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## 15 PLANT DIFFERENCES

**Learning Objectives:**

1. Describe the basic design differences between the various Combustion Engineering plant generations.
2. Explain how later Combustion Engineering plants were able to increase their operating power densities.
3. Describe the basic control and protection system differences between the various Combustion Engineering plant generations.

### 15.1 Introduction

The purpose of this chapter is to describe the differences in systems installed in Combustion Engineering (CE) designed nuclear steam supply systems (NSSS). CE plants can be grouped into the following six categories based on the general fuel element configuration and thermal power rating of the core:

1. Palisades has 204 fuel assemblies and a thermal power rating of 2565 Mw(t).
2. Fort Calhoun has 133 fuel assemblies and a thermal power rating of 1500 Mw(t).
3. Calvert Cliffs 1 & 2, Millstone 2, and Saint Lucie 1& 2 have 217 fuel assemblies that are 137 inches long. The thermal power rating of these units is 2700 Mw(t).
4. Arkansas Nuclear One-Unit 2 (ANO-2) has 177 fuel assemblies and a thermal power rating of 3026 Mw(t).
5. San Onofre 2 &3 and Waterford 3 have 217 fuel assemblies that are 150 inches long. San Onofre 2 &3 are rated at 3438 Mw(t). Waterford 3 is rated at 3716 Mw(t).
6. Palo Verde 1, 2, & 3 have 241 fuel assemblies that are 150 inches long. The thermal power rating of these plants is 3990 Mw(t).

Plants in the first three groups operate at a relatively lower power density than plants in the latter two groups. Palisades and Fort Calhoun both operate at an average power density of 80 kW/liter. Palisades has a unique core design that uses 204 (15 X 15) fuel assemblies and cruciform shaped control element assemblies. The Fort Calhoun core is comprised of 133 (14 X 14) fuel assemblies that are designed for use with multi-finger CEAs. The Calvert Cliffs, Millstone 2, and Saint Lucie cores all consist of 217 (14 X 14) fuel assemblies and operate at power densities in the range from 75 to 83 kW/liter.

ANO-2 is a unique core design that operates at a relatively high power density of 96.6 kW/liter with 177 (16 X 16) fuel assemblies. The ANO-2 fuel assembly is 150 inches long.

In the high power groups, San Onofre 2 and 3 and Waterford 3 reverted to the 217 fuel assembly core with 16 X 16 fuel assemblies that operate at a power density of about 95 kW/liter. The Palo Verde units have a larger 241 fuel assembly core that operate at a

power density of 95.6 kW/liter. The Palo Verde fuel assemblies are also 150 inches long.

## 15.2 Reactor Vessel Differences

The differences in reactor vessel construction, other than size, involve the adaptations required for incore instrumentation penetrations and thermal shields.

### 15.2.1 Incore Instrumentation

#### Penetrations

Unlike the Calvert Cliffs vessel design, several of the CE design reactor vessels have penetrations into the lower head that are used by the incore instrumentation system. As shown in Figure 15-1, nozzles penetrate the lower head and mate with the core support guide tubes. The incore instrument passes through the incore instrument nozzles, through the core support guide tubes, and into the center guide tube of the instrumented fuel assemblies. This design is applicable to Fort Calhoun, and the Palo Verde units.

### 15.2.2 Reactor Vessel Thermal Shield

The purpose of a thermal shield is to minimize reactor vessel radiation damage and its associated nil ductility transition temperature shift. The thermal shield (Figure 15-2) is installed around the core area on the outside of the core support barrel. Fort Calhoun has thermal shields. The core support barrel minimizes reactor vessel radiation damage in those vessels without a thermal shield.

An interesting side issue is the April 1983 incident at Saint Lucie Unit 1. During refueling foreign objects were seen on the core support plate. The core was completely unloaded and the core support barrel removed for inspection. Two of nine thermal shield pins were missing; two of nine upper positioning pins were gone; and all pins including seventeen lower positioning pins showed some wear or damage. The lugs welded to the core support barrel to support the thermal shield were damaged including some damage to base metal and to welds. The thermal shield was removed, and the damage to the core support barrel was repaired. The unit was returned to service.

## 15.3 Incore Instrumentation Differences

The first difference in the incore instrumentation systems involves the number of self-powered neutron detectors that are included in the incore instrument assembly. A major difference in the system design is the addition of movable incore detectors.

### 15.3.1 Incore Detector Assemblies

The fixed incore detector, installed in ANO-2 and later plants, contains five rhodium detectors, one Cr-Al thermocouple, and one calibration tube to permit the use of movable detectors. The five rhodium detectors have their centers spaced at 10, 30, 50, 70, and 90 % of the active core height. With the exception of the fifth detector and the calibration tube, the incore detector assembly is identical to the Calvert Cliffs assembly.

### 15.3.2 Movable Incore System

As shown in Figure 15-3, the movable incore detector system consists of two drive machines, two transfer machines, a passive wye, a purge gas system, a leak detection

switch, and two movable incore detectors. The system is normally controlled by the plant computer, but a portable control box is included in the design.

To enable the drive system to insert and withdraw the movable detector, a drive helix is wrapped over the flat wrap (Figure 15-4). The flat wrap and helix are welded to the detector sheath. A protective spring and bullet nose tip are installed to protect the detector. The drive machines drive the detectors by means of a hobbed drive wheel which mates with the drive helix. Detector position is sensed and transmitted to the computer by the position encoder mounted on the drive wheel shaft. Before the detector enters a transfer machine, it passes through the drive path selector switch which allows either transfer machine to be entered by either detector (Figure 15-5). The transfer machines have one entrance at the top and outlet at the bottom, allowing either movable detector to access any one of the calibration tubes.

A set of microswitches, which close when the detector actually goes through the selected path, provides a redundant position indication. Upon withdrawal, limit switches confirm detector positions for safety and control purposes. A passive wye is added to the movable incore system to allow cross calibration of both movable detectors. Once a detector enters an individual detector tube, it travels the portion of the path outside the reactor at high speed (typically 12 inches/second). The detector enters the in-vessel portion of the incore instrumentation assembly and traverses the active fuel region at low speeds (typically 2.4 inches/second).

The calibration tubes are nonisolable pressure boundaries in the reactor. The entire system is maintained in a nitrogen environment supplied by the nitrogen purge system connected to the transfer machine. The purge gas system fills the transfer machine (and the outgoing calibration tubes) with an inert gas each time the detector is withdrawn from the transfer machine. This reduces moisture and oxygen levels in the drive tubes and detectors to minimize friction.

The movable incore detector system has five modes of operation:

1. Manual,
2. Semi-automatic,
3. Automatic,
4. Reset and
5. Terminate.

The manual mode allows the console operator to position the detector anywhere in a particular incore assembly. Only one detector can be manipulated at a time. This mode is normally used for verification and test programs.

In semi-automatic, a computer program automatically positions the movable detector to the fully inserted position. Upon reaching the full core insertion position, the detector is withdrawn while data is sampled at one inch intervals. During both the insertion and withdrawal phase, the probe travels at low speed. The semi-automatic mode requires the operator to select the desired movable detector and the desired fuel assembly location. The computer will then determine which drive switch configuration is required based on the desired movable detector and fuel assembly location.

The automatic mode is identical to the semi-automatic mode except that the computer will automatically sequence through the entire core complement of incore locations. Both drive and transfer machines will operate simultaneously and asynchronously. Data can be collected using detector A or B or through a dual mode in which both detectors operate simultaneously in the normal or alternate path configurations. The dual mode allows the system to collect and process the data at twice the rate of the single detector mode of operation.

The reset mode is used to prematurely cancel any mode request and repositions one or both detectors to the detector home position.

The terminate mode is used to prematurely cancel any mode and cause one or both detectors to halt in place.

The movable incore detector system may be equipped with rhodium self powered neutron detectors or fission chambers.

### 15.4 CEA Differences

The feature with the most diversity seems to be the control element assembly (CEA) design. There are two different types of mechanisms used to move the CEAs and at least six different CEA designs. The magnetic jack mechanism is used on all CE units with the exception of Palisades and Fort Calhoun. These units use a motor driven rack and pinion CEA mechanism.

#### 15.4.1 Rack-and-Pinion CEA Mechanism

The control element drive mechanism (CEDM), used at Palisades and Fort Calhoun, is of the vertical rack-and-pinion type (Figure 15-6) with the drive shaft running parallel to the rack and driving the pinion gear through a set of bevel gears. The rack is driven by an electric motor operating through a gear reducer and magnetic clutch. By de-energizing the magnetic clutch, the CEA drops into the reactor under the influence of gravity. The drive assembly is equipped with a magnetic brake and an anti-reversing clutch which maintain the position of the CEA with the drive in the holding condition and prevent upward movement of the CEA when in the tripped condition.

For actuating partial length CEAs (applicable to Palisades) which maintain their position during a reactor trip, the CEDM is modified by replacing the magnetic clutch with a solid shaft assembly which eliminates the trip function. Otherwise, this CEDM is the same as those attached to the full length CEAs.

The drive shaft penetration through the pressure housing is closed by means of a face-type rotating seal.

The rack is connected to the CEA blade by means of a tie bolt which extends through the rack to a connecting shaft engaged with the upper end of the CEA. The rack is connected to the CEA by means of a rack extension containing a bayonet-type coupling. The rack extension is connected to the rack through a tie rod by means of a nut and locking device at the upper end of the rack. The tie bolt is fixed to the rack by means of a nut and locking device at the upper end of the rack. A small diameter closure is provided at the top of the pressure housing for access to this nut for releasing the CEA from the CEDM. The rack is guided at its upper end by a section having an

enlarged diameter which operates in a tube extending the full length of the CEA travel. The final cushioning at the end of a CEA drop is provided by dashpot action of the guiding section of the rack entering the reduced diameter in the guide tube.

The pressure housing consists of a lower and upper section joined near the top of the drive by means of a threaded autoclave-type closure. The housing is designed for steady-state, as well as all anticipated pressure and thermal transients.

The lower housing is a stainless steel tubular section welded to an eccentric reducer and flange piece at the lower end. This flange fits the nozzle flange provided on the reactor vessel closure head and is seal welded to it by an omega-type seal. Once seal welded and bolted into place, the lower pressure housing need not be removed since all servicing of the drive is performed from the top of this housing. The upper part of the lower housing is machined to form the closure and is provided with a recessed gasket surface for a spirally wound gasket.

The upper part of the pressure housing has a flange which mates with the lower housing closure, a cavity which contains the drive rotating seal, and a tubular housing extension with a small flange closure which provides access for attaching and detaching the CEA.

The shaft seals are hydraulically balanced face seals utilizing stationary O-rings for the shaft and pressure housing seals. The rotating, axially movable member has a carbon-graphite seating surface which mates with a chromium oxide seating surface.

The two parts of the seal are fitted with O- rings to prevent leakage around the seal. The O- rings are static seals. A cooling jacket surrounds the seal area to maintain the temperature of the seal and O-rings below 250°F. A seal leakage collection cup is provided with a thermocouple in the seal leak-off line to monitor for cooling water or seal failure.

The rack-and-pinion assembly is an integrated unit which fits into the lower pressure housing and couples to the motor drive package through the upper pressure housing. The unit carries the bevel gears which transmit torque from the vertical drive shaft to the pinion gear. The vertical drive shaft has splined couplings at both ends and may be lifted out when the upper pressure housing is removed. Ball bearings are provided for supporting the bevel gears and the pinion gear. The rack engages the pinion, and is held in proper engagement with the pinion by the backup rollers which carry the load due to gear tooth reactions.

The gear assembly is attached to a stainless steel tube supported by the upper part of the pressure housing. This tube also carries and positions the guide tube which surrounds the rack. The rack is a tube with gear teeth on one side of its outer surface and flats on the opposite side which form a contact surface for guide rollers. Flats are cut on two opposite sides of the rack tube for forming the rack teeth and for a contact surface for the backup rollers. The upper end of the rack is fitted with an enlarged section which runs in the guide tube and provides lateral support for the upper end of the rack. It also acts as a piston in controlling water flow in the lower guide tube dashpot. The top section carries a permanent magnet which is used to operate a CEA position indicator outside the pressure housing.

The load on the guide tube is transferred through a connection at its upper end to the support tube, then to the pressure housing. The support for the guide tube contains an energy absorber at the top end of the tube which deforms to limit the stresses on the tie rod, connector shaft, and CEA in case the mechanism is tripped without water in the dashpot. If such a dry trip should occur, the mechanism and CEA would not be damaged; however, it would be necessary to disassemble the drive and replace the guide energy absorber.

Power to operate the drive is supplied by a synchronous, fractional horse power, 120 volt, single-phase, 60 hertz motor. The output is coupled to the vertical drive shaft through a magnetic clutch and an anti-reverse clutch operating in parallel. When the magnetic clutch is energized, the drive motor is connected to the main shaft and can drive the CEA either up or down. With the magnetic clutch de-energized, the CEA will drop due to its own weight.

The motor shaft is equipped with an electrically operated brake which is connected to release the brake when the motor is energized. When the motor is de-energized, the brake is set by means of springs. This brake prevents driving except by means of the motor and thus holds the drive and CEA in position. The magnetic clutch, when de-energized, separates the drive between the pinion gear and the brake, thus permitting the CEA to drop. The anti-reverse clutch and the brake prevent rotation of the drive in the up direction, and hold the CEA in position against upward forces on the CEA. This action is completely mechanical and does not rely on any outside source of power.

Two independent position readout systems are provided for indicating the position of the CEA. One (primary system) is a synchro-transmitter geared to the main shaft with readout provided by synchro-receivers connected to the transmitter. The other (secondary system) position indicator consists of a series of accurately located reed switches built into a subassembly which is fastened to the outside of the CEDM along the pressure housing. The permanent magnet built into the top of the rack actuates the reed switches one at a time as it passes by them. An appropriate resistor network and the above-mentioned servo actuate the readouts to position indication.

Limit switches located in the motor drive package are gear driven from the shaft and are used to provide indication of CEA position at certain predetermined points. Two of these switches are used as limit switches on the drive system and indicate the fully withdrawn and inserted positions.

The CEA design that is driven by the rack-and-pinion drive system is unit dependent. Palisades uses a cruciform shaped CEA that is inserted between four fuel assemblies. Fort Calhoun uses a five-fingered CEA.

### 15.4.2 Multi-fuel Assembly CEAs

Some CE plants have CEAs with fingers that fit into the CEA guide tubes of more than one fuel assembly. The CEAs consist of four, eight, or twelve neutron absorber fingers arranged to engage the peripheral guide tubes of fuel assemblies.

The neutron absorber fingers are connected by a spider which couples to the CEA drive mechanism drive extension shaft. The fingers of a four element CEA (Figure 15-7) engage the four corner guide tubes in a single fuel assembly. The four element CEAs

are used for power shaping functions and make up the first control group to be inserted at high powers.

The eight and twelve finger CEAs (Figure 15-8) engage the four corner guide tubes in one fuel assembly and the two nearest corner guide tubes in adjacent fuel assemblies, two adjacent fuel assemblies for the eight finger CEAs and the four adjacent fuel assemblies for the twelve finger CEAs. The eight and twelve finger CEAs make up the balance of the control groups of CEAs and provide a group of strong shutdown CEAs.

The pattern of CEAs is shown in Figure 15-9. This CEA design is applicable to Palo Verde units 1, 2, and 3.

In order to guide the eight and twelve finger CEAs into the correct fuel assemblies during withdrawal, insertions, and reactor trips, the design of the CEA shroud is different from the Calvert Cliffs CEA shroud. The required modifications to the CEA shroud are shown in Figure 15-10. This figure should be compared with the Calvert Cliffs upper guide structure shown in Figure 15-11.

### 15.4.3 Dual CEAs

Dual CEA refers to two CEAs which are connected by a yoke and driven by one magnetic jack type control element drive mechanism. Dual CEAs are generally used in the shutdown CEA groups. The dual CEA design is applicable to Calvert Cliffs, Millstone 2, and the Saint Lucie units.

### 15.4.4 Part Length CEAs

Part length CEAs (Figure 15-12) contain a small poison section and were designed to provide axial shape index control. San Onofre 2 & 3 and the three Palo Verde units have installed part length CEAs. The remaining CE units included part length CEAs as a part of the original design, but have replaced these CEAs with additional shutdown or regulating group CEAs.

Fort Calhoun replaced the part length CEAs with a group of four non-trippable full length CEAs which are manually inserted following a manual or automatic shutdown.

## 15.5 Power Operated Relief Valves

The ANO-2, San Onofre 2&3, Palo Verde 1, 2, &3, and Waterford 3 designs do not have pressurizer power operated relief valves (PORVs). These units have large secondary steam dump capacities which help to limit RCS pressure excursions caused by losses of heat removal events such as load rejections and turbine trips.

The CE Owners Group Emergency Procedure Guidelines (CEN-152) require the use of the PORVs as a core heat removal method if the steam generator heat sink is lost. This method of core heat removal is called once through core cooling and is initiated by starting all available high pressure safety injection pumps and opening the PORVs to depressurize the plant and provide a flow path for the low temperature ECCS water. Since the plants listed in the first paragraph do not have PORVs, this method of heat removal is not an option. Plant specific emergency procedures should be consulted for core heat removal options.

It should be noted that ANO-2 has two motor operated valves that will allow the pressurizer to be vented directly to the containment building. These valves provide this unit with a once through core cooling capability.

## 15.6 System 80 Steam Generator

The CE System 80 design has two heat transport loops, each loop contains one steam generator. Each steam generator is a vertical U-tube heat exchanger with an integral economizer. The integral economizer utilizes a portion of the cold leg half of the steam generators to preheat the incoming feedwater.

By separating the colder feedwater from the evaporator section and heating it with the colder RCS, the logarithmic mean temperature difference is increased. This enables the steam generator to operate at a higher steam pressure without an increase in heat transfer area.

Feedwater is introduced into a water box of rectangular cross-section that forms a half ring around the cold leg portion of the tube bundle (Figure 15-13). The discharge ports in the rectangular distribution box ensure uniform flow over the entire circumference of the box.

The feedwater then flows radially across the tube sheet below a flow distribution plate (Figure 15-14) which allows the feedwater to pass evenly upward around the generator tubes into the axial flow region. This region is basically a counter flow heat exchanger.

As feedwater passes upward, it is heated to near saturated conditions at the outlet of the economizer region where it now flows into the evaporation section of the steam generator.

Two feedwater injection systems are provided for the steam generators. The main injection path is through two 14-inch nozzles which feed into the economizer water box. Two nozzles are used to promote optimum flow distribution to the integral economizer. The feedwater then passes through the economizer as previously described. When the feedwater exits the economizer and enters the evaporator region, it mixes with the recirculation water from the moisture separating equipment.

The second water injection is a six inch down comer feedwater nozzle which discharges through an internal header and vertical stand pipes to the top of the steam separator deck where it mixes with the recirculation water. The use of the down comer feedwater is dependent upon several factors discussed below.

First, during transient conditions which result in a low steam generator inventory, it is necessary to supply emergency feedwater from the condensate storage system. Emergency feedwater enters the steam generators without being preheated. By admitting the emergency feedwater to the down comer, feedwater preheating is accomplished by mixing with the recirculation water. This eliminates the possibility of brittle fracture to parts in the economizer region which are under pressure stress.

Next, feedwater is admitted to the steam generators via the down comer system at low power levels for the same reason that emergency feedwater is admitted at this point. At low power levels, there is little or no preheat available to the feedwater. From 0 to 15%

power, the feedwater control system will direct all feedwater to the downcomer. Above 15%, the flow will be redirected to the economizer region.

Finally, the down comer system is used again when power is above 50%. From 50% to full power, 10% of the feedwater is directed to the down comer feedwater header. This 10% provides some sub-cooling for the recirculating water and promotes an increased recirculation ratio. This steam generator design is only applicable to the Palo Verde units.

## 15.7 Plant Protection System Design Differences

### 15.7.1 RPS/ESFAS Interfaces

The reactor protection system (RPS) and engineered safety features actuation system (ESFAS) sensor and actuation logic is combined to form a plant protection system (PPS) at ANO-2, Waterford 3, San Onofre 2 & 3, and the three Palo Verde units. The PPS concept is shown in Figure 15-15.

As shown in Figure 15-16, the detector input is supplied to a bistable card where the parameter is compared with set point. If the setpoint is exceeded, the RPS bistable relays are de-energized, and in addition, the engineered safety features (ESF) bistable relays are also de-energized. The RPS bistable relays operate contacts in logic matrices similar to those at Calvert Cliffs. These relays will be used to generate low pressurizer pressure, low steam generator pressure, and low steam generator level reactor trips. The ESF bistable relays (located on an auxiliary relay card) also de-energize relays in the ESF logic matrices (Figure 15-17). The pressurizer pressure logic matrix will actuate the safety injection actuation signal (SIAS), the steam generator pressure logic matrix will actuate the main steam isolation signal (MSIS), and the steam generator level logic matrix will actuate the auxiliary feedwater actuation signal (AFAS).

The output of the RPS logic matrices operate contacts that control the under voltage and shunt trip coils located in the reactor trip circuit breakers.

The output of the ESFAS logic matrices control contacts in valve and pump relay cabinets. The valve and pump relays control contacts that open or close valves and start or stop safety related pumps. The valve and pump relays are associated with ESF trains.

As shown on Figure 15-16, the bistable relay card is equipped with a variable set point generator. This set point generator is used during plant cool downs and depressurizations. As plant temperatures and pressures are reduced, the operator will receive pre-trip signals on low pressurizer and steam generator pressures. When the pre-trip signal is received, the operator depresses bypass switches and the set points are automatically lowered. The lowered set points are used in both the RPS and ESFAS systems. The lowered set points will remain in effect until the bypass switches are once again depressed.

A graph of steam generator pressure set point versus time is shown in Figure 15-18, and pressurizer pressure set point versus time is shown in Figure 15-19. The steam generator pressure set point can be reduced to zero (0) psia, but the pressurizer pressure set point has a minimum value of approximately 300 psia. When pressurizer

pressure has decreased to less than 400 psia, the operator turns a key switch (Figure 15-20) to completely bypass the low pressurizer pressure signal. The purpose of the variable setpoint is to provide reactor trip and ESF protection during the cool down. Recall that the Calvert Cliffs ESFAS and RPS designs bypassed the low pressurizer and steam generator pressure signals at fixed set points. If an accident happened below these set points, the operator would have to manually initiate the required systems. With a variable set point, if an accident occurs, the required equipment is automatically actuated when the set point is reached.

As the plant is heated up, the pressurizer and steam generator pressure set points are automatically increased and remain above actual pressurizer and steam generator pressures. The set point increases terminate at the normal at-power set points.

### 15.7.2 Excore Instrumentation Input

The safety related excore instrumentation system consists of four channels with each channel containing three axially stacked neutron detectors. Fission chambers are used as neutron detectors and supply two RPS inputs.

The first input originates with the center fission chamber and is used to determine logarithmic power. The output of each individual fission chamber is supplied to the core protection calculators (CPCs) and the linear power channel circuitry.

The logarithmic power channel supplies a signal to the high logarithmic power trip which has a set point of approximately $10^{-1}$ % power. The high logarithmic power trip provides start-up protection and replaces the high start-up rate trip used in older RPS designs. If the plant is to operate at power, provisions must be made to bypass the trip. The bypass logic is shown in Figure 15-21. When reactor power is ≥ $10^{-4}$ %, the operator presses the high logarithmic power bypass push button, and the trip signal is bypassed. When plant power is lowered to below $10^{-4}$ %, the trip is automatically reinstated.

## 15.8 Safety Injection System Differences

### 15.8.1 High Pressure Safety Injection System Differences

The high pressure safety injection system designs used vary little. The most prevalent design has three high pressure injection pumps, with the third pump as backup for the others. San Onofre 2 & 3 and Millstone 2 have the third pump as a valved out standby pump, while Calvert Cliffs, ANO-2, St. Lucie, Waterford and Fort Calhoun use the third pump the same as the other pumps unless the diesel generators are in use then it can only be started manually. The other variations occur at Palisades and Palo Verde which have two pumps. All the plants use the charging pumps during a safety injection condition to inject additional boron from the boric acid tanks.

The flow rates vary little from plant to plant with all but Fort Calhoun and Palo Verde having design flows from 300 to 400 gpm and maximum flows from 600 to 1000 gpm at low discharge pressures. Fort Calhoun has lower capacity pumps with design flow at 150 gpm and maximum flow at 400 gpm. Palo Verde has higher capacity pumps with design flow at 700 gpm and maximum flow at 1100 gpm. All of the plants have design flows at a discharge head of about 2500 to 2800 feet of water or about 1100 to 1200 psig.

### 15.8.2 Safety Injection Tank (SIT)

Two different values of nitrogen pressure are used to force water from the SITs into the RCS during loss-of-coolant accidents. Palisades, Fort Calhoun, Millstone 2, Calvert Cliffs 1 & 2, and Saint Lucie 1 & 2 have SITs that are pressurized to about 200 psig. The remainder of the CE units have SITs with 600 psig nitrogen pressure. Also most of the plants run around 1720 to 2500 ppm boron concentration. The big exception is Palo Verde with 4200 ppm boron in the injection tanks.

### 15.8.3 Low Pressure Safety Injection

The low pressure safety injection systems are basically the same at all plants except Waterford and Palo Verde. There are two pumps with separate suctions off the refueling water tank and they discharge to a common header that will feed all the cold legs. The two site exceptions have a split discharge header with each header feeding only two of the four cold legs.

The design flow rates vary from 3000 to 4000 gpm at a discharge head of about 350 feet of water or about 150 psig. The maximum flowrates run from 4500 to 5500 gpm at a discharge head of 250 feet of water or about 100 psig. The only plant that differs markedly is Fort Calhoun with design flow of 1500 gpm at 403 feet of water or 175 psig and maximum flow of 2400 gpm at 363 feet of water or 157 psig.

## 15.9 Instrumentation and Control Systems

In this section, the instrumentation and control systems installed in plant categories 4 through 6 will be described.

These systems are the reactor power cutback system ((RPCS) not installed at ANO-2 or SONGS), the feedwater control system (FWCS), and the steam dump and bypass control system (SDBCS). These three systems are more complex than the systems installed in the older CE plants (categories 1 through 3); however, time will only permit a general description of these systems.

In addition to the three control systems installed on the later CE units, the low power feedwater control system backfit will also be described.

### 15.9.1 Reactor Power Cutback System

The RPCS functions to rapidly reduce reactor power in order to prevent reactor trips in the event of a loss of main feedwater pump or a large load rejection.

Should one of these events occur, the RPCS would initiate the dropping of selected CEA subgroup(s). The dropping of selected CEA subgroup(s) rapidly adds negative reactivity and reduces reactor power. The reduction of reactor power during loss of feedwater events decreases the heat transfer to the steam generators to a value within the capacity of the remaining feedwater pump and helps to prevent low steam generator level reactor trips.

If a load rejection occurs, reactor power is greater than turbine power, and CEAs are dropped to reduce the power mismatch. The reduction in reactor power helps to prevent reactor trips on low steam generator level (level shrinks due to the large reduction in steam flow) and high pressurizer pressure. In addition to dropping selected

CEA groups, the RPCS also sends setback and runback signals to the turbine control system. A block diagram of the RPCS is shown in Figure 15-22.

In order to accomplish its function, the RPCS must have the ability to sense loss of feedwater pump and load rejection events.

The loss of feedwater pump input consists of redundant pressure switches located in the feedpump control oil system. Redundancy is required to prevent unnecessary system actuation in the event of a pressure switch failure. The pressure switches supply an input to a two out of two logic.

The load rejection input is supplied by the SDBCS. The load rejection results in a rapid reduction in steam flow from the steam generators to the turbine. The reduction in steam flow from the steam generators also results in a lower heat transfer from the RCS to the steam generators, and the excess RCS heat rapidly increases pressurizer pressure. The SDBCS looks at the rate of change of steam flow and pressurizer pressure to determine if a load rejection has occurred. If the rate of change of these two parameters exceeds a predetermined value, the SDBCS will send a signal to the RPCS. Two redundant calculators with steam flow and pressurizer pressure inputs are used to determine if a load rejection has occurred. Again, redundancy prevents system actuation in the event of instrumentation failures. The SDBCS load rejection signals are input to a two out of two logic.

In addition to the load rejection signal, the SDBCS also sends signals that are used in the generation of a turbine runback. The signals are turbine first stage pressure and a Tavg biased steam pressure signal. If, after the RPCS initiates a CEA drop, the heat removal by the turbine is greater than the heat generation by the reactor, the runback signal will reduce turbine load. The turbine is runback to avoid low steam generator pressure when turbine load is less than 50% as sensed by turbine first stage pressure. During the runback condition, turbine load is reduced at a rate of 200% per minute.

To actually drop CEA subgroup(s), the RPCS must supply two signals to the control element drive control system. The signals are called arm and drop commands.

The arm command is generated by the plant computer. Above 75% reactor power, the plant computer algorithm selects the CEA subgroups required to reduce reactor power. The plant computer uses reactor power and temperature parameters to calculate the amount of negative reactivity required to reduce reactor power to a target value (typically 75%). Meanwhile, the position of the CEA groups is monitored by the computer, and the available reactivity worth of each group is calculated.

A pattern of CEA subgroups is then selected that will reduce reactor power below but as close as possible to its target value of 75%. This CEA pattern is transmitted to the RPCS where it is stored until changes in power or CEA position require a new pattern.

The drop command is generated by the RPCS. If a loss of feedwater pump or load rejection occurs, the RPCS will generate a drop command. As previously stated, both the drop command and the arm command must be present to drop CEA subgroups.

In addition to the CEA drop commands and the turbine runback signal, the RPCS generates a load increase inhibit signal and a turbine setback signal. The load inhibit

signal prevents turbine load increases during RPCS initiated CEA drops, and the turbine setback signal rapidly reduces turbine load during RPCS actuation.  The setback signal positions the turbine steam admission valves to a position corresponding to 50% of rated steam flow at a rate of 480% per minute.

To illustrate the functioning of the RPCS, the following assumptions will be made:

1. The reactor power target value is 75%,
2. The SDBCS valves have a capacity of 65% and
3. The capacity of one main feedwater pump is 60%.

Since system functions are dependent upon plant power level, RPCS actions will be described with power less than 50%, power between 50% and 75%, and power greater than 75%.

If plant power is less than 50% at the time of an initiating event, no RPCS action is taken except for inhibiting turbine power increases.  No CEA drop occurs because the plant computer senses power below 75% and does not generate an arm command for selected CEA subgroups.  Although a drop command will be generated by the initiating event, CEAs will not drop.  The turbine setback command will be generated during an initiating event, however, it will have no effect because load is already less than 50%.

If the event is a loss of feedwater pump, no significant power excursion will occur.  The remaining feedwater pump is capable of supplying all feedwater flow when power is 50%.  If a load rejection occurs, the primary to secondary power mismatch can be accommodated by the 65% capacity SDBCS.

If power is between 50 and 75% and an initiating event occurs, the RPCS sends a turbine setback command to the turbine steam admission valves.  A drop signal is generated by the RPCS, but the plant computer algorithm does not generate an arm command.

For events initiated by a loss of feedwater pump, the reactor regulating system (RRS) causes automatic CEA insertion to reduce reactor power to match the 50% turbine power, and the feedwater control system (FWCS) controls feedwater flow to maintain steam generator level.

A load rejection occurring between 50 and 75% power will not cause the dropping of any CEA subgroups.  The SDBCS in conjunction with the RRS can adequately accommodate load rejections up to a 75% magnitude using the total bypass capacity and CEA reactivity rates.

If power is greater than 75% at the time of an initiating event, a turbine setback to 50% is commanded, and the CEA subgroup(s) selected by the computer algorithm are commanded to drop into the core to reduce reactor power.  The initiating event generates the drop command and the plant computer generates the arm command.

If, following the subgroup(s) drop, reactor power is greater than turbine power RCS and steam generator temperatures and pressures increase.  These increases are limited by actions of the SDBCS which effectively balance primary and secondary power.  Automatic insertion of CEAs is commanded by the RRS to reduce RCS temperature until Tavg returns to its programmed value.  For events caused by feedwater pump

trips, the automatic CEA insertion proceeds rapidly enough to allow total steam flow to be reduced to below the capacity of the remaining feedwater pump.

If maintainable reactor power is less than turbine power following the initiating event, a turbine runback will be initiated to eliminate the power mismatch.

A reactor power cutback control panel is installed in the control room to provide an operator interface. The following actions may be performed from the panel:

1. Automatic or manual system operation selection,
2. Manual initiation of the RPCS and
3. Manual selection of the CEA subgroups to be dropped during an initiating event.

### 15.9.2 Feedwater Control System

There is one three element FWCS for each steam generator performing the following:

1. Automatically controls the feedwater flow rate to maintain water level during steady state operations, during a 10% step change in load between 15% and 100% power, during a 5% per minute ramp in turbine load between 15% and 100% power, and during load rejections of any magnitude.
2. Provides satisfactory automatic operation during reactor trips and high steam generator level conditions.
3. Displays the necessary process information to enable the operator to evaluate FWCS performance.
4. Provides the capability to control feedwater flow rate manually with the operator acting in response to changes in steam generator level.

Each FWCS is a combination of a three element control system and analog programs whose function is to maintain its associated steam generator level at the operator selected setpoint during power maneuvers and steady state operations. This is accomplished by simultaneous adjustments to the main and bypass feedwater regulating valves and to the main feedwater pump speed set point.

The three element control system (Figure 15-23) processes the input values of steam generator water level, feedwater flow, and steam flow of its associated steam generator to develop an output signal called flow demand. The output is indicative of the required feedwater flow and is used to position the regulating valves and to program the speed of the feedwater pump.

#### 15.9.2.1 Calculation of the Compensated Level Signal

Each FWCS takes its associated steam generator level, dynamically compensates the signal for rate of change and for the rate of change of the flow error (steam flow - feedwater flow) signal. The resultant signal is called compensated level.

Each steam generator has two differential pressure transmitters that provide level inputs to the FWCS. Either or both transmitters may be used dependent upon the position of the level selector switch (located in the FWCS cabinets). If both is selected, only the highest level signal is used in the flow demand calculations. A typical value for the measured span of the level transmitters is 181 inches with the lower level tap located

approximately five feet below the steam generator feed ring and the upper tap located in the steam separator area of the steam generator.  The transmitters are usually calibrated from 0 to 100% of the measured span.

The measured level signal is dynamically compensated to improve control system stability.  This compensation is in the form of a lead/lag network that uses the actual value of level plus the rate of change (dynamic signal) of the level as inputs to the compensated level calculation.  This dynamic level input will be positive when level is increasing, negative when decreasing, and zero when not changing.  This results in a higher amplification of rapidly changing input than of slowly changing inputs.  Thus, for a rapidly changing steam generator level, the adjustments to main and/or bypass feedwater regulating valves and feedwater pump speed are quicker than for a slowly changing steam generator level.

Flow error is defined as the difference between the steam flow exiting the steam generator and the feedwater flow entering the steam generator.  The flow error is dynamically compensated by a derivative network that has an output proportional to the rate of change of the flow error signal.

The network has a steady state gain of zero.  This means that when the flow error is not changing or is zero, the compensated flow error signal is zero.  When the flow error is changing, the magnitude of the compensated flow error signal is dependent on the rate of change of the flow error signal.  This feature minimizes the need for extremely accurate and frequently cross-calibrated steam and feed flow signals.

Use of the compensated flow error signal assures satisfactory level response during power change transients, when increasing or decreasing steam generator pressure causes a temporary shrink or swell in water level.

Three values are summed to develop the compensated level signal:

1. Actual measured level, which will always be positive or zero,
2. Dynamic level, rate of change, which will be positive if level is increasing, negative if level is decreasing, zero if level is stable and
3. Compensated flow error, rate of change of steam flow/feedwater flow error, which will be zero if flow error is zero or not changing, positive if steam flow is increasing and/or feedwater flow is decreasing and negative if steam flow is decreasing and/or feedwater flow is increasing.

Level and dynamic level are added and compensated flow error is subtracted to develop the compensated level signal.  The compensated level signal is transmitted to the master feedwater controller where it is displayed to the operator on a 0-100% indicator. The displayed value is roughly equal to steam generator level in steady state conditions.

The compensated level signal is summed with the operator entered level set point at the master controller manual/automatic station and results in a summed error signal. Summed error is positive if compensated level is greater than setpoint and negative if level is less than setpoint.

The summed error signal is dynamically compensated by a proportional plus integral network in the master controller and results in a flow demand signal.  This signal is the

sum of the gained input signal plus the integral of the gained input signal and is a constant value when the summed error signal is zero.

A non-zero input is integrated causing the output signal to move toward its maximum value when steam generator compensated level is less than set point and toward its minimum value when level is greater than set point.  Any level error will be forced equal to zero by increasing or decreasing feedwater flow as a function of the flow demand signal.

### 15.9.2.2 Analog Programs

Each FWCS generates, as a function of its flow demand signal, three programs that are used to control the feedwater delivery rate to its steam generator:

1. Bypass regulating valve position demand (recall that the bypass valve is controlled by a single element control system at the older CE units),
2. Main regulating valve position demand and
3. Main feedwater pump speed setpoint.

Each FWCS generates a bypass regulating valve demand as a function of flow demand. The bypass regulating valve position demand is zero when the flow demand is zero and varies linearly with flow demand values between zero and 7½ %.

At demands greater than 7½ %, the bypass regulating valve should be fully open.  If each bypass valve is positioned fully open at 7½ % demand from each FWCS, plant power should be 15%.  At power levels above 15%, flow through the main feedwater regulating valves is required to maintain steam generator levels.  The output of the bypass regulating valve position demand is sent the bypass regulating valve manual/automatic station.  In automatic, the position demand signal is transferred to the valve.  In manual, the operator controls the position of the bypass valve.

Each FWCS generates a main regulating demand as a function of flow demand signal. This signal is used to provide satisfactory operation of the main feedwater valve from 0 to 100% power.  At low flow conditions, the main feedwater regulating valve demand program provides hysteresis in the position demand signal.  This prevents cycling of the valve and continued operation with small valve opening which extends the valve life.

At low flow conditions, the main feedwater regulating valve is closed.  As flow demand increases, a point is reached where the valve opens to a minimum position.  As flow demand continues to increase, the valve position demand signal will vary linearly with the flow demand.  At 100% power, the valve will be fully open.  As flow demand decreases, the valve position decreases linearly until its minimum value is reached. The valve will remain in this position until flow demand drops to approximately four percent, then the valve will close.  The output of the main feedwater regulating position demand calculation is routed to the valve controller via a manual/automatic station.  In automatic, the calculation positions the valve, in manual the valve is positioned by the operator.

Each FWCS generates a feedwater speed setpoint demand as a function of the flow demand signals from each FWCS.  The larger signal is utilized to obtain feedpump speed setpoints and assures adequate feedwater flow.  This feature is especially

important during single feedpump operation. At low flow demand conditions, the pump speed set point demand program provides for a pre-determined minimum speed (3900 rpm). As flow conditions increase, the speed of the feed pump is increased linearly with flow demand. At 100% power, feedwater pump speed is approximately 5200 rpm. It should be noted that when the main feedwater regulating valve demand signal and the main feed pump speed demand signal are in the linear portion of the operating curves, feedwater flow is being controlled by valve position and pump speed.

#### 15.9.2.3 Overrides

In addition to controlling steam generator level, the FWCS provides a high steam generator level override (HLO) to terminate feedwater flow to the affected steam generator. The values of the HLO set point vary from 85 to 93% of indicated level. Regardless of the set point value, the HLO functions to prevent moisture carryover from the steam generators to the turbine.

When a HLO signal is generated, the following actions take place:

1. A zero percent flow demand signal replaces the flow demand signal generated by the master controller,
2. The zero signal closes the affected steam generator’s main and bypass feed regulating valves and
3. The feedwater pump speed program uses the highest of the two FWCS flow demand signals. If only one steam generator has a HLO, then the pump speed would be controlled by the unaffected steam generator’s FWCS.

These actions should return steam generator level to below the HLO setpoint. When the HLO clears, feedwater flow is controlled by the FWCS.

A reactor trip override (RTO) of the FWCS is provided to minimize pressurizer level loss and pressure decrease caused by overcooling of the RCS due to excessive feedwater addition following a reactor trip.

When the RTO signal is present, a flow demand signal of sufficient magnitude to fill, but not overcool, the steam generator is applied to the pump (minimum speed) and the bypass regulating valve program. With a RTO present, the main feedwater regulating valve will be closed, and the flow necessary for removing decay heat and increasing level to its set point is supplied to the bypass valve. When the compensated level error decreases to less than five percent as sensed through a two out of three logic, the system automatically returns to the no override condition.

### 15.9.3 Steam Dump and Bypass Control System (SDBCS)

The purposes of the SDBCS are:

1. The SDBCS, operating in conjunction with the RPCS and other control systems, automatically dissipates excess energy in the NSSS by regulating the flow of steam through the turbine bypass valves or atmospheric dump valves (if installed). This controls the main steam header pressure so that:

a. A load rejection from any power level can be accommodated without tripping the reactor or lifting either the pressurizer or steam generator safety valves,

b. NSSS thermal conditions are controlled to prevent the opening of safety valves following a unit trip,

c. The NSSS can be maintained at hot zero power and

d. NSSS thermal conditions can be achieved when it is desirable to have reactor power greater than turbine power (during turbine synchronization).

2. The SDBCS allows for manual control of RCS temperature during NSSS heat ups and cool downs,

3. The SDBCS sends an Automatic Withdrawal Prohibit (AWP) signal to the CEA control system when the SDBCS senses excess energy in the NSSS such as when any SDBCS valve is open and

4. The SDBCS sends an automatic motion inhibit (AMI) signal to the CEA control system whenever reactor power is less than 15%, or when reactor and turbine power fall below preselected thresholds and the SDBCS can accommodate the excess reactor power.

This section will describe the Waterford 3 system which does not include atmospheric dump valves and is more properly called the steam bypass control system (SBCS); however, SDBCS is a more common term.

The SBCS is comprised of bypass valves and associated controls and instrumentation. Six parallel air-operated valves are connected to the main steam header outside of the containment and downstream of the main steam isolation valves (MSIVs). Each valve has a capacity of 10.83% of rated steam flow (65% total).

Protection against spurious valve opening is provided by incorporating two redundant demand channels for each valve control mode. The channels are termed main and permissive. A demand must be present from both channels before any valve will open. This ensures that no single operator error or equipment malfunction (except valve failure) will cause an inadvertent opening. There are two modes of valve control, they are the modulating mode and the quick opening mode.

An excess of energy in the NSSS caused by a load reduction transient or other conditions will result in an increase in main steam header pressure. If that pressure increases above a programmed set point value, the SBCS will sequentially modulate the turbine bypass valves open to limit the main steam header pressure to the setpoint value.

Since the conditions that cause excess energy in the NSSS are variable, the SBCS can modulate the bypass valves open or closed sequentially based on the amount of steam flow needed to equal the power generated in the NSSS, however, the rate of change of excess NSSS energy that may be dissipated by the modulating mode is limited due to the 15 to 20 second stroke time required for the valves.

For turbine load reductions of large magnitude and rate, the amount of energy accumulated in the NSSS while the valves modulate open could be large enough to cause the RCS pressure to increase quickly to the point of tripping the reactor and possibly opening the pressurizer or steam generator safety valves. The SBCS has a quick opening feature to alleviate this problem.

The quick opening network continuously monitors the magnitude and rate of change of NSSS power. If a load reduction of a magnitude and/or rate of change too large for the modulation speed of the valves occurs, the quick opening feature will open the valves in less than one second.

To obtain good transient responses for large load rejections, the six SBCS valves are divided into two quick opening groups of three valves each. Each group is programmed to open at predetermined thresholds of stored NSSS energy.

#### 15.9.3.1 System Operation (Figure 15-24)

The SBCS continuously monitors main steam header pressure using two independent pressure transmitters (PS1, PS2). When the pressure increases above a programmed setpoint, the turbine bypass valves are sequentially modulated open to control pressure at setpoint.

To prevent a single component failure from opening a bypass valve, the coincidence of two independently generated demand signals is necessary to open any valve. These parallel demand signals are termed main and permissive demand. PS1 and PS2 are low selected by the main controller and high selected by the permissive controller.

There are two identically generated steam header pressure set points (SP1, SP2) that represent the pressure which the SBCS will maintain whenever its action is demanded. These setpoints are obtained from a curve that is a linear fit to the normal steady state main steam pressure that will exist from 15% to 100% power, as sensed by steam flow (WS1 and WS2). The curve has an upper limit on pressure below 15% power that is equal to the hot zero power steam pressure. The set point curve is biased about 40 psia above actual operating pressure so that the SBCS valves will not open on a 10% step decrease in load.

The highest value of the independently generated set points is compared to the lowest value of measured steam header pressure, and if pressure is greater than set point, an analog main demand signal is generated. Meanwhile, the lowest set point value is compared to the highest steam header pressure and, if pressure is greater than set point, a binary (on or off) permissive demand signal is generated. The purpose of this arrangement is to avoid interference by the permissive channel on the control action of the main channel by ensuring that the permissive signal is present whenever the main signal is present. If pressure is higher than the set point as sensed by both the main and permissive channels, the SBCS valves will open to reduce pressure to set point.

#### 15.9.3.2 Pressure Set Point Generation

The permissive demand channel selects the lowest of the two independently generated set points (SP1 or SP2). These set points are generated by a program which primarily

considers steam flow from the steam generators but the set point is also biased by a pressurizer pressure input.

The steam flow input (WS1) for SP1 generation is flow from steam generator 1 as transmitted from FWCS 1. The SP2 program receives its steam flow (WS2) from steam generator 2 as transmitted from FWCS 2. Both steam flow signals are made to pass through a lag compensation network to increase system stability and response. This circuit retards the motion of the set point away from its original value so that the SBCS has a quicker response to pressure increases caused by load rejection events.

To enable the SBCS to respond quickly to disturbances originating in the RCS, the set point is biased by a signal that is proportional to the deviation of the pressurizer pressure from its normal operating value. This bias will lower or raise the pressure set point one psia as the pressurizer pressure increases or decreases one psia.

The set point networks sum the set point value based on steam flow with the bias value based on deviation from normal pressurizer pressure. The resultant signals are called SP1 and SP2. An adjustable bias is provided to ensure that the permissive set point is at least 20 psia below the main set point.

The main channel set point is generated in an identical manner as the permissive setpoint except that the higher value of SP1 or SP2 is chosen as the main controller set point.

#### 15.9.3.3 Modulation Signal Generation

The highest of the two steam pressure inputs (PS1 or PS2) is compared to the permissive set point by a blind permissive controller located in the SBCS cabinet assembly. When pressure exceeds the permissive setpoint, the controller generates a positive output to a comparator that provides a binary signal called an automatic modulation permissive.

The automatic modulation permissive is sent to a permissive solenoid that controls the air supply to the SBCS valve. The modulation permissive signal will energize the permissive solenoid and allow the modulation signal from the electrical to pneumatic (E/P) controller to position the valve. Two conditions (labeled no interlock on Figure 15-24) must be satisfied to allow the permissive solenoid to be energized.

The first condition is the position of the valve permissive switch. There is a three position (off-manual-auto) switch for each of the SBCS valves. In the off position, the permissive solenoid is de-energized, and the valve will remain closed. In the manual position, the permissive solenoid is always energized. The manual position is normally used during plant cool downs when the operator is manually positioning the SBCS valves. The auto position allows the permissive signal to energize the solenoid.

The SBCS master controller algebraically sums the highest of the two main steam header pressure set points (SP1 or SP2) with the lowest of the two steam header pressure measurements (PS1 or PS2). The resultant error signal is modified by a proportional-integral-derivative (PID) controller.

The derivative function is performed only on the steam header pressure input to compensate for rate of change. The compensated pressure (positive input) is summed

with the steam header pressure set point (negative input) and results in a summed error signal. The error signal is modified by a proportional plus integral network resulting in a master controller signal output.

The master controller output signal is sent to four valve group demand programs. Only one of the demand programs is shown on Figure 15-24.

The bypass valves are divided into groups as follows:

Group 1 - Valve 1
Group 2 - Valve 2
Group 3 - Valve 3
Group 4 - Valves 4, 5, and 6

The purpose of the first three valve group demand programs is to produce a sequential opening for the first three valves. When valve 1 is fully open, valve 2 starts to open. When valve 2 is fully open valve 3 starts to open. This sequential operation gives good control ability and minimizes valve operation time at highly throttled conditions. The fourth valve group demand program opens the last three valves at the same time (after valve 3 is fully open). Group four is only expected to be used in a large pressure transient.

From the valve group demand programs, separate modulation demands are sent to each valve's manual/automatic station. In automatic, the demand signal is sent to the E/P converter. From the E/P, the air signal is routed to the valve through a normally de-energized quick opening solenoid and the permissive solenoid. The positioning of the SBCS valves increases steam flow and reduces steam pressure to its setpoint value.

A condenser interlock is located in the signal flow path upstream of the E/P converter. If condenser pressure is high, this interlock will prevent the transfer of the modulation signal to the E/P. This interlock protects the condenser from high pressure conditions. The condenser is not designed to accommodate pressures in excess of atmospheric pressure.

#### 15.9.3.4 Quick Opening Signals

When the SBCS detects a turbine load decrease so large that it cannot be accommodated by the modulation of the bypass valves, a valve quick opening (QO) signal is generated. The QO signal bypasses the modulation signal and opens the valves in less than one second. To prevent a valve opening due to a single failure, two independently generated demand signals are required. One of these signals is generated by the main channel, and the other is generated by the permissive channel.

The main channel QO signal is generated by summing steam flow input (WS1) and pressurizer pressure (PP1). The sum is supplied to a change detector. The output of the change detector is proportional to the magnitude and rate of change to its input. The output of the change detector is supplied to three bistables. The first bistable generates quick opening signal X1, the second bistable generates quick opening signal Y1, and the third bistable generates one of the two required RPCS load rejection signals.

The permissive channel QO signal is also generated by summing steam flow input (WS2) and pressurizer pressure (PP2). The sum is supplied to a change detector. The output of the change detector is proportional to the magnitude and rate of change to its input. The output of the change detector is supplied to three bistables. The first bistable generates quick opening signal X2, the second bistable generates quick opening signal Y2, and the third bistable generates the second of the two required RPCS load rejection signals.

The SBCS valves are divided into two QO groups. The first group consists of valves 1, 2, and 3, and the second group is made up of valves 4, 5, and 6. In order to quick open group 1, the master channel must generate quick opening signal X1 and the permissive channel must generate quick opening signal X2. Valve group 2 is controlled by quick opening signals Y1 and Y2. If both channels sense the need for quick opening, the quick opening solenoid will energize. When this solenoid is energized, the port from the E/P is closed, and the port from the instrument air system is opened. The opening of the instrument air port directs full instrument air pressure to the SBCS opening the valve quickly. As shown on Figure 15-24, the permissive solenoid must also be energized. This is accomplished by signals X1 and X2 for group 1 valves and Y1 and Y2 for group 2 valves.

There are two inputs to the AND gate used to control the quick opening solenoid that will prevent the energizing of the solenoid. The first input is labeled no interlocks and blocks the QO signal if any of the following exist:

1. The emergency off switch is actuated. The emergency off switch is installed to allow the operator to close all SBCS valves in the unlikely event of an overcooling transient. The emergency off switch also prevents energizing the permissive solenoid.
2. The Condenser Interlock is also included in the no interlocks input. This prevents condenser over pressurization during quick opening actuations.

The second input is labeled no QO block. When the reactor trips, the QO signal to valve 6 is blocked because its capacity is not needed to return the plant to no load $T_{avg}$. If the reactor trips and $T_{avg}$ decreases to 566°F, then the QO signal is blocked to all SBCS valves. Note that the permissive solenoid also contains the no QO block input.

### 15.9.4 Automatic Motion Inhibit (AMI) Signals

The purpose of the AMI circuit is to allow the NSSS to be maintained at a relatively high power level following a load rejection. Once the cause of the load rejection has cleared, the turbine can be immediately reloaded and electrical output increased to the NSSS power level. An AMI will also be generated anytime reactor power drops below 15%. This allows the operator to take manual control of the CEAs and feedwater before the plant enters a region of operation where plant stability rapidly deteriorates. An AMI signal prevents insertion and withdrawal of the CEAs by the RRS. A block diagram of the AMI circuitry is shown in Figure 15-25.

The generation of the AMI when power is below 15% is the easiest to understand and will be explained first. The control channel reactor power input from the selected RRS is compared with a set point of 15%. If power is less than set point, an AMI will be

generated. This is illustrated on Figure 15-25 by the graph on the low power comparator. If reactor power is greater than 15%, the output of the comparator is zero. Inputs less than 15% will result in a logic 1 which is supplied to the AMI or gate. When either of the two inputs to the OR gate is a logic 1, an AMI will be generated.

The load rejection AMI requires the coincidence of two signals, a AMI permissive and a AMI demand. The main objective of the AMI is to allow the quick reloading of the turbine by maintaining a high reactor power level. However, it is not desirable to have an AMI generated every time reactor power drops below the AMI set point during normal load changes. To prevent this, a permissive signal is needed to generate an AMI. The permissive indicates that turbine power, as sensed by turbine first stage pressure, has decreased below the AMI permissive set point. The permissive set point may be set from 15% to 100% turbine power.

As shown on Figure 15-25, a summer and a comparator are used to determine if turbine power has reached the permissive set point. The summer algebraically combines the AMI permissive set point and turbine first stage pressure. As illustrated by the graph on the permissive comparator, if the output of the summer is positive (first stage pressure < set point), the comparator will have an output. An output from the comparator indicates that a load rejection has taken place. The output of the comparator is supplied to the AMI and gate as a logic 1 signal. However, this is only one of the two required inputs to the AMI and gate. The other input is the AMI demand signal. Both inputs must be present to generate the AMI.

The AMI demand is the lowest of the following values:

1. The AMI demand set point (adjustable from 15% to 100% power) or
2. The sum of turbine power (first stage pressure) and SBCS valve capacity. This sum represents the total heat removal from the RCS.

The use of the low value in determining the set point prevents the setting of an AMI demand set point greater than the heat removal capacity of the secondary plant. The output of the low select is used as one of two inputs into a summer. The second input is reactor power. If the summer has a positive output, then reactor power has decreased below the AMI set point. The summer output is supplied to the AMI demand comparator. As illustrated by the graph of the comparator, a logic 1 signal will be generated if the output of the summer is zero (0).

The remaining portion of the block diagram illustrates the AMI permissive and reset features. To prevent the loss of the AMI when turbine load is increased above the permissive setpoint during recovery, the AMI permissive signal is sealed in until turbine power increases above the existing reactor power. The output of the AMI AND gate is routed to the input of the seal-in AND gate. If an AMI signal is present, a logic 1 is available to the AND gate. The second input to the seal-in and gate is from the CEA control system. This automatic withdrawal will be a logic 0 as long as automatic withdrawal is not demanded ($T_{avg} > T_{ref}$). This input is inverted by the NOT box resulting in a logic 1 input to the seal-in AND gate. Of course, when both input signals are logic ones, the output of the AND gate will be a logic 1. The output of the seal-in AND gate is combined in an OR gate with the AMI permissive signal. As long as CEA withdrawal is

not demanded, the OR gate will maintain the permissive signal regardless of the value of turbine first stage pressure.

To illustrate the functioning of the AMI circuitry, assume the following plant conditions are established:

1. An AMI permissive set point of 15%,
2. An AMI demand set point of 30%,
3. All SBCS valves are operable. The total valve capacity is 65%. The system determines valve capacity from the auto position of the valve permissive switches,
4. The RPCS is operational,
5. The CEAs are in automatic sequential and the selected RRS is operable and
6. A 100% load rejection occurs because of operator error; therefore, the turbine can be immediately returned to service.

When the load rejection occurs, two control systems will react. First, the RRS will sense a rapid change in power error (reactor power - turbine power) and will insert CEAs in high speed. Next, the SBCS will sense the rapid change in steam flow and will generate quick opening of the SBCS valves. The SBCS will also generate a drop signal to selected CEA subgroup(s). Since power is greater than 75%, the RPCS will generate arm signals. With both the arm and drop commands generated, selected CEA subgroups will drop. Also, when the load rejection occurs, turbine first stage pressure will drop below the AMI permissive set point. When first stage pressure drops below the permissive setpoint, one of the two required AMI signals will be generated.

The quick opening of the SBCS valves and the dropping of selected subgroups helps to reduce the excess energy from the RCS. After the QO signal clears, the SBCS valves will be positioned by the modulation signal. Meanwhile, the insertion of the CEAs by the RRS continues.

When reactor power drops to the AMI demand set point, an AMI will be generated and all CEA motion will stop.

The action of the control systems should stabilize the reactor at ~30% power with the heat being dissipated to the condenser via the turbine bypass valves. Plant recovery can begin.

After resetting the RPCS, the operator can withdraw the dropped CEAs in manual individual. Once the CEAs are realigned, the CEAs can be placed in the automatic sequential mode. The operator will synchronize the turbine with the distribution system and increase turbine load.

When turbine load exceeds 30%, the AMI permissive signal will be lost; however, the seal-in circuit will maintain the AMI signal until the RRS calls for outward CEA motion ($T_{avg} < T_{ref}$).

### 15.9.5 Low Power Digital Feedwater Control

A major contributor to the lack of plant availability is both high and low steam generator level trips during low power operation. Operating plant data for 1978 to 1984 indicated that 82% of steam generator low level trips occurred below 20% power and 31% of the

plant shutdowns were caused by the main feedwater system, which in turn accounts for 12% of the total outage hours. The problem is worst during startup where operators have had relatively little experience in steam generator level control. The number of trips falls off as the operators gain experience and confidence. However, because most of the plants are base loaded, the operators have little opportunity to maintain their skills through actual operating experience and use plant simulators for practice. Unfortunately, the ability of the plant simulators to accurately model steam generator level dynamics during low power operation is limited. In response to this need, Combustion Engineering has developed an automatic, microprocessor based, Low Power Feedwater Control System (LPFCS).

The complexity of the low power feedwater control process and the need for a reliable, cost effective control system led to the use of a microprocessor based control system. It has programming capability for control algorithms that are non-linear and have varying time dependency. The microprocessor allows for flexibility, in adjustments of the control algorithms and customizing or tuning of the LPFCS for an individual steam generator. This flexibility allows for the expansion to full automatic control to 100% power by reprogramming the software and incorporation of other inputs and outputs.

The design of the LPFCS incorporates the design characteristics of the particular feed train, steam generator and primary system with which it will interface. Figure 15-26 provides an outline of the components influencing the steam generator level control. A successful controller design is demonstrated in Figure 15-27

The microprocessor based feedwater control system is capable of taking a better look at the modeling involved in the steam generators, auxiliary feedwater and main steam systems. The level of detail extends into the feed systems where models of the turbine extractions for feedwater heating, the heater drain, the condensate and the main feedwater pumps have been developed. The pump models are further enhanced by simulating their recirculation systems. Failure to include this system can lead to incorrect pump performance and apparent system stability which may not be present during actual plant operation. The necessary level of modeling is confirmed by comparison to actual overall plant performance.

In addition to the many process models, it is necessary to accurately model the control system. Factors which must be considered in these models include valve and actuator characteristics. Not accounting for these variables can lead to incorrect conclusions concerning system stability. It is important to accurately model the individual modules of each control system. This allows for the inclusion of module output limits, individual transfer characteristics and non-linearities.

One method of testing the effectiveness of a control process is to operate the system under controlled conditions. This method is not practical for extensive testing at a plant, so a second approach, using a developed mathematical simulation of the process has been developed. This approach is used with a limited amount of experimental data to verify the process models. The digital simulation also provides flexibility in analyzing off-design conditions, plus it provides complete control over the perturbations and events that are to be evaluated.

Figure 15-28 is a schematic of a typical recirculating steam generator. Feedwater enters through the feedwater sparger and flows into the down comer where it mixes with the recirculating saturated liquid. The combined flows move down the down comer and enter the tube bundle region at the bottom of the generator. As the fluid rises through the tube bundle, it absorbs heat from the primary loop, exiting the bundle region as a two phase fluid. It then flows upward through the riser region to the separators. The separators remove the liquid from the steam, returning the liquid to the down comer and allowing the steam to rise to the chevrons, where the steam is further dried before entering the main steam lines to the turbine.

This recirculation process, essential to the modeling of steam generator level dynamics, is sustained by the imbalance in hydraulic heads of fluid in the down comer and in the tube bundle/riser region. During high power operation, the differences in these driving heads is significant and leads to relatively stable operation. The high differential head causes the fluid within the steam generator to circulate at a relatively high rate, causing an increased pressure drop. However, as the power is reduced, the amount of boiling is reduced in the tube bundle, causing a reduction in the quality of the fluid and hence an increase in the density. This in turn reduces the amount of driving head, reducing the amount of recirculation. As this occurs, the generator approaches a manometer type condition, where the down comer and tube bundle/riser region hydraulic heads approach each other. Under these manometer type conditions the steam generator level becomes very difficult to control. In the limit, a condition can be reached where recirculation will stop. This phenomena known as recirculation breakdown can occur momentarily, during transient or steady state operation, when under low level and/or low power conditions.

This difficulty is characterized in several ways. One characteristic that is particularly frustrating is the unconventional level response under these conditions. When the operator attempts to increase steam generator level, by increasing feedwater flow rate, the initial response of the level is to actually fall rather than rise. If the operator is not aware of this phenomenon, they may respond by adding additional water into the steam generator which only aggravates the problem. Adding additional feedwater produces an upset in the balance of the two hydraulic heads. As the cold water enters the down comer, it increases the hydraulic head, causing liquid to move from the down comer to the tube bundle region without a corresponding increase in recirculation.

Over feeding the steam generator can lead to another phenomena that will ultimately trip the plant on high steam generator level. As the operator continues to add feedwater, the level does eventually start to rise. When the steam generator level is restored the operator then starts to reduce the feed flow. But he is now confronted with another problem as the level continues to rise. During the filling process the operator has created a non-equilibrium condition. Having filled the generator too rapidly, he has in effect added too much water. Now that he has reduced the feed rate, the water within the bundle region starts to boil creating an excess amount of steam voids. These steam voids swell the two phase volume and displace saturated liquid over into the down comer region where it creates a high steam generator level condition.

Generally steam generator level control is enhanced if feedwater is fed so as to minimize the deviation from equilibrium conditions. In fact, the more experienced operators have learned this through actual plant operation. The design of the LPFCS takes all these factors into consideration.

It should be noted that there is not a unique time dependency that the operator should follow when increasing feedwater flow at low power. For example, an adequate response at 5% power would be much too slow at 15% power.

In order to define the steam generator behavior, analytical studies have been performed where the steam generator has been subjected to primary and secondary side perturbations, including step, ramps and sinusoidal perturbations. The perturbation techniques were used to characterize the non-linear behavior of the steam generators. The steps and sinusoids provide an indication of increasing responsiveness of the steam generators at low power and also provide an indication of the delays in the system.

The successful design of the LPFCS requires incorporation of the design characteristics of the particular feed train, steam generator and the primary system with which it will interface as well as the steam generator level response and control behavior. For example, the operation at low power from beginning to end of life conditions varies due to the changes in moderator temperature coefficient.

Automation of the feedwater flow at low power along with an automatic steam bypass control system will allow the operator to gradually increase power allowing the feed flow and steam flow to follow. This minimizes the perturbations to the steam generator which can occur in a manual system. The operator altering the reactor power has to be synchronized with two other operators controlling the feedwater flow and adjusting steam flow to the turbine. The low power feedwater control system, which provides anticipatory action, compensates for the state of the steam generator and provides stable level control thereby limiting the perturbations in the primary and secondary systems.

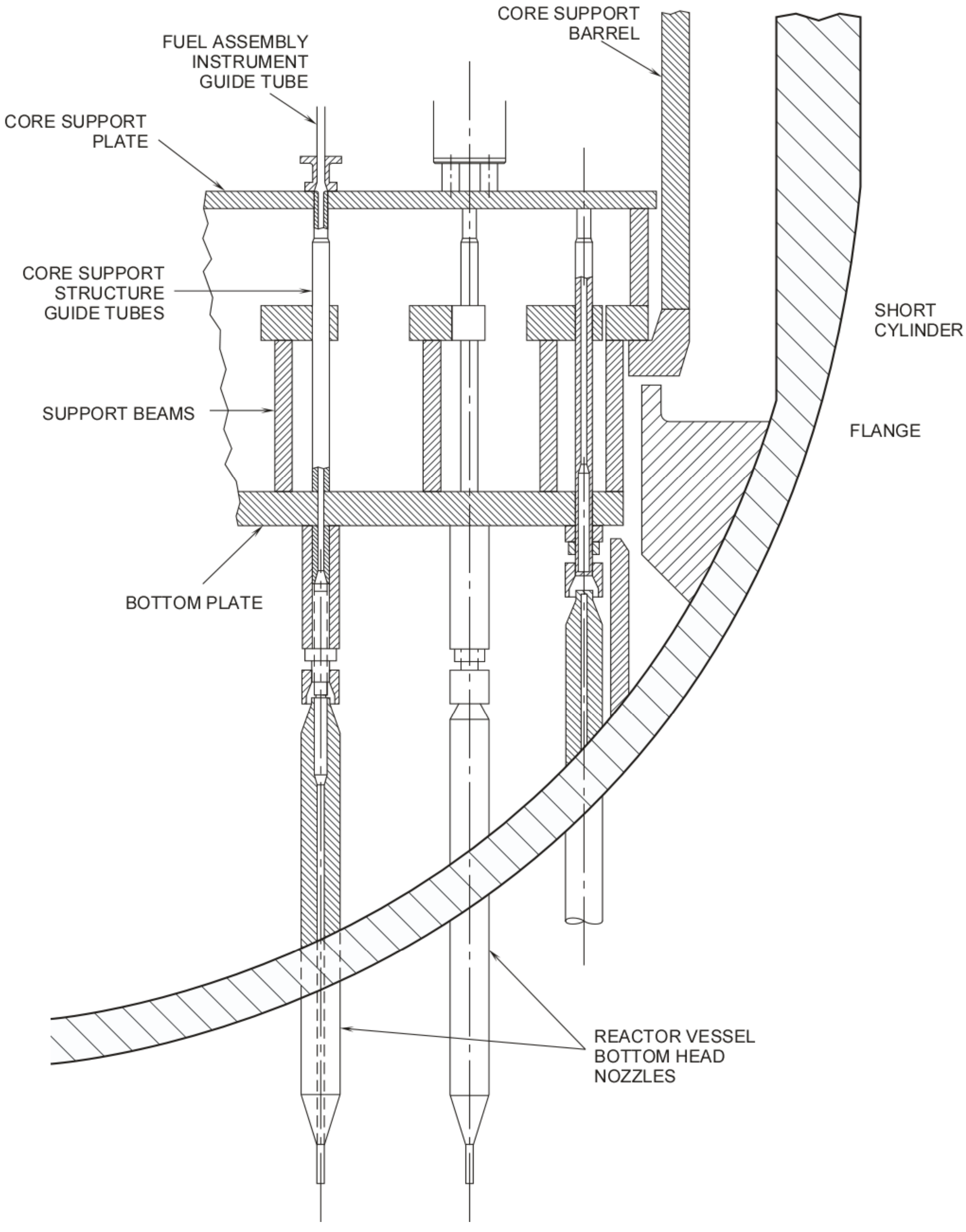



**Figure 15-1 Core Support Plate and Lower Support Structure**

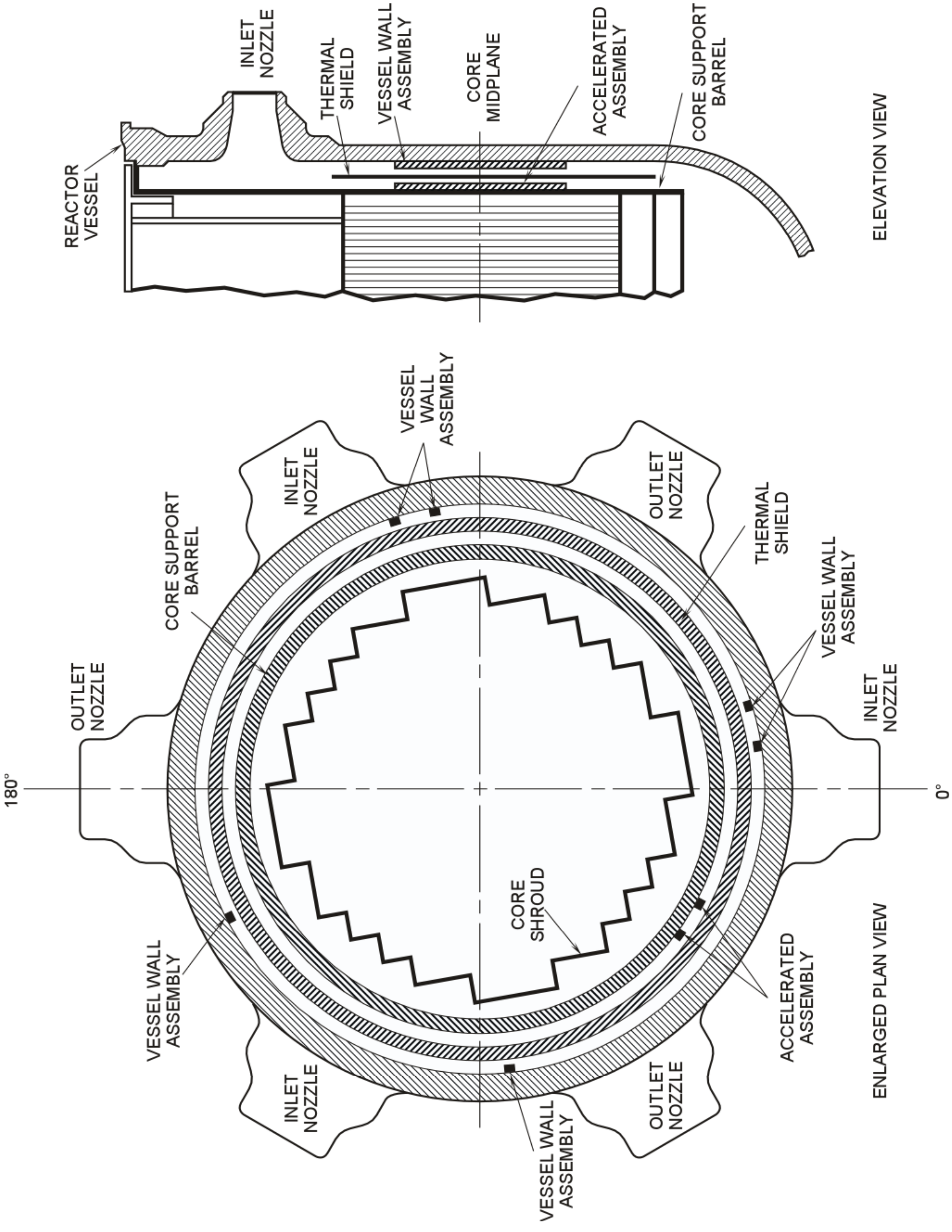



**Figure 15-2 Typical Locations of Maine Yankee Surveillance Capsule Assemblies**

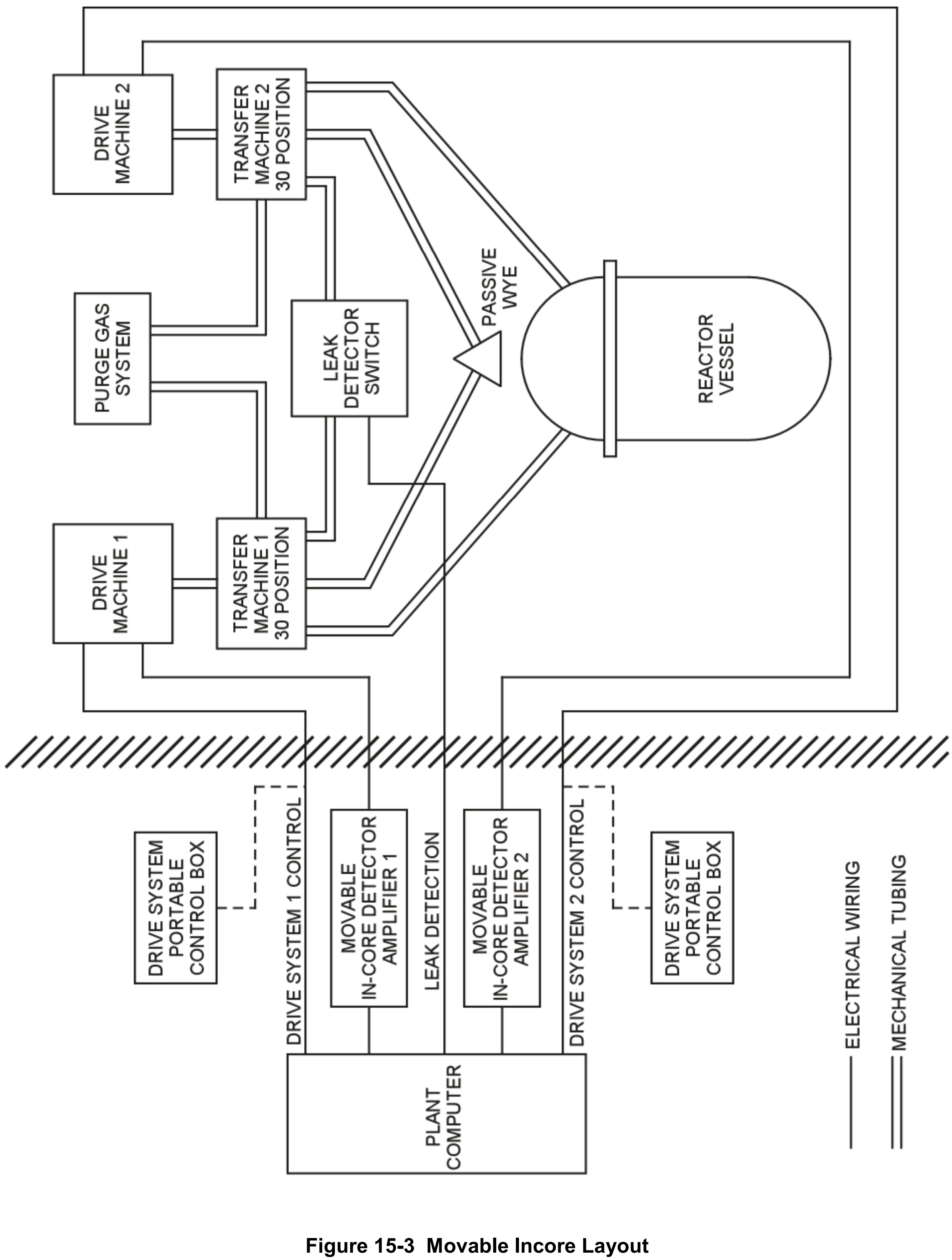



**Figure 15-3 Movable Incore Layout**

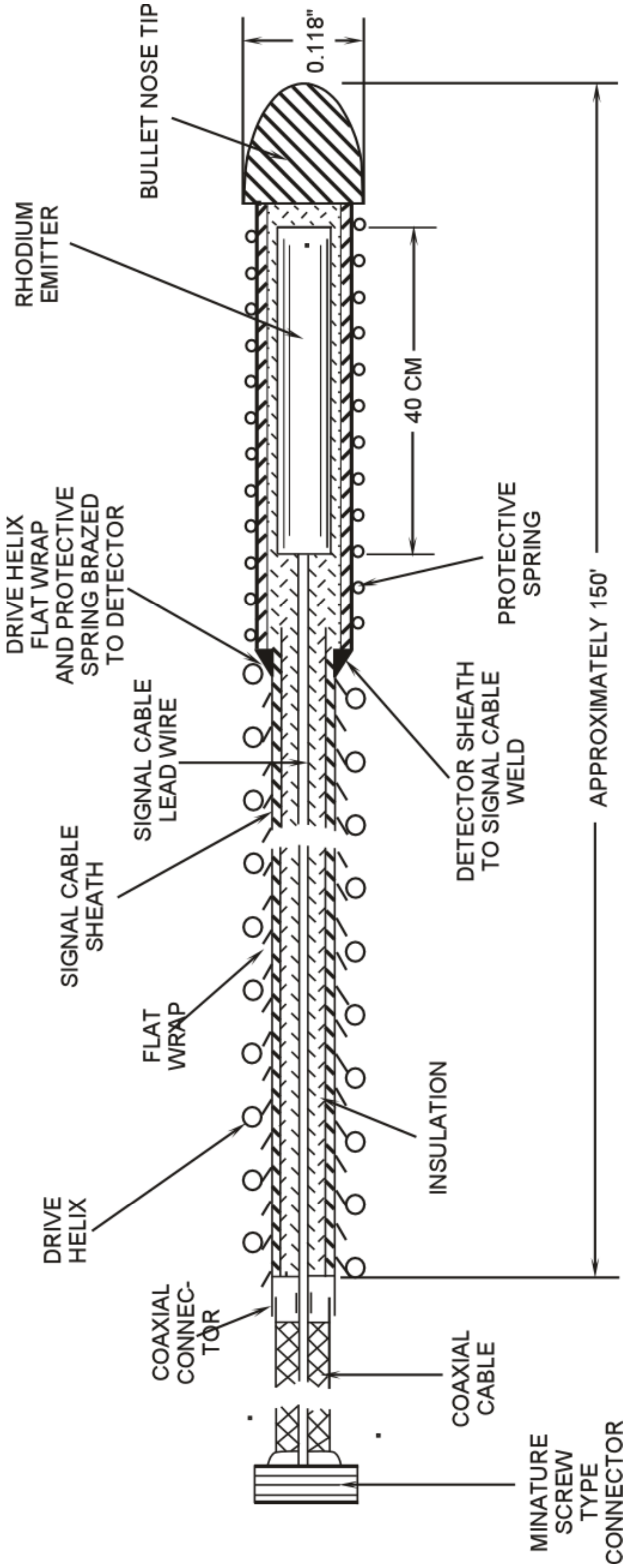



**Figure 15-4 Movable Incore Detector**

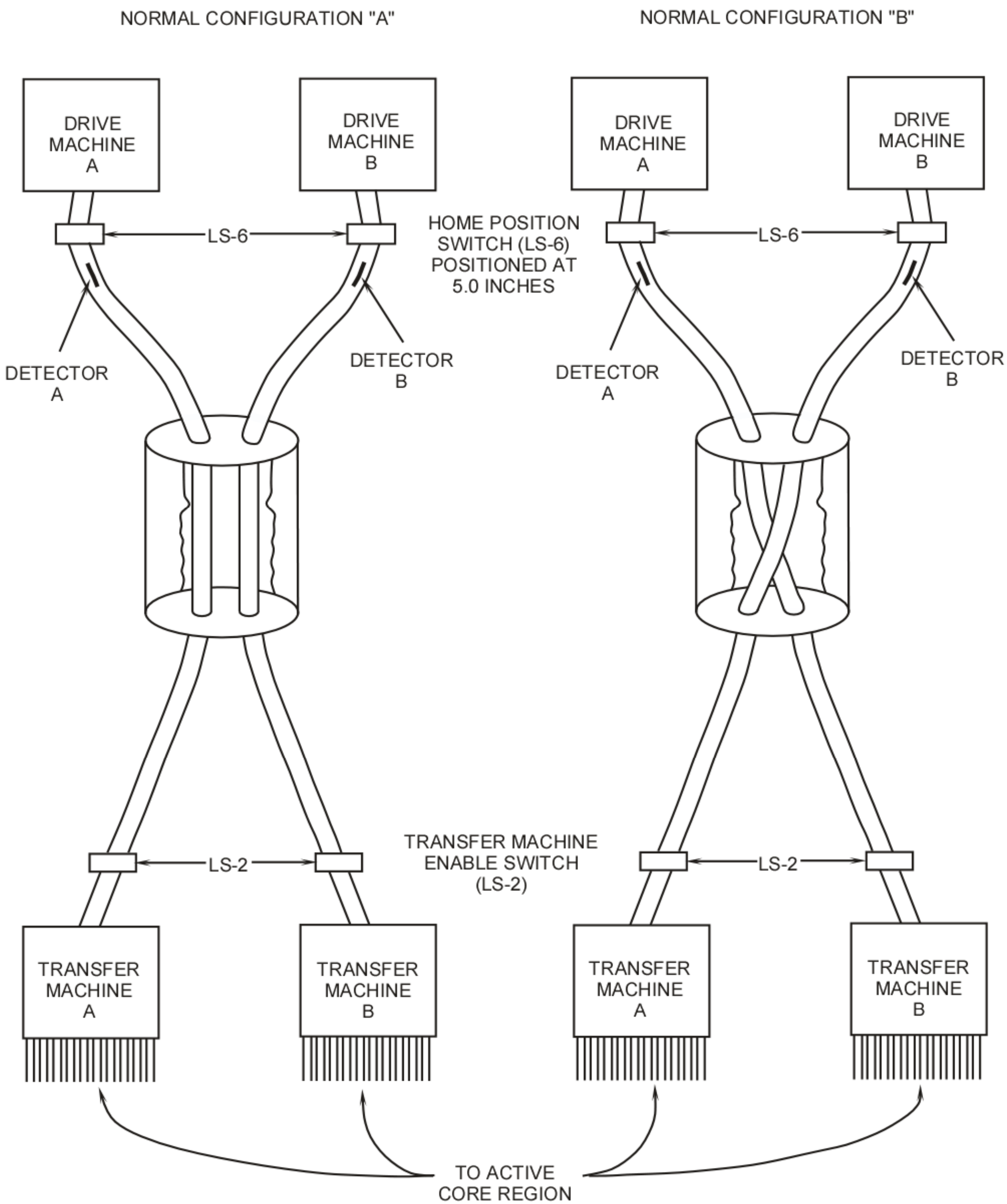



**Figure 15-5 Drive Path Switching**

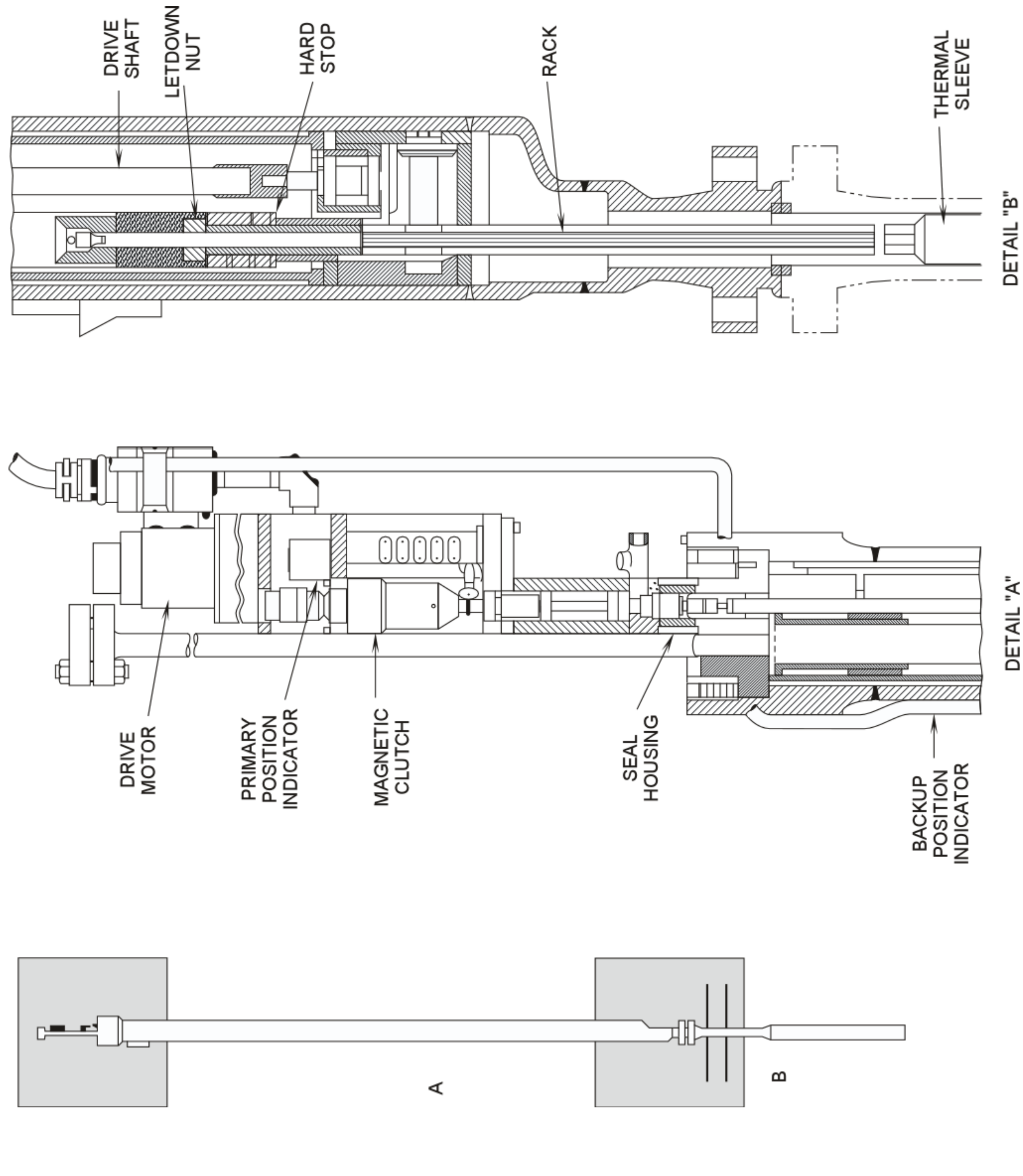



**Figure 15-6  Control Rod Drive Mechanism**

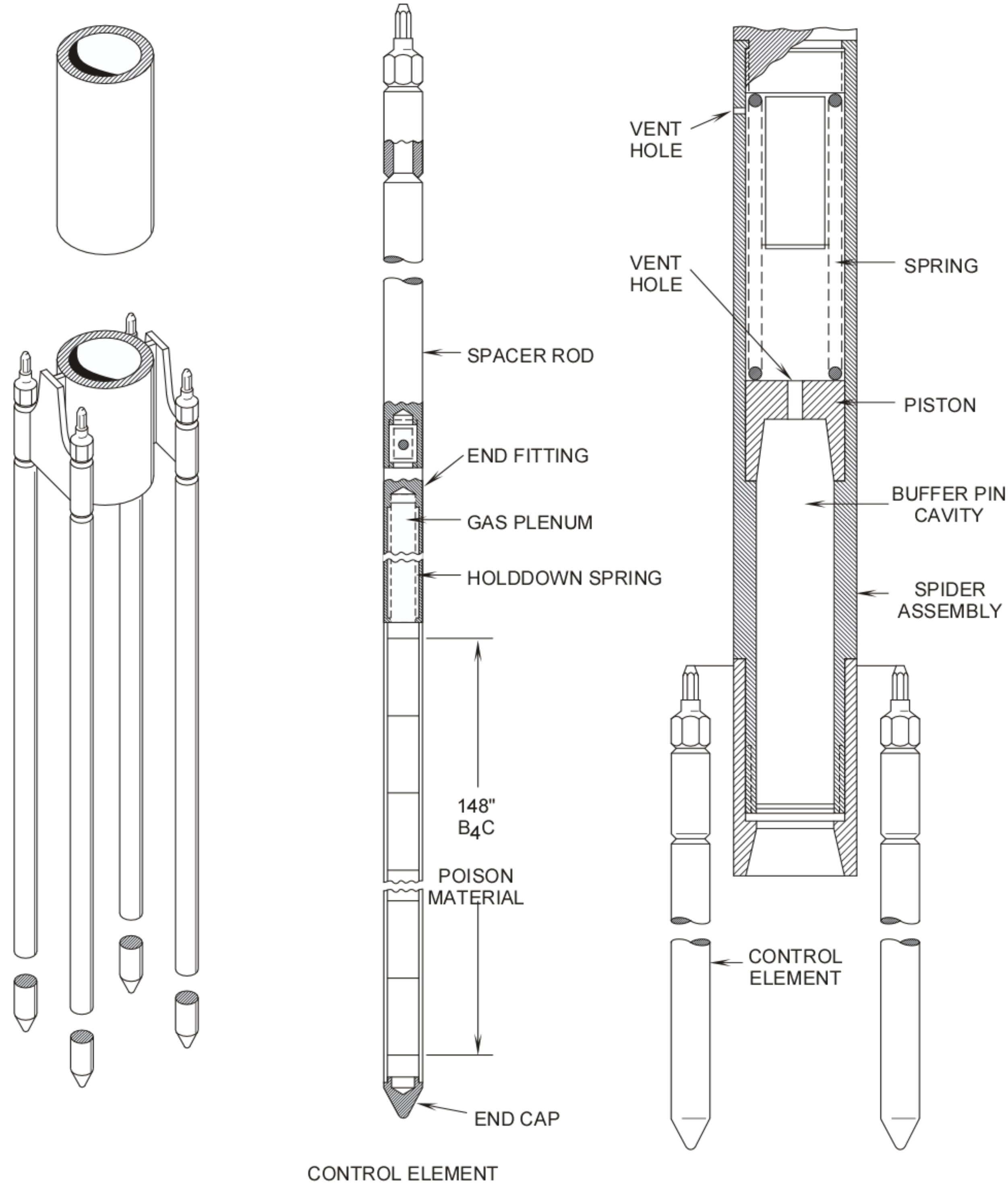



**Figure 15-7 Four Element Control Element Assembly**

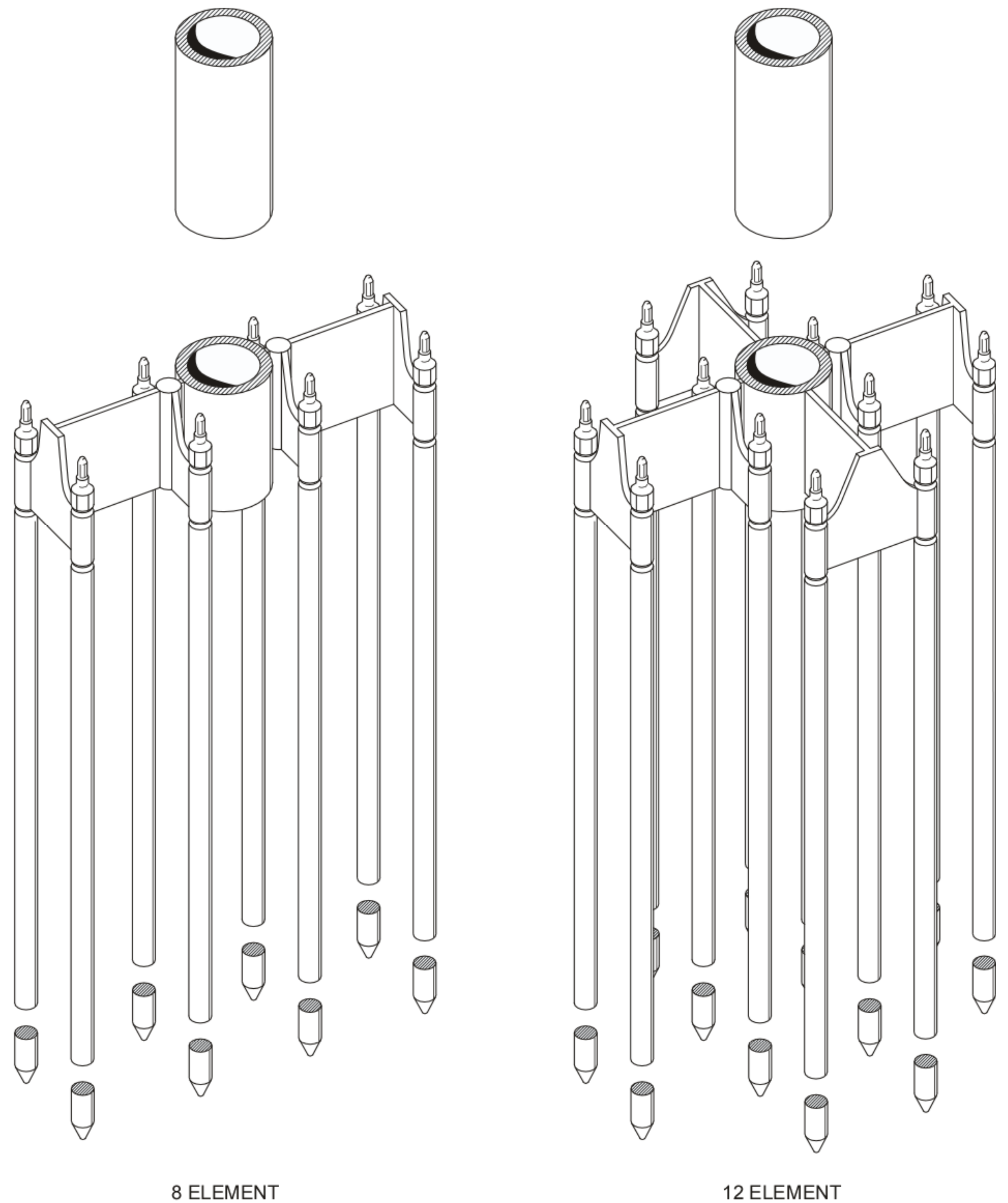
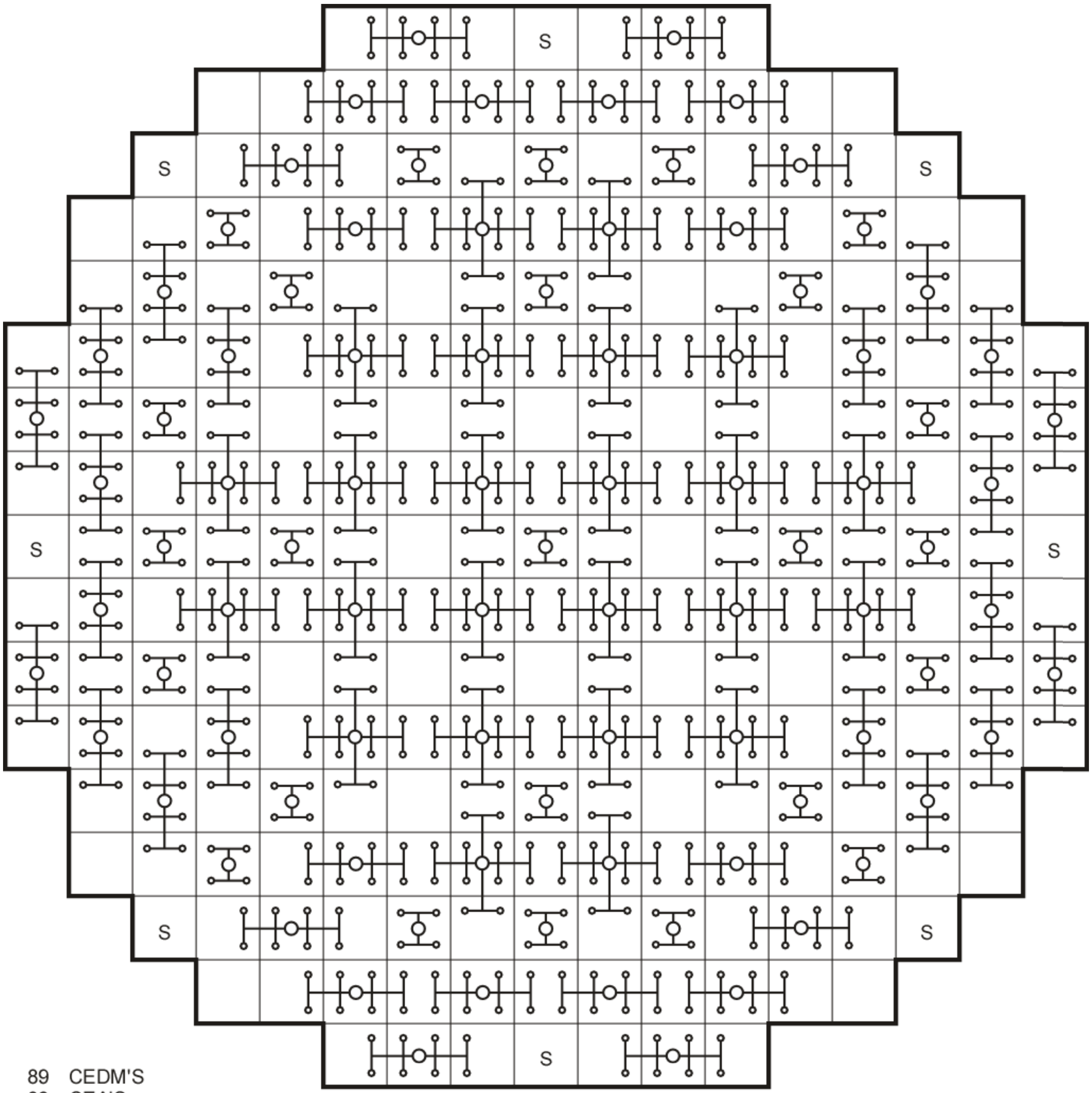



**Figure 15-8 8 and 12 Element control Element Assemblies**




89 CEDM'S
89 CEA'S
241 FUEL ASSEMBLIES

S INDICATES ADDITIONAL CEA LOCATIONS AVAILABLE

**Figure 15-9 Control Element Pattern**

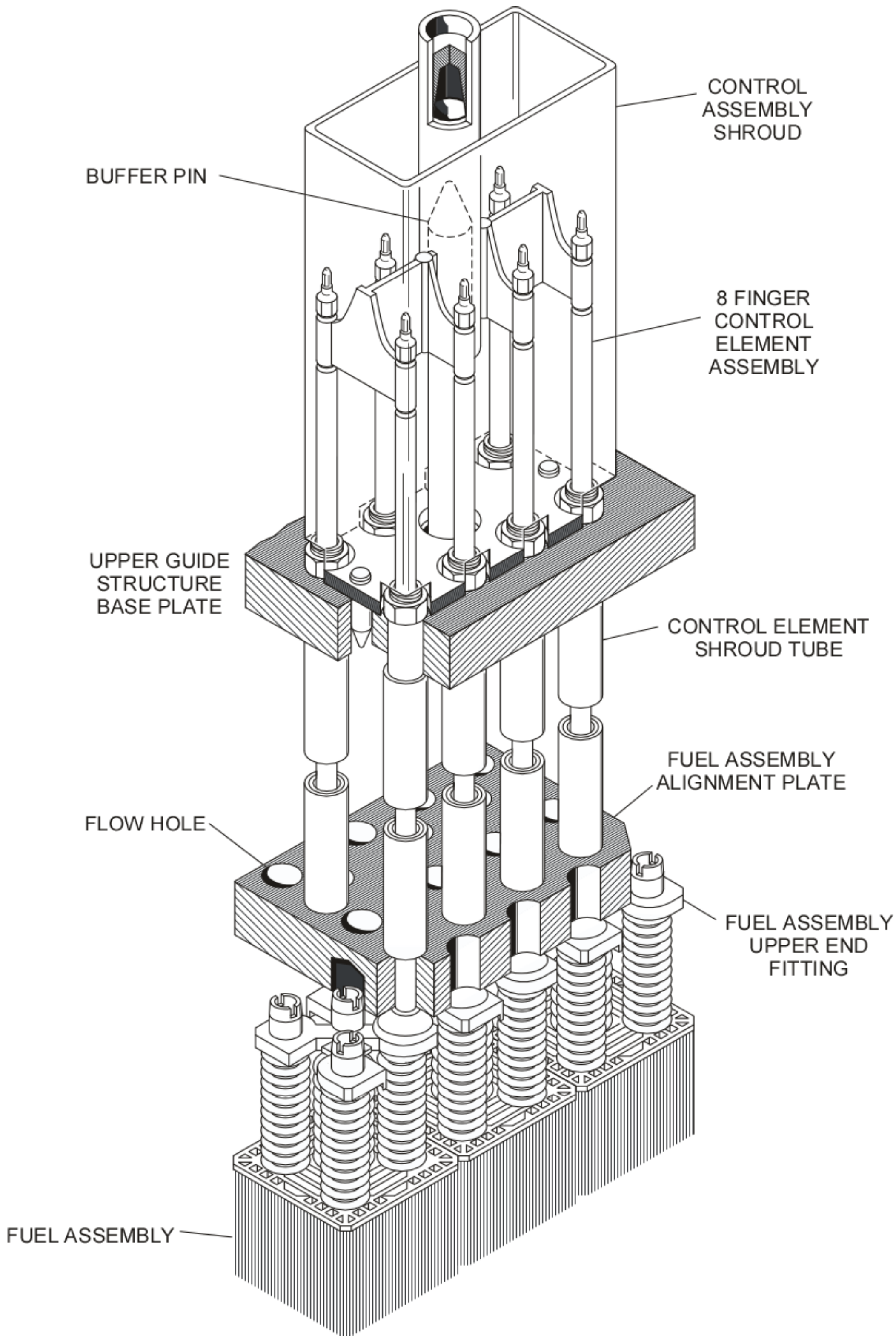



**Figure 15-10 Fuel/Control Element/Upper Guide Structure Interface**

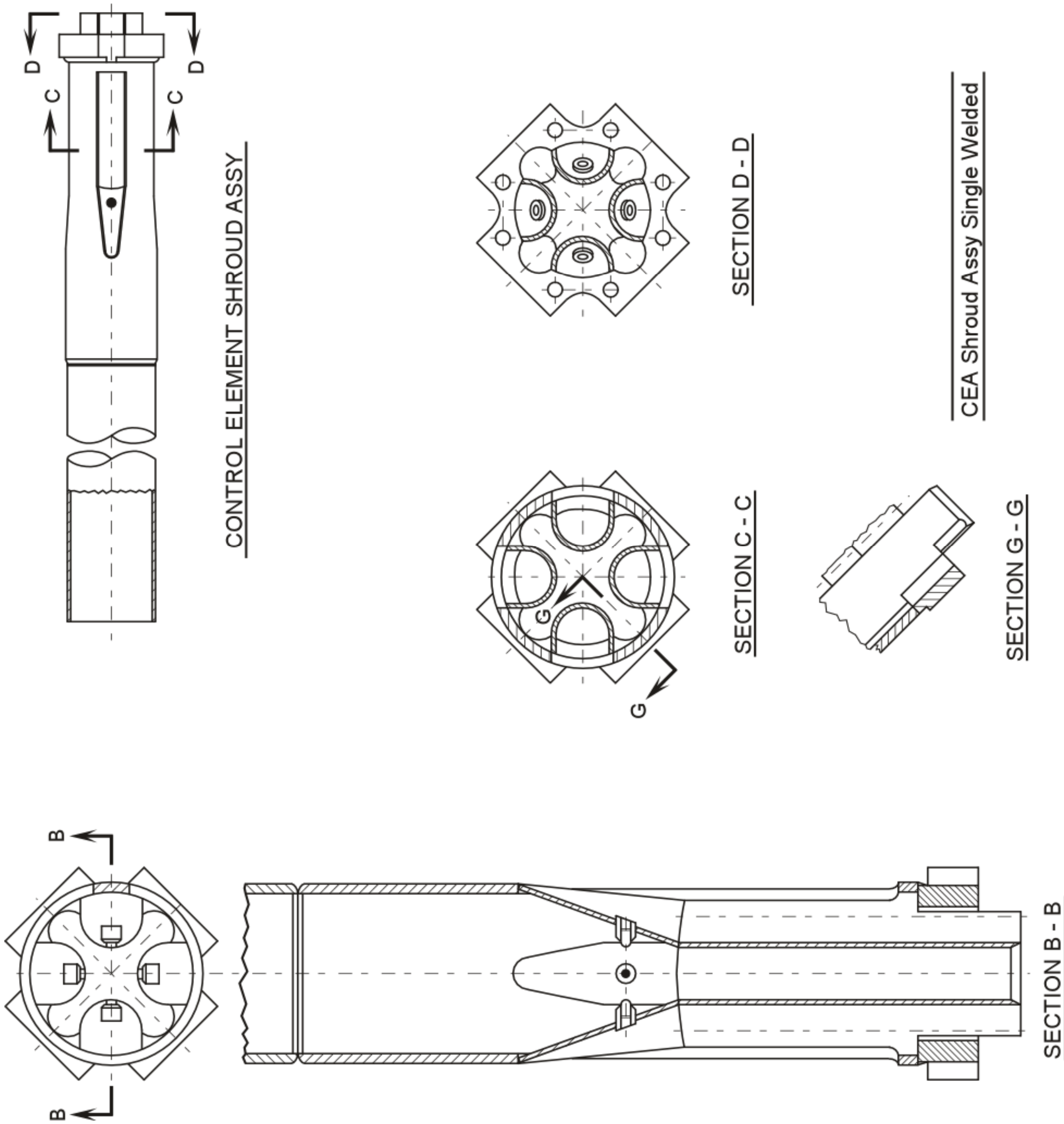



**Figure 15-11  CEA Shroud**

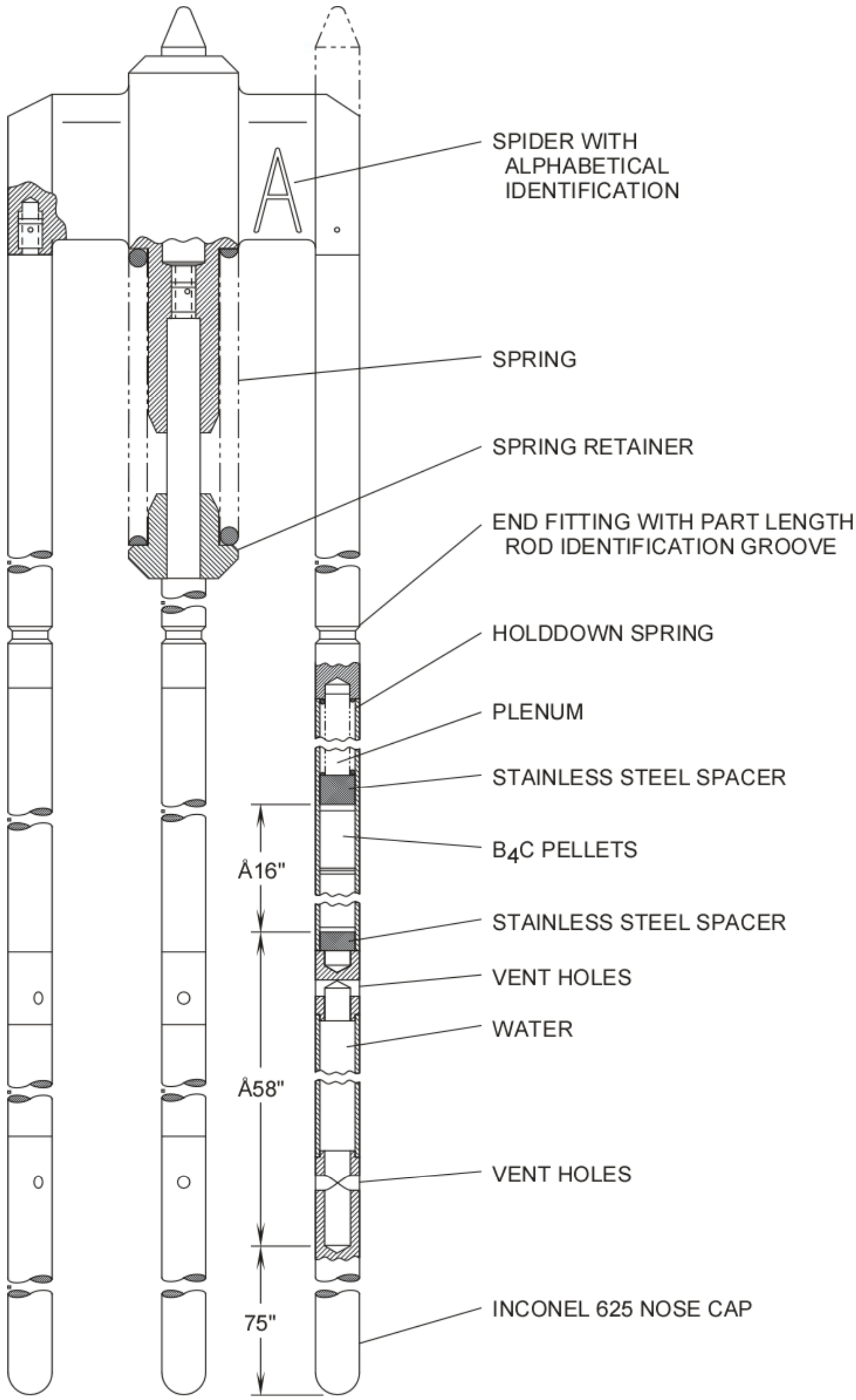



**Figure 15-12  Part Length CEA**

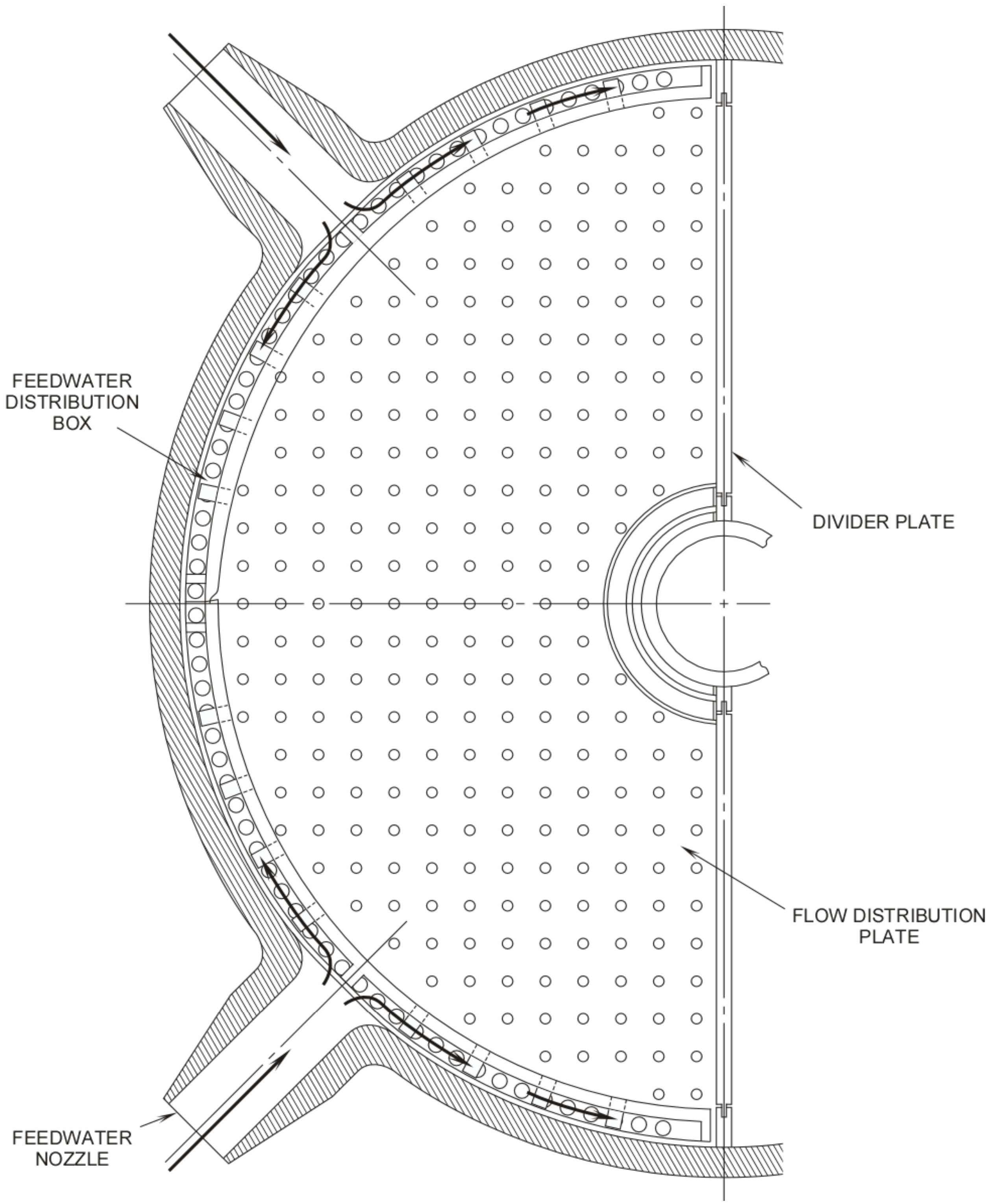



**Figure 15-13 Economizer Plan View**

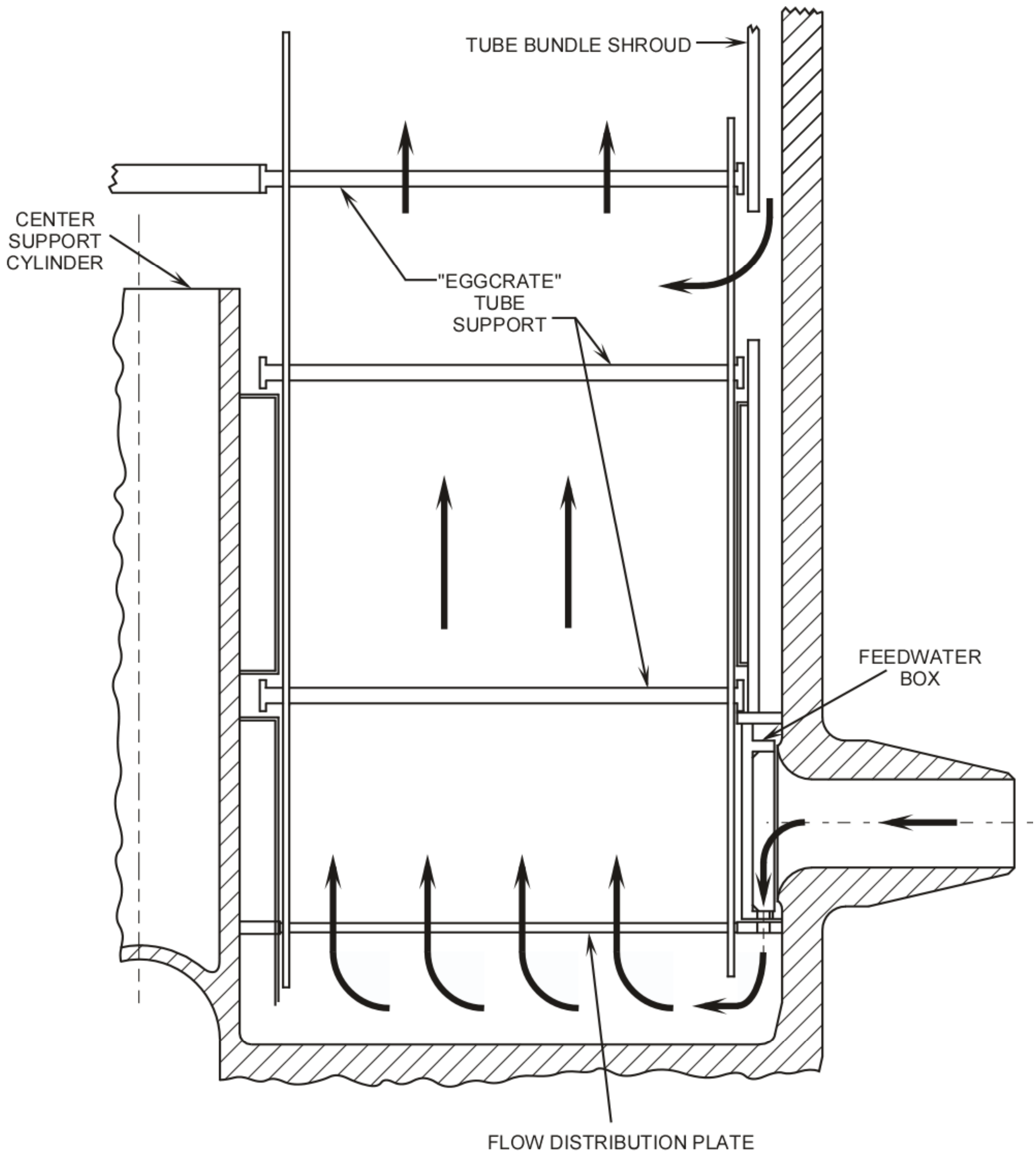



**Figure 15-14 Economizer Elevation View**

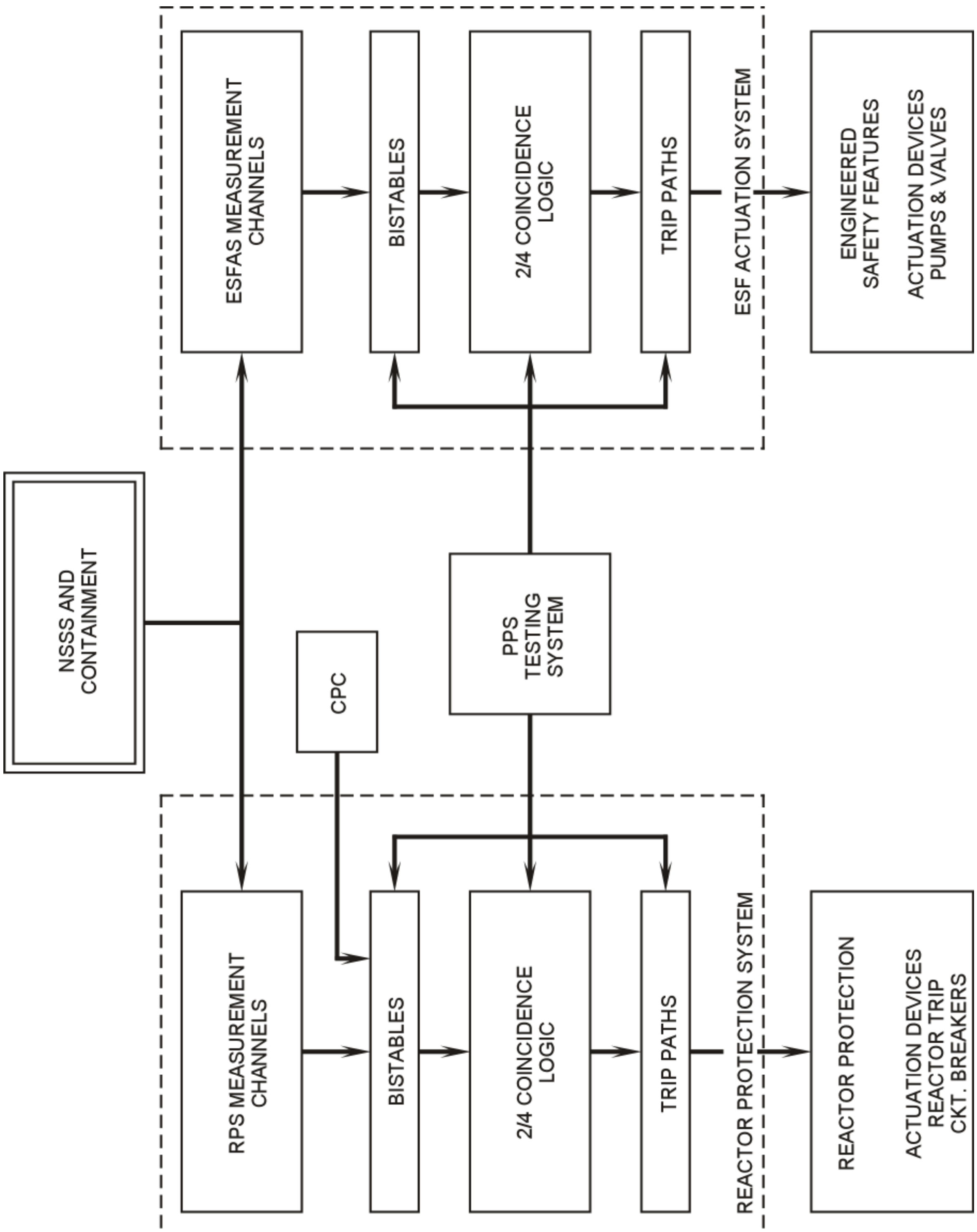



**Figure 15-15 Plant Protection System Basic Block Diagram**

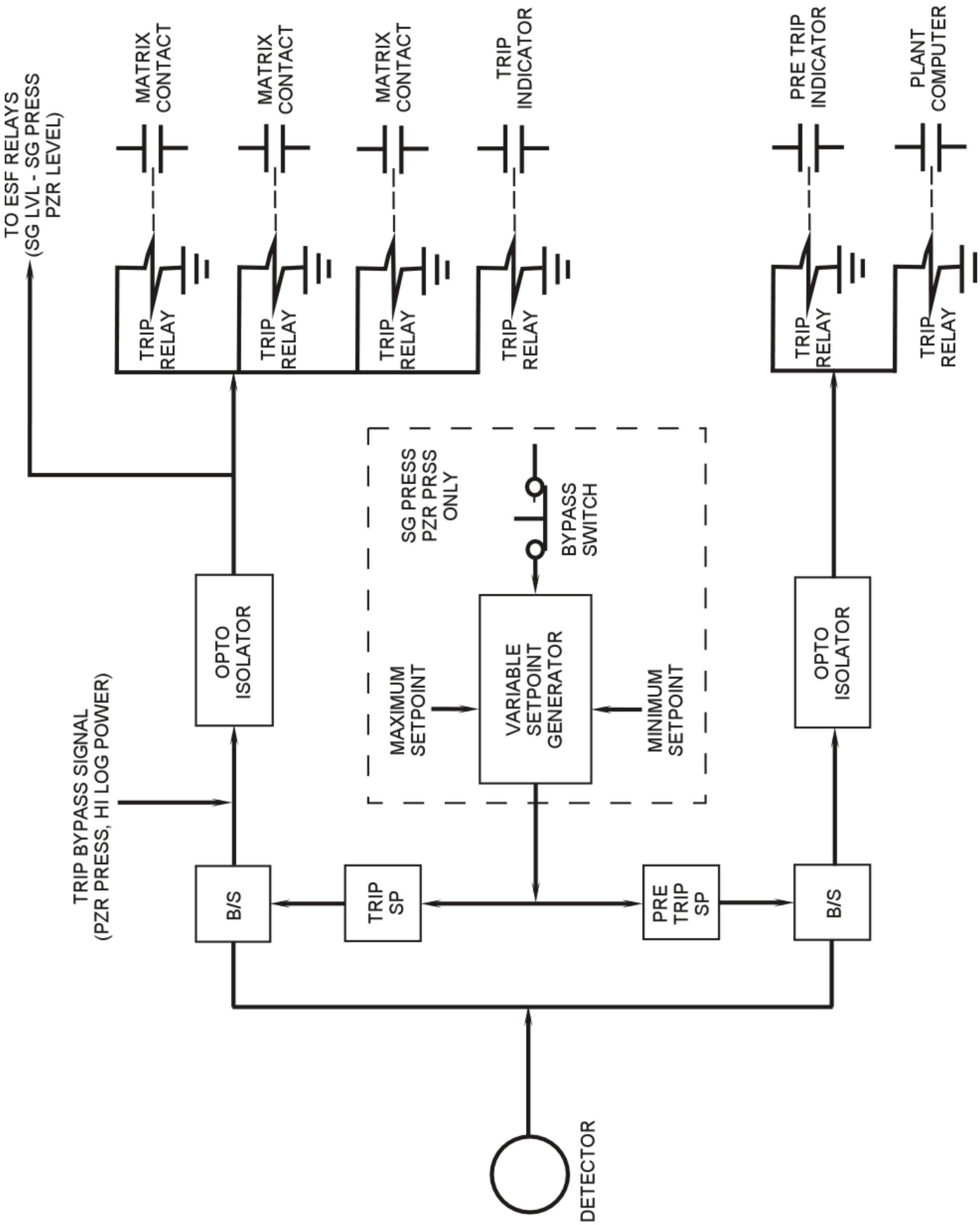



**Figure 15-16  Analog Bistable Relay**

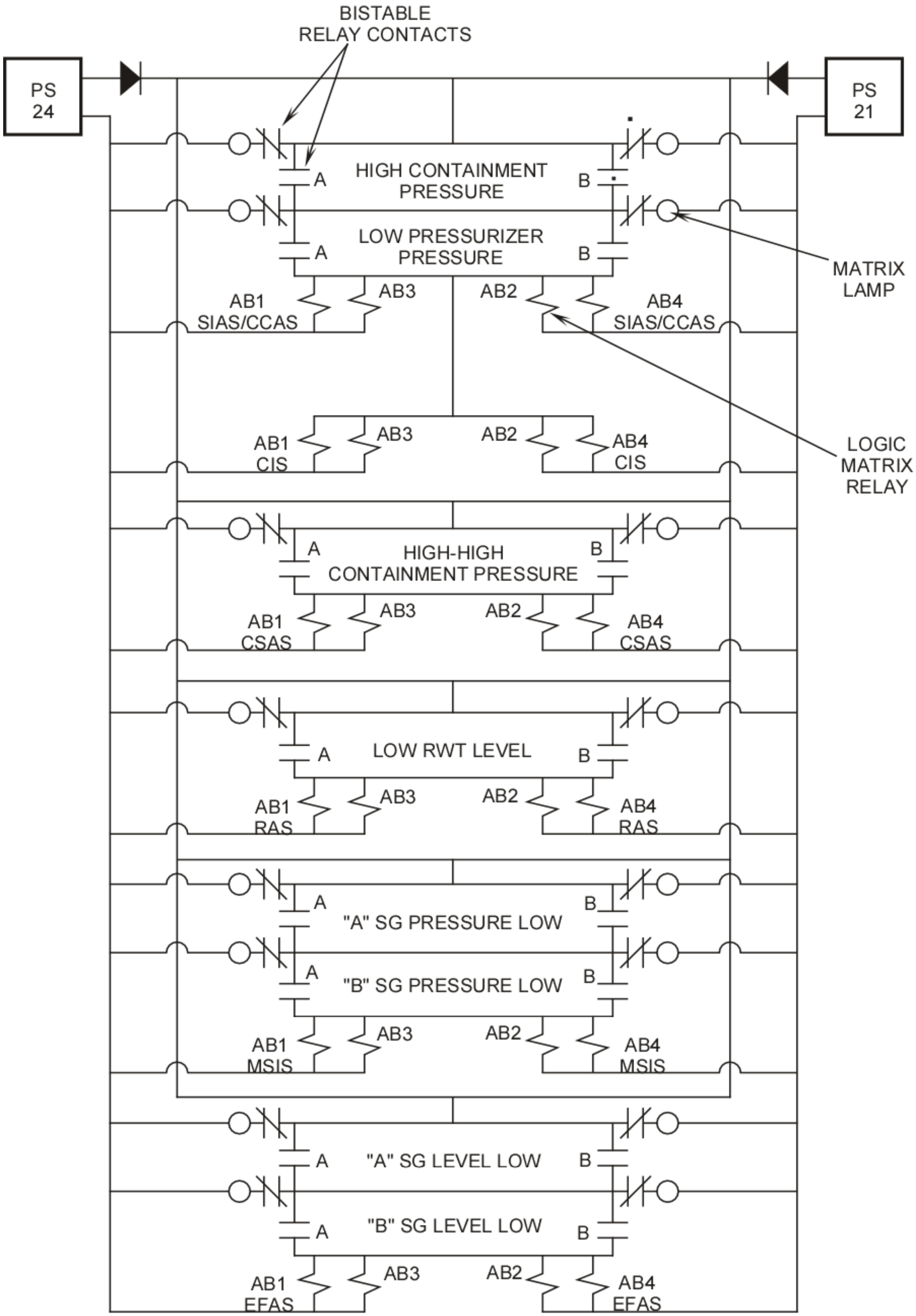



**Figure 15-17 ESF Matrix**

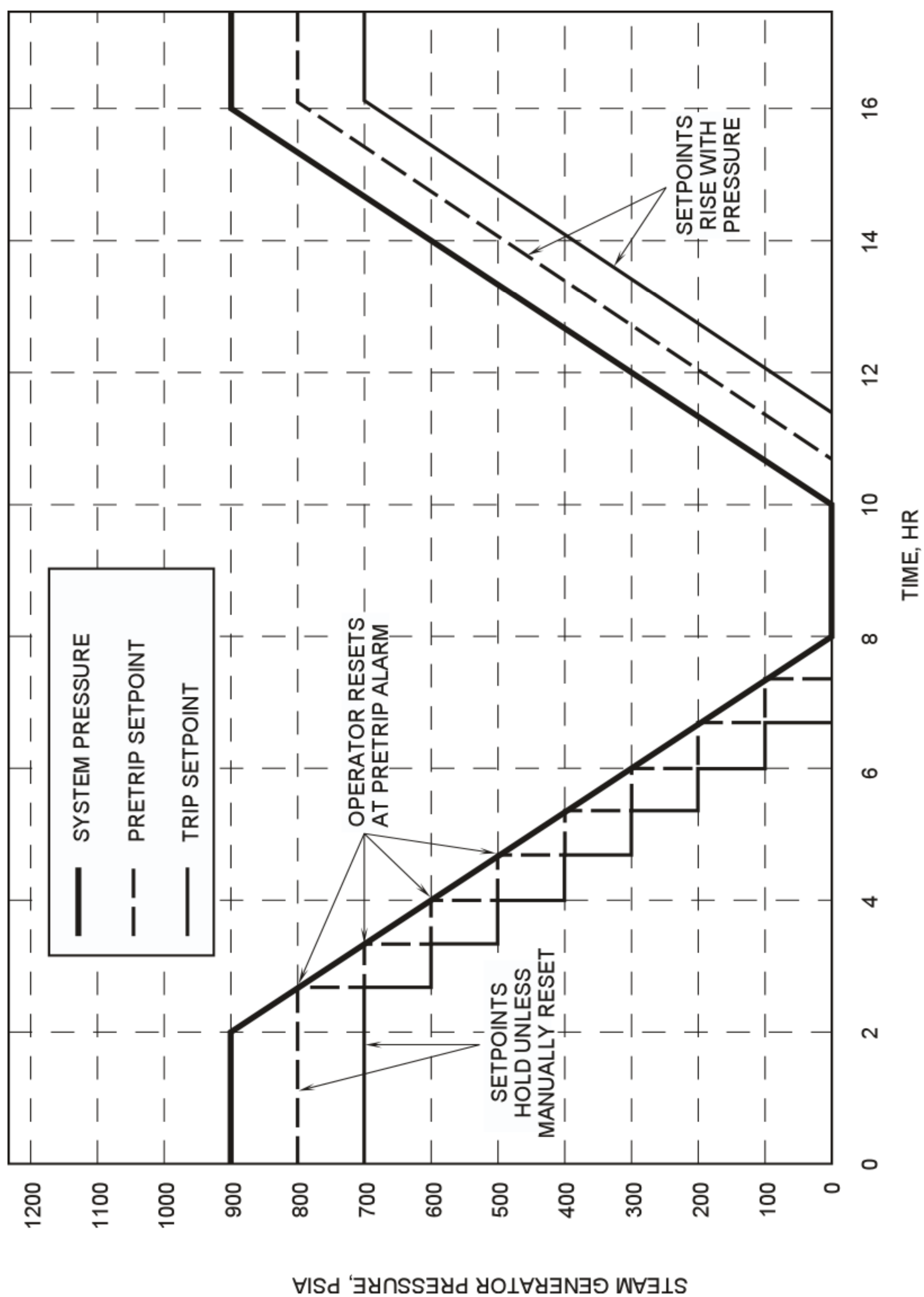



**Figure 15-18 Steam Generator Variable Setpoint**

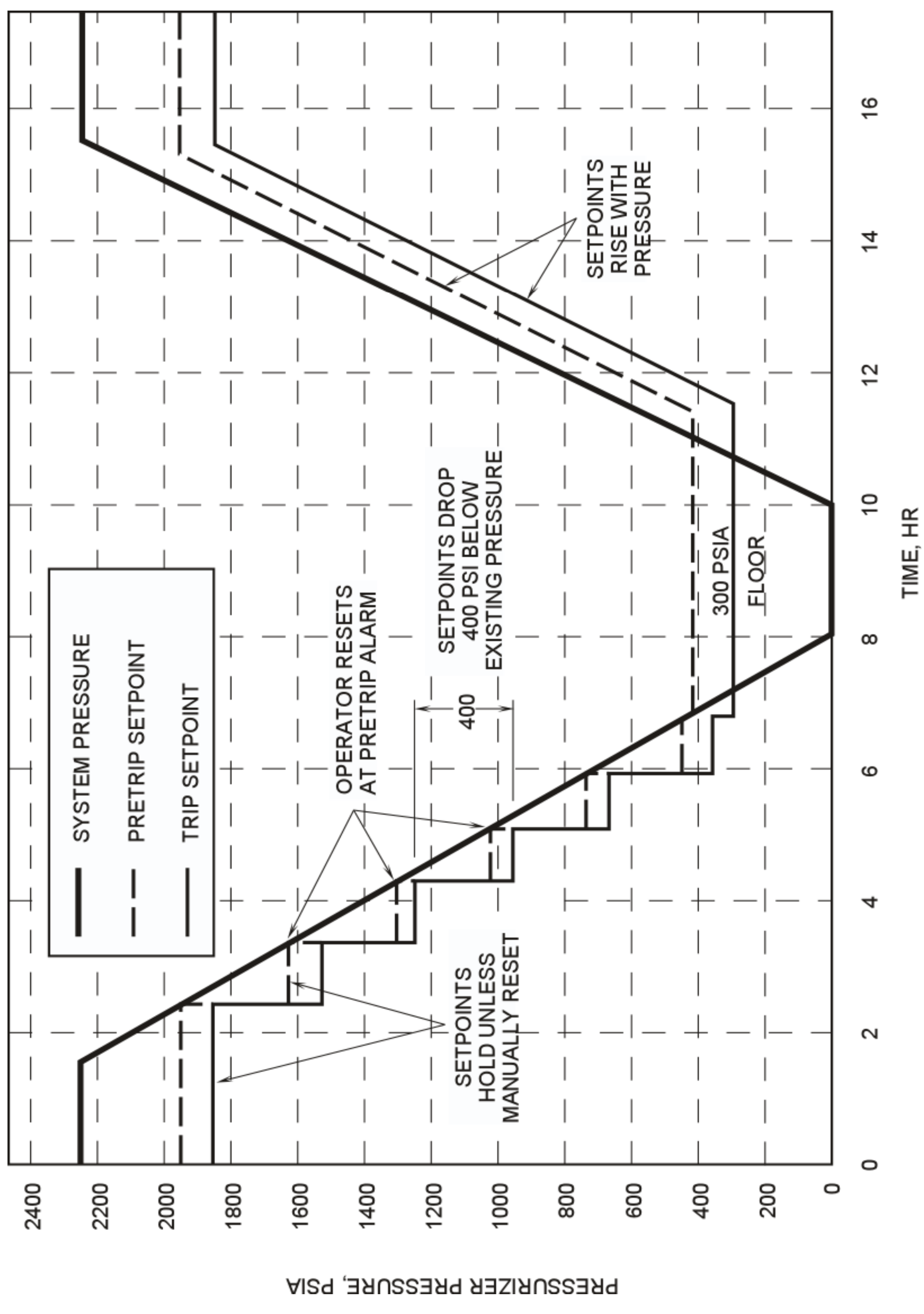



**Figure 15-19 Pressurizer Pressure Variable Setpoint**

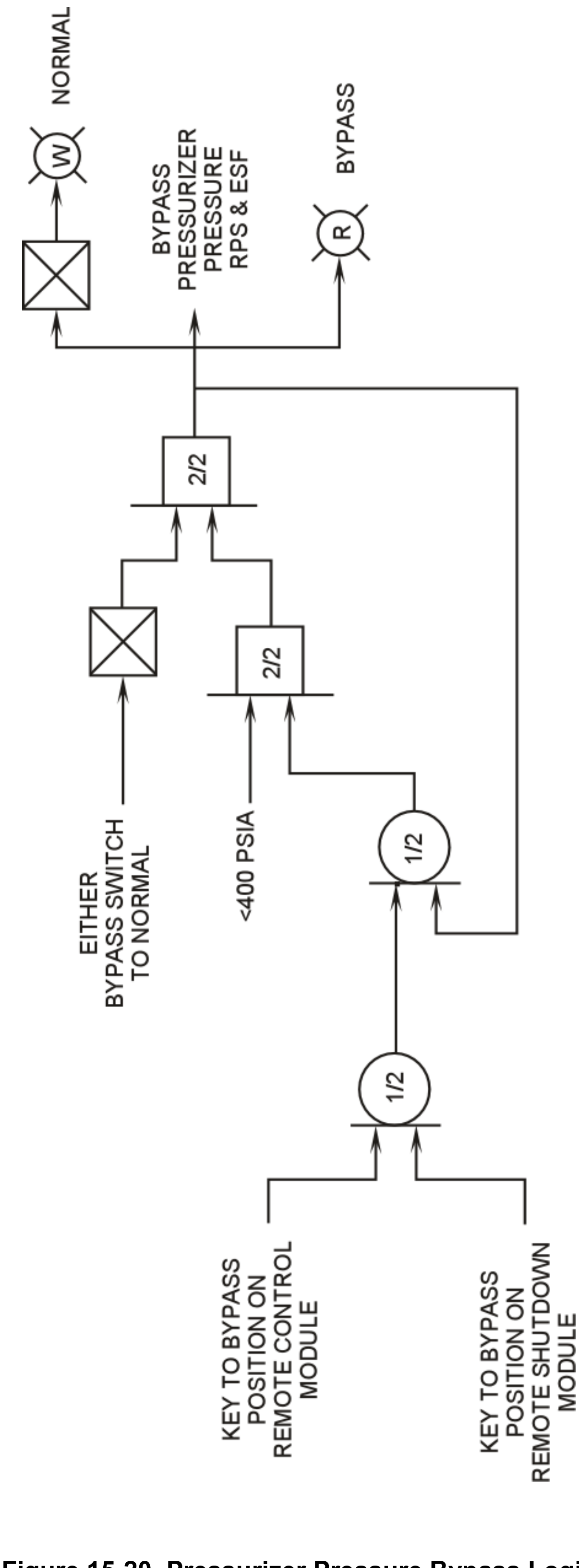



**Figure 15-20  Pressurizer Pressure Bypass Logic**

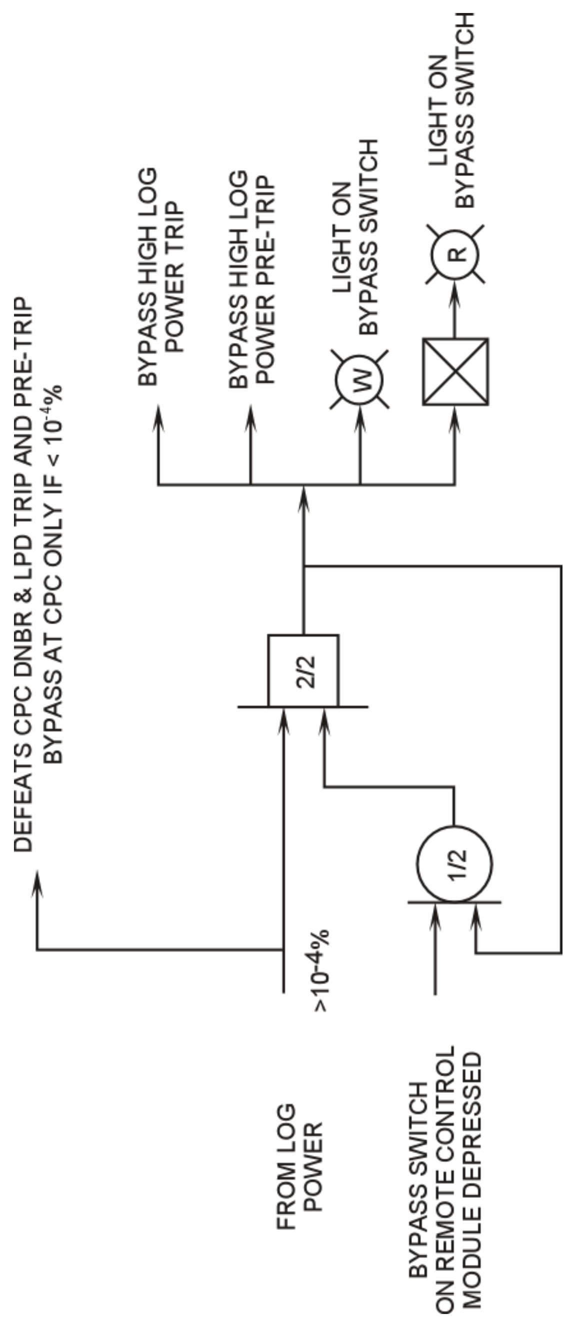



**Figure 15-21 High Logarithmic Power Bypass Logic**

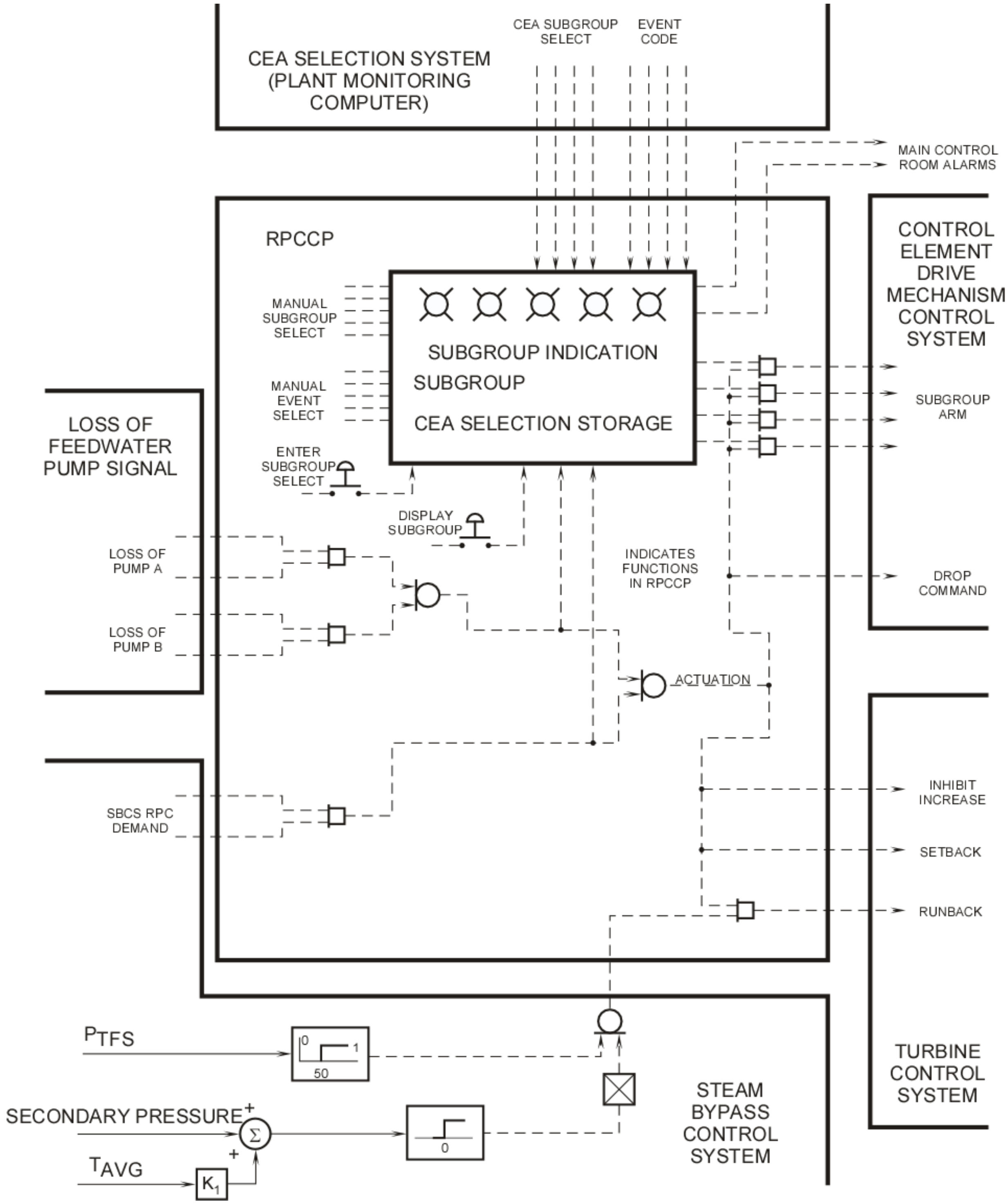



**Figure 15-22 RPCS Functional Diagram**

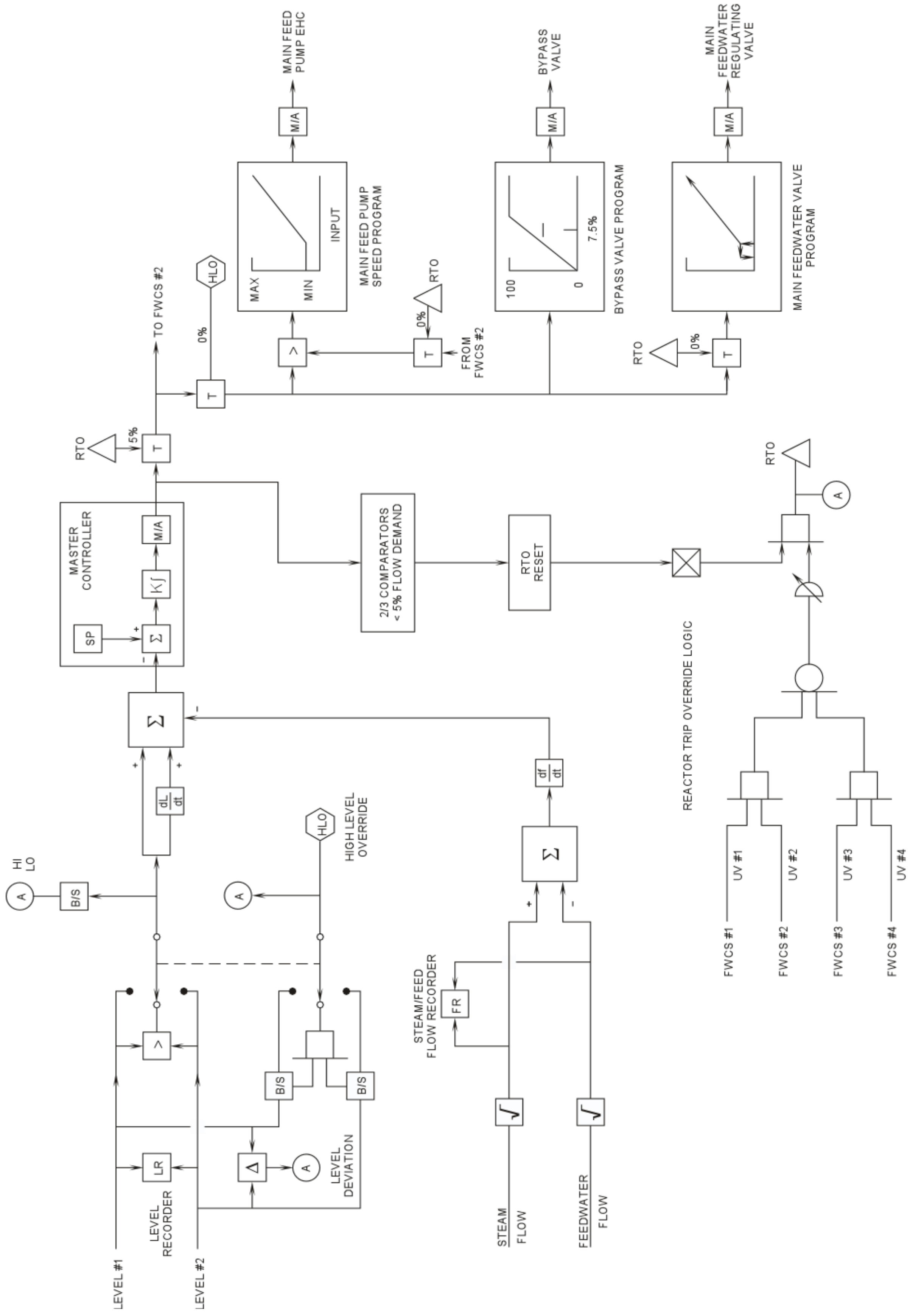



**Figure 15-23  Feedwater Control System**

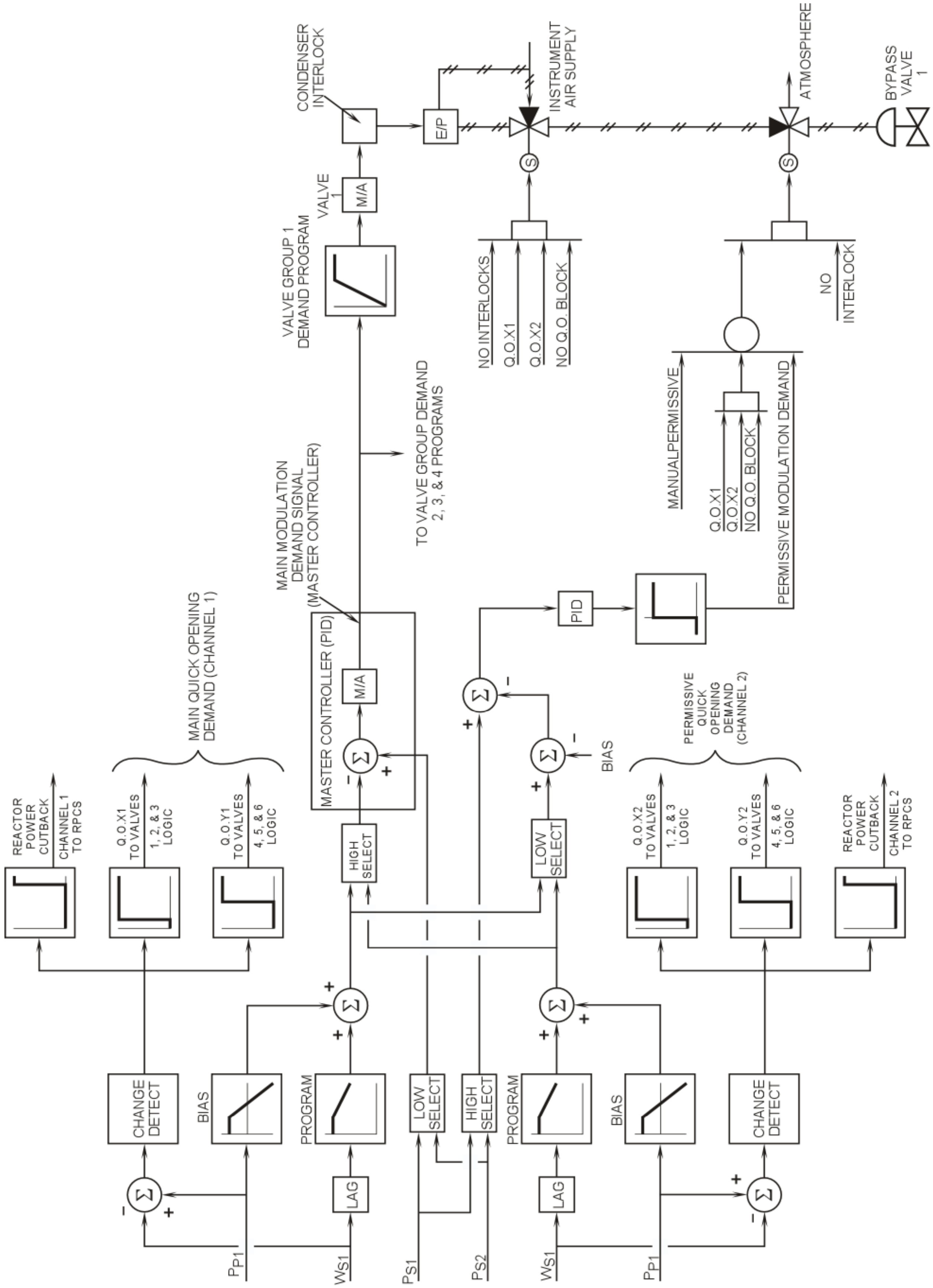



**Figure 15-24 SBCS Simplified Functional Block Diagram**

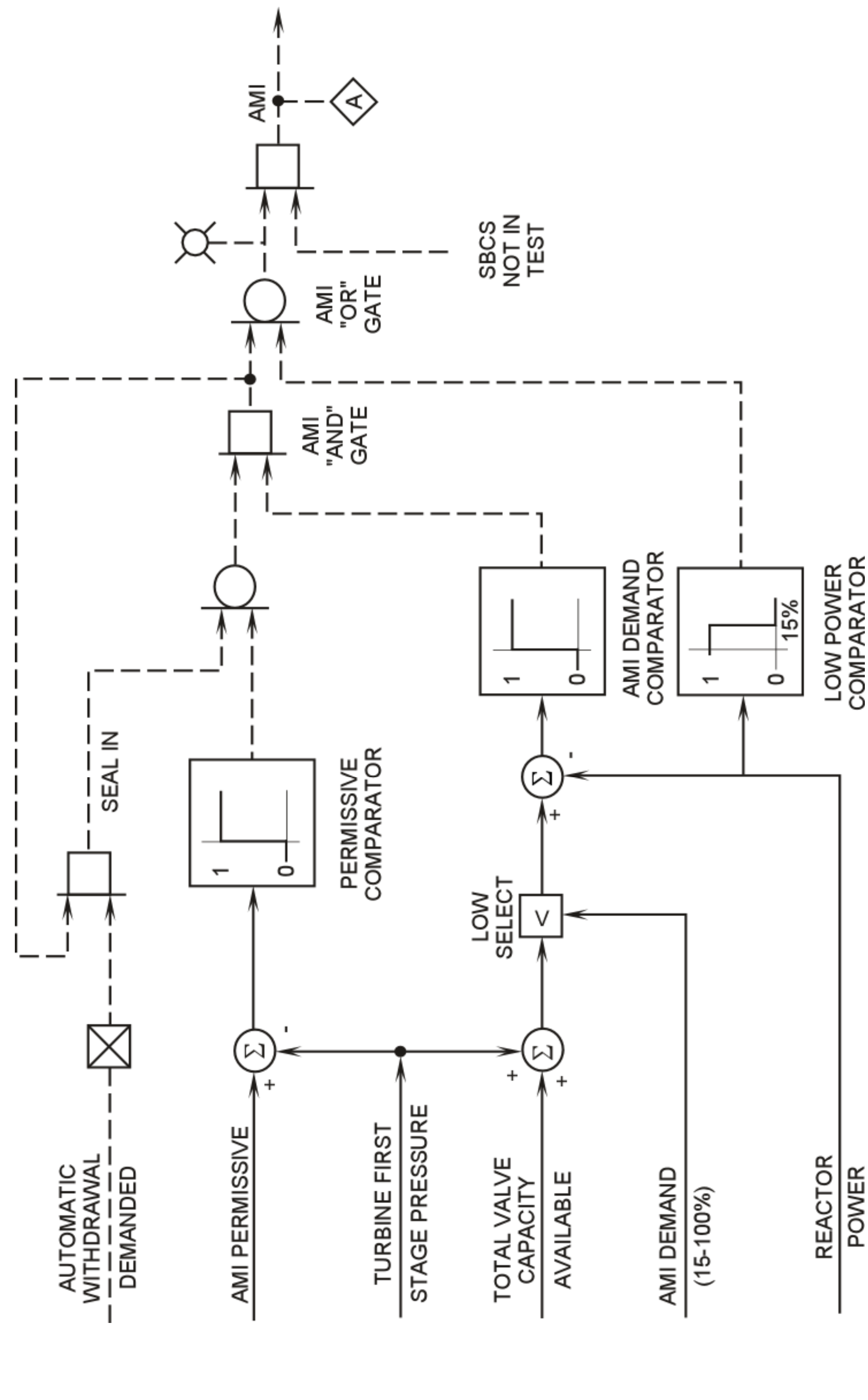



**Figure 15-25 Automatic Motion Inhibit**

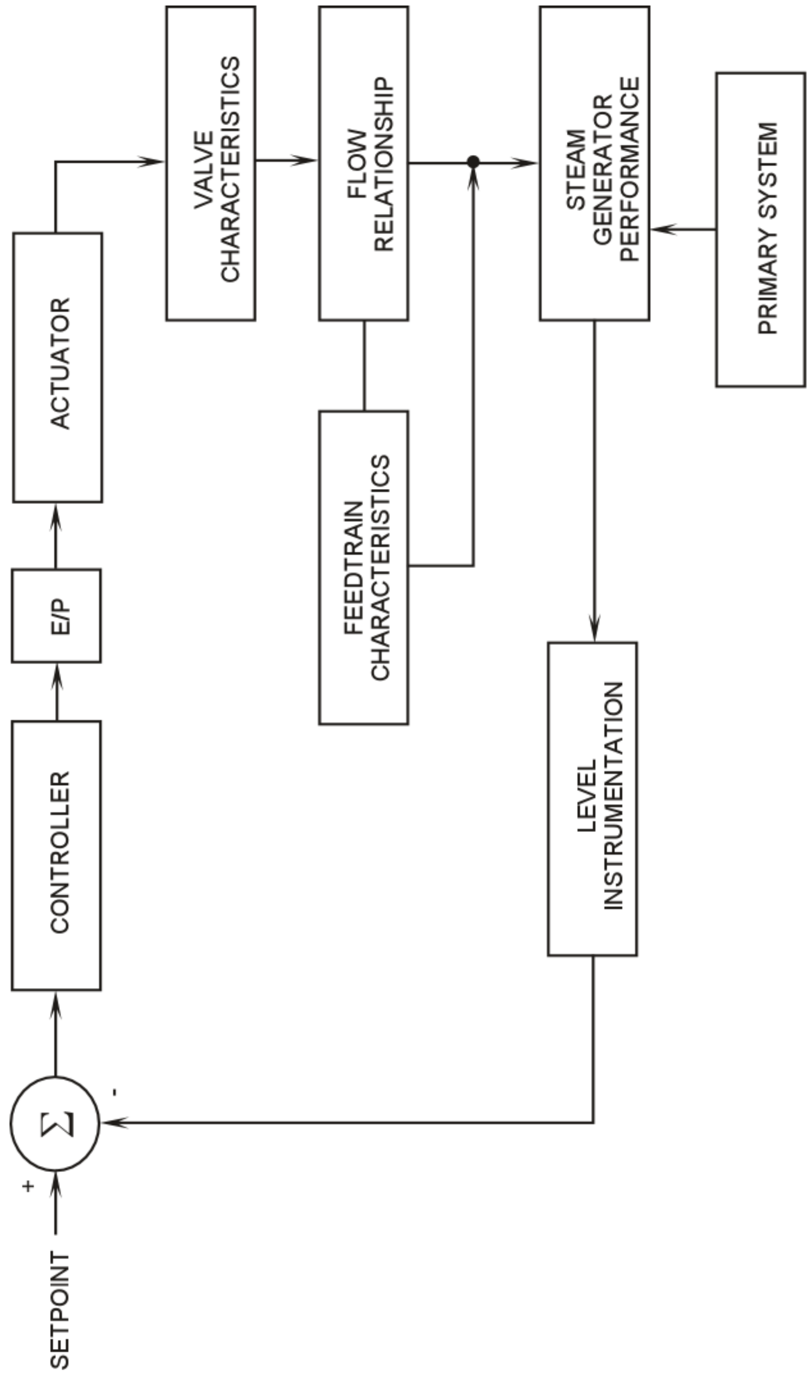



**Figure 15-26 Feedwater Flow and Steam Generator Level Loop Block Diagram**

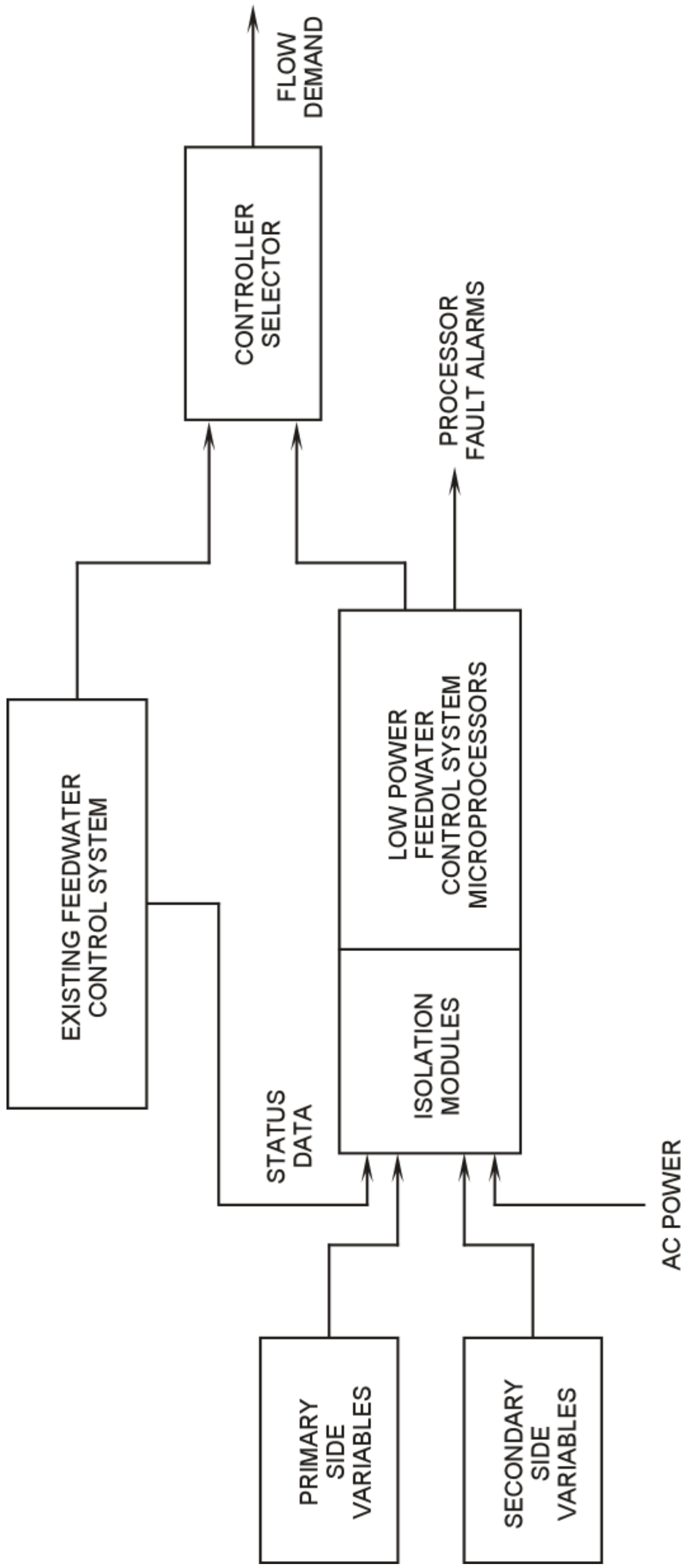



**Figure 15-27 Low Power Feedwater Control System Block Diagram**

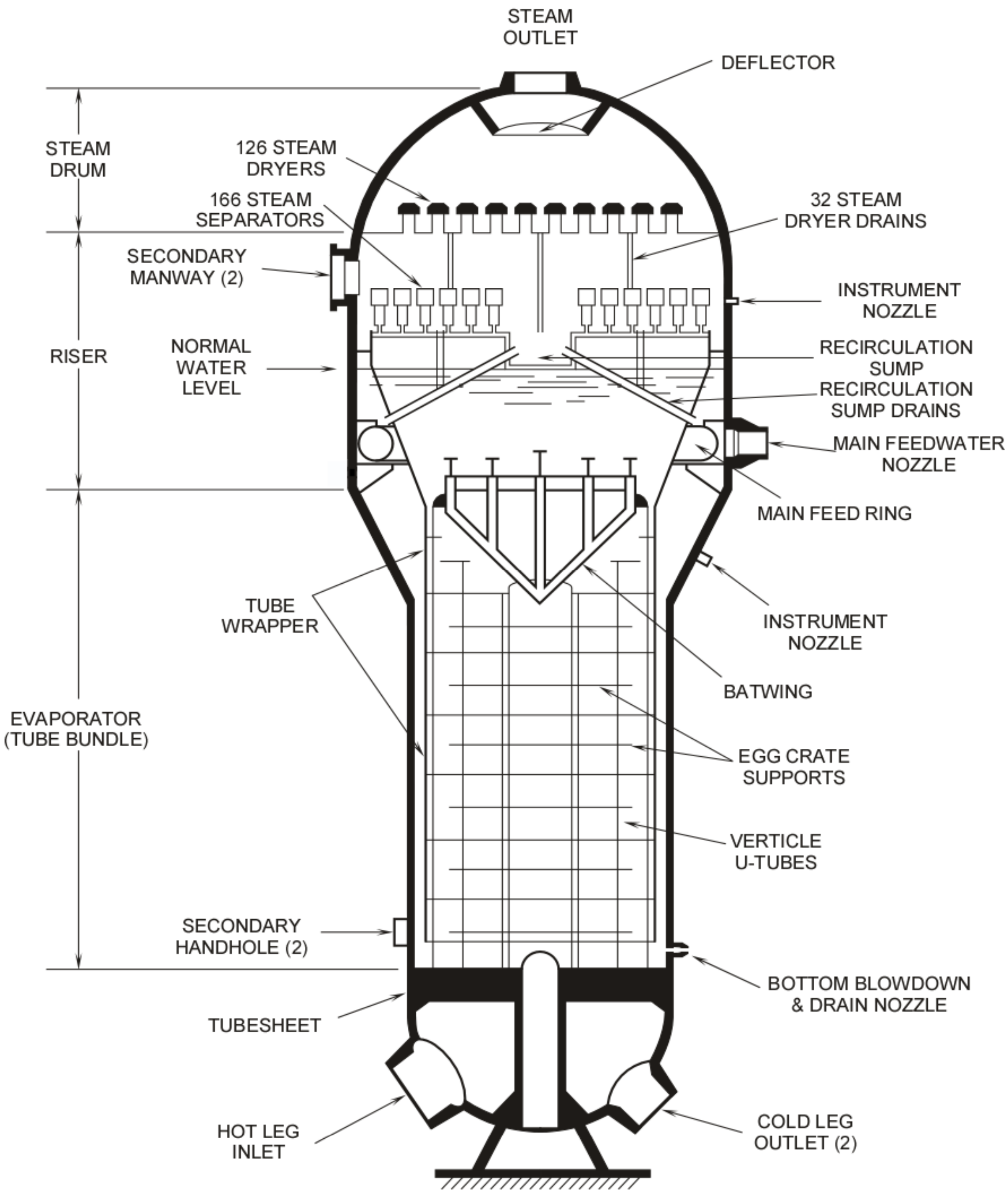



**Figure 15-28 Steam Generator Schematic**