SECTION 7

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# SECTION 7

## 7.0 INSTRUMENTATION AND CONTROL

The instrumentation and control systems include the following:

Reactor Protection System (RPS)
Safety Features Actuation System (SFAS)
Steam and Feedwater Line Rupture Control System (SFRCS)
Control Rod Drive Control System (CRDCS)
Auxiliary Shutdown Panel (ASP)
Integrated Control System (ICS)
Nuclear Instrumentation (NI)
Non-Nuclear Instrumentation (NNI)
Incore Monitoring System (IMS)
Post Accident Monitoring System (PAMS)
Anticipatory Reactor Trip System (ARTS)
Station Computer System
Station Annunciator
Safety Parameter Display System (SPDS)

The RPS is a protection system, as defined by IEEE Standard 279-1968, which performs the sole function of causing a trip of all reactor shim and safety rods (by actuating the associated CRDCS trip devices) when station conditions require such action.

The SFAS is a protection system as defined by IEEE Standard 279-1971 which initiates action of various safety actuation devices to protect the reactor core during a LOCA and to mitigate the consequences of a LOCA.

The SFRCS is a protection system as defined by IEEE Standard 279-1971 which initiates the auxiliary feedwater system and isolates the affected steam generator on a steam or feedwater line rupture.

The CRDCS is divided into two portions. The trip portion performs the safety function of tripping the shim and safety rods when commanded to do so by the RPS. The control portion of the CRDCS performs the function of positioning control rods in response to commands from the ICS or the reactor operator.

The ASP is a control panel designed to provide the operator with the necessary controls and instrumentation to maintain the station in a safe shutdown condition from outside the control room.

The ICS is a non-safety system which automatically controls the station in response to commands preset by the operator. The ICS provides control rod motion (when CRDCS is in the automatic mode), normal feedwater control, and turbine control; the operator is also provided with the capability for manual override control of the station.

The NI is divided into two portions. The Power Range instruments provide safety signals to the RPS (and therefore are considered a portion of the RPS). The Source and Intermediate Range instruments do not perform safety functions but are intended to provide information during reactor startup and shutdown.

The NNI System consists of various instrumentation and controls. Some functions performed are pressurizer heater control, pressurizer level control and monitoring of primary parameters.

The IMS provides fuel management personnel and the operator with reactor core information based on signals detected by fixed incore neutron detectors and thermocouples. The system does not perform any safety or control functions.

The PAM is a redundant channel safety related instrumentation and control system as defined by NUREG 0737. The instrumentation and controls are designed to monitor the course of an accident condition and to provide additional plant information to bring the plant back to normal condition.

The ARTS is a redundant channel safety related instrumentation and control system as defined by IEEE Standard 279-1971. The instrumentation and controls are designed to trip the reactor when a parameter exceeds its setpoint indicating the approach of an unsafe condition, i.e., trip will de-energize the associated undervoltage coils for the CRDCS.

The Station Computer and Annunciator are non-safety recording and alarm systems.

The SPDS is a non-safety related display system that aids control room and supporting personnel during abnormal and emergency conditions in determining the safety status of the plant.

# 7.1 INTRODUCTION

## 7.1.1 Identification of Safety-Related Systems

### 7.1.1.1 Systems Supplied by Babcock & Wilcox

The safety-related systems supplied by Babcock & Wilcox for Davis-Besse Unit 1 which directly relate to the public safety are as follows:

a. Protection System:

   NI/RPS (portions required to sense approach to unsafe conditions and initiate a reactor trip)

b. Systems Required for Safe Shutdown:

   CRDCS (trip portions)

c. Safety-Related Display Instrumentation:

   1. RPS indication

   2. Display instrumentation required to maintain safe hot shutdown

   Refer to Section 7.5 for a discussion of safety-related display instrumentation.

The major initial design features of all the above safety-related systems were identical to those of the Sacramento Municipal Utility District's Rancho Seco station with the exception that Davis-Besse has two manual trip switches instead of one. In addition, the design of the CRDCS trip devices which are actuated by the RPS has been improved. Refer to Subsection 7.4.1.1 for a detailed discussion.

### 7.1.1.2 Other Systems

a. SFAS

   The SFAS is required to sense unsafe conditions and actuate engineered safety features.

b. Steam and Feedwater Line Rupture Control System (SFRCS)

   The SFRCS is required to ensure adequate feedwater supply to remove reactor decay heat upon loss of the normal feedwater supply.

c. PAMS

   The PAMS is required to monitor the course of an accident condition and provide additional plant information to return plant to normal condition.

d. ARTS

The ARTS is required to monitor protective functions and trip the reactor when a parameter exceeds its trip setpoint.

e. ASP

The ASP is required to maintain the station in a safe hot shutdown condition should the main control room become unavailable.

f. The essential power supply is discussed in Chapter 8.

#### 7.1.1.3 SFAS Comparison with Another Plant

The major design features of the SFAS and equipment as originally supplied by Consolidated Controls Corp. (CCC) for the Davis-Besse Nuclear Power Station Unit One are compared to Millstone Unit 2 in FSAR 7.1.1.3.

#### 7.1.1.4 SFRCS Comparison with SFAS

The major design features of SFRCS supplied by Consolidated Controls Corp. for the Davis-Besse Nuclear Power Station Unit One are similar, except where noted, to those of the SFAS.

| Features | SFAS | SFRCS |
|---|---|---|
| Manufacturer | CCC | CCC |
| System Logic | 2 out of 4 | 2 out of 2 per actuation channel |
| Channel bypass reduces to | 2 out of 3 | Not provided[1] |
| Number of sensor channels | 4 | 2 |
| Number of actuation channels | 2 | 2 |
| Logic components | Solid state | Solid state |
| Output components | Rotary relays | Balanced armature relay[2] |
| Operating bypasses included | Yes | Yes |
| Automatic test features included | No | No |
| Bistable setpoint surveillance | Yes | Yes[4] |
| Manual test features included | Yes | Yes |
| Surveillance features included | Yes | Yes |
| Half-trip features | Yes | Yes |
| Power loss causes | Half-trip | Half-trip |
| Isolation devices (digital) | Opto-electronic | Opto-electronic and relays[3] |
| Isolation devices (analog) | I/I converter | I/I Converter |
| Loss of sensor channel | Alarm | Alarm |
| Seismic qualification | Analysis & test | Analysis & Test |
| Design qualification | Identical | Identical |
| Environmental qualification | Test | Test |

### 7.1.2 Identification of Safety Criteria

#### 7.1.2.1 Listing of Safety Criteria

Refer to Table 7.1-1.

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[1]Refer to "Channel Bypass," Paragraph 7.4.1.3.4.

[2]Function similar; same tests have been satisfactorily performed

[3]SFRCS does not require interconnection between the redundant channels.

[4]Steam Generator Level only

### 7.1.2.2 Quality Assurance

The Davis-Besse Quality Assurance program is discussed in Chapter 17.

### 7.1.2.3 Criteria for Preservation of Separation and Independence of Redundant Portions of Protections Systems, etc.

Each channel of the RPS, SFAS, SFRCS, ARTS, and PAMS is contained in its own cabinet. The cabinets provide a fire barrier as well as a means of mechanically protecting the equipment. Interconnecting wire between redundant channels of each system satisfies the criteria for maintaining the necessary separation between channels.

All signals leaving or entering the RPS, SFAS and ARTS are isolated from the system by either isolation amplifiers (for analog signals) or relay contacts (for digital signals). This isolation prevents faults occurring to signal lines outside the RPS, SFAS and ARTS cabinets from being reflected into more than one essential channel. The isolation thus provided also ensures that two or more protective channels cannot interact through the cross-coupling or faulting of related signal lines.

Faults, such as short, open or grounded circuits and cross-coupling of external signals from two or more channels, have no effect on the protective channels or their functions. The isolation amplifier circuits of the RPS have been prototype-tested to assess their effectiveness to isolate the input signal from output circuit faults. They are capable of withstanding a short-circuit or a maximum of 400V DC or peak AC potential across their output without affecting the input source. The redundance and coincidence logics of the systems permit them to tolerate a failure and thus reduce the chance of an inadvertent reactor trip or actuation of engineered safety features. Each RPS, SFAS, SFRCS, and ARTS channel is powered from a different essential bus, so that power supply faults can affect only one channel at a time.

The need for physical isolation has been met in the physical arrangement (each RPS, SFAS, SFRCS and ARTS channel is equipped with separate cabinets and wiring within the cabinets separating power and signal wiring; power here is considered to be the wires feeding cabinet interior area lighting, convenience outlets, and space heaters) to reduce the possibility of a physical event impairing system functions.

Redundant Class 1E sensors and their connections to the process system have been sufficiently separated to ensure that the functional capability of the protection system has been maintained despite any single basis event or result therefrom. Sensor-to-sensor separation is a minimum of three feet.

Some sensor-to-process connections of redundant sensors have a common section of line. This is justified since failure of this connection will cause the sensors to fail in the safe position.

The CRDCS (trip portion) is discussed in Subsection 7.4.1.1.

#### 7.1.2.3.1 Spacing of Wiring and Components in Control Boards, Panels, and Instrument Racks

Isolation of wiring and components between essential redundant channels on control boards and panels is accomplished with a minimum of 12 inches of separation. This separation consists of free panel space, or recorders and indicators isolated from the redundant electrical systems by isolation amplifiers or power supplies.

Wherever the 12-inch separation cannot be met, metallic barriers are provided between essential redundant channels. A matrix for conduit separation has been developed (see Figure 7.1-1).

Isolation of wiring and components between essential redundant channels is accomplished in field instrument racks by locating not more than one essential channel per instrument rack. Physical separation between field racks for redundant channels is maintained at 3 feet minimum. Whenever the minimum separation cannot be met, rigid barriers are provided between essential redundant channels. Structural protection is provided for rack-mounted instruments on an individual basis if the probability of physical damage from any event (pipe whip or falling objects) is considered probable.

The equipment vendor has the responsibility for assuring that the design meets the applicable criteria enumerated in the procurement specification. The system design is subject to the approval of the equipment purchaser.

The criteria and bases for installation of electrical cable for the protection systems are discussed in Subsection 8.3.1.

The identification and physical separation of redundant channels of the RPS and SFAS are described in Subsection 8.3.1.2.

#### 7.1.2.4 Compliance with IEEE Standard 323-1971

The RPS has been qualified to provide conformance with the requirements of the applicable design criteria. Since IEEE Standard 323-1971 was not available at the time of the equipment procurement, Topical Report BAW-10003A, Rev. 4 “Qualification Testing of Protection System Instrumentation,” does not follow the format of IEEE Standard 323-1971. However, BAW-10003A, Rev. 4 does establish that each type of equipment is qualified for its application. The documentation includes the application requirements, the equipment test specification and data from the qualification testing. Subsequent to the submittal and approval of BAW-10003A, Rev. 4, replacement RPS Reactor Trip Modules manufactured by Framatome have been approved for installation in the RPS. These Reactor Trip Modules are qualified in accordance with FTI Reactor Trip Module Qualification Test Report 51-5006947-00.

#### 7.1.2.5 Physical Identification of the RPS, SFAS and CRDCS (Trip Portions)

Instruments, instrument racks, cabinets, cables, conduits, cable trays, etc., associated with the RPS, SFAS, and CRDCS (trip portion) are color coded or tagged in order to easily identify them and their channel association. Additional discussion is found in Subsection 8.3.1.2.

#### 7.1.2.6 Compliance with IEEE Standard 317-1971

The electrical penetrations comply with the IEEE Standard 317-1971, including all applicable codes and standards mentioned therein.

The design of the electrical penetrations utilizes header plate assemblies of modular construction. The header plates are bolted to the welding neck flanges, which are field welded to the penetration nozzles.

The Amphenol modules are redundantly sealed to the header plate assemblies by means of spring loaded pressure seals and o-rings. The Conax and Amphenol replacement modules are

redundantly sealed to the header plate by means of two sets of o-rings and a three piece ferrule assembly. The Conax modules are redundantly sealed to the Conax header plate by means of a three piece ferrule assembly. The header plate assemblies are redundantly sealed to the weld neck flange by means of double o-rings.

#### 7.1.2.7 Compliance with IEEE Standard 338-1971

The protection systems are designed in compliance with the periodic testing requirements outlined in Sections 4.9 and 4.10 of IEEE Standard 279-1971 and as further interpreted and defined in IEEE Standard 338-1971. Due to the redundancy and separation of the multi-channel protection system designs, testing and calibration of components and modules can be performed during power operation. A preventive maintenance program has been developed which includes frequent on-line tests while the station is in full-power operation as well as during the infrequent periods when the reactor is shut down. Periodic testing and preventive maintenance procedures are an integral part of station operation.

Only in the method of determining test intervals is there any deviation from the method prescribed in IEEE Standard 338. Initially the determination of the test interval was based on equipment technical specifications, past-operating experience, and empirical test data on like equipment. Throughout the life of the plant, the frequency of these periodic, on-line tests are modified as required to reflect current operating requirements.

Unit testing, operating and maintenance procedures have been developed. The use of jumpers or other temporary forms of bypassing functions for operation or maintenance of safety related systems is very limited. Preoperational tests, by their nature, required greater use of jumpers or lifted wires.

Temporary forms of bypassing are allowed when they neither compromise nuclear safety, nor the intent of the procedure. In addition, the use of temporary forms of bypassing functions do not violate the Technical Specifications of the Operating License.

The use of temporary forms of bypassing is controlled in individual safety related procedures or Administrative Procedures. This procedure includes a log to document the status of temporary modifications to maintain cognizance by the station personnel as to the operability of a system and to prevent inadvertent safety function bypassing.

The instrument ranges of instruments used for the engineered safety features system, reactor protection system and other safety related systems were established by making the actuated setpoint settings required to operate in the accurate portion of scale for the automatic initiation of the protective function.

Instrumentation setpoints are established by considering the range of values in which protective action must occur before safety implications could be reached. The setpoint is then established within that tolerable range by allowing sufficient margins between the setpoint and the technical specification allowable limits to preclude the possibility of drifting out of technical specification allowable limits.

TABLE 7.1-1

SAFETY CRITERIA USED IN THE DESIGN OF SAFETY RELATED CONTROL AND INSTRUMENT SYSTEMS

| System | Applicable criteria |
|---|---|
| RPS | -- IEEE Standard 279-1968<br>-- IEEE Standard 338-1971<br>-- IEEE Standard 344-1971<br>-- AEC General Design Criteria (7-7-71) 1, 2, 3, 4, 5, 12, 13, 20, 21, 22, 23, 24, 25, 29<br>-- AEC Safety Guides 6, 22, 29 |
| SFAS | -- IEEE Standard 279-1971<br>-- IEEE Standard 308-1971<br>-- IEEE Standard 323-1971<br>-- IEEE Standard 338-1971<br>-- IEEE Standard 344-1971<br>-- AEC General Design Criteria 1, 2, 3, 4, 13, 15, 20, 21, 22, 23, 24<br>-- AEC Safety Guide 22, 29<br>-- In Addition, relevant ANSI, IPCEA and NEC recommendations are used as a guide in the system design |
| CRDCS (trip portion) | -- Intent of IEEE Standard 279-1971<br>-- IEEE Standard 344-1971<br>-- AEC General Design Criteria (7-7-71) 1-5, 20-29<br>-- AEC Safety Guides 6, 22, 29 |
| SFRCS | -- Applicable Sections of IEEE Standard 279-1971<br>-- IEEE Standard 308-1971<br>-- IEEE Standard 383-1974<br>-- IEEE Standard 384-1974<br>-- IEEE Standard C37.90.1-1974<br>-- IEEE Standard 338-1971<br>-- IEEE Standard 344-1975<br>-- AEC General Design Criteria (7-7-71) 1, 2, 3, 4, 13, 15, 20, 21, 22, 23, 24<br>-- AEC Safety Guides 22, 29 |
| ASP | -- Applicable Sections of IEEE Standard 279-1971<br>-- IEEE Standard 323-1971<br>-- IEEE Standard 338-1971<br>-- IEEE Standard 344-1971<br>-- AEC General Design Criteria (7-7-71) 1, 2, 3, 4, 13, 15, 19, 21, 22, 23, 24<br>-- AEC Safety Guides 22, 29 |

TABLE 7.1-1 (Continued)

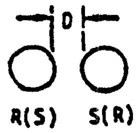
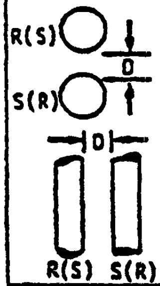
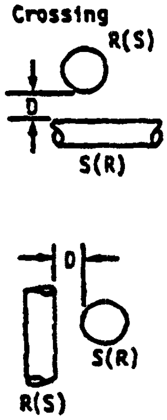
SAFETY CRITERIA USED IN THE DESIGN OF SAFETY RELATED CONTROL AND INSTRUMENT SYSTEMS

| System | Applicable criteria |
|---|---|
| ARTS | -- Applicable Sections of IEEE Standard 279-1971<br>-- IEEE Standard 323-1974<br>-- IEEE Standard 336-1971<br>-- IEEE Standard 338-1971<br>-- IEEE Standard 344-1975<br>-- IEEE Standard 384-1971<br>-- AEC Safety Guides 22, 29<br>-- AEC General Design Criteria (7-7-71)<br>1, 2, 3, 4, 13, 15, 20, 21, 22, 23, 24 |
| PAMS | -- Applicable Sections of IEEE Standard 279-1971<br>-- IEEE Standard 338-1971<br>-- IEEE Standard 323-1974<br>-- IEEE Standard 344-1975<br>-- Reg. Guide 1.118<br>-- Reg. Guide 1.97, Revision 3<br>-- Reg. Guide 1.89<br>-- AEC General Design Criteria (7-7-71)<br>1, 2, 3, 4, 13, 15, 19, 20, 21, 22, 23, 24, 64 |
| Normal Decay Heat Removal Valve Control System | -- Applicable Sections of IEEE Standard 279-1971<br>-- IEEE Standard 323-1971<br>-- IEEE Standard 338-1971<br>-- IEEE Standard 344-1971<br>-- AEC General Design Criteria (7-7-71)<br>1, 2, 3, 4, 13, 20, 21, 22, 23, 24<br>-- AEC Safety Guide 29 |

TABLE 7.1-1 (Continued)

SAFETY CRITERIA USED IN THE DESIGN OF SAFETY RELATED CONTROL AND INSTRUMENT SYSTEMS

| System | Applicable criteria |
|---|---|
| Core Flooding Tank Isolation Valve Control System | -- Applicable Sections of IEEE Standard 279-1971<br>-- IEEE Standard 323-1971<br>-- IEEE Standard 338-1971<br>-- IEEE Standard 344-1971<br>-- AEC General Design Criteria (7-7-71) 1, 2, 3, 4, 13, 20, 22<br>-- AEC Safety Guide 22, 29 |
| Containment Spray Pump Anti-Cavitation Control System | -- Applicable Sections of IEEE Standard 279-1971<br>-- IEEE Standard 323-1971<br>-- IEEE Standard 338-1971<br>-- IEEE Standard 344-1971<br>-- AEC General Design Criteria (7-7-71) 1, 2, 3, 4, 13, 20, 21, 22, 23, 24<br>-- AEC Safety Guides 22, 29 |

| Configuration | Conduit "R" Channel | Conduit "S" Channel | Conduit "R" Function | Conduit "S" Function | Minimum Separation |
|---|---|---|---|---|---|
| Horizontal   | X | X | C,I,P1,P2,P3 | C,I,P1,P2,P3 | D=0" |
| | ESS X | ESS Y | C,I,P1,P2 | C,I,P1,P2 | D=0" |
| | | | P3 | C,I,P1,P2,P3 | D=1" |
| | NON-ESS X | NON-ESS Y | C,I,P1,P2,P3 | C,I,P1,P2,P3 | D=0" |
| | | ESS Y | C,I,P1,P2 | C,I,P1,P2,P3 | D=0" (D=0") |
| | | | P3 | C,I,P1,P2,P3 | D=0" (D=1") |
| Vertical   | X | X | C,I,P1,P2,P3 | C,I,P1,P2,P3 | D=0" |
| | ESS X | ESS Y | C,I,P1 | C,I,P1 | D=0" |
| | | | P2,P3 | C,I,P1,P2,P3 | D=1" |
| | NON-ESS X | NON-ESS Y | C,I,P1,P2,P3 | C,I,P1,P2,P3 | D=0" |
| | | ESS Y | C,I,P1 | C,I,P1,P2,P3 | D=0" (D=0") |
| | | | P2,P3 | C,I,P1,P2,P3 | D=0" (D=1") |
| Crossing   | X | X | C,I,P1,P2,P3 | C,I,P1,P2,P3 | D=0" |
| | ESS X | ESS Y | C,I,P1 | C,I,P1 | D=0" |
| | | | P2 | C,I,P1,P2 | D=1/8" |
| | | | P3 | C,I,P1,P2,P3 | D=1" |
| | NON-ESS X | NON-ESS Y | C,I,P1,P2,P3 | C,I,P1,P2,P3 | D=0" |
| | | ESS Y | C,I,P1 | C,I,P1,P2,P3 | D=0" (D=0") |
| | | | P2 | C,I,P1,P2,P3 | D=0 (D=1/8") |
| | | | P3 | C,I,P1,P2,P3 | D=0 (D=1") |

Notes:
1. X means conduit channel (i.e., 1,2,3,4,A,B,C).
2. Y means conduit channel (i.e., 1,2,3,4,A,B,C) different from conduit X.
3. Minimum separations identified in parentheses apply when Non-Ess conduit bridges ESS redundant conduits. Only one end of the bridge must satisfy separation, the separation may be zero at the other end.
4. C means Control.
5. I means Instrumentation.
6. P1 means Power (Size ≤ 12 AWG).
7. P2 means Power (Size > 12 AWG but not 13.8 KV, 4.16 KV, 480 V Sub).
8. P3 means Power (13.8 KV, 4.16 KV, 480 V Sub).

DAVIS-BESSE NUCLEAR POWER STATION
GUIDE TO ASSESS CONDUIT TO
CONDUIT SEPARATION

FIGURE 7.1-1

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## 7.2 REACTOR PROTECTION SYSTEM (RPS)

The purpose of the RPS is to initiate a reactor trip when a sensed parameter (or group of parameters) exceeds a setpoint value indicating the approach of an unsafe condition. In this manner, the reactor core is protected from exceeding design limits and the Reactor Coolant (RC) System is protected from overpressurization.

The scope of the RPS includes all electronics, signal processing equipment, and cabling from the system sensors to the input terminals of the CRDCS.

### 7.2.1 Description

#### 7.2.1.1 Design Bases

Reference BAW-10003A, Rev 4.

1. The generating station conditions which require protective action are described below:

    a. Departure from Nucleate Boiling (or Quality) and Kilowatt-Per-Foot Limits:

    To maintain the integrity of the fuel cladding and to prevent fission product release, it is necessary to prevent overheating of the cladding under normal operating conditions. This is accomplished by operating within the nucleate boiling regime of heat transfer, wherein the heat transfer coefficient is large enough so that the clad surface temperature is only slightly greater than the coolant temperature. The upper boundary of the nucleate boiling regime is termed “Departure from Nucleate Boiling (DNB)”. At this point there is a sharp reduction of heat transfer coefficient, which would result in high cladding temperatures and the possibility of cladding failure. Although DNB is not an observable parameter during reactor operation, the observable parameters of neutron power, reactor coolant flow, temperature and pressure can be related to DNB through the use of the W-3 and BAW-2 correlations. The W-3 and BAW-2 correlations have been developed to predict DNB and the location of DNB for axially uniform and non-uniform heat flux distribution. The local DNB ratio (DNBR), defined as the ratio of the heat flux that would cause DNB at a particular core location to the actual heat flux, is indicative of the margin to DNB. The minimum value of the DNBR, during steady-state operation, normal operational transients, and anticipated transients is limited to 1.3. A DNBR of 1.3 corresponds to a 94.3% probability at 99% confidence level for the W-3 correlation and a 95% probability at a 95% confidence level for the BAW-2 correlation that DNB will not occur. This is considered a conservative margin to DNB for all operating conditions. The W-3 correlation was used for the first fuel cycle and the BAW-2 correlation for several subsequent fuel cycles. The critical heat flux correlation used in the design of the current fuel cycle is described in the applicable reload report (see Appendix 4B).

    Kilowatt-per-foot limits are based on the combination radial and axial peak that prevents central fuel melting at the hot spot and are given in Appendix 4B, Reload Report.

Power peaking is not a directly observable quantity and therefore limits have been established on the basis of the reactor axial power imbalance produced by the power peaking.

b. RC System Overpressurization:

The RC system serves as a barrier to prevent radionuclides in the RC from reaching the atmosphere. In the event of a fuel cladding failure, the RC system is a barrier agent against the release of fission products. Establishing a system pressure limit helps to assure the integrity of the RC system. The maximum transient pressure allowable in the RC system pressure vessel under the ASME Code, Section III, is 110% of design pressure. The maximum transient pressure allowable in the RC system piping, valves, and fittings under ANSI Section B31.7 is 110% of design pressure. Thus, the safety limit of 2750 psig (110% of the 2500 psig design pressure) has been established. The settings for the RPS high RC pressure trip and the pressurizer code safety valves have been established to ensure that the RC system pressure safety limit is not exceeded (See Technical Specifications).

As required by 10 CFR 50.62, “Requirements for reduction of risk from anticipated transients without scram (ATWS) events for light-water-cooled nuclear power plant”, a diverse scram system (DSS) was installed. The only function of the DSS is to provide a diverse method of deenergizing the regulating and safety rods in the event that the reactor protection system (RPS) does not function as designed. This is accomplished by sensing reactor coolant pressure, diverse from RPS sensor output, and degating the CRDM motor power supply silicon controlled rectifiers (SCRs), independent from the RPS degating contacts, in the control rod drive control system (CRDCS) on high reactor coolant system pressure. The DSS reactor coolant pressure setpoint is higher than the RPS high pressure trip setpoint and below the primary code safety valve setpoint.

Trip setpoints are established to provide the necessary protection so that DNB, kW/ft limits, and pressure limits are not exceeded. Subsection 7.2.1.2.2 provides a description of each RPS trip.

2. Generating station variables that are required to be monitored in order to provide protective actions:

   a. Total out-of-core neutron flux (power level).

   b. RC system flow. The number and location of operating RC pumps are also monitored in order to provide a rapid indication of an imminent change in flow.

   c. RC system reactor outlet temperature.

   d. RC system pressure. The Containment Vessel (CV) pressure is also monitored in order to provide a backup measurement parameter for rapidly decreasing RC system pressure due to a loss-of-coolant accident.

e. Out-of-core neutron flux imbalance (power in the top half of the core minus power in the bottom half of the core).

3. Minimum number and location of sensors required to monitor adequately, for protective function purposes, those variables that have spatial dependence:

   To maintain complete separation between RPS channels, each has its own sensor. Therefore, one sensor per RPS channel is provided for each measured parameter listed in item 2 above, except for item 2.b, which has two RC flow sensors per RPS channel (one for each loop) and four RC pump monitors per RPS channel (one for each pump). Refer to Figure 5.1-2 which depicts the layout of primary system sensors. Refer to Section 7.8.1.1 and Figure 7.8-3 for locations of power range neutron detectors.

4. Prudent operational limits for each variable in each applicable reactor operation mode: Refer to the Technical Specifications.

5. Margin between each operational limit and level marking onset of unsafe conditions: Refer to the Technical Specifications.

6. The level that when reached will require protective action: Refer to the Technical Specifications.

7. Range of transient and steady-state conditions of the energy supply and the environment during normal, abnormal, and accident circumstances throughout which the system must perform: Refer to Table 7.2-3.

8. The malfunctions, accidents, or other unusual events which could physically damage Protection system components for which provisions must be incorporated to retain necessary protection system action:

   The RPS is designed to maintain the capability to perform its protective function during and after an earthquake (refer to Section 3.10). The vessel containing the equipment will protect it from flood, lightning, and wind. The RPS cabinets are housed in the control room where they are protected against fire, explosion, and missiles. All sensors and cables are located to minimize damage caused by fire, explosion, or missiles. The redundancy of the system will satisfactorily operate under all conditions. The system cabinets provide protection against mechanical damage and spread of fires between RPS channels. All sensors, signal transmission circuits, and signal conditioning devices are designed to function in postulated deteriorated environments to which they may be subjected for the length of time required to provide the protective action.

9. Minimum performance requirements including system response times, system accuracies, and ranges of the magnitudes of sensed variables to be accommodated until proper conclusion of the protection system action: Refer to the Technical Requirements Manual and Framatome Technologies document 32-1172392-02, “Reactor Protection System String Error Calculations” for response times and accuracies. Ranges are as follows:

| Variable | Range |
|---|---|
| Reactor Power | 0 to 125% FP |
| RC Flow | 0 to 160 mpph |
| RC outlet temperature | 520 to 620°F |
| RC pressure | 1700 to 2500 psig |
| Containment Pressure | 0 to 20 psig |
| Reactor power imbalance | -62.5 to +62.5% FP |

#### 7.2.1.2 System Description

##### 7.2.1.2.1 System Logic

The RPS, as shown in Figure 7.2-1, consists of four identical protection channels which are redundant and independent. Each channel is served by its own independent sensors which are physically isolated from the sensors of the other protective channels. Each sensor supplies an input signal to one or more signal processing strings in the RPS channel. Each signal processing string terminates in a bistable which electronically compares the processed signal with trip setpoints. All bistable contacts are connected in series. In the normal untripped state, the contact associated with each bistable will be closed, thereby energizing the channel terminating relay (KA, KB, KC, or KD).

Consider Channel 2 in Figure 7.2-1. Assume there is a trip of one of the bistables in Channel 2, thereby de-energizing relay KA, which causes contacts to open which in turn de-energize relays KA1, KA2, KA3, and KA4, causing one contact on each side of the vital power supply to the respective CRDCS Channel to open and causing the contact in series with light L3 in each channel to close. Should Channel 1 trip while Channel 2 is tripped, relay KB will de-energize causing contacts to open which in turn de-energize relays KB1, KB2, KB3, and KB4. When these relays de-energize, two more contacts will open in the vital power supply to each CRDCS channel. Thus when two out-of-four RPS channels trip, each of the four RPS channels will cause their respective CRDCS trip devices to trip.

The manual trip switches are interposed between each reactor trip module and its associated CRDCS channel. Depressing a manual trip switch causes all four CRDCS channels to trip.

##### 7.2.1.2.2 Protection Channel Functions

As shown in Figure 7.2-1, contacts from seven trip bistables and a CV pressure switch contact buffer module are normally in series with the power supply to each of the protective channel trip relays. The trip bistables included are high pressure, low pressure, pressure-temperature, power/imbalance/flow, overpower, power/pumps, and high temperature. The first three compare RC pressure with fixed high and low pressure setpoints and a pressure setpoint which is a function of RC outlet temperature. The second three compare the output of the power range neutron flux monitor related to the protective channel with the total RC flow and core imbalance, a fixed high power setpoint, and a high power setpoint which is a function of the pump configuration. The seventh trip bistable compares RC outlet temperature with a high temperature setpoint. The CV pressure switch compares the CV pressure with a high pressure setpoint.

The trip functions of each RPS channel are as follows (refer to Figure 7.2-1):

1. High RC Pressure - Each RPS channel receives signals from a separate narrow-range RC pressure transmitter. Each pressure transmitter is powered from its own power supply, which is packaged in a module and mounted in the associated RPS channel cabinet. The output of each pressure transmitter is applied directly to the input of a buffer amplifier. The buffer amplifier module consists of an input stage amplifier driving a primary output amplifier and up to nine additional output amplifiers. The primary output amplifier supplies the signal to the RPS pressure bistables. The high RC pressure bistable module compares this input signal to an internal trip setpoint power supply. When the input signal from the buffer amplifier exceeds the setpoint of the bistable, its relay contact will open and de-energize (trip) the channel terminating relay.

2. Low RC Pressure - The same pressure transmitter and buffer amplifier described above supplies a signal to the low RC pressure bistable. When this input signal decreases below a preset setpoint of the bistable, its relay contact will open and de-energize (trip) the channel terminating relay.

3. High RC Temperature Trip - Each RPS channel receives reactor outlet temperature signals from a separate resistance temperature element. The element is supplied with a matched resistance bridge unit that is mounted in the associated RPS channel cabinet. The linear bridge produces an analog output that is fed to the signal converter which conditions the signal and produces two prime outputs. One output signal is supplied to the variable low RC pressure bistable. The other output is applied to the high RC temperature trip bistable. When the input temperature signal from the signal converter exceeds the trip setpoint of the high RC temperature bistable, its relay contact will open and de-energize (trip) the channel terminating relay.

4. Variable Low RC Pressure - A pressure signal is sent to the pressure/temperature bistable from the same primary output amplifier of the buffer amplifier that supplies the high and low RC pressure bistables. This signal is compared to the pressure setpoint generated as a function of the temperature input to the signal converter described in (3) above. When the pressure signal is outside the allowable bounds, the pressure/temperature bistable will trip, opening its relay contact and de-energizing (tripping) the channel terminating relay. This trip allowable value as a function of temperature is contained in the Technical Specifications.

5. Overpower - Each RPS channel contains a two-section power range neutron flux detector. The signals from each half are summed to produce a total power signal. This power signal is sent to the overpower, power/pumps, and power/imbalance/flow bistables. When the total power signal exceeds the overpower trip setpoint of the bistable, its relay contact will open, de-energizing (tripping) the channel terminating relay.

6. Power/Pumps - RC pump status (on-off) and information as to the loops in which pumps are operating, is monitored by pump monitors. The pump monitors provide an open or closed contact as the input to the RPS. The pump contact monitor module provides a variable signal which is a function of the number of running pumps and the loop in which they are running. This signal is used as a variable setpoint signal in the power/pumps bistable. If the total reactor power exceeds the

power/pumps setpoint, as determined by the pump configuration, the bistable will cause its associated relay contact to open, de-energizing (tripping) the channel terminating relay.

7. Power/Imbalance/Flow - Each RPS channel receives two differential pressure signals (one from each reactor coolant loop). The signals are developed by differential pressure transmitters that measure pressure drop across gentile tubes mounted in the two reactor coolant loops. The analog output of the transmitters is proportional to flow squared. The square root extractor converts the signal to one directly proportional to flow. The proportional flow signals from both RC loops are summed to produce a total RC flow signal in the summing amplifier.

   Each RPS channel monitors reactor power imbalance. This is the difference between the power measured in the top half of the core and the power measured in the bottom half of the core by the two separate power range neutron flux detectors (refer to Section 7.8).

   The imbalance signal and the flow signal are combined in a Function Generator and the resultant function signal is compared with the total power signal in a bistable. The bistable will trip when the total reactor power signal exceeds the trip envelope limit in Appendix 4B. When this bistable trips, its relay contact opens, de-energizing (tripping) the channel terminating relay.

8. High CV Pressure - Each RPS channel monitors CV pressure by means of a pressure switch. If the CV pressure setpoint is exceeded, the pressure switch will open causing the high CV pressure contact buffer to open its contact. This will de-energize (trip) the channel terminating relay.

In addition, the RPS is designed to trip a channel upon loss of power or removal of any module required to perform a protective function.

1. Loss of Power - As shown in Figure 7.2-1, the primary sources of 120V AC power for the RPS are the four essential busses. Each channel is powered from a different essential bus. Within the system cabinets, each RPS channel is powered by separate plus and minus 15V DC channel power supplies. All bistables operate in a normally energized state and go to a de-energized state to initiate trip action. Loss of power thus automatically forces the bistables into the tripped state. Failure of an essential bus or a channel power supply causes the affected channel to trip.

2. Equipment Removal - The removal of any module required to perform a protective function initiates the trip normally associated with that portion of the system. For example, removal of a bistable module trips the associated channel terminating relay, and removal of a reactor trip module activates the associated control rod drive trip mechanism. In the first case, removing a bistable not only breaks the contact chain leading to the channel reactor trip module, but it also breaks the contact chain leading to the module test interlock relay KT2, both of which result in a trip of the channel terminating relay. In the second case, removing a reactor trip module separates the essential instrument bus from the control rod drive trip mechanism, causing a control rod breaker trip. At the same time, a one-out-of-four trip input is sent to the other three reactor trip modules.

#### 7.2.1.2.3 Maintenance Bypasses

A channel bypass is provided to allow maintenance and periodic testing to be performed on individual channels. When initiated, the channel bypass will prevent the terminating relay of the bypassed channel from de-energizing (tripping). Therefore when a channel is bypassed, the overall system trip coincidence is two-out-of-three. If two of the remaining three unbypassed channels trip, all four RPS channels will de-energize their associated CRDCS trip channels. The bypass is initiated using key switches and when one channel is bypassed, an interlock prevents the other channels from being bypassed. The station annunciator will give the operator continuous visual indication when a channel is bypassed.

Refer to Figure 7.2-1. When the key switch is turned, two associated contacts close, applying -15V to the terminating relay in the affected channel. Thus, the trip contacts of all the bistables are bypassed.

A shutdown bypass is provided to allow rod withdrawal testing with the unit shutdown. To initiate the bypass the operator must turn a key switch in each RPS channel. Turning the key switch removes the following trips from the logic train: power/imbalance/flow, power/pumps, variable low RC pressure, and low RC pressure. The key switch also inserts the shutdown bypass high pressure trip. The setpoint of this trip is lower than the setpoint of the low pressure trip. (Refer to the Technical Specifications for setpoint values.)

During normal operation the shutdown bypass high pressure trip bistable is normally tripped since operating pressure is greater than the trip setpoint.

If the operator initiates the shutdown bypass with the unit at power, that RPS channel trips. The procedure for effecting this bypass is to wait until primary pressure is below the trip setpoint and the plant is shut down. The operator is then free to reset the tripped bistable and to turn the key switch in each channel.

Figure 7.2-1 shows schematically how the bypassing of trip bistables is accomplished. When the bypass switch is turned, a normally closed contact opens and a normally open contact closes, connecting the trip bistables that will remain effective to the shutdown bypass high pressure trip bistable and the -15V power source. The other bistables are disconnected from the string.

#### 7.2.1.2.4 Interlocks

Electro-mechanical interlocks initiate an RPS channel trip whenever: (1) a test module that is used to test one of the seven trip bistables or the CV pressure switch contact buffer is placed in the test mode; or (2) any module vital to a trip signal is withdrawn, unless the RPS channel is bypassed. (Removal of the reactor trip module in any condition will trip its associated CRD breaker.) The station annunciator and computer give the operator visual indication of the RPS trip status.

Another interlock is used to prevent the bypassing of more than one channel. Once a bypass is initiated, the other three channels are prevented from being bypassed by the removal of the ground Return path to the bypass circuits. Refer to Figure 7-3 in B&W Topical Report BAW 10003A, Rev. 4. The station annunciator and computer give the operator visual indication when a channel is bypassed. This interlock is in addition to normal administrative controls.

#### 7.2.1.2.5 Diversity

The RPS provides protection through the use of the diverse trip functions and sensors discussed in Subsection 7.2.1.2.2 and in Chapter 15 and the Technical Specifications.

#### 7.2.1.2.6 Information Display

Each RPS channel contains meters and indicators mounted in the system cabinets which display each input analog signal and visual indication of the state of each trip logic element. Total power (in percent power) and power imbalance (in percent power) are available to the operator on the control console. A strip chart recorder is available for continuously recording auctioneered total power (in percent power).

Each RPS channel contains an alarm panel which is visible at all times and indicates the following:

1. Channel trip.
2. Cabinet fan failure.
3. Trip of any of the other three channels.
4. Channel bypass.
5. Shutdown bypass.
6. Breaker trip.

The station computer system monitors all analog input signals, all channel power supplies, and all trip modules. The station computer system will alarm if there is a power supply fault, a fan fails, or a cabinet door is open. The station annunciator indicates that an RPS channel trip has occurred, shutdown bypass has been initiated in a channel, or a channel has been bypassed. It also has the capability to indicate that a power range detector power supply fault has occurred, but this provision is not currently used.

The station computer alarms and the station annunciator are not required to be tested as part of the Technical Specification surveillance testing requirements, but are functionally tested on a periodic basis to verify their proper operation.

Information on displays is contained in Section 7.5.

#### 7.2.1.2.7 Equipment Identification

Refer to Subsection 7.1.2.5.

### 7.2.1.3 Systems Supporting the RPS

The following systems provide support to the RPS:

1. Essential power supply (refer to Chapter 8).
2. CRDCS (refer to Subsection 7.4.1.1).

#### 7.2.1.4 Portions of RPS Not Required for Safety

Within the scope of the RPS, as defined in Section 7.2, the nonessential portions of the RPS (i.e., those portions performing no safety functions) are the displays of system parameters and test circuits. The power range test circuit does, however, provide continuity for safety-related signals leaving the detector before they enter signal conditioning modules.

#### 7.2.1.5 Comparison of RPS with That of Another Station

The major initial design features of the RPS at the Davis-Besse station are compared to that of Sacramento Municipal Utility District's Rancho Seco station in FSAR Section 7.2.1.5.

#### 7.2.1.6 RPS Drawings

Drawings depicting RPS design are contained in Toledo Edison Specification M-536.

### 7.2.2 Analysis

#### 7.2.2.1 Compliance with IEEE Standard 279-1968

The following discussions are keyed to Paragraph 4 of IEEE Standard 279-1968 and demonstrate compliance.

(4.1) General Functional Requirements - The RPS will automatically perform its protective functions, that of tripping the reactor whenever station conditions exceed preset levels, under the design conditions listed in Section 7.2.1.1.

(4.2) Single Failure Criteria - No single failure can prevent the RPS from performing its protective functions. A detailed single failure analysis of those portions of the system where a single failure might affect more than one channel is contained in Chapter 7 of Topical Report BAW-10003A, Rev. 4 "Qualification Testing of Protection System Instrumentation (January 1976)." The redundancy of all other RPS ensures that no single portions of the RPS ensures that no single failure will affect more than one channel. A single failure analysis of changes to the Anticipatory Reactor Trip System (ARTS) interfacing with the RPS was performed and submitted to the NRC in January 1986 (Serial 1231). The analysis concluded that the RPS meets the single failure criteria of IEEE-279.

(4.3) Quality of Components and Modules - Equipment manufacturers were required to use high quality components and modules in equipment construction. Quality control procedures, used during fabrication and testing verify compliance with this requirement. Details of the QA procedures are contained in Chapter 17 of the FSAR.

(4.4) Equipment Qualification - Qualification type tests are performed, in accordance with accepted procedures, to insure that the RPS equipment will perform under applicable design basis conditions. Refer to Topical Report BAW-10003A, Rev. 4 for applicable test data. Subsequent to the submittal and approval of BAW-10003A, Rev. 4, replacement RPS Reactor Trip Modules manufactured by Framatome have been approved for installation in the RPS. These Reactor Trip

Modules are qualified in accordance with FTI Reactor Trip Module Qualification Test Report 51-5006947-00.

(4.5) Channel Integrity - Each RPS channel is designed and fabricated so that channel integrity will be maintained under the conditions specified in the system design bases.

(4.6) Channel Independence - Each RPS channel is located in its own cabinets. The cabinets act as a barrier against fire and mechanical damage from external sources. Therefore physical damage (for instance, an internal fire) can, in the worst case disable only one of the four RPS channels.

A minimum of channel interaction is required for the RPS to perform its protective action. The interaction occurs in the reactor trip module. A single failure analysis of this scheme is contained in Topical Report BAW-10003A, Rev. 4. The results of this failure analysis envelope both the original Bailey Reactor Trip Modules, as well as replacement RPS Reactor Trip Modules manufactured by Framatome, which were approved for installation in the RPS subsequent to the submittal and approval of BAW-10003A, Rev. 4.

(4.7) Control and Protection System Interaction - The RPS provides inputs to control systems as follows: Four reactor power level signals to the NNI/ICS auctioneering circuitry, a flow differential pressure signal from each RC loop to the ICS via the NNI, and an RC pressure signal to the NNI. The RC loop flow D/P signals and the RC pressure signal that are supplied to the NNI can be selected from either RPS Channel 1 or Channel 2 using a plug and jack arrangement located in Channel 2. Additionally, the RPS provides a flow signal from each RC loop and four signals each of the following three parameters to the ICS for use in the Core Thermal Power (CTP) calculation: Reactor coolant narrow range pressure, reactor coolant total flow and reactor coolant narrow range temperature.

If a single failure can cause a control system to malfunction and at the same time cause a protection channel to fail, the remaining channels must be capable of providing protection even when degraded by another single failure.

Since only one RPS channel can share a given signal with a control system, a failure of that channel and another channel must be predicated in order to satisfy IEEE 279. Since the RPS is a four-channel system and uses two-out-of-four logic, the system will still be capable of causing a trip at the system level.

The flow of the power range neutron flux signals is as follows. The flux signal from each channel is transmitted through individual isolation amplifiers. The signals from Channels 1 and 2 are sent to an auctioneer in the NNI. The signals from Channels 3 and 4 are sent to a second auctioneer in the NNI. The auctioneered outputs are sent to a third auctioneer in the ICS. The highest of the four signals is ultimately used by the ICS for reactor control.

Destructive tests of the isolation amplifiers have established that they will block the passage, to the input, of + or - 400V DC or 400V AC (peak to peak) when applied to their output. Other tests demonstrate that the output of any isolation amplifier can be open, shorted, or grounded in any manner without effect upon

the input. Therefore, the reactor power level signals leaving the RPS and going to the control system are adequately isolated from the signals used to accomplish protection system functions.

For a single failure to cause an ICS induced transient that requires protective action, the failure must either (1) occur downstream of an isolation amplifier, which would prevent the failure from adversely affecting the RPS, or (2) result in proper action of the RPS channel in which the failure occurred. In either case IEEE 279 is satisfied.

(4.8) Derivation of System Inputs - The measured variables, listed in the Technical Specifications, are direct measurements of the required parameters.

(4.9) Capability for Sensor Checks - Each RPS channel contains readouts for all analog signals. This allows the operator to check most sensors by monitoring the variable after it is perturbed or by cross checking the same variable in different RPS channels or other systems such as the NNI or station computer. A substitute input to the sensor of the same nature as the measured variable can be used in some cases to check sensor operation.

(4.10) Capability for Test and Calibration - The use of two-out-of-four logic between channels permits an RPS channel to be tested on-line without initiating a reactor trip. Maintenance to the extent of removing and replacing any module within a channel may be accomplished in the on-line state without a reactor trip.

The test scheme for the RPS is based on the use of comparative measurements between like variables in the four channels, and the substitution of externally introduced digital and analog signals, as required, together with measurements of actual protective function trip points. A digital voltmeter is provided for accurate measurement of trip point and analog signal voltages. The test circuits allow the operator to completely test the RPS channels at any time during reactor operation. The bistable test consists of inserting an analog input from an externally simulated signal or one of the channel test modules and varying the input until the bistable trip point is reached. The value of the inserted test signal, as monitored by both the system analog indicator and the test digital voltmeter, represents the true value of the bistable trip point. Thus, the test verifies not only that the bistable functions but also that the trip point is correctly set. During the test, satisfactory operation of the bistable can be observed by watching the "output state" light on the bistable module and the "channel (subsystem) trip" light on the reactor trip module.

The reactor trip module two-out-of-four logic and the associated control rod drive trip breaker are tested by pressing various combinations of the logic test switches on the reactor trip module to simulate the six combinations of trips possible in a two-out-of-four coincidence logic. During the test, satisfactory performance of the trip logic relays is observed by watching the "RPS TO UVD AC PWR AVAIL" light on the CRD trip breaker cabinet. This test also verifies that the control rod drive trip breakers are actuated independently by the undervoltage and shunt trip devices.

A regular visual check of all RPS indications is required, including such things as comparing the value of analog variables between channels and observing the

status of equipment. Such visual checks are made during each shift. On a regular schedule, the visual check includes the comparison of power range channel readings with a thermal calculation of reactor power. These frequent checks permit detection of the majority of failures that might occur in the analog portions of the system as well as the self-annunciating type of failure that could occur in the digital portions of the system. The electrical tests are designed for the detection of more subtle failures that are detectable only by testing. Electrical tests are conducted on a rotational basis in accordance with the Technical Specifications.

(4.11) Channel Bypass or Removal From Operation - The RPS channel bypass is described in Subsection 7.2.1.2.3. This feature permits the testing and maintenance of a single channel during power operations. With the bypass in effect, the three remaining channels provide the necessary protection. Since only two channel trips are required to cause a reactor trip, a single failure will not prevent the RPS from fulfilling its protective function.

The RPS is a de-energize-to-trip system. Therefore, if power is lost to a channel, that channel will trip, reducing the system trip coincidence to one-out-of-three. In the event that a module, which performs a protective function is removed from its rack, that RPS channel will trip (unless that channel is bypassed).

(4.12) Operating Bypasses - The RPS contains no operating bypasses.

(4.13) Indication of Bypasses - Initiation of the channel bypass is indicated locally on the RPS cabinets, and on the station annunciator board. Initiation of the shutdown bypass is continuously indicated locally on the RPS cabinets and on the station annunciator board.

In the event a channel is de-energized, that channel trips. That fact is continuously indicated locally, on the RPS cabinets, by the station computer, and on the station annunciator board.

(4.14) Access to Means for Bypassing - Activation of RPS bypass is accomplished using key switches. The keys are under administrative control. Also to effect a bypass, the normally locked RPS cabinet doors must be opened. These keys are also under administrative control.

(4.15) Multiple Setpoints - The only multiple setpoint in the RPS is used by the overpower trip. The overpower trip setpoints are given in the Technical Specifications.

In order to effect the shutdown bypass (refer to Subsection 7.2.1.2.3), the reactor must be shut down, and the overpower trip reset to $\leq$ 5% of rated power. After removing the shutdown bypass, with the station shutdown, the operator must reset the overpower trip to the normal trip setpoint value before the reactor can be started up.

It is not necessary to automatically reset the overpower trip setpoint to $\leq$ 5% of rated power to provide adequate protection during shutdown bypass operation. (The lower trip setpoint is not credited in any Chapter 15 accident analysis.) Therefore, it is acceptable that the RPS design does not provide positive means

of assuring that this lower setpoint is used. Administrative control via Technical Specifications is sufficient.

(4.16) Completion of Protective Action Once It is Initiated - All RPS trips are lock-in types so that a tripped channel remains in that state until deliberately reset by the operator.

(4.17) Manual Actuation - Two manual trip switches in series are provided which are positioned downstream of the RPS trip modules just before the input terminals of the CRDCS. Depressing either switch will interrupt power from all four RPS channels to the CRDCS. Because the manual trip is downstream of the automatic trips, no failure of the automatic trips will inactivate the manual trip. The two RPS trip switches are located in the control room and are mounted on either side of the CRDM Control System Operator Control panel. The trip switches are recessed to prevent accidental actuation.

(4.18) Access to Setpoint Adjustments, Calibration and Test Points - Setpoint adjustments, calibration and test points in the control room cabinet room are accessible only when the cabinets are open. The cabinet keys are under administrative control. Access to sensing equipment (transmitters, switches, etc.) is administratively controlled as part of general station access control to the protected and vital areas, as described in the security plan. Access is also administratively controlled through compliance with station procedures.

(4.19) Identification of Protective Action - The station annunciator indicates when an RPS channel has tripped. The station computer indicates when a channel has tripped and the cause of the trip (e.g., high temperature, overpower, etc.). Each cabinet alarm panel indicates that the channel has tripped. The bistable modules inside the cabinets indicate which bistable in the channel was tripped.

(4.20) Information Readout - Each RPS channel provides readouts for all analog signals as well as indication of channel trip status, status of each RC pump and CV pressure switch status. The station computer monitors most RPS analog signals and the status of each RPS channel trip. The station annunciator indicates when an RPS channel trips.

Total power and power imbalance are continuously indicated on the control console.

Refer to Section 7.5 for additional information on available indications.

(4.21) System Repair - The RPS is designed so that periodic testing can locate failure down to the module level, at a minimum. The modular design of the system allows quick repair of malfunctions.

(4.22) Identification - Refer to Subsection 8.3.1.2 for discussion of identification of Protection System Components.

#### 7.2.2.2 Compliance with IEEE Standard 338-1971

Refer to Subsection 7.1.2.7 for a discussion on compliance.

#### 7.2.2.3 Compliance with AEC General Design Criteria

Refer to Section 3.1.

#### 7.2.2.4 Compliance with Safety Guide 22

The RPS does incorporate a scheme of testing which complies with Safety Guide 22, Section D, Paragraph 2, (b) and (d). Utilizing logic toggle switches on the front face of the RPS reactor trip module, the output from any RPS channel can be tripped so that the associated CRDCS trip device (trip breaker) will open. This can be done without disrupting station operation since at least two trip devices in parallel must trip in order to cause rod insertion. Test circuits allow the operator to completely test the RPS channels at any time during reactor operation.

#### 7.2.2.5 Compliance with Safety Guide 29

The RPS is seismically qualified as required by Safety Guide 29. A discussion relating to the qualification is contained in Section 3.10.

TABLE 7.2-3

ENVIRONMENTAL CONDITIONS FOR INSTRUMENTATION AND CONTROLS

| Parameter | Normal Operating Range | Calculated Max. Worst Case Condition | Design Value |
|---|---|---|---|
| 1. Containment Vessel - inside primary shield - out of core detectors | | | |
| Temperature, °F | 70-200 | 300 | 212 |
| Pressure, psig | $0 \pm 0.5$ | 40 | 40 |
| Relative Humidity, % | 10-80 | 100 | 90 |
| 2. Containment Vessel - inside secondary shield - RTDs | | | |
| Temperature, °F | 40-140 | 265 | 286 |
| Pressure, psig | $0 \pm 0.5$ | 40 | 40 |
| Relative Humidity, % | 10-80 | 100 | 100 |
| Radiation, rads | 1300 rads/hour x 40 years = $3.7 \times 10^8$ * | $5.7 \times 10^4$ (24 hr. period) | $3.7 \times 10^8$ * (40 yrs. period) |
| Containment Spray Chemicals: $H_3BO_3$, $Na_3PO_4$ LiOH, $Na_2S_2O_3$, $H_2$. pH:4 to 9 | None | for 24 hours | for 24 hours |

* This dose is for a point inside the hot leg. For points outside the pipe the dose is a factor of 10 less.

| Parameter | Normal Operating Range | Calculated Max. Worst Case Condition | Design Value |
|---|---|---|---|
| 3. Containment Vessel - outside secondary shield - transmitters, preamps | | | |
| Temperature, °F | 40-140 | 265 | 286 |
| Pressure, psig | $0 \pm 0.5$ | 40 | 40 |
| Relative humidity, % | 10-80 | 100 | 100 |
| Radiation, rads | 25 millirads/hour x 40 years = $0.7 \times 10^4$ | $5.7 \times 10^4$ (24 hr. period) | $7.0 \times 10^4$ (40 yrs. period) |

TABLE 7.2-3 (Continued)

ENVIRONMENTAL CONDITIONS FOR INSTRUMENTATION AND CONTROLS

| Parameter | Normal Operating Range | Calculated Max. Worst Case Condition | Design Value |
|---|---|---|---|
| 4. Auxiliary Building, Switchgear Rooms<br>585 ft. elev. Room No. 323, 324 and 325<br>603 ft. elev. Room No. 428, 428A, 428B, 429, 429A and 429B | | | |
| Temperature, °F | 60-104 | | 104 |
| ▪ Low Voltage Switchgear/Battery Room | | 112.3 | |
| ▪ Electrical Isolation Rooms | | 123 | |
| ▪ High Voltage Switchgear Rooms and Aux. Shutdown Panel Room (Rooms 323, 324, and 325) | | 120 | |
| Pressure, psig | 0 | 0 | 0 |
| Relative Humidity, % | 30-70 | 70 | 70 |
| Radiation, rads | | | |
| in line components | 35 rds/hour x 40 years = $1 \times 10^7$ | $1 \times 10^7$ (24 hr period) | $2.0 \times 10^7$ (40 yr. period) |
| Non-in line | 25 millirads/hour x 40 years = $0.7 \times 10^4$ | $0.7 \times 10^4$ (24 hr. period) | $1.5 \times 10^4$ (40 yr. period) |
| 5. Auxiliary Building,<br>Emergency Diesel Generator Rooms<br>585 ft. elev. Room No. 318 and 319 | | | |
| Temperature, °F. | 60-125 | 131 | 125 |
| Pressure, psig | 0 | 0 | 0 |
| Relative Humidity, % | 30-80 | 80 | 80 |
| Radiation, rads | | | |
| In line components | 35 rad/hour x 40 years = $1 \times 10^7$ | $1 \times 10^7$ (24 hr. period) | $2.0 \times 10^7$ (40 yr. period) |
| Non-in line | 25 millirads/hour x 40 years = $0.7 \times 10^4$ | $0.7 \times 10^4$ (24 hr. period) | $1.5 \times 10^4$ (40 yr. period) |

TABLE 7.2-3 (Continued)

ENVIRONMENTAL CONDITIONS FOR INSTRUMENTATION AND CONTROLS

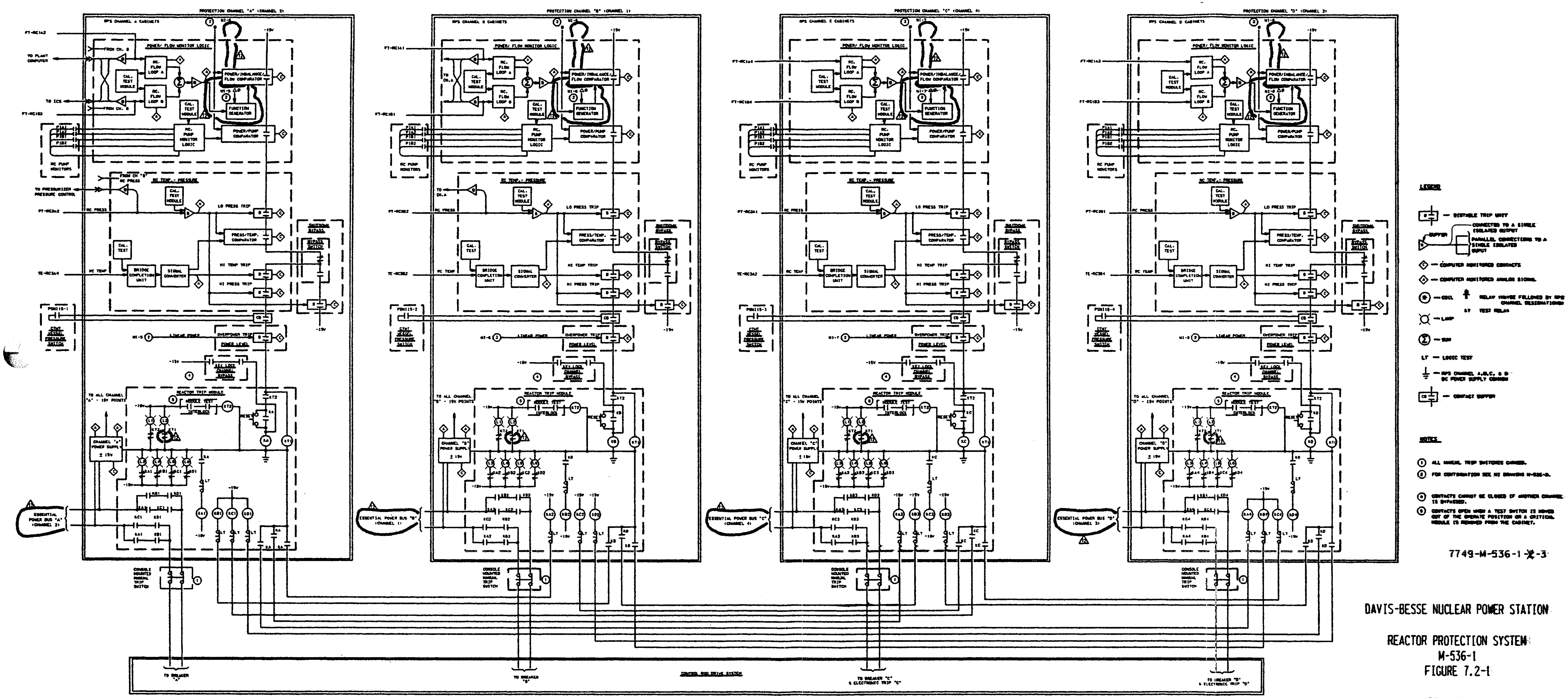
| Parameter | Normal Operating Range | Calculated Max. Worst Case Condition | Design Value |
|---|---|---|---|
| 6. Auxiliary Bldg., other areas | | | |
| Temperature, °F | 40-120 | 120 | 140 |
| Pressure, psig | 0 | 0.5 | 1.0 |
| Relative Humidity, % | 30-80 | 100 | 100 |
| Radiation, rads | | | |
| In line components | 35 rads/hour x 40 years = 1 x $10^7$ | 1 x $10^7$ (24 hr. period) | 2.0 x $10^7$ (40 yr. period) |
| Non-in line | 25 millirads/hour x 40 years = 0.7 x $10^4$ | 0.7 x $10^4$ (24 hr. period) | 1.5 x $10^4$ (40 yr. period) |
| 7. Control Room | | | |
| Temperature, °F | 60-80 | 110 | 40-110 |
| Pressure, psig | Atmospheric | Atmospheric | Atmospheric |
| Relative Humidity, % | 20-60 | 80 | 80 |
| Radiation, rads | Background | Background | Background |

8. Power Requirements for Instrumentation and Controls

| | |
|---|---|
| Voltage | 117V AC ± 10% |
| Frequency | 60 Hz ± 5% harmonic content ≤ 5% total and with 10% peak max. deviation from sine wave. |

9. Seismic Requirements
Refer to Section 3.10

NOTE: Normal operating range radiation values for the 40 year life of the plant were adjusted to account for periods of reactor shutdown and operation at less than full reactor power. Refer to Section 11.0.




DAVIS-BESSE NUCLEAR POWER STATION

REACTOR PROTECTION SYSTEM
M-536-1
FIGURE 7.2-1

REVISION 21
NOVEMBER 1998

## 7.3 SAFETY FEATURES ACTUATION SYSTEM (SFAS)

The design goal of the SFAS is to automatically prevent or limit fission product and energy release from the core, to isolate the containment vessel and to initiate the operation of the ESF equipment in the event of a loss-of-coolant accident (LOCA).

The SFAS instrumentation and controls extend from the generating station variables to the input terminals of the safety features actuation control devices such as motor controllers and solenoid valves. The SFAS is divided into initiating or sensing channels, logic channels, and actuating channels.

### 7.3.1 Description

#### 7.3.1.1 Instrumentation and Control

##### 7.3.1.1.1 Initiating Circuits

The initiating circuits of the SFAS are the sensing circuits monitoring the following station variables:

1. CV radiation level.*
2. CV pressure.
3. RC pressure.
4. BWST level.

* Amendment 221 to the Technical Specification eliminated the requirement for SFAS actuation on high containment radiation. The SFAS containment RE's are turned off.

##### 7.3.1.1.2 Logic

The logic channels of the SFAS are made up of solid state components. Relays are used as terminating devices of the SFAS logic, as isolation devices for remote control pushbuttons, and as output signals to the station annunciator and computer.

The SFAS, as shown in Figures 7.3-1 and 7.3-2, SFAS, Logic and Signal Diagrams, consists of four identical redundant sensing and logic channels and two identical redundant actuation channels. Each sensing channel includes analog circuits with analog isolation devices, and each logic channel includes trip bistable modules with digital (opto-electronic) isolation devices. The isolated output of the trip bistable module is used to comprise coincidence matrices with the terminating relays within the actuation channel of the SFAS. These opto-electronic isolation devices also provide isolation between channels.

The trip bistables monitor the station variables and normally feed continuous electrical (fail-safe) signals into two-out-of-four coincidence matrices. Should any of the station variables exceed their trip setpoints, the corresponding bistables in each of the four channels will trip and cease sending output signals. Should two of the four channel bistables monitoring the same station variable cease to send output signals, the corresponding normally energized terminating relays on all channels will trip.

The terminating relays of sensing and logic Channels No. 1 and No. 3, must both be de-energized to activate safety actuation Channel No. 1. Similarly, sensing and logic Channels 2 and 4 are de-energized to activate safety actuation channel 2.

The terminating relays act on the actuation control devices such as motor controllers and solenoid valves.

The SFAS is a failsafe (de-energize-to-trip) system. Therefore, if power supply is lost to a channel, that channel will trip, reducing the system coincidence matrices from two-out-of-four to one-out-of-three mode.

In the event that a module which performs a protective function is removed from its cabinet, that SFAS channel will trip unless it is bypassed (refer to Subsection 7.3.1.1.3).

7.3.1.1.3 Bypasses

The SFAS includes channel bypasses, operating bypasses, and shutdown bypasses:

1. Channel Bypass - Each SFAS sensing and logic channel is provided with one key operated rotary test trip bypass switch. This switch enables the operator to change the two-out-of-four coincidence matrices into a two-out-of-three mode for one given generating station variable. In effect, the operator may (for one channel only) bypass one of the following variables:

   a. CV radiation.*

   b. RC pressure.

   c. CV pressure.

   d. BWST level.

   * Amendment 221 to the Technical Specifications eliminated the requirements for SFAS actuation on high containment radiation. The SFAS containment RE's are turned off.

   These channel bypasses permit test, calibration or maintenance of the analog circuits of the SFAS including the transmitters of the generating station variables. The key and the operation of the switch is under administrative control.

   The switches are all keyed alike, with the key being removable only in the off-position (bypass non-activated).

   Electro-mechanical features are provided to prohibit the insertion and operation of more than one channel bypass.

   The off-position will be indicated at the SFAS cabinets and monitored and displayed by the station computer and annunciator.

   Motor controller bypasses are not provided. Controllers for motors driving equipment, the operation of which could damage any equipment or disrupt station operation, will only be tested during reactor shutdown.

2. Operating Bypasses - Each sensing and logic channel of the SFAS system includes two operating bypasses of the RC pressure trips, one for the RCS Low Pressure trip signal and the other for the RCS Low-Low Pressure trip signal to allow the depressurization of the RC system without initiating the RC pressure trips. For this purpose eight pushbuttons are located at the main control console, two for each channel.

   The operating bypasses can only be actuated manually and only when the RC pressure is below the associated setpoints, not to exceed 1800 psig or 660 psig respectively. The bypasses will be automatically reset before the RC pressure exceeds 1800 psig or 660 psig, respectively.

   No operating bypasses are provided to prevent actuation of the SFAS on high CV pressure, or low BWST level.

   A minimum of three of the four pushbuttons of the RCS low pressure or RCS Low-Low Pressure bypass setpoints must be actuated to effectively bypass the RC Low or Low-Low pressure trips.

   Indications that bypassing is permissible and that bypassing has been effected are provided at the main control console, in the SFAS cabinets, and at the station computer and annunciator.

3. Shutdown Bypass - The SFAS Shutdown Bypass is provided to prevent spurious actuation of the SFAS and will be used only when the SFAS is not required to be operable by the Technical Specification. Use of the Shutdown Bypass will allow maintenance, modification and testing of the bypassed portion of the SFAS without the possibility of spurious equipment actuation. Under no circumstances will use of the Shutdown Bypass be allowed in any mode other than Mode 5, 6 and when the reactor is defueled.

   The bypass is provided with a key actuated switch in each SFAS Logic cabinet (a total of eight) and individual push button switches, one push button switch for each piece of equipment in each Logic Channel. The bypass is provided by latch type relays which require electrical power to be set in the bypass position or reset from the bypass position. This scheme prevents any repositioning of the relays without energization of the bypass circuitry. The key and the operation of the switch is under administrative control.

   The bypass will be continuously indicated at the station annunciator and the station computer whenever any of the key switches are in bypass or when any of the latch type relays are in the bypass position.

#### 7.3.1.1.4 Interlocks

The SFAS provides interlocks to prohibit any manual or automatic override of the protective action until the trip signals of the SFAS are reset or blocked by the operator.

Fault current conditions on motor operated equipment will override the interlocks and trip the equipment.

Interlocks which inhibit protective actions are described in Section 7.3.1.1.3.

7.3.1.1.5 Sequencing

The SFAS will automatically sequence the protective action by loading equipment in steps to the emergency diesel generators if normal or reserve power is not available. Refer to Chapter 8. Figure 7.3-1 contains the sequence logic for the SFAS.

7.3.1.1.6 Redundancy

The SFAS has redundancy as follows:

1. Each of the station variables listed in Subsection 7.3.1.4 (2) is monitored by at least one trip bistable in each of four redundant SFAS sensing and logic channels.

2. The signal from each trip bistable is divided into four independent signals, electrically isolated (buffered) from each other and fed into four redundant SFAS logic channels.

3. The logic terminating relays as outlined in Subsection 7.3.1.1.2 are combined into two redundant safety actuating channels to independently control the safety actuated devices.

7.3.1.1.7 Diversity

Diversity in the SFAS is provided by monitoring RC pressure and CV pressure, to sense loss of coolant and activate protective action systems. Refer to the Technical Specifications.

7.3.1.1.8 Safety Actuated Devices

The safety actuation devices are tabulated in Figures 7.3-3 through 7.3-8, “SFAS Actuated Equipment Tabulation” and described in Chapter 5, 6, 8, and 9.

7.3.1.2 Supporting Systems

The supporting system of the SFAS is the essential power supply (Chapter 8)

7.3.1.3 Non-Safety Systems

The non-safety systems and equipment associated with the ESF system are listed below:

1. Station annunciator (Section 7.11).

2. Station computer (Section 7.10).

3. Instrumentation systems to monitor the following ESF parameters:

   a. Containment spray flow

   b. CV emergency sump level

   c. BWST temperature

d. CV Radiation

### 7.3.1.4 Design Basis

The design basis information of the SFAS as required by Section 3 of IEEE Standard 279-1971 are as follows:

1. Generating station conditions which require protective actions:

   a. Loss of coolant accident (LOCA)

   b. Steam line break

2. Generating station variables that are required to be monitored in order to provide protective actions:

   a. CV pressure

   b. RC pressure

   c. BWST level (permissive only)

3. The number and location of protective function sensors provided to monitor those variables that have spatial dependence:

   Four (4) sensors (one for each channel) of each of the station variables as listed above. Refer to the EI&C drawings for the location drawings of the RC pressure sensors. For the relative locations of the CV pressure and BWST level sensors, refer to Figure 9.4-11a and 6.3-2a, respectively.

6. The levels, (Trip Setpoints) that when reached, will activate protective action are tabulated in Table 7.3-3. Allowable values are tabulated in the Technical Specifications.

7. The range of operating requirements for both the energy supply and the environment during normal, abnormal, and accident circumstances throughout which the system will perform are tabulated in Table 7.3-4.

8. The accidents or other unusual events which could physically damage protection system components or could cause environmental changes leading to functional degradation of system performance, and for which provisions are incorporated to retain the necessary protective action, are fire, missiles, flood, earthquake, and high energy line break for equipment outside the containment vessel, and fire, missiles, flood, earthquake, and LOCA for equipment inside the containment vessel.

9. The minimum performance requirements to be accommodated until proper conclusion of the protective action is assured, including system response times, system accuracies and ranges of the magnitudes of sensed variables are tabulated in Table 7.3-5.

#### 7.3.1.5 Drawings

The following drawings are related to the SFAS:

1. Logic diagrams: Figures 7.3-1 through 7.3-8.

2. Wiring Diagrams: Refer to the E&IC drawings.

3. Location drawings: Refer to the E&IC drawings and Figure 12.1-10.

4. Functional drawings: Figures 5.1-2, 6.3-1, 6.3-1A, 6.3-2, 6.3-2A, 7.3-9, 9.2-1, 9.2-2, 9.2-4a, 9.3-1, 9.3-16, 9.4-9, 9.4-11, 9.4-11A, 9.4-12.

### 7.3.2 Analysis of ESF Instrumentation and Controls

#### 7.3.2.1 Implemented Design Documents

The design criteria incorporated in the design of the SFAS include the documents as tabulated in Table 7.1-1.

#### 7.3.2.2 Compliance with AEC General Design Criteria

The SFAS complies with the AEC General Design Criteria as tabulated in Table 7.1-1 and as discussed in Appendix 3D.

#### 7.3.2.3 Compliance with IEEE Standard 279-1971

The following discussions are keyed to Section 4 of IEEE Standard 279-1971 and demonstrate compliance with the above mentioned standard.

(4.1) General Functional Requirement - The SFAS will, with precision and reliability, automatically perform its protective function, whenever the station conditions monitored by the SFAS reach a preset level, under the design conditions described in Subsections 7.3.1.4 (7), (8), and (9). The operating requirements of the SFAS components are listed in Table 7.3-4.

(4.2) Single Failure Criterion - No single failure can prevent the SFAS from performing its protective function.

(4.3) Quality of Components and Modules - The SFAS consists of high quality components and modules with minimum maintenance requirements and low failure rates. Quality control procedures were used during fabrication and testing to verify compliance with the requirements specified for the particular equipment. Details of the QA procedures are provided in Chapter 17 of the FSAR and Chapter 17 of the USAR.

(4.4) Equipment Qualification - Type test data is available to verify that the SFAS equipment meet, on a continuing basis, the performance requirements determined to be necessary for achieving the system requirements.

(4.5) Channel Integrity - Each SFAS channel is designed, manufactured, and located so that channel integrity is maintained under the design condition listed in Subsections 7.3.1.4 (7) and (9).

(4.6) Channel Independence - Each SFAS logic channel is located in its own cabinets. The cabinets act as a barrier against fire and mechanical damage from external sources. The distance between cabinets of redundant channels are 4 feet to 13 feet to satisfy the single failure criterion. (Refer to Figure 12.1-10.)

The cabinets are in a room which offers environmental and missile protection. Channel independence criteria for the balance of the SFAS are described in Chapter 8.

(4.7) Control and Protection System Interaction

a. Classification of Equipment - Equipment that is used for protective and control function is classified as part of the protection system and meets the requirements of IEEE Standard 279-1971.

The protective action is designed to override and block any control function as shown on the schematics

b. Isolation Devices - Safety features actuation signals are transmitted only to the control system to accomplish the protective action, in which case, the control system is assumed to form part of the SFAS and is subject to the same criteria. Therefore, no isolation devices are used between signal and controller.

The control signals to close normal decay heat valve DH-11 (refer to Subsections 6.3.2.16 and 7.6.1.1) and to open the core flooding tank isolation valves (refer to Subsections 6.3.2.15 and 7.6.1.2) originate in the SFAS logic cabinets but are isolated by relay contacts from the SFAS. The bistables (one in each SFAS channel), which control these relays, share sensors with the SFAS, but are independent of those bistables used for the SFAS signals; they therefore act as second isolation devices.

Other than the above, signals from the SFAS are not utilized for any other control system use.

c. Single Random Failure - A single random failure resulting in a control system action simultaneously causing a channel failure and a station condition requiring protective action is incredible.

d. Multiple Failures Resulting From a Credible Single Event - No control system action can result in a condition requiring protective action and concurrently prevent the protective action of any SFAS channel.

(4.8) Derivation of System Inputs - The SFAS inputs are derived from signals that are direct measures of the station variables as listed in the Technical Specifications.

(4.9) Capability for Sensor Checks - Each SFAS sensing channel contains readouts at the main control panels for each monitored station variable, which permits cross-checking between channels.

(4.10) Capability for Test and Calibration - Manual testing and calibration features have been provided to perform periodic testing and calibration operations.

a. Manual Testing of Bistables - Each bistable monitoring a station variable has built-in provisions for testing.

   To test a bistable, a test voltage is applied to its input by pressing a momentary pushbutton, this causes the bistable to trip. Local light, station annunciator and computer displays will verify proper operation.

b. Manual Calibration of the SFAS Sensing Channels - Each SFAS sensing channel has one built-in adjustable signal generator with test jacks for connection to a precision indicating instrument. By means of a selector switch and momentary switches, the maintenance personnel are able to connect this signal generator to any one station variable of a given channel, while disconnecting the remote signal transmitter. The following calibration functions can be performed:

   1. Calibrate bistable trip setpoint dial.

   2. Calibrate the indicating instruments at the SFAS cabinets and compare with the indicating instruments at the main control panel. The printout and the CRTs of the station computer provide the same information.

c. Manual Testing of the System Logic - Each two-out-of-four logic coincidence matrix of a system logic (see Subsection 7.3.1.1.2) includes a local independent momentary pushbutton which, when operated, changes the matrix functioning to a one-out-of-four logic. This test with the simultaneous presence of a bistable test trip on any channel will de-energize the output relays of one channel of the protective action system being tested. See Table 7.3-2 for the list of the protective action systems (i.e., SFAS System No. and Description).

   Any combination of two or more bistable trips of redundant channels associated with the same coincidence matrix logic will cause a trip of the related protective action system. In each case the trip is monitored by local lights, the station annunciator, and computer displays.

d. Manual Testing of SFAS Equipment - Hand control switches for each SFAS control device are provided at the main control panel and locally to allow test of each individual safety actuated device.

(4.11) Channel Bypass or Removal From Operation - The SFAS station variable channel bypass is described in Subsection 7.3.1.1.3 (1). The channel bypass permits the testing, calibration and maintenance of a particular generating station variable of a single channel during power operation. With the bypass in effect

the three remaining channels of that station variable provide the necessary protection.

Since only two channels of a variable need exceed the trip setpoint to cause a trip, a single failure will not prevent the station variable SFAS logic from fulfilling its protective function.

(4.12) Operating Bypasses - The SFAS operating bypasses are described in Subsection 7.3.1.1.3 (2). Whenever the permissive conditions are not met, the bypasses will not be allowed or will be removed automatically. The bypass circuits used to prevent or achieve automatic removal of the bypasses are part of the protection system and are designed in accordance with IEEE Standard 279-1971.

(4.13) Indication of Bypasses - Initiation of the channel bypass will be continuously indicated at the SFAS cabinets, by the station computer, and annunciator. Initiation of the operating bypasses will be continuously indicated at the SFAS logic cabinet, at the main control board, and by the station computer and annunciator.

(4.14) Access to Means for Bypassing - The activation of SFAS channel bypass is accomplished by using key switches, which are under administrative control. Also, to initiate a bypass, a corresponding SFAS cabinet door must be opened. The cabinet door keys are also under administrative control.

The activation of SFAS operating bypass is accomplished by depressing pushbuttons at the main control board.

(4.15) Multiple Setpoints - The SFAS does not use multiple setpoints for any bistable monitoring the station variables.

(4.16) Completion of Protection Action once it is initiated - The trip signals of the Bistables, the coincidence matrices, and the actuation control devices on the safety features actuation system are seal-in type, such that once initiated, a protective action at the system level shall go to completion and remain in the tripped state until deliberately reset by operator action.

(4.17) Manual Initiation - Four manual trip switches are provided at the main control board; two switches to activate the two redundant CV Spray Systems and the remaining two switches to activate the two redundant SFAS channels exclusive of the Containment Spray Systems and the CV Emergency Sump Recirculation Systems.

A manual control switch for each actuation device related to the SFAS is also located at the main control board in close proximity of the manual trip switches. Trip switches for each individual protective action system are provided in the SFAS logic cabinets.

(4.18) Access to Setpoint Adjustments, Calibrations, and Test Points - Setpoint adjustments, calibration and test points in the control room cabinet room are accessible only when the SFAS logic cabinet doors are open. The door keys are under administrative control. Open doors will be alarmed by the station computer

and annunciator. Access to sensing equipment (transmitters, etc.) is administratively controlled as part of general station access control to the protected and vital areas, as described in the security plan. Access is also administratively controlled through compliance with station procedures.

(4.19) Identification of Protective Action - Protective action will be initiated by tripping the corresponding bistable whenever the generating station variable sensed exceeds the setpoint. The tripping of these bistables will be indicated and identified by the station computer and annunciator with the exception of the BWST Level Bistable. The annunciation of the BWST Level Trip will be by logic modules.

Each trip will also be indicated at the corresponding module in the SFAS logic cabinets.

(4.20) Information Read-Out - Each SFAS channel provides, in the SFAS logic cabinets and at the main control panel, a readout for each monitored generating station variable as well as an indication of the SFAS trip status. The station computer monitors each SFAS station variable and the trip status of each SFAS channel. The station annunciator will indicate any SFAS channel trip with the exception of the BWST Level channel trip. The BWST Level channel trip annunciation occurs at the logic module which requires two bistable trips (two channel trips).

(4.21) System Repair - The periodic testing can locate failure in an individual module. The modular design of the SFAS allows for quick repair of malfunctions.

(4.22) Identification - The identification of the equipment including cabinets, trays and cables of the SFAS between redundant portions is accomplished by color coding and numbering as described in Chapter 8.

#### 7.3.2.4 Compliance with IEEE Standard 323-1971

The SFAS complies with the basic requirements for the qualifications of Class 1E electrical equipment and meets IEEE Standard 323-1971.

#### 7.3.2.5 Compliance with IEEE Standard 338-1971

The SFAS includes provision to permit testing in accordance with Section 5 of IEEE Standard 338-1971. (Refer to item (4.10) of Subsection 7.3.2.3).

#### 7.3.2.6 Compliance with AEC Safety Guide 22

The SFAS design includes flexibility for periodic tests of the system during reactor operation. In general, the test of any protective action system (Reference Table 7.3-2) and the corresponding system logics can be performed during reactor operation. A half trip test of the logic and terminating relays is performed at the frequency required by Technical Specifications for the instrumentation system. The motive power and actuated equipment are tested in accordance with the applicable system Technical Specifications. The Safety Features Actuation System and the actuated equipment are tested while the plant is shutdown for refueling at the frequency required by Technical Specifications, with the exceptions noted in Table 7.3-2. The tests assure that the protective action system will respond to an actuation condition.

When the operation of the actuated equipment or testing of the terminating relays may damage station equipment, disrupt reactor operation, or is precluded by Technical Specifications or NRC commitment, the testing will be performed during refueling shutdowns. The containment isolation valves noted in Table 7.3-2 are also only tested while the plant has been shutdown for refueling due to the potential to interrupt power operation.

TABLE 7.3-2

PERIODIC TEST ON SFAS AND ACTUATED EQUIPMENT

| | OCCURRENCES | | | | | | | PERIODIC TEST FREQUENCY Actuated Equipment Test | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| SFAS-PROTEC-TIVE ACTION SYSTEM No. * | INCI-DENT No. | CV PRESS HI | CV PRESS HI HI | RC PRESS LO | RC PRESS LO LO | BWST LVL LO | SYSTEM DESCRIPTION* | Logic and Terminating Relays Half-trip test | During Plant Operation | During Refueling Shutdown | Remarks |
| 11 | 1 | X | | X | | | Emergency ventilation system | Note 6 | Quarterly | Yes | |
| 12 | 1 | X | | X | | | Containment purge and sample valve isolation system | Note 6 | Quarterly | Yes | Note 1 |
| 21 | 2 | X | | X | | | High pressure injection system | Note 6 | Quarterly | Yes | |
| 22 | 2 | X | | X | | | Containment Air Cooling system | Note 6 | Quarterly | Yes | |
| 23 | 2 | X | | X | | | Component Cooling Water System | Note 6 | Quarterly | Yes | Note 2 |
| 24 | 2 | X | | X | | | Service Water System | Note 6 | Quarterly | Yes | |
| 25 | 2 | X | | X | | | Containment spray valve | Note 6 | Quarterly | Yes | |
| 26 | 2 | X | | X | | | Emergency diesel generator | Note 6 | Monthly | Yes | |
| 27 | 2 | X | | X | | | CV Isolation System No. 1 Group 1 | Note 6 | Quarterly | Yes | MU2A, MU3 tested at Refueling Shutdown only per Note 5. |
| 28 | 2 | X | | X | | | CV Isolation System No. 1 Group 2 | Note 6 | Quarterly | Yes | DH7A, DH7B, DH9A, DH9B tested at Refueling Shutdown only per Note 5. |
| 29 | 2 | X | | X | | | CV Isolation System No. 1 Group 3 | Note 6 | Quarterly | Yes | |
| 31 | 3 | X | | | X | | Low Pressure Injection System | Note 6 | Quarterly | Yes | |

TABLE 7.3-2 (Continued)

PERIODIC TEST ON SFAS AND ACTUATED EQUIPMENT

| | OCCURRENCES | | | | | | | PERIODIC TEST FREQUENCY | Actuated Equipment Test | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| SFAS-PROTECTIVE ACTION SYSTEM No.* | INCIDENT No. | CV PRESS HI | CV PRESS HI HI | RC PRESS LO | RC PRESS LO LO | BWST LVL LO | SYSTEM DESCRIPTION* | Logic and Terminating Relays Half-trip test | During Plant Operation | During Refueling Shutdown | Remarks |
| 32 | 3 | X | | | X | | CV Isolation System No. 2 Group 1 | Note 6 | Quarterly | Yes | |
| 33 | 3 | X | | | X | | CV Isolation System No. 2 Group 2 | Note 6 | N/A | Yes | Note 5 |
| 41 | 4 | | X | | | | Containment spray pump | Note 6 | Quarterly | Yes | |
| 42 | 4 | | X | | | | CV Isolation System No. 3 Group 1 | Note 6 | Quarterly | Yes | Note 5 |
| 43 | 4 | | X | | | | CV Isolation System No. 3 Group 2 | | | | Note 3 |
| 51 | 5 | | | | | X | CV Emergency Sump Recirculation System | Note 6 | N/A | Yes | Note 5 |

* USAR Figures 7.3-1 through 7.3-8 provide further information on SFAS system numbers and equipment actuated by SFAS.

Notes

1. The system includes actuated equipment of the control room normal air conditioning system. Twice monthly logic testing for containment purge valves (CV 5005 through CV 5008) is not required.
2. Steam Generator Auto Level Setpoint Control tested only during refueling shutdown due to potential interference to power operation.
3. Components no longer actuated by SFAS signal.
4. For periodic actuated equipment testing performed during plant operation, control room hand switches are normally used to actuate equipment.
5. The CV isolation valves of this system will be tested during refueling shutdown only due to potential interference to power operation.
6. As required by Technical Specifications.

TABLE 7.3-3

SAFETY FEATURES ACTUATION SYSTEM TRIP SETPOINTS

| Functional Units | Trip Setpoints | Allowable Values* |
|---|---|---|
| Instrument Strings | | |
| 1. Containment Pressure - High | 18.7 psia | |
| 2. Containment Pressure - High - High | 40.0 psia | |
| 3. RCS Pressure - Low | 1600 psig | |
| 4. RCS Pressure - Low - Low | 470 psig | |
| 5. BWST Level | 108.5 inches | |

*Refer to Technical Specification Table 3.3.5-1 for the Allowable Values

TABLE 7.3-4

SFAS OPERATING REQUIREMENTS

| Equipment | Parameters | Nominal value | Allowable Range for abnormal conditions | Allowable Range for accident conditions |
|---|---|---|---|---|
| 1. SFAS equipment in cabinet room | Power supply voltage | 118V AC | 118V AC ± 10% | 118V AC ± 10% |
| | Power supply Frequency | 60Hz | 60Hz ± 3Hz | 60Hz ± 3Hz |
| | Ambient temperature | 75°F | 40-110°F | 40-130°F (for 168 hours) |
| | Ambient humidity | 40% RH | Up to 80% RH | Up to 100% RH (without condensation) |
| | Ambient pressure | Atmospheric | Atmospheric | Atmospheric |
| 2a. RC pressure sensors inside the CV | Ambient temperature | 40-160°F | 40-284°F ** | 40-284°F ** |
| | Ambient humidity | 100% RH | 100% RH, saturated steam | 100% RH, saturated steam |
| | Ambient pressure | Atmospheric | 40 psig | 40 psig |
| | Ambient radiation | 1 rad/hr | $2.47 \times 10^7$ rad accum | $2.47 \times 10^7$ rad accum |
| 2b. solenoids inside the CV | Ambient temperature | 30-120°F | 30-284°F ** | 30-284°F ** |
| | Ambient humidity | 100% RH | 100% RH, saturated steam | 100% RH, saturated steam |
| | Ambient pressure | Atmospheric | 40 psig | 40 psig |
| | Ambient radiation | 1 rad/hr | $2.47 \times 10^7$ rad accum | $2.47 \times 10^7$ rad accum |
| 3. CV pressure sensors, outside CV | Ambient temperature | 80°F | 40-120°F | 40-120°F |
| | Ambient humidity | 50% | 30-100% RH | 30-100% RH |
| | Ambient pressure | Atmospheric | Atmospheric | Atmospheric |
| 4. BWST level sensors outdoors | Ambient temperature | -30 to 110°F | -30 to 110°F | -30 to 110°F |
| | Ambient humidity | 40-100% RH | 40-100% RH | 40-100% RH |
| | Ambient pressure | Atmospheric | Atmospheric | Atmospheric |

TABLE 7.3-4 (Continued)

SFAS OPERATING REQUIREMENTS

| Equipment | Parameters | Nominal value | Allowable Range for abnormal conditions | Allowable Range for accident conditions |
|---|---|---|---|---|
| 5. Motor control centers, low voltage unit sub-stations, medium voltage switchgear, solenoids outside CV | Ambient temperature | 32 to 104°F * | 32 to 104°F * | 32 to 104°F * |
| | Ambient humidity | 40 to 100% RH | 40 to 100% RH | 40 to 100% RH |
| | Ambient pressure | Atmospheric | Atmospheric | Atmospheric |
| | Control power supply voltage | 120V AC<br>120V DC | 120V AC ± 10%<br>90 to 140V DC | 120V AC ± 10%<br>90 to 140V DC |
| | Control power supply frequency | 60Hz | 60Hz | 60Hz ± 3Hz |
| 6. All above, 1 thru 5 | Seismic requirements | | Refer to Section 3.10 | |
| 7. Items 1, 3, 4, and 5 | Ambient radiation outside CV | N/A | N/A | N/A |
| 8. Items 1. 3. and 5 | High energy line break environment outside CV | | Refer to Section 3.6 | |

*High Voltage Switchgear Rooms, Auxiliary Shutdown Panel Room and Component Cooling Water Pump Room (Rooms 323, 324, 325 and 328) have a maximum worst case temperature of 120°F. ECCS Pump Rooms and Decay Heat Exchanger Pit (Rooms 105, 113 and 115) have a maximum worst case temperature of 140°F.

**Equipment is qualified for a maximum containment temperature of 284 degrees F. Refer to Section 3.11 for maximum accident analysis temperatures.

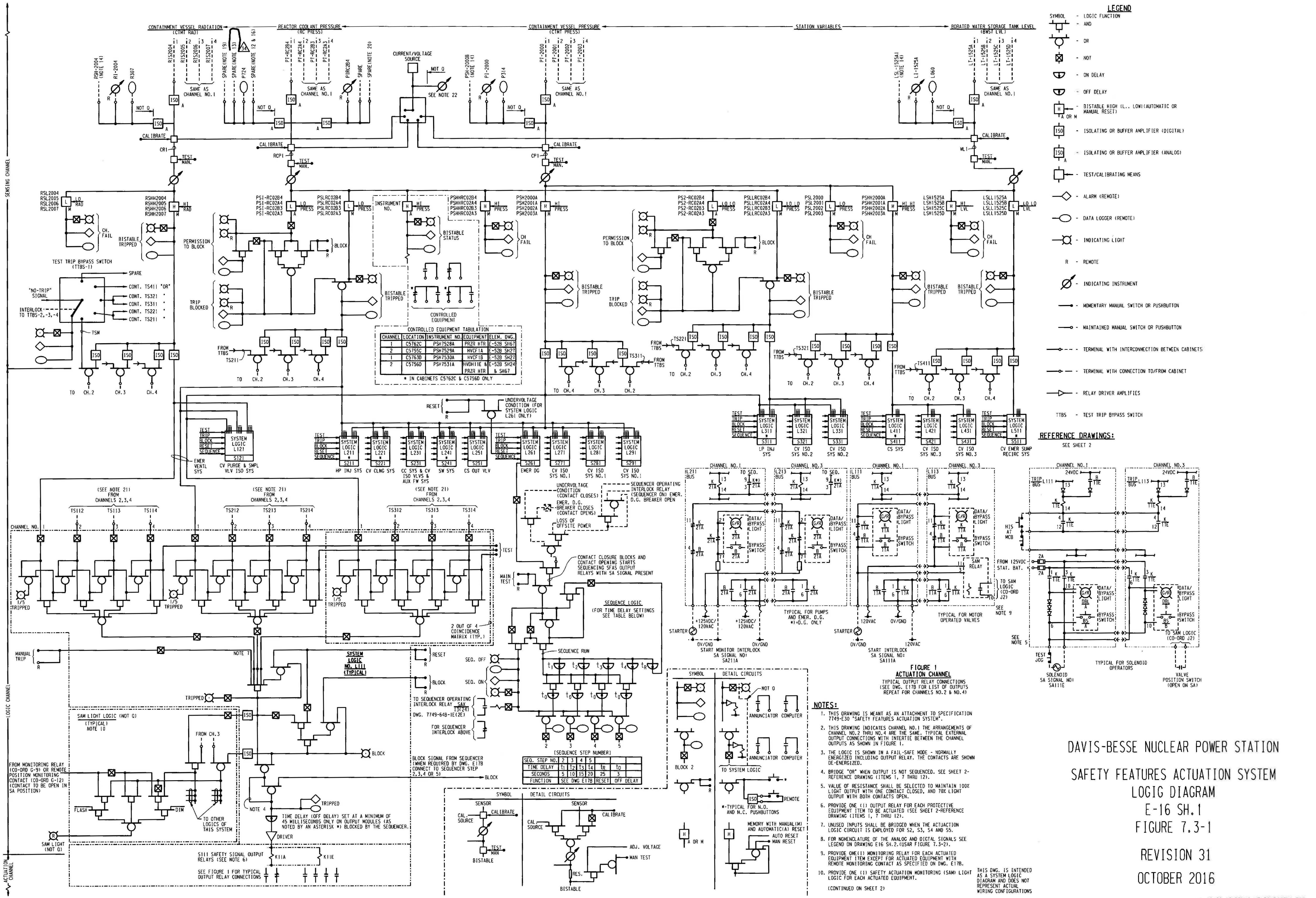
TABLE 7.3-5

SFAS PERFORMANCE REQUIREMENTS

| Measured station variable | System response times (a) | System accuracies | Ranges of sensed variables to be accommodated |
|---|---|---|---|
| 1. CV pressure | $\leq$ 5 sec | (b) | 0 - 60 psia |
| 2. RC pressure | $\leq$ 5 sec | (b) | 0 - 2500 psig |
| 3. BWST level | $\leq$ 5 sec | (b) | 0 - 50 feet |

(a) System response times do not include response time of the actuated equipment.

(b) System accuracy requirements are factored into Technical Specification Allowable Values determined in accordance with approved setpoint methodology




CONTROLLED EQUIPMENT TABULATION

| CHANNEL | LOCATION | INSTRUMENT NO. | EQUIPMENT | ELEM. DWG. |
|---|---|---|---|---|
| 1 | C5762C | PSH7528A | PRZR HTR | E-52B SH67 |
| 2 | C5755C | PSH7529A | HVCF1A | E-52B SH27 |
| 1 | C5763D | PSH7530A | HVCF1B | E-52B SH27 |
| 2 | C5756D | PSH7531A | HVDH11E & PRZR HTR | E-52B SH24 & SH67 |

* IN CABINETS C5762C & C5756D ONLY

| SEQ. STEP NO. | 2 | 3 | 4 | 5 | | | |
|---|---|---|---|---|---|---|---|
| TIME DELAY | $t_1$ | $t_2$ | $t_3$ | $t_4$ | $t_R$ | $t_0$ | |
| SECONDS | 5 | 10 | 15 | 20 | 25 | 3 | |
| FUNCTION | SEE DWG E17B | | | | RESET | OFF DELAY | |

FIGURE 1
ACTUATION CHANNEL
TYPICAL OUTPUT RELAY CONNECTIONS
(SEE DWG. E17B FOR LIST OF OUTPUTS
REPEAT FOR CHANNELS NO.2 & NO.4)

## NOTES:

1. THIS DRAWING IS MEANT AS AN ATTACHMENT TO SPECIFICATION 7749-E30 "SAFETY FEATURES ACTUATION SYSTEM".
2. THIS DRAWING INDICATES CHANNEL NO.1 THE ARRANGEMENTS OF CHANNEL NO.2 THRU NO.4 ARE THE SAME. TYPICAL EXTERNAL OUTPUT CONNECTIONS WITH INTERTIE BETWEEN THE CHANNEL OUTPUTS AS SHOWN IN FIGURE 1.
3. THE LOGIC IS SHOWN IN A FAIL-SAFE MODE - NORMALLY ENERGIZED INCLUDING OUTPUT RELAY. THE CONTACTS ARE SHOWN DE-ENERGIZED.
4. BRIDGE "OR" WHEN OUTPUT IS NOT SEQUENCED. SEE SHEET 2-REFERENCE DRAWING (ITEMS 1, 7 THRU 12).
5. VALUE OF RESISTANCE SHALL BE SELECTED TO MAINTAIN 100% LIGHT OUTPUT WITH ONE CONTACT CLOSED, AND 70% LIGHT OUTPUT WITH BOTH CONTACTS OPEN.
6. PROVIDE ONE (1) OUTPUT RELAY FOR EACH PROTECTIVE EQUIPMENT ITEM TO BE ACTUATED (SEE SHEET 2-REFERENCE DRAWING (ITEMS 1, 7 THRU 12).
7. UNUSED INPUTS SHALL BE BRIDGED WHEN THE ACTUACTION LOGIC CIRCUIT IS EMPLOYED FOR S2, S3, S4 AND S5.
8. FOR NOMENCLATURE OF THE ANALOG AND DIGTAL SIGNALS SEE LEGEND ON DRAWING E16 SH.2.(USAR FIGURE 7.3-2).
9. PROVIDE ONE(1) MONITORING RELAY FOR EACH ACTUATED EQUIPMENT ITEM EXCEPT FOR ACTUATED EQUIPMENT WITH REMOTE MONITORING CONTACT AS SPECIFIED ON DWG. E17B.
10. PROVIDE ONE (1) SAFETY ACTUATION MONITORING (SAM) LIGHT LOGIC FOR EACH ACTUATED EQUIPMENT.

(CONTINUED ON SHEET 2)

THIS DWG. IS INTENDED AS A SYSTEM LOGIC DIAGRAM AND DOES NOT REPRESENT ACTUAL WIRING CONFIGURATIONS

DAVIS-BESSE NUCLEAR POWER STATION

SAFETY FEATURES ACTUATION SYSTEM
LOGIC DIAGRAM
E-16 SH.1
FIGURE 7.3-1

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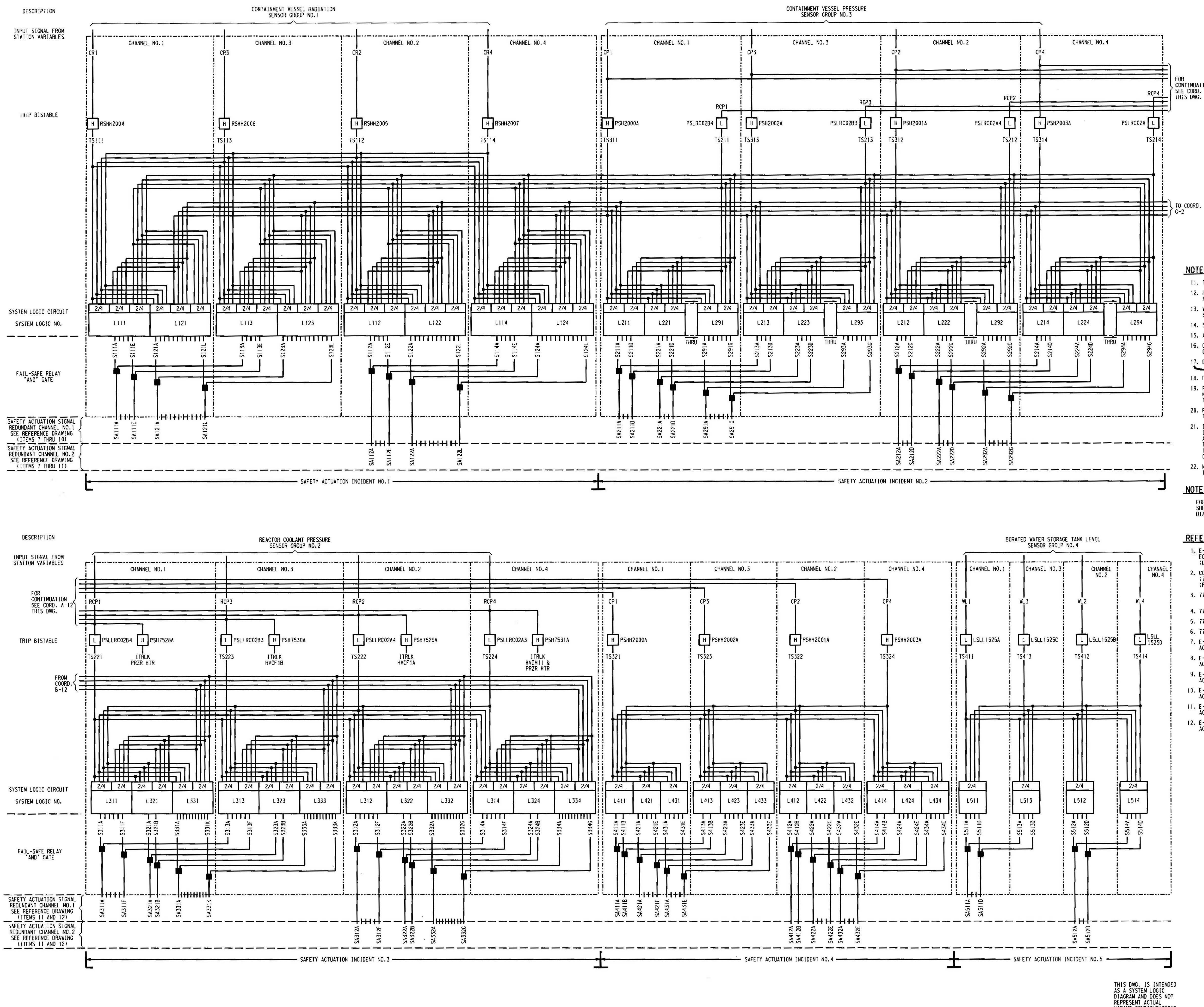
DB 06-06-16 DFN=I:/ELEC/E16SH1.DGN




## LEGEND:

ANALOG SIGNALS

CR 1 — CHANNEL
CR — CONTAINMENT VESSEL RADIATION

CP — CONTAINMENT VESSEL PRESSURE
RCP — REACTOR COOLANT PRESSURE
WL — BORATED WATER STORAGE TANK LEVEL

DIGITAL SIGNALS

TRIP SIGNAL TS221
- CHANNEL
- BISTABLE NO. OF SENSOR GROUP
- SENSOR GROUP

LOGIC NUMBER L321
- CHANNEL
- SYSTEM
- INCIDENT

NOTE: SAFETY SIGNAL (S) AND SAFETY ACTUATION SIGNAL (SA) NUMBERS ARE SIMILAR TO LOGIC NUMBERS

A,B,C... ARBITRARY OUTPUT SIGNAL SEQUENTIAL LETTERS.

FAIL-SAFE RELAY "AND" GATE AS SHOWN ON FIGURE 1, SHEET 1.

## NOTES: (SHEET 1 CONTINUED)

11. TO BE PROVIDED IN CH.1 & CH.2 ONLY.
12. REACTOR COOLANT PRESSURE INDICATION OUTPUT FOR CH.3 AND CH.4 ONLY.
13. WIDE RANGE PRESSURE SIGNAL TO NNI; DWG. 7749-E-607A SH.9 (FOR CHANNEL 2 ONLY)
14. SIGNAL OUTPUT USED ON CH.1 & CH.2 ONLY.
15. ALL ANNUNCIATOR AND COMPUTER ALARMS ARE NOT Q.
16. OUTPUT SIGNAL TO PSH7528B AND PSH7531B IN CH.1 & CH.4 RESPECTIVELY.
17. DELETED. 19
18. DELETED.
19. REACTOR COOLANT WIDE RANGE PRESSURE SIGNAL TO T-SAT METER IN ALL FOUR CHANNELS, BUFFERED OUTPUT SIGNAL TO BE 1 TO 5 VOLTS D.C.
20. REACTOR COOLANT WIDE RANGE PRESSURE SIGNAL TO IE T-SAT METER IN ALL FOUR CHANNELS.
21. INPUT LOGIC WIRING SEQUENCE FROM CHANNELS (1,2,3 & 4) IS SHOWN DIAGRAMATICALLY AND MAY NOT REPRESENT THE ACTUAL WIRING SEQUENCE CONFIGURATION. THE INPUT FROM THE ASSOCIATED CHANNEL (I.E. THE INPUT FROM THE CHANNEL 1 TRIP BISTABLE INTO THE CHANNEL 1 OUTPUT MODULE) ALWAYS COMES INTO GATES SHOWN FOR CHANNELS 1 OR 2.
22. M & TE EQUIPMENT IS USED AS THE INDICATOR UTILIZING TEST JACKS PROVIDED ON THE CABINET PANEL.

## NOTES: (SHEET 2)

FOR CHANNEL BYPASSES OPERATING BYPASSES, CHANNEL FAILURE SURVEILLANCES, SEQUENCERS AND BUFFER CIRCUITS, SEE LOGIC DIAGRAM DWG. E-16 SH.1 (USAR FIG. 7.3-1).

## REFERENCE DRAWING

1. E-17B (SHEET 7) "SAFETY FEATURES ACTUATION SYSTEM ACTUATED EQUIPMENT TABULATION LEGEND, SIGNAL DESCRIPTION & NOTES" (USAR FIG. 7.3-3).
2. CONSOLIDATED CONTROLS CORPORATION DWG. S9N16-1 THRU 4 (7749-E30-13 THRU 16,23 THRU 30,33 THRU 38,47 & 48) (FSAR APPENDIX 7-B)
3. 7749-E-760 BLOCK DIAGRAM, SFAS REMOTE POSITION SWITCH MONITORING
4. 7749-E-761 BLOCK DIAGRAM, INTERCONNECTING CABLES
5. 7749-E-762 BLOCK DIAGRAM, SFAS MISC. CIRCUITS
6. 7749-E-540 CONNECTION DIAGRAM, SFAS
7. E-17B (SHEET 1) "SAFETY FEATURES ACTUATION SYSTEM ACTUATED EQUIPMENT TABULATION" (USAR FIG. 7.3-3A).
8. E-17B (SHEET 2) "SAFETY FEATURES ACTUATION SYSTEM ACTUATED EQUIPMENT TABULATION" (USAR FIG. 7.3-4).
9. E-17B (SHEET 3) "SAFETY FEATURES ACTUATION SYSTEM ACTUATED EQUIPMENT TABULATION" (USAR FIG. 7.3-5).
10. E-17B (SHEET 4) "SAFETY FEATURES ACTUATION SYSTEM ACTUATED EQUIPMENT TABULATION" (USAR FIG. 7.3-6).
11. E-17B (SHEET 5) "SAFETY FEATURES ACTUATION SYSTEM ACTUATED EQUIPMENT TABULATION" (USAR FIG. 7.3-7).
12. E-17B (SHEET 6) "SAFETY FEATURES ACTUATION SYSTEM ACTUATED EQUIPMENT TABULATION" (USAR FIG. 7.3-8).

THIS DWG. IS INTENDED AS A SYSTEM LOGIC DIAGRAM AND DOES NOT REPRESENT ACTUAL WIRING CONFIGURATIONS

DAVIS-BESSE NUCLEAR POWER STATION

SAFETY FEATURES ACTUATION SYSTEM
SIGNAL DIAGRAM
E-16 SH.2
FIGURE 7.3-2

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LEGEND

- A ..... ALARM/PERMISSIVE
- I ..... INTERLOCK
- F ..... FUNCTION
- ST ..... START
- SH ..... START HALF SPEED
- SP ..... STOP
- O ..... OPEN
- C ..... CLOSE
- T ..... TRIP
- RC ..... RELAY CONTACT CLASSIFICATION (NOTE 2)

NOTES:

1. THIS DRAWING IS MEANT AS AN ATTACHMENT TO DRAWING 7749-E16.
2. THE RELAY CONTACTS ARE CLASSIFIED TO ACTUATE THE CONTROL DEVICES AS FOLLOWS:

   3

   RC 1 ... 4.16 KV & 480 V SWGR
   RC 2 ... 480 V STARTER SIZE ONE
   RC 3 ... 480 V STARTER SIZE FOUR, EXCEPT FOR C1-1, C1-2 AND C1-3 WHICH USE POTTER BRUMFIELD TYPE MDR RELAY
   RC 4 ... 125 V DC SOLENOID VLV

   SEE SECTION 10.6.2.3 OF SPEC 7749-E30
3. BLOCK SIGNAL TO SYSTEM LOGIC WILL AUTOMATICALLY RESET ON AN UNDERVOLTAGE CONDITION.
4. SA511A/B AND SA512A/B PROVIDE A PERMISSIVE SIGNAL TO VALVES DH7A/B AND DH9A/B TO ALLOW THE OPERATOR TO REPOSTION THE VALVES AFTER BLOCKING SFAS LEVEL 2.

   IN ADDITION, SA511A/B AND SA12A/B INITIATE THE CONTROL ROOM ANNUCIATOR TO ALERT THE OPERATOR TO PERFORM THIS FUNCTION.
5. SURVEILLANCE, SAM LOGIC, AND PUMP JUMPER MODULE DEFINITIONS:

   1X - MOTOR OPERATED VALVE MODULE
   2I - SOLENOID OPERATED VALVE MODULE - INTERNALLY WIRED CABINET MODULE
   2F - SOLENOID OPERATED VALVE MODULE - FIELD WIRED CABINET MODULE
   3X - PUMP, FAN AND DIESEL GENERATOR MODULE
   4I - SAM RELAY BOARD - NEEDED ON INTERNALLY WIRED CABINET ONLY
   5X - PUMP JUMPER MODULE

   ** - 3X MODULES USED FOR DEISEL GENERATOR CIRCUITS MUST HAVE JUMPER INSTALLED AS SHOWN ON VENDOR DRAWING E-30-343.

SAFETY ACTUATION SIGNAL DESCRIPTION

SA411A
- A — SEQUENTIAL LETTER
- 1 — ACTUATION CHANNEL
- 41 — SYSTEM
- A — INCIDENT
- S — SAFETY ACTUATION SIGNAL

*ACTUATED EQUIPMENT WITH REMOTE MONITORING CONTACT (SEE NOTE 9 OF DWG. 7749-E-16, SH.1)

DAVIS-BESSE NUCLEAR POWER STATION
SAFETY FEATURES ACTUATION SYSTEM
ACTUATED EQUIPMENT TABULATION
SHEET 7 OF 7
E-17B SH. 7
FIGURE 7.3-3

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# ACTUATED EQUIPMENT TABULATION

| EQUIPMENT ITEM NO. | EQUIPMENT DESCRIPTION | SA SIGNAL NO. | FUNCTION | SURVEILL MOD TYPE 1(2)/3(4) | SAM LOGIC MOD TYPE 1(2)/3(4) | PUMP JMPR MOD TYPE 1(2)/3(4) | SEQ. STEP | RC | SCHEME DWG. NO. | VDWG. NO. CH. 1(2) | VDWG. NO. CH. 3(4) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| C 30-1 | EMER VENT FAN 1 | SA 111A | ST | 1X 1X | 4I | | 1 | 2 | E58B-8 | E-30-14 | E-30-35 |
| HV 5439 | ECCS RM 105 HV & A/C ISO VLV | SA 111B | C | 1X 1X | 4I | | 1 | 2 | E60B-5 | E-30-14 | E-30-35 |
| HV 5440 | ECCS RM 105 HV & A/C ISO VLV | SA 111C | C | 1X 1X | 4I | | 1 | 2 | E60B-5 | E-30-14 | E-30-35 |
| HV 5024 | EMER VENT FAN 1 VLV FRM AUX. BLDG. | SA 111D | C | 1X 1X | 4I | | 1 | 2 | E58B-11 A&B | E-30-14 | E-30-35 |
| SV 5716 | ECCS RM 115 ISO DMPR. | SA 111E* | C | 2F 2I | | | 1 | 4 | E60B-23 | E-30-14 | E-30-35 |
| C 30-2 | EMER VENT FAN 2 | SA 112A | ST | 1X 1X | 4I | | 1 | 2 | E58B-8 | E-30-24 | E-30-28 |
| HV 5441 | ECCS RM 115 HV & A/C ISO VLV | SA 112B | C | 1X 1X | 4I | | 1 | 2 | E60B-5 | E-30-24 | E-30-28 |
| HV 5442 | ECCS RM 115 HV & A/C ISO VLV | SA 112C | C | 1X 1X | 4I | | 1 | 2 | E60B-5 | E-30-24 | E-30-28 |
| HV 5025 | EMER VENT FAN 2 VLV FRM AUX. BLDG. | SA 112D | C | 1X 1X | 4I | | 1 | 2 | E58B-11 A&B | E-30-24 | E-30-28 |
| SV 5715 | ECCS RM 105 ISO DMPR. | SA 112E* | C | 2F 2I | | | 1 | 4 | E60B-23 | E-30-24 | E-30-28 |
| | SPARE | SA 121A | | | | | 1 | 3 | | E-30-14 | E-30-35 |
| HV 5008 | CTMT PURGE OUT ISO VLV | SA 121B* | C | 2F 2I | | | 1 | 4 | E58B-7 A&B | E-30-14 | E-30-35 |
| HV 5011A | CTMT AIR SAMPLE ISO VLV | SA 121C* | C | 1X 1X | | | 1 | 2 | E58B-14 A-C | E-30-14 | E-30-35 |
| HV 5011B | CTMT AIR SAMPLE ISO VLV | SA 121D* | C | 1X 1X | | | 1 | 2 | E58B-15 A&B | E-30-14 | E-30-35 |
| HV 5011C | CTMT AIR SAMPLE ISO VLV | SA 121E* | C | 1X 1X | | | 1 | 2 | E58B-14 A-C | E-30-14 | E-30-35 |
| HV 5011D | CTMT AIR SAMPLE ISO VLV | SA 121F* | C | 1X 1X | | | 1 | 2 | E58B-15 A&B | E-30-14 | E-30-35 |
| HV 5006 | CTMT PURGE IN ISO VLV | SA 121G* | C | 2F 2I | | | 1 | 4 | E58B-6 | E-30-14 | E-30-35 |
| HV 5009 | MECH PENT RMS 2 & 4 PURGE VLV | SA 121H* | C | 2F 2I | | | 1 | 4 | E58B-7 A&B | E-30-14 | E-30-35 |
| HV 5016 | MECH PENT RMS 1 & 3 PURGE VLV | SA 121I* | C | 2F 2I | | | 1 | 4 | E58B-7 A&B | E-30-14 | E-30-35 |
| HV 5011E | CTMT AIR SAMPLE RET ISO VLV | SA 121J* | C | 1X 1X | | | 1 | 2 | E58B-14 A-C | E-30-14 | E-30-35 |
| | SPARE | SA 121K | | | | | 1 | 2 | | E-30-14 | E-30-35 |
| SV 5301 | CTRM AIR HANDL VLV 1 | SA 121L* | C | 2F 2I | | | 1 | 4 | E60B-14 A-D | E-30-14 | E-30-35 |
| | SPARE | SA 122A | | | | | 1 | 3 | | E-30-24 | E-30-28 |
| HV 5010D | CTMT AIR SAMPLE ISO VLV | SA 122B* | C | 1X 1X | | | 1 | 2 | E58B-14 A-C | E-30-24 | E-30-28 |
| HV 5004 | MECH PENT RMS 1 & 3 PURGE VLV | SA 122C* | C | 2F 2I | | | 1 | 4 | E58B-7 A&B | E-30-24 | E-30-28 |
| HV 5021 | MECH PENT RMS 2 & 4 PURGE VLV | SA 122D* | C | 2F 2I | | | 1 | 4 | E58B-7 A&B | E-30-24 | E-30-28 |
| HV 5005 | CTMT PURGE IN ISO VLV | SA 122E* | C | 2F 2I | | | 1 | 4 | E58B-7 A&B | E-30-24 | E-30-28 |
| HV 5007 | CTMT PURGE OUT ISO VLV | SA 122F* | C | 2F 2I | | | 1 | 4 | E58B-6 | E-30-24 | E-30-28 |
| HV 5010A | CTMT AIR SAMPLE ISO VLV | SA 122G* | C | 1X 1X | | | 1 | 2 | E58B-15 A&B | E-30-24 | E-30-28 |
| HV 5010B | CTMT AIR SAMPLE ISO VLV | SA 122H* | C | 1X 1X | | | 1 | 2 | E58B-14 A-C | E-30-24 | E-30-28 |
| HV 5010C | CTMT AIR SAMPLE ISO VLV | SA 122I* | C | 1X 1X | | | 1 | 2 | E58B-15 A&B | E-30-24 | E-30-28 |
| HV 5010E | CTMT AIR SAMPLE RET ISO VLV | SA 122J* | C | 1X 1X | | | 1 | 2 | E58B-14 A-C | E-30-24 | E-30-28 |
| | SPARE | SA 122K | | | | | 1 | 2 | | E-30-24 | E-30-28 |
| SV 5311 | CTRM AIR HANDL VLV 2 | SA 122L* | C | 2F 2I | | | 1 | 4 | E60B-14 A-D | E-30-24 | E-30-28 |
| P 58-1 | HP INJ PMP 1 | SA 211A* | ST | 3X 3X | | 5X 5X | 2 | 1 | E52B-5 A&B | E-30-14 | E-30-35 |
| HV HP2C | HP INJ 1-1 VLV | SA 211B | O | 1X 1X | 4I | | 2 | 2 | E52B-26 A&B | E-30-14 | E-30-35 |
| HV HP2D | HP INJ 1-2 VLV | SA 211C | O | 1X 1X | 4I | | 2 | 2 | E52B-26 A&B | E-30-14 | E-30-35 |
| | SPARE | SA 211D* | | | | | 2 | 4 | | E-30-14 | E-30-35 |

DAVIS-BESSE NUCLEAR POWER STATION
SAFETY FEATURES ACTUATION SYSTEM
ACTUATED EQUIPMENT TABULATION
SHEET 1 OF 7
E-17B SH. 1
FIGURE 7.3-3A

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## ACTUATED EQUIPMENT TABULATION

| EQUIPMENT ITEM NO. | EQUIPMENT DESCRIPTION | SA SIGNAL NO. | FUNCTION | SURVEILL MOD TYPE 1(2)/3(4) | SAM LOGIC MOD TYPE 1(2)/3(4) | PUMP JMPR MOD TYPE 1(2)/3(4) | SEQ. STEP | RC | SCHEME DWG. NO. | VDWG. NO. CH. 1(2) | VDWG. NO. CH. 3(4) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| P 58-2 | HP INJ PMP 2 | SA 212A* | ST | 3X 3X | | 5X 5X | 2 | 1 | E52B-5 C&D | E-30-24 | E-30-28 |
| HV HP2A | HP INJ 2-1 VLV | SA 212B | 0 | 1X 1X | 4I | | 2 | 2 | E52B-26 A&B | E-30-24 | E-30-28 |
| HV HP2B | HP INJ 2-2 VLV | SA 212C | 0 | 1X 1X | 4I | | 2 | 2 | E52B-26 A&B | E-30-24 | E-30-28 |
| | SPARE | SA 212D* | | | | | 2 | 4 | | E-30-24 | E-30-28 |
| C 1-1 | CTMT CLR FAN 1 | SA 221A | SH | 1X 1X | 4I | | 5 | 3 | E58B-1 A&B | E-30-14 | E-30-35 |
| C 1-3 | CTMT CLR FAN 3 | SA 221B | SH | 1X 1X | 4I | | 5 | 3 | E58B-2 A&B | E-30-14 | E-30-35 |
| | SPARE | SA 221C | | | | | 5 | 2 | | E-30-14 | E-30-35 |
| | SPARE | SA 221D* | | | | | 5 | 4 | | E-30-14 | E-30-35 |
| C 1-2 | CTMT CLR FAN 2 | SA 222A | SH | 1X 1X | 4I | | 5 | 3 | E58B-1 A&B | E-30-24 | E-30-28 |
| C 1-3 | CTMT CLR FAN 3 | SA 222B | SH | 1X 1X | 4I | | 5 | 3 | E58B-2 C&D | E-30-24 | E-30-28 |
| | SPARE | SA 222C | | | | | 5 | 2 | | E-30-24 | E-30-28 |
| | SPARE | SA 222D* | | | | | 5 | 4 | | E-30-24 | E-30-28 |
| P 43-1 | CC PUMP 1 | SA 231A* | ST | 3X 3X | | 5X 5X | 1 | 1 | E50B-3 C&D | E-30-14 | E-30-35 |
| P 43-3 | CC PUMP 3 | SA 231B* | ST | 3X 3X | | 5X 5X | 1 | 1 | E50B-4 A-F | E-30-14 | E-30-35 |
| HV 5070 | CTMT VACM RLF ISO VLV | SA 231C | C | 1X 1X | 4I | | 1 | 2 | E58B-10 A&B | E-30-14 | E-30-35 |
| HV 5071 | CTMT VACM RLF ISO VLV | SA 231D | C | 1X 1X | 4I | | 1 | 2 | E58B-10 A&B | E-30-14 | E-30-35 |
| HV 5072 | CTMT VACM RLF ISO VLV | SA 231E | C | 1X 1X | 4I | | 1 | 2 | E58B-10 A&B | E-30-14 | E-30-35 |
| HV 5073 | CTMT VACM RLF ISO VLV | SA 231F | C | 1X 1X | 4I | | 1 | 2 | E58B-10 A&B | E-30-14 | E-30-35 |
| HV 5074 | CTMT VACM RLF ISO VLV | SA 231G | C | 1X 1X | 4I | | 1 | 2 | E58B-10 A&B | E-30-14 | E-30-35 |
| LY 6453 | SG AUTO LVL CTRL | SA 231H | T | 1X 1X | 4I | | 1 | 2 | E44B-24 | E-30-14 | E-30-35 |
| P 43-2 | CC PUMP 2 | SA 232A* | ST | 3X 3X | | 5X 5X | 1 | 1 | E50B-3 A&B | E-30-24 | E-30-28 |
| P 43-3 | CC PUMP 3 | SA 232B* | ST | 3X 3X | | 5X 5X | 1 | 1 | E50B-4 A-F | E-30-24 | E-30-28 |
| HV 5075 | CTMT VACM RLF ISO VLV | SA 232C | C | 1X 1X | 4I | | 1 | 2 | E58B-10 A&B | E-30-24 | E-30-28 |
| HV 5076 | CTMT VACM RLF ISO VLV | SA 232D | C | 1X 1X | 4I | | 1 | 2 | E58B-10 A&B | E-30-24 | E-30-28 |
| HV 5077 | CTMT VACM RLF ISO VLV | SA 232E | C | 1X 1X | 4I | | 1 | 2 | E58B-10 A&B | E-30-24 | E-30-28 |
| HV 5078 | CTMT VACM RLF ISO VLV | SA 232F | C | 1X 1X | 4I | | 1 | 2 | E58B-10 A&B | E-30-24 | E-30-28 |
| HV 5079 | CTMT VACM RLF ISO VLV | SA 232G | C | 1X 1X | 4I | | 1 | 2 | E58B-10 A&B | E-30-24 | E-30-28 |
| LY 6454 | SG AUTO LVL CTRL | SA 232H | T | 1X 1X | 4I | | 1 | 2 | E44B-24 | E-30-24 | E-30-28 |
| P 3-1 | SW PUMP 1 | SA 241A* | ST | 3X 3X | | 5X 5X | 4 | 1 | E48B-6 A&B | E-30-14 | E-30-35 |
| P 3-3 | SW PUMP 3 | SA 241B* | ST | 3X 3X | | 5X 5X | 4 | 1 | E48B-11 A-D | E-30-14 | E-30-35 |
| TV 1424 | SW FROM CC HX 1 ISO VLV | SA 241C* | 0 | 2I 2F | | | 4 | 4 | E48B-30 | E-30-14 | E-30-35 |
| TV 1429 | SW FROM CC HX 3 ISO VLV | SA 241D* | 0 | 2I 2F | | | 4 | 4 | E48B-31 A&B | E-30-14 | E-30-35 |
| | SPARE | SA 241E | | | | | 4 | 2 | | E-30-14 | E-30-35 |
| P 3-2 | SW PUMP 2 | SA 242A* | ST | 3X 3X | | 5X 5X | 4 | 1 | E48B-6 C&D | E-30-24 | E-30-28 |
| P 3-3 | SW PUMP 3 | SA 242B* | ST | 3X 3X | | 5X 5X | 4 | 1 | E48B-11 C-F | E-30-24 | E-30-28 |
| TV 1434 | SW FROM CC HX 2 ISO VLV | SA 242C* | 0 | 2I 2F | | | 4 | 4 | E48B-30 | E-30-24 | E-30-28 |

DAVIS-BESSE NUCLEAR POWER STATION

SAFETY FEATURES ACTUATION SYSTEM
ACTUATED EQUIPMENT TABULATION
E-17B SH. 2
FIGURE 7.3-4

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DB 11-15-00 DFN=I:/ELEC/E17BSH2.DGN

# ACTUATED EQUIPMENT TABULATION

| EQUIPMENT ITEM NO. | EQUIPMENT DESCRIPTION | SA SIGNAL NO. | FUNCTION | SURVEILL MOD TYPE 1(2)/3(4) | SAM LOGIC MOD TYPE 1(2)/3(4) | PUMP JMPR MOD TYPE 1(2)/3(4) | SEQ. STEP | RC | SCHEME DWG. NO. | VDWG. NO. CH. 1(2) | VDWG. NO. CH. 3(4) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| TV 1429 | SW FROM CC HX 3 ISO VLV | SA 242D* | O | 2I 2F | | | 4 | 4 | E48B-31 A&B | E-30-24 | E-30-28 |
| | SPARE | SA 242E | | | | | 4 | 2 | | E-30-24 | E-30-28 |
| HV 1530 | CS 1 ISO VLV | SA 251A | O | 1X 1X | 4I | | 1 | 2 | E52B-21 A&B | E-30-15 | E-30-36 |
| | SPARE | SA 251B | | | | | 1 | 2 | | E-30-15 | E-30-36 |
| | SPARE | SA 251C* | | | | | 1 | 4 | | E-30-15 | E-30-36 |
| HV 1531 | CS 2 ISO VLV | SA 252A | O | 1X 1X | 4I | | 1 | 2 | E52B-21 A&B | E-30-25 | E-30-29 |
| | SPARE | SA 252B | | | | | 1 | 2 | | E-30-25 | E-30-29 |
| | SPARE | SA 252C* | | | | | 1 | 4 | | E-30-25 | E-30-29 |
| K 5-1 | EMER DG 1 | SA 261A* | ST | 3X** 3X** | | 5X 5X | 1 | 2 | E64B-1 A-F NOTE 3 | E-30-15 | E-30-36 |
| | SPARE | SA 261B | | | | | 1 | 2 | | E-30-15 | E-30-36 |
| | SPARE | SA 261C* | | | | | 1 | 4 | | E-30-15 | E-30-36 |
| K 5-2 | EMER DG 2 | SA 262A* | ST | 3X** 3X** | | 5X 5X | 1 | 2 | E64B-2 A-F NOTE 3 | E-30-25 | E-30-29 |
| | SPARE | SA 262B | | | | | 1 | 2 | | E-30-25 | E-30-29 |
| | SPARE | SA 262C* | | | | | 1 | 4 | | E-30-25 | E-30-29 |
| HV MU2A | RC LETDOWN DELAY COIL OUT VLV | SA 271A | C | 1X 1X | 4I | | 1 | 2 | E49B-18 | E-30-15 | E-30-36 |
| | SPARE | SA 271B | | | | | 1 | 2 | | E-30-15 | E-30-36 |
| | SPARE | SA 271C* | | | | | 1 | 4 | | E-30-15 | E-30-36 |
| HV 2012A | CTMT NORM SUMP ISO VLV | SA 271D | C | 1X 1X | 4I | | 1 | 2 | E56B-24 A&B | E-30-15 | E-30-36 |
| HV 240A | RC PRZR SAMPLE VLV | SA 271E | C | 1X 1X | 4I | | 1 | 2 | E52B-15 | E-30-15 | E-30-36 |
| HV 1399 | SW ISO VLV TO CLNG WTR | SA 271F | C | 1X 1X | 4I | | 1 | 2 | E48B-9 A&B | E-30-15 | E-30-36 |
| HV 1773A | RC DT HDR ISO VLV | SA 271G* | C | 2I 2F | | | 1 | 4 | E52B-39 | E-30-15 | E-30-36 |
| HV 1719A | CTMT VENT HDR ISO VLV | SA 271H* | C | 2I 2F | | | 1 | 4 | E52B-39 | E-30-15 | E-30-36 |
| HV 607 | SG 1 SAMPLE ISO VLV | SA 271I* | C | 2I 2F | | | 1 | 4 | E46B-23 A&B | E-30-15 | E-30-36 |
| | SPARE | SA 271J* | | | | | 1 | 4 | | E-30-15 | E-30-36 |
| HV 235A | PRZR QNCH TK SAMPLE ISO VLV | SA 271K* | C | 2I 2F | | | 1 | 4 | E52B-32 | E-30-15 | E-30-36 |
| HV 1544 | CF TK 1 $H_2O$ & $N_2$ FILL ISO VLV | SA 271L* | C | 2I 2F | | | 1 | 4 | E52B-29 A&B | E-30-15 | E-30-36 |
| HV MU3 | RC LETDOWN HI TEMP VLV | SA 272A* | C | 2I 2F | | | 1 | 4 | E49B-22 A-C | E-30-25 | E-30-29 |
| | SPARE | SA 272B* | | | | | 1 | 4 | | E-30-25 | E-30-29 |
| HV 2012B | CTMT NORM SUMP ISO VLV | SA 272C | C | 1X 1X | 4I | | 1 | 2 | E56B-25 A&B | E-30-25 | E-30-29 |
| HV 240B | RC PRZR VAPOR SAMPLE VLV | SA 272D | C | 1X 1X | 4I | | 1 | 2 | E52B-16 A&B | E-30-25 | E-30-29 |
| HV 1542 | CF TK VENT ISO VLV | SA 272E* | C | 2I 2F | | | 1 | 4 | E52B-29 A&B | E-30-25 | E-30-29 |
| HV 1395 | SW ISO VLV TO CLNG WTR | SA 272F | C | 1X 1X | 4I | | 1 | 2 | E48B-9 A&B | E-30-25 | E-30-29 |
| HV 1773B | RC DT HDR ISO VLV | SA 272G* | C | 2I 2F | | | 1 | 4 | E52B-40 | E-30-25 | E-30-29 |
| HV 1719B | CTMT VENT HDR ISO VLV | SA 272H* | C | 2I 2F | | | 1 | 4 | E52B-40 | E-30-25 | E-30-29 |
| HV 598 | SG 2 SAMPLE ISO VLV | SA 272I* | C | 2I 2F | | | 1 | 4 | E46B-23 A&B | E-30-25 | E-30-29 |
| | SPARE | SA 272J* | | | | | 1 | 4 | | E-30-25 | E-30-29 |

DAVIS-BESSE NUCLEAR POWER STATION

SAFETY FEATURES ACTUATION SYSTEM
ACTUATED EQUIPMENT TABULATION
E-17B SH. 3
FIGURE 7.3-5

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## ACTUATED EQUIPMENT TABULATION

| EQUIPMENT ITEM NO. | EQUIPMENT DESCRIPTION | SA SIGNAL NO. | FUNCTION | SURVEILL MOD TYPE 1(2)/3(4) | SAM LOGIC MOD TYPE 1(2)/3(4) | PUMP JMPR MOD TYPE 1(2)/3(4) | SEQ. STEP | RC | SCHEME DWG. NO. | VDWG. NO. CH. 1(2) | VDWG. NO. CH. 3(4) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| HV 235B | PRZR QNCH TK SAMPLE ISO VLV | SA 272K* | C | 2I 2F | | | 1 | 4 | E52B-33 | E-30-25 | E-30-29 |
| HV 1541 | CF TK 2 $H_2O$ & $N_2$ FILL ISO VLV | SA 272L* | C | 2I 2F | | | 1 | 4 | E52B-29 A&B | E-30-25 | E-30-29 |
| HV DH9B | CTMT EMER SUMP VLV | SA 281A | C | 1X 1X | 4I | | 1 | 2 | E52B-19 A-C | E-30-16 | E-30-37 |
| | DELETED | | | | | | | | | | |
| | DELETED | | | | | | | | | | |
| | DELETED | | | | | | | | | | |
| | DELETED | | | | | | | | | | |
| | SPARE | SA 281F | | | | | 1 | 2 | | E-30-16 | E-30-37 |
| HV DH7B | BWST OUT VLV | SA 281G | O | 1X 1X | 4I | | 1 | 2 | E52B-19 A-C | E-30-16 | E-30-37 |
| HV 236 | N2 CTMT ISO VLV | SA 281H* | C | 2I 2F | | | 1 | 4 | E62B-5 | E-30-16 | E-30-37 |
| HV 229A | PRZR QNCH TK OUT ISO VLV | SA 281I* | C | 2I 2F | | | 1 | 4 | E52B-34 | E-30-16 | E-30-37 |
| | SPARE | SA 281J* | | | | | 1 | 4 | | E-30-16 | E-30-37 |
| | DELETED | | | | | | | | | | |
| | DELETED | | | | | | | | | | |
| | DELETED | | | | | | | | | | |
| | SPARE | SA 281N* | | | | | 1 | 4 | E30-16 | E-30-16 | E-30-37 |
| HV 232 | PRZR QNCH TK IN ISO VLV | SA 282A* | C | 2I 2F | | | 1 | 4 | E52B-36 | E-30-26 | E-30-30 |
| HV 229B | PRZR QNCH TK OUT ISO VLV | SA 282B* | C | 2I 2F | | | 1 | 4 | E52B-35 | E-30-26 | E-30-30 |
| | DELETED | | | | | | | | | | |
| HV 1545 | CF TK SAMPLE VLV | SA 282D* | C | 2I 2F | | | 1 | 4 | E52B-29 A&B | E-30-26 | E-30-30 |
| HV DH9A | CTMT EMER SUMP VLV | SA 282E | C | 1X 1X | 4I | | 1 | 2 | E52B-19 A-C | E-30-26 | E-30-30 |
| | DELETED | | | | | | | | | | |
| HV DH7A | BWST OUT VLV | SA 282G | O | 1X 1X | 4I | | 1 | 2 | E52B-19 A-C | E-30-26 | E-30-30 |
| HV 2011 | CTMT INSTR AIR ISO VLV | SA 282H* | C | 2I 2F | | | 1 | 4 | E62B-4 | E-30-26 | E-30-30 |
| HV 2010 | CTMT SERV AIR ISO VLV | SA 282I* | C | 2I 2F | | | 1 | 4 | E62B-4 | E-30-26 | E-30-30 |
| | SPARE | SA 282J* | | | | | 1 | 4 | | E-30-26 | E-30-30 |
| | DELETED | | | | | | | | | | |
| | SPARE | SA 282L | | | | | 1 | 2 | | E-30-26 | E-30-30 |
| HV 5090 | CTMT H2 DILUTION IN ISO VLV | SA 291A | C | 1X 1X | 4I | | 1 | 2 | E58B-5 A&B | E-30-16 | E-30-37 |
| | SPARE | SA 291B | | | | | 1 | 2 | | E-30-16 | E-30-37 |
| HV 6831A | RCP STDP DEMIN WTR ISO VLV | SA 291C* | C | 2I 2F | | | 1 | 4 | E49B-20 | E-30-16 | E-30-37 |
| | SPARE | SA 291D* | | | | | 1 | 4 | | E-30-16 | E-30-37 |
| HV 5038 | CTMT H2 DILUTN OUT ISO VLV | SA 291E | C | 1X 1X | 4I | | 1 | 2 | E58B-5 A&B | E-30-16 | E-30-37 |
| | SPARE | SA 291F | | | | | 1 | 2 | | E-30-16 | E-30-37 |
| | SPARE | SA 291G | | | | | 1 | 2 | | E-30-16 | E-30-37 |
| | SPARE | SA 292A | | | | | 1 | 2 | | E-30-26 | E-30-30 |
| HV 5065 | CTMT H2 DILUTION IN ISO VLV | SA 292B | C | 1X 1X | 4I | | 1 | 2 | E58B-5 A&B | E-30-26 | E-30-30 |
| HV 6831B | RCP STDP DEMIN WTR ISO VLV | SA 292C* | C | 2I 2F | | | 1 | 4 | E49B-19 A&B | E-30-26 | E-30-30 |
| | SPARE | SA 292D* | | | | | | 4 | | E-30-26 | E-30-30 |
| HV 5037 | CTMT H2 DILUTN OUT ISO VLV | SA 292E | C | 1X 1X | 4I | | 1 | 2 | E58B-5 A&B | E-30-26 | E-30-30 |

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E-17B SH. 4
FIGURE 7.3-6

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| ACTUATED EQUIPMENT TABULATION | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| EQUIPMENT ITEM NO. | EQUIPMENT DESCRIPTION | SA SIGNAL NO. | FUNCTION | SURVEILL MOD TYPE 1(2)/3(4) | SAM LOGIC MOD TYPE 1(2)/3(4) | PUMP JMPR MOD TYPE 1(2)/3(4) | SEQ. STEP | RC | SCHEME DWG. NO. | VDWG. NO. CH. 1(2) | VDWG. NO. CH. 3(4) |
| | SPARE | SA 292F | | | | | 1 | 2 | | E-30-26 | E-30-30 |
| | SPARE | SA 292G | | | | | 1 | 2 | | E-30-26 | E-30-30 |
| P 42-1 | DH PMP 1 | SA 311A* | ST | 3X 3X | | 5X 5X | 3 | 1 | E52B-6 A&B | E-30-14 | E-30-35 |
| | SPARE | SA 311B | | | | | 3 | 2 | | E-30-14 | E-30-35 |
| HV 1467 | CC FROM DH CLR 1 OUT VLV | SA 311C* | O | 2F 2I | | | 3 | 4 | E50B-11 | E-30-14 | E-30-35 |
| HV 2733 | DH PMP 1 SUCT VLV FROM BWST | SA 311D | O | 1X 1X | 4I | | 3 | 2 | E52B-23 A&B | E-30-14 | E-30-35 |
| HV DH14B | DH CLR 1 OUT VLV | SA 311E* | O | 2F 2I | | | 3 | 4 | E52B-25 A&B | E-30-14 | E-30-35 |
| HV DH13B | DH CLR 1 BYPASS VLV | SA 311F* | O | 2F 2I | | | 3 | 4 | E52B-25 A&B | E-30-14 | E-30-35 |
| P 42-2 | DH PMP 2 | SA 312A* | ST | 3X 3X | | 5X 5X | 3 | 1 | E52B-6 C&D | E-30-24 | E-30-28 |
| | SPARE | SA 312B | | | | | 3 | 2 | | E-30-24 | E-30-28 |
| HV 1469 | CC FROM DH CLR 2 OUT VLV | SA 312C* | O | 2F 2I | | | 3 | 4 | E50B-11 | E-30-24 | E-30-28 |
| HV 2734 | DH PMP 2 SUCT VLV FROM BWST | SA 312D | O | 1X 1X | 4I | | 3 | 2 | E52B-23 A&B | E-30-24 | E-30-28 |
| HV DH14A | DH CLR 2 OUT VLV | SA 312E* | O | 2F 2I | | | 3 | 4 | E52B-25 A&B | E-30-24 | E-30-28 |
| HV DH13A | DH CLR 2 BYPASS VLV | SA 312F* | O | 2F 2I | | | 3 | 4 | E52B-25 A&B | E-30-24 | E-30-28 |
| HV 1495 | CC AUX EQUIP IN VLV | SA 321A* | C | 2F 2I | | | 1 | 4 | E50B-15 A&B | E-30-15 | E-30-36 |
| | SPARE | SA 321B | | | | | 1 | 2 | | E-30-15 | E-30-36 |
| HV 1460 | CC VLV TO MAKE UP PUMP | SA 322A* | C | 2F 2I | | | 1 | 4 | E50B-12 A&B | E-30-25 | E-30-29 |
| | SPARE | SA 322B | | | | | 1 | 2 | | E-30-25 | E-30-29 |
| | SPARE | SA 331A | | | | | 1 | 2 | | E-30-15 | E-30-36 |
| | SPARE | SA 331B | | | | | 1 | 2 | | E-30-15 | E-30-36 |
| | SPARE | SA 331C* | | | | | 1 | 4 | | E-30-15 | E-30-36 |
| | SPARE | SA 331D* | | | | | 1 | 4 | | E-30-15 | E-30-36 |
| HV MU59A | RCP 2-1 SEAL RET VLV | SA 331E | C | 1X 1X | 4I | | 1 | 2 | E52B-30 A&B | E-30-16 | E-30-37 |
| HV MU59B | RCP 2-2 SEAL RET VLV | SA 331F | C | 1X 1X | 4I | | 1 | 2 | E52B-30 A&B | E-30-16 | E-30-37 |
| HV MU59C | RCP 1-1 SEAL RET VLV | SA 331G | C | 1X 1X | 4I | | 1 | 2 | E52B-30 A&B | E-30-16 | E-30-37 |
| HV MU59D | RCP 1-2 SEAL RET VLV | SA 331H | C | 1X 1X | 4I | | 1 | 2 | E52B-30 A&B | E-30-16 | E-30-37 |
| | SPARE | SA 331I* | | | | | 1 | 4 | | E-30-16 | E-30-37 |
| HV MU66B | RCP 2-2 SEAL IN ISO VLV | SA 331J* | C | 2I 2F | | | 1 | 4 | E52B-18 A&B | E-30-16 | E-30-37 |
| HV MU66C | RCP 1-1 SEAL IN ISO VLV | SA 331K* | C | 2I 2F | | | 1 | 4 | E52B-18 A&B | E-30-16 | E-30-37 |
| | SPARE | SA 332A | | | | | 1 | 2 | | E-30-25 | E-30-29 |
| | SPARE | SA 332B | | | | | 1 | 2 | | E-30-25 | E-30-29 |
| | SPARE | SA 332C* | | | | | 1 | 4 | | E-30-25 | E-30-29 |
| | SPARE | SA 332D* | | | | | 1 | 4 | | E-30-25 | E-30-29 |
| HV MU66A | RCP 2-1 SEAL IN ISO VLV | SA 332E* | C | 2I 2F | | | 1 | 4 | E52B-18 A&B | E-30-26 | E-30-30 |
| HV MU38 | RCP SEAL RET ISO VLV | SA 332F* | C | 2I 2F | | | 1 | 4 | E49B-19 A,B&C | E-30-26 | E-30-30 |
| HV MU66D | RCP 1-2 SEAL IN ISO VLV | SA 332G* | C | 2I 2F | | | 1 | 4 | E52B-18 A&B | E-30-26 | E-30-30 |
| P 56-1 | CS PMP 1 | SA 411A* | ST | 3X 3X | | 5X 5X | 5 | 1 | E52B-7 A&B | E-30-15 | E-30-36 |
| | SPARE | SA 411B | | | | | 5 | 2 | | E-30-15 | E-30-36 |
| P 56-2 | CS PMP 2 | SA 412A* | ST | 3X 3X | | 5X 5X | 5 | 1 | E52B-7 A&B | E-30-25 | E-30-29 |
| | SPARE | SA 412B | | | | | 5 | 2 | | E-30-25 | E-30-29 |

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E-17B SH. 5
FIGURE 7.3-7

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## ACTUATED EQUIPMENT TABULATION

| EQUIPMENT ITEM NO. | EQUIPMENT DESCRIPTION | SA SIGNAL NO. | FUNCTION | SURVEILL MOD TYPE 1(2)/3(4) | SAM LOGIC MOD TYPE 1(2)/3(4) | PUMP JMPR MOD TYPE 1(2)/3(4) | SEQ. STEP | RC | SCHEME DWG. NO. | VDWG. NO. CH. 1(2) | VDWG. NO. CH. 3(4) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| HV 1411A | CC IN ISO VLV TO CTMT | SA 421A | C | 1X 1X | 4I | | 1 | 2 | E50B-23 A&B | E-30-15 | E-30-36 |
| HV 1407A | CC OUT ISO VLV FROM CTMT | SA 421B | C | 1X 1X | 4I | | 1 | 2 | E50B-9 A&B | E-30-15 | E-30-36 |
| HV 1567A | CC IN ISO VLV TO CRD | SA 421C | C | 1X 1X | 4I | | 1 | 2 | E50B-7 A&B | E-30-15 | E-30-36 |
| HV 1328 | CC CRD BOOSTER PMP 1 SUCT VLV | SA 421D | C | 1X 1X | 4I | | 1 | 2 | E50B-8 A&B | E-30-15 | E-30-36 |
| | SPARE | SA 421E* | | | | | 1 | 4 | | E-30-15 | E-30-36 |
| HV 1411B | CC IN ISO VLV TO CTMT | SA 422A | C | 1X 1X | 4I | | 1 | 2 | E50B-24 A&B | E-30-25 | E-30-29 |
| HV 1407B | CC OUT ISO VLV FROM CTMT | SA 422B | C | 1X 1X | 4I | | 1 | 2 | E50B-10 A&B | E-30-25 | E-30-29 |
| HV 1567B | CC IN ISO VLV TO CRD | SA 422C | C | 1X 1X | 4I | | 1 | 2 | E50B-21 A&B | E-30-25 | E-30-29 |
| HV 1338 | CC CRD BOOSTER PMP 2 SUCT VLV | SA 422D | C | 1X 1X | 4I | | 1 | 2 | E50B-8 A&B | E-30-25 | E-30-29 |
| | SPARE | SA 422E* | | | | | 1 | 4 | | E-30-25 | E-30-29 |
| | SPARE | SA 431A* | | | | | 1 | 4 | | E-30-15 | E-30-36 |
| | SPARE | SA 431B | | | | | 1 | 2 | | E-30-15 | E-30-36 |
| | SPARE | SA 431C | | | | | 1 | 2 | | E-30-15 | E-30-36 |
| | SPARE | SA 431D | | | | | 1 | 2 | | E-30-15 | E-30-36 |
| | SPARE | SA 431E* | | | | | 1 | 4 | | E-30-15 | E-30-36 |
| | SPARE | SA 431F | | | | | 1 | 2 | | E-30-15 | E-30-36 |
| | SPARE | SA 432A* | | | | | 1 | 4 | | E-30-25 | E-30-29 |
| | SPARE | SA 432B | | | | | 1 | 2 | | E-30-25 | E-30-29 |
| | SPARE | SA 432C | | | | | 1 | 2 | | E-30-25 | E-30-29 |
| | SPARE | SA 432D | | | | | 1 | 2 | | E-30-25 | E-30-29 |
| | SPARE | SA 432E | | | | | 1 | 4 | | E-30-25 | E-30-29 |
| | SPARE | SA 432F | | | | | 1 | 2 | | E-30-25 | E-30-29 |
| HV DH9B | CTMT EMER SUMP VLV | SA 511A | A | 1X 1X | 4I | | 1 | 2 | E52B-19 A-C NOTE 4 | E-30-16 | E-30-37 |
| HV DH7B | BWST OUT VLV | SA 511B | A | 1X 1X | | | 1 | 2 | E52B-19 A-C NOTE 4 | E-30-16 | E-30-37 |
| | SPARE | SA 511C* | | | | | 1 | 4 | | E-30-16 | E-30-37 |
| | SPARE | SA 511D* | | | | | 1 | 4 | | E-30-16 | E-30-37 |
| HV DH9A | CTMT EMER SUMP VLV | SA 512A | A | 1X 1X | 4I | | 1 | 2 | E52B-19 A-C NOTE 4 | E-30-26 | E-30-30 |
| HV DH7A | BWST OUT VLV | SA 512B | A | 1X 1X | | | 1 | 2 | E52B-19 A-C NOTE 4 | E-30-26 | E-30-30 |
| | SPARE | SA 512C* | | | | | 1 | 4 | | E-30-26 | E-30-30 |
| | SPARE | SA 512D* | | | | | 1 | 4 | | E-30-26 | E-30-30 |

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E-17B SH. 6
FIGURE 7.3-8

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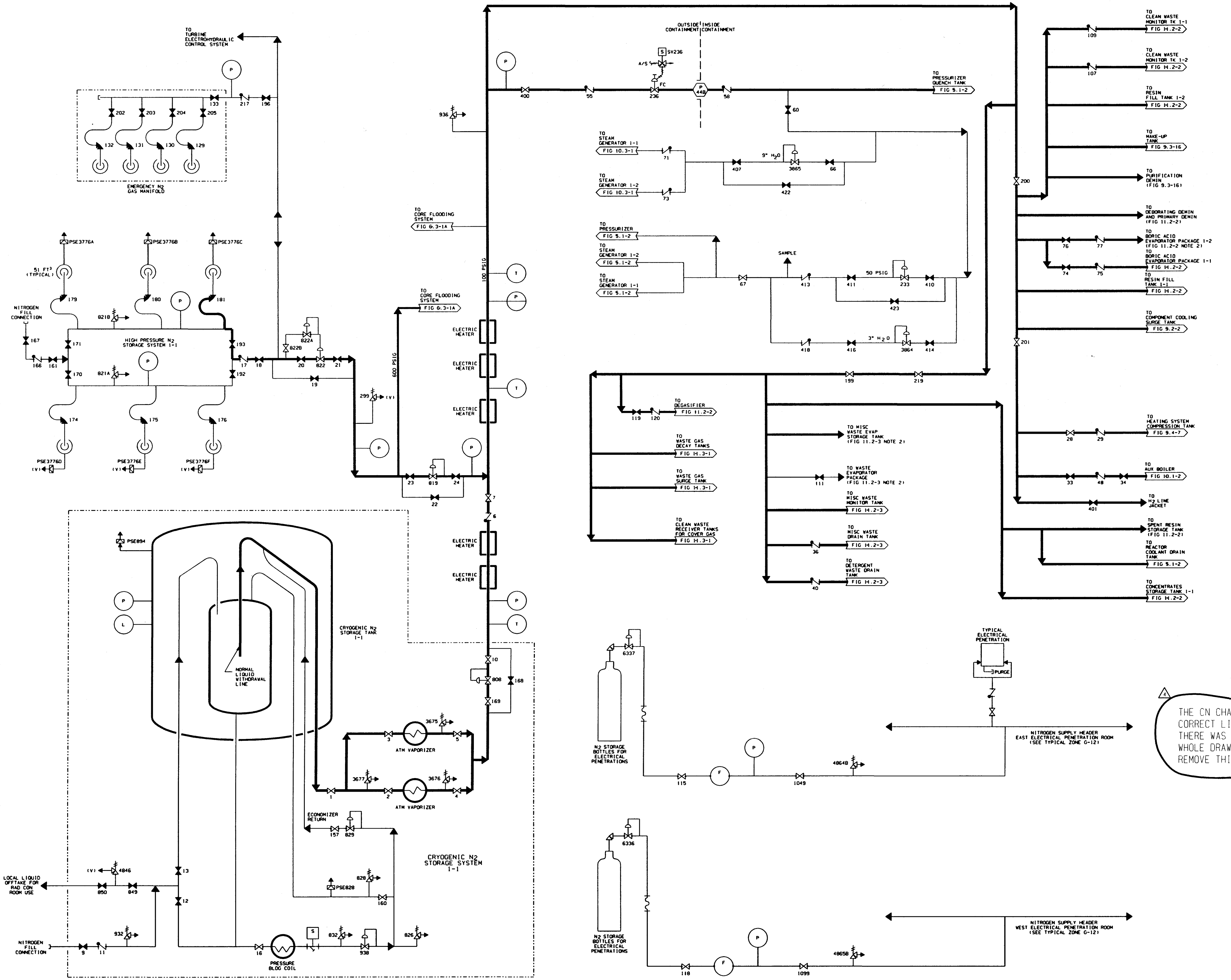



## NOTES

1. ALL VALVES ARE PREFIXED WITH "NN" UNLESS OTHERWISE NOTED.
2. FOR VALVES SHOWN ON THIS FIGURE, ACTUAL POSITIONS ARE CONTROLLED BY PLANT PROCEDURES.

THE CN CHANGE FOR THIS FIGURE WAS TO REPRINT IT TO SHOW CORRECT LINE WEIGHT AS REQUIRED BY DBBP-CM-1002, ATTACHMENT 11. THERE WAS NO PHYSICAL OR TECHNICAL CHANGES MADE. WHOLE DRAWING NOT CLOUDED FOR CLARITY. REMOVE THIS NOTE AT NEXT UPDATE.

| NO | DATE | REVISIONS | BY |
|---|---|---|---|
| 4 | | INC CN 14-245 | SBW |
| 3 | | INC LCN 02-0070 | INITIALS ON FILE |
| 2 | | INC LCN 94-047 | INITIALS ON FILE |
| 1 | | INC LCN 92-068 | INITIALS ON FILE |
| 0 | 6-29-90 | INFORMATION ONLY | INITIALS ON FILE |

SCALE NONE | DESIGNED ENG | DRAWN PAG | DATE 06-05-90

**DAVIS-BESSE NUCLEAR POWER STATION UNIT NO 1**
THE TOLEDO EDISON COMPANY

FUNCTIONAL DRAWING
NITROGEN SUPPLY SYSTEM

FIGURE NO: FIGURE 7.3-9 | REV: 4

REVISION 30
OCTOBER 2014

OS2-(75,27310SO49.DGN

DFN=/USAR/UFIG739.DGN
DB 10-01-14

# 7.4 SYSTEMS REQUIRED FOR SAFE SHUTDOWN

## 7.4.1 Description

The design of the systems required for safe shutdown is to provide for positive and safe reactor shutdown from all operating and transient load conditions without damage to the reactor. This is accomplished by a combination of automatic and manual systems. With regard to these systems, safe reactor shutdown is defined as that station condition in which the reactor is 1.0 percent subcritical and the reactor coolant system temperature and pressure are in the normal operating range.

### 7.4.1.1 Control Rod Drive Control System (CRDCS) - Trip Portion

#### 7.4.1.1.1 Design Bases

The design bases for the CRDCS trip circuits are listed below: (keyed to applicable parts of Section 3 of IEEE Standard 279-1968).

(3.1) The CRDCS is required to trip the shim-safety control rod drive mechanisms (CRDMs) whenever it receives an automatic trip command signal from the RPS or ARTS or a manual trip command signal from the operator.

(3.2) The CRDCS monitors the output voltage of the RPS network.

(3.6) The NI/RPS monitors primary plant parameters to operate the logic network. Refer to the Technical Specifications.

(3.7) The trip command does not require electrical power and is so arranged that the shim-safety CRDMS will trip upon loss of power. The CRDCS is designed to operate continuously at a temperature of 122°F (maximum) and a relative humidity of 80 percent (maximum).

(3.8) All CRDCS components influencing trip action are designed such that trip action is neither prevented nor delayed during or following a safe shutdown earthquake.

(3.9) The maximum allowable trip command time delay (difference between time power is interrupted to the CRDMS and time trip input is received from the RPS) within the CRDCS is 100 milliseconds.

#### 7.4.1.1.2 System Description

The control rods are inserted into the core upon receipt of the RPS, ARTS, DSS, or manual trip signals, which act to de-energize the CRDMs. This reactor shutdown feature (the trip portion) of the CRDCS is the only aspect of the CRDCS which affects public safety and as such it is designed to very exacting and restrictive criteria.

The function of the CRDCS trip devices, shown in Figure 7.4-1, is to interrupt power to the CRDMs.

The CRDCS trip logic is designed so that when power is removed from the control rod drive mechanism, the roller nuts disengage from the lead screw, and a free-fall gravity insertion of the

control rods occurs. Two diverse and independent trip methods, in series, are provided for removal of power to the mechanisms. First, a trip is initiated when power is interrupted to the undervoltage (UV) coils of the main AC feeder breakers and to the undervoltage relays in the shunt trip circuits. Second, a trip is initiated when the gating signals to the silicon controlled rectifiers (SCRs) are interrupted. Since parallel power feeds are provided, interruption of both feeds is required for trip action in either method of trip.

The trip circuits consists of four independent RPS trip channels (Channels 1, 2, 3 and 4), an ARTS trip signal, two manual reactor trip switches in series, and at least one trip actuation device for each channel. Each of the four RPS trip channels receives power from the RPS and is energized for the non-tripped (normal) condition. A channel is defined as tripped when it is de-energized. Two diverse and independent methods of CRDM power interruption are provided in order to ensure that trip will occur when commanded. These methods are in series within the system.

The primary method of trip interrupts the three-phase AC power to the CRDM motor power supplies. Three-pole, metal-clad power circuit breakers equipped with instantaneous undervoltage coils and shunt trip devices are used as primary trip devices. Because two parallel power circuits feed the CRDM motor power supplies, two AC trip breakers are provided in series in each feed. RPS Channel 2 energizes the undervoltage coil of breaker A and RPS Channel 4 energizes the undervoltage coil of breaker C to form the trip mechanism for the main bus. RPS Channel 1 energizes the undervoltage coil of breaker B and RPS Channel 3 energizes the undervoltage coil of breaker D to form the trip mechanism for the secondary bus. The trip breaker can remain closed only if its undervoltage coil is energized. Upon loss of voltage at the undervoltage coil due to interruption by an RPS, ARTS or manual trip signal, the breaker trips (opens). No external power is required to trip the breakers which have stored-energy trip mechanisms. The trip breakers must be manually reset once tripped. Breaker reset is possible only after the trip signal is reset to the untripped state. Each trip breaker’s shunt trip circuit operates as follows. An undervoltage (UV) relay is installed in parallel with the undervoltage coil of the trip breaker. Again, voltage interruption due to a trip signal deenergizes the UV relay causing it to energize the shunt trip device which is powered from essential 125 VDC, thereby tripping the breaker.

The second trip method interrupts the gate control signals to the SCRs in each of the sixty-one pairs of individual CRDM motor power supplies. The trip is provided by means of an electronic trip relay (K2) connected across the undervoltage device of trip breakers C and D. Loss of power to a K2 relay will cause a contact to open to notify the Control Rod Drive Control System (CRDCS) controller to degate the CRDM motor power supply SCRs through interrupting the gate control signals to the SCR’s in each CRD motor power supply. When the gate signals are interrupted, the SCR’s will revert to their open state on the next negative half-cycle of the applied AC voltage, thus removing all power at the outputs of the motor power supplies. Because the power supplies have redundant halves, two sets of SCRs for each CRDM motor power supply are provided. RPS channel 3 provides the trip signal for one set of SCRs through the K2 relay in trip breaker D and RPS Channel 4 provides the trip signal to the other set of SCRs through the K2 relay in trip breaker C. The K2 trip relays and the associated SCR gate trip signals can remain in their non-tripped state only if the associated RPS channel is energized. When an RPS channel trips, the associated trip relays de-energize, interrupting the SCR gate control signals through the CRDCS controller.

RPS Channel 3 acts as a functional back-up to Channel 1. RPS Channel 4 acts as a functional back-up to Channel 2. The trip relays must be manually reset once tripped. This reset is possible only if the RPS trip channels are in the reset mode.

No trip bypasses or interlocks are provided in the trip circuits.

7.4.1.1.3 Supporting Systems

The CRDCS circuits have the reactor protection system as the supporting system. The RPS provides the power to the four trip channels. Also, the essential 125VDC system is a supporting system, providing power to the shunt trip devices, and the essential 120VAC system powers the undervoltage coils and relays through the RPS system.

7.4.1.1.4 Portion of System Not Required for Safety

The remainder of the CRDCS is described in Section 7.7.

7.4.1.1.5 Comparison with SMUD Rancho Seco Station CRDCS Trip Circuits

CRDCS trip circuits at Davis-Besse are compared to SMUD Rancho Seco in FSAR Section 7.4.1.1.5.

7.4.1.1.6 Drawings

Refer to EI&C drawings.

7.4.1.2 Reactor Protection System (RPS)

The RPS monitors parameters related to safe operation and trips the reactor to protect the reactor core against damage. It also protects against Reactor Coolant System overpressure caused by energy input to the system by the reactor. A detailed description of the RPS is given in Section 7.2.

7.4.1.3 Steam and Feedwater Line Rupture Control System (SFRCS)

The design goal of the SFRCS is to mitigate release of high energy steam, to automatically start the Auxiliary Feedwater System in the event of a main steam line or main feedwater line rupture, to automatically start the Auxiliary Feedwater System on the loss of both main feed pumps (via the S/G low level or high FW/SG reverse differential pressure trips) or the loss of all four RC pumps, and to prevent steam generator overfill and subsequent spillover into the main steam lines. The SFRCS also provides a trip signal to the Anticipatory Reactor Trip System (ARTS), see Section 7.4.1.4.

7.4.1.3.1 System Description

The SFRCS is required to ensure an adequate feedwater supply to the NSSS steam generators to remove reactor decay heat during periods when the normal feedwater supply and/or the electric power supply to essential auxiliaries has been lost.

The “auto-essential” steam generator level control includes a dual setpoint. Following automatic actuation of auxiliary feedwater by the SFRCS, steam generator level will be controlled to the

minimum level required to maintain natural circulation if no SFAS Level 2 actuation (low RCS pressure or high reactor building pressure) occurs. For accident conditions where both auxiliary feedwater and SFAS Level 2 are automatically actuated, the auto-essential level control will maintain a minimum actual level of 120 inches above the lower tube sheet.

In the event of a main steam line rupture, the SFRCS will close both main steam isolation valves and all main feedwater control and stop valves and trip the main turbine. Initiation will occur no later than when the pressure in the main steam line drops to the steamline pressure-low setpoint. The Auxiliary Feedwater System (AFS) will also be initiated at this level, and both auxiliary feed pump turbines will be aligned with the unaffected steam generator. After automatic initiation of the auxiliary feed system, the operator may assume manual control. The manual control system is essential, and a manual speed control is provided for each turbine at the main control board and the auxiliary shutdown panel to control the auxiliary feedwater flow to each steam generator.

The auxiliary feed pump turbine steam inlet isolation valves are also containment isolation valves that can be remote manually closed when required by station conditions.

In the event of a main feedwater line rupture, the SFRCS will close both main steam isolation valves, close both main feedwater control and stop valves, trip the main turbine and initiate the auxiliary feedwater system when the pressure downstream of the last check valve in a main feedwater line to a steam generator exceeds upstream pressure by more than the SFRCS Main Feedwater/Steam Generator reverse differential pressure setpoint.

SFRCS trip setpoints are listed in the Technical Requirements Manual. Annunciator alarms audio and visual) are provided for the following SFRCS trip conditions:

1. Steam Generator Low Pressure

2. Steam Generator to Feedwater Differential Pressure and Steam Generator High Level

3. Loss of four Reactor Coolant Pumps and Steam Generator Low Level

A complete description of the Auxiliary Feedwater System is provided in Subsection 9.2.7.

#### 7.4.1.3.2 Initiating Circuits

The initiating circuits of the SFRCS are the sensing circuits monitoring the following station parameters. Required trip setting Allowable Values are listed in Technical Specifications.

1. Main steam line pressure

2. Main feedwater/steam generator reverse differential pressure

3. Steam generator level

4. RC pump monitor

#### 7.4.1.3.3 Logic

The logic channels of the SFRCS are made up of solid state components. Relays are used as output isolation and terminating devices of the SFRCS logic, as isolation devices for remote control pushbuttons, and as output signals to the station annunciator and computer.

The SFRCS, as shown in Figures 7.4-2 and 7.4-3, consists of two identical redundant and independent channels. Each channel consists of two AC supplied logic trains. The logic trains are identical and are maintained separate and independent within the channel cabinet. The sensor-to-cabinet cable runs are maintained separate by physical space or metallic conduit.

The logic for the SFRCS and the SFRCS actuated equipment is shown in Figures 7.4-2 through 7.4-6.

The SFRCS is a failsafe (de-energize-to-trip) system. Therefore, if power to a logic system is lost, that logic system will trip. The SFRCS and the SFRCS actuated equipment are designed to allow single failure without preventing the system from performing the required operation.

#### 7.4.1.3.4 Bypasses

The SFRCS includes channel bypasses and operating bypasses.

1. Channel bypass: The only bypasses provided are those on the Main Control Board (MCB) and Auxiliary Shutdown Panel (ASP) for the Auxiliary Feedwater System. The operation of these switches is under administrative control. The switch position of these bypasses are indicated on the MCB and/or ASP and alarmed in the control room.

2. Operating bypasses: Two out of two logic is provided to allow the operator to bypass each channel to prevent initiation under normal cool down when the main steam line pressure drops below the Technical Specification value.

The bypasses are automatically reset by a one out of two logic before the main steam line pressure exceeds the Technical Specification value.

#### 7.4.1.3.5 Interlocks

Fault current conditions on motor operated equipment will override the trip to the equipment.

Interlocks which inhibit protective actions are described below.

The SFRCS close signal to the following valves may be blocked to allow manual opening if an SFRCS actuation has closed them:

| | | |
|---|---|---|
| SP7A | Main Feedwater 2 | Start Up Control Valve |
| SP7B | Main Feedwater 1 | Start Up Control Valve |
| FW 601 | Main Feedwater 2 | Stop Valve |
| FW 612 | Main Feedwater 1 | Stop Valve |

This will allow feeding the steam generators with the start-up feed pump to remove core decay heat in the event both MFP's/MFPT's and AFPs/AFPTs are lost, providing additional diversity in cooling to the steam generators.

Also, the SFRCS close signal to the following valves may be blocked after an SFRCS actuation:

| | |
|---|---|
| PV-ICS11A | Atmospheric Vent Valve |
| PV-ICS11B | Atmospheric Vent Valve |

This will facilitate the control of steam generator pressure using the Atmospheric Vent Valves after an SFRCS actuation.

The SFRCS signal to the following valves may be blocked to allow repositioning of the valves if an SFRCS actuation has occurred:

| | |
|---|---|
| MS 106 | MS Line 1 to AFPT 1-1 Isolation Valve |
| MS 106A | MS Line 2 to AFPT 1-1 Isolation Valve |
| MS 107 | MS Line 2 to AFPT 1-2 Isolation Valve |
| MS 107A | MS Line 1 to AFPT 1-2 Isolation Valve |
| AF 3869 | Aux. Feed 1-1 to SG 1-2 Stop Valve |
| AF 3870 | Aux. Feed 1-1 to SG 1-1 Stop Valve |
| AF 3871 | Aux. Feed 1-2 to SG 1-1 Stop Valve |
| AF 3872 | Aux. Feed 1-2 to SG 1-2 Stop Valve |
| MS 603 | SG 2 Drain Line Isolation Valve |
| MS 611 | SG 1 Drain Line Isolation Valve |

This will allow the operator to reposition the valves as he deems necessary after automatic SFRCS actuation.

Low pressure switches are provided to close the steam supply isolation valves on low AFP suction pressure. See USAR section 9.2.7.3 for more details.

Low pressure switches in a 2 out of 2 (with one set of 2 required for actuation) logic are provided to close the steam supply isolation valves for each Auxiliary Feedpump Turbine.

The SFRCS has a built in block feature when the main steam line pressure drops below the low pressure block permissive value specified in the Technical Specifications to allow blocking the Steam Generator Low Pressure or High Level Trip Initiation during normal plant startup or shutdown. This block is automatically reset before the main steam line pressure exceeds the Technical Specification block reset value.

#### 7.4.1.3.6 Redundancy

The SFRCS redundancy is provided through independent logic and power circuits as described in Subsection 7.4.1.3.3 and shown on Figures 7.4-2 through 7.4-6.

#### 7.4.1.3.7 Diversity

Diversity in the SFRCS is provided by monitoring main steam line pressure, main feedwater/steam generator reverse differential pressure, main steam generator level to sense

main steam line or main feedwater line rupture and to provide steam generator isolation, main turbine trip, and Auxiliary Feedwater System initiation.

7.4.1.3.8 Supporting Systems

The supporting system of the SFRCS is the essential power supply (Chapter 8).

7.4.1.3.9 Non-Safety Systems

The non-safety systems and equipment utilized in the SFRCS system are listed below:

1. Station annunciator (Section 7.11).

2. Station computer (Section 7.10).

3. Startup and main feedwater control valves (used as backup protection to main feedwater stop valves).

4. Steam generator main feedwater isolation (block) valves.

5. Main turbine trip. (Section 10.2.3)

7.4.1.3.10 Design Bases

The design bases of the SFRCS (in accordance with IEEE Standard, 279-1971) are listed below.

1. Generating station conditions which require protective action:

   SFRCS initiation is required following -

   Low or high* level in either steam generator
   Main steam line rupture (low pressure)
   Main feedwater line rupture
   Loss of all four reactor coolant pumps

   *The high level trip is not required for mitigation of any Chapter 15 design basis accident analyses and should not be construed as a USAR/license requirement.

2. Generating station variables that are required to be monitored in order to provide protective action:

   Main steam pressure
   Steam generator level
   Differential pressure across the feedwater line
   check valve
   RC pump status

3. Minimum number and location of sensors required to monitor adequately, for protective function purposes, those variables that have spatial dependence:

   Main steam pressure -

      Four pressure switches located on each main steam line upstream of the main steam isolation valve.

   Steam generator level -

      Four level transmitters located on each steam generator.

   Differential pressure between main feedwater line and steam generator -

      Four differential pressure switches across each main feedwater line check valve downstream of the main feedwater control valve.

   RC pump status

   Pump current monitors on each motor circuit.

4. Prudent operational limits for each variable in each reactor operation mode:

   Main steam pressure -

      The normal operational limits of the pressure in each main steam line is controlled at 880 ± 10 psig, at the turbine header. During plant startup turbine header pressure is controlled at 870 ± 10 psig until sometime after 50% power turbine header pressure is increased to 880 psig.

   Steam generator level -

      The normal operational level in each steam generator ranges from the bottom of the operate range instrumentation (102 inches above the lower tube sheet) to the high level alarm which can be set as high as 96% on the operate range (the 96% elevation is 382 inches above the lower tube sheet).

   Differential pressure across the main feed line check valve -

      The normal operating value of differential pressure is zero psid under all reactor power conditions.

5. Margin between operational limit and level marking onset of unsafe conditions:

   Main steam pressure -

      With turbine header pressure maintained at approximately 880 psig, there is sufficient margin between normal operation and the specified SFRCS trip value.

Steam generator level -

The steam generators are operated at approximately 40” indicated SG startup level when on their low level limit. This is sufficiently above the approximately 23” indicated level (16.9” actual above top of lower tube sheet) required by Technical Specifications for a low level trip Allowable Value. These levels are based on operating conditions.

The replacement OTSG indicated level remains unchanged because the location of the level sensing connections remains unchanged, however the actual water level of above the top of lower tube sheet will increase because the replacement OTSG tubesheet is 1.8125” thinner than the original tubesheet.

For the replacement OTSG the maximum operational level in each steam generator is 96% on the operating level (approximately 383.8 inches above the lower tube sheet). A minimum of 60.3°F superheat ensures that the ROTSG will be operating in the acceptable range as shown on the Maximum Allowable Steam Generator Level curve in the Technical Specification when the operating level is 96%.

The high level SFRCS limit is analyzed in Calculation C-NSA-083.03-005. The high level trip is not expressed in units of inches above the lower tube sheet.

Differential pressure across the main feedwater line check valve -

The minimum operational differential pressure between each main feedwater line and its respective steam generator is zero psi. This differential pressure provides a margin between the minimum operational differential pressure and the differential pressure Allowable Value requiring protective action.

6. The levels, that when reached, will activate protective actions are tabulated in the Technical Specifications, except for high steam generator level, which is discussed in previous item number 5.

7. The range of transient and steady-state conditions of the energy supply and the environment during normal, abnormal, and accident circumstances throughout which the system must perform:

Power source requirements for the SFRCS for all conditions are as follows:
AC: 120 volts ± 10%, 60 Hz ± 3 Hz, grounded
DC: 125 volts (105 - 140 volts) ungrounded

The SFRCS equipment needed to mitigate an accident is qualified for the environment in which it is located, for the accidents the equipment is designed to mitigate, per the station’s environmental qualification program. Normal, abnormal/accident conditions are considered as part of this program. Peak room temperatures are listed in USAR Table 3.6-11. The environmental qualification program uses 100% relative humidity for high energy line break accidents.

8. Malfunctions, accidents, or other unusual events which could physically damage protection system components for which provisions must be incorporated to retain necessary protection system action:

   The SFRCS is designed to withstand physical damage or loss of function caused by earthquakes. The control system is also located in a building area designed to protect the equipment from flood, lightning, wind, and missiles.

9. The SFRCS is digital/analog, therefore, the system response time is virtually instantaneous except for steam generator level transmitters, which have a 1.6 $\pm$ 0.2 sec. response time and for the main feedwater/steam generator reverse differential pressure signals, which have 1/2 second time delay. The required response times for SFRCS components are contained in the Technical Requirements Manual.

7.4.1.3.11 Drawings

The following drawings are related to SFRCS equipment:

1. Functional drawings - Figure 10.3-1, 10.4-12, and 10.4-12A

2. Logic drawings - Figures 7.4-2 through 7.4-6.

3. Wiring diagrams - EI&C drawings (USAR Section 1.5.3.12)

7.4.1.4 Anticipatory Reactor Trip System (ARTS)

The purpose of the ARTS is to initiate a reactor trip when a sensed parameter exceeds its setpoint value, indicating the approach of an unsafe condition thereby reducing the magnitude of pressure and temperature transients on the Reactor Coolant System caused by loss of feedwater events or turbine generator trips.

The scope of the ARTS includes all electronic signal processing equipment and cabling from the system sensors to the RPS cabinets.

The following discussion is keyed to Section 3 of IEEE Standard 279-1971.

1. Generation station conditions which require protective action:

   (a) Turbine generator trip

   (b) Both Main Feedpump Turbines trip

2. Generating station variables that are required to be monitored in order to provide protective actions:

   (a) Turbine-Generator Status

   (b) Main Feedpump Turbine Status

3. Although these variables do not have spatial dependency, the number and location of sensors which are provided to monitor for protection function purposes:

   (a) Turbine Generator Status:

   Four pressure switches monitoring the hydraulic oil pressure at the fast acting solenoids for the turbine generator main stop valves.

   (b) Main Feedpump Turbine Status:

   Four pressure switches for each pump monitoring the oil pressure of the feedpump turbine high pressure stop valve.

4. Prudent operational limits for each variable during reactor operational mode:

   (a) Turbine Generator Status:

   Although the nominal system pressure in the hydraulic oil system is 1600 psig, the nominal minimum operational limit was historically determined to be the point at which the standby pump starts, 1300 psig. However, during testing of any one main stop valve, when pressure to the associated ARTS pressure switch goes to approximately 0 psig, low pressure transients could be detected by ARTS pressure switches on other ARTS channels (located on other main stop valves). These low pressure transients caused a trip of one

   of the other three ARTS channels. To preclude this, the nominal field settings were reduced to 275 psig and hydraulic snubbers were added to the pressure switch sensing lines. The actual minimum operational limits for each pressure switch during main stop valve testing were not determined.

   (b) Main Feedpump Status:

   Although the nominal system pressure in the control oil system is above 200 psig, the minimum operational limit was determined to be the nominal setpoint for the low pressure alarm, 130 psig.

5. The margin between operational limit and level marking onset of an unsafe condition:

   (a) Turbine Generator Status:

   Since the hydraulic oil pressure at the main stop valves quickly approaches 0 psig for a turbine trip, the pressure value marking onset to an unsafe condition is any value less than that normally expected during normal operation or testing. Based on this, and considering that the minimum operational limits were not determined, the margins between the operational limits and the levels marking onset of an unsafe condition cannot be determined. Lack of ARTS channel trips since the setpoints were lowered and the snubbers were installed supports the conclusion that sufficient margin exists to preclude inadvertent trips. Additionally, the 275 psig nominal

setpoint provides sufficient margin to ensure the pressure switches trip prior to the hydraulic oil pressure stabilizing at approximately 0 psig.

(b) Main Feedpump Turbine Status:

Since during normal operation the control oil pressure at the high pressure stop valves is above 130 psig, and this pressure quickly approaches 0 psig for a turbine trip, the pressure value marking onset to an unsafe condition is any value less than that normally expected during normal operation. Based on this, there is no margin between the minimum operational limit and the level marking onset to an unsafe condition. However, the 75 psig nominal setpoint provides sufficient margin to ensure the pressure switch trips prior to the control oil pressure stabilizing at approximately 0 psig.

6. The trip levels that, when reached, will produce protective actions:

(a) Turbine Generator Status:

The reactor will be automatically tripped when the Turbine Generator Stop Valve oil pressure decreases below the setpoint.

(b) Main Feedpump Status:

The reactor will be automatically tripped when the oil pressure of both Feedpump Turbine High Pressure Stop Valves decreases to 75 psig.

7. Range of transient and steady-state conditions of the energy supply and the environment during normal, abnormal, and accident circumstances throughout which the system must perform:

The ARTS cabinets are located in the main cabinet room. All other sensors are located in the turbine building where the environmental conditions are 40 to 100 percent humidity, atmospheric pressure and temperatures to 120°F.

8. Malfunctions, accidents or other unusual events which could physically damage protection components and for which design provisions must be incorporated to retain necessary protective action:

Except for the portion of the system located within the Turbine Building, the ARTS is designed to withstand physical damage or loss of function during and after an earthquake. The system is also located in a building area designed to protect the equipment from flood, lightning, wind, and missiles.

Pressure switches on main turbine generator and on main feed pumps conform to IEEE Standard 279-1971 and are environmentally qualified. However, seismic criteria is not included in qualification regarding mounting location for that portion of the trip system located within the nonseismic Category I Turbine Building.

9. For minimum performance requirements, including system response times, system accuracies, range of the magnitudes and a rate of change of the sensed variables to be accommodated until proper conclusion of the protection system action, refer to Toledo Edison Specification E-241Q (cabinets) and M-367Q (pressure switches).

7.4.1.4.1 System Description

7.4.1.4.1.1 System Logic

The ARTS contains four redundant and independent channels. The turbine trip input is automatically bypassed at 45% of rated thermal power or less. The other two inputs (MFPT and SFRCS) are active in Mode 1. One group of pressure switches will monitor the hydraulic oil pressure at the fast acting solenoids for the turbine generator main stop valves and will trip the reactor when the main turbine is tripped. Another group of pressure switches will monitor the oil pressure which is associated with the high pressure stop valves for both main feedwater pump turbines. When these sensors detect the loss of both main feedpumps, the reactor will be tripped. Associated with each of these main feedwater pump turbine oil pressure switches is a test toggle switch. The administratively controlled toggle switch simulates a trip condition to the logic when the respective main feedwater pump turbine is not tripped yet not providing flow to the steam generator, such as during plant startup. Four additional input signals from the SFRCS, providing a diverse means of tripping the reactor but not required by the Technical Specifications, will trip the reactor when the SFRCS is initiated, see Section 7.4.1.3.

Each group of four sensing channels is connected to two out of four logic gates by additional isolation devices. The output from these two out of four logic gates is applied to the associated undervoltage coils for the control rod drive trip breakers and to the undervoltage relays for the shunt trip circuits for trip breakers. The logic channels are made up of solid state components. Relays are used as output isolation and termination devices of the ARTS logic and as isolation devices for output signals to the station annunciator and computer.

The ARTS system is shown in Figure 7.4-8. The ARTS is a fail-safe, de-energize-to-trip system. Therefore, if the power supply is lost to a logic system, that logic system will trip. The ARTS actuating equipment is designed to allow single failure without preventing the system from performing the required operation.

7.4.1.4.1.2 Bypasses

Channel Bypass or Removal from operation - Each safety grade ARTS sensing and logic channel is provided with three test bypass switches. These switches enable the operator to change the two-out-of-four coincidence matrices into a two-out-of-three mode for a given variable. The channel bypass permits the testing, calibration, and maintenance of a particular generating station variable of a single channel during power operation. With the bypass in effect, the three remaining channels of that station variable provide the necessary protection.

Because only two channels of a variable need exceed the trip setpoint to cause a trip, a single failure will not prevent the station variable logic from fulfilling its protective function.

All four ARTS Main Feed Pump bypass switches are placed in the bypass position during plant shutdown to allow both Main Feed Pump Turbines to be tripped without tripping the reactor. Also, all four ARTS Main Feed Pump bypass switches are placed in the bypass position during

plant startup which allows ARTS channels to be reset and control rod drive breakers to be closed. During startup, the switches are returned to the normal position at two percent power after a Main Feed Pump Turbine is placed in service.

Operating Bypass - The operating bypass automatically blocks the Turbine-Generator Status input when the reactor power is at 45% power or less. The bypass is automatically removed when reactor power is above the blocking bistable setpoint. The reactor power signals originate from the Reactor Protection System.

BAW-1893, Basis for Raising Arming Threshold for Anticipatory Reactor Trip on Turbine Trip, (Reference 2) provided justification for establishing the 45% reactor power arming level based, in part, on available secondary steam relief capacity. Serial letter 1487 (Reference 3) addressed the acceptability of the 45% reactor power arming level with an available first-bank (1050 psig setpoint) Main Steam Safety Valve capacity of 20% of full power steam flow.

The ARTS Turbine Trip arming level of 45% is based on the following:

- Turbine Bypass Valves capacity of 25% of full power steam flow,
- First - bank (1050 psig setpoint) Main Steam Safety Valves capacity of 20% of full power steam flow, and
- A 5% reactor power reduction from the time at which the turbine trip occurs until the RPS high-pressure setpoint is reached.

7.4.1.4.1.3 Interlocks

An interlock is provided which prevents reset of the ARTS until the initiating signals of the station parameters are returned to normal.

7.4.1.4.1.4 Redundancy

ARTS redundancy is provided by four redundant and independent sensing, logic, and actuation channels as shown on Figure 7.4-8.

7.4.1.4.1.5 Diversity

Diversity for the ARTS system is provided by the use of signals from the Turbine-Generator, Feedpump Turbine, and Steam and Feedwater Line Rupture Control System.

7.4.1.4.1.6 Supporting Systems

The ARTS interfaces with RPS. Reference Figure 7.4-8.

An isolated reactor power output signal from the RPS is used to block the Turbine-Generator Trip input signal when reactor power is at 45% power or less. This signal is transmitted to an isolated bistable located in each of the four ARTS channels. The bistables reset automatically when the reactor power is above the blocking bistable setpoint.

The output from the ARTS is terminated in the RPS cabinet as part of the reactor trip circuit. The signals are isolated and independent. No single failure will create an adverse effect on plant safety. All interfaces between protection systems and the ARTS are isolated. The isolation devices are qualified to withstand any adverse condition which could degrade the

operation of the protection system. Also, SFRCS (subsection 7.4.1.3), Essential Power (Chapter 8) and CRDCS (Subsection 7.4.1.1) form a part of supporting system.

7.4.1.4.1.7 Non-Safety Systems

The non-safety systems and equipment utilized in ARTS system with no credit taken for operability, except item 3 and 4 are listed below:

1. Station Annunciator
2. Station Computer
3. Main Feedpump Turbine Stop Valves.
4. Main Turbine Stop Valves.

7.4.1.4.1.8 Design Bases

The design bases of the final ARTS in accordance with IEEE Standard 279-1971 are detailed in Subsection 7.4.1.4.2.

7.4.1.4.1.9 Setpoint Bases

Setpoint Bases for the ARTS are provided in subsection 7.4.1.4 paragraphs 4 and 5.

7.4.1.4.1.10 Drawings

Drawings depicting (ARTS) design are contained in Figure 7.4-8 and the EI&C drawings.

7.4.1.4.2 Compliance with IEEE Standard 279-1971

The following discussion is keyed to Section 4 of IEEE Standard 279-1971 and demonstrates compliance with the above mentioned Standard:

(4.1) General Functional Requirements - The Safety Grade ARTS will, with precision and reliability, automatically perform its protective function, whenever the station conditions monitored by the system reach a preset level, under the design condition listed in the discussion of Section 3 of IEEE Standard 279-1971.

(4.2) Single Failure Criterion - No single failure can prevent the system from performing its protective function.

(4.3) Quality of Components and Modules - The system consists of high quality components and modules with minimum maintenance requirements and low failure rates. Quality control procedures were used during fabrication and testing to verify compliance with requirements specified for the particular equipment.

(4.4) Equipment Qualification - Type test data is available to verify that the system equipment meets, on a continuing basis, the performance requirements.

(4.5) Channel Integrity - Each channel of the system is designed, manufactured, and located so that the channel integrity is maintained under the design conditions listed in the discussion of Section 3 of IEEE Standard 279-1971.

(4.6) Channel Independence - Each system channel is located in its own cabinet. The cabinets act as a barrier against fire and mechanical damage from external sources. The cabinets are in a room which offers environmental and missile protection.

(4.7) Control and Protection System Interaction

(a) Classification of Equipment - Equipment that is used for protection and control functions is classified as part of the protection system and meets the requirements of IEEE Standard 279-1971.

(b) Isolation Devices - Output signals from the system are through isolation devices which are classified as part of the system and meet all the requirements of IEEE Standard 279-1971.

(4.8) Derivation of System Inputs - The ARTS pressure switches monitoring the Turbine Generator Hydraulic Oil pressure and the Main Feedpump Turbine Control Oil pressures provide a direct means for sensing turbine trips. The isolated reactor power output signal from RPS provides a direct measurement of that parameter. The SFRCS status input provides a diverse means of tripping the reactor, but is not required within the ARTS for safe shutdown.

(4.9) Capability for Sensor Checks - Each ARTS pressure switch is provided with manual calibration capability as discussed in (4.10) and being located in the turbine building, is accessible during reactor operation.

(4.10) Capability for Test and Calibration

a. Manual testing capability is provided for each input signal to the system to simulate sensor operation.

b. Manual calibration capability is provided for pressure switches from the Turbine-Generator and Main Feedpump Turbines. These can be independently isolated and simulated process parameters applied to check calibration.

(4.11) Channel Bypass or Removal From Operation - The ARTS station variable channel bypass is described in Subsection 7.4.1.4.1.2 and 7.4.1.4.2 item (4.13).

(4.12) Operating Bypasses - The ARTS operating bypass is described in Subsection 7.4.1.4.1.2 and 7.4.1.4.2 item (4.13).

(4.13) Indication of Bypasses - Initiation of the channel bypass will be continuously indicated at the system cabinets, the station computer and the annunciator. Initiation of the operating bypass will be continuously indicated at the ARTS system cabinet, the station computer and the annunciator.

(4.14) Access to Means for Bypassing - The activation of the ARTS channel bypass is accomplished by using switches, which are under administrative control. To initiate a bypass, a corresponding cabinet door must be opened. The cabinet door keys are under administrative control.

(4.15) Multiple Setpoints - The ARTS does not use multiple setpoints for any station parameter.

(4.16) Completion of Protective Action Once it is Initiated - The reactor, once tripped by the system, cannot be restarted until the operator deliberately resets the individual cabinets and recloses the CRDM breakers when station parameters return to normal.

(4.17) Manual Initiation - Manual initiation of the system's protective actions is accomplished by means of the reactor trip buttons located on the main control board, as described in Subsection 7.2.2.1 Paragraph (4.17).

(4.18) Access to Setpoint Adjustments, Calibrations, and Test Points - Setpoint adjustment and calibration of the station parameter sensing switches are under administrative controls. Test points will be accessible only when the system cabinet doors are open. The door keys are under administrative control. Open doors will be alarmed by the station computer and annunciator.

(4.19) Identification of Protective Actions - Protective action will be initiated whenever the generating station parameters sensed exceed the setpoint. These parameters are alarmed on the station computer.

Each trip will also be indicated by the logic system in the system logic cabinets. Failures of 118 volt AC power sources are also monitored at the station computer and annunciator and indicated at the logic cabinets.

(4.20) Information Readout - Reactor power is the only ARTS associated generating station variable which as Control Room indication and it is described in Section 7.2, Reactor Protection System. Indications of the status of ARTS are discussed in item (4.19).

(4.21) System repair - The periodic testing can locate failure in a logic system. The modular design of the system will allow for quick repair of malfunctions.

(4.22) Identification - The identification of the equipment, including cabinets, trays and cables of the system redundant portions, is accomplished by color coding and numbering as described in Chapter 8.

#### 7.4.1.5 Steam Relief

Steam pressure control following a reactor trip is provided to prevent excessive cooling of the RC fluid by controlled steam release to the atmosphere. Steam relief is accomplished by the code safety valves on each main steam line. A description of the safety valves is given in Chapter 10.

#### 7.4.1.6 Auxiliary Shutdown Panel

##### 7.4.1.6.1 Hot Shutdown

If temporary evacuation of the control room is required due to some abnormal station condition, the operator can establish and maintain the station in a safe hot shutdown condition through the use of an Auxiliary Shutdown Panel located outside the control room. The following controls and instrumentation are provided on this panel to accomplish hot shutdown:

1. Pressurizer level indicators.
2. Pressurizer heater controls and control transfer switches (to or from the Main Control Boards).
3. RC pressure indicators.
4. RC temperature indicators.
5. Steam generator level indicators.
6. Main steam pressure indicators.
7. Auxiliary feed pump governor controls and control transfer switches (to or from the Main Control Boards).
8. Service water isolation valve switches and control transfer switches (to or from the Main Control Boards).

Two each of the above controls and instrumentation are provided and are identical and redundant to one another.

Procedures directing use of the Auxiliary Shutdown Panel and equipment outside the control room to establish and maintain hot shutdown conditions are provided in the station Abnormal Procedures.

##### 7.4.1.6.2 Cold Shutdown

Inasmuch as the station can be maintained in a safe hot shutdown condition from outside the control room until access to the control room is regained, the need for taking the station to a cold shutdown condition from outside the control room is not anticipated. However, the ability to bring the station to a cold shutdown condition from outside the control room exists with the present station design. Through local controls, all necessary functions can be performed outside the control room, and with proper manpower and coordination the station can be cooled down over an extended period of time. Such an action includes the formulation at that time of a procedure based on an assessment of the situation.

7.4.1.6.3 Design Bases

In accordance with Criterion 19, the capability of establishing a hot shutdown condition and maintaining the station in a safe status during the mode is considered an essential function. To ensure availability of the Auxiliary Shutdown Panel after control room evacuation, the following design features have been utilized:

a. The Auxiliary Shutdown Panel, including all instrumentation mounted on it, is designed to withstand any physical damage or loss of function caused by earthquakes.

b. The panel, including instrumentation, is designed to comply with the requirements of IEEE Standard 279-1971.

c. The operator is required only to trip the reactor prior to control room evacuation.

7.4.1.6.4 Drawing

The ASP location is shown on Figure 3.6-3 (panel C3630). Figure 7.4-9 is the layout drawing of the ASP. Figures 5.1-2, 10.3-1, and 10.4-12A are the functional drawings for the devices controlled by the ASP.

7.4.1.7 Surveillance

The instrumentation utilized to monitor the necessary station variables for the systems required for safe shutdown is discussed in Section 7.5.

7.4.2 Analysis

7.4.2.1 Control Rod Drive Control System (CRDCS) (Trip Portion)

7.4.2.1.1 Conformance to IEEE Standard 279-1971

The trip portion of the CRDCS complies with the following applicable portions of IEEE Standard 279-1971:

(4.2) Single Failure Criterion - Any single failure within the CRDCS will not prevent proper initiation at the system level.

(4.3) Quality of Components and Modules - Equipment manufacturers are required to use high quality components and modules in equipment construction. Quality control procedures, used during fabrication and testing, verify compliance with this requirement.

(4.4) Equipment Qualification - Type test data is available to verify that the CRDCS equipment meets the performance requirements necessary for achieving the required system response.

(4.6) Channel Independence - The essential controls for safe shutdown are packaged in two independent and physically separated channels to reduce the likelihood of

interactions between channels during maintenance operations or in the event of channel malfunction.

(4.7) System Interaction - There is no interaction between control systems and the CRDCS trip portion.

(4.9) Capability for Test and Calibration - Manual testing facilities have been built into the CRDCS Trip Channels for on-line testing in conjunction with the RPS. The test routines are designed to demonstrate, without interfering with normal reactor or plant operation, that the CRDCS Trip Channels can fulfill their required safety functions. All tests may be performed with the CRDCS on-line with no sacrifice of independence.

(4.16) Completion of Protective Action Once Initiated - Once initiated the full insertion of the shim safety control rods is only dependent upon gravity. Therefore, the action continues to completion after trip initiation. Return to operation requires subsequent deliberate operator action.

(4.17) Manual Initiation - Two manual trip switches in series are provided which are positioned upstream of the CRDCS. Depressing either switch interrupts power from all four RPS channels to the CRDCS. Since the operator manual trips are downstream of the RPS automatic trips, no failure of the automatic trips will inactivate the manual trips.

(4.18) Access to Setpoint Adjustments, Calibrations, and Test Points - Setpoint adjustments and test points are accessible and calibration is possible only when the Reactor Trip Breaker (RTB) cabinets are open. Access to the RTB cabinets is administratively controlled as a part of general station access control to the protected and vital areas as described in the security plan. Access to the RTB cabinets is also administratively controlled through compliance with station procedures.

(4.19) Identification of Protective Action - The plant annunciator indicates that an RPS channel has tripped sending a trip signal to the CRDCS and indicates that the CRDCS has tripped.

(4.20) Information Readouts - As a minimum, the following are indicated on the cabinet front panels:

1. Cabinet fan failure, where fans are used.

2. Trip state of CRD trip devices housed in the cabinets.

(4.21) System Repair - The CRDCS is designed to facilitate the recognition, location, replacement, repair, or adjustment of malfunctioning components.

(4.22) Identification - Refer to Subsection 8.3.1.2 for a discussion of identification of protection system components.

#### 7.4.2.1.2 Compliance with AEC General Design Criteria

Refer to Appendix 3D for criteria discussions.

#### 7.4.2.1.3 Compliance with AEC Safety Guides 22 and 29

Refer to Section 7.2.2.4 for discussion concerning compliance with Safety Guide 22. The trip portions of the CRDCS are seismically qualified to comply with Safety Guide 29.

### 7.4.2.2 Reactor Protection System (RPS)

The analysis of the RPS is described in detail in Section 7.2.

### 7.4.2.3 Steam and Feedwater Line Rupture Control System (SFRCS)

#### 7.4.2.3.1 Compliance with IEEE Standard 279-1971

The following discussions are keyed to Section 4 of IEEE Standard 279-1971 and demonstrate compliance with the above mentioned standard.

(4.1) General Functional Requirement - The SFRCS, with precision and reliability, automatically performs its protective function, whenever the station conditions monitored by the SFRCS reach a preset level, under the design conditions described in Subsection 7.4.1.3.10.

(4.2) Single Failure Criterion - No single failure prevents the SFRCS from performing its protective function.

(4.3) Quality of Components and Modules - The SFRCS consists of high quality components and modules with minimum maintenance requirements and low failure rates. Quality control procedures were used during fabrication and testing to verify compliance with the requirements specified for the particular equipment.

(4.4) Equipment Qualification - Type test data is available to verify that the SFRCS equipment meets, on a continuing basis, the performance requirements determined to be necessary for achieving the system requirements.

(4.5) Channel Integrity - Each SFRCS channel is designed, manufactured, and located so that channel integrity is maintained under the design conditions listed in Subsection 7.4.1.3.10.

(4.6) Channel Independence - Each SFRCS actuation channel is located in its own set of cabinets. The cabinets act as a barrier against fire and mechanical damage from external sources.

The cabinets are in a room which offers environmental and missile protection.

(4.7) Control and Protection System Interaction

a. Classification of Equipment - Equipment that is used for protection and control function is classified as part of the protection system and meets the requirements of IEEE Standard 279-1971.

b. Isolation Devices - No output signals from the SFRCS are used for controlling purposes.

c. Single Random Failure - A single random failure resulting in a control system action simultaneously causing a channel failure and a station condition requiring protective action is incredible.

d. Multiple Failures Resulting From a Credible Single Event - No control system action can result in a condition requiring protective action and can concurrently prevent the protective action of any SFRCS channel.

(4.8) Derivation of System Inputs - With the exception of the steam generator level transmitters, the SFRCS inputs are digital signals that are direct measures of the station parameters as listed in Subsection 7.4.1.3.2.

(4.9) Capability for Sensor Checks - Input sensor indicating lights are provided. Test pushbuttons for these input signals are also provided at the SFRCS cabinets. The four level transmitters are checked by monitoring the variable after it has been perturbed or by cross checking the same variable in different channels or other systems.

(4.10) Capability for Test and Calibration

a. Manual testing is provided for each input signal to the SFRCS to simulate sensor operation.

b. Manual calibration capability is provided by the level transmitter, the pressure switch differential pressure switch and the current transducer/dual alarm module. These can be independently isolated and simulated process parameters applied to check calibration.

(4.11) Channel Bypass or Removal From Operation - The SFRCS channel bypass is described in Subsection 7.4.1.3.4. Maintenance is permissible to each separate, independent logic system without necessity for bypasses. Removing one logic system will reduce the channel coincidence matrices from two-out-of-two logic to a one-out-of-one logic, or a half-trip state. For logic descriptions refer to Subsection 7.4.1.3.3.

(4.12) Operating Bypasses - The SFRCS operating bypasses are described in Subsection 7.4.1.3.4. Whenever the permissive conditions are not met, the bypasses will not be allowed or will be removed automatically. The bypass circuits used to prevent or achieve automatic removal of the bypasses are part of the protective system and are designed in accordance with IEEE Standard 279-1971.

(4.13) Indication of Bypasses - Initiation of the channel bypass will be continuously indicated at the MCB or the ASP. Initiation of the operating bypasses will be continuously indicated at the SFRCS logic cabinet, at the main control board, and by the station computer and annunciator.

(4.14) Access to Means for Bypassing - The channel and operating bypasses are under administrative control as described in Subsection 7.4.1.3.4.

A bypass capability is provided for normalizing all digital trip inputs into the SFRCS to facilitate testing. This switch bypass provision is to be used only in modes 4, 5, and 6 when the SFRCS is not required by tech specs, is alarmed when in bypass, and is administratively controlled by use of keyswitch.

(4.15) Multiple Setpoints - The SFRCS does not use multiple setpoints for any station parameters.

(4.16) Completion of Protective Action Once It Is Initiated - The actuated Class 1E equipment once initiated by the SFRCS will remain in the actuated state until deliberately and individually reset by operator action. Some of the equipment actuated by SFRCS will change to a different actuated state if a second, different SFRCS trip (SG low pressure) occurs.

(4.17) Manual Initiation - Manual initiation at system level is provided by two (2) trip switches for each channel, at the main control board. The function of these control switches are as follows:

1a. Initiate AFW from SFRCS actuation Channel 1 taking steam from SG 1 and providing flow to SG 1.

1b. Initiate AFW from SFRCS actuation Channel 2 taking steam from SG 2 and providing flow to SG 2.

2a. Provide AFW flow as described in 1a and, in addition, isolate SG 1.

2b. Provide AFW flow as described in 1b and, in addition, isolate SG 2.

(4.18) Access to Setpoint Adjustments, Calibrations, and Test Points - Set-point adjustment and calibration of the station parameter sensing switches are under administrative controls. The test points in the SFRCS cabinets are accessible only when the cabinet doors are open. The door keys are under administrative control. Open doors are alarmed by the station computer and annunciator. Access to sensing equipment (transmitters, switches, etc.) is administratively controlled as part of general station access control to the protected and vital areas, as described in the security plan. Access is also administratively controlled through compliance with station procedures.

(4.19) Identification of Protective Actions - Protective action will be initiated whenever the generating station parameters sensed exceed the setpoint. These parameters are alarmed on the station annunciator or the station computer. Each trip is also indicated by the logic system in the SFRCS logic cabinets.

Failures of power supplies are also monitored at the station computer and annunciator and indicated at the logic cabinets.

(4.20) Information readout - This is a digital system but analog signals provided from instrumentation outside of the SFRCS are displayed on the main control boards and the station computer. One SFRCS SG level transmitter from each SG provides level input to a level indicator on the main control board. Another transmitter from each SG, from diverse power sources, provides level input to the Post Accident Monitoring (PAM) Panel. Additionally all eight of the SFRCS steam generator level transmitters have level indication in the SFRCS cabinet.

(4.21) System Repair - The periodic testing can locate failure in a logic system. The modular design of the SFRCS allows for quick repair of malfunctions.

(4.22) Identification - The identification of the equipment, including cabinets, trays, and cables of the SFRCS redundant portions, is accomplished by color coding and numbering as described in Chapter 8.

7.4.2.3.2 Compliance with IEEE Standard 338-1971

The SFRCS includes provision to permit testing in accordance with Section 5 of IEEE Standard 338-1971. (Refer to item 4.10 of Subsection 7.4.2.3.1 and to Subsection 7.4.2.3.3).

7.4.2.3.3 Compliance with AEC Safety Guide 22

The SFRCS is designed to provide the greatest possible flexibility for periodic tests of the system during reactor operation. In general, the test of any protective action system, including the corresponding system logics, actuation devices, and actuated equipment, can be performed during reactor operation. A half-trip test of the logic and actuation devices is performed twice monthly (once from each logic channel). Actuated equipment tests are performed in accordance with the plant Technical Specifications.

When the actuation of the actuated equipment may damage station equipment or disrupt reactor operation, the tests are performed when the reactor is shutdown.

The following equipment is routinely tested ONLY when the reactor is shut down:

| Equipment Item No. | Equipment Description |
|---|---|
| MS 101 | Main steam line 1 isolation valve |
| FW 612 | Main feedwater 1 stop valve |
| MS 100 | Main steam line 2 isolation valve |
| FW 601 | Main feedwater 2 stop valve |
| SP6A | Main feedwater 2 control valve |
| SP6B | Main feedwater 1 control valve |
| FW 779 | SG #2 main feedwater isolation (block) valve |
| FW 780 | SG #1 main feedwater isolation (block) valve |
| SP 7A | Startup feedwater 2 control valve |
| SP 7B | Startup feedwater 1 control valve |
| ICS 11A | Atmospheric vent valve 2 |
| ICS 11B | Atmospheric vent valve 1 |
| MS 603 | SG #2 blowdown isolation valve |
| MS 611 | SG #1 blowdown isolation valve |

#### 7.4.2.4 Anticipatory Reactor Trip System (ARTS)

The analysis of ARTS is described in detail in Section 7.4.1.4.

#### 7.4.2.5 Auxiliary Shutdown Panel (ASP)

##### 7.4.2.5.1 Compliance with IEEE Standard 279-1971

The Auxiliary Shutdown Panel is designed to meet the intent of IEEE Standard 279-1971. The manual control circuits located on the panel are designed such that any single failure will not prevent proper protective action (maintaining safe hot shutdown) when required. This is accomplished by fully redundant manual controls for the systems required for safe shutdown utilizing separate essential power supplies. Indications provided meet IEEE Standard 279-1971 with the exception of Sections 4.1, 4.11 thru 4.17 and 4.19 which deal with automatic controls. To prevent interaction between the redundant systems, the manual control channels are wired independently and separated with no electrical connections between redundant manual control systems. Normal automatic control circuits and non-essential monitor circuits are electrically isolated from essential controls and indications to prevent jeopardizing the reliability of the systems required for safe shutdown.

##### 7.4.2.5.2 Compliance with AEC General Design Criteria

1. General Design Criterion 1

   The Auxiliary Shutdown Panel utilizes high quality components. Quality control procedures were used during fabrication and testing to verify compliance with the requirements specified.

2. General Design Criterion 2

   The Auxiliary Shutdown Panel is designed to withstand damage or loss of function from earthquakes and is located in a building designed to protect the system from wind, flood and lightning.

3. General Design Criterion 3

   The Auxiliary Shutdown Panel is designed and constructed of materials to prevent fire and resulting loss of function. A fire-stop seal of silicone rubber foam is provided at the interconnection of the two-panel Subsections where a common grounding bar is routed.

4. General Design Criterion 4

   The Auxiliary Shutdown Panel is designed and located to prohibit damage or loss of function from missiles. Loss of function due to missile damage to both redundant manual control systems is considered incredible.

5. General Design Criterion 13

   The Auxiliary Shutdown Panel is provided with adequate manual controls and indications of monitored station variables to provide positive safe hot shutdown of the RC system from outside the control room.

6. General Design Criterion 15

   The Auxiliary Shutdown Panel provides sufficient manual controls to maintain the station in a safe hot shutdown condition without exceeding the design limits of the RC system and components.

7. General Design Criterion 19

   Refer to the discussion in Appendix 3D.

8. General Design Criterion 21

   The ASP has been designed for high functional reliability and inservice testability commensurate with the safety functions to be performed. The redundancy and independence designed into the ASP are sufficient to ensure that no single failure results in loss of the protection function and that removal from service of any component or channel does not result in loss of the required minimum redundancy. The ASP has been designed to permit periodic testing of its functioning when the reactor is in operation, including the capability to detect any loss of redundancy that may have occurred.

9. General Design Criterion 22

   The ASP has been designed to ensure that the effects of natural phenomena and of normal operating, maintenance, testing, and postulated accident conditions do not result in loss of the protection function.

10. General Design Criterion 23

    This criterion is not applicable, per se, to the ASP but to the manual control systems located on this panel. See Subsection 7.4.2.5.1 for discussion of the criterion.

11. General Design Criterion 24

    The protection systems associated with the ASP have been separated from control systems to the extent that failure of any single control system component or channel, or failure or removal from service of any single protection system component or channel that is common to the control and protection systems, leaves intact a system satisfying all reliability, redundancy, and independence requirements of the protection system. Interconnection of the protection and control systems has been limited to ensure that safety is not significantly impaired.

7.4.2.5.3 Compliance with AEC Safety Guides

1. Safety Guide 22

   The ASP is designed to be tested periodically during station operation.

2. Safety Guide 29

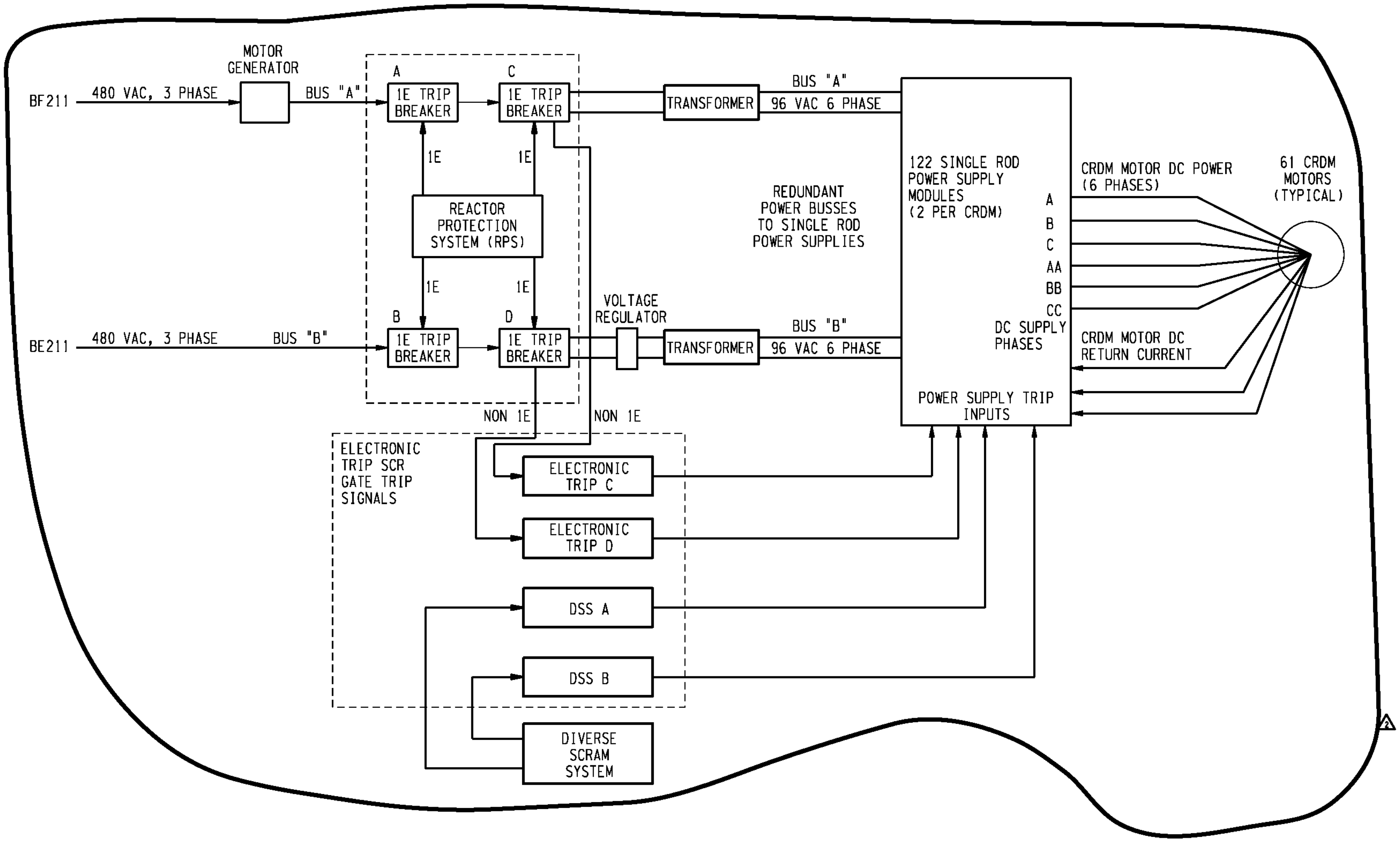
   The ASP is designed to withstand the effects of an earthquake without loss of function or physical damage. The ASP is classified Seismic Class I in accordance with the guide.

7.4.2.6 Station Load Rejection

An analysis of the station conditions following a load rejection is given in Chapter 15.

7.4.2.7 Turbine Trip

An analysis of the station conditions following a turbine trip is given in Chapter 15.

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DAVIS-BESSE NUCLEAR POWER STATION
UNIT NO 1
THE TOLEDO EDISON COMPANY

FUNCTIONAL DRAWING
CRDM REACTOR TRIP AND POWER SUPPLY CONFIGURATION

FIGURE NO: FIG. 7.4-1 | REV: 2

REVISION 31
OCTOBER 2016

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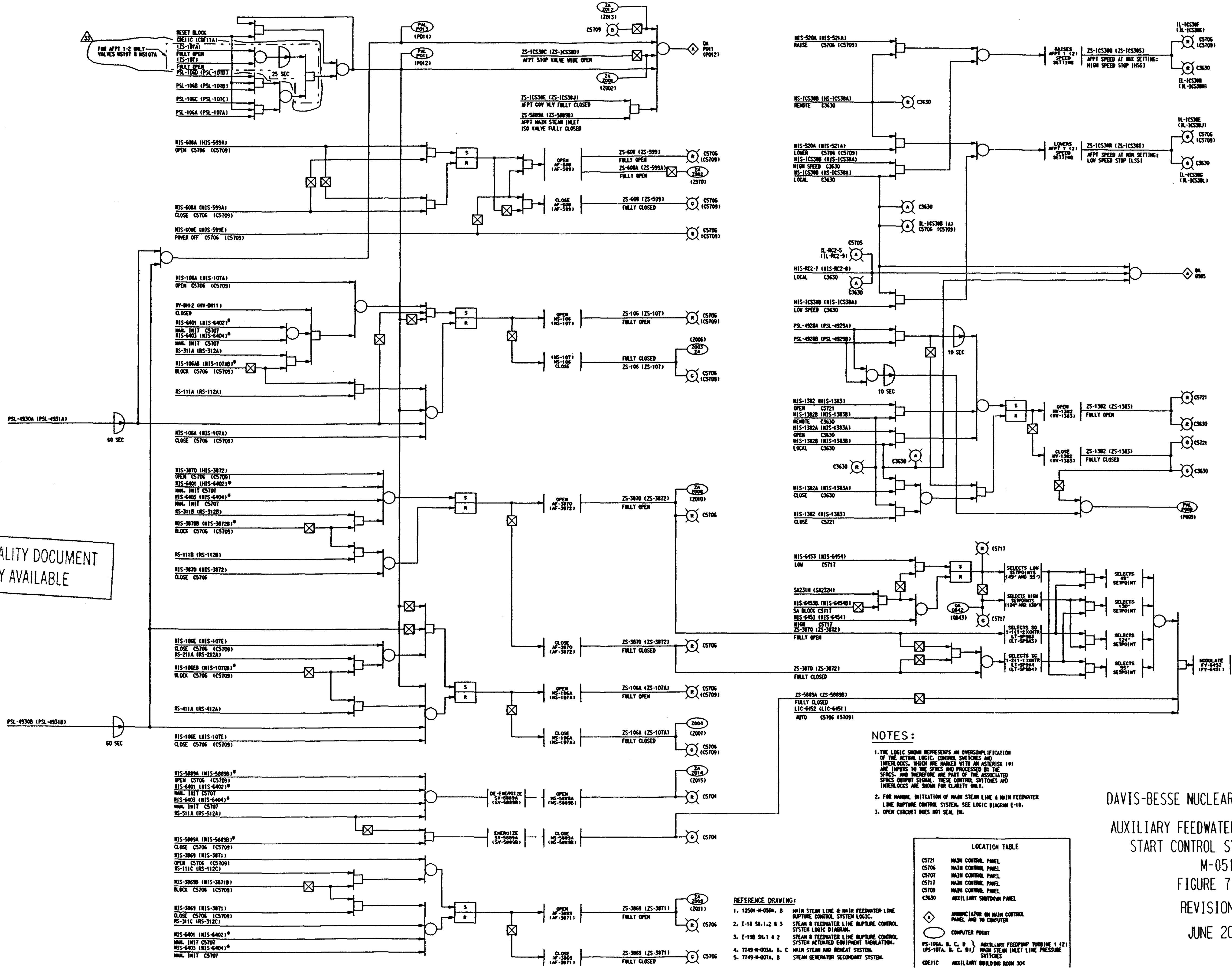

MARGINAL QUALITY DOCUMENT
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NOTES:

1. THE LOGIC SHOWN REPRESENTS AN OVERSIMPLIFICATION OF THE ACTUAL LOGIC. CONTROL SWITCHES AND INTERLOCKS, WHICH ARE MARKED WITH AN ASTERISK (*) ARE INPUTS TO THE SFRCS AND PROCESSED BY THE SFRCS, AND THEREFORE ARE PART OF THE ASSOCIATED SFRCS OUTPUT SIGNAL. THESE CONTROL SWITCHES AND INTERLOCKS ARE SHOWN FOR CLARITY ONLY.
2. FOR MANUAL INITIATION OF MAIN STEAM LINE & MAIN FEEDWATER LINE RUPTURE CONTROL SYSTEM, SEE LOGIC DIAGRAM E-18.
3. OPEN CIRCUIT DOES NOT SEAL IN.

REFERENCE DRAWING:

1. 12501-M-050A, B — MAIN STEAM LINE & MAIN FEEDWATER LINE RUPTURE CONTROL SYSTEM LOGIC.
2. E-18 SH.1,2 & 3 — STEAM & FEEDWATER LINE RUPTURE CONTROL SYSTEM LOGIC DIAGRAM.
3. E-19B SH.1 & 2 — STEAM & FEEDWATER LINE RUPTURE CONTROL SYSTEM ACTUATED EQUIPMENT TABULATION.
4. 7749-M-003A, B, C — MAIN STEAM AND REHEAT SYSTEM.
5. 7749-M-007A, B — STEAM GENERATOR SECONDARY SYSTEM.

LOCATION TABLE

| | |
|---|---|
| C5721 | MAIN CONTROL PANEL |
| C5706 | MAIN CONTROL PANEL |
| C5707 | MAIN CONTROL PANEL |
| C5717 | MAIN CONTROL PANEL |
| C5709 | MAIN CONTROL PANEL |
| C3630 | AUXILIARY SHUTDOWN PANEL |
| A (diamond) | ANNUNCIATOR ON MAIN CONTROL PANEL AND TO COMPUTER |
| (oval) | COMPUTER POINT |
| PS-106A, B, C, D (PS-107A, B, C, D) | AUXILIARY FEEDPUMP TURBINE 1 (2) MAIN STEAM INLET LINE PRESSURE SWITCHES |
| C0E11C | AUXILIARY BUILDING ROOM 304 |

DAVIS-BESSE NUCLEAR POWER STATION

AUXILIARY FEEDWATER PUMP TURBINE START CONTROL SYSTEM LOGIC

M-051

FIGURE 7.4-2

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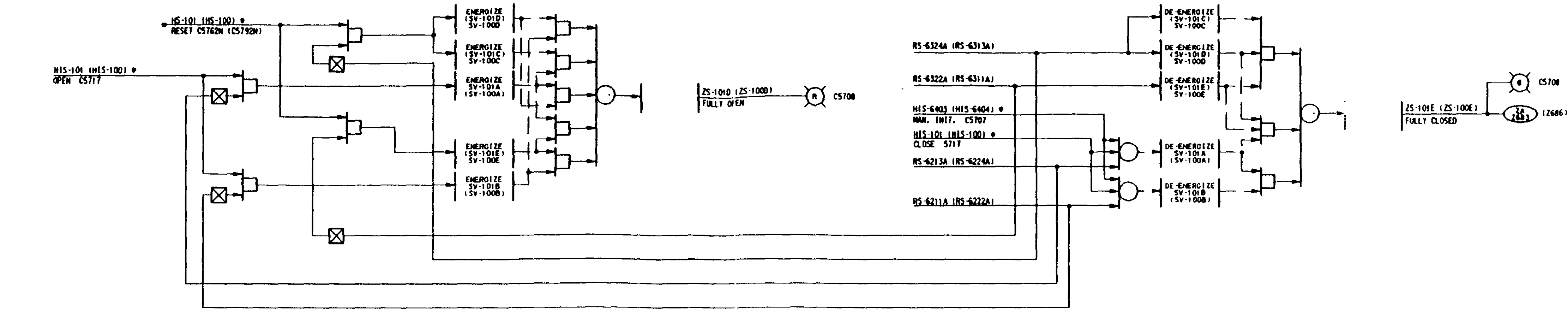
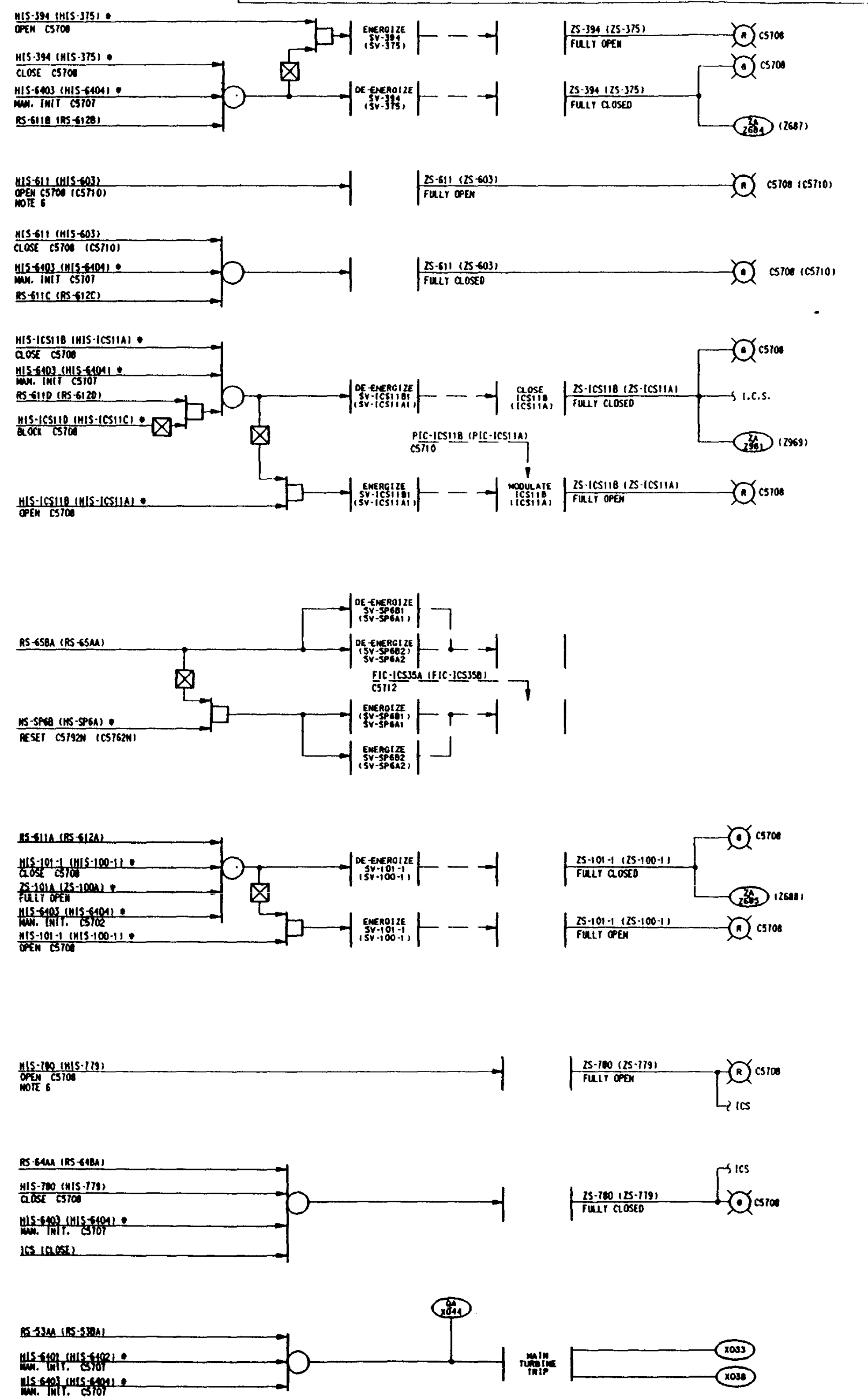
JUNE 2004

DB 03-30-04 DFM-1:/PIDS/M051





NOTES:

. FOR NOTES AND REFERENCE DRAWINGS SEE DWG. M-050B.

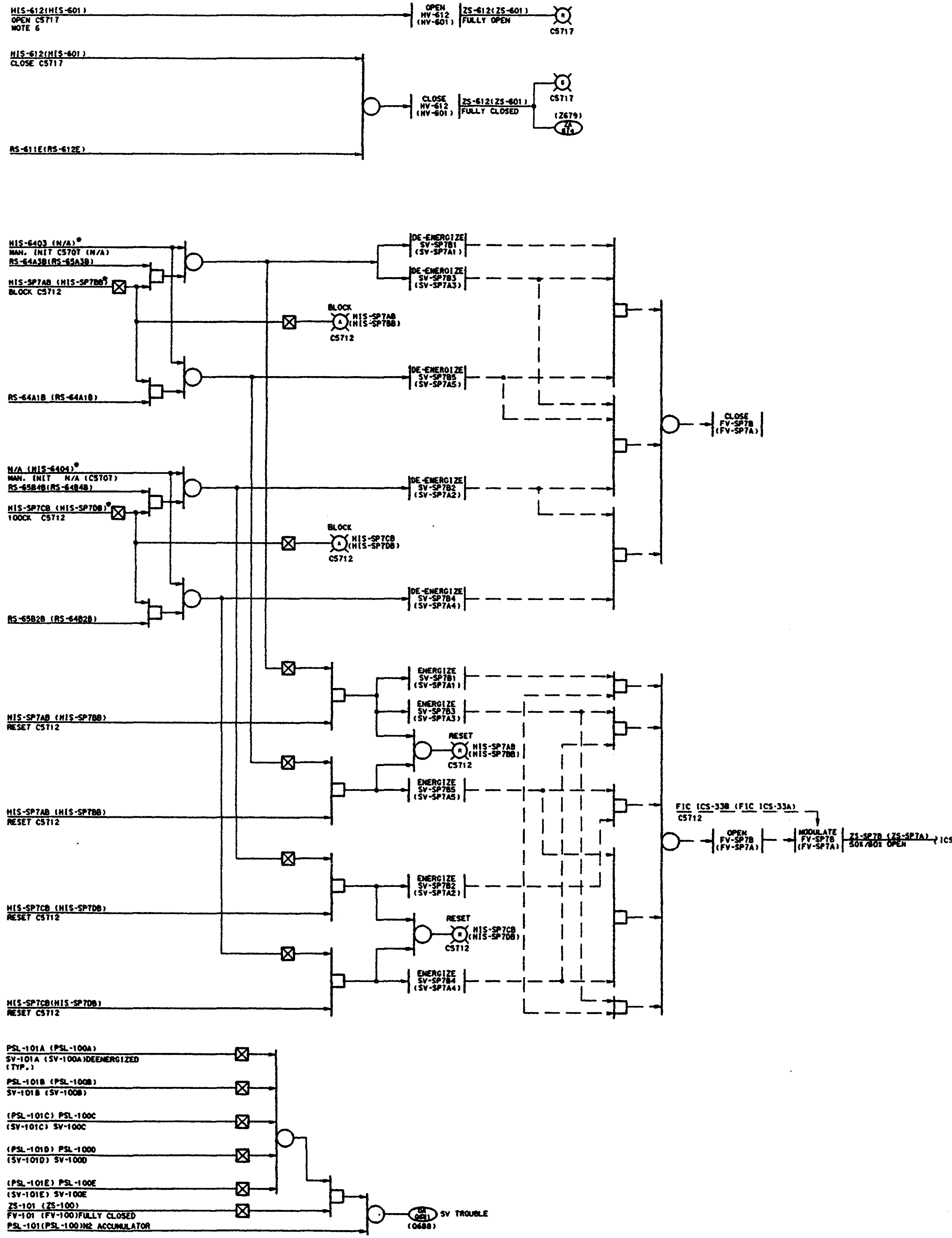
LOCATION TABLE

| | |
|---|---|
| NSY 100 | LOCAL CONTROL STATION |
| NSY 101 | LOCAL CONTROL STATION |
| NSY 100E | LOCAL CONTROL STATION |
| NSY 101E | LOCAL CONTROL STATION |
| C5707 | MAIN CONTROL PANEL |
| C5708 | MAIN CONTROL PANEL |
| C5710 | MAIN CONTROL PANEL |
| C5712 | MAIN CONTROL PANEL |
| ⬭ | COMPUTER POINT |

DAVIS-BESSE NUCLEAR POWER STATION

MAIN STEAM LINE AND MAIN FEEDWATER LINE
RUPTURE CONTROL SYSTEM LOGIC
M-050A
FIGURE 7.4-3

REVISION 22
NOVEMBER 2000




## NOTES:

1. THE LOGIC SHOWN REPRESENTS AN OVERSIMPLIFICATION OF THE ACUTAL LOGIC. CONTROL SWITCHES AND INTERLOCKS. WHICH ARE MARKED WITH AN ASTERISK (*) ARE INPUTS TO THE SFRCS AND PROCESSED BY THE SFRCS AND THEREFORE ARE PART OF THE ASSOCIATED SFRCS OUTPUT SIGNAL. THESE CONTROL SWITCHES AND INTERLOCKS ARE SHOWN FOR CLARITY ONLY.
2. PNEUMATIC LINES ARE INDICATED BY DASHED LINES(-----)AND ELECTRICAL LINES ARE INDICATED BY SOLID LINES (——).
3. FOR MANUAL INITIATION OF MAIN STEAM LINE & MAIN FEEDWATER LINE RUPTURE CONTROL SYSTEM, SEE LOGIC DIAG. E-18 SH.1-3.
4. SIGNALS SHOWN ARE ESSENTIAL ACTUATION CHANNELS 1(2) WHICH ARE COMPRISED OF LOGIC CHANNELS 1 & 3(2 & 4)AS DEFINED ON E-18 SH.1-3.
5. ANNUNCIATOR WINDOW 0963, SFRCS FULL TRIP, HAS A SEPARATE ACKNOWLEDGE BUTTON, HS-5891 LOCATED IN CONTROL ROOM CENTER CONSOLE C5709. SEE DRAWING E-428 SH. 54 FOR DETAILS.
6. DEPRESSING THE OPEN CONTROL SWITCH WILL OPEN THE VALVE EVEN WITH AN SFRCS SIGNAL TO CLOSE THE VALVE PRESENT. HOWEVER, THE VALVE WILL CYCLE CLOSED AFTER STROKING FULL OPEN IF THE SFRCS CLOSE SIGNAL STILL EXISTS.

## REFERENCE DRAWINGS:

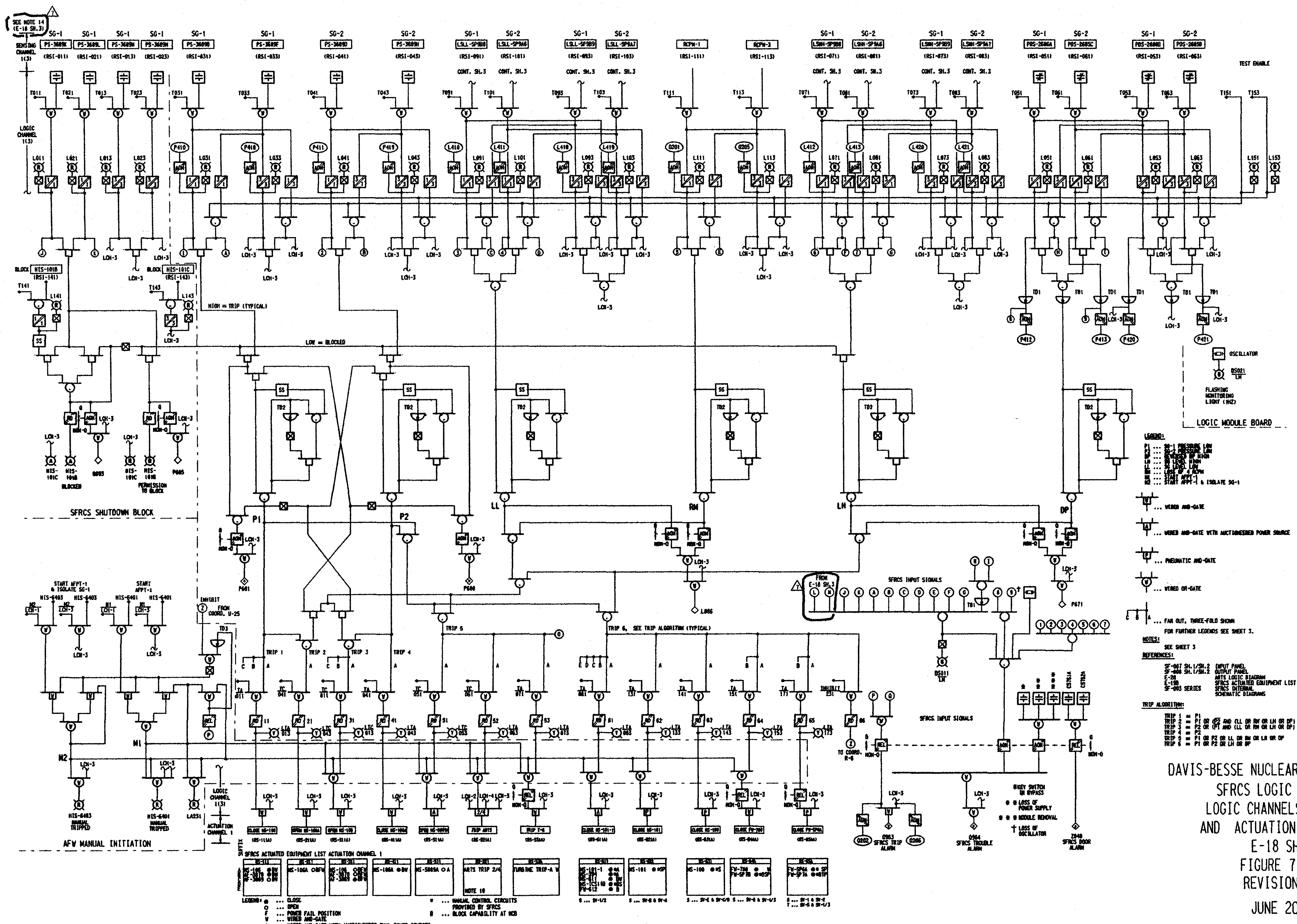
| | |
|---|---|
| 1. 7749-M-051 | AUXILIARY FEEDWATER PUMP TURBINE START CONTROL SYSTEM LOGIC. |
| 2. E-18 SH.1,2 & 3 | STEAM & FEEDWATER LINE RUPTURE CONTROL SYSTEM LOGIC DIAGRAM. |
| 3. E-19B SH.1 & 2 | STEAM & FEEDWATER LINE RUPTURE CONTROL SYSTEM ACTUATED EQUIPMENT TABULATION. |
| 4. 12501-M-003A,B,C | MAIN STEAM AND REHEAT SYSTEM. |
| 5. 7749-M-007A & B | STEAM GENERATOR SECONDARY SYSTEM. |
| 6. 12501-E-28 | ANTICIPATORY REACTOR TRIP SYSTEM LOGIC DIAGRAM |
| 7. 12501-M-050A | MAIN STEAM LINE & MAIN FEEDWATER LINE RUPTURE CONTROL SYSTEM LOGIC |



DAVIS-BESSE NUCLEAR POWER STATION

MAIN STEAM LINE AND MAIN FEEDWATER LINE RUPTURE CONTROL SYSTEM LOGIC
M-050B
FIGURE 7.4-3A

REVISION 21
NOVEMBER 1998




DAVIS-BESSE NUCLEAR POWER STATION

SFRCS LOGIC DIAGRAM

LOGIC CHANNELS 1 AND 3

AND ACTUATION CHANNEL 1

E-18 SH.1

FIGURE 7.4-4

REVISION 27

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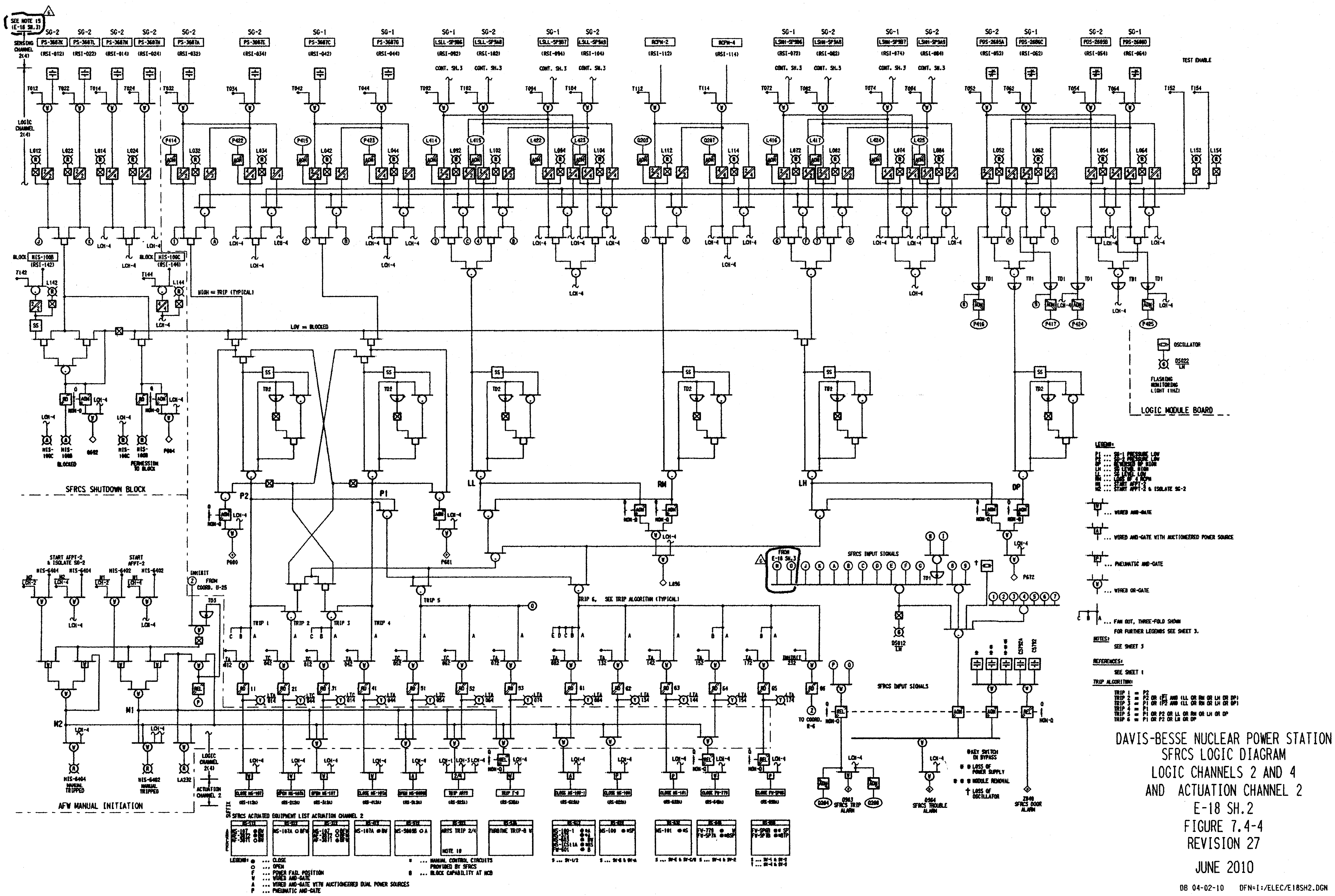
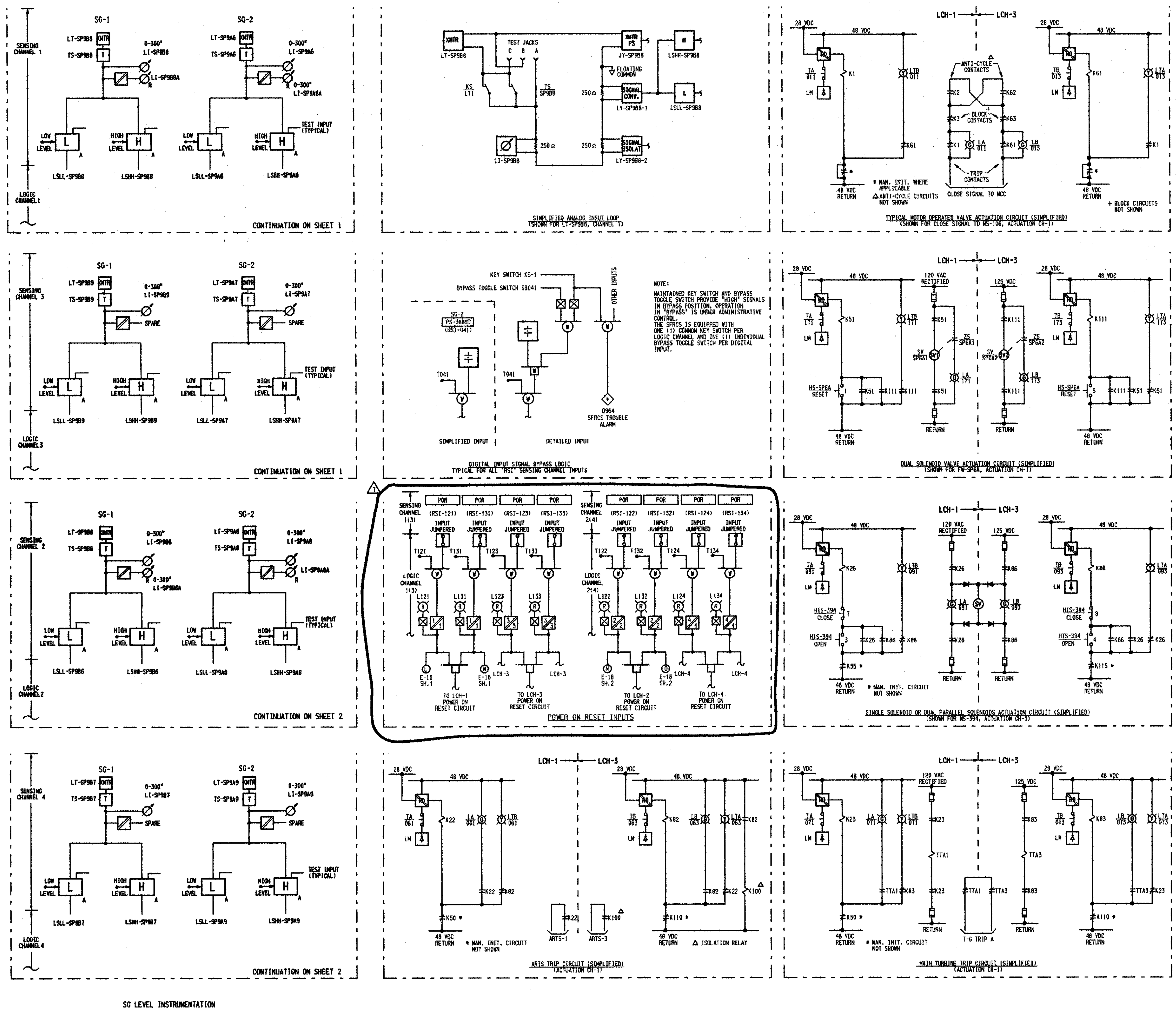
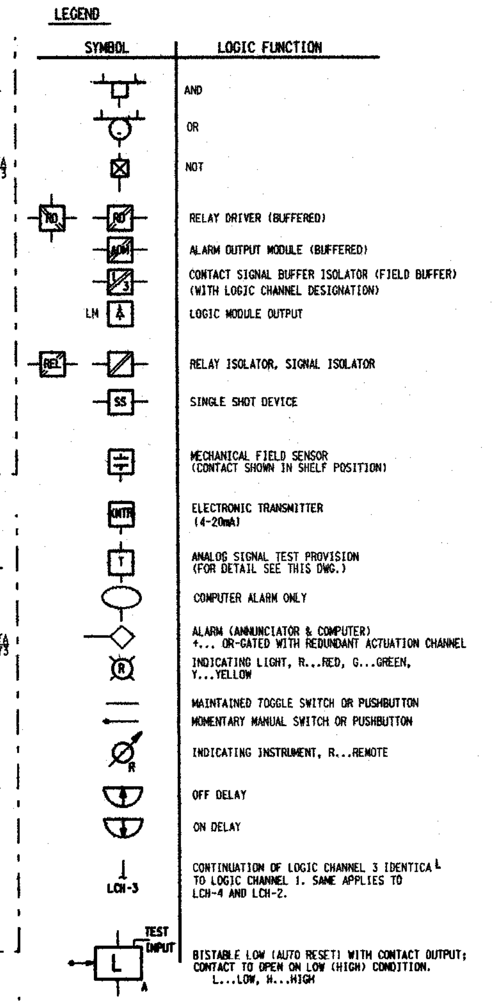
DB 04-02-10 DFN=I:/ELEC/E18SH1.DGN




DAVIS-BESSE NUCLEAR POWER STATION
SFRCS LOGIC DIAGRAM
LOGIC CHANNELS 2 AND 4
AND ACTUATION CHANNEL 2
E-18 SH.2
FIGURE 7.4-4
REVISION 27

JUNE 2010




NOTES:

1. THIS DRAWING IS PART OF THE TECHNICAL SPECIFICATION FOR STEAM AND FEEDWATER LINE RUPTURE CONTROL SYSTEM E-30AQ.
2. SHEET 1 OF THIS DRAWING INDICATES SFRCS ACTUATION CHANNEL 1, WITH LOGIC CHANNEL 1, AND LOGIC CHANNEL 3 SHOWN PARTIALLY.
3. SHEET 2 OF THIS DRAWING INDICATES SFRCS ACTUATION CHANNEL 2 LOGIC CHANNEL 2, AND LOGIC CHANNEL 4 SHOWN PARTIALLY.
4. SHEET 3 OF THIS DRAWING INDICATES THE SFRCS ANALOG CIRCUITS OF THE SG LEVEL INSTRUMENTATION AND BISTABLES FOR ALL FOUR LOGIC CHANNELS AND MISC. CIRCUITS.
5. THE SFRCS SHALL BE HOUSED IN 4 SEPARATE ESSENTIAL CABINETS. THE SFRCS CABINET LOCATIONS ARE:
   C5761A ... LOGIC CABINET, LOGIC CHANNEL 1 & 3
   C5762A ... TERMINATION CABINET, LOGIC CHANNEL 1 & 3
   C5792A ... LOGIC CABINET, LOGIC CHANNEL 2 & 4
   C5792 ... TERMINATION CABINET, LOGIC CHANNEL 2 & 4
   FOR MISC. NON-ESSENTIAL CIRCUITS,
   THE FOLLOWING NON-ESSENTIAL SFRCS INTERFACE CABINETS ARE PROVIDED:
   C5762Z ... CHANNEL A
   C5792Z ... CHANNEL B
6. THE LOGIC AND ALL OUTPUT TRIP RELAYS SHALL BE POWER FAIL-SAFE (DE-ENERGIZE TO TRIP).
7. ALARM CIRCUIT CONTACTS SHALL OPEN TO ALARM, WITH THE COIL CIRCUIT (IN GENERAL) DE-ENERGIZED TO ALARM.
8. THE INPUT SENSOR CONTACTS ARE CLOSED UNDER NORMAL (NO TRIP) OPERATING CONDITIONS.
9. ONE DOOR SWITCH ON EACH DOOR SHALL BE PROVIDED. WITH NORMALLY CLOSED CONTACTS (WHEN DOORS ARE CLOSED). CONTACT OPEN TO ALARM.
10. SFRCS OUTPUTS TO ARTS: LOGIC CHANNEL 1 THRU CHANNEL 4 ARE CONNECTED TO ARTS CHANNEL 1 THRU CHANNEL 4 RESPECTIVELY.
11. INPUT SIGNALS FROM MAIN FEEDWATER PRESSURE DIFFERENTIAL SWITCHES ARE TO BE TIME DELAYED BY TD1 BEFORE ACTUATING LOGIC. SEE NOTE 12 FOR SETTING.
12. MAXIMUM TIME DELAY SETTINGS ARE (NOTE: THESE VALUES ARE REFLECTIVE OF MAXIMUM PROCUREMENT SPECIFICATION VALUES. SEE NOTE 1):
   . TD1 ... 0.5 SECONDS ± 20%
   . TD2 ... 2.0 SECONDS ± 20%
   . TD3 ... 5.0 SECONDS ± 20%
13. THIS DRAWING IS INTENDED AS A SYSTEM LOGIC DIAGRAM AND DOES NOT REPRESENT ACTUAL WIRING CONFIGURATION.
7
14. FIELD BUFFER INPUTS 121,131,123 AND 133 ARE SHOWN ON DRAWING E-018 SHEET 3 (ZONES M-12 AND M-15).
15. FIELD BUFFER INPUTS 122,132,124 AND 134 ARE SHOWN ON DRAWING E-018 SHEET 3 (ZONES M-17 AND M-20).

REFERENCES:
SEE SHEET 1

DAVIS-BESSE NUCLEAR POWER STATION

SFRCS LOGIC DIAGRAM
MISCELLANEOUS CIRCUITS
E-18 SH.3
FIGURE 7.4-4
REVISION 27

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# SFRCS ACTUATED EQUIPMENT TABULATION

| EQUIPMENT ITEM NO. | P & ID NO. | OPERATIONAL SCHEMATIC | EQUIPMENT DESCRIPTION | SIGNAL NO. | ELEMENTARY DWG. NO. | SFRCS DWG. NO. | SFRCS FUNCTION | BLOCK SWITCH NO. | MANUAL INIT SWITCH NO. | REMARKS |
|---|---|---|---|---|---|---|---|---|---|---|
| SV-101A | M-003A | OS-008 SH.1 | MN. STM. LINE 1 ISO VALVE | RS-6213A | E-46B SH.1D | SF-003B SH.9 | DE-ENERGIZE | N/A | HIS-6403 | CLOSE MS-101 |
| SV-101B | M-003A | OS-008 SH.1 | MN. STM. LINE 1 ISO VALVE | RS-6211A | E-46B SH.1A | SF-003B SH.9 | DE-ENERGIZE | N/A | HIS-6403 | |
| SV-101C/D | M-003A | OS-008 SH.1 | MN. STM. LINE 1 ISO VALVE | RS-6324A | E-46B SH.1F | SF-003B SH.8 | DE-ENERGIZE | N/A | N/A | CLOSE MS-101 |
| SV-101E | M-003A | OS-008 SH.1 | MN. STM. LINE 1 ISO VALVE | RS-6322A | E-46B SH.1E | SF-003B SH.8 | DE-ENERGIZE | N/A | N/A | |
| SV-100A | M-003A | OS-008 SH.1 | MN. STM. LINE 2 ISO VALVE | RS-6224A | E-46B SH.1D | SF-003B SH.10 | DE-ENERGIZE | N/A | HIS-6404 | CLOSE MS-100 |
| SV-100B | M-003A | OS-008 SH.1 | MN. STM. LINE 2 ISO VALVE | RS-6322A | E-46B SH.1A | SF-003B SH.10 | DE-ENERGIZE | N/A | HIS-6404 | |
| SV-100C/D | M-003A | OS-008 SH.1 | MN. STM. LINE 2 ISO VALVE | RS-6313A | E-46B SH.1F | SF-003B SH.7 | DE-ENERGIZE | N/A | N/A | CLOSE MS-100 |
| SV-100E | M-003A | OS-008 SH.1 | MN. STM. LINE 2 ISO VALVE | RS-6311A | E-46B SH.1E | SF-003B SH.7 | DE-ENERGIZE | N/A | N/A | |
| MS-106 | M-003C | OS-017B | AFPT-1 MN. STM. 1 IN ISO VALVE | RS-111 A | E-46B SH.54A/B | SF-003B SH.13 | CLOSE | HIS-106AB | N/A | |
| MS-106 | M-003C | OS-017B | AFPT-1 MN. STM. 1 IN ISO VALVE | RS-311 A | E-46B SH.54A/B | SF-003B SH.13 | OPEN | HIS-106AB | HIS-6401/3 | |
| MS-107 | M-003C | OS-017B | AFPT-2 MN. STM. 2 IN ISO VALVE | RS-112 A | E-46B SH.4A/B | SF-003B SH.14 | CLOSE | HIS-107AB | N/A | |
| MS-107 | M-003C | OS-017B | AFPT-2 MN. STM. 2 IN ISO VALVE | RS-312 A | E-46B SH.4A/B | SF-003B SH.14 | OPEN | HIS-107AB | HIS-6402/4 | |
| AF-3870 | M-007B | OS-017A | AFPT-1 DISCH. TO SG-1 VALVE | RS-111 B | E-44B SH.20 | SF-003B SH.5 | CLOSE | HIS-3870B | N/A | |
| AF-3870 | M-007B | OS-017A | AFPT-1 DISCH. TO SG-1 VALVE | RS-311 B | E-44B SH.20 | SF-003B SH.5 | OPEN | HIS-3870B | HIS-6401/3 | |
| AF-3872 | M-007B | OS-017A | AFP-2 DISCH. TO SG-2 VALVE | RS-112 B | E-44B SH.15 | SF-003B SH.6 | CLOSE | HIS-3872B | N/A | |
| AF-3872 | M-007B | OS-017A | AFP-2 DISCH. TO SG-2 VALVE | RS-312 B | E-44B SH.15 | SF-003B SH.6 | OPEN | HIS-3872B | HIS-6402/4 | |
| AF-3869 | M-007B | OS-017A | AFP-1 DISCH. TO SG-2 VALVE | RS-311 C | E-44B SH.14A/B | SF-003B SH.3 | CLOSE | HIS-3869B | HIS-6401/3 | |
| AF-3869 | M-007B | OS-017A | AFP-1 DISCH. TO SG-2 VALVE | RS-111 C | E-44B SH.14A/B | SF-003B SH.3 | OPEN | HIS-3869B | N/A | |
| AF-3871 | M-007B | OS-017A | AFP-2 DISCH. TO SG-1 VALVE | RS-312 C | E-44B SH.14A/B | SF-003B SH.4 | CLOSE | HIS-3871B | HIS-6402/4 | |
| AF-3871 | M-007B | OS-017A | AFP-2 DISCH. TO SG-1 VALVE | RS-112 C | E-44B SH.14A/B | SF-003B SH.4 | OPEN | HIS-3871B | N/A | |
| SV-SP6A1 | M-007B | OS-012A SH.2 | MN. FW. 2 CTRL. VALVE | RS-65A1A | E-44B SH.9 | SF-003B SH.29 | DE-ENERGIZE | N/A | N/A | CLOSE FW-SP6A |
| SV-SP6A2 | M-007B | OS-012A SH.2 | MN. FW. 2 CTRL. VALVE | RS-65A3A | E-44B SH.9 | SF-003B SH.29 | DE-ENERGIZE | N/A | N/A | |
| SV-SP7A1/3 | M-007B | OS-012A SH.2 | MN. FW. 2 SU. CTRL. VALVE | RS-65A3B | E-44B SH.21B | SF-003B SH.31 | DE-ENERGIZE | HIS-SP7BB | N/A | CLOSE FW-SP7A |
| SV-SP7A5 | M-007B | OS-012A SH.2 | MN. FW. 2 SU. CTRL. VALVE | RS-65A1B | E-44B SH.21C | SF-003B SH.31 | DE-ENERGIZE | HIS-SP7BB | N/A | |
| SV-SP7A2 | M-007B | OS-012A SH.2 | MN. FW. 2 SU. CTRL. VALVE | RS-64B4B | E-44B SH.21A | SF-003B SH.34 | DE-ENERGIZE | HIS-SP7DB | HIS-6404 | CLOSE FW-SP7A |
| SV-SP7A4 | M-007B | OS-012A SH.2 | MN. FW. 2 SU. CTRL. VALVE | RS-64B2B | E-44B SH.21D | SF-003B SH.34 | DE-ENERGIZE | HIS-SP7DB | HIS-6404 | |
| FW-780 | M-007B | OS-012A SH.2 | SG-1 MN. FW. ISO. VALVE | RS-64A A | E-44B SH.5 | SF-003B SH.27 | CLOSE | N/A | HIS-6403 | |
| SV-101-1 | M-003A | OS-008 SH.1 | MN. STM. LINE 1 WU. ISO. VALVE | RS-611 A | E-46B SH.32A | SF-003B SH.11 | DE-ENERGIZE | N/A | HIS-6403 | CLOSE MS-101-1 |
| SV-ICS11B1/2 | M-007A | OS-008 SH.1 | SG-1 ATM. STM. VENT VALVE | RS-611 D | E-46B SH.78A/B | SF-003B SH.23 | DE-ENERGIZE | HIS-ICS11D | HIS-6403 | CLOSE ICS11B |
| SV-394 | M-003A | OS-008 SH.1 | MN. STM. LINE 1 WU. DRAIN ISO. VALVE | RS-611 B | E-46B SH.3 | SF-003B SH.17 | DE-ENERGIZE | N/A | HIS-6403 | CLOSE MS-394 |
| FW-612 | M-007B | OS-012A SH.2 | MN. FW. 1 STOP VALVE | RS-611 E | E-44B SH.4A/B | SF-003B SH.25 | CLOSE | HIS-612A | HIS-6403 | |
| MS-611 | M-007B | OS-008 SH.1 | SG-1 DRAIN VALVE | RS-611 C | E-46B SH.33/A | SF-003B SH.19 | CLOSE | HIS-611B | HIS-6403 | |
| SV-5889A | M-003C | OS-017B | AFPT-1 MN. STM. IN ISO. VALVE | RS-511 A | E-46B SH.71 | SF-003B SH.21 | DE-ENERGIZE | N/A | HIS-6401/3 | OPEN MS-5889A |

SFRCS OUTPUT TRIP SIGNAL DESCRIPTION

RS-4213C
- SIGNAL FAN-OUT LETTER (A-E)
- LOGIC CHANNEL (OMITTED IF COMBINED SIGNAL)(1-4)
- ACTUATION CHANNEL (1,2,A,B)
- TRIP CONDITION FAN-OUT (1-6)
- UNIQUE TRIP CONDITION (1-6)
- RUPTURE CONTROL SYSTEM TRIP OUTPUTS

REFERENCES:

| | |
|---|---|
| E-18 SH.1 | SFRCS LOGIC DIAGRAM - LOGIC CHANNELS 1 & 3 AND ACTUATION CHANNEL 1 |
| E-18 SH.2 | SFRCS LOGIC DIAGRAM - LOGIC CHANNELS 2 & 4 AND ACTUATION CHANNEL 2 |
| E-18 SH.3 | SFRCS LOGIC DIAGRAM - MISCELLANEOUS CIRCUITS |
| SF-003 SERIES | SFRCS INTERNAL SCHEMATIC DIAGRAMS |

DAVIS-BESSE NUCLEAR POWER STATION
SAFETY FEATURES ACTUATION SYSTEM
ACTUATED EQUIPMENT TABULATION
E-19B SH. 1
FIGURE 7.4-5

Q

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JUNE 2008

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# SFRCS ACTUATED EQUIPMENT TABULATION

| EQUIPMENT ITEM NO. | P & ID NO. | OPERATIONAL SCHEMATIC | EQUIPMENT DESCRIPTION | SIGNAL NO. | ELEMENTARY DWG. NO. | SFRCS DWG. NO. | SFRCS FUNCTION | BLOCK SWITCH NO. | MANUAL INIT SWITCH NO. | REMARKS |
|---|---|---|---|---|---|---|---|---|---|---|
| ARTS-1 | N/A | N/A | ANTICIPATORY REACTOR TRIP SYSTEM-1 | RS-5211A | E-65B SH.10 | SF-003B SH.35 | TRIP | N/A | HIS-6401/3 | TRIP REACTOR |
| ARTS-3 | N/A | N/A | ANTICIPATORY REACTOR TRIP SYSTEM-3 | RS-5213A | E-65B SH.10 | SF-003B SH.35 | TRIP | N/A | HIS-6401/3 | |
| SV-SP6B1 | M-007B | OS-012A SH.2 | MN. FW. 1 CTRL. VALVE | RS-65B2A | E-44B SH.9 | SF-003B SH.30 | DE-ENERGIZE | N/A | N/A | CLOSE FW-SP6B |
| SV-SP6B2 | M-007B | OS-012A SH.2 | MN. FW. 1 CTRL.VALVE | RS-65B4A | E-44B SH.9 | SF-003B SH.30 | DE-ENERGIZE | N/A | N/A | |
| SV-SP7B1/3 | M-007B | OS-012A SH.2 | MN. FW. 1 SU. CTRL. VALVE | RS-64A3B | E-44B SH.21B | SF-003B SH.33 | DE-ENERGIZE | HIS-SP7AB | HIS-6403 | CLOSE FW-SP7B |
| SV-SP7B5 | M-007B | OS-012A SH.2 | MN. FW. 1 SU. CTRL. VALVE | RS-64A1B | E-44B SH.21C | SF-003B SH.33 | DE-ENERGIZE | HIS-SP7AB | HIS-6403 | |
| SV-SP7B2 | M-007B | OS-012A SH.2 | MN. FW. 1 SU. CTRL. VALVE | RS-65B4B | E-44B SH.21A | SF-003B SH.32 | DE-ENERGIZE | HIS-SP7CB | N/A | CLOSE FW-SP7B |
| SV-SP7B4 | M-007B | OS-012A SH.2 | MN. FW. 1 SU. CTRL. VALVE | RS-65B2B | E-44B SH.21D | SF-003B SH.32 | DE-ENERGIZE | HIS-SP7CB | N/A | |
| FW-779 | M-007B | OS-012A SH.2 | SG-2 MN. FW. ISO. VALVE | RS-64B A | E-44B SH.5 | SF-003B SH.28 | CLOSE | N/A | HIS-6404 | |
| SV-100-1 | M-003A | OS-008 SH.1 | MN. STM. LINE 2 WU. ISO. VALVE | RS-612 A | E-46B SH.32A | SF-003B SH.12 | DE-ENERGIZE | N/A | HIS-6404 | CLOSE MS-100-1 |
| SV-ICS11A1/2 | M-007A | OS-008 SH.1 | SG-2 ATM. STM. VENT VALVE | RS-612 D | E-46B SH.79A/B | SF-003B SH.24 | DE-ENERGIZE | HIS-ICS11C | HIS-6404 | CLOSE ICS11A |
| SV-375 | M-003A | OS-008 SH.1 | MN. STM. LINE 2 WU. DRAIN ISO. VALVE | RS-612 B | E-46B SH.3 | SF-003B SH.18 | DE-ENERGIZE | N/A | HIS-6404 | CLOSE MS-375 |
| FW-601 | M-007B | OS-012A SH.2 | MN. FW. 2 STOP VALVE | RS-612 E | E-44B SH.4A/B | SF-003B SH.26 | CLOSE | HIS-601A | HIS-6404 | |
| MS-603 | M-007B | OS-008 SH.1 | SG-2 DRAIN STOP VALVE | RS-612 C | E-46B SH.33/A | SF-003B SH.20 | CLOSE | HIS-603B | HIS-6404 | |
| SV-5889B | M-003C | OS-017B | AFPT 2 MN. STM. IN. ISO VALVE | RS-512 A | E-46B SH.71 | SF-003B SH.22 | DE-ENERGIZE | N/A | HIS-6402/4 | OPEN MS-5889B |
| ARTS-2 | N/A | N/A | ANTICIPATORY REACTOR TRIP SYSTEM-2 | RS-5222A | E-65B SH.10 | SF-003B SH.36 | TRIP | N/A | HIS-6402/4 | TRIP REACTOR |
| ARTS-4 | N/A | N/A | ANTICIPATORY REACTOR TRIP SYSTEM-4 | RS-5224A | E-65B SH.10 | SF-003B SH.36 | TRIP | N/A | HIS-6402/4 | |
| MS-106A | M-003C | OS-017B | AFPT-1 MN. STM. 2 IN. ISO. VALVE | RS-211 A | E-46B SH.46A/B | SF-003B SH.15 | OPEN | HIS-106EB | N/A | |
| MS-106A | M-003C | OS-017B | AFPT-1 MN. STM. 2 IN. ISO. VALVE | RS-411 A | E-46B SH.46A/B | SF-003B SH.15 | CLOSE | HIS-106EB | N/A | |
| MS-107A | M-003C | OS-017B | AFPT-2 MN. STM. 1 IN. ISO. VALVE | RS-212 A | E-46B SH.46A/B | SF-003B SH.16 | OPEN | HIS-107EB | N/A | |
| MS-107A | M-003C | OS-017B | AFPT-2 MN. STM. 1 IN. ISO. VALVE | RS-412 A | E-46B SH.46A/B | SF-003B SH.16 | CLOSE | HIS-107EB | N/A | |
| TTA | N/A | N/A | TURBINE TRIP-A | RS-53A A | E-42B SH.53 | SF-003B SH.37 | TRIP | N/A | HIS-6401/3 | TRIP TURBINE |
| TTB | N/A | N/A | TURBINE TRIP-B | RS-53B A | E-42B SH.53 | SF-003B SH.38 | TRIP | N/A | HIS-6402/4 | TRIP TURBINE |

**SFRCS OUTPUT TRIP SIGNAL DESCRIPTION**

RS-4213C
- SIGNAL FAN-OUT LETTER (A-E)
- LOGIC CHANNEL (OMITTED IF COMBINED SIGNAL)(1-4)
- ACTUATION CHANNEL (1,2,A,B)
- TRIP CONDITION FAN-OUT (1-6)
- UNIQUE TRIP CONDITION (1-6)
- RUPTURE CONTROL SYSTEM TRIP OUTPUTS

**REFERENCES:**

SEE E-19B SH.1

DAVIS-BESSE NUCLEAR POWER STATION

SFRCS - ACTUATED EQUIPMENT TABULATION

E19B SH. 2

FIGURE 7.4-6

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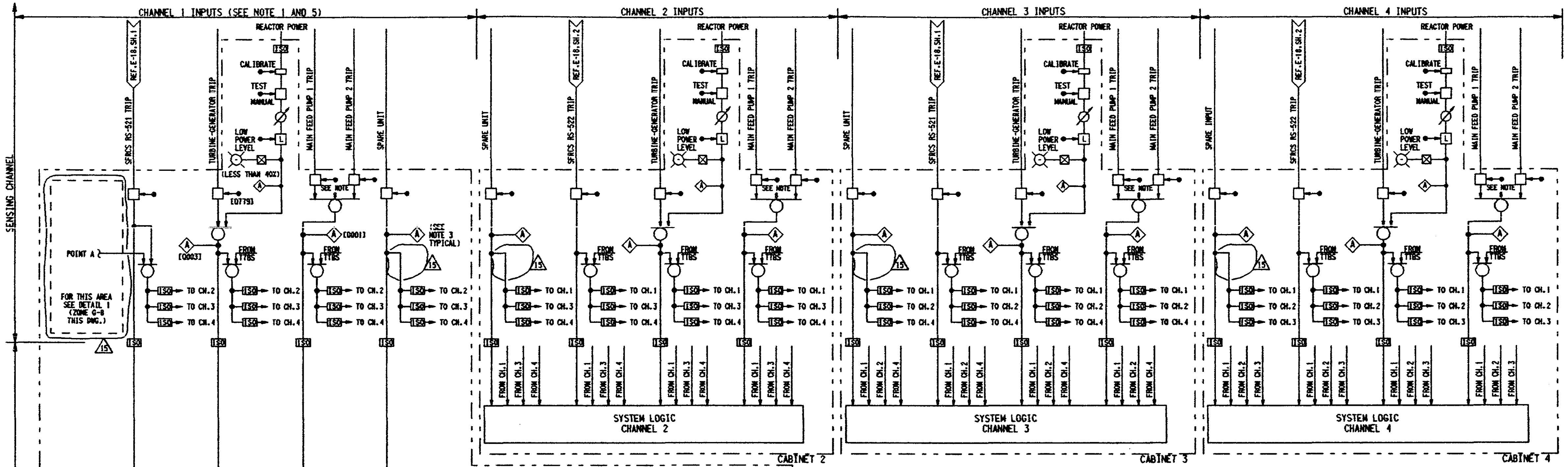
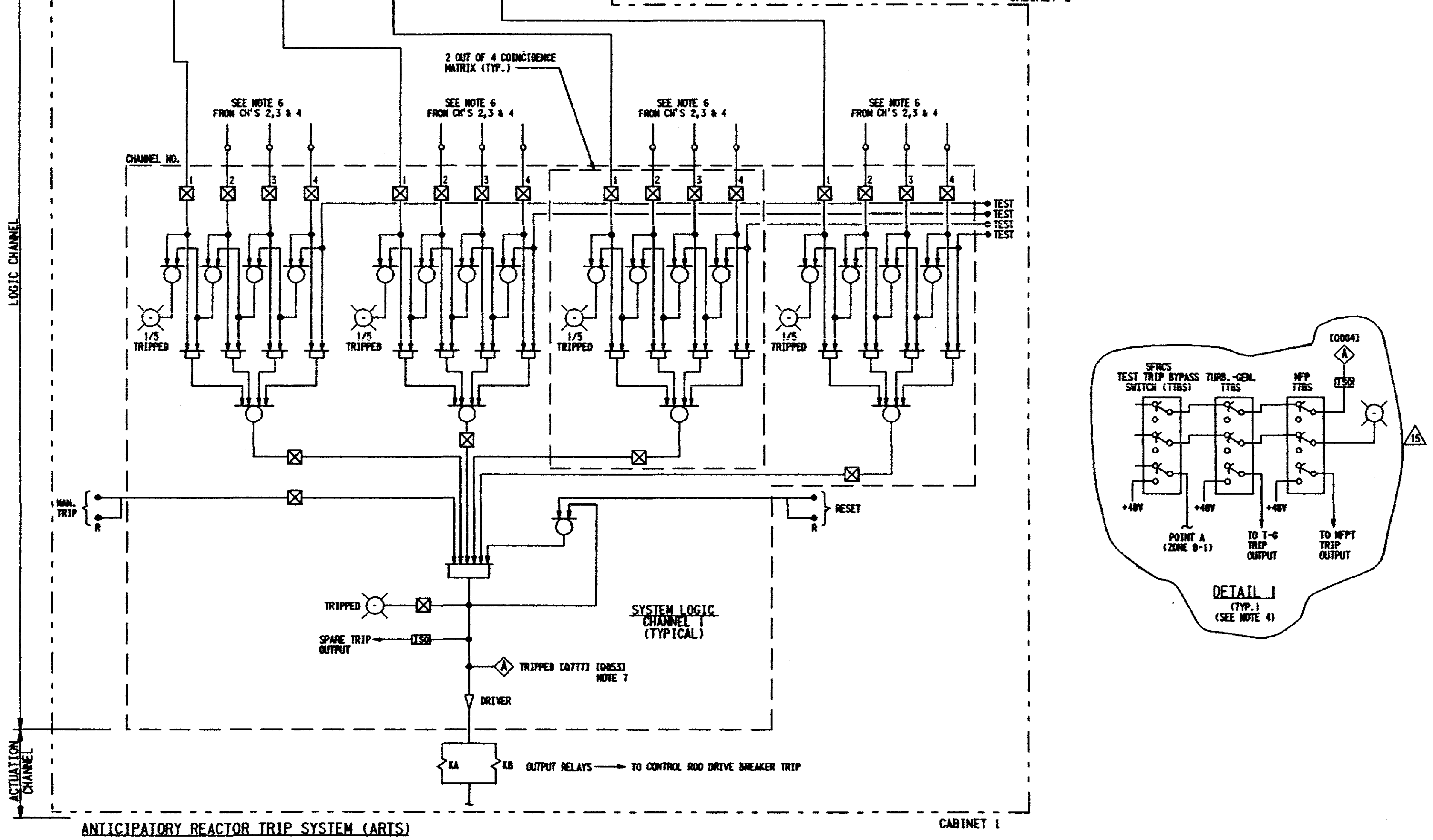
JULY 1990




## ANTICIPATORY REACTOR TRIP SYSTEM (ARTS)

### 1. DESIGN CRITERIA

A. THE DESIGN AND OPERATION OF THE "ARTS" WILL NOT DEGRADE THE RELIABILITY OF THE RPS OR SFRCS.

B. SEPARATION SHALL BE MAINTAINED BETWEEN REDUNDANT 1E CHANNELS AND BETWEEN 1E AND NON 1E CHANNELS. SEPARATION CRITERIA SHALL MEET THE REQUIREMENTS OF IEEE 279-1971 EXCEPT FOR THE PORTION OF THE SYSTEM IN RPS WHICH MEETS THE REQUIREMENTS OF IEEE 279-1968.

C. THE SYSTEM SHALL BE FULLY TESTABLE.

D. NO SINGLE FAILURE WILL ADVERSELY AFFECT THE OPERATION OF THE SYSTEM.

E. LOSS OF CONTROL POWER OR REMOVAL OF A MODULE WILL CAUSE THE ASSOCIATED CHANNEL TO TRIP.

F. THE SYSTEM WILL BE SEISMICALLY QUALIFIED AND INSTALLED WITH THE EXCEPTION OF THE PRESSURE SIGNALS FROM THE TURBINE-GENERATOR AND THE MAIN FEED PUMP TURBINES. THE COMPONENTS USED AND ALL CABLES ASSOCIATED WITH THESE CIRCUITS SHALL BE INSTALLED AS 1E SYSTEMS. HOWEVER, SEISMIC CRITERIA WILL NOT APPLY REGARDING THE MOUNTING AND INSTALLATION OF THE DEVICES LOCATED WITHIN THE TURBINE BUILDING WHICH IS NOT A SEISMIC CAT. 1 STRUCTURE.

G. THE RESPONSE TIME OF THE SYSTEM SHALL BE LESS THAN OR EQUAL TO 50 MILLISECONDS.

H. COMPUTER/ANNUNCIATOR ALARMS SHALL BE PROVIDED TO MONITOR ALL INPUTS INTO THE SYSTEM, THE OUTPUT TRIP CIRCUIT, CABINET LOSS OF POWER AND CABINET DOOR OPEN.

### 2. SYSTEM DESCRIPTION

THE "ARTS" IS REQUIRED TO TRIP THE REACTOR WHEN THE TURBINE-GENERATOR IS TRIPPED OR BOTH MAIN FEED PUMPS ARE TRIPPED OR THE STEAM AND FEEDWATER RUPTURE CONTROL SYSTEM (SFRCS) IS TRIPPED. THE "ARTS" TURBINE-GENERATOR TRIP INPUT WILL BE BLOCKED WHEN REACTOR POWER IS LESS THAN 45%. 15

THE "ARTS" IS DIVIDED INTO FOUR CABINETS. EACH CABINET CONSISTS OF IDENTICAL REDUNDANT SENSING, LOGIC AND OUTPUT CHANNELS POWERED FROM DIFFERENT CLASS 1E POWER SUPPLIES. AN OUTPUT FROM EACH CHANNEL WILL TRIP ONE "CRDM" BREAKER. EACH INPUT SIGNAL, ONCE ISOLATED FROM THE ACTUATING DEVICE, IS USED TO COMPRISE TWO OUT OF FOUR COINCIDENCE LOGICS IN EACH OF THE FOUR CABINETS.

THE TURBINE-GENERATOR TRIP SIGNAL IS DERIVED FROM FOUR REDUNDANT PRESSURE SWITCHES CONNECTED TO THE FAST ACTING SOLENOIDS FOR THE TURBINE-GENERATOR STOP VALVES. ANY TRIP OF THE TURBINE-GENERATOR EITHER MANUALLY OR AS A RESULT OF A FAULT ON THE TURBINE OR THE GENERATOR WILL CAUSE A LOSS OF OIL PRESSURE IN THIS LINE WHICH WILL GIVE A TRIP SIGNAL TO THE "ARTS". A SIGNAL FROM EACH "RPS" CABINET, WILL BE USED TO AUTOMATICALLY BLOCK THE TRIP SIGNAL FROM THE TURBINE-GENERATOR WHEN REACTOR POWER IS LESS THAN 45%. 15

A TRIP SIGNAL FROM EACH MAIN FEED PUMP TURBINE (MFPT) IS DERIVED FROM FOUR REDUNDANT PRESSURE SWITCHES ON EACH MAIN FEED PUMP TURBINE. THE PRESSURE SWITCHES WILL MONITOR THE OIL PRESSURE OF THE CONTROL VALVES. ANY TRIP OF THE TURBINE WILL CAUSE A LOSS OF CONTROL OIL PRESSURE. A TRIP OF BOTH IS REQUIRED TO GIVE A TRIP SIGNAL TO THE "ART".

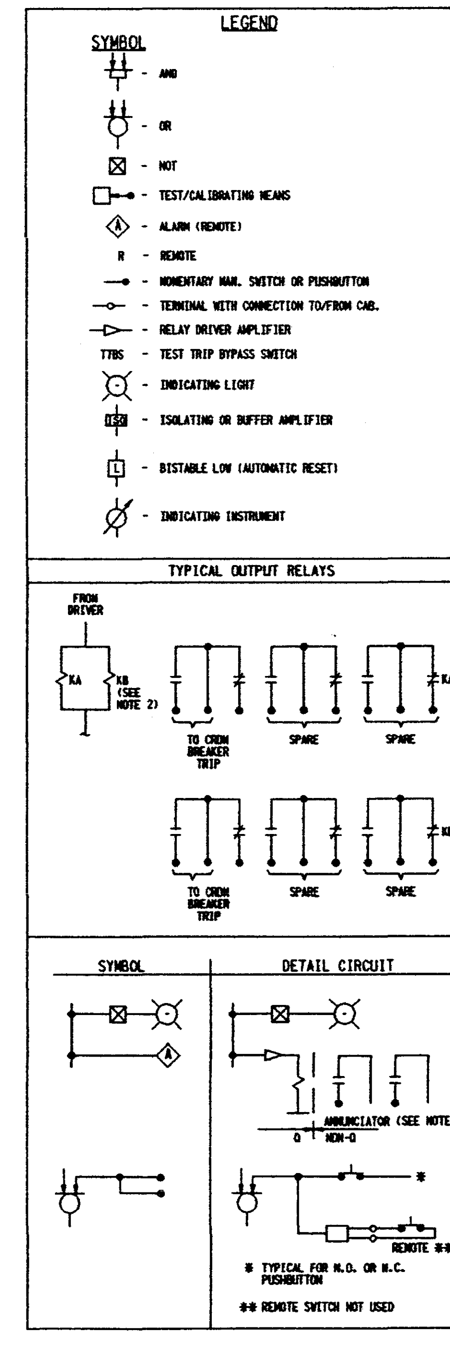
THE TRIP SIGNAL FROM THE "SFRCS" (RS-521 & RS-522) IS PRODUCED WHENEVER ANY INPUT PARAMETERS IS TRIPPED. THESE SIGNALS INCLUDE LOW STEAM GENERATOR (SG) PRESSURE IN EITHER "SG" OR LOW LEVEL IN EITHER "SG" OR HIGH REVERSE DIFFERENTIAL PRESSURE ACROSS THE MAIN FEEDWATER CHECK VALVES ON EITHER "SG" OR HIGH LEVEL IN EITHER "SG" OR RCP MONITOR.

AN OUTPUT FROM EACH "ARTS" CABINET IS USED TO TRIP THE ASSOCIATED CHANNEL "CRDM" BREAKER. THIS IS ACCOMPLISHED BY HAVING THE TRIP CIRCUIT FROM THE "ARTS" WIRED IN SERIES TO THE "RPS" TRIP CIRCUIT. EITHER THE "RPS", "ARTS" OR MANUAL TRIP WILL TRIP THE REACTOR. THE BREAKER MUST BE MANUALLY CLOSED BEFORE THE "CRDM" CAN BE RE-ENERGIZED.

COMPUTER/ANNUNCIATOR ALARMS SHALL BE PROVIDED TO ALARM WHEN ANY OF THE INPUT PARAMETERS TRIP AND WHEN THERE IS AN OUTPUT ACTUATION. LOCAL INDICATION SHALL ALSO BE PROVIDED ON EACH CABINET. FOR THE "SFRCS" TRIP SIGNAL, COMPUTER POINT Q963 WILL ALARM ON ANY "SFRCS" TRIP OF THE "SFRCS" SYSTEM, AS WELL AS ON LOSS OF ALL 4 RCPS. 15

15 TEST TRIP BYPASS SWITCHES (TTBS) SHALL BE PROVIDED IN EACH CABINET TO ALLOW FOR TESTING OR MAINTENANCE OF THE INPUT SIGNALS, EXCEPT REACTOR POWER, DURING MODE 1, POWER OPERATIONS. INITIATION OF THE TTBS CHANGES THE LOGIC OF THE REMAINING THREE CHANNELS FROM A TWO OUT OF FOUR LOGIC TO A TWO OUT OF THREE LOGIC. ADMINISTRATIVE CONTROLS ARE IMPLEMENTED TO ALLOW THE BYPASSING OF ONLY ONE SIGNAL AT A TIME DURING MODE 1.

COMPUTER/ANNUNCIATOR ALARMS ARE ALSO PROVIDED TO ALARM WHEN ANY OF THE 4 ARTS CABINETS EXPERIENCE A LOSS OF 120VAC POWER [Q006] AND IF ANY ARTS CABINET DOOR IS OPENED [Z840].




## REFERENCE DRAWINGS

| | |
|---|---|
| 7749-E-18 | STEAM AND FEEDWATER LINE RUPTURE CONTROL SYSTEM LOGIC DIAGRAM |
| 7749-E-19 | SFRCS-ACTUATED EQUIPMENT TABULATION |
| 7749-E-65B SH.10-12 | MISC. SFAS AND SFRCS CIRCUITS |

## NOTES

1. ALL INPUTS EXCEPT THE RPS REACTOR POWER SIGNAL ARE DIGITAL SIGNALS (CONTACTS) PROVIDED BY OTHERS. NORMAL STATE IS CLOSED CONTACT.
2. OUTPUT RELAYS (KA & KB) WILL BE DE-ENERGIZED IN THE TRIP (ACTUATED) MODE.
3. ALARM RELAYS WILL BE DE-ENERGIZED TO ALARM. CONTACT TO OPEN IN ALARM MODE. ALL ANNUNCIATORS ALARMS ARE NON-Q. COMPUTER/ANNUNCIATOR POINT No. IN [ ].
4. THREE TEST TRIP BYPASS SWITCHES (TTBS) SHALL BE PROVIDED IN EACH CABINET SO THAT THE INPUT LOGIC CAN BE CHANGED FROM A TWO OUT OF FOUR LOGIC TO A TWO OUT OF THREE LOGIC, DURING POWER OPERATIONS. 15
5. NORMAL INPUTS SHALL BE CONSIDERED AS HIGH (1) WITH OUTPUT ACTUATION AS A LOW (0). PUSHBUTTONS WILL BE NORMALLY LOW (0). REACTOR POWER INPUT SHALL BE CONSIDERED LOW (0) ABOVE THE BISTABLE SETPOINT AND CHANGE TO HIGH (1) BELOW THE TRIP SETPOINT.
6. INPUT LOGIC WIRING SEQUENCE FROM CHANNELS (1,2,3 & 4) IS SHOWN DIAGRAMATICALLY AND MAY NOT REPRESENT THE ACTUAL WIRING SEQUENCE CONFIGURATION. THE INPUT FROM THE ASSOCIATED CHANNEL (I.E. THE CHANNEL 1 TRIP INPUT INTO THE CHANNEL 1 2 / 4 LOGIC MODULE) ALWAYS COMES INTO GATES SHOWN FOR CHANNEL 1.
7. COMPUTER POINT Q053 IS CHANNEL 1 TRIP ONLY. COMPUTER POINT Q054 IS FOR CHANNEL 2 TRIP, Q055 FOR CHANNEL 3 TRIP AND Q056 FOR CHANNEL 4 TRIP.
8. MAIN FEED PUMP TRIP TEST SWITCHES ARE NON- MOMENTARY MANUAL SWITCHES.

DAVIS-BESSE NUCLEAR POWER STATION

ANTICIPATORY REACTOR TRIP
SYSTEM LOGIC DIAGRAM
E-28
FIGURE 7.4-8

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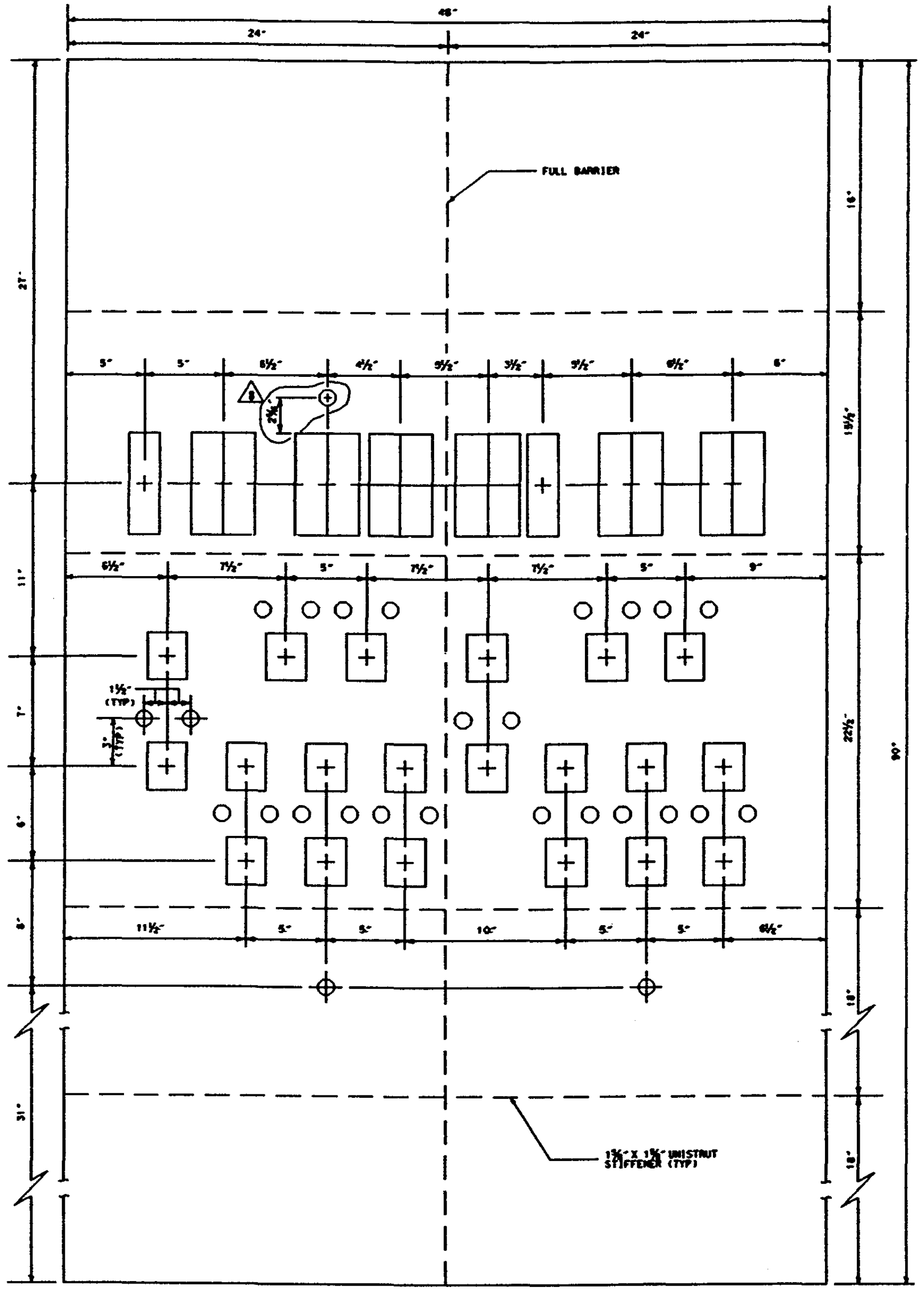
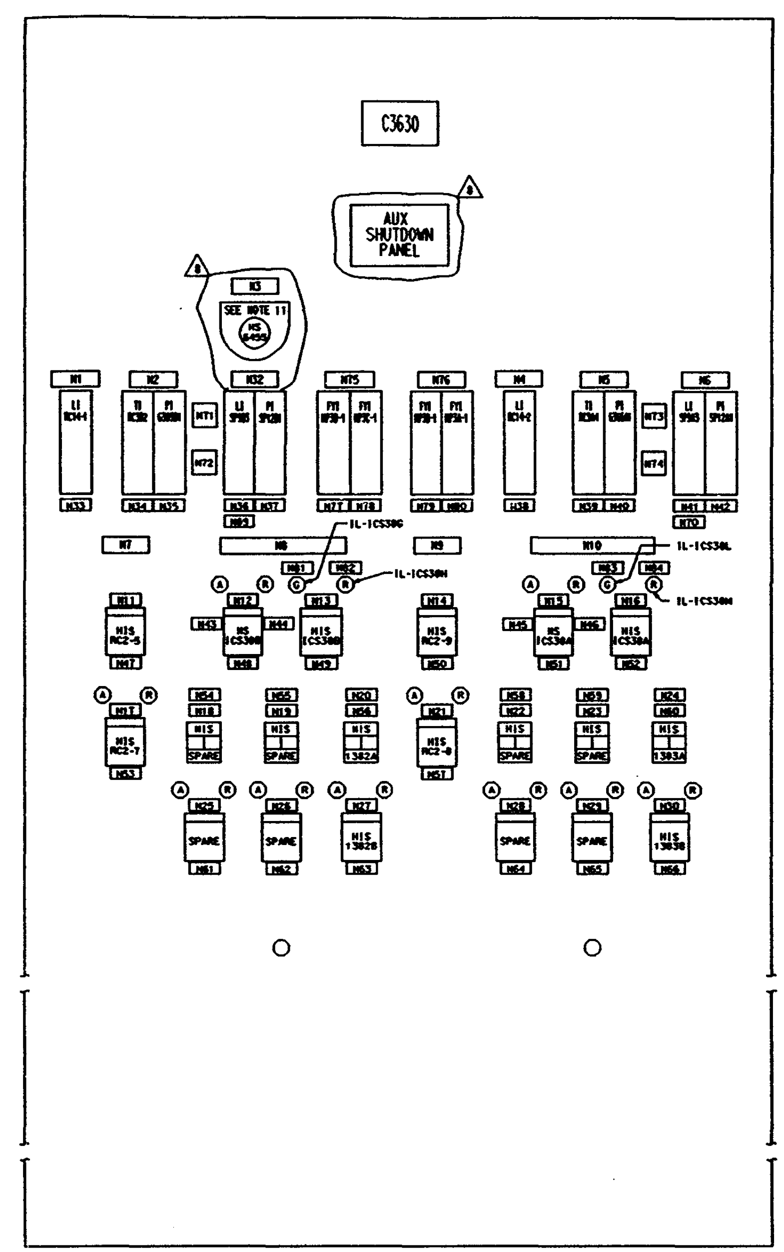
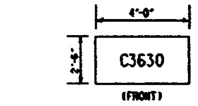
C3630 DEVICE LOCATIONS (SEE NOTE 8)

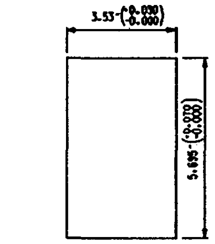



C3630 FRONT LAYOUT




PLAN VIEW
(N.T.S.)



CUTOUT DETAIL FOR T.10

DIXSON INDICATORS MOUNTED SIDE BY SIDE

APPLICABLE FOR:
FYI-HP3D-1/3C-1
FYI-HP3B-1/3A-1

MARGINAL QUALITY DOCUMENT
BEST COPY AVAILABLE

NOTES:

1. EQUIPMENT REQUIRING QUALITY ASSURANCE IS IDENTIFIED ON BILL OF MATERIAL, M-6208.
2. SWITCHES TO BE LEFT MOUNTED AND WIRED WITH ORIGINAL ESCUTCHEON NAMEPLATES REMOVED.
3. SPARE SWITCHES H18, H19, H22 AND H23 ARE COVERED WITH "CUTLER HAMMER" GUARDS (CAT. NO. E30KR31). SPARE SWITCHES H25, H26, H28 AND H29 ARE WITHOUT HANDLES.
5. NO WIRING TO CROSS 3/16" STEEL BARRIER (IEEE 279 REQ.) UNISTRUT TO BE UTILIZED FOR PANDUIT TO ENCLOSE WIRING.
6. WEIGHT OF EQUIPMENT 80 LBS. APPROX. ON FRONT OF PANEL.
7. ET16 LIGHTS H13 AND H16 ARE 125VDC ALL OTHERS ARE 120VAC.
8. REFERENCE THE FRONT LAYOUT FOR DEVICE DESIGNATORS.
9. NAMEPLATE IS LOCATED ON TOP OF SWITCH.
10. NAMEPLATES ARE COLOR CODED AS FOLLOWS:
    1-68 & 75-85 WHITE SURFACE, BLACK CORE
    69, 70 RED SURFACE, WHITE CORE
    71-74 RED SURFACE, YELLOW CORE
11. NAMEPLATE ENGRAVED AS FOLLOWS:
    LEFT POSITION: S01
    RIGHT POSITION: S02

| N.P. No. | QUANT. | LETTER SIZE | SIZE | ENGRAVING FIRST LINE | ENGRAVING SECOND LINE | ENGRAVING THIRD LINE |
|---|---|---|---|---|---|---|
| 1 | 1 | 3/8" | 1" X 3" | PRZR | | |
| 2 | 1 | 3/8" | 1" X 3" | REACTOR | COOLANT | |
| 3 | 1 | 3/8" | 1" X 3" | STEAM | GENERATOR | |
| 4 | 1 | 3/8" | 1" X 3" | PRZR | | |
| 5 | 1 | 3/8" | 1" X 3" | REACTOR | COOLANT | |
| 6 | 1 | 3/8" | 1" X 3" | STEAM | GEN 2 | |
| 7 | 1 | 3/8" | 1" X 3" | PRZR HTR | | |
| 8 | 1 | 3/8" | 1" X 7" | AFPT 1 GOV VLV CONT | | |
| 9 | 1 | 3/8" | 1" X 3" | PRZR HTR | | |
| 10 | 1 | 3/8" | 1" X 7" | AFPT 2 GOV VLV CONT | | |
| 11 | 1 | 5/16" | 1" X 3" | PRZR HTR CTRL | | |
| 12 | 1 | 5/16" | 1" X 3" | AFPT 1 GOV CONT SELECT | | |
| 13 | 1 | 5/16" | 1" X 3" | AFPT 1 GOV SPD CONT | | |
| 14 | 1 | 5/16" | 1" X 3" | PRZR HTR CTRL | | |
| 15 | 1 | 5/16" | 1" X 3" | AFPT 2 GOV CONT SELECT | | |
| 16 | 1 | 5/16" | 1" X 3" | AFPT 2 GOV SPD CONT | | |
| 17 | 1 | 1/4" | 1" X 3" | PRZR HTR | CTRL SELECT | |
| 18 | 1 | 3/8" | 1" X 3" | SPARE (SEE NOTE 2&3) | | |
| 19 | 1 | 3/8" | 1" X 3" | SPARE (SEE NOTE 2&3) | | |
| 20 | 1 | 1/4" | 1" X 3" | SERVICE WTR | ISO VLV | |
| 21 | 1 | 1/4" | 1" X 3" | PRZR HTR | CTRL SELECT | |
| 22 | 1 | 3/8" | 1" X 3" | SPARE (SEE NOTE 2&3) | | |
| 23 | 1 | 3/8" | 1" X 3" | SPARE (SEE NOTE 2&3) | | |
| 24 | 1 | 1/4" | 1" X 3" | SERVICE WTR | ISO VLV | |
| 25 | 1 | 3/8" | 1" X 3" | SPARE (SEE NOTE 2&3) | | |
| 26 | 1 | 3/8" | 1" X 3" | SPARE (SEE NOTE 2&3) | | |
| 27 | 1 | 5/16" | 1" X 3" | SERVICE WTR | ISO SELECT | |
| 28 | 1 | 3/8" | 1" X 3" | SPARE (SEE NOTE 2&3) | | |

| N.P. No. | QUANT. | LETTER SIZE | SIZE | ENGRAVING FIRST LINE | ENGRAVING SECOND LINE | ENGRAVING THIRD LINE |
|---|---|---|---|---|---|---|
| 29 | 1 | 3/8" | 1" X 3" | SPARE (SEE NOTE 2&3) | | |
| 30 | 1 | 5/16" | 1" X 3" | SERVICE WTR | ISO SELECT | |
| 31 | | | | | | |
| 32 | 1 | 1/4" | 1/2" X 1 3/8" | HS6455 | | |
| 33 | 1 | 1/4" | 1/2" X 1 3/8" | LI RC14-1 | | |
| 34 | 1 | 1/4" | 1/2" X 1 3/8" | TI RC3B2 | | |
| 35 | 1 | 1/4" | 1/2" X 1 3/8" | PI 6365B1 | | |
| 36 | 1 | 1/4" | 1/2" X 1 3/8" | LI SP9B3 | | |
| 37 | 1 | 1/4" | 1/2" X 1 3/8" | PI SP12B1 | | |
| 38 | 1 | 1/4" | 1/2" X 1 3/8" | LI RC14-2 | | |
| 39 | 1 | 1/4" | 1/2" X 1 3/8" | TI RC3A4 | | |
| 40 | 1 | 1/4" | 1/2" X 1 3/8" | PI 6365A1 | | |
| 41 | 1 | 1/4" | 1/2" X 1 3/8" | LI SP9A3 | | |
| 42 | 1 | 1/4" | 1/2" X 1 3/8" | PI SP12A1 | | |
| 43 | 1 | 5/16" | 1/2" X 2" | ASP CONTROL | | |
| 44 | 1 | 5/16" | 1/2" X 2" | CTRM CONTROL | | |
| 45 | 1 | 5/16" | 1/2" X 2" | ASP CONTROL | | |
| 46 | 1 | 5/16" | 1/2" X 2" | CTRM CONTROL | | |
| 47 | 1 | 1/4" | 1/2" X 1 3/8" | HIS RC2-5 | | |
| 48 | 1 | 1/4" | 1/2" X 1 3/8" | HS ICS38B | | |
| 49 | 1 | 1/4" | 1/2" X 1 3/8" | HIS ICS38B | | |
| 50 | 1 | 1/4" | 1/2" X 1 3/8" | HIS RC2-9 | | |
| 51 | 1 | 1/4" | 1/2" X 1 3/8" | HS ICS38A | | |
| 52 | 1 | 1/4" | 1/2" X 1 3/8" | HIS ICS38A | | |
| 53 | 1 | 1/4" | 1/2" X 1 3/8" | HIS RC2-7 | | |
| 54 | 1 | 1/4" | 1/2" X 1 3/8" | HIS 106B | | |
| 55 | 1 | 1/4" | 1/2" X 1 3/8" | HIS 608B | | |
| 56 | 1 | 1/4" | 1/2" X 1 3/8" | HIS 1382A (SEE NOTE 9) | | |

| N.P. No. | QUANT. | LETTER SIZE | SIZE | ENGRAVING FIRST LINE | ENGRAVING SECOND LINE | ENGRAVING THIRD LINE | ENGRAVING FOURTH LINE |
|---|---|---|---|---|---|---|---|
| 57 | 1 | 1/4" | 1/2" X 1 3/8" | HIS RC2-8 | | | |
| 58 | 1 | 1/4" | 1/2" X 1 3/8" | HIS 107B | | | |
| 59 | 1 | 1/4" | 1/2" X 1 3/8" | HIS 599B | | | |
| 60 | 1 | 1/4" | 1/2" X 1 3/8" | HIS 1383A (SEE NOTE 9) | | | |
| 61 | 1 | 1/4" | 1/2" X 1 3/8" | HIS 106D (SEE NOTE 3) | | | |
| 62 | 1 | 1/4" | 1/2" X 1 3/8" | HIS 608D (SEE NOTE 3) | | | |
| 63 | 1 | 1/4" | 1/2" X 1 3/8" | HIS 1382B | | | |
| 64 | 1 | 1/4" | 1/2" X 1 3/8" | HIS 107D (SEE NOTE 3) | | | |
| 65 | 1 | 1/4" | 1/2" X 1 3/8" | HIS 599D (SEE NOTE 3) | | | |
| 66 | 1 | 1/4" | 1/2" X 1 3/8" | HIS 1383B | | | |
| 67 | | | | | | | |
| 68 | | | | | | | |
| 69 | 1 | 5/16" | 1" X 2" | DRY S/G <16" | | | |
| 70 | 1 | 5/16" | 1" X 2" | DRY S/G <16" | | | |
| 71 | 1 | L1 1/4" L2-4 5/16" | 1 3/8" X 2 1/4" | SFRCS-SA | 124 IN WITH AFP 1-1 | OR | 130 IN WITH AFP 1-2 |
| 72 | 1 | L1 1/4" L2-4 5/16" | 1 3/8" X 2 1/4" | SFRCS-NON SA | 49 IN WITH AFP 1-1 | OR | 55 IN WITH AFP 1-2 |
| 73 | 1 | L1 1/4" L2-4 5/16" | 1 3/8" X 2 1/4" | SFRCS-SA | 124 IN WITH AFP 1-2 | OR | 130 IN WITH AFP 1-1 |
| 74 | 1 | L1 1/4" L2-4 5/16" | 1 3/8" X 2 1/4" | SFRCS-NON SA | 49 IN WITH AFP 1-2 | OR | 55 IN WITH AFP 1-1 |
| 75 | 1 | 1/2" | 1" X 3" | HPI1-1 | | | |
| 76 | 1 | 1/2" | 1" X 3" | HPI1-2 | | | |
| 77 | 1 | 1/4" | 1/2" X 1 1/2" | FYI-HP3D-1 | | | |
| 78 | 1 | 1/4" | 1/2" X 1 1/2" | FYI-HP3C-1 | | | |
| 79 | 1 | 1/4" | 1/2" X 1 1/2" | FYI-HP3B-1 | | | |
| 80 | 1 | 1/4" | 1/2" X 1 1/2" | FYI-HP3A-1 | | | |
| 81 | 1 | 5/16" | 1/2" X 1" | LSS | | | |
| 82 | 1 | 5/16" | 1/2" X 1" | HSS | | | |
| 83 | 1 | 5/16" | 1/2" X 1" | LSS | | | |
| 84 | 1 | 5/16" | 1/2" X 1" | HSS | | | |

DAVIS-BESSE NUCLEAR POWER STATION

AUXILIARY SHUTDOWN PANEL
(ASP)
M-592
FIGURE 7.4-9

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## 7.5 SAFETY-RELATED DISPLAY INFORMATION

The necessary information to monitor the nuclear steam supply system, the containment system and the balance of station is displayed on the operator's console and the various vertical boards located within the control room. Essential information is also displayed on the auxiliary shutdown panel. These indications include the information to control and operate the station through all operating conditions of the station including anticipated operational occurrences and accident and post-accident conditions.

### 7.5.1 Description

Safety surveillance instrumentation, which includes indicators, recorders, lights, annunciators, CRT displays and the station computer, is provided for the following systems.

1. CV Environment.
2. Reactor Coolant.
3. Reactor.
4. CRDCS (trip portion).
5. Auxiliary Feedwater.
6. Auxiliary Shutdown Panel.
7. ESF Status.
8. RPS Status.
9. ARTS Status.
10. PAMS Status.

Sufficient information is provided to enable the operator to maintain the station in a safe condition following both anticipated operational occurrences and accident and post-accident conditions.

For the convenience of the operating personnel, all reactor safety systems are presented graphically on the main control panels designated for the Safety Features Status Display. Instruments are either located on process mimic lines or are shown connected to certain systems by influence lines. The Containment Vessel, Reactor, Core Flooding Tanks, pumps, heat exchangers, etc., are shown schematically in the systems. Pumps, fans, and valves are in most cases represented by their respective control switches and status indicating lights. All mimic process lines and equipment are in color.

Safety related equipment which is automatically initiated by SFAS to satisfy safety functions is provided with a Safety Actuation Monitoring (SAM) amber indicating light/switch. These SAM lights are located primarily on the safety features status display panels and operate as follows:

1. Light off:

   Conditions: No safety actuation demand or a safety actuation demand with equipment failing to actuate.

2. Light dim:

   Condition: Safety actuation demand and the equipment successfully in safety actuation mode of operation.

3. Light full on:

   Condition: Safety actuation demand but safety signal is blocked. The equipment item associated with the blocked system logic is still in the safety actuation mode of operation.

4. Light flashing:

   Condition: Safety actuation demand but safety signal is blocked. The equipment item associated with the blocked system logic is in a non-safety actuation mode of operation.

The remote manual block signal has no effect as long as no trip signal exists in the safety actuation system logic.

Position indicating lights for motor-operated valves or running lights for pumps and fans are provided in the control room. All safety related solenoid valves are fail safe upon loss of control voltage, and are indicated by position lights independent of the control voltage.

Located on the main control panel, in clear view of the operator, are manually operated indicator lights provided to warn the operator of a safety system that is inoperable because of previous failure, repair work in progress, or routine maintenance being performed on the system. These manually operated indicator lights are for systems identified below.

Auxiliary Feedwater System
Component Cooling System
Service Water System
HPI System
Core Flooding System
Emergency Ventilation System
Emergency Diesel Generator
Control Room Cooling System
BWST System
Containment Air Cooling System
Steam Generator Isolation
Containment Isolation
Low Pressure Injection System
Containment Spray System

This indication is manual “on-off” type that will be initiated by the operator or other qualified personnel when a safety system is not in service. These indication lights will be illuminated as long as the system is inoperable, in compliance with Regulatory Guide 1.47.

Regulatory Guides 1.40 and 1.41 apply to components as discussed in Chapters 3 and 8.

## 7.5.2 Analysis

### 7.5.2.1 Criteria

The following criteria have been utilized for those surveillance systems required for safety:

1. General Design Criteria 1, 2, 3, 4, 13, 19, 64.

2. Safety Guide 29.

3. IEEE Standard 279-1971 excluding Sections 4.1, 4.11 through 4.17 and 4.19, as these apply to actuation systems.

4. The NI instrumentation, as described in Section 7.8, meets the requirements for separation of protection and control systems and for single failure as specified in IEEE Standard 279-1968.

Those surveillance systems required for safety are the indications for the systems required for safe shutdown, protection systems status (including actuated devices), and post-accident CV monitoring. Seismic design ensures availability of the display information throughout a safe shutdown earthquake. The indicators are seismically qualified and will remain undamaged by such an earthquake, with the calibration unaffected.

### 7.5.2.2 Compliance With Criteria

The required safety surveillance systems comply with the criteria listed in Subsection 7.5.2.1 as follows:

#### 7.5.2.2.1 Criterion 1

All required surveillance systems are manufactured and tested to QC procedures described in Chapter 17.

#### 7.5.2.2.2 Criterion 2

All required surveillance systems are Seismic Class I design.

#### 7.5.2.2.3 Criterion 3

Required surveillance systems are wired with fire retardant wire.

#### 7.5.2.2.4 Criterion 4

All required surveillance systems are located in areas that remain virtually free of adverse environmental effects resulting from abnormal station operating conditions.

#### 7.5.2.2.5 Criterion 13

The required surveillance systems provide indication to assure adequate safety for normal operation, anticipated operational occurrences, and accident conditions.

#### 7.5.2.2.6 Criterion 19

Adequate surveillance systems are provided both in the control room and outside the control room to enable the operator to take appropriate actions as may be required by station operations.

#### 7.5.2.2.7 Criterion 64

CV radiation monitoring is available for normal operation, anticipated operational occurrences, and accident conditions.

#### 7.5.2.2.8 Safety Guide 29

All surveillance instrumentation required in shutting down the reactor and maintaining the reactor in a safe condition, monitoring the status of station protection systems and monitoring the CV hydrogen and radiation levels are Seismic Class I.

#### 7.5.2.2.9 IEEE Standard 279-1971

All required surveillance systems meet the intent of IEEE Standard 279-1971 on a point by point basis with the previously stated exceptions of 4.1, 4.11 through 4.17, and 4.19.

### 7.5.2.3 Available Readouts

Table 7.5-1 lists the information readouts available for monitoring conditions in the reactor, reactor coolant system, CV, ECC system, and steam generators.

### 7.5.2.4 Design Adequacy

The utilization of the design criteria listed in Subsection 7.5.2.1 for required surveillance systems ensures the availability of these systems during all station operating modes including accident.

Surveillance systems not required for station safety but that do serve as operating aids are generally redundant in available means of display. This diversity plus the interrelation that exists among display information ensures their availability to the operator during all station operating modes except the worst possible cases in which these surveillance systems are not required.

TABLE 7.5-1

INFORMATION READOUTS AVAILABLE TO THE OPERATOR FOR MONITORING CONDITIONS IN REACTOR, REACTOR COOLANT SYSTEM, CONTAINMENT VESSEL, ECCS, AND STEAM GENERATORS

| Measured Parameter | Type of Readout | | Number of Sensor Channels | Indicator Range | Indicator Accuracy, % of Full Scale | Indicator Location |
|---|---|---|---|---|---|---|
| Source range neutron level (NI) | B, F, E | | 2 | $10^{-1}$ to $10^{+6}$ cps | ± 1 | A, B, D |
| Source range neutron level # | B, F | | 2 | $10^{-1}$ - $10^{5}$ cps | ± 1 | B, D |
| Source range startup rate (NI) | A, F | | 2 | -1 to 10 dpm | ± 1 | A, B, D |
| Intermediate range neutron level (NI) | B, F | | 2 | $10^{-11}$ to $10^{-3}$ amp | ± 1 | A, B, D |
| Intermediate range neutron level (NI) | E | | 1 | $10^{-11}$ to $10^{-3}$ amp | ± .5 | B |
| Intermediate range startup rate (NI) | A, F | | 2 | -1 to 10 dpm | ± 1 | A, B, D |
| Power range neutron level (NI) | A, F | | 4 | 0 to 125% FP | ± 1 | A, B, D |
| Power range neutron level (NI) | E | | 1 | 0 to 125% FP | ± 0.5 | B |
| Wide Range Log Power # | B, F | | 2 | $10^{-8}$ - 2 x $10^{2}$% | ± 1 | B, D |
| Power range neutron level Imbalance (NI) | A, F | | 4 | 60 to +65% FP | ± 1 | A, B, D |
| RC loop outlet temperature** | A, F | ANN. | 4 in each loop | 520-620°F | ± 1 | A, B, C, D |
| RC unit outlet temperature | E, F | ANN. | * | 520-620°F | ± .5 | B, D |
| RC loop outlet temperatures** | A, D, F | | 2 in each loop | 120-920°F | ± 1 | B, D |
| RC loop inlet temperature | A, F, | | 4 in each loop | 520-620°F | ± 1 | B, D |
| RC loop inlet temperature | A, D, F | | 2 in each loop | 50-650°F | ± 1 | B, D |
| RC unit inlet temperature | A, F, | ANN. | * | 520-620°F | ± 1 | B, D |
| RC loop average temperature | A, F, | ANN. | * | 520-620°F | ± 1 | B, D |
| RC unit average temperature | D, E, F | ANN. | * | 520-620°F | ± .2 | B, D |
| RC loop temperature difference | A, F, | ANN. | * | 0 to 70°F | ± 1 | B, D |
| RC unit temperature difference | A, F, | ANN. | * | -10 to +10°F<br>0 to 70°F | ± 1 | B, D |

TABLE 7.5-1 (Continued)

INFORMATION READOUTS AVAILABLE TO THE OPERATOR FOR MONITORING CONDITIONS IN REACTOR, REACTOR COOLANT SYSTEM, CONTAINMENT VESSEL, ECCS, AND STEAM GENERATORS

| Measured Parameter | Type of Readout | | Number of Sensor Channels | Indicator Range | Indicator Accuracy, % of Full Scale | Indicator Location |
|---|---|---|---|---|---|---|
| Incore Temperature # | A, D, F | | 2 (2/Core Quad) | 0 - 2300°F | ± 1 | B, D |
| RC loop pressure # | A, D, E, F, | | 2 | 0 - 3000 psig | ± 1 | B, C, D |
| RC loop pressure** | A, E, F | ANN. | 4 | 0 - 2500 psig | ± 1 | A, B, C, D |
| | | | 4 | 1700 - 2500 psig | | |
| RC loop low range pressure | A | | 1 in loop two | 0 to 500 psig | ± 1 | B |
| Pressurizer level ** | A, F, | ANN. | 2 | 0 to 320 in. | ± 1.5 | B, C, D |
| Pressurizer level | A, E, F | ANN. | 1 | 0 to 320 in. | ± 1.5 | B, C, D |
| Pressurizer temperature | A, F | | 2 | 0 to 700°F | ± 1 | B, D |
| Pressurizer Relief Valves # | A, C, F | | 2 | 0 - 100% | ± 1 | B, D |
| RC loop flow | A, F, | ANN. | 4 in each loop | 0 - 90 x $10^6$ lb/hr | ± 1 | A, B, D |
| RC total flow | E, F, | ANN. | * | 0 - 180 x $10^6$ lb/hr | ± .5 | A, B, D |
| BWST level** | A, F, | ANN. | 4 | 0 - 50 ft. | ± 1.5 | B, D |
| Steam generator startup range level ** | A, F, | ANN. | 2 in each loop | 0 - 250 in. | ± 1.5 | B, C, D |
| Steam generator startup range level (SFRCS) # | A, D | | 4 in each loop SFRCS cabinets, 2 in each loop in CTRM | 0 - 300 in. | ± 1 | A, B, D |
| Steam generator operating range level | E | ANN. | 1 in each loop | 0 - 100% | ± 0.5 | B, D |
| Steam generator operating range level | F | | 2 in each loop | 0 - 100% | -- | D |
| Steam generator full range level | A, F, | ANN. | 1 in each loop | 0 - 650 in. | ± 1 | B, D |
| RC saturation *# | D, F, | ANN. | 2 | NA | - | B, D |
| RC Hot Leg Level *# | F | | 2 | NA | - | D |

TABLE 7.5-1 (Continued)

INFORMATION READOUTS AVAILABLE TO THE OPERATOR FOR MONITORING CONDITIONS IN REACTOR, REACTOR COOLANT SYSTEM, CONTAINMENT VESSEL, ECCS, AND STEAM GENERATORS

| Measured Parameter | Type of Readout | | Number of Sensor Channels | Indicator Range | Indicator Accuracy, % of Full Scale | Indicator Location |
|---|---|---|---|---|---|---|
| Station electrical distribution | A, C, F | | 2 | -- | ± 2 | B, D |
| Auxiliary feedwater status ** | C, F, | ANN. | 1 per loop | -- | -- | B, C, D |
| Auxiliary feedwater flow # | A, D, F | | 2 per SG | 0 - 1000 gpm | ± 1 | B, D |
| Containment vessel wide range pressure # | A, F, D | | 2 | 0 - 200 psia | ± 1 | B, D |
| Containment vessel pressure | A, F, | ANN. | 4 | 0 - 60 psia | ± 1 | A, B, D |
| Containment vessel hydrogen **# | A, F | ANN. | 2 | 0 - 10% | ± 1.5 | A, B, D |
| Containment vessel radiation (RE's are turned off) | B, F, | ANN. | 4 | 0 - 1000 mR/hr | ± 1 | A, B, D |
| Containment vessel radiation | B, F, E, | ANN. | 2 | $10^{-7}$ - $10^{-1}$ µCi/cc | ± 1 | A, B, D |
| Containment High Range Radiation # | B, F | | 2 | $10^{0}$ - $10^{8}$ R/HR | ± 1 | B, D |
| Containment vessel isolation status ** | C, F | | 1 per valve | -- | -- | B, D |
| Containment vessel temperature | A, F, | ANN. | 6 | -- | ± 1.5 | B, D |
| Containment vessel normal sump level # | A, F, D | | 2 | 534.5 - 538.5 ft. | ± 1 | B, D |
| Containment vessel wide range water level # | A, F, D | | 2 | 538 - 593 ft. | ± 1 | B, D |
| ARTS Status | C, F | ANN. | 4 | -- | -- | A, B, D |
| SFAS status ** | C, F, | ANN. | 4 | -- | -- | B, D |
| Safety features equipment status ** | C, F, | | 2 | -- | -- | B, D |
| RPS status ** | C, F, | ANN. | 2 | -- | -- | B, D |
| SFRCS status ** | C, F, | | 2 | -- | -- | B, D |
| HPI system status | C | | Manual | -- | -- | B |
| LPI system status | C | | Manual | -- | -- | B |
| Containment spray system status | C | | Manual | -- | -- | B |

TABLE 7.5-1 (Continued)

INFORMATION READOUTS AVAILABLE TO THE OPERATOR FOR MONITORING CONDITIONS IN REACTOR, REACTOR COOLANT SYSTEM, CONTAINMENT VESSEL, ECCS, AND STEAM GENERATORS

| Measured Parameter | Type of Readout | | Number of Sensor Channels | Indicator Range | Indicator Accuracy, % of Full Scale | Indicator Location |
|---|---|---|---|---|---|---|
| Core flood system status | C | | Manual | -- | -- | B |
| BWST system status | C | | Manual | -- | -- | B |
| Emergency Diesel Generator System Status | C | | Manual | -- | -- | B |
| Containment air cooling system status | C | | Manual | -- | -- | B |
| Emergency ventilation system status | C | | Manual | -- | -- | B |
| Aux. Feedwater System Status | C | | Manual | -- | -- | B |
| Component Cooling System Status | C | | Manual | -- | -- | B |
| Service Water System Status | C | | Manual | -- | -- | B |
| Control Room Cooling System Status | C | | Manual | -- | -- | B |
| Steam Generator Isolation Status | C | | Manual | -- | -- | B |
| Containment Isolation Status | C | | Manual | -- | -- | B |
| Steam generator outlet pressure ** | A, F | | 1 in each loop | 0 - 1200 psig | ± 1 | B, C, D (@ c acc. = ± 1.5%) |
| Steam generator outlet pressure | A, F | | 1 in each loop | 0 - 1200 psig | ± 1 | B, D |
| High pressure injection flow ** | A, D, F, | ANN. | 2 in each loop | 0 - 500 gpm | ± 1 | B, D, C |
| Low pressure injection (DHR) flow ** | A, F | ANN. | 1 in each loop | 0 - 5000 gpm | ± 1 | B, D |
| Containment spray flow | A, F, | ANN. | 1 in each loop | 0 - 2000 gpm | ± 1.5 | B, D |
| Core flood tank pressure | A, F, | ANN. | 2 in each tank | 0 - 700 psig | ± 1 | B, D |
| Core flood tank level | A, | ANN. | 2 in each tank | 0 - 14 ft. $H_2O$ | ± 1 | B |
| Decay heat pump suction temp. | A, | ANN. | 1 in each loop | 0 - 400°F | ± 1 | B |
| Decay heat cooler outlet temp. | A, | ANN. | 1 in each loop | 0 - 400°F | ± 1 | B |
| HPI system pump and valve status ** | C, F | | 1 in each loop | -- | -- | B, D |
| LPI system pump and valve status ** | C, F | | 1 in each loop | -- | -- | B, D |
| Containment spray pump and valve status ** | C, F | | 1 in each loop | (valves, 2 in each loop) | -- | B, D |

TABLE 7.5-1 (Continued)

INFORMATION READOUTS AVAILABLE TO THE OPERATOR FOR MONITORING CONDITIONS IN REACTOR, REACTOR COOLANT SYSTEM, CONTAINMENT VESSEL, ECCS, AND STEAM GENERATORS

| Measured Parameter | Type of Readout | | Number of Sensor Channels | Indicator Range | Indicator Accuracy, % of Full Scale | Indicator Location |
|---|---|---|---|---|---|---|
| Core flood valve status ** | C, F, | ANN. | 1 in each loop | -- | -- | B, D |
| BWST valve status ** | C, F | | 1 in each loop | -- | -- | B, D |
| Containment emergency sump valve status ** | C, F | ANN. | 1 in each valve | -- | -- | B, D |
| Containment air recirculation fan status | C, F | | 1 in each loop | -- | -- | B, D |
| Containment air cooling fan status ** | C, F | | 1 in each loop | -- | -- | B, D |
| Emergency ventilation system fan and damper status ** | C, F | | 1 in each loop | -- | -- | B, D |
| MSIV status | C | | 1 in each loop | -- | -- | B |
| Core Tilt/ imbalance | A, F | ANN. | 4 | -- | ± 1% | B, D |

Legends: Type of Readout

A - Linear scale indicator
B - Log scale indicator
C - Indicator light
D - Digital indicator
E - Recorder
F - Station computer output and/or SPDS output (this output non-Class 1E)

ANN. - Audiovisual indication (non-Class 1E)

Indicator Location

A - System cabinets
B - Main control boards
C - Auxiliary panel
D - Station computer printout

Notes:
* Two or more signals are combined to produce the indicated parameter
** Indications are required surveillance equipment on safety systems for safe shutdown and/or post-accident monitoring and utilize the design criteria listed in Subsection 7.5.2.1 (Readout types A, D, and C only).
# Post-accident monitoring by redundant essential sensors.

## 7.6 ALL OTHER SYSTEMS REQUIRED FOR SAFETY

### 7.6.1 Description

The following control systems are provided for station safety in addition to the Reactor Protection System and Safety Features Actuation system previously discussed in Sections 7.2 and 7.3. These controls are used to prevent overpressurization of low pressure systems, prohibit possible malfunctions in safety equipment, or to enable safety equipment to perform as designed.

#### 7.6.1.1 Normal Decay Heat Removal Valve Control System

##### 7.6.1.1.1 Design Bases

The design bases of the Normal Decay Heat Removal Valve Control System (in accordance with IEEE Standard 279-1971) are listed below:

1. Generating station conditions which require protective action:

   RC system pressure above the design pressure of the decay heat removal system.

2. Generating station variables that are required to be monitored in order to provide protective action:

   RC system pressure

3. Minimum number and location of sensors required to monitor adequately, for protective function purposes, those variables that have spatial dependence and diversity:

   One RC pressure switch located on RC loop one (1) is utilized to operate one isolation valve. The RC wide range pressure transmitter on RC loop two (2) is utilized to operate the other, redundant, isolation valve.

4. Prudent operational limits for each variable in each operation:

   The normal operational limit of the Decay Heat Removal System is 30-260 psig.

5. Margin between each operational limit and level marking onset of unsafe conditions:

   The Decay Heat Removal System is normally initiated when RC pressure is below 270 psig. The lowest design pressure rating of the Decay Heat Removal System piping is 300 psig. This provides a margin of 30 psi between the normal operational limit of 270 psig.

6. The level that when reached will require protective action:

   The normal decay heat removal valves will require closure when the reactor coolant pressure reaches the pressure stated in Subsection 7.6.1.1.2.

7. Range of transient and steady-state conditions of the energy supply and the environment during normal, abnormal and accident circumstances throughout which the system must perform:

   The range of the environment of the valves, pressure transmitter, and pressure switch varies from normal conditions of 40% relative humidity, atmospheric pressure and 120°F to 100% relative humidity, 38 psig and up to 284°F. The essential power supply is discussed in Chapter 8.

8. The malfunctions, accidents or other unusual events which could physically damage protection system components for which provisions must be incorporated to retain necessary protection system action:

   The normal decay heat removal valve control system is designed to withstand physical damage or loss of function caused by earthquakes and missiles. The control system is also located in a building area designed to protect the equipment from flood, lightning and wind. In addition, 480V AC power is removed from DH-11 and DH-12 when the valves are closed and the plant is in Mode 1, 2 or 3 to prevent inadvertent opening in case of fire. Control power is removed from DH 11 and DH 12 when the Decay Heat Removal system is in operation to prevent inadvertent closure during cooldown. This protects the suction of the Decay Heat Pumps.

9. Minimum performance requirements including system response times, system accuracies, ranges of the magnitudes and rates of change of sensed variables to be accommodated until proper conclusion of the protection system action:

   The response and accuracy of the signal comparator are discussed in Section 7.3. The valves and process instruments are capable of withstanding normal operating reactor coolant pressure of 2155 psig, transient operations causing pressure to go as high as 2350 psig, and anticipated accident pressure transient of 2500 psig.

#### 7.6.1.1.2 System Description

The design of the Decay Heat Removal system includes controls on each of the high-pressure motor operated valves in the suction line from the RC system. These independent and diverse controls are designed to prevent the valves from being opened when the RCS pressure is above the design pressure of the Decay Heat Removal System. DH-11 can not be opened until RCS pressure decreases below approximately 251 psig (referenced to RCS pressure tap at elevation 633') or approximately 281 psig referenced to the center line of the valve (elevation 599' 9"). DH-12 can not be opened until RCS pressure decreases below approximately 266 psig at the RCS pressure tap or approximately 296 psig at the centerline of the valve. The interlocks will also cause an automatic close signal to the valves when the interlocks reset on increasing RCS pressure. The setpoint of the resets are not significant. PSV-4849, the relief valve in the suction line, will terminate any overpressurization transient once the suction line valves have been opened.

In addition, interlocks are provided which trip the pressurizer heaters if the primary system reaches approximately 301 psig at the RCS pressure taps (elevation 633') and one or both of the suction line valves are not fully closed. However, as noted above, the relief valve in the

Decay Heat suction line should prevent RCS pressure from reaching this setpoint unless one of the suction line valves is closed.

The allowable value for the automatic closure on DH-11 and DH-12 is < 328 psig (referenced to the RCS pressure instrument tap) which is 34.8 psi higher than the setpoint of the decay heat removal suction line relief valve referenced to the same elevation.

Control power is removed from DH-11 and DH-12 when the Decay Heat Removal system is in operation to prevent inadvertent closure during cooldown. This protects the suction of the Decay Heat pumps. Power is removed from DH-11 and DH-12 after they are closed and the plant is in MODE 1, 2, or 3. This prevents inadvertent opening during plant operation, particularly in the case of fire. Power is only restored to the valves after RCS pressure has been reduced to below the interlock setpoint during cooldown.

The pressure interlock signal to DH-12 is derived from an RC pressure switch located in RC loop one (1). The interlock signal to DH-11 is derived from a signal comparator located in the SFAS cabinet. The signal comparator receives its RC pressure signal from the RC loop two (2) wide range RC pressure transmitter that supplies the signal to the SFAS. By using two different devices to sense RC pressure and provide the interlock signals, diversity is achieved in the system.

The decay heat valve interlocks do not have a manual bypass. Remote manual operation is prevented as long as the RC pressure is above the setpoint of the signal comparator and the pressure switch. Procedural guidance for overriding the interlocks has been provided if they interfere with a normal, controlled cooldown.

The pressurizer heater trip interlock signals are derived from the signal comparators located in the SFAS cabinets. The signal comparators receive their reactor coolant pressure signal from RC loop 1 or 2 wide range pressure signal from the RC loop 1 or 2 wide range pressure transmitter that supplies the signal for the corresponding SFAS cabinet.

The pressurizer heater trip interlocks are provided by means of relay logic on redundant essential relay cabinets. A separate output relay is provided for the essentially powered pressurizer heater control circuits and the non-essentially powered pressurizer heater control circuits, in each redundant “trip interlock logic.” A contact from the same signal comparator in the SFAS that provides the RC pressure closing signal to one DH valve is used in one “trip interlock logic” to indicate RC pressure above 301 psig at the RCS pressure instrument tap. A similar signal comparator is provided in a redundant SFAS channel for the other “trip interlock logic.” To provide limit switch contact to indicate that either valve is not fully closed into each redundant “trip interlock logic,” a stem-mounted limit switch is provided on both DH-11 and DH-12. Each stem-mounted switch is redundant to the limit switch provided in the motor operator. Thus all the necessary wiring into the “trip interlock logic” is completely separate and independent.

Valves DH-11 and DH-12 are ensured to be closed prior to raising RCS pressure as described above and they are also inside the CV. Therefore, the valves are not controlled by SFAS.

#### 7.6.1.1.3 Supporting Systems

The normal decay heat removal valve control system obtains control power from the essential power supply (Chapter 8).

#### 7.6.1.1.4 Portion of System Not Required for Safety

The alarms to the station annunciator and station computer are not required for safety.

#### 7.6.1.1.5 Drawings

Electrical schematic diagrams of the normal decay heat removal valve control system are shown in Figures 7.6-1, 7.6-2, 7.6-3, and 7.6-4.

### 7.6.1.2 Core Flooding Tank Isolation Valve Control System

A control system is provided to open the core flooding tanks injection isolation valves and prevent their closing when the RC pressure rises above a preset level. A complete description of the control system is given in Subsection 6.3.2.15.

### 7.6.1.3 Containment Spray Pump Anti-Cavitation Control System

#### 7.6.1.3.1 Design Basis

The design bases of the Containment Spray pump anti-cavitation control system (in accordance with IEEE Standard 279-1971) are listed below.

1. Generating station conditions which require protective action:

   The station condition which requires action is a safety features mode of operation and suction required from the CV Emergency Sump.

2. Range of transient and steady-state conditions of the energy supply and the environment during normal, abnormal, and accident circumstances throughout which the system must perform:

   The valve actuators are designed for temperatures of 60 to 120°F, 40 to 100% relative humidity and atmospheric pressure. The essential power supply is discussed in Chapter 8.

3. The malfunctions, accidents or other unusual events which could physically damage protection system components for which provisions must be incorporated to retain necessary protection system action:

   The Containment Spray pump anti-cavitation control system is designed to withstand physical damage or loss of function caused by earthquakes and located to prevent missile damage. The control system is also located in a building area designed to protect the equipment from flood, lightning and wind.

4. Minimum performance requirements including system response times, system accuracies, ranges of the magnitudes and rates of change of sensed variables to be accommodated until proper conclusion of the protection system action:

   The valves fully stroke in less than 35 seconds.

7.6.1.3.2 System Description

Controls are provided to automatically throttle the Containment Spray pumps discharge isolation valves when the pumps take suction from the CV Emergency Sump to prevent cavitation of the pumps due to lower NPSH from the CV Emergency Sump.

When 2-out-of-4 level sensors on the BWST sense low tank level, a permissive signal is provided to allow the manual opening of the CV Emergency Sump valves after blocking the SFAS incident level 2. The BWST outlet valve closes and the spray discharge valves throttle down when the sump valves open.

The spray discharge valves are part of the CV cooling systems and are controlled by the SFAS, which opens the valves during initial Engineered Safety Features operation.

Manual control of the valves is available from the Safety Features Actuation panel in the main control room.

7.6.1.3.3 Supporting Systems

The Containment Spray pump anti-cavitation Control system receives control power from the essential power supply (Chapter 8) and control signals from the SFAS (Section 7.3).

7.6.1.3.4 Portions of System not Required for Safety

Alarms to the station annunciator and station computer are not required for safety.

7.6.1.4 Deleted

7.6.2 Analysis

7.6.2.1 Normal Decay Heat Removal Valve Control System

7.6.2.1.1 IEEE Standards

1. IEEE Standard 279-1971

   The Normal Decay Heat Removal Valve Control System is designed to meet the intent of IEEE Standard 279-1971. The control circuits are designed such that any single failure will not prevent proper protective action (normal decay heat removal valve closure) when required. This is accomplished by using two completely redundant control systems, one for each normal decay heat removal valve. Each redundant control system receives control power from a separate essential supply. In order to prevent interaction between the redundant systems, the control channels are wired independently and separated with no electrical connections between control channels.

   Sections 4.11 through 4.15 of IEEE Standard 279-1971 are not considered applicable to this control system.

2. IEEE Standard 338-1971

   The Normal Decay Heat Removal Valve Control System includes provisions to permit testing the valves sequentially during normal station shutdown. No means to bypass the controls on these valves is provided.

7.6.2.1.2 AEC General Design Criteria

1. General Design Criterion 1

   The control system utilizes high quality components manufactured and tested in compliance with quality control procedures. The QA program is described in Chapter 17.

2. General Design Criterion 2

   The control system is designed to withstand damage or loss of function from earthquakes and is located in a building designed to protect the system from wind, flood and lightning.

3. General Design Criterion 3

   The control system is designed and constructed of materials to prevent propagation of fire.

4. General Design Criterion 4

   The control system is designed and located to prohibit damage or loss of function from missiles. Loss of both valve control systems, either of which serves to prevent overpressurizing the decay heat removal system, is considered incredible.

5. General Design Criterion 13

   Instrumentation to monitor the RCS pressure and the status of the normal decay heat removal valves is available in the main control room. Independent control for each valve is also available in the main control room for routine testing and manual operation (prior to the automatic closure control).

6. General Design Criterion 20

   The SFAS has been designed to automatically close the normal decay heat removal valves when the RC pressure exceeds the pressure stated in Subsection 7.6.1.1.2.

7. General Design Criterion 21

   The Normal Decay Heat Removal Valve Control System has been designed for high functional reliability commensurate with the safety functions to be performed. The redundancy and independence designed into the protection system are sufficient to ensure that no single failure results in loss of the protection function

and that removal from service of any component or channel does not result in loss of the required minimum redundancy.

8. General Design Criterion 22

   The Normal Decay Heat Removal Valve Control System has been designed to ensure that the effects of natural phenomena and of normal operating, maintenance, testing, and postulated accident conditions do not result in loss of the protection function. Diverse principles of operation in the form of manual as well as automatic control have been used to prevent loss of the protection function.

9. General Design Criterion 23

   The Normal Decay Heat Removal Valve Control System will fail into a state considered acceptable since failure of the signal to close one valve will not prevent an independent signal from closing the other valve. One closed valve is sufficient to ensure that the DH system will not be subjected to pressure in excess of design conditions.

10. General Design Criterion 24

    The automatic control system has been separated from the manual control system, to the extent that failure of any single manual control system component or channel, or failure or removal from service of any single automatic control system component or channel that is common to the manual and automatic control systems, leaves intact a system satisfying all reliability, redundancy, and independence requirements of the protection system. Interconnection of the automatic and manual control systems has been limited to ensure that safety is not significantly impaired.

#### 7.6.2.1.3 AEC Safety Guide 29

The Normal Decay Heat Removal Valve Control System is designed to withstand the effects of an earthquake without loss of function or physical damage. The control system is classified Seismic Class I in accordance with the guide.

### 7.6.2.2 Core Flooding Tank Isolation Valve Control System

#### 7.6.2.2.1 IEEE Standards

1. IEEE Standard 279-1971

   The Core Flooding Tank Isolation Valve Control System is designed to meet the intent of IEEE Standard 279-1971. The control circuits are designed such that any single failure will not prevent proper protective action (Core Flooding Tank isolation valve opening) when required. Both Core Flooding Tank isolation valves shall be full open before the reactor can go critical. This is accomplished by using two completely redundant control systems, one for each core flooding tank isolation valve. Each redundant control system receives control power from a separate essential supply. In order to prevent interaction between the redundant systems, the control channels are wired independently and separated with no electrical

connections between control channels. After the Core Flooding Tank isolation valves are fully open, the breaker of the combination line starter of each isolation valve will be manually tripped open and padlocked. The keys will be under administrative control. Sections 4.11 through 4.15 of IEEE Standard 279-1971 are not considered applicable to this control system.

2. IEEE Standard 338-1971

   The Core Flooding Tank isolation valve control system includes provisions to permit testing the valves during refueling. No means to bypass these valves is provided.

7.6.2.2.2 AEC General Design Criteria

1. General Design Criterion 1

   The control system utilizes high quality components manufactured and tested in compliance with quality control procedures. The QA program is described in Chapter 17.

2. General Design Criterion 2

   The control system is designed to withstand damage or loss of function from earthquakes and is located in a building designed to protect the system from wind, flood, and lightning.

3. General Design Criterion 3

   The control system is designed and constructed of materials to prevent propagation of fire.

4. General Design Criterion 4

   The control system is designed and located to prohibit damage or loss of function from missiles.

5. General Design Criterion 13

   Instrumentation to monitor the status of the Core Flooding Tank isolation valves and the RC system pressure is available in the main control room. Independent control for each valve is also available in the main control room (prior to automatic opening).

6. General Design Criterion 20

   The SFAS has been designed to automatically open the Core Flooding Tank isolation valves before the RC pressure exceeds 800 psig, to ensure that specified fuel design limits cannot be exceeded as a result of anticipated operational occurrences.

7. General Design Criterion 22

   The Core Flooding Tank isolation valve control system has been designed to ensure that the effects of natural phenomena and of normal operating, maintenance, testing, and postulated accident conditions do not result in loss of the protection function. Diverse principles of operation in the form of manual as well as automatic control have been used to prevent loss of the protection function.

7.6.2.2.3 AEC Safety Guides 22 and 29

1. Safety Guide 22

   The Core Flooding Tank isolation valve control system can be tested periodically during refueling.

2. Safety Guide 29

   The Core Flooding Tank Isolation Valve Control System is designed to withstand the effects of an earthquake without loss of function or physical damage. The control system is classified Seismic Class I in accordance with the guide.

7.6.2.3 Containment Spray Pump Anti-Cavitation Control System

7.6.2.3.1 IEEE Standards

1. IEEE Standard 279-1971

   The Containment Spray Pump Anti-Cavitation Control System is designed to meet the intent of IEEE Standard 279-1971. The control circuits are designed such that any single failure will not prevent proper protective action (spray isolation valve throttling) when required. This is accomplished by using two completely redundant control systems, one for each containment spray isolation valve. Each redundant control system receives control power from a separate essential supply. In order to prevent interaction between the redundant systems, the control channels are wired independently and separated with no electrical connections between control channels.

   Sections 4.11 through 4.15 of IEEE-Standard 279-1971 are not considered applicable to this control system.

2. IEEE Standard 338-1971

   The Containment Spray Pump Anti-Cavitation Control System includes provisions to permit testing the valves sequentially during normal station operation. Testing will be done in such a manner as not to inject spray into the CV or to jeopardize station safety.

#### 7.6.2.3.2 AEC General Design Criteria

1. General Design Criterion 1

   The control system utilizes high quality components manufactured and tested in compliance with quality control procedures. The QA program is discussed in Chapter 17.

2. General Design Criterion 2

   The control system is designed to withstand damage or loss of function from earthquakes and is located in a building designed to protect the system from wind, flood and lightning.

3. General Design Criterion 3

   The control system is designed and constructed of materials to prevent propagation of fire.

4. General Design Criterion 4

   The control system is designed and located to prohibit damage or loss of function from missiles. Loss of both Containment Spray Systems, either of which is adequate for safety, is considered incredible.

5. General Design Criterion 13

   Instrumentation to monitor the status of the Containment Spray isolation valves and the CV Emergency Sump valves is available in the main control room. Independent control for each spray system including valves is available also in the main control room.

6. General Design Criterion 20

   The Containment Spray Pump Anti-Cavitation Control System has been designed to automatically throttle the Containment Spray pumps discharge valves when the pumps take suction from the CV Emergency Sump to prevent cavitation and subsequent loss of the pumps due to lower NPSH from the CV Emergency Sump.

7. General Design Criterion 21

   The Containment Spray Pump Anti-Cavitation Control System has been designed for high functional reliability and inservice testability commensurate with the safety functions to be performed. The redundance and independence designed into the protection system are sufficient to ensure that no single failure results in loss of the protection function and that removal from service of any component or channel does not result in loss of the required minimum redundancy. The protection system has been designed to permit periodic testing of its functioning when the reactor is in operation, including the capability to detect any loss of redundancy that may have occurred.

8. General Design Criterion 22

   The Containment Spray Pump Anti-Cavitation Control System has been designed to ensure that the effects of natural phenomena and of normal operating, maintenance, testing, and postulated accident conditions do not result in loss of the protection function. Diverse principles of operation in the form of manual as well as automatic control have been used to prevent loss of the protection function.

9. General Design Criterion 23

   The Containment Spray Pump Anti-Cavitation Control System, responsible for throttling a Containment Spray pump discharge valve, will fail into a state considered acceptable since failure of the signal to throttle one valve will not prevent an independent signal from throttling the other valve. One pump in conjunction with its throttled discharge valve in addition to one containment air cooler fan will provide sufficient containment atmosphere cooling capability.

10. General Design Criterion 24

   The automatic control system has been separated from the manual control system to the extent that failure of any single manual control system component or channel, or failure or removal from service of any single automatic control system component or channel that is common to the manual and automatic control systems, leaves intact a system satisfying all reliability, redundancy, and independence requirements of the protection system. Interconnection of the automatic and manual control systems has been limited to ensure that safety is not significantly impaired.

7.6.2.3.3 AEC Safety Guides 22 and 29

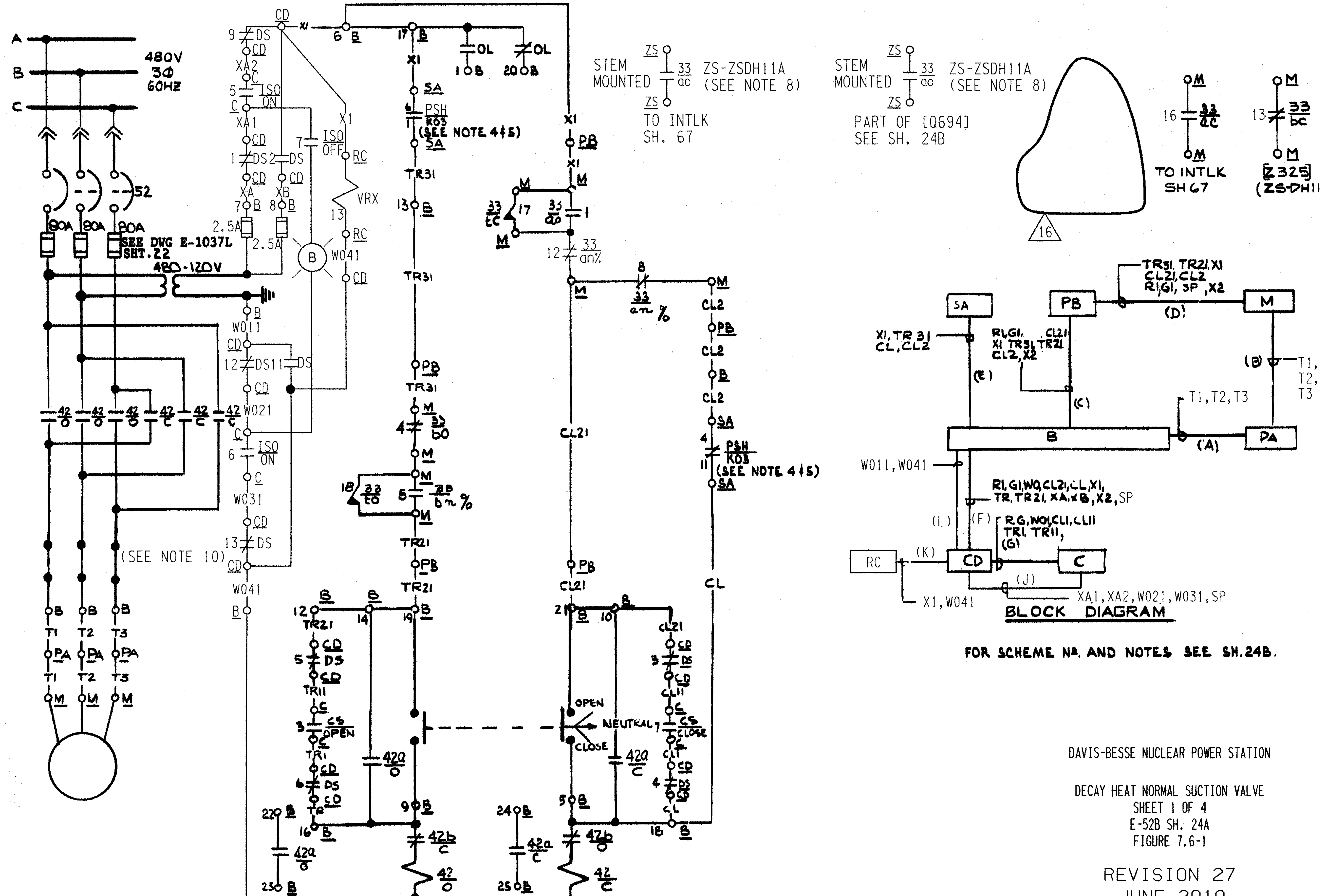
1. Safety Guide 22

   The Containment Spray Pump Anti-Cavitation Control System can be tested periodically during station operation.

2. Safety Guide 29

   The Containment Spray Pump Anti-Cavitation Control System is designed to withstand the effects of an earthquake without loss of function or physical damage. The control system is classified Seismic Class I in accordance with the guide.

7.6.2.4 Deleted



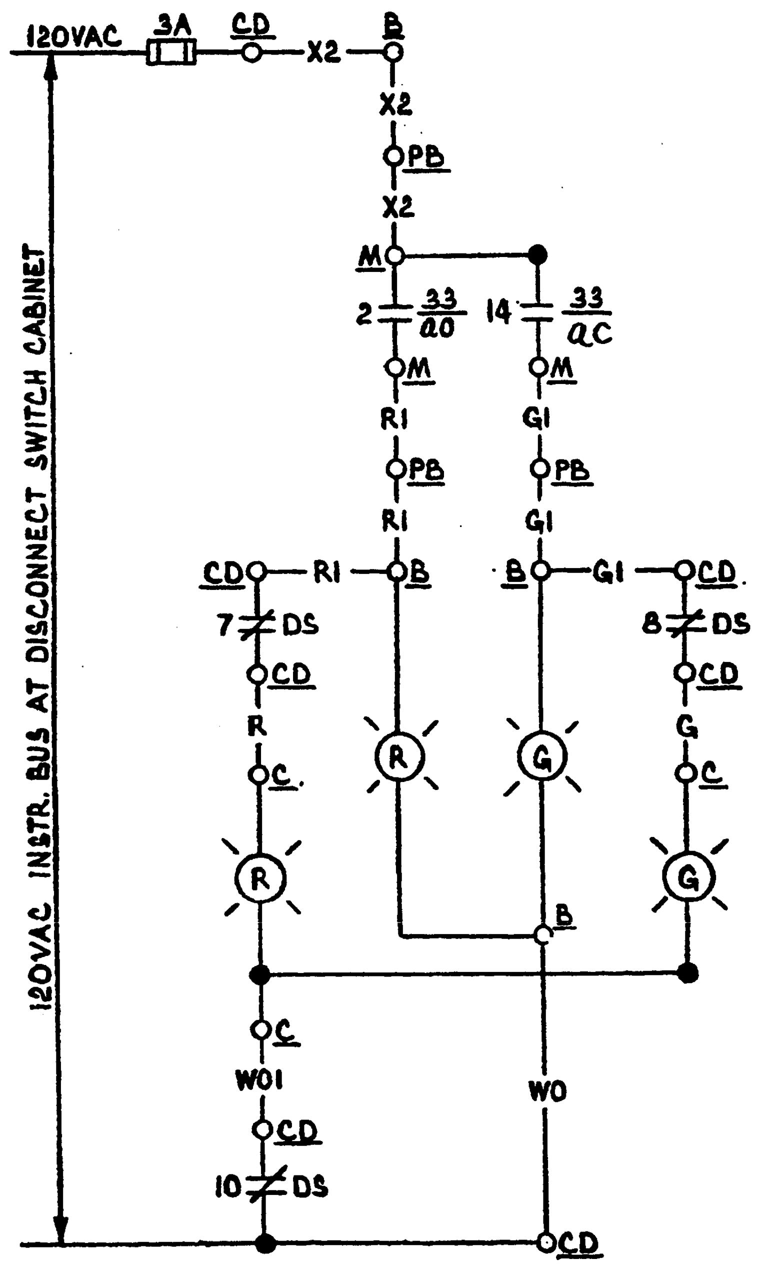

FOR SCHEME No. AND NOTES SEE SH. 24B.

DAVIS-BESSE NUCLEAR POWER STATION

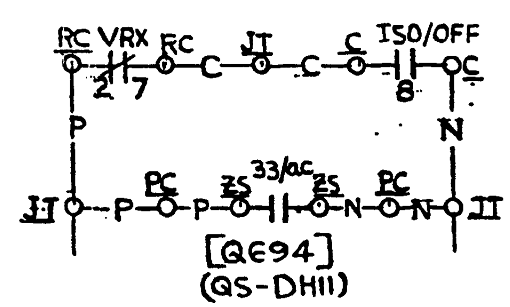
DECAY HEAT NORMAL SUCTION VALVE
SHEET 1 OF 4
E-52B SH. 24A
FIGURE 7.6-1

REVISION 27
JUNE 2010

| SCHEME | MCC | S.U. NO | CHANNEL | WIRE PREFIX | CS | EQUIPMENT NUMBERS | | | | | | | | PSH | ISO | DESCRIPTION |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | C | CD | B | M | PA | PB | SA | RC | | | |
| BF1130 | F11A | 49 | 2 | DSA | HISDH110 | C5704 | CDF11A-1 | BF1130 | MVDH110 | P2P5F | P2C5G | C5756D | RC3702 | PSH7531A | HISDH11A | DH NORMAL SUCT LINE VLV |




RC-RC3702 ZS-ZSDH11A
C - C5704
PC - PAC3E
JT - JT3702




**NOTES**

1. FOR GENERAL NOTES SEE DWG INDEX E52B
2. FOR SWITCH DETAILS SEE DWG E30B SH7 FIG7.
3. FOR VALVE LIMIT SWITCH DEVELOPMENT SEE DWG. E30B SH. 8A FIG.C (SEE NOTE 11 THIS SHEET) 13
4. PSH/K05 SHOWN AT HIGH REACTOR COOLANT PRESSURE OR LOSS OF POWER AT SFAS CABINET C5756D
5. FOR SA SCHEMATIC SEE DWG. 7749-E-30-27
6. DELETED
7. DELETED
8. ZS IS A STEM-MOUNTED LIMIT SWITCH.
9. FOR DETAILS OF ISOLATION SWITCH & BLUE INDICATOR LIGHT. SEE DWG E-30B SH 17 FIG. 1
10. OVERLOAD HEATER: REPLACED BY SHORTING BAR.
11. FIELD TO ADJUST ROTOR #2 WITH SWITCH CONTACTS 5 THRU 8 TO ACTUATE WHEN VALVE REACHES 20%. $^{+5}_{-0}$ %
12. FIELD TO ADJUST ROTOR #4 SO THAT LIMIT SWITCH CONTACTS 14, 15, 16 CLOSE AND LIMIT SWITCH CONTACT 13 OPENS WHEN THE VALVE IS FULLY CLOSED.
13. FIELD TO ADJUST ROTOR #3 SUCH THAT CONTACT 12 WILL PROVIDE SPECIFIED TARGET THRUST ON SEATING. 13

DAVIS-BESSE NUCLEAR POWER STATION

DECAY HEAT NORMAL SUCTION VALVE
SHEET 2 OF 4

E52B SH. 24B

FIGURE 7.6-2

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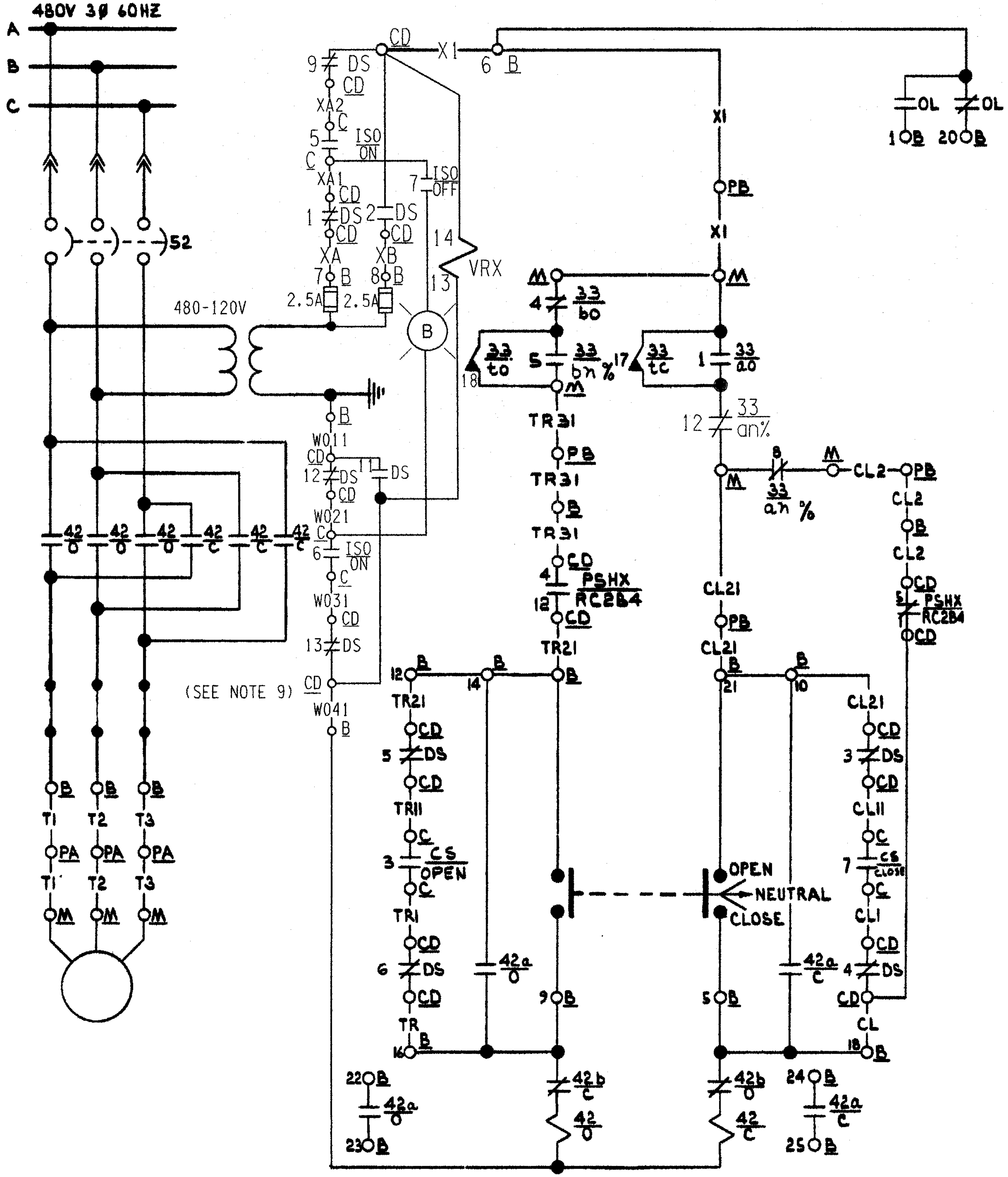
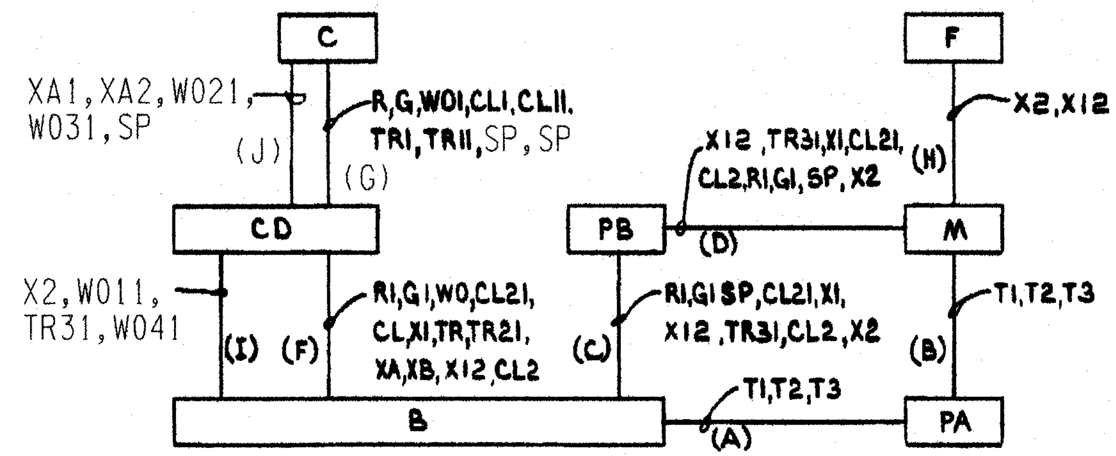
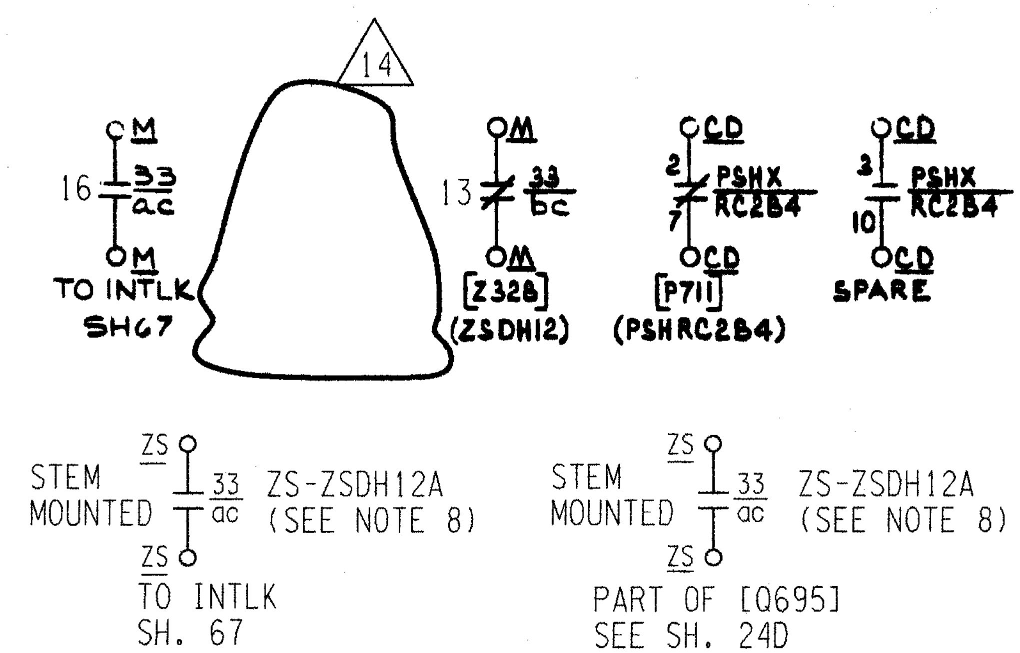



FOR SCHEME NO. & NOTES SEE SHEET 24D




DAVIS-BESSE NUCLEAR POWER STATION

DECAY HEAT NORMAL SUCTION VALVE
SHEET 3 OF 4
E-52B SH. 24c
FIGURE 7.6-3

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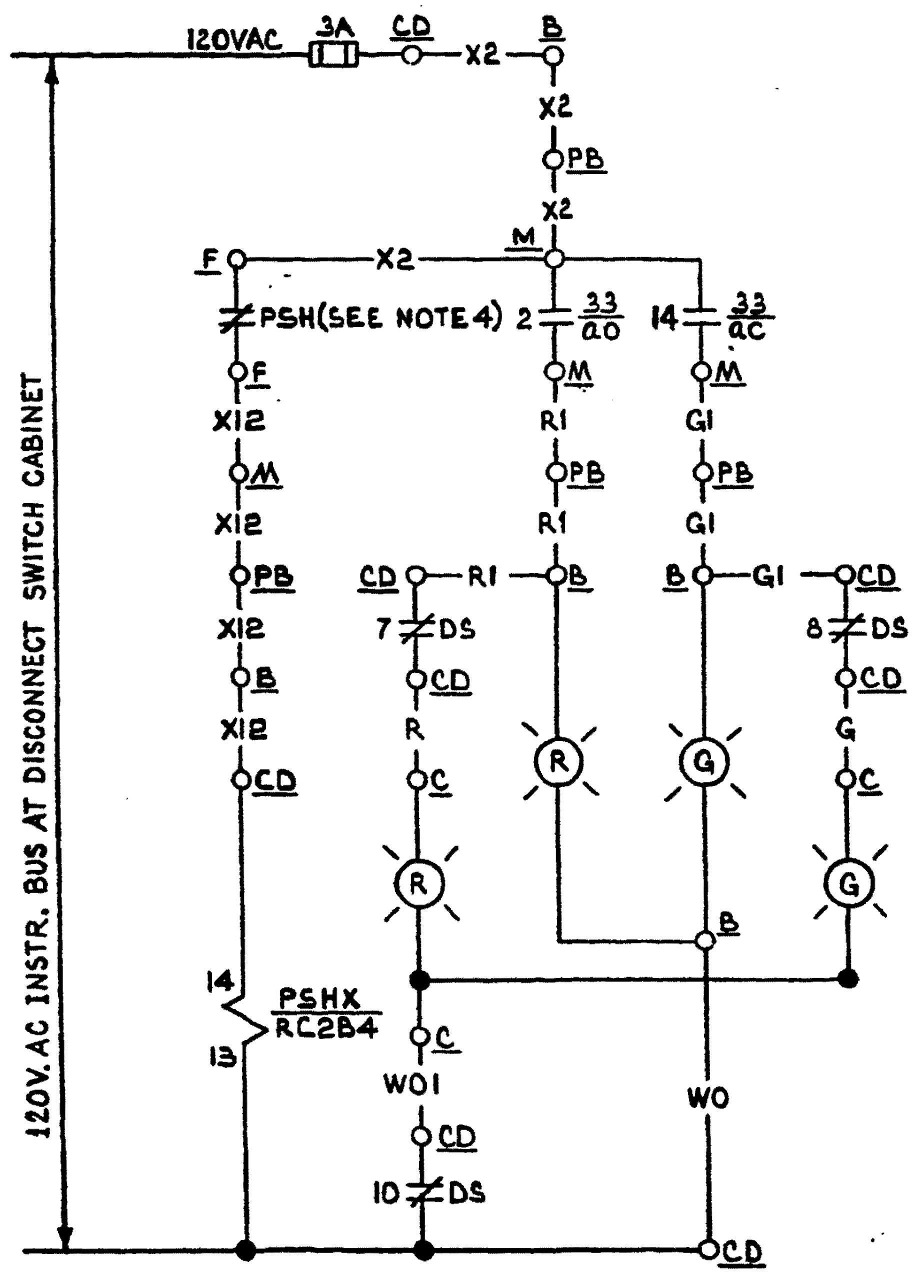
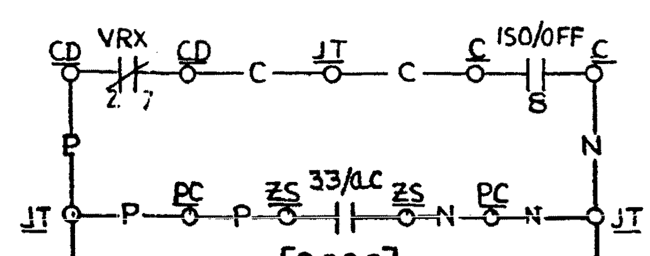
JUNE 2010

DB 04-15-10 DFN=J/RASDGN/E52BSH24C.DGN/CIT

| SCHEME No. | MCC | S.U. No. | CHANNEL | WIRE PREFIX | CS | EQUIPMENT NUMBERS | | | | | | | ISO | DESCRIPTION |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | C | CD | B | M | PA | PB | F | | |
| BE1183 | E11B | 49 | 1 | DSB | HISDH120 | C5704 | CDE11B-2 | BE1183 | MVDH120 | PIP2M | PIC2L | PSHRC2B4 | HISDH12A | DH. NORMAL SUCTION LINE VALVE |




CD-CDE11B-2
C-C5704
ZS-ZSDH12A
JT-JT3701
PC-PBC2D




[Q695]
(QS-DH12)

NOTES:

1. FOR GENERAL NOTES SEE DWG. INDEX E52B.
2. FOR SWITCH DETAILS SEE DWG. E30B, SH.7, FIG.7
3. FOR VALVE LIMIT SW. DEVELOPMENT SEE DWG. E30B. SH. 8A FIG. C (SEE NOTE 10 THIS SHEET).
4. PSH SHOWN AT LOW REACTOR COOLANT PRESSURE.
5. DELETED
6. DELETED
7. ZS IS A STEM-MOUNTED LIMIT SWITCH.
8. FOR DETAILS OF ISOLATION SWITCH AND BLUE INDICATOR LIGHT SEE DWG. E-30B SH.17, FIG.1.
9. OVERLOAD HEATERS REPLACED BY SHORTING BARS.
10. FIELD TO ADJUST ROTOR #2 WITH SWITCH CONTACTS 5 THRU 8 TO ACTUATE WHEN VALVE REACHES 20% OPEN +5%/-0%.
11. FIELD TO ADJUST ROTOR #4 SO THAT SWITCH CONTACTS 14,15,16 CLOSE AND SWITCH CONTACT 13 OPENS WHEN THE VALVE IS FULLY CLOSED.
12. FIELD TO ADJUST ROTOR #3 SUCH THAT CONTACT 12 WILL PROVIDE SPECIFIED TARGET THRUST ON SEATING

9

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DECAY HEAT NORMAL SUCTION VALVE
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FIGURE 7.6-4

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# 7.7 CONTROL SYSTEMS

## 7.7.1 Description

### 7.7.1.1 Non-Nuclear Instrumentation (NNI) Station Control Systems

Instrumentation and control systems, the functions of which are not essential to station safety are:

1. Automatic RC Pressure Control - The pressurizer heaters are grouped into banks which are energized automatically when the RC pressure drops below setpoint values. The first bank utilizes proportional control through an SCR controller. During normal steady state operation, this bank varies with RC pressure to compensate for pressurizer spray operation. There is also an Auto plus Base Load position on the number two non-essential heater bank designed to replace ambient heat losses. The remaining banks of pressurizer heaters are automatically controlled by bistable relays in the pressure control instrument, which energize each bank progressively, on decreasing pressure setpoints. Each bank also has manual controls.

   Pressurizer spray is controlled by a motor operated valve which is opened or shut by a bistable relay in the instrument string monitoring RC pressure.

   The pilot operated relief valve is controlled by an on-off signal from an electronic pressure switch. The valve is opened when the pressurizer pressure exceeds the high pressure setpoint, and is closed when the pressure is reduced.

   On a loss of NNI power, the pressurizer heaters, pressurizer spray valve, and PORV will not function in Automatic. They can, however, be controlled manually with their respective hand switches.

2. Automatic Pressurizer Level Control - The pressurizer level signal for level control is manually selected from one of three differential pressure transmitters and is temperature compensated. This level signal is recorded, used for high and low alarms, interlocks to prevent energizing pressurizer heaters in automatic with a low pressurizer level, and supplies a level control signal. The level controller automatically positions the makeup control valve in the Makeup and Purification System (see Chapter 9) to maintain a preset pressurizer level selected by the operator in the control room.

3. Makeup System Feed and Bleed Control - The batch controller is used to add a preset amount of borated water to the RC system (refer to Subsection 7.7.1.2.6). The batch controller receives an electrical signal from the borated water feed flow transmitter. The batch controller automatically closes the feed control valve when the batch sizer shutdown point is reached. The batch size is adjustable. The feed control valve can be manually controlled. On a loss of NNI power, the valves require local, manual control.

#### 7.7.1.1.1 Comparison of NNI Control Systems with Those of Another Station

The initial design of the NNI control systems for the Davis-Besse Nuclear Power station were essentially the same as those for the Sacramento Municipal Utility District, Rancho Seco station.

#### 7.7.1.1.2 Major Design Criteria

Refer to Section 7.12.

### 7.7.1.2 Integrated Control System (ICS)

The ICS provides the proper coordination of the reactor, steam generator feedwater control, and turbine under all operating conditions. Proper coordination consists of producing the best load response to the unit load demand while recognizing the capabilities and limitations of the reactor, steam generator feedwater system, and turbine. When any single portion of the station is at an operating limit or a control section is on manual, the integrated control system uses the limited or manual section as a load reference. The ICS maintains the control consistent with current operating conditions of the unit by operation in the following modes.

1. “Integrated reactor-steam generator-turbine mode” for normal conditions.
2. “Turbine following mode” if the capabilities of the reactor or steam generator feedwater systems are limited.
3. “Reactor-steam generator following mode” if the capability of the turbine-generator system is limited.

The ICS maintains constant average RC temperature between low level limits and 100% rated power and constant steam pressure at all loads. Optimum unit performance is maintained by limiting steam pressure variations; by limiting the unbalance between the steam generator, turbine, and the reactor; and by limiting the total unit load demand upon loss of capability of the steam generator feed system, the reactor, or the turbine generator. The control system provides limiting actions to assure proper relationships between the generated load, turbine valves, feedwater flow, and reactor power. The normal response of the RC system and the feedwater system to increasing and decreasing power transients is limited by the ICS.

The combined actions of the control system and the turbine bypass to the condenser permits a 40% load rejection without code safety valve operation. The combined actions of the control system, the turbine bypass to the condenser and the code safety valves are designed to permit a 100% load rejection without reactor trip. A reactor trip may occur on a loss of load at high power due to the addition of the Anticipatory Reactor Trip System (ARTS) and the raising of the Pilot Operated Relief Valve (PORV) setpoint. See Section 15.2.7.3.

Table 7.7-2 lists all of the functions of the ICS and the applicable subsystem which accomplishes the action. These functions increase station reliability but are not required for safe operation of the station. As explained in Chapter 15, the safety analysis assumes no credit for any ICS function which might be available to prevent or mitigate the consequences of an accident.

#### 7.7.1.2.1 General Description

The ICS includes four independent subsystems as shown in Figure 7.7-1: (1) The Unit Load Demand Control, (2) the Integrated Master Control, (3) the Steam Generator Control and (4) the Reactor Control. The system philosophy is that control of the station is achieved through feedforward control from the unit load demand control. The Unit Load Demand Control produces demands for parallel control of the turbine, reactor, and steam generator feedwater system through respective subsystems. The boron feed and bleed controller, a subsystem of the reactor control, exercises permissive control of continuous feed and bleed operation of the makeup and purification system.

The Integrated Master Control is capable of automatic or manual turbine load to full output, and of manual control below minimum turbine load.

The steam generator control is capable of automatic or manual feedwater control from startup to full power output. The reactor control is designed for automatic or manual operation above the low level limit, and for manual operation below the low level limit.

The basic function of the ICS is matching megawatt generation to unit load demand. The ICS does this by coordinating the steam demand required by the turbine with the rate of steam generation. To accomplish this efficiently, the following basic reactor/steam-generator requirements are satisfied:

1. Feedwater flow to the steam generators is normally balanced as required to obtain desired steam conditions. Feedwater flow to the steam generators may be ratioed provided the flowrate to each steam generator is less than the limit to preclude flow induced vibrations of the steam generator tubes or the design limit, whichever is more restrictive. A cycle specific evaluation must be completed to evaluate the flowrate limit prior to ratioing the feedwater flow to each steam generator.

2. Feedwater flow is controlled:

    a. To compensate for changes in fluid and energy inventory requirements at each power level.

    b. To compensate for temporary deviations in feedwater temperature resulting from load change, feedwater heating system upsets or final steam pressure changes.

#### 7.7.1.2.2 Unit Load Demand Control

The Unit Load Demand (ULD) is designed to accomplish two objectives related to the operation of the station.

First, the ULD permits the operator to manually establish power output of the station and allow for automatic operation of the unit at the specified setting; and secondly, the ULD initiates load limiting and runback functions to restrict operation within prescribed limits. Figure 7.7-2 illustrates the functions incorporated in the subsystem.

In manual operation, the ULD obtains a load demand signal from the operator. In automatic operation, the ULD obtains a Core Thermal Power (CTP) demand signal from the operator. The

demand is compared against the ULD calculated CTP, and the error is processed by Proportional-Integral (PI) control, which provides the load demand. The load demand is restrained by a maximum load limiter, a minimum load limiter, and a rate limiter.

Rate limiting is designed as a function of load, so normal transients are limited as shown below:

1. Loss of any number of RC pumps; runback at 20% per minute to the power corresponding to the remaining pumping capability.

2. Deleted

3. Loss of one main feedwater pump; runback at 20% per minute to within the remaining pump capability.

4. Low deaerator level; runback at 20% per minute to 55% of rated thermal power.

5. High main feed pump discharge pressure; runback at 20% per minute to 60% of rated thermal power.

The controlling subsystem of the ICS (turbine control, steam generator feedwater control and reactor control) normally operate in the automatic mode in response to a demand signal from the ULD. The subsystems control function is kept within pre-established bounds under other than normal automatic operation by a "load tracking" mode. The system will switch to the load tracking mode if any of the conditions listed in Table 7.7-2, Item 2, exist.

In the load tracking mode, the load demand is made to follow the manual or limited control subsystem by using the actual generator output as the demand input to the ULD. Load tracking continues until the limiting condition is brought back to within the pre-established deadband or the subsystem is returned to automatic operation.

The output of the limiter is a megawatt demand signal which is forwarded to the integrated master control subsystem.

#### 7.7.1.2.3 Integrated Master Control

The Integrated Master Control has been designed to receive the megawatt demand signal from the Unit Load Demand subsystem and convert this signal into a demand for the feedwater, turbine, and reactor control. A functional diagram of the Integrated Master Control is shown in Figure 7.7-3. For turbine control, the megawatt demand is compared with the generator megawatt output, and the resulting megawatt error signal is used to change the steam pressure setpoint. The turbine valves then change position to control steam pressure. As the megawatt error reduces to zero, the steam pressure setpoint is returned to the steady state value. By limiting the effect of megawatt error on the steam pressure set point, the system can adjust steam pressure to achieve the desired rate of turbine response to megawatt demand.

The megawatt demand is also utilized as the feedforward demand to the steam generator and reactor while operating in the integrated control mode. This demand is compensated by deviations in the steam header pressure from its setpoint. The pressure error increases the steam generator and reactor demands if the pressure is low. It decreases the steam generator and reactor demands if the pressure is high. The control signal to the steam generator subsystem is feedwater demand and the control signal to the reactor is megawatt demand.

The Turbine Bypass System operates from the main steam header pressure error or individual steam generator pressures as an overpressure relief for the turbine header. The Turbine Bypass System will bypass 25% of steam flow to the condenser or vent ~10% of steam flow to the atmosphere via atmospheric vent valves. Normal bypass is to the condenser for startup, shutdown, or load changes. The bypass control prevents operation of the turbine bypass valves when the condenser is not available and switches the control to the atmospheric vent valves.

7.7.1.2.4 Steam Generator Control

Control of the steam generator is based on matching feedwater flow to the feedwater demand produced in the Integrated Master Control. Figure 7.7-4 illustrates the steam generator feedwater controls.

The basic control actions for parallel steam generator operation are as follows:

1. Unit load demand, modified by megawatt error and turbine header pressure error, is converted to a total feedwater demand.

2. Total feedwater flow demand split into feedwater flow demand for each steam generator.

3. Feedwater demand compared to feedwater flow for each steam generator. The resulting error signals position the feedwater flow control system to match feedwater flow to feedwater demand for each steam generator.

For operation below the low level limit, the Steam Generator Control System acts to maintain a preset minimum downcomer water level in the steam generator. The conversion to level control is automatic and is introduced into the feedwater control train through an auctioneer. At electrical loads below the low level limit turbine bypass valves will operate to control steam pressure rise.

The steam generator control also provides ratio, limit, and runback actions as shown in Figure 7.7-4 which include:

1. Steam Generator Load Ratio Control - Under normal conditions the steam generators will each produce one-half of the total load. Steam generator load ratio control is provided to balance RC inlet temperature during operation with unbalanced RC loop flow to minimize undesirable core power distribution.

2. High Level Limits - A maximum water level limit prevents flooding of the steam generator aspirating ports.

3. A low level limit is provided to ensure a minimum water level in the downcomer section.

4. RC Flow Limits - Upon transition from 4 to 3 RCP operation, primary flow rates begin to shift towards 104% in the primary loop with two operating RCP's, and towards 46% flow in the loop with one RCP. The FW ratio circuits will immediately ratio feedwater demands based on the difference in measured RC flows.

5. Deleted

6. Feedwater demand is cross limited to the reactor neutron error. If the neutron error is outside a (-5% to +10%) deadband, the feedwater demand is modified to more closely follow neutron flux.

7. Deleted

8. Deleted

9. Feedwater Valve Control - Valve position demand for each steam generator is applied to both the startup and the main feedwater valves, through control stations. These valves are sequenced into operation so that the startup valve opens first (from zero to 15% load) followed by the main feedwater valve.

10. Main Feedpump Control - Main feedpump speed is controlled to maintain a constant differential pressure drop across the feedwater valves.

7.7.1.2.5 Reactor Control

The ICS Reactor Control is designed to maintain a constant average RC temperature over the load range from the low level limit to 100% of rated power. The average RC temperature decreases over the range from approximately 28% to zero load. Figure 5.5-6 shows the RC and steam temperatures over the entire load range.

The ICS Reactor Control consists of analog computing equipment with inputs of megawatt demand, core power, and RC average temperature. The output of the controller is an error signal that causes the control rod drive to be positioned until the error signal is within a deadband. A block diagram of the reactor control is shown on Figure 7.7-6.

First, reactor power demand ($N_d$) is computed as a function of the megawatt demand ($MW_d$) and the RC system average temperature deviation ($\Delta T$) from the setpoint, according to the following equation:

$$N_d = K_1\ MW_d + K_2\left(\overline{\Delta T} + \frac{1}{\tau}\ \overline{\Delta T}\ dt\right).$$

Megawatt demand is introduced as a part of the demand signal through a proportional unit having an adjustable gain factor ($K_1$). The temperature deviation is introduced as a part of the demand signal after proportional plus reset (integral) action is applied. For the temperature deviation, ($K_2$) is the adjustable gain and $\tau$ is the adjustable integration factor.

The reactor power level demand ($N_d$) is then compared with the reactor power level ($N_i$), which is derived from the nuclear instrumentation. The resultant error signal, ($N_d$ - $N_i$) is the reactor power level error signal ($E_n$).

When the reactor power level error signal ($E_n$) exceeds the deadband settings, the CRDCS receives commands that withdraw or insert control rods depending upon the polarity of the power error signal.

The following additional features are provided with the reactor power controller:

1. A high limit on reactor power level demand ($N_d$).

2. A low limit on reactor power level demand (Nd).

The ICS Reactor Control incorporates automatic or manual rod control above the low level limit of rated power and manual ICS reactor control below low level limits.

The reactor control subsystem also generates the following interlock signals:

1. A signal to the CRDCS to prevent placing the rod drive controls in the automatic mode if a large error (En) exists in the ICS.

2. A signal to the CRDCS to cause the rod drive controls to revert to the manual mode if power for automatic operation of the ICS is lost.

3. A signal to the CRDCS indicating that reactor power is greater than 60% which is used to generate the “Out Inhibit” signal.

4. A signal to the RC pump motor controls which prevents starting an idle pump when reactor power is greater than 60%. This pump interlock system, although useful in preventing a cold water accident, is not necessary for reactor protection and does not meet safety feature criteria (Subsection 15.2.6).

7.7.1.2.6 Boron Feed and Bleed Control

The boron feed and bleed controller is made up of digital logic from rod position. The outputs from the controller is a permissive signal to Makeup and Purification System to allow continuous feed-and-bleed.

The controller allows continuous feed-and-bleed when control rod groups 1, 2, 3 and 4 are 100% withdrawn and control rod group 5 is greater than 25% withdrawn. The controller will terminate feed-and-bleed if any safety group is not 100% withdrawn and/or control rod group 5 is not greater than 25% withdrawn.

7.7.1.2.7 System Failure Considerations

Redundant sensors for major system parameters are available to the ICS. The operator can select any of the redundant sensors from the control room.

There are Smart Analog Selector Switches (SASS) designed to monitor for failed parameter signals. The SASS modules monitor:

- Feedwater Flow (both loops)
- OTSG Pressure (both loops)
- Feedwater Temperature
- Feedwater Valve Delta P (both loops)
- OTSG Operate Level (both loops)
- OTSG Startup Level (both loops)
- Turbine Throttle Pressure

- RC Hot Leg Temperature (both loops)
- RC Cold Leg Temperature (both loops)
- Loop Delta T Cold
- RC Average Temperature
- Megawatt Electric

The SASS modules are normally selected to the NNI-X powered instrument and will automatically transfer to the NNI-Y instrument if the X fails.

Redundant process inputs are utilized in the Core Thermal Power (CTP) calculation derived in the ULD subsystem of the ICS. The CTP algorithm monitors the input process variables for quality, and selects a redundant input in the event that an out-of-range input is found.

Manual reactivity control is available at all power levels. Redundant power supplies are provided in the event of an electric power failure.

7.7.1.2.8 System Limits

Maximum and minimum limits on the reactor power level demand signal (Nd) prevent the automatic reactor controls from initiating undesired power excursions.

Maximum and minimum levels on the megawatt demand signal (MWd) prevent the unit load demand controls from initiating undesired power excursions.

Cross limiting between the steam generators and the reactor minimize the effects of undercooling and overcooling transients.

7.7.1.2.9 Modes of Control

The ICS is designed to revert to a “load tracking” mode of control to tie the unit to the subsystem on manual or to the subsystem being limited. In the track mode, the operator demand for MWe is replaced by the actual electrical generation of the power plant.

In startup control mode, the controls are arranged so that the steam system follows reactor power rather than turbine system power demand.

The controls will transfer steam line pressure control from the turbine bypass valves to the atmospheric vent valves on inadequate condenser vacuum or when either MSIV is less than 90% open.

7.7.1.2.10 Loss-of-Load Considerations

The nuclear unit is designed to accept 10% step load rejection without safety valve or turbine bypass valve action. The combined actions of the control system, and the turbine bypass to the condenser permit a 40% load rejection without code safety valve action. The controls will limit steam bypass to the condenser when condenser vacuum is inadequate.

The features that permit continued operation under load rejection conditions include the following:

1. ICS - During normal operation the ICS controls the unit load in response to load demand from the operator. During normal load changes and small frequency changes, turbine control is through the speed changer to maintain constant steam pressure.

2. 100% Relief Capacity in the Steam System - This provision acts to reduce the effect of large load drops on the reactor system.

   Consider, for example, a sudden load rejection greater than 10%. When the turbine generator starts accelerating, the governor valves and the intercept valves begin closure to maintain set frequency. At the same time the megawatt demand signal is required, which reduces the governor speed changer setting, feedwater flow demand, and reactor power level demand. As the governor valves close, the steam pressure rises and acts through the control system to reinforce the feedwater flow demand reduction already initiated by the reduced megawatt demand signal. In addition, when the load rejection is of sufficient magnitude, the turbine bypass valves open to reject excess steam to the condenser and safety valves open to exhaust steam to the atmosphere. The rise in steam pressure and the reduction in feedwater flow cause the average reactor coolant temperature to rise which reinforces the reactor power level demand reduction, already established by reduced megawatt demand, to restore RC temperature to the set value. A reactor trip may occur on a loss of load at high power due to the addition of the Anticipatory Reactor Trip System (ARTS) and the raising of the Pilot Operated Relief Valve (PORV) setpoint. See Section 15.2.7.3.

7.7.1.2.11 System Design Comparison

The initial design of the ICS for Toledo Edison Company's, Davis-Besse Nuclear Power Station is compared to the Sacramento Municipal Utility District Rancho Seco Station in FSAR Section 7.7.1.2.11.

7.7.1.3 CRDCS - Without Trip Portion

7.7.1.3.1 General

The CRDCS provides for withdrawal and insertion of groups of control rod assemblies (CRAs) to produce the desired reactor power output. These functions are achieved through CRDCS automatic control by the ICS, or, through CRDCS manual control by the operator. The controls provide shut down capability and compensate for short-term reactivity changes by positioning the 53 regulating CRA's and the 8 axial power-shaping rod (APSR) assemblies. The 53 CRA's are arranged in seven groups: four rod groups function as safety groups and three rod groups function as regulating rod groups. Each of the seven groups may be assigned from 4 to 12 rods.

The CRDCS utilizes triple modular redundant (TMR) processing of inputs, outputs, and commands. This results in making the CRDCS control logic hardware single failure proof. The TMR scheme within processor hardware is used to achieve internal redundancy on all critical circuits. There are three identical slices in each processor module that perform identical functions simultaneously and independently. The processor output of each slice is voted in a majority voting circuit to provide the processor output.

There are two independent processor controllers in the CRDCS. Processor 1 (P1) and Processor 2 (P2). Both processors work in parallel with one another while performing separate tasks. Processor P1 is responsible for critical logic tasks as well as monitoring for IN and OUT limits, receiving input from the Operator Control Panel (OCP) and other plant systems. Processor P1 also controls the rod power supply Pulse Generator / Monitor (PG/M) modules for developing SCR gating signals, rod power monitoring and development of the Relative Position Indication (RPI) information. Processor P2 is responsible for monitoring Absolute Position Indication (API) information, zone reference switches and AC input voltage acceptability.

To increase the fault tolerance, the processor modules are configured such that both P1 and P2 operate with a primary module and also have a backup standby module located in its adjacent slot. The standby processor module will automatically perform all controls and communication functions should the primary module's self-diagnostics determine that a transfer to the standby processor is necessary.

The speed of the drive mechanism and the worth of the rod group provide the reactivity change rates required. Each CRDM has an inherent speed-limiting feature that is accomplished through the use of the CRDCS Pulse Generator / Monitor modules which each contain a quartz crystal controlled clock. Thus, the speed of rod motion is fixed, and the rod group size is the only CRDCS parameter that modifies the reactivity addition rate.

The rod grouping capability is for flexibility in meeting any possible configuration dictated by fuel cycle and maneuverability considerations. Control rods are arranged into groups within the CRDCS controller programming. Typically, 28 rods might be assigned to the regulating groups, and 25 rods assigned to the safety groups.

A typical rod grouping arrangement might be as follows:

| Safety group/rods | Regulating group/rods | Axial power-shaping group/rods |
|---|---|---|
| Group 1/4 | Group 5/12 | Group 8/8 |
| Group 2/8 | Group 6/8 | |
| Group 3/4 | Group 7/8 | |
| Group 4/9 | | |

The safety groups are normally fully withdrawn when the reactor is operating at power. The axial power-shaping group serves to correct flux imbalances within the core of the reactor. The regulating groups serve as the principal reactor reactivity control medium.

During startup, safety groups 1 through 4 are withdrawn first, enabling withdrawal of regulating control group 5. Once group 5 is equal to or greater than 75% withdrawn, group 6 will be enabled and can be withdrawn. Similarly, withdrawal of group 7 will be enabled when group 6 is equal to or greater than 75% withdrawn. Upon regulating group insertion, group 6 is enabled when group 7 is equal to or less than 25% withdrawn and group 5 is enabled when group 6 is equal to or less than 25% withdrawn. Overlap was established to counteract the dropping off of rod worth near the ends of rod travel.

The CRDCS receives interlock signals from the ICS and Nuclear Instrumentation (NI). The ICS interlock signals are used to permit automatic mode selection if the ICS neutron error is less

than +1% of the power demand while the Nuclear Instrumentation Interlock signals inhibit out-motion for high startup rates as determined by source range and intermediate range NI.

A requirement for continuous boron addition and dilution, controlled by the ICS, is the full withdrawal of groups 1-4 and the 25% or greater withdrawal of group 5.

7.7.1.3.2 Equipment Description

The CRDCS consists of three basic components: (1) motor control system, (2) system logic, and (3) trip circuitry (described in Subsection 7.4.1.1).

Motor Control System:

The motor control system contains sixty-one pairs of individual CRDM motor power supply modules for the 61 CRDM motors. Two channels of three phase AC input power are converted into six phase AC power through two CRDCS power system transformers. The AC input power is then rectified to DC power in the individual CRDM motor power supply modules through silicone controlled rectifiers. Redundant pairs of individual CRDM motor power supplies are provided to allow for on-line maintenance since a single power supply is capable of supplying power to its assigned control rod motor. Each individual power supply of the power supply pair is powered from one of two separate AC input power sources. Together the power supply pairs develop reliable redundant power. The power supplies sequentially energizes first two, then three, then two of the six CRDM motor-stator windings in stepping fashion to produce a rotating magnetic field for the CRDM motor to position the CRA. Switching is achieved by gating the associated SCR's on for the period of time that each winding must be energized. Because each of the six CRDM motor stator windings utilizes SCR's to supply power, six gating signals are required. When motion is not required, a fixed rod position is achieved by continuously energizing two adjacent windings of the CRDM motor stator. This static energizing of the windings maintains a latched CRDM and a fixed rod position.

Gating signals for the SCRs in the individual CRDM motor power supplies are generated by microprocessor controlled Pulse Generator / Monitor modules and associated gate drive boards. Command signals to position the control rod drives are introduced at the Pulse Generator / Monitor module's input from the CRDCS microprocessor based controller.

The desired rate of change of CRA reactivity insertion and uniform reactivity distribution over the core are provided for by the control rod drive and power supply design and the selection of rods in a group. The motor, leadscrew, and power supply designs are fixed to provide a uniform rate of speed of 30 in./min in the run mode. The reactivity change is then controlled by the rod group worth. To ensure flexibility in this area, software programming has been included in the CRDCS microprocessor controller to enable the interchange of rod worth between rod groups. Any rod may be assigned into any group (with the exception of group 8) through CRDCS controller software changes.

The individual CRDM motor power supplies, are identical. Each half of a single rod power supply is powered from a separate source and is capable of holding or maneuvering the individual rods.

Each individual rod is grouped so that a uniform and symmetrical group reactivity insertion rate can be achieved by synchronous withdrawal of all rods in that group. A set of control rods is assigned to a specific group of rods and the CRDCS operates this set of rods together.

The CRDCS can be used to reposition a single rod if an individual rod has to be repositioned.

System Logic and Rod Position Indication:

The CRDCS microprocessor controllers contain those functions that control rod motion in the manual or automatic modes of operation and functions which monitor system operation. Major subsystems of the CRDCS include the operator's control panel, CRA position indication displays, automatic control logic functions and system monitoring functions.

Switches are provided at the Operator Control Panel (OCP) for selection of the desired control mode. The control modes are (1) automatic mode, in which rod motion is commanded by the ICS, and (2) manual mode, in which motion is commanded by the operator. Manual control permits operation of a single rod and unsequenced group withdrawal. Indicator lamps on the control panel and assigned plant computer points inform the operator of the system status at all times. Indicators on the OCP show full insertion, full withdrawal, and enabled for motion, for each of the eight control rod groups. Trip Confirm, Asymmetric Fault, System Fault, In Travel, Out Travel, Inhibit Out, Inhibit Sequence, and Inhibit Auto indications are also provided on the OCP.

In the CRDCS, two methods of position indication are provided: absolute position indication and relative position indication. The absolute position transducer is essentially fully redundant consisting of two independent voltage dividers each with a series of magnetically operated reed switches mounted in a tube parallel to the CRDM motor tube extension. Switch contacts close when a permanent magnet mounted on the upper end of the CRA leadscrew extension comes near. As the leadscrew (and the control rod assembly) moves, the switches operate sequentially, producing a stepped analog voltage proportional to position. This analog voltage consists of two output channels which are inputs to the CRDCS. The two Absolute Position Indication (API) inputs are considered independent and under normal operations are averaged together. If during the CRDCS API median select checking process a channel of API is determined to be bad or inactive, the CRDCS controller will automatically select only the good channel which will be used for API calculations and display. If both channels are considered bad, the average of the two channels will be used for all API calculations and display. The full scale accuracy with both circuits in operation is approximately $\pm$ 3 inches (full scale = 139 inches). The accuracy with one circuit in operation is approximately $\pm$ 4 inches. Other reed switches included in the same tube with the position indicator matrix provide full-in and full-out limit indications.

The relative position indication (RPI) is determined in the CRDCS controller by calculating the individual rod position based on CRDM motor power supply SCR gating commands (full scale = 139 inches). The accuracy of this indication is 1.53% of full travel. If the RPI is in error compared to the Absolute Position Indication (API), the RPI may be reset by selecting the group or rod and pressing the RPI reset pushbutton on the Operator Control Panel. When RPI reset is selected from the OCP, the CRDCS Controller sets the value of RPI equal to the current API value for each selected CRDM or group. The API value will be the average of the two API inputs unless one of the API inputs has been removed as a result of deviating from the median value by more than the assigned limit. In this situation, the one good API value is used to set RPI. The CRDM to be reset will be selected by the same method used to select them for movement.

Regulating group sequencing utilizes API rod group average position signals to generate control interlocks which regulate rod group withdrawal and insertion. Sequencer control may be operated in the automatic mode or in the manual mode to control regulating groups 5 through 7 only. The group average signal serves as an input to the CRDCS controller logic to activate group overlap at approximately 25% or 75% of group rod withdrawal. The CRDCS controller provides outputs to the individual CRDM motor power supplies to command the rod groups to be moved in the proper sequence.

The selection of the manual control mode and sequence bypass mode functions permits intentional out-of-sequence conditions. This condition is indicated to the operator on the OCP.

Control rod position-indicating readout devices in the control room consist of two control panel-mounted video monitors. Collectively the monitors are called the Position Indication Panel (PIP). Relative, absolute position and group average position information is displayed on the rod position displays.

The group average values displayed on the position indication panel is the arithmetic average of the absolute position signals of all CRAs in a group that do not have an asymmetric fault condition present.

Each of the two position indication monitors normally displays 4 groups, 1 – 4 and 5 – 8. Either monitor can display either set of rod groups. The PIP displays each rod’s API value via a bar graph and numeric percentage and the RPI value via a numeric percentage. The PIP indicates if a rod is ON Control and indicates if the rod has an asymmetric alarm or fault compared to the API group average. The PIP also indicates percentage withdrawn for each group from the calculated API group average. Below the PIP are LEDs for each rod 0% withdrawn zone reference indication. These LEDs have a battery back-up to ensure 0% indication is available upon a loss of all power to the CRD system.

Failures which could result in improper system operation are continuously monitored by the CRDCS fault detection algorithms. When failures are detected, indicator lights and alarms remain on until the fault condition is cleared by the operator. A list of indicated faults is shown below:

1. Asymmetric rod patterns (indicators and alarm).

2. Sequence faults (indicator and alarm).

3. Safety rods not withdrawn (indicators and alarm).

Faults serious enough to warrant immediate action produce automatic correction commands from the fault detection algorithms.

A description of each fault detector follows:

1. Asymmetric Rod Monitor:

    a. Design Basis - To detect and alarm if any control rod deviates from its group reference position.

b. System Operation - Each of the 61 control rods has its API signal continuously compared with its absolute group reference (average position) signal. The absolute value of the difference between the two signals is computed, and if this difference is less than the alarm setpoint, no output results. If, however, the difference is greater than the setpoint, a device is actuated which alarms the asymmetric condition. Two alarm setpoints are provided. One setpoint is programmed for a 7-inch signal differential (maximum 11-inch true position separation) and initiates an alarm only. The other setpoint is a 9-inch signal differential (maximum 13-inch true position separation) and initiates the action described below.

c. Control Action - Action taken upon detection of an asymmetric rod fault depends on the control mode and the power level in effect at the time the fault is detected. Control action is the same for any asymmetric condition including “stuck-in,” “stuck-out,” or dropped control rods.

Detection of a 7-inch signal differential is defined as an “asymmetric rod alarm.” Actuation of this alarm causes the alarm indicator on the PI monitor panel for that rod to be illuminated and an alarm signal to be sent to the station computer and annunciator.

If the condition is not corrected and the separation increases to a 9-inch signal difference, the following actions occur:

(1) “Asymmetric fault” lamp on the operator’s console is energized. If operation is in the manual control mode, operator action is required.

(2) ICS sends a signal to the Control Rod Drive System to indicate when Reactor Power is greater than 60% of rated power. If the Control Rod Drive System is in Automatic, an “Out Inhibit” signal is generated which disables the “Out” command. “Out Inhibit” signals are sent to the Control Rod Drive Operator Control Panel and computer.

2. Sequence Inhibit:

a. Design Basis - To detect any motion of the rod groups outside the predetermined sequence patterns, and to prevent further sequenced motion when such conditions occur.

b. System Operation - The sequence monitor function continuously compares the relative group average (position) signals for each regulating group with discrete, predefined rod positions.

c. Control Action - When an out-of-sequence condition is detected and operation is in the automatic control mode, the automatic mode disengages, sequence bypass mode is selected and a sequence inhibit alarm lamp on the OCP and a station annunciator alerts the operator to the malfunction. Control reverts to manual and remains in manual until the fault is corrected and the system is reset by the operator.

3. Safety Rods Not Withdrawn:

a. Design Basis - To prevent, on station startup, withdrawal of the regulating rods until the safety rods are fully withdrawn.

b. System Operation - The CRDCS continuously monitors the group “out” limits for the four safety rod groups. When the four groups are all fully withdrawn, signals are sent to the controller sequencer algorithm which then permits regulating group withdraw.

c. Resultant Action – Annunciator is actuated.

Station annunciators monitor the status of the trip devices in the CRDCS and will alarm for a trip condition.

4. System Fault:

Design Basis – The CRDCS controller shall activate an internal flag within the application software and system fault indication to alert operators to CRDCS off normal conditions.

System Operation – The CRDCS continuously monitors for off-normal conditions and alerts the control room operator through the OCP, Annunciator System and plant Computer for the following conditions:

AC Power Bus Fault – Improper AC voltage to the CRDCS controllers or improper system Power transformer output.

Single Rod Power Supply Fault – Rod power supply output low or not firing correctly.

Position Indication Fault – CRDCS detects a mismatch between API and RPI, or failure of an API, RPI, In Limit or Out Limit.

Regulating group sequencing error fault.

Automatic rod latching failure fault.

Asymmetric rod in a given rod group when not in Asymmetric Rod bypass.

Patch fault error in rod group patching assignment.

CRDCS Cabinet Cooling Fault – Cabinet high temperature.

DC Power Supply (5 V API) Fault – High or low voltage on either 5 V API power supply.

DC Power Supply (24 V) Fault – DC Failure or Overtemperature on any CRDCS 24 V power supply.

System power, Field power or Power Supply input or output breaker open.

Group Select or insert/withdraw switch failure fault.

Triplex Module Fault – Failure or fault on any CRCS module that leads to degraded or non-functional condition.

Resultant Action – Annunciator Alarm, OCP System Fault lamp and Computer Point Alarm are actuated.

CRDCS Peripheries

An Engineering Work Station (EWS) can be connected to the CRDCS for the review of alarms and system status. The EWS can also be used for introducing programming changes such as CRDM group patching modifications. The ability to change CRDM Patching will only be available when the system is offline and requires the application software be recompiled before changes take effect. The EWS is password protected.

The CRDCS also has a rod drop timer assembly to capture rod drop times following a reactor trip or in support of rod drop time testing.

#### 7.7.1.4 Turbine Generator Electro-Hydraulic Controls (EHC)

##### 7.7.1.4.1 System Identification

The turbine generator electro-hydraulic controls (EHC) accomplish the following functions:

1. Control turbine speed and acceleration.
2. Control generator load to match load demand.
3. Control steam flow through the turbine to satisfy the load demands.

##### 7.7.1.4.2 Equipment Design

Normal turbine control system operating control is accomplished with an electro-hydraulic servo-positioning system using a triple modular redundant (TMR) digital control system. The digital system combines speed and load demand signals to modulate the positioning signal to the turbine control valves. The principle control programs are for speed, load, and flow. The descriptions of these programs are as follows:

Speed Control Program:

Speed control is used to control turbine speed and acceleration to rated speed, and as a means of controlling overspeed. The main speed control program function is to control speed and acceleration according to operator selected setpoints. The speed control program produces a speed error signal by comparing the desired speed with the actual turbine speed.

Discrete setpoints for speed and acceleration are available during startup. When a higher speed setpoint is selected, the speed control system will accelerate the turbine at the set rate up to the selected speed. The speed control will then maintain speed at the setpoint.

Load Control Program:

The load control program develops the steam flow load reference signal representing the desired turbine load. The load reference signal is ramped to the load setpoint. The operator provides the load setpoint and loading rate inputs in manual mode; in auto mode the Integrated Control System provides the input that raises or lowers the load.

The load control program limits and modifies the load reference signal based on valve position limit, power load unbalance runback, stator cooling water runback, and combines them to modify or limit the output signals. The load control program also applies the rate of change in the load reference signal based on the system need.

Flow Control Program:

The flow control program uses the load reference signal and the speed error signal to produce a turbine power control valve reference signal. This signal controls the servo control modules that position the control valves and the intercept valves.

Control Valve Positioning and Testing:

All four control valves may be operated and positioned continuously over their entire stroke range by the effective control valve flow demand. The servo control modules produce the output to the servo valves that position the control valves. Each valve's position is fed back to the control module; the servo regulators provide closed loop control valve positioning.

A power load unbalance event energizes a fast-acting solenoid valve on the control valve mechanism which will close the respective valve.

Each control valve can be tested during normal operation using special programming that lowers the control valve slowly until it is near the closed position; the program then actuates the fast acting solenoid valve to close the control valve rapidly for the remaining portion. Pushbuttons on the operator display screen in the control room are used to initiate the tests. The pressure disturbance caused by closing one of the steam admissions to the turbine will cause the other control valves to open somewhat so that the steady-state steam flow will be approximately constant. Control valve testing is done at approximately 96% load or less to provide enough margin for other valves to open sufficiently to compensate for the drop in load. Stop valve testing can be performed at 100% load. Areva calculation 32-5012132-00, Davis-Besse TSV Test FIV Analysis, evaluated the effects from the increased steam flow through the steam generator tubes which is not having its respective stop valve tested and concluded the effects acceptable with the steam generator tube stabilizer designs for the original once through steam generators.

The replacement once through steam generators (ROTSG) were analyzed for increased steam flow which bounds turbine stop valve testing. These analyses conclude that the effects of increased steam flow are acceptable with plugged and stabilized tubes in the ROTSG. The ROTSG stabilizer is not qualified for use in a severed tube.

The program includes interlocks that permit only one control valve or one stop valve to be tested at a time. Position indicating instruments, driven by the position transducers on each control valve are used to indicate valve position on the operator display screen.

Intercept Valve and Intermediate Stop Valve Positioning and Testing:

Intercept valves control flow to the low pressure turbine hoods. One intercept valve in each hood is operated by the flow control program. The servo control modules produce the output to the servo valves that position these two intercept valves. Each valve's position is fed back to the control module; the servo regulators provide closed loop control valve positioning.

The system controls the position of the intercept valve in the opposite hood based on the servo controlled positioning valve position. It will remain closed until the positioning valve is nearly open; then it will open wide, returning to the closed position when the positioning valve closes to about half stroke.

The intercept valves respond to an IV trigger function that may be required to quickly reduce turbine power and to limit peak speed. If a servo controlled intercept valve position lags the reference position by more than 10% all intercepts valves will rapidly close.

When the cold reheat steam pressure is less than approximately 10% of rated and intercept valve fast closing is not essential, the fast acting logic is inhibited to prevent unnecessary intercept valve slamming, particularly during startup.

When the emergency trip fluid system is tripped, the intercept valves and intermediate stop valves will be closed by the same signal as the control valves.

Test controls are provided similar to those for the stop valves to test one intercept valve at a time in conjunction with the respective intermediate stop valve.

#### 7.7.1.4.3 Operational Considerations

Control and supervisory equipment is provided for remote operation from the turbine generator control panel in the control room. The ability of the station to follow system load demand is accomplished by the load control of the turbine generator in conjunction with the ICS regulation of reactor power and steam generation. However, the turbine speed governor can override the steam pressure controls, and the turbine control valves and throttle stop valves will close when a loss of generator load causes the speed of the turbine to increase beyond the overspeed set point.

Speed status, control and stop valve position lights and indicators, main steam pressure, and generator load indications are displayed in the control room.

## 7.7.2 Analysis

### 7.7.2.1 Non-Nuclear Instrumentation (NNI) Station Control Systems

The safety analyses of Chapter 15 do not assume contributions from the control systems; however, Chapter 15 includes analyses to demonstrate the adequacy of the protection systems in coping with NNI control system malfunctions.

### 7.7.2.2 Integrated Control System (ICS)

The ICS is not safety related. However, it has functions important to safe plant operation. All functions to be performed by the ICS can also be manually performed from the main control

panels or at the Auxiliary Shutdown Panel (ASP). Therefore, the functions assumed to have been performed can be performed either by the ICS or manually. Chapter 15 contains analyses to demonstrate the adequacy of the protection systems to cope with ICS malfunctions.

#### 7.7.2.3 Control Rod Drive Control System (CRDCS)

Only the CRDCS trip circuitry performs a safety function. The other portions of the CRDCS are not required to function in any safety analysis. Chapter 15 contains analyses to demonstrate the adequacy of the protection systems to cope with CRDCS malfunctions.

#### 7.7.2.4 Turbine Generator Electro-Hydraulic Controls (EHC)

The turbine generator control system design provides a stable control response to normal load fluctuations. Total loss of the turbine generator control system, either by failure of the electric power supplies or loss of hydraulic fluid system pressure, will result in the closure of the turbine control valves and intercept valves.

The main turbine bypass valves are capable of responding to the maximum closure rate of the turbine control valves so that the total steam flow is not significantly affected until the magnitude of the load rejection exceeds the capacity of the bypass valves. Load rejection in excess of bypass valve capacity will cause the code safety valves to open. The heat sink thus provided enables an orderly reduction in reactor power.

The loss-of-load accident does not result in fuel damage or excessive pressure in the RC system.

Abnormal operational transient analyses have been made for a load rejection of the turbine generator system and are included in Chapter 15.

#### 7.7.2.5 System Monitoring

NNI and ICS signals are monitored with a Data Acquisition and Analysis System (DAAS) unit. A DAAS unit is installed in Room 502 (control cabinet area) for monitoring NNI and ICS signals. The DAAS unit is used mainly for system trending and for diagnosis of system anomalies. Operators also use ICS DAAS displays to back-up Control Room indications.

A DAAS unit consists of a computer, keyboard, monitor, and isolation rack. Signal cables are connected between the system cabinets and DAAS unit. The ICS DAAS unit includes a second monitor installed in the Control Room for use by operators. Isolation of the DAAS unit from the system signals is provided by an interface box that prevents the DAAS unit from causing an NNI or ICS malfunction.

The EHC system does not provide input to the DAAS. The EHC has its own digital system (DEHC) that includes the monitoring functions and therefore is not required to interface with the DAAS.

The DAAS system also interfaces with the Plant Process Computer and Start up test panel systems.

TABLE 7.7-2

INTEGRATED CONTROL SYSTEM FUNCTIONS

A. RUNBACKS:

The following conditions will cause an ICS initiated runback:

1. Loss of one or more reactor coolant pumps will runback reactor power to the remaining pump capability.

2. Loss of one feedwater pump will runback reactor power to the remaining pump capability.

3. Low deaerator tank level will runback reactor power to 55%.

4. High main feedpump discharge pressure will runback reactor power to 60%.

B. INTERLOCKS:

1. A reactor coolant pump is prevented from being started if reactor power is above 60% (RC subsystem).

2. DELETED

3. The turbine is prevented from going to automatic ICS control if a large throttle pressure error exists (Integrated Master Subsystem).

C. CONTROL FUNCTIONS:

The following control functions are performed by the ICS:

1. Load Limiting (ULD subsystem) - The ICS contains a maximum load limiter, a minimum load limiter, and a rate of change limiter to keep the unit within pre-established limits for normal operation.

TABLE 7.7-2 (Continued)

INTEGRATED CONTROL SYSTEM FUNCTIONS

2. Load Tracking: (ULD subsystem) - The ICS reverts to the “load tracking” mode to follow the device or component being limited. The following conditions cause the ICS to go the load tracking mode of control:

   a. Reactor cross limit - difference between reactor power and reactor demand exceeds +10 (Power > Demand) or -5% (Power < Demand).

   b. Feedwater cross limit - feedwater demand exceeds feedwater flow by plus 5 percent.

   c. Transfer of both feedwater loop demand control stations to manual.

   d. Transfer of the diamond rod control station to manual.

   e. Transfer of the reactor demand control station to manual.

   f. Transfer of the reactor/steam generator control station to manual.

   g. Transfer of the turbine control station to manual.

   h. Tripping open of both turbine-generator output breakers.

   i. Reactor tripped.

   j. Main turbine trip.

3. Feedwater Ratio Control: (SG subsystem) - The ICS controls the ratio of the feedwater demands for an unbalanced reactor coolant flow condition (loss of a reactor coolant pump or unbalanced feedwater flowrates (fouled OTSG). The feedwater control is ratioed/limited to the respective steam generator to permit proper control for the unbalanced condition. This function includes an input from the reactor coolant cold leg temperature instrumentation to prevent more than a 1°F cold leg temperature difference with balanced MFW flow. When the SG load ratio controller is set to induce a $\Delta$Tc and unbalanced MFW flows, the maximum SG load ratio setpoint will be limited to prevent exceeding a cold leg temperature difference of more than 3°F. Intentional changes in $\Delta$Tc shall be limited to 1°F during any 30 minute period.

TABLE 7.7-2 (Continued)

INTEGRATED CONTROL SYSTEM FUNCTIONS

4. Turbine Bypass Control: (Integrated Master subsystem) - The ICS controls the steam bypass system in order to

   a. Provide pressure control at low loads before the turbine is capable of accepting pressure control. (Bleed excess steam to maintain constant header pressure.)

   b. Provide high-pressure relief if the turbine throttle pressure exceeds its setpoint by 50 psi in normal operation.

   c. Provide pressure control after a reactor trip.

   d. Provide a means of load rejection from partial loads without opening steam line safety valves.

5. Steam Generator Level Control (SG subsystem) - The ICS controls steam generator water level to prevent the following:

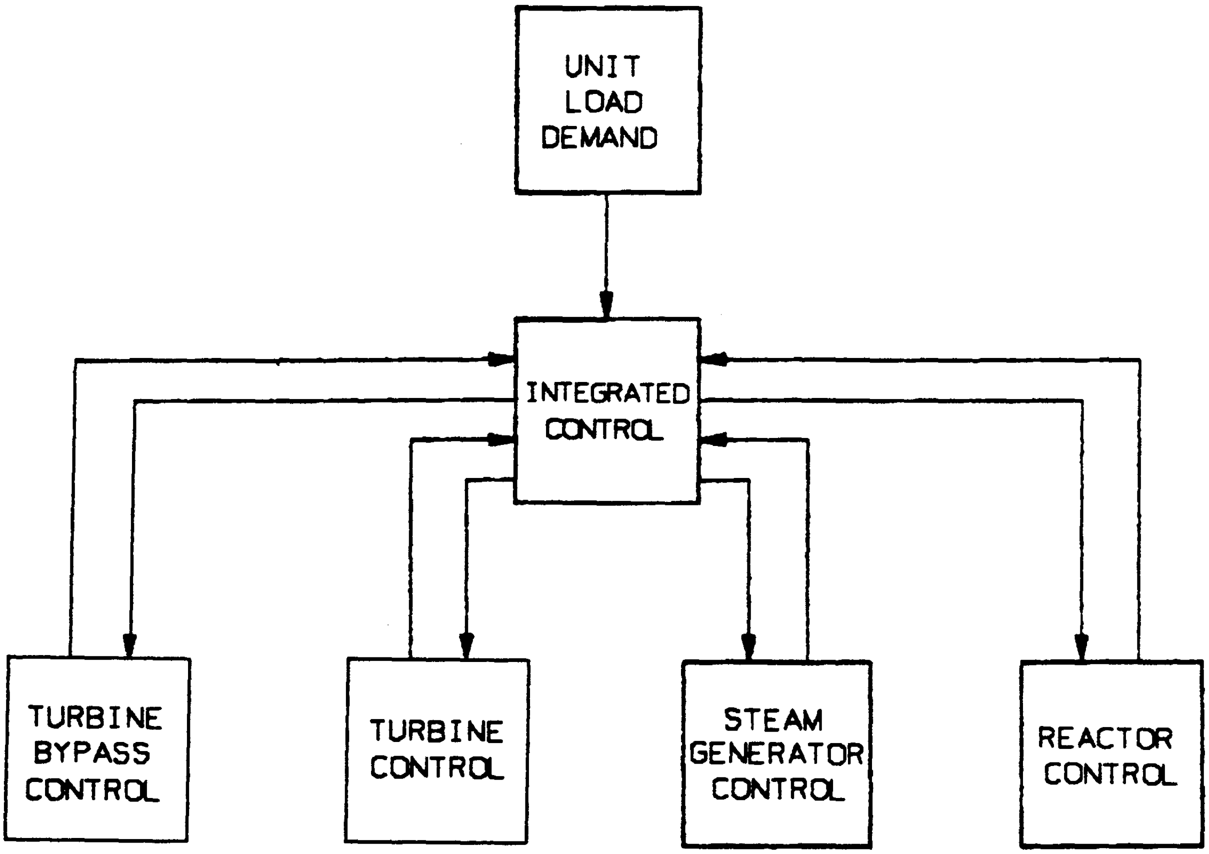
   a. Loss of all water (low level) in the steam generators, and

   b. Overfilling (high level). This limit ensures superheated steam under all operating conditions between the low level limit and 100% load.

6. Btu Limit Alarm (SG subsystem) - The ICS monitors the reactor coolant flow, feedwater temperature, reactor coolant outlet temperature, and steam generator outlet pressure and controls provides an alarm to assist the operator in ensuring that the required degree of superheat is maintained.

7. Feedwater Demand Calculator (SG subsystem) - In order to remove a constant amount of energy from the steam generators, the ICS controls the feedwater demand based on feedwater temperature. If feedwater temperature is lower than expected, total feedwater demand will be decreased; if feedwater temperature is high, total feedwater demand will be increased.

8. Reactor Power Limit (RC subsystem) - A high limit on reactor power demand prevents the ICS from commanding a power greater than 103% to avoid creating a high flux reactor trip. A low limit on reactor power demand prevents automatic control action at low power levels, thus providing stable low load, startup, and shutdown control.




NOTES:

1. TURBINE CONTROL IS FURNISHED WITH THE TURBINE EQUIPMENT.

DAVIS-BESSE NUCLEAR POWER STATION
INTEGRATED CONTROL SYSTEM (ICS)

FIGURE 7.7-1

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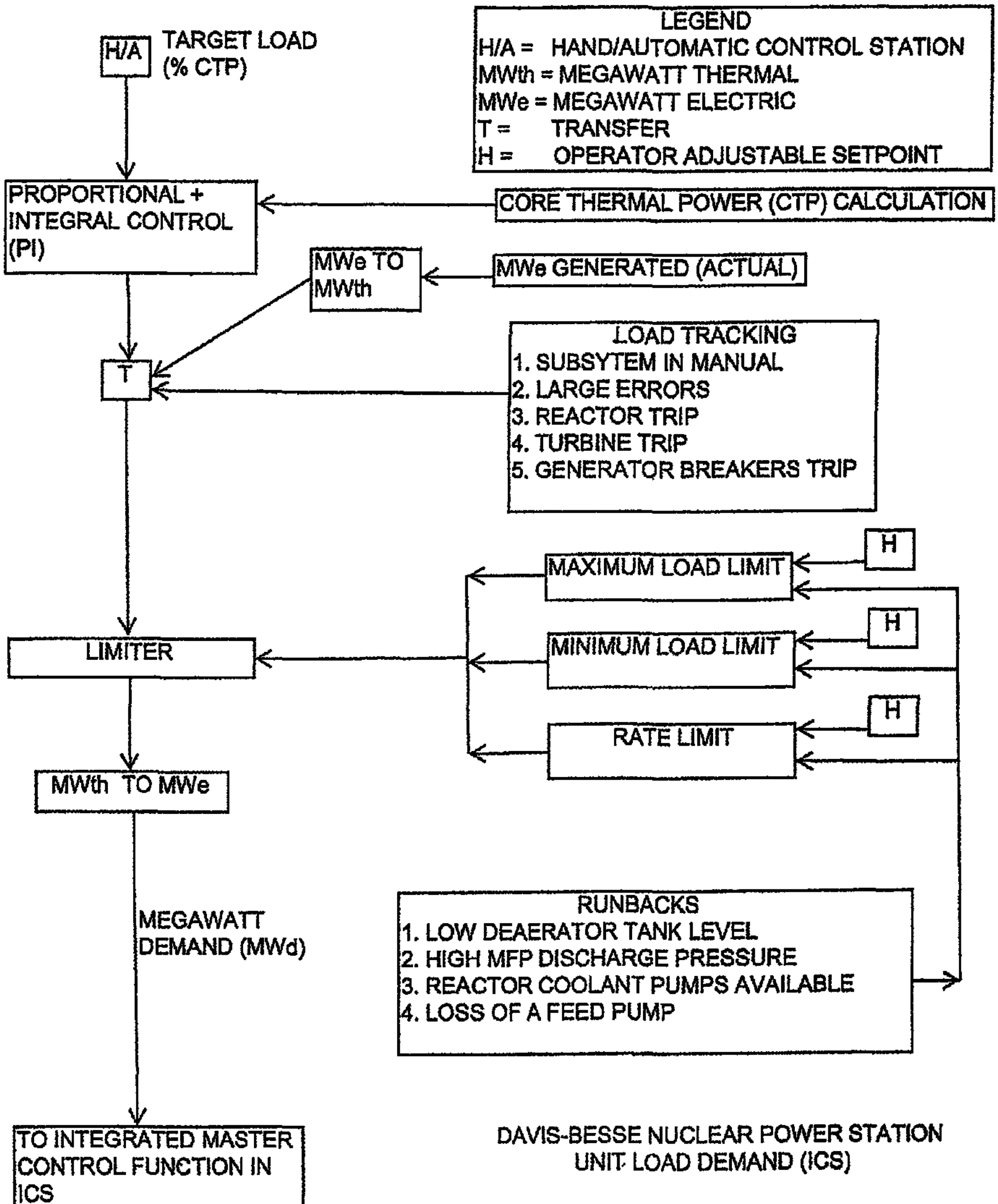
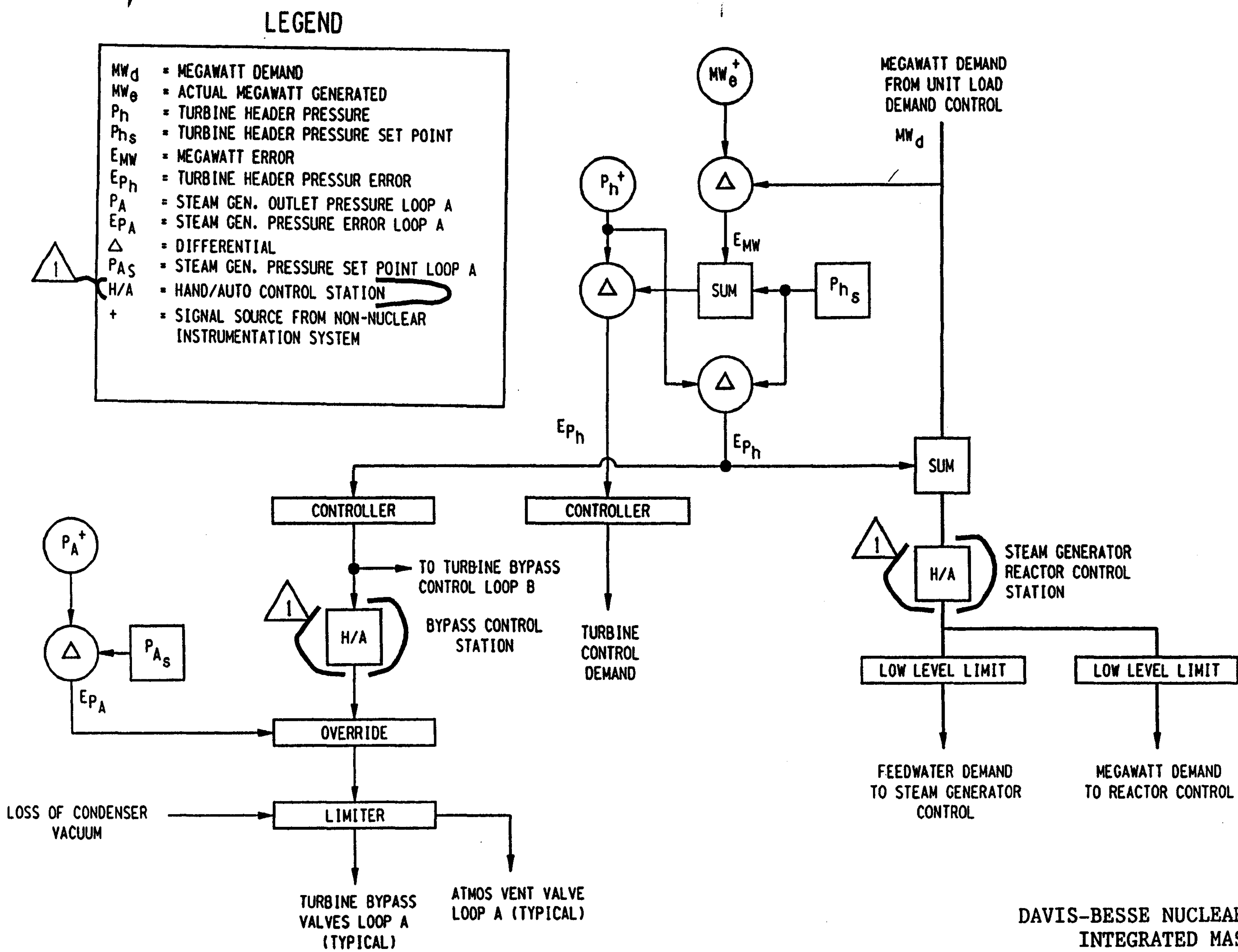



DAVIS-BESSE NUCLEAR POWER STATION
UNIT LOAD DEMAND (ICS)

FIGURE 7.7-2




DAVIS-BESSE NUCLEAR POWER STATION
INTEGRATED MASTER (ICS)

FIGURE 7.7-3

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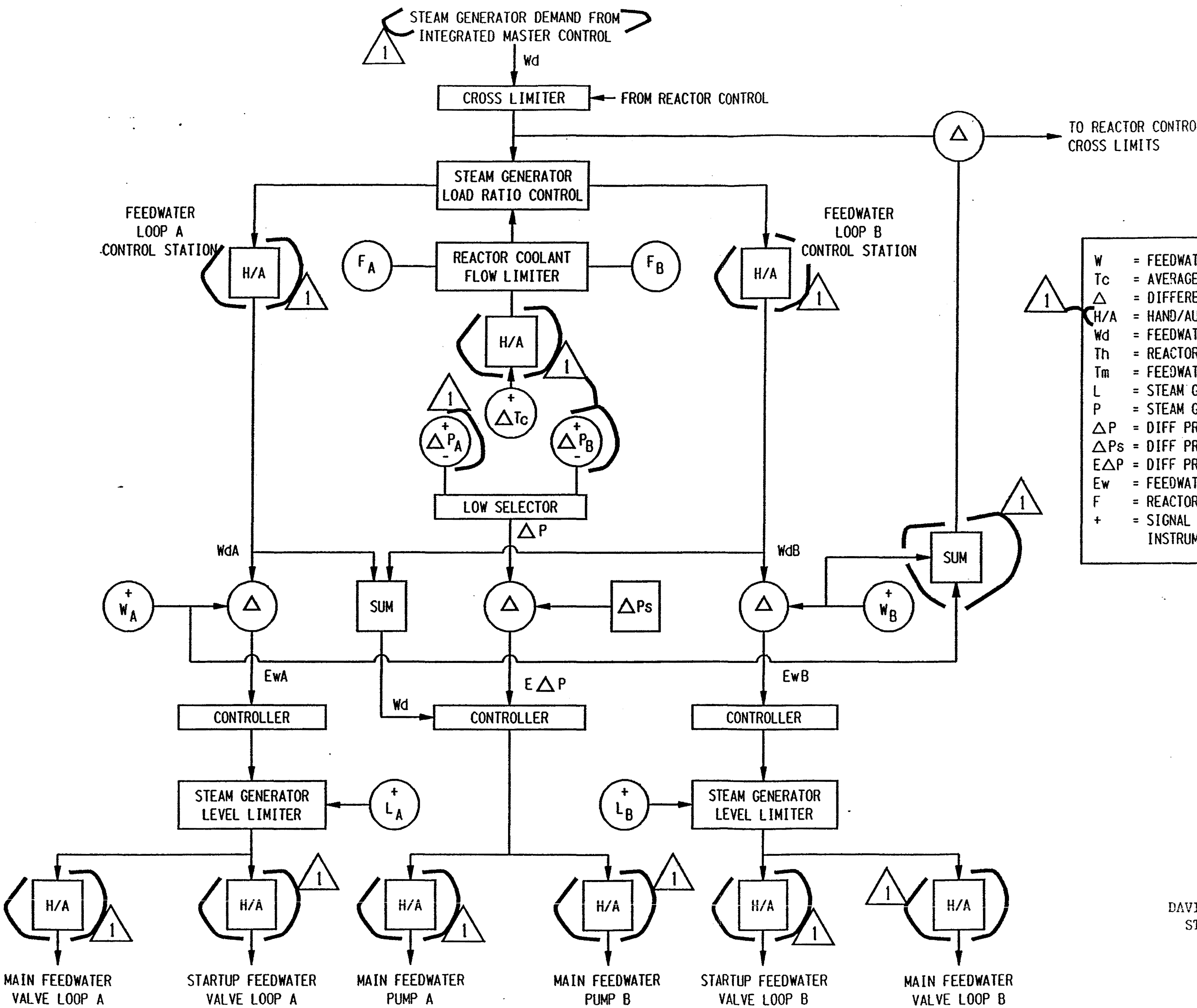


## LEGEND

| | |
|---|---|
| W | = FEEDWATER FLOW |
| Tc | = AVERAGE REACTOR INLET TEMP (COLD LEG) |
| △ | = DIFFERENTIAL |
| H/A | = HAND/AUTO CONTROL STATION |
| Wd | = FEEDWATER DEMAND |
| Th | = REACTOR OUTLET TEMPERATURE (HOT LEG) |
| Tm | = FEEDWATER TEMPERATURE |
| L | = STEAM GENERATOR LEVEL |
| P | = STEAM GENERATOR OUTLET PRESSURE |
| △P | = DIFF PRESSURE ACROSS FEEDWATER VALVES |
| △Ps | = DIFF PRESSURE SET POINT |
| E△P | = DIFF PRESSURE ERROR |
| Ew | = FEEDWATER ERROR |
| F | = REACTOR COOLANT FLOW |
| + | = SIGNAL SOURCE FROM NON-NUCLEAR INSTRUMENTATION SYSTEM |



DAVIS-BESSE NUCLEAR POWER STATION
STEAM GENERATOR CONTROL (ICS)

FIGURE 7.7-4

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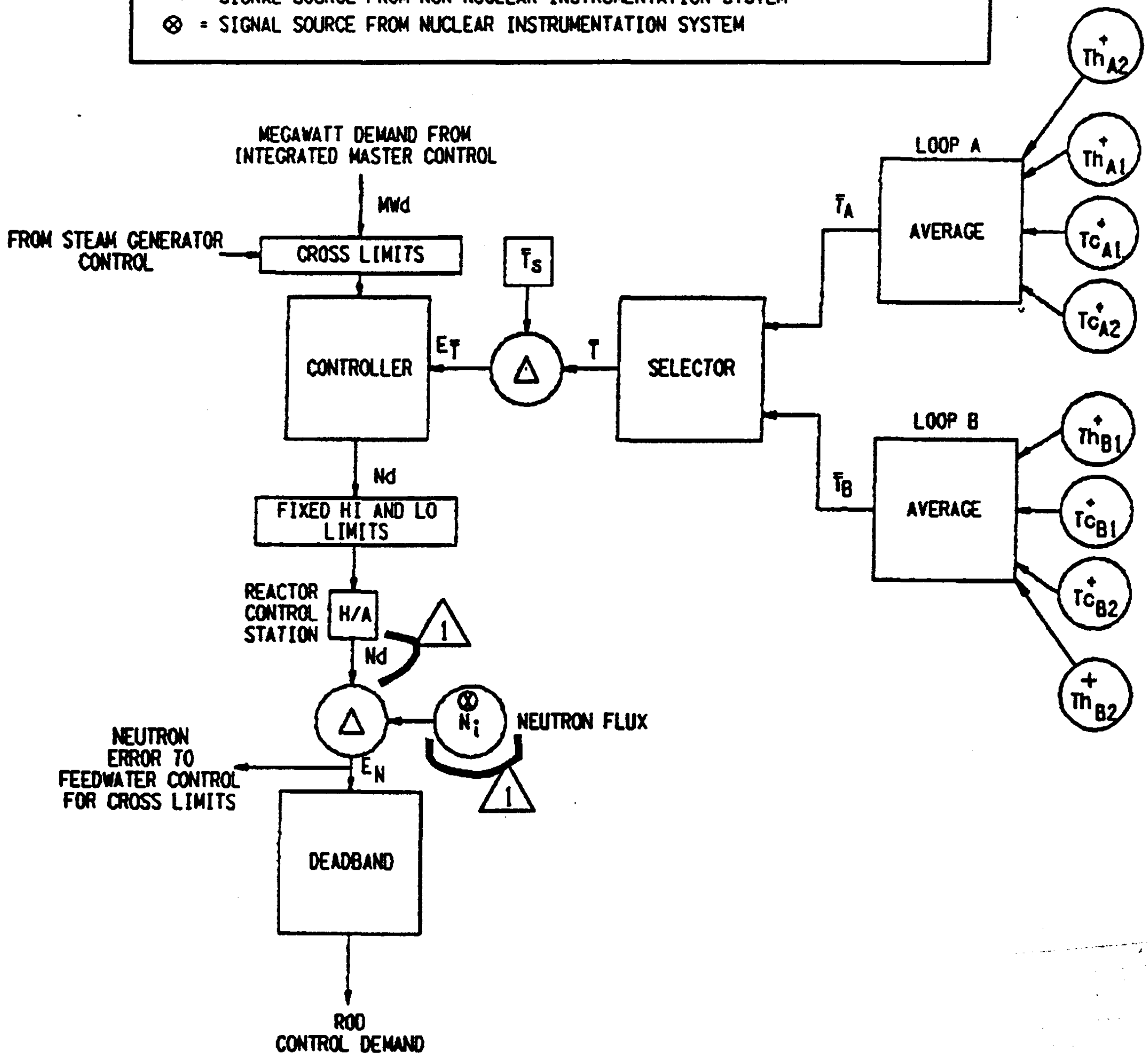
MAY 1995

## LEGEND

$\bar{T}_S$ = AVERAGE TEMPERATURE SET POINT
Tc = REACTOR COOLANT SYSTEM COLD LEG TEMPERATURE
Th = REACTOR COOLANT SYSTEM HOT LEG TEMPERATURE
$\bar{T}$ = REACTOR AVERAGE COOLANT TEMPERATURE
$E_{\bar{T}}$ = DEVIATION OF AVERAGE TEMPERATURE FROM SET POINT
$\Delta$ = DIFFERENTIAL
H/A = HAND/AUTO CONTROL STATION
Nd = REACTOR POWER LEVEL DEMAND
$N_i$ = REACTOR POWER LEVEL
$E_N$ = REACTOR POWER LEVEL ERROR
MWd = MEGAWATT DEMAND
+ = SIGNAL SOURCE FROM NON-NUCLEAR INSTRUMENTATION SYSTEM
⊗ = SIGNAL SOURCE FROM NUCLEAR INSTRUMENTATION SYSTEM

1




DAVIS-BESSE NUCLEAR POWER STATION
REACTOR CONTROL (ICS)

FIGURE 7.7-6

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MAY 1995

## 7.8 NUCLEAR INSTRUMENTATION (NI)

The NI (see Figure 7.8-1) is designed to provide neutron flux information over the full range of reactor operations. To provide total monitoring, three ranges of neutron flux detectors are furnished: source range, intermediate range and power range. The power range detectors are required by the RPS to perform safety functions, and are part of the RPS (refer to Section 7.2). The power range instrumentation is discussed in this section for consistency.

### 7.8.1 Description

The nuclear instrumentation consists of two source range channels, two intermediate range channels and four power range channels. This arrangement allows continuous monitoring of neutron flux level from source range to 125% of rated power. A minimum of one decade overlap between ranges is provided. Figure 7.8-2 presents a pictorial representation of the relation between instrument ranges.

The source range instrumentation consists of two redundant count rate channels which use high sensitivity proportional counters as sensors. Each channel monitors neutron flux over the range of $10^{-1}$ to $10^{6}$ counts per second and provides readouts of log count rate and startup rate for operator information. Control rod withdrawal is inhibited if the startup rate in either channel exceeds 2 decades/minute. The functioning of this interlock is not assumed in any accident analyses. Audible indication of the source range counts in the control room and containment during refueling operations is provided by the Ex-Core Neutron Flux Monitoring System (see Section 7.13.3.11).

The intermediate range instrumentation consists of two redundant channels which utilize gamma-compensated ion chambers as sensors. Each channel provides eight decades of flux level information in terms of the log of ion chamber current and startup rate. The ion chamber measuring range is from $10^{-11}$ to $10^{-3}$ amperes. A high startup rate of 3 decades/min in either channel will initiate a control rod withdrawal inhibit. The functioning of this interlock is not assumed in any accident analysis.

The power range instrumentation consists of four redundant, linear channels which utilize uncompensated ion chambers as sensors. The channel output is directly proportional to reactor power and covers the range from 1% to 125% of rated power. The gain of each channel is adjustable, providing a means of calibrating the output against a reactor heat balance.

The circuitry for the measurement of power level for reactor control uses one auctioneering circuit to combine inputs from two power range channels and a second auctioneering circuit to combine the remaining two power range channels. These circuits are in the NNI cabinets. The two resultant signals are then auctioneered in the ICS cabinets to provide the highest power level to the Integrated Control System. To ensure that failures in the control system cannot produce a failure in the protection system, each signal that goes to a control system is isolated by isolation amplifiers. The resultant systems meet the requirements for separation of protection and control and for single failure as specified in IEEE Standard 279-1968 and the AEC General Design Criteria.

#### 7.8.1.1 Neutron Detectors

Proportional counters are used in the source range channels. The high voltage of both detectors is automatically switched off when the flux level is approximately one decade above

the useful operating range, or flux level is above $10^{-9}$ amps in both intermediate range channels or 10% power in power range channels NI-5 or NI-6 and NI-7 or NI-8. The high voltage is turned on automatically when the flux level returns to within one decade of the maximum useful range of the detector.

The source range detectors are located on opposite sides of the core, 180 degrees apart.

The intermediate range compensated ion chambers are electrically adjustable, gamma-compensating detectors. Each has a separate adjustable high voltage power supply and an adjustable compensating voltage supply. The two intermediate range detectors are also located on opposite sides of the core, but are rotated approximately 90 degrees from the source range detectors.

An uncompensated ion chamber is used in each of the four redundant power range channels. Each power range detector consists of two 72-inch sections with a single high voltage connection and two separate signal connections. The outputs of the two sections are amplified by linear amplifiers and then summed in the associated power range channel. A signal proportional to the difference in the percentage of rated power between the top and bottom halves of the core is derived from the difference in currents from the top and bottom sections of the detector. The difference signal is displayed on the control console to permit the operator to maintain proper axial power distribution. Each detector has a combined sensitive volume extending approximately from the bottom to the top of the reactor core.

The physical locations of the neutron detectors are shown in Figure 7.8-3. The power range detectors are spaced approximately 90 degrees apart around the reactor.

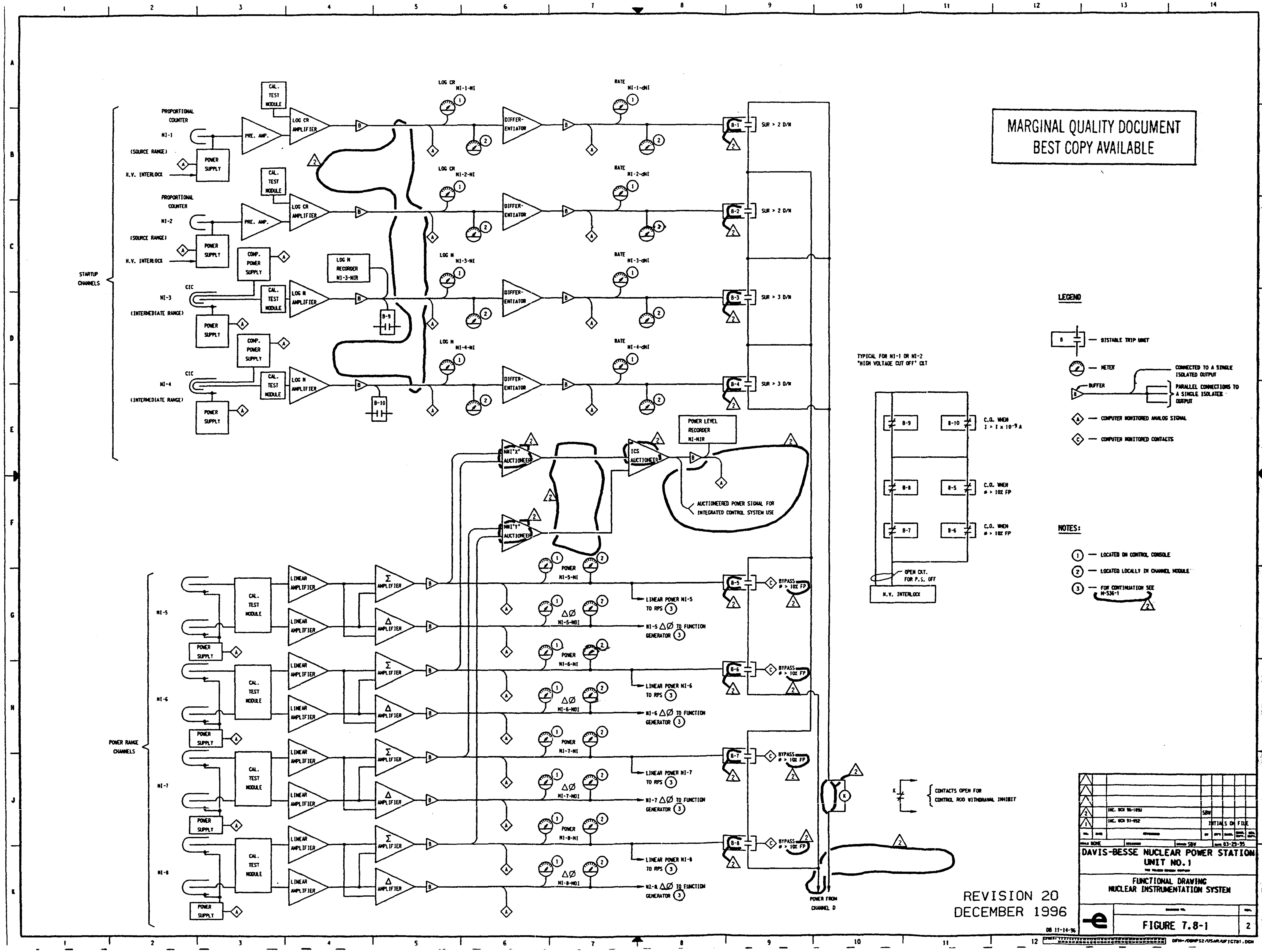
The radial flux distribution within the reactor core is measured by the incore neutron detectors (refer to Section 7.9). Both out-of-core and incore detectors are used to obtain the axial power distribution. The sum of the outputs from the two sections of each power range detector is calibrated to within $\pm$ 2% of heat balance at 100 percent of rated thermal power (RTP). The power range detectors are allowed to indicate more than 2 percent above the heat balance power at power levels less than 100 percent of RTP. The specific allowance is a function of power level and is controlled administratively by plant procedures. The power range detectors must not indicate more than 2 percent below the heat balance power at any power level. The difference signal is unaffected by calibration of the sum. (This is controlled by procedure vice inherent design features.) Periodically the operator compares the difference indication from the power range channels with the difference obtained from the Incore Monitoring System (IMS).

License Amendment No. 278 increased core rated thermal power by 1.63% from 2772 MWt to 2817 MWt, based on the use of more accurate instrumentation for heat balance measurement. The heat balance measurement uncertainty, based on use of the Caldon CheckPlus™ instrumentation, is 0.37%.

The original design overpower limit of 112 percent of 2772 MWt includes a 2 percent allowance for potential transient neutron measurement errors. This error could be larger than 2 percent RTP for transients that result in an overcooling of the RCS coolant in the reactor vessel downcomer region. This is because the reduced downcomer temperature increases the shielding effect and lowers the neutron leakage measured by the power range detectors. Since the transient neutron measurement uncertainty could be larger than 2 percent RTP, actual core power could exceed the assumed 112 percent RTP design value prior to initiation of a high flux reactor trip. Reference 1 provides an evaluation of the temperature induced neutron

measurement errors for Davis-Besse. Results demonstrate that the DNBR penalty associated with power levels greater than 112 percent RTP is offset by the beneficial effect of the lower RCS temperature at the core inlet. Because of this, DNBR margin is maintained for power levels up to 123 percent RTP.

Additional calculations have been performed and are evaluated for each fuel cycle that result in core power levels near 136 percent. Again, this is offset by the beneficial effect of the lower RCS temperature at the core inlet. Furthermore, for each reload, the RPS power/imbalance/flow reactor trip setpoint is verified to provide protection for these cases.


MARGINAL QUALITY DOCUMENT
BEST COPY AVAILABLE
STARTUP CHANNELS
PROPORTIONAL COUNTER
NI-1
(SOURCE RANGE)
H.V. INTERLOCK
POWER SUPPLY
PRE. AMP.
CAL. TEST MODULE
LOG CR AMPLIFIER
LOG CR NI-1-NI
DIFFER-ENTIATOR
RATE NI-1-dNI
SUR > 2 D/M
NI-2
LOG CR NI-2-NI
RATE NI-2-dNI
CIC
NI-3
(INTERMEDIATE RANGE)
COMP. POWER SUPPLY
LOG N AMPLIFIER
LOG N RECORDER NI-3-NIR
LOG N NI-3-NI
RATE NI-3-dNI
SUR > 3 D/M
NI-4
LOG N NI-4-NI
RATE NI-4-dNI
NNI "X" AUCTIONEER
NNI "Y" AUCTIONEER
ICS AUCTIONEER
POWER LEVEL RECORDER NI-NIR
AUCTIONEERED POWER SIGNAL FOR INTEGRATED CONTROL SYSTEM USE
POWER RANGE CHANNELS
NI-5
NI-6
NI-7
NI-8
LINEAR AMPLIFIER
Σ AMPLIFIER
Δ AMPLIFIER
POWER NI-5-NI
ΔØ NI-5-NOI
LINEAR POWER NI-5 TO RPS
NI-5 ΔØ TO FUNCTION GENERATOR
BYPASS Ø > 10% FP
POWER FROM CHANNEL D
TYPICAL FOR NI-1 OR NI-2 "HIGH VOLTAGE CUT OFF" CKT
C.O. WHEN I > 1 x 10^-9 A
C.O. WHEN Ø > 10% FP
OPEN CKT. FOR P.S. OFF
H.V. INTERLOCK
CONTACTS OPEN FOR CONTROL ROD WITHDRAWAL INHIBIT
LEGEND
BISTABLE TRIP UNIT
METER
BUFFER
CONNECTED TO A SINGLE ISOLATED OUTPUT
PARALLEL CONNECTIONS TO A SINGLE ISOLATED OUTPUT
COMPUTER MONITORED ANALOG SIGNAL
COMPUTER MONITORED CONTACTS
NOTES:
1 — LOCATED ON CONTROL CONSOLE
2 — LOCATED LOCALLY IN CHANNEL MODULE
3 — FOR CONTINUATION SEE M-536-1
DAVIS-BESSE NUCLEAR POWER STATION UNIT NO. 1
FUNCTIONAL DRAWING NUCLEAR INSTRUMENTATION SYSTEM
FIGURE 7.8-1
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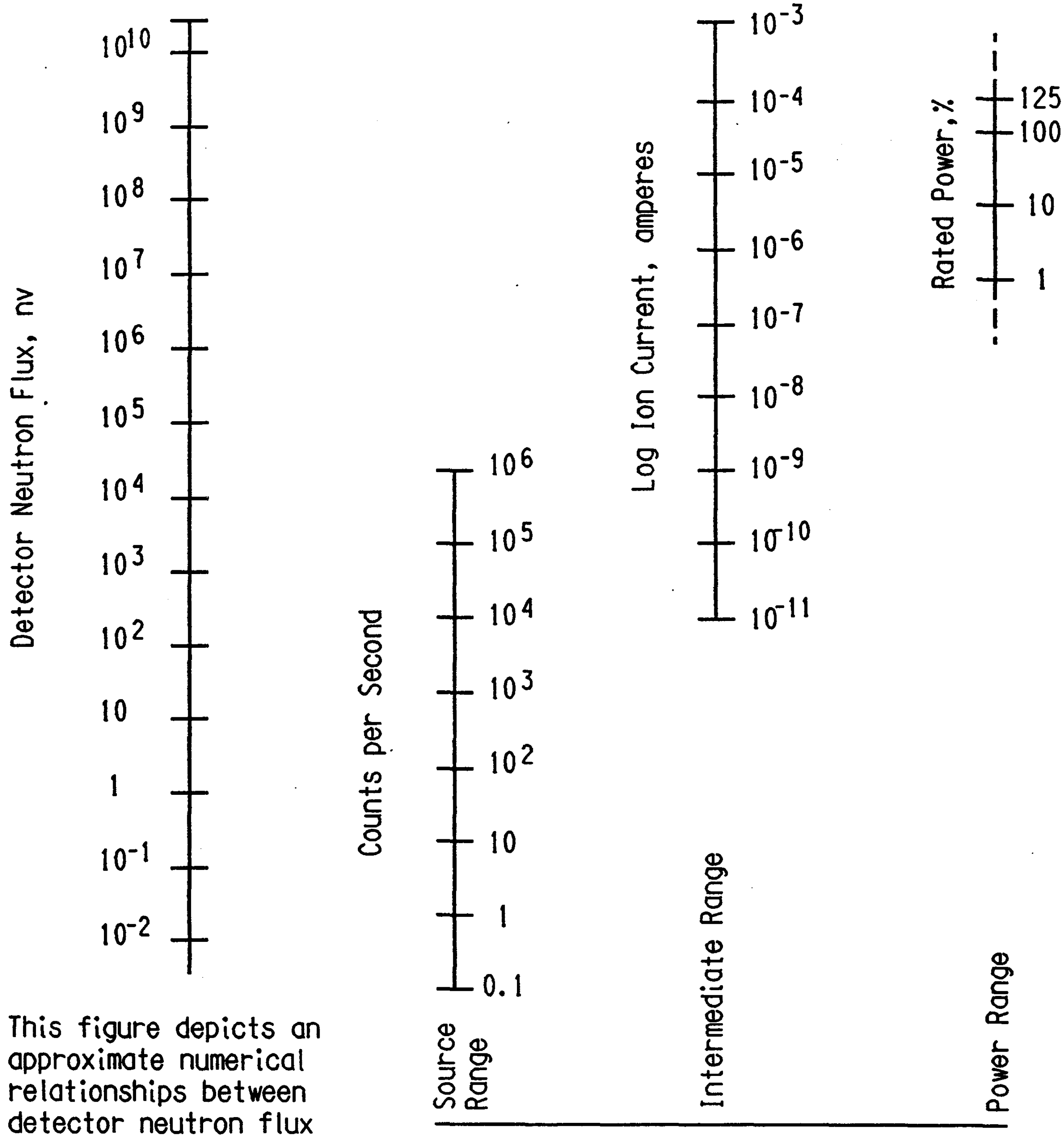
DECEMBER 1996




NOTE: This figure depicts an approximate numerical relationships between detector neutron flux and the various instrument range indications.

DAVIS-BESSE NUCLEAR POWER STATION
NUCLEAR INSTRUMENTATION- FLUX RANGES

FIGURE 7.8-2

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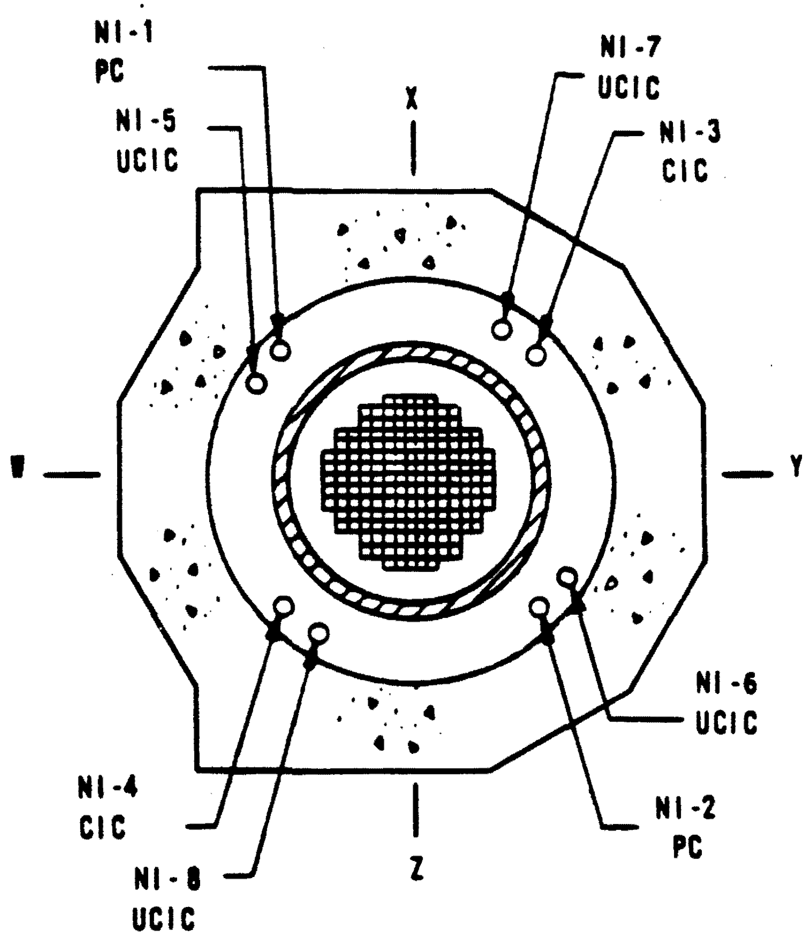


LEGEND

PC - PROPORTIONAL COUNTER - SOURCE RANGE DETECTOR

CIC - COMPENSATED ION CHAMBER - INTERMEDIATE RANGE DETECTOR

UCIC - UNCOMPENSATED ION CHAMBER - POWER RANGE DETECTOR

**DAVIS-BESSE NUCLEAR POWER STATION**
**NUCLEAR INSTRUMENTATION -**
**DETECTOR LOCATIONS**

FIGURE 7.8-3

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## 7.9 INCORE MONITORING SYSTEM (IMS)

The IMS provides neutron flux detectors and core outlet thermocouples to monitor core performance. Incore self-powered neutron detectors measure the neutron flux in the core to provide a history of power distribution during operation. The thermocouples measure the temperature of the RC leaving the top of the core to provide a record of core exit temperature. In addition, the thermocouples in the sixteen symmetrical locations provide environmentally qualified and physically separated signals in accordance with NUREG 0737, Item II.F.2, and Regulatory Guide 1.97, Revision 3. Data obtained from the neutron flux detectors provides power distribution information and fuel burnup data to provide assistance in fuel management. The station computer provides normal system readout.

### 7.9.1 Description

The IMS consists of assemblies of self-powered neutron detectors and thermocouples located at 52 positions within the core. The incore detector and thermocouple locations are shown in Figure 7.9-1. In this arrangement, an incore detector assembly consisting of seven local flux detectors, one background average flux detector and one core outlet thermocouple is installed in the instrumentation tube of each of 52 fuel assemblies as shown in Figure 7.9-1. The local detectors are positioned at seven different axial elevations to provide the axial flux gradient. The average background flux detector provides an integrated flux measurement along the axial length of the core.

Readout for the IMS is performed by the station computer.

When the reactor is depressurized, the IMS assemblies can be inserted or withdrawn through incore monitoring system piping which originates at a shielded area in the CV as shown in Figure 7.9-2 This piping enters the bottom head of the reactor vessel where internal guides extend up to the instrumentation tubes of 52 selected fuel assemblies. The instrumentation tube serves as the guide for the IMS assembly. During refueling operations, the IMS assemblies are withdrawn approximately 13 feet to allow free transfer of the fuel assemblies. After the fuel assemblies are placed in their new locations, the IMS assemblies are returned to their fully inserted positions.

The capability is provided for selecting 1 of 8 qualified incore thermocouples as an input to each of the $T_{sat}$ meters. This addition provides the flexibility to substitute appropriate combinations of incore thermocouples for the loop resistance temperature detectors (RTDs) which are used for primary temperature input to the subcooling meters.

### 7.9.2 Analysis

#### 7.9.2.1 Calibration Techniques

The nature of the detectors permits the manufacture of nearly identical units which produce a high relative accuracy. The detector signals are compensated continuously for burnup of the neutron sensitive material by the plant computer.

Calibration of detectors is not required. The incore self-powered detectors are controlled to precise levels of initial sensitivity by Quality Control during manufacturing. The sensitivity of the detector changes over its lifetime due to such factors as detector burnup, control rod positions, and fuel burnup. The results of experimental programs to determine the magnitude of these

factors have been incorporated into calculations and are used to correct the outputs of the incore detector for these factors.

The station computer calculates a depletion correction factor for each detector, based on detector geometry and the total neutron flux to which the detector has been exposed. Therefore, this correction factor is calculated as a function which varies with burnup. This factor, combined with experimental data on detector sensitivity as a function of detector length, is used to correct detector signals for conversion to power. The heat balance calculated by the station computer is used to normalize the reactor power data derived from the incore detectors. Operation of incore detectors in both power and test reactors has demonstrated that this means of detector compensation provides an accurate readout.

The IMS is not used in the calibration of the power range total power signal. The power range total power signal is calibrated to a station heat balance when the difference between them exceeds a predetermined value. The axial imbalance is maintained during this calibration. The station computer continuously monitors the difference between the calculated heat balance and reactor power as measured by the out-of-core detectors, providing an alarm when the difference is greater than a preset value.

The power range imbalance is calibrated to the IMS imbalance by adjusting the RPS linear amplifier modules' gain settings. The maximum allowable deviation between the imbalance indicated by the Power Range Detectors and the value measured by the IMS is specified by Technical Specification.

7.9.2.2 Operating Experience

Self-powered incore neutron detectors have been operated since 1962. Such detectors have been assembled and irradiated in a Babcock & Wilcox development program that began in 1964.

The B & W Development Program included these tests:

1. Parametric studies of the self-powered detector.
2. Detector ability to withstand PWR environment.
3. Multiple detector assembly irradiation tests.
4. DELETED
5. DELETED
6. DELETED
7. High pressure seal tests.
8. Relationship of flux measurement to power distribution experiments.

Conclusions drawn from the results of the test program are as follows:

1. The detector sensitivity, resistivity, and temperature effects are satisfactory for use.

2. A multiple detector assembly can provide axial flux data in a single channel and can withstand a reactor environment.

3. Background effects will not prevent satisfactory operation in a PWR environment.

4. Station computer systems are compatible as readout systems for incore monitors.

For IMS development program results and conclusions, refer to B&W Topical Report BAW-10001-A, “In-Core Instrumentation Test Program.”

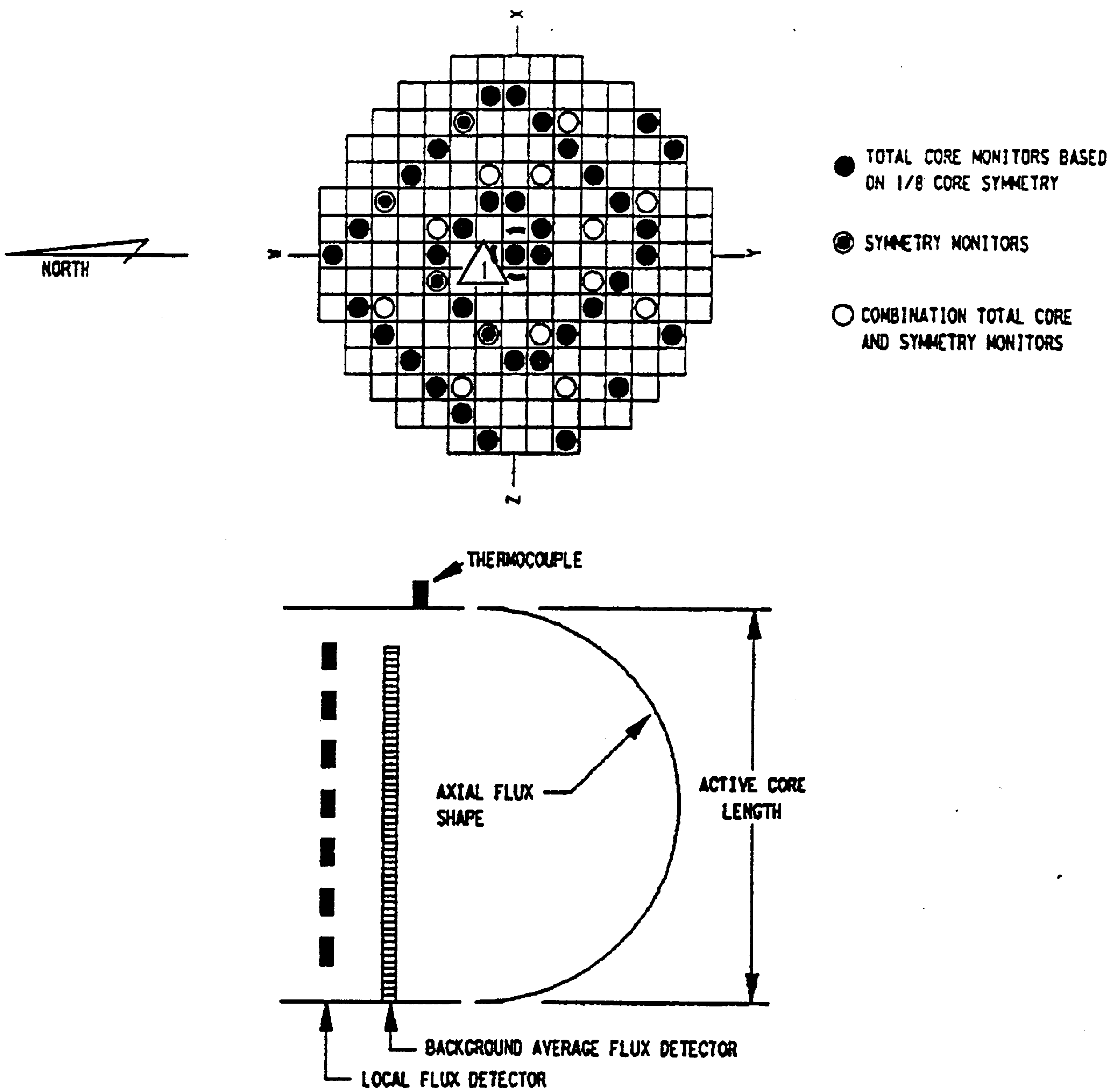
7.9.2.3 Detection of Power Distribution

Under normal operating conditions, the incore detectors supply information to the operator in the control room.

Each individual detector measures the neutron flux in its vicinity and is used to determine the local power density. The individual power densities are then averaged and a peak-to-average power ratio calculated. This information can be used to ensure core design limits are not violated, detect power oscillations, and detect misloaded fuel assemblies.

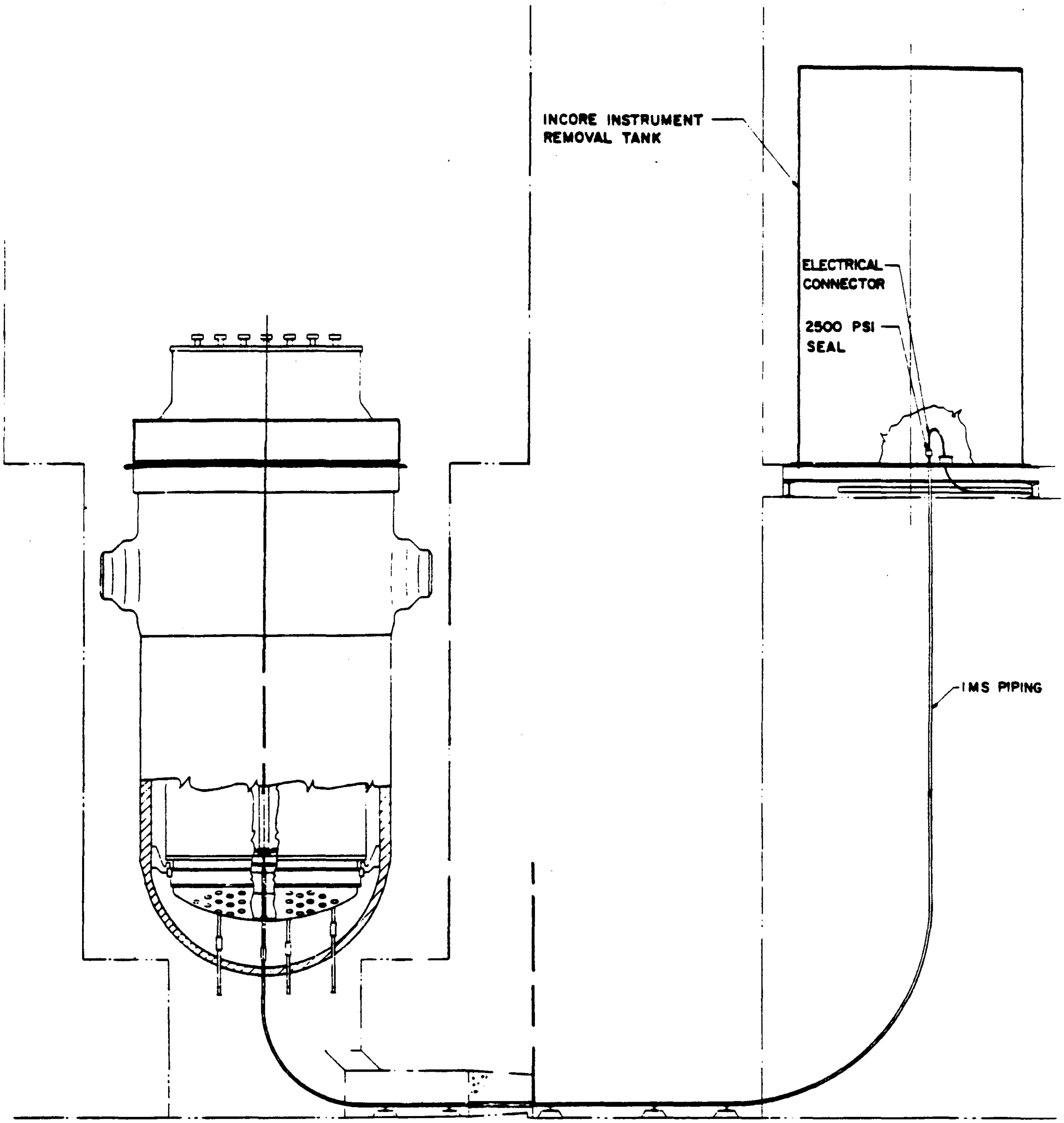
The application of this system for detection of power distribution and its minimum sensitivity has been examined through the analysis of experimental data. A series of Physics Verification Program Reports developed under AEC Contract No. AT(30-1)-3647 and B&W Contract No. 41-2007 have previously been submitted to the Commission for review. Much of the data compiled was taken by self-powered detectors and shows the performance capabilities of the detectors. Upon initial installation, the self-powered detector has the capability to measure the relative flux with an accuracy of 5%.

The use of the IMS to detect xenon oscillations is described in B&W Topical Report BAW-10010, Part 1, “Stability Margins for Xenon Oscillations-Modal Analysis.”




DAVIS-BESSE NUCLEAR POWER STATION
INCORE DETECTOR LOCATIONS

FIGURE 7.9-1




**DAVIS-BESSE NUCLEAR POWER STATION**
**TYPICAL ARRANGEMENT -**
**INCORE INSTRUMENT CHANNEL**

FIGURE 7.9-2

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JULY 1982

## 7.10 STATION COMPUTER SYSTEM

The purpose of the station computer is to monitor plant performance and display this information to the plant operator. It also performs calculations to support nuclear fuel management and checks input signals for abnormal ranges. Calculations are performed to provide operators with the status of plant nuclear and thermohydraulic conditions. No direct or indirect reactor protection or process control action is taken by the computer system. Should the computer be out of service for any reason, the ability of the plant to operate safely under manual or automatic control is not impaired.

The plant process computer system of multiple computer work stations located throughout the station. All equipment is interconnected through a plant computer network. Redundant equipment with monitoring and fail over is provided for critical processing equipment. Printers are available to provide hardcopy printouts of alarms, logs, screen prints and reports. Critical processing equipment is powered from one of two separate uninterruptable power supplies.

Plant data is acquired by sampling over 3000 station inputs via multiplexers located throughout the station. Typical inputs include flow, level, pressure, temperature, valve position and status of pumps or motors. Station status is obtained by scanning these inputs and providing the digital values for use by any of the workstations. The display of alarm messages is provided automatically.

Operator-requested displays may consist of a single plant input, calculated variable or a group of pre-assigned inputs or calculated variables. All requests are done through the workstations via the keyboard or mouse. A sequence of event function is also provided by the plant process computer. The sequence of event function records off normal and return to normal events, the time of occurrence and the sequence of occurrence. The Plant Computer includes the Safety Parameter Display System (SPDS). Refer to Section 7.14 for the function of the SPDS.

## 7.11 STATION ANNUNCIATOR

The station annunciator, located at the main control board, provides the operator with visual and audible indications if limiting conditions are approached or abnormal conditions exist for any system so annunciated.

In the event of annunciator non-operability or malfunction, station safety will not be compromised and station operation will not be prevented.

## 7.12 NON-NUCLEAR INSTRUMENTATION (NNI)

Discussions relating to the instrumentation systems which monitor various station processes are included in the descriptions of various systems.

The major design criteria related to NNI Control and instrumentation systems and listed below:

1. Regulating and control system instrumentation are separate from protective system equipment.

2. Sufficient instrumentation is provided to enable the operator to monitor all station operating conditions.

3. Instrumentation ranges shall be selected to measure the maximum process system design conditions as a minimum.

4. Where measurements of wide process ranges is required and precise control is also involved, both wide range and narrow range instruments are provided.

5. Process parameters used by the ICS during power operations are derived from selectable redundant transmitters.

## 7.13 POST ACCIDENT MONITORING SYSTEM (PAMS)

The purpose of the Post Accident Monitoring System (PAMS) is to follow the course of an accident condition with wide range instrumentation, which will provide to the plant operators the essential safety status information allowing the operators to return the plant to a maintained, safe, shutdown condition.

The scope of the PAMS Category 1 instrumentation includes all electronic signal processing equipment and cabling from the safety grade, Class 1E sensors (channels 1 and 2 of each variable) to the post accident instrument racks in the main control room and cabinet room. The racks house the indicating, recording, storing, calculating, and displaying modules for the essential accident condition information.

Category 1 is intended for key variables. Category 2 generally applies to instrumentation for indicating system operating status. Category 3 instrumentation provides for backup and diagnostic functions.

This section does not provide details for Category 2 and 3 instrumentation except for instruments identified in Section 7.13.3.

### 7.13.1 <u>Design and Qualification Criteria</u>

The following information demonstrates the compliance with the NRC Regulatory Guide 1.97, Revision 3, for category 1. The PAMS also meets Regulatory Guide 1.89 and the methodology described in NUREG 0588.

#### 7.13.1.1 Single Failure

No single failure within the PAMS, its auxiliary support features, or its power sources, concurrent with a failure that is a condition or result of the specific accident will prevent the operator from being provided the essential information to determine the safety status of the Generating Station.

#### 7.13.1.2 Power Sources

All PAMS instrumentation is energized from the plant essential power bus which is backed up by batteries. Each channel is electrically independent for each measured variable. Essential power supplies are discussed in Chapter 8.

#### 7.13.1.3 Availability

The PAMS instrumentation is designed to be available for any accident condition, except as defined by Paragraph 4.11 of IEEE-279 1971 or as specified by Test Specification.

#### 7.13.1.4 Quality Assurance

NRC Regulatory Guides 1.33, 1.38, 1.39, 1.58 and 1.64 were used, to the extent possible on PAMS for quality assurance.

#### 7.13.1.5 Indication Requirements

Where required, indication for both channels for each variable, has been provided. Where two or more instruments are required, overlapping instrument spans have been provided.

#### 7.13.1.6 Recording Requirements

Recorders or plant computers for each variable have been provided where trend and transient information are essential for operator action.

#### 7.13.1.7 Accuracy

The PAMS instrumentation will continue to read within the required accuracy following but not necessarily during a safe shutdown earthquake.

#### 7.13.1.8 Identification

The identification of the PAMS equipment including cabinets, trays, cables between redundant portions, is accomplished by color coding and numbering as described in Chapter 8.

#### 7.13.1.9 Service and Testing

Service testing and calibration programs have been provided to maintain the capability of PAMS. Instruments which require a shorter interval than refueling shutdowns are provided with built-in testing features which allow testing during power operation. Checking, testing and calibration is performed in accordance with Regulatory Guide 1.118.

#### 7.13.1.10 Bypass

Administrative controls to prevent a channel from being removed and thereby allowing access to all setpoints adjustments, module calibration adjustments and test points, have been provided by the use of cabinet door locks requiring keys. Out of service intervals are specified in the Technical Specification.

#### 7.13.1.11 Isolation

The transmission of PAMS signals for use by other systems has been provided with isolation devices (buffers). The isolation devices are located in an accessible rack for maintenance during accident conditions.

#### 7.13.1.12 Quality of Components

The PAMS consists of Class 1E high quality sensors and components to the extent possible. Inputs are provided which measure the desired variable. Utilization of instruments used during normal plant operation has been considered in the design and qualification criteria.

#### 7.13.1.13 Environmental Qualification

For PAMS Class 1E equipment installed to meet the requirements of Regulatory Guide 1.97, IEEE Standard 323-1974 and IEEE Standard 344-1971 have been utilized for the environmental qualification. While all PAMS Class 1E equipment satisfies the requirements of 10 CFR 50.49,

some were original plant equipment and are in compliance with earlier versions of IEEE standards. All environmental envelopes except that pertaining to the variable measured by the information display channel are those associated with design basis accident events. Type test data is available to verify that the PAMS Class 1E equipment meet on a continuing basis the performance requirements.

## 7.13.2 Supporting Systems

### 7.13.2.1 Safety System Interface

Wide range RC pressure signals from Safety Features Actuation System (SFAS) Channel 1 and 2 are supplied through isolation devices (buffers) for use in the subcooling margin processing instrumentation for the required reactor coolant system subcooling margin calculation.

### 7.13.2.2 Non-Class 1E Interfaces

The PAMS interfaces with the non-safety (Non-Class 1E) equipment where no credit is taken for its operability.

1. Station Annunciator
2. Station Computer
3. SPDS multiplexer (MUXA)

## 7.13.3 System Description

The PAMS Category 1 instrumentation consists of Class 1E, safety grade systems which contain independent instrumentation strings to monitor the following plant parameters:

1. Containment High Range Radiation Monitors
2. Containment Wide Range Pressure Monitors
3. Containment Normal Sump and Wide Range Water Level Monitors*
4. Containment Hydrogen Monitors # #
5. RC System Subcooling Margin Monitors* #
6. Incore Thermocouples
7. PORV and Pressurizer Safety Valves Position Indicators*
8. Wide Range Noble Gas Monitors*
9. Reactor Coolant Hot Leg Level Monitoring (HLLMS)**
10. Reactor Coolant Loop Pressure Monitors
11. Neutron Flux Detectors

12. Steam Generator Start-Up Range Level Indicators

13. Steam Generator Outlet Steam Pressure

14. Reactor Coolant Loop Outlet Temperature

15. Pressurizer Level

16. High Pressure Injection Flow

17. Low Pressure Injection (DHR) Flow

18. Auxiliary Feedwater Flow Rate

19. Borated Water Storage Tank Level**

* Containment Normal Sump Level, RC System Subcooling Margin Monitors, PORV and Pressurizer Safety Valves Position Indicators are Category 2 instrumentation, and Station Vent Wide Range Noble Gas Monitors.

** Exceptions have been taken and approved in Regulatory Guide 1.97 submittals and correspondence.

# The Subcooling Margin Monitor indicators are Non-1E and not safety grade.

## The Containment Hydrogen Monitors have been reclassified by the NRC as Category 3 as a result of a revision to 10 CFR 50.44 (Reference 4).

7.13.3.1 Containment High Radiation Monitors

The Containment High Radiation Monitor consists of two (2) safety grade, electrically independent, physically separated gamma photon radiation level instrument strings, with a calibrated range of $10^0$ -$10^8$ Rad/hr. Continuous indicators have been provided in the post accident racks located in the main control room. In addition, one string provides a signal output (non-class 1E) to the SPDS multiplexer (MUXA) and both strings provide an output (non-class 1E) to recorders in the radiation monitoring panels located in the main control room.

7.13.3.2 Containment Wide Range Pressure Monitors

The Containment Wide Range Pressure Monitors consist of two (2) safety grade, Class 1E, electrically independent, and physically separated, pressure instrument strings with a maximum calibrated range of 200 psia. Local indicators are provided in the post accident panels in the main control room. One of the signals goes to the SPDS multiplexer (MUXA).

7.13.3.3 Containment Normal Sump And Wide Range Water Level Monitors

The Containment Normal Sump and Wide Range Water Level Monitors each consist of two (2) safety grade water level instrument strings. Each normal range sump pit level instrument has

an indicator in the main control room with a range of 0-4 feet. Actual sump pit depth is 2 feet 7 inches.

The wide range water level monitors each have an indicator in the main control room with a range of 0-55 feet (i.e., containment bottom to 600,000 gallon calculated CTMT flood level). The wide range sensors overlap approximately 4 inches with the normal range sensors.

Both normal and wide range instruments provide Non-Class 1E signals to the station computer. Also one each of the normal and wide range signals goes to the SPDS multiplexer (MUXA).

#### 7.13.3.4 Containment Hydrogen Monitors

The Containment Hydrogen Monitors consist of two cabinet cubicles. Each cubicle provides one channel with a metal barrier separating Channels 1 and 2.

The Hydrogen Analyzer has a range of 0-10% hydrogen under both positive and negative containment pressure. Indicators have been provided in the control room and on the front panel of the cubicles. A redundant pump has been supplied with fail circuit pressure switch and alarm. When the initial pump fails, the parallel redundant pump provides flow.

The hydrogen analyzer equipment is not required to operate in a continuous mode. Startup on the system is required 30 minutes after containment spray has been initiated during accident conditions.

In addition, instrument signals have been provided to the station computer. One of the signals also goes to the SPDS multiplexer (MUXA).

Note that 10 CFR 50.44 relaxes the requirements for the containment hydrogen monitors (Reference 4).

#### 7.13.3.5 RC System Subcooling Margin Monitors

The RC System Subcooling Margin Monitors are PAMS Category 2 instrumentation, as defined in Regulatory Guide 1.97. They consist of two (2) electrically independent, physically separated instrument processor strings. Each processor channel is provided with isolated Class 1E signal inputs from 100 ohm RTD detector instrument strings and pressure instrument strings (Hotleg Temperature 120-920°F and Wide Range Reactor Pressure 0-2500 psig from the SFAS system isolation buffers.) Providing the isolation at the inputs to the meters meets the requirements of Regulatory Guide 1.97, which states that if an instrumentation channel signal is to be used in a computer-based display, recording, or diagnostic program, qualification applies from the sensor up to and including the channel isolation device. The $T_{sat}$ meters are signal processors and therefore fall under this allowance. The processor channels calculate reactor coolant system subcooling and display the calculated value on digital meters located in the post accident racks in the main control room. Digital meters in the cabinet room will display, on demand, the temperature or pressure input values as well as reactor coolant system subcooling, saturation pressure, or saturation temperature. In addition, separate signal outputs are provided for the SPDS multiplexer (MUXA), station annunciator, and station computer.

7.13.3.6 Incore Thermocouples

The Incore Thermocouples consist of two (2) thermocouples from each reactor quadrant, for a total of (8), selectable for each $T_{sat}$ meter located in the post accident racks. The thermocouples are redundant to the hot leg RTD's. All components except the $T_{sat}$ meters are Class 1E. Buffer inputs are provided for the SPDS multiplexer (MUXA) and station computer. The hand switch and temperature indicators are located in the main control room. The range of the thermocouples is 0-2300°F.

7.13.3.7 PORV and Pressurizer Safety Valves Position Indicators

The PORV and Pressurizer Safety Valves Position Indicators are designed to monitor the power operated relief valve and safety valves positions. Flow through these valves generates acoustical levels or vibration which is detected on the discharge pipe by piezoelectric sensors that provide a charged output.

An alarm module to test and display annunciator conditions and Open/Closed light indication is provided in the main control room. In addition, signal outputs are provided to the SPDS multiplexer (MUXA), station annunciator, and station computer.

7.13.3.8 Wide Range Noble Gas Monitors

The wide Range Noble Gas Monitors consists of Normal Range and Accident Range Station Vent Monitors, which detect and measure the gross beta/gamma activity level of the isotopes present in gaseous form in the containment atmosphere or from the auxiliary building in the effluent release vents. The monitors utilize two detectors to cover the gaseous activity range from $10^{-7}$ $\mu$Ci/cc to $10^{5}$ $\mu$Ci/cc. In addition, a collection system for particulates and halogens permits data gathering for levels at or below $10^{2}$ $\mu$Ci/cc.

See section 11.4.2.2.4 for additional information.

7.13.3.9 Reactor Coolant Hot Leg Level Monitoring

The Reactor Coolant Hot Leg Level Monitoring System (HLLMS) instrument strings (one per hot leg) are classified as important to safe operation, but not nuclear safety related, and are designed to safety Class 1E for the electrical portion up to and including the isolation device wired to non Class 1E equipment. The piping portions of the HLLMS are designed as ASME Section III Class 1 from the reactor coolant system tie-ins to the first isolation valve and Section III Class 2 from the first isolation up to and including the instrument shut off valves.

The transmitters and sensing lines from each hot leg pipe are spatially separated. The lower tap for each transmitter is common, but each line is separately routed to the respective transmitter. Electrical separation for each redundant channel is provided by the routing of cable in separate conduits. Redundant Class 1E power is provided to each channel.

The HLLMS provides a means to trend reactor coolant inventory. The HLLMS provides supplementary information to assist the operator in the assessment of the effectiveness of automatic safety functions (ESFAS).

The HLLMS is only operational when the reactor coolant pumps are not running, and natural circulation is possible.

The Level Transmitter and density compensation signals are sent to the plant computer. The channel 2 signals also go to the SPDS multiplexer (MUXA). An HLLMS algorithm takes these signals and RCS flow, temperature, pressure, and pump status signals and executes to determine actual hot leg level. The level can be accessed and displayed provided that the RCS pumps are off and the RCS is not experiencing rapid depressurization.

7.13.3.10 Reactor Coolant Loop Pressure Monitors

The Reactor Coolant (RC) Loop Pressure Monitors consist of two (2) safety grade, Class 1E, electrically independent, physically separated, pressure instrument strings with a calibration range of 0-3000 psig. Indicators are provided in both the post accident panels in the main control room and the auxiliary shutdown panel. In addition, isolated signal outputs are provided to a chart recorder and the SPDS multiplexer (MUXA).

7.13.3.11 Neutron Flux Detectors

The Neutron Flux Detectors consist of two (2) safety grade, Class 1E, electrically independent, physically separated fission chamber radiation level instrument strings, with the capability of a calibrated range of $10^{-2} - 10^{10}$ n/cm$^2$ sec. This signal is processed for source range ($10^{-1} - 10^{5}$ cps) and wide range indication ($10^{-8}$ - $2 \times 10^{2}$ % power). Continuous indicators have been provided in the post accident racks located in the main control room. The signal processor also provides audible indication in the main control room and in containment.

7.13.3.12 Steam Generator Start-up Range Level Indicators

The Steam Generator Start-up Range Level Indicator consists of four (4) safety grade, Class 1E, electrically independent, physically separated readouts. Two readouts are 0-250” of water, two are 0-300” of water. Indicators are located on the main control board (fed from the Auxiliary Shutdown Panels) and on the Post Accident Monitoring (PAM) panels (fed from SFRCS). Two of these instrument strings have corresponding plant computer and SPDS multiplexer (MUXA) points.

7.13.3.13 Steam Generator Outlet Steam Pressure

PAMS contains two (one per SG) safety grade Steam Generator Outlet Steam Pressure strings with indicators in the control room and corresponding plant computer points. The range of these strings is 0-1200 psig. These strings are redundant to two (one per SG) non-safety grade Steam Generator Outlet Steam Pressure strings with indicators in the control room and corresponding plant computer points. The safety grade instrument strings also go to SPDS multiplexer (MUXA) points.

7.13.3.14 Reactor Coolant Loop Outlet Temperature

PAMS contains four (two per loop) safety grade RC loop Outlet Temperature strings with indicators in the control room and corresponding plant computer points. Two of these computer points also go to the SPDS multiplexer (MUXA). These strings have a range of 120-920°F.

#### 7.13.3.15 Pressurizer Level

PAMS contains two safety grade, Pressurizer Level strings with indicators in the control room and corresponding plant computer points. One of these signals also goes to the SPDS multiplexer (MUXA). These strings have a 0-320 inch range.

#### 7.13.3.16 High Pressure Injection Flow

PAMS contains four (two per train) safety grade High Pressure Injection Flow strings with indicators in the control room and corresponding plant and SPDS multiplexer (MUXA) points. These strings have a 0-500 GPM range.

#### 7.13.3.17 Low Pressure Injection (DHR) Flow

PAMS contains two (one per train) safety grade Low Pressure Injection Flow strings with indicators in the control room and corresponding plant and SPDS multiplexer (MUXA) points. These strings have a 0-5000 GPM range.

#### 7.13.3.18 Auxiliary Feedwater Flow Rate

PAMS contains four (two per train) safety grade Auxiliary Feedwater Flow strings with indicators in the control room. Two of these signals also go to the SPDS multiplexer (MUXA). The range of these strings is 0-1000 GPM.

#### 7.13.3.19 Borated Water Storage Tank Level

PAMS contains four safety grade Borated Water Storage Tank Level strings with isolated non-1E indicators in the control room and corresponding plant computer points. One of these signals also goes to the SPDS multiplexer (MUXA). The range of these strings is 0-50 feet.

### 7.13.4 Design Bases

The design bases for the PAMS instrument strings are applicable to Regulatory Guides 1.97, Revision 3 and 1.89 and NUREG 0737 requirements.

## 7.14 SAFETY PARAMETER DISPLAY SYSTEM

The principal purpose and function of the SPDS is to aid the Control Room personnel during abnormal and emergency conditions in determining the safety status of the plant.

### 7.14.1 Description

Information from plant instrumentation provides input to both the station computer and a separate multiplexer that is used as the primary source of data to the SPDS.

The display and archive system provides the displays to workstations located in the Control Room, Technical Support Center (TSC), and Emergency Operations Facility (EOF) via the plant data network. Data and displays are also available to other locations with access to the plant data network.

### 7.14.2 Design Bases

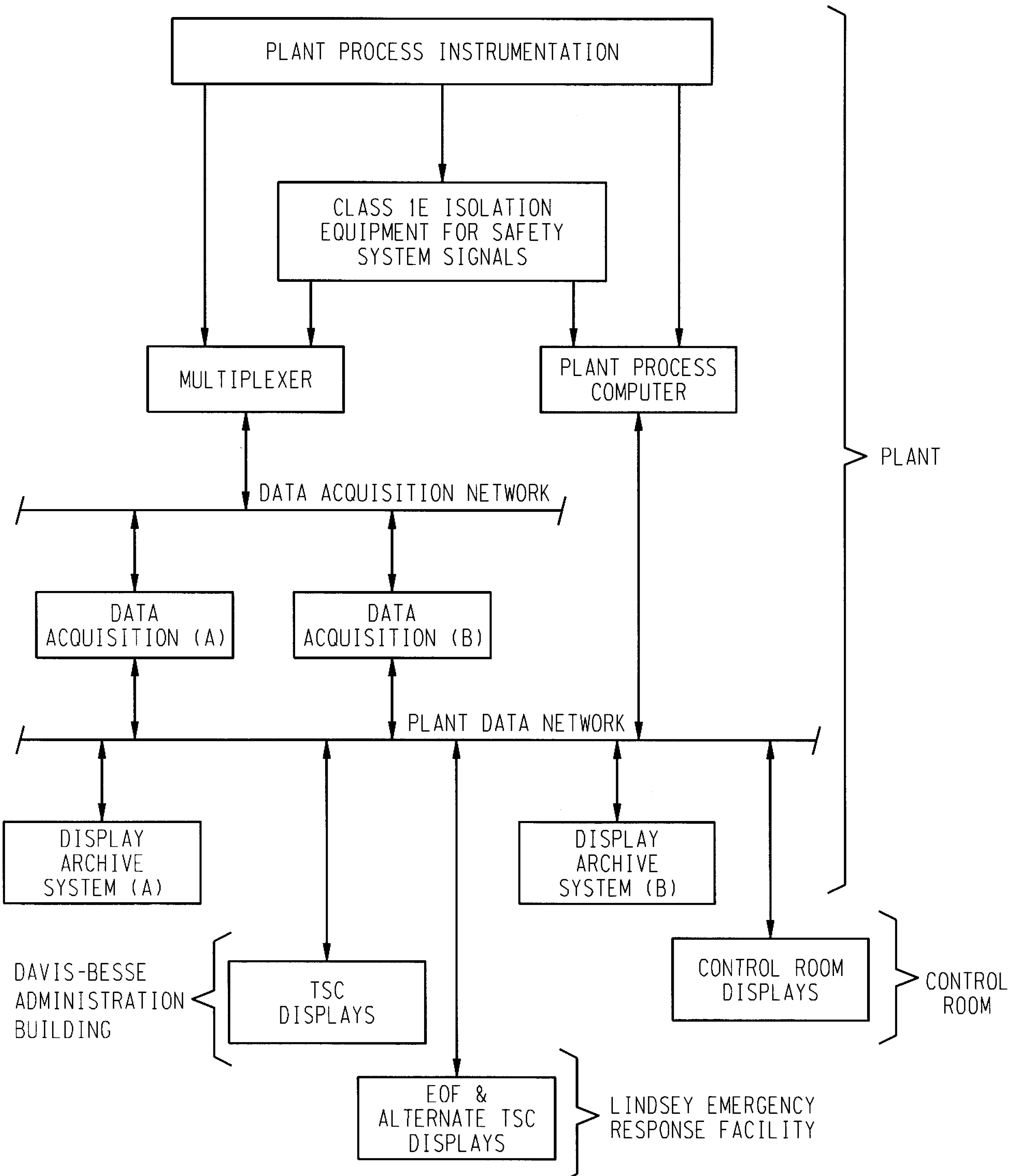
The SPDS displays are located convenient to the control room operators. The displays aid the Control Room operator in determining the status of the plant with a series of six alarms boxes. Each box represents the status of a critical safety function. The critical safety functions for NUREG 0737 Supplement 1 include; reactivity control, reactor core cooling and heat removal from the primary system, reactor coolant system integrity, radioactivity control, and containment conditions. Note that the extra safety function used in the Davis-Besse SPDS results from splitting the "reactor core cooling and heat removal from the primary system" function into two functions. The first of these is associated with the core heat removal from the standpoint of the primary system. The second function is related to secondary plant heat removal capabilities.

These alarm boxes are located on all displays associated with SPDS. A list of alarm conditions associated with each box is also available to assist the Control Room operator in determining the cause of the alarm. The alarm conditions are activated by parameters reaching specified setpoints, which can be fixed or derived from the other parameters. This design provides a concise method of directly displaying the alarm conditions without requiring an analysis by the operator. The intent of this design is to provide indications of potential threats to the fulfillment of a critical safety function. These alarm conditions were developed to be consistent with the normal and emergency operating procedures. Historical trends of these parameters can also be selected for display to assist the operator in determining the status of critical safety functions. These displays and alarm boxes constitute the minimum SPDS display format. The SPDS displays incorporate accepted human factors principles.

The operator is trained to identify unsafe plant conditions with, or without, an SPDS. The conservative design of the SPDS alarm logic is such that an omission of an alarm is preferable to an invalid alarm. The alarms have been designed with sufficient logic to eliminate false or inaccurate alarms. Thus, the design minimizes the possibility of an invalid alarm detracting the Control Room operator from safety-related instrumentation. The SPDS alarm logic is also designed to augment rather than duplicate other alarm indications available in the Control Room.

A dedicated computer multiplexer (MUXA) provides the primary source of data for the SPDS. Those signals originating in Class 1E instrumentation strings are isolated from the safety grade portion of the system using the appropriate Class 1E-isolation devices. The parameters evaluated as most useful in determining the safety status of the plant were included on the input

list of the dedicated multiplexer to provide a means of information redundant to data from the station computer. All data received from the station computer and the dedicated multiplexer is archived for future use. Historical SPDS information is readily available for displaying parameter trends at any plant computer workstation such as the Control Room, TSC, and EOF.




DAVIS-BESSE NUCLEAR POWER STATION
SPDS BASIC CONFIGURATION
FIGURE 7.14-1
REVISION 32
SEPTEMBER 2018

DB 11-20-17 DFN: G/USAR/UFIG7141.DGN

## 7.15 REFERENCES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