipment containing the solution is installed in a room in which the air temperature is to be maintained within the range of  $60^\circ$  to  $100^\circ\text{F}$ . In addition, a heater system maintains the solution temperature at  $75^\circ$  to  $85^\circ\text{F}$  to prevent precipitation of the sodium pentaborate from the solution during storage. High or low temperature, or high or low liquid level, causes an alarm in the control room.

Each positive displacement pump is sized to inject the solution into the reactor in 50 to 125 minutes. The pump and system design pressure between the explosive valves and the pump discharge is 1400 psig. The two relief valves are set slightly under 1400 psig. To prevent bypass flow from one pump in case of relief valve failure in the line from the other pump, a check valve is installed downstream of each relief valve line in the pump discharge pipe.

The two explosive-actuated injection valves provide assurance of opening when needed and ensure that boron will not leak into the reactor even when the pumps are being tested.

Each explosive valve is closed by a plug in the inlet chamber. The plug is circumscribed with a deep groove so the end will readily shear off when pushed with the valve plunger. This opens the inlet hole through the plug. The sheared end is pushed out of the way in the chamber; it is shaped so it will not block the ports after release.

The shearing plunger is actuated by an explosive charge with dual ignition primers inserted in the side chamber of the valve. Ignition circuit continuity is monitored by a trickle current, and an alarm occurs in the control room if either circuit opens. Indicator lights show which primary circuit opened.

The SLC system is actuated by a three-position keylocked switch on the control room console. This assures that switching from the "off" position is a deliberate act. Switching to either side starts an injection pump, actuates both of the explosive valves, and closes the reactor cleanup system outboard isolation valve to prevent loss or dilution of the boron.

## SSSES-PSAR

A light in the control room indicates that power is available to the pump motor contactor and that the contactor is deenergized (pump not running). Another light indicates that the contactor is energized (pump running).

Storage tank liquid level, tank outlet valve position, pump discharge pressure, and loss of continuity on the explosive valves indicate that the system is functioning. If any of those items indicate that the liquid may not be flowing, the operator may immediately change the other switch status to "run" thereby activating the redundant train of the SLC system. The local switch will not have a "stop" position. This prevents the isolation of the pump from the control room. Pump discharge pressure and valve status are indicated in the control room.

Equipment drains and tank overflow are not piped to the radwaste system but to separate containers (such as 55-gal. drums) that can be removed and disposed of independently to prevent any trace of boron from inadvertently reaching the reactor.

Instrumentation consisting of solution temperature indication and control, solution level, and heater system status is provided locally at the storage tank. Table 9.3-11 contains the process data for the various modes of operation of the SLC.

### 9.3.5.3 Safety Evaluation

The standby liquid control system is a reactivity control system and is maintained in an operable status whenever the reactor is critical. The system is expected never to be needed for safety reasons because of the large number of independent control rods available to shut down the reactor.

To assure the availability of the SLC system, and to facilitate maintenance and testing, two sets of the components required to actuate the system - pumps and explosive valves are provided in parallel redundancy.

The system is designed to bring the reactor from rated power to a cold shutdown at any time in core life. The reactivity compensation provided will reduce reactor power from rated to zero level and allow cooling the nuclear system to room temperature, with the control rods remaining withdrawn in the rated power pattern. It includes the reactivity gains that result from complete decay of the rated power xenon inventory. It also includes the positive reactivity effects from eliminating steam voids, changing water density from hot to cold, reduced Doppler effect in uranium, reducing neutron leakage from boiling to cold, and decreasing control rod worth as the moderator cools.

## SSSES-FSAR

The minimum average concentration of natural boron in the reactor to provide adequate shutdown margin, after operation of the SLC system, is 660 ppm. Calculation of the minimum quantity of sodium pentaborate to be injected into the reactor is based on the required 660 ppm average concentration in the reactor coolant including recirculation loops, at 70°F and reactor normal water level. The result is increased by 25% to allow for imperfect mixing and leakage. Additional sodium pentaborate is provided to accommodate dilution by the RHR system in the shutdown cooling mode. This concentration will be achieved if the solution is prepared as defined in Subsection 9.3.5.2 and maintained above saturation temperature.

Cooldown of the nuclear system will require a minimum of several hours to remove the thermal energy stored in the reactor, cooling water, and associated equipment. The controlled limit for the reactor vessel cooldown is 100°F per hour, and normal operating temperature is approximately 550°F. Use of the main condenser and various shutdown cooling systems requires 10 to 24 hours to lower the reactor vessel to room temperature (70°F); this is the condition of maximum reactivity and, therefore, the condition that requires the maximum concentration of boron.

The specified boron injection rate is limited to the range of 6 to 25 ppm per minute. The lower rate assures that the boron is injected into the reactor in approximately two hours. This resulting reactivity insertion is considerably quicker than that covered by the cooldown. The upper limit injection rate assures that there is sufficient mixing so that boron does not recirculate through the core in uneven concentrations that could possibly cause reactor power to rise and fall cyclically.

The SLC system is required to be operable in the event of a station power failure, therefore the pumps, heaters, valves, and controls are powered from or connectable to the standby a-c power supply. The pumps and valves are powered and controlled from separate buses and circuits so that a single electrical failure will not prevent injection of sodium pentaborate on demand.

The SLC system and pumps have sufficient pressure margin, up to the system relief valve setting of approximately 1400 psig, to assure solution injection into the reactor above the normal pressure in the bottom of the reactor. The nuclear system relief and safety valves begin to relieve pressure above approximately 1100 psig. Therefore, the SLC system positive displacement pumps cannot overpressurize the nuclear system.

Only one of the two standby liquid control pumps is needed for system operation. If a redundant component (e.g., one pump) is found to be inoperable, there is no immediate threat to shutdown capability, and reactor operation can continue during repairs. The time during which one redundant component upstream of the explosive valves may be out of operation should be consistent

## SSSES-FSAR

with the following: the probability of failure of both the control rod shutdown capability and the alternate component in the SLC system; and the fact that nuclear system cooldown takes several hours while liquid control solution injection takes approximately two hours. Since this probability is small, considerable time is available for repairing and restoring the SLC system to an operable condition while reactor operation continues. Assurance that the system will still fulfill its function during repairs is obtained by demonstrating operation of the operable pump.

In the event of a loss of the thermostatically-controlled storage tank heater "A", a low temperature alarm would eventually be annunciated in the control room and would alert the operator to control storage tank temperature manually from the local panel by means of the mixing heater "B".

A low-temperature alarm will also annunciate in the control room if there is a loss of the suction piping heat tracing. The alarm setpoint is sufficiently above saturation temperature of the sodium pentaborate solution such that, even in the unlikely event that ambient temperature is below 70°F, sufficient time will be available to enable the operating personnel to take appropriate temporary measures to heat the suction piping before precipitation occurs.

The SLC system is evaluated against the applicable General Design Criteria as follows:

Criterion 2: The SLCS is located in the area outside of the primary containment (drywell) and below the refueling floor. In this location it is protected by the containment and compartment walls from external natural phenomena such as earthquakes, tornadoes, hurricanes and floods and internally from effects of such events and internal postulated events.

Criterion 4: The SLCS is designed for the expected environment in the containment and specifically for the compartment in which it is located. In this compartment, it is not subject to the more violent conditions postulated in this criterion such as missiles, whipping pipes, and discharging fluids. This system is only called upon to perform a pseudo-safety function under normal operation conditions.

Criterion 21: Criterion 21 is applicable to protection systems only. The SLC system is a reactivity control system and should be evaluated against Criterion 29.

Criterion 26: The SLCS is the second reactivity control system required by this criterion. The requirements of this criterion do not apply within the SLCS itself.

Criterion 27: This criterion applies no specific requirements onto the SLCS and, therefore, is not applicable. See the General Design Criteria Section (Section 3.1) for discussion of combined capability.

Criterion 29: The SLCS pumps and valves outboard of the isolation valves are redundant. Two pumps, and two injection valves are arranged and cross-tied such that operation of any one of each results in successful operation of the system. The SLCS also has test capability. A special test tank is supplied for providing test fluid for the yearly injection test. Pumping capability may be tested at any time. A trickle current continuously monitors continuity of the firing mechanisms of the injection squib valves.

The SLC system is evaluated against the applicable regulatory guides as follows:

Regulatory Guide 1.26 Revision 2: Because the SLCS is a reactivity control system, all mechanical components are at least Quality Group B. Those portions which are part of the Reactor Cooling Pressure Boundary are Quality Group A. This is shown in Table 3.2-1.

Regulatory Guide 1.29 Revision 1: All GE supplied components of the SLCS which are necessary for injection of neutron absorber into the reactor are Seismic Category I. This is shown in Table 3.2-1.

Since the SLC system is located within its own compartment within the reactor building, it is adequately protected from flooding, tornadoes, and internally and externally generated missiles. SLC system equipment is protected from pipe break by providing adequate distance between the seismic and non-seismic SLC system equipment where such protection is necessary. In addition, appropriate distance is provided between the SLC system and other piping systems. Where adequate protection cannot be assured, barriers have been considered to assure SLC system protection from pipe break (See Section 3.6).

It should be noted that the SLC system is not required to provide a safety function during any postulated pipe break events. This system is only required under an extremely low probability event where all of the control rods are assumed to be inoperable while the reactor is at normal full power operation. Therefore, the protection provided is considered over and above that required to meet the intent of APCSB 3-1 and MEB 3-1.

This system is used in a couple of special plant capability demonstration events cited in Appendix A of Chapter 15. Specifically Events 51, 52, and 53 which are extremely low probability non-design basis postulated incidents. The analyses

given there are to demonstrate additional plant safety consideration far beyond reasonable and conservative assumptions.

A system-level, qualitative-type failure mode and effects analysis is presented in Subsection 15A.6.6.

#### 9.3.5.4 Testing and Inspection Requirements

Operational testing of the SLC system is performed in at least two parts to avoid inadvertently injecting boron into the reactor.

With the valve from the storage tank closed and the valves to and from the test tank opened, demineralized water in the test tank can be recirculated by locally starting either pump.

During a refueling or maintenance outage, the injection portion of the system can be functionally tested by valving the suction line to the test tank and actuating the system from the control room. System operation is indicated in the control room.

After functional tests, the injection valve shear plugs and explosive charges must be replaced and all the valves returned to their normal positions as indicated.

After closing a local locked-open valve to the reactor, leakage through the injection valves can be detected by opening valves at a test connection in the line between the containment isolation check valves. Position indicator lights in the control room indicate that the local valve is closed for tests or open and ready for operation. Leakage from the reactor through the first check valve can be detected by opening the same test connection in the line between the Containment Isolation Check Valves when the reactor is pressurized.

The test tank contains demineralized water for approximately 3 minutes of pump operation. Demineralized water from the makeup system or the condensate storage system is available for refilling or flushing the system.

Should the boron solution ever be injected into the reactor, either intentionally or inadvertently, then after making certain that the normal reactivity controls will keep the reactor subcritical, the boron is removed from the reactor coolant system by flushing for gross dilution followed by operating the reactor cleanup system. There is practically no effect on reactor operations when the boron concentration has been reduced below approximately 50 ppm.

The concentration of the sodium pentaborate in the solution tank is determined periodically by chemical analysis. Electrical

supplies and relief valves are also subjected to periodic testing (see Chapter 16).

The SLC system is preoperationally tested in accordance with the requirements of Chapter 14.

#### 9.3.5.5\_\_Instrumentation\_Requirements

The instrumentation and control system for the SLC is designed to allow the injection of liquid poison into the reactor and the maintenance of the liquid poison solution well above the saturation temperature. A further discussion of the SLC instrumentation may be found in Chapter 7.



TABLE 9.3-10

EQUIPMENT AND FLOOR DRAINAGE SYSTEM  
COMPONENT DESCRIPTION

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## SUMPS AND DRAIN TANKS

	Equipment Nos.	Type	Quantity	Material Liner/Cover	Sump (Tank) Live/ Nominal Capacity Each, gal	Manhole	Oil Inter- ceptor Type	Oil Sump Capacity Each, gal
Drywell Floor Drains	Unit #1	Lined Sump W.	2	SS/-	230/ 450	No	-	-
Drywell Floor Drains	Unit #2	Cooling Coil	2	SS/-	230/ 450	No	-	-
Drywell Equipment Drains	1T-218	Vert. Tank	1	CS	1000/1060	Yes	-	-
Drywell Equipment Drains	2T-218	Vert. Tank	1	CS	1000/1060	Yes	-	-
Reactor Building Drains	Unit #1	Lined Sump	1	SS/18" Conc.	2510/4050	Yes	API-500 gpm	670
Reactor Building Drains	Unit #2	Lined Sump	1	SS/18" Conc.	2510/4050	Yes	API-500 gpm	670
Turbine Bldg. Outer Area Drains	Unit #1	Lined Sump	1	SS/9" Conc.	2570/4130	Yes	API-500 gpm	670
Turbine Bldg. Outer Area Drains	Unit #2	Lined Sump	1	SS/9" Conc.	2570/4130	Yes	API-500 gpm	670
Turbine Bldg. Central Area Drains	Unit-#1	Lined Sump	1	SS/9" Conc.	2570/4130	Yes	API-500 gpm	670
Turb. Bldg. Central Area Drains	Unit #2	Lined Sump	1	SS/9" Conc.	2570/4130	Yes	API-500 gpm	670
Turb. Bldg. Condenser Area Drains	Unit #1	Lined Sump	1	SS/1" CS	- / 692	No	-	-
Turb. Bldg. Condenser Area Drains	Unit #2	Lined Sump	1	SS/1" CS	- / 692	No	-	-
Turbine Bldg. Chemical Drains	Unit #1	Lined Sump	1	SS/1" CS	486/ 935	No	-	-
Turbine Bldg. Chemical Drains	Unit #2	Lined Sump	1	SS/1" CS	486/ 935	No	-	-
Chem. Radwaste Drains	OT-114	Vert. Tank	1	SS	280/ 378	No	-	-
Laundry Radwaste Drains	OT-115	Vert. Tank	1	SS	280/ 378	No	-	-
Radwaste Building Drains	Common	Lined Sump	1	SS/12" Conc.	970/1940	Yes	-	-
Radwaste Building Chem. Drains	Common	Lined Sump	1	SS/12" Conc.	630/1215	Yes	-	-
Pipe Tunnel Drains	Unit #1 Only	Lined Sump	1	SS/1" CS	150/ 360	No	-	-
Circ. Water Pump House Drains	Common	Unlined Sump	1	-/15" Conc.	920/1550	Yes	AP & Baffle	250
Diesel Generator Bldg. Drains	Common	Unlined Sump	1	-1/4" CS	920/1390	Yes	Baffle	135
Cl and Acid Storage Bldg.	Common	Unlined Sump	1	-/12" Conc.	790/4110	Yes	-	-
Water Treat. Bldg. Chem. Drains	Common	Unlined Sump	1	-/15" Conc.	600/1190	Yes	-	-

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10.4.6 CONDENSATE CLEANUP SYSTEM10.4.6.1 Design Bases

The condensate demineralizer system has no safety-related functions and is designed to maintain the condensate at the required purity by removal of the following contaminants:

- a) Products resulting from corrosion that occur in the main steam and turbine extraction piping, feedwater heater shells, and drains
- b) Suspended and dissolved solids that may be introduced by small leakages of circulating water through condenser tubes
- c) Fission and activation products that are entrained in reactor steam and retained in condensate leaving the hotwell
- d) Solids carried into the condenser by makeup water and miscellaneous drains.

The system design is based on the influent concentrations given in Table 10.4-2.

At 4800 gpm per vessel, and with the influent quality listed in Table 10.4-2, the ion exchangers effluent will not exceed the following quality:

a)	Conductivity at 25°C	0.1 micromho/cm
b)	pH at 25°C	6.5 to 7.5
c)	Silica (SiO <sub>2</sub> )	5 ppb
d)	Iron, total (Fe)	5 ppb
e)	Copper (Cu)	2 ppb
f)	Nickel (Ni)	2 ppb
g)	Chloride (Cl)	1 ppb
h)	Total metallic impurities*	9 ppb

\*Total metallic residue retained on a 0.45 micron film filter.

Piping is furnished in accordance with ANSI B31.1.0. Pressure vessels that fall within the jurisdiction of ASME Section VIII are furnished in accordance with that Code.

The design pressure of the condensate demineralizer system is 740 psig at 150°F, which is above the shut-off head of the condensate pumps.

10.4.6.2. System Description

The condensate demineralizer system (Figure 10.4-2) is designed to purify condensate continuously at 131°F and 550 psig at a flow rate of 28,800 gpm. Each demineralizer vessel has a flow capacity of 4,800 gpm and is capable of operating at flow rates up to 5,760 gpm for short periods.

10.4.6.2.1 Condensate Demineralizer System

The condensate demineralizer system consists of a battery of seven ion exchangers, each containing a bed of mixed resin in the proportion of two parts cation resin to one part anion resin by volume. Six exchangers are in service at one time during normal conditions. The seventh exchanger is held on standby for replacement of an inservice unit at the end of its service run and in the event of an abnormal condenser leak. The condensate demineralizers are piped directly into the feedwater cycle and receive condensate under pressure from the condensate pumps.

Regeneration of a specific demineralizer unit occurs when one of three endpoints is reached:

1. Total flow through a unit reaches a preset limit (130,000,000 gallons),
2. If the pressure drop across the influent and effluent headers exceeds 50 psid and it is the lowest-flow demineralizer unit.
3. Conductivity measurements at the outlet of each unit reach a preset level (0.1  $\mu$  mho/cm).

Based on a total throughput of 130,000,000 gallons, regeneration frequency is approximately every 19 days for each resin bed based on influent quality listed in Table 10.4-2 at full load.

These endpoints have been chosen in order that each resin bed be taken out of service prior to reaching an unacceptable level of operation. In particular, the conductivity measurements provide indication that a specific bed may be ionically exhausted in order that it may be regenerated before an unacceptable level of overall condensate water quality is reached.

The control room alarm setpoint for the outlet of each demineralizer vessel, indicating resin bed exhaustion, is 0.1  $\mu$  mho/cm as is the control room alarm setpoint for the condensate effluent header. Condensate influent to the

demineralizers is alarmed in the control room at 0.2  $\mu$  mho/cm conductivity.

The resin beds are transferred from the ion exchangers to the external regeneration system for cleaning and chemical regeneration. A spare charge of resins is held in the external regeneration system for immediate replacement of an exhausted bed in an ion exchanger so that the exchanger may be made available promptly for replacement of another exhausted exchanger.

#### 10.4.6.2.2 External Regeneration System

The system provided for cleaning and chemical regeneration of the resins used in the condensate demineralizer is shown in Figure 10.4-3. It consists essentially of three vessels: a cation, an anion, and a resin storage tank. The cation tank also serves as a resin receiving, resin cleaning, and resin separation tank, through which exhausted resins are transferred from the ion exchanger to the regeneration system. Interlocks are provided so that an off-line demineralizer cannot detect condensate pressure unless it is isolated from the external regeneration system. In addition, if high pressure occurs in the resin transfer line, an isolation valve in the line will automatically close and a relief valve will open to protect the system. The regeneration system is designed for 75 psig and 150°F.

The removal of crud accumulation on the resins is accomplished by a cycle of draining, air backwashing, and rinsing in the cation tank. The regeneration system is designed for use with an ultrasonic resin cleaner and space and connections are provided so that one may be added later. The cleaned resins are transferred back to the original ion exchange vessel for further ion exchange.

Resins in need of complete regeneration are transferred to the cation regeneration tank and cleaned as described in the preceding paragraph. The anion and cation resins are then separated by backwashing before the anions are transferred to the anion regeneration tank. At the end of regeneration the resins are mixed and stored in the resin storage tank.

#### 10.4.6.2.3 Acid and Caustic Dilution Systems

Solutions of acid and caustic required for regeneration of cation and anion resins are prepared by in-line dilution of 66 degree Baume' sulfuric acid and 50 percent sodium hydroxide pumped from bulk storage tanks below the regeneration equipment.

Approximatey 5-1/2 percent concentration of acid solution is required to regenerate the cation resins. The strong acid is mixed in a mixing tee with clean condensate as needed. Water is supplied at a constant rate by condensate transfer pumps through a pressure control valve.

Approximately 5-1/2 percent concentration of caustic at 120°F is required to regenerate the anion resins. Strong caustic is mixed with dilution water at 120°F in a mixing tee as needed. Dilution water is produced by blending 180°F water from the caustic dilution hot water tank with cool water.

#### 10.4.6.2.4 Waste System

Three types of wastes are segregated from the regeneration waste discharge. These are: high conductivity, low conductivity and low solids content, and low conductivity and high solids content.

High conductivity wastewater (conductivity above 100 micromhos) is channeled to the chemical waste neutralizer tanks where it is neutralized and pumped to the radwaste evaporators for distillation. Low conductivity condensate from this process is returned to the condensate storage tank.

Low conductivity, low solids wastewater is channeled to the turbine buildings outer area sump where it is pumped to the liquid radwaste collection tanks.

Low conductivity, high solids waste water (greater than 3 JTU) is channeled to the regeneration waste surge tanks. The tanks are designed with cone bottoms. From there the wastewater is pumped at 35 gpm to the waste sludge phase separator.

See Section 11.2 for the effect of the Condensate Cleanup System on the radwaste system.

#### 10.4.6.3 Safety Evaluation

The equipment and controls in the condensate demineralizer system are of the same design and operational integrity as those in the radwaste system.

Spare capacity is provided in the system to negate the possibility of difficulties in handling radioactive waste when the system is operating. If the radwaste handling system approaches design capacity, such as when condenser tube leaks require maximum rates of regeneration of ion exchangers, the unit

load is reduced to eliminate the possibility of exceeding operational limits.

The effluent water quality stated in Subsection 10.4.6.1 will not be exceeded with an 11.5 gpm condenser leak when circulating water contains 1000 ppm of total dissolved solids. The system will sustain an effluent conductivity of 0.15 micromho with a 46 gpm condenser leak when circulating water contains 1000 ppm of total dissolved solids. The circulating water quality used in the design of the CCS is given in Table 10.4-3. Conductivity is recorded at 12 locations in the condenser, at analysis stations located on the common influent and effluent header to the condensate demineralizer system, on the discharge of each ion exchange vessel, and at the discharge header of the reactor feed pumps. High conductivity alarms are provided to alert the plant operators to an abnormal condition.

Treated condensate conductivity levels are maintained within the limits of Table 2 of Regulatory Guide 1.56, Rev. 1 in the following manner:

Individual demineralizer vessel outlet conductivity is monitored and continuously recorded locally at the Turbine Building Sample Station Control Panel. High conductivity, indicating ionic exhaustion, is alarmed locally and at the main control room panel. The high conductivity alarm setpoint is  $0.1 \mu\text{mho/cm}$ , thus an ionically exhausted resin bed is removed from service and regenerated before reaching the Table 2 of Regulatory Guide 1.56, Rev. 1 lower limit of  $0.2 \mu\text{mho/cm}$ . In addition, a regenerated resin bed being brought on line is automatically recycled to the condenser prior to being placed in service to ensure that the vessel is not brought on stream at high conductivity levels.

The combined demineralizer outlet conductivity is also monitored and continuously recorded locally at the Turbine Building sample station control panel. High conductivity of the combined effluent is alarmed locally and at the main control room panel at  $0.1 \mu\text{mho/cm}$ . Since each vessel is alarmed when conductivity reaches  $0.1 \mu\text{mho/cm}$ . The likelihood of the combined effluent reaching the alarm point is remote except under conditions of a large condenser leak. However, demineralizer inlet conductivity is monitored in the same manner as the outlet flows, with an alarm setpoint of  $0.2 \mu\text{mho/cm}$  indicating condenser leakage. (Table 2 of Regulatory Guide 1.56, Rev. 1 lower limit is  $0.5 \mu\text{mho/cm}$ ).

The condensate demineralizer system is designed to operate in a manner such that corrective action is initiated prior to reaching the lower limits of Table 2 of Regulatory Guide 1.56, Rev. 1.

The values shown in Table 10.4-4 are arrived at assuming 100 percent removal efficiency for all dissolved principal fission

and corrosion activation products. However, because the removal efficiency for suspended solids is 50 to 75 percent, the overall removal of corrosion activation products is somewhat less than 100 percent for the system. Tables 10.4-4 and 10.4-5 provide the design bases for radiation shielding in the condensate demineralizer area.

The effluent strainer in the discharge from each ion exchanger protects the feedwater system against a massive discharge of resins in the event of an underdrain failure.

#### 10.4.6.4 Tests and Inspections

Piping is inspected and tested in accordance with ANSI B31.1.0. All pressure vessels are hydrostatically tested to 1.5 times their design pressure.

The system will be preoperationally tested in accordance with the requirements of Chapter 14.

#### 10.4.6.5 Controls and Instrumentation

The condensate demineralizer and regeneration systems are controlled from a local control panel for all modes of operation, including transfer of resins for cleaning and returning these resins to the exchange vessel, or the transfer of resins for cleaning and regeneration and transferring previously regenerated stored resins to the exchanger for standby.

The conductivities are monitored by a multipoint recorder for the following:

- a) Influent and effluent of the condensate polishing demineralizer system
- b) Effluent from each condensate polishing demineralizer.

In addition, conductivity alarms are provided to alert the operator for off-normal conditions. Resin condition is monitored in accordance with Regulatory Guide 1.56. A differential pressure transmitter is provided to monitor the differential pressure across the condensate demineralizer system. Flow transmitters, recorders, and flow totalizers are provided in the effluent of each condensate polishing demineralizer.

11.3 GASEOUS WASTE MANAGEMENT SYSTEMS11.3.1 DESIGN BASES11.3.1.1 Design Objective

The gaseous waste management systems (GWMS) are designed to process and control the release of gaseous radioactive wastes to the site environs so that the total radiation exposure of persons in offsite areas is as low as reasonably achievable and does not exceed applicable guidelines. This is to be accomplished while maintaining the occupational exposure as low as reasonably achievable and without limiting plant operation or availability.

11.3.1.2 Design Basis

The gaseous waste systems are designed to limit offsite doses from routine station releases to significantly less than the limits specified in 10CFR20, and to operate within the dose objectives established in 10CFR50, Appendix I.

The design basis and maximum expected source terms correspond to 100,000 and 60,000  $\mu$  Ci/sec respectively of noble radiogas after a 30 minute delay. Table 11.3-1 lists the quantities of nuclides expected to be released to the environs when operating at the maximum expected failed fuel levels. The expected doses to individuals at or beyond the site boundary are shown in Subsection 11.3.4 and Environmental Report Subsection 5.2.4.2.

A description of the major equipment items in the offgas system is provided in Table 11.3-5. The seismic and quality group classifications of the GWMS components, piping and structures housing them are listed in Section 3.2.

Conservative analyses similar to those presented in Ref 11.3-1 demonstrate that equipment failure cannot result in doses exceeding acceptable guidelines; thus, neither the offgas system nor the buildings housing the equipment were designed to meet Seismic Category I requirements; however, the offgas structural walls are part of the total structural shear wall system and were analyzed to withstand the effects of earthquakes.

The failure of the Ambient Temperature Charcoal Offgas Treatment system is analyzed in Subsection 15.7.1.1. The related failure of the steam jet air ejector lines and failure of the main turbine gland sealing system are analyzed in Subsections 15.7.1.3 and 15.7.1.2 respectively.



### 11.3.2 SYSTEM DESCRIPTIONS

#### 11.3.2.1 Offgas System

Noncondensable radioactive offgas is continuously removed from the main condenser by the steam jet air ejector (SJAE) during plant operation. This is the major source of gaseous releases from the plant and is larger than all other sources combined. The SJAE offgas will normally contain activation gases, principally N-16, O-19, and N-13. The N-16 and O-19 have short half-lives and are readily decayed. The N-13, with a 10-minute half-life is present in small amounts that are further reduced by delay. The SJAE offgas will also contain various isotopes of the radioactive noble gases Xe and Kr, precursors of biologically significant Sr-89, Sr-90, Ba-140, and Cs-137. The concentration of these noble gases depends on the amount of tramp uranium in the coolant and on the cladding surfaces (usually extremely small) and the number and size of fuel cladding leaks. An offgas system has been provided to treat these radioactive sources. This system utilizes catalytic recombination and charcoal adsorption as discussed below.

The building layout and equipment location of the offgas system components is shown on Figures 11.2-3 through 11.2-7.

#### 11.3.2.1.1 Process Flow Description

The noncondensable gases in the main turbine condenser are removed by a two stage steam jet air ejector (SJAE) and discharged to the offgas recombiner system. During startup, clean auxiliary steam maybe used to drive the SJAE and the recombiner system to minimize operation of and untreated noncondensable releases from the mechanical vacuum pump. After startup, pressure reduced steam from the main steam line is used.

Because of the limited motive steam capacity of the second stage SJAE, additional dilution steam to maintain the H<sub>2</sub> concentration below 4% by volume in the offgas stream, bypasses around the ejector nozzle to the discharge. This arrangement allows adjusting the total dilution steam flow without sacrificing SJAE performance. The offgas-steam flow then enters the associated or the common standby catalytic recombiner system through an electrically heat traced piping manifold. This prevents condensation of the dilution steam particularly during cold start-up. The purpose of the recombiner system is to reduce the offgas volume and eliminate the potential for explosion by controlled recombination of the radiolytic hydrogen with oxygen to less than 1% concentration by volume on a dry basis of 5 scfm

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air flow and less than 0.5% concentration for an air flow of at least 10 scfm.

The offgas first passes through the recombiner preheater in order to minimize the moisture contents prior to entering the catalyst bed. The recombination process takes place inside the recombiner vessel which is electrically preheated during standby to a range of 240°F to 270°F strip heaters on the outside. The reaction temperature is approximately 800°F.

The moisture in the offgas leaving the recombiner vessel is removed in the recombiner condenser where the offgas is cooled to 150°F. A motive steam jet then boosts the saturated gas stream pressure from below to slightly above atmospheric pressure.

The reduced pressure main or auxiliary motive steam used in the motive jet is then removed from the offgas stream in the motive steam jet condenser and the 150°F offgas passes through a delay pipe from the recombiner system in the turbine building to the ambient temperature charcoal offgas system in the radwaste building.

The pressure differential between the condensers in the recombiner systems and the main condenser is sufficient to drain the condensate without additional motive force to the main condenser, while the delay pipe is drained by level controlled valves to the turbine building radwaste sump.

The delay line varies in diameter from 8 to 16 in. and is approximately 600 ft in length. At the design flow rate of 30 scfm, this pipe provides for approximately nine minutes of decay of the radioactive products in the offgas stream prior to entering the adsorption train.

After exiting this line, the gas is cooled to approximately 40°F by a refrigerated chiller unit and reheated to approximately 65°F to prevent condensation. Moisture and temperature instrumentation measure the process conditions downstream of the chiller to monitor the performance of the water removal assemblies and to guard against degraded charcoal performance that might result from either an increase in the moisture content or temperature of the gas.

Prior to entering the main charcoal vessels, the process stream passes through a sacrificial guard bed. The principal function of this guard bed is to absorb impurities that may be entrained in the process gas that might adversely affect the performance of the charcoal adsorbent. Each guard bed has been sized to absorb the moisture that might result from a failure of the chiller over a period of 48 hours. This design feature, in conjunction with the moisture and temperature instrumentation, should provide adequate protection against the contamination of the charcoal

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adsorber bed. Differential pressure indication is provided as a backup to the moisture instrumentation.

After passing through the guard bed, the gas enters the main charcoal adsorption bed. This bed, operating in a controlled temperature vault, selectively adsorbs and delays the xenon and krypton from the bulk carrier gas. This delay on the charcoal permits the xenon and krypton to decay in place. After undergoing a sufficient decay in the charcoal vessels, the process stream passes through a HEPA outlet filter, where radioactive particulate matter and possible charcoal fines are retained. This stream is continuously monitored and an alarm will annunciate any abnormal releases from this system.

The process stream is then directed to the turbine building ventilation exhaust duct where it is diluted with minimum 42,000]scfm of air prior to being released from the top of the reactor building. Table 11.3-1 indicates the estimated annual release rates from the turbine building of various isotopes.

### 11.3.2.1.1.1 Process Flow Diagram

Figure 11.3-1 is the process flow diagram for the system. The process data for startup and normal operating conditions are contained in Table 11.3-8.

### 11.3.2.1.1.2 Process and Instrumentation Diagram (P&ID)

The P&ID is shown as Figures 10.4-9, 11.3-3, A&B and 11.3-4.

### 11.3.2.1.1.3 Process Design Parameters

The krypton and xenon holdup times are closely approximated by the following equation:

$$T = \frac{K_D M}{V} \quad (\text{Equation 11.3-1})$$

Where:

- T = holdup time of a given gas
- $K_D$  = dynamic adsorption coefficient for a given noble gas
- M = mass of charcoal adsorber

$V$  = flow rate of the carrier gas.

Conservative dynamic adsorption coefficients of 420 cc/gm for xenon and 23.7 cc/gm for krypton were assumed for the charcoal adsorbent material. They were derived by adjusting the values presented in NUREG 0016 for the temperature and humidity conditions of the Susquehanna SES offgas process stream.

Dynamic adsorption coefficients for xenon and krypton have been reported by Browning (Ref. 11.3-2). General Electric has performed pilot plant tests at their Vallecitos Laboratory, and the results were reported at the Twelfth AEC Air Cleaning Conference (Ref. 11.3-6). Further data on a similar system operating at ambient temperature are reported in Ref 11.3-3.

The temperature adjustment was obtained by a straight-line interpolation of the coefficients provided, in NUREG 0016 for the following data points: 77°F, dew point 0°F and 0°F, dew point -20°F. The moisture content of a gas mixture at these two points is relatively low and thus the variations in adsorption coefficients between these points is mainly a function of temperature. The coefficients thus obtained were adjusted to reflect the effects of moisture content in a manner consistent with that employed in NUREG 0016.

With a design condenser air in-leakage of 30 scfm, and above adsorption coefficients this system provides a design delay of 32 hours for krypton and 23.7 days for xenon. Since the expected condenser in-leakage is below the design value, the actual delay times should be several times longer than the design delay times. Table 11.3-1 lists isotopic activities at the discharge of the turbine building exhaust vent.

After passing thru the recombiner section, the off gas stream consists primarily of the air in-leakage from the main condenser. The air in-leakage design basis is conservatively assumed at 30 scfm. The Sixth Edition of the Heat Exchange Institute Standards for Steam Surface Condensers (Ref 11.3-4, paragraph 5.16(c) (2)) indicates that with certain conditions of stable operation and suitable construction, noncondensibles should not exceed 6 scfm for large condensers. Dresden-2, Fukushima-1, Tsuruga, and KRB have all operated at 6 scfm or less.

### 11.3.2.2 Component Description

#### 11.3.2.2.1 Recombiner System

The offgas treatment system is divided into two sections to facilitate plant arrangement: the recombiner system and the charcoal offgas system. Three recombiner assemblies are located in the turbine building in a shielded area below the main condenser steam jet air ejectors. Each recombiner assembly consists of the following major components: a recombiner preheater, recombiner vessel, recombiner condenser, motive steam jet, motive steam jet condenser and a condensate cooler.

One recombiner assembly is primarily designated for the service of each nuclear unit and the third assembly is a common standby to both units. Each recombiner assembly is sized to accommodate the design flow from one nuclear unit. The piping and valve manifold upstream of the recombiner assemblies permit the transfer of the offgas stream between a unit designated assembly and the common standby recombiner assembly.

The materials of construction, design pressures and temperatures, and the design codes for the components associated with the recombiner assemblies are listed in Table 11.3-5.

#### 11.3.2.2.2 Charcoal Offgas System

After the radiolytic hydrogen and oxygen have been removed from the process stream by the recombiner assembly, the remaining gas enters a delay line which is approximately 600 ft in length and varies in size from 8 to 16 in. The purpose of this delay line is to permit the large quantity of N-16 to decay to a reasonable activity concentration prior to entering the charcoal adsorption portion of the offgas system. Although there is a separate delay line for each recombiner assembly, these lines are joined into a single common header in the radwaste building. However, the process offgas stream from each unit is segregated by the use of isolation valves that are installed in this common header.

After entering the common inlet header, the gas mixture from each unit can be directed to either of two parallel equipment subtrains consisting each of a water removal/temperature reduction assembly, and a charcoal guard bed. The utilized charcoal adsorption train of each offgas treatment system is primarily designated for the service of the associated nuclear unit. Each adsorption train consists of five charcoal adsorber beds in series. The trains and subtrains are isolable at both the inlet and outlet by remotely operated valves. The following

## 12.2--RADIATION SOURCES

In this section the sources of radiation that form the basis for shield design calculations and the sources of airborne radioactivity required for the design of personnel protective measures and for dose assessment are discussed and identified.

### 12.2.1--CONTAINED SOURCES

The shielding design source terms are based on a noble gas fission product release rate of 0.1 Ci/sec (after 30 minutes decay) and the corresponding fission, activation, and corrosion product concentrations in the primary coolant. The sources in the primary coolant are discussed in Section 11.1 and listed in Tables 11.1-1 through 11.1-5. Throughout most of the primary coolant system, activation products, principally nitrogen-16, are the primary radiation sources for shielding design. For all systems transporting radioactive materials, conservative allowance is made for transit decay, while at the same time providing for daughter product formation.

Basic reactor data and core region description used for this section are listed in Tables 12.2-1 through 12.2-5.

In this subsection the design sources are presented by building location and system. General locations of the equipment discussed in this section are shown on the shielding and zoning drawings, Figures 12.3-8 through 12.3-27. Detailed data on source descriptions for each shielded plant area are presented in Tables 12.2-38 through 12.2-40.

Shielding source terms presented in this section and associated tables are based on conservative assumptions regarding system and equipment operations and characteristics to provide reasonably conservative radioactivity concentrations for shielding design. Therefore, the shielding source terms are not intended to approximate the actual system design radioactivity concentrations.

### 12.2.1.1 Drywell

#### 12.2.1.1.1 Reactor Core

The primary radiations within the drywell during full power operation are neutron and gamma radiation resulting from the fission process in the core. Tables 12.2-4 and 12.2-5 list the multigroup neutron and gamma ray fluxes at the outside surfaces of the reactor pressure vessel and the primary shield at the core midplane. The gamma fluxes include those resulting from capture or inelastic scattering of neutrons within the reactor pressure vessel and core shroud and the gamma radiation resulting from prompt fission and fission product decay.

The largest radiation sources after reactor shutdown are the decaying fission products in the fuel. Table 12.2-9 lists the core gamma sources as a function of shutdown time. Secondary sources are the structural material activation of the RPV, its internals, and the piping and equipment located in the primary containment and also the activated corrosion products accumulated or deposited in the internals of the RPV, the primary coolant piping, and other process system piping in the primary containment.

#### 12.2.1.1.2 Reactor Coolant System

Sources of radiation in the reactor coolant system are fission products estimated to be released from fuel and activation and corrosion products that are circulated in the reactor coolant. These sources are listed in Tables 11.1-1 thru 11.1-5 and their bases are discussed in Section 11.1. The nitrogen-16 concentration in the reactor coolant is assumed to be  $61\mu$  Ci/gm of coolant at the reactor recirculation outlet nozzle.

#### 12.2.1.1.3 Primary Steam System

Radiation sources in the primary steam system piping include activation gases, principally nitrogen-16, and the corrosion and fission products carried over to the steam system.

The nitrogen-16 concentration in the main steam is assumed to be  $100\mu$  Ci/gm of steam leaving the reactor vessel at the main steam outlet nozzle. Fission product activity corresponds to an offgas release rate of  $100,000\mu$  Ci/sec at 30 minutes delay from the reactor steam nozzle. Partition fractions for activity into the

### 12.3.1.3 Radiation Zoning and Access Control

Access to areas inside the plant structures and plant yards is regulated and controlled. Each radiation zone defines the radiation level range to which the aggregate of all contributing sources must be attenuated by shielding.

All plant areas are categorized into radiation zones according to expected radiation levels and anticipated personnel occupancy, with consideration given toward maintaining personnel external exposures ALARA and within the standards of 10CFR20. Each room, corridor, and pipeway of every plant building is evaluated for potential radiation sources during normal operation and shutdown; for maintenance occupancy requirements, and for general access requirements to determine appropriate zoning. Radiation zone categories used and their descriptions are given in Table 12.3-1 and the specific zoning for each plant area is shown on Figures 12.3-8 through 12.3-27. All frequently accessed areas, ie, corridors, are shielded for Zone I and Zone II access.

The control of ingress or egress of plant operating personnel to controlled access areas and procedures employed to ensure that radiation levels and allowable working time are within the limits prescribed by 10CFR20 as described in Section 12.5.

### 12.3.1.4 Control of Activated Corrosion Products

In order to minimize the radiation exposure associated with the deposition of activated corrosion products in reactor coolant and auxiliary systems, the following steps have been taken:

- (1) The reactor coolant system consists mainly of austenitic stainless steel, carbon steel and low alloy steel components. Nickel content of these materials is low, and it is controlled in accordance with applicable ASME material specifications.

A small amount of nickel base material (Inconel 600) is employed in the reactor vessel internal components. Inconel 600 is required where components are attached to the reactor vessel shell and the coefficient of expansion must match the thermal expansion characteristics of the low alloy vessel steel. Inconel 600 was selected because it provides the proper thermal expansion characteristics, adequate corrosion resistance and can be readily fabricated and welded.

- (2) Materials employed in the reactor coolant system are purchased to ASME material specification requirements. No



special controls on levels of cobalt impurities are specified.

- (3) Hardfacing and wear materials having a high percentage of cobalt are restricted to applications where no satisfactory alternate materials are available. Studies currently are being made to determine whether any alternate low cobalt alloys are satisfactory for long term use in nuclear reactor applications. To date, no satisfactory replacement materials have been found.
- (4) A high temperature filtration system was not employed in the Reactor Water Clean-up System. The reasons for this included:
  - a. Lack of quantitative data on the removal efficiency for insoluble cobalt by the high temperature filter;
  - b. Uncertainty in the deposition model including the relative effectiveness of cobalt removal on deposition rate;
  - c. Doubtful cost-effectiveness in an area where other methods under study (such as decontamination) may prove better at reducing dose rates while also being more cost-effective.
- (5) Items 1, 2, and 3 above also apply to valve materials in contact with reactor coolant. Valve packing materials are selected primarily for their properties in the particular environment.
- (6) Subsections 12.1.2.2, 12.3.1.1, and 12.3.1.2 describe the various flushing, draining, testing, and chemical addition connections which have been incorporated into the design of piping and equipment which handle radioactive materials. If decontamination is to be performed, these connections would be used for that purpose.
- (7) The plant is designed with a 1% mixed resin, a pressure precoat clean-up system for the primary coolant in the reactor and a full flow deep bed condensate demineralizer system for the feedwater. See Figures 10.4-2, 10.4-3, 5.4-16 and 5.4-18.

### 12.3.2 SHIELDING

In this subsection the bases for the nuclear radiation shielding and the shielding configurations are discussed.

### 12.3.2.1 Design Objectives

The basic objective of the plant radiation shielding is to reduce personnel exposures, in conjunction with a program of controlled personnel access to and occupancy of radiation areas, to levels that are within the dose regulations of 10CFR50 and are as low as reasonably achievable (ALARA) within the dose regulations of 10CFR20. Shielding and equipment layout and design are considered in ensuring that exposures are kept ALARA during anticipated personnel activities in areas of the plant containing radioactive materials,.

Basic plant conditions considered in the nuclear radiation shielding design are normal operation at full-power, and plant shutdown.

The shielding design objectives for the plant during normal operation, including anticipated operational occurrences, and for shutdown operations are:

- a) To ensure that radiation exposure to plant operating personnel, contractors, administrators, visitors, and proximate site boundary occupants are ALARA and within the limits of 10CFR20
- b) To ensure sufficient personnel access and occupancy time to allow normal anticipated maintenance, inspection, and safety related operations required for each plant equipment and instrumentation area
- c) To reduce potential equipment neutron activation and mitigate the possibility of radiation damage to materials
- d) To sufficiently shield the control room so that the direct dose plus the inhalation dose (calculated in Chapter 15) in the event of design basis accidents will not exceed the limits of 10CFR50, Appendix A, General Design Criterion 19.

### 12.3.2.2 General Shielding Design

Shielding is provided to attenuate direct radiation through walls and penetrations and scattered radiation to less than the upper limit of the radiation zone for each area shown in Figures 12.3-8 through 12.3-27. The minimum shielding requirements (see Subsection 12.3.2.3) for all plant areas are presented on those scaled layout drawings. General locations of the plant areas and

equipment discussed in this subsection are also shown on those drawings.

The material used for most of the plant shielding is ordinary concrete with a minimum bulk density of 145 lb/ft<sup>3</sup>. Whenever poured-in-place concrete has been replaced by concrete blocks or other material, design ensures protection on an equivalent shielding basis as determined by the characteristics of the concrete block selected. Compliance of concrete radiation shield design with Regulatory Guide 1.69 is discussed in Section 3.13. Water is used as the primary shield material for areas above the spent fuel transfer and storage areas.

Special features employed to maintain radiation exposures ALARA in routinely occupied areas such as valve operating stations and sample stations are described in Subsections 12.3.1.1 and 12.3.1.2.

#### 12.3.2.2.1 Reactor Building Shielding Design

During reactor operation, the steel-lined, reinforced concrete drywell wall and the reactor building walls protect personnel occupying adjacent plant structures and yard areas from radiation originating in the reactor vessel and associated equipment within the reactor building. The reactor vessel shield wall, drywell wall, and various equipment compartment walls together with the reactor building walls minimize the radiation levels outside the reactor building.

Where personnel and equipment hatches or penetrations pass through the drywell wall, additional shielding is designed to attenuate the radiation to below the required level defined by the radiation zone outside the drywell wall during normal operation and shutdown and to acceptable emergency levels as defined by 10CFR50 during design basis accidents.

#### 12.3.2.2.2 Reactor Building Interior Shielding Design

Inside Drywell Structure: Areas within the drywell are designed as Zone V areas and are normally inaccessible during plant operation. The reactor vessel shield provides shielding for access in the drywell during shutdown, and reduces the activation of and radiation damage to drywell equipment and materials.

Outside Drywell Structure: The drywell wall is designed to reduce radiation levels in normally occupied areas of the reactor building from sources within the drywell to less than the maximum level for Zone II.

Penetrations and hatch openings in the drywell wall are shielded, as necessary, to meet adjacent area radiation zoning levels. Shielding requirements for the personnel, equipment, and CRD removal hatch openings are shown on Figure 12.3-19 in the areas numbered 412, 413, and 402, respectively. Drywell piping and electrical penetrations are shielded by providing either local shields within the penetration assembly or a shielded penetration room. Shielded piping penetration room locations and bulk shielding requirements are shown on Figures 12.3-18 through 12.3-20. These rooms, numbered 202, 204, 205; 403, 411, 501, 504, 506, 515; are designated radiation Zone V during reactor power operation and are provided with personnel access controls. Electrical penetrations which are not located within these rooms are provided with supplementary local shielding as needed to meet outside zoning levels. Six inches of lead, in addition to the self-shielding by the electrical cables, is furnished in each electrical penetration assembly to attenuate drywell radiation sources.

The components of the reactor water cleanup (RWCU) system described in Section 5.5 are located in shielded compartments which are designed as Zone V, restricted access areas. Shielding is provided for each piece of equipment in the RWCU system consistent with its postulated maximum activity Subsection 12.2.1 and with the access and zoning requirements of the adjacent areas. This equipment includes:

- a) Regenerative heat exchanger
- b) Nonregenerative heat exchanger
- c) RWCU pumps and piping
- d) RWCU filter demineralizers and holdup pumps
- e) RWCU backwash receiving tank and piping.

The traversing in-core probe (TIP) system is located inside a shielded compartment to protect personnel from the neutron activated portion of the TIP cable.

Main steamlines are located within shielded structures from the drywell wall to the reactor building wall.

Spent fuel is a primary source of radiation during refueling. Because of the extremely high activity of the fission products contained in the spent fuel assemblies and the proximity of Zone II areas, shielding is provided for areas surrounding the fuel transfer canal and pool to ensure that radiation levels remain below zone levels specified for adjacent areas.

After reactor shutdown, the Residual Heat Removal (RHR) System pumps and heat exchangers are in operation to remove heat from the reactor water. It is anticipated that the radiation levels in the vicinity of this equipment will temporarily reach Zone V levels due to corrosion and fission products in the reactor water. Shielding is designed to attenuate radiation from RHR equipment during shutdown cooling operations to levels consistent with the radiation zoning requirements of adjacent areas. Adequate shielding will also be provided to maintain radiation zoning requirements during hot standby operation of the RHR system.

During functional testing operations of the Reactor Core Isolation Cooling (RCIC) System and the High Pressure Coolant Injection (HPCI), the steam driven turbine and the inlet and exhaust piping are shielded consistent with the maximum steam activities in the lines and the access zone requirements of surrounding areas.

The concrete shield walls surrounding the spent fuel cask loading, storage, and transfer areas, as well as the shield walls surrounding the fuel transfer and storage areas, are designed to provide Zone II maximum dose rates in accessible areas outside of the shield walls.

Water in the spent fuel pool provides shielding above the spent fuel transfer and storage areas. Direct radiation levels at the fuel handling equipment are calculated to be less than 2.5 mrem/hr from spent fuel during normal operations.

Water is also used as shielding material above the steam dryer and separator storage area. Concrete walls and water in the pool are designed to provide Zone II dose rates in adjacent accessible areas during storage of the dryer and separator.

The Fuel Pool Cooling and Cleanup (FPCC) System (see Section 9.1.3) shielding is based on the maximum activity discussed in Subsection 12.2.1 and the access and zoning requirements of adjacent areas. Equipment in the FPCC system to be shielded includes the FPCC heat exchangers, pumps and piping, filter demineralizers, and backwash receiving tank.

#### 12.3.2.2.3 Radwaste Building Shielding Design

Shielding is provided as necessary around the following equipment in the radwaste building to ensure that the radiation zone and access requirements are met for surrounding areas.

- a) Laundry drain tank and pumps

- b) Chemical waste tank and pumps
- c) Radwaste evaporators
- d) Radwaste evaporator tanks and pumps
- e) Liquid radwaste collection tanks and pumps
- f) Liquid radwaste surge tanks
- g) Liquid radwaste sample tanks and pumps
- h) Reactor water cleanup phase separator and pumps
- i) Waste sludge phase separator and pumps
- j) Spent resin tank
- k) Waste filling and capping station
- l) Waste liner transfer and storage areas
- m) Liquid radwaste demineralizer and piping
- n) Waste mixing tanks
- o) Liquid radwaste filters
- p) Gaseous radwaste equipment.

#### 12.3.2.2.4 Turbine Building Shielding Design

Radiation shielding is provided around the following equipment in the turbine building to ensure that zone access requirements (Figures 12.3-10 through 12.3-15) are met for the following surrounding areas:

- a) Condensate filter demineralizers and piping
- b) Regeneration waste surge tanks and pumps
- c) Chemical waste neutralizing tanks and pumps
- d) Reactor feed pump turbines and piping
- e) Condensate pumps and piping
- f) Main condensers and hotwell
- g) Mechanical vacuum pump

- h) Recombiners and piping
- i) Steam packing exhausters
- j) Condensate demineralizer resin regeneration tanks
- k) Air ejectors and gland steam condensers
- l) Feedwater heaters, heater drains, and piping
- m) Main steam piping
- n) Steam seal evaporator and drain tank
- o) Moisture separator and drain tanks
- p) High pressure and low pressure turbines
- q) Offgas piping.

Areas within most of these shield walls have high radiation levels and limited access.

#### 12.3.2.2.5 Control Room Shielding Design

Figures 12.3-9 and 12.3-28 represent layout and isometric drawings of the control room, showing its relationship to the reactor building.

The design basis loss-of-coolant accident (LOCA) dictates the shielding requirements for the control room. Shielding is provided to permit access and occupancy of the control room under LOCA conditions with radiation doses limited to 5 rem whole body from all contributing modes of exposure for the duration of the accident, in accordance with 10CFR50 Appendix A, General Design Criterion 19.

The design basis LOCA is described in Subsection 15.1.13 and is based on Regulatory Guide 1.3. The direct radiation from airborne fission products inside the reactor building would contribute less than 361 mrem to personnel inside the control room for the 30-day period following the LOCA, based on radioactivity sources described in Subsection 12.2.1.6.

The parameters used in the demonstration of the control room habitability are listed below and in Regulatory Guide 1.3. (The ventilation system parameters are listed in Subsection 12.3.3).

For all isotopes that escape from the drywell to the reactor building, no credit is taken for shielding by the internal structures in the reactor building. Shielding credit is taken for the reactor and control building walls. For all isotopes that remain within the drywell, shielding credit is taken for the drywell wall.

#### 12.3.2.2.6. Diesel Generator Building Shielding Design

There are no radiation sources in the diesel generator building; therefore, no shielding is required for the building.

#### 12.3.2.2.7 Miscellaneous Plant Areas and Plant Yard Areas

Sufficient shielding is provided for all plant buildings containing radiation sources so that radiation levels at accessible areas outside buildings are minimized. Plant yard areas which are frequently occupied by plant personnel are accessible during normal operation and shutdown. Some operations, such as loading solidified waste into shield casks, require access restrictions in adjacent areas. These areas are surrounded by a security fence and closed off from areas accessible to the general public.

#### 12.3.2.2.8 Counting Room Shielding

Because the counting room contains sensitive instruments to radioactivity measurements, it is imperative that the background radiation levels are minimized. To accomplish this, no flyash was used in the concrete mix for the walls and slabs surrounding the counting room. Flyash normally contains a relatively large amount of slow decaying radioactive isotopes. In addition, the shield walls and slabs were sized to maintain a background radiation level of less than 130 mrem/year for anticipated operational occurrences and 45 mrem/year for normal operation.

#### 12.3.2.3 Shielding Calculational Methods

The shielding thicknesses provided to ensure compliance with plant radiation zoning and to minimize plant personnel exposure are based on maximum equipment activities under the plant operating conditions described in Subsection 12.2.1. The thickness of each shield wall surrounding radioactive equipment is determined by approximating as closely as possible the actual



geometry and physical condition of the source or sources. The isotopic concentrations are converted to energy group sources using data from standard Refs 12.3-1 through 12.3-5.

The geometric model assumed for shielding evaluation of tanks, heat exchangers, filters, demineralizers, and evaporators is a finite cylindrical volume source. For shielding evaluation of piping, the geometric model is a finite shielded cylinder. In cases where radioactive materials are deposited on surfaces such as pipe, the latter is treated as an annular cylindrical surface source. Typical computer codes that are used for shielding analysis are listed in Table 12.3-2. Shielding attenuation data used in those codes include gamma class attenuation coefficients (Ref. 12.3-6), gamma buildup factors (Ref. 12.3-7), neutron-gamma multigroup cross sections (Ref. 12.3-20), and albedos (Ref. 12.3-12).

The shielding thicknesses are selected to reduce the aggregate computed radiation level from all contributing sources below the upper limit of the radiation zone specified for each plant area. Shielding requirements are evaluated at the point of maximum radiation dose through any wall. Therefore, the actual anticipated radiation levels in the greater region of each plant area is less than this maximum dose and therefore less than the radiation zone upper limit.

Where shielded entryways to compartments containing high radiation sources are necessary, labyrinths or mazes are designed using a general purpose gamma-ray scattering code G-33 (Ref. 12.3-11). The mazes are constructed so that the scattered dose rate plus the transmitted dose rate through the shield wall from all contributing sources is below the upper limit of the radiation zone specified for each plant area.

### 12.3.3 VENTILATION

The plant heating, ventilating, and air conditioning (HVAC) systems are designed to provide a suitable environment for personnel and equipment during normal operation and anticipated operational occurrences. Parts of the plant HVAC systems perform safety related functions.

#### 12.3.3.1 Design Objectives

The systems are designed to operate such that the in-plant airborne activity levels for normal operation (including anticipated operational occurrences) in the general personnel access areas are within the limits of 10CFR20. The systems

operate to reduce the spread of airborne radioactivity during normal and anticipated abnormal operating conditions.

During post accident conditions the ventilation system for the plant control room provides a suitable environment for personnel and equipment and ensures continuous occupancy in this area. The plant ventilation systems are designed to comply with the airborne radioactivity release limits for offsite areas during normal operation.

#### 12.3.3.2 Design Criteria

Design criteria for the plant HVAC systems include the following:

- a) During normal operation and anticipated operational occurrences, the average and maximum airborne radioactivity levels to which plant personnel are exposed in restricted areas of the plant is ALARA and within the limits specified in 10CFR20. The average and maximum airborne radioactivity levels in unrestricted areas of the plant during normal operation and anticipated operational occurrences will be ALARA and within the limits of Appendix B, Table II of 10CFR20.
- b) During normal operation and anticipated operational occurrences, the dose from concentrations of airborne radioactive material in unrestricted areas beyond the site boundary will be ALARA and within the limits specified in 10CFR20 and 10CFR50.
- c) The plant siting dose guidelines of 10CFR100 will be satisfied following those hypothetical accidents, described in Chapter 15, which involve a release of radioactivity from the plant.
- d) The dose to control room personnel shall not exceed the limits specified in General Design Criterion 19 of Appendix A to 10CFR50 following those hypothetical accidents, described in Chapter 15, which involve a release of radioactivity from the plant.

#### 12.3.3.3 Design Guidelines

In order to accomplish the design objectives, the following guidelines are followed wherever practicable.

12.3.3.3.1 Guidelines to Minimize Airborne Radioactivity

- a) Access control and traffic patterns are considered in the basic plant layout to minimize the spread of contamination.
- b) Equipment vents and drains are piped directly to a collection device connected to the collection system instead of allowing any contaminated fluid to flow across the floor to the floor drain.
- c) All-welded piping systems are used on contaminated systems to the maximum extent practicable to reduce system leakage. If welded piping systems are not used, drip trays are provided at the points of potential leakage. Drains from drip trays are piped directly to the collection system.
- d) The valves in some systems are provided with leak-off connections piped directly to the collection system.
- e) Suitable coatings are applied to the concrete floors of potentially contaminated areas to facilitate decontamination.
- f) Where practicable, metal diaphragm or bellows seat valves are used on those systems where essentially no leakage can be tolerated.
- g) Contaminated equipment has design features that minimize the potential for airborne contamination during maintenance operations. These features may include flush connections on pump casings for draining and flushing the pump prior to maintenance or flush connections on piping systems that could become highly radioactive.
- h) Exhaust hoods are used in plant areas to facilitate processing of radioactive samples by drawing contaminants away from the personnel breathing areas and into the ventilation and filtering systems.
- i) Equipment decontamination facilities are ventilated to ensure control of released contamination and minimize personnel exposure and the spread of contamination.

Accuracy: The overall accuracy within the design range of temperature, humidity, line voltage, and line frequency variation should be such that the actual reading relative to the true reading, including susceptibility and energy dependence (100 KeV to 3 MeV), should be within 9.5 percent of equivalent linear full scale recorder output for any decade.

Reproducibility: At design center the reading shall be reproducible within  $\pm 10$  percent of point with constant geometry.

#### Environmental Conditions

<u>Parameter</u>	<u>Sensor Location</u>		<u>Control Room</u>	
	<u>Design Center</u>	<u>Range</u>	<u>Design Center</u>	<u>Range</u>
Temperature (degrees C)	25	0 to 60	25	5 to 50
Relative Humidity (Percent)	50	20 to 100	50	20 to 90

#### 12.3.4.1.2 Criteria for Location of Area Monitors

Generally, area radiation monitors are provided in areas to which personnel normally have access and for which there is a potential for personnel unknowingly to receive high radiation doses (e.g., in excess of 10CFR20 limits) in a short period of time because of system failure or improper personnel action. Any plant area that meets one or more of the following criteria is monitored:

- a) Zone I areas which, during normal plant operation, including refueling, could exceed the radiation limit of 0.5 mrem/hr upon system failure or personnel error or which will be continuously occupied following an accident requiring plant shutdown
- b) Zone II areas where personnel could otherwise unknowingly receive high levels of radiation exposure due to system failure or personnel error
- c) Area monitors are in accordance with General Design Criterion 63 of 10CFR50 Appendix A.

### 12.3.4.1.3 System Description (Area Radiation Monitoring)

#### General

The area radiation monitoring system is shown in diagram form in Figure 12.3-29. Each channel consists of a combined sensor/converter unit, a local auxiliary unit (readout with visual and audible alarm), a combined indicator/trip unit, a shared power supply, and a shared multipoint recorder. The location of each area radiation detector is indicated on the shielding and zoning drawings, Figures 12.3-8 through 12.3-27, and is listed in Table 12.3-7.

#### Circuit Description

Sensor/Converter: Each sensor/converter contains all silicon semiconductors in sealed enclosure with a Cooke-Yarborough courtyard circuit which combines a long integrating time constant at low radiation levels with fast overall response at high radiation levels.

Auxiliary Unit: Each auxiliary unit gives instant local readout at the sensor location with a visual alarm. An audible alarm is connected to the auxiliary unit to alert personnel of excessive area radiation.

Indicator and Trip Unit: The indicator and trip unit provides channel control for the area radiation monitoring system. Its circuitry provides an upscale trip that indicates high radiation and a downscale trip that may indicate instrument trouble or loss of power. The module has an analog readout, a low and high trip indicating light, a trip test device, an alarm reset and an output for a multipoint recorder.

Ranges and Sensitivity: Ranges and sensitivities are selected for each location based on the anticipated radiation level as provided by experimental measurements of levels in similar plants and shielding calculations. Refer to Table 12.3-7 for detail.

Accuracy: The overall accuracy is such that the actual reading relative to the true reading is within  $\pm 7.5$  percent of equivalent full scale.

### 12.3.4.1.4 Area Radiation Monitoring Instrumentation

Power Sources: The power source for the area radiation monitoring system is the 120 V ac instrument bus and local lighting panels. The area radiation monitor instrumentation is powered by a high and low voltage electrically regulated power

supply capable of handling up to 10 channels. The system has no emergency power supply.

Alarm Set Points: Refer to Table 12.3-7.

Recording Devices: Two multipoint recorders are located in the control room for recording channels pertaining to Unit 1, Unit 2, and channels which are common to both units. This data is also stored in computer history files and can be retrieved and printed using the PMS Historical Recording service program.

Location of Devices: Refer to details in Table 12.3-7.

Readouts and Alarms: Readouts, visual and audible alarms are provided locally for each monitoring channel. Readouts and visual alarms are provided by each indicator/trip unit in the Control Structure (Upper Relay Room). Multipoint recorders, visual alarms and PMS displays are provided in the Control Structure (Control Room), with the exception of the three Technical Support Center channels (43, 44, 45).

The following annunciators are located in the main control room to alert the operator:

- a Reactor Building Area High Radiation (Units 1 and 2)
- b Turbine Building Area High Radiation (Units 1 and 2)
- c Radwaste Building Area High Radiation
- d Refueling Floor Area High Radiation (Units 1 and 2)
- e Spent Fuel Pool Area High Radiation (Units 1 and 2)
- f Reactor Building Common Area High Radiation
- g Administration Building Area High Radiation
- h Control Structure Area High Radiation
- i Area Radiation Monitoring Downscale (ganged for all channels)

#### 12.3.4.1.5 Safety Evaluation

The area radiation monitoring system is designed to operate unattended for extended periods and is designed for high reliability. Failure of one monitor has no effect on any other.

The system is not essential for safe shutdown of the plant, and serves no active emergency function during operation. The system

is not safety related and is constructed to Quality Group D Requirements.

#### 12.3.4.1.6 Calibration Method and Testability

Facilities for calibrating these monitor units are provided, which include a test unit designed for use in the adjustment procedure for the area radiation monitor sensor and converter unit. These provide several gamma radiation levels between 1 and 250 mrem/hr.

A cavity in the calibration unit receives the sensor and converter unit. A window through which radiation from the source emanates is located on the back wall of the cylindrical lower half of the cavity. A chart on each calibration unit indicates the radiation levels available from the unit for the various control settings.

An internal trip test circuit, adjustable over the full range of the trip circuit, is provided. The test signal is fed into the indicator and trip unit input so that a meter reading is provided in addition to a real trip. All trip circuits are the latching type and must be manually reset in the Upper Relay Room.

The radiation monitors will be calibrated at regular time intervals in accordance with station procedures.

#### 12.3.4.2 Airborne Radioactivity Monitoring

Refer to Subsections 12.5.2.6.3 and 12.5.3.5.4 for information on air borne radioactivity monitoring.

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TABLE 12.3-7

## AREA RADIATION MONITORING SYSTEM UNIT 1 &amp; COMMON

Page 1

Channel No.	Monitor Description	Bldg.	Approx. Loc.	Elev.	Range (mR/hr)	Set Point (mR/hr)
1	Chan 1 RX Bldg. Residual heat removal area	RB	T/22	645'	0.1-1000	100
2	Chan 2 RX Bldg. RCIC pump turbine room	RB	T/21	645'	0.01-100	2.5
3	Chan 3 RX Bldg. HPCI pump turbine room	RB	S/21	645'	0.01-100	2.5
4	Chan 4 RX Bldg. Radwaste sump area	RB	S/28	645'	0.1-1000	15
5	Chan 5 RX Bldg. Contr. rod drive Hyd. Units north	RB	R/21	719'	0.1-1000	15
6	Chan 6 RX Bldg. Contr. rod drive Hyd. Units south	RB	R/29	719'	0.1-1000	15
7	Chan 7 Off-Gas Bypass Line	TB	G/25	656'	0.1-1000	200
8	Chan 8 RX Bldg.. Cleanup recirc. pump access area	RB	R/21	749'	0.01-100	2.5
9	Chan 9 RX Bldg. CRD Repair Area	RB	U/27	719'	0.1-1000	2.5
10	Chan 10 RX Bldg. Fuel pool pump room	RB	R/27	749'	0.1-1000	200
11	Chan 11 RX Bldg. Sample Station (1C210) Room	RB	P/26	779'	0.01-100	15
12	Chan 12 RX Bldg. Recirculation fan room	RB	U/27	799'	0.01-100	15
13	Chan 13 RX Bldg. New Fuel Area	RB	P/26	799'	0.01-100	2.5

TABLE 12.3-7 (Continued)

## AREA RADIATION MONITORING SYSTEM UNIT 1 &amp; COMMON

Page 2

Channel No.	Monitor Description	Bldg..	Approx. Loc.	Elev.	Range (mR/hr)	Set Point (mR/hr)
14	Chan 14 RX Bldg. Spent fuel pool	RB	S/27	818'	0.1-1000	15
15	Chan 15 RX Bldg. refueling floor area	RB	P/22	818'	0.01-100	2.5
16	Chan 16 RX Bldg. Access to remote shutdown panel	RB	P/21	670'	0.01-100	2.5
17	Chan 17 TB Bldg. Condensate pumps area	TB	J/26	656'	0.01-100	50
18	Chan 18 TB Bldg. RPPT area	TB	L/21	676'	0.01-100	2.5
19	Chan 19 TB Bldg. Air ejector room	TB	H/25	682'	0.1-1000	700
20	Chan 20 TB Bldg. Feedwater heater area	TB	N/21	699'	0.1-1000	200
21	Chan 21 TB Bldg. Reactor recirc pump M.G. area	TB	M/20	729'	0.01-100	2.5
22	Chan 22 TB Bldg. generator bay area	TB	J/26	729'	0.01-100	2.5
23	Chan 23 TB Bldg. Heat and vent. equipment room	TB	L/23	762'	0.01-100	2.5
24	Chan 24 TB Bldg. Turbine front end	TB	K/15	729'	0.01-100	2.5
25	Chan 25 RX Bldg. Residual heat removal area	RB	T/24	645'	0.1-1000	100
26	Chan 26 RX Bldg. TIP drive area	RB	Q/22	719'	0.1-1000	15

TABLE 12.3-7 (Continued)

## AREA RADIATION MONITORING SYSTEM UNIT 1 &amp; COMMON

Page 3

Channel No.	Monitor Description	Bldg..	Approx. Loc.	Elev.	Range (mR/hr)	Set Point (mR/hr)
27	Chan 27 Admin. Bldg Access (TB)	TB	N/13	729'	0.01-100	2.5
28	Chan 28 Admin Bldg. Access (RW)	ADM BLDG	N/10	691'	0.01-100	0.5
29	Chan 29 RW Bldg. Corridor pers. access area	RW	K/3	646'	0.1-1000	2.5
30	Chan 30 RW Bldg. Opt. surveillance control area	RW	G/8	646'	0.1-1000	2.5
31	Chan 31 RW Bldg. Corridor to collection tank	RW	J/12	646'	0.1-1000	2.5
32	Chan 32 RW Bldg. Controlled zone shop	RW	K/12	676'	0.1-1000	2.5
33	Chan 33 RW Bldg. RW Control Room	RW	J/9	676'	0.1-1000	2.5
34	Chan 34 RW Bldg. Storage and equipment area	RW	G/6	676'	0.1-1000	2.5
35	Chan 35 RX Bldg. Shipping cask storage area	RB	S/29	818'	0.01-100	15
36	Chan 36 RX Bldg. Railroad access area	RB	U/29	670'	0.01-100	0.5
37	Chan 37 Ctr. Twr. Standby gas treatment room	CTR TWR	K/27	806'	0.01-100	0.5
38	Chan 38 Ctr. Twr. Rad. chem. laboratory	CTR TWR	N/27	676'	0.01-100	0.5

TABLE 12.3-7 (Continued)

## AREA RADIATION MONITORING SYSTEM UNIT 1 &amp; COMMON

Page 4

Channel No.	Monitor Description	Bldg..	Approx. Loc.	Elev.	Range (mR/hr)	Set Point (mR/hr)
39	Chan 39 Ctr. Twr. Control room	CTR TWR	L/29	729'	0.01-100	0.5
40	Chan 40 Admin Bldg. Access Unit 2 (Railroad Bay)	TB	N/12	676'	0.01-100	0.5
41	Channel 41 Tip Chamber Shield Area	RB	P/22	719'	0.1-1000	200
42	Channel 42 Refueling Floor Area	RB	P/26	818'	0.01-100	5
43	Channel 43 Observation Deck	CTR TWR	L/30	741'	0.01-100	5
44	Channel 44 Document Control Area	CTR TWR	N/32	741'	0.01-100	5
45	Channel 45 Conference Room	CTR TWR	N/26	741'	0.01-100	5

TABLE 12.3-7 (Continued)

## AREA RADIATION MONITORING SYSTEM UNIT 2

Page 5

Channel No.	Monitor Description	Bldg..	Approx. Loc.	Elev.	Range (mR/hr)	Set Point (mR/hr)
1	Chan 1 RX Bldg. Residual heat removal area	RB	T/31	645'	0.1-1000	100
2	Chan 2 RX Bldg. RCIC pump turbine room	RB	T/30	645'	0.1-1000	2.5
3	Chan 3 RX Bldg. HPCI pump and turbine room	RB	S/30	645'	0.1-1000	2.5
4	Chan 4 RX Bldg. Radwaste sump area	RB	S/36	645'	0.1-1000	15
5	Chan 5 RX Bldg. Contr. rod drive Hyd. Units north	RB	S/30	719'	0.1-1000	15
6	Chan 6 RX Bldg. Contr. rod drive south	RB	R/37	719'	0.1-1000	15
7	Chan 7 Off-Gas Bypass Line	TB	G/33	656'	0.1-1000	15
8	Chan 8 RX Bldg. Cleanup recirc pump access area	RB	R/37	749'	0.01-100	2.5
9	Chan 9 RX Bldg. CRD Repair Area	RB	U/35	749'	0.1-1000	2.5
10	Chan 10 RX Bldg. Fuel pool pump room	RB	S/38	749'	0.1-1000	200
11	Chan 11 RX Bldg. Sample Station (2C210) Room	RB	P/33	779'	0.01-100	2.5
12	Chan 12 Recirculation Fan Room	RB	U/35	799'	0.1-100	15
13	Chan 13 RX Bldg. New Fuel Area	RB	Q/31	799'	0.01-100	2.5

TABLE 12.3-7 (Continued)

## AREA RADIATION MONITORING SYSTEM UNIT 2

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41	Channel 41 TIP Chamber Shield Area	RB	P/31	719'	.1-100	200
42	Channel 42 Refueling Floor Area	RB	P/34	818'	0.01-100	2.5

Note: All set points are estimated values. Actual set points may vary depending on operational considerations and will be determined by measured radiation levels.

## 13.2 TRAINING PROGRAM

### 13.2.1 PLANT PERSONNEL TRAINING PROGRAM

The Training Program for the Susquehanna Steam Electric Station is formulated to develop and maintain an organization qualified to assume the responsibility for operation, maintenance, and technical considerations for the facility. In order to accomplish these objectives and to provide the necessary control of the overall plan, three separate training programs listed below are utilized:

- a. Initial Plant Staff Training Program
- b. Requalification Training Program, and
- c. Replacement Training

The Initial Plant Staff Training Program is designed to produce competent, trained personnel at all levels of the plant organization. The programs are designed to allow placement of personnel into specific levels based on employee experience and intended position.

The Requalification Training Program provides continuing training for plant personnel commensurate with their area of responsibility.

The Replacement Training Program is designed to supply qualified personnel for the station organization.

The Superintendent of Plant may waive portions of the training program for individuals based on their previous experience and/or qualifications.

#### 13.2.1.1 Program Description

##### 13.2.1.1.1 Initial Plant Staff Training

Figure 13.2-1 shows the present schedule for the various Initial Plant Training Programs. Should significant differences or changes occur in those courses not yet conducted, the appropriate course outline and description will be revised by amendment.



13.2.1.1.2 Operations Section Training Program

This program is designed for individuals who are to assume responsibility for the licensed and non licensed operator positions and fulfills the general requirements and qualifications set forth in ANSI N18.1-1971. The program is structured to allow personnel of varying experience and education to enter the Cold Licensing Training Program at various levels and still fulfill the eligibility requirements for NRC cold licensing prior to fuel loading.

13.2.1.1.2.1 Initial Cold License Training

The program is designed for cold license candidates with no formal power plant experience or training. The program is divided into seven phases to ensure proper administration, documentation, and completeness of training.

- o. Phase I - Conventional Power Plant Operator Experience Program.
- o. Phase II - Academic Program for Nuclear Power Plant Personnel.
- o. Phase III - Basic BWR Technology
- o. Phase IV - BWR Simulator Training
- o. Phase V - BWR Observation Training
- o. Phase VI - Systems, Procedures and On-The-Job Training
- o. Phase VII - BWR Refresher Training

Those plant control operator license candidates with no power plant experience will participate and qualify in all seven phases, while those with only a conventional power plant background will participate and qualify in Phases II through VII. Operators, and other staff members, who will be cold licensed with a nuclear background and/or related academic or technical training will participate and qualify in selected portions of phases II through VI and all of Phase VII. The extent of their participation in Phases II through VI will be based on their background and documented in station training records.

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### o Phase I - Conventional Power Plant Experience Program

The Conventional Power Plant Experience Phase of the Susquehanna SES Training Program is designed to provide power plant experience to those license candidates who lack the minimum power plant experience requirements. This experience will be provided prior to the start of the formal License Training Program (Phases II-VII), so that by the time of the Nuclear Regulatory Commission Licensing Examination, the candidate will have had two years of power plant experience of which a minimum of one year will have been nuclear power plant experience. This program is approximately one year in duration and includes supervised on-the-job training in major operator positions (excluding fossil boiler related positions) at a PP&L conventional power plant. Also included in the one year experience program are approximately ten weeks of formal classroom training which includes but is not limited to the following areas:

Basic Power Plant Operation

Steam Turbine Fundamentals

Power Plant Mathematics

Basic Thermodynamics and Fluid Mechanics

Plant Cycle and Plant Performance

Basic Electrical and Plant Instrumentation

Basic Print Reading

Basic Water Chemistry

Introduction to Nuclear Power and Nuclear Plant Systems

### o Phase II - Academic Program for Nuclear Power Plant Personnel

This course is conducted by the General Physics Corporation of Columbia, Maryland. It is designed to refresh basic courses received in high school and to acquaint those personnel, with little or no nuclear background, with nuclear phenomenon and the BWR concept as they apply to practical reactor technology. The course material and the approximate number of classroom hours allotted to each major topic are as follows:

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<u>Subject</u>	<u>Classroom Hours</u>
<b>First Segment - Mathematics and Classical Physics 200</b>	
Review of Introductory Mathematics	16
Exponents and Logarithms	36
Algebra	64
Geometry and Trigonometry	24
Mathematics of Dynamic Systems	20
Classical Physics	40
<b>Second Segment - Physics 200</b>	
Atomic Physics	24
Nuclear Physics	60
Reactor Core Physics	68
Reactor Operations	48
<b>Third Segment - Related Technologies 200</b>	
Introduction to Nuclear Power Plant Systems	28
Chemistry	28
Health Physics	56
Fundamentals of Electricity and Electronics	48
Nuclear Instrumentation	40
<b>Fourth Segment - Nuclear Power Plant Technology 200</b>	
Theory and Application of Nuclear Power Plant Systems	88
Physics Review	56
Overall Nuclear Power Plant Operations	<u>56</u>
	800

Cold license applicants, with no previous nuclear experience, will be assigned to a Research Reactor Training Course conducted by the Pennsylvania State University. This 2-week, course gives the student actual hands-on experience with an open pool nuclear reactor and allows the cold license applicant to obtain at least the minimum of 10 reactor startups necessary to establish cold license eligibility requirements. The course includes, but is not limited to, the following subject material:

- o Reactor Operations
- o Fuel Handling
- o Flux Mapping
- o Normal Reactor Operation

- o Instrumentation Effects
- o Control Rod Calibration
- o Laboratory Demonstrations, and
- o Control Transient Effects
- o Phase III--Basic BWR Technology

The Basic BWR Technology course is designed to impart the details of the BWR nuclear steam supply system to the operator trainees.

The course consists of approximately 5 weeks of classroom lecture on BWR nuclear steam supply system components, fuel description, thermal-hydraulics, radiation monitoring and nuclear instrumentation system operations. Important interfaces with the balance of plant systems are also taught.

The lectures are presented by GE BWR Training personnel using conventional classroom techniques. Classes are scheduled for approximately 7 hours per day and suggested study assignments are normally made daily. Progress is measured by weekly written and final comprehensive examinations.

It is anticipated that the course material covered will be as follows.

Schedule changes and adjustments to course content will be made as necessary to meet the particular needs of the students

#### Week 1

Introduction to Course  
 Plant Orientation  
 Reactor Principles Review  
 Reactor Vessel and Internals  
 BWR Thermal Hydraulics Review  
 Fuel Description  
 Nuclear Boiler Instrumentation

#### Week 2

Examination 1  
 Control Rod Drive Mechanism  
 Control Rod Drive Hydraulic System  
 Rod Control and Information System  
 Rod Pattern Control System  
 Recirculation System  
 Recirculation Flow Control System  
 Reactor Water Cleanup System

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Source Range Monitoring System  
Intermediate Range Monitoring System  
Local Power Range Monitoring System  
Average Power Range Monitoring System

### Week 3

Examination 2  
Traversing In-Core Probe System  
Main Steam System  
Reactor Pressure Control (Electro-Hydraulic Control)  
Feedwater Control System  
Reactor Protection  
Containment and Related Systems  
Introduction to Radwaste Systems (Off Gas,  
Liquid and Solid Radwaste)

### Week 4

Examination 3  
Introduction to Electrical Distribution  
Reactor Core Isolation System  
Introduction to Emergency Core Cooling System  
High Pressure Core Spray System  
Auto Depressurization System  
Low Pressure Core Spray  
Residual Heat Removal System and Hot Standby Operation  
Emergency Core Cooling Systems Integrated Response  
Standby Liquid Control System  
Process Radiation Monitoring  
Area Radiation Monitoring

### Week 5

Examination 4  
Performance Monitoring System  
BWR Materials  
BWR Chemistry  
Fuel Pool Cooling System  
Reactor Refueling  
Plant Operations  
Transient Analysis  
Review

Final Examination

o Phase IV -- BWR Simulator Training

The BWR simulator course is taught at the General Electric BWR Training Center, Morris, Illinois, and is designed to provide the operator trainee with the skills necessary to safely operate a large Boiling Water Reactor power plant.

The course consists of approximately 12 weeks of classroom lectures, simulator control room exercises, and in-plant oral seminars. This combination of instructional techniques affords the optimum mixture for successful skill training. The final examination consists of written, control room performance, and plant oral examinations.

Lectures and exercises are presented and guided by qualified, GE BWR Training Personnel. Classroom lectures are scheduled for approximately 8 teaching hours per day. Suggested reading and study assignments are made daily; written examinations are given weekly to monitor progress. In addition, at approximately the mid-point of the course, oral examinations are given to monitor the progress of each student's skill acquisition. The control room portion of the course is normally accomplished on night shifts of 8 hours. Four hours are spent in the simulator control room (total approximately 112 hours) with exercises and demonstrations guided by the licensed instructor. The other 4 hours are devoted to oral seminars. Each student rotates to appropriate control room operating positions, including shift supervisor, so that all personnel have equal opportunity to perform plant evolutions from each operating position.

The following is an anticipated week-by-week schedule of the course. Schedule changes and adjustments to course content will be made as necessary to meet the particular needs of the students.

Week 1

Introduction to the BWR Training Center  
Reactor Vessel and Internals  
Reactor Fuel  
Nuclear Boiler Instrumentation  
Control Rod Drive Mechanism  
Control Rod Drive Hydraulics  
Reactor Manual Control  
Recirculation System  
Recirculation Flow Control  
Reactor Water Cleanup System  
Shutdown Cooling and Head Spray  
Source Range Monitoring (SRM)  
Intermediate Range Monitoring (IRM)

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Local Power Range Monitoring (LPRM)  
Average Power Range Monitoring (APRM)  
Rod Block Monitor

### Week 2

Week 1 Examination  
Traversing In-Core Probe (TIP)  
Rod Worth Minimizer (RWM)  
Main Steam  
Turbine and Lube Oil System  
Electro-Hydraulic Control System (EHC)  
EHC Pressure Control and Logic  
Condensate and Feedwater  
Feedwater Control  
Circulating Water  
Generator and Auxiliaries  
Generator Excitation  
AC Electrical Distribution  
Diesel Generators and DC Electrical Distribution  
Reactor Protection System (RPS)  
Primary and Secondary Containment

### Week 3

Week 2 Examination  
Fuel Pool Cooling and Cleanup  
Off Gas System  
Liquid Radwaste  
Water Systems  
Isolation Condenser  
Introduction to Emergency Core Cooling System (ECCS)  
High Pressure Coolant Injection (HPCI)  
Automatic Depressurization System (ADS)  
Low Pressure Coolant Injection (LPCI)  
Core Spray  
Emergency Core Cooling System Integrated Response  
Standby Liquid Control  
Process Radiation Monitoring  
Area Radiation Monitoring  
Reactor Physics Review

### Week 4

Pre-Start and Functional Checks  
Reactor Startups  
Heatups  
Manipulation of Auxiliary Systems  
Power Changes in the Intermediate Range  
Surveillance Testing  
Transfer to Run Mode

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Turbine Warmup and Roll

Week 5

Reactor Heatup and Transfer to Run Mode  
Turbine Roll  
Generator Synchronization and Loading  
Surveillance Testing  
Continued Loading to 100% Power  
Operations at Full Power  
Transient Analysis  
Quiz 1  
Maneuvering by Flow Control  
Reactor Shutdown  
Discussion on Decay Heat Operation and Removal  
Plant Problems  
Drills on Abnormal and Emergency Conditions

Week 6

Pre-Startup and Functional Checks  
Reactor Startups and Heatups  
Manipulation of Auxiliary Systems  
Plant Problems  
Drills on Abnormal and Emergency Conditions  
Power Changes in the Intermediate Range  
Surveillance Testing  
Transfer to Run Mode  
Turbine Warmup and Roll  
Operator Synchronization and Loading  
Quiz 2  
Mid-Course Performance Examination

Week 7

Technical Specifications Bases Review  
Review Certification Exam Format and Content  
Physics Problem Solving  
Mid-Course Control Room Checks  
Solid Radwaste  
Health Physics Review  
BWR Chemistry  
Thermal-Hydraulics  
Process Computer  
Circuit Breaker Control  
Fuel Handling and Fuel Loading Physics



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Week 8

Steady-State Operation at 50% Load  
Surveillance Testing  
Increase to Full Load  
Drills on Abnormal and Emergency Conditions  
Operations at Full Power  
Maneuvering by Flow Control  
Begin Reactor Shutdown  
Reactor Shutdown and Cooldown  
Flooding of Reactor Vessel  
Plant Problems  
Reactor Startups and Heatups  
Scram and Scram Recoveries

Week 9

Operation at Full Load  
Drills in Abnormal and Emergency Conditions  
Shutdown to Hot Standby  
Quiz 3  
Plant Startup from Hot Standby to Full Power  
Reactor Heatup  
Generator Synchronization and Loading

Week 10

Operation at 50% Load  
Scrams and Scram Recoveries  
Surveillance Testing  
Operation at Full Power  
Drills  
Individual Student Operations  
Quiz 4  
Transient Analysis Review

Week 11

Review and Study  
Reactor Operator Certification Examination

Week 12

Control Room and Dresden Plant Oral Examination  
Control Room Performance Demonstration  
Senior Reactor Operator Certification Examination

o. Phase V - BWR Observation Training

BWR observation training is designed to acquaint the operator trainee with the day-to-day routine of an operating BWR. This will involve exposure to plant operating and maintenance evolutions, station record keeping, and procedures.

The course consists of approximately 4 weeks of guided observation of an operating BWR. All observation is conducted under the guidance of an experienced GE training personnel.

The course is structured to provide experience in various aspects of plant operation. The flexibility is achieved by allowing the course director to adjust the group schedule to fit important plant evolutions. Daily work and observational assignments are made at the beginning of each work day.

The following are weekly highlights of a typical BWR observation schedule:

Week 1

Plant Evacuation Procedures/Station Emergency Plan  
Health Physics Procedures  
Electrical Distribution  
Reactor Instrumentation  
Control Rods and Hydraulic Drive System  
Recirc MG set, support systems, and controls  
Main Steam System Controls and Instrumentation  
Residual Heat Removal System - All Modes

Week 2

Turbine, EHC System, and Turbine Support Systems  
Generator, Generator Excitation, and Generator Support Systems  
Turbine and Reactor Building Closed Cooling Water System  
Circulating and Service Water Systems  
Fire Protection Systems  
Core Spray System

Week 3

High Pressure Coolant Injection System  
Reactor Core Isolation Cooling System  
Reactor Protection MG sets  
Automatic Depressurization System  
Traversing In-core Probe System  
Neutron Monitoring and Associated Control Systems  
Radioactive Waste Handling Equipment and Procedures  
Performance of Routing Plant Equipment Checks

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### Week 4

Instrument and Service Air Systems  
Process and Area Radiation Monitoring Systems  
Fuel Pool Cooling System  
Standby Liquid Control System  
Plant Performance Logs  
Observance of Routine Plant and/or Surveillance Procedures  
In Progress  
Review  
Final Exam and Walk-Through

### o Phase VI - SYSTEMS, PROCEDURES, and ON-THE-JOB TRAINING

The systems, procedures, and on-the-job training phase will be approximately 20 weeks in length of which a minimum of 8 weeks will be class room instruction. However, the weeks may not be scheduled consecutively due to plant testing and work load considerations. This phase will provide cold license candidates with an in-depth study of Susquehanna SES systems and equipment; nuclear characteristics; and Normal, Abnormal, Emergency and Administrative Procedures and Technical Specifications. Further operational training is accomplished as components, systems, or parts of systems are checked, tested, and placed in routine operation to provide necessary auxiliary support for other systems.

Instructors for the various Phase VI lectures will be supplied by the Susquehanna staff, other PP&L organizations, vendors or consultants. Selections of the particular individual to conduct a specific training lecture will be based upon individual availability and knowledge of the subject matter involved.

The course will consist of, but not be limited to:

- a. Theory and principles of operations
- b. General and specific plant operating characteristics
- c. Plant instrumentation and control systems
- d. Plant protection, safety and emergency systems
- e. Normal, abnormal and emergency operating procedures
- f. Radiation control and safety
- g. Technical Specifications
- h. Applicable portions of Title 10, Chapter 1, Code of Federal Regulations

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- i. Reactor Theory
- j. Handling, disposal and hazards of radioactive materials
- k. Fuel handling and core parameters
- l. Administrative procedures, conditions and limitations

A comprehensive examination will be given during this phase to determine student weak areas.

### o. Phase VII - BWR Pre-License Refresher Training

Prior to the initial NRC Operator Licensing examination, a Pre-License Refresher Course will be conducted. This course will be presented by PP&L employees or by outside personnel, and will be a summary and review of material presented in previous phases. If necessary an update of plant modifications and training to upgrade any identified weak areas will be presented.

### 13.2.1.1.2.2. Non-Licensed Operator Training Program

The program is designed for non-licensed operators and is divided into three phases which provide a logical progression from the entry level to final job qualification.

- o. Phase I - Academic Training
- o. Phase II - Susquehanna SES System Lectures
- o. Phase III - Susquehanna SES System Qualification

This training is progressive and candidates for non-licensed positions must successfully complete the training appropriate to their assigned job. Phase I may be exempted by passing a written exam.

- o. Phase I: The course consists of basic training in Nuclear Power Plant Fundamentals. The program is about 160 hours long and consists of classroom training or equivalent self-study time. The areas to be covered will include such subjects as math, chemistry, atomic and nuclear physics, health physics, nuclear instrumentation and reactor operations. Progress is measured by periodic quizzes and examinations.

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- o Phase II - The phase consists of basic lectures on Susquehanna SES systems and covers, as applicable, the following areas of each system:

- General System Description
  - Major Components and Flow Paths
  - Instruments and Controls
  - Alarms and Trips
  - Power Feeds
  - Operating and Emergency Procedures

The phase will be approximately 4 weeks in length and during each week, approximately 80% of the time will be spent in class and the remaining 20% will be spent in the plant tracing systems. There will be weekly quizzes and a final exam at the end of the course.

- o Phase III - This phase must be completed by operators on the systems for which they are responsible. This phase will take about 10 weeks to complete. However, the 10 weeks may not be consecutive due to work-load considerations. Operators will be checked out on each system to assure they can operate these systems under normal, abnormal, and emergency situations. The check out will consist of an oral and/or written test on each system.

### 13.2.1.1.3 Maintenance Section Training Program

The Supervisor of Maintenance will receive training Level III Health Physics training as described in Subsection 12.5.3.7, selected training in plant systems operation and specialized vendor training on specific plant equipment.

Foremen will receive additional experience on-the-job during the preoperational test program through the supervision of maintenance activities.

Station Mechanics and Leaders for the initial plant staff will generally be selected from other PP&L facilities and will have practical experience in one or more crafts, and will through their previous experience and/or selection testing demonstrate a high degree of manual dexterity and capability of learning and applying the basic skills in maintenance operations.

Maintenance personnel will receive on-the-job training during the preoperational test program by performing maintenance activities. Selected personnel will receive specialized vendor training on specific equipment or skills such as control rod drive repair and welding.

Maintenance personnel requiring access to Radiation Work Permit Areas will receive Level II Health Physics training as described in Subsection 12.5.3.7.

#### 13.2.1.1.4 Technical Section Training Program

The objective of the initial training program of the Technical Section is to provide competent personnel to support in the safe, efficient operation of the Susquehanna SES.

Selected supervisory and professional/technical personnel will attend GE's Design Orientation courses (or other formal instruction with a similar intent) to familiarize them with the design principles of a BWR. The major topics covered will include BWR components, core design, thermal-hydraulics, process and nuclear instrumentation design and operation and auxiliary systems.

##### 13.2.1.1.4.1 Chemistry Personnel

By initial fuel loading, in addition to those courses described in Subsection 13.2.1.1.4, selected chemistry supervisory personnel will receive specialized training through a course such as "BWR Chemistry" offered by GE. The course enables students to complete both radiological and chemical analyses for process control, waste disposal, effluent monitoring, process and laboratory instrument calibration and evaluation. The course also covers compliance with and interpretation of chemical and radiochemical aspects of the technical specifications, licenses and plant warranties.

The Chemistry Leaders and Chemistry Analysts will receive in-house training as developed by supervisory chemistry or other appropriate personnel, covering topics similar to those in the "BWR Chemistry" course. As appropriate, they may also attend vendor-sponsored training sessions to assure understanding and proper operation of laboratory instruments. Progress will be measured through oral and/or written examinations.

##### 13.2.1.1.4.2 Instrumentation & Control Personnel

By initial fuel loading, in addition to those courses described in Subsection 13.2.1.1.4, appropriate I&C supervisory personnel and selected I&C technicians will attend the GE "Nuclear

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Instrumentation" and "Process Instrumentation and Controls" courses or other formal instruction with similar intent.

The "Nuclear Instrumentation" course is broken into classroom and laboratory phases. The classroom phase covers the theory of operation and equipment demonstrations for the GE BWR nuclear, process and area radiation monitoring, control rod position information, reactor protection and traversing incore probe systems. The laboratory phase teaches detailed circuitry study, setup, calibration, testing, maintenance and repair for the various components of these systems and where possible for the overall system.

The "Process Instrumentation and Control" course teaches the theory of operation, setup, calibration, testing, maintenance and repair techniques for the basic instrumentation and control loop components for the GE BWR. Components to be covered include level, temperature, electrical properties, movement, chemical properties, sensing devices, transmitters, power supplies, signal conditioning modules and controllers. Primary instrument control loops will also be studied.

I&C technicians will also receive training covering topics such as AC/DC circuit fundamentals, transistor circuits, solid state devices and operational amplifiers and including "hands-on" experience with electrical and electronic circuits and components. As necessary, I&C personnel will attend courses offered by equipment vendors on various plant components.

Progress will be measured through oral and/or written examinations.

### 13.2.1.1.4.3 Reactor Engineering Personnel

By initial fuel loading, in addition to the courses described in Subsection 13.2.1.1.4, selected Reactor Engineering personnel will receive training through a course such as GE's "Station Nuclear Engineering". The course covers topics like reactor behavior, control rods, shutdown margins, technical specifications and Fuel Warranty Operation Provisions, core flow and thermal limit calculations, fuel failure and PCICMR and water chemistry among others.

Progress will be measured through oral and/or written examinations.

13.2.1.1.5 Health Physics Training Program

Selected Health Physics supervisory personnel will receive specialized professional training in a course such as "Radiological Engineering" offered by GE or equivalent.

Health Physics Monitor Training Program is described in Subsection 12.5.3.7.

13.2.1.1.6 General Employee Training

All permanent plant personnel granted unescorted vital area access at the station will be trained in the following areas:

1. Appropriate plans and procedures, including applicable plant security and emergency procedures.
2. Radiological Health and Safety in accordance with Subsection 12.5.3.7
3. Industrial Safety.
4. Fire Protection Program.
5. Quality Assurance Program.

This training will be the responsibility of the Plant Training Supervisor and will be repeated on a two-year cycle. Personnel will be examined in the above areas to determine the effectiveness of general employee training.

Temporary Maintenance and Service personnel will be trained in the areas listed to the extent necessary to assure safe execution of their duties.

13.2.1.1.7 Fire Safety Training

The object of the fire safety training program is to provide training for the plant fire brigade, training for maintenance and inspection of fire protection equipment and training for the fire protection staff.



#### 13.2.1.1.7.1 Fire Brigade Training

In addition to general employee training, individuals assigned to fire fighting duties will receive training in order that an effective fire fighting brigade will be available for fire emergencies. Fire brigade training sessions will be held a minimum of four times per year, with the basic program being repeated every two years. Training will be a blend of classroom sessions, practice sessions and fire fighting drills. Fire brigade members will receive instruction on fixed and portable fire fighting equipment, fire protection measures of other plant features and will be trained in hands on experience with fire fighting equipment and techniques. The local fire departments will be invited and encouraged to participate in at least one training session per year.

#### 13.2.1.1.7.2 Fire Protection Staff and Training

No training program is planned for the off site fire protection engineer. The position description requires that the incumbent be a qualified fire protection engineer with suitable background experience to meet the job requirements. A major part of the on site fire protection engineer's training will be on the job training and informal discussions with the off site fire protection engineer. This training will be augmented by vendor training schools and state fire fighting schools as necessary to carry out the job responsibilities. The on site fire protection engineer will have the responsibility of training or arranging for the training of fire brigade personnel, on site fire department training and training of personnel in charge of the maintenance of fire detection and fire suppression systems.

#### 13.2.1.2 Coordination with Preoperational Tests and Fuel Loading

Figure 13.2-1 illustrates the relationship of the Plant Staff Training to preoperational testing and fuel loading.

## 13.2.2 REQUALIFICATION AND REPLACEMENT TRAINING

### 13.2.2.1 Licensed-Operator Regualification Program-

The Regualification Program for licensed and senior licensed individuals will be established and ready for implementation no later than 3 months following issuance of the station operating license. The program consists of lectures, plant operational evolutions, simulator activities, drills, evaluations, self-study, and tests. A minimum of 40 hours of simulator training will be scheduled each year. The program is based on a 2 year license renewal cycle with periodic quizzes, written tests, and annual simulator and oral examinations administered throughout to ensure training effectiveness and technical competency.

#### 13.2.2.1.1 Lectures

Licensed operators will be required to attend classroom lectures on the following subjects annually:

- Reactor Theory and Principles of Reactor Operation
- Features of Facility Design
- General and Specific Plant Operating Characteristics
- Instrumentation and Control Systems
- Protection Systems
- Emergency Core Cooling Systems
- Radiation Control and Safety
- Technical Specifications
- Code of Federal Regulations
- Heat Transfer and Fluid Flow
- Design, Procedure, License Changes
- Recent LERs, Industry Events, Plant Activities
- General and Emergency Procedure Reviews

Failing to attend a scheduled lecture, an operator will be required to achieve mastery of this material prior to the examination. This achievement can be accomplished by attending another lecture, if scheduled; or by satisfactorily taking and passing a quiz on the subject.

### 13.2.2.1.2-----Plant Operational Evolutions

Each individual shall perform or participate in a combination of at least 10 reactivity control manipulations either in the plant or on the simulator. The following control manipulations and plant evolutions are acceptable for meeting the ten reactivity required by 10CFR55, Appendix A. The use of the Technical Specifications should be maximized during the simulator control manipulations. Personnel with senior licenses are credited with these activities if they direct or evaluate control manipulations as they are performed. These items should be signed off by Shift Supervisor or Instructor. The asterisked items shall be performed annually.

#### Performance Item

- \* (1) Plant or reactor startups to include a range that reactivity feedback from nuclear heat addition is noticeable and heatup rate is established.
- \* (2) Plant shutdown.
- \* (3) Manual control of feedwater during startup and shutdown.
- \* (4) Any significant (>10%) power changes in manual rod control or recirculation flow.
- \* (5) Loss of coolant.
  - (a) Inside and outside primary containment.
  - (b) Large and small, including leak-rate determination.
- (6) Loss of instrument air. o
- (7) Loss of electrical power (and/or degraded power sources).
- \* (8) Loss of core coolant flow/natural circulation.
- (9) Loss of condenser vacuum.
- (10) Loss of service water.
- o (11) Loss of shutdown cooling.
- (12) Loss of component cooling system or cooling to an individual component.
- (13) Loss of normal feedwater or normal feedwater system failure.

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- \* (14) Loss of all feedwater (normal and emergency).
- (15) Loss of protective system channel.
- (16) Mispositioned control rod or rods (or rod drops).
- (17) Inability to drive control rods.
- (18) Conditions requiring use of standby liquid control system.
- (19) Fuel cladding failure or high activity in reactor coolant or offgas.
- (20) Turbine or generator trip.
- (21) Malfunction of automatic control systems(s) which affect reactivity.
- (22) Malfunction of reactor coolant pressure control system.
- (23) Reactor trip.
- (24) Main steam line break (inside or outside containment).
- (25) Nuclear instrumentation failure(s).
- (26) Any reactor power change of 10 percent or greater where load change is performed with load limit control.

### 13.2.2.1.3 Operator Proficiency Evaluations

At least once per year during the term of an individual's license, he will be observed and formally evaluated while responding to actual or simulated casualties. In the case of simulated casualties, a hypothetical situation would be presented followed by a discussion of plant and operator response. The simulator will be used as the major basis for operator proficiency evaluation, actual manipulation of plant controls is not required. A poor performance is defined as not being able to competently and expeditiously perform the specified evolution. This will result in the implementation of a Performance Review as specified in Subsection 13.2.2.1.5. All evaluations will be critiqued with the individual concerned and filed in the individual's training records.

13.2.2.1.4 Tests

- (a) Periodic quizzes will be administered during and/or after each lecture series to monitor program effectiveness.
- (b) Comprehensive written tests which are similar in scope and difficulty to the NRC exam will be given periodically and will cover the following topics over a 2 year period:
  - 1) Theory and Principles of Operations
  - 2) General and Specific Plant Operating Characteristics
  - 3) Plant Instrumentation and Control Systems
  - 4) Plant Protection Systems
  - 5) Normal, Abnormal, and Emergency Operating Procedures
  - 6) Radiation Control and Safety
  - 7) Technical Specifications
  - 8) Applicable Portions of Title 10, Chapter 1, Code of Federal Regulations
  - 9) Thermal Hydraulics, Heat Transfer, and Fluid Flow Training.

To successfully complete this exam, the license holder must score greater than or equal to 70 percent on each quarterly exam and greater than or equal to 80 percent average over the two year period. Any license holder who scores less than 80 percent average overall or less than 70 percent on any test will receive accelerated upgrade training and a re-examination will be administered within 2 weeks. If the re-examination is failed the license holder shall be removed from license duties immediately and the Performance Review Program per 13.2.2.1.6 shall be implemented.

13.2.2.1.5 Performance Review Program

The Performance Review Program shall be implemented whenever any one of the following situations occurs. During such review programs the individual shall not perform any license duties until the individual has been properly evaluated and judged competent.

- (a) The quarterly examination score of less than 70 percent or less than 80 percent average during the 2 year license period.
- (b) "Poor" rating on operator proficiency evaluation.

## (c) Prolonged absence from license duties.

The Superintendent of Plant, Supervisor of Operations, and Manager Nuclear Training will meet to determine a course of action necessary to upgrade the individual's performance to an acceptable level. This review shall determine the minimum requirements on an individual basis. The nature of the action taken will be dependent on such factors as examination performance, operating performance, observed operational and theoretical understanding and overall operator competence.

When receiving less than 80 percent overall average or less than 70 percent on any test, an oral examination may be administered to determine whether or not an individual may resume licensed duties. However, the individual shall remain on the Performance Review Program until a score of greater than 70 percent or greater than 80 percent average is obtained on a written examination which specifically covers those areas of the exam where the licensee receives less than satisfactory marks. Management will complete a performance review summary which, upon completion, will be filed in the individual's training folder.

13.2.2.1.6 Prolonged Absence From License Responsibilities

In the event a licensed individual is absent from the site for a period of four months or longer, he will not be permitted to resume operational responsibilities until the following criteria have been met:

- (a) The satisfactory completion of an upgrading program determined under the provisions of Subsection 13.2.2.
  - 1) This program shall include as a minimum, the review of any facility design, operating procedure or license changes which have taken place during the absentee period.
  - 2) The individual must receive greater than or equal to 70 percent on a written or satisfactory on an oral exam covering the material in item 1 above. When an oral exam is used, it shall be administered by the Supervisor of Operations or designated senior licensee.
- (b) This certification shall be documented in the individual's training record.

13.2.2.1.7 Record Retention

The Manager-Nuclear Training will be responsible for maintaining license holder requalification training records. Records of the requalification program shall be maintained to document each licensed operator's and senior operator's participation in the requalification program. The records shall contain copies of written examinations administered, the answers given by the licensee, results of evaluations and documentation of any additional training administered in areas in which an operator or senior operator has exhibited deficiencies. Records shall be maintained for the duration of the unit operating license.

13.2.2.1.8 Licensed Staff Participation

Licensed staff personnel participate in the following areas of the requalification program:

- (a) Complete the quarterly written examination and participate in the lecture series based on the results.
- (b) Manipulate the controls or supervise the manipulation of controls through 10 reactivity changes.
- (c) Review day-to-day changes in the facility design procedures, and technical specification.
- (d) Review abnormal and emergency procedures annually.
- (e) Are evaluated regarding actions to be taken during simulated abnormal and emergency conditions by a walkthrough of the applicable procedure.

13.2.2.2 Refresher Training for Nonlicensed Personnel

As a minimum, all non-licensed personnel shall receive refresher instruction on administrative, radiation protection, emergency and security procedures once every two years.

13.2.2.2.1 Refresher Training for Nonlicensed Operators

Nonlicensed operators assigned on shift will participate in a requalification program and be trained, tested, and evaluated on a two year schedule.

13.2.2.2.2 Refresher Training for Maintenance Personnel

A retraining program is provided for maintenance personnel to ensure that they remain proficient in their particular job.

Retraining in specific areas is provided to the extent necessary for personnel to safely and efficiently carry out their assigned responsibilities in accordance with established policies and procedures.

Such training may consist of vendor presentations, technical training sessions, on-the-job work experience or programmed instruction. Maintenance personnel are evaluated on an annual basis where individual needs for retraining will be identified.

13.2.2.2.3 Refresher Training for Technical Section Personnel

Refresher courses will be provided to maintain an individual's level of expertise equal to or exceeding that required by his or her job responsibilities.

13.2.2.3 Replacement Training

Replacement training is designed to supply qualified personnel for all levels of the plant organization. It is the policy of PP&L to promote qualified personnel into job vacancies from candidates that are next in the line of promotion. Such individuals will receive training appropriate to the new position. Permanent replacement personnel procured from other sources will meet or exceed the requirements of the vacant position.

13.2.2.3.1 NRC Licensed Operator Replacement

Through a system of required operator qualification steps, personnel assigned as nonlicensed operators are provided training that prepares them for eventual NRC licensed operator positions. At such time as a need exists for replacement of licensed operators, individual preparation in theory, systems, operating procedures, emergency procedures, and health physics is conducted. Additionally, individual on-the-job training involving manipulation of the nuclear reactor plant controls during day-to-day operation, startups and shutdowns of the reactor or appropriate reactor simulator, is conducted.



Progress is reviewed as the replacement moves through the program. The review consists of periodic written and/or oral examinations.

#### 13.2.2.3.2 Non-licensed Operator Replacement Training

Replacement training is designed to insure fully qualified personnel for all levels of plant operation. To the extent possible, persons who have already achieved the level of training required for a specific job will be advanced. In all cases the requirements of Subsection 13.2.1.1.2.2 or equivalent will be satisfied.

#### 13.2.2.3.3 Maintenance Personnel Replacement Training

Replacement training is designed to supply qualified personnel for all levels of the Maintenance organization. It is the policy of PP&L to promote qualified personnel into job vacancies for candidates that are next in the line of promotion. Permanent replacement personnel will meet or exceed the requirements of the vacant position by virtue of previous education and experience. The Maintenance organization is specifically intended to provide the opportunity for personnel in lower level jobs to receive on-the-job-training that will prepare them for advancement.

The same quality of training provided for the original staff will be provided to personnel designated to fill vacancies in the maintenance organization.

#### 13.2.2.3.4 Technical Section Personnel Replacement Training

Replacement training is designed to assure fully qualified personnel for all levels of the Technical Section. To the extent possible, persons who have already achieved the level of training required for a specific job will be advanced. In all cases the requirements of Subsection 13.2.1.1.4 or equivalent will be satisfied.

#### 13.2.2.4 Records

Training records are established for each permanent plant employee. These records include, but are not limited to, lecture/annual examination questions and answers, lecture

attendance records, performance evaluation records, and other records as may be required to adequately document all training received by station personnel.

Training records will be periodically reviewed in accordance with station procedures to assess the effectiveness of the training program.

13.2.2.5 Responsible Individual

The Plant Training Supervisor is responsible for the administration and conduct of the Susquehanna SES training program.

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CHAPTER 14.0

TABLES

<u>Table Number</u>	<u>Title</u>
14.2-1	Preoperational Test Procedures
14.2-2	Acceptance Test Procedures
14.2-3	Startup Test Procedures
14.2-4	Test Plateau Schedule - Test Condition Sequence
14.2-5	Control Rod Drive System Tests

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CHAPTER 14.0

FIGURES

<u>Figure Number</u>	<u>Title</u>
14.2-1	Integrated Startup Group Organization
14.2-2a	Preoperational Test Procedure Standard Format
14.2-2b	Startup Test Procedure Standard Format
14.2-3	Initial Test Program Schedule
14.2-4a	Unit 1 Preoperational Test Sequence
14.2-4b	Unit 2 Preoperational Test Sequence
14.2-5 Sh. 1	Individual Startup Test Sequence
14.2-5 Sh. 2	Individual Startup Test Sequence
14.2-6 Sh. 1	Power Flow Map and Startup Test Conditions
14.2-6 Sh. 2	Power Flow Map and Power Test Conditions

14.2 SPECIFIC INFORMATION TO BE INCLUDED IN FINAL SAFETY ANALYSIS REPORT

14.2.1 SUMMARY OF TEST PROGRAM AND OBJECTIVES

As construction of systems/components is completed, the construction organization relinquishes jurisdictional control of these systems/components through a formal turnover to PP&L. Eventually all plant systems/components are turned over to PP&L.

The Initial Test Program encompasses the scope of events that commence with system/component turnover and terminate with the completion of power ascension testing. The Initial Test Program is conducted in two separate and sequential subprograms, the Preoperational Test Program and the Startup Test Program. At the conclusion of these subprograms the plant is ready for normal power operation. Testing during the Initial Test Program is accomplished in five distinct and sequential phases:

- a. Phase I - Component Inspection and Testing Phase
- b. Phase II - Preoperational and Acceptance Testing Phase
- c. Phase III - Initial Fuel Loading Phase
- d. Phase IV - Initial Heatup and Low Power Testing Phase
- e. Phase V - Power Ascension Test Phase

Phase I and Phase II are sequential on a system basis while Phases III, IV and V are sequential on a plant basis.

14.2.1.1 Preoperational Test Program

The Preoperational Test Program is defined as that part of the Initial Test Program that commences with system/component turnover and terminates with commencement of nuclear fuel loading. The program is subdivided into two phases in which plant equipment and systems are prepared for a higher degree of operability. The phases are:

- 1) Component Inspection and Testing Phase (Phase I)
- 2) Preoperational and Acceptance Test Phase (Phase II)

Component inspection and testing will insure that components and equipment are calibrated and checked, construction work on a particular system has been completed to the degree required and

the system is initially operated and prepared for subsequent testing. After component inspection and testing is complete on a system, formal tests denoted as preoperational or acceptance tests are conducted during the Preoperational and Acceptance Test Phase. The Preoperational tests demonstrate, to the extent practicable, the capability of safety-related structures, systems, and components to meet their safety-related performance requirements. The completion of preoperational testing constitutes completion of Phase II of the Initial Test Program. Tests similar to preoperational tests denoted as acceptance tests (Table 14.2-2), may be conducted on additional non safety-related structures, systems, and components to demonstrate their capability to perform their nonsafety-related performance requirements.

To the extent practicable, the objectives of the Preoperational Test Program are to:

- a. Verify the adequacy of plant design
- b. Verify that plant construction is in accordance with design.
- c. Demonstrate proper system/component response to anticipated transients and postulated accidents
- d. Confirm the adequacy of plant operating and emergency procedures
- e. Familiarize plant staff operating, technical, and maintenance personnel with plant systems

#### 14.2.1.2--Startup Test Program

The Startup Test Program is defined as that part of the Initial Test Program that commences with the start of nuclear fuel loading and terminates with the completion of power ascension testing. Formal tests, denoted as startup tests, are conducted during this program. These tests confirm the design bases and demonstrate, to the extent practicable, that the plant will operate in accordance with design and is capable of responding as designed to anticipated transients and postulated accidents. Startup testing is sequenced such that the safety of the plant is never totally dependent upon the performance of untested structures, systems, or components. The completion of startup testing constitutes completion of Phases III, IV, and V of the Initial Test Program.

The objectives of the Startup Test Program are to:

- a. Accomplish a controlled, orderly, and safe initial core loading
- b. Accomplish a controlled, orderly, and safe initial criticality and heatup
- c. Conduct low power testing sufficient to ensure that design parameters are satisfied and safety analysis assumptions are correct or conservative
- d. Perform a controlled, orderly, and safe power ascension

#### 14.2.2 ORGANIZATION AND STAFFING

The Superintendent of Plant - Susquehanna, has overall responsibility for the Initial Test Program. The Plant Staff and Integrated Startup Group (ISG) conduct the different phases of the test program. Responsibility for the ISG may be delegated to the Assistant Superintendent of Plant-Outages. In addition to these basic organizational units the Superintendent of Plant - Susquehanna is assisted by two review organizations, the Plant Operations Review Committee (PORC) and the Test Review Board (TRB). The organization, authority, responsibility, and degree of participation of each of these organizational units during the Initial Test Program are described in the following sections.

##### 14.2.2.1 Plant Staff

The Plant Staff consists of the permanent onsite PP&L personnel responsible for the safe operation and proper maintenance of the plant. Chapter 13 describes the Plant Staff organization. This section also establishes responsibilities, reporting relationships, and minimum qualification requirements for principal Plant Staff supervisory personnel.

The Plant Staff also includes the Startup Test Group which is a temporary group established to prepare for and implement the Startup Test Program. The Startup Test Group Supervisor reports to the Technical Supervisor and supervises the activities of the Startup Test Group. Activities include; preparation and implementation of startup tests; review and analysis of startup test results; preparation of startup test reports; and participation in test planning meetings. During the implementation of startup tests, the Startup Test Directors will report to the Startup Test Group Supervisor. The Shift Technical Advisors, Reactor Engineers and other qualified personnel will function as the Startup Test Directors during the Unit 1 Startup

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Test Program. Also reporting to the Startup Test Group Supervisor is one or more Startup Test Engineers.

The Plant Staff is utilized, to the fullest extent practicable, during the Initial Test Program. Specific responsibilities of the Plant Staff during the Initial Test Program are:

- a. Performing selected preventive and corrective maintenance.
- b. Operating plant equipment.
- c. Calibrating instruments, meters.
- d. Performing chemical and radiological inspections and tests
- e. Providing required replacement and spare parts
- f. Providing operator, technician, and maintenance support to the ISG
- g. Ensuring that vendors, consultants, or other temporary personnel assisting the Plant Staff work in accordance with established project procedures
- h. Confirming the adequacy of plant operating and emergency procedures to the extent practicable.
- i. Authorizing and ensuring proper documentation, identification, and restoration of temporary modifications made during the Startup Test Program.
- j. Authorizing and monitoring rework, modification, testing and maintenance during the Startup Test Program.
- k. Coordinating preparation, review and approval of startup test procedures.
- l. Coordinating performance of startup testing.
- m. Coordinating review and approval of startup test results.
- n. Planning and scheduling Startup Test Program activities.



#### 14.2.2.2 Integrated Startup Group - Organization and Responsibilities

The Integrated Startup Group (ISG) is a temporary organizational unit established to augment the Plant Staff during the Initial Test Program. The ISG is comprised of individuals of various organizations (Bechtel, General Electric, PP&L, and others). Figure 14.2-1 shows the organizational structure of the ISG. The responsibility and qualification requirements of principal ISG supervisory personnel, the structure of the basic constituents comprising the ISG, and the responsibilities delegated to the ISG are described in the following sections.

##### 14.2.2.2.1 ISG Supervisor

The ISG Supervisor has overall responsibility for supervising the conduct of the ISG. The ISG Supervisor reports to the Superintendent of Plant - Susquehanna, or the Assistant Superintendent of Plant-Outages, on matters pertaining to the Initial Test Program. The minimum qualifications for the ISG Supervisor are one of the following:

- a. Graduate of a four-year accredited engineering or science college or university, plus five years of experience in testing or operation (or both) of power plants, nuclear facilities, or similar industrial installations. At least two years of this experience should be associated with nuclear facilities; or if not, the individual shall have training sufficient to acquaint him thoroughly with the safety aspects of a nuclear facility; or,
- b. High school graduate, plus ten years of experience in testing or operation (or both) of power plants, nuclear facilities, or similar industrial installations. At least two years of this experience should be associated with nuclear facilities; or if not, the individual shall have training sufficient to acquaint him thoroughly with the safety aspects of nuclear facilities.

##### 14.2.2.2.2 Assistant ISG Supervisor

The Assistant ISG Supervisor performs a line function and reports to the ISG Supervisor. The Assistant ISG Supervisor is specifically responsible for supervision of Systems Group Leaders and assumes the responsibilities of the ISG Supervisor in his absence.

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The minimum qualifications of the Assistant ISG Supervisor are the same as the ISG Supervisor and are as described in Subsection 14.2.2.2.1.

### 14.2.2.2.3 Group Leaders

Group Leaders perform line functions and report to the Assistant ISG Supervisor. Group Leaders are assigned a staff of System Startup Engineers. Group Leaders have overall responsibility for assigned systems.

### 14.2.2.2.4 ISG Coordinator

The ISG Coordinator performs a staff function and reports to the ISG Supervisor. The ISG Coordinator is responsible for coordinating ISG interfacing activities with Plant Staff, Construction and various project support organizations involved in the Initial Test Program.

The ISG Coordinator is responsible for all ISG administrative activities, which includes tracking the development, review, approval and revision of all Preoperational and Acceptance Test Procedures. This also includes the development, review, approval and revision of all ISG Startup Administrative Manual and Startup Technical Manual Procedures.

### 14.2.2.2.5 ISG Specialists Supervisor

The ISG Specialist Supervisor performs a staff function and reports to the ISG Supervisor. The ISG Specialist Supervisor is responsible for the coordination and supervision of activities relating to Design Change Packages, Material Procurement Expediting, Advance Control Room/Power Generation Control Complex work coordination, Scoping, and I&C coordination.

### 14.2.2.2.6 ISG Schedule Supervisor

The ISG Schedule Supervisor performs a staff function and reports directly to the ISG Supervisor. He is responsible for the development and coordination of all startup schedules.

#### 14.2.2.2.7 ISG Quality Engineer/Record Control Group Supervisor

The ISG Quality Engineer/Record Control Group Supervisor performs a staff function and reports to the ISG Supervisor. The Quality Engineer/Record Control Group Supervisor is responsible for the coordination and interface of quality matters within and external to the ISG Organization. He is also responsible for the control and review of records associated with ISG System/Component testing.

#### 14.2.2.2.8 GE STO Site Manager

The General Electric Startup Test Organization Site Manager performs a staff function reporting to the ISG Supervisor during the Preoperational Test Program and to the Superintendent of Plant during the Startup Test program. The General Electric Startup Test Organization Site Manager is responsible for directing and coordinating activities of the GE field engineers assigned to him for the conduct of test or surveillance activities on NSSS systems.

#### 14.2.2.2.9 Responsibilities

Specific responsibilities of the ISG during the Initial Test Program are:

- a. Recommending acceptance or rejection of system/component turnover to PP&L
- b. Coordinating initial instrument, relay, and meter calibration
- c. Coordinating initial digital and analog control loop checkout
- d. Coordinating initial equipment operation
- e. Coordinating system cleanliness verification after turnover
- f. Ensuring that assigned vendors or other consultants perform work in accordance with approved procedures
- g. Authorizing and ensuring proper identification, documentation, and restoration of temporary modifications made during the Preoperational Test

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Program (for selected systems/components this responsibility may be assumed by the Plant Staff prior to conclusion of the Preoperational Test Program).

- h. Documenting and reporting design problems identified during the Initial Test Program until PP&L permanent plant procedures are implemented to perform this function, at which time this becomes a Plant Staff responsibility. Implementation of permanent plant procedures may be on a system, unit, or plant basis.
- i. Documenting and reporting construction problems identified during the Initial Test Program until PP&L permanent plant procedures are implemented to perform this function, at which time this becomes a Plant Staff responsibility. Implementation of permanent plant procedures may be on a system, unit, or plant basis.
- j. Authorizing and monitoring rework, modification, and maintenance during the Preoperational Test Program (for selected systems/components this responsibility may be assumed by the Plant Staff prior to conclusion of the Preoperational Test Program).
- k. Coordinating preparation, review, and approval of component and preoperational test procedures.
- l. Coordinating performance of component and preoperational testing.
- m. Coordinating review and approval of component and preoperational test results.
- n. Planning and scheduling Preoperational Test Program activities.

### 14.2.2.3 Plant Operations Review Committee

The Plant Operations Review Committee (PORC) consists of the individuals assigned independent review responsibility in accordance with the requirements of Chapter 13. The responsibilities, reporting relationships, and qualification requirements of PORC members are also described in Chapter 13. During the Initial Test Program additional responsibilities of PORC include reviewing and recommending approval of startup test procedures prior to testing and reviewing and recommending approval of startup test results following testing.

#### 14.2.2.4 Test Review Board

The Test Review Board (TRB) is a temporary review organization established specifically for the Preoperational Test Program. Test Review Board members may consist of individuals of various organizations (Bechtel, General Electric, PP&L, or others). The Test Review Board is responsible for review of preoperational test procedures prior to testing and for review of preoperational test results after testing. The TRB recommends approval to the Superintendent of Plant.

The Superintendent of Plant is responsible for the assignment of individuals to the Test Review Board. These assignments may be on a permanent or temporary basis. The TRB Chairman is responsible for the conduct of the TRB and is directly responsible to the Superintendent of Plant. The minimum qualifications of the TRB Chairman are the same as identified in Subsection 14.2.2.2.1.

#### 14.2.3 TEST PROCEDURES

The Initial Test Program is conducted in accordance with detailed component, preoperational, and startup test procedures. PP&L maintains overall responsibility for test procedure preparation, review, and approval. These activities are completed in a timely fashion to ensure that these procedures are suitable for NRC review at least 60 days prior to their intended use.

##### 14.2.3.1 Procedure Preparation

Component test procedures are initially prepared by designated organizations (Bechtel, General Electric, PP&L or others). The completed drafts are reviewed by other cognizant organizations and approved by the ISG Supervisor.

Preoperational and Startup test procedure drafts are initially prepared by designated organizations (Bechtel, General Electric, PP&L, or others) in accordance with the standard format of Figures 14.2-2A & B. The completed drafts are then reviewed by cognizant design organization representatives to ensure that test procedure objectives and acceptance criteria are consistent with current design document requirements. Review comments are resolved between the writing organization and the cognizant design organization representative.

The following items are the responsibility of the ISG for component and preoperational test procedures and the Plant Staff for Startup test procedures:

- a. Updating procedure references to latest revisions.
- b. Verifying the procedure has been revised to incorporate design changes.
- c. Verifying procedure compatibility with field installation of equipment.
- d. Resolving comments on procedures received from TRB, PORC or the Superintendent of Plant.
- e. Evaluating reactor operating and testing experiences as supplied by the Manager-Nuclear Support in the development of the procedures.

#### 14.2.3.2 Procedure Review and Approval

Following initial preparation the component tests are reviewed by cognizant organizations and sent back to the ISG for inclusion of comments. The ISG Supervisor then approves the component test procedures.

Following initial preparation, the Preoperational and Startup test procedures are processed through a formal review and approval cycle. The responsibility for coordinating this process and for resolving review comments lies with the ISG Supervisor or his designee for preoperational tests and with the Technical Supervisor or his designee for startup tests.

Specific review responsibilities are as follows:

- a. For preoperational and acceptance test procedures the Test Review Board, under the direction of the TRB Chairman, is responsible for:
  - 1. Verifying procedure conformance with the FSAR, environmental technical specifications, and plant operating technical specifications.
  - 2. Ensuring technical adequacy of procedures.
  - 3. Recommending approval of test procedures.
  - 4. The Test Review Board is responsible for review of preoperational test procedures prior to testing and for review of preoperational test results after testing.
- b. For the Startup Test Program test procedures the Plant Operations Review Committee, as described in Chapter 13 is responsible for:

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1. Verifying procedure conformance with the FSAR, environmental technical specifications, and plant operating technical specifications.
2. Performing a nuclear safety review as required by the plant technical specifications.
3. Ensuring technical adequacy of the procedures.
4. Recommending approval of test procedures.

Upon completion of review and inclusion of required changes preoperational and startup test procedures are submitted for approval by the Superintendent of Plant.

### 14.2.4 - Conduct of Test Program

The administrative controls that govern conduct of the Plant Staff and of the Integrated Startup Group during the Initial Test Program are specified by administrative procedures. These administrative procedures are PP&L controlled and approved documents. Administrative procedures define tasks to be performed, prescribe methods, and assign responsibilities for performing them.

The administrative procedures governing conduct of the Integrated Startup Group are contained in the Startup Administrative Manual which is approved by the Superintendent of Plant. These procedures do not establish the administrative controls of other project groups or organizations except as they interface with the Integrated Startup Group. The Startup Administrative Manual will be approved for use prior to start of the Initial Test Program. The administrative procedures governing conduct of the Plant Staff are as specified in Chapter 13. The schedule for preparation, review, and approval of these procedures is also described in Chapter 13. This schedule provides sufficient time for procedures to be available for use prior to the time they are required to be implemented.

#### 14.2.4.1 Test Performance

Preoperational and Startup testing performed during the Initial Test Program is in accordance with approved test procedures. The method for preparing, reviewing, and approving these test procedures is detailed in Subsection 14.2.3. Prior to start of testing, a test director(s) is assigned to each procedure. The test director(s) is the individual designated as being responsible for coordinating test performance. Test directors

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for preoperational tests are assigned from the ISG or the Plant Staff by the ISG Supervisor or his designee. Test directors for startup tests are assigned by the Technical Supervisor or his designee.

Specific responsibilities of the test director include but are not limited to:

- a. Verifying test prerequisites are complete and properly documented, except as provided by Subsection 14.2.4.2
- b. Ensuring that required test apparatus/equipment is available and calibrated.
- c. Documenting test performance on a single copy of the procedure, denoted as the official test copy
- d. Ensuring that test precautions are observed during testing
- e. Adhering to the detailed instructions of the approved procedure, except as provided by Subsection 14.2.4.3
- f. Ensuring test personnel have been properly briefed
- g. Documenting and reporting test exceptions

The plant operating staff is responsible for the safe and proper operation of equipment during testing. Should an unsafe condition arise, the plant operating staff shall take whatever action is necessary including, but not limited to, stopping the test in order to restore safe plant conditions. During startup testing, the plant operating staff is specifically responsible for compliance with operating technical specifications, and compliance with the provisions of the operating license.

### 14.2.4.2 Test Prerequisites

Specific test prerequisites are identified in each preoperational test procedure. The test director verifies that each prerequisite is completed and properly documented prior to signoff in the official test copy of the procedure. If a prerequisite in a preoperational test cannot be satisfied, the test director will institute a procedure modification to the Preoperational Test.

As a prerequisite to preoperational testing, proper operation of each alarm loop is verified and listed in an appendix to the test. During the preoperational test, system parameters are varied and interlocks are tested which cause alarms to actuate.



Those alarms which are actuated during the course of the test will be documented in the body of the preoperational test.

#### 14.2.4.3 Procedure Modifications

Tests are conducted in accordance with approved procedures. If necessary, these procedures may be modified to complete testing. Such procedure modifications are documented on a test change notice form. In addition to generation of a test change notice form for preoperational tests, the test director marks up the official test copy of the procedure and initials/dates the change.

Review and approval for test change notices on preoperational test procedures is provided by the TRB.

Review and approval for test change notices on startup test procedures is provided by the PORC.

Preparation, review and approval activities are accomplished before or after performance of associated testing based on the following criteria:

a) Non-Intent Changes

For procedure modifications that do not change acceptance criteria and do preserve the intent of the test, the test change notice may be approved after performance of associated testing. Non-Intent changes for startup tests shall be initialed/dated by an on-shift licensed senior operator in addition to the test director prior to performance of associated changes.

b) Intent Changes

For procedure modifications that alter the acceptance criteria or the intent of the test, the test change notice is approved before performance of associated testing.

#### 14.2.4.4 Design Problems

In the process of checkout, initial operation, and preoperational or startup testing design problems may be encountered. Such design problems are formally documented and reported to appropriate design organization representatives for resolution. Typical design problems include:

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- a. Errors or discrepancies in approved project design documents
- b. Items that represent a potential hazard to personnel safety
- c. Proposed facility modifications to meet design objectives
- d. Failure of a tested system or component to satisfy design requirements or acceptance criteria
- e. Operating problems where operation is in accordance with design requirements

Design response for all such reported items is mandatory. Should the response require a facility modification, the appropriate design documents are revised and issued to the field. Subsequent control of these modifications is described in Subsection 14.2.4.5.

### 14.2.4.5 Control of Rework, Modifications, and Repairs

A comprehensive listing of outstanding work items is maintained for each system during the Initial Test Program. This listing is maintained to ensure that identified work is performed. Typical listed work items include:

- a. Incomplete or incorrect equipment installation
- b. Equipment repairs (corrective maintenance)
- c. Approved facility modifications
- d. New or additional construction

This work is performed by the construction organization, the plant maintenance staff or a contract organization in accordance with approved procedures. In any event, in order to maintain the required controls, formal authorization is required to perform the work. During the Preoperational Test Program, this written authorization is obtained from the ISG through implementation of the appropriate ISG or Plant Staff administrative procedure. During the Startup Test Program, this written authorization is obtained from the Plant Staff through implementation of the appropriate Plant Staff administrative procedure. These administrative procedures, in addition to authorizing performance of the work, specify any retesting required as a result of the work and document completion of both the work and associated

retesting. Closure of the work list item requires completion of both the specified work and the specified retesting, if required.

#### 14.2.4.6 Test Phase Prerequisites

Completion of Phase I is a prerequisite of Phase II for each system. The completion of Phase II on safety-related systems is a prerequisite for commencement of the Startup Test Program with the following exception: Startup Testing required to be completed prior to fuel loading as identified in Figure 14.2-5 may be implemented during Phase II.

Completion of each major phase of the Startup Test Program is a prerequisite to starting the succeeding phase. Subsection 14.2.11 identifies the specific testing scheduled to be conducted during each of these phases. A phase is considered complete only after the results of required testing are evaluated, reviewed, and approved, and test exceptions resolved per the requirements of Subsection 14.2.5.

#### 14.2.5 REVIEW, EVALUATION, AND APPROVAL OF TEST RESULTS

PP&L has overall responsibility for review, evaluation, and approval of test results. The following sections establish the requirements for review, evaluation, and approval of individual test results, major test phase test results, and test plateau test results.

##### 14.2.5.1 Individual Test Results

Upon completion of a component test, the System Engineer assembles the test results and submits them to the Group Leader for approval.

Upon completion of a preoperational or a startup test, the test director assembles a test package that includes the official test copy of the procedure and all related documentation. The preoperational test package is submitted to the Test Review Board Chairman who disseminates copies of the test package to TRB members responsible for performing an in-depth review and evaluation of test results. For startup test results the package is submitted to the chairman of PORC.

Test discrepancies, deficiencies, and omissions identified during testing or during review of test results are documented as test

exceptions. Test exceptions occurring because of design problems are reported to appropriate design organization representatives for resolution per Subsection 14.2.4.4. Following TRB or PORC review and resolution of TRB or PORC comments, the chairmen have three options:

- a. Recommend that the entire test be repeated.
- b. Recommend that test results are unacceptable until all or part of the outstanding exceptions are resolved, in which case the test package is returned to the test director for further action.
- c. Recommend acceptance of test results with or without exceptions, in which case the test package is submitted to the appropriate approval authority for final review and approval.

Final review and approval of preoperational test and startup test results is by the Superintendent of Plant. Final review and recommendation for approval of startup test results is by the Plant Operations Review Committee. Approval is by the Superintendent of Plant.

For test results approved with exceptions, each exception will be evaluated and assigned a required completion date relative to the different phases of the Initial Test Program. Test exceptions are resolved by processing them through the same review and approval cycle as associated test results.

#### 14.2.5.2 Major Test Phase -- Test Results

Commencement of each major test phase of the Startup Test Program, requires that outstanding work items be reviewed and the following commitments be satisfied:

- a. Commencement of Initial Fuel Loading requires that the preoperational test results of Figure 14.2-4 be reviewed and approved.
- b. Commencement of Initial Heatup and Low Power Testing requires that the Phase III startup test results be reviewed and approved.
- c. Commencement of Power Ascension Testing requires that the Phase IV startup test results be reviewed and approved.

14.2.5.3 Power Ascension Testing - Test Results

Testing during the Power Ascension Test Phase is sequenced in distinct test plateaus. Prior to proceeding from one plateau to the next, the startup test results of the preceeding plateau are required to be reviewed and approved.

14.2.6 TEST RECORDS

A single copy of each approved procedure, denoted as the official test copy, is used as the official record of the test. Because of the format of startup test procedures, there will be one official test copy of a subtest for each Test Condition or plant operating condition in which the subtest is implemented. The completed official test records are assembled into a test package at the end of testing. This test package is retained in accordance with PP&L requirements for record retention.

14.2.7 CONFORMANCE OF TEST PROGRAMS WITH REGULATORY GUIDES

The safety-related performance requirements of the safety-related structures, systems, and components identified in Chapter 3 are tested in conformance with the regulatory positions established in the following regulatory guides or justification for exceptions is provided.

<u>Number</u>	<u>Title</u>
1.20	Vibration Measurements on Reactor Internals (Revision 2, May 1976).
1.41	Preoperational Testing of Redundant On-site Electric Power Systems to Verify Proper Load Group Assignments (March 16, 1973).
1.52	Design, Testing, and Maintenance Criteria for Engineered-Safety-Feature Atmosphere Cleanup System Air Filtration and Absorption Units of Light-Water-Cooled Nuclear Power Plants (Revision 1, July 1976).
	Testing will be performed on the Control Structure Emergency Outside Air Supply System in accordance with the exceptions taken on Regulatory Guide 1.52 in Section 3.13.

1.56

Maintenance of Water Purity in Boiling Water Reactors (June 1973).

1.68

Initial Test Programs for Water-Cooled Reactors Power Plants (Revision 1, January 1977).

- (1) Reference: Section C.1 of the Regulatory Guide.

Testing will be conducted on safety-related structures, systems, and components identified in Table 14.2-1 as required by 10CFR50.

- (2) Reference: Section C.9 of the Regulatory Guide.

The requirements of Preoperational Test results documentation and reporting are satisfied by the format and content of the completed test procedures; generation of additional reports is not contemplated.

- (3) Reference: Appendix A, Section 1.h (10) of the Regulatory Guide.

Not applicable because SSES does not use containment recirculation fan for post accident containment heat removal.

- (4) Reference: Appendix A, Section 5.1.1 of the Regulatory Guide. The two pump trip is done at Test Condition 3 (approximately 100% core flow and 75% power).

- (5) Reference: Appendix A, Section 5.c.c of the Regulatory Guide.

Demonstration of the operability of liquid radioactive waste system is provided in the preoperational test program. No additional testing is necessary during the power-ascension test phase.

1.68.1

Preoperational and Initial Startup Testing of Feedwater and Condensate systems for Boiling Water Reactor Power Plants (Revision 1, January 1977).

Testing may be limited by the availability of auxiliary steam.

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- 1.68.2 Initial Startup Test Program to Demonstrate Remote Shutdown Capability for Water-Cooled Nuclear Power Plants (January 1977).
- 1.70 Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants (September 1975).
- 1.80 Preoperational Testing of Instrument Air Systems (June 1974).

The Instrument Air System is not safety related. However, the various components in the Instrument Gas System will be tested to verify that they fail as designed per the statement in Section 3.13. The movement of affected valves will be verified as part of the test associated with each respective valve's corresponding system test.

The action and flow of decay air is not an essential criteria of operation in relation to the affected valves. The valves are to fail with loss of gas to a safe position. Whether decaying pressure will hold some or all of the valves (except for those on the affected line) in normal operating positions is not of critical importance.

- 1.104 Overhead Crane handling Systems for Nuclear Power Plants (February, 1976).

Exceptions for testing of the cranes are outlined in Section 3.13.

- 1.108 Periodic Testing of Diesel Generators Used as Onsite Electric Power Systems at Nuclear Power Plants (August 1977).

The testing of diesel generators will conform to Regulatory Guide 1.108 per regulatory position 2.a.

Since sequence of events capability was not part of the design, testing will also take the same exceptions as outlined in Section 3.13.

- 1.140 Design, Testing and maintenance criteria for normal ventilation exhaust system air filtration and absorption units of light-water-cooled nuclear power plants (Revision 1).

Preoperational testing will comply with regulatory position C.5.

**14.2.8 UTILIZATION OF REACTOR OPERATING AND TESTING  
EXPERIENCE IN THE DEVELOPMENT OF THE TEST PROGRAM**

The Manager-Nuclear Support is responsible for ensuring that reactor operating and testing experiences of similar power plants are made known to the ISG and the Plant Staff during the Initial Test Program. The primary sources of experience information are NRC License Events and experiences of industry contacts. This information will be sorted and reported for a period of two years prior to fuel load on the first unit. The Manager-Nuclear Support is addressed in Subsection 17.2.1.

**14.2.9 TRIAL USE OF PLANT OPERATING AND EMERGENCY PROCEDURES**

The adequacy of Plant Operating and Emergency Procedures will be confirmed by trial-use during the Initial Test Program. Those procedures that do not require nuclear fuel are confirmed adequate to the extent practicable during the Preoperational Test Program. Those procedures that require nuclear fuel are confirmed adequate to the extent practicable during the Startup Test Program.

The plant operating staff is responsible for confirmation of operating and emergency procedures. The Superintendent of Plant is responsible for ensuring that comments/changes identified during confirmation are incorporated in finalized procedures.

It is not intended that preoperational test procedures explicitly incorporate or reference plant operating and emergency procedures. These tests are intended to stand on their own since they are not necessarily compatible with configurations and conditions required for confirmation of facility operating and emergency procedures. Startup test procedures will incorporate and reference plant operating and emergency procedures to the extent practical.

**14.2.10 INITIAL FUEL LOADING AND INITIAL CRITICALITY**

Initial fuel loading is accomplished in accordance with startup test procedure, ST-3 Fuel Loading. Initial criticality is accomplished in accordance with startup test procedure ST-4, Full Core Shutdown Margin. These procedures comply with the general guidelines and regulatory positions contained in Regulatory Guide 1.68 (Revision 1, January 1977). Test abstracts establishing the objectives, prerequisites, test method, and acceptance criteria for these procedures are presented in Subsection 14.2.12.



14.2.11 TEST PROGRAM SCHEDULE

The Preoperational Test Program is scheduled for 15 months duration on the Unit 1 and Common components and for 12 months duration on the remaining Unit 2 components (see Figure 14.2-4a and 14.2-4b). The subsequent Startup Test Programs are scheduled for six months on each unit.

The Preoperational Test Program sequential test schedules presented on Figures 14.2-4a and 14.2-4b offer one possible plan for an orderly and efficient progression of the program. While these sequences may be preferred, numerous alternatives exist. The schedule will be updated periodically at the jobsite to reflect construction status, manpower availability, and the required test prerequisites.

The safety-related structures, systems, and components will be preoperationally tested. The Preoperational Test Procedures are scheduled to be developed from September 1977 to January 1979.

The schedule of Unit 1 and Unit 2 Startup Tests is presented in Figure 14.2-5. This schedule establishes the required testing as a function of test condition. The test conditions are described on Figure 14.2-6. All testing is assigned to a specific test condition for convenience even though some testing, as identified in figure 14.2-5, is performed outside the bounds of the assigned test condition. Not all subtests of a Startup Test are performed at each assigned test condition. Startup testing will be divided into three Major Test Phases, and, within the Power Ascension Test Phase, into distinct test plateaus. The testing included in each Major Test Phase and test plateau is described in Table 14.2-4. Even though this basic order of testing is required, there is still considerable flexibility in sequencing the startup testing specified to be conducted at each plateau. Detailed startup testing schedules, commensurate with the requirements of this schedule, will be developed at the job site.

14.2.12 INDIVIDUAL TEST DESCRIPTIONS

The individual preoperational tests to be conducted on safety-related structures, systems, and components are listed in Table 14.2-1. The abstracts of these preoperational tests are contained in Subsection 14.2.12.1 in numerical order. The Startup Test Program procedures are listed in Table 14.2-3. The abstracts of Startup Test procedures are contained in Subsection 14.2.12.2 in numerical order. The abstracts identify each test by title and number, describe the test objectives, specify the test prerequisites, provide a summary description of the test method, and establish the test acceptance criteria.

#### 14.2.12.1 Preoperational Test Procedure Abstracts

##### (P2.1) 125 Volt DC System Preoperational Test

Test Objective - To demonstrate the ability of the 125 Volt dc system to perform the following:

- A. The batteries can endure a complete discharge, based on their ampere hour rating, without exceeding the battery bank minimum voltage limit. (Performance Test)
- B. The batteries can provide reliable stored energy to selected loads, indicated in Table 8.3-6, in the event of a design base accident. (Service Test)
- C. The battery chargers can deliver their rated output.
- D. The battery chargers can fully charge their associated batteries from design minimum charged state (i.e., after the service test) simultaneously providing power to the distribution panels for normal station loads.
- E. That the alarms operate and annunciate at their specified abnormal condition.
- F. The reliable 125V DC power is delivered to the ESF DC distribution panels.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required calibration and operation of instruments, protective devices, and breakers is verified. 480V AC Power, Resistor Load Bank, Battery Room Ventilation and Emergency Eyewash is available and/or in service.

Test Method - The Battery Performance Test is manually initiated by connecting the battery bank to the resistor load bank and discharging the batteries at a constant current for a specified period of time. The Battery Service Test is manually initiated by connecting the battery bank to the resistor load bank and simulating, as closely as possible, the load the batteries will supply during a design base accident. Then the battery charger is connected to the batteries and the distribution panels to verify that they can charge the batteries while simultaneously providing power to the normal plant loads. The battery charger is also connected to the resistor load bank and current is increased to its maximum rating with the charger isolated from its associated battery bank. Alarms are simulated and verified to be operated properly.

Acceptance Criteria - The batteries can satisfactorily deliver stored energy for the specified amount of time as required for the Performance and Service Test. The battery chargers can deliver rated output and can charge their associated battery bank from minimum voltage to a fully charged state in a specified amount of time while simultaneously supplying normal plant loads. The alarms operate at their engineered setpoints and annunciate in the Control Room.

(P4.1) 4.16 kV System Preoperational Test

Test Objective - To demonstrate the proper operation and load - carrying capability of breakers, switchgear, transformers, and cables. Also to demonstrate proper operation of protective devices, relaying and logic, transfer and trip devices, permissive and prohibit interlocks, and instrumentation and alarms.

Prerequisites - Construction is completed to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and controls are operable. Required electrical power supply systems including 125 volt dc systems are operable.

Test Method - The 4.16 kV system is energized. Required controls are operated or simulated signals are applied to verify proper operation of protective devices, relaying and logic, transfer and trip devices, permissive and prohibit interlocks, instrumentation and alarms, breakers, switchgear, transformers and cables.

Acceptance Criteria - The system performance parameters are in accordance with applicable design documents.

(P5.1) 480 Volt System Preoperational Test

Test Objective - To demonstrate the capability of the 480 Volt Load Centers and 480 Volt Motor Control Centers systems to provide electrical power to connected 480 Volt Load Centers and Motor Control Centers by demonstrating the proper operation of breakers, transfer and trip devices, relaying and logic, permissive and prohibit interlocks, instrumentation and alarms, motor-generator sets, and automatic transfer switches.

Prerequisites - Construction is completed to the extent necessary to perform this test and the system is turned over to the ISG. Required electrical power supply systems are available to energize the 480 Volt system. Required instruments and protective relays are calibrated and controls are operable.

Test Method - Feeder breakers are opened and closed by operating or simulating controls. Voltages on the bus being fed are measured to verify breaker operations, relaying and logic,

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permissive and prohibit interlocks and alarms. Signals are applied to verify alarms and instrumentation. Buses are de-energized and energized to verify automatic transfer, switch transfer, and re-transfer and motor-generator set operation.

Acceptance Criteria - The system performance parameters are in accordance with applicable design documents.

### (Pl3.1) Fire Protection Water Systems

Test Objective - To demonstrate the proper operation of the Fire Protection Water System. The test will specifically demonstrate the following:

For Unit #1 testing:

- 1) Automatic and manual operation and reliability of the fire pumps OP511 and OP512.
- 2) Yard Loop Integrity and ability to provide water through any flow path to yard fire hydrants.
- 3) Hose Stations in Unit 1 and common are operational and water is available to the stations.
- 4) Automatic and manual operation of the Unit one and common sprinkler systems.

For Unit #2 testing:

- 1) Hose stations in Unit 2 are operational and water is available to the stations.
- 2) Automatic and manual operation of the Unit 2 sprinkler systems.

Prerequisite - Construction is complete to the extent necessary to perform this test and the system is turned over to ISG. Required instruments are calibrated and controls are operational. The river water makeup system, instrument air system, and the required electrical power supplies are available.

Test Method - The operating modes are initiated manually and, where applicable, automatically. Fire pump performance is determined for OP511 and OP512. Automatic and manual initiation of the individual sprinkler systems are conducted. Flow tests are conducted on end of line fire hydrants. Flow verification is established at the hose stations. Required controls are operated or simulated signals are applied to verify proper operation and proper alarm annunciation locally and remotely.

Acceptance Criteria - The system performance parameters are in accordance with applicable codes and design documents.

(P13.2) --- Carbon Dioxide Fire Protection System

Test Objective - To demonstrate the proper operation of the CO<sub>2</sub> fire extinguishing system. The test will specifically demonstrate the following:

- 1) The CO<sub>2</sub> storage tank and refrigeration system operate automatically to maintain the concentration of CO<sub>2</sub> in the tank.
- 2) The proper operation of the CO<sub>2</sub> automatic flooding systems.
- 3) The proper operation of the manual spurt CO<sub>2</sub> systems.

Prerequisite - Construction is complete to the extent necessary to perform this test and the system is turned over to ISG. Required instruments are calibrated and controls are operational. The required electrical power supplies are available.

Test Method - The operating modes are initiated manually and, where applicable, automatically. Required dampers and ducts close off the hazard area. The timers for CO<sub>2</sub> discharge agree with design criteria. The required controls are operated or simulated signals and are applied to verify system interlocks and alarms.

Acceptance Criteria - System performance parameters are in accordance with applicable codes and design documents.

(P13.3) --- Fire and Smoke Detection Systems

Test Objective - To demonstrate the proper operation of the Fire and Smoke Detection System and related alarms.

Prerequisite - Construction is complete to the extent necessary to perform this test and the system is turned over to ISG. The required instruments are calibrated and controls are operational. The required electrical power supplies are available.

Test Method - The fire and smoke detector system required controls and instruments are operated or simulated signals are applied to ensure proper operation of interlocks and alarms.

Acceptance Criteria - The system performance parameters are in accordance with applicable codes and design documents.

(P13.4) Halon 1301 Extinguishing Systems

Test Objective - To demonstrate proper operation of the Halon Fire Protection system and related alarms.

Prerequisite - Construction is complete to the extent necessary to perform this test and the system is turned over to ISG. Required instruments are calibrated and controls are operable. Required electrical power supplies are available.

Test Method - The operating modes are initiated manually and automatically. The required controls are operated or simulated signals are applied to verify system interlocks and alarms.

Acceptance Criteria - The system performance parameters are in accordance with the applicable codes and design documents.

(P14.1) Reactor Building Closed Cooling Water System  
Preoperational Test

Test Objective - To demonstrate the Reactor Building Closed Cooling Water System functions as designed.

Prerequisite - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and controls are operable. Required electrical power supply systems are available. The Service Water System, Instrument Air System and a makeup water source for the RBCCW System are available.

Test Method - The system operation is initiated manually and the performance of the pumps is determined. Required controls are operated or simulated signals are applied to verify; automatic change of Service Water flow from RBCCW System with changes in the closed cycle water temperature; and system interlocks and alarms.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

(P16.1) RHR Service Water System Preoperational Test

Test Objective - To demonstrate the capability of RHR Service Water System to provide cooling water to connected components/systems and the ability of the system controls to alarm when abnormalities occur in the system and to operate in accordance with design intent.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and controls are operable. Required electrical power supply systems are available. The

spray pond and a make-up water source to it are available. RHR Emergency Service Water is required to conduct the flow balancing test.

Test Method - System operation is initiated manually and where applicable automatically. The system is operated in the system design modes and RHR service water pump performance is determined. Required controls are operated or simulated signals are applied to verify automatic loop/valve alignments, system interlocks and alarms.

Acceptance Criteria - The system performance parameters are in accordance with applicable design documents.

(P17.1) Instrument AC Power System Preoperational Test

Test Objectives - To demonstrate the ability of the 120V Instrument AC Power System to perform the following:

- A. That full load power is delivered to the four class 1E electrically independent ESF load groups.
- B. That full load power is delivered to the two non-class 1E distribution panels and that their automatic transfer switches shift load to their emergency sources upon loss of their normal sources, and back to normal power when it is restored.
- C. That the alarms operate and annunciate upon loss of power.
- D. That the four class 1E ESF distribution systems are electrically isolated from each other.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. The alarms operate properly, and 480V AC power and resistor load bank are available.

Test Method - The four class 1E ESF distribution panels are energized by manually closing their respective feeder breakers. A resistor load bank is connected to each distribution panel and current is increased to full load while maintaining required voltage of the three other distribution panels still energized. The remaining panel is de-energized to show that it does not affect the operation of the other three distribution panels. (This is performed for all four distribution panels.) Also, the undervoltage alarms are checked when each panel is de-energized. The two non-class 1E distribution panels are also energized by manually closing their respective feeder breakers. A resistor load bank is connected to each distribution panel and current is increased to full load. The automatic transfer switch normal supply breaker is manually opened to simulate a loss of normal

power and the output voltage of the distribution panel is monitored to verify that the supply voltage switched from normal to emergency in a specified time period. The emergency supply breaker is opened and the output voltage of the distribution panel is monitored to verify that output voltage is not present. The emergency supply breaker is closed and the normal supply breaker is closed to restore normal power. Output voltage is monitored to verify that supply voltage switched from emergency to normal in the specified period of time. The non-class 1E distribution panel undervoltage alarms are verified when both normal and emergency supply breakers in the automatic transfer switches are opened.

Acceptance Criteria - That reliable 120V AC Power, at design load, is supplied to all instrument buses. That loss of normal supply to the automatic transfer switches causes a shift, in a specified time period, to the emergency supply and vice-versa when normal supply voltage is restored. That the four class 1E distribution panels are electrically isolated from each other and that loss of power alarms operate and annunciate in the Control Room.

#### (P23.1) Diesel Fuel Oil System Preoperational Test

Test Objective - To demonstrate that the diesel fuel oil system is capable of supplying fuel oil to connected plant equipment.

Prerequisite - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instrumentation is calibrated and controls are operable. Required electrical power supply systems are available. The diesel oil storage tank is at its normal operating level.

Test Method - System operation is initiated manually. The performance of the diesel transfer pumps is determined and the diesel day tank capacity is verified. Simulated signals are applied to verify system interlocks and alarms.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

#### (P24.1) Diesel Generator System Preoperational Test

Test Objective - To demonstrate system reliability, proper voltage and frequency regulation under transient and steady-state conditions, proper logic correct setpoints for trip devices, and proper operation of initiating devices and permissive and prohibit interlocks. Starting, cooling, heating, ventilating, lubricating and fueling auxiliary systems will also be tested to demonstrate that their performance is in accordance with design.



Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and controls are operable. Emergency service water, Diesel Building H&V, 125 Volt dc Power, and Instrument Air are available. The diesel oil day tank is filled and a make-up source is available.

Test Method - System operation is initiated manually and diesel generator capability to start and attain rated voltage within the specified time are verified. Diesel generators are loaded to the rated load and the performance is determined. Required controls are operated or simulated signals are applied to verify automatic start, sequential loading, D-G protection, load rejection capability and other system interlocks and alarms. Reliability is demonstrated through 69 consecutive valid start tests of station diesel generators, with a minimum of 23 valid start tests per individual diesel generator.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

(P25.1) Primary Containment Instrument Gas System Preoperational Test

Test Objectives - To demonstrate that the Containment Instrument Gas system functions as designed.

Prerequisite - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and controls are operable. Required electrical power supply systems, the Reactor Building Closed Cooling Water System and Instrument Air System are available.

Test Method - System operation is initiated manually to determine the performance of compressors, moisture separators, dryers and filters. Required controls are operated or simulated signals are applied to verify; instrument air system backup, isolation on primary containment isolation signal, and other system interlocks and alarms.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

(P28.1) ESSW Pumphouse H&V System Preoperational Test

Test Objective - To demonstrate the capability of ESSW Pumphouse Heating and Ventilating System to maintain the required ambient temperature inside the ESSW Pumphouse.

Prerequisite - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG.

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Required instruments are calibrated and controls are operable. Required electrical power supply systems and the Instrument Air System are available.

Test Method - System operation is initiated manually and the fan air flow, damper operation, heater operation and ambient conditions inside the pumphouse are determined. Required controls are operated or simulated signals are applied to verify fan(s) automatic starts with associated pump starts and system interlocks and alarms.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

### (P28.3) Diesel Generator Building Heating and Ventilation System -----Preoperational Test-----

Test Objective - To demonstrate the capability of the system to maintain the required ambient temperatures inside the diesel generator building.

Prerequisite - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and controls are operable. Required electrical power supply systems, the Instrument Air System and Control Structure Chilled Water System are available.

Test Method - System operation is initiated manually and fan air flow, damper operation, heater operation and ambient temperatures inside the diesel generator building are determined. Required controls are operated or simulated signals are applied to verify fan automatic starts with associated D-G starts and system interlocks and alarms.

Acceptance Criteria - The system performance parameters are in accordance with applicable design documents.

### (P30.1) Control Structure H&V System Preoperational Test

Test Objective - To demonstrate the operability of the Control Structure H&V System and its interlocks inside the control structure building to demonstrate this system's ability to maintain a positive pressure above atmospheric during normal operation and high radiation signal when the emergency outside air supply mode is running. To demonstrate the ability of the Control Structure H&V to isolate before chlorine reaches the isolation dampers when chlorine is detected in the outside air intake.

Prerequisite - Construction is complete and the system is turned over to the ISG. Required instruments are calibrated and controls are operable. The Control Structure Chilled Water

System, Instrument Air System and turbine building vent are available. Required electrical power supply systems are available.

Test Method - The system operation is initiated manually and fan performance, damper operations and heating element operation are determined. The differential pressures with respect to outside atmosphere are measured. Required controls are operated or simulated signals are applied to verify the emergency filter operation on high radiation signal, automatic recirculation on high chlorine signal, system manual isolation and other system interlocks and alarms.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

(P30.2) Control Structure Chilled Water System Preoperational Test

Test Objective - To demonstrate the ability of the Control Structure Chilled Water System to provide chilled water flow to Control Structure Heating/Ventilating Units and Control room floor and computer room floor cooling units.

Prerequisite - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and controls are operable. The Service Water System, Emergency Service Water System, and Instrument Air System are available. Required electrical power supply systems are available.

Test Method - The system is operated to demonstrate chiller operation and chilled water pump performance. Required controls are operated or simulated signals are applied to verify automatic alignment of the system under emergency conditions (start of emergency condenser water recirculation pump) and other system interlocks and alarms.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

(P34.1) Reactor Building H&V System Preoperational Test

Test Objective - To demonstrate the capability of the Reactor Building H&V System to maintain the required thermal environment inside the reactor building.

Prerequisite - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments and controls are operable. The Instrument Air System is available. Required electrical power supply systems and Reactor Building Vent are available. The Reactor Building ventilation flow balancing, High Efficiency Particulate

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Air (HEPA) filter and charcoal absorber efficiency, and in-place leak tests are completed.

Test Method - The system is operated to measure the fan performance and determine the capability to maintain the Reactor Building at negative pressure within the required thermal environment and areas of greater potential contamination at a lower pressure than the rest of the building.

Required controls are operated or simulated signals are applied to verify the system isolation on LOCA and/or high radiation signal, and other system interlocks and alarms.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

### (P34.2) Reactor Building Chilled Water System Preoperational Test

Test Objective - To demonstrate that the Reactor Building Chilled Water System provides the required cooling water to connected coolers under normal and emergency conditions.

Prerequisite - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and controls are operable. The Reactor Building Closed Cooling Water System, Service Water System, Instrument Air System, Make-up Demineralizer Water System and required electrical power supply systems are available.

Test Method - The system is operated to demonstrate the chiller and chilled water pump operation. Required controls are operated or simulated signals are applied to verify system isolation, automatic valve alignment, equipment operation under emergency condition and system interlocks and alarms.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

### (P45.1) Feedwater System Preoperational Test

Test Objectives - The general objective of this test is to demonstrate proper operation of the Feedwater System. This will be accomplished to the extent possible utilizing the Auxiliary Boilers as a steam supply. The test will specifically demonstrate:

- 1) All RFP and RFPT instruments have been calibrated in accordance with the vendor's instruction manuals and instrument data sheets.
- 2) All RFP and RFPT alarm and trip points have been set properly.

- 3) All recorders, indicators, annunciators, and computer inputs function correctly.

#### Prerequisites

- 1) Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG.
- 2) The Service Water System is operational.
- 3) The Main Turbine Lube-Oil System is filled and operational.
- 4) The Instrument Air System is operational.
- 5) The Computer is operational to the extent necessary to verify inputs from the feedwater system.
- 6) The 480 volt motor control centers necessary for this test are operational.
- 7) The 250 volt DC control centers necessary for this test are operational.
- 8) RFPT A, B, and C Lube-Oil reservoirs are filled.

Test Method - Normal and emergency responses of the lube oil and turbine trip systems are verified following simulation or process manipulation of the controlling variable.

#### Acceptance Criteria

- 1) Interlocks of the reactor feed pump turbine (RFPT) and of the alternate and emergency lube oil pumps and their corresponding alarms function as designed.
- 2) All abnormal conditions providing trip signals to the RFPTs function as designed.

#### (P45.2) Feedwater Control System Preoperational Test

Test Objectives - The general objective of this test is to demonstrate proper operation of the Feedwater Control System. This will be accomplished to the extent possible without actually pumping water with the feed pump turbines. The test will specifically demonstrate:

- 1) All feedwater control instruments have been calibrated over their full range in accordance with the vendor's instruction manuals and instrument data sheets.

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- 2) All feedwater alarm and trip points have been set properly.
- 3) All recorders, indicators, annunciators, and computer inputs function correctly.
- 4) Interlocks to the main turbine, recirculation system, and feed pumps function correctly.
- 5) Feedwater control signals to the start-up regulating valve and turbine-driven feed pumps function correctly with simulated inputs and step commands originating from their respective control stations.

Prerequisites - The prerequisites for this test are as follows:

- 1) Construction of the system is complete to the extent required to conduct this test and the system is turned over to the ISG.
- 2) The 125 Volt DC system is operational.
- 3) The Instrument AC system is operational.
- 4) The 24 Volt DC system is operational.
- 5) Panel 1C651 annunciator is energized.

Test Method - Various level, flow, pressure, and speed signals will be simulated and the proper responses will be verified.

### Acceptance Criteria

- 1) The reactor, main steam, and feedwater pressure and flow indicators, recorders, computer inputs, and trip points respond within designed tolerances.
- 2) Speed regulation response of each RFP Turbine is within design limits.
- 3) The response of the startup regulating valve is within design tolerances.
- 4) Changes in the control mode, selection of control channels, or integrity of incoming signal do not produce adverse changes in the controlled variables.

### (P49.1) Residual Heat Removal System Preoperational Test

Test Objective - To demonstrate that the Residual Heat Removal System (RHRS) delivers cooling water as designed for each of the following system modes of operation: shutdown cooling,

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suppression pool spray, low pressure coolant injection (LPCI), suppression pool cooling, and fuel pool cooling.

Demonstrate operability of interlocks and isolation valves provided for overpressure protection from the reactor coolant system.

Testing will include demonstrations of proper operation of initiating devices, correct logic, proper operation of bypasses, proper operation of prohibit and permissive interlocks, and proper operation of equipment protective devices that could shut down or defeat the operation or functioning of such features.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and controls are operable. Required electrical power supply systems and the Instrument Air Systems are available. Reactor pressure vessel, suppression pool, fuel pool, and fuel pool skimmer surge tank are filled up to required level to provide enough suction head to the RHR pumps. Makeup water sources are available.

Test Method - The operating modes of the system are initiated manually and where applicable, automatically. RHR pump performance is determined for each operating mode. Control devices are operated or simulated signals are applied to verify valve alignment, LPCI mode operation for low reactor water level and high drywell pressure, and other system interlocks and alarms.

Acceptance Criteria - The system performance parameters are in accordance with applicable engineering design documents.

### (P50.1) Reactor Core Isolation Cooling System Preoperational Test

Test Objective - To demonstrate the capability of the Reactor Core Isolation Cooling (RCIC) System to deliver water to the reactor pressure vessel.

Prerequisites - Construction is complete to the extent necessary to perform these tests and the system is turned over to ISG. Required instruments are calibrated and controls are operable. Required electrical power supply systems and the Instrument Air System are available. Suppression pool and condensate storage tank are filled to provide enough suction head to RCIC pump and reactor pressure vessel is available to receive water. Auxiliary steam is available for RCIC turbine operation. Part of the RHR system will also be available to provide a suction flow path for RCIC pump.

Test Method - The system operation is initiated manually and automatically. The system is operated to determine the

performance parameters for the RCIC turbine and pump and the barometric condensate pump. Control devices are operated or simulated signals are applied to verify automatic valve alignment (system isolation), turbine trip and start modes, and other system interlocks and alarms.

Acceptance Criteria - The system performance parameters are in accordance with applicable engineering design documents.

(P51.1) Core Spray System Preoperational Test

Test Objectives - To demonstrate the ability of the Core Spray System to accept water from both the suppression pool (normal) and the condensate storage tank (backup) and deliver flow at adequate pressure to the reactor pressure vessel in an acceptable spray pattern.

Prerequisites - Construction is complete to the extent necessary to perform these tests and the system is turned over to the ISG. Power and control voltage is available for the motors, valves and instruments associated with this system. Required instruments are calibrated and controls are operable. The suppression pool and condensate storage tanks are filled to the required level. The reactor pressure vessel head is removed and the vessel can accept water. The condensate transfer system is available.

Test Method - The normal system operation is initiated automatically by simulating a Design Base Accident. The pumps are started and the appropriate valves and instruments are operated to ensure that water flow is established to the reactor pressure vessel. System logic, interlocks, and alarms are verified to be in accordance with design intent and system flows and pressures are verified to ensure that they are adequate to inject water into the reactor pressure vessel via the core spray spargers. The system is operated manually through the test line back to the suppression pool. Also, the system is manually lined up to accept water from the condensate storage tank and deliver core cooling water to the reactor pressure vessel.

Acceptance Criteria - That the core spray system can deliver cooling water at design flow and pressure to the reactor pressure vessel within a specified period of time for various simulated operating conditions.

(P51.1A) Core Spray System Pattern Preoperational Test

Test Objective - To demonstrate the ability of the Core Spray System to deliver a proper spray pattern at rated and runout conditions. This procedure shall also verify satisfactory physical response of system components within the reactor pressure vessel. The system discharge line restriction flow



orifices shall be verified as being properly sized such that runout flow does not exceed system design values.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Power and control voltage is available for the motors, valves and instruments associated with this system. Required instruments are calibrated and controls are operable. The suppression pool is filled to the required level. The reactor pressure vessel head is removed and the vessel can accept water. The condensate transfer system is available.

Test Method - System operation shall be manually initiated, monitored and controlled such that vessel injection is achieved in accordance with test objectives.

Acceptance Criteria - The Core Spray System can deliver cooling water at design flow with an acceptable spray pattern to the reactor pressure vessel. During this test photographic records shall be made, no system abnormalities shall be observed, restriction flow orifices shall be properly sized, and free route from the core spray junction box vent holes shall be verified.

(P52.1) High Pressure Coolant Injection System Preoperational  
-----Test-----

Test Objective - To demonstrate that the High Pressure Coolant Injection System (HPCIS) delivers coolant water to the reactor.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to ISG. Required instruments are calibrated and controls are operable. The suppression pool and condensate storage tank are filled to provide the required suction head to the HPCI pump. The reactor pressure vessel head is off and the vessel is ready to receive water from the HPCI system. Required electrical power supply systems, Standby Gas Treatment, required ventilation systems and Instrument Air System are available. The Auxiliary Boiler or another source of steam supply is available to run the HPCI turbine.

Test Method - System operation is initiated manually and where applicable automatically. Reactor water low level and drywell high pressure signals are simulated to verify HPCI turbine automatic functions. System isolation is verified by operating required controls and or simulated signals. Steamline high differential pressure signals are simulated to verify automatic functions. Limited turbine and pump operation (depending upon auxiliary steam conditions) and automatic valve alignment are demonstrated. Containment isolation valves are functionally tested. Required controls are operated or simulated signals are applied to verify interlocks, trips and alarms.

Acceptance Criteria - The system performance characteristics are in accordance with applicable design documents.

(P53.1) Standby Liquid Control System Preoperational Test

Test Objective - To demonstrate the operation of the system with demineralized water. Demonstrate operability of instrumentation, controls, interlocks, and alarms. Verify operability of heaters, air spargers, and heat tracing. Conduct test firings of squib-actuated valves, and demonstrate design injection capability. Tests should be conducted as appropriate to verify redundancy and electrical independence.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and controls are operable. The reactor vessel is available to receive water injected from the Standby Liquid Control System. Required electrical power supply systems and a source of demineralized makeup water are available.

Test Method - System operation is initiated manually. Demineralized water is used for testing the system. The pumps are run taking suction from the standby liquid storage tank and the test tank. Squib valves are fired and the rate of demineralized water injection into the reactor vessel from each pump is measured. Required controls are operated or simulated signals are applied to verify interlocks and alarms.

Acceptance Criteria - The system performance characteristics are in accordance with the applicable design documents.

(P54.1) Emergency Service Water System Preoperational Test

Test Objective - To demonstrate that the Emergency Service Water System provides a supply of cooling water to the plant emergency equipment, to demonstrate the ability to start the ESW pumps from the remote shutdown panel, to demonstrate the ability of an ESW pump to start automatically when the associated diesel-generator unit starts, to demonstrate the proper operation of system automatic valve transfer schemes, and to demonstrate the proper operation of spray pond components.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and controls are operable. Required electrical power supply systems are available. The spray pond is filled to provide enough suction head for the ESW pumps, and a makeup source to the spray pond is available. The RHR service water system is in operation.

Test Method - The system is started manually and automatically through the associated diesel generator start signal. Pump flow paths are established and pump flows are measured for each loop. Flow balancing of the RHR Service Water System and Emergency Service Water System is performed. Proper operation of the line break detection system is verified. Required controls are operated and simulated signals are applied to verify interlocks and alarms.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

(P55.1) Control Rod Drive System Preoperational Test

Test Objective - To demonstrate the operation of the Control Rod Drive System including control rod drive hydraulic system and CRD mechanisms.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and controls are operable. Required electrical power supply systems are available. The condensate storage tank is filled to provide enough suction head to the CRD pump. The TBCCW System and Instrument Air System are available. The Reactor Manual Control System is operational to the point required for continuing with this test. Initial coupling and venting is completed.

Test Method - System operation is initiated manually and the system flow and pressure control stations are adjusted. CRD pump performance parameters are measured. Control rod drives are exercised to verify, position indication and insert/withdraw speeds. Scram tests are conducted and scram times are measured for each control rod drive. Required controls are operated or simulated signals are applied to verify system interlocks and alarms. Rod buffer performance is also tested.

Acceptance Criteria - System performance parameters are in accordance with the applicable design documents.

(P56.1A) Reactor Manual Control System Preoperational Test

Test Objectives - To verify the operation of the Reactor Manual Control System, including relays, control circuitry, switches, rod blocks, indicating lights and control valves.

Prerequisites - Construction is complete to the extent necessary to perform this test and system is turned over to the ISG. Required instruments are calibrated and controls are operable. Required electrical power supply systems are available.

Test Method - System integrated operation is initiated manually. Controls are operated and simulated signals are applied to verify: rod blocks, alarms and interlocks of the reactor mode switch; proper operation of the rod position information system; and rod drift alarm circuit directional control valve time sequence for insert and withdraw commands.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

(P56.1B)...Rod Sequence Control System Preoperational Test

Test Objectives - To demonstrate and verify the operation of the Rod Sequence Control System, including the Rod Pattern Controller and its associated external test circuitry.

Prerequisites - Construction is complete to the extent necessary to perform this test and system is turned over to the ISG. Required instruments are calibrated and controls are operable. Required electrical power supply systems are available.

Test Method - The Rod Pattern Controller will be tested and verified to operate correctly in the "Self Test" mode. All RSCS operator display functions and controls as well as the ability of the RSCS to substitute rod position data will be demonstrated and verified. Systems operations of all control rod withdraw and insert blocks and forced single match rod motion will be verified by conducting rod movements under the control of both sequence "A" and "B".

Acceptance Criteria - The System performance parameters are in accordance with the applicable design documents.

(P56.1C)...Rod Worth Minimizer System Preoperational Test

Test Objectives - To demonstrate and verify the operation of the Rod Worth Minimizer System, including the ability of the system to provide insert and withdraw blocks below low power setpoint, when the control rod insert/withdraw sequences are not within pre-set sequences, and the ability to provide visual displays and alarms between low power setpoint and low power alarm point.

Prerequisites - Construction is complete to the extent necessary to perform this test and system is turned over to the ISG. Required instruments are calibrated and controls are operable. Required electrical power supply systems are available.

Test Method - The Rod Worth Minimizer will be tested and verified to operate under various acceptable and non-acceptable rod position modes, while demonstrating rod blocks and alarms for low power interlocks.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

(P57.1) Uninterruptable AC Power System Preoperational Test

Test Objective - To demonstrate the ability of the Uninterruptable AC Power System to perform the following:

- 1) That full load power is supplied to the distribution panel
- 2) That the static transfer switch will automatically shift load from the preferred to the alternate source upon loss of the preferred source
- 3) That the static transfer switch will automatically shift load from the preferred source to the alternate source when the preferred source becomes overloaded and shift back to the preferred source when the overload condition is cleared
- 4) That loads can manually be switched from preferred to alternate source and vice-versa
- 5) That alarms operate and annunciate at their specified abnormal condition

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required calibration and operation of instrument, protective devices and breakers is verified. 480V AC Power, 250 V DC Power, and Resistor Load Bank are available.

Test Method - The Uninterruptable Power Supply is energized by manually closing the 250 V DC preferred breaker (inverter) and the 480 V AC Alternate Breaker (Voltage Regulating Transformer). With the static transfer switch in normal mode, the load is increased by use of the Resistor Load Bank while the voltage and current is monitored. The current is gradually increased above normal rating until the automatic transfer switch shifts the overload to the alternate source. Then the load is slowly decreased to clear the overload and to verify that the automatic transfer switch shifts the load back to the preferred source. A loss of the preferred source is simulated to verify that the automatic transfer switch will shift the load to the alternate source. Then with both sources available the transfer switch is manually switched from the preferred to alternate source and vice versa by means of the bypass mode and normal mode pushbuttons. Alarms are either simulated or functionally checked throughout the above procedure.

Acceptance Criteria - That reliable 120 V AC Power, at design load is supplied to the distribution panel. That the automatic transfer switch will shift loads from the preferred to the

alternate source with neqliqable power interruption upon loss of preferred source. That the automatic transfer switch will shift load from the preferred to the alternate source in an overloaded condition and back to the preferred source when the overload condition is cleared and, that the load can manually be shifted from the preferred to the alternate source and vice-versa that alarms operate at their engineered set points and annunciate in the control room.

(P58.1) Reactor Protection System Preoperational Test

Test Objective - To demonstrate the proper operation of the Reactor Protection System (RPS) in all combinations of logic and to demonstrate redundancy, electrical independence, mode switch operation, and safe failure on loss of power.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and controls are operable. Required electrical power supply systems are available. The Control Rod Drive System preoperational test is completed to the extent necessary to perform this test.

Test Method - Integrated system operation is initiated manually to verify M-G set performance and electrical independence. Required controls are operated or simulated signals are applied to verify: sensor relay-to-scrum trip actuator response time, the ability to scram CRDs in conjunction with the CRD hydraulic system, scram reset delay time, mode switch operation, and system interlocks and alarms.

Acceptance Criteria - System performance is in accordance with the applicable design documents.

(P59.1) Primary Containment System Preoperational Test

Test Objective - To demonstrate the operability and isolation capability of the Primary Containment System. Containment isolation valve functional tests will be performed.

To test the vacuum breakers and show proper operation of the controls and actuators, which will demonstrate the ability to limit the drywell and suppression pool internal and differential pressures.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and controls are operable. The suppression pool is filled with demineralized water to the required level and the hotwell is available. The Containment Instrument Gas System, Instrument Air System and required

electrical power supply systems are available. All primary containment isolation valves are operable.

Test Method - The suppression pool cleanup system will be tested for proper operation; the primary containment isolation system will have signals simulated with the valves in the non-isolation position, to verify the primary containment isolates when an isolation signal is received. Valve closure times are verified for those valves specified in the PSAR in the various system preoperational tests. The test method is described in the General Test Statement. Vacuum breakers will be actuated to show proper directional movement when permissives are available to control circuitry.

Acceptance Criteria - The Suppression Pool Cleanup System functions are as designed.

The Primary Containment isolation functions are designed when appropriate isolation signals are present.

#### TP 2.14 Nuclear Boiler System Level Instrumentation Verification Test

Test Objective - To demonstrate that the nuclear boiler level instruments function as desired.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and controls are operable. Required Electrical Power Supply Systems are available. A method to raise and lower the reactor vessel water level is available.

Test Method - The actual reactor vessel water level will be changed to verify level switch trip points, indicating functions and alarms.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

#### (P59.2) Containment Integrated Leak Rate Test

Test Objective - To demonstrate that the total leakage from the containment does not exceed the maximum allowable leakage rate (La) at the calculated peak containment internal pressure (Pa), as defined in 10 CFR50, Appendix J.

Prerequisites - Construction of the primary containment, including installation of all portions of mechanical, fluid, electrical, and instrumentation systems penetrating containment is complete. Type B and Type C local leakage rate is satisfactorily complete. Required test equipment instruments and

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data acquisition systems are operable. Systems required to support the ILRT are operational.

Test Method - The test shall be conducted in accordance with the requirements of Subsection 6.2.6 of the FSAR.

Acceptance Criteria - Acceptance criteria for this test are in accordance with the requirements of Chapter 16 of the FSAR.

### (P59.3) Primary Containment Isolation Valve Timing

Test Objective - To demonstrate that containment isolation valves receiving an automatic isolation signal meet the closing time requirements as stated in Table 6.2-12.

Pre-requisites - Construction is complete to the extent necessary and the various systems are turned over to the ISG. Required instruments are calibrated and control schemes have been checked and are operable. The required electrical power supply systems are available.

Test Method - Each valve receiving an automatic isolation signal will be closed (opened) by simulating the isolation signal of the interlock relay contacts. Upon initiation of the simulated signals, the valve(s) will be timed from their pre-isolation to their post-isolation position.

Acceptance Criteria - Valve receiving automatic isolation signals close (open) within the required time noted in FSAR Table 6.2-12.

### (P60.1) Containment Atmosphere Circulation System Preoperational Test

Test Objective - To demonstrate the capability of the Containment Atmosphere Circulation System to cool and circulate air inside the Containment.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and controls are operable. Required electrical power supply systems are available. The Reactor Building Chilled Water System or an alternate cooling water supply is available.

Test Method - The system operation is initiated manually, and flow for each fan is determined. Required controls are operated or simulated signals are applied to verify; automatic start of standby units and other system interlocks and alarms. No heat loads are simulated during the test.

Acceptance Criteria - The system performance is in accordance with the applicable design documents.



(P61.1) Reactor Water Cleanup System Preoperational Test

Test Objectives - To demonstrate the operability of the Reactor Water Cleanup and Filter Demineralizer System. In particular the following items are to be demonstrated:

- 1) The ability of individual components, instrumentations, alarms and interlocks to function properly.
- 2) Verify proper system performance by verifying all flow paths, flow rates and component performances to be in accordance with design specifications.
- 3) The ability of the system and filter to isolate by simulating each sensor to its trip point.
- 4) Verify the RWCU system containment isolation valves will respond properly to all control signals and closing times are within required specifications.
- 5) The ability of the filter/demineralizer valve and pump operating sequence to operate properly.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. The Reactor vessel is filled to provide enough suction head to the Reactor Water Cleanup Recirculation Pumps. The Reactor Building Closed Cooling Water System, Instrument Air System, condenser hotwell or Liquid Radwaste Collection System, and the RWCU Precoat System are available. Required electrical power supply systems are available.

Test Method - System operation is initiated manually. Pump flow and filter and demineralizer differential pressures are determined. Precoat and backwash cycles are tried. Controls are operated or simulated signals are applied to verify system isolation upon initiation of the respective NSSS isolation relay, other system interlocks and alarms.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

(P64.1) Reactor Recirculation System Preoperational Test

Test Objectives - To demonstrate the operability of the Reactor Recirculation components and the system.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and controls are operable. Required electrical power supply systems are available. The Reactor Building Closed Cooling Water System, is available. The

reactor vessel is filled with demineralized water to the required level.

Test Method - System operation is initiated manually. The system is tested by individual and integrated operation of M-G sets, pumps, and valves. Performance of the M-G sets, recirculation pumps, and jet pumps are determined to the extent possible during this test. Required controls are operated or simulated signals are applied to verify interlocks and alarms.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

#### TP 2.16 Reactor Internals Vibration and Inspection

Test Objective - The test objective is to detect damage, excessive wear, loose parts, or other evidence of unacceptable vibration which could result from assembly errors or undesirable deviations from the previously qualified prototype plant construction.

This test is a quality assurance measure which experimentally confirms the absence of excessive vibration of core support structures, jet pumps, lower plenum components, and other major internal structures. The test is conducted without fuel and is not intended to be a test of fuel or incore instrument vibration. However, the specified test conditions, without fuel present, provide a level of vibration excitation of major internal structures which is at least as high as that measured in normal power operation.

Prerequisites - To the extent necessary to perform this test all reactor internals components are installed except as follows.

1. The core matrix is empty; there are no fuel assemblies, incore instrumentation tubes, or neutron source rods. Control blades are withdrawn or not installed. Fuel support castings are installed.
2. The dryer assembly need not be installed.
3. One or both of the access hole covers on the shroud support plate must remain unwelded until after the test to provide access for inspection. Temporary closures must be provided.

The reactor vessel is closed, filled, and ready for pressurization. The recirculation pumps are operable. The RHR system pumps are operable to provide necessary temperature rise. Clean-up system heat exchangers are operable for temperature control.

Test Method - A visual inspection is made before and after the required maximum allowable speed pump runs. These flow runs include 35 hours of two-loop operation and 14 hours each for loops A and B. These hours may not be sequential, but they must be between the initial and final inspections.

Acceptance Criteria - Initial and final inspection results are acceptable.

(P69.1) Liquid Radwaste Collection System Preoperational Test

Test Objective - To demonstrate the capability of the Liquid Radwaste Collection System to collect liquid waste.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and controls are operable. Required electrical power supply systems are available. Liquid Radwaste Collection System and storage tanks are available.

Test Method - Sump pumps are operated and performance characteristics are determined. Level controls are operated to verify pump starts and alarms. Liquid radwaste discharge valves from primary containment are verified to close upon containment isolation signal.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

(P70.1) Standby Gas Treatment System And Secondary Containment Isolation Preoperational Test

Test Objective - To demonstrate the capability of the Standby Gas Treatment System (SGTS) to function as designed.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and controls are operable. Required electrical power supply systems are available. The Reactor Building Heating and Ventilation System, SGTS vent, and Instrument Air System are available.

Test Method - System operation is initiated manually and where applicable automatically. Required controls are operated or simulated signals are applied to verify secondary containment isolation and start of SGTS. SGTS performance is determined by measuring secondary containment pressures, system pressures and fan flow rates. System interlocks and alarms are verified.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

(P73.1) Containment Atmospheric Control System Preoperational Test  
Test Objective - To demonstrate the operability of the purge supply and exhaust systems, and to show the valves work according to the designed permissives and interlocks.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instrumentation are calibrated and controls are operable. Required electrical power supply system are available.

Test Method - The system valves will be operated to demonstrate proper operation. Simulated signals are applied to verify interlocks and alarms.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

(P73.2) Containment Hydrogen Recombiner Preoperational Test

Test Objective - To demonstrate the operability of the hydrogen recombiners (actual process is not demonstrated at this time).

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instrumentation is calibrated and controls are operable. Required electrical power supply system is available.

Test Method - The Hydrogen Recombiner System will be operated to the extent practical.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

(P73.3) Containment Oxygen-Hydrogen Analyzer Preoperational Test

Test Objective - To demonstrate the Containment Oxygen-Hydrogen Analyzer System to analyze containment hydrogen and oxygen content.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instrumentation is calibrated and controls are operable. Required electrical power supply system is available.

Test Method - The oxygen and hydrogen analyzers are utilized to determine the containment atmospheric analysis.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

(P75.1) 24 Volt DC System Preoperational Test

Test Objective - To demonstrate the ability of the  $\pm$  24 Volt DC System to perform the following:

- 1) That the batteries can ensure a complete discharge, based on their ampere-hour rating, without exceeding the battery bank minimum voltage limit. (Performance Test)
- 2) That the batteries can provide reliable stored energy to their design loads as indicated in Table 8.3-8 in the event of a Design Base Accident.
- 3) That the battery chargers can deliver their rated output.
- 4) That the battery chargers can fully charge their associated batteries from design minimum discharge (i.e., after the service test) while simultaneously providing power to the distributed panel for normal station loads.
- 5) That alarms operate and annunciate at their specified abnormal condition.
- 6) That reliable  $\pm$  24 Volt DC is delivered to the distribution panels.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required calibration and operation of instrument protective devices and breakers is verified. 120 V AC, Resistor Load Bank, Battery Room Ventilation and Emergency Eyewash is available and/or in service.

Test Method - The battery performance test is manually initiated by connecting the battery bank to the Resistor Load Bank and discharging the batteries at a constant current for a specified period of time.

The Battery Service Test is manually initiated by connecting the battery bank to the Resistor Load Bank and simulating, as closely as possible, the load the batteries will supply during a Design Base Accident.

Then the battery charger is connected to the batteries and the distribution panels to verify that they can equalize charge the batteries while simultaneously providing power to the normal plant loads. The battery charger is also connected to the Resistor Load Bank and current is increased to its maximum rating with the charger isolated from its associated battery bank.

Alarms are simulated and verified to operate properly.

Acceptance Criteria - The batteries can satisfactorily deliver stored energy for the specified amount of time as required for the performance and service tests. The battery chargers can deliver rated output, and can charge their associated battery bank from minimum voltage to a fully charged state in a specified amount of time while simultaneously supplying normal plant loads. The alarms operate at their engineered setpoints and annunciate in the control room.

(P76.1) Plant Leak Detection System Preoperational Test

Test Objective - To demonstrate the operability of the Plant Leak Detection System.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and controls are operable. Required electrical power supply systems are available.

Test Method - Sump levels will be varied (if practicable) or simulated signals are applied to level sensors to verify the leak detection system alarms.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

(P76.3) Post Accident Sampling System

Test Objective - To demonstrate the capability of the Post Accident Sampling System (PASS) to function as designed.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to ISG. Required instruments are calibrated and controls are operable. Required electrical power supply systems are available.

Test Method - Control switches will be manipulated and proper relay and indicating light operation will be verified. Response of valves will be checked functionally (i.e. voltage used as an indication that the valve is open or closed.) The system will then be operational checked by taking actual samples.

Acceptance Criteria - Control switches and associated interlocks function properly and the system shall be capable of obtaining a sample in less than one hour from initiating the sampling operation.

(P78.1) Source Range Monitoring System Preoperational Test

Test Objective - To demonstrate the operability of the Source Range Monitoring (SRM) System.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required reactor internals are installed, instruments are calibrated and controls are operable. Required electrical power supply systems are available.

Test Method - Source Range Monitor Detector insert/retract drive mechanisms are operated to verify proper operation. Required simulated signals are applied to verify SRM channel trips, indicating lights and alarms.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

(P78.2) Intermediate Range Monitoring System Preoperational Test

Test Objective - To demonstrate the operability of the Intermediate Range Monitoring (IRM) System.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required reactor internals are installed, instruments are calibrated and controls are operable. Required electrical power supply systems are available.

Test Method - Intermediate Range Monitors detector insert/retract drive mechanisms are operated. Required simulated signals are applied to verify IRM channel trips, rod blocks, indicating lights and alarms.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

(P78.3) Average Power Range Neutron Monitoring System  
-----Preoperational Test-----

Test Objective - To demonstrate the operability of the Average Power Range Neutron Monitoring (APRM System) including LPRM's, Recirc. flow bias signals and Rod Block Monitor.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required reactor internals are installed. Instruments are calibrated and controls are operable. Required electrical power supply systems are available.

Test Method - Each LPRM is checked from detector to its end function. Required input signals are simulated to verify LPRM channel trip lamps, remote meters and alarms. Required signals from the LPRM System are simulated to each APRM channel to verify trip functions, indicating meters, lights and alarms. Each flow transmitter is checked from flow element to its end function.

Signals are simulated to verify flow inducted trips, remote meters and alarms. Required signals from the LPRM and flow bias systems are simulated to each RBM channel to verify trip functions, indicating lights, and alarms.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

(P78.4) Traversing Incore Probe System Preoperational Test

Test Objective - To demonstrate the proper operation of the Traversing In-Core Probe System. Specific objectives are to demonstrate the following:

- 1) Manual and automatic operation.
- 2) Proper operation of all interlocks, overrides and automatic functions.
- 3) Proper operation of all indications and alarms.
- 4) Simulated operation of the shear valves.
- 5) Proper interface between the TIP system and process computer.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. LPRMs are installed inside the reactor vessel and required instruments are calibrated and controls are operable. TIP tracing X-Y recorder and purge system are available.

Test Method - System operation is initiated manually. The indexer interlock, shear valve control and monitoring, ball valve control and monitoring, squib circuits and purging operations are verified. Required controls are operated or simulated signals are applied to verify interlocks external to the system and system alarms.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

(P79.1 & P79.2I) Area Radiation Monitoring System Preoperational Test

Test Objective - To demonstrate the operability of the Area Radiation Monitoring System.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and required electrical power



supply systems are available. The required radioactivity sources with known strengths are available.

Test Method - The radioactive sources are used or simulated signals are applied to verify area radiation monitor channel trips, indicating lights, and alarms.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

(P79.2A-H) Process Radiation Monitoring System Preoperational  
-----Test-----

Test Objective - To demonstrate the operability of the Process Radiation Monitoring System.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and required electrical power supply systems are available. The required radioactivity sources with known strengths are available.

Test Method - The radioactive sources are used or simulated signals are applied to verify process radiation monitor channel trips, locating lights, interlocks, and alarms.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

(P80.1) Reactor Non-nuclear Instrumentation System Preoperational Test

Test Objective - To demonstrate that the Reactor Non-nuclear Instrumentation System functions as designed.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and the controls are operable. All relays that are initiated from reactor vessel level and pressure sensors are placed in the untripped condition.

Test Method - Simulated signals are applied to instrument loops and trip functions, indicating functions and alarms are verified.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

(P81.1) Fuel Handling System Preoperational Test

Test Objective - To demonstrate that the refueling platform, refueling grapple and the reactor servicing tools function as designed.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and controls are operable. Required electrical power supply systems are available. The fuel pool or reactor cavity are available to test the fuel grapple. The Reactor Manual Control System is available to test the refueling platform interlocks.

Test Method - The refueling platform travel speed and interlocks with the Reactor Manual Control System are verified. All servicing tools are tried for proper operation. Load tests for the fuel grapple are performed and the fuel grapple is operated at designated speeds. System alarms are verified by operating the controls or simulating the required signals.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

(P83.1A) Main Steam - Nuclear Steam Supply Shutoff System  
-----Preoperational Test-----

Test Objectives - The general objective of this test is to demonstrate the proper operation of the Nuclear Steam Supply Shutoff System. Specific objectives are to demonstrate the following:

- (1) The ability of the Main Steam Isolation Valves (MSIV's) to close on receipt of the appropriate signals.
- (2) The ability of the Main Steam drip leg drains to function properly.
- (3) The ability of the valve isolation logic to function properly.
- (4) The ability of the steam jet air ejector steam supply valves to function properly.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to ISG. Required instruments are calibrated and controls are operable. Required electrical power supply systems, Instrument Air System, and the Containment Instrument Gas System are available.

Test Method - The Main Steam Isolation Valves are exercised and functionally checked for closure by their logic circuit trips, loss of control power and loss of normal air supply using their charged accumulator. The Nuclear Steam Supply Shutoff System isolation logic is tested by verifying it sends appropriate signals to isolate the RHR System, the RWC System and the Main Steam drains. The Main Steam Line Drip Leg Drain Valves and the

Main Steam Line branch valves are functionally checked for proper operation.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

(P83.1B) Main Steam Relief Valves/Automatic Depressurization  
-----System Preoperational Test-----

Test Objectives - To demonstrate the proper operation of the Main Steam Safety Relief Valves to operate correctly in the safety and automatic depressurization modes.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to ISG. Required instruments are calibrated and controls are operable. Required electrical supplies are available and the Containment Instrument Gas System is available.

Test Method - The Automatic Depressurization System is functionally checked for proper in automatic and manual modes. Each Safety/Relief valve is verified operational when any one of its control solenoids is energized. The Remote Shutdown Panel operation is also demonstrated. Valves are also checked for the following: fail close on loss of air, loss of power, and full stroke operation. The acoustic Monitor System is functionally tested to verify proper operation.

Acceptance Criteria - The system performance parameters are in accordance with the applicable documents.

(P83.1C) Main Steam Leakage Control System Preoperational Test

Test Objectives - To demonstrate the proper operation of the Main Steam Isolation Valve Leakage Control System to collect steam lines by operation of its air blowers, heaters, and motor operated valves.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to ISG. Required instruments are calibrated and controls are operable. The required electrical power supply systems are also available.

Test Method - The Main Steam Isolation Valve Leakage Control System interlocks are verified, and the system is initiated manually and checked for proper operation.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

(P83.1D) Main Steam Leak Detection System Preoperational Test

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Test Objectives - To demonstrate the proper operation of the Steam Leak Detection System to monitor area temperatures and give isolation signals to the Nuclear Steam Supply Shutoff system isolation logic.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated, controls are operable, and electrical power supplies are available.

Test Method - The Main Steam Leak Detection System is functionally tested to verify the ability of the area temperature monitors to monitor changes in temperature and to give isolation signals into the Nuclear Steam Supply Shutoff System logic.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

### (P88.1) 250 Volt DC System Preoperational Test

Test Objective - To demonstrate the capability of the 250 volt dc system to provide dc power to connected buses.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and controls are operable. Required electrical power supply systems and a load resistor bank are available. The Battery Room Ventilation system is also available.

Test Method - The system is operated and a load capacity test is conducted for the battery with the battery charger disconnected. Required controls are operated or simulated signals are applied to verify battery charger performance, system interlocks and alarms.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

### (P99.1) Reactor Building Crane Preoperational Test

Test Objective - The general objectives of this test are to demonstrate the following:

- 1) The performance of the reactor building crane's components.
- 2) Establishment of baseline data for all functional components.
- 3) That all warning signals are working per design intent.

- 4) The capability of the crane to operate in a designated area in accordance with design requirements.

Prerequisites - Construction is complete and the system is turned over to the ISG. Required electrical power supply systems are available and controls are operable. Required loads are available to perform load testing of this crane. Construction phase static load testing (125% of rated load) is completed.

Test Method - The lighting system for the crane is energized and observed for proper operation. The bridge and the trolley are speed-tested in both directions. Current and voltage readings are taken in both directions. The proximity switches are tested for both the bridge and the trolley including trolley movement restriction switches in zones A, B, and C.

The main hoist and the auxiliary hoist are speed-tested traveling up and traveling down. Current and voltage readings are taken in both directions. All limit switches are tested. A loss of power situation is created for both hoists to check the brakes ability to hold without power. An overspeed test is simulated for each hoist. The main hoist load limit switch is also tested.

The above listed tests are run from the pendant pushbutton control system. Operability of the crane is also demonstrated from the cab and by radio control. The anticollision system is tested and the crane power source is verified.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

## TP2.23\_\_REACTOR\_BUILDING\_CRANE\_TESTING

### OBJECTIVE:

To supplement load testing of the reactor building overhead crane.

### PREREQUISITES:

Construction is complete to the extent required to perform the test, and the crane is available for service.

### TEST METHOD:

1. Braking capability of the main and auxiliary hoist under rated load is verified (all brakes operational).
2. The ability of each individual main and auxiliary hoist brake to stop and hold rated load while lowering at rated speed is tested.

3. The capability of limiting movement of the main hook to 1/32" and the auxiliary hook to 1/16" in both raise and lower direction at rated load is tested from a complete standstill over an average of ten successive movements.
4. Voltage and current of all crane motors is recorded while running at rated load and rated speed.
5. The capability of the main hoist to limit an uncontrolled drop at rated load and rated speed to less than 1/2" hook movement is verified.
6. Simultaneous bridge and trolley movement at rated load and the ability of the zone proximity switches to restrict crane movement within safe limits is also verified.

#### ACCEPTANCE CRITERIA:

All crane parameters are within design limits.

#### (P100.1) Cold Functional Test

Test Objective - To demonstrate that the plant systems are capable of operating on an integrated basis in normal and emergency modes, to demonstrate that adequate power supplies for the class IE equipment will exist, and to assure that optimum tap settings have been selected for transformers supplying power from offsite sources to class IE busses.

Prerequisites - Required system preoperational tests have been completed and plant systems are ready for operation on an integrated basis.

Test Method - Emergency Core Cooling Systems (RHR & Core Spray) are lined up in their normal standby mode. The plant electrical system is lined up per normal electrical system lineup (For Unit 1 this lineup may be different than the lineup for two unit operation). Loss of coolant accident signals are initiated with and without a loss of offsite power. Voltages and loads are adjusted, as practical, to simulate the anticipated ranges of variations. Proper response of the electrical distribution system, diesel generators, and ECCS pumps will be verified.

Acceptance Criteria - Systems performance parameters are in accordance with the applicable design documents.

#### 14.2.12.2 Startup Test Program Procedure Abstracts

All those tests comprising the Startup Test Program (Table 14.2-3) are discussed in this section. For each test a description is provided for test purpose, test prerequisites, test description and statement of test acceptance criteria, where

applicable. Additions, deletions, and changes to these discussions are expected to occur as the test program progresses. Such modification to these discussions will be reflected in amendments to the PSAR.

In describing the purpose of a test, an attempt is made to identify those operating and safety-oriented characteristics of the plant which are being explored.

Where applicable, a definition of the relevant acceptance criteria for the test is given and is designated either Level 1 or Level 2. A Level 1 criterion normally relates to the value of a process variable assigned in the design of the plant, component systems or associated equipment. If a Level 1 criterion is not satisfied, the plant will be placed in a suitable hold-condition until resolution is obtained. Tests compatible with this hold-condition may be continued. Following resolution, applicable tests must be repeated to verify that the requirements of the Level 1 criterion are now satisfied.

A Level 2 criterion is associated with expectations relating to the performance of systems. If a Level 2 criterion is not satisfied, operating and testing plans would not necessarily be altered. Investigations of the measurements and of the analytical techniques used for the predictions would be started.

For transients involving oscillatory response, the criteria are specified in terms of decay ratio (defined as the ratio of successive maximum amplitudes of the same polarity). The decay ratio must be less than unity to meet a Level 1 criterion and less than 0.25 to meet Level 2.

#### (ST-1) Chemical and Radiochemical

Test Objectives - The principal objectives of this test are a) to secure information on the chemistry and radiochemistry of the reactor coolant, and b) to determine that the sampling equipment, procedures and analytic techniques are adequate to supply the data required to demonstrate that the chemistry of all parts of the entire reactor system meet specifications and process requirements.

Specific objectives of the test program include documentation of radwaste liquid discharge, documentation of baseline piping radiation levels, determination of steam quality, evaluation of the Condensate Polishing system, and evaluation of the Reactor Water Cleanup system. Data for these purposes is secured from a variety of sources: plant operating records, regular routine coolant analysis, radiochemical measurements of specific nuclides, and special chemical tests.

Prerequisites - The required preoperational tests have been completed. Instrumentation has been checked or calibrated as appropriate.

Test Method - Prior to fuel loading, chemical samples are taken to ensure that reactor coolant and Fuel Pool Cooling and Cleanup System sample stations are functioning properly and to determine initial concentrations. Additionally, subsequent to fuel loading, during reactor heatup, and at each major power level change, a complete set of samples are taken to verify that all plant sample stations are functioning properly and to determine the chemical and radiochemical quality of reactor water and reactor feedwater, and performance of filters and demineralizers.

Acceptance Criteria - Level 1 - Chemical factors defined in the Technical Specifications and Fuel Warranty must be maintained within the limits specified. The activity of gaseous and liquid effluents must conform to license limitations. Water quality must be known at all times and should remain within the guidelines of the Water Quality Specifications.

Level 2 - Not applicable.

#### (ST-2) Radiation Measurements

Test Objectives The objectives of this test are (a) to determine the background radiation levels in the plant environs prior to operation for base data on activity buildup and (b) to monitor radiation at selected power levels to assure the protection of personnel during plant operation.

Prerequisites - The required preoperational tests have been completed; the Superintendent of Plant has reviewed and approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

Test Method - A survey of natural background radiation at selected locations throughout the plant will be made prior to fuel loading. Subsequent to fuel loading, during reactor heatup and at power levels of approximately 25%, 60% and 100% of rated power, gamma radiation level measurements and, where appropriate, thermal and fast neutron measurements will be made at selected locations throughout the plant.

Acceptance Criteria - Level 1 - The radiation doses of plant origin and the occupancy times of personnel in radiation zones shall be controlled consistent with the guidelines of the standards for protection against radiation outlined in 10CFR20.

Level 2 - The radiation doses of plant origin shall meet the following limits depending upon which Radiation Zone the radiation base survey point is located:



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Radiation_Zone	Limit
I	0.5 mRem/hr.
II	2.5 mRem/hr.
III	15 mRem/hr.
IV	100 mRem/hr.

Note: All areas designated Radiation Zone V have potential radiation doses of 100 mRem/hr. Readings taken in Zone V during the Startup Test Program may be less than 100 mRem/hr; however, since Zone V is defined in terms of potential levels, there are no Acceptance Criteria for Zone V base survey points.

## (ST-3)\_\_\_Fuel>Loading

Test Objective - The objective of this test is to achieve the full and proper core complement of nuclear fuel assemblies through a safe and efficient fuel loading evolution.

Prerequisites - The required Preoperational Tests have been completed. In addition, prior to starting this test procedure, the following prerequisites will be met:

- a. Fuel and Control Rod inspections will be complete.
- b. Control Rods will be installed and tested.
- c. Reactor vessel water level will be established and minimum level prescribed.
- d. The standby liquid control system will be operable and in readiness.
- e. Fuel handling equipment will have been checked and dry runs completed.
- f. The status of protection systems, interlocks, mode switches, alarms, and radiation protection equipment will be prescribed and verified.
- g. Water quality must meet required specifications.

The following prerequisites will be met prior to commencing actual fuel loading to assure that this operation is performed in a safe manner:

- a. The status of all systems required for fuel loading will be specified and will be in the status required.
- b. At least three movable neutron detectors will be calibrated and operable. At least three neutron detectors will be connected to the high flux scram trips. They will be

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located so as to provide acceptable signals during fuel loading.

- c. Source range monitoring Nuclear instruments will be checked with a neutron source prior to fuel loading or resumption of fuel loading if sufficient delays are incurred.
- d. The status of secondary containment will be specified and established.
- e. Reactor vessel status will be specified relative to internal component placement and this placement established to make the vessel ready to receive fuel.
- f. The high flux trip points will be set for a relatively low power level.
- g. Neutron sources will be installed near the center of the core and at other specified locations.

Test Method - Before the first fuel assembly is taken from the fuel pool and inserted into the reactor, core components (fuel support castings, blade guides, control rod drives, etc.) will be installed, tested and/or verified. This procedure begins with the steps required to assemble and load neutron sources, includes the activities necessary to monitor neutron population using specially constructed fuel loading chambers (FLCs), and culminates with the insertion of fuel assemblies into the reactor core. Fuel loading continues until the core is fully loaded, verified and ready to perform subsequent Startup Tests.

Control rod functional tests, subcriticality checks, and shutdown margin demonstrations will be performed periodically during the loading.

Acceptance Criteria - Level 1 - The partially loaded core must be subcritical by at least  $0.38\% \Delta k/k$  with the analytically determined, highest worth rod fully withdrawn.

### (ST-4) Full Core Shutdown Margin

Test Objective - The purpose of this test is to demonstrate that the reactor will be subcritical throughout the first fuel cycle with any single control rod fully withdrawn.

Prerequisites - The following prerequisites will be complete prior to performing the full core shutdown margin test:

- a) The predicted critical rod position is available
- b) The Standby Liquid Control System is available

- c) Nuclear instrumentation is available with neutron count rate of at least three counts per second and signal to noise ratio greater than two to one
- d) High-flux scram trips are set conservatively low
- e) Instrumentation has been checked or calibrated as appropriate

Test Method - This test will be performed in the fully loaded core in the xenon-free condition. The shutdown margin test will be performed by withdrawing the control rods from the all-rods-in configuration until criticality is reached. If the highest worth rod will not be withdrawn in sequence, other rods may be withdrawn providing that the reactivity worth is equivalent. The difference between the measured  $K_{eff}$  and the calculated  $K_{eff}$  for the in-sequence critical will be applied to the calculated value to obtain the true shutdown margin.

Acceptance Criteria - Level 1 - The shutdown margin of the fully loaded, cold (68°F), xenon-free core occurring at the most reactive time during the cycle must be at least  $0.38\% \Delta k/k$  with the analytically strongest rod (or its reactivity equivalent) withdrawn. If the shutdown margin is measured at some time during the cycle other than the most reactive time, compliance with the above criterion is shown by demonstrating that the shutdown margin is  $0.38\% \Delta k/k$  plus an exposure dependent correction factor which corrects the shutdown margin at that time to the minimum shutdown margin.

Level 2 - Criticality should occur within  $\pm 1.0\% \Delta k/k$  of the predicted critical.

#### (ST-5) Control Rod Drive System

Test Objective - The objectives of the Control Rod Drive System test are; a) to demonstrate that the Control Rod Drive (CRD) System operates properly over the full range of primary coolant temperatures and pressures from ambient to operating, and b) to determine the initial operating characteristics of the entire CRD System.

Prerequisites - The required preoperational tests have been completed.

Test Method - The CRD tests performed during the startup test program are designed as an extension of the tests performed during the preoperational CRD system tests. Thus, after it is verified that all control rod drives operate properly when installed, they are tested periodically during heatup to assure that there is no significant binding caused by thermal expansion

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of the core components. A list of all control rod drive tests to be performed during startup testing is given in Table 14.2-5.

Acceptance Criteria - Level 1 - Each CRD must have a normal withdraw time greater than or equal to 40 seconds.

The mean scram time of all operable CRDs must not exceed the values specified in the plant technical specifications. (Scram time is measured from the time the pilot scram valve solenoids are deenergized.)

The mean scram time of the three fastest CRDs in a two by two array must not exceed the values specified in the plant technical specifications. (Scram time is measured from the time the pilot scram solenoids are deenergized)

Level 2 - Each CRD must have a normal insert speed of  $3.0 \pm 0.6$  inches per second, indicated by a full 12-foot stroke in 40 to 60 seconds. With respect to the control rod drive friction tests, if the differential pressure variation exceeds 15 psid for a continuous drive in, a settling test must be performed, in which case, the differential settling pressure should not be less than 30 psid nor should it vary by more than 10 psid over a full stroke.

### (ST-6) SRM Performance and Control Rod Sequence

Test Objectives - The objective of this test is to demonstrate that the operational sources, SRM instrumentation, and rod withdrawal sequences provide adequate information to achieve criticality and increase power in a safe and efficient manner for each of the specified rod withdrawal sequences.

Prerequisites - The required preoperational tests have been completed.

Test Method - The operational neutron sources will be installed and source range monitor count-rate data will be taken during rod withdrawals to critical and compared with stated criteria on signal and signal count-to-noise count ratio.

A withdrawal sequence has been calculated which completely specifies control rod withdrawals from the all-rods-in condition to the rated power configuration. Each sequence will be used to attain cold criticality.

Movement of rods in a prescribed sequence is monitored by the Rod Worth Minimizer and rod sequence control system, which will prevent out of sequence withdrawal.

Acceptance Criteria - Level 1 - There must be a neutron signal count-to-noise count ratio of at least 2 to 1 on the required

operable SRMs. There must be a minimum count rate of 3 counts/second on the required operable SRMs.

The IRMs must be on scale before the SRMs exceed the rod block set point.

#### (ST-7) Reactor Water Cleanup System

Test Objectives - The objective of this test is to demonstrate specific aspects of the mechanical operability of the Reactor Water Cleanup System. (This test, performed at rated reactor pressure and temperature, is actually the completion of the preoperational testing that could not be done without nuclear heating).

Prerequisites - The required preoperational tests have been completed. Instrumentation has been checked or calibrated as appropriate.

Test Method - With the reactor at rated temperature and pressure, process variables will be recorded during steady state operation in three modes as defined by the System Process Diagram: Blowdown, Hot Standby, and Normal. Additional system configurations will also be aligned to verify proper performance of the bottom head flow and temperature indicators.

Acceptance Criteria - Level 1 - Not applicable.

Level 2 - The temperature at the tube side outlet of the non-regenerative heat exchangers (NRHX) shall not exceed 130°F in the blowdown mode and 120°F in the normal mode.

The pump available NPSH will be 13 feet or greater during the hot standby mode defined in the process diagrams.

The cooling water flow to the NRHX's shall be limited to 6% above the flow corresponding to the heat exchanger capacity (as determined from the process diagram) and the existing temperature differential across the heat exchangers. The cooling water outlet temperature shall not exceed 180°F.

During two pump operations at rated core flow, the bottom head temperature as measured by the bottom drain line thermocouple should be within 30°F of the recirculation loop temperatures.

Bottom head flow indicator FI-1R610 shall indicate within 25 gpm of RWCU flow indicator FI-R609 when total system flow is thru the bottom head drain.

#### (ST-8) Residual Heat Removal System

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Test Objectives - The objectives of this test are to demonstrate the ability of the Residual Heat Removal (RHR) System to: 1) remove heat from the reactor system so that the refueling and nuclear system servicing can be performed and 2) condense steam while the reactor is isolated from the main condenser.

Prerequisites - The required preoperational tests have been completed. Instrumentation has been checked or calibrated as appropriate.

Test Method - The suppression pool cooling mode and shutdown cooling mode will be used to measure the RHR heat exchanger capacity. Data will be obtained to determine the heat transfer rate with rated flow on both sides of the heat exchanger. For the suppression pool cooling mode test, attempts will be made to establish a large temperature differential between the service and suppression pool water by extended RCIC or relief valve operations. (An ideal demonstration of the RHR heat exchanger capacity would consist of measuring the heat transfer rate in the shutdown cooling mode with the reactor at 50 psig or less. Unfortunately, the decay heat load is insignificant during the startup test period. Use of this mode with low core exposure results in exceeding the 100°F/hr cooldown rate of the vessel.) The shutdown cooling mode will be demonstrated after a trip or a cooldown from Test Condition 6.

The RHR system steam condensing mode is used to condense steam while the reactor is isolated from the main condenser and reactor vessel water level is being maintained by RCIC. This test will demonstrate system operability and stability.

Acceptance Criteria - Level 1 - The transient response of any system-related variable to any test input must not diverge.

Level 2 - The RHR system shall be capable of operating in the steam condensing, suppression pool cooling and shutdown cooling modes at the heat exchanger capacities indicated on the process diagrams. Both simultaneous operation of RHR loops and single loop operation shall be tested in the steam condensing and shutdown cooling modes. Each RHR loop shall be tested independently in the suppression pool cooling mode. System-related variables may contain oscillatory modes of response. In these cases, the decay ratio for each controlled mode of response must be less than or equal to 0.25.

The time to place the RHR heat exchangers in the steam condensing mode with the RCIC using the heat exchanger condensate flow for suction shall average one half hour or less.

(ST-9) Water Level Measurement

Test Objectives - The objective of this test is to determine actual reference leg temperature and recalibrate instruments if necessary.

Prerequisites - The required preoperational tests have been completed. All system instrumentation is installed and calibrated.

Test Method - At rated temperature and pressure under steady state conditions, the reference leg temperature will be measured and compared to the value assumed during initial calibration. If the difference of the two temperatures exceed the Acceptance Criteria, then the instruments will be recalibrated using the measured value.

Acceptance Criteria - Level 1 - Not applicable.

Level 2 - The difference between the actual reference leg temperature(s) and the value(s) assumed during calibration shall be less than that amount which will result in a scale end point error of 1% of the instrument span for each range.

#### (ST-10) - IRM Performance

Test Objectives - The objective of this test is to adjust the Intermediate Range Monitor System to obtain the desired overlap with the SRM and APRM systems.

Prerequisites - The required preoperational tests have been completed.

Test Method - Initially the IRM system is set during the Preoperational Test Program. SRM-IRM and IRM-APRM overlap is verified the first time sufficient neutron flux conditions arise. After the APRM calibration, the IRM gains will be adjusted as necessary to optimize the IRM overlap with the SRMs and APRMs.

Acceptance Criteria - Level 1 - Each IRM channel must be adjusted so that overlap with the SRMs and APRMs is assured.

#### (ST-11) - LPRM Calibration

Test Objectives - The objective of this test is to calibrate the Local Power Range Monitoring System.

Prerequisites - The required preoperational tests have been completed. Instrumentation for calibration has been checked.

Test Method - The LPRM channels will be calibrated to make the LPRM readings proportional to the neutron flux in the water gap at the chamber elevation. Prior to this calibration, LPRM

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response to control rod movement is verified. Calibration factors will be obtained through the use of either an off-line or a process computer calculation that relates the LPRM reading to average fuel assembly power at the chamber height.

Acceptance Criteria - Level 1 - Not applicable.

Level 2 - Each LPRM will be within 10% of its calculated value.

### (ST-12) APRM Calibration

Test Objective - The objective of this test is to calibrate the Average Power Range Monitoring (APRM) system.

Prerequisites - The required preoperational tests have been completed. Instrumentation for calibration has been checked.

Test Method - A heat balance will be made after initially achieving power level associated with each test plateau. Each APRM channel reading will be adjusted to be consistent with the core thermal power as determined from the heat balance. During heatup a preliminary calibration will be made by adjusting the APRM amplifier gains so that the APRM readings agree with the results of a constant heatup rate heat balance. The APRMs should be recalibrated in the power range by a heat balance as soon as adequate feedwater indication is available.

Acceptance Criteria - Level 1 - The APRM channels must be calibrated to read equal to or greater than the actual core thermal power.

Level 2 - Not applicable.

### (ST-13) NSSS Process Computer

Test Objective - The objective of this test is to verify the NSSS performance of the process computer under plant operating conditions.

Prerequisites - The required preoperational tests have been completed.

Test Method - The Dynamic System Test Case will be run to verify that the results of NSSS performance calculations are correct.

Acceptance Criteria - Level 1 - Not applicable.

Level 2 -

- (1) The MCPR calculated by an independent method and the process computer either:



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- a. Are in the same fuel assembly and do not differ in value by more than 2% or,
  - b. For the case in which the MCPR calculated by the process computer is in a different assembly than that calculated by the independent method, for both assemblies, the MCPR and CPR calculated by the two methods shall agree within 2% for the same assembly.
- (2) The maximum LHGR calculated by the independent method and the process computer either:
- a. Are in the same fuel assembly and do not differ in value by more than 2%, or
  - b. For the case in which the maximum LHGR calculated by the process computer is in a different assembly than that calculated by the independent method, for both assemblies, the maximum LHGR and LHGR calculated by the two methods shall agree within 2% for the same assembly.
- (3) The MAPLHGR calculated by the independent method and the process computer either:
- a. Are in the same fuel assembly and do not differ in value by more than 2%, or
  - b. For the case in which the MAPLHGR calculated by the process computer is in a different assembly than that calculated by the independent method for both assemblies, the MAPLHGR and APLHGR calculated by the two methods shall agree within 2% for the same assembly.
- (4) The LPRM calibration factors calculated by the independent method and the process computer agree to within 2%.

### (ST-14) RCIC System

Test Objective - The objectives of this test are to verify the proper operation of the Reactor Core Isolation Cooling (RCIC) system at the minimum and rated operating pressures and flow ranges, and to demonstrate reliability in automatic mode starting from cold standby when the reactor is at power conditions.

Prerequisites - The required preoperational tests have been completed. Initial turbine operation (uncoupled) must have been performed to verify satisfactory operation and over-speed trip. Instrumentation has been installed and calibrated.

Test Method - The RCIC System is designed to be tested in two ways: (1) by flow injection into a test line leading to the Condensate Storage Tank (CST), and (2) by flow injection directly into the reactor vessel.

The earlier set of CST injection tests consist of manual and automatic mode starts at approximately 150 psig and near rated reactor pressure conditions. The pump discharge pressure during these tests is throttled to be approximately 100 psi above the reactor pressure to simulate the largest expected pipeline pressure drop. This CST testing is done to demonstrate general system operability and stability.

Reactor vessel injection tests are also done which consist of manual and automatic mode starts near rated reactor pressure and automatic mode start at approximately 150 psig reactor pressure conditions to demonstrate operability and stability.

After all final controller and system adjustments have been determined, a defined set of demonstration tests must be performed with that one set of adjustments. Two consecutive reactor vessel injections starting from cold conditions in the automatic mode must satisfactorily be performed to demonstrate system reliability. Following these tests, a set of CST injections starting from cold conditions in the automatic mode are done to provide a benchmark for comparison with future surveillance tests. ("Cold" is defined as a minimum three days without any kind of RCIC operation.)

After the manual start portion of certain of the above tests is completed, and while the system is still operating, small step disturbances in speed and flow command are input (in manual and automatic mode respectively) in order to demonstrate satisfactory stability. This is to be done at both low (above minimum turbine speed) and near rated flow initial conditions to span the RCIC operating range. During testing at 150 psig, this is done only near rated flow initial conditions.

A demonstration of extended operation of up to 2 hours (or until pump and turbine oil temperature is stabilized) of continuous running at rated flow conditions is to be scheduled at a convenient time during the Startup test program.

Acceptance Criteria - Level 1 - The average pump discharge flow must be equal to or greater than the 100% rated value in 30 seconds or less from automatic initiation at any reactor pressure between 150 psig (+15, -0) (10.5 kg/cm<sup>2</sup>) and rated.

The RCIC turbine shall not trip or isolate during auto or manual start tests.

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Note: If any Level 1 criteria are not met, the reactor will only be allowed to operate up to a restricted power level defined by Figure 14.2-7 until the problem is resolved. Also consult the plant Technical Specifications for actions to be taken.

Level 2 - In order to provide an overspeed and isolation trip avoidance margin, the transient start first and subsequent speed peaks shall not exceed 5% above the rated RCIC turbine speed.

The speed and flow control loops shall be adjusted so that the decay ratio of any RCIC system related variable is not greater than 0.25.

The turbine gland seal condenser system shall be capable of preventing steam leakage to the atmosphere.

The delta P switch for the RCIC steam supply line high flow isolation trip shall be calibrated to a differential pressure corresponding to less than or equal to 300% of the maximum required steady state flow, with the reactor assumed to be near the pressure for main relief valve actuation.

### (ST-15) HPCI System

Test Objective - The objective of this test is to verify the proper operation of the High Pressure Coolant Injection (HPCI) system at the minimum and rated operating pressures and flow ranges, and to demonstrate reliability in automatic mode starting from cold standby when the reactor is at rated pressure conditions.

Prerequisites - The required preoperational tests have been completed. Initial turbine operation (uncoupled) must have been performed to verify satisfactory operation and over-speed trip. Instrumentation has been installed and calibrated.

Test Method - The HPCI system is designed to be tested in two ways: (1) by flow injection into a test line leading to the Condensate Storage Tank (CST), and (2) by flow injection directly into the reactor vessel.

The earlier set of CST injection tests consist of manual and automatic mode starts at approximately 150 psia and near rated reactor pressure conditions. The pump discharge pressure during these tests is throttled to be approximately 100 psi above the reactor pressure to simulate the largest expected pipeline pressure drop. This CST testing is done to demonstrate general system operability and stability.

Reactor vessel injection tests are also done which consist of manual and automatic mode start near rated reactor pressure to demonstrate operability and stability.

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After all final controller and system adjustments have been determined, a defined set of demonstration tests must be performed with that one set of adjustments. Two consecutive reactor vessel injections starting from cold conditions in the automatic mode must satisfactorily be performed to demonstrate system reliability. Following these tests, a set of CST injections starting from cold conditions in the automatic mode ("cold" is defined to a minimum three days without any kind of HPCI operation) are done to provide a benchmark for comparison with future surveillance tests.

After the manual start portion of certain of the above tests is completed, and while the system is still operating, small step disturbances in speed and flow command are input (in manual and automatic mode respectively) in order to demonstrate satisfactory stability. This is to be done at both low (above minimum turbine speed) and near rated flow initial conditions to span the HPCI operating range. During testing at 150 psig this is done only near rated flow initial conditions.

A continuous running test is to be scheduled at a convenient time during the Startup Test Program. This demonstration of extended operation should be for up to 2 hours or until steady turbine and pump conditions are reached or until limits on plant operation are encountered.

Pump flow testing will also be verified since auxiliary boiler supply is insufficient to fully test the system during the Preoperational Test Program.

Acceptance Criteria - Level 1 - The average pump discharge flow must be equal to or greater than the 100% rated value in 25 seconds or less from automatic initiation at any reactor pressure between 150 psig (+15, -0) (10.5 kg/cm<sup>2</sup>) and rated.

The HPCI turbine shall not trip or isolate during auto or manual start tests.

Level 2 - In order to provide an overspeed and isolation trip avoidance margin, the transient start first peak shall not come closer than 15% (of rated speed) to the overspeed trip, and subsequent speed peaks shall not be greater than 5% above rated turbine speed.

The speed and flow control loops shall be adjusted so that the decay ratio of any HPCI system related variable is not greater than 0.25.

The turbine gland seal condenser system shall be capable of preventing steam leakage to the atmosphere.

The delta-P switch for the HPCI steam supply line high flow isolation trip shall be calibrated to actuate at no greater than 300% of the maximum required steady state flow, with the reactor assumed to be near the pressure for main relief valve actuation.

(ST-16) Selected Process Temperatures

Test Objectives - The objective of this procedure is to establish the proper setting of the low speed limiter for the recirculation pumps to avoid coolant temperature stratification in the reactor pressure vessel bottom head region.

Prerequisites - The required preoperational tests have been completed. System instrumentation has been calibrated.

Test Method - During initial heatup while at hot standby conditions, the bottom drain line temperature, recirculation loop suction temperature and applicable reactor parameters are monitored as the recirculation flow is slowly lowered to minimum stable flow. Utilizing this data it can be determined whether coolant temperature stratification occurs when the recirculation pumps are on and if so, what minimum recirculation flow will prevent it.

Monitoring the preceding information during planned pump trips will determine if temperature stratification occurs in the idle recirculation loops or in the lower plenum when one or more loops are inactive.

Acceptance Criteria - Level 1 - The reactor recirculation pumps shall not be started nor flow increased unless the coolant temperatures between the steam dome and bottom head drain are within 145°F.

The recirculation pump in an idle loop must not be started unless the loop suction temperature is within 50°F of the active loop.

Level 2 - Not Applicable.

(ST-17) System Expansion

Test Objectives - The purposes of this test are to demonstrate that reactor recirculation, main steam inside containment, and those piping systems identified in Table 3.9-33 respond to thermal expansion consistent with stress analysis results. (Note that this test now includes piping previously contained in ST-38.)

Prerequisites - Instrumentation has been installed and calibrated.

Test Method - Hanger positions of major equipment and piping in the Nuclear Steam Supply System and auxiliary systems in the reactor drywell are recorded prior to initial heatup and after a planned cold shutdown. During initial heatup, a visual inspection is made at an intermediate reactor water temperature to assure components are free to move as designed. Adjustments are made as necessary. Devices for measuring continuous pipe deflections are mounted on main steam, recirculation and other selected lines. Motion during heatup is compared with calculated values.

Acceptance Criteria - Level 1 - There shall be no obstructions which will interfere with the thermal expansion of the main steam and recirculation piping systems. Piping systems identified in Table 3.9-33 will not be restrained against thermal expansion except by design intent.

The measured displacements at the established transducer locations on the main steam and recirculation systems shall not exceed the allowable values calculated for the specific points.

Level 2 - The measured displacements at the established transducer locations on the main steam and recirculation systems shall not exceed the expected values calculated for the specific points. The measured displacements at the established transducer locations on the piping systems identified in Table 3.9-33 shall be within the acceptable range calculated for the specific points.

#### (ST-18) - TIP Uncertainty

Test Objectives - The objective of this test is to determine the uncertainty of the TIP system readings.

Prerequisites - System installation completed and required preoperational tests completed and verified. Instrumentation has been calibrated and installed.

Test Method - The TIP uncertainty consists of a random noise component and a geometric component, the geometric component being due to variation in the water gap geometry and TIP tube orientation from TIP location to location. Measurement of these components is obtained by taking repetitive TIP readings at a single TIP location, and by analyzing pairs of TIP readings taken at TIP locations which are symmetrical about the core diagonal of fuel loading and control rod symmetry.

The random noise uncertainty is determined from successive TIP runs made at the common location (32-33) with each of the TIP machines making six runs at index position 10. The TIP data will be obtained by simultaneous operation of the Process computer OD-

2 program which provides 24 nodal TIP values for each TIP traverse. The standard deviation of the random noise is derived by taking the square root of the average of the variances at nodal levels 5 through 22, where the nodal variance is obtained from the fractional deviations of the successive TIP values about their nodal mean value.

The total TIP uncertainty is determined by performing a complete set of TIP traverses as required by Process Computer program OD-1. The total TIP uncertainty is obtained by dividing the standard deviation of the symmetric TIP pair nodal ratios by the square root of 2. The nodal TIP ratio is defined as the nodal BASE value of the TIP in the lower right half of the core divided by its symmetric counterpart in the upper left half.

The geometric component of TIP uncertainty is obtained by statistically subtracting the random noise component from the total TIP uncertainty.

The TIP data will be taken with the reactor operating with an octant symmetric rod pattern and at steady state conditions. One set of TIP data will be taken at approximately 50% power and at least one other set at 75% power or above. The acceptance criteria for this subtest uses the "average uncertainties" for all data sets. Therefore additional performance of the subtest may be scheduled and the previous values of uncertainty will be used in the averaging to determine the acceptability of the results.

Acceptance Criteria - Level 1 - Not applicable.

Level 2 - The total TIP uncertainty (including random noise and geometrical uncertainties) obtained by averaging the uncertainties for all data sets must be less than 6.0%.

NOTE: A minimum of two and up to six data sets may be used to meet the above criteria.

#### (ST-19) Core Performance

Test Objectives - The objectives of this test are a) to evaluate the core thermal power and b) to evaluate the following core performance parameters: 1) maximum linear heat generation rate (MLHGR), 2) minimum critical power ratio (MCPR) and 3) maximum average planar linear heat generation rate (MAPLHGR).

Prerequisites - The required preoperational tests have been completed.

Test Method - The core performance evaluation is employed to determine the principal thermal and hydraulic parameters associated with core behavior. These parameters are:

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Core flow rate

Core thermal power level

MLHGR

MCPR

MAPLHGR

Prior to the verification of the Process Computer in ST-13, an independent method will be used to calculate these parameters. After the successful completion of ST-13, the process computer will be used.

Acceptance Criteria - Level 1 - The Maximum Linear Heat Generation Rate (MLHGR) of any rod during steady-state conditions shall not exceed the limit specified by the Plant Technical Specifications.

The steady-state Minimum Critical Power Ratio (MCPR) shall not exceed the limits specified by the Plant Technical Specifications.

The Maximum Average Planar Linear Heat Generation Rate (MAPLHGR) shall not exceed the limits specified by the Plant Technical Specifications.

Steady-state reactor power shall be limited to the rated MWT and values on or below the licensed analytically determined power-flow line.

Level 2 - Not applicable.

### (ST-20) - Steam Production Verification

Test Objective - The objective of this test is to demonstrate that the NSSS is providing steam sufficient to satisfy all appropriate warranties.

Prerequisites - Required preoperational tests have been completed. All required instrumentation is installed and calibrated.

Test Method - A NSSS steam output performance test of 100 hours of continuous operation at the warranted steam output will be performed.

Acceptance Criteria - Level 1 - The NSSS parameters as determined by using normal operating procedures shall be within the appropriate license restrictions. Each NSSS shall be capable of supplying 13,432,000 pounds per hour of steam of not less than



99.7% quality at a pressure of 985 psia at the outlet of the second main steam line isolation valve, as based upon a final feedwater temperature of 380°F, measured as near the reactor pressure vessel as practicable, and a control rod drive feed flow of 39,000 pounds per hour at 80°F. The reactor feedwater flow must equal the steam flow less the rod drive feed flow. Thermal-dynamic parameters are consistent with 1967 ASME Steam tables. Correction techniques for conditions that differ from the preceeding will be mutually agreed to prior to the performance of the test.

Level\_2 - Not applicable.

(ST-21)\_\_\_Core\_Power-Void\_Mode\_Response

Test Objectives - The objective of this test is to verify the stability of the core power-void dynamic response.

Prerequisites - The required preoperational tests have been completed. Instrumentation has been calibrated.

Test Method - The core power void loop mode that results from a combination of the neutron kinetics and core thermal hydraulic dynamics is least stable near the natural circulation end of the rated 100 percent power rod line. A fast change in the reactivity balance is obtained by moving a very high worth rod only 1 or 2 notches and by simulating a failure of the pressure regulator.

Acceptance Criteria - Level 1 - The transient response of any system related variable to any test input must not diverge.

Level\_2 - Not applicable.

(ST-22)\_\_\_Pressure\_Regulator

Test Objectives - The objectives of this test are to demonstrate the takeover capability of the backup pressure regulator upon failure of the controlling pressure regulator and to demonstrate smooth pressure control transition between the control valves and bypass valves when reactor steam generation exceeds steam flow used by the turbine.

Prerequisites - The required preoperational tests have been completed. Instrumentation has been checked or calibrated as appropriate.

Test Method - The pressure set point will be decreased rapidly and later increased rapidly by about 10 psi and the response of the system will be measured in each case. It is desirable to accomplish the set point change in less than 1 second. At specified test conditions the load limit setpoint will be set so

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that the transient is handled by control valves, bypass valves and both. The backup regulator will be tested by simulating a failure of the operating pressure regulator so that the backup regulator takes over control. The response of the system will be measured and evaluated.

Acceptance Criteria - Level 1 - The transient response of any pressure control system related variable to any test input must not diverge.

### Level 2

- a) Pressure control system related variables may contain oscillatory modes of response. In these cases, the decay ratio for each controlled mode of response must be less than or equal to 0.25 when operating above lower limit of the automatic load following range.
- b) When in the recirculation manual mode, the pressure response time from initiation of pressure setpoint step change to the turbine inlet pressure peak shall be  $\leq 10$  seconds.
- c) Pressure control system deadband, delay, etc., shall be small enough that steady state limit cycles (if any) shall produce steam flow variations no larger than  $\pm 0.5$  percent of rated steam flow.
- d) The normal difference between regulator set points must be small enough that the peak neutron flux and/or peak vessel pressure remain below the scram settings by 7.5 percent and 10 psi respectively, for the Regulator Failure Test performed at Test Condition 6.

### (ST-23) Feedwater System

Test Objectives - The objectives of this test are a) to demonstrate acceptable response to the feedwater control system for reactor water level control, b) to demonstrate stable reactor response to subcooling changes, i.e., loss of feedwater heating, c) to demonstrate the capability of the automatic core flow runback feature to prevent low water level scram following the trip of one feedwater pump, and d) to demonstrate the maximum feedpump runout capability is compatible with licensing assumptions.

Prerequisites - The required preoperational tests have been completed. Instrumentation has been checked or calibrated as appropriate.

Test Method - At Test Condition (TC) 1 with the water level being automatically controlled using the low load valve and the

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recirculation system in Manual,  $\pm 5$  inch step changes in the water level setpoint will be made to demonstrate proper response and operability of the feedwater system at low reactor power.

At Test Conditions 2, 3 and 6, with one feedwater pump in manual and the others in auto, a  $\pm 5\%$  change in the manually controlled feed pump will be made. The response of the feedwater system to these steps will be analyzed and compared to the applicable acceptance criteria. The recirculation system will be in manual for these tests. At Test Conditions 1, 2, 3, 4, 5 & 6, with the recirculation system in manual,  $\pm 5$  inch changes in the water level setpoint will be made to demonstrate proper response and stability of the feedwater system. At TC 6, this test will also be done with the recirculation system in auto.

At approximately 80% power, a simulated loss of power to the extraction steam bleeder-trip valves will be initiated which will result in the most severe restriction of extraction steam to one feedwater heater string. Recordings of the transient will be as analyzed and compared to the predicted response and acceptance criteria.

At Test Condition 6, one feedwater pump will be tripped to demonstrate the capability to avoid a scram and prevent a low reactor water level trip due to the loss of one feedwater pump.

A maximum feedwater runout capability test will be done to demonstrate that the actual capability is compatible with licensing assumptions.

Acceptance Criteria - Level 1 - The transient response of any level control system-related variable to any test input must not diverge.

For the feedwater heater loss test, the maximum feedwater temperature decrease due to a single failure case must be less than or equal to  $100^{\circ}\text{F}$ . The resultant MCPR must be greater than the fuel thermal safety limit.

The increase in heat flux cannot exceed the predicted Level 2 value by more than 2%. The predicted value will be based on the actual test values of feedwater temperature change and power level.

The feedwater flow runout capability must not exceed the assumed value in the FSAR.

Level 2 - Level control system-related variables may contain oscillatory modes of response. In these cases, the decay ratio for each controlled mode of response must be less than or equal to 0.25.

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The open loop dynamic flow response of each feedwater actuator (turbine or valve) to small ( $\leq 10\%$ ) step disturbances shall be:

- |  |             |
|--|-------------|
| (1) Maximum time to 10% of a step disturbance          | 1.1 sec.    |
| (2) Maximum time from 10% to 90% of a step disturbance | 1.9 sec.    |
| (3) Peak overshoot (% of step disturbance)             | $\leq 15\%$ |

The average rate of response of the feedwater actuator to large ( $\geq 20\%$  of pump flow) step disturbances shall be between 10 percent and 25 percent rated feedwater flow/second. This average response rate will be assessed by determining the time required to pass linearly through the 10 percent and 90 percent response points.

The increase in heat flux cannot exceed the predicted value referenced to the actual Feedwater temperature change and the initial power level.

A scram must be avoided from low water level with at least a 3 inch margin following a trip of one of the operating feedwater pumps.

### (ST-24) Turbine Valve Surveillance

Test Objectives - The objective of this test is to demonstrate acceptable procedures and maximum power levels for periodic surveillance testing of the main turbine control, stop, intercept and bypass valves without producing a reactor scram.

Prerequisites - The required preoperational tests have been completed. Instrumentation has been checked or calibrated as appropriate.

Test Method - Starting at 45 to 65% power, and continuing at progressively higher power levels, each turbine control, main stop and intermediate stop valve will be closed individually and the response of the reactor will be observed. The margin to scram for reactor pressure and neutron flux and the margin to main steam line isolation will be plotted for each tested power level. These plots will be used to determine the maximum power level at which turbine valve surveillance testing can be performed. The test of the control, main stop, intermediate stop and bypass valves are performed near the predicted highest power level to demonstrate that the Acceptance Criteria are satisfied. Rate of valve stroking and timing of the close-open sequence will be such that minimum practical disturbance is introduced and that PCIOMR limits are not exceeded.

Acceptance Criteria - Level 1 - Not applicable.

Level 2 - Peak neutron flux must remain at least 7.5% below the Neutron flux scram trip value. Peak vessel pressure must remain

at least 10 psi below the high pressure scram setting. Peak steam flow in each line must remain at least 10% below the high flow isolation trip setting. Peak simulated heat flux must remain at least 5% below its scram trip point.

#### (ST-25) Main Steam Isolation Valves

Test Objectives - The objectives of this test are (a) to functionally check the main steam isolation valves (MSIVs) for proper operation at selected power levels, (b) to determine reactor transient behavior during and following simultaneous full closure of all MSIVs, (c) to determine isolation valve closure time and (d) to determine the maximum power at which a single valve closure can be made without a scram.

Prerequisites - The required preoperational tests have been completed. Instrumentation has been checked or calibrated as appropriate.

Test Method - The Main Steam Isolation Valves (MSIVs) are operated during this test to verify their functional performance and to determine closure times. While functionally testing the operation of the MSIVs, the time necessary for closing each individual valve will be noted. The fastest MSIV will then be tested to determine what power level an MSIV can experience fast closure without causing a scram. All MSIVs will later be used to demonstrate a full isolation subsequently leading to a scram. (The Nuclear Steam Supply Shutoff System (NSSS) logic will be used to initiate the full isolation). The acceptability of the fast criteria (3 seconds) is determined by utilizing the full stroke time without delay extrapolated from measured stroke times between 10% closed and 90% closed. The acceptability of the slow criteria (5 seconds) is determined by utilizing the full stroke time with delay extrapolated for the final 10% of stroke.

#### Acceptance Criteria - Level 1

The positive change in vessel dome pressure occurring within 30 seconds after closure of all MSIVs must not exceed predicted values by more than 25 psi.

The positive change in heat flux following closure of all MSIVs shall not exceed predicted values by more than 2% of rated value.

Following the closure of all MSIV's, the reactor must scram.

The average of the closure times for the fastest MSIV in each steam line, exclusive of delay, shall not be less than 3.0 seconds.

Closure time for any MSIV, including delay, shall not be greater than 5.0 seconds.

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Closure time for the fastest MSIV shall be greater than or equal to 2.5 seconds.

Feedwater control settings must prevent flooding the main steam lines during the full isolation test.

The time delay between the close initiation signal and the extrapolated initial valve movement from 100% open for any MSIV shall be less than or equal to 0.5 seconds.

Level\_2 - The positive change in vessel dome pressure occurring within the first 30 seconds after the closure of all MSIVs must not exceed the predicted values. Predicted values will be referenced to actual test conditions of initial power level, scram timing and dome pressure and will use beginning of life nuclear data.

The positive change in heat flux occurring within the first 30 seconds after the closure of all MSIVs must not exceed the predicted values. Predicted values will be referenced to actual test conditions of initial power level, and dome pressure and will use beginning of life nuclear data.

If water level reaches Level 2 setpoint during the MSIV full closure test, RCIC shall automatically initiate and reach rated flow.

During the MSIV full closure test, the relief valves must reclose properly (without any detectable leakage) following the pressure transient.

During full closure of individual MSIVs, peak vessel dome pressure must remain at least 10 psi below the flow biased scram setting value.

During full closure of individual MSIVs, peak neutron flux must remain at least 7.5% below its scram value.

During full closure of individual MSIVs, steam flow in individual lines must remain at least 10% below the high flow isolation trip setting.

During full closure of individual MSIVs, the peak simulated heat flux must remain at least 5% less than its scram value.

### (ST-26) Relief Valves

Test Objectives - The objectives of this test are to verify that the relief valves function properly, reseal properly after operation and contain no major blockages in the relief valve discharge piping.

Prerequisites - The required preoperational tests have been completed. Instrumentation has been checked or calibrated as appropriate. Factory test results on SRV flow and operating times have been reviewed.

Test Method - Testing done at 250 psig reactor pressure consists of cycling each relief valve to verify proper operation. The transient monitoring system will be used to record the results of this test. The data collected will compare the operation of individual relief valves against the operation of all relief valves. During relief valve operation, core power - and therefore steam generation rate - is maintained constant. The pressure control system will close the bypass valves an amount proportional to the relief valve steam flow to maintain constant reactor pressure. This bypass valve motion will be monitored and a comparison of the response for each relief valve operation will be made. If differences exist, it could suggest a partial obstruction of the relief valve or its tailpipe. Tailpipe temperature will be recorded to verify the relief valve has properly reseated. Reactor variables will also be recorded to verify system stability during opening and closing each relief valve.

Testing done at rated reactor pressure consists of manually operating each relief valve at rated reactor pressure. The decrease in Main Generator output will be monitored during the operation of each relief valve to provide an indication of relief valve flow. By comparison of the generator output response for each relief valve operation, any flow obstruction in the valve or its tailpipe can be identified. Each valve will be opened for approximately 10 seconds to allow for variables to stabilize. Reactor variables will also be recorded to verify system stability during opening and closing each relief valve.

#### Acceptance Criteria - Level 1

There should be a positive indication of steam discharge during the manual actuation of each valve.

Level 2 - Pressure control system-related variables may contain oscillatory modes of response. In these cases, the decay ratio for each controlled mode of response must be less than or equal to 0.25.

The temperature measured by thermocouples on the discharge side of the valves shall return to within 10°F of the temperature recorded before the valve was opened.

During the low pressure functional tests, the change in bypass valve position for each SRV opening shall be greater than or equal to a value corresponding to the average change minus 10% of one bypass valve.

During the rated pressure tests, the change in MWe for each SRV opening shall be greater than or equal to a value corresponding to the average change minus 0.5% of rated MWe.

(ST-27) Turbine Trip and Generator Load Rejection

Test Objectives - The objective of this test is to demonstrate the response of the reactor and its control systems to protective trips in the turbine and generator.

Prerequisites - The required preoperational tests have been completed. All instrumentation has been calibrated.

Test Method - At Test Condition 3, a turbine trip will be manually initiated by depressing the Turbine Trip pushbutton in the main control room. At Test Condition 6, a generator load rejection will be manually initiated by remotely opening the generator synchronizing breaker from the control room. During both transients, reactor water level, pressure, neutron flux and simulated heat flux will be recorded and compared to predicted results and acceptance criteria.

At approximately 24% power, a generator load rejection within bypass capacity will be manually initiated as described above. This will demonstrate the ability to ride through a load rejection within bypass capacity without a scram.

During all 3 transients, main turbine stop, control and bypass valve positions and reactor water level will be recorded and compared to the acceptance criteria.

Acceptance Criteria - Level 1

- a) For Turbine and Generator trips there should be a delay of no more than 0.1 seconds following the beginning of control or stop valve closure before the beginning of bypass valve opening. The bypass valves should be opened to a point corresponding to greater than or equal to 80 percent of full open within 0.3 seconds from the beginning of control or stop valve closure motion.
- b) Feedwater system settings must prevent flooding of the steam line following these transients.
- c) The positive change in vessel dome pressure occurring within 30 seconds after either generator or turbine trip must not exceed the Level 2 criteria by more than 25 psi.



- d) The positive change in simulated heat flux shall not exceed the Level 2 criteria by more than 2% of rated value.

Level 2

- a) There shall be no MSIV closure in the first 3 minutes of the transient and operator action shall not be required in that period to avoid the MSIV trip.

- b) The positive change in vessel dome pressure and in simulated heat flux which occur within the first 30 seconds after the initiation of either generator or turbine trip must not exceed the predicted values.

(Predicted values will be referenced to actual test conditions of initial power level, dome pressure, scram timing, and the time from the start of stop/control valve motion to start of control rod motion, and will use beginning of life nuclear data.)

- c) For the Generator trip within the bypass valves capacity (initial thermal power values less than or equal to 25 percent of rated) the reactor shall not scram.

(ST-28) Shutdown from Outside the Main Control Room

Test Objective - The objective of this test is to demonstrate that the reactor can be shutdown, maintained in a hot shutdown condition, and cooled down from outside the main control room. Also, the adequacy of the Emergency Operating Procedures will be verified.

Prerequisites - The required preoperational tests have been completed. Instrumentation has been checked or calibrated as appropriate.

Test Method - While operating at approximately 20% power synchronized to the grid with normal electrical system alignment, the reactor will be scrammed and the MSIV's will be closed from inside the main control room. The control room will then be evacuated, and reactor level and pressure will be controlled from outside the main control room. The Shutdown Cooling mode of RHR will be placed into service with cooling water supplied from the ultimate heat sink. During this demonstration, some supervisory and operating personnel will remain in the control room to protect non-safety-related equipment from unnecessary damage if conditions arise and to assume control of the plant if conditions warrant. A test will be run to demonstrate that the reactor can be scrammed and isolated from outside the control room.

Acceptance Criteria -- Level 1 - Not applicable.

Level 2 - During a simulated control room evacuation, the reactor must be brought to the point where cooldown is initiated and under control, and the reactor vessel pressure and water level are controlled using equipment and controls outside the control room. The test is deemed successful when reactor pressure is less than 98 psia (permissive setpoint) and the RHR shutdown cooling mode has been put in operation.

The reactor must be capable of being scrammed and isolated from outside the control room.

(ST-29) -- Recirculation Flow Control System

The objectives of this test are:

- a) To demonstrate the flow control capability of the plant over the entire pump speed range, including individual local manual, combined Master Manual Operation and Automatic Load Following.
- b) To determine that all electrical compensators and controllers are set for desired system performance and stability.

Prerequisites - The required preoperational tests have been completed.

All instrumentation has been calibrated.

Test Method - At Test Conditions 2, 3, 5 and 6, the stability of the recirculation flow control system is demonstrated by performing step changes in recirculation pump speed while in the manual mode. This testing is also done in the auto mode at Test Conditions 3, 5 and 6. Step changes in recirculation pump speed are done along the 100% rod line to demonstrate operability and stability in the auto mode and to set the lower limit of auto mode operation.

Acceptance Criteria -- Level 1 - The transient response of any system-related variable to any test input must not diverge.

Level 2 - A scram shall not occur due to recirculation flow control maneuvers.

The APRM neutron flux trip avoidance margin shall be greater than or equal to 7.5% and the simulated heat flux trip avoidance margin shall be greater than or equal to 5% when the power maneuver effects are extrapolated to those that would occur along the 100% rated rod line.

The decay ratio of any oscillatory controlled variable must be less than or equal to 0.25.

Steady state limit cycles (if any) shall not produce turbine steam flow variations greater than  $\pm 5\%$  of rated steam flow.

In the scoop tube reset functions, the speed demand meter must agree with the speed meter within 6% of rated generator speed, along the 100% rated rod line.

### (ST-30) Recirculation System

Test Objectives - The objectives of this test are:

- a. Obtain recirculation system performance data during pump trip, flow coastdown, and pump restart.
- b. Verify that the feedwater control system can satisfactorily control water level without a resulting turbine trip and associated scram.
- c. Record and verify acceptable performance of the recirculation two pump circuit trip system.
- d. Verify the adequacy of the recirculation runback to mitigate a scram.
- e. Verify that no recirculation system cavitation will occur in the operable region of the power-flow map.

Prerequisites - The required preoperational tests have been completed. Instrumentation has been checked or calibrated as appropriate.

Test Method - Single recirculation pump trips will be made at Test Condition (TC) 3 and TC-6. These trips will be initiated by tripping the M-G Set Drive Motor Breaker from the control room. Reactor parameters will be recorded during the transient and analyzed to verify non-divergence of oscillatory responses, adequate margins to RPS scram set points, and capability of the feedwater system to prevent a high level trip. The capability to restart the recirc. pump at a high power level will also be demonstrated. At TC-3, both recirculation pumps RPT breakers will be simultaneously tripped using a temporarily installed test switch. The data gathered will be used to demonstrate acceptable pump coastdown performance prior to high power turbine trips and generator load rejects.

Appropriate conditions will be simulated at TC-3 to demonstrate the proper operation of the recirculation pump runback circuits. This is done prior to an actual planned feed pump trip at rated power.

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Both the jet pumps and the recirculation pumps will cavitate at conditions of high flow and low power where NPSH demands are high and little feedwater subcooling occurs. However, the recirculation flow will automatically runback upon sensing a decrease in feedwater flow. The maximum recirculation flow is limited by appropriate stops which will run back the recirculation flow from the possible cavitation region. At TC-3, it will be verified that these limits are sufficient to prevent operation where recirculation pump or jet pump cavitation occurs.

Acceptance Criteria - Level 1 - The response of any level related variables during a single pump trip must not diverge.

The two pump drive flow coastdown transient, during the first 3 seconds of an RFT trip, must fall within the specified bounds.

Level 2 - The reactor shall not scram during the one pump trip.

The APRM margin to avoid a scram shall be at least 7.5% during the one pump trip recovery.

The reactor water level margin to avoid a high level trip shall be at least 3.0 inches during the one pump trip.

Peak simulated heat flux must remain at least 5% below its scram trip point.

Runback logic shall have settings adequate to prevent recirculation pump operation in areas of potential cavitation.

The recirculation pumps shall runback upon a trip of the runback circuit.

### (ST-31) Loss of Turbine-Generator and Offsite Power

Test Objectives - The objectives of this test are to demonstrate that the required safety systems will initiate and function properly without manual assistance, the electrical distribution and diesel generator systems will function properly, and the HPCI and/or RCIC systems will maintain water level if necessary during a simultaneous loss of the main turbine-generator and offsite power.

Prerequisites - The required preoperational tests have been completed. Instrumentation has been checked or calibrated as appropriate.

Test Method - With the unit synchronized to the grid at approximately 30% power, the main turbine-generator will be manually tripped immediately followed by a manual trip of the unit's offsite power source breaker, both trips initiated from the control room. To ensure a full simulation of the loss of all

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offsite power to Unit 1 during Unit 1 testing, all Unit 1 and Common loads will be transferred to Unit 1 Auxiliary and Startup Busses and appropriate breakers racked out to prevent automatic transfer of the loads to Unit 2 sources. During Unit 2 testing, to ensure a full simulation of the loss of all offsite power to Unit 2 while minimizing the impact on Unit 1 operations, all Unit 2 loads will be transferred to Unit 2 Auxiliary and Startup busses, all Unit 1 and common loads will be transferred to Unit 1 Auxiliary and Startup Busses, and appropriate breakers will be racked out to prevent automatic transfer of Unit 2 loads to Unit 1 sources.

Reactor water level and the operation of safety systems will be monitored to verify that the acceptance criteria are satisfied. The proper response of the electrical distribution system will be checked.

The loss of offsite power condition will be maintained for at least 30 minutes to demonstrate that necessary equipment, controls, and indication are available following station blackout to remove decay heat from the core using only emergency power supplies and distribution system.

Acceptance Criteria - Level 1 - All safety systems, such as the Reactor Protection System, the diesel-generator, RCIC and HPCI must function properly without manual assistance, and HPCI and/or RCIC system action, if necessary, shall keep the reactor water level above the initiation level of Core Spray, LPCI and ADS.

Level 2 - Not applicable.

### (ST-32) Containment Atmosphere and Main Steam Tunnel Cooling

Test Objective - The objective of this test is to verify the ability of the drywell coolers/recirculation fans and the reactor building portion of the main steam tunnel coolers to maintain design conditions in the drywell and reactor building portion of the mainsteam tunnel, respectively, during operating conditions and post scram conditions. This test also demonstrates that containment main steamline penetrations do not overheat adjacent concrete.

Prerequisites - The required preoperational tests have been completed. Instrumentation has been checked or calibrated as appropriate.

Test Method - During heatup, at test conditions 2 and 6, and following a planned scram from 100% power, data will be taken to ascertain that the containment atmospheric conditions are within design limits.

Acceptance Criteria - Level 1 - not applicable

Level 2 - The general drywell area is maintained at an average temperature less than or equal to 135°F, with maximum local temperature not to exceed 150°F.

The area beneath the reactor pressure vessel is maintained at an average temperature less than or equal to 135°F, maximum local temperature not to exceed 165°F, with minimum local temperature above 100°F.

The area around the recirculation pump motors is maintained at an average temperature less than or equal to 128°F, with maximum local temperature not to exceed 135°F.

The inside base of the shield wall in the RPV skirt area is maintained at temperatures greater than 100°F.

The reactor building portion of the mainsteam pipeway is maintained at or below 120°F.

The concrete temperature surrounding the main steamline penetrations is maintained at less than 200°F.

#### (ST-33) Piping Steady State Vibration

Test Objectives - The objectives of this test is to demonstrate that steady state vibration levels on reactor recirculation, main steam inside containment, and those piping systems identified in Table 3.9-33 are within acceptable limits. (Note that this test now includes piping previously contained in ST-40. Also note that dynamic transient vibration testing previously contained in this test have been merged into ST-39.)

Prerequisites - Instrumentation has been installed and calibrated.

Test Method - Devices for measuring continuous vibration are mounted on main steam and recirculation lines and vibration during steady state operation is compared with calculated values.

Acceptance Criteria - Level 1 - The measured amplitude (peak to peak) of each remotely monitored point on the main steam inside containment and reactor recirculation lines shall not exceed the allowable value for that point.

Level 2 - The measured amplitude (peak to peak) of each remotely monitored point on the main steam inside containment and reactor recirculation lines shall not exceed the expected value for that point.

The vibratory response of non-remotely monitored systems or portions of systems identified in Table 3.9-33 shall be judged to be within acceptable limits by a qualified test engineer.

The maximum measured amplitude of the piping response for each remotely monitored point on systems identified in Table 3.9-33 shall not exceed the acceptable value for that point.

(ST-34) Control Rod Sequence Exchange

(This test number was previously assigned to the RPV Internals Vibration test which is now performed during the Preoperational Test Program. The test description for the RPV Internals Vibration test is now in TP2.16 which follows the abstract for P64.1.)

Test Objective - The objective of this test is to perform a representative sequence exchange of control rod patterns at the power level at which such exchanges will be done during plant operation and demonstrate that core limits and PCIOMR threshold limits will not be exceeded.

Prerequisites - Instrumentation has been checked or calibrated as appropriate.

Test Method - The control rod sequence exchange begins on the design flow control line with core flow near minimum. Control rods will be inserted as necessary to increase the margin to local core thermal limits. Core power is maintained above the low power setpoint of the Rod Worth Minimizer and Rod Sequence Control System and below the power which will keep fuel assembly nodal power at the PCIOMR threshold. The exchange is performed in accordance with the plant operating procedure RE-TP-009. Data taken during the exchange will be reviewed to verify that the Acceptance Criteria were satisfied.

Acceptance Criteria - Level 1 - Completion of the exchange of one rod pattern for the complimentary pattern with continual satisfaction of all licensed core limits constitutes satisfaction of the requirements of this procedure.

Level 2 - All nodal powers shall remain below their PCIOMR threshold limit during this test.

(ST-35) Recirculation System Flow Calibration

Test Objectives - The objective of this test is to perform a complete calibration of the installed recirculation system flow instrumentation.

Prerequisites - The required preoperational tests have been completed. Instrumentation has been checked or calibrated as appropriate.

Test Method - During the testing program at selected operating conditions which allow the recirculation system to be operated at

speeds required for rated flow at rated power, the jet pump flow instrumentation will be adjusted to provide correct flow indication based on the jet pump flow.

After the relationship between drive flow and core flow is established, the flow biased APRM/RBM system will be adjusted to match this relationship.

Acceptance Criteria - Level 1 - Not applicable.

Level 2 - Jet pump flow instrumentation shall be adjusted such that the jet pump total flow recorder will provide a correct core flow indication at rated conditions.

The APRM/RBM flow-bias instrumentation shall be adjusted to function properly at rated conditions.

### (ST-36) Cooling Water Systems

Test Objectives - The objective of this test is to verify that the performance of the Reactor Building Closed Cooling Water (RBCCW), the Turbine Building Closed Cooling Water (TBCCW), and Service Water Systems are adequate with the reactor at rated temperature.

Prerequisites - The required preoperational tests have been completed. Instrumentation has been checked or calibrated as appropriate.

Test Method - With the reactor operating at 100% power, data will be obtained to verify that the heat exchanger outlet temperatures are within design values.

Acceptance Criteria - Level 1 - Not applicable.

Level 2 - The Service Water Pump discharge header temperature is less than 95°F. The RBCCW Heat Exchanger RBCCW outlet temperature is at 100° ± 5°F. The TBCCW Heat Exchanger TBCCW outlet temperature is at 100° ± 5°F.

### (ST-37) Gaseous Radwaste System

Test Objectives - The objective of this test is to demonstrate that the Gaseous Radwaste System operates within the Technical Specification and design limits during a full range of plant power operation and to demonstrate the proper operation of the containment nitrogen inerting system during plant operation.

Prerequisites - The required preoperational tests have been completed. Instrumentation has been checked or calibrated as appropriate. In addition, the 100% power trip testing shall have



been completed or 120 effective full power days shall not have elapsed prior to performing the nitrogen inerting test.

Test Method - The test will consist of collecting data and performing quantitative analysis of the off gas system influent and effluent to determine if the performance is acceptable per design and Technical Specification. For the nitrogen inerting system, the proper nitrogen concentration will be verified by the as installed plant oxygen detectors/instruments in the two major volumes of the primary containment.

Acceptance Criteria - Level 1 - The release of radioactive gaseous and particulate effluents must not exceed the limits specified in the site technical specifications.

Level 2-The system flow, pressure, temperature, and relative humidity shall comply with design specifications. The catalytic recombiner, the hydrogen analyzer, the activated carbon beds and the filters shall be performing their required function. There shall be no less than 8000 lb/hr. of dilution steam flow when the steam jet air ejectors are pumping. The containment nitrogen inerting system shall be capable of inerting the primary containment free volume within 24 hours from the start of the test and the resulting oxygen concentration shall be less than or equal to 4%.

(ST-38) ROP Piping System Expansion

(The system expansion testing previously contained in this test has been merged into ST-17.)

(ST-39) Piping Vibration During Dynamic Transients

Test Objective - The objective of this test is to demonstrate that vibration levels on main steam inside containment, reactor recirculation, and system piping identified in Table 3.9-33 meet acceptable limits during selected dynamic transients.

Prerequisites: Instrumentation has been installed and calibration.

Test Method - Devices for measuring continuous loads, displacements, accelerations and pressures are mounted on piping systems and responses during transients are compared with calculated values. Those portions of the systems which are non-safety related are visually inspected prior to, during and subsequent to the transient loading condition.

Acceptance Criteria - Level 1 - The measured vibration amplitude (peak to peak) for each remotely monitored point of main steam inside drywell and/or reactor recirculation piping shall not exceed the allowable value for each specific point.

Level 2 - The maximum measured loads, displacements, accelerations and pressures on those systems listed in Table 3.9-33 shall not exceed the design maximum expected values at each specific point.

The vibratory response of non-remotely monitored systems identified in Table 3.9-33 shall be judged to be within acceptable limits by a qualified test engineer.

Based on visual inspection during a post transient walkdown, there shall be no signs of excessive piping response (such as damaged insulation, markings on piping, structural or hanger steel, or walls, damaged pipe supports, etc.) on systems listed in Table 3.9-33.

The measured vibration amplitude (peak to peak) for each remotely monitored point of main steam inside drywell and/or reactor recirculation piping shall not exceed the expected value for each specific point.

#### (ST-40) BOP Piping Steady State Vibration

(The steady state vibration testing previously contained in this test has been merged into ST-33.)

#### 14.2.12.3 Requested Acceptance Test Procedure Abstracts

Tests comprising the Acceptance Test procedures are listed in Table 14.2-2. For each test a description is provided for objective, prerequisites, method and acceptance criteria, where applicable. Modifications to these descriptions will be reflected in amendments to the FSAR.

#### A3.1 13.8 KV SYSTEM ACCEPTANCE TEST

Test Objective - To demonstrate the capability of the 13.8 kV system to provide electrical power to the Startup and Unit Auxiliary 13.8 kV Busses by demonstrating the proper operation of breakers, relaying and logic, permissive and prohibit interlocks, and instrumentation and alarms.

Prerequisites - Construction is completed to the extent necessary to perform this test and the systems are turned over to the ISG. Required 230 kV transmission lines are available to energize the 13.8 kV system. Required instruments and protective relays are calibrated and controls are operable.

Test Method - Breakers are opened and closed by operating or simulating controls to verify breaker operation, relaying and

logic, permissive and prohibit interlocks, instrumentation and alarms, and automatic transfers.

Acceptance Criteria - The system performance parameters are in accordance with applicable design documents.

#### A7.1 LIGHTING SYSTEM AND MISCELLANEOUS 120V DISTRIBUTION

##### -----ACCEPTANCE TEST-----

Test Objectives - To demonstrate the ability of the Station Battery Lighting System to automatically transfer on loss of the Normal power feed, to demonstrate the ability of the Control Room Emergency Lighting Units to provide limited illumination upon loss of the Essential Lighting System, and to provide a format for tabulation of Technical Procedures (TPs) performed on system components during startup testing.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Normal and essential 480 volt AC and 125 volt DC power is available. Required test instruments are calibrated and controls are operable.

Test Method - The Station Battery Lighting System and Control Room Emergency Lighting System are tested by interrupting normal power supply feeds and verifying proper switchover from normal to emergency power.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design document.

#### A11.1 STATION SERVICE WATER SYSTEM ACCEPTANCE TEST

Test Objective - To demonstrate the capability of Station Service Water System to provide cooling water to connected components/systems.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and controls are operable. Required electrical power supply systems are available. Water supply from the cooling tower is available.

Test Method - System operation is initiated normally. The system is operated in the different design modes and Service Water Pump performance is determined. Required controls are operated or simulated signals are applied to verify automatic features, system interlocks and alarms.

Acceptable Criteria - The system performance parameters are in accordance with applicable design documents.

### A15.1 TBCCW SYSTEM ACCEPTANCE TEST

Test Objective - To demonstrate proper operation of the TBCCW system, specifically to furnish cooling water to miscellaneous turbine plant heat exchangers, coolers, and chillers, and to demonstrate the ability of a standby pump to automatically replace the operating pump in case of pressure loss in the header.

Prerequisites - Construction is completed to the extent necessary to perform this test and the system is turned over to the ISG. Required electrical power supply systems are available to energize the necessary 480 volt motor control centers. Required instruments are calibrated and controls are available. The service water system is available. The instrument air system is available.

Test Method - The system operation is initiated manually, and where applicable automatically. The system is operated in the system design modes and TBCCW pumps performance is determined. Required controls are operated or simulated to verify automatic system functions and alarms.

#### Acceptance Criteria

- 1) Each of the two TBCCW pumps is capable of delivering a minimum flow of 292.5 gpm.
- 2) With one pump in operation, the standby pump starts automatically at a low header pressure of less than or equal to 70 psig.
- 3) The TBCCW system provides cooling water to the following:
  - a. Control rod drive pump bearing and oil coolers
  - b. Condensate pump motor bearing coolers
  - c. Instrument air compressor coolers
  - d. Service air compressor coolers
  - e. EHC fluid coolers
  - f. Turbine Building sample station chillers
  - g. Auxiliary Boiler sample station chillers

### A18.1 INSTRUMENT AIR SYSTEM ACCEPTANCE TEST

Test Objective - The general objective of this test is to demonstrate proper operation of the Instrument Air System. Specific objectives are to demonstrate the following:

- 1) The ability of the Instrument Air System to provide air to outlets located throughout the plant.
- 2) System controls function in accordance with design intent.

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- 3) Alarms function properly to provide alert of an abnormality in the Instrument Air System.
- 4) Instrument air dryers reduce instrument air moisture in accordance with design requirements.
- 5) Standby Instrument Air Unit, under AUTO Mode, starts automatically when the system pressure is down.

Prerequisites - Construction turnover of the system is complete to the extent required to conduct the test. The system has been walked through, verified complete and air blowing has been completed. The required Technical Tests have been completed and the required instruments are calibrated.

Test Method - Both compressors are fully tested in both Manual and Auto mode of operation. The Dryer packages are tested for effectiveness and all automatic trips and alarms are verified.

Acceptance Criteria - The system performance parameters are in accordance with applicable engineering design documents.

### A19.1-----SERVICE AIR SYSTEM ACCEPTANCE TEST

Test Objectives - The objectives of this test are as follows:

- 1) To demonstrate that the compressors can provide pressurized air (115-130 psig) to outlets located throughout the plant.
- 2) To demonstrate that system controls and alarms function in accordance with the design intent.
- 3) To demonstrate that the standby compressor will start automatically if the system pressure is low.

Prerequisites - The prerequisites of this test are as follows:

- 1) Construction is complete to the extent necessary to conduct this test and system is turned over to ISG.
- 2) All component inspections, tests and calibrations have been completed satisfactorily.

Test Method - The system will be pressurized by starting the compressors. Compressor modes and functions will be checked for proper operation. Alarms will be verified as they are induced during normal operation or simulation.

Acceptance Criteria

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- 1) The service air compressors have the capacity to deliver 440 scfm of air each and provide air to outlets located throughout plant.
- 2) The compressors will automatically trip when an abnormal condition exists and alarms perform their design function.
- 3) The standby compressor will automatically start if the lead compressor fails or if its operation cannot meet service air system demand.
- 4) The Service Air System is capable of providing backup supply to the Instrument Air System

### A20.1 BUILDING DRAINS -- NON RADIOACTIVE ACCEPTANCE TEST

Test Objectives - The objectives of this test are as follows:

- 1) To demonstrate that system controls and alarms function in accordance with the design intent.
- 2) To demonstrate the waste filter is capable of automatically dewatering sludge.
- 3) To demonstrate the diesel generator floor drain sump pumps operate automatically.

Prerequisites - Construction is complete to the necessary extent and the system is turned over to ISG. Required instrumentation is calibrated and controls are operable. Required electrical power supply systems are available. Instrument air is available.

Test Method - Low, High and High-High sump levels are simulated to verify pumps start and stop as required.

Acceptance Criteria - The system performs in accordance with design documents.

### A22.1 MAKEUP DEMINERALIZER SYSTEM ACCEPTANCE TEST

Test Objective - To demonstrate the capability of the Makeup Demineralizer System to provide quality water consistent with the requirements of the Final Safety Analysis Report.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to ISG. All instrumentation contained in this system is calibrated and the controls are operational. The Water Pretreatment System and the Neutralization Basins are available.

Test Method - A normal, automatic regeneration of makeup demineralizers shall be performed verifying all regeneration

sequence interlocks and verifying that the Makeup Demineralizer conforms to FSAR requirements.

All interlocks shall be verified that will remove the Makeup Demineralizer from service upon its effluent water quality not meeting specifications.

Acceptance Criteria - The Makeup Demineralizer shall be capable of making water in accordance with FSAR requirements at a flow rate between 20 and 120 gpm. It shall also be capable of performing automatic shutdowns, startups and regenerations per its design requirements.

### A30.3 CONTROL STRUCTURE MISCELLANEOUS H&V SYSTEM ACCEPTANCE TEST

Test Objectives - To demonstrate that the Control Structure Miscellaneous H&V maintains temperature and delivers an adequate air supply and exhaust to various areas in accordance with design requirements.

Prerequisites - Construction is complete and the system is turned over to the ISG. Required instruments are calibrated and controls are operable. The Turbine Building Vent and Instrument Air Systems are in service. Required electrical power supply systems are available.

Test Method - The system operation is initiated manually and fan performance, damper operations and heating or cooling operation (where applicable) are determined. Required controls are operated or simulated signals are applied to verify fan interlocks, high-high temperature from charcoal filters (where applicable), electric duct heater operation and associated alarms.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

### A31.1 COMPUTER UNINTERRUPTIBLE POWER SUPPLY ACCEPTANCE TEST

Test Objective - The general objective of this test is to demonstrate proper operation of the Computer Uninterruptible Power Supply. Specific objectives are to demonstrate the following:

- 1) The ability of the static transfer switch to provide automatic transfer of the 120 VAC distribution panel loads from the preferred to the alternate supply on loss of the preferred supply or overcurrent or in case of load side fault.
- 2) The ability of the manual transfer switch and manual operation of the static transfer switch to transfer

distribution panel loads between the preferred and the alternate source.

Prerequisites - Construction turnover of the system is complete to the extent required to conduct this test. The system has been walked through and verified complete. The required Technical Tests have been completed and the required instruments are calibrated.

Test Method - The power supply is operated at full load, the static transfer switch is tested, the manual transfer is tested and all alarms and computer inputs associated with the system are verified.

Acceptance Criteria - The system performance parameters are in accordance with applicable engineering design documents.

### A31.2\_\_PROCESS\_COMPUTER\_ACCEPTANCE\_TEST

Test Objective - The objective of this test is to demonstrate proper operation of the computer. Specific objectives are to demonstrate the ability of the DCS to monitor unit operation and generate video displays for operator use; the PMS to perform BOP calculations, log data, make historical records, generate video displays and generate alarm status summary displays; the NSS subsystem program to provide an accurate determination of the core thermal performance and data loading, and to supplement procedural requirements for control and manipulation during reactor startup and shutdown.

Prerequisites - Construction turnover of the system is complete to the extent required to conduct this test. The system has been walked through and verified complete. The required Technical Tests have been completed and the required instruments are calibrated.

Test Method - Computer inputs are verified, the software programs are tested and computer self-protection and alarm functions are verified.

Acceptance Criteria - The system performance parameters are in accordance with applicable engineering design documents.

### A32.1\_\_SECURITY\_125V\_DC\_SYSTEM\_NO.\_1\_ACCEPTANCE\_TEST

Test Objective - To demonstrate the ability of the 125 Volt DC system to perform the following:

- 1) The batteries can endure a complete discharge based on their ampere hour rating without exceeding the battery bank minimum voltage limit.



- 2) The batteries can provide reliable stored energy to selected loads in the event of a loss of normal power.
- 3) The battery chargers can deliver their rated output.
- 4) The battery chargers can fully charge their associated batteries from design minimum charged state simultaneously providing power to the distribution panels for normal security loads.
- 5) That the alarms are simulated and verified to operate properly.
- 6) The reliable 125V DC power is delivered to the security DC distribution panel.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required calibration and operation of instruments, protective devices, and breakers is verified. 480V AC Power, Resistor Load Bank, Battery Room Ventilation and Emergency Eyewash is available and/or in service.

Test Method - The Battery Performance Test is manually initiated by connecting the battery bank to the resistor load bank and discharging the batteries at a constant current for a specified period of time. The Battery Service Test is manually initiated by connecting the battery bank to the resistor load bank and simulating, as closely as possible, the load the batteries will supply during a design basis accident. Then the battery charger is connected to the batteries and the distribution-panels to verify that they can charge the batteries while simultaneously providing power to the normal security loads. The battery charger is also connected to the resistor load bank and current is increased to its maximum rating with the charger isolated from its associated battery bank. Alarms are simulated and verified to be operated properly.

Acceptance Criteria - The batteries can satisfactorily deliver stored energy for the specified amount of time as required for the Performance and Service Test. The battery chargers can deliver rated output and can charge their associated battery bank from minimum voltage to a fully charged state in a specified amount of time while simultaneously supplying normal security loads. The alarms operate at their engineered setpoints and annunciate in the Security Control Center.

A32.2 SECURITY UNINTERRUPTIBLE POWER SUPPLY NO. 1  
 -----ACCEPTANCE TEST-----

Test Objective - The general objective of this test is to demonstrate proper operation of the Security Uninterruptible Power Supply. Specific objectives are to demonstrate the following:

- 1) The ability of the static transfer switch to provide automatic transfer of the 120 V AC distribution panel loads from the preferred to the alternate supply on loss of the preferred supply or overcurrent or in case of load side fault.
- 2) The ability of the manual transfer switch and manual operation of the static transfer switch to transfer distribution panel loads between the preferred and the alternate source.

Prerequisites - Construction turnover of the system is complete to the extent required to conduct this test. The system has been walked through and verified complete. The required Technical Tests have been completed and the required instruments are calibrated.

Test Method - The power supply is operated at full load, the static transfer switch is tested, the manual transfer is tested and all alarms associated with the system are verified.

Acceptance Criteria - The system performance parameters are in accordance with applicable engineering design documents.

#### A32.4 SECURITY BACKUP DIESEL AND ASSOCIATED 480 VOLT DISTRIBUTION -----ACCEPTANCE TEST-----

Test Objective - To demonstrate system reliability, proper voltage and frequency regulation under transient and steady-state conditions, proper logic, correct setpoints for trip devices, and proper operation of initiating devices and permissive and prohibit interlocks. Starting, cooling, heating, ventilating, lubricating and fueling auxiliary systems will also be tested to demonstrate that their performance is in accordance with design.

To demonstrate the capability of the 480 Volt Load Centers and 480 Volt Motor Control Centers systems to provide electrical power to connected 480 Volt Load Centers and Motor Control Centers by demonstrating the proper operation of breakers, transfer and trip devices, relaying and logic, permissive and prohibit interlocks, instrumentation and alarms.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and controls are operable.

24 Volt DC Power is available. The diesel oil day tank is filled and a make-up source is available.

Required electrical power supply systems are available to energize the 480 Volt system. Required instruments and protective relays are calibrated and controls are operable.

Test Method - System operation is initiated manually and diesel generator capability to start and attain rated voltage within the specified time are verified. Diesel generator is loaded to the rated load and the performance is determined. Required controls are operated to verify automatic start, D-G protection.

Feeder breakers are opened and closed by operating or simulating controls. Voltage on the bus being fed are measured to verify breaker operations, relaying and logic, permissive and prohibit interlocks and alarms. Signals are applied to verify alarms and instrumentation. Buses are de-energized and energized to verify automatic transfer, switch transfer, and re-transfer and motor-generator set operation.

Acceptance Criteria - The system performance parameters are in accordance with applicable design documents.

#### A32.9 SECURITY 125 V DC AND UNINTERRUPTIBLE POWER SUPPLY -----No. 2 ACCEPTANCE TEST-----

Test Objective - To demonstrate the ability of the 125 Volt DC system to perform the following:

- 1) The batteries can endure a complete discharge, based on their ampere hour rating, without exceeding the battery bank minimum voltage limit.
- 2) The batteries can provide reliable stored energy to selected loads in the event of a design basis accident.
- 3) The battery chargers can deliver their rated output.
- 4) The battery chargers can fully charge their associated batteries from design minimum charged state simultaneously providing power to the distribution panels for normal security loads.
- 5) That the alarms operate and annunciate at their specified abnormal condition.
- 6) The reliable 125 V DC power is delivered to the security DC distribution panel.

- 7) The ability of the static transfer switch to provide automatic transfer of the 120 V AC distribution panel loads from the preferred to the alternate supply on loss of the preferred supply or overcurrent or in case of load side side fault.
- 8) The ability of the manual transfer switch and manual operation of the static transfer switch to transfer distribution panel loads between the preferred and the alternate source.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required calibration and operation of instruments, protective devices, and breakers is verified. 480 V AC Power, Resistor Load Bank, Battery Room Ventilation and Emergency Eyewash is available and/or in service.

Test Method - The Battery Performance Test is manually initiated by connecting the battery bank to the resistor load bank and discharging the batteries at a constant current for a specified period of time. The Battery Service Test is manually initiated by connecting the battery bank to the resistor load bank and simulating, as closely as possible, the load the batteries will supply during a design basis accident. Then the battery charger is connected to the batteries and the distribution panels to verify that they can charge the batteries while simultaneously providing power to the normal security loads. The battery charger is also connected to the resistor load bank and current is increased at its maximum rating with the charger isolated from its associated battery bank. Alarms are simulated and verified to be operated properly. The power supply is operated at full load, the static transfer switch is tested, the manual transfer is tested.

Acceptance Criteria - The batteries can satisfactorily deliver stored energy for the specified amount of time as required for the Performance and Service Test. The battery chargers can deliver rated output and can charge their associated battery bank from minimum voltage to a fully charged state in a specified amount of time while simultaneously supplying normal plant loads. The alarms operate at their engineered setpoints and annunciate in the Security Control Center. The system performance parameters are in accordance with applicable engineering design documents.

### A33.1 TURBINE BUILDING HEATING & VENTILATING SYSTEM ACCEPTANCE TEST Test Objectives - The objectives of this test are as follows:

- 1) To provide filtered and tempered air to all areas of the Turbine Building.

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- 2) To maintain air flow from areas of lesser potential contamination to areas of greater potential contamination.
- 3) To exhaust air from potentially contaminated spaces to particulate and charcoal filters.
- 4) To maintain the Turbine Building at a slightly negative pressure with respect to atmosphere to minimize exfiltration to outside atmosphere.
- 5) To recirculate and cool Turbine Building air to reduce exhaust volume.
- 6) To discharge all exhaust air through the Turbine Building Exhaust Vent.
- 7) To supply cool air to the Reactor Recirculation Motor - Generator sets.

### Prerequisites

- 1) Flow balancing is completed
- 2) Instrument Air System is operational.
- 3) Fire Protection System is operational.

Test Method - The system will be tested with manual controls and automatically where applicable. All interlocks, start and trip schemes will also be verified.

### Acceptance Criteria

- 1) Maintain building temperature above 40°F.
- 2) Maintain building spaces below the following maximum temperatures:
  - a) General areas 104° F
  - b) Electrical rooms 104° F
  - c) Mechanical areas 120° F

### A33.2 TURBINE BUILDING CHILLED WATER SYSTEM ACCEPTANCE TEST

Test Objectives - The objectives of this test are as follows:

- 1) To demonstrate the ability of the Turbine Building Chilled Water System to maintain design temperature.

- 2) To demonstrate the ability of the Service Water System to remove the chiller condenser heat.

Prerequisites

- 1) Construction is complete to the extent required to complete this test.
- 2) The following systems are operational:
  - a) Instrument Air System
  - b) Turbine Building H&V is functionally checked
  - c) Service Water System
  - d) Makeup Demineralizers
  - e) Expansion tank IT-123 is filled halfway and pressurized to 20 psi

Test Method - The system will be initiated manually and automatically with all automatic functions verified. All interlocks will be verified and alarms checked as they occur during normal process variation.

Acceptance Criteria - Turbine Building Chilled Water System will supply water at 50°F.

A35.1 FUEL POOL COOLING AND CLEANUP SYSTEM ACCEPTANCE TEST

Test Objective - To demonstrate that the Fuel Pool Cooling and Cleanup System filters, demineralizes and cools the fuel pool water. The system is able to maintain a minimum differential pressure in the heat exchangers and will prevent siphoning of water from the fuel pool to any cooling water supply line.

Prerequisite - Construction is complete to the extent necessary to perform this test and the system is turned over to ISG. Required instruments are calibrated and controls are operable. The Demineralized Water Transfer System, Service Water System, Sample System, Condensate System, Instrument Air System, Residual Heat Removal System, Liquid Radwaste Drain System, Emergency Service Water System, Solid Radwaste System and required electrical power supply systems are available.

Test Method - The system is operated to demonstrate the demineralizer heat exchangers and fuel pool cooling pumps operation. Required controls are operated or simulated signals are applied to verify system operation, automatic valve alignment and system interlocks and alarms.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design requirements.

### A37.1 DEMINERALIZED WATER TRANSFER SYSTEM ACCEPTANCE TEST

Test Objectives - To demonstrate proper operation of the Demineralized Water Transfer system by verifying the following: The ability to supply condensate for various plant systems, including the condenser hotwells. The ability to supply condensate to the suction of the high pressure coolant injection (HPCI), reactor core isolation cooling (RCIC), core spray, and control rod drive (CRD) pumps. The ability to supply demineralized water as makeup to the reactor, radwaste, and closed coolant systems. The ability to supply demineralized water to the condensate storage tank & refueling water storage tank.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to ISG. Hydrostatic testing, velocity flushing and air blowing have been complete to the extent required to perform this test. Required instruments are calibrated and controls are operable. Required electrical power supply systems, makeup demineralizers, and instrument air are available. The associated plant systems which are capable of receiving water from the Demineralized Water System are available to the extent required to perform this test.

Test Method - The operating modes of this system are initiated manually and, where applicable, automatically. The system is operated to determine performance of all pumps. Control devices are operated or simulated signals are applied to verify system automatic functions and alarms.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents. All automatic trips and alarms actuate within their allowable limits.

### A38.1 LOW PRESSURE AIR SYSTEM ACCEPTANCE TEST

Test Objectives - The objective of this test is to demonstrate proper operation of the Low Pressure Air System; specifically to demonstrate the ability to provide air for the liquid radwaste filters, and the liquid radwaste demineralizers, as these processes require. The ability to provide backup air to the cement silo and to operate intermittently on demand is demonstrated. The protection of the compressor against low oil pressure, high oil temperature, high air discharge temperature, high cooling water temperature and low cooling water pressure is demonstrated.

Prerequisites - Construction is complete to the extent necessary to perform the test and the system is turned over to the ISG.

Required instruments are calibrated and Technical Tests are complete.

Test Method - The system is operated in the Manual and Automatic modes of operation. The Flow Rate is verified and all trips and alarms are tested.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

### A39.1 CONDENSATE DEMINERALIZER SYSTEM ACCEPTANCE TEST

Test Objective - To demonstrate the ability of the Condensate Demineralizer System to process full condensate flow producing effluent of acceptable quality thereby providing reasonable assurance that contaminants which may be introduced to the condenser during normal and abnormal plant operation will be removed. Also demonstrate that resin transfer, cleaning and regeneration are pushbutton initiated, fully automatic processes that clean and regenerate for reuse. Demonstrate valving and controls are such that a ready standby unit can be placed in service, or any operating unit can be taken out of service from the local control panels.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Component technical procedures, component calibrations have been completed satisfactorily.

Test Method - The system will be tested while processing water at 100% rated flow and at 120% rated flow, verifying that monitored influent and effluent parameters do not exceed design values. Resin capacity will be tested (one bed minimum) by processing the design quantity of water and verifying that monitored effluent parameters do not exceed design values prior to achieving the design output. Control functions related to all modes of operation shall be demonstrated. Flow paths will be verified under actual operation as will all valve operations, motor-driven equipment performance, demonstration of all monitoring control and support equipment while processing dirty, exhausted resin charges exposed to condensate flow, through the regeneration modes, returning the resin charge to inservice processing condensate to design quality effluent. Simulation of functions will be used where off-normal conditions cannot be established or redundant testing of the same function under actual conditions serves no purpose.

Acceptance Criteria - Each vessel passing rated flow will produce water quality at design spec or better. Each vessel is capable of passing 120% rated flow for a short period of time. The condensate demineralizer and regeneration systems are pushbutton initiated, automatically controlled from a local control panel



for all modes of operation. An automatically controlled isolation valve protects the resin transfer system from condensate system pressure. A proper concentration of acid solution is supplied to regenerate the cation resins and the proper concentrations of caustic solution at the proper temperature is supplied to regenerate the anion resins.

#### A40.1 LUBE OIL TRANSFER, STORAGE, & PURIFICATION SYSTEM -----ACCEPTANCE TEST-----

Test Objective - To demonstrate the ability of the system to transfer lube oil from one lube oil reservoir to another at rated flowrates and to demonstrate proper operation of the controls and the alarms of the lube oil centrifuge.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to ISG. Required instruments are calibrated and the controls are operable. Demineralized water transfer system and Instrument air system are operational. Required electrical supply systems are available and lube oil is available in sufficient quantity.

Test Method - The lube oil transfer pump performance parameters are measured and recorded. The batch oil tank pump performance parameters are measured and recorded. The centrifuge and oil heaters control and alarm circuits are tested and the operating parameters are measured and recorded. All flowpaths are then verified.

Acceptance Criteria - The system performance is in accordance with the applicable design documents.

#### A41.1 MAIN COOLING TOWER AND AUXILIARIES ACCEPTANCE TEST

Test Objectives - To demonstrate the proper operation of the cooling tower, cooling tower makeup and level control, chlorination system, sulfuric acid addition system, and the blowdown treatment system.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG.

Required instruments are calibrated and controls are operable. Required electrical power supply systems, instrument air system, plant makeup water system, and chlorination building H&V are available.

Test Method - Sliding gate valves and bypass valve operation is verified. Makeup system is verified to keep basin water level at the proper level. Chlorination addition capabilities are verified, and the acid system is verified to control pH at the proper value. The blowdown treatment system will remove enough

chlorine to allow the plant to meet the requirements of its environmental discharge permit.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

#### A42.1 CIRCULATING WATER SYSTEM ACCEPTANCE TEST

Test Objectives - To demonstrate proper operation of the Circulating Water System.

Prerequisites - Construction is complete to the extent necessary to run this test and the system is turned over to the ISG.

Required instruments are calibrated and controls are operable. Required electrical power supply systems and the cooling tower system are available.

Test Method - Pump protective interlocks and system design pressures and flows are verified.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

#### A43.1 MAIN CONDENSER AIR REMOVAL SYSTEM ACCEPTANCE TEST

Test Objectives - The objectives of this test are as follows:

- 1) To demonstrate the ability of the mechanical vacuum pump to pull a vacuum on the condenser.
- 2) To demonstrate the ability of the SJAE's to maintain condenser vacuum when pump is tripped.
- 3) To demonstrate system ability to remove noncondensable gases from the main condenser and discharge them to the off-gas system.
- 4) To condense any steam removed from the condenser with the noncondensable gases and return the condensate to the condenser.

Prerequisites - The prerequisites for this test are as follows:

- 1) Construction is complete to the extent necessary to perform this test and system is turned over to ISG.
- 2) The main turbine is on turning gear.
- 3) The aux. boiler is operational and the main turbine seals are established.

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- 4) Instrument Air System is operational.
- 5) Turbine Bldg. H&V is operational.
- 6) The Condensate System is operational.
- 7) The Off-Gas System is operational.
- 8) The separator-silencer 1T-107 is filled to the proper level.
- 9) All steam lines are properly drained of condensate.

Test Method - A vacuum will be pulled on the condenser using the mechanical vacuum pump and it will be maintained using the SJAE's. Valve interlocks will be checked as will all automatic functions. Alarms will be verified as they are induced during normal system change or simulation.

### Acceptance Criteria

- 1) The mechanical vacuum pump can pull a vacuum of 5 in. Hga in 95 min. on the main condenser.
- 2) The SJAE's can maintain the vacuum after the mechanical vacuum pump is shutdown.
- 3) Valve sequencing operates per design.

### A44.1 CONDENSATE SYSTEM ACCEPTANCE TEST

Test Objectives - To demonstrate the following:

- (1) The ability of the condensate pumps and their associated valves to function properly.
- (2) The ability of the system to maintain minimum recirculation flow through each condensate pump.
- (3) The ability of the Turbine Building Closed Cooling Water System to provide sufficient cooling flow for the condensate pump bearings.
- (4) The ability of the Hotwell Load Control to maintain condenser at normal operating level.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Power and control voltage is available for the associated motors, valves and instruments. Required calibration and operation of instruments, protective devices and controls is verified. Motor bearing cooling and pump seal water and instrument air is available. Main condensers are cleaned and filled with water.

Test Method - The system operation is manually initiated by starting the condensate pumps and establishing flow through various paths. System logic, interlocks and alarms are verified to be in accordance with design intent and system flows, pressures are within engineering specifications under various simulated operating conditions.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents for the conditions simulated during the test.

#### A46.1 EXTRACTION STEAM SYSTEM ACCEPTANCE TEST

Test Objectives - The general objective of this test is to demonstrate proper operation of the Extraction Steam System and Feedwater Heaters - Drains and Vents System. Specific objectives are to demonstrate the following:

- 1) The isolation valves in the Extraction Steam Sytem, the Feedwater Heater Drain System, and the Feedwater Heater Vents operate as required by their design.
- 2) All associated systems that drain to the feedwater heater systems isolate when required by the Feedwater Heater System design.
- 3) The alarms function to provide indication of an abnormality in the system.

Prerequisites - Construction is completed to the necessary extent and the system is turned over to ISG. Required instrumentation is calibrated and controls are operable. Required electrical power supply systems are available. Plant demineralized water and instrument air is available.

Test Method - Extraction Steam and Feedwater Heater System tests are simulated and performed with no steam present to the turbine. All system interlocks are tested.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

#### A65.1 RADWASTE BUILDING AIR FLOW SYSTEM ACCEPTANCE TEST

Test Objective - To demonstrate the ability of the Radwaste Building Air Flow System to provide an adequate amount of filtered air to the Radwaste Building and to exhaust an adequate amount of air from the Radwaste Building.

Prerequisites - Construction is complete to the extent necessary for the test and the system is turned over to the ISG. 480 V

power and instrument air are available. The required instruments are calibrated and controls are operable.

Test Method - The system is put into operation manually. Proper operation of all interlocks between system components is verified. The system air balance report and filter test reports are reviewed to ensure conformance with design specifications.

Acceptance Criteria - The system performs in accordance with design documents.

#### A65.2 RADWASTE BUILDING CHILLED WATER SYSTEM ACCEPTANCE TEST

Test Objectives - To demonstrate the ability of the Radwaste Building Chilled Water System to provide an adequate amount of chilled water to the Radwaste Building Air Supply System cooling coils.

Prerequisites - Construction is complete to the extent necessary for performing this test and the system is turned over to the ISG. 480V power and instrument air are available. The Makeup Demineralized Water System is available to provide makeup water as needed. The required instruments are calibrated and controls are operable.

Test Method - The system is placed in operation. Proper operation of all interlocks between system components is verified. All safety switches on both chillers are tested to ensure that they will shut down the associated unit when necessary. The system flow balance report is reviewed to verify that flowrates are within design specifications.

Acceptance Criteria - The system performs in accordance with design documents.

#### A67.1 Loose Parts Monitoring System

Test Objectives - To demonstrate that the Loose Parts Monitoring System is capable of detection of a loose part resulting in an alarm and automatically starting the tape recording equipment.

Prerequisites - Construction is complete to the extent necessary and the various systems are turned over to the ISG. Required instruments are calibrated and control schemes have been checked and are operable.

Test Method - Each Loose Part Detection (LPD) channel is tested by causing an impact on the piping monitored and verification that a corresponding visual alarm is activated. The Digital Loose Part Location (DLPL) is functionally tested by placing any two LPDs in alarm test condition and then verifying that the DLPL

visible and audible alarms annunciator are activated and that the tape recorder starts recording the signal on the alarming channel.

Acceptance Criteria - A predetermined impact on a specified coolant piping will result in a corresponding visual alarm. A series of impacts, based on the logic indicating a loose part, will initiate an audible and visual alarm and the tape recorder will start automatically.

#### A68.1 RADWASTE SOLIDS HANDLING SYSTEM ACCEPTANCE TEST

Test Objective - To demonstrate the capability of the Radwaste Solids Handling System to control, collect, handle, process, package, solidify and temporarily store the wet waste sludges, spent resins and evaporator concentrates.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and controls are operable. Required electrical power supply systems are available.

Test Method - System operation is initiated manually. Required controls are operated and process is varied to verify interlocks and alarms.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

#### A68.2 SPENT RESIN HANDLING SYSTEM ACCEPTANCE TEST

Test Objective - To demonstrate the capability of the spent resin collection system to control, collect, handle and discharge spent resin to the liquid radwaste filters.

The Prerequisites, Test Method, and Acceptance criteria are the same as those for A68.1.

#### A69.2 LIQUID RADWASTE SUBSYSTEMS ACCEPTANCE TEST

Test Objective - To demonstrate the capability of the subsystems to collect, process, store and monitor for reuse or disposal all potentially radioactive liquid waste.

Prerequisites - Construction is complete to the extent necessary to perform this test and the subsystems are turned over to the ISG. Required instruments are calibrated and controls are operable. Required Electrical Power Supply Systems are available. Liquid radwaste subsystem storage tanks and sample tanks are available to be filled with water.

Test Method - Subsystem pumps are operated and performance characteristics are determined. Level controls are operated to verify alarms, pump starts and pump shutoffs. Performance of the liquid radwaste filtration, demineralization, chemical waste neutralization, chemical radwaste evaporation system, laundry radwaste filtration and effluent isolation is determined to the extent possible during this test.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

#### A71.1 GASEOUS RADWASTE RECOMBINER CCW ACCEPTANCE TEST

Test Objective - To demonstrate the proper operation of the GRRCCW system, specifically, that the cooling pumps supply the rated flow to the system, the cooling water is temperature controlled, and the chemical addition tank has flow capabilities for adding chemicals to the system.

Prerequisites - Construction is completed to the extent necessary to perform this test and the system is turned over to the ISG. Required electrical power supply systems are available. Required instruments are calibrated and controls are available. The instrument air system is available. The service water system is operational and lined up to the GRRCCW heat exchangers.

Test Method - The system operation is initiated manually, and where applicable automatically. The system is operated in the system design modes and GRRCCW pumps performance is determined. Required controls are operated or simulated to verify automatic system functions and alarms.

Acceptance Criteria - The Unit One (1) and Common cooling water flow through the heat exchangers is temperature controlled through a range of 90° to 120°F. The Unit One (1) and common cooling water pumps deliver 1124 gpm to the respective system. Chemicals can be added to the system when flow is established through the Unit One (1) and common chemical addition tanks.

#### A72.1 OFF GAS RECOMBINER SYSTEM ACCEPTANCE TEST

Test Objective - To demonstrate the operation of the Off-Gas Recombiner System, specifically, that the system will operate in the standby, pre-start and process modes and that the standby recombinder can be brought on line within 10 minutes.

Prerequisites - Construction is completed to the extent necessary to perform this test and the system is turned over to the ISG. Required electrical power supply systems are available. Required instruments are calibrated and controls are available. The instrument air system is operational. The following systems are

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operational as needed: Condensate system, GRRCCW System, RBCCW, Auxiliary Boiler, and Main Condenser.

Test Method - The system operation is initiated manually, and, where applicable, automatically. The system is operated in the system design modes, required controls are operated or simulated to verify automatic system functions and alarms.

Acceptance Criteria - The Unit I and common Off-Gas Recombiner Systems perform the following:

- 1) The Off Gas Recombiner System will operate in the Standby, Prestart and Process modes.
- 2) A standby recombinder can maintain recombinder temperature close to 300°F and can be brought on line in 10 minutes.
- 3) The Off Gas Recombiners can be transferred and shut down locally and from the main control room.
- 4) The Charcoal Absorber subtrains are capable of being transferred and isolated locally and from the main control room.

### A74.1 NITROGEN STORAGE AND SUPPLY SYSTEM ACCEPTANCE TEST

Test Objective - To demonstrate the capability of the Nitrogen Storage and Supply to provide and control the supply of nitrogen gas for primary containment purging and to maintain an inert atmosphere in containment.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and controls are operable. Required electrical power supply systems are available.

Test Method - System operation is initiated manually. The system is operated in the different design modes, system performance is determined and a purge flow will be established to demonstrate proper operation. Required controls are operated or simulated signals are applied to verify automatic features, system interlocks and alarms.

Acceptance Criteria - The system performance parameters are in accordance with applicable design documents.

### A76.2 PROCESS SAMPLING SYSTEM ACCEPTANCE TEST

Test Objective - To demonstrate proper operation of the Process Sampling System. This is performed by proving:



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- 1) The operability of the reactor and turbine building thermal baths.
- 2) The ability of the chemical fume hood to control out-leakage when drawing grab samples.
- 3) The ability of the system to provide required monitoring of sample fluids.
- 4) Capability of obtaining grab samples.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to ISG. Required instrumentation is calibrated and controls are operable. Required electrical power supply systems are available. Plant demineralized water is available. Turbine Bldg. and Reactor Bldg. closed cooling water is available.

Test Method - Tests whenever feasible will be performed when the process being sampled is in operation. Other tests, such as main steam samples, will be simulated. All sampling devices will be calibrated and alarm conditions set.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

### A84.1 MOISTURE SEPARATORS ACCEPTANCE TEST

Test Objective - To demonstrate the ability of the moisture separator drain tank level controls to maintain level and provide a main turbine trip signal as a result of high level.

PREREQUISITES - Construction is complete to the extent necessary to perform this test and the system is turned over to ISG. Hydrostatic testing, velocity flushing and air blowing have been completed. Required instruments are calibrated and controls are operable. Required electrical power supplies, water supplies and instrument air are available. The associated plant systems which are capable of receiving water are available to the extent necessary to perform this test.

TEST METHOD - The water level in the drain tank will actually be varied and the proper operation of the level controls, level alarms and level trips will be verified.

ACCEPTANCE CRITERIA - The system performance parameters are in accordance with the applicable design documents. All automatic trips and alarms actuate within their allowable limits.

### A85.2 FREEZE PROTECTION SYSTEM ACCEPTANCE TEST

Test Objective - To demonstrate the ability of the system to supply and interrupt power to the individual heater circuits at the correct voltage and current in both the AUTO and MANUAL modes of operation and to demonstrate the system's ability to detect a loss of source supply voltage on a faulty heater circuit.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to ISG. The required instruments are calibrated and the controls are operable.

Test Method - Each control panel is energized and proper source supply voltage verified. The required controls will be operated and signals simulated as necessary to verify the individual heater circuits function per design in the AUTO, OFF, and Manual modes, and are providing the design specified heat requirements for the applications.

ACCEPTANCE CRITERIA - The system performance parameters are in accordance with the applicable design documents, technical spec's. and vendor prints.

#### A91.1 ANNUNCIATOR SYSTEM ACCEPTANCE TEST

Test Objective - The objective of this test is to demonstrate the ability of the main control room annunciators to provide audible and visual indication of an alarm condition.

Prerequisites - Construction turnover of the system is complete to the extent required to conduct this test. The system has been walked through, verified complete and the component technical tests have been completed.

Test Method - Simulated alarms are applied and the audible and visual indication verified. Annunciator loss of power and ground detection feature are also tested, where applicable.

Acceptance Criteria - The system performance parameters are in accordance with applicable engineering design documents.

#### A92.1 TURBINE STEAM SEALS & DRAINS ACCEPTANCE TEST

Test Objective - The objective of this test is to demonstrate the proper operation of the turbine steam seal system and drains using the auxiliary boiler steam supply to the turbine steam seal header. Also, the test will demonstrate the ability of the steam packing exhauster to maintain a proper vacuum on the steam seal exhaust header.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and controls are operable.

Required electrical supply systems are available. The instrument air system is operational. The auxiliary boilers are available and in the standby mode. The condensate system is operational. The main turbine and feedwater turbines are available to be placed on turning gear. The main condensers are lined up to receive drains and to provide support to seal the main and reactor feed pump turbines.

Test Method - The auxiliary boilers will provide a continuous and regulated supply of steam to the steam seal evaporator header. The performance of the steam packing exhauster to maintain a proper vacuum on the exhaust header is verified. Simulated and automatic signals are applied to verify system interlocks and alarms for the seal steam evaporator drain tank, seal steam system and steam packing exhauster.

Acceptance Criteria - The steam packing exhauster will maintain an approximate vacuum of 5.0 inches H<sub>2</sub>O on the seal steam evaporator exhaust header during normal operating conditions. The auxiliary steam system can provide a continuous amount of clean steam to the seal steam evaporator header at approximately 4 psig to supply the following with sealing steam: the main turbine shaft seals, the stem packings of the main steam stop valves, control valves, and bypass valves, the combined intermediate valves, the shaft seals of the reactor feed pump turbines, and the stem packings of the reactor feed pump turbine stop and control valves.

#### A93.1 TURBINE LUBE OIL SYSTEM ACCEPTANCE TEST

Test Objectives - To demonstrate the proper operation of the Turbine Lube Oil System.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and controls operable. Required electrical power supply systems are available. The Service Water System and the Main Turbine-Generator Assembly is available.

Test Method - System operation is initiated manually and automatically testing all trips and interlocks. The main reservoir vapor extractor is tested manually and automatically to verify proper vacuum in the main reservoir and isolation on detection of fire. All main lube oil pumps are tested for proper manual and automatic start to verify proper bearing oil supply pressures during all conditions including loss of AC power. Bearing lift pumps are tested manually and automatically to verify proper bearing lift for turning gear operation. The main turbine turning gear is tested for both manual and auto engaging and starting to ensure proper rotation during shaft cooldown.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

A93.2 TURBINE VALVES, VALVE TEST, EHC AND SUPERVISORY SYSTEMS  
-----ACCEPTANCE TEST-----

Test Objectives - To demonstrate the proper operation of the turbine EHC and supervisory system.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and controls operable. Required electrical power supply systems are available. The Main Condenser, Stator Cooling and Instrument Air Systems are available.

Test Method - Hydraulic System Manual and Automatic Modes are tested. All turbine trip paths are verified. All system stop, control and bypass valves are tested for EHC operation. Turbine warm-up, speed select, and load ramp functions are verified. Turbine steam lead drain valves are tested for proper operation.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

A98.1 MAIN GENERATOR AND EXCITATION SYSTEM ACCEPTANCE TEST

Test Objectives - To demonstrate the ability of the protective relays and their associated interlocks to shutdown the generator.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Component calibrations and alarm verifications are complete to the extent necessary to perform this test.

Test Method - Through the use of jumpers, lifted leads, pulled fuses, and manual manipulation of relay contacts conditions are simulated to initiate automatic responses of the generator protection circuitry. Proper operation of the generator protection circuitry is verified.

Acceptance Criteria - The following is verified:

- (1) The ability of the voltage regulator to transfer from auto to manual upon initiation of design events.
- (2) The ability of the exciter field breaker to function according to design basis events.
- (3) The ability of the primary and backup lockout relays to trip the generator upon initiation of design basis events.

A99.2 Communications System Acceptance Test

Test Objective - To demonstrate the ability of the three part communications system (PA, Plant Maint./Test Jack, and Plant Evacuation and Alarm Systems) components to function as an integrated system. The PA system to provide communications and a medium for transmitting plant alarms in conjunction with the Plant Evacuation Alarm System. The Plant Evacuation Systems ability to generate the necessary tones and frequencies and the Plant Maint./Test Jack Systems ability to provide an additional independent means of communication.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to ISG. The required instruments are calibrated and the controls are operable.

Test Method - By operating the required controls each Public Address station will be tested in the transmit and receive modes on all channels. The associated speakers will be tested for functional audibility. The systems loop separation and muting features will be operationally verified.

The Plant Maint./Test Jack System will be tested by operating the required controls and verifying each Jack Stations transmit/receive capability on all of the systems 23 channels. An integrated test with several remote Jack Stations attached will also be performed.

The Plant Evacuation and Alarm System will be used in conjunction with the PA system to broadcast all 5 of the possible tones and frequencies generated by the system. Also the systems isolation and silencing features will be operationally verified.

Acceptance Criteria - The systems performance is in accordance with the applicable design documents.

A99.6 Seismographical Monitoring System Acceptance Test

Test Objective - To verify the operability of the seismic monitoring instrumentation (digital cassette accelerographs, playback unit, response spectrum analyzer and triaxial accelerometers) and to demonstrate proper integrated response of the system to activate upon occurrence of a seismic event as designed.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and controls are operable. The required electrical power supply system is available. All

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recorders have ample paper and all accelerographs are loaded with the proper magnetic tape cassettes.

Test Method - Both an internal calibration feature on the SMR-102 (seismic monitoring recorder) and a simulated seismic event at each triaxial accelerometer are used as "trigger input" to the seismic monitoring system to verify automatic initiation and alarm actuations. Playback (production of time-history seismic graphs) is demonstrated by manual transfer of cassette tapes from the digital cassette accelerographs to the seismic monitoring recorder.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.

## A99.2 - Communications System Acceptance Test

Test Objective - To demonstrate the ability of the three part communications system (PA, Plant Maint./Test Jack, and Plant Evacuation and Alarm Systems) components to function as an integrated system. The PA system to provide communications and a medium for transmitting plant alarms in conjunction with the Plant Evacuation Alarm System. The Plant Evacuation Systems ability to generate the necessary tones and frequencies and the Plant Maint./Test Jack Systems ability to provide an additional independent means of communication.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to ISG. The required instruments are calibrated and the controls are operable.

Test Method - By operating the required controls each Public Address station will be tested in the transmit and receive modes on all channels. The associated speakers will be tested for functional audibility. The systems loop separation and muting features will be operationally verified.

The Plant Maint./Test Jack System will be tested by operating the required controls and verifying each Jack Stations transmit/receive capability on all of the systems 23 channels. An integrated test with several remote Jack Stations attached will also be performed.

The Plant Evacuation and Alarm System will be used in conjunction with the PA system to broadcast all 5 of the possible tones and frequencies generated by the system. The siren will be operationally tested. Also the systems isolation and silencing features will be operationally verified.

Acceptance Criteria - The systems performance is in accordance with the applicable design documents.

## A99.6 - Seismographical Monitoring System Acceptance Test

Test Objective - To verify the operability of the seismic monitoring instrumentation (digital cassette accelerographs, playback unit, response spectrum analyzer and triaxial accelerometers) and to demonstrate proper integrated response of the system to activate upon occurrence of a seismic event as designed.

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and controls are operable. The required electrical power supply system is available. All

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recorders have ample paper and all accelerographs are loaded with the proper magnetic tape cassettes.

Test Method - Both an internal calibration feature on the SMR-102 (seismic monitoring recorder) and a simulated seismic event at each triaxial accelerometer are used as "trigger input" to the seismic monitoring system to verify automatic initiation and alarm actuations. Playback (production of time-history seismic graphs) is demonstrated by manual transfer of cassette tapes from the digital cassette accelerographs to the seismic monitoring recorder.

Acceptance Criteria - The system performance parameters are in accordance with the applicable design documents.



Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to ISG. The required instruments are calibrated and the controls are operable.

Test Method - By operating the required controls each Public Address station will be tested in the transmit and receive modes on all channels. The associated speakers will be tested for functional audibility. The systems loop separation and muting features will be operationally verified.

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The Plant Maint./Test Jack System will be tested by operating the required controls and verifying each Jack Stations transmit/receive capability on all of the systems 23 channels. An integrated test with several remote Jack Stations attached will also be performed.

The Plant Evacuation and ALRM system will be used in conjunction with the PA system to broadcast all 5 of the possible tones and frequencies generated by the system. The siren will be operationally tested. Also the systems isolation and silencing features will be operationally verified.

Acceptance Criteria - The systems performance is in accordance with the applicable design documents.

#### A99.6 Seismographical Monitoring System Acceptance Test

Test Objective - To verify the operability of the seismic monitoring instrumentation (digital cassette accelerographs, playback unit, response spectrum analyzer and triaxial accelerometers) and to demonstrate proper integrated response of the system to activate upon occurrence of a seismic event as designed.

20

Prerequisites - Construction is complete to the extent necessary to perform this test and the system is turned over to the ISG. Required instruments are calibrated and controls are operable. The required electrical power supply system is available. All recorders have ample paper and all accelerographs are loaded with the proper magnetic tape cassettes.

Test Method - Both an internal calibration feature on the SMR-102 (seismic monitoring recorder) and a simulated seismic event at each triaxial accelerometer are used as "trigger input" to the seismic monitoring system to verify automatic initiation and alarm actuations. Playback (production of time-history seismic graphs) is demonstrated by manual transfer of cassette tapes from the digital cassette accelerographs to the seismic monitoring recorder.

.20 | Acceptance-Criteria.- The system performance parameters are in  
accordance with the applicable design documents.

TABLE 14.2-1PREOPERATIONAL TEST PROCEDURES

Page 1

Test Number    Test Definition

P2.1	125 volt dc System
P4.1	4.16 KV System
P5.1	480 volt System
P13.1	Fire Protection Water System
P13.2	Fire Protection & Generator Purge Systems
P13.3	Smoke Detection System
P13.4	Control Room Halon System
P14.1	Reactor Building Closed Cooling Water System
P16.1	RHR Service Water System
P17.1	Instrument ac Power System
P23.1	Diesel Fuel Oil System
P24.1	Diesel Generator System
P25.1	Primary Containment Instrument Gas System
P28.1	ESSW Pumphouse H&V System
P28.3	Diesel Generator Building H&V System
P30.1	Control Structure H&V System
P30.2	Control Structure Chilled Water System
P34.1	Reactor Building H&V System
P34.2	Reactor Building Chilled Water System
P45.1	Feedwater System
P45.2	Feedwater Control System
P49.1	Residual Heat Removal System
P50.1	Reactor Core Isolation Cooling System

TABLE 14.2-1. CONTINUED.

P51.1	Core Spray System
P51.1A	Core Spray System Pattern
P52.1	High Pressure Coolant Injection System
P53.1	Standby Liquid Control System
P54.1	Emergency Service Water System
P55.1	Control Rod Drive System
P56.1A	Reactor Manual Control System
P56.1B	Rod Sequence Control System
P56.1C	Rod Worth Minimizer System
P57.1	Uninterruptable ac Power System
P58.1	Reactor Protection System
P59.1	Primary Containment System
P59.2	Containment Integrated Leak Rate Test
P60.1	Containment Atmosphere Circulation System
P61.1	Reactor Water Cleanup System
P64.1	Reactor Recirculation System
P69.1	Liquid Radwaste Collection System
P70.1	Standby Gas Treatment System and Secondary Containment Isolation
P73.1	Containment Atmospheric Control System
P73.2	Containment Hydrogen Recombiner System
P73.3	Containment Oxygen and Hydrogen Analyzer System
P75.1	24 volt dc System
P76.1	Plant Leak Detection System
P78.1	Source Range Monitoring System

TABLE 14.2-1 CONTINUED

P78.2	Intermediate Range Monitoring System
P78.3	Average Power Range Neutron Monitoring System
P78.4	Traversing Incore Probe System
P79.1 & P79.2I	Area Radiation Monitoring System
P79.2A-H	Process Radiation Monitoring System
P80.1	Reactor Nonnuclear Instrumentation System
P81.1	Fuel Handling System
P83.1A	Main Steam-Nuclear Steam Supply Shutoff System Preoperational Test
P83.1B	Main Steam Relief Valves/Automatic Depressurization System Preoperational Test
P83.1C	Main Steam Leakage Control System Preoperational Test
P83.1D	Main Steam Leak Detection System Preoperational Test
P88.1	250 volt dc System
P99.1	Reactor Building Crane
P100.1	Cold Functional Test

TABLE 14.2-2ACCEPTANCE TEST PROCEDURES

<u>Test Number</u>	<u>Test Definition</u>
A-3.1	13.8 kV System
A-7.1	Lighting System and Miscellaneous 120V Distribution
A-8.1	Domestic Water Sytem
A-9.1	River Water Makeup System
A-9.2	Intake Structure Compressed Air System
A-10.1	Screens & Screen Wash System
A-11.1	Station Service Water System
A-15.1	Turbine Building Closed Cooling Water System
A-18.1	Instrument Air System
A-19.1	Service Air System
A-20.1	Building Drains - Nonradioactive
A-21.1	Water Pretreatment System
A-22.1	Makeup Demineralizer System
A-27.1	Auxiliary Boiler System
A-28.2	River Intake Structure H&V System
A-28.4	Chlorination Building H&V System
A-28.5	Circulating Water Pump House H&V System
A-30.3	Control Structure Miscellaneous H&V System
A-31.1	Computer
A-31.2	Process Computer
A-32.1	Security System 125 VDC
A-32.2	Security UPS

TABLE 14.2-1 CONTINUED

P52.1	High Pressure Coolant Injection System
P53.1	Standby Liquid Control System
P54.1	Emergency Service Water System
P55.1	Control Rod Drive System
P56.1	Reactor Manual Control System
P57.1	Uninterruptable ac Power System
P58.1	Reactor Protection System
P59.1	Primary Containment System
P59.2	Containment Integrated Leak Rate Test
P60.1	Containment Atmosphere Circulation System
P61.1	Reactor Water Cleanup System
P64.1	Reactor Recirculation System
P69.1	Liquid Radwaste Collection System
P70.1	Standby Gas Treatment System and Secondary Containment Isolation
P73.1	Containment Atmospheric Control System
P75.1	24 volt dc System
P76.1	Plant Leak Detection System
P78.1	Source Range Monitoring System
P78.2	Intermediate Range Monitoring System
P78.3	Average Power Range Neutron Monitoring System
P78.4	Traversing Incore Probe System
P79.1	Area Radiation Monitoring System
P79.2	Process Radiation Monitoring System
P80.1	Reactor Nonnuclear Instrumentation System
P81.1	Fuel Handling System

TABLE 14.2-1 CONTINUED

P83.1	Main Steam System
P88.1	250 volt dc System
P99.1	Reactor Building Crane
P100.1	Cold Functional Test





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TABLE 14.2-2

ACCEPTANCE TEST PROCEDURES

Page 1

<u>Test Number</u>	<u>Test Definition</u>
A-3.1	13.8 kV System
A-7.1	Lighting System and Miscellaneous 120V Distribution
A-8.1	Domestic Water Sytem
A-9.1	River Water Makeup System
A-9.2	Intake Structure Compressed Air System
A-10.1	Screens & Screen Wash System
A-11.1	Station Service Water System
A-15.1	Turbine Building Closed Cooling Water System
A-18.1	Instrument Air System
A-19.1	Service Air System
A-20.1	Building Drains - Nonradioactive
A-21.1	Water Pretreatment System
A-22.1	Makeup Demineralizer System
A-27.1	Auxiliary Boiler System
A-28.2	River Intake Structure H&V System
A-28.4	Chlorination Building H&V System
A-28.5	Circulating Water Pump House H&V System
A-29.1	Administration Building H&V System
A-30.3	Control Structure Miscellaneous H&V System
A-31.1	Computer
A-31.2	Process Computer
A-32.1	Security System 125 VDC
A-32.2	Security UPS



TABLE 14.2-2 CONTINUED

A-32.3	Security 480 Volt
A-32.4	Security Backup Diesel
A-32.5	Security 480/120 Volt
A-32.6	Security Bldgs. H&V
A-32.7	Security Bldgs. Halon
A-33.1	Turbine Building H&V System
A-33.2	Turbine Building Chilled Water System
A-35.1	Fuel Pool Cooling and Cleanup System
A-37.1	Demineralized Water Transfer System
A-38.1	Low Pressure Air System
A-39.1	Condensate Demineralizer System
A-40.1	Lube Oil Transfer, Storage & Purification System
A-41.1	Cooling Tower System
A-42.1	Circulating Water System
A-43.1	Main Condenser Air Removal System
A-43.2	Condenser Tube Cleaning System
A-44.1	Condensate System
A-46.1	Extraction Steam System
A-65.1	Radwaste Building Air Flow System
A-65.2	Radwaste Building Chilled Water System
A-68.1	Radwaste Solids Handling System
A-69.2	Liquid Radwaste Subsystems
A-71.1	Gaseous Radwaste Recombiner Closed Cooling Water
A-72.1	Off-Gas Recombiner System
A-74.1	Nitrogen Storage & Supply System
A-74.2	Bulk Hydrogen System

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TABLE 14.2-2 CONTINUED

Page 3

A-76.2	Process Sampling System
A-84.1	Moisture Separators
A-85.1	Cathodic Protection System
A-85.2	Freeze Protection System
A-91.1	Annunciator System
A-92.1	Turbine Steam Seals & Drains
A-93.1	Turbine Lube Oil Systems
A-93.2	Turbine Valves, Valve Test, EHC and Supervisory Systems
A-95.1	H2 Seal Oil System
A-97.1	Stator Cooling System
A-98.1	Main Generator & Excitation System
A-99.2	Communications System
A-99.4	Radiation Area Doors
A-99.6	Seismographical Monitoring System



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TABLE 14.2-3

STARTUP TEST PROCEDURES

<u>Test Number</u>	<u>Test Definition</u>
ST-1	Chemical and Radiochemical
ST-2	Radiation Measurements
ST-3	Fuel Loading
ST-4	Full Core Shutdown Margin
ST-5	Control Rod Drive System
ST-6	SRM Performance and Control Rod Sequence
ST-7	Reactor Water Cleanup System
ST-8	Residual Heat Removal System
ST-9	Water Level Measurement
ST-10	IRM Performance
ST-11	LPRM Calibration
ST-12	APRM Calibration
ST-13	NSSS Process Computer
ST-14	RCIC System
ST-15	HPCI System
ST-16	Selected Process Temperatures
ST-17	System Expansion
ST-18	TIP Uncertainty
ST-19	Core Performance
ST-20	Steam Production Verification
ST-21	Core Power - Void Mode Response
ST-22	Pressure Regulator
ST-23	Feedwater System
ST-24	Turbine Valve Surveillance
ST-25	Main Steam Isolation Valves





TABLE 14.2-3 (Cont)STARTUP TEST PROCEDURES

ST-26	Relief Valves
ST-27	Turbine Trip and Generator Load Rejection
ST-28	Shutdown From Outside the Main Control Room
ST-29	Recirculation Flow Control System
ST-30	Recirculation System
ST-31	Loss of Turbine Generator and Offsite Power
ST-32	Containment Atmosphere and Main Steam Tunnel Cooling
ST-33	Piping Steady State Vibration
ST-34	Control Rod Sequence Exchange
ST-35	Recirculation System Flow Calibration
ST-36	Cooling Water Systems
ST-37	Gaseous Radwaste System
ST-38	BOP Piping System Expansion
ST-39	Piping Vibration During Dynamic Transients
ST-40	BOP Piping Steady State Vibration

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TABLE 14.2-4

MAJOR TEST PHASE AND TEST PLATEAU SCHEDULE  
-----TEST CONDITION SEQUENCE-----

Test Phase	Test Plateau	Test Condition Sequence
III	-	Open Vessel Test Condition
IV	-	Heatup Test Condition
V	A	Test Condition 1
V	B	Testing during approach to Test Condition 2 Test Condition 2
V	C	Testing during approach to Test Condition 3 Test Condition 3
V	D*	Testing during approach to Test Condition 5 Test Condition 5 Testing during approach to Test Condition 6 Test Condition 6 Test Condition 4
V	E	100% Power Warranty Run

\* Because of the transitory nature of testing performed along the 100% rod line during Test Phase V Test Plateau D, all testing assigned to Test Condition 6 may not be completed prior to entering Test Condition 4.

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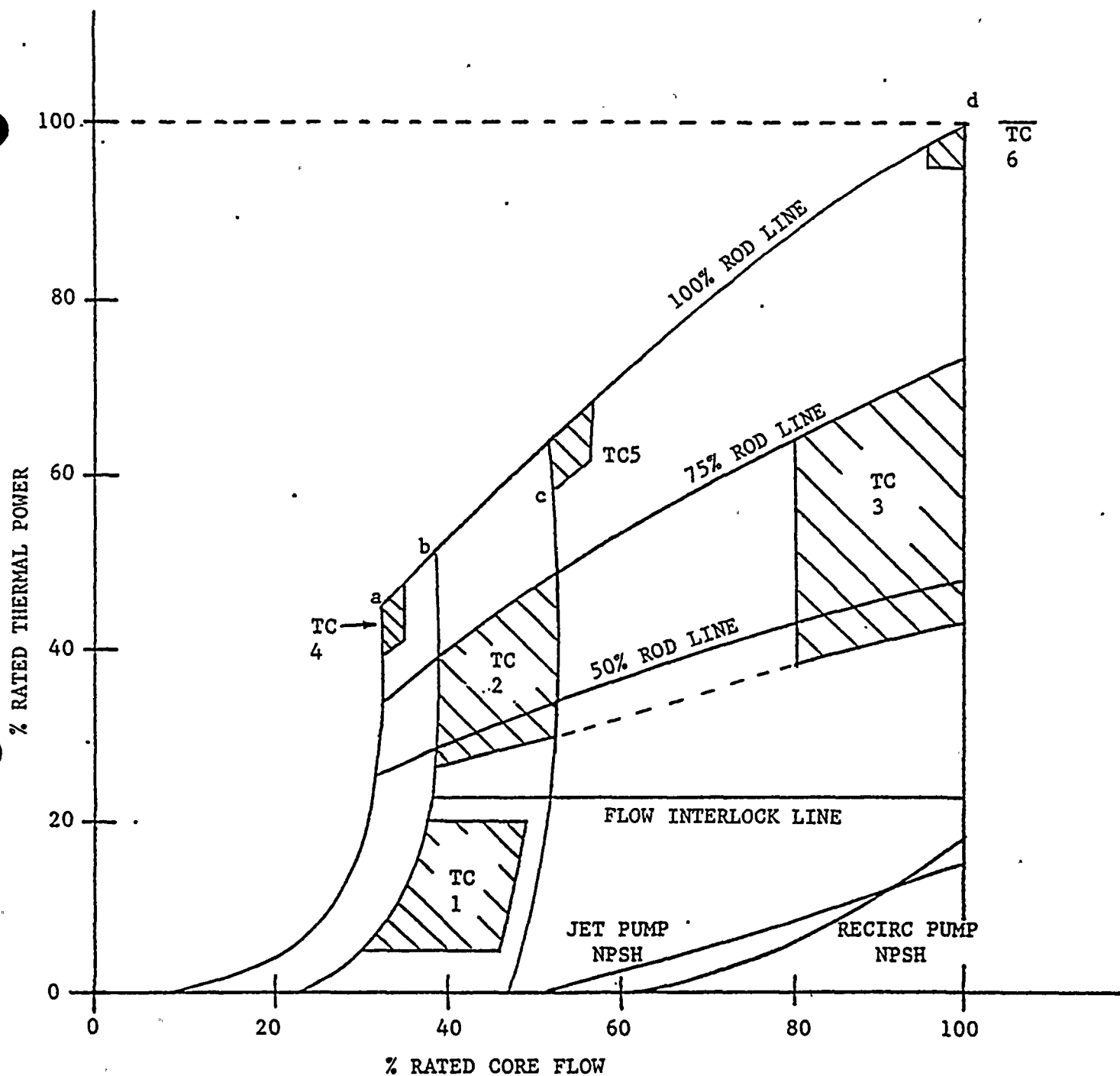
TABLE 14.2-5

CONTROL ROD DRIVE SYSTEM STARTUP TESTS

<u>Action</u>	<u>Accumulator Pressure</u>	<u>Reactor Pressure With Core Loaded</u>			
		<u>0</u>	<u>600</u>	<u>psig 800</u>	<u>Rated</u>
Position Indication		all			
Normal Times Insert/Withdraw		all			4*
Coupling		all			
Friction		all			all
Scram Times	Normal	all	4*	4*	all
Scram Times	Minimum	4*			
Scram Times	Zero				4*
Scram Times	Normal				4**

\* Refers to 4 CRDs selected for continuous monitoring based on slow normal accumulator pressure scram times, or unusual operating characteristics, at zero reactor pressure or rated reactor pressure when this data is available. The 4 selected CRDs must be compatible with the rod worth minimizer, RSCS system, and CRD sequence requirements.

\*\* Scram times of the four slowest CRDs (based on scram data at rated pressure) will be determined at Test Conditions 2 & 6 during planned reactor scrams.



#### NOTES

1. SEE FIGURE 14.2-6 SHEET 2 FOR DEFINITION TEST CONDITIONS
2. CONSTANT PUMP SPEED LINES
  - a. NATURAL CIRCULATION
  - b. MINIMUM RECIRCULATION PUMP SPEED
  - c. ANALYTICAL LOWER LIMIT OF MASTER FLOW CONTROL
  - d. ANALYTICAL UPPER LIMIT OF MASTER FLOW CONTROL

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SUSQUEHANNA STEAM ELECTRIC STATION  
UNITS 1 AND 2  
FINAL SAFETY ANALYSIS REPORT

POWER FLOW MAP AND STARTUP TEST  
CONDITIONS

FIGURE 14.2-6 SH. 1

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Test Condition  
Number

## Power-Flow Map Region and Notes

- 1 Core thermal power between approximately 5% and 20% rated (1).  
Recirculation pump speed within +10% of minimum pump speed.  
Before and after main generator synchronization.
- 2 Core thermal power between the 45% power rod line (2) and 75% power rod line.  
Recirculation pump speed between minimum and lowest pump speed corresponding to Master Manual Mode. Lower power corner is within Bypass valve capacity.
- 3 Core thermal power between 45% power rod line and 75% power rod line. Total core flow between 80% and 100% rated.
- 4 On the natural circulation core flow, line within +0, -5% of the intersection with the 100% power rod line.
- 5 Core thermal power within +0, -5% of the 100% power rod line. Recirculation pump speed within +5% of the minimum recirculation pump speed corresponding to Master Manual Mode.
- 6 Core thermal power between 95% and 100% rated. Total Core flow +0, -5% rated core flow.

### Notes:

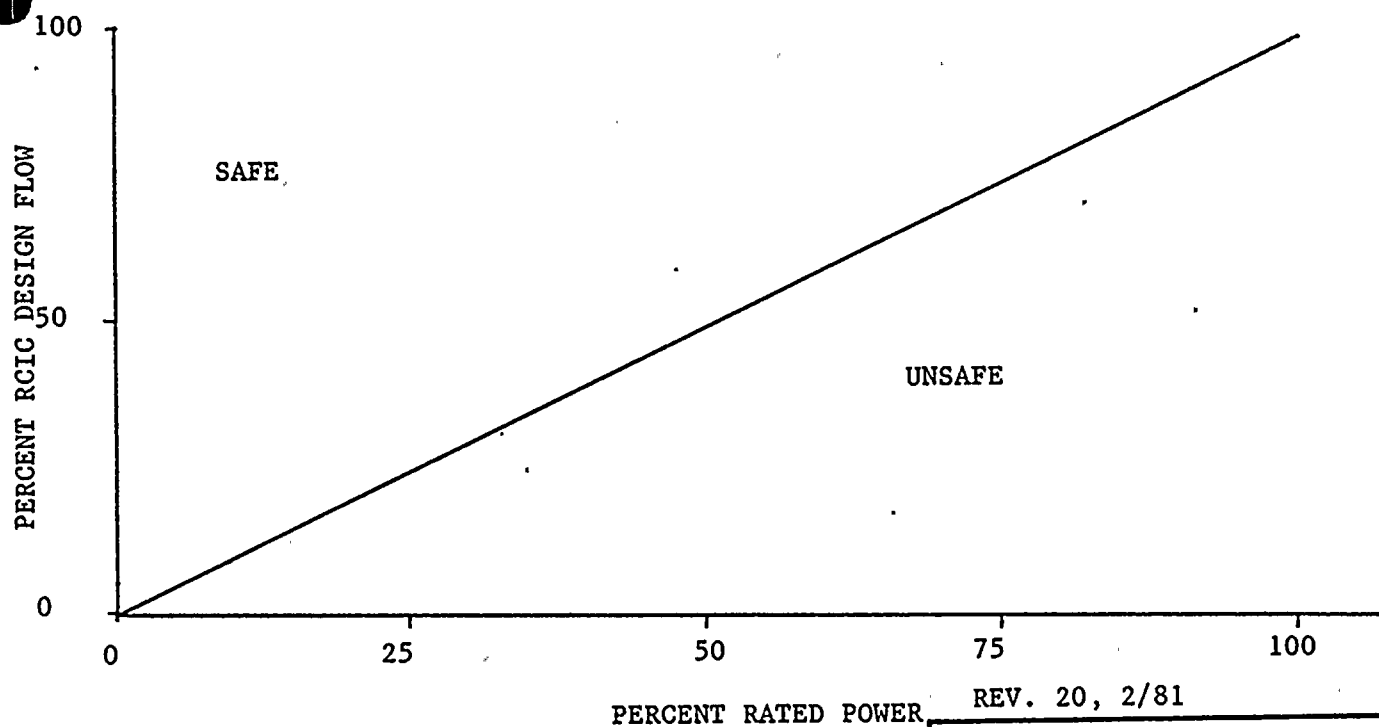
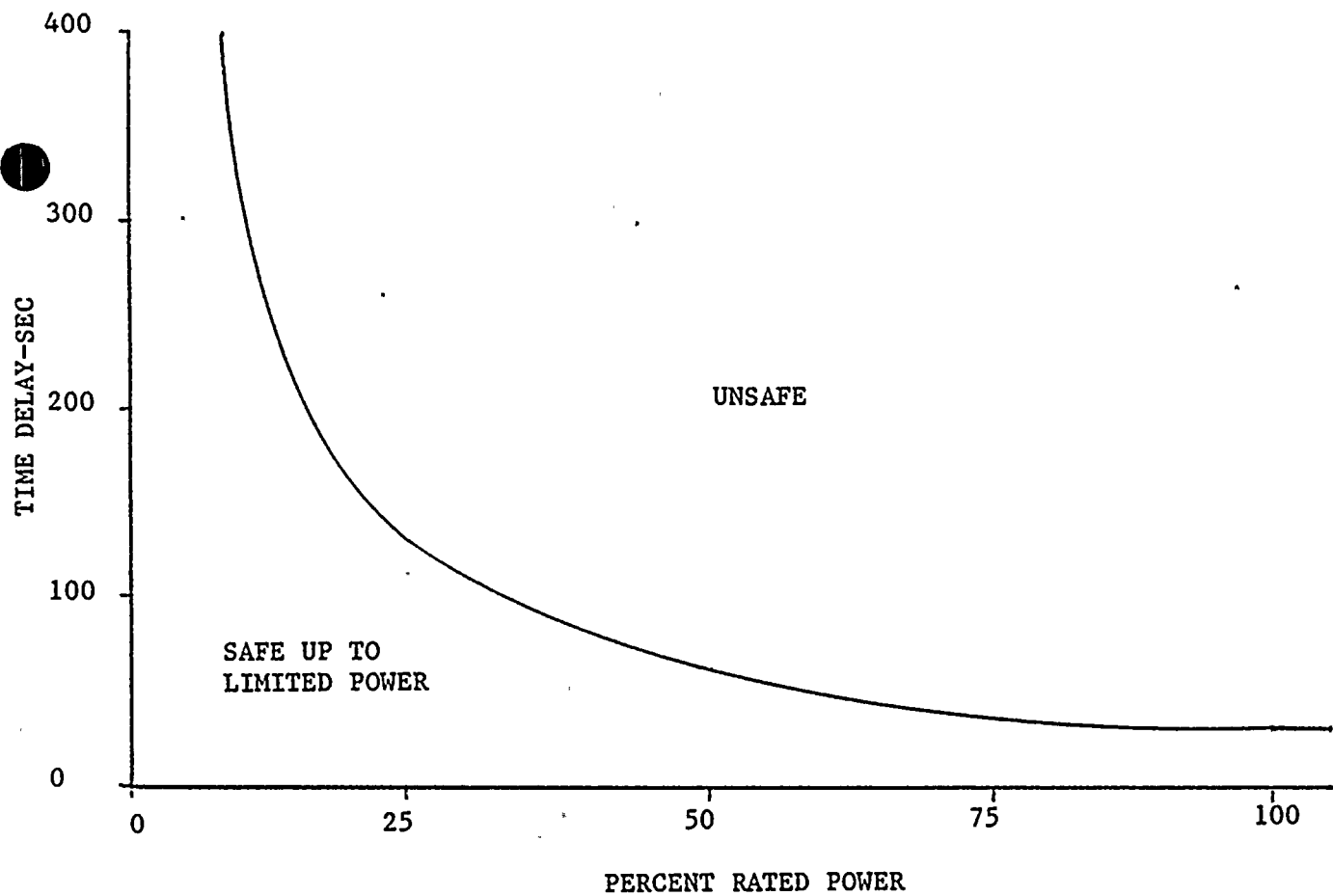
- (1) Rated core thermal power is 3293 MW. Rated core flow is  $106.5 \times 10^6$  lb/hr.
- (2) 45% power rod line goes through 45% rated core thermal power and 100% rated core flow.  
75% power rod line goes through 75% rated core thermal power and 100% rated core flow.  
100% power rod line goes through 100% rated core thermal power and 100% rated core flow.

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SUSQUEHANNA STEAM ELECTRIC STATION  
UNITS 1 AND 2  
FINAL SAFETY ANALYSIS REPORT

POWER FLOW MAP AND POWER  
TEST CONDITIONS

FIGURE 14.2-6 Sh. 2



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SUSQUEHANNA STEAM ELECTRIC STATION  
UNITS 1 AND 2  
FINAL SAFETY ANALYSIS REPORT

RCIC ACCEPTANCE CRITERIA  
CURVES FOR CAPACITY  
AND ACTUATION TIME

FIGURE -14.2-7

16.2 PROPOSED FINAL TECHNICAL SPECIFICATIONS

This section will be submitted later using the NRC's Standard Technical Specifications.

17.2 QUALITY ASSURANCE DURING THE OPERATIONS PHASE17.2.0 INTRODUCTION

PP&L is fully responsible for testing, operating, maintaining, refueling and modifying the Susquehanna SES in compliance with Federal, State, and local laws and the plant operating license requirements. These activities are also performed in response to required codes and specified QA related NRC regulatory guides. These regulatory guides and associated ANSI standards are listed in Table 17.2-1.

To assure compliance with 10CFR50, Appendix B requirements, PP&L has established and implemented a management control plan for assuring the quality of safety-related activities during the operations phase. The plan consists of a) this Operational Quality Assurance (OQA) Program which contains PP&L's quality assurance commitments to the Nuclear Regulatory Commission; b) the OQA Manual which contains Operational Policy Statements (OPS) and defines PP&L's policies for meeting these commitments; and c) Nuclear Department Instructions and functional unit procedures which contain the detailed steps necessary for a functional unit to comply with the OQA Program requirements. The relationships between these documents are shown in Figure 17.2-1.

In implementing the OQA Program, PP&L assures that its activities comply with Federal Regulations which are designed to protect the health and safety of the public.

The OQA policies, goals and objectives of PP&L are stated in the following Nuclear Quality Philosophy and Intent statement:

For the Susquehanna Steam Electric Station, Pennsylvania Power & Light Company will comply with the requirements of 10CFR50, Appendix B, Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants and other applicable federal regulations with respect to all safety-related activities which include engineering, design, procurement, construction, preoperational testing, power testing, operation, maintenance, refueling, repairing, modification and in-service inspection. PP&L is also committed to be responsive to the applicable Regulatory Guides, Industrial Codes and Standards, or parts thereof, as specifically noted in controlling documents. The applicability of these Guides, Codes, and Standards, or parts thereof, and their effectiveness shall be interpreted by the responsible managers. If Guides, Codes, or Standards are nonexistent or inadequate, PP&L shall develop the required practices and procedures with the controls necessary for their implementation.



17.2.1 ORGANIZATION

PP&L has established the Nuclear Department in order to provide a cohesive management team with the primary objective of providing long term technical and management support for Susquehanna SES. In addition to the resources within the Nuclear Department, auxiliary support is provided by the Construction Manager and the Manager-Procurement. The key management positions responsible for the performance of safety related activities are described in the following subsections. Figure 17.2-2 shows the organizational structure and lines of responsibility for the groups that provide technical and management support for Susquehanna SES.

The positions listed below are described in the following subsections:

- Senior Vice President-Nuclear
- Vice President-Engineering and Construction (E&C)-Nuclear  
(Project Director)
- Vice President-Nuclear Operations
- Assistant Project Directors
- Manager-Nuclear Plant Engineering (NPE)
- Project Construction Manager
- Manager-Nuclear Quality Assurance (NQA)
- Superintendent of Plant
- Assistant Superintendent of Plant
- Assistant Superintendent-Outages
- Integrated Startup Group Supervisor
- Manager-Nuclear Support
- Manager-Nuclear Training
- Manager-Nuclear Safety Assessment
- Manager-Nuclear Licensing
- Manager-Nuclear Administration
- Construction Manager
- Manager-Procurement

In addition to the above individuals, the Susquehanna Review Committee (SRC) is established as a review, audit and advisory group, comprised of at least five key Nuclear Department managers, whose function is to verify independently that the Susquehanna SES is being tested, operated and maintained in accordance with all safety related, ALARA and environmental requirements. The SRC will perform the independent review mandated by ANSI N18.7.

17.2.1.1 Senior Vice President - Nuclear

The Senior Vice President - Nuclear has overall authority and responsibility for the Susquehanna OQA Program and, as a result, he:

- (a) Requires the performance of an annual, preplanned and documented assessment of the OQA Program in which corrective action is identified and tracked.
- (b) Sets OQA Policies, goals and objectives for safe operation of Susquehanna SES.
- (c) Commits PP&L to an OQA Program designed to assure compliance with regulatory requirements.
- (d) Requires compliance with the provisions of the OQA Program and causes periodic assessments of PP&L commitments and established practices for safe plant operation.

In order to maintain a continuing involvement in QA matters, the Senior VP-Nuclear receives monthly written reports on the status and adequacy of the OQA Program issued by the Manager-NQA and reviews and approves the Operational Policy Statements contained in the OQA Manual prior to their issuance.

The Senior VP - Nuclear delegates to the VP - E&C - Nuclear and the VP-Nuclear Operations those responsibilities for attaining specified quality levels and to the Manager-Nuclear Quality Assurance those responsibilities for verifying that those quality levels have been met.

The Senior VP - Nuclear delegates to the Manager-Nuclear Safety Assessment the responsibility for performing the on-site Independent Safety Engineering Group (ISEG) function mandated by NUREG-0731.

In addition, the Senior Vice President-Nuclear has overall corporate responsibility for Susquehanna SES activities related to engineering, construction, startup and operations. The Senior VP-Nuclear delegates these responsibilities to the Vice President-E&C-Nuclear, and the Vice President-Nuclear Operations. The reporting relationships are shown in Figure 17.2-2.

17.2.1.1.1 Vice President - Engineering & Construction (E&C) - Nuclear

The VP - E&C - Nuclear (also identified as the Project Director on Figure 17.2-2) has overall corporate responsibility for the Susquehanna engineering, construction and licensing activities as delegated by the Senior VP-Nuclear. In addition, as Project Director, he directs and is accountable for all facets of project performance through project completion.

17.2.1.1.1.1 Assistant Project Directors

The Assistant Project Directors at the site (APD-S) and Allentown (APD-A) are responsible to the Project Director for the engineering and construction aspects of the project. Their responsibilities encompass the day-to-day decision-making process, conduct of project activities, and contract administration. They also coordinate the support functions of other company departments as they interface with the project.

The (APD-S) has a direct coordination and integration relationship with the NQA Resident Nuclear Quality Assurance Engineer (RNQAE). The RNQAE, in turn, has the responsibility to support the APD-S objectives by alerting the APD-S to quality related matters which have the potential for adversely affecting construction activities.

17.2.1.1.1.2 Manager - Nuclear Plant Engineering

The Manager - NPE is responsible for engineering activities (including those related to nuclear fuel) and their quality management. These activities include a) design and design verification related to plant modifications, b) the technical evaluation and approval of acceptable suppliers of parts, components, equipment, and systems, c) specifying technical requirements for the procurement of spare parts, d) modifications to the "as-built" plant, and e) engineering outage support.

17.2.1.1.1.3 Project Construction Manager

The Project Construction Manager is responsible for the performance of construction activities at Susquehanna SES, including that of prime contractors, and for the preparation of equipment and systems for turnover to the Integrated Startup Group for testing. The Project Construction Manager receives

administrative and project technical direction from the Project Director through the Assistant Project Director-site.

#### 17.2.1.1.1.4\_\_Manager\_-\_Nuclear\_Licensing

The Manager-Nuclear Licensing is responsible for directing the licensing aspects for Susquehanna SES. This includes interfacing with the Licensing Branch of the NRC, updating and changing the PSAR to reflect as-built conditions or modifications, and coordinating responses to the NRC relative to IE Bulletins.

#### 17.2.1.1.2\_\_Vice\_President\_-\_Nuclear\_Operations

The Vice President-Nuclear Operations is responsible for the Initial Test Program and operation of Susquehanna SES. This includes formulating and establishing the necessary technical and administrative staff and planning and coordinating the activities of these personnel.

The Vice President-Nuclear operations delegates responsibilities to the Superintendent of Plant, Manager-Nuclear Support, Manager-Nuclear Training, and Manager-Nuclear Administration.

#### 17.2.1.1.2.1\_\_Superintendent\_of\_Plant

The Superintendent of Plant is responsible for Susquehanna SES during plant testing, startup, and operation and has overall responsibility for the Initial Test Program conducted by the Integrated Startup Group.

The Superintendent of Plant is responsible for the safe operation of Susquehanna SES and has overall responsibility for the execution of the administrative controls at the plant to assure safety. The Superintendent of Plant ensures that plant operations are conducted in accordance with the plant operating license, technical specifications, the PSAR, and the OQA Program with its implementing documents. The Superintendent of Plant delegates his authority for performing activities related to operation of the plant to the Assistant Superintendent of Plant, Assistant Superintendent-Outages, Supervisor of Operations, Supervisor of Maintenance, Technical Supervisor, and other personnel assigned to the staff organization.

The Superintendent of Plant reports to and is directly accountable to the Vice President-Nuclear Operations for activities directly related to plant support of preoperational testing.

17.2.1.1.2.1.1 Assistant Superintendent of Plant

The Assistant Superintendent of Plant assists the Superintendent of Plant in all matters and assumes the responsibilities of the Superintendent of Plant in his absence.

17.2.1.1.2.1.2 Assistant Superintendent-Outages

The Assistant Superintendent-Outages reports to the Superintendent of Plant and is responsible for outage management at Susquehanna SES including planning, establishment of goals, and performance.

17.2.1.1.2.1.2.1 Integrated Startup Group Supervisor

The Integrated Startup Group Supervisor has the responsibility for supervising the conduct of the Integrated Startup Group (ISG). The ISG Supervisor reports to the Assistant Superintendent-Outages on matters pertaining to the Initial Test Program (ITP). The qualifications for this position are listed in Chapter 14.2.

17.2.1.1.2.2 Manager - Nuclear Support

The Manager - Nuclear Support is responsible for coordinating both Nuclear Department activities and selected outside service organization activities in support of Susquehanna SES startup and operation.

The Manager - Nuclear Support provides technical assistance to the Susquehanna SES Plant Staff in the areas of operation and maintenance.

The Manager - Nuclear Support advises the VP-Nuclear Operations of activities within or affecting the Nuclear Department and advises the Susquehanna SES Plant Staff of potential changes to plant operating and maintenance requirements by reviewing changes to Regulatory Guides, Industry Standards and other industry literature.

17.2.1.1.2.3 Manager - Nuclear Training

The Manager-Nuclear Training is responsible for assessing the long term training needs regarding Susquehanna SES and developing training programs commensurate with those needs.

#### 17.2.1.1.2.4 Manager - Nuclear Administration

The Manager-Nuclear Administration is responsible for developing and implementing a nuclear records management system and directing all interfacing organizations toward the implementation of the system. The Manager-Nuclear Administration is also responsible for establishing and maintaining a document control system for Susquehanna SES.

#### 17.2.1.1.3 Manager - Nuclear Safety Assessment

The Manager-Nuclear Safety Assessment is responsible for independently reviewing and monitoring all nuclear activities to ensure that they are performed in a manner which results in safe reliable operation.

#### 17.2.1.1.4 Manager - Nuclear Quality Assurance

The Manager-NQA is responsible for:

- (a) Directing and coordinating the development and updating of PP&L's OQA Program.
- (b) Assuring overall implementation of the OQA Program.
- (c) Interpreting the OQA Program, subject to the approval of the Senior Vice President - Nuclear.
- (d) Auditing, monitoring, inspecting and witnessing, as necessary, contractor, vendor and plant safety-related activities to assess compliance with the requirements of the OQA Program and/or procurement documents, and reporting the results of these activities to responsible management.
- (e) Reviewing Nuclear Department Instructions and functional unit procedures to assure compliance with the OQA Program.
- (f) Providing training assistance in OQA Program requirements.

- (g) Implementing the QA and site QC activities identified in the OQA Program.
- (h) Reviewing and auditing the OQA Program provisions that are applied to the fire protection program and reporting the results of these activities to responsible management.
- (i) Implementing the nondestructive examination training, qualification and certification program.
- (j) Evaluating potential suppliers of material equipment and services to determine their capabilities for providing quality products or services.
- (k) Overseeing the administrative integration of the OQA and Environmental auditing programs for Susquehanna SES.
- (l) Reviewing and approving quality assurance requirements in procurement documents.

The Manager - NQA is responsible for taking action (including work stoppage), as necessary to correct conditions adverse to quality. The Manager - NQA is responsible for informing the Superintendent of Plant when it is determined that safety-related components or the activities performed on these components fail to comply with approved specifications, plans, or procedures. The Superintendent of Plant retains the responsibility for the evaluation of conditions adverse to quality with regard to plant operation and is responsible for determining when an operating unit(s) is to be shut down.

PP&L requires that the Manager-NQA shall have qualifications that are commensurate with the responsibilities of that position. As a minimum, these shall include a B.S. in Engineering and ten years experience in Engineering and/or Construction. At least one year of this ten years experience shall be nuclear power plant experience in the overall implementation of the quality assurance program.

The Manager - NQA and the NQA Staff are independent of organizations responsible for performing safety-related activities. The NQA Section has sufficient authority and organizational freedom to identify quality problems, to initiate, recommend or provide solutions through designated channels, and to verify implementation of solutions.

The PP&L Nuclear Quality Assurance functional structure is shown in Figure 17.2-3. The Manager - NQA delegates functional responsibilities for accomplishing quality assurance activities as follows:

A. Quality Engineering & Procurement

1. Quality Engineering

- (a) Interface with engineering organizations to accomplish the incorporation of quality requirements in design, test, & procurement documents via the specification, review and approval process.
- (b) Interface to provide QA coverage of nuclear fuel.
- (c) Review and maintain cognizance of applicable codes and standards.
- (d) Review and support responses to NRC Bulletins, Circulars, and Information Notices.
- (e) Review and support for reporting items per 10CFR50.55(e) and 10CFR21.
- (f) Provide technical support for auditing.
- (g) Coordinate responses to NRC Inspections.
- (h) Provide administrative support functions.

2. Procurement

- (a) Perform vendor QA program evaluations, surveys and performance trending and rating, vendor audits.
- (b) Perform technical review/acceptance of vendor QA records.
- (c) Provide for post award vendor meetings (review P.O. provisions).
- (d) Perform Source surveillance/verification.

B. Construction

- (a) Interface with QA and QC organizations for plant construction support.
- (b) Interface with NRC construction inspectors.
- (c) Provide direct support of the preservice inspection activities.
- (d) Retain direct responsibility for the review of NDE procedures.



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- (e) Provide QA support for specified major modifications during plant operations.
- (f) Interface with the Authorized Nuclear Inspector.
- (g) Perform audits of construction activities.
- (h) Review of construction procedures and instructions.
- (i) Perform field checks and verification of responses to NRC citations, bulletins, circulars and reportable conditions related to construction activities.
- (j) Provide for completion of N-3 Forms.
- (k) Perform quality trending of construction related activities.

### C. Operations

#### 1. Quality Assurance

- (a) Interface with the Plant Staff and ISG for the QA support of preoperational, startup testing and plant operations.
- (b) Review administrative, preoperational and startup test procedures.
- (c) Interface with NRC operations inspectors.
- (d) Perform field checks and verification of responses to NRC citations, bulletins, circulars and reportable conditions related to operations activities.
- (e) Perform audits of operations.
- (f) Perform quality trending of plant operations related activities.

#### 2. Quality Control

- (a) Inspect maintenance, modification, repair, testing and PP&L Construction activities.
- (b) Perform and interpret the results of NDE.
- (c) Perform receipt inspection and acceptance of material, equipment and consumables.

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- (d) Evaluate NCRs for trends.
- (e) Review procedures for insertion of hold/notification points.
- (f) Perform inspection planning.

### 3. Quality Systems & Training

- (a) Provide for auditor training, qualification and certification.
- (b) Provide for Inspector training, qualification and certification.
- (c) Coordinate QA indoctrination and training for the NQA section and other PL organizations.
- (d) Maintain the Construction QA Program.
- (e) Develop and maintain the Operational QA Program.
- (f) Develop and maintain NQA Section procedures.

### D. Auditing

- 1. (a) Schedule and scope programmatic audits of PP&L and other organizations.
- (b) Coordinate the implementation of programmatic audits and the allocation of auditor resources through the other NQA supervisors.
- (c) Perform audits of other NQA subsections.
- (d) Evaluate and trend the results of the auditing effort.
- (e) Perform audit follow-up and verification/close-out.

The Manager-NQA is responsible for initiating correspondence such that the NRC is notified of changes to (1) the accepted FSAR QA program description prior to their implementation, and (2) organizational elements within thirty (30) days after their announcement. (Note--editorial changes or personnel reassignments of a non-substantive nature do not require NRC notification.)

### 17.2.1.2 Construction Manager

The Construction Manager is responsible for providing the necessary organization, trained resources and equipment for the performance of maintenance tasks during normal operations and for outages. The same organization and resources will also be responsible for completion of plant modifications, repairs and/or additions to the operating plant. These operations will encompass projects/tasks assigned by the Superintendent of Plant either directly or through the on-site organization.

Activities will be defined in procedures developed in accordance with OQA Program requirements.

#### 17.2.1.3 Manager - Procurement

The Manager - Procurement is responsible for the purchase of equipment, materials, supplies and services that conform to all applicable purchasing specifications and for procuring equipment, materials, supplies, and services from approved suppliers (except for nuclear fuel as specified in Subsection 17.2.1.1.2.5). Procedures shall define how the procurement process is controlled in accordance with OQA Program requirements.

#### 17.2.2 QUALITY ASSURANCE PROGRAM

The Operational Quality Assurance (OQA) Program is applied to all safety-related Susquehanna SES structures, systems, components, and activities.

SAFETY-RELATED is a generic term applied to:

1. Those systems, structures, and components that meet one or more of the following requirements:
  - (a) Maintain the integrity of the Reactor Coolant System pressure boundary.
  - (b) Assure their capability to prevent or mitigate the consequences of accidents that could cause the release of radioactivity in excess of 10CFR100 limits.
  - (c) Preclude failures which could cause or increase the severity of postulated accidents or could cause undue risk to the health and safety of the public due to the release of radioactive material.
  - (d) Provide for safe reactor shutdown and immediate or long term post accident control.

2. Those activities that affect the systems, structures and components discussed in Item 1 above such as their design, procurement, construction, operation, refueling, maintenance, modification and testing.

The Manager - NPE is responsible for maintaining a list designating those structures, systems, and components which are safety-related based upon the applicable portions of Table 3.2-1.

The OQA Program will be implemented at least 90 days prior to fuel load. Safety-related activities occurring prior to the implementation of the OQA Program will be controlled by the Susquehanna QA Program. The Susquehanna QA Program will be modified through amendments to the PP&L QA Manual, as necessary, to cover new activities occurring during the preoperational testing phase.

The Senior Vice President - Nuclear has assigned to the Manager - Nuclear Safety Assessment the responsibility for regularly assessing the scope, status, implementation, and effectiveness of the OQA Program. This will assure that the Program is adequate and complies with 10CFR50, Appendix B.

The OQA Program requires that safety-related activities be performed using specified equipment under suitable environmental conditions and that prerequisites have been satisfied prior to inspection and test.

The Manager - NQA is responsible for establishing and maintaining the OQA Program and for insuring that it provides adequate control of all activities. The Manager - NQA is responsible for assuring that functions delegated to principal contractors are being properly accomplished. Supplier QA programs are evaluated to determine that the requirements of 10CFR50 Appendix B will be implemented and this evaluation is documented.

The corporate OQA policies, goals, and objectives are transmitted to the persons performing activities which are required by the OQA Program and supporting documents. The commitments of the OQA Program are described in Chapter 17 which also assigns responsibilities for implementing OQA Program commitments. The OQA Manual contains Operational Policy Statements (OPS) which stipulate PP&L QA policies, goals and objectives for implementing the OQA Program commitments. These policies give generic direction for the performance of activities. A synopsis of the OPS and a matrix which cross-references them to each criterion of Appendix B to 10 CFR Part 50, is contained in Table 17.2-2.

The OQA Program is patterned after and fully complies with ANSI N18.7-1976 as modified by NRC Regulatory Guide 1.33, Revision 2 except for the review frequency of certain procedures (i.e. reagent preparation) which employ standardized methods for

performance of plant-support evolutions. The review frequency for these procedures will be established appropriate to the nature of the activities addressed by the procedures. The degree of compliance with other regulatory guides and associated ANSI Standards is listed in Table 17.2-1. Where guides, codes or standards are nonexistent or inadequate, PP&L will develop methods to provide the necessary control.

The OQA Program requirements are mandatory for all safety-related activities. Each functional unit manager is responsible for assuring that safety-related activities performed by that functional unit, meet the requirements of the OQA Program. The Manager - NQA is responsible for the audit, review, inspection and verification of activities both onsite and offsite to assure that they are accomplished according to the OQA Program requirements. QC activities shall be performed in compliance with the OQA Program requirements.

Disagreements between NQA and other department personnel (such as Engineering, Construction, Fuels, Plant Staff, and Procurement) concerning the OQA Program and related activities will be resolved between the Manager-NQA and the affected department's supervisor or manager. Disagreements not resolved at these levels will be referred to the Senior Vice President - Nuclear for resolution.

The OQA Manual, which contains OPS, is controlled and distributed by the NQA Section. All managers responsible for the performance of safety-related activities will be issued controlled copies of the OQA Manual.

The Manager - NQA is responsible for obtaining appropriate review and approval of the content and changes to the OQA Program and Manual. Any group performing activities governed by the OQA Program and Manual may propose changes to these documents. All OQA Program (FSAR Section 17.2) changes require review by the Manager - NQA, the Vice President - E&C - Nuclear and the V.P. - Nuclear Operations, and approval by the Senior Vice President - Nuclear. All OQA Manual changes shall be reviewed by functional unit managers affected by the change and reviewed and approved by the Manager - NQA, Vice President - E&C - Nuclear, V.P. - Nuclear Operations and Senior VP - Nuclear. Nuclear Department Instructions which implement the OQA Program shall be reviewed by the Manager-NQA and approved by the appropriate Vice President. Functional unit procedures shall be reviewed by the Manager - NQA and reviewed and approved by the appropriate functional unit manager. Control of QA programs other than the applicant's is addressed in Subsection 17.2.7.

Individuals performing inspection, examination and testing functions associated with normal operations of the plant, such as surveillance testing, routine maintenance and certain technical

reviews normally assigned to the on-site operation organization shall be qualified to ANSI 3.1-1978. Personnel whose qualifications are not required to meet those specified in ANSI 3.1 and who are performing inspection, examination and testing activities during the operational phase of the plant shall be qualified to ANSI 3.1-1978 N45.2.6-1978, except that the QA experience cited for Levels I, II and III shall be interpreted to mean actual experience in carrying out the types of inspection, examination and testing activity being performed.

Managers are responsible for assuring that their personnel receive the indoctrination and training necessary to properly perform their activities. The indoctrination and training program shall be such that personnel performing activities are knowledgeable in procedures and requirements and proficient in implementing those procedures. The program assures that:

- (a) Personnel responsible for performing activities are instructed as to the purpose, scope, and implementation of the safety-related manuals, instructions, and procedures which control their activities.
- (b) Personnel performing activities are trained and qualified in the principles and techniques of the activity being performed.
- (c) The scope, the objective, and the method of implementing the indoctrination and training program are documented.
- (d) Proficiency of personnel performing activities is maintained by retraining. Re-examination and/or recertification will be utilized as applicable.
- (e) Methods are provided for documenting training sessions, including a description of the content and results and a record of attendance.

The Management and technical interfaces between Bechtel, General Electric and PP&L during the Initial Test Program are described in the Start-up Administrative Manual. The Susquehanna SES QA Program as modified by amendments to the QA Manual will describe the receipt and processing of QA records by PP&L.

In addition, certain provisions of the OQA Program are applied to fire protection. These provisions apply to those items within the scope of the fire protection program such as fire protection systems, emergency lighting, communication, and breathing apparatus, as well as the fire protection requirements of applicable safety-related equipment. Specifically, the OQA Program applies to the 10 criteria listed in Regulatory Position

C.3 in the U.S. NRC Regulatory Guide 1.120 Revision 1, Fire Protection Guidelines for Nuclear Power Plants.

The OQA Program is also structured and implemented such that the requirements of 10CFR71, Appendix E, Quality Assurance Criteria for Shipping Packages for Radioactive Material, are fulfilled.

### 17.2.3 DESIGN CONTROL

The OQA Program documents identify those managers responsible for performing design activities and describe their responsibilities and methods for meeting the OQA Program requirements.

The functional unit's procedures detail the steps necessary for its compliance with the requirements for its associated design activities. These procedures assure that design activities including changes in the design are carried out in a planned, controlled, and orderly manner.

Applicable design inputs such as regulatory requirements, codes and standards, and design bases shall be reflected in design output documents such as specifications, drawings, written procedures, and instructions. These design output documents shall specify the appropriate quality standards and any deviations from these quality standards will be accomplished in accordance with OQA Program requirements.

The design control process shall include, but not be limited to, the following, where applicable:

- (a) Reactor physics
- (b) Seismic, stress, thermal, hydraulic, radiation, and accident analyses
- (c) Material compatibility
- (d) Accessibility of items for in-service inspection, maintenance, and repair
- (e) Verification that the design characteristics can be controlled, inspected and tested
- (f) Identification of inspection and test criteria

The design engineer shall evaluate and select suitable materials, parts, equipment, and processes for safety-related structures, systems, and components. This evaluation and selection shall include the use of appropriate industry standards and specifications. Materials, parts, and equipment which are

standard, commercial (off the shelf), or which have been previously approved for a different application, shall be reviewed for suitability in the intended application prior to use.

Internal and external interfaces between organizations performing work affecting quality of design shall be identified. Procedures shall be established to control the flow of design information between organizations. These procedures shall include the review, approval, release, distribution, and revision of documents involving design interfaces with other organizations.

Designs shall be reviewed to assure that design characteristics can be verified and acceptance criteria are identified.

Designs shall be verified by reviewing, alternate calculations, or qualification testing. Design verification shall be performed by a qualified person or group other than the original designer or the designer's immediate supervisor. However, supervisors may perform design verification subject to the restrictions of Paragraph C.2 of Regulatory Guide 1.64, Revision 2. Procedures for design verification shall identify the responsibility and authority of persons or groups performing design verifications. When a test program is used to verify the adequacy of a design, the test will be performed on a prototype unit or initial production unit and shall demonstrate adequacy of performance under the most adverse design conditions.

Changes to design output documents, including field changes, shall be subjected to design control measures the same as, or equivalent to, the original measures.

Responsible plant personnel are made aware of design changes/modifications which may affect the performance of their duties by:

- (a) Plant Operations Review Committee review of all modification packages prior to installation.
- (b) Installation of modifications are controlled by the plant work authorization system.
- (c) Nuclear Plant Engineering notifies plant supervisors of design changes to allow updating of procedures.
- (d) Effects of modifications are incorporated into the plant training program.

Errors and deficiencies in the design or the design process that could adversely affect safety-related structures, systems, and components will be documented and corrective action will be taken



in accordance with Subsection 17.2.16. Design documents, including changes are filed as described in Subsection 17.2.17.

#### 17.2.4 PROCUREMENT DOCUMENT CONTROL

OQA Program documents identify those managers responsible for activities related to the control of procurement documents and describe their responsibilities and methods for meeting the OQA Program requirements. Procedures detail the steps to be accomplished in the preparation, review, approval and control of procurement documents. Managers are responsible for establishing, maintaining and implementing procedures as required for their functional unit to comply with OQA Program requirements.

Procurement documents shall contain or reference as applicable:

- (a) Design basis technical requirements including the applicable regulatory requirements.
- (b) Component and material identification requirements.
- (c) Drawings.
- (d) Specifications.
- (e) Codes and industry standards.
- (f) Manufacturers' test and inspection requirements.
- (g) Special process instructions.

Procurement documents shall identify a) the applicable quality requirements which must be met and described in the supplier's QA program, b) the documentation (such as drawings, specifications, procedures, inspection and fabrication plans, inspection and test records, personnel and procedure qualifications and material, chemical and physical test results) to be prepared, maintained and submitted to PP&L for review and approval, and c) those records which shall be retained, controlled, maintained or delivered to PP&L prior to use or installation of the purchased items. Procurement documents shall also contain provisions for PP&L or its agent, as applicable, to have the right of access to suppliers' and subtier suppliers' facilities and records for source inspection and audits. Procurement documents shall also require that the supplier submit, when required, its QA Program or portions thereof to PP&L for review and approval by qualified QA personnel prior to initiation of activities controlled by the Program.

Procurement documents shall be reviewed by qualified personnel for adequacy of quality requirements (such as acceptance and rejection criteria). Quality requirements shall be correctly stated, inspectable and controllable. Prior to their release, procurement documents shall have been prepared, reviewed and approved in accordance with OQA Program requirements. The procurement document review and approval is documented and filed as described in Subsection 17.2.17.

When procurement documents are revised, they are subject to the same or equivalent review and approval as the original document.

Procurement documents for safety-related spare or replacement parts for structures, systems and components are subject to controls the same as or equivalent to those used for the original equipment. All activities described in this subsection are to be performed by personnel qualified to perform the activity.

#### 17.2.5 INSTRUCTIONS, PROCEDURES AND DRAWINGS

Activities shall be accomplished in accordance with documented instructions, procedures or drawings. This subsection applies to internal PP&L instructions, procedures and drawings. Such requirements for contractors and vendors are included in procurement documents as discussed in Subsection 17.2.4.

There are three general levels of OQA Program documents which are used to implement the OQA Program. The first document level is comprised of Operational Policy Statements (OPS) which describe PP&L's policies for complying with 10CFR50, Appendix B and OQA Program requirements. These OPS delineate the requirements for preparing, reviewing, approving, and controlling instructions, procedures, and drawings.

The second level of documents used to implement the OQA Program consists of Nuclear Department Instructions (NDI). These documents describe inter- and intra-department interfaces and may provide detailed instructions for implementing the OQA Program requirements. The third level of documents consists of functional unit procedures, which detail the specific instructions required to implement the Operational Quality Program requirements. These documents require that instructions, procedures or drawings specify the methods utilized in complying with OPS requirements. Instructions, procedures and drawings controlled by the OQA Program shall include quantitative (such as dimensions, tolerances, and operating limits) and qualitative (such as workmanship samples) acceptance criteria for use in determining that important activities have been satisfactorily accomplished.

The functional unit manager shall prepare, obtain the appropriate review, approve, issue, and revise the Nuclear Department Instructions and the functional unit procedures which control the activities of that group. These procedures are reviewed by cognizant functional unit personnel for accuracy and workability and by QA personnel for compliance with OQA Program requirements.

Inspection plans; test, calibration, special process, maintenance, modification and repair procedures; drawings and specifications; and changes thereto are subject to audit for their compliance with OQA Program requirements.

#### 17.2.6 DOCUMENT CONTROL

The document control system described in OQA Program documents requires that, prior to their release, documents and changes thereto are reviewed for their adequacy and approved and released by authorized personnel and distributed for use at the location where the prescribed activity is to be performed. The documents controlled under this subsection as a minimum include:

- (a) Design Specifications
- (b) Procurement Documents
- (c) Test Procedures
- (d) Design, Manufacturing, Construction and Installation Drawings
- (e) Manufacturing, Inspection, and Testing Instructions
- (f) Final Safety Analysis Report
- (g) OQA Program Documents
- (h) Maintenance and Modification Procedures
- (i) Non-conformance Reports

The NQA Section or other qualified individuals delegated by NQA, but other than the person who generated the document, shall review and concur with the document and changes thereto, with regard to QA-related aspects prior to implementation.

Each manager who is responsible for issuing a document is also responsible for obtaining the proper review and approval of that document. Changes to documents are reviewed and approved by the same organizations that performed the original review and approval unless specifically delegated to other qualified

organizations. This review will be completed prior to issuing the document except for temporary procedures/instructions issued by the Susquehanna SES Plant Staff. This special case is described in Section 6 of the Technical Specifications and the Susquehanna Plant Administrative Procedures.

Each functional unit manager is responsible for preparing and periodically issuing distribution lists and/or revision status lists, where necessary, for the control of quality documents issued by that functional unit. These lists identify the additions and changes made to documents since the previous report period and assist recipients in maintaining up-to-date files. Each recipient is responsible for reviewing the latest list(s) to confirm that the current revision of each document is available. Prior to implementation, approved changes are included in instructions, procedures, drawings, or other documents by procedurally controlled change mechanisms.

It is the responsibility of each functional unit supervisor/manager to assure that the proper documents such as instructions, procedures, and drawings are available at the location where the prescribed activities are performed.

The issuing department is responsible for describing and implementing measures which provide controls to prevent the inadvertent use of obsolete or superceded documents.

Individuals or groups responsible for preparation, review, approval, issue and distribution of quality documents and their revisions are identified in the OQA Program documents.

#### 17.2.7 CONTROL OF PURCHASED MATERIAL, EQUIPMENT & SERVICES

PP&L OQA Program documents list those managers responsible for performing activities related to the control of purchased material, equipment and services; describe their responsibilities; and specify their methods for meeting the OQA requirements. Each functional unit's procedures detail the steps necessary for complying with these requirements for their activities.

PP&L's system for control is comprised of supplier evaluation, surveillance of the supplier during production, receipt inspection of items or services, and evaluation of supplier records. The extent and methods of control used assure compliance with applicable technical, manufacturing, and quality requirements.

Prior to the award of a purchase order or contract, PP&L evaluates the prospective supplier's ability to provide material,

equipment, and services which comply with the technical, design, manufacturing and quality requirements. The suppliers judged capable of meeting the requirements are considered approved suppliers for the specific article. The results of supplier evaluations are documented and the records maintained in accordance with Subsection 17.2.17.

The evaluation includes, as necessary, reviews of the records and performance of suppliers who have previously supplied similar articles, surveys of their facilities, and evaluations of their quality assurance programs to determine their ability to meet the design, manufacturing and quality requirements of the procurement document. These quality requirements include the applicable elements of 10CFR50 Appendix B.

Suppliers' activities during the design, fabrication, inspection, testing, and preparation for shipment of material, equipment and components are subject to surveillance to assure their compliance with the procurement document requirements.

The surveillance of suppliers is planned and performed in accordance with written procedures as described in Subsection 17.2.18. These procedures specify the characteristics or processes to be witnessed, inspected or verified and accepted; the method of surveillance; the extent of documentation required; and those responsible for implementing these procedures. These procedures also specify the audits and surveillances required to assure that the supplier complies with the quality requirements where compliance cannot be determined by receipt inspection.

As applicable, qualified personnel perform receipt inspection of material, equipment and services to assure that:

- (a) The material, component or equipment is properly identified and corresponds with the receiving documentation.
- (b) The material, component or equipment and its acceptance records are judged acceptable in accordance with pre-determined inspection instructions prior to installation or use.
- (c) Inspection records or certificates of conformance attesting to the acceptability of material, components, and equipment are available at Susquehanna SES prior to its installation or use.

Upon completion of the receipt inspection, items accepted and released are identified as to their inspection status prior to forwarding them to a controlled storage area or releasing them for installation or further work.

Supplier furnished records shall be reviewed and accepted by a qualified individual knowledgeable in quality assurance. These records shall, as a minimum, contain:

- (a) Documentation that specifically identifies by purchase order number the purchased material or equipment and the specific procurement requirements, such as codes, standards, and specifications met by the items.
- (b) Documentation that identifies any procurement requirements which have not been met together with a description of those nonconformances dispositioned "accept as is" or "repair".

The requirements of this subsection shall also be applied to the purchase of spare and replacement parts and shall assure that these parts have a level of quality consistent with their importance, complexity, and quantity.

Supplier certificates of conformance are periodically evaluated to verify their validity.

The effectiveness of the control of quality by suppliers is assessed by PP&L at intervals consistent with the importance, complexity, and quantity of an item.

#### 17.2.8 IDENTIFICATION AND CONTROL OF MATERIALS, PARTS & COMPONENTS

OQA Program documents list those managers responsible for performing activities related to the identification and control of materials, parts and components, including partially fabricated subassemblies, describe their responsibilities, and specify the methods for meeting the OQA program requirements. Detailed steps necessary to comply with these requirements are specified in procedures.

Procurement documents specify the requirements that PP&L suppliers must comply with for the identification of material, parts, and components (including partially fabricated subassemblies).

Item identification is maintained either on the item or on records traceable to the item to prevent the use of incorrect or defective items throughout fabrication, erection, installation and use. The location, type, and application method of the identification shall not affect the fit, function, or quality of the item being identified.

Materials and parts, as required by their importance to plant safety and applicable codes, standards and regulatory

requirements, shall be traceable to appropriate documentation such as drawings, specifications, purchase orders, manufacturing and inspection documents, deviation reports and physical and chemical mill test reports.

The correct identification of materials, parts, and components is verified and documented prior to release for fabrication, assembly, installation or shipping.

#### 17.2.9 CONTROL OF SPECIAL PROCESSES

Special processes are those that require interim in-process controls in addition to final inspection to assure quality. OQA Program documents identify those managers responsible for the writing, qualifying, approving and issuing of procedures for special processes. Procedures for special processes are prepared in accordance with applicable codes, standards, specifications, criteria, and other special requirements to control processes such as welding, heat treating, nondestructive examination (NDE), and chemical cleaning. Personnel performing special processes and the procedures and equipment used for this activity are qualified in accordance with applicable codes, standards and specifications. The procedures for special processes specify the requirements for their control, the parameters to be considered, the methods of documentation, and applicable codes, standards, specifications or supplementary requirements which govern their qualification. The special processes are accomplished in accordance with written process sheets, or equivalent, with recorded evidence of verification. When special processes are not covered by existing codes and standards, or when item quality requirements exceed the requirements of established codes or standards, the necessary qualifications for personnel, procedures or equipment are defined.

Records verifying the qualification of personnel to perform special processes are maintained in a current status.

Procurement documents specify contractor responsibility for controlling special processes and for maintaining records to verify that special processes are performed in accordance with established requirements.

#### 17.2.10 INSPECTION

OQA Program documents identify those managers responsible for the preparation, approval, and issuance of inspection procedures. The documents also identify those managers responsible for the performance of inspections. Onsite and offsite activities

affecting quality are inspected in accordance with written controlled procedures to verify conformance with applicable procedures, design documents, codes and specifications for accomplishing the activity. Activities affecting quality are subject to inspections in areas such as:

- (a) Special Processes as identified in Subsection 17.2.9.
- (b) Modifications to the Plant.
- (c) Receipt of Materials, Parts or Components.
- (d) Plant Operations.
- (e) Repairs or Replacement of Equipment.
- (f) Inservice Inspection.

Inspection activities conform to the following requirements:

- (a) Inspection personnel are qualified individuals other than those who performed or directly supervised the activity being inspected.
- (b) Mandatory inspection hold points are identified in inspection procedures.
- (c) Modifications, repairs and replacements are inspected in accordance with the original design and inspection requirements or approved alternatives.
- (d) Maintenance and modification procedures are reviewed by qualified personnel knowledgeable in quality assurance requirements to determine the need for (a) inspection, (b) identification of inspection personnel, and (c) documenting inspection results. The criteria for performing inspections are based upon an activity's complexity, uniqueness and impact on safety.
- (e) If direct inspection of processed material or products is impossible or disadvantageous, indirect control by monitoring processing methods, equipment, and personnel is provided.
- (f) Inspectors are trained and qualified in accordance with appropriate codes, standards, and company training programs and their qualifications and certifications are kept current.
- (g) Inspection instrumentation is calibrated and has an uncertainty (error) equal to or less than the tolerance stated in the acceptance criteria.



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- (h) Inspection of activities is accomplished according to approved procedures, instructions, and check lists. These inspection documents contain the following:
  - (1) Identification of the items or activities to be inspected.
  - (2) Identification of the characteristics of the items or activities inspected.
  - (3) Identification of the individuals or groups responsible for performing the inspection.
  - (4) Identification of acceptance and rejection criteria.
  - (5) A description of the method of inspection including necessary measuring and test equipment.
  - (6) Evidence of completion and verification of a manufacturing inspection, or test.
  - (7) A record of the inspector, or data recorder, the date and results of the inspection.
- (i) Inspection procedures or instructions contain or reference necessary procedures, drawings and specifications to be used when performing inspection operations.
- (j) Provisions for inspection results to be documented, evaluated and accepted by the supervisor responsible for the inspection function.

### 17.2.11--TEST CONTROL

The OQA Program documents identify those managers responsible for testing structures, systems and components during the preoperational testing, power testing and operations phases of Susquehanna SES. (Prior to implementation of this OQA Program preoperational testing will be performed under the control of the Susquehanna Quality Assurance Program as supplemented by interim procedures to the PP&L Quality Assurance Manual.) The test program described herein and further detailed in Operations Policy Statements is designed to assure that structures, systems and components will perform satisfactorily in service. Modifications, repairs and replacements are tested in accordance with the original design and testing requirements or by approved alternates.

Testing is established, documented and accomplished in accordance with written controlled procedures. These procedures contain or reference:

- (a) The requirements and acceptance limits specified in the applicable design and procurement documents.
- (b) The instructions for performing the test.
- (c) The test prerequisites such as:
  - 1 That test instrumentation is calibrated and has an uncertainty (error) equal to or less than the tolerance stated in the acceptance criteria.
  - 2 That testing equipment is adequate and appropriate for the test.
  - 3 That personnel performing the test are properly trained, qualified and licensed or certified as required.
  - 4 That the item is sufficiently complete to be tested.
  - 5 That environmental conditions are suitable and controlled.
  - 6 That provisions are made for data collection and storage.
- (d) The mandatory inspection hold points for witness by PP&L, their contractor or agent.
- (e) The test acceptance and rejection criteria.
- (f) The methods of documenting or recording the test data and test results.

Tests are required to be performed:

- (a) Periodically to provide assurance that failures or substandard performance do not remain undetected and that the required reliability of safety-related systems is maintained.
- (b) Following maintenance, modification or procedural changes to demonstrate satisfactory performance.

The test results are documented and evaluated to determine the acceptability of the test. The individuals or groups responsible

for evaluating the test results shall be qualified to perform this evaluation.

When by evaluation of the test results, the structure, system or component is determined to be nonconforming, it shall be controlled in accordance with Subsection 17.2.15.

#### 17.2.12 CONTROL OF MEASURING AND TEST

PP&L's OQA Program documents provide measures to assure that tools, gauges, instruments and other measuring and testing devices are controlled. Calibrations are scheduled with sufficient frequency to maintain required accuracy. The measuring and test equipment controls assure that:

- (a) Procedures are used to control measuring and test equipment. These procedures describe the calibration technique and frequency, maintenance and method of control of measuring and test equipment (such as instruments, tools, gauges, fixtures, reference and transfer standards, and nondestructive examination equipment) which are used in the measurement, inspection, and monitoring of components, systems and structures.
- (b) Measuring and test equipment is identified and traceable to the calibration test data.
- (c) Measuring and test instruments are calibrated at specific intervals based on the required accuracy, purpose, degree of usage, stability characteristics and other conditions affecting the measurement.
- (d) Measuring and test equipment is labeled or tagged to indicate the date of the calibration and the due date of the next calibration.
- (e) When measuring or test equipment is found to be out of calibration, measures are taken and documented to determine the validity of previous inspections performed since the last valid calibration.
- (f) Calibration standards have an uncertainty (error) of no more than 1/4 of the tolerance of the equipment being calibrated, unless limited by the "state-of-the-art".
- (g) A complete status of all items under the calibration system is recorded and maintained.

- (h) Reference and transfer standards are traceable to nationally recognized standards; or, where national standards do not exist, provisions are established to document the basis for calibration.

#### 17.2.13 HANDLING, STORAGE, AND SHIPPING

OQA Program documents list those managers responsible for the handling, preserving, storing, cleaning, packaging and shipping of materials, parts and components; and, describe their authorities and methods for meeting the quality requirements.

Procedures control each functional unit's activities and assure compliance with the quality requirements contained in drawings, specifications and procurement documents. These requirements include those necessitated by the design, as outlined in the design output documents, and those submitted by the supplier. These procedures provide control to prevent damage and loss or deterioration by environmental conditions, such as temperature or humidity, and specify the personnel qualifications required to accomplish the activity satisfactorily.

Consumables such as chemicals, reagents, weld rod, lubricants, etc. shall be stored in accordance with manufacturer's instructions or other approved methods to prevent harmful deterioration of the item. Materials with an identified shelf life shall be controlled such that they are used or discarded prior to expiration date.

#### 17.2.14 INSPECTION, TEST, AND OPERATING STATUS

OQA Program documents list those managers responsible for the development and implementation of procedures to assure that the inspection, test, and operating status of structures, systems, and components is properly identified and controlled.

These procedures incorporate the following provisions:

- (a) The inspection, test, and operating status of structures, systems, and components is identified to the affected parties.
- (b) Application and removal of inspection and welding stamps and status indicators, such as tags, markings, labels, and stamps are procedurally controlled.

- (c) Methods for bypassing of required inspection, tests, and other critical operations are controlled through documented functional unit procedures.
- (d) The status of nonconforming, inoperative, or malfunctioning structures, systems or components is identified to prevent their inadvertent use.

#### 17.2.15 NONCONFORMING MATERIALS, PARTS OR COMPONENTS

OQA Program documents list those managers responsible and their methods for handling nonconforming materials, parts, components, or services. Procedures control the identification, documentation, segregation, review, disposition and notification to affected organizations of nonconforming materials, parts, components, or services.

Materials, parts, components or services which do not meet established drawing, specification, or workmanship requirements, are identified as nonconforming and documented. Nonconforming items are identified as discrepant and segregated from acceptable items until they are properly dispositioned.

The manager of each functional unit is responsible for the review and disposition of nonconforming items which fall under the scope of responsibility of that manager. The manager is also responsible for notifying or obtaining input from other functional units who may have a specific interest in the nonconforming item.

Documentation related to the identification, disposition and correction of nonconformances is maintained in accordance with Subsection 17.2.17.

Documentation pertaining to nonconforming items or services shall include the details of the nonconformance, the disposition, and the approval signature(s).

Acceptability of rework or repair of materials, parts, components, systems, and structures is verified by re-inspecting and re-testing the item by a method which is the same as or comparable to the original inspection and test and in accordance with written procedures.

Inspection, testing, rework, and repair procedures are documented. Vendor nonconformance reports dispositioned "accept as is" or "repair" are made part of the inspection records and forwarded with the hardware to PP&L for review and assessment.

Nonconformances are periodically analyzed for quality trends, and the results are reported to management for review and assessment.

#### 17.2.16\_\_CORRECTIVE ACTION

PP&L's OQA Program establishes the requirements for controlling conditions adverse to quality (such as nonconformances, failures, malfunctions, deficiencies, deviations, and defective material and equipment).

Conditions adverse to quality are promptly identified, reported, evaluated, corrected and documented. OQA Program documents identify the methods used and personnel responsible for these activities.

Conditions adverse to quality are identified and reported to the appropriate levels of management of the affected organizations. The responsible organization evaluates the conditions to determine if they are significant conditions adverse to quality and to determine the corrective action required.

If significant conditions adverse to quality are detected, the cause of the condition and the corrective action taken are reported to the appropriate management levels of affected home office organizations, plant staff and quality assurance for review and assessment.

The corrective action for conditions adverse to quality shall correct the specific conditions. For conditions determined to be significant, the corrective action provides measures to correct specific conditions and preclude recurrence.

The responsible organization shall implement the corrective action and document the details of the conditions including their resolution. Follow-up action is conducted to determine that the required corrective action has been completed and that the corrective action documentation has been closed out.

#### 17.2.17\_\_QUALITY ASSURANCE RECORDS

A QA record system, detailed in OQA Program documents, has been established by PP&L which assures that records are identifiable, retrievable and that sufficient records are maintained to provide documentary evidence of the quality of items and services. The system assures that requirements and responsibilities for record transmittal, retention (such as duration, location, fire protection and assigned responsibilities) and maintenance,

subsequent to completion of work, are consistent with applicable codes, standards and procurement documents. QA records include:

- (a) Plant Historical Records
- (b) Operating Logs
- (c) Principle Maintenance and Modification Activities
- (d) Reportable Occurrences
- (e) Results of Independent Reviews, (e.g., Plant Operations Review Committee or Susquehanna Review Committee), Inspections, Tests, Audits and Materials Analysis
- (f) Monitoring of Work Performance
- (g) Qualification of Personnel, Procedures and Equipment

These records also include other documentation such as drawings, specifications, procurement documents, calibration procedures and reports, nonconformance reports, and corrective action reports.

Each manager is responsible for developing procedures which control the origination and transmittal of QA records within that functional unit. Each manager is responsible for transmitting QA records to the storage location designated for that record.

PP&L record storage facilities are constructed, located, and secured to prevent destruction of the records by fire, flooding, theft, and deterioration by environmental conditions such as temperature or humidity.

#### 17.2.18 AUDITS

The PP&L audit program requires the planning, performing, documenting, and evaluating of audits. It assures compliance with license commitments, OQA Program requirements, Technical Specifications, and other applicable requirements. It also assures that corrective measures are taken in response to audit findings to resolve the original problem and minimize the probability of its recurrence.

Audits of selected operational phase activities are performed by NQA. These audits include areas which require implementation of 10CFR50, Appendix B. These areas include activities associated with:

- (a) Plant Operation, Maintenance and Modification.

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- (b) The Preparation, Review, Approval and Control of Designs, Specifications, Procurement Documents, Instructions, Procedures and Drawings.
- (c) Receiving and Plant Inspections.
- (d) Indoctrination and Training Programs.
- (e) The Implementation of Operating and Test Procedures.
- (f) Calibration of Measuring and Testing Equipment.

Audits are regularly scheduled based on the status and safety importance of the activity. Audits are also scheduled according to the requirements of Section 6 of the Technical Specification. The audit schedule assures proper coverage of all applicable activities. Additionally, the audit program provides for scheduling audits which can be conducted on short notice to respond to specific quality problems.

Audits are structured with a sufficiently defined scope to permit objective evaluation of the activity observed. Quality-related practices, procedures, and instructions are audited to measure both the effectiveness of their implementation and their conformance to OQA Program requirements.

The audit process is conducted according to procedures which require that a written audit plan be prepared. The audit plan ensures the proper scope, team preparation, and depth of coverage. The audit process includes, as applicable, an evaluation of work areas, activities, processes, and items. Audits include a review of associated documents and records.

Audit teams consist of trained personnel, not directly responsible for the areas audited. Each team shall have a designated leader who is responsible for the planning, conduct, and reporting of the audit.

The auditor qualification program ensures that audit team members are qualified to perform their assigned tasks.

Audit results are documented in a formal audit report which is transmitted to the responsible levels of management.

Audit team leaders, through their supervisors, ensure that responsible management takes necessary action to correct deficiencies noted, and provide a basis for preventing their recurrence. Team leaders verify, either through review of documentation resulting from corrective action, or if necessary, re-audit, that deficiencies have been properly corrected.



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Formal audit reports are reviewed by NQA Management to determine the effectiveness of the OQA program, and indications of quality trends. If additional management action is required, the results of these reviews are formally reported to the appropriate manager of the responsible organization.

Table 17.2-2  
OPERATIONAL POLICY STATEMENT CROSS REFERENCE MATRIX  
WITH 10CFR50 APPENDIX B CRITERIA

OPS TITLE	SYNOPSIS	CRITERIA 1, 2
1 Operational Quality Assurance Program	Defines the scope and applicability of the OQA Program. Establishes requirements for the OQA Manual and defines the tiers of documents comprising the OQA Program.	II, V, VI
2 Terms and Definitions	Defines those terms having particular meaning within the context of the OQA Program.	II
3 Control and Issuance of Documents	Establishes controls for the issuance and use of documents. Defines those documents controlled by the OQA Program and requires review, approval, and use of documents at required locations.	V, VI
4 Document Reviews	Establishes the requirements for performing and documenting document reviews.	III, IV, VI
5 Deficiency Control System	Delineates those activities associated with the control and correction of nonconforming material, parts or components; other conditions adverse to quality; and significant conditions adverse to quality.	VIII, XV, XVI
6 Qualification, Training and Certification of Personnel	Establishes the requirements for the training, qualification and certification of personnel performing activities affecting quality to assure that they achieve and maintain suitable proficiency.	II, IX, XVIII
7 Auditing and Surveillance Activities	Establishes the requirements for the development of programs for auditing and monitoring quality related activities and includes performance, qualifications, reporting, and follow-up action.	II, XVIII
8 The Collection, Storage, and Maintenance of Quality Assurance Records	Establishes the requirements for the collection, storage, and maintenance of quality assurance records.	XVII
9 Control of Modifications & Design Activities	Establishes the requirements for ensuring that the quality of modified structures, systems or components is at least equivalent to that specified in the original design bases, material specifications, and inspection requirements.	III
10 Procurement Control	Establishes the requirements for the procurement of material, parts, components, services and spare parts.	IV, VII
11 Nuclear Fuel Management	Establishes the requirements for the management of nuclear fuel activities	IV, VII
12 Administrative Control of Plant Operations	Establishes the requirements for the administrative and procedural controls that ensure the plant is operated in a safe and efficient manner.	V
13 Maintenance, Installation of Modifications and Related Activities	Establishes the requirements for ensuring that structures, systems, and components are maintained in a condition to perform their intended function. The field activities associated with modifications are also included.	IX, XIV

Table 17.2-2 (Cont.)

14	Control of Inspection and Testing	Establishes the requirements for testing and inspection activities.	X, XI, XIV
15	Inservice Inspection	Establishes the requirements for the quality-related Inservice Inspection activities.	X, XI
16	Instrument and Calibration Control	Establishes the requirements for the calibration and control of calibration standards, installed plant instrumentation, and measuring and test equipment.	XII
17	Control of Plant Material	Establishes the requirements for the control of plant material and includes receipt inspection, handling, storage, and shipping.	VII, VIII, XIII
18	ASME Supplement	Establishes the requirements for PP&L to perform engineering, fabrication, and repair activities in accordance with Section XI of the ASME Code.	N/A
19	Reporting of Substantial Safety Hazards, Licensee Event Reports and Significant Events	Establishes the requirements for reporting substantial safety hazards (10 CFR 21) and reportable occurrences and requirements for inclusion of 10 CFR 21 requirements in procurement documents.	N/A

Footnotes:

- (1) Criterion I, Organization, is covered extensively in Section 17.2.1 and is not repeated in a separate OPS. However, the "Responsibility" section in each OPS identifies the managers responsible for implementation and verification of the OPS' requirements.
- (2) Criteria such as V, Instructions, Procedures, and Drawings, and XVII, Records, could be cross referenced with the majority of OPS identified. A deliberate effort was made to cross reference the Criteria only to those OPS which have a direct relationship.

Table 17.2-2  
OPERATIONAL POLICY STATEMENT CROSS REFERENCE MATRIX  
WITH 10CFR50 APPENDIX B CRITERIA

OPS	TITLE	SYNOPSIS	CRITERIA 1, 2
1	Operational Quality Assurance Program Definition	Defines the scope and applicability of the OQA Program. Establishes requirements for the OQA Manual and defines the tiers of documents comprising the OQA Program.	II, V, VI
2	Terms and Definitions	Defines those terms having particular meaning within the context of the OQA Program.	II
3	Control and Issuance of Documents	Establishes controls for the issuance and use of documents. Defines those documents controlled by the OQA Program and requires review, approval, and use of documents at required locations.	V, VI
4	Document Reviews	Establishes the requirements for performing and documenting document reviews.	III, IV, VI
5	Deficiency Control	Delineates those activities associated with the control and correction of nonconforming material, parts or components; other conditions adverse to quality; and significant conditions adverse to quality.	VIII, XV, XVI
6	Personnel Qualification and Training	Establishes the requirements for the training and qualification of personnel performing activities affecting quality to assure that they achieve and maintain suitable proficiency.	II, IX, XVIII
7.	Auditing/Quality Verification Activities	Establishes the requirements for the development of programs for auditing and monitoring quality related activities and includes performance, qualifications, reporting, and follow-up action.	II, XVIII
8	Records	Establishes the requirements for the collection, storage, and maintenance of quality assurance records.	XVII
9	Control of Modifications & Design Activities	Establishes the requirements for ensuring that the quality of modified structures, systems or components is at least equivalent to that specified in the original design bases, material specifications, and inspection requirements.	III
10	Procurement	Establishes the requirements for the procurement of material, parts, components, services and spare parts.	IV, VII
11	Procurement of Nuclear Fuels	Establishes the requirements for the procurement of reload nuclear fuel.	IV, VII
12	Administrative Control of Plant Operations	Establishes the requirements for the administrative and procedural controls that ensure the plant is operated in a safe and efficient manner.	V
13	Control of Maintenance	Establishes the requirements for ensuring that structures, systems, and components are maintained in a condition to perform their intended function. The field activities associated with modifications are also included.	IX, XIV
14	Control of Testing and Inspection Activities	Establishes the requirements for testing and inspection activities.	X, XI, XIV
15	Inservice Inspection	Establishes the requirements for the quality-related Inservice Inspection activities.	X, XI
16	Instrument and Calibration Control	Establishes the requirements for the calibration and control of calibration standards, installed plant instrumentation, and measuring and test equipment.	XII
17	Control of Plant Material	Establishes the requirements for the control of plant material and includes receipt inspection, handling, storage, and shipping.	VII, VIII, XIII
18	ASME Supplement	Establishes the requirements for PP&L to perform engineering fabrication, and repair activities in accordance with Section III of the ASME Code.	N/A

Footnotes:

- (1) Criterion I, Organization, is covered extensively in Section 17.2.1 and is not repeated in a separate OPS. However, the "Responsibility" section in each OPS identifies the managers responsible for implementation and verification of the OPS' requirements.
- (2) Criteria such as V, Instructions, Procedures, and Drawings, and XVII, Records, could be cross referenced with the majority of OPS identified. A deliberate effort was made to cross reference the Criteria only to those OPS which have a direct relationship.

## 18.0 ORGANIZATION

This chapter contains a response for each TMI-related requirement. The chapter is divided into sections which contain the responses to all requirements for applicants for operating licenses. The table of contents identifies which section provides the responses for a given document.

Each section addresses all the requirements in its corresponding document. A response is only given to the most recent in the series of requirements which contains an explanatory text. For example, if an explanatory text of requirement I.A.1.1 appears on both NUREG 0737 and NUREG 0694, a response is provided to NUREG 0737 since it supersedes all previous requirements. If requirement I.A.1.2 appears in both NUREGs 0737 and 0694, but the only explanatory text is in NUREG 0694, the response is provided to NUREG 0694 utilizing the implementation dates of NUREG 0737.

The responses in this chapter are applicable to Unit 1 and systems common to Units 1 and 2.



18.1 RESPONSE TO REQUIREMENTS IN NUREG 0737

18.1.1 SHIFT TECHNICAL ADVISOR (I.A.1.1)

18.1.1.1 Statement of Requirement

Each licensee shall provide an on-shift technical advisor to the shift supervisor. The shift technical advisor (STA) may serve more than one unit at a multiunit site if qualified to perform the advisor function for the various units.

The STA shall have a bachelor's degree or equivalent in a scientific or engineering discipline and have received specific training in the response and analysis of the plant for transients and accidents. The STA shall also receive training in plant design and layout, including the capabilities of instrumentation and controls in the control room. The licensee shall assign normal duties to the STAs that pertain to the engineering aspects of assuring safe operations of the plant, including the review and evaluation of operating experience.

The need for the STA position may be eliminated when the qualifications of the shift supervisors and senior operators have been upgraded and the man-machine interface in the control room has been acceptably upgraded. However, until those long-term improvements are attained, the need for an STA program will continue.

The staff has not yet established the detailed elements of the academic and training requirements of the STA beyond the guidance given in the Vassallo letter on November 9, 1979. Nor has the staff made a decision on the level of upgrading required for licensed operating personnel and the man-machine interface in the control room that would be acceptable for eliminating the need of an STA. Until these requirements for eliminating the STA position have been established, the staff continues to require that, in addition to the staffing requirement specified in Subsection 18.1.3, an STA be available for duty on each operating shift when a plant is being operated in Modes 1-3 for a BWR. At other times, an STA is not required to be on duty.

Since the November 9, 1979 letter was issued, several efforts have been made to establish, for the longer term, the minimum level of experience, education, and training for STAs. These efforts include work on the revision to ANS-3.1, work by the Institute of Nuclear Power Operations (INPO), and internal staff efforts.

INPO has made available a document entitled "Nuclear Power Plant Shift Technical Advisor--Recommendations for Position Description, Qualifications, Education and Training." Sections 5 and 6 of the INPO document describe the education, training, and experience requirements for STAs. The NRC staff finds that the descriptions as set forth in Sections 5 and 6 of Revision 0 to the INPO document are an acceptable approach for the selection and training of personnel to staff the STA positions. (Note: This should not be interpreted to mean that this is an NRC requirement at this time. The intent is to refer to the INPO document as acceptable for interim guidance for a utility in planning its STA program over the long term (i.e., beyond the January 1, 1981 requirement to have STAs in place in accordance with the qualification requirements specified in the staff's November 9, 1979 letter).

Applicants for operating licenses shall provide a description of their STA training and requalification program in their application, or amendments thereto, on a schedule consistent with the NRC licensing review schedule.

Applicants for operating licenses shall provide a description of their long-term STA program, including qualification, selection criteria, training, and possible phaseout. The description shall be provided in the application, or amendments thereto, on a schedule consistent with the NRC licensing review schedule. The description shall include a comparison of the long-term program with the above mentioned INPO document.

#### 18.1.1.2 Interpretation

The applicant is to develop a training program in compliance with the November 9, 1979 letter and submit a description to the NRC. The applicant is to provide STA coverage for all operating shifts. Candidates will complete a training program and pass a certification examination prior to assumption of duties. The applicant is to develop a long-term program to maintain or phaseout STAs.

#### 18.1.1.3 Statement of Response

The program for the selection and training of STA's is detailed in the Nuclear Department Instruction NDI-4.2.2, Selection, Training and Certification of Shift Technical Advisors".

STA coverage will be provided on operating shifts in accordance with Subsection 6.2.2 of the Technical Specifications. STA's



will perform the duties and have the responsibilities outlined in plant procedure AD-QA-400, "Conduct of Technical Support."

STAs will meet the qualification requirements of the Vassallo letter of November 9, 1979. All STA training will be completed and STAs will be ready for shift assignment prior to fuel load. The STA program described above will be maintained long-term until such time as phaseout is permitted in accordance with NRC instructions.

#### 18.1.2 SHIFT SUPERVISOR RESPONSIBILITIES (I.A.1.2)

No requirement stated in NUREG 0737. Refer to Subsection 18.2.2 which contains the response to the requirement stated in NUREG 0694.

#### 18.1.3 SHIFT MANNING (I.A.1.3)

##### 18.1.3.1 Statement of Requirement

Applicants for operating licenses shall include in their administrative procedures (required by license conditions) provisions governing required shift staffing and movement of key individuals about the plant. These provisions are required to assure that qualified plant personnel to man the operational shifts are readily available in the event of an abnormal or emergency situation. Interim requirements for shift staffing are given in Table 18.1-1.

These administrative procedures shall also set forth a policy, the objective of which is to prevent situations where fatigue could reduce the ability of operating personnel to keep the reactor in a safe condition. The controls established should assure that, to the extent practicable, personnel are not assigned to shift duties while in a fatigued condition that could significantly reduce their mental alertness or their decision making ability. The controls shall apply to the plant staff who perform safety-related functions (e.g., senior reactor operators, reactor operators, auxiliary operators, health physicists, and key maintenance personnel).

IE Circular No. 80-02, "Nuclear Power Plant Staff Work Hours," dated February 1, 1980 discusses the concern of overtime work for members of the plant staff who perform safety-related functions. The guidance contained in the IE Circular No. 80-02 was amended by the July 31, 1980 letter. In turn, the overtime guidance of the July 31, 1980 letter was revised in Section I.A.1.3 of NUREG-

0737. The NRC has issued a policy statement which further revises the overtime guidance as stated in NUREG-0737. This guidance is as follows:

Enough plant operating personnel should be employed to maintain adequate shift coverage without routine heavy use of overtime. The objective is to have operating personnel work a normal 8-hour day, 40-hour week while the plant is operating. However, in the event that unforeseen problems require substantial amounts of overtime to be used, or during extended periods of shutdown for refueling, major maintenance or major plant modifications, on a temporary basis, the following guidelines shall be followed:

- (a) An individual should not be permitted to work more than 16 hours straight (excluding shift turnover time).
- (b) An individual should not be permitted to work more than 16 hours in any 24-hour period, no more than 24 hours in any 48-hour period, no more than 72 hours in any seven day period (all excluding shift turnover time).
- (c) A break of at least eight hours should be allowed between work periods (including shift turnover time).
- (d) Except during extended shutdown periods, the use of overtime should be considered on an individual basis and not for the entire staff on shift.

Recognizing that very unusual circumstances may arise requiring deviation from the above guidelines, such deviation shall be authorized by the plant manager or his deputy, or higher levels of management. The paramount consideration in such authorization shall be that significant reductions in the effectiveness of operating personnel would be highly unlikely. Authorized deviations to the working hour guidelines shall be documented and available for NRC review.

In addition, procedures are encouraged that would allow licensed operators at the controls to be periodically relieved and assigned to other duties away from the control board during their tours of duty.

Operating license applicants shall complete these administrative procedures before fuel loading.

#### 18.1.3.2. Interpretation

None required.

18.1.3.3 Statement of Response

The facility staffing requirements are presented in Subsection 6.2.2 of the Technical Specifications. These requirements are consistent with those given in Table 18.1-1.

The plant policy on operations personnel working hours is discussed in administrative procedure AD-QA-300, "Conduct of Operations."

18.1.4 IMMEDIATE UPGRADING OF REACTOR OPERATOR AND SENIOR REACTOR  
 ----- OPERATOR TRAINING AND QUALIFICATIONS (I.A.2.1) -----

18.1.4.1 Statement of Requirement

Applicants\* for senior operator licenses shall have 4 years of responsible power plant experience. Responsible power plant experience should be that obtained as a control room operator (fossil or nuclear) or as a power plant staff engineer involved in the day-to-day activities of the facility, commencing with the final year of construction. A maximum of 2 years power plant experience may be fulfilled by academic or related technical training, on a one-for-one time basis. Two years shall be nuclear power plant experience. At least 6 months of the nuclear power plant experience shall be at the plant for which he seeks a license. Effective date: Applications received on or after May 1, 1980.

Applicants for senior operator licenses shall have held an operator's license for 1 year. Effective Date: Applications received after December 1, 1980. The NRC has not imposed the 1-year experience requirement on cold applicants for SRO licenses. Cold applicants are to work on a facility not yet in operation; their training programs are designed to supply the equivalent of the experience not available to them.

Senior operator\*: Applicants shall have 3 months of shift training as an extra man on shift.

Control room operator\*: Applicants shall have 3 months training on shift as an extra person in the control room. Effective date: Applications received after August 1, 1980.

\*Precritical applicants will be required to meet unique qualifications designed to accommodate the fact that their facility has not yet been in operation.

Training programs shall be modified, as necessary, to provide:

- 1) Training in heat transfer, fluid flow and thermodynamics.
- 2) Training in the use of installed plant systems to control or mitigate an accident in which the core is severely damaged.
- 3) Increased emphasis on reactor and plant transients. Effective date: Present programs have been modified in response to Bulletins and Orders. Revised programs should be submitted for OLB review by August 1, 1980.

Content of the licensed operator requalification programs shall be modified to include instruction in heat transfer, fluid flow, thermodynamics, and mitigation of accidents involving a degraded core. Effective date: May 1, 1980.

The criteria for requiring a licensed individual to participate in accelerated requalification shall be modified to be consistent with the new passing grade for issuance of a license; 80% overall and 70% each category. Effective date: Concurrent with the next facility administered annual requalification examination after the issue date of this requirement.

Programs should be modified to require the control manipulations listed in Enclosure 4 of NUREG 0737, item I.A.2.1. Normal control manipulations, such as plant reactor startups, must be performed. Control manipulations during abnormal or emergency operations must be walked through with, and evaluated by, a member of the training staff at a minimum. An appropriate simulator may be used to satisfy the requirements for control manipulations. Effective date: Programs modified by August 1, 1980. Renewal applications received after November 1, 1980 must reflect compliance with the program.

Certifications completed pursuant to Sections 55.10(a)(6) and 55.33a(4) and (5) of 10 CFR Part 55 shall be signed by the highest level of corporate management for plant operation (for example, Vice President for Operations). Effective date: Applications received on or after May 1, 1980.

#### 18.1.4.2 Interpretation

None required.

18.1.4.3 Statement of Response

A program is established to assure that all reactor operator and senior reactor operator license candidates (beyond the initial compliment required to startup Units 1 & 2) have the prescribed experience, qualifications, and training. Candidates will be prepared and certified in accordance with Nuclear Department Instruction NDI-4.2.1. Administrative procedure AD-QA-304, "Operator Selection Training and Qualifications," details the process by which the qualifications of candidates for operations positions will be evaluated in the future.

The initial startup crews will have completed extensive training devised in part to recognize the non-operational status of the units. This program includes real time training on the Susquehanna SES simulator which duplicates the actual unit and thus in many respects equates to the experience requirements. Subsection 13.1.3 describes the qualifications commitments for the existing plant staff.

18.1.5. ADMINISTRATION OF TRAINING PROGRAMS (I.A.2.3)18.1.5.1 Statement of Requirement

Pending accreditation of training institutions, licensees and applicants for operating licenses will assure that training center and facility instructors who teach systems, integrated responses, transient, and simulator courses demonstrate senior reactor operator (SRO) qualifications and be enrolled in appropriate regualification programs.

Training center and facility instructors who teach systems, integrated responses, transient and simulator courses shall demonstrate their competence to NRC by successful completion of a senior operator examination. Effective date: Applications should be submitted no later than August 1, 1980 for individuals who do not already hold a senior operator license.

Instructors shall be enrolled in appropriate regualification programs to assure they are cognizant of current operating history, problems, and changes to procedures and administrative limitations. Effective date: Programs should be initiated May 1, 1980. Programs should be submitted to OLB for review by August 1, 1980.

18.1.5.2 Interpretation

The "instructors" referenced in this requirement are those individuals who teach systems specific to BWRs, integrated responses, transients, and simulator courses to licensed operators or license candidates.

18.1.5.3 Statement of Response

Certification of instructors is described in Nuclear Department Instruction NDI-QA-4.1.3.. This procedure delineates which instructors are required to pass an examination for certification of senior reactor operators (SRO). All instructors who teach materials identified in Subsection 18.1.5.2 are certified as SROs.

18.1.6 REVISE SCOPE AND CRITERIA FOR LICENSING EXAMINATIONS  
-----(I.A.3.1)-----

18.1.6.1 Statement of Requirement

A new category shall be added to the operator written examination entitled, "Principles of Heat Transfer and Fluid Mechanics."

A new category shall be added to the senior operator written examination entitled, "Theory of Fluids and Thermodynamics."

Time limits shall be imposed for completion of the written examinations:

1. Operator: 9 hours.
2. Senior Operator: 7 hours.

The passing grade for the written examination shall be 80% overall and 70% in each category.

All applicants for senior operator licenses shall be required to be administered an operating test as well as the written examination. Effective date: Examinations administered on or after May 1, 1980.

Applicants will grant permission to NRC to inform their facility management regarding the results of the examinations for purposes of enrollment in requalification programs. Applications received on or after May 1, 1980.

Simulator examinations will be included as part of the licensing examinations.

### 18.1.6.2 Interpretation

None required.

### 18.1.6.3 Statement of Response

The reactor operator and senior reactor operator training program has been upgraded to include the subject material described in this requirement. Refer to Subsection 18.1.4.3 for the response to requirement I.A.2.1, "Immediate Upgrading of Reactor Operator and Senior Reactor Operator Training and Qualifications." Candidates will be prepared and certified in accordance with Nuclear Department Instruction NDI-QA-4.2.1. The Susquehanna SES simulator is available for the simulator portion of exams. Application packages will include a release which permits the NRC to inform PP&L management of exam results.

## 18.1.7 EVALUATION OF ORGANIZATION AND MANAGEMENT (I.B.1.2)

### 18.1.7.1 Statement of Requirement

Each applicant for an operating license shall establish an onsite independent safety engineering group (ISEG) to perform independent reviews of plant operations.

The principal function of the ISEG is to examine plant operating characteristics, NRC issuances, Licensing Information Service advisories, and other appropriate sources of plant design and operating experience information that may indicate areas for improving plant safety. The ISEG is to perform independent review and audits of plant activities including maintenance, modifications, operational problems, and operational analysis, and aid in the establishment of programmatic requirements for plant activities. Where useful improvements can be achieved, it is expected that this group will develop and present detailed recommendations to corporate management for such things as revised procedures or equipment modifications.

Another function of the ISEG is to maintain surveillance of plant operations and maintenance activities to provide independent verification that these activities are performed correctly and that human errors are reduced as far as practicable. The ISEG will then be in a position to advise utility management on the overall quality and safety of operations. The ISEG need not perform detailed audits of plant operations and shall not be

responsible for sign-off functions such that it becomes involved in the operating organization.

The new ISEG shall not replace the plant operations review committee (PORC) and the utility's independent review and audit group as specified by current staff guidelines (Standard Review Plan, Regulatory Guide 1.33, Standard Technical Specifications). Rather, it is an additional independent group of a minimum of five dedicated, full-time engineers, located onsite, but reporting offsite to a corporate official who holds a high-level, technically oriented position that is not in the management chain for power production. The ISEG will increase the available technical expertise located onsite and will provide continuing, systematic, and independent assessment of plant activities. Integrating the shift technical advisors (STAs) into the ISEG in some way would be desirable in that it could enhance the group's contact with and knowledge of day-to-day plant operations and provide additional expertise. However, the STA on shift is necessarily a member of the operating staff and cannot be independent of it.

It is expected that the ISEG may interface with the quality assurance (QA) organization, but preferably should not be an integral part of the QA organization.

The functions of the ISEG require daily contact with the operating personnel and continued access to plant facilities and records. The ISEG review functions can, therefore, best be carried out by a group physically located onsite. However, for utilities with multiple sites, it may be possible to perform portions of the independent safety assessment function in a centralized location for all the utility's plants. In such cases, an onsite group still is required, but it may be slightly smaller than would be the case if it were performing the entire independent safety assessment function. Such cases will be reviewed on a case-by-case basis.

This requirement shall be implemented prior to issuance of an operating license.

Refer to Subsection 18.2.6 for the response to additional requirements contained in NUREG 0694.

#### 18.1.7.2 Interpretation

None required.

#### 18.1.7.3 Statement of Response



The functions of the ISEG will be performed by the Nuclear Safety Assessment Group (NSAG). PP&L's commitment to the NSAG is addressed in a letter from N. W. Curtis to B. J. Youngblood on December 8, 1980 (PLA-585) and are further addressed in Nuclear Department Instruction NDI-1.1.2. NSAG will be functional by fuel load.

#### 18.1.8 SHORT-TERM ACCIDENT AND PROCEDURE REVIEW (I.C.1)

##### 18.1.8.1 Statement of Requirement

Reanalysis of small break LOCAs, transients, accidents, and inadequate core cooling and preparation of guidelines for development of emergency procedures should be completed and submitted to the NRC for review by January 1, 1981. The NRC staff will review the analyses and guidelines and determine their acceptability by July 1, 1981, and will issue guidance to licensees on preparing emergency procedures from the guidelines. Following NRC approval of the guidelines, licensees and applicants for operating licenses issued prior to January 1, 1982, should revise and implement their emergency procedures at the first refueling outage after January 1, 1982. Applicants for operating licenses issued after January 1, 1982 should implement the procedures prior to operation. This schedule supersedes the implementation schedule included in NUREG-0578, Recommendation 2.1.9 for item I.C.1(a)3, Reanalysis of Transients and Accidents. For those licensees and/or owners groups that will have difficulty in attaining the January 1, 1981 due date for submittal of guidelines, a comprehensive program plan, proposed schedule, and a detailed justification for all delays and problems shall be submitted in lieu of the guidelines.

##### 18.1.8.2 Interpretation

The BWR Owners' Group guidelines may be utilized to develop emergency procedures for accidents and transients.

##### 18.1.8.3 Statement of Response

In the Clarification of the NUREG-0737 requirement "for reanalysis of transients and accidents and inadequate core cooling and preparation of guidelines for development of emergency procedures," NUREG-0737 states:

Owners' group or vendor submittals may be referenced as appropriate to support this reanalysis. If owners' group or vendor submittals have already been forwarded to the staff for review, a brief description of the submittals and justification of their adequacy to support guideline development is all that is required.

PP&L has participated, and will continue to participate, in the BWR Owners' Group program to develop Emergency Procedure Guidelines for General Electric Boiling Water Reactors. Following are a brief description of the submittals to date, and a justification of their adequacy to support guideline development.

A. Description of Submittals

- (1) NEDO-24708A, "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors," Revision 1, December 1980.
  - (a) Description and analysis of small break loss-of-coolant events, considering a range of break sizes, location, and conditions, including equipment failures and operator errors; description and justification of analysis methods.
  - (b) Description and analysis of loss of feedwater events, including cases involving stuck-open relief valves, and including equipment failures and operator errors; description and justification of analysis methods.
  - (c) Description and analysis of each FSAR Chapter 15 event resulting in a reactor system transient; demonstration of applicability of analyses to each event; demonstration of applicability of Emergency Procedure Guidelines to each event.
  - (d) Description of natural and forced circulation cooling; factors influencing natural circulation, including noncondensibles; reestablishment of forced circulation under transient and accident conditions.
  - (e) Description and analysis of loss-of-coolant events, loss of feedwater events, and stuck-open relief valve events, including severe multiple equipment failures and operator errors which, if not mitigated, could result in conditions of inadequate core cooling.

- (f) Description of indications available to the BWR operator for the detection of adequate core cooling.
- (g) Description and justification of analysis methods for extremely degraded cases.
- (2) NEDO 24934, "BWR Emergency Procedure Guidelines BWR 1-6," Revision 1, January 1981.

Guidelines for BWR Emergency Procedures based on identification and response to plant symptoms; including a range of equipment failures and operator errors; including severe multiple equipment failures and operator errors which, if not mitigated, would result in conditions of inadequate core cooling; including conditions when core cooling status is uncertain or unknown.

B. Adequacy of Submittals

The submittals described in paragraph A have been discussed and reviewed extensively among the BWR Owners' Group, the General Electric Company, and the NRC staff. The NRC staff has found (NUREG-0737, page I.C.1-3) that "the analysis and guidelines submitted by the General Electric Company (GE) Owners' Group...comply with the requirements (of the NUREG-0737 clarification)." In Reference 18.1-1, the Director of the Division of Licensing states, "we find the Emergency Procedure Guidelines acceptable for trial implementation (on six plants with applications for operating licenses pending)."

PP&L believes that in view of these findings, no further detailed justification of the analyses or guidelines is necessary at this time. Reference 1 further states, "during the course of implementation we may identify areas that require modification or further analysis and justification." The enclosure to Reference 18.1-1 identifies several such areas. PP&L will work with the BWR Owners' Group in responding to such requests.

By our commitment to work with the Owners' Group on such requests, on schedules mutually agreed to by the NRC and the Owners' Group, and by reference to the BWR Owners' Group analyses and guidelines already submitted, our response to the NUREG-0737 requirement "for reanalyses of transients and accidents and inadequate core cooling and preparation of guidelines for development of emergency procedures" by January 1, 1981, is complete.

Emergency procedures based on those guidelines have been developed and are currently in trial use on the Susquehanna SES Simulator. These procedures have been reviewed by the NRC. Final versions which incorporated NRC comments were submitted in a letter from N. W. Curtis to B. J. Youngblood on May 15, 1981 (PLA-791).

18.1.9 SHIFT RELIEF AND TURNOVER PROCEDURES (I.C.2)

No requirement stated in NUREG 0737. Refer to Subsection 18.2.8 which contains the response to the requirement in NUREG 0694.

18.1.10 SHIFT SUPERVISOR RESPONSIBILITY (I.C.3)

No requirement stated in NUREG 0737. Refer to Subsection 18.2.9 which contains the response to the requirement in NUREG 0694.

18.1.11 CONTROL ROOM ACCESS (I.C.4)

No requirement stated in NUREG 0737. Refer to Subsection 18.2.10 which contains the response to the requirement in NUREG 0694.

18.1.12 FEEDBACK OF OPERATING EXPERIENCE (I.C.5)

18.1.12.1 Statement of Requirement

Applicants for an operating license shall prepare procedures to assure that information pertinent to plant safety originating inside or outside the utility organization is continually supplied to operators and other personnel and is incorporated into training and retraining programs. These procedures shall:

- (1) Clearly identify organizational responsibilities for review of operating experience, the feedback of pertinent information to operators and other personnel, and the incorporation of such information into training and retraining programs;
- (2) Identify the administrative and technical review steps necessary in translating recommendations by the operating experience assessment group into plant actions (e.g., changes to procedures, operating orders);

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- (3) Identify the recipients of various categories of information from operating experience (i.e., supervisory personnel, shift technical advisors, operators, maintenance personnel, health physics technicians) or otherwise provide means through which such information can be readily related to the job functions of the recipients;
- (4) Provide means to assure that affected personnel become aware of and understand information of sufficient importance that should not wait for emphasis through routine training and retraining programs;
- (5) Assure that plant personnel do not routinely receive extraneous and unimportant information on operating experience in such volume that it would obscure priority information or otherwise detract from overall job performance and proficiency;
- (6) Provide suitable checks to assure that conflicting or contradictory information is not conveyed to operators and other personnel until resolution is reached; and,
- (7) Provide periodic internal audit to assure that the feedback program functions effectively at all levels.

This requirement shall be implemented prior to issuance of an operating license.

### 18.1.12.2 Interpretation

None required.

### 18.1.12.3 Statement of Response

PP&L has developed a comprehensive program for feedback of operating experience. Components of the program are as follows..

Operating experience from other utilities and other industry sources is initially reviewed and dispositioned by the Industry Events Review Program (IERP). The IERP is designed to assure plant personnel do not routinely receive extraneous and unimportant information, that information is not contradictory or conflicting, that information is resolved prior to dissemination and that important information is rapidly routed to the appropriate personnel. A description of the organization, responsibilities and procedures of the IERP can be found in Nuclear Department Instruction NDI-QA-6.2.2.

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The Shift Technical Adviser (STA) as part of the Operations Assessment Function will be the focal point for dissemination of operating experience information to appropriate plant personnel. This will include:

- o Feedback of pertinent information to operators and other station personnel and transmittal of information to the Nuclear Training Group for incorporation into appropriate training programs.
- o Initiating, when required, plant procedure changes and/or plant modification requests.
- o Discussing with shift personnel operating experience information of sufficient importance that it cannot be deferred to the retraining program.
- o Editing information provided to plant personnel to minimize excessive or conflicting information and distributing information to appropriate functional units.

Administrative Procedure AD-QA-406 is being developed to further define this function and the interfaces among the STAs and the Nuclear Safety Assessment Group, Nuclear Training, Operations and the Industry Events Review Program.

General information from the nuclear industry and information of general interest from inside the company will be disseminated to appropriate personnel. The details of this program are described in Nuclear Department Instruction NDI-QA-6.2.1.

The NQA organization will audit selected portions of the feedback program to assure it functions effectively at all levels.

### 18.1.13 VERIFY CORRECT PERFORMANCE OF OPERATING ACTIVITIES ----- (I.C.6) -----

#### 18.1.13.1 Statement of Requirement

Licensees' procedures shall be reviewed and revised, as necessary, to assure that an effective system of verifying the correct performance of operating activities is provided as a means of reducing human errors and improving the quality of normal operations. This will reduce the frequency of occurrence

of situations that could result in or contribute to accidents. Such a verification system may include automatic system status monitoring, human verification of operations and maintenance activities independent of the people performing the activity (see NUREG-0585, Recommendation 5), or both.

Implementation of automatic status monitoring if required will reduce the extent of human verification of operations and maintenance activities but will not eliminate the need for such verification in all instances. The procedures adopted by the licensees may consist of two phases--one before and one after installation of automatic status monitoring equipment, if required, in accordance with item I.D.3.

Procedures must be reviewed and revised prior to fuel load.

#### 18.1.13.2 Interpretation

None required.

#### 18.1.13.3 Statement of Response

Administrative procedure AD-QA-306, "System Status and Equipment Control," will provide the means to verify correct performance of surveillance and maintenance activities. Status verification will utilize control room indications, presently available, operability testing where appropriate, or independent verification by a second qualified person. The procedure defines circumstances when independent human verification is required. The procedure also incorporates the requirements of item II.K.1.10 (see Subsection 18.2.26) for the removal from and restoration to service of safety related systems and components during normal operations and maintenance activities.

#### 18.1.14 NSSF VENDOR REVIEW OF PROCEDURES (I.C.7)

No requirement stated in NUREG 0737. Refer to Subsection 18.2.12 which contains the response to the requirement in NUREG 0694.

#### 18.1.15 PILOT MONITORING OF SELECTED EMERGENCY PROCEDURES FOR NEAR TERM OPERATING LICENSES (I.C.8)

No requirement stated in NUREG 0737. Refer to Subsection 18.2.13 which contains the response to the requirement in NUREG 0694.

18.1.16 CONTROL ROOM DESIGN REVIEW (I.D.1)

18.1.16.1 Statement of Requirement

All licensees and applicants for operating licenses will be required to conduct a detailed control-room design review to identify and correct design deficiencies. This detailed control-room design review is expected to take about a year. Therefore, the Office of Nuclear Reactor Regulation (NRR) requires that those applicants for operating licenses who are unable to complete this review prior to issuance of a license make preliminary assessments of their control rooms to identify significant human factors and instrumentation problems and establish a schedule (to be approved by NRC) for correcting deficiencies. These applicants will be required to complete the more detailed control room reviews on the same schedule as licensees with operating plants.

Applicants will find it of value to refer to the draft document NUREG/CR-1580, "Human Engineering Guide to Control Room Evaluation," in performing the preliminary assessment. NRR will evaluate the applicants preliminary assessments including the performance by NRR of onsite review/audit. The NRR onsite review/audit will be on a schedule consistent with licensing needs.

This requirement shall be met prior to fuel load.

18.1.16.2 Interpretation

Applicants for operating licenses are required to perform a preliminary control room design assessment which should be based on NUREG/CR-1580. This assessment will be reviewed by the NRC, who will subsequently recommend changes for correcting deficiencies. Applicants must submit for NRC approval a schedule for correcting these deficiencies.

Applicants will be required to perform a detailed control room design assessment following NUREG 0700 issuance. This assessment is not required to be completed prior to issuance of an operating license.

18.1.16.3 Statement of Response

A detailed control room review to identify significant human factors problems was conducted by PP&L with assistance from



experienced human factors personnel from General Physics Corporation. This review was based on the criteria given in draft NUREG/CR-1580.

During the week of October 27, 1980, the NRC performed an onsite review of the Susquehanna control room. The results of this review were formally transmitted to PP&L on January 31, 1981. A meeting was held on February 3, 1981 in Bethesda to discuss and clarify the NRC findings. On February 27, 1981 PP&L submitted a formal response to all NRC findings (refer to PLA-648). This response included a schedule for implementing the findings addressed in the NRC report.

#### 18.1.17 PLANT SAFETY PARAMETER DISPLAY SYSTEM (I.D.2)

##### 18.1.17.1 Statement of Requirement

Each applicant and licensee shall install a safety parameter display system (SPDS) that will display to operating personnel a minimum set of parameters which define the safety status of the plant. This can be attained through continuous indication of direct and derived variables as necessary to assess plant safety status.

The operational date for the SPDS is October 1, 1982.

##### 18.1.17.1.1 Function

The purpose of the safety parameter display system (SPDS) is to assist control room personnel in evaluating the safety status of the plant. The SPDS is to provide a continuous indication of plant parameters or derived variables representative of the safety status of the plant. The primary function of the SPDS is to aid the operator in the rapid detection of abnormal operating conditions. The functional criteria for the SPDS presented in this section are applicable for use only in the control room.

It is recognized that, upon the detection of an abnormal plant status, it may be desirable to provide additional information to analyze and diagnose the cause of the abnormality, execute corrective actions, and monitor plant response as secondary SPDS functions.

As an operator aid, the SPDS serves to concentrate a minimum set of plant parameters from which the plant safety status can be assessed. The grouping of parameters is based on the function of enhancing the operator's capability to assess plant status in a

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timely manner without surveying the entire control room. However, the assessment based on SPDS is likely to be followed by confirmatory surveys of many non-SPDS control room indicators.

Human-factors engineering shall be incorporated in the various aspects of the SPDS design to enhance the functional effectiveness of control room personnel. The design of the primary or principal display format shall be as simple as possible, consistent with the required function, and shall include pattern and coding techniques to assist the operator's memory recall for the detection and recognition of unsafe operating conditions. The human-factored concentration of these signals shall aid the operator in functionally comparing signals in the assessment of safety status.

All data for display shall be validated where practicable on a realtime basis as part of the display to control room personnel. For example, redundant sensor data may be compared, the range of a parameter may be compared to predetermined limits, or other quantitative methods may be used to compare values. When an unsuccessful validation of data occurs, the SPDS shall contain means of identifying the impacted parameter(s). Operating procedures and operator training in the use of the SPDS shall contain information and provide guidance for the resolution of unsuccessful data validation. The objective is to ensure that the SPDS presents the most current and accurate status of the plant possible and is not compromised by unidentified faulty processing or failed sensors.

The SPDS shall be in operation during normal and abnormal operating conditions. The SPDS shall be capable of displaying pertinent information during steady-state and transient conditions. The SPDS shall be capable of presenting the magnitudes and the trends of parameters or derived variables as necessary to allow rapid assessment of the current plant status by control room personnel.

The parameter trending display shall contain recent and current magnitudes of the parameter as a function of time. The derivation and presentation of parameter trending during upset conditions is a task that may be automated, thus freeing the operator to interpret the trends rather than generate them. Display of time derivatives of the parameters in lieu of trends to both optimize operator-process communication and conserve space may be acceptable.

The SPDS may be a source of information to other systems, and the functional criteria of these systems shall state the required interfaces with the SPDS. Any interface between the SPDS and a safety system shall be isolated in accordance with the safety system criteria to preserve channel independence and ensure the integrity of the safety system in the case of SPDS malfunction.

Design provisions shall be included in the interfaces between the SPDS and nonsafety systems to ensure the integrity of the SPDS upon failure of nonsafety equipment.

A qualification program shall be established to demonstrate SPDS conformance to the functional criteria of this document.

#### 18.1.17.1.2 Location

The SPDS shall be located in the control room with additional SPDS displays provided in the TSC and the EOF. The SPDS may be physically separated from the normal control boards; however, it shall be readily accessible and visible to the shift supervisor, control room senior reactor operator, shift technical advisor, and at least one reactor operator from the normal operating area. If the SPDS is part of the control board, it shall be easily recognizable and readable.

#### 18.1.17.1.3 Size

The SPDS shall be of such size as to be compatible with the existing space in the control area. The SPDS display shall be readable from the emergency operating station of the control room senior reactor operator. It shall not interfere with normal movement or with full visual access to other control room operating systems and displays.

#### 18.1.17.1.4 Staffing

The SPDS shall be of such design that no operating personnel in addition to the normal control room operating staff are required for its operation.

#### 18.1.17.1.5 Display Considerations

The display shall be responsive to transient and accident sequences and shall be sufficient to indicate the status of the plant. For each mode of plant operation, a single primary display format designed according to acceptable human-factors principles (a limited number of parameters or derived variables and their trends in an organized display that can be readily interpreted by an operator) shall be displayed, from which plant safety status can be inferred. It is recognized that it may be desirable to have the capability to recall additional data on secondary formats or displays.

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The primary display may be individual plant parameters or may be composed of a number of parameters or derived variables giving an overall system status. The basis for the selection of the minimum set of parameters in the primary display shall be documented as part of the design.

The important plant functions related to the primary display while the plant is generating power shall include, but not be limited to:

- o Reactivity control
- o Reactor core cooling and heat removal from primary system
- o Reactor coolant system integrity
- o Radioactivity control
- o Containment integrity

The SPDS may consist of several display formats as appropriate to monitor and present the various parameters or derived variables. For each plant operating mode, these formats may either be automatically displayed or manually selected by the operator to keep control room operating personnel informed. Flexibility to allow for interaction by the operator is desirable in the display designs. Also, where feasible, the SPDS should include some audible notification to alert personnel of an unsafe operating condition.

The SPDS need not be limited to the previously stated functions. It may include other functions that aid operating personnel in evaluating plant status. It is desirable that the SPDS be sufficiently flexible to allow for future incorporation of advanced diagnostic concepts and evaluation techniques and systems.

### 18.1.17.1.6 Design Criteria

The total SPDS need not be Class 1E or meet the single-failure criterion. The sensors and signal conditioners (such as preamplifiers, isolation devices, etc.) shall be designed and qualified to meet Class 1E standards for those SPDS parameters that are also used by safety systems. Furthermore, sensors and signal conditioners for those parameters of the SPDS identical to the parameters specified within Regulatory Guide 1.97 shall be designed and qualified to the criteria stated in Regulatory Guide 1.97. For SPDS application, it is also acceptable to have Class 1E qualified devices from the sensor to a post-accident-accessible location, such as outside containment, and then non-1E devices from containment to the display (or processor) on the presumption that these components can be repaired or replaced in an accident environment. The processing and display devices of the SPDS shall be of proven high quality and reliability.

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The function of the SPDS is to aid the operator in the interpretation of transients and accidents. This function shall be provided during and following all events expected to occur during the life of the plant, including earthquakes. To achieve this function, the display system shall not only take adequate account of human factors--the man-machine interface--but shall also be sufficiently durable to function during and after earthquakes. Because of current technology, it may not be possible to satisfy these criteria within one SPDS system.

From an operational viewpoint, it is preferred that only one display system be used for evaluating the safety status of the plant. One display system simplifies the man-machine interface and thus minimizes operator errors. However, in recognition of the restraints imposed by current technology, an alternative is to design the overall SPDS function with a primary and backup display system: (1) the primary SPDS display would have high performance and flexibility and be human factored but need not be seismically qualified; and (2) the backup display system would be operable during and following earthquakes, such as the normal control room displays needed to comply with Regulatory Guide 1.97. The display system (or systems) provided for the SPDS function shall be capable of functioning during and following all design basis events for the plant.

In all cases, both the primary SPDS display and the backup SPDS seismically qualified portion of the display shall be sufficiently human factored in its design to allow the control room operations staff to perform the safety status design to allow the control room operations staff to perform the safety status assessment task in a timely manner. Dependence on poorly human-engineered Class 1E seismically qualified instruments that are scattered over the control board, rather than concentrated for rapid safety status assessment, is not acceptable for this function. An acceptable approach would be to concentrate the seismically qualified display into one segment of the control board.

The dynamic loading limitations of the SPDS design shall be defined and incorporated into the training program. The control room operations staff shall be provided with sufficient information and criteria to allow for performance of an operability evaluation of SPDS if an earthquake should occur.

The SPDS as used in the control room shall be designed to an operational unavailability goal of 0.01, as defined in Section 1.5 of NUREG 0696. The cold shutdown unavailability goal for the SPDS during the cold shutdown and refueling modes for the reactor shall be 0.2, as defined in Section 1.5 of NUREG 0696.

Technical specifications shall be established to be consistent with the unavailability design goal of the SPDS and with the

compensatory measures provided during periods when the SPDS is inoperable. Operation of the plant with the SPDS out of service is allowed provided that the control board is sufficiently human factored to allow the operations staff to perform the safety status assessment task in a timely manner. Dependence on poorly human-engineered instruments that are scattered over the control board rather than concentrated for rapid safety status assessment is not acceptable for this function.

The operational date for the SPDS is October 1, 1982.

#### 18.1.17.2 Interpretation

None required.

#### 18.1.17.3 Statement of Response

The proposed method of responding to this requirement was submitted by a letter to B. J. Youngblood from N. W. Curtis on April 2, 1981 (PLA-704). Details on the SPDS are presented in Appendix I of the Emergency Plan.

#### 18.1.18 TRAINING DURING LOW-POWER TESTING (I.G.1)

No requirement stated in NUREG 0737. Refer to Subsection 18.2.15 which contains the response to the requirement in NUREG 0694.

#### 18.1.19 REACTOR COOLANT SYSTEM VENTS (II.B.1)

##### 18.1.19.1 Statement of Requirement

Each applicant and licensee shall install reactor coolant system (RCS) and reactor pressure vessel (RPV) head high point vents remotely operated from the control room. Although the purpose of the system is to vent noncondensable gases from the RCS which may inhibit core cooling during natural circulation, the vents must not lead to an unacceptable increase in the probability of a loss-of-coolant accident (LOCA) or a challenge to containment integrity. Since these vents form a part of the reactor coolant pressure boundary, the design of the events shall conform to the requirements of Appendix A to 10 CFR Part 50, "General Design Criteria." The vent system shall be designed with sufficient redundancy that assures a low probability of inadvertent or irreversible actuation.

Each licensee shall provide the following information concerning the design and operation of the high point vent system:

- (1) Submit a description of the design, location, size, and power supply for the vent system along with results of analyses for loss-of-coolant accidents initiated by a break in the vent pipe. The results of the analyses should demonstrate compliance with the acceptance criteria of 10 CFR 50.46.
- (2) Submit procedures and supporting analysis for operator use of the vents that also include the information available to the operator for initiating or terminating vent usage.

Documentation shall be submitted by July 1, 1981. Modifications shall be completed by July, 1982.

#### 18.1.19.2 Interpretation

None required.

#### 18.1.19.3 Statement Of Response

The present design of reactor coolant and reactor vessel vent systems meet these requirements.

The RPV is equipped with various means to vent the reactor during all modes of operation. All the valves involved are safety grade, powered by essential busses and are capable of remote manual operation from the control room.

The largest portion of non-condensables are vented through sixteen (16) safety relief valves (PSV 141F013A-S) mounted on the main steam lines. These power operated relief valves satisfy the intent of the NRC position. Information regarding the design, qualification, power source of these valves has been provided in Sections 5.1, 5.2.2, 6.2, 6.3, 7.3 and 15.

In addition to power operated relief valves, the RPV is equipped with various other means of high point venting. These are:

1. Normally closed RPV head vent valves (HV141-F001 and F002), operable from control room which discharges to drywell equipment drain tank. (Subsection 5.1 and Figure 5.1-3a).

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2. Normally open reactor head vent line 2 DBA-112 which discharges to main steam line "A". (Subsection 5.1 and Figure 5.1-3a).
3. Main steam driven RCIC and HPCI system turbines, operable from the control room which exhaust to suppression pool. (Subsections 5.3 and 6.3 and Figures 5.4-9a and 6.3-1a).

Although the power operated relief valves fully satisfy the intent of the NRC requirement these other means also provide protection against accumulation of non-condensables in the RPV.

The design of the RCS and RPV vent systems is in agreement with the generic capabilities proposed by the BWR Owners' Group, with the exception of isolation condensers. Susquehanna SES is not equipped with isolation condensers. The BWR Owners' Group position is summarized in NEDO-24782.

Operation of the equipment described above during abnormal operating conditions is controlled by the Emergency Operating Procedures. While these procedures do not specifically address venting of non-condensable gases, they do address proper utilization of equipment to recover from undesirable conditions presented by the presence of non-condensables or by other circumstances.

The RCS and RPV vent systems are part of the original SSES design basis. A pipe break in either of these systems would be the same as a small mainsteam line break. A complete mainsteam line break is within the design basis (see Subsections 6.2.1.1.3.3.2 and 6.3.3). Smaller size breaks have been shown to be of lesser severity (see Subsections 6.2.1.1.3.3.5 and 6.3.3.7.3). Therefore, no new supporting analysis is necessary in response to NUREG 0737. In addition, no new 10CFR50.46 conformance calculations or containment combustible gas concentration calculations are necessary. Non-condensable gas releases due to a vent line break would be no more severe than the releases associated with a mainsteam line break. Mainsteam line break analyses included continuous venting of non-condensable gases with high hydrogen concentrations. These analyses demonstrate conformance to 10CFR50.46.

### 18.1.20 Plant Shielding (II.B.2)

#### 18.1.20.1 Statement of Requirement

With the assumption of a postaccident release of radioactivity equivalent to that described in Regulatory Guides 1.3 and 1.4



(i.e., the equivalent of 50% of the core radioiodine, 100% of the core noble gas inventory, and 1% of the core solids are contained in the primary coolant), each licensee shall perform a radiation and shielding-design review of the spaces around systems that may, as a result of an accident, contain highly radioactive materials. The design review should identify the location of vital areas and equipment, such as the control room, radwaste control stations, emergency power supplies, motor control centers, and instrument areas, in which personnel occupancy may be unduly limited or safety equipment may be unduly degraded by the radiation fields during postaccident operations of these systems.

Each licensee shall provide for adequate access to vital areas and protection of safety equipment by design changes, increased permanent or temporary shielding, or postaccident procedural controls. The design review shall determine which types of corrective actions are needed for vital areas throughout the facility.

#### 18.1.20.1.1 Documentation Required for Vital Area Access

For vital area access, operating license applicants need to provide a summary of the shielding design review, a description of the review results, and a description of the modifications made or to be made to implement the result of the review. Also to be provided by the licensee:

- (1) Source terms used including time after shutdown that was assumed for source terms in systems.
- (2) Systems assumed to contain high levels of activity in a post-accident situation and justification for excluding any of those given in the "Clarification" of NUREG 0737.
- (3) Areas assumed vital for post-accident operations including justification for exclusion of any of those given in the "Clarification" of NUREG 0737.
- (4) Projected doses to individuals for necessary occupancy times in vital areas and a dose rate map for potentially occupied areas.

#### 18.1.20.1.2 Documentation Required for Equipment Qualification

Item II.B.2 states, "Provide the information requested by the Commission Memorandum and Order on equipment qualification (CLI-80-21)." This memorandum, with regard to equipment qualification, requests infor-

mation on environmental qualification of safety related electrical equipment.

### 18.1.20.2 Interpretation

#### 18.1.20.2.1 Source Terms

The source term for recirculated depressurized coolant need not be assumed to contain noble gases, therefore the RHR shutdown cooling system which may initiate at low reactor pressure only will be assumed to contain solely halogens and particulates. The HPCI and LPCI systems do not recirculate reactor coolant but, rather, suppression pool water. They will also be essentially void of noble gases.

Leakage from systems outside of containment need not be considered as potential sources. Also, containment and equipment leakage (from systems outside containment) need not be considered as potential airborne sources within the reactor building. It follows that airborne sources and any other uncontained sources in the reactor building do not need be considered in this shielding review.

#### 18.1.20.2.2 Post-Accident Systems

The standby gas treatment system, or equivalent, is given as a system which may contain high levels of radioactivity after an accident. Airborne activity from leakage of equipment outside containment has been clearly established as being outside the review requirements. Drywell leakage must then provide the activity processed by the SGTS. This review will assume the drywell does indeed leak to the reactor building to provide a source within the SGTS. However, this airborne source will not be evaluated any further in the review.

#### 18.1.20.2.3 Equipment Qualification

Provide a description of the environmental qualification program and results for safety related electrical equipment both inside and outside of containment. It is our understanding that radiation qualification of non-electrical safety related equipment need not be reported.

18.1.20.3 Statement of Response

The required post-accident study is divided into two parts; one dealing with a summary of the shielding design review plus vital area access, another dealing with equipment qualification. A summary of the shielding design review, results, and methodology used to determine radiation doses is presented below. The results of the equipment qualification program are scheduled to be submitted separately, and in compliance with commission memorandum and order CLI-80-21.

The results of the shielding review of contained sources are that all vital areas are accessible post-accident and no shielding modifications are necessary to comply to NUREG 0737.

18.1.20.3.1 Introduction

If an accident is postulated in which large amounts of activity are released from the reactor core, then pathways exist which can transfer this activity to various areas of the reactor building. These large radiation source terms present a hazard regarding potentially high doses to personnel. In order to deal with this problem it has become necessary to quantify these source terms, trace their presence and determine their effects on the efficient performance of post-accident recovery operations. To this end, the plant shielding of Units 1 and 2 has been reviewed for post-accident adequacy.

This summary presents the analytical bases by which the review was carried out. Systems required or postulated to process primary reactor coolant outside the containment during post-accident conditions were selected for evaluation. Large radiation sources beyond the original selected systems. Radiation levels in adjacent plant areas due to contained sources in piping and equipment of these systems were then estimated to yield the desired information. Also included herein is a discussion of radiation exposure guidelines for plant personnel, identification of areas vital to post-accident operations and availability of access to these areas.

As a byproduct of this review, several radiation zone maps and associated curves have been produced. The maps will allow operations personnel to identify potential high exposure vital areas of the plant should an accident occur which contaminates the system considered in this study. The curves will allow them to estimate radiation levels in these areas at various times following an accident.

18.1.20.3.2 Design Review Bases18.1.20.3.2.1 Systems Selected for Shielding Review

A review was made to determine which systems could be required to operate and/or be expected to contain highly radioactive materials following a postulated accident where substantial core damage has occurred. The documentation governing the approach to the shielding review is NUREG-0737.

A review of containment isolation provisions was conducted in accordance with item II.E.4.2. This was done to assure isolation of non-essential systems penetrating the containment boundary. Thus, systems other than those identified as having a specified function following an accident are assumed not to contain post-accident activity and do not need to be considered in the shielding review.

18.1.20.3.2.1.1 Core Spray, HPCI, RCIC and RHR (LPCI mode)

The Core Spray, RHR (LPCI mode), HPCI (water side) and RCIC (water side) systems would contain suppression pool water being injected into the reactor coolant system. Although the HPCI and RCIC systems could also draw from the condensate storage tank, suppression pool water is assumed to be their only source of water for injection. The steam sides of the HPCI and RCIC systems would operate on reactor steam and would not be required when the reactor is depressurized. However, as a first estimate for equipment qualification, it is assumed that these systems should also be available until one year post-accident.

18.1.20.3.2.1.2 RHR (Shutdown Cooling Mode)

The RHR system recirculates reactor waste heat when it operates in the shutdown cooling mode. Operation in this mode requires that the reactor be in depressurized condition. Depressurization is expected to remove substantially all of the noble gases released into the reactor coolant whether it be by direct venting to the drywell or by quenching reactor steam in the suppression pool. Another consideration is, following a postulated serious accident, the HPCI, RCIC, RHR (LPCI Mode) and/or Core Spray systems would inject a substantial amount of water into the reactor coolant system. This shielding review will assume that there are no noble gases in the reactor water in the RHR system from the shutdown cooling mode. However, since the exact amount

of dilution of the reactor water is difficult to determine, no dilution in addition to the reactor coolant volume is assumed.

18.1.20.3.2.1.3 RHR (Suppression Pool Cooling Mode)

The RHR system in this mode circulates and removes heat from suppression pool water to prevent pool boiling. This assures availability of suppression pool water as a source for cooling the reactor and increases the efficiency of a given cooling operation with this source.

18.1.20.3.2.1.4 RHR (Containment Spray Mode)

Under post-accident conditions, water pumped from the suppression pool through the RHR heat exchanger may be diverted to spray header system loops located high in the drywell and above the suppression pool. This mode of operation provides the ability to reduce containment pressure by condensing atmospheric steam while cooling the suppression pool water. No credit is taken for spray removal of iodines.

18.1.20.3.2.1.5 CRD Hydraulic System

The operation of the CRD system was reviewed to determine if the scram discharge headers will contain highly radioactive water following a postulated accident. Prior to a scram the CRD housings contain condensate water delivered by the CRD pumps. When a scram occurs some of this condensate water from the CRD system is discharged to the scram discharge header. After the scram, some condensate and reactor water flows to the scram discharge header which fills in a matter of a few seconds.

Since the vents and drains in the scram discharge headers are isolated by the scram, all discharge flow then stops. Since it is not reasonable to assume that significant core damage occurs in the first few seconds following a scram, the scram discharge header will initially contain only a mixture of condensate and pre-accident reactor water following this postulated accident. After the reactor scram, the scram discharge and instrument volumes will contain about 700 gallons of pre-accident water, isolated by a single drain valve leak tested to 20 cc/hr. If the initial scram closed the drain valve, then this leakage is insignificant compared to the scram discharge volume and insignificant as a post-accident concern. If the drain valve fails to close, operator action is required to reset the scram and close the soft-seated scram discharge valve. If this action

is not taken or fails to close the valve, then post-accident sources can enter the liquid radwaste system by leaking past the CRD seals. The CRD withdraw line does not directly communicate with the reactor coolant.

In light of the anticipated small leak rates and the lack of single failure criteria consideration requirements, the scram discharge drain valve was assumed to remain closed and any leakage was disregarded.

#### 18.1.20.3.2.1.6 RWC System

For a major accident with resulting core damage, the RWC system would automatically isolate on a low reactor coolant level signal and would contain no highly radioactive materials beyond the second isolation valve. Since the cleaning capacity for this system is small, it would be impractical to use it for TMI type accident recovery and it is excluded from this shielding review.

#### 18.1.20.3.2.1.7 Liquid Radwaste System

Equipment drains and compartment floor drains servicing ECCS systems are isolated from the reactor building sump. All piping that may contain high activity post-accident water is also isolated from the reactor building sump and radwaste systems. CRD system isolation is discussed in Subsection 18.1.20.3.2.1.5. Since no significant amounts of post-accident activity can reach the liquid radwaste system, it is excluded from this shielding review.

#### 18.1.20.3.2.1.8 MSIV Leakage Control System

Subsequent to a postulated accident, system operation may begin upon actuation of the manual switches in the control room. This system may only be activated upon a permissive reactor pressure signal (35 psig). The method used to depressurize the reactor to this level has a large effect on the amount of activity potentially available for passage through this system. For example, the HPCI system can deplete the reactor steam activity considerably with only a few minutes operation. Whichever depressurization method is chosen, the MSIV-LCS system remains as one that must be included in the shielding review.

18.1.20.3.2.1.9 Sampling Systems

Sampling systems required or desired for post-accident use include the Containment Atmosphere Monitoring System, the Plant Vent Sampling System and the Post-Accident Sampling System. Each of these systems/stations may contain post-accident sources and is included in the shielding review.

18.1.20.3.2.1.10 Standby Gas Treatment System

The Reactor Building Recirculation system is used after an accident. This disperses airborne activity throughout the reactor building and refueling floor. The SGTS system collects airborne activity, concentrating halogens within the charcoal filters while releasing noble gases outside the secondary containment. The charcoal filter is considered to be a source of contained activity and is included in this shielding review. The assumptions used in determining this contained source are:

- 1) Drywell leakage at 1% per day.
- 2) SGTS process rate of 1 reactor building/refueling floor volume per day.
- 3) 99% charcoal filter efficiency for halogens. 0% charcoal filter efficiency for noble gases.

18.1.20.3.2.1.11 Containment Atmosphere (Drywell)

The free volume of the primary containment is assumed to initially contain large amounts of post-accident activity, namely 100% of the core noble gases and 25% of the core halogens. Shine through the drywell wall was examined to determine the effects on reactor building radiation levels. Results indicate the six foot thick drywell shield wall reduces shine to radiation Zone I levels. Shine through penetrations presents no additional hazard because piping is directed to penetration rooms where area dose rates will be dominated by internal piping.

18.1.20.3.2.1.12 Suppression Pool (Wetwell)

The suppression pool is assumed to initially contain 50% of the core halogens and 1% of the core particulates post-accident. Shine through the wetwell wall was examined to determine the effects on radiation levels in the reactor building. It was

determined that the six foot thick wetwall shield wall reduces wetwell shine to radiation Zone I levels in the reactor building.

#### 18.1.20.3.2.2 Radioactive Source Release Fractions

The following release fractions were used as a basis for determining the concentrations for the shielding review:

Source A: Containment Atmosphere: 100% noble gases, 25% halogens

Source B: Reactor Liquids: 100% noble gases, 50% halogens, 1% solids

Source C: Suppression Pool Liquid: 50% halogens, 1% solids

Source D: Reactor Steam: 100% noble gases, 25% halogens

The above release fractions were applied to the total curies available for the particular chemical species (i.e., noble gas, halogen, or solid) for an equilibrium fission product inventory for Susquehanna as listed in Table 18.1-2.

The Regulatory Guide 1.7 solids release fraction of 1% was used for Cs and Rb on this review. Further evaluations of the TMI radioactivity releases may conclude that higher release fractions are appropriate. However, until the release mechanisms and release fractions have been quantified, the existing regulatory guidance will be followed. No noble gases were included in the suppression pool liquid (Source C) because Regulatory Guide 1.7 has also set this precedent in modeling liquids in the pool (See References 18.1-4 and 18.1-10). Furthermore, cursory analyses have indicated that the halogens dominate all shielding requirements and that contributions to the total dose rates from noble gases are negligible for the purposes of shielding design review.

#### 18.1.20.3.2.3 Source Term Quantification

Subsection 18.1.20.3.2.2 above outlines the assumptions used for release fractions for the shielding design review. These release fractions are, however, only the first step in modeling the source terms for the activity concentrations in the systems under review. The important modeling parameters, decay time and dilution volume obviously also affect any shielding analysis. The following sections outline the rationale for the selection of values for these key parameters.



18.1.20.3.2.3.1. Decay Time

For the first stage of the shielding design review process, minimal decay time credit was used with the above releases. The primary reason for this was to develop a set of accident radiation zone maps normalized to 1 hour decay.

18.1.20.3.2.3.2 Dilution Volume

The volume used for dilution is important, affecting the calculations of dose rate in a linear fashion. The following dilution volumes were used with the release fractions and decay times listed above to arrive at the final source terms for the shielding review:

Source A: Drywell and suppression pool free volumes.

Source B: Reactor coolant system normal liquid volume  
(based on reactor coolant density at the operating temperature and pressure).

Source C: The volume of the reactor coolant system plus the suppression pool volume.

Source D: The reactor steam volume.

18.1.20.3.2.4 System/Source Summary

- o Core Spray System: Source C
- o High Pressure Coolant Injection System
  - Liquid: Source C
  - Steam: Source D (with credit for steam specific activity reduction due to turbine operation)
- o Reactor Core Isolation Cooling System
  - Liquid: Source C
  - Steam: Source D (with credit for steam specific activity reduction due to turbine operation).
- o Residual Heat Removal System
  - LPCI Mode: Source C

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Shutdown Cooling Mode: Source B (with credit for noble gas release during vessel depressurization).

Suppression Pool Cooling and Containment Spray  
Modes: Source C

o Main Steam Isolation Valve-Leakage Control System

Steam: Source D (with credit for steam specific Activity reduction due to RCIC turbine operation).

o Sampling Systems

Containment air sample: Source A  
Reactor coolant sample: Source B  
Plant vent sample: 1% per day Drywell leakage following the filtration by the Standby Gas Treatment System (see subsection 18.1.20.3.2.1.10 for discussion of SGTS source assumptions)

o Standby Gas Treatment System

Charcoal filter: 1% per day drywell leakage (See Subsection 18.1.20.3.2.1.10 for discussion of source assumptions).

o Drywell: Source A

o Wetwell: Source C

For each of these systems, piping associated with the appropriate operating mode was identified on piping and instrumentation drawings and traced throughout the plant to their final destination.

### 18.1.20.3.2.5 Dose Integration Factors for Personnel

Cummulative radiation exposure to personnel in vital areas (continuous occupancy) is determined based upon a maximum one year exposure period. The integrated doses are modified using Reference 18.1-8 occupancy factors listed below.

<u>Time (days)</u>	<u>Occupancy Factors</u>
0 to 1	1.0
1 to 4	0.6
over 4	0.4

Exposures for areas not continuously occupied (frequent and infrequent occupancy) must be determined case by case, that is, multiply the task duration by the area dose rate at the time of exposure.

### 18.1.20.3.3 Shielding Review Methodology

#### 18.1.20.3.3.1 Radiation Dose Calculation Model

The previous sections outlined the rationale and assumptions for the selection of systems that would undergo a shielding design review as well as the formulation of the sources for those systems. The next step in the review process was to use those sources along with standard point kernel shielding analytical techniques (Ref. 18.1-14 and 18.1-15) to estimate dose rates from those selected systems.

Scattered radiation (e.g., shine over partial shield walls) was considered but was not significant since the net reduction in dose is several orders of magnitude and no vital area is separated from a high activity source solely by a partial wall.

Radiation levels for compartments containing the systems under review were based on the maximum contact dose rate for any component in the compartment. Radiation levels in areas not containing unshielded sources were based on maximum dose rates transmitted into areas through walls of these adjacent compartments. Checks were also made for any piping or equipment that could directly contribute to corridor dose rates, i.e., piping that may be running directly in the corridor or equipment/piping in a compartment that could shine directly into corridors with no attenuation through compartment walls. There is no field routed small piping (i.e., piping less than 2" in diameter) for ECCS systems.

Dose rates are cumulative and are summed over all systems in simultaneous operation in most cases. The exception is steam piping for the RCIC and HPCI systems. Both are high pressure systems and cannot be operated simultaneously with low pressure systems such as core spray. This becomes a moot point, since these steam lines are routed in well shielded compartments, causing no appreciable personnel doses.

18.1.20.3.3.2 Post-Accident Radiation Zone Maps

One of the principal products of this review is the series of accident radiation zone maps (Figures 18.1-2 to 8). The zone boundaries used in the maps are defined in Table 18.1-3. The zone maps present the calculated dose rates at one hour after the accident due to the sources described in Subsection 18.1.20.3.2.4 in various areas of the plant site. The principal sources of radiation in each area are identified in Table 18.1-5.

The dose rates presented do not include contributions from normal operating sources which may be contained in the plant at the time of the accident since these contributions will be minor outside of well defined and shielded areas. They also do not include dose rate contributions due to potential airborne sources resulting from equipment or drywell leakage.

The zone maps were used to determine the accessibility of vital areas described in Subsection 18.1.20.3.3.4.

18.1.20.3.3.3 Personnel Radiation Exposure Guidelines

In order that doses to occupied areas take on meaningful proportions, it is necessary to establish exposure goals or guidelines. The general design basis for these guidelines is 10CFR50, Appendix A, GDC 19. That material addresses control room habitability, including access and occupancy under worst case conditions. Exposures are not to exceed 5 rem whole body, or its equivalent to any part of the body, for the duration of any postulated accident. GDC 19 is also used to govern design bases for the maximum permissible dosage to personnel performing any task required post-accident. These requirements translate roughly into the objectives to be met in the post-accident review as given below.

Radiation Exposure Guidelines		
Occupancy	Dose Rate Objectives	Dose Objective
Continuous	15 mR/hr	5 Rem for duration
Frequent	100 mR/hr	5 Rem for all activities
Infrequent	500 mR/hr	5 Rem per activity
Accessway	5 R/hr	Included in above doses

#### 18.1.20.3.3.4 Vital Area Identification and Access

##### 18.1.20.3.3.4.1 Vital Area Clarification

Vital areas are those "which will or may require occupancy to permit an operator to aid in the mitigation of or recovery from an accident". Reference (18.1-16) further defines recovery from an accident as, "when the plant is in a safe and stable condition." "This may either be hot or cold shutdown, depending on the situation." The 10 CFR 73.2 definition of vital area shall not apply here.

For the purposes of this study, the evaluation to determine necessary vital areas considers all of those listed in Reference (18.1-3). Upon examination several plant areas were determined not to be vital. Instrument panels were excluded because essential equipment control and alignment has been established in the control room and requires no local actions. The radwaste control room is excluded because 1) no local actions are required to prevent spread of postaccident sources into the liquid radwaste system; 2) gaseous radwaste processing is not required, and; 3) activity sources early in the post-accident transient are much too high to be effectively processed through the liquid and eventually solid radwaste systems. Also excluded are the post-LOCA hydrogen control system and the containment isolation reset control area (which are operator actuated from the main control room). Lastly the emergency power supply (i.e., diesel generators) was excluded since system initiation comes from the control room and requires no local actions.

The resulting list of areas considered vital for post-accident operations at Susquehanna appears in Table 18.1-4. Note that security facilities are included as vital areas with regards to maintaining plant security.

##### 18.1.20.3.3.4.2 Vital Area Access

Those operator actions required post-accident were reviewed to assure that first priority safety actions can be achieved in the postulated radiation fields. This review assures that access is available and required operator actions can be achieved.

Ingress and egress area dose rates to those vital areas identified in Table 18.1-4 were examined to ensure compatibility with the areas being accessed.

Plant effluent monitoring stations are located at five (5) plant vents: two (2) for the Reactor Building, two (2) for the Turbine

Building, and one (1) for the Standby Gas Treatment System. The reactor building monitors are automatically isolated post-LOCA and will contain no post-accident activity. The SGTS effluent sample station will contain post-accident activity in sample cartridges: one (1) volumetric and one (1) charcoal filter. The samples are locally shielded and present no access problems in the area of the station. However, transportation and handling of the filter cartridges will require local shielding.

The Turbine Building Plant Vent Sample Station (PVSS) may also contain post-accident activity. Doses, if any, will be of a lower magnitude than that of the SGTS effluent filters because of environmental dispersion and re-entry to the Turbine Building ventilation system. In the worse case, the Turbine Building PVSS doses will be much lower than those of the SGTS. In the best case, control room personnel may shut down the Turbine Building HVAC system (which is non-safety related). In this case, the Turbine Building PVSS may be void of post-accident activity.

#### 18.1.20.3.4 Results

##### 18.1.20.3.4.1 Radioactive Decay Effects

Results of the radiation level evaluation for the shielding design review are presented in Figures 18.1-1 to 8. Table 18.1-5 identifies the sources contributing to dose rates in each of the plant areas shown on those figures. This table can be used in conjunction with the decay curves (Figures 18.1-9 and 10) to estimate radiation levels at times other than one hour. The procedure for times less than one day, is to multiply the radiation level (i.e., radiation zone limit) by the decay factor given in Figure 18.1-9. For times greater than one day, it is necessary to multiply by the decay factor in Figure 18.1-9 at 24 hours and by the decay factor in Figure 18.1-20 at the desired decay time. This procedure is conservative for areas in which the sources are shielded because it does not rigorously take into account the softening of the energy spectrum and consequent increase in attenuation for longer decay times. A decay curve for source D, reactor steam, is not included because the depletion effects due to steam usage by HPCI or RCIC removes much of this source shortly after the accident. In addition, HPCI and RCIC piping containing source D is run in shielded cubicles and does not contribute significantly outside those cubicles.

18.1.20.3.4.2 Integrated Personnel Exposures

Personnel integrated exposures in continuously occupied areas were calculated based on 100% occupancy for the first day, 60% occupancy from day one through four and 40% occupancy for the duration (1 year). These calculations showed that personnel exposures would be within the design objective of 5 Rem. Exposures in Zones I, II and III of the control structure are 0.24, 1.6 and 3.1 Rem, respectively. These doses do not include the shielding effects of interior walls, equipment, etc., therefore they represent the maximum dose to control building personnel due to contained sources. Personnel doses to the North Gate House (ASCC) and Security Control Center from contained sources were found to be insignificant (i.e., < 0.1 Rem). These areas are a minimum of 300 feet from the reactor building whose walls are a minimum of 2.5 feet of concrete.

Personnel doses at the Post-Accident Sample Station, Chemistry Laboratory, and Plant Vent Sample Station are calculated based on an estimated task duration at specified times post-accident for a one person task force (Refer to Table 18.1-4)

18.1.20.3.4.3 Reactor Building Accessibility

The results show that the reactor building will be generally inaccessible for several days after the accident due to contained radiation sources. High radiation levels can be expected at Elevation 645'-0" (Figure 18.1-3) regardless of which system(s) is (are) in operation. Radiation levels at Elevation 719'-0" (Figure 18.1-5) and above are expected to generally be within Zone IV limits if the core spray and RHR containment spray systems have not been operated following the accident. This is because these are the only unshielded post-accident system sources at these elevations. Other system sources are contained in shielded cubicles.

Exceptions to these general Zone IV levels are areas in the vicinity of reactor coolant and containment atmosphere sampling lines which are routed to the reactor building sample station at Elevation 779'-0". The dose rate 10 feet from the reactor coolant sampling line one hour after the postulated accident may exceed 100 R/hr.

Results for contained radiation sources show that the vital area in the Reactor Building is accessible post-accident.

18.1.20.3.4.4 Control Building Accessibility

Results for contained radiation sources show that vital areas in the control structure are accessible post-accident.

18.1.21 POST-ACCIDENT SAMPLING (II.B.3)18.1.21.1 Statement of Requirement

A design and operational review of the reactor coolant and containment atmosphere sampling line systems shall be performed to determine the capability of personnel to promptly obtain (less than 1 hour) a sample under accident conditions without incurring a radiation exposure to any individual in excess of 3 and 18-3/4 rem to the whole body or extremities, respectively. Accident conditions should assume a Regulatory Guide 1.3 or 1.4 release of fission products. If the review indicates that personnel could not promptly and safely obtain the samples, additional design features or shielding should be provided to meet the criteria.

A design and operational review of the radiological spectrum analysis facilities shall be performed to determine the capability to promptly quantify (in less than 2 hours) certain radionuclides that are indicators of the degree of core damage. Such radionuclides are noble gases (which indicate cladding failure), iodines and cesiums (which indicate high fuel temperatures), and nonvolatile isotopes (which indicate fuel melting). The initial reactor coolant spectrum should correspond to a Regulatory Guide 1.3 or 1.4 release. The review should also consider the effects of direct radiation from piping and components in the auxiliary building and possible contamination and direct radiation from airborne effluents. If the review indicates that the analyses required cannot be performed in a prompt manner with existing equipment, then design modifications for equipment procurement shall be undertaken to meet the criteria.

In addition to the radiological analyses, certain chemical analyses are necessary for monitoring reactor conditions. Procedures shall be provided to perform boron and chloride chemical analyses assuming a highly radioactive initial sample (Regulatory Guide 1.3 or 1.4 source term). Both analyses shall be capable of being completed promptly (i.e., the boron sample analysis within an hour and the chloride sample analysis within a shift).



The following items are clarifications of requirements identified in NUREG-0578, NUREG-0660, or the September 13 and October 30, 1979 clarification letters.

- (1) The licensee shall have the capability to promptly obtain reactor coolant samples and containment atmosphere samples. The combined time allotted for sampling and analysis should be 3 hours or less from the time a decision is made to take a sample.
- (2) The licensee shall establish an onsite radiological and chemical analysis capability to provide, within the 3-hour time frame established above, quantification of the following:
  - (a) certain radionuclides in the reactor coolant and containment atmosphere that may be indicators of the degree of core damage (e.g., noble gases; iodines and cesiums, and nonvolatile isotopes);
  - (b) hydrogen levels in the containment atmosphere;
  - (c) dissolved gases (e.g., hydrogen), chloride (time allotted for analysis subject to discussion below), and boron concentration of liquids.
  - (d) Alternatively, have inline monitoring capabilities to perform all or part of the above analyses.
- (3) Reactor coolant and containment atmosphere sampling during postaccident conditions shall not require an isolated auxiliary system (e.g., the letdown system, reactor water cleanup system to be placed in operation in order to use the sampling system.
- (4) Pressurized reactor coolant samples are not required if the licensee can quantify the amount of dissolved gases with unpressurized reactor coolant samples. The measurement of either total dissolved gases or hydrogen gas in reactor coolant samples is considered adequate. Measuring the oxygen concentration is recommended, but is not mandatory.
- (5) The time for a chloride analysis to be performed is dependent upon two factors: (a) if the plant's coolant water is seawater or brackish water and (b) if there is only a single barrier between primary containment systems and the cooling water. Under both of the above conditions the licensee shall provide for a chloride analysis within 24 hours of the sample being taken. For all other cases, the licensee shall provide for the

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analysis to be completed within 4 days. The chloride analysis does not have to be done onsite.

- (6) The design basis for plant equipment for reactor coolant and containment atmosphere sampling and analysis must assume that it is possible to obtain and analyze a sample without radiation exposures to any individual exceeding the criteria of GDC 19 (Appendix A, 10 CFR Part 50) (i.e., 5 rem whole body, 75 rem extremities). (Note that the design and operational review criterion was changed from the operational limits of 10 CFR Part 20 (NUREG-0578) to the GDC 19 criterion (October 30, 1979 letter from H.R. Denton to all licensees).)
- (7) The analysis of primary coolant samples for boron is required for PWRs. (Note that Revision 2 of Regulatory Guide 1.97, when issued, will likely specify the need for primary coolant boron analysis capability at BWR plants.)
- (8) If inline monitoring is used for any sampling and analytical capability specified herein, the licensee shall provide backup sampling through grab samples, and shall demonstrate the capability of analyzing the samples. Established planning for analysis at offsite facilities is acceptable. Equipment provided for backup sampling shall be capable of providing at least one sample per day for 7 days following onset of the accident and at least one sample per week until the accident condition no longer exists.
- (9) The licensee's radiological and chemical sample analysis capability shall include provisions to:
  - (a) Identify and quantify the isotopes of the nuclide categories discussed above to levels corresponding to the source terms given in Regulatory Guide 1.3 or 1.4 and 1.7. Where necessary and practicable, the ability to dilute samples to provide capability for measurement and reduction of personnel exposure should be provided. Sensitivity of onsite liquid sample analysis capability should be such as to permit measurement of nuclide concentration in the range from approximately  $1 \mu \text{ Ci/g}$  to  $10 \text{ Ci/g}$ .
  - (b) Restrict background levels of radiation in the radiological and chemical analysis facility from sources such that the sample analysis will provide results with an acceptably small error (approximately a factor of 2). This can be

accomplished through the use of sufficient shielding around samples and outside sources, and by the use of ventilation system design which will control the presence of airborne radioactivity.

- (10) Accuracy, range, and sensitivity shall be adequate to provide pertinent data to the operator in order to describe radiological and chemical status of the reactor coolant systems.
- (11) In the design of the postaccident sampling and analysis capability, consideration should be given to the following items:
  - (a) Provisions for purging sample lines, for reducing plateout in sample lines, for minimizing sample loss or distortion, for preventing blockage of sample lines by loose material in the RCS or containment, for appropriate disposal of the samples, and for flow restrictions to limit reactor coolant loss from a rupture of the sample line. The postaccident reactor coolant and containment atmosphere following a transient or accident. The sample lines should be as short as possible to minimize the volume of fluid to be taken from containment. The residues of sample collection should be returned to containment or to a closed system.
  - (b) The ventilation exhaust from the sampling station should be filtered with charcoal adsorbers and high-efficiency particulate air (HEPA) filters.

Operating License Applicants--Provide a description of the implementation of the position and clarification including P&IDs, together with either (a) a summary description of procedures for sample collection, sample transfer or transport, and sample analysis, or (b) copies of procedures for sample collection, sample transfer or transport, and sample analysis, in accordance with the proposed review schedule but in no case less than four months prior to the issuance of an operating license.

#### 18.1.21.2 Interpretation

None required.

18.1.21.3 Statement of Response18.1.21.3.1 Introduction

A design and operational review of the existing reactor coolant and containment atmosphere sampling system was performed to determine its ability to meet this requirement. The existing sampling system does not meet this requirement and therefore an additional system dedicated to post-accident sampling will be installed. This system was designed to satisfy all the requirements as stated in NUREG-0578 and the clarification of item II.B.3. The system will be installed and operational by fuel load.

The Post-Accident Sampling System (PASS) concept is based upon obtaining grab samples for remote laboratory analysis, having a minimum of operating complexities, having very little "in-line" instrumentation, having modular construction for maintenance and contamination control purposes, and being compact in size so as to require less shielding and to better fit into existing plants. This concept results in a three-step sampling/analysis process. The samples are obtained via a Post Accident Sample Station located adjacent to secondary containment. They are then transported to a sample preparation area which consists of a wet chemistry laboratory with the capability to perform the required chemical analyses as well as prepare the samples for radioisotopic analysis. The final step involves transporting the samples to a counting area with a sufficiently low background to permit accurate gamma-ray spectroscopic analysis.

18.1.21.3.2 Description of Sampling System

The underlying philosophy in the design of the sampling system is to meet the requirements of item II.B.3, to minimize exposure by minimizing the required sample sizes, to optimize the weight of the shielded sample containers in order to facilitate movement through potentially high-level radiation areas, and to provide adequate shielding at the sample station. The system is designed to provide useful samples under all conditions, ranging from normal shutdown and power operation to post-accident conditions.

The P&ID for the PASS is shown in Figure 18.1-11. The equipment includes isolation and control valves, piping station, sample station, and control panels.

18.1.21.3.2.1 Sample Points

## a) Wetwell and Drywell Atmosphere

Provision will be made to obtain gas samples from two separate areas in both the drywell and wetwell. The sample lines will tap into the containment air monitoring system sample lines outside of primary containment and after the second containment isolation valve. The two drywell sample taps are on the highpoint line, sampling at elevation 790', and the midpoint line, sampling at elevation 750'.

## b) Secondary Containment Atmosphere

A sample line will be installed to allow sampling of the secondary containment atmosphere. The location of this point has yet to be determined. This sample point would be useful in determining the post accident accessibility of the reactor building.

## c) Reactor Coolant and Suppression Pool Liquid Samples.

When the reactor is pressurized reactor coolant samples will be obtained from a tap off the jet pump pressure instrument system. The sample point will be on a non-calibrated jet pump instrument line outside of primary containment and after the excess flow check valve. This sample point location is preferred over the normal reactor sample points on the reactor water clean up system inlet line and recirculation line since the reactor clean-up system is expected to remain isolated under accident conditions, and it is possible that the recirculation line containing the sample line may be secured. The jet pump instrument line has been determined to be the optimum sample point for accident conditions since: 1) the pressure taps are well protected from damage and debris, 2) if the recirculation pumps are secured, there is normally excellent circulation of the bulk of the coolant past these taps (natural circulation), and 3) the taps are located sufficiently low to permit sampling at a reactor water level which is even below the lower core support plate.

A single sample line is also connected to both loops in the RHR system. The sample lines will tap off the high pressure switch instrument lines coming off the common section of the RHR system return line. This sample point provides a means of obtaining a reactor coolant sample when the reactor is not pressurized and at least one of the RHR loops is operated in the shutdown cooling mode. Similarly, a suppression pool sample can be obtained from an RHR loop lined up in the suppression pool cooling mode.

### 18.1.21.3.2.2. Isolation Valves and Sample Lines

Containment isolation for the drywell and wetwell gas sample lines is provided by the existing containment air monitoring sample line isolation valves. The jet pump instrument sample line containment isolation is provided by an existing isolation valve and excess flow check valve upstream of the sample tap. All gas sample lines from the sample taps to and including the first flow control valves are seismic category 1 except for the secondary containment sample line which has no control valve before it enters the sample panel. The sample lines from the RHR system are seismic category 1 through both system isolation valves and a flow restricting orifice. The sample line from the jet pump instrument system is seismic category 1 to the flow control/isolation valve. All containment isolation valves upstream of the sample taps can be overridden from the control room. All isolation and control valves shown in Figure 18.1-11 which are within the Q boundary are controlled by a single permissive switch in the control room and individually controlled at the sampling control panel located adjacent to the sample station.

The solenoid isolation and control valves which are part of the post accident sample system to the Q boundary will be environmentally qualified. The gas sample lines are heat traced to prevent precipitation of moisture and the resultant loss of iodine in the sample lines.

### 18.1.21.3.2.3. Piping Station

The piping station, which is to be installed within the reactor building, includes sample coolers and control valves which determine the liquid sample flow path to the sample station. The location for the piping station is shown in Figure 18.1-12. Cooling water will come from the Reactor Building Closed Cooling Water System.

### 18.1.21.3.2.4. Sample Station and Control Panels

The location of the sample station, control panels and associated equipment is shown in Figure 18.1-13. The sample station consists of a wall mounted frame and enclosures. Included within the sample station are equipment trays which contain modularized liquid and gas samplers. The lower liquid sample portion of the sample station is shielded with 6 inches of lead brick, whereas the upper gas sampler has 2 inches of lead shielding. The control instrumentation is installed in two control panels. One

of these panels contains the conductivity, and radiation level readouts. The other control panel contains the flow, pressure, and temperature indicators, and various control valves and switches. A graphic display directly below the main control panel which shows the status of the pumps and valves at all times. The panel also indicates the relative position of the pressure gauges and other items of concern to the operator. The use of this panel will improve operator comprehension and assist in trouble shooting operations. The various sample lines and return lines enter the sample station enclosure (which is mounted flush against the secondary containment wall) through the back by way of a penetration in the steam tunnel wall.

#### 18.1.21.3.2.4.1-----Gas Sampler

The gas sample system is designed to operate at pressure ranging from sub-atmospheric to the design pressures of the primary containment one hour after a loss-of-coolant accident. The gas samples may be passed through a particulate filter and silver zeolite cartridge for determination of particulate activity and total iodine activity by subsequent gamma spectroscopic analysis. A radiation monitor is mounted close to the filter tray to measure the activity buildup on the cartridges. Alternately, the sample flow bypasses the iodine sampler, is chilled to remove moisture, and a 15 milliliter grab sample can be taken for determination of gaseous activity and for gas composition by gas chromatography. The gas is collected in an evacuated vial using hypodermic needles in a manner analogous to the normal off-gas samples. When purging the drywell and wetwell gas sample lines to obtain a representative sample, the flow is returned to the wetwell; however, during purging of the secondary containment line and when flushing the sample panel lines with air or nitrogen, flow is returned to secondary containment. The sample station design allows for flushing of the entire sample panel line from the four position selector valve through the needles with either air, nitrogen, or the gas to be sampled. This capability will minimize any possible cross contamination between the various samples.

#### 18.1.21.3.2.4.2-----Liquid Sampler

The liquid sample system is designed to operate at pressures from 0 to 1500 psi. The design purge flow of 1 gpm is sufficient to maintain turbulent flow in the sample line and serves to alleviate cross contamination between samples. The purge flow is returned to the suppression pool. The liquid sampling system is designed to allow routine demineralized water flushing of the system lines from a point between the two coolers in the piping

station through the sampling needles. Using the hydro-test connection which is outside the sample panel, it is also possible to backflush all the liquid sample lines through the sample tap point. This will allow for clearing of plugged lines. All liquid samples are taken into 15 milliliter septum bottles mounted on sampling needles. In the normal lineup, the sample flows through a conductivity cell (0.1 to 1000 micromhos/cm and through a ball valve bored out to 0.10 milliliter volume. After flow through the sample panel is established, the ball valve is rotated 90° and a syringe, connected to a line external to the panel, is used to flush the sample plus a measured volume of diluent (generally 10 milliliters) through the valve and into the sample bottle. This provides an initial dilution of up to 100:1. The sample bottle is contained in a shielded cask and remotely positioned on the sample needles through an opening in the bottom of the sample enclosure. Alternately, the sample can be diverted through a 70 milliliter bomb to obtain a large pressurized volume. This 70 milliliter volume can be circulated and depressurized into a gas sampling chamber. A 15 milliliter gas sample can then be obtained through a hypodermic needle for gas chromatographic and radioisotopic analyses of the dissolved gases associated with the 70 milliliter liquid volume. Ten milliliter aliquots of this degassed liquid can then be taken for off-site (or on-site depending on activity level) analyses which require a relatively large undiluted sample. This sample is obtained remotely using the large volume cask and cask positioner through needles on the underside of the sample station enclosure.

#### 18.1.21.3.2.4.3 Sample Station Ventilation

The sample station enclosure will be vented to secondary containment via the main steam line tunnel. Ventilation is motivated by differential pressure between the turbine and reactor buildings. The ventilation rate required for heat removal during operation is about 40 scfm. The ventilation duct is sized for less than 100 scfm at 1/4 inch of water differential pressure when the enclosure is opened for maintenance. Standby air flow will be about 3 scfm and can be reduced by taping all openings. A pressure gauge is attached to the sample station enclosure to monitor the pressure differential between the enclosure and the general sampling area in the turbine building. This will assure the operator that airborne activity in the sample enclosure will be swept into secondary containment.

#### 18.1.21.3.2.4.4 Sample Station Sump

The sample station is provided with a sump at the bottom of the sample enclosure which will collect any leakage within the



enclosure. This sump can be isolated and pressurized, discharging into the sample station liquid return line to and hence into the suppression pool.

#### 18.1.21.3.2.4.5      Sample Handling Tools and Transport ----- Containers -----

Appropriate sample handling tools and transporting casks are provided. Gas vials are installed and removed by use of a vial positioner through the front of the gas sampler. The vial is then manually dropped into a small shielded cask directly from the positioning tool. This allows the operator to maintain a distance of about three feet from the unshielded vial. This cask provides about 1-1/8 inches of lead shielding. A 1/8 inch diameter hole is drilled in the cask so that an aliquot can be withdrawn from the vial with a gas syringe without exposing the analyst to the unshielded vial.

The particulate and iodine cartridges are removed via a drawer arrangement. The quantity of activity which is accumulated on the cartridge is controlled by a combination of flow orificing and time control of the flow valve opening. In addition, the deposition of iodine is monitored during sampling using a radiation detector installed in the sample station next to the cartridge. These samples will hence be limited to activity levels which will not require shielded sample carriers.

The small volume (diluted) liquid sample cask is a cylinder with a lead wall thickness of about two inches. The cask weighs approximately 65 pounds and has a handle which allows it to be carried by one person.

The 10 milliliter undiluted sample is taken in a 700 pound lead shielded cask which is transported and positioned by a four-wheel dolly. The sample is shielded by about 5-1/2 inches of lead.

#### 18.1.21.3.2.4.6      Sample Station Power Supply

The PASS isolation and control valves, sample station control panels, and auxiliary equipment are connected to an Instrument AC Distribution Panel which is powered from an Engineered Safeguard System (ESS) bus. Following a loss of off-site power, the ESS bus is powered from the on-site diesel generators and backed up by batteries. The Reactor Building Closed Cooling Water System, which is needed for the sample coolers, is also powered from the emergency diesel generators following a loss of off-site power. Compressed air for the air-operated valves comes from compressed

air cylinders, thus eliminating any dependence on the plant compressed air system.

#### 18.1.21.3.3 Description of Sample Preparation/Chemistry and -----Nuclear Counting Facilities-----

After the samples are obtained from the sample station, they will be transported to a sample preparation/chemistry area. There they will be diluted as necessary and appropriate aliquots taken for chemical and radioisotopic analyses. The radioisotopic analysis will be done in a separate counting area where background radiation can be kept to a minimum. Two different facilities will be available to plant personnel to perform the above tasks. The primary facility is the existing chemistry laboratory and counting room which is at elevation 676', the ground level of the control structure. A backup sample preparation/chemistry area and counting room will be built as part of the Emergency Operations Facility (EOF) which is located 2500 feet south-west of the control structure. In addition to these on-site and near-site facilities, which are intended to handle the gas samples and the diluted liquid samples, prior arrangements will be made with an independent off-site laboratory for analysis of the undiluted 10 ml liquid samples.

##### 18.1.21.3.3.1 On-Site Chemistry Laboratory and Counting Room

The plant shielding study results, presented in Subsection 18.1.20.3, show that following an accident, the chemistry laboratory will be a Zone II area ( $\leq 100$  mR/h). Therefore, the existing facilities will be accessible at least for intermittent use following an accident. The most direct route between the sample station and these facilities is through areas of the turbine building which should be Zone I areas ( $\leq 15$  mR/h) following an accident. The chemistry laboratory is or will be equipped to provide the capability to handle the gas samples and the 0.1 ml diluted liquid samples. The maximum activity of these samples will be 0.7 Ci and 0.3 Ci, respectively, using one-hour decay and the fractional releases of core inventory specified by NUREG-0578 (see Section 18.1.21.3.5).

The laboratory will maintain a dedicated inventory of items such as lead bricks for shielding, gas syringes, gloves, reagents for analyses, etc., which will be needed in case of an accident. The laboratory will be equipped with a gas chromatograph, pH meter, conductivity meter, turbidimeter and other instrumentation needed to perform the required analyses. This equipment however, may not be dedicated exclusively to post-accident analysis. Supplied air or self-contained breathing masks will be available in the

event of high activity levels in the ventilation supply or accidental spills in the laboratory.

The existing counting facility located adjacent to the chemistry laboratory is well equipped to handle the gamma spectra analyses required for post-accident samples. The counting room is equipped with two Ge (Li) detectors with four inch lead shields connected to a computer based analyzer system. The system has automatic peak search and isotope identification capabilities. The Ge(Li) detector and shelf assembly in the lead shield can be well isolated and the capability to purge the volume within the shield with compressed gas will be provided. This will help prevent atmospheric noble gas activity released during an accident from swamping the detector.

#### 18.1.21.3.3.2 EOF Sample Preparation/Chemistry and Counting Facilities

The sample preparation and counting rooms located in the near-site EOF will serve as backups to the on-site facilities. The EOF is 2500 feet from the control structure and is directly accessible from the site by road. Travel time from the sample station to the EOF will be less than 30 minutes. The backup facilities will be activated whenever the on-site facility becomes inaccessible or if additional lab space or counting equipment is needed to handle the increased work load in the on-site facility resulting from an accident. The sample preparation/chemistry room will be furnished with a radioisotope laboratory hood, about 14 feet of laboratory cabinets and benchtop working space, a small sink draining to a removable carboy, and at least a 5-gallon supply of demineralized water in plastic carboy mounted on the wall over the sink. The hood will be equipped with a HEPA filter unit. Although some analytical instrumentation may be kept in this room, it is not meant to completely duplicate that in the on-site laboratory. However, the facility will be fully equipped to handle the necessary dilutions and manipulations to prepare samples which come directly from the sample station for gamma spectroscopic analysis. Additional instrumentation for the required chemical analyses will be brought from the on-site laboratory as needed. Chemical reagents, glassware and other miscellaneous equipment will be stocked in the facility. A supply of lead bricks will also be kept in this room for use as temporary shielding. A lead brick cave for storage of samples will also be provided. The EOF counting room will contain as a minimum a high resolution gamma-ray spectrometer system. The system will be capable of characterizing and quantifying the gamma activities of reactor coolant and containment atmosphere samples. The intent is to make this system similar to the on-site system.

The EOP will have its own diesel generator which will be capable of supplying the electrical power needs for the facility during loss of off-site power.

#### 18.1.21.3.3.3 Arrangements for Off-Site Analyses

A key part of the SSES approach to post-accident sampling is the establishment of prior arrangements with an off-site independent laboratory for confirmatory and supplemental analyses. The capability of the off-site laboratory will also be used to meet the requirement for chloride analysis. The reason for using the off-site laboratory for chloride and as a backup for other analyses is to prevent having to handle and analyze undiluted coolant samples which may have activity levels in the curie per milliliter range. The on-site and EOP facilities are not designed to handle sources of this magnitude. The analyses of undiluted samples can be done in a safer manner by laboratories with facilities and personnel specifically built and trained to handle high-activity sources. The following is a description of the significant features being requested of the off-site laboratory:

- a) A formal mechanism will be established to allow for initiation of post-accident services at any time (24 hours/day).
- b) Written procedures will be established, controlled, and maintained for each of the analyses described in Table 18.1-6. The analysis procedures must be qualified for use at the activity levels given in the table. This requirement may be satisfied by referencing the appropriate literature, by calculations, or by undertaking a testing program.
- c) Laboratory equipment and facilities for the required analyses must be available and maintained in working order such that analyses may be completed within 24 hours of the receipt of the sample.
- d) Provision will be made for the practice or exercise of each aspect of the off-site analysis work at the option of the utility.
- e) Equipment will be available for the timely transmission and receipt of information and results (telecopier and/or telex)
- f) The laboratory will be operational for at least chloride analysis by fuel load.

18.1.21.3.4 Summary Description of Procedures18.1.21.3.4.1 Sample Collection and Transport Procedures

After a decision is made to obtain a sample, the designated sample station operators (2) will proceed to the sample station with the necessary equipment.

Since all the post-accident sample lines (except for the secondary containment atmosphere) tap off-lines which are isolated following a containment isolation signal, the sample station operator must confirm with the control room that the necessary isolation valves are open. (A telephone extension to the control room will be installed close to the sample control panels for this purpose). The control room must also activate the "Accident Sample Station Permissive Switch" to allow the sample station operator control of the "isolation and control valves" which are part of the post-accident sampling system.

After switching the "Master Shutoff Valve Control" to the "open" position, the operator is ready to open the valve(s) controlling flow from the desired source to the sample station. After opening the necessary control valve(s), the operator goes to the "sample station control panel". This panel controls the valves which are part of the piping station and those in the sample station enclosure in the turbine building.

Following a series of presampling checks and procedures including: adjustment of the enclosure damper to insure adequate cooling, checks of demineralized water and nitrogen supplies, flushing of system with demineralized water, draining the trap and sump, etc., the system is ready for obtaining the samples.

18.1.21.3.4.1.1 Procedure for Obtaining Gas Sample

A standard 14.7 milliliter off-gas vial is placed in the gas vial positioner and inserted into the gas port on the front of the sample station. The desired sample location is selected by switch and the gas is circulated until the sample lines are flushed out with the gas being sampled. The vial and a small volume of tubing remains unflushed; however, the vial and this tubing volume are then evacuated. The sample is then drawn into the vial by pressing and holding a pushbutton switch. If cross-contamination is suspected due to incomplete evacuation of the vial, the evacuation and fill sequence can be repeated using air or nitrogen flush before taking the final sample, or the sequence can be repeated with the desired sample gas until the operator is assured that he has a representative sample. Following an air or

nitrogen purge of the sample lines, the gas vial positioner is then removed from the port and the vial inserted into the gas vial cask. The length of the vial positioner allows the operator to remain about three feet from the vial during this operation. The cask has a 10-inch carrying handle and can be easily carried by one person down the stairs in the turbine building to the chemistry laboratory.

#### 18.1.21.3.4.1.2 Procedure for Obtaining an Iodine Particulate Sample

The desired filter cartridge(s) are placed into a cartridge retainer which is placed into the gas filter drawer. This drawer slides into an opening in the front of the sample station enclosure. The appropriate critical orifice is also chosen and placed in the cartridge retainer. This will determine the flow rate through the sampler and thereby control the amount of activity deposited on the filters. The operator then selects a sample location and flushes the sample line except for a short piece of tubing going to the sample drawer. However, this line can be flushed with air or nitrogen prior to sampling if cross-contamination between samples is suspected. In addition, as part of the normal sampling procedures, this line is flushed with air or nitrogen after completion of each sample sequence and should therefore be free of contamination for the following sample. The operator has the option of using an automatic timer to obtain samples with collection times between 0 and 30 seconds or of manually timing the sample for longer collection times. After starting the sample collection sequence, the operator will be able to follow activity buildup on the filters by observing the radiation level readout on the control panel from the probe inserted next to the cartridges in the gas sample panel. After sample collection is completed, the cartridges are evacuated using the vacuum from the gas pumps and then flushed with air or nitrogen to remove the noble gases. The filter drawer is withdrawn and the cartridge retainer with filters is placed in a plastic bag. The bag is then closed, and depending on the measured dose rate, it is carried by hand or attached to a pole and carried to the chemistry laboratory. No shielding cask is provided for these samples since it is possible to regulate the amount of activity deposited on them. In addition, for ease of counting, it is desirable to keep the activity levels on these samples low.

#### 18.1.21.3.4.1.3 Procedure for Obtaining a Diluted Liquid Sample

A 15 milliliter sample bottle with a neoprene cap is placed in the small volume cask which is then placed into a positioner

attached to the sample station support frame. The sample needles are exposed by pulling out the lead shielding drawer under the sample station enclosure. The cask holding the sample bottle is then swung into position under the sample station and the sample bottle raised into position so the needles penetrate the neoprene cap. After aligning the proper valves, the sample lines from the selected source through the piping station are flushed with return flow to the wetwell. After these lines are flushed, the bypass valve in the piping station is closed and the sample flows to the sample station through the calibrated volume sample valve and back to the wetwell. After sufficient flushing, the calibrated valve is rotated 90° into alignment with the line to the sample bottle. A syringe filled with up to 10 ml of demineralized water is connected onto a line at the front of the sample station and this water is injected to wash the sample captured in the ball valve into the sample bottle. The syringe is then removed, filled with air, re-attached and the air injected to force out all water remaining in the line through the sample needle and into the sample bottle. The rinsing action of the water followed by the air purge of the line should reduce cross-contamination between different samples. The calibrated sample valve is returned to the purge position and the sample lines, from the second cooler in the piping station, through the sample valve and back to the suppressor pool are rinsed with demineralized water. The operator then returns to the sample station, remotely lowers the sample bottle into the cask, screws a top plug with carrying handle into the cask. The cask is then carried down the stairs to the chemistry laboratory. Although one person can carry the cask, a pole with a hook in the middle will be available to allow two people to carry the cask more easily.

18.1.21.3.4.1.4 Procedure for Obtaining a Large Liquid Sample  
 -----(undiluted) and/or a Dissolved Gas Sample-----

A standard off-gas sample vial is placed in the gas vial positioner and inserted into the dissolved gas sampling port on the front of the liquid sample panel and a 15 milliliter sample bottle is placed in the large volume sample cask. The sample cask is positioned under the sample enclosure using a four-wheeled cart. The cask is raised into position and the sample bottle raised out of the cask and onto two needles using a remote mechanism. When the cask is properly positioned, the operators will be shielded from the sample during all subsequent operations. After attaining the proper valve lineup, the sample lines are first flushed through the piping station and then through the sample station lines including the 70 milliliter hold up cylinder and gas breakdown circulation loop. After completing the flush cycle a fixed volume of the pressurized liquid is isolated and a measured amount of a tracer gas is injected. The

isolated volume is then depressurized by opening a valve to a previously evacuated 15 milliliter gas collection chamber. The operator now has the option of either collecting the dissolved gas sample in an evacuated vial or releasing it to the suppression pool atmosphere. If a dissolved gas sample is collected, it is handled and transported in the same manner as the containment gas sample discussed previously. The operator also has the option of collecting a 10 milliliter sample of the degassed liquid or allowing it to be flushed to the suppression pool during the subsequent demineralized water flush cycle. If a large volume sample is desired, it is drawn into the evacuated 14.7 milliliter sample bottle. To minimize cross-contamination, the system can be cycled several times through all the above steps before taking the final large volume sample. The dissolved gas and liquid sample system is then flushed with demineralized water to minimize radiation levels while removing samples from the station.

The sample bottle is then remotely lowered from the needles into the shielded sample cask which is lowered on the cart and pulled out from under the sample enclosure. A lead plug is then inserted in the opening of the cask and the cask can be easily moved to the elevator in the control structures using the positioning cart. By using this elevator no steps are encountered when moving the cask from the sample station to ground level. The shielding study results (see Subsection 18.1.20.3) indicate that this elevator should be accessible from a radiation level standpoint. In case of loss of off-site power, the elevator will be out of service since no emergency power is provided. However, the undiluted sample is only essential for determining the chloride concentration which is not required until four days after sampling. This will allow a reasonable time for the restoration of off-site power. However, if after two days off-site power is not restored, arrangements can be made to lower the sample cask from the turbine operating floor to ground level through one of three open hatches. Since the undiluted sample is to be sent to an off-site laboratory, prior arrangements will be made to have a shipping container sent from the off-site laboratory or have one available on-site. The current intent is to have several shipping containers built which will hold the large volume casks, thus avoiding the exposure which would result from trying to transfer the sample from the sampling cask to another container.



18.1.21.3.4.2 Chemical/Radiochemical Procedures18.1.21.3.4.2.1 Introduction

The PASS provides a means of obtaining primary coolant, suppression pool, and primary and secondary containment air samples for radiochemical and chemical analysis following a major reactor accident. Because of the extremely high radioactivity levels associated with extensive fuel damage, the PASS and its auxiliary support was developed with the philosophy of providing the capability of obtaining the necessary samples and of performing on a timely basis those analyses, as required, for immediate plant needs, or as defined by regulatory requirements. Procedures and arrangements will be established for shipping samples to facilities having the experience and equipment appropriate to performing detailed and accurate chemical analyses on multi-Curie level samples.

The analytical procedures chosen will satisfy the philosophy of performing only those analyses as required for operational support, of minimizing personnel exposure and contamination hazards, and of depending upon outside analysis for extensive analysis and long-range operational needs. Tests were performed by General Electric to assess the effects of high fission product levels on the suggested analytical methods. The type of fuel damage associated with the release of megacurie quantities of iodine and other activities also has the potential for releasing kilogram quantities of stable or very long lived fission products. It is conceivable that the primary coolant might contain 10-20 ppm of iodide and bromide. Also, the release of a major fraction of the core inventory of cesium and rubidium may slightly raise the primary coolant pH. Such releases will also cause an increase in the coolant conductivity while radiolysis of the water will probably contribute to the formation of low levels of hydrogen peroxide. Depending upon the concentrations, these are all possible analytical interferences with the required analysis. Of these, the iodide/bromide interference with the chloride procedure is probably the most severe. However, since the requirement for chloride analysis will be satisfied by sending the samples to an off-site laboratory, the chloride procedure being proposed for the on-site laboratory is only to obtain a rough upper limit. The effects of radiation interference have been generally evaluated and are summarized in Subsection 18.1.21.3.6.

18.1.21.3.4.2.2 Sample Preparation

All sample bottles, iodine cartridges, etc., will be numbered or otherwise identified prior to sampling. This will eliminate unnecessary exposure as a result of handling high level samples for the purpose of attaching labels. A centralized logging system will be developed to keep track of sample aliquot identification, dilution factors, sample disposition, etc.

Liquid samples will be taken at the sample station in septum type bottles and transported to the analysis facility in lead containers. Sample aliquots are then taken from the septum bottles for analysis or further dilution. Aliquoting and transfer will be performed using shielded containers, or behind a lead brick pile. Calibrated hypodermic syringes will be used for aliquoting the higher activity samples. Tongs or other holding/clamping devices will be available for holding the sample bottle during the transfer and dilutions to reduce hand and body exposure. Unless prohibited by the intended analysis, dilutions will be done using very dilute (about 0.01N) nitric acid as the diluent to minimize sample plate-out problems.

Reactor coolant activity levels on the order of 1 to 3 Curies per gram would require a dilution factor of  $1 \times 10^5$ , or larger, for gamma ray spectroscopy samples. As an example, a typical series of dilutions might be 0.1 ml (100 lambda) added to 10.0 ml at the sample station, followed by further diluting of 0.1 ml to 100 ml in the laboratory. An aliquot of 0.1 ml would then be taken from the second dilution for counting purposes.

Gas samples are taken at the sample station in the same 14.7 ml septum bottle used in the normal offgas sampler. A lead carrier is furnished with a small hole at the septum end so that a gas sample can be withdrawn from the carrier using a hypodermic syringe without having to handle the bottle.

Samples taken from the gas sample bottle will either be injected into a gas chromatograph for analysis or used to dilute the gaseous activity for gamma spectroscopy purposes. The dilutions will be performed in a manner analogous to the liquid samples. Fractional milliliter samples can be transferred to new 14.7 ml gas bottles without concern for sample leakage due to pressurization. For larger volume aliquots a gas syringe will be used to draw a partial vacuum in the bottle prior to sample transfer.

Since there is no initial dilution of the gaseous activity at the sample station, extensive dilution may be required in the laboratory.

18.1.21.3.4.2.3 Chemical Analysis

## a. Introduction

The chosen procedures are not necessarily the most sensitive nor the most accurate. They were chosen primarily on the basis of simplicity, stability and availability of reagents, minimum radiation exposure, and least likely to cause major contamination problems. They have been tested for radiation sensitivity and are suitable for use at the PASS design basis source term of 2.8 Ci/qm, and where applicable, with the design basis 0.1 ml to 10 ml dilution at the sample station.

## b. Boron Analysis - Carminic Acid Method

The chosen HACH method closely follows the ASTM D3082-74, "Standard Test Method for Boron in Water, Method A - Carminic Acid Colorimetric Method." The HACH procedure is suggested because the reagents and standards are available in small quantities, are conveniently packaged, and can be quickly prepared. It is estimated that the complete analysis, including reagent preparation, can be performed in 40 minutes.

This method was tested to be satisfactory for use at the maximum expected activity levels. The analysis is designed for boron concentrations in the range of 0.1 to 10 ppm of boron. This sensitivity is particularly suited to the sample station's 0.1 ml to 10.0 ml dilutions since this corresponds to a range of 100 to 1000 ppm in the undiluted coolant.

## c. Chloride Analysis - Turbidimetric Method (see also the discussion on conductivity)

The chosen method was developed by the General Electric Reactor Chemistry Training group. The procedure is very similar to a HACH Chemical Co. procedure, "Turbidimetric Determination of Trace Chloride in Water".

The minimum quantity of measurable chloride by this procedure is 0.5 g. If 5 ml of the 0.1 to 10 ml primary coolant dilution is used for analysis, the minimum measurable concentration would be 10 ppm.

Using the 10 ml. direct primary coolant sample greatly increases the sensitivity for measuring chloride. A one ml of aliquot of this sample could be analyzed at the 0.5 to 1.0 ppm level.

Tests of the radiation sensitivity of the method showed that activity levels comparable to the PASS design basis source terms resulted in the equivalent of 1.8 ppm Cl<sup>-</sup> in the primary coolant

for the 0.1 to 10 ml dilution. This was deemed to be insignificant, as it is below the sensitivity limit, and more importantly, interference from the large amount of stable fission product halides potentially associated with the source terms will far out-shadow the radiation effect itself.

Tests were also performed on the addition of 500  $\mu\text{g}$  of boron added to 0.5 to 20  $\mu\text{g}$  of chloride. No interference was observed with the turbidimetric procedure.

#### d. Measurement of pH

Indicator paper for pH will be used for activity levels below 10% of the design basis source terms.

The irradiation tests indicated that at 10% of the design basis source terms, the color stability was adequate given only a drop of solution and less than a 5-minute exposure.

Using this method, pH measurements can be taken at the small volume sampler by placing a piece of the paper into the sample bottle and using an air filled syringe to blow several approximately 0.1 ml aliquots from the sample valve into the bottle to moisten the paper.

This type of sampling approach can also be used to obtain a small sample for possible electrochemical pH measurement. Lazar Research Labs, Inc. manufactures a micro-pH electrode which functions on microliter samples. This electrode or similar micro-probe is currently being evaluated for use at source term greater than 10% of design basis.

Indicator paper for pH can cover the range from 1-11 and distinguish differences of 0.25 pH units.

At very low conductivities, conductivity itself may be the best indicator of the pH. For instance, at 0.2 micromho/cm, the pH is bounded by 6.3 to 7.6, which is well within the technical specifications for normal operation. Thus, the conductivity should serve as an adequate indicator of pH as long as conductivity is sufficiently low that it is impossible to be outside the technical specifications limit.

#### e. Conductivity Measurements

The Post Accident Sample Station is equipped with a 0.1  $\text{cm}^{-1}$  conductivity cell. The conductivity meter has a linear scale with a six position range selector switch to give conductivity ranges of 0-3, 0-10, 0-30, 0-100, 0-300, and 0-1000 micromho/cm when using the 0.1  $\text{cm}^{-1}$  cell. This conductivity measurement system will be used to determine the primary coolant or suppression pool conductivity. During normal operation the BWR

technical specifications require maintaining the primary coolant below 1 micromho/cm, and conductivity measurements are the primary method of coolant chemical control.

Conductivity measurements are, of course, non-specific, but they serve the important function of indicating changes in chemical concentrations and conditions. Perhaps even more important, in the case of the BWR primary coolant, the conductivity measurements can establish upper limits of possible chemical concentrations and can eliminate the need for additional analyses. For example, if the conductivity is measured to be 5.0 micromho/cm, the upper limit on the chloride concentration is 1.4 ppm.

The conductivity measurement can also be used to bound the possible range of pH values. This relationship is shown in Figure 18.1-14.

At a specific conductance of 1.0 micromho/cm the pH must be between 5.6 and 8.7. Furthermore, a pH of 5 and a specific conductance of 1.0 is an impossible situation since the conductivity is not large enough to support a hydrogen ion concentration of  $10^{-5}N$ . Figure 18.1.21-4 can, therefore, be used to great advantage in checking on agreement between pH and conductivity measurements and possibly eliminating the need for pH measurement if the conductivity is very low. In general, accurate pH measurements are difficult to make in very low conductivity water as the impedance of the solution may be significant compared to the impedance of the measuring device, and conductivity measurements are usually considered a better indicator of the maximum  $H^+$  or  $OH^-$  concentration.

#### 18.1.21.3.4.2.4-----Radiochemical Analysis--Gamma Ray Spectroscopy

After the samples have been brought to the chemistry laboratory and appropriately diluted, they can be carried without shielding to the counting room which is adjacent to the chemistry laboratory. The appropriate dilution factors will be somewhat dependent upon the detector and shelf arrangements available. A prior determination of the maximum desirable dose rates for the various shelf configuration will be made to minimize this problem. The present high resolution, high efficiency Ge(Li) detectors, coupled with the multichannel analyzers, and computer data reduction in the on-site counting room will easily handle the analysis of these samples.

The gas samples will be counted in the standard off-gas sample vials and the liquid samples will be counted in the standard sample bottles used during normal operation since calibration curves for these geometries will be available and regularly

updated. Calibration curves will also be available for the particulate filter and iodine cartridge geometries. In general, the counting of the post-accident samples will follow the normal counting room procedures. A special post-accident library will have to be developed for use by the computer peak search and identification routine to supplement the normal isotope library. The post-accident peak search and identification library will contain the principal gamma rays of the following isotopes in addition to the standard activated corrosion products:

Noble gases:	Kr-85, Kr-85m, Kr-87, Kr-88, Xe-131m, Xe-133, Xe-133m, Xe-135
Iodines:	I-131, I-132, I-133, I-135
Cesiums:	Cs-134, Cs-137
Others:	Ba/La-140, Ce-141, Ce-144, Ru-106, Te-129, Te-129m, Te-131, Te-131m, Np-239

If the levels of noble gases in the ambient atmosphere surrounding the detector is high enough to cause significant interference or overload the detector, a compressed air or nitrogen purge of the detector shield volume will be maintained.

#### 18.1.21.3.4.2.5 Gas Analysis-Gas Chromatography

A gas chromatograph will be used to measure hydrogen, nitrogen and oxygen concentrations in containment atmosphere and dissolved gas samples. The gas chromatograph will be located in the chemistry laboratory and vented to a laboratory hood. Samples for gas analysis will be used undiluted from the sample vials and injected into the gas chromatograph. Since the sample sizes needed for the analysis will range from 0.1 to 1 milliliter, it may be necessary to place a temporary lead shield around the instrument. The analysis of the drywell, wetwell, and secondary containment samples will be done using standard procedures. Calibration curves for the instrument will be prepared and periodically updated.

In the mixture of hydrogen, oxygen, nitrogen, and possibly krypton, the analysis sensitivity should be sufficient to detect any of these constituents at the 0.1% by volume level, or lower, providing the Kr:N ratio in this mixture does not vary by more than a factor of 10 in either direction. At the 0.5% level the analysis should be accurate to within 20% of the measured concentration. At concentrations above 1%, the analysis should be accurate to within 5% of the measured concentration.

The dissolved gas sample will contain krypton or other tracer in addition to oxygen, nitrogen, and possibly hydrogen. Although the analysis of the dissolved gas sample for hydrogen should be

reliable, the analysis for oxygen and nitrogen presents several difficulties. The major problem is due to the incomplete evacuation of the sample vial which initially contains air. A partial vacuum (4-5 psia) is drawn on the vial before the sample is taken, however, this leaves a significant amount of air in the vial. This may not be a significant problem if the amount of dissolved oxygen or nitrogen stripped from the coolant is large compared to that left in the evacuated vial, since a correction can be made based on the pressure measurements taken before and after taking the sample. However, dissolved oxygen and nitrogen is not required by NUREG-0737, which states that determination of dissolved hydrogen gas in the coolant is adequate. In case the need should arise, a procedure will be established to tap off the sample line in the sample station and run this to an in-line oxygen monitor. The flow would then return to the liquid return line to the wetwell.

#### 18.1.21.3.4.3 Storage and Disposal of Sample

Short term sample storage areas will be provided in the chemistry laboratory and counting rooms in both the on-site and EOF facilities. An area for long term storage of the samples will be designated at a later date. Low level wastes generated by the chemistry procedures will be flushed to radwaste in the on-site chemistry laboratory and collected in removable carboys in the EOF. The carboys will then be taken to an on-site location for disposal to the radwaste system. Ultimate procedures for disposal of the samples will be determined later; however, after a sufficiently long decay period, the activity levels will be significantly reduced. This will ease exposure problems during disposal.

#### 18.1.21.3.4.4 System Testing and Operator Training

To ensure the long-term operability of the PASS, it will be tested semiannually. Samples will be taken from all gas sample points; however, the number and type of liquid samples taken will be based on the operating status of the reactor at the time. The semiannual functional testing will also serve to maintain operator proficiency. In addition to the scheduled tests, the system will be used for operator training on an as-needed basis.

To ensure an adequate pool of qualified PASS operators, a formal training program will be established. This program will be part of the chemistry technician qualification program. All plant chemistry technicians and chemistry management personnel will be required to show competence in the operation of the sample station and the chemical analysis procedures.

18.1.21.3.5 ----- Dose Rate Analysis

Radioactivity source terms were calculated for use in design of the PASS shielding. These source terms are for a LOCA assuming a release of fission product activity as defined by NUREG 0578. Source terms were calculated for a three year reactor operation at 3293 MWt. For the purposes of specifying shielding design source terms, a decay period of one hour has been assumed between reactor shutdown and initial sampling. Although there is no decay period specified in NUREG 0578 the source terms calculated for PASS still result in a conservative design. The PASS is designed to limit operator whole body exposure to 100 mRem as a result of taking and analyzing the sample. NUREG 0737, on the other hand, limits the operator exposure to less than 5 Rem whole body exposure for the entire operation.

Using a one hour decay and the fractional releases of core inventory specified by NUREG 0578, the primary coolant and primary containment atmosphere fission product concentrations are calculated to be 2.6 Ci/gm and 0.046 Ci/cc, respectively. Using these fission product concentrations, gamma radiation source terms were determined in terms of MeV/sec for ten gamma energy groups. These radiation source terms were used for shielding design and sample dose rate calculations. Assuming point sources, the calculated dose rates per unit volume of coolant and containment atmosphere are 125 R/h/gm and 1.8 R/h/cc at 4 inches, respectively.

Thus, the 0.1 milliliter reactor sample would have a maximum exposure rate of about 12 R/h at 4 inches and 14.7 milliliter vial of containment atmosphere at STP would have an exposure rate of 25 R/h at 4 inches. Using the calculated source terms, dose rate estimates resulting from activity in the sample station and sample casks were calculated for various distances. The results are given in Table 18.1-7. These dose rates will be used in a time-motion study to estimate the total integrated dose expected during sampling and analysis after the sample station is operational.

18.1.21.3.6 ----- Irradiation Effect On Analytical Procedures

Some scoping tests were performed to study the effect of high fission product levels on the proposed analytical procedures. The core inventory of individual nuclide beta energies in terms of MeV/second/MWt after one hour decay was taken from the same CINDER run as used to calculate the PASS activity source terms. The NUREG-0578 release fractions were used to determine the fraction of the core inventory dissolved in the primary coolant. The "all other" category was ignored as at a 1% release fraction



the dose contribution from these nuclides is negligible compared to the 50% halogen and 100% noble gas releases. The results are shown in Table 18.1-13. For the sake of simplicity, it was assumed that the gamma energy deposition in the sample was negligible compared to the beta energy deposition. It was also assumed that 100% of the beta energy was absorbed in the sample. The net result,  $1.92 \times 10^6$  Rads/hr, is conservative as the gamma energy absorption for small samples would be much less than the beta energy escaping the solution.

Dose rates approaching  $2 \times 10^6$  R/h are available in the VNC Co-60 irradiation facility. At 93 ergs/g/R/h, this corresponds to  $1.8 \times 10^6$  Rads/hr, and approximates the calculated maximum energy deposition possible for the reactor coolant. Tests were run to determine the effects of radiation on the conductivity, pH, chloride, and boron analytical procedures. The true energy deposition within the irradiated sample holders was determined by Fricke dosimetry using the sample holders as dosimeters. Except for conductivity and pH measurements, the dose rates were considerably larger than would be encountered with the PASS source terms. These higher dose rates were used to achieve a better measurement of the radiation effect, and it was then assumed that this effect would be linear with dose rate. It is hoped to verify this assumption in later studies.

#### 18.1.21.3.6.1 Conductivity Cell

A 0.1 cm Balsbaugh conductivity cell and stainless steel holder was irradiated at various positions in the 4 1/4-in. dia. Co-60 irradiation tube. The flow path from this conductivity cell was connected to a 0.1 cm Beckman conductivity cell downstream of the cell under irradiation. Both static and flowing irradiation tests were performed. The flow tests were performed at ca. 125 cc/min with a 3 to 4 min flow delay between the Balsbaugh and Beckman cells. The Beckman cell, therefore, served to determine if there were any relatively long lived radiation products remaining in solution. An in-line thermometer was mounted in the flow system downstream of the Beckman cell.

#### 18.1.21.3.6.2 Purification

A Gelman Water-I<sup>R</sup> purification unit was installed in the conductivity cell flow loop. The output conductivity of the water from the purification unit was 0.055  $\mu$ S/cm, as indicated by the purification units built in the conductivity meter. The water flow was from the purification unit through the two conductivity cells under study and back to the reservoir of the purification unit. The output of the conductivity meter

associated with the irradiated cell was continuously recorded. The highest radiation field in the 4 1/4 in. irradiation tube, as measured by a Victoreen R Meter, was  $7.4 \times 10^5$  R/h. The actual cell energy absorption rate at this position was determined by removing the conductivity element and using the cell holder as a Fricke dosimeter container. The result,  $9.8 \times 10^5$  Rads/hr was also used to convert the R/h measurements at the other elevations to Rads/hr by assuming a constant ratio between the field intensity and the energy absorption. (This is not strictly true as the photon energy distribution varies with the elevation in the irradiation facility. Consequently, the fraction of the photons penetrating the stainless steel cell holder will vary slightly.)

The results of these experiments are summarized in Table 18.1-14. There was apparently some pickup of impurities from the flow loop materials as  $0.10 \mu\text{S/cm}$  was the lowest loop conductivity observed. The  $0.06 \mu\text{S/cm}$  at the output of the purification unit was confirmed by connecting one of the flow cells immediately as the output.

In the case of the flowing measurements, there was a steady increase in conductivity from  $0.11$  to  $0.65 \mu\text{S/cm}$  as the irradiation intensity increased from  $1.3 \times 10^4$  to  $6.6 \times 10^5$  Rads/hr. The conductive species which were formed were relatively stable as there was little difference between the conductivity as measured at the irradiated cell and the downstream cell. In fact, when the flow was stopped and the conductivity of the irradiated cell was allowed to come to equilibrium, the cell could be removed from the radiation field and the conductivity would remain constant, at least up to several hours, the longest period observed. The flow was secured at each irradiation intensity and the conductivity was monitored until a steady-state condition was attained. From the data in Table 2 it would appear that a maximum conductivity is attained at about  $2.2 \text{ S/cm}$ , and that the conductivity diminishes with increasing radiation intensity. The steady-state difference in cell behavior at  $6.6 \times 10^5$  and  $9.8 \times 10^5$  Rads/hr is unexplained.

It is suspected that the conductivity is due to the formation of hydrogen peroxide, but this has not been confirmed. It is obvious that there will be some radiation effect on the conductivity at very high fission product concentrations. This does not appear too serious, however, as  $2.2 \mu\text{S/cm}$  corresponds to a NaCl concentration of 1.0 ppm. The concentration of stable fission products, particularly I-127 and I-129, associated with the high Curie concentrations will at the same time result in considerably higher conductivities.

18.1.21.3.6.3 Conductivity of 10 ppm Chloride (Cl<sup>-</sup>) Solution

Irradiation tests were performed to determine the radiation effect on the conductivity of a dilute NaCl solution. It was anticipated that if the pure water conductivity increases under irradiation were due to the formation of H<sub>2</sub>O<sub>2</sub>, this might be suppressed by the presence of the Cl<sup>-</sup> ions. In this experiment the NaCl solution was pumped from a reservoir through the two conductivity cells and back to the reservoir. A common conductivity bridge was used to alternately determine the conductance of each cell, and thereby eliminate any bias between different bridges. The testing was done at the highest available irradiation level,  $9.8 \times 10^5$  Rads/hr. The solution temperature, as indicated by a flow thermometer downstream of the unirradiated cell, ranged from 59.5 to 60.2°F. Several alternate conductivity readings were taken on each cell approximately five minutes after each change in condition, and when the cell conductances had reached a steady value. The average result for each condition is given in Table 18.1-15. The difference between the cell readings for any given set conditions is attributed to errors in the stated cell constants. The conductivity of the flowing stream increased by approximately  $0.6 \mu\text{S/cm}$  for both cells before and after irradiation, which may be the result of the generation of some long lived species. This possibly is supported by the Beckman cell, which although located outside the radiation field, showed a  $0.6 \mu\text{S/cm}$  increase in conductivity during irradiation. The puzzling observation was the large drop in conductivity of the static solution during irradiation. This should be investigated further.

18.1.21.3.6.4 pH

Solutions of pH 3.8 and 10.0 were made up using HCl and NaOH, respectively. LO-Ion pH test paper was placed in aliquots of these solutions and the solution was inserted into the  $9.8 \times 10^5$  Rads/hr position (as determined by Fricke dosimeter). A 10.0 minute exposure for a total dose of  $1.6 \times 10^5$  Rads completely destroyed the color in the acid solution and reduced the color intensity of the basic solution to a pale green. This test was then repeated using a 1.0 min exposure at the same intensity level for an exposure of  $1.6 \times 10^4$  Rads. This exposure shifted both solutions about 1/2 pH unit to the more acid side. The results would not necessarily indicate that pH indicator paper cannot be used at the highest dose rates, but more importantly, that the paper cannot be immersed in a relatively large volume of solution. If the paper were merely moistened by a drop or so of solution, most of the beta particles would escape the paper with little energy deposition and the paper would not be surrounded by a highly radioactive solution with the resultant beta field and

water excitation products. This subject is still under consideration.

At source terms on the order of 10% or less of the maximum\*, the irradiation effect, for even an immersed strip, would be tolerable at exposures less than 5 min, as it would result in less than an 0.5 pH unit shift.

Some measurements were also made to determine the effect of irradiation on pH electrodes. Long leads are needed on the pH electrodes in order to reach in the Co-60 irradiation facility, and these electrodes were not available. We intend to order some new electrodes and will continue this study. In the meantime, we have irradiated a glass membrane pH electrode to  $1.6 \times 10^6$  Rads at a  $9.85 \times 10^5$  Rad/hr intensity and found it still functions following irradiation.

#### 18.1.21.3.6.5 Turbidimetric Chloride Procedure

Using the maximum source term of  $2 \times 10^8$  Rads/hr, ml diluted primary coolant sample would have an internal beta exposure of  $2 \times 10^6$  Rad/hr. The turbidimetric method calls for a total volume of 25 ml. Therefore, even if the entire 10 ml of diluted sample were used, the dose rate of the final analysis solution would be less than  $8 \times 10^6$  Rad/hr. Test solutions containing 0, 1, 5, and 20 /gm of chloride in 25 ml were processed through the chloride test methods in pairs. During the 15 min turbidity-formation period, one sample of each set was irradiated at an absorbed dose rate of  $4.4 \times 10^6$  Rad/hr as determined by Fricke dosimetry. The

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\* The originally calculated source term was  $1.9 \times 10^8$  Rads/hr. Thirty-five percent of this source intensity, however, is due to noble gases which would escape solution in the sampling process. A 10% source term for pH measurement would then be approximately  $1.2 \times 10^8$  Rads/hr and a 5-min exposure would correspond to a  $1 \times 10^6$  Rad energy absorption, which is approximately the exposure causing a 0.5 pH shift.

maximum observed radiation effect was a difference of about 10 turbidity units between the irradiated and unirradiated 1 gm Cl solutions. This difference is equivalent to about 10  $\mu$ /gm of chloride in the 25 ml of solution being processed. Assuming this increase in turbidity is proportional to the dose, the maximum effect would be  $(10 \mu\text{gm})(8 \times 10^3 / 4.4 \times 10^5) = 0.18 \text{ gm}$ . If only 0.1 ml of reactor water were used for the original sample, this would be equivalent to 1.8 ppm of  $\text{Cl}^-$  in the primary coolant. This error is probably insignificant as the interference from all the stable iodine associated with the high radiation intensity is likely to be far larger.

The test data also indicates that as little as 5  $\mu\text{gm}$  of  $\text{Cl}^-$  in the 25 ml of test solution inhibits the formation of the radiation-induced turbidity. It is suspected that the increased turbidity is due to the precipitation of silver peroxide and the 5  $\mu\text{gm}$   $\text{Cl}^-$  inhibited the formation of hydrogen peroxide. In any event, it was concluded that the test method is useful for highly radioactive solutions above the 10 ppm level, or for less radioactive solutions above the 1 ppm level. For low activity samples which do not need to be diluted and where at least a 1 ml of sample is available, the method is useful above the 100 ppb level.

#### 18.1.21.3.6.6 Carminic Acid Boron Analysis

Using the maximum source term of  $2 \times 10^6 \text{ Rad/hr}$ , an 0.1 ml to 10 ml diluted primary coolant sample would have an internal beta exposure of ca.  $2 \times 10^4 \text{ Rad/hr}$ . The colorimetric method calls for a total volume of 25 ml. Therefore, even if the entire 10 ml of diluted solution were used, the dose rate of the final analysis solution would be less than  $8 \times 10^3 \text{ Rad/hr}$ . Test solutions containing 0 and 20 gm of boron were processed through the boron test methods in pairs. During the 40-min color development phase, one sample of each pair was irradiated at an absorbed gamma-radiation dose level of  $4.4 \times 10^5 \text{ Rad/hr}$  as determined by Pricke dosimetry. The maximum irradiation effect observed was a difference of 0.854 absorbance units between the irradiated and unirradiated blank solutions. This difference is equivalent to about 27  $\mu\text{gm}$  of boron in 25 ml of solution being processed. Assuming this difference in absorbance is proportional to the dose, the maximum effect would be  $(27 \mu\text{gm})(8 \times 10^3 / 4.4 \times 10^5) = 0.49 \mu\text{gm}$ . If only 0.1 ml of reactor water were used for the original sample, this is equivalent to a 5 ppm error in the primary coolant analysis. This error is totally negligible in terms of the levels of boron required for reactor shutdown.

18.1.22 TRAINING FOR MITIGATING CORE DAMAGE (II.B.4)

18.1.22.1 Statement of Requirement

Licensees are required to develop and implement a training program to teach the use of installed equipment and systems to control or mitigate accidents in which the core is severely damaged.

Shift technical advisors and operating personnel from the plant manager through the operations chain to the licensed operators shall receive all the training indicated in Table 18.1-8.

Managers and technicians in the instrumentation and control, health physics, and chemistry departments shall receive training commensurate with their responsibilities.

Applicants for operating licenses should develop a training program prior to fuel loading and complete personnel training prior to full-power operation.

18.1.22.2 Interpretation

None required.

18.1.22.3 Statement of Response

A course titled "Mitigating Core Damage" has been developed. This course or a similar one will have been given to all shift technical advisors and operations personnel from the plant manager through the operations chain to and including licensed operators prior to fuel load to fulfill this training requirement. A course outline is provided in Table 18.1-9.

Managers and technicians in instrumentation and controls, health physics, and chemistry will be given training commensurate with their responsibilities during accidents which involve severe core damage.

18.1.23. RELIEF AND SAFETY VALVE TEST REQUIREMENTS. (II.D.1)

18.1.23.1 Statement of Requirement

Boiling-water reactor licensees and applicants shall conduct testing to qualify the reactor coolant system relief and safety valves under expected operating conditions for design-basis transients and accidents.

Licensees and applicants shall determine the expected valve operating conditions through the use of analyses of accidents and anticipated operational occurrences referenced in Regulatory Guide 1.70, Revision 2. The single failures applied to these analyses shall be chosen so that the dynamic forces on the safety and relief valves are maximized. Test pressures shall be the highest predicted by conventional safety analysis procedures. Reactor coolant system relief and safety valve qualification shall include qualification of associated control circuitry, piping, and supports, as well as the valves themselves.

Preimplementation review will be based on EPRI, BWR, and applicant submittals with regard to the various test programs. These submittals should be made on a timely basis as noted below, to allow for adequate review and to ensure that the following valve qualification date can be met:

Final BWR Test Program--October 1, 1980

Postimplementation review will be based on the applicants' plant-specific submittals for qualification of safety relief valves. To properly evaluate these plant-specific applications, the test data and results of the various programs will also be required by the following dates:

BWR Generic Test Program Results--July 1, 1981

Plant-specific submittals confirming adequacy of safety and relief valves based on licensee/applicant preliminary review of generic test program results--July 1, 1981

Plant-specific reports for safety and relief valve qualification--October 1, 1981

Plant-specific submittals for piping and support evaluations--January 1, 1982

18.1.23.2 Interpretation.

None required.

### 18.1.23.3 Statement of Response

PP&L is participating in the BWR Owner's Group (BWROG) program to test safety/relief valves (SRVs). Wyle Laboratories in Huntsville, Alabama has been contracted to design and build a test facility. The design is complete and construction is well underway. The facility will be capable of high and low pressure valve tests.

Documentation of the BWROG testing program was sent to the NRC on September 17, 1980 by a letter from D.B. Waters to R.N. Vollmer. A summary of this document is provided below.

An engineering evaluation was done to identify the expected operating conditions for SRVs during design basis transients and accidents. This evaluation indicates the SRVs may be required to pass low pressure liquid as a result of the Alternate Shutdown Mode (described in Subsection 15.2.9). No other significantly probable event, even combined with a single active failure or single operator error, produces expected operating conditions that justify qualification of SRVs for extreme operating conditions. Therefore a test program was developed to demonstrate the SRVs' capabilities as may be necessary during the Alternate Shutdown Mode.

The test results were submitted by a letter to A. Schwencer from N. W. Curtis on July 1, 1981 (PLA-865). A plant specific SRV qualification report was submitted to the NRC on October 1, 1981 (PLA-940). This report includes all necessary evaluations of piping and supports.

### 18.1.24 SAFETY/RELIEF VALVE POSITION INDICATION (II.D.3)

#### 18.1.24.1 Statement of Requirement

Reactor coolant system relief and safety valves shall be provided with a positive indication in the control room derived from a reliable valve-position detection device or a reliable indication of flow in the discharge pipe.

The basic requirement is to provide the operator with unambiguous indication of valve position (open or closed) so that appropriate operator actions can be taken.

The valve position should be indicated in the control room. An alarm should be provided in conjunction with this indication.



The valve position indication may be safety grade. If the position indication is not safety grade, a reliable single-channel direct indication powered from a vital instrument bus may be provided if backup methods of determining valve position are available and are discussed in the emergency procedures as an aid to operator diagnosis of an action.

The valve position indication should be seismically qualified consistent with the component or system to which it is attached.

The position indication should be qualified for its appropriate environment (any transient or accident which would cause the relief or safety valve to lift) and in accordance with the Commission order on May 23rd, 1980 (CLI-20-81).

It is important that the displays and controls added to the control room as a result of this requirement do not increase the potential for operator error. A human-factor analysis should be performed taking into consideration:

- (a) the use of this information by an operator during both normal and abnormal plant conditions,
- (b) integration into emergency procedures,
- (c) integration into operator training, and
- (d) other alarms during emergency and need for prioritization of alarms.

Documentation should be provided that discusses each item of the clarification, as well as electrical schematics and proposed test procedures in accordance with the proposed review schedule, but in no case less than four months prior to the scheduled issuance of the staff safety evaluation report. Implementation must be completed prior to fuel load.

#### 18.1.24.2 Interpretation

None required.

#### 18.1.24.3 Statement of Response

Each of the 16 safety/relief valves (SRVs) will be provided with a safety grade acoustic monitoring system to detect flow through the valve. An acoustic sensor will be mounted on the discharge piping, downstream of each valve.

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The monitors will be grouped into two divisions with 8 valves each. Each division will have group annunciation for valve opening and for division loss of power. A red annunciator window will be provided for valve opening and white annunciator window for loss of power on a front row control panel for these annunciations. Each division will be powered from a 1E vital instrument bus.

Individual indication of an open valve will be provided by a red light (1 light for each valve) on front row control room panel 1C601. Individual indication of valve position is also available on a back row control room panel where the signal conditioning instruments are located.

The acoustic monitoring system is designed to be safety grade. This equipment has been qualified to IEEE-344-1975, IEEE-323-1974 and NUREG-0588 in accordance with the Commission order on May 23, 1980 (CLI-20-81).

Additional design information will be presented in Subsection 7.6.1b.1.7.

A human factors review of the front row control panel on which these indicators are located has been completed. This same analysis is being applied to the SRV position indicators which are being added to this panel.

Installation of this system will be complete by fuel load.

For modifications to plant systems and components such as the SRV position indicators, procedures are developed or revised as necessary and appropriate training is provided when the final design documents are approved and the equipment is available for use.

The use of tailpipe temperature detectors in the emergency procedures is discussed in a letter from N. W. Curtis to B. J. Youngblood on April 30, 1981 (PLA-736).

### 18.1.25 AUXILIARY FEEDWATER SYSTEM EVALUATION (II.E.1.1)

This requirement is not applicable to Susquehanna SES.

### 18.1.26 AUXILIARY FEEDWATER SYSTEM INITIATION AND FLOW (II.E.1.2)

This requirement is not applicable to Susquehanna SES.

18.1.27 EMERGENCY POWER FOR PRESSURIZER HEATERS (II.E.3.1)

This requirement is not applicable to Susquehanna SES.

18.1.28 DEDICATED HYDROGEN PENETRATIONS (II.E.4.1)

18.1.28.1 Statement of Requirement

Plants using external recombiners or purge systems for postaccident combustible gas control of the containment atmosphere should provide containment penetration systems for external recombiner or purge systems that are dedicated to that service only. These systems must meet the redundancy and single-failure requirements of General Design Criteria 54 and 56 of Appendix A to 10 CFR 50, and that are sized to satisfy the flow requirements of the recombiner or purge system.

The procedures for the use of combustible gas control systems following an accident that results in a degraded core and release of radioactivity to the containment must be reviewed and revised, if necessary.

Operating license applicants must have design changes completed by July 1, 1981 or prior to issuance of an operating license, whichever is later.

18.1.28.2 Interpretation

None required.

18.1.28.3 Statement of Response

Susquehanna SES design includes 100% redundant internal hydrogen recombiner systems for postaccident combustible gas (hydrogen) control. Therefore this requirement is not applicable to Susquehanna SES.

18.1.29 CONTAINMENT ISOLATION DEPENDABILITY (II.E.4.2)

18.1.29.1 Statement of Requirement

- (1) Containment isolation system designs shall comply with the recommendations of Standard Review Plan (SRP) Section 6.2.4 (i.e., that there be diversity in the parameters sensed for the initiation of containment isolation).
- (2) All plant personnel shall give careful consideration to the definition of essential and nonessential systems, identify each system determined to be essential, identify each system determined to be nonessential, describe the basis for selection of each essential system, modify their containment isolation designs accordingly, and report the results of the reevaluation to the NRC.
- (3) All nonessential systems shall be automatically isolated by the containment isolation signal.
- (4) The design of control systems for automatic containment isolation valves shall be such that resetting the isolation signal will not result in the automatic reopening of containment isolation valves. Reopening of containment isolation valves shall require deliberate operator action.
- (5) The containment setpoint pressure that initiates containment isolation for nonessential penetrations must be reduced to the minimum compatible with normal operating conditions.
- (6) Containment purge valves that do not satisfy the operability criteria set forth in Branch Technical Position CSB 6-4 or the Staff Interim Position of October 23, 1979 must be sealed closed as defined in SRP 6.2.4, item II.3.f during operational conditions 1, 2, 3, and 4. Furthermore, these valves must be verified to be closed at least every 31 days.
- (7) Containment purge and vent isolation valves must close on a high radiation signal.

Applicants for an operating license must be in compliance with positions 1 through 4 before receiving an operating license. Applicants must be in compliance with positions 5 and 7 by July 1, 1981, and position 6 by January 1, 1981 or before they receive their operating license, whichever is later for each position.

### 18.1.29.2 Interpretations

From item 4, the opening of containment isolation valves must require a deliberate operator action.

From item 5, the containment isolation setpoint pressure should be optimized to prevent unnecessary isolations during normal operations. However, containment isolation must not be prevented or delayed during an accident.

### 18.1.29.3 Statement of Response

- (1) Containment isolation signals are actuated by several sensed parameters (refer to Table 3.3.2-1 in the Technical Specifications). This complies with SRP Subsection 6.2.4, Paragraph II-6.
- (2) Each process line penetrating containment was reviewed to determine whether it is an essential or non-essential line for purposes of isolation requirements. The classification for each line is given in Table 18.1-10.

Justification for the classification as an essential or non-essential line was also developed and is provided in Table 18.1-11. Systems identified as essential are those which may be required to perform an indispensable safety function in the event of an accident. Non-essential systems are those not required during or after an accident. Since instrument lines are not governed by isolation signals but are equipped with a manual isolation valve followed by an excess flow check valve outside the containment, the review of these lines was limited to ensure compatibility with the penetration listing in Table 6.2-12a.

- (3) All lines to non-essential systems are provided with isolation capability. All isolation valves in these lines, except the reactor water clean-up system (RWC) discharge valves (G33-1FC042 and 1P104 receive auto-isolation signals (refer to Table 18.1-10). The isolation function for the RWC discharge lines is provided by three series check valves (141-1F010A,B, HV-14107A,B and G33-1F039A,B) which prevents back flow from the reactor vessel. The RWC discharge isolation valves are not closed to prevent the loss of the filter cake in the RWC filter demineralizer system and injection of resin into the vessel on restart of the RWC system.
- (4) All containment isolation valves, except those listed below, will not automatically open on logic reset. Some valves

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require corrective action to comply with this requirement. All such actions will be completed prior to fuel load. Refer to a letter from N. W. Curtis to B. J. Youngblood on April 14, 1981 (PLA-715) for this commitment. An override of any isolation signal will not cause automatic opening of any isolation valve.

- a) The following valves in the Liquid Radwaste, Reactor Water Sample, and Reactor Building Chilled Water systems are normally open valves and will close upon a containment isolation signal.

HV-16116	A1 & A2
HV-16108	A1 & A2
HV-18781	A1 & A2 & B1 & B2
HV-18782	A1 & A2 & B1 & B2
HV-18791	A1 & A2 & B1 & B2
HV-18792	A1 & A2 & B1 & B2
B31-1F019	
B31-1F020	

When the containment isolation logic is reset the above valves would have reopened. The logic for these valves will be modified by fuel load to ensure that they will not reopen on logic reset. Table 18.1-10 reflects the modified configuration of these valves.

- b) The RCIC and HPCI turbine steam supply line isolation valves (HV-1F007, HV-1F008, HV-1F002 and HV-1F003) are normally open valves and will close upon a steam line break isolation signal. These valves are essential valves and do not receive a containment isolation signal. Reopening of these valves will occur if the hand switches are not placed in the closed position by the operator prior to actuation of the reset switch and the isolation parameters have cleared.

These valves are equipped with key-locked maintained contact switches to insure that these valves are open during ECCS initiation. If a pipe break condition were detected, then these valves will be automatically closed. After the pipe break problems are cleared these valves can be reopened to their normal emergency positions by deliberate operator action using the key-locked reset switches for each system. The operator is required to ensure that the valve switches are in the correct position prior to operating the keylock reset switch.

- c) The inboard HPCI and RCIC isolation valves each have a pressure equalization valve (HV-1F100 and HV-1F088) around them. The equalization valves are normally

closed and are only used to equalize the pressure around the inboard isolation valve in order to open them. If open, the valves will close upon a steam line break isolation signal. Reopening of these valves will occur if the hand switches are not placed in the closed position by the operator prior to actuation of the reset switch and the isolation parameters have cleared.

As with the HPCI/RCIC isolation valves the equalization valves will reopen upon deliberate manual logic reset using the key-locked reset switches. These valves must open in order to allow the inboard isolation valves to reopen to their normal emergency positions when the pipe break problems have cleared. If the equalization valve switches are not in the open position the operator must manually open them to equalize the pressure around the inboard HPCI/RCIC valves.

- d) The RHR containment isolation valves (HV-1F016A,B, and HV-1F028A,B) associated with the drywell and suppression pool spray lines will reopen if their handswitches are placed in the open position prior to actuation of the reset switch, the LPCI injection signals are clear, and the LPCI injection valves are closed. These spray line valves are normally closed and are provided key-locked hand switches and receive an isolation signal as described in Tables 18.1-10 and 18.1-12. If the valves were open before an LPCI injection event, these valves will automatically close and can not be reopened if the LPCI injection signals still exist or the LPCI injection valves are still open. This is to insure that the LPCI injection function will not be inadvertently jeopardized by opening of the spray line isolation valves. If these spray line valves were closed before the LPCI injection event, the valves will remain closed after reset even after all injection signals are clear and the LPCI injection valve are closed.

As noted in Table 18.1-10 only the outermost valve is considered a containment isolation valve for these penetrations. The three inboard valves HV-1F021A, HV-1F-27A and HV-1F024A are spring return to "AUTO" switches and will not automatically reopen after logic reset and all signals clear. These inboard valves have not been considered containment isolation valves because they can not be leak tested in the "forward" direction. Since these valves effectively function as containment isolation valves, a logic reset will not automatically result in a breach of containment integrity for these penetrations.

- 5) The BWR Owners' Group has performed a generic analysis which is summarized as follows. The containment isolation analytical setpoint pressure for Mark I, II, and III containments is approximately 2 psig (drywell pressure). Under normal operating conditions, fluctuations in the atmospheric barometric pressure as well as heat inputs (from such sources as pumps) can result in containment pressure increases on the order of 1 psi. Consequently, the isolation setpoint of 2 psig provides a 1 psi margin above the maximum expected operating pressure. The 1 psi margin to isolation has proved to be a suitable value to minimize the possibility of spurious containment isolation. At the same time, it is such a low value (particularly in view of the small drywell volume of Mark I, II, and III containments) that it provides a very sensitive and positive means of detecting and protecting against breaks and leaks in the reactor coolant system. No change of the setpoint is necessary for these containment types.

PP&L concurs with this position. Therefore, no modifications to the containment isolation pressure setpoint are necessary in response to this requirement.

- 6) The design of the containment atmosphere purge valves was reviewed against Branch Technical Position CSB6-4. This review identified several valves that do not meet this criteria. These valves will be qualified to meet this criteria as stated in a letter to B. J. Youngblood from N. W. Curtis on April 1, 1981 (PLA-700). Valves will be qualified to the interim criteria in NUREG-0737 item II.E.4.2 by fuel load. Valves will be fully qualified prior to the first refueling.
- (7) Two redundant safety grade radiation monitors are installed down stream of the Standby Gas Treatment System. A high radiation level will trip the Standby Gas Treatment System. This signal will be used to close the following containment isolation valves in the vent and purge system: HV-15703, HV-15704, HV-15705, HV-15711, HV-15713, HV-15714, HV-15721, HV-15722, HV-15723, HV-15724, HV-15725, SV-15736A, SV-15737, SV-15767 and SV-15776A.

The radiation setpoint will be set to so that the 10CFR 100 limits are not exceeded. The high radiation alarm for these detectors is annunciated on control room front row panel 1C653. The radiation level measured by these detectors is recorded on control room backrow panel 1C600.



These modifications will be complete by fuel load.

### 18.1.30 ACCIDENT-MONITORING INSTRUMENTATION (II.F.1)

#### 18.1.30.1 Statement of Requirement

The following equipment shall be added:

- (1) Noble gas effluent radiological monitor;
- (2) Provisions for continuous sampling of plant effluents for postaccident releases of radioactive iodines and particulates and onsite laboratory capabilities;
- (3) Containment high-range radiation monitor;
- (4) Containment pressure monitor;
- (5) Containment water level monitor; and
- (6) Containment hydrogen concentration monitor.

It is important that the displays and controls added to the control room as a result of this requirement not increase the potential for operator error. A human-factors analysis should be performed which considers:

- (a) the use of this information by an operator during both normal and abnormal plant conditions,
- (b) integration into emergency procedures,
- (c) integration into operator training, and
- (d) other alarms during emergency and need for prioritization of alarms.

Each piece of equipment is further discussed below.

#### 18.1.30.1.1 Noble Gas Effluent Monitor

Noble gas effluent monitors shall be installed with an extended range designed to function during accident conditions as well as during normal operating conditions. Multiple monitors are considered necessary to cover the ranges of interest.

- (1) Noble gas effluent monitors with an upper range capacity of  $10^5 \mu\text{Ci/cc}$  (Xe-133) are considered to be practical and should be installed in all operating plants.
- (2) Noble gas effluent monitoring shall be provided for the total range of concentration extending from normal condition (as low as reasonably achievable concentrations to a maximum of  $10^5 \mu\text{Ci/cc}$  (Xe-133)). Multiple monitors are considered to be necessary to cover the ranges of interest. The range capacity of individual monitors should overlap by a factor of ten.

Licensees and licensing applicants should have available for review the final design description of the as-built system, including piping and instrument diagrams together with either (1) a description of procedures for system operation and calibration, or (2) copies of procedures for system operation and calibration. License applicants will submit the above details in accordance with the proposed review schedule, but in no case less than four months prior to the issuance of an operating license.

#### 18.1.30.1.2-----Sampling and Analysis of Plant Effluents

Because iodine gaseous effluent monitors for the accident condition are not considered to be practical at this time, capability for effluent monitoring of radioiodines for the accident condition shall be provided with sampling conducted by adsorption on charcoal or other media, followed by onsite laboratory analysis.

Licensees shall provide continuous sampling of plant gaseous effluent for postaccident releases of radioactive iodines and particulates to meet the requirements of Table II.F.1-2 in NUREG 0737. Licensees shall also provide onsite laboratory capabilities to analyze or measure these samples. This requirement should not be construed to prohibit design and development of radioiodine and particulate monitors to provide online sampling and analysis for the accident condition. If gross gamma radiation measurement techniques are used, then provisions shall be made to minimize noble gas interference.

The shielding design basis is given in Table II.F.1-2 of NUREG 0737. The sampling system design shall be such that plant personnel could remove samples, replace sampling media and transport the samples to the onsite analysis facility with radiation exposures that are not in excess of the criteria of GDC 19 of 5-rem whole-body exposure and 75 rem to the extremities during the duration of the accident.

The design of the systems for the sampling of particulates and iodines should provide for sample nozzle entry velocities which are approximately isokinetic (same velocity) with expected induct or instack air velocities. For accident conditions, sampling may be complicated by a reduction in stack or vent effluent velocities to below design levels, making it necessary to substantially reduce sampler intake flow rates to achieve the isokinetic condition. Reductions in air flow may well be beyond the capability of available sampler flow controllers to maintain isokinetic conditions; therefore, the staff will accept flow control devices which have the capability of maintaining isokinetic conditions with variations in stack or duct design flow velocity of  $\pm 20\%$ . Further departure from the isokinetic condition need not be considered in design. Corrections for non-isokinetic sampling conditions, as provided in Appendix C of ANSI 13.1-1969 may be considered on an ad hoc basis.

Effluent streams which may contain air with entrained water, e.g. air ejector discharge, shall have provisions, e.g., heaters, to ensure that the adsorber is not degraded while providing a representative sample.

License applicants will submit final design details in accordance with the proposed review schedule, but in no case less than four months prior to the issuance of an operating license.

#### 18.1.30.1.3 Containment High-Range Radiation Monitor

In containment radiation-level monitors with a maximum range of  $10^8$  rad/hr shall be installed. A minimum of two such monitors that are physically separated shall be provided. Monitors shall be developed and qualified to function in an accident environment.

The specification of  $10^8$  rad/hr in the above position was based on a calculation of postaccident containment radiation levels that include both particulate (beta) and photon (gamma) radiation. A radiation detector that responds to both beta and gamma radiation cannot be qualified to post-LOCA (loss-of-coolant accident) containment environments but gamma-sensitive instruments can be so qualified. In order to follow the course of an accident, a containment monitor that measures only gamma radiation is adequate. The requirement was revised in the October 30, 1979 letter to provide for a photon-only measurement with an upper range of  $10^7$  R/hr.

The monitors shall be located in containment(s) in a manner as to provide a reasonable assessment of area radiation conditions inside containment. The monitors shall be widely separated so as to provide independent measurements and shall "view" a large

fraction of the containment volume. Monitors should not be placed in areas which are protected by massive shielding and should be reasonably accessible for replacement, maintenance, or calibration. Placement high in a reactor building dome is not recommended because of potential maintenance difficulties.

The monitors are required to respond to gamma photons with energies as low as 60 keV and to provide an essentially flat response for gamma energies between 100 keV and 3 MeV, as specified in Table II.F.1-3 of NUREG 0737. Monitors that use thick shielding to increase the upper range will under-estimate postaccident radiation levels in containment by several orders of magnitude because of their insensitivity to low energy gammas and are not acceptable.

License applicants will submit the required documentation in accordance with the appropriate review schedule, but in no case less than four months prior to the issuance of the staff evaluation report for an operating license.

#### 18.1.30.1.4 Containment Pressure Monitor

A continuous indication of containment pressure shall be provided in the control room of each operating reactor. Measurement and indication capability shall include three times the design pressure of the containment for concrete, four times the design pressure for steel, and -5 psig for all containments.

Operating license applicants with an operating license dated before January 1, 1982 must have design changes completed by January 1, 1982; those applicants with license dated after January 1, 1982 must have all design modifications completed before they can receive their operating license. Documentation is due 6 months for the expected date of operation.

#### 18.1.30.1.5 Containment Water Level Monitor

A continuous indication of containment water level shall be provided in the control room for all plants. A wide range instrument shall be provided to cover the range from the bottom to 5 feet above the normal water level in the suppression pool.

The containment wide-range water level indication channels shall meet appropriate design and qualification criteria. The narrow-range channel shall meet the requirements of Regulatory Guide 1.89.

For BWR pressure-suppression containments, the emergency core cooling system suction line inlets may be used as a starting

reference point for the narrow-range and wide-range water level monitors, instead of the bottom of the suppression pool.

The accuracy requirements of the water level monitors shall be provided and justified to be adequate for their intended function.

Operating license applicants with an operating license date before July 1, 1981 must have design changes completed by July 1, 1981, whereas those applicants with license dates past July 1, 1981 must have all design modifications completed before they can receive their operating license.

Submittals from operating reactors licensees and applicants for operating licenses (with an operating license date before January 1, 1982) shall be provided by January 1, 1982. Applicants with operating license dates beyond January 1, 1982 shall provide the required design information at least 6 months before the expected date of operation.

#### 18.1.30.1.6 Containment Hydrogen Monitor

A continuous indication of hydrogen concentration in the containment atmosphere shall be provided in the control room. Measurement capability shall be provided over the range of 0 to 10% hydrogen concentration under both positive and negative ambient pressure.

Operating license applicants with an operating license date before January 1, 1982 must have design changes completed by January 1, 1982 must have all design modifications completed before they can receive their operating license.

Operating reactors and applicants for operating license receiving an operating license before January 1, 1982 will submit documentation before January 1, 1982. Applicants with operating license issued after January 1, 1982 shall provide the required design information at least 6 months prior to the expected date of operation.

#### 18.1.30.2 Interpretation

None required.

18.1.30.3 Statement of Response

The response for each equipment requirement is given below. All equipment will be installed by the required dates. A human factors evaluation will be performed for changes that involve control room instrumentation. Drawings showing the location of equipment were submitted in a letter from N. W. Curtis to A. Schwencer on June 15 (PLA-842).

For modifications to plant systems and components such as addition of new post-accident monitoring capability, procedures are developed or revised as necessary and appropriate training is provided when the final design documents are approved and the equipment is available for use.

18.1.30.3.1 Noble Gas Effluent Monitor

Each of the five plant vents will be monitored by an Eberline Model FAAM (Fixed Airborne Activity Monitor). The FAAM's analyze representative samples which are provided by isokinetic probes which are in compliance with ANSI 13.1-1969. Each FAAM has three noble gas detectors which provide overlapping ranges of  $1 \times 10^{-7}$  Ci/cc to  $1 \times 10^5$   $\mu$ Ci/cc for Xe-133 gas. The sample stream is filtered by a HEPA filter and a charcoal filter, which are contained in a SA-13 assembly before passing the noble gas detectors. The charcoal filter can be replaced with a silver zeolite filter when required.

The plant effluent noble gas data is continuously monitored and stored in solid state memory. The flow through the sample line is also measured and stored in solid state memory. The FAAM then calculates and stores activity per unit of volume. This information can be displayed upon request and is periodically printed out for record keeping purposes. This information is displayed and recorded on backrow panel 1C669.

High activity alarms for the reactor and turbine buildings will be annunciated on control room front row panel 1C651. High activity alarms for the Standby Gas Treatment System will be annunciated on control room front row panel 1C601.

The low-range noble gas channel is calibrated using Kr 85 and Xe 133 gas standards traceable to the National Bureau of Standards. The mid-range noble gas channel is calibrated using a Cs 137 stick source. The high-range noble gas channel is calibrated using a Kr 85 gas standard traceable to the National Bureau of Standards.

## SSSES-FSAR

The system is powered from non-class IE instrument AC power. An independent battery backup is provided which is capable of providing power for 8 hours.

This equipment is installed and will be operational by fuel load.

### 18.1.30.3.2 Sampling and Analysis of Plant Effluents

Each of the five plant vents has a continuous isokinetic sample drawn from it in accordance with ANSI-N13.1. Each sample is then taken through short runs of heat traced tubing to a Eberline Model FAAM (Fixed Airborne Activity Monitor). In the FAAM the sample stream then passes through a HEPA filter which removes particulates. Upon leaving the HEPA filter the sample stream passes through a charcoal filter which removes iodines. When required this filter can be replaced with a silver zeolite filter. Capabilities for purging the sample line with compressed air are provided under manual control. The sample stream is next measured for noble gas activity and then returned to the plant vent. During normal operation the HEPA and charcoal filters are monitored by radiation detectors and this information is presented to the operator in the control room. Under accident conditions these detectors will saturate and the filters must be removed, placed in a shielded container, and analyzed in a laboratory. The FAAM also has provisions for obtaining a grab samples.

The isokinetic sample is in compliance with ANSI-N13.1-1969. To accomplish this, each vent has an air profile (final gas treatment) station to eliminate turbulent and rotating gas flow. The average stack velocity and volume are then measured by means of a multipoint, self-averaging Pitot transverse station. An air flow controller then simultaneously withdraws a multipoint sample under isokinetic flow conditions by means of an isokinetic sample rack. This isokinetic sample is then directed to the Final Airborne Activity Monitor.

The system is designed such that plant personnel can remove samples, replace sample media and transport the samples in shielded containers to an analysis facility. Radiation exposures for this process are not in excess of 3 rem whole-body exposure and 18.5 rem to the extremities during the duration of the accident.

Procedures for analyzing samples both normal and accident conditions are described in Subsection 12.5.3.5.5. The equipment used to analyze these samples is described in Subsection 1.2.5.2.7.1. Additional instrumentation and procedures for sampling and analyzing implant iodine are described in Subsection 18.1.70.

The installation plant vent sampling and monitoring system is complete.

#### 18.1.30.3.3 Containment High-Range Radiation Monitor

Redundant Class 1E in-containment radiation monitors will be provided. The monitors will be General Atomic high range radiation monitors. These monitors are capable of measuring radiation levels of 1R/hr to  $1 \times 10^6$  R/hr (Gamma) for photon energies of between 80 KeV to 3 MeV. An accuracy of  $\pm 20\%$  is obtained on lower decades.

The detectors will be unshielded and physically separated on opposite sides of the reactor pressure vessel.

Logarithmic indicating recorders will be provided for Channels A and B on front row panel 1C601.

A common red high radiation annunciator for both channels will be provided on control room front row panel 1C601. A common white system trouble light will also be provided for both channels on control room front row panel 1C601.

The containment radiation monitoring system is designed to be safety grade. This equipment will be qualified to IEEE-344-1975, IEEE-323-1974 and NUREG-1588 in accordance with the Commission order on May 23rd, 1980 (CLI-20-81).

The installation of the containment radiation monitoring system will be complete by fuel load.

#### 18.1.30.3.4 Containment Pressure Monitor

Two Class 1E redundant drywell chamber pressure measurements will be provided as follows:

SERVICE	RANGE
LOCA Range	0 to 65 psia
HI Range	0 to 250 psig

The LOCA and HI ranges are divided into two divisions. Continuous, individual indication of all four Division I and II pressure measurements will be provided by indicating recorders for the operation on front row panels 1C601.

Normal operating pressures in the drywell and wetwell are monitored by a -1 to +3 psig instrument installed in each



chamber. An indicator on control panel 1C601 will display these pressures. A selector switch is provided to allow the operator to monitor either drywell or wetwell pressure. These instruments are non-safety grade with the exception of the transmitters, which are designed to meet containment pressure boundary service.

The accuracy of these instruments is  $\pm 2\%$  of full scale.

The containment accident range pressure monitors are designed to be safety grade. This equipment will be qualified to IEEE-344-1975, IEEE-323-1974 and NUREG 0588 in accordance with the Commission order on May 23rd, 1980 (CLI-20-81).

The containment pressure instrumentation will be installed by fuel load.

#### 18.1.30.3.5 Containment Water Level Monitor

Redundant wide and narrow range safety grade instruments will be installed to continuously monitor suppression pool water level. The channel A measurements will be displayed on control room front row panel 1C601. The channel B measurements will be recorded on front row panel 1C601.

The narrow range instruments measure between 18 and 26 feet. The wide range instruments measure between 4.5 and 49 feet. This covers the required range of from the lowest ECCS suction to 5 feet above normal water level. Normal water level is approximately 23 feet.

The accuracy of these instruments is  $\pm 2\%$  of full scale.

Installation of the suppression pool water level instrumentation will be complete by January 1982.

#### 18.1.30.3.6 Containment Hydrogen Monitor

Continuous and redundant indication and recording of hydrogen will be provided on control room front row panel 1C601. These instruments will have a range of 0 to 30%.

The containment hydrogen monitoring system is designed to be safety grade. The equipment will be qualified to IEEE-344-1975, IEEE-323-1974 and NUREG-0588 in accordance with the Commission order on May 23rd, 1980 (CLI-20-81).

The accuracy of these instruments is  $\pm 2\%$  of full scale.

## SSES-PSAR

Installation of the hydrogen monitoring instrumentation will be complete by fuel load.

### 18.1.31 INSTRUMENTATION FOR DETECTION OF INADEQUATE CORE COOLING ----- (II.F.2) -----

#### 18.1.31.1 Statement of Requirement

Licensees shall provide a description of any additional instrumentation or controls (primary or backup) proposed for the plant to supplement existing instrumentation (including primary coolant saturation monitors) in order to provide an unambiguous, easy-to-interpret indication of inadequate core cooling (ICC). A description of the functional design requirements for the system shall also be included. A description of the procedures to be used with the proposed equipment, the analysis used in developing these procedures, and a schedule for installing the equipment shall be provided.

#### 18.1.31.2 Interpretation

None required.

#### 18.1.31.3 Statement of Response

The Susquehanna SES reactor vessel water level instruments utilize redundant cold reference legs. The reference legs are connected to redundant and diverse level instruments by parallel instrument lines. The level instruments provide a range of measurement from below the active fuel to above the main steam lines. The fuel zone instruments are calibrated to LOCA conditions. This configuration provides optimum performance for all operating conditions and credible transients. The reactor vessel water level instruments are standard for BWR/5's and later BWR/4's and were evaluated by the BWR Owners' Group and found to be adequate to detect inadequate core cooling (ICC). This instrumentation is described and documented in NEDO-24708, "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors". Since the present design uses the optimum reference leg configuration, no additional instrumentation or modifications to instrumentation are needed for detection of ICC.

Symptom based procedures are being developed (in response to requirement I.C.1) for proper identification of ICC. These

procedures will assist the operator in detecting the approach to ICC. Refer to Subsection 18.1.8 for the response to requirement I.C.1.

PP&L has developed a Display Control Sub-system (DCS) format to promote operator detection of inadequate core cooling. The format consists of three distinct functional areas: a graphic representation of reactor water level, a twenty minute reactor water level trend, and water level supporting data.

The graphic display will provide a qualitative representation of reactor water level from -150 to + 170 inches relative to instrument level zero. Several vessel components are statically depicted as points of reference. The water level indication is normally displayed in yellow, however, if level decreases to or below -38 inches it will turn from yellow to red.

The reactor water level trend portion of the display will provide a twenty-minute history, in one minute increments, of the water trend. Slowly increasing or decreasing levels should be apparent from this trend. The trend display will turn from yellow to red if the level decreases to or below -38 inches.

Other supportive data, which may be useful in monitoring reactor water level, has also been provided.

The format is subject to possible revisions or refinements, however, the fundamental concept of graphically indicating reactor water level will always be provided by the display. A typical format sample is provided in Figure 18.1-16.

#### 18.1.32 EMERGENCY POWER FOR PRESSURIZER EQUIPMENT (II.G.1)

This requirement is not applicable to Susquehanna SES.

#### 18.1.33 REVIEW ESF VALVES (II.K.1.5)

No requirement stated in NUREG 0737. Refer to Subsection 18.2.25 which contains the response to the requirement in NUREG 0694.

#### 18.1.34 OPERABILITY STATUS (II.K.1.10)

No requirement stated in NUREG 0737. Refer to Subsection 18.2.26 which contains the response to the requirement in NUREG 0694.

18.1.35 TRIP PRESSURIZER LOW-LEVEL COINCIDENT SIGNAL BISTABLES  
----- (II.K.1.17) -----

This requirement is not applicable to Susquehanna SES.

18.1.36 OPERATOR TRAINING FOR PROMPT MANUAL REACTOR TRIP  
----- (II.K.1.20) -----

This requirement is not applicable to Susquehanna SES.

18.1.37 AUTOMATIC SAFETY GRADE ANTICIPATORY REACTOR TRIP  
----- (II.K.1.21) -----

This requirement is not applicable to Susquehanna SES.

18.1.38 AUXILIARY HEAT REMOVAL SYSTEM PROCEDURES (II.K.1.22)

No requirement stated in NUREG 0737. Refer to Subsection 18.2.30 which contains the response to the requirement in NUREG 0694.

18.1.39 REACTOR VESSEL LEVEL PROCEDURES (II.K.1.23)

No requirement stated in NUREG 0737. Refer to Subsection 18.2.31 which contains the response to the requirement in NUREG 0694.

18.1.40 COMMISSION ORDERS ON BABCOCK AND WILCOX PLANTS (II.K.2)

These requirements are not applicable to Susquehanna SES.

18.1.41 AUTOMATIC POWER-OPERATED RELIEF VALVE ISOLATION  
----- SYSTEM (II.K.3.1) -----

This requirement is not applicable to Susquehanna SES.

18.1.42 REPORT ON POWER-OPERATED RELIEF VALVE FAILURES  
 -----(II.K.3.2)-----

This requirement is not applicable to Susquehanna SES.

18.1.43 REPORTING SAFETY/RELIEF VALVE FAILURES AND  
 -----CHALLENGES (II.K.3.3)-----

No requirement stated in NUREG 0737. Refer to Subsection 18.2.33 which contains the response to the requirement in NUREG 0694.

18.1.44 AUTOMATIC TRIP OF REACTOR COOLANT PUMPS DURING  
 -----A LOCA (II.K.3.5)-----

This requirement is not applicable to Susquehanna SES.

18.1.45 EVALUATION OF POWER-OPERATED RELIEF VALVE  
 -----OPENING PROBABILITY (II.K.3.7)-----

This requirement is not applicable to Susquehanna SES.

18.1.46 PROPORTIONAL INTEGRAL DERIVATIVE CONTROLLER  
 -----MODIFICATION (II.K.3.9)-----

This requirement is not applicable to Susquehanna SES.

18.1.47 PROPOSED ANTICIPATORY TRIP MODIFICATION (II.K.3.10)

This requirement is not applicable to Susquehanna SES.

18.1.48 POWER-OPERATED RELIEF VALVE FAILURE RATE (II.K.3.11)

This requirement is not applicable to Susquehanna SES.

18.1.49 ANTICIPATORY REACTOR TRIP ON TURBINE TRIP (II.K.3.12)

This requirement is not applicable to Susquehanna SES.

18.1.50 SEPARATION OF HIGH PRESSURE COOLANT INJECTION AND  
REACTOR CORE ISOLATION COOLING SYSTEM INITIATION LEVELS  
(II.K.3.13)

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18.1.50.1 Statement of Requirement

Currently, the reactor core isolation cooling (RCIC) system and the high-pressure coolant injection (HPCI) system both initiate on the same low-water-level signal and both isolate on the same high-water-level signal. The HPCI system will restart on low water level but the RCIC system will not. The RCIC system is a low-flow system when compared to the HPCI system. The initiation levels of the HPCI and RCIC system should be separated so that the RCIC system initiates at a higher water level than the HPCI system. Further, the initiation logic of the RCIC system should be modified so that the RCIC system will restart on low water level. These changes have the potential to reduce the number of challenges to the HPCI system and could result in less stress on the vessel from cold water injection. Analyses should be performed to evaluate these changes. The analyses should be submitted to the NRC staff and changes should be implemented if justified by the analyses.

All applicants for operating license should submit the results of an evaluation and proposed modifications four months prior to the expected issuance of the staff safety evaluation report for an operating license or four months prior to the listed implementation date (July 1, 1981), whichever is later.

18.1.50.2 Interpretation

None required.

18.1.50.3 Statement of Response

PP&L concurs with the BWR Owners' Group position on the separation of the HPCI and RCIC setpoints which was transmitted to the NRC by letter from R. H. Buchholz (GE) to D. G. Eisenhut (NRC), October, 1, 1980 (MFN-169-80).

This letter forwarded a GE study which showed that HPCI and RCIC initiations at the current low water level setpoints is within the design basis thermal fatigue analysis of the reactor vessel and its internals. Separating HPCI and RCIC setpoints as a means of reducing thermal cycles has been shown to be of negligible benefit. In addition, raising the RCIC setpoint or lowering the

HPCI setpoint have undesirable consequences which outweigh the benefit of the limited reduction in thermal cycles. Therefore, when evaluated on this basis, PP&L concludes that no change in RCIC or HPCI setpoints is required.

PP&L also concurs with the BWR Owners' Group position that RCIC should restart automatically following a trip of the system at high reactor vessel water level. This position was transmitted to the NRC by letter from D. B. Waters (BWROG) to D. G. Eisenhower (NRC), December 29, 1980.

PP&L will implement the recommended option 2 which is described in detail in the GE study forwarded with the BWR Owners' Group position. Implementation is discussed in a letter from N. W. Curtis to B. J. Youngblood on May 20, 1981 (PLA-792).

#### 18.1.51 MODIFY BREAK-DETECTION LOGIC TO PREVENT SPURIOUS ISOLATION OF HIGH PRESSURE COOLANT INJECTION AND -----REACTOR CORE ISOLATION COOLING (II.K.3.15)-----

##### 18.1.51.1 Statement of Requirement

The high-pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) systems use differential pressure sensors on elbow taps in the steam lines to their turbine drives to detect and isolate pipe breaks in the systems. The pipe-break-detection circuitry has resulted in spurious isolation of the HPCI and RCIC systems due to the pressure spike which accompanies startup of the systems. The pipe-break-detection circuitry should be modified so that pressure spikes resulting from HPCI and RCIC system initiation will not cause inadvertent system isolation.

All applicants for operating license should submit documentation four months prior to the expected issuance of the staff safety evaluation report for an operating license or four months prior to the listed implementation date (July 1, 1981), whichever is later.

##### 18.1.51.2 Interpretation

None required.

18.1.51.3 Statement of Response

The BWR Owners' Group has performed an evaluation and recommends the following modification to the steamline break detection logic. In order to minimize inadvertent HPCI/RCIC isolation due to pressure transients during system initiation, a time delay relay, set at approximately three (3) seconds, is to replace the existing relay in the steamline high differential pressure circuitry. The time delay feature assures that the steamline break isolation signal is, in fact, due to continuous high steam flow. See Subsections 7.3.1.1a.1.3.4, 7.6.1a.4.3.3.4.2 and Fig. 18.1-13.

The time delay relay shall be class 1B, with an adjustable time delay setting of 0-5 seconds. This classification is compatible with the system's existing circuitry. Two time delay relays are required for the trip system logic for both the HPCI and RIC systems.

A design assessment study shall confirm the appropriate time-delay setting. Implementation is discussed in a letter from N. W. Curtis to B. J. Youngblood on May 20, 1981 (PLA-792).

18.1.52 REDUCTION OF CHALLENGES AND FAILURES OF RELIEF VALVES  
 -----(II.K.3.16)-----

18.1.52.1 Statement of Requirement

The record of relief-valve failures to close for all boiling-water reactors (BWRs) in the past 3 years of plant operation is approximately 30 in 73 reactor-years (0.41 failures per reactor-year). This has demonstrated that the failure of a relief valve to close would be the most likely cause of a small-break loss-of-coolant accident (LOCA). The high failure rate is the result of a high relief-valve challenge rate and a relatively high failure rate per challenge (0.16 failures per challenge). Typically, five valves are challenged in each event. This results in an equivalent failure rate per challenge of 0.03. The challenge and failure rates can be reduced in the following ways:

- (1) Additional anticipatory scram on loss of feedwater,
- (2) Revised relief-valve actuation setpoints,
- (3) Increased emergency core cooling (ECC) flow,
- (4) Lower operating pressures,
- (5) Earlier initiation of ECC systems.



- (6) Heat removal through emergency condensers,
- (7) Offset valve setpoints to open fewer valves per challenge,
- (8) Installation of additional relief valves with a block- or isolation-valve feature to eliminate opening of the safety/relief valves (SRVs), consistent with the ASME Code,
- (9) Increasing the high steam line flow setpoint for main steam line isolation valve (MSIV) closure,
- (10) Lowering the pressure setpoint for MSIV closure,
- (11) Reducing the testing frequency of the MSIVs,
- (12) More-stringent valve leakage criteria, and
- (13) Early removal of leaking valves

An investigation of the feasibility and contraindications of reducing challenges to the relief valves by use of the aforementioned methods should be conducted. Other methods should also be included in the feasibility study. Those changes which are shown to reduce relief-valve challenges without compromising the performance of the relief valves or other systems should be implemented. Challenges to the relief valves should be reduced substantially (by an order of magnitude).

Results of the evaluation shall be submitted by April 1, 1981 for staff review. The actual modification shall be accomplished during the next scheduled refueling outage following staff approval or no later than 1 year following staff approval. Modification to be implemented should be documented at the time of implementation.

#### 18.1.52.2 Interpretation

None required.

#### 18.1.52.3 Statement of Response

The BWR Owners' Group (BWROG) has performed an evaluation and developed recommendations to comply with this requirement. These recommendations were transmitted by a letter from B. D. Waters to D. G. Eisenhut on March 31, 1981. This evaluation shows that Crosby SRVs (as will be installed in Susquehanna) have a probability of sticking open which is approximately a factor of ten less than the three stage Target Rock valves. It is our

understanding that the goal of this requirement is to reduce the probability of a stuck open SRV by a factor of 10 relative to a reference valve, which is the Target Rock valve. Therefore we meet the intent of this requirement without modifications. Implementation of the modification proposed by the BWROG will not significantly reduce this failure probability. Therefore no modifications are necessary in response to this requirement.

18.1.53 REPORT ON OUTAGES OF EMERGENCY CORE COOLING SYSTEMS  
 -----(II.K.3.17)-----

18.1.53.1 Statement of Requirement

Several components of the emergency core-cooling (ECC) systems are permitted by technical specifications to have substantial outage times (e.g., 72 hours for one diesel-generator; 14 days for the HPCI system). In addition, there are no cumulative outage time limitations for ECC systems. Licensees should submit a report detailing outage dates and lengths of outages for all ECC systems for the last 5 years of operation. The report should also include the causes of the outages (i.e., controller failure, spurious isolation).

18.1.53.2 Interpretation

None required.

18.1.53.3 Statement of Response

PP&L will submit a report which summarizes emergency core cooling system outages accumulated during the first five years of operation.

18.1.54 MODIFICATION OF AUTOMATIC DEPRESSURIZATION SYSTEM  
 -----LOGIC (II.K.3.18)-----

18.1.54.1 Statement of Requirement

The automatic depressurization system (ADS) actuation logic should be modified to eliminate the need for manual actuation to assure adequate core cooling. A feasibility and risk assessment study is required to determine the optimum approach. One

possible scheme that should be considered is ADS actuation on low reactor-vessel water level provided no high-pressure coolant injection or high-pressure coolant system flow exists and a low-pressure emergency core cooling system is running. This logic would complement, not replace, the existing ADS actuation logic.

Applicants for operating license shall provide results of feasibility study 1 year prior to issuance of operating license. A description of the proposed modification for staff approval is required four months prior to issuance of an operating license.

#### 18.1.54.2 Interpretation

The ADS actuation logic may not be automatically actuated for steam line breaks (SLB) outside containment. The operator must manually actuate the ADS after diagnosing that an SLB has occurred. The ADS actuation logic should be modified to provide automatic actuation for all Design Basis Accidents.

#### 18.1.54.3 Statement of Response

Pennsylvania Power & Light Company adopts the BWR Owners Group position (date February 5, 1982) on delaying ADS modifications until the completion of a study by General Electric Company. The study is scheduled for completion by 9/30/82.

As stated in a letter from N. W. Curtis to A. Schwencer on June 17, 1981 (PLA-851), the required system modifications will be installed prior to the startup following the first refueling outage for Unit 1 and prior to fuel load for Unit 2 contingent on the results of the GE study and contingent upon delivery of qualified equipment.

### 18.1.55 RESTART OF CORE SPRAY AND LOW PRESSURE COOLANT INJECTION SYSTEMS (II.K.3.21)

#### 18.1.55.1 Statement of Requirement

The core-spray and low-pressure, coolant-injection (LPCI) system flow may be stopped by the operator. These systems will not restart automatically on loss of water level if an initiation signal is still present. The core spray and LPCI system logic should be modified so that these systems will restart, if required, to assure adequate core cooling. Because this design modification affects several core-cooling modes under accident

conditions, a preliminary design should be submitted for staff review and approval prior to making the actual modification.

All applicants for operating license should submit documentation four months prior to the expected issuance of an operating license or four months prior to the listed implementation date, whichever is later.

#### 18.1.55.2 Interpretation

None required.

#### 18.1.55.3 Statement of Response

PP&L concurs with the BWR Owners' Group position which was forwarded to the NRC by letter from D. B. Waters (BWROG) to D. G. Eisenhut (NRC), December 29, 1980.

The BWROG report states that the current ECCS design represents the optimum approach to BWR safety. No modifications to existing LPCI and core spray systems are necessary in response to this requirement.

#### 18.1.56 AUTOMATIC SWITCHOVER OF REACTOR CORE ISOLATION -----COOLING SYSTEM SUCTION (II.K.3.22)

##### 18.1.56.1 Statement of Requirement

The reactor core isolation cooling (RCIC) system takes suction from the condensate storage tank with manual switchover to the suppression pool when the condensate storage tank level is low. This switchover should be made automatically. Until the automatic switchover is implemented, licensees should verify that clear and cogent procedures exist for the manual switchover of the RCIC system suction from the condensate storage tank to the suppression pool.

Documentation must be submitted four months prior to issuance of the staff safety evaluation report or four months prior to the implementation date, whichever is later. Modifications shall be completed by January 1, 1982.

18.1.56.2 Interpretation.

None required.

18.1.56.3 Statement of Response

Manual switchover of the RCIC suction from the condensate storage tank (CST) to the suppression pool on low CST level is covered in the Emergency Operating Procedures.

Specifically, this item is addressed in the following Emergency Operating Procedures:

EO-00-022 (Cooldown) Section 2.C.

EO-00-023 (Containment Control) Section 2.D.

This procedural guidance is an interim measure and will be revised to discuss automatic switchover of the RCIC suction when the design change is implemented.

The design changes for automatic switchover are being developed. All modifications will be completed by January 1982.

18.1.57 CONFIRM ADEQUACY OF SPACE COOLING FOR HIGH  
PRESSURE COOLANT INJECTION AND REACTOR  
CORE ISOLATION COOLING SYSTEMS (II.K.3.24)

18.1.57.1 Statement of Requirement.

Long-term operation of the reactor core isolation cooling (RCIC) and high-pressure coolant injection (HPCI) systems may require space cooling to maintain the pump-room temperatures within allowable limits. Licensees should verify the acceptability of the consequences of a complete loss of alternating-current (AC) power. The RCIC and HPCI systems should be designed to withstand a complete loss of offsite AC power to their support systems, including coolers, for at least 2 hours.

All applicants for operating license should submit documentation four months prior to the expected issuance of the staff safety evaluation report for an operating license or four months prior to the listed implementation date, whichever is later.

18.1.57.2 Interpretation

Confirm that HPCI and RCIC room cooling can be maintained to enable continuous operation during a loss of offsite AC power for 2 hours.

18.1.57.3 Statement of Response

The HPCI and RCIC room unit coolers and their support systems are designed to withstand the consequences of a complete loss of offsite AC power since these are powered from onsite diesel generators. Each HPCI and RCIC room is provided with a 100% capacity redundant unit cooler. Refer to Subsection 9.4.2.2.

18.1.58 EFFECT OF LOSS OF ALTERNATING-CURRENT POWER ON  
RECIRCULATION PUMP SEALS (II.K.3.25)

18.1.58.1 Statement of Requirement

The licensees should determine, on a plant-specific basis, by analysis or experiment, the consequences of a loss of cooling water to the reactor recirculation pump seal coolers. The pump seals should be designed to withstand a complete loss of alternating-current (AC) power for at least 2 hours. Adequacy of the seal design should be demonstrated.

Applicants for operating licenses shall submit the evaluation and proposed modifications no later than 6 months prior to expected issuance of the staff safety evaluation report in support of license issuance, whichever is later. Modifications must be completed by January 1, 1982.

18.1.58.2 Interpretation

Evaluate the effect of a loss of offsite AC power for 2 hours on the recirculation pump seals.

18.1.58.3 Statement of Response

The system(s) providing cooling water to the recirculation pump seals will be modified to automatically receive emergency power following a loss of offsite power. These modifications will be completed prior to the first refueling outage.

18.1.59 PROVIDE A COMMON REFERENCE LEVEL  
 -----FOR VESSEL LEVEL INSTRUMENTATION (II.K.3.27)-----

18.1.59.1 Statement of Requirement

Different reference points of the various reactor vessel water level instruments may cause operator confusion. Therefore, all level instruments should be referenced to the same point. Either the bottom of the vessel or the top of the active fuel are reasonable reference points.

All applicants for operating license should submit documentation four months prior to the expected issuance of the staff safety evaluation report for an operating license or four months prior to the listed implementation date, whichever is later.

18.1.59.2 Interpretation

None required.

18.1.59.3 Statement of Response

Susquehanna SES will be modified so that all reactor water level indications use the same reference point, the bottom of the steam dryer skirt. This commitment was previously stated in letters from N. W. Curtis to A. Schwencer on July 21 and August 4, 1981 (PLA-888, -987).

18.1.60 VERIFY QUALIFICATION OF ACCUMULATORS ON AUTOMATIC  
 -----DEPRESSURIZATION SYSTEM VALVES (II.K.3.28)-----

18.1.60.1 Statement of Requirement

Safety analysis reports claim that air or nitrogen accumulators for the automatic depressurization system (ADS) valves are provided with sufficient capacity to cycle the valves open five times at design pressures. GE has also stated that the emergency core cooling (ECC) systems are designed to withstand a hostile environment and still perform their function for 100 days following an accident. Licensee should verify that the accumulators on the ADS valves meet these requirements, even considering normal leakage. If this cannot be demonstrated, the

licensee must show that the accumulator design is still acceptable.

The ADS valves, accumulators, and associated equipment and instrumentation must be capable of performing their functions during and following exposure to hostile environments and taking no credit for nonsafety-related equipment or instrumentation. Additionally, air (or nitrogen) leakage through valves must be accounted for in order to assure that enough inventory of compressed air is available to cycle the ADS valves.

All applicants for operating license shall submit documentation four months before the expected issuance of the staff safety evaluation report for an operating license or four months before the listed implementation date, whichever is later.

#### 18.1.60.2 Interpretation

None required.

#### 18.1.60.3 Statement of Response

The design basis and justification for the ADS accumulators are given below. This design basis is different than stated in NUREG 0737, Requirement II.K.3.28.

The criteria for short-term and long-term ADS operations, as specified in the FSAR, are as follows:

(a) Short-Term ADS Operation -

Accumulator capacity is sufficient for each ADS valve to provide two actuations against 31.5 psig (70% of 45 psig) drywell pressure (see FSAR Subsection 5.2.2.4.1 and response to Question 211.67).

(b) Long-Term ADS Operability of 100 Days -

The safety related nitrogen storage system contains adequate gas in storage ( $N_2$ -bottles could be replaced periodically to provide capacity for at least 100 days operation of the ADS.

Justification for meeting these criteria is given below.

(1) Short-Term ADS Design Basis

Short-term is defined for this discussion as the time required to depressurize the reactor to the residual heat



removal (RHR) shutdown cooling pressure permissive setpoint, stabilize the reactor water level and place the reactor in the shutdown cooling mode.

Each ADS accumulator is presently sized to provide two ADS safety/relief valve (S/RV) actuations at 70% of drywell design pressure. This is equivalent to six actuations of the ADS S/RVs at atmospheric pressure in the drywell. The ADS valves are designed to operate at 70% of drywell design pressure because that is the maximum pressure for which rapid reactor depressurization through the ADS valves is required (greater drywell pressures are associated only with the short duration primary system blowdown in the drywell immediately following a large pipe break). For large breaks which result in higher drywell pressure, sufficient reactor depressurization occurs due to the break to preclude the need for ADS. One ADS actuation at 70% of drywell design pressure is sufficient to depressurize the reactor and allow inventory makeup by the low pressure ECC systems. However, for conservatism, the ADS accumulators are sized to allow two ADS actuations at 70% of drywell design pressure.

This design provides sufficient nitrogen to the ADS valves to permit depressurization until the RHR shutdown cooling mode can be initiated.

Preoperational testing of the ADS valves at 70% of design drywell pressure is not practical because it would require pressurizing the drywell during the ADS valve testing. Thus, an equivalent number of valve actuations at atmospheric pressure is normally included in the ADS system test specification.

## (2) Long-Term ADS Design Basis

The basis for the long-term ADS requirement is derived from the long-term cooling acceptance criterion (Criterion 5) of 10CFR50.46. Criterion 5 states:

"Long-Term Cooling. After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core.

This criterion requires that either ADS be operable in conjunction with the low pressure ECCS pumps or that RHR shutdown cooling and water makeup capability be operable, to ensure long-term core cooling.

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The primary purpose of long-term ADS is to keep the reactor pressure low enough so that low pressure ECCS systems can be used to keep the core cooled. The ADS is not required after the decay heat is low enough so the vessel will not be pressurized above the shutoff head of the low pressure ECCS pumps.

The duration for which the ADS must be available is dependent on factors such as the power of the reactor at the time of the LOCA, break size and location, available injection systems, and availability of RHR shutdown cooling. The long-term ADS design requirement is 100 days. This is based on a judgment of the time required to make any necessary repairs to the RHR shutdown cooling system or ADS, thus ensuring the core would be kept cool.

Based on the 10CFR50 requirement, a long-term depressurization capability is provided by supplying nitrogen to the ADS accumulators using a safety grade system. The safety related nitrogen storage (N<sub>2</sub> bottles) system contains adequate gas in storage for 30 days after a postulated DBA. However, these nitrogen bottles could be replaced periodically by bringing portable N<sub>2</sub>-bottles to provide long-term operation of the ADS. (At Susquehanna, these bottles are located in an area that is accessible following a loss-of-coolant accident.)

From the above discussion, PP&L concludes that the Susquehanna design of ADS pneumatic supply system meets the intent of NUREG-0737, Item II.K.3.28.

### 18.1.61 REVISED SMALL-BREAK LOSS OF COOLANT ACCIDENT METHODS (II.K.3.30)

#### 18.1.61.1 Statement of Requirement

The analysis methods used by nuclear steam supply system vendors and/or fuel suppliers for small-break loss-of-coolant accident (LOCA) analysis for compliance with Appendix K to 10 CFR Part 50 should be revised, documented and submitted for NRC approval. The revisions should account for comparisons with experimental data, including data from the LOFT test and Semiscale Test facilities.

The Bulletins and Orders Task Force identified a number of concerns regarding the adequacy of certain features of small-break LOCA models, particularly the need to confirm specific model features (e.g., condensation heat transfer rates) against applicable experimental data. These concerns, as they applied to

each light-water reactor (LWR) vendor's models, were documented in the task force also concluded that, in light of the TMI-2 accident, additional systems verification of the small-break LOCA model as required by II.4 of Appendix K to 10 CFR 50 was needed. This included providing experimental verification of the various modes of single-phase and two-phase natural circulation predicted to occur in each vendor's reactor during small-break LOCAs.

Based on the cumulative staff requirements for additional small-break LOCA model verification, including both integral system and separate effects verification, the staff considered model revision as the appropriate method for reflecting any potential upgrading of the analysis methods.

The purpose of the verification was to provide the necessary assurance that the small-break LOCA models were acceptable to calculate the behavior and consequences of small primary system breaks. The staff believes that this assurance can alternatively be provided, as appropriate, by additional justification of the acceptability of present small-break LOCA models with regard to specific staff concerns and recent test data. Such justification could supplement or supersede the need for model revision.

The specific staff concerns regarding small-break LOCA models are provided in the analysis sections of the B&O Task Force reports for each LWR vendor, (NUREG-0635, -0565, -0626, -0611, and -0623). These concerns should be reviewed in total by each holder of an approved emergency core cooling system model and addressed in the evaluation as appropriate.

The recent tests include the entire Semiscale small-break test series and LOFT Tests (L3-1) and L3-2). The staff believes that the present small-break LOCA models can be both qualitatively and quantitatively assessed against these tests. Other separate effects tests (e.g., ORNL core uncover tests) and future tests, as appropriate, should also be factored into this assessment.

Based on the preceding information, a detailed outline of the proposed program to address this issue should be submitted. In particular, this submittal should identify (1) which areas of the models, if any, the licensee intends to upgrade, (2) which areas the licensee intends to address by further justification of acceptability, (3) test data to be used as part of the overall verification/upgrade effort, and (4) the estimated schedule for performing the necessary work and submitting this information for staff review and approval.

Licensees shall submit an outline of a program for model justification/revision by November 15, 1980. Licensees shall submit additional information for model justification and/or revised analysis model for staff approval by January 1, 1982. Licensees shall submit their plant-specific analyses using the

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revised models by January 1, 1983 or one year after any model revisions are approved. Applicants shall submit appropriate information in accordance with the licensing review schedule.

### 18.1.61.2 Interpretation

None required.

### 18.1.61.3 Statement Of Response

PP&L considers that the reactor vendor, General Electric, is the most appropriate party to work with the staff in resolving staff concerns with small break LOCA models for BWRs. Accordingly, the staff should direct their questions regarding the scope and schedule for this requirement to General Electric (attn. R. H. Buchholz, Manager, BWR Systems Licensing). Copies of correspondence on this item should be sent to PP&L so that we may remain cognizant of the progress of the program to resolve the staff's concerns on this requirement.

### 18.1.62 PLANT-SPECIFIC CALCULATIONS TO SHOW COMPLIANCE WITH 10CFR PART 50.46 (II.K.3.31)

#### 18.1.62.1 Statement of Requirement

Plant-specific calculations using NRC-approved models for small-break loss-of-coolant accidents (LOCAs) as described in item II.K.3.30 to show compliance with 10 CFR 50.46 should be submitted for NRC approval by all licensees.

#### 18.1.62.2 Interpretation

None required.

#### 18.1.62.3 Statement of Response

Plant specific calculations will be performed, if required, following NRC approval of LOCA model revisions required by item II.K.3.30 (see Subsection 18.1.61).

18.1.63 EVALUATION OF ANTICIPATED TRANSIENTS WITH SINGLE  
FAILURE TO VERIFY NO FUEL CLADDING FAILURE (II.K.3.44)

18.1.63.1 Statement of Requirement

For anticipated transients combined with the worst single failure an assuming proper operator actions, licensees should demonstrate that the core remains covered or provide analysis to show that no significant fuel damage results from core uncover. Transients which result in a stuck-open relief valve should be included in this category.

All applicants for operating license should submit documentation four months prior to the expected issuance of the staff safety evaluation report for an operating license or four months prior to the listed implementation date, whichever is later.

18.1.63.2 Interpretation

None required.

18.1.63.3 Statement of Response

The BWR Owners' Group has prepared a generic response to this requirement. The report was transmitted to D. G. Eisenhut by a letter from D. B. Waters on December 29, 1980. This response contains an evaluation of analyses performed to demonstrate the core remains covered or no significant fuel damage occurs from an anticipated transient with a single failure. PP&L has reviewed this response and finds it is applicable to Susquehanna SES. The report concludes that the core remains covered for all evaluated combinations of anticipated transients and single failures.

18.1.64 EVALUATION OF DEPRESSURIZATION WITH OTHER THAN THE  
AUTOMATIC DEPRESSURIZATION SYSTEM (II.K.3.45)

18.1.64.1 Statement of Requirement

Analyses to support depressurization modes other than full actuation of the automatic depressurization system (ADS) (e.g., early blowdown with one or two safety relief valves) should be provided. Slower depressurization would reduce the possibility of exceeding vessel integrity limits by rapid cooldown.

All applicants for operating license should submit documentation four months prior to the expected issuance of the staff safety evaluation report for an operating license or four months prior to the listed implementation date, whichever is later.

18.1.64.2 Interpretation

None required.

18.1.64.3 Statement of Response

The BWR Owners' Group submitted a generic response to this requirement. This response was transmitted by letter to D. G. Eisenhut from D. B. Waters on December 29, 1980. PP&L has reviewed this response and find it applicable to Susquehanna SES. The report concludes that no improvement can be gained by a slower depressurization and actually could be detrimental to core cooling. Therefore no additional action is necessary in response to this requirement.

18.1.65 MICHELSON CONCERNS (II.K.3.46)

18.1.65.1 Statement of Requirement

A number of concerns related to decay heat removal following a very small break LOCA and other related items were questioned by Mr. C. Michelson of the Tennessee Valley Authority. These concerns were identified for PWRs. GE was requested to evaluate these concerns as they apply to BWRs and to assess the importance of natural circulation during a small-break LOCA in BWRs.

18.1.65.2 Interpretation

None required.

18.1.65.3 Statement of Response

The General Electric Company has responded to the questions posed by Mr. Michelson. This response was sent by letter from R. H. Buchholz to D. F. Ross on February 21, 1980. These responses are

applicable to Susquehanna SES and no further response is necessary.

18.1.66 EMERGENCY PREPAREDNESS-SHORT TERM (III.A.1.1)

No requirement stated in NUREG 0737. Refer to Subsection 18.2.38 which contains the response to the requirement in NUREG 0694.

18.1.67 UPGRADE EMERGENCY SUPPORT FACILITIES (III.A.1.2)

18.1.67.1 Statement of Requirement

A detailed statement of the requirement can be found in NUREG-0696. The implementation schedule was announced in Generic Letter 81-10 on February 18, 1981. This schedule is as follows: Design information for emergency response facilities should be provided in connection with the operating license review process. These facilities shall be operational by October 1, 1982 or prior to fuel load, whichever is later. Interim facilities, as described in NUREG-0694 shall be provided by fuel load.

18.1.67.2 Interpretation

None required.

18.1.67.3 Statement of Response

The proposed method of responding to this requirement was submitted by a letter to B. J. Youngblood from N. W. Curtis on April 2, 1981 (PLA-704). Details on the emergency response facilities are presented in Appendix I of the Emergency Plan.

18.1.68 EMERGENCY PREPAREDNESS-LONG TERM (III.A.2)

18.1.68.1 Statement of Requirement

Each nuclear facility shall upgrade its emergency plans to provide reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency. Specific criteria to meet this requirement is delineated in

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NUREG-0654 (FEMA-REP-1), "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparation in Support of Nuclear Power Plants."

NUREG-0654, Revision 1; NUREG-0696, "Functional Criteria for Emergency Response Facilities;" and the amendments to 10 CFR Part 50 and Appendix E to 10 CFR Part 50 regarding emergency preparedness, provide more detailed criteria for emergency plans, design, and functional criteria for emergency response facilities and establishes firm dates for submission of upgraded emergency plans for installation of prompt notification systems. These revised criteria and rules supersede previous Commission guidance for the upgrading of emergency preparedness at nuclear power facilities.

Requirements of the new emergency-preparedness rules under paragraphs 50.47 and 50.54 and the revised Appendix E to Part 50 taken together with NUREG-0654 Revision 1 and NUREG-0696, when approved for issuance, go beyond the previous requirements for meteorological programs. To provide a realistic time frame for implementation, a staged schedule has been established with compensating actions provided for interim measures.

Specific milestones have been developed and are presented below.

Milestones are numbered and tagged with the following code; a-date, b-activity, c-minimum acceptance criteria. They are as follows:

- (1) a. Fuel load.
  - b. Submittal of radiological emergency response plans.
  - c. A description of the plan to include elements of NUREG-0654, Revision 1, Appendix 2.
- (2) a. Fuel load.
  - b. Submittal of implementing procedures.
  - c. Methods, systems, and equipment to assess and monitor actual or potential offsite consequences of a radiological emergency condition shall be provided.
- (3) a. Fuel load.
  - b. Implementation of radiological emergency response plans.



- c. Four elements of Appendix 2 to NUREG-0654 with the exception of the Class B model of element 3, or

Alternative to item (3) requiring compensating actions:

A meteorological measurements program which is consistent with the existing technical specifications as the the baseline or an element 1 program and/or element 2 system of Appendix 2 to NUREG-0654, or two independent element 2 systems shall provide the basic meteorological parameters (wind direction and speed and an indicator or atmospheric stability) on display in the control room. An operable dose calculational methodology (DCM) shall be in use in the control room and at appropriate emergency response facilities.

The following compensating actions shall be taken by the licensee for this alternative:

- (i) If only element 1 or element 2 is in use:
  - o The licensee (the person who will be responsible for making offsite dose projections) shall check communications with the cognizant National Weather Service (NWS) first order station and NWS forecasting station on a monthly basis to ensure that routine meteorological observations and forecasts can be accessed.
  - o The licensee shall calibrate the meteorological measurements program at a frequency no less than quarterly and identify a readily available source of meteorological data (characteristic of site conditions) to which they can gain access during calibration periods.
  - o During conditions of measurements system unavailability, an alternate source of meteorological data which is characteristic of site conditions shall be identified to which the licensee can gain access.
  - o The licensee shall maintain a site inspection schedule for evaluation of the meteorological measurements program at a frequency no less than weekly.
  - o It shall be a reportable occurrence if the meteorological data unavailability exceeds

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the goals outline in Proposed Revision 1 to Regulatory Guide 1.23 on a quarterly basis.

- (ii) The portion of the DCM relating to the transport and diffusion of gaseous effluents shall be consistent with the characteristics of the Class A model outlined in element 3 of Appendix 2 to NUREG-0654.
- (iii) Direct telephone access to the individual responsible for making offsite dose projections (Appendix E to 10 CFR Part 50 (IV) (A) (4)) shall be available to the NRC in the event of a radiological emergency. Procedures for establishing contact and identification of contact individuals shall be provided as part of the implementing procedures.

This alternative shall not be exercised after July 1, 1982. Further, by July 1, 1981, a functional description of the upgraded programs (four elements) and schedule for installation and full operational capability shall be provided (see milestones 4 and 5).

- (4) a. March 1, 1982.
- b. Installation of Emergency Response Facility hardware and software.
- c. Four elements of Appendix 2 to NUREG-0654, with exception of the Class B model of element 3.
- (5) a. July 1, 1982.
- b. Full operational capability of milestone 4.
- c. The Class A model (designed to be used out to the plume exposure EPZ) may be used in lieu of Class B model out to the ingestion EPZ. Compensating actions to be taken for extending the application of the Class A model out to the ingestion EPZ include access to supplemental information (meso and synoptic scale) to apply judgment regarding intermediate and long-range transport estimates. The distribution of meteorological information by the licensee should be as described in Table 18.1-13 by July 1, 1982.
- (6) a. July 1, 1982 or at the time of the completion of milestone 5, whichever is sooner.
- b. Mandatory review of the DCM by the licensee.

- c. Any DCM in use should be reviewed to ensure consistency with the operational Class A model. Thus, actions recommended during the initial phases of a radiological emergency would be consistent with those after the TSC and EOF are activated.
- (7)
- a. September 1, 1982.
  - b. Description of the Class B model provided to the NRC.
  - c. Documentation of the technical bases and justification for selection of the type Class B model by the licensee with a discussion of the site-specific attributes.
- (8)
- a. June 1, 1983.
  - b. Full operational capability of the Class B model.
  - c. Class B model of element 3 of Appendix 2 to NUREG-0654, Revision 1

Applicants for an operating license shall meet at least milestones 1, 2, and 3 prior to the issuance of an operating license. Subsequent milestones shall be met by the same dates indicated for operating reactors. For the alternative to milestone 3, the meteorological measurements program shall be consistent with the NUREG-75/087, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," Section 2.3.3 program as the baseline or element 1 and/or element 2 systems.

#### 18.1.68.2 Interpretation.

None required.

#### 18.1.68.3 Statement of Response

Milestones 1, 2 and 3 are being addressed as a part of the short term emergency preparedness requirement III.A.1.1. Refer to Subsection 18.2.38 for response. Responses to these and other milestones will be incorporated into Appendix I of the Emergency Plan.

18.1.69 INTEGRITY OF SYSTEMS OUTSIDE CONTAINMENT LIKELY TO CONTAIN  
RADIOACTIVE MATERIAL (III.D.1.1)

18.1.69.1 Statement of Requirement

Applicants shall implement a program to reduce leakage from systems outside containment that would or could contain highly radioactive fluids during a serious transient or accident to as-low-as-practical levels. This program shall include the following:

- (1) Immediate leak reduction.
  - (a) Implement all practical leak reduction measures for all systems that could carry radioactive fluid outside of containment.
  - (b) Measure actual leakage rates with system in operation and report them to the NRC.
- (2) Continuing Leak Reduction--Establish and implement a program of preventive maintenance to reduce leakage to as-low-as-practical levels. This program shall include periodic integrated leak tests at intervals not to exceed each refueling cycle.

This requirement shall be implemented prior to issuance of a full-power license.

Applicants shall provide a summary description, together with initial leak-test results, of their program to reduce leakage from systems outside containment that would or could contain primary coolant or other highly radioactive fluids or gases during or following a serious transient or accident. Applicants shall submit this information at least four months prior to fuel load.

18.1.69.2 Interpretation

None required.

18.1.69.3 Statement of Response

1. Program summary description:

# SSES-FSAR

1.1 The following systems will be leak tested (the frequency is indicated in ( ) after each item):

- |    |                                |             |
|----|--------------------------------|-------------|
| A. | Residual Heat Removal          | (18 months) |
| B. | Reactor Core Isolation Cooling | "           |
| C. | Core Spray                     | "           |
| D. | High Pressure Core Injection   | "           |
| E. | Scram Discharge                | "           |
| F. | Reactor Water Clean-up*        | "           |
| G. | Standby Gas Treatment          | "           |
| H. | Containment Air Monitors       | "           |
| I. | Post Accident Sampling         | "           |

Initial leak-test results will be available when the first measurements are made, prior to completion of the startup test program.

\* NOTE: The RWCU system will not have significant post-accident radioactivity because the suction is isolated by containment isolation signals (refer to Table 18.1-10). However, this system may conceivably be used in some post-accident scenarios, and will therefore be leak tested.

1.2 The following systems contain radioactive material but are excluded from our program (justification for exclusion follows each item):

- A. Main Steam - identified by NEDO-24782 as not to be regarded as containing highly radioactive fluid following an accident.
- B. Feed water - same justification as A.
- C. Main Steam Line Drain - this system is isolated following a LOCA.
- D. Reactor Water Sample - this system will not be used following an accident, a separate post-accident sampling station is being developed in response to item II.B.3.
- E. Recirculation Pump Seal Water (from CRD pumps) - lines are protected by check valves and an excess flow check valves.
- F. Floor & Equipment Drains - this system isolated following a LOCA and will not be used following an accident.

- G. Suppression Pool Clean-up & Drain - same justification as F.

1.3 Method for obtaining actual leak rates

- A. Water - leakage will be collected in a graduated measuring device and timed to determine GPM leak rate. Implementing procedures will establish criteria for initiation of leak rate quantification.
- B. Steam - an estimate of the size of the leak will be made (i.e. equivalent pipe diameter steam flow). Flowrate will be determined using standard Handbook data. This will be converted to a GPM flowrate using the specific volume of the steam at the given conditions.

2. The two gaseous systems are tested as follows:

- A. Standby Gas Treatment System - This system is subject to filter efficiency testing in accordance with the Technical Specifications which includes "DOP" and refrigerant injection.
- B. Containment Air Monitors - These are tested while the system is under normal running conditions by checking each mechanical joint with liquid soap.

3. Consideration was given to the Standby Gas system regarding the incident at North Anna Unit 1 in 1979. The standby gas piping and duct work from the containment to the filters are gas tight and do not include any pressure relief devices which would allow gases to escape to the Reactor Building. The piping is rated at 150 psig and the duct work is HVM-GS-G (High Velocity Medium Pressure - Galvanized Steel - Gas tight).

In light of the above, the actions stated in 1.1.G and 2.A have resulted.

4. Technical Specifications will incorporate an acceptance criteria of 5 GPM total leakage rate for the systems listed in 1.1 with the exception of:

- A. Standby Gas Treatment - which is limited to the acceptance criteria stated in Technical Specifications Subsection 4.6.5.3 and

- B. The containment air monitors - which has an acceptance criteria of zero leakage as determined by a liquid soap test.

The program is implemented.

18.1.70 INPLANT IODINE RADIATION MONITORING (III.D.3.3)

18.1.70.1 Statement of Requirement

Each licensee shall provide equipment and associated training and procedures for accurately determining the airborne iodine concentration in areas within the facility where plant personnel may be present during an accident.

Effective monitoring of increasing iodine levels in the buildings under accident conditions must include the use of portable instruments using sample media that will collect iodine selectively over xenon (e.g., silver zeolite) for the following reasons:

- (1) The physical size of the auxiliary and/or fuel handling building precludes locating stationary monitoring instrumentation at all areas where airborne iodine concentration data might be required.
- (2) Unanticipated isolated "hot spots" may occur in locations where no stationary monitoring instrumentation is located.
- (3) Unexpectedly high background radiation levels near stationary monitoring instrumentation after an accident may interfere with filter radiation readings.
- (4) The time required to retrieve samples after an accident may result in high personnel exposures if these filters are located in high-dose-rate areas.

After January 1, 1981, each applicant and licensee shall have the capability to remove the sampling cartridge to a low-background, low-contamination area for further analysis. Normally, counting rooms in auxiliary buildings will not have sufficiently low backgrounds for such analyses following an accident. In the low background area, the sample should first be purged of any entrapped noble gases using nitrogen gas or clean air free of noble gases. The licensee shall have the capability to measure accurately the iodine concentrations present on these samples under accident conditions. There should be sufficient samplers to sample all vital areas.

18.1.70.2 Interpretation

PP&L is in basic agreement with the technical discussion as outlined in this requirement. It should be noted that Susquehanna SES is a BWR and does not possess an auxiliary building. Consequently, it is premature to suggest that our counting facilities within the control structure will be inadequate to effectively count air samples. Additionally, purging of the air sample cartridges may not be necessary if an effective collection media is used for radioiodine air sampling.

18.1.70.3 Statement of Response

PP&L will meet the requirements defined in this item. To summarize the program, three (3) particulate and gaseous continuous air monitoring systems are provided for air sampling plant areas where personnel may be present during accident conditions. The systems are cart mounted for ease of relocation.

Grap samples are obtained using the equipment specified in Subsection 12.5.2.6.3. During accident conditions silver zeolite cartridges will be used for radioiodine analysis in conjunction with two (2) Eberline stabilized assay meters (SAM-2) or equivalent.

Air samples are evaluated as specified in Subsection 12.5.3.5.5. In addition to initial training provided for Health Physics personnel, periodic drills are conducted in accordance with the Susquehanna Emergency Plan Section 8.1.2 (See Amendment 25 of Operating License Application).

Analysis of iodine cartridges will be performed in a low background, low contamination area. During accident conditions, preliminary analysis will be performed by onsite radiation monitoring teams in the counting room, if accessible using a SAM-2. Final analysis will be performed in the emergency off-site facility where appropriate sensitivity can be achieved. Prior to analysis, cartridges will be purged using station service air or bottled nitrogen, if necessary to reduce noble gas interference.

All equipment and procedures will be available for use by fuel load.



18.1.71 CONTROL ROOM HABITABILITY REQUIREMENTS (III.D.3.4)

18.1.71.1 Statement of Requirement

Licensees shall assure that control room operators will be adequately protected against the effects of accidental release of toxic and radioactive gases and that the nuclear power plant can be safely operated or shut down under design basis accident conditions (Criterion 19, "Control Room," of Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50).

All licensees must make a submittal to the NRC regardless of whether or not they met the criteria of the Standard Review Plans (SRP) sections listed below. The new clarification specifies that licensees that meet the criteria of the SRPs should provide the basis by referencing past submittals to the NRC and/or providing new or additional information to supplement past submittals.

18.1.71.1.1 Requirements for Licensees that Meet Criteria

All licensees with control rooms that meet the criteria of the following sections of the Standard Review Plan:

- 2.2.1-2.2.2 Identification of Potential Hazards in Site Vicinity
- 2.2.3 Evaluation of Potential Accidents;
- 6.4 Habitability Systems

shall report their findings regarding the specific SRP sections as explained below. The following documents should be used for guidance:

- (a) Regulatory Guide 1.78, "Assumptions for Evaluating the Habitability of Regulatory Power Plant Control Room During a Postulated Hazardous Chemical Release";
- (b) Regulatory Guide 1.95, "Protection of Nuclear Power Plant Control Room Operators Against an Accident Chlorine Release"; and,
- (c) K. G. Murphy and K. M. Campe, "Nuclear Power Plant Control Room Ventilation System Design for Meeting General Design Criterion 19," 13th AEC Air Cleaning Conference, August 1974.

Licensees shall submit the results of their findings as well as the basis for those findings by January 1, 1981. In providing the basis for the habitability finding, licensees may reference their past submittals. Licensees should, however, ensure that

these submittals reflect the current facility design and that the information requested in Attachment 1 of NUREG 0737 is provided.

18.1.71.1.2 Requirements for Licensees that Do Not  
Meet Criteria

All licensees with control rooms that do not meet the criteria of the above-listed references, Standard Review Plans, Regulatory Guides, and other references shall perform the evaluations and identify appropriate modifications, as discussed below.

Each licensee submittal shall include the results of the analyses of control room concentrations from postulated accidental release of toxic gases and control room operator radiation exposures from airborne radioactive material and direct radiation resulting from design-basis accidents. The toxic gas accident analysis should be performed for all potential hazardous chemical releases occurring either on the site or within 5 miles of the plant-site boundary. Regulatory Guide 1.78 lists the chemicals most commonly encountered in the evaluation of control room habitability but is not all inclusive.

The design-basis-accident (DBA) radiation source term should be for the loss-of-coolant accident LOCA containment leakage and engineered safety feature (ESF) leakage contribution outside containment as described in Appendix A and B of Standard Review Plan Chapter 15.6.5. In addition, boiling-water reactor (BWR) facility evaluations should add any leakage from the main steam isolation valves (MSIV) (i.e., valve-stem leakage, valve seat leakage, main steam isolation valve leakage control system release) to the containment leakage and ESF leakage following a LOCA. This should not be construed as altering the staff recommendations in Section D of Regulatory Guide 1.96 (Rev. 2) regarding MSIV leakage-control systems. Other DBAs should be reviewed to determine whether they might constitute a more-severe control-room hazard than the LOCA.

In addition to the accident-analysis results, which should either identify the possible need for control-room modifications or provide assurance that the habitability systems will operate under all postulated conditions to permit the control-room operators to remain in the control room to take appropriate actions required by General Design Criterion 19, the licensee should submit sufficient information needed for an independent evaluation of the adequacy of the habitability systems. Attachment 1 of NUREG 0737, item III.D.3.4 lists the information that should be provided along with the licensee's evaluation.

18.1.71.1.3 Documentation and Implementation

Applicants for operating licenses shall submit their responses prior to issuance of a full-power license. Modifications needed for compliance with the control-room habitability requirements specified in this letter should be identified, and a schedule for completion of the modifications should be provided. Implementation of such modifications should be started without awaiting the results of the staff review. Additional needed modifications, if any, identified by the staff during its review will be specified to licensees.

18.1.71.2 Interpretation

None required.

18.1.71.3 Statement of Response

The control room HVAC system layout and functional design includes protection of the control room from radioactive and toxic gases. Subsection 6.4 provides a complete description of this system and compliance to habitability requirements. Refer to Subsection 6.4 for the response to this requirement.

The revision to Subsection 6.4 will incorporate the following commitments:

1. Supplies of food and potable water adequate to support 10 people for 5 days will be maintained onsite.
2. Supplies of potassium iodide adequate to protect 30 people will be maintained onsite.
3. Self contained breathing apparatus and bottled air supply adequate to support 5 operations personnel for 6 hours will be maintained onsite. For those situations requiring use of SCBA's within the control room HVAC envelope, the Technical Support Center activities will be relocated to the Emergency Operations Facility.

REFERENCES

SSES-PSAR

- 18.1-1 Letter, D. G. Eisenhower (NRC) to S. T. Rogers (BWR Owners' Group), regarding Emergency Procedure Guidelines, October 21, 1980
- 18.1-2 U.S. Nuclear Regulatory Commission, "TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations" USNRC Report NUREG-0578, July 1979, Recommendation 2.1.6b.
- 18.1-3 U.S. Nuclear Regulatory Commission, "NRC Action Plan Developed as a Result of the TMI-2 Accident," USNRC-0660, Vols. 1 and 2, May 1980, Section II.B.2.
- 18.1-4 Letter from D. G. Eisenhower (NRC) to All Licensees of Operating Plants and Applicants for Operating Licenses and Holders of Construction Permits, Subject: Preliminary Clarification of TMI Action Plan Requirements, dated September 5, 1980.
- 18.1-5 U.S. Nuclear Regulatory Commission, "Clarification of TMI Action Plan Requirements," USNRC Report NUREG-0737, November, 1980, Item II.B.2.
- 18.1-6 U.S. Nuclear Regulatory Commission, IE Bulletin No. 79-01B, "Environmental Qualification of Class IE Equipment", January 14, 1980.
- 18.1-7 U.S. Nuclear Regulatory Commission, "Interim Staff Position on Environmental Qualification Report NUREG-0588, December 1979.
- 18.1-8 USNRC Standard Review Plan 6.4, "Habitability Systems", Revision 1.
- 18.1-9 USNRC Regulatory Guide 1.3, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss of Coolant Accident for Boiling Water Reactors", Revision 2, June 1974.
- 18.1-10 USNRC Regulatory Guide 1.7, "Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident," Revision 2, November 1978.
- 18.1-11 USNRC Regulatory Guide 1.89, "Qualification of Class IE Equipment for Nuclear Power Plants," November 1974.
- 18.1-12 Code of Federal Regulations, 10CFR Part 50, Appendix A, GDC 19, Revised as of January 1, 1980.
- 18.1-13 C. Michael Lederer, et al., Table of Isotopes, Lawrence Radiation Laboratory, University of California, March 1968.

SSES-FSAR

- 18.1-14 D. S. Duncan and A. B. Spear, GRACE I - An IBM 704-709 Program Design for Computing Gamma Ray Attenuation and Heating in Reactor Shields, Atomics International, (June 1959) .
- 18.1-15 D. S. Duncan and A. B. Spear, GRACE II - An IBM 709 Program for Computing Gamma Ray Attenuation and Heating in Cylindrical and Spherical Geometries, Atomics International, November 1959.
- 18.1-16 Memorandum of Telephone Conversation, S. Ford of LIS to N. Anderson of NRC's Lessons Learned Task Force, Subject: TMI Requirements at SHNPP, April 9, 1980.
- 18.1-17 USNRC Regional Meeting Minutes, Region I, Subject: TMI Review Requirements at SHNPP, April 9, 1980.
- 18.1-18 USNRC Regional Meeting Minutes, Region IV and V, Subject: TMI Review Requirements, 9/26/79.



TABLE 18.1-10 (Page 8 of 9)REMARKS

- (1) Essential or non-essential classification basis codes are described in Table 18.1-11.
- (2) Automatic actuation signal codes are described in Table 18.1-12.
- (3) Where the control power source is left blank, the control power source is the same as the valve motor power source.
- (4) E32-1F001B automatic actuation signal is dependent upon action of MSIV's, time, RPV pressure. The valve is normally closed and interlocked when RPV pressure is greater than 35 psig. The valve cannot be opened unless the inboard MSIV is closed. Information presented is representative of that for main steam lines B, C and D.
- (5) Automatic signal code UA for B21-1F028A, et al (Reactor Vessel pressure) prevents operation of condenser low vacuum bypass.
- (6) Reactor recirculation system sample line valves B31-1F019 and 1F020 receive high radiation signals for isolation but since the line does not provide an open path from the containment to the environs, the radiation isolation signal may be considered a diverse signal in accordance with Standard Review Plan 6.2.4. This judgement is based on our definition of an open path as a direct, untreated path to the outside environment.
- (7) Hand Switch Nos. are from the P&ID rather than referenced Schematic Diagram.
- (8) Automatic actuation signals for E11-1F015A and B: codes UB and Z are isolation signals; codes G and T are initiation signals.
- (9) Automatic actuation signals for E11-1F050A and B, and 1F122A, B: code Z is an isolation signal; no initiation signals.
- (10) Either valve opening (or closing) will energize a common open (close) status light. HS-11314 controls both valves. Typical for HV-11345 and HV-11346.
- (11) Closes on "LOCA" signal but can be reopened after 60 minutes. Valves can be administratively reopened if the high drywell pressure is due to plant heat up or loss of drywell cooler.
- (12) Closes on "LOCA" signal but can be reopened after 10 minutes.

FOR THE P&ID FOR PASS  
SEE FIGURE 9.3-9a

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UNITS 1 AND 2  
FINAL SAFETY ANALYSIS REPORT

PASS P&ID

FIGURE 18.1-11





FOR LOCATION OF PASS  
SEE FIGURE 1.2-20

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LOCATION OF PASS -  
EL. 719'-1"

FIGURE 18.1-12

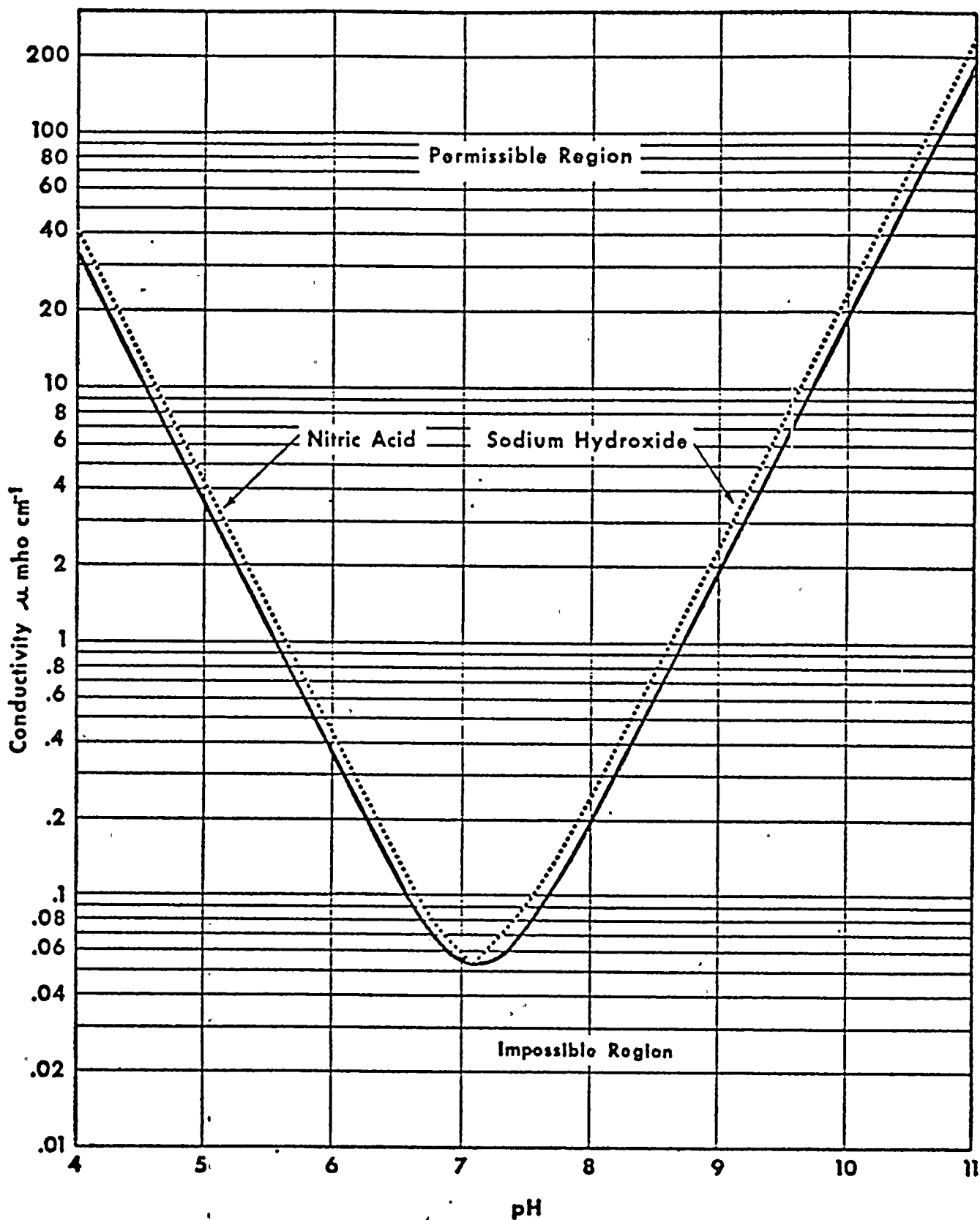
FOR THE LOCATION OF PASS  
SEE FIGURE 1.2-4

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LOCATION OF PASS -  
EL. 729'

FIGURE 18.1-13

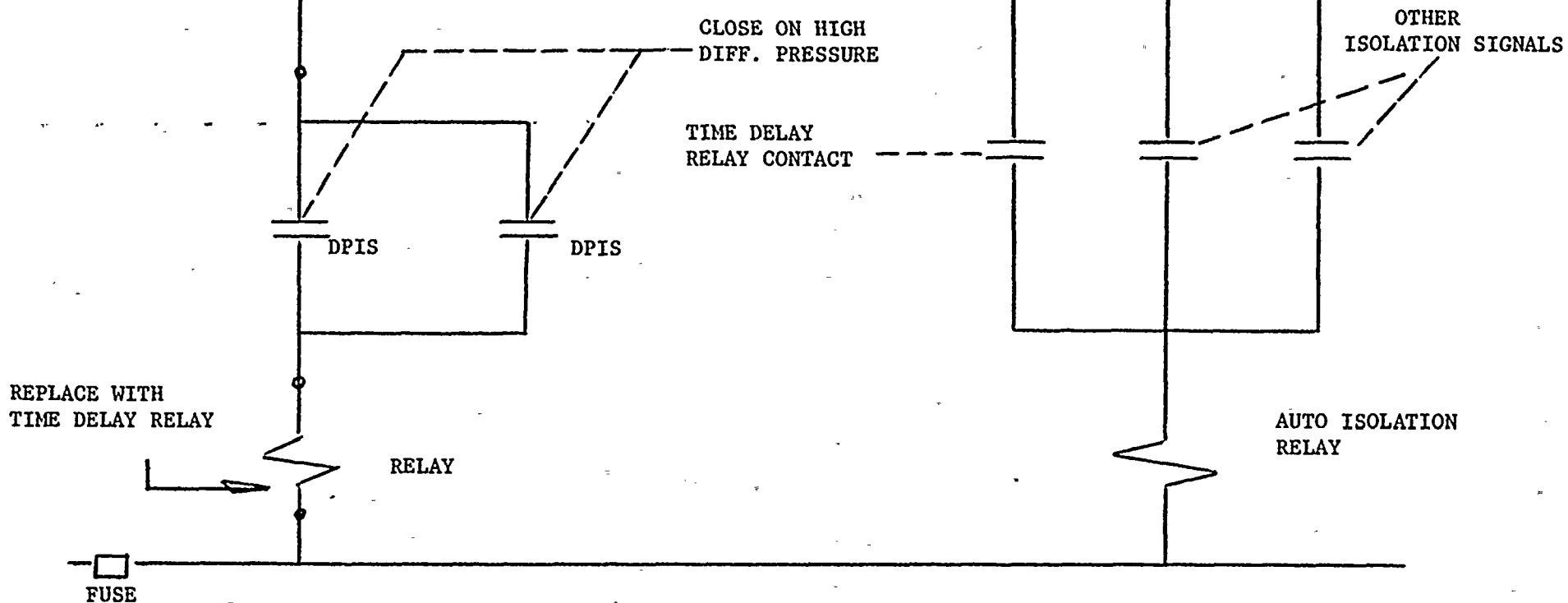


Rev. 27, 10/81

**SUSQUEHANNA STEAM ELECTRIC STATION  
UNITS 1 AND 2  
FINAL SAFETY ANALYSIS REPORT**

SPECIFIC CONDUCTANCE AND pH  
of AQUEOUS SOLUTIONS AT  
25°C

FIGURE 18.1-14



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TYPICAL HPCI/RCIC STEAMLIN  
BREAK DETECTION LOGIC

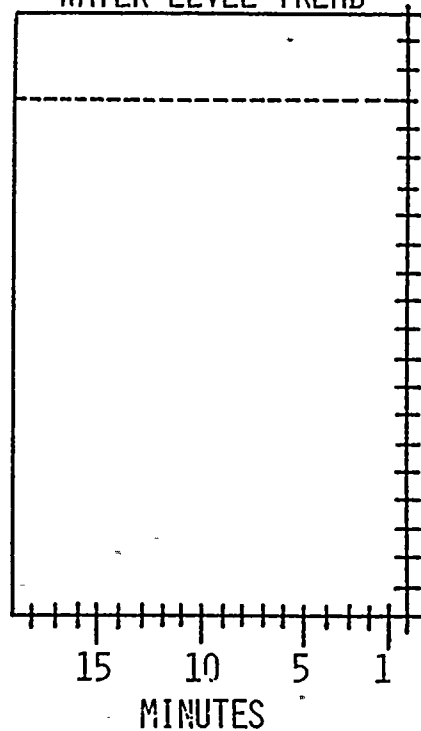
FIGURE 18.1-15



INCHES RELATIVE TO  
INSTRUMENT 0

RXPRESSXXXXPSIG

WATER LEVEL TREND



160  
140  
120  
100  
80  
60  
40  
20  
0  
-20  
-40  
-60  
-80  
-100  
-120  
-140  
-160

STEAM  
DRYER

STEAM  
SEPARATOR

— UPPER SHROUD —  
TOP OF ACTIVE FUEL

INCHES ABOVE VESSEL 0  
MAIN STEAM LINES  
658.5"

— WATER LEVEL —

SHUTDOWN RNG XXX IN  
UPSET RANGE XXX IN  
NAR RANGE A XX IN  
NAR RANGE B XX IN  
NAR RANGE C XX IN  
WIDE RANGE XXXX IN

527.5"

CORE SPRAY INLET  
484.5"

— FLOWS —

RHR LP A XXXXX GPM  
RHR LP B XXXXX GPM  
RCIC XXX GPM

377.5"  
366.3"

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UNITS 1 AND 2

FINAL SAFETY ANALYSIS REPORT

TYPICAL REACTOR

WATER LEVEL DISPLAY

FIGURE 18.1-16

18.2 RESPONSE TO REQUIREMENTS IN NUREG 0694

NUREG-0694 supersedes NUREG 0578. The clarifications given in the Vassallo letter on November 9, 1979 were used in the development of applicable responses.

18.2.1 SHIFT TECHNICAL ADVISOR (I.A.1.1)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.1 for response.

18.2.2 SHIFT SUPERVISOR ADMINISTRATIVE DUTIES (I.A.1.2)

18.2.2.1 Statement of Requirement

Review the administrative duties of the shift supervisor and delegate functions that detract from or are subordinate to the management responsibility for assuring safe operation of the plant to other personnel not on duty in the control room. This requirement shall be met before fuel load.

18.2.2.2 Interpretation

None required.

18.2.2.3 Statement of Response

PP&L has restructured the operations organization and redefined responsibilities of shift personnel to relieve the shift supervisor of routine administrative duties.

Administrative procedure AD-QA-300, "Conduct of Operations," implements this policy.

The Vice President - Nuclear Operations will review and approve assignment of the Shift Supervisor's responsibilities to ensure proper delegation of duties that detract from or are subordinate to the safe operation of the plant.



18.2.3 SHIFT MANNING (I.A.1.3)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.3 for response.

18.2.4 IMMEDIATE UPGRADING OF OPERATOR AND SENIOR OPERATOR  
TRAINING AND QUALIFICATION (I.A.2.1)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.4 for response.

18.2.5 REVISE SCOPE AND CRITERIA FOR LICENSING  
EXAMINATIONS (I.A.3.1)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.6 for response.

18.2.6 EVALUATION OF ORGANIZATION AND MANAGEMENT IMPROVEMENTS  
OF NEAR-TERM OPERATING LICENSE APPLICANTS (I.B.1.2)

18.2.6.1 Statement of Requirement

The licensee organization shall comply with the findings and requirements generated in an interoffice NRC review of licensee organization and management. The review will be based on an NRC document entitled Draft Criteria for Utility Management and Technical Competence. The first draft of this document was dated February 25, 1980, but the document is changing with use and experience in ongoing reviews. These draft criteria address the organization, resources, training, and qualifications of plant staff, and management (both onsite and offsite) for routine operations and the resources and activities (both onsite and offsite) for accident conditions. This requirement shall be met prior to fuel load.

18.2.6.2 Interpretation

None required.

18.2.6.3 Statement of Response

A review of organization and management has been completed in accordance with draft NUREG 0731, "Guidelines for Utility Management Structure and Technical Competence." An NRC audit of the organization was conducted March 2-6, 1981.

18.2.7 SHORT TERM ACCIDENT ANALYSIS AND PROCEDURE  
REVISION (I.C.1)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.8 for response.

18.2.8 SHIFT RELIEF AND TURNOVER PROCEDURES (I.C.2)

18.2.8.1 Statement of Requirement

Revise plant procedures for shift relief and turnover to require signed checklists and logs to assure that the operating staff (including auxiliary operators and maintenance personnel) possess adequate knowledge of critical plant parameter status, system status, availability and alignment. This requirement shall be met prior to fuel load.

18.2.8.2 Interpretation

None required.

18.2.8.3 Statement of Response

Administrative procedure AD-QA-300, "Conduct of Operations," discusses operations personnel responsibilities at shift turnover. Administrative procedure AD-QA-303, "Shift Routine," specifically defines the shift turnover process.

18.2.9 SHIFT SUPERVISOR RESPONSIBILITIES (I.C.3)

18.2.9.1 Statement of Requirement

Issue a corporate management directive that clearly establishes the command duties of the shift supervisor and emphasizes the primary management responsibility for safe operation of the plant. Revise plant procedures to clearly define the duties, responsibilities and authority of the shift supervisor and the control room operators. This requirement shall be met prior to fuel load.

18.2.9.2 Interpretation

None required.

18.2.9.3 Statement of Response

The Senior Vice President - Nuclear shall issue prior to fuel load a statement of policy establishing the primary responsibility of the Shift Supervisor for safe operation of the plant under all conditions and establishing authority to direct actions leading to safe operation in the Shift Supervisor. The Senior Vice President - Nuclear shall re-issue this statement of policy on an annual basis.

Administrative Procedure AD-QA-300, "Conduct of Operations," sets forth the plant policy on Shift Supervisor duties.

Training for Shift Supervisors includes plant Administrative Procedures, and will encompass AD-QA-300.

18.2.10 CONTROL ROOM ACCESS (I.C.4)

18.2.10.1 Statement of Requirement

Revise plant procedures to limit access to the control room to those individuals responsible for the direct operation of the plant, technical advisors, specified NRC personnel, and to establish a clear line of authority, responsibility, and succession in the control room. This requirement shall be met prior to fuel load.

18.2.10.2 Interpretation

None required.

18.2.10.3 Statement of Response

Administrative procedure AD-QA-300, "Conduct of Operations," provides the authority and instructions for control room access control.

18.2.11 PROCEDURES FOR FEEDBACK OF OPERATING EXPERIENCE TO  
PLANT STAFF (I.C.5)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.12 for response.

18.2.12 NSSS VENDOR REVIEW OF PROCEDURES (I.C.7)

18.2.12.1 Statement of Requirement

Obtain nuclear steam supply system vendor review of low-power testing procedures to further verify their adequacy. This requirement shall be met prior to fuel load.

Obtain NSSS vendor review of power-ascension test and emergency procedures to further verify their adequacy. This requirement must be met before issuance of a full-power license.

18.2.12.2 Interpretation

None required.

18.2.12.3 Statement of Response

The General Electric Company, through its site startup organization, will review all startup tests associated with NSSS systems and will review all Emergency Operating procedures that were submitted to NRC in response to item I.C.8 (see Subsection 18.2.13). The startup tests encompass the low power testing and

the power ascension testing phases. These reviews will be completed prior to fuel load.

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

18.2.13.1 Statement of Requirement

Correct emergency procedures, as necessary, based on the NRC audit of selected plant emergency operating procedures (e.g., small-break LOCA, loss of feedwater, restart of engineered safety features following a loss of AC power or, steam-line break).

18.2.13.2 Interpretation

None required.

18.2.13.3 Statement of Response

Emergency procedures based on those guidelines have been developed and are currently in trial use on the Susquehanna SES Simulator. These procedures have been reviewed by the NRC. Final versions which incorporated NRC comments were submitted in a letter from N. W. Curtis to B. J. Youngblood on May 15, 1981. (PLA-791).

18.2.14 CONTROL ROOM DESIGN (I.D.1)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.16 for response.

18.2.15 TRAINING DURING LOW POWER TESTING (I.G.I)

18.2.15.1 Statement of Requirement

Define and commit to a special low-power testing program approved by NRC to be conducted at power levels no greater than 5 percent for the purposes of providing meaningful technical information beyond that obtained in the normal startup test program and to

provide supplemental training. This requirement shall be met before fuel load.

Supplement operator training by completing the special low-power test program. Tests may be observed by other shifts or repeated on other shifts to provide training to the operators. This requirement shall be met before issuance of a full-power license.

#### 18.2.15.2 Interpretation

None required.

#### 18.2.15.3 Statement of Response

The BWR Owners' Group has prepared a generic response to this requirement. This was transmitted to D. G. Eisenhut by a letter from D. B. Waters on February 4, 1981. PP&L concurs with this response. This generic approach outlines an extensive testing program designed to contribute to and provide for extensive training opportunities during the start-up program. The objectives of this program are to provide:

1. A plant that has been thoroughly tested.
2. An operating staff that has received the maximum experience and in-plant training to safely operate it.
3. Plant procedures that have been reviewed and revised to provide the staff with proven directions and controls.

Susquehanna's Operator Training Program has been in progress since 1977 and is completing the final phases of training at this time. This program utilizes the Susquehanna Simulator located at the plant site and provides the operators with extensive training prior to actual operations in the plant itself. The Simulator is also used for procedure development and check out.

The Operator Training Program that is being developed for the Preoperational and Low Power Testing Program incorporates and builds on the extensive training already completed by the operations section. It will include the recommendation presented in the BWR Owners' Group position but goes beyond those recommendations by maximizing the use of the Susquehanna Simulator in preparing the operators for the start-up tests to be performed.

The objective of the Operator Training Program is to provide each operator with the maximum learning experience during the start-up

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phase. In order to achieve this objective, a comprehensive training program is being developed that utilizes the many training opportunities that are available during this period and ensures actual testing. This program covers the period from Preoperational/Acceptance Testing through the Power Test Program on Unit I. To support this amount of training the operations section which is staffed for six sections has reorganized into four sections. This reorganization provided the benefit of allowing more operators off shift to attend formal training as well as provide more operating experience for each shift team. Every effort is being made to keep the shifts intact and provide training that promotes the "Shift Team" concept.

The training program being developed covers the areas of activities listed below but recognizes the overlap that exists between some of the areas.

- I. Preoperational/Acceptance Testing
- II. Cold Functional Testing
- III. Hot Functional Testing
- IV. Start-up Tests
- V. Additional Testing

Each area of testing has activities that lend itself to operator training. The major ones are outlined in Table 18.2-1. The training program provides a vehicle to identify activities that have a significant benefit for training, documents this training, and ensures that all shift crews receive equal experience opportunities. The program also attempts to schedule repeats of certain evolutions that are considered critical and cannot be routinely performed at a later time. The training program will identify areas of testing/training that while not required by start-up program would have additional training benefit. This testing/training could then be scheduled into the testing program as additional testing.

Finally this program will develop the basis for the In-Plant Drill Program. This comprehensive approach to testing/training more than adequately satisfies the requirements of NUREG 0737.

Susquehanna SES will conduct a test which simulates a loss of AC power condition for the reactor and containment systems. The purpose of this test will be to obtain data relative to the performance of these systems under the imposed condition of no AC power available for mitigation of transient effects. Several key factors associated with performance of this test include:

- (a) No blocking of low pressure ECCS functions will be provided. Transient conditions imposed by the test are not expected to initiate these systems on low water level. Adequate data will be obtained prior to injection of low pressure ECCS flow on a high drywell pressure signal in conjunction with a

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confirmatory low reactor pressure signal. If initiation points are reached earlier in the test, this would represent a criteria for test termination and the ECCS would be allowed to function as designed.

- (b) In most if not all cases, Limiting Conditions for Operation will not be violated. It is possible that as test plans are developed, certain LCO's will be identified as inhibiting test performance. However, for LCO's that are being approached as a result of transient effects during the test, this will represent criteria for test termination to insure plant safety.
- (c) Loss of power to plant instrumentation will not be simulated. To accomplish the major goal of this test, instrumentation will be maintained functional for proper data collection. This constraint is also considered necessary to insure plant safety. Training of licensed operators in response to the loss of all station AC condition will be provided at PP&L's plant specific simulator. This will provide the opportunity to experience the instrumentation blackout condition without placing the plant in jeopardy.
- (d) Plant AC busses will remain energized, the emergency diesel generators will be available or operating, and breakers to safeguards equipment will not be racked out. These precautions are considered necessary for plant safety.
- (e) Test termination criteria will be established for parameters such as reactor vessel temperature limits, containment pressure and temperature, reactor vessel level, suppression pool temperature, HPCI and RCIC room temperatures, and CRD temperatures.

The test will be conducted at a convenient point during the first fuel cycle, with the constraint that adequate decay heat exists to provide a valid test. Several options are being explored for test initiation (e.g., turbine trip from 5% power following load reduction, turbine trip from 85% power, etc.) It is our position that the method finally selected will have little bearing on the test, since plant performance during the initial state of such transients is adequately tested in startup tests.

The commitments previously made in response to Item I.G.1 for additional testing and training will be fulfilled, as it is felt that valuable input will be obtained for the loss of AC power test.

The test may cause certain conditions which are inconsistent with NRC requirements. We therefore will provide the NRC with the



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test plan and pertinent documents for review and approval. Performance of this test is contingent upon a favorable safety evaluation and obtaining appropriate commission approvals.

Since the NRC has indicated that they may not require a test at Susquehanna SES if results from a test at another plant resolve their concerns, PP&L's commitment is contingent on a continuing NRC requirement for this test.

### 18.2.16 REACTOR COOLANT SYSTEM VENTS (II.B.1)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.19 for response.

### 18.2.17 PLANT SHIELDING (II.B.2)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.20 for response.

### 18.2.18 POSTACCIDENT SAMPLING (II.B.3)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.21 for response.

### 18.2.19 TRAINING FOR MITIGATING CORE DAMAGE (II.B.4)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.22 for response.

### 18.2.20 RELIEF AND SAFETY VALVE TEST REQUIREMENTS (II.D.1)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.23 for response.

### 18.2.21 RELIEF AND SAFETY VALVE POSITION INDICATION (II.D.3)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.24 for response.

18.2.22 CONTAINMENT-ISOLATION DEPENDABILITY (II.E.4.2)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.29 for response.

18.2.23 ADDITIONAL ACCIDENT MONITORING INSTRUMENTATION (II.F.1)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.30 for response.

18.2.24 INADEQUATE CORE COOLING INSTRUMENTS (II.F.2)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.31 for response.

18.2.25 ASSURANCE OF PROPER ESF FUNCTIONING (II.K.1.5)

18.2.25.1 Statement of Requirement

Review all valve positions, positioning requirements, positive controls and related test and maintenance procedures to assure proper ESF functioning. This requirement shall be met by fuel load.

18.2.25.2 Interpretation

None required.

18.2.25.3 Statement of Response

Operating and surveillance procedures are currently being developed. Writing the procedures to reflect ESF requirement is a key objective of procedure originators. Additionally, these procedures will receive a review (independent of the originator) to provide further assurance that the procedure is technically correct and provides for accomplishment of procedural objectives (including maintenance of proper safety function).

18.2.26 SAFETY RELATED SYSTEM OPERABILITY STATUS (II.K.1.10)

18.2.26.1 Statement of Requirement

Review and modify, as required, procedures for removing safety-related systems from service (and restoring to service) to assure operability status is known. This requirement shall be met by fuel load.

18.2.26.2 Interpretation

None required.

18.2.26.3 Statement of Response

Surveillance testing will be controlled by administrative procedure AD-QA-422. This procedure, which is currently being drafted, will require that surveillance implementing procedures contain a review of redundant component operability prior to removing the system to be tested from service, (if such removal is required by the test), a review of proper system status prior to return of the tested system to service, and provide for notification to Operations of the need for system status changes.

Administrative Procedure AD-QA-306, "System Status and Equipment Control," (see Subsection 18.1.13.3) establishes control of system status as an operations responsibility and will provide the same reviews described above during normal operations and maintenance activities. Maintenance procedures will only cover activities while systems and components are removed from service, the Operations section will actually accomplish changes in system status as controlled by the described Instruction.

18.2.27 TRIP PRESSURIZER LOW-LEVEL COINCIDENT SIGNAL BISTABLES (II.K.1.17)

This requirement is not applicable to Susquehanna SES.

18.2.28 OPERATOR TRAINING FOR PROMPT MANUAL REACTOR TRIP (II.K.1.20)

This requirement is not applicable to Susquehanna SES.

18.2.29 AUTOMATIC SAFETY GRADE ANTICIPATORY TRIP (II.K.1.21)

This requirement is not applicable to Susquehanna SES.

18.2.30 AUXILIARY HEAT REMOVAL SYSTEMS OPERATING PROCEDURES  
(II.K.1.22)

18.2.30.1 Statement of Requirement

Describe the automatic and manual actions necessary for proper functioning of the auxiliary heat removal systems that are used when the main feedwater system is not operable. This requirement shall be met by fuel load.

18.2.30.2 Interpretation

None required.

18.2.30.3 Statement of Response

A generic response to this requirement was provided by General Electric in NEDO-24708, "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors," (August, 1979) and supplement I. A plant specific description is provided below.

If the main feedwater system is not operable, a reactor scram will be automatically initiated when reactor water level falls to Level 3 (540.5 inches above vessel bottom or 178.2 inches above the top of the active fuel). The operator can then remote manually initiate the reactor core isolation cooling system from the main control room, or the system will be automatically initiated when reactor water level decreases to Level 2 (489.5 inches above vessel bottom or 127.2 inches above the top of the active fuel) due to boil-off. At this point, the high pressure coolant injection system will also automatically start supplying makeup water to the vessel. These systems will continue automatic injection until the reactor water level reaches Level 8 (581.5 inches above vessel bottom or 219.2 inches above top of the active fuel), at which time the high pressure coolant injection turbine and the reactor core isolation cooling turbine are automatically tripped.

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In the nonaccident case, the reactor core isolation cooling system is utilized to furnish subsequent makeup water to the reactor pressure vessel. The Reactor core isolation cooling system and the high pressure coolant injection system will restart automatically when the level falls to Level 2 (The reactor core isolation cooling system is being modified to automatically restart, see subsection 18.1.50). No manual actions are required for these systems to restart. Reactor vessel pressure is regulated by the automatic or remote manual operation of the main steam relief valves which blow down to the suppression pool.

To remove decay heat, assuming that the main condenser is not available, the steam condensing mode of the residual heat removal system is initiated by the operator. This involves remote manual alignment of the residual heat removal system valves. If the steam condensing mode is unavailable for any reason, the main steam relief valves can be manually actuated from the control room. Remote manual alignment of the residual heat removal system into the suppression pool cooling mode is then required for suppression pool heat removal. Makeup water to the vessel is still supplied by the reactor core isolation cooling system under manual control.

For the accident case with the reactor pressure vessel at high pressure, the high pressure coolant injection system is utilized to automatically provide the required makeup flow. No manual operations are required since the high pressure coolant injection system will cycle on and off automatically as water level reaches Level 2 and Level 8, respectively. If the high pressure coolant injection system fails under these conditions, the operator can manually depressurize the reactor vessel using the automatic depressurization system to permit the low pressure emergency core cooling systems to provide makeup coolant. Automatic depressurization will occur if all of the following signals are present: high drywell pressure 1.69 psig, Level 3 water level permissive, Level 1 water level (398.5 inches above vessel bottom or 36.2 inches above the top of the active fuel), pressure in at least one low pressure injection system and the run out of a 120 second timer (set at 105 seconds) which starts with the coincidence of the other four signals.

### 18.2.31 REACTOR LEVEL INSTRUMENTATION (II.K.1.23)

#### 18.2.31.1 Statement of Requirement

For boiling water reactors, describe all uses and types of reactor vessel level indication for both automatic and manual initiation of safety systems. Describe other instrumentation

that might give the operator the same information on plant status. This requirement shall be met before fuel load.

18.2.31.2 Interpretation

None required.

18.2.31.3 Statement of Response

The response to this requirement was provided by General Electric in NEDO-24708, Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors," (August 1979) and Supplement I.

18.2.32 COMMISSION ORDERS ON BABCOCK AND WILCOX PLANTS (II.K.2)

These requirements are not applicable to Susquehanna SES.

18.2.33 REPORTING REQUIREMENTS FOR SAFETY/RELIEF VALVE FAILURES OR CHALLENGES (II.K.3.3)

18.2.33.1 Statement of Requirement

Assure that any failure of a PORV or safety valve to close will be reported to the NRC promptly. All challenges to the PORVs or safety valves should be documented in the annual report. This requirement shall be met before issuance of a full-power license.

18.2.33.2 Interpretation

Prompt reporting to the NRC consists of notification within 24 hours by telephone with confirmation by telegraph, mailgram or facsimile transmission, followed by a written report within 14 days.

The annual operating report has been supplanted by more detailed Monthly Operating Reports. Documentation required to be included in the annual report will be supplied in Monthly Operating Reports.

18.2.33.3 Statement of Response

Subsection 6.9.1.8 of the Technical Specifications will be changed to require prompt reporting with written followup for failures of main steamline Safety/Relief Valves to reclose after actuation. Procedure(s) for reporting of Reportable Occurrences are being written addressing Technical Specification requirements.

| Subsection 6.9.1.6 of the Technical Specifications currently requires documentation of all challenges to main steamline Safety/Relief Valves to be included in the Monthly Reactor Operating Report. Procedure(s) for preparation and submittal of these monthly reports are being written incorporating this reporting requirement.

18.2.34 PROPORTIONAL-INTEGRAL DERIVATIVE CONTROLLER (II.K.3.9)

This requirement is not applicable to Susquehanna SES.

18.2.35 ANTICIPATORY REACTOR TRIP MODIFICATION (II.K.3.10)

This requirement is not applicable to Susquehanna SES.

18.2.36 POWER OPERATED RELIEF VALVE FAILURE RATE (II.K.3.11)

This requirement is not applicable to Susquehanna SES.

18.2.37 ANTICIPATORY REACTOR TRIP ON TURBINE TRIP (II.K.3.12)

This requirement is not applicable to Susquehanna SES.

18.2.38 EMERGENCY PREPAREDNESS-SHORT TERM (III.A.1.1)

18.2.38.1 Statement of Requirement

Comply with Appendix E, "Emergency Facilities," to 10 CFR Part 50, Regulatory Guide 1.101, "Emergency Planning for Nuclear Power Plants," and for the offsite plans, meet essential elements of

TABLE 18.2-1 (Continued)

2. Conduct preselected start-up tests on the simulator prior to the actual test in the plant.
3. Feedback of data/response to the Nuclear Training Department to update the simulator & materials.
4. Provide each shift with training on testing that they did not perform.

V. Additional Testing

A group of supplemental tests will be developed, to be performed during the Preoperational Test Program, which will provide meaningful technical information in addition to established tests programs. The following procedures will be written or revised to incorporate the supplemental tests as developed by the BWR Owners' Group. The FSAR will be revised as appropriate.

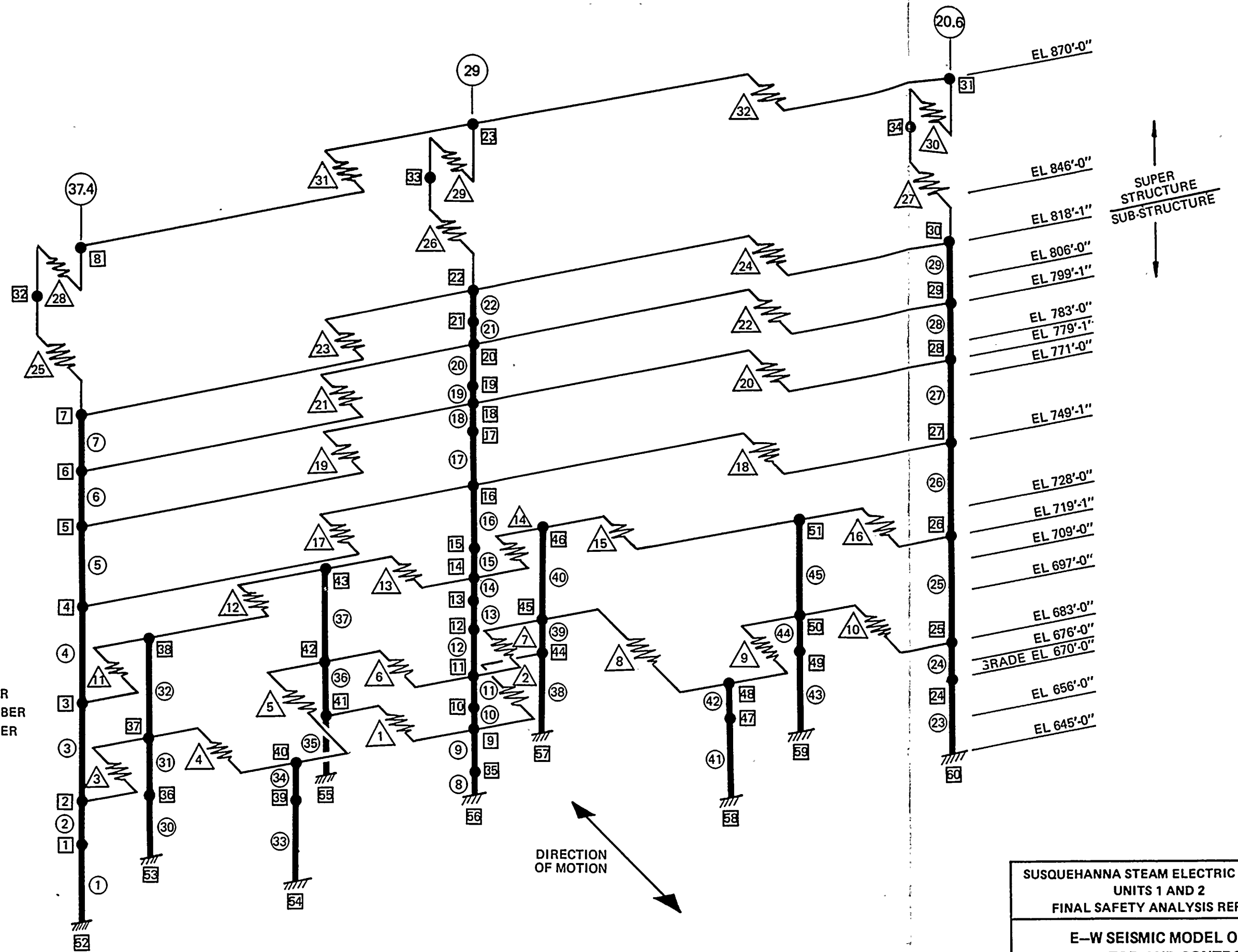
1. TP 2.14 will be revised to incorporate the "Integrated Reactor Pressure Vessel Level Instrument Test."
2. P59.2 will be revised to incorporate the "Integrated Containment Pressure Instrumentation Test."
3. New Technical Procedures (TP's) will be written to incorporate three RCIC System Tests.
  - a. Start-up of the RCIC system after a loss of alternating current (AC) power to the system.
  - b. Operation of the RCIC system with a sustained loss of AC power to the system.
  - c. Operation of the RCIC system to verify direct current power separation.

A new test procedure will be written to perform a station blackout test during the first cycle as described in subsection 18.2.15.





LEGEND  
 ● MASS POINT  
 □ JOINT NUMBER  
 ○ MEMBER NUMBER  
 △ SPRING NUMBER

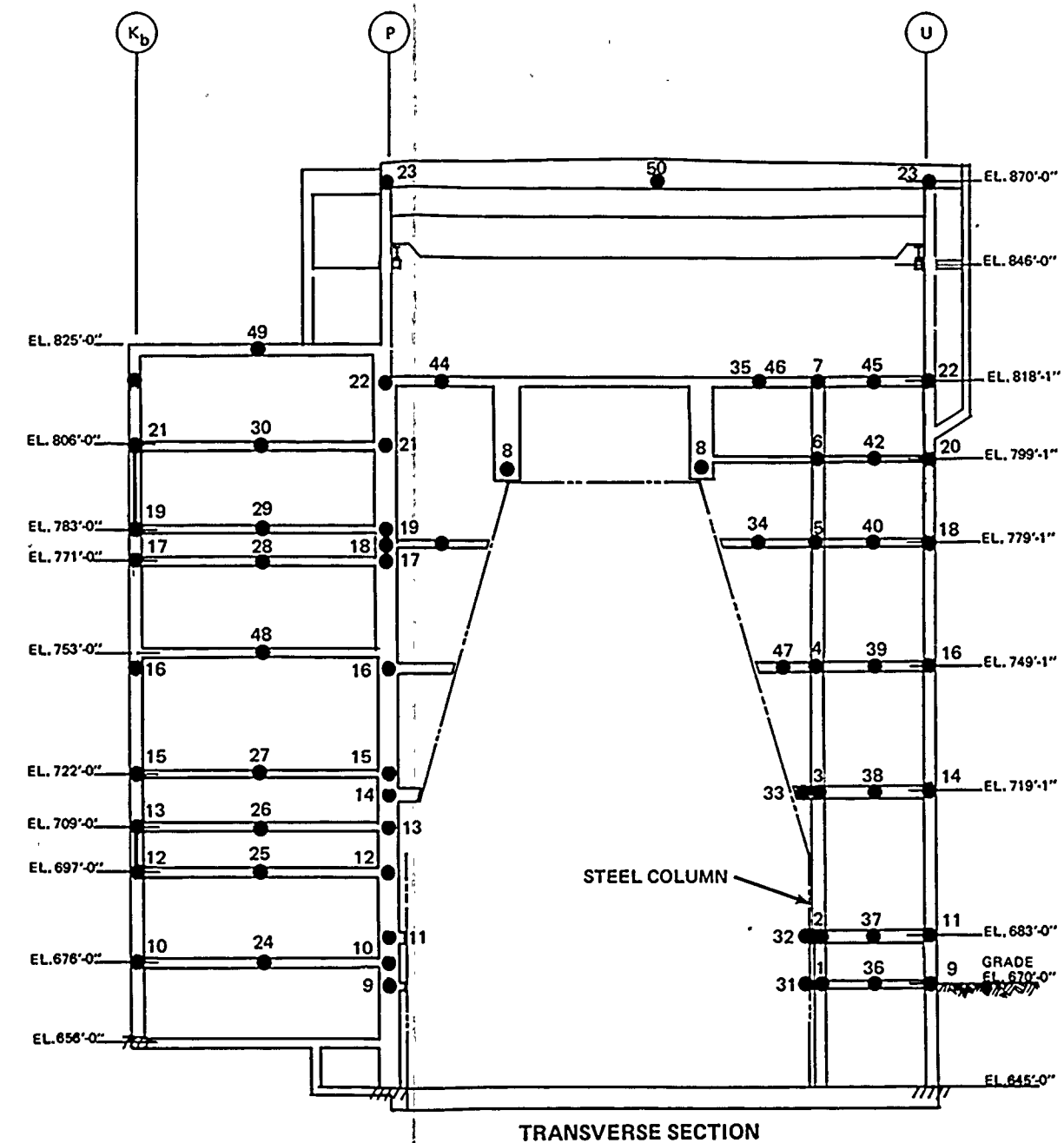
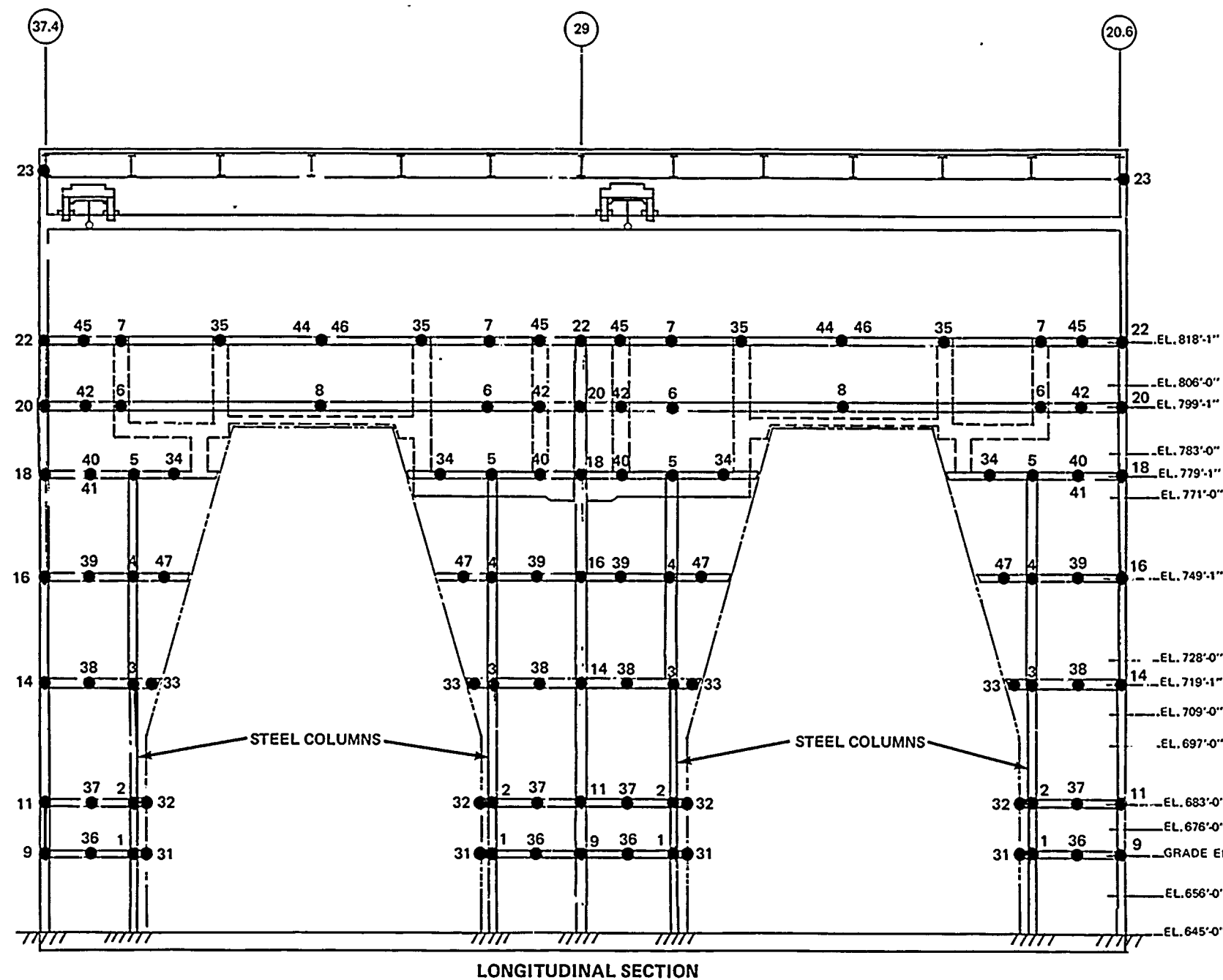


SUSQUEHANNA STEAM ELECTRIC STATION  
 UNITS 1 AND 2  
 FINAL SAFETY ANALYSIS REPORT

E-W SEISMIC MODEL OF  
 REACTOR AND CONTROL  
 BUILDING

FIGURE 3.7b-9



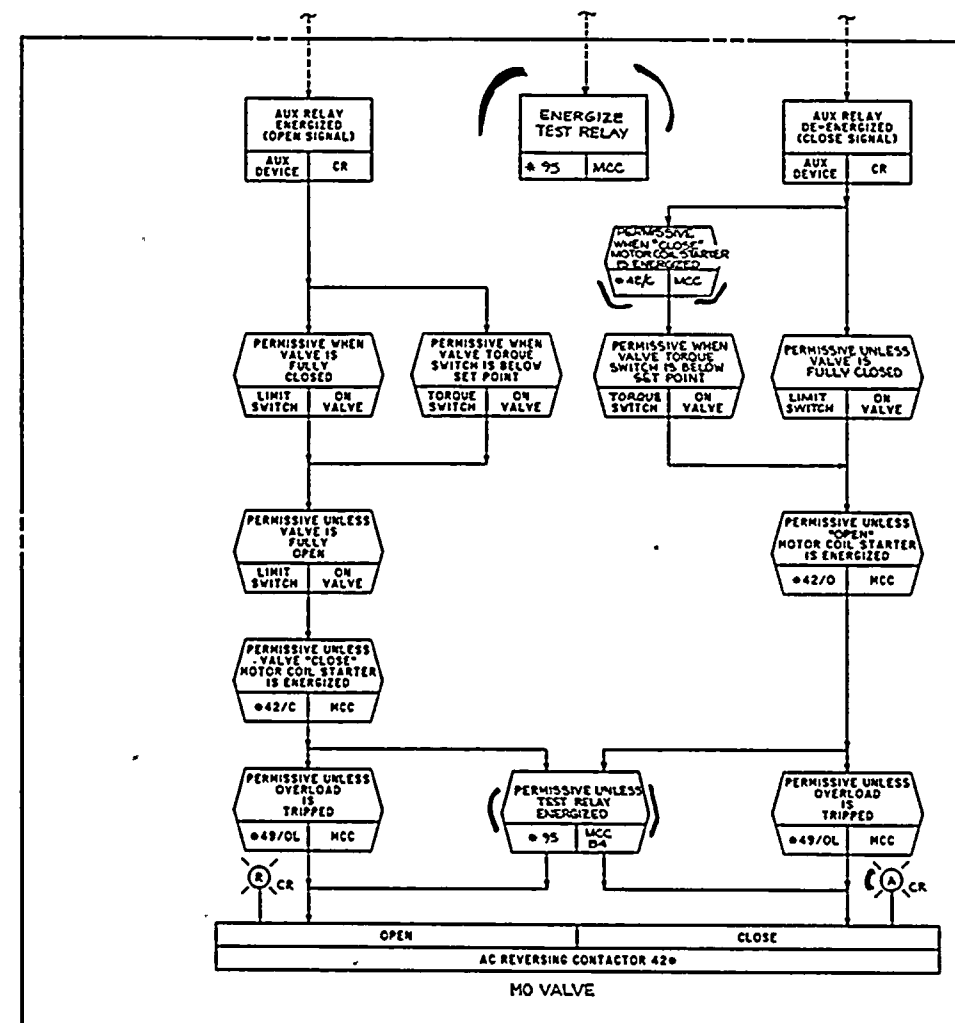


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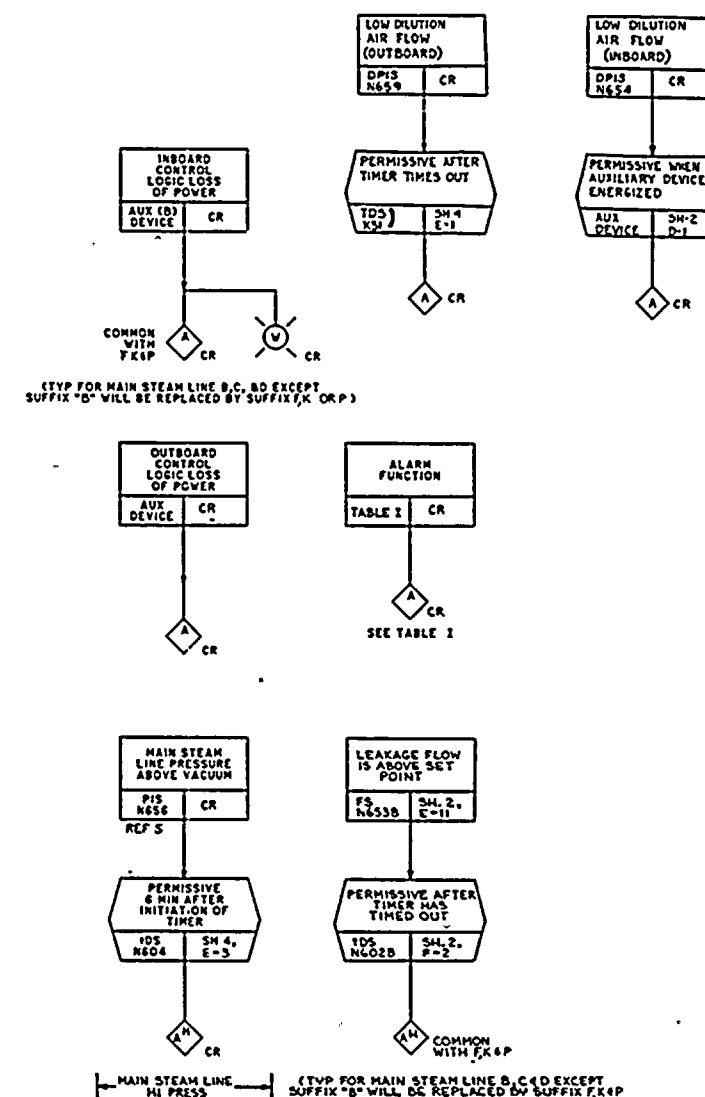
CORRELATION OF VERTICAL  
SEISMIC MODEL MASSPOINTS TO  
THE PHYSICAL STRUCTURE

FIGURE 3.7b-13





DETAIL I



NUCLEAR SAFETY RELATED

NOTES:

1. POWER SUPPLY FOR ALL EQUIPMENT IN THIS SYSTEM TO BE "AC SAFEGUARD POWER".
2. ALL DEVICES ARE E32- UNLESS OTHERWISE SPECIFIED.

REFERENCE DOCUMENTS:

1. MSIV LEAKAGE CONTROL ELEM DIAG-----E32-1050
2. LOGIC SYMBOLS-----E32-1050
3. MSIV LEAKAGE CONTROL P&ID-----E32-1010
4. MSIV LEAKAGE CONTROL SYS. DESIGN SPEC.-----E32-1010
5. MSIV LEAKAGE CONTROL I/O-----E32-1050

LEGEND:

- = SWITCH GEAR DEVICE #1 ANSI SPEC. C37.2
- = MATCH LETTER
- = ZONE
- = SHEET NUMBER
- = MATCH CIRCLE

TABLE 2	
ALARM	INITIATING DEVICE
1. INBOARD HEATER LOSS OF POWER	MCC AUX DEVICE
2. INBOARD (OUTBOARD) VALVE MCC LOSS OF POWER	MCC AUX DEVICE (MCC AUX DEVICE)
3.	
4. INBOARD SYSTEM STEAM LINE A, B, C & D VALVE IN TEST	AUX DEVICE, TEST SW
5. OUTBOARD SYSTEM VALVE IN TEST	AUX DEVICE
6. INBOARD (OUTBOARD) BLOWER MCC LOSS OF POWER	MCC AUX DEVICE (MCC AUX DEVICE)
7. INBOARD (OUTBOARD) SYSTEM MSIV LCS TROUBLE	
8.	

\* EACH STEAM LINE TO BE INDIVIDUALLY ANNUNCIATED OUTBOARD SYSTEM SHOWN IN ( )

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MSIV LEAKAGE  
CONTROL SYSTEM  
FCD

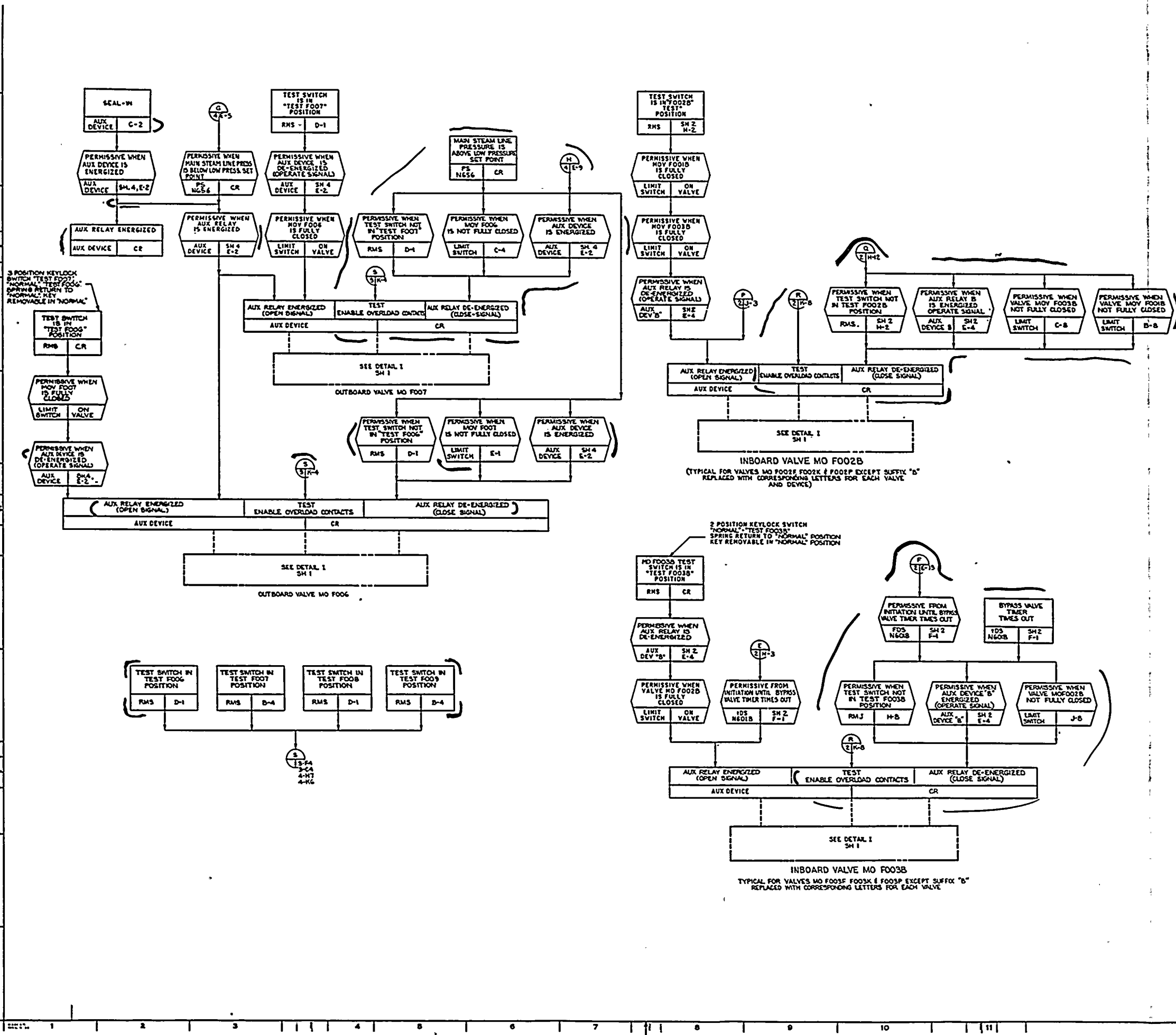
FIGURE 6.7-3 Sheet 1





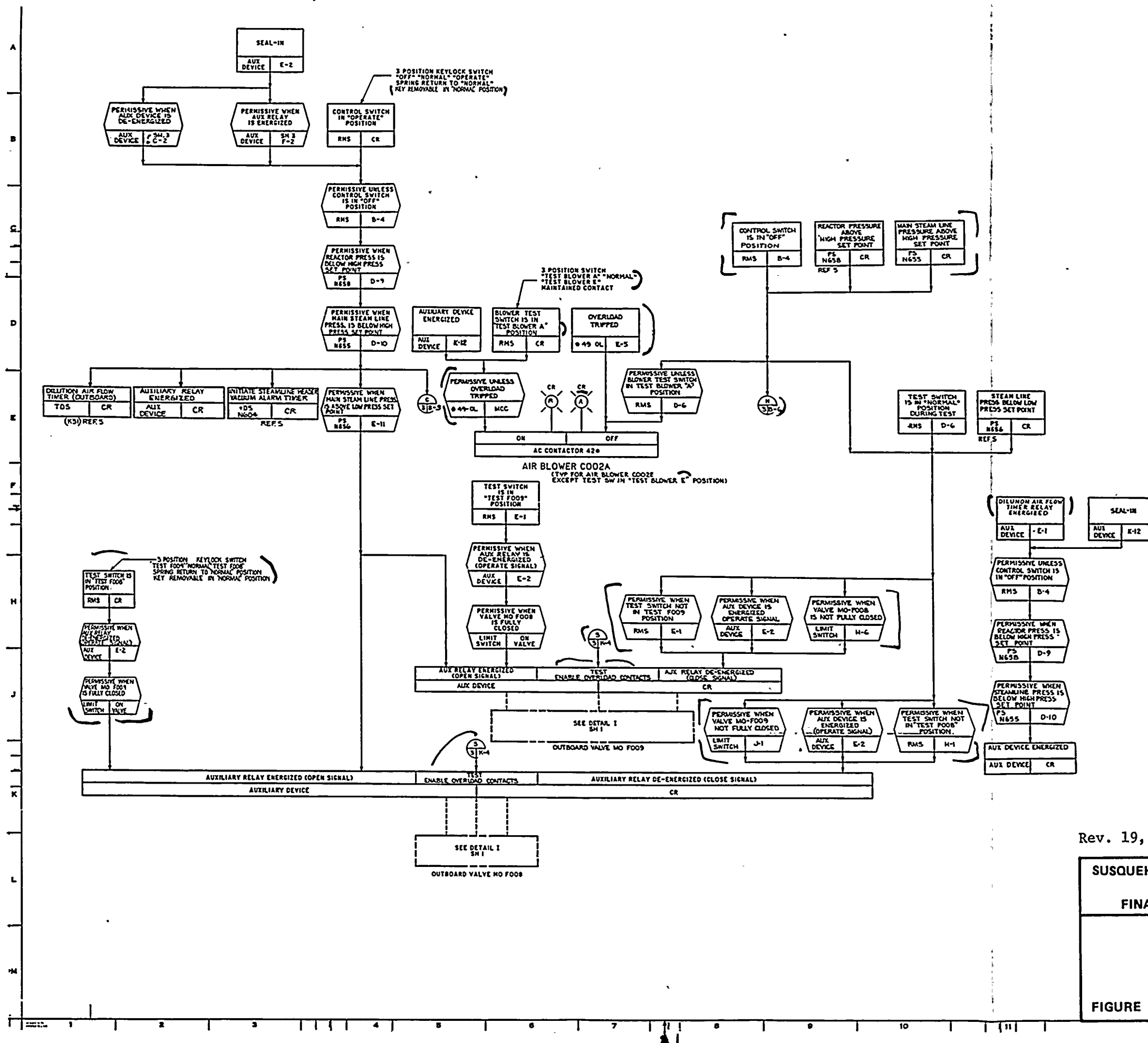






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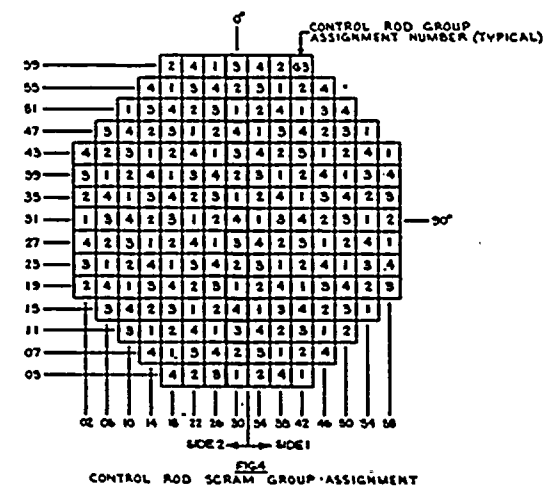
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MSIV LEAKAGE  
CONTROL SYSTEM

FIGURE 6.7-3 Sheet 4





1. DEVICES USED IN TRIP SYSTEM "A" ARE IDENTIFIED BY LETTERS A, C, E, G, ETC. THOSE USED IN TRIP SYSTEM "B" ARE B, D, F, H, ETC.
  2. ACTIVATION SHALL BE SUCH THAT ALTERNATE SCRAM SYSTEMS WILL BE ARRANGED SO THAT THE BUS CANNOT BE ENERGIZED FROM THE IN-SERVICE SET AND ALTERNATE SOURCE SYSTEMS IN CONJUNCTION.
  3. ONE RESET SWITCH SHALL BE USED FOR BOTH TRIP SYSTEMS A AND B AND SO THE RESET SWITCH AFTER THE ACTIVATION OF THE SWITCH WILL RESET ALL SCRAM PILOT VALVES (A AND B) IN GROUP 1 AND GROUP A AS WELL AS BACKUP SCRAM VALVE WITH DIFFERENT ACTIVATION OF THE SWITCH WILL RESET ALL SCRAM PILOT VALVES (A AND B) IN GROUP 2 AND GROUP B AS WELL AS BACKUP SCRAM VALVE WITH ACTIVATION OF THE SWITCH TO BOTH GROUPS AND GROUP B POSITIONS SHALL BE REQUIRED BEFORE THE ALLOW CRIM DRAIN AND VENT VALVES RESET. THE RESET SWITCH SHALL BE SO CONSTRUCTED THAT RPS CHANNELS A1 AND B2 ARE ACTIVELY SECURED BY CHANNELS A1 AND B2.
  4. MAIN STEAM LINE ISOLATION VALVE BE ISOLATED TRIP SHALL BE ARRANGED SO THAT ANY ONE STEAM LINE MAY BE ISOLATED (BY FULL CLOSURE OF ITS ISOLATION VALVES) AND THE ISOLATION VALVE FOR ANY OTHER STEAM LINE SHALL BE CLOSED (OR MORE THAN 10% WITHOUT CAUSING A TRIP OF EITHER TRIP SYSTEM A OR B.)
  5. LOGIC FOR THE "TURBINE STOP VALVE CLOSURE" TRIP SHALL BE ARRANGED SO THAT CLOSURE OF 3 OUT OF 4 STOP VALVES WILL CAUSE A RPS TRIP. PROVISION SHALL BE MADE FOR THE CLOSURE OF ONE STOP VALVE (FOR TEST PURPOSES) WITHOUT CAUSING A TRIP OF EITHER TRIP SYSTEM A OR B.
  6. TRIP CHANNELS FOR THE "TURBINE CONTROL VALVE FAST CLOSURE" TRIP SHALL BE DERIVED FROM THOSE EVENTS CAUSING FAST CLOSURE OF THE CONTROL VALVES.
  7. EQUIPMENT RATINGS ARE ESTIMATED AND PRELIMINARY. ACTUAL VALUES TO BE DETERMINED AT TIME OF EQUIPMENT PROCUREMENT.
  8. THIS SIGNAL/ALARM ASSEMBLY DE-ENERGIZES THE SCRAM CONTACTOR AND INITIATES A SCRAM WHEN BOTH A TRIP SYSTEM A CONTACTOR AND A TRIP SYSTEM B CONTACTOR ARE DE-ENERGIZED.
  9. EACH MAIN STEAM RADIATION MONITOR MONITORS ALL FOUR MAIN STEAM LINES.
  10. ALL EQUIPMENT INSTRUMENTS ARE PREFIXED BY SYSTEM NUMBER (C72) UNLESS OTHERWISE NOTED.
  11. FOR LOCATION AND IDENTIFICATION OF INSTRUMENTS SEE INSTRUMENT DATA SHEET LISTED IN THE PPE FOR EACH INSTRUMENT.
  12. SELENIUM TETRACON SUPPRESSORS (OR EQUIVALENT) SHALL BE USED TO SUPPRESS ELECTRICAL ARCS OF SCRAM SIGNALS.
  13. THIS DISCHARGE VOLUME HIGH LEVEL BYPASS SWITCH SHALL BE SO CONSTRUCTED THAT RPS CHANNELS A1 AND B1 ARE PHYSICALLY SEPARATED FROM CHANNELS A2 AND B2.
  14. FOR ANY SINGLE ROD GROUP, (E1 ETC.), A AND B SENSING CARRIES MAY BE RUN TOGETHER IN ONE CONTACT.
  15. THIS POWER SUPPLY SHALL NOT BE AN ESSENTIAL POWER SOURCE.
  16. LAMP FLUORE OP WHEN APPLICABLE, ONE SOLIDNO VOLTAGE SETS SIGNAL TO DE-ENERGIZE
- | REFERENCE SYMBOLS                                    | REF. NO. |
|--|----------|
| 1. REACTION PROTECTION SYS DESIGN SPEC               | 722-0410 |
| 2. PLANT REQUIREMENT TITING, GEN. & STEAM BYPASS SYS | 662-0620 |
| 3. PROCESS RADIATION MONITORING SYS REQ              | 722-1010 |
| 4. NEUTRON MONITORING SYS REQ                        | 534-1010 |
| 5. NEUTRON MONITORING SYS REQ                        | 534-1020 |
| 6. NUCLEAR BARRIER SYS REQ                           | 532-1010 |
| 7. CONTROL ROD DRIVE AND SYS REQ                     | 532-1010 |
| 8. CONTROL ROD DRIVE AND SYS REQ                     | 532-1010 |
| 9. NUCLEAR BARRIER SYS REQ                           | 532-1010 |
| 10. RESIDUAL HEAT INTRAP. SYS REQ                    | 532-1010 |
| 11. LOGIC SYMBOLS                                    | 664-1030 |
| 12. PIPING & INSTRUMENT SYMBOLS                      | 664-1010 |
| 13. PROCESS COMPUTER INPUT/OUTPUT MECHANISMS         | 532-0410 |
- 152520
- W = SWITCH/CLAMP RELEASE FUNCTION NUMBER AND SPEC. 722.2.

**FIG. 4**

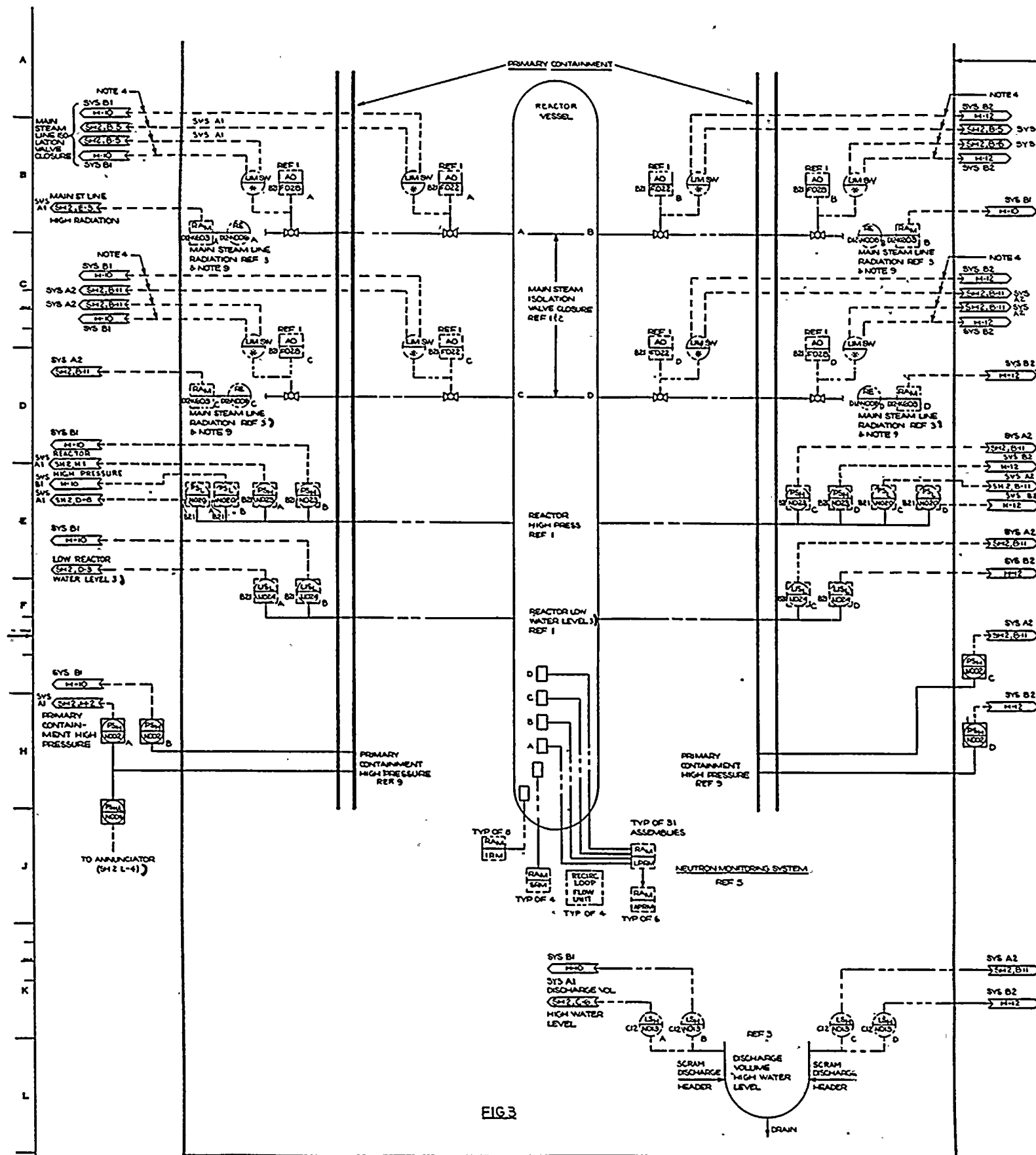
FIGURE 7.2-1 Sheet 1



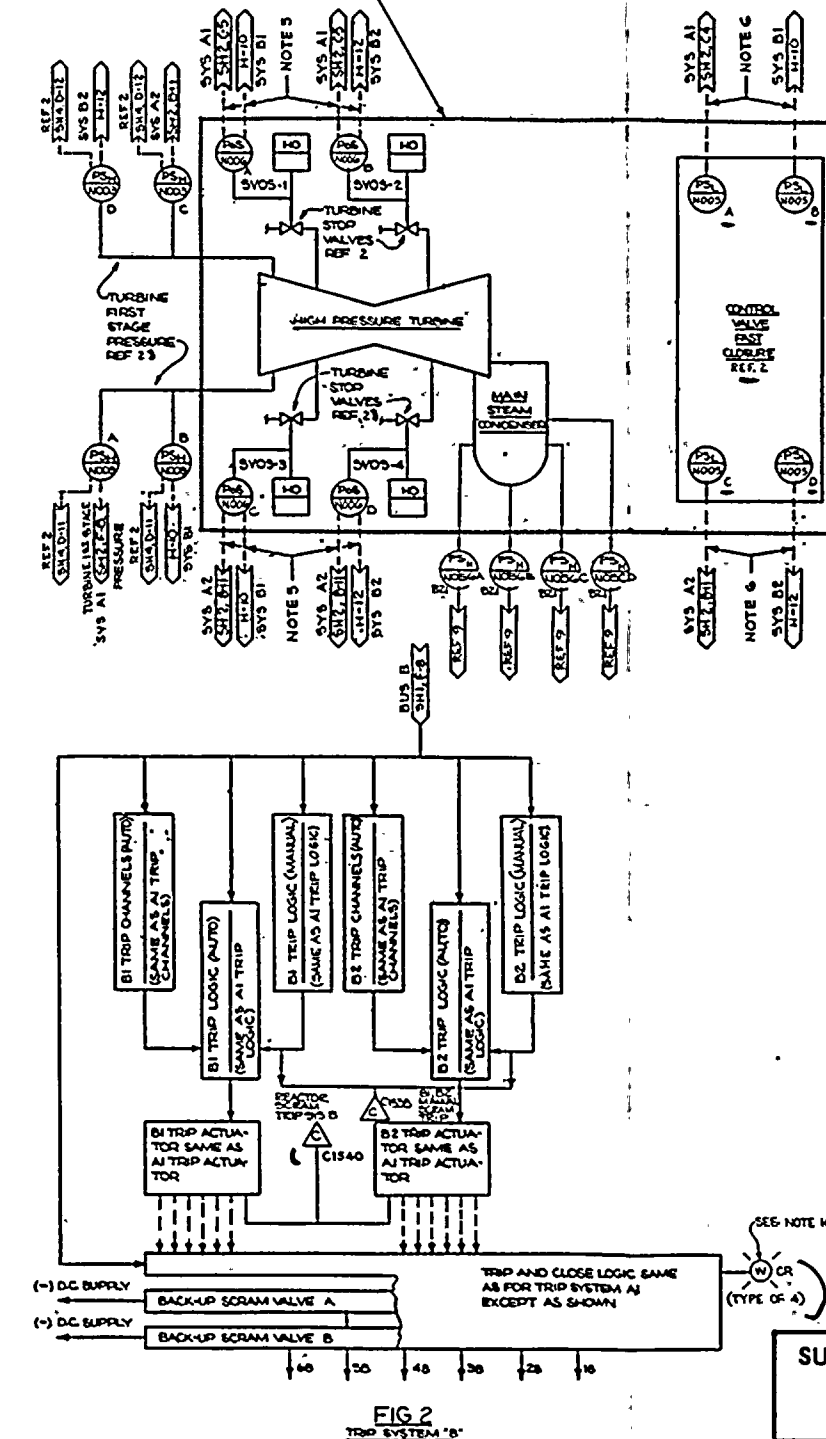








PARTS SHOWN INSIDE THIS BOUNDARY ARE FOR REF AND ARE SHOWN ONLY TO CLARIFY THE REACTOR PROTECTION SYSTEM



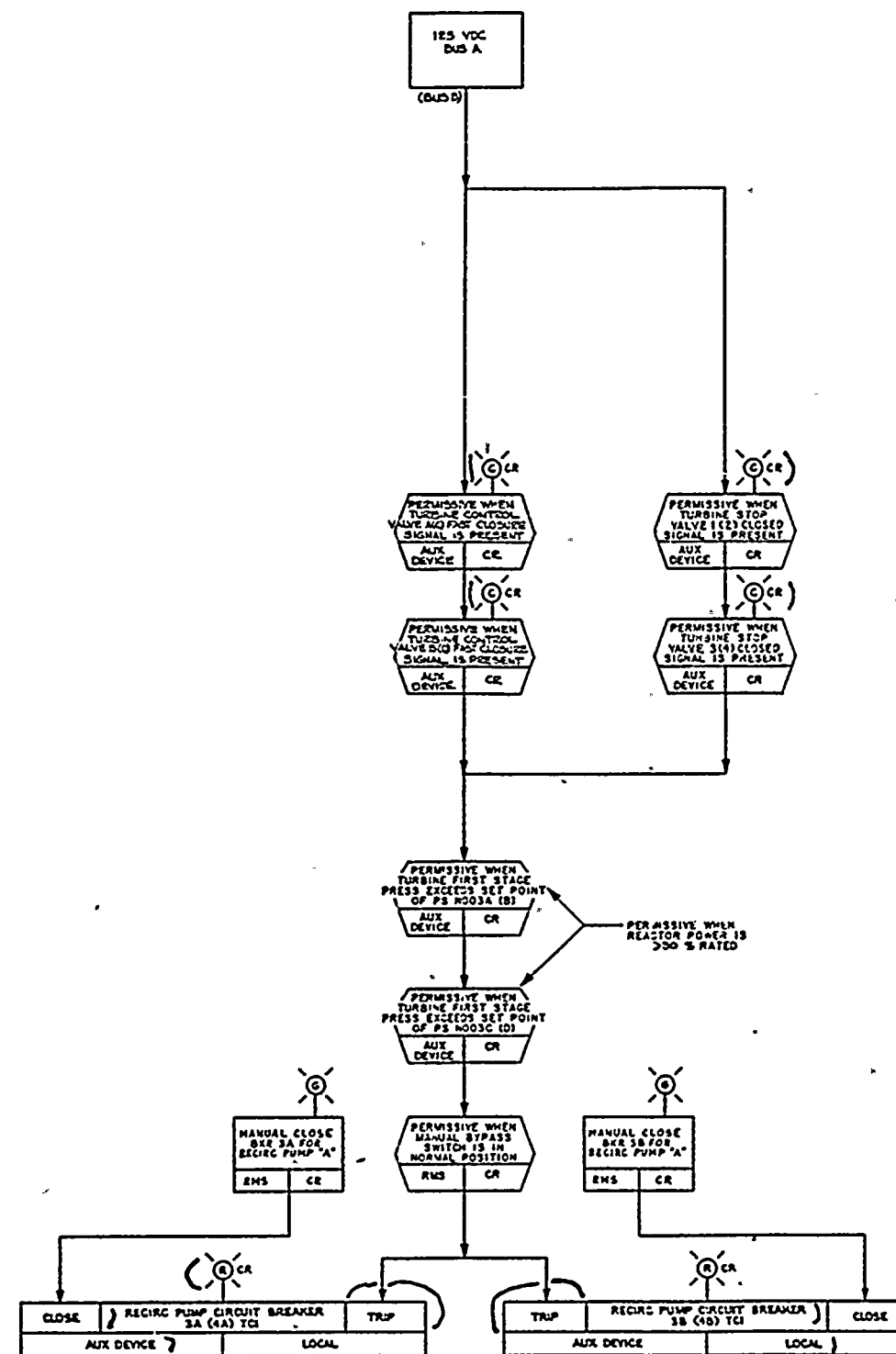
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UNITS 1 AND 2  
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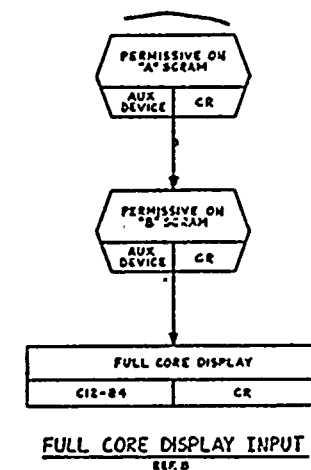
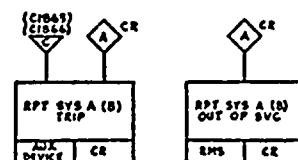
REACTOR PROTECTION SYSTEM  
IED

FIGURE 7.2-1 Sheet 3





RECIRC PUMP TRIP LOGIC A  
TYPICAL FOR LOGIC B, SUFFIXES SHOWN IN ( )



REV. 31, 7/82

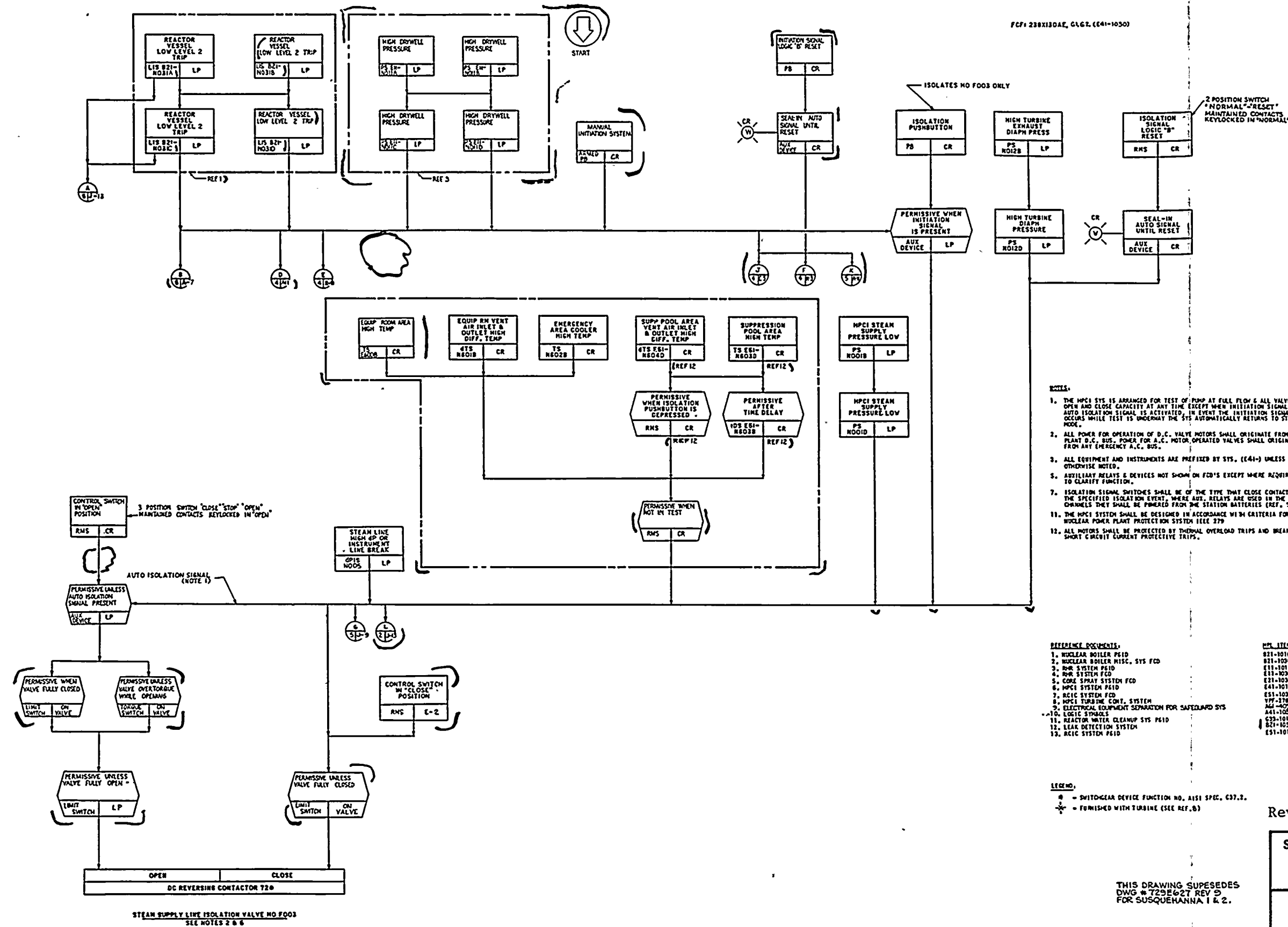
SUSQUEHANNA STEAM ELECTRIC STATION  
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REACTOR PROTECTION SYSTEM  
IED

FIGURE 7.2-1 Sheet 4



FCF 23813DAE, G162, (E41-1050)



- 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. MOTOR OPERATED VALVES SHALL ORIGINATE FROM ANY EMERGENCY A.C. BUS.
  3. ALL EQUIPMENT AND INSTRUMENTS ARE PREFIXED BY SYS. (E41-) UNLESS OTHERWISE NOTED.
  5. AUXILIARY RELAYS & DEVICES NOT SHOWN ON FCD'S EXCEPT WHERE REQUIRED TO CLARIFY FUNCTION.
  7. ISOLATION SIGNAL SWITCHES SHALL BE OF THE TYPE THAT CLOSE CONTACTS FOR THE SPECIFIED ISOLATION EVENT. WHERE AUT. RELAYS ARE USED IN THE ISOLATION CHANNELS THEY SHALL BE POWERED FROM THE STATION BATTERIES (REF. 9).
  11. THE HPCI SYSTEM SHALL BE DESIGNED IN ACCORDANCE WITH CRITERIA FOR NUCLEAR POWER PLANT PROTECTION SYSTEM IEEE 279
  12. ALL MOTORS SHALL BE PROTECTED BY THERMAL OVERLOAD TRIPS AND BREAKER SHORT CIRCUIT CURRENT PROTECTIVE TRIPS.

- REFERENCE DOCUMENTS:
1. NUCLEAR BOILER FEID
  2. NUCLEAR BOILER MISC. SYS FCD
  3. RWR SYSTEM FEID
  4. RWR SYSTEM FCD
  5. CORE SPRAY SYSTEM FCD
  6. HPCI SYSTEM FEID
  7. RCIC SYSTEM FCD
  8. HPCI TURBINE CONT. SYSTEM
  9. ELECTRICAL EQUIPMENT SEPARATION FOR SAFEGUARD SYS
  10. LOGIC SYMBOLS
  11. REACTOR WATER CLEANUP SYS FEID
  12. LEAK DETECTION SYSTEM
  13. RCIC SYSTEM FEID

- REF. ITEM NO.
- 831-1010
  - 831-1050
  - 831-1010
  - 831-1030
  - 831-1030
  - 841-1010
  - 851-1030
  - 799-2783-2A
  - 841-1050
  - 841-1050
  - 831-1010
  - 831-1050
  - 831-1010

LEGEND:

⊗ = SWITCHGEAR DEVICE FUNCTION NO. AIST SPEC. C37.2.

⊗ = FURNISHED WITH TURBINE (SEE REF. 8)

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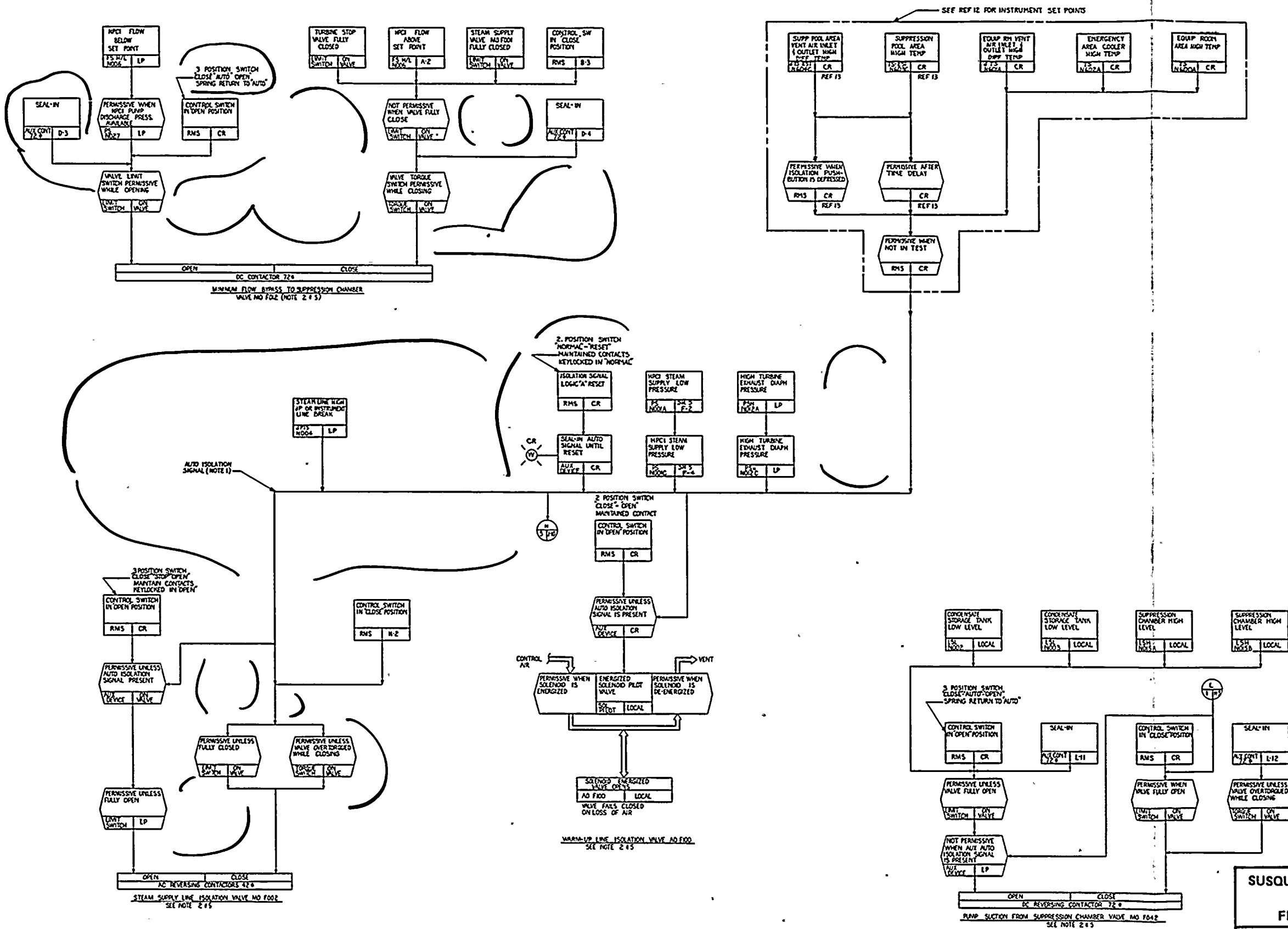
HPCI SYSTEM  
FCD

FIGURE 7.3-7 Sheet 1

THIS DRAWING SUPERSEDES  
DWG # 729627 REV 9  
FOR SUSQUEHANNA 1 & 2.

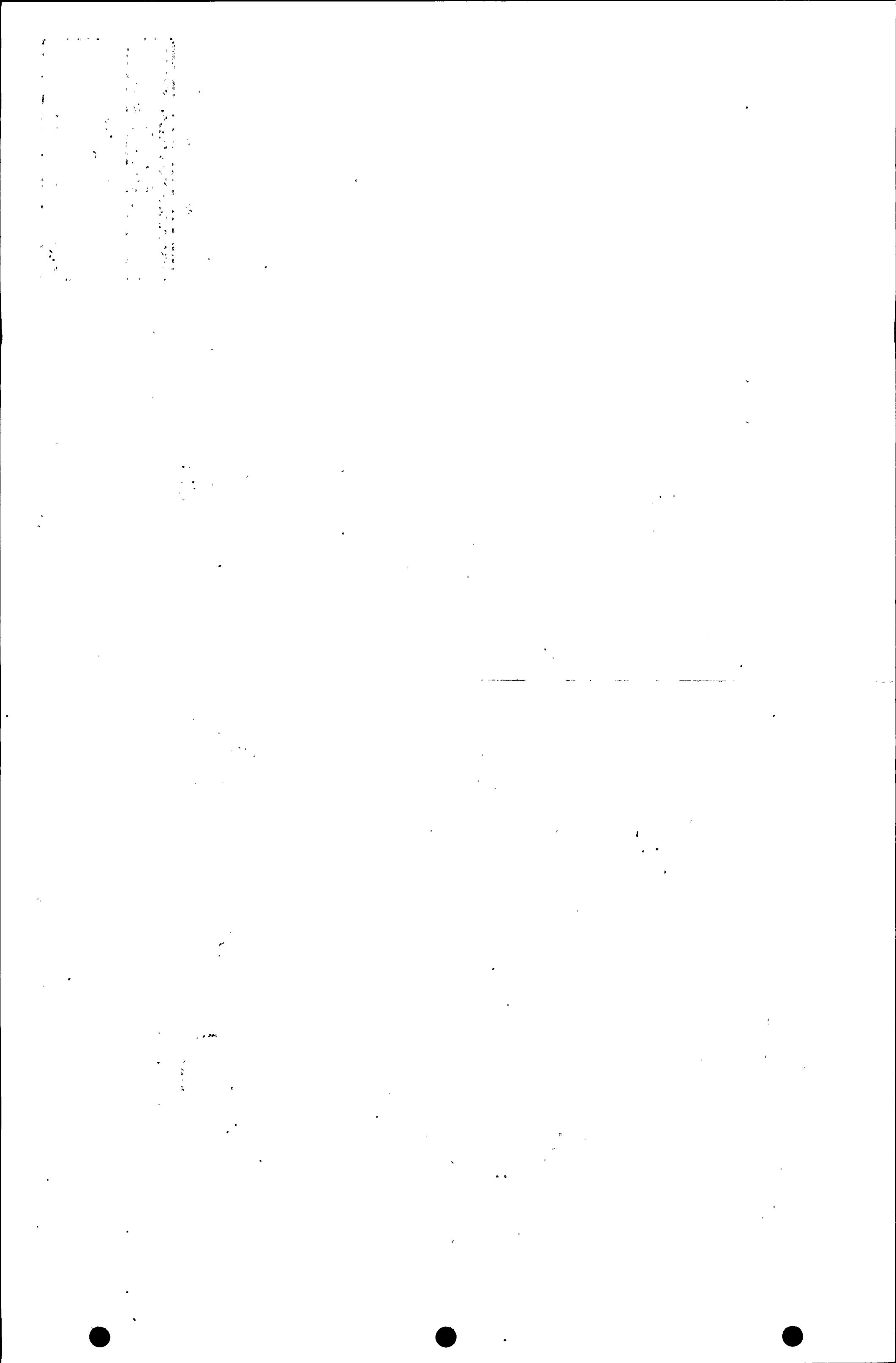


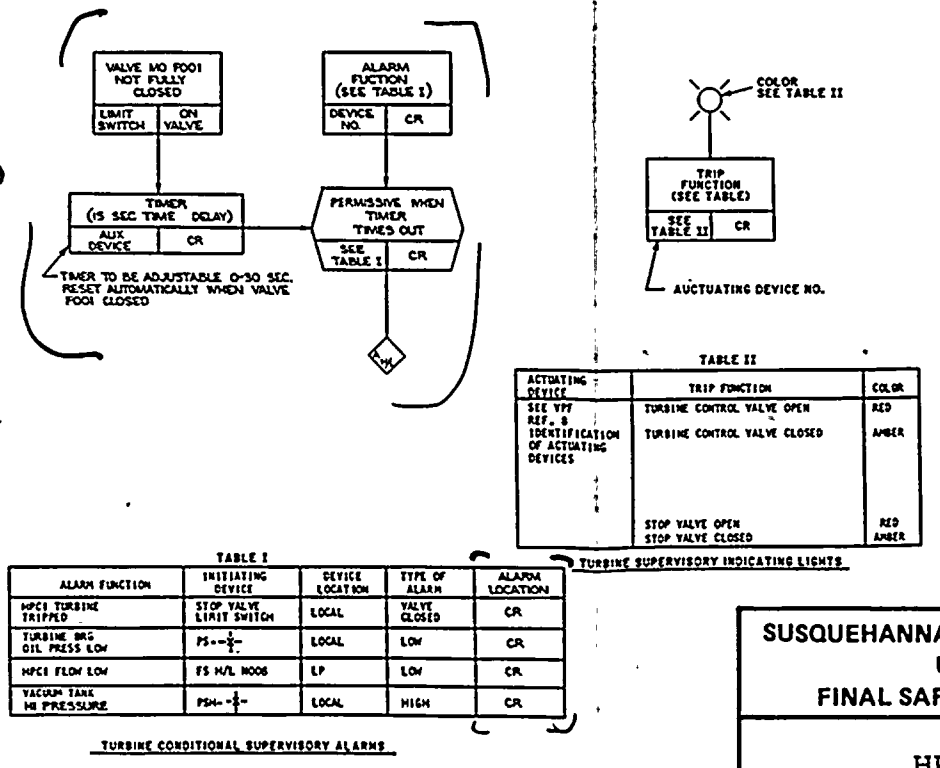
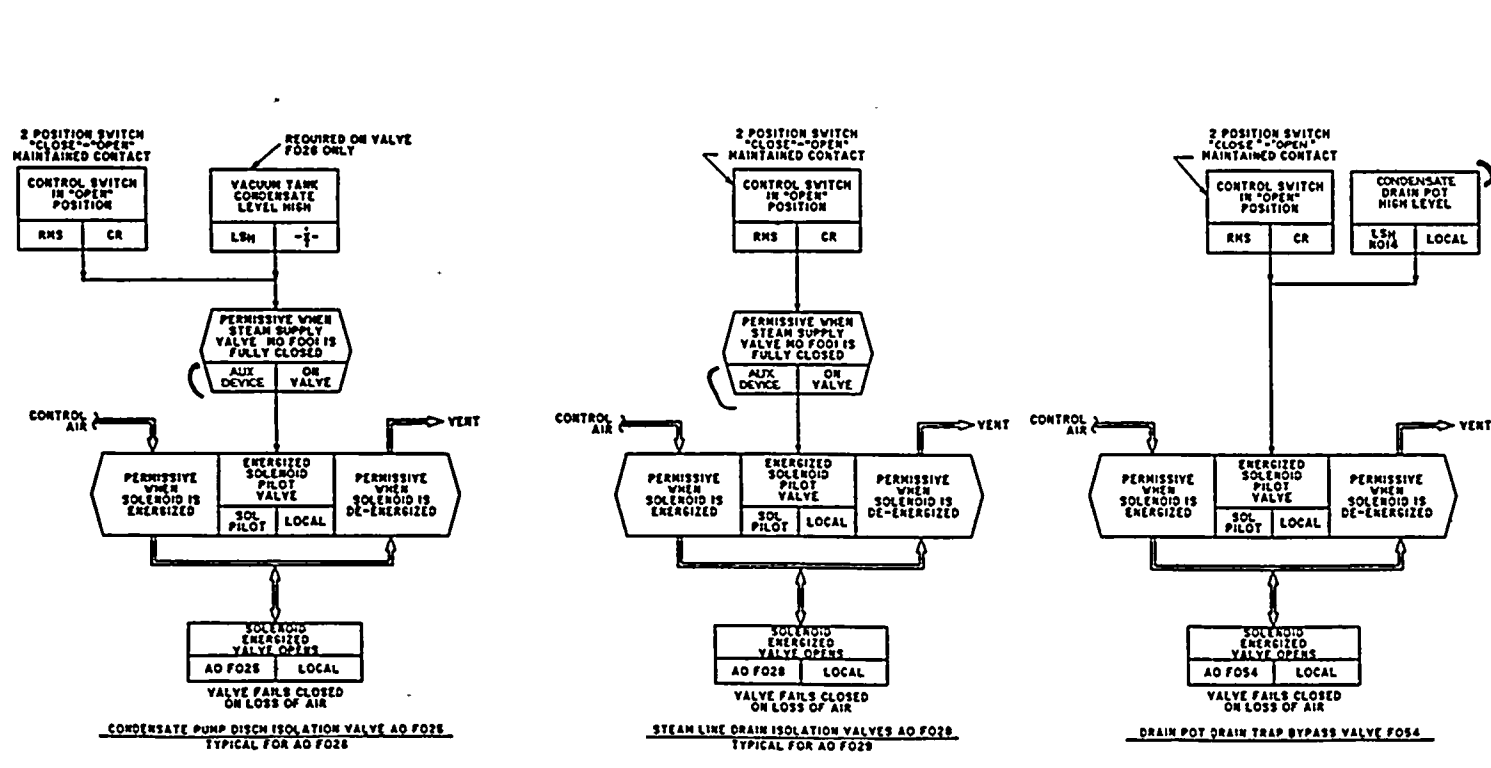
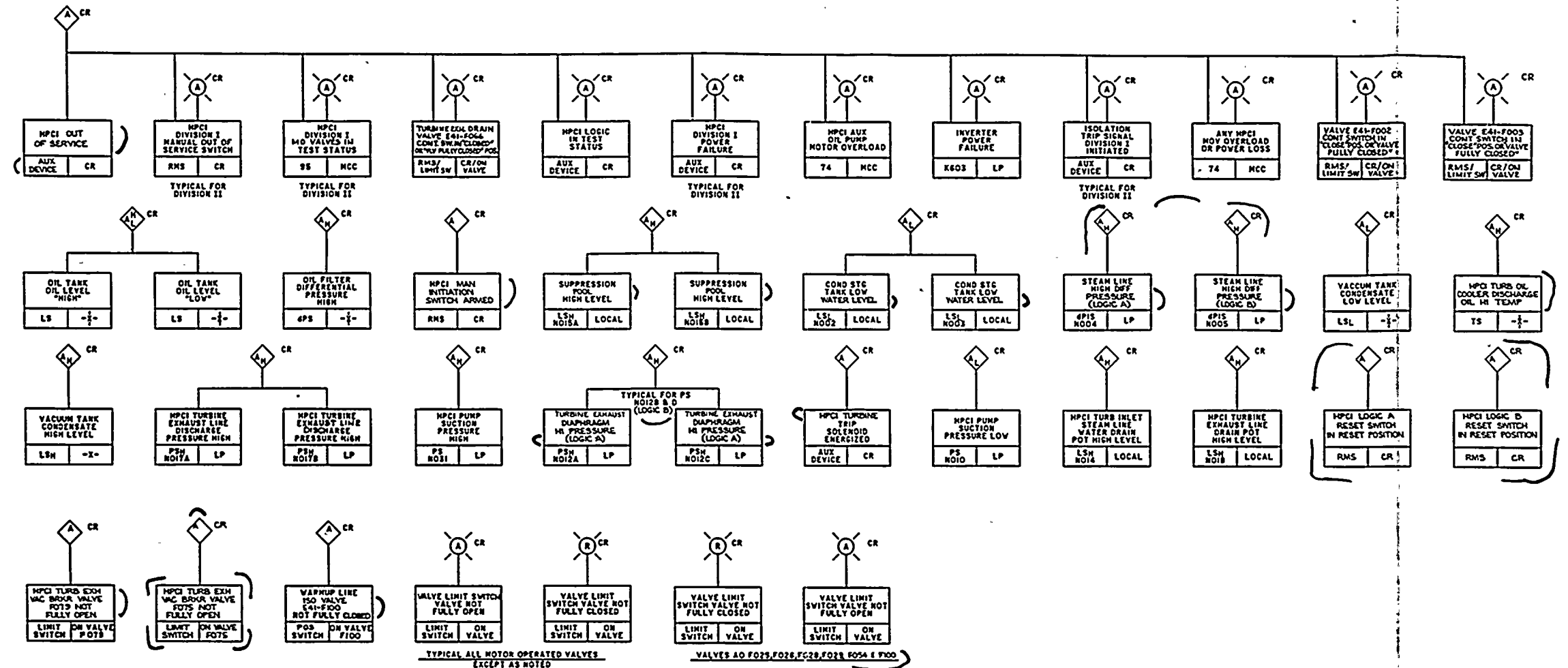
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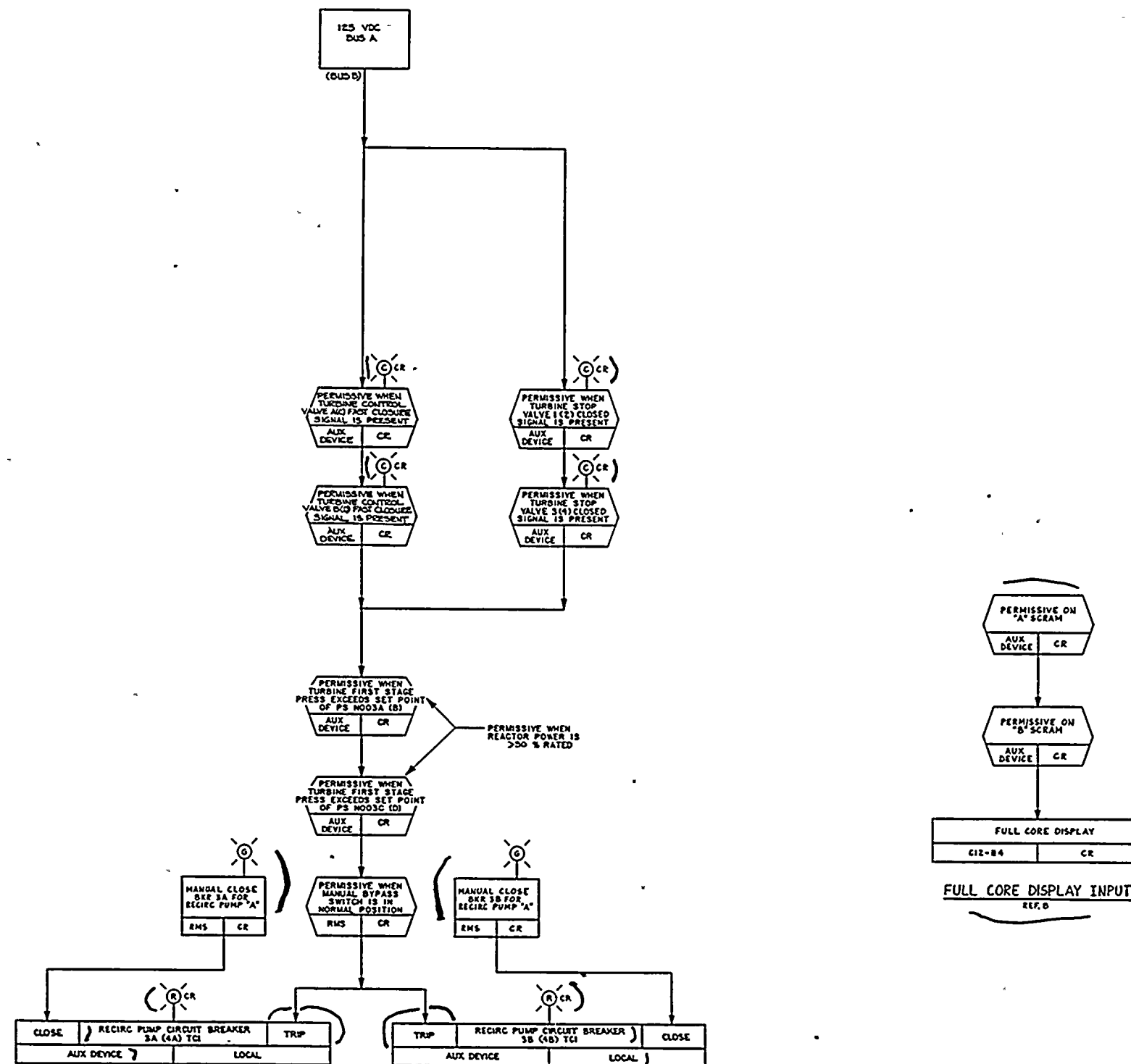


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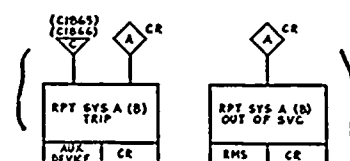
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**HPCI SYSTEM  
FCD**





RECIRC PUMP TRIP LOGIC A  
TYPICAL FOR LOGIC B, SUFFIXES SHOWN IN ( )



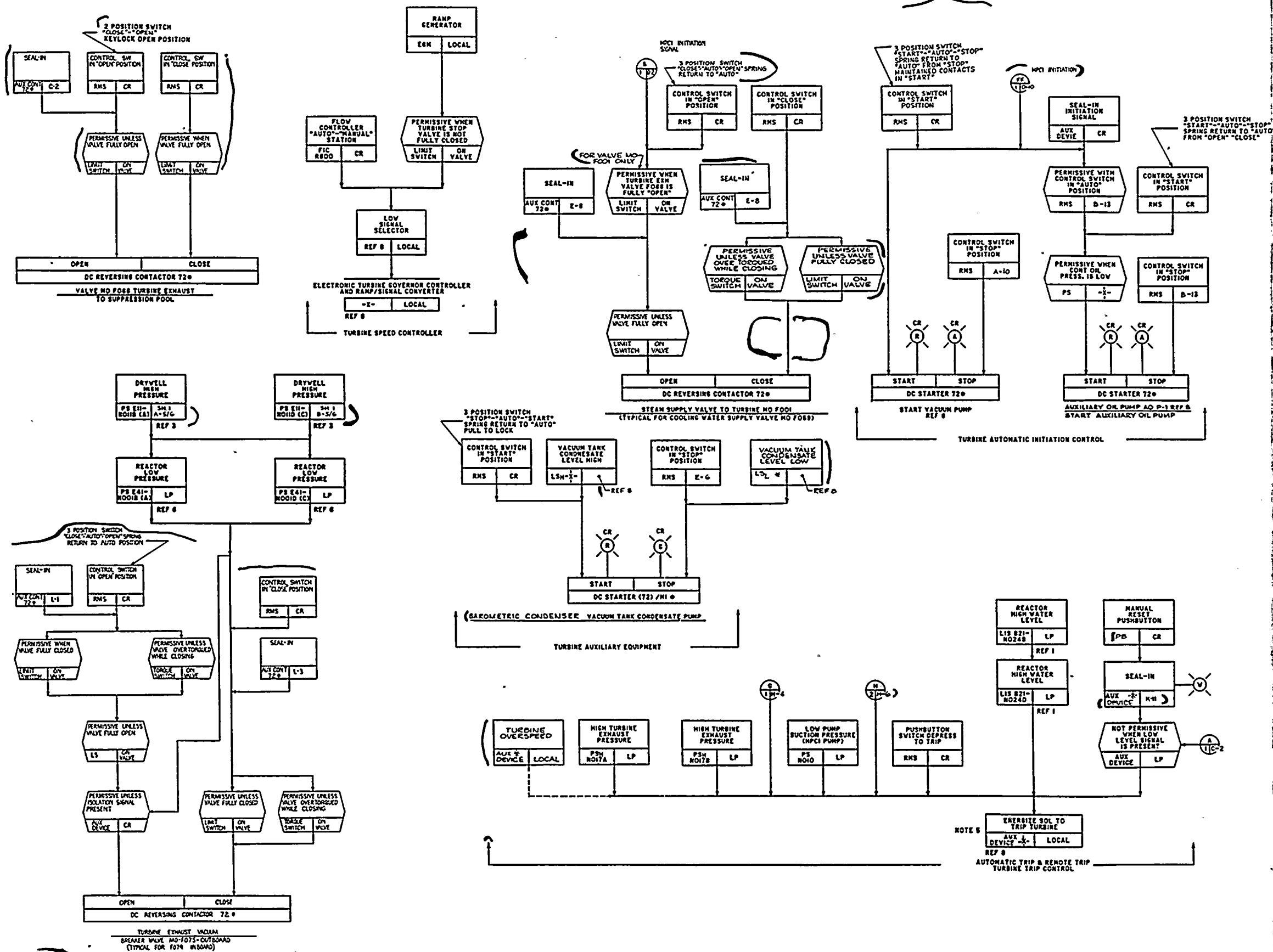
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REACTOR PROTECTION SYSTEM  
IED

FIGURE 7.2-1 Sheet 4

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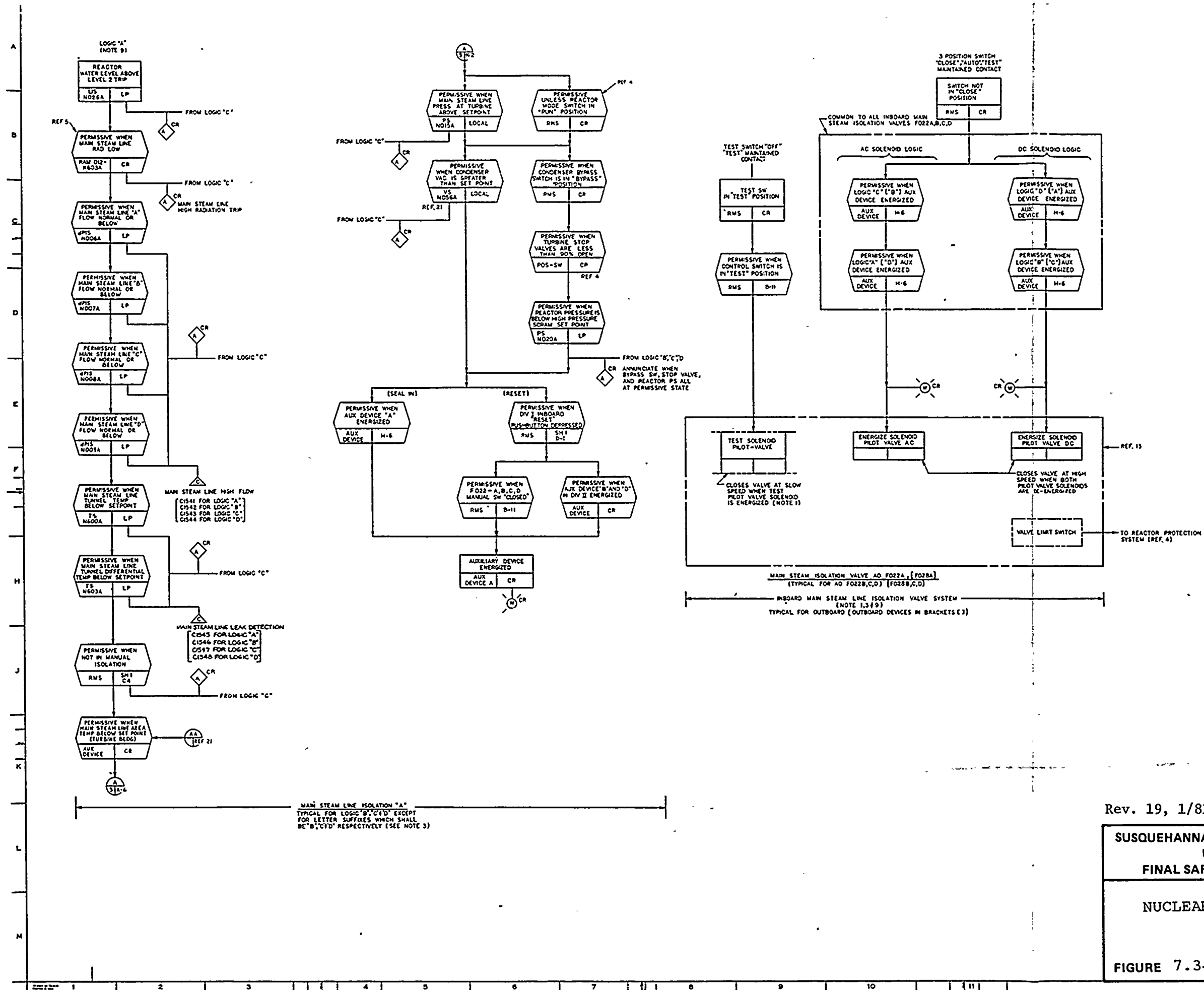
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HPCI SYSTEM  
FCD

FIGURE 7.3-7 Sheet 5

SECRET  
NO FORN DISSEM  
EXCLUDED FROM AUTOMATIC  
DOWNGRADING AND  
DECLASSIFICATION



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NUCLEAR BOILER SYSTEM  
FCD

FIGURE 7.3-8 Sheet 2

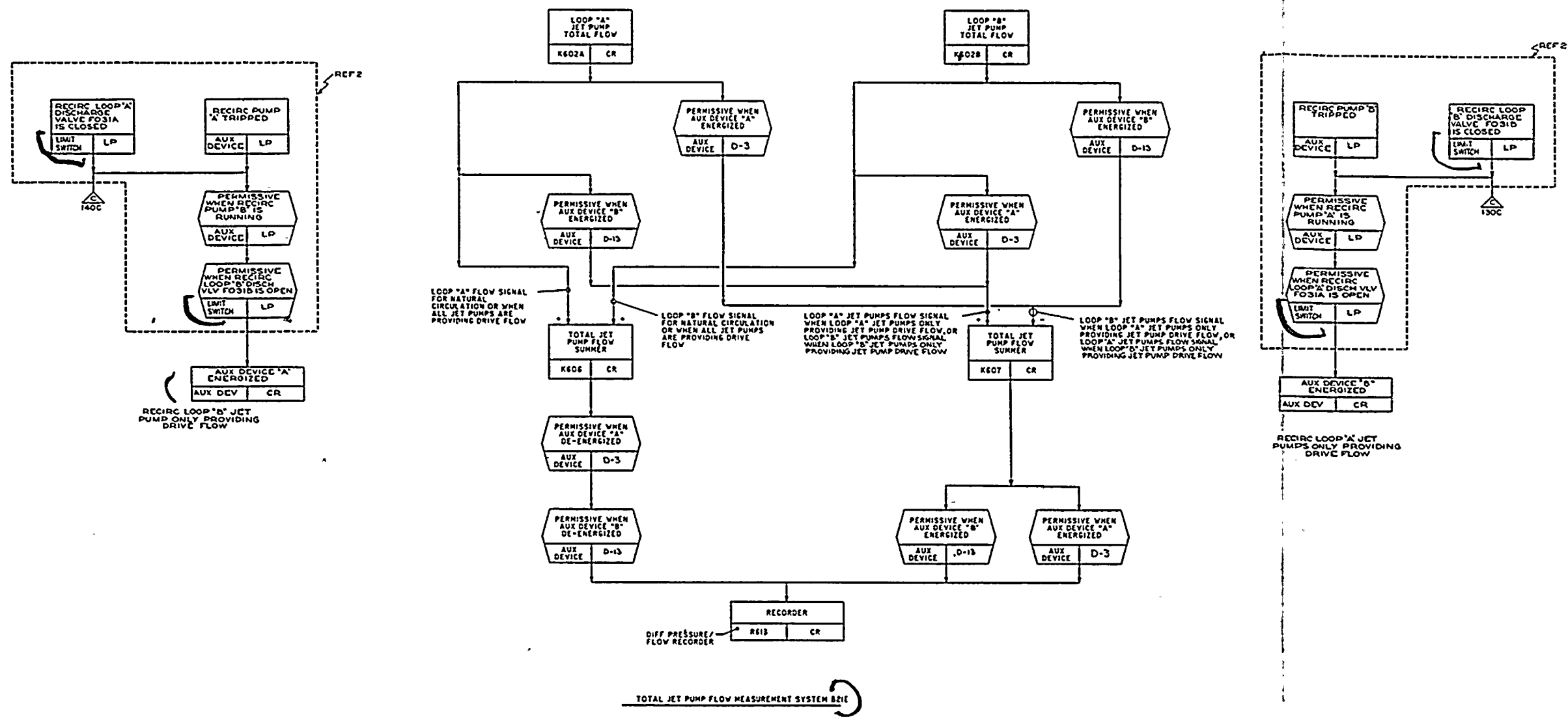








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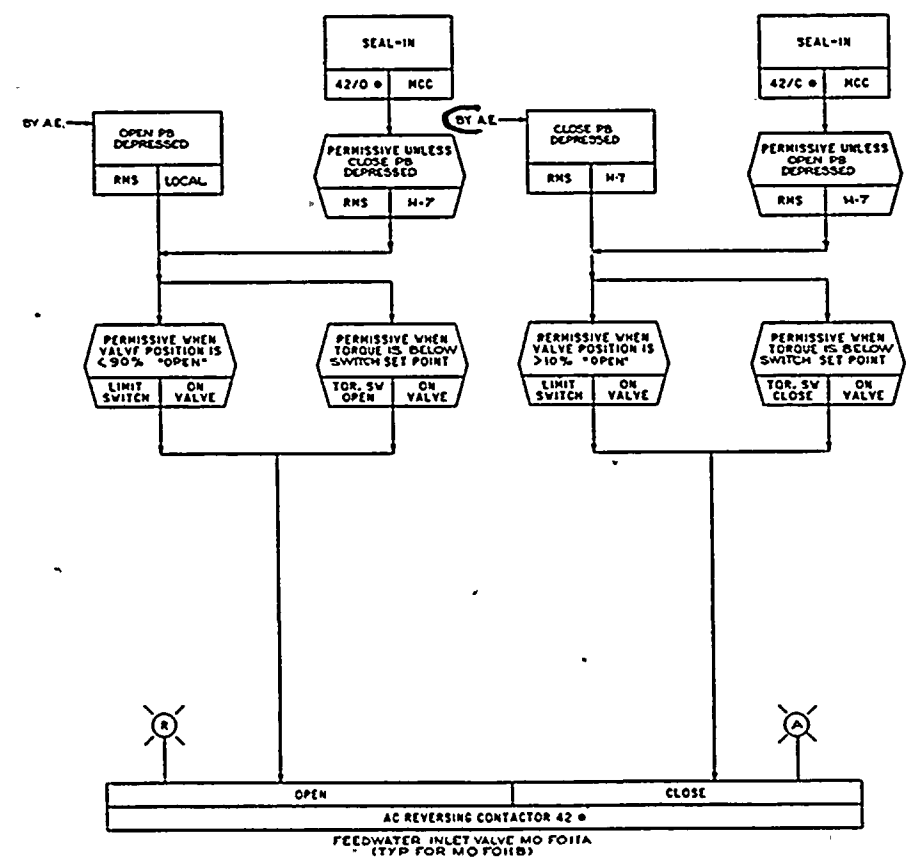
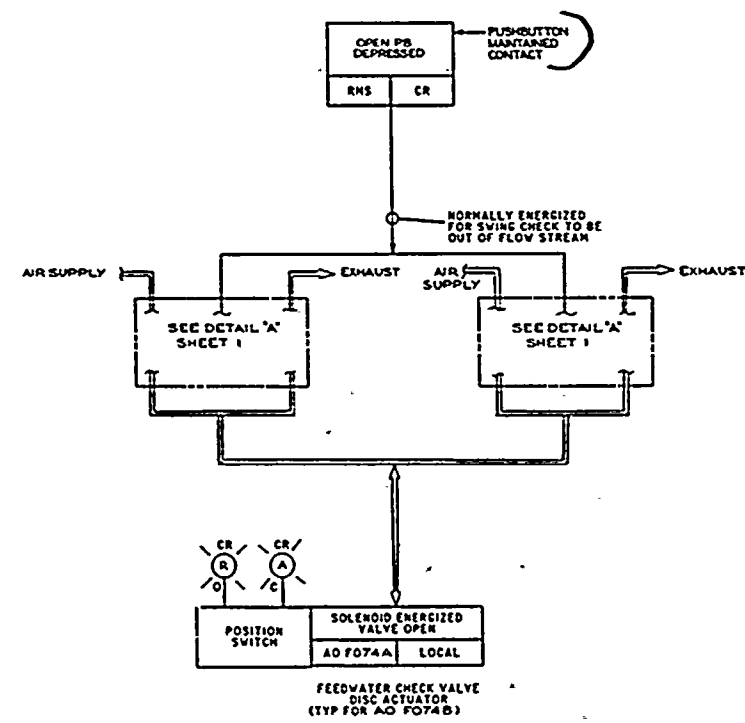
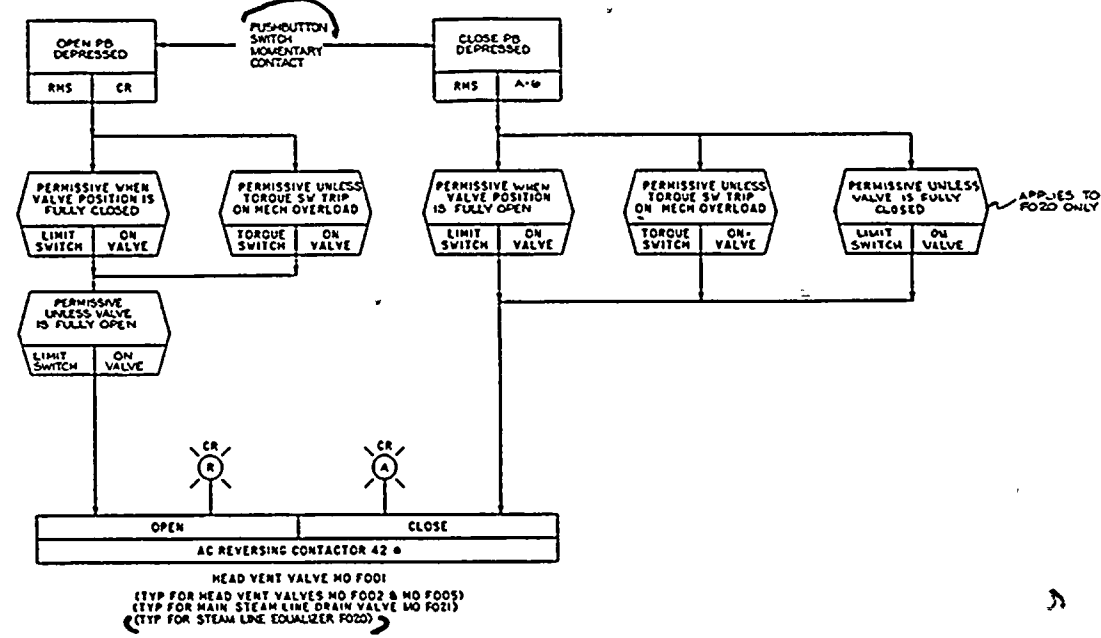
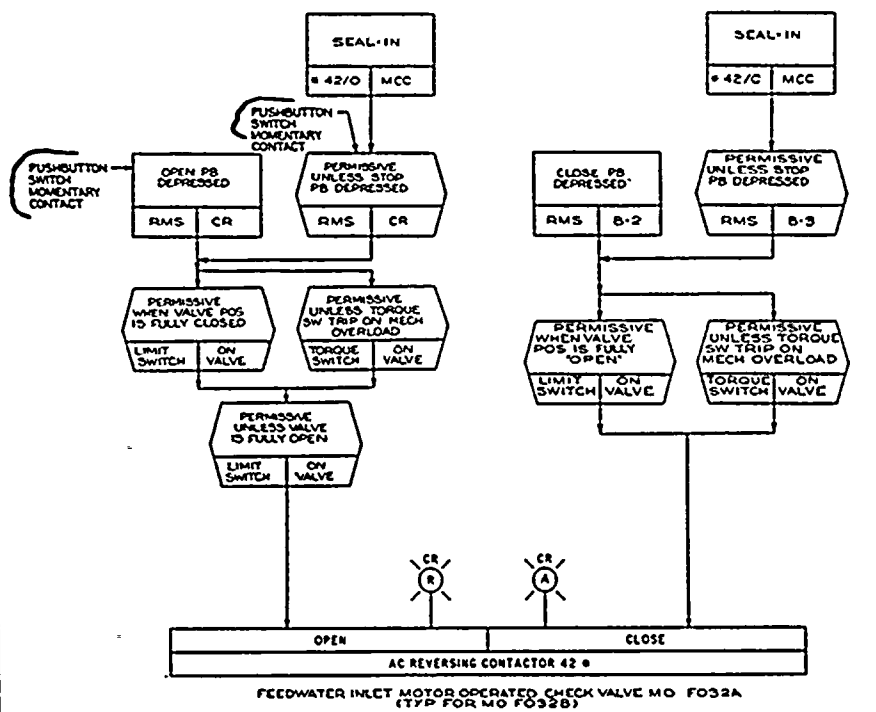
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NUCLEAR BOILER SYSTEM  
 FCD

FIGURE 7.3-8 Sheet 4





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NUCLEAR BOILER SYSTEM  
FCD

— 10 —

NOTES:

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

CONDITION A ACTIVE PUMPS:	WITH PLANT ON NORMAL AUXILIARY POWER
COOLIA/C	SYSTEM 1 STARTS - NO SEC DELAY
COOLIB/D	SYSTEM 11 STARTS - NO SEC DELAY
VALVES:	
FOOSA	SYSTEM 1 - OPENS AFTER REAC. LOW PRESS. PERM.
FOOSB	SYSTEM 11 - OPENS AFTER REAC. LOW PRESS. PERM.
FOISA	SYSTEM 1 - CLOSING IF OPEN - NO DELAY
FOISB	SYSTEM 11 - CLOSING IF OPEN - NO DELAY
FOOIA	SYSTEM 1 - CLOSING AFTER FLOW ESTABLISHED
FOOIB	SYSTEM 11 - CLOSING AFTER FLOW ESTABLISHED

CONDITION B ACTIVE PUMPS:	WITH PLANT ON STANDBY DIESEL POWER
COOLIA/C	10 SEC.
COOLIB/D	NO SEC.

VALVES: SAME SEQUENCE AS CONDITION A

2. SYSTEM 11 CIRCUIT IDENTICAL TO CIRCUIT FOR SYSTEM 1 EXCEPT COMPONENT PARTS ARE IDENTIFIED AS FOLLOWS:

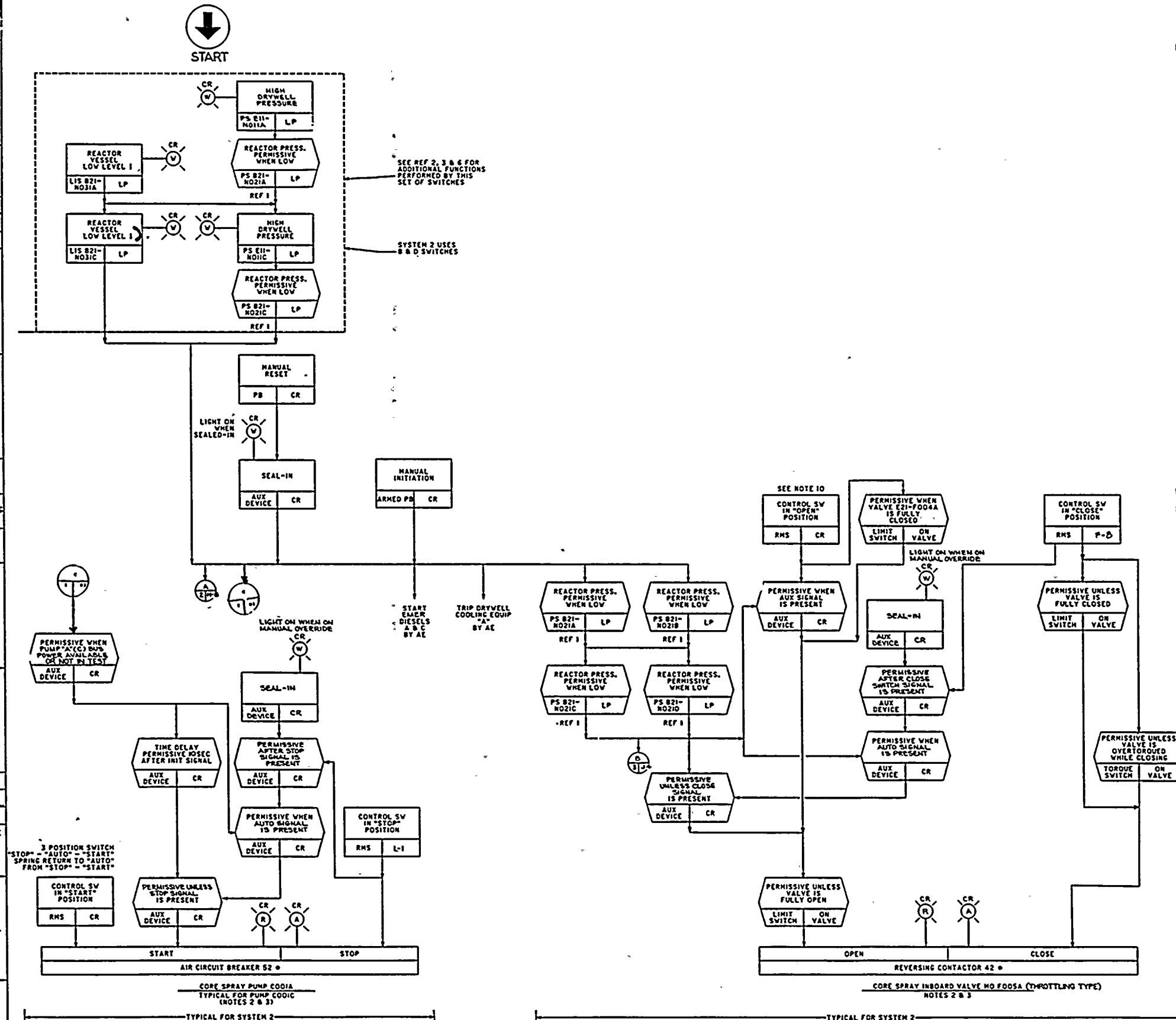
	SYSTEM 1	SYSTEM 11
TESTABLE CHECK VALVE-BYPASS	FOOIA, C	FOOIB, D
MIN FLOW BYPASS VALVES	FOOIA	FOOIB
INBOARD ISLN VALVES	FOOSA	FOOSB
TESTABLE CHECK VALVES	FOOIA	FOOIB
PUMP SUCTION VALVE	FOOIA	FOOIB
TEST BYPASS VALVE	FOOIA	FOOIB
OUTBOARD VALVE	FOOIA	FOOIB

3. PUMP MOTORS SHALL BE PROTECTED WITH OVERLOAD PROTECTION. OVERLOAD RELAYS TO BE APPLIED SO AS TO MAINTAIN POWER ON MOTOR AS LONG AS POSSIBLE WITHOUT IMMEDIATE DAMAGE TO MOTORS OR HARM TO EMERGENCY POWER SYS. OVERLOAD TRIPS TO BE BYPASSED UNLESS VALVE UNDER TEST. VALVE MOTORS SHALL BE PROVIDED WITH THERMAL OVERLOAD TRIPS AND ANNUNCIATION IN ADDITION. VALVE MOTOR CIRCUITS ARE TO BE PROVIDED WITH BREAKER SHORT CIRCUIT PROTECTIVE TRIPS.
4. MOTIVE POWER FOR SYSTEM 1 PUMPS SHALL ORIGINATE FROM A DIFFERENT EMERGENCY AC BUS THAN POWER FOR SYSTEM 2 PUMPS.
5. POWER FOR VALVES IN EACH SYSTEM SHALL ORIGINATE FROM THE SAME BUS SUPPLYING PUMP POWER. CONTROL POWER FOR PUMPS & VALVES OF SYSTEM 1 SHALL BE FROM A DIFFERENT SOURCE THAN CONTROL POWER FOR SYSTEM 2.
6. " = SWITCH-GEAR DEVICE FUNCTION NUMBERS ANSI SPEC. C37.2.
7. ALL EQUIPMENT AND INSTRUMENTS ARE PREFIXED BY SYSTEM NO. (E21) UNLESS OTHERWISE NOTED.
8. SEE REFERENCE PE10'S FOR ADDITIONAL INFORMATION ON ALARMS, VALVE INDICATING LIGHTS AND PROCESS INSTRUMENTATION.
9. REMOVED

10. THE CORE SPRAY SYSTEM SHALL BE DESIGNED IN ACCORDANCE WITH REF 10.
11. UNLESS OTHERWISE NOTED, ALL RMS SHALL BE 3 POSITION SWITCHES "CLOSE" - "HOLD" - "OPEN" SPRING RETURN TO "HOLD" FROM "CLOSE" OR "OPEN".
12. NO FOOA/B, FOOSA/B, FOOIA/B VALVES ARE PROVIDED WITH REVERSIBILITY FEATURE.

REFERENCE DOCUMENT

1. B21-1010 NUCLEAR BOILER SYSTEM PE10.  
2. B21-1020 NUCLEAR BOILER SYSTEM FCD  
3. E11-1030 RESIDUAL HEAT REMOVAL SYSTEM FCD  
4. E21-1010 CORE SPRAY SYSTEM PE10  
5. E21-1010 CORE SPRAY SYSTEM DES. SPEC.  
6. E41-1020 MFC SYSTEM FCD  
7. E51-1030 RCIC SYSTEM FCD  
8. A41-1030 LOGIC SYMBOLS  
9. E11-1010 RMS SYSTEM PE10  
10. A61-4050 ELEC. EQUIP. SEP. FOR SAFEGUARD SYS.



REV. 31, 7/82

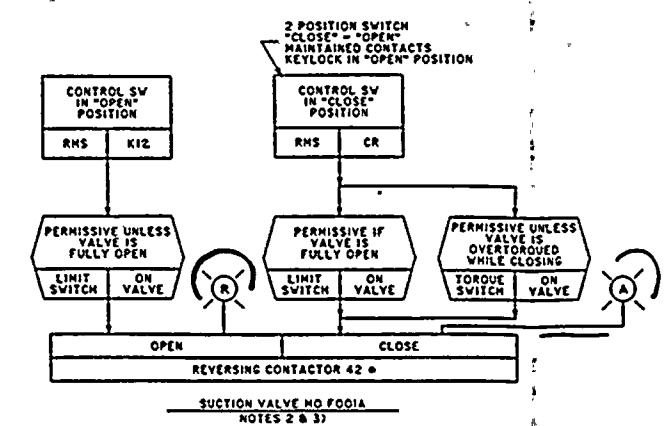
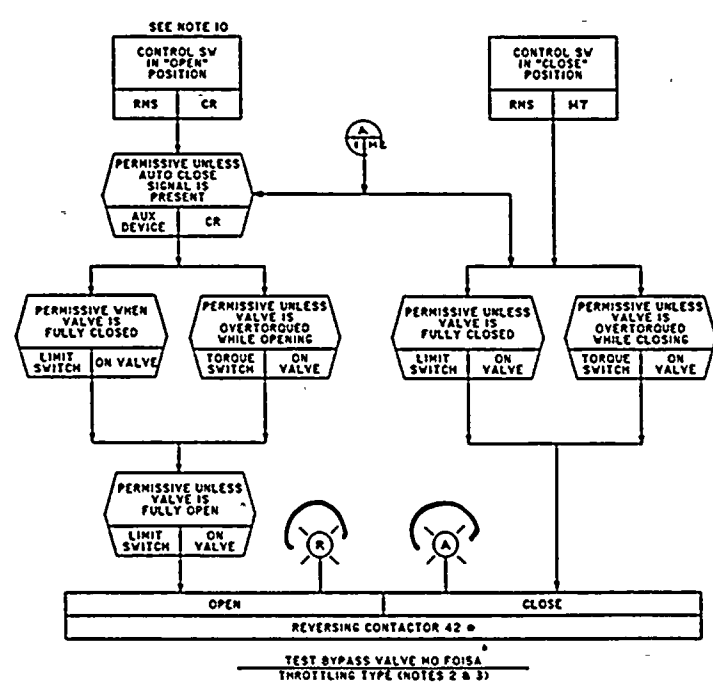
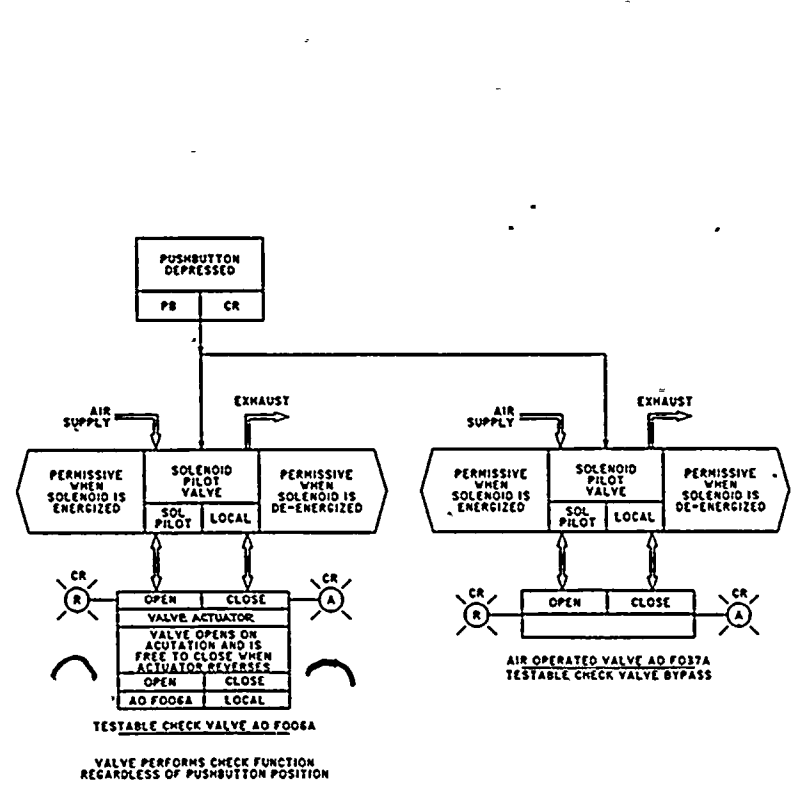
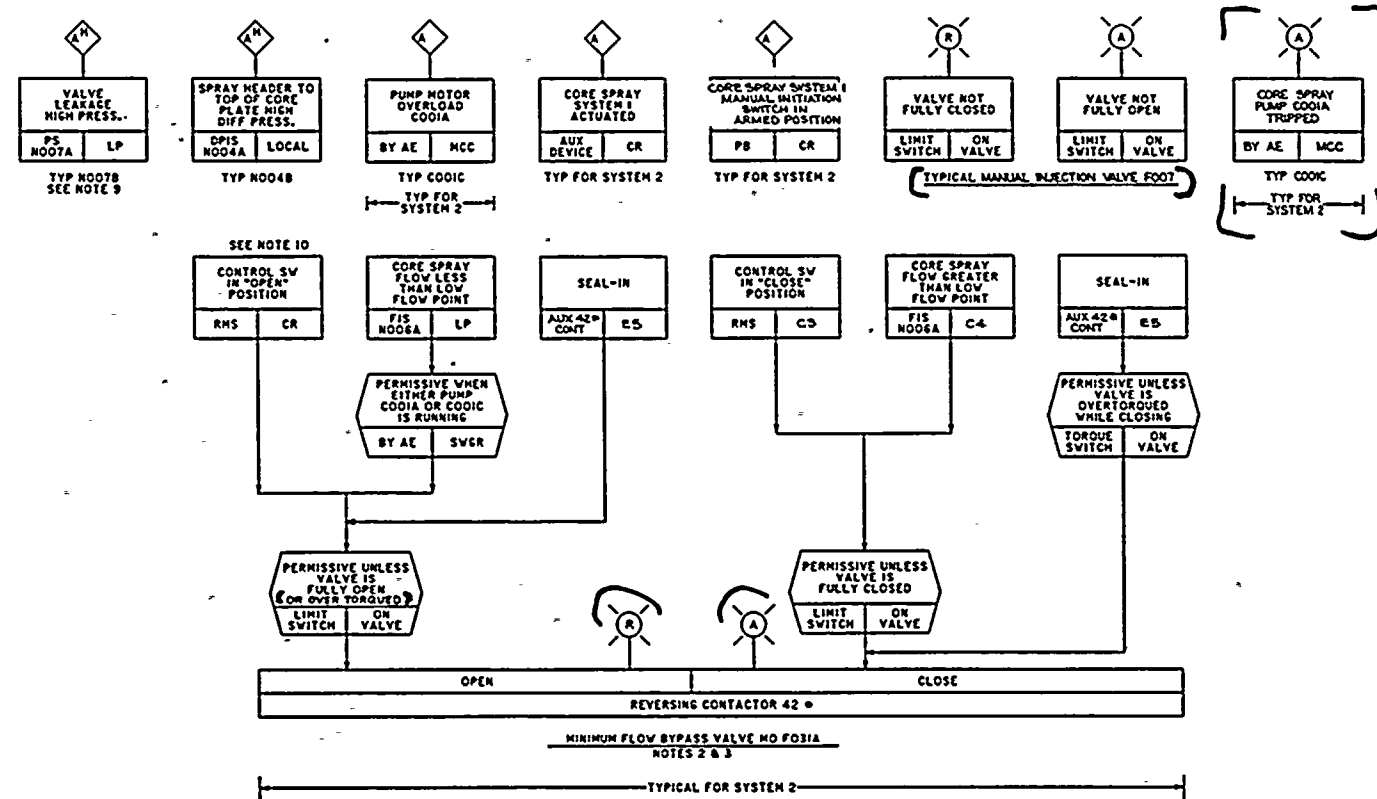
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CORE SPRAY SYSTEM  
FCD



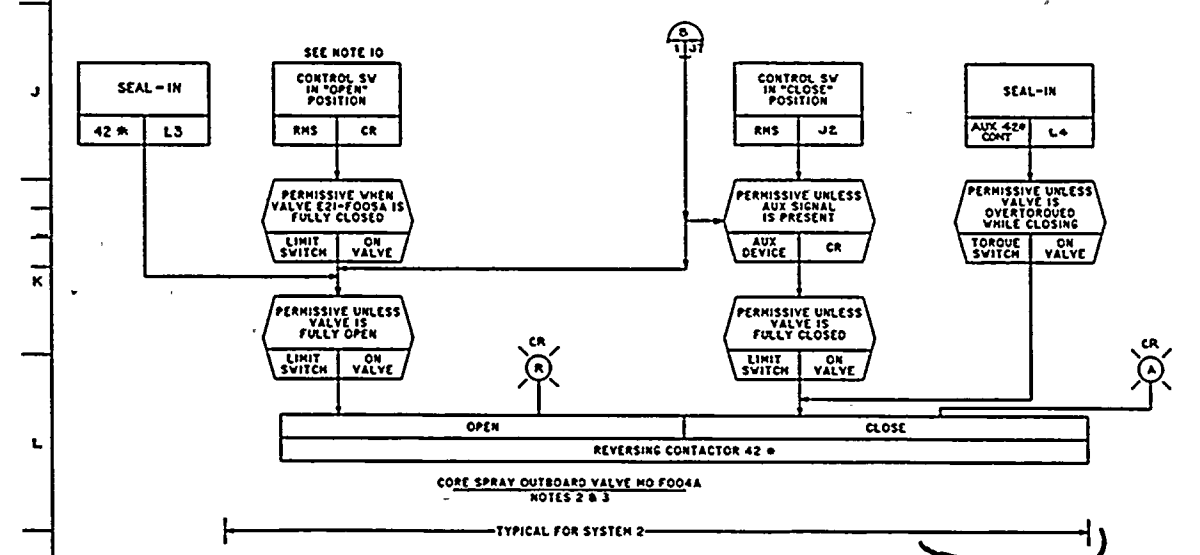
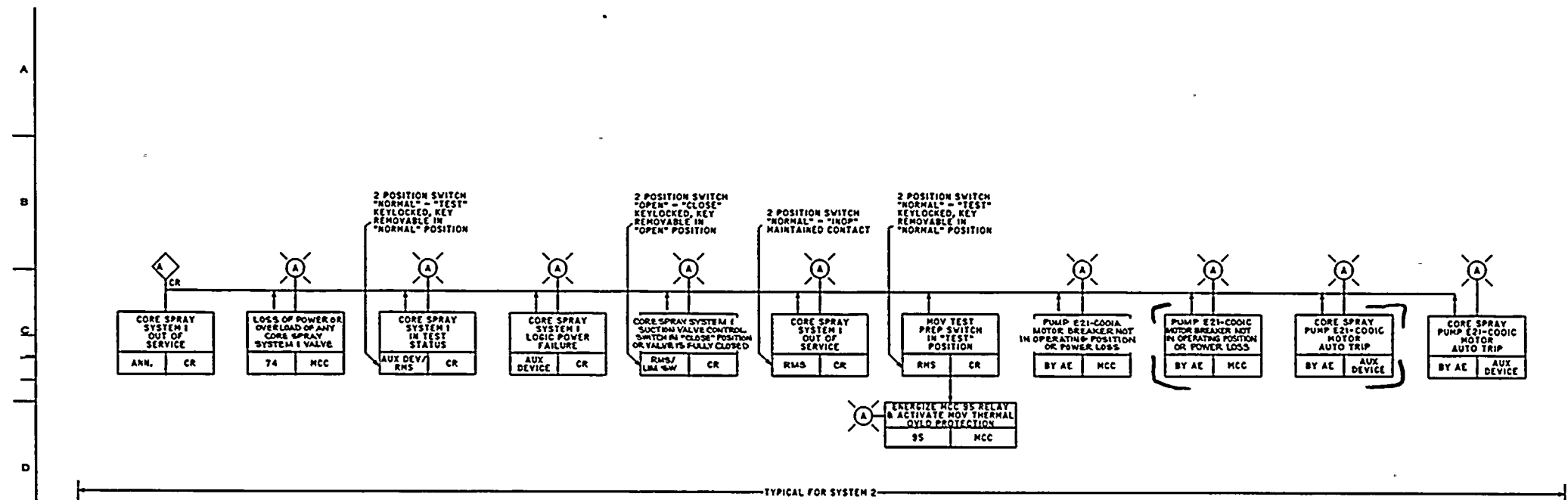
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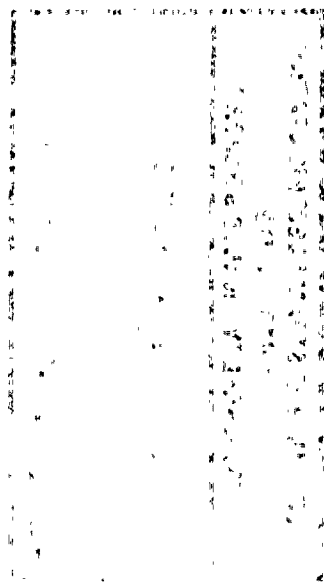
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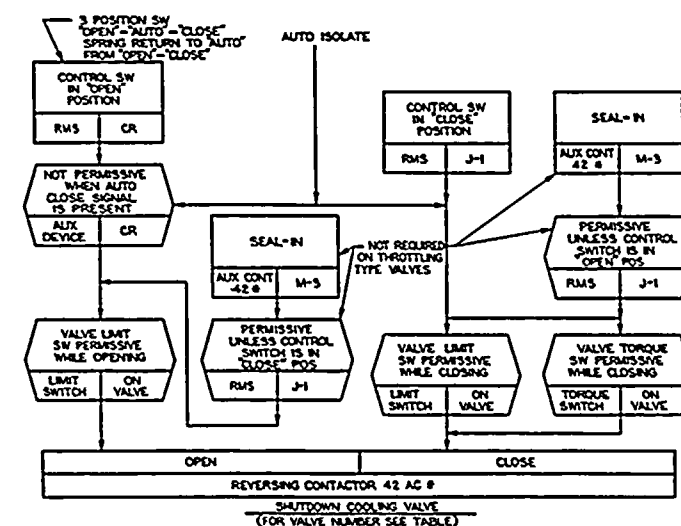
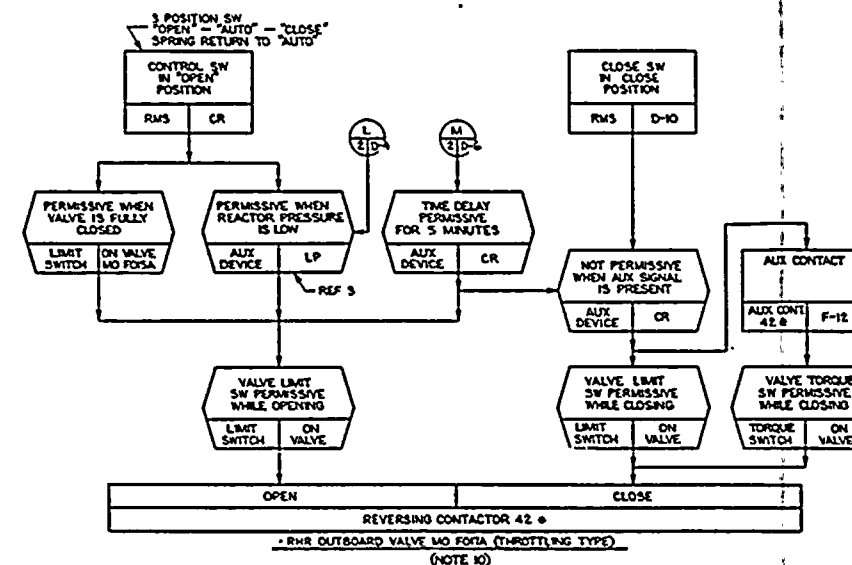
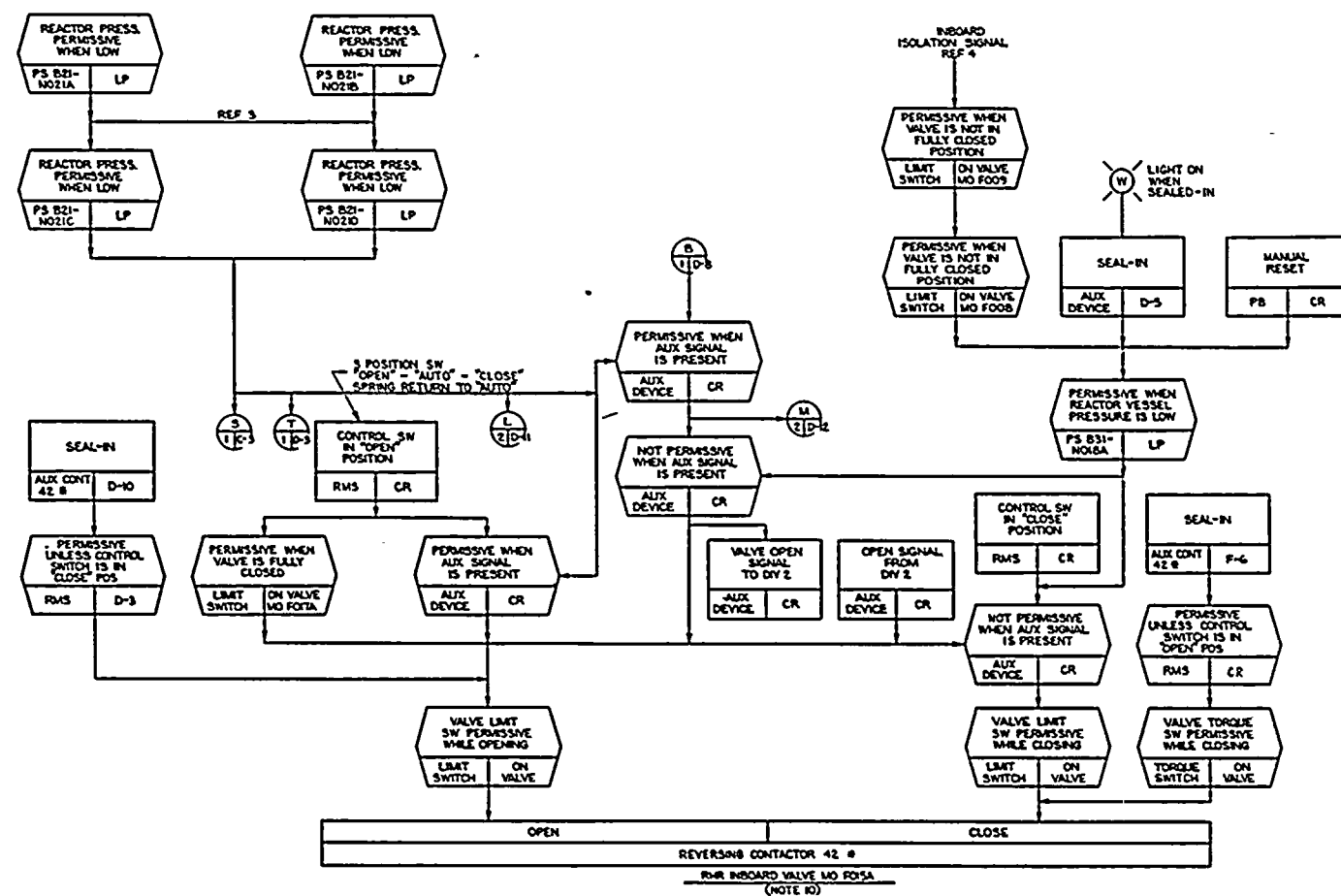
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<p><b>SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT</b></p>
<p><b>CORE SPRAY SYSTEM FCD</b></p>
<p><b>FIGURE 7.3-9      Sheet 3</b></p>





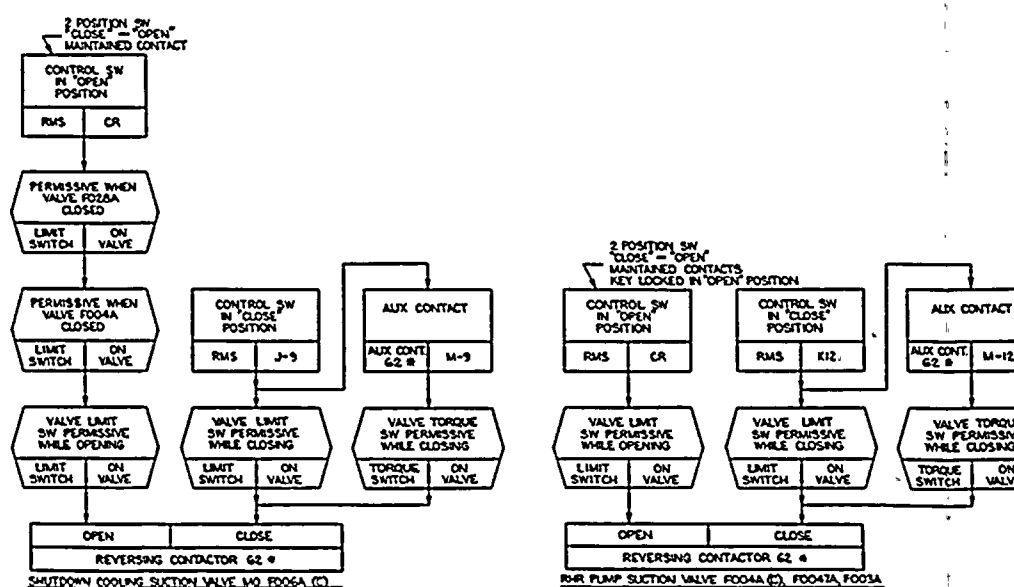




ISOLATION VALVE TABLE REF 4

RHR LOCATION	INBOARD	OUTBOARD
HEAD SPRAY ISOLATION	MO FO22	MO FO23 #
RHR SUCTION ISOLATION	MO FO09	MO FO06
RADIASTE DISCHARGE	MO FO40 #	MO FO49

# THROTTLING TYPE



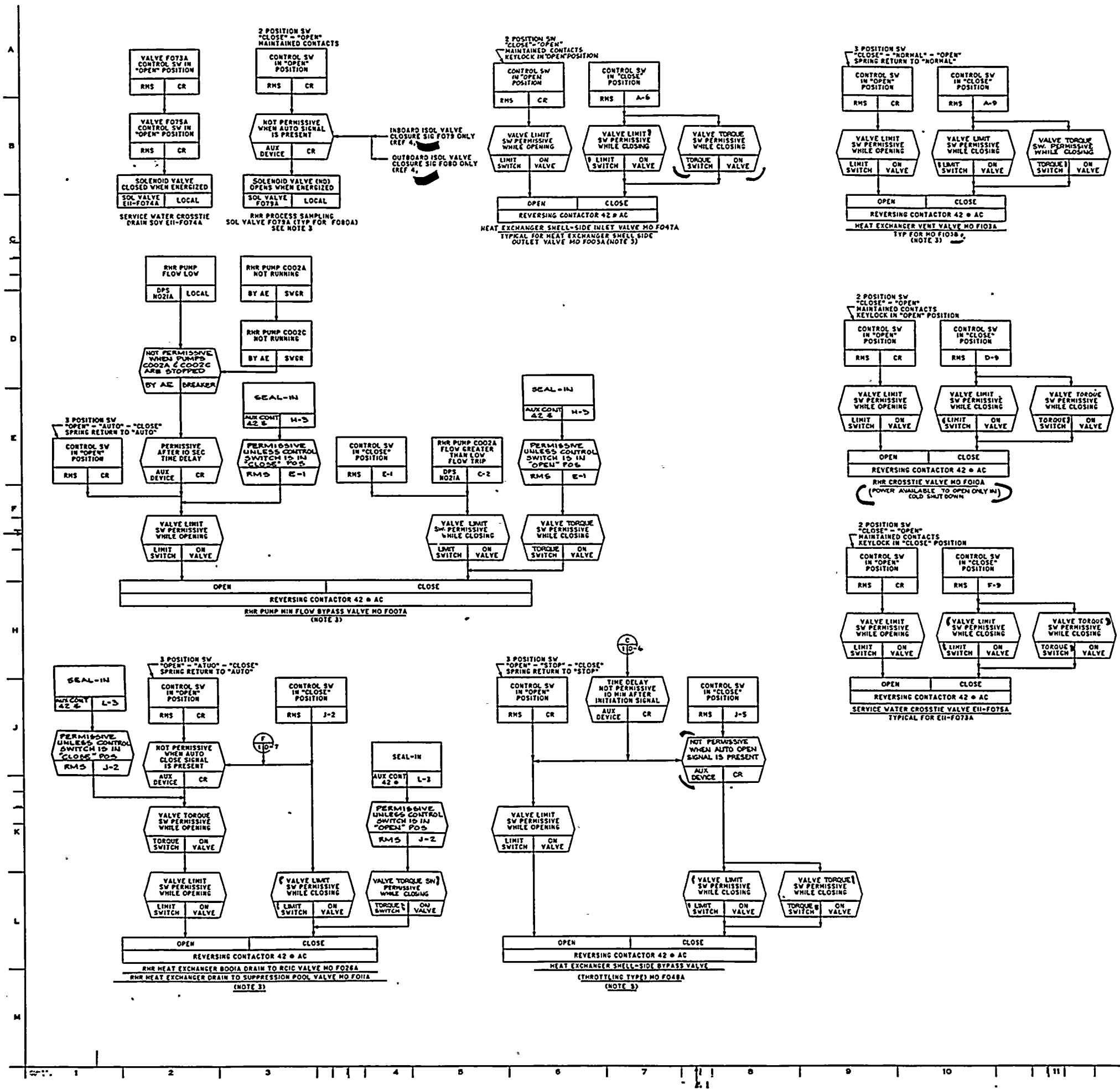
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**RHR SYSTEM  
FCD**

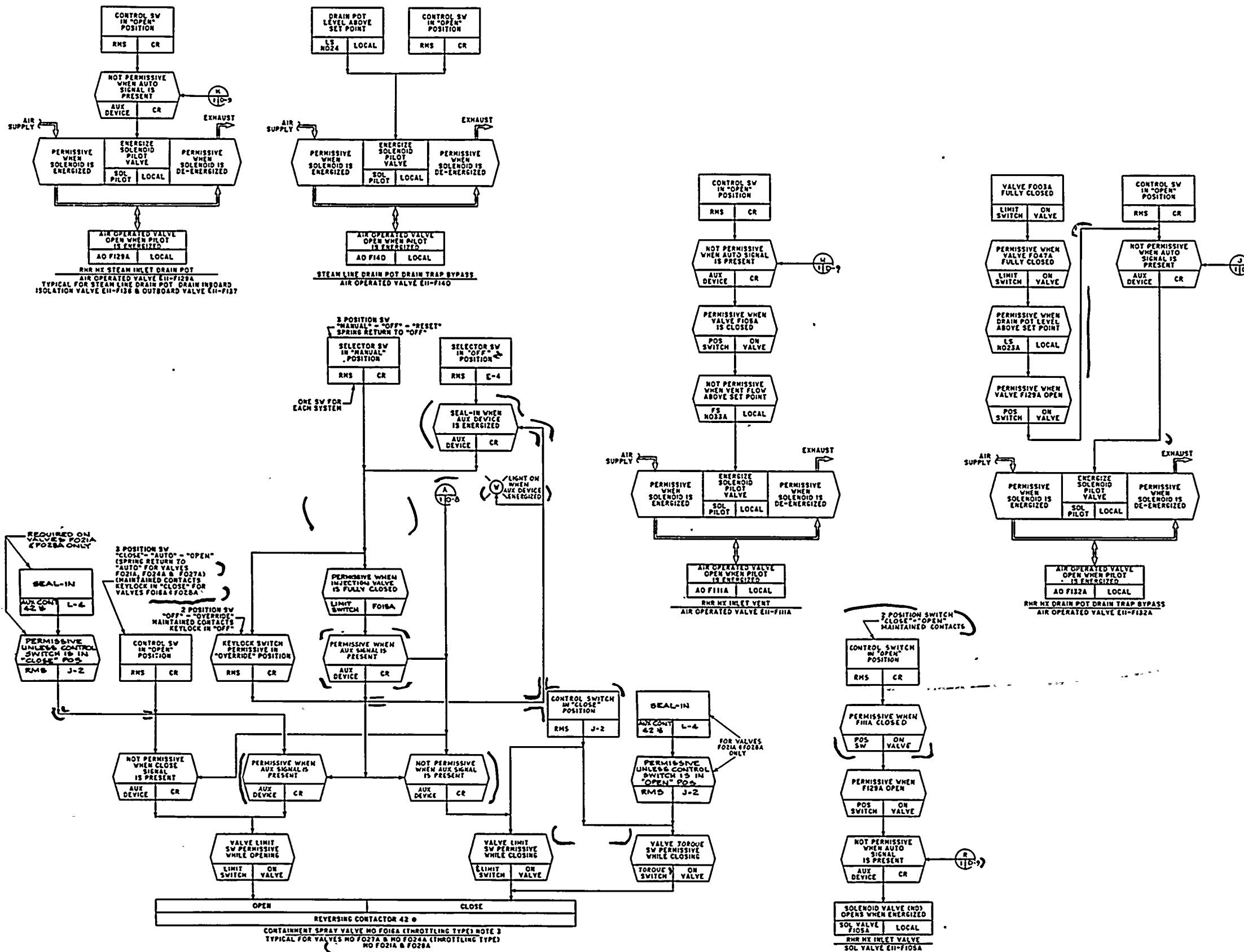






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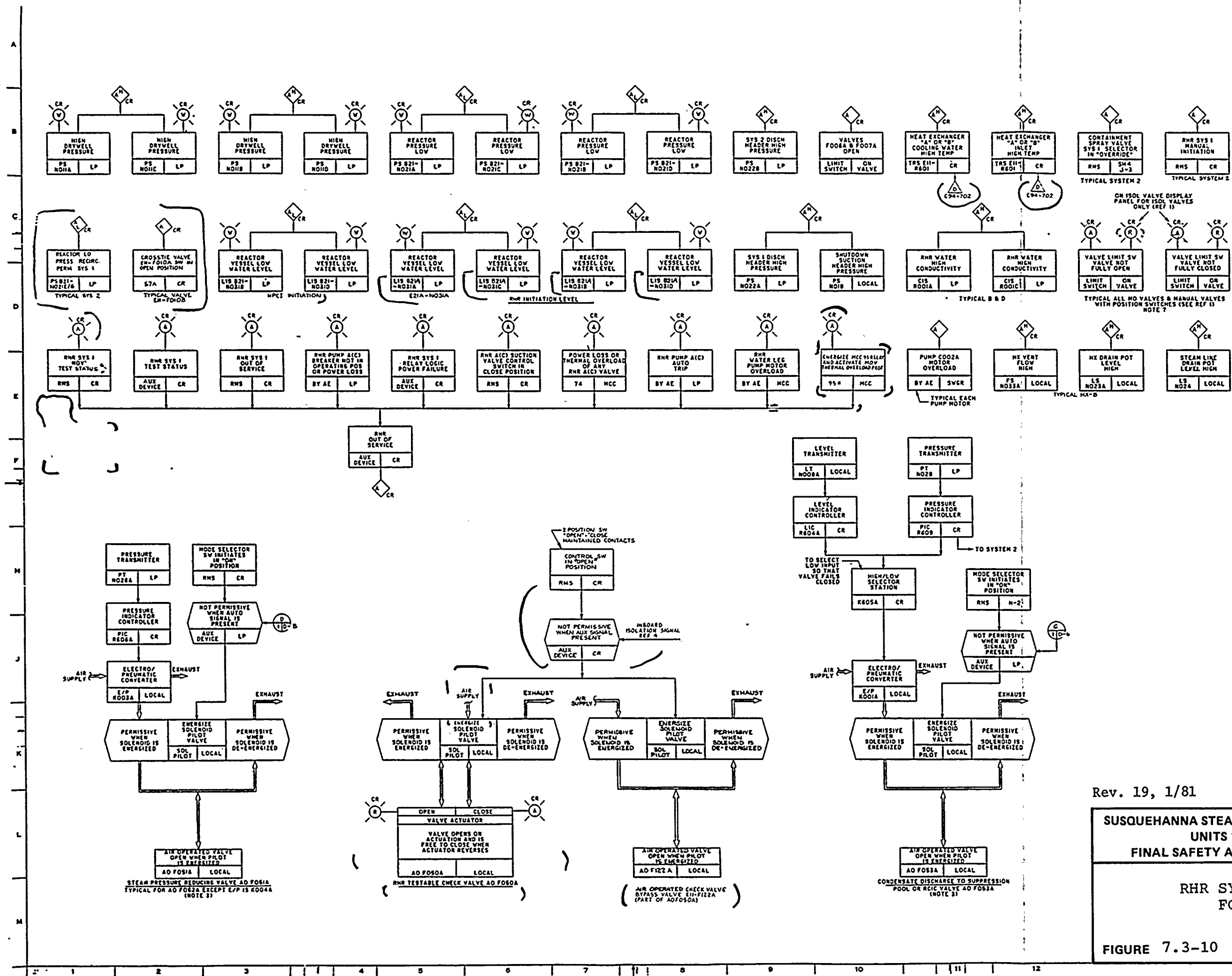


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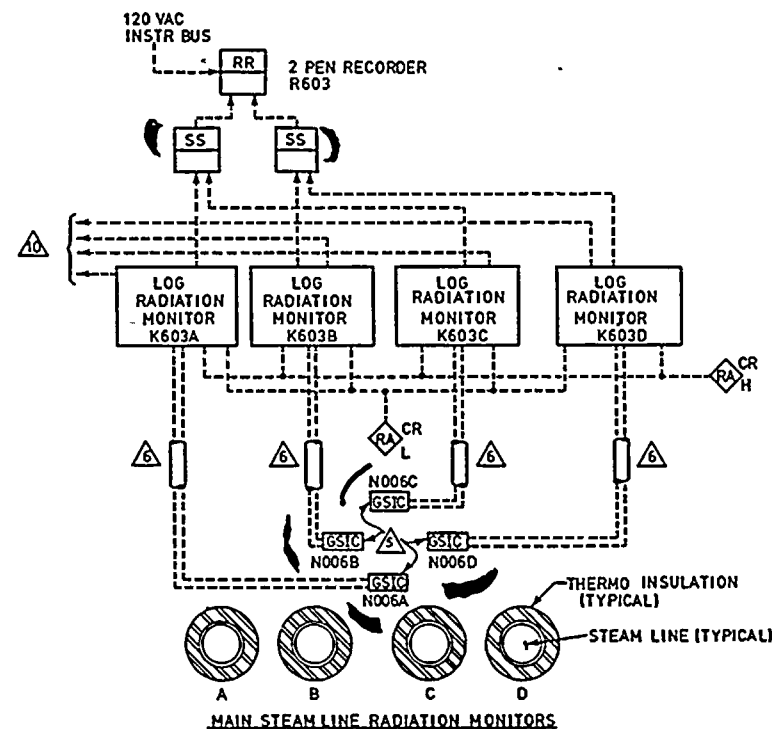
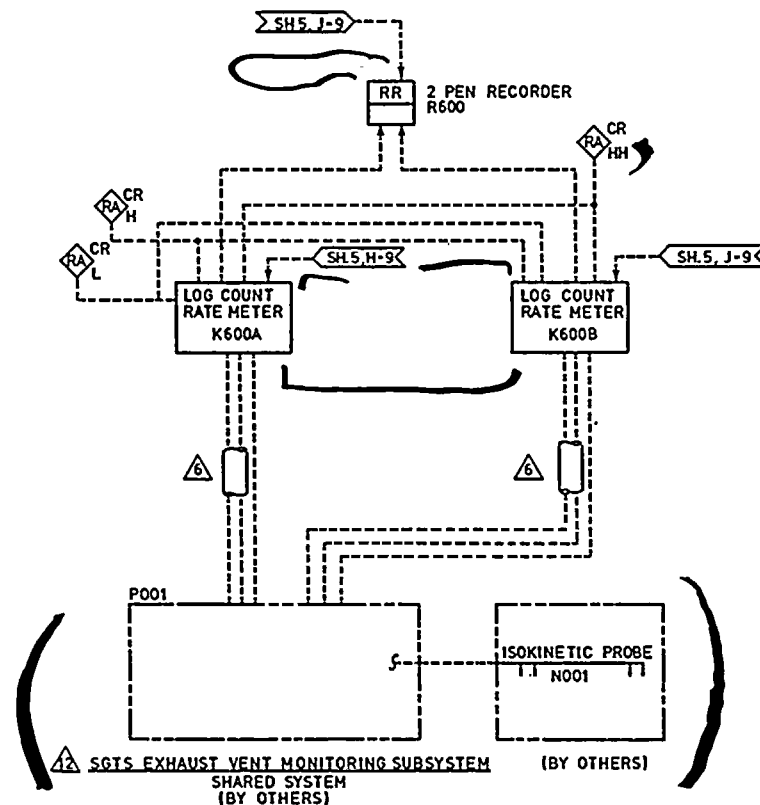
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**RHR SYSTEM  
FCD**









#### LEGEND:

SJAE	STEAM JET AIR EJECTOR
DET	GAMMA DETECTOR (ION CHAMBER)
RAHH	RADIATION ALARM HIGH-HIGH
RAH	RADIATION ALARM HIGH
RAL	INSTRUMENT TROUBLE (RADIATION ALARM LOW)
CR	LOCATED IN CONTROL ROOM
SCIN	SCINTILLATION DETECTOR
FA	FLOW ALARM
RR	RADIATION RECORDER
GSIC	GAMMA SENSITIVE ION CHAMBER
SS	SELECTOR SWITCH
SGTS	STANDBY GAS TREATMENT SYSTEM

#### REFERENCE DOCUMENTS:

	MPL ITEM NO.
1. RADIATION MONITORING OF PROCESS FLUIDS AND GASES DES. SPEC.	D12-4010
2. SPECIAL WIRE AND CABLE	A61-4010
3. PLANT REQUIREMENTS	A61-4020
4. SEPARATION & IDENT. OF ELECT. EQUIP. FOR ENGRD SAFEGUARDS	A61-4050
5. PIPING & INST SYMBOLS	A41-1010
6. INSTRUMENT SYMBOLS	A41-1020

#### NOTES:

1. THE GAS SAMPLE LINE SHALL BE 1" X 0.050 WALL THICKNESS SEAMLESS STAINLESS TUBING. THE TUBING MIN. BEND SHALL BE 20'. THE TUBING LENGTH SHALL BE JOINED WITH SWAGelok TYPE 1610-6-316 OR ENGINEERING APPROVED EQUIVALENT UNIONS. THE TUBING SHALL SLOPE SO THAT CONDENSATE WILL RUN TO DRAIN TEE.
2. REMOVAL SECTION SHALL BE PROVIDED NEAR THE ISOKINETIC PROBE FOR THE INSERTION OF A CHARCOAL FILTER HOLDER. THE FITTINGS ETC. SHALL PROVIDE SMOOTH TRANSITIONS WITHOUT DISCONTINUITIES OR REDUCING THE CROSS-SECTIONAL AREA OF THE FLOW STREAM.
3. TEE SHALL BE UNION TEE SWAGelok TYPE 1610-3-316 OR ENGINEERING APPROVED EQUIVALENT.
4. ALARM ACTUATED BY RELAYS IN TRIP AUX. UNIT ASSEMBLY PART K607.
5. THE DETECTORS (N006) SHALL BE LOCATED AS CLOSE AS PRACTICAL TO THE PRIMARY CONTAINMENT. THE DETECTOR SHALL BE ARRANGED SUCH THAT EACH DETECTOR WILL VIEW ALL STEAM LINES WITH APPROXIMATELY THE SAME RESPONSE. THE DETECTOR OR DETECTOR ASSEMBLY MAY BE FASTENED TO A ROD OR A PIPE AND INSERTED INTO SEALED PIPE WELLS FROM OUTSIDE THE STEAM TUNNEL. CAREFULLY ROUTE CABLES TO MINIMIZE HEAT EXPOSURE.
6. ALL CABLE SHALL COMPLY WITH GE ENGR. SPEC. REF. 2.
7. REMOVED.
8. REMOVED.
9. ALL PART NUMBERS ARE PREFIXED BY D12 UNLESS OTHERWISE SPECIFIED.
10. ONE HIGH-HIGH RADIATION TRIP (RAHH) OR INOPERATIVE TRIP OUT OF TWO IN TRIP SYSTEM "A" AND ONE HIGH-HIGH RADIATION TRIP (RAHH) OR INOPERATIVE TRIP OUT OF TWO IN TRIP SYSTEM "B" SHALL:
  - (1) CLOSE MAIN STEAM LINE ISOLATION VALVES
  - (2) SHUTDOWN REACTOR AND
  - (3) TURN OFF MECHANICAL VACUUM PUMP & CLOSE MECHANICAL LINE VALVE. (REF. 3)
 ANY ONE HIGH-HIGH RADIATION SHALL ALARM (RAHH).
11. REMOVED.
12. ALL EQUIPMENT APPLICABLE TO THIS SUB-SYSTEM IS SUPPLIED FOR UNIT 1 ONLY, & IS SHARED BY BOTH UNITS.
13. THE OFF GAS SAMPLE CHAMBER SHALL BE MOUNTED VERTICALLY AND THE TUBING SHALL SLOPE AWAY FROM THE CHAMBER SO THAT THE CONDENSATE WILL RETURN TO THE PROCESS.
14. HEATER TO BE APPROXIMATELY SIZED AND SUPPLIED BY CUSTOMER. HEATER SWITCH IS SUPPLIED.
15. FILTER ASSEMBLY SUPPLIED AS PART OF ASSOCIATED ISOKINETIC PROBE.

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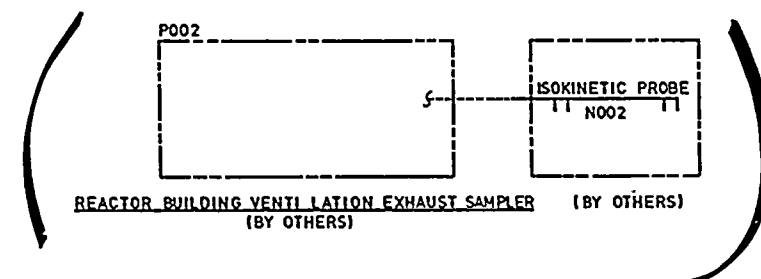
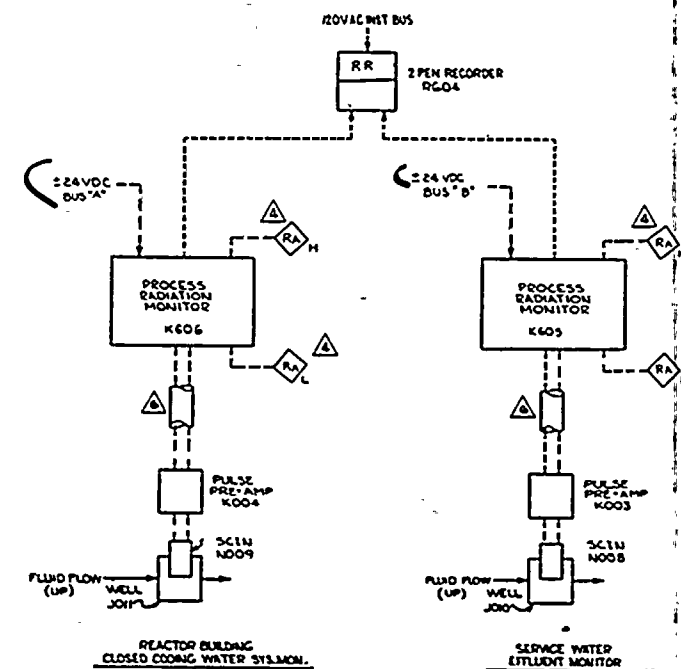
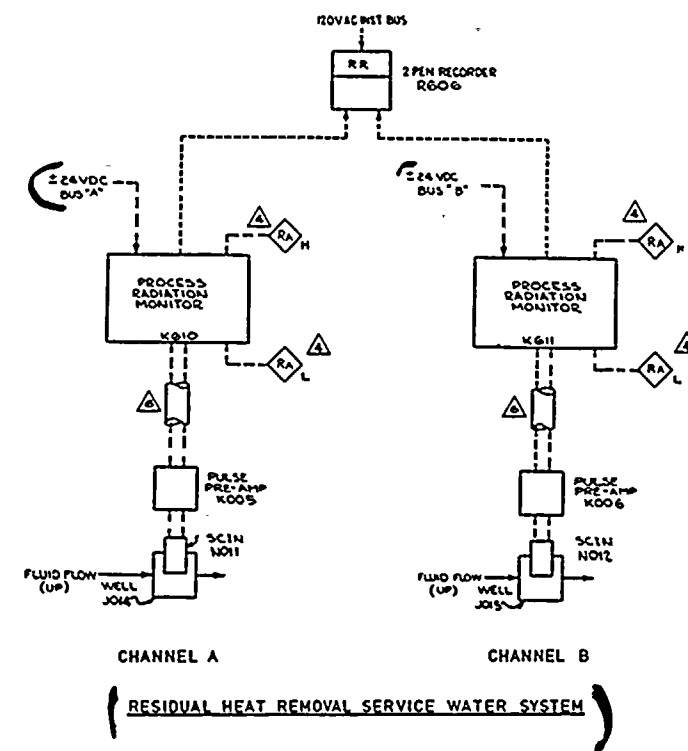
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### PROCESS RADIATION MONITORING SYSTEM IED

FIGURE 7.3-11 Sheet 1







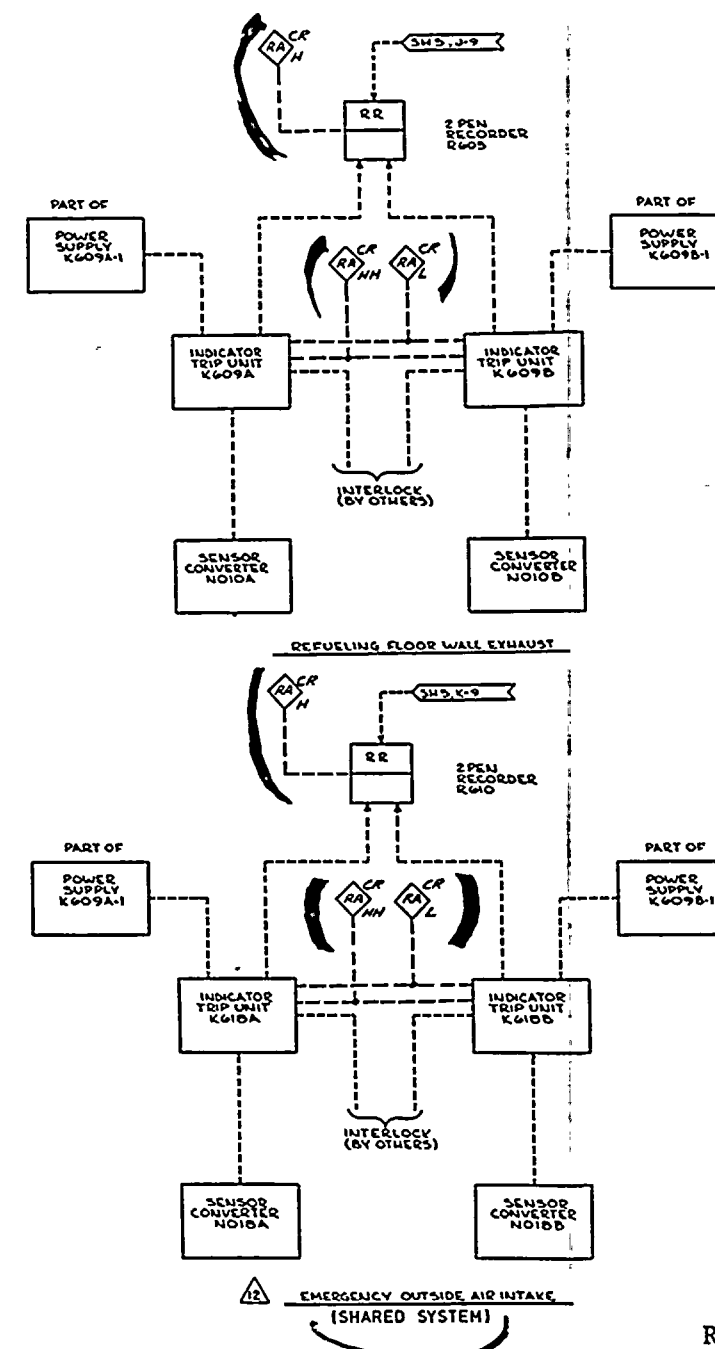
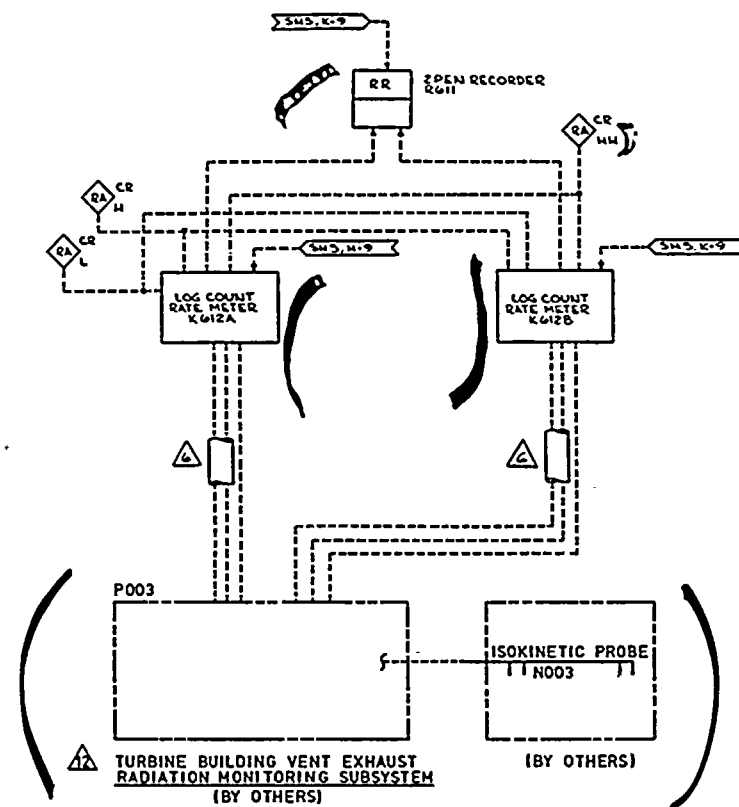
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PROCESS RADIATION  
MONITORING SYSTEM  
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FIGURE 7.3-11 Sheet 2





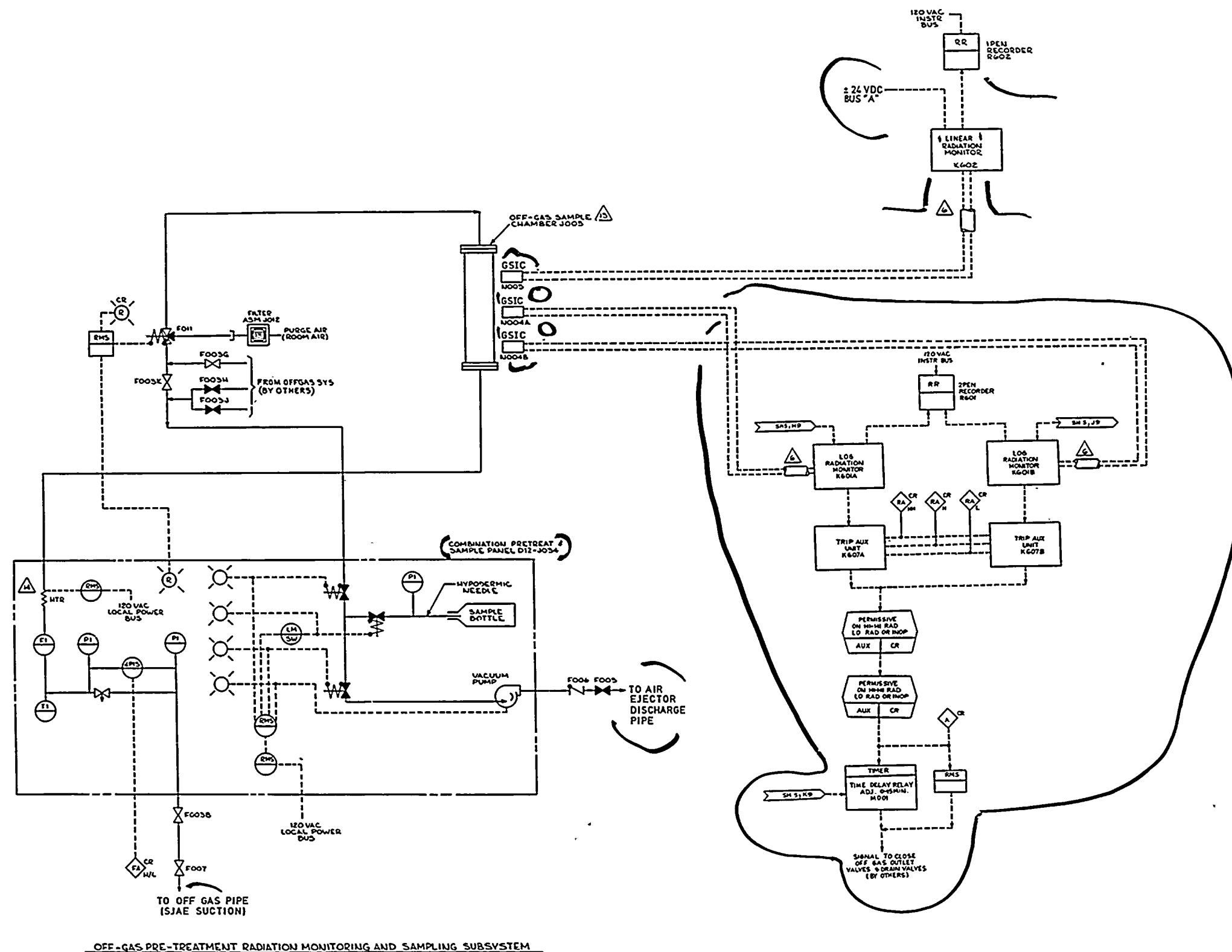
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UNITS 1 AND 2  
FINAL SAFETY ANALYSIS REPORT

PROCESS RADIATION  
MONITORING SYSTEM  
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FIGURE 7.3-11 Sheet 3



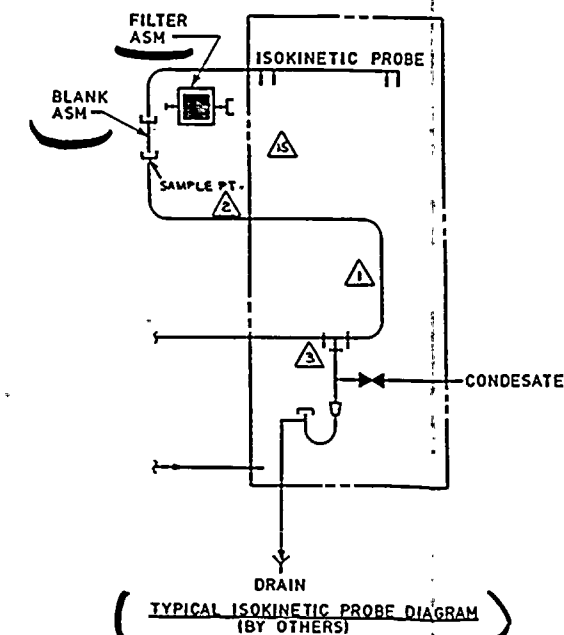
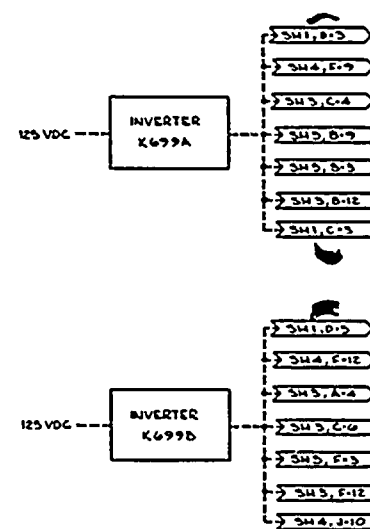
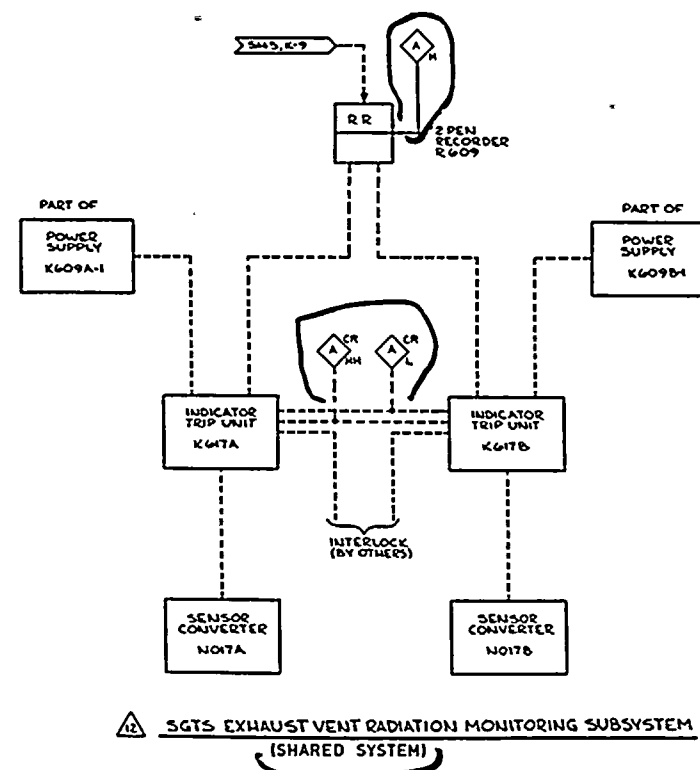
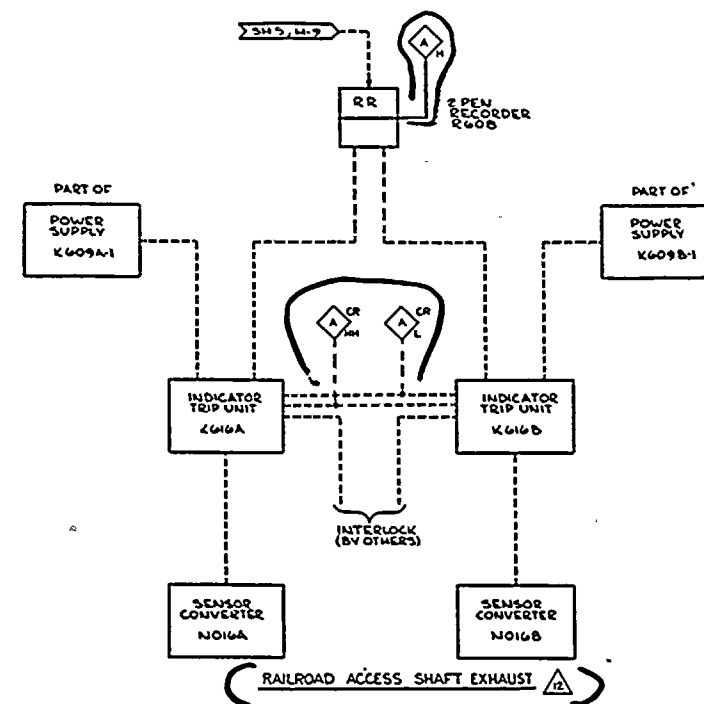
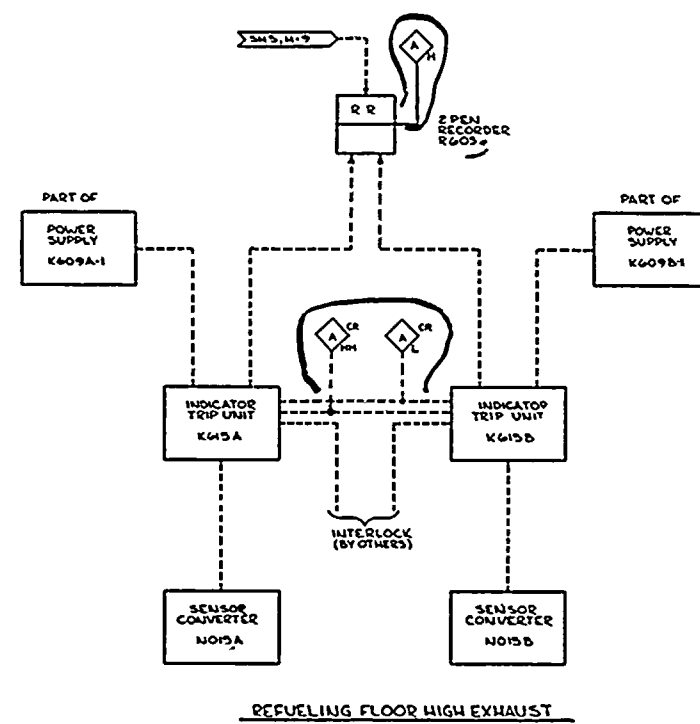


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**PROCESS RADIATION  
MONITORING SYSTEM  
IED**





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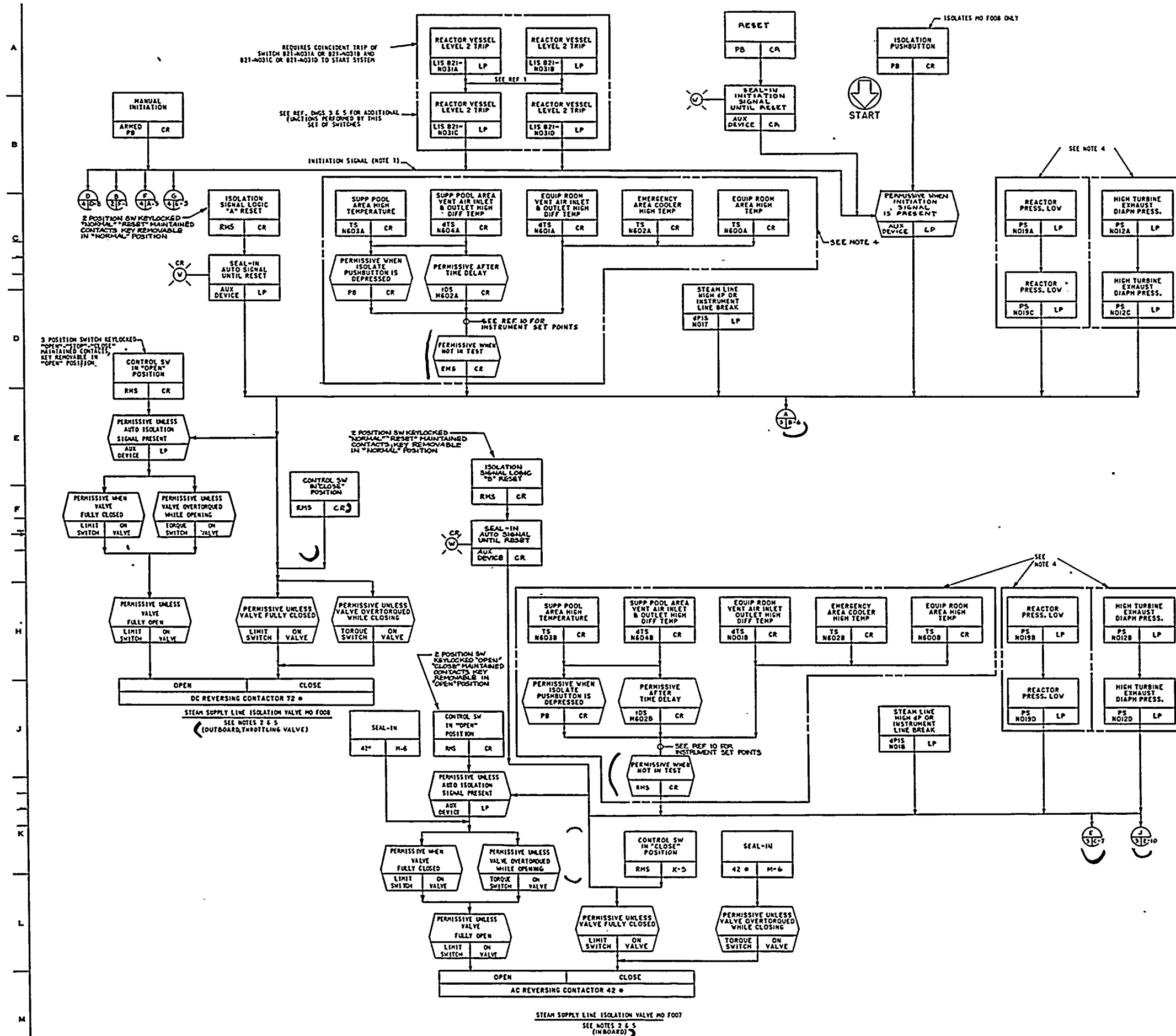
SUSQUEHANNA STEAM ELECTRIC STATION  
UNITS 1 AND 2  
FINAL SAFETY ANALYSIS REPORT

PROCESS RADIATION  
MONITORING SYSTEM  
IED

FIGURE 7.3-11 Sheet 5







FCF 298X134E G462 (E51-1030)

- NOTES:
1. THE REIC SYSTEM IS ARRANGED FOR TEST OF PUMP AT FLOW & ALL VALVES RUN, WHEN A CLOSE CAPABILITY AT ANY TIME EXCEPT WHEN INITIATION SIGNAL OR AUTO ISOLATION SIGNAL IS ACTIVATED, THE TEST OF THE ISOLATION SIGNAL DOES HAVE TO BE UNDERWAY THE SYSTEM AUTOMATICALLY RETURNS TO START-UP MODE.
2. ALL POWER FOR OPERATION OF DC VALVE MOTORS SHALL ORIGINATE FROM A PLANT DC BUS. POWER FOR AC OPERATED VALVES SHALL ORIGINATE FROM AN EMERGENCY AC BUS.
3. ALL EQUIPMENT & INSTRUMENT PREFIXED BY SYSTEM NO. (ESS) UNLESS OTHERWISE NOTED.
4. ISOLATION SIGNAL SWITCHES SHALL BE OF THE TYPE CLOSE CONTACTS FOR THE SPECIFIED ISOLATION EVENT. WHEN AUTO IS USED IN THE ISOLATION CHANGES THEY SHALL BE POWERED FROM THE STATION BATTERIES.
5. AUXILIARY RELAYS & DEVICES NOT SHOWN ON FUNCTIONAL CONTROL DIAGRAMS EXCEPT WHERE REFERRED TO CLARIFY THE OPERATION.
6. FURNISHED WITH TURBINE.
7. THE REIC SYSTEM SHALL BE DESIGNED IN ACCORDANCE WITH REF. 11.
8. THE REIC SYSTEM SHALL BE DESIGNED IN ACCORDANCE WITH CRITERIA FOR NUCLEAR POWER PLANT PROTECTION SYSTEM IEEE - 279.
9. REIC PUMP MOTOR COMBINATION STARTERS SHALL BE PROVIDED WITH THERMAL OVERLOADS WHICH TRIP ON OVERLOAD. THESE DEVICES SHALL PROVIDE SHORT CIRCUIT PROTECTION, TRIPPING OF EITHER TYPE OF DEVICE IS ANNOUNCED VIA AN ALARM RELAY.
10. VALVE MOTORS ARE TO BE PROVIDED WITH THERMAL OVERLOAD TRIPS AND LOSS OF POWER ANNUNCIATOR OVERLOAD TRIPS TO BE PROVIDED UNDER TEST- IN ADDITION VALVE MOTOR CIRCUITS ARE TO BE PROVIDED WITH SHORT CIRCUIT PROTECTIVE TRIPS.
11. LIGHTS TO BE PART OF LIGHT BOX LOCATED BELOW REGULAR REIC ANNUNCIATOR LEGEND AS SHOWN.

REFERENCE DOCUMENTS	IMP. ITEM NO.
1. NUCLEAR BOILER PGID-----	821-1010
2. NUCLEAR BOILER MISC SYS FCD-----	821-1030
3. HWY SYSTEM FCD-----	821-1030
4. CORE SPRAY SYSTEM FCD-----	821-1030
5. IMCI SYSTEM FCD-----	841-1030
6. RECIC SYSTEM PGID-----	851-1010
7. LOGIC SYMBOLIC-----	851-1030
8. TURBINE CONT SYS & ELEC WIRING-----	875-2055
9. REAC WATER CLEAN-UP SYS PGID-----	831-1010
10. LEAK DETECTION SYS-----	461-4040
11. ELEC COOL SEPARATION FOR S&W GROUPED SYSTEMS-----	461-4050
12. INSTRUMENT DATA SHEET-----	451-2050

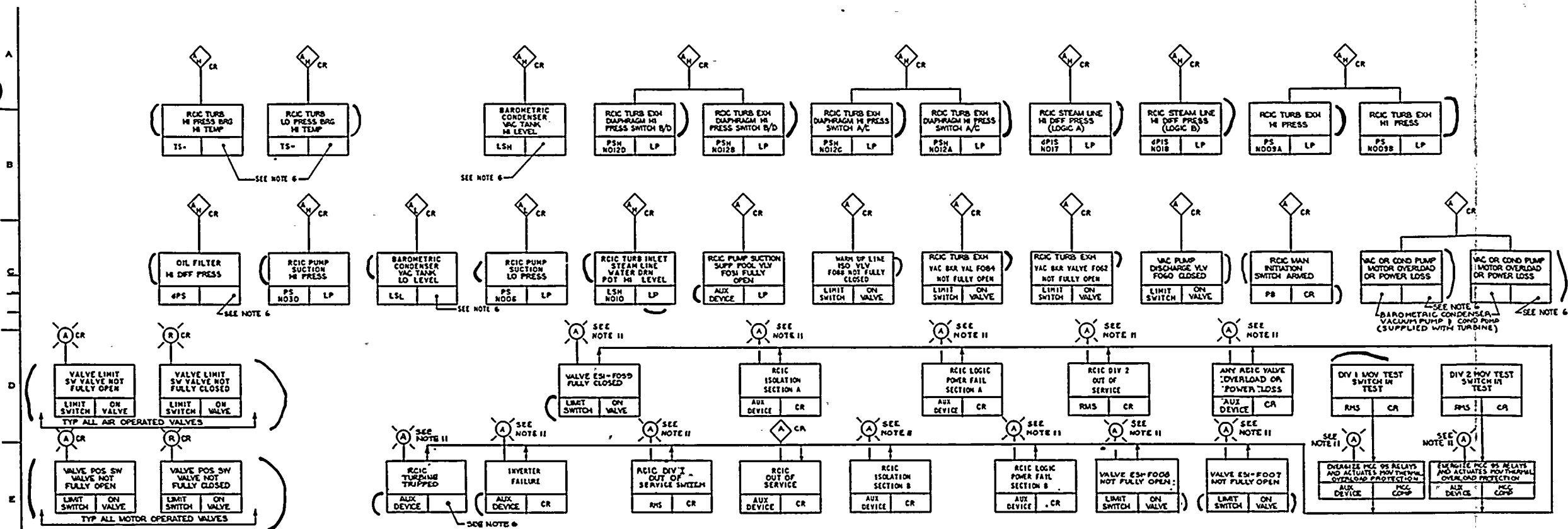
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**SUSQUEHANNA STEAM ELECTRIC STATION  
UNITS 1 AND 2  
FINAL SAFETY ANALYSIS REPORT**

REACTOR CORE ISOLATION  
COOLING SYSTEM  
FCD

FIGURE 7.4-2 Sheet 1





TURBINE SUPERVISORY INSTRUMENTATION ALARMS & VALVE INDICATIONS

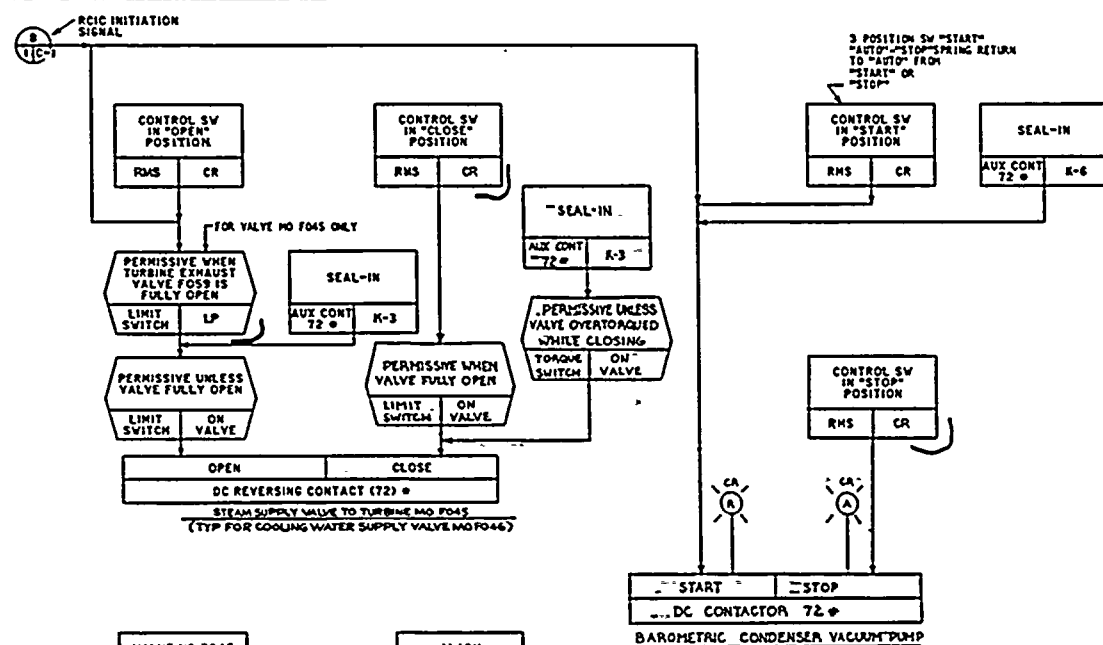


TABLE I

ALARM FUNCTION	INITIATING DEVICE	DEVICE LOCATION	TYPE OF ALARM	ALARM LOCATION
RCIC TURBINE HI PRESS	PSL	SEE NOTE 6	LOW	CR
RCIC TURBINE LO PRESS	PSL	SEE NOTE 6	HIGH	CR
RCIC TURBINE HI PRESS	PSL	SEE NOTE 6	LOW	CR

TURBINE CONDITIONAL SUPERVISORY ALARMS

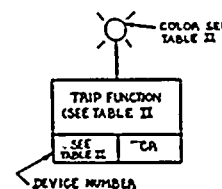


TABLE II

ACTUATING DEVICE	TRIP FUNCTION	COLOR	LOC. LOCATION
REF. 6	TRIP THROTTLE VALVE OPEN	RED	CR
	TRIP THROTTLE VALVE CLOSED	RED	CR
	GOVERNOR VALVE OPEN	RED	CR
	GOVERNOR VALVE CLOSED	RED	CR

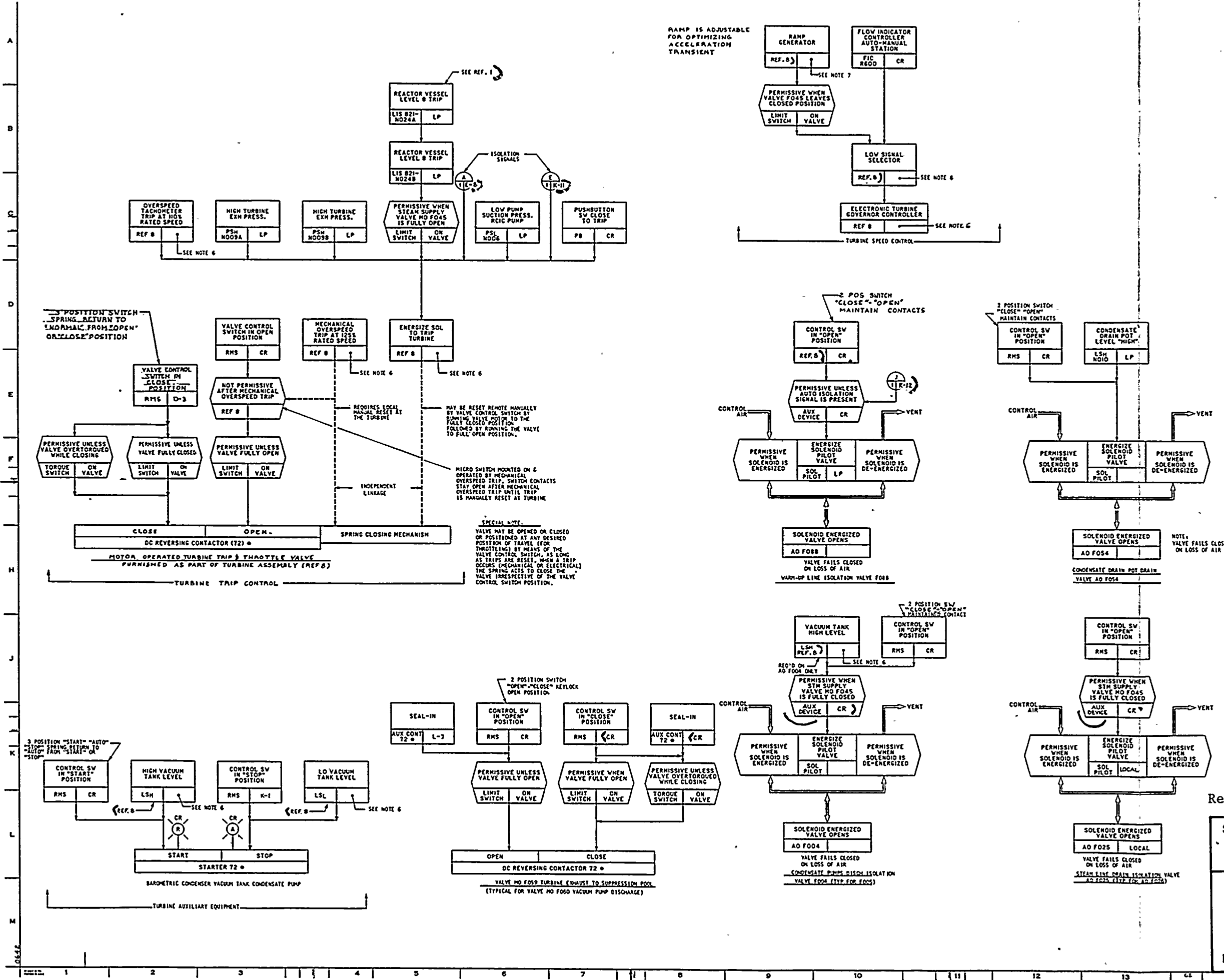
TURBINE INDICATING LIGHTS

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UNITS 1 AND 2  
FINAL SAFETY ANALYSIS REPORT

REACTOR CORE ISOLATION  
COOLING SYSTEM  
FCD





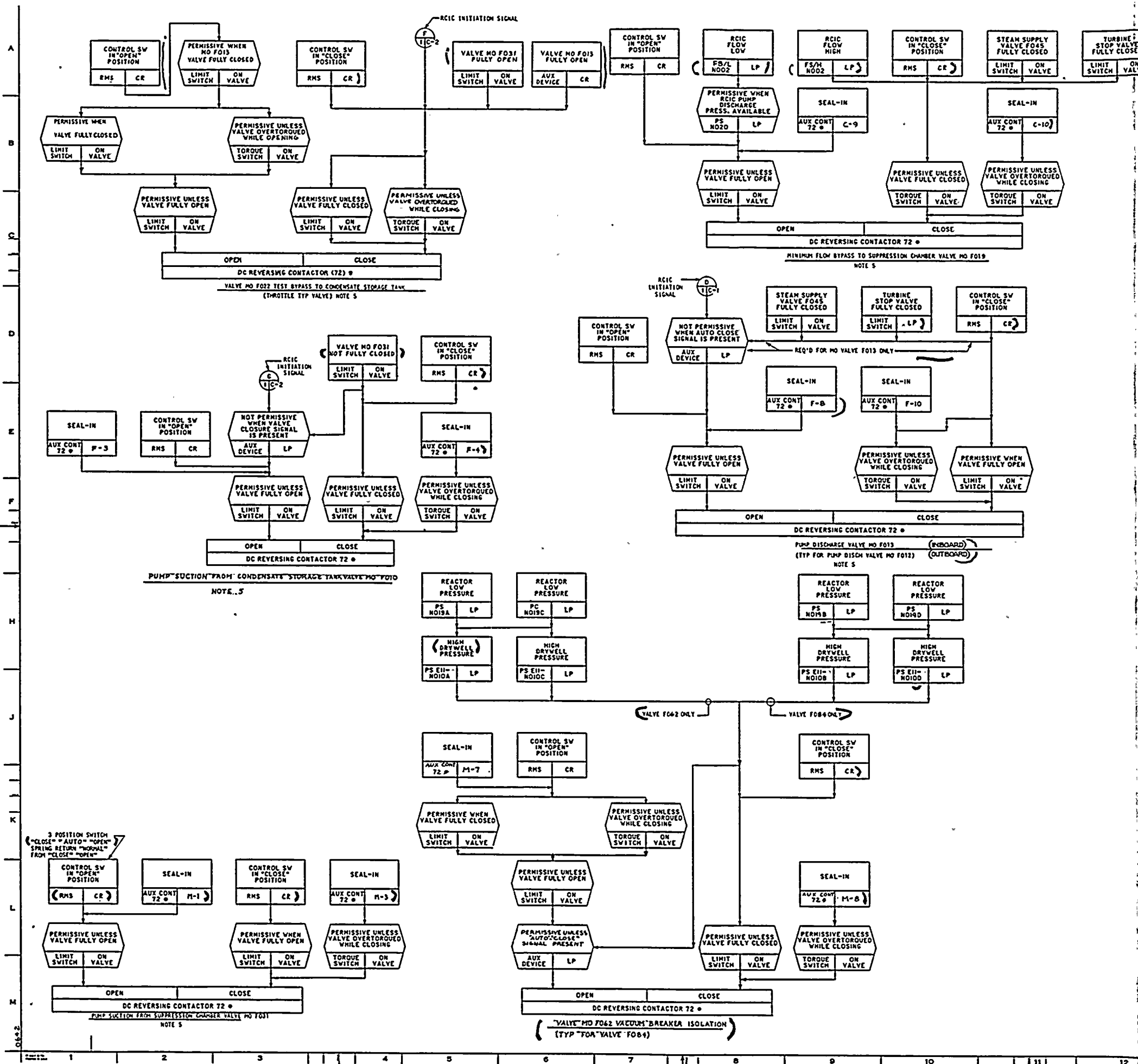
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**SUSQUEHANNA STEAM ELECTRIC STATION  
UNITS 1 AND 2  
FINAL SAFETY ANALYSIS REPORT**

**REACTOR CORE ISOLATION  
COOLING SYSTEM  
FCD**

**FIGURE 7.4-2 Sheet 3**

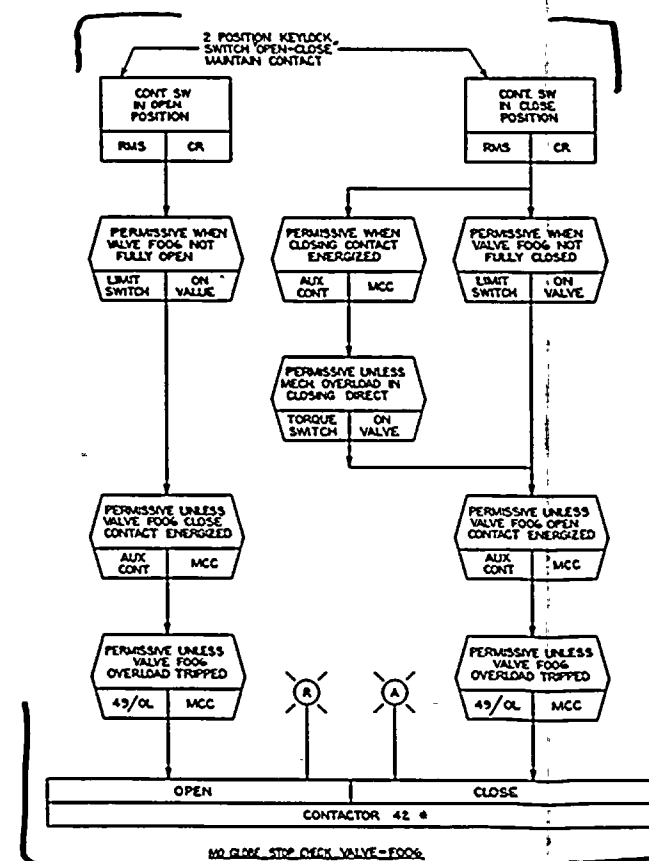
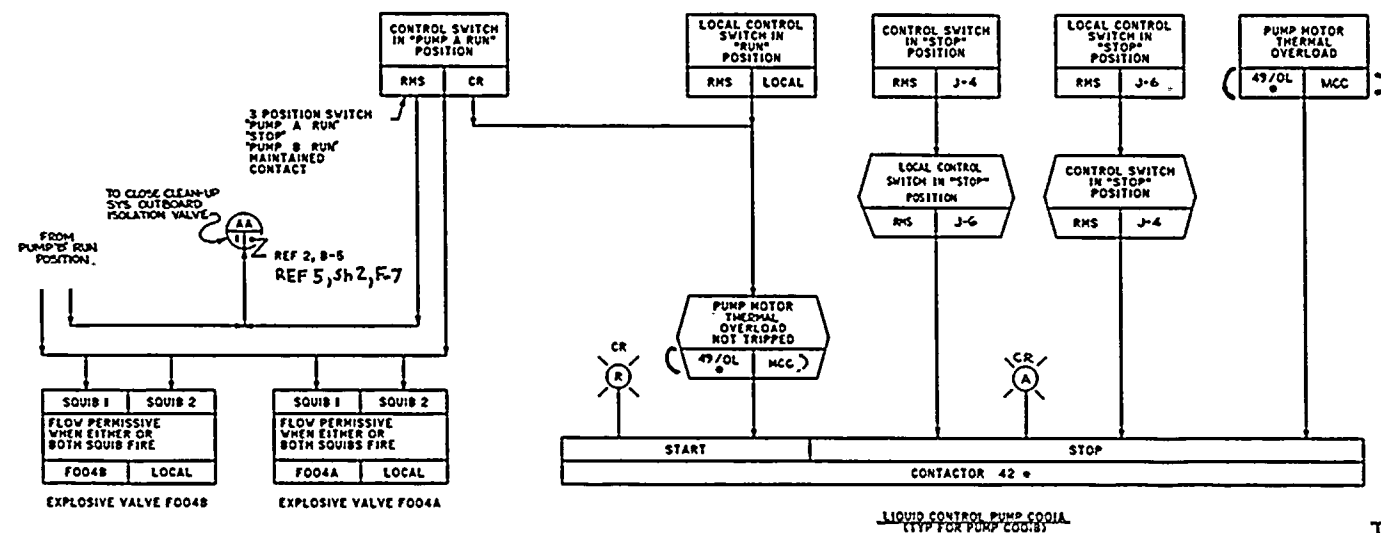
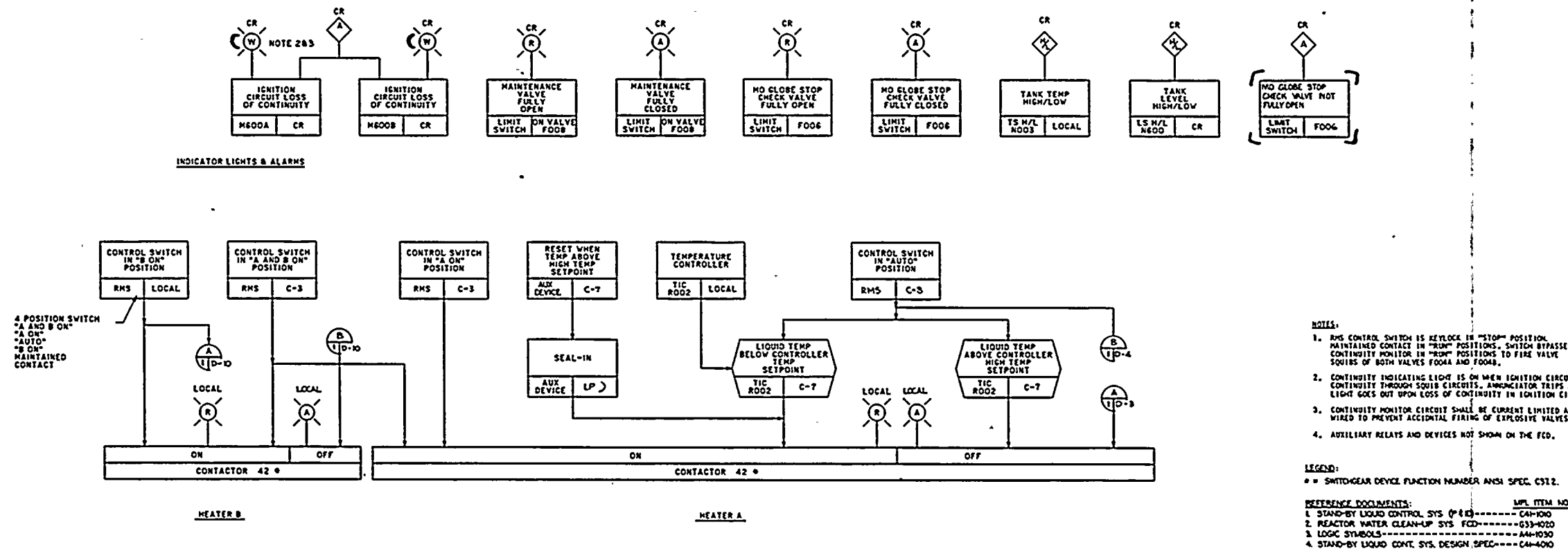




SUSQUEHANNA STEAM ELECTRIC STATION  
 UNITS 1 AND 2  
 FINAL SAFETY ANALYSIS REPORT  
 REACTOR CORE ISOLATION  
 COOLING SYSTEM  
 FCD  
 FIGURE 7.4-2 Sheet 4







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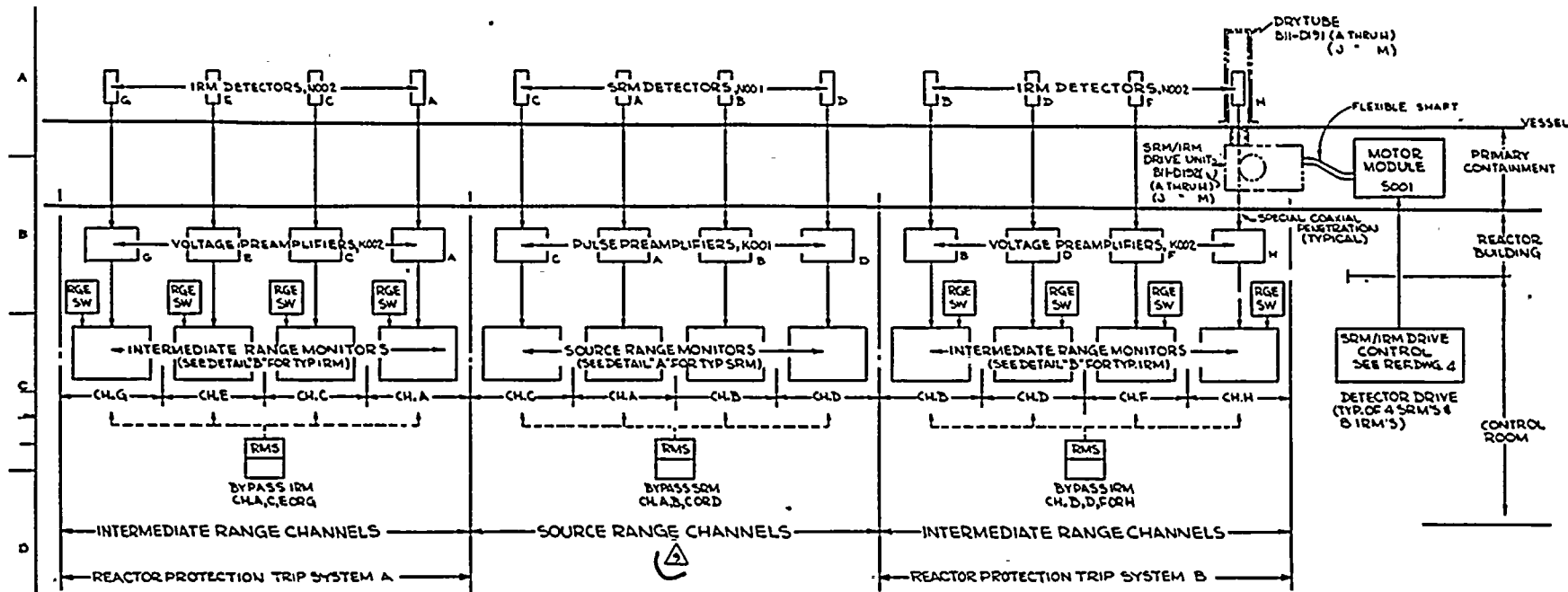
**SUSQUEHANNA STEAM ELECTRIC STATION  
UNITS 1 AND 2  
FINAL SAFETY ANALYSIS REPORT**

**STANDBY LIQUID  
CONTROL SYSTEM  
FCD**

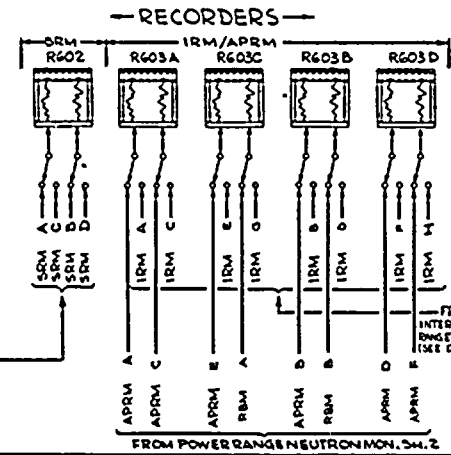
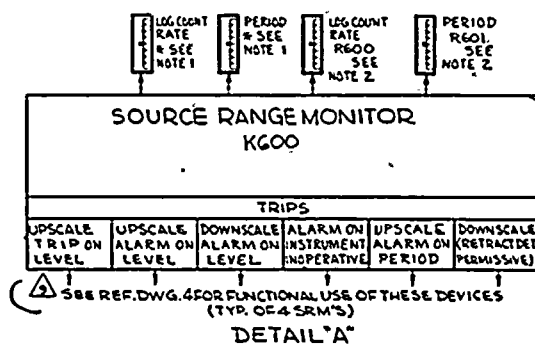
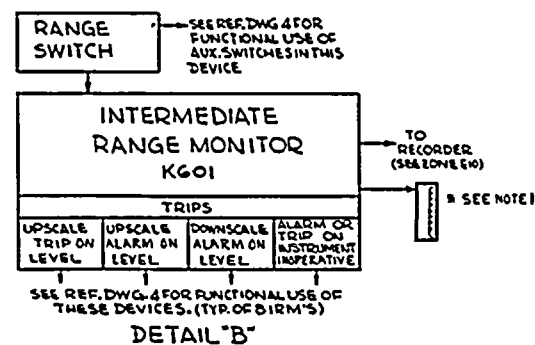
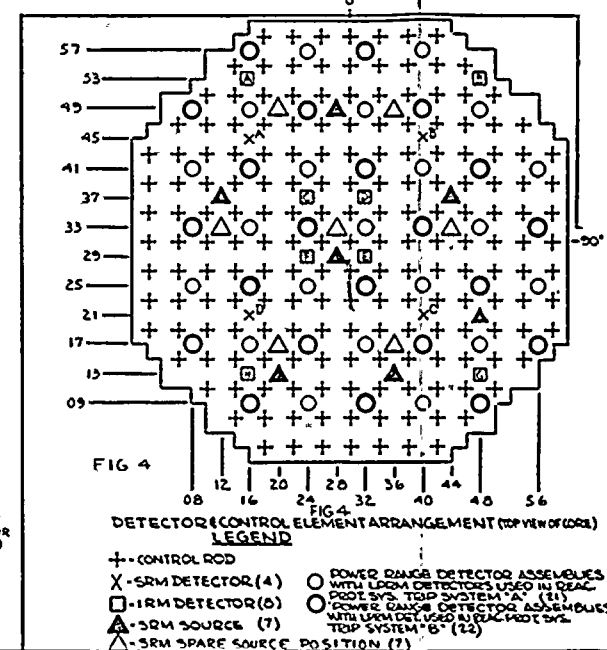
**FIGURE 7.4-4**

THIS DWG SUPERSEDES  
DWG 919D694 REV 6  
FOR SUSQUEHANNA 112

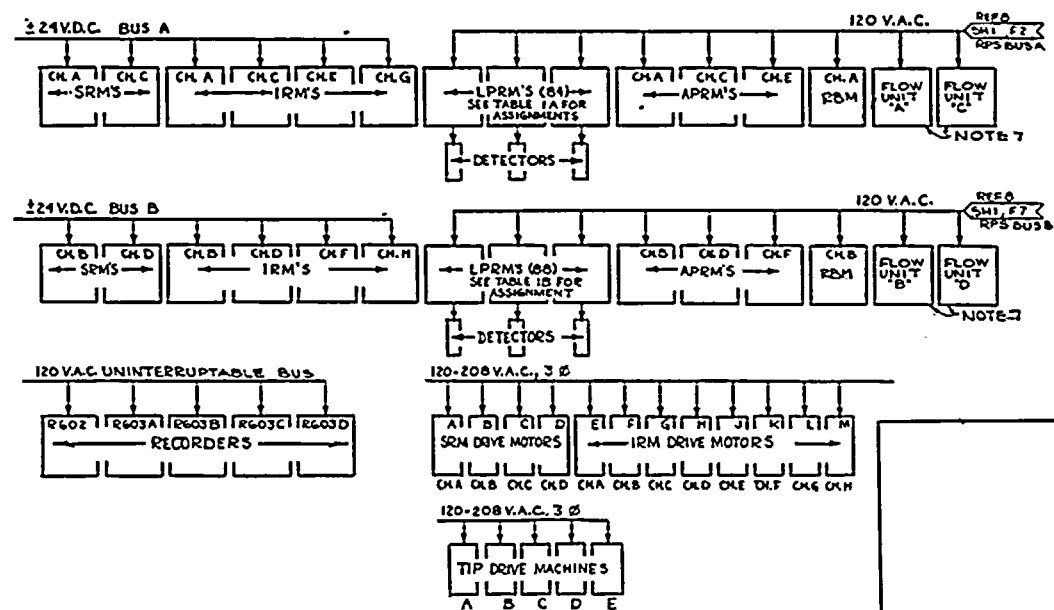




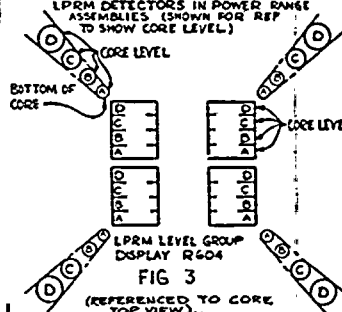
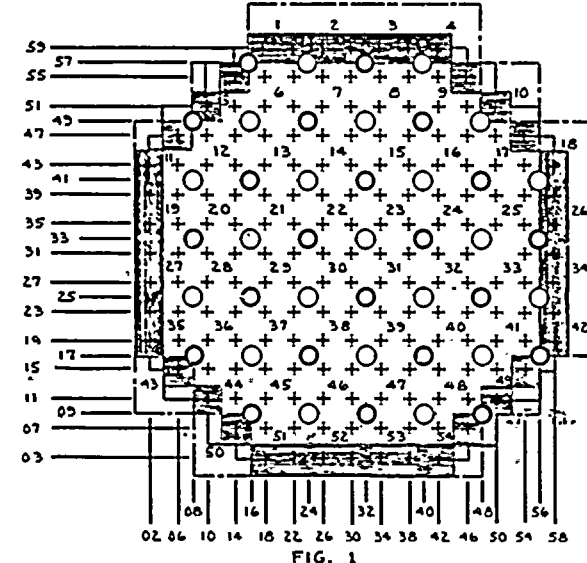
- NOTES:
1. PARTS NAMED "A" ARE LOCATED ADJACENT TO OR ON THE SIGNAL CONDITIONING EQUIPMENT PERFORMING THE FUNCTION INDICATED.
  2. PARTS ARE LOCATED ON THE MAIN CONTROL PANEL.
  3. POSITION INFORMATION IS INPUT EVERY 1 INCH, FLUX LEVEL INFORMATION IS INPUT EVERY 3 INCHES OR MORE.
  4. ALL EQUIPMENT & INSTRUMENTS ARE PREFIXED BY SYSTEM NO. C51 UNLESS OTHERWISE NOTED.
  5. FOR LOCATION AND IDENTIFICATION OF INSTRUMENTS SEE INSTRUMENT DATA SHEET LISTED IN HPI FOR EACH INSTRUMENT.
  6. FLOW UNIT INCLUDES FLOW SENSER, POWER SUPPLY & SOURCE ROOT FUNCTIONS AS SHOWN ON REFERENCE DNG 2.
  7. EXCEPT FOR PART NO. 10, THE EXACT ASSIGNMENT OF TIP GUIDE TUBES FROM SPECIFIC INDEXING MECHANISMS TO SPECIFIC POWER RANGE DETECTOR ASSEMBLIES IN RESPECTIVE GROUPS SHOWN IS DETERMINED BY OTHERS AND WILL BE DELINEATED LATER.
  8. SRM CHANNELS PROVIDE NON-CONCURRENT TRIP SIGNALS TO THE REACTOR PROTECTION SYSTEM DURING INITIAL FUEL LOAD ONLY.



### START-UP RANGE NEUTRON MONITORING



### POWER DISTRIBUTION



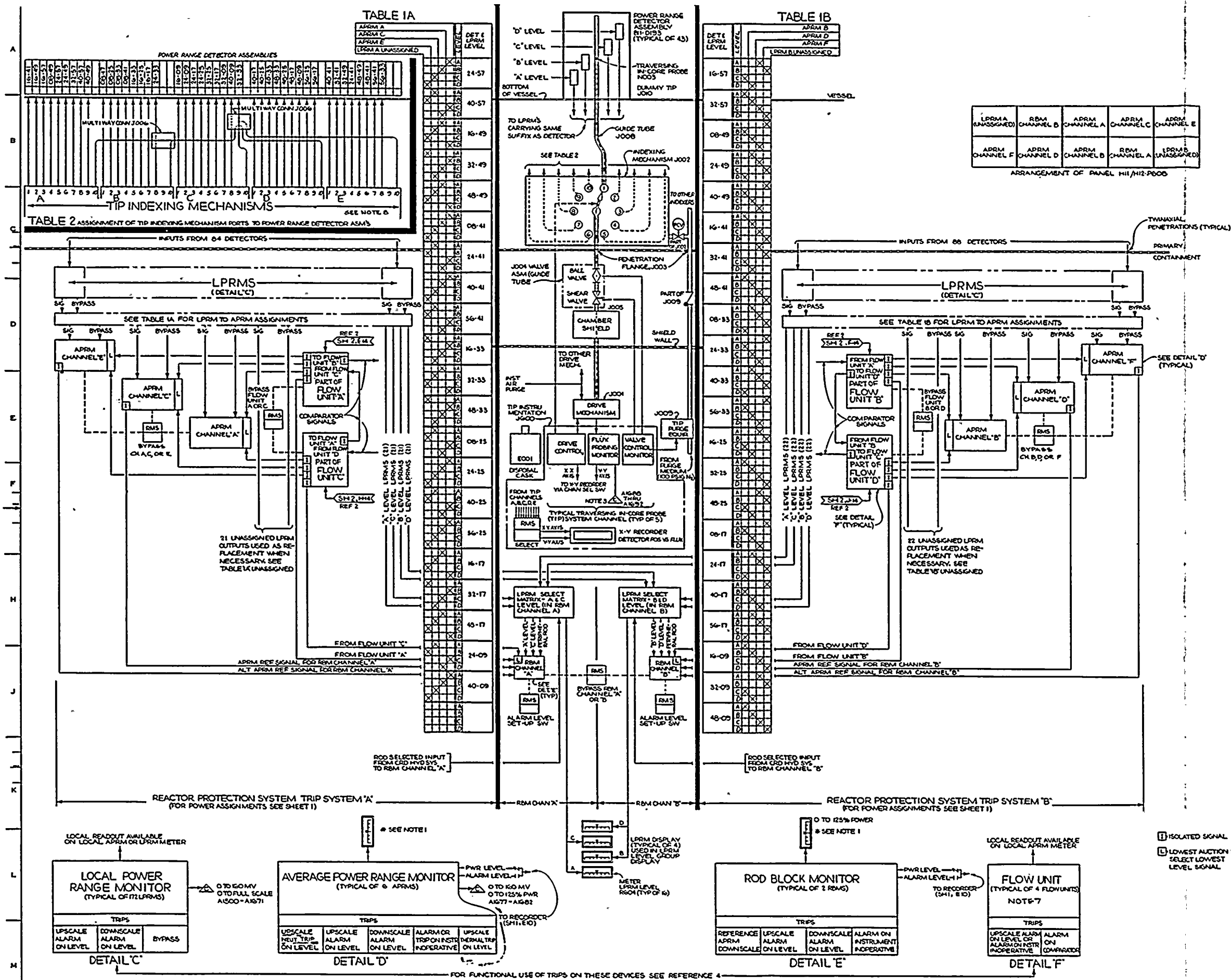
- REFERENCE SYMBOLS:
1. ONE LINE DIAGRAM PLANT D.C. & INSTRUMENT AC SYS - BY SYMBOL
  2. FLOW REACTOR REACTOR SYS - BY SYMBOL
  3. FLOW CONTROL ROD DRIVE HYDRAULIC SYS - BY SYMBOL
  4. FLOW NEUTRON MONITORING SYS - BY SYMBOL
  5. DESIGN SPEC. NEUTRON MONITORING SYS - BY SYMBOL
  6. ARRANGEMENT DRAWING NEUTRON MONITORING SYS - BY SYMBOL
  7. ASSEMBLY DRAWING, REACTOR - BY SYMBOL
  8. IED REACTOR PROTECTION SYSTEM - BY SYMBOL

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## SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT

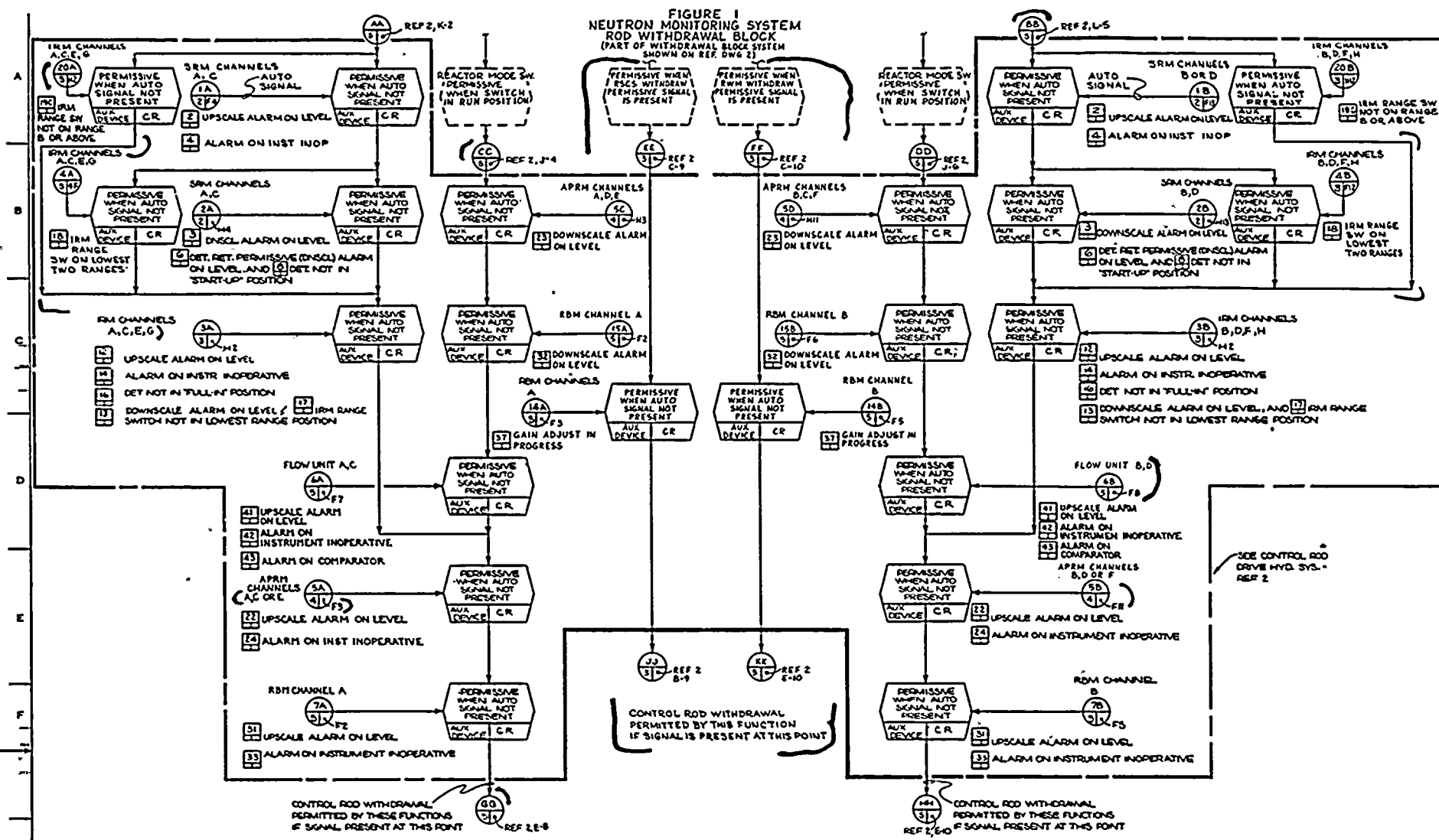
### NEUTRON MONITORING SYSTEM IED





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- NOTES:
1. INPUTS TO COMPUTER ARE ISOLATED CLOSE TO ALARM CONTACTS.
  2. SEE SHEET 7.
  3. SEE SHEET 7.
  4. THE ENTIRE NEUTRON MONITORING SYSTEM IS A FULLY AUTOMATIC SYSTEM EXCEPT FOR MANUAL OPERATED SWITCHES.
  5. ALL EQUIPMENT & INSTRUMENTS ARE PREFIXED BY CSI UNLESS OTHERWISE NOTED.
  6. CHANNELS A, C, E & G ARE FOR TRIP SYSTEM A. CHANNELS B, D, F & H ARE FOR TRIP SYSTEM B.

LEGEND:

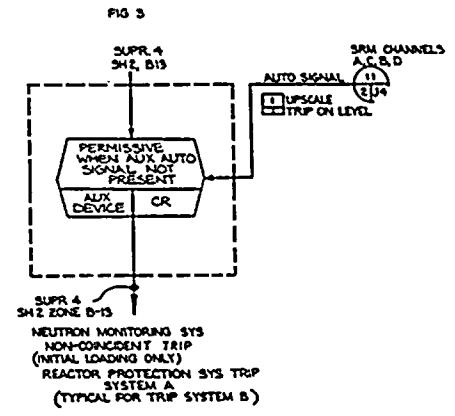
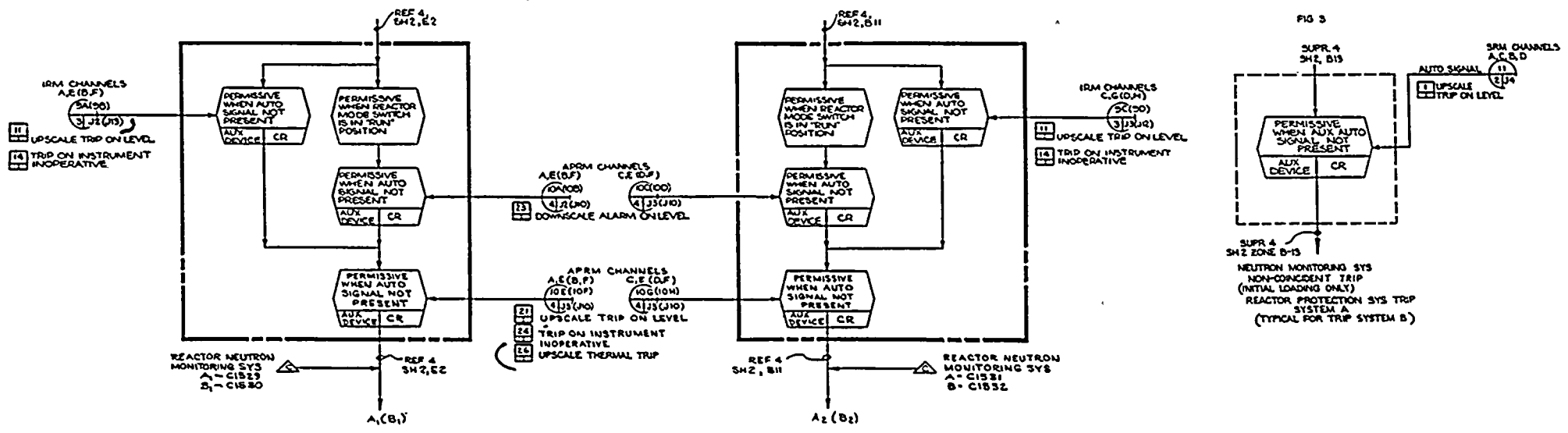
- IRM - INTERMEDIATE RANGE MONITOR
- RBM - ROD BLOCK MONITOR
- APRM - AVERAGE POWER RANGE MONITOR
- SRM - SOURCE RANGE MONITOR
- LRM - LOCAL POWER RANGE MONITOR
- TIP - TRAVELING IN-CORE PROBE
- MOC - MULTIPLE OUTPUT CONTROLLER
- RSCS - ROD SEQUENCE CONTROL SYSTEM

REFERENCE DOCUMENTS:

NOTE: SYSTEM SELECTION OPTIONS ARE INDICATED BY MULTIPLE MPL ITEM NUMBERS

	MPL ITEM NO.
1. NEUTRON MONITORING SYSTEM IED	CS1 100
2. CONTROL ROD DRIVE HYD SYS FCD	CS1 512-1030
3. NUCLEAR BOILER SYS FCD	CS1 1030
4. REACTOR PROTECTION SYS IED	CS1 512-1030
5. PROCESS COMPUTER SYSTEM INPUT/OUTPUT REQUIREMENTS DESIGN SPEC	CS1 512-1030
6. LOGIC SYMBOLS	CS1 512-1030
7. NEUTRON MONITORING SYS. ARRANGEMENT	CS1 512-1030

FIGURE 2  
NEUTRON MONITORING  
SYSTEM TRIP  
REACTOR PROTECTION  
SYSTEM TRIP SYSTEM A.  
(TYPICAL FOR TRIP SYSTEM B~)



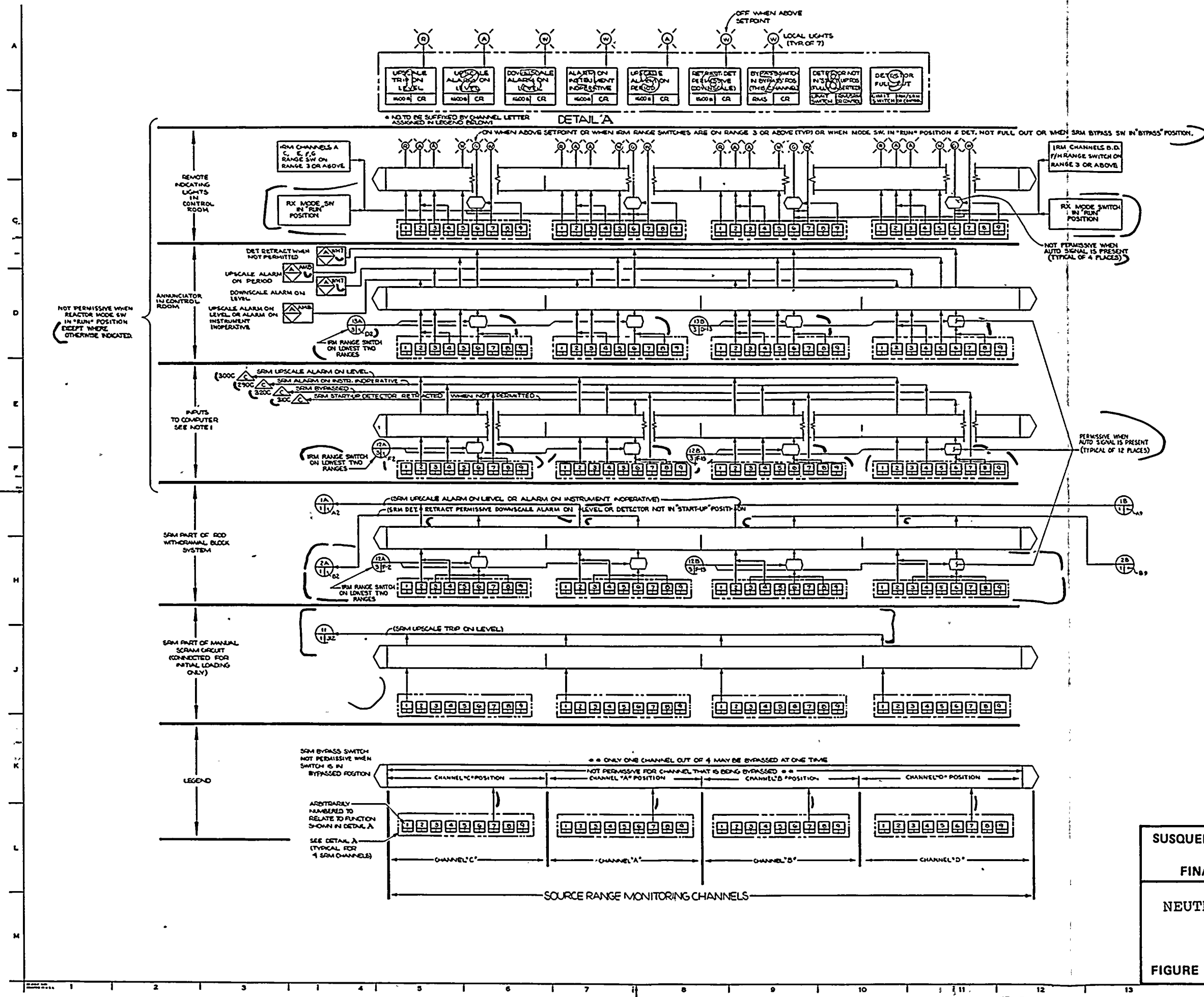
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UNITS 1 AND 2  
FINAL SAFETY ANALYSIS REPORT

NEUTRON MONITORING SYSTEM  
FCD







SUSQUEHANNA STEAM ELECTRIC STATION  
 UNITS 1 AND 2  
 FINAL SAFETY ANALYSIS REPORT

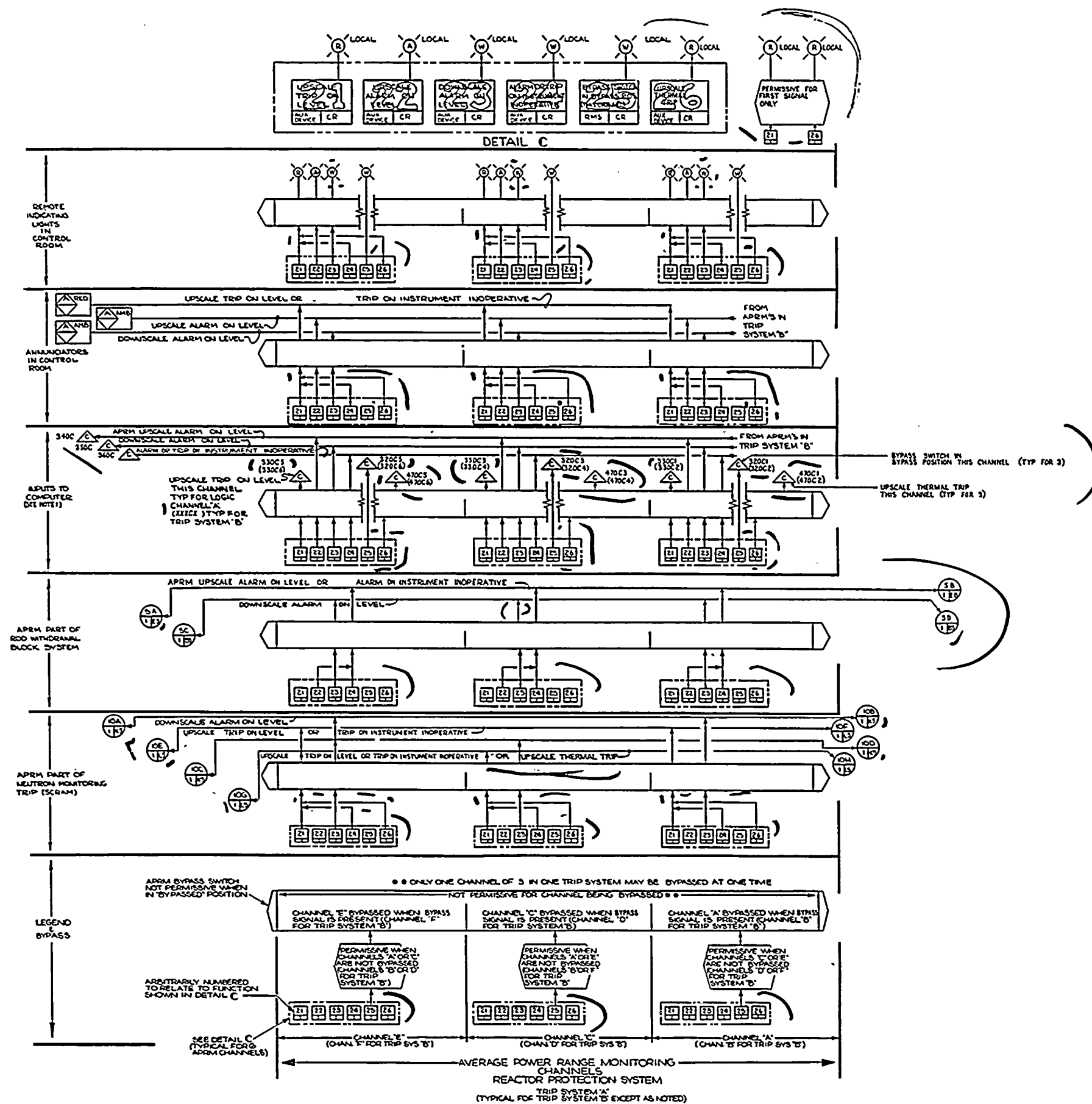
NEUTRON MONITORING SYSTEM  
 FCD

FIGURE 7.6-7 Sheet 2









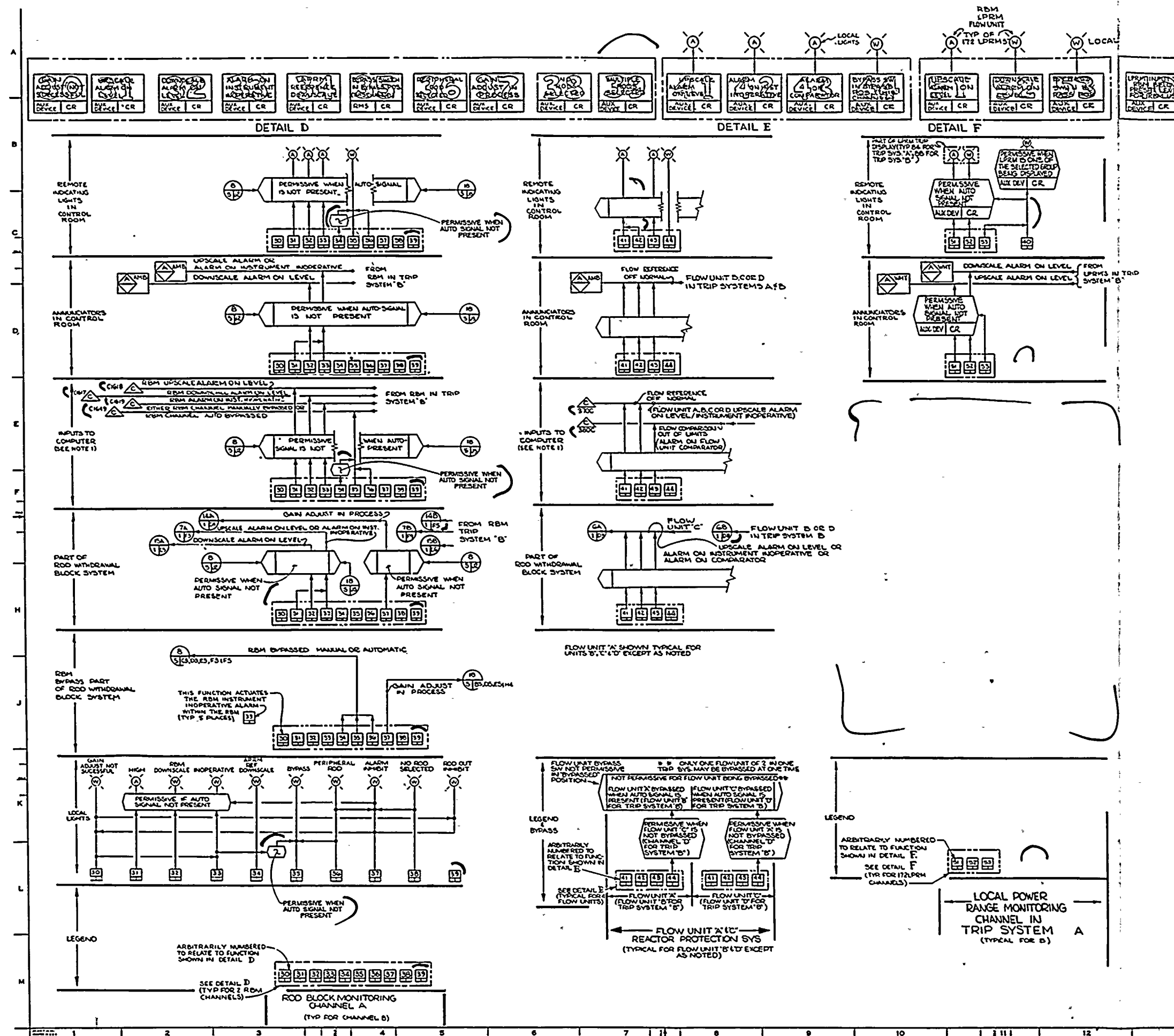
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UNITS 1 AND 2  
FINAL SAFETY ANALYSIS REPORT

NEUTRON MONITORING SYSTEM  
FCD

FIGURE 7.6-7 Sheet 4





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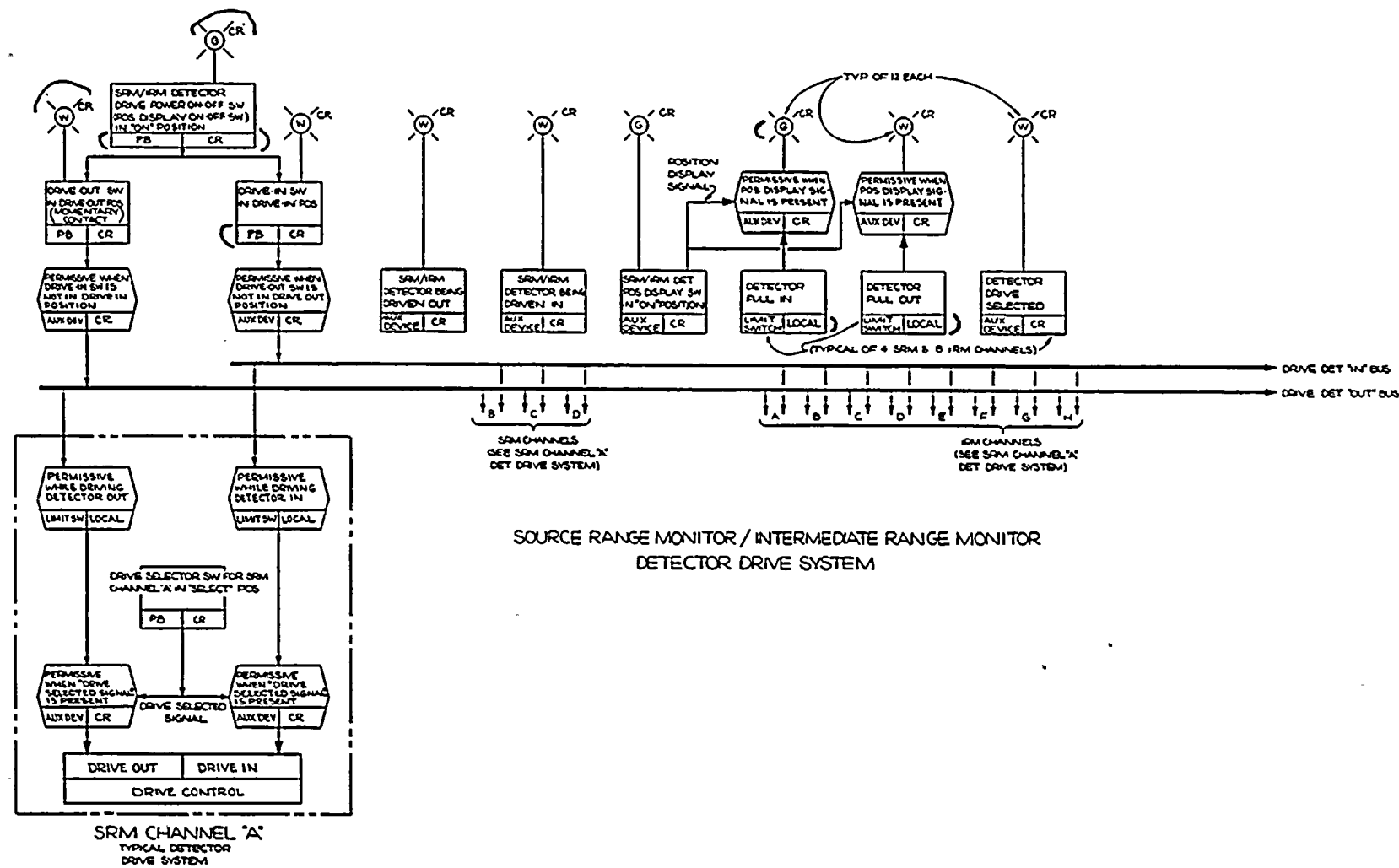
SUSQUEHANNA STEAM ELECTRIC STATION  
UNITS 1 AND 2  
FINAL SAFETY ANALYSIS REPORT

NEUTRON MONITORING SYSTEM  
FCD

FIGURE 7.6-7 Sheet 5







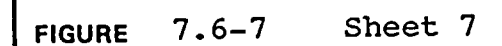
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UNITS 1 AND 2  
FINAL SAFETY ANALYSIS REPORT

NEUTRON MONITORING SYSTEM  
FCD

FIGURE 7.6-7 Sheet 6







CONTROL ROD POSITION INDICATOR  
PROBE (TYPICAL FOR EACH ROD)  
(REF 5 & 7) NOTE 1 - S45, D-12

SYSTEM PARAMETER VALUES

PARAMETER	VALUE	TOLERANCE	UNITS
INSERT CYCLE			
$t_{11}$	0.36	$\pm 0.05$	SEC.
$t_{12}$	9.16	$\pm 0.02$	SEC.
$t_{21}$	0.42		
$t_{22}$	3.32		
$t_{31}$	3.22		
$t_{32}$	8.62	$\pm 0.02$	SEC.
WITHDRAW CYCLE			
$t_{41}$	0.36	$\pm 0.05$	SEC.
$t_{42}$	9.16	$\pm 0.02$	SEC.
$t_{51}$	0.42		
$t_{52}$	1.02		
$t_{61}$	1.12		
$t_{62}$	2.62		
$t_{71}$	2.52	$\pm 0.02$	SEC.
$t_{72}$	8.62		

FCF 238X17AE G4-62 (C2-1030)

LEGEND

- \* = SWITCHGEAR DEVICE FUNCTION NUMBER ANSI SPEC C37.2
- RWM = ROD WORTH MINIMIZER
- LPRM = LOCAL POWER RANGE MONITOR
- RPS = ROD POSITION INFORMATION SYSTEM
- IRIA = INTERMEDIATE RANGE MONITOR
- NMS = NEUTRON MONITORING SYSTEM
- APRM = AVERAGE POWER RANGE MONITOR
- RBM = ROD BLOCK MONITOR
- SRJ = SELECT ROD INSERT

RSCS = ROD SEQUENCE CONTROL SYSTEM.

RPS = REACTOR PROTECTION SYSTEM.

NOTES:

- EACH CONTROL ROD, AS IT TRAVELS UP (INSERTED) OR DOWN (WITHDRAWN) PASSES A NUMBER OF SWITCHES. THE TOP TWO POSITION SWITCHES ARE CALLED "OVERTRAVEL" AND THE BOTTOM TWO POSITIONS ARE CALLED "WITHDRAWN" (BACKSEAT & DISCONNECT). SWITCHES IN BETWEEN ARE DIVIDED INTO "ODD (DRIFT)" AND "EVEN (LATCH)" POSITIONS. AS THE ROD TRAVELS OVER ANY SWITCH AN INDICATING SIGNAL IS ACTUATED. ANY EVEN SWITCH WILL INDICATE NUMERIC POSITION (9,00,01,...,48) AND ANY ODD SWITCH WILL INDICATE "ODD".
- WIRING FROM HCU (SCRAM VALVES AND ACCUMULATOR) TO CONTROL ROOM FOR ANNUNCIATION SHALL BE IN SERIAL CONNECTION FOR ALL HCUS.
- WIRING FROM HCU (ROD SCRAM TEST SWITCH IN TEST POSITION AND DISPLAY OF THOSE CONTROL RODS CHOSEN FOR "SELECT ROD INSERT FUNCTION") SHALL BE IN SERIAL CONNECTION FOR ALL HCUS.
- EACH ACCUMULATOR FAILURE WILL INITIATE AN ANNUNCIATION (ANNUNCIATOR WORK & FLASHING ANNUNCIATOR WARNING) AND AN INDIVIDUAL FLASHING INDICATOR (PART OF THE WHOLE CORE DISPLAY). OPERATION OF THE "ACCUMULATOR TROUBLE ACKNOWLEDGE" SWITCH WILL CLEAR THE INPUT TO THE ANNUNCIATOR AND CHANGE THE INDIVIDUAL INDICATOR FROM FLASHING TO STEADY. CLEARING THE ANNUNCIATOR TROUBLE WILL CLEAR THE INDIVIDUAL INDICATORS.
- THE CORE IS DIVIDED INTO 4 ROD GROUPS - DISTRIBUTED SUCH THAT A SINGLE GROUP FAILURE WILL NOT CAUSE A THERMAL STRESS CONDITION. FOR SIMPLICITY 1 ROD OF SCRAM GROUP 1 IS ILLUSTRATED. WIRING IS LOGIC TO EACH OF THE 4 GROUPS IS SEPARATE & INDEPENDENT.

REFERENCE DOCUMENTS

- |  |               |
|--|---------------|
| 1. CONTROL ROD DRIVE HYDRAULIC SYS. IED            | ----- C2-100  |
| 2. NEUTRON MONITORING SYS. IED                     | ----- C2-100  |
| 3. FEEDWATER CONTROL SYS. IED                      | ----- C2-100  |
| 4. FEEDWATER CONTROL SYS. DESIGN SPEC.             | ----- C2-100  |
| 5. CONTROL ROD DRIVE HYDRAULIC SYS. DESIGN SPEC.   | ----- C2-100  |
| 6. PROCESS COMPUTER SYS. INPUT/OUTPUT REQUIREMENTS | ----- C2-100  |
| 7. (REMOVED)                                       |               |
| 8. LOGIC SYMBOLS                                   | ----- A1-1000 |
| 9. NEUTRON MONITORING SYS. IED                     | ----- C2-100  |
| 10. REACTOR PROTECTION SYS. IED                    | ----- C2-100  |
| 11. SOLID STATE LOGIC SYMBOLS                      | ----- A1-1000 |
| 12. REACTOR MANUAL CONTROL SYS. ELEMENTARY DIAGRAM | ----- C2-100  |

INSERT CYCLE

- $t_{11}$  -  $t_{12}$  = DELAY UNTIL ROD MOTION BEGINS
- $t_{12}$  -  $t_{21}$  = DRIVE IN TIME
- $t_{21}$  -  $t_{22}$  = SETTLE TIME
- $t_{21} < t_{22}$  = TIME, WHEN CONTINUOUS INSERT CAN BE REQD.
- $t_{21} < t_{22}$  = CYCLE STOP POINT FOR CONTINUOUS INSERT.

WITHDRAW CYCLE

- $t_{31}$  -  $t_{32}$  = DELAY UNTIL ROD MOTION BEGINS
- $t_{32}$  -  $t_{41}$  = DRIVE IN TIME (UNLATCH)
- $t_{41}$  -  $t_{42}$  = DELAY AFTER UNLATCH
- $t_{42}$  -  $t_{51}$  = DRIVE OUT TIME
- $t_{51}$  -  $t_{52}$  = SETTLE TIME
- $t_{51} < t_{52}$  = TIME, WHEN CONTINUOUS WITHDRAW CAN BE REQUESTED
- $t_{51} < t_{52}$  = CYCLE STOP POINT FOR CONTINUOUS WITHDRAW

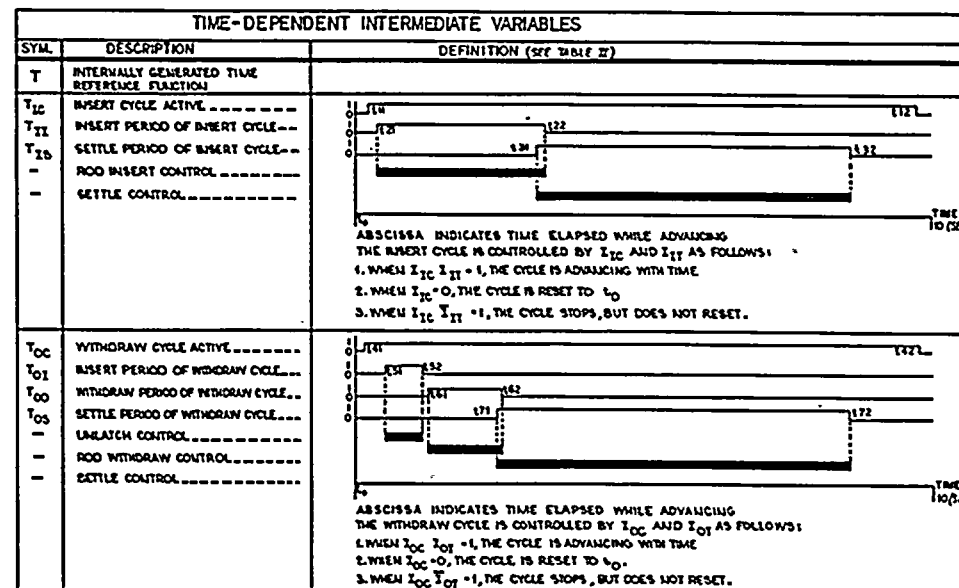
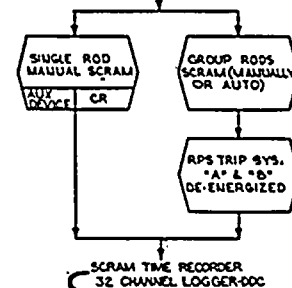


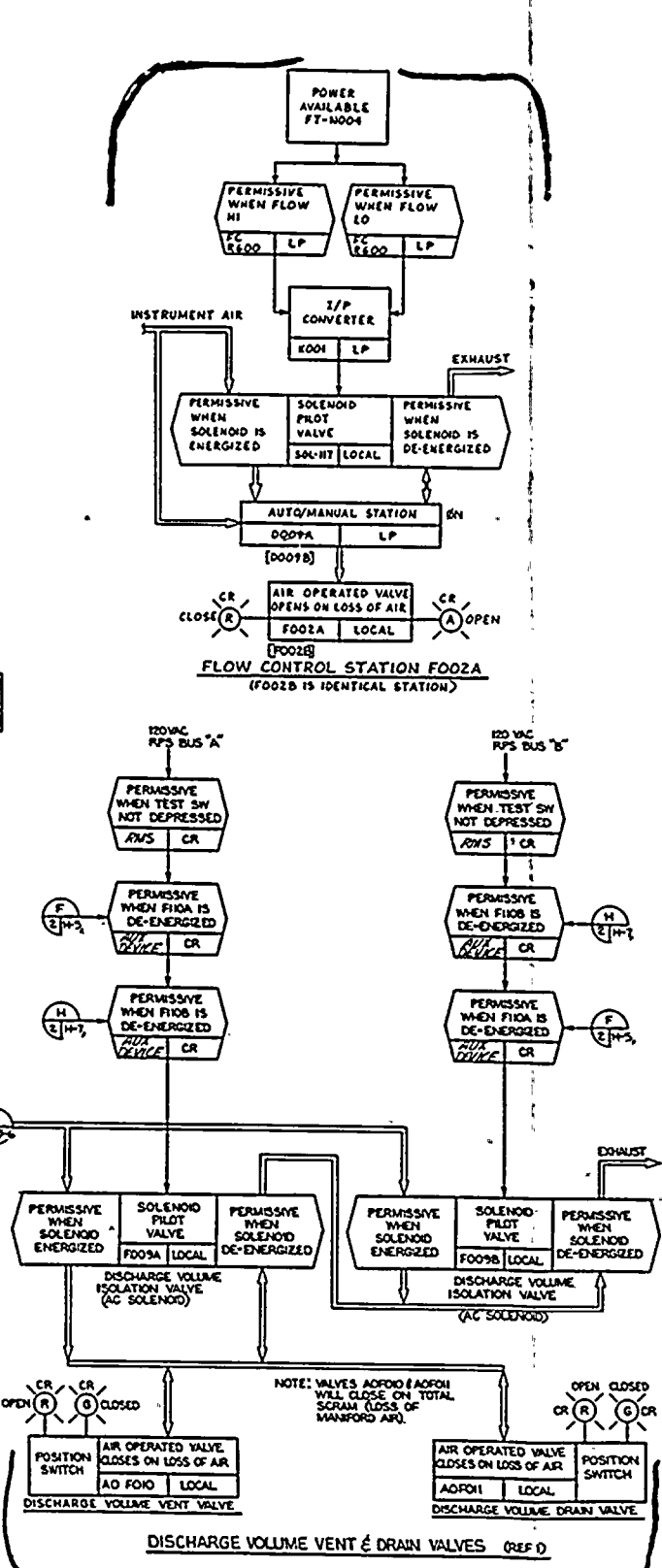
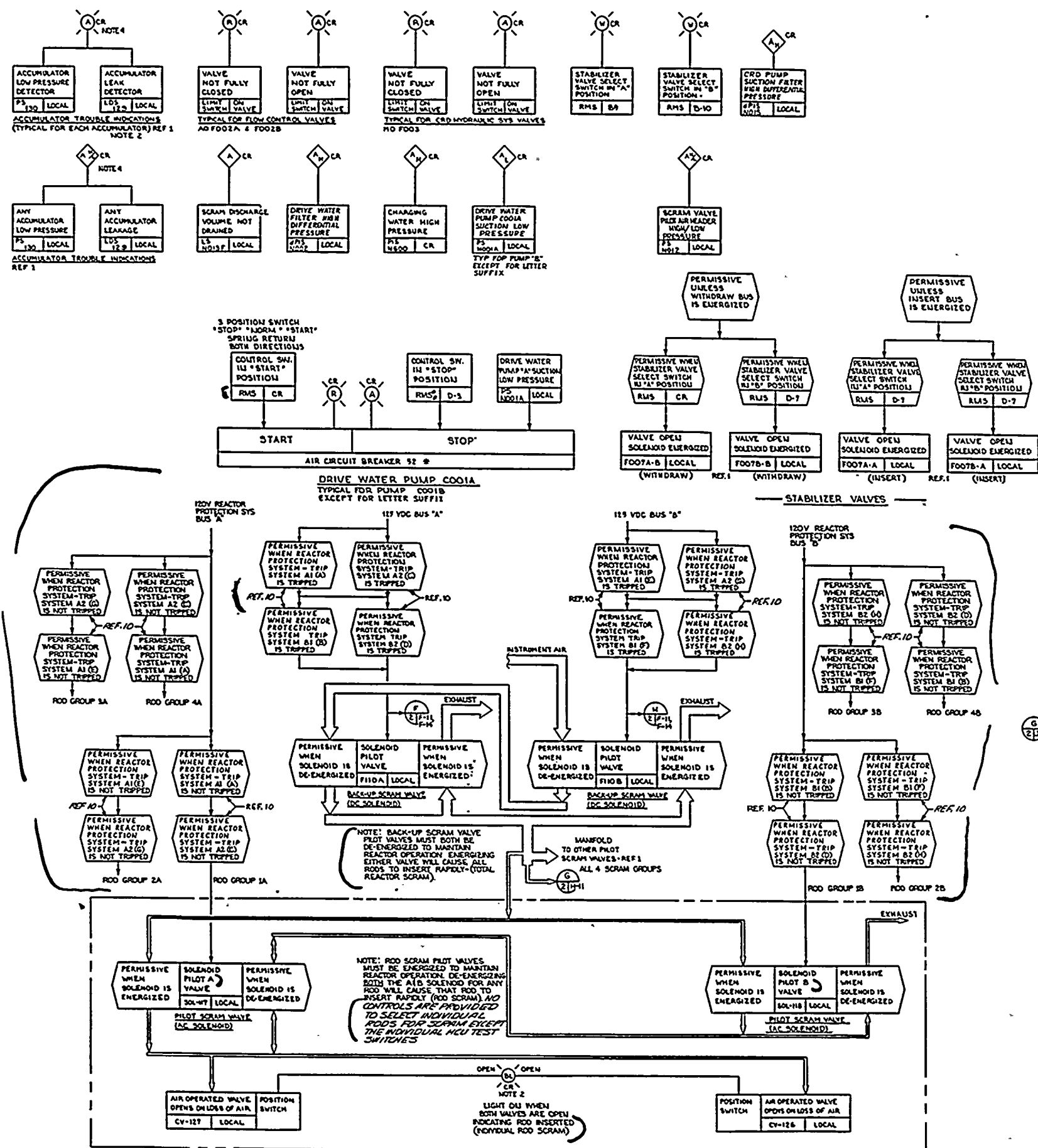
TABLE I

Rev. 19, 1/81

SUSQUEHANNA STEAM ELECTRIC STATION  
UNITS 1 AND 2  
FINAL SAFETY ANALYSIS REPORT

CONTROL ROD DRIVE  
FCD

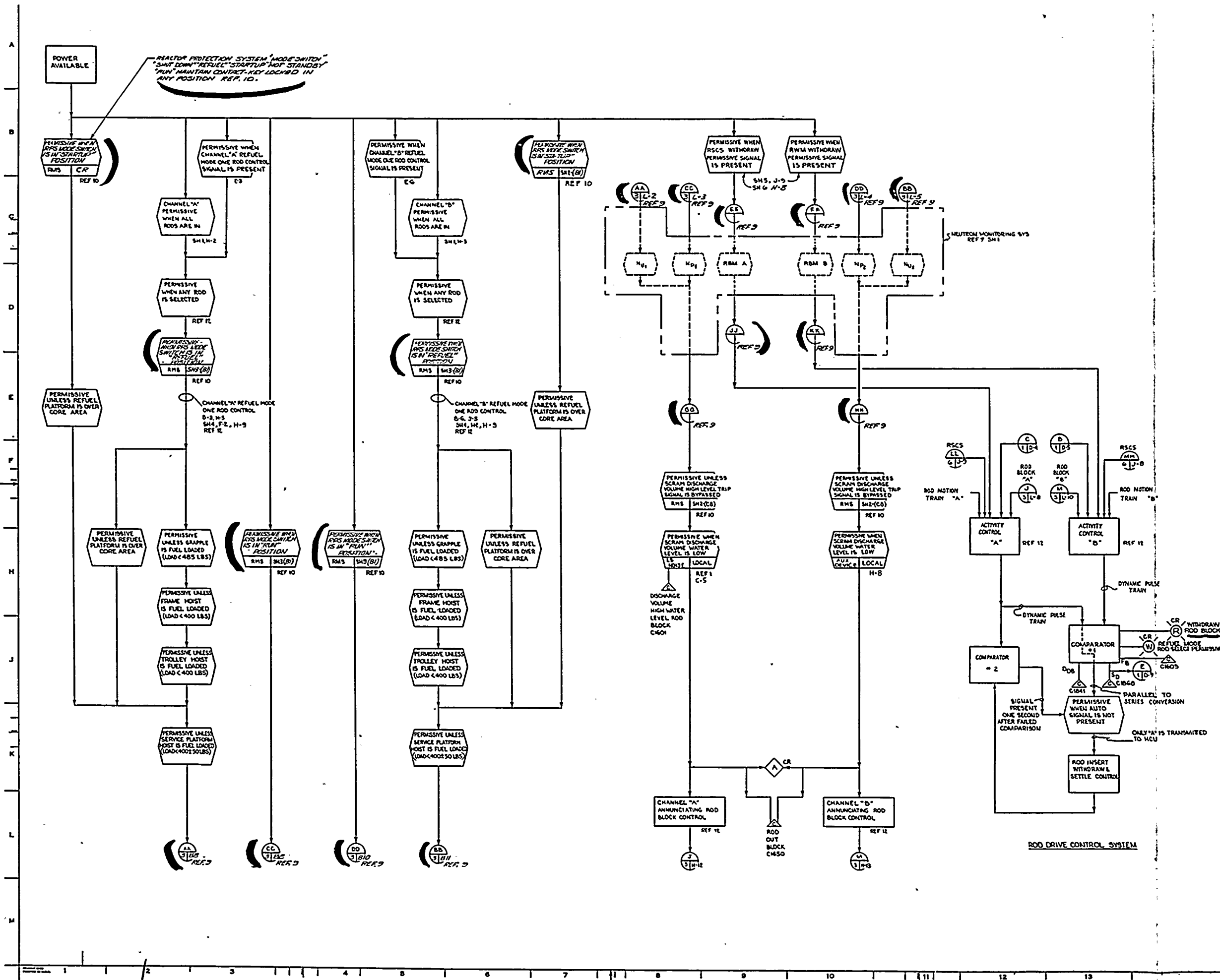




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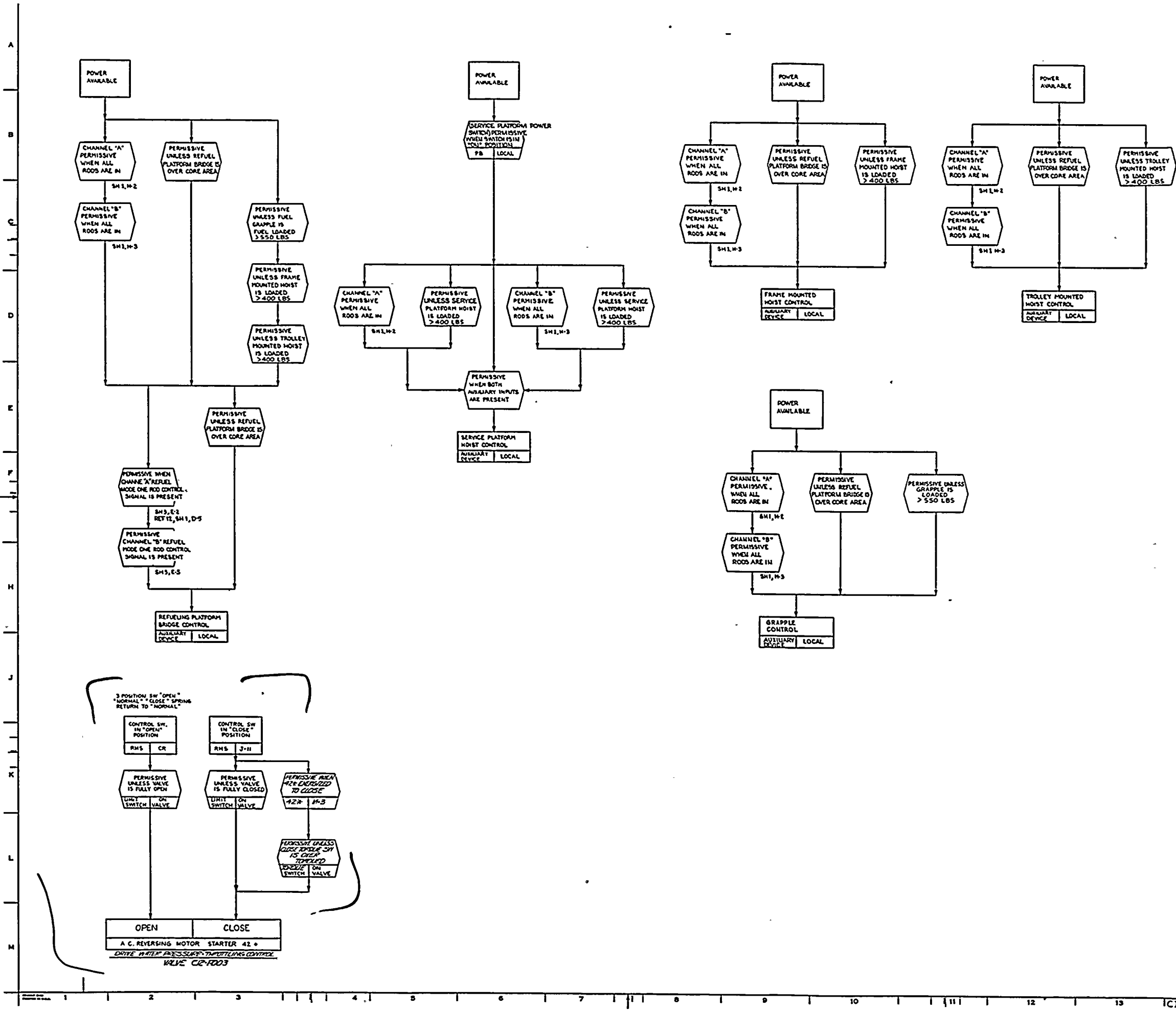


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UNITS 1 AND 2  
FINAL SAFETY ANALYSIS REPORT

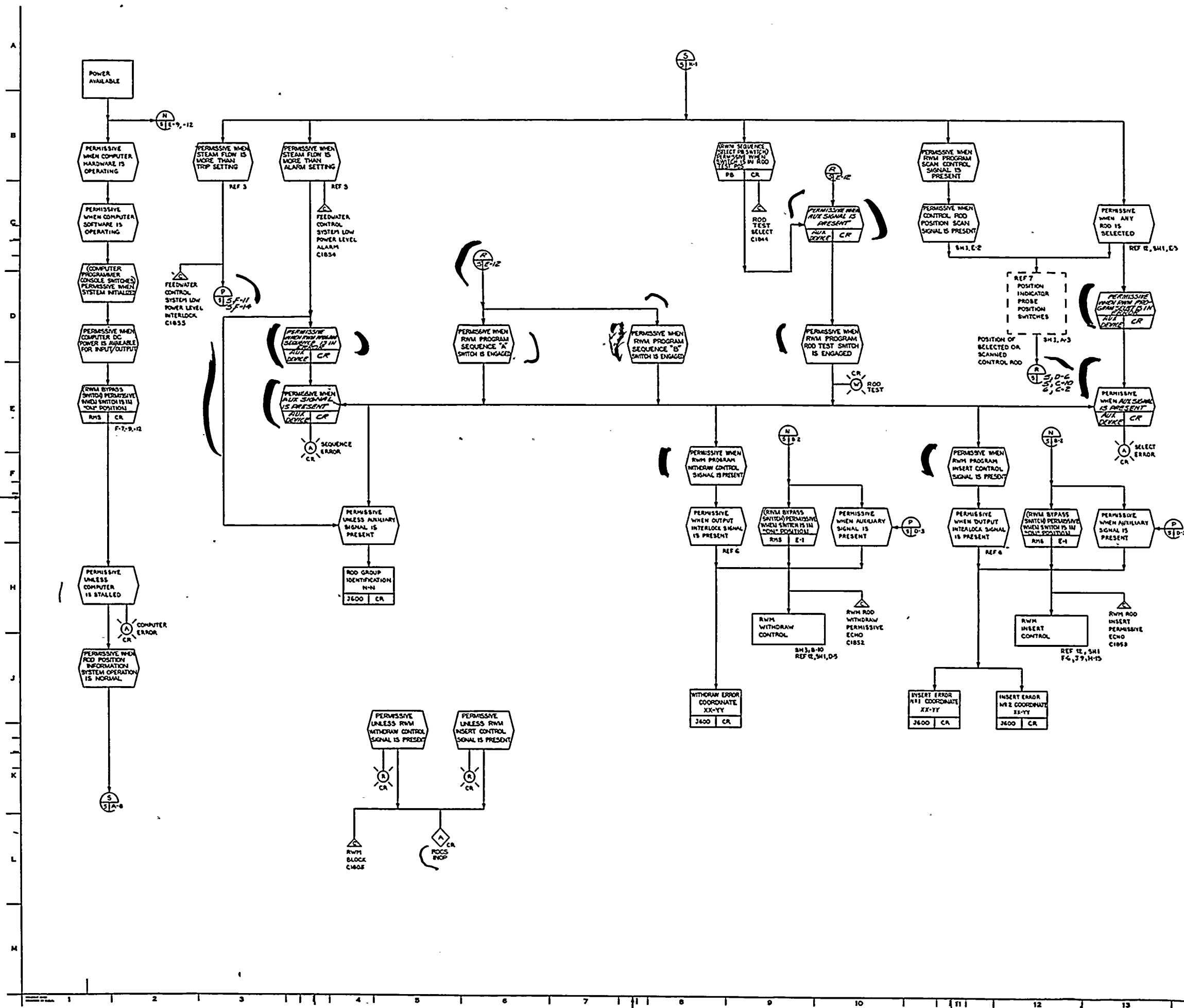
CONTROL ROD DRIVE  
FCD





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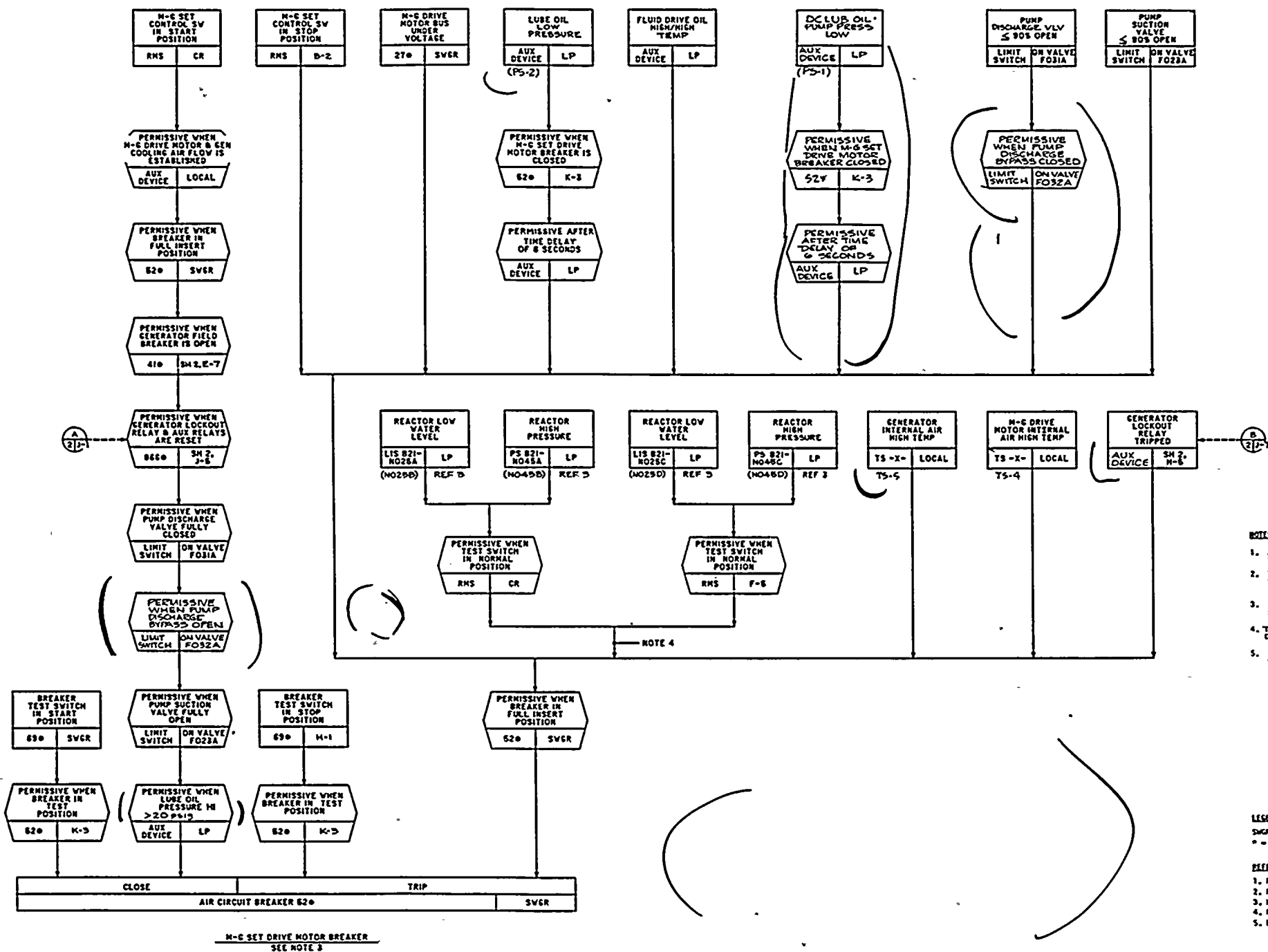




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<p><b>SUSQUEHANNA STEAM ELECTRIC STATION</b>  <b>UNITS 1 AND 2</b>  <b>FINAL SAFETY ANALYSIS REPORT</b></p>
<p><b>CONTROL ROD DRIVE</b>  <b>FCD</b></p>
<p><b>FIGURE 7.7-2      Sheet 5</b></p>





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THIS DWG SUPERSEDES  
 DWG 729E625 REV 4  
 FOR SUSQUEHANNA 1&2  
 PER D.F. ECA 40520-3 & 50127-3

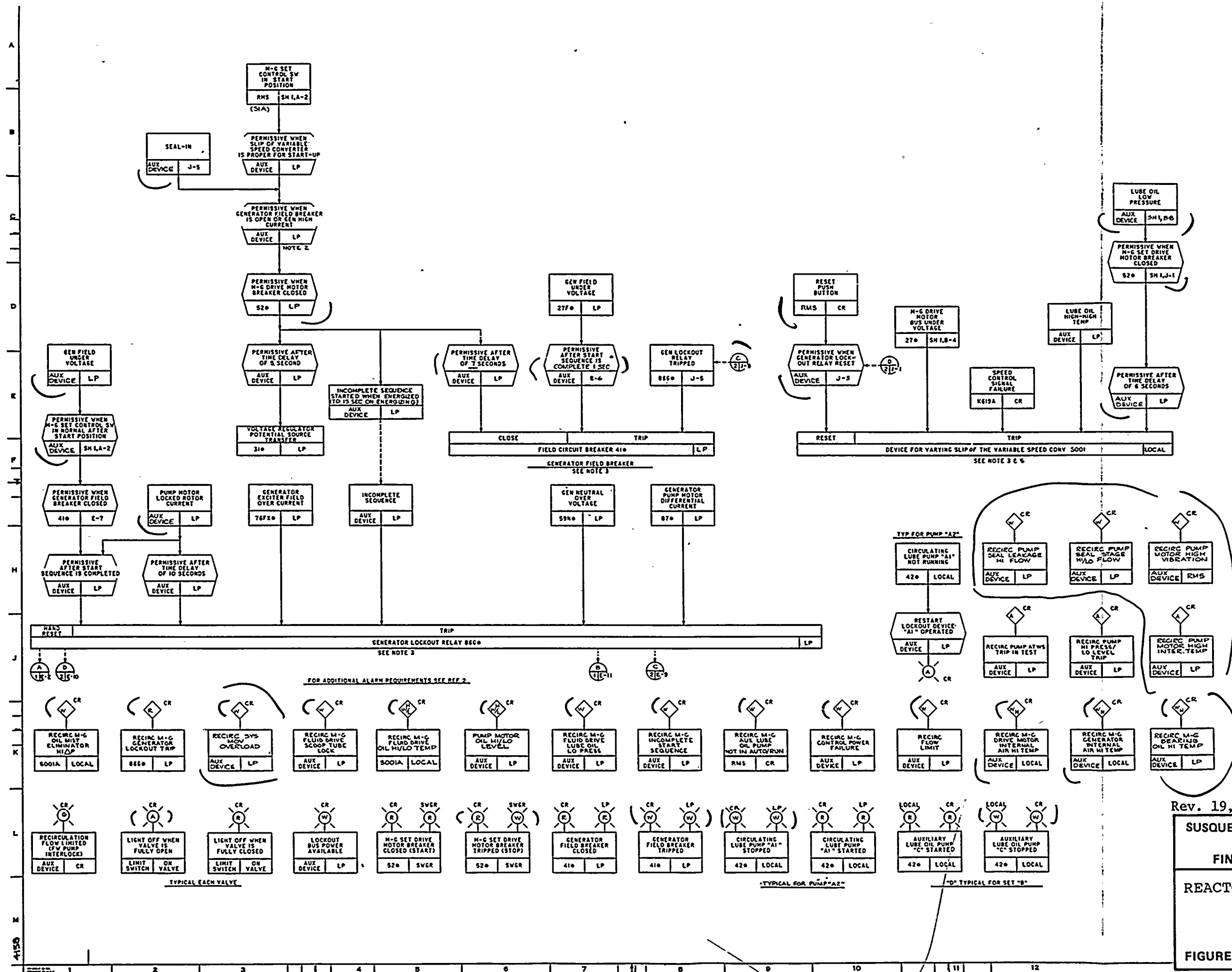
SUSQUEHANNA STEAM ELECTRIC STATION  
 UNITS 1 AND 2  
 FINAL SAFETY ANALYSIS REPORT

REACTOR RECIRCULATION SYSTEM  
 FCD

FIGURE 7.7-7 Sheet 1







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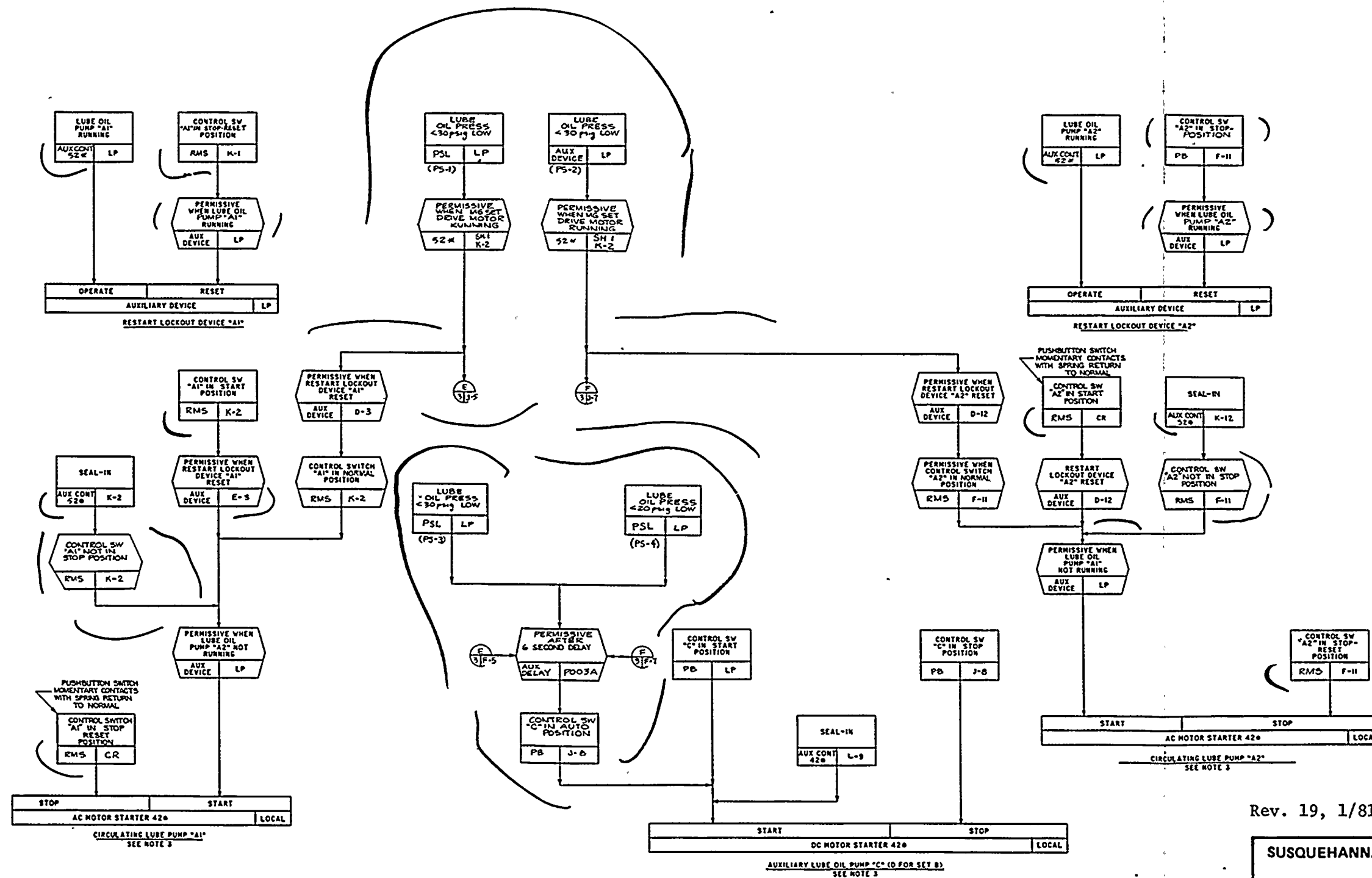
**SUSQUEHANNA STEAM ELECTRIC STATION  
UNITS 1 AND 2  
FINAL SAFETY ANALYSIS REPORT**

**REACTOR RECIRCULATION SYSTEM  
FCD**

**FIGURE 7.7-7 Sheet 2**



4159 1 2 3 4 5 6 7 8 9 10 11 12



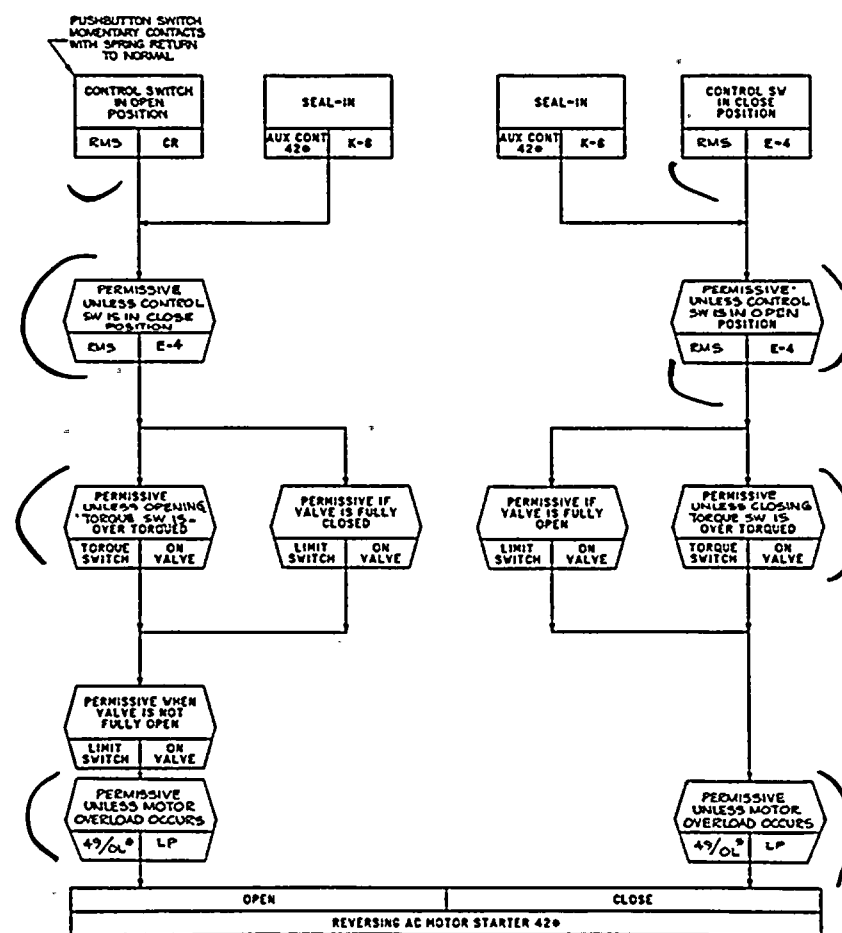
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SUSQUEHANNA STEAM ELECTRIC STATION  
UNITS 1 AND 2  
FINAL SAFETY ANALYSIS REPORT

REACTOR RECIRCULATION SYSTEM  
FCD

FIGURE 7.7-7 Sheet 3





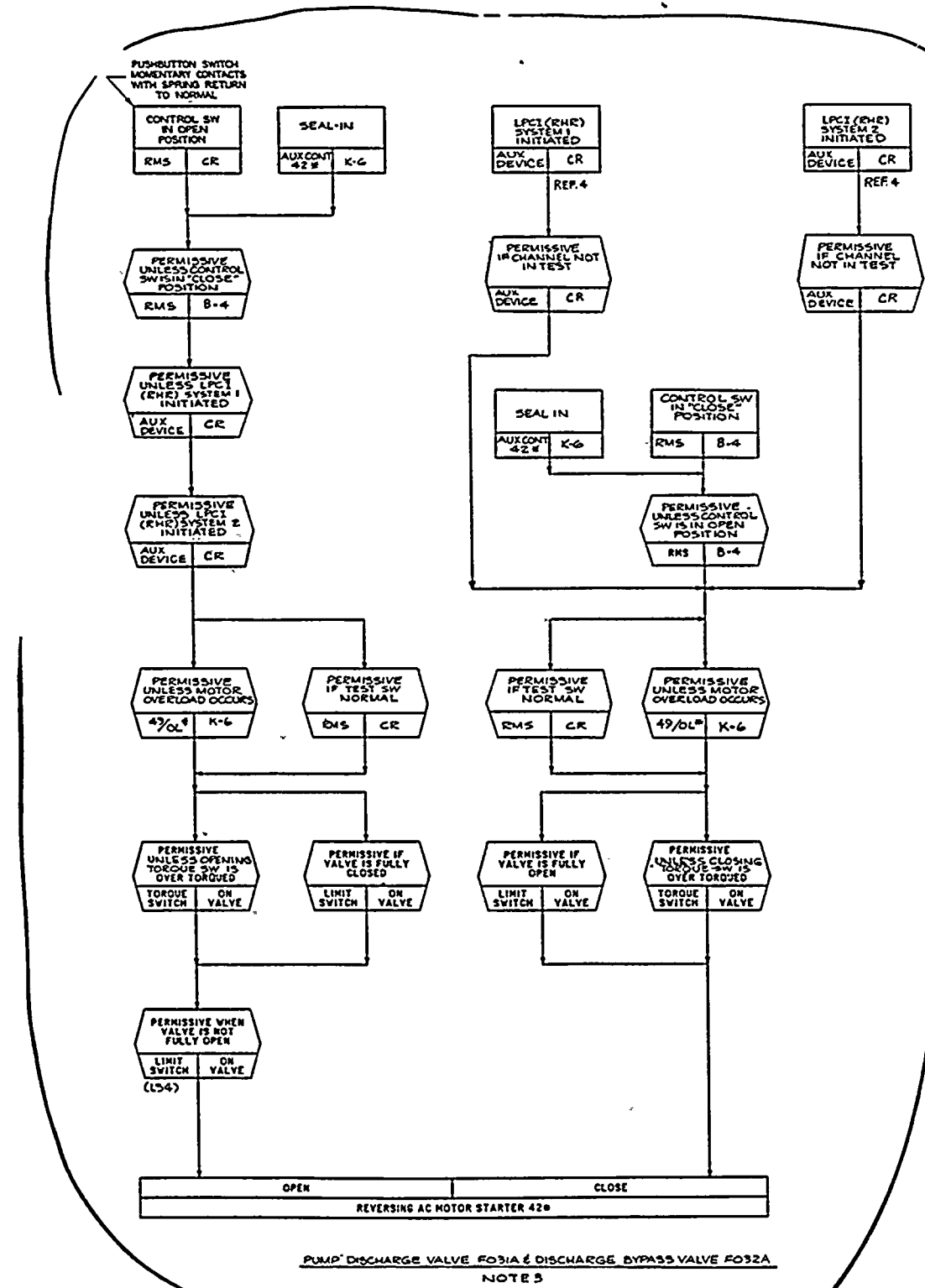
PUMP SUCTION VALVE F023A  
NOTE 3

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REACTOR RECIRCULATION SYSTEM  
FCD

FIGURE 7.7-7 Sheet 4

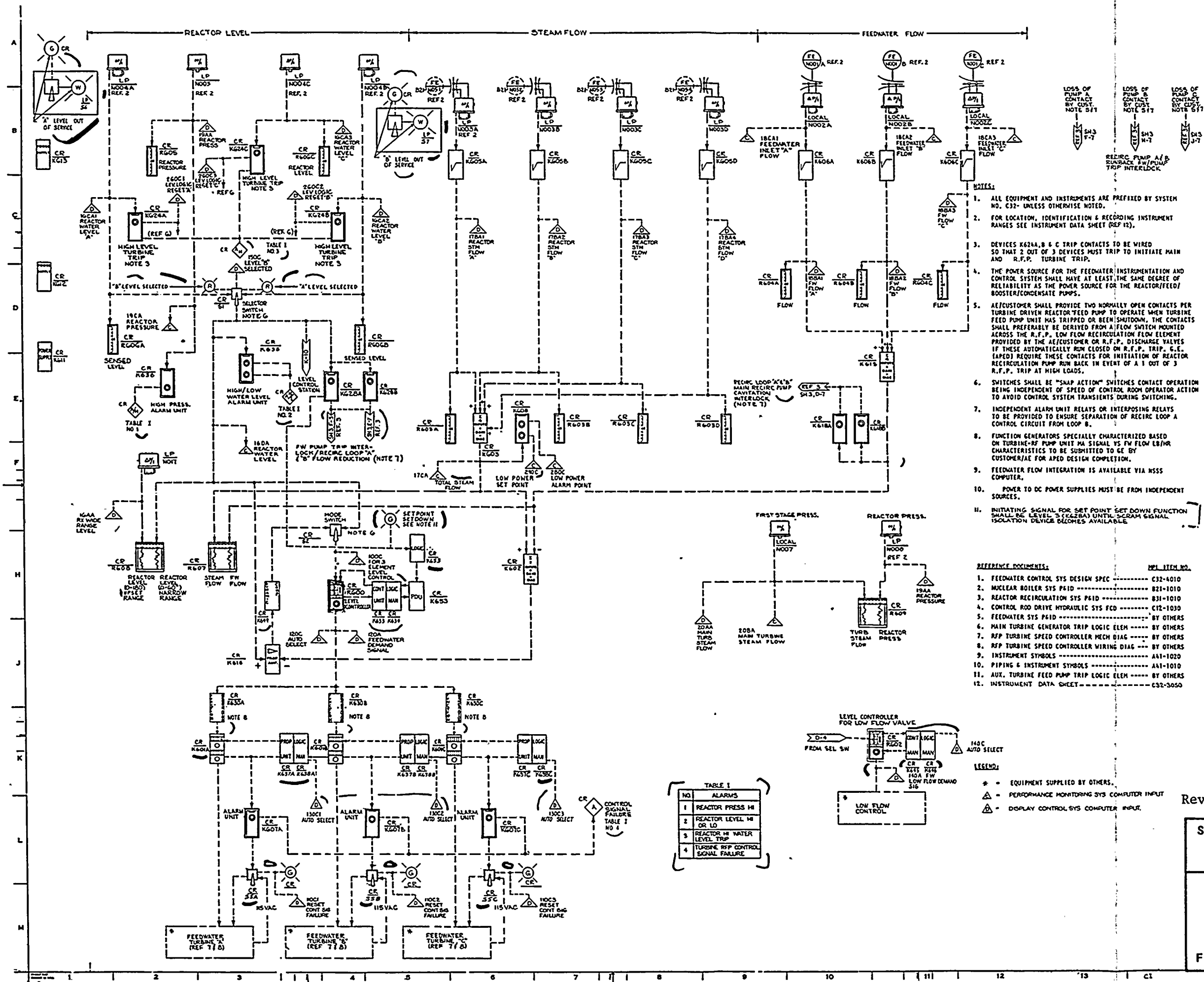




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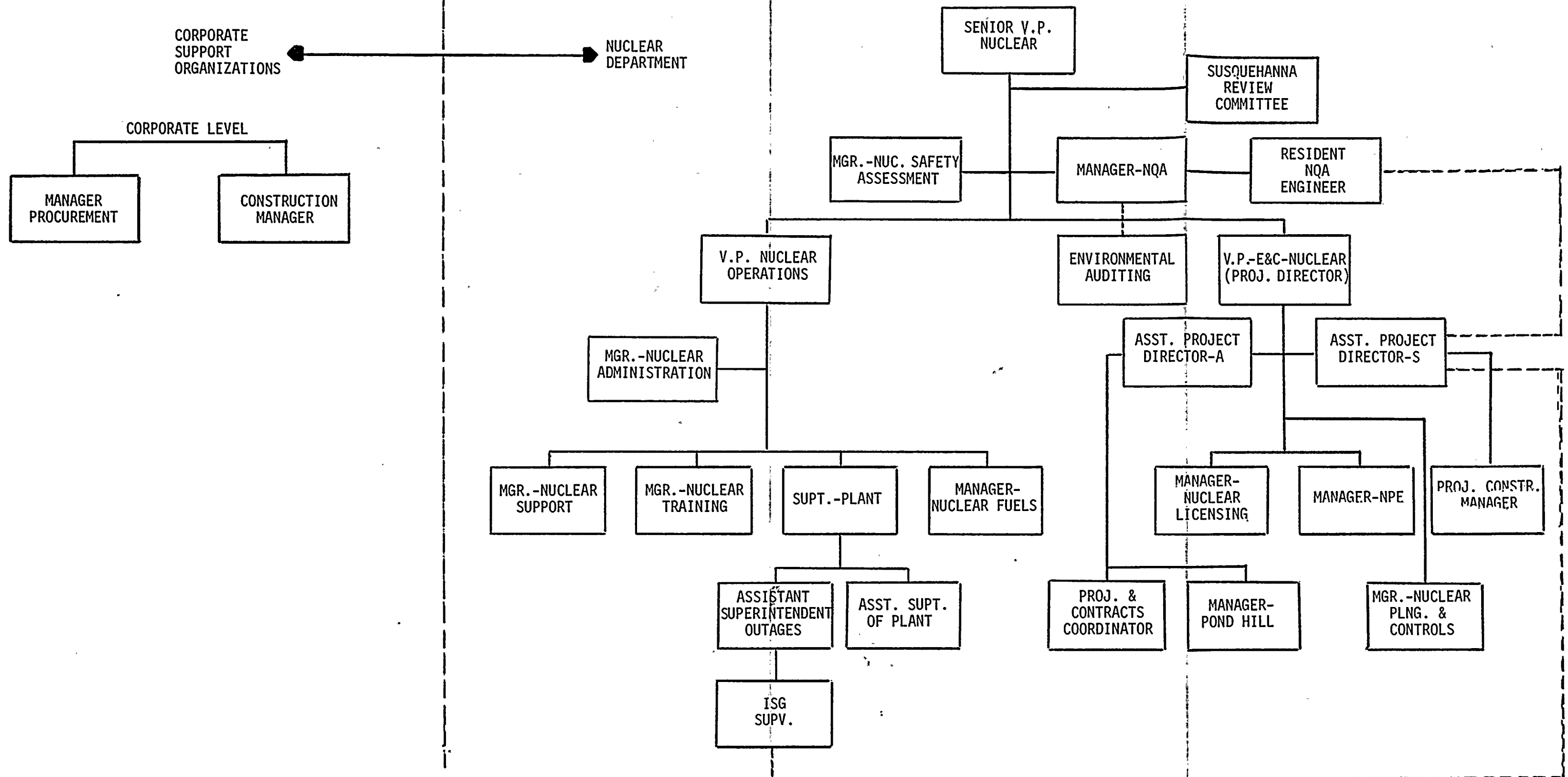
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UNITS 1 AND 2  
FINAL SAFETY ANALYSIS REPORT  
FEEDWATER CONTROL SYSTEM  
TURBINE FEED PUMP  
IED**

FIGURE 7.7-9







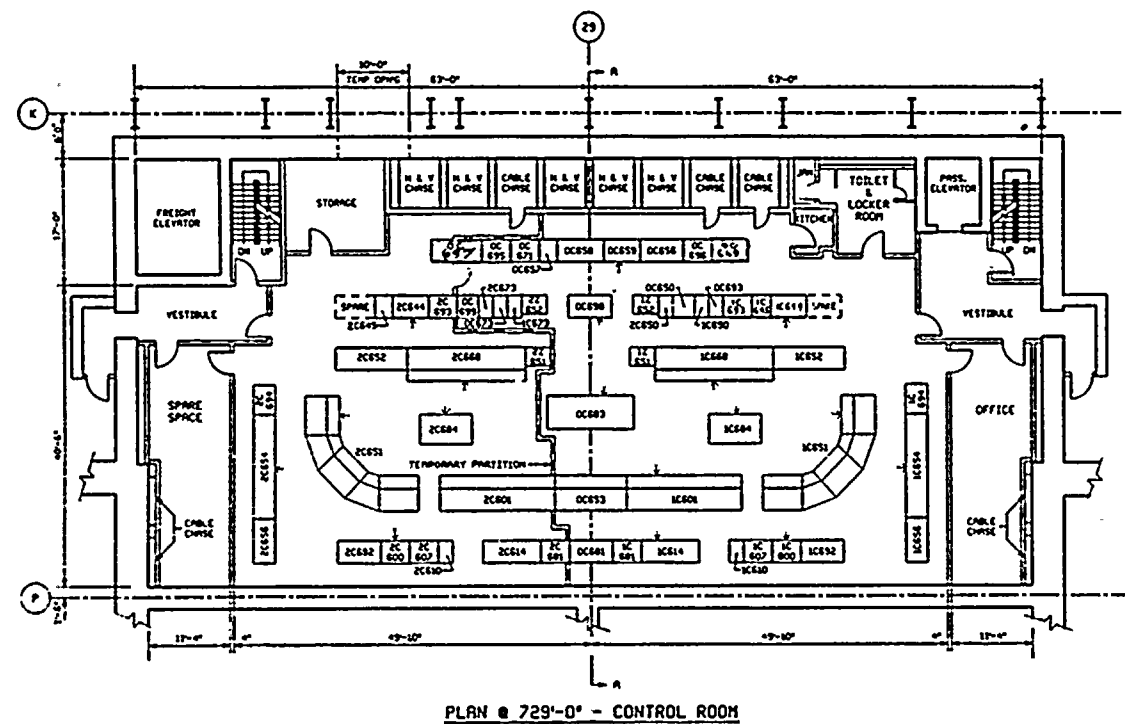












CONTROL ROOM PANELS  
Panel No.

Unit 1	Common Plant	Unit 2	Description
1C600	-	2C600	Process Radiation Record V.B
1C601	-	2C601	Reactor Core Cooling B. B.
1C607	-	2C607	T.I.P. Control & Monitor Cabinet
1C610	-	2C610	Control Rod Test Cabinet
1C614	-	2C614	NSS Temp. Record & Leak Detect. V.B.
1C644	-	2C644	MSIV Leak Control V. B. Div. 2
1C645	-	2C645	MSIV Leak Control V. B. Div. 1
1C650	OC650	2C650	Fire Protection V. B.
1C651	-	2C651	Unit Operation B. B.
1C652	-	2C652	Standby Information Panel, (V.B.)
1C654	OC653	2C654	Plant Operating B.B. Generator & Transfer Prot. Relay V.B.
1C656	OC656	2C656	Electrical Metering V. B.
	OC657		Startup Transformer Prot. V. B.
	OC658		Span Prot., Swyd Cont. & Display V. B.
	OC659		500 & 230KV Swyd Cont. & Display V. B.
1C668	OC669	2C668	Unit Services B.B.
	OC671		Stack Effl. Monitor Console
			Meteorological & River Telemeter V. B.
1C673	OC673	2C673	Off-gas Recombiner Control V. B.
1C681	OC681	2C681	Heating & Ventilation V. B.
	OC683		Plant Operating Monitor Console
1C684		2C684	Unit Operating Monitor Console
1C692		2C692	Misc. Systems Record V. B.
1C693	OC693	2C693	Misc. Plant Inst. & Reocrd V. B.
1C694		2C694	Bypass Indication V. B.
	OC695		P.A. & Emergency V. B.
	OC696		Earthquake Monitor V. B.
	OC697		Motor Overload Bypass V. B.
	OC698		Plant Security Console
	OC699		Plant Security Cabinet

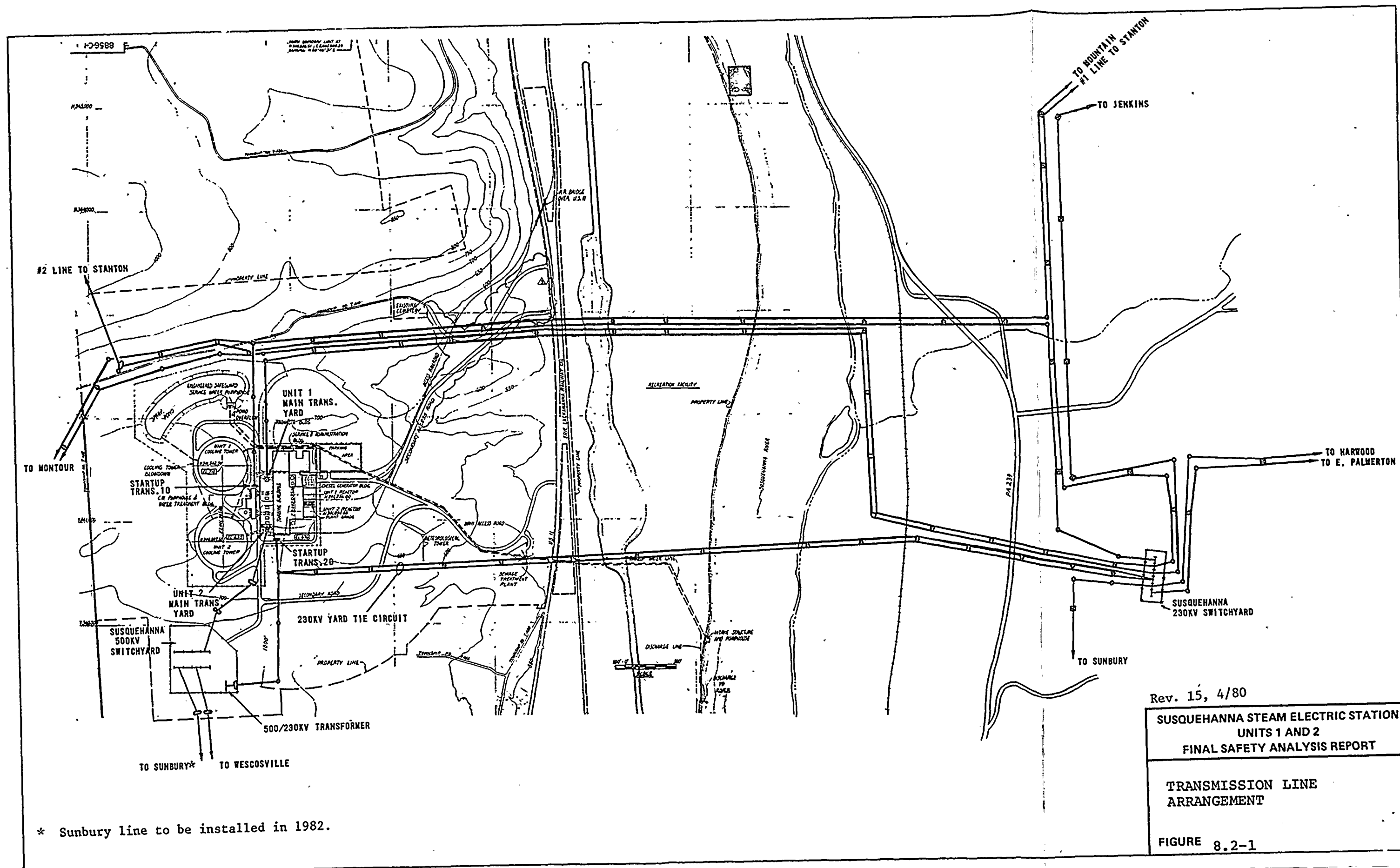
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SUSQUEHANNA STEAM ELECTRIC STATION  
UNITS 1 AND 2  
FINAL SAFETY ANALYSIS REPORT

CONTROL ROOM LAYOUT

FIGURE 7.7-13

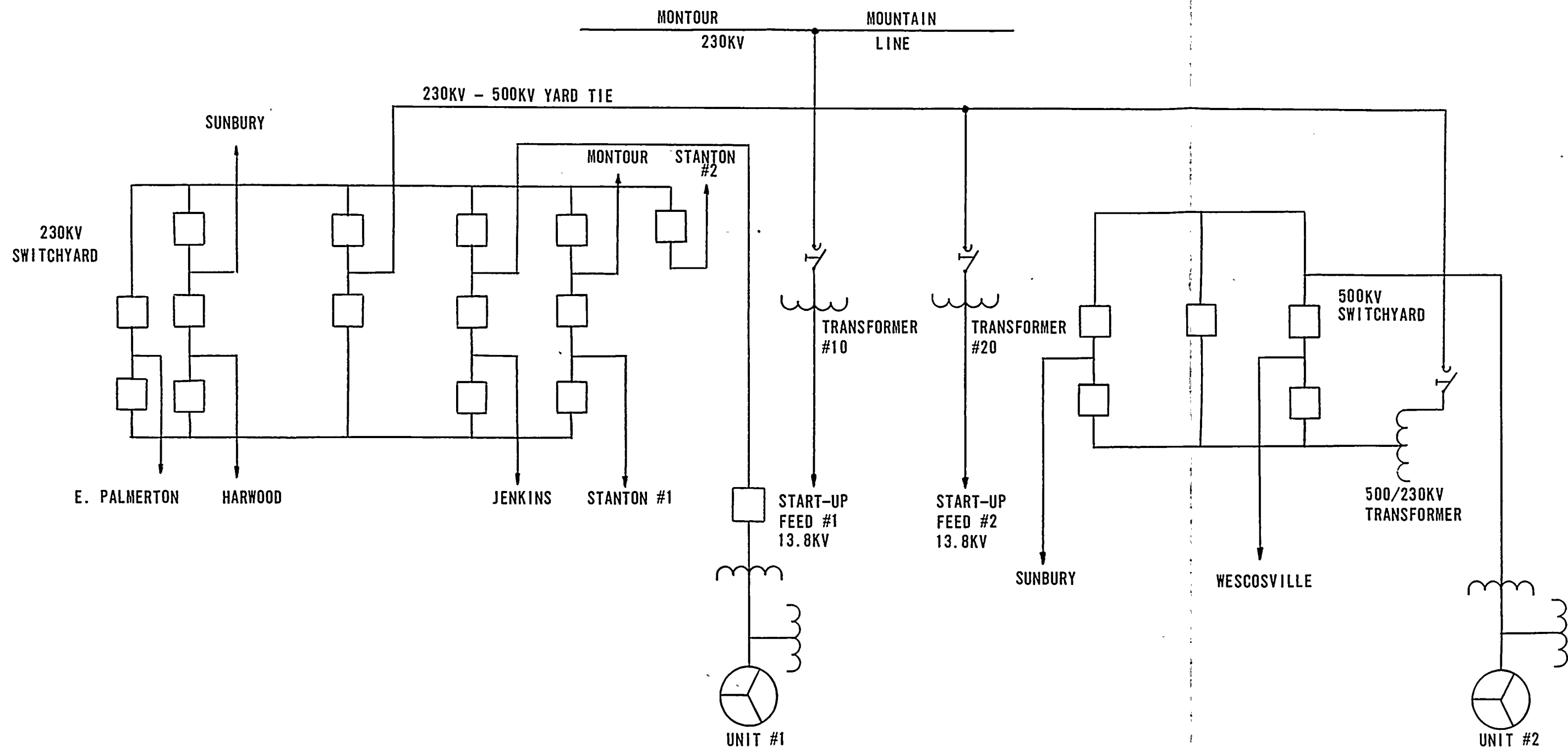












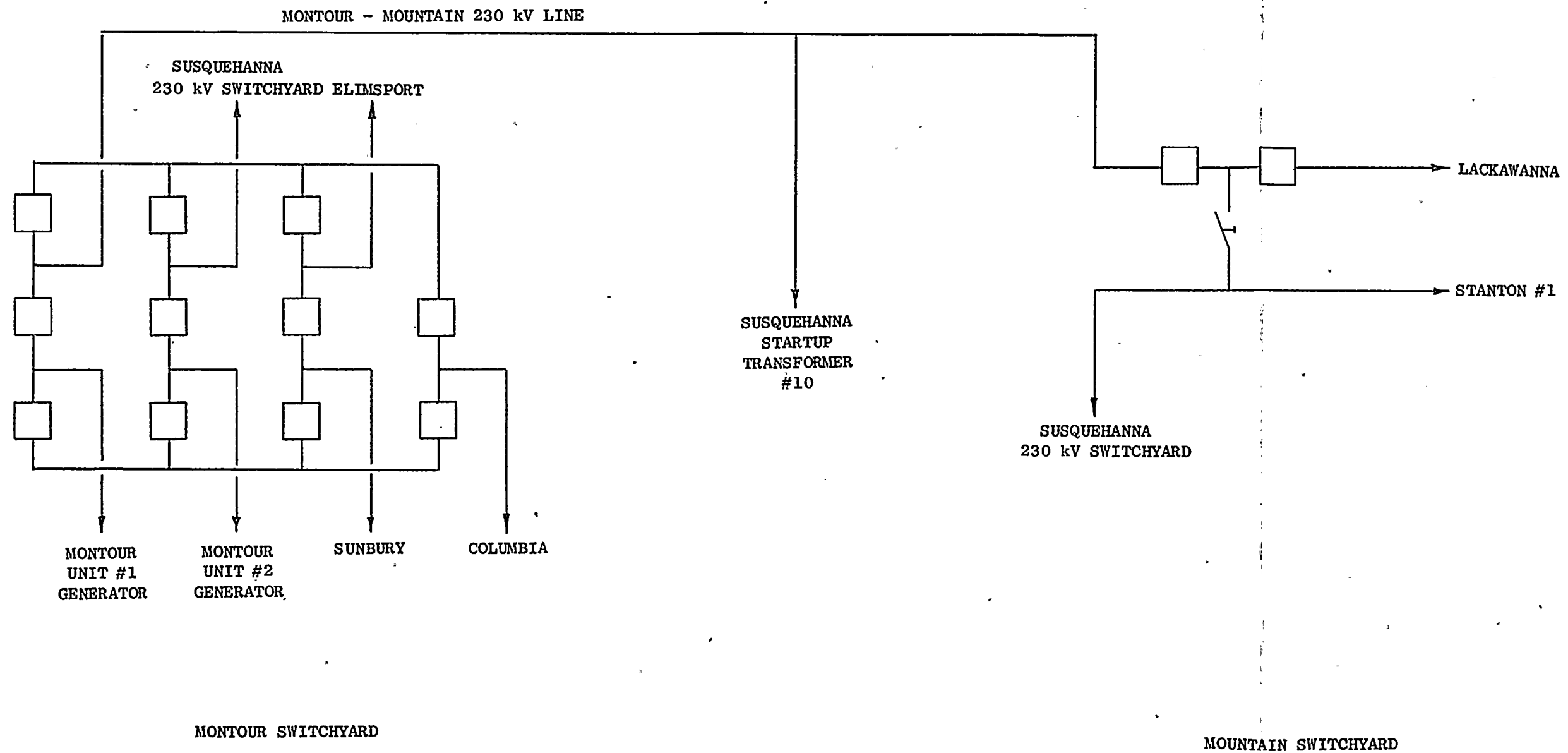
SUSQUEHANNA STEAM ELECTRIC STATION  
UNITS 1 AND 2  
FINAL SAFETY ANALYSIS REPORT

TRANSMISSION SYSTEM

FIGURE 8.2-4



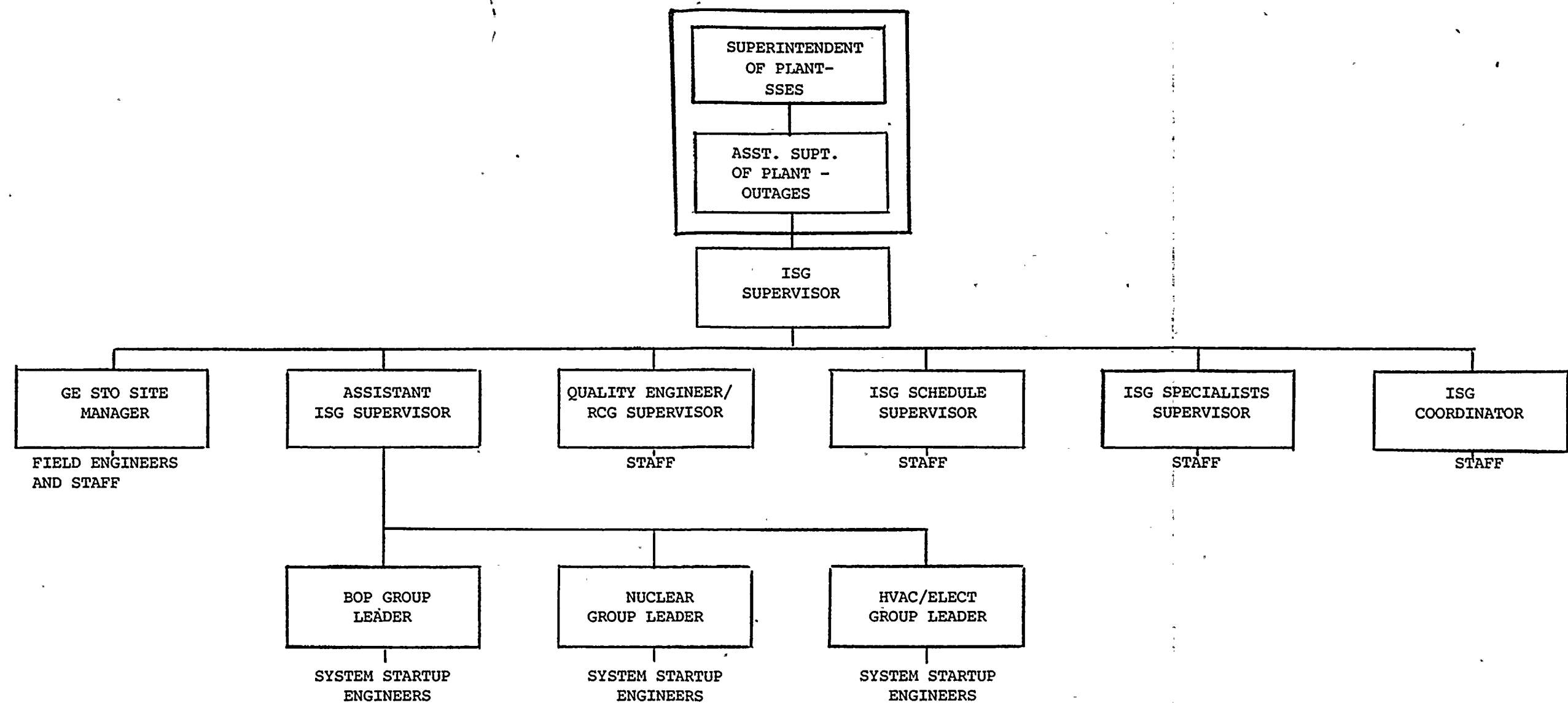




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<b>SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT</b>
<b>MONTOUR AND MOUNTAIN SWITCHYARDS ONE LINE DIAGRAM</b>
<b>FIGURE 8.2-5</b>





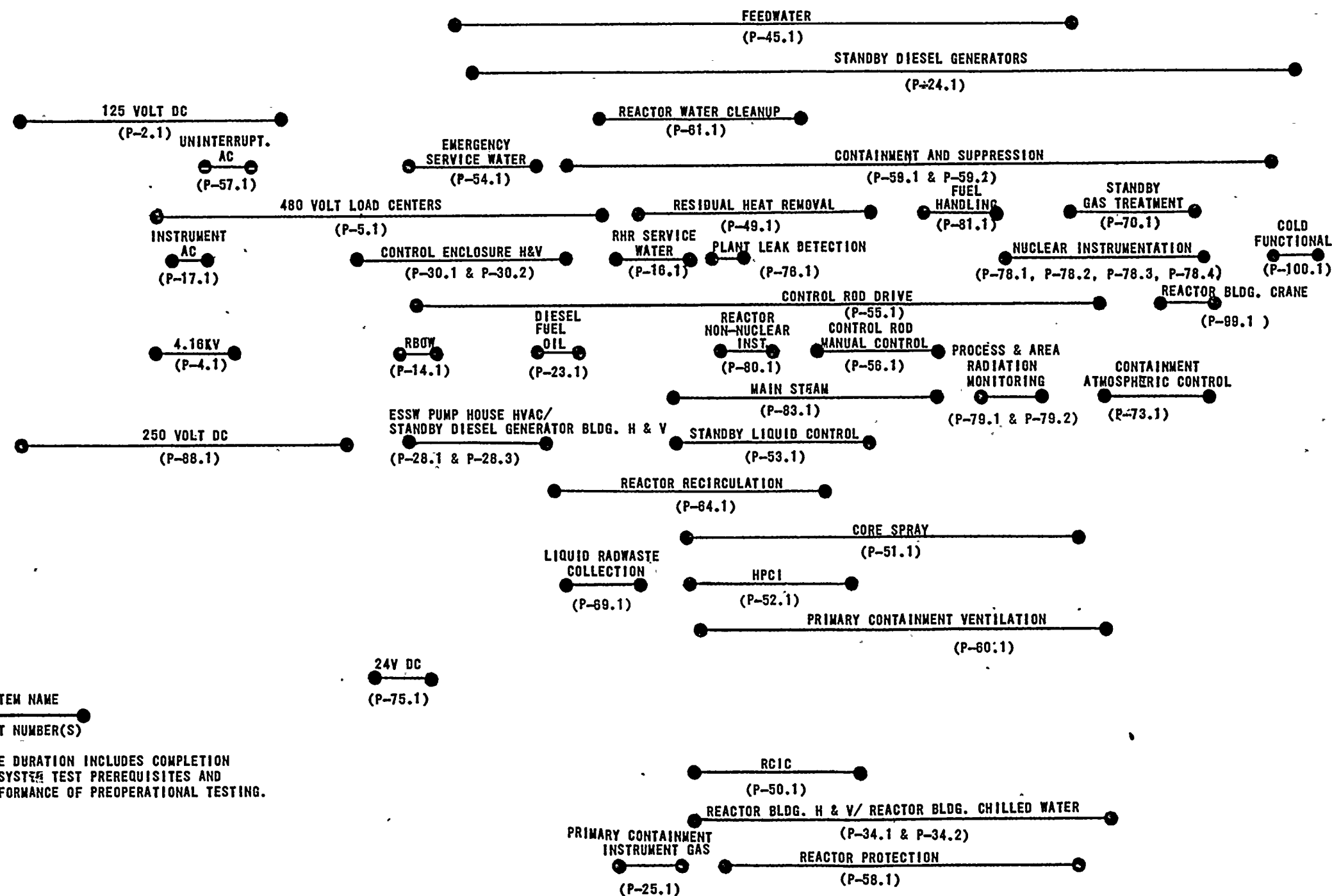
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**SUSQUEHANNA STEAM ELECTRIC STATION  
UNITS 1 AND 2  
FINAL SAFETY ANALYSIS REPORT**

**INTEGRATED STARTUP GROUP  
ORGANIZATION**

**FIGURE 14.2-1**





# NOTES

1. SYSTEM NAME  
TEST NUMBER(S)
2. LINE DURATION INCLUDES COMPLETION  
OF SYSTEM TEST PREREQUISITES AND  
PERFORMANCE OF PREOPERATIONAL TESTING.

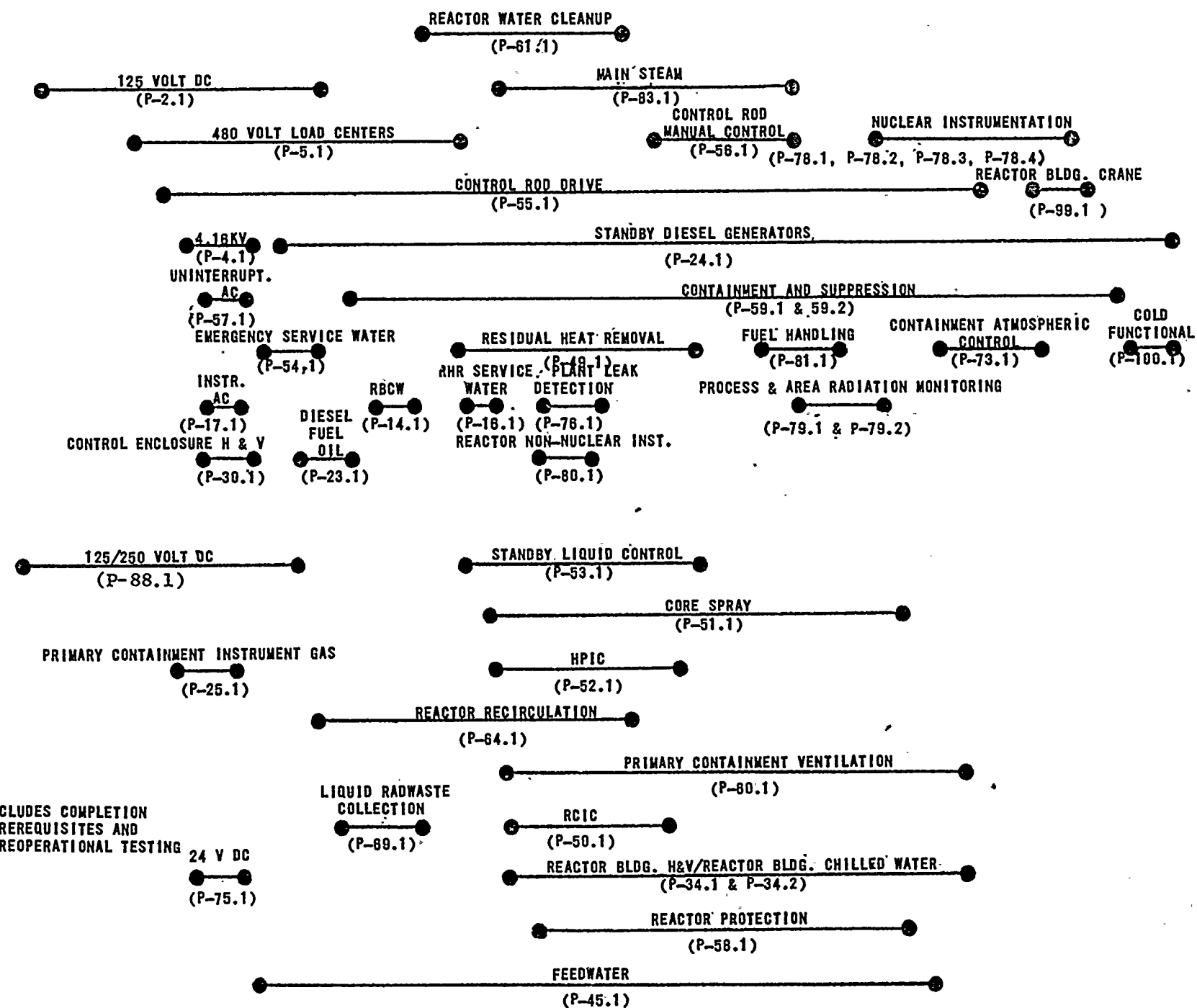
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SUSQUEHANNA STEAM ELECTRIC STATION  
UNITS 1 AND 2  
FINAL SAFETY ANALYSIS REPORT

UNIT 1 PREOPERATIONAL TEST  
SEQUENCE

FIGURE 14.2-4a





NOTES:

1. SYSTEM NAME  
TEST NUMBER(S)

2. LINE DURATION INCLUDES COMPLETION  
OF SYSTEM TEST PREREQUISITES AND  
PERFORMANCE OF PREOPERATIONAL TESTING

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SUSQUEHANNA STEAM ELECTRIC STATION  
UNITS 1 AND 2  
FINAL SAFETY ANALYSIS REPORT

UNIT 2 PREOPERATIONAL TEST  
SEQUENCE

FIGURE 14.2-4b





FIGURE 14.2-5, Sht. 1

Test No.	Test Name	Open Vessel	Heat Up	1	2	Test Condition (1)		5	6	Warranty
						3	4			
ST-1	Chemical & Radiochemical	X <sup>(2)</sup>	X	X	X	X		X	X	X
ST-2	Radiation Measurements	X <sup>(2)</sup>	X	X		X			X	
ST-3	Fuel Loading	X <sup>(2)</sup>								
ST-4	Full Core Shutdown Margin		X <sup>(6)</sup>							
ST-5	Control Rod Drive	X <sup>(2,3)</sup>	X <sup>(3)</sup>	X <sup>(3)</sup>	X <sup>(3)</sup>	X <sup>(3)</sup>			X <sup>(3)</sup>	
ST-6	SRM Perf. & Control Rod Seq.		X <sup>(6)</sup>					X <sup>(12)</sup>	X <sup>(12)</sup>	
ST-7	Reactor Water Cleanup		X	X <sup>(7)</sup>		X				
ST-8	Residual Heat Removal				X				X <sup>(9,13)</sup>	
ST-9	Water Level Measurements		X							
ST-10	IRM Performance		X <sup>(6)</sup>		X <sup>(8)</sup>					
ST-11	LPRM Calibration			X <sup>(7)</sup>	X	X			X	
ST-12	APRM Calibration		X	X	X	X		X	X	X
ST-13	Process Computer				X	X				
ST-14	RCIC		X	X <sup>(7)</sup>	X <sup>(8,9)</sup>					
ST-15	HPCI		X			X		X <sup>(8,9)</sup>	X <sup>(8)</sup>	
ST-16	Selected Process Temps		X <sup>(6)</sup>			X	X <sup>(14)</sup>		X <sup>(14)</sup>	
ST-17	System Expansion				X <sup>(8)</sup>				X <sup>(9,13)</sup>	
ST-18	TIP Uncertainty					X			X	
ST-19	Core Performance			X	X	X	X	X	X	X
ST-20	Steam Production									X
ST-21	Core Power-Void Mode Response						X		X <sup>(17)</sup>	
ST-22	Pressure Regulator			M	M	M,A	X	M	M	
ST-23	Feedwater			X	X	X	X	X	X <sup>(8,15)</sup>	
ST-24	Turbine Valve Surv.					X		X	X <sup>(8,16)</sup>	
ST-25	MSIVs		X	X		X		X	X <sup>(8,16)</sup>	
ST-26	Relief Valves		X		X					
ST-27	Turbine Stop Valve Trip									
	Generator Load Rejection				M <sup>(10)</sup>	M			M	
ST-28	Shutdown From Outside Control Room			X						
ST-29	Recirculation Flow Control				M	M,A		M,A	M,A	
ST-30	Recirculation System					M <sup>(11)</sup>			M	
ST-31	Loss of T-G & Offsite Power				M					
ST-32	Containment Atmosphere and									
	Main Steam Tunnel Cooling		X		X				X <sup>(13)</sup>	
ST-33	Piping Steady State Vibration		X		X	X		X	X <sup>(8,13,9)</sup>	
ST-34	Rod Sequence Exchange								X <sup>(17)</sup>	
ST-35	Recirculation System Flow Calibration					X			X	
ST-36	Cooling Water Systems			X		X			X	
ST-37	Gaseous Radwaste System		X	X		X		X	X	X
ST-38	BOP Piping System Expansion <sup>(4)</sup>									
ST-39	Piping Vibration During Dynamic									
	Transients		X		X	X	X		X	
ST-40	BOP Piping Steady State Vibration <sup>(5)</sup>									

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UNITS 1 AND 2  
FINAL SAFETY ANALYSIS REPORT

INDIVIDUAL STARTUP  
TEST SEQUENCE

FIGURE 14.2-5, Sheet 1



Descriptive Notes:

- (1) See Figure 14.2-6 for Test Condition (TC) region map.
- (2) Some Subtests required to be completed prior to fuel load and may be performed during Phase II.
- (3) Refer to Table 14.2-5.
- (4) Testing merged into ST-17.
- (5) Testing merged into ST-33.
- (6) May be done during Open Vessel Testing.
- (7) May be done during Heatup.
- (8) Some Subtests done during approach to Test Condition.
- (9) May be done during earlier Test Condition if conditions warrant.
- (10) Done within steam bypass capacity.
- (11) The simultaneous trip of two Reactor recirculation pumps is done at 100% core flow on the 75% rod line.
- (12) Started during approach to Test Condition 5, continued during approach to Test Condition 6.
- (13) Some Subtests done after planned major trips from 100% power.
- (14) Started during Test Condition 6 and continued during Test Condition 4.
- (15) Loss of feedwater heating test done at 80% power.
- (16) Determine maximum power Subtest can be performed without causing reactor scram.
- (17) Done on 100% rod line near minimum core flow with recirc pumps on.

Legend:

- M - Master Manual Flow Control Mode  
A - Automatic Flow Control Mode  
X - Test Independent of Flow Control

43-14.2-5  
4FSAR

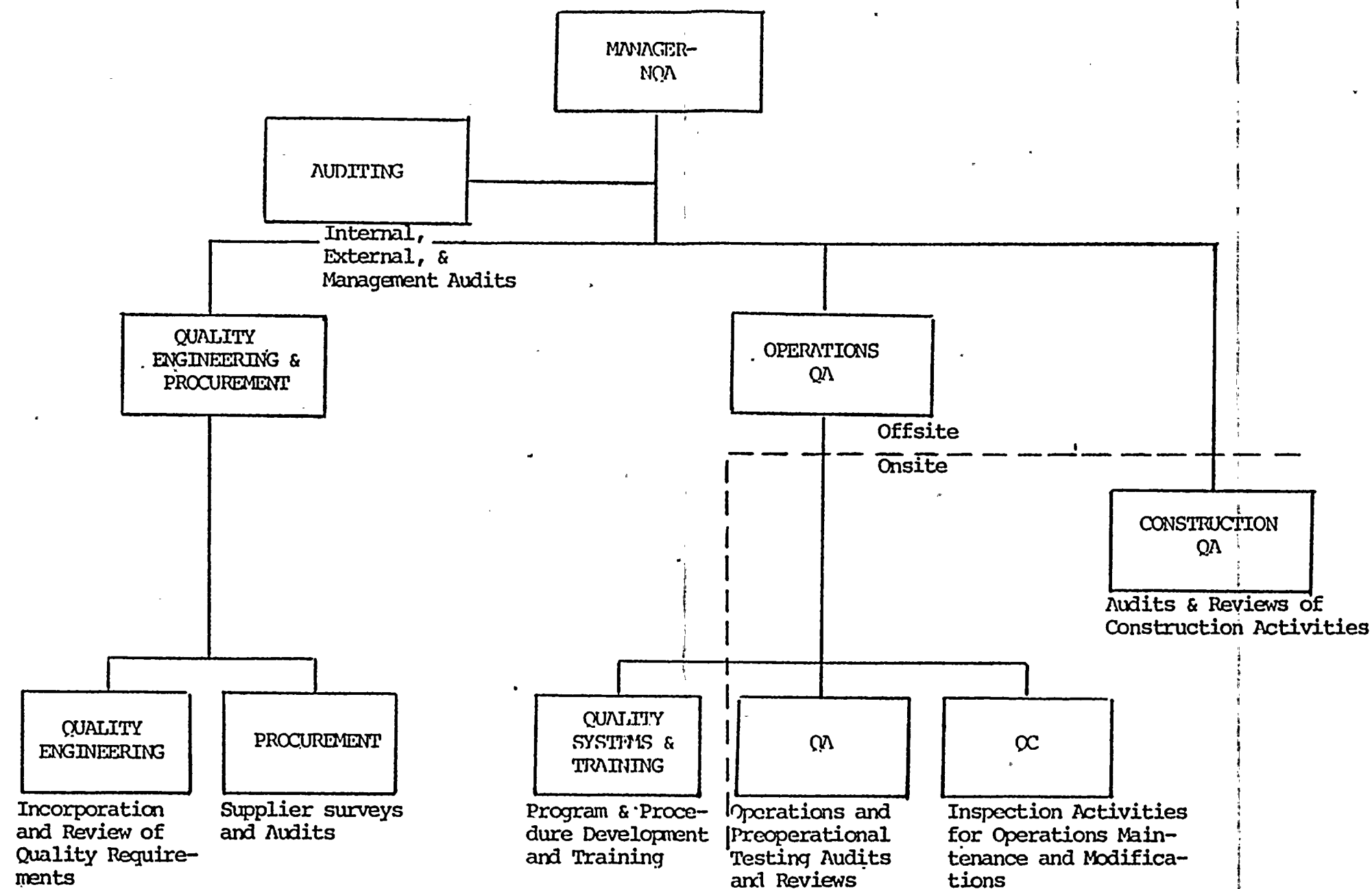
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UNITS 1 AND 2  
FINAL SAFETY ANALYSIS REPORT

INDIVIDUAL STARTUP  
TEST SEQUENCE

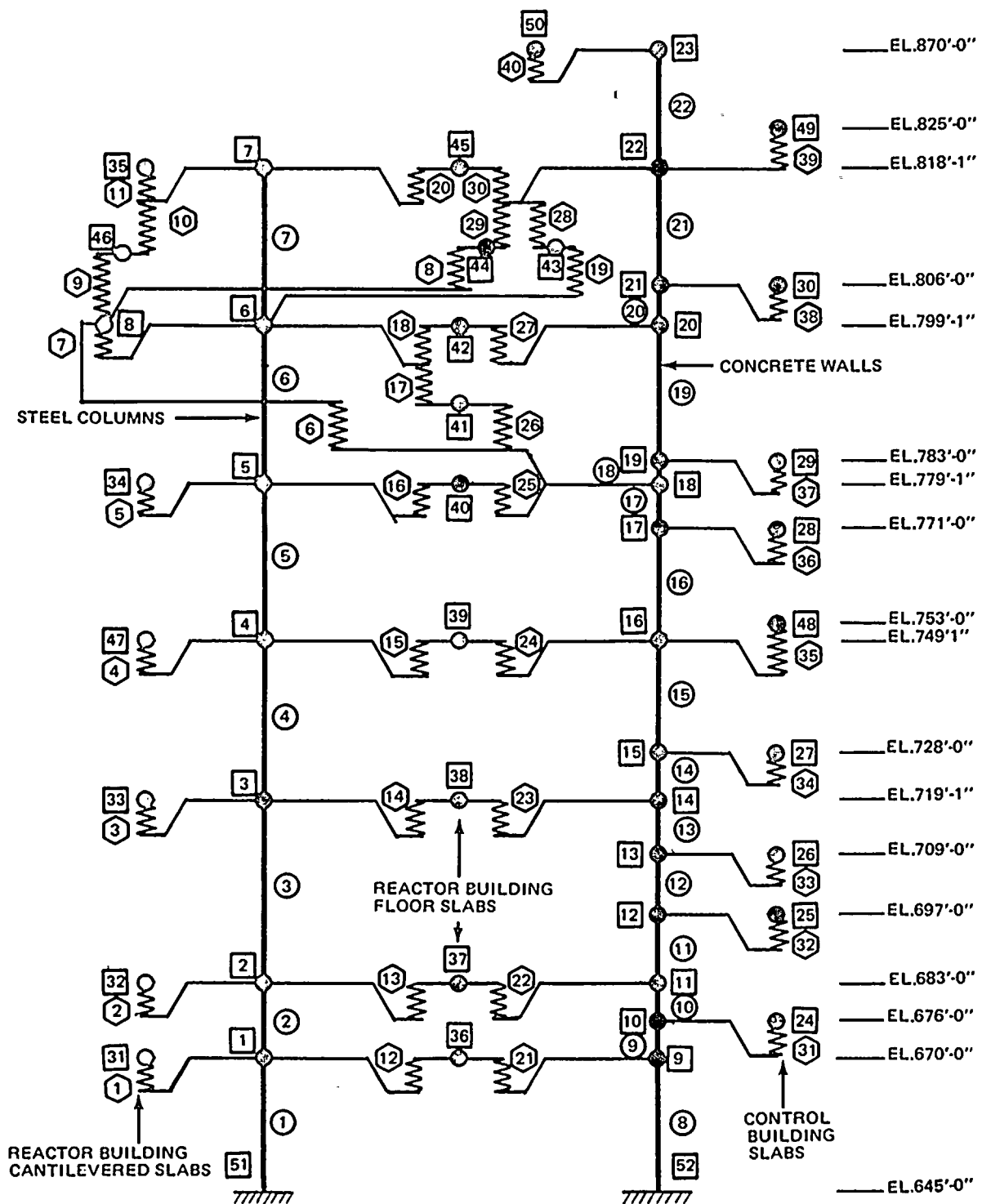
FIGURE 14.2-5, Sheet 2





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**LEGEND**

○ MASS POINT

□ JOINT NUMBER

○ MEMBER NUMBER

○ SPRING NUMBER

**SUSQUEHANNA STEAM ELECTRIC STATION**  
**UNITS 1 AND 2**  
**FINAL SAFETY ANALYSIS REPORT**

**VERTICAL SEISMIC MODEL**  
**OF REACTOR AND CONTROL**  
**BUILDING**

**FIGURE 3.7b-11**



- 1.0 OBJECTIVES
- 2.0 ACCEPTANCE CRITERIA
- 3.0 REFERENCES
- 4.0 PREREQUISITES
- 5.0 PRECAUTIONS AND NOTES
- 6.0 TEST EQUIPMENT
- 7.0 SYSTEM TEST
  - (a) TEMPORARY INSTALLATIONS
  - (b) INITIAL STATUS
  - (c) TEST INSTRUCTIONS
  - (d) RESTORATION
- 8.0 APPENDICES, FIGURES, TABLES

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**SUSQUEHANNA STEAM ELECTRIC STATION  
UNITS 1 AND 2  
FINAL SAFETY ANALYSIS REPORT**

**PREOPERATIONAL TEST PROCEDURE  
STANDARD FORMAT**

**FIGURE 14.2-2A**

ST.0     MAIN BODY

ST.0.1     OBJECTIVES

ST.0.2     TEST DESCRIPTION

ST.0.3     ACCEPTANCE CRITERIA

ST.0.4     REFERENCES

ST.0.5     PREREQUISITES

ST.0.6     PRECAUTIONS

ST.0.7     TEST EQUIPMENT

ST.0-A     GENERAL APPENDICES

ST.X     SUBTEST

ST.X.1     DISCUSSION

ST.X.2     INITIAL STATUS

ST.X.3     TEST INSTRUCTIONS

ST.X.4     ANALYSIS

ST.X-A     SPECIFIC APPENDICES

Legend: ST - Startup Test Number

X - Subtest Number

A - Appendix Designator

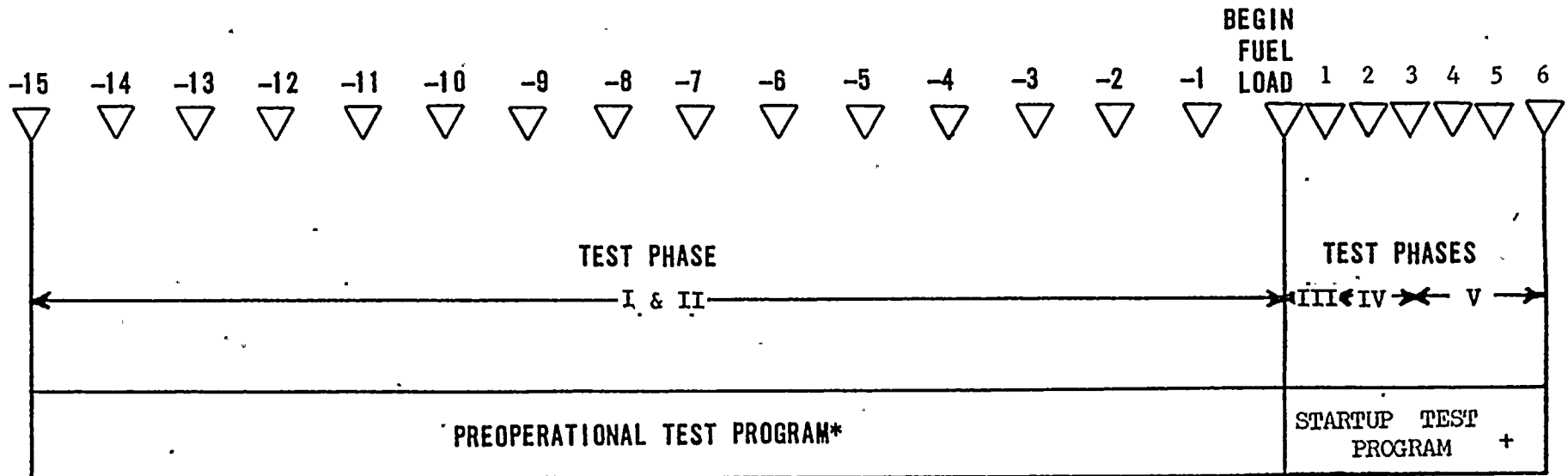
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SUSQUEHANNA STEAM ELECTRIC STATION  
UNITS 1 AND 2  
FINAL SAFETY ANALYSIS REPORT

STARTUP TEST PROCEDURE  
STANDARD FORMAT

FIGURE 14.2-2B

# MONTHS RELATIVE TO INITIAL FUEL LOAD



## NOTES:

- Test Phase I - Component and Inspection Testing
- Test Phase II - Preoperational and Acceptance Testing
- Test Phase III - Initial Fuel loading
- Test Phase IV - Initial Heatup and Low Power Testing
- Test Phase V - Power Ascension Testing

(\*) Reference Figure 14.2-4 for individual preoperational test sequence.

(+) Reference Figure 14.2-5 for startup test requirements by test condition.

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FIGURE 14.2-3

SUSQUEHANNA STEAM ELECTRIC STATION  
UNITS 1 AND 2  
FINAL SAFETY ANALYSIS REPORT  
INITIAL TEST PROGRAM SCHEDULE

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CHAPTER 7.0

FIGURES

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7.2-2	Reactor Protection System Scram Functions
7.2-3	Arrangement of Channels and Logics
7.2-4	Actuators and Actuator Logics
7.2-5	Logics in One Trip System
7.2-6	Relationship Between Neutron Monitoring System and Reactor Protection System
7.2-7	Configuration for Turbine Stop Valve Closure Reactor Trip
7.2-8	Configuration for Main Steamline Isolation Reactor Trip
7.2-9	Block Diagram - RPS Protective Circuit - EPA
7.3-1	ECCS Mechanical and Instrumentation Network Models
7.3-2	Isolation Control System for Main Steamline Isolation Valves
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7.3-8 Sht. 3	Nuclear Boiler System - FCD
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7.3-9 Sht. 1	Core Spray - FCD
7.3-9 Sht. 2	Core Spray - FCD
7.3-9 Sht. 3	Core Spray - FCD
7.3-10 Sht. 1	RHR-FCD
7.3-10 Sht. 2	RHR-FCD
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7.3-10 Sht. 4	RHR-FCD
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7.3-11 Sht. 1	Process Radiation Monitoring - IED
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7.6-9	Functional Block Diagram of IRM Channel
7.6-10	Power Range Monitor Detector Assembly Location
7.6-11 Sht. 1	Reactor Recirculation System - P&ID



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7.6-11 Sht. 2	Reactor Recirculation System - P&ID
7.6-11 Sht. 3	Reactor Recirculation System - P&ID
7.6-12	APRM Circuit Arrangement for Reactor Protection System Input
7.6-13	(This Figure intentionally left blank)
7.6-14	Ranges of Neutron Monitoring System
7.6-15	(This Figure intentionally left blank)
7.6-16	(This Figure intentionally left blank)
7.6-17	(This Figure intentionally left blank)
7.7-1	Water Level Range Definition
7.7-2 Sht. 1	Control Rod Drive Hydraulic System - FCD
7.7-2 Sht. 2	Control Rod Drive Hydraulic System - FCD
7.7-2 Sht. 3	Control Rod Drive Hydraulic System - FCD
7.7-2 Sht. 4	Control Rod Drive Hydraulic System - FCD
7.7-2 Sht. 5	Control Rod Drive Hydraulic System - FCD
7.7-3 Sht. 1	Reactor Manual Control System
7.7-3 Sht. 2	Reactor Manual Control System
7.7-4	Reactor Manual Control System Operation
7.7-5	Reactor Manual Control Self-Test Provisions
7.7-6	Eleven-Wire Position Probe
7.7-7 Sht. 1	Reactor Recirculation System - FCD
7.7-7 Sht. 2	Reactor Recirculation System - FCD
7.7-7 Sht. 3	Reactor Recirculation System - FCD
7.7-7 Sht. 4	Reactor Recirculation System - FCD
7.7-7 Sht. 5	Reactor Recirculation System - FCD
7.7-8	Recirculation Flow Control Illustration
7.7-9	Feedwater Control System - IED



7.6.1a.4.3.8.2.2 Logic and Sequencing

No action is initiated by the reactor vessel head pressure monitoring circuit.

7.6.1a.4.3.8.2.3 Bypasses and Interlocks

There are no bypasses or interlocks associated with this subsystem.

7.6.1a.4.3.8.2.4 Redundancy and Diversity

Redundant pressure-sensing instrumentation for detecting inner seal failure is not provided. The outer seal assembly provides back-up in the event that inner seal leak should occur.

7.6.1a.4.3.9 HPCI System Leakage Detection7.6.1a.4.3.9.1 Subsystem Identification

The steamline of the high pressure coolant injection (HPCI) system are constantly monitored for leaks by the leak detection system. Leaks from the HPCI steamline will cause a change in at least one of the following monitored operating parameters: sensed area temperature, steam pressure, or steam flow rate. If the monitored parameters indicate that a leak may exist, the detection system responds by activating an alarm and, depending upon the activating parameter, initiates HPCI autoisolation action.

The HPCI leakage detection system consists of three types of monitoring circuits. The first of these monitors area ambient temperature, triggering the alarm circuit when the temperature rises above the preset maximum. The second type of circuit utilized by the leakage detection system monitors the flow rate, or differential pressure, through the steam line, triggering an alarm circuit when the flow rate exceeds a preset maximum. The third type of circuit utilized by the HPCI leakage detection system monitors the steam line pressure upstream of the differential pressure element. Alarm outputs from all three circuits are also used to generate the HPCI auto-isolation signal. The ambient temperature monitoring is similar to that described in main steamline leakage detection system.

#### 7.6.1a.4.3.9.2. HPCI Area Temperature Monitoring

##### 7.6.1a.4.3.9.2.1. Circuit Description

The HPCI area and tunnel ambient and differential temperature sensing elements are thermocouples. Their outputs go to temperature switches set to activate at a preset temperature. Closing the temperature switches will light the point module alarm indicator and sound the high temperature alarm in the main control room. In addition, activation of the tunnel temperature switches will start the timer, which after a suitable delay period, initiates HPCI isolation valve closure. If at any time during the timing cycle, the temperature switch contacts are opened, the timer will automatically reset and no isolation valve closure will result. Before timer timeout, the operator can initiate isolation by depressing pushbutton switch HPCI ISOLATE. This action will bypass the timer circuits and, providing no logic test is in progress, the HPCI isolation valves will close.

High ambient and differential temperature from the HPCI area initiates immediate isolation valve closure.

##### 7.6.1a.4.3.9.2.2. Logic and Sequencing

The two division HPCI temperature monitors work on a one out of two logic that initiates the isolation logic. There are five temperature monitors per division which consist of three area (two ambient and one differential) and two tunnel (one ambient and one differential) temperature monitors. The tunnel temperature signals are time delayed before initiating the isolation logic.

##### 7.6.1a.4.3.9.2.3. Bypasses and Interlocks

A bypass/test switch is provided in each logic division for the purpose of testing the HPCI logic without initiating HPCI system isolation. Placing the keyswitch in Bypass position in one division will not prevent operation of the temperature monitor in the opposite division when required for HPCI system isolation. No interlocks are provided from this subsystem.

#### 7.6.1a.4.3.9.2.4 Redundancy and Diversity

There are two independent HPCI leakage detection divisions. The HPCI area ambient temperature monitoring is a diverse method of HPCI leak detection to the HPCI steam line pressure and flow rate (differential pressure) monitoring.

#### 7.6.1a.4.3.9.3 HPCI Steam Flow Monitoring

##### 7.6.1a.4.3.9.3.1 Description

The steamline from the nuclear boiler leading to the HPCI turbine is instrumented so that the steam flow rate through it, and its pressure, can be monitored and used to indicate the presence of a leak or break. In the presence of a leak, the HPCI system responds by operating the auto-isolation signal. This portion of the discussion on HPCI system leakage detection is limited to the flow rate instrumentation and does not cover the system isolation procedures. Steam flowing through the steam line will develop a differential pressure head across the elbow located inside the primary containment. The magnitude of the head proportional to the square of the flow rate is measured by a dPIS. Flow rates in excess of the predetermined maximum indicative of a line leak or break will generate differential pressure heads of sufficient magnitude to cause a dPIS actuation. Actuation occurs following a preset time delay to prevent inadvertent isolation. HPCI isolation is discussed in Subsection 7.3.1.1a.1.3.7.

##### 7.6.1a.4.3.9.3.2 Logic and Sequencing

Using one-out-of-two logic, the HPCI steam flow monitoring circuit initiates a HPCI isolation signal when the flow rate exceeds a preset limit.

##### 7.6.1a.4.3.9.3.3 Bypasses and Interlocks

See paragraph 7.6.1a.4.3.9.2.3.

##### 7.6.1a.4.3.9.3.4 Redundancy and Diversity

There are two independent HPCI leakage detection channels.

#### 7.6.1a.4.3.9.4 HPCI Steamline Pressure Monitoring

##### 7.6.1a.4.3.9.4.1 Circuit Description

Steamline pressure to the HPCI turbine is monitored to detect gross system leaks that may occur upstream of the dp element, causing the line pressure to drop to an abnormally low level. Line pressure is monitored by pressure switches, actuating on low pressure to also generate the auto-isolation signal.

##### 7.6.1a.4.3.9.4.2 Logic and Sequencing

Using two-out-of two logic, the HPCI steamline pressure monitoring circuit initiates a HPCI isolation signal when the pressure falls below a preset limit.

##### 7.6.1a.4.3.9.4.3 Bypasses and Interlocks

See Subsection 7.6.1a.4.3.9.2.3 for discussion

##### 7.6.1a.4.3.9.4.4 Redundancy and Diversity

There are two independent HPCI leakage detection channels.

##### 7.6.1a.4.4 System and Subsystem Separation Criteria

See Section 3.12 for discussion on separation.

##### 7.6.1a.4.5 System and Subsystem Testability

The proper operation of the sensor and the logic associated with the leak detection systems is verified during the leak detection system preoperational test and, during inspection tests that are provided for the various components during plant operation. Each temperature switch, both ambient and differential types, is connected to dual thermocouple elements.

Each temperature switch contains a trip light which lights when the temperature exceeds the set point. In addition, keylock test switches are provided so that logic can be tested without sending an isolation signal to the system involved. Thus, a complete system check can be confirmed by checking activation of the isolation relay associated with each switch.

RWC differential flow leak detection alarm units are tested by inputting a millivolt signal to simulate a high differential flow. Alarm and indicator lights monitor the status of the trip circuit.

Testing of flow, reactor vessel level, and pressure leak detection equipment is described in Subsections 7.3.1.1a.1, and 7.3.1.1a.2.

#### 7.6.1a.4.6 System and Subsystem Environmental Considerations

The sensors, wiring, and electronics of the leak detection system which are associated with the isolation valve logic are designed to withstand the envelope conditions that follow a LOCA. (See Tables 3.11-1, 3.11-2, and 3.11-3.)

All portions of the leak detection system which provide for isolation of other systems or portions of systems are environmentally qualified to meet the requirements for Class I electrical equipment (See Section 3.11.).

#### 7.6.1a.4.7 System and Subsystem Operational Considerations

The operator is kept aware of the status of the leak detection system through meters and recorders which indicate the measured variables in the control room. If a trip occurs, the condition is continuously annunciated in the main control room.

Leak detection system bypass switches are provided on a backrow panel in the main control room to allow bypassing of certain trip functions during testing.

The operator can manually operate valves which are affected by the leak detection system during normal operation. When a trip conditions exists, the isolation logic must be reset before further manual valve operations can be performed. Manual reset switches are provided in the main control room.

There is no vital supporting system which supplies direct support for the leak detection systems.

#### 7.6.1a.5 Neutron Monitoring System-Instrumentation and Controls

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The neutron monitoring system consists of six major subsystems:

- (1) Source range monitor subsystem (SRM),
- (2) Intermediate range monitor subsystem (IRM),
- (3) Local power range monitor subsystem (LPRM),
- (4) Average power range monitor subsystem (APRM),
- (5) Rod block monitor subsystem (RBM), and
- (6) Traversing in-core probe subsystem (TIP).

##### 7.6.1a.5.1 System Identification

The purpose of this system is to monitor the power in the core and provide signals to the RPS and the rod block portion of the reactor manual control system. It also provides information for operation and control of the reactor.

The IRM and APRM subsystems provide a safety function, and have been designed to meet particular requirements established by the NRC. The LPRM subsystem has been designed to provide a sufficient number of LPRM inputs to the APRM subsystem to meet the APRM requirements. All other portions of the Neutron Monitoring System have no safety function. The system is classified as shown in Table 3.2-1. The safety related subsystems are qualified in accordance with Sections 3.10 and 3.11.

##### 7.6.1a.5.2 Power Source

The power sources for each system are discussed in the individual descriptions.

##### 7.6.1a.5.3 Source Range Monitor (SRM) Subsystem

The SRM is a non-safety subsystem. See Subsection 7.7.1.13



#### 7.6.1a.5.4. Intermediate Range Monitor (IRM) Subsystem

##### 7.6.1a.5.4.1. Equipment Design

##### 7.6.1a.5.4.1.1. Description

The IRM monitors neutron flux from the upper portion of the SRM range to the lower portion of the power range. The IRM subsystem has eight IRM channels, each of which includes one detector that can be positioned in the core by remote control. The detectors are inserted into the core for a reactor startup and are withdrawn after the reactor mode selector switch is turned to RUN.

##### (1) Power Supply

Power is supplied separately from two 24 V dc sources. The supplies are split according to their uses so that loss of a power supply will result in loss of only one trip system of the reactor protection system.

##### (2) Physical Arrangement

Each detector assembly consists of a miniature fission chamber attached to a low-loss, quartz-fiber-insulated transmission cable. When coupled to the signal conditioning equipment, the detector produces a reading of full scale on the most sensitive range with a neutron flux of  $4 \times 10^8$  nv. The detector cable is connected underneath the reactor vessel to a triple-shielded cable that carries the pulses generated in the fission chamber to the preamplifier.

The detector and cable are located in the drywell. They are movable in the same manner as the SRM detectors and use the same type of mechanical arrangement (see Figures 7.6-5 and 7.6-6 and Reference 7.6-1).

##### (3) Signal Conditioning

A voltage amplifier unit located outside the drywell serves as a preamplifier. This unit converts the current pulses to voltage pulses, modifies the voltage signal, and provides impedance matching. The preamplifier output signal is coupled by a cable to the IRM signal conditioning electronics (see Figure 7.6-9).

Each IRM channel receives its input signal from the preamplifier and operates on it with various combinations of preamplification gain and amplifier attenuation ratios. The amplification and attenuation ratios of the IRM and preamplifier are selected by a remote range switch that provides 10 ranges of increasing attenuation (the first 6 called low range and the last 4 called high range) acting on the signal from the fission chamber. As the neutron flux of the reactor core increases from  $1 \times 10^8$  nv to  $1.5 \times 10^{13}$  nv, the signal from the fission chamber is attenuated to keep the input signal to the inverter in the same range. The output signal, which is proportional to neutron flux at the detector, is amplified and supplied to a locally mounted meter. Outputs are also provided for a remote meter and recorder.

#### (4) Trip Functions

The IRM Scram Trip Functions are discussed in Section 7.2. The IRM trips are shown in Table 7.6-3. The IRM Rod Block Trip Functions are discussed in Subsection 7.7.1.2.6.

#### 7.6.1a.5.4.1.1.1 Bypasses and Interlocks

The arrangement of IRM channels allows one IRM channel in each group to be bypassed without compromising intermediate range neutron monitoring.

#### 7.6.1a.5.4.1.2 Redundancy

The IRM system consists of 8 IRM channels, four of which are connected to one trip system, and the other four are connected to the other trip system. The redundancy and single failure requirements are met because any single failure with the IRM system cannot prevent needed safety action of the IRM system. (See also Subsection 7.2.1.1.4.2).

#### 7.6.1a.5.4.1.3 Testability

Each IRM channel is tested and calibrated using the procedures listed in the IRM instruction manual. The IRM detector drive

mechanisms and the IRM rod blocking functions are checked in the same manner as for the SRM channels. Each IRM channel can be checked to ensure that the IRM high flux scram function is operable.

#### 7.6.1a.5.4.2 Environmental Conditions

The wiring, cables, and connectors located in the drywell are designed for the same environmental conditions as the SRMs.

The IRM pre-amplifier, located in the reactor building and the monitor, located in the control room, are designed to operate under all expected environmental conditions in those areas. The IRM system components are designed to operate during and after certain design basis events such as earthquakes, accidents, and anticipated operational occurrences.

#### 7.6.1a.5.4.3 Operational Considerations

The IRM range switches must be upranged or downranged to follow increases and decreases in power within the range of the IRM to prevent either a scram or a rod block. The IRM detectors must be inserted into the core whenever these channels are needed, and withdrawn from the core, when permitted, to prevent their burnup. The identification scheme for the IRM subsystem is given in Subsection 7.2.2.1.2.3.1.22.

The method used for identifying power and signal cables and raceways as safety-related equipment, and the identification scheme used to distinguish between redundant cables, raceways, and instrument panels is in accordance with the recommendations of IEEE 279-1971, Paragraph 4.6.

#### 7.6.1a.5.5 Local Power Range Monitor (LPRM) Subsystem

##### 7.6.1a.5.5.1 Equipment Design

##### 7.6.1a.5.5.1.1 Description

The LPRM consists of fission chamber detectors, signal conditioning equipment, and trip functions. The LPRM also provides outputs to the APRM, the RBM, and the process computer.

## (1) Power Supply

Power for the LPRM is supplied by the two RPS buses. Approximately half of the LPRMs are supplied from each bus. Each LPRM amplifier has a separate power supply in the control structure, which furnishes the detector polarizing potential. This power supply is adjustable from 75 to 200 V dc. The maximum current output is three milliamps. This ensures that the chambers can be operated in the saturated region at the maximum specified neutron fluxes. For maximum variation in the input voltage or line frequency, and over extended ranges of temperature and humidity, the output voltage varies no more than two volts. Each "page" of amplifiers is supplied operating voltages from a separate low voltage power supply.

## (2) Physical Arrangement

The LPRM includes 43 LPRM detector strings having detectors located at different axial heights in the core; each detector string contains four fission chambers. These assemblies are distributed to monitor four horizontal planes throughout the core. Figure 7.6-3 shows the LPRM detector radial layout scheme that provides a detector assembly at every fourth intersection not containing control crosses of the water channels around the fuel bundles. Thus, the uncontrolled water gap has either an actual detector assembly or a symmetrically equivalent assembly in some other quadrant. The detector assemblies (see Figure 7.6-10) are inserted in the core in spaces between the fuel assemblies. They are inserted through thimbles mounted permanently at the bottom of the core lattice and penetrate the bottom of the reactor vessel. These thimbles are welded to the reactor vessel at the penetration point. They extend down into the access area below the reactor vessel where they terminate in a flange. The flange mates to the mounting flange on the in-core detector assembly. The detector assemblies are locked at the top end to the top fuel guide by means of a spring loaded plunger. Special water sealing caps are placed over the connection end of the assembly and over the penetration at the bottom of the vessel during installation or removal of an assembly. This prevents loss of reactor coolant water on removal of an assembly and also prevents the connection end of the assembly from being immersed in the water during installation or removal.

Each LPRM detector assembly contains four miniature ion chambers with an associated solid sheath cable. The chambers are vertically spaced in the LPRM detector assemblies in a way that gives adequate axial coverage of the core, complementing the radial coverage given by the horizontal arrangement of the LPRM detector assemblies. Each ion chamber produces a current that is coupled with the LPRM signal conditioning equipment to provide the desired scale indications.

Each miniature chamber consists of two concentric cylinders, which act as electrodes. The inner cylinder (the collector) is mounted on insulators and is separated from the outer cylinder by a small gap. The gas between the electrodes is ionized by the charged particles produced as a result of neutron fissioning of the uranium-coated outer electrode. The chamber is operated at a polarizing potential of approximately 100 V.d.c. The negative ions produced in the gas are accelerated to the collector by the potential difference maintained between the electrodes. In a given neutron flux, all the ions produced in the ion chamber can be collected if the polarizing voltage is high enough. When this situation exists, the ion chamber is considered to be saturated. Output current is then independent of operating voltage, (Reference 7.6-1).

Each assembly also contains a calibration tube for a traversing in-core probe. The enclosing tube around the entire assembly contains holes that allow circulation of the reactor coolant water to cool the ion chambers. Numerous tests have been performed on the chamber assemblies including tests of linearity, lifetime, gamma sensitivity, and cable effects, (Reference 7.6-1). These tests and experience in operating reactors provide confidence in the ability of the LPRM subsystem to monitor neutron flux to the design accuracy throughout the design lifetime.

- (3) **Signal Conditioning** The current signals from the LPRM detectors are transmitted to the LPRM amplifiers in the control room. The current signal from a chamber is transmitted directly to its amplifier through coaxial cable. The amplifier is a linear current amplifier whose voltage output is proportional to the current input and therefore proportional to the magnitude of the neutron flux. Low level output signals are provided that are suitable as an input to the computer, recorders, etc. The output of each LPRM amplifier is isolated to prevent interference of the signal by

inadvertent grounding or application of stray voltage at the signal terminal point.

The LPRM amplifier signals are indicated on the unit operating benchboard. Subsection 7.7.1.1 describes the indications on the reactor control panel.

#### (4) Trip Functions

The trip circuits for the LPRM provide trip signals to activate lights, instrument inoperative signals, and annunciators. These trip circuits use the dc power supply and are set to trip on loss of power. They also trip when power is not available for the LPRM amplifiers. Table 7.6-4 indicates the trips.

The trip levels can be adjusted to within  $\pm 0.5\%$  of full-scale deflection and are accurate to  $\pm 1\%$  of full-scale deflection in the normal operating environment.

#### 7.6.1a.5.5.1.2 Bypasses and Interlocks

Each LPRM channel may be individually bypassed. When the maximum number of bypassed LPRMs associated with any APRM channel has been exceeded, an inoperative trip is generated by that APRM.

#### 7.6.1a.5.5.1.3 Redundancy

The LPRM channels meet the redundancy criterion because of the multiplicity of sensing channels. The minimum number of LPRMs that must be in service is shown in Figure 7.6-4.

#### 7.6.1a.5.5.1.4 Testability

LPRM channels are calibrated using data from previous full power runs and TIP data and are tested with procedures in the applicable instruction manual.

#### 7.6.1a.5.5.2 Environmental Considerations

Each individual chamber of the assembly is a moisture-proof, pressuresealed unit. The chambers are designed to operate up to 600°F and 1250 psig. The wiring, cables, and connectors located

within the drywell are designed for continuous duty up to 270°F; 100% relative humidity and a 4-hour single exposure rating of 482°F at 100% relative humidity. The LPRMs are capable of functioning during and after certain design basis events such as earthquakes and anticipated operational occurrences.

#### 7.6.1a.5.5.3 Operational Considerations

The LPRM is a monitoring system with no special operating considerations.

#### 7.6.1a.5.6 Average Power Range Monitor (APRM) Subsystem

##### 7.6.1a.5.6.1 Equipment Design

##### 7.6.1a.5.6.1.1 Description

The APRM subsystem has six APRM channels. Each channel uses input signals from a number of LPRM channels. Three APRM channels are associated with each trip system of the reactor protection system.

##### (1) Power Supply

The APRM channels receive power from the 120 V ac supplies used for RPS power. Power for each APRM trip unit is supplied from the same power supply as the APRM it services. APRM Channels A, C, and E are powered from the ac bus used for Trip System A of the reactor protection system; APRM Channels B, D, and F are powered from the ac bus used for Trip System B. The ac bus used for a given APRM channel also supplies power to its associated LPRMs.

##### (2) Signal Conditioning

The APRM channel uses electronic equipment that averages the output signals from a selected set of LPRMs, trip units that actuate automatic devices, and signal readout equipment. Each APRM channel can average the output signals from as many as 24 LPRMs. Assignment of LPRMs to an APRM follows the pattern shown in Figure 7.6-4. Position A is the bottom position, Positions B and C are above Position A, and

Position D is the topmost LPRM detector position. The pattern provides LPRM signals from all four core axial LPRM detector positions.

The APRM amplifier gain can be adjusted by combining fixed resistors and potentiometers to allow calibration. The averaging circuit automatically corrects for the number of unbypassed LPRM amplifiers providing inputs to the APRM.

Each APRM channel receives two independent, redundant flow signals representative of total recirculation driving flow. Each signal is provided by summing the flow signals from the two recirculation loops. These redundant flow signals (Figure 7.6-11) are sensed from four pairs of elbow taps, two in each recirculation loop. No single active component failure can cause more than one of these two redundant signals to read incorrectly. To obtain the proper (most conservative) reference signal under single failure conditions, these flow signals are routed to a low auction circuit. This circuit selects the lower of the two signals for use as the reference in the thermal power scram trip for that particular APRM. Because there are two redundant flow units assigned to each trip system, one flow unit in each trip system can be bypassed for a short time. This design meets the intent of IEEE 279-1971.

### (3) Trip Function

APRM system trips are summarized in Table 7.6-5. The APRM Scram Trip Function is discussed in Section 7.2. The APRM circuit arrangement for RPS trip input is shown in Figure 7.6-12. The APRM Rod Block Trip Function is discussed in Subsection 7.6.1a.6.2.

#### 7.6.1a.5.6.1.2 Bypasses and Interlocks

One of the two flow units in each trip system may be bypassed at any time. One of the three APRMs in each trip system may be bypassed at any time. An interlock circuit provides an inoperative trip output from an APRM whenever the minimum number of LPRM inputs to it is not met.