Main Steam Supply and Feedwater System

Training Objectives

The participant will be able to describe or understand:

- The function of the Steam and Feedwater system and its role in the Candu overall energy cycle.
- The Functional requirements, both process and safety related.
- The system description, including a comparison between a CANDU 6 and Ontario Hydro Stations.
- The major equipment and components.
- The system layout
- An understanding of the control of major components.
- System operation, normal and abnormal.
- Protective devices used.
- Interactions with other systems.
- Hazards, both radiological and conventional.

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1. Steam and Feedwater System Overview

The steam/feedwater system is the principal system available for the removal of heat energy from the steam generator. This removes energy from the heat transport system and so provides a means to keep fuel cool. The transport of this energy from the steam generator in the form of saturated steam, and the return of warm feedwater is the subject of these lessons.

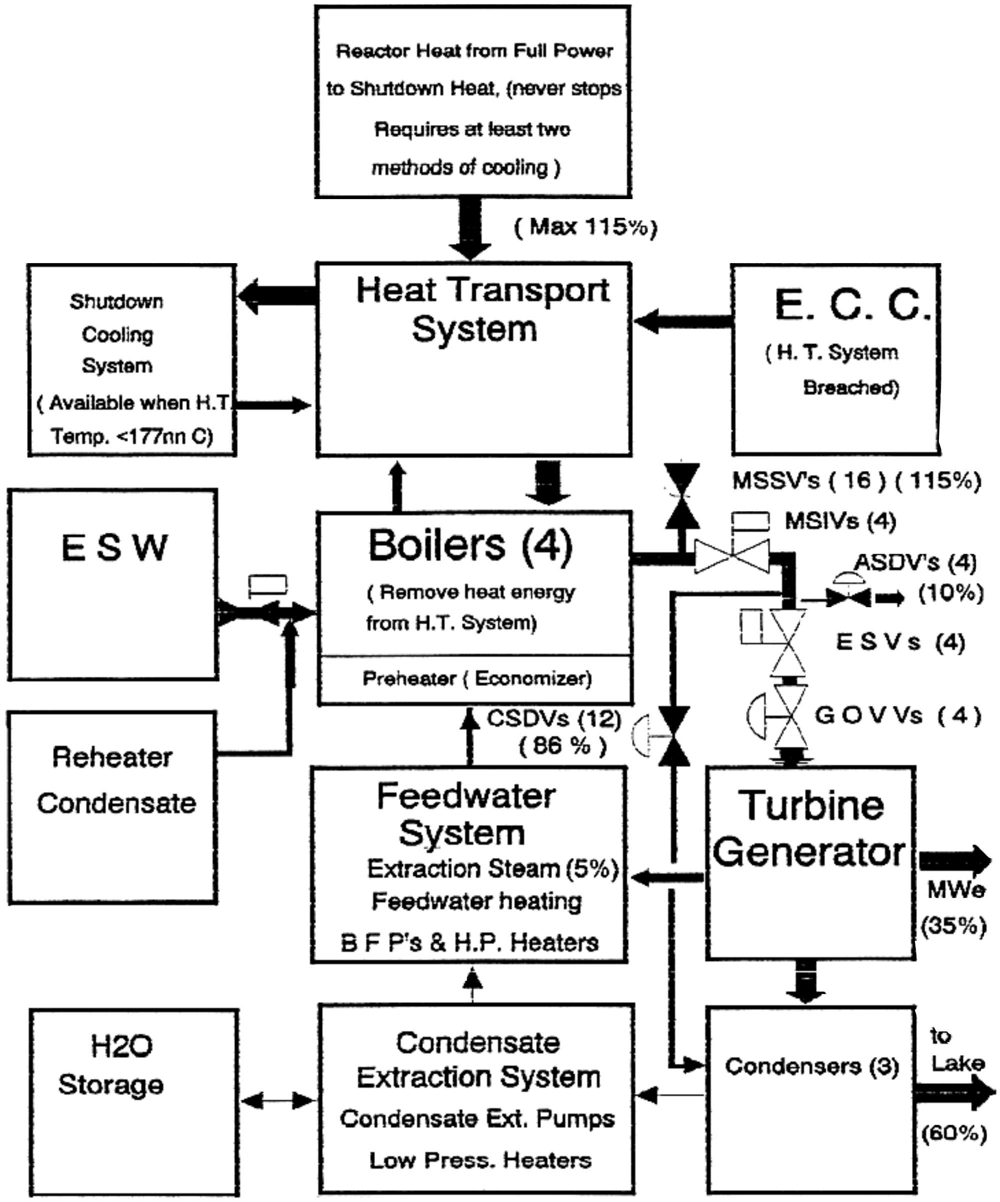
The methods available to transport this energy in order of preference are:

1. delivery of steam to the turbine to produce electrical power; about 35% of this energy is used to produce electrical power, 60% is rejected to the lake via the condenser and about 5% is returned to the boiler as warm feedwater.
2. delivery of steam directly to the condenser bypassing the turbine. Up to 86% of the normal full power steam flow to the turbine can be handled in this way. Most of this energy (98.8%) is rejected to the lake and the remainder (1.2%) is returned to the boiler as cool feedwater. This of course is uneconomical, but it provides a means of prevention of reactor poison out. It also has the advantage of keeping the fluid within the steam/feedwater cycle while maintaining the reactor in the operating state.
3. discharge of steam directly to the atmosphere. This means that 100% rejection to the atmosphere of the system energy and loss of feedwater from the steam/feedwater cycle. Its use is limited depending on the availability of an alternate feedwater source. There are two operating modes. The first uses the Atmospheric Steam Discharge Valves (ASDVs) to reject up to 10% of normal steam flow. The main purpose is to control the rate of warm-up and/or cool down of the Heat Transport System. The second is a safety mode whereby up to 115% of normal steam flow can be discharged to the atmosphere through 16 Main Steam Safety Valves. This provides both overpressure protection and auto-depressurization. Auto-depressurization is a violent action and is only initiated under Emergency Core Cooling (ECC) conditions or on a very low level in two or more steam generators with a coincident low feedwater supply pressure.

These functions are illustrated in Figure. 1.1. The lightly shaded area of figure 1.1 shows the area covered by this lesson. It should also be noted that the flow lines refer to energy and not necessarily fluid flow. The few valves shown illustrate valve position under normal conditions. (valve symbols filled in solid colour = normally closed, while no colour = normally open.)

Note; The terms "Steam Generator" and "Boiler" are used interchangeably throughout these lessons. eg. the terms Boiler Level Control and Boiler Pressure Control refer to control of the level and pressure in the steam generator.

Figure 1.1
Typical Candu Energy Flow Diagram



2. Functional Requirements

Steam and Feedwater System Function
The steam and feedwater system is composed of the main steam lines and feedwater supply to the steam generators (boilers). The main steam lines supply steam from four steam generators in the reactor building to the turbine through the steam balance header at a constant pressure. The system controls the feedwater flow to maintain the required steam generator level. Steam generator

pressure is controlled by use of one or more of the following devices:
- The four turbine governor valves (GOVs)
- The twelve condenser steam discharge valves (CSDVs)
- The four atmospheric steam discharge valves (ASDVs)

The sixteen main steam safety valves (MSSVs) are provided for overpressure protection of the steam generator secondary side, as well as auto-depressurization. (Auto-depressurization has sometimes been called crash cooldown because of the high rate of temperature reduction in both the heat transport system and the steam generator.)

The feedwater system takes hot, pressurized feedwater from the feedwater train and discharges the feedwater into the preheater section of the steam generators. Main steam isolating valves (MSIVs) are provided to isolate the main steam supply to the turbine, the ASDVs and CSDVs from the steam generators after a reactor shut down in the event of a steam generator tube leak.

A schematic of the system is given in Figure 3.1 and a simplified flow diagram in Figure 3.2.

Process Related Requirements

The steam and feedwater system is designed to meet the following process requirements:

a. to supply steam produced in the steam generator to the turbine generator;
b. to control steam pressure using reactor power and/or the turbine speeder (governor), ASDVs, CSDVs;
c. to be able to dump steam through the ASDVs to the atmosphere during plant warm-up and cooldown and also when the main condenser is unavailable or Class IV power is lost;
d. to dump steam directly to the condenser through the CSDVs during balance of plant (BOP) upsets such as a turbine trip or loss of line, without causing the MSSVs to lift or a reactor trip. This manner of operation can also be used to prevent reactor poison out (Poison Prevent). In Poison Prevent conditions, the generator load is less than that required to keep the reactor power above it's poison out level. It is a short term condition in which the turbine and the CSDVs share the steam flow, or the CSDVs alone take the flow;
e. the pumps providing main feedwater flow pumps will continue to operate at full capacity following a turbine trip and pressure decay at the deaerator. In the event of a failure of an operating pump a standby main feedwater pump will start automatically;
f. an auxiliary feedwater pump will start automatically in the event of the tripping of all main feedwater pumps. This auxiliary feedwater pump supplies the steam generators with feedwater. The pump is on Class III power and provides a feed water flow up to 3% of full power feedwater flow. The feedwater flow to the steam generators when auxiliary feed pumps are operating can be either through the HP feedwater heater bank, or around

them. Sufficient water must be supplied to maintain long term reactor decay heat cooling;

g. an auxiliary condensate extraction pump operating on Class III power will start automatically in the event of the tripping of all main condensate extraction pumps. The requirement is to maintain the normal operating feedwater level in the deaerator storage tank when the auxiliary feedwater pump is in operation. The design flow of the auxiliary feedwater pump is 4% of full condensate extraction flow;

h. on sudden loss of extraction steam or at low loads where the extraction steam supply is not high enough to maintain minimum deaerator heater outlet temperature, throttled main steam will be supplied to the deaerator.

Safety Related Requirements

The steam and feedwater system is designed to meet the following safety requirements:

a. it will be able to remove heat from, or rapidly depressurize, the heat transport system during accident conditions. This is achieved by discharging steam through the MSSVs. The systems will also be able to provide overpressure protection of the steam generator secondary side. The MSSVs are designed to Design Basis Earthquake, group 2, standards;

b. in the event of steam generator tube leaks there will be provision for isolating the individual steam lines from each generator. This capability is to minimize the release of radioactive steam into the atmosphere or the Balance of Plant (BOP) in the event of a steam generator tube leak. The isolation is by remote, manually operated, Main Steam Isolating Valves (MSIVs) on the individual steam lines from each steam generator. These MSIV's are sometimes referred to as "Boiler Stop Valves".

c. On low steam generator level in two or more steam generators, conditioned by low feedwater header pressure, auto- depressurization will be initiated. Depressurization is accomplished by opening the MSSVs and introducing an emergency make-up water supply (EWS) into the steam generators;

d. The MSSVs will open on a LOCA (Loss of Coolant Accident) signal (low pressure in the HT system combined with high pressure inside containment or one of other conditioning signals) following a time delay to crash cool the secondary side of the steam generators. This is to ensure rapid cooldown of the steam generators to depressurize the HT system and allow emergency core cooling system (ECCS) injection;

e. In the event that the normal feedwater is unavailable, two alternative sources of water supply will be available. One source is by gravity feed from the dousing tank via the Emergency Service Water (ESW) valves. The second source is from the ESW reservoir via the ESW pumps and valves. Both the feedwater system and the ESW system are designed to DBE group 2 standards;

f. To ensure rapid automatic starting of the standby and auxiliary feed pumps, all services to the pumps are kept active (e.g. idle pumps are kept warm by warm-up flow circulation; lube oil cooling system and gland seal system are kept in service). The auxiliary feedwater pump(s) are designed to DBE group 2 standards.

g. All feedwater heaters require protection from overpressure on both the shell and tube sides. (see section 3.2.)
h. Back flow of steam and feedwater to the turbine through the extraction steam lines must be prevented. (see section 3.2)

3. System Description

3.0 System Description - Overview

This section describes the steam and feedwater system for a typical CANDU 6 design. The major components, their layout and operation will be described. (Figure 3.1and 3.2)

3.1 The Steam System

General

Under normal operating conditions at full power, steam is supplied from the steam generator at a pressure of 4.69 MPa(a), temperature of 260°C and a maximum moisture content of 0.25%.. Carbon steel steam pipes bring steam from the reactor building to the turbine building, where they join to form a common steam header. The following components are connected to each steam pipe coming out of the reactor building:

a. Four safety relief valves which provide overpressure protection to the steam generator and the capability to cool quickly the HT system under emergency condition.
b. Two small lines, one for nitrogen addition and the other for extraction of a steam sample.
c. One main steam isolation valve for steam line isolation, in the event of an unacceptable steam generator tube leak.
d. One atmospheric steam discharge valve (ASDV) to reject steam to the atmosphere. The capacity of the ASDV is 10% of rated steaming rate of one steam generator.

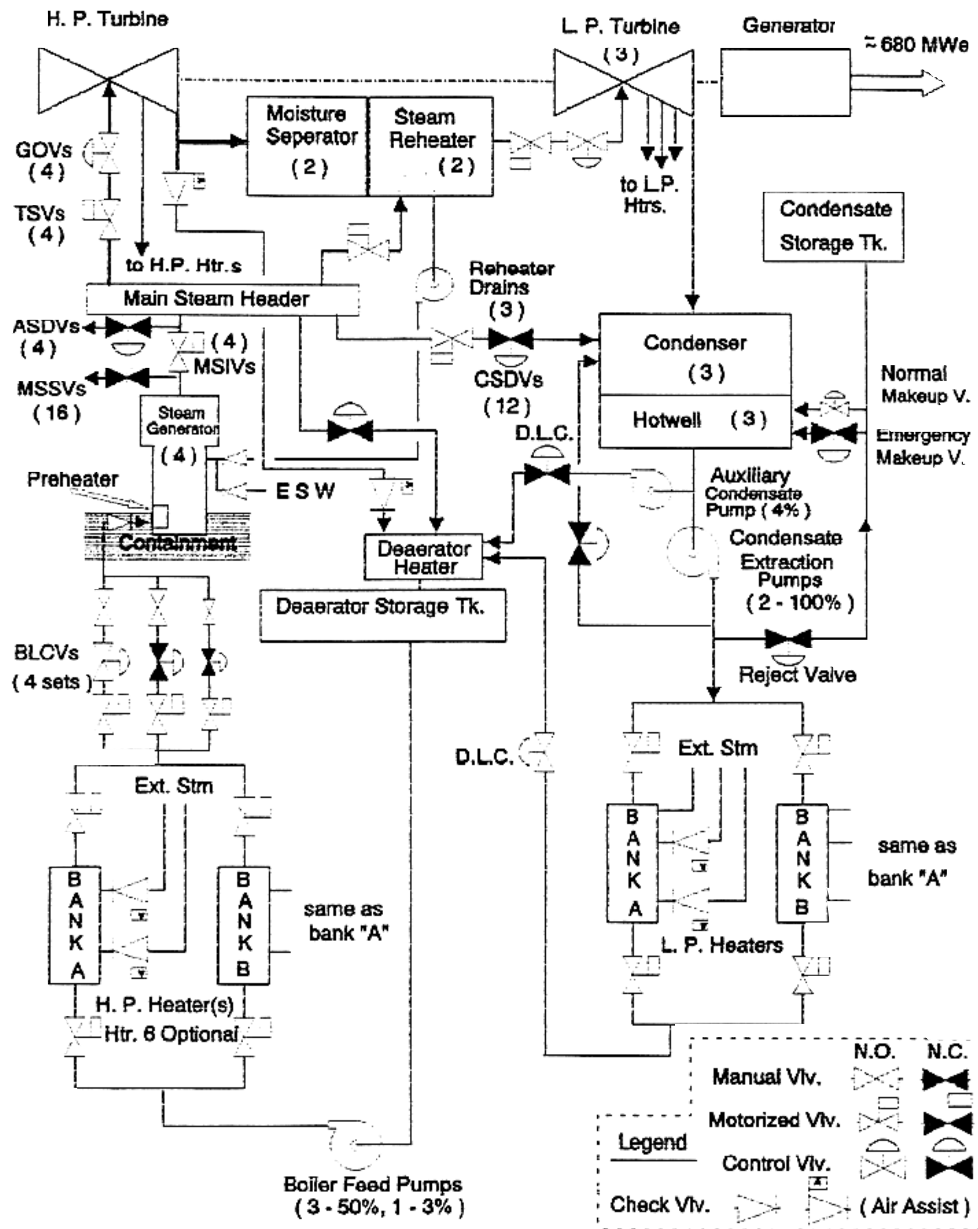
Pressure losses in the steam lines result in a pressure of 4.55 MPa(a) at the turbine stop valves.

Steam flow through each steam main is measured by flow elements across elbow taps. Rated steaming capacity of each steam generator is 0.943×10^6 kg/hr.

The main steam header in the turbine building normally supplies steam to the turbine through four turbine stop valves (TSVs) and supplies steam to the steam reheater. However, under certain conditions the header may discharge steam directly to the condenser via 12 condenser steam discharge valves (CSDVs). The CSDVs are used to discharge steam during severe transients such as turbine trip or loss of line to avoid activating the safety relief valves. The CSDVs are sized to permit continuous discharge of up to 86% of full power steam flow.

There can also be other low capacity uses of the main steam supply including building heating, flow to steam air ejectors, supply to steam glands, a heavy water upgrader and possibly a turbine driven feedwater pump.

Figure 3.1
Simplified Steam/Feedwater Flow Diagram

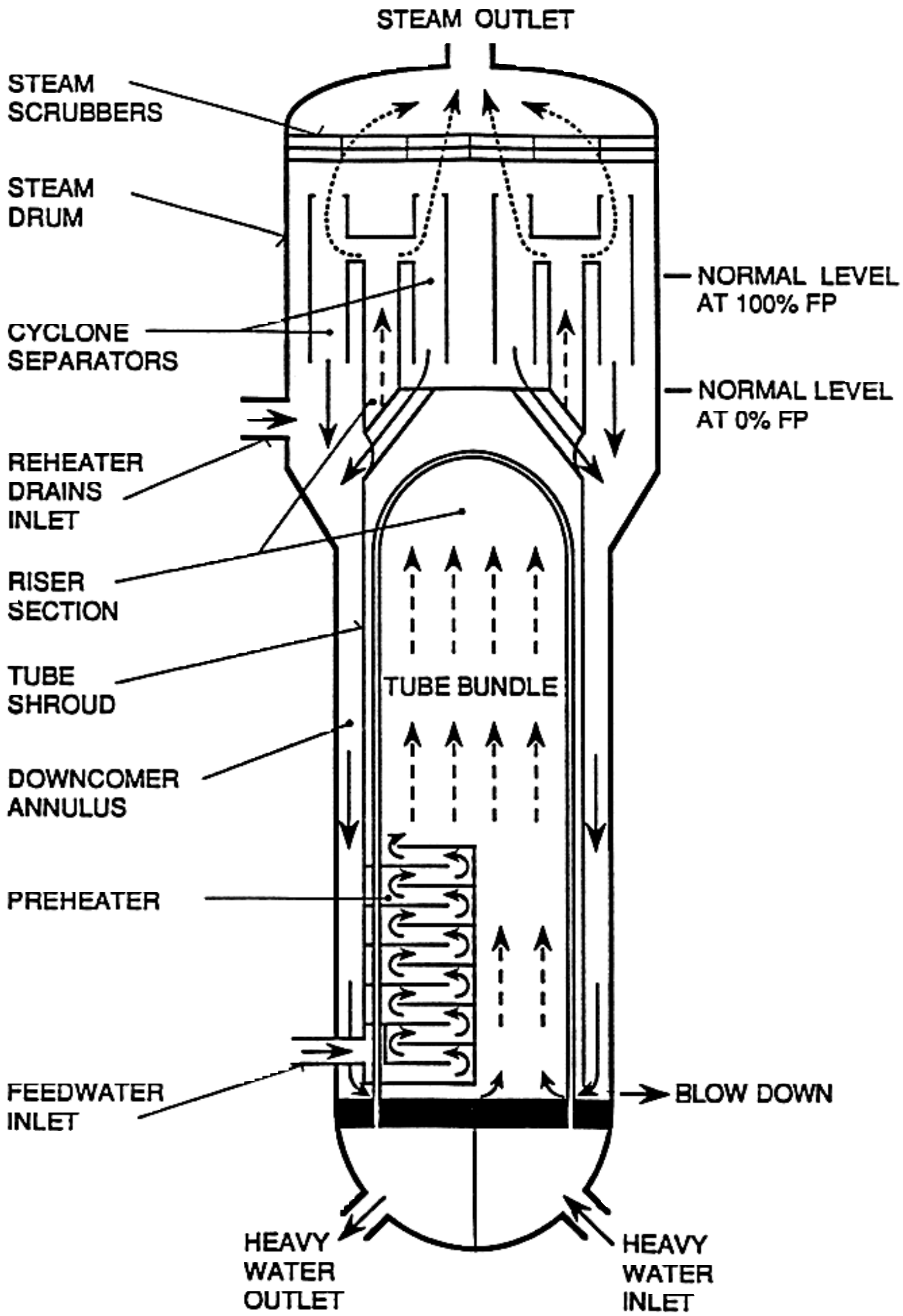


3.1.1 The Steam Generators (Boilers)

Four identical steam generators of the recirculation type with integral preheaters, generate steam by heat transfer from the heavy water on the heat transport side to the light water on the secondary side. (The preheater is equivalent to an economizer in conventional boilers) The steam generators consist of an inverted vertical U-tube bundle installed in a shell. Steam separating equipment is housed in the upper end of the shell.

Four steam generators are located in the steam generator room which is accessible during normal operation.

Figure 3.3
Simplified Boiler (Steam Generator) with built-in preheater



The CANDU 6 steam generators are natural circulation, integral preheater, integral steam drum, inverted U-tube units. The components are shown in Figure 3.3. The reactor coolant passes through the U-tubes, boiling the secondary side fluid and creating two-phase flow around the tube bundle. The two-phase flow increases in quality towards the top. It then passes through cyclone separators. The two-phase fluid is separated into 99.75 % dry steam which passes out of the steam generator by the steam outlet pipe and saturated liquid which returns to the bottom of the tube bundle via the annular downcomer completing the circulation loop. To replace the outflow of steam, feedwater is pumped into the preheater. It is the difference in static head between the saturated downcomer fluid and the less dense two-phase flow in the riser which creates the driving force for natural circulation within the steam generator. Hot reheater drains water enters the secondary side about mid level of the heat exchanger. This reheat drains nozzle is also the entry point of the ESW system.

During a power increase more steam is produced around the tube bundle. Since this is a fixed volume, the liquid which the steam is replacing is forced into the steam drum, and the change in power is reflected by a increase in water level. Similarly, if power goes down, so does the level. It is the change in drum water level that is referred to as "swell" during power increases and "shrink" during power decreases. The SGLC program programs the level set point (increases with load) to reduce the impact of this phenomena on the feedwater circuit as well as the impact on the heat transport pressure control.

Steam Generator Blowdown

Each steam generator has eight connections for blowdown from the downcomer area, two connections from the tube free lane area and four connections from the preheater area. Blowdown is used as a part of control of steam generator water chemistry. Steam generators will be blown down continuously to the condenser water outfall via a blowdown tank at the rate of 0 to 3% of full power steaming rate.

To protect the Ni-Fe-Cr steam generator tubes, strict control of steam generator water and feedwater chemistry is required. The control is achieved by addition of the necessary amounts of hydrazine and cyclohexylamine at the condensate extraction pump discharge. There are also provisions for adding sodium phosphate (Di- and Tri-sodium phosphate) at the discharge of the steam generator feed pumps, in case of condenser leakage only.

3.1.2 Steam Valves

Safety relief valves (MSSVs), MSIV and ASDVs are usually located in the Turbine Building.

Main Steam Safety Valves (MSSV)

Steam generator overpressure protection is supplied by a total of sixteen safety valves. These valves are both spring loaded and pneumatically operable valves.

There are four on each steam main. The combined relief capacity of three out of four MSSVs is 115% of the steam flow from each steam generator. The steam relief capacity of 115% has been chosen because reactor power could, under a slow loss of regulation, go as high as 115% before reactor shut down occurs. These valves are only required when the steam generator pressure control system fails to limit pressure. The relief valves have staggered set pressures, between 5.01 MPa(g) and 5.14 MPa(g), and are designed to achieve full lift at 4% above their set pressures.

The steam generator is protected against overpressure during the following operations; warmup, cooldown, and hold. Pressure in the steam generator is normally controlled at a constant value by varying reactor power to suit the load. The turbine bypass system is sized to permit a continuous steam flow to the condenser of up to 86% of full power steam flow. This provides steam generator pressure control and continued reactor operation following a loss of line or a turbine trip.

Auto-depressurization of the steam generator secondary side is required to permit ESW to enter the steam generators. If a total loss of Class IV and Class III power occurs, the three main feedwater pumps and the auxiliary feedwater pump are disabled and normal feedwater flow is lost. The ESW reservoir water and the dousing tank water are the remaining sources of feedwater to maintain the steam generator as a heat sink for the heat transport system. However, the EWS system is a low pressure system. If action is not taken to depressurize the steam generators, the steam generator pressure will be held at set pressure by the main steam safety valves as steam is produced by decay heat after reactor shutdown, and steam generator dryout will follow. Therefore, the main steam safety valves are opened by auto-depressurization to bring down the secondary pressure. This allows water from the dousing tank to enter the steam generators to maintain a heat transfer capability.

Main Steam Isolation Valves (MSIV)
The MSIVs, installed downstream of the main steam safety valves, are motorized and may be remotely operated from the main control room, by decision of the operator only. Appropriate MSIVs will only be closed after reactor shutdown following leakage from the primary side of the steam generator to the secondary side. They could also be closed to isolate the steam generator for maintenance or all four could be close to isolate a serious steam leak in the B.O.P. The MSIV closing time is approximately two minutes to avoid steam hammer.

Atmospheric Steam Discharge Valves (ASDV)
A total of four globe type control valves are provided to permit steam to be discharged from the steam generators to the atmosphere. These valves have a total capacity of 10% of the nominal steam flow.
These valves are used to reject system heat when the main condenser is either unavailable or is inadequate. The valves are actuated in response to the steam generator pressure control program demands.

The ASDVs are used under loss of Class IV power, loss of condenser, turbine trip or loss of the high voltage transmission line. They are also used to control the warmup and cooldown of the boilers and the heat transport system.

Condenser Steam Discharge Valves (CSDV)
The main function of these 12 valves is to discharge live steam from the main steam balance header to the condenser. They are used to discharge steam during severe transients, such as turbine trip, to avoid activating the safety valves.

Their operating characteristics are as follows:
- During normal operation, they are on pressure control with an offset to bias them closed.
- During poison prevent, their steady-state opening is proportional to the power mismatch between poison prevent level and actual turbine steam consumption. Their opening is however conditioned by the condenser protective system which may automatically cause them to trip; in the event that this occurs, a manual reset is required before they can be reopened.
- On a turbine trip, a signal is applied to open quickly. They will revert to the pressure control mode after they have opened fully. This feature is required to prevent a reactor trip (high pressure) and inadvertent opening of the MSSVs.
- Provision is made to allow the operator to open them via the computer.

3.2 The Water System

Demineralized light water is used in the turbine steam and feedwater cycle. Steam, after passing through the turbine, condenses in the turbine condenser and collects in the condenser hotwell. From there condensate pumps (2 x 100% + 1 x 4%) pass the water through a series/parallel network of L.P. feed heaters to the deaerator (direct contact deaerating feedwater heater and associated storage tank). Steam generator feed pumps ("Boiler Feed Pumps") (3 x 50% + 1 x 3%) pump water from the deaerator storage tank to four steam generators through parallel sets of high pressure heaters and feedwater control valves. Each steam generator has three control valves (2 x 110% + 1 x 15%). At full power the temperature of the feedwater entering the steam generators is 187°C.

Three 50% reheater drain pumps pump the condensate from the reheater drains tank directly to the four steam generators.

Four 30 cm feedwater lines run from the turbine building to the reactor building. Each line is equipped with a swing check valve located inside the reactor building (containment) to prevent backflow of water out of the steam generators on loss of feedwater supply. All 12 feedwater control valves have manual isolating valves between them and the steam generator and motorized isolating valves between them and the last feedwater heater.

Thermal stress limitations at the steam generator preheater inlet impose additional limitations on the feedwater circuit. The preheater temperature is assumed to be equal to the steam generator saturation temperature. The ΔT limit is in the 130 to 150 Celsius degree range and therefore at normal load with a saturation temperature of 258°C the feedwater temperature should be greater than 130°C. The normal feedwater temperature being in the 170°C range is well above this limit. However startup and severe transients can cause this limit to be exceeded. On startup after an extended shutdown the deaerator electric heaters may have to be in service for > 48 hours to achieve this temperature.

If feedwater is unavailable, the emergency water system provides long term cooling to the steam generators. One emergency water line is provided for each steam generator. A check valve in each line prevents back flow and circulation during normal operation. Emergency water is ordinary lake water. A phosphate addition line joins each feedwater main downstream of steam generator level control valves.

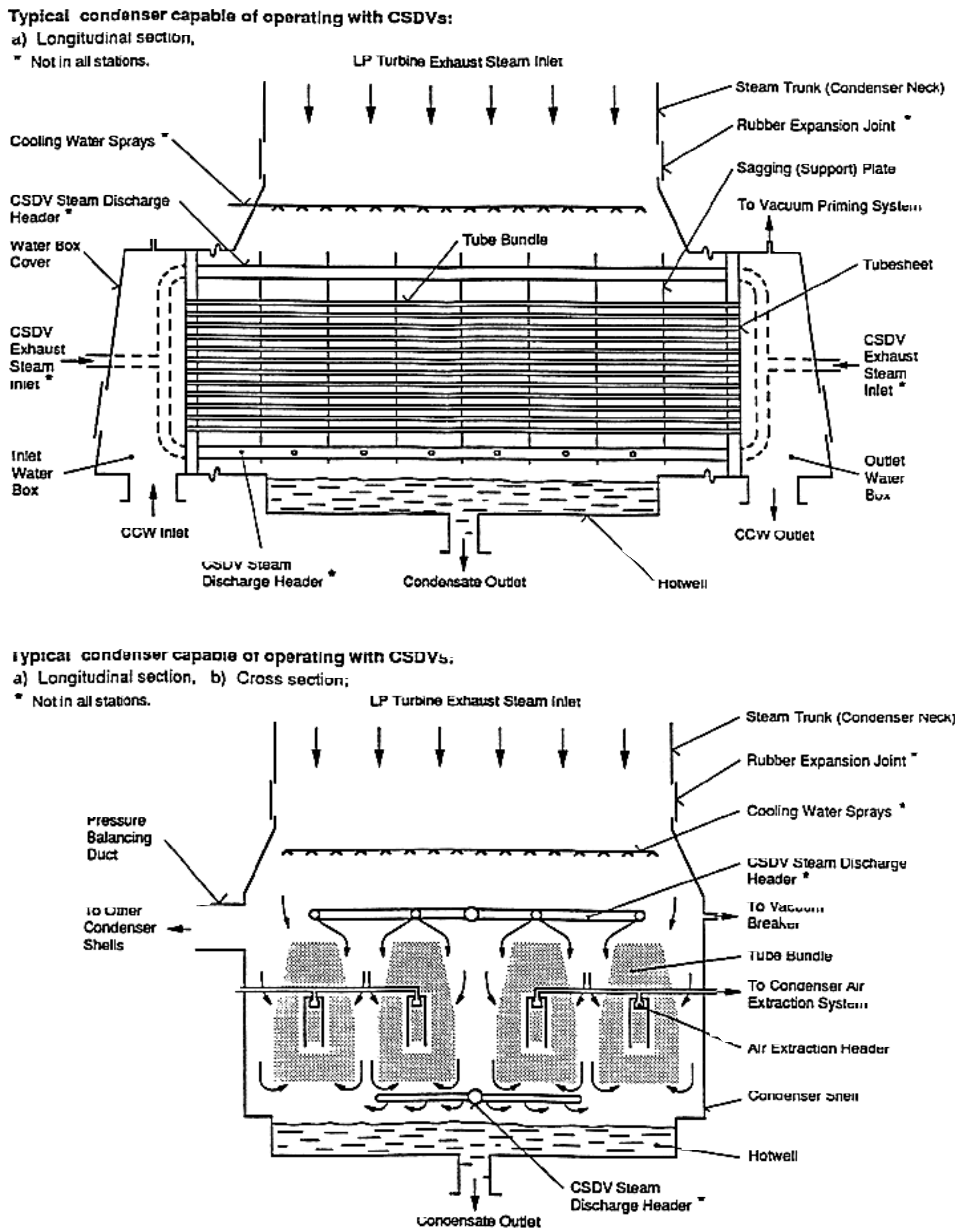
As can be seen in Figure 3.2 there is redundancy in almost all of the feedwater circuit except with the exception of the deaerator and deaerator storage tank. This storage tank typically contains about a five minute supply of water at full load conditions. It therefore imperative that this vessel is available and has an assured supply of water.

3.2.1 The Condensate and LP Feedwater System

The three main condensers are located immediately below the three low pressure turbines. The condensed steam at 5 kPa(a) is collected in the hotwell and piped to the condensate extraction pumps. The hotwells along with the condensate storage tank also perform the function of a surge tank to allow for any mismatch between the required condensate flow and the steam flow to the condenser. Large external demineralized storage tanks act as a back up to the storage tank through suitable valves and piping to accommodate a large mismatch. There is normally a small make-up flow from these tanks to the hotwell (approximately. 1 - 2 %). This value will vary depending on blowdown rate, leaks (both condensate and steam) and discharges from the ASDV'a and MSSV's.

The condensate extraction pumps (2 of 100% and 1 of 4% capacity) are vertical multistage centrifugal pumps. To gain sufficient NPSH they are located in wells below the condenser hotwell. This type of pump requires a high minimum flow which is accomplished by rejecting condensate back to the hotwell via a recirculation valve if the current flow does not meet this minimum. If the condenser air extraction system uses steam ejectors, then this recirculation line will be downstream to supply the required cooling flow to the ejectors under all conditions.

Figure 3.4
Typical Condenser capable of operating with CSDVs



The condensate flow then splits into two paths through the series parallel L.P. heater banks before entering the deaerating heater.

The condensate system also supplies water to secondary circuits such as condenser sprays, sealing circuits etc.

The auxiliary (4 %) condensate extraction pump is powered by Class III power and can deliver condensate directly to the deaerator bypassing the L.P. feedwater banks. At this point in the condensate system amine is injected into the condensate. Amine is a chemical used in PH control of the feedwater cycle

3.2.2 The Feedwater Heaters

The feedwater cycle contains two types of feedwater heaters. There are 8 to 10 horizontal U-tube feedwater heaters and 1 direct contact deaerating feedwater heater. Simplified sketches of these two types are shown in Figures 3.5 and 3.6.

The main source of heat to these heaters is from the turbine extraction steam lines. Feedwater heaters using this source have a self-regulating feature. There are no control valves on the extraction steam supply lines. The steam flow adjusts itself by a thermal equilibrium process. When the feedwater temperature approaches the saturated steam temperature then condensation of the extraction steam diminishes and therefore the flow of extraction steam to the feedwater heater tends towards zero. This is an oversimplification, but it can be generally stated that the steam flow is directly proportional to both the ΔT and the mass flow of the feedwater.

A secondary source of heat is drain water cascading from high pressure to low pressure heaters and/or moisture separator drains. In the case of the deaerator, secondary heat sources include,

a) Main Steam via PCV's at low turbine loads;
b) Electric immersion heaters near the bottom of the storage tank;
c) The use of the boiler feed pumps in the recirculation mode.

These U-tube feedwater heaters are vented to the Main Condenser to remove all non-condensable gases. The condenser is used as it is the lowest pressure point in the cycle and pressure in these heaters can be subatmospheric at very low loads and during startup. The deaerator is normally vented to the atmosphere as its pressure is usually > atmospheric.

U-Tube Feedwater Heaters

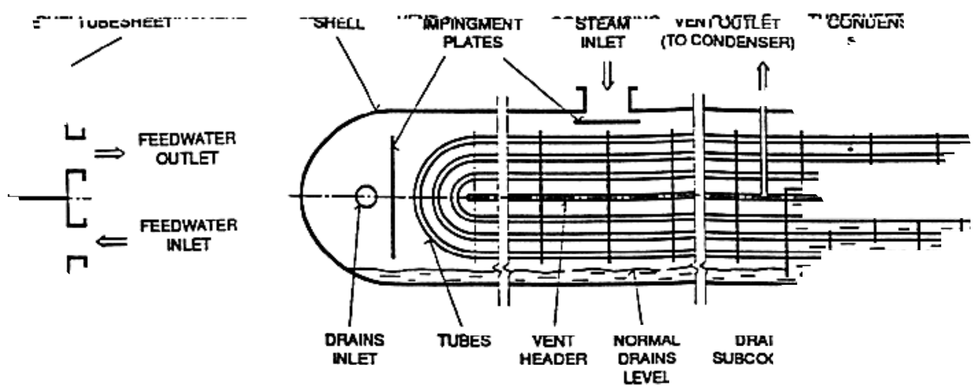
The U-tube heaters are equipped with two drainage lines. In the normal level range the drains cascade from the next upstream heater. At low loads the steam pressure difference between heaters is low. This condition as well as tube leaks and process upsets cause the level to rise above normal and a second drain line opens up to some lower pressure device (often the main condenser).

Both the low and high pressure heaters are split into two streams and each stream is capable of approximately 66% to 100% of full feedwater flow depending on the station design.

Over pressure protection on the feedwater supply side (U-tube side) is supplied by low capacity relief valves. They are located on the heater side of the heater isolation valves and supply this protection for expansion of water on the U-tube side while the heater is isolated. The shell side is protected by high capacity safety valves. Over pressure protection is covered in more detail in a later section.

The extraction steam supply line to each H.P. heater has a check valve (non-return valve) with a power assisted close feature (see Section 3.2.4). These valves are given a spring assist to close on a turbine trip and/or a high heater level. This feature can be tested in operation.

Figure 3.5
Simplified Horizontal U-tube Feedheater

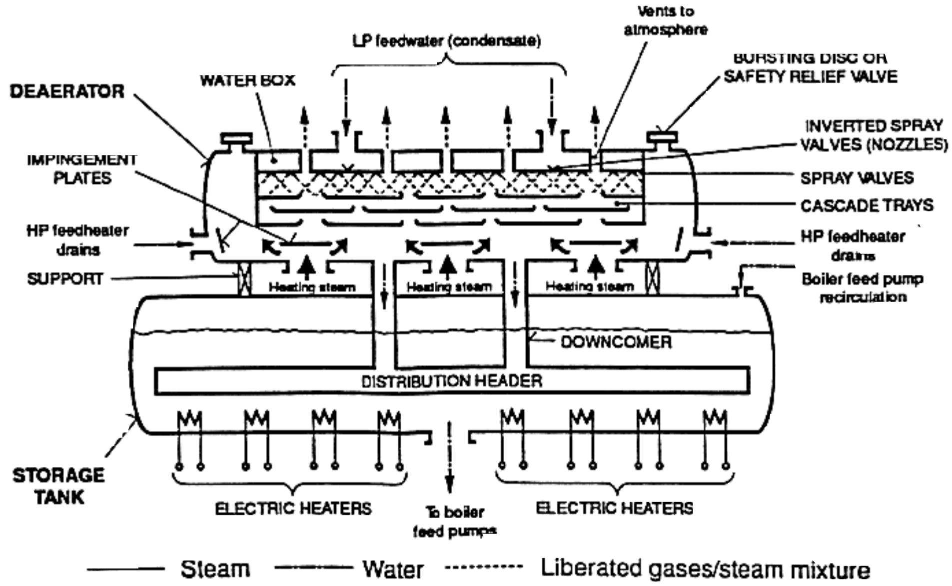


The Deaerator
The deaerator and it's associated storage tank are very large pressure vessels. To meet the required boiler feed pump NPSH they are located 30 to 35 metres above the boiler feed pumps. This is the only source of water to the boiler feed pumps and must be heated to a minimum value (about 130°C) for protection of the steam generator. The normal heat source is extraction steam from the turbine which mixes with the condensate as it is sprayed into the deaerator section. As a backup during low loads and turbine upset, steam is supplied from the main steam line to different lines called Startup Steam lines and Poison Prevent steam lines. The loss of significant turbine load mode of operation is commonly called "poison prevent". During shutdown conditions the storage tank is kept warm via electric emersion heaters.

The extraction steam supply line has two power assisted close check valves in series (see section 3.2.4). The one near the turbine is activated by a turbine trip and the one near the deaerator is activated by very high level in the deaerator. On a turbine trip or high heater level the air is removed from the air assist piston and allows a spring to place a closing force on the check valve (NRV).

The deaerator is also the place in the feedwater system where hydrazine is injected. Hydrazine is an oxygen scavenger and by injecting hydrazine between the D/A and the D/A storage tank the hydrazine can control any excess oxygen in the feedwater circuit.

Figure 3.6
Simplified Deaerator and Storage Tank assembly



3.2.3 Boiler Feed Pumps

The boiler feed pumps have a horizontally split casing with multi-stage impellers. These centrifugal pumps are built with very close tolerances and require a minimum flow of at least 30% to cool and lubricate the pump's internals. Loss of the minimum flow for greater than a few seconds usually results in a seized pump. Inlet flow is monitored and automatically opens a recirculation valve which returns the minimum flow back to the deaerator storage tank. The motors for the main pumps are totally enclosed and require an external cooling water supply. The auxiliary pump motor is air cooled and thus does not require an external cooling supply during emergent use.

The pumps handle relatively hot water (in the 150° to 160° C range) and therefore require a high NPSH. This high NPSH is obtained by locating the deaerator storage tank some 30 to 35 metres above these pumps. Under upset conditions it is possible to have insufficient NPSH which can cause loss of suction to these pumps. This problem is discussed more fully in a later section.

The auxiliary (3%) boiler feed pump is powered by Class III power and can deliver feedwater from the deaerator to the steam generators to provide long term reactor decay heat cooling.

The Steam Generator Level Control Valves

Because of maintenance and flow range requirements each of the steam generators has three parallel feedwater control valves. One of two main control valves, each having a capacity of 110% full flow, are used to control feedwater for on power conditions and one start-up control valve, having a capacity of 15% full flow, is used for start-up and shutdown conditions.

To enable any control valve to be isolated from the system, manual shutoff valves are mounted downstream of each feedwater control valve. Similarly motorized shutoff valves are mounted immediately upstream of the feedwater control valves. The control function of these control valves is covered briefly in section 4, Steam Generator Level Control.

3.2.4 Protection of Water system Components

Overpressure Protection

Feedwater heater overpressure protection is supplied by steam safety valves on the steam side of the heat exchangers. With the exception of the deaerator the shell side of the heat exchangers pressure will not exceed the extraction steam supply to the respective heater and these heat exchangers have been designed for full turbine load pressure. (extraction steam line pressure is proportional to turbine load.) As stated in the earlier discussion of feedwater heaters these heaters reach an equilibrium steam flow and should not exceed the turbine extraction steam supply to the heater. The possible causes of shell side overpressure are;

a) A "U" tube leak where the feedwater or condensate is entering the shell side at a rate greater than the drains flow.
b) The loss of one or more rows of blades of the turbine upstream of the extraction steam take off point.

The deaerator has a backup steam supply (Poison Prevent) from the main steam line and a malfunction of this system as well as b) above could cause an overpressure in the deaerator. As the deaerator is a direct contact heater there can be no condensate tube leak, but a condensate overpressure condition could occur on a failure of the level control system which would result in total flooding of the heat exchanger. Over pressure protection is provided by:

a Pressure Control Flow Orfices during normal operation
b Safety Valves
c Rupture Discs

As mentioned earlier, the tube side of the heat exchangers are protected with low capacity relief valves. Their principal use is to protect from fluid expansion during a heat exchanger isolation. They will also lift during pressure transients caused by surging (water hammer) from the rapid filling of the feedwater piping and heat exchangers.

Back or Reverse Flow Protection

The turbine has protective devices to prevent overspeeding etc., but with the exception of the power assist close extraction steam check valves are not covered in this lesson. The shell sides of feedwater heaters contain considerable stored energy in the form of hot water, (the deaerator is the largest stored energy device outside of the reactor building). On a turbine trip the machine tends to overspeed due to its trapped steam, within the rows of blades and in its reheater and extraction steam lines. To prevent a back flow of steam and/or water (shell flooding) check valves are installed in the extraction steam lines. The higher energy lines are also equipped with a check valve closing assist device. This device has an air piston which compresses a spring and allows the valve to perform as a normal check valve. When this device is activated by a turbine trip and/or a very high level in the associated feedwater heater the air piston is depressurised. This action allows the spring to impose a closing force on the check valve.

These closing assist devices are capable of being tested on load. During the test the check valve will partially close until the spring closing force matches the opening force on the check valve disc caused by the pressure resulting from throttling the normal extraction steam flow to the respective heater. This test does not stop all flow to the heater (an unacceptable event) but does prove that the check valve is free to operate.

4. Comparison Between CANDU 6 and Ontario Hydro Stations

Steam Systems
At Bruce B there are four steam lines going from the eight steam generators to the turbine. The steam lines from the pair of steam generators at each reactor face in each loop are joined together near the steam generators. Darlington A and the CANDU 6 stations each have four steam lines from four steam generators.

Darlington A, Bruce B and recent CANDU 6 designs have remote manual main steam isolating valves on each steam line. The other stations do not have main steam isolating valves.

Emergency Water System
The Emergency Water Systems on the Darlington A, Bruce B and CANDU 6 stations provide feedwater to the steam generators. The systems are brought into operation if the main steam generator feedwater system and the auxiliary feedwater system are unavailable.

Darlington A has a steam generator emergency cooling system designed to provide an interim water supply to the steam generators following a postulated main steam line rupture and/or loss of the feedwater supply until the emergency service water system is available. The system consists of two air accumulators pressurized by instrument air and two water tanks. An accumulator and water tank supplies two steam generators. This function is performed by a piping connection to the reactor building dousing tank on the Bruce B and CANDU 6 stations.

Steam Generator Blowdown
Darlington A, Bruce B and CANDU 6 stations are designed with a steam generator blowdown system capable of continuous blowdown of 0.1% to 3% of

the steaming rate. The maximum blowdown rate would is used when system chemistry conditions are unsatisfactory.

At Darlington A and Bruce B, an intermittent blowdown circuit is provided in parallel with the continuous blowdown. It has a capacity of 3% of steaming rate and is used when continuous blowdown is inadequate to maintain chemistry control. Only one steam generator can blowdown by the intermittent system at a time.

The water extracted from the steam generators is discharged to the condenser cooling water discharge. In some cases part of the energy in the blowdown system is recovered to help heat the incoming cooling water.

5. Simplified Control

5.1 Steam Generator Level Control

The steam generator level control (SGLC) maintains the water-steam interface at or near a specified setpoint in the steam generator. Steam demand is the principal factor influencing the control of this setpoint. The SGLC system attempts to maintain roughly constant steam generator inventory (constant mass inventory) rather than a constant steam generator level. This approach makes use of shrink and swell calculated by the computer as a feed forward term to maintain stability during large power changes. This results in a level control which varies with reactor power. This arrangement has the advantage of providing a considerable range of level within the safe high and low level limits, as well as reducing the required steam drum size.

The steam generator level is controlled at a computer generated set-point, variable with reactor power, by the so-called 3-element level control system, i.e., the feedwater control valve is regulated by three variables, steam flow, feedwater flow and steam generator level. Station load change is detected as steam flow change and fed forward as a primary index for the feedwater flow change (fast loop). The steam generator level is a feedback system (slow loop) which trims feed valve position for fine level control.

Each steam generator has two sets of triplicated level measurements, one for levels above 25 cm and the other for levels below 25 cm.

The level controller operates in two modes:
- 3-element mode,
- Single element mode (no feed forward).

On increasing power, the controller switches to the 3-element mode when the steam flow exceeds 25%. But on power reduction the controller returns to the single element mode when the steam flow drops below 20%. In the single element mode, the system responds to level signals only. At low loads, the steam and feedwater flow signals are not considered accurate enough for control.

High and low steam generator levels are annunciated in the control room. At levels higher than the alarm level, the turbine trips, and the CSDVs trip. At levels lower than the alarm point, there is a reactor power setback and/or a reactor trip.

This is discussed in greater detail in another lesson

5.2 Steam Generator Pressure Control

The energy level in the steam generator can be measured by monitoring the steam generator water temperature or the steam generator pressure. The easiest and most convenient variable to measure is the pressure. As a consequence steam pressure is used for control. The steam generator pressure and consequently temperature will change when;

a) heat input > heat output (both rise),
b) heat input < heat output (both drop),
c) heat input = heat output (no change),

Case a) above occurs when;

i) the heat transport system is warming up,
ii) the turbine trips or has a load rejection,
iii) the turbine is unloading with reactor power following
iv) the unit is loading with the reactor power leading

Case b) above occurs when;

i) during cooldown of the steam generator and the heat transport system,
ii) a reactor trip,setback or stepback occurs
iii) the unit is unloading with reactor power leading,
iv) the unit is loading with turbine leading,

Case c) above occurs in any steady state condition.

The steam generator pressure control program (SGPC or BPC) will attempt to maintain the pressure at the set point. It will also change the steam pressure set point for warmup, cooldown and will ramp the set point in proportion to load. This control is exercised by controlling the heat input (reactor power (Normal Mode)) or by controlling the heat output by controlling the turbine load, or the opening of the CSDVs or the ASDVs (Alternate Mode).

This is discussed in greater detail in another lesson.

Control of ASDVs

Each of the four ASDVs has a three position handswitch (CLOSE-AUTO-OPEN).

In the AUTO position these valves are controlled by the station digital computer via the Steam Generator Pressure Control (SGPC) program. The program demands a valve opening proportional to the pressure error with respect to a setpoint. The setpoint is kept higher than the normal operating pressure so that under normal operating conditions these valves are closed. In the AUTO position the valves can also be controlled manually through a computer keyboard instruction.

In the CLOSE or OPEN position the valves do not respond to the SGPC signals, but open or close and remain in that position even after a turbine trip.

The ASDVs close on failure of air supply or when both computers are unavailable.

Control of CSDVs

One common 2-position (CLOSE/RESET-AUTO) handswitch has been provided for all the twelve CSDVs. In the CLOSE/RESET position the valves do not respond to any computer signals but will close and remain closed even after a turbine trip. In the AUTO position, the valves are controlled by SGPC as follows:

a) During normal operation they are on pressure control with an offset in setpoint to bias them closed.
b) On a turbine trip, the offset in the setpoint is removed and the valves open automatically. They revert to pressure control after they have opened fully.
c) During poison prevent mode of operation, their steady state opening is proportional to the power mismatch between the poison prevent level and the actual turbine steam input.
d) Their opening is limited (override) by the software CSDV vacuum unloader.

They can also be opened through computer keyboard instruction.

In addition, there is a hardware trip facility which trips these valves closed to protect the condenser in case of:

- Low condenser vacuum (only the CSDVs associated with the condenser which has low vacuum are tripped).
- High level in any steam generator (all CSDVs are tripped).

The CSDVs close on failure of Class II control power or both computers.

5.3 Condenser Level Control

The condenser hotwell and/or a condensate makeup system are used to absorb the shrink and swell of the boiler/feedwater circuit. They are also required to make up any losses from the boiler/feedwater circuit. Under heavy loss conditions demineralized water is also available from the demineralized water storage tank to supply the Condensate Storage Tank.
In normal operation there is a small exchange of water between the condenser

hotwell and the condensate storage tank. If the hotwell level is slightly below normal then the make-up will open to correct the level. This is the normal mode of operation. Make-up is required for, steam generator blowdown, steam losses, and losses from the condensate cycle. If the level drops well below normal the large capacity emergency make-up valve opens. This can be the result of ASDVs opening, excessive boiler blowdown, or a significant leak in the steam/feedwater cycle. An above normal level can be caused by warmup (swell) which is usually of a short term nature, or a flow failure in the feedwater circuit. This latter circumstance requires immediate operator action to rectify the problem. Another serious cause of increase in the normal level of the steam/feedwater could be a steam generator leak with the resultant ingress of radiological contaminants into the secondary side.

5.4 Deaerator Level/Pressure/Temperature Control

Deaerator Level Control

The deaerator storage tank is the reservoir of hot water required for the Boiler feed pumps and is usually sized to contain at least a five minute full load feedwater supply. The level must be maintained as high as possible to meet this requirement (typically 75% level), but must not be so high as to cause flooding of the deaerator section under normal and abnormal operating conditions. Sudden or rapid flooding will damage the trays in the deaerator, while very high level will make the heater section ineffective and could lead to water passing to the turbine below.

The level is controlled by adjusting the condensate inflow via two of the three 50% LCVs. There is also a second small LCV installed on the separate auxiliary condensate extraction pump supply line. In newer stations at significant loads the level control system uses the three element control principle, where the incoming flow is matched to the outgoing flow with the tank level acting as a trim control. This method anticipates the required flow without waiting for a level change to adjust the LCV.

Deaerator Pressure Control

The normal mode of pressure control is the self-regulating equilibrium process mentioned in section 3.2 (Feedwater Heaters). On startup, shutdown and upset conditions main steam is used to supply the heater with the energy to heat the feedwater. The control system is simple in that it automatically supplies throttled main steam when the deaerator pressure drops and thus maintains a temperature >> 100°C. Whenever the extraction steam pressure exceeds this set point the main steam control valve closes.

The steam flow demand to maintain pressure at startup and in the poison prevent mode is very significant and two PCVs are provided to supply this flow. A small PCV is used for startup, while a much larger PCV comes into operation in the poison prevent mode.

A sudden loss of normal steam supply along with a high demand for feedwater can cause a very rapid boiling within the storage tank as the hot stored water rapidly boils to maintain its saturation pressure. Considerable damage to both the deaerator and the associated feedwater system can result, therefore the PCV is made to respond quickly, but because of the excess demand it may not be capable of maintaining the desired pressure. (see also section 7 on the Turbine).

Deaerator Temperature Control

The feedwater system has an operating requirement of a minimum of 130°C for the protection of the steam generator preheater. Under normal operation the deaerator temperature is 136°C (a function of extraction steam pressure) and the downstream temperature after the H.P. heaters is ≈ 170°C. If steam is available at the balance header deaerator pressure (hence temperature) is controlled as described above. The deaerator storage tank is equipped with electric immersion heaters and they are capable of maintaining the required minimum temperature under no flow conditions.

5.5 Control of Feedwater Control Valves

Control of the level in each steam generator is through one of two main (110%) feedwater control valves and a startup control valve (15%). Associated with each steam generator is a two position handswitch to select either of the two main feedwater control valves.

As the feedwater demand, as determined by the boiler level controller, rises from 0%, the small valve supplies the demand up to 13% of full demand. When the demand exceeds 13% the selected main feedwater valve opens equivalent to 13% full demand and the startup control valve closes at the same time. To avoid unnecessary changeover of control from the startup control valve to the main control valve and vice versa, a hysteresis has been provided at the changeover point. On falling feedwater demand, the valve changeover takes place at 8% full demand instead of 13%.

The main control valves fail closed on loss of air supply or loss of both computers, while the startup control valves fail open under these conditions.

On a steam generator high level the motorized valve upstream of the control valve of that steam generator will automatically close if the control switch of the motorized valve is left in the `AUTO' position.

6. System Operation

Overview
This section gives a very brief description of plant operation with emphasis on the steam/feedwater systems.

6.1 Shutdown

In the shutdown state, the HT system is cold (less than 100°C), the steam generator water temperature is less than 100°C, the levels are at ~-100 cm and the steam space is filled with nitrogen at a pressure of 10 cm H_2O gauge to prevent the ingress of air.

6.2 Startup (Warmup)

With the 3-position SGPC mode handswitch (WARMUP-HOLD- COOLDOWN) in the WARMUP position, the desired temperature rate of increase is selected via the computer keyboard. WARMUP up to 177°C is achieved by manually setting reactor power in the ALTERNATE mode at a level for allowable maximum warmup rate. Alternately the Heat Transport Circulating Pumps can be used to heat up the system using pump heat. Above 177°C the ASDVs have reasonable discharge capacity and are used to modulate the boiler pressure to achieve the desired warmup rate. The maximum allowed rate of increase of temperature is 2.8°C/min in order to avoid excessive thermal stresses in the steam generators and associated piping.

When the warmup is in progress, at 100°-105°C, the nitrogen supply is isolated, and then steam line drains are opened to warmup the steam lines and the header in parallel with the steam generators.

Figure 6.1 shows major activities during startup and loading of the steam and feedwater cycle systems. This is a dynamic phase for these systems and has a higher than normal risk of system upset and/or equipment damage. To reduce these risks the operator is equipped with a detailed startup plan, which of course is much more detailed than figure 6.1. A few examples of what is occurring during the steps are;

a) step 1-4 requires the use of the auxiliary condensate pump to fill all the system piping and equipment without water hammer,
b) step 4-5 will fill the system and may also be needed to raise the deaerator temperature to a value which will meet the required ΔT limits of the preheater section of the steam generator,
c) step 5-5a-9 if not carried out correctly can result in exceeding thermal warmup rates as well as very serious steam/water hammer in piping and equipment.

6.3 Operating State (Hold)

At the end of the warmup (when steam pressure is 4.55 MPa(a) the SGPC mode handswitch is selected for HOLD mode and the steam generator pressure is controlled to a setpoint equal to the pressure before the mode switch was turned from WARMUP to HOLD.

The steam generator feedwater system supplies the water requirement of the steam generators for power manoeuvring. The steam generators are blown down continuously at 0.1% to 3% to control the boiler water chemistry.

6.4 Cooldown

Figure 6.2 shows major activities during unloading and shutting down of the steam and feedwater cycle systems. This is a dynamic phase for these systems and presents a higher than normal risk of system upset and/or equipment damage. To reduce these risks the operator is equipped with a detailed shutdown plan, which of course is much more detailed than figure 6.2. Steps 1-3 can also be an unplanned event!

After unloading and tripping the turbine, cooldown of the system is started by selecting the SGPC mode switch to COOLDOWN. The SGPC ramps down the pressure set point to achieve the keyboard entered cooling rate (2.8°C/min) from the operating temperature to about 177°C-180°C, by opening the CSDVs and/or the ASDVs. Cooling below 177°C-180°C, is most effectively done by the shutdown cooling system. When the steam generator pressure falls to near atmospheric a nitrogen blanket is applied to the steam space.

Figure 6.1

Major activities during startup and loading of the steam and feedwater systems

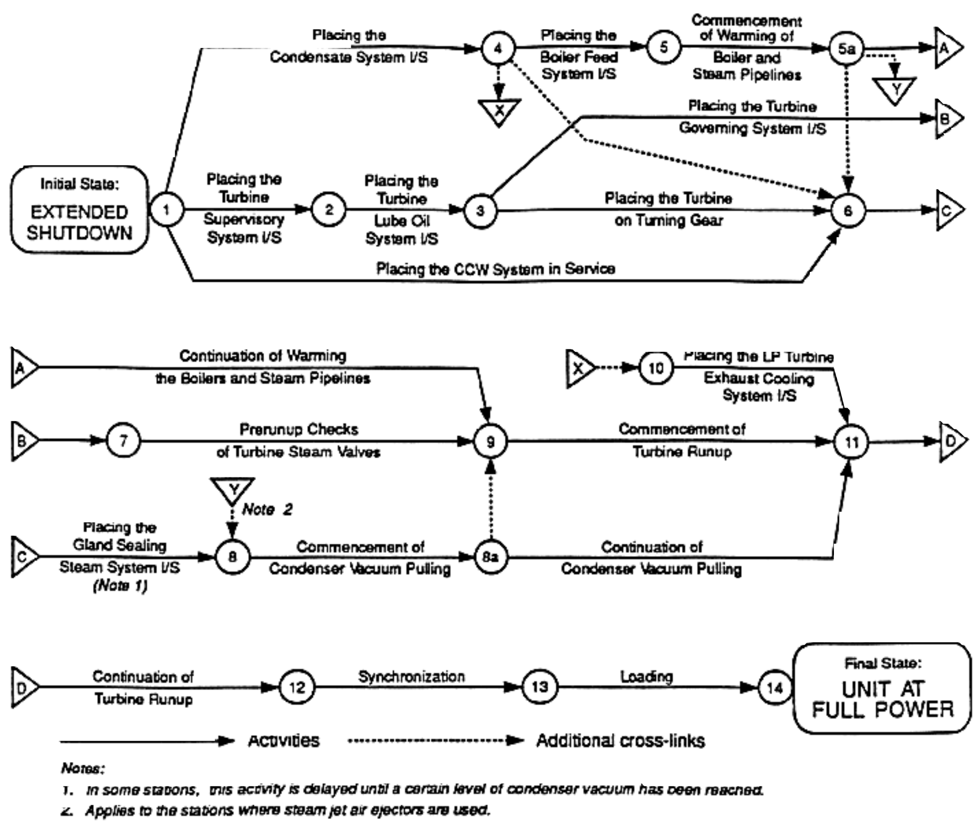
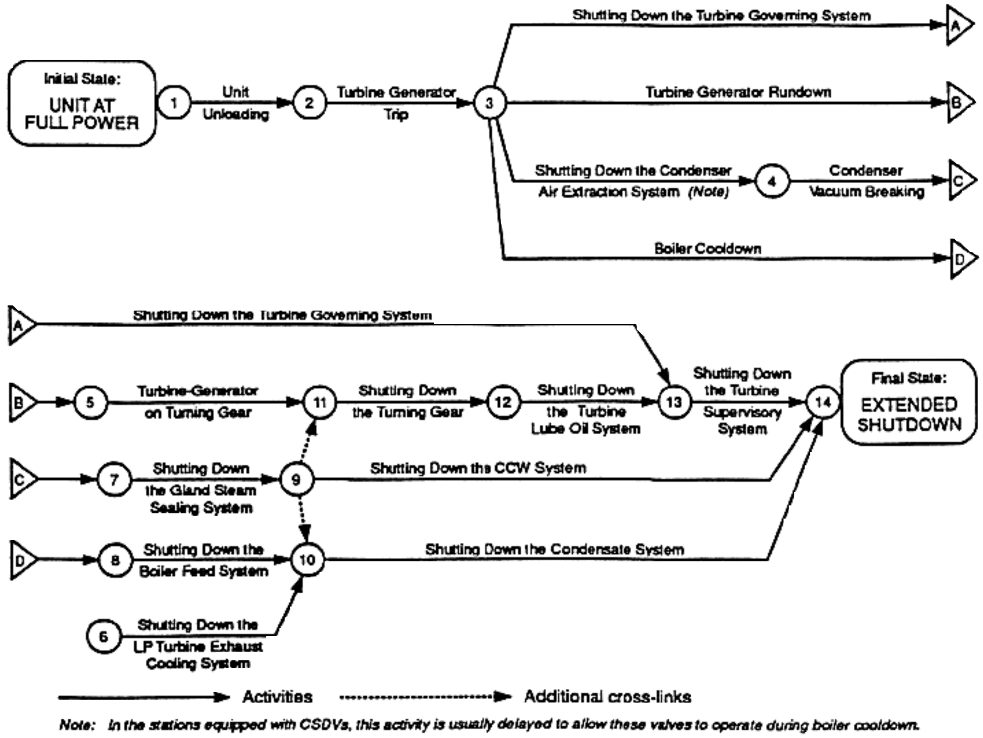


Figure 6.2
Major activities during unloading and shutting down of the steam and feedwater systems



6.5 Poison Prevent

A reduction in reactor power is accompanied by an increase in the amount of xenon in the fuel. Xenon is a strong absorber of neutrons and imposes a large negative reactivity load. If there is any significant delay in raising reactor power this excess xenon is not burned off and the xenon level continues to rise till the reactor has insufficient reactivity to maintain power. The reactor shuts down (poisons out) and a lengthy outage occurs until the xenon finally decays. Placing an artificial load on the reactor to prevent this poison out is Poison Prevent.

'Poison Prevent*' operation follows a turbine trip or a load rejection, provided other plant systems (eg. class IV power and reactor auxiliary systems) are operational. During Poison Prevent the turbine generator load will be 0% (turbine/generator trip) or about 6% (generator line breaker open, but still supplying station service). The reactor power is maintained typically at 60 to 70 % full power by discharging steam to the condenser (CSDVs). Steam will also be supplied to the deaerator to attempt to maintain the deaerator temperature. Additional steam can also be discharged to the atmosphere, but this is undesirable as it results in a loss fluid from the steam/feedwater cycle.

Operation in this mode is relatively short term. If the problem, loss of line or turbine trip, cannot be rectified in a reasonable time then poison prevent will be terminated with the shutting down of the reactor. Other processes can also cause termination of Poison Prevent, for example the steam generator preheater ΔT limit or the inability of the condenser to cool and maintain condenser vacuum when operating in this manner.

When the problem requiring operation in the Poison Prevent mode is rectified then as the turbine reloads the poison prevent steam load gradually reduces to zero until the turbine has taken it up. This operation is almost transparent to reactor power which is still in the 60 to 70 % range. The rest of the turbine loading will be accomplished by raising reactor power to pre-incident level.

6.6 Auto-Depressurization

Auto-depressurization of the steam generator secondary side is required in response to the following situations:

a) After a loss of the normal feedwater to the steam generators, due to a total loss of Class IV and Class III power disabling all the feedwater pumps.
b) After a loss of the normal feedwater to the steam generators, due to physical events such as a piping failure an incorrect valve lineup (operator error) etc.
c) Very low steam generator level in two or more steam generators with low feedwater supply pressure.
d) The requirement of the ECC system.

If action is not taken to obtain alternate sources (EWS and dousing tank) the steam generator pressure will be held at the set pressure of the MSSVs until steam generator dryout occurs.

All of the above events require rapid depressurization of the steam generators to allow the alternate low pressure sources of feedwater to supply water to the steam generators as a heat sink to keep the fuel cool. Any of the above events also causes an immediate reactor shutdown.

7. Interaction with other Systems

Interdependencies with other systems

This section covers the requirements imposed by the main steam supply and feedwater system on the interfacing systems. It also describes some upsets and/or cautions which may result on upsets in these other systems.

Heat Transport System

Boiler Pressure cannot be less than the saturated temperature equivalent of the heat transport (outlet header) temperature. Thus unlike conventional boilers where over pressure can occur when energy in is > energy out, this can only happen in a Candu Station by a rise in heat transport temperature. Thus a change in one system will cause an immediate change in the other.

Examples are:

1) If the energy out of the boilers is greater than the energy in, the boiler pressure will fall, and consequently the saturation temperature drops

causing a lowering of the average heat transport temperature.

2) A sudden increase in feedwater flow or a lowering of feedwater temperature will result in an immediate lowering of the heat transport (inlet header) temperature due to heat transfer in the preheater section of the boiler. Both the conditions cause a shrinking action which tends to drive the heat transport pressure down.
3) If the energy out of the boilers is less than the energy in, the boiler pressure will increase and consequently the saturation temperature rises causing an increase of the average heat transport temperature. This causes a swelling action in the heat transport system which tends to drive the heat transport pressure up.

From the above examples it can be seen a change in one system will cause an immediate change in the other. This interaction is quite pronounced and necessitates several enhancements to the control systems.

Steam Generator
In the event of a steam line break or an auto-depressurization, the resultant pressure transient should not cause any damage to the internal structure of the steam generator as it has been designed for this eventuality.

Carryover is the entrainment of boiler water or gaseous impurities in the steam leaving the steam drum. There are four types of carryover: mist (normal), priming, foaming, and volatile. The first three being water will therefore contain the same impurities that are present in the boiler water. These impurities can deposit out on turbine blades reducing the turbine efficiency. They can also be deposited on moving parts of equipment and there have been cases where they have deposited on valve stems. These deposits on Emergency Stop Valves have resulted in these valves failing to close when required.

Improper Steam Generator level can cause significant effects on other systems, and they are outlined below.

- High Drum level can cause increased carryover of water with its associated impurities from the boiler water (both gaseous and solids) and these can lead to chemical problems in lines, valves, the turbine and condensers. Water carried in steam also greatly accelerates erosion of piping, valves, turbine blades etc. Remember that the design carryover is ≈ 0.25% and sounds small but this is equivalent to a carryover of 216 Mg. of water per day. At very high drum levels carryover can be high enough to carry slugs of water to cause steam line water hammer and/or turbine blade failure. The turbine is protected by a "very high drum level" trip.
- Low Drum level can jeopardize reactor cooling by the uncovering of the steam generator tubes thus reducing the heat transfer. It will also decrease the post-accident heat sink (on loss of feedwater the operator has less time to secure alternate cooling). Low level also reduces the margin to trip and

spurious trips could result from even minor level fluctuations.

Emergency Water System
The main steam supply and feedwater system requires the emergency water system to provide feedwater following a total loss of main feedwater.

D_2O in H_2O Detection
The main steam system is connected to the D_2O in H_2O detection system from each steam line to permit detection of higher than normal levels of heavy water in the steam. Each sampling line includes a low pressure, low temperature grab sample valve. These samples are used for periodic assessment of condensed steam chemistry and tritium in steam measurements and also serve as indication of a steam generator tube leak.

Instrument Air
On the loss of instrument air the steam/feedwater system components must assume a fail safe state. Some examples are;
a) the steam generator main level control valves will fail close, while the start-up control valve will fail open.
b) the extraction steam air assisted check valve will be subject to a spring closing force.

Main Condensers and Circulating Water System
The main steam system requires that the condenser be able to operate under conditions where there is increased thermal load due to 100% main steam bypass for a few minutes and 60% steam flow continuously. To remove this heat the Circulating Water System must be in operation.

Reheater
The main steam system has connections to provide live steam to the reheaters. Tube leaks in the reheater heat exchangers are of serious concern as they represent a bypass of the turbine governing system. They could cause turbine overspeed problems at little or no load on the turbine or during turbine shutdown.

Turbine
The main steam system provides steam to the high pressure turbine. Upset conditions (turbine trip, sudden loss of load etc.) can have dramatic effects on the steam generator, feedwater and heat transport systems. Many special control features are used to minimize these disturbances. The major upsets on the steam/feedwater systems are briefly discussed in point form below;
- If steam is discharged to the atmosphere a large condensate makeup is required,
- In conventional boiler/turbine cycles this sudden loss of load results in;

a) a rapid rise in boiler pressure,

b) because of the rise in boiler pressure, a sudden reduction of the two phase condition in the steam generator (steam bubbles collapse) causes a rapid drop in the steam generator level,
c) because of b) a sudden increase of feedwater flow also occurs,
d) all extraction steam lines pressure has decayed (often to sub-atmospheric values) thus there is no feedwater heating,
e) because of c) the feedwater flow to the deaerator is > 100%
f) the high flow of cool feedwater to the deaerator, which has no steam supply, causes a very rapid reduction in the pressure of the deaerator storage tank and has been known to cause the still relatively hot water at the suction of the feed pumps to flash. This condition causes loss of suction and if maintained for many seconds can cause seizure of the running feed pump. A secondary concern is when this steam bubble collapses very severe water hammer can occur at both the feed pumps and at the deaerator.

In early Candu reactors a sudden loss turbine/generator load nearly always caused a reactor trip on low heat transport pressure. With the advent of programmed boiler level control, deaerator backup steam supply and the use of CSDV's these problems are not common now, but these problems tend to explain the need for these advanced control systems and devices.

Deaerator

The main steam system has a connection to provide pegging steam to the deaerator. (see above for upsets)

Other Balance of Plant (BOP) Steam Loads

The steam systems supply a few services to other BOP systems. The steam system often supplies steam for building heating usually via turbine extraction steam, or directly when extraction steam is inadequate. It also provides steam to other BOP loads including main steam sampling, auxiliary steam supply, turbine glands, and auxiliary feedwater pump turbine (if supplied).

The condensate system provides water to other BOP loads including L.P. turbine exhaust cooling, condenser cooling sprays and boiler feed pump gland injection. It may also accept condensate from the building heating system, but it must exert some quality control on this returned condensate. If the heating condensate is outside specifications the water is rejected and makeup flow increases (hotwell level control) to compensate for the fluid loss from the cycle.

Reactor Shutdown Systems

Signals are provided from the main steam system to SDS1/SDS2 for steam generator level and low steam generator feed line pressure trips.

Reactor Regulating System

Reactor power is controlled to a setpoint provided by the SGPC program.

8. Hazards

There are normally no radiological hazards associated with this system except the boiler or parts thereof that are located inside containment or confinement. A steam generator tube leak will allow radiologically contaminated heat transport water (D_2O) to enter the secondary cycle and has potential of becoming a hazard if the leak develops to a significant amount.

There are, of course, many conventional hazards as found in any power station. These hazards include high temperature, high pressure, rotating devices and chemical. Steam leaks are hazardous as they may contain an invisible high energy fluid as well as high temperatures.

The various systems are controlling enormous masses of energy. Loss of control of this energy can have very serious consequences. Some examples of loss of energy control are:

- Improper warming of equipment and pipe lines can result in over stress and possible failure of the device. Rotating equipment may seize and pipe line may vibrate and move large distances as a result of water hammer. There have been cases where the resulting water hammer has resulted in piping failure, equipment damage and personal injury.
- Failure of valves to perform their function can lead to overpressure in the case of safety valves and overspeed of rotating equipment in the case of trip valves (eg. the failure of a TSV and its associated Governing valve). This overspeed of rotating equipment can result in the generation of missiles when the speed of the device exceeds the design limits. A 60 MWe turbine reached 170% of normal speed in about 12 seconds after the generator tripped (generator breaker opened) while the trip and governing valves failed to close. The generator then disintegrated sending many missiles through the plant. Three people were killed and five were injured. Fortunately the destruction of the turbine/generator resulted in enough vibration to close the trip valves thus preventing the release of the boiler steam into the station with the potential of killing many more.

The above examples are not meant to scare people, but to emphasis the importance of having equipment in proper working order and proving it with adequate testing.

Control of Boiler Level

Training Objectives

On completion of this lesson the participant will be able to describe;

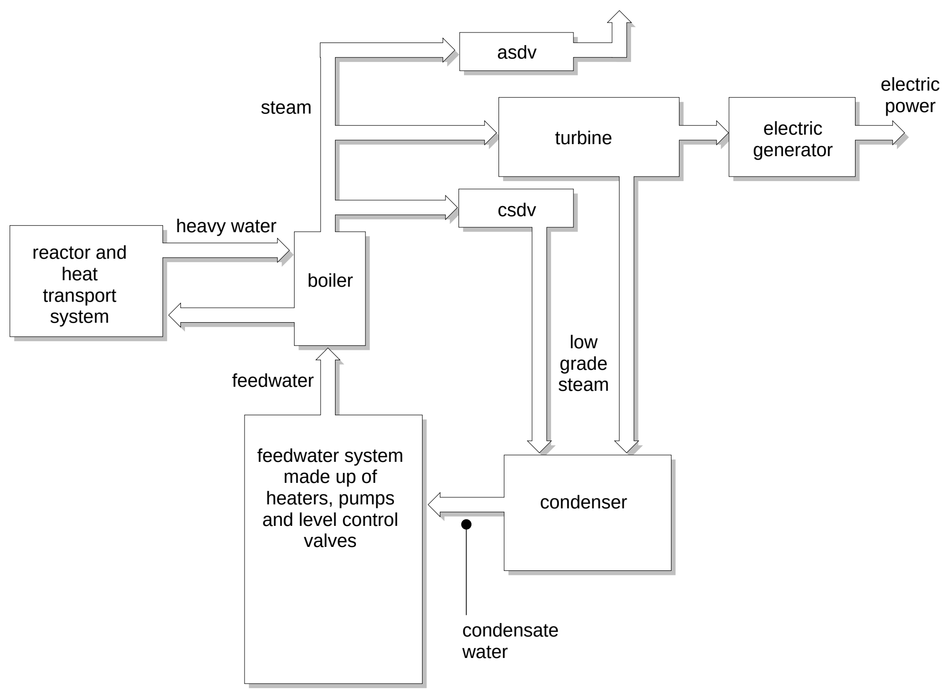
- The requirements of the steam generator level control system.
- The equipment and how it is used to control the level in the steam generators over the range from zero power hot to full power.
- The inputs to the steam generator level control programme and what purpose they serve.
- The information available in the control room to monitor the performance of the level control system.
- The action taken when the control is less than adequate.

Table of Contents

1.0 Introduction

The boiler provides a barrier between the radioactive water of the heat transport system and the non-radioactive water of the boiler steam and feedwater systems. The boiler is the connecting piece between the nuclear and the non-nuclear parts of the overall plant process. The components in the overall plant process are shown in Figure 1. A failure of the tubes in the boiler could lead to contamination of parts of the power house and the release of radioactivity from the station during an accident. Within the boiler, heat is transferred from the reactor coolant, ie heat transport water (D_2O), to the feedwater (H_2O) and steam is produced.

Figure 1
Major Plant Components



The boiler level control is important because;

- the boiler is the heat sink for the reactor and too little water means the possibility of inadequate cooling
- the boiler is the source of steam for the turbine and too much water means the possibility of the steam flow carrying water over into the turbine and damaging it.

The boiler level is controlled as a function of power. It is raised with power to accommodate the swell due to increased voiding associated with increased boiling. By doing this, there is a minimum change in the mass inventory in the steam generator. The terms Boiler and Steam Generator are interchangeable. The information given is typical of a CANDU 6 reactor.

The level in each boiler is controlled by its own valve station consisting of three valves; two one hundred and ten percent (10%) control valves and one fifteen percent (15%) control valve in parallel. The smaller valve is used at low power. Two large valves are provided for redundancy. Each control valve can be isolated by a motorized isolating valve so as to prevent leakage when it is not in use.

Boiler level control is complicated by swell and shrink. For example, the effect on the boiler level of the addition of feedwater is delayed because the cool feedwater collapses voids in the riser which causes the level to drop initially.

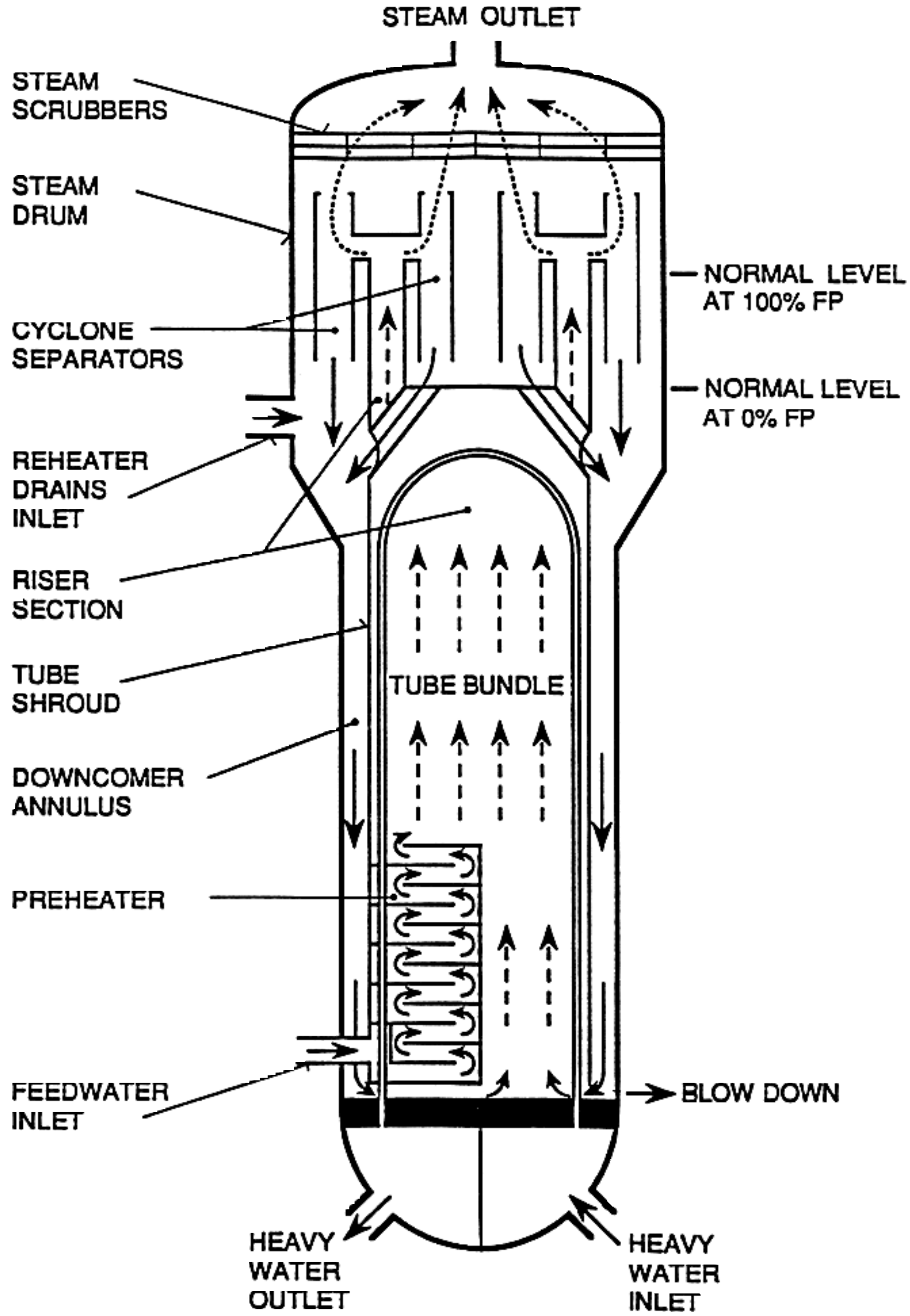
Level excursions in either direction can cause problems - an undue drop in level causes a reactor trip; an excessive rise in level causes a turbine trip (to protect the turbine from damage from a slug of water). On high boiler level, the CSDV also are tripped closed, as are the motorized isolating valves at the feedwater valve stations.

On program failure the large feedwater control valves close and the small control valves open. If at high power, this decrease in the supply of water to the boiler will initially cause a drop in the level, which will be followed by a reactor trip. The level then drops rapidly due to shrink. Eventually the level starts rising again as the feedwater supply through the small valves exceeds steam production. Eventually the operator has to intervene to avoid flooding the steam generators.

2.0 Boiler Operation

The CANDU 6 boilers are natural circulation, integral preheater, integral steam drum, inverted U-tube units. The components are shown in Figure 2.0.

Figure 2
Boiler Components



The reactor coolant passes through the U-tubes, boiling the secondary side fluid and creating two-phase flow around the tube bundle. The two-phase flow increases in quality towards the top. It then passes through cyclone separators. The two-phase fluid is separated into dry steam which passes out of the boiler by the steam outlet pipe and saturated liquid which returns to the bottom of the tube bundle via the annular downcomer, thus completing the circulation loop.

To replace the outflow of steam, feedwater is pumped into the preheater. It is the difference in static head between the saturated downcomer fluid and the less dense two-phase flow in the riser which creates the driving force for natural circulation within the steam generator.

During a power increase more steam is produced around the tube bundle. Since this is a fixed volume, the liquid which the steam is replacing is forced into the steam drum, and the change in power is reflected by a increase in water level. Similarly, if power goes down, so does the level. It is the change in drum water level that is referred to as "swell" during power increases and "shrink" during power decreases.

The easiest way to accommodate shrink/swell during transients is to operate the boiler using a "constant mass inventory" approach. As long as the amount of feedwater entering the boiler at any time equals the steam flow leaving, the power can be varied at any rate and swell will be accommodated within the steam generator. Once this "constant inventory control line" is established, any power manoeuvre up or down, regardless of rate, will simply result in the boiler water level moving up or down accordingly on the control line.

3.0 Boiler Level Control Design Requirements

The functional requirements of the boiler level control system are;

- to balance feedwater flow to steam flow while maintaining the boiler level at the desired setpoint.
- to vary the level to cope with boiler swell or shrinkage during load variation.

The control programme must be able to accommodate normal and abnormal operating conditions. These conditions include;

- normal steam flow to meet power setpoint
- manoeuvring rates of up to 4% present power per second. This rate is significantly greater than the loading rate of the turbine.
- manual control of feedwater flow while shutdown, warmup or cool-down periods
- operation of second feedwater pump or closing or opening of feedwater pump recirculation valves shall not cause an excessive transient change in boiler levels.

There are three ranges of level measurement; narrow, medium and wide.

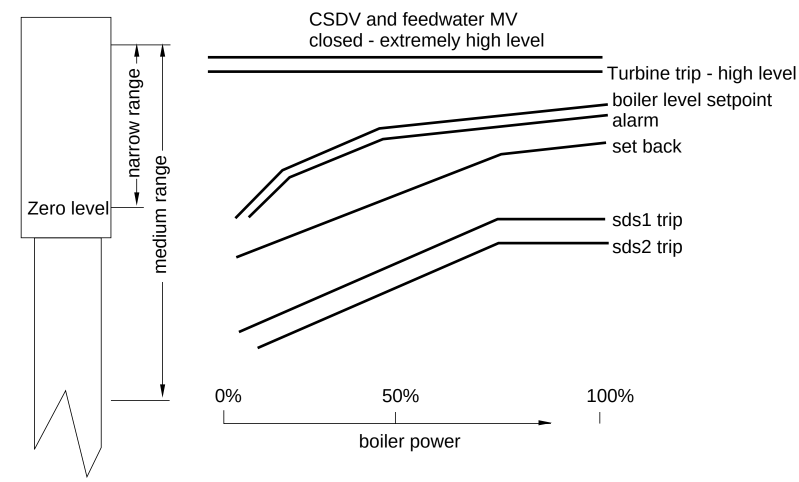
- The narrow range boiler level measurements are triplicated on each boiler and provide the following information or logic:
- Input to the boiler level control program, turbine trip logic, feedwater motorized isolation valve closing logic and condenser steam discharge valves (CSDV) closing logic.
- Level indication and level error indication in the control room
- High level, very high level and low level annunciation in the control room

- The medium range boiler level, triplicated on each boiler provide the following information and logic:
- Input to boiler level control program.
- Level indication and low level annunciation in the control room
- Wide range boiler level on each boiler provides;
- level indication in the control room and in the secondary control room.

Temperature and steam flow for each boiler is measured and supplied to the thermal power measurement calculation programme.

The alarm and trip points, and the level setpoint over the power range is shown in Figure 3.0

Figure 3.0
Action taken for different boiler levels



4.0 Boiler Level Control System Description

4.1 Instrumentation

4.1.1 Boiler Level Measurement (Narrow Range) for Control

Since the boiler level control directly affects plant reliability, triplicated measurements are used. The measurement has a full range of 3.5 m and measures the level above 0.2 m below the bottom of the separator arms. The transmitters are calibrated to the specific gravity of H_2O at the design operating condition of the boiler and the signal is corrected by the computer for variation in boiler pressure before being used in the boiler level control program.

The median of the three signals is used for the input to the boiler level control program. This program is described in 4.2..

One of the three measurements for each boiler is displayed on the control room panel.

4.1.2 Boiler Level Measurement (Medium Range) for Control

In order to avoid excessive high boiler level resulting from boiler swell when the boiler power increases rapidly from zero power to about 60% F.P., the boiler level is kept below the bottom level tap of narrow range measurement when the boiler is at the zero power hot condition. The earlier CANDU 6 units with smaller steam drums required this more so than the newer designs. Triplicated differential pressure transmitters are used for the medium range of boiler level measurements. The level is measured from 2.68 m below the zero of the narrow range measurements to the same upper level of the steam generator; the total range is 6.18 m . The signal from the level transmitters, corrected by the computer for variation in steam pressure, is used in the boiler level control program.

A signal from each transmitter, proportional to the boiler level, is transmitted to both computers for CRT readout on demand and low boiler level annunciation. The median of the three level signals is used as the input to the boiler level control program.

4.1.3 Boiler Level Measurement (Wide Range) for Monitoring

Each boiler has one wide range boiler level measurement for main control room CRT display on demand. The level is measured from 9.243 m below the narrow range zero level to 3.5 above that level.

There will be a large amount of error introduced in the measurement during normal operation due to the boiler downcomer flow. Therefore this measurement is not suitable for use during normal operation, but is used only during boiler maintenance after the reactor is shutdown.

4.1.4 Boiler Level Very High and Very Low Alarms

The protective action for very high boiler level is done by hardware logic while the protective action for very low boiler level is done by the computer.

Boiler Level Very High, and Extremely High

If the boiler water rises to the very high level, water carryover could damage the turbine. In order to avoid this, the turbine is tripped when any two level measurements on any boiler exceed the very high level setpoint.

When any two narrow range level measurements on a boiler exceed the extremely high water level (which is slightly higher than the very high water level), the main motorized feedwater isolating valve associated with that boiler is tripped closed. This trip signal does not affect the operation of the main motorized isolating valves on the other steam generators. Since the main motorized isolating valve is tripped at a level which is higher than the turbine trip level, feed water will be available after a turbine trip, preventing water level from falling to the reactor trip level.

When any two level measurements on a boiler exceed the extremely high water level, all the CSDV are tripped closed. Since this level setpoint is higher than the turbine trip setpoint the CSDV will be available on a turbine trip, to prevent lifting of the main steam safety valves.

Boiler Level Very Low

When any two mid range level measurements on a boiler fall below the reactor stepback level setpoint, a reactor power stepback is initiated. Further decrease in level will cause both shutdown systems to trip.

4.1.5 Steam Flow Measurement

The steam flow measurement is used in boiler level control when above 20% of full power, because of inaccuracy and noise at low flows. The steam flow measurement is also used in calculating reactor thermal power when the reactor neutron power is above 50% of full power. Below 50% of full power, ΔT measurements across the reactor are used.

Elbow taps for steam flow measurement have advantages of low cost, low pressure losses in the line, and acceptable repeatability. The taps are located outside the reactor building.

The inherent inaccuracy of elbow tap measurement can be overcome by calibrating the elbow during commissioning, using the accurate feedwater flow element. Thus the overall loop accuracy of elbow tap flow measurement can be expected to be close to ±1% at full power, and ±1.3% at 50% full power.

No alarm is associated with steam flow.

4.1.6 Feedwater Flow Measurement

The feedwater flow to each boiler is measured by a flow element located outside the reactor building. The feedwater flow transmitter provides the signal to both computers for the boiler level control program and for reactor thermal power calibration.

The flow element itself will be calibrated by the manufacturer to within ±0.25% inaccuracy or better.

The flow transmitter is calibrated at the normal full power operating temperature.

No alarm is required for feedwater flow measurements.

4.2 Boiler Level Control

The boiler level control program resides in the plant control computers.

4.2.1 General

The purpose of the boiler level control system is to maintain the water level at or near a specified setpoint in the steam generator. The major disturbances on boiler level are a change in steam demand or a change in reactor power. The first design objective is to provide control of mass balance, i.e., steam flow out and feedwater flow into the boiler as the primary control function, yet remain within the operational limitation of keeping the boiler level at the setpoint. The second design object is to compensate for the swell/shrink effect on the boiler level during power manoeuvring and pressure transients.

The boiler swell is very sensitive to power changes, particularly in the low power range.

4.2.2 Boiler Level Control System

There are four steam generators, and each has its own level control system, with its own steam flow, feedwater flow and boiler level signals.

To cover the range of control necessary and for maintenance considerations, each steam generators has a set of three parallel feedwater control valves. Two main control valves, each having a capacity of 110% full flow, are used to control feedwater for on-power conditions and one start-up control valve, having a capacity of 15% full flow, is used for shutdown and startup conditions.

To enable any control valve to be isolated from the system, manual shutoff valves are mounted downstream of each feedwater valve and motorized valves are mounted upstream of each feedwater control valve.

Signals from boiler level transmitters both narrow and medium range, feedwater flow transmitter, reheater drains flow transmitter and steam flow transmitter, are fed to the station computers which carry out the boiler level control and monitoring functions.

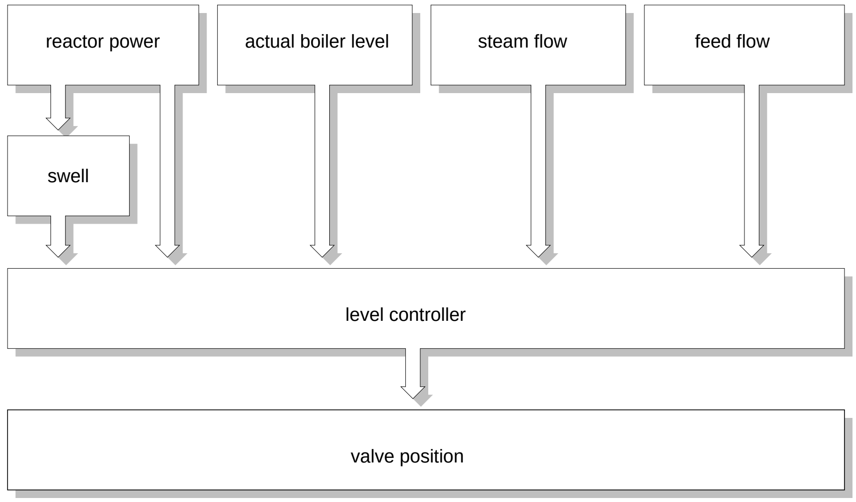
The setpoint of the boiler level controller is programmed as a function of power is shown in Figure 3.0.

This setpoint is based on constant inventory information provided by the boiler manufacturer.

4.2.3 Boiler Level Controller

Each boiler has its own boiler level control programme which consists of a level feedback loop corrected for steam and water flow, reactor power and an allowance for swell. Figure 4 illustrates the components of the level control programme.

Figure 4
Components of level control programme



Boiler Level
This term consists of a proportional and integral controller, which compares the level signal with the level setpoint and sends a corrective control signal to position the feedwater control valve for keeping the boiler level at setpoint.

Steam and Water Flows
At constant reactor power, the steam flow should be the same as the sum of feedwater and reheater drains flows, to maintain a steady stream generator level. This is the mass balance in the steam generator. The steam flow changes due to either change of turbine power or reactor power. The change of turbine power has an immediate effect on the steam flow.

Since the steam and feedwater flow measurements are not accurate and are noisy when the flow is below 20% F.P., this term is not used when the flow is below 20% F.P.

Reactor Power
During steady state conditions, boiler level error should be zero, and the steam flow is equal to the feedwater flow plus the reheater drains flow. The feedwater control valve is opened by signals from the reactor power term and the integral action of the boiler level feedback loop. The reactor power term is used to develop the boiler level setpoint.

Rate of Swell Term
The swell or shrinkage in the boiler during power manoeuvring is a function of the rate of change of steam flow. The rate of change of steam flow depends on the rate of change of reactor power with a time constant of about 20 seconds, the swell term is computed from the neutron power.

This term predicts boiler swell or shrinkage which must be recognized by the feedwater flow. Without this term, the feedwater flow control would initially react in the wrong direction, i.e.increased power would cause level to rise, and initially the feedwater would decrease only to have to come back to where it was and then increase further to match the increase power.

4.2.4 Feedwater Control Valves

Each boiler control system consists of two main feedwater control valves and one start-up feedwater control valve. The range over which the feedwater must be controlled cannot be readily satisfied by any single valve size so a small and a large valve are used in parallel. In addition, two main control valves are used to allow for on-power maintenance and testing.

The two large valves are designed to fail closed on loss of air supply or loss of both computers.

The start-up control valve is designed to fail open on loss of air supply or on loss of both computers.

The start-up valve can also be controlled by the operator from an auto/manual station on the main panel to facilitate control of level when the reactor is shut down or when both computers are not available.

Normally, one main feedwater control valve is used to modulate the feedwater flow, and the other valve is closed. The start-up control valve closes shortly after the main valve begins opening during startup. When the start-up control valve is used to modulate the feedwater flow, the two main control valves are closed.

4.3 Effects of Malfunctioning on other Systems

The following is a brief discussion on the effects of malfunctioning of other systems.

4.3.1 Class IV and Class III Power Failure

Three 50% boiler feedwater pumps are supplied from Class IV power and the 4% boiler auxiliary feedwater pump is supplied from Class III power. A total loss of Class IV and Class III power would stop the operating feed pumps, which results in the loss of feedwater supply to the steam generators. Approximately 4 seconds after loss of power, the reactor is tripped on heat transport system high pressure.

After a reactor trip, boiler water falls to a very low level due to the shrinkage in the steam generator.

About three minutes after loss of Class IV power, Class III power will be available from on site diesel generators, which results in the operation of the auxiliary feedwater pump. Feedwater is then supplied to the boiler as required.

The boiler level control program should bring the water level to the zero power level after reactor trip.

After total failure of Class IV and Class III power, both computers are still operating, and the feedwater control valves are still under normal control.

4.3.2 Partial Failure Of Feedwater Supply

Two main feedwater pumps are running during normal operation, with the third one on standby. When one operating pump is tripped, the standby pump starts automatically within 60 seconds. If the standby pump does not start, the operating pump can not meet the demand and the feedwater control valve will open fully due to the flow mismatch but the level will fall in any case. .

4.3.3 Failure Of Both Computers

Failure of both computers would result in the loss of the boiler level control system and the reactor would be shut down by its control devices.

This would close the operating main feedwater control valve and open the start-up feedwater control valve. The boiler water level would rise and eventually water could fill the steam lines. The operator must take action to prevent it. The boiler level can be manually controlled by the operator by means of the start-up feedwater control valves through their associated computer-manual stations on the main panel, and with the aid of the narrow and medium range boiler level indicators on the main panel.

4.3.4 Partial Failure of Boiler Level Control

The following failure conditions are considered as partial failures of boiler level control.

- Any one of the analog outputs to the main feedwater control valves fails to zero, which causes that valve to close fully. The operator has to switch to the standby main feedwater control valve for level control.
- Any one of the analog outputs to the start-up feedwater control valves fails to zero , which causes that valve to open fully. The operator would control start-up control valves through their associated computer-manual stations on the main panel.
- If the analog outputs to the main and start-up feedwater control valves fail full scale, the main feedwater control valve will open fully and the start-up feedwater control valve will close. This condition is annunciated as a computer analog output malfunction (this is done by computer software program). While the main feedwater control valves are open, the boiler water level will increase and the high boiler level alarm will come in. The turbine will be tripped on very high boiler level and the reactor steps back to 60% power. The CSDV open to discharge the steam to the condenser. The boiler level falls due to the void collapse in the boiler and rises again due to the full opening of the large feedwater control valve. As the water level rises

to the extremely high water level, the CSDV and the main feedwater motorized valves are tripped closed.

4.3.5 Loss of Instrument Air

The loss of instrument air to the feedwater control valves would result in the main control valves being fully closed and the start-up control valves being fully open. As a result the boiler level would fall to a very low level and a reactor power stepback would be initiated.

4.3.6 Loss of 40 V (dc) Instrument Power

If there is a failure of the 40 V (dc) instrument power to the three narrow range level transmitters or the three medium range level transmitters on one steam generator, the boiler level control program for all steam generators will be terminated; the system does not remain on automatic level control. Turbine and condenser protection would be lost.

If the 40 V (dc) instrument power fails on all steam flow transmitters, an irrational alarm is initiated in the main control room and the steam/feedwater term in the level control program is not used. This also applies to the feedwater flow measurement.

4.3.7 Loss of 120 V (ac) Instrument Power

If the 120 V (ac) power fails on one current alarm switch, the very high water level alarm is initiated in the main control room. If the 120 V (ac) power fails on any two channelized level switches on any one steam generator, the following action is initiated:

- Very high water level alarm in the main control room.
- Turbine trip.
- All the CSDV are tripped.
- The main motorized valves on the steam generators are tripped closed, provided that their handswitches are in the "auto" position.

5.0 Boiler Level Control System Alarms

Alarm messages are displayed on the CRT and are printed out for;

- water level low on any boiler
- water level high on any boiler
- water level very high on any boiler
- high boiler tube sheet differential temperature
- main control valves malfunctioning
- start-up control valves malfunctioning

6.0 CRT Display

The following process variables can be called up for display on the CRT;

variable	number of indications available
narrow range water level for any boiler	3 measurements for each boiler
medium range water level for any boiler	3 measurements for each boiler
wide range water level for any boiler	1 measurement for each boiler
feedwater inlet temperature for any boiler	1 measurement for each boiler
steam flow from any boiler	1 measurement for each boiler
feedwater flow to any boiler	1 measurement for each boiler
main control valve position	4 measurements for each valve
start-up control valve position	4 measurements for each valve
feedwater pressure	3 measurements

7.0 Summary

The boiler tubes are a barrier between the radioactive water of the heat transport system and the non-radioactive water of the boiler steam and feedwater systems.

The boiler level control is important because;
- the boiler is the heat sink for the reactor and too little water means possibility of inadequate cooling
- the boiler is the source of steam for the turbine and too much water means the possibility of the steam flow carrying water over into the turbine and damaging it.

Boiler level is controlled as a function of reactor power. It is raised with power to accommodate the swell due to increased voiding associated with increased boiling. By doing this, there is a minimum change in the mass inventory in the steam generator.

Level excursions in either direction can cause problems - an undue drop in level causes a reactor trip; an excessive rise in level causes a turbine trip (to protect the turbine from damage from a slug of water). On high boiler level, the CSDV also are tripped closed, as are the motorized isolating valves at the feedwater valve stations.

Control of Boiler Pressure (BPC)

Training Objectives

On completion of this lesson the participant will be able to describe;

- Why the control of steam pressure is the heart of overall plant control.
- What plant components are involved in the control of steam pressure.
- How the pressure is controlled during normal operation.
- How the pressure is controlled without using the turbine.
- How the pressure is controlled while changing electric power output.
- How the "warm-up" and "cool-down" are accomplished by the BPC.

Table of Contents

1.0 Introduction

The Boiler Pressure Control (BPC) programme controls boiler pressure to a constant setpoint (except during warm-up and cool-down) by changing the reactor power setpoint (normal mode), or by adjusting the plant loads (alternate mode). That is, control is accomplished by varying reactor power, or turbine power along with the opening of the Atmospheric Steam Discharge Valves (ASDV) or Condenser Steam Discharge Valves (CSDV) as necessary. Turbine power, ASDV and CSDV are known as the plant loads. BPC also controls the rate of heat transport system warm-up and cool-down. The program resides in the plant control computers. The information given is typical of a CANDU 6 reactor.

Overpressure protection for the steam system is provided by four safety relief valves connected to each steam main.

The boiler pressure control programme is the heart of overall plant control. It controls boiler pressure to its setpoint and also provides automatic warm-up or cool-down of the plant by changing the boiler pressure setpoint at an appropriate rate (the maximum of which corresponds to a rate of change of temperature of 2.8°C/minute) to limit thermal stresses to acceptable values.

When the pressure is being controlled by changing the reactor power, ie in normal mode, the required reactor setpoint is calculated using factors representing turbine power, warm-up rate, boiler pressure and its error.

When the pressure is being controlled by changing the electrical output, ie in alternate mode, the turbine governor valves are positioned (through the operation of the speeder motor) by the sum of terms representing boiler pressure error, rate of change of reactor power, and rate of change of boiler pressure.

In both modes the CSDV and ASDV openings are calculated as the sum of factors representing the mismatch between reactor and turbine power, pressure error and a valve closing bias.

Normally, the ASDV open first and the CSDV start to open only when the ASDV are fully open. However, during a turbine trip or a sudden turbine load reduction exceeding 40% the CSDV (and ASDV if necessary) are opened on a process interrupt, and returned to their normal mode of control after four seconds.

On BPC failure the ASDV and CSDV fail closed, the contacts to the turbine fail open and control switches to ALTERNATE mode. The boiler safety valves limit the possible increase in boiler pressure. Excessive drops in boiler pressure are prevented by the hardware low pressure limiter within the turbine controller that runs back the turbine.

2.0 Control Design Requirements

2.1 Functional Requirements

The boiler pressure controller (BPC) is a computer program designed to meet the following requirements:

- BPC must be able to control the rate of heat transport system temperature change during warm-up and cool-down by changing the boiler pressure setpoint at the appropriate rate, regardless of whether the plant is in the "normal" or in the "alternate" mode. The maximum warm-up and cool-down rate of the heat transport system is 2.8°C/min should be achieved.
- During normal operation in the "hold" mode, BPC controls boiler pressure at a fixed setpoint of 4.59 MPa.
- In the normal mode BPC controls boiler pressure to a specified setpoint by changing the reactor power setpoint. That is, reactor power follows changes in steam consumption using boiler pressure as the controlled variable.
- If the reactor power setpoint cannot be manoeuvred, then boiler pressure is controlled via plant load, i.e., BPC controls the turbine speeder motor (load setpoint motor), or steam discharge valves.
- During turbine trip, BPC opens the condenser steam discharge valves (CSDV) quickly to prevent the boiler pressure from rising to the steam relief valve setting.
- During a reactor trip, setback or stepback, BPC reduces the turbine load quickly to prevent the boiler pressure from falling excessively.
- When the ASDV handswitches are in the "auto" position, BPC controls the ASDV automatically.
- BPC controls the CSDV when the valve handswitch is in the "auto" position subject to proper condenser vacuum and boiler level.
- BPC controls the CSDV automatically to discharge live steam to the condenser after cool-down is initiated or after a turbine trip.
- Provisions are made for the ASDV and the CSDV to be controlled through keyboard instructions.
- All annunciation is initiated by the boiler pressure control program.

2.2 System Operation

BPC forms part of the overall plant control, so its operation should be considered in relationship to the other components of the overall plant control system.

BPC can operate in one of three ways: "warm-up", "hold" and "cool-down" in both "normal" or in "alternate" mode. The operator makes the choice.

Warm-up

Although BPC is intended to start operating in the 150°C to 177°C range, it can operate from any initial heat transport temperature, even as low as ambient temperature. The operator selects warm-up control and makes a keyboard entry of the desired temperature rate of increase. The boiler pressure is increased accordingly.

If, at any time during warm-up, the setpoint exceeds steam pressure by more than 140 kPa then setpoint ramp is suspended until the steam pressure has returned close to the setpoint. A message to that effect is issued to the operators.

Once the boiler has reached its operating pressure, a CRT message is given to inform the operator that warm-up is complete. To acknowledge the message, the operator turns the selection handswitch from the "warm-up" to the "hold" position.

Hold

With steam pressure at its normal operating value, BPC is switched to the "hold" mode. In this mode the computer tries to hold the steam pressure constant by manipulating either the reactor power setpoint or the plant loads.

Once BPC is selected "hold", the turbine load can be increased or adjusted by suitably positioning the turbine speeder. Normally, this adjustment is done by the unit power regulator in response to local or remote commands, and BPC manoeuvres the reactor power setpoint through the demand power routine.

At very low reactor power (thermal or neutron power), the plant will be in the "alternate" mode, because a significant relative change in reactor power will have negligible effect on boiler pressure. Therefore, reactor power is controlled by the operator's action on the flux setpoint. In the "alternate" mode, the steam pressure is controlled via the plant loads (mainly the ASDV). Once reactor power is sufficient to control steam pressure reasonably well (at approximately 5% reactor power), the plant can be switched to the "normal" mode of plant control. The reactor power setpoint will be adjusted automatically by BPC response to the boiler pressure error and the load changes.

If for any reason, such as a severe disturbance, the steam pressure has dropped by more than 700 kPa from the setpoint, the pressure setpoint will be reduced to keep the pressure error within 700 kPa.

To return the setpoint to its normal operating value, the operator must turn the handswitch from the "hold" to the "warm-up" position and the pressure setpoint will ramp-up to the operating value at the rate corresponding to the warm-up rate R°C/min.

Cool-down

Operation is similar to the that during warm-up except usually the reactor power setpoint is not available. That is, reactor power setpoint is reduced to zero and steam pressure is brought down under control via plant loads (primarily the steam discharge valves) at a specified rate.

On cool-down a message is initiated to inform the operator that 827 kPa has been reached and the cool-down can be terminated anywhere between 827 kPa and 360 kPa by turning the selection switch in the "hold" position.

When the pressure setpoint reaches 360 kPa, a message is given to indicate that the cool-down is complete. The message is cancelled when the operator selects the "hold" position.

The ASDV are used to control the pressure when the plant is in the "warm-up" mode and in the "hold" mode at the normal power level. During cool-down caused by poor condenser vacuum, the ASDV will be used.

3.0 Boiler Pressure Control System Description

3.1 Instrumentation

3.1.1 Boiler Pressure Measurement for Control System

The pressure in each boiler is measured by one pressure transmitter. The pressure measurement is made on the steam line from the steam generator. Each transmitter input to the boiler pressure control program. The range of the pressure measurement is 0 to 6.00 MPa.

The pressure in one of the steam generators can be selected for display in the control room. Measurement rationality checks and signal selection for BPC input are incorporated in the program rules.

Alarms are initiated by the Control Program.

3.1.2 Atmospheric Steam Discharge Valves (ASDV).

There are four ASDV used for boiler pressure control. They have a combined capacity of 10% F.P. steam flow. The valves are located on each of the four steam lines from the boilers to the common steam header and are operated simultaneously when controlled by BPC. The valves can travel from full closed to full open in 2 seconds.

The valve position can be controlled from the control room. Each valve can be selected open, auto or closed. When the valves are selected auto they are under the control of the BPC. In the "open" or "close" position, the valve does not respond to computer signals, but will open or close and remain in that position even after a turbine trip.

The ASDV will close on failure of air supply or when both computers are unavailable. This will prevent unnecessary discharge of steam to atmosphere.

If an ASDV is fully closed or fully open while in auto and this position is not called for by the program, then annunciation is initiated in the main control room.

3.1.3 Condenser Steam Discharge Valves (CSDV).

There are three air operated CSDV, with a combined capacity of 100% at boiler operating pressure. They are used to bypass the turbine and discharge live steam to the condenser. The stroking time for these valves is one second.

A manual control allows the operator to manually close the CSDV's or to leave them on BPC control.

Each CSDV is operated by an analogue output signal from the computer. The CSDV are closed on failure of power supply, or on loss of air supply, or on failure of both computers.

If a CSDV is fully closed or fully open while in auto and this position is not called for by the program, then annunciation is initiated in the main control room to inform the operator of the valve malfunction.

3.1.4 "Warm-up - Hold - Cool-down" Handswitch

The boiler pressure mode can be selected for one of three conditions; warm-up - hold - cool-down. The hold is the normal full power condition, the others allow the boiler pressure to ramp up or down so that the HTS will warm-up or cool-down.

3.1.5 Turbine First Stage and Condenser Vacuum Pressure Measurement

The turbine first stage pressure is measured by two pressure transmitters. The pressure signals are equivalent to turbine power.

The condenser vacuum is used in the boiler pressure control programme; each condenser provides a signal. Low condenser vacuum closes the CSDV.

Measurement rationality checks and signal selection for BPC input are incorporated in the boiler pressure control program rules.

3.2 Overview of Control System

3.2.1 Complete Process System

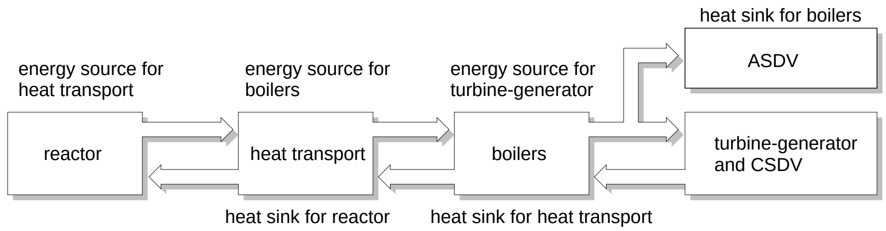
The relationship between the steam generator, turbine and reactor is best understood by following the energy flow through the main process systems. The relationship is illustrated in the simplified flow sheet Figure 1.

Under normal operation the energy flows from the reactor into the HTS, then to the water in the boiler causing it to boil. The steam carries the energy to the turbine which rotates the generator, producing electrical energy.

Electrical power produced by the turbine is controlled by the amount of steam admitted to the turbine through the governor valves. The position of the governor valves is set by a combination of the speeder setting, and frequency error.

The total steam consumed by the plant load is the sum of the steam flow to CSDV, ASDV and turbine.

Figure 1
Energy Flows



3.2.2 General Description of Control System

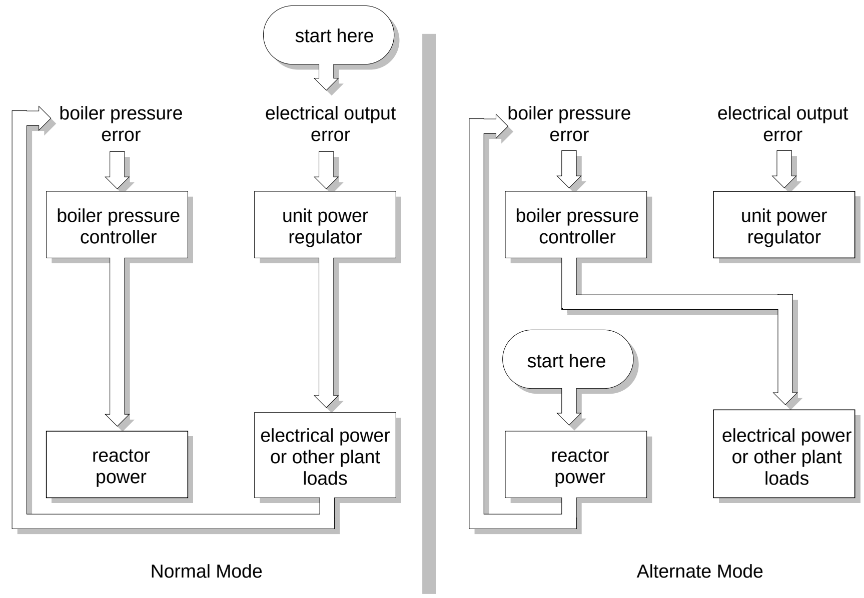
Boiler pressure control is part of the overall plant control system and its function is to control either the reactor power setpoint in the normal mode of plant operation or the turbine speeder setting in the alternate mode. In the normal mode BPC calculates the reactor power setpoint, using boiler pressure as the controlled variable. Under certain abnormal conditions, such as reactor or turbine trip, reactor setback or stepback, BPC loses control of reactor power setpoint and boiler pressure control is by plant loads - turbine, atmospheric steam discharge valves and condenser steam discharge valves. Figure 2 outlines the differences between normal and alternate modes.

Normal Mode:
This is the mode at the high power levels. The reactor regulating system responds to the power demands from BPC. The operator can set upper and lower limits of reactor power in this mode.

Alternate Mode:
This is the normal mode at the low power levels, where the boiler pressure control via reactor power is not desirable. The reactor regulating system responds to manual changes in the demanded power. This mode is entered automatically when reactor power is sufficiently low, when a reactor trip or stepback has occurred, or when a setback goes all the way to its endpoint.

While the setback is in progress, the boiler pressure is controlled by manipulating the plant loads as in the "alternate" mode. The setback clears either when the power reaches the endpoint or when the condition clears. If the latter, the plant reverts to the mode of operation prior to the occurrence of the setback, otherwise the plant is left in the "alternate" mode.

Figure 2
Normal and Alternate Modes



3.2.3 System Control Variables

This system can be disturbed by any of the following process or control inputs:

- Turbine speeder setting
- Reactor power
- Condition of the Grid - grid frequency swings will be sensed by the turbine governor and change the governor valve position.
- Turbine protection system inputs
- Reactor protection system inputs
- Condenser steam discharge valve setting
- Atmospheric steam discharge valve setting

During normal operation and manoeuvring, only the first two are changed, all others are either constant or zero.

Normally the grid frequency swings are very small and are not likely to contribute towards changes in power production except during large grid upsets like loss of a large generating station, or separation from the grid.

The turbine and reactor protection systems come into action only during system malfunction. They tend to bring the turbine and the reactor powers out of step and special features are provided to accommodate them during abnormal operation.

The effect of opening the CSDV is identical to that of increasing the turbine speeder setting, and a similar control function is used. The CSDV opening is artificially delayed to improve control of boiler pressure.

One of the uses of the ASDV is the control of boiler pressure during plant start-up or in the alternate mode of operation when reactor power is not easily manoeuvrable for controlling boiler pressure. Another use is to trim pressure error without using the large CSDV.

The two variables of prime concern are electrical power output and boiler pressure. The first is the main controlled variable - the output of the plant. The second is important because it directly influences the reactor power and hence the heat transport system temperature, amount of boiling and hence the swell. The control of boiler pressure is the single most important element of the plant control system. Because of large delays and transport lags in the boiler pressure control loop, compensation will be required to avoid large swings in boiler pressure and possible instability. Obviously, the best control system is the one that allows for power adjustment without severe over or undershoot in reactor power or boiler pressure.

In order to maintain the boiler pressure during a change in reactor power (setback, stepback, trip) steam consumption must be kept in step with production. This is achieved by reducing the flow to the turbine by changing speeder setpoint. But because normal feedback control is stopped during such reactor power reduction, and because instrument calibration is never perfect, boiler pressure control would be lost. During this condition, the boiler pressure feedback is achieved by adjusting the turbine speeder and/or steam discharge valves using boiler pressure error. This amounts to temporarily changing the mode of control such that the reactor acquires the leading role and the turbine is expected to follow it. This mode of control is the alternate mode.

A turbine trip suddenly eliminates the heat sink provided by the turbine. The steam discharge valves become the heat sink in this case, and allow the reactor to continue to operate, preventing poison out.
A sudden increase in turbine load due to grid upsets cannot be compensated for quickly. The reactor power is called to increase by boiler pressure error. If the upset comes near full power it cannot increase steam flow too much because of limited capacity of the governor valve. However, if boiler pressure drops below a certain value, a turbine unloader comes into operation. In practice, severe grid upsets are rare and they can cause a severe and sudden increase in load (steam flow) only when the turbine is at low power.

3.3 Boiler Pressure Control System

Regardless of whether the plant is in the "normal" or the "alternate" mode, BPC can operate in one of three ways; "warm-up", "hold" and "cool-down". The basic difference between these three is the way the boiler pressure setpoint is manipulated. In "warm-up", the setpoint is raised at a rate corresponding to a specified rate of temperature rise in the heat transport system ie the reactor power is raised. In "hold", the pressure setpoint is held constant, and in "cool-down", steam pressure is brought down by ramping the setpoint down and controlling steam pressure by means of the plant loads.

3.3.1 "Warm-up"

Figure 3 illustrates the control of boiler pressure while in the warm-up mode.

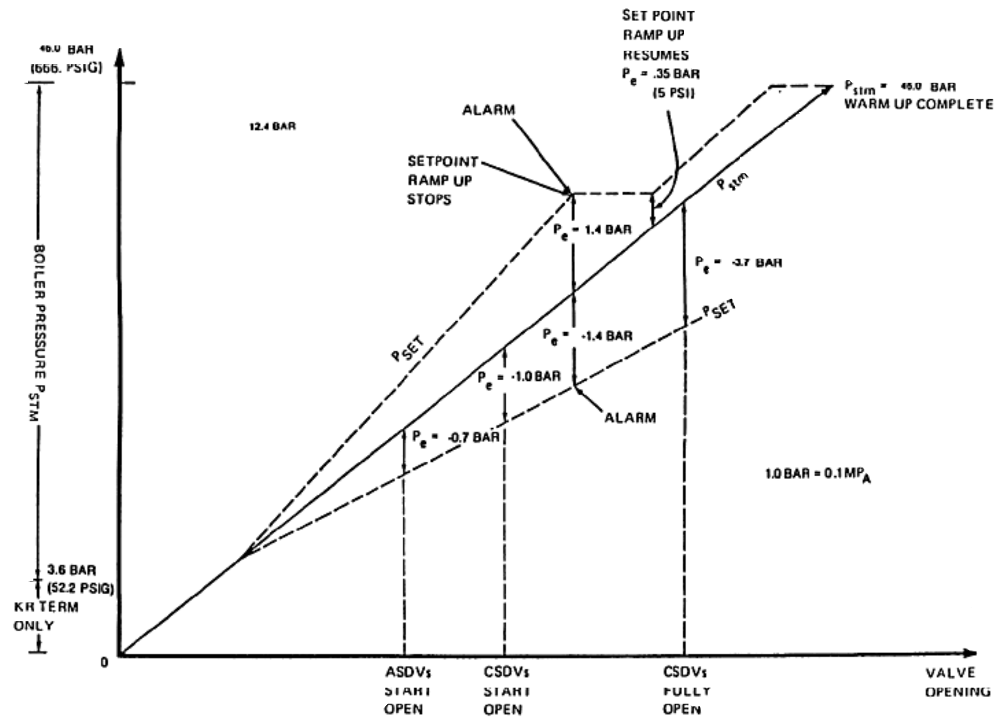
There are two sources of energy which heat up the primary heat transport system; that generated by the main heat transport pumps or that from the reactor. The reactor power is set by a signal from the BPC which is provided by combining the steam pressure error, the difference between the actual steam pressure and its setpoint, with the demanded rate. The rate signal is a function of pressure.

Warm-up is achieved by varying the boiler pressure setpoint such that the resulting temperature rate in the heat transport system, measured at the reactor inlet header, is roughly constant. This method is effective beyond about 150°C where the ASDV have a reasonable discharge capacity. For warm-up from 54°C to 150°C, either the reactor power setpoint is manually set by the operator for a maximum warm-up rate of 2.8°C/min. or automatic warm-up of the boiler is achieved by using the feed forward temperature rate term KR in BPC (this term is discussed in section 3.3.5).

The operator selects the warm-up control mode by placing the handswitch in the "warm-up" position and makes a keyboard entry of the desired temperature rate of increase. The maximum allowed rate of increase is 2.8°C/min. in order to avoid excessive thermal stresses in the boiler and associated piping and to ensure that the swell rate in the heat transport system can be handled by the inventory control system.

During warm-up the reactor power set point can be changed in two ways. Under automatic control and in normal mode, it is formed by combining the steam pressure error with the demanded rate. The rate signal is a function of pressure.   Automatic warm-up is effective from 360 kPa to 4.6 MPa. Under manual control the operator using the alternate mode can change the reactor power to achieve the warm-up required.

Figure 3
Boiler Pressure Control in Warmup



If the actual warm-up rate exceeds 3.36°C/min there is a CRT alarm in the main control room. If the pressure exceeds the setpoint the pressure control programme will first open the ASDV, and if that does not control the pressure it will open the CSDV. Normally the ASDV are used for pressure control during the warm-up period. The ASDV start opening when the pressure error is greater than 70 kPa and the CSDV start when the error reaches 100 kPa. The CSDV are fully open at 370 kPa. If the pressure is less than the set point, i.e. the warm-up is slow for some reason, the increase of the pressure setpoint is suspended when the error is 140 kPa and does not resume until the pressure error becomes less than 35 kPa. This is to prevent setpoint runaway during abnormal conditions.

An error of 140 kPa or more on either side of the setpoint for longer than 2 minutes will cause an alarm.

3.3.2 "Hold"

With this selection, the pressure setpoint is fixed to whatever value it was when the selection is made, up to a maximum of 4.59 MPa. The control system holds the pressure constant by control of reactor power or steam consumption.

Normally BPC will be switched to "hold" after the pressure setpoint has reached 4.59 MPa the normal operating steam pressure setpoint for the plant.

After cool-down to below 149°C or the cool-down completion pressure determined by the operator after 177°C has been reached, the switch is placed in the "hold" position. However, in this case the setpoint is not fixed and is allowed to drift down with steam pressure.

To safeguard against a steam pressure runaway following a severe pressure drop, pressure setpoint capture is provided. This automatically reduces the pressure setpoint, to keep the error within 70 kPa. The setpoint is latched to the lowest value and will be returned to its normal operating value by the operator selecting warm-up.

3.3.3 "Cool-down"

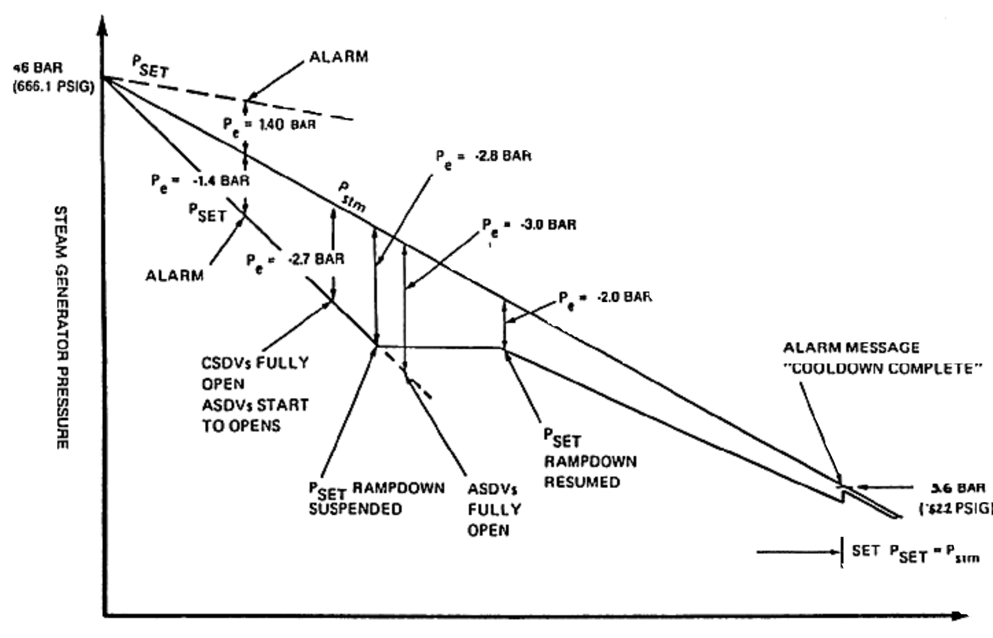
Figure 4 illustrates the control of boiler pressure during cool-down.

In this case the reactor power is zero and the turbine stop valves are closed. The pressure setpoint is ramped down. The heat sinks are the CSDV and the ASDV.

The operator chooses when to terminate the cool-down mode. When the boiler pressure is cooled down to 830 kPa, an alarm is initiated by BPC to inform the operator that that pressure has been reached and that cool-down mode could be terminated by turning the mode switch to 'hold''. In the meantime, the setpoint is made to drift down with steam pressure. Cool-down mode can also be terminated in the same way for a pressure range of 830 to 360 kPa.

Figure 4

Pressure Control in Cool-down



If the operator does not acknowledge the message at 830 kPa or below, the cool-down will continue with the same rate until 360 kPa corresponding to 149°C has been reached. This initiates a message "BPC - Cool-down Complete". The message is cancelled when the operator places the switch in the "hold" position.

If the actual cool-down rate exceeds 3.36°C/min. there is an alarm message in the main control room to inform the operator.

If the pressure setpoint is 280 kPa below steam pressure, then setpoint decrease is suspended and does not resume until the pressure error is less than 200 kPa. The setpoint decrease is suspended to allow the CSDV to open.

An error of 140 kPa or more on either side of the setpoint for longer than 2 minutes will cause an alarm.

3.3.4 Reactor Power Setpoint Calculation

During operation at substantial power, the plant is expected to be in the "normal" mode. Reactor power is adjusted to maintain boiler pressure at its setpoint.

The program also permits warm-up in the "normal" mode of plant control. That is, once the operator enters the required rate of warm-up, BPC calculates the required reactor power setpoint.
In the "normal" mode, the demanded reactor power setpoint, Jsp, is calculated by the BPC and consists of the following terms:

$$J_{sp} = J_T + bP_e + I_p + KR$$

where

J_{sp} is the demanded reactor power set point
J_T is the turbine power term, % F.P. (F.P. refers to the reactor power)
b is a proportional gain
P_e is a pressure error, MPa
I_p is an integral term
K is a weighting factor, % F.P./°C/s
R is the warm-up up Rate, °C/s

A description of each of these terms follows;

J_T is defined as the percentage of the reactor thermal power required to produce the turbine power. The use of the turbine power term is to anticipate the effect of load changes on pressure, in order to prevent large pressure deviations from occurring. The turbine first stage pressure is proportional to turbine power and is used to measure turbine power. The exact relationship between the turbine power and the first stage pressure is obtained during commissioning.

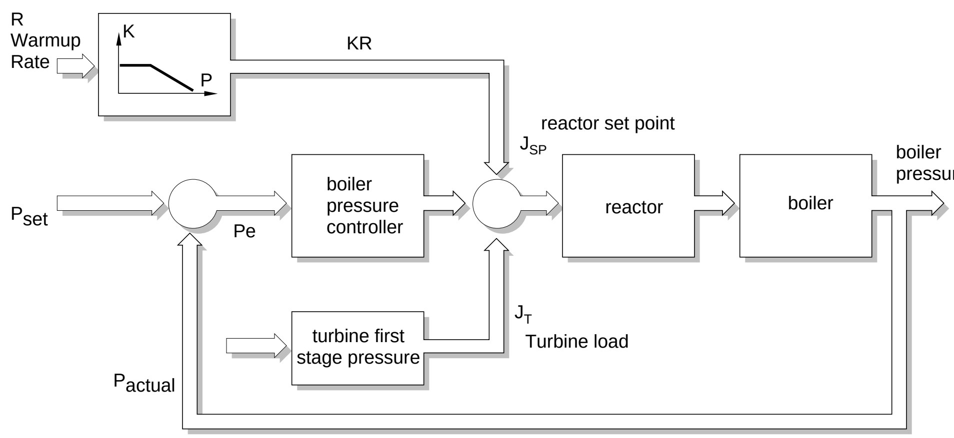
The part of the expression for the reactor power setpoint, $bP_e + I_p$, is the feedback term, and consists of a proportional and an integral term. When the reactor power is varied by more than 1% in a period of 10 seconds, the integral action is omitted since it could cause overdemand in the reactor power, and possibly cause excessive swell in the primary circuit,

An additional feedforward term, KR, is added to the setpoint during warm-up to allow BPC to be used from a H.T. system temperature lower than 150°C. R is the required rate of warm-up and K is the rate-to-power conversion factor, varied to reduce the effect of R as the boiler pressure increases, and becoming zero when the boiler pressure is above 4.59 MPa. The exact value of K is found during commissioning.

The relationships between these terms is illustrated in figure 5.

Figure 5

Reactor Power SetPoint in Normal Mode



Generally at low power levels, the reactor power setpoint is controlled manually by the operator, i.e., the plant is in the "alternate" mode and the operator enters the required reactor power setpoint. If he decides to warm-up the system, he places the handswitch in the warm-up position and enters the heat transport system warm-up rate.

Cool-down is similar to warm-up, except that if a unit is to be shutdown, then the reactor is expected to have been shutdown when cool-down is initiated.

3.3.5 Turbine Speeder Control

The steam flow to the turbine, i.e. the turbine power, is controlled by the turbine control valves (known also as the turbine governor valves) which in turn are controlled by the turbine governor. The governor is an electro-hydraulic system which uses signals of turbine speeder position, turbine speed, load limiter and turbine unloader settings to position the turbine control valves. The turbine control valves are positioned by the speeder but the speeder can be overridden by the turbine speed, the load limiter and the turbine unloader.

When the plant is in the "normal" mode, the turbine speeder is controlled through the unit power regulator (UPR) program, i.e. UPR calculates what the speeder position should be to give the desired electrical power and adjusts the speeder to that position. The turbine speeder is driven by the load set motor at a rate equivalent of ±2.5%/s loading. However, there is a load rate limiter in the turbine governor, which limits the load increase rate to 0.1667%/s (10%/min). Small deadbands are required to prevent continuous adjustment of the load set motor due to noise.

When the plant is in the "alternate" mode, or if a reactor setback is in progress, BPC controls the turbine speeder in response to the boiler pressure error.

There are two exceptions to this split between UPR and BPC. They are;
- If boiler pressure falls below 4.13 MPa, regardless of which mode selected, BPC will run back the turbine at the rate determined by, the pressure error, the rate of change of this error, and the rate of change of the reactor power.
- When the turbine is first synchronized and before the initial block loading of MW has been completed, the plant UPR has control of the turbine speeder. This continues until the ASDV and CSDV combined opening < 5% F.P. steam flow equivalent, regardless of the control mode or existence of setback. Once the the turbine block loading has been completed, and the ASDV and CSDV combined opening < 5% F.P., and the control is selected for "alternate" mode, BPC takes control of turbine.

3.3.6 Control of Atmospheric Steam Discharge Valves

The atmospheric steam discharge valves (ASDV) operation is as follows:
- During normal operation in "warm-up" or "hold", the ASDV open first to release the excessive boiler pressure resulting from the mismatch between the reactor power and plant loads. Under steady state conditions when the reactor power matches the plant loads this will be insignificant.
- During "cool-down" and when the CSDV are available, the ASDV start to open after the CSDV have been opened fully. When the CSDV are not available, the ASDV open to achieve a reasonable cooling rate before the shutdown cooling system is operational.
- The ASDV are always controlled by BPC and accept keyboard instructions when the valve handswitch is in the "auto" position.

The ASDV are controlled by the error between steam pressure and pressure setpoint, with an offset to bias the valves closed under normal operation and by a feed forward term proportional to the difference between the reactor and turbine powers. The amount of offset depends on the operating mode and availability of the CSDV. During "warm-up" or "hold", the offset is at 70 kPa. During "cool-down" and provided the CSDV are available or BPC in poison prevent mode, offset Po is increased to 270 kPa so that the ASDV start to open after the CSDV are fully open. Finally, on "cool-down" and if the CSDV are not available, the offset is reduced to 35 kPa.

3.3.7 Control of Condenser Steam Discharge Valves

The condenser steam discharge valves (CSDV) operate as follows:

- The CSDV are always controlled by BPC when the valve handswitch is in the "auto" position, subject to condenser vacuum being adequate and provide release of excessive boiler pressure resulting from a mismatch between reactor power and plant loads. They respond rapidly to any severe transients, such as a turbine trip. Under steady state conditions, when reactor power matches the plant loads, they are biased shut. During "warm-up" or "hold" the offset is at 70 kPa. During the "cool-down" or the poison prevent (as would follow a turbine trip) the offset is removed.
- During normal operation in "warm-up" and "hold", the ASDV open before the CSDV. During cool-down, the CSDV open first.
- During turbine trip or loss of line, the CSDV open immediately to discharge live steam to the condenser so that the reactor can continue to operate at the power required to prevent a poison out and to prevent the lifting of steam safety valves if possible.
- The CSDV do not automatically reopen (reload) themselves after being closed due to the poor condenser vacuum. This is done by the BPC via a pushbutton.
- The CSDV trip closed on very high boiler water level and poor condenser vacuum. This is done by separate hardware relay logic. The CSDV do not automatically reopen (reload) themselves after being closed due to the above condition.
- CSDV can be controlled through keyboard instructions.

The CSDV are always on pressure control. The CSDV are controlled by the error between steam pressure and pressure setpoint, with an offset to bias the valves closed under normal operation and by a feed forward term proportional to the difference between the reactor and turbine powers. If the condenser vacuum deteriorates, the valves will be closed by the computer CSDV unloader to protect the condenser.

The CSDV unloader is calculated from a direct measurement of condenser vacuum; the CSDV start closing at an absolute pressure of 10 kPa (3 inches of Hg) and close fully at 14 kPa (absolute) (4 inches of HG). The CSDV unloading protects the condenser when the condenser vacuum deteriorates. Once the CSDV unloader has come into operation, manual intervention by the operator is required for the unloader to return to normal after the vacuum has been restored.

Whenever any one of the CSDV starts to open the condenser spray water valves will be open to spray water into the condenser for improving condenser vacuum. The signal to open the condenser spray valves comes from the limit switches on the CSDV. If condenser spray valves fail to open, the CSDV will not be tripped close, but will still be subject to condenser vacuum restriction. An alarm will warn the operator if the spray valve fails to open within 5 seconds of the CSDV opening. If condenser vacuum deteriorates due to the failure of the condenser spray valves, the CSDV will be tripped closed by the vacuum signal.

The CSDV have separate hardware protective systems that trip the valves closed on low condenser vacuum or very high water level in any steam generator.

The amount of opening of the CSDV is restricted by the level of turbine power. The condenser is normally taking about 68% F.P. live steam and it is set to accept 90% F.P. live steam continuously. The CSDV are sized to 100% F.P. live steam at normal pressure. At low turbine power and high reactor power, the total steam going to the condenser via the turbine and CSDV may exceed the condenser capacity. If the steam going to the condenser exceeds the condenser capacity, the condenser vacuum becomes poor. BPC unloads the CSDV on poor vacuum. The turbine and condenser are thus protected. Therefore, it is not necessary to have a restriction on CSDV opening due to the turbine power.

3.3.8 Process Interrupt to the Computer Programme.

When a turbine trip occurs, normal mode control of the reactor is suspended. In order to avoid lifting of the boiler safety valves, in view of their valve stroking time and 2 second sampling interval of the routine, a process interrupt is generated for the computer programme. The following action is taken;
-If the turbine power is above 70% F.P., the CSDV are opened fully for two sampling intervals. This is done by changing the offset for both the CSDV and ASDV; the offset for the ASDV is increased to 270 kPa and the offset for the CSDV is decreased to 0 MPa. The CSDV return to normal pressure control after two sampling intervals. This is the poison prevent mode, which is cleared when ASDV and CSDV opening < 5% F.P. steam flow equivalent.

- If turbine power is between 30% and 70% F.P., the CSDV are opened in a linear fashion in relation to the 30% to 70% power level span. This interrupt instruction will be ignored if for any reason the valves are required to open to more than the interrupt requirement, in which case the valves return to normal control immediately.
- If the turbine power is below 30% F.P., then the interrupt will be ignored and the CSDV and the ASDV are allowed to open under normal operation of the BPC program.
- If abnormal conditions arise during plant operation so as to cause either a reactor trip, or stepback, or setback, the reactor will be removed from boiler pressure control, and its power setpoint is automatically switched to the "alternate" mode by the Demand Power Routine (DPR), i.e. BPC controls boiler pressure via plant loads. Generally manual reset is required before the reactor setpoint is back on "normal" control. The steam discharge valves however, are under pressure control all the time.

3.3.9 Turbine Hardware Control

There is only one low boiler pressure hardware unloader for turbine control. This will override directly the turbine governor action including the BPC signal and cause a fast runback of the turbine. The unloading action is a proportional action. Steam pressure unloading starts at 90% of normal boiler pressure, 4.13 MPa, and is complete at 85%. The low condenser vacuum hardware unloader unloads the turbine from 90% to 85% vacuum. Normal condenser vacuum operating point is at a negative pressure of 6 kPa (1-3/4 inch of Hg), turbine trip is initiated at a very low vacuum.

3.4 Effects of other Systems Malfunctioning

The following is a brief discussion on the effects of other systems malfunctioning.

3.4.1 Class IV Power Failure

On loss of Class IV power, the condenser cooling water pumps are inoperative. The condenser vacuum is lost. The CSDV are closed by the BPC and by the hardware vacuum unloader.

3.4.2 Loss of 40 V (dc)

Loss of 40 V (dc) instrument power on any measurement loop will give an "irrational" annunciation in the control room. If three of the pressure measurements are irrational, the BPC will stop its function. Refer to Section 3.4.6 for total failure of BPC.

Loss of the condenser vacuum measurements will result in setting the unloader signal to zero; this will close the CSDV.

Total loss of three measurements of turbine steam first stage pressure will cancel the feedforward term in the CSDV and the ASDV control algorithm and put the CSDV and ASDV on boiler pressure error control only. The plant is switched to the "alternate" mode by the BPC and it controls the turbine.

3.4.3 Loss of Instrument Air

The loss of instrument air to the ASDV and CSDV will cause the valves to close.

3.4.4 Loss of 48 V (dc) Power Supply

On loss of 48 V (dc) power the solenoid valves on the CSDV and ASDV close, causing the CSDV and ASDV to close.

3.4.5 Both Computers Failure

On failure of both computers BPC will be inoperative, ASDV and CSDV will close, reactor power will reduced and no CRT displays will be available.

3.4.6 Total Failure of BPC

If only one boiler pressure measurement is rational (for both X and Y computers), BPC will fail totally.

The following actions will occur on total failure of BPC:

- Boiler pressure control will be lost..
- No change to the BPC operation selection ie if in "hold" , "cool-down" or "warm-up" it will stay there.
- The computer will signal the CSDV and the ASDV to close fully.
- Operator cannot open the CSDV and the ASDV manually through computer keyboard, but he can open the ASDV by putting the valve handswitches in the "open" position.
- The plant is switched to the "alternate" mode and the reactor power setpoint is held at its last setpoint.
- If the boiler pressure increases suddenly to the safety valve pressure relief setpoint due to the loss of BPC, the safety valves will start to open. Before opening the safety valves, a reactor setback occurs on high pressure. If boiler pressure decreases to 90% of normal operating pressure, turbine unloading starts and is complete at 85%.
- Indicating light on the main control panel illuminates to indicate that BPC is terminated.
- Alarm is initiated - BPC failed, boiler pressure unavailable.

3.4.7 Partial Failure of BPC

The following failure conditions are considered as partial failure of BPC:

- When any of the analogue outputs to the CSDV fails to zero mA (from 4 mA), the CSDV closes fully. Computer analog output malfunctioning annunciation is initiated in the main control room.
- When any one of the analogue outputs to the CSDV fails to 20 mA, the CSDV opens fully.

The above failure conditions also apply to the ASDV.

3.5 Alarms

All annunciation shall be initiated by BPC and mainly indicates errors in its inputs or outputs. They include;

- boiler, or first stage turbine pressure not available
- pressures not rational or error signals large
- turbine not synchronized, tripped or line lost
- "warm-up" or "cool-down" action complete
- ASDV and CSDV on key board control
- irrational CSDV and ASDV positions
- malfunctioning of CSDV and ASDV

In addition, "Off-Normal" discrepancy lights show when handswitches for ASDV are not selected "auto".

3.6 CRT Display

Boiler pressure of each of the four boilers, condenser vacuum from each of three condensers, turbine first stage pressure, and the load limiter setpoint position are displayed on the CRT.

Turbine-Generator and Associated Systems

Training Objectives

On completion this lesson the participant will be able to:

- Given a sketch, identify the major parts of a turbine generator component layout.
- Indicate the approximate magnitude of the pressures, temperatures and flows in a typical Candu 600 turbine-generator.
- Describe the pressure gradient through a turbine and be able to explain how this pressure gradient can be used to diagnose the health of the turbine.
- Illustrate the difference between a live steam reheater and a two stage reheater by means of a simple sketch.
- Show by means of a simple sketch the effect a reheater has on the steam quality in the latter stages of the turbine.
- Illustrate a simple steam/exhaust cooling circuit and be able to explain the cause of the turbine and exhaust overheating.
- Draw a simple sketch of the typical turbine gland seal.
- Show the basic principle of the turbine steam valve actuator.
- List the hazards associated with minor contamination of the Fire Resistant Fluid (FRF).
- Draw a simple sketch of a typical FRF System.
- Identify the fail safe position of the turbine steam valves and explain the reasoning for this position.
- Explain the expected response of the governor system to load changes resulting from system upsets.
- Give a simple explanation of why changing the turbine set point will result in a change in generator load when the unit is synchronized and a change in speed when unsynchronized.
- List initiating events which will produce a turbine runback.
- Describe the operation of the Emergency Overspeed Trip Protection and explain why one is needed.
- Explain how the turbine-generator is capable of generating missiles and list possible causes of the phenomena.
- Indicate the routine tests that are required to ensure that a safe environment exists for turbine/generator operation.
- List the parameters of the Turbine Supervisory System.

- Explain when the use of the Turning Gear is required.
- Identify the major components of a generator.
- Give an estimate of the amount of heat that must be removed from a typical Candu 6 generator.
- Illustrate the flow path of hydrogen within the generator casing.
- List the advantages and disadvantages of using hydrogen as the coolant gas.
- Name the two types of hydrogen seals and give the advantage of the axial seal.
- Indicate the safe purity level of hydrogen in the generator.
- Sketch a typical stator water cooling system and explain why the purity of the coolant is important.
- Explain why the pressure in both the stator water cooling and the service water in the hydrogen coolers is maintained lower than the hydrogen pressure.
- Sketch a typical seal oil system.
- State two consequences of the following turbine-generator conditions:
  - overspeed
  - low condenser vacumn
  - moisture carryover
  - bearing failure
- State the difference between a sequential and non-sequential trip of the turbine.

Table of Contents

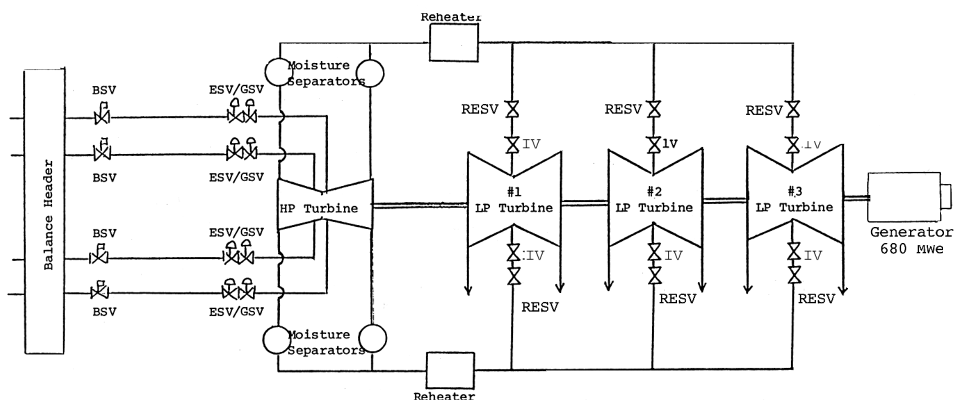
1. Turbine - Generator & Auxiliaries Overview

The turbine-generator and its associated auxiliary systems comprise a major part of a nuclear power station. They have a key role in the electricity production process. The turbine-generator systems do not normally contain radioactive material but their availability and protective systems are of major importance in the safe operation of the station. Leaks in the boiler tubes will however contaminate some of these systems with radioactive heat transport water. A sound knowledge of turbine-generator and auxiliary systems operation is essential in total plant risk assessment.

The specific Turbine/Generator set for a CANDU Station will vary from station to station depending on the manufacturer. This lesson will therefore deal with generic turbine/generator systems.

Figure 1 shows a typical CANDU-6 Turbine Generator unit. More detail of the operation of various components is provided in the sections following.

Figure 1
Typical CANDU-6 Turbine Generator



B.S.V. - Boiler Stop Valves
E.S.V. - Emergency Stop Valves
G.S.V. - Governor Stop Valves
H.P. - High Pressure
L.P.. - Low Pressure
I.V. - Intercept Valves
RESV. - Reheater Emergency Stop Valves

1.1 Turbine/Generator & Auxiliaries - Introduction

This is a description of a typical 600 MW(e) nuclear steam supplied turbine-generator set.

The turbine/generator set is one of the key components in the power production cycle. This equipment is found in nearly every type of thermal generating station. Because of their widespread use in the electrical generating industry the standards for the design and manufacture of this equipment are highly refined.

The function of the turbine/generator set is to convert the thermal energy of the steam from the boilers to mechanical energy in the turbine and then to electrical energy in the generator. It has a speed of 1800 r.p.m. (60 Hz) and a gross output of 680 MW(e)

The steam conditions at full load (rated continuous turbine capacity) are 4.55 MPa(a), 258°C at the high pressure turbine throttle valves. The exhaust from the high pressure turbine is reheated using live steam to 243°C before entering the low pressure turbine sections.

The corresponding steam flows are: 957 kg/s to the turbine throttle valves, and a 90 kg/s live steam to the steam reheater for a total of 1047Kg/s.

The turbine generator and auxiliaries are intended for indoor installation and ancillary equipment is located within reach of the turbine hall crane wherever practical. Provisions are made to ensure shutdown without damage of any equipment in case of a power outage. Start-up, normal operation and shutdown are controlled from the Main Control Room (MCR) except when otherwise specified.

Steam which cannot be utilized by the turbine during start-up or turbine load reduction is discharged to the condenser through a turbine bypass system, the Condenser Steam Discharge Valves (CSDVs). The capacity of the CSDVs is sufficient to avoid a reactor shutdown in the event of a full load rejection. This process is sometimes referred to as "Poison Override" or "Poison Prevent".

1.2 Turbine.

The turbine consists of a double flow high pressure and multiple double flow low pressure cylinders in tandem, directly coupled to the generator. The turbine consists of one double flow high pressure cylinder followed by external moisture separators, live steam reheaters and three double-flow low pressure cylinders. Four external main steam chests are mounted along the end of the turbine generator block at the steam end. Each steam chest contains an emergency stop valve and a governor valve.

Intercept and reheat emergency stop valves are located in the steam lines carrying the reheated steam to the three low pressure cylinders. The governor and intercept valves close on loss of load to limit the speed rise of the machine.

Release valves, adjacent to the reheaters, open to discharge steam from the high pressure turbine, separators and reheaters to the condenser.

The turbine startup, from turning gear to synchronization, is performed from the MCR. Turbine instrumentation monitors conditions such as bearing vibration and eccentricity. This allows corrective action by the operator if permissible limits are exceeded. The turbine-generator speed and load control is maintained by a high speed electro-hydraulic governor (EHG). The turbine is fitted with normal overspeed and trip protection.

All pressure vessels described in this section are designed to Section VIII of the ASME Unified Pressure Vessels Code. Additional standards are mentioned wherever required. Tests were carried out in accordance with the ASME Power Test Code as far as applicable.

Inlet steam to the high pressure turbine has a water content of approximately 0.3% by weight and as it expands through the turbine the water content increases. After the high pressure turbine exhaust, the steam,which is now quite wet, passes through the separators where the water is removed. Removed water is drained to the high pressure feedwater heater. The steam passes to reheaters where it is reheated by main steam from the main steam header. The live reheating steam is condensed in the reheaters and pumped back to the boilers. Extraction points are located on the turbine casings and separators to provide extraction steam to six stages of feedwater heating (two high pressure (HP) stages, the deaerator, and three low pressure (LP) stages).

In order to prevent the turbine exhaust hoods from overheating at low loads, water sprays are provided at the exit of the last stage blades.

The turbine has following auxiliary equipment:
- moisture separators and reheaters
- governor and emergency stop valves
- overspeed protection
- turbine control system
- safety, alarm and test devices
- instrumentation and accessories, (Turbine Supervisory System)
- intercept and reheat emergency stop valves between the reheaters and LP turbines
- release valves adjacent to the reheaters discharging into the condenser
- rupture disks adjacent to the reheaters discharging to atmosphere
- permanent strainers on all four lines entering the high pressure turbine

The main stop valves, governor valves, intercept and reheat emergency stop valves, positive assist check valves and motorized isolation valves on extraction lines close automatically when the turbine trips.

The turbine control system includes the following items:

- speed governor with speed changer, load limiter, acceleration detector, electrical, mechanical and hydraulic connections to the controlled parts,
- governor control cabinet which is installed in the control equipment room,
- governor fluid system (containing Fire Resistant Fluid) with pumps, tanks, strainers, coolers, piping and accessories.

The governor is of the electro-hydraulic type. The governor fluid system is independent of the lubricating system and is equipped with two high pressure, 100% capacity trains, each containing two pumps, one booster pump and one main pump.

The electrical control system is an analog device using low voltage solid state circuitry. In addition to the control system the following safety , alarm and test devices are provided:

- turbine emergency trip
- rupture discs on the high pressure turbine exhausts
- lifting discs on the low pressure turbine exhausts
- devices for testing free movement of all trip and control components which are to be checked during unit operation
- supervisory and other instruments for any variable to be checked during unit operation including detectors, amplifiers and recorders

1.3 Generator

The generator is of the three phase armature, rotating field type, rated at 800 MVA, 0.85 power factor and 410 kPa(g) hydrogen pressure. The terminal voltage is 26 kV. The field is four pole and the stator winding is constructed of hollow copper conductors through which cooling water at low pressure is circulated. The generator rotor and the stator core are hydrogen cooled.

The generator stator cooling water is kept at a controlled conductivity in a closed system which includes water-to-water heat exchangers to carry away the heat generated in the stator windings. The excitation is of the static type, consisting of a solid state automatic voltage regulator controlling a convertor which supplies the generator field via a field circuit breaker, generator sliprings and brushgear. Permanent current transducers are provided for checking the current distribution among the four sliprings

Protection and alarms are included for the following:

- generator,
- the main and unit transformers and their bus ducts,
- the excitation system and static exciter,
- the seal oil system,
- the hydrogen system,
- and the stator water cooling system,

The generator is also equipped with temperature and vibration detectors. The power from the generator is fed to the main step-up transformer through a forced air cooled isolated phase duct bus duct, with tap-offs to the unit service transformer, excitation transformer and the potential transformer cubicle. Current transformers for metering and protection are installed on the main power output bushings of the generator.

The generator is equipped with a microprocessor-based power system stabilizer. The purpose of the stabilizer is to respond to deviations in generator speed or frequency and properly condition this signal before it is fed into the generator voltage regulator. The stabilizer provides positive damping of power oscillations, thereby improving system stability and reliability and prevention of system-induced unit deratings.

1.4 Turbine Missile Protection

The turbine is a very large piece of machinery rotating at high speed and so is subject to very high mechanical stresses. The design, construction and factory test procedures ensure sound rotating discs that equal or exceed specified design requirements. Each turbine rotor assembly has undergone an overspeed test at 120% of rated speed at the factory. Routine non-destructive examination of the discs and rotors throughout the life of the machine will assure protection against catastrophic failure.

For Point Lepreau, the normal governing control system operates to ensure that the governing valves are fully closed at 3% overspeed, and that the mechanical-hydraulic overspeed system is set to operate at 10% overspeed (66 Hz). Each system contains fully redundant and testable components. The systems operate to ensure that the turbine cannot attain sufficient speed to cause any rotating component to fail, thereby generating missile-like pieces that might penetrate the turbine casing.

An overspeed limiting feature is provided by the EHG. This feature comes into effect when overspeed exceeds 102% and provides a maximum allowable governor valve (GV) closure dependent on the extent of overspeed. The feature would close the GVs fully if overspeed exceeds 103%. In addition the EHG also contains an acceleration-sensitive circuit. If this circuit detects acceleration greater than 9% per second it rapidly closes governor and intercept valves, holds them closed for 0.5 seconds and then returns the valves to speed setpoint control. This action is expected to be initiated after a load rejection from greater than 75% full load.

2. Functional Requirements

2.1 Safety Related

- The turbine-generator will trip on any overspeed condition at 10% overspeed.
- The turbine-generator will trip on any fault that will produce a significant potential for damage to the unit.
- The turbine-generator will trip immediately on an electrical fault in the generator or its associated transformers. (non sequential trip)
- Over pressure protection of the HP Turbine outlet, separator and reheater shell is supplied by safety valves or rupture discs.
- Over pressure protection of the LP turbines and main condensers is supplied by blowout discs on the top of the LP casings.

2.2 Process Related

- Convert the heat energy of the steam supplied to the balance header into electrical energy.
- Supply both electrical power and reactive power as required to the grid.
- Supply electrical power to the station electrical distribution system to allow safe operation of all equipment. During loss of line conditions, this power will be supplied at a frequency of ≈ 60 Hz.
- Return the condensed steam to the feedwater system to maintain boiler water inventory.
- Supply extraction steam to the feedwater heaters to raise the feedwater above the minimum temperature required by the preheater section of the boilers as well as improving the efficiency of the cycle.
- Maintain enough steam flow from the balance header to the condenser via the CSDV's when the turbine is unable to accept all of the required flow. This process called Poison Prevent.

3. System Description

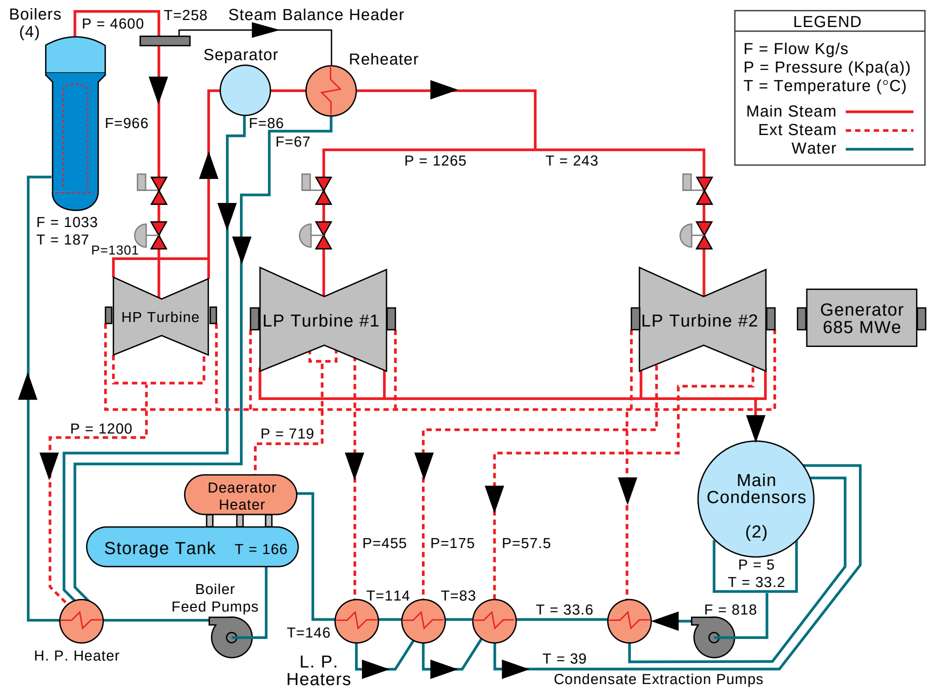
3.1 General

The turbine converts heat energy of steam into kinetic energy in many stages through the turbine. A stage consists of a stationary nozzle or blade and a rotating blade. These stationary nozzles or blades direct the steam onto the rotating blades which are attached to the main shaft of the turbine causing it to rotate. This shaft is coupled to a generator which converts the kinetic energy to electrical power.

In the turbine, there are many of these stages. During the removal of energy the steam expands by a factor of 500 in passing through the turbine. As a result of this high expansion the turbine has a relatively small first stage and very large, often multiple last stages. Details of blade design and construction will not be covered in this lesson, but a brief comment on how stages perform at different loads follows. At high loads in each stage a fixed blade or nozzle accelerates and directs the steam onto the moving blade at the required velocity. As the load is lowered a point is reached at which there is insufficient heat energy in the steam to accelerate the steam to the required velocity in all stages. The last stages are affected first but as the load becomes less this effect propagates to earlier turbine stages. When this occurs in the latter stage(s) of the LP turbine, the stage(s) are now taking energy from the turbine (or generator in the case of motoring). The result of this 'windage' loss is overheating of these stages. This overheating can lead to L.P. turbine damage. To allow for this, the L.P. turbine is equipped with an exhaust cooling system or a steam cooling 'attemperating' water system or both. The exhaust cooling system sprays cool condensate into the exhaust hood. Excessive use of the L.P. cooling spray can result in erosion at the trailing edge of the last row of moving blades due to recirculation steam carrying in moisture from the sprays.

The simplified secondary cycle heat balance diagram, Figure 2, shows the major components of this system and their relationship to each other. The diagram also indicates the more significant temperatures, pressures and flows within the cycle at full power.

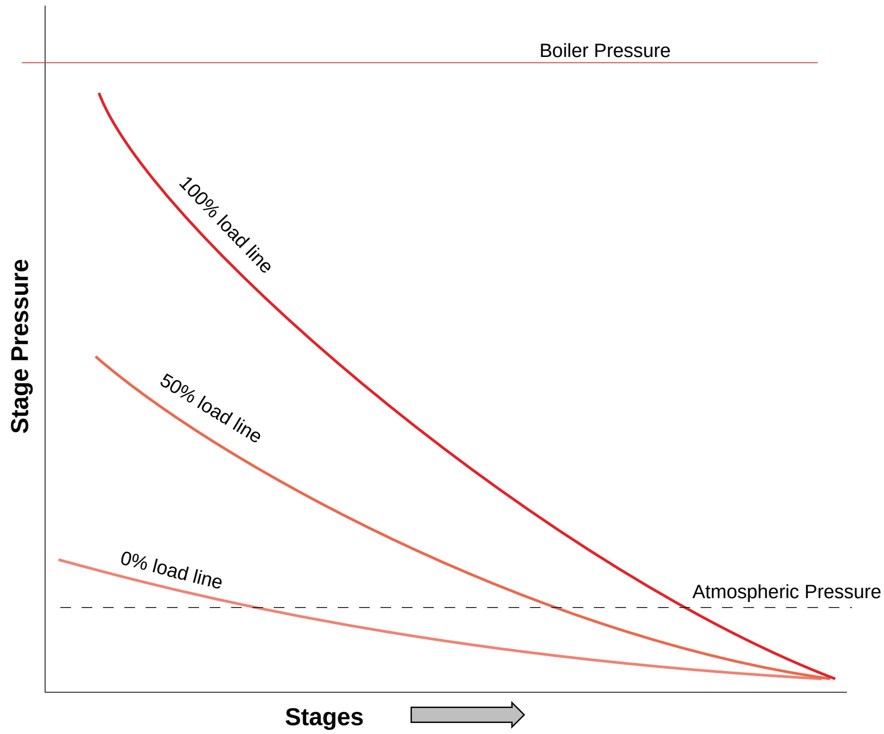
Figure 2
Point Lepreau



3.2 Pressure Profile

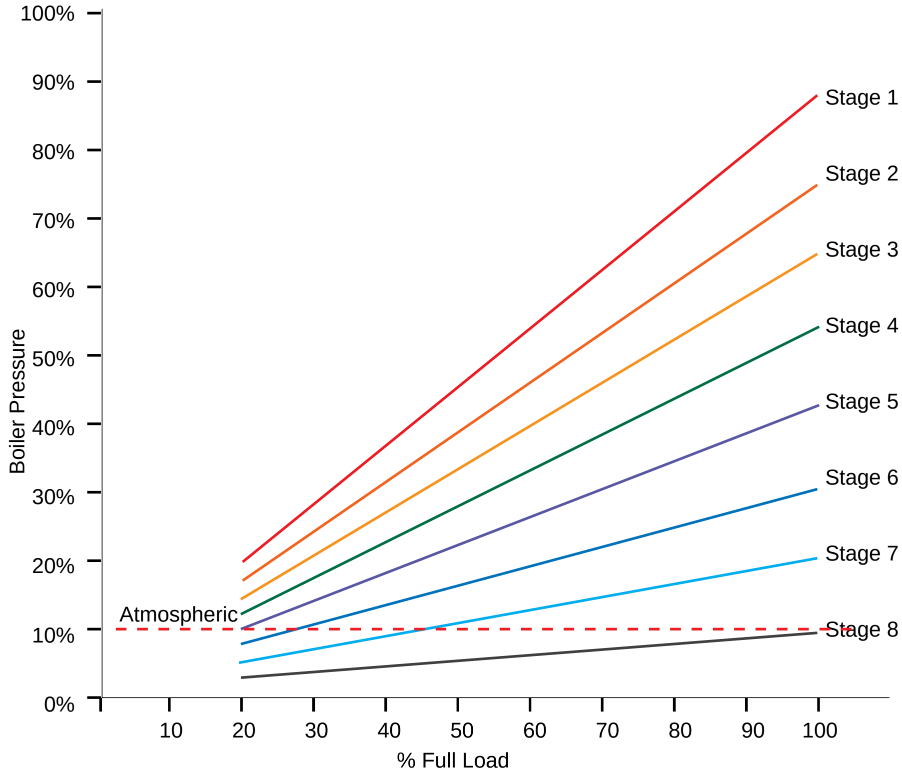
The pressure profile throughout a turbine is a useful tool in determining its health and any operational problems that may exist. Figure 3 shows this pressure profile at three turbine loads. The 100% load line shows that the first stage pressure is close to boiler pressure with the governor valves full open. The 50% load line shows a considerable drop in first stage pressure due the throttling of the steam pressure by the governor valves. The 0% load line shows an even greater pressure drop across the governor valves. As the load decreases more of the turbine operates at sub-atmospheric pressure. During startup even the first stage will be sub-atmospheric. The shape of this curve will vary depending on the blade and nozzle design.

Figure 3
Turbine Pressure Profile



It can also be shown that the pressure in any given stage is proportional to the turbine load. Figure 4 illustrates the stage pressures of an eight stage turbine at various loads. In the early turbine's life a group of signature readings are taken at various loads. These readings can then be compared to current values to ascertain the current health of the turbine.

Figure 4
Turbine Stage Pressure



Turbines normally last a long time without significant wear. Dismantling for inspection is expensive and time consuming. Monitoring stage pressures will show any significant deterioration and alert the operator to a need for inspection or overhaul.

An extreme example of stage pressure change indicating a fault occurred when a turbine lost a row of blades. The loss of these blades did not show up on any turbovisory equipment (ie no high vibration), but the operator noted that the deaerator safety valve was continuously blowing. Since a row of blades were gone the next downstream stage was subject to the previous stage pressure. In this case the extraction steam from this stage was the supply to the deaerator and the pressure was now high enough to lift the safety valve.

Steam Conditions Throughout The Turbine
As the steam passes through the turbine it transfers energy to the rotating blades. The source of this energy is the heat in the steam. The heat energy comes from two sources - the heat from condensation of steam to water and a drop in temperature of the steam. The steam therefore becomes laden with moisture. If nothing were done to counteract this wetting of the steam it would contain about 20% water which would result in serious erosion of components and some operational problems. The solution is to extract the water using a separator and reheat the steam to superheated (dry) condition.

Figure 5
A Mollier Chart

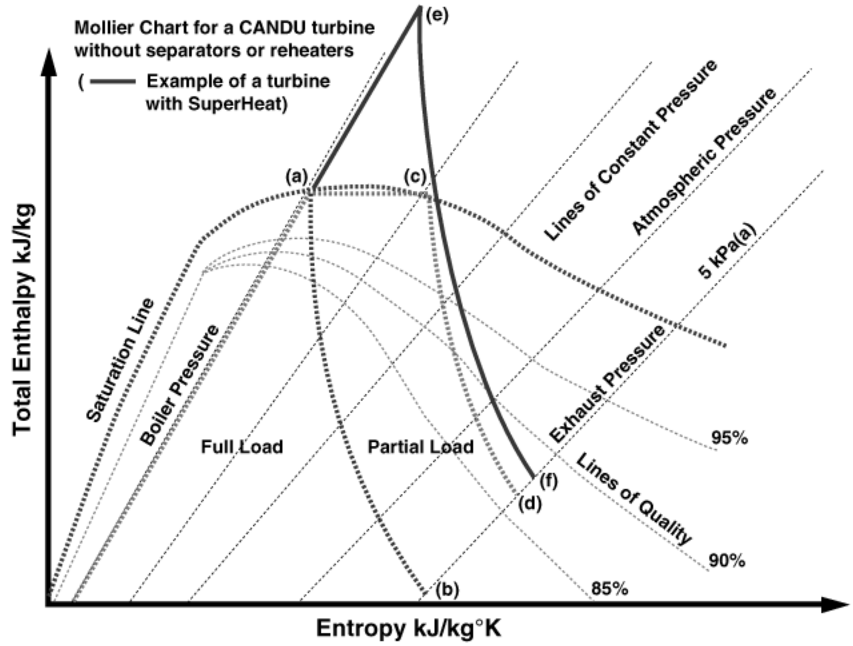


Figure 5 (a Mollier Chart) shows typical steam conditions at full and partial loads in a system without a separator and reheater. Line a-b is the full load line and under these conditions the last stage steam has a high water content (>20%). Line (a-c-d) is the partial load line, where a-c shows the steam being throttled by the governor valves, and line c-d is the partial load line. Figure 5 (dashed line) also shows a fossil fuelled station with the superheated steam supplied to the turbine (line a-e) with a full load line e-f. The last stage is much drier and in most cases the H.P. turbine exhaust would be reheated in the furnace before entering the L.P. turbine. Superheating is not practical in a nuclear station and the steam at the inlet to the HP turbine is saturated. Reheating is essential on large nuclear turbines.

Figure 6
Mollier Chart - CANDU with Reheat

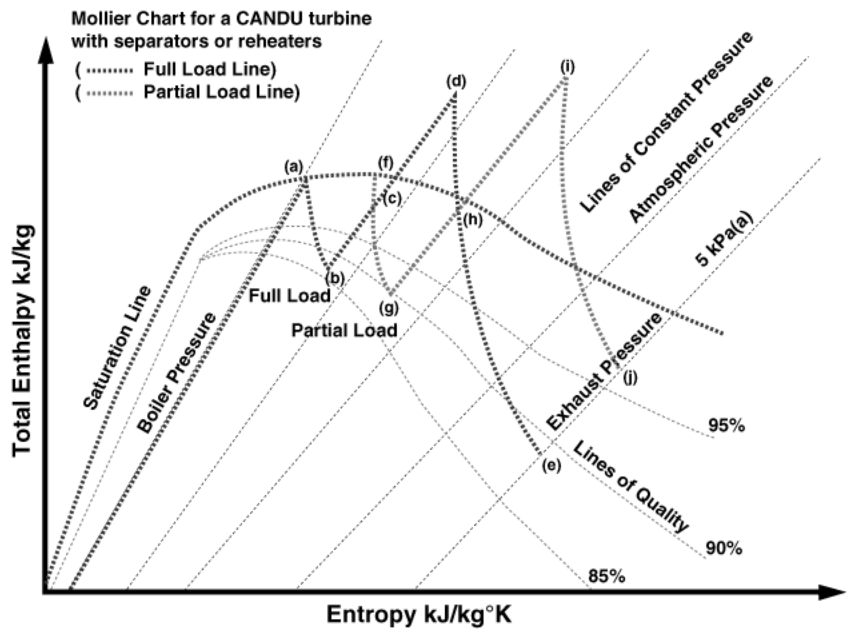


Figure 6 shows the effect of reheating at full and partial load on a nuclear unit. At full load the steam passes through the HP turbine (line a-b) . When it passes through the separator excess water is removed mechanically (line b-c). The steam then passes through a live steam reheater (line c-d) where its temperature is raised to 250°C. The steam is now dry as it passes into the LP turbine (line d-e). The overall result is steam that is much drier throughout the turbine. The advantages are improved cycle efficiency and decreased component wear. Under partial load conditions the steam pressure drops before entering the turbine due to throttling by the governor valves (line a-f). The steam then expands through the HP turbine (line f-g) and then through the separator (line g-h), is dried and reheated (line h-i) and then expands through the LP turbine (line i-j). In addition to water removal using a separator CANDU turbines are designed to remove water at each stage.

In summary, moisture in turbine steam:

- reduces efficiency by its retarding effect on turbine blades,
- causes erosion due to impact, wire drawing and washing,
- favours corrosion mechanisms
- increases the potential for turbine overspeeding as water flashes to steam when the pressure drops inside the turbine casing on interruption of the steam supply.

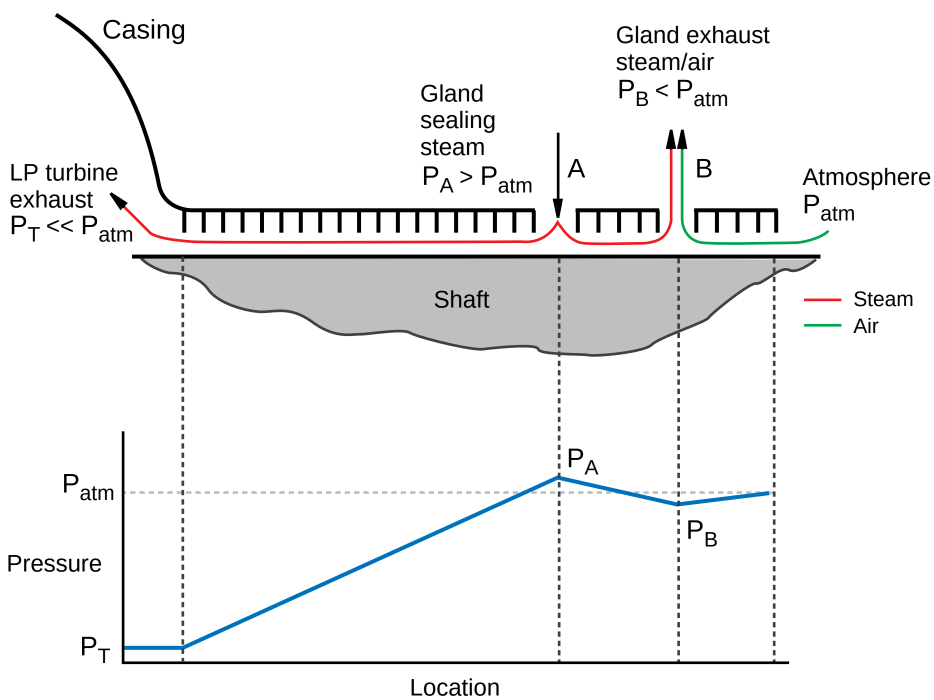
3.3 Keeping Steam In And Air Out of the Turbine

Figures 3 and 4 show that there is a considerable pressure range throughout the turbine. Atmospheric pressure is illustrated on these figures. At zero load, during motoring conditions and at startup and shutdown pressure throughout the entire turbine is sub-atmospheric. Even at full load parts of the LP turbine, the condenser and parts of the feedwater system are sub-atmospheric. At higher loads the H.P. Turbine shaft area pressure is greater than atmospheric pressure. A seal is required to keep the steam in and the air out of the turbine. The LP gland seals, that is the seals around the shaft of the turbine where the shaft exits the LP casing are always sub-atmospheric. The HP gland seals, particularly the turbine inlet side on a single flow experience a wide range of pressures.

Gland seals on CANDU turbines are usually labyrinth seal type. Labyrinth seals consist of number of thin circular strips or serrations fastened to the casing so that the clearance between the shaft and the edges of these strips is very small. The resistance offered by this series of obstructions to steam flow is enough to hold leakage to a minimum. The LP glands which see relatively constant ΔP are supplied with gland steam. See point "A" on Figure 7. Some steam flows into the turbine and some flows away from the turbine to the exhaust connection, item "B".

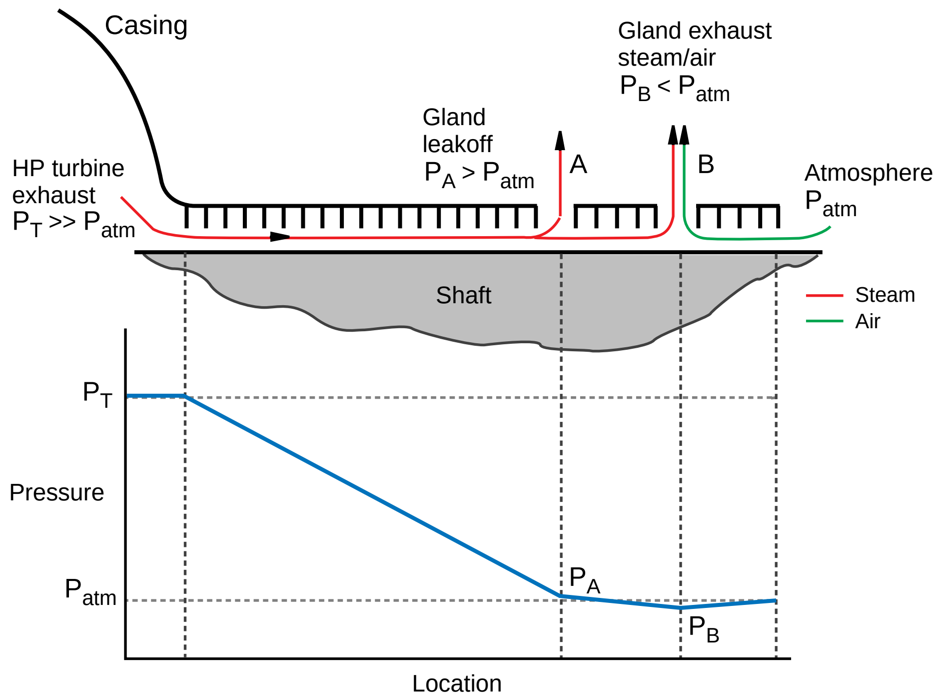
Figure 7

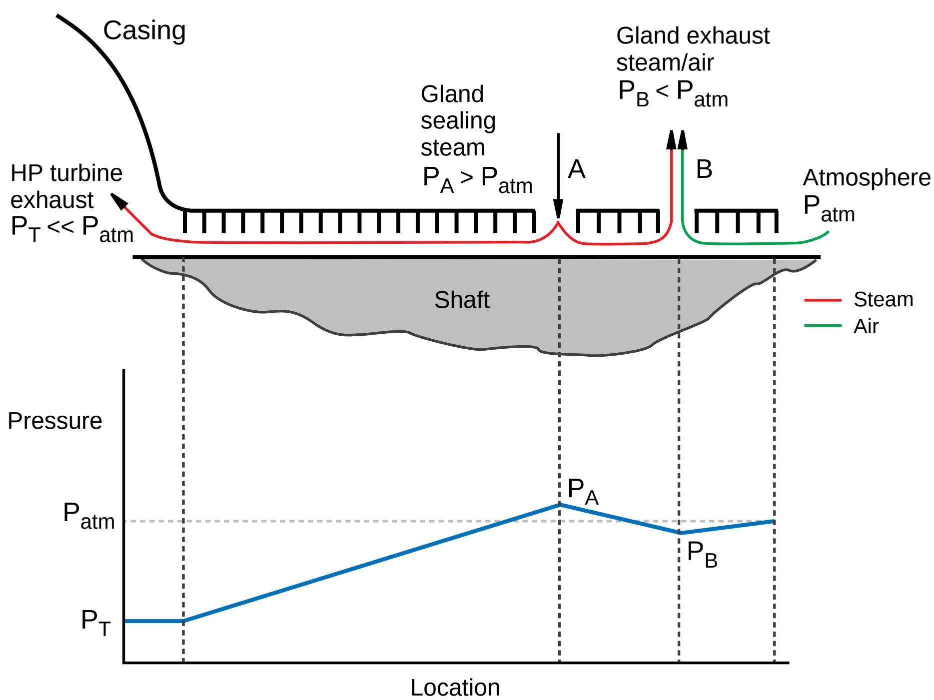
Normal Operation of LP turbine with gland seal



There are several designs of HP glands. Their principle of operation is shown in Figure 8. At high loads (Figure 8a) the sealing steam comes from the turbine and exhausts to a gland leakoff. At very low loads and start-up steam is supplied to the gland at A and it operates the same as an LP gland.

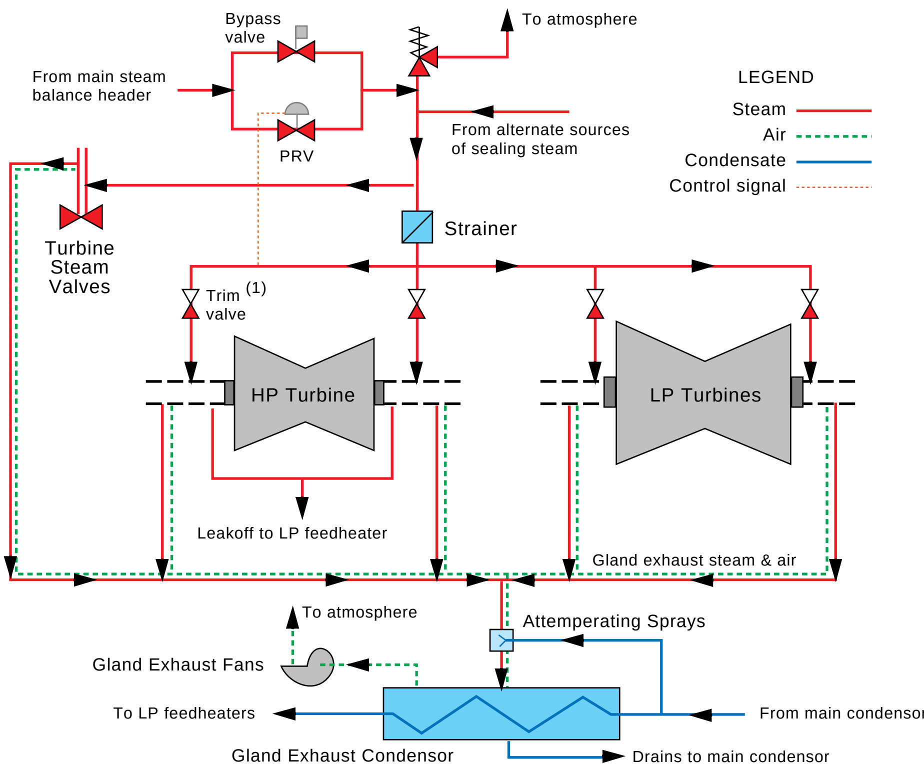
Figure 8
Normal Operation of LP turbine with gland seal





Gland rubbing may become an operational problem. Light rubbing can be tolerated but heavy rubbing can damage seals, cause turbine vibrations and forced turbine outages. A simplified gland steam sealing system is shown in Figure 9.

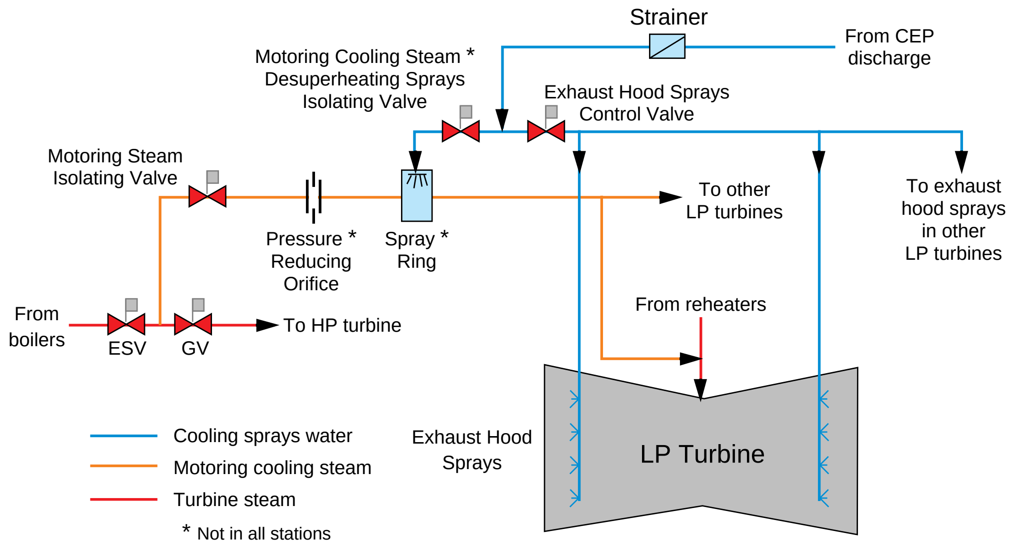
Figure 9
Simplified gland steam sealing system



3.4 Turbine Overheating

At very low loads some of the turbine blades are not supplying energy to drive the turbine. When the turbine is motoring (being driven by the generator) none of the blades are supplying energy to drive the turbine. In these situations the rotor is churning the blades in stagnant steam causing them to heat up. The steam in turn, heats up the blades and turbine casing. To alleviate the problem a cooling system (hood sprays and/or cooling steam) is used. Figure 10 is a simplified LP turbine cooling system illustrating both systems.

Figure 10
Simplified LP turbine exhaust cooling system



Overheating can cause damage due to:
•rotor vibration as a result of rubbing and/or bearing misalignment due to thermal distortion of the LP casing and exhaust cover
•rubbing of internal parts due to thermal expansion,
•permanent distortion.

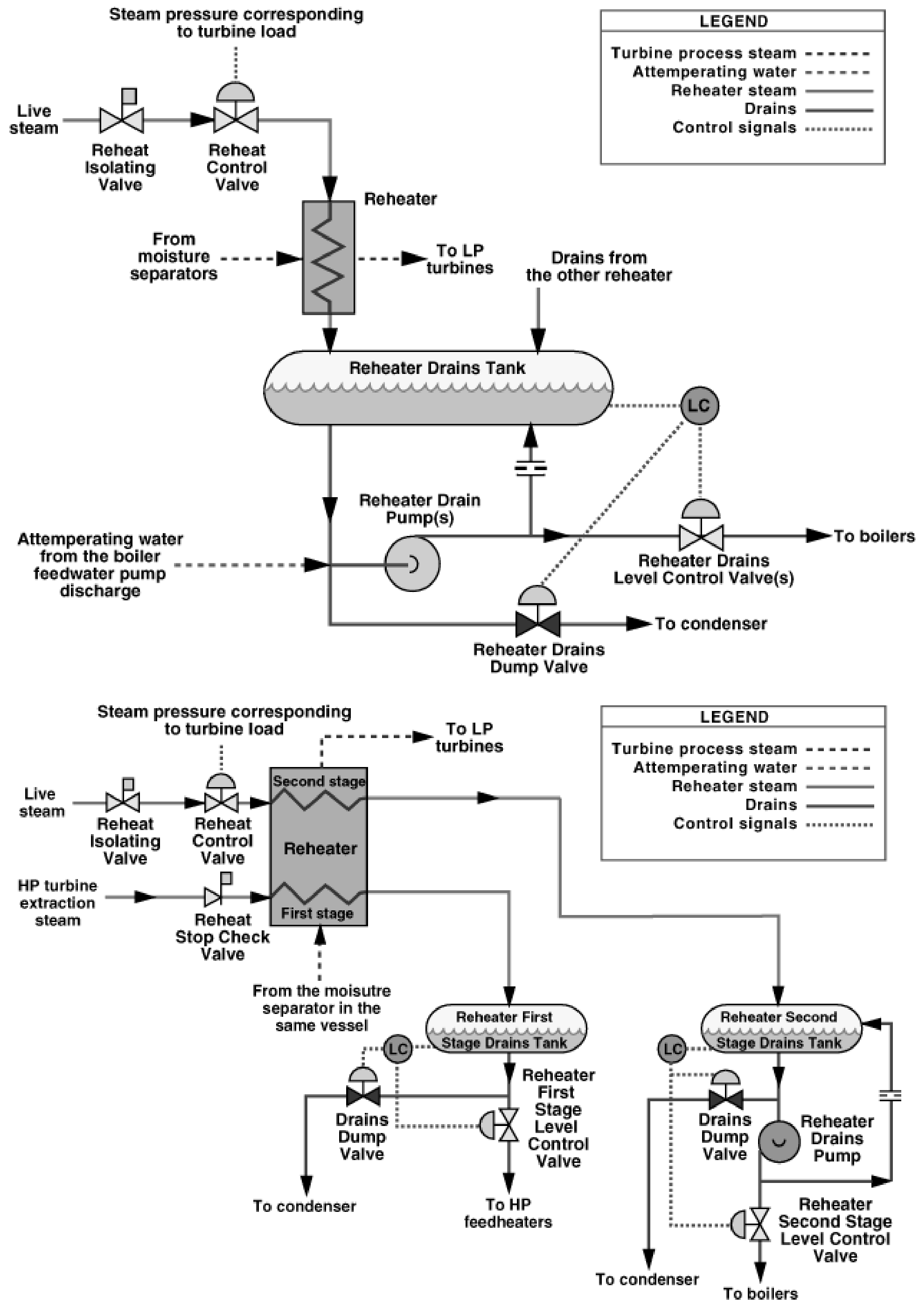
The operator has two choices if overheating cannot be controlled:
1. put load on the turbine - the increased steam flow will tend to return temperature to normal value or
2. if loading is not possible, due to high condenser pressure or reactor problems, trip the turbine.

3.5 Reheat System

In all reheat systems exhaust steam from the HP turbine passes through a separator where the excess moisture is mechanically removed from the steam. Two types of reheat systems are used on CANDU units, either a single stage live steam reheater or a two stage reheater. In the two stage type the HP turbine exhaust stream is first heated by HP turbine extraction steam. The final heating is by a live steam reheater where steam is taken directly from the boiler. Figure 11 shows a simplified flow diagrams of these two systems.

Steam flow to the reheater is usually manually controlled. At low loads or start-up the steam is either isolated or limited to prevent high temperatures at the LP turbine outlet. At high loads the steam flow is self regulating. Loss of reheat increases the steam wetness in the LP turbine.

Figure 11
Reheat systems in CANDU stations



In a reheater there is a high ΔP between the main steam supply and the HP turbine exhaust steam being reheated (main steam ~4.5 Mpa and HP turbine exhaust steam < 1.2 Mpa). If a leak exists in the reheater then steam will pass from the main steam supply to the HP turbine exhaust. The throttling effect at the leak point will cause this steam entering the steam flow to the LP turbine to drop in temperature (from 250°C to say 180°C). If the leak is large then the steam entering the LP turbine may be reduced considerably in temperature from its normal value of about 240°C. As there are two reheater flows this could result in high side to side ΔT at the LP turbine inlet. To correct this the steam flow to the non-leaking reheater may have to be throttled. Operating with a leaking reheater has some undesirable effects as follows:

- the moisture content of the LP steam will increase,
- the HP turbine exhaust pressure may increase and the LP turbine stages may become overloaded,
- the leaking steam entering the LP turbine flow is bypassing the governor valves and could result in overspeeding when the generator is not synchronized.
- a turbine trip will cause the intercept valves to close and the HP turbine, separator and reheaters will tend to rise to boiler pressure. The reheater rupture discs which protect these components and the low pressure end of the high pressure turbine from overpressure may then blow.

3.6 Turbine Steam Valves and FRF

The hydraulic fluid system which controls all the turbine steam valves uses an organic fire resistant fluid (FRF). This self contained system has two 100% duty pumps which supply hydraulic fluid to the turbine valves at about 10 Mpa(g) pressure. The hydraulic actuators and other parts of the governing valves are built to very close tolerances. Foreign material in the fluid can accelerate wear and affect the performance of the components. The purity of this hydraulic fluid is maintained at a high level by continuous purification

On loss of FRF pressure the turbine steam valve actuators are designed to close.

Main steam valves include the emergency stop valves, reheat emergency stop governor valves and intercept valves. Refer back to Figure 1.

Figure 12
Typical turbine hydraulic fluid system

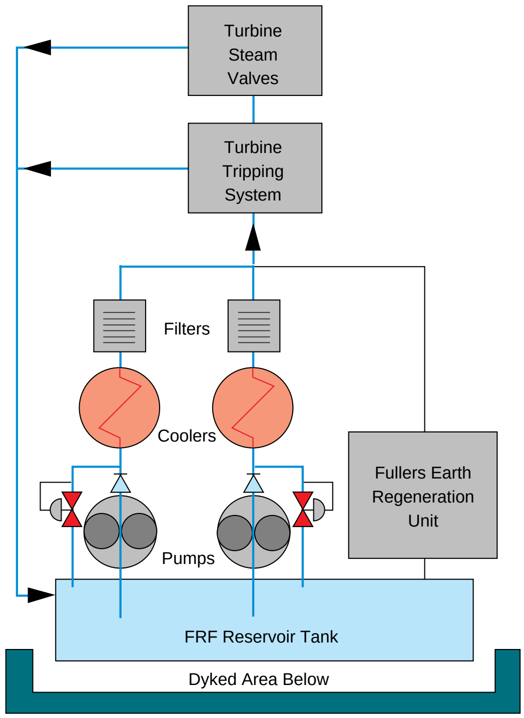


Figure 12 is a simplified diagram of a turbine-generator FRF system for a typical CANDU station. The hydraulic fluid system supplies high pressure fluid to all the steam valves via a tripping system. If no trip is present then the fluid can pass on to the valve actuators and position the valves as required by the speed/load mechanism.
There are very close tolerances in these components and it is therefore important that this FRF system fluid be very clean, otherwise turbine steam valve malfunction is possible.

Figure 13 is a simplified diagram of a steam valve hydraulic actuator. A summary of its operation is as follows:

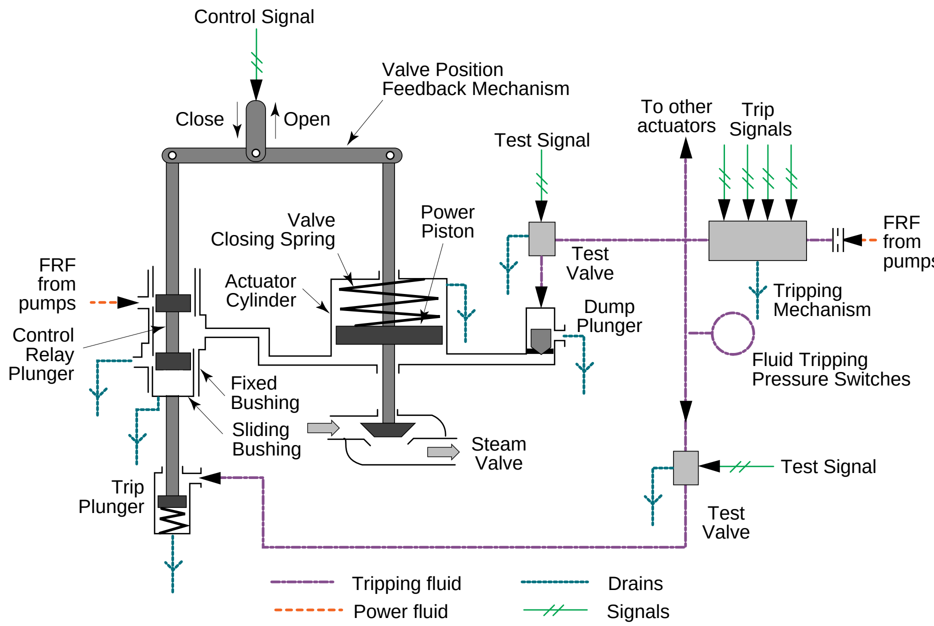
- When the control signal calls for a valve movement, the control relay plunger moves in the appropriate direction, uncovering either the fluid supply port, if the valve is to be opened more, or the drain port if the valve is to be closed more. The resultant valve movement returns (via the valve position feedback mechanism) the control relay plunger back to its neutral position once the valve has reached the demanded position.
- Upon a turbine trip signal, the tripping fluid pressure drops rapidly. The hydraulically unbalanced dump plunger rises from its seat, opening a drain path for the fluid under the power piston. At the same time, the spring-loaded trip plunger rises, driving the sliding bushing of the control relay upward. This action uncovers the drain port in the bushing , thereby

opening another path for the evacuation of the hydraulic fluid from the actuator cylinder,

- On-power tests of the dump and trip plungers are performed using test valves which dump to drain the tripping fluid supplied to either plunger while maintaining essentially normal fluid pressure elsewhere.

Figure 13

Steam valve hydraulic actuator



3.7 Turbine Tripping System

The purpose of the Turbine Tripping System is to detect a fault condition and to automatically shut off steam supply to the T/G and electrically separate the generator from the grid. This must be done before any mechanical damage can occur to either turbine or generator.

There are two types of turbine trips employed. A sequential trip operates for conditions that are generally turbine related such as low lubricating oil pressure low vacuum and high boiler level. During a sequential trip, the main steam valves are closed, shutting off steam to the turbine prior to opening the electrical output breakers. This has the effect of dissipating all of the steam in the turbine prior to separating from the grid, thus preventing T/G overspeed.

A non-sequential trip is generally generator related, such as generator protection and main transformer protection.

During a non-sequential trip the generator output breakers are opened and the main steam valves are closed at the same time. The steam entrained downstream of the main steam valves expands through the turbine causing it to accelerate to approximately 1860 RPM.

The tripping circuit which detects faults in the turbine is usually 250Vdc Class I power and is a two channel system. Either channel can initiate a trip even when one channel of the system is isolated for testing.

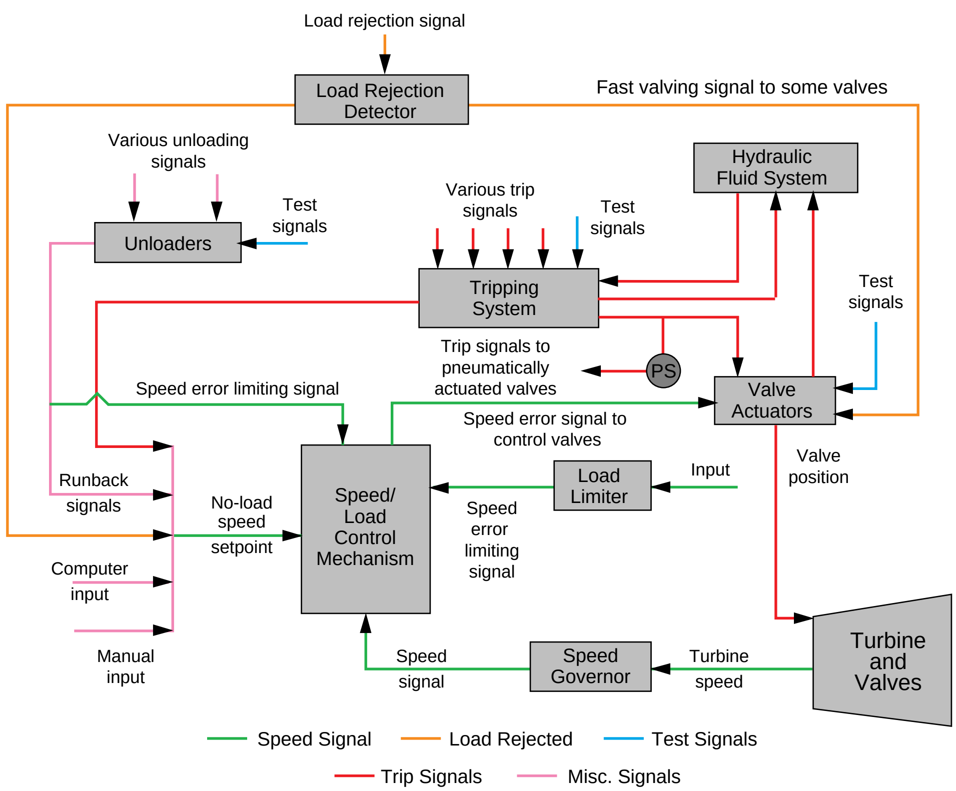
4. Operation of the Turbine Governing System During Various Unit Operating Conditions

The following operating conditions are discussed in this section
- Turbine runup and power manoeuvres,
- Steady power operation,
- Turbine trip, load rejection and reactor trip.

In addition the causes and reasons for various types of turbine runbacks will be discussed.

4.1 Turbine Runup and Power Manoeuvres

Figure 14
Load limiter and unloaders in a typical turbine electro/hydraulic governing system

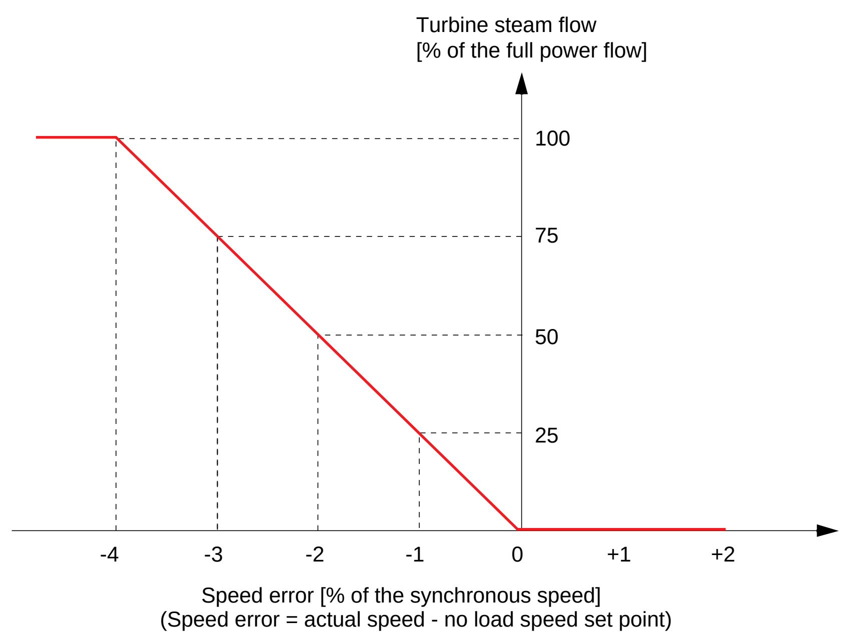


Turbine speed (during runup) and load (when the generator is connected to the grid) are controlled by positioning of the valves which control the turbine steam flow. Figure 14 shows that valve positioning is controlled by a speed error signal (also called valve demand signal). The signal is generated by the speed/load control mechanism which compares the actual turbine speed with the no-load speed setpoint. The latter can be adjusted either manually or, more typically, by the digital control computer (DCC) controlling unit operation. While in different stations the physical nature of all these signals may be completely different (they can be voltages, mechanical displacements, hydraulic fluid pressures, etc.), the effect of the speed error signal on the turbine is the same. Note that to increase the turbine steam flow, the speed/load control mechanism (which is essentially a proportional controller) must tolerate a larger and larger speed error. Figure 15 is an example of a governor system response with a 4% speed droop. 4% speed error (droop) is required to open governor valves full from 0 to 100% FP.

To raise the turbine speed during runup, the no-load speed setpoint is increased. The actual speed follows the setpoint with nearly no offset because the speed error is very close to zero. This stems from the fact that the turbine steam flow is very small, because there is no-load on the generator (See Figure 15)

Figure 15

Effect of the speed error signal on the turbine steam



Once the generator is synchronized, turbine speed is locked into the grid frequency, regardless of the no-load speed setpoint. The latter can, therefore, be used to control the turbine-generator load. For example, to operate the turbine at full load, the no-load speed setpoint must be raised to about 104%. Because the actual speed remains at 100%, a minus 4% speed error signal is generated (100% - 104% = - 4%) as required to admit the full load power steam flow to the turbine (Figure 15). Likewise to reduce load to 75% the no-load speed setpoint must be lowered to about 103%, there by producing a minus 3% speed error signal.

4.2 Steady Power Operation

If all operating parameters were perfectly constant there would be no need to adjust the no-load speed setpoint. Practically, however, various flows, temperatures pressures and other parameters fluctuate continuously. When the fluctuations are too large, the no-load speed setpoint to the turbine governing system must be adjusted.

For example, in the reactor leading mode of unit operation ("Alternate Mode"), changes in boiler pressure, if large enough, cause the BPC to adjust the speed setpoint such that the boiler pressure error is minimized. In the reactor lagging mode("Normal Mode"), maintenance of a constant generator MW(e) output despite fluctuations in boiler pressure, condenser vacuum, feedheater performance, may require minor adjustments of the setpoint. This is normally performed automatically by the DCC, using a control program called Unit Power Regulator. This subject will be discussed in Overall Plant Control.

4.3 Turbine Trip

Regardless of cause, any turbine trip activates the tripping mechanism, causing it to dump the hydraulic fluid to drains which is normally supplied to the turbine valve actuators. When the fluid pressure is lost, the spring-loaded actuators close the valves as described earlier in the manual. Loss of the fluid pressure is also sensed by some pressure switches (Figure 13) which send a trip signal to pneumatically actuated valves such as extraction steam check valves. At the same time, a fast runback of the no-load speed setpoint is initiated. This action is continued until the setpoint is reduced to zero. In the meantime, resetting of the turbine is inhibited. The purpose of the runback is to prevent rapid re-opening of turbine valves when the trip is reset, i.e. when the normal hydraulic fluid pressure is restored. Otherwise, the valves would open as requested by the unchanged no-load speed setpoint. An uncontrolled turbine runup and another turbine trip (on overspeed or excessive acceleration) would result.

4.4 Load Rejection

Any modern turbine governing system has some specialized components whose function is to detect a load rejection as soon as it happens. Early detection of this by an anticipatory signal without waiting for the turbine speed to increase is important. Initiating the response of the turbine steam valves greatly reduces the transient overspeed. During a load rejection from high power the turbine-generator rotor accelerates rapidly, due to steam trapped in the turbine and reheaters.

In Figure 12 the components that provide early detection of a load rejection are shown as a load rejection detector. In different stations generation of this signal is based on various events that accompany this upset. Listed below are some examples:

- Opening of the generator main circuit breakers,
- Rapid acceleration of the turbine generator rotor
- Large unbalance between the turbine power and the generator MW(e) load.

When a load rejection is detected the load rejection detector sends a special fast valving signal to the turbine valves that overrides the normal valve demand signal. This makes the valves operate quickly. The fast valving signal is quickly terminated, at which time the speed/load control mechanism resumes the control of turbine valves based on the speed error signal. This signal is now so large that the valves remain closed until the overspeed transient subsides, (Figure 14).

Meanwhile a fast runback of the no-load speed setpoint is carried out. The purpose of this action is to lower the speed setpoint so that after the overspeed transient the unit service load is supplied at a frequency as close to 60 Hz as possible, and the generator is ready for resynchronization with the grid. Without the runback the no-load speed setpoint would be too high, causing the turbine speed and generator frequency too stabilize at too high a level.

In some stations the runback is continued until the no-load speed setpoint has reached 100% synchronous speed. If there were no load on the generator, the machine's speed would stabilize approximately at this level. However because the generator is supplying station load through the service transformer, typically 6-7% of full load, the turbine generator speed settles somewhat below 100% producing a speed error signal to provide the required steam flow. The speed/load setpoint must therefore be adjusted to bring the machine speed to 100% In some stations the need for this adjustment is minimized by having the runback terminate earlier such that the typical unit service load can be supplied at 100% speed.

4.5 Reactor Trip

In most stations the governing system responds to a reactor trip by a fast runback of the no-load speed setpoint which is continued until the steam flow is completely stopped. Typically the runback is requested by the BPC responding to decreasing boiler pressure and reducing reactor power. If the runback fails to keep boiler pressure sufficiently high, the low boiler pressure unloader operates as describe in the Steam Generator Pressure Control Module.

4.6 Turbine Runback

The term 'turbine runback' refers to a reduction of the no-load speed setpoint at a fixed preset rate of between 1 and 10% of full power per second. The rate varies from station to station.

Typically two rates of runback are available, slow and fast. These can be of two types:

1. Unlatched - meaning that the runback ends when the initiating condition has cleared;
2. Latched - meaning that the runback continues until the no-load speed setpoint has reached a pre-determined level.

Table 1 illustrates turbine runbacks performed automatically in response to various operating events. Only the most common initiating events are listed. In addition a manual turbine runback can also be completed, either remotely from the control room or locally from a control console in the turbine hall.

Table 1:
Examples of Typical Automatic Turbine Runbacks

Initiating Event	Runback Event	Purpose of the Runback
Turbine trip	Fast, latched	To prevent rapid reopening of turbine valves on resetting the turbine trip which would cause an uncontrolled runup and another turbine trip on overspeed and excessive acceleration.
Load rejection	Fast, unlatched	To supply the unit service load at the correct frequency
BPC request	Slow Unlatched	To reduce the turbine steam flow in order to return boiler pressure to its setpoint
Low condenser vacuum or boiler pressure unloading	Fast, unlatched	To prevent turbine load cycling
Low generator stator coolant flow	Slow, latched or unlatched.	To reduce generator MW(e) load in order to prevent generator damage due to overheating

5. Emergency Overspeed Protection

This section covers:

- turbine speed reaching the overspeed trip level
- the enhancement of overspeed protection by the emergency overspeed
- how the governor operates and how it is tested

5.1 Introduction

Among various turbine emergency conditions excessive overspeed is probably the most dangerous. It can result in massive destruction of equipment and create acute safety hazards to personnel. Owing to the potential severity of such an accident, numerous design and operating precautions are taken to reduce the chances of its happening. One of these precautions is the provision of an emergency overspeed protection which is part of the tripping mechanism. The trip protection should operate whenever the turbine speed reaches a preset overspeed level which is typically about 110% of the synchronous speed. This can happen during the following operating conditions:

1. Actual overspeed testing of the governor.During this testing the turbine-generator is disconnected from the grid and its speed is raised to the level at which the emergency overspeed trip protection should operate.
2. A load rejection or a nonsequential turbine trip combined with the failure of some components of the turbine governing system and/or some turbine valve.

The emergency overspeed trip protection greatly reduces the likelihood of the turbine reaching a destructive speed if the circumstances outlined in condition 2 above arise. The emergency overspeed trip protection has a high degree of reliability of operation for the following reasons:

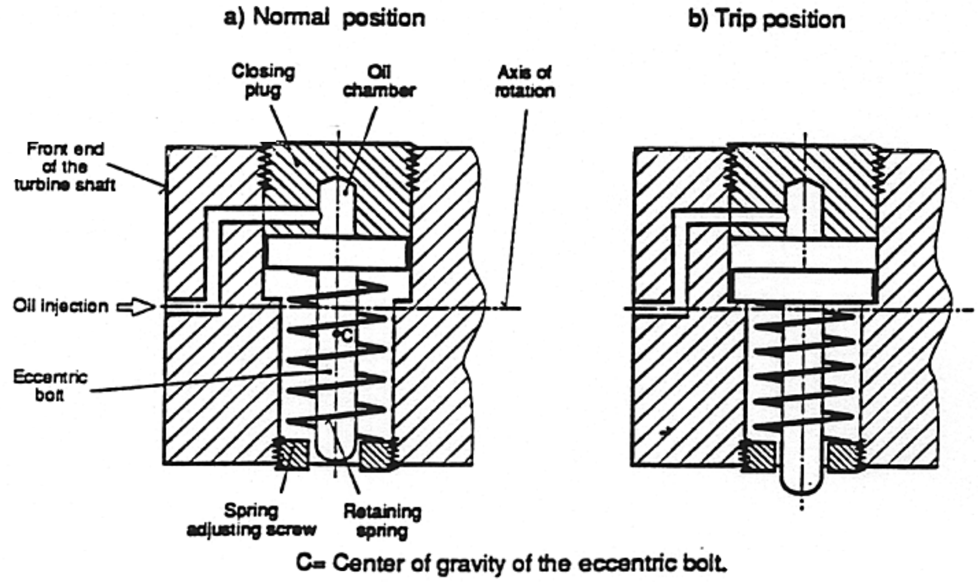
1. This trip protection is independent of other components of the turbine governing system which normally respond to a load rejection or initiate a non-sequential turbine trip caused by reasons other than excessive overspeed.
2. In comparison to a load rejection, additional turbine valves are called upon to stop the turbine steam flow when the overspeed trip protection initiates a turbine overspeed trip. The EHG action can compensate for some failures of turbine valves being the cause of overspeed.
3. The emergency trip protection governor itself has two independent channels either of which can fail without rendering the protection unavailable. Routine tests of the trip protection are performed to confirm its availability

Even although the emergency overspeed trip protection reduces the probability of an overspeed accident considerably it does not eliminate the risk totally. For example, combined failure of the ESV and GV in the same steam admission line, if not discovered in time, would cause such an accident. Similarly failure of the tripping mechanism to execute the trip signal produced by the emergency overspeed trip protection could also have disastrous consequences. Maintaining turbine valves and the governing system in good operating condition is the essential primary activity to ensure plant safety. The emergency overspeed protection provides secondary backup protection.

5.2 Principle of Operation

A typical emergency overspeed bolt is a mechanical device mounted on the HP turbine end of the turbine-generator rotor. To improve reliability the bolts are duplicated. The core of each bolt is a spring loaded centrifugally unbalanced object mounted inside the turbine rotor. The object may be of various shapes. A common design is an 'eccentric bolt' as shown in Figure 16. The word eccentric is applied because the centre of gravity of the bolt is offset with respect to the axis of rotation. Figure 16 shows only one of two identical halves of the overspeed bolt protection.

Figure 16
Simplified typical emergency overspeed trip bolt



When the turbine shaft is turning the eccentric position of the bolt inside the turbine shaft causes a centrifugal force to be exerted on the bolt opposing the spring force. The design is such that the force increases very rapidly as the turbine speed increases in the speed range of concern. The compression of the spring and therefore the trip action can be adjusted by the adjusting screws. If the overspeed bolt is adjusted properly the spring force dominates, holding the bolt inside the shaft when the turbine speed is below the overspeed trip setpoint. On reaching the trip setpoint the unbalance centrifugal force overcomes the spring force causing the bolt to move outward. The magnitude of this displacement is limited by the collar of the bolt striking a recess inside the shaft.

The movement is however sufficient for the bolt to strike a trip (pallet) lever close to the shaft surface which activates a turbine tripping mechanism. When the turbine speed subsides the centrifugal force decreases below the spring force and the bolt retracts to its normal speed position. The turbine tripping mechanism must be reset before normal hydraulic fluid pressure can be restored to the turbine governing system.

5.3 Testing

To confirm its availability the emergency overspeed trip is periodically tested in two different ways. One of them is actual overspeed testing. Testing requires that the turbine-generator be unloaded and disconnected from the grid. The test is done at startup or shutdown, when the unit is carrying no load and is unsynchronized. The test however does subject the machine to stress and an alternative way of testing the overspeed trip mechanism is provided which can be carried out at power and without causing a turbine trip.

Overspeed is simulated by the injection of turbine lubricating oil into the oil chamber of the overspeed bolt (Figure 16). This can be accomplished in a controlled manner so that not only can the freedom of movement of the mechanism be tested but also the speed at which the trip occurs.

Failure of either channel of the emergency overspeed trip to pass an **actual** overspeed test is an unsafe operating condition because of the importance of the system to plant safety. If a test is failed this requires mandatory turbine shutdown to repair the emergency overspeed bolt. Failure of an on-power simulated overspeed test may be caused by a fault in the test circuitry. This has to be investigated and if the fault cannot be repaired or the operation of the emergency overspeed bolt is suspect then turbine shutdown is required.

Failure to keep the turbine speeds below 104% of synchronous speeds, operation for long periods of time with high vibration, allowing thermal excursions (high temperatures or high ΔT) or water induction can lead to serious mechanical damage and possible turbine-generator failure with the production of high speed missiles.

This type of incident is not likely to happen in CANDU plants as routine testing of the steam valves is a normal practice and this will detect sticking steam valves. As a further precaution the turbine is oriented to minimize possible damage in the event of a speed runaway and missile walls are constructed to protect other sensitive equipment and provide a high degree of assurance that control of the plant will be maintained.

6. Turbine Supervisory System

The turbine supervisory system monitors the following:

- turbine-generator bearing vibrations,
- rotor eccentricity
- HP casing expansion
- HP and LP turbine differential expansion
- shaft axial position
- turbine speed
- temperatures of turbine casings and bearings

6.1 Turbine-Generator Bearing Vibrations

Vibration detectors provide early identification of excessive vibration of the turbine and potentially dangerous operational problems. Partial loss of turbine blades may be identified in this way.

6.2 Rotor Eccentricity

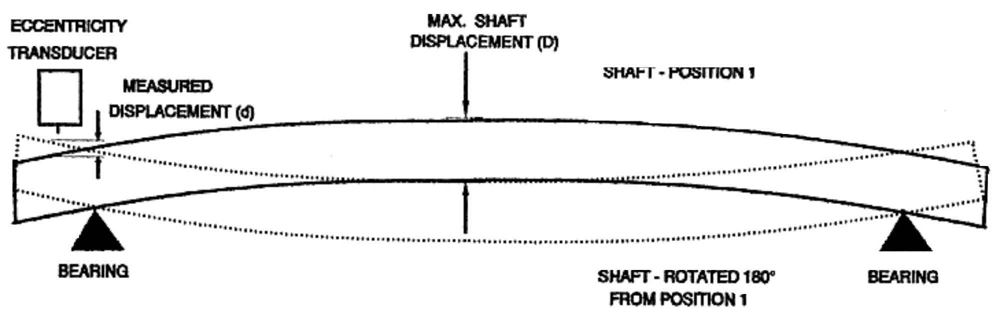
An Eccentricity detector measures how much the rotor is bent and is used mainly at low speeds. It is used to determine when the shaft is straight enough to go to high speed. Vibration detectors will not give satisfactory warning at low speeds. Unbalanced centrifugal forces that cause turbine vibration are proportional to the square of the rotational speed. Eccentricity is used in the first one third of normal speed range. Above this speed vibration detection is used to detect imbalance problems.

Figure 17 is an exaggerated illustration of a bent rotor with an eccentricity detector. It illustrates that the measured displacement is not necessarily the same as the actual shaft displacement.

The transducer only provides an eccentricity signal when the shaft is rotating. Owing to the need to locate the transducer in accessible locations near bearings the actual eccentricity (d) is much smaller than the rotor displacement (D).

Figure 17

Exaggerated illustration of a bent rotor



6.3 HP Casing Expansion

The HP casing is normally supported on its foundations in such a way that the generator end is fixed in the axial direction. The support at the other end allows axial movement while still maintaining proper alignment. Casing expansion is measured at this end. The major reason for taking this measurement is to detect excessive resistance to movement of the casing. The effects of sticking or no movement will be discussed later in this manual.

6.4 HP and LP Turbine Differential Expansion

The rotor and casing expand differentially. To prevent rubbing damage of the rotating and stationary blades this differential expansion has to be kept within certain limits. The differential expansion detector is usually mounted on the floating end of the casing and it measures the distance between this point and a point on the shaft, usually a collar. Operational use will be discussed later in the manual under 'Major Operational Concerns'.

6.5 Shaft Axial Position

This detector is mounted on the thrust bearing pedestal and measures the shaft position relative to the thrust bearing. It detects abnormal axial thrust on the turbine generator rotor. It is also used to detect excessive wear or failure of the thrust bearing.

6.6 Turbine Speed

This measurement is used during start-up, shutdown, synchronization and overspeed tests. During start-up and shutdown it is used to verify that certain automatic operations occur as required. The measurement is also used to monitor the approach to critical speeds (speeds which are natural vibration frequencies) and move quickly past this speed. It also indicates to the operator the approach to synchronous speed.

During overspeed tests accurate speed measurement is needed to ensure that the tripping speed is correct and that the machine speed does not exceed its limit (usually 110%).

6.7 Temperatures

There are several operational temperature limits. Warm-up rates, steam to metal differential top and bottom casing temperature are examples. These limits are supplied by the turbine manufacturer and will vary slightly from turbine to turbine. Lubricating oil temperatures are also monitored to detect problems in this system.

7. Turning Gear

A turbine shaft is very long and heavy. When the rotor is not rotating and is cool it will sag between the bearings and when the rotor is not rotating and is hot it will hog. The hogging is due to the hot gases (steam or air) rising to the upper part of the casing.

The turning gear consists of gearing and a motor which when engaged will rotate the shaft at 150 rpm. The use of the turning gear is inhibited if lube oil and/or jacking pressures are too low. The turning gear is used to roll out eccentricity due to sagging or hogging before running up speed. The time required to bring the shaft to the required straightness can be many hours. The straightness can be ascertained by eccentricity instrumentation. Using the turning gear also permits uniform pre-warming during start-up. Once steam is admitted to the turbine at 15 rpm the turning gear will disengage automatically.

At shutdown the shaft should not be left stationary for more than a few minutes. If it is necessary to do so great care must be exercised in rotating the shaft again as serious mechanical binding may occur. Excessive use of the turning gear is not recommended, mainly because it promotes copper dusting in the generator rotor which can lead to generator ground faults.

If the turning gear is not available at turbine rundown then the machine may be rotated using 'handbarring' or special electric or hydraulic tools. Some units have an auxiliary turning gear. If handbarring indicates an excessive force is required, indicating an excessively bent rotor, then the turning gear must not be engaged. The machine must be left until rotor cools down and then manual hand barring tried again.

8. Turbine-Generator Lubricating Oil System

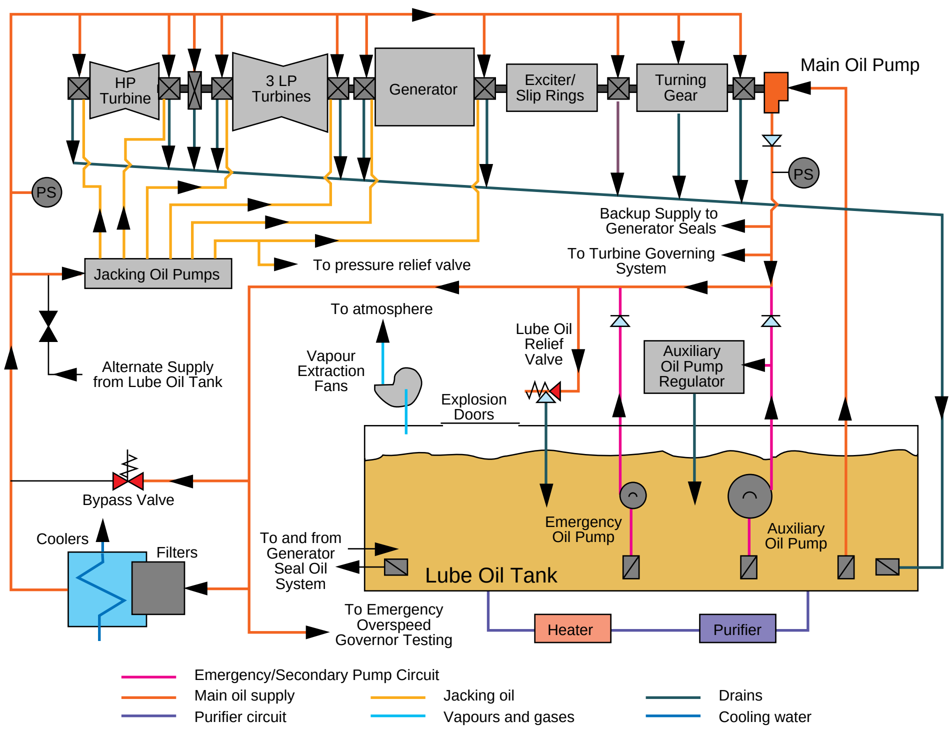
The turbine-generator lubricating oil system supplies oil to the turbine generator bearings, the turbine overspeed bolts, the turning gear bearings and mechanism, the jacking oil pumps and seal oil systems.

Figure 18 is a simplified schematic of a typical lube oil system showing the major components. The main oil pump is driven by the turbine-generator shaft and delivers oil at 300-400 kPa(g) pressure to the system. This oil supply is backed up by a full capacity AC driven auxiliary oil pump. An emergency lower capacity Class I or Class II oil pump supplies oil to the bearings at 40 - 60% of normal pressure.

The turbine-generator rotors are very heavy pieces of equipment. When they are stationary the lube oil is squeezed out from between the journal and the bearing and metal to metal contact is established. To start rotation via the turning gear under these conditions would require a very large force and some wiping of the bearing surfaces would occur. To prevent this, high pressure lube oil at 10 Mpa(g) is injected under all the journals to "float the shaft" to allow for easy rotation and establishment of the required 'oil wedge'. This high pressure oil is supplied by the Jacking Oil Pumps.

Most of the oil pumps are positive displacement type and pressure regulation and overpressure protection is provided by relief valves. The filter/cooler units are also equipped with a bypass relief valve to ensure oil reaches the bearings even during

Figure 18
Simplified turbine lubricating oil system



9. The Generator

A generator is a electro-mechanical device which converts mechanical energy into electrical energy. Before going into details on generators a review of a few basic principles are listed.

- Current flowing through a conductor produces a magnetic field around the conductor.
- The polarity of this magnetic field changes with the change in direction of the current flow in the conductor.
- The strength of the magnetic field is proportional to the magnitude of the current flow in the conductor.
- Voltage can be induced in a conductor by a magnetic field where there is relative motion between the conductor and the magnetic field.
- The voltage induced is proportional to the flux density, the length of the conductor and the relative velocity of the conductor to the field.
- Current flow in a conductor produces heat (I^2R losses).

The physical size and format of a large ac generator is determined primarily by the magnitude of its output power. From the principles stated above there are two physical format possibilities for a practical ac generator. These are:

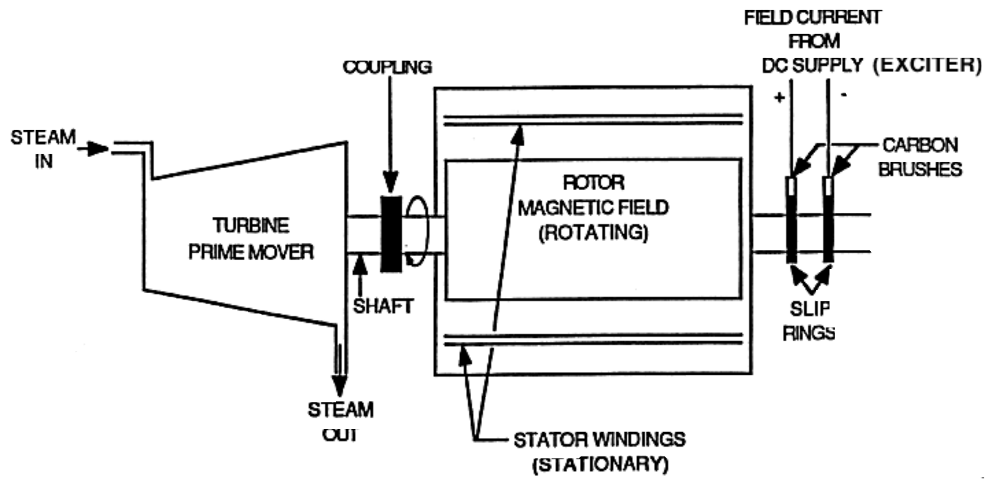
- The magnetic field can be stationary and the conductors can be moved through it, or

- The conductors can be held stationary and the magnetic field can be swept past them.

The stator (armature) current can be as high as 30,000 amps, while the field current is in the 4,000 amp range. This results in a much more massive armature. Large turbo-generators therefore use the latter format.

Figure 20: shows "A Simplified Turbo-Generator". This figure shows that a DC current is fed into the rotor producing a rotating electro -magnet. This rotating magnetic field is cutting the conductors of the stationary stator windings (the Armature).

Figure 20:
A Simplified Turbo-Generator



9.1 Generator Heat - Production and Removal

The heat produced within the generator components, typically 6-7 MW in a CANDU 6 has resulted in several standard designs.

- The I^2R losses in the stator conductors, typically 3 MW, requires the use of a liquid coolant.
- The I^2R losses in the rotor conductors, typically >1 MW, requires the use of a gaseous coolant (liquid coolant is not practical in the rotor conductors).
- Eddy currents produced in all the metal parts (stator iron, retaining rings, casing structure etc.) produce about 1 MW of heat which is removed by the gaseous coolant.
- Windage losses in moving the rotor within the gaseous coolant produce about 1.5 MW of heat.

Since the liquid coolant is circulated inside the copper conductors which are at a relatively high voltage, the coolant must not be capable of conducting electricity. The liquid coolant used is ion free water. This water is circulated by pump(s) through the conductors, an external heat exchanger and a purification circuit. This system is called "Stator Water Cooling". This system will be discussed in the "Generator Auxiliaries Section".

The gaseous coolant should have a high heat removal capacity, low windage losses, not support combustion and a reduced corona effect. The gas used in large generators is hydrogen. The efficiency of cooling is improved by keeping the gas at a relatively high pressure (300kPa(g)). This results in:

- The generator casing becoming smaller and a pressure vessel.
- The requirement to seal the casing where it is penetrated by its rotor shaft.
- The generator must be leak proof to prevent the egress of hydrogen and/or the ingress of air, hydrogen/air mixtures are explosive.
- The hydrogen coolers installed within the generator casing.

This requires two additional systems, namely "Generator Hydrogen Cooling System" and the "Seal Oil System". These systems will be discussed in the "Generator Auxiliaries Section".

Figure 21:
Main Design and Principles of a 4-Pole Turbo-generator

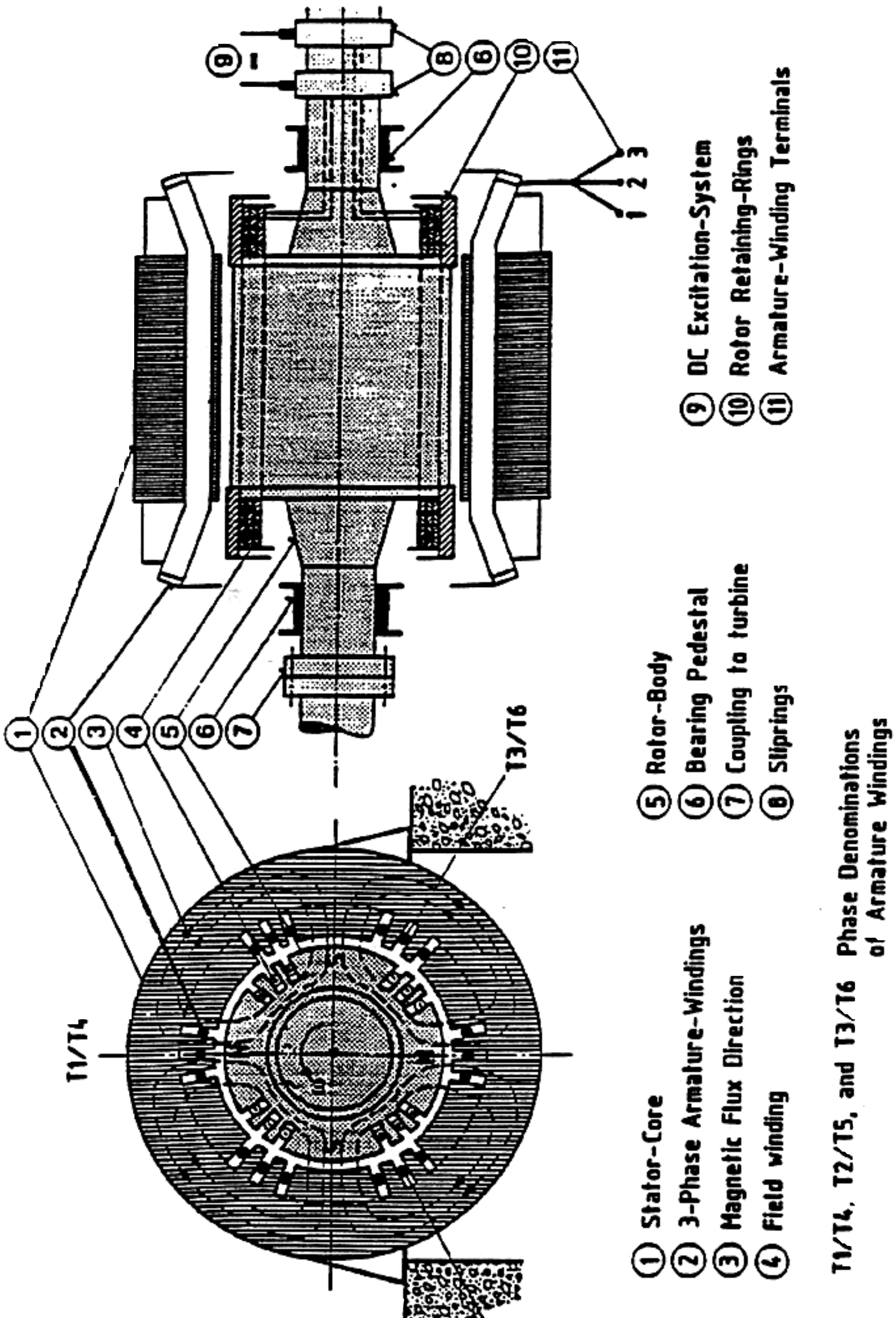


Figure 21 illustrates the main components of a generator. A simplified sectional diagram of a large AC Generator is illustrated in Figure 22.

A brief description of the illustrated major components follows.

9.2 Description of Major Components

Drive Coupling
The drive coupling is a bolted hub assembly which connects the generator shaft to the turbine shaft.

Bearings
The sleeve type babbitted bearings are located outside the generator. They provide support and low friction rotation for the generator rotor.

Outer Pressure Casing or Yoke
The yoke supports the stator assembly and end covers. It is also a pressure vessel which contains the pressurized hydrogen used to cool the generator rotor and stator iron. It also carries the hydrogen coolers.

End Covers
The end covers are sealed and bolted onto the ends of the yoke. They carry the hydrogen seals and connection points for the hydrogen coolers. They form part of the pressure vessel containing the hydrogen.

Hydrogen Seals
The hydrogen seals provide the moving seal, between the generator end covers and the rotor shaft. They keep the hydrogen in the generator at operating pressures and they also keep air out of the generator at low operating pressure. Figures 23a and 23b illustrate the major components of both types of Hydrogen Seals.

Hydrogen Coolers
The hydrogen coolers mounted in the generator yoke use recirculated cooling water to cool the hydrogen gas which is circulating continuously inside the generator.

Stator Iron
The stator iron carries many stator bars wedged tightly in the slots running axially along the inner circumference of the iron. The stator iron also acts as part of the magnetic field circuit and concentrates the magnetic flux produced by the rotor around the stator assembly.

Stator iron is composed of "low-hysteresis" alloy laminations. Each laminate is insulated from the others by a glass or varnish coating. The laminates are assembled in packets with spaces to provide for circulation of cooling hydrogen throughout the stator assembly. (see Figure 24: Stator Iron Laminations)

End Core Magnetic Screen
At each end of the stator iron there is a water cooled copper annulus called the end core magnetic screenplate. These magnetic screens minimize flux losses from the end of the stator iron.

Stator Bars or Windings
The stator bars are bundles of partially flattened small diameter copper tubes, which have a voltage induced in them by the rotating magnetic field. They carry the ac load current demanded by the grid and/or station load and cooled by demineralized water flowing through them. The stator bars are series-parallel connected to form the required three-phase star-wound configuration. The combination of stator iron and stator bars is called the armature.

Water Boxes
The water boxes feed the demineralized water to and from the stator bars. They also provide for the series/parallel electrical interconnections of the stator bars needed to achieve the required terminal voltage and load current output. In many units the water boxes have been replaced with feeder rings and teflon hose connections to individual stator bars.

Resistance Columns
The resistance columns are epoxy resin tubes which are used to carry the stator cooling water to and from the stator bars. They isolate the high voltage generator stator bars electrically from the cooling system.

Stator Cooling Water System Outlet Manifold
This manifold is the point from which the demineralized cooling water enters the generator from the cooling system. It is located at the turbine end of the generator.

Stator Cooling Water System Inlet Manifold
This manifold is the point at which the demineralized water leaves the generator and is returned to the cooling system. It is located at the outboard end of the generator.

Star Point Connection
The star point connection is located just above the resistance columns, at the cooling water system inlet manifold. It is the point at which the neutral ends of the red, white and blue phases are joined together and taken to ground, via a grounding transformer.

Electrical Outlet Connections
The red, white and blue phase electrical output connections are located just above the resistance columns at the cooling water system inlet manifold. Only one of these is shown in Figure 22.

The Rotor
The rotors in the main generators at all CANDU stations in Canada are four-pole, and therefore rotate at 1800 RPM. The rotor is a massive, single, solid forging of high grade steel, into which are machined four sets of slots for the rotor windings. A partial view of a machined forging is shown in Figure 25 .

The rotor windings are copper bars having a "U" cross-section, and holes along their length and are shown in Figure 26. These bars are wedged firmly into the rotor slots to prevent moving or chaffing during operation. Without these wedges the centrifugal forces would drive these windings out of the rotor onto the stator. Electrically the rotor bars are connected to form four coils in series with each other.

End Bells or End Rings

The end bells mounted on each end of the rotor support the rotor windings against centrifugal forces. They also direct the flow of cool hydrogen into both ends of the rotor windings. Figure 26 illustrates the end rotor windings that are restrained by this end bell, the end bell is not shown in this figure. Figure 27 illustrates the location of one of the end bells. These end bells are one of the most highly stressed components of the generator and have been known to fail resulting in severe damage to the turbine generator.

Centrifugal Fans

The fans, mounted at each end of the rotor move heated hydrogen out of the air gap, through the coolers and back into ducts or passages in the stator iron and rotor. Figure 28 illustrates the hydrogen gas flow pattern.

The Air Gap

The air gap is the space (≈ 6 cm) between the outside diameter of the rotor and the inside diameter of the stator iron. The air gap permits the rotor to spin, at all speeds, without touching the stator iron. Heated hydrogen flows from both the rotor and the stator iron into the air gap. The air gap is also part of the magnetic field circuit.

Slip Rings

The slip rings are mounted on the outboard end of the generator shaft. They work in conjunction with the brush gear to feed the dc field or excitation current to the rotor windings.

Figure 22:
Simplified Sectional Diagram of a Large AC Generator

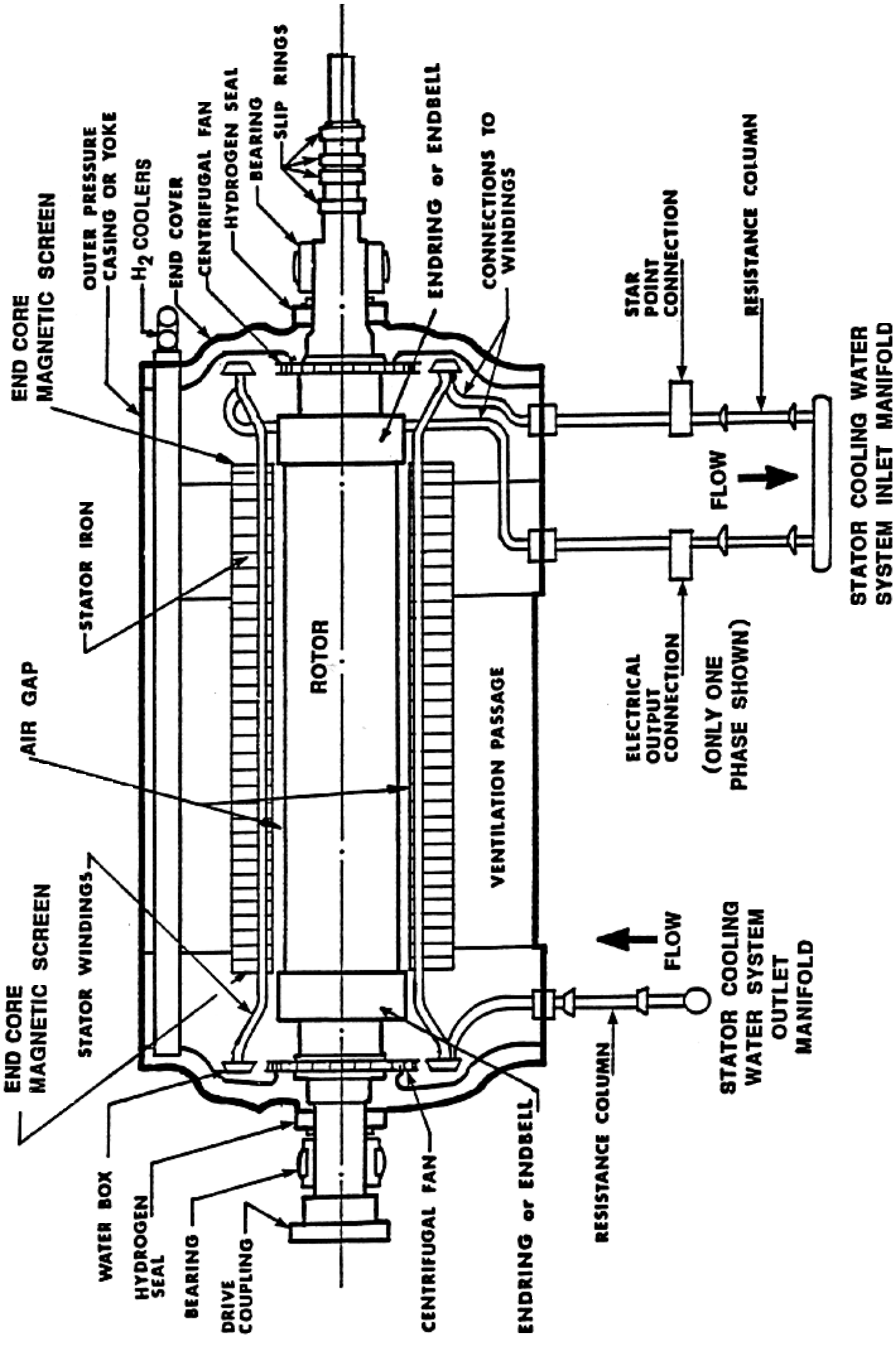


Figure 23a:
A Section of a Typical Generator Radial Seal

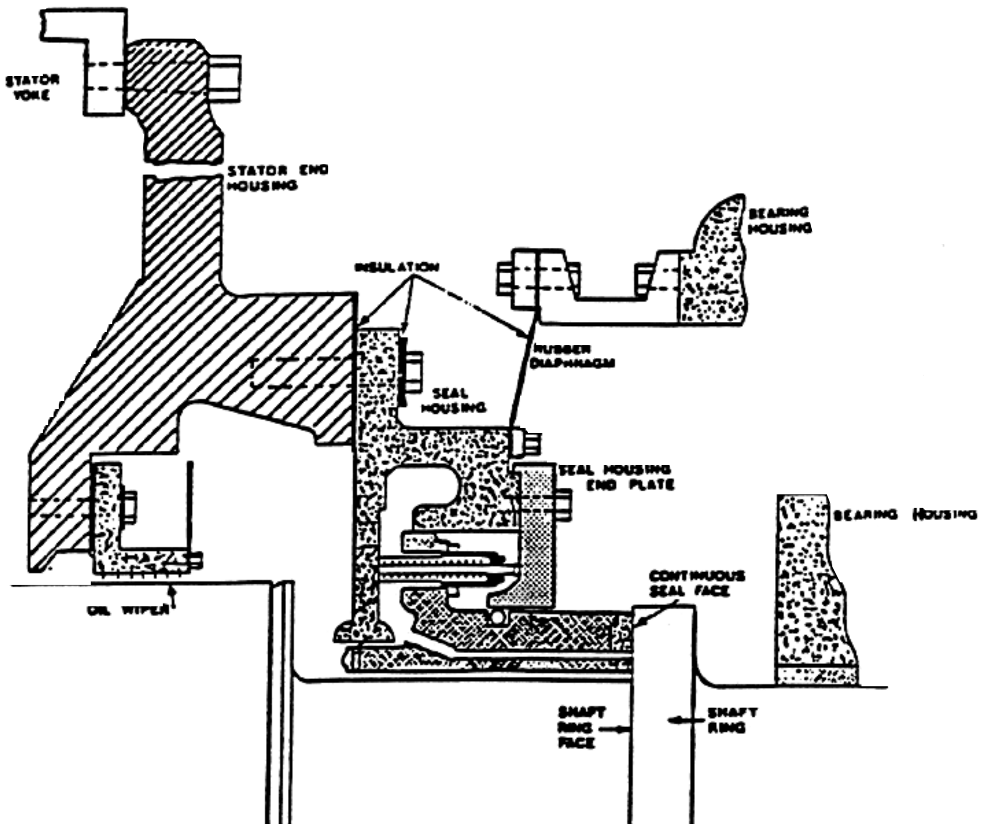


Figure 23b
Principle of a Generator Radial Seal

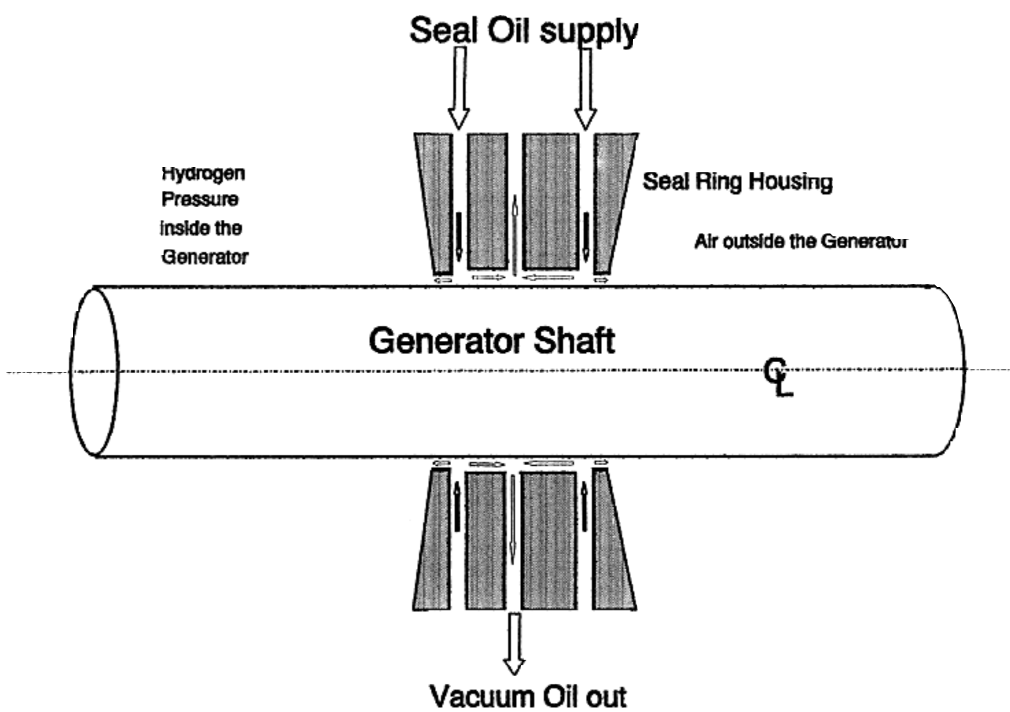


Figure 24:
Stator Iron Laminations With Ducts for Cooling and Slots for Windings

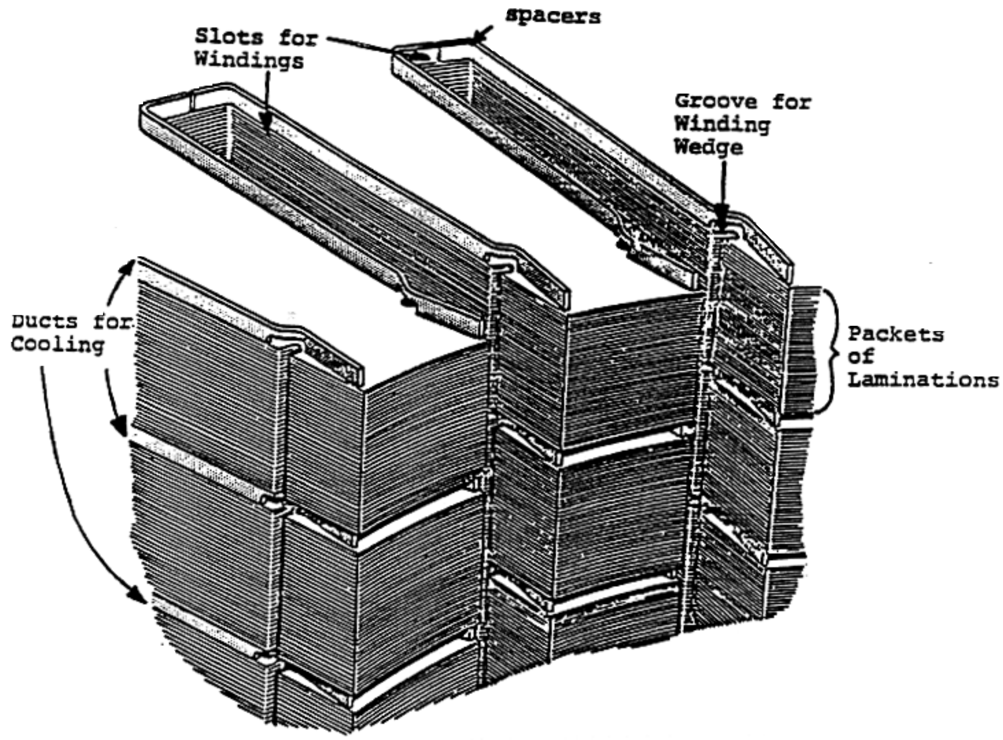


Figure 25:
View of the End of a Generator Rotor Showing the Detail of the Slotting

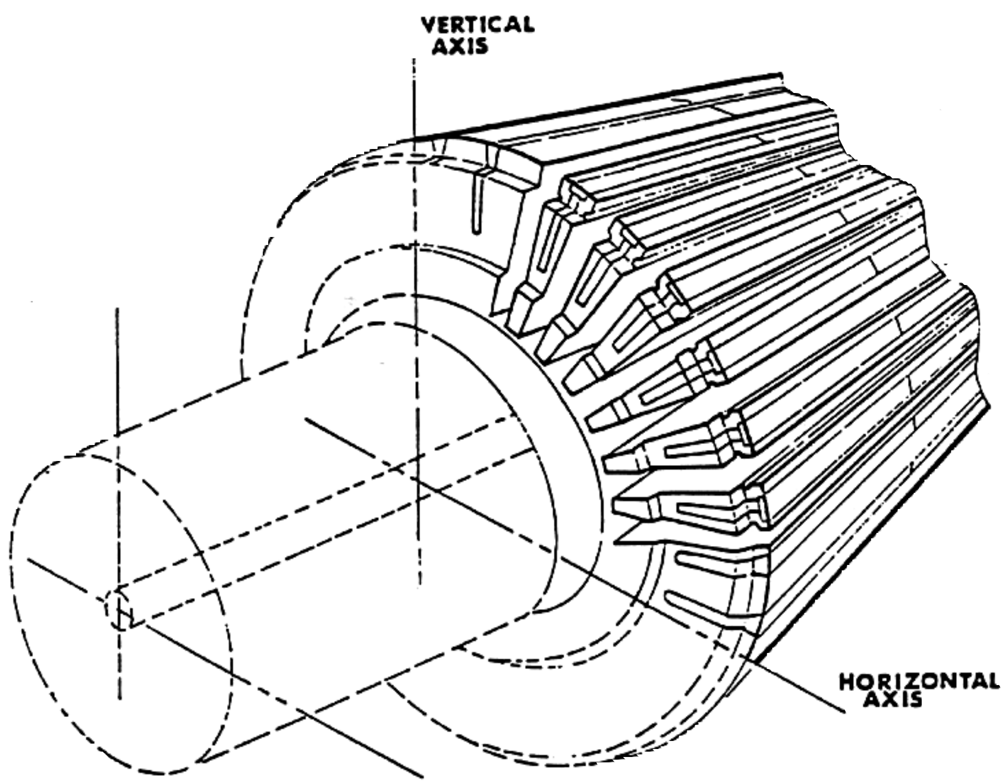


Figure 26:

Diagrams Showing Sections of Rotor Windings and How Gas Enters, Travels Along and Leaves the Windings

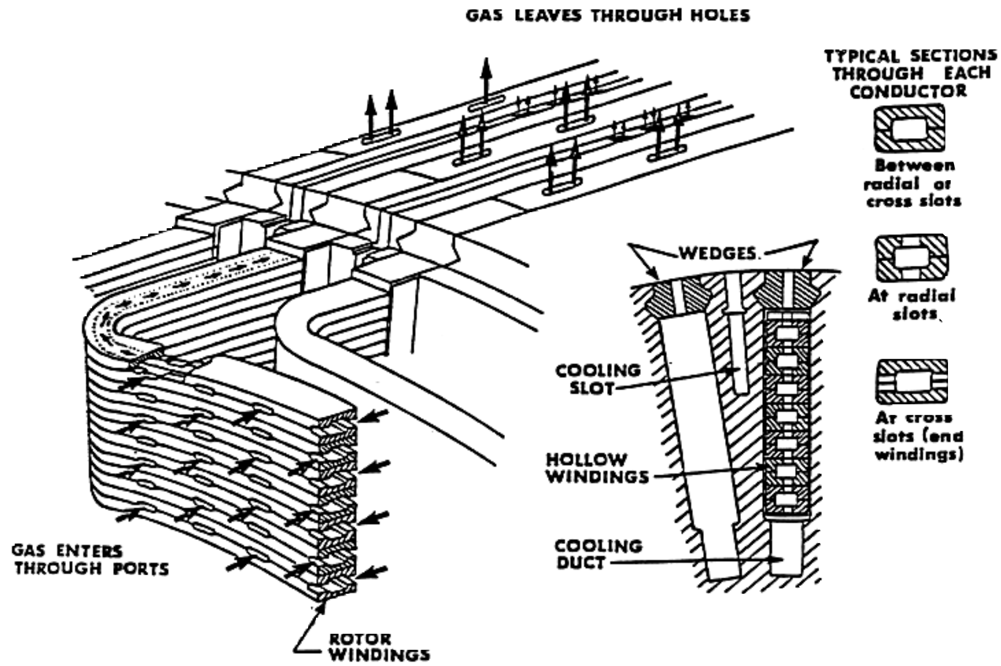


Figure 27:

Diagram Showing Windings on a Generator Rotor and the Flow of the Hydrogen Cooling Gas

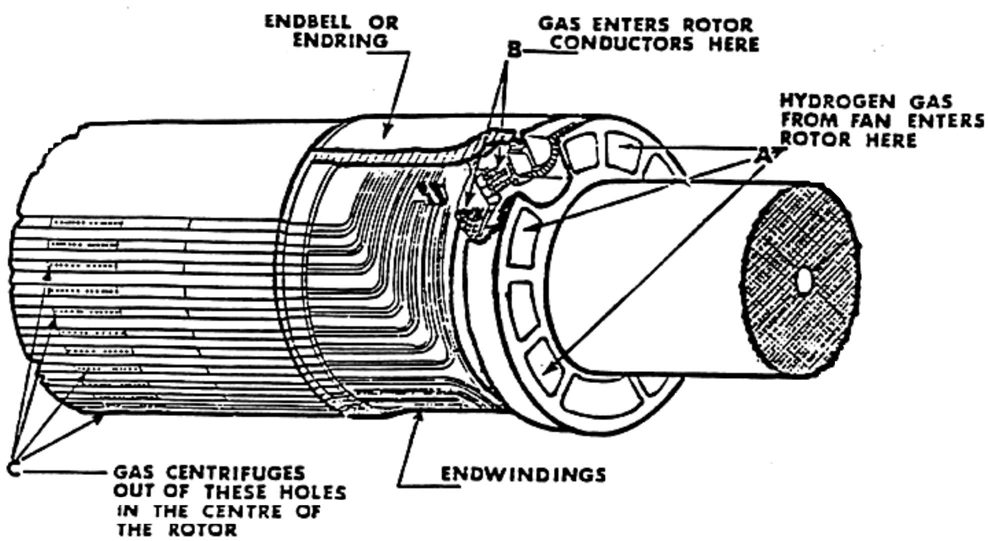
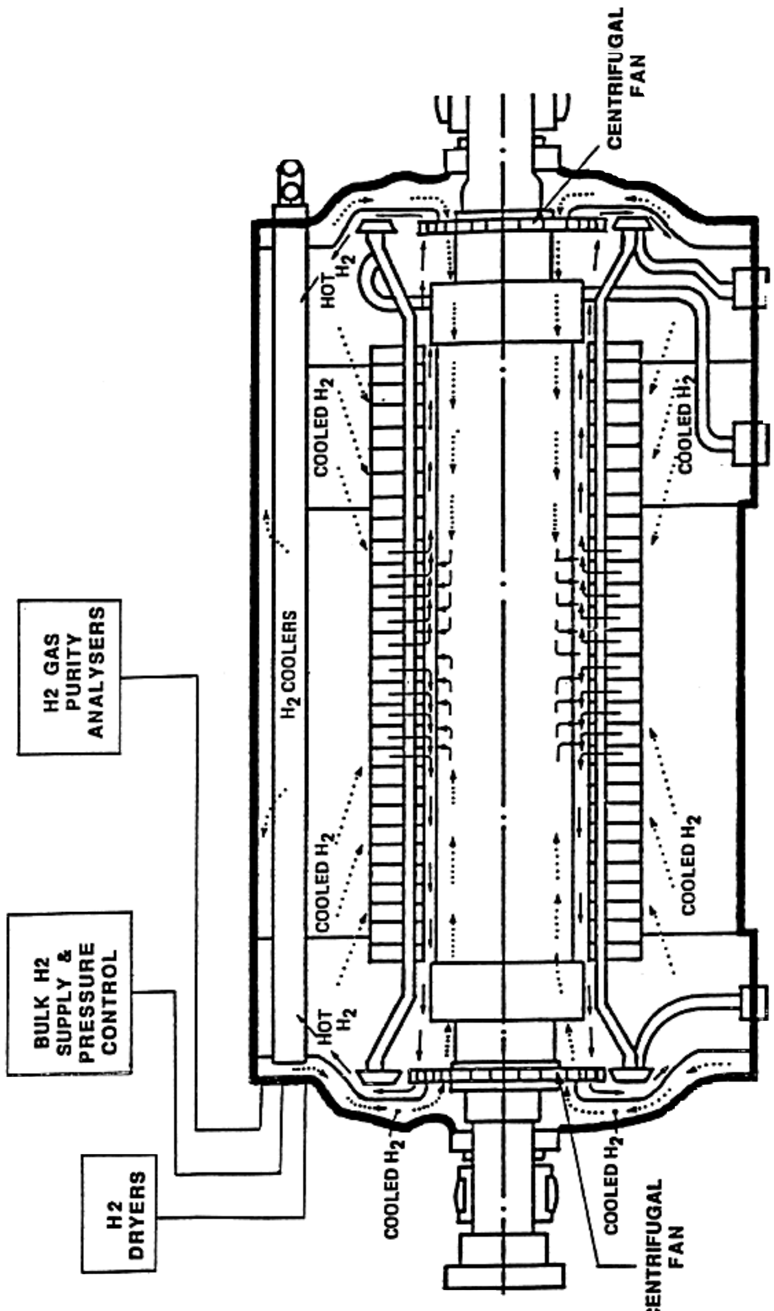


Figure 28:
A Typical Generator Hydrogen Cooling System



10. The Generator Auxiliaries and Support Systems

The generator auxiliaries consist of the generator stator water cooling system, the generator hydrogen seal oil system, the generator hydrogen cooling systems and the generator hydrogen support systems.

10.1 Stator Water Cooling System

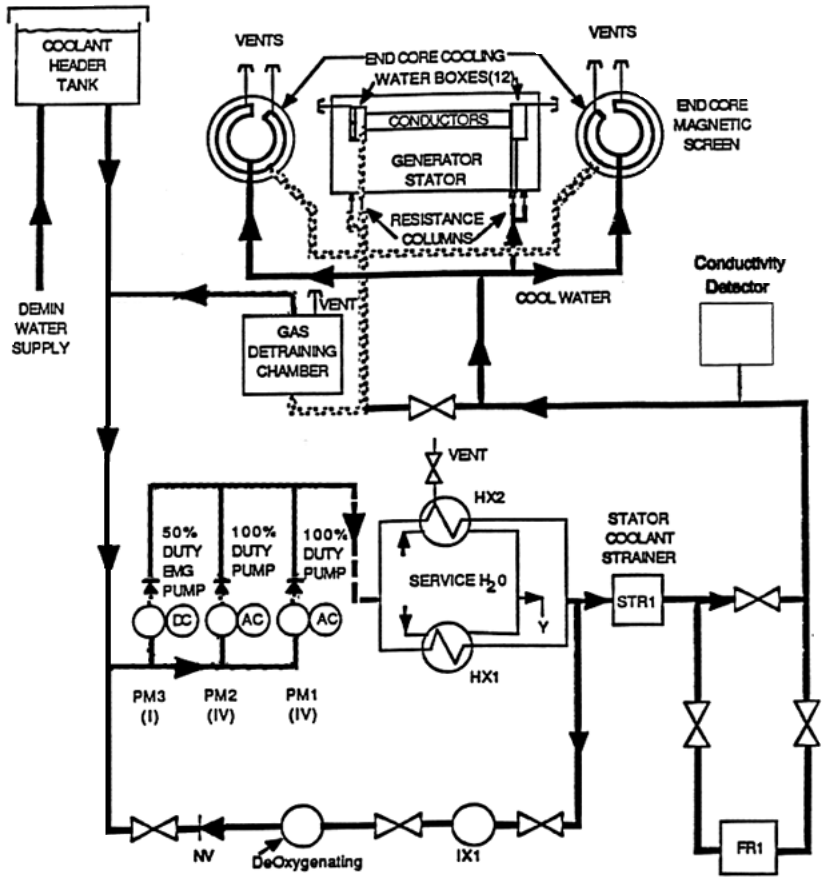
Since the liquid coolant is circulated inside the copper conductors which are at a relatively high voltage the coolant must not be capable of conducting electricity. The liquid coolant used is ion free water. Figure 29 illustrates a typical Stator Water Cooling System. The cooling flow to the end core magnetic screen plates are not illustrated in Figure 29. The cooled water is shown as a solid line and the returning warm and possibly gaseous water is shown as a dashed line. As well as two 100% duty pumps, the typical system has a 50% duty Class I DC pump which starts automatically if both AC pumps fail.

The purpose of this system is to maintain both the copper stator bars and the end core magnetic screen plates at their required operating temperatures, by circulating cool demineralized water through them.

This system will:

- Supply this cooled demineralized water to the generator stator windings and end core magnetic screen plates at a controlled pressure less than the generator hydrogen pressure, thus ensuring that any leaks which may occur will result in hydrogen gas entering the stator coolant rather than water entering the generator.
- Prevent any fault to ground by monitoring the conductivity of the demineralized water. If the conductivity of this approaches an unsafe level, the operator will receive an alarm and then takes steps to correct this trend. A typical operating conductivity is ≈ 0.5 μS/cm.
- Provide filtration to remove any particulates which could plug the very small bores of the stator tubes.
- Provide a Gas Detraining Chamber with a vent to remove any entrained hydrogen gas.
- Have a reserve of coolant in a head tank. This head tank will supply make up for any losses and it also controls the pump suction pressure in the system.

Figure 29:
Simplified Diagram of a Typical Stator Water Cooling System



10.2 Hydrogen Seal and Seal Oil

Hydrogen seals are provided at each end of the generator to provide isolation of the generator hydrogen environment from the outside atmosphere. There are two types of hydrogen seals, namely axial and radial. Figure 23a illustrates a typical axial seal and Figure 23b illustrates the principle of the radial hydrogen seal. In either case they are mounted in the generator end cover and they are required to maintain a continuous seal for operating periods of up to one year, at pressures of 300 kPa(g) with rotor speeds ranging from 0 to 1980 RPM.

The hydrogen seal is required to provide a seal between the generator rotor and the stationary end cover, while allowing for a significant axial movement of the rotor shaft. It must also minimize the ingress of oil and/or air into the generator cavity.

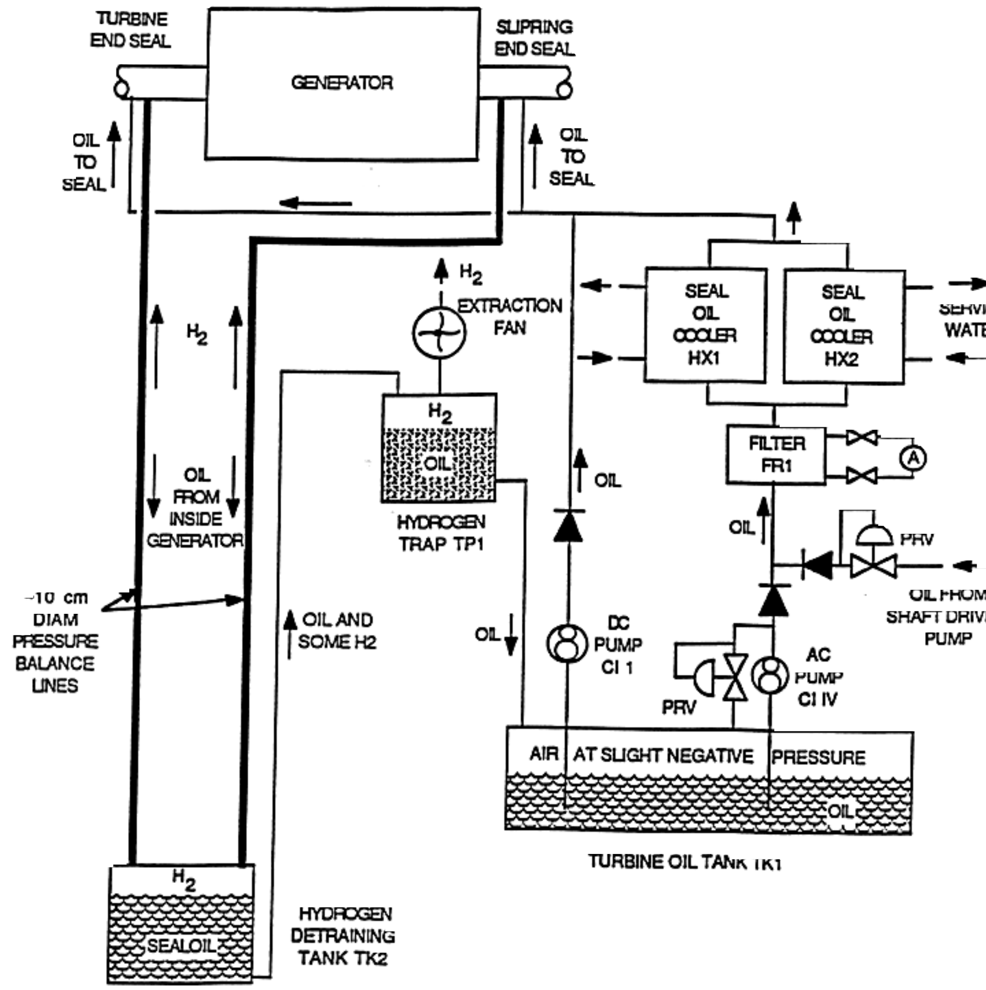
The axial seal (Figure 23a) has a spring loaded stationary seal face with internal ports for seal oil supply. This oil is maintained at a pressure greater than the hydrogen pressure in the generator. This seal oil flows through the seal ports to the bearing face, where the bulk of the oil flows outward to the bearing housing cavity and cools and lubricates the seal surfaces. Since the oil flow to the hydrogen side is small, the quantity of entrained air released into the hydrogen is very small. This give the advantage of not having to vacuum treat the seal oil to remove entrained air. This seal type is the more common type of seal used.

The purpose of the generator hydrogen seal oil system is to clean, lubricate and cool the hydrogen seal face while providing the required seal pressure. A simplified Hydrogen Seal Oil System is shown if Figure 30. The normal oil supply, turbine lubricating oil, is from the main turbine shaft driven oil pump. This is backed up by an AC (Class IV) driven oil pump which is used when the turbine-generator is not in service. There is also a DC (Class I) driven oil pump used to maintain seal oil pressure when both the turbine-generator and Class IV power are not available.

The Hydrogen Detraining Tank operates in the same environment as the Generator Casing and it delays the seal oil long enough for it to release most of the entrained hydrogen. The seal oil flow sight glasses allow monitoring of the small flow of seal oil in each balance line to detect any seal problems. This sight glass, of course, also contains the pressurized hydrogen.

The hydrogen trap allows the extraction fan to remove any hydrogen caught by the trap before the seal oil is returned to the Turbine Oil Tank.

Figure: 30
A Simplified Circuit of a Seal Oil System



10.3 Generator Hydrogen Cooling System

As previously mentioned, there is about 3.5 MW of heat that has to be removed by the gaseous coolant. The purpose of the hydrogen cooling system is to remove this heat and maintain the generator rotor and stator iron within its proper operating temperature ranges under all operating conditions. This hydrogen gas is continuously recirculated within the casing by the centrifugal fans as illustrated in Figure 28. The Raw Service Water Hydrogen Coolers are within this circuit. The water pressure within these coolers is maintained at a pressure less than the Generator Hydrogen pressure so that any leakage will be the hydrogen out into the coolers rather than water leaking into the generator casing. The generator casing also has a liquid alarm to warn of any liquid (water or oil) in the generator casing.

The system also contains a dryer circuit to maintain the hydrogen at the required dewpoint. This system also includes a pressure controlled makeup system from the bulk hydrogen supply, a gas purity system to monitor the hydrogen gas purity. The hydrogen purity must be >96% or < 5% to avoid an explosive hydrogen/air mixture.

There are also connections for CO_2 and compressed air for purging and charging the generator. When changing the casing atmosphere from air to hydrogen or hydrogen to air it is necessary to have a CO_2 interface.

11 Turbine-Generator Upsets and Operational Problems

As steam turbine units increase in size and complexity the operational problems also increase in magnitude. Not only has construction and control become more complex but materials have been pushed closer to their operating limits. As structures have become more massive, thermal gradients and pressure stresses have become more complex. In addition, with the increase in size it is no longer possible to build operational models and test them exhaustively before putting them into commercial operation. Today's turbine units go directly from the drawing board to on-site erection and commissioning.

Problems due to design errors are reasonably rare, but they do occur and because these occurrences are generally catastrophic it is becoming practice to build mathematical models of the system. Computer programs are then used to simulate normal, abnormal and casualty operations so that an assessment of in-service performance can be obtained prior to commissioning. By this method it is often possible to establish operating limitations before the design leaves the drawing board.

Owing to the large capital investment in any modern generating station, reliability of the unit becomes a significant concern. This is particularly true of nuclear stations where the cost of alternate electrical energy sources can be truly phenomenal. For this reason it is becoming standard practice to assign a dollar value to estimated unreliability and factor this into the initial cost of the unit. This practice hopes to avoid an initial low price which turns out to be no bargain in service.

Despite these precautions, problems do occur particularly in the first year or so following commissioning. Not only do problems more frequently occur with a new plant but the operating and maintenance personnel require some time to familiarize themselves with the station.

The problems discussed in this manual are derived from significant event reports and operating experience in nuclear and non-nuclear stations. Particular problems are included either because they occur with some frequency or because they represent a significant hazard to the turbine unit. The comments in this lesson are only of a general nature and are not intended as a substitute for design or operating manuals which constitute the manufacturer's specific recommendations on the operation of a specific turbine unit.

11.1 Overspeed

The hazards of an unterminated overspeed generally fall into one of four categories:

- speed will rise to a level where the centrifugal forces on the largest diameter wheels will cause tensile failure (rupture) of the wheel,
- speed will rise into a critical speed region and remain there long enough for the resulting amplification of vibration to cause failure,
- speed will rise to a level where the added stress due to centrifugal force will fail a component which has been weakened through fatigue, erosion or some other long-term phenomena, or,
- speed will rise to a level where the centrifugal forces on the generator rotor will rupture the rotor, or will loosen rotating parts which can then contact stationary parts.

The potential for an actual overspeed of the turbine unit occurs from two principle conditions: load rejection and testing of the overspeed trip mechanism.

The periodic testing of the operation of the overspeed bolts to trip the unit on an actual overspeed condition places the unit in a condition which can easily result in damage. Since the operation of the overspeed bolts is the last protective feature which functions to limit overspeed, the testing of this trip requires either the disabling of protective features which operate at lower overspeeds or raising the setpoint of these features above the trip point of the overspeed bolts. If the protective features fail to operate properly, the unit speed can be raised to dangerous levels. The testing of overspeed tripping devices is always a hazardous evolution and requires a detailed operating procedure. At least, two independent methods of monitoring turbine speed should be used and personnel conducting the test should be in continuous communication with each other. There should be no question under what conditions the test will be terminated. The raising of speed to the trip point should be smooth and rapid enough to limit the time above operating speed to that required to allow monitors to follow the speed of the unit. Personnel conducting the test should constantly ask themselves if the unit is safe, even if none of the trips function as expected. The vast majority of turbine casualties involving overspeed occur during this type of testing.

11.2 Motoring

When the reactor heat production is lost through a reactor trip, the governor steam valves will shut to prevent the turbine steam consumption from lowering heat transport system temperature and pressure. If the generator output breaker is left shut, the turbine generator unit will motor with the turbine being driven by the generator acting as a synchronous motor. There are certain advantages to maintaining the turbine unit motoring during a reactor trip. Keeping the unit at operating speed shortens the time from steam admission to generator loading on the subsequent startup. This enables a faster recovery: firstly to avoid xenon poison-out and secondly to return the generator capacity to the grid.

During motoring the turbine blading is turning through dead steam and the friction between the steam and the blading rapidly overheats the long turbine blades at the exhaust end of the low pressure turbine. The problem is made more severe if the vacuum decreases and the blading encounters higher than design steam densities. The problem can be partially alleviated by an exhaust spray system and a cooling steam system as shown in Figure 10.

The exhaust spray system uses water from the discharge of the condensate extraction pump which is sprayed into the exhaust annulus of the turbine. This spray helps cool the dead steam as it is circulated by the rotation of the final low pressure turbine stages. To aid this system, steam is taken from the high pressure steam line ahead of the governor valves and routed to the inlet to the LP turbine. This "cooling steam" keeps a positive direction of steam flow through the LP turbine stages which helps to remove the windage heat.

Even with both cooling steam and exhaust sprays in operation, the final stage LP blading will overheat in an hour. This will require discontinuing the motoring of the unit. However, since the reactor will poison-out in about the same time frame, there would be little advantage in extending this limit.

11.3 Low Condenser Vacuum

When the condenser vacuum decreases below design values, the turbine unit is subjected to a variety of unusual conditions. Heat rate increases as less work is extracted from each kilogram of steam; the turbine internal pressure profile changes, extraction steam pressure and temperature change; the distribution of work between the high and low pressure turbine changes. However, the most immediate problem associated with vacuum decreasing below design is that the condenser will eventually not be able to condense all the steam being exhausted. In order to restore equilibrium to the condenser, the amount of steam rejected must be decreased. For this reason when vacuum has fallen below the minimum at which full power can be handled, the turbine will automatically begin to unload to a power level where the condenser can again reach equilibrium. With a design pressure 5 kP(a), unloading will start at around 13 kP(a) and will continue until either pressure stops increasing or 10% power is reached at 25 kP(a). If the pressure increases further the turbine will trip at 27kP(a). The actual pressures vary depending on the plant.

The combination of a low power level and low condenser vacuum imposes particularly severe conditions on the low pressure turbine blading. Not only do the long blades have to pass through a higher density steam-air mixture but the absence of adequate steam flow through the turbine decreases the rate of heat removal. The adverse effect of low vacuum, low steam flow is the reason for terminating vacuum unloading before the governor steam valve fully shuts off steam. This effect also explains why, on a startup, vacuum should be the best obtainable before rolling the turbine with steam. It is desirable to maintain condenser vacuum on a shutdown until the turbine speed has decreased to about 50-60% of synchronous speed, to avoid a no steam flow, low vacuum condition.

11.4 Water Induction

Water damage to modern saturated steam turbines can be roughly divided into two categories: long-term erosion by wet steam and catastrophic damage due to ingress of large quantities of water. The latter cause of turbine damage is covered in this section.

Slugs of water can enter the turbine through a number of places, however, the two most common sources of turbine damage are due to water induction through the governor steam valve and through the extraction steam lines. Water induction causes damage in three principle ways:

- direct impact damage on turbine components such as blading, diaphragms and blade wheels,
- excessive thrust caused by water impingement leading to thrust bearing failure or hard rubbing between components, and
- thermal damage to components due to quenching by water which may result in excessive thermal stresses, thermal distortion, or permanent warping. This is particularly true in the superheated section of the low pressure turbine.

Slugs of water which enter a turbine at high velocity will take the shortest path through the turbine, possibly clearing out both fixed and moving blades in the process. Because of the greater fluid density and the resulting impact on the rotor, induction of water from the steam generator may result in thrust loads much higher than design values. A failure of the thrust bearing can result in excessive axial travel of the rotor and subsequent severe rubbing damage to blading, blade wheels, diaphragms, glands and other components. Because of its high heat capacity, water contacting hot turbine parts can cause severe thermal stresses and distortion. This distortion can cause secondary damage if a turbine is restarted before the distortion has dissipated. While thermal distortion is not particularly severe in saturated steam portions of the turbine, it can be a significant cause of damage in the superheated sections.

Prevention of water induction requires both proper operation of protective features and careful avoidance of operating errors. The induction of water from the main steam line is minimized by the steam generator level control system, the high level alarm and by closure of the governor steam valve on high water level. However, improper or inadequate draining of steam lines during startup and subsequent loading can result in slugs of water being accelerated down the steam lines and into the turbine.

Water induction into the turbine can have particularly severe consequences on startup. While running under load, the steam flow can be of some benefit in absorbing water and minimizing thermal distortion, particularly in superheated sections of the turbine. Moreover, damage from rubbing can be increased when rotor speed is in the critical speed range.

If high vibration or other serious problems necessitate shutting down the turbine, the unit should not be restarted until all the water has been drained from the unit and the cause of water entry found and corrected. In addition, sufficient time should be allowed for relief of thermal distortion of the casing and rotor. Experience has shown that the most serious damage from water induction often occurs considerably after the first indication of water induction and attempting to restart may result in extensive damage due to rubbing between fixed and moving parts.

11.5 Moisture Carryover

Carryover is the continuous entrainment of liquid boiler water in the steam leaving the steam generators. The cyclone separators and steam scrubbers in the steam generators are designed to remove virtually all of the liquid water and under normal conditions, the steam leaving the steam generators is less than 0.2% liquid water (moisture). Both design and operating engineers are very sloppy in their use of the term "carryover". This is because these people are concerned not only with the quantity of liquid boiler water leaving the steam generators but also with the quantity of chemicals which is carried along with the water droplets. A water droplet is a mini-sample of boiler water and its makeup is more or less representative of boiler chemistry. Depending on boiler chemistry, the moisture entrained in the steam may contain SiO_2, Cl^+, Na^+, soluble and insoluble calcium and magnesium salts, OH^- and a wide variety of other chemicals. The water which leaves a steam generator can thus cause damage in three ways:

- moisture erosion which would occur even if the water were pure,
- chemical corrosion from active ions carried with the water, and
- chemical deposits on valve seats and steams and on turbine blades.

Depending on which of these effects we are concerned about, one may talk about carryover as the amount of moisture or as the amount of dissolved and undissolved solids in this moisture. You can see that if the amount of solids in the boiler water increases, more solids will leave the boiler, even if no more water leaves the boiler. The point of all this is that when one discusses the causes of increased carryover you have to know whether he is talking about the increase in the quantity of water leaving the steam generator or the increase in chemicals leaving in that water. Suffice it to say that in this manual carryover will be defined as the amount of **water** leaving with the steam. The reader is cautioned, however, that this definition is not universal.

Carryover of water can be increased by two methods: mechanical and chemical.

Mechanical methods which increase carryover are generally those which decrease the effectiveness of the cyclone separators and/or steam scrubbers. **High boiler level** can physically flood the separators and decrease their effectiveness. Under certain conditions, **low boiler** level can cause carryover. If boiler level drops below the bottom of the separator columns, level oscillations can cause overloading of some separators with resultant carryover. **Rapid power increases** can increase carryover not only through swell flooding the separators but through temporarily overloading the separators as steam rushes from the steam generators. **If steam flow is above design** either from one steam generator or all steam generators, increased carryover can result. The moisture separators are intended to produce dry steam at some maximum power level. If the steam generator is forced to supply more than this design maximum, steam quality will suffer. This method of inducing carryover can be a particular problem if one steam generator is isolated, possibly forcing the others to operate at higher power levels.

The turbine can be protected against mechanical carryover by:

- monitoring boiler level,
- adherence to specified loading rates, and
- closure of the steam admission valves on very high boiler level.

Chemical induced carryover results when the chemicals in the boiler water break the surface tension of the water or allow foaming to occur. The presence of oil in steam generators causes foaming to occur on the water surface. This foaming can cause severe carryover and oil in the boilers is an extremely serious problem. The designers have made it virtually impossible for oil to enter the steam/feedwater system. One way is through leaking or standing oil being sucked into sub-atmospheric piping in the condensate or makeup water system.

Both high undissolved solids and high dissolved solids, particularly the former, can promote carryover through breaking the surface tension of the water. This promotes liquid water being carried off with the steam. In addition, such high solids will be carried over with the moisture and may foul blading and cause control valve sticking and leakage.

11.6 Blade Failure

If there is a complete failure of a turbine blade in operation the effects may be disastrous as sections of blades get stuck between rows of fixed and moving blades and can strip the blade wheel. The resulting vibration can severely damage the turbine. This type of failure due to metal failure is extremely rare due to advanced metallurgical developments and methods of blade attachment. However, because of the high stresses imposed on rotating blades and shroud bands, even minor errors during installation or replacement of blading may lead to early blade vibration, cracking and ultimate failure.

Probably the most significant source of blade failure is damage induced by water impact and erosion. Not only is the quality of steam entering the turbine important but in addition the ability of the blade to shed water can influence blade life. Use of cantilevered blades without shrouds is becoming reasonably widespread in nuclear steam HP turbines as the shroud tends to restrict the centrifuging of water droplets off of the blade. There have also been cases of blade tip and shroud band erosion and failure due to inadequately sized stage drains which resulted in standing water in the turbine casing.

Water erosion in the exhaust end of the HP and LP turbines has caused failure of lacing wires and damage to the leading edges of the blading. The erosion of blading causes pieces of metal to break off which may cause damage to fixed and moving blades in subsequent stages. Defects of this kind are minimized by having a very hard stellite or chrome steel insert welded to the leading edge of LP turbine blades. In cases of extreme water erosion, however, these inserts may become undercut and themselves break loose to become a source of impact damage.

In operation, centrifugal stresses, bending stresses and thermal stresses may ultimately cause fatigue cracking of the blade roots. These cracks can only be detected during shutdown by non-destructive testing. Any evidence of blade cracking should be treated with caution as it is not only indicative of an abnormality within the turbine but also can lead to catastrophic blade failure.

11.7 Expansion Bellows Failure

Expansion bellows are used extensively in large turbines on LP pipework and between LP turbines and the condenser when the main condenser is being used as a reject or dump condenser.

In practice the bellows develop hairline cracks due mainly to thermal cycling as a result of load changes. Failure may also be caused by overload, for example, if an expansion bellows is fitted between the LP turbine and the condenser, the bellows may become strained if the condenser is over-filled with condensate without supporting jacks in position to take the weight.

11.8 Bearing Failure or Deterioration

Recent experience indicates that approximately half of all major turbine problems involved the bearings and lubricating oil system. With only a few exceptions most bearing problems can be traced directly to malfunctioning or maloperation of the lube oil system. Provided the lube oil system performs its primary function of supplying clean lube oil at the proper temperature and pressure to the bearings at all times when the turbine/generator shaft is rotating, there is usually little problem with the bearings.

Since even a brief failure of the lube oil flow to the bearings can result in considerable damage to the unit, the system is designed to provide continuous oil flow under a variety of pump shutdowns and power failures. The automatic features which provide the backup lube oil supply must be tested frequently to insure satisfactory operation. In particular the pressure switches which detect low lube oil pressure should be tested not only for proper annunciation but also to insure that they are capable of starting the appropriate backup pump. In addition the response time of backup pumps should be tested to insure that continuity of lube oil flow is maintained. Testing should be conducted with consideration given to the consequences of a failure of the system to operate as designed. For example, if the starting of the dc emergency lube oil pump is tested by turning off the auxiliary oil pump, with the unit on the turning gear, the shaft will be left rotating with no oil flow if the dc pump fails to start.

Of almost equal importance to bearing well-being is the cleanliness of the lube oil. Contamination of the turbine lube oil with water, fibers, particulates, dirt, rust and sludge can not only destroy the lubricating properties of the oil but also can cause accelerated bearing wear due to deposition of grit between the bearing and shaft journal. The lubricating oil should be sampled frequently. The results can be used to assess the quality of the oil and the efficiency of the purification system. Sample points should be chosen to insure samples represent not only the oil in the sump but also the oil samples or the strainers should receive particular attention as they may indicate bearing, journal or pump deterioration.

One of the most effective ways to monitor proper bearing performance is through bearing metal temperature. A gradual increase in metal temperature over a period of several weeks or months can indicate a gradual deterioration of the bearing. Bearing metal temperature is influenced primarily by load, shaft speed and the type of bearing. Of a lesser importance under normal conditions are bearing journal surface, alignment, oil flow and inlet oil temperature. With the shaft at rated speed and oil flow and temperature normal, an upward trend in bearing metal temperature indicates a change in bearing load, alignment or journal surface condition. Temperature spikes can be excellent indicators of bearing deterioration. High spots on the journal or bearing can cause metal to metal rubbing until wear has eliminated the contact. This is particularly true on shutdown or startup when the oil film in the bearing is thinner and, therefore, there is more susceptibility to scoring. The use of the jacking oil pump ensures bearing float at first rotation and as the turbine comes to rest.

Bearings should be inspected for wear and alignment at least each time the turbine unit undergoes a major overhaul. Journals bearings should be checked for smoothness and uniform roundness and diameter from one end to the other. Journals should be inspected for scoring or an uneven surface which occurs from scoring and self-lapping over an extended period.

Table 2

Action of Major Turbine-Generator Valves etc. on Upsets

Event Response	Reactor Trip	Load Rejection	Turbine Trip Sequential	 Nonsequential
Objective	Maintain Boiler Pressure (Hence H.T. Pressure & Temperature Stable) Prevent O/S Return Speed To ≈	100 % Maintain Station Service Supply	Protect Turbine (Low Lube Oil, High Vibration, Low Vacuum, Very High Boiler Level)	Protect Generator Or Connected Transformers (Electrical Fault Or Overspeed)
Emergency Stop Valve (Esv)			Close	Close
Governor Valve (Gv)	BPC Closes Gradually	Close < 0.5 S Readmit Steam Control Speed ≈ 100 %	Close	Close
Release Valves (If Installed)		Quick Open Reclose After Iv's Reopen	Open	Open
Reheat Emergency Stop Valves (Resv)			Close	Close
Intercept Valves (Iv)	May Follow Gv's	Close < 0.5 S Reopen Slowly When Speed Approaches 100%	Close	Close
Extraction Steam Check Valves	Close	Close Reopen When Δ Pressure +	Close	Close
Generator Breaker(s)	Stays Closed (Generator Motoring)	Stays Closed, Gen. Main Bkr. May Trip	Open After Turbine Steam Valves Close Immediate	Open

Station Electrical Systems

Training Objectives

At the end of this lesson the participant will have acquired the knowledge to:

- State four design criteria for the Electrical Distribution System.
- Briefly describe the ODD and EVEN concept.
- List the Classes of power and state its source and use in the Electrical Distribution System.
- Produce a sketch of the Station Electrical Distribution System and identify its parts.
- State the purpose of the Class III System.
- List four loads to be powered by the Class II System.
- List three roles that the EPS System must fulfill.
- Briefly describe the three transfer schemes for the 13.8 kV system.
- Identify on a chart of station loads which class of power would supply these loads.
- State three conditions that would require class III power to be provided by the Standby Generators.
- State how electrical grounding is provided for the station.

Table of Contents

1.0 Introduction

Electrical power throughout the station is distributed by networks of transformers, circuit breakers, motor starters, distribution panels, bus ducts, cable trays and cables. To meet nuclear safety requirements for reliability of operation two (2) 100% redundant power distribution systems are provided for nuclear safety related loads. These are known as ODD and EVEN load groups. In addition, three (3) 100% redundant power systems are provided for control and instrumentation purposes on special safety systems. The preferred sources of power to the electrical power distribution system are: (a) the off site network during startup and shutdown conditions, and (b) during normal operating conditions either the main turbine generator (MTG) alone or the MTG and the off site network shared on a 50/50 basis. The latter is the preferred mode of operation. If the preferred sources are unavailable for any reason, on-site standby generators (SG) provide electrical power to designated safety-related and economic loads. These SGs, together with on-site battery systems, have the capacity to effectively shut down the plant and maintain it in a safe condition until the preferred source is restored.

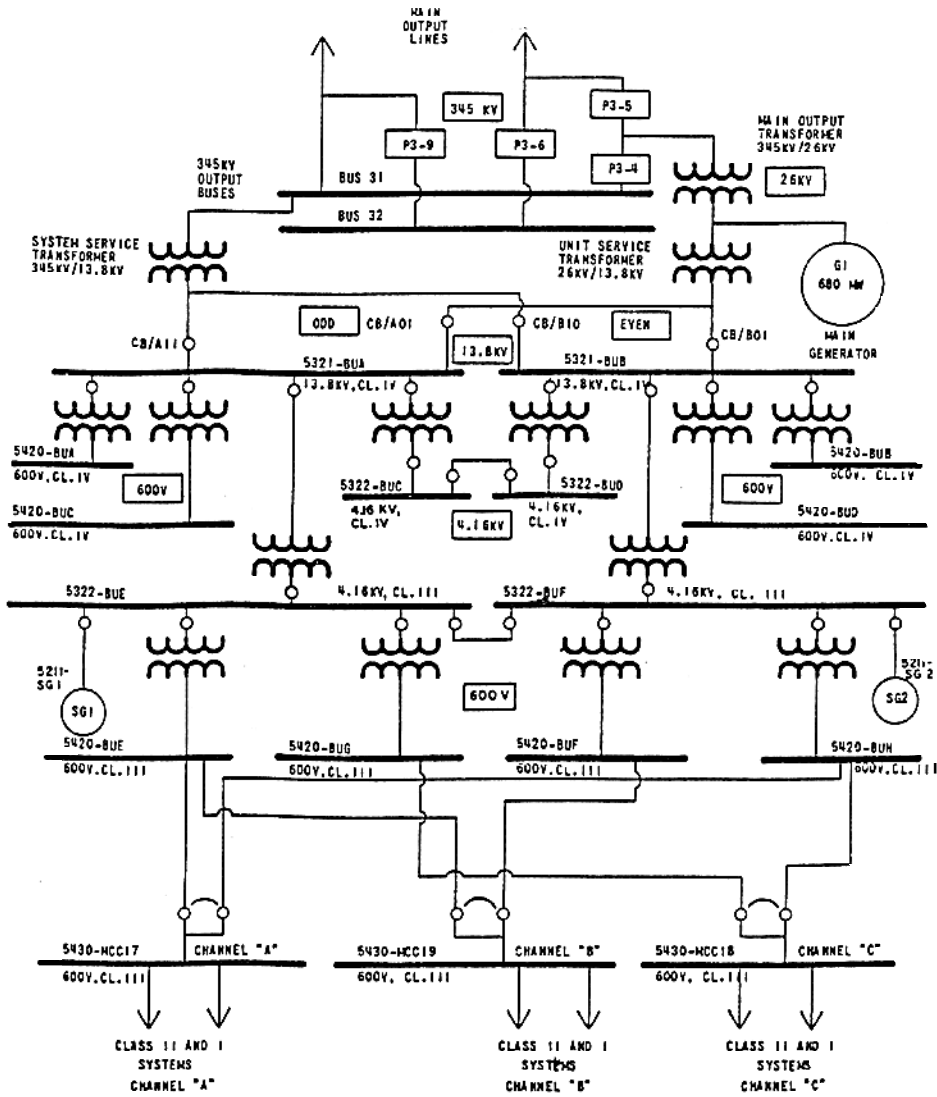
If both the preferred source and the standby generator system fail, an independent emergency power system (EPS) provides power to selected safety-related systems and their loads. This system also guards against common mode events which could result in the unavailability of the main control room (MCR) or other vital equipment.

The electrical distribution system of a typical plant is shown in Figure 1.

The main electrical distribution components (circuit breakers, motor starters, batteries, etc.) are located in the turbine auxiliary bay. Some motor starters and distribution panels are also located in the service building. Because of restricted access and possibility of LOCA conditions, no active components (e.g. motor starters) are located inside containment.

Distribution equipment associated with the ODD load group is physically and electrically separated from equipment associated with the EVEN load group. Similarly, equipment associated with one load group in the triplicated network is physically and electrically separated from equipment associated with any of the other two load groups. The minimum separation between equipment in any load group is 1.5 m in any direction. However, where it is impossible to achieve the above requirements, closer separation limits are allowed, provided suitable precautions (e.g. fire barriers) are provided. The design target to achieve maximum separation between load groups.

Figure 1
Electrical Systems



1.1 Design Criteria

In general, Station Service Systems are designed to meet several major design criteria from a safety and reliability point of view:

- After severance of the station from the utility grid, the unit must be able to supply its own station service load.
- Increased reliability through redundancy and physical separation between redundant systems and components must be provided.
- The system must be stable under fault conditions.
- The design must meet the requirements of all four classes of power, the requirements of the emergency power supply system, and lend itself to automatic and emergency transfer schemes.
- Simplicity and economy are to be maintained.

1.2 The Odd And Even Concept

The Odd and Even bus concept was used as follows:

(a) The Class III and IV electrical systems are divided into Odd and Even buses at all voltage levels, so that dual bus, or better, reliability is provided.

(b) Loads and redundant auxiliaries are connected such that half of any process requirements are supplied from an Odd bus, and the other half from an Even bus.

(c) Auxiliaries supplied at a lower voltage than the associated primary element are connected to an Odd or Even bus to match the source for the primary element.

(d) The Odd and Even concept was applied to the cable tray system, junction boxes, etc., in order to maintain physical separation between the Odd and Even systems to achieve maximum reliability under normal and abnormal conditions.

1.3 Classes Of Power

The station service electrical systems are classified as follows:

Class I – Uninterruptible direct current (dc) supplies with directly connected batteries for essential auxiliaries, instrumentation, protection and control equipment.

Class II – Uninterruptible alternating current (ac), through converters, for essential auxiliaries, instrumentation, protection and control equipment.

Class III – Alternating current (ac) supplies to essential auxiliaries which can tolerate short interruptions. These essential auxiliaries are necessary for an orderly cooldown of the reactor.

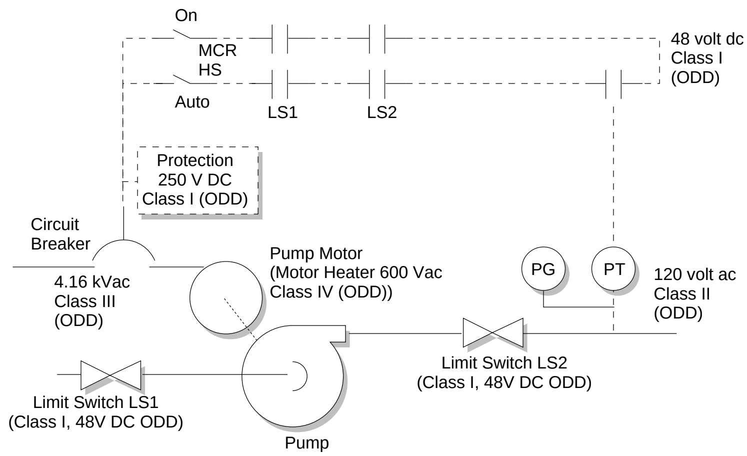
Class IV – Normal alternating current (ac) supplies to auxiliaries and equipment which can tolerate long duration interruptions without affecting personnel or equipment safety. Complete loss of Class IV power will initiate a reactor shutdown.

A seismically qualified emergency power supply entirely separate from the above composed of alternating current (ac) and direct current (dc) supplies for emergency shutdown loads is provided and is controlled from the secondary control area.

Figure 2 shows a simple control diagram for a class III power supplied pump. Note that all classes of power are used in this simple circuit and that all power supplies are from the ODD buses.

Figure 2

Simple Control System



2.0 Class IV Power Distribution System

The Class IV power distribution system obtains its power directly from either the unit and/or station service transformers. Power is distributed at the 13.8 kv, 4.16 kv, 600 v 3 ϕ 60 Hz levels. It is also available at the 120 v 1 ϕ 60 Hz level for service and maintenance outlets. Electrical distribution equipment in the Class IV system includes transformers, circuit breakers, motor starters, and is grouped into ODD and EVEN load groups.

The 13.8 kV system consists of two Class IV buses, 5321-BUA and BUB, as illustrated in Figure 3. Each bus can be connected to the secondary windings of either the system service transformer (SST) or the unit service transformer (UST). For normal running, one bus is supplied from each transformer. During startup, the station auxiliary service power to both buses is supplied from the SST which is connected directly to the 345 kV switchyard.

The 13.8 kV Class IV system supplies the heat transport (HT) pumps and the main boiler feedwater pumps (BFPs) and the 13.8 - 4.16 kV Class III and IV distribution transformers.

The 4.16 kV systems consists of two Class IV buses, 5322-BUC and BUD, as illustrated in Figures 3 and 4, supplied from the secondary windings of two liquid-filled 13.8 kV - 4.16 kV distribution transformers, rated 7.5/10 MVA.

The 4.16 kV Class IV system supplies the condensate extraction pumps (CEPs) and the condenser cooling water (CCW) pumps.

To provide electrical power with higher than usual reliability to the Class IV and Class III loads, an automatic transfer system is incorporated on the 13.8 kV buses, which ensures continuity of supply in the event of a failure of the unit, or a failure of the system service supply. There are three methods by which the load may be transferred from one service transformer to the other, i.e., parallel, fast open, and residual voltage transfers.

A parallel transfer is initiated by closing the incoming supply breaker for a bus, and then automatically tripping the alternate supply breaker. The two service transformers are in parallel for a few cycles. This system is used for normal transfers, and is manually initiated after station startup and before shutdown. It is automatically initiated from UST to SST for mechanical trips on the turbine.

A fast transfer is automatically initiated whenever the 13.8 kV incoming supply breaker is tripped by a fault, other than a bus bar fault. The tripping action results in a closing signal being sent to the alternate supply breaker. There are, therefore, a few cycles during which the bus is disconnected from both transformers. The transfer is fast enough so that the voltage and phase difference between the incoming supply and the residual on the motors is small enough to avoid excessive inrush currents. The fast transfer is automatically initiated by electrical faults on the generator, UST or main output transformer (UST to SST) and for faults in the SST (SST to UST).

A residual voltage transfer is automatically initiated whenever both incoming breakers to a bus are tripped, either intentionally, or due to operator error. This transfer mode is specifically designed as a backup to the fast transfer, and replaces the parallel transfer when it cannot be executed due to lack of synchronism between the UST and SST.

Only one automatic transfer operation is allowed, after which all further automatic operations will be blocked. The system must then be reset by the operator.

Complete failure of the Class IV power occurs if both odd and even sources of supply fail, resulting in a reactor trip.

The 13.8 and 4.16 kV switchgear assemblies consist of metal-clad enclosures with copper bus bars and magnetic blowout type breakers. Each breaker is electrically operated with a spring-loaded mechanism and all breakers of the same rating are interchangeable.

The Class IV system is continuously monitored in the Main Control Room to ensure it is capable of performing its functions.

The Class IV system is the preferred power source for the Class III system. Loads connected to the Class IV system are able to tolerate possible long term interruptions in electrical power.

Figure 3

Typical 13.8 kV Class IV Distribution

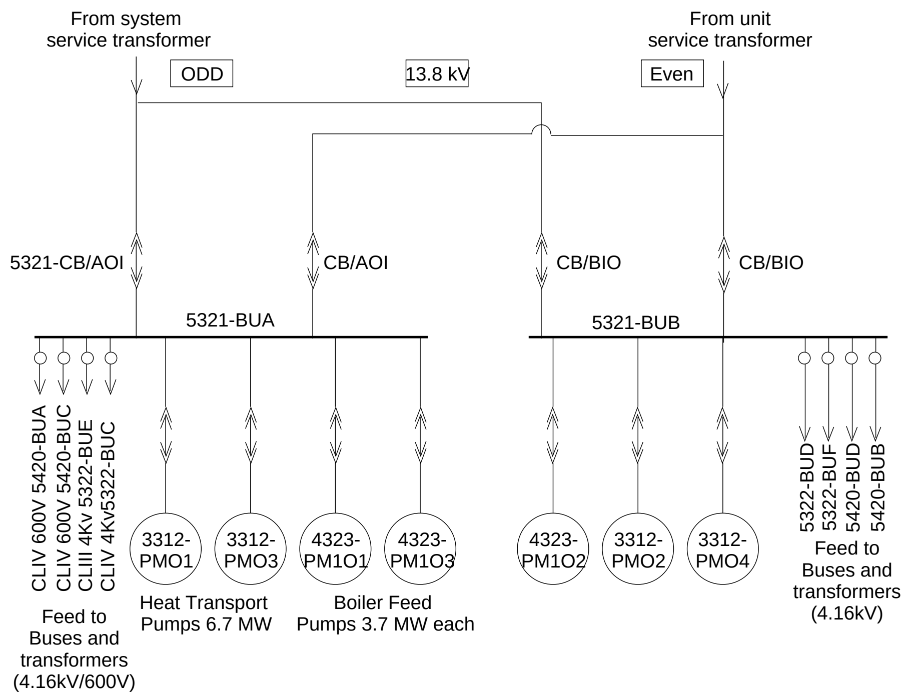
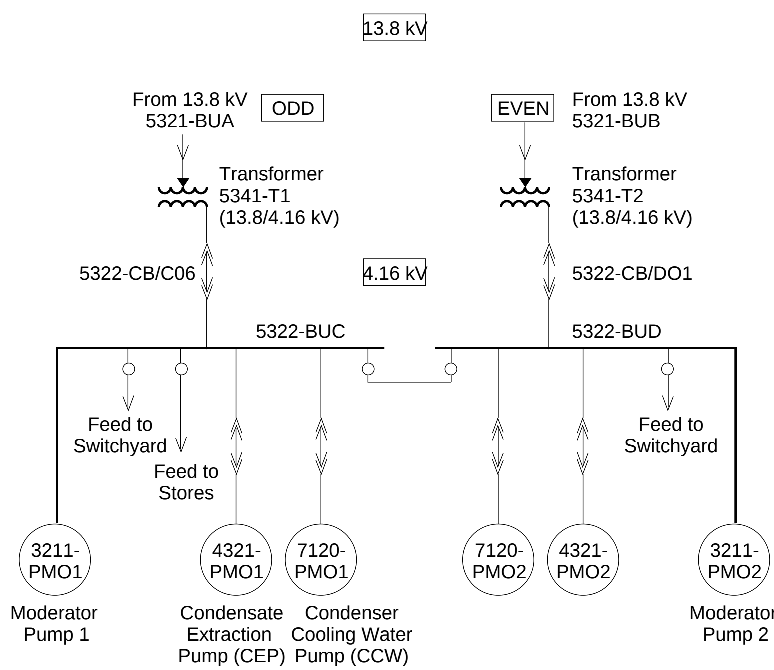


Figure 4

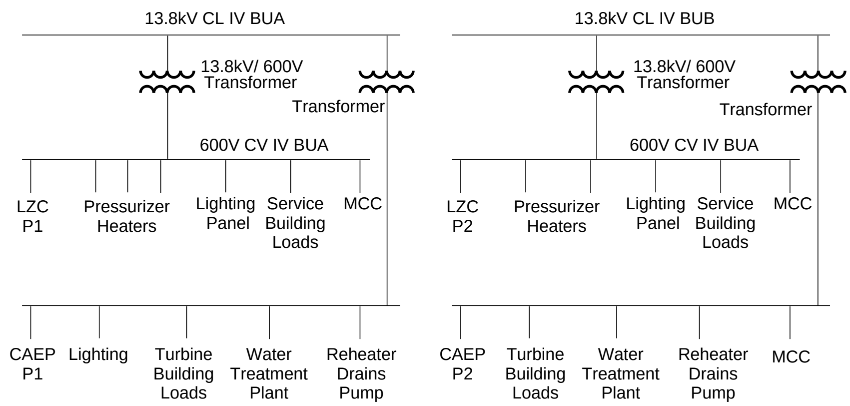
Typical 4.16 kV Class IV Distribution



Station Class IV 600 V Supply Distribution
The 600 V Class IV system consists of four buses, 5420-BUA, BUB, BUC and BUD, supplied through four 13.8 kV/600 V transformers fed from 5321-BUA and BUB. Loads supplied by 600 V Class IV include Liquid Zone Compressor, Pressurizer heaters, Condenser Air Extraction Pump, Reheater drains pumps and the main turbine building crane, as well as feeds to numerous MCCs.

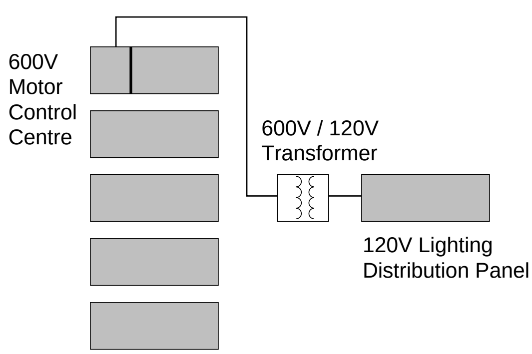
The 600 V switchgear consists of a metal clad enclosure with magnetic blowout, drawout type breakers. All breakers are electrically operated and breakers of the same rating are interchangeable.

A simplified drawing of the Class IV 600V system is shown below.



208/120 V Supply Distribution
The general services are supplied from the 600-120/208 V three-phase transformers which are located in the 600 V motor control centres (MCCs).

Distribution panels, located in selected MCCs equipped with moulded case breakers, supply the general control circuits.



Motor Control Centres (M.C.C.'s)
Motors of over 75 kW and up to 244 kW are supplied directly from the 600 V switchgear. Motors above 244 kW are supplied from the 13.8 kV or 4.16 kV system. Motors of 75 kW and less are supplied from MCCs.

3.0 Class III Power Distribution System

The Class III power distribution system is a nuclear safety support system which normally obtains power from the Class IV system on a redundant (ODD/EVEN) basis. If power is not available from Class IV, two 100 % on-site standby generators provide power. One standby generator is connected to the ODD load group and one to the EVEN load group. Power is normally distributed at the 4.16 KV, and 600 V 3ϕ 60 Hz levels. Where 120V 1ϕ 60 Hz power is required for individual loads appropriate transformers are provided. Electrical distribution equipment in the Class III system includes transformers, circuit breakers and motor starters, and is grouped into ODD and EVEN load groups.

There are no automatic closures of tie breakers between the ODD and EVEN load groups at any voltage level.

Equipment in the Class III distribution system is not required to be seismically qualified to either the SDE or DBE levels.

Connected to the Class III system are safety related system loads and equipment protection loads, which require reliable power, but which can tolerate the interruptions necessary when transferring from the preferred source (Class IV) to the alternate source (standby generators) a period of no longer than three minutes.

The unavailability of the power supply to each load group at the load terminals is not allowed to exceed 10^{-2} under any circumstances.

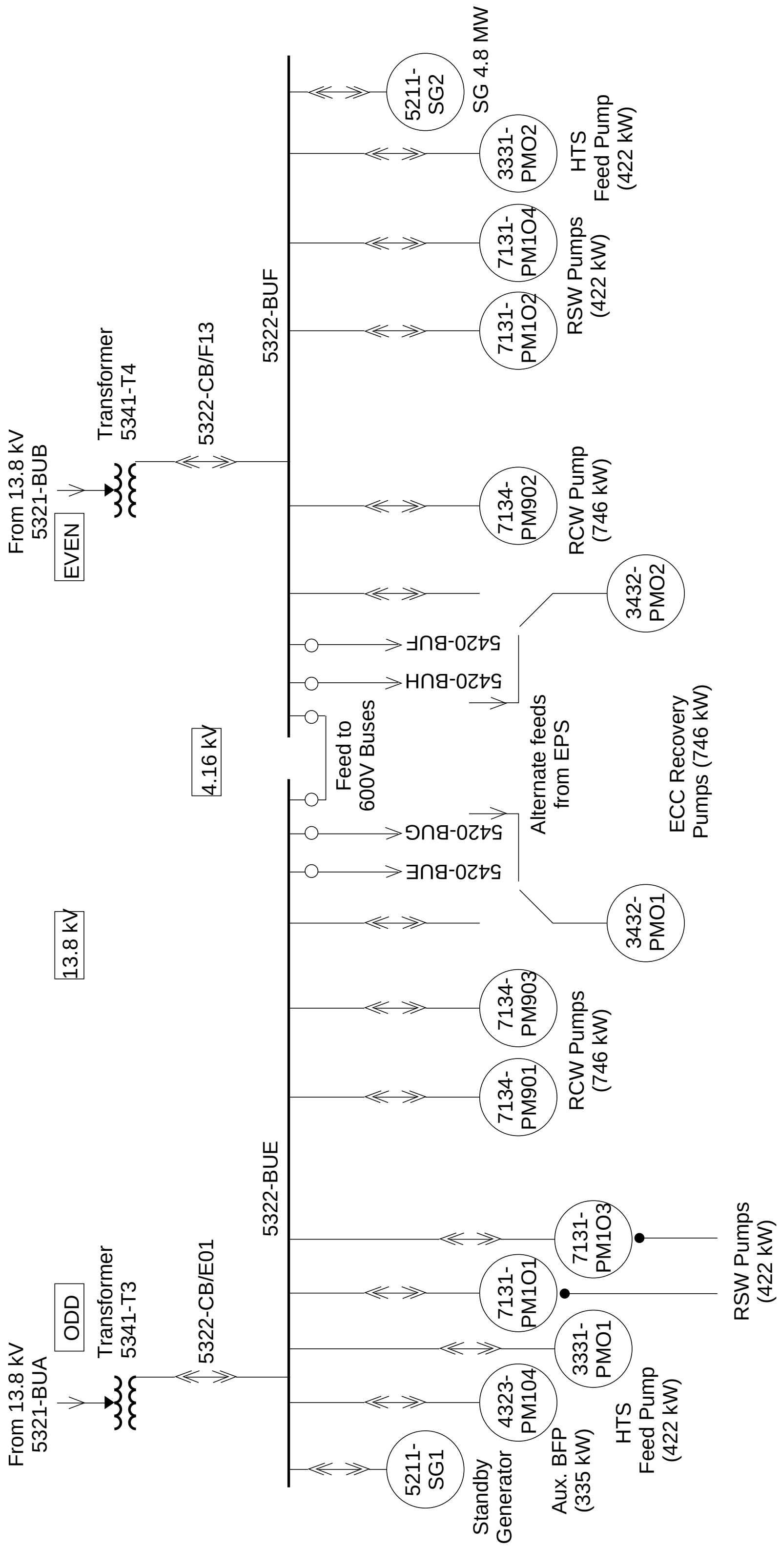
The 4.16 KV system consists of two Class III buses 5322-BUE and BUF as illustrated in Figure 5 supplied from secondary windings of two liquid filled 13.8 KV - 4.16 KV distribution transformers.

The 4.16 KV system supplies HTS feed pumps, auxiliary boiler feed pump, raw service water pumps, , recirculated cooling water pumps and ECC recovery pumps.

The Class III system is continuously monitored to ensure that it is capable of performing its functions.

Figure 5

Typical 4.16 kV, Class III Distribution



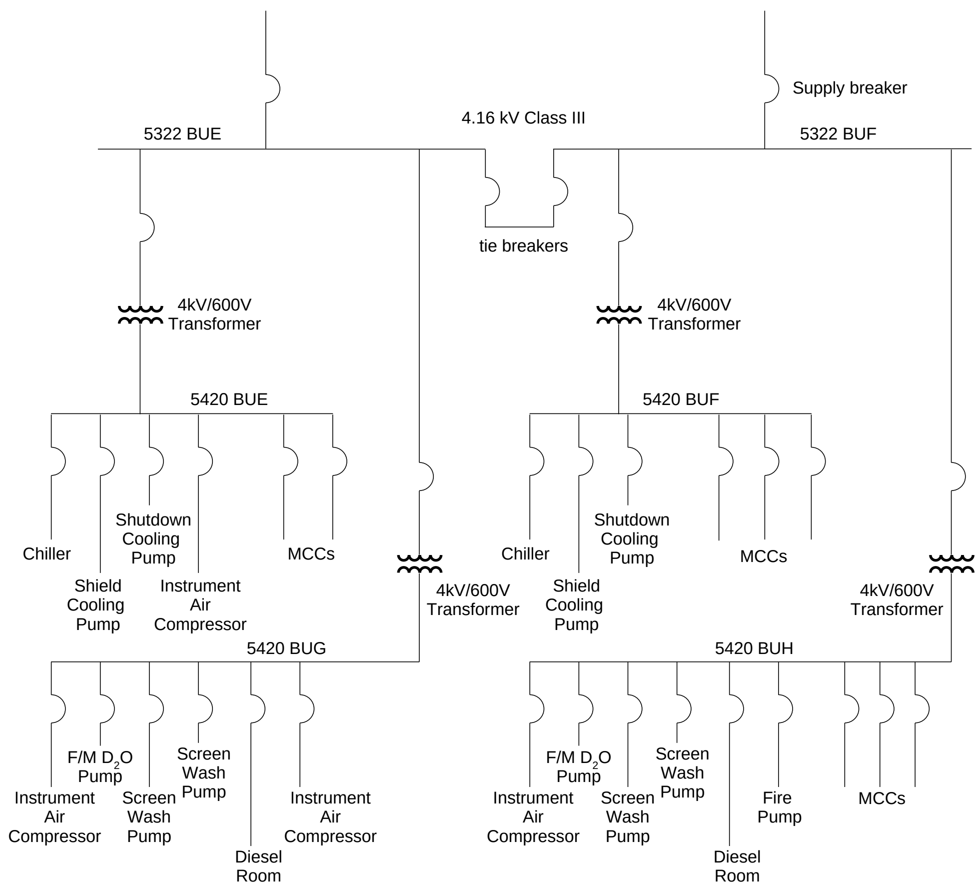
Class III 600 V Supply

The 600 V Class III system consists of four buses 5420 BUE, BUF, BUG and BUH supplied through four 4.16 KV 600V transformers fed from 5322 BUE and BUF. Loads supplied include shutdown cooling pumps, instrument air compressors, shield cooling pumps, chillers, FM D_2O pressurizing pumps, screen wash pumps and numerous MCCs.

As in the Class IV system, the 600 V switchgear consists of a metal clad enclosure with magnetic blowout, drawout type breakers that are electrically operated and interchangeable when the same rating.

A simplified drawing of the 600V Class III system is shown in Figure 6.

Figure 6
Simplified 600 Vac CL III Power.



Design Requirements For Class III Power Under Abnormal Conditions

General

Class III power may be defined as power which, although subject to minor interruptions, is sufficiently reliable to ensure safe plant shutdown and decay heat removal even though the plant may be devoid of power from off-site sources.

Class IV power, which is normally obtained from the station service transformer and/or the unit service transformer, is the normal source for the Class III system. However, in case of failure of the Class IV system, on-site standby generators provide alternate sources of power.

The Class III system provides the following power sources for safety related loads:

- 4.16 kV ac 3-phase 60 Hz
- 600 V ac 3-phase 60 Hz
- Other loads connected to Class III system
  1. essential lighting
  2. Class I dc: 250 V and 48 V
  3. Class II ac: 600 V, 208 V, 120 V and 40 Vdc

The requirements which determine whether an electro-mechanical process load is connected to the Class III system are:

- The operation of the load is necessary to ensure safe plant shutdown, including reactor decay heat removal.

and/or

- The operation of the load is required to prevent equipment damage.
- The load can tolerate the short interruptions in power necessary to start the standby generators.

The standby generators provide power to the Class III buses whenever the Class IV supply is unavailable. From a reactor safety standpoint it is postulated that when this abnormal event occurs there could exist a variety of reactor conditions. These conditions are classified as follows:

a. Total loss of Class IV power when the reactor is operating normally and the station is producing power.
b. Total loss of Class IV power when the reactor is shut down and operating under shutdown cooling conditions.
c. Total loss of Class IV power following a loss of coolant accident (LOCA) prior to which the reactor had been operating normally.

Within categories (a) and (c), short term and long term operation have differing requirements.

Under conditions (a) and (b) above, the duty of the Class III power system is to operate those loads which are necessary to cool the reactor without causing equipment damage or failure which could result in the release of radioactive material. Under condition (c) the duty of the Class III power system is to operate loads which are necessary to ensure that release of radioactive materials to the public is within limits prescribed for that site.

"ODD" and "EVEN" load groups and power sources are both physically and electrically independent, and automatic closure of breakers between the two groups is avoided. This is necessary to avoid common mode faults which could completely disable the on-site power sources.

Transfer schemes designed into the plant provides alternate sources of power to the Class IV system if the preferred source is not available. Thus the total or even partial loss of the Class III system if the preferred source is not available, is a very unlikely event.

The Class III on-site power scheme consists of two 100% standby generators, buses and breakers.

The standby generators (SG) are assigned specifically to "ODD" and "EVEN" load groups (i.e., SG1 "ODD", SG2 "EVEN").

When Class IV power, as established by the emergency transfer scheme, is unavailable, the standby generators are started automatically. The standby generators are also started automatically on a LOCA signal but are not connected to the buses unless a loss of Class IV power occurs.

The standby generators must be capable of operating for a minimum of 15 minutes without load in this situation. The safe time to operate a standby generator with no load is specified by standby generator manufacturer.

When the standby generators have reached rated output (frequency and voltage) and provided Class IV has failed, they are connected to the Class III bus and loading commences through an automatic sequencing system. Automatic load sequencing is necessary:

a. because of the inherent characteristics of the standby generators, and
b. in order to have loads connected in priority order and within time limits specified to meet safety related system criteria.

Start Period and Load Sequence of Standby Generators

Both Class III standby generators are signalled to start on:

a. loss of Class IV power signal,

or

b. loss of coolant accident signals (provided by the ECC system logic).

Independent starting signals are provided for the ODD and EVEN generators.

Under condition (a), when a standby generator has reached rated voltage and frequency, generator connecting scheme will connect the generator to its bus after checking bus integrity. The other standby generator, if available, will be connected to its bus in similar way to the first generator.

Tie breakers between ODD and EVEN group will be closed only manually on failure of either ODD or EVEN standby generator start and is at the discretion of the operator.

Under condition (b) both standby generators will receive signal to start. However, the generators will be connected to each bus automatically only when a loss of Class IV signal is also received. The connecting scheme will be the same as described under condition (a).

When a standby generator is connected to the bus, automatic load sequencing will commence. The load sequencing will connect essential safety related loads to the bus without waiting for the other generator to be connected to its bus.

Starting standby generators and sequence of connecting essential loads should be completed within 180 sec of receipt of the signal from the emergency transfer scheme indicating loss of Class IV.

The standby generators are required to start during LOCA Loss of Class IV Power to regenerate the ECC Pumps within 40 seconds of a pump trip due to loss of Class IV Power

Operator action will be required to connect non-safety related loads to the bus after a suitable interval and after checking generator's loading.

Class III Load Sequencer Testing and Generator Testing

- A provision is made for testing of the sequencer with and without a simulated LOCA signal.
- For the purpose of testing the Class III generators, each generator is equipped with all instrumentation necessary to assist the plant operator to synchronize the generator with the incoming Class IV power supply. This synchronizing system can also be used to synchronize and parallel generators (with the ODD-EVEN tie breakers closed) for long term operation or in emergency.

4.0 Class II Power Distribution System

The Class II power distribution consists of inverters, motor control centres and distribution panels. Power will be distributed at 600 V 3ϕ 60 Hz for motor and lighting loads and 120 V 1ϕ 60 Hz for instrumentation and control loads. 600 V 60 Hz power is distributed to the ODD and EVEN load groups from two separate buses. 120 V 60 Hz power is distributed on a triplicated basis from three separate buses.

Connected to the Class II system are loads which require essentially uninterruptible ac power to perform safety related, equipment protection, and monitoring and control functions.

Class II buses supply power to both NSP (nuclear) and BOP (balance of plant) systems, but separate breakers are provided for systems within the two groups.

In addition, within the NSP, separate breakers are provided for each channel of the special safety systems.

Equipment which comprises the Class II system is not required to be seismically qualified to either the SDE or DBE levels.

Class II Power Supply
The Class II supply is considered uninterruptible for all practical purposes and therefore supplies all ac loads which are critical for safe shutdown and which cannot tolerate the interruption during SG start-up.

The Class II 600 V power supply is normally supplied from the station battery 250 V dc buses by means of static inverters. On an inverter failure the Class II 600 V power supply is supplied from Class III through a solid state switch.

Two 150 kVA 600 V inverters supply the Class II motor and safety lighting loads.

Feeds from the 600 V inverters supply three 208 V Class II MCCs via transformers as follows. One MCC feeds the shutoff rod assembly ODD drive motors via a transformer. A second MCC feeds the shutoff rod assembly EVEN drive motors via a transformer. Either of these MCCs can supply, via a manually operated transfer switch and transformer, the third MCC which feeds the Control Absorber and Adjuster Rod drive motors.

The Control Absorber and Adjuster Rod motors are designed to operate at 208 V through a variable frequency controller.

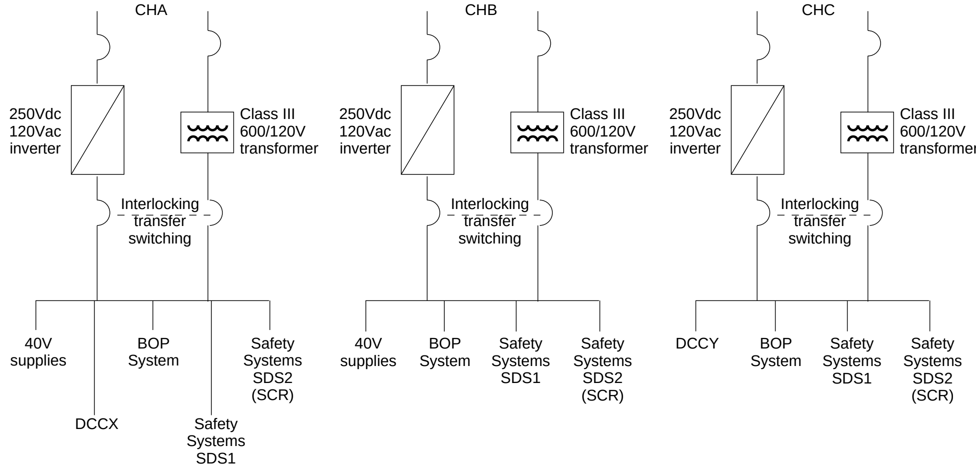
The Class II 120 V single-phase power is normally supplied from the station battery 250 V dc buses by means of static inverters. On an inverter failure, the Class II ac requirements are automatically met by a regulated supply from Class III MCCs, through solid state switches. This power supply supplies ac instrumentation loads and the station control computers. The Class II system is illustrated in Figure 7.

The three 120 V Class II buses 5522-BUTA, BUTB and BUTC are supplied by means of three 60 kVA inverters, 5552-INV1a, 1b AND 1c.

The Class II system is continuously monitored to ensure that it is capable of performing its functions.

The unavailability of the power supply to each load group (at the load terminals) is not allowed to exceed 10^{-2} under any circumstances.

Figure 7
Typical Simplified Class II 120 Vac Power System



5.0 Class I Power Distribution System

The Class I power distribution system consists of batteries, motor control centres and distribution panels. Power is distributed at 250 V dc for motor loads and for operation of switchgear circuit breakers. Power is distributed at 48 V dc for operation of control relays, handswitches, and control panel indicating devices. 48 V dc power is also used for solenoid valves. 250 V dc power is also used to provide input power to the Class II 120 V ac inverters.

Connected to the Class I system are loads which require essentially uninterruptible dc power to perform safety related, equipment protection, monitoring and control functions.

Class I 250 V dc buses supply power to both NSP and BOP systems but separate breakers are provided for systems within the two groups. Class I 48 V dc buses supply power to both NSP and BOP systems, but separate breakers and distribution panels are provided for systems within the two groups. In addition, within the NSP, separate breakers and distribution panels are provided for each channel of the special safety systems.

Equipment which comprises the Class I system is not required to be seismically qualified to either the site SDE or DBE levels.

A simplified Class I system is shown in Figure 8 and Figure 9.

Class I Power Supply

The Class I power supply comes directly from the 250 V dc and 48 V dc buses which are supplied with directly connected batteries, to ensure an uninterruptible supply. On failure of Class III, the 48 V battery banks are sized to last 3.5 hours, and the 250 V battery banks are sized to last four hours.

Figure 8

Simplified Class I 250 V DC

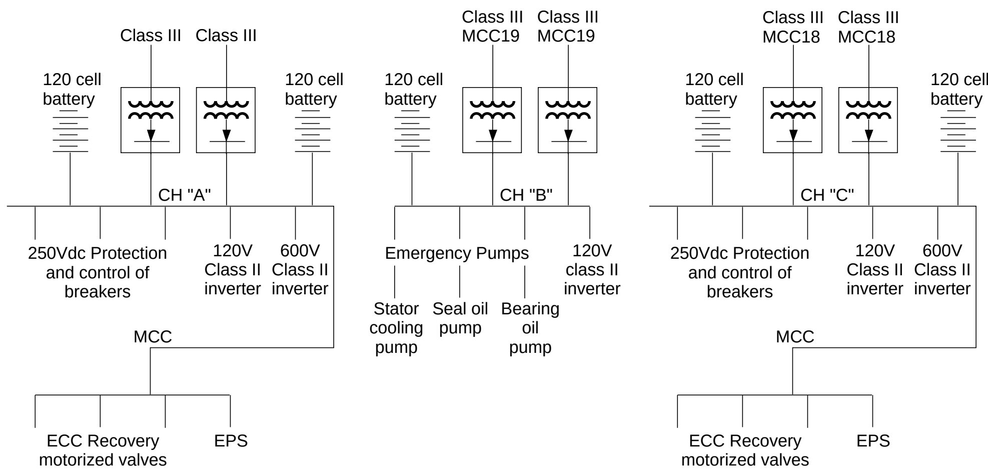
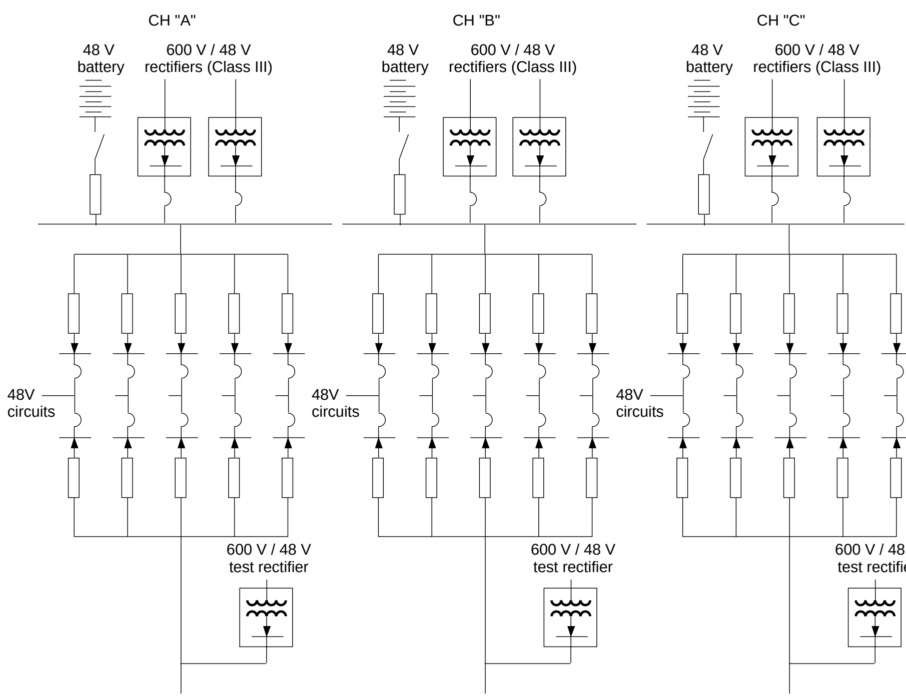


Figure 9

Simplified Class I 48 V DC



Station 250 V dc System

The 250 V system has three separate channelized buses 5521-BUA, B and C.

Channel A and C buses are each supplied by two battery banks each containing 120 cells, with two 100% capacity support supplies via rectifiers from separate MCCs. Channel A and C buses supply a variety of circuit breaker operation and protection circuits and MCCs for ECC Injection and Recovery valve operation. Channel B bus is supplied by one 120 cell battery bank and two 100% capacity rectifiers from a third MCC. Channel B supplies the emergency DC Stator Cooling Pump, DC Seal Oil Pump and DC Bearing Oil Pump associated with the main turbine generator. Each of the three buses also supply the respective 120 V ac Class II system through 60 kVa inverters to provide power for computers and instrumentation loads. The 600 V three-phase Class II system is supplied through inverters, from the A and C channel 250 V battery banks, to power Class II motor loads.

Station 48 V dc System

The dc power source supplying the control and instrumentation system is provided by three separate channelized buses. Each bus is supplied by a 24 cell, 48 V battery bank. Each bank is continuously supplied by two 100% rectifiers, fed from separate Class III MCCs.

These three buses supply eight distribution panels in the control equipment room (CER), and three distribution panels in the secondary control area (SCA).

The Class I system is continuously monitored to ensure that it is capable of performing its functions.

The unavailability of the power supply to each load group (at the load terminals) is not allowed to exceed 10^{-2} under any circumstances.

6.0 Emergency Power System

General
As part of the protection against postulated manmade common mode events, (e.g. fire) the safety related systems are placed into two separate groups. The preferred power supplies to both groups come from the Class I, II, and III buses. However, if the common mode event disables the Class I, II, and III buses, a separate power supply is required to provide power to one group of special safety systems. As a result, the Emergency Power System (EPS) system supplies power to the second shutdown system (SDS2) and the containment system. These systems form group 2 of the safety related systems.

In the event of an earthquake the reactor unit must be capable of being shutdown and the decay heat removed. On loss of power the special safety systems will shutdown the reactor. The systems which operate to remove decay heat require a seismically qualified source of power. In addition, systems which monitor the condition of the plant also require seismically qualified power.

The above requirements have been combined and thus the emergency power system (EPS) fulfills the following roles:

- An alternate source of power to group 2 safety systems in the event of a common mode event disabling the preferred source of power.
- A seismically qualified source of power to the emergency core cooling pumps and emergency water supply pumps in order to remove decay heat in the event of a natural common mode event disabling the preferred sources of power.
- Provides power to reactor monitoring systems after a common mode event has resulted in a reactor shutdown and disabled the preferred sources of power.

Power is distributed at 4.16 KV 3ϕ, 600 V 3ϕ, 120 V 1ϕ 60 Hz and 48 V dc on an ODD/EVEN redundant and triplicated basis. Power for EPS system is provided by two emergency power generators (either diesel or combustion turbine units depending on the plant), which are connected to two redundant load groups comprising circuit breakers, transformers, motor starters and distribution panels. Manual switches are provided to allow transfer between the preferred power sources and the emergency power sources.

Equipment which comprises the emergency power system is required to operate following a design basis earthquake (DBE).

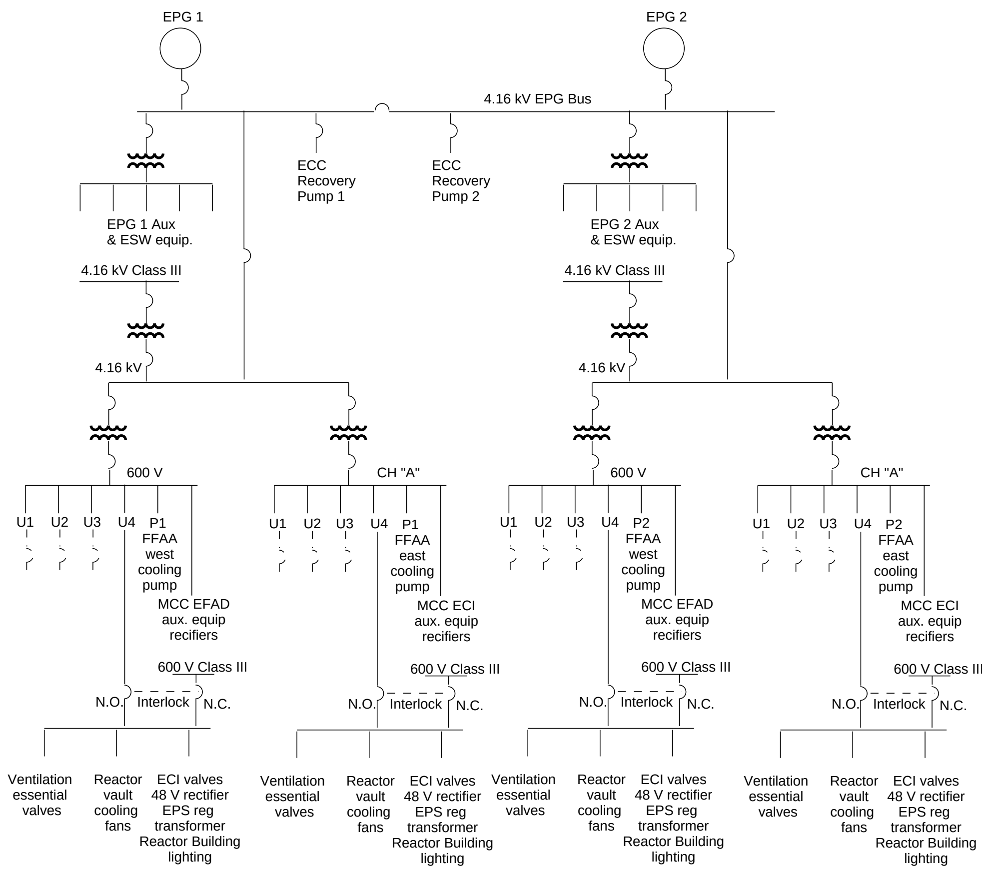
Automatic starting of the emergency power system is not a requirement, but power will be available under operator control, within 20 minutes of a design basis event which has resulted in a loss of the preferred power sources.

The unavailability of the power supply to each load group (at the load terminals) is not allowed to exceed 10^{-2} when the system is operating.

The operational readiness of the Emergency Power System is continuously monitored.

When the EPS system is functioning its operation is continuously monitored.

Figure 10
Simplified EPS System



7.0 Station Grounding

There are two grounding networks within the station. The main network consists of several bare stranded copper wires, buried in the ground and connected at fixed intervals to grounding rods. This network encircles the buildings and is connected to two other grounding grids, one covering the switchyard area, the other consisting of metal conductors installed in the main water intake channel. All electrical apparatus, control panels, cubicles and all metal work in the building structures, stairs, reservoirs, etc., are connected to this grounding system.

The second grounding network is used for the station instrumentation. It consists of a network of copper conductors insulated with polyvinyl chloride or equivalent. To avoid ground loop currents which could affect the instrumentation, this grid will be connected to ground only at one point, as close as possible to the geographical centre of the main grounding system.

The 48 V dc and 250 V dc systems are ungrounded. Ground fault detectors, which alarm whenever a ground occurs, are provided for each bus.

Monitoring, Protection and Transfer Schemes

Training Objectives:

On completion of this lesson the participant will have the required knowledge to:

- Describe how the monitoring information for the electrical distribution system is derived and displayed in the control room.
- Describe the events which occur in the control room when an operator changes a breaker handswitch position from closed to open (or visa versa).
- List the requirements of the protection schemes for electrical equipment.
- List the qualities that a protective scheme must possess, in order to meet these requirements.
- Describe the operating characteristics of fuses, and state their advantages and disadvantages.
- List the two categories of relay protection.
- Given a sketch of a simple thermal type protective relay, describe how it operates.
- List the additional features that a P&B Golds thermal relay has over a simple thermal relay.
- Explain why stall protection is required and how it is achieved.
- Given a sketch of a simple electromagnetic relay, describe its operation.
- Describe how an attracted armature relay can be adapted for use in motor protection.
- Given a diagram of an induction disc relay, describe its operation.
- State the main disadvantage of the induction disc relay when used for motor protection.

- Given a sketch of a simple undervoltage protection scheme for protecting a number of motors, describe how undervoltage protection is achieved and why it is used.
- Given a sketch of a typical power circuit and protection scheme for a small motor, label the protective equipment used.
- List the difference between a small motor protection circuit and a large motor protection circuit.
- Explain why O/C relays and fuses are not used to protect buses/generators/transformers.
- Given a sketch of a simple differential protection scheme, explain the principle of operation and list its advantage.
- Explain the term "Protected Zone".
- Describe the possible consequences of prolonged paralleling of two sources of supply to a station distribution bus.
- Given a diagram, explain how a manual transfer is performed from one service transformer to another.
- Explain the difference between a fast transfer and a parallel transfer.
- Explain how the residual voltage transfer scheme operates, and why it is needed.
- Describe the consequences of failure of:
  - the Parallel Transfer Scheme
  - the Fast Transfer Scheme

Table of Contents

1.0 Introduction

In this manual we will examine some of the features of the Distribution System which enable the operator in the control room to be aware, at all times, of the status of the system; to have his attention called to any changes in that status; and to confirm that any operations which he may initiate actually do occur.

The various forms of electrical protection and how they are applied will be described.

Finally, the automatic transfer scheme will be examined in detail.

2.0 Monitoring

The status of the electrical system is defined for the operator by:
- bus voltages
- circuit breaker positions.

Bus voltages are too high to display directly on a meter, and it is not practical to run high voltage wiring to the control room for remote locations in the plant. Therefore, instrument transformers are used, which step down the (high) bus voltage to a standard nominal 120 volts. These are usually called potential transformers or PT's. Current transformers or CT's do the same thing for high currents, with transformation ratios selected to produce a nominal full scale of 5.0 amps (Figure 1).

Circuit breaker positions (CLOSED or OPEN) are indicated in the control room by low voltage electromechanical indicators or EMI's (Figure 2).

Circuit breakers have auxiliary contacts which operate in unison with the main contacts. A pair of these contacts are used to operate the EMI in the control room (to show the breaker position).

Figure 1

Drawings of Typical PT's and CT's

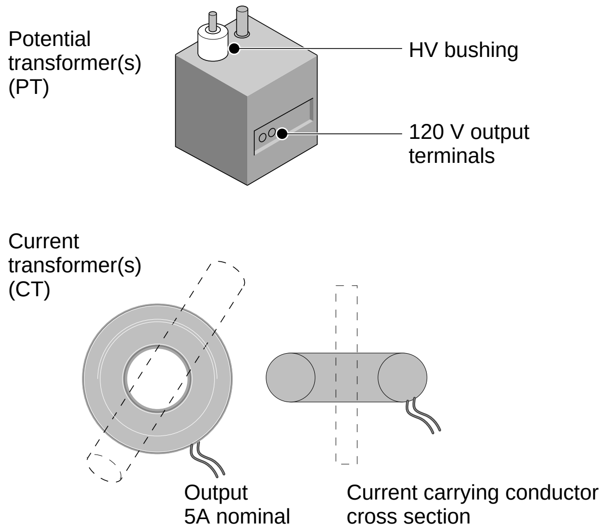
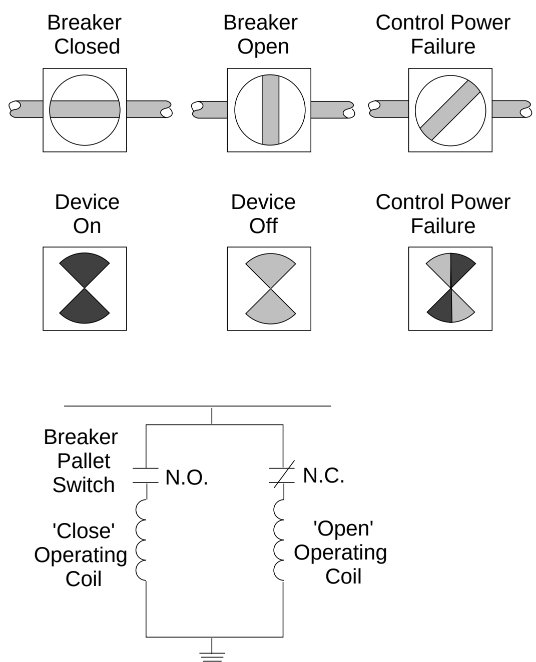


Figure 2

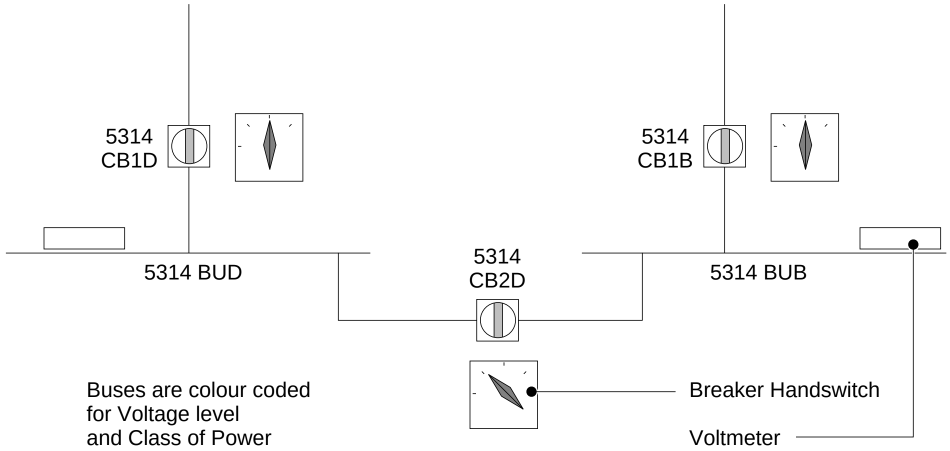
Two Typical EMI's and their Operating Circuit



Mimic Bus

The electrical system is represented on the control room panels in the form of a mimic bus (Figure 3), which shows the various buses as lines, colour-coded for voltage and Class of power, circuit breakers by EMI's, and edge meters to show bus voltages.

Figure 3
Section of Mimic Bus

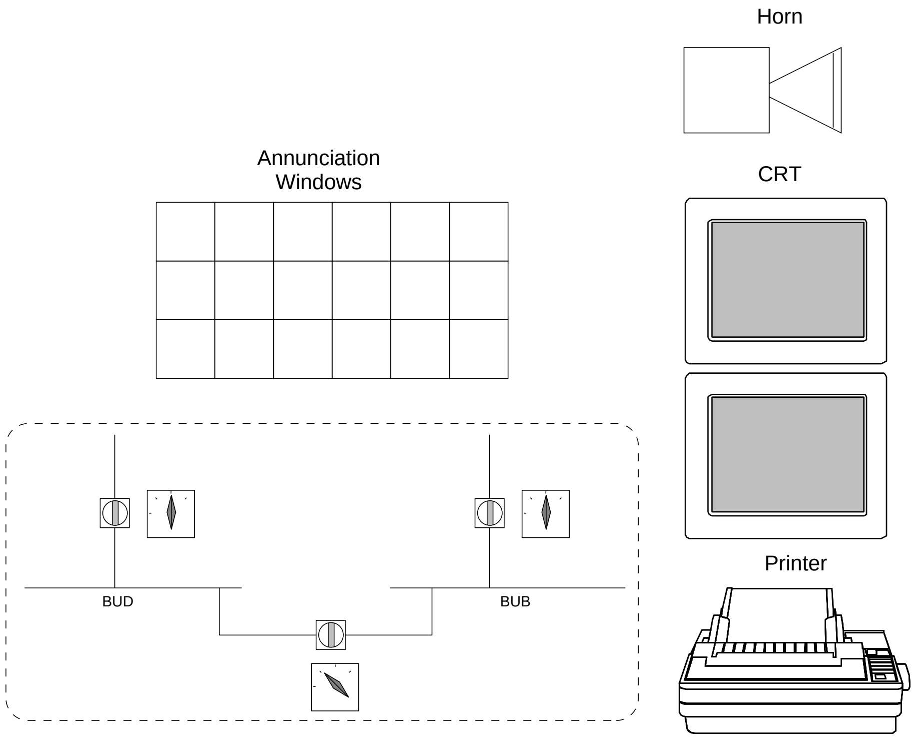


Circuit breakers are controlled from handswitches adjacent to the EMI representation on the mimic bus.

Annunciation System
In addition to the mimic bus display, the operator is provided with an annunciation system, which calls his attention to any change of state in the electrical system (as well as other systems). This system has the following outputs (Figure 4):

- annunciation windows (colour-coded to indicate significance)
- horn
- CRT messages
- printer

Figure 4
Monitoring Devices in Control Room



The control room operator also relies on reports from field operators to maintain his awareness of system conditions which are not monitored by the above equipment and systems. For example, before the operator begins to synchronize the main generator to the power grid, he requires confirmation from a field operator that the motor-operated disconnect switch between the main transformer and the output breakers (one of which is selected for synchronizing the generator) has, in fact, moved to its closed position and the contact blade of each of the three poles has rotated in its jaws.

3.0 Protection of Electrical Equipment And Systems

Requirements for Protection

Every item of electrical equipment should have some form of electrical protection which will remove it from service in the event that it becomes faulty or over-loaded. This is necessary to ensure that:

- damage to faulty equipment is minimized and is not allowed to spread to other equipment,
- healthy equipment is left in service,
- equipment is protected from damage due to overload,
- system stability is not compromised.

The complexity of the electrical systems in a nuclear power station requires a comprehensive protection scheme which must possess the following qualities:

- Reliability: the protective system must function whenever it is called upon to operate.
- Selectivity: the protection must be able to select and shut down that equipment or section of the system which is faulty, while allowing healthy equipment to continue to operate.
- Sensitivity: the protection must be able to detect a fault before it reaches a dangerous condition, without being too sensitive and thus operate unnecessarily.
- Speed: the protection must operate quickly to minimize the time that the fault persists, and thus minimize damage to the equipment. On the other hand, protection of electric motors, which take large starting currents, must be time-delayed to prevent unnecessary tripping.

Fuse Protection

Fuses used in industrial applications are usually designated as HRC (for High Rupture Capacity). Fuses have an inverse time/current characteristic, which means that they will have a fast operating time for currents several times their normal rating, but will have slow operating time for currents only slightly above normal. For lighting and other equipment which does not have a high starting current surge, fuses need only be rated slightly higher than full load current. Electric motors, however do take a high starting current surge, which persists for several cycles, and this feature makes fuses of limited value for motor protection, particularly for large motors. For such equipment, the more flexible relay protection is used, in which the protection required can be tailored to meet the exact needs of the motor.

Relay Protection

Protective relays usually fall into one of two categories:

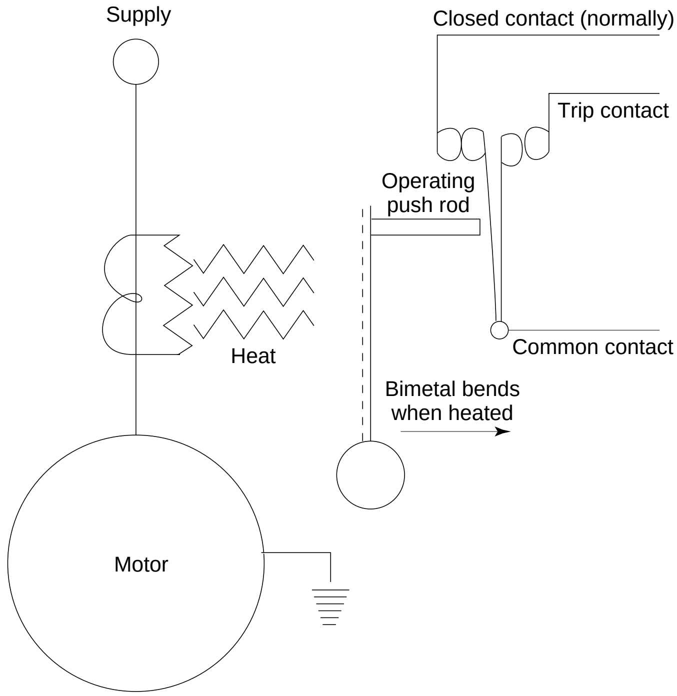
- thermal,
- electromagnetic.

Thermal Relays

Thermal Relays depend upon the heating effect of the load current acting upon a bimetallic element, which bends to operate a contact. The basic principle is shown in Figure 5.

The motor current, or a fraction of it (as "measured" by a current transformer), passes through a heater adjacent to a bimetallic strip. As the heater and the bimetal takes time to heat up, a thermal relay has an inherent time delay, which is similar in some respects to the inverse time characteristic of a fuse. However, by careful choice of heater and bimetal characteristics, the relay can be made to produce a "thermal image" of the heating in the motor, and can therefore protect the motor. Because motors can only withstand approximately 115% of full load current continuously, the thermal relay would have to be set to operate at a figure below this value. A setting of 110% of full load current would be typical.

Figure 5
Principle of a thermal relay



The P & B Golds relay, a typical thermal overload relay for a large motor as used to drive a HT circulating pump, is pictured in Figure 6 (a), with its electrical schematic in Figure 6 (b).

Figure 6a

Diagrams showing the construction and basic schematic diagram for a P&B Golds thermal overload relay.

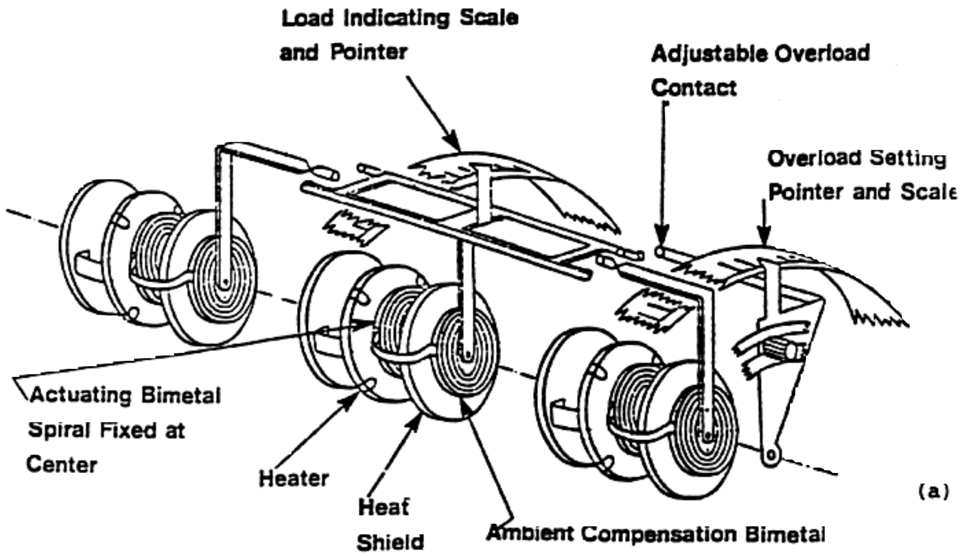
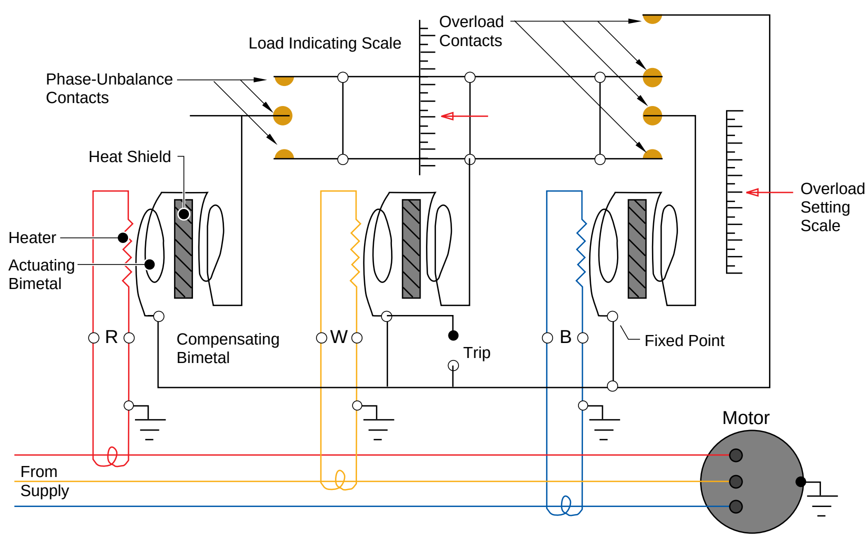


Figure 6b



This is a complex relay and contains several additional features not found in the simple relay of Figure 5:

- each of the three phases has its own heating element and spiral bi-metallic strip,
- compensation for changes in ambient temperature,
- load indicating scale for accurate measurement of load current after the motor has been running for a long time,
- phase unbalance protection.

Because the relay takes a long time to heat up to its normal operating temperature, it does not provide protection for the motor during starting or stalled conditions. The (P&B Golds) relay described here will protect the motor after it has been running for about 350 seconds, but not during this high current period. To overcome this, a stalling relay is provided which has a fast response time and provides an accurate thermal image of the motor during starting or when its current is greater than 3 times normal.

In the P&B Golds relay (Figure 7), this is achieved in two ways:

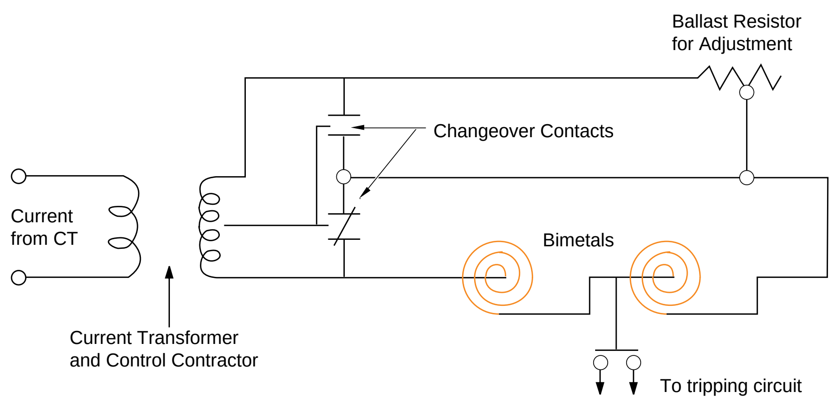
- when the motor current is at or above 3 times full load, an auxiliary contact operates to switch the stalling relay into service, and switch it out when the current falls below 2 times full load.
- high speed is achieved by having the load current (as seen by the CT's) flow in the bimetallic helices themselves, rather than through separate heaters.

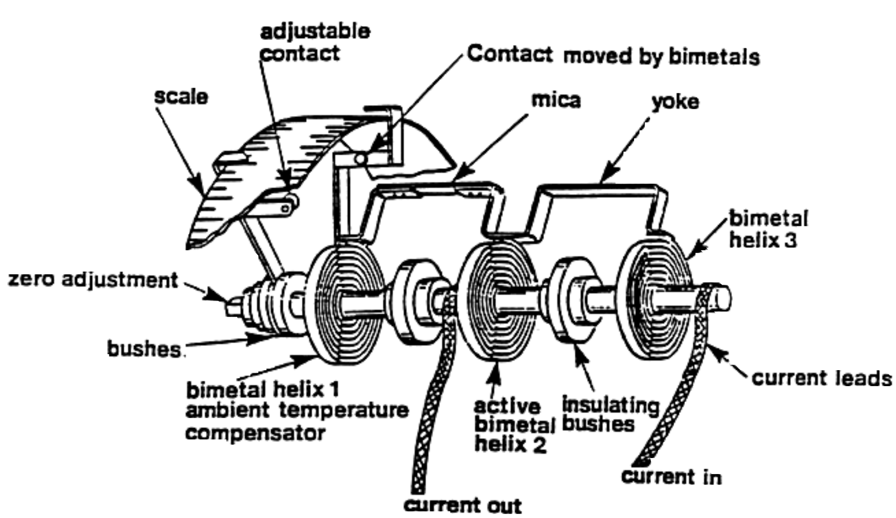
The P&B Golds relay also provides:

- instantaneous overcurrent protection (against short circuits)
- ground fault protection.

These will be discussed in more detail later.

Figure 7
Diagram showing the stalling relay bimetal helixes and tripping contacts.
Electromagnetic Relays



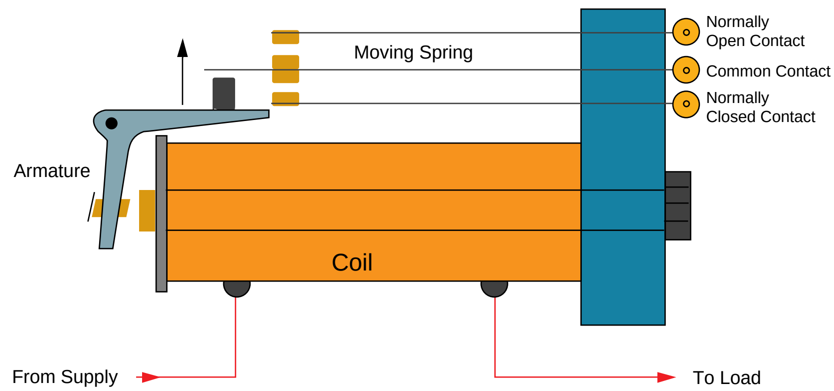


Attracted Armature Relay

This type of relay operates on the principle of the current in a coil attracting an armature of plunger. In its simplest form, often called the "telephone relay", as shown in Figure 8, this relay has numerous applications in nuclear stations, particularly in low voltage (48 V dc) logic or control applications.

Figure 8

Simple attracted armature relay connected to operate when the load current reaches a preset value.



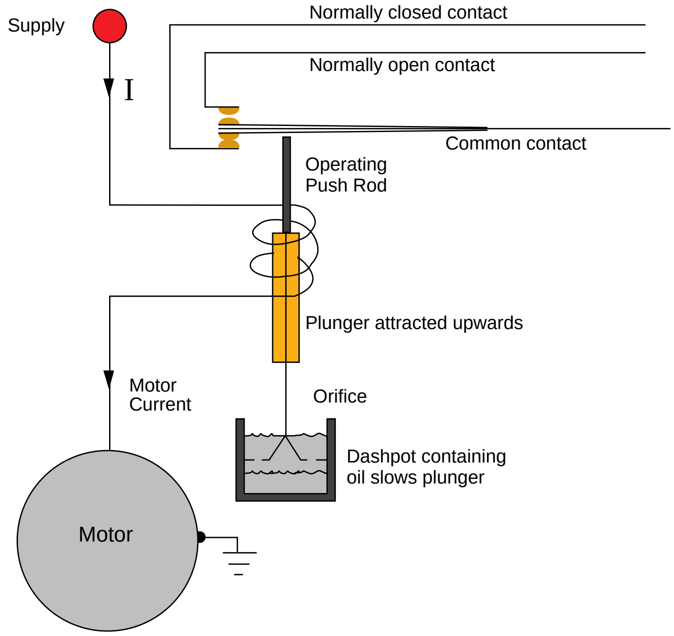
This type of relay is almost instantaneous in operation and is unsuitable for protecting motors with large starting currents. This problem can be overcome by using a time delay unit such as:

- a small clockwork timer,
- an air or oil dashpot.

Figure 9 shows a different form of electromagnetic relay as used for motor protection in which a plunger is drawn into the operating coil. The plunger is fitted with an oil dashpot time delay unit. By adjustment of the operating current of the coil and the orifice in the oil dashpot, the desired characteristic can by obtained.

Figure 9

Principle of a magnetic relay with a time delay to allow for starting currents.



Induction Disc Relays

A typical induction disc relay is shown in Figure 10a and its electrical schematic in Figure 10b.

Figure 10a

Induction Disc Type Overcurrent Relay

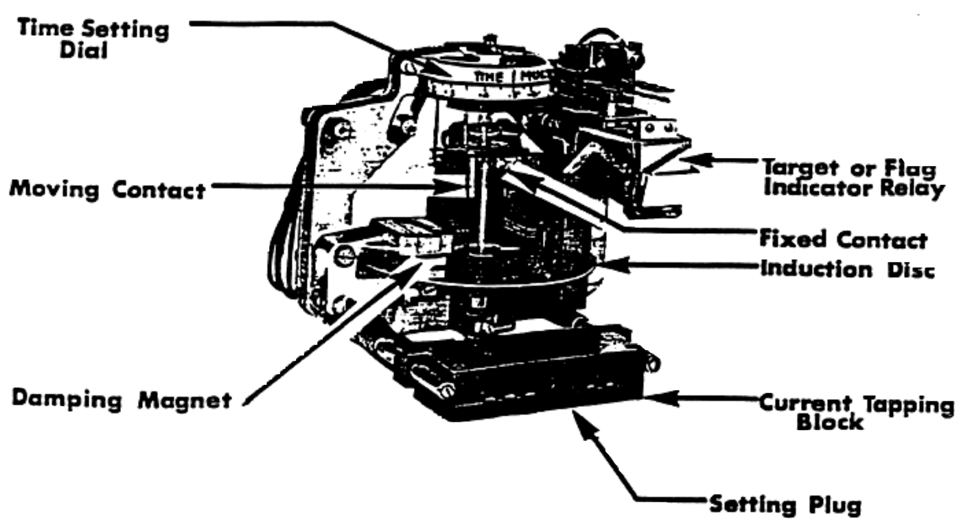
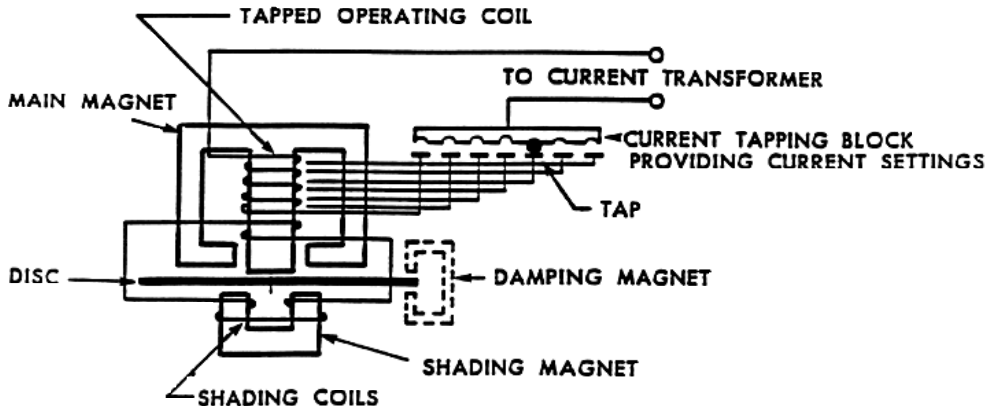


Figure 10b
Electrical Schematic for a Disc Overcurrent Relay



The principles of operation of this relay are as follows:

- a current proportional to the load current (from a CT) flows in the main coil.
- this current produces a flux in the main magnetic circuit which induces a current in the shading coils. The shading coils are mounted on a separate core and are wound to produce a flux which is out of phase with the flux in the main magnetic circuit. The two fluxes, one out of phase with the other, produce a torque on the disc.
- a restraining hairspring provides a bias or reverse torque on the disc.
- when the current in the main coil is greater than the current setting or operating current of the relay, an operating torque is produced by the disc which overcomes the spring torque and the disc will begin to rotate. Increasing the current in the coil will increase the torque and hence the speed of rotation of the disc.
- a braking or damping magnet is provided to give the disc the correct speed and hence the correct time characteristic. The magnet also prevents the disc from over-running when the current in the coil has returned to its normal value.
- the shaft of the induction disc carries a moving contact, and when the disc rotates far enough, the moving contact meets a fixed contact, energizing the trip circuit.
- at the same time, an auxiliary contact energizes an indicator relay which uncovers a "flag" to show that the relay has operated. The flag remains visible after the relay returns to normal, and must be manually reset. If the operator finds the relay flagged, he will know that the relay has operated at least once, but must rely upon other sources to determine whether more than one fault has occurred since the flag was last reset.

The induction disc relay has an inverse time characteristic similar to that of a fuse, and similar difficulties arise when applying this form of protection:

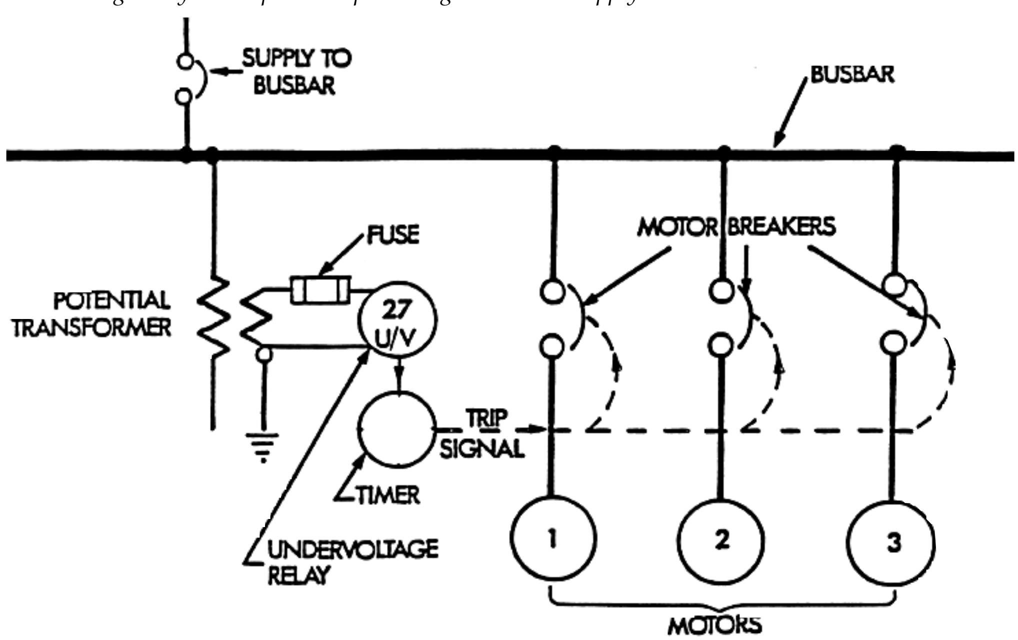
- fault currents greater than load currents must flow for the relay to operate
- a lengthy time delay is involved

4.0 Motor Protection Schemes

Undervoltage Protection
Motors in power plants are designed to produce rated power when rated voltage is supplied to the terminals of the motor. Because the torque developed by an induction motor is proportional to the square of the applied voltage, a small drop in voltage will produce a large drop in output capability of the motor.

If the supply voltage to a bus supplying a number of motors drops to a low value or fails completely, all motors will slow down and eventually stop. When the supply voltage returns to normal all motors will attempt to start together, and will take starting current together. The combined starting current would probably be sufficient to trip the incoming supply.

Figure 11
Undervoltage relay and trip scheme protecting motors and supply to bus bar.



To guard against these problems, two forms of undervoltage protection are used:

- the contactor which feeds each motor is designed to "drop out" or open if the voltage drops below a given value. This stops the motor and a new starting signal is required to close the contactor.
- an undervoltage relay is used which trips the contactors or motor breakers. This relay is usually of the simple attracted armature type and is supplied with a fraction of the bus voltage from a potential transformer (PT). It trips all motor circuits through a timer which is usually set to operate in about 5 seconds, so that spurious trips due to transients are avoided.

A typical application of undervoltage protection is shown in Figure 11.

Motor Protection Schemes
For "small" motors with ratings less than 30kW, the 600 Vac supply circuit comprises:

- a circuit interrupter - used as a disconnect switch and a device for interrupting high levels of fault current. It has current sensing elements which trips the interrupter in the event of a short circuit.
- a contactor - used to control the load, operated by control and/or logic circuits.
- a thermal overload relay - used to trip the contactor in the event that the motor draws excessive current for a time longer than specified.

Figure 12 is a typical power circuit and protection scheme for a small motor. Figure 12a shows the three phase circuit and Figure 12b is the single line representation of the circuit as it might appear on the station operating flow sheets.

Figure 12
Typical power circuit and protection scheme for a small motor.

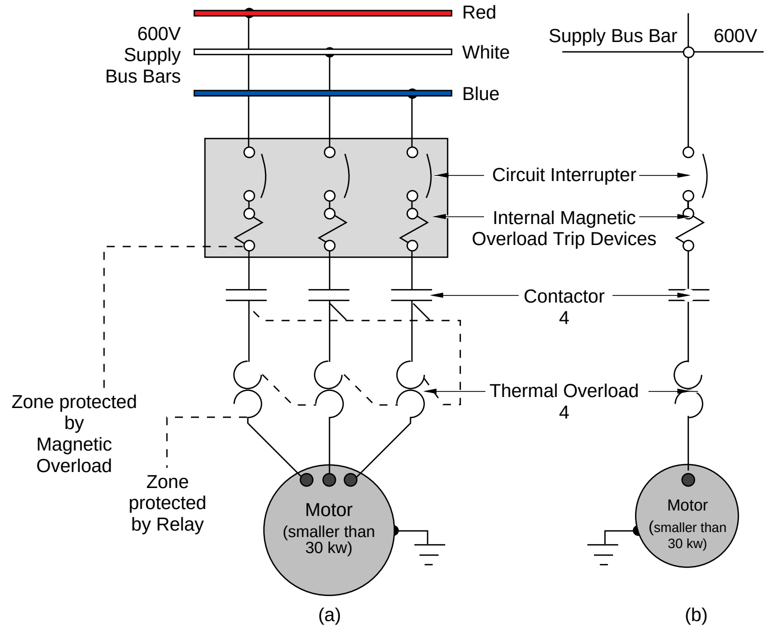


Figure 13

Typical power circuit and protection scheme for medium and large sized motors.

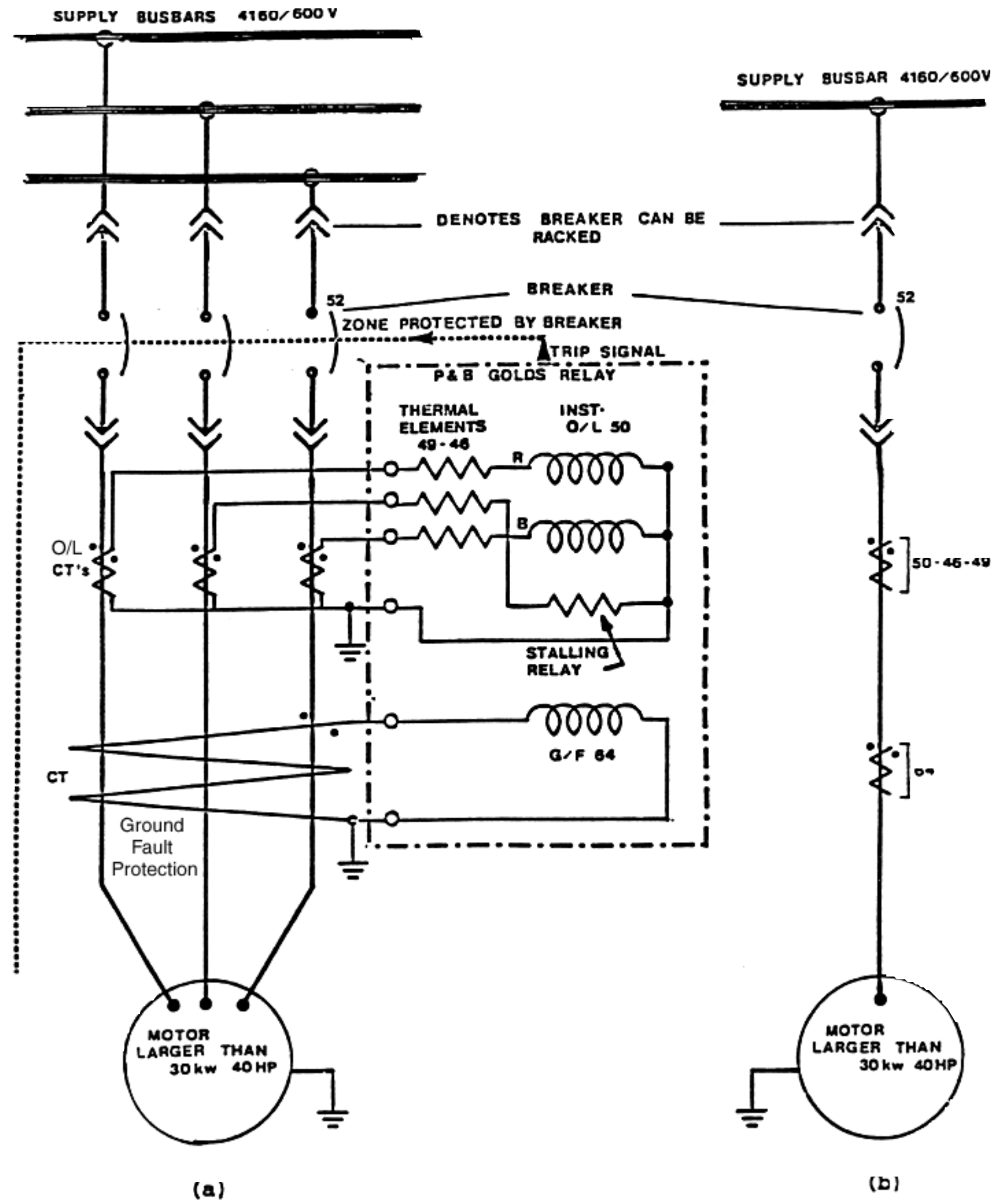


Figure 13 introduces the concept of "protected zone". the zone protected by the thermal overload relay covers the motor and its supply cables. The zone protected by the magnetic overload device includes the motor and its supply cable but also protects against failures or faults associated with the contactor.

For 4.16 kV and 600 V motors rated higher than 30 kW, the contactor and circuit interrupter are replaced by a circuit breaker for control and fault interruption purposes. Further protection against overloads and faults is provided by relays such as the P&B Golds, described earlier. Such protection includes:

- thermal overload,
- phase unbalance,

- instantaneous overcurrent on the red and blue phases - set to operate at approximately 11 times full load current, to protect against short circuits in the cables, terminal boxes and motor windings,
- ground faults - relay fed from a CT which encircles all three conductors to the motor. Normally the three phase currents balance and no current flows in the CT output; but if a ground fault occurs, the currents do not balance and the CT will give an output to operate the ground fault (G/F) relay and trip and circuit breaker. The G/F relay is an instantaneous relay and will have a setting of approximately 20% full load current,
- stalled rotor.

Protection of Electrical Equipment Other Than Induction Motors

We have seen that the protection requirements of electric motors can be adequately met by combinations of relatively inexpensive fuses, induction disc or thermal overload relays. However, overcurrent relays or fuses are not normally used to protect buses and windings of generators and transformers for the following reasons:

- fuses take too long to blow, unless the fault current is very high,
- overcurrent relays
  - have to be time delayed to take care of starting or inrush surges
  - operate only when current greater than full load current flows
- fault currents flowing for a long time produce excessive damage.

For generators, transformers and buses, protection must operate at low values of fault current, (usually less than full load) and at the same time have fast operation. To meet these requirements a scheme called differential protection is used.

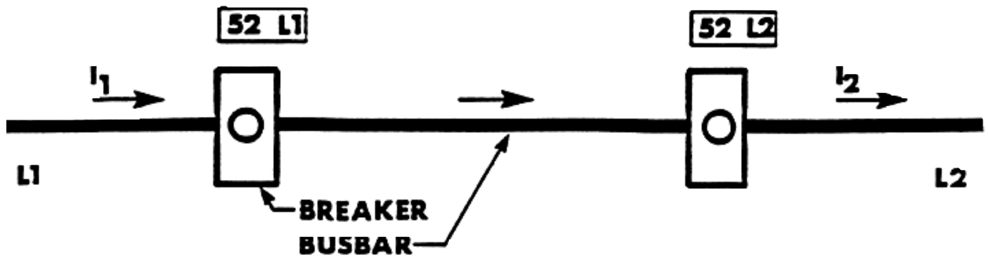
Differential Protection

Differential current protection is based upon the principle that in a healthy piece of equipment, current flowing out of the device must equal the current flowing into it. If a fault or leakage should occur, then these currents would not be equal. this difference can be measured and used to operate a protective relay. This principle is illustrated in Figure 14, and its practical application is shown in Figure 15.

When a fault occurs outside of the protected zone, current into the bus will equal current out, and although this current may be high, no current will flow in the relay, and it will not operate for this so-called "through" fault. Because of this feature, the differential relay can be set to operate at a low value of fault current, thus ensuring rapid operation when a fault occurs within the protected zone. a typical setting for a differential relay is 20% of full load current. Furthermore, there is no need for a time delay; and thus a fast acting attracted armature type of relay is used.

Figure 14

Healthy Bus Bar, Equal Currents Flow In and Out of the Bus Bar.



Faulty Bus Bar. The Fault at F Causes the Current Entering the Bus Bar to be Greater Than the Current Leaving the Bus Bar.

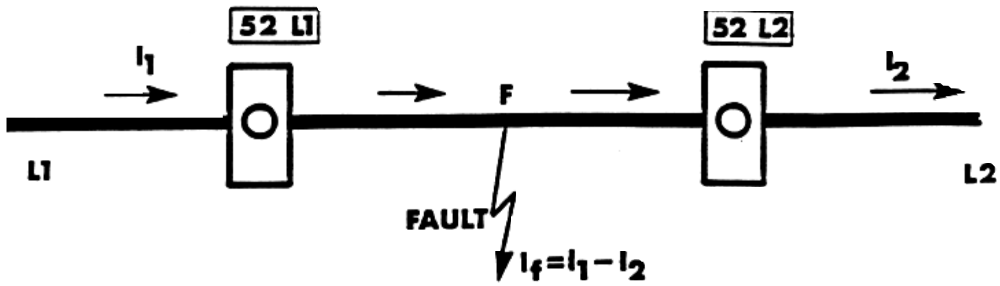


Figure 15

Differential Bus Protection Healthy Bus

Healthy Busbar - Currents in Relay Balance; Relay Does Not Operate

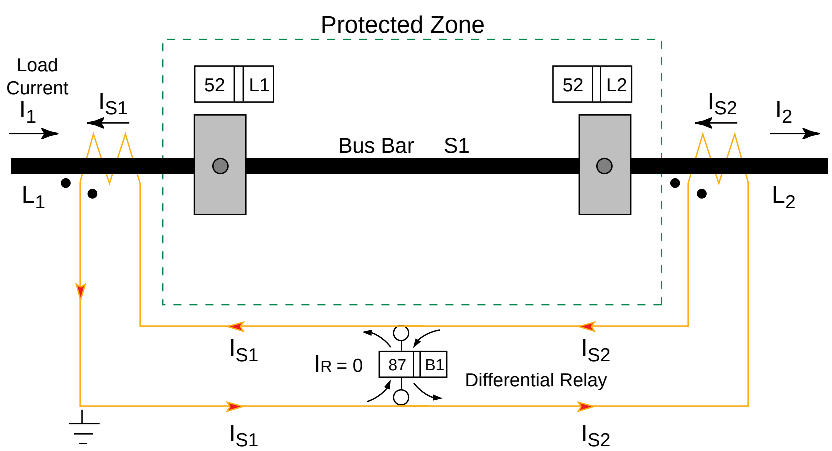
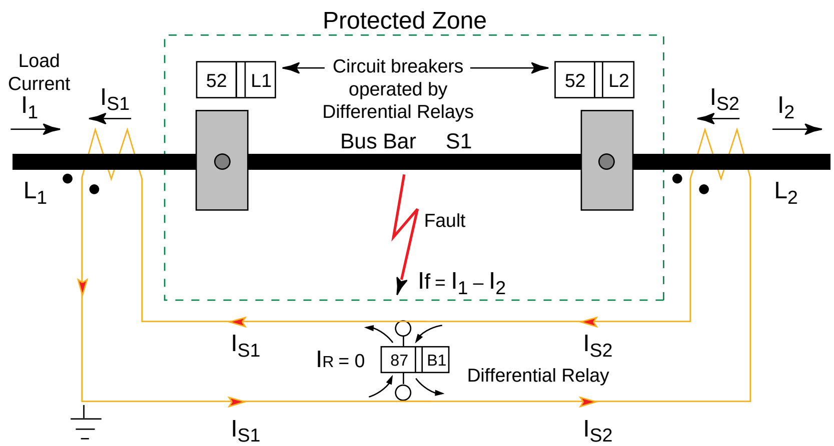


Figure 15 shows a section of bus between two breakers, with CT's of equal ratios installed "outside" the breakers. When a relay is connected between the two wires connecting the CT's the relay will measure the difference in current from the CT's and it is therefore called a differential relay. When this differential current flowing in the relay reaches the setpoint, the relay will operate and trip the two breakers to protect the faulted bus. This situation is illustrated in Figure 16.

Figure 16
Differential Bus Protection Faulted Bus
Unhealthy Busbar - Relay Operates with Current IS1 - IS2



Protected Zones and Differential Relaying

When we wish to expand our protection scheme to include more than one section of bus, as would be the case in any practical installation, the concept of protected zone becomes much more significant. It is important that there are no sections of bus or equipment left uncovered in the protective scheme. This situation is illustrated in Figure 17a where one section of bus has been left unprotected; and Figure 17b shows how this problem can be overcome.

Figure 17a
Busbars B1 and B3 protected by differential protection.
Note that busbar B2 is unprotected because zones do not overlap.

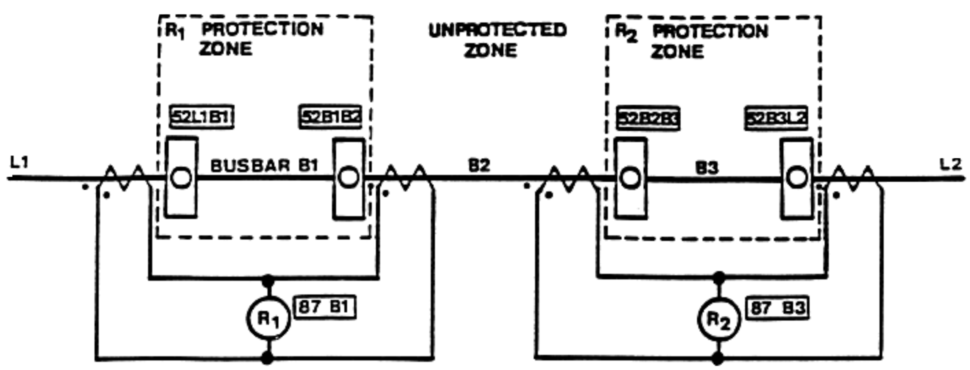
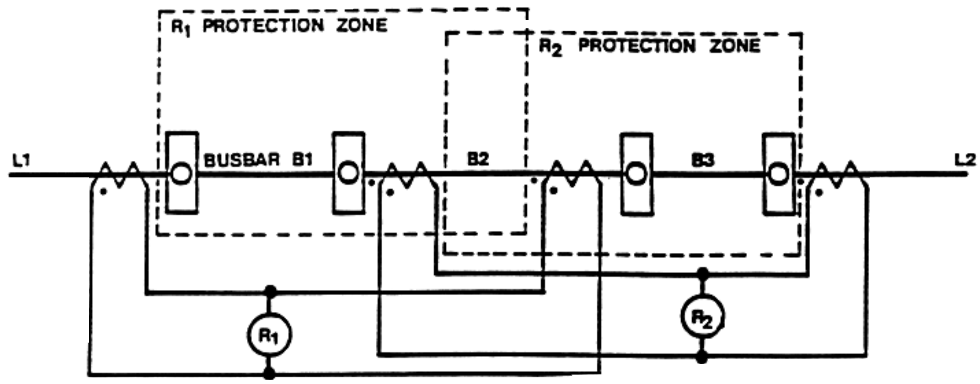
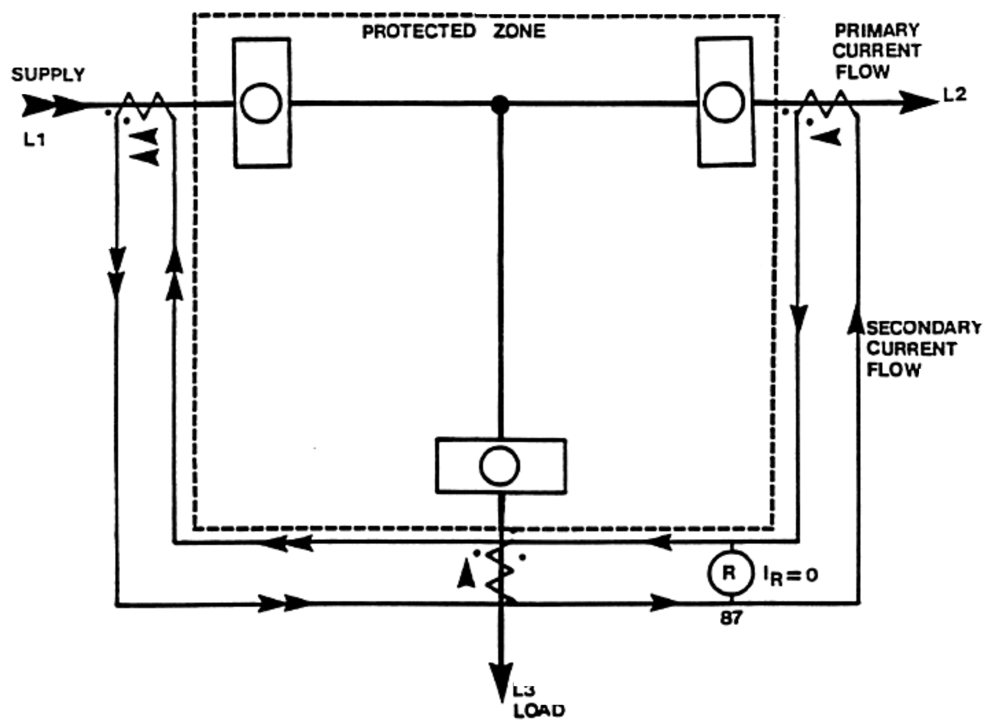


Figure 17b
Busbars B1, B2 and B3 protected by relays R1 and R2.
Note overlapping of zones.



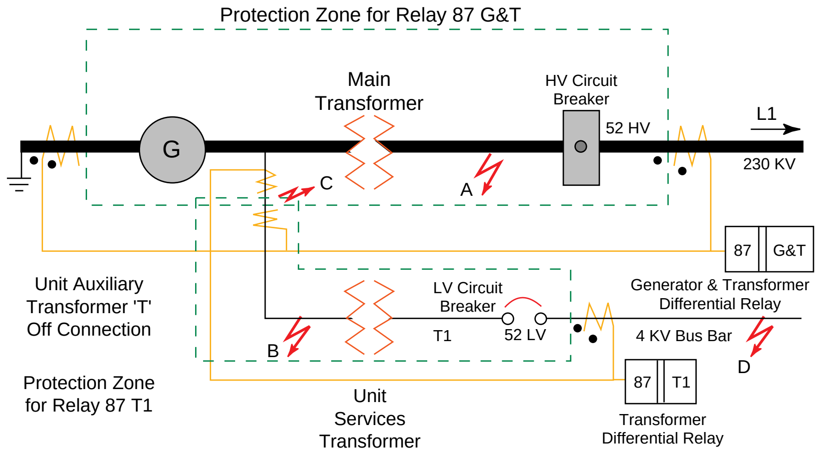
Differential protection schemes can be used to protect circuits which have more than one incoming or outgoing current paths. This is achieved by careful selection of CT ratios and locations. An example of the protection scheme for a "T" feeder is shown in Figure 18.

Figure 18
Differential protection applied to a "T" feeder.
Note primary & Secondary Current Flow.



Generator and Transformer Protection
Figure 19 shows how differential relaying schemes are usually used to protect a generator and its associated transformers, using single line diagrams for both the main power circuit and the relay circuits.

Figure 19
Typical protection Diagram for a Generator and its Transformers showing two differential protection schemes.



Note that:

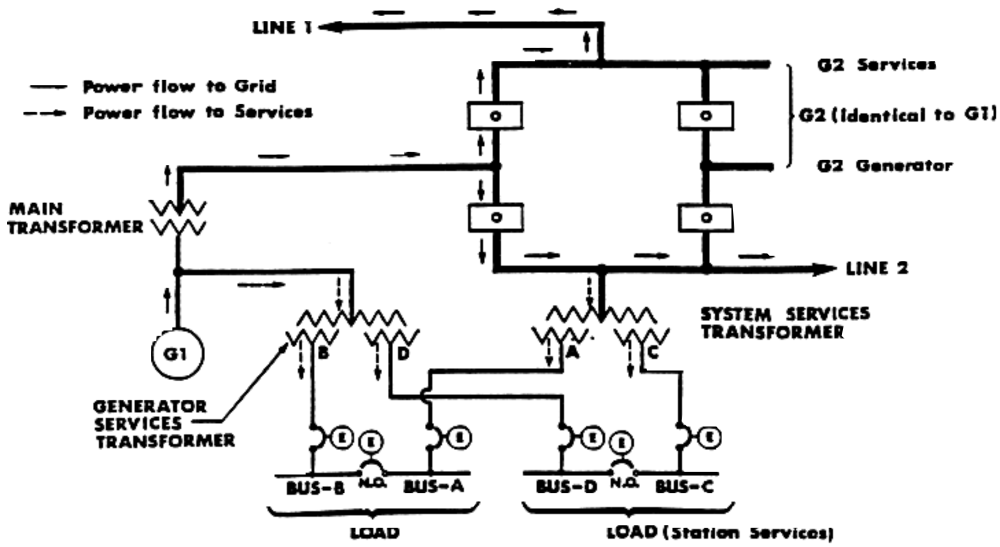
- two differential schemes are used, and that the protected zones overlap at the T-connection,
- relay 87G and T has three CT's feeding it,
- 87 T1 is fed by two CT's,
- when transformers are included in the primary circuit, the ratios of the CT's may not be the same, but their secondary outputs will be the same for the same value of load power,
- for a fault at A, only relay 87 (G & T) will operate,
- for a fault at B, only relay 87 T1 will operate,
- for a fault at C, both relays will operate,
- for a fault at D, relays 87 (G&T) and 87 T1 will not operate. This fault will have to be cleared by the protection for the 4 kV bus which will open the circuit breaker 52 LV.

5.0 Automatic Transfer System

To ensure the continuity of supply to the distribution system in the event of a failure of either the unit or system power, an automatic transfer scheme is provided for the station service buses. For review purposes, Figure 20 shows the main output circuits and the high voltage feeds to the distribution system of a typical Nuclear Generating Station.

Figure 20

Simplified Generation and Distribution System



Power flow from the main generator to the grid is shown in solid arrows, and power flow to the unit distribution system is shown in dashed arrows. The Generator or Unit Service Transformer (UST) and the System Service Transformer (SST) are shown, each with separate secondaries to supply the four buses A, B, C and D. During normal operation, buses A and B carry half the load, and buses C and D carry the other half. The tie breakers joining the bus pairs are normally open (NO). We will see that these breakers play a very important role in transfers between the two sources of power. However, before we approach the subject of transfers of load between the SST and UST, we should examine the problems and possible consequences of operating with two power sources in parallel.

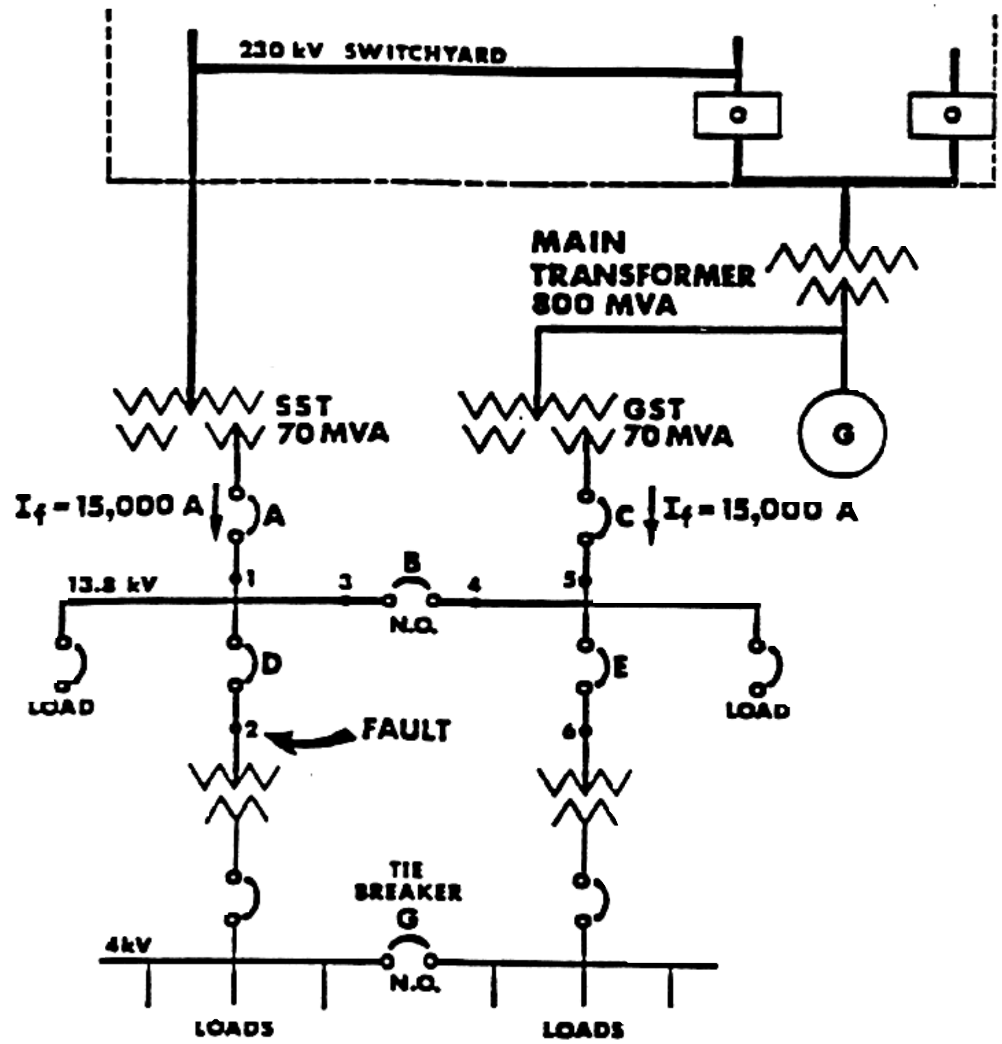
Paralleling Two Power Sources

On the face of it, there would seem to be several advantages to parallel operation of two power sources:

- switching of loads between sources is extremely simple - no auto transfer scheme is required,
- no power interruption to the load if one of the sources fails or is taken out of service.

These apparent advantages are however outweighed by some rather serious possible consequences. Figure 21 is a diagram of a simplified electrical system from a typical station.

Figure 21
Simplified Electrical System



Under short circuit or fault conditions on the low voltage side of either of the 70 MVA System Service or Unit Service Transformers, 15000 amperes will flow. The 13.8 kV circuit breakers in this case must have interrupting current ratings of at least 15000 amperes. If tie breaker B is closed, and a fault occurs at the arrow in Figure 21, there will be two infeeds to the fault totalling 30000 amperes flowing through the load circuit breaker D. While breakers A, B, and C will only be carrying 15000 amps each, breaker D will be subjected to twice the fault current from either source alone. If breaker D is only rated to interrupt 15000 amperes, there is a strong possibility that it will be severely damaged; and may, in fact, explode. Notwithstanding the above, momentary paralleling may be necessary during switching from one source to another, and is used quite often in auto transfer schemes, when the exposure time to possible faults is very small.

Parallel Transfer - UST To SST (MBB)

The parallel transfer of load from one service transformer to another is normally a manually initiated operation.

When it is required to take the main generator out of service, it will be necessary, at some point during unloading of the machine, to transfer all of the auxiliary loads to the SST. This is a make-before-break transfer (MBB).

Referring to Figure 22, initial conditions are:

- both UST and SST in service, each carrying half the load
- supply breakers CB 1, 5, 8 and 12 are CLOSED
- the tie breakers are OPEN--the transformers are not paralleled.

The transfer is initiated by selecting the breaker P/B you want to trip, i.e. CB 12 and then moving the control handswitch of tie breaker 11 to CLOSE, momentarily paralleling the UST and SST. CB 12 is tripped to avoid the problems of paralleling the two sources. Buses C and D will now be fed from the SST, and the other half of the changeover for buses A and B can be completed in the same way, so that all auxiliary loads are fed from the SST.

Parallel Transfer - SST to UST (MBB)

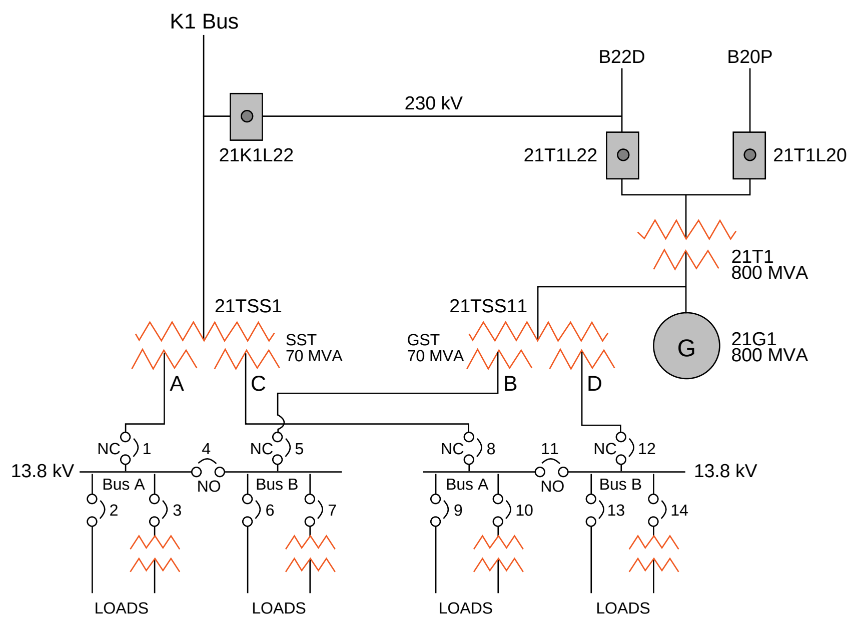
This transfer is carried out after the generator has been synchronized and is being run up to full power. This is again a make-before-break transfer (MBB).

Initial conditions are:

- SST supply breaker 8 CLOSED,
- tie breaker 11 CLOSED,
- UST supply breaker 12 OPEN.

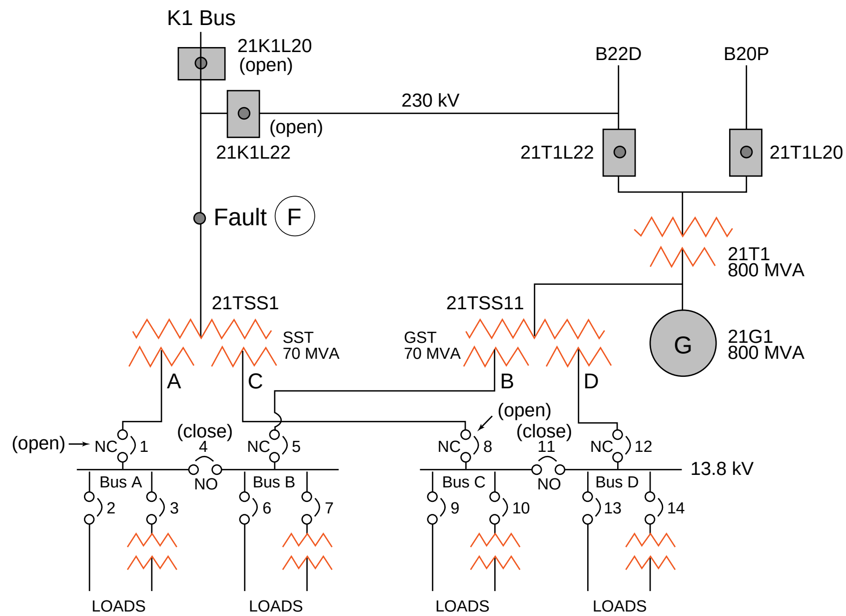
CB 12 can now be closed by manual operation of its control handswitch on the CR panel. When CB 12 closes, buses C and D are momentarily in a parallel supply situation, and CB 11 is tripped immediately. Once the tie breaker is tripped, the operator is required to reset breaker before proceeding. The load on buses A and B can now be transferred in the same way, by closing CB 5 and tripping CB 4.

Figure 22
Electrical Distribution System (4 Busses)



Fast Transfer (BBM)
A fast transfer is automatically initiated whenever a 13.8 kV incoming supply breaker is tripped by a fault. The trip results in a CLOSE signal being sent to the alternate supply breaker or a tie breaker. There is, therefore, a period of a few cycles during which the bus is disconnected from both transformers. However, the transfer is fast enough that the voltage and phase difference between the incoming supply and the residual on any motors in service is small enough to avoid excessive inrush currents. This is in the order of six cycles or less. This is a break-before-make transfer. Referring to Figure 23, an example is shown of a fault on the HV side of the SST.

Figure 23
Electrical Distribution System--Faulted at Point F



Initial conditions are:

- SST and GST sharing load equally,
- SST supplying Buses A and C,
- UST supplying Buses B and D,
- breakers CB 1, 5, 8, and 12 CLOSED,
- tie breakers CB 4 and 11 OPEN.

When the fault occurs at "F":

- SST is removed from service,
- CB 1,8 and 21K1L22 and 21K1L20 are tripped,
- K1 bus is de-energized,
- two to four cycles later, CB4 and 11 CLOSE, restoring power to bus A and C.

When the fault has been cleared and the SST is ready to be returned to service, a parallel transfer can be carried out to return to the original conditions.

Residual Voltage Transfer
A residual voltage transfer occurs when the incoming breaker of a bus is tripped and the bus is de-energized. After the residual voltage has decayed by approximately 70%, the alternate breaker will be automatically closed. This transfer mode is designed to back up the fast transfer, and replaces the parallel transfer when it cannot be executed because of lack of synchronism between the UST and the SST.

Consequences of Failure of the Transfer Scheme
Parallel Transfer--SST to UST

If the selected UST supply breaker fails to close:
- no action occurs,
- SST continues to supply auxiliary power,
- generator loading can continue to full load,
- transfer can take place once breaker closing problem is repaired.

If the supply breaker closes but the associated tie breaker fails to open, the two sources of supply are paralleled, and this situation must be corrected immediately by operator action:
- trip the breaker manually,
- fault should be investigated and repaired as quickly as possible,
- if the tie breaker does not respond to a manual OPEN signal the UST supply breaker must be opened until the fault is repaired.

Parallel Transfer - UST to SST
Again, this transfer is manually initiated. If the selected tie breaker fails to close, the UST can continue to supply its share of the auxiliary power until the fault is repaired, unless the generator must be unloaded without delay, as in the case of a reactor problem.

In this situation, no equipment has been removed from service and operator action would be required. These actions might include:
- attempt a second transfer (only one repeat is allowed),
- attempt a local close of the affected tie breaker,
- investigate and repair failure of breaker to close,
- attempt to transfer the companion bus load to the SST,,
- if time becomes short, assess consequences of manually initiating a fast transfer of the affected bus by opening its UST supply breaker.

Operator actions are identified in Operating Manuals, and may vary from one station to another; depending on station layout, and operating policies and procedures.

If the UST supply breaker fails to open, the problem of two sources in parallel arises, which must be corrected immediately.

Operator actions might be as follows:
- trip the failed breaker manually,
- investigate failure to trip, and initiate repairs.

Fast Transfer
If a fault occurs calling for a fast transfer, and one or both of the affected tie breakers fails to close, the residual voltage transfer scheme would initiate another CLOSE signal go the affected breakers. If this also fails:
- attempt manual CLOSE signals to the affected breakers.

If this also fails, a partial loss of Class IV power has now occurred. Automatic actions will have taken place to reduce power, and those will depend on which buses have been lost. Equipment which may be affected will include:
- one HT circulating pump--stepback to 65% RP,
- two HT pumps--reactor trips,
- static exciter--leading to turbine/generator trip, setbacks or stepbacks of reactor power, etc.,
- Class III back-ups will start.

This situation might lead to a Unit shutdown, and would be covered in the station Abnormal Incidents Manual. The actions required of the operator would be specified precisely.

Residual Transfer
Partial (1 bus) loss of Class IV--the consequences are the same as a Fast Transfer.

Generation and Transmission of Electrical Power

Training Objectives:

On completion of this lesson the participant will have the required knowledge to:

- Describe how the power utility electrical grid system is constructed.
- Describe the operation of the generator auxiliary systems.
- Describe how generator protection is achieved and the types of protection used.
- Explain the purpose of the generator excitation system and describe its operation.
- List the equipment making up the station output system.
- Describe how the main transformer protection is achieved and the types of protection used.
- Describe the operation of the following equipment used in the main power output system:
  - high voltage circuit breakers
  - high voltage disconnect switches
- Describe the interface between tower lines and transmission lines.
- List the types of relays used for transmission line protection.
- Explain action required if all protection fails.
- Explain how transmission line zone protection protects transmission lines from one station to another.
- Briefly describe the operation of transmission line underfrequency protection.

Table of Contents

1.0 Introduction

In this lesson we will discuss the distribution of electrical power, with the focus on the external environment of the nuclear station. That is to say, how the Nuclear GS fits in with its customer, the power utility; the equipment and systems it interfaces with, and what requirements and limitations result from this relationship. The approach adopted will be to take an overall look at the power utility, then examine each component or system involved, beginning with the generator itself, tracing the path of generated power through the main transformer, switchyard and out to the transmission lines and the utility's power grid.

2.0 The Power Utility

A power utility, whether national or provincial, is composed of generators, transmission facilities and distribution networks to feed individual customers, and in most cases, interconnections with other utilities. Figure 1 illustrates, in a very simplified form, how generators in different geographical locations feed power into a grid system, arranged so that power can be fed to customers at any other location in the country or province. The purpose of tie lines with other utilities is twofold: it enables the purchase and sale of power between the two utilities, and provides increased stability in the event of a disturbance to either system. Figure 1 also shows a system control centre, and the main function of this facility can be understood by referring to Figure 2. Figure 2 shows how the load on a typical system varies throughout a typical weekday. The main function of the System Control Centre is to ensure that sufficient generation is available to meet the constantly changing demand.

Figure 1
Simplified Power Grid

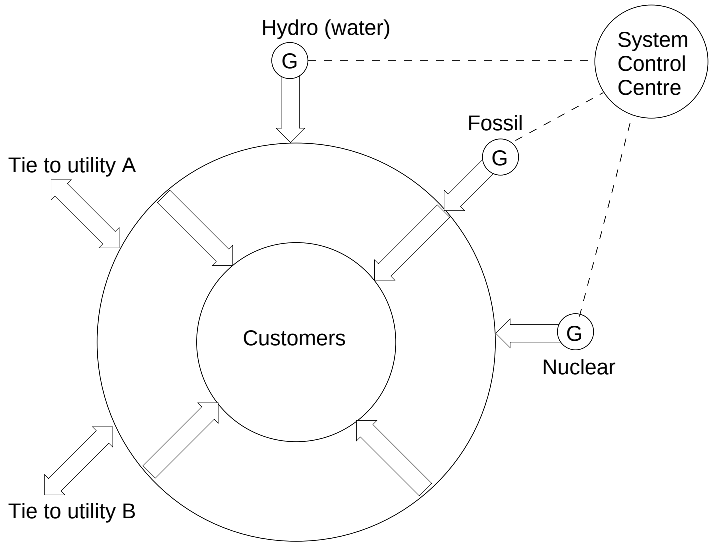


Figure 2
Typical Work Day

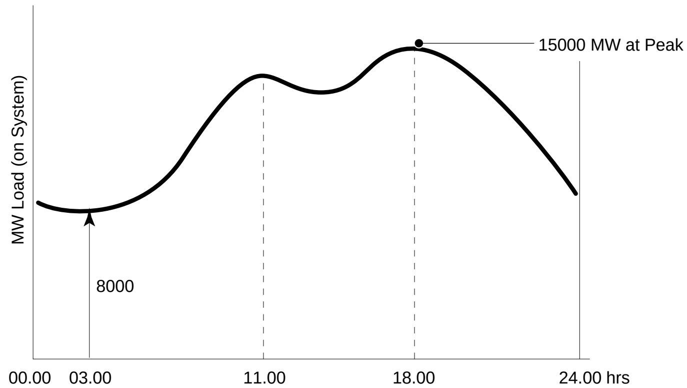
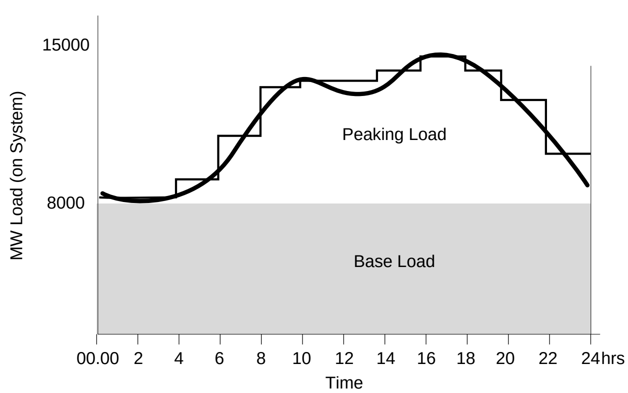


Figure 3 also indicates how this is achieved:

- base load generators scheduled to run 24 hours a day
    - those with lowest Unit Energy cost (UEC) are scheduled first,
    - generators whose start-up time is long,
    - generators which do not lend themselves to large and rapid load changes, such as nuclear-powered units.

- peaking load generators which respond to short-term load changes
    - generators which can be started up and loaded quickly, such as hydraulic units,
    - generators which can be selected for automatic control of their output by the System Control Centre, in response to second-by-second system load changes; called regulating control,
    - as load increases, additional machines are started up and placed on regulating control.

Figure 3
Hourly Base Load and Peaking Load



3.0 Generator Auxiliaries

3.1. Cooling Systems

In generators of 500 MW and up, large amounts of heat are generated by resistive and magnetic effects as well as friction between moving parts. To carry away this heat, two systems are required:
- hydrogen cooling,
- stator cooling.

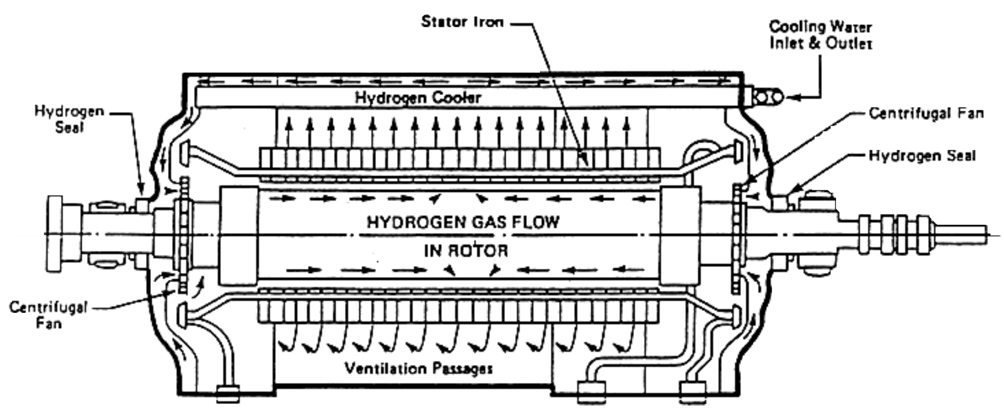
3.1.1 Hydrogen Cooling

There are two reasons for using hydrogen as a cooling medium in generators:
- high specific heat, for efficient heat transfer,
- low density, for low windage or friction losses.

Disadvantages are:
- explosion hazard,
- complex oil seal at the generator shaft.

Hydrogen gas is circulated by shaft-mounted fans, through passages within both the stator and rotor, and internal heat exchangers which are cooled by Recirculated Cooling Water. Hydrogen is also circulated through an external drying system, to remove any moisture which might be picked up due to leaks in the heat exchangers. The system is closely monitored for leaks and its purity is rigidly controlled.

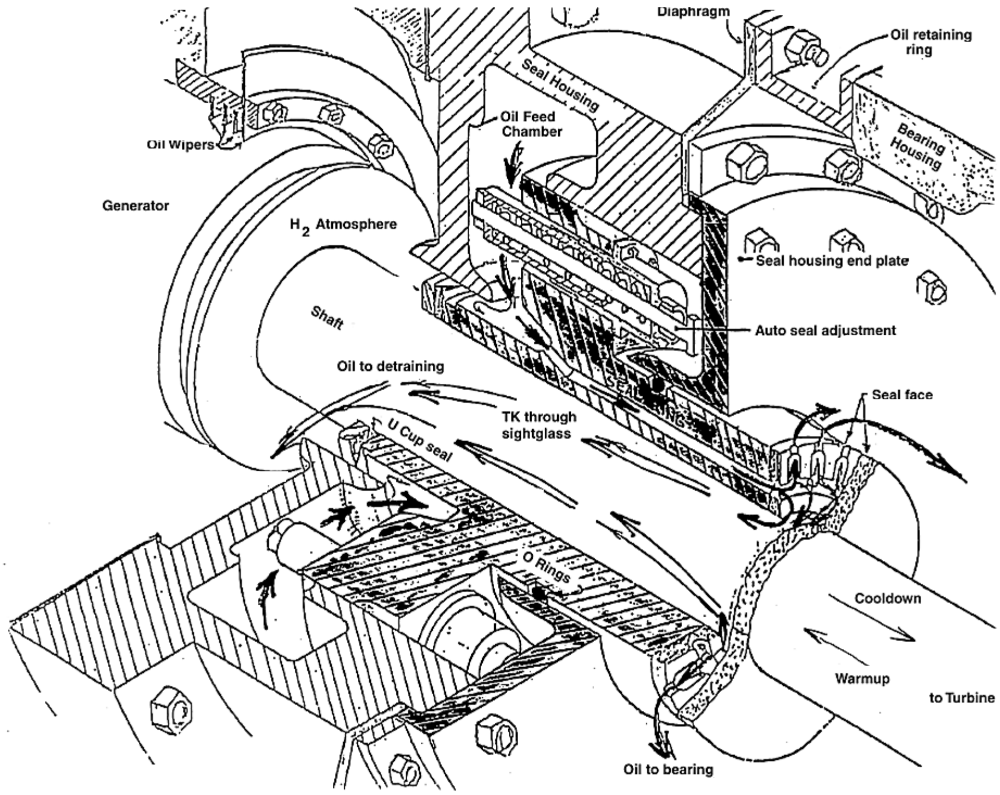
Figure 4
Hydrogen Gas Cooling Circuit



3.1.2 Seal Oil

Seal oil is circulated through the generator shaft hydrogen seal by Class IV 600Vac pumps with Class I (dc) backup. The seal oil is cooled in external heat exchangers, and entrained hydrogen is removed in detraining tanks and vented to atmosphere (outside) along with vapour, extracted by a fan, from the seal oil tank. Seal oil from the tank is also passed through vacuum treatment equipment to remove any residual entrained hydrogen, and filtered to remove impurities which might affect the efficiency of the oil seal itself.

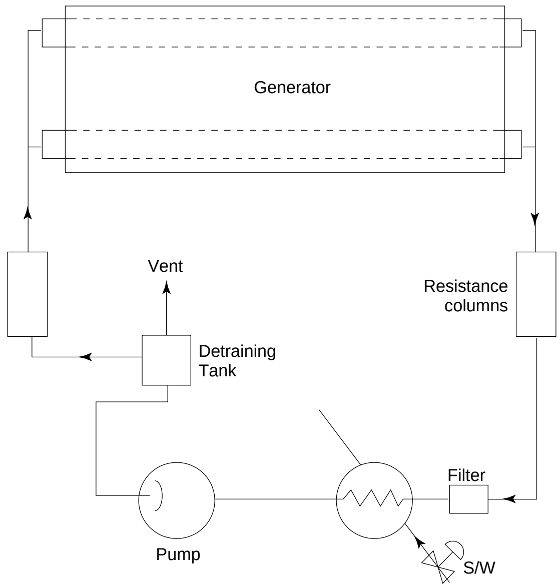
Figure 5
Generator Shaft Seal



3.1.3 Stator Cooling

In the large generators, the stator conductors are hollow, and demineralized water is circulated through them for cooling. The stator conductors are electrically isolated from the external piping by hollow tubes made of a high resistance material such as polystyrene. Demineralized water is circulated through ion exchange purification columns, strainers and filters; to ensure that low conductivity is maintained and to remove any solid impurities which could interfere with coolant flow. AC pumps circulate the water through external heat exchangers cooled by service water, and a DC pump is provided for backup.

Figure 6
Simplified Stator Coolant Flowsheet



3.1.4 Lubrication

The generator shaft is bolted to the main turbine shaft and is supported by bearings at each end, outboard of the hydrogen seals. These bearings receive their lubricating oil from the main turbine lubricating oil system, and the oil is filtered, purified and cooled as a part of that system.

3.2. Generator Protection

3.2.1 Purpose of the System

The purpose of the generator protective relaying (generator protection) system is to detect abnormal generator electrical conditions and to initiate appropriate trip actions in sufficient time to prevent generator damage or limit its extent.

Conditions of voltage, current and frequency are continuously monitored both on the generator primary side (rotor - excitation) and secondary side (stator - ground, phases, output) while the generator is either on-line or off-line. As abnormal conditions develop, appropriate generator protective relays are activated to initiate the protective trip.

3.2.2 Description of the System

General Layout and Major Components

The generator protective relaying system consists generally of field sensing devices, current transformers (CTs), potential transformers (PTs) and neutral ground transformer and protective relaying equipment, protective relays and auxiliary tripping relays.

The field sensing devices are used to monitor current and voltage at the generator neutral and output terminals. They provide inputs to the protective relays. Whenever a protective relay "pick-up" setting is exceeded, the associated auxiliary tripping relays are actuated to perform the appropriate trips so that generator damage can be avoided or minimized.

A number of different protections are available to protect the generator against various fault conditions. These protections are divided into two groups "A" and "B". This dual protection is designed to provide greater reliability and every effort has been made to keep the two groups as independent as possible, ie:

- separate Class I supplies,
- separate inputs from CTs and PTs where possible,
- physical separation of wiring and equipment where possible,
- separate trip coils where practical.

The main protections for the generator are duplicated in both groups (phase differential, stator ground and loss of excitation). All other protections have been split between A and B groups such that if two protections tend to protect for similar conditions they appear in different groups.

In addition to group separation of protections, generator protective trips are divided into four classes - A, B, C and D - in order to be able to provide different trip actions depending upon both the unit condition and the initiating event.

Table 1 lists the various group A and B protections, the classes of trips, and the automatic actions that occur for each.

Table 1

Types of Fault Protection

	Group A	Class		Group B	Class
1.	Phase Differential	A	1.	Phase Differential	A
2.	Stator Ground	A	2.	Stator Ground	A
3.	Loss of Excitation	A	3.	Loss of Excitation	A
4.	Overexcitation - Hi Set	A,C	4.	Phase Unbalance	A
	- Lo Set	C			
5.	Supplementary Start (Phase and Ground)	D	5.	System U/F - Hi Set	B
				- Lo Set	B
			6.	Out-of-Step	B

Classes of Trips

Class A - Full T-G Trip	- unit synchronized, at power
Class B - Load Rejection	- unit synchronized, at power
Class C - Excitation Trip	- unsynchronized, at 1800 rpm
Class D - T-G Trip	- unsynchronized, at 1800 rpm

3.2.3 Types of Protection

Each of the eight different types of protection is discussed below. In addition, some general notes on generator neutral grounding are included. Refer to the functional diagrams in Figure 8 and 9 and to Figure 7 as required.

Figure 7

Generator Protection Layout

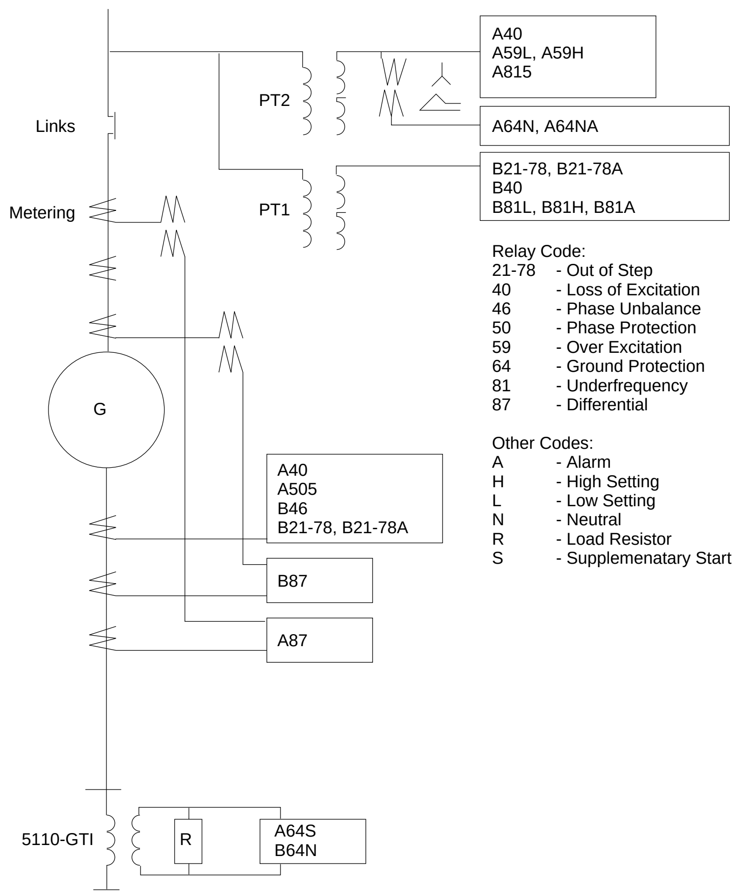


Figure 8

Group A Functional Diagram

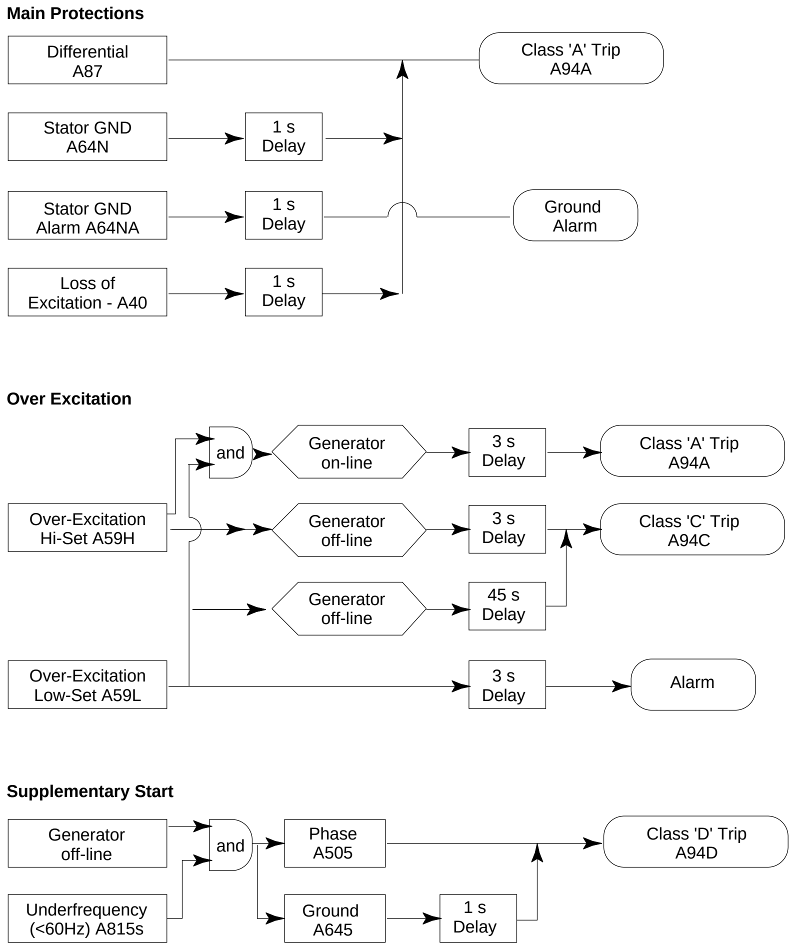
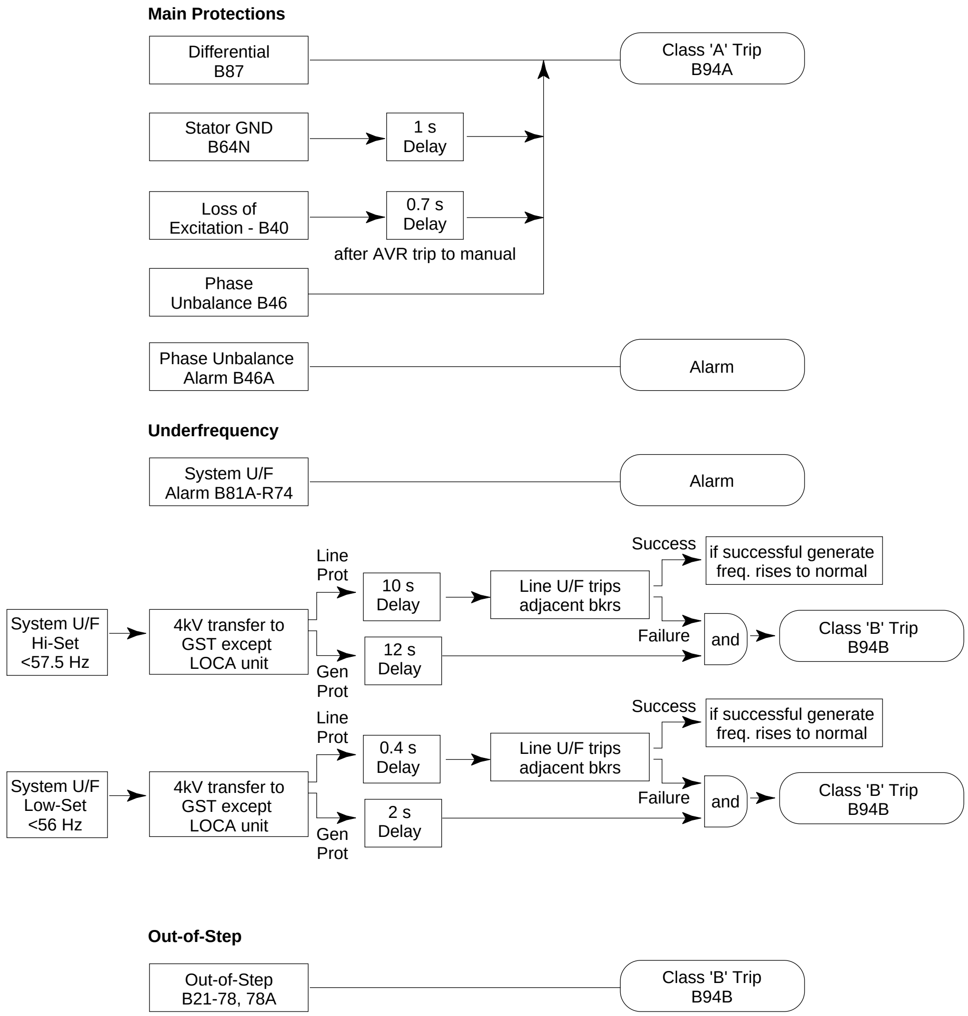


Figure 9
Group B Functional Diagram



(a) Differential (87)
Each phase of the 3ϕ stator windings is monitored on the ground and output sides for equal current flow. This differential protection detects significant differences in current that may indicate phase-to-phase or phase-to-ground faults. It does not, however, detect unbalanced currents between phases.

(b) Stator Ground (64)
In the event of a ground fault in the stator winding, an unbalanced voltage would develop across the PTs monitored by the group A over-voltage relay. As well, excessive currents would flow in the neutral circuit causing a voltage to develop across the loading resistor in the secondary of the neutral grounding transformer, as monitored by the group B over-voltage relay.

Normally, all phase voltages and currents sum to about zero*, therefore, the PTs should measure minimal voltage and the neutral current should be minimal. However, if a phase-to-ground, or phase-to-phase fault occurs, or if a large unbalanced loading exists, these protections will be activated. Nominal time delays of one second are included to prevent spurious trips.

* Note: The relays are tuned to 60 Hz since third, sixth, etc, harmonics of voltage and current are in phase for all three phases and therefore, do not sum to zero.

(c) Loss of Excitation

Loss of excitation to the generator can rapidly lead to instability as the generator exceeds the under-excited reactive power limit. In this condition, there is a large reactive power flow into the generator. The group A loss-of-field relay detects this large leading MVars condition by measuring phase currents, in or out, and voltages at the generator neutral and output terminals, respectively.

The group B protection monitors both the generator field voltage, ie, rotor volts, via a transducer in the generator field breaker cubicle, and generator output voltage via the loss-of-field relay. The protection provides for both under and over-excited conditions and will trip the automatic voltage regulator to manual after the appropriate delay. Should the condition persist, the turbine will be tripped after a further 0.7 seconds.

Note: A class A trip is initiated if an inadvertent opening of the main exciter or generator field breaker occurs.

(d) Phase Unbalance

The current in each phase is measured by CTs located at the generator neutral bushing. A relay is used to determine whether there is an unbalance in the phase currents. Normally, of course, the magnitudes of all three phases are equal under balanced load conditions. Phase unbalance protection will, therefore, detect not only load unbalances but phase/phase and phase/ground faults as well.

(e) Underfrequency

It is important to realize that generator underfrequency protection acts only as a backup to the line U/F protection.

Underfrequency situations are generally a system problem, ie, insufficient generation capacity to match demand. Note that operation of either the line or generator U/F protection will initiate a parallel transfer prior to activating the class "B" trip.

(f) Out-of-Step

Out-of-step protection is designed to prevent generator instability that could lead to pole slipping and turbine overspeed. It provides some degree of loss of excitation protection as well as protection against system-related transients that could cause the generator to go out of synchronism with the grid.

Similarly to the loss of excitation protection, the out-of-step protection monitors phase currents at the generator neutral and phase voltages at the output. These are input relays, both of which must be picked up to activate the trip.

(g) Over-excitation
The over-excitation protection is intended to protect the main and generator service transformers as well as the generator from damage due to overfluxing. The protection is available during start-ups and shutdowns as well as normal operation.

The V/Hz ratio is used (ie, generator terminal volts/frequency) since this is proportional to the flux density in the iron circuits of the machines.

Under overfluxed conditions the core losses (and hence temperature rise) become excessive, leading to transformer damage and in the extreme case, structural steel components of the transformer can become flux paths leading to dangerous temperature rises.

Note: That some over-excitation protection is also provided by the group B loss of excitation protection.

(h) Supplementary Start
During start-ups and shutdowns, the supplementary start protection provides two of the more basic protections - stator ground and phase unbalance - at frequencies other than 60 Hz, when all other protection may not be effective.

Generator Neutral Grounding
The purpose of the neutral grounding transformer is threefold:
1. To limit generator winding stresses to maximum design levels by limiting fault currents.
2. To raise neutral above ground potential to provide sensitivity to protective relaying.
3. To block capacitive voltage transients from any relaying operation.

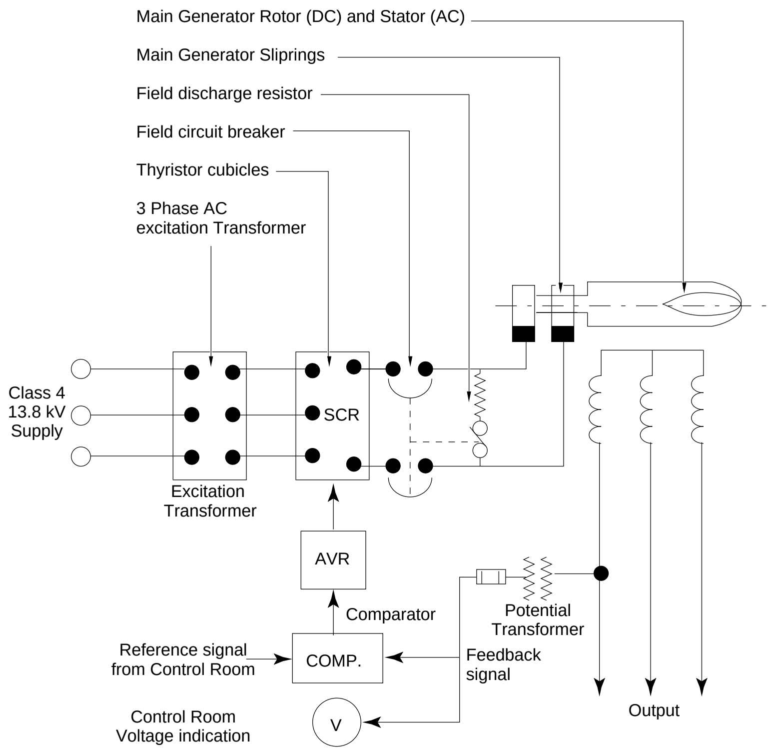
Stator ground fault protection relays B64N and A64S are located in the neutral grounding transformer circuit (providing group B class A and group A class D trips, respectively). Since there are no alarms associated with the disconnect switch position, it is very important to ensure that the switch is closed prior to unit start-up (after a long outage involving T-G work) and during normal operation to ensure that these protections are available. See figure 8 and 9.

3.3 Generator Excitation
The purpose of the generator excitation system is to provide a means of supplying rotor field current to the main generator to control generator output voltage. During normal operation, the excitation can be changed by the control

room operator at system request in order to vary the generator output voltage.

Figure 10 shows a simplified version of the Bruce A excitation.

Figure 10
Simplified Version of Bruce `A' Excitater



The following is a description of the Bruce A excitation system:

The excitation transformer is supplied from the Class IV 13.8 kV supply. The voltage is reduced and supplies the silicon controlled rectifier which changes the ac voltage to dc.

The output of the silicon controlled rectifier (SCR) is varied by the action of the automatic voltage regulator (AVR). The dc voltage is then applied to the generator slip rings once the main field breaker is closed. The generator output voltage varies as the field that is applied.

The generator output voltage is measured by the PT and a feedback signal is produced which enters a comparator and compares the voltage from the generator with the set voltage that the control room operator has set from the control room. Any change is then sent to the AVR which adjusts the main field current to reduce any voltage difference to zero.

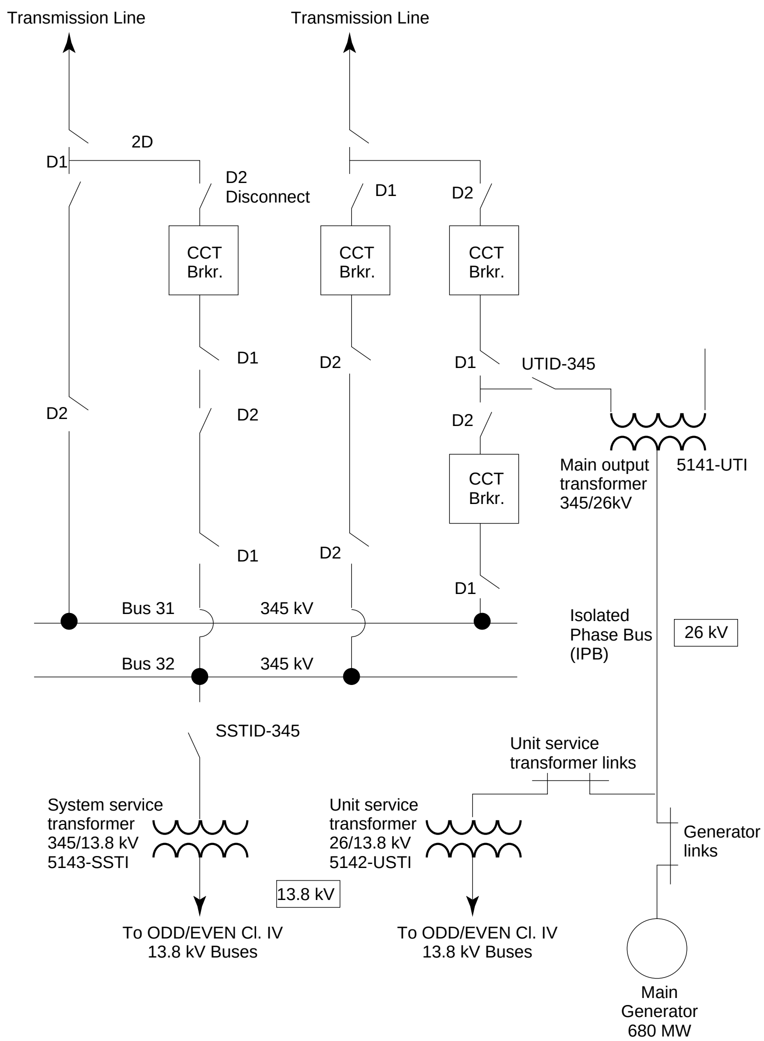
4.0 The Output System

The station output system comprises:

- generator output bus,
- main transformer,
- High Voltage (H.V.) buses,
- High Voltage (H.V.) circuit breakers,
- transmission line.

These components are shown on the simplified flowsheet for part of the main power output system shown in Figure 11.

Figure 11
Main Power Output



4.1 Generator Output Bus

The generator is connected to the UST and Main Output Transformer via the Isolated Phase Bus and removable links are provided for isolation purposes when maintenance is required.

4.2 Main Transformer

The main transformer carries approximately 90-93% of the main generator output. Transformers of this size are usually made up of 3 single phase transformers, for several reasons:

- the size of one single 3 phase transformer of this rating would be prohibitively large, both to build and to transport to the site.
- a permanent fault in one phase requires the replacement of one phase only, simplifying the job of the maintenance crew.
- only one spare single phase transformer needs to be provided at the station.
- each phase can be housed separately, an advantage for fire protection.

4.2.1 Cooling - Main Transformer

Transformers of this size are usually cooled by pumping the insulating oil through heat exchangers, which in turn are cooled by Service Water.

4.2.2 Fire Protection - Main Transformer

Heat Activated Devices (HAD's) are located at various locations around and above the transformer(s) which are used to trigger a deluge system. In the event of a fire, the transformer is doused with a fine spray of water from the firewater system.

4.2.3 Electrical Protection - Main Transformer

Basic electrical protection of the main transformer is provided by differential protection. Additional protection is provided for ground faults on the HV side, gas accumulation alarm, and gas pressure trip. Annunciations are provided for cooling system failure, oil high temperature, winding high temperature, and phase winding very high temperature. In addition, the transformer is protected by remote tripping from the HV bus.

The main transformer protection can be divided into four schemes:

a) gas protection
b) winding temperature protection
c) differential protection
d) ground fault protection

The following is an overview of each of the above protection schemes.

(a) Gas Protection
The transformer gas relay is a protective device installed on the top of oil filled transformers. It performs two functions. It detects the slow accumulation of gases, providing an alarm after a given amount of gas has collected. Also, it responds to a sudden pressure change that accompanies a high rate of gas production promptly initiating tripping of the transformer.

Operation of a Transformer Gas Relay
A typical transformer gas relay consists of two chambers, each performing a distinct function. A simplified cross-section of a gas relay is shown in Figure 12.

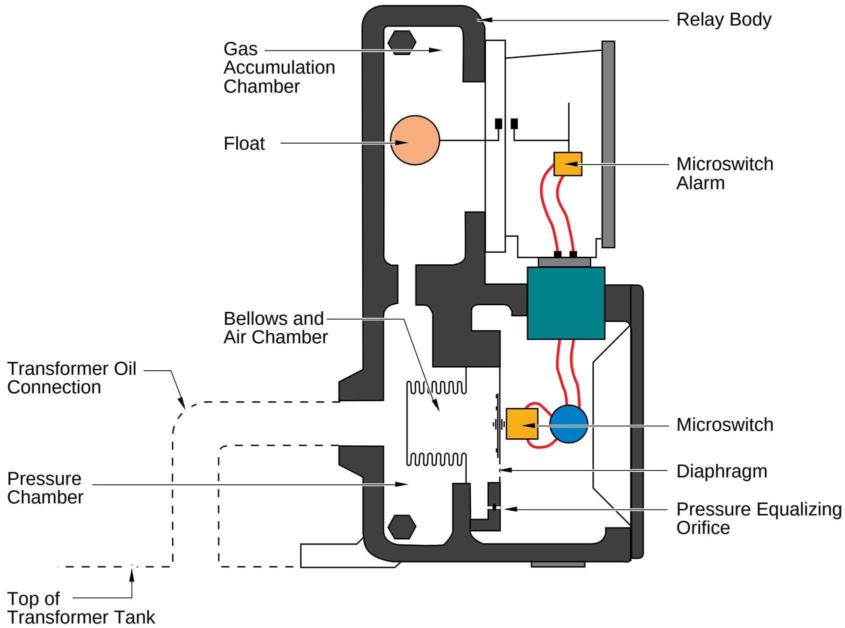
The relay assembly consists of a gas accumulation chamber mounted directly over a pressure chamber. The accumulation chamber collects slowly produced gases. A float located in this partially oil-filled chamber moves as the gas volume increases. It operates an alarm switch when the amount of gas collected reaches a specified level. An indicator coupled to the float also provides a means to monitor the rate at which gas is being generated.

The second chamber, a pressure chamber, connects directly to the transformer oil circuit. It connects vertically to the accumulation chamber, providing a path for the rising gas. An air-filled bellows within the pressure chamber acts as the pressure change detector. A sudden pressure surge in the oil compresses the bellows and forces the air within to move a diaphragm. The moving diaphragm actuates a switch that initiates tripping of the transformer.

The relay must be configured in such a way as to act on pressure changes caused by internal faults, but compensate for pressure changes occurring under normal operating conditions.

"Steady state" pressure changes occur at a much slower rate than those resulting from internal faults, and a pressure equalizing orifice is provided on the relay to make it insensitive to these relatively slow pressure changes. This orifice is a very small opening in the diaphragm support. Should the bellows be compressed slowly, the pressure will not build up in the air chamber and the microswitch is not operated. If, however, a sudden pressure is applied, the pressure equalizing orifice is too small to relieve the pressure and the micro-switch will operate.

Figure 12
Cross Section of a Typical Transformer Gas Relay



Sudden pressures, such as oil circulating pump surges, are normal operating events and the relay must be set to ride through them. In practice, it is necessary to make sure the relay is set to operate at about 7 kPa above the maximum oil circulating pump surge pressure.

Dangerously high pressure increases from major faults are relieved by an explosion vent on the top of the transformer tank. This is basically a diaphragm sealed pipe with its open end directed away from the transformer. A significant increase in pressure bursts the diaphragm and discharges gases and hot oil with a possibility of resulting fire.

(b) Transformer Winding Temperature

Heat is generated in a power transformer by current flow in the primary and the secondary windings as well as internal connections due to I^2R losses. At low loads, the quantity of heat produced will be small. But, as the load increases, the amount of heat becomes significant. At full load, the windings will be operating at or near their design temperature. The nameplate on a transformer will provide information on the maximum allowable "in-service" temperature rise for its windings and connections and will indicate what method of cooling is employed to remove the heat generated under load. A temperature of about 105°C is considered to be the normal maximum working value for large power transformers, based on an assumed maximum ambient temperature of 40°C.

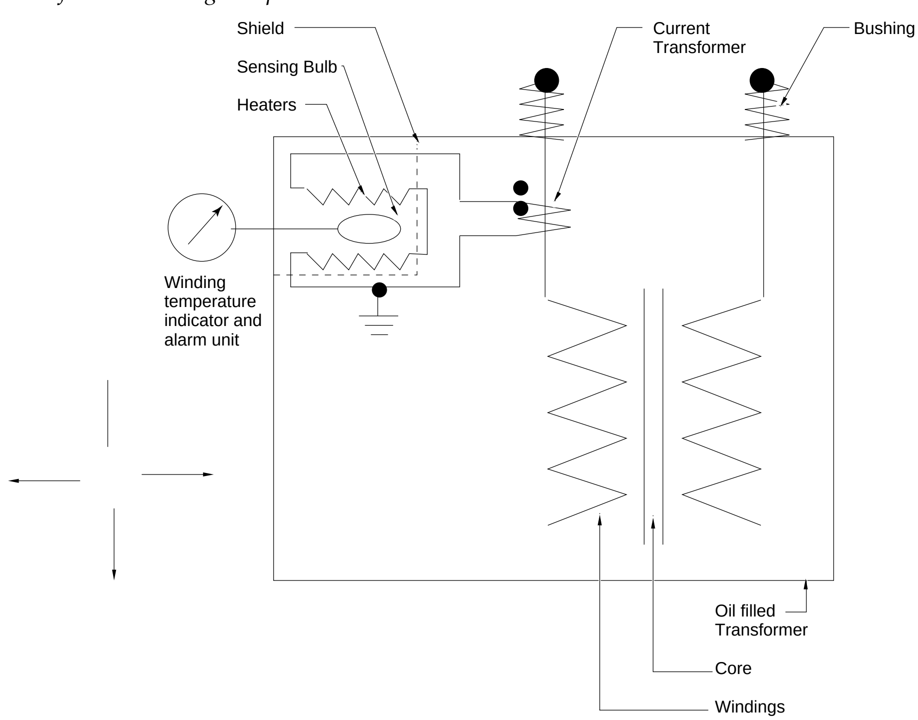
The winding temperature is sensed and indicated by a winding temperature gauge/alarm assembly. Figure 13 shows a typical arrangement. The purpose of this gauge is to provide a thermal image of the hottest point within the transformer. The sensing bulb of the assembly is placed in a well, located near the top of the transformer tank. The well is immersed in the hot transformer oil. A heating coil, supplied from a load sensing current transformer, is installed around the sensing bulb to provide a local temperature rise above the general oil temperature. The effect of the heating coil, coupled with the heat of the oil on the bulb, allows the gauge to simulate the winding temperature "hot spots".

Operation of the transformer above its rated voltage by even 10% can cause a significant temperature rise, initiating an over-temperature alarm. Overvoltage operation may be a result of tap changer or voltage regulation problems. Such over-temperature operation can lead to physical insulation damage reducing the useful life of the insulation and thus the life of the unit.

A temperature rise of 8-10°C beyond the normal maximum working value, if sustained, will halve the life of the unit. Unchecked overloading of a power transformer can cause a sufficient temperature rise to yield similar damage.

Figure 13

Transformer Winding Temperature Sensor



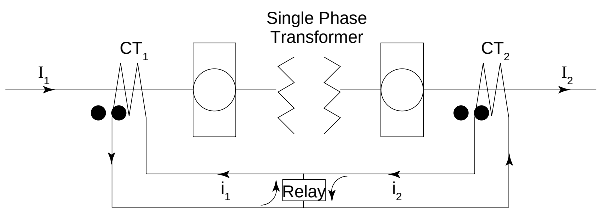
(c) Differential Protection

Transformer windings can be protected by differential protection methods. A simple transformer differential protection circuit is shown in Figure 14.

Inter-winding faults (short circuits) and ground faults within power transformers can be detected by this protection scheme. Failure to detect these faults and quickly isolate the transformer may cause serious damage to the device.

The transformer shown in Figure 14 is a single phase step-up transformer. Note that CT1 and CT2 will have ratios such that, under normal full load conditions on the power transformer, the currents i1 and i2 will be equal. Thus, the relay has no current flow and will not operate.

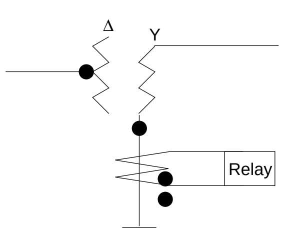
Figure 14
Simple Differential Protection for a Transformer



(d) Ground Fault Protection
Large power transformers are protected from ground faults by the use of current transformers on the grounded neutral of their star or wye connections. The CT connects to a relay that detects any current flow (since this is the return path for fault current) and trips the power transformer. For example, a single CT is located on the grounded neutral of the high voltage side of the Main Transformer as the primary ground fault protection. Other power transformers, such as the Unit Service Transformer, employ a CT on the low voltage grounded neutral as a means of back-up ground protection. The back-up relay will operate for ground faults outside of the differential protection zone for the transformer, if employed.

Figure 15 shows a typical ground fault protection circuit for a power transformer star connection.

Figure 15
Ground Fault Protection for a Star Winding



4.3 High Voltages Buses

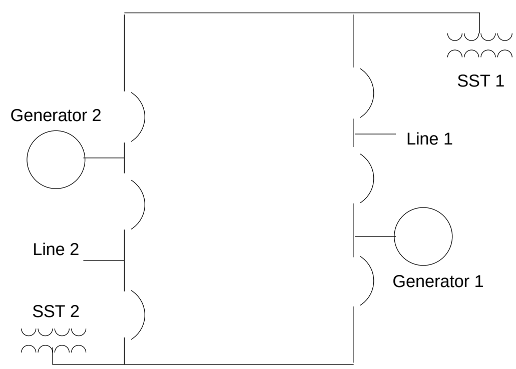
The power output system consists of many high voltage buses that are used to transfer the power produced in the generator to the transmission lines. These buses are protected by differential protection relays which cause the associated circuit breakers to operate when ever a fault is detected.

The high voltage buses are layed out in such a way as to form a ring. This ring bus configuration provides multiple paths for the transmission of power produced by the generator.

Multiple transmission lines decrease the probability of full load rejection and increase station and electrical system reliability/security. A single failure of a bus will not disrupt power flow. See Figure 16.

Figure 16

Simple Switchyard Ring Bus



4.4 Circuit Breakers

There are a number of different styles of circuit breakers used in the main power output systems. At Pickering, the circuit breakers for Pickering A are of the air blast type while the Pickering B breakers are of the oil filled type. However, all circuit breakers in the main power system have the same function that is to isolate the equipment when ever called upon by the operator or by protective relaying.

The breakers on the main power output system are all controlled from the control room. The operator has the electrical panel on which he can perform the following functions: open or close a desired breaker; isolate a desired bus or line or synchronize a generator to the power grid. All these functions require a circuit breaker to operate.

All circuit breakers have at least two positions on the handswitch: trip and close. Some however, the ones used for synchronizing the generator have three positions: trip/auto-sync/close. The logic for these HSs is as follows:

- trip -will open breaker
- close -will close the breaker provided synchro-check relay allows, or synchro-check bypass P/B is depressed.
- auto-sync -will close breaker automatically via the auto synchronizing unit (ASU) once synchronism conditions are met.

The circuit breakers are operated via air pressure or spring action. On the oil filled type the breakers are closed via air pressure and are opened via spring action.

The electrical protection uses relays to activate trip coils and the spring action then opens the breaker.

In the event of a breaker failing to operate, a breaker failure occurs, which sends a signal to surrounding breakers to operate. This type of protection is required to remove any faults that could cause major damage or collapse of the power grid. If "breaker failure" protection is initiated the associated breakers will open in order to isolate the fault. In some cases however, automatic transfer schemes are not initiated and supply buses are de-energized causing major loads to be lost.

4.5 High Voltage Disconnect Switches

Disconnect switches in the main power output system are used for isolation purposes. They isolate equipment such as:

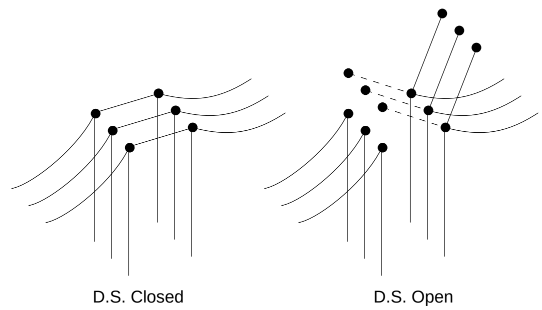
- generators,
- transformers,
- circuit breakers,
- transmission lines.

Each generator, transformer circuit breaker and transmission line has a motorized disconnect switch associated with it. Each breaker has an additional manual disconnect switch associated with it.

The motorized disconnect switches are all controlled from the control room, via a handswitch control.

The handswitch has two positions: open/close. All disconnect switches require field inspection to physically check if the disconnect switch has opened or closed. There are a number of different disconnect switches used. Some open past the vertical position while others open slightly before the vertical position. See Figure 17.

Figure 17
Disconnect Switch



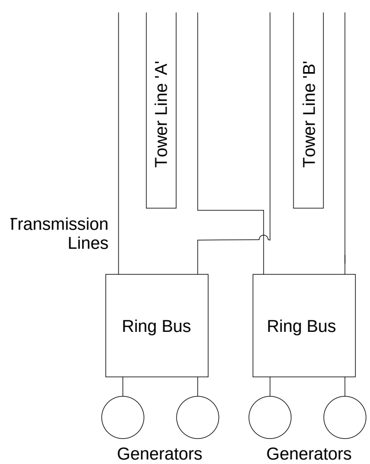
In the closed position, the field operator must check that the disconnect switch has closed and has rotated to ensure a locked position.

All manual disconnect switches are locally operated by the field operator.

4.6 Transmission Lines

Transmission lines are the means of transporting the power from the generator to the customer. The generating station is connected to the transformer station or switching station by a number of tower lines. Each tower line carries two transmission lines. The transmission lines are connected such that if one tower line failed (ie. a tower collapses) then the power is transferred to the other tower line without a power interruption.

Figure 18
Transmission Lines Connection to Ring Bus



4.6.1 Transmission Line Protection

Transmission line protection uses two types of protective relays and each relay is associated with a different group.

Like transformer protection, line protection has two groups; group A and group B. Group A protection uses electromagnetic relays. Group B protection uses solid state relays. The protective function of both groups is identical.

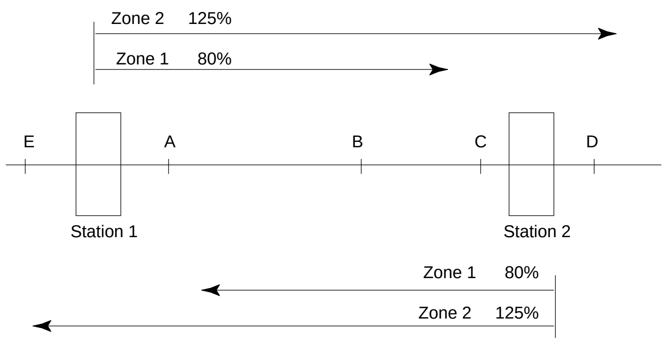
Group A and B protections provide the primary and back-up protective devices during normal operation. Similar to the odd/even concept, only one protective device of a duplicated pair can be removed from service for maintenance at any one time.

If all protection fails while the equipment is energized, every effort will be made to restore protection or the equipment will be removed from service.

Transmission line protection is looked at by zone protection. There are two zones per station. For example, zone 1 covers 80% of the line while zone 2 covers 125% of the line. Thus, total line coverage is obtained.

Figure 19

Line Protection Scheme



Another protection scheme used in line protection is the underfrequency protection. Underfrequency protection is used in line protection and generator protection. Line protection being the first line of defense where as generator protection is the back-up.

The following is an explanation of how the underfrequency protection works at Pickering `B'. (See Figure 16).

When the line protection relays sense an underfrequency, the following sequence occurs:
1) SST loads transfer to the GST,
2) Time delay 10 secs.,
3) Line breakers operate to isolate the line,
As a result the generator is supplying its own loads, while the line is de-energized.

The generator underfrequency relays are a back-up to the line underfrequency.

If the generator underfrequency relays operate, the following sequence occurs:
1) SST loads transfer to the GST,
2) Time delay 12 secs,
3) Generator breakers open to isolate the generator from the fault.

The result is similar to line underfrequency however, the sister units SST is de-energized.

Station Electrical Systems Abnormal Events

Training Objectives

At the end of this lesson the participant will have the knowledge to:

- Define "Abnormal Incident".
- State the "operating philosophy" regarding unit upset.
- State three safety related concerns when a total loss of Class I and II power occurs.
- List four major consequences of a total loss of Class III power occurs.
- State four operating concerns when a total loss of Class IV power occurs.
- State five major consequences of a total loss of Class IV and III power.
- State the major events that occur during the first ten minutes of a total loss of Class IV and III power.
- State two actions required of the plant operator on discovering that the EPS system is unavailable for service.

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1.0 Abnormal Incident

An abnormal incident may be defined as any process upset where there is a direct threat to fuel integrity such that an immediate sustained power reduction is required.

Examples of such events would include:
- loss of heat transport flow
- loss of heat transport coolant
- loss of high power heat sinks
- loss of Class IV / III power.

2.0 Operating Philosophy

The operating philosophy of nuclear plants is to:
- Control reactivity
- Cool the fuel
- Contain the radioactivity.

3.0 Loss of Class IV Power

The Class IV power system supplies the following major loads:
- Class III loads
- heat transport pumps
- boiler feedwater pumps
- condensate extraction pumps
- condenser cooling water pumps
- liquid zone control pumps
- pressurizer heaters
- turbine auxiliaries
- D_20 vapour recovery driers.
- Moderator Pumps

When a total loss of Class IV power occurs, the reactor is stepped back on loss of all HTS pumps, followed by a reactor trip on low heat transport flow on SDS1.

A total loss of Class IV power creates a coincident total loss of Class III power until the Standby Generators are automatically started up and the Class III buses loaded by the Emergency Transfer Scheme.

During this two-minute period, the plant can safely operate without Class III power. There is adequate inventory of feedwater in the Steam Generators to provide the heat sink for the fuel.

The main heat transport pumps are no longer available to provide forced circulation of the heat transport coolant. Decay heat will be removed by thermosyphoning in the HTS. When Class III power is restored heat transport pressure will be maintained by the pressurizing pumps. Feedwater will be supplied by the auxiliary BFP. Condensate will be supplied by the auxiliary condensate pump. The turbine will trip immediately on a low vacuum trip as the Condensor Cooling Water pumps are no longer available.

The liquid zone control pumps and compressors are unavailable. The liquid zones will fill, providing maximum negative reactivity to the reactor core.

Most turbine auxiliaries are unavailable. The emergency seal oil, bearing oil, and stator cooling pumps supplied from Class I power will provide cooling and lubrication as the turbine runs down to rest. The turning gear may be unavailable and the turbine may have to be rotated manually using the hand barring gear.

The plant can continue operating at shutdown power level for a lengthy period until Class IV power is restored. The Class III power supply, provided by the Standby Generators, ensures that the operating philosophy of "Cool, Control and Contain" is maintained.

4.0 Loss of Class III Power

The Class III power system supplies the following major loads:

- auxiliary boiler feed pumps
- HT feed pumps
- Raw Service Water (RSW) pumps
- moderator pumps pony motors
- Recirculated Cooling Water (RCW) pumps
- ECC recovery pumps
- lighting panels
- shutdown cooling pumps
- shield cooling pumps
- instrument air compressors
- supply to Class I and II.

When a total loss of Class III power occurs, the reactor does not immediately trip. The setback on high moderator temperature will occur and reduce power to 2% FP over the following minutes, due to the loss of the heat sink (RSW/RCW).

A loss of moderator heat sink produces swell in the moderator and an increase in level, leading to a trip on high moderator temperature of 87°C on SDS1. The moderator system's ability to act as "the ultimate heat sink" is impaired.

Moderator temperature will rise at 5°C per minute at full power. The auxiliary boiler feed system is impaired as the ABFP is unavailable, but the Class IV supplied pumps will maintain Steam Generator level. The HTS feed pumps are not available and HTS pressure will eventually decrease to saturation pressure. The Raw Service Water pumps and Recirculated Cooling Water pumps fail and all systems cooled by the RSW and RCW increase in temperature.

The ECC system is impaired as the ECC recovery pumps are not available if required on Class III power. The shutdown cooling pumps are unavailable and the heat transport system must be cooled down by use of alternate approved method for the plant.

The shield cooling pumps are unavailable and temperatures in the end shield and shield tank will slowly increase towards limits. The instrument air compressors will shut down and air pressure will decrease, depending on leakage and usage of the system. All valves will eventually fail to their safe state as air pressure decays.

The reactor must be shut down. This will occur either by the initiation of a manual trip or on a setback and trip on high moderator temperature.

The EPS and EWS systems will be prepared for service.

The heat transport system must be cooled down, as heat input to moderator and end shield continues to be transferred from the HTS system. The HTS cooldown will be by an alternate approved method for the plant, as shutdown cooling is not available, i.e. no SDC pumps or heat sink. It can be therefore seen that the total loss of Class III power is a very serious event which includes the potential for one or all of the following major events:

- loss of Raw Service Water
- loss of Recirculated Cooling Water
- loss of instrument air
- loss of HTS pressure control
- loss of Class I and II power
- loss of shield cooling

5.0 Total Loss of Class III and IV Power

If, during a total loss of Class IV, there is a failure of both Standby Generators, there will be a total loss of Class III and IV power.

In addition to the concerns stated in Sections 4.0 and 5.0, there is a potential for a total loss of Class I and II power and an initiation of ECC.

Fuel cooling will be provided by thermosyphoning, which will be established in approximately five minutes, with a reactor outlet header temperature in the range of 275°C to 295°C and a reactor core temperature difference (Core ΔT) of 25°C ± 10°C.

Heat transport pressure will recover to the saturation pressure equivalent to the reactor outlet header pressure in the range of 7.0 Mpa(g).

Adequate fuel cooling is provided by single phase and two-phase thermosyphoning. The inlet header will be sub-cooled by some 15°C to 35°C.

Feedwater inventory is limited to the steam generators and emergency makeup water from the dousing tank through the EWS valves.

The EPS and EWS systems will be prepared for service and the secondary control centre will be manned in preparation for a loss of feedwater, instrument air, Class I and II power. Cooldown of the HTS must be commenced as soon as possible and monitored to ensure continued fuel cooling.

If the heat sink becomes inadequate, i.e. cooldown rate very slow, the EWS system will be placed in service to add EWS water to the steam generators so that cooldown may continue and a long term heat sink is established.

In the event that the ECC system is initiated, HTS conditions will be stabilized by ECC and the main steam system will be fully depressurized by ECC actions and therefore cooldown of the HTS is assured. The EPS system will be energized and monitoring and control of critical systems will be completed from the SCR when Class I and II power become unavailable.

6.0 Loss of Class I And II Power

The Class I and II power systems supply the following major loads:
- protection and control of a large circuit breakers, 13.8 kV, 4.16 kV and 600 V
- ECC recovery and Injection motorized valves
- DC emergency turbine pumps for stator cooling, bearing lubrication, and generator seals
- digital control computers (DCC)
- instrumentation and control.

In the unlikely event that a total loss of Class I and II power were to occur, the reactor will safely shut down by actuation of SDS 1 and SDS 2, although there will be no indication of this or means of controlling it.

Severe impairments of safety and safety support systems exist. All 13.8 kV, 4.16

kV and some large 600 V motors cannot be shut down or started automatically or manually from the main control room. Protection to these breakers is lost.

The ECC system is impaired as the recovery valves cannot be opened automatically.

The control computers stall and fail controlled devices to the safe state. Standby power from the Standby generators will not be available to automatically start if required. The turbine generator may not trip automatically, as the tripping circuit is impaired. If the turbine is tripped, a Class IV power transfer may not occur.

The unit must be placed in the guaranteed shutdown state after the heat transport system has been cooled down and must remain in the GSS until Class I and II power supplies are available. Manual field control and field monitoring of station systems will be required.

The EPS and EWS systems will be placed in service to supply Group II systems and monitored in case Class I and II power systems remain unavailable in the long term.

7.0 Loss of Class IV Power Following a Loss of Coolant Accident (LOCA)

If a loss of Class IV power occurs following a LOCA, the Standby Generators will be automatically connected to the Class III buses. The SGs will provide power to all Class III loads to ensure safe monitoring of the plant and cooling of the fuel, ensuring public safety.

8.0 Loss of Emergency Power System

The EPS must be available at any time the reactor is not in the guaranteed shutdown state to provide an alternate source of power to Group 2 systems in the event of a loss of normal supply or a seismic event.

If the EPS is found to be unavailable, the reactor must be shut down and cooled down and placed in the guaranteed shutdown state within a specified time limit.