Switching Operator's Manual (Rev 4)

Distribution Switching

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Regional Managers	Works Delivery Managers
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RECORD OF REVISIONS

Revision No.	Date	Revised By	Description
01	17/10/2018	Stuart Smit	Section 9. Paragraph 9.6.3 revised to include additional information pertaining to single phase / three phase spur disconnections.
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SECTION ONE

Introduction: Distribution Switching

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1. Introduction: Distribution Switching

1.1 Purpose

Manual One provides the switching operator with information on the distribution network configuration, apparatus and switching operations. The manual covers the Horizon Power distribution networks associated with the microgrid and Pilbara Grid systems.

Manual Two provides the switching operator with information on the transmission network configuration, apparatus and switching operations. This manual covers the transmission network associated with the Pilbara Grid.

Both manuals are intended to be used as a resource for all switching operators and also a major resource for the training modules in Switching Operations.

1.2 Content

1.2.1 Manual One

Manual One covers the network and switching associated with the distribution high voltage (HV) and low voltage (LV) network, which is common to both microgrid and Pilbara Grid systems. The LV distribution network connects electrical power to the majority of the Horizon Power's customers, and the HV distribution network supplies HV power to the distribution transformers which is stepped down in voltage to supply the LV network.

A brief description of the contents of each section is provided below.

Section 1

Section One (this section) provides a brief overview of the contents of the manuals and a more detailed overview of the sections related to the distribution HV and LV networks.

Section 2

Section Two is a general introduction to Horizon Power's Power systems. It provides an overview of both microgrid and the interconnected Pilbara Grid systems. An overview of generation stations, transmission substations and lines and the distribution HV and LV networks is provided. The responsibility for switching on these networks is also discussed.

Section 3

Section Three describes in detail the LV distribution network configuration, apparatus and switching operations. This is the most extensive network and both overhead and underground forms are common. This network connects and provides electrical power to the majority of Horizon Power’s customers.

Section 4

Section Four describes in detail the HV distribution overhead network configuration, apparatus and switching operations. This is an extensive network and exists in both three-phase and the single-phase forms common in regional areas.

Section 5

Section Five describes in detail the HV underground network configuration, apparatus and switching operations. This network tends to be located in built-up areas and exists in both three-phase and the single-phase forms.

Section 6

Section Six describes in detail the substations which provide the source of supply for the HV distribution network. It includes a description of the substation configurations and the associated primary and ancillary apparatus.

Section 7

Section Seven describes the protection systems used on both the HV and LV distribution systems. It includes descriptions of the grading introduced to ensure only the faulted section of the distribution system is disconnected.

Section 8 – (also applicable to Transmission switching)

Section Eight describes the critical matters relating to safe switching operations, it is applicable to both distribution and transmission switching. The section includes a description of the switching related documentation and the roles and responsibilities. Also detailed are the principles and practice of isolation and earthing, permits and barriers, locking and tagging. Details are provided on common switching operation tasks, the practical checks before and after switching apparatus and switching related hazards.

Section 9 – (also applicable to Transmission switching)

Section Nine describes the roles and responsibilities, tools and procedures associated with the creation and running of switching programs which are applicable to both distribution and transmission switching. Also included in the section are the program writing considerations which must be reflected on and included if appropriate to create a successful switching program.

Section 10

Section 10 describes the testing and commissioning documentation, equipment and practices required to carry out the testing and commissioning of distribution apparatus which is to be placed in service. Also included is an example of a commissioning switching program.

1.2.2 Manual Two

Manual Two covers matters relating to transmission network switching.

It should be noted Sections 8 and 9 as described above are also applicable to transmission switching.

1.3 Switching Operator Authorisation Levels

Horizon Power's Switching Operator Authorisation Levels are described in the table below.

Level	Description
1	Fault response – initial response to faults including switching to disconnect faulted apparatus on de-energised distribution systems.
2	Distribution switching – all primary apparatus associated with HV and LV overhead and underground networks.
3	Substation switching – allows switching operations on primary apparatus located within Pilbara Grid and microgrid substations.
4	Transmission switching – all primary apparatus associated with Transmission lines, zone substations and terminal stations.
5	Protection and other secondary systems – isolation and commissioning of protection and secondary systems.
6	Generation switching – HV and LV switching on generation sites.
7	HPCC controller switching – switching coordination and remote switching of Pilbara Grid and microgrid apparatus.

Field Instruction – *Switching Authorisation* details the requirements of obtaining a switching operator’s authority.

SECTION TWO

Horizon Power's Power Systems

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2. Horizon Power’s Power Systems

2.1 Introduction

Horizon Power generates, distributes and retails electricity through its range of power systems in regional Western Australia. The components and structure of Horizon Power's power systems are described in this section.

Two types of power systems are used (see Figure 2-1):

- the non-interconnected systems, known as microgrid systems, and
- the interconnected systems.

The type of system used is determined by local conditions such as the number of customers, customers load, and the distance to the power supply source.

2.2 Horizon Power's Two Systems

2.2.1 Microgrid Systems

Horizon Power’s microgrid systems are designed to suit load centres in regional and remote areas. Figure 2-1 shows the location of the microgrid systems and the fuel type used for generation. (Note that all locations outside the Pilbara Grid network are microgrids, although there is an interconnection between Kununurra and Wyndham in the Kimberley region.) Because of their remote location, each microgrid system operates independently and does not connect to other microgrid systems.

Figure 2-2 shows the basic components of a microgrid system. The system can be divided into generation, HV distribution and LV distribution.

The generating plant consist of conventional generation which may also be supplemented with local distributed generation. Conventional generation uses gas turbines or diesel engines fuelled by natural gas or diesel. Distributed generation mainly comprises photovoltaic panels, both in the form of customer rooftop solar arrays and commercial solar farms, and wind turbines. Hydro generation is also used in the Kimberley region to supply the towns of Kununurra and Wyndham.

Step up transformers are used to increase the voltage to 11, 22 or 33kV. The HV distribution feeders supply distribution transformers with electrical energy which is further stepped down to the LV distribution voltages (480/415/240V), to supply the customers via overhead and underground LV networks.

Figure 2-1 Horizon Power's microgrid and interconnected systems

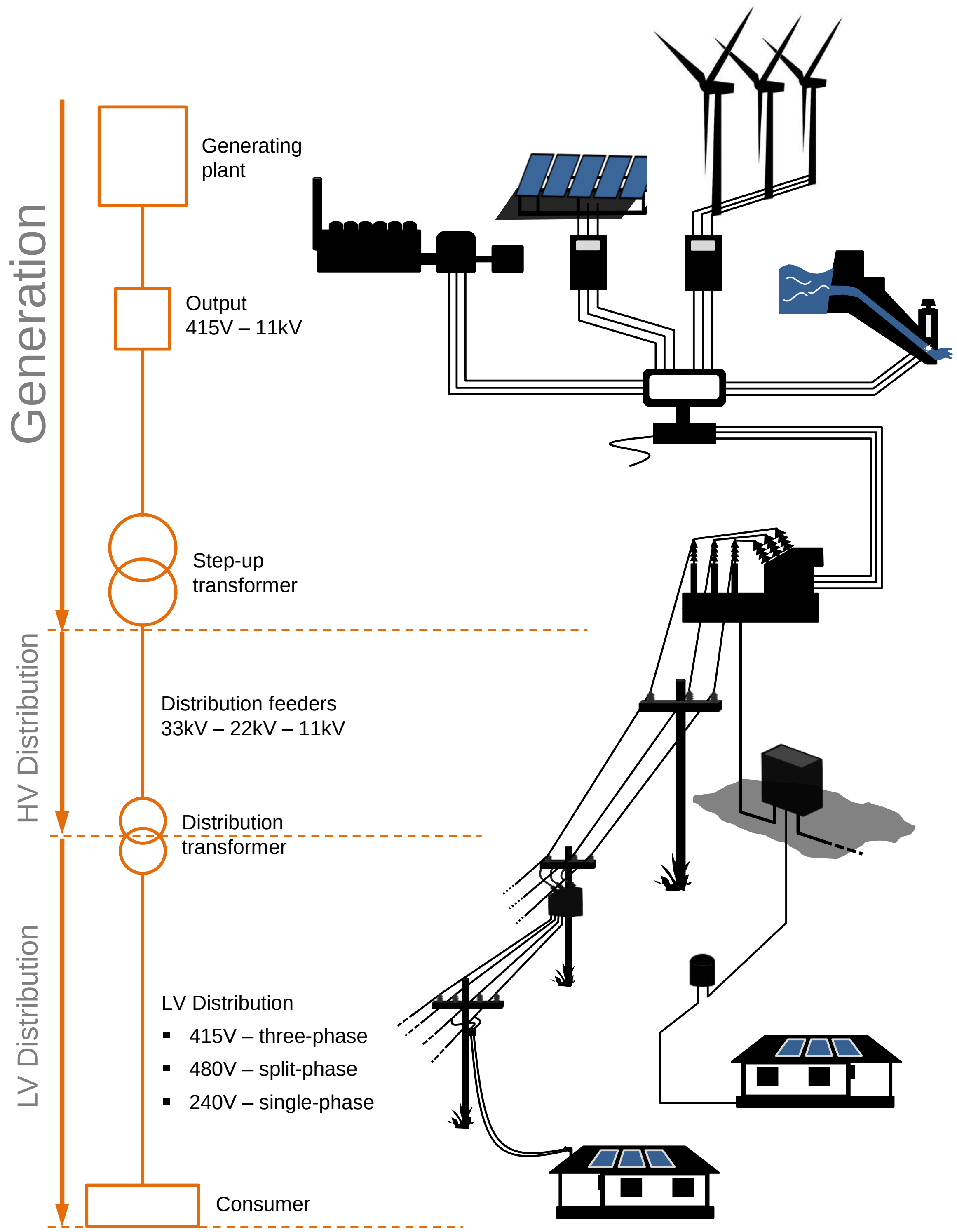

Figure 2-2 Components of a microgrid system

2.2.2 Interconnected Systems

Horizon Power's Pilbara Grid is of the interconnected system type and is designed to accommodate large load centres and use several generating stations connected together with a transmission network. Figure 2-1 shows the location of the Pilbara Grid system supplying the Karratha and Port Hedland areas. The fuel used for generation is predominantly natural gas, with diesel fired generation being available for shortages in natural gas supply.

Figure 2-3 shows the basic components of a typical interconnected system. The system can be divided into generation, transmission, HV distribution and LV distribution.

The generating stations produce electrical energy using large gas turbines. Generator step up transformers increase the voltage to higher transmission voltages of 66, 132 or 220kV to reduce the electrical system losses. The HV transmission lines transport the electrical energy to the terminal stations which are the bulk supply points for the zone substations.

The zone substations connect the transmission network to the distribution network using step down transformers to reduce transmission voltages (66 or 132kV) down to HV distribution voltages (11, 22 or 33kV). The distribution feeders supply distribution transformers with electrical energy which is further stepped down to the LV distribution (415/240V), to supply the customers via overhead and underground LV networks (see Figure 2-4 below).

Figure 2-4 shows a simplified representation of the Pilbara Grid, where the Karratha and Port Hedland systems are connected together with a long 220kV transmission line. It can be seen the terminal stations connect the generation stations together and supply the zone substations. For increased supply security most zone substations have more than one source of high voltage transmission supply.

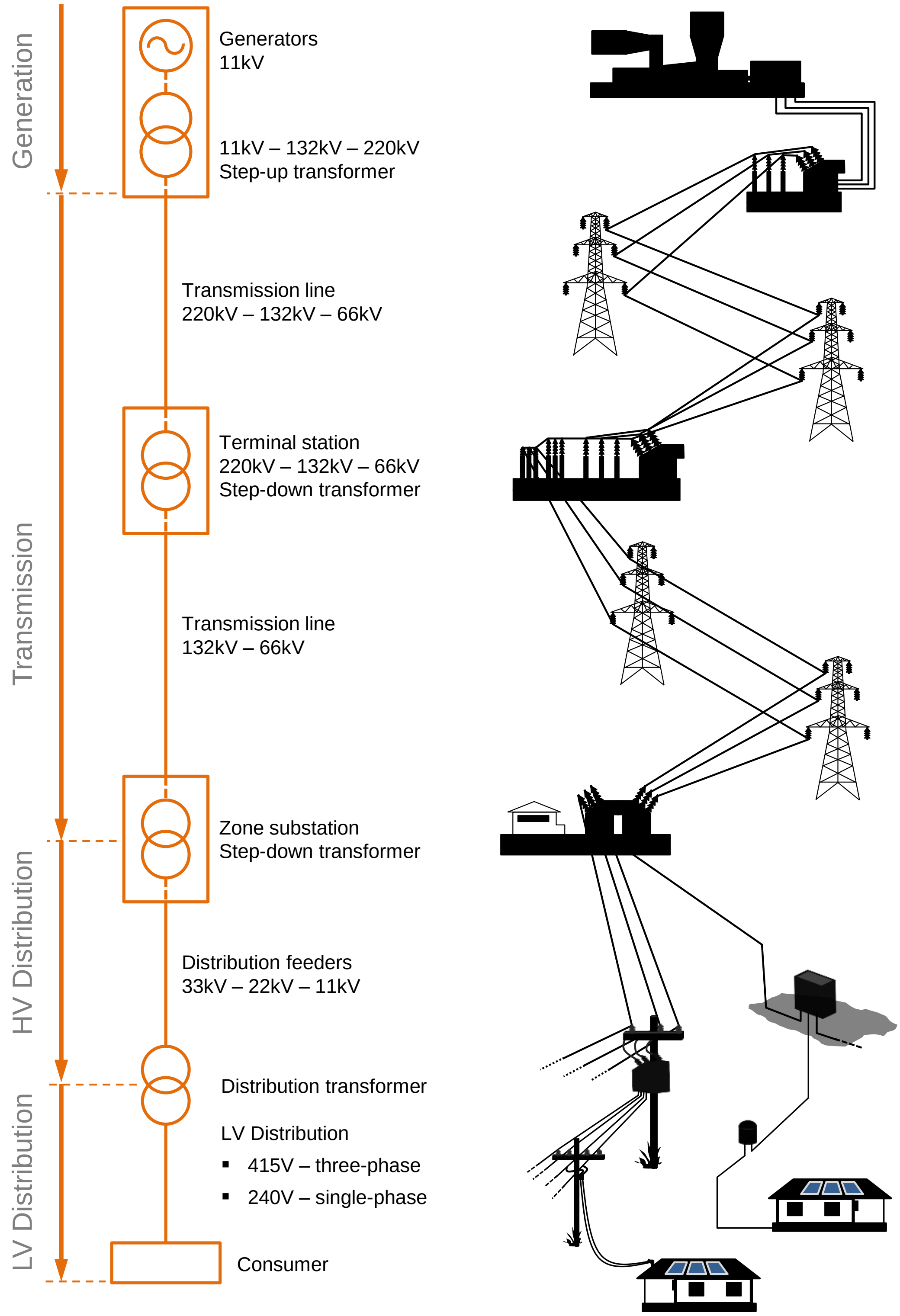

Figure 2-3 Components of an interconnected system

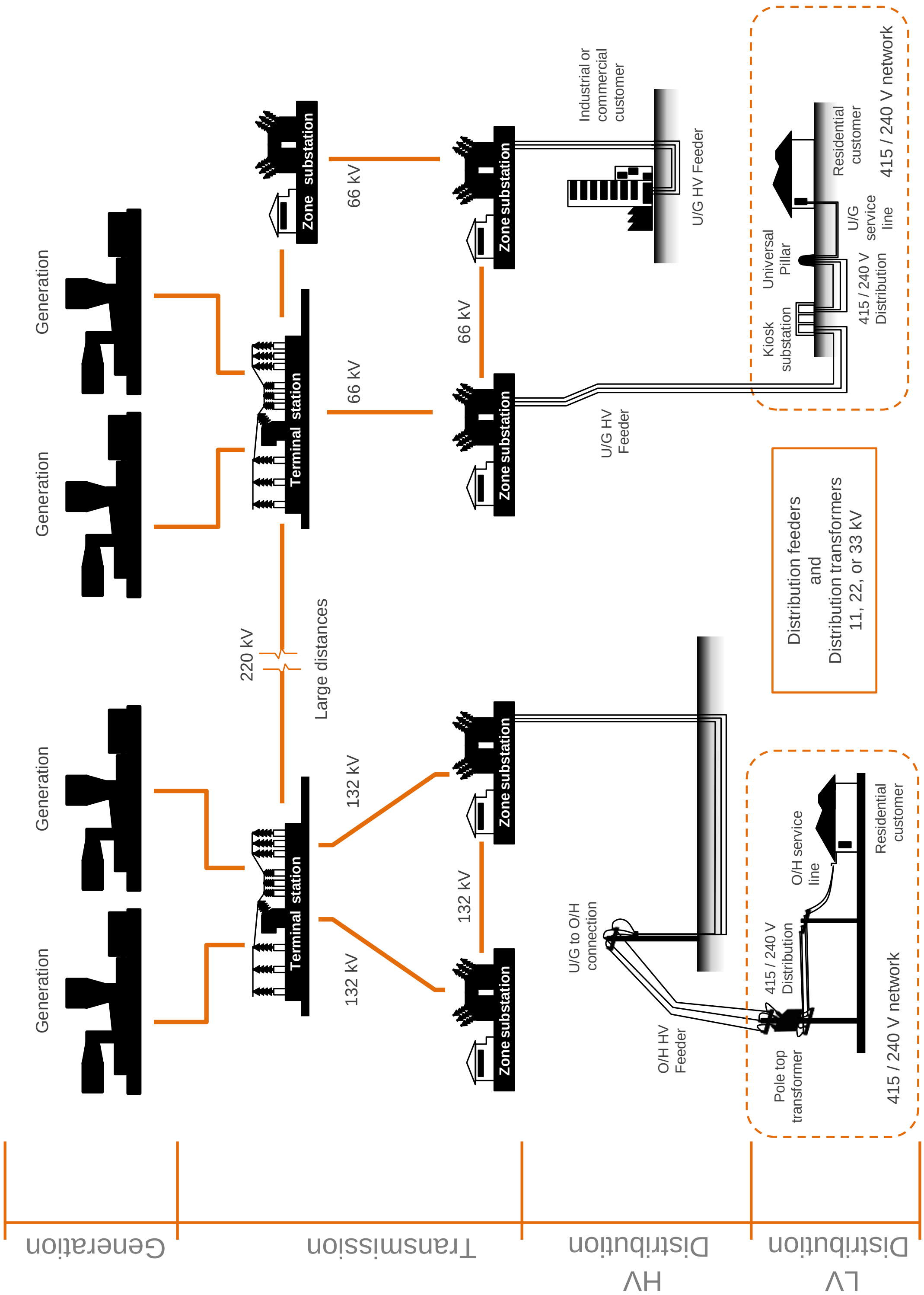

Figure 2-4 Interconnected system: The interconnection of components

2.3 System Components

The major components of microgrid systems are generating stations, transformers, distribution feeders and LV circuits.

The interconnected system is much larger and has a transmission system which requires the additional components of transmission lines, terminal stations and zone substations

2.3.1 Generating Stations

Generation is the conversion of mechanical or renewable energy into electrical energy. Horizon Power generates or purchases power derived mainly from mechanical means such as gas turbines and diesel engines. This is being increasingly supplemented with localised distributed generation.

Pilbara Grid is supplied mainly from:

- privately-owned and operated gas turbines, and
- power stations owned and run by local mining companies.

Microgrid towns can be supplied from a range of generation which can include combinations of the following (dependent on the specific installation):

- gas- or diesel-fired turbines
- diesel combustion engines
- wind turbines
- photovoltaic solar farms
- consumer solar arrays and battery storage, and
- hydro power on the Ord river.

The size of generating units is dependent on the load to be supplied from the kilowatt range to many megawatts. The smaller generating units will generate at low voltage 415V, whilst the larger units will generate around 11kV with step up transformers to match the voltage of the network to which they connect.

In the Pilbara Grid to increase efficiency, because of the large amounts of power required and long distances involved, the voltage may be stepped up to 132 or 220kV. In microgrids the generator or step up transformer voltage will match the local distribution voltage.

Generating stations usually have multiple generating units to allow for multiple units to run at high load and also make individual units available for maintenance.

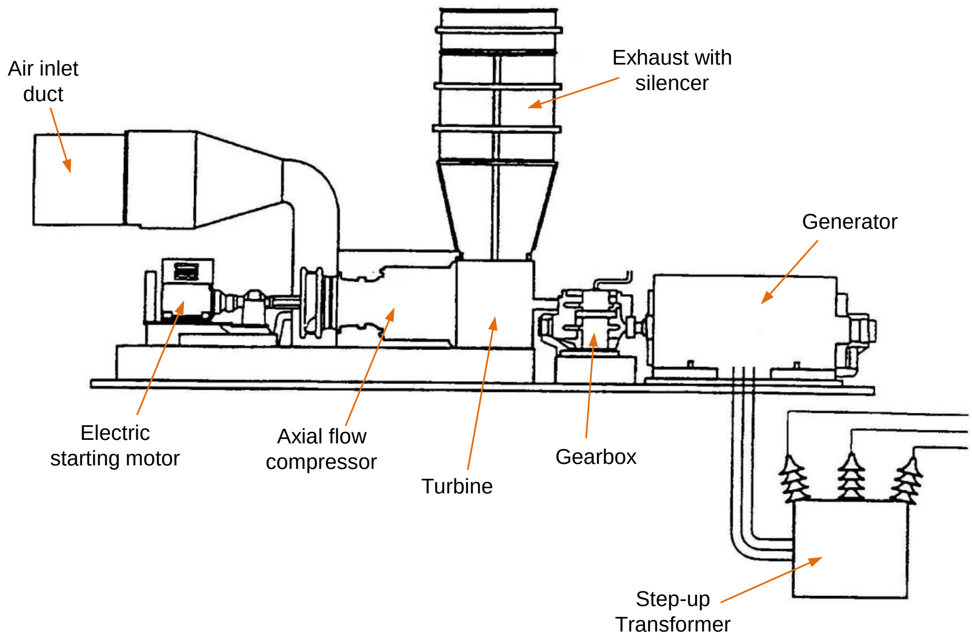

Figure 2-5 Typical gas turbine generator

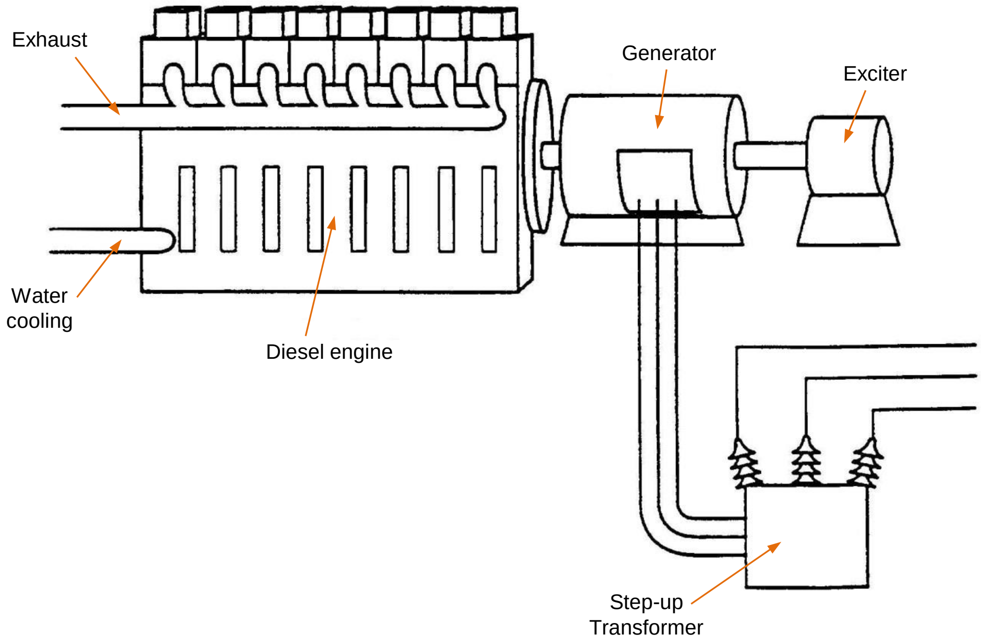

Figure 2-6 Typical diesel fuel-fired power station

2.3.2 Transmission Lines

These lines transmit power over long distances using very high voltages. This reduces power losses. However, the cost and availability of equipment (step up transformers, insulators, circuit breakers, towers etc.) limit the degree to which the voltage may be increased.

Figure 2-7 shows the network and voltages used in the Pilbara Grid.

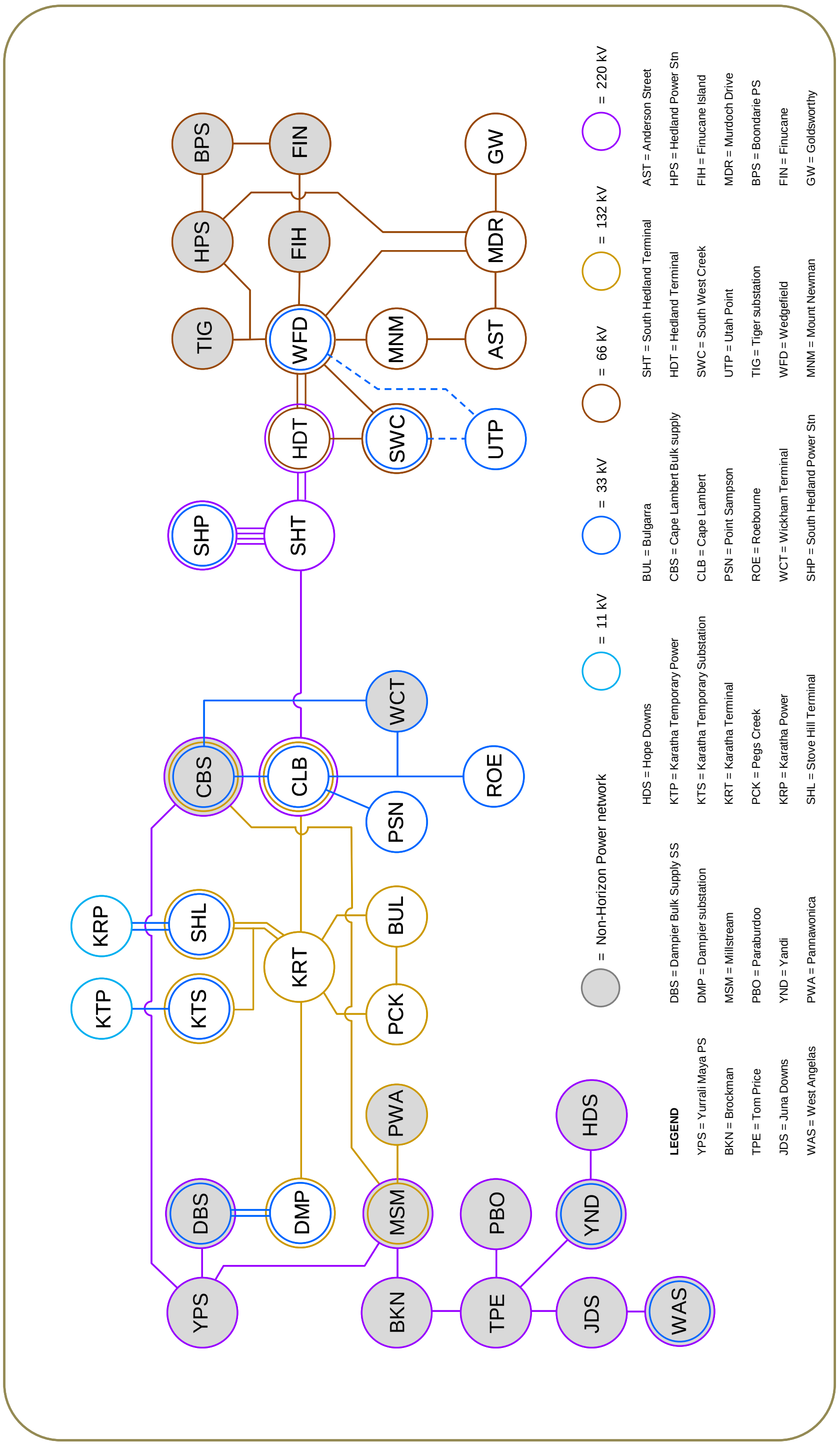

Figure 2-7 Horizon Power's Pilbara Grid transmission system

2.3.3 Terminal Stations

As the interconnected networks became more complex and a greater variety of voltages were used, terminal stations were introduced to interconnect the various voltages (see typical examples in Figure 2-8 and Figure 2-9). Terminal stations allow flexibility to control and transform power to lower levels of transmission.

Voltage of 66kV, 132kV or 220kV are used in terminal stations. These voltages may be stepped up for further transmission to other terminal stations or stepped down for transmission to lower levels of transmission at zone substations. Transmission to zone substations is carried out at voltages of 66kV or 132kV.

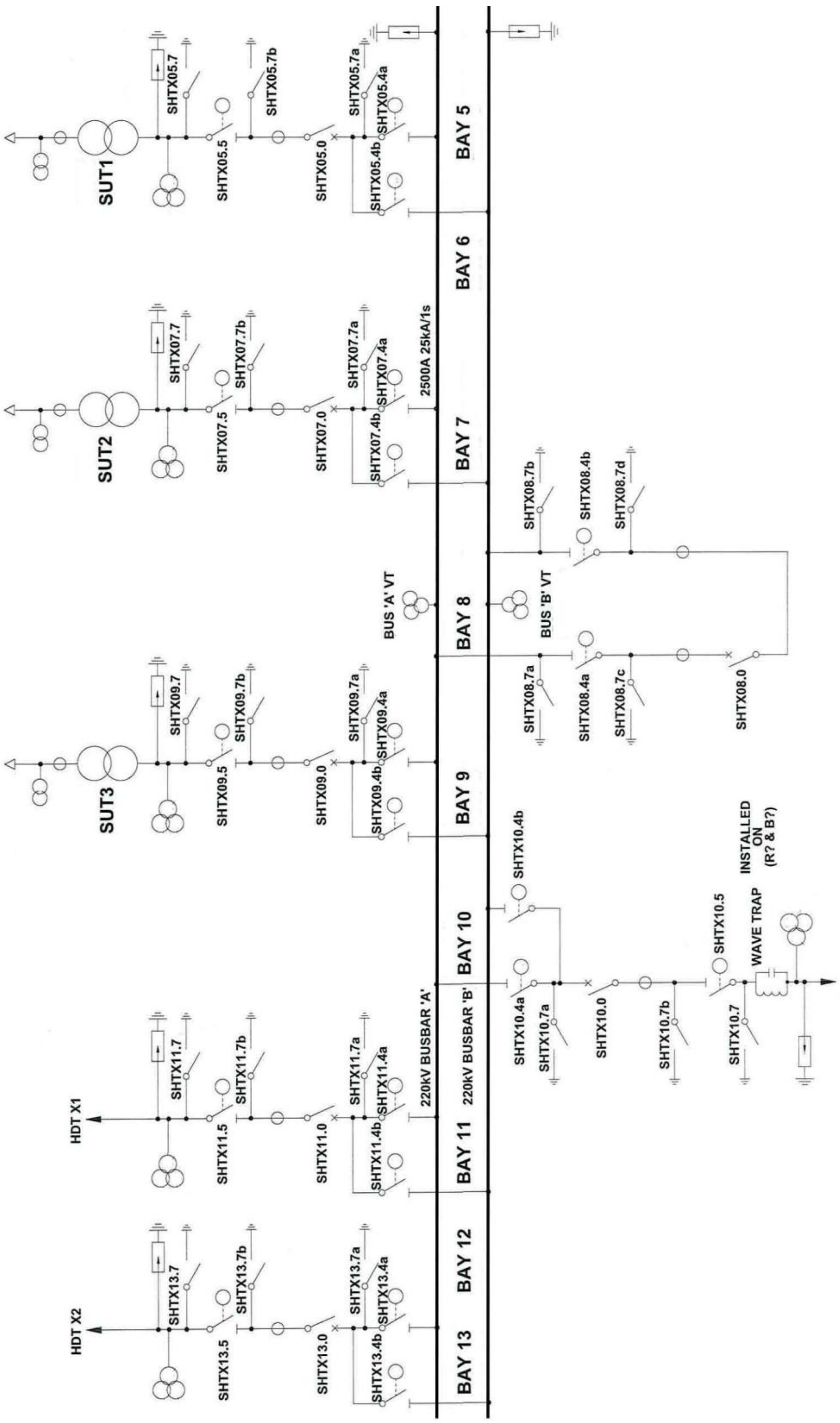

Figure 2-8 South Hedland Terminal Station
Incoming 11kV generation connected to generation step up transformers (SUT 1-3) which change voltage 11/220kV to supply Hedland Terminal Station (HDT) and Cape Lambert Terminal Station (CLB)

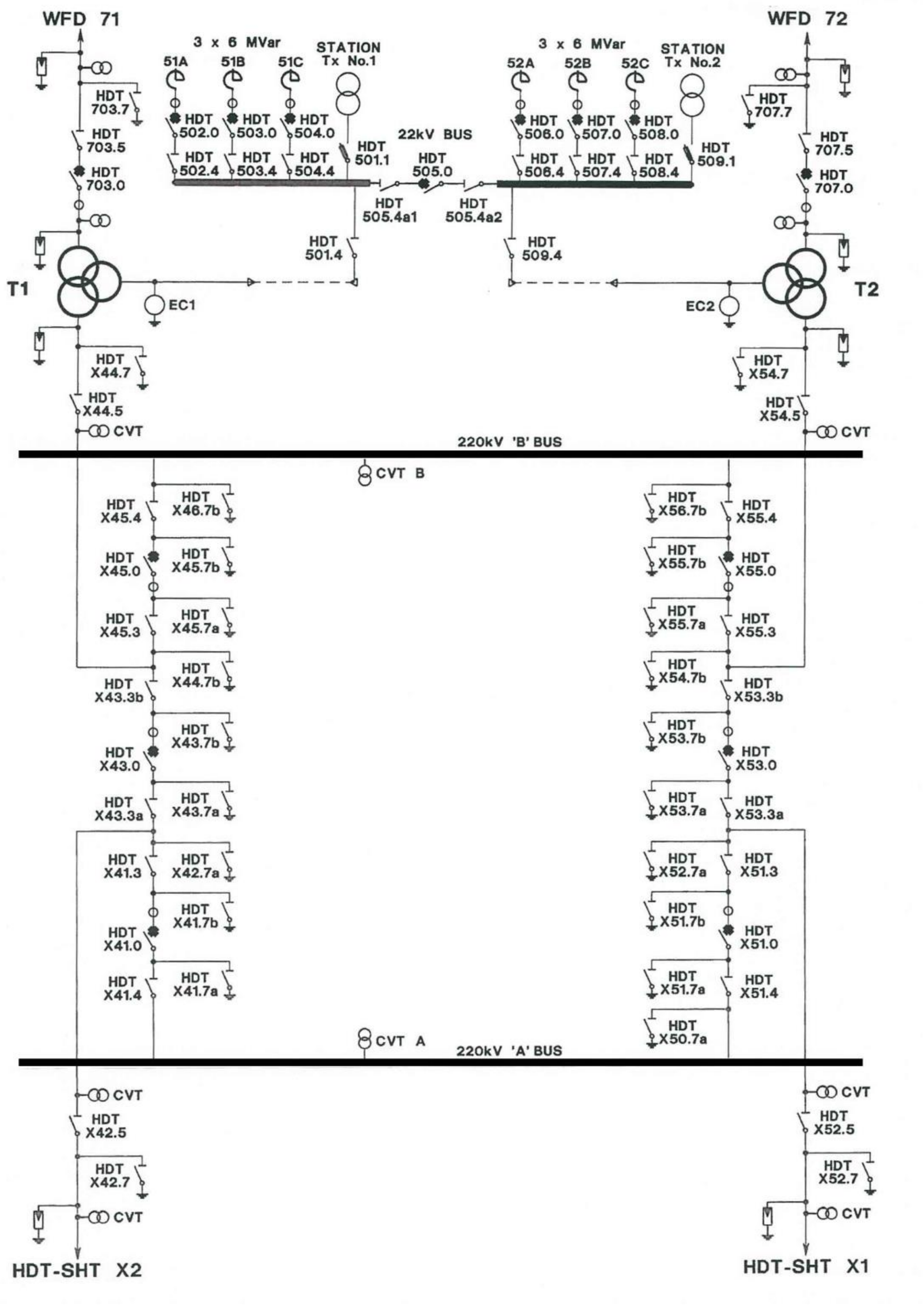

Figure 2-9 Hedland Terminal Station
Incoming 220kV supply from South Hedland Terminal Station (SHT)
with transformers supplying 66kV to outgoing circuits to Wedgefield (WFD) zone substation

2.3.4 Zone Substations

Zone substations are used as the final stage of transmission and the first level of distribution networks. Zone substations are fed mainly from 66kV or 132kV transmission lines and are usually connected in a ring network to other zone substations and terminal stations. The ring network is used to maintain continuity of supply during faults and planned outages.

The transmission voltage supplied to the zone substation is transformed down to distribution high voltage by means of a step down transformer.

Zone substations use two busbar configurations:

- single bus, and
- double bus.

The double bus configuration has better flexibility of supply than the single bus configuration.

There are also two types of switchgear used for distribution from the zone substation:

- indoor
- outdoor.

Zone substations can have distribution voltages of 11, 22 or 33kV. This depends on local conditions and design factors.

Typical examples are shown in Figure 2-10 and Figure 2-11.

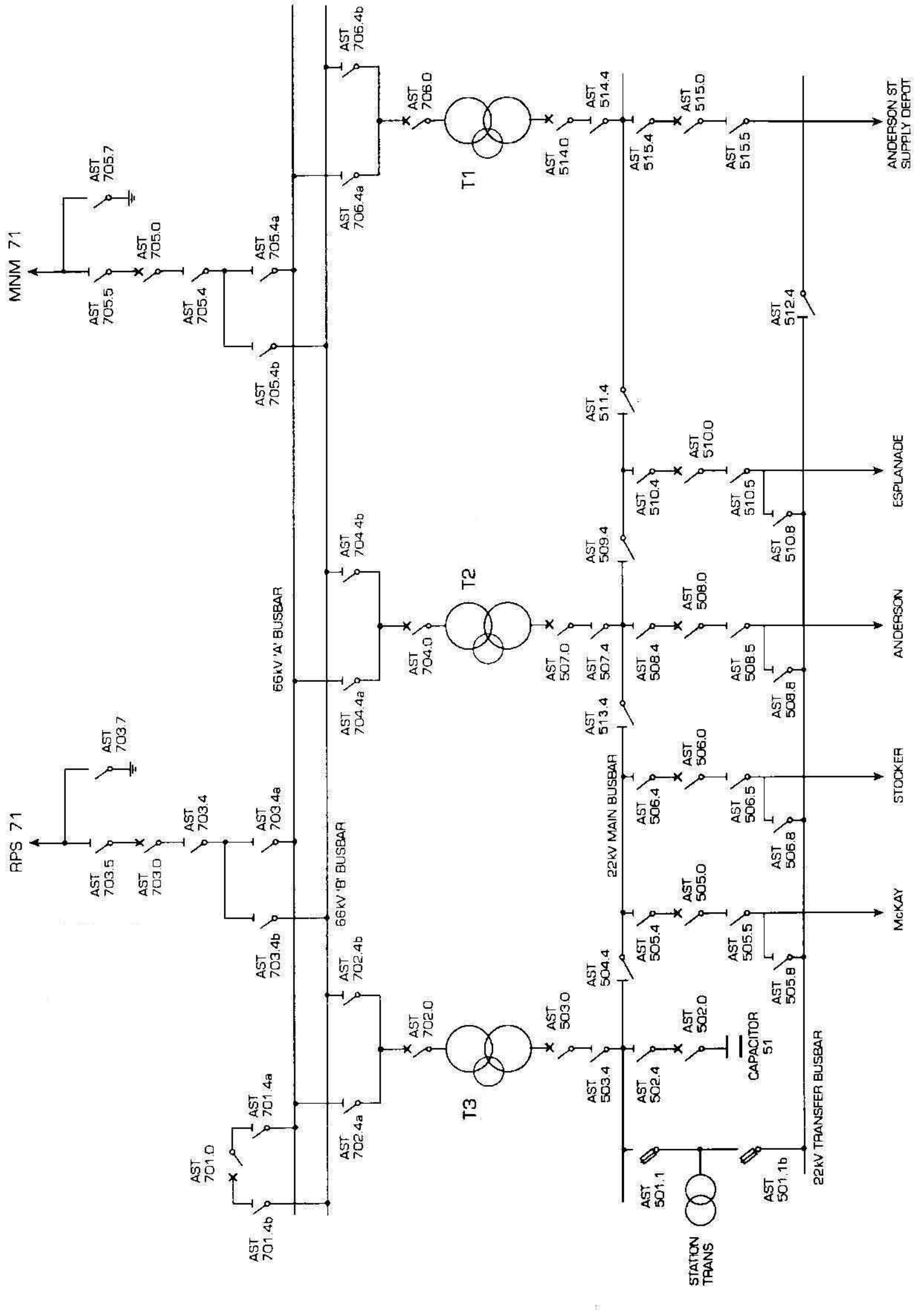

Figure 2-10 Anderson Street Zone Substation
66kV double busbar to 22kV single busbar
(with transfer bus) outdoor switchgear

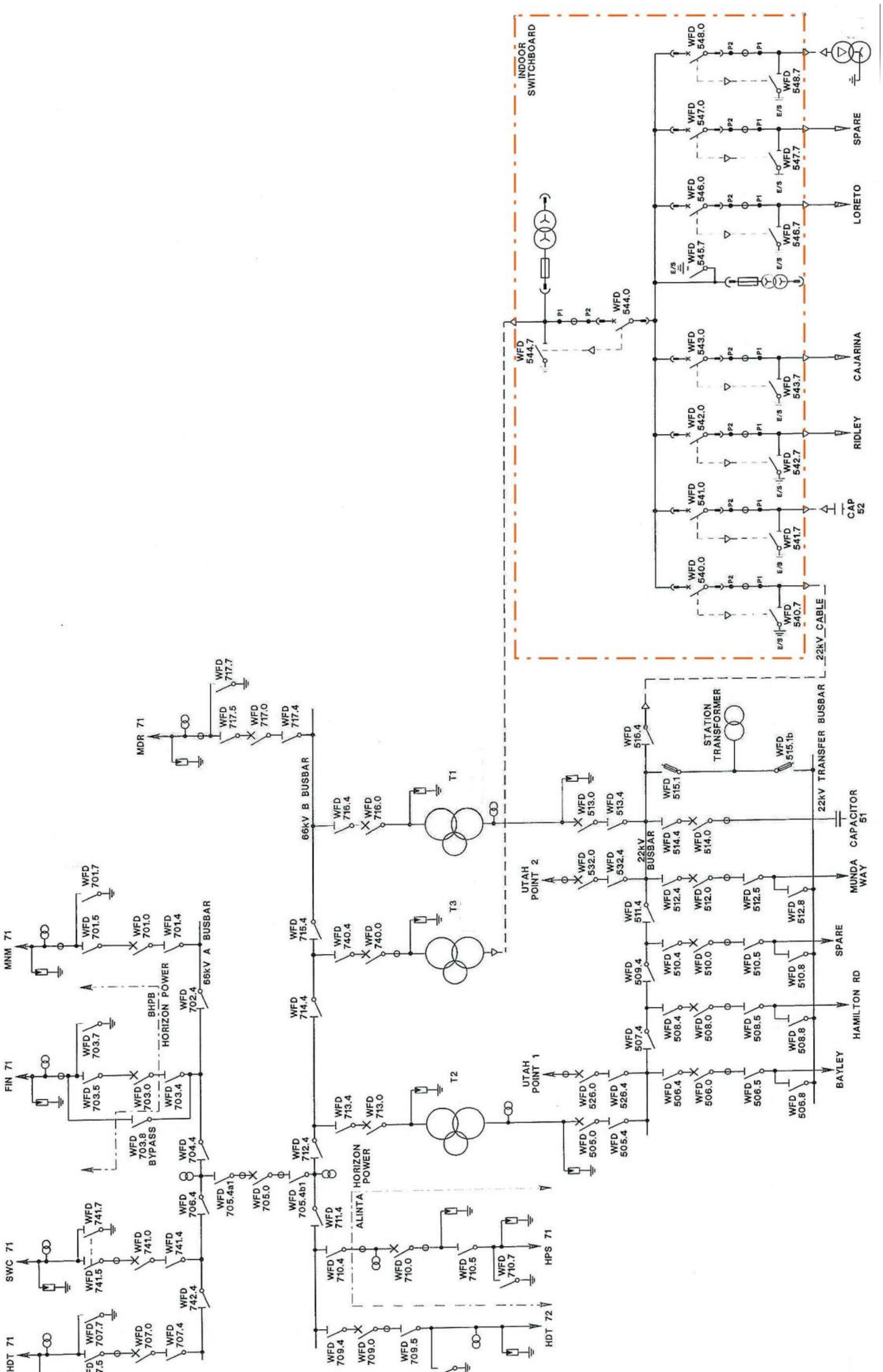

Figure 2-11 Wedgefield Zone Substation 66kV single busbar

2.3.5 Distribution High Voltage Feeders – Underground Overhead

Feeders distribute high voltage power to distribution transformers in local areas around a substation (see Figure 2-12). To allow for flexibility, distribution feeders interconnect with other feeders from the same substation or other substations in an interconnected network. Interconnection between substations is possible only if the voltage output from the substations is the same.

Feeders are three-phase circuits and can be overhead line networks, underground cable networks or a combination of both.

The distribution high voltages used are 11kV, 22kV and 33kV. The choice of voltage is determined by the load and location.

Long rural feeders are often supplied at 33kV to reduce line losses.

In some remote areas the rural feeders extend from the substation as three-phase overhead lines and branch into single-phase spurs. These spurs combine with a running earth to feed several small distribution transformers. These single-phase spurs can be overhead or be installed in an underground system, referred to as a single-phase underground distribution system (SPUDS).

2.3.6 Distribution Low Voltage (LV) Circuits

Each distribution transformer steps down the feeder high voltage to supply the distribution low voltage circuits. Depending on the circuit arrangements, the distribution low voltage circuit provides customers with a range of voltages:

- 415V three-phase
- 240V single-phase
- 480V split-phase (only single-phase rural areas)

The low voltage circuit may feed a single rural customer, a large commercial customer or several streets in a residential area.

The area of the circuit is determined by:

- the size of the transformer (load)
- the volt drop within the LV circuit, and
- the type of load to be supplied.

Low voltage circuits are designed to allow the transformers to be run as near as possible to their rated values. Various sizes of conductors maintain set voltage limits around the circuit.

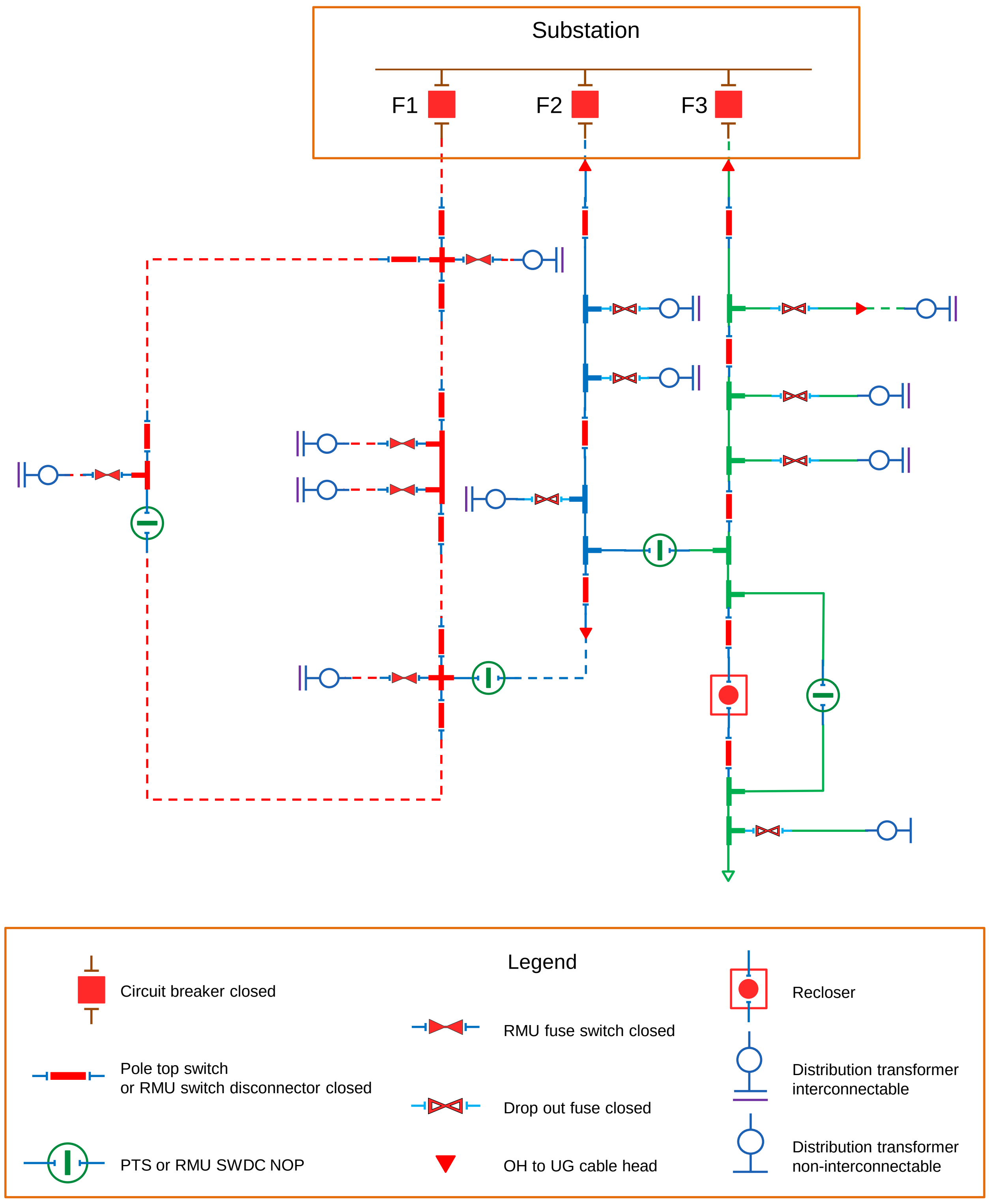

Figure 2-12 Typical distribution feeders

2.3.7 Component Responsibility

Responsibilities for the components of the Horizon Power microgrid and Pilbara Grid systems are shown below. Horizon Power Control Centre (HPCC) located in the Perth suburb of Bentley is the control authority.

Component	Responsibility	Activity
Pilbara Grid power stations under HP control	HPCC	Generation dispatch
Transmission Lines	HPCC Switching Operator	Operate plant and coordinate outages Control operations on transmission circuits Perform field switching
Terminal Stations	HPCC Switching Operator	Coordinate terminal station circuit operations and perform remote switching Perform field switching
Zone and Microgrid Substations	HPCC Switching Operator	Coordinate zone substation circuit operations and perform remote switching Perform field switching
Distribution Lines	HPCC Switching Operator	Coordinate daily operations and perform remote switching Perform field switching
LV Circuits	Switching Operator	Perform all operations
Microgrid power stations	HP Generation Asset Manager or Private IPP	Coordinate and perform daily operations

Table 2-1 Responsibility for components of Horizon Power microgrid and Pilbara Grid systems

2.4 Connection of Components

The extent of the connection of components determines whether the system is interconnected or non-interconnected.

Recall that the Horizon Power microgrids (non-interconnected systems) consist of one or more local generating sources which feed straight into a distribution network.

Recall also that the Horizon Power Pilbara Grid (an interconnected system) consists of all the components already presented. These components connect many generating sources to customers through various levels of transmission and distribution.

The relative advantages and disadvantages of the microgrid and Pilbara Grid systems are shown in Table 2-2. The most appropriate system is set up according to the particular conditions of the location. However, wherever possible, an interconnected type of system is preferred.

Microgrid systems	
Advantages	**Disadvantages**
Less capital outlay	Low efficiency of generating plant
Fewer transmission line losses	Low system security
Less equipment and maintenance	Requires specialist spares for plant
	Poor fault performance
Pilbara Grid	
Advantages	**Disadvantages**
High system security	Large potential losses (line and distribution)
Large efficient generating plant	Very complex to operate
Relatively minimum plant and spares	
Centralised control of a single system	

Table 2-2 System advantages and disadvantages

2.5 Switching Responsibility

(Microgrid and Pilbara Grid)

Horizon Power Control Centre (HPCC) is the operating authority for Horizon Power's networks. HPCC has a Supervisory Control and Data Acquisition (SCADA) system which monitors switchyard apparatus and enables remote switching of specific apparatus in the networks.

After successful training and assessment, personnel are authorised with level-specific switching authorities which allow operators to undertake switching duties in a particular part of the network.

These switching operators are based in the regional depots. Switching operators are required to write switching programs and undertake manual switching to provide safe access for the maintenance, construction and testing as required on the network.

SECTION THREE

LV Distribution System

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3. LV Distribution System

3.1 Introduction

This section is designed for the switching operator to refer to before and during switching. It aims to promote safe switching practice and ensure continuity of supply within the LV distribution system.

The low voltage distribution system extends from the distribution system transformer to the customer's point of supply (see Figure 3-1). It is the point where the majority of customers receive their supply.

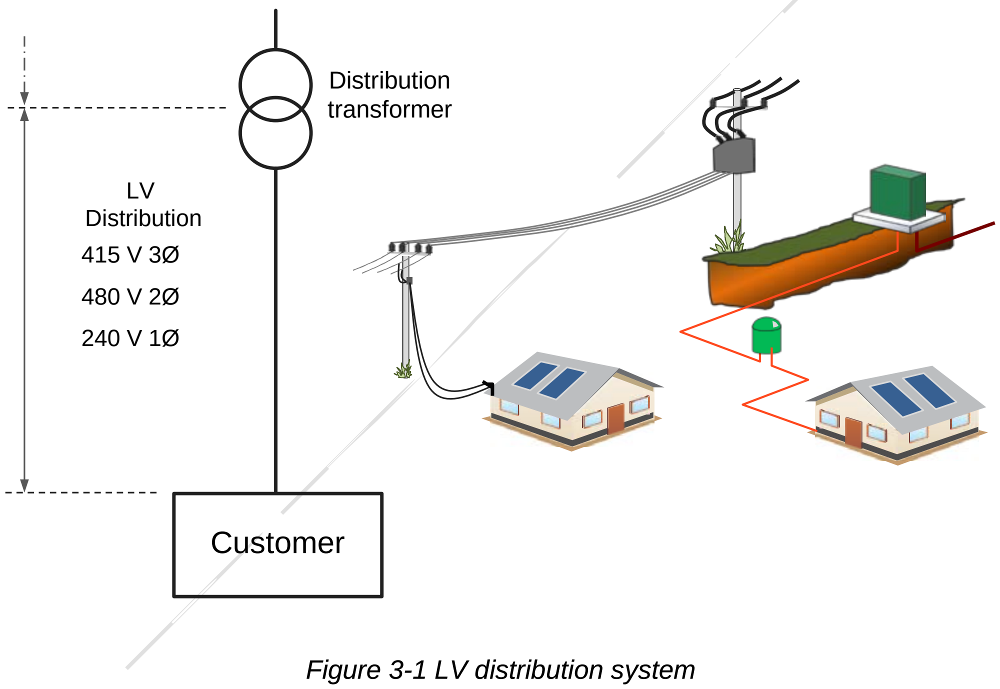


Figure 3-1 LV distribution system

Horizon Power is required to maintain its supply within 6% (either side) of the nominated voltage (240V phase to neutral, 415V phase to phase). Where the power quality tests verify it is found to be outside these limits, modification to the network is required.

	Nominal Voltage (V)	Lower limit (V)	Upper limit (V)
Single-phase	240	226	254
Three-phase	415	390	440

Table 3-1 Voltage ranges at customer level meter position

In accordance with AS 61000.3.100 – 2011, Horizon Power expects to adopt the new voltage standard 230 V +6%, -10% for single phase and 400 V +6%, -10% for three-phase supplies. At the time of adaption, a further publication and review will be issued.

3.2 Components of LV Distribution System

This section describes each component of the LV Distribution System and the switching operations required. Further information can be found in Horizon Power's *Distribution Design Rules.*

The major components include transformers, aerial conductors, disconnectors (isolators), fuses, underground cables, pillars and LV switchboards.

3.2.1 Distribution Transformers

Distribution transformers are used to transform power from the HV distribution system to the LV distribution system.

Those used by Horizon Power are either pole mounted or ground mounted, depending on size.

Pole Mounted Transformers

Pole mounted transformers in the network range from single-phase 10kVA to three-phase 315kVA. Single-phase pole mounted transformers normally feed rural installations or small loads. Figure 3-2 shows a typical single line diagram of a transformer and its circuit.

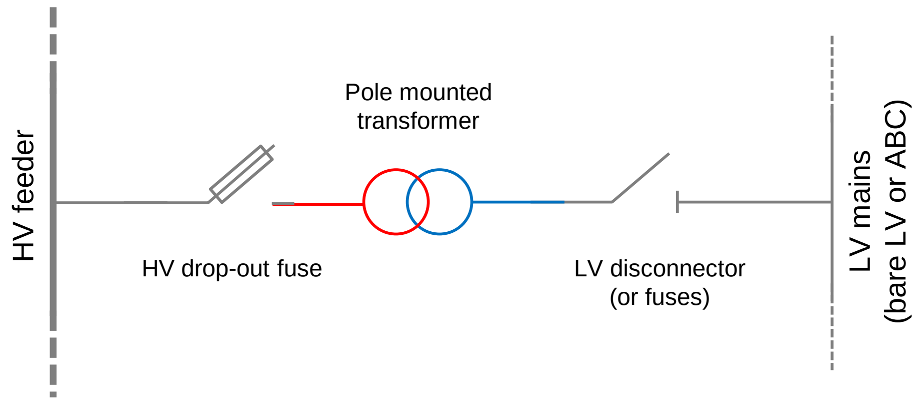


Figure 3-2 Circuit of pole mounted transformers

For safety reasons, the distance between a three-phase transformer and the drop-out fuse is normally as short as possible.

Ground Mounted Transformers

Ground mounted transformers may be padmount, compound, or indoor distribution substations. They may be fed from drop-out fuses (DOFs) or a ring main unit (RMU) (see Figure 3-3). Drawings of each type of distribution substation are available in Horizon Power's *Distribution Construction Manual*.

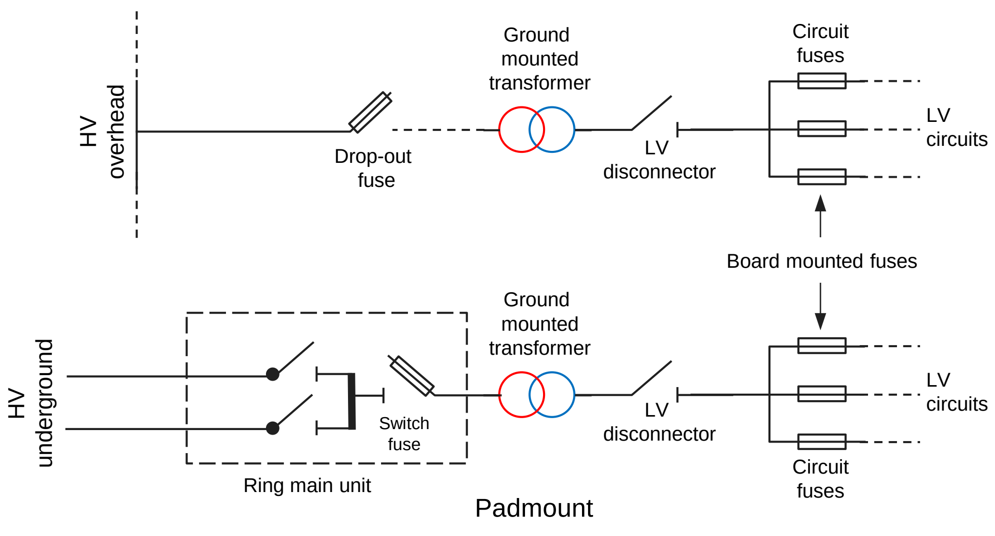


Figure 3-3 Typical schematic circuit of ground mounted transformers

Standard transformer ratings used by Horizon Power for underground distribution schemes are:

- 63kVA
- 160 kVA
- 315 kVA
- 630 kVA
- 1000 kVA.

Note: Other transformer sizes exist as a legacy of earlier design standards.

Purpose

Three-phase LV distribution transformers are normally wired HV delta/LV star. They provide three-phase and a neutral to the LV supply.

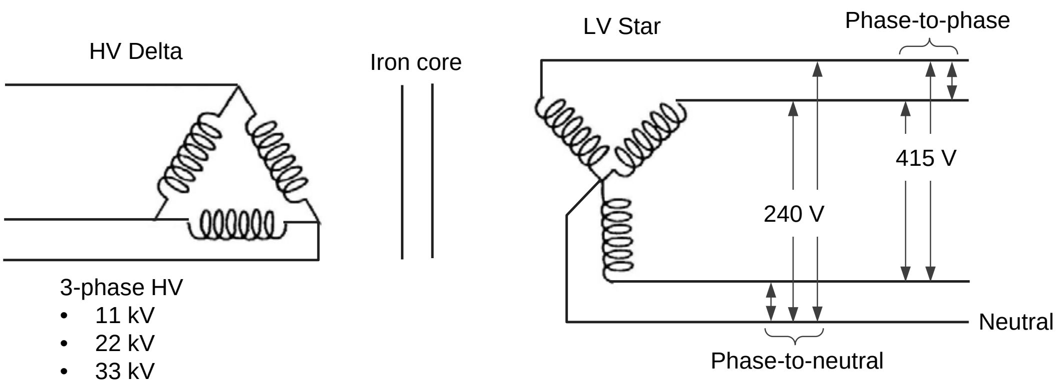


Figure 3-4 Distribution transformer

The rural system is an exception, for the high voltage supplying the transformer may be single-phase. Rural transformers supply single-phase (240V) or split-phase (480V). See Figure 3-5.

Each transformer has a tap changer to provide a constant LV voltage with variable HV levels. Table 3-2 shows the five-stage variation with 2.5% steps for a 22kV/415V transformer.

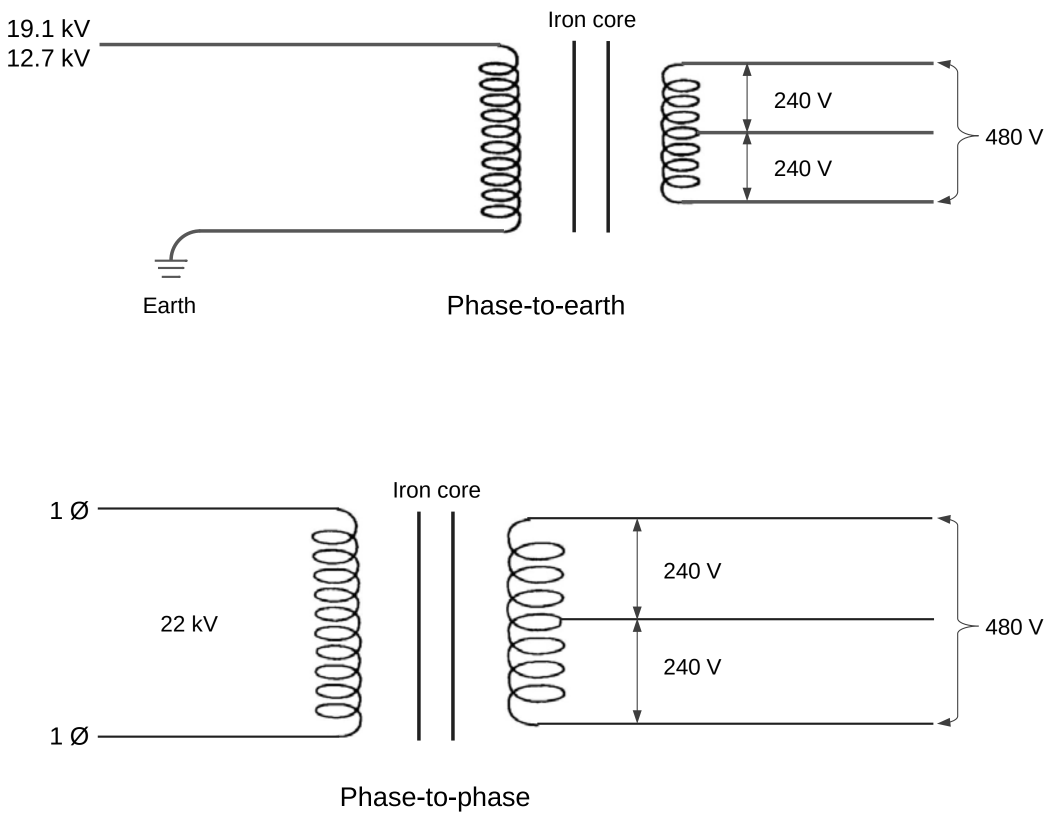


Figure 3-5 Single-phase transformer circuits

Tap	HV Nameplate Voltage (volts)	Percentage (%)	LV Voltage (Φ to N)
1	23 100	-5	415/240
2	22 550	-2.5	415/240
3	22 000		415/240
4	21 450	+2.5	415/240
5	20 900	+5	415/240
2.5% = 550 volts on HV side			

Table 3-2 Transformer five stage variation on input voltage

Switching operators should find out what localised tap requirements are necessary to obtain the correct voltages for all types of transformers in each locality.

Operations and Checks – Fault/Short Circuit Current

When a fault occurs on the LV distribution system, the current flowing from the transformer into the fault will be very large. The higher the rating of the transformer, the larger the fault current or short circuit current.

Note: The fault/short circuit current for:

- a 1000kVA transformer is 21 000 amps
- two 500kVA transformers run in parallel exceeds 31 000 amps on the 415V side.

This highlights the need to keep interconnected transformers to a minimum.

Distribution Transformer Tap Setting

The tap changer is a no-load tap changer, requiring the de-energisation of the transformer before the tap is changed. See Table 3-2 for tap settings. The tap selector handle is required to be locked or otherwise secured after a required tap is selected.

Pole Mounted.

To change taps on a pole mounted transformer, the transformer must be isolated, earthed and an Electrical Access Permit (EAP) issued. If a safe approach distance (SAD) to overhead supply conductors cannot still be maintained whilst a tap change is undertaken, then the isolation boundary must be increased to include the overhead conductors in question.

Ground Mounted.

To change taps on a ground mounted transformer, the transformer must be de-energised following an approved switching program with all relevant isolation points locked / barriers fitted and tagged with a Do Not Operate Tag. An EAP is not necessary as tapping is considered an operating activity under such a condition.

Ratings

The switching operator must understand the transformer capacities used in the switching program. Check the ratings and loads that are required when planning interconnection for feeding up of the load.

For example, a 200kVA transformer (22kV/415V) draws 5.2 amps/phase on the HV side and 278 amps/phase on the LV side at full load.

Transformers operate within a range that is influenced by temperature and the type of load being supplied. Both a cyclic rating and a nameplate rating are allocated to each transformer.

Cyclic rating is higher than nameplate rating because the transformer takes approximately 4 hours to heat to maximum temperature. The transformer may be run higher than its nameplate rating for the 2 to 4 hour period of daily peaks. During this time, the oil will not rise to a temperature where insulation breakdown could occur, or the flashpoint of the oil is reached. Figure 3-6 shows there are two peak loads for each 24-hour period.

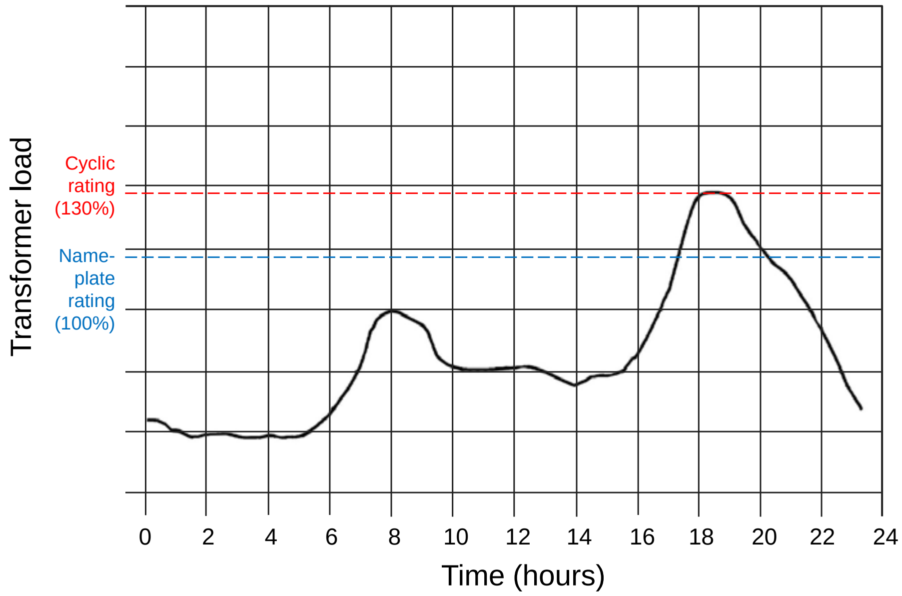


Figure 3-6 Typical peak loads for 24-hour period

Note: These peak load times may vary depending on weather conditions and location.

3.2.2 Aerial Conductors

Aerial conductors making up overhead distribution vary in size and type (copper, aluminium, aluminium alloy).

Horizon Power typically uses the following conductors for open aerial mains:

- 7/2.50 AAAC (street lighting, three-phase HV radial, running earths)
- 7/4.75 AAAC (HV and LV in rural towns, rural three-phase HV rings)
- 19/3.25 AAAC (LV mains from ground mount substations, heavy HV feeders).

There is also a legacy of other conductors size and types in use.

For details of overhead bare LV conductors see the *Distribution Design Rules*.

Aerial bundled cable (ABC) has been introduced to replace bare conductors on the LV distribution network. There are only two sizes:

- 95 mm^2
- 150 mm^2 (used predominantly).

For details of ABC conductors and accessories, see the *Distribution Design Rules*.

Each type of conductor has a summer and winter rating. The switching operator must know these capacities to note the rating for the switching process. The rating changes because of a higher average temperature during summer. This reduces the current carrying capacity of the conductors.

More than one type and size of conductor is commonly fed from one transformer. When interconnecting two or more transformers, there may be even more sizes and types involved.

Configuration

Bare LV overhead distribution is connected in a mesh configuration where possible (see Figure 3-7). This reduces volt drop problems in the circuit.

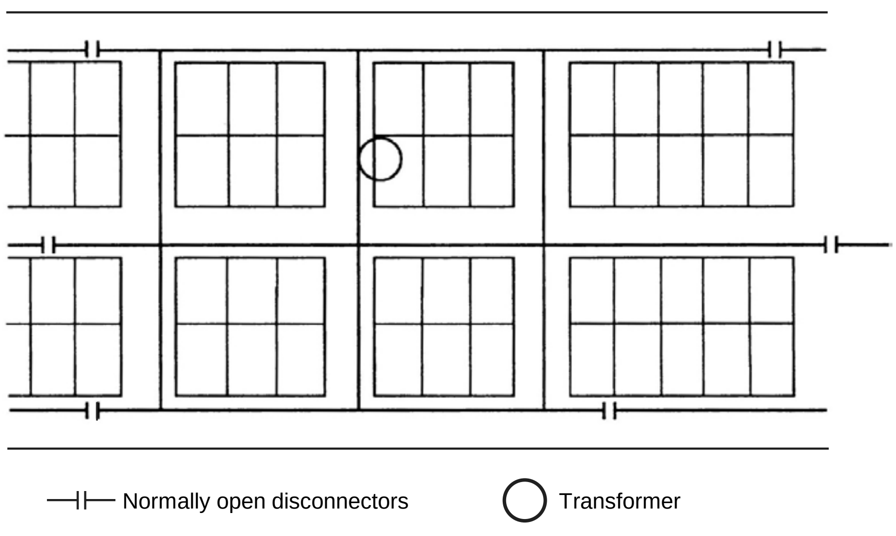


Figure 3-7 LV overhead distribution connected in mesh

Volt drop depends on the conductor size, the load current and the length of conductor. Connecting the circuit in mesh has historically been the most efficient way of ensuring maximum voltage at every point of the supply.

Note: LV aerial bundled cable circuits are not connected in mesh, but as radial feeds.

3.2.3 LV Disconnectors and Fuses

Types of LV disconnectors and fuses used by Horizon Power are:

- underslung pole mounted disconnectors
- pole mounted Krone units, and
- distribution board mounted disconnectors or fuses.

Underslung Pole Mounted Disconnectors

These disconnectors are rated at either 400 or 600 amps operating current (see Figure 3-8).

They may be used to make or break this load. Commonly, these disconnectors:

- isolate a distribution transformer
- allow an open point between two distribution transformers. (Open points enable interconnection of distribution transformers during switching or whenever required.)

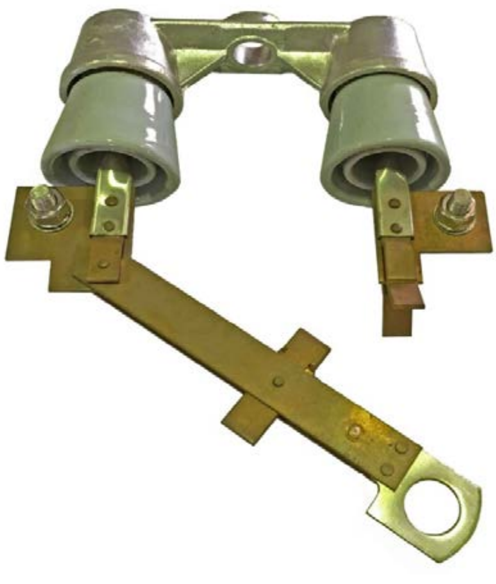


Figure 3-8 LV underslung pole mounted disconnector

LV disconnectors are mounted under the crossarm and may be operated from below. An insulated HV operating stick is used to pull the blade out, making the operation reasonably fast and uncomplicated.

Figure 3-9 Pfisterer (l) and Krone (r) ganged fuse units

Three-phase switched disconnectors (or fuses) are used as transformer isolation points or LV interconnection points. Krone units are currently used, however there is a legacy of Pfisterer units being still in service.

!	**Although rated to carry a 400 or 600 amps continuous load, the switching operator should avoid operating them at full load current because of arcing and contact damage.**

Distribution Board Disconnectors

Distribution board disconnectors may be used in universal pillars, LV kiosks, and padmount and compound distribution substations. Distribution board disconnectors are normally interchangeable with fuses (see Figure 3-10).

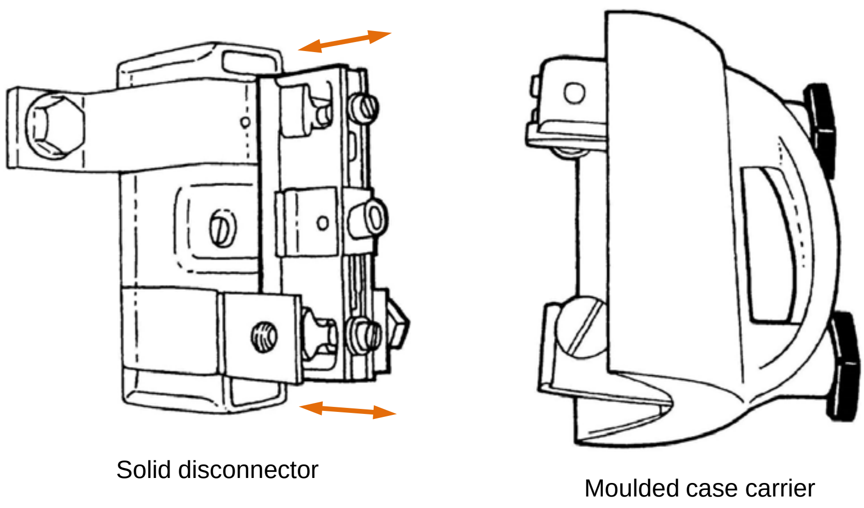


Figure 3-10 Distribution board disconnector

A moulded case carrier may be used as a disconnector or fuse disconnector. The solid disconnector above requires a special link screwdriver to fit and remove the disconnector.

Distribution Board Fuses

The HRC (high rupturing capacity) fuses are used to protect LV cable circuits. The fuses fit into a range of carriers including mounted case carriers (see Figure 3-10) and ABB SLBM carriers (see Figure 3-16). Table 3-3 lists the advantages of HRC fuses.

Advantages of HRC fuses
Operation of fuse does not emit flame
Consistent performance
Does not deteriorate
Operates silently
Has a tamper-proof fuse element
Cuts off power before current reaches maximum fault level
Does not deteriorate

Table 3-3 Advantages of HRC fuses

The HRC fuses (see Figure 3-11) used in Horizon Power's LV distribution system include meter board, pole and LV distribution board fuses.

The HRC fuses shown below are two of the types of fuses used by Horizon Power. All fuses have one or more parallel silver fuse elements, each with multiple narrow sections. When fault current exists, the fuse element narrow sections will melt and arc simultaneously, ensuring the arc is rapidly extinguished. High current rating fuses use multiple silver elements in parallel.

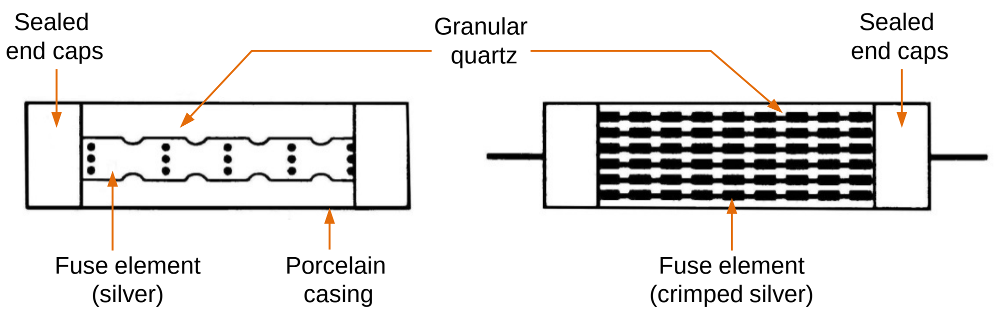


Figure 3-11 Two types of HRC fuse

Function

HRC fuses are more effective than rewirable fuses because they limit fault current or overcurrent to less than a dangerous level.

Figure 3-12 shows the point at which the HRC fuse interrupts power during the first quarter of the phase cycle.

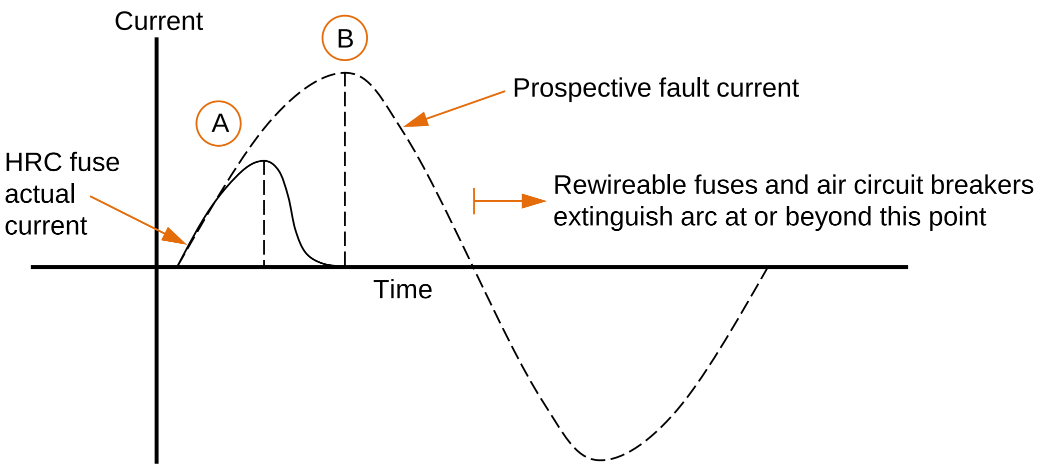


Figure 3-12 Current limiting HRC fuse

In Figure 3-12, point B is the peak fault current. This may be thousands of amps causing excessive damage to equipment. Point A shows the point where the HRC fuse has blown. In this case, the fault current is interrupted in less than 5 milliseconds (ms), that is, 0.005 seconds.

Note: The HRC fuse is designed to give a specific characteristic under fault conditions. If the fuse is tampered with, it will not operate correctly.

Rating

The amperage rating is marked on the end cap of HRC fuses and is easily seen when replacing the cartridge.

Make sure that the replacement fuse is appropriately rated.

Horizon Power fuses in the LV supply range in size from 32 to 400 amps. (See Figure 3-13).

Figure 3-13 shows how the fuses are used to protect the underground LV distribution system. A fuse is also installed on the consumer switchboard.

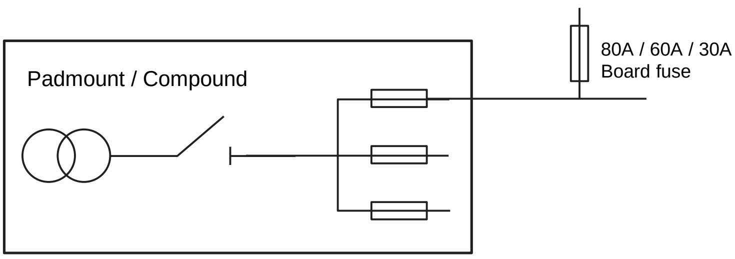


Figure 3-13 HRC fuse system (underground system)

Transformer LV Distribution Board Unit

There are various types of board mounted disconnectors and fuses. The disconnectors are used for isolation or interconnection and fuses are used for isolation.

Opening and closing at full load should be avoided if possible.

Board mounted disconnectors and fuses are either mounted on a three-phase carrier (see Figure 3-14) or individually mounted on a rack (see Figure 3-15). Both types are manually operated. This makes the operation potentially hazardous because:

- the close proximity of a switching operator to the disconnector may result in injury if a fault occurs on the distribution board, and
- installation and removal are sometimes difficult, causing arcing and chattering.

When installing board mounted disconnectors, the bottom connection should be made first. The top connection should then be made using a rocking action.

Figure 3-14 Distribution board mounted disconnectors (extractable)

Figure 3-15 Distribution board mounted disconnectors (hinged)

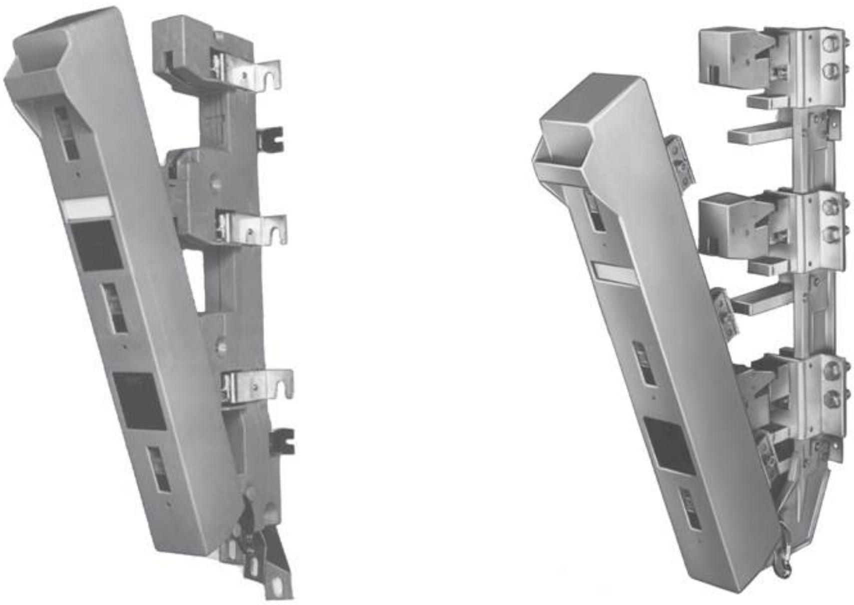


Figure 3-16 ABB SLBM 400 fuse and BSL 1600 disconnector

Distribution board disconnectors of the type shown in Figure 3-16 consist of a removable cover with three-phase fuses/disconnectors mounted inside the cover.

To operate the disconnector, the switching operator grasps the handle at the top and pulls briskly outward to open. To close, the operator engages the bottom pivots, then moves the cover toward the closed position, and while holding a safe distance away, checks alignment and then briskly closes by pushing forward.

When used as an isolation point, the fuses/disconnectors inside the cover must be removed and the cover replaced and Danger–Do Not Operate (D–DNO) tagged. An alternative is to fit a D–DNO tagged replacement cover with the fuses/disconnectors removed.

Where large capacity transformers are installed, a circuit breaker (see Figure 3-15) or moulded air break switches can be installed between the transformer and the LV board. This replaces the transformer disconnectors which are used on smaller capacity transformers.

PENDA – Public Electricity Network Distribution Assemblies.

A new type of low voltage distribution board is available to Horizon Power as a result of ABB switch gear becoming obsolete as from 2020.

The new gear using the Weber South Pacific type is frame mounted LV distribution switchgear. Standard components, such as fuse switch strips, isolators, circuit breakers and load break switches, are assembled together to make switchgear configurations.

Vertical fuse switches and isolators are a core product of Weber South Pacific switchgear design. They are ideally suited to power distribution in electricity networks because of the efficient shape of the switch and busbar mounting.

Figure 3-17: Single Switch-Fuse / Isolator

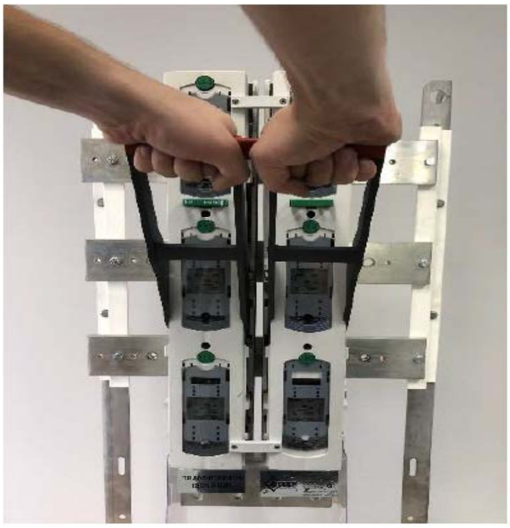


Figure 3-18: Double Switch-Fuse / Isolator

Figure 3-19: Testing busbar and cable side.

Applications

- Indoor installation (fire rated substation room) – PENDA I
- Outdoor installation (non-fire rated substation) – PENDA O

Figure 3-20: Type 1.1 Kiosk rated at 630A/415V

Figure 3-21: Type 2 Kiosk rated at 1400A/415V

Figure 3-22: Type 3.1 Kiosk rated at 2800A/415V

Improved features of PENDA switchgear compared to the ABB type used previously, include but not limited to:

- Improved Operator and Public Safety
- ARC Fault protection
- Larger busbars
- Improved ventilation and as a result higher current rating than old switchgear
- Operation earthing / shorting point
- Larger doors for easier access to cable terminations
- Fuse and circuit test points
- Visible and lockable open points

3.2.4 Underground Cables

There are several types and sizes of cables that are used in the underground system. Initially, lead or lead alloy sheathed underground cables were used. Now, all new underground cable is XLPE (cross-linked polyethylene) insulated.

Copper of various sizes in stranded formation and aluminium in stranded or solid-form are used. All underground cables in the Horizon Power network include either a nylon termite protection layer or Termitex® termite repellent impregnated into outer LDPE (low density) or HDPE (high density) sheaths.

A typical example of an XLPE cable is shown in Figure 3-17 below. The application of underground cables is shown in Table 3-4.

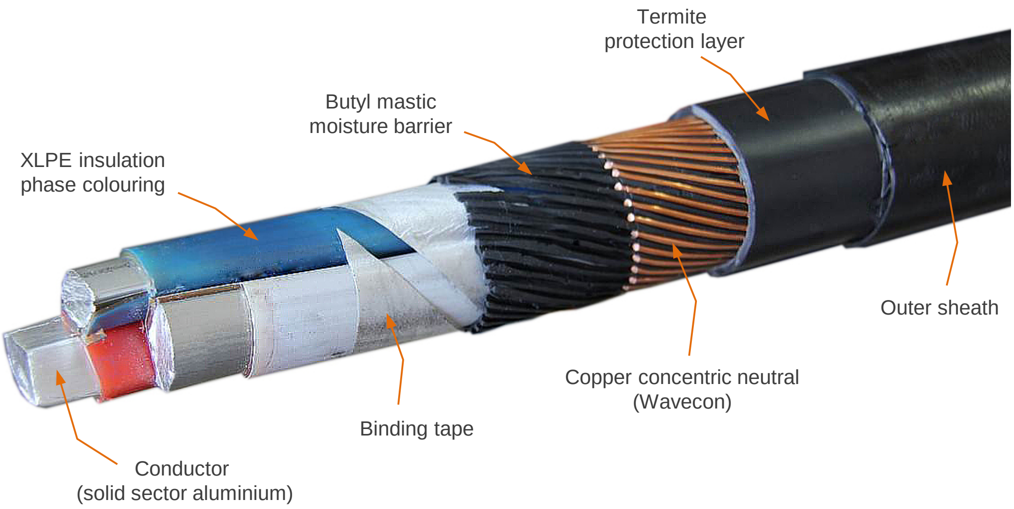


Figure 3-23 Three core LV XLPE Cable (Wavecon)

Use	Size	Phase	Type
Street lights	16 mm^2	single	copper
Customer service	25 mm^2	three	copper
LV distribution	240 mm^2	three	aluminium
LV substation	630 mm^2	single	aluminium

Table 3-4 Commonly-used LV underground cables

Details and sizes of all Horizon Power underground cables can be found in the Horizon Power *Distribution Design Rules.*

Apart from the physical location, underground cables differ from the overhead system because:

- larger conductor sizes are used
- underground cables are not connected in mesh.

Larger cables are used for a number of reasons:

- feeding larger more concentrated loads
- they ensure efficient feeding up of other areas
- they maintain a standard sizing to rationalise sizes
- cables are more difficult to upgrade, in comparison with overhead conductors
- there is less heat dissipation.

Underground LV circuits are connected radially with interconnection points within the network to afford transfer of loads to alternative sources (see Figure 3-18).

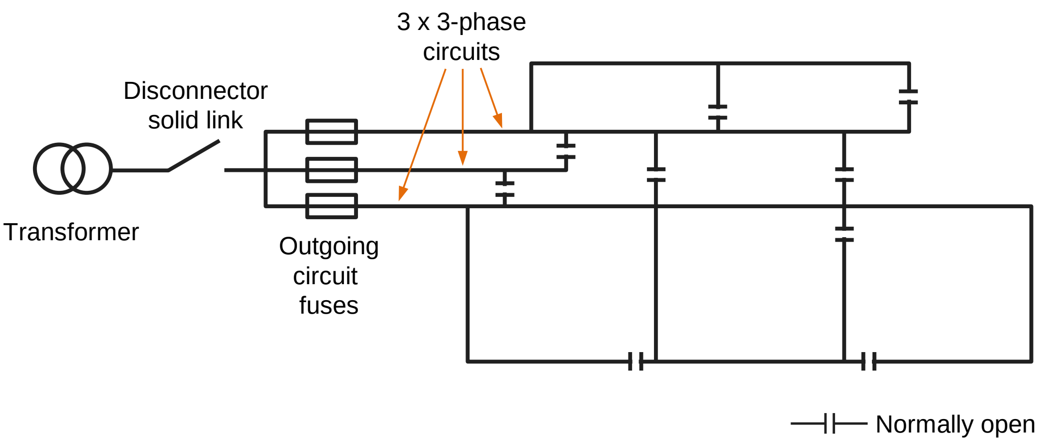


Figure 3-24 LV underground radial connections

3.2.5 Pillars

There are three common types of pillar:

- mini
- universal
- feeder (mounted on a wall or footpath), flushmount pit, 100A or 200 A wall box .

Mini Pillars

These are usually located inside a customer's property. The pillar becomes the connection point for the property's consumer main. It may also service the property next door. They also supply street light circuits and unmetered supply pillars and pits.

Figure 3-19 shows a mini pillar. Customer service connections are unfused, while street light and unmetered supplies are fused in the pillar.

Isolation of street light circuits and unmetered supplies requires load-side tail to be removed from the fuse holder. This practice is required because the holder can become conductive because of water condensation in the pillar.

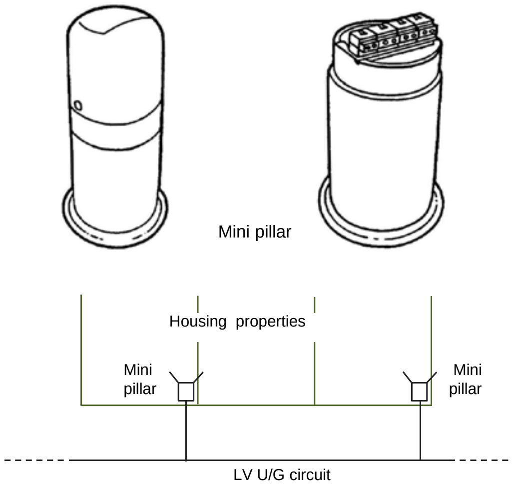


Figure 3-25 Mini pillar

Universal Pillars

These are used in the LV circuit as open points and/or switching points, and to supply customers with larger load requirements of up to 315A, e.g. commercial or industrial lots.

Figure 3-20 shows that the universal pillar normally has no fuses, only removable disconnectors. These disconnectors can be removed or installed, as required for interconnection, load distribution or isolation

Sometimes, universal pillars are used for connection points for only one large customer. As fuses may be installed, fuse grading must be observed.

The maximum load at which a universal pillar can run is 400 amps. The load depends on the cable sizes being used.

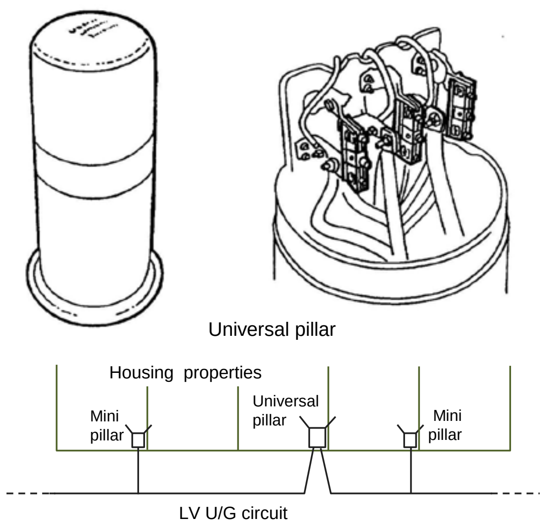


Figure 3-26 Universal pillar

For large demand LV customers a universal pillar with fuses is used to connect the customer rather than a mini-pillar.

Figure 3-21 shows the rear view of the universal pillar, the customer service connection blocks and a HRC fuse for a street light or unmetered supply.

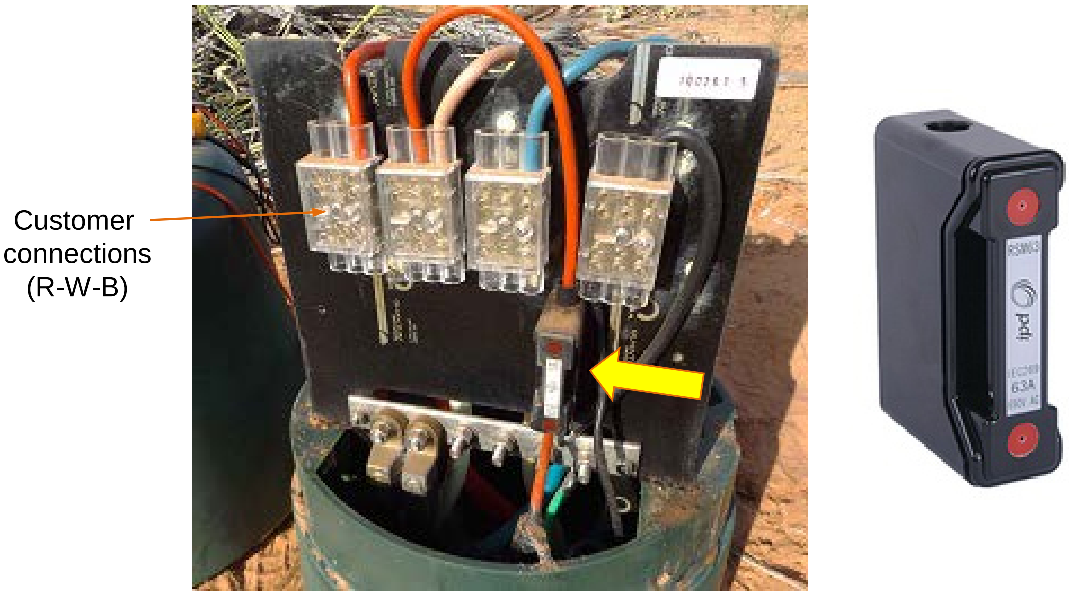


Figure 3-27 Universal pillar rear view

Feeder Pillars (LV Distribution Board)

Feeder pillars are used in high-density underground areas and are generally located on the cable alignment or in a distribution substation compound. They allow isolation of underground cables, interconnection and load distribution.

Their mounted disconnectors are similar to distribution board connection units (see Figure 3-22). However, the circuit from the pillar servicing the customer may be fused and there is no transformer directly connected to the busbar.

Feeder pillars (or LV kiosks) provide Horizon Power with a convenient place to marshal its underground LV circuits and provide switching flexibility. They can also be used to provide a customer's point of supply.

The only operation on feeder pillars is the removal and installation of disconnectors or fuses for switching (interconnection, isolation and load distribution).

Figure 3-28 Feeder pillar

3.3 Design

LV distribution consists of two systems; underground and overhead. Each system is different in design but both serve the same purpose.

Frequently the overhead and underground systems complement each other by being used together in an area. This usually occurs when an underground system is replacing an older overhead system or where a new underground distribution system (UDS) is connected to the existing overhead system.

Both the underground and overhead systems are described in the following sections.

3.3.1 Underground

The underground system consists of high voltage feeders which supply ground mount transformers required to step the voltage down to LV (415V). The transformer LV then supplies the underground LV cable circuits running down each street to connect the houses via their service connections. Each transformer will have multiple separately-fused LV circuits.

An example of an underground LV distribution system is shown below in Figure 3-23.

1 Coolajacka Transformer 1
2 Coolajacka Transformer 1 LV circuits (orange)
3 Coolajacka Transformer 2
4 Coolajacka Transformer 2 LV circuits (green)
5 Coorbeeli Transformer
6 Coorbeeli Transformer LV circuits (red)
7 LV Normally open point (NOP) between Coolajacka Transformer 1 and Coorbeeli Transformer circuits
8 LV Normally open point (NOP) between Coolajacka Transformer 2 and Coorbeeli Transformer circuits
9 LV Normally open point (NOP) between Coolajacka Transformer 2 and Coorbeeli Transformer circuits

Figure 3-29 Underground LV distribution system

LV underground circuits are not run in mesh configuration, as is sometimes used in the overhead system. The normally open points (NOPs) are installed between different LV circuits to allow flexibility for interconnection, which can be used to maintain supply during transformer outages. These NOPs can be established on the universal pillars or LV boards.

Low voltage circuits are not normally run in parallel, however there are occasions when interconnection may be required. If these circuits are left permanently interconnected, the problems that may occur are:

- one fault on either circuit may blow both fuses and totally cut power
- a minor fault on the cable may result in neither set of fuses blowing but cause overload on each circuit.

Fuse protection of cables is most important. If a cable is overloaded, it is much harder to repair than in an overhead system. Therefore, cables are fused at their source to prevent damage.

Different size ratings can be used according to the size of the cable required:

- 400 amp fuses are normally used for 240 mm^2 XLPE cables
- 315 amp fuses are normally used for 185 mm^2 XLPE cables.

Note: Because of the grading problems between 400 amp LV HRC fuses and some HV HRC fuses, sometimes it is necessary to reduce the rating of the LV fuse, usually to 315 amp.

To prevent grading problems, no additional fuses are usually installed along the cable feed. Instead, disconnector links are used for all additional connection or interconnection. This is an advantage if a customer loses supply, because there is only one location to be checked for blown LV fuses. However, this also means all customers connected to the cable will lose supply and depending on the fault current the fuses at the source may not blow.

The main advantages of underground systems are:

- reduced volt drop problems
- no street poles or wiring, which is aesthetically pleasing
- fewer outages due to plant failure, and
- less maintenance, because the apparatus is not exposed to weather.

3.3.2 Overhead

The overhead system consists of high voltage feeders which supply transformers required to step the voltage down to LV (415V). The transformer LV then supplies the overhead LV circuits (LV mains) running down each street to connect the houses via their service connections.

An example of an overhead LV distribution system is shown in Figure 3-24 below.

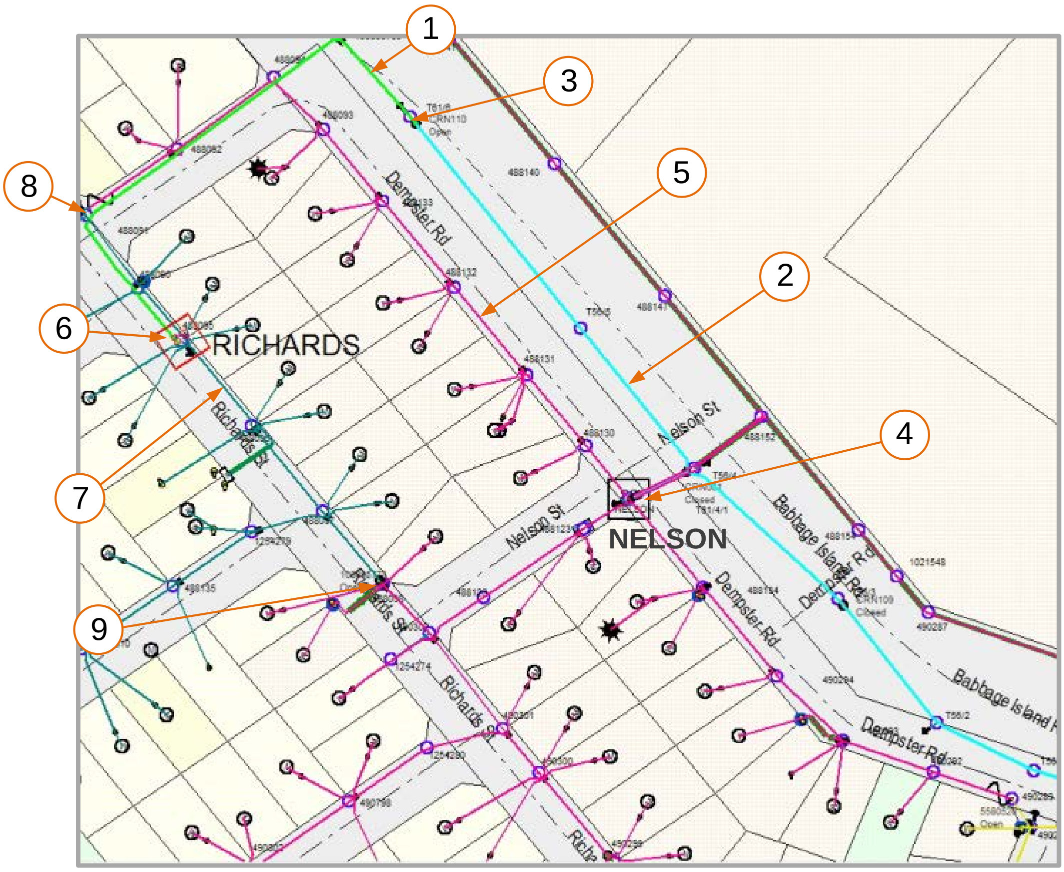
The NOPs between LV different circuits are installed to allow flexibility for interconnection, which can be used to maintain supply during transformer outages.

Common variations on the LV system include:

- large ground mounted transformers feeding overhead LV circuits. These transformers have LV fused circuits protecting the cable and overhead LV circuit

- mesh LV mains are sometimes connected in mesh to reduce voltage drop.

The overhead system has the advantage of being visible for inspection and quickly accessible for maintenance and repair.



1 HV feeder 1 (light green)
2 HV Feeder 2 (turquoise)
3 Normally open point (NOP) between Feeder 1 and Feeder 2
4 Nelson Transformer
5 Nelson Transformer LV circuit (magenta)
6 Richards Transformer
7 Richards Transformer LV circuit (dark green)
8 LV Normally open point (NOP) between Nelson and Richards transformers
9 LV Normally open point (NOP) between Nelson and Richards transformers

Figure 3-30 Overhead LV distribution system

3.4 Switching Procedures

An approved LV switching program is required to undertake LV switching.

The main switching functions in the LV distribution system are:

- interconnection
- isolation
- fault location.

It is recommended practice when switching on the LV distribution system for a competent safety observer to be in attendance.

3.4.1 Interconnection

When a transformer is taken out of service for replacement or maintenance, the LV area (normally fed by that transformer) may be fed from another source.

When connecting extra transformers to feed up an area, the switching operator should remember the following.

Before Interconnection

1. Check the load on both the transformer to be taken out and the transformers being used to feed up. (This helps the operator to decide whether there is enough capacity available to feed up from the other sources.)

Note: When two transformers are interconnected, they tend to share the load between them. If transformers of different sizes are interconnected for a long time, the load should be checked at each transformer. This will show if either transformer is overloaded.

---

2. Check for small conductor size and long route length. These may cause volt drop or overload problems. Where possible, use the largest conductors available and the shortest possible route length.

3. Plan to interconnect the minimum number of transformers. The more transformers the switching operator interconnects, the greater will be the fault current if there is a fault in the interconnected area. Each connected transformer will share the fault current. The drop-out fuses protecting these transformers may not blow, as they may not 'see' the full overload current. This creates a potential hazard to personnel and may damage plant in the fault area.

4. The switching operator should check to see if they are parallelling two substation feeders together via the LV circuits. (If one of the feeders trips off completely, the other feeder will try to pick up all that feeder's load through the interconnected LV system. This will cause major damage to transformers and conductors.)

   If a feeder is tripped momentarily and restored by auto reclose, the transformers feeding up the interconnected area may blow a drop-out fuse.

   Interconnecting two feeders through the LV network should be avoided, it is often possible to reconfigure the HV feeders by switching to place all interconnected transformers are all on one feeder. If this is not possible, LV interconnection can be made using LV fused jumpers or fuses.

5. The switching operator should check circuit labels before operating underground interconnected apparatus. Additional checks should be made before installation, including general cleanliness of the units, corrosion or condensation on the links or fuses (causing bad contacts), and continuity of fuses.

After Interconnection

6. The switching operator should check whether they are within the statutory voltage limits at all points of supply. Do not forget to check the voltage at the furthest point from the transformer! (See Table 3-1).

Restoration

7. Check all closed normally open point disconnectors have been opened. If transformers are left interconnected, load sharing will continue. When a fault occurs, both transformers will share the fault current.

3.4.2 Isolation

When isolating any equipment on the LV distribution system, the isolation points must be prevented from inadvertent closure which can result in re-energisation. This is achieved by using a form of physical barrier or where locking facilities are available they are to be used. A Danger–Do Not Operate tag is also to be fitted.

All isolation points must be off, D–DNO tagged and barriered. All lockable apparatus that can be locked must be locked and D–DNO tagged.

Where necessary, a section of conductor can be removed to create an isolation point and D–DNO tagged.

Actions for consideration when performing isolations include the following points.

- It may be possible to feed up parts of the LV system not directly involved in the isolated area. This will depend on the duration of isolation. (For example, disconnect the PG (parallel groove) clamps at appropriate poles either side of the isolation. This is better than isolating the whole LV circuit from the transformer.)

- For overhead LV disconnectors (see Figure 3-8), extra security must be provided to prevent them from being accidentally closed. The operator must use barriers whenever possible. Figure 3-25 shows the typical types of barriers which can be used to prevent inadvertent re-energisation.

- Where barriers cannot be installed, the disconnector connection tap is to be disconnected.

- For underground cables, use a voltmeter to prove the cable is isolated. The operator should D-DNO tag isolation points. Where it is suspected that there may be an HV cable in the same area, signal injection may be required to prove LV cable identification.

- As a general rule, isolation should begin at the LV level.

- ABC fuse box inserts when used as an isolation point must be removed with a Danger–Do Not Operate tag attached.

- Where work is performed on isolated and shorted LV apparatus an Electrical Access Permit must be issued for the work.

Figure 3-31 Examples of barriers for disconnectors

3.4.3 Fault Location

Due to different construction and components the detection of LV faults differs between overhead and underground systems.

Overhead

Overhead circuits are reasonably short in length and faults are usually easy to find. Most faults can be found by patrolling the circuit.

SECTION FOUR

HV Distribution – Overhead

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4. HV Distribution – Overhead

4.1 Introduction

This section examines components of the overhead HV distribution system, its design principles and switching procedures. It is designed to give the switching operator a working knowledge of HV overhead supply in the Horizon Power distribution system.

This section is written to reflect current standards and may not include many of the legacy installations and apparatus.

The HV overhead distribution system is designed to allow:

- feeding of distribution transformers
- load transfer
- interconnection
- back up in fault situations.

The overhead high voltage distribution system extends from the zone or microgrid substation to the distribution transformers (see Figure 4-1).

Overhead HV circuits are connected radially, most having open points which permit the interconnection of other feeders (see Figure 4-2). However, some feeders cannot be interconnected with any other feeders. This causes a problem when isolating sections of these feeders. If interconnection is not available, the power to the isolated sections is interrupted for the duration of the isolation.

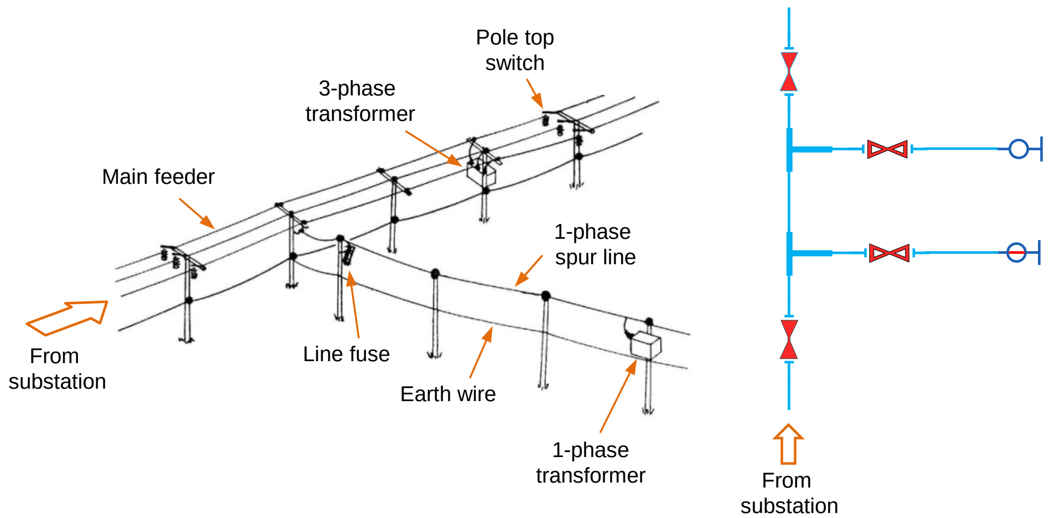


Figure 4-1 HV overhead distribution system

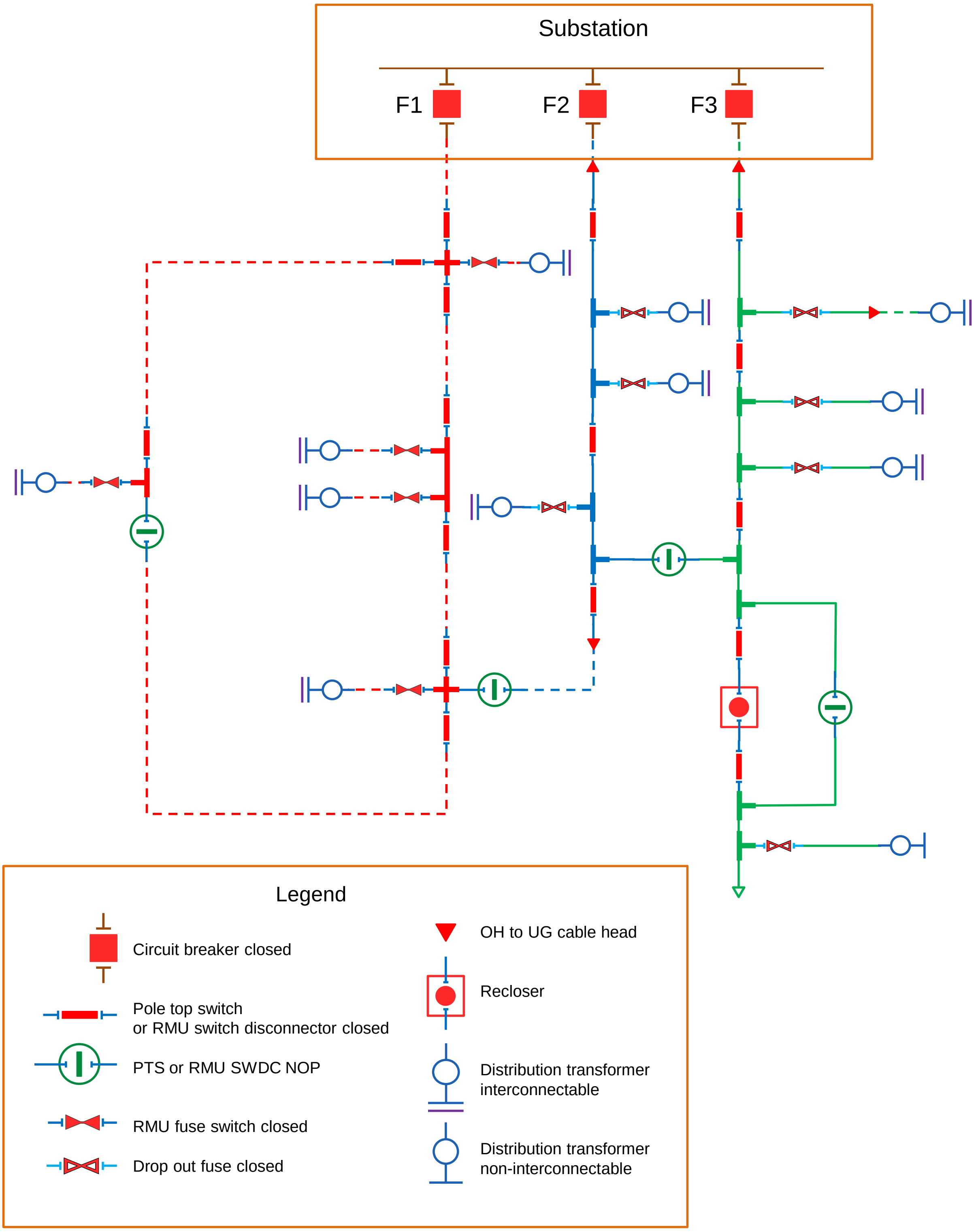


Figure 4-2 Typical microgrid network
showing both overhead and underground HV feeders

4.2 Components

The main components of this system are conductors, fuses, pole top switches, disconnectors, surge diverters, reclosers, regulators, sectionalisors, fault indicators, transformers, distribution line reactors and capacitors.

4.2.1 Conductors

Typical conductor types used are :

- AAAC - All Aluminium Alloy Conductor – sizes include 7/2.50 and 7/4.75

- SC/AC - Steel Conductor Aluminium Clad – size = 3/2.75

Only AAC, AAAC, SC/GZ (for repairs only) and SC/AC are now purchased as standard bare overhead conductors. ACSR/AZ is also used for special applications. However, the following conductor types may also be found in Horizon Power networks:

- ACSR - Aluminium Conductor Steel Reinforced

- AAC - All Aluminium Conductor

- HDBC - Hard Drawn Bare Copper Conductor

- FE/GZ - Galvanised Steel

- Hendrix-configured conductors.

The switching operator should be aware of conductor's current rating, particularly when interconnecting to transfer load.

Further details of conductors may be found in the *Distribution Design Rules*.

4.2.2 Fuses

Horizon Power uses expulsion drop-out fuses (DOF) in overhead HV distribution.

Drop-out Expulsion Fuse

This fuse is designed to operate when current flow exceeds the fuse element rating. Although the expulsion fuse is mainly a protective device, it may be used as an isolation point, by removing the barrels from their frames and tying the barrels to the pole with a Danger–Do Not Operate (D–DNO) tag.

There are two types of drop-out fuses used:

- single vent – this is the most-commonly used type. Single vent DOFs do not permit venting through the top.
- double vent – has a vent cap fitted allowing venting through the top should the barrel be blocked (for example, a mud wasp nest), or the fault current be too high.

Many brands of fuses are available but the design is basically the same.

The single shot drop-out fuse is most common (see Figure 4-3). It is used in the three-phase system to protect distribution transformers (one fuse per phase). It is also used in rural areas to protect the single-phase spurs which feed many transformers.

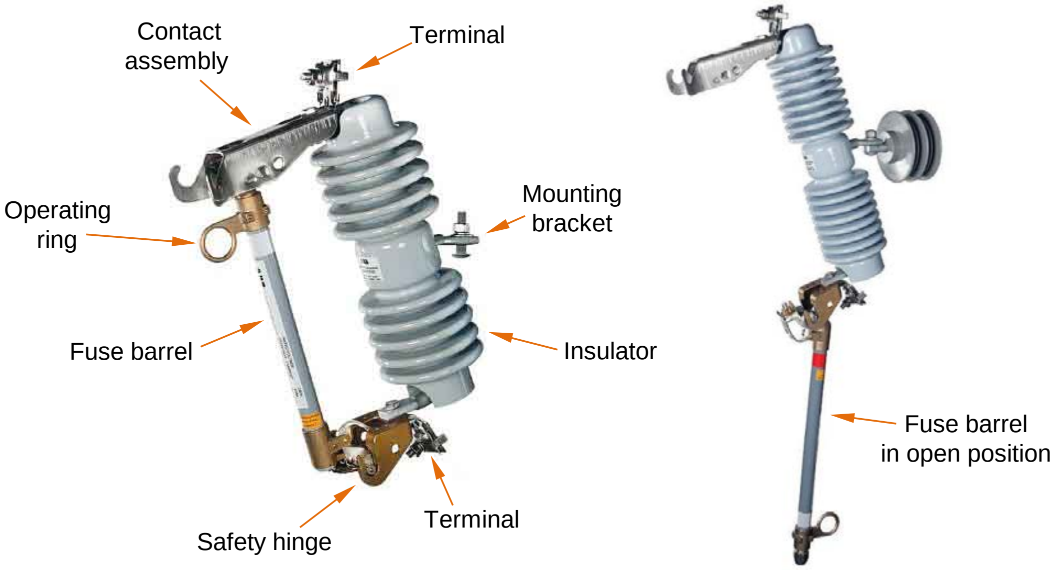


Figure 4-3 Single shot drop-out expulsion fuse

Table 4-1 shows the normal ratings of HV drop-out fuses.

Phase	Fuses				
	kVA	**11kV**	**22kV**	**33kV**	**LV**
Single	5	-	2.0	2.0	30A HRC
	10	-	3.15	3.15	60A HRC
	20/25	-	3.15	3.15	100A HRC
Three	25	3.15	3.15	3.15	80A HRC
	50/63	5.0	3.15	3.15	100A HRC
	100	10.0	5.0	5.0	No LV Fusing
	200	16.0	10.0	8.0	
	160	25.0	10.0	8.0	
	300/315	25.0	16.0	10.0	
	500	40.0	25.0	16.0	
	630	63.0	31.5	25.0	
	750	63.0	31.5	25.0	
	1000	90.0	40.0	31.5	

Table 4-1 HV and LV fuse ratings

There are different types and sizes of fuse element.

The correct fuse element must be used to replace the fuse that has been blown. This ensures appropriate grading is maintained. In emergencies, this may not be possible.

Where an incorrect size is used, the correct size must be fitted as soon as possible.

When replacing a fuse, the barrel must not be slammed with excessive force but closed firmly and sharply. Care must be taken to check that the barrel has made good contact and is seated correctly.

Insulated HV operating sticks are used to replace a fuse barrel into the mechanism. The operator must wear appropriate PPE when operating these devices.

Horizon Power uses sparkless fuse elements to reduce the risk of ground fires. The construction of a sparkless fuse is shown in Figure 4-4. The nylon tubing contains a fuse element of lower melting point than the older types of fuse. A carbon-doped Terylene cord is used to take the strain of the installed fuse.

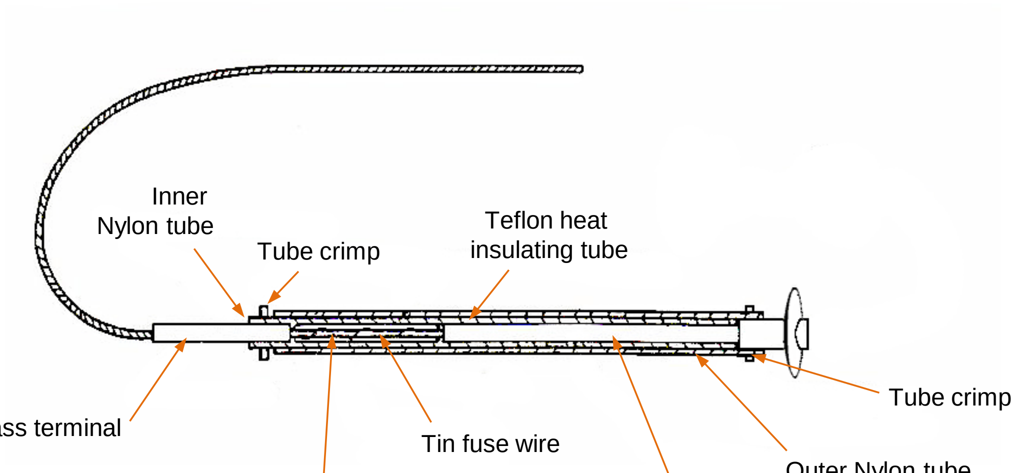


Figure 4-4 Sparkless fuse element

When the fuse element operates, arcing inside the barrel causes the internal barrel lining (typically horne fibre) to produce a gas which vents through the bottom of the barrel. This venting gas blows the arc outside the barrel where it extinguishes.

The fuse barrel then drops to release the top catch and then the barrel drops fully away. This physically separates the circuit, preventing the arc from restriking and providing visual indication the fuse element has blown.

Care must be taken when replacing a fuse element. The switching Operator must check:

- the mechanism is operational
- the fuse element size is correct
- the vent cap is always fitted, and
- the fuse barrel is not obstructed.

The switching operator should use an expulsion fuse wear rod to check the internal diameter of the fuse barrels, as they have a limited life span. The wear rod is used to determine whether the barrel is serviceable. The smaller diameter end of the wear rod must be able to pass freely through the centre of the barrel, indicating there are no obstructions.

If there is insufficient clearance inside the barrel, the fuse element may not clear and the barrel may not drop away, causing extensive damage to the fuse barrel. A flashover may result, shorting out the adjacent phases and tripping the feeder.

The fuse wear rod larger diameter must not be able to enter the barrel, to ensure there is an adequate amount of gas producing material lining (typically horne fibre) the inside of the barrel. This gas producing material is required to extinguish the arc inside the barrel.

The notch on the end of the wear rod is used to check the shrinkage of the gas producing material inner tube. The shrinkage of the gas producing material should not exceed this distance.

The fuse barrel must be replaced if any of these tests cannot be correctly performed. A typical expulsion fuse wear rod is shown in Figure 4-5.

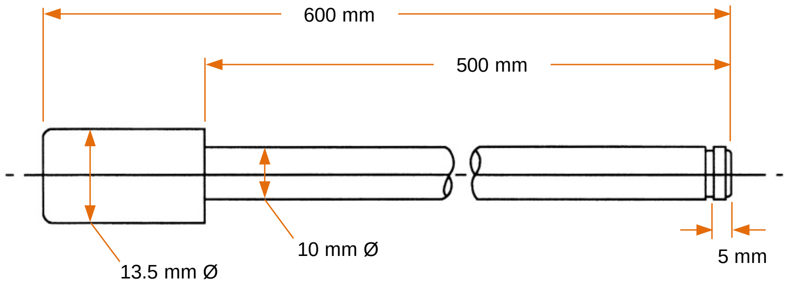


Figure 4-5 Typical wear rod – expulsion drop-out fuse

This information is also provided in Field Instruction – *Expulsion Drop Out Fuse Barrel Inspection and Fuse Rating Requirements*.

4.2.3 Pole Top Switch Disconnectors (PTS)

Pole top switch disconnectors are usually called pole top switches and are three-phase air break switches used to provide:

- flexibility of supply
- open points for interconnection, and
- isolation points, when required.

Essentially, they are three single disconnectors ganged together to give simultaneous operation driven from a ground level operating handle (see Figure 4-6).

Pole top switches used for 11kV and 22kV systems are rated to 22kV. 33kV systems use a larger pole top switch than the 22kV switch because they require higher levels of insulation. 33kV-36kV-rated pole top switches are sometimes used on the 22kV system in areas of high pollution.

Pole top switches are normally rated at 400 amps continuous load current and a limited load breaking rating of 200kVA.

When operating pole top switches, the operator should remember the following.

If there is any doubt relating to any of the following actions, do not proceed with the switching program.

1. Confirm the location of the pole top switch is correct against its asset label and as identified on the switching program.

2. Before switching, check the pole top switch to see if it is in the expected operational position.

   (For example, if the switching program directs the switching operator to open a pole top switch, before opening first check that the switch is closed. If the switch is not closed, something is wrong with the program or the operator is at the wrong switch.)

3. Before operating, check the mechanism for defects. Check earthing of the switch handle and connections to the earthing mat. Also check that the flexi tail is bent in the correct direction.

4. Install the portable equipotential earthing mat in readiness for switching operation. Refer to Field Instruction – *Use of portable equipotential mat for switching*.

5. Ensure the correct PPE for switching is being used. Refer to the Field Instruction Manual for the PPE appropriate to the switching operation.

6. When operating the switch, the switching operator should stand with feet together on the earth mat to avoid any effects of step potential.

7. When opening or closing, make sure that the operation of the switch handle is smooth and complete. A brisk speed of the operation should be used and the operation must not be interrupted.

8. After the operation, visually check again to make sure both the main switch contacts and the arc suppression contacts have been properly made or broken.

9. All pole top switches have locking facilities that must be used at all times (unless the switch is actually being operated). If the pole top switch is being used as an isolation point, D–DNO tags are locked onto the operating handle.

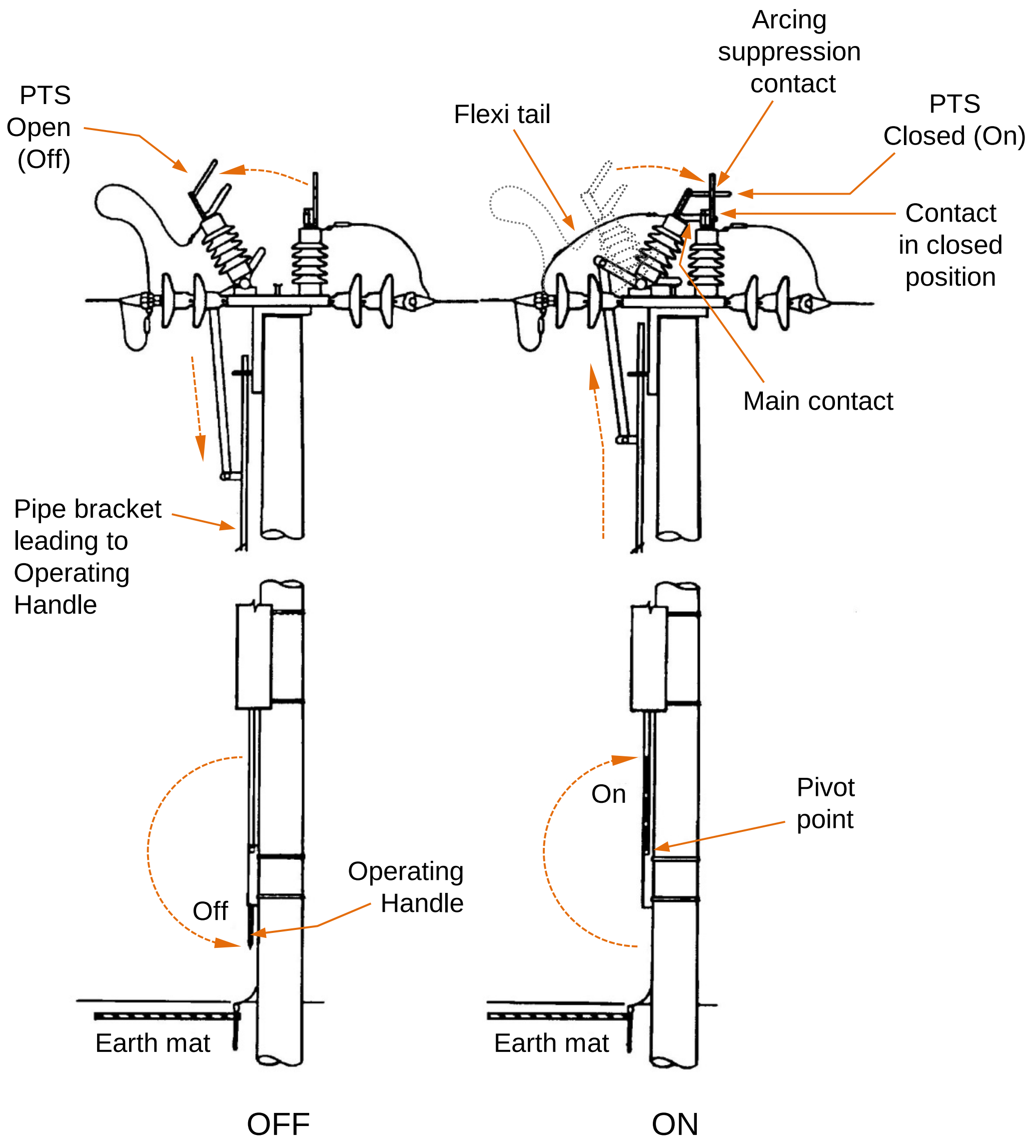


Figure 4-6 Pole top switch

4.2.4 Disconnectors (Isolators)

The HV disconnector or isolator is basically a single-phase knife switch mounted on suitable insulators. Its body is similar to the drop-out fuse, but it has a solid conductive blade instead of a fuse barrel. Unlike the drop-out fuse, the blade is not normally removable (see Figure 4-6).

HV disconnectors have a lower rating than a pole top switch, 100 amps being typical. Normally, they are used to open or close on no load, or to open and close on limited interconnection loads.

HV disconnectors are generally mounted on a crossarm and operated by an insulated HV operating stick. An open disconnector provides a visual break in the circuit for isolation. When a disconnector is used as an isolation point, the blade must be fully opened and a Danger–Do Not Operate tag must be attached through the eye of the blade.

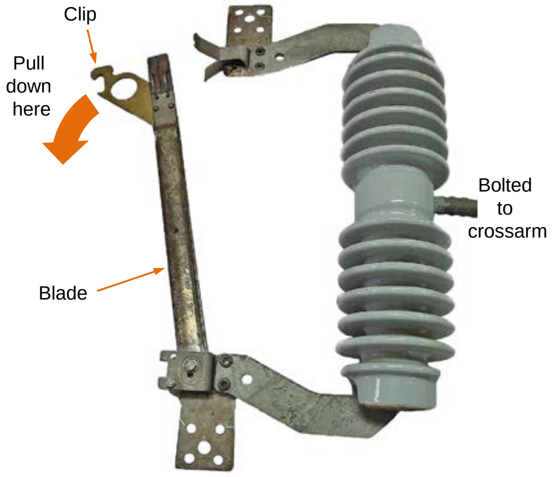


Figure 4-7 Single HV disconnector (isolator)

Where single-phase DISOs are used to parallel or unparallel feeders, the earth fault and sensitive earth fault protection must be disabled for the duration of the switching to prevent possible out-of-balance feeder tripping.

The switching operator should pay attention to the following.

1. Confirm the location of the HV disconnector is correct against its asset label and as identified on the switching program.

2. Before switching, check the HV disconnector to see if it is in the expected operational position.

   (For example, if the switching program directs the switching operator to open HV disconnector, before opening first check that the disconnector is closed. If the switch is not closed, something is wrong with the program or the operator is at the wrong disconnector.)

3. Before operating, visually check the HV disconnector insulator and contacts for defects

4. Ensure the correct PPE for switching is being used. Refer to the Field Instruction Manual for the PPE appropriate to the switching operation.

5. Where HV disconnectors are used in a three-phase application additional steps a) and b) must be performed:

   a) When paralleling or unparalleling feeders with HV disconnectors, the earth fault protection and SEF must be disabled to prevent the protection tripping the feeders on out-of-balance current.

   b) The sequence for opening disconnectors under load is shown as 1, 2 and 3 in Figure 4-8.

6. When opening or closing, make sure that the operation of the blade is smooth and complete. A brisk speed of the operation should be used and the operation must not be interrupted.

   When closing, the blade must not be slammed shut with undue force. This action must be firm.

7. After closing, the operator must check the blade is fully shut and correctly aligned between the contact points.

8. After the operation, visually check again to make sure both the main blade contacts and, where fitted, the arc suppression contacts have been properly made or broken.

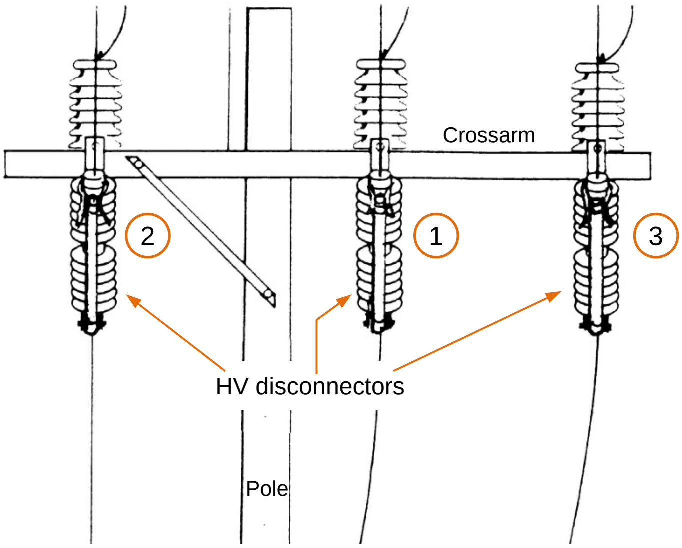


Figure 4-8 Opening disconnectors under load

Note: The operation should be carried out in the sequence 1–2–3 to give maximum clearance to the second operation (as it produces the largest arc).

4.2.5 Surge Diverters and Arresters

Surge diverters protect transformers, cables, and conductors from harmful overvoltages resulting from lightning strikes. Surge diverters are designed to discharge lightning current to earth before any damage to equipment can occur. To be effective surge diverters must be no more than 2.5m from the apparatus they are protecting eg transformer.

Note: The internal failure of a surge diverter may result in a permanent phase to earth fault.

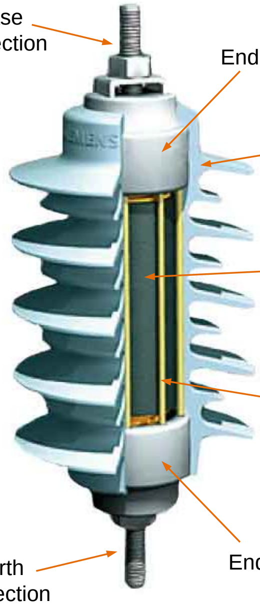


Figure 4-9 Surge diverter

4.2.6 Reclosers

The recloser is a pole mounted circuit breaker connected in-line (series) in a feeder or spur. It is used to interrupt fault current, automatically restoring power after a transient outage. Recloser protection is required to grade with distribution feeder circuit breaker protection for correct protection operation.

In the event of a transient fault, reclosers:

- clear the fault and restore service with the minimum delay
- prevent a transient fault from causing long term outage.

In the event of a permanent fault, a recloser:

- opens and locks out after a set number of reclose operations
- restricts the outage to the smallest possible section of the system.

Reclosers are set to trip and restore power multiple times before locking out. The time lapse between trips may also be changed to suit different circumstances.

Note: A recloser must never be used by itself as an isolation point, because inadequate electrical clearance cannot be assured under all circumstances.

Types of reclosers

Reclosers are available in many different forms as shown in the table below:

	Characteristics		
Number of phases	Three-phase	Single-phase	Single-phase
Contact insulating medium	SF_6 gas (modern type)	Oil (old type)	SF_6 gas (modern type)
Operation	Electronic control (modern type)	Hydraulic (old type)	Electronic control (modern type)

Table 4-2 Types of reclosers used on Horizon Power networks

Number of phases

Three-phase and single-phase reclosers are used to match the distribution system where they are installed.

Contact insulating medium

Modern type three-phase reclosers have three vacuum interrupters housed in an SF_6-insulated tank, while modern single-phase reclosers have a single vacuum interrupter mounted in an epoxy bushing.

Old type reclosers are oil-insulated, requiring routine maintenance because operation under load and fault currents reduce the oil insulating properties.

Operation

Both electronic and hydraulic control reclosers are currently in use. Electronic controls panels are used with the Nu-Lec reclosers, and the Kyle E recloser is a lever-operated hydraulic recloser.

Three-phase recloser

The three-phase recloser used on HV lines is the Nu-Lec N-series. Figure 4-10 shows a typical Nu-Lec recloser and electronic control box installation.

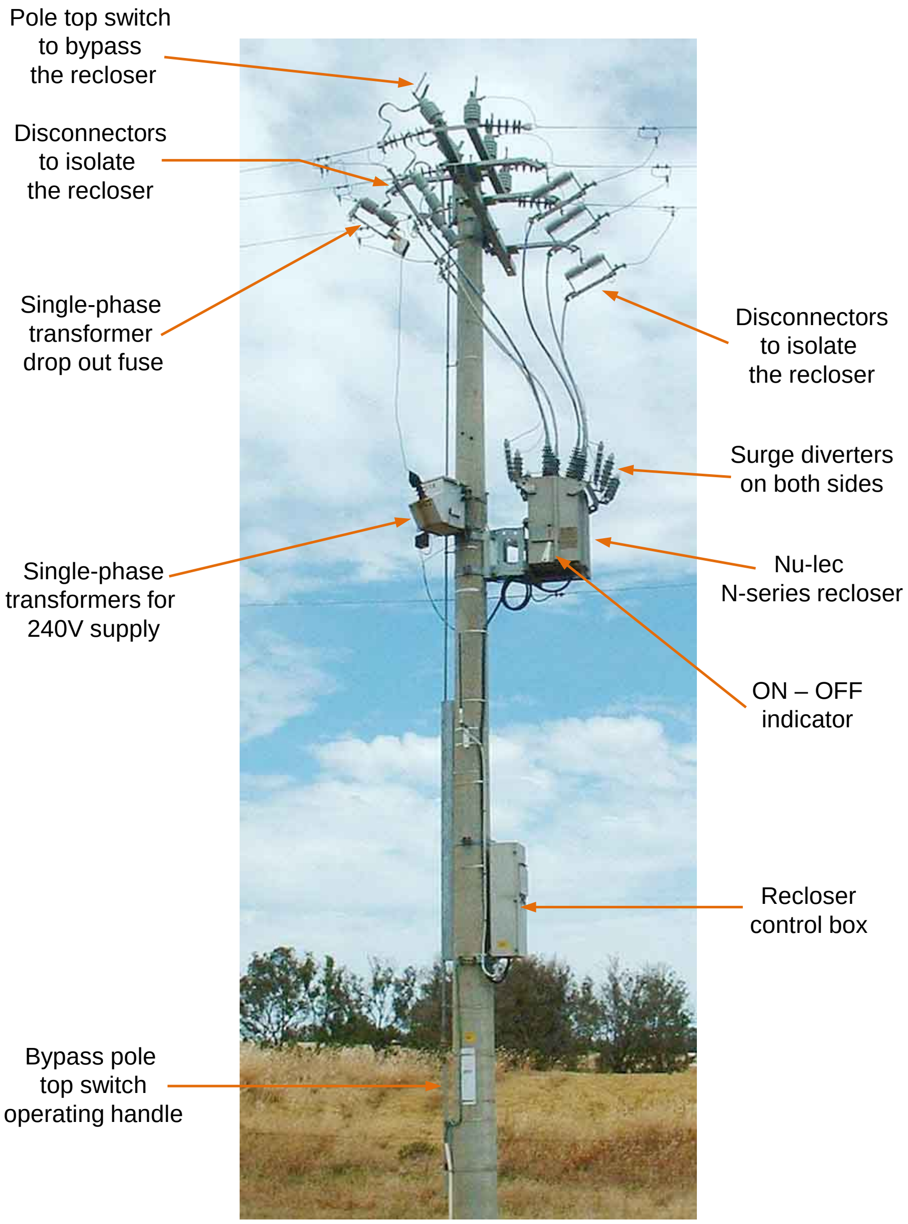


Figure 4-10 Nu-lec N-series recloser installation in the field

The features of the N-series recloser are:

- the Nu-Lec three-phase recloser has three vacuum interrupters housed in an SF_6 insulated tank.
- the electronic control panel is mounted in a box at the bottom of the structure or pole. Figure 4-11 shows the operator controls and indication.

- a separate power supply is required for the control panel. This can be provided by a nearby LV supply or where this is not available, a single-phase HV fused transformer is mounted on the recloser pole (see Figure 4-10) or a nearby pole.

- a bypass pole top switch and three disconnectors on each side of the recloser are installed to enable continuity of supply and isolation of the recloser for maintenance work. At some locations, such as Leonora, the disconnectors have not been installed.

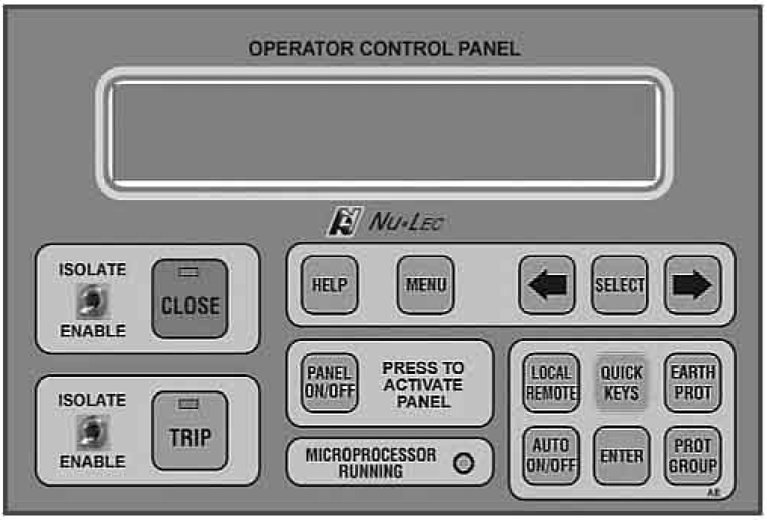


Figure 4-11 Nu-Lec operator control panel

Note: The switching operator is responsible for basic recloser switching operations, not programming.

Single-phase Reclosers

These reclosers are used on single-phase HV spurs. The main types used by Horizon Power are:

- Kyle E which is used in conjunction with a bypass fuse, and

- Nu-Lec W type

Figure 4-12 shows a Kyle E hydraulic single-phase recloser.

The features are:

- single-phase oil contact insulation

- hydraulic operating mechanism with operating lever and a ‘single shot’ non-reclosing lever which are operated with an insulated HV operating stick. The switching operator should recognise the operating positions of the recloser levers shown in Figure 4-12 (on/off/single shot).

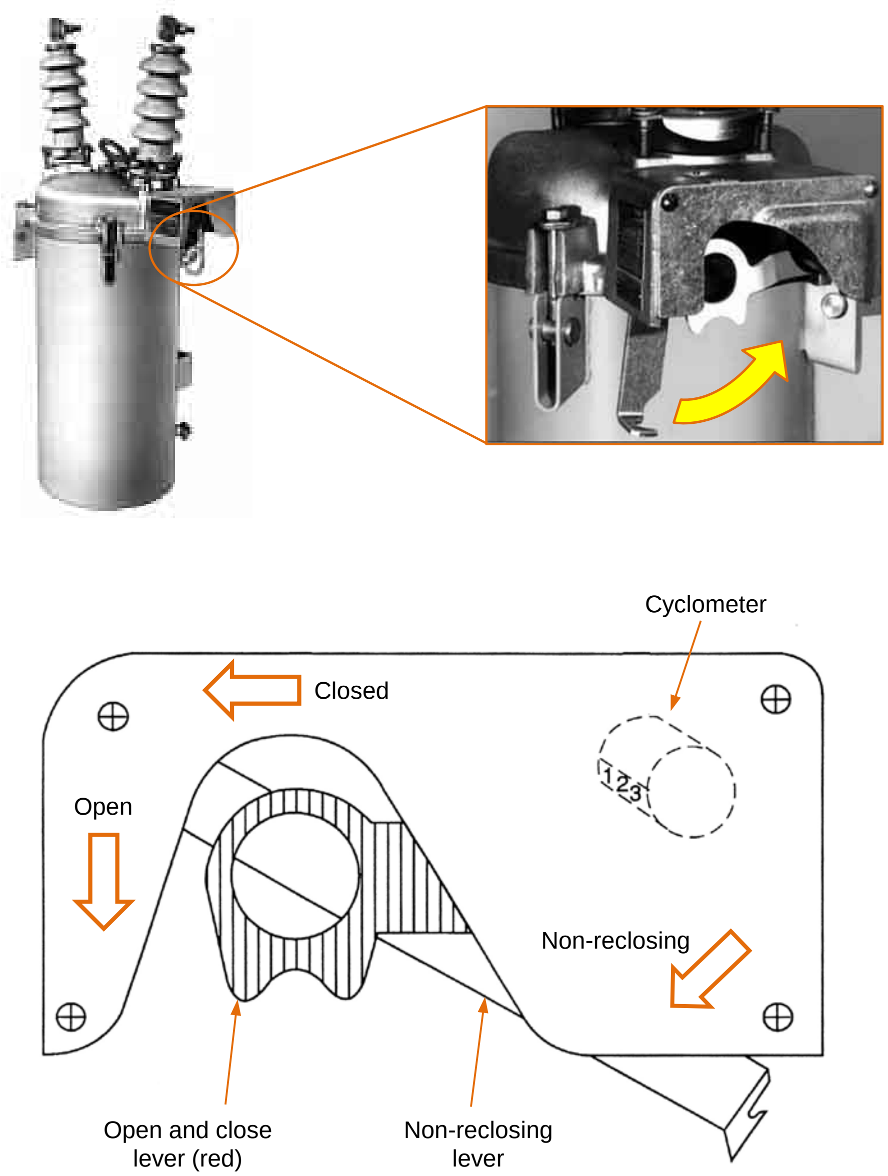


Figure 4-12 Kyle E hydraulic single-phase recloser (top left) showing the ‘single shot’ non-reclosing lever in the non-reclosing position (top right), which moves upwards to its normal operating position (arrowed). Bottom shows the operating lever in its opened, closed, and non-reclosing operating positions.

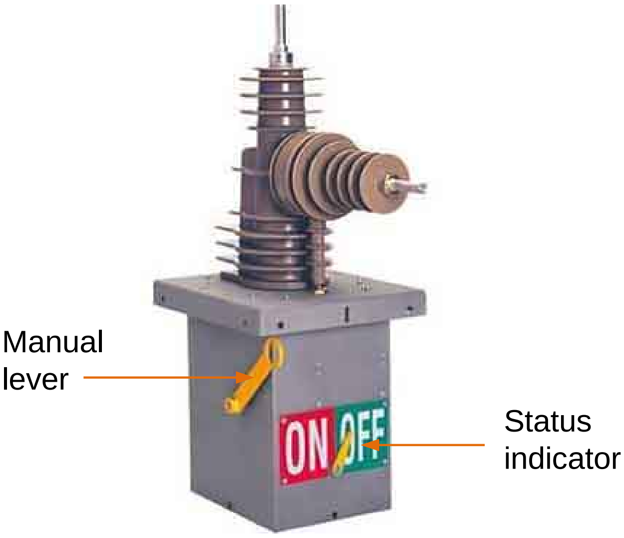


Figure 4-13 Nu-Lec W-type single-phase recloser

Shown in Figure 4-13 is a Nu-Lec W-type single-phase recloser. The features of this W-type recloser are:

- single-phase vacuum interrupter
- electronic control panel operation
- manual lever – UP position allows for normal operation, and in the DOWN position the recloser is tripped and both mechanically and electronically locked open.

When isolating a recloser via disconnectors, the switching operator must:

1. set the recloser to manual or non-auto reclose
2. close the bypass
3. open the recloser
4. open disconnectors on each side of recloser.

The recloser connections should not be earthed until both sides are isolated.

Comparison of electronic control and hydraulic operating reclosers

The advantages of electronic reclosers over hydraulic reclosers include:

- improved flexibility of operation, thus solving many grading problems
- the ease of changing operating values, without de-energising the recloser
- remote operation is possible
- greater accuracy of operation
- maintaining the quality of operation at all times
- the ease of designing operating curves for specific application purposes
- temperature changes not affecting operating features, and
- the ease of routine testing.

The main disadvantages include:

- the need for a separate power supply for control, and
- the location of the control box, making them targets for vandalism.

4.2.7 Single-phase Sectionalisers

Single-phase sectionalisers are typically used on 19.1kV (33kV) rural single-phase lines. The sectionaliser is used to disconnect a faulted section of line. It opens its contacts automatically, only after the circuit is de-energised by a recloser. It is always used in series with a fault-interrupting device (recloser), as it is not designed to interrupt fault current.

Normally, sectionalisers have a bypass drop-out fuse mounted on the same pole. When sectionalisers are removed for any reason, the fuse barrel may be installed to protect the line and maintain supply for the period of removal.

To explain sectionaliser operations on the detection of a fault, consider Figure 4-14 below. Assume F1 is a permanent fault, the recloser R1 is set for three shots to lock out, and sectionaliser S1 is set for two shots to open.

When a fault F1 occurs down the line from the sectionaliser S1 (in its normal zone of protection), the fault current is sensed by both the recloser R1 and the sectionaliser S1. The recloser R1 trips and de-energises the line. The sectionaliser S1 count is one, due to the fault current.

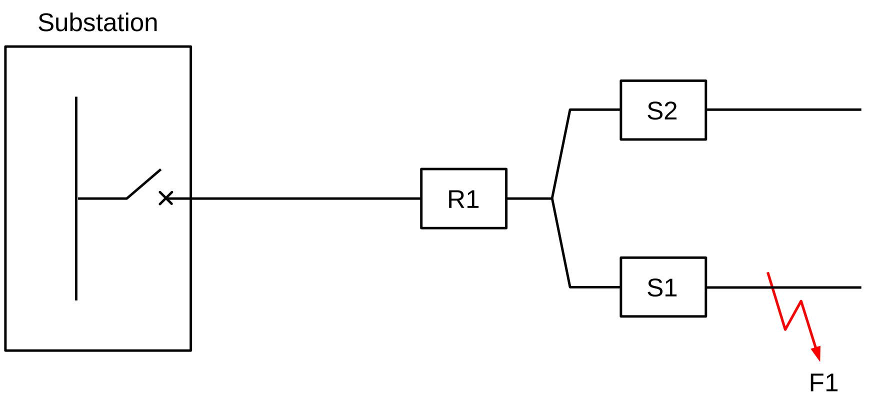


Figure 4-14 Sectionaliser operations on detection of a fault

The recloser R1 recloses again and fault current is sensed by R1 and S1. R1 trips again and S1 has now reached its count of 2; it opens, disconnecting the fault F1 whilst the recloser is open. The recloser R1 again recloses and the feeder is restored with the exception of the faulted line section after S1.

In another scenario, the recloser R1 and sectionaliser S1 have the same settings as above. However, this time F1 is a transient fault (the first reclose attempt is successful).

On seeing the fault, recloser R1 and sectionaliser S1 sense the fault current. Recloser R1 opens and the sectionaliser S1 count is one. The recloser R1 recloses, this time successfully as the fault has cleared. Sectionaliser S1 has not reached its count and remains closed. The complete feeder is restored. Both the recloser R1 and sectionaliser S1 fault counts are reset back to zero after a set time delay.

Sectionalisers may be used in series. Where this occurs, the sectionaliser further down the line will be set for fewer counts. (Normally, they are set for either two or three shots.)

Sectionalisers have the advantages of:

- being more economical than reclosers
- allowing transient faults to clear before operating
- isolating only the faulted section of line
- aiding fault finding, and
- opening easily for de-energisation, in the same way as a drop-out fuse.

Before the line tap is removed, the load current must be broken with the sectionaliser.

An Haycolec electronic sectionaliser link is shown in Figure 4-15. The sectionaliser link fits in a standard drop out fuse holder. The link electronic measurement unit is in the middle section.

This electronic unit counts the times fault current passes through the link and activates the latch mechanism, allowing the link to open by swinging down on the bottom hinge point when its set count is reached. The desired count is set with switches on the link.

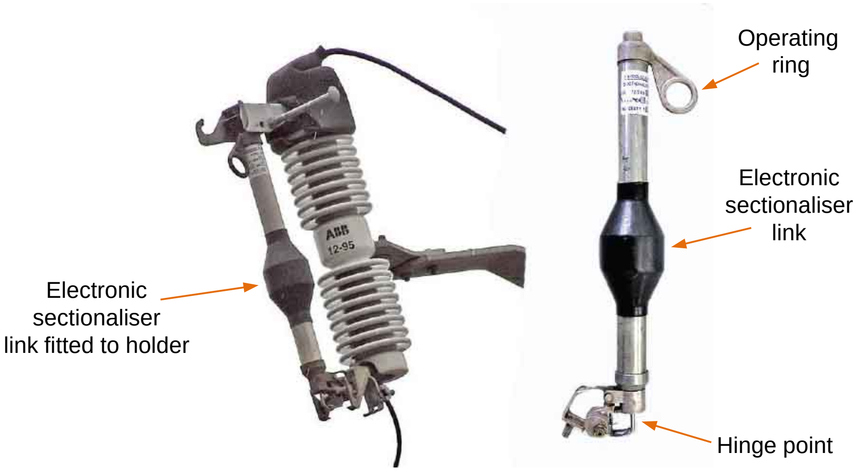


Figure 4-15 Haycolec sectionaliser

When used as an isolation point, the sectionaliser link must be fully removed from the holder and tied to the pole with a D–DNO tag.

4.2.8 Fusesaver

A Fusesaver™ is a high speed outdoor vacuum circuit breaker with integrated protection which can operate within the first half cycle of fault current.

Fuse savers are used on single-phase spurs and connected in series with the associated drop out fuse. Figure 4-16 shows a Fusesaver.

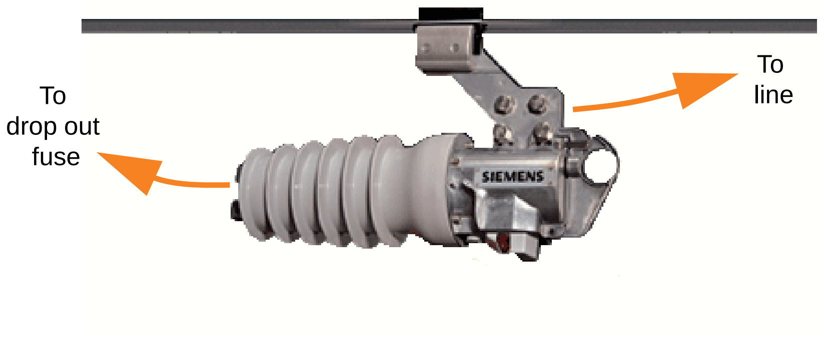


Figure 4-16 Typical Fusesaver™ installation

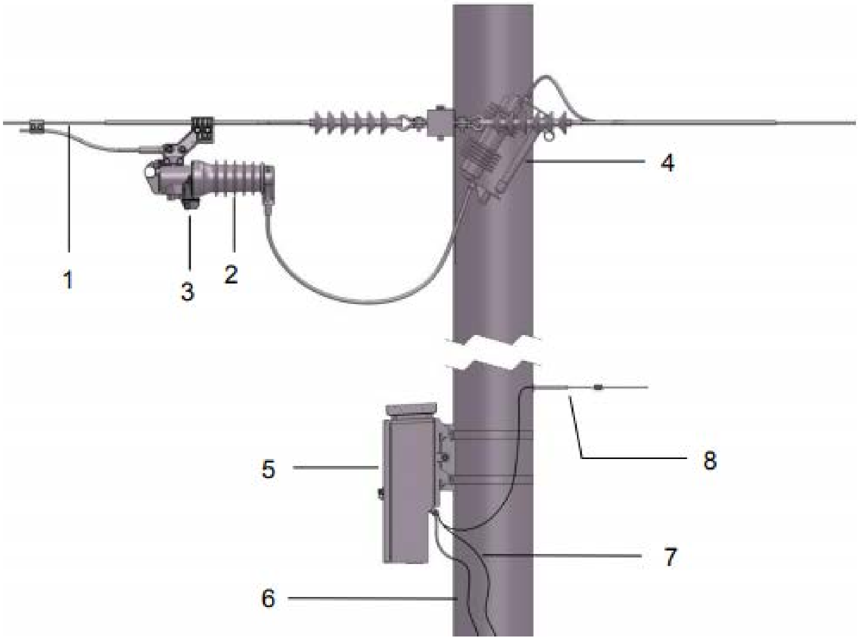
When a fault occurs the Fusesaver vacuum interrupter opens, disconnecting the line before the associated drop out fuse element can melt. The Fusesaver remains open for a period of one to 30 seconds dependent on the setting, giving time for a transient fault to clear. The Fusesaver vacuum interrupter then closes. Therefore, for a transient fault the power is fully restored. However, for a permanent fault the associated drop out fuse blows, resulting in a loss of power.

The Fusesaver has the capability to improve system reliability, because a transient fault does not cause the drop out fuses to blow.

Remote Control and Monitoring of Fusesavers.

Fusesavers have the ability to be incorporated into a SCADA system via a Remote Control Unit (RCU). The RCU works in partnership with a Fusesaver to increase network automation by allowing the Utility Control Centre to be able to remotely monitor and control Fusesavers.

Additionally, the RCU can be equipped with a local control panel to enable a local Switching Operator control of the Fusesaver. Remote Control Units are outdoor installed devices that are normally pole mounted close to a single or ganged set of Fusesavers.

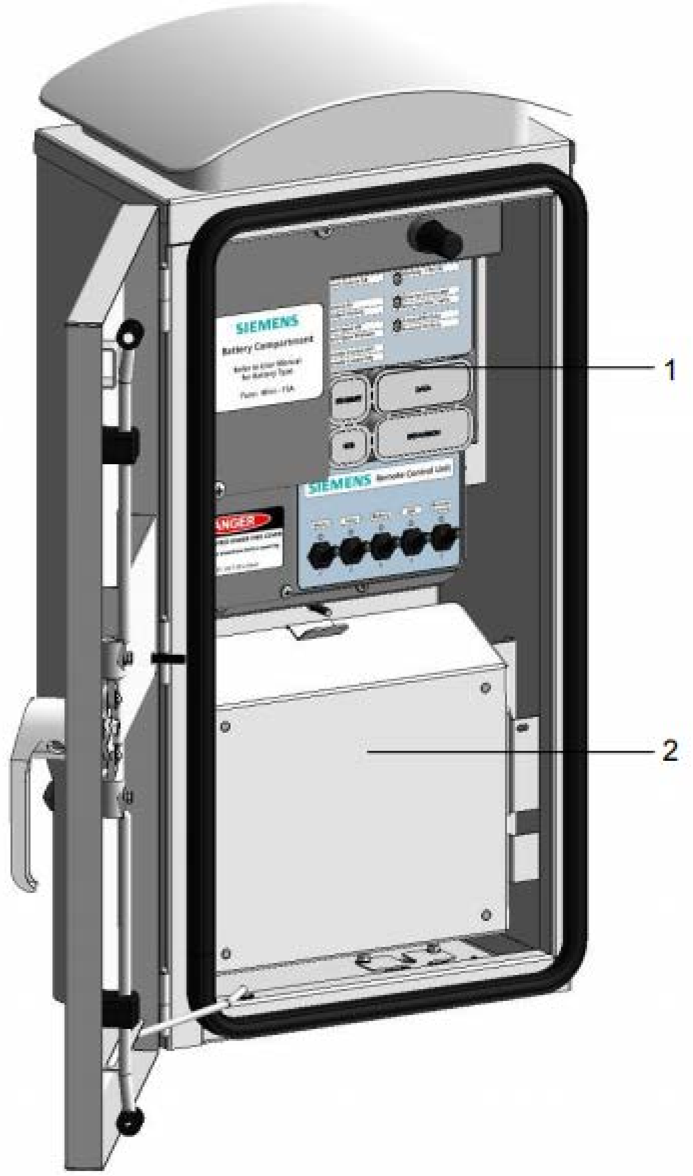


Installation of RCU with Fusesavers

1 Conductor
2 Fusesaver
3 Communications Module
4 Fuse or isolating link
5 Remote Control unit
6 Earth Connection
7 Mains Connection
8 Antenna for long range communications

Figure 4-17 Installation of RTU & Fusesaver

Remote Control Unit (RCU).



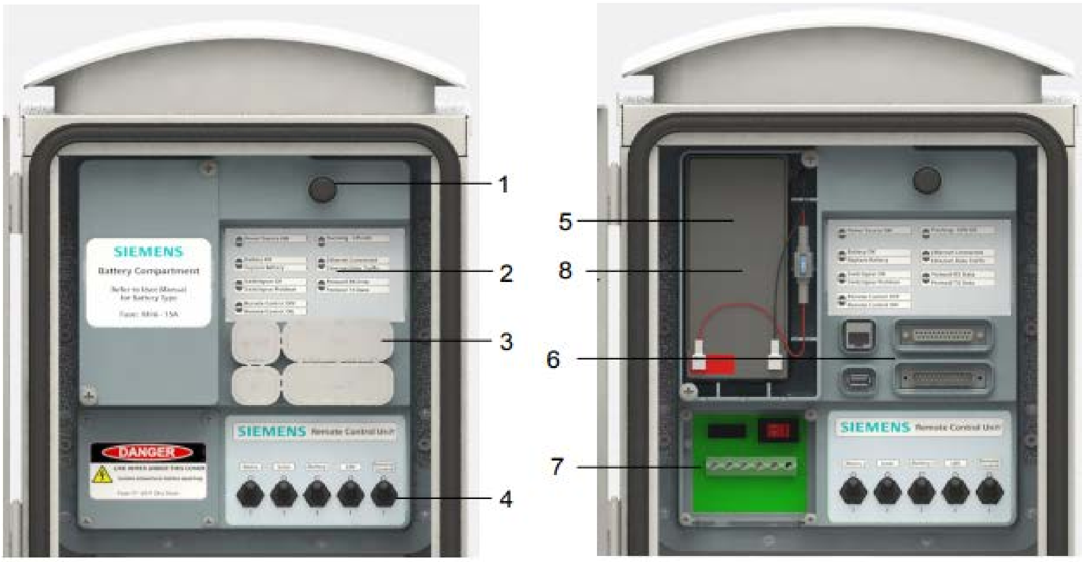
Main Internal Elements

1 Electronics Housing
2 Radio Tray

Figure 4-18 Remote Control Unit

Electronic Housing of the RCU.

The electronic housing contains the micro-processor, battery, power terminals, data connection points and the user interface for the RCU. The RCU has a simple user interface for operations and maintenance purposes. The panel makes use of LED indicators, which are not illuminated when the door to the panel is closed to save power.

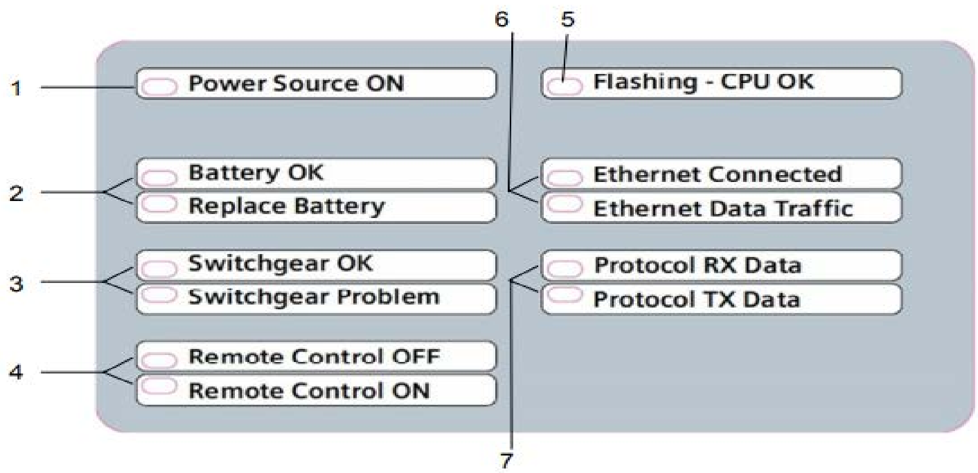


Electronics Housing

1	Door Switch	5	Battery
2	LED Display	6	USB, Ethernet, Linesman, operator panel & Radio interface connectors
3	Connector Covers	7	Power supply and earth connection
4	Toggle Switches	8	Battery fuse

Figure 4-19 Remote Control Unit

LED Indicator Display of RCU.



1 GREEN light ON – Power source (solar or mains) providing power

Light OFF – No incoming power

2 GREEN light ON – Battery is OK

Light OFF – Battery off or disconnected

RED light ON – Battery needs replacing

3 GREEN Light ON – Fusesavers OK

GREEN Light Flashing – Searching for Fusesavers

RED light ON – Fusesaver configuration or communication problem

4 GREEN light ON – Remote Control Off.

RED light ON – Remote Control On.

5 GREEN FLASH – Microprocessor OK.

GREEN Light ON or OFF – Microprocessor problem

6 GREEN light ON – Ethernet Connected

RED FLASH – Network traffic

7 GREEN FLASH – SCADA message received

RED FLASH – SCADA message sent

Figure 4-20 Remote Control Unit Display

SCADA Operator Controls of Fusesaver.

The purpose of SCADA connecting through the RCU is to allow remote operation of the devices it controls as well as to review event data.

Typically, the following functions are available via SCADA:

1). View RCU status and event information.

2). Issue trip and close commands to the Fusesaver via the RCU. The RCU must have the Remote Control Switch set to “ON” for this to be possible.

3). Change protection settings in the Fusesaver via the RCU. The RCU must have the Remote Control Switch set to ON for this to be possible.

4). Issue a command to the Fusesaver to force the protection to be armed regardless of whether there is adequate line current to power the Fusesaver. The protection will remain armed until a command to disable the forced arming is received, or a time limit that is set by the Fusesaver policy file is reached.

4.2.9 Load break switches

An RL series load break switch/sectionaliser (LBS) is shown in Figure 4-17 below. The load break switch contacts are sealed inside the tank which contains sulphur hexafluoride (SF_6) gas. Because sufficient SF_6 gas pressure is required to achieve the full load current make and break rating, the LBS will lock out, preventing further operation on low gas pressure.

The LBS can be operated from the local electronic control panel attached to the pole, or manually operated using an insulated HV operating stick in the operating lever rings. The electronic control panel requires an external power supply and when fitted with a communications system will provide remote operation.

The LBS provides a mechanical indicator for the switching operator to verify the switch status. The LBS lockout lever is provided to mechanically lock the switch contact mechanism in the open position. This is part of the requirement to use the LBS as an isolation point. Further details are provided in Field Instruction – *Nu-Lec RL (SF_6) load break switch as an isolation point*.

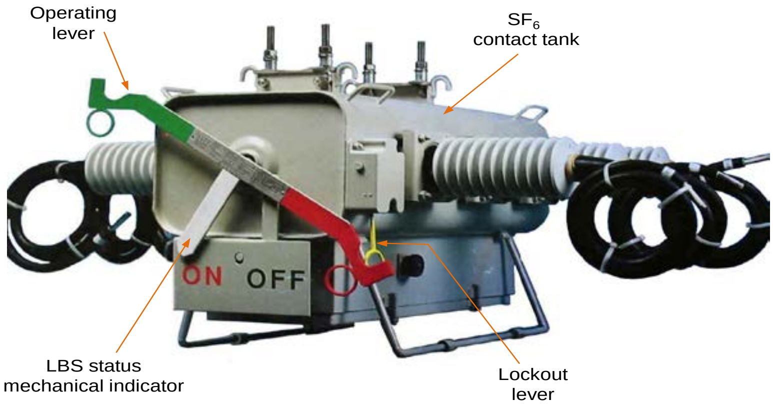


Figure 4-21 RL series load break switch/sectionaliser

Shown in Figure 4-18 is a typical LBS installation, showing the pole mounted LBS fitted with surge diverters on each side, an external power supply transformer with DOFs, and the in-line insulators in the main feeder.

Figure 4-22 Load break switch/sectionaliser in the field

4.2.10 Line Voltage Regulating Transformers

Line voltage regulating transformers (commonly called regulators) are used to provide voltage regulation to maintain voltage levels within prescribed limits at a particular point along a HV feeder. This is commonly required on long and/or heavily loaded feeders. Horizon Power regulators are model VR-32 (see Figure 4-19).

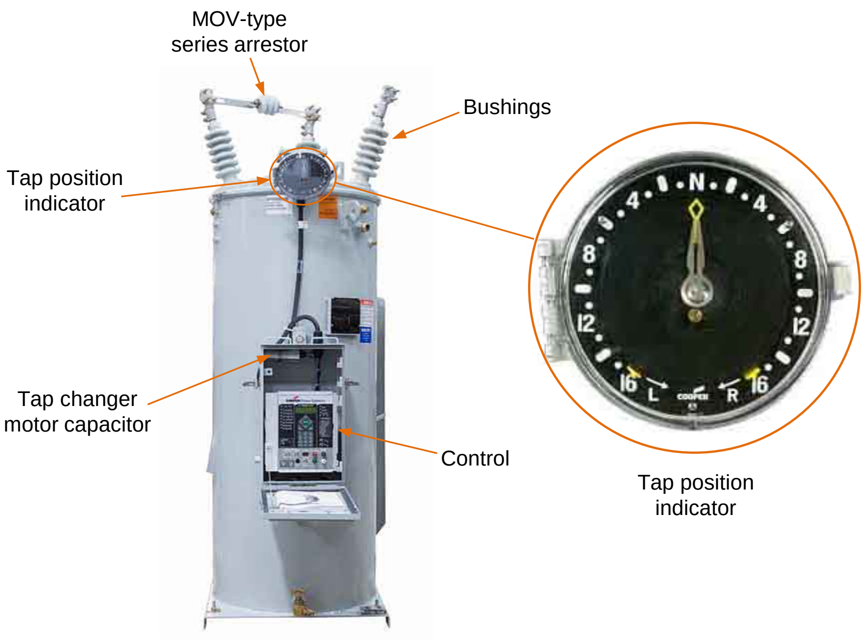


Figure 4-23 Horizon Power's VR-32 voltage regulator

A conventional transformer has primary and secondary windings connected magnetically, not electrically (see Figure 4-20a). The windings of the regulators are autotransformers connected both electrically and magnetically. Figure 4-20b shows that part of one winding is common to both the primary and secondary sides of the transformer.

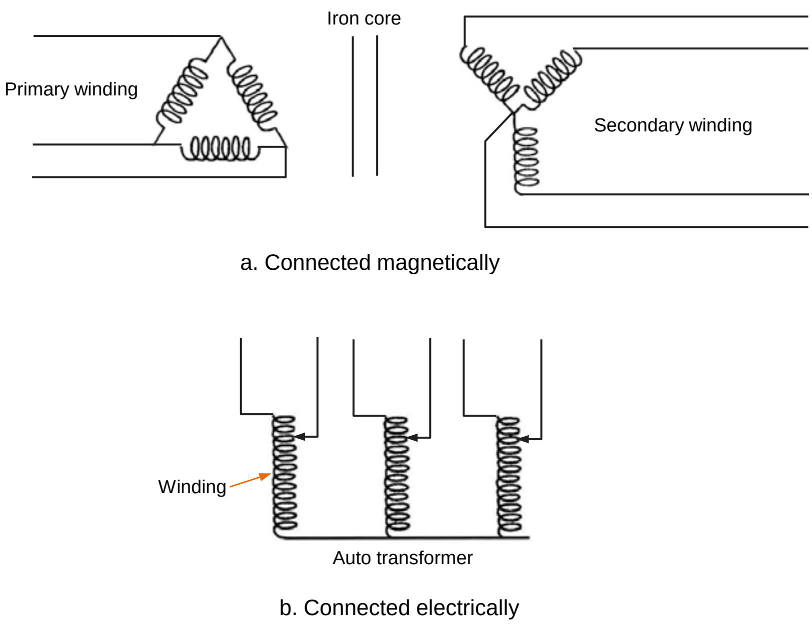


Figure 4-24 Windings

A number of connection methods are available for regulators on three-phase systems. Figure 4-21 shows star connected three-phase line voltage regulator with bypass disconnector and isolation disconnectors A and B.

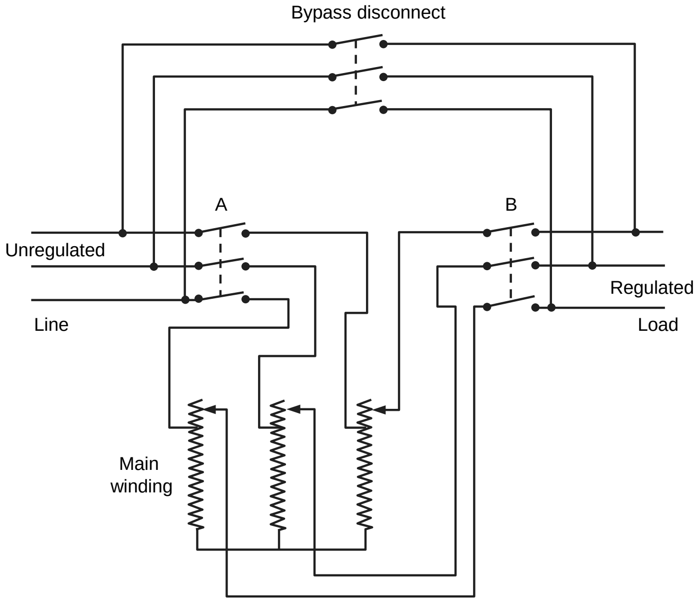


Figure 4-25 Circuits of line voltage regulator

The regulator on-load tap changer has 32 tap positions (see Figure 4-22). This allows the regulated load voltage to range from 90-110% of the unregulated line voltage. The tap changer is controlled by automatic voltage regulating relays with line drop compensation.

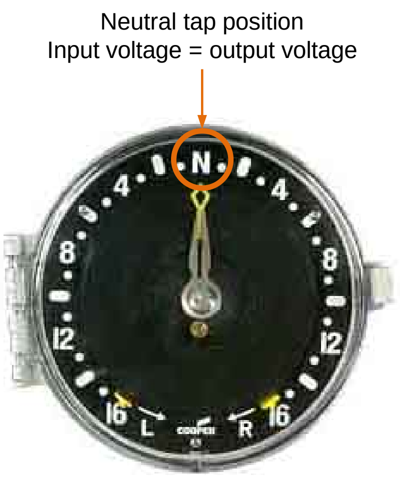


Figure 4-26 Tap position indicator
on the VR-32 voltage regulator

Note: When closing the bypass disconnector, the tap changer must be in the neutral position so the unregulated line and regulated load voltages are the same.

If the tapping mechanism is in any position but neutral, closing the bypass switch short-circuits the tapped winding coils and results in heavy circulating current flows.

The correct switching procedure is essential or serious damage to the regulator may result.

Switching Procedure to Isolate Regulator

1. Place the regulator on manual control.

2. Using the push button control, adjust the regulator to the neutral tap position. Check all indicators.

   (A light may indicate when the mechanism is on the neutral tap. The switching operator must check the mechanical tap indicator and nameplate for the neutral tap setting.)

   As an added precaution, open off the mechanism supply switch or fuses. (The neutral tap position is where output voltage equals input voltage.)

3. Close the bypass switch. (This may have a mechanical or electrical interlock.)

4. Open the disconnectors on the line and load sides of the regulator.

Switching Procedure to Place in Service

1. Check the regulator is on manual control and in the neutral tap position.

2. Close the disconnectors on the line and load sides of the regulator and remove any D–DNO tags.

3. Open the bypass switch.

4. Energise the mechanism supply, if necessary.

5. Reinstate the supply fuses or switch.

6. Place the regulator to auto control. If necessary, check the operation. To check auto operation, use the manual control to raise or lower the taps.

To avoid errors, the switching operator must check each step and work methodically.

4.2.11 Fault Indicators

Fault indicators are used to assist in locating faults by indicating the path fault current has flowed. A range of fault indicators are used in Horizon Power; a common example is the SEL AR360 AutoRANGER® fault indicator (shown in Figure 4-23). This fault indicator is clipped onto the overhead line conductor using an insulated HV operating stick.

Figure 4-27 Typical Horizon Power fault indicator
This is the SEL AR360 AutoRanger® device.

Fault indicators detect the presence of a fault by the sudden increase in current flow, caused by the fault current which is followed by the loss of voltage as the protective device operates to disconnect the fault.

A successful auto reclose would indicate a temporary fault and the fault indicator flashes amber. However, an unsuccessful auto reclose resulting in permanent loss of supply would cause the fault indicator to flash alternately red-amber.

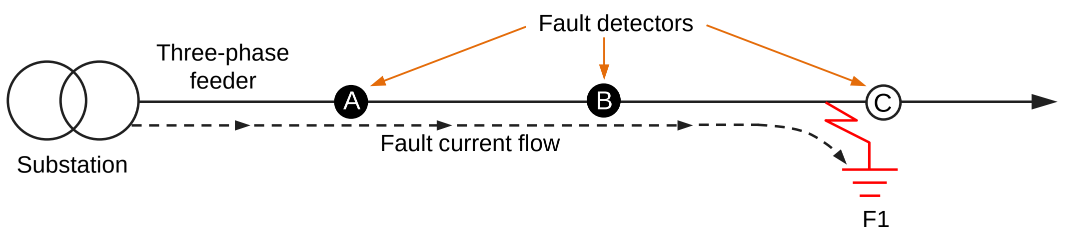


Figure 4-28 Fault indicator operation

In Figure 4-24, a line fault F1 is located between fault indicators B and C. Fault indicators A and B operate as the fault current has passed through them, however fault indicator C does not operate as the fault current did not pass through C.

Most fault indicators will self-reset after a set time period. Others must be reset manually after the fault is found.

Note: The manual fault indicator must be reset as soon as possible. In the event of a further fault before resetting, the operator will not be able to tell whether the fault current passed the indicator point. The indicator would still show the previous fault.

4.2.12 Transformers

The transformers used by Horizon Power include:

- pole top
- padmount
- ground mount (compound).

Refer to Section 3.2.1 – Distribution Transformers for further details.

4.2.13 Reactors

Reactors have high voltage windings similar to transformers but have no LV windings. Reactors absorb reactive power and they are installed on long three-phase lines to control high voltages caused by the type of construction and length of the line (capacitive effect).

Reactors are used mainly on 33kV distribution lines. Normally, they are protected by drop out fuses.

4.3 Interconnection of Feeders

This section should be read with Section Six. Interconnection of transformers involves the connection of two different feeders at any one point.

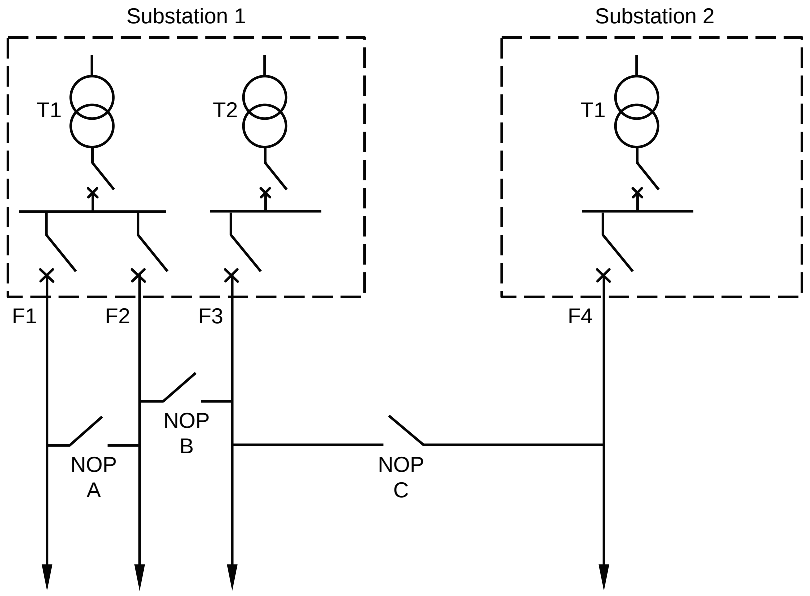


Figure 4-29 Types of feeder interconnection

Figure 4-25 shows two substations S1 and S2 and four feeders F1, F2, F3 and F4 with normally open points A, B and C. There are two basic types of feeder interconnection:

- feeders may be interconnected from different substations, e.g. F3 and F4 via NOP C
- feeders may be interconnected from the same substation supplied by:
    - different transformers, e.g. F2 and F3 via NOP B, or
    - the same transformer, e.g. F1 and F2 via NOP A.

Note: Interconnection is also possible via the LV system.

Interconnection of feeders is necessary for the following reasons:

- to move open points
- to transfer load
- to isolate a section of line or apparatus without outage to customers.

Before interconnection is carried out, the following factors must be considered:

- the feeder loads before and after interconnection

- the selection of the best location for interconnection (for example, for circuit breaker isolation, interconnection should be close to the substation)
- the extra load on conductors after interconnection
- the need for two or more connection points, where required by the load
- the type of switchgear used for interconnection (for example, pole top switches or disconnectors)
- the level of circulating current between zone substation transformers
- interconnection of extensive underground areas may result in high through currents, depending upon transformer impedances and lengths of cables.

Figure 4-26 shows circulating current. T1 and T2 are set at different taps, therefore, the secondary busbars will be at different voltages.

If the bus coupler A is closed under this condition, a current will be driven around the transformers, as shown. This is called circulating current and may be several hundred amps for large tap differences. The smaller the tap difference, the less circulating current will occur.

The same principle applies when bus coupler A is left open and two feeders F2 and F3 on opposite bars are interconnected with a pole top switch or ring main unit outside the substation. To minimise the circulating current through the feeders, transformer T1 and T2 taps need to be set reducing the voltage difference. Failure to reduce the circulating current may result in the interconnected feeders tripping on overcurrent.

The circulating current will lessen the further the pole top switch or ring main unit is from the substation because of the increased line impedance. For example, the circulating current through NOP C will be less than NOP B. The circulating current is negligible over two kilometres from the substation, unless most of the feeder is underground cable.

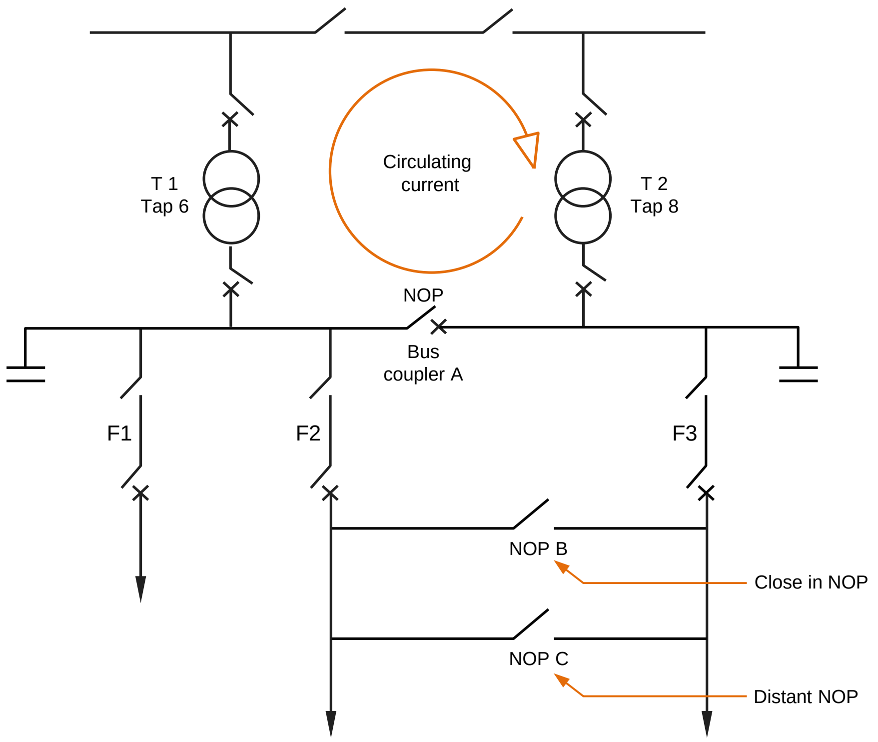


Figure 4-30 Circulating current

Local knowledge and careful analysis of circuits is required when planning interconnection. Table 4-3 shows the general requirements for feeder interconnection but specific local conditions may overrule these requirements.

Configuration	Tap Change to Manual	Adjust Taps	Feeder/ Recloser Set to Manual	Feeder/ Recloser Earth Fault Out	Bus Coupler Closed	Capacitor Off	Sensitive Earth Fault Out
One Transformer or Two Transformers in Parallel	No	No	See Note 7	PTS No DISO Yes (Note 3)	No	No	Yes (Note 5)
Two Transformers Feeding Separate Bars. Switching outside 2km from sub-station	No (Note 1)	No (Note 1)	See Note 7	PTS No DISO Yes (Note 3)	No	No	Yes (Note 5)
Two Transformers Feeding Separate Bars. Inter-connecting inside 2km from sub-station	Yes	Yes (See Section 6.9.2)	See Note 7	PTS No DISO Yes (Note 3)	See Section 6.9.2	See Section 6.9.2 (Note 4)	Yes (Note 5)
Separate Substations (greater than 2 km)	No (Note 2)	No (Note 6)	See Note 7	PTS No DISO Yes (Note 3)	No	No	Yes (Note 5)

Note 1 Transformers must be set to manual and the taps must be matched if the length of the feeder route is more than 50% cable.

Note 2 Transformers need only to be set to manual when the feeder length route is more than 50% cable.

Note 3 This applies to reclosers installed in feeders as well as substation feeder breakers.

Note 4 This applies only for outdoor substations with a disconnector type bus coupler.

Note 5 Sensitive Earth Fault – Flag 14.

Note 6 Taps may need to be adjusted if separate substations have extreme voltage differences.

Note 7 If the switching operator is concerned that there may be a flashover or fault on the switching apparatus they are operating, they must set the feeders/reclosers to manual to prevent multiple automatic reclose operations when paralleling feeders.

Table 4-3 Interconnection switching table

Tap Changer to Manual

This is done to guard against tap changer runaway (transformers tapping in opposite directions) due to circulating currents.

Adjust Taps

Adjusting transformers to the same tap or voltage is carried out when switching inside two kilometres of the substation. Circulating current result if switching inside two kilometres, while on different taps. The current may trip the feeder or cause excessive arcing on the interconnecting apparatus.

Feeder Circuit Breaker Set to Manual

This is done as a precaution to eliminate multiple automatic reclose operations if a fault occurs during switching.

Feeder Earth Fault Out

When switching with pole top switches, 'feeder earth fault out' is not necessary. (However, it is necessary when switching a three-phase set of single-phase disconnectors. If this is not done, the feeder may trip. This is due to the out-of-balance load as the first disconnector is operated during interconnection.)

Always switch with a ganged three-phase device rather than a single-phase device, where ever possible.

Note: When carrying out three-phase isolation of a rural feeder connected with single-phase spurs, earth fault protection may operate due to out-of-balance current.

Hydraulic Reclosers and Sectionalisers

When interconnection involving reclosers and/or sectionalisers is being carried out the recloser and/or sectionaliser by-pass must be closed.

Nu-Lec Reclosers

When interconnection involves Nu-Lec reclosers, by-passing the recloser is not necessary because the overcurrent protection has been pre-set to take the additional load. As these reclosers are fitted with SEF protection, the SEF is disabled before paralleling feeders downstream of the recloser. The SEF can be returned to service after the feeders are separated.

Bus Coupler Closed

The bus coupler may need to be closed when interconnection is carried out:

- within two kilometres of a zone substation
- where transformers are feeding separate busbars, and
- the feeders are fed from different busbars.

This procedure effectively parallels the transformers, making further interconnection and switching safe at the interconnection point in the field.

The bus coupler (circuit breaker or switch) is closed, because it has a higher rating than field equipment. It may also be fault rated.

The reverse is true when reinstating the bus coupler to normal. The switching operator should first open the interconnection point in the field and then open the bus coupler.

The switching operator must remember to adjust the taps before operating the bus coupler.

Capacitor Bank Off

In outdoor substations, the bus coupler is normally a switch, not a circuit breaker. When interconnecting with the bus coupler, with the substation capacitor banks in service, there is a danger of flashover.

If the bus coupler has to be operated at a zone substation, all capacitor banks may need to be taken out of service, according to local conditions. The operation of capacitor banks may cause unwanted transient spikes through the system. (Local rulings determine when capacitor banks should be operated.)

Sensitive Earth Fault

When interconnecting feeders, the sensitive earth fault must be made inoperative. This is because the slightest out-of-balance load may be detected and trip the feeder. The out-of-balance may be caused by something as simple as poor contact on a pole top switch.

Note: Not all overhead feeders have sensitive earth fault protection activated. Underground feeders will not have sensitive earth fault protection enabled.

4.4 Common Distribution Faults

Common faults in the HV and LV distribution system include vehicles hitting poles, trees touching or falling on mains, pollution failures, pole top fires, animals and a variety of unknown causes. Single-phasing, drop out fuses failing to clear (flashover) and faults on pole top switches also are common.

4.4.1 Vehicles Hitting Poles

When a vehicle hits a pole, a power failure may occur due to the conductors clashing or shorting to earth. At times, the feeder successfully recloses.

4.4.2 Trees Touching or Falling on Mains

Foliage and wet limbs of trees touching the mains can conduct electricity and cause short circuits between conductors. This may result in a circuit breaker tripping or a high voltage fuse blowing. Falling or swaying trees, and their limbs, may also damage or break conductors, resulting in live wires falling or hanging dangerously.

4.4.3 Pollution Failures

The pollution from industrial areas and exposed coastal areas may result in flashovers, pole top fires or radio interference.

4.4.4 Pole Top Fires

Pole top fires normally occur on those structures that have loose connections or are poorly bonded. Pollution, lightning damage and rain also contribute. Fires are more frequent with the first light rains following a long dry summer and also occur with high humidity at the end of summer. The fires are caused by leakage from, or damage to, the insulator. As a result, the current may track down the insulator to earth, or flow between the conductors. The tracking current through the wooden pole and wooden crossarm will heat the wood and may eventually, set them on fire.

4.4.5 Animals

Both domestic animals and wild life may interfere with mains by short-circuiting the phases. Cats, birds and flying foxes may create problems.

4.4.6 Transient Faults

Faults with no known cause may trip a feeder that then successfully recloses. These are called *transient faults*. On the other hand, a feeder may trip and lock out. Switching operators will then be called upon to patrol and then sectionalise the line to determine the position of the fault.

For recurrent transient faults, the relevant part of the feeder or spur must be patrolled.

Transient faults may be caused by the following situations.

- High winds cause tree limbs to come into contact with mains. This problem may be observed by the burning ends of branches and dead leaves. (The switching operator should find, cut and remove the problem limbs of trees using suitable safety procedures.)

- High winds and slack bays of mains may result in conductors swinging together and clashing. (When patrolling lines, the switching operator should look for burn marks or pitting on the conductors.)

- Hot weather may cause excessive sag in long bays. Lines may touch trees in the heat of the day but be quite clear early in the morning or at night. (When patrolling, the switching operator should carefully examine the height of trees near the middle of long bays.)

- Heavily loaded conductors carrying excessive current (amps) become heated and droop. They may come into contact with trees or other conductors.

- Vehicles hitting poles may stretch street light circuits, customer services, stays and mains. Lines may become so taut that they break, whip up into the HV mains, cause a short circuit and then fall clear. These accidents may also break conductor ties or split crossarms. (Close checking of pole tops is required here.)

- Faults near water and grain storage areas may be caused by birds that fly into exposed lines, especially at dusk or sunrise. (The switching operator should look for signs of dead wildlife or feathers when patrolling the line.)

- Vandals constantly cause faults by throwing wires or rubbish over mains. These may be difficult to detect. (The switching operator should carefully observe the area and make local enquiries.)

- Insulation failures may be transient. Surge diverters may be faulty but look perfectly normal. Pin insulators may puncture beneath the conductor and trip the line when moisture fills the puncture. (These faults are extremely difficult to find.)

- Faults caused by lightning may be only transient. Lightning strikes do not have to strike a line directly to cause an outage. Strikes in close proximity can induce high currents in lines, which trip the controlling circuit breakers.

- Bush fires beneath lines send up dense clouds of smoke containing conductive particles. These particles may cause outages due to a flashover between conductors or the conductor and earth.

4.4.7 Single-phasing Faults (Loss of one HV phase)

In a three-phase system, single-phasing faults are caused by the open circuiting of one HV phase. This causes abnormal voltages on the LV side of distribution transformers and is commonly reported by customers as a ‘dim supply’ or ‘partial supply’.

The open circuiting of one HV phase will not operate feeder circuit breaker protection, because of the balanced current on the healthy two phases.

Most of these faults on a three-phase system are caused by the following:

- a HV drop out fuse has blown

- a tap may burn off at a pole top switch, a corner tapping pole, or a termination.

- the contacts on a pole top switch may overheat and burn so badly that the contacts become highly resistive. They may also melt away from each other resulting in an open circuit.

- a broken conductor caused by weather conditions or mechanical damage.

After the repair and restoration of a permanent phase to phase or earth fault, or the successful reclose after a transient fault, complaints about dim lights or partial supplies may be received. Such complaints may indicate the fault current from the previous fault has also caused an open circuit HV conductor or a blown HV fuse.

4.4.8 Feeder Faults – Drop Out Fuses Failing to Clear

Sometimes faults occur on fused spurs or circuits that feed transformers. A whole feeder may trip for the following reasons:

- The fuse operates too slowly, because it may be incorrectly sized or have been hard wired.
- The expulsion tube (in which the arc extinguishes) fails to function correctly. A flashover then results, causing the feeder to trip instead of the drop out fuse (DOF).

4.5 Fault Finding Process

HPCC manages all unplanned HV outages and will advise the switching operator of specific actions required to be undertaken in the fault finding process.

The fault finding process requires a close review of any protection or fault indicator operation and a systematic approach to the trial restoration process.

Field Instruction – *Replacing fuses on the HV/LV underground and overhead network after a fault has occurred* provides details of the procedures for overhead HV/LV faults. The switching operator must perform risk assessment and line patrols in accordance with this field instruction. Line patrolling is an essential part of the fault finding process and is undertaken to ensure that the line is not hazardous to the public, livestock and equipment and to locate any obvious cause of the fault.

Note: Line patrols for faults are mandatory for overhead HV circuits within town boundaries and overhead LV circuits.

Risk assessment and line patrol requirements for feeder and auto-recloser lockout and sectionaliser operation are similar to those for fuses.

Examples of the approach typically used for fault finding specific types of faults are given below.

4.5.1 Single-phase Spur Faults

Single-phase HV spurs are often protected by single and multiple drop out fuses. They may have disconnection points (live line taps) at several points throughout the spur.

HPCC manages HV fault switching and will guide the switching operator to ensure compliance with Field Instruction – *Replacing fuses on the HV/LV underground and overhead network after a fault has occurred* for line patrol requirements. HPCC will then the request the operator at the appropriate time to perform the following steps:

- Reload the HV fuse and try to reinstate the line.
    - If the fault was transient, the fuse will hold. A full line patrol is required at the earliest practical time, if not already carried out.
    - If the fuse blows when it is replaced the fault is permanent , the line will then need to be sectionalised and reenergised until the fault is located:
        - Once the faulted section is found, the healthy sections of the line may be reinstated.
        - The line fault can then be rectified and the line may be returned to normal.

Note: The fault may cause arcing and sparks every time the fuse is replaced. (Dry conditions present a real danger of fire in this case.)

The fault may be a conductor close to the ground. (This places people and stock at great risk.)

The fault may be in a transformer and not visible. (In this case, each transformer or group of transformers must be disconnected in order to locate the fault.)

For two and three shot fuses, the fault finding process is the same as for single shot drop out fuses.

Single-phase Reclosers and Sectionalisers

Single-phase spurs are often protected by reclosers and sectionalisers.

Fault finding for recloser and sectionaliser operation is described in Section 4.2. The switching operator should consider the following.

- To locate a fault when fault switching, the reclosers must be set to 'manual' (single shot or non-reclosing). The recloser is fully rated for fault switching.
- Reclosers and sectionalisers have a bypass fuse that can be used as a substitute to prove the recloser or sectionaliser. It may also be used to protect the line and maintain supply, if repairs to the recloser or sectionaliser are required.

- The sectionaliser must not be used for fault switching. The sectionaliser bypass fuse should be used, where available. If it is not available, use the recloser.

Note: Regular records of the number of reclose attempts are kept. This assists district staff to identify any spur that has a high percentage of transient faults. Such spurs can be patrolled and the problems identified.

Records should also be kept for three-phase reclosers protecting the whole feeder or parts of the feeder.

4.5.2 Three-phase Feeder Faults

Feeder faults are serious because:

- many customers will lose power
- phase-to-phase voltage is greater than for single-phase spurs
- more complicated switching is involved (LV feeder, feeder interconnection and substation switching).

HPCC manages three-phase fault switching and the manual reclosing of feeders and will direct the switching operator on the actions required. Details of the typical actions are provide below.

Transient Faults

Transient faults on feeders are reinstated by auto reclose of the circuit breakers at the substations or line reclosers. Where the number of reclose attempts is high in normal conditions, the line will be requested by HPCC to be patrolled to locate and rectify the transient fault.

Manual Reclose

At times, the complete feeder trips and, following the required number of reclose attempts, the circuit breaker locks out at the substation. HPCC will request field staff to investigate the fault with a line patrol. If called to attend a substation, the switching operator must record all flagging in the logbook before resetting the flags.

For short feeder lengths, the line is patrolled from the substation. If required the patrolled sections can be progressively reinstated.

For long 22kV and 33kV feeders it may be necessary to patrol, sectionalise and attempt trial reclose operations to locate the fault. Therefore, the feeder should be opened at an appropriate point of the feeder, approximately half way. After manual reclose, if the first half of the feeder stays in, the remaining half of the feeder should be opened at its half way point.

The feeder may then be tripped at the substation and the first open pole top switch should be closed. If the pole top switch is fault-rated, the feeder does not need to be tripped. If the reinstated feeder stays in, the fault must be contained in the last quarter of the feeder. The feeder may be broken again or patrolled, depending on the length of the remaining feeder.

During fault switching, after location and isolation of the fault, further faults may be found as the feeder is restored. This is because the high fault current travelling to the fault may cause more damage to other parts of the feeder. The following problems may occur under these circumstances:

- Dim supplies may be caused by the following:
    - drop out fuse flashover causing the original trip – once the feeder is reinstated, the drop out fuse still needs to be replaced
    - a burnt off tap – during the transient fault, the fault current has been sufficiently large to burn off a connection. If the live side falls clear of all other apparatus when it is energised after a reclose, the feeder will hold in. However, dim supplies will occur past the burnt off connection.
- failure of lightning arrestors – sudden changes of voltage may cause failure of deteriorated lightning arrestors. The failure may occur at the time of the fault or during the fault switching process
- blown drop out fuses – a drop in voltage may cause the operation of deteriorated fuses or fuses with a very small rating.

Note: When fault switching, the minimum number of re-energising operations should be used. This helps to limit the fault current through other parts of the feeder. In turn, this reduces the stresses on all apparatus.

In summary, fault finding for feeders should be conducted as follows.

- HPCC manage all unplanned outages and will request the required line patrols.
- HPCC must be advised of all flags recorded at the substation (if attendance is required).
- Safety is most important. Use only approved methods, equipment and personal protective equipment.
- Pole top switches are designed to make fault current, but not break fault current.

- The auto reclose device must be taken out of service when fault switching at zone substations and/or feeder reclosers which are installed along the line.

- While the faulted section is being located and repaired, the unfaulted line sections may reinstated. For example, unfaulted line sections may be fed from the zone substation or be interconnected using another feeder.

- The same fault finding principles, as those for a feeder from a zone substation, apply to fault finding beyond a recloser.

Note: If the stated rating is not exceeded when closing on a fault, the pole top switch may be used instead of the circuit breaker.

4.5.3 Distribution Transformer Faults

See Section 3.4.3 for a description of overhead transformer faults and the associated procedures required.

SECTION FIVE

HV Distribution – Underground

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5. HV Distribution – Underground

5.1 Introduction

This section deals with the operations of HV (11kV to 33kV) underground distribution systems. These systems may be combined within an overhead system or used solely from the zone substation to the distribution transformers.

The fundamental principles of the underground HV system are the same as those of the overhead system. However, certain areas require different designs for operation procedures.

Underground systems are the standard construction for distribution systems in cyclonic regions. They are also used in high-density commercial areas, heavy industry, and new residential developments, typically underground distribution schemes (UDS).

This section is written to reflect current standards and may not include many of the legacy installations and apparatus.

5.2 System Components

The main components in the HV underground system are cables, ring main units, HV metering and ground mounted distribution transformers.

5.2.1 Cables

Horizon Power uses cables in a variety of sizes and voltages, depending on the need. The main cables are shown in Table 5-1.

In addition to those listed, many older sizes and types of cables are found in Horizon Power's system.

Application	Voltage (kV)	Cable (mm^2)	
Feeder	11	300	Cu and Al
		240	Cu and Al
		185	Cu
	22	240	Cu and Al
		400	Al
		185	Cu
	33	185	Al
Distribution transformer	11	70	Al
	22	35	Al
		50	Al
	33	50	Al

Table 5-1 Cable applications

XLPE Cables

Cross-linked polyethylene (XLPE) cables are the standard cable. Polyethylene has the following advantages over previous insulants:

- low cost
- low capacitance
- ease of extrusion
- low dielectric loss, and
- high electrical strength.

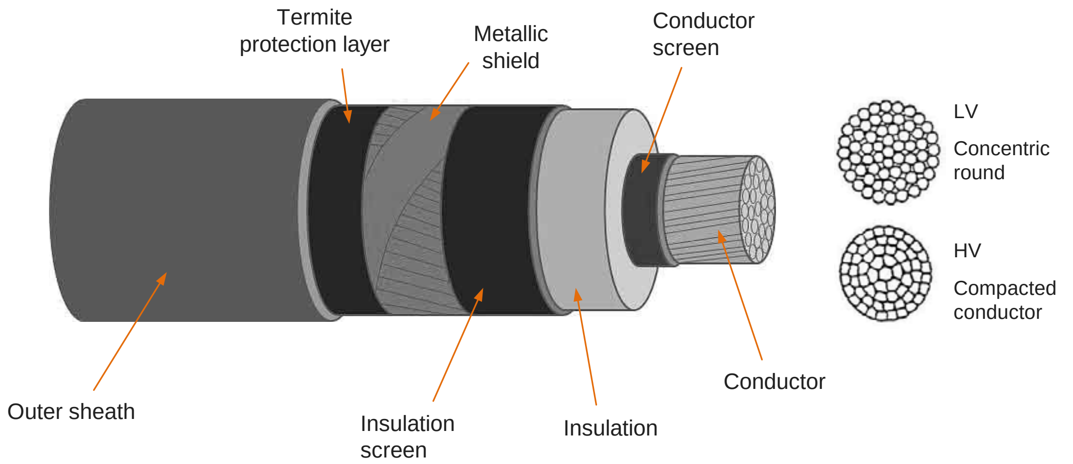


Figure 5-1 Single core XLPE cable

PILCSWA Cables

PILCSWA cables are paper insulated with lead sheathing and steel wire armour. The cable has a conductive screen of metal tape around each core that aids the detection of any earth leakage current from an individual core. The lead sheath prevents moisture from entering the cable while the wire armours provide mechanical protection around the cable.

Where the cable is terminated, the screening, the lead sheath and the steel wire armours are each connected to the earth system of the zone or distribution substation.

This means that there is a fully screened system bonded to earth, except for the small area where the screening does not meet the cable box bushings at the terminations. Therefore, nearly all cable faults will be detected and cleared by earth fault relays.

Although no longer installed, these PILCSWA type cables will be found in older systems.

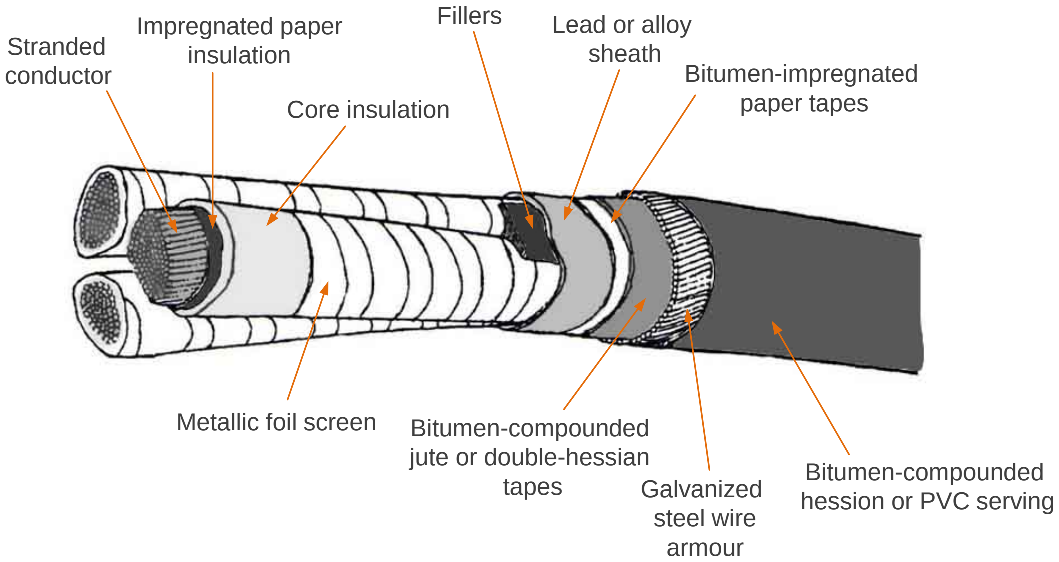


Figure 5-2 PILCSWA cable

5.2.2 High Voltage Cable Terminations

High voltage cable terminations are used to connect high voltage cables to Horizon Power's indoor and outdoor switchgear and pole mounted terminations. The integrity of the connection is paramount to ensure terminations are able to withstand peak load requirements and not fail during fault events.

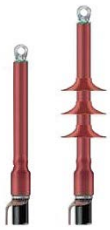
Apparatus	Use
	**630A elbow connector** Used to terminate HV UG cables into Horizon Power switchgear including ring main units and possibly circuit breakers. These connections are used on Horizon Power's feeder connections.
	**200A deadbreak elbow connector** Used to terminate HV UG cables into Horizon Power padmount transformers.
	**200A deadbreak straight connector** Used to terminate HV UG cables into Horizon Power fusible ring main switch units.
	**200A deadbreak Insulated cap** Used to create insulated protection for non-used high voltage bushings on Horizon Power's padmount transformers.
	**HV indoor / outdoor terminations** Used to terminate HV UG cables into Horizon Power indoor/outdoor switchgear, mostly substation and outdoor pole terminations. Note: When installed outdoors, the termination must have weather shields, applicable for the operating voltage of the cable, installed along the termination.

Figure 5-3 HV cable terminations used to connect HV cables to Horizon Power's indoor and outdoor switchgear, and pole mounted terminations.

Horizon Power's cable terminations are not rated as switching devices. Any removal or modification will need to be done under an Electrical Access Permit (EAP). Before switching and where possible, a visual inspection should be performed to check integrity, including baling assemblies and terminations for tracking or other defects.

5.2.3 Ring Main Units

Ring main switchgear is installed in HV underground cable systems throughout the distribution system. All ring main units are made up of one or more of the following:

- a ring main switch, which is a load-break, fault-make switch
- a switch fuse, also called a fuse switch, which is a load-break, fault-make switch equipped with HRC fuses to break fault current
- an HV metering tank.

The ring main switch enables:

- the underground cable system to be isolated in sections, and
- the interconnection of adjacent feeders.

The switch fuse allows the following functions:

- the connection and protection of distribution transformers, and
- an isolation point for distribution transformers.

Many styles and designs of ring main units are used by Horizon Power (for details see Table 5-2). They are mainly non-withdrawable units with a few remaining withdrawable units.

Make	Type
Areva/Alstom	FBA
Schneider/Merlin Gerin	RM6 VM6
Areva	FBE 33kV
Brown Boveri	Withdrawable

Table 5-2 Typical makes and types of ring main units

Ring main switch and fuse switch contacts have a ganged three-phase operation. The insulating materials used in the switch contact chamber to extinguish arcing during operation are:

- sulphur-hexafluoride (SF_6) in a pressurised sealed chamber
- air (no longer commonly used).

A typical ring main unit is shown Figure 5-4 below. The ring main unit has a fuse switch in centre position with a switch on either side.

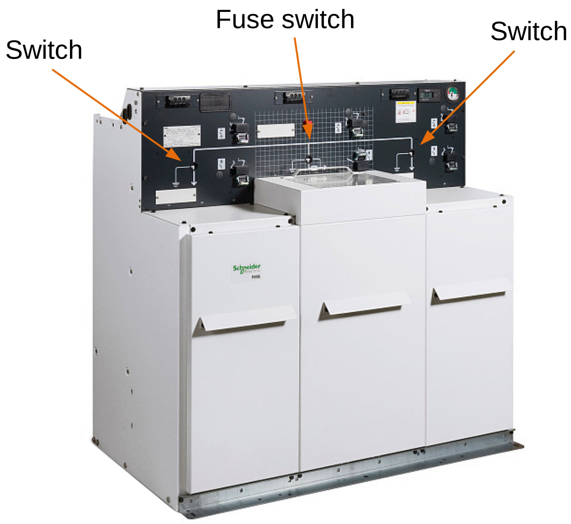


Figure 5-4 Typical ring main unit
This RMU is a Schneider RM6 in 2+1 configuration

Ring Main Switches

These switches are used on distribution underground systems for the same purpose as pole top switches on overhead systems.

These three-phase switches are used for interconnection, load movement or isolation of sections of feeder cables.

Ring main switches are connected between the internal bus bar and the cable as shown in Figure 5-7 and incorporate either an internal earth function or facilities for external earthing. The earth function works on the cable side and not the busbar side of the ring main switch.

The normal configuration of a ring main unit is two ring main switches and a number of switch fuses, although other configurations may be installed where required.

Typically, the maximum full load rating of a ring main switch is 630 amps. Particular details for each type of ring main unit can be found on the nameplate.

Ring Main Fuse Switches (Fuse Switches)

Fuse switches are used on distribution underground systems for the same purpose as drop out fuses on overhead systems.

Switch fuses are used extensively in ring main systems, as an economical means of protecting distribution transformers. They are similar to ring main switches in construction, but include a HV HRC fuse to provide fault interruption and an associated automatic three-phase trip as shown in Figure 5-6.

The advantages of correctly graded fuses are:

- quick isolation of the fault, minimising the risks of injury and damage to equipment
- isolation of only the faulted transformer, keeping maximum supply available to customers.

Switch fuses typically have a maximum full load rating of 200 amps.

The size of the fuse to be used depends on the size of the transformer to be protected. For example, an 11kV 500kVA transformer is protected by 63 amp HRC fuses. The fuse sizes range from 6.3 amps to 80 amps (see Table 5-3).

	Ring Main HRC Fuses			
Three-phase	kVA	11kV	22kV	33kV
	160	25	10	6.3
	315	31.5	16	16
	500	40	25	-
	630	50	31.5	20
	750	63	40	-
	1000	80	40	40

Table 5-3 Ring main HRC fuse ratings

Note: 33kV ground mounted distribution transformers are mainly fed via overhead drop out fuses.

HV HRC fuses consist of a porcelain cylinder with end caps and an internal fuse element and striker pin. The fuses are located in a dry air insulated chamber attached to the switch tank.

The components of an HV HRC fuse are shown in Figure 5-5.

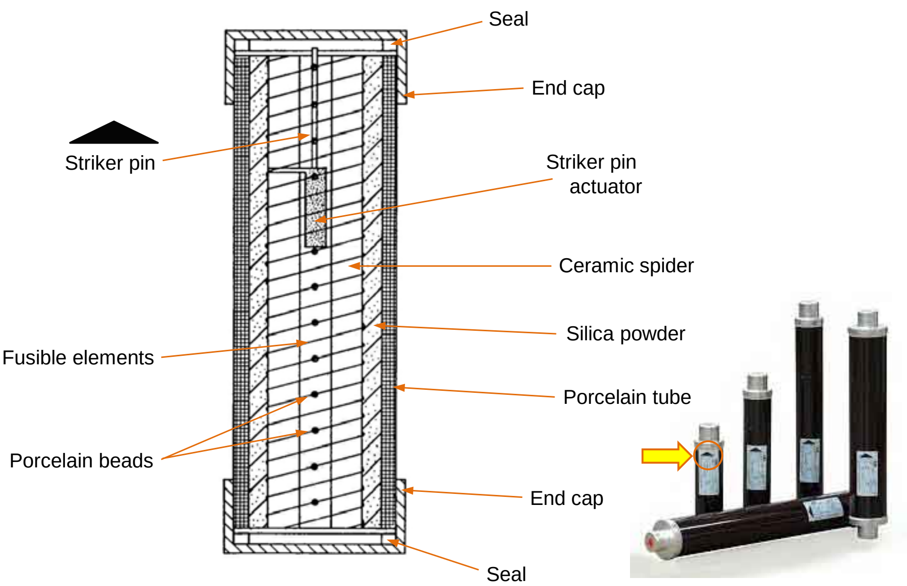


Figure 5-5 Sectional view of a HV HRC fuse
Note the yellow arrow on the fuse body, indicating the direction of the striker pin.

When the fuse blows, the striker pin in the cartridge is released. This protrudes outside the cartridge, striking the trip bar device on the fuse switch. The switch then trips to the 'off' position. An indicator on the face of the fuse cabinet may be provided to show the fuse has blown.

Because fuse striker pins are fitted at one end only, the striker pin must be correctly located adjacent to the trip bar mechanism. Note the arrow on the fuse body in Figure 5-5, indicating the correct direction of the striker pin.

Access to a fuse is not possible unless it is isolated, that is, the switch fuse is switched 'off'. Where switches have an internal earth function, the switch must be put to the 'earth' position before access to the fuse chamber is possible. Where switch fuses are withdrawable, they must be switched 'off' and racked out for access to the fuses.

Note: When changing fuses, the switching operator must remember:

- the internal bus bar section of the ring main unit is normally energised, and
- the fuse must be fitted with the striker pin towards the trip mechanism.

Ring Main Unit Configuration

The ring main units consist of the required number of switches and fuse switches to match their application in the network. Figure 5-6 shows a ring main unit with two switches and two fuse switches. This arrangement is commonly referred to as a 2+2 unit. Figure 5-7 shows a unit with only four switches (4+0 unit).

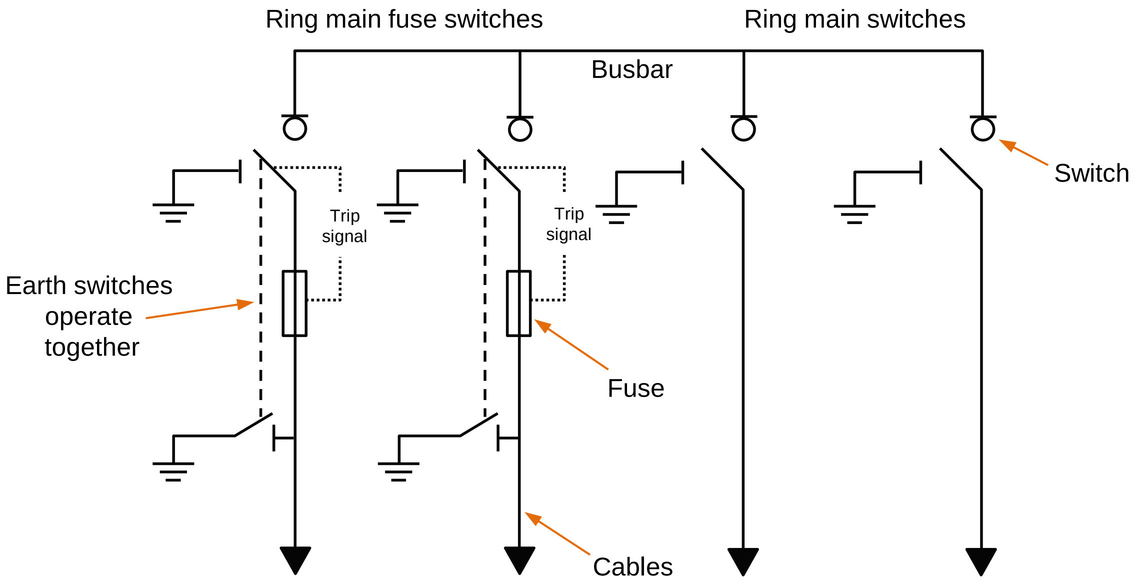


Figure 5-6 Schneider RM6 two ring main switch and two switch fuse

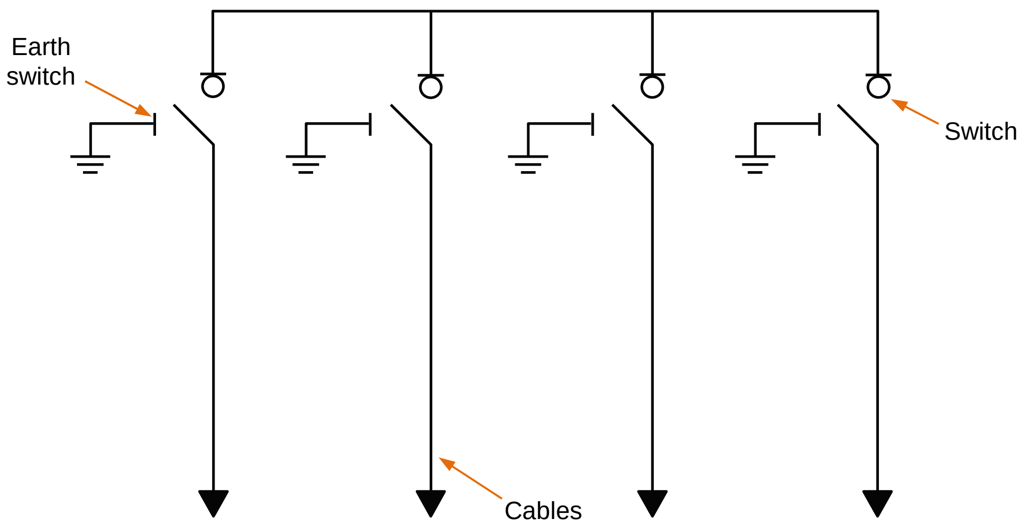


Figure 5-7 Typical Schneider RM6 four ring main switch

Ring main units can be supplied as an extendable or combined (non-extendable) units as shown in Figure 5-8.

Extendable units provide the capability to build the required configuration by joining together the required number of switch and fuse switch modules. Each module is joined to the next with air-insulated connection joints. Where the switch and fuse switch modules are SF_6-insulated, each module has a separate SF_6 chamber and associated pressure gauge.

Combined (non-extendable) units are built by the manufacturer to required configuration inside one tank. Therefore in combined SF_6 units there will only be one pressure gauge. Combined units are commonly used for standard configurations such as 2+1.

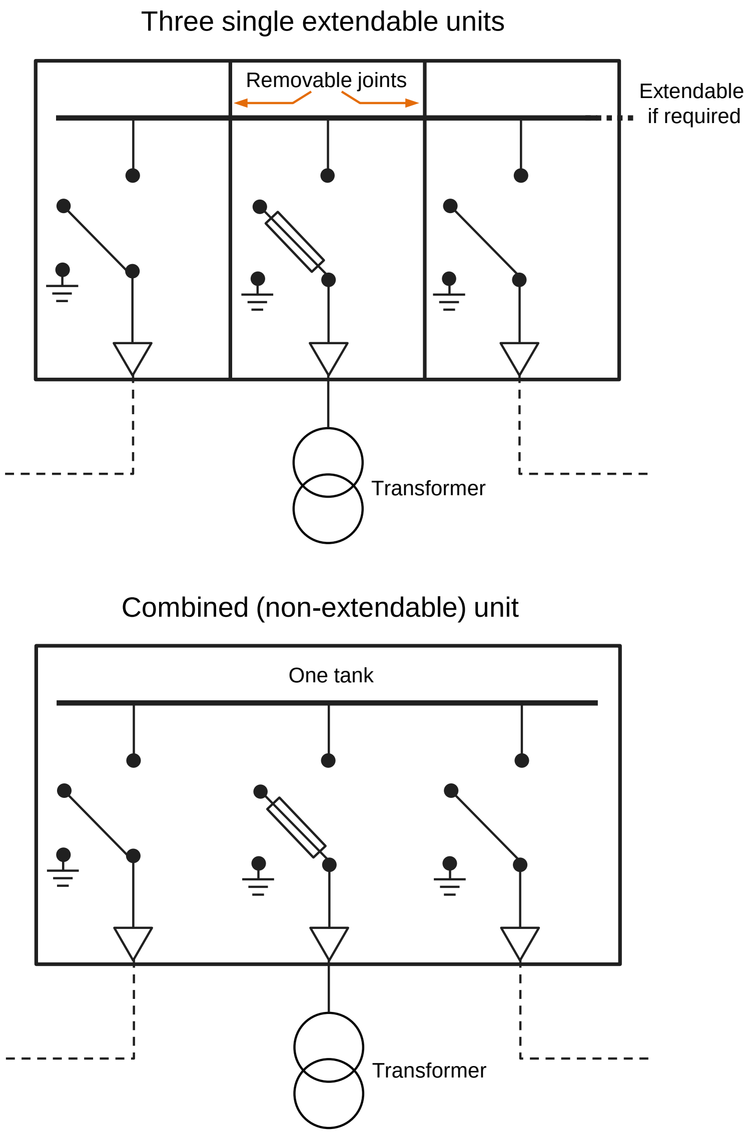


Figure 5-8 Extendable and combined ring main units

Withdrawable and non-withdrawable switches and fuse switches can also be provided. In non-withdrawable units, the switch and fuse switch cannot be withdrawn, disconnecting them from the busbar and cable circuits. Non-withdrawable units are most commonly used.

Shown in Figure 5-9 below is the principle of withdrawable ring main units with a withdrawable truck unit for both a ring main switch and a switch fuse. The figure shows the truck C may be moved in or out of the housing D. When the ring main switch is inserted into its correct position, it plugs into the HV cable spouts A and the busbar spouts B. When physically withdrawn the switch separates from the busbar and cable connections as shown for the ring main switch in the right image of Figure 5-9.

In its correctly plugged-in position, the interlock of the ring main switch may be set to the 'service' position. The switch can then be operated to 'on' or 'off', as required, usually by means of a spring charged device.

The interlock prevents the switch from being withdrawn while it is in the 'on' position. It also prevents the switch being racked in if the truck is in the 'on' position.

The withdrawable switch fuse is constructed and operated in the same way as a ring main switch but contains three fuses (see Figure 5-9 left). It must be switched 'off' and racked out into the withdrawn position out before the fuses can be replaced.

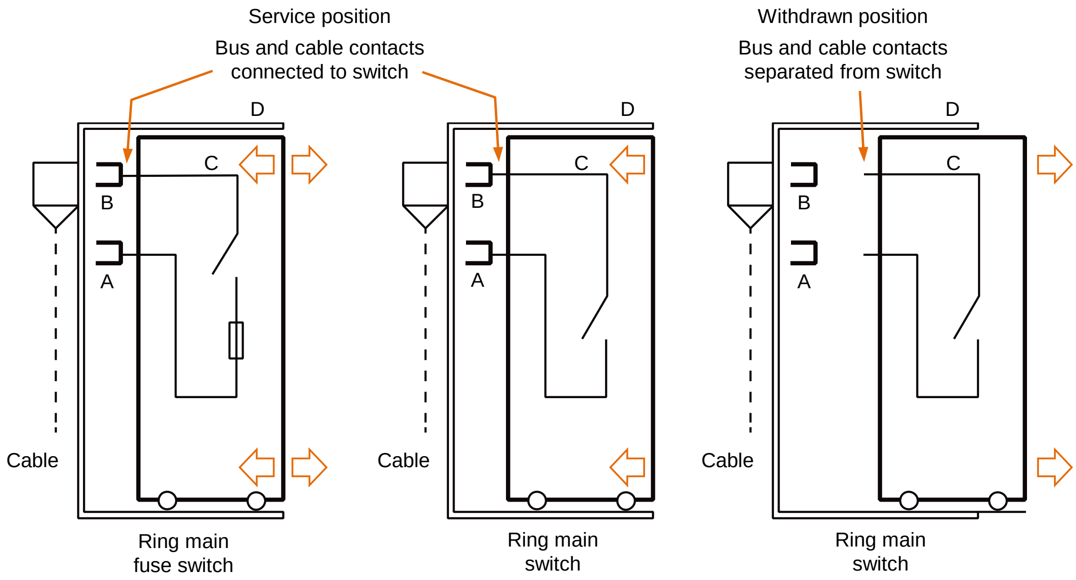


Figure 5-9 Ring main switch in the service and withdrawn positions
Note the ring main fuse switch on the left is also a withdrawable unit.

Comparison of the underground and overhead system

It can be seen that underground and overhead systems are almost identical in operation but there are important differences.

- Ring main units have a cable earthing facility. This may be a switch or manual plug-in device that is used instead of portable overhead earth sets.

- Ring main equipment is designed as full load-break fault-make units. This is not so for pole top switches that have limited capacities.

- Ring main units are designed so that the transformer's switch fuse opens if a fuse blows. This produces a three-phase trip if any fuse blows. (Drop out fuses only trip one phase).

- The switch contacts are inside the chamber and are not visible. The switching operator must prove the circuit is de-energised before the earths are applied. (Some units have neon indicators while others have external testing devices.)

- Faults that develop on an underground cable are mostly permanent. Therefore, the substation circuit breaker should not be set to 'auto reclose' on circuits that are mainly cable.

- A section of cable may be isolated without loss of supply to a distribution transformer. Usually, this is not possible in the overhead system.

Operation of Switches

Ring main switches and fuse switches have three operational positions – ON, OFF and EARTH. A description of the electrical status for each position is shown in Table 5-4 below.

Operational position	Electrical status
ON	Busbar is connected to cable
OFF	Busbar is disconnected from cable
EARTH	The cable is connected to earth

Table 5-4 Operational positions and their electrical status

Most ring main switches and fuse switches have separate switch operating mechanisms or earth switch operating mechanisms, whereby a handle is inserted to operate the switch or earth switch. Switching is restricted to one operation at a time to ensure each operation is separate and deliberate.

Mechanical interlocks between the switch and earth switch mechanisms restrict the allowable combination of the switch and earth switch position to those shown in Table 5-5 below.

Operational position	Electrical status	Switch position	Earth switch position
ON	Busbar is connected to cable	ON	OFF
OFF	Busbar is disconnected from cable	OFF	OFF
EARTH	The cable is connected to earth	OFF	ON

Table 5-5 Mechanical interlock status in relation to operational positions

One exception to this arrangement is the Brown Boveri ring main unit, which has a plug-in portable earth rather than an earth switch.

Figure 5-10 shows an example of the mechanisms and indicators on the front panel of a ring main unit.

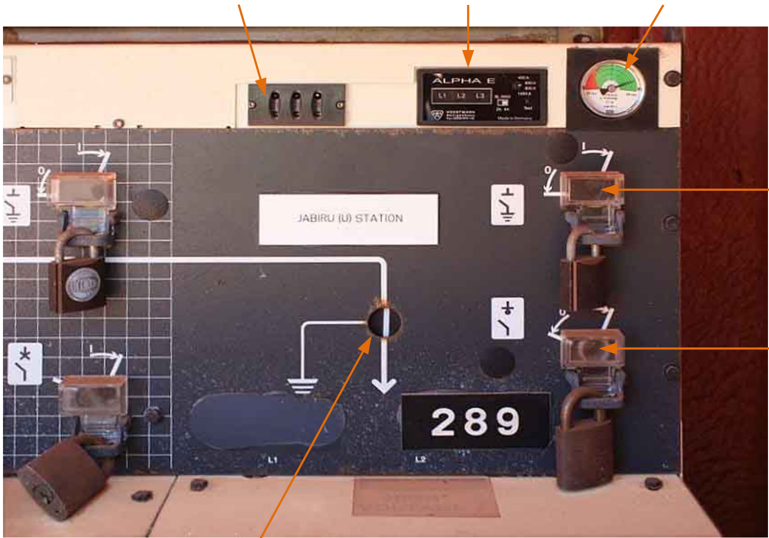


Figure 5-10 Ring main switch front panel

Spring assisted operation

Ring main switches and earth switches typically have some form of spring assistance in the operating mechanism to ensure the switch contacts move at the rate required to achieve the nominated switching current ratings.

As the handle of the switch is operated, it charges a spring that takes over the switching action. This release of stored energy quickly transfers the switch to the selected position, giving a consistent operation every time.

On closing a fuse switch, a stored charge is first made to enable the fuse switch to trip if the HRC fuse blows and operates the striker pin. To trip a fuse switch, the switching operator is required to either press a button or move the handle in the opposite direction.

Earth switches are spring-assisted on closing to ensure rapid earthing of the circuit but in some cases are not assisted on opening.

Drive Motor Spring Charged.

Certain types of Schneider switches and breakers make use of a DC drive motor to charge the closing spring. This feature is used when remote switching operations are required on apparatus using a RTU via SCADA.

The design of some apparatus does however not include a standard feature to isolate the DC supply to the spring charge motor. This is a problem when the switch needs to be isolated for the issue of an EAP.

To overcome the problem of the apparatus not having an integrated means to isolate the DC supply to the spring change motor, a separate external DC isolator is fitted to each switch. The position of the DC isolator in circuit not only isolates the spring charge motor, but also isolates the electrical supply for “remote control” functioning of the apparatus as well.

Operation of the DC isolator must be included in the switching program by the Switching Operator when isolation of the circuit / apparatus is required.

Figure 5-11 DC Isolator

Remote Terminal Unit (T300).

Remote control functionality of some ring main units via SCADA is achieved by means of a T300 Remote Terminal Unit (RTU).

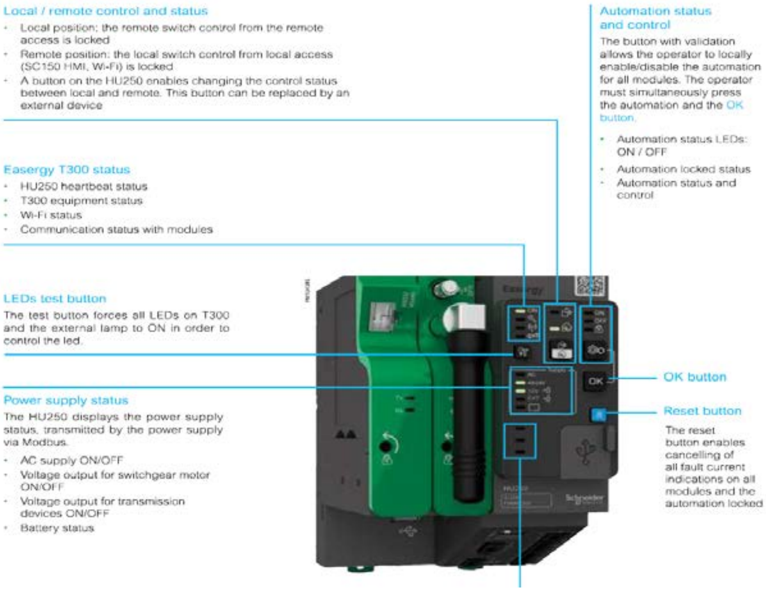


Figure 5-12 T300 Remote Terminal Unit

A single T300 Remote Control Unit is designed to allow remote operation (close, open) of the switches it controls at a particular location.

To inhibit remote operation of the RTU and the associated switches it controls, a selection to “local control” must be made on the unit. When the unit is selected to “local control”, a LED is illuminated to indicate this.

The T300 remote terminal unit is housed in a weather proof lockable enclosure. To prevent the T300 unit from being accessed and inadvertently selected to “remote control” after being selected to “local control”, it must be locked.

Figure 5-13 T300 Locked Enclosure.

Voltage indicators (neon indicators)

Voltage indicators are provided on the ring main unit front panel to show the electrical status of the associated cable. Earth switches must not be closed unless the indicators on each phase show the cable is de-energised.

An example of voltage indicators is shown in Figure 5-11 below. The markings L1, L2 and L3 represent the R, W and B phases respectively. The neon indicators glow to show the presence of voltage on each phase of the cable

Neon indicator for each phase

Glowing = voltage is present

Socket to plug in voltmeter
as alternative indication

Figure 5-14 'Voltage presence' indicating neon lights as fitted to a RM6 ring main unit.

It is good switching practice to observe the three voltage indicators are operational prior to de-energising a circuit. As an alternative method of proving de-energised, three sockets are often provided near the indicators to allow the use of a voltmeter.

Some ring main units have removable voltage indicators. This facilitates proving the indicators are working on live circuits before and after switching to de-energise a cable.

Before applying an earth, the switching operator must use an approved testing method to positively prove the circuit is de-energised.

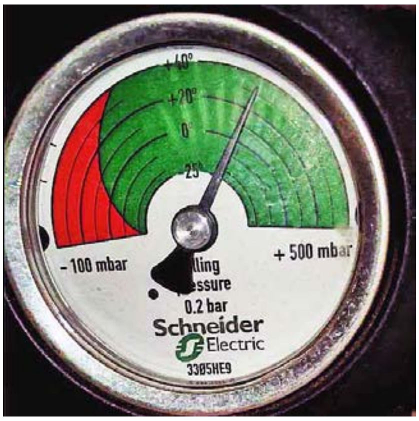
SF_6 gas pressure indicator

SF_6 ring main units require adequate gas pressure at the operating temperature to achieve the rated switching current. An energised switch must not be operated with low gas pressure. The switching operator must check the gas gauge to ensure adequate pressure before operating a switch.

An example of a gas pressure gauge is shown in Figure 5-12. The gas pressure is indicated by the black needle. As pressure varies with temperature, the gauge has a number of concentric circles indicating temperature between the range of –25°C to +40°C. The green and red areas are used to show adequate or low gas pressure respectively.

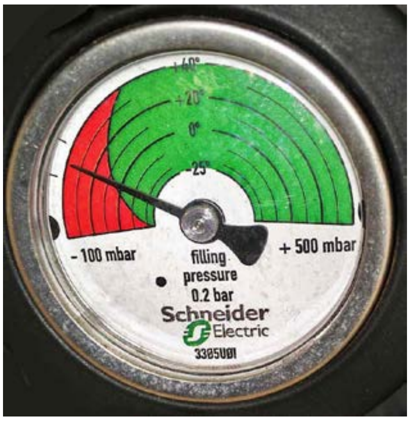
One method of reading the gauge is to look if the needle crosses anywhere into the red area. If so, the temperature of where the needle crosses from the green into the red area is estimated using the concentric temperature circles. If the actual switchgear temperature (usually ambient temperature) is above this temperature read from the gauge then the gas pressure is low and switching is not to proceed.

For example, in Figure 5-12 the left-hand image shows the needle in the green area over the entire temperature range; therefore the gas pressure is adequate. The right-hand image shows the needle crossing into the red area at an estimate 5°C from the concentric circles. This is interpreted as the gas pressure is low if the actual temperature of the switchgear (usually ambient temperature) is above 5°C (that is, a temperature in the red area). Therefore if the actual temperature of the switchgear at the time of switching is above 5°C this switchgear must not be operated.



Needle in green area
for all temperatures.

Gas pressure is adequate.



Needle in red area above 5°C.
Gas pressure is low
for all temperatures above 5°C
(red area).

Figure 5-15 Gas level gauge on RM6 ring main unit

Where RMUs are fitted with a gas pressure indicator, this indicator must be checked to ensure the gas pressure is adequate for the switch to be operated.

Switching must not proceed if the gas pressure is outside acceptable limits.

Earthing of Circuits Connected to Withdrawable Ring Main Units' Switchgear

Withdrawable ring main units are not fitted with an integral earthing switch. Earthing of the cable circuits must be done manually.

Earths must be applied as soon as possible after testing. If a circuit is proved to be de-energised, but earths cannot be applied at the time, the switching operator must prove the circuit is de-energised again, just before applying the earths.

An example of a withdrawable ring main unit is the Brown Boveri unit (shown in Figure 5-13). Proving de-energised and earthing is performed through the cable access cover. The portable earths are applied with the insulated earthing handle. Because of interlocking arrangements this earthing access cover can only be opened when the switch/fuse switch is in the withdrawn position.

Before applying an earth, the switching operator must use an approved HV testing device to positively prove the circuit is de-energised.

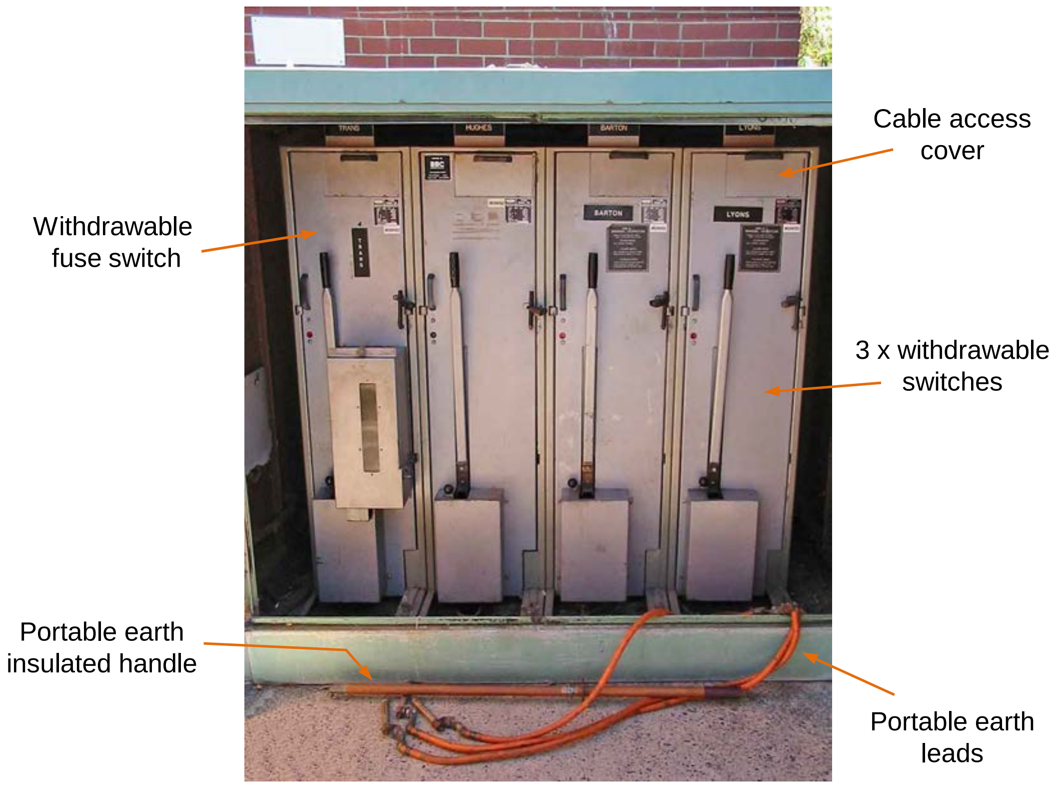


Figure 5-16 Brown Boveri withdrawable ring main unit

Changing fuse switch fuses

Fuse switches are used to supply distribution transformers. To change the fuses in the fuse switch the following conditions are required:

- The transformer must be isolated on the LV side – transformer LV disconnectors removed, barriers fitted and Danger–Do Not Operate (D–DNO) tagged.
- The fuse switch must be OFF and D–DNO tagged.
- The fuse switch earth switch must be ON – this earths both side of the fuses and enables access to remove covers and change the fuses.
- The fuse must be inserted with the fuse striker pin facing toward the trip bar.

5.2.4 HV Metering

Where customers require a sole use distribution substation (usually over 2 MVA), HV metering can be installed instead of LV metering. This allows customers to run HV supplies within their own installations and have different rates for power consumption. Depending on the ring main switchgear type the metering may be installed as part of the ring main unit or as a separate unit.

In this type of installation, the HV distribution system has one, two or three incoming feeds entering a common busbar. From here, the power passes through the HV metering tank, where current and voltage transformers measure power consumption. The common busbar then feeds a series of customer owned switch fuses or circuit breakers.

Note: When insulation resistance testing switchgear with HV metering tanks, switching operators must remember to remove the HV voltage transformer fuses.

If this is not done, incorrect readings will result during the tests.

5.2.5 Ground Mounted Distribution Transformers

The principles of both overhead and ground mounted transformers are the same. However, enclosed HV and LV cable boxes are normally fitted to ground mounted transformers, in contrast with the open HV and LV bushings used on pole mounted transformers.

Because of the inherent danger of electrocution, all compound ground mounted transformers with open HV bushing are required to be converted to enclosed cable box transformers. If any open HV bushing ground mounted transformer compounds are found, the switching operator must not enter them. The operator must report the details to their formal leader for remedial action.

The standard sizes of ground mounted transformers range from 160kVA to 1000kVA. These transformers are installed in padmounts, compounds or fully fire-rated indoor substations.

5.3 Design Principles

An underground system is designed in basically the same way as an overhead system. The feeders run radially and are interconnected with other feeders, where possible. Distribution transformer feeders are teed-off as required.

The switch fuse replaces the drop out fuse. The ring main switch replaces the pole top switch.

Where a ground mounted transformer is required to supply customer installations, one of the five following methods may be used:

- Method 1 – Standard RMU single transformer
- Method 2 – Single RMU with multiple transformers
- Method 3 – Overhead supply to transformer
- Method 4 – Piggy-back transformers (not approved for new installations)
- Method 5 – Single-phase underground distribution system.

5.3.1 Method 1 – Standard RMU single transformer

The most common method for supplying padmount transformers in the network is via ring main switchgear with at least two ring main switches and a switch fuse (see Figure 5-14). This method enables flexibility of feeder loads and continuity of supply during minor outages.

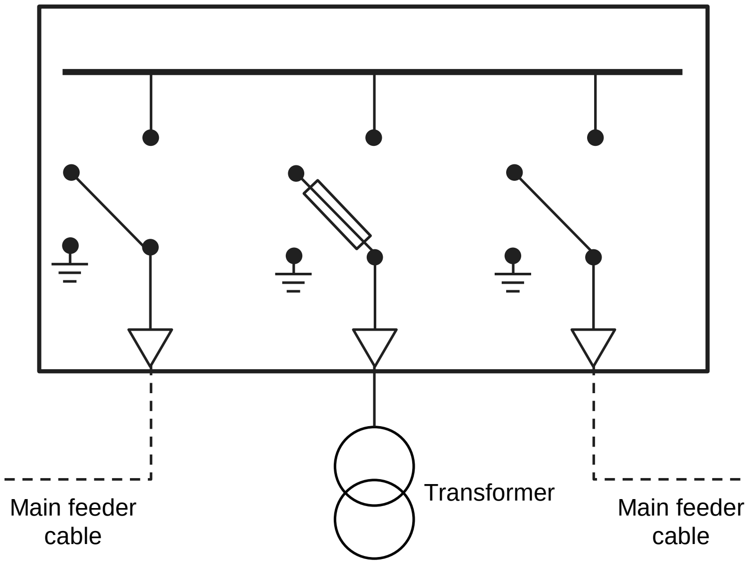


Figure 5-17 Method 1 – Standard RMU single transformer

5.3.2 Method 2 – Single RMU with multiple transformers

In this method, a remote transformer is supplied from a ring main substation (see Figure 5-15).

There may be problems when the ring main unit has to be isolated. Both the substation's transformer and the remote transformer must be fed up on LV circuits to avoid customer outage.

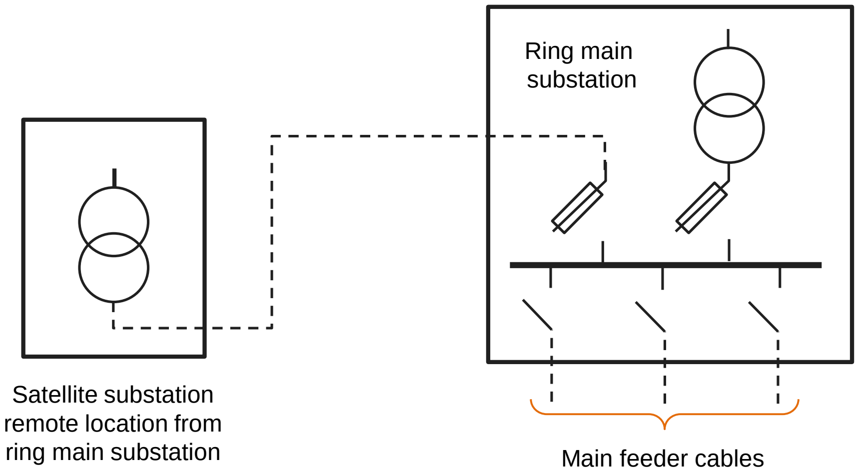


Figure 5-18 Method 2 – Single RMU with multiple transformers

5.3.3 Method 3 – Overhead supply to transformer

This method is used to connect ground mounted transformers to the overhead network. Drop out fuses are used (instead of a HV switch fuse) to feed a cable to the ground mounted transformers (see Figure 5-16).

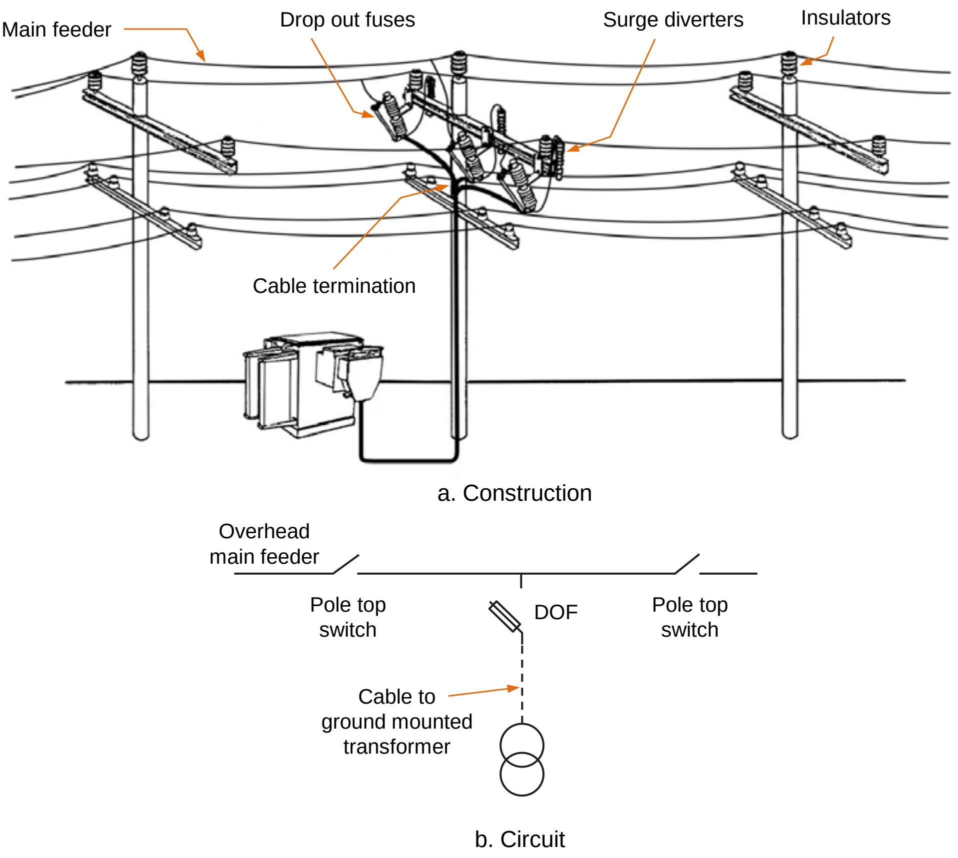


Figure 5-19 Method 4 – Overhead supply to transformer

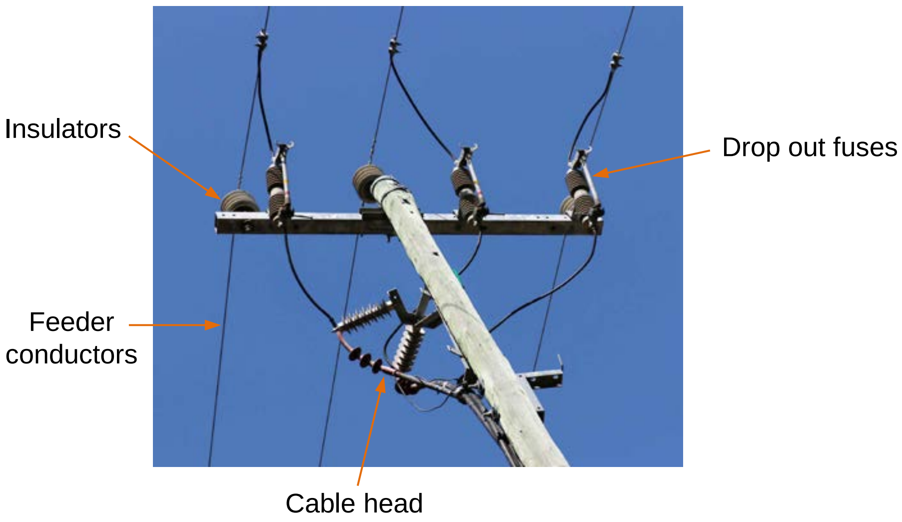


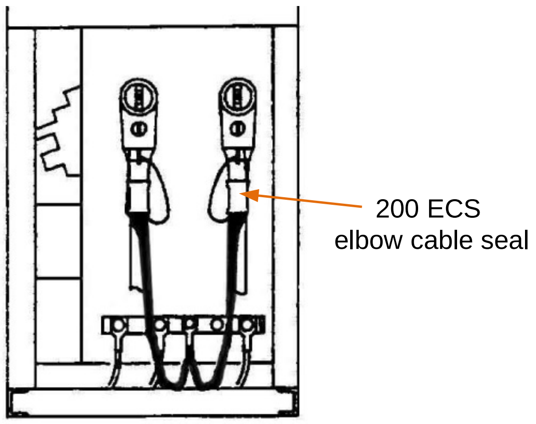
Figure 5-20 Cable pole with drop out fuses

5.3.4 Method 4 – Piggy-back transformers

This section is included as piggy-back transformers have been installed in some locations. However, it should be noted piggy-back transformers are not approved for new installations.

The term ‘piggy-backing’ is used in a HV “tee-off” arrangement where two or more transformers are switched and protected by a common device upstream. The HV supply to each transformer loops in and loops out. This is facilitated by providing two bushings or bushing wells, for each phase winding terminal on the transformers.

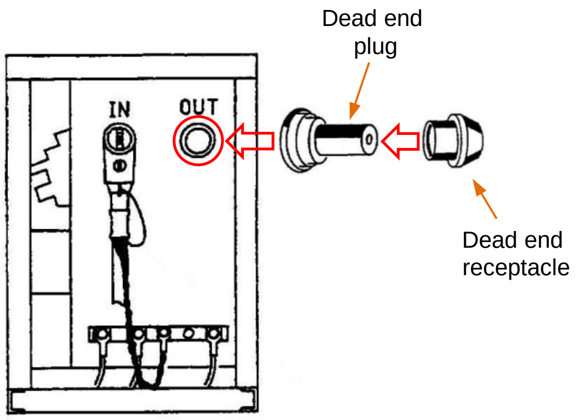
Shown below in Figure 5-18 are the transformer connections in a ‘piggy-back’ arrangement.



All fittings shown are ‘Elastimold’

Figure 5-21 Transformer connections in a ‘piggy-back’ arrangement

The last transformer in the HV feed is obviously not looped out, and must have its vacant or unused bushing of each phase covered by a dead-end receptacle insulated connector when energised. This is illustrated in Figure 5-19 below.



All fittings shown are ‘Elastimold’

Figure 5-22 End transformer connections in a “piggy-back” arrangement

The Table 5-6 below should be used for piggy-backed transformers supplied with drop out fuses (DOF). These fuse sizes are required to ensure non-operation of DOFs for transformer energisation.

Transformers Piggy Backed	DOF Fuse Size Required (K Class)
2 x 500kVA	40A
2 x 315kVA	25A
2 x 315kVA + 1 x 500kVA	40A

Table 5-6 DOF sizes for piggy backed transformers

Piggy-backing increases the risk of loss of supply to a larger number of customers but a significant cost saving is achieved with fewer HV fuse switches installed in the system.

5.3.5 Method 5 – Single-phase underground distribution system

The HV reticulation in the single-phase underground distribution system (SPUDS) is designed as a single-phase SWER system, operating at 19.1kV.

The system is based on servicing semi-rural residential lots using several 25kVA single-phase padmount transformers, each servicing up to six customers. Each transformer is internally fused to protect the system from internal transformer faults.

The single-phase SWER supply is provided by a single core 35mm² HV underground cable with a heavy duty copper screen to provide the earth return path. The single core cable loops in and out of a string of 25kVA transformers using separate non-loadbreak connectors.

5.3.6 Combination of Methods

An underground or underground/overhead feeder may use several of the previously stated methods. Figure 5-20 is an example of a combined overhead and underground distribution network, incorporating feeder circuits from a zone or regional substation feeding a simplified HV ring main reticulation network. The different configurations of the ring main units should be noted.

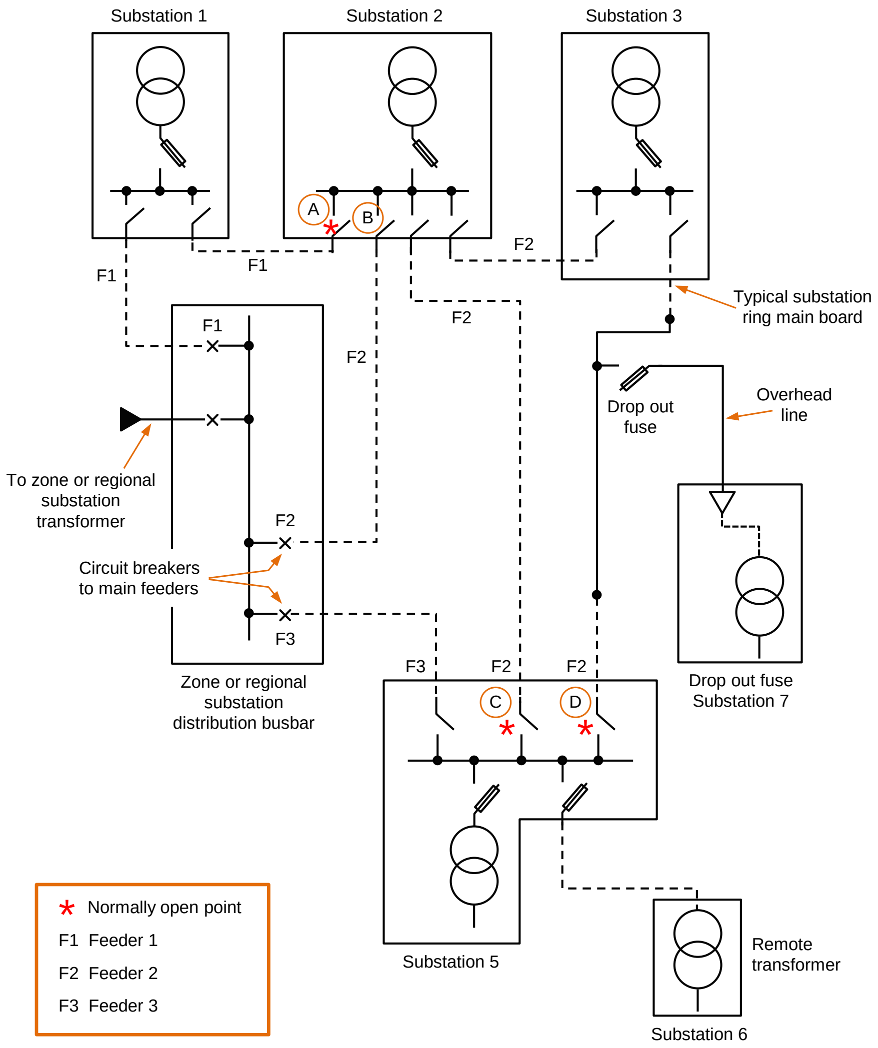


Figure 5-23 Simplified ring main reticulation

In Figure 5-20 substation 1 is being fed via feeder F1, which also feeds through to open point A at substation 2. Feeder F2 feeds substations 2, 3, and 7, and through to the open points at ring main switches C and D at substation 5. Feeder F3 feeds substation 5 and its remote transformer at substation 6. The diagram shows that it is the open points on feeders that enable flexibility of supply and adjustment of loads on distribution feeders.

If open point A is moved to B, feeder F1 will take up the load of substations 2, 3, and 7. The load on feeder F2 then drops to zero. Because open points are located on the basis of load assessment and convenience, they may need to be changed from time to time.

Note: The particular types of ring main units are not shown in Figure 5-20. The switching operator must have local knowledge of the type of ring main unit and its characteristics when choosing open points and switching arrangements.

5.4 Switching Procedures

Horizon Power's main switching procedures include planned switching and unplanned fault switching.

5.4.1 Planned Switching

Before a switching operator commences switching on a ring main system, it is essential to have the following:

- an authorised switching authority
- up-to-date plans
- an approved switching program registered with HPCC
- the correct PPE, and
- local knowledge.

Standard procedures must be adopted for the safety of the switching operator and work crews, as well as for the security of the system.

If in doubt, the operator must ASK.

If still in doubt, STOP!

Ring main switching can be complicated and more technically demanding than overhead switching because of the inherent layout and concealed nature underground distribution networks. A switching operator is required to keep continuous contact with HPCC.

Switching operators must pay attention to the following:

- Ring main switchgear is operated at close quarters. The operator must use all correct PPE. The second operator must stand outside the substation, holding the door open while switching is being carried out.
- The operator must know how to operate the switch and its interlocks. Interlocks on switch fuses are similar to ring main switches, but extra precautions must be taken when changing fuses.

- Operations on ring main units are carried out without any visual confirmation of the circuit route. Only the labels on switchgear and schematic plans are available. The switching operator must be satisfied that they are operating the correct switch.

- The switching operator needs to have a mental picture of each operation in order to know how the operation will affect the distribution system.

  Do not rely solely on the program. If the program is faulty, the careless operator may follow the program blindly, thus operating incorrect items.

Figure 5-21 shows two feeders supplying four ring main units.

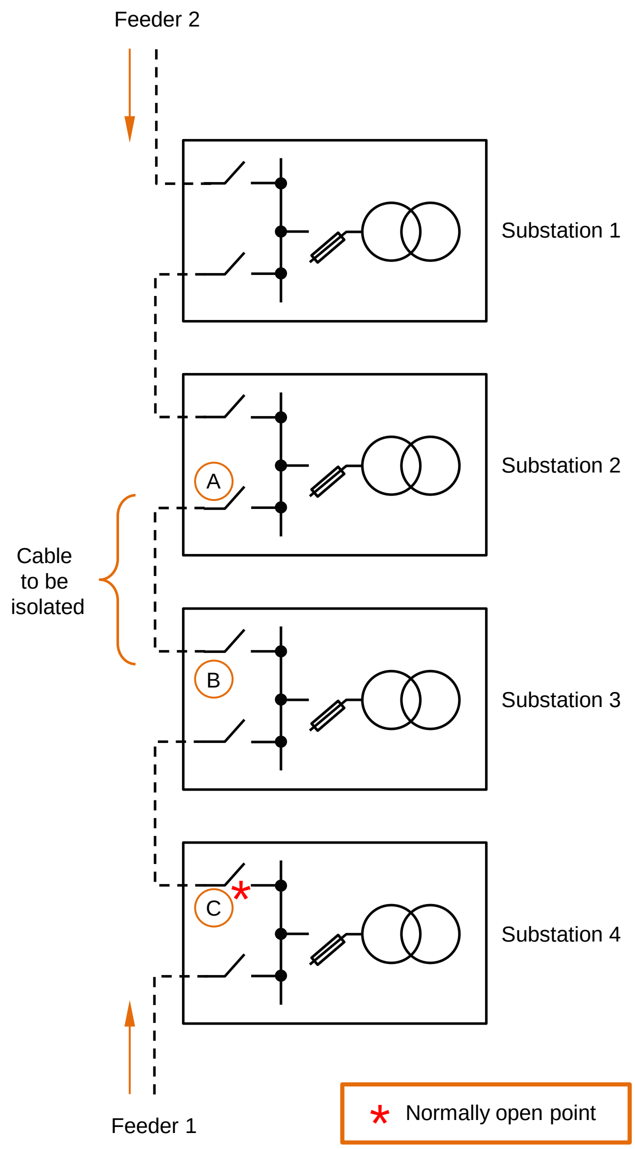


Figure 5-24 Procedure for isolation of a cable

Planned Switching Example 1 – Feeder cable access

To isolate a cable within the ring main system, the switching operator must be sure that work can be carried out with safety and system security. Loads must be within acceptable limits.

The standard way of isolating a cable, and a brief description of what happens in each operation, are given in the following procedure.

1. In Figure 5-21 when the normally open point C is closed, both feeders are interconnected. (At this point the fault level will be at its highest.) If a fault on either feeder occurs at this time, both feeders will trip.

2. Ring main switch B is opened and D–DNO tagged to create the first isolation point which separates the interconnected feeders and transfers substation 3 from feeder F2 to feeder F1.

3. Ring main switch A can then be opened and D–DNO tagged to create the second isolation point which de-energises the cable. This arrangement gives a cable isolated at both ends whilst maintaining supply to all ring main units and distribution transformers.

If access to the cable is required, earth switches at both ends of the cable must be applied after proving de-energised.

Normally, restoration follows the reverse of the procedure above, although phasing out or other testing may be necessary depending on the nature of the work performed.

Note: If the interconnected feeders are supplied from different substation transformers, the tap changers will need to be set to manual and the taps adjusted before interconnection of the feeders. The transformer tap changers can be returned to auto after the feeders are separated.

Planned switching Example 2 – Access to Substation 3 ring main unit

With reference to Figure 5-22, to access substation 3 ring main unit for maintenance or replacement, all HV feeder cables and transformer cables connected to this ring main unit must be isolated at their remote ends. The feeder cables are isolated and earthed at the remote end ring main units. The transformer cable is isolated on the transformer LV side.

Important LV switching note:

When feeding up substation 3 transformer LV load, care must be taken to ensure that if LV supplied from different HV feeders is used, it does not remain in parallel for the outage duration.

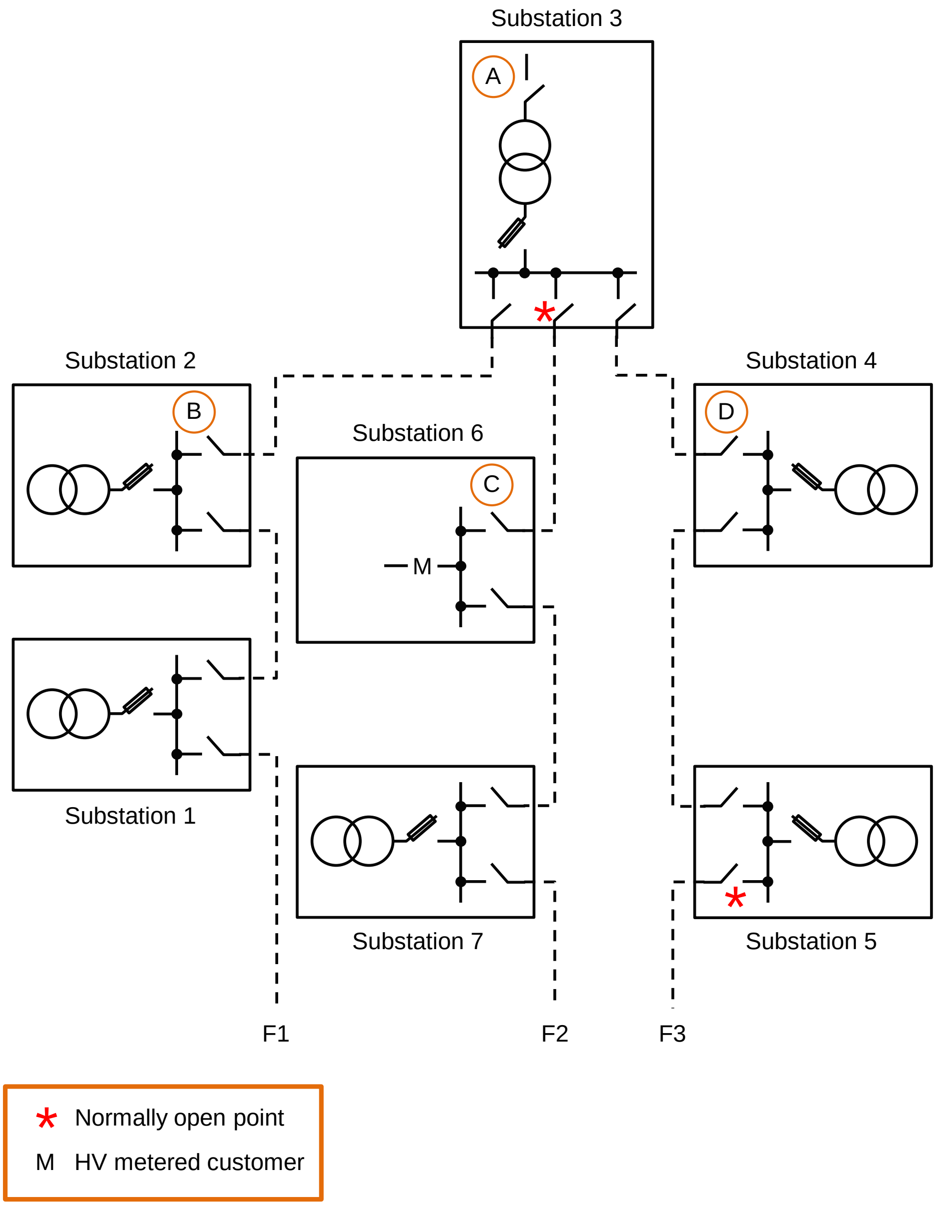


Figure 5-25 Ring main isolation at distribution substation

To isolate distribution substation 3 ring main unit shown in Figure 5-22, the following isolation points are required:

1. Substation 3 – transformer LV disconnector A
2. Substation 2 – ring main switch B
3. Substation 6 – ring main switch C
4. Substation 4 – ring main switch D.

The switching operator must carry out the following steps:

LV interconnection followed by isolation

1. Start by interconnecting to transfer load then isolate the LV supply from the transformer at substation 3.
    a) Interconnect Substation 3 transformer LV as required. (from other transformers on the same feeder).
    b) Isolate Substation 3 transformer at its LV disconnectors at A.
    c) De-energise Substation 3 transformer at its HV fuse switch.
    d) Prove transformer de-energised at the transformer side of the LV disconnectors at A.

HV interconnection followed by isolation

1. Close the normally open point at substation 5. (This interconnects F1 and F3.)
2. Open and D–DNO tag the isolation point D at substation 4. (This breaks the interconnection from F1 to F3 and moves the load of substation 4 and substation 5 onto F3.)
3. Open and D–DNO tag the isolation point C at substation 6. (This de-energises the cable between substation 6 and substation 3.)
4. Open and D–DNO tag the isolation point B at substation 2. (This de-energises all incoming supplies to substation 3 including its distribution transformer.)
5. The switching operator should return to substation 3 to check that all incoming feeds are isolated. This is done by checking the ring main voltage indicators on the three switches and fuse switch at substation 3.

6. The switching operator may then prove de-energise and earth each cable at B, C and D.

7. At substation 3 the switching operator should open the closed ring main switches (switches to substation 2 and substation 4), then prove de-energised and close the earth switches on the three switches and the fuse switch. (This indicates to the work crew that each possible incoming supply to substation 3 is isolated and earthed.

   It must be remembered that this action isolates, but does not earth, the busbar of the ring main unit.

5.4.2 Fault Indicators

Shown below in Figure 5-23 is a typical ring main switchgear fault indicator which is fitted on the switch circuits. The L1 (R), L2 (W) and L3 (B) phase flags will drop to indicate the presence of fault current exceeding the operating current setting.

When pressed, the test button will drop the flags down and when pressed again the flags will reset. The flags will automatically reset after the period indicated on the automatic reset time setting (that is, two or four hours).

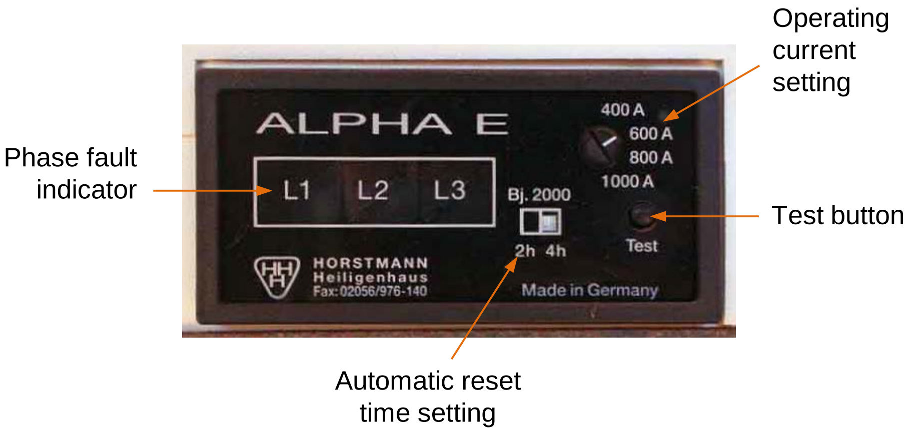


Figure 5-26 Ring main unit fault indicator

Fault indicators are installed on the front panel of most ring main unit switches. These fault indicators have a current measuring device (current transformer) around the termination bushing of each phase of the ring main switch cables. Secondary wiring connects the current measuring devices to the front panel indicator as shown above in Figure 5-23. Normal load current does not operate the fault indicator, however when fault current flows the corresponding fault phase indicator will operate.

To determine the fault location the switching operator visits the substations, inspecting fault indicators to determine passage of the fault current. In the example in Figure 5-23, all fault indicators up to and including ring main unit 4 have operated and all fault indicators from ring main unit 5 to the end of the feeder have not operated. This would indicate fault is located in the cable connected between ring main units 4 and 5.

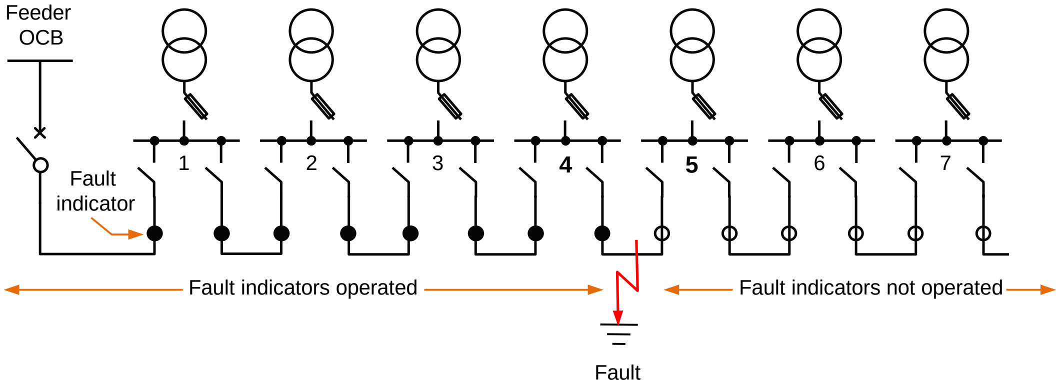


Figure 5-27 Fault location using indicators

Once fault switching or the fault indicators locate the faulted section, the exact location of the damage must be identified. In most cases, fault location is obvious, for example, digging or fencing along the cable route. If damage is not visible, specialist personnel must be called to locate the exact location of the fault.

5.4.3 Fault Switching

Fault switching refers to the isolation and feed up of distribution systems under fault conditions. This may involve closing switches onto faulted sections of the system.

Feeders with over 50% cable have their auto reclose relay taken out of service, due to the risk of further damage to the cable.

The switching operator must never attempt a trial reclose if the auto recloser facility of a feeder is already out of service.

Fault indicators are used to locate the faulted section of the cable. Once the faulted section is isolated, healthy parts of the feeders can be fed up from other sources.

Where fault indicators are not operating correctly, the switching operator is confronted with a difficult situation. The fault must be located by fault switching on a ring main switch or the feeder circuit breaker. To fault switch on a ring main switch, the switching operator must first establish that the switchgear is fit for that purpose.

Horizon Power has designed the network to ensure ring main unit switchgear ratings exceed the expected fault level, however this assumes the switchgear is in good working order and operates correctly. To minimise any risk, the switching operator must conduct pre-operation switchgear visual checks and other available checks (such as checking the SF_6 gas pressure) or use the alternative method described below.

Where the switching operator is concerned about closing a particular switch during fault switching, an alternative method is described below:

1. HPCC open the feeder circuit breaker feeding up to the open point (the feeder which is going to be used to feed up to the potentially faulted area).

2. The switching operator closes the suspect open point switch under the de-energised condition.

3. HPCC reinstate the feeder circuit breaker. This means that the circuit breaker is being used to close onto the fault rather than the suspect ring main switch. This ensures maximum safety for the switching operator and reduces possible damage to Horizon Power apparatus.

This procedure may have to be done a number of times along the feeder. However, the number of operations onto faulted circuits should be kept to a minimum as high fault currents can cause further damage along the feeder.

When fault switching, the switching operator must remember the following:

- Use correct PPE.

- A fault switching program is required in consultation with HPCC.

- Before operating switchgear, make the standard pre-switching visual inspections of switchgear and indicators.

- Before performing each switching operation, consider the affect that step will have on the network.

Refer to Field Instruction – *Replacing fuses on the HV/LV underground and overhead network after a fault has occurred* for additional information on the required checks before replacing fuses.

5.5 Ferroresonance

Ferroresonance may occur in three-phase underground distribution systems when an unloaded delta/star distribution transformer becomes energised or de-energised by single-phase switching. Ferroresonance is a problem only when the length of cable exceeds the critical length for a given transformer.

Tests have shown that excessive phase to earth voltages, 3.3 times the normal voltage, may be developed in distribution circuits conducive to ferroresonance. Once developed, they have a steady value that persists for the duration of the switching operation.

This sustained overvoltage will shorten the insulation life of distribution equipment, by accelerating its deterioration. Surge diverters, reclosers and distribution transformers all are prone to the effects of ferroresonance.

Table 5-7 and Table 5-8 show broad guidelines for areas where ferroresonance is likely to be a problem, that is, where cable lengths longer than those specified are used.

XLPE cable – System voltage 11kV					
	Critical cable lengths (metres)				
Tx kVA	**35 mm^2**	**95 mm^2**	**185 mm^2**	**240mm^2**	**400mm^2**
63	17	12	9	8	7
160	43	30	24	21	17
315	84	59	46	41	33
500	133	93	74	64	52
630	168	117	93	81	65
1000	267	186	146	129	104
XLPE cable – System voltage 22kV					
	Critical cable lengths (metres)				
Tx kVA	**35 mm^2**	**95 mm^2**	**185 mm^2**	**240mm^2**	**400mm^2**
63	4	3	2	2	2
160	11	7	6	5	4
315	21	15	12	10	8
500	33	23	18	16	13
630	42	29	23	20	16
1000	67	46	37	32	26
XLPE cable – System voltage 33kV					
	Critical cable lengths (metres)				
Tx kVA	**50 mm^2**	–	**185 mm^2**	–	–
63	2	–	1	–	–
160	4	–	3	–	–

315	8	–	7	–	–
500	13	–	11	–	–
630	16	–	13	–	–
1000	26	–	21	–	–

Table 5-7 Critical cable length for ferroresonance – XLPE cable

PILCSWA cable – System voltage 11kV				
	Critical cable lengths (metres)			
Tx kVA	**25 mm^2**	**70 mm^2**	**95 mm^2**	**185 mm^2**
160	18	11	10	8
315	36	23	20	15
500	57	36	33	24
630	72	45	41	30
1000	114	72	65	47

Table 5-8 Critical cable length for ferroresonance – PILCSWA cable

There are two methods to eliminate ferroresonance while switching.

- Method 1 – The transformer may be energised and de-energised by three phases switching simultaneously (e.g. pole top switch).

- Method 2 – Ferroresonance may also be prevented by the switching operator connecting load to the low voltage side of the transformer by means of a load box, to de-energise and energise the transformer when switching single-phase (e.g. drop out fuses).

Note: The low voltage side of the transformer should be disconnected before switching the high voltage.

Further details on ferroresonance are available in the Horizon Power Field Instruction – *Ferroresonance in the Underground Distribution System*.

5.6 Traps

The switching of underground systems is complex, therefore a high level of competency is required. The switching operator must be aware of likely traps with the following tasks and equipment:

- Isolating both ends of the cable before earthing
- Switchgear interlocks
- Switchgear testing facilities
- Not having a mental picture of the circuit
- Ferroresonance
- Maps and diagrams not up-to-date
- Not using meters or indicators
- Lack of local knowledge
- Equipment labelling
- Ring main unit locks
- Voltage indicators.

These problems are examined in detail on the following pages.

5.6.1 Isolating Both Ends of Cable before Earthing

Interlocks are available on ring main units to stop a switching operator earthing a unit before the switch is opened. However, it is possible to earth a cable which is energised from the remote end.

To avoid this, the switching operator must make sure that the ring main switches at both ends of the cable are isolated (off and D–DNO tagged) and the neon indicators used to prove the circuit de-energised before the earth switch is closed.

5.6.2 Switchgear Interlocks

A variety of interlocking systems are used in different ring main units, some having more complex interlocks than others. The switching operator must know the function of each type of interlock before conducting any operation.

The switching operator will find standard operational padlocks on ring main switches and different earth padlocks on earth switches. Before operation, the operator must verify the correct padlock is on the appropriate switch. If this is not done, it is possible to think that they are operating a ring main switch when it is actually an earth switch that is being operated.

5.6.3 Switchgear Testing Facilities

Testing facilities on all Horizon Power ring main switchgear are provided to allow access to and testing of cables. Specialised equipment must be used on some switchgear to allow testing to be carried out.

5.6.4 Not having a Mental Picture of the Circuit

When switching on an underground system, no visual confirmation of the cable sections is available. If the switching operator does not keep a mental picture of the circuit status during switching, potential errors of the switching program are unlikely to be identified before they occur.

The switching operator must keep a clear mental picture and understand how each operation affects the total configuration of the circuits being switched.

5.6.5 Ferroresonance

The potential problem of ferroresonance is serious. Therefore, the switching operator must be aware of the hazard and take all necessary precautions.

5.6.6 Maps and Diagrams not Up-to-Date

As computer systems are used to write planned and fault switching programs it is essential the computer single line schematic accurately reflects the actual system.

This requires all changes made to the system are accurately recorded and incorporated into these schematics.

If the switching operator is faced with a situation where the switching program and the physical system appear to be in conflict, no operations should be carried out until the conflict is resolved.

5.6.7 Not Using Meters or Indicators

Switching operators should use voltmeters, ammeters and mechanical indicators to check conditions of the system before, during, and after switching. This information helps the operator to decide if operations are correct and if problems are likely to occur.

The condition of the switchgear must also be checked before switching; this includes checking SF_6 gas pressure.

5.6.8 Lack of Local Knowledge

Before switching, switching operators should beware of any peculiarities of the system or limiting conditions within the locality. If the operator has doubts about any operation, they should seek advice before switching. Checks should include the types of switches to be operated and how to access the building where the switchgear is installed.

5.6.9 Equipment Labelling

Where apparatus is not labelled to the required Horizon Power standard, the switching operator must be satisfied that the label on the apparatus in question is accurate and correct for the switching operation. If there are any doubts about the labelling of apparatus, the switching program is to stop until clarification has been made.

5.6.10 Ring Main Unit Locks

When performing multiple steps on a single ring main unit, only the padlock on the switch or earth switch to be operated is to be unlocked. After the switching operation is complete, the padlock must be replaced and locked before proceeding to the next switching operation. This action ensures that access to only one switch is possible at any time.

The switching operator must not identify the switch and earth switch by the type of lock fitted. Always carefully inspect the front panel to identify the switch and earth switch. It has been known for the locks to be reversed as a result of taking multiple locks off and replacing them incorrectly.

5.6.11 Voltage Indicators

Ring main unit voltage indicators must be proven to work before and after (where possible) switching to prove a cable de-energised.

Where an indicator is not usable, a hand held voltmeter can be used as an alternative test device to check that no voltage is present on the test sockets (where fitted), thereby proving that the cable is de-energised.

SECTION SIX

Substation Distribution Feeders

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6. Substation Distribution Feeders

6.1 Introduction

The zone substation transforms high voltage transmission power to lower voltages for local distribution. Typically, the substation's high voltage input is either 66kV or 132kV, while the lower voltage output varies between 11kV and 33kV.

In Pilbara Grid the components of zone substations include incoming transmission lines, transmission busbars, transmission circuit breakers and disconnectors, zone substation transformers, voltage transformers, current transformers, distribution busbars, distribution circuit breakers and disconnectors, relays and control apparatus.

In microgrid systems the distribution busbar is supplied from generator step up transformers or express power station feeders rather than transformers connected to the transmission network.

This section examines only those components associated with the operation of distribution feeders. This includes outdoor and indoor busbar configurations, circuit breakers, local and battery power supplies, alarm panels, voltage control mechanisms and under frequency load shedding.

The operation of this equipment is complex. Therefore, the principles of interconnecting zone substation transformers and the procedures for fault switching are also included.

The Horizon Power Switchgear Instruction Manual provides detailed photographs and descriptions for the operation of specific switchgear. The manual should be consulted by switching operators to ensure the correct methods and sequences are used. This is particularly important for switchgear with significant interlocking such as indoor switchgear.

6.2 Outdoor Distribution Busbar Configurations

The busbar is the connection point from the zone substation transformer to the outgoing circuits (distribution feeders). Horizon Power uses two types of busbar configuration for outdoor zone substations:

- single bus, and
- single bus with transfer bus.

6.2.1 Outdoor Single Bus

The single bus configuration is the simplest form of substation. Single bus outdoor substations supply feeders from one common busbar (see Figure 6-1 below). One, two or three transformers are used, depending upon the load and required level of system security. The single busbar is broken into sections with busbar disconnectors. This allows several transformers to feed different parts of the busbar separately, or one transformer to feed the whole busbar.

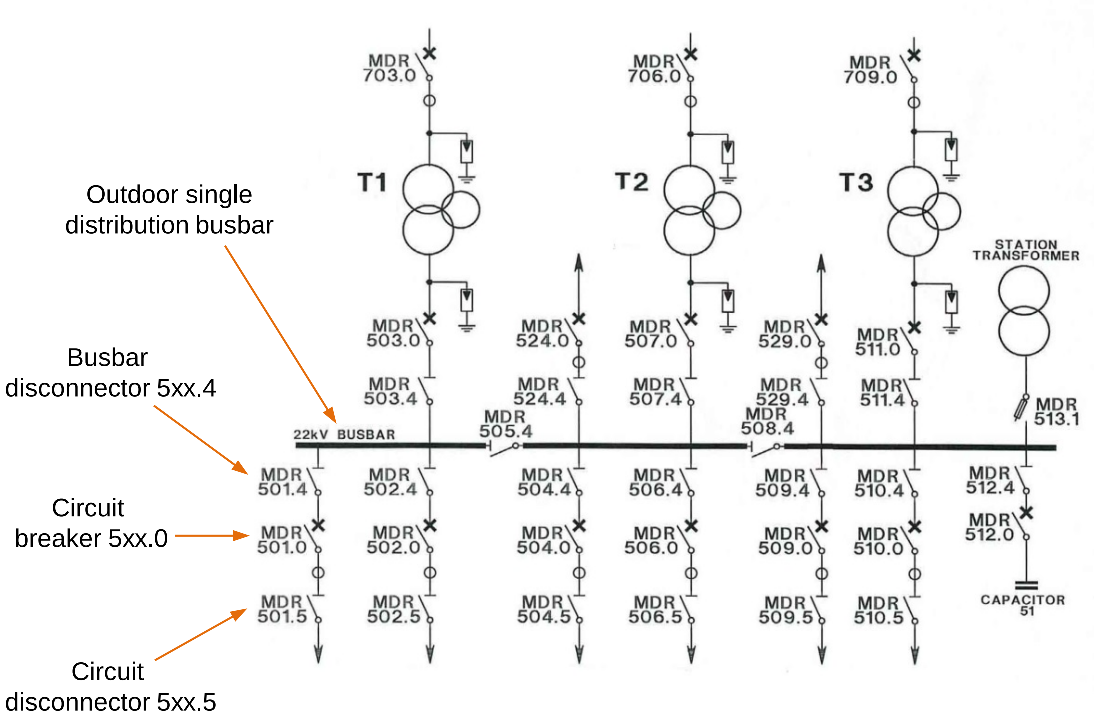

Figure 6-1 Outdoor single distribution bus

Each feeder circuit breaker has disconnectors on each side to provide a visual break for isolation of circuit breakers and feeders. Some substations provide only one disconnector on the busbar side of the circuit breaker.

There are two main disadvantages of single bus configuration:

- its operation is not as flexible as other types of bus configurations, and
- feeder loads need to be arranged to ensure that the transformers are reasonably balanced where the busbar is split using the busbar disconnectors.

6.2.2 Outdoor Single Bus with Transfer Bus

The single bus with transfer bus substation is most commonly used in rural areas. The same principle as the single bus configuration applies. The only difference is that a second busbar or transfer bus is added to the outgoing side of the feeder circuits. The transfer bus is used to interconnect feeder circuits within the substation, making it unnecessary to interconnect feeders on the distribution overhead circuits.

The use of the transfer bus is clearly shown in Figure 6-2. Where WFD 506.8 and WFD 508.8 are closed, and WFD 506.0 is opened, the Bailey feeder is effectively transferred to the Hamilton Rd feeder via the transfer bus.

The breaker WFD 506.0 may be taken out of service with further isolation (open WFD 506.5 and WFD 506.4). This does not require major interconnection of the distribution system. The method is flexible, saves time and makes the operation quite simple.

Note: Before attempting to transfer one feeder onto another, the switching operator must determine the combined loads. Check that the circuit breaker setting is capable of carrying the extra current.

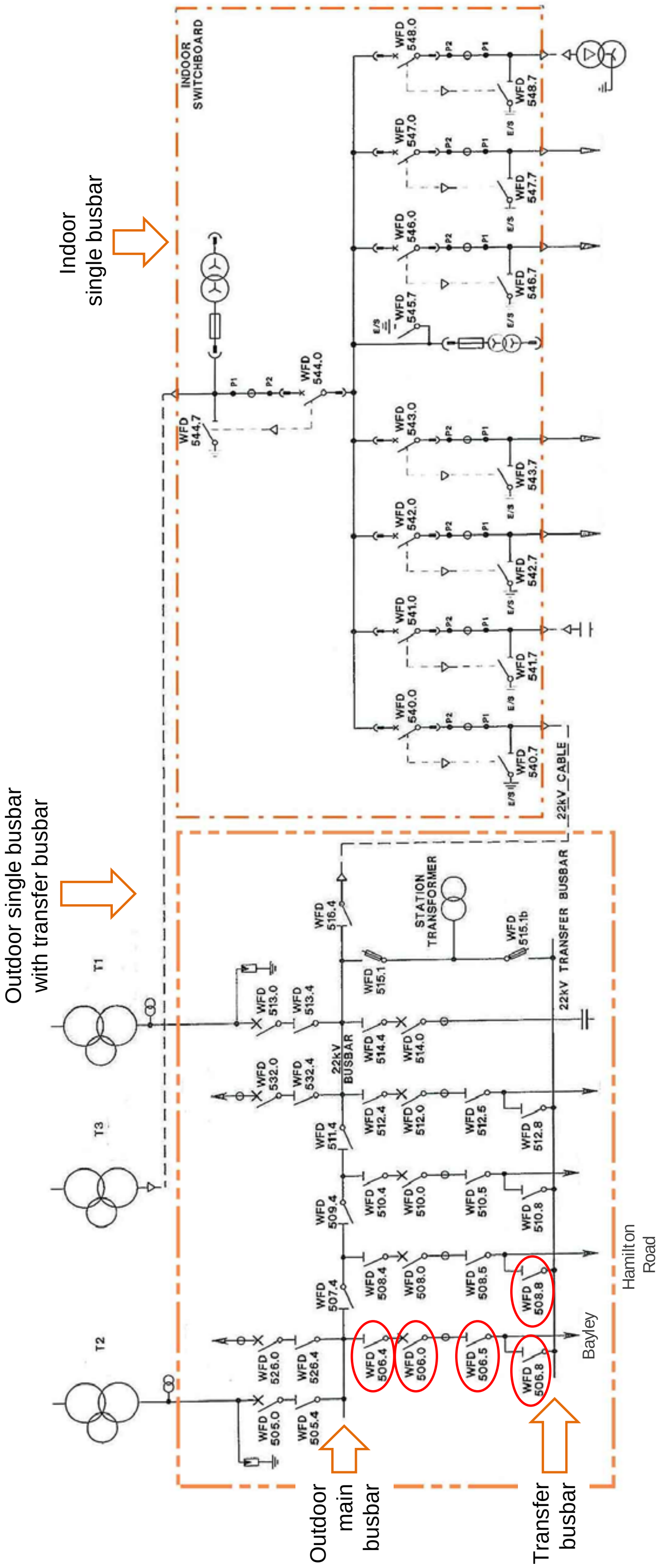

Figure 6-2 Outdoor single with transfer busbar and indoor single busbar configurations

6.2.3 Indoor Single Bus

Indoor single busbar substations have a similar configuration to the outdoor equivalent. However, the indoor substation has withdrawable (rackable) circuit breakers which provide a visual break for isolation in place of the disconnectors in the outdoor substations.

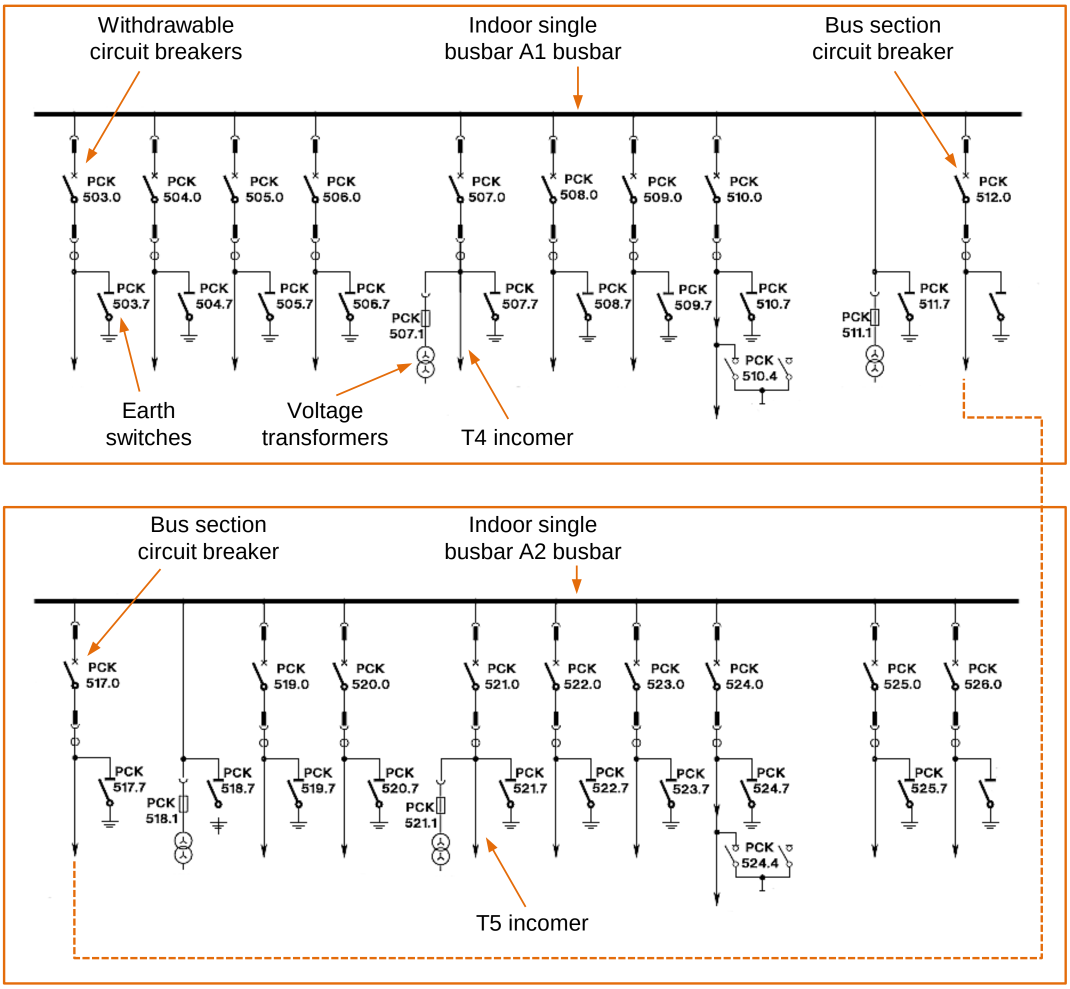

Figure 6-3 Indoor single busbar configuration

In indoor single busbar configurations all circuit breakers are attached to one busbar (see Figure 6-3). There may be bus section circuit breakers along the busbar's length, to split the bus as required (see PCK 512.0 and PCK 517.0 in Figure 6-3, top and bottom respectively). This differs from outdoor substations that use disconnectors for this purpose.

If the bus section breakers are closed, all feeder circuit breakers can be fed from the one transformer. If the load is too high for one transformer, the second transformer can be turned 'on' and a bus section circuit breakers can be opened. The load is then split between two or more transformers.

Earth switches

Earth switch are provided on the cable side of each circuit (e.g. PCK 503.7 in Figure 6-3 top).

The earth switch closing is spring assisted to ensure rapid earth switch operation regardless of the speed of operating handle movement.

6.3 Circuit Breakers

Circuit breakers are a major component of distribution zone substations. A circuit breaker is a fault-make/fault-break rated switch capable of being opened and closed, while carrying the manufacturer's specified fault currents. It is the main apparatus used for the connection and disconnection of outgoing feeders from the substation.

All circuit breakers are designed to create an arc, control it and then destroy it at the most convenient time. The current flowing through the arc depends upon the voltage between its ends.

Note An arc is a conductor made up of a body of ionised gas at a high temperature. Its electrical conductivity compares to graphite.

At the instant the contacts separate in a circuit breaker, the electrons (which make up the current) attempt to flow through the very small gap of the contact. They collide with the atoms of the insulation medium and cause the atoms to rapidly break up as more electrons and energy are released. This raises the temperature of the contact gap.

This process continues as the contacts open. As the length of the arc increases, more and more energy is required to sustain it. When the arc lengthens and cools, it will break quite easily.

In Horizon Power's 50Hz alternating current (AC) system, the current falls to zero at every half cycle or every 10 milliseconds (ms). This means that, for a brief time, there will be no electron movement to sustain the arc.

Immediately after zero, the voltage across the contacts attempts to re-establish the current. If the conducting path of the arc is still present, the current will be re-established. However, the current will not be re-established when:

- the arc path is too long
- the temperature has dropped sufficiently
- the ionised atoms making up the arc path have been dispersed.

If one or more of these conditions is met, the circuit breaker will successfully break the current flow.

In the case of vacuum circuit breakers the contacts separate in a vacuum and therefore absence of atoms in the vacuum assists in interrupting the arc as the contact separate.

Horizon Power has the following type of circuit breakers:

- minimum oil circuit breaker
- SF_6 gas-insulated circuit breakers
- vacuum circuit breakers.

SF_6 and vacuum circuit breakers are used in new substations, as it is cost effective and provides an acceptable level of operation with reduced maintenance requirements.

6.3.1 Minimum Oil Circuit Breaker

This type of oil circuit breaker is common in older substations. The circuit breaker contacts are immersed in a small quantity of insulating oil.

The minimum oil circuit breaker is manufactured to cater for a wide variety of voltages and breaking capacities this varies the amount of oil required.

A three-phase minimum oil circuit breaker consists of three identical units which are operated by a common linkage from the single mechanism box. The cross section of a typical minimum oil circuit breaker is shown in Figure 6-4 below.

The circuit breaker is made up of two sections mounted one above the other. The upper section is the switching chamber, while the lower section houses some of the mechanical linkages and insulation to the ground.

The operating cam drives the insulated operating rod and moving contact up to close and down to open the moving contact and fixed contact.

On opening, the fixed and moving contacts rapidly separate drawing an arc inside the arc extinguishing chamber which is filled with insulating oil. The action of the arc extinguishing chamber is to divide the arc into several sections and force it into cool oil. The result of rapidly lengthening, dividing and cooling the arc extinguishes the arc.

Closing is a less onerous operation for a circuit breaker because the arc will only strike at the point where the oil insulation breaks down. As the moving contact is rapidly moving towards the fixed contact the arc length is continually shortened until the contacts meet at which time the arcing stops.

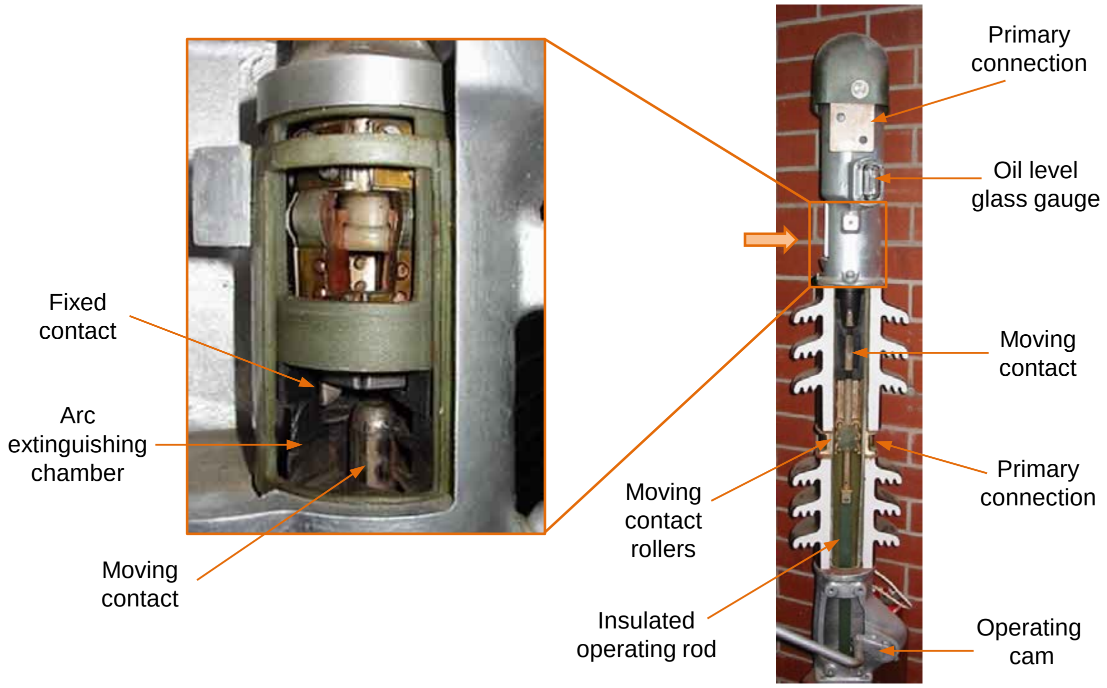

Figure 6-4 Minimum oil circuit breaker

Gas vents with filters are fitted to all circuit breakers to allow free passage of gas and prevent oil from being thrown out during operations. They are constructed to prevent moisture entering and contaminating the oil.

The level of oil is most important, as this affects the degree of turbulence caused by the arc. The oil level glass gauges must be inspected regularly.

The switching operator must report all low oil levels, especially if one phase is lower than the other two phases.

Operators should not attempt to switch an oil circuit breaker if the oil level cannot be seen in the inspection window.

All oil stains or droplets on oil filled equipment should be referred immediately to the responsible authority. (Often the oil leak is visible long before the drop in oil is able to be detected.)

6.3.2 SF_6 Gas-Insulated Circuit Breakers

The SF_6 circuit breaker is a modern type, which is used indoor and outdoor substations. Shown below in Figure 6-5 is the puffer type circuit breaker in the closed position (top view A.) and during opening (bottom view B.). When the circuit breaker is opening SF_6 gas is forced through the separating contact to extinguish the arc.

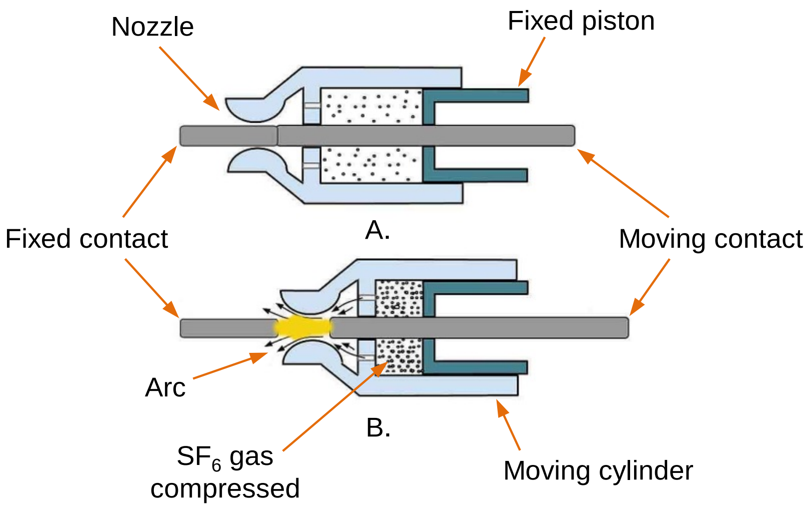

Figure 6-5 Puffer-type SF_6 circuit breaker
which uses SF_6 gas to extinguish the arc produced on opening.

Its arc quenching function is similar to the minimum oil circuit breaker, but much more efficient. SF_6 gas (sulphur hexafluoride) has better insulating properties than mineral oil and does not break down under arcing.

The gas is held inside the arc chamber under pressure. If a leak occurs, the switch will lose part of its switching capabilities. For this reason, Horizon Power's SF_6 breakers have a low gas alarm and lockout function built into their operation.

Figure 6-6 shows the indoor Yorkshire SF_6 switchboard with a circuit breaker picture inset. Gas pressure gauges are typically fitted to these circuit breakers.

Where possible, SF_6 pressure gauges should be checked before carrying out switching operations.

Switching operators must not attempt to operate SF_6 circuit breakers that have a low gas alarm initiated.

The relevant authorities must be notified as soon as possible.

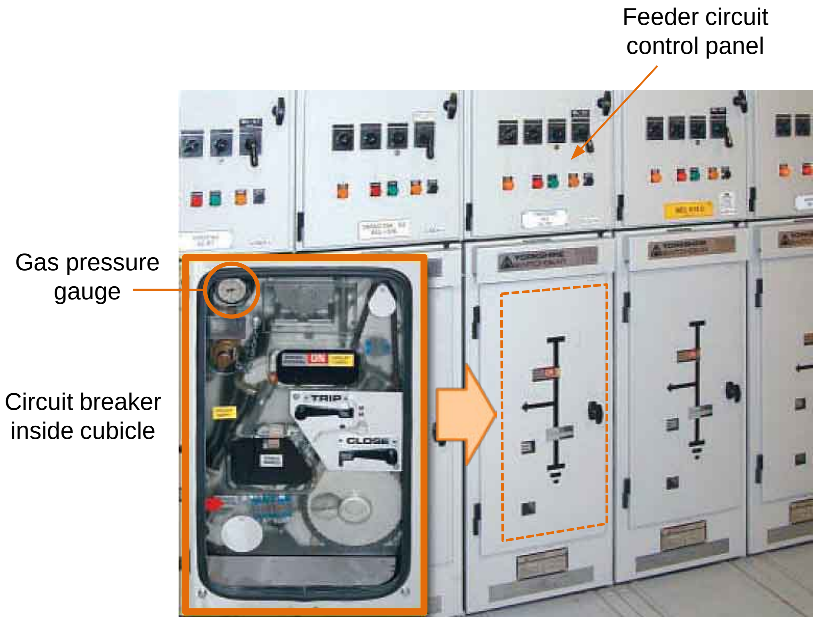

Figure 6-6 Indoor Yorkshire SF6 Circuit Breaker

6.3.3 Vacuum Circuit Breakers

The vacuum circuit breaker is a modern type, which is commonly used in indoor substation switchboards. Figure 6-7 below shows the circuit breaker interrupter in the open position. When the circuit breaker is opening, the fixed and moving contacts separate rapidly causing the arc to lengthen whilst passing through a vacuum. Because the arc cannot sustain itself within the vacuum, it rapidly extinguishes.

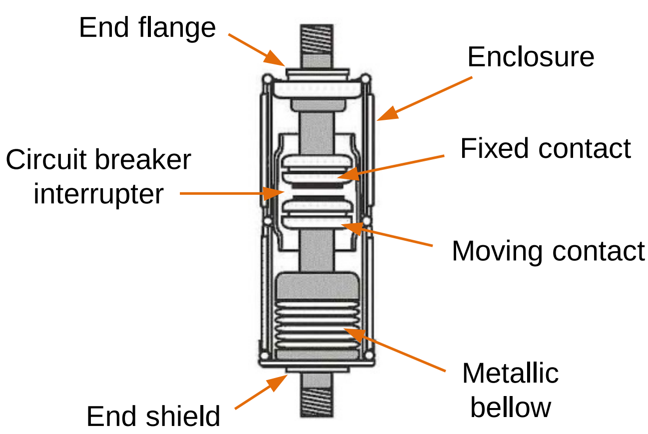

Figure 6-7 Vacuum circuit breaker interrupter

An example of an outdoor feeder circuit with a vacuum circuit breaker is shown in Figure 6-8.

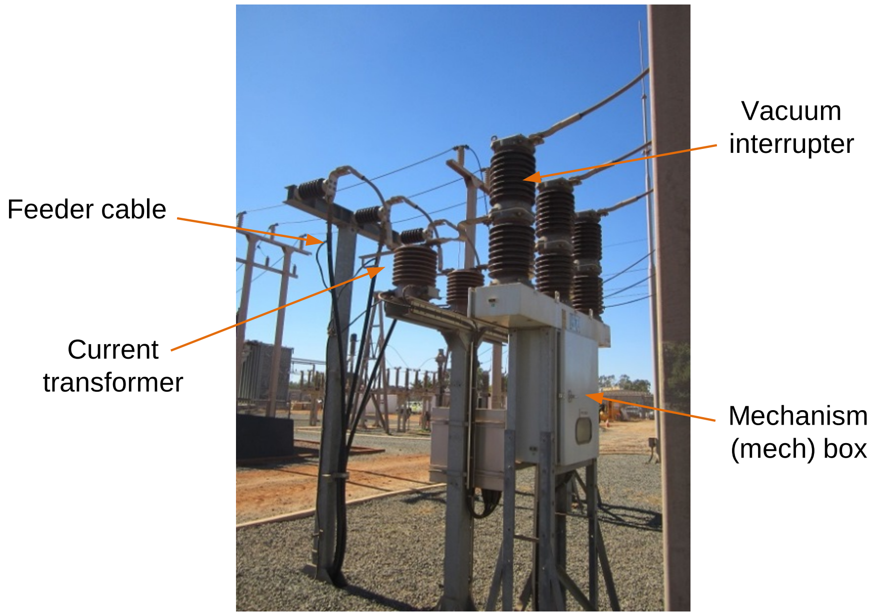

Figure 6-8 Outdoor vacuum circuit breaker

An example of an indoor switchboard with vacuum circuit breakers inside the cubicles is shown in Figure 6-9.

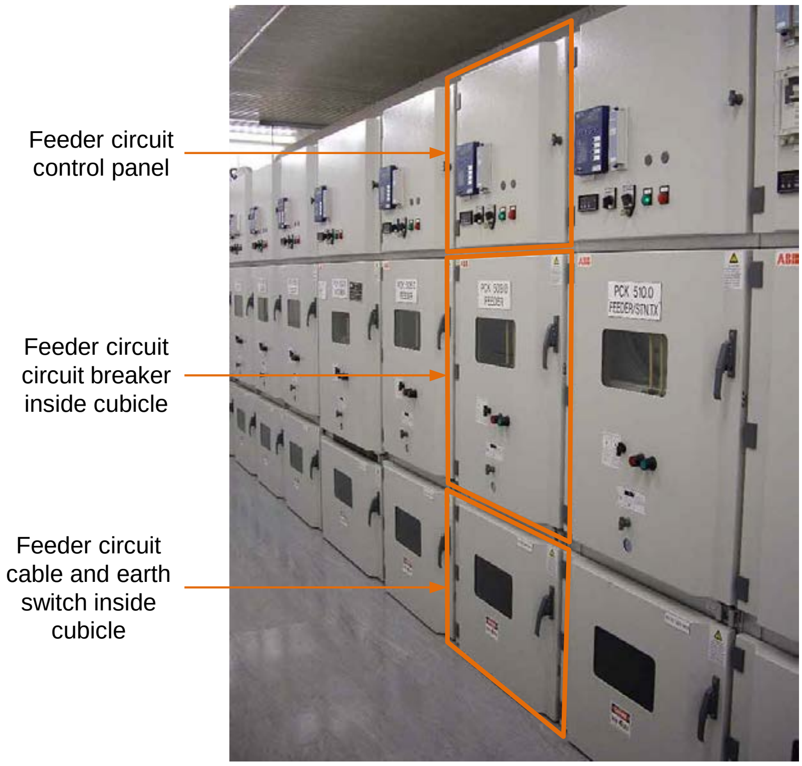

Figure 6-9 Indoor switchboard with vacuum circuit breakers installed

Figure 6-10 Indoor vacuum circuit breaker

Shown in Figure 6-11 is the cross-sectional view of an indoor switchgear, showing the various components.

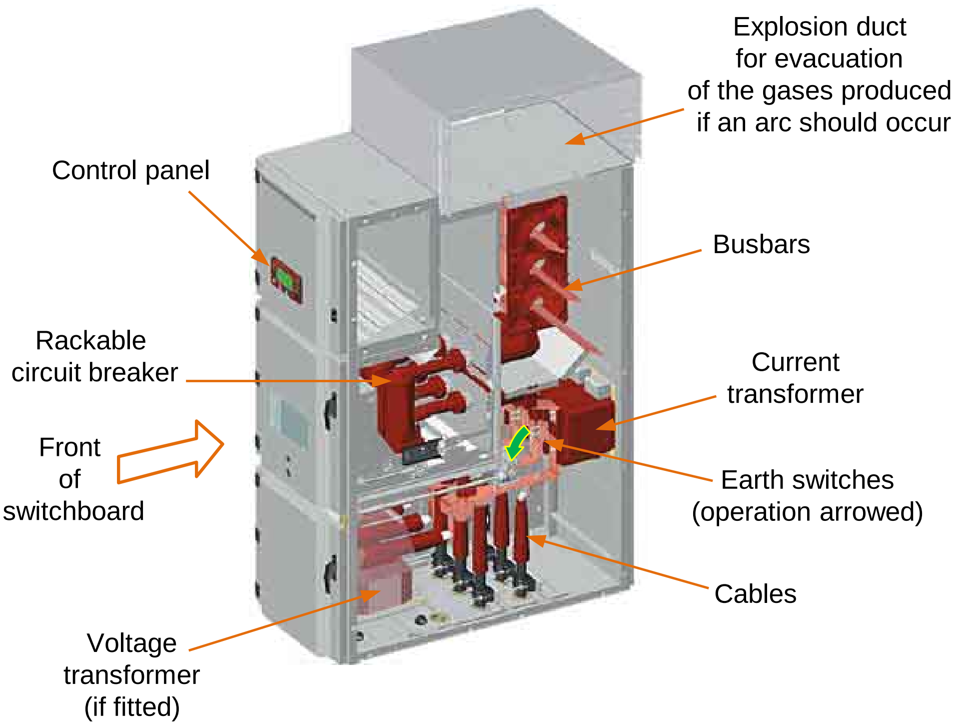

Figure 6-11 Cross-sectional view of a typical indoor switchboard

6.3.4 Circuit Breaker Control Mechanisms

The operating mechanisms of circuit breakers are designed to ensure effective closing and opening:

- The circuit breaker must close cleanly and quickly, with no hesitation at the 'contact touch'. (This means that the moving contacts are in the 'fully home' position that firmly latches the circuit breaker closed).
- The holding toggles or latch must be released as the tripping (opening) device operates, allowing the circuit breaker to open.

Correct opening and closing are most important, for example, when the circuit breaker is being closed onto a fault where the fault current will be high. The moving contacts must reach a position which provides ample pressure between the contacts to prevent 'chatter' and possibly 'welding in'.

The mechanism must be trip-free at all times. It should not be possible for a circuit breaker to be held closed against an opening operation. For example, when closing a circuit breaker onto a fault, it will need to trip very quickly.

For distribution circuit breakers the common method of storing energy for opening and closing the circuit breakers is springs.

Spring Method

There are single-spring and multi-spring closing mechanisms that are charged by hand or an electric motor.

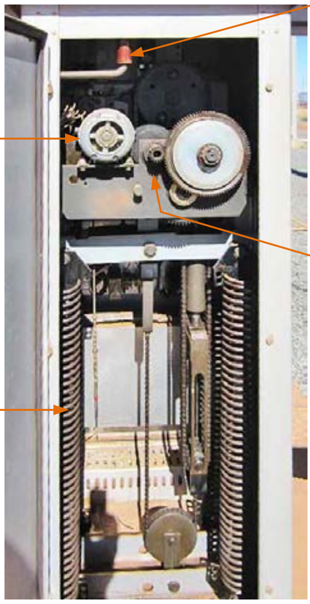

Figure 6-12 Circuit breaker mechanism box showing closing springs

Single Spring

The fully charged closing springs store sufficient energy for one operation. Upon closing, the spring discharges fully, in turn charging the tripping springs to allow a trip function. This allows automatic reclose or manual reclose, despite loss of the auxiliary supply. Spring charging by hand may be carried out if the electric motor fails to charge the spring.

In most cases, the stored energy of the spring is released by a small electric solenoid. Spring mechanisms are normally recharged automatically immediately after a close function.

Multi Spring

When in operation, all spring operated mechanisms for distribution feeders have pre-charged springs. These are designed to perform a trip-close-trip sequence, when auxiliary power to the circuit breaker is lost. Although a breaker has no auxiliary power to charge the spring after locking out, the breaker may be closed to restore power to a feeder while the supply problem is investigated and rectified. The circuit breaker also has a trip function in reserve, which is essential when a circuit is in the faulted condition.

Sometimes, the breaker motor may charge the spring partially or not at all. When this occurs, the spring must be charged by hand. A typical procedure follows:

1. remove and check the fuse feeding the circuit breaker motor, or switch the motor 'off'
2. insert the crank handle
3. observe the arrow showing the direction of return
4. the spring is fully charged when the crank handle runs free or reaches a stop and a click is heard
5. the motor fuse of the circuit breaker must then be replaced or its switch turned 'on'
6. the circuit breaker may then be operated as required.

There are two major advantages of power operated spring close mechanisms:

- Once the closing operation has been initiated, it may be completed without any further action by the operator. (This is because its power supply is independent of the operator. It does not rely on manual force for its operation).
- The trip-close-trip function allows back up of breaker operation after a trip.

Drive Motor Spring Charge.

Certain types of Schneider circuit breakers and switches make use of a DC drive motor to charge the closing spring. This feature is used when remote switching operations are required using a RTU via SCADA.

The design of the RM6 and Flusarc apparatus does however not include a standard feature to isolate the DC supply to the drive motor. This is a problem when the breaker or switch needs to be isolated for the issue of an EAP.

To overcome the problem of the apparatus not having an integrated means to isolate the DC supply, an external DC isolator is fitted to isolate the DC supply to the particular breaker / switch.

6-13 Typical positioning of DC Isolator on Control Panel.

The position of the DC isolator in the circuit not only isolates the drive motor, but also effectively isolates the electrical supply for remote control functioning of the apparatus.

Operation of the DC isolator must be included in the switching program by the Switching Operator when isolation of the apparatus is required.

Besides isolating the DC at the isolator as described above, a selection to “local control” must be made on the apparatus to inhibit remote operation via the RTU of the breaker or switch.

6-14 Schneider RM6

6-15 Schneider Flusarc.

6.3.5 Circuit Breaker Control Locations

Circuit breakers may be controlled from several locations as indicated in Table 6-1 below. The table shows the location, mode, description, control system and switching preference for each switching position.

Site	Mode	Description	Control system	Switching preference
Bentley	Remote (SCADA)	HPCC all CBs	SCADA supervisory control	Preferred location
Substation	Remote (Switchroom Relay room)	* HMI all CBs Outdoor CBs (at relay panel)	HMI computer Relay control panel	Used when SCADA not available
	Local (at circuit breaker)	Indoor CBs (at control panel)	CB cubicle control panel	
		Outdoor CBs (at mech box)	CB mechanism box control	Maintenance only

* Note that HMIs are not installed in all substations.

Table 6-1 Circuit breaker control locations

If possible, all switching should be carried out in the remote location, SCADA switching is the preferred location.

When SCADA switching fails, local switching is necessary. Switching operators should remember to check ammeters and other indicators before operating the circuit breaker.

SCADA Control

The SCADA system provides remote monitoring and control facilities for a range of apparatus in the network. In zone substations the controllable apparatus includes circuit breakers and transformer tap changers.

This is the preferred operating location for all SCADA controllable apparatus.

On site operation will be required for all manually-operated apparatus such as disconnectors, earth switches and racking circuit breakers.

Shown below in Figure 6-13 is a simplified SCADA system. The control room client computers are connected to master station computer when then communicates to the remote terminal units (RTUs) located at each substation. The RTUs are hard-wired to the relay racks which can then control and obtain data from the associated substation apparatus.

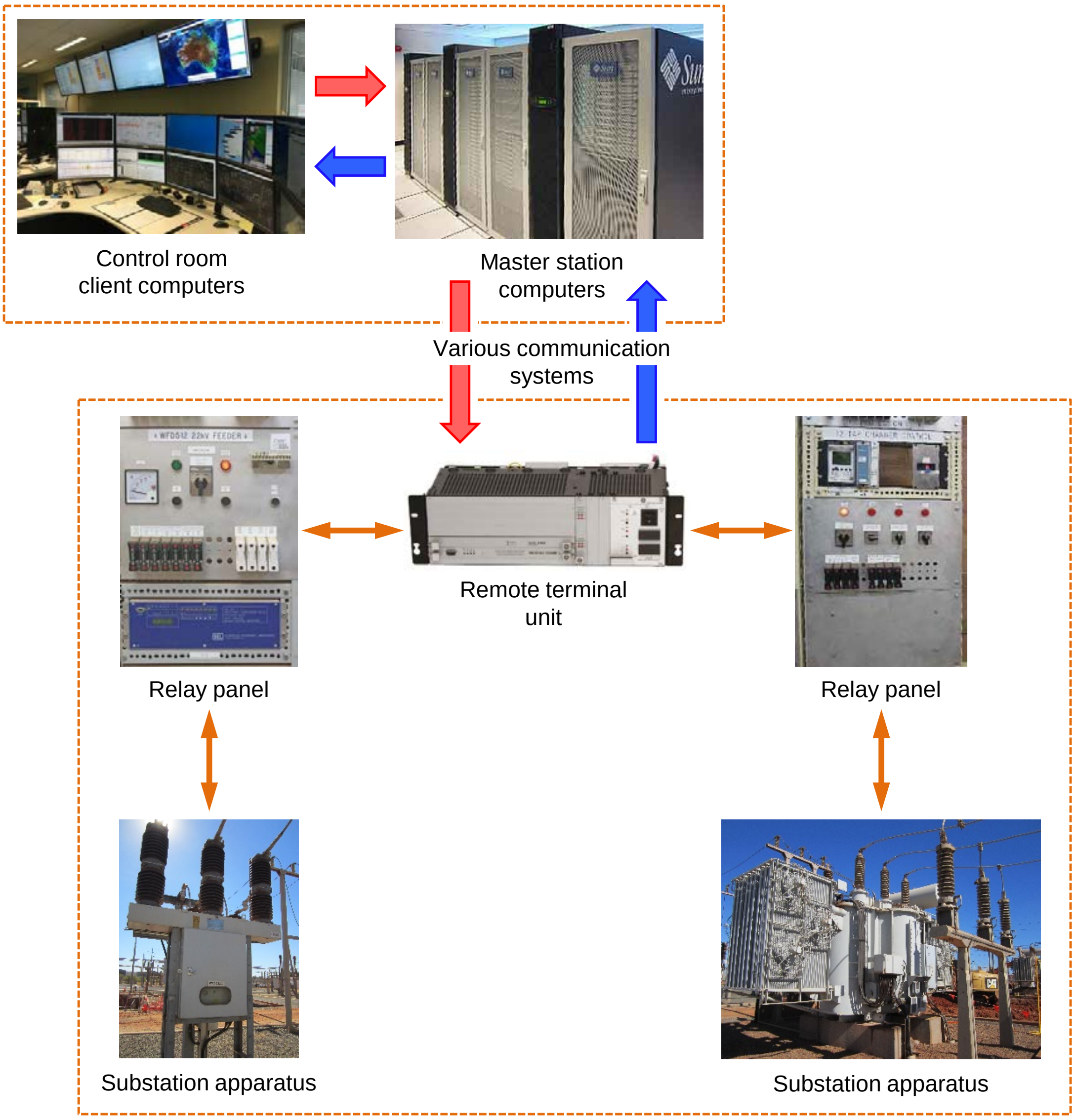

Figure 6-16 The typical SCADA system (simplified)

In Figure 6-13, the red arrows show the path of the control signals to the substation apparatus. The blue arrows show the path of the data from the substation such as voltage, current, transformer tap position, circuit breaker status ON/OFF and equipment alarms. The orange arrows represent the hard wiring in the substation between the RTU, relay panel and substation apparatus.

Human Machine Interface (HMI) (Remote)

A human machine interface (HMI) is a local substation computer system with a graphic interface which provides the switching operator a range of capabilities including:

- single line representation showing of the substation apparatus status
- switching facilities for apparatus such as circuit breakers and transformer controls.
- representation of quantities – voltage, current, power, tap position, etc.
- alarms – showing the status of substation apparatus
- events recorder – provides a timed list of events.

The substation operations must still be performed via HPCC except where authority has been given by HPCC for local operation. Switching operators must make themselves familiar with the operation of the screen, where these have been installed in their area.

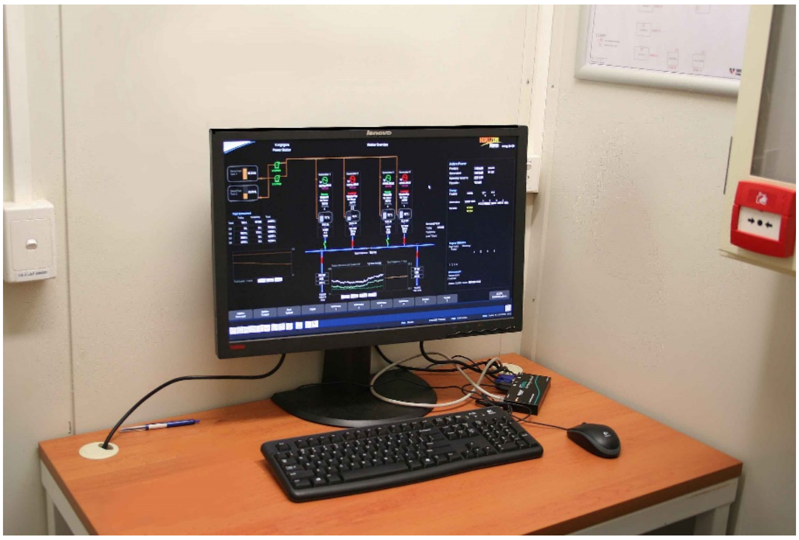

Figure 6-17 Typical substation human machine interface

Relay Room Feeder Panel (Remote)

Outdoor feeders circuit breakers may be operated remotely from the feeder control panel.

Shown below in Figure 6-15 are the instruments that are most likely to be on a feeder relay panel. They include TRIP-CLOSE control switch, ON-OFF indicators, load current ammeter, sensitive earth fault control, auto-reclose control, protection relay, control fuses and protection links.

Note: Interchangeable terms are used in descriptions, labels and circuit breaker indicator and controls - 'Off/On', 'Open/Close' and 'Trip/Close'.

'Off', 'open' and 'trip' mean the circuit breaker contacts are open.

On' or 'close' means the circuit breaker contact are closed.

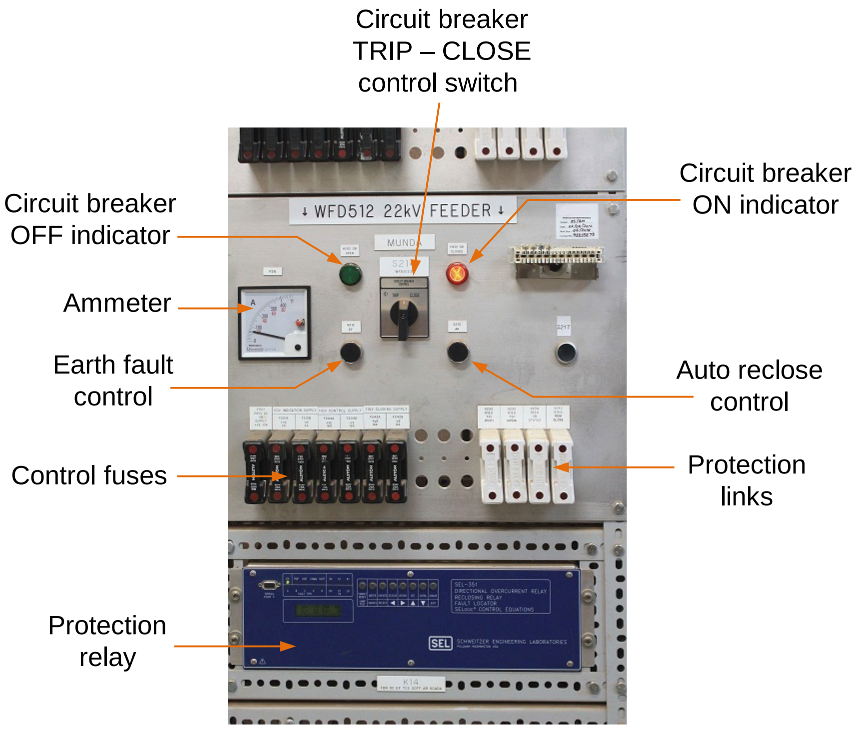

Figure 6-18 Outdoor feeder panel controls

The following procedures should be observed for operating outdoor circuit breakers from remote relay panels and operating indoor circuit breakers from their control panel:

- Before operating the circuit breaker, the feeder auto-reclose function (if fitted) must be disabled (or placed in “manual”). (Where applicable the auto reclose function must be re-enabled when the circuit breaker is return to service at the end of switching.

Note: Some feeders have auto reclose permanently disabled because greater than 50% of the feeder is cable.

- The circuit breaker control switch marked 'trip/close'. The switching operator turns the knob to the left ('trip') or right ('close'), according to the operation required. (When released, the switch always returns to a central position).
- Before and after operating the circuit breaker, the ammeter should be checked. (This ensures that the required operation is complete. For example, if the breaker is switched 'off', the load drop to zero is shown on the ammeter.

  Switching operators should also check other ammeters in the substation that may provide more information on changes of substation status such as transfer or load to interconnected feeder).

The maximum demand indicator (MDI) is provided on some ammeters. This requires an extra needle which stays in the highest position recorded by the ammeter since the last reset. Be careful to distinguish the MDI needle from the ammeter needle.

- Circuit breaker indicator lamps are red and green, according to the state of the breaker:
  - red glowing = 'on' (OCB closed)
  - green glowing - 'off' (OCB open).
- Controls (and indicators) are provided to disable and enable the sensitive earth fault and auto-reclose functions.
- Protection relays, links and control fuses are also mounted on the feeder panel. They provide isolation and protection for the secondary control circuits.

Note: The ON–OFF indicator lamps can fail at any time, and the associated indication circuit relies on circuit breaker mechanism box auxiliary switches which can occasionally lose correct adjustment.

The switching operator must not rely on the first look at the lamps, and check all available indicators such as ammeters and mechanical indicators.

The circuit breaker mechanism mechanical indicators are the most reliable indicators of the circuit breaker status and should be used by the switching operator to confirm the circuit breaker status.

The indoor switchgear control panel shown below in Figure 6-16. This circuit breaker is currently in the ‘off’ position as indicated by the green light glowing.

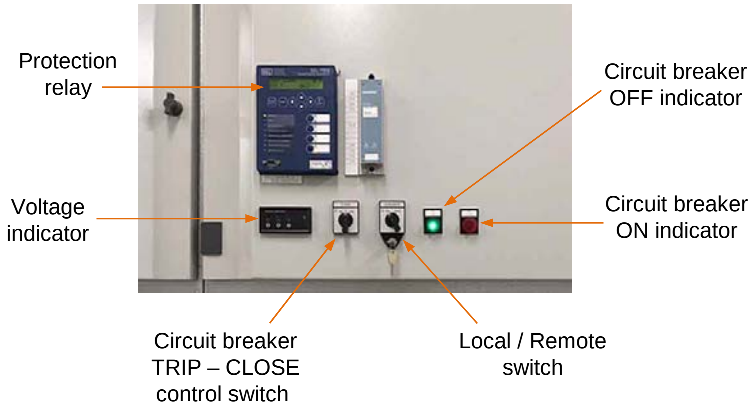

Figure 6-19 Indoor switchgear feeder control panel

Circuit breaker mechanism box (local)

The local panel is intended for maintenance purposes and is not used in normal switching.

To locally operate the breaker, the local /remote switch is to be set to local. This will prevents operation from a remote position. There may also be mechanical ON and OFF buttons or control switch; this interacts directly with the mechanical operating mechanism. Electrical ON and OFF buttons or a control switch use the control close/trip solenoids to activate the operating mechanism. (see Figure 6-17 below).

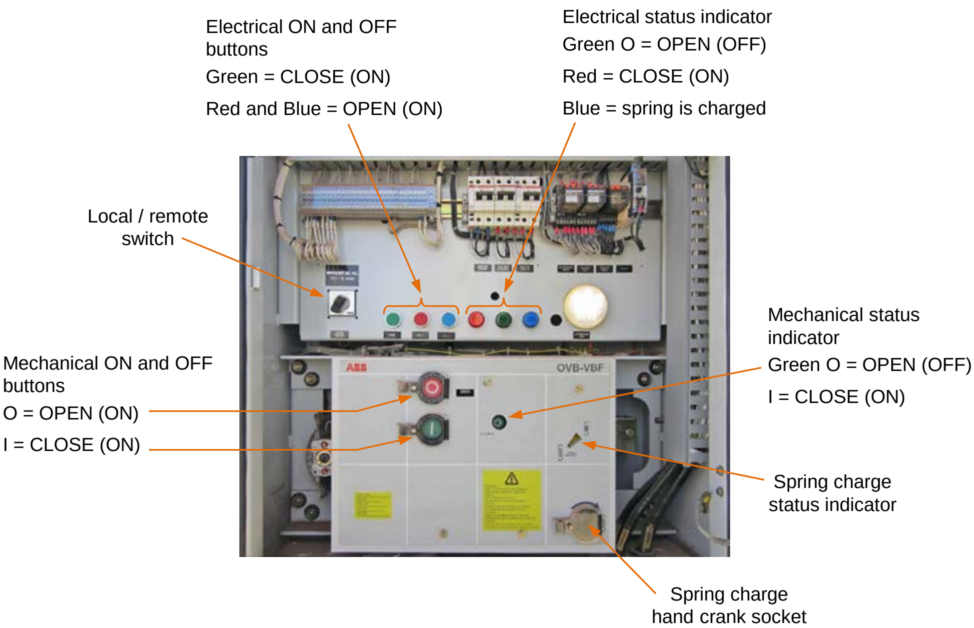

Figure 6-20 Typical outdoor circuit breaker mechanism box controls and indicators

6.3.6 Circuit breaker status indication

The switching operator should use the circuit breaker mechanical indicator to confirm the status is “off” prior to operating an outdoor circuit breakers associated disconnector or racking an indoor breaker. The electrical lamp indicators that are also available use the circuit breaker’s auxiliary switches and are not considered as reliable at the mechanical indicators. An example of the mechanical status indicators is shown in Figure 6-17 above. In some cases the mechanical status indicator is located on the outdoor circuit breaker poles.

6.4 Outdoor Substation Disconnectors

Air break disconnectors are installed in outdoor substations to provide:

- isolation points
- bus section switches, and
- transfer busbar switches.

Disconnectors are air break switches and have limited current switching capability, therefore they are not to be used to make or break load current because of the risk of a flashover.

Disconnector can be used to:

- make and break parallel of transformer secondaries provided the transformer secondary voltages are equalised
- energise unload sections of busbar or apparatus, and
- make and break parallel feeders on the transfer busbar.

Disconnectors have a manual operating handle and therefore the speed of contact movement is linked to the speed of the operating handle movement. To reduce the risk of flashover during opening and closing operations the movement of the handle must be brisk and continuous.

The pre and post checks conducted by the switching operator when operating a disconnector are similar to the requirements for pole top switches.

In a switchyard the connection of the operating handle to the earth mat and the connection to the main earth can be visually inspected by the switching operator before operation, therefore the installation of a portable operator mat is not required.

A disconnector can be used as an isolation point where the disconnector contacts are visually confirmed as fully open and the operating handle is locked with a Danger–Do Not Operate (D–DNO) tag.

Shown below in Figure 6-18 is an example of a feeder circuit disconnector and another as a bus section disconnector.

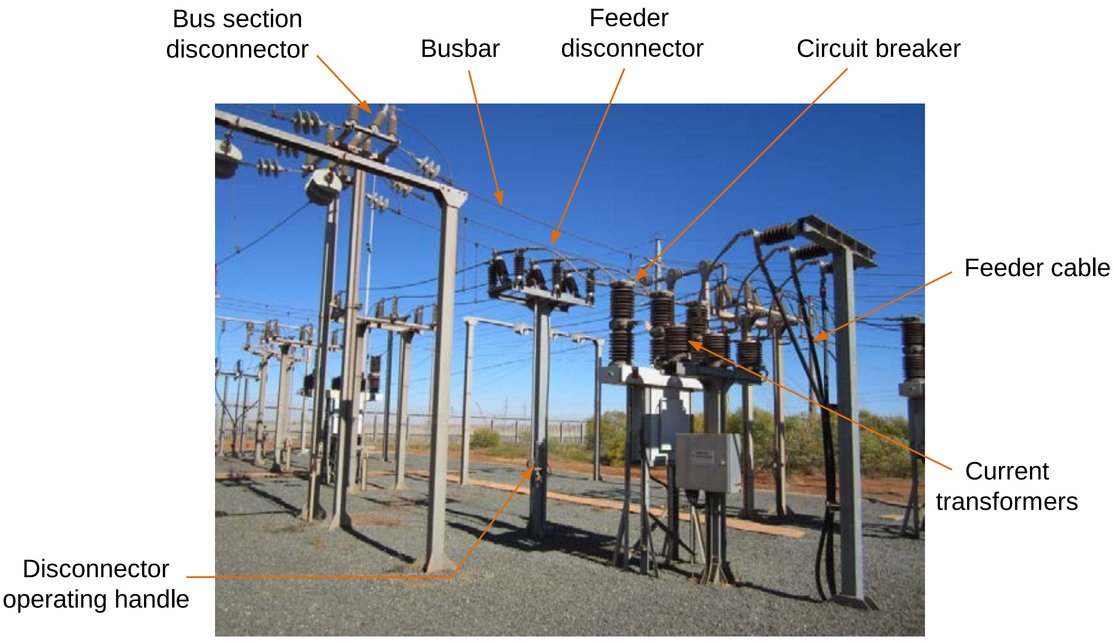

Figure 6-21 Feeder circuit disconnector

6.5 Indoor switchgear safety features

Indoor switchgear has a number of features to improve switching operator safety. The features include:

- switchgear interlocks
- busbar and circuit shutters, and
- circuit voltage indicators.

Switchgear Interlocks

Indoor switchgear interlocks are designed to prevent a number of unsafe conditions. Interlock must not be forced or overridden unless specifically provided for in the switchgear operating instructions.

Typical switchgear interlocks include:

- the circuit breaker can only be racked out when the circuit breaker is OFF
- the circuit breaker can only be racked in when the circuit breaker is OFF and cubicle door is closed and secured

- the circuit breaker cubicle door can only be open when the circuit breaker is racked out
- the earth switch cannot be closed unless the associated circuit breaker is OFF and racked out
- the circuit breaker cannot be racked in if the earth switch is ON, and
- the cable cubicle door cannot be opened unless the earth switch is ON. The means a VT (where fitted) cannot be racked out unless the earth switch is ON
- On some indoor switchboards with capacitor bank CB's the umbilical cords need to remain connected to maintain a supply for the Castell key or Sentry key interlock system timer to operate.

Switchgear interlocks should be considered as a second level safety measure and are not to be relied on to keep the switching operator safe under all conditions.

The first level safety measure requires the switching operator to be proficient in operating the switchgear and to use the correct operational sequence so that the interlocks are not normally encountered.

Note that regardless of the above interlocks, it is still possible for a switching operator to earth a live circuit if it is being backfed from another source of supply.

Bus and circuit shutters

Shown below in Figure 6-19 is the inside of the circuit breaker cubicle with the busbar and circuit shutters. The busbar and circuit shutters move to cover the busbar and circuit contacts as the circuit breaker is racked out.

When the circuit breaker is removed from the cubicle, inadvertent access to live busbar and circuit contacts is prevented by locking and D–DNO tagging the busbar and circuit shutters in the closed position.

In some cases it's not always possible to lock and D DNO-tag the shutters to create an isolation point, when this occurs the CB cubicle door needs to become the isolation point with the cubicle door locked and D DNO-tag attached. E.g. if a CB trolley is unavailable and more than one CB needs to be racked.

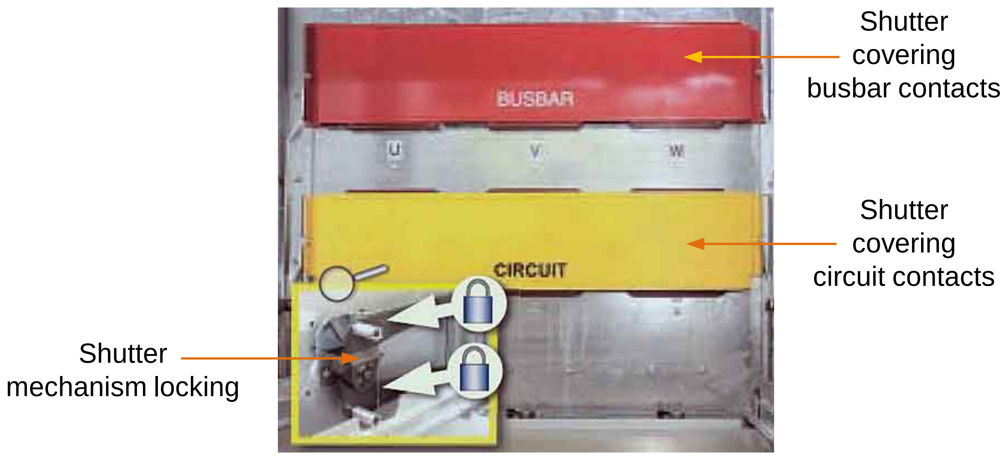

Figure 6-22 Shutters inside circuit breaker cubicle

To avoid damage, the shutter mechanism locks must be removed before attempting to insert the circuit breaker in the cubicle and rack it in.

Circuit voltage indicators

Each circuit is provided with voltage indicators which are connected on the circuit (cable side of the circuit breaker). These indicators are to be used to confirm the cable is de-energised before the earth switch is closed.

A typical voltage indicator is shown in Figure 6-20.

Figure 6-23 Typical voltage indicator

Test sockets are also provided so a multimeter can be used to confirm de-energisation. After testing to verify the test sockets secondary wiring is internally connected to correct phase the sockets can use used to phase out using a voltmeter.

6.6 Substation AC and DC Power Supplies

Substations requires both a 415V AC power supply to operate ancillary equipment and a DC supply provided by batteries banks for the operation of protection and alarms systems.

6.6.1 AC Local Supplies

Substations require a 415V AC supply to operate ancillary equipment such as battery chargers, transformer tap changers, pumps and fans, circuit breaker spring and hydraulic charging mechanisms.

For reliability, it is standard practice to have two incoming 415V AC supplies to the main control panel which has automatic changeover relays. If the supply currently supplying the substation fails, the change-over contactors swap the substation load to the alternate healthy supply (see Figure 6-21).

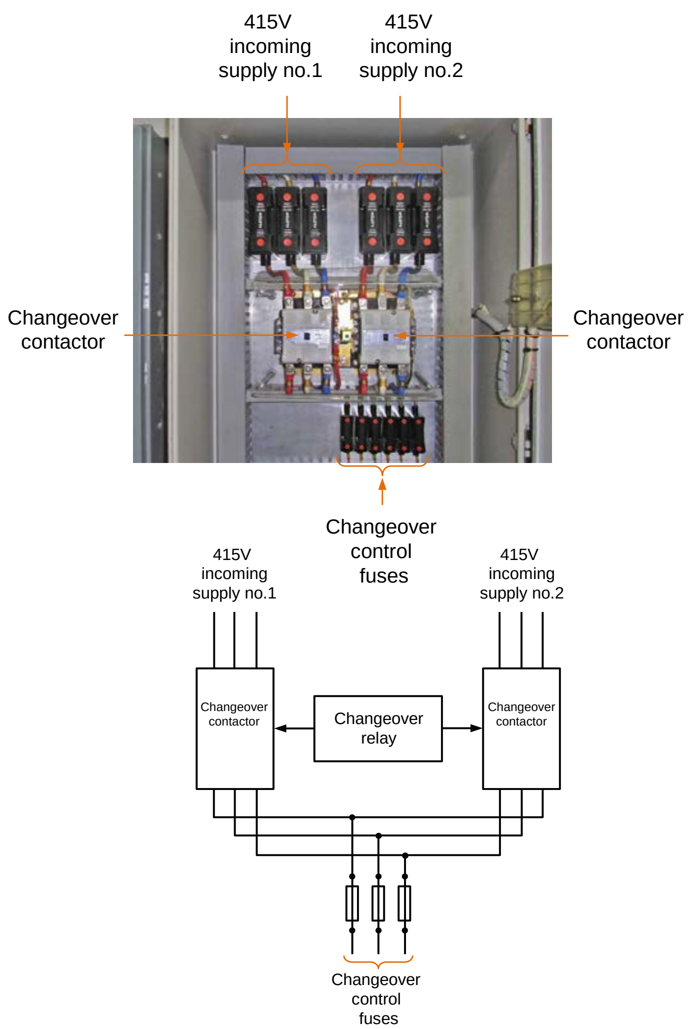

Figure 6-24 415V AC local supply changeover boards with simplified circuit shown below.

As part of routine substation checks, both 415V supplies should be checked to be healthy and the changeover function activated.

A range of sources is available to provide the 415V local supplies. These include:

- station transformer supplied from the substation busbar
- distribution transformer supplied from a distribution feeder, and
- local 415V generator.

Because of the importance of local supplies, it is a sound operational practice to provide diversity in the source of local supply, so, where possible, a single fault does not cause the loss of both local supplies.

Shown below in Figure 6-22 is a typical station transformer.

Figure 6-25 Typical substation transformer

The range of substation ancillary equipment using the 415V AC local supply and the impact is dependent on a number of factors as indicated in Table 6-2 below.

415/240VAC Local Supply Usage	
Purpose	**Implication of total loss of local supply**
Battery chargers 2 x 110V protection batteries and 1 x 50V SCADA battery. (Usually 2 x 110VDC and 1 x 50VDC, except old switchyards may use 2 x 32VDC)	Delayed impact pending battery discharge. If protection batteries are not in an adequately charged state, the protection system will not function and the switchyard primary circuits will have to be deenergised (or remain deenergised if the switchyard is 'black'). If SCADA batteries go flat, the SCADA control, status indicators, and analog values will not be available.
Transformer tap changer control	Immediate impact on voltage control. The secondary distribution HV voltage will not be able to be regulated automatically. Personnel will have to be dispatched to manually crank tap changer mechanism.
Transformer cooling – oil pump and radiator fans	Impact is transformer load-dependent. Dependent on present transformer temperature and pending load profile. The transformer reverts to its ONAN rating without the availability of the forced cooling of oil pump and radiator fans. Transformer offloading may be required.
Relay room air conditioning	Impact probably delayed to keep electronic apparatus (protection, SCADA, etc.) within operating temperature range.
Circuit breaker – Spring/hydraulic close charging systems	Immediate impact if stored closing charge is used. Spring charge closing – stored spring charge will not be replenished if used. Hydraulic charge closing – loss of pressure will result in the circuit breaker not being able to be closed.
General power outlets	Immediate impact. GPOs throughout the switchroom and switchyard will be unpowered.
Lighting	Impact dependent on lighting system installed. Switchyard and switchroom will be in darkness unless DC lighting system is installed. DC lighting is not installed in old zone substations.
Panel status indicator lamps (ON-OFF indicators)	Immediate impact where indicator lamps supply is derived from the 240VAC supply.

Table 6-2 Implications of losing substation local supply

Note: Spring charged and hydraulic operated switchgear have stored energy for a trip-close-trip sequence, that is, the next close operation is stored within the switchgear mechanism.

6.6.2 Battery Systems

Because the AC supply to a zone substation cannot be guaranteed under all conditions (particularly during faults), it is essential multiple DC supplies are provided for protection, alarm and SCADA systems. These systems are designed to run on various DC voltages including 32V, 50V, 110V or higher.

Battery Banks

Shown in Figure 6-23 below is the battery charging arrangement. The 415V AC local supply provides the energy for the battery chargers to charge the battery banks. The protection, alarm and SCADA systems are connected to the batteries via DC distribution panels.

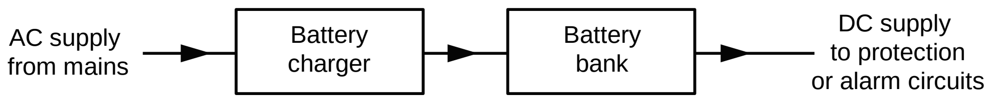

Figure 6-26 Single line circuit

Because the protection, alarm, and SCADA systems are connected to the battery banks they will continue to operate regards of the state of the 415V AC local supplies.

The length of time the batteries can continue to supply their load without being charged, depends upon the standing load and rating of the battery bank. Normally, these banks are designed for a six- to eight-hour load without being charged. Typically this enables most faults affecting battery charging to be investigated and appropriate action taken before any battery voltage problems occur.

Different battery voltages are used for different purposes within a substation. The voltages used may also differ with the age of a substation or the type of equipment installed.

Newer substations are designed with more elaborate and secure protection systems. Two 110V battery banks are used for the transmission system and distribution system (in some case only one battery bank is used for distribution). 50V battery banks are used for alarm systems and SCADA apparatus. (see Figure 6-24.)

Microgrid substations and older substations typically use lower voltage battery banks for most functions.

Because substation design has changed, switching operators now find different combinations of battery banks in different substations. Field staff should familiarise themselves with the types of battery systems used within their local area.

Note: Battery systems are the most important component within a substation. The battery banks must be kept in good working order to ensure protection systems will detect fault, and trip the associated circuit breakers under all conditions.

Figure 6-27 Typical battery chargers and banks

Problems

The main problems experienced with battery systems are low DC voltage output, battery earth faults, and loss of AC supply. Any of these problems may cause a fleeting (intermittent) alarm.

- **Low DC voltage output**

  This occurs for a number of reasons, mainly when the AC supply is removed from the battery charger, or one or more battery cell fails.

  To check the 415V AC supply, a voltmeter may be used, or checks can be made on the LV fuses. A DC voltmeter must be used to check each cell of the battery bank. If one or more cells are defective, the cell(s) will be detected by the low readings on the meter.

- **Battery earth faults**

  Gases are produced and emitted from the chemical reaction within batteries. If these gases dry and crystallise, leakage current from the battery may track along the path formed.

  If the batteries have been insulated from the earth system of the battery bank, meters can be installed to measure the leakage current. When the leakage reaches a certain level, an alarm is triggered.

Batteries emit explosive flammable gases.

Naked flames and sparks near battery systems must be avoided at all times.

- **Loss of AC supply**

  If there is a major dip on the incoming AC supply (for example, faults or LV changeover board operation), the alarm system may detect this as a permanent condition and trigger fleeting or transient alarms. If the alarms are operated, the substation must be inspected and the battery charger must be checked for operation.

Note: Do not leave a battery charger off for any length of time. If faults are detected in any battery system, immediate steps must be taken to return the system to full operation.

Testing

Most battery chargers have a built in test facility. This is usually a switch or push button that is wired for two functions. When operated, it first removes the AC supply to the charger and then places a load across the battery bank. This load normally is a resistive element.

When the switch is put in the test position, the operator should check the voltage across the battery bank. This can be done by inspecting the voltmeter on the front of the charger or by placing a DC voltmeter across the battery bank. If the voltage drops below the battery charger's rating, further investigation must be carried out.

Note: Test facilities on chargers must not be held 'on' for more than 15 seconds at one time. If held on for longer periods, the load resistors may fail due to overload.

Because test switches remove the AC supply from the charger, an alarm may be operated. Before any tests are carried out on battery systems, the HPCC should be notified.

Battery-parallelling boards have been installed in some substations. These allow isolation of the batteries for maintenance or back up. Where these are installed, an operation guide is located on the inside door panel. If the battery parallelling board is unavailable, a separate battery bank should be used to replace the one being taken out of service.

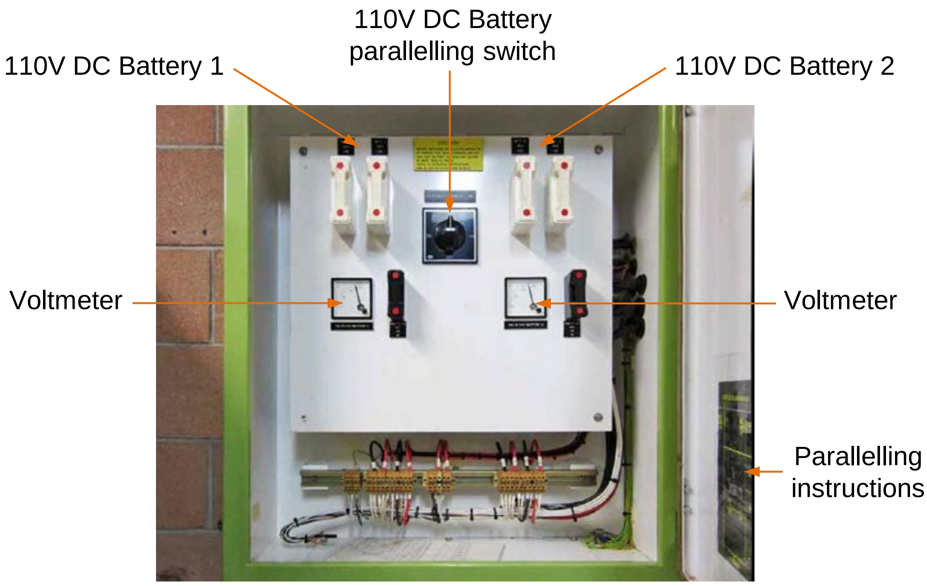

Figure 6-28 Typical substation battery paralleling panel

6.7 Alarm Panels

A variety of alarm panels are used by Horizon Power ranging from local HMI comprehensive alarm systems used in the microgrid system to minimal local systems at substation as the alarms are monitored by HPCC.

In many cases the alarms presented to HPCC are grouped or general in description and a switching operator or other maintenance or protection personnel are required to attend the substation to determine the specific source of the alarm.

6.8 Voltage Regulation

Voltage regulation is required to maintain relatively constant high voltage feeder voltages irrespective of variation in transmission voltages and load. On the transmission system, voltages can vary by up to 10% dependent on load and system conditions.

Also the feeder voltage drop is caused by the feeder load and the length which affects the line resistance and reactance. For a heavy load current, the voltage drop over the feeder is large. For example, a 22kV feeder may have a voltage of only 21kV after it has travelled 5km from the substation.

6.8.1 Voltage Regulation Principles

Voltage control requires several components:

- tap changing transformer
- automatic voltage regulating relay, and
- line drop compensation.

The voltage control method used has a voltage transformer (VT) connected to the secondary side of the transformer which supplies a proportional voltage (around 110V) to the Automatic Voltage Regulating (AVR) relay. The AVR measures this voltage against a reference set point and if required will activate the tap changer mechanism to raise or lower the tap position to adjust the secondary voltage.

Typical settings on AVR is 112.5V, which on a 22kV system is 22000/110*112.5 = 22500V.

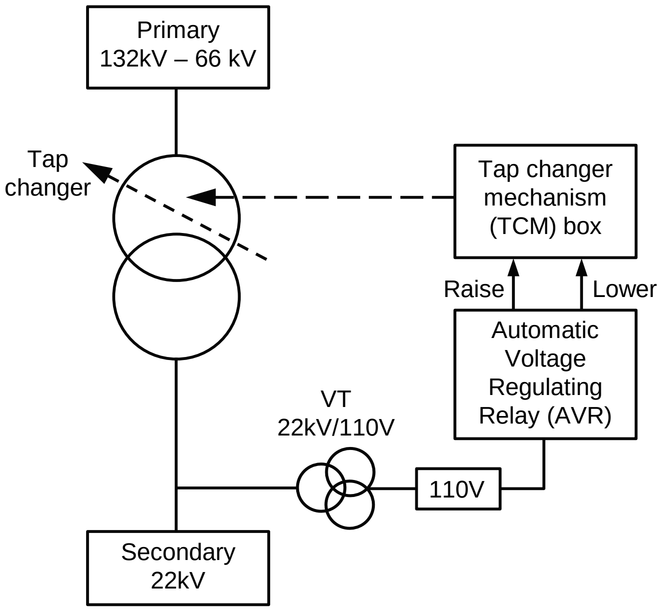

Figure 6-29 Circuit showing the principle of automatic voltage regulation

6.8.2 Tap Changing Transformers

The secondary voltages of a transformer can be controlled by changing the ratio of number of turns between the primary and secondary windings. This involves using a tap changer to switch in sections of a winding.

Usually, tapping takes place on the higher voltage winding because this is the low current side compared to the higher current on the low voltage side of the transformer.

There are two types of tap changing transformers:

- *off-load* is used on distribution transformers (pole top and ground mounted transformers), and
- *on-load* is used on substation transformers.

The off-load transformer must be disconnected from all sources of supply before the tap change is made. The tap change is usually done by some operating device, such as a wheel or handle which is external to the unit.

On-load tap changing transformer circuits are designed to be operated at full load without interruption to the supply as the tap change occurs. To achieve this, a special high speed change-over switch is used to move from one tap the next without interrupting the flow of current.

Shown below in Figure 6-27 is a zone substation transformer with an on-load tap changer built into the tank. The tap changer mechanism box contains a 415V three-phase AC motor which can turn in either direction to tap up or down.

Figure 6-30 Substation transformer showing tap changer mechanism box

This means that some form of compensation is necessary for variations in both the substation voltage and line voltage.

Voltage regulating relays may be used in conjunction with line drop compensation, to give automatic control for on-load tap changing transformers (and distribution line regulators). Electric control of the tap changer is normally used, however manual operation of the tap changing mechanisms is also possible, by using a manually-controlled electric motor or hand-cranked lever. A tap changing mechanism box with its main component parts is shown in Figure 6-28.

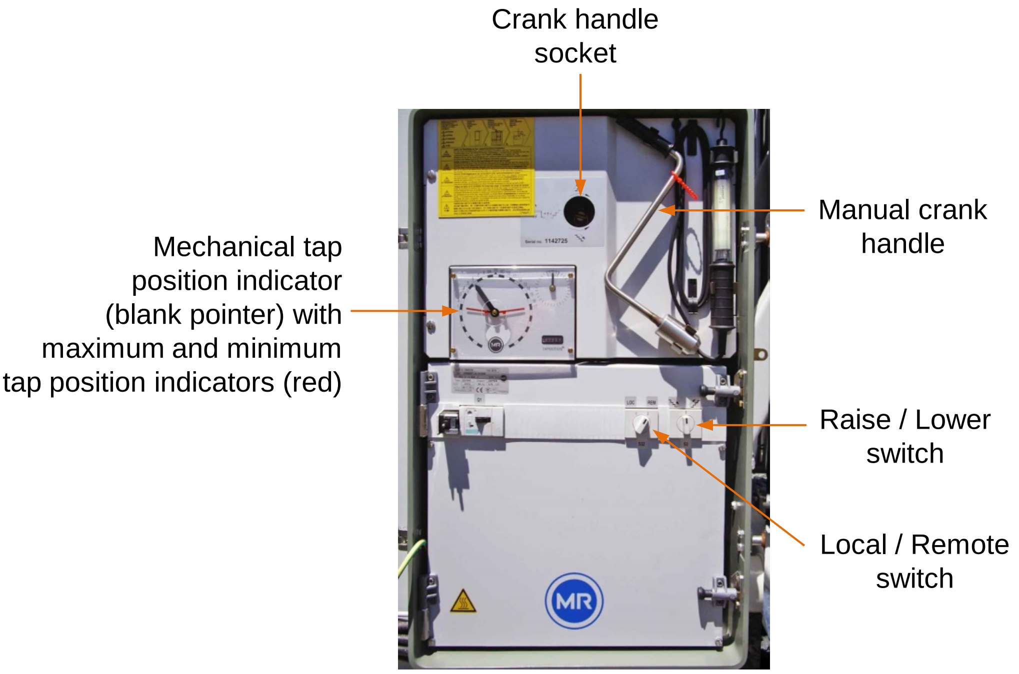

Figure 6-31 Tap changer mechanism box showing controls

Note: When hand cranking, the switching operator must check the motor is isolated. Before any operation is carried out, the operator must remove the fuses or turn the motor switch 'off'.

Shown in Figure 6-29 is an automatic voltage regulator/tap changer control panel located in the relay room. The panel has a solid-state automatic voltage regulator (AVR) and a digital remote tap position indicator. There are a number of switches for controlling the operation of the tap changer, including:

- the master / slave / independent / lockout switch, for selecting the operating mode of the tap changer
- the raise / lower switch, to manually adjust the tap position, and
- the automatic / manual mode switch is used to select the control from the AVR relay or the manual raise / lower switches.

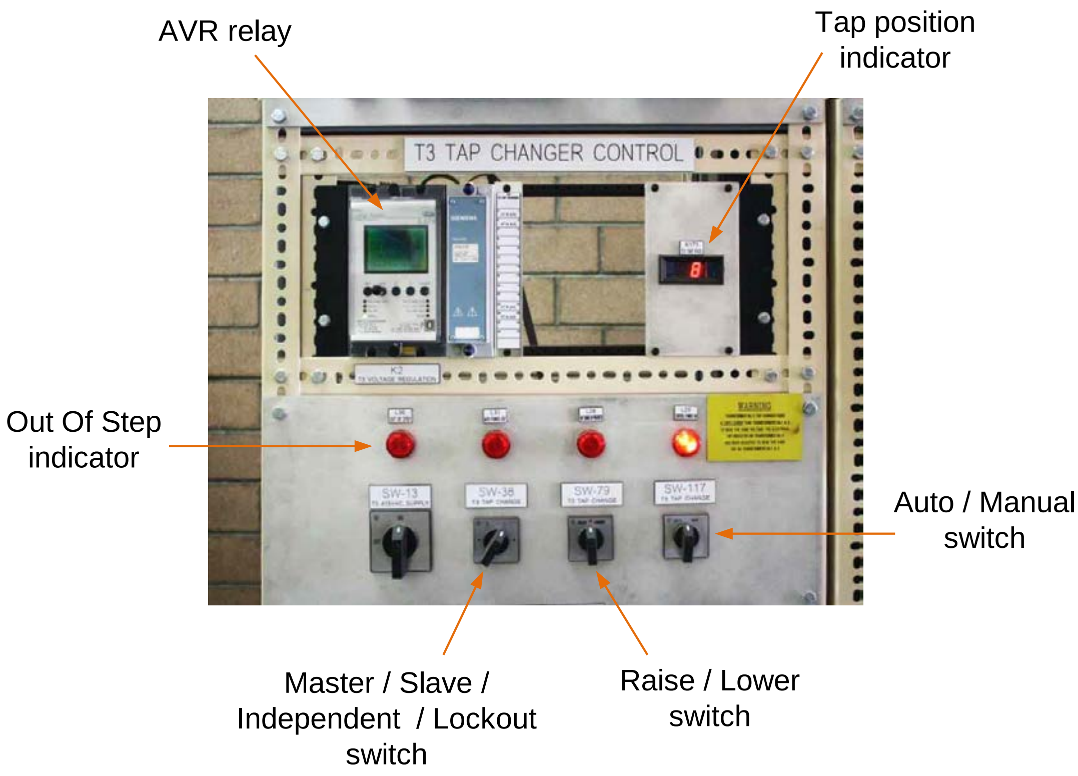

Figure 6-32 Automatic voltage regulator / tap change panel

6.8.3 Regulating Relays and Line Drop Compensation

A range of electronic automatic voltage regulating relays are used; an example is shown in Figure 6-30 below.

The AVR relay compares the actual distribution system voltage against the reference set point which has been stored in the relay. The relay also has a voltage band setting which allows small changes in the actual voltage either side of the reference setting without initiating a tap change.

When the voltage moves outside the band the relay starts a timer. If the voltage remains outside the band for the timer setting (typically around 60 seconds) one or more tap changes are initiated. This will return the voltage to within the band around the reference set point. The purpose of the band setting and the timer reduce unnecessary tap changer operations.

An under-voltage blocking function is used to prevent the automatic voltage regulating relay driving the tap changer to the top tap when the transformer is switched off.

These relays also have line drop compensation and metering and event recording.

Line drop compensation (LDC) is a function provided in electronic AVR relays to adjust the substation voltage to counteract for the feeder voltage drop.

Figure 6-33 Typical AVR relay

Line drop compensation settings representing the resistance and reactance of the feeder line are applied to the AVR relay settings. This ensures the line voltage drop with respect to current is correctly modelled.

For example, as the feeder line voltage drop increases with increasing load, the LDC function will proportionally reduce the voltage seen by the AVR voltage sensing circuit. This will cause the AVR to see low voltage, causing the tap changer to tap up, boosting the substation voltage to compensate for the line voltage drop.

6.9 Under Frequency Load Shedding

Stable power system operation requires the system frequency to be maintained at nominal 50 cycles per second (49.75-50.50Hz). An imbalance of the power generated and the load demand will cause the system frequency to deviate from the nominal. Excess generation causes the frequency to rise and a shortage of generation will cause the frequency to drop.

With the loss of a significant amount of generation which cannot be compensated for by the remaining online generators, the frequency will begin to drop. When the frequency drops more than a few cycles, serious damage can occur to power station generation units and the power system can become unstable. Therefore, to restore the generation/load balance and stabilise the frequency, the load must be dropped off or shed. This is called under frequency load shedding (UFLS).

The UFLS function is typically incorporated into the electronic feeder protection relays. The relay settings specify the frequency at which the feeder trips. UFLS occurs in stages such that additional feeders will trip as the frequency drops lower.

6.9.1 HPCC Operation

HPCC dispatches generation to cater for the expected load and, in unusual circumstances where a shortage of generation will occur, feeders can be shed by HPCC to maintain stable system operation. It is normal practice to rotate the feeders which are off at regular intervals to minimise customer inconvenience where the generation shortage continues for an expended time.

HPCC must be aware of the substation local supply arrangements to ensure the local supply is not affected by the load shedding.

6.9.2 Restoration Procedures

Following an UFLS event, HPCC will manage the feeder restoration to match the available generation.

6.10 Zone Substation Interconnection

This section should be read in conjunction with Section 4.2.13. Interconnection of zone substation transformers is an area that may be quite involved. The switching operator must be familiar with the following principles and standard procedures before attempting interconnection.

HPCC will manage the paralleling of zone substation transformers with the switching operator carrying out any field switching activities which cannot be performer remotely from HPCC, e.g. air break bus section switch. The following material is provided as additional information and explanation.

6.10.1 Principles

Horizon Power transformers vary in size, tap selection and impedance. These factors, together with feeder loads and capacitor banks, must be considered when paralleling transformers. This is necessary in order to determine what current will flow through the interconnecting switch.

HPCC will manage the paralleling of transformers including setting the taps, however switching operators must be aware of the issues associated with the paralleling of transformers.

Certain principles must be applied for the following interconnection tasks paralleling:

- transformers with feeder load imbalance
- transformers with different tap positions (circulating current)
- different types of transformer
- transformers with capacitor banks in service.

Paralleling Transformers with Feeder Load Imbalance

When transformers are interconnected at a zone substation, the current flow will change on each circuit, according to transformer impedance and secondary voltage. When two transformers of equal impedance and voltage are paralleled, their loads will balance (see Figure 6-31). Each transformer will feed half the total load of the combined circuit. (The current flowing through the bus coupler is also shown).

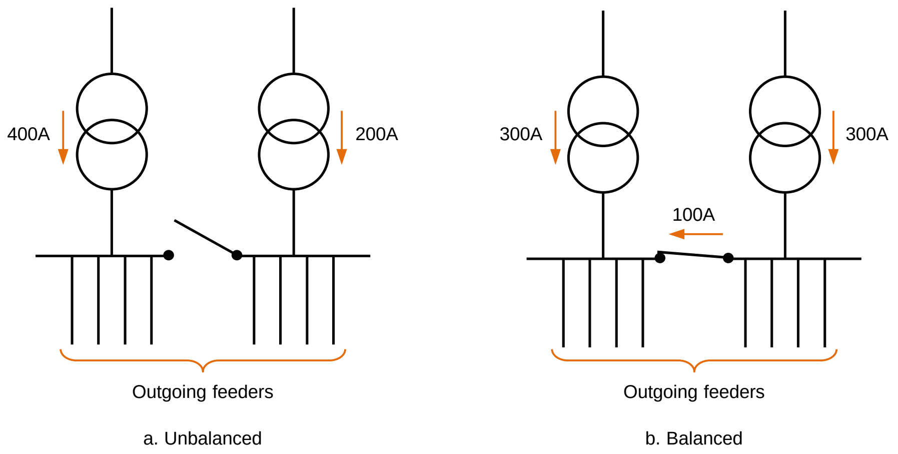

Figure 6-34 Transformer interconnections

Paralleling Transformers with Different Tap Positions (Circulating Current)

The previous principle holds only if both transformers have the same output voltage. If the voltage is different, it is more difficult to calculate the load that each transformer will supply. Circulating current will develop between the transformers and increase with voltage difference. It also alters the current through the interconnecting switch.

The circulating current's power factor is very different from the load current. This means that operations on transformers with voltage differences must be limited.

Figure 6-32 shows two transformers connected together with different tap settings (voltage outputs).

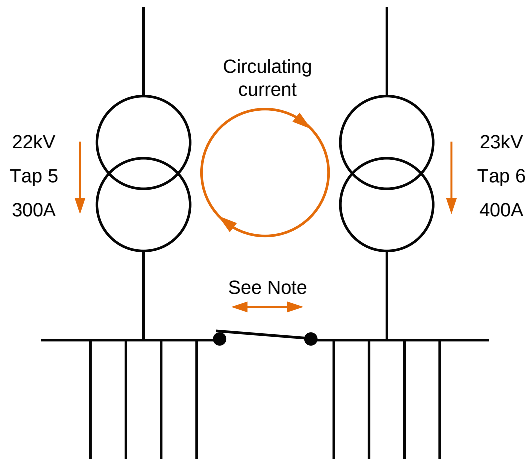

Figure 6-35 Transformers with different tap settings

Note: The following values are presented as a guide to switching operators.

For 22kV zone substations, where transformers are one tap out of step, approximately 50 amps circulating current flows between the transformers when paralleled.

Therefore, if the transformer is three taps out of step, the circulating current will be approximately 150 amps.

For 11kV zone substations, each tap difference results in approximately 100 amps, when transformers are paralleled.

Paralleling Different Types of Transformers

Horizon Power uses different types of zone substation transformers in its transmission network. The transformers vary in make, size, type of tap selection and impedance. When paralleling zone substation transformers at the one location, switching operators must be aware of the load transfer resulting from transformer differences.

Case 1

Some zone substation transformers may have different tap change mechanisms or different tap step ratios. (This may be due to different makes).

Before paralleling, switching operators must check each transformer to establish any tap change differences of ratio or position. This is done by comparing the nameplates of both transformers. The transformers may have to be switched to the same ratio before paralleling can be attempted.

Case 2

Zone substations are normally designed to have two or three transformers of the same size, for example, two 20/27 MVA or two 10/13 MVA units.

Where two transformers of different sizes are installed at the same substation, transformer loads will not balance if they are paralleled. Depending upon feeder loads, the imbalance may cause high currents to flow through the interconnecting switch.

This imbalance may be calculated using the following mathematical formula. (MVA and impedance values are indicated on each transformer's nameplate).

$$Tx_1 \text{ load} = \text{Total load by } \frac{\dfrac{MVA_1}{Tx_1 \text{ impedance}}}{\dfrac{MVA_1}{Tx_1 \text{ impedance}} + \dfrac{MVA_2}{Tx_2 \text{ impedance}}}$$

Example

Tx_1 = 20MVA

Tx_2 = 10MVA

Tx_1 and Tx_2 = 10% impedance

Substation Total Load (load between transformers being interconnected)

= 800 Amps

$$Tx \text{ load} = 800 \text{ by } \frac{\dfrac{20}{10}}{\dfrac{20}{10} + \dfrac{10}{10}} = 533.3 \text{ Amps}$$

Therefore,

$$Tx_1\ 20\,MVA = 533.3\,A$$
$$Tx_2\ 10\,MVA = 266.6\,A$$

Note: If three transformers are in service, the given substation total load refers only to the load of the two transformers being interconnected.

Case 3

Different types of transformers may have different impedances. When switching, the switching operator should check impedances by inspecting each transformer's nameplate.

Switching operators may be required to parallel transformers with different impedances. The previous formula indicates that the impedance difference of each transformer affects the load each transformer will take when paralleled.

Example

Tx_1 and Tx_2 = 20 MVA

Tx_1 = 8% impedance

Tx_2 = 12% impedance

Total Substation Load = 800A

$$Tx_1 \text{ load} = 800 \text{ A by } \frac{\frac{20}{8}}{\frac{20}{8} + \frac{20}{12}} = 480 \text{ A}$$

Therefore,

Tx_2 load = Total load – Tx_1 load

= 800A – 480A

= 320 amps

This example shows the load expected on each transformer, given ideal conditions of the same size and tap ratio for each transformer. However, this condition may not occur as there may be out of step tap changers.

Note: Cases 1, 2 and 3 demonstrate that transformers may not evenly share load when paralleled. This may cause higher than normal currents to pass through the interconnecting switch.

Capacitor Banks

Where paralleling is being carried out on an outdoor 22kV air break bus section switch, the switching operator may have to remove the capacitor from service before commencing any switching operation. This is necessary only when the load on the section of transformer bus (with the capacitor installed) is less than 8 MVA (209 amps at 22kV).

This action must be carried out to make sure that the power factor of the bus section load with the capacitor does not differ significantly from the other section.

Note: Capacitor operation is of no concern in substations that have circuit breaker bus section switches.

6.10.2 Standard Procedures

Circulating current, out-of-balance current and transformer characteristics must all be considered when interconnecting transformers. The switching operator must also select which interconnection point is best suited for the particular purpose.

Interconnection of Two Zone Substation Transformers at Different Substations

Distribution interconnection is usually carried out for load movement on feeders. Normally, substations are some distance apart (over 2km on each feeder). Experience demonstrates that the overhead lines, used during the interconnection, have enough impedance to limit any circulating current or out-of-balance current. Therefore, when carrying out this operation, it is not necessary to alter, or set to manual, the tap setting on each zone substation transformer. (Extreme voltage differences may require tap adjustment).

The exception to this is when feeders which are 50% or more cable are being used for interconnection. Tap changers at both substations must be put in manual. Voltage checks should be made to determine whether both feeds have approximately equal voltages.

Interconnection of Two Zone Substation Transformers at the Same Substation

If interconnection is carried out in areas more than two kilometres out on each feeder, the previous principle still applies.

If interconnection is close to the substation (within two kilometres), the switching operator must consider circulating current, out-of-balance current and voltage difference.

Shown in Figure 6-33 are two ways of interconnecting transformers at the same substation:

- a bus coupler/bus section switch, and
- a pole top switch.

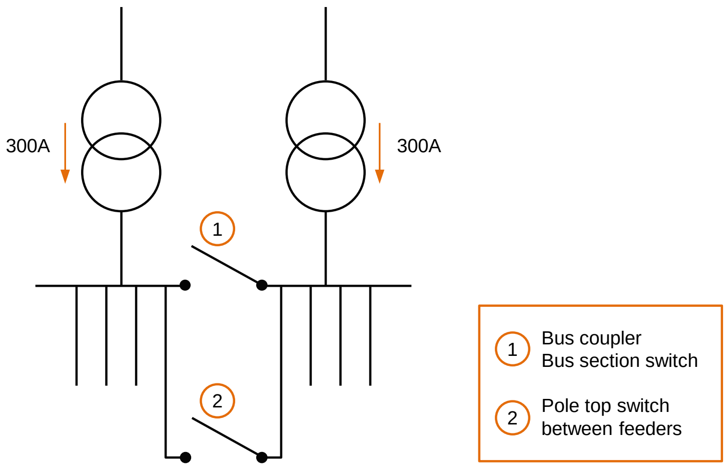

Figure 6-36 Two ways of interconnecting transformers

Pole Top Switch

Because of the problems already identified, there are limitations on how a pole top switch can be used within two kilometres of a substation. However, if the following three circumstances apply, pole top switches may be used:

- Both zone substation transformers are put on 'manual' and set to equivalent tap or voltage output. (Transformer nameplates should be checked if the switching operator is unsure of voltage outputs. This ensures the same voltage output when transformers are paralleled).
- Both zone substation transformers have approximately the same load.
- Any out-of-balance transformer load can be easily picked up on the interconnecting feeders with no overloading occurring.

Bus Coupler/Bus Section Switch

If the above circumstances do not apply, the bus coupler/bus section switch must be used to interconnect and break interconnection during operations.

This means that any circulating current, or high out-of-balance current, will flow through the busbar and not a feeder circuit. The following procedure should then be adopted:

1. set the tap change switches to 'manual'
2. manually set taps to the appropriate tap setting
3. close the bus coupler/bus section switch
4. close the normally open point pole top switch
5. open the new pole top switch for the work required
6. open the bus coupler/bus section switch
7. set the tap change switch back to 'auto', and make sure that the voltage levels stabilise.

When manually setting taps, switching operators should remember that the substation output voltage changes with changing tap position. It may be necessary for the operator to reduce the taps on one transformer and increase the taps on the other, to be able to parallel successfully. This action changes the voltage on the outgoing feeders.

Note: When adjusting taps, switching operators should not change the tap setting by more than two taps either way.

Circulating current occurs if the taps are not exactly equal. To limit this, transformers should not be paralleled, if their final tap selection is more than two taps out for 22kV or one tap for 11kV. This, together with the tap limit above, results in the following overall guide.

Note: If transformers are six taps out of step for 22kV, or five taps out for 11kV, the switching operator should not interconnect until alterations to the system are completed.

Taps can be brought closer together by either altering the load on the transformers (load movement) or by switching out capacitor banks. In most circumstances, it is better to move the load.

6.11 Zone Substation Fault Switching

Depending on the design of the zone substation, operators are likely to find a large variety of different fault situations to handle. Only those areas directly concerned with distribution feeders are examined here. Areas affected by transmission circuit problems are examined in the Horizon Power *Switching Operator's Manual Two*.

The procedures for fault switching examined here include:

- faults in a feeder
- recharging a spring assisted circuit breaker
- faulty operation of a circuit breaker.

6.11.1 Faults on a Feeder

All feeder faults are managed by HPCC.

If switching operators are concerned about any operations on feeder switchgear for any reason (fear of flashover, etc.), the operation should not be attempted. The feeder circuit breaker should be tripped and the switchgear should be operated in a de-energised condition. (Switchgear includes pole top switches, ring main units, etc.).

Because most of Horizon Power switchgear is rated for fault switching (to sectionalise and test for fault location), it should not normally be necessary to trip feeders under these conditions.

If a transient fault is suspected, a trial reclose may be carried out. The procedure for this is given in Section 4.5.2

6.11.2 Recharge Spring Charged Circuit Breakers

Spring charged circuit breakers have a trip-close-trip function. If the circuit breaker trips on fault, it still has close and trip functions in reserve before its springs need recharging.

If the trip-close-trip function has been used, and no LV supply is available, the operator must recharge the springs manually. Normally, a crank handle is inserted into the appropriate socket and winding (in the direction indicated on the gear wheel), until the handle runs free or the spring latches. The circuit breaker may then be operated normally.

The switching operator should consult the Switchgear Instruction Manual (SIM) as required if this hand charging is required.

Note: Spring charging can be carried out with the busbar or circuit energised. After the springs are fully charged the circuit breaker can be operated normally from a remote location.

6.11.3 Faulty Operation of Circuit Breakers

At times, switching operators find that a circuit breaker malfunctions during operation. The breaker may fail to operate at all, or close and trip (fire through) in the one operation.

If the breaker fails to operate, the following checklist may be used to solve the problem.

Outdoor Spring Charged Breakers

1. If the breaker does not operate, check the auto reclose switch is on 'manual'.

2. Check whether the springs are charged within the breaker drive box. If discharged, check the AC motor fuses. Manual charging may be needed.

3. If the operation still does not work, check the control supply fuses.

4. If the circuit breaker fires through (does not latch closed and trips) during the close operation, check the relay panel for flags which have not been reset or relays which may not reset themselves.

Indoor Spring Charged Breakers

1. Complete all checks for the outdoor spring charged circuit breakers.

2. Check the interlocks on the circuit breakers, to make sure they are fully home in the correct position.

3. Check that the breaker is racked up into the correct position and the auxiliary contacts are connected.

DC Drive Motor Spring Charged Breakers / Switches.

1. Ensure that the DC supply is healthy.

2. Ensure that the DC circuit isolator is closed.

- **Labels on the cable circuits not conforming to the drawings**

  The switching operator must check whether the cable circuit labels conform to the drawings. Before proceeding with switching, the operator must know exactly what is being interconnected or isolated.

- **Corroded connections**

  If the connection to be used for interconnection is corroded, poor connections may result. This may cause fluctuating volts or loss of supply. Before installing fuses/links, the operator must inspect the connections to make sure they are serviceable.

- **Fuses continuity**

  Before installation on underground systems, the operator must check fuse continuity to ensure they are serviceable.

- **Interconnected LV circuits**

  At the completion of a switching program, the switching operator must ensure LV circuits have not been left interconnected.

- **Installing more than one set of fuses along the LV underground circuit**

  Fuses must be installed only at the source of supply of LV underground circuits. If fuses are graded along the length of the circuit, fault finding becomes difficult.

- **Air break LV circuit breakers**

  Where a circuit breaker is used on the LV side of a large transformer (see Figure 3-15 above), the switching operator must check the mechanical indication to verify the circuit breaker status as the internal contacts are not visible. If the circuit breaker is rackable it must be racked out to create an isolation point.

- **Shorting busbars**

  When performing LV board switching operations, the switching operator must ensure loose objects on the top of the switchboard or in pockets, cannot fall and short circuit the busbars or contacts.

SECTION SEVEN

Distribution Protection

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7. Distribution Protection

7.1 Introduction

This section describes the principles and operation of distribution feeder protection.

Electrical power in Horizon Power's system is transmitted and distributed via a three-phase system. In rural areas involving vast distances, a single-phase system is often used for final distribution.

The phase conductors are insulated (normally done by insulators on poles) from the ground and from each other. If the insulation fails, the power will not flow to the load but will flow as an uncontrolled short circuit to earth or other phases. These faults may cause damage to plant, interruption of power to customers and loss of revenue.

Protection equipment is added to the system to limit the effects of these faults. Various devices are designed to:

- protect personnel
- detect all faults quickly, so they can be disconnected from the system
- minimise damage to all apparatus, such as transformers, feeders, etc., and
- ensure maximum reliability of supply by removing only the faulted section of the power system. This means the minimum number of customers are affected by the fault.

7.2 Protection Zones

The whole power system must be protected. This is achieved by dividing it into zones. If a fault occurs in a particular zone, only the protection system covering that zone should operate. Those systems relating to other zones should not operate. In some cases, adjacent zones may operate after a preset time-delay, to provide backup.

Protection zones enable the protection equipment to disconnect only the faulted zone. Any fault occurring within a zone will cause circuit breakers, reclosers or fuses in that zone to operate and trip. When this happens, protection equipment in other zones should not operate.

Zones of protection are shown in Figure 7-1. Earth fault protection for a zone substation may extend through several zones.

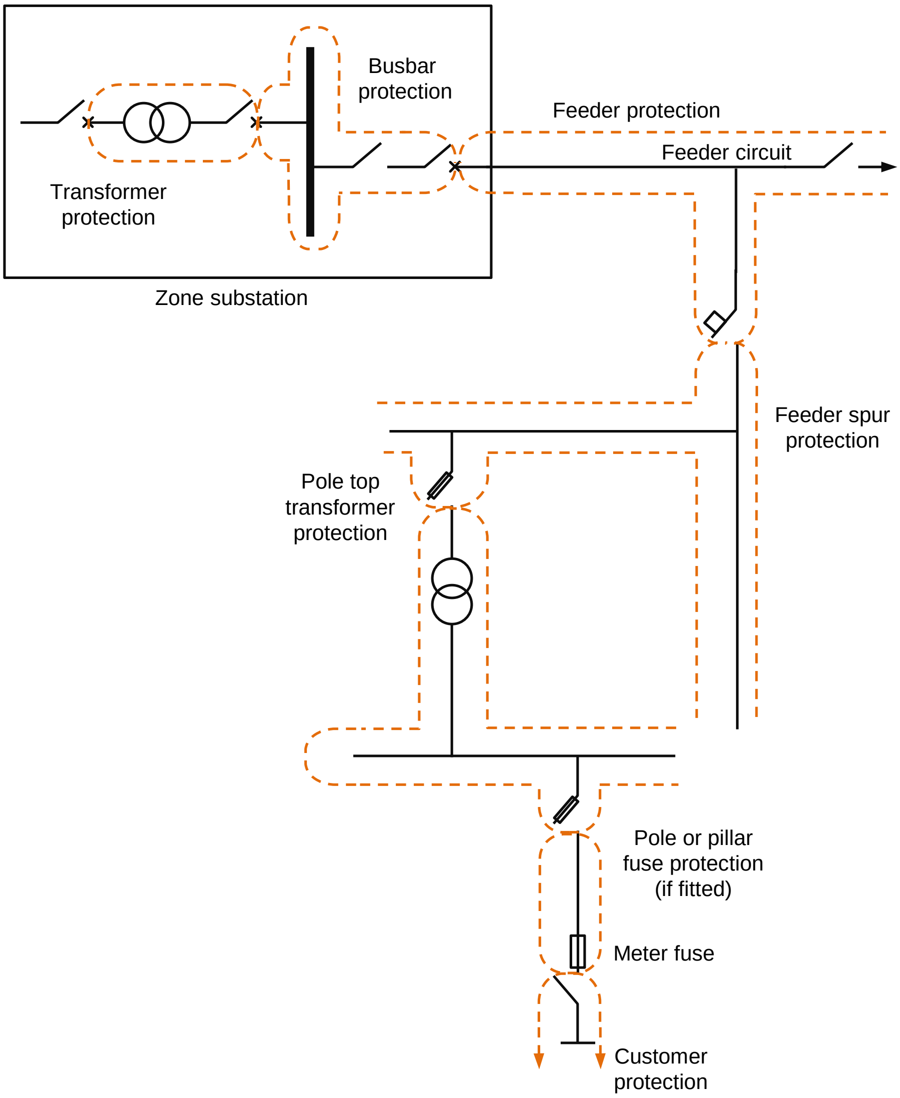


Figure 7-1 Zones of protection

7.3 Distribution System Protection Equipment

The distribution system commences at the zone substation, where a number of radial feeders start. Each distribution feeder picks up load through distribution transformers (pole top or ground mounted). The main protection control for these feeders is the circuit breaker at the zone substation.

The protection devices for feeders detect the existence of a fault, generally by measuring overcurrent. (Overcurrent is a higher-than-normal current which is above a preset value). Each device's operating time is determined by its operating characteristic and the amount of fault current.

Protection equipment for the distribution system includes current and voltage transformers, circuit breakers, reclosers, sectionalisers, fuses and relays. Figure 7-2 shows the location of protection equipment in a distribution system.

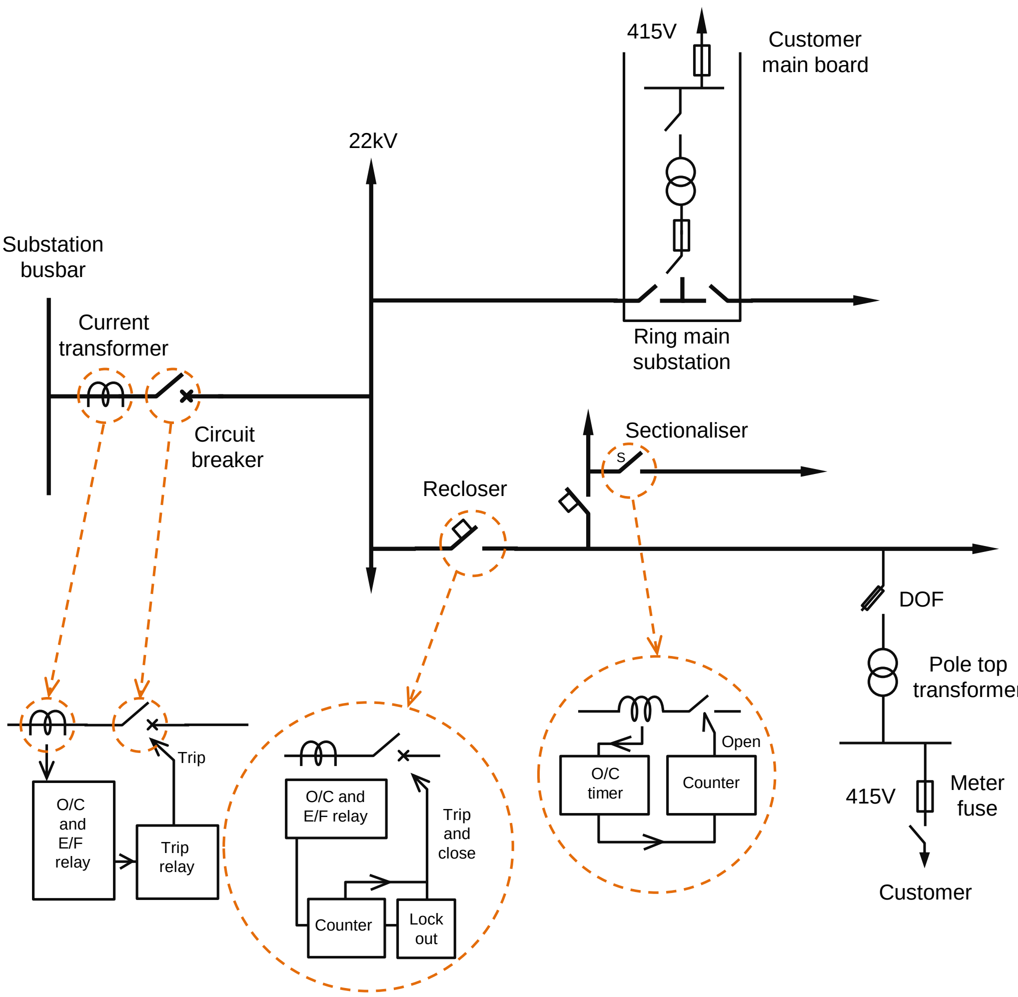


Figure 7-2 Location of protection equipment in distribution system

7.3.1 Fuses

Fuses consist of:

- a fusible element
- an arc quenching medium, and
- a suitable enclosure.

The fuse operating time decreases as the overload or fault current increases. This is called the inverse time/current characteristic (see Figure 7-3).

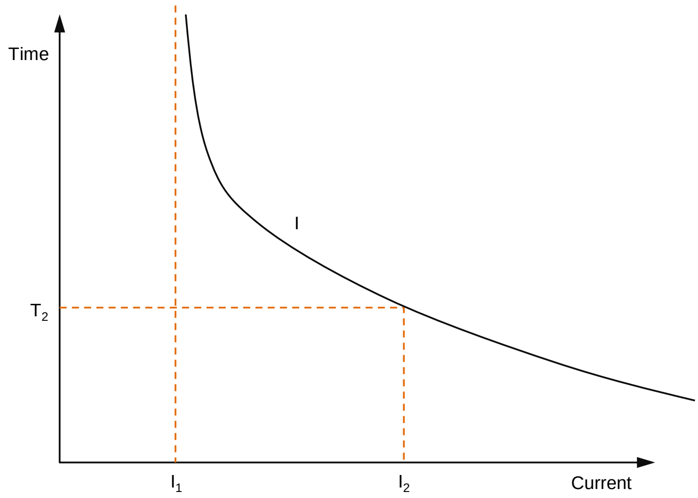


Figure 7-3 Minimum operating current

For current I1, the operating time is very high. This value is usually called the minimum operating current.

For current I2, the corresponding fuse operating time is T2. This is the time taken for the fuse element to clear the fault. The larger the current flowing through the fuse, the faster the fuse operates.

Horizon Power uses different types of fuses, the most common being HV drop-out, HV HRC fuses and LV HRC fuses.

High voltage expulsion drop-out fuse

This is the most common type of fuse found in Horizon Power's high voltage overhead distribution system.

It consists of a fusible element inside an insulating barrel. A flexible tail is brought through the opening at the lower end of the barrel and attached to a hinged assembly.

Fault current will cause the fuse element to melt and the barrel assembly to swing down.

High voltage HRC fuse

HV high rupturing capacity (HRC) fuses are used in the fuse switch of ring main switchgear for transformer protection.

It is a porcelain tube containing a fuse element. The tube is filled with silica powder and sealed.

When the operating current causes the fuse element to blow and the silica powder surrounding it to melt, a glass shield forms around the element. The striker pin is released through the end cap. This is designed to trip the three-phase switch in the fuse switch.

Low voltage HRC fuses

This fuse is also silica powder-filled but does not have a striker pin. Usually, its fuse element is made from pure silver wire or strip.

HRC fuses are designed to operate very quickly and under extreme short circuit conditions.

7.3.2 Current and Voltage Transformers

Horizon power's high voltage system voltages range from 11kV to 220kV. Currents extend up into hundreds of amps under normal conditions and thousands of amps under fault conditions.

It is not possible to connect the small, delicate relays into these high voltage/high current circuits. The currents and voltages must be reduced to manageable levels before connection is possible. Current transformers reduce current. Voltage transformers reduce voltage to acceptable levels.

Current transformers are inserted in series with the circuit. They develop a secondary current that is a small fraction of the line current. (Under normal conditions this secondary current is a few amps, but under fault conditions it will be much higher – up to 100A).

The location current transformers on outdoor feeders is shown in Figure 7-4 and the CT primary and secondary circuits in Figure 7-5.

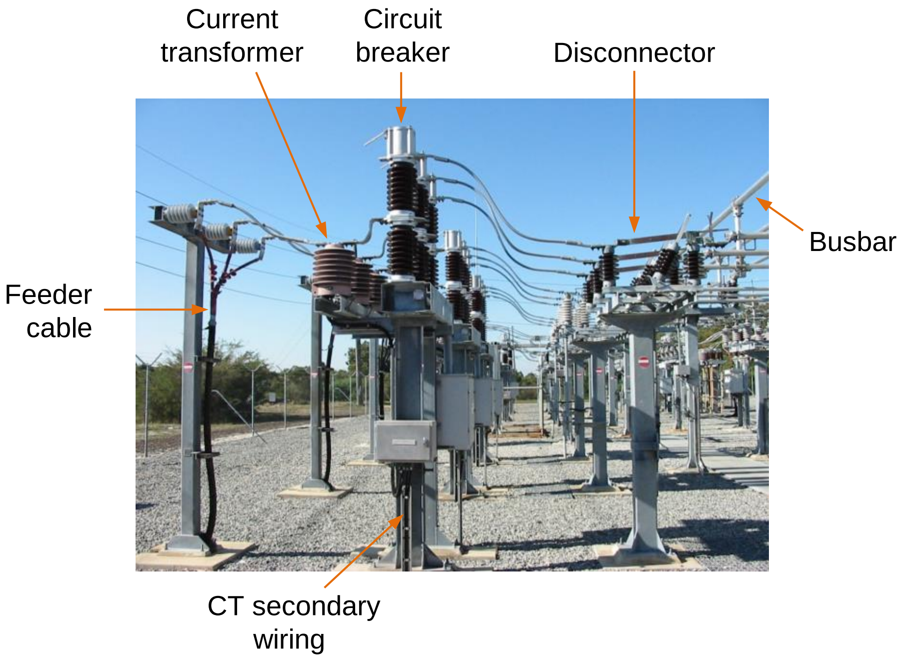


Figure 7-4 Location of current transformer in feeder

Voltage transformers are connected between phases or from phase to earth. They reduce the phase to phase voltage to 110V (phase to earth 63.5V) .

Relays handle these reduced voltages and currents quite easily.

A voltage transformer is shown in Figure 7-6.

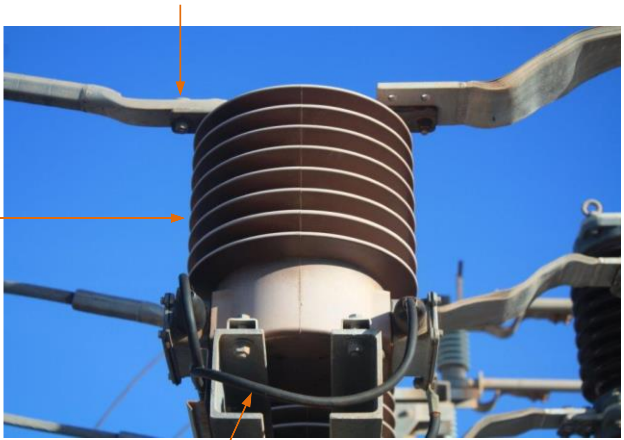


Figure 7-5 Current transformer

Figure 7-6 Voltage transformer

7.3.3 Relays

Most relays measure the current or voltage, or sometimes a combination of both, to detect faults. Relays are also built to operate with gas pressure or electrical frequency, for example, the transformer Buchholz relay or under frequency load shedding (UFLS) relays.

The relay operates contacts when the input reaches a preset level or condition. The circuit breaker is then directly tripped by the output contact or may be indirectly tripped via the trip relay.

The electrical power required to trip the circuit breaker (or operate trip relays) and alarms is supplied by a substation battery system.

Figure 7-7 shows the relay input and output functions.

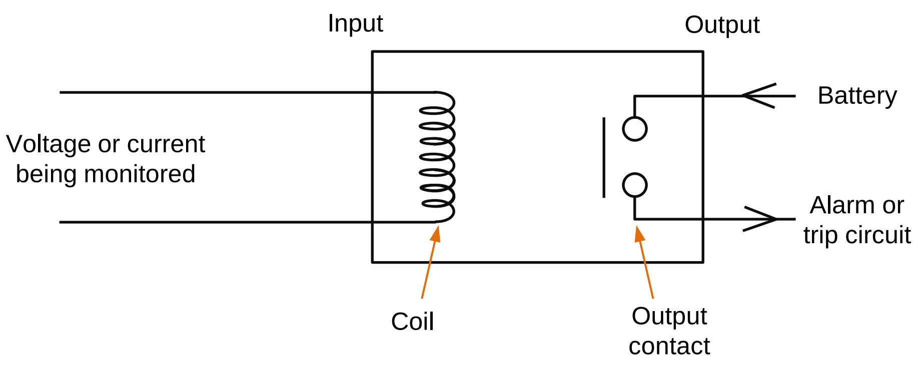


Figure 7-7 Relay single line diagram

Figure 7-8 shows how the relay output contacts are wired to the circuit breaker trip coil. Relay output contacts can also be used to activate alarms.

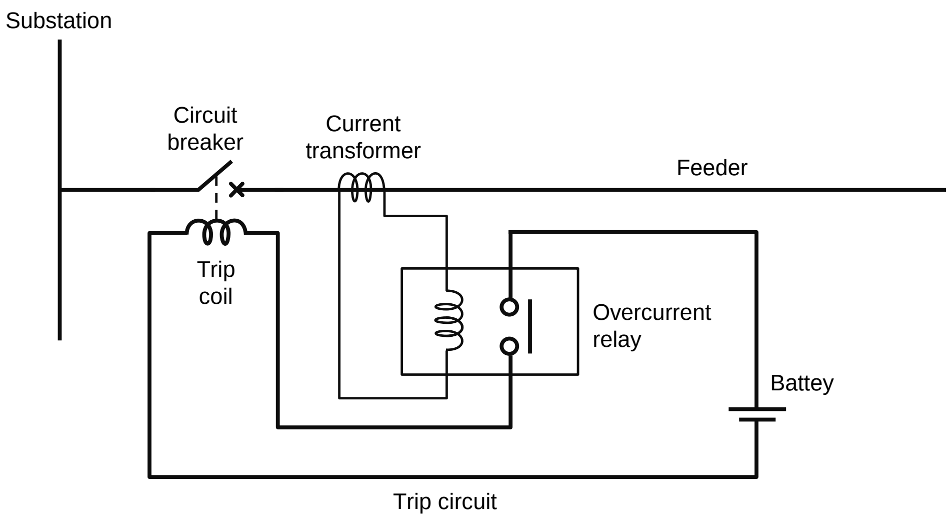


Figure 7-8 Operation circuit for protection relay

Overcurrent and earth fault protection schemes

Overcurrent protection is widely used in distribution feeder protection schemes. It has two elements:

- the time-delay overcurrent element starts to operate with currents above the level of the relay setting. The time delay has an inverse relationship with the current magnitude (called inverse time relationship), this means the higher the current the shorter the tripping time.
- the instantaneous (hiset) element operates without any introduced delay to trip the circuit breaker when the current reached the level of the relay setting. This is used to rapidly clear high current faults very close to the substation.

Overcurrent protection is used on each feeder phase and must be set above the normal feeder load to avoid tripping under full load conditions. Typical setting are shown in Table 7-1.

Overcurrent protection is also applied to detect earth faults. However, as a healthy balanced three-phase feeder will have zero or near zero earth fault current the relay earth fault element settings are set to small current values well below the phase overcurrent settings. See Table 7-1.

The sensitive earth fault (SEF) is designed to detect low earth fault currents which are not detected by the standard earth fault protection (e.g. HV conductors falling across a dry bitumen road). The SEF has a very low current setting of several amps and therefore is very sensitive to earth fault current, however it has a long time delay of several seconds to allow the normal overcurrent and earth fault operation for normal faults.

SEF protection is used in highly populated built up areas on HV overhead feeders where the risk of contact with a fallen conductor is high. It is not applicable to underground feeders (as earth fault protection adequately detects the high current faults) or rural feeders (as the single-phase spurs unbalance the line).

When the overcurrent or earth fault elements in a digital relay operate, a visual indication is provided on the face of the relay, using LEDs or text on a display. The relay shown in Figure 7-9 has LED indicators showing the instantaneous, phase overcurrent, earth fault (GND/NEUTRAL OVERCURRENT) as well LEDs for other elements.

The older electro-mechanical relays have numbered flags drop to indicate relay operation.

Figure 7-9 Digital relay – with multiple elements (overcurrent, earth fault, UFLS, CB failure)

Overcurrent Amps (A)		**Earth Fault Amps (A)**		**Sensitive Earth Fault Amps (A)**
Time-delay Overcurrent Relay	Instant-aneous Relay	Time-delay Current Relay	Instant-aneous Relay	Time-delay Current Relay (see Note)
Town Feeders				
250-300	4000	40	not used	8A (9 seconds)
Rural Feeders				
50-200	1000	10-20	not used	not used

Table 7-1 Typical minimum tripping currents

Note: Town feeders are generally fitted with sensitive earth fault relays to trip the feeder for low current faults, such as a conductor on the ground.

These relays cannot be fitted to rural feeders because the single-phase spurs unbalance the line.

Figure 7-10 shows the curve for the inverse relationship between operating time and current for a typical overcurrent relay element. The relay overcurrent element settings allow the curve to be moved in both the horizontal direction (changing the current) and the vertical direction (changing the time).

The minimum pick up current shown in Figure 7-10 is the current below which the relay element will not operate. A temporary overcurrent may go above the minimum pick-up level and then return to levels below the pickup level for durations less than the tripping time shown on the curve without the tripping the circuit breaker. If however, the temporary overcurrent time duration reaches the tripping time the circuit breaker will trip.

In summary, the inverse curve shows the higher the fault current the shorter the tripping time.

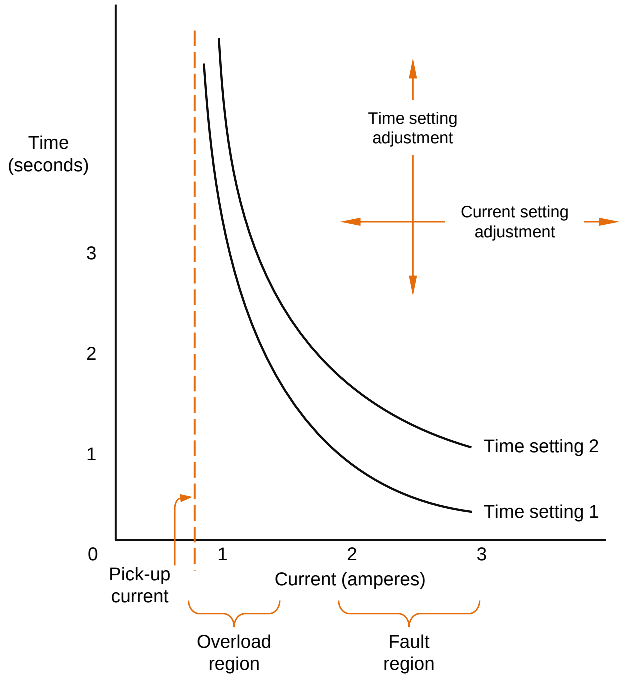


Figure 7-10 Inverse time/current curve

Phase and earth fault detection

Figure 7-11 shows typical distribution feeder overcurrent and earth fault protection at a substation. The operation of the protection for an overcurrent (F1) and earth fault (F2) is shown.

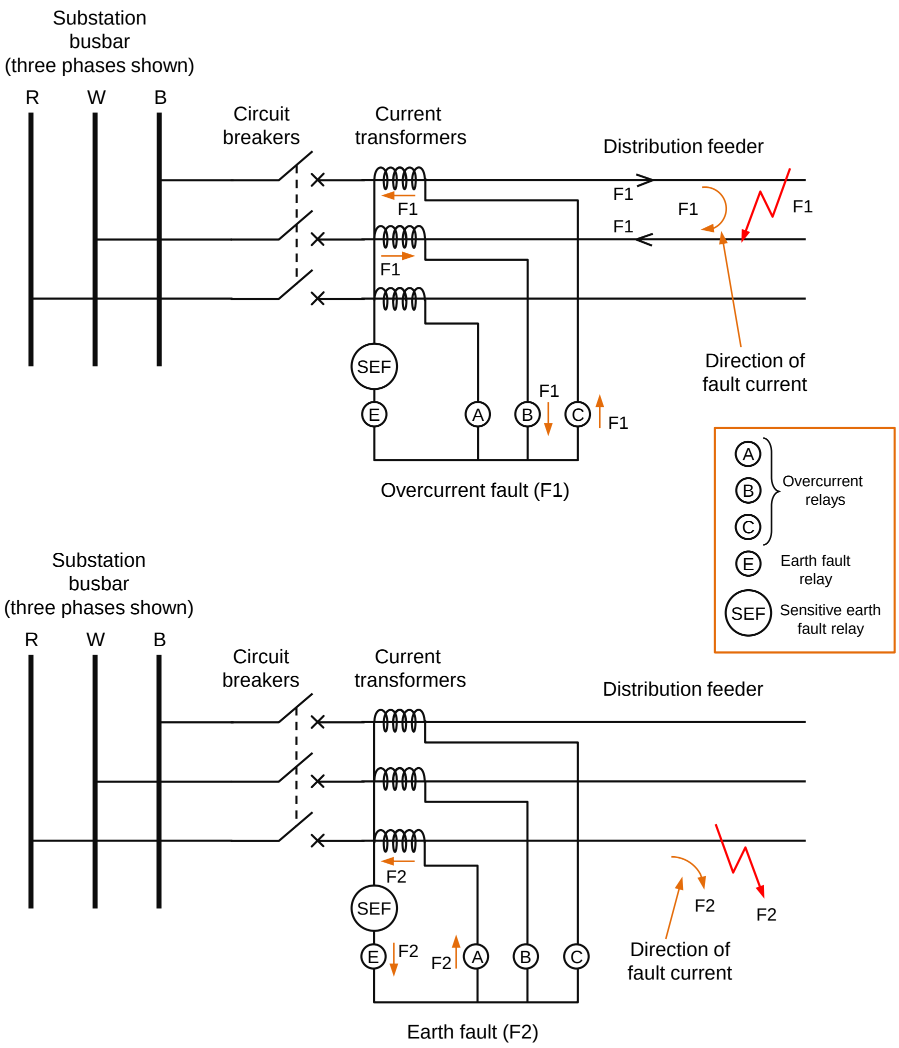


Figure 7-11 Distribution feeder protection

In Figure 7-11 (top), the phase-to-phase fault F1 (W phase-to-B phase) flows through the respective CTs produces equivalent fault level secondary currents to flow in relay elements B and C causing them to operate. Notice the current flowing out on W phase flows back through B phase and is balanced, therefore no secondary current flows in elements A, E and SEF.

In Figure 7-11 (bottom), the phase-to-earth fault F2 (red phase) primary fault current flows through the R CTs which produces equivalent fault level secondary current to flow in elements A, E and SEF. In this case the E element will have the shortest operating time tripping the circuit breaker. Notice the R phase current flows back to the substation through the ground and not on the other phases creating an out-of-balance on the phase conductors.

If the earth fault F2 was a low level fault and the current too low to be detected by the E or A after of several seconds the SEF element will operate tripping the feeder circuit breaker.

Parallelling three-phase feeders on single-phase disconnectors

As stated before, earth fault protection is sensitive and detects an out balance on the phase conductors. When two feeders are parallelled on single-phase disconnectors, there is a significant risk of out-of-balance being detected and operating the earth fault protection.

To eliminate this tripping risk, the earth fault protection must be disable before the feeders are interconnected and returned to service after the feeders are separated. Interconnection of three-phase feeders should be performed on three-phase switchgear (e.g. pole top switch) wherever possible to avoid the necessity of disabling earth fault protection.

Figure 7-12 shows the first phase of a set of single-phase disconnectors closing on a feeder near a substation. This creates an out-of-balance load on the feeder.

The secondary current flows through both the overcurrent and the earth fault relay. As the earth fault relay is set to be more sensitive, it will often operate under these conditions. This differs from balanced loads, where the three phases cancel each other out at the earth fault relay and prevent the relay from operating.

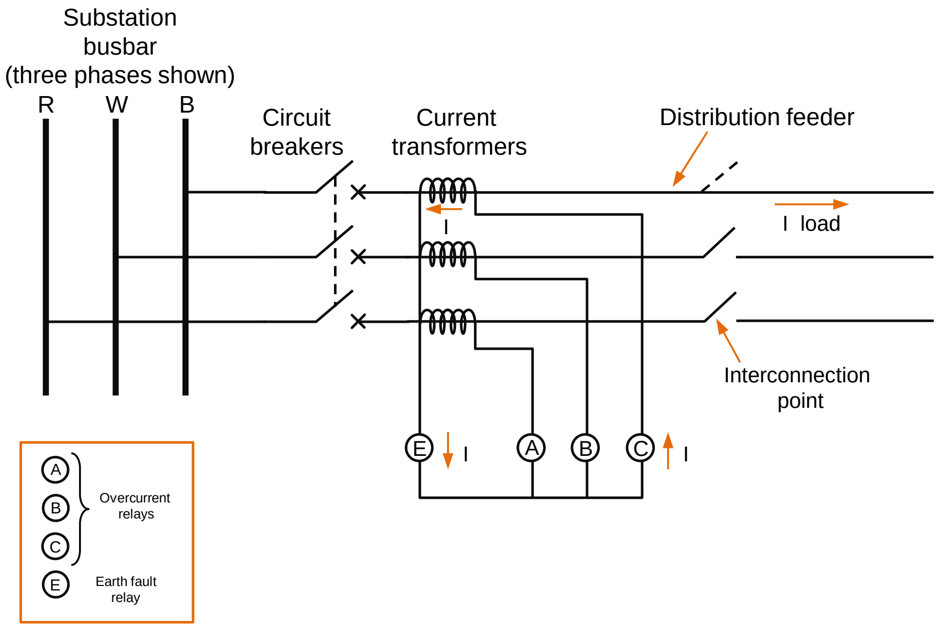


Figure 7-12 Out-of-balance earth fault tripping

Trip relay

It can be seen that different relays pick up and operate for different types of faults. To prevent too many relays firing into the trip coil of the protected circuit breaker, a trip relay is used. This collects all relay operations and gives one signal to the breaker.

The relay works immediately. As soon as one input gives an operation signal, the output is closed. This is necessary, for the timing of the complete operation from fault to tripping should be determined by the protection relay characteristics, not those of the trip relay.

Parallelling three-phase feeders with SEF protection

As described before, sensitive earth fault (SEF) relays are installed on overhead distribution feeders to detect low current earth faults (high resistance faults) which may do not produce enough fault current to operate the standard earth fault and overcurrent relays.

Similar to standard earth fault protection, SEF detects the out-of-balance current in the three-phase HV system That is, at all instants in time the current flowing out on a phase must be balanced by currents returning on the other two phases. Where current flows out on a phase but does not return on the other phases of that feeder, this indicates an out-of-balance current and is seen by the protection as an earth fault.

Shown in Figure 7-13 is a basic example with two HV feeders and their respective loads before and after switching a pole top switch to parallel the feeders.

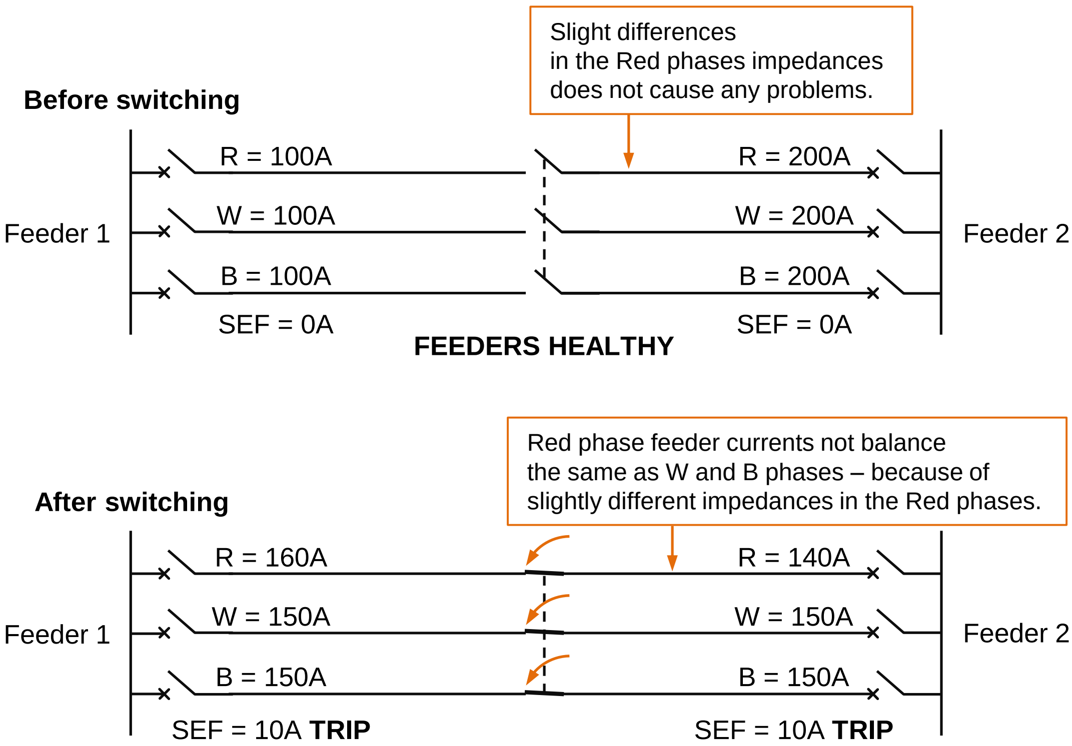


Figure 7-13 Example of parallelling feeders with sensitive earth fault.

Assume the SEF settings are an operating current of 8A with a delay of 9 seconds.

Before the Feeders 1 and 2 are parallelled it can be seen the out-of-balance in the SEF on both feeders is zero. After the feeders are parallelled, a slight imbalance in the R phase line impedances causes Feeder 1 R current to increase by 10 amps with respect to the W and B phases, and conversely the R phase current on Feeder 2 is reduced by 10 A with respect to W and B. The SEF relay element on both Feeder 1 and 2 see the 10A out-of-balance. If the SEF setting are 8A then after the time delay of 9 seconds one or both feeders will trip on SEF.

Therefore to prevent inadvertent out-of-balance SEF feeder trips when parallelling three-phase feeders, the SEF protection is switched out of service (disabled).

The above is also applicable to reclosers with SEF protection. The basic rule is all SEF protection devices inside a feeder loop created by switching must be disabled.

Feeder reclosing (auto reclosing)

Substations with outdoor feeders usually have protection relays with the auto reclosing function enabled to improve system performance for transient faults.

The auto reclosing function operates to reclose the circuit breaker at a predetermined time (about four seconds) after the circuit breaker trips for an overcurrent or earth fault. In most cases, faults are temporary (transient faults) and an auto reclose will permanently restore power to the feeder.

If the feeder is cable for more than half its length, auto reclosing is not used. (The auto reclose function is either not installed or it is taken out of service). Cable faults are usually permanent, and reclosing of the feeder will not restore the feeder but further adds to any fault damage.

Multifunction solid state relays

Microprocessor based multifunctional relay incorporating overcurrent, earth fault, SEF, auto reclose and UFLS elements, can be utilised in many protection schemes such as transformer, busbar and feeder protection. Examples of multifunction relays commonly used are the SEL-351 (shown in Figure 7-14) and the SEL-751A (shown in Figure 7-9).

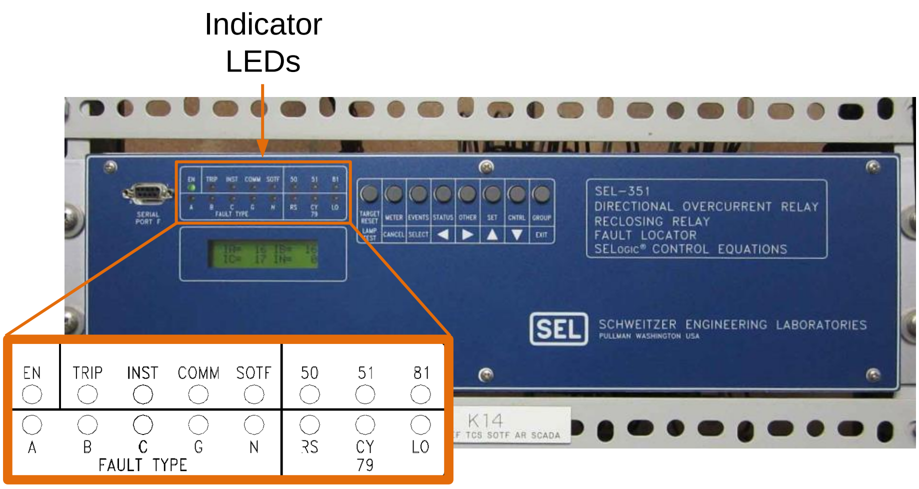


Figure 7-14 SEL351 relay

The LEDs illuminated on the front panel provides detail of the relay elements which operated. This information which consists of a combination of LEDs illuminated can be equated to the flag numbering system shown in Table 7-2.

Interpretation and Reporting of LED Indications for SEL351 Relay			
LED	**Phase LED**	**Meaning**	**Flag No**
Trip+ 51+	A	Overcurrent Time Red	1
	B	Overcurrent Time White	2
	C	Overcurrent Time Blue	3
	G or N *	Earth Fault Time	15
Trip+ 50+	A	Overcurrent Instant Red	4
	B	Overcurrent Instant White	5
	C	Overcurrent Instant Blue	6
	G or N *	Sensitive Earth fault	14
Trip+81	-	UFLS	850

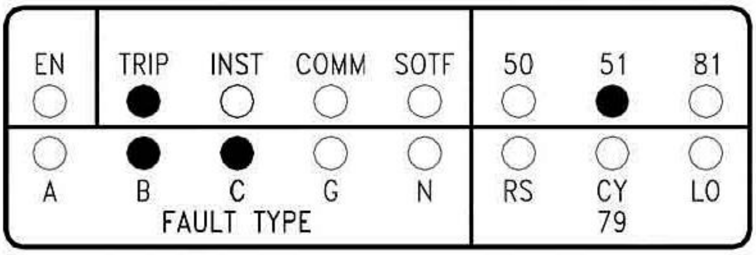
* Either G or N indicates an earth fault. Phases (A, B or C) may also be indicated but it does not affect the flag number.

Table 7-2 SEL351 LED indicator interpretation and reporting

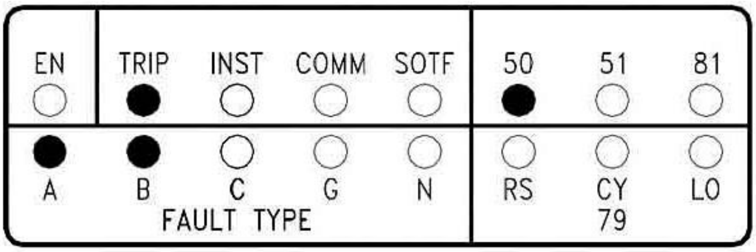
The LEDs marked **EN**, **INST**, **COM**, **SOTF**, **RS**, **CY**, and **LO** do not impact on the flag number and can be ignored.

Some examples of the interpretation of the LEDs is provided in Figure 7-15.

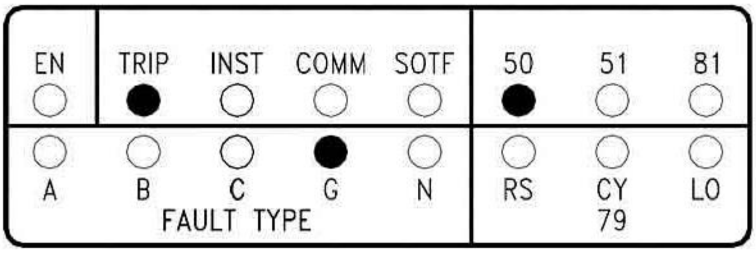
Example 1 – White–Blue Phase Overcurrent Time (IDMT)



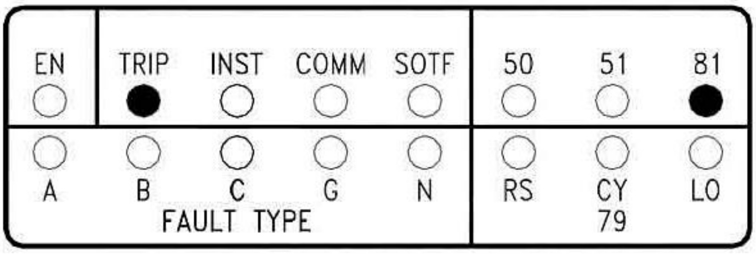
Example 2 – Red–White Phase Instantaneous



Example 3 – Sensitive Earth Fault



Example 4 – UFLS



LED On LED Off

Figure 7-15 SEL351 protection indication

It is most important that all flags are accurately recorded before the relays are reset. Do not reset the relays and then record the flags from memory.

The flag operation information may be checked at a later date to establish whether the protection has operated according to its design specifications.)

7.3.4 Principles of Time/Current Protection

As previously indicated the most widely used form of protection on distribution feeders is a relay with inverse time/current overcurrent and earth fault elements which is represented in the graph shown in Figure 7-17.

Figure 7-16 shows circuit breaker A and recloser B and fault at location F1. Fault F1 causes the fault current to flow through the circuit breaker A and recloser B. If recloser B can be made to open before circuit breaker A, the fault would be de-energised and circuit breaker A would remain closed.

The operation of the closest protective device to the fault operating first is called *correct discrimination*. The customers from the circuit breaker A to the recloser B remain energised and the customers in the faulted section downstream from recloser B lose the supply.

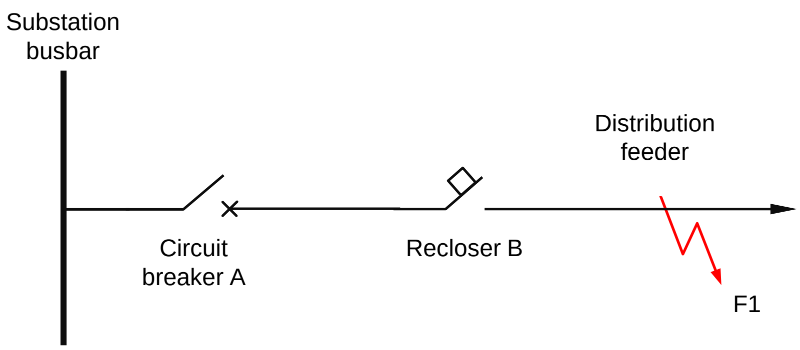


Figure 7-16 Correct discrimination

The circuit breaker A and recloser B have their individual protection relays. The setting on these relays are shown in Figure 7-17 as the time/current curves relay A and relay B.

The fault current is shown by the vertical dotted line. Relay B operates in time T1 for the value of fault current shown. If the fault current is not cleared, relay A would operate in time T2. Usually, a margin of 0.3 seconds is allowed, to give the recloser B time to operate and clear the fault. If the margin is too short, the fault current may not cease before relay A operates and trips the entire feeder.

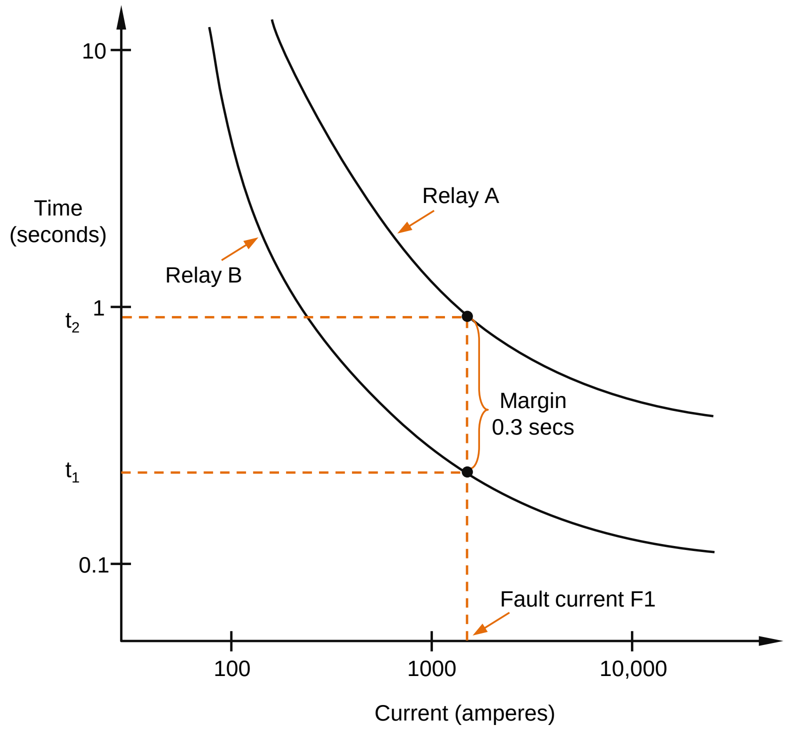


Figure 7-17 Inverse time/current operating characteristic grading

7.3.5 Reclosers

High voltage distribution feeders frequently are protected by single-phase or three-phase automatic reclosers. Reclosers are used to de-energise the faulted section of circuit or spur line.

The recloser is a self-contained device that senses and interrupts distribution fault currents. If the fault is temporary, it automatically reclose will be successful. If the fault is permanent, the recloser locks out after two, three or four preset trip operations (dependent on the setting applied). If the fault clears before lockout, the recloser after a period of time will reset the count for another full cycle of reclose operations.

The time interval the recloser remains closed before tripping can be set selecting the appropriate fast or slow curve. See Figure 7-18.

The basic principle of recloser operation is that fast operations will clear temporary faults before spur line fuses can blow. (However, this is not always possible. The small spur fuses may operate to clear the fault before the recloser operates.) Delayed openings allow time for fuses to clear so that a permanent fault can be confined to smaller sections of the line. See Figure 7-18.

Figure 7-18 shows typical slow and fast time overcurrent curves for a recloser. The options for slow close is 'B' and 'C' or 'D' and 'E'.

For a recloser set to four shots the range of possible combinations is:

- 4 fast reclose attempts
- 3 fast and 1 slow reclose attempts
- 2 fast and 2 slow reclose attempts
- 1 fast and 3 slow reclose attempts
- 4 slow reclose attempts.

The typical sequence is 2 fast and 2 slow reclose attempts.

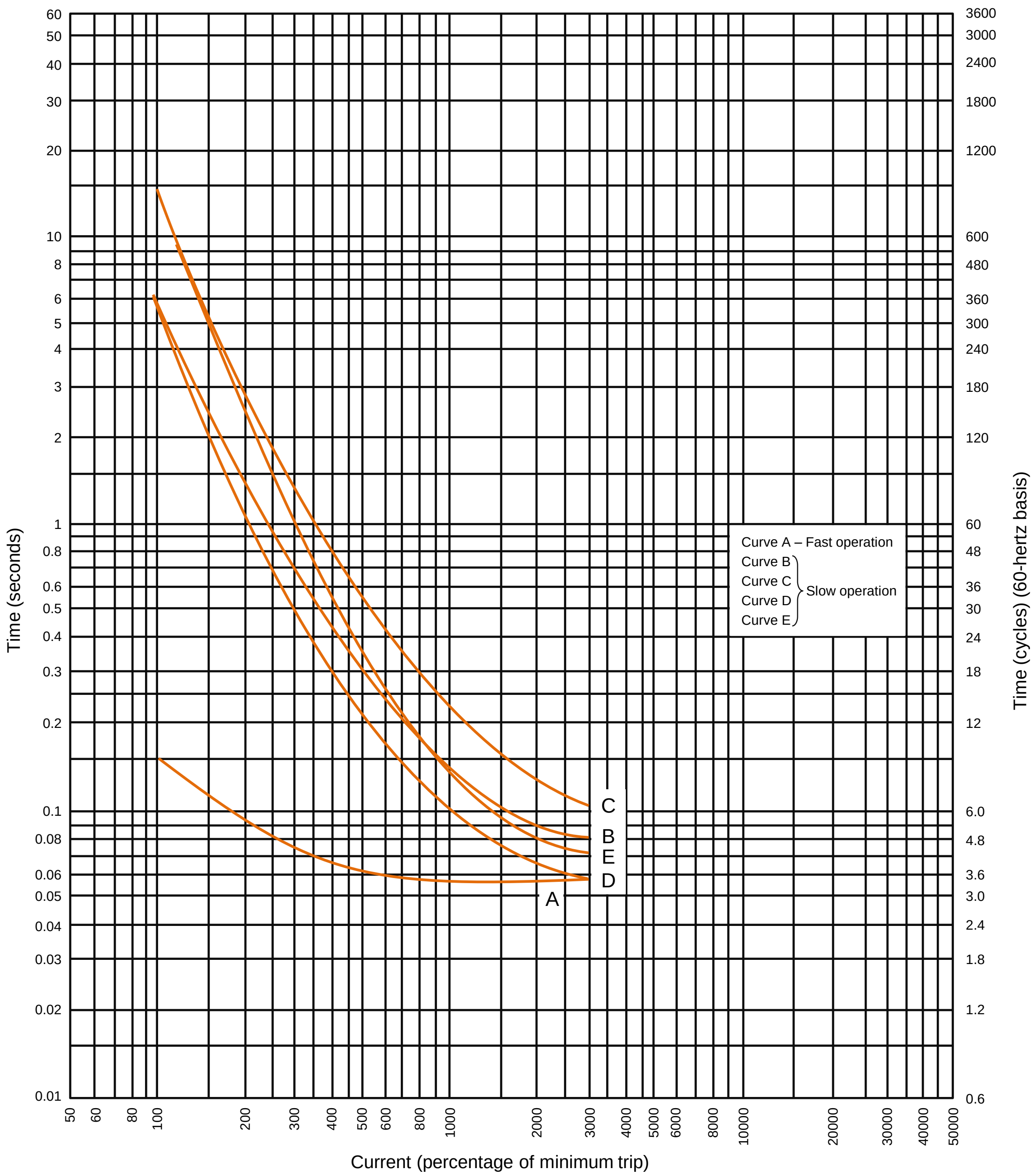


Figure 7-18 Typical overcurrent curves for a recloser

7.3.6 Sectionalisers

Sectionalisers are designed to work in conjunction with reclosers. Sectionalisers have no fault-breaking capacity, therefore they are used on the load side of the recloser and can only open after the recloser has opened to de-energised the circuit.

The sectionaliser measures the current to determine if it is normal load or fault current. The sectionaliser increments the counts each time fault current has passed through it as recloser attempts reclose operations.

7.3.7 Operation of the Recloser Sectionaliser Combination

A description of the operation of a recloser set for three shots and sectionaliser set for two shots is given below.

When a fault occurs, the recloser opens the circuit. Simultaneously, both the recloser and the sectionaliser register one fault. The recloser then closes and restores supply. If the fault has cleared, the recloser and sectionaliser reset automatically after a period of time reset the counts to zero. However, if the fault still persists, the recloser trips again the recloser and sectionaliser increment their counter to two.

At this point, a sectionaliser set to two shots automatically opens disconnecting the faulted section of line. The recloser then closes a third time, restoring supply up to the sectionaliser but not beyond.

The recloser shot setting must always be one or more greater than the sectionaliser shot setting to ensure the recloser will reclose after the sectionaliser has opened disconnecting the fault.

7.4 Protection of Typical Distribution Feeders

The protection of a distribution feeder requires the coordination of different types of equipment.

Each feeder has a main circuit breaker at the substation. The feeder circuit breaker protects main feeder backbone up to the next downstream protective devices. A fault in this backbone section will result in the entire loss of the feeder and all customers.

The downstream protective devices include reclosers, sectionalisers and fuses. These devices will operate for a fault in the zone they protect. This limits the size of the outage area and the number of customers inconvenienced. The operation of the local protective device to the fault also assists reducing the time to locate the fault and restore supply to customers.

The protection of a typical distribution feeder is shown in Figure 7-19.

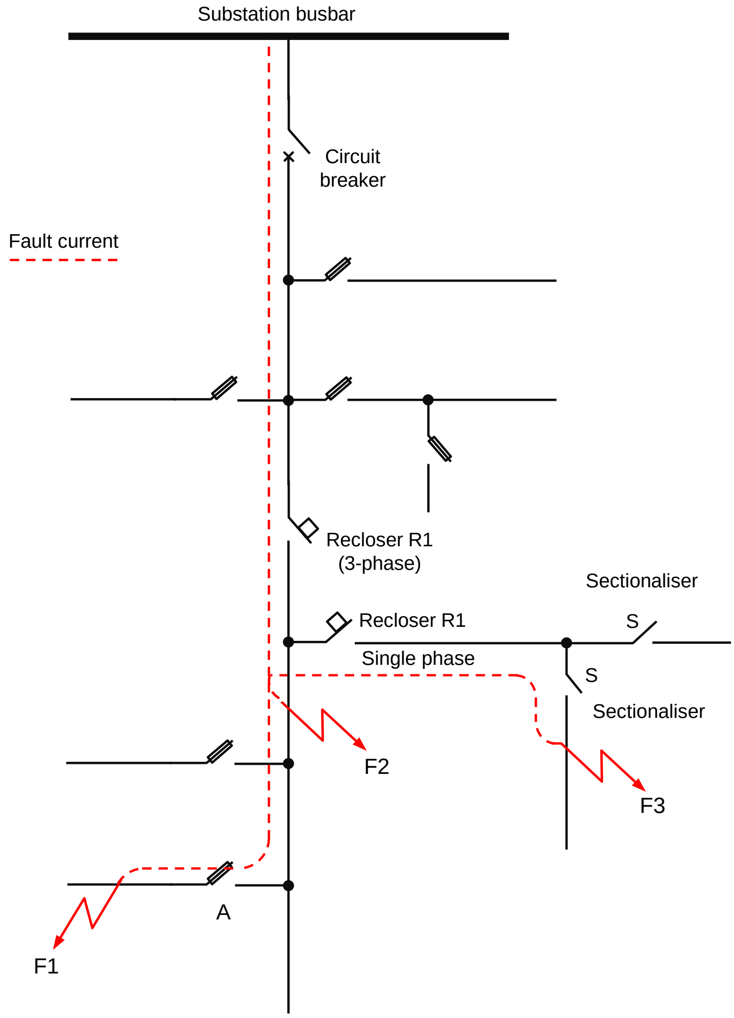


Figure 7-19 Protection of typical distribution feeder

7.4.1 Fault on Single-phase Fuse Protected Spur Line

In Figure 7-19 fault F1 causes fault current to flow from the substation, through the feeder circuit breaker, the three-phase recloser R1 and fuse A, to the fault.

Fuse A must detect the fault and operate in a time that limits the faults damage to the feeder. The recloser and feeder circuit breaker's protection also “see” the fault. However, what is finally required is the operation of fuse A only.

This is called *grading of protection*. It is carried out by selecting the required time/current characteristics of each protection element.

Figure 7-20 shows the time/current characteristics of the circuit breaker, recloser and fuse. At fault current F1, the lower fast trip curve of the recloser is below the fuse curve. Therefore, the recloser will perform a fast trip and reclose. If the fault is temporary, then the system may be fully restored without fuse A even operating.

For a permanent fault, the recloser trips and closes again until the delayed trip allows enough fault current to operate fuse A. The recloser then closes and restores the rest of the line.

If however, the recloser fast curve is located above the curve A then fuse A will operate before the recloser, even for a temporary fault.

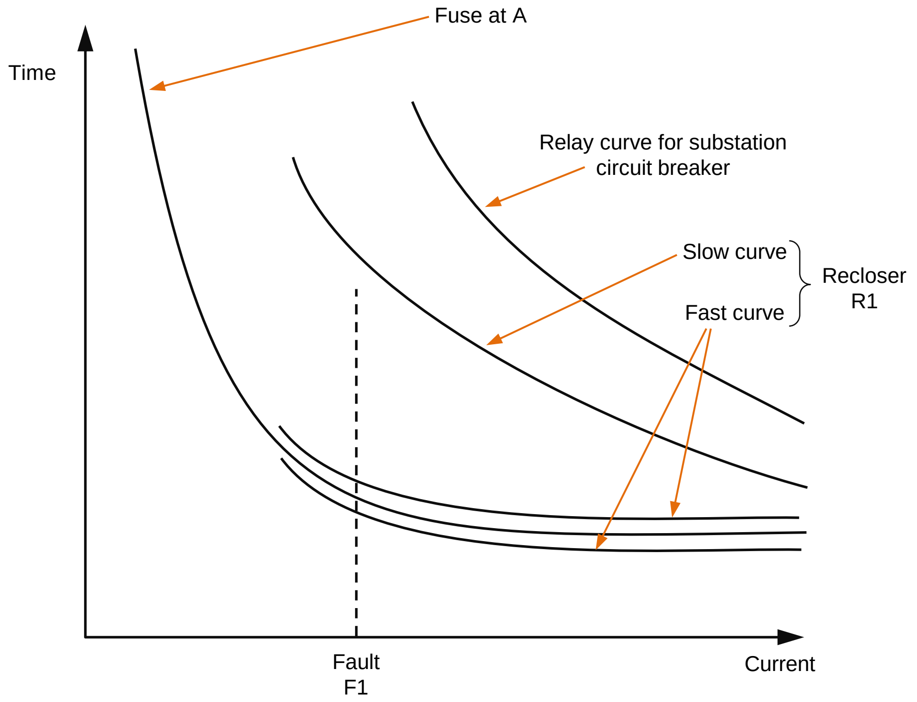


Figure 7-20 Time/current characteristics of a circuit breaker and recloses and fuses

7.4.2 Fault on Section of Main Feeder Past Recloser

In Figure 7-19, fault F2 should cause the recloser R1 to open. If F2 is a permanent fault, R1 closes, trips the set number of times and then locks out. The recloser R1 has isolated the fault to the last half of the feeder. If grading is correct, the fault will be located between the recloser and any further fuses or reclosers.

7.4.3 Fault on Single-phase Recloser Protected Spur Line with Sectionaliser

For temporary fault F3 in Figure 7-19, the single-phase recloser R2 trips and closes successfully. For a permanent fault the single-phase recloser trips and closes up to four times. The sectionaliser opens after the third trip of the recloser, if it is a three shot sectionaliser. The recloser closes for the fourth time and stays closed, as fault F3 is isolated beyond the sectionaliser.

SECTION EIGHT

Switching for Safety

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8. Switching For Safety

8.1 Introduction

This section describes the safety requirements the switching operator must comply with when undertaking switching, and providing access for others required to work on the network.

8.2 Switching Safety-Related Documents

The following sections describe the documents related to the duties of the switching operator.

8.2.1 Electricity (Network Safety) Regulations 2015

The Electricity (Network Safety) Regulations 2015 places specific requirements on Horizon Power as the network operator and the persons (including contactors) who undertake prescribed activities, such as switching on the network.

In relation to the switching operator role, Horizon Power is required to:

- develop, implement and maintain adequate work practices
- provide adequate instruction, training and supervision
- ensure compliance with work practices
- investigate any matter which is or may be a risk.

The switching operator is required to comply with Horizon Power’s standards and work practices and must document and notify their supervisor if a procedure is not followed. Notification is required to initiate procedure review and adjustments if required.

Under these regulations, provisions exist for fines for non-compliance by Horizon Power or the switching operator.

8.2.2 Electrical Safety Standards

Horizon Power’s Electrical Safety Standards (ESS) provide the basic safety principles applicable to employees and contractors working on or in the vicinity of electrical apparatus controlled by Horizon Power.

The ESS is designed primarily to:

- protect Horizon Power staff and contractors
- protect the general public
- prevent damage to Horizon Power assets and public and private property, and
- maintain continuity of supply.

Personnel who are required to work on or near electrical apparatus must be appropriately trained and authorised, in accordance with procedures and standards established by Horizon Power.

In particular, personnel must:

- be aware of all hazards
- be trained in safe working practices
- apply adequate supervision and control
- communicate effectively, and
- think SAFETY.

No employee should allow or request any personnel to perform any work that is known to be unsafe or which may expose the person to a hazard.

A hazard is the risk of danger to personnel untrained in safe working procedures. The hazard ceases to be dangerous when trained personnel employ correct and safe procedures.

An employee must not work on or be in the vicinity of live electrical apparatus without the necessary instructions or permission. Work on HV apparatus must be covered by the use of work permits issued by authorised personnel.

8.2.3 Network Permit to Work Training Manual

The Network Permit to Work Training Manual (NPWTM) describes the responsibilities and procedures applicable to the permit to work process. Switching operators must fully understand their responsibilities and be competent in the work permit issue and cancellation process.

8.2.4 Field Instructions

Horizon Power Field Instructions (FIs) contains a number of documents providing descriptions of requirement and procedures when undertaking a range of field activities. The switching operator must be familiar with the content of Field Instructions which are related to switching. Reference to switching-related Field Instructions have been made throughout this manual.

8.2.5 Switching Operator Manual

This Switching Operator Manual (SOM) is intended as a reference and training manual for switching operations. It assembles switching-related information and elaborates on the practical aspects of the switching operator role. The other documents referenced in this section should be referred to by the switching operator for additional switching-related information.

8.3 Authorities

Several Western Australian authorities are involved with safe switching procedures in Horizon Power. The requirements of these authorities must be met when switching. The table below summarises the role of each authority.

Authority	Responsibility
WorkSafe WA	Regulations to cover the occupational health, safety and welfare in the workplace. This does not include electrical safety.
EnergySafety WA	All aspects of electrical safety including investigation of electrical incidents.
Horizon Power Control Centre (HPCC)	Controlling authority for all transmission and HV distribution switching on the Pilbara Grid and HV microgrids.
Construction or commissioning authority	The group in control of electrical assets before the authority is transferred to HPCC.
Regional depots	The operating authority for the LV network within their area of responsibility. The Works Delivery Coordinator in these depots delegates responsibility for initiating programs and all LV network switching to distribution workers.
Switching operators	Conduct switching in accordance with procedures and instructions

Table 8-1 Western Australian and Horizon Power authorities involved in safe switching

8.4 Reporting of Incidents

To improve the safety of its infrastructure and the safety of the public and electrical workers, Horizon Power is required to investigate and report on incidents and unsafe/defective work though the Cintellate reporting system.

Energy Safety regulations require that electrical incidents and accidents be reported to their office within a given timeframe. For a comprehensive table on reportable and notifiable incidents refer to *Notifiable reportable definitions for ENSMS* – CS10 #4994236.

8.5 Switching Roles and Responsibilities

The main roles and responsibilities of HPCC and switching operators associated with the execution of switching programs are described in the following sections.

8.5.1 Horizon Power's Control Centre

HPCC controllers are authorised by Horizon Power and responsible for:

- coordinating all high voltage switching activities
- performing switching of SCADA controlled primary and secondary apparatus
- electronically recording work permit issue and cancellation, and
- ensuring the compatibility of work permits.

8.5.2 Switching Operator

Switching operators are authorised by Horizon Power and responsible for:

- field switching of non-SCADA controlled apparatus associated with:
    - interconnection, creation of isolation points, program earthing and the reverse sequence switching for restoration
    - disabling remote or automatic operation of apparatus
- the issuing and cancellation of work permits
- the flagging and barricading of safe working areas inside switchyards, and
- installing appropriate signs.

8.5.3 Switching Operator in Charge

The switching operator in charge is the nominated switching operator to manage field switching operations. They are the person through which all communications with HPCC are managed.

8.6 Personal Protective Equipment

The switching operator must at all times use the correct protective clothing and equipment for the switching operation being undertaken.

Protective clothing which Horizon Power provides includes overalls, helmet, switching gloves, boots, safety glasses, goggles, flash jackets and hoods. The intent of protective clothing is to protect the switching operator against safety risks which may occur during switching operations.

Specific information on the PPE requirements for distribution and transmission switching can be found in Tables 1 and 2 in Field Instruction – *Worksite Clothing / Personal Protective Equipment Requirements*.

8.7 Switching Operation Modes

The three switching operation modes are planned switching, unplanned switching and emergency switching. Each of these modes occur in response to particular circumstances and have the specific requirements as described below.

8.7.1 Planned Switching

Planned switching is the usual switching mode for all work that is scheduled in advance. In this mode a switching program is written and checked by switching operators and approved by HPCC in advance of the switching occurring. The program is executed under the control of HPCC.

8.7.2 Unplanned Switching

Unplanned switching occurs in response to an unforeseen network event such as a network asset failure, which does not result in an immediate threat to life or property.

Where the unplanned event requires switching by a switching operator, a switching program is required to be produced in collaboration and agreement between the HPCC controller and the switching operator.

Where a switching program is subsequently required to provide access for repair of the failed network asset, this will follow planned switching requirements. The normal lead time for submission of programs for planned switching will be waivered by HPCC in this instance.

Example

An excavator damages a feeder cable between two RMUs. The feeder circuit breaker has tripped and the faulted cable is required to be isolated to enable power restoration.

8.7.3 Emergency Switching

Emergency switching can occur in response to an unplanned event such as network asset failure, which presents an immediate threat to life or property. Emergency switching to remove an immediate threat may be undertaken without a switching program.

Emergency switching to remove the immediate threat can be performed by a HPCC controller or by a switching operator or other competent person directed by the HPCC controller or switching operator.

It is preferred HPCC is notified prior to the action to remove the immediate threat where possible. However, where this is not possible, HPCC is to be notified immediately after the necessary action to remove the threat has been completed.

Where the emergency threat has been removed, further switching is to follow the unplanned switching requirements.

Example

A severely injured passenger is trapped in a vehicle with wires dangerously close to the vehicle. Medical advice is given that the passenger must be removed from the vehicle immediately, to receive life-saving medical attention.

8.8 Isolation, Earthing and Safe Work Areas

8.8.1 Overview

This section details the isolation and earthing requirements to create a safe work area surrounding the work site on the electrical apparatus.

8.8.2 Fundamental Principles

The fundamental principle to work on HV apparatus is – the HV apparatus to be worked on under an EAP must be securely disconnected and earthed from all sources of electrical supply.

The apparatus to be worked on is called the work site. Depending on the nature of the work, the work site could be a single point or a wide area covering the outermost points of the network where work will be performed.

A secure disconnection point is required on each source of HV electrical supply into the work site. These secure disconnection points are called isolation points. The area of the network inside these isolation points is called the isolated area.

Earths must be installed between the work site and all sources of HV electrical supply into the work site. These earths are called program earths. The area of the network inside the program earths is called the safe work area.

For overhead networks, where any program earth is not visible from the work site, a working earth which is visible from the work site must be added by the RIC between the work site and that program earth. The work site is limited to the area inside the visible earths.

The principles outlined above are described in more detail in the sections which follow

Switchgear Electrical States

To understand the creation of isolation points and safe work areas it is necessary to comprehend the different electrical states of switchgear.

Switchgear can have a number of unique electrical states as described in Table 8-2 below.

Electrical State	Description
ON	Switchgear has its primary contacts closed which electrically connects both sides of the switchgear together.
OFF	Switchgear has its primary contacts open which electrically separates each side of the switchgear.
ISOLATED	Switchgear is securely OFF and requiring a deliberate physical act to turn back ON. This state is not available on all switchgear.
EARTHED	Switchgear has an internal earth applied to the circuit. This state is not available on all switchgear.

Table 8-2 Apparatus electrical state

Each of the above electrical states have unique requirements, therefore terms such as OFF and ISOLATED are not interchangeable. The switching operator must understand the meaning of these terms and use the correct terms when describing the electrical state of apparatus.

De-energised Area

A de-energised area in the network is created by having the switchgear on all sources of supply into the area in the OFF state.

Isolation Points

Isolation points are switchgear in the network which can provide a safe and secure disconnection from an electrical source.

For switchgear to be used as an isolation point the switchgear is required to be:

in the OFF state
AND rendered incapable of being inadvertently switched to the ON state by one or more of the following: • racking out/down • removing conducting switchgear parts • locking to prevent the isolation point requirements being changed (where switchgear locking facilities are provided) • fitting of insulating barriers • other approved methods for specific switchgear type
AND capable of preventing access to live parts by the fitting of barriers or other methods
AND fitted with a Danger–Do Not Operate tag to provide warning, ensuring the isolation point requirements are not changed.

Some apparatus, whilst in the isolated state, may require further fitting of barriers or other methods to prevent access to live parts.

The above requirements are general in nature and due to the large range of switchgear types the actual implementation of these requirements will vary. Table 8-3 below describes the specific requirements for common types of switchgear to be used as an isolation point. The switching operators must be able to correctly create an isolation point for all switchgear they are required to switch .

Electrical Apparatus Approved for Isolation			
		Isolation requirements	
Apparatus	PoA code	Condition	Locking requirements
Pole top switch	PTSD	Off and attach D DNO	Isolation lock applied
HV three-phase disconnector	ISOL	Off and attach D DNO	Isolation lock applied
HV single-phase disconnector	ISOL	Off and attach D DNO	Cannot be locked
HV Drop out fuse	DOF	Off – remove barrel and attach D DNO	Cannot be locked
Approved load break switch	LBS	Off and attach D DNO	See FI – NULEC RL (SF_6) Load Break Switch as an isolation point
RMU switch / fuse switch	SWDC / FSSW	Off and attach D DNO	Isolation lock applied
HV circuit breaker – withdrawable	CB	Off, racked out, removed and bus and circuit shutters locked and attach D DNO s or Off, racked out with cubicle door locked and attach D DNO s or Off, racked out, locked in isolated position and attach D DNO s	Isolation lock(s) applied Note 1: Isolations lock(s) and D DNO (s) must be applied to ensure: the CB cannot be racked in, and persons cannot access live parts.
LV circuit breaker – withdrawable	CB	Off, racked out, locked in isolated position and attach D DNO s	Isolation lock(s) applied See Note 1 above
HV live line clamps		Disconnected (Off) and attach D DNO to pole	Cannot be locked
Temporary disconnector	TEMP	Off – and attach D DNO	Cannot be locked
LV disconnectors		OFF barrier and attach D DNO	Cannot be locked
LV fuses		OFF barrier and attach D DNO	Cannot be locked

Table 8-3 Switchgear isolation requirements

Not all switchgear meet the requirements of an isolation point. Examples of switchgear which cannot be used as an isolation point includes:

- non-withdrawable circuit breakers (typically outdoor circuit breakers)
- reclosers
- sectionalisers with non-removable blades, and
- unapproved load break switches.

Where switchgear cannot be used as an isolation point it will be necessary to isolate further back in the network at an approved isolation device.

Work Site

A work site is the location in the network where work is to be undertaken. A worksite may be one specific point in the network or cover a wider area in the network. Examples of a work site which is a specific point in the network is shown in Figure 8-1 at the cable termination or a work site which cover a wider area is shown in Figure 8-3 which may cover the entire transmission line for insulator changes.

Isolated Area

An isolated area in the network is created by disconnecting all sources of supply using isolation points. See the isolated area in Figure 8-1 and Figure 8-3.

Earthing

Earthing is applied for safety reasons to:

- limit the rise in potential difference in the work area and trigger the protection equipment to disconnect the supply, if supply is inadvertently restored
- control induction when used in conjunction with equipotential bonding techniques, and
- safely discharge electrical charges caused by lightning, wind, changes in ambient conditions or altitude.

Each earth will short circuit all three-phase conductors together and connect them to ground. Earthing may be in the form of switchgear earth switches or portable earths.

There are two types of earths, program earths and working earths and each has a specific purpose.

Program earths are applied for the purpose of protecting against inadvertent energisation into the work area through any isolation point. If an isolation point is inadvertently energised, program earths will immediately cause the supply protection device to operate, de-energising that supply. Program earths are applied and removed as steps in the switching program by the switching operator. These earths are required to be applied before the work permit is issued and removed after the work permit is cancelled. The application and removal of program earths must be noted on the EAP or STT. Depending on the location of program earths, one program earth may cover more than one isolation point.

As switchgear earths are rated switchgear, where available they are preferred for program earths over portable earths.

Working earths are additional earths fitted and removed within the safe work area as required for the work being undertaken. The purpose of these earths is to:

- provide visible earths at the work site where the program earths cannot be seen
- to manage induction
- protect against lightning and static charge
- ensure all conductors being worked on remain earthed even when disconnected as part of the work.

These earths are managed by the Recipient in Charge or Tester in Charge and are fitted after the work permit is accepted and removed before the work permit is relinquished. The application and removal of working earths must be noted on the EAP or STT.

Portable Earths

Portable earths can be used as program earths or working earths.

Overhead HV distribution systems do not have earth switches installed therefore portable earths are required to be fitted. In the public space where the distribution systems are located, a spike is required to be driven into the ground to provide the main earth point. The spike must not interfere with other services. The pole alignment is the preferred location.

For substations with overhead apparatus where portable earths are required the earths must be connected to the main earth grid via the earth studs placed on the structures at convenient intervals around the area.

Where a running earth is available, portable earths must be applied by bonding each conductor to the running earth and to the portable earth spike in the ground.

All portable earth connections must be firmly attached to ensure good electrical contact and also to ensure that the earth will remain effective if subjected to inadvertent energisation.

Field Instruction *Portable Earthing Requirements* provides additional information on using portable earths.

Earth Switches

Indoor switchboard circuit breakers typically have built in earth switches associated with each circuit breaker. Similarly ring main units have a built in earth switch associated with each switch and fuse switch. Due to the large range of switchgear types the actual operations required for applying earths will vary. The switching operator is required to be able to correctly apply earthing on each type of switchgear.

There are several basic facts applicable to earth switches:

- Indoor switchgear interlocks require the circuit breaker to be racked out/down before the earth can be applied.
- Ring main unit interlocks require the ring main switch/fuse switch to be OFF before the earth can be applied. Similarly, the ring main switch/fuse switch cannot be turned ON if the earth switch is ON.
- The earth switch on each circuit is connected on the cable side of the circuit breaker or ring main switch or fuse switch.

Transmission outdoor disconnectors such as line circuit disconnectors usually have an associated line earth switch. Before this earth switch can be closed the associated disconnector must be opened and the line proved de-energised. (Also, an interlock in the operating mechanism of the disconnector and earth switch prevents the disconnector from being turned ON when the earth switch is ON.)

An earth switch when used as a program earth must be ON, locked and a Danger– Do Not Operate tag attached.

Because earth switches are rated switchgear they are normally applied before portable earths.

Safe Work Area

A safe work area is the area within the isolated area and inside the program earths. Therefore a safe work area has two electrical safety measures employed. The first safety measure is all sources of electrical supply into the work area have been securely disconnected at the isolation points and the second safety measure is the program earths are applied to ensure the work area cannot be inadvertently energised through the isolation points. The safe work area is commonly referred to as being 'boxed in' by isolation points and program earths.

Figure 8-1 shows part of the distribution network, where a section of HV overhead line connects to an underground cable at the cable termination pole. The work site is cable termination pole. The two isolation points (IP1 and IP2) create the isolated area and the earthing requires two program earths (Portable Earth PE1 and RMES PE2) creating the safe work area. Inside the safe work area is the work location (cable termination pole) and an EAP is issued for work on the cable termination.

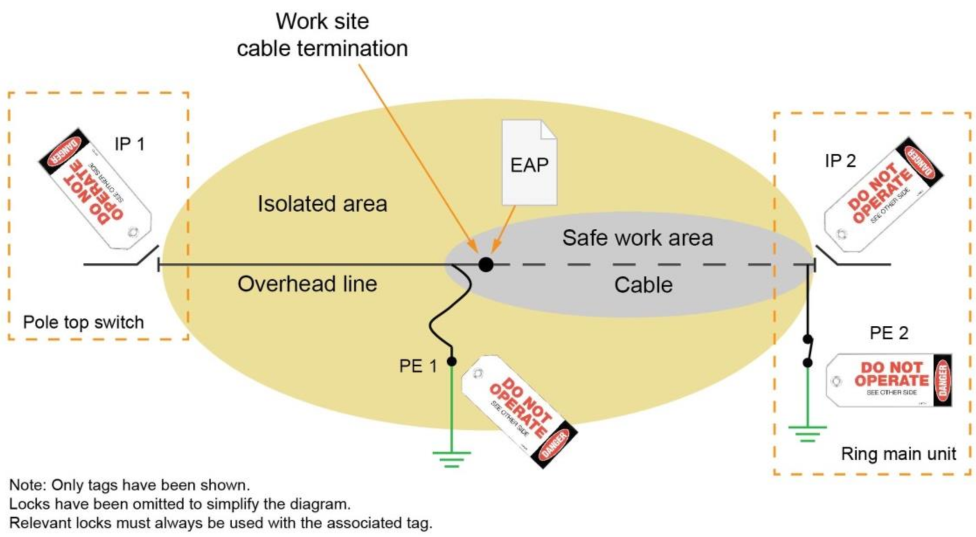


Figure 8-1 Distribution safe work area

Figure 8-3 shows a transmission line connecting two substations. The transmission line is the work site. There are isolation points IP1 and IP2 at each end of the line creating an isolated area. The earthing requires program earths PE1 and PE2 at each end of the line. This creates the safe work area as shown.

However, as the work party is required to work between visible earths, working earths WE1 and WE2 (both portable earths) must be installed on each side of the work site. If the work site progresses along the line, the working earths must be moved by the work party, so they remain visible from the work site. If working near one end of the line and program earth PE1 or PE2 is visible then only one working earth will be required on the side of the worksite where the program earth is not visible.

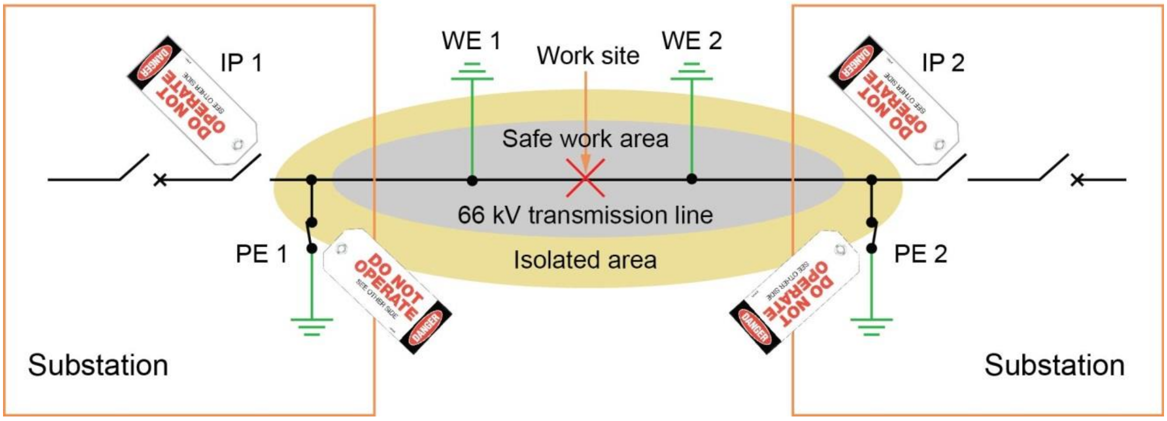


Figure 8-2 Transmission safe work area

8.8.3 Summary of Apparatus State

Figure 8-3 below shows the stages network apparatus progresses through from an energised state to an isolated and then earthed state for the issue of an EAP. The terms live, de-energised, isolated and earthed must be correctly used to describe the specific state of the network.

Figure 8-3 Transition from live to earthed network state for EAP

8.9 Distribution Isolation and Earthing

The overhead HV distribution system commonly will have one or more transformer circuits between HV feeder switchgear, which can be used as isolation points. The interconnectable transformers have a possible source of supply from the LV network. The non-interconnectable transformers have an unlikely, but possible source of LV supply from customers generation. This includes grid connected inverters on renewable generation and defective backup generation wiring.

In each case if a LV back-feed does occur, the transformer will step the LV voltage up and become a HV source of supply onto the HV feeder. Each transformer must be appropriately isolated on the LV side and earthed on the HV depending on the transformer type and location relative to the work site.

Below is a set of rules to assist in planning the creation of a safe work area on a HV feeder. The first part covers the HV feeder isolation and earthing rules and the second part deals with the transformer isolation and earthing rules for the transformers connected between the HV feeder isolation points.

1. Rule for feeders:

    1.1. All main feeder HV sources of supply into the work site must be isolated.

    1.2. Program earth(s) must be fitted between step 1.1 isolation point(s) and the work site AND as close as possible to the work site.

2. Rules for all transformers inside the isolated area defined by step 1:

    2.1. for interconnectable transformers, the LV must be isolated.

    2.2. for each transformer, there must be a program earth between the transformer and the work site AND as close as possible to the work site.

    2.3. Note: the placement of the program earths fitted in step 1.2 determines the earthing needed for transformers in step 2.2.

The planning process for distribution feeder and associated transformer isolation and earthing is shown in the flowchart below (Figure 8-4).

Note: Remember, when writing the switching program all HV feeder and transformer isolations must be completed before the program earthing is commenced.

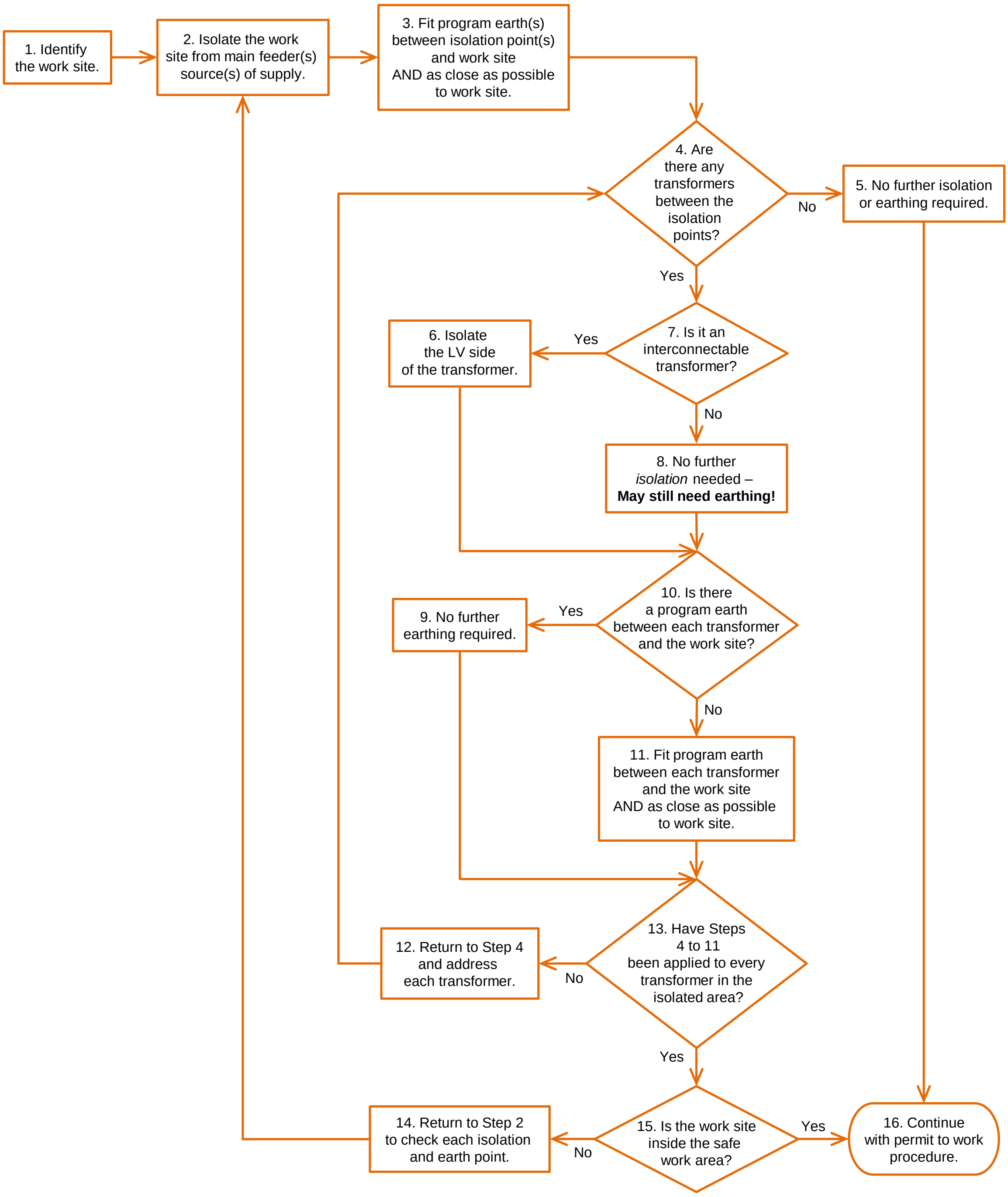


Figure 8-4 Flowchart of planning process for distribution feeder and associated transformer isolation and earthing.

To illustrate the application of isolation and earthing principles and rules to create safe work areas on the distribution network consider Figure 8-5.

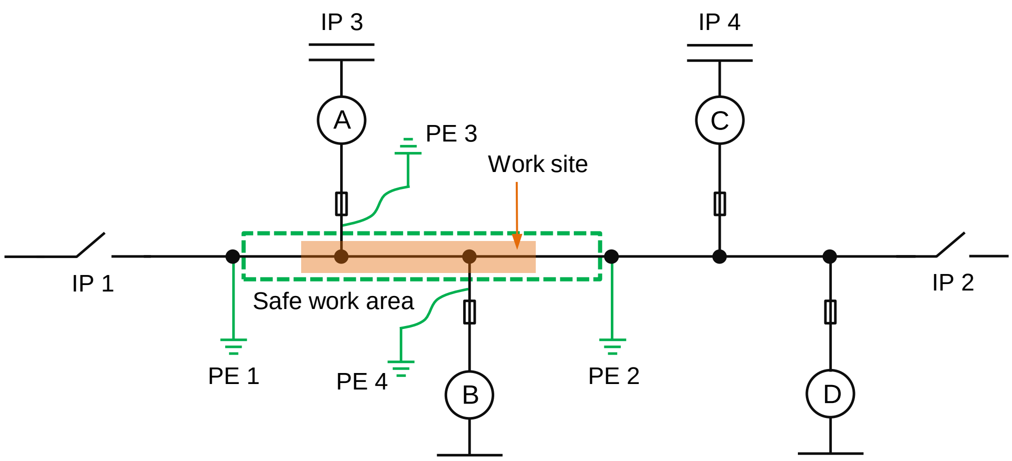


Figure 8-5 Distribution isolation and earthing

Figure 8-5 shows the work site on the main feeder which includes the HV connections to transformer A and B. The two sources of feeder supply must be isolated at IP1 and IP2. These sources of supply must have program earths PE1 and PE2 placed between these isolation points and the work site. Program earths must be placed as close to the work site as practicable.

Each transformer between IP1 and IP2 must now be managed:

Transformer A is interconnectable and must be isolated on the LV side and a program earth PE3 fitted on the transformer HV conductors into the work site.

Transformer B is non-interconnectable and must have a program earth PE4 fitted on the transformer HV conductors into the work site.

Transformer C is interconnectable and must be isolated on the LV side. As program earth PE2 will be fitted between the transformer and the work site no additional earthing is required.

Transformer D is non-interconnectable and as program earth PE2 will be fitted between the transformer and the work site no additional earthing is required.

The safe work area is between the program earths and surrounds the work site.

The switching program can now be written, remembering all isolations must occur before program earthing is commenced.

Further examples of the practical application of isolation and earthing principles to typical distribution networks are provided below.

8.9.1 Example 1

Figure 8-6 shows a three-phase overhead network, the work site, a three-phase transformer X, and a number of single-phase spurs each with multiple transformers.

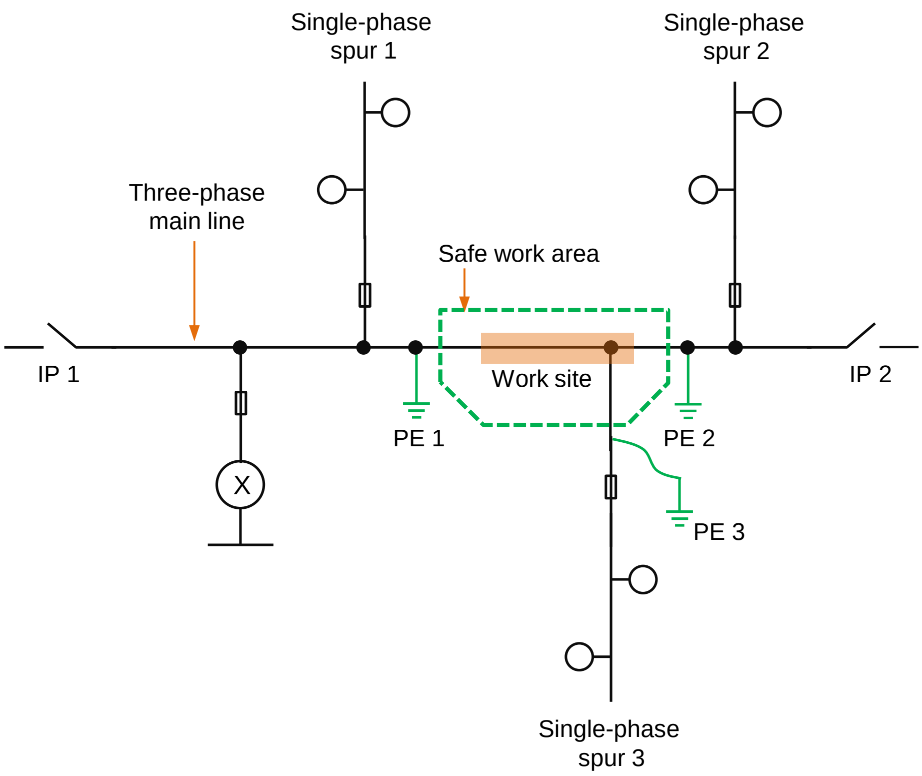


Figure 8-6 Earthing of rural distribution system with spurs

In Figure 8-6, the work site on the main feeder requires isolation points IP1 and IP2. These sources of supply must have program earths PE1 and PE2 placed between these isolation points and the work site. Program earths must be placed as close to the work site as practicable.

Each transformer between IP1 and IP2 must now be managed:

Transformer X is non-interconnectable and as program earth PE1 will be fitted between the transformer and the work site no additional earthing is required.

Single-phase spur 1 has non-interconnectable transformers and as program earth PE1 will be fitted between the transformers and the work site no additional earthing is required.

Single-phase spur 2 has non-interconnectable transformers and as program earth PE2 will be fitted between the transformers and the work site no additional earthing is required.

Single-phase spur 3 has non-interconnectable transformers and must have a program earth PE3 fitted on the transformer HV conductor into the work site.

The safe work area is between the program earths and surrounds the work site.

The switching program can now be written, remembering all isolations must occur before program earthing is commenced.

8.9.2 Example 2

Figure 8-7 shows a diagram of a three-phase overhead network with a single-phase spur. The work site is part way along the single-phase spur.

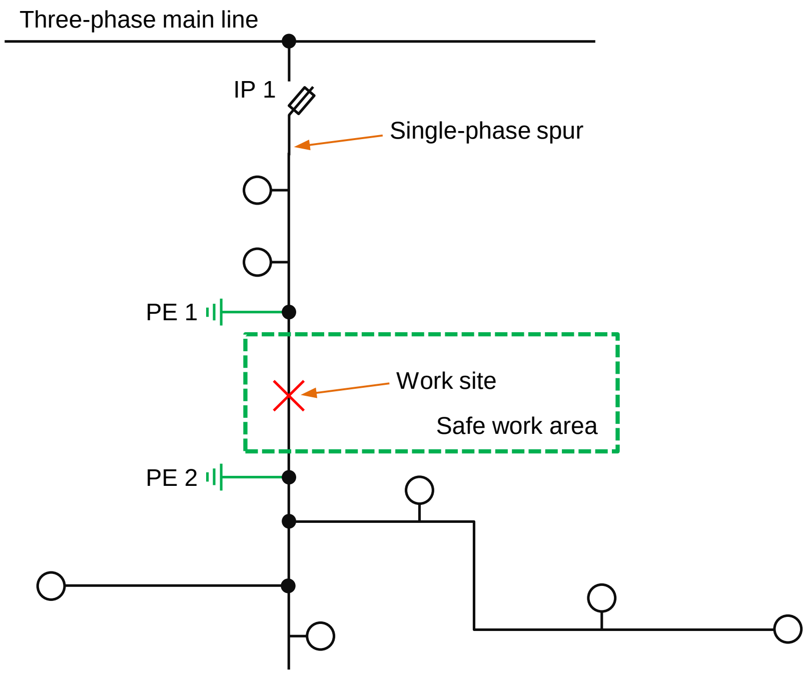


Figure 8-7 Single-phase spur earthing

The work site requires isolation from the feeder at isolation point IP1. This source of supply must have program earth PE1 fitted between this isolation point and the work site. Program earth must be placed as close to the work site as practicable.

All transformers in Figure 8-7 are non-interconnectable. Therefore PE1 provides the earth required for the transformers between IP1 and PE1. Program earth PE2 is required to be fitted to provide an earth between the work site and the remaining transformers at the bottom end of the spur.

The safe work area is between the program earths and surrounds the work site.

The switching program can now be written, remembering all isolations must occur before program earthing is commenced.

8.9.3 Example 3

Figure 8-8 shows a diagram of the work site on a three-phase overhead network with three transformers.

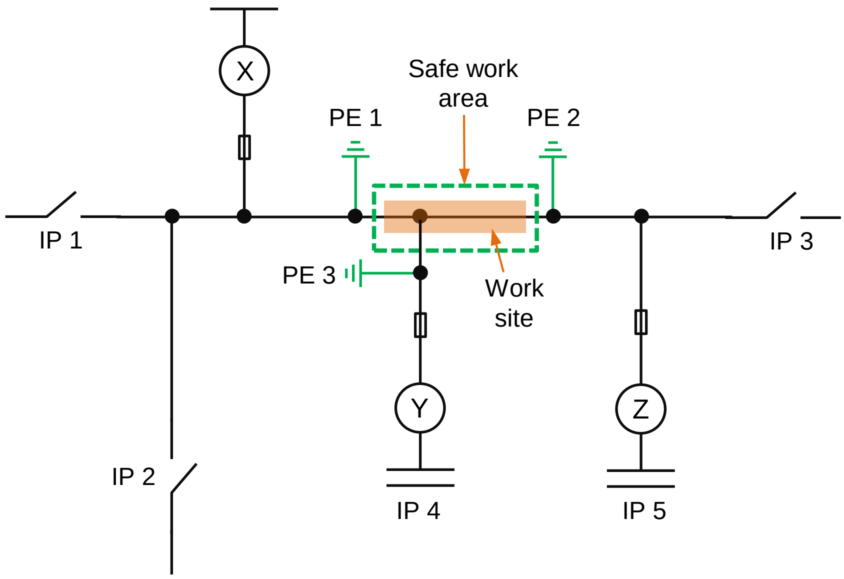


Figure 8-8 Distribution system earthing

In Figure 8-8, the work site on the main feeder requires isolation points IP1, IP2 and IP3. These sources of supply must have program earths PE1 and PE2 placed between the isolation points and the work site. Program earths must be placed as close to the work site as practicable.

Each transformer between IP1, IP2 and IP3 must now be managed :

Transformer X is non-interconnectable and as program earth PE1 will be fitted between the transformer and the work site no additional earthing is required.

Transformer Y is interconnectable and must be isolated on the LV side IP4 and a program earth PE3 fitted on the transformer HV conductors into the work site.

Transformer Z is interconnectable and must be isolated on the LV side IP5, as program earth PE2 will be fitted between the transformer and the work site no additional earthing is required.

The safe work area is between the program earths and surrounds the work site.

The switching program can now be written, remembering all isolations must occur before program earthing is commenced.

8.9.4 Example 4

Figure 8-9 shows an HV overhead feeder with a cable head pole and cable connecting to a ring main switch. The work site is at the cable head pole and requires isolation and earthing on all three sources of HV supply. There is one isolation point IP1 on the ring main switch and two overhead isolation points IP2 and IP3. Program earth PE1 is the ring main earth switch and program earths PE2 and PE3 are applied to the overhead line on each side of the work site.

The safe work area is between the program earths and surrounds the work site.

The switching program can now be written, remembering all isolations must occur before program earthing is commenced.

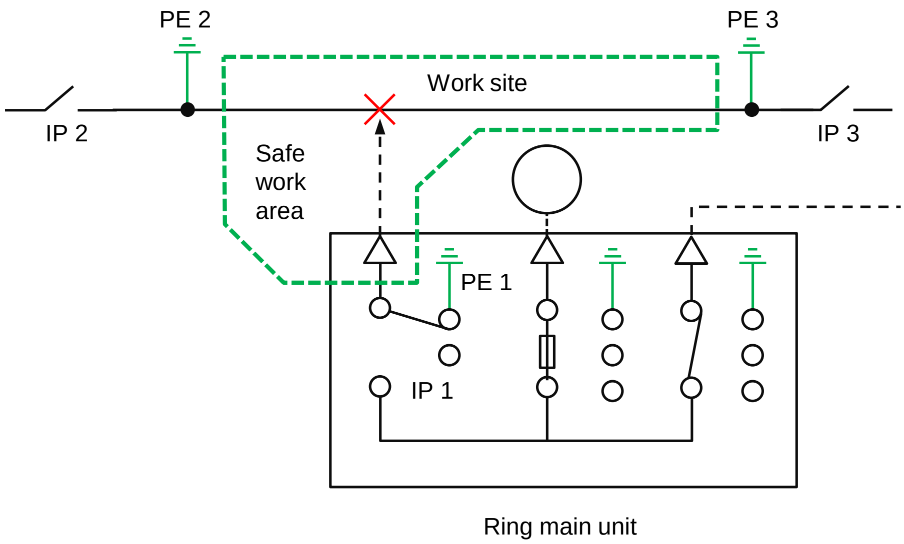


Figure 8-9 Distribution system earthing

8.10 Substation Safe Work Area Delineation

When work is to be carried out in a substation under a work permit, the switching operator is required to mark out the safe work area by the installation of approved insulated chain, rope flagging or the use of fixed barriers. The switching operator is to ensure the following requirements are met:

- the barrier is to be highly visible and at a height that a person cannot inadvertently cross over or under the barrier

- the barrier is to be arranged with a visible opening so the equipment to be worked on is accessible without interfering with or crossing over, or under the barrier

- walls, fences or other impassable permanent barriers can be used as part of the boundary for the safe work area, and

- perimeter signs identifying the controlling authority shall be erected (free standing or attached to rope) adjacent to the visible opening and to all sides of the work area.

Refer to *ESS* for specific clearance zones and safe working distances.

An example of a safe work area is shown in Figure 8-10 below.

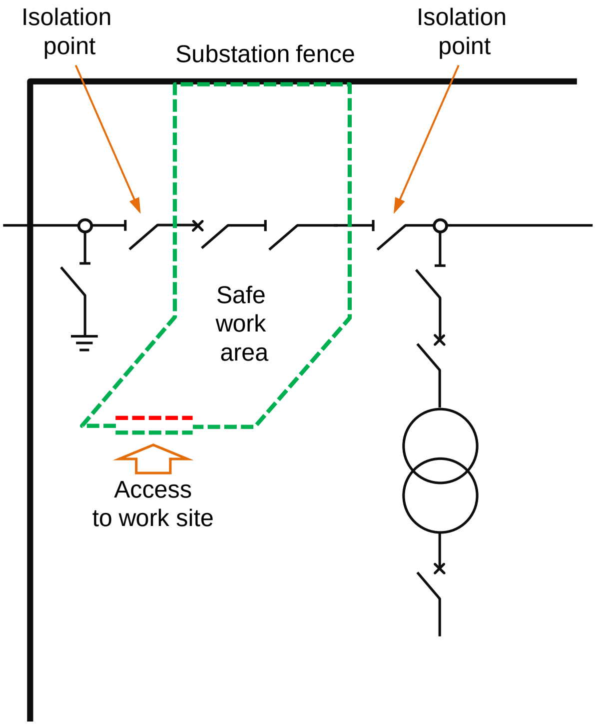


Figure 8-10 Example of safe work area

8.11 Work Permits

8.11.1 Network Permit to Work

The *Network Permit to Work Training Manual* describes the following topics relating to work permits and procedures:

- roles and responsibilities
- work permits
- tags
- locks
- application of work permits, and
- work permit procedural flowcharts.

The switching operator is required to fully understand the *Network Permit to Work* procedures.

This manual includes an overview of work permits and activities specifically applicable to switching operators.

Work Permits

Access on or near the network to carry out work requires the issue of a work permit. Work permits provide a written record of the safety information transferred between the switching operator and the work party.

Three work permits are provided to cover the range of access requirements and types of work to be undertaken. The three work permits are:

- Electrical Access Permit (EAP)
- Sanction to Test (STT)
- Vicinity Authority (VA).

Work Permit Stages

All work permits progress through several stages involving the switching operator, Recipient in Charge or Tester in Charge and the Recipients. The table below provides a description of the activities, the responsible role and the name of the work permit stage.

Description	Responsible role	Stage
Preparation of work permit	Switching Operator	
Work permit issued to RIC/TIC (Work permit registered with HPCC)		ISSUE
Work permit is accepted	RIC or TIC	ACCEPTANCE
RIC/TIC manages Recipients' work permit sign on	RIC or TIC Recipients	SIGN ON
Work proceeds under the supervision of the RIC/TIC	RIC or TIC Recipients	WORK
RIC/TIC manages Recipients work permit sign off on work completion	RIC or TIC Recipients	SIGN OFF
Work permit is relinquished	RIC or TIC	RELINQUISH-MENT
Work permit is cancelled (Work permit registered with HPCC)	Switching Operator	CANCELLATION

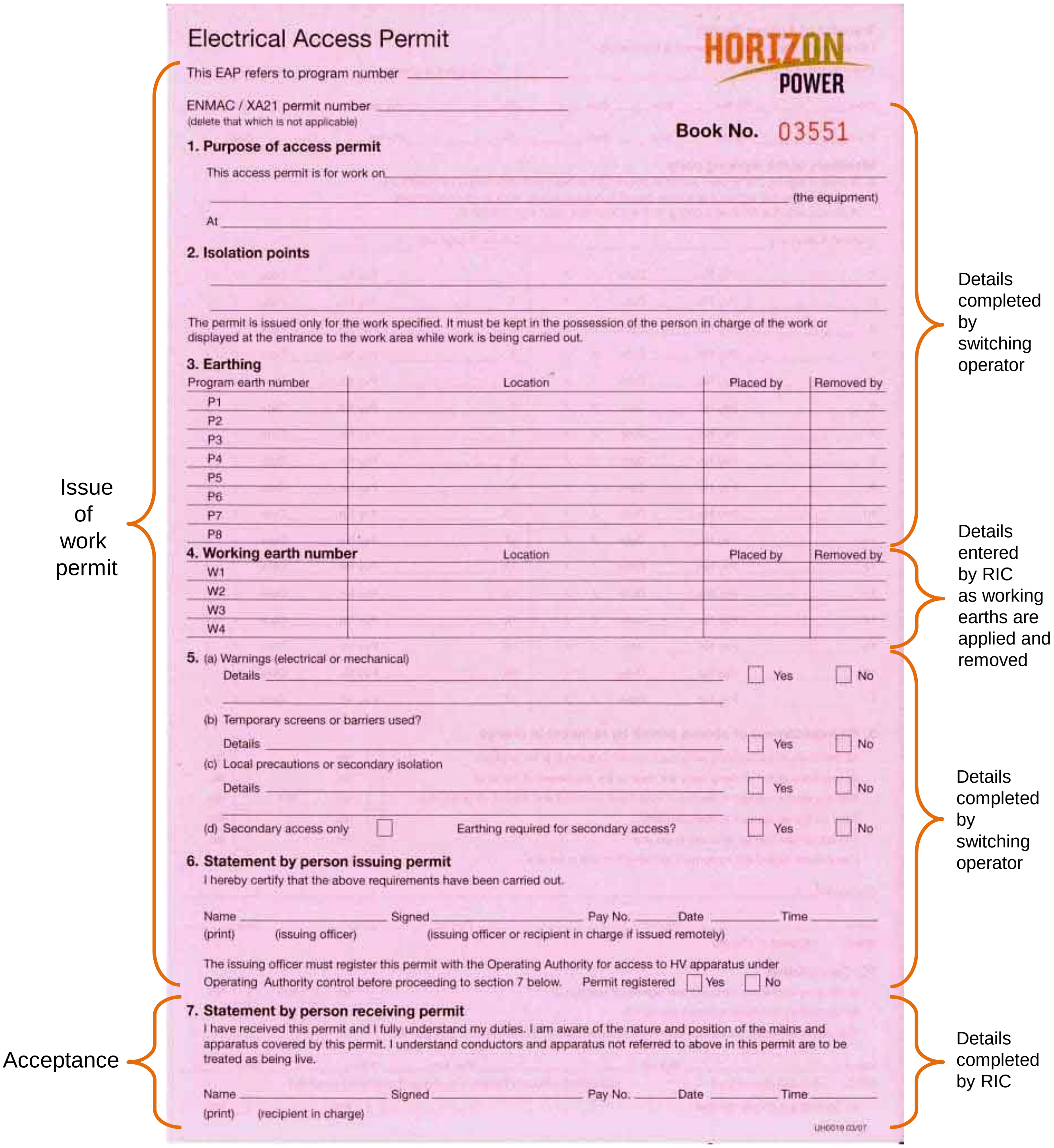
Table 8-4 Work stages and responsibilities

Electrical Access Permit

An Electrical Access Permit (EAP) is a work permit required for work which involves direct access to network apparatus.

To work on network apparatus under an EAP, a safe work area is required to be formed surrounding the apparatus. An example of a safe work area for the issue of an EAP for work on the cable termination pole is shown in Figure 8-1.

The EAP document is shown in Figure 8-11 and Figure 8-12 below. The diagram has annotations to show the stage and the responsible role for completing the written details.



Electrical Access Permit

HORIZON POWER

This EAP refers to program number ____________

ENMAC / XA21 permit number ____________
(delete that which is not applicable)

Book No. 03551

1. Purpose of access permit

This access permit is for work on ____________

____________ (the equipment)

At ____________

2. Isolation points

____

____

The permit is issued only for the work specified. It must be kept in the possession of the person in charge of the work or displayed at the entrance to the work area while work is being carried out.

3. Earthing

Program earth number	Location	Placed by	Removed by
P1			
P2			
P3			
P4			
P5			
P6			
P7			
P8			

4. Working earth number	Location	Placed by	Removed by
W1			
W2			
W3			
W4			

5. (a) Warnings (electrical or mechanical)
Details ____________ ☐ Yes ☐ No

(b) Temporary screens or barriers used?
Details ____________ ☐ Yes ☐ No

(c) Local precautions or secondary isolation
Details ____________ ☐ Yes ☐ No

(d) Secondary access only ☐ Earthing required for secondary access? ☐ Yes ☐ No

6. Statement by person issuing permit

I hereby certify that the above requirements have been carried out.

Name ________ Signed ________ Pay No. ____ Date ______ Time ______
(print) (issuing officer) (issuing officer or recipient in charge if issued remotely)

The issuing officer must register this permit with the Operating Authority for access to HV apparatus under Operating Authority control before proceeding to section 7 below. Permit registered ☐ Yes ☐ No

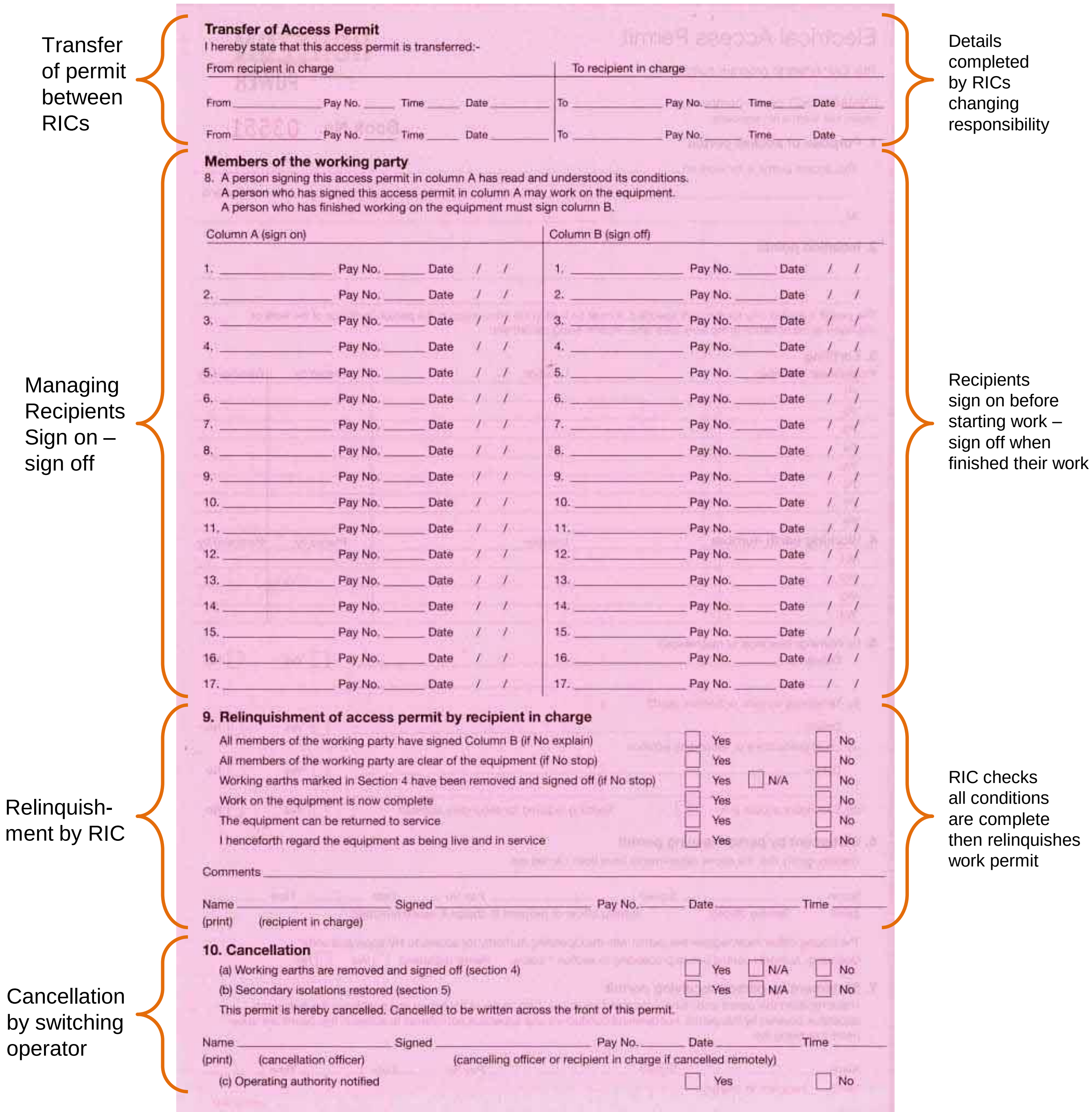
7. Statement by person receiving permit

I have received this permit and I fully understand my duties. I am aware of the nature and position of the mains and apparatus covered by this permit. I understand conductors and apparatus not referred to above in this permit are to be treated as being live.

Name ________ Signed ________ Pay No. ____ Date ______ Time ______
(print) (recipient in charge)

UH0019 03/07

Figure 8-11 Electrical Access Permit – Front showing the sections of the permit and the people responsible for completing those sections.



Transfer of Access Permit

I hereby state that this access permit is transferred:-

From recipient in charge	To recipient in charge
From ______ Pay No. ______ Time ______ Date ______	To ______ Pay No. ______ Time ______ Date ______
From ______ Pay No. ______ Time ______ Date ______	To ______ Pay No. ______ Time ______ Date ______

Members of the working party

8. A person signing this access permit in column A has read and understood its conditions.
A person who has signed this access permit in column A may work on the equipment.
A person who has finished working on the equipment must sign column B.

Column A (sign on)	Column B (sign off)
1. ______ Pay No. ______ Date / /	1. ______ Pay No. ______ Date / /
2. ______ Pay No. ______ Date / /	2. ______ Pay No. ______ Date / /
3. ______ Pay No. ______ Date / /	3. ______ Pay No. ______ Date / /
4. ______ Pay No. ______ Date / /	4. ______ Pay No. ______ Date / /
5. ______ Pay No. ______ Date / /	5. ______ Pay No. ______ Date / /
6. ______ Pay No. ______ Date / /	6. ______ Pay No. ______ Date / /
7. ______ Pay No. ______ Date / /	7. ______ Pay No. ______ Date / /
8. ______ Pay No. ______ Date / /	8. ______ Pay No. ______ Date / /
9. ______ Pay No. ______ Date / /	9. ______ Pay No. ______ Date / /
10. ______ Pay No. ______ Date / /	10. ______ Pay No. ______ Date / /
11. ______ Pay No. ______ Date / /	11. ______ Pay No. ______ Date / /
12. ______ Pay No. ______ Date / /	12. ______ Pay No. ______ Date / /
13. ______ Pay No. ______ Date / /	13. ______ Pay No. ______ Date / /
14. ______ Pay No. ______ Date / /	14. ______ Pay No. ______ Date / /
15. ______ Pay No. ______ Date / /	15. ______ Pay No. ______ Date / /
16. ______ Pay No. ______ Date / /	16. ______ Pay No. ______ Date / /
17. ______ Pay No. ______ Date / /	17. ______ Pay No. ______ Date / /

9. Relinquishment of access permit by recipient in charge

All members of the working party have signed Column B (if No explain) ☐ Yes ☐ No
All members of the working party are clear of the equipment (if No stop) ☐ Yes ☐ No
Working earths marked in Section 4 have been removed and signed off (if No stop) ☐ Yes ☐ N/A ☐ No
Work on the equipment is now complete ☐ Yes ☐ No
The equipment can be returned to service ☐ Yes ☐ No
I henceforth regard the equipment as being live and in service ☐ Yes ☐ No

Comments ______

Name (print) ______ (recipient in charge) Signed ______ Pay No. ______ Date ______ Time ______

10. Cancellation

(a) Working earths are removed and signed off (section 4) ☐ Yes ☐ N/A ☐ No
(b) Secondary isolations restored (section 5) ☐ Yes ☐ N/A ☐ No
This permit is hereby cancelled. Cancelled to be written across the front of this permit.

Name (print) ______ (cancellation officer) Signed ______ (cancelling officer or recipient in charge if cancelled remotely) Pay No. ______ Date ______ Time ______

(c) Operating authority notified ☐ Yes ☐ No

Figure 8-12 Electrical Access Permit – Back showing the sections of the permit and the people responsible for completing those sections.

Sanction To Test

A Sanction to Test (STT) is a work permit required to perform testing work on network apparatus. The apparatus electrical state required for the issue of a STT is variable and dependent on the nature of intended testing as requested by the Tester in Charge.

This variable nature of the apparatus electrical state allows a wide range of test types, and includes apparatus which is initially isolated and earthed or isolated and not earthed, de-energised or in the energised state. Typically for distribution testing (such as VLF testing) the initial state is isolated and earthed, this allows the connection of test equipment. The earths are removed for the testing and then reapplied for removal of test equipment. Transmission testing work involves a wider range of test types and therefore STT may be required to be issued in one of the several states described above.

Note: The STT is shown in Figure 8-13 and Figure 8-14 below.

The diagram has annotations to show the stage and the responsible role for completing the written details.

An EAP and STT cannot be issued at the same time, on the same apparatus, due to the conflicting requirements of the EAP to have a safe work area which is isolated and earthed and the STT to apply test voltages to apparatus.

HORIZON POWER

Sanction to Test Electrical Circuit/Apparatus (STT)

Issue of work permit

Details completed by switching operator

This STT refer to Program No. ______________ (if required)

ENMAC / XA21 Permit No. ____________________
(delete that which is not applicable)

Book No. 03901

1. Purpose of STT

This permit gives access to the following circuit/apparatus for testing ______________________________

____

at ______________________________

2. The curcuit/apparatus is in the following configuration for testing purpose only ______________________________

____

____

____

The permit is issued only for the work specified. It must be kept in the possession of the tester in charge of the work.

3. Earthing

Earth No.	Location	Placed by	Removed by
1			
2			
3			
4			
5			
6			
7			
8			

4. (a) Warnings (electrical or mechanical)

Details ______________________________ ☐ Yes ☐ No

____

(b) Temporary screens or barriers used?

Details ______________________________ ☐ Yes ☐ No

(c) Local precautions

Details ______________________________ ☐ Yes ☐ No

____

(d) Secondary access only ☐

5. Statement by person issuing permit

I hereby certify that the above requirements have been carried out.

Name (print) ______________ Signed ______________ (issuing officer or tester in charge if issued remotely) Pay No. ________ Date ________ Time ________

Acceptance

Accepted by TIC

6. Statement by person receiving permit

I have received this Permit and I fully understand my duties. I am aware of the status of the apparatus covered by this permit.
I understand conductors and apparatus not referred to above in this permit are to be treated as being live and in service.

Name (print) (tester in charge) ______________ Signed ______________ Pay No. ________ Date ________ Time ________

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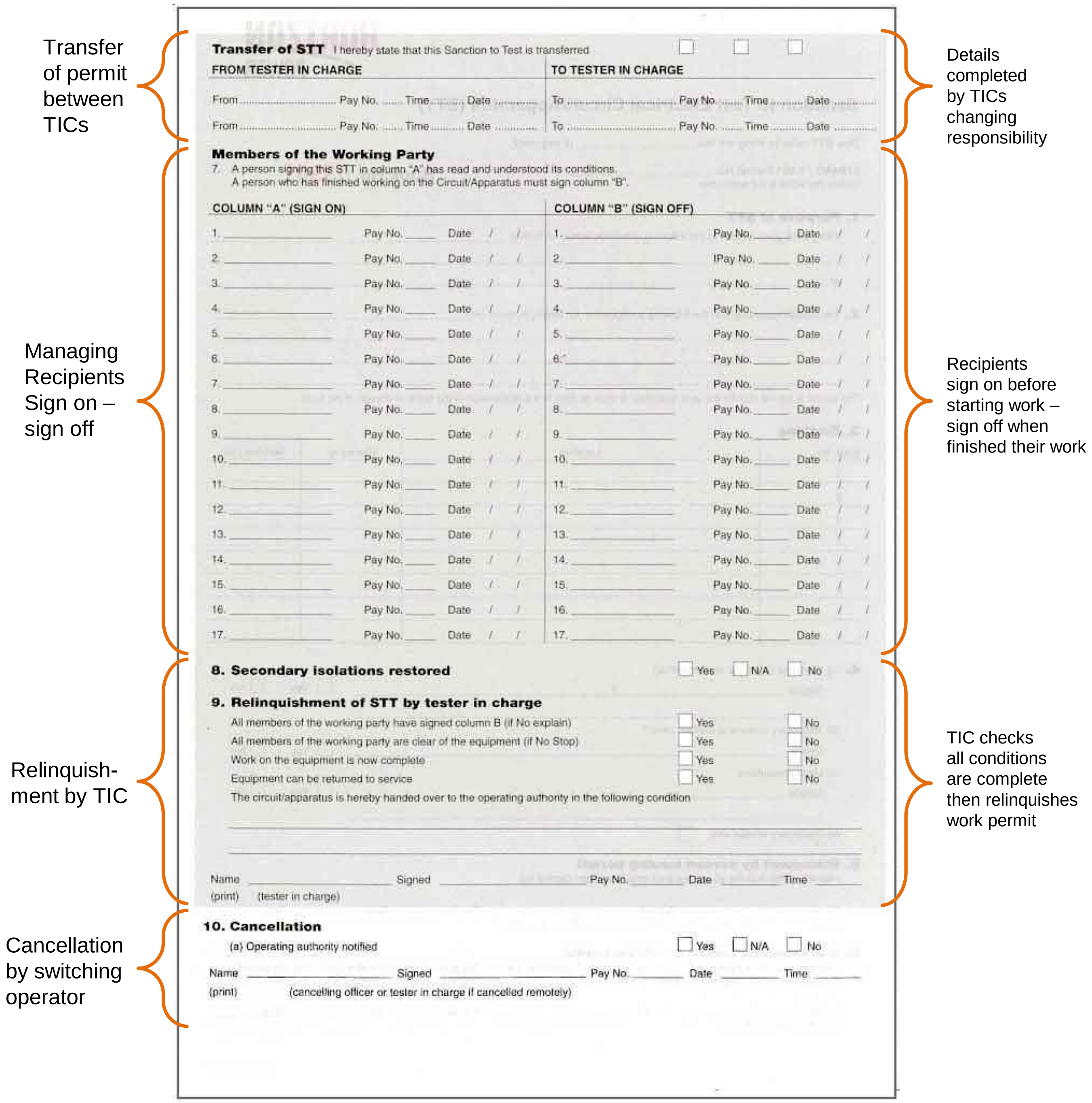
Figure 8-13 Sanction To Test – Front
showing the sections of the permit and the people responsible
for completing those sections.



Transfer of STT I hereby state that this Sanction to Test is transferred

FROM TESTER IN CHARGE	TO TESTER IN CHARGE
From .... Pay No. ...... Time ...... Date	To .... Pay No. ...... Time ...... Date ....
From .... Pay No. ...... Time ...... Date	To .... Pay No. ...... Time ...... Date ....

Members of the Working Party

7. A person signing this STT in column "A" has read and understood its conditions.
A person who has finished working on the Circuit/Apparatus must sign column "B".

COLUMN "A" (SIGN ON)			COLUMN "B" (SIGN OFF)		
1.	Pay No.	Date / /	1.	Pay No.	Date / /
2.	Pay No.	Date / /	2.	Pay No.	Date / /
3.	Pay No.	Date / /	3.	Pay No.	Date / /
4.	Pay No.	Date / /	4.	Pay No.	Date / /
5.	Pay No.	Date / /	5.	Pay No.	Date / /
6.	Pay No.	Date / /	6.	Pay No.	Date / /
7.	Pay No.	Date / /	7.	Pay No.	Date / /
8.	Pay No.	Date / /	8.	Pay No.	Date / /
9.	Pay No.	Date / /	9.	Pay No.	Date / /
10.	Pay No.	Date / /	10.	Pay No.	Date / /
11.	Pay No.	Date / /	11.	Pay No.	Date / /
12.	Pay No.	Date / /	12.	Pay No.	Date / /
13.	Pay No.	Date / /	13.	Pay No.	Date / /
14.	Pay No.	Date / /	14.	Pay No.	Date / /
15.	Pay No.	Date / /	15.	Pay No.	Date / /
16.	Pay No.	Date / /	16.	Pay No.	Date / /
17.	Pay No.	Date / /	17.	Pay No.	Date / /

8. Secondary isolations restored ☐ Yes ☐ N/A ☐ No

9. Relinquishment of STT by tester in charge

All members of the working party have signed column B (if No explain) ☐ Yes ☐ No
All members of the working party are clear of the equipment (if No Stop) ☐ Yes ☐ No
Work on the equipment is now complete ☐ Yes ☐ No
Equipment can be returned to service ☐ Yes ☐ No
The circuit/apparatus is hereby handed over to the operating authority in the following condition

Name ________ Signed ________ Pay No. ______ Date ______ Time ______
(print) (tester in charge)

10. Cancellation

(a) Operating authority notified ☐ Yes ☐ N/A ☐ No

Name ________ Signed ________ Pay No. ______ Date ______ Time ______
(print) (cancelling officer or tester in charge if cancelled remotely)

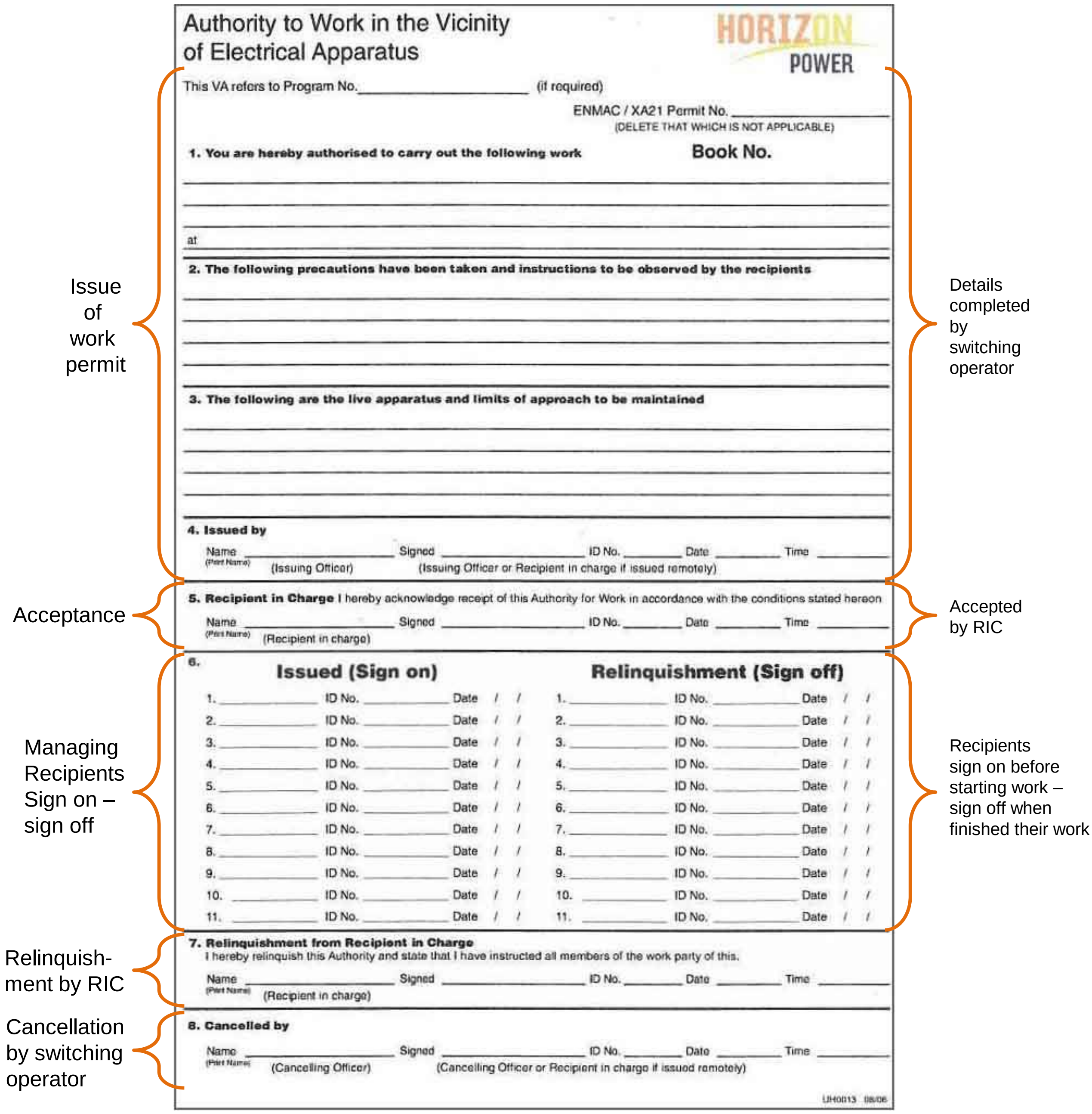
Figure 8-14 Sanction To Test – Back
showing the sections of the permit and the people responsible
for completing those sections.

Vicinity Authority

A Vicinity Authority (VA) is the work permit required to perform work near energised electrical apparatus. The safe approach distance which must be maintained at all times from the apparatus is specified in Field Instruction *Safe Approach Distances*.

Where the required safe approach distance cannot be maintained during the work, the apparatus must have a safe work area created by being isolated and earthed and an EAP issued.

An EAP and VA can be issued on the same apparatus at the same time, as the EAP requires the apparatus to be isolated and earthed, whilst the VA requires the same apparatus to be treated as alive and the required safe approach distance maintained at all times.


Authority to Work in the Vicinity of Electrical Apparatus

HORIZON POWER

This VA refers to Program No.________________ (if required)

ENMAC / XA21 Permit No. ________________
(DELETE THAT WHICH IS NOT APPLICABLE)

1. You are hereby authorised to carry out the following work Book No.

at

2. The following precautions have been taken and instructions to be observed by the recipients

3. The following are the live apparatus and limits of approach to be maintained

4. Issued by

Name (Print Name) ________ (Issuing Officer) Signed ________ (Issuing Officer or Recipient in charge if issued remotely) ID No. ____ Date ____ Time ____

5. Recipient in Charge I hereby acknowledge receipt of this Authority for Work in accordance with the conditions stated hereon

Name (Print Name) ________ (Recipient in charge) Signed ________ ID No. ____ Date ____ Time ____

6.

Issued (Sign on)	ID No.	Date	Relinquishment (Sign off)	ID No.	Date
1.		/ /	1.		/ /
2.		/ /	2.		/ /
3.		/ /	3.		/ /
4.		/ /	4.		/ /
5.		/ /	5.		/ /
6.		/ /	6.		/ /
7.		/ /	7.		/ /
8.		/ /	8.		/ /
9.		/ /	9.		/ /
10.		/ /	10.		/ /
11.		/ /	11.		/ /

7. Relinquishment from Recipient in Charge
I hereby relinquish this Authority and state that I have instructed all members of the work party of this.

Name (Print Name) ________ (Recipient in charge) Signed ________ ID No. ____ Date ____ Time ____

8. Cancelled by

Name (Print Name) ________ (Cancelling Officer) Signed ________ (Cancelling Officer or Recipient in charge if issued remotely) ID No. ____ Date ____ Time ____

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Figure 8-15 Vicinity Authority showing the sections of the permit and the people responsible for completing those sections.

8.11.2 Operating Agreements and Handover Certificates

Two additional documents which do not give authority to undertake any work on the network are used to formalise agreements made between different authorities.

These documents are:

- Operating Agreements
- Handover Certificates

Operating Agreement

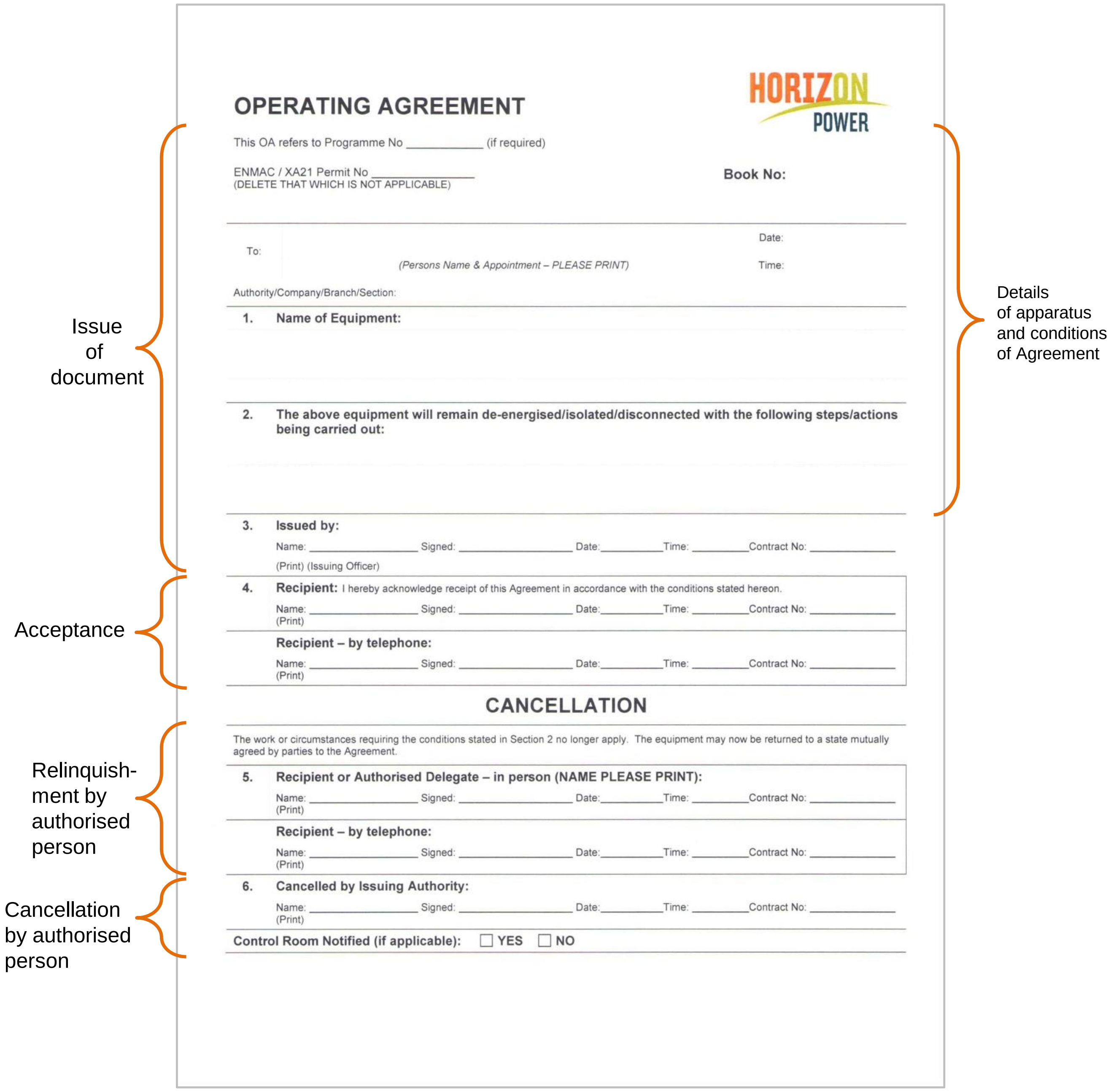
An Operating Agreement (OA) is an agreement between two operating authorities, declaring the operational state in which electrical apparatus will be held for the duration of the OA.

An OA is used when:

- one party needs to work on an item of plant or electrical apparatus which requires isolation and/or earthing from the adjacent Operating Authority, or
- work on secondary systems or mechanisms requiring the primary electrical apparatus to be held in a particular state for safety reasons.

An OA is *not* a work permit, and does not authorise any work to be undertaken. The appropriate work permit must be issued to allow work to take place. The conditions stated on the work permit must reference the OA in place. An OA is issued by a switching operator or Issuing Officer.

Additional information on Operating Agreement requirements is provided in the Field Instruction *Operating Agreement*.



OPERATING AGREEMENT

HORIZON POWER

This OA refers to Programme No ___________ (if required)

ENMAC / XA21 Permit No _______________
(DELETE THAT WHICH IS NOT APPLICABLE)

Book No:

To: (Persons Name & Appointment – PLEASE PRINT) Date: Time:

Authority/Company/Branch/Section:

1. Name of Equipment:

2. The above equipment will remain de-energised/isolated/disconnected with the following steps/actions being carried out:

3. Issued by:
Name: ____________ Signed: ____________ Date: ________ Time: ________ Contract No: ____________
(Print) (Issuing Officer)

4. Recipient: I hereby acknowledge receipt of this Agreement in accordance with the conditions stated hereon.
Name: ____________ Signed: ____________ Date: ________ Time: ________ Contract No: ____________
(Print)

Recipient – by telephone:
Name: ____________ Signed: ____________ Date: ________ Time: ________ Contract No: ____________
(Print)

CANCELLATION

The work or circumstances requiring the conditions stated in Section 2 no longer apply. The equipment may now be returned to a state mutually agreed by parties to the Agreement.

5. Recipient or Authorised Delegate – in person (NAME PLEASE PRINT):
Name: ____________ Signed: ____________ Date: ________ Time: ________ Contract No: ____________
(Print)

Recipient – by telephone:
Name: ____________ Signed: ____________ Date: ________ Time: ________ Contract No: ____________
(Print)

6. Cancelled by Issuing Authority:
Name: ____________ Signed: ____________ Date: ________ Time: ________ Contract No: ____________
(Print)

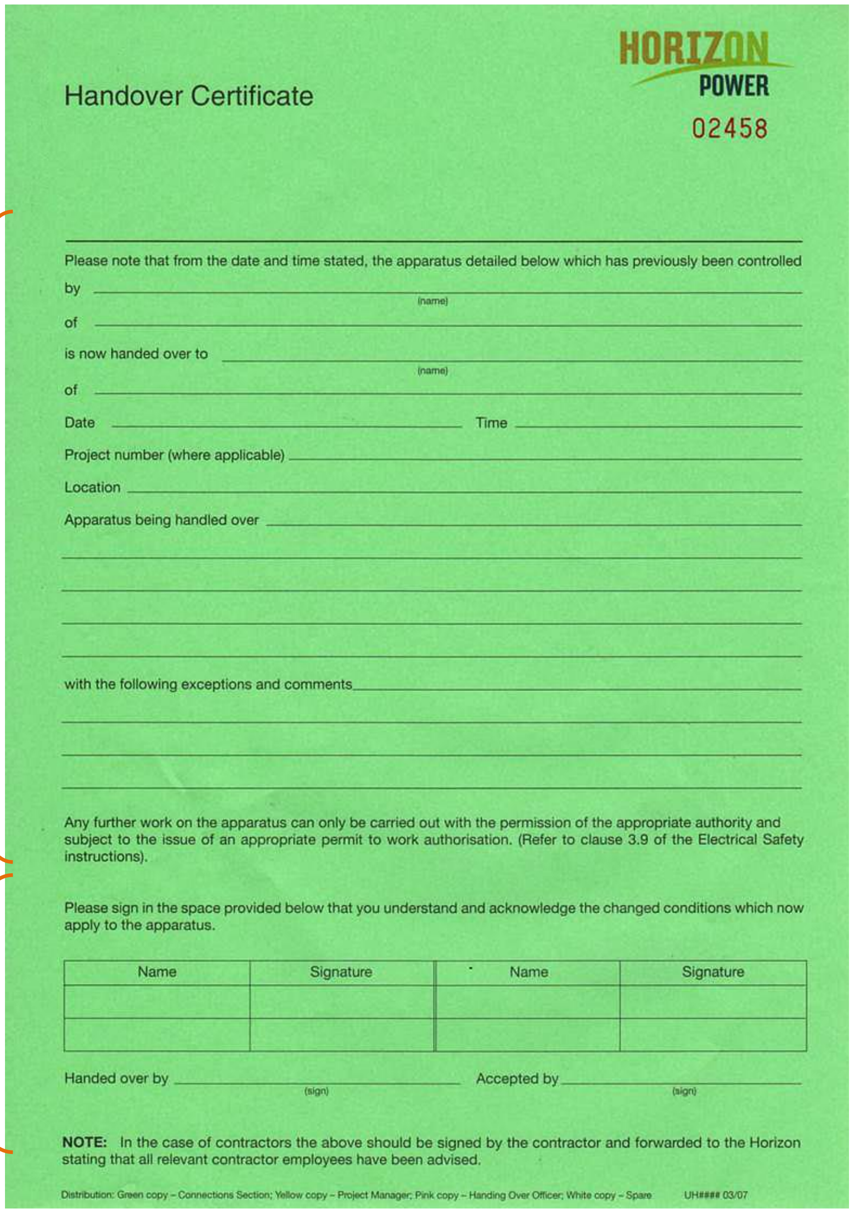
Control Room Notified (if applicable): ☐ YES ☐ NO

Figure 8-16 Operating Agreement

Handover Certificate

Handover Certificates are used where the responsibility for electrical apparatus is transferred from one authority to another. An example of this is where network apparatus is constructed and then transferred from the construction authority to the Operating Authority, who subsequently energises and is responsible for the apparatus operation. Any future access to this apparatus will require a work permit provided by the Operating Authority.

It is a requirement all persons working in the construction phase sign the Handover Certificate to acknowledge they will treat the apparatus as energised and will need a work permit for future access to the apparatus.



Handover Certificate

HORIZON POWER

02458

Please note that from the date and time stated, the apparatus detailed below which has previously been controlled

by ______________________ (name)

of ______________________

is now handed over to ______________________ (name)

of ______________________

Date ______________ Time ______________

Project number (where applicable) ______________________

Location ______________________

Apparatus being handled over ______________________

with the following exceptions and comments ______________________

Any further work on the apparatus can only be carried out with the permission of the appropriate authority and subject to the issue of an appropriate permit to work authorisation. (Refer to clause 3.9 of the Electrical Safety instructions).

Please sign in the space provided below that you understand and acknowledge the changed conditions which now apply to the apparatus.

Name	Signature	Name	Signature

Handed over by ______________ (sign) Accepted by ______________ (sign)

NOTE: In the case of contractors the above should be signed by the contractor and forwarded to the Horizon stating that all relevant contractor employees have been advised.

Distribution: Green copy – Connections Section; Yellow copy – Project Manager; Pink copy – Handing Over Officer; White copy – Spare UH#### 03/07

Details of apparatus and conditions

Acknowledgement by parties of apparatus and conditions

Figure 8-17 Handover Certificate

8.12 Tagging, Locks and Barriers

Control and warning tags, locks and barriers are methods used to warn against and prevent the operation of electrical switching devices.

Note: The formal term used by Horizon Power is *tag*, however the term *label* is interchangeable and often used.

The following tags are used by Horizon Power:

- Danger–Do Not Operate
- Caution–Vicinity Work in Progress
- Danger–Restricted Use
- Warning–Out of Service.

Danger–Do Not Operate

The Danger–Do Not Operate tag is an approved tag attached to electrical apparatus as an instruction against the operation of that electrical apparatus. It is used to protect all parties from inadvertent operation of the apparatus at the isolation points.

Danger–Do Not Operate tags shall only be used in conjunction with switching programs and electrical apparatus access requirements.

Each Danger–Do Not Operate tag shall be securely attached in a prominent position to the electrical apparatus being used as a point of isolation. The electrical apparatus to be worked on must not have a Danger–Do Not Operate tag attached.

Figure 8-18 Danger–Do Not Operate tag

Caution–Vicinity Work in Progress

The Caution–Vicinity Work in Progress tag is used with the VA and its associated switching program. It is attached to apparatus listed on the VA, for example, auto-reclose devices, circuit breakers.

The Caution–Vicinity Work in Progress tag is attached by an appropriately authorised person to the point of control for that protection equipment. Electrical apparatus with a Caution–Vicinity Work in Progress tag attached shall not be operated, altered, or removed by any person other than the switching operator or, for remote operation, the RIC who attached the tag. Where that switching operator or RIC is unavailable, another authorised switching operator or RIC can operate, alter, or remove that tag in accordance with Horizon Power's switching operation procedures.

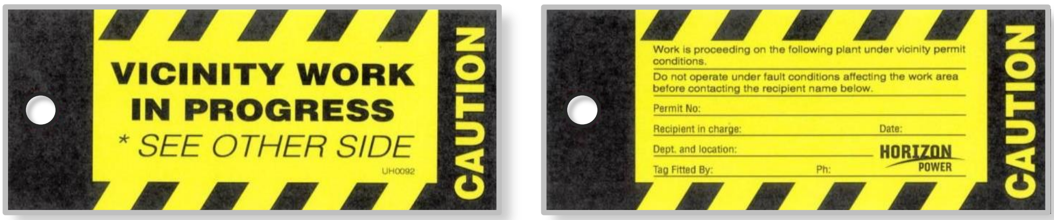


Figure 8-19 Caution–Vicinity Work in Progress warning tag

Danger–Restricted Use

The Danger–Restricted Use tag can be used with the STT permit. It is attached by the switching operator to the apparatus in a prominent position and listed on the STT permit. This apparatus may be operated in a restricted capacity by the RIC or TIC under the work permit.

The Danger–Restricted Use tag shall only be permanently removed by an authorised switching operator. The Danger–Restricted Use tag can be temporary removed by the RIC/TIC when operating the apparatus and then immediately replaced.

Specific information shown on the Danger–Restricted Use tag is:

- the item of plant to which the tag is attached
- the PoA work permit or switching program number
- the switching operator and their authorisation number
- the date the STT has been issued
- the telephone number of the person who attached the tag.

Figure 8-20 Danger–Restricted Use tag

Warning–Out of Service

Where a Warning–Out of Service tag and Danger–Do Not Operate tag is attached to the same electrical apparatus, the Warning–Out of Service tag shall be removed before the Danger–Do Not Operate tag is removed. The Warning–Out of Service tag shall not be removed until that apparatus is ready for service.

Figure 8-21 Warning–Out of Service tag

The only exception to this is under emergency switching conditions where the appropriate authority permits the Danger–Do Not Operate tag to be removed while the Warning–Out of Service tag is still attached.

Each Warning–Out of Service tag shall be securely attached in a prominent position to the electrical apparatus.

Specific information shown on the Warning–Out of Service tag is:

- the electrical apparatus covered by the tag
- the reason for attaching the tag
- a reference number, e.g. the apparatus ID number or serial number
- the name of person attaching the tag, and

- the date tag is fitted and the telephone number of the person attaching the tag.

Further details on tags is available in Field Instruction *Network Tags*.

8.12.2 Locks

Horizon Power uses a Lock Out Tag Out (LOTO) procedure which includes tagging when isolating HV electrical apparatus. The lock out process includes dedicated isolation locks incorporated with control and individual personal locks to create a safe and secure working environment.

Isolation lock	Control lock	Personal lock
Used by the switching operator to isolate apparatus	Used by the switching operator as a control lock on the lockout station	Fitted to the lockout station by individual Recipients as their personal lock

Figure 8-22 Isolation locks used to isolate apparatus

When isolating a part of the electrical network all network security locks are replaced with isolation locks and the isolation lock keys are placed in a lockout station. The lockout station is locked with a control lock and all members of the work party fit their personal lock to the lockout station.

8.13 Common Switching Operations

Switching programs have many single step tasks which may require the switching operator to complete several actions for each step. Examples of these single step tasks are ‘check off and rack out’, ‘phase out’ and ‘prove de-energised and apply earths’.

When the switching operator undertakes a single step task it is important the actions are performed in a systematic and sequential manner to correctly achieve the required outcome. The following sections elaborate on the actions and sequence required to complete some of the common single step tasks.

8.13.1 Proving De-energised

Proving de-energised requires the following activities:

1. Prove the test instrument is working.

2. Test instrument is used to prove each phase of the circuit under test is de-energised.

3. Prove the test instrument is working.

This ensures the test is valid and must be performed at each location where earths are to be applied.

8.13.2 Applying Earths

Portable Earths

Each set of earths to be applied requires the following activities.

1. Inspect the portable earth leads and connections to ensure they are in good working order and appropriately rated.

2. Layout the portable earths on the ground at the location where the earths are to be applied.

3. Connect the main earth to the appropriate earthing point:

    a. inside substations use the earth studs on the structures which are connected the main earth grid

    b. outside substations a spike is driven in the ground a minimum of 600mm in the pole alignment, usually one pole from the work site.

4. Prove de-energised at the location the earths are to be applied.

5. Remain clear of the earth leads and apply to each phase earth with a positive action. Ensure the phase connections are firmly made and the clamps are tight.

Earth Switches

Each earth switch to be applied requires the following activities.

1. Prove de-energised at the location the earths are to be applied using a Modiewark for outdoor switchgear or the voltage indicators provided on indoor switchgear and ring main units. In many cases the voltage indicators are non-removable and therefore they must be checked working prior to de-energisation.

2. Confirm the earth switch is in the ON state, lock and apply danger tag.

8.13.3 Phasing Out

The procedure for LV and HV phasing out has been described in Section 10.

8.13.4 Rack Out and Rack In

Racking out and racking in of indoor switchgear requires a full understanding of the operation of the interlocks. The typical range of interlocks and their features is provided in Section 6.5 – *Indoor Switchgear Safety Features – Switchgear Interlocks*.

8.14 Switchgear Pre- and Post-switching Checks

When approaching switchgear the switching operator should always perform the look, listen and smell checks. Pre-switching checks are performed before switching operation is undertaken and post-switching checks are performed after the switching operation is completed.

8.14.1 Pre-switching Checks

The look, listen and smell checks which can be performed before a switching operation is undertaken are given below.

LOOK

The switching operator should look and visually check the mechanical and electrical condition of the switchgear which is to be operated. This is to confirm as far as practically possible that the switchgear is fit for switching and is in the expected electrical state. The actual switchgear type will determine which of the visual checks listed in Table 8-5 can actually be performed.

Checks	Description	Example of possible problems
Earthing system	Check earthing conductors and connections are present and in good order. Particular emphasis on the operating handle and earth mat connections.	Missing or damaged sections of earthing conductor. (Copper earthing conductor theft has occurred in the past.) Corroded earthing braids on operating handles.
Operating mechanism	Check the operating linkages appear in good order.	Faulty or bent linkages.
Insulators	Check the insulators appear in good order.	Broken or cracked insulators.
Contacts	Primary contacts appear to be in good order and not burnt. Contacts are in the correct open or closed position. Conducting braids are in good order.	Burnt or welded in contacts.
Status indicators – mechanical and electrical	Check ON and OFF mechanical and electrical indicators confirm the expected electrical state.	Outdoor circuit breaker electrical indicator driven from the mech box auxiliary switches may show OFF whilst mechanical indicator shows ON due to a broken drive shaft.
Instrumentation	Voltmeter and ammeter instruments show expected electrical state concur with the status indicators.	Voltmeter and ammeter indications do not agree with status.
Insulation medium condition	SF_6 gas pressure checks. Oil level checks.	Switchgear leaking insulation material depending on the amount may prevent the switchgear being operated.

Table 8-5 Pre-switching visual checks

LISTEN

The switching operator should listen for the abnormal sound of arcing. It should be noted that dependent on the humidity and level of insulator pollution, outdoor transmission HV switchyards can have a low sound level which is not considered abnormal.

SMELL

The switching operator should be aware if the smell of insulation burning or the pungent smell of ozone is detected, it is an indication of abnormal electrical arcing or tracking. Consideration must be given to de-energising the switchgear, pending further investigation.

8.14.2 Post-switching Checks

After performing the required switching operation the switching operator should undertake a subset of the look, listen and smell checks as described in the pre-switching checks. In Table 8-5 the operating mechanism, insulators, contacts, status indicators and instrumentation checks are applicable. Listening for arcing after switching is also appropriate, however the smell check may not be effective because it can take time for the smell to accumulate.

8.15 Switching-related hazards

Switching is a task that has various potential hazards that switching operators should be aware of and consider. The correct application of PPE and switching procedures assist in reducing the risk to the switching operator of the hazard.

8.15.1 Electric Shock

Due to the proximity of live exposed apparatus the switching operator must always be aware of the risk of electric shock and ensure that safe approach distances are maintained. Details of safe approach distances is given in Field Instruction *Safe Approach Distances.*

8.15.2 Switchgear Explosion

Due to the possible, albeit unlikely risk of an unexpected switchgear explosion, it is normal practice to operate switchgear from a remote location where ever possible. Furthermore, as remote operation is usually from HPCC, the switching operator must not be in the immediate vicinity of the switchgear when operated by HPCC.

8.15.3 Touch Potential

When switchgear fails resulting in fault current flowing into the ground via the earthing system, this will create a risk of touch potential to the switching operator. This fault current and related touch potential risk will be removed when the associated protective device operates.

Touch potential is the voltage difference between the switching device earthing and the surrounding earth (ground). This voltage is graded and decreases as the distance from the switch increases as shown below.

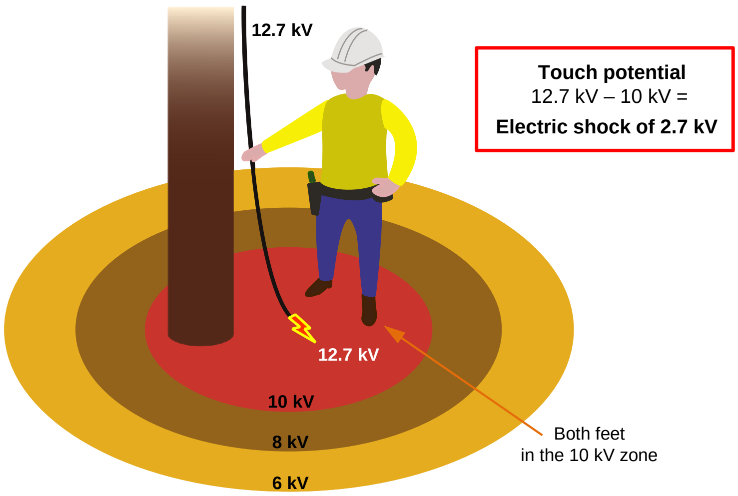


Figure 8-23 Touch potential

To mitigate the risk of touch potential the switching operator must wear switching gloves and insulated footwear. Where the installed earth mat may not be effective (such as a pole top switch) an equipotential mat is placed at the foot of a switch and connected to the earthing conductor of the switch. This places the operator's hands and feet at the same potential.

8.15.4 Step Potential

When switchgear fails resulting in fault current flowing into the ground via the earthing system this will create a risk of step potential to the switching operator. This fault current and related step potential risk will be removed when the associated protective device operates.

Step potential is an electric shock hazard that occurs when a person's feet are exposed to voltage differential created by the fault current flowing in the ground.

To mitigate the risk of step potential the switching operator must wear insulated footwear. Where the installed earth mat may not be effective (such as a pole top switch) an equipotential mat is placed at the foot of a switch and connected to the earthing conductor of the switch. Provided the switching operator remains with both feet on the equipotential mat during the switching operation the risk of step potential is removed as both feet will be at the same potential.

For this reason the switching operator must inspect the switch prior to approaching the site for loose or broken switch connection, conductors or insulators.

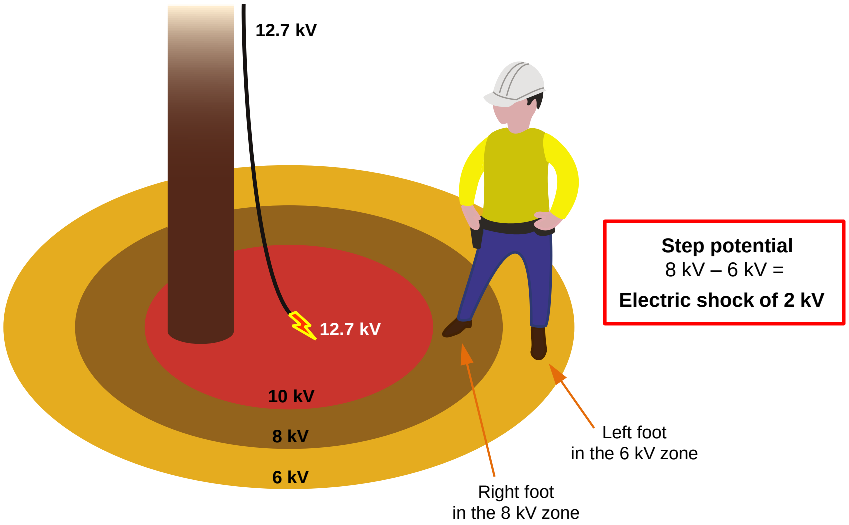


Figure 8-24 Step potential

8.15.5 Toxic Fumes from Fire or Explosion

In the event of a fire or explosion involving electrical apparatus and insulating materials, the switching operator must be aware that toxic gases may result from burning materials. It is essential for the operator to fully ventilate enclosed spaces before entering the area.

Substances that may emit toxic fumes when heated or burning are:

- plastic insulated cable
- PILCSWA cable
- insulating oil
- SF_6 gas.

8.15.6 Arc Flash and Arc Blast

One of the most dangerous consequences of a switching incident is an arc flash and the accompanying arc blast. A description of arc flash and arc blast and the possible impact to the switching operator is provided below.

Arc Flash

An arc flash is the heat and light energy released when an arc occurs and current flows through a normally nonconductive medium such as air. An arc flash can happen in less than one millisecond (1/1000 of a second).

Causes of arc flash can include inadvertent bridging of energised electrical contacts, breaking current on contacts not designed to interrupt current, dropped tools, corrosion of materials or a failure of insulation.

The flash produced because of this breakdown is similar to the light radiation emitted by a commercial electrical arc welder. The heat that is released from an arc flash can be in excess of 20,000°C. Such temperatures will vaporise any known material on earth. Obviously, any unprotected flesh or eyes of a switching operator may be severely burned if exposed to an arc flash.

Arc Blast

The arc flash produces an arc blast which is an explosion where the massive amount of energy rapidly vaporises metal conductors, blasting molten metal and superheated material (plasma) outward with extreme force.

This violent event can cause the destruction of switchgear and nearby equipment. The high velocities of molten metal particles can cause severe and possibly fatal burns, or blindness, internal organ damage or death through inhalation of the superheated air or fumes.

Figure 8-25 below shows an arc flash on an indoor switchboard.

Figure 8-25 Indoor switchboard arc flash and arc blast

The switching operator must always wear the PPE appropriate to the switching task as detailed in Field Instruction *Worksite Clothing / Personal Protective Equipment Requirements.*

8.15.7 Switchroom Egress

Before switching begins in switchroom buildings and other confined spaces, the switching operator must ensure all available exits are functioning and unobstructed to allow rapid egress if required.

All persons not required to be present during switching operations should vacate the switchroom building.

8.15.8 Portable Equipotential Mat

Due to the risk of damaged earthing which will not be discovered by visual inspection the switching operator is to fit an equipotential mat when switching pole top switches. Together with appropriate PPE this will minimise the risk of touch and step potential. Full details of the requirements and procedures for the use of equipotential mats are provided in Field Instruction *Use of Portable Equipotential Mat for Switching.*

8.15.9 Switching Tools and Test Equipment

The switching operator must ensure switching tools and test equipment are appropriately rated for the task intended to be performed.

Before use by the switching operator, all switching tools and test equipment must be checked to ensure they are in good working order and up-to-date if a routine test date is applicable. Where provided, built-in or self-test accessories are to be used by the switching operator to prove the test equipment is functional.

For example, the HV insulated operating stick (also known as ‘hot sticks’ or HV live line sticks) may be used for HV and LV switching. Six monthly HV insulation tests are required and the sticks marked to show the expiry date. Where the date has expired, re-testing must be completed before the sticks can be used for HV switching.

Refer to Field Instruction *Testing and Use of High Voltage Insulated Equipment* for further information.

8.15.10 Switchgear Operation Competence

Switchgear operation can involve many individual sequenced steps which are specific to the switchgear make and type. Therefore, a switching operator must only operate switchgear they have previously operated and are competent in its operation.

The *Switchgear Instruction Manual* provides visual images of switchgear operation and it is intended to be used as a reminder for switching operators that may not have operated that type of switchgear for some time.

Where a switching operator has not previously operated switchgear of a particular make and type or do not feel competent in its operation, they must be instructed by an experienced switching operator competent in the switchgear operation.

An opportunity to become familiar with particular switchgear operation (including newly introduced switchgear) also exists during the construction stage before the switchgear is connected to the network and the reading of switchgear manuals.

SECTION NINE

Distribution Switching Programs

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9. Distribution Switching Programs

9.1 Introduction

The switching program is one of the most important parts of safe and successful switching on the Horizon Power network. It is a list of switching operations that are placed in a logical sequence to ensure the operation of electrical apparatus is carried out safely, and includes:

- remote switching by the HPCC controller
- field switching by the switching operator, and
- issue and cancellation of work permits.

The switching program is a means of communication between switching operators and HPCC. It states what is to be done and the exact sequence of operations, thus reducing possibilities for error.

Switching programs are required whenever switching operators perform switching operations on the network. This switching is most frequently carried out to provide access to network apparatus for the issue of a work permit, however there are also occasions where a switching program does not involve a work permit.

9.2 Roles and Responsibilities

A planned switching program is prepared and approved through a sequence that includes a program writer, a program checker and a final network compatibility check by the HPCC controller prior to commencement of the program.

When unplanned switching is required due to fault or overload conditions the switching program is prepared by the HPCC controller in collaboration with the on-site switching operator. These programs will be prepared by the HPCC controller and checked by the switching operator.

9.2.1 Program Writer

The program writer is the person who initiates and prepares the switching program. This person must be authorised and hold the appropriate switching operator's authority for the task involved.

The program writer must have a clear understanding of what is required when they prepare a program. They must be aware of the scope of work to be undertaken and the switching operations required to safely allow the work to be completed.

As switching programs are most frequently written to provide access to network apparatus for the issue of a work permit, the program writer must ensure the switching program contains the necessary switching operations to place network apparatus in the appropriate electrical state for the required work permit.

9.2.2 Program Checker

The program checker is the person who reviews the switching program for errors and to verify that it is fit for purpose. They must be authorised and hold the appropriate switching operator's authority for the task involved.

The program checker must have a clear understanding of what is required when they check a program. They must be aware of the scope of work to be undertaken and the switching operations required to safely allow the work to be completed.

9.2.3 HPCC Controller

The HPCC controller is the final authority to review a switching program. They must be authorised at the appropriate switching authorisation level.

Prior to execution of a switching program the HPCC controller is responsible for conducting a final check to verify network compatibility and for conflicts with other switching programs.

In the event of unplanned network conditions (e.g. a fault or overload), the HPCC controller will prepare a program in collaboration with the on-site switching operator. In these situations the HPCC controller will be the program writer and the program checker will be the on-site switching operator.

9.3 Program Writing Tools and Software

Switching programs are prepared using the PowerOn Advantage (PoA) Network Management System (NMS).

9.3.1 PowerOn Advantage

PowerOn Advantage (PoA) is a computer-based SCADA system that allows for switching programs to be electronically compiled in list form. PoA clients are used in HPCC and in the regional depots for the preparation of switching programs.

Switching programs are normally executed using PowerOn Advantage mobile which allows the switching operator to accept and confirm switching operations using a mobile tablet. Where mobile tablet technology is available, it is used by both the HPCC controller and the switching operator to execute and communicate the instruction and completion of each step in the switching program.

If mobile tablet program delivery is unavailable, a paper copy of the program is used in the field by the switching operator. (See section 9.8 for more information in this regard).

Some of the many functions contained in PoA are:

- remote control and operation of telemetered devices from HPCC
- recording of switching programs with work permits displayed on the network diagram
- maintaining Horizon Power's network model in real time, and
- remote network monitoring with associated alarm processing.

The PoA system includes Geo Viewer (a geocentric distribution database) and Trouble Call System (TCS) which models the network diagram with real time accurate information as switching and network outages occur.

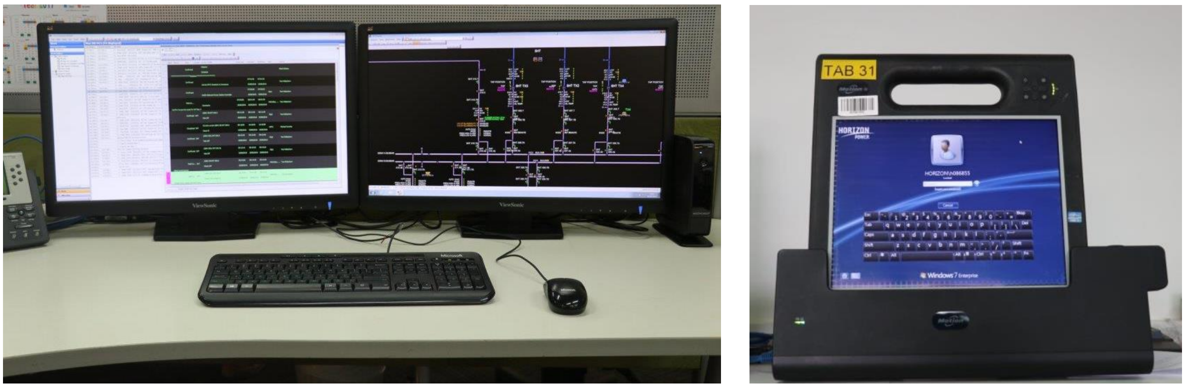

Figure 9-1 PoA virtual client and mobile tablet

9.4 Switching Program Overview

9.4.1 Purpose

The primary concerns when writing a switching program are:

- safety of the switching operator, staff and contractors
- safety of the general public
- welfare of Horizon Power apparatus, public and private property, and
- where possible, to maintain supply to customers.

9.4.2 Requirement for a Switching Program

Switching programs are required whenever switching operators perform switching operations on the network. This switching is most frequently carried out to provide access to network apparatus for the issue of a work permit, however there are also occasions where switching does not involve a work permit.

Notification Period for a Switching Program

To ensure there is sufficient time for HPCC to perform compatibility checks on programs, switching programs are required to be sent to HPCC 3 days in advance of the planned work start date.

Network changes that require the creation of a “patch” in PowerOn will need to be sent to HPCC 10 days in advance of the planned work start date.

Type of work permit or document	Recommended notification period (days)
Planned work	3
System Change	10

Table 9-1 Recommended switching program notification period.

Work Permit Switching

Switching programs are required to establish network apparatus in an appropriate electrical state for the issue of work permits. The switching program will also include steps for the issue and cancellation of the work permit. Details of the switching program requirements for the three work permits which Horizon Power use are described below.

Electrical Access Permit

Direct access to network apparatus for construction, maintenance and repair work requires an Electrical Access Permit (EAP). The switching program must create a safe work area by establishing isolation points and applying program earths on each possible source of supply into the work area.

Sanction to Test

Testing and commissioning access to network apparatus requires a Sanction To Test (STT) work permit. For this permit, the switching program provides the network apparatus in the state requested by the Tester in Charge.

For example, when VLF insulation testing is required, the switching program will provide the apparatus with established and unchangeable isolation points, however the earths which were initially applied for access to the cable connections, may be operated as required by the test procedure.

Vicinity Authority

A Vicinity Authority (VA) authorises work near live network apparatus whilst remaining outside the safe approach distance for the voltage concerned. The switching program will include steps to disable any installed auto-reclose on the protection apparatus on the supply side of the work area.

Non-work permit switching

Switching programs are also required for switching which does not involve the issue of a work permit. An example of this is where distribution feeders require load balancing by a permanent change in the location of a network normally open point.

9.4.3 Switching Program Structure

A switching program has a defined structure and usually consists of an isolation and restoration stage, each of which have many steps. These individual steps can be broadly classified into three groups, namely communication, switching and work permit steps.

Communication Steps

Communication steps occur between the HPCC controller and the switching operator at the commencement and completion of both the isolation and restoration stages. Work permit issue and cancellation is also communicated as part of isolation and restoration stages.

Switching Steps

HPCC controller switching steps are required to operate remotely-controlled primary apparatus remotely controlled secondary protection and equipment control systems.

Switching operator switching steps are required to operate non-telemetered and manually operated primary apparatus and the application and removal of portable earths. The switching operator steps will also include the fitting of barriers and tags such as Danger–Do Not Operate tags on isolation points.

Depending on the nature of the work, testing and commissioning steps may also be included in the program.Work Permit Steps

Switching operator steps are also included for work permit issue and cancellation.

An outline of the typical distribution switching program steps for the creation of a safe work area and issue of an EAP is provided in the left hand column in Table 9-2 the other columns indicate the program step type.

Switching program contents	Step type		
	Comms	Switching	Permit
Isolation			
Switching operator – Contact HPCC and request permission to proceed	✓		
HPCC and switching operator switching to: • HPCC set conditions as required (e.g. disable auto-reclose, SEF) • interconnection/back feed as required to maintain supply (e.g. closing open points) • establish de-energised area Switching operator – establish isolated area Switching operator – establish safe work area by proving de-energised and applying program earths		✓ ✓ ✓ ✓ ✓	
Switching operator – Advise HPCC isolation complete and issue of work permit (EAP).	✓		✓
Restoration			

Switching operator – advise HPCC of work complete and cancellation of work permit (EAP).	✓		✓
Switching operator – removes program earths Switching operator – restores isolations HPCC and switching operator switching to: • re-energise area • remove interconnection / back feed established in the isolation HPCC restore conditions as required (e.g. enable auto-reclose, SEF)		✓ ✓ ✓ ✓ ✓	
HPCC and switching operator confirm program complete	✓		

Table 9-2 Typical EAP switching program outline

9.5 PoA Switching Programs

PoA provides the program writer with facilities to write and safety check switching programs. Switching programs are written as switching schedules in PoA which then allows the PoA inbuilt safety logic to provide a basic safety check of the switching program.

To write a switching program in PoA the program writer populates the fields in the switching program by selecting on-screen apparatus and selecting the appropriate operation options from drop down menus.

Writing a PoA switching program requires the completion of the header page and the switching steps to provide:

- interconnection of HV and LV (where necessary)
- isolating the required work area
- proving de-energised and earthing
- issuing the permit, and
- restoration steps.

A PowerOn Advantage *Introduction Program Writer Training Manual* is included in the Appendices.

9.5.1 Switching Program Header

The header provides a summary of the purpose of the switching program and allows the HPCC controller a quick reference when conducting compatibility checks between programs and during fault activity.

The program header *Job Name/Description* should be completed by the switching operator in the concise format below (see Figure 9-3):

VERSION — DD/MM/YYYY – CIRCUIT – JOB DESCRIPTION – SWITCHING OPERATOR

Switching programs are stored as individually numbered jobs in the Work Package Manager module in PoA.

Information such as supply interruptions and customer notifications are populated in the appropriate fields relevant to the required work task.

Further information is included in the header to provide clear reference to who created, checked and approved the program.

Request No.37015
Job No.J17-3836-v
Job Status Running
View detailed version (not suitable for printed programs)

Job Name/Purpose of Work	V1 - 24/05/2017 - EHR 304 - POLE REPLACEMENT - COREY BENNIER				
Start Date/Time	24-May-2017 09:00	**Created by**	Corey Bennier	**Date/Time**	24-May-2017 10:36
End Date/Time	24-May-2017 17:00	**Checked by**	Carl Weinert	**Date/Time**	24-May-2017 10:41
Plan Duration (hrs)	8	**Approved by**	Brett Taylor	**Date/Time**	24-May-2017 11:24
Requested By					

Switch Operator IC	BENNIER,COREY-0419812050(1to6)	**Telephone No.**	0419812050	**Radio No.**	
Switch Operator		**Telephone No.**			

Operation District/Zone	Esperance	**Desk Contact No.**	9159 7244
Comments/Notes			

Substation/Feeders/Reclosers	
EHR 304.0 , EHR 307.0 ,	
Supply Interruption	No
Involves Permanent System Change	No
Customer Notification	No

Limits of Isolation
GLADSTONE ST,4 N CNR WINDICH ST,CHADWICK, 11kV DOF ESP0112 (DOF)
NORSEMAN RD,3 NE CNR GLADSTONE ST,CHADWICK, 11kV PTSD 2022
DEMPSTER ST SOUTH SIDE,CNR GLADSTONE ST,ESPERANC, 11kV DOF ESP0011 (DOF)
BRAZIER ST,7 E CNR RANDELL ST,CHADWICK, 11kV PTSD 2085

Limits of Work Area
DEMPSTER ST SOUTH SIDE,CNR GLADSTONE ST,ESPERANC, 11kV DOF ESP0011 (DOF)
Work Site, 11kV Junction 2421578
Work Site, 11kV Junction 2812660

Figure 9-2 PoA Switching Program Header

9.5.2 Switching Program Steps

In this area of the switching program the program writer must include the steps for communication, HPCC and switching operator switching, and permit management.

Program writers should attempt to keep the size of the isolated area to a minimum. However, there may be instances where the isolated area will need to be expanded to accommodate larger clearances, e.g. for cranes and other work site vehicles.

Furthermore when writing the switching program steps, consideration needs to be given to maintaining supply by interconnection (back feeds) of circuits when necessary before creating the isolated area.

Figure 9-3 shows the fields in a PoA switching program for the switching steps and their purpose. These fields are required to uniquely identify who, where and what needs to be done.

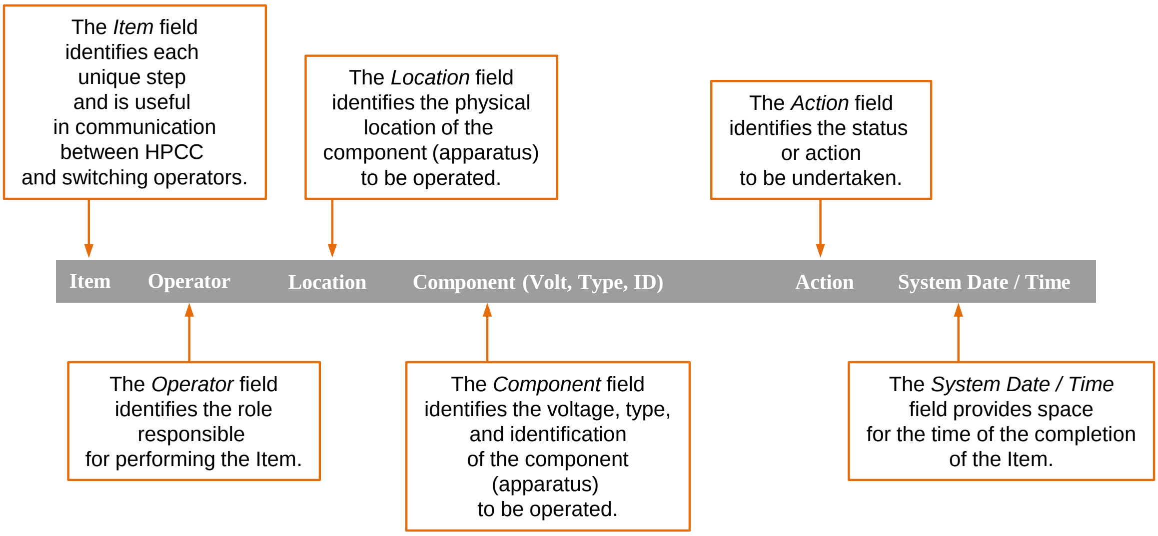

Figure 9-3 The fields in the PoA switching program

PoA Switching Program Example

A typical PoA switching program is shown below and the series of figures which follow illustrate the network diagram at particular stages of running the switching program.

Note: The formal term used by Horizon Power is *tag*, however the term *label* is interchangeable and often used.

Item	Operator	Location	Component (Volt, Type, ID)	Action	System Date / Time
1				Schedule	
2	BENNIER,COREY-0419812050(1to6)			Contact HPDC,Req Perm to Commence	
3	BENNIER,COREY-0419812050(1to6)	GLADSTONE ST,4 N CNR WINDICH ST,CHADWICK	11kV TX ESP0112 LV	Apply Backfeed/Interconnect LV	
4	BENNIER,COREY-0419812050(1to6)	GLADSTONE ST,4 N CNR WINDICH ST,CHADWICK	11kV TX ESP0112 LV	LV DISO OFF, Fit Barriers & DL	
5	BENNIER,COREY-0419812050(1to6)	NORSEMAN RD,L223, A/4 DEMPSTER ST,ESPERANCE	11kV TX ESP0011 LV	Apply Backfeed/Interconnect LV	
6	BENNIER,COREY-0419812050(1to6)	NORSEMAN RD,L223, A/4 DEMPSTER ST,ESPERANCE	11kV TX ESP0011 LV	LV DISO OFF, Fit Barriers & DL	
7	HPDC	EHR	Circuit 307 A/R	Tele Set Disable	
8	HPDC	EHR	Circuit 304 A/R	Tele Set Disable	
9	BENNIER,COREY-0419812050(1to6)	DEMPSTER ST SOUTH SIDE,CNR GLADSTONE ST,ESPERANC	11kV DOF ESP0011 (DOF)	Off & Attach DL	
10	BENNIER,COREY-0419812050(1to6)	GLADSTONE ST,4 N CNR WINDICH ST,CHADWICK	11kV DOF ESP0112 (DOF)	Off & Attach DL	
11	BENNIER,COREY-0419812050(1to6)	NORSEMAN RD,5S IRENE ST,CASTLETOWN	11kV PTSD 2019	On	
12	BENNIER,COREY-0419812050(1to6)	NORSEMAN RD,3 NE CNR GLADSTONE ST,CHADWICK	11kV PTSD 2022	Off & Attach DL	
13	BENNIER,COREY-0419812050(1to6)	BRAZIER ST,7 E CNR RANDELL ST,CHADWICK	11kV PTSD 2085	Off & Attach DL	
14	BENNIER,COREY-0419812050(1to6)	Work Site	11kV Junction 2812660	Prove De-energise, Attach Earth	
15	BENNIER,COREY-0419812050(1to6)	Work Site	11kV Junction 2421578	Prove De-energise, Attach Earth	
16	BENNIER,COREY-0419812050(1to6)		Permit Issue Details	Comments	
17	BENNIER,COREY-0419812050(1to6)		EAP-5691-v on/at O/H Main between Work Site, 11kV Junction 2421578 and Work Site, 11kV Junction 2812660	Issue EAP	
18	HPDC	EHR	Circuit 307 A/R	Tele Set Enable	
19	HPDC	EHR	Circuit 304 A/R	Tele Set Enable	
20	BENNIER,COREY-0419812050(1to6)			Advise HPDC Isolation Complete	
21	BENNIER,COREY-0419812050(1to6)			Advise HPDC Restoration to Start	

Item	Operator	Location	Component (Volt, Type, ID)	Action	System Date / Time
22	BENNIER,COREY-0419812050(1to6)			Check Staff & Equipment Clear	
23	BENNIER,COREY-0419812050(1to6)			Cancel EA No#	
24	BENNIER,COREY-0419812050(1to6)	Work Site	11kV Junction 2421578	Remove Earth	
25	BENNIER,COREY-0419812050(1to6)	Work Site	11kV Junction 2812660	Remove Earth	
26		EHR	Circuit 304 A/R	Tele Set Disable	
27		EHR	Circuit 307 A/R	Tele Set Disable	
28	BENNIER,COREY-0419812050(1to6)	BRAZIER ST,7 E CNR RANDELL ST,CHADWICK	11kV PTSD 2085	Remove DL & On	
29	BENNIER,COREY-0419812050(1to6)	NORSEMAN RD,3 NE CNR GLADSTONE ST,CHADWICK	11kV PTSD 2022	Remove DL & On	
30	BENNIER,COREY-0419812050(1to6)	NORSEMAN RD,5S IRENE ST,CASTLETOWN	11kV PTSD 2019	Off	
31	BENNIER,COREY-0419812050(1to6)	DEMPSTER ST SOUTH SIDE,CNR GLADSTONE ST,ESPERANC	11kV DOF ESP0011 (DOF)	Remove DL & On	
32	BENNIER,COREY-0419812050(1to6)	GLADSTONE ST,4 N CNR WINDICH ST,CHADWICK	11kV DOF ESP0112 (DOF)	Remove DL & On	
33		EHR	Circuit 304 A/R	Tele Set Enable	
34		EHR	Circuit 307 A/R	Tele Set Enable	
35	BENNIER,COREY-0419812050(1to6)	GLADSTONE ST,4 N CNR WINDICH ST,CHADWICK	11kV TX ESP0112 LV	LV DISO ON, Remove Barriers & DL	
36		GLADSTONE ST,4 N CNR WINDICH ST,CHADWICK	11kV TX ESP0112 LV	Remove Backfeed	
37	BENNIER,COREY-0419812050(1to6)	NORSEMAN RD,L223, A/4 DEMPSTER ST,ESPERANCE	11kV TX ESP0011 LV	LV DISO ON, Remove Barriers & DL	
38	BENNIER,COREY-0419812050(1to6)	NORSEMAN RD,L223, A/4 DEMPSTER ST,ESPERANCE	11kV TX ESP0011 LV	Remove Backfeed	
39	BENNIER,COREY-0419812050(1to6)			Advise HPDC Restoration Complete	

Figure 9-4 Sample of a PoA switching program

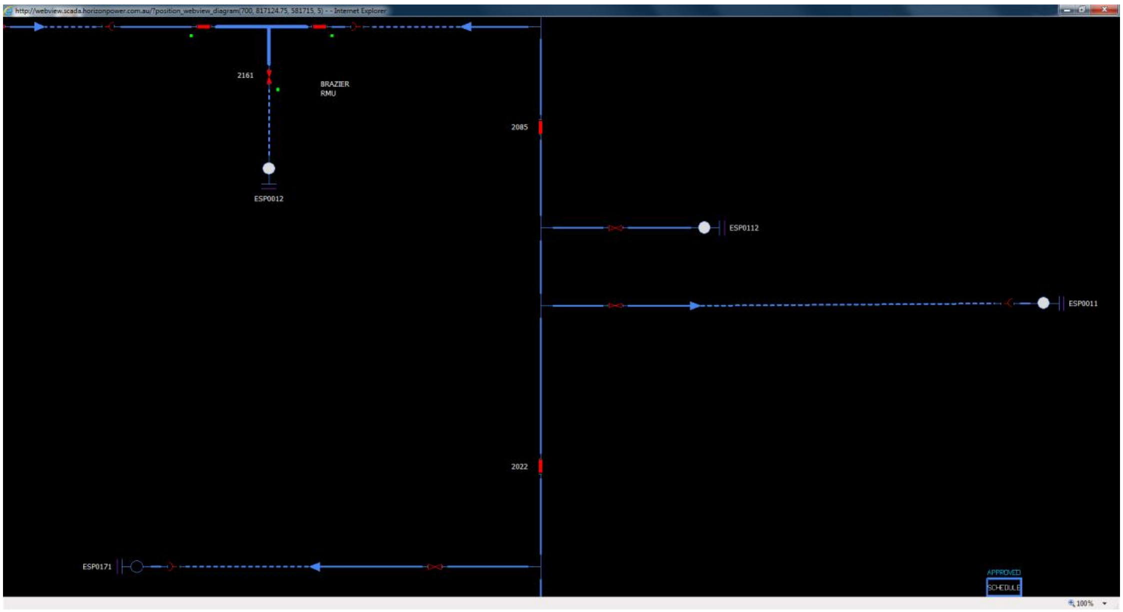

Figure 9-5 Network diagram before commencing the switching program

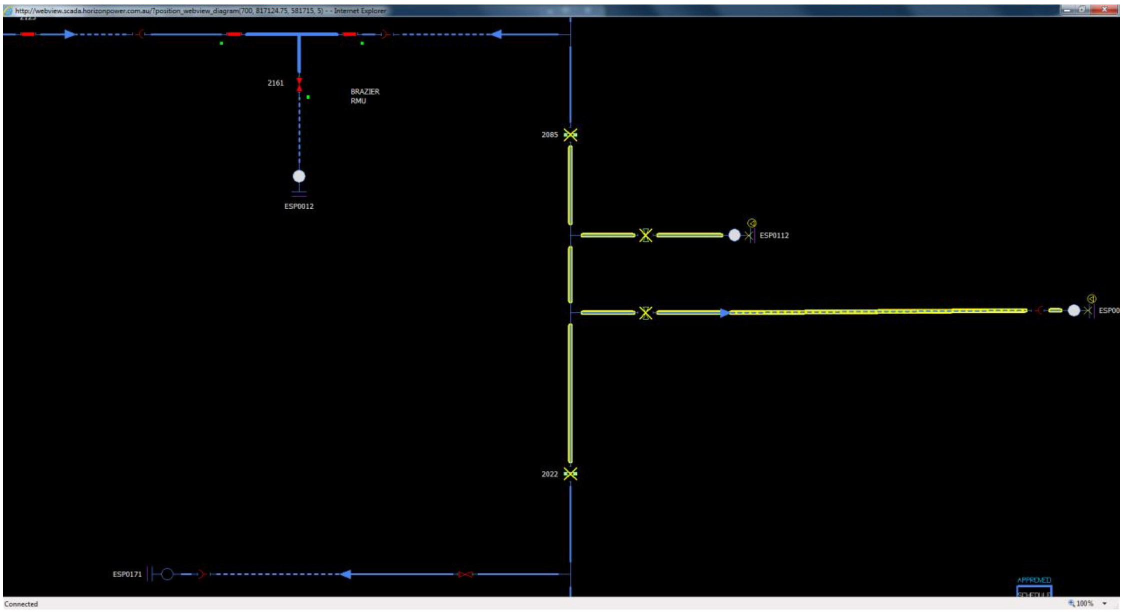

Figure 9-6 Network diagram showing worksite isolated
Program completed up to and including item 13.

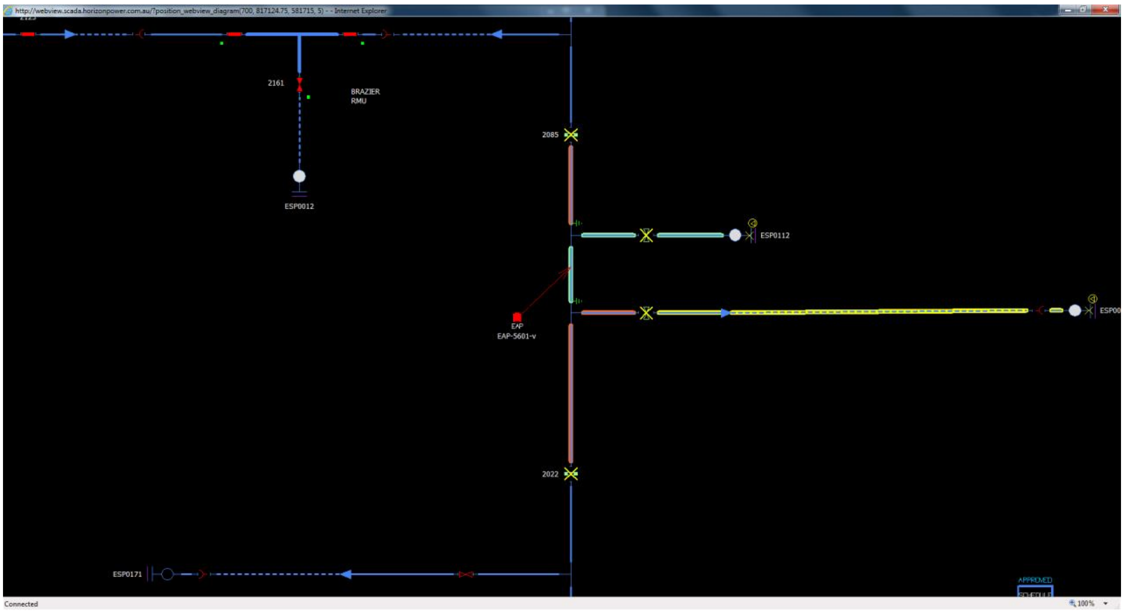

Figure 9-7 Network diagram showing worksite isolated, earthed and EAP issued
Program completed up to and including item 17.

9.6 Program Writing Considerations

The switching program writer must be aware of the wide range of technical, network specific and customer related considerations discussed in this section. This will enable the writer to determine those issues which are relevant and required to be addressed as part of writing each switching program. In most cases many issues may not be relevant to a particular program and can be readily excluded from further consideration.

9.6.1 Load

Switching programs may require load to be moved or reduced in order that the job may be done.

Where load is moved, the program writer must decide:

- where to transfer the load
- if capacity is available
- if the time is important (hour, day, season)
- if there are any other limiting factors, e.g. a section of undersized overhead conductor or cable.

Where it is not possible to transfer load resulting in customer interruptions, the program writer must:

- ensure notifications are provided for all customers who will have their supply interrupted
- negotiate outages for commercial and industrial customers.

9.6.2 Voltage Levels

The program writer should determine whether any voltage checks are required.

If checks are needed, the program writer must decide:

- where they will be made
- when (before, during or after switching), and
- if there are to be further checks.

Typical checks include the following:

- confirm that supply has been maintained within satisfactory limits at the point of isolation
- if necessary, repeat the checks if the load pattern is irregular, and
- take notice of possible voltage variations, where customers have voltage sensitive equipment.

9.6.3 HV Tap Removal to Create an Isolation Point.

When selecting isolation points for a switching program it may be necessary to remove HV taps to limit the size of an isolated area.

Due to the hazards encountered when removing taps live line, there are conditions that apply, depending on the connection types.

Single-phase Spur

Removing a single-phase live line clamp off a single-phase network is considered switching, similar to removing a DOF, a VA permit is therefore not required. This operation does not require a recloser or circuit breaker to be set to manual, although when working on steel pole networks disabling auto reclose is preferred.

A switching operator may at any time request HPCC to disable the auto reclose should they feel it necessary due to safety concerns.

Single-Phase Tap and Three-phase Tap Removal from a Three-phase Line.

	Switching Activity	**VA Required**	**Method**	**Auto reclose function disabled**
Single Phase Tap. Live Line Clamp disconnection	Yes	No	Link Stick	Yes
Three Phase Tap. Live Line Clamp disconnection	Yes	No	Link Stick	Yes
Single Phase Tap. Parallel Groove Clamp disconnection	No	Yes	Glove & Barrier	Yes
Three Phase Tap. Parallel Groove Clamp disconnection	No	Yes	Glove & Barrier	Yes

Single-Phase Tap (Live Line Clamp).

The following risk mitigation measures shall apply when disconnecting a single phase live line clamp using link sticks from a three phase overhead line for the purposes of creating an isolation point.

The measures being:

- A Switching Job Risk Assessment (JRA) shall be carried out by the Switching Operator.
- The length of the spur being disconnected shall be kept as short as possible to limit capacitive charging as far as practically possible.
- Maximum unloaded spur lengths.
  a). 11kV / 12.7kV rated line - 15km
  b). 19.1kV /22kV rated line - 4km
  c). 33kV rated line - 1.5km
- The respective upstream protective device with respect to the line tap removal i.e. re-closer shall be disabled and reflected on the program.
- The removal of the line tap itself must be reflected as an isolation step and point in the program.
- Removal of the line tap shall be carried out by a Competent Person. *Note: The Switching Operator and Competent Person may be the same person in some instances.*

- An Observer must be posted when the line tap is disconnected and reconnected.
- The removed line tap shall be tagged as an isolation point with a Do Not Operate Tag for the later Electrical Access Permit (EAP).
- The removed tap and section of conductor must be mechanically secured to the running earth conductor and not be left dangling.

Note: There would be no need for the issue of a Vicinity Access Permit to Work (VA) as the above is considered an operating switching activity / activities.

Three-Phase Tap (Live Line Clamp).

The following risk mitigation measures shall apply when disconnecting a three phase line tap on a three phase system by means of using link sticks for the purpose of creating an isolation point.

These being:

- A Switching Job Risk Assessment (JRA) shall be carried out by the Switching Operator.
- The length of the spur being disconnected shall be kept as short as possible in order to limit any capacitive charging as far as practically possible.
- Maximum unloaded spur lengths.
  a). 11kV / 12.7kV rated line - 15km
  b). 19.1 kV / 22kV rated line - 4km
  c). 33kV rated line - 1.5km
- The respective upstream protective device with respect to the line tap removal i.e. re-closer shall be disabled and reflected on the program.
- A specific comprehensive Job Risk Assessment shall be carried out for the removal and replacement of the line taps.
- Removal of the line tap shall be carried out by a Competent Person. *Note: The Switching Operator and Competent Person may be the same person in some instances.*
- The removal of the line tap itself must be reflected as an isolation step and point in the program required for the later Electrical Access Permit (EAP).
- As a critical step in the process, an Observer must be posted when the line taps are disconnected and reconnected.
- The removed line taps shall be tagged as isolation points with a Do Not Operate Tag for the later issue of the EAP.
- The removed taps and sections of conductor must be mechanically secured and not be left dangling.

Note: There would be no need for the issue of a Vicinity Access Permit to Work (VA) as the above is considered an operating switching activity / activities.

Single-Phase Tap (Parallel Groove Clamp).

The following risk mitigation measures shall apply when disconnecting a parallel groove tap by means of glove and barrier methods for the purposes of creating an isolation point.

These being:

- A Switching Job Risk Assessment (JRA) shall be carried out by the Switching Operator.
- The length of the spur being disconnected shall be kept as short as possible in order to limit any capacitive charging as far as practically possible.
- Maximum unloaded spur lengths.
  a). 11kV / 12.7kVrated line - 15km
  b). 19.1kV /22kV rated line - 4km
  c). 33kV rated line - 1.5km
- The respective upstream protective device for the clamp disconnection i.e. re-closer shall be disabled and reflected on the switching program.
- The issue and cancellation of Vicinity Access Permit (VA) for the disconnection of the clamps shall be reflected in the switching program.
- The removed line tap shall be tagged as an isolation point with a Do Not Operate Tag for the issue of the later Electrical Access permit (EAP).
- The removed tap and section of conductor must be mechanically secured to the running earth conductor and not be left dangling.
- The removal of the line tap itself must be reflected as an isolation step and point in the program required for the later EAP.
- A Vicinity Access Permit (VA) shall be used for the reconnection of the clamps once the later EAP has been cancelled.

Three-phase Tap (Parallel Groove Clamp).

The following risk mitigation measures shall apply when disconnecting a three phase parallel groove tap by means of glove and barrier methods for the purposes of creating an isolation point.

These being:

- A Switching Job Risk Assessment (JRA) shall be carried out by the Switching Operator.
- The length of the spur being disconnected shall be kept as short as possible in order to limit any capacitive charging as far as practically possible.
- Maximum unloaded spur lengths.
  a). 11kV / 12.7 kV rated line - 15km
  b). 19.1 kV / 22kV rated line - 4km
  c). 33kV rated line - 1.5km
- The respective upstream protective device with respect to the line tap removal i.e. re-closer shall be disabled and reflected on the program.
- The removal of the line tap itself must be reflected as an isolation step and point in the program required for the later EAP.
- A comprehensive Job Risk Assessment shall be carried out in conjunction with the issue of a Vicinity Access permit (VA) for the removal of the line taps.
- Glove and Barrier methods for disconnecting the line taps shall be followed.
- As a critical step in the process, an Observer must be posted when the line taps are disconnected and reconnected.
- The removed line taps shall be tagged as isolation points with a Do Not Operate Tag for the later issue of the EAP.
- The removed taps and sections of conductor must be mechanically secured and not be left dangling.

- A Vicinity Access Permit (VA) shall be used for the reconnection of the clamps once the EAP has been cancelled.

9.6.4 Switching using Single-Phase Devices

Where non-ganged switches (three single-phase switches) exist in the network, there may be situations where these switches need to be operated to interconnect feeders or to achieve isolation. Some network configurations may be susceptible to load imbalance due to extensive single-phase spurs or phase differences across open points. When feeders are interconnected by non-ganged single-phase switches, the following may occur:

- load imbalance between interconnecting feeders
- load imbalance on the power transformers on the busbar.

When interconnecting three-phase feeders with single-phase devices, the following options should be considered:

- moving to next gang switch
- using the substation transfer bar
- short interruption for customers.

9.6.5 Constraint with Live Line Tap Removal

Maximum lengths of network apply when removing taps on unloaded overhead distribution lines. This is due to an increase in capacitance (charging current) as the line length increase.

Maximum line lengths for live line tap removal are:

- 11kV = 15 km
- 22kV = 4 km
- 33kV = 1.5 km

9.6.6 Paralleling of Feeders and Transformers

The program writer must be aware the fault level (fault current) is increased at times when supplies are paralleled (interconnected).

For HV feeder interconnection the method to minimise fault current in order of preference is:

1. interconnect onto the same feeder (frequently this not possible due to network configuration)

2. interconnect on adjacent feeders supplied from the same zone substation transformer

3. interconnect on adjacent feeders supplied from different zone substation transformers.

9.6.7 For LV interconnection, only the minimum number of transformers required to supply the load should be interconnected. It is desirable the interconnected transformers should be on the same HV feeder where possible.LV Isolation and Distribution Transformer Management

Consideration needs to be given when applying LV back-feeds or running transformers in parallel. These considerations are:

- LV isolations and back-feed text steps should be included in the HV switching program when work involves both HV and LV networks.
- When a transformer is to be back-fed, the ‘Apply back-feed’ step must be added prior to the transformer LV disconnectors being opened and Danger– Do Not Operate tagged. If a transformer is to be back-fed via a generator, the step ‘Apply generator’ must be included in the program.

9.6.8 Phasing Out

Phasing out is required when conductors are to be connected together or interconnected for the first time without having been previously checked for correct phasing.

The program writer should first determine whether phasing out is necessary and, if so, where it should be done.

The program writer must check whether:

- there is a built-in facility
- special equipment is needed, available and in good condition

- phasing out is required at more than one point, and
- if disabling of an auto reclose device is required for HV phasing out.

If the equipment is uncommissioned, built in phasing facilities should not be used until they are proved operational.

9.6.9 Ferroresonance

Ferroresonance is a phenomenon that may produce high voltages in a HV cable transformer combination when the supply is either applied of disconnected via single-phase switches or drop out fuses.

The program writer must understand how ferroresonance occurs and where it may be encountered during a switching program.

Field Instruction *Ferroresonance in the Underground Distribution System* describes methods to eliminate ferroresonance whilst switching.

9.6.10 Use of LV Fused Jumpers

When multiple distribution transformers are interconnected on the LV, but supplied from different HV feeders, there is a risk if one feeder trips on fault the healthy feeder will supply the tripped feeder load and fault via the interconnected LV. This can possibly result in severe overload and permanent damage to the LV interconnection.

To avoid the above problem, LV fused jumpers are used for interconnection where:

- overhead transformers without LV fuses are supplied by different feeders
- overhead transformers without LV fuses, are on the same feeder, but have a recloser or sectionaliser between the LV interconnected transformers.

LV fused jumpers are not required when:

- a transformer has fused LV circuits which are used for interconnection
- HV switching has taken place to insure the interconnected transformers are on the same feeder.

9.6.11 Switchgear Ratings

An important consideration when writing a switching program is the rating and load breaking capacity of the electrical apparatus being switched.

Many items of electrical apparatus while able to carry significant load current have limited ability to break load current without damage to the contacts or drawing a substantial arc.

It is therefore important to check the ratings of each item to be switched and adjust the program where necessary to avoid breaching their capacities.

Specific information on rating can be found in the Horizon Power *Distribution Design Rules*.

9.6.12 Customer Outages

Where a customer outage occurs as an intended part of a switching program, the following must be considered:

- impact on life support (LS) customers and general customers and the associated notification requirements
- supply outage impact on sensitive connections, such as traffic lights and sewerage pumps and appropriate notification and liaison with respective authorities, and
- time restrictions applicable to supply outages above the 26th parallel.

9.6.13 Efficient Switching Program Sequence

Where possible, the switching program sequence should minimise the travelling time and distances required by the switching operator. For example, where several isolation points are required to be created, and there is no technical reason for this to be performed in a particular sequence, the sequence which minimises the travelling time and distances should be selected.

9.6.14 Preparation of System Change Documentation

Where the work performed results in a change to the network, the system change documentation must be completed by the program writer prior to execution of the switching program.

9.7 Running a Switching Program

All HV switching is coordinated by HPCC. In the running of a switching program the switching operator must be aware of the following requirements.

9.7.1 Commencement of Switching

Switching operators must not commence switching until they are specifically instructed by the HPCC. This is normally included as a “Contact HPCC, request permission to commence “ step in the switching program.

9.7.2 Sequence of Instructions

Unless otherwise stated in the switching program, all switching operations will be carried out in the consecutive sequence of step numbers in the switching program.

Where, due to unforeseen circumstances, a program sequence cannot be strictly followed, the switching operator and the HPCC controller will determine whether the program can be continued with minor changes or whether the program should be discontinued.

Where the program requires minor changes, HPCC and the switching operator will agree on the changes required to enable the program to proceed. HPCC will amend the program and ensure that all operators at the locations involved in the switching program are informed of and note the program changes. The amended switching program will then proceed.

Where the switching program requires major change, a new program will be written by the switching operator.

9.8 Backup Process. Job dispatch via phone and using paper copy of the Switching Schedule.

The backup process:

- The backup process will make use of a paper copy of the checked and approved switching schedule.
- A copy of the switching schedule must be in possession of the Switching Operator before any switching is carried out, even if switching is to be carried out using a tablet.
- HPSC and the SWOP will enter the backup process once all reasonable steps have failed to restore switching operations via the tablet in the field.
- The backup process will be supported by phone communication between the Switching Operator and HPSC.
- Should the backup process be initiated during the tablet switching process for whatever reason, the Switching Operator and the HPSC shall review the current paper copy of the switching schedule and check which steps were last confirmed by tablet before proceeding with the next step of switching.

If this is not possible, then the Switching Operator must go back go to the last location of the last known step and check the status of the switched device is correct, before proceeding with any further switching actions.

Any other additional switching steps which were added when using the tablet must also be discussed and added to the paper copy of the program as required at this time. This can be done manually by the Switching Operator in the field or if possible it should be reprinted.

- A mandatory stand down time of 15 minutes must be respected when the need arises to change over from tablet switching to the backup system by the Switching Operator. This will ensure that the Switching Operator remains focused as a result of the change in switching process. The Switching Operator must revisit his risk assessment before recommencing switching by means of the paper schedule.

9.8.1 Paper Switching Schedule

Once the decision is made to use a backup paper switching schedule the following will apply or be in place:

- Telephonic communication shall be established and checked between the Switching Operator and HPCC.
- All communication between the SWOP and HPSC will be concise and clear.
- Instructed steps issued to the SWOP shall be “repeated back” to the HPSC to ensure that each instruction has been understood.
- Important information received from the SWOP shall be repeated back by HPSC to ensure that it has been understood.
- There must be a clear distinction in all telephonic discussion between what is “instruction” and what is “other” general information being shared between the parties.
- The word “Instruction” shall be used in context when the HPSC issues an instruction to the Switching Operator.
- Every time a new call is made to HPCC, the Switching Operator shall state his name, location and program number.
- When a HPSC receives a call, he shall identify himself by name and the control centre (HPCC).
- If at any time the SWOP or the HPSC are unable to give full attention to the operation of the schedule, the schedule should be halted until such time as it can carry on without interruption.
- HPSC is the controlling authority on the power network. This position of authority must be upheld during all communication and field operations.

9.8.2 Actions by SWOP before contacting HPSC for Operating Instructions (initially and for multiple switching locations).

- The SWOP has checked against the switching schedule that he is at the correct location.
- He has confirmed the next sequential step in the switching schedule.
- He has identified the apparatus to be switched on.
- He has confirmed that the state of the apparatus is in the expected position.
- He has confirmed as far as reasonably possible that the apparatus to be switched is fit for operation and service.
- He has noted any alarms or unusual situations that could potentially affect safe operation of the apparatus in question.

9.8.3 Place keeping practises when using the Backup Process.

Hatching and Cross Hatching shall be used to ensure that the SWOP does not lose his place on the paper copy of the switching schedule.

This shall be achieved by following process:

- The Switching Operator must confirm he has the correct authorised version of the switching schedule in his possession.
- Once an instruction has been received by the SWOP, a diagonal line (/) shall be drawn through that switching step in the block indicating the "Item number" on the schedule.

23	Field Confirmed	CASUARINA WAY,O/S # 108,KUNUNURRA	22kV PTSD KUN115 (PTSD)	Remove DL & On	FRANCIS, DARREN	26-Nov-2018 12:48	26-Nov-2018 13:00	FRANCIS, DARREN
24	Field Confirmed	CELTIS ST,L1667 CELTIS ST,KUNUNURRA	22kV TX KUN198 LV	LV DISO ON, Remove Barriers & DL	FRANCIS, DARREN	26-Nov-2018 12:48	26-Nov-2018 13:08	FRANCIS, DARREN
25	Field	CELTIS ST,L1667 CELTIS	22kV TX KUN198 LV	Remove Backfeed	FRANCIS,	26-Nov-2018 12:48	26-Nov-2018 13:14	FRANCIS,

- Once the instruction has been executed by the SWOP, another line must be made through this line to form an (X). Steps instructed but not yet executed will clearly be visible etc. No step must be executed without a diagonal line (/) adjacent to it.

22	Field Confirmed	Gardenia Dr,LOT 251 GARDENIA,KUNUNURRA	22kV RMU SW KUN178	Remove DL & On	FRANCIS, DARREN	26-Nov-2018 12:48	26-Nov-2018 12:55	FRANCIS, DARREN
23	Field Confirmed	CASUARINA WAY,O/S # 108,KUNUNURRA	22kV PTSD KUN115 (PTSD)	Remove DL & On	FRANCIS, DARREN	26-Nov-2018 12:48	26-Nov-2018 13:00	FRANCIS, DARREN
24	Field Confirmed	CELTIS ST,L1667 CELTIS ST,KUNUNURRA	22kV TX KUN198 LV	LV DISO ON, Remove Barriers & DL	FRANCIS, DARREN	26-Nov-2018 12:48	26-Nov-2018 13:08	FRANCIS, DARREN

- Steps that do not require an action from the Switching Operator that have been communicated by the HPSC as complete, for example tele steps, must be indicated with a tick (√) adjacent to that step in the program.

[illegible]	[illegible] Confirmed			[illegible] Perm to Commence	[illegible] DARREN	[illegible]	[illegible]	[illegible] DARREN	
3	Confirmed	KUN	Circuit 532 A/R LAKESIDE FEEDER	Tele Set Disable	TELE	26-Nov-2018 11:27	26-Nov-2018 11:27	John McCaskie	√
4	Confirmed	KUN	Circuit 532 SEF LAKESIDE FEEDER	Tele Set Disable	TELE	26-Nov-2018 11:27	26-Nov-2018 11:27	John McCaskie	√
5	Field Confirmed	CELTIS ST,L1667 CELTIS ST,KUNUNURRA	22kV TX KUN198 LV	Apply Backfeed/Interconnect	FRANCIS, DARREN	26-Nov-2018 11:31	26-Nov-2018 11:50	FRANCIS, DARREN	

9.8.4 Recording of Operating Times.

Times when the switching instruction has been completed; must be recorded by the Switching Operator adjacent to the switching step on the paper copy in the “Confirmed Date / Time” section.

This shall be done by using standard 24 hour clock times to record when the switching operation was completed e.g. 12h36.

9.8.5 Error Correction.

If at any time an error is made when writing information on the paper copy of the program, for example the date / time of an operation, a single line shall be drawn through the incorrect information and the correct information rewritten.

SECTION TEN

Distribution Testing and Commissioning

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10. Distribution Testing and Commissioning

10.1 Introduction

This section is designed to give the switching operator an overview of the equipment and the procedures required for the testing and commissioning of equipment on Horizon Power's distribution networks.

Horizon Power has detailed documentation available for distribution testing and commissioning, note this information will not be repeated here.

10.2 Documentation

Switching operators required to carry out testing and commissioning must ensure they are knowledgeable of the requirements specified in the related Horizon Power documentation.

The core documentation is *The Network Testing and Commissioning Standards – CS10# 1897047* which provides procedures and further information on testing and commissioning requirements. This is supported with the *Distribution Commissioning Test Sheets* provided for each type of apparatus which describes the testing and commissioning requirements and provide space for recording of the related results.

Examples of additional support documentation include:

- *Test Before Touch Prior to Commencement with Work*
- *Instruments – Testing and Calibration*
- *Testing and Use of High Voltage Insulated Equipment*
- *Commissioning of New Low Voltage UDS Cables*
- *Commissioning of High and Low Voltage Cables and Apparatus*
- *Identifying and Proving of HV Cables*
- *Ferroresonance in the Underground Distribution System*
- *Testing of High Voltage Cables – CS10# 3651308*
- *Guideline: Technical Maintenance for Equipment Earthing – CS10# 4064717.*

The range of testing and commissioning tasks the switching operator may need to carry out include voltage tests, phasing out tests, cable identification, insulation resistance tests and earth resistance tests. The test equipment used to conduct these tasks is briefly described below.

Specific instruments do vary, therefore the documentation specific to the instrument being used must be consulted *before* its use.

10.3 Testing Equipment

The test equipment is required to meet detailed safety and accuracy standards and must be treated carefully. Switching operators should ensure that all test equipment is stored and transported so as not to damage testing equipment.

Test equipment is used in the following broad categories:

- voltage testing, including phasing out testing
- insulation testing
- earth testing, and
- other specialised testing, including cable identification

10.3.1 Voltage Testing Equipment

Voltage test equipment includes voltmeters, neon testers and amplifier type testers (e.g. a Modiewark® device).

Voltage testing equipment performs the essential functions of :

- measuring voltages to check they are within limits
- proving de-energised before applying earths, and
- phasing out to confirm apparatus is connected in the correct phase sequence.

Test equipment must be checked before and after the test.

This is done by measuring a known voltage on energised equipment or by using the test instrument's own test facility.

Voltmeters

Voltmeters may be used on the LV system to measure voltage and phasing out tests. A hand held voltmeter is shown in Figure 10-1.

Figure 10-1 Typical LV Voltmeter

Voltmeters are self-contained with a digital display. To make measurements, the test probes are required to make actual contact with the circuit under test.

> **When using LV voltmeters on bare conductors or exposed energised busbars, the operator must wear the correct PPE.**

Amplifier Type Voltage Tester (Modiewark®)

This instrument has an electronic amplifier which is used to detect the electric field near an energised conductor. This instrument has internal batteries.

Direct contact with the conductor under test is not required, however close proximity is preferred for correct indication.

> **An amplifier type voltage tester must not be used to prove the status of low voltage apparatus.**
>
> **When testing for high voltage, this tester must not be hand held. Approved HV insulated operating sticks must be used**.

The Modiewark is Horizon Power's main device for checking de-energised HV circuits before earthing (see Figure 10-2).

A neon light and buzzer indicate if the conductor/busbar is energised when the Modiewark is set to its prescribed voltage setting and placed adjacent to the conductor/busbar. The following test methods must be used to prove the Modiewark for testing.

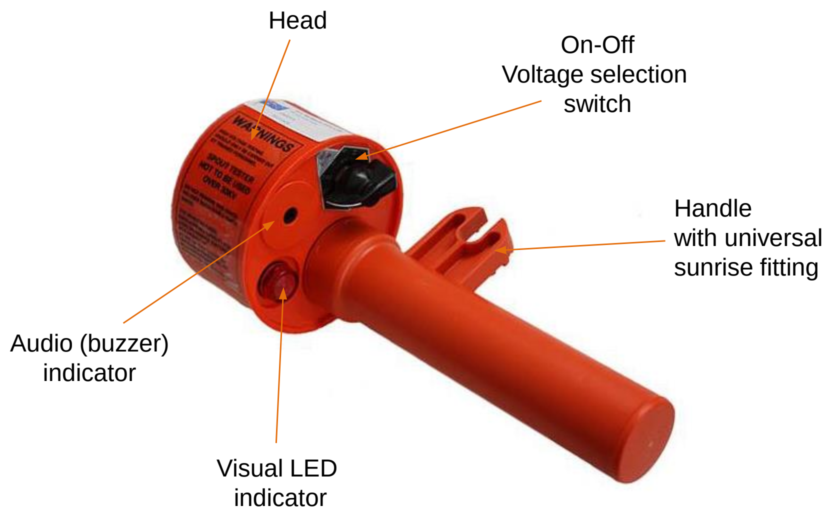

Figure 10-2 Amplifier type voltage tester (the Modiewark®)

Modiewark testing methods

Before and after testing a de-energised circuit, the preferred method of proving that the Modiewark is operational is by testing a similar voltage on an adjacent energised line.

Current models of Modiewarks have a self-testing feature, in that when the Modiewark is turned on, an intermittent ‘beep’ occurs to indicate the device is working, and when placed near a voltage source, the ‘beep’ becomes continuous.

The Modielive® EMF generator is an accessory device used with the Modiewark voltage tester. The Modielive produces an electromagnetic field (EMF) which can be detected by the Modiewark to prove the Modiewark is working correctly.

Figure 10-3 The Modielive® EMF generator (right)
used to test the integrity of the Modiewark’s testing function.

Note: The Modiewark will not be damaged by placing it against a high voltage conductor, even when selected to 'Test/240V'.

An amplifier type voltage tester must not be used to prove the status of cables with an earth screen, because the electric field of the phase conductors cannot be detected through the earthed screen.

Voltage Indicator (Neon Indicator)

Horizon Power's high voltage switchgear such as indoor switchboards and ring main units frequently have built-in neon indicators. (see Figure 10-4).

Figure 10-4 Ring main unit Neon indicator

A capacitive bushing is used on each phase to provide the neon with a reduced voltage which is proportional to the primary conductor voltage (see Figure 10-5).

The screen develops a voltage somewhere between the primary conductor voltage and earth (0 volts), dependent on its physical location between the primary conductor and earth. The screen is typically located to provide voltages around 100-200V, but this can vary between bushings.

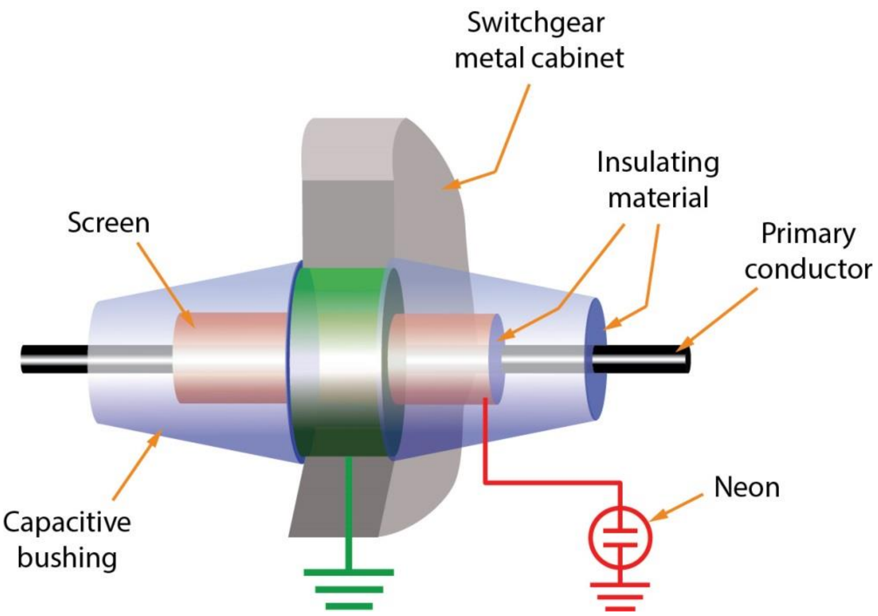

Figure 10-5 Capacitive bushing and neon circuit

LV Phasing out

Phasing out is also required as part of testing and commissioning of new LV overhead and underground apparatus and transformers.

LV phasing out requires the use of a voltmeter as shown in Figure 10-6 below.

Figure 10-6 Phasing LV disconnectors

The phasing out process is described below.

Figure 10-7 shows two LV supplies at a normally open point. As this open point is interconnecting the two supplies, it is necessary to ensure the two supplies phase out. Table 10-1 shows the series of tests to be performed and the expected results for correct phasing out. An open point which does not phase out must not be closed.

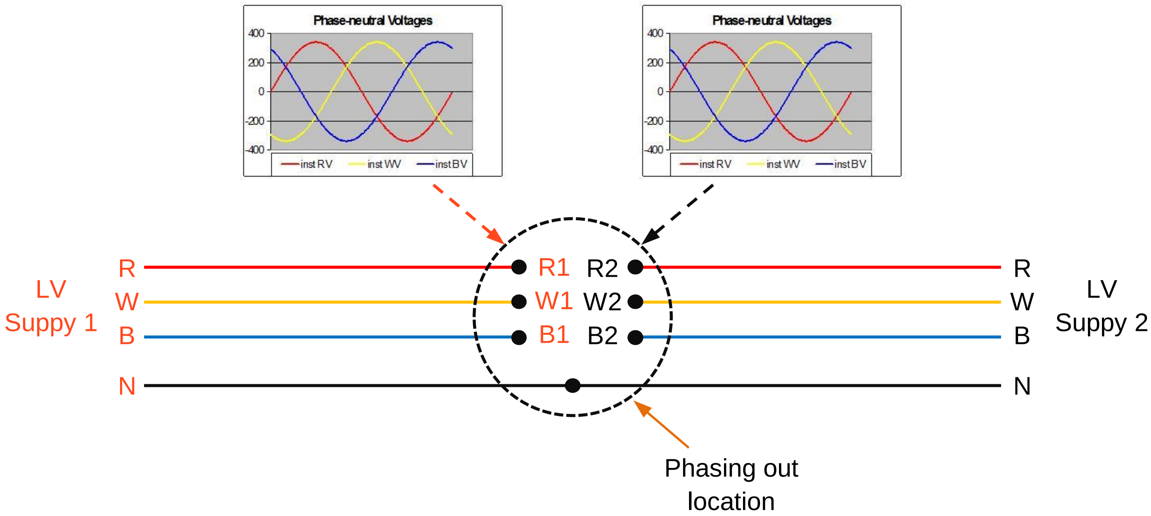

Figure 10-7 LV phasing out diagram

Test connections		Voltage reading	Voltmeter Volts (V)
Test supply 1 – Each phase to neutral		**Phase to neutral voltage**	**Approx. 240**
Test supply 2 – Each phase to neutral		**Phase to neutral voltage**	**Approx. 240**
R1	**R2**	**No significant voltage**	**Less than 30**
R1	W2	Full phase to phase voltage	Approx. 415
R1	B2	Full phase to phase voltage	Approx. 415
W1	R2	Full phase to phase voltage	Approx. 415
W1	**W2**	**No significant voltage**	**Less than 30**
W1	B2	Full phase to phase voltage	Approx. 415
B1	R2	Full phase to phase voltage	Approx. 415
B1	W2	Full phase to phase voltage	Approx. 415
B1	**B2**	**No significant voltage**	**Less than 30**

Note: Because last test was ‘no significant voltage’, test the instrument is still working using any phase to phase or phase to neutral voltage reading.

Table 10-1 LV phasing out tests and readings

LV underground switching requirements

Because of the close proximity of the switching operator to LV apparatus during underground switching operations, the switching operator *must always* test for correct phasing and supply (i.e. phase out) before installing fuses or disconnectors in a normally open point. The process of phasing out is described in the section above.

Proving de-energised problems

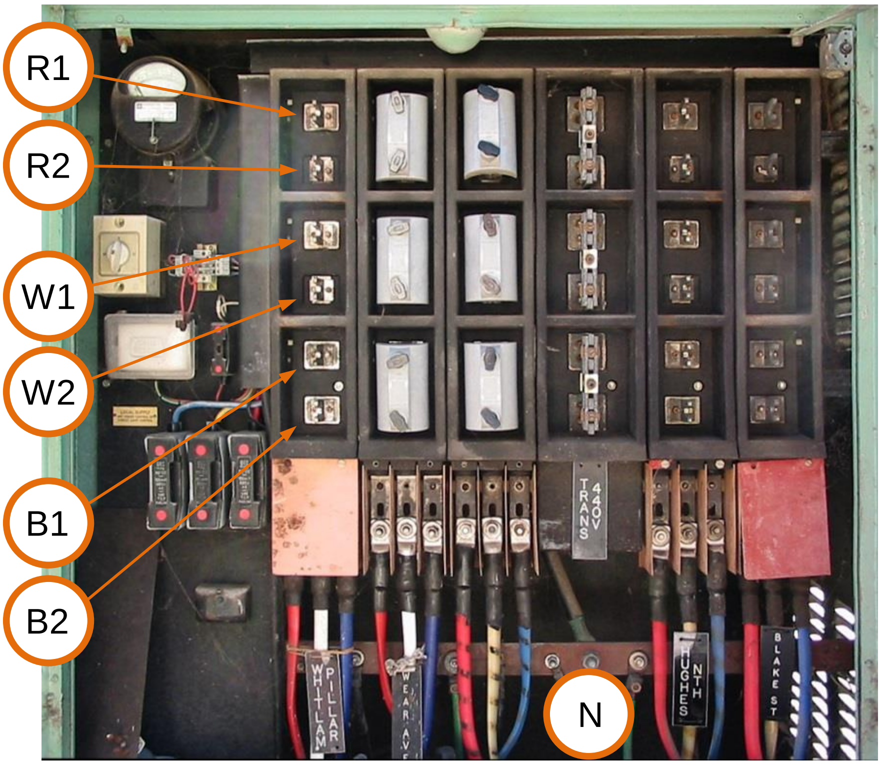

Figure 10-8 Proving de-energised and phasing out

When conducting voltage checks to prove a cable de-energised the following problems may occur. Refer to Figure 10-8.

- The switching operator should measure the incoming cable voltages between each phase and neutral (R2 to N, W2 to N and B2 to N) to check if the cable is de-energised. If the voltage records zero, the cable is de-energised.
- Where the incoming cable is de-energised and an electronic voltmeter is used, a voltage (approximately 240V) may be measured from R1 to R2, W1 to W2 and B1 to B2, due to the presence of kWh meter potential coils connected between phase and neutral.
- Where the incoming cable is energised, if voltages higher than 30V are measured from R1 to R2, W1 to W2 and B1 to B2 , the phasing out is not

correct and interconnection cannot proceed. (This may be caused by the phases being crossed or one phase having a much lower voltage than its corresponding phase.)

HV Overhead Phasing out

Shown in Figure 10-9 below is the typical phasing out test equipment used on the HV overhead.

Figure 10-9 HV overhead wireless phasing out equipment

This instrument consists of two parts; grey (transmitter) and blue (receiver). The transmitter and receiver are connected, using insulated HV operating sticks to each side of the apparatus to be phased out (e.g. pole top switch).

The test sequence is similar to the LV phasing out in Table 10-1, except the transmitter unit alone is used to prove the presence of voltage on supply 1 and 2, and then the transmitter and receiver combination is used between phases on supply 1 and 2 to phase out. An audible signal is issued when both parts of the instrument are connected to the same phase.

HV Indoor Switchgear Phasing out

Indoor switchgear can be phased out using specialised HV test instruments such as shown in Figure 10-10. This instrument functions as a high voltage volt meter.

Figure 10-10 High voltage test sticks

An alternative method is to phase out with a voltmeter, using the voltage indicators (neon indicators) sockets on the front panel of the switchgear. This requires the neon sockets have been proven to be connected to the correct HV phases before being used to phase out.

HV Ring Main Switchgear Phasing Out

The voltage indicators (neon indicators) sockets on the front panel of the switchgear and a hand-held voltmeter can be used to phase out HV supplies. This requires the neons sockets have been previously commissioned and proven to be connected to the correct HV phases before being used to phase out.

10.3.2 Insulation Test Equipment

The main types of insulation test equipment used by Horizon Power include the insulation resistance meter (Megger®) and the high voltage paper insulated cable tester (hipot).

Insulation Resistance Meter (Megger®)

This device is used to measure the insulation resistance value of the apparatus by applying a voltage (usually 1kV to 5kV) from phase to phase or phase to neutral (or earth for HV).

Figure 10-11 Typical 5kV HV Megger testing unit

VLF Testing

Very low frequency (VLF) cable testing is a technique used for testing of high voltage cables.

The cable being tested must withstand a VLF AC voltage for a specified testing time without flashover. This method yields a ‘Pass/ Fail’ result. Frequency ranges used are within the range of 0.01 Hz to 0.1 Hz, with 0.1 Hz being the Horizon Power standard.

Figure 10-12 Horizon Power's standard VLF tester – the HVA60 VLF Tester

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Note: XLPE cables must not be tested with a High Voltage DC Cable Tester (Hipot) because it may shorten the life of the cable.

10.3.3 Earth Testing

Principle of Operation

For safety reasons it is essential electrical apparatus is effectively earthed. This ensures step and touch potential are limited and reliable earth fault protection operation.

Horizon Power uses multiple techniques to test and record the resistance of its earthing systems. As there are a range of test instruments used the specific manual must be consulted to ensure correct test setup and measurement technique.

A range of test instruments and associated test methods are used. The most common test methods include:

- fall of potential test
- stakeless hand-held test (single core tester), and
- stakeless hand-held test (two core tester).

Each method is briefly described below.

Method 1: Fall of potential test

Figure 10-13 shows the fall of potential test method used to measure the effectiveness of the earth electrode under test. This method requires a known test current to be passed between the electrode under test and the test stake (current).

The voltage is measured at the test stake (voltage) in positions 1, 2 and 3 and the average voltage value is calculated. Using Ohm's Law R = V/I = (average voltage value) / (test current) is used to determine the resistance of the electrode under test resistance.

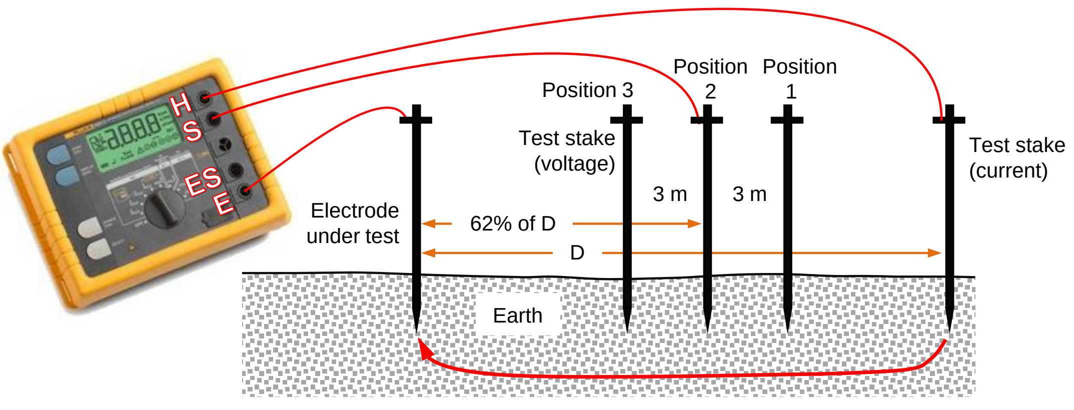

Figure 10-13 Method 1: Fall of potential test

Method 2: Stakeless hand-held test (single core tester)

Figure 10-14 shows the instrument applied to the electrode under test whilst it remains connected in the earth system. The clamp-on head has two internal cores, the first core induces a constant AC voltage into the earth rod under test and the second core measures the induced current which flows.

Because the induced voltage is constant, the current flowing is proportional to the electrode under test resistance. This method requires multiple earth electrodes to provide the loop current required for measurement.

The greater the number of additional electrodes, the greater the accuracy of the measurement. The instrument-induced voltage is at a very high frequency to ensure the measurement is not affected by any 50Hz current which may be flowing in the electrode under test.

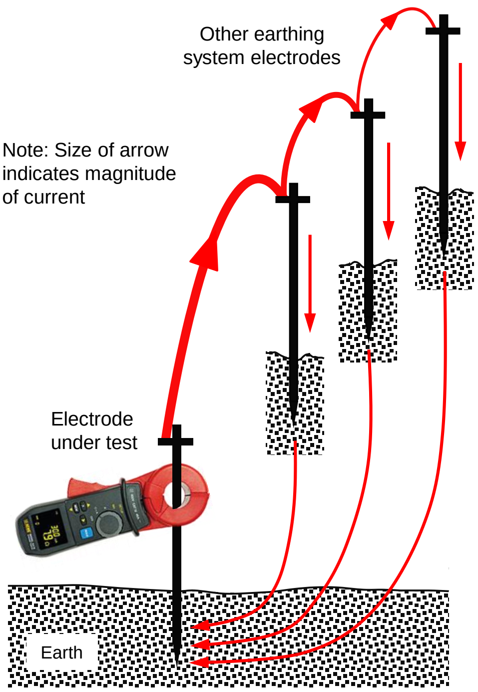

Figure 10-14 Method 2: Stakeless hand held test

Method 3: Stakeless hand-held test (separate core tester)

This method is similar to Method 2, except the voltage inducing and current measurement cores are separately attached to the electrode under test. See Figure 10-15.

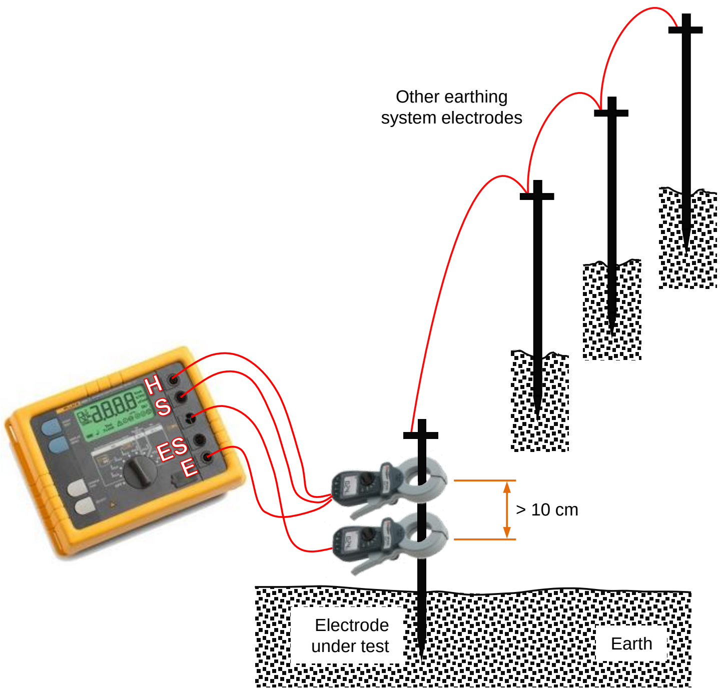

Figure 10-15 Method 3: Stakeless test

10.3.4 Other Specialised Testing Equipment

Other specialised equipment includes phase rotation meters and cable location meters.

Phase Rotation Meter

The phase rotation meter is a device used to test for correct phase rotation (see Figure 10-16). The phase to neutral voltages in Figure 10-17 show the correct sequence R > W > B as each phase reaches its peak value. Phase rotation determines the direction three-phase electric motors will spin. The swapping of any two phases will cause the motor to spin backwards.

It is most important that phase rotation meters are *not* used for phasing out, as different phasing can give the same phase rotation.

Phase rotation meters may be used for checking supplies that cannot be interconnected or for the rotation of kilowatt-hour meters.

Figure 10-16 Typical phase rotation meter

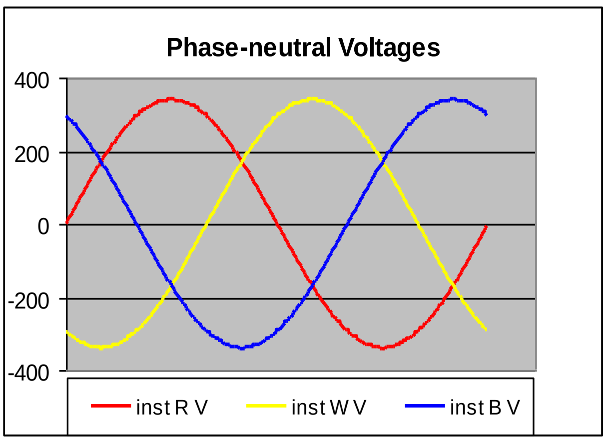

Figure 10-17 The phase to neutral voltages
showing the correct sequence R > W > B the phases reach their peak value.

Cross-phasing producing incorrect rotation can cause extensive damage to large motors. (This occurs because electric motors run in the reverse direction.)

Cable Locator Detectors

Generally, cable locator detectors have two different functions:

- measurement of a magnetic field, and
- signal injection.

Both functions may be available in the one instrument.

The measurement of magnetic field (due to the load current in the cable) is used to establish whether a cable is in the vicinity (including its alignment and depth). This knowledge is necessary, for example, when excavation is occurring near buried cables.

Note: The cable detector uses the measurement of magnetic field to locate cables. It will not detect an energised cable that is unloaded.

If a cable is deenergised, a signal generator/ injector will be required because of the absence of a magnetic field.

One of the problems of the magnetic field cable detector is that it is difficult to distinguish a specific de-energised cable from surrounding cables.

It is standard procedure to work on live LV cable. This means there is the danger of an HV cable being worked on live, because it has been incorrectly identified as a LV cable.

For this reason, it is necessary to use signal injection for cable detection when several similar cables are run in the same alignment and positive identification of only one cable is necessary.

When an LV cable is to be worked upon, it is necessary to identify all HV cables in the work area. This must be done by signal injection, unless the LV cable may be clearly identified by its dimensions or construction.

Where it is not possible to positively identify an LV cable, the required cable must be made dead and spiked using a HV cable spiking gun. The width of the blade should be across the cable to ensure contact is make with all three phases.

Note: Before removing the spike from the cable, the point of LV supply must first be checked for blown fuses or any HV protection operation.

Approved gloves must be used when removing the spike.

To accurately identify the location of cables, a signal is injected into the cable at a convenient point. The cable detector is then able to follow the route of the particular cable. However, there may be difficulties in avoiding the injected signal flowing into other cable neutrals. This makes the method unsatisfactory for the identification of LV cables.

Signal injection is accurate for HV cables, because the signal may be isolated from earth. This is achieved by short circuiting the cable between two phases at the remote end and injecting a signal between the two phases at the signal point. The signal is then picked up by the signal detection instrument current at any point along the cable route.

A signal injector for cable identification is shown in Figure 10-18.

Figure 10-18 Signal injector for cable identification

HV Cable Spiking Tool

In general, HV apparatus must be tested and earthed at the work site, if the program earthing points cannot be seen. Because this is impractical for HV cables, the method of proving the cable de-energised requires a spiking tool to penetrate all cable phases at the work site. Once this has been done, the cable can be worked on with no visual earths.

The recommended spiking tool is a wireless remote-controlled cutter/crimper. The existing explosive-powered chisel spiking tools are to be replaced in accordance with existing tool replacement procedures.

For further information refer to the Field Instruction *Identifying and Proving of HV Cables*.

Figure 10-19 Typical HV spiking tools

Note: It is the switching operator's responsibility to ensure that the identification and spiking of a HV cable is included as a step in a switching program.

The switching operator must also ensure that the auto reclose function is disabled on the cable to be spiked and on all cables in the vicinity.

During the spiking action, contact must be made with HPCC to verify that the spiking action has not affected the network by tripping other feeders.

10.4 Testing and Commissioning Distribution Apparatus

All new apparatus connected to Horizon Power's HV and LV network is required to be tested and commissioned. Testing and commissioning new electrical equipment has great potential for hazardous consequences and the need to consider safety at each step in the process cannot be stressed too highly.

The testing and commissioning of new electrical apparatus is necessary to:

- ensure quality of workmanship
- prove condition of the new apparatus is safe, and

- ensure correct operation of the apparatus and suitability for integration into the network.

It is most important to check that the apparatus is safe to operate. It must be electrically sound and phased correctly.

Commissioning requires that new apparatus is initially energised from a remote location using proven apparatus.

Testing and commissioning is technically demanding, and requires appropriately trained staff. Commissioning of most distribution apparatus is carried out by the switching operator who must have the appropriate level of Horizon Power's switching operator's authority.

The requirements for testing and commissioning of specific electrical apparatus is provided in *Network Testing and Commissioning Standards* – CS10# 1897047.

Distribution Commissioning Test Sheets describe the required tests and provide space for the recording of test results for electrical apparatus.

Note: Where testing has been carried out by other competent persons, the associated test sheets and handover sheets must be provided to the switching operator for review before equipment energisation can occur.

Where required on the commissioning sheet, the switching operator will add test results obtained during the energisation of the equipment.

Distribution Commissioning Test Sheets are available for the following apparatus:

Aerial and pole mounted installations

- Pole top distribution transformers
- Pole top switches and disconnectors
- HV overhead conductor
- LV overhead conductor
- LV aerial bundled conductor

Underground and ground mounted installations

- Ground mounted and padmounted distribution transformers
- HV switchgear
- HV cables
- LV switchgear
- LV cables and pillars

Customer-owned installations

- Distribution substations
- Private parallel generators

SCADA and communications installation and commissioning

- Distribution substations
- Reclosers
- Fault indicators

Testing requirements

- LV XPLE cable testing
- LV continuity and phasing testing
- LV cable testing after repair
- HV XPLE cable testing
- HV paper insulated cable testing
- HV mixed cable testing
- HV cable testing after repair of obvious fault
- Earth testing
- LV switchgear inspection and testing
- HV extensible switchgear testing
- Substation design/installation check list

Switching example for RMU commissioning

A typical example of the process of phasing out, cable identification and commissioning of Substation A ring main (2+2) unit is described below. This example assumes all switchgear pre-commissioning and cable testing has been completed.

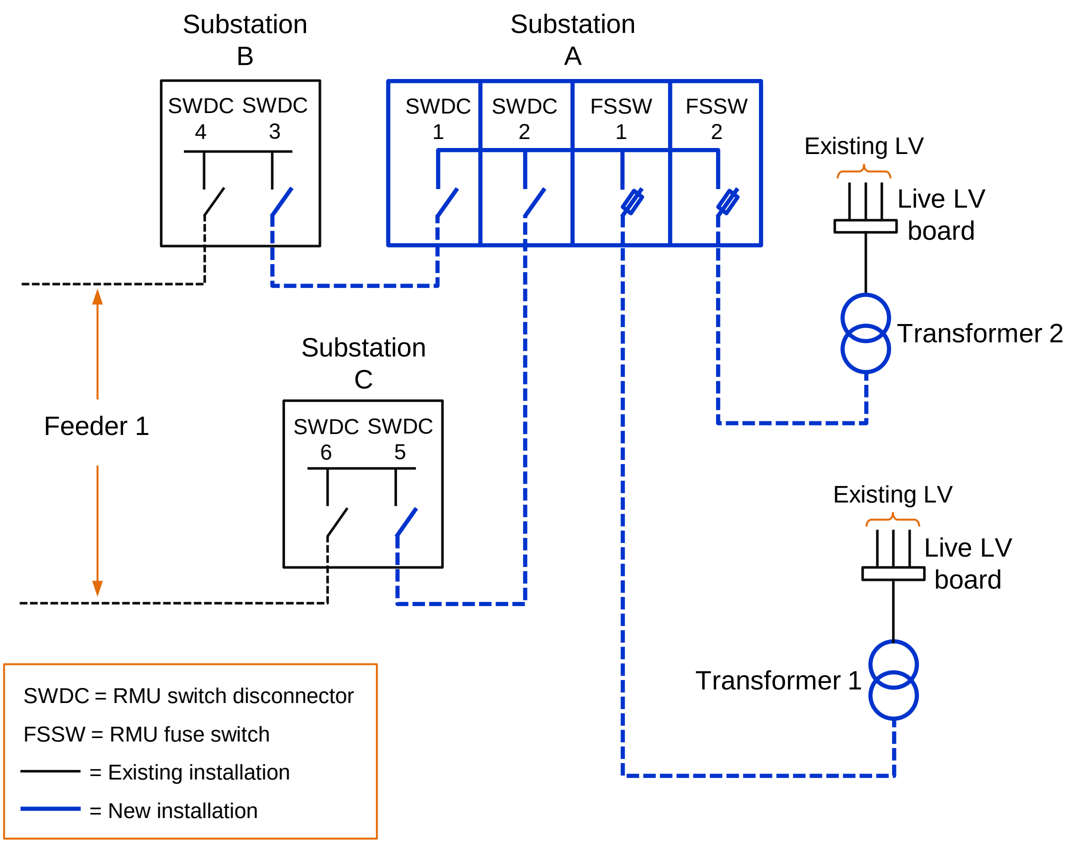

Figure 10-20 Commissioning ring main unit

Phasing Out and Proving of Labels on a New 2+2 Ring Main Unit

The following steps are required to be carried out, to prove the switchgear operation on potential, HV and LV phasing out and circuit label designations on a new 2 + 2 ring main unit (RMU) as shown in Figure 10-20.

This is an example of the switching sequence that can be used for commissioning Substation A RMU, however there are other switching sequence variations which could alternatively be used to achieve satisfactory commissioning.

Initial conditions are that Substations B and C are energised via RMU SWDC 4 and RMU SWDC 6 respectively. All other switches are OFF and all earth switches are OFF.

1. Set the auto reclose on Feeder 1 to manual, if applicable.

2. At Substation A check that all HV switches are OFF and earth switches are OFF.

3. Check the transformer disconnectors are OFF on the LV board at Transformer 1.

4. Check the transformer disconnectors are OFF on the LV board at Transformer 2.

5. Switch RMU FSSW 1 ON at Substation A.

6. Switch RMU SWDC 1 ON at Substation A.

7. Switch RMU SWDC 3 ON at Substation B. (Steps 5, 6, and 7 allow the new ring main unit Substation A and the Transformer 1 to be energised remotely.)

8. Check the no load voltage at the Transformer 1. If the Transformer is energised, this proves that the correct labels are fitted to RMU SWDC 1, RMU FSSW 1, and the Transformer 1.

9. Phase out across the transformer LV disconnectors at the Transformer 1 to the existing LV supply. This proves if the phasing is correct from Substation B.

10. Switch RMU SWDC 1 OFF at Substation A. This proves the operation of the switch while energised.

11. Switch RMU SWDC 2 ON at Substation A.

12. Switch RMU SWDC 5 ON at Substation C. (Steps 11 and 12 allow RMU SWDC 2 at Substation A to be energised remotely. If the Transformer 1 is energised it proves that the label on switch RMU SWDC 2 is correct.)

13. Phase out again across transformer LV disconnectors at the Transformer 1 to the known LV supply. This proves whether the phasing is correct from Substation C.

    Note: Transformer 1 has been supplied from the two HV supplies (Substation B then Substation C) and phased out both times using the LV side of Transformer 1 to an existing LV system – this proves both HV supplies must phase out.

14. Switch RMU FSSW 1 OFF at Substation A. This proves the operation of RMU FSSW 1 while energised.

15. Switch RMU SWDC 2 OFF at Substation A. This proves the operation of RMU SWDC 2 while energised.

16. Switch RMU SWDC 5 OFF at Substation C.

17. Switch RMU FSSW 2 ON at Substation A.

18. Switch RMU SWDC 2 ON at Substation A.

19. Switch RMU SWDC 5 ON at Substation C. (Steps 17, 18 and 19 allow RMU FSSW 2 and the Transformer 2 to be energised remotely.)

20. Check the no load volts at the Transformer 2. If the transformer is energised, this proves that the correct labels are fitted to RMU FSSW 2 and the Transformer 2.

21. Phase out across the transformer LV disconnectors at the Transformer 2 to the known supply. This proves whether the phasing is correct for RMU FSSW 2 and the Transformer 2.

22. Switch RMU FSSW 2 OFF at Substation A. This proves the operation of RMU FSSW 2 while energised.

23. Switch RMU SWDC 1 ON at Substation A. This proves that the new HV circuits parallel successfully.

The switching may then be completed to the required final circuit arrangement and the normal open points set to the designated positions.

All phasing out and switching operations shall be written as part of the switching program.

Using neons to phase out HV

It would also be possible to use the voltage indicators (neon indicators) sockets with a voltmeter to phase out the two HV supplies (from RMU SWDC 3 and RMU SWDC 5). This requires the neons sockets have already been proven to be connected to the correct HV phases inside the switchgear.

An example of the switching sequence required to prove the neons sockets is:

1. With RMU SWDC 3, RMU SWDC 5, RMU FSSW 1 and RMU FSSW 2 all OFF

2. RMU SWDC 1 and RMU SWDC 2 both ON

3. Switch RMU SWDC 3 ON – energises RMU SWDC 1 and RMU SWDC 2 cables

4. Phase out on the neon sockets on RMU SWDC 1 and RMU SWDC 2.

As both RMU SWDC 1 and RMU SWDC 2 cables are supplied from a single HV source (RMU SWDC 3), the correct phasing out proves the neon sockets connections inside the switchgear are correct.

These neon sockets can now be used to phase out the two separate HV supplies to Substation A from RMU SWDC 3 and RMU SWDC 5.

SECTION ELEVEN

To Be Confirmed