DISTRIBUTION BUSINESS

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MANUAL:

DISTRIBUTION NETWORK OPERATION MANUAL

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REVISIONS

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5	Feb 2011	Clauses 11.5.1, 11.5.2 & 11.5.3 changed to comply with PSSR	OT & RTM
6	Dec 2013	Complete document review and Switching Sheet procedures added.	GM AIP

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1. APPLICATION

1.1 Scope

This document provides standard references for operating on the Low and High Voltage Distribution Network. This document must be read in conjunction with the Power System Safety Rules (PSSR) and any relevant approved procedures.

Nothing in this document overrides any requirement of the PSSR.

1.2 Definitions

The principal terms used within this manual are defined in the Power System Safety Rules.

Distribution Network

Aurora owned and operated electrical, mechanical and civil assets that are under operational control.

Authorisation

All authorisations shall comply with NP R NO 17 Distribution Operator Training and Authorisation Standard.

2. SAFETY AND SAFETY EQUIPMENT

AuroraSafe is Aurora's Safety Management System that provides the standards for safe work, to ensure we satisfy our obligations to our employees, contractors and the community. Nothing is this manual overrides the general and specific responsibilities placed upon an Operator by AuroraSafe.

For approved equipment and guidelines Refer AuroraSafe Personal Protection Equipment Guidelines, DM ref CO10610395.

Should there be any doubt of the Operator's capability to operate certain equipment or of the equipment to perform satisfactorily, seek advice.

2.1 Electrical Insulating Gloves

AuroraSafe and live line procedures outlines the use of gloves for mechanical and electrical protection. The following describes the minimum requirements for the use of gloves while operating on the distribution network.

2.1.1 High Voltage Electrical Insulating Gloves for Operating

HV electrical insulating gloves are not to be considered as providing effective insulation from high voltage. They are used to provide protection against possible potential differeneces that may occur while operating.

HV electrical insulating gloves shall be used when operating on the electrical system when:

- Application (High Voltage Overhead Switchgear)
  - Operating uninsulated metal handles, e.g. ganged isolator;
  - When operating extendable operating/measuring sticks;
  - When applying and removing portable earths; and
  - In wet weather when operating, including proving de-energised, phasing and height measuring HV equipment with operating sticks.

- Application (High Voltage Ground Mounted Switchgear)
  - When using phasing out and proving de-energised equipment to High Voltage terminals;
  - When applying portable earths; and
  - When racking switchgear.

2.2 Low Voltage Electrical Insulating Gloves

LV electrical insulating gloves shall be used when operating on the electrical system when:

- Operating / working on or near live low voltage electrical apparatus / equipment;
- Working on de-energised low voltage, which could become energised due to error, accident, embedded generation or system failure; and
- When operating, including proving de-energised, phasing and height measuring HV equipment with operating sticks in dry weather unless an approved work practice allows another method.

2.3 Footwear

Hard-toe-capped footwear is a minimum requirement when on a field worksite or when operating.

2.4 Arc Flash Protective Clothing

Arc Flash Protection shall be applied according to the Personal Protective Equipment Procedure DM ref CO10610395.

2.5 Head and Eye Protection

Safety Helmets and Safety Glasses / face shield are to be worn when an Operator is undertaking the operation of all distribution network equipment.

2.6 Operating Sticks

Only approved operating sticks shall be used and they must be examined before use to ensure that they are sound, dry and free from defects.

The Operator shall be ensured that the insulating medium of an operating stick in use is not ‘bridged out’ by adjacent live conductors or by earthed apparatus.

Operating sticks must be wiped with an appropriate silicon cloth or equivalent before every use when operating on the HV system.

2.6.1 Routine Inspection and Testing

The operating stick shall be examined before use for signs of cracks, surface damage or mechanical defects and shall be wiped thoroughly with a clean dry cloth.

Silicon cloth pads shall be used regularly, at least weekly, to wipe the surface of each glass fibre operating stick to ensure the surface glazing is maintained in good condition.

An electrical test shall be carried out every twelve (12) months. Operating Sticks must have current compliance test information showing date of test and expiry date.

(Refer ESAA Code of Practice for Acceptance Test Procedures and Precautions in Use of Insulated Switch Sticks and Associated Equipment C (b) 6 - 1968.)

2.6.2 Care and Maintenance – Storage

Care must be taken in the handling of operating sticks so as to avoid damage to their surface.

Sticks must be stored in a dry location.

Storage shall be such as to ensure that the operating sticks are not subjected to unnecessary strain or pressure and that the sticks are kept free from contact with sharp implements or other possible causes of damage.

2.7 Notices

Where aparataus has been recently commissioned or energised, hazardous condition tags shall be used in appropriate situations, for example, recently commissioned substations and underground subdivisions.

2.8 Pole Safety Precautions

Pole steps or spikes must be tested by hand before entrusting full weight upon them.

Before climbing any pole, particularly in the dark, the proximity of live LV conductors and street light wires to the operating position and or pole spikes should be noted. Where necessary, exposed live LV conductors shall be covered with approved insulating equipment in an approved manner.

Before putting a ladder against any pole, a check is to be made of the condition of the pole in accordance with approved procedures. If it is branded with a condemned cross or appears to be rotten at the base or unsafe, do not ascend and make other operating arrangements. Impaired poles that have been marked with a half-cross and staked are to be treated as a pole that has not been condemned.

Rescue kits shall be in place ready for use prior to climbing a pole. An Operator must be accompanied by a person who is competent and qualified in Pole Top Rescue and Resuscitation.

2.9 Emergency Operations

In cases of an emergency, an Operator is authorised, even when alone, to carry out any operation necessary to protect life or equipment, provided always that in so doing, the Operator does not place themself in danger.

3. SWITCHGEAR TYPES AND SPECIFICATIONS

3.1 General

Aurora Energy's indoor distribution switchgear and pole mounted line reclosers are rated for breaking the load, magnetising or charging currents likely to be encountered in the system. All such switchgear is rated for fault making, that is, it is capable of being closed onto the maximum fault likely to be encountered.

An exception to this is Hazemeyer switchgear. It is not rated for fault making and shall not be used for sectionalising during fault finding.

Pole mounted switchgear has more limitations on its use and the suitability of this switchgear to safely isolate system components must be considered before operation.

There is a combination of single phase and three phase devices within the network. It is important to understand the limitations of using single phase devices as described in this manual.

3.2 Types of Switchgear

Switchgear comes in four main classes.

These are:

1. Fault make – fault break;
2. Fault make – load break;
3. Load make – load break; and
4. Isolators.

3.2.1 Fault Make – Fault Break

3.2.1.1 Circuit Breakers

A circuit breaker is a device that can make and break maximum fault current likely to occur on the section of system controlled by the circuit breaker. They can automatically clear a fault when detected by an associated relay.

Some circuit breakers are fitted with an auto-reclose function.

Various fault-detecting relays are used to trip circuit breakers and these are discussed later in the manual.

3.2.1.2 FuseSavers

A device that can make and break maximum fault current likely to occur on the section of system controlled by the FuseSaver. They can automatically clear a fault when detected and operate in conjunction with partner EDOs.

3.2.1.3 Pole Mounted Reclosers

These are essentially circuit breakers with integral control gear to provide auto reclosing, remote control, remote monitoring and other functions.

3.2.2 Fault Make – Load Break

3.2.2.1 Switch

Generally ground-mounted equipment.

Switches have no protection function.

If a switch is closed on to a fault, the switch should close normally with no danger to the Operator. The fault should then be cleared by a circuit breaker on the supply side of the switch.

3.2.2.2 Switch Fuse

Generally ground-mounted equipment.

They are a switch with fuses in series with the mechanism.

They are used to switch and protect short lengths of cables and transformers. Most switch-fuses are fitted with trip-all-phases devices to prevent ‘single phasing’.

The fuses are each fitted with a striker pin that protrudes from one end of the fuse when blown. The striker pin hits a tripping bar which trips all three phases of the switch.

3.2.2.3 Pole Mounted Load Break Switch

An SF6 insulated, fully metal enclosed, pole mounted switch.

They provide full fault making and load breaking capability.

3.2.3 Load Make – Load Break

3.2.3.1 Pole Mounted Sectionalisers

Pole mounted sectionalisers are devices designed to work in conjunction with an automatic recloser. They are set to operate after a specific count of recloser operations (often 3, one less than the upstream recloser). They open during the recloser dead time when there is no current flow.

An actuator is used to measure current changes and initiates the opening of phases simultaneously.

3.2.3.2 Pole Mounted Ganged Isolators

Pole-mounted ganged isolators have the ability to carry load, but only limited ability (according to its category) to interrupt load, magnetising or charging currents.

3.2.3.3 Pole Mounted Fuses

Pole-mounted isolators/ fuses have the ability to carry load, but only limited ability (according to its category) to interrupt load, magnetising or charging currents.

3.2.3.4 Isolators

Isolators are generally non-load operating equipment. On the Distribution Network isolators such as HV links and fuses have limited load breaking capacity.

3.3 Choice of Switchgear

Where there is a choice of suitable equipment to de-energise or re-energise a section of the distribution system, the equipment should be used in the following order of preference:

1. Ground mounted circuit breaker;
2. Ground mounted switch, Pole mounted line recloser, Load Break Switch or FuseSaver;
3. Pole mounted ganged isolator or links with arc breaking device;
4. Pole mounted ganged isolator or links without arc-break device; and
5. Pole mounted fuses.

Notes:

Switching Sheets should not be unnecessarily extended to enable the use of switchgear higher on the order of preference when other equipment will adequately and safely perform the required operations.

In some circumstances, the use of single-phase devices may not be possible because ferroresonance situations may be created, or mal-operation of earth fault protection may occur which will cause circuit breakers to operate.

4. IDENTIFICATION

All apparatus and associated switchgear shall be identified and labelled according to approved procedures prior to commissioning. If any identification is found to be inadequate, steps must be taken to rectify immediately.

5. FAMILIARITY WITH LOCAL SYSTEM

Local knowledge will benefit an Operator and allow them to identify errors or omissions more easily. Operators should be encouraged to study the local system layout diagrams with particular reference to the following points:

1. Terminal Substation points of supply;
2. Sub transmission Feeders;
3. Zone Substations;
4. Voltage Regulators and their special requirements;
5. Primary Feeders;
6. Distribution Substations;
7. The areas of supply of the above components;
8. Restrictions for inter-connection of these components;
9. The types of switchgear in the local area;
10. Potential system hazards such as fault level which may exceed switchgear or line capacity, two HV circuits on the same pole and areas of different phasing;
11. Local reclosing instructions following faults including auto-reclosing facilities where used;
12. Local instructions for fault location including the location of fault indicators;
13. Local communication systems; and
14. Intertripping or interlocking facilities used in substations.

6. OPERATING PROCEDURES

The Operator's function is to carry out operation of equipment that generally performed from pre-prepared written switching sheets.

On occasions, the Operator will be required to prepare their own switching sheet and must be aware of the consequences of each switching action at all times and conform to the procedures set out in the Power System Safety Rules.

The requirements of any customers affected must have been considered and dealt with by approved procedures. Various aspects of operating are dealt with under the following headings so that the Operator will have a better understanding of recommended operating procedures.

6.1 Paralleling of High Voltage Feeders

There are four main categories of paralleling on the High Voltage system.

These are:

1. Paralleling of sections of the same feeder;
2. Paralleling of feeders originating at the same substation busbar section;
3. Paralleling of feeders originating from the same substation connected to different busbar sections; and
4. Paralleling of feeders originating at different substations or different supply transformers.

Paralleling Conditions will be prepared for situations involving parallels between feeders from major substations.

In addition, Transmission Control, Distribution Control and Operators at terminal substations may be involved and be responsible for taking certain precautions.

6.1.1 Paralleling of Sections of the Same Feeder

This is generally known as section parallels or section rings or ringing.

Connections through the open paralleling point to have been phased out previously

Where earth fault relays are fitted within the loop (e.g. associated with line reclosers), switching on single phase devices should be avoided where ever possible.

If the situation cannot be avoided, the earth fault protection must be disabled.

Where voltage regulator(s) are installed within the loop formed when two branches of a feeder are inter-connected, the regulator(s) should be switched to manual control and adjusted to neutral tap unless otherwise directed by Distribution Control.

6.1.2 Paralleling of Feeders Originating at the Same Substation Busbar Section

Where voltage regulator(s) are installed within the loop formed when two branches of a feeder are inter-connected, the regulator(s) should be switched to manual control and adjusted to neutral tap unless otherwise directed by Distribution Control.

Where Line Reclosers exist within the loop their protection function must be disabled.

Auto-reclose facility at the feeder circuit breaker must be switched out of service.

Switching on single-phase devices should be avoided where possible.

If the situation cannot be avoided any earth fault protection within the parallel must be disabled.

6.1.3 *Paralleling via Single Phase Devices*

Paralleling using single-phase devices is only allowed subject to:

1. The parallel involves the same feeder or two feeders off the same section of busbar and supplied by the same transformer(s);
2. Paralleling condition being investigated and approved;
3. The individual paralleling conditions have been analysed. This is to ensure that hazardous conditions especially transfer and out of balance currents, have been considered. Where these are beyond the rating of the device being operated, the parallel is not permitted; and
4. Disabling the earth fault protection involved in the parallel. This is to ensure that the ensuing single phasing does not trip the protection equipment.

Where earth fault relays are fitted within the loop (e.g. associated with line reclosers), switching on single-phase devices should be avoided where possible.

If the situation cannot be avoided, the earth fault settings on protection relays may be switched out of service, or higher settings may be employed temporarily on the earth fault relays.

6.1.4 Paralleling of Feeders Originating from the Same Substation Connected to Different Busbar Sections OR Paralleling of Feeders Originating at Different Substations or Different Supply Transformers

Distribution Control shall investigate such parallels prior to approving.

Where voltage regulator(s) are installed within the loop formed when two branches of a feeder are inter-connected, the regulator(s) should be switched to manual control and adjusted to neutral tap unless otherwise directed by Distribution Control.

Where Line Reclosers exist within the loop their protection function must be disabled.

Auto-reclose facility at the feeder circuit breaker must be switched out of service.

Paralleling using single-phase devices SHALL not be conducted.

6.2 General Precautions when Paralleling on High Voltage System

6.2.1 Overcurrent Protection

Since the paralleling operation is usually for the purpose of transferring load, it follows that on the feeders involved, over current relay settings and line recloser ratings must be high enough to ensure that there is no danger of operation due to the increase in load. A reasonable margin in settings is required due to uncertainty in the balance of load sharing during the parallel and also because reactive load flow currents may be quite large.

It is deemed inappropriate to parallel through fuses.

6.2.2 Earth Fault/Leakage Protection

Earth fault protection systems based on residually connected current transformers or core balance current transformers, may see unbalance in the phases during an earth fault.

This unbalance can occur while the parallel is being made, broken, or during the period in parallel, and hence cause a circuit breaker or line recloser to operate.

Making or breaking the parallel with a single phase switching device will exacerbate this problem and may cause tripping and such switching should be avoided when possible.

6.2.3 Operational

In preparing switching sheets care must be taken to include setting and restoring to normal any changes made to protection. Any changes must be approved by Distribution Control and should be made only by Operators authorised for the circuit breaker or device that the protection is controlling.

6.2.4 Automatic Tap Changers

6.2.4.1 Substation Supply Transformers

When paralleling feeders, various actions may be necessary including changing the tap change controls to manual.

The bus section voltages at each substation shall be adjusted to minimise transfer currents when necessary.

Tap changers at each substation may need to be switched to manual control for the duration of the parallel.

If the parallel is expected to be required for an extended period, it may be necessary to monitor the feeder ammeters and adjust taps accordingly.

6.2.4.2 Regulators

One or more voltage regulating transformers may be installed along the route of an HV feeder. When feeders originate from different sources or from separate supply transformers, interaction of automatic voltage regulating equipment may lead to high circulating currents. During the parallel, the voltage regulators should be placed on manual control.

Where appropriate calculations have been conducted, the regulating transformers may be allowed to remain in normal operation. Such paralleling conditions shall be approved by Distribution Control

6.2.4.2.1 *Single Phase Regulator Units*

Consideration must be given when making a parallel where there are multiple Open-Delta Regulators. Each one may introduce a level of Sensitive Earth Fault relevant to the load on the feeder/s. Such paralleling conditions are to be approved by Distribution Control.

6.2.5 Pole Mounted Auto Reclosers

One or more pole mounted line reclosers may be installed along the route of an HV feeder. Before the parallel of such a feeder the following precautions should be taken:

Recloser to be bypassed or protection disabled.

6.2.6 Substation Circuit Breaker Auto Reclosers

The auto reclosers on Substation Feeder Circuit Breakers are to be switched out of services during feeder parallels.

6.2.7 Duration of Parallel Condition

The time during which feeders are operated in parallel should be kept as short as practicable.

6.2.8 Phasing

All new construction shall be phased out prior to bringing into service.

If any high voltage connections are broken during any other work and there is a possibility that they could be incorrectly reconnected then phasing checks must be performed. Generally, if more than one phase connection has been broken then a phasing check will be required.

One exception is where a high voltage line is disconnected and because its construction is straight through and impossible to connect incorrectly.

6.2.9 Load Balance

When paralleling two feeders of different load capabilities, length, or impedance, it is possible that a large transfer current may occur due to the voltage differential at the open point. This can cause one feeder to carry a disproportionate load, possibly overloading it causing it to trip out. Load checks may need to be carried out to ensure the load transfer is within the feeder capabilities.

6.3 General Precautions when Paralleling on the Low Voltage System

6.3.1 General

Transformers are normally not operated in parallel for lengthy periods but where possible they should be paralleled to minimise interruption to customers.

6.3.2 Requirements

Transformers may only be operated in LV parallel when their voltages are in phase and their secondary voltages are of the same order, and preferably supplied by the same HV Feeder.

If the phasing is not known then paralleling points must be phased out prior to closing.

Loading on LV shall not exceed the capability of the conductors.

Transformers should not be overloaded.

Immediately after LV parallels have been made, checks shall be made to ensure that LV conductor ratings have not been exceeded. If these checks are not carried out at peak period further tests will be required.

LV parallels should only be made if a supply of acceptable quality can be achieved.

Low voltages (below 230 volts) may cause damage to customers' installations and should be avoided.

All LV parallels should be removed as soon as possible after completion of work.

6.3.3 LV Paralleling Risks

When an LV parallel is across HV Feeders, loss of either HV feeder can cause the low voltage circuit to supply the existing load of the feeder. This will potentially cause significant overload on conductors that will lead to high risks to public due to loss of circuit clearance, or annealing and damage to fittings.

The tripped feeder may remain 'live' via the LV parallel to the energised feeder(s).

Damage to loops, links and conductors may result and transformer and substation fuses may blow depending on the magnitude of currents.

All paralleled transformers and LV circuits must be thoroughly checked for possible damage.

6.3.4 LV Parallels Causing HV Parallels

Parallels involving transformers connected to feeders supplied from different zone or terminal substations i.e. 'across zone or terminal' parallels, should only be made when absolutely necessary and feeder re-arrangements cannot be made to avoid them.

Where it is absolutely imperative that LV parallels are made involving transformers connected to:

1. Different feeders supplied from the same terminal or zone substation; or
2. Different feeders supplied from two zone or terminal substations,

then:

1. Paralleling conditions must be investigated and the risks outlined in this section must be understood; and
2. An appropriate risk mitigation strategy be produced.

6.4 Transmission Network Control Requirements

Except in the case of an emergency, a period of notice is required for planned paralleling of feeders that originate at different terminal substations or bus sections. The amount of notice that is required is detailed in the agreement between those responsible for Transmission and Distribution Operations.

This is to enable checks to be made to ensure that any load transfer can be accommodated and that system conditions permit the parallel.

Where the feeders concerned originate at the same substation, Distribution Operations expects that the Transmission Control should be able to handle requests for paralleling with minimal notice. Even so, as much notice as possible should be given, except in emergencies.

Communication must be maintained between Distribution Operations and the Transmission Control. Transmission Control should be notified immediately prior to the making of the parallel and again as soon as the parallel is broken.

6.5 Fault Reclose Procedure

6.5.1 Fault and cause identification

Where protection equipment controlling lines has caused the line to trip and lock out, information regarding the cause and location of the fault may be available from:

1. Protection relay flags;
2. Line Fault Indicators;
3. Reports of flashes, explosions, trees on lines, car hit pole, wires down, lightning etc.;
4. Investigation of reports;
5. History of the line;
6. Certainty of cause of fault or location from other sources; and
7. An inspection of the line.

6.5.2 Line Inspection/Patrol

Consideration whether a line inspection is warranted should include:

1. Length of line;
2. Accessibility of line;
3. Time of day and visibility;
4. Potential risk of personnel undertaking patrol;
5. Traffic and road conditions;
6. High or extreme fire danger periods; and
7. Weather Conditions.

6.5.2.1 Severe Weather Warning

The line must be patrolled to its extremities where both:

1. A line has tripped and locked out on days where a Severe Weather Warning has been issued by the Bureau Of Meteorology; and
2. Multiple calls are received advising of wires down in areas supplied by the line.

Note: This may involve the isolation of spur-lines off the main trunk enabling restoration of the feeder followed by further patrol and restoration of the spurs.

6.5.3 Manual Reclosure after Fault Trip and Lockout

6.5.3.1 General Principles

Immediately before each reclose is attempted, Distribution Operations shall gather information regarding the cause of fault by making enquiries to:

1. Call Centre;
2. Ambulance;

3. Police;
4. Fires service (in high or extreme fire danger periods); and
5. Relevant work crews working on or near the line under fault eg live-line, vegetation, switching and repair crews etc.

   Reclosing shall not be performed until relevant work crews are clear of the line and have been advised that a reclose is to be attempted.

6.5.3.2 Minimum Time of Initial Reclose

Before a reclose of the line is attempted, a minimum of 15 minutes shall elapse from:

1. The time of initial lockout; or
2. The first communication from affected customers.

This period of time may be reduced if the cause of the fault has been established or removed and it is no longer a hazard to persons or equipment.

6.5.3.3 Removal of Fault Cause

If the cause of the fault is removed or proved to no longer be a possible hazard to persons or equipment, the line may be reclosed immediately.

6.5.3.4 Restoration to Non Fault Areas

Power should be restored as soon as possible to areas that are without supply but are not part of the faulted section of line.

Priority shall be given to:

1. Critical supplies customers eg hospitals, sewage works etc.; and
2. Feeder trunks.

6.5.3.5 Considerations Prior to Reclose

The following aspects shall be given due consideration before a reclose is attempted so that Distribution Controller can make appropriate decisions about a reclose and its possible lockout:

1. Probable cause of fault;
2. Relevant information gained eg customer reports, relay and fault indicator operations etc.;
3. Interruption time to critical supplies eg hospitals, sewage works etc.;
4. Impact of interruption upon customers;
5. Route of the line eg local knowledge;
6. Weather conditions existing at the time;
7. The location of work groups in the fault area;
8. Length of HV underground cable installed;
9. The demand of cold load pickup on the line; and
10. Reducing fault level at tripped device.

6.5.3.6 Disabling Auto-reclose Facilities

Where automatic reclosing facilities are fitted, the auto-reclosing facility shall be disabled (e.g. made to 'one shot' or 'one trip to lockout') before a reclose is attempted.

6.5.3.7 Sectionalising

Sectionalising is the process where sections of the distribution network are sequentially de-energised and re-energised to locate the fault.

Once the fault is located and isolated, priority shall be given to restoring supply to customers outside the isolated section.

6.5.3.8 Manual Reclosure

6.5.3.8.1 *Overhead System*

See also General Principles (Section 6.5.3.1).

An initial reclose can be undertaken without sectionalising.

Any known fault indicator operations shall be analysed before selecting sectionalising point(s).

Where a line supplies both an urban and a rural area, it should generally be isolated at the first available position past the urban area.

A repeat reclose may be performed 30 minutes or greater after an initial manual reclose.

6.5.3.8.2 *Underground System*

See also General Principles (Section 6.5.3.1).

Initial reclosure of the line should only occur after the line has been sectionalised as more expensive equipment is involved, every effort should be made to keep the number of recloses to a minimum.

6.5.3.8.3 *Combined Overhead and Underground System*

See also General Principles (Section 6.5.3.1).

Where the overhead portions of the feeder are significantly larger than the underground portions, greater than 80% overhead, the chances are in favour of the fault being in the overhead area.

At the earliest opportunity, the major overhead and underground components are to be separated and treated as per Table 1.

Table 1: Manual Reclose Methods

System Type	Manual Reclose Method
Majority overhead	To be treated as an overhead system (Section 6.5.3.8.1) after the majority of the underground system has been isolated.
Majority underground	To be treated as an underground system (Section 6.5.3.8.2).

6.6 Single Phase Switching and Ferroresonance

Ferroresonance is a ‘tuned circuit’ effect that can exist when transformers (inductance) and/or insulated cables (capacitance) are closely connected.

When a voltage is applied to a series circuit containing capacitance and inductance, a condition known as resonance occurs if the reactive ohms of the capacitance are equal to the reactive ohms of the inductance. The result of resonance is the formation of high voltages (or voltage magnification) across the inductance and the capacitance.

This series circuit may be set up during single phase switching, as a length of HV cable provides a capacitance while a transformer provides inductance.

6.6.1 Precautions

Wherever possible avoid switching underground cable connected transformer installations on single-phase devices eg pole mounted fuses or Hazemeyer Magnefix switchgear, etc.

High voltages across the single-phase devices may exist whilst switching is in progress to energise or de-energise an unloaded transformer connected to an underground cable.

6.6.1.1 Where Single Phase Switching Devices have to be Used

The following is a guide to where single-phase devices are to be used and there may be ferroresonance conditions created.

Switch from a point close to, and preferably at, the transformer first and then, when necessary, carry out switching at more remote points.

If necessary, switching may be able to be carried out on the nearest three-phase switch and the single-phase devices operated only while de-energised.

If more than 30 metres of HV cable has to be switched with the transformer, where possible ensure that some resistive (heating) load is connected on all three LV phases of the transformer. Depending on the length of cable a load of approximately 5 to 10% is required.

6.6.1.2 Recommended Values

The following table shows commonly used combinations of cables and transformers. Isolation or breaking of load currents may be performed on single-phase devices where the cable length, as shown in Table 2, is not exceeded.

Table 2: Ferroresonance cable length

Ferroresonance – Energising or de-energising load			
Transf. Rating (kVA)	**Voltage**	**Cable size**	**Max length (metres)**
300	11kV	95mm²	16
500	11kV	95mm²	30
500	11kV	240mm²	25
750	11kV	95mm²	45
500	22kV	50mm²	7
750	22kV	50mm²	10

6.7 Single Phasing

6.7.1 General

Overhead transformer and high voltage fuses are not normally fitted with ‘trip all-phases devices’ to trip the three phases when one or more fuses blow.

This means that if one phase fuse blows, a transformer will remain energised from the other two phases. This condition is known as single phasing.

The result is low and unbalanced voltage on the low voltage side of the transformers and damage may be caused to customer's motors or other equipment where the customer has not protected against this. A ‘single phasing’ condition must therefore be removed as soon as possible.

6.7.2 *Overhead Devices*

Single-phase conditions can be removed by:

1. Opening of a series connected ganged isolator or line recloser if the connected capacity is excessive or if a ferroresonance condition may exist; or
2. Draw the remaining fuses (if conditions above do not exist).

6.7.3 *Ground Mounted Devices*

Hazemeyer-MD4 switch-fuses are not fitted with trip-all-phases devices to trip out the switch when one or more fuses blow. This will cause single phasing.

6.8 Intertripping

Sometimes it is necessary for more than one circuit breaker or switch-fuse to trip when faults occur in certain circumstances or in certain positions in the distribution system.

The Operator must know if this facility is used in the Operator's area and where the intertrip may be switched off.

The intertrip must be switched off if only one of the circuit breakers or switch-fuses is to be opened for any reason, otherwise the others will open when the first is opened. It is also important that the intertrip is switched back into service after all circuit breakers or switch-fuses are restored to their normally closed position.

Intertripping may be achieved by two different methods:

1. Intertripping via protection relays; and
2. Intertripping via circuit breaker/switch status auxiliary switch.

6.8.1 Intertripping via Protection Relays

In some situations, a fault-detecting relay is used to trip more than one circuit breaker, either directly or via auxiliary relays usually employing a DC trip supply. The circuit breakers concerned are normally in different substations. Operators must be aware if the facility is used in their area and, when faults and trippings occur, must check all circuit breakers involved in the intertripping arrangement.

For normal switching operations, no additional precautions are necessary as the operation of one circuit breaker will have no effect on the others.

6.8.2 Intertripping via Circuit Breaker/Switch Status Auxiliary Switch

The other intertripping method used employs auxiliary switches in a circuit breaker or switch-fuse to directly trip one or more neighbouring devices, usually within the one substation.

These auxiliary switches are mechanically operated by the movement of the circuit breaker or switch-fuse. They close when the circuit breaker or switch-fuse opens.

The auxiliary switch then connects an AC or a DC trip supply to the trip coils of the other devices involved. A further simple on-off switch is provided in order that the intertripping facility can be removed from service when required.

6.9 Protection Alterations for Work on or in the Vicinity of Live HV Assets

Where work activities necessitates altering the normal setting of feeder circuit breaker or line recloser Sensitive Earth Fault (SEF), Live Line, and Auto Reclose (A/R) protection, the following is to be adopted.

Notes:

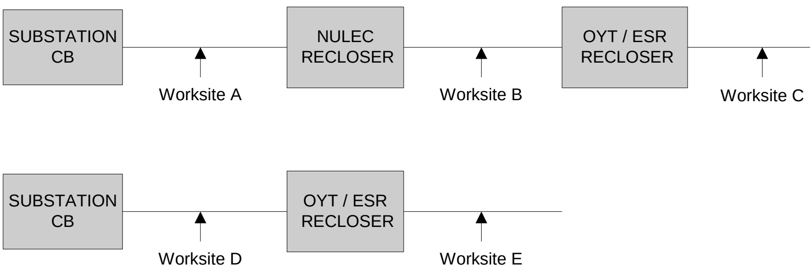
'Live Line Setting' switches the substation circuit breaker protection auto-reclosing facility to one (1) trip-to-lockout and sets the tripping time for overcurrent, earth and sensitive earth faults to a fast setting. (i.e. reduces the time to trip)

'Work Tag Setting' is the same as 'Live Line Setting' when applied to a Nulec pole-mounted recloser

Examples of Line work where protection alteration is required includes:

- Live HV Line Work;
- Running LV conductor under live HV;
- Erecting pole near live HV; and
- Close-vicinity vegetation management work.

Any alterations to protection settings shall be performed by an Operator



6.9.1 Alteration of Protection Settings

6.9.1.1 Worksite A:

Substation Circuit Breaker:

- Set the substation circuit breaker protection to 'Live Line Setting'.

If the substation circuit breaker protection does not have a 'Live Line Setting' then:

- Set the substation circuit breaker Sensitive Earth Fault (SEF) relay to the 'Instantaneous' mode; and
- Set the substation circuit breaker Auto-reclosing facility to 'One (1) Trip-To-Lockout'.

6.9.1.2 Worksite B:

Nulec Recloser:

- Set the Nulec Recloser protection setting to 'Work Tag Setting'.

6.9.1.3 Worksite C:

OYT Recloser:

- Set the OYT Recloser protection Auto-reclosing facility to 'One (1) Trip-To-Lockout'.

AND

Nulec Recloser:

- Set the Nulec Recloser protection setting to 'Work Tag Setting'.

6.9.1.4 Worksite D:

Substation Circuit Breaker:

- Set the substation circuit breaker protection to 'Live Line Setting'.

If the substation circuit breaker protection does not have a 'Live Line Setting', then:

- Set the substation circuit breaker Sensitive Earth Fault (SEF) relay to the 'Instantaneous' mode and
- Set the substation circuit breaker Auto-reclosing facility to 'One (1) Trip-To-Lockout'.

6.9.1.5 Worksite E:

OYT /Recloser:

- Set the OYT Recloser protection Auto-reclosing facility to 'One (1) Trip-To-Lockout'.

AND

Substation Circuit Breaker:

- Set the substation circuit breaker protection to 'Live Line Setting'.

If the substation circuit breaker protection does not have a 'Live Line Setting', then:

- Set the substation circuit breaker Sensitive Earth Fault (SEF) relay to the 'Instantaneous' mode

6.9.2 Period of Setting

The setting of these facilities is to be conducted in a prudent manner. Where these settings are maintained for extended periods, the possibility of lock-outs place System Reliability at risk. This activity can clearly cause widespread interruption should a transient fault occur and the extent of time engaged in such fashion should be limited.

Wherever possible the alteration of any protection for Live Line work is to be conducted as soon as practicable PRIOR to the close proximity work. The protection is to be returned to normal as soon as practicable once the work has finished.

For vegetation work it is acceptable to set Auto-Reclose facilities for planned work at the commencement of the working day. Vegetation crews need to confirm this has been set prior to commencing their work, and must call Distribution Control as soon as their work on that feeder is completed.

6.9.3 Requests

The work party leader must ensure that permission to commence work is obtained from the Distribution Control prior to commencement and provide immediate advice when the work is completed.

6.9.4 Notice

A suitable entry advising, 'live-line work is in progress', shall be logged in the control room.

6.9.5 Completion of Work

On completion of work protection is to be returned to its normal setting.

7. SWITCHING SHEETS

7.1 General

Switching Sheets are required for all High and Low Voltage switching on Aurora's Distribution Network.

Details of when required and exceptions are outlined in the Power System Safety Rules (PSSR).

Service and street light work are generally exempt from Switching Sheets. Where service or LV phasing or phase rotation is affected by switching items on the LV distribution network then embedded notes or items shall be added to ensure correct phasing and rotation. For example, where an LV open point that does not phase out is moved.

Removal of service fuses for guarding against back feeds is not normally included on a switching sheet.

The intent of a Switching Sheet is to provide as much information possible for an Operator to operate the correct device in the correct sequence maintaining system and switchgear integrity and provide an understanding of the consequence of the operation.

7.2 Authorisation

Persons who compile/prepare or check Switching Sheets must have undertaken appropriate training and be authorised by Operating Standards as a Distribution Operator. Operators shall only prepare and check Switching Sheets that involve devices that they are authorised to operate. Distribution Control DC Operators are authorised to prepare and check switching sheets for all device types.

This does not preclude persons in training preparing a switching sheet and having it co-signed by an Authorised Operator.

7.3 Request to Access the Distribution System (RADS)

Permissions for all planned switching sheets shall be generated using the online Request to Access the Distribution System (RADS) tool. The RADS tool is the responsibility of Distribution Control and includes timelines for the creation and actioning of all planned switching sheets.

7.4 Operator in Charge

It is necessary for the overall control of switching sheet operations to be controlled by one person. This person shall be known as the Operator In Charge and is responsible for ensuring authorised persons complete all items in the correct sequence. The Operator in Charge may also be an Operator involved in the switching. The Operator In Charge shall be clearly identified on page one of all copies of all switching sheets.

Where there are multiple operating parties and the Operator in Charge delegates the actioning to other Operators, they must ensure the other Operator has a copy of the switching sheet and must enter a time against each switching item prior to actioning or delegating the next item.

7.5 Authorised Operators

Authorised Operators are to operate only equipment and devices that they are authorised to operate.

7.6 Unplanned Switching Sheets

Unplanned Switching Sheets are, in principle, prepared as for normal planned operation work. The main difference is that due to the unknown nature of faults, the Switching Sheet items may be prepared and consequent actions conducted one at a time.

Distribution Control is responsible for preparing all unplanned Switching Sheets in the standard format. Preparation and checking may be delegated to field Operators if Distribution Control has received a copy of and approved the switching sheet prior to actioning.

The Operator will verify its correctness by reference to system diagrams and onsite inspection. If a Generic Switching Sheet is fit for purpose then Distribution Control may approve the use providing it is prepared and checked by two Authorised Operators, one of which may be from Distribution Control.

Permission to commence must be received from Distribution Control for all Switching Sheets.

The Distribution Control Operator shall be the Operator in Charge unless responsibility has been delegated to another Operator.

Operators are permitted to execute any appropriate switching operation to remove an existing or potential hazard to life or property provided that such action is reported to Distribution Control as soon as possible.

Where an Access Authority is issued as a consequence of a non-generic unplanned Switching Sheet then the isolation and earthing content of the switching shall be checked by an Authorised Operator, field or Distribution Controller other than the person who prepared.

7.7 Oral Instructions

An Operator receiving the oral instruction must write it down and confirm by reading it back to the Operator in Charge before carrying out the switching operation.

7.8 Embedded Notes

Embedded notes may be added where additional information assists the Operator to understand system, service or customer requirements relating to single or multiple items. Such notes must be on the same page and prior to the first related item. All embedded notes shall be formatted the same as the following items 1 and 2 to include an item number and time column.

ITEM No.	STATION No. AND NAME	SWITCHGEAR EQUIPMENT NAME/LETTER	OPERATOR	OPERATION	REMARKS	TIME
1.	Approval to commence Switching Sheet given by ______________________________________of Distribution Control					
2.	Customers have been notified of outages, confirmed by: _____________________________					
3.	C123 Pole 2 Smith Street	11kV Links		Close	Rings Feeder 51-001	
4.	C456 Pole 12 Green Street	11kV Links		Open	Breaks ring Feeder 51-001	

Any actions that must be done as part of the switching sequence shall be identified as a switching item.

7.9 General Principles for Preparing and Checking of Switching Sheets

1. The Switching Sheet shall have its own unique number on each page of the switching sheet;
2. The objective of the Switching Sheet must be clearly defined within the description;
3. Only approved abbreviations from PSSR shall be used within Switching Sheets headers;
4. When using more than one sheet for an operating objective eg. Page 1 of 2 and Page 2 of 2 cross referencing must be used;
5. The Switching Sheet shall include confirmation of permission to start from Distribution Control as item 1 as an embedded note, if required;
6. The Switching Sheet shall include confirmation of customer notification as item 2 as an embedded note if required;
7. A separate Switching Sheet shall be prepared for each objective;

8. All devices/equipment must be identified by Station Number and Name, Device Type/Number and Label;

9. Where the operation of a device is by remote control/SCADA, the Operator shall be identified on the Switching in the Operator column;

10. The Switching Sheet must be checked against the latest versions of schematics and asset records when used;

11. Switching Sheet shall include approved terminology, where applicable;

12. The switching sequence shall be arranged with safety of the Operator in mind;

13. The switching sequence shall satisfy device capability;

14. The switching sequence shall satisfy system capability;

15. The switching sheet shall include confirmation of any required pre-commissioning tests or checks;

16. The switching sequence shall allow for transfer of load such that minimum interruption of supply occurs;

17. Concurrent switching items shall have an identifying embedded note at the start of and at the end of the concurrent items;

18. Isolation items shall be identified by entering ‘Isolation Point – Apply DO NOT OPERATE Tag’ in the remarks column;

19. Where devices require a specific action for isolation after opening to ensure against inadvertent closing, such as locking out a RL27 load break switch. All such actions shall be described as a switching item;

20. Earthing items shall be highlighted;

21. All items shall be legible and clearly defined;

22. All switching sheet pages shall be signed by the person who prepares and checks prior to approval. Generic switching sheet are an exception as they are approved for use prior to. The intent is for the signature to clearly identify the person signing, where the signature does not achieve this then the person must print their name prior in addition to signing. Electronic signatures are acceptable for the preparer;
23. All items shall be checked for accuracy and completeness before each page is signed;
24. The Operator who signs as prepared cannot sign as checked;
25. The end of a switching sequence shall be clearly defined, ruled off for pad format or end statement for electronic format; and
26. The consequence of the switching items shall be described in the remarks column.

7.10 Approval

Distribution Control must approve all Switching Sheets. In some cases where a switching is prepared in the field from information not available to Distribution Control then approval is assuming that the information from the field is correct. For example, low voltage circuit detail.

Generic Switching sheets are approved prior to preparation.

7.11 General Principles for Actioning of Switching Sheets

1. Only Operators authorised for the devices concerned will perform the operations, this does not preclude trainee Operators operating under the direct supervision of an Authorised Operator;
2. The Operator In Charge must check to ensure the switching is appropriate prior to commencement;

3. There must be a time inserted for each item prior to actioning the next item;

4. For all operating other than Distribution Control, immediately prior to actioning a switching item, it must be confirmed that the device to be operated corresponds to the information on the switching sheet by the Operator and a second person. Each person shall initial each item before actioning the next. The second person is not required where other approved control measures are in place;

5. When taking over a partly-actioned Switching Sheet, the contents must be fully understood before continuing;

6. Where a Switching Sheet has an Access Authority or Apparatus Interface Statements involved, the document number and name of the person it is issued to must be passed to Distribution Control for entry into the Daily Log;

7. Switching Sheet start, stop and completion times must be entered into the Daily Log;

8. Distribution Control must hand address any schematic changes as soon as possible after the completion of a Switching Sheet; and

9. DO NOT OPERATE tag shall only be removed by an Authorised Operator actioning a switching sheet corresponding to the detail on the tag. Where a tag has not been removed and found later then it may only be removed by an Authorised Operator with permission from Distribution Control.

7.12 Switching Sequence

The switching sequence must be followed exactly in all cases unless concurrent items have been identified on the Switching Sheet.

Concurrent Items are items that are identified, grouped together and may be completed in any order. The intent is to only make items concurrent when they are of a similar nature. It is permissible to carry out items concurrently as long as such switching does not compromise the safety of the system or operating personnel. The concurrent items shall be identified on the switching sheet at the start and at the end of each concurrent sequence by an embedded note.

ITEM No.	STATION No. AND NAME	SWITCHGEAR EQUIPMENT NAME/LETTER	OPERATOR	OPERATION	REMARKS	TIME
5.	Items 6,7,8 can be done concurrently					
6.		LV links		Close		
7.		LV links		Close		
8.		LV links		Close		
9.	Confirm items 6,7,8 have been completed					
10.	Items 11,12,13 can be done concurrently					
11.		11kV Ganged Isolator		Open	Isolation Point Apply DO NOT OPERATE tag	
12.		11kV Ganged Isolator		Open	Isolation Point Apply DO NOT OPERATE tag	
13.		11kV Ganged Isolator		Open	Isolation Point Apply DO NOT OPERATE tag	
14.	Confirm items 11,12,13 have been completed					
15.	Items 16,17,18 can be done concurrently					

ITEM No.	STATION No. AND NAME	SWITCHGEAR EQUIPMENT NAME/LETTER	OPERATOR	OPERATION	REMARKS	TIME
16.		***11kV Overhead Conductors***		***Prove De-energised and Earth***		
17.		***11kV Overhead Conductors***		***Prove De-energised and Earth***		
18.		***11kV Overhead Conductors***		***Prove De-energised and Earth***		
19.	Confirm items 16,17,18 have been completed					

7.13 Alterations

If a switching sheet has to be altered in any way then approval must be given by Distribution Control. Any alterations or error must be initialled and clearly ruled out with a single line. Correction tapes or fluids must not be used.

Where approval to change the operating sequence is granted by Distribution Control, the Switching Sheet must be amended, checked and re-authorised before work resuming. Re-countersigning is the normal method of re-authorising the Switching Sheet. Switching must not commence on an altered Switching Sheet until the alterations have been initialled by an Authorised Operator. The alteration must be checked by an Authorised Operator with appropriate knowledge and not be the person amending.

Where a field Operator is involved the field Operator shall record the name of the Distribution Control approving officer on the Switching Sheet. The Distribution Control approving officer shall record the name of the field Operator on the Switching Sheet.

The altered switching sheet shall be clearly identified by some means of version control to ensure the correct switching is being actioned. Where there are multiple field copies of a switching sheet all participating Operators must be made aware of the alterations by the

Operator in Charge. Those Operators actioning altered items must have the changes recorded on their copy as above.

7.14 Do Not Operate Tags

Where an open point has been checked open and a DO NOT OPERATE tag fitted then there must be a corresponding item on the switching sheet to remove the tag.

7.15 Earthing

All earthing items shall be highlighted.

There shall be a separate item for each set of earths applied or earthing device operated.

Where Earth Switches are operated they shall be identified in the SWTCHGEAR EQUIPMENT NAME/LETTER column as Earth Switches with a prefix of their operating voltage and followed by the device number and cubicle label in inverted commas.

Where Earth Switches are being closed then there shall be a separate switching item for proving de-energised immediately prior to the closing item.

Where portable earths are being installed then proving de-energised and the application of the earths shall be described within the one switching item. For example, ‘Prove De-Energised and Earth’.

‘Apply DO NOT OPERATE tag’ must be entered in the remarks column when appropriate.

7.16 Removable or Rackable Switch or Circuit Breaker Carriages

If a removable or rackable switch or circuit breaker carriage is racked or moved then each action must be shown as a switching item.

7.17 Switchgear Maintenance

If the objective of a switching sheet is switchgear maintenance then the switching sheet shall include all items necessary to access the switchgear to be maintained. That is, if the switchgear mechanism needs to be racked down and withdrawn from its cubicle then the switching sheet shall describe every movement of such mechanisms.

7.18 Removal of Switchgear Carriages Exposing Live HV Conductors or Busbar Shutters

If HV conductors have been exposed and are accessible as a consequence of a switching item then additional items must immediately follow to ensure the conductors are covered. For example, if a RGB24 line switch is removed and the bus remains live then an item must be included to fit a blank or covering device immediately. Locks and tags must be placed to prevent access to exposed Bus Bar Shutters and cable spouts that remain live.

7.19 Standard Format

The following formats shall be used for all planned and unplanned Switching.

1. The standard format generated by Distribution Control's Switching writing program.
2. Page 1 and 2 in pad format available from stores.

Any other formats used shall be approved by Distribution Control prior to use.

The following describes the minimum information required on the header of page 1 of all switching sheets:

DATE	Commencement date of the Switching Sheet
ADVERTISED TIMES	Times advertised to affected customers
PERMIT TIMES	Times access authorities are required
NUMBER	A unique number issued by Distribution Control
COMMENCE TIME	Planned commence time
WORK LOCATION/ DESCRIPTION	Location of switching followed by a clear description of its objective
WORK GROUP	The work group that the switching is being performed for
OPERATOR IN CHARGE	Name of Operator In Charge
OTHER OPERATORS	Name of other Operators involved

The following describes the information required within the seven columns of the switching sheet body:

ITEM NO	The first item shall be number 1 with all following items numbered sequentially. Note: Items 1 & 2 will be permission to commence and customer notification confirmation where required.
STATION No. AND NAME	Description of where the device to be operated is located. Where the device has a unique control station number then it must be used followed by the address or pole location. Pole locations must include Pole number and Street name. The six digit ID number may be used but is not mandatory. For locations without a control station number then the identifying number, if available, and address must be used. Where the device to be operated is within a building type or ground mounted substation then the station number and name must be included in full, no abbreviations.

SWITCHGEAR EQUIPMENT NAME/LETTER:	Description of voltage and device to be operated. The operating voltage must always be entered first followed by the device description. Eg; 11kV Ganged Isolator, 11kV Fuses, 11kV Line Switch, 22kV Earth Switch, and 22kV Circuit Breaker. Where a Substation device # exists they shall be included after the device description. If the device has an identifying label then it must be included in inverted commas following the device description. The information within the inverted commas must reflect exactly what exists on the device label. Eg; 11kV Circuit Breaker 'A-University No. 1 Substation'
OPERATOR:	Operators name. For remotely operated items then the responsible control room's name shall be entered during switching preparation. For local operations then this column shall be left blank. Field Operators shall be identified using this column when actioning.
OPERATION:	Describes required operations. Eg; OPEN or CLOSE etc.
REMARKS:	Describes the consequence of the operation and additional relevant remarks.
TIME:	Time when item was actioned

7.20 Switching Sheet Approved Terminology

Switching Sheets shall include, where appropriate, but not limited to the following table of descriptors. Refer PSSR attachment F for approved abbreviations.

SWITCHGEAR EQUIPMENT NAME/LETTER	OPERATION	REMARKS
??V Miniature Circuit Breaker	Adjust to ?? kV	Across Fuses
??kV Auto-Reclose Protection	Adjust to	Across Ganged Isolator
??kV Bus Section Circuit	AUTOMATIC	Across Links
Breaker	Control	Breaks ring in feeder ??
??kV Bus Bar Shutters	Adjust to LOCAL	Breaks Ring in LV Circuit
??kV Bypass Ganged Isolator	Control	Confirm Volts Greater Than
??kV Cable	Adjust to MANUAL	230 volts
??kV Cable Links	Control	Connect to Overhead Line
??kV Capacitor Bank	Adjust to REMOTE	De-energises HV Cable
??kV Circuit Breaker	Control	De-energises HV
??kV Earth Fault Protection	Adjust to NEUTRAL	Conductors
??kV Earth Switch	Tap	Earthing Point
??kV Feeder	Check & Record	Earths cable
??kV Fuses	Loads	Energises HV Cable
??kV Ganged Isolator	Check & Record	Energises HV Conductors
??kV Incoming Ganged Isolator	Phase Rotation	Energises Regulator
??kV Incoming Links	Check & Record	From Overhead
??kV Isolator	Phasing	Conductors
??kV Line Switch	Check & Record	If correct, then:
??kV Links	Position	If the same as Previously
??kV Live Line Clamps	Check & Record	Recorded, then:
??kV Load Break Switch	Voltages	Interrupts ??? kVA
Lockout Lever	Check CLOSED	Isolates HV Cable
??kV Loops	Check Earths	Isolates HV Conductors
??kV Midspan Fuse/Links	Applied	Isolation Point Apply DO
??kV Outgoing Ganged Isolator	Check Earths	NOT OPERATE tag
??kV Outgoing Links	Removed	Remove DO NOT
??kV Overhead Conductors	Check INSERTED	OPERATE tag
??kV Recloser	Check OPEN	Lock in CLOSED position
??kV Recloser Protection	Check REMOVED	Parallels feeders ?? and ??
??kV Recloser TRIP & CLOSE	Close	Parallels transformers
Toggle Switches	Confirm in DELAY	Phase --> N ______ Volts
??kV Regulator	Mode	Restores ??? kVA
??kV Regulator Tapchanger	Confirm on	Restores Supply
??kV Sectionaliser	AUTOMATIC	Rings feeder ??
??kV Sensitive Earth Fault	Control	Rings LV Circuit
Protection	Confirm on LOCAL	RN______ CN______
??kV Switch	Control	PN______
??kV Switch Fuse	Confirm on	RN______ WN______
??kV Switch Caps	MANUAL	BN______
??kV Three Phase Switch caps	Control	Tap _____ /
??kV Temporary Ganged	Confirm on	__________Volts
Isolator	REMOTE	To Overhead Conductors

SWITCHGEAR EQUIPMENT NAME/LETTER	OPERATION	REMARKS
??kV Transformer Droppers ??kV Transformer Intertrip ??kV Transformer Tapchanger Control Selector Switch LV Board LV Bus Bars LV Bus Section Links LV Cable LV Cable Links LV Circuit Breaker LV Conductors LV Midspan Fuse/Links LV Fuses LV Links LV Loops LV Switch LV Transformer Fuses LV Transformer Link/Fuses LV Transformer Terminals Transformer No. ? LV Circuit Breaker Transformer No. ? LV Links	Control Confirm NEUTRAL Tap Confirm PASSED Connect MGU & Supply Load Connect to Overhead Conductors Discharge Disconnect from Overhead Conductors Disconnect MGU Insert Insert Fuses Install cubicle maintenance cover Lock in CLOSED position Make Ready for Service Open Phase Out Prove De-energised Prove De-Energised and Close Prove De-Energised and Earth Pull DOWN Push UP Rack to Isolated position Rack to Isolated position and Remove Rack to Service position Insert and Rack to Service position Remove Remove Earths Remove cubicle maintenance cover Remove Fuses Select AUTO RECLOSE Select	To Suit Transformer Rating Unparallels feeders ?? and ?? Unparallels transformers

SWITCHGEAR EQUIPMENT NAME/LETTER	OPERATION	REMARKS
	Instantaneous Select One TRIP TO LOCKOUT Select TIME DELAY Short OUT Switch Earth Fault Protection OFF Switch Earth Fault Protection ON Switch IN to Service Switch OFF Switch ON Switch OUT of Service Switch Protection IN Switch Protection OUT Switch Sectionaliser OFF Switch Sectionaliser ON Unlock	

7.21 Terminology Examples

Nulec RL27 Load Break Switch		
SWITCHGEAR EQUIPMENT NAME/LETTER	**OPERATION**	**REMARKS**
11kV Load Break Switch	Open	Interrupts ???kVA
11kV Load Break Switch	Close	Restores ???kVA
?? Kv Load Break Switch Lockout Lever	Push UP	Remove DO NOT OPERATE tag
?? Kv Load Break Switch Lockout Lever	Pull DOWN	Isolation Point Apply DO NOT OPERATE tag

Reyrolle LMT and EE OLX isolate and earth cable		
SWITCHGEAR EQUIPMENT NAME/LETTER	**OPERATION**	**REMARKS**
11kV Circuit Breaker ’Label’	Open	De-energises HV Cable
11kV Circuit Breaker ’Label’	*Close*	Energises HV Cable
11kV Circuit Breaker ‘*Label’*	Rack to Isolated position	
11kV Circuit Breaker ‘*Label’*	Rack to Isolated position and Remove	
11kV Circuit Breaker ‘*Label’*	Insert and Rack to Feeder Earth position	
11kV Circuit Breaker ‘*Label’*	Insert and Rack to Service position	
11kV Busbar Shutters ‘*Label’*	Lock in CLOSED position	
11kV Busbar Shutters ‘*Label’*	Unlock	
11kV Cable ‘Label’	Prove De-energised	
11kV Earth Switch ‘Label’	***Open***	***Apply DO NOT OPERATE tag***
11kV Earth Switch ‘Label’	***Close***	***Apply DO NOT OPERATE tag***

Schneider RM6 and equivalent		
SWITCHGEAR EQUIPMENT NAME/LETTER	**OPERATION**	**REMARKS**
11kV Line Switch 'Label'	Open	De-energises HV Cable Isolation Point Apply DO NOT OPERATE tag
11kV Line Switch 'Label'	Close	Energises HV Cable
11kV Cable 'Label'	*Prove De-energised*	
11kV Earth Switch 'Label'	***Close***	***Apply DO NOT OPERATE tag***
11kV Earth Switch 'Label'	***Open***	**Remove DO NOT OPERATE tag**

Brown Boveri RGB 12/24		
SWITCHGEAR EQUIPMENT NAME/LETTER	**OPERATION**	**REMARKS**
11kV Line Switch 'Label'	Open	De-energises HV Cable
11kV Line Switch 'Label'	Close	Energises HV Cable
11kV Line Switch 'Label'	Rack to Isolated position	Isolation Point Apply DO NOT OPERATE tag
11kV Line Switch 'Label'	Rack to Isolated position and Remove	Isolation Point Apply DO NOT OPERATE tag
11kV Cable 'Label'	Install Cubicle Maintenance Cover	
11kV Cable 'Label'	Remove Cubicle Maintenance Cover	
11kV Cable 'Label'	Install Bus Bar Cover	
11kV Cable 'Label'	Remove Bus Bar Cover	
11kV Cable 'Label'	***Prove De-energised and Earth***	
11kV Cable 'Label'	***Remove Earths***	

11kV Switchgear Cambridge Zone ABB D4		
SWITCHGEAR EQUIPMENT NAME/LETTER	**OPERATION**	**REMARKS**
11kV Feeder Circuit Breaker Device # ‘Label’	Open	De-energises HV Cable
11kV Feeder Circuit Breaker Device # ‘Label’	Close	Energises HV Cable
11kV Transformer Circuit Breaker Device # ‘Label’	Open	
11kV Transformer Circuit Breaker Device # ‘Label’	Close	
11kV Bus Tie Circuit Breaker Device # ‘Label’	Open	
11kV Bis Tie Circuit Breaker Device # ‘Label’	Close	
11kV Feeder Circuit Breaker Device # ‘Label’	Rack to Isolated position	Isolation Point Apply DO NOT OPERATE tag
11kV Feeder Circuit Breaker Device # ‘Label’	Rack to Service position	Remove DO NOT OPERATE tag
11kV Cable ‘Label’	*Prove De-energised*	
11kV Earth Switch ‘Label’	***Close***	***Apply DO NOT OPERATE tag***
11kV Earth Switch ‘Label’	***Open***	***Remove DO NOT OPERATE tag***

Hazemeyer Magnefix MD4		
SWITCHGEAR EQUIPMENT NAME/LETTER	**OPERATION**	**REMARKS**
11kV Switchcaps 'Label'	Remove	De-energises HV Cable Isolation Point Apply DO NOT OPERATE tag
11kV Switchcaps 'Label'	Insert	Energises HV Cable Remove DO NOT OPERATE tag
11kV Three Phase Switchcaps 'Label'	Remove	De-energises HV Cable Isolation Point Apply DO NOT OPERATE tag
11kV Three Phase Switchcaps 'Label'	Insert	Energises HV Cable Remove DO NOT OPERATE tag
11kV Cable 'Label'	***Prove De-energised and Earth***	
11kV Cable 'Label'	***Remove Earths***	
11kV Switchcaps 'Label'	Install Access Cover and Lock	
11kV Switchcaps 'Label'	Remove Access Cover	

7.22 Retention of Documents

All field copies of completed Switching Sheets and associated Access Authorities shall be returned to Operating Standards within two weeks of completion.

7.23 Generic Switching Sheets

7.23.1 Discussion

Generic Switching Sheets have been created so that Field Operators can prepare and check Switching Sheets using standard templates. The use and suitability of these templates are to be approved by Distribution Control.

It is intended that Generic Switching Sheets will be available for simple common tasks that are performed on a regular basis. They will not include Low Voltage parallels or manipulation of high voltage feeder trunks where interconnection is possible. Where reconductoring is being performed, generic switching sheets shall not be used.

7.23.2 Approval

The use of and suitability of a Generic Switching Sheet must be agreed to and approved for use by Distribution Control at the time of RADS submission.

7.23.3 Preparation

All Generic Switching Sheets are to be prepared by an Operator authorised for the apparatus involved or a Distribution Controller. All items, other than those deleted, must have all appropriate control station, switchgear and operation detail completed prior to being checked. The preparer must print and sign their name on all pages prior to the switching being checked.

7.23.4 Checking

All Generic Switching Sheets are to be checked by an Operator authorised for the apparatus involved or a Distribution Controller, but not the preparer. The checker must print and sign his or her name on all pages prior to the switching being commenced.

7.23.5 Items or Access Authorities Not Required

When an Item or Access Authority is not required, it must be clearly ruled out with one line through all columns including the time and initialled by the preparing person.

7.23.6 Additional Items Required

Additional Items must not be added to a Generic Switching Sheet. If a Generic Switching Sheet cannot achieve the desired objective without additional items being added, then another switching sheet shall be prepared in accordance with this procedure.

7.23.7 Use of Multiple Generic Switching Sheets

Multiple Generic Switching Sheets must not be used in conjunction with one another to achieve one objective. If a single Generic Switching is not fit for purpose then another Switching Sheet shall be prepared in accordance with this procedure.

7.23.8 Format

All Generic Switching Sheets are available in a PDF format that will allow printing only. This is to ensure the format and content remains consistent and accurate.

7.23.9 Available Generic Switching Sheets

Note: A PDF file of each Generic Switching Sheet can be downloaded from the Operating Standards Intranet Web Site.

http://thevolt/divisions/network/Dist_Ops_Stds/default.aspx

1. Transformer replacement with top of high voltage fuses remaining live
2. Transformer replacement with fuses disconnected via live line clamps
3. Transformer replacement with fuses disconnected using Live Line Crew
4. Transformer tap change
5. Spur isolation

6. Replace spur fuse carriers with fuses disconnected using Live Line Crew
7. Replace spur fuse carriers with fuses disconnected via Live Line Clamps
8. Install 1 transformer on spur
9. Install 2 transformer on spur
10. Isolate spur and replace 1 transformer
11. Overhead low voltage Isolation
12. Isolate three phase regulator
13. Commission low voltage underground cable
14. Isolate Tee Off with two Transformers via Live Line Clamps and Install Transformer
15. Isolate Tee Off with two Transformers via Live Line Clamps and replace Pole
16. Commission O/H Transformer
17. Commission LV Underground Cable Extension
18. Isolate spur with up to 3 transformers via live line
19. Commission spur without spur fuses with up to 3 transformer via live line
20. Commission spur with spur fuses with up to 3 transformer via live line
21. Extend HV spur from a transformer pole and commission up to 2 transformers
22. Commission Spur with Spur Fuses with up to three transformers via Live Line Clamps
23. Ground Mounted Transformer Tap Change with LV Links
24. Ground Mounted Transformer Tap Change with LV CB

7.23.10 User Guide

7.23.10.1 Generic Switching 1, 2 and 3

To be used for replacing overhead transformers where there is no LV interconnection. In sheet 1 the top of the HV fuses remain live therefore the fuses are the 'Isolation Point' and cannot be worked on. The transformer droppers cannot be disconnected.

If the droppers need to be replaced or disconnected then sheet 2 or 3 must be used. These will allow disconnection of the fuses from the overhead mains via live line clamps using sheet 2 or live line crew using sheet 3.

7.23.10.2 Generic Switching 4

To be used for changing transformer tap position.

7.23.10.3 Generic Switching 5

To be used for completing simple tasks on a spur where connections are not broken and phasing checks are not required. Suitable for replacing pin pole, vegetation cutting, replace conductor tie or replace crossarm.

7.23.10.4 Generic Switching 6 and 7

To be used for replacing single phase spur fuses or three phase spur fuses where it is impossible to alter the phase connections. If the connections between the overhead conductors and the fuses are to be replaced then these will not suit, as there are no phase rotation checks.

7.23.10.5 Generic Switching 8 and 9

To be used for installing one or two new single or three phase transformers on a spur with no low voltage interconnection.

7.23.10.6 Generic Switching 10

To be used for replacing one single or three phase transformer on a spur with no low voltage interconnection.

7.23.10.7 Generic Switching 11

For low voltage isolation of up to two circuits with up to four associated normally open points.

7.23.10.8 Generic Switching 12

For the isolation of a Ground Mounted three phase regulator. NOT for single phase Cooper's regulators.

7.23.10.9 Generic Switching 13

Used to commission a new low voltage cable with no interconnection. Would typically be a LV cable providing a point of attachment for customer connections.

7.23.10.10 Generic Switching 14

To commission a new single or three phase transformer on a tee off which is connected by live line clamps and has up to two transformers already connected. Not suitable if there is any LV interconnection on new transformer.

7.23.10.11 Generic Switching 15

To replace pole, without breaking connections, on a tee off which is connected by live line clamps and has up to two transformers already connected.

7.23.10.12 Generic Switching 16

To commission a new overhead transformer connected to the overhead mains via live line clamps. Could be used when live line connect the fuses to the overhead mains the commission transformer.

7.23.10.13 Generic Switching 17

Used to commission a low voltage underground cable extension supplied from a pole or substation with no interconnections. Items 1 or 2 should be used but not both.

7.23.10.14 Generic Switching 18

To isolate a tee off using live line procedures and complete simple tasks where connections are not broken and phasing checks are not required. OK for replacing pin pole, vegetation cutting, replace conductor tie or replace crossarm.

7.23.10.15 Generic Switching 19 and 20

Used for live line to commission new high voltage tee off or spur with or without spur fuses with up to three single or three phase transformers.

7.23.10.16 Generic Switching 21

Used to extend a high voltage spur from a transformer pole and commission up to two single or three phase transformers.

7.23.10.17 Generic Switching 22

Used for non-Live Line Crews to commission a HV spur with up to three transformers where a Live Line Crew has installed the spur fuses with live line clamps.

7.23.10.18 Generic Switching 23

Used to adjust transformer tap on ground mounted transformer where transformer is fitted with LV isolating links. Not suitable when low voltage parallels are used to maintain supply.

7.23.10.19 Generic Switching 24

Used to adjust transformer tap on ground mounted transformer where transformer is fitted with a LV Circuit Breaker. Not suitable when low voltage parallels are used to maintain supply.

7.23.11 Request for Change or Addition to Generic Switching Sheets

Change requests to be emailed to Aurora Energy Operating Standards at:

operating.standards@auroraenergy.com.au

for consideration

8. ISOLATING HV CONDUCTORS OR APPARATUS

The Power System Safety Rules states that apparatus shall be Isolated by the use of an approved method. The following describes minimum approved isolation methods.

8.1 Locking of Switchgear

Switchgear can often be locked in the 'closed', 'open', 'open and isolated' and where applicable, in the 'earthed' position. Unless some unusual circumstance applies, such as switchgear that may be accessible to unauthorised persons, switches should not be locked in the 'closed' position.

When work is to be carried out on equipment made de-energised and isolated, or isolated and earthed by the action or position of an indoor HV switch, then the switch shall be locked in position for the duration of the work.

8.2 Overhead Reclosers

Overhead Reclosers shall not be used as isolation points.

8.3 Isolation of Substation Equipment

8.3.1 Circuit Breaker – Non-Withdrawable

Series isolator to be opened to provide adequate isolation, if available.

8.3.2 Circuit Breaker – Withdrawable

Circuit breaker to be racked to the isolated position.

8.3.3 Switches – Non-Withdrawable

An approved earthing device shall be applied to confirm isolation.

Note: Merlin Gerin Circuit Breakers are to be treated as a non-withdrawable switch and are to have the earth switch closed to confirm isolation.

8.3.4 Switches / Switch Fuse – Withdrawable

Switches / Switch Fuses are to be racked to the isolated position.

Hazemeyer - Withdrawable Switch-Caps

Removal of the switch-caps and installation of spout covers and Access Cover are required to provide isolation.

8.3.5 Switch-Fuses – Non-Withdrawable

The fuse cartridges are to be removed, after opening the switch.

8.4 Isolating Pole Mounted Transformers

8.4.1 Work on Transformer and Fuse Leads

8.4.1.1 HV Isolation

Isolation is to be provided from the overhead HV by removal of the Transformer HV fuses and application of earths. This will allow access to the fuse leads but not the fuse terminals as work on an isolation point is not allowed. If access to the fuses is required to change the fuse leads then further isolation is necessary, for example disconnecting the fuses from the overhead mains via live line tap tails or isolating the overhead mains.

8.4.1.2 LV Isolation

If the LV circuit supplied by the transformer is de-energised, the transformer LV links/fuses or one series break between de-energised LV conductors and the work site is required.

There is to be two series breaks between live LV conductors and the work site if:

1. The LV circuit supplied by the transformer remains energised from adjacent circuit(s);
2. The transformer LV circuit terminates on the same pole as other live LV conductors; or
3. The transformer LV circuit passes above, below or adjacent to other live LV conductors.

9. PROVING DE-ENERGISED – ISOLATED HV CONDUCTORS

9.1 Switchgear with No Accessible Live Parts

Where the switchgear has no accessible live parts or when proving de-energised equipment is otherwise not provided, it is permissible to prove de-energised at other positions near the switchgear or on the LV side of a connected transformer.

If such positions are not available and earthing can be carried out using an integral fault rated earth switch, then earthing is permitted after all precautions have been taken.

9.2 Approved Testing Devices

Several types of approved testing devices are provided for use on various voltages and for application to different types of switchgear and conductors.

All testing devices are labelled with the voltage for which they are suitable.

The section of the device that may be held by hand is identified, where applicable. In specified circumstances, some devices may only be used with additional insulation such as by holding with an operating stick.

Under no circumstances shall an approved testing device be applied to conductors that may be at a higher voltage than the voltage for which the device is intended.

No person shall endeavour to use an approved testing device, unless they have received instructions in the method of use or a practical demonstration and is fully competent to use the device.

9.2.1 Contact Type

The contact type requires the head of the testing device to touch the conductor to be tested and accordingly have adequate insulation to permit the Operator to apply the device with safety.

Contact type testing devices are to be tested as per manufacturer’s instructions and test reports recorded.

9.2.2 Non Contact Type – Portable

The non-contact type must **not** be brought into contact with energised equipment while hand-held and must be attached to an approved operating stick.

Should the required distance to obtain indication be less than the minimum safe approach distance from live conductors, as specified in the Power System Safety Rules, then additional insulation must be provided.

9.2.3 Non Contact Type – Equipment Mounted

In the later range of indoor substation equipment being installed 'in built voltage' detection devices are available. These generally are small neon indicators housed on the face of the equipment, and are approved for use.

9.2.4 Non- approved Testing Devices

Under no circumstances shall an operating stick alone or ‘buzz-stick’ be used for proving de-energised conductors.

9.2.5 Indication of Live Conductors

The correct application of the proving de-energised procedure will have proved that the conductors are safe for earthing. However, further voltage may still occur on the conductors due to induction from adjacent parallel-energised feeders or due to the existence of sections of underground cable in the isolated section, which may retain a voltage charge until earthed.

Accordingly, the isolated conductors must be treated as live until earthed.

If the testing device indicates the existence of any voltage on the isolated conductors, all points of isolation shall be physically confirmed and additional testing shall be performed.

10. EARTHING ISOLATED HV CONDUCTORS

10.1 Earthing Requirements

Earths shall be connected to recognised earthing points in accordance with the requirements of the Power System Safety Rules.

10.2 Approved Earthing Equipment

Portable earthing and short circuiting devices shall be of an approved design and have the required size of conductors and fittings to safely conduct possible fault currents. Earthing devices for HV applications shall be rated at 14.0 kA.

Earthing devices may be incorporated in switchgear or be supplied separately for manual use.

10.3 Application of Earthing

10.3.1 General

The Authorised Operator shall be responsible for the application of earths to a recognised earthing point and the isolated conductors. All HV conductors within the work site as described on an Access Authority MUST be isolated, proved de-energised and earthed prior to the Access Authority being issued.

10.3.2 Placement of Operational Earths

Earths shall be placed at either:

1. At the work site, provided an earth is placed between the work site and all points of isolation;
2. Between the work site and all points of isolation; or
3. At all points of isolation.

10.3.3 Transformer Fuse Leads and Fused Spurs within the Worksite

Fused spurs or transformer fuse leads within the work site as described on an Access Authority MUST be isolated, proved de-energised and earthed prior to that Access Authority being issued.

10.3.4 Earthing Aerial Transformers

Work On Transformer and Fuse Leads

Isolation is to be provided from the overhead HV and LV.

The degree of isolation required depends on the transformer LV circuit arrangement. See 'Isolating HV. Conductors or apparatus' - 'Isolation Aerial Transformers'.

10.3.5 Work on Overhead Line Incorporating Aerial Transformers

When work is to be performed on overhead line conductors, earths need not be applied to transformer HV leads provided that earths are placed between the transformer and the work location.

If there is no earth applied to the transformer leads and no earth between the transformer and the work location, then additional isolation is required by removing the HV fuses and opening the LV transformer link/fuses.

10.3.6 Work Earths

It is the responsibility of the Person In Charge of an Access Authority to ensure that work earths are connected at or within sight of the work location - except as provided in the Power System Safety Rules - 'Substations and Underground Cables'.

10.3.7 Application of Earths to Overhead Line Conductors

Earths shall be applied to the overhead line conductors by clamping onto any of the following:

1. ‘Earthing bolt’ attached to the connecting plate of HV links or fuses;
2. Main conductors; and
3. Conductor loops.

Earths must not be applied to the helical termination where it does not fully enclose the conductor or to HV link blades.

The selection of the location as described above is dependent on safety requirements.

Where an earth lead passes through live bare LV conductors, insulated mats or covers shall be applied to the conductors it passes between or adjacent to.

11. COMMISSIONING / RE-ENERGISING HV APPARATUS

Where a cable and or associated equipment, including switchgear, has remained de-energised for periods in excess of 30 continuous days, it shall not be brought into service without suitable energising tests being conducted.

12. GENERAL OPERATING INFORMATION

12.1 Use of Fault Indicators

In some areas of the distribution system, fault indicators have been installed to provide additional fault location information. A fault indicator will operate when a current of approximately double the normal value is followed by a loss of supply.

Fault indicators are incorporated in some makes of ground-mounted switchgear. They are commonly used on overhead line conductors.

Where a number of fault indicators are installed at various locations on a feeder, a detected fault would be beyond the furthest fault indicator from the source that has operated.

Most fault indicators are designed to not register a fault due to feeder inrush or cold-load pickup.

Most line fault indicators automatically reset themselves after a set period of time following restoration of supply to the powerline.

In some earth fault situations, fault indicators may not operate successfully. This can be misleading when identifying the cause or direction of a fault. Any instances are to be reported to Distribution Operations so HV Plans can be altered appropriately.

Where practicable following a fault, all Ground Mounted Substation fault indicators are to be reset.

12.2 Replacement of Fuses

12.2.1 HV Overhead Transformer and Section Fuses

When replacing fuses, ALL fuses should be replaced at the same time.

The reason being that, even though the other phase fuses may not have blown, they may have been weakened by the fault current. It would take a less current to rupture the fuse(s) next time due to the elements within the fuse(s) being significantly damaged. This effectively down rates the fuse size.

The only exception is where the line or transformer was exposed to a single phase fault such as a lightning strike on one phase. However, when in doubt, all fuses should be replaced.

12.2.2 Boric Acid Fuses

When replacing Boric Acid fuses only replace the faulted fuse.

12.2.3 HV Ground-mounted Fuses

Replaced ground-mounted fuses should be retested by micro-ohm meter to identify whether the fuse is within its resistance rating.

Fuses outside of the resistance rating are to be discarded.

Fuses inside of the resistance rating are to be returned to stock.

12.2.4 LV Fuses

12.2.4.1 Phase to Phase Contact

Replace all fuses.

12.2.4.2 Phase to Earth Contact

Replace the blown fuse.

12.2.4.3 Overload

Replace the blown fuse.

12.3 Abnormal Transformer LV Voltages

12.3.1 Normal Voltage Two Phases to Neutral, No Voltages on Third Phase to Neutral

Caused by one phase open circuited in the LV windings or connections.

Check the external connections at the LV terminals. If the fault persists the transformer should be removed from service.

12.3.2 No Voltage or High Voltage

Between any phase and neutral at the LV terminals with no load connected or high voltage across one phase to neutral and low voltages across other phases to neutral with unbalanced load connected.

Caused by the neutral open circuited.

To locate the open circuit, use a voltmeter and Network Analyser to check the voltages to neutral at various points. If external to the tank it can be rectified on site, but if internal and neutral cable connection is satisfactory, the transformer should be removed from service.

A misaligned tap change switch may also cause the above.

12.3.3 High Voltage Phase to Neutral

Caused by short-circuited turns on the HV winding.

This condition will usually cause heavy currents to flow in the affected portion and will be accompanied by the smell of burnt oil and insulation.

The transformer should be removed from service.

12.3.4 Low Voltage Phase to Neutral

Caused by short-circuited turns on the LV winding.

This condition will usually cause heavy currents to flow in the affected portion and will be accompanied by the smell of burnt oil and insulation.

The transformer should be removed from service.

12.3.5 Normal Voltage One Phase to Neutral, Half of Normal Voltage on Other Two Phases to Neutral

Caused by open circuit on one HV lead.

Check the connections of the HV leads. If the fault persists, the transformer should be removed from service.

12.3.6 Normal Voltage Two Phases to Neutral, Low Voltage One Phase to Neutral

Caused by open circuit in the HV winding.

The tap change switch should be checked and if the fault persists, the transformer should be removed from service.

12.4 Switching Transformers

Individual transformers should, wherever possible, be switched in the following manner.

Transformers **with** ganged three phase switching facilities (Primary and Secondary sides):

1. Open HV isolating device first
2. Open LV isolator device second

Transformers **with** ganged three phase switching facilities (Primary side only):

1. Open HV isolating device first
2. Open LV isolator device second

Transformers **without** ganged three phase switching facilities, i.e. no operation:

1. Open LV isolator/s first
2. Open H V fuses second

12.4.1 Restoration

The restoration should be conducted in the reverse order of isolation.

12.5 Embedded Generators and Alternative Supplies

Embedded generators are capable of supplying voltage into the distribution system from customers' installations. The common types are; hydro generators, diesel generators, inverters via solar cells etc.

Considering the amount of embedded generation now connected to the Distribution Network every customer service MUST be treated as a possible source of supply.

Embedded generators can supply at either high or low voltages and are dependent upon the method of incoming supply that the individual customer has. ie it can only supply back into the system at the voltage the customers takes their supply at.

12.5.1 Precautions when Working on the System

Special precautions must be adopted when working on apparatus within the section that embedded generators are connected to.

These precautions being:

1. The embedded generator is to be considered as live.
2. The section to be worked upon is isolated from the embedded generator;
3. Appropriate application of earthing; or
4. Live work covered by Approved procedures.

The low voltage Network must be isolated according to approved procedures. Every customer service must be considered a source of supply. The low voltage Network must not be considered isolated unless all primary supplies and customer installations are isolated.

Where service fuses are removed to guard against inadvertent back feeds then such isolations would not normally be part of a switching sheet.

Where the low voltage Network has been isolated from the supply transformer and the customer services remain connected then the circuit shall be considered to be de-energised but not isolated. If work is to be performed on a de-energised circuit then additional safety measures must be used to guard against an inadvertent back feed. If an Access Authority is issued for a low voltage circuit then it must include the status of the circuit, isolated or de-energised. When de-energised the Access Authority must note the additional safety measures in place to guard against any possible back feed. The use of insulating gloves is the minimum safety measure required.

13. APPENDIX A: PROTECTION SYSTEMS

13.1 Scope and Application

This section provides a general description of some components of protection systems and their method of operation.

A general understanding of these principles, together with detailed familiarity with the types of protection used in local areas and in substations is essential for safe operating and maintenance of supply.

After receiving initial instruction, any opportunity should be taken to maintain knowledge of this equipment either by inspection or by study of protection diagrams.

13.2 Protection Circuits and Equipment

13.2.1 Security of System

13.2.1.1 Safety

The safety of the public, personnel, and the prevention of damage to equipment depends entirely upon the security of protection systems.

Protection systems are normally called upon to operate only when abnormalities occur. To ensure that the devices will operate speedily and correctly on those comparatively rare occasions, adequate maintenance and routine observation are essential.

13.2.1.2 DC supply

A vital part of the security of the system is the DC supply.

The condition of battery supplies including output voltage and state of charge should be checked regularly; e.g. batteries associated with automatic line reclosers, and substation circuit breakers. There are various maintenance regimes run by Distribution Business field personnel for this purpose.

13.2.1.3 Abnormalities

Any abnormalities in protection systems such as relay flags showing, fuses blown, links out or switches off should be reported immediately to Distribution Operations.

13.2.2 Voltage Transformers

A voltage transformer, as used in protection and metering systems, is a specially wound transformer for connection to the high voltage system and designed to produce a secondary voltage in an accurate ratio from primary to secondary winding. The standard secondary output voltage is 110 volts.

13.2.2.1 Voltage Transformer Output

The output of a voltage transformer is used for:

1. Metering: either indicating voltmeters, recording voltmeters, or energy meters e.g. pole mounted HV metering units.
2. Voltage Regulation: Operation of transformer voltage regulating relay associated with automatic voltage regulating transformers, and to detect direction of current flow in reversible voltage regulators.
3. Protection: the secondary voltage is used in some relays; e.g. to supply the directional element of directional overcurrent, directional earth leakage and distance relays.

13.2.2.2 Other Uses

In other forms of protection the voltage transformers may also be used to supply an earth fault type of protection that detects an out of balance voltage condition. The V.T. may also be used to supply various forms of under-voltage relay.

13.2.3 Current Transformers

A current transformer is a specially wound transformer for connection to the high voltage or low voltage system and designed to reproduce a secondary current in an accurate primary to secondary ratio. The standard secondary current produced by current transformers is generally 5 amps or 1 amp with a primary current of, for example, either 50 amps, 100 amps, 200 amps, 400 amps or 800 amps.

13.2.3.1 Secondary Voltage

The secondary voltage produced by a current transformer under normal conditions is relatively low namely 20 to 30 volts.

The full-load secondary current normally produced by the current transformers of high voltage reclosers, is one amp.

13.2.3.2 Connections

It is essential that the secondary connections of a current transformer should never be open-circuited while the primary winding is energised. Under such conditions high voltages can occur across the open-circuited secondary terminals.

13.2.3.3 Functions

The functions of a current transformer are two-fold, namely:

1. Metering: to provide a convenient means of metering high voltage current at low voltage, such as indicating ammeters or recording ammeters or wattmeters, etc., e.g. pole mounted HV metering units.
2. Protection: to provide low voltage current to supply relays in various forms of protection systems. Protection type current transformers are designed to higher orders of accuracy at overload and under fault conditions, and are capable of accepting higher overloads than metering current transformers. The secondary output of protection current transformers is used to operate many varieties of protection relay. Types in general use will be described later in this Section.

Note:

A protection current transformer differs from a metering current transformer in that it is required to maintain given accuracy over an extended overload range, e.g. 20 times rated current.

13.2.4 Relays – General

13.2.4.1 Classes

Relays may be classified in two general types according to their functions:

1. Detection Relays - to which the secondaries of current transformers or voltage transformers are directly connected.
2. Auxiliary Contact Relays - which may be connected between a detection relay and a circuit

breaker trip coil, or connected to supply annunciators (alarm indicators) or alarms.

Both of the above types of relay may, or may not, be equipped with flag indicators. The contacts may be either automatically or manually reset.

13.2.4.2 Operation

The magnitude of the energy required to operate a detection type relay can generally be varied by alterations to settings or connections within the relay. The accuracy or correctness of relay settings determines the effectiveness of any given protection system. Substation or Protection Engineers, calculate the appropriate settings of individual relays that are required to provide correct co-ordination between the components in the protection system. Relay settings must not be altered by Operators unless specifically authorised to do so.

13.2.4.3 Familiarity

It is essential that Operators are familiar with the types of relays that are installed on feeders or substations within their area. It is particularly necessary to be able to identify detection relays from contact relays, namely relays that will initiate a tripping which may then pass via a tripping relay to a circuit breaker. In resetting relays after operation it is necessary to firstly reset the initiating detection relay.

13.2.4.4 Recording

The information provided by relays (and counters) after a fault condition is vital. This information must always be recorded in a Log Book or Note Book before resetting and considered in detail before any attempt is made to reclose a tripped circuit breaker, or a locked-out automatic line recloser.

13.2.5 Principles of Protection Operation

A basic protection circuit consists of several components, namely:

1. A device for converting the quantity or energy which it is desired to measure into manageable proportions - such a device commonly being a current transformer or voltage transformer.
2. A detection relay that measures a quantity or energy concerned and compares it with pre-determined values and closes contacts when necessary.
3. A tripping-coil, mounted on the circuit breaker and energised from the relay.

13.2.5.1 Operation

The protection transformer and associated relays are in circuit continuously. That is, energy at normal levels is passed without any action from the relays.

However, when a fault condition occurs current flow is increased many times, e.g. 20 times normal. For example, in a simple overcurrent fault on a feeder where the normal load current is say approximately 300 amps, the fault current may amount to 3000 amps, or more.

When such current under fault conditions exceeds the settings of the protection relays the trip coil on the circuit breaker is energised and tripping of the circuit breaker results.

13.2.5.2 Clearing Times

Since the distribution system is not designed to supply currents of high magnitude for long periods of time it is necessary for the protection system to clear such faults as quickly as possible. Normal protection operation would permit a fault to be cleared within approximately

1/5th of a second after detection. Protection settings (which determine the clearing times) are dependent on variables such as fault level and the number of downstream protection devices on the feeder trunk. The settings are designed to ensure the effective coordination of downstream devices.

13.3 Installed Protection – Method of Operation

13.3.1 Transformer Protection

13.3.1.1 Buchholz

The Buchholz relay provides a means for the detection of internal faults at an early stage of development, thereby avoiding major breakdown. The relay is only fitted on large transformers (750 kVA and above).

The Buchholz relay can only be fitted to transformers having conservator vessels and is installed in the pipeline between the transformer and its conservator tank.

The relay comprises an oil-tight container fitted with two internal floats which operate mercury switches connected to external alarm and tripping circuits, e.g. via a fault throwing switch. The relay may be operated by a slow collection of gas, a surge of oil, or a drop in oil level.

It is not advisable to return a transformer to service after the occurrence of a Buchholz trip without extensive testing to determine the cause.

13.3.1.2 Gas Impulse

The gas impulse relay is a similar device to the Buchholz relay as described above but does possess some basic differences. In this system a conservator tank on the transformer is not installed. The gas impulse relay is installed via a breather pipe on the lid of the transformer. The relay contains a diaphragm actuated by gas pressure produced by internal transformer faults. The diaphragm operates a mercury switch that activates an alarm or trip as desired. A valve in the diaphragm allows normal breathing of the transformer.

13.3.1.3 Oil Surge

The oil surge relay is a further variation of the Buchholz relays in which a single vane is rotated by the violent passage of oil up the conservator pipe. Relay contacts produce an immediate tripping of the transformer circuit breaker(s).

13.3.1.4 Oil and Winding Temperature

The load which a transformer of specified conductor size and design may carry is determined ultimately by the operating temperature of the windings. In the case of large power transformers such as those installed in zone substations, it is desirable to monitor this operating temperature. The useful life of a transformer is also dependent on the life of its insulation which ages rapidly at elevated temperatures. It is estimated that an increase of 8°C above maximum prescribed operating temperature in the temperature of normal insulation doubles the rate of deterioration.

To provide adequate protection, two temperature indicators are generally provided:

1. A thermometer or temperature indicator which measures the temperature of the upper layer of transformer oil.
2. An indicator that measures the temperature of the transformer winding either directly or by reference to a current transformer

The oil temperature indicator would normally only operate an alarm circuit and may be set at approximately 70°C. The winding temperature indicator may be used to operate either an alarm circuit or trip or both. The setting of the indicator may produce an alarm at approximately 90°C and a trip at approximately 110°C.

On some types of zone transformer, contacts from the temperature indicator are also used to switch on cooling fans or a pump in the oil circulating circuit.

13.3.1.5 Differential

In order to provide speedy tripping of larger power transformers in the event of faults on the transformer windings, a type of protection known as Differential or Biased-Differential is used. This type of protection detects phase to phase or phase to earth transformer winding faults and is capable of tripping a transformer generally before the liberation of gas and the consequent operation of the Buchholz relay as previously described.

This system requires a current transformer installed on the high voltage side of the transformer and a second current transformer installed on the low voltage side of the transformer with the secondaries of both C.Ts connected to a Differential Relay. The principle upon which this protective system depends is that the current entering the protected zone is equal to that leaving it.

Obviously in the case of power transformers due allowance must be made for the transformation ratio by the correct choice of protective current transformers.

The purpose of these ratios is to provide approximately the same current in the secondaries of each current transformer under normal or through fault conditions.

During internal fault conditions, ie a fault within the transformer between the two sets of current transformers, the out-of-balance current or difference in current will flow through the coil of the differential relay.

This basic form of differential protection is known as the Merz-Price circulating current system.

In most installations the type of protection installed on transformers is known as Biased-Differential protection. This scheme is essentially the same as the simple Merz-Price system with the exception that restraining or bias coils are inserted in series with the wiring connecting the secondary windings of the current transformer. The relay operating coils are connected to the centre point of the bias coils. By employing this improvement, difficulties arising from transformer inrush magnetising current, change of turns ratio due to tap changing or through fault instability, are reduced due to the action of the bias coils, which when carrying current exert a restraining torque on the relay, to prevent mal-operation.

On any occasion when a differential relay operates, reclosure of the transformer must not be performed until all possible causes have been investigated and the supervisor advised.

13.3.1.6 Sensitive Earth Fault Protection

In some sections of the system a form of protection known as Sensitive Earth Fault protection is installed.

This would generally apply only to zone substation transformers. The function of this type of protection is to detect low value earth faults that may otherwise go unnoticed. It becomes necessary in sections of a system where there is no normal earth leakage protection on feeders, such as will later be described.

In the case of a zone substation power transformer, with a star connected secondary winding, the protection may be operated from a current transformer connected in the transformer neutral that is between the neutral point of the secondary winding and the station earth mat.

When a zone substation power transformer has a delta-connected secondary winding the current transformer is installed in the connection from the neutral earthing transformer to earth. The ratio of such current transformers would normally be fairly low, such as 150/5 amps.

As the name of the system also implies the setting would normally be quite low, such as 20%, namely, operating at only 30 amps of primary current. In order to provide time for any other auxiliary protection to operate, a fairly long time setting is normally applied, such as 5.0 seconds. That is, the fault must remain for this time before the sensitive earth leakage operates.

From the example of the relay setting quoted, it is apparent that such protection will operate at fault conditions that may not be normally detected by other forms of feeder protection. However, there are also disadvantages in the use of this type of protection. In particular, considerable care must be exercised when paralleling a feeder supplied from a transformer employing such protection with a feeder from another source.

Out-of-balance currents, that is, not fault currents, are quite sufficient to operate this type of protection or even less sensitive forms of earth leakage protection.

To prevent mal-operation during conditions of paralleling it is necessary to isolate the return path for out-of-balance current by opening the transformer neutral earthing isolator (where it is fitted to the transformer) at one of the supply sources.

Alternatively, mal-operation may be prevented by temporarily increasing the current settings of the earth leakage relays. Such actions should only be taken on the advice or request of Distribution Control.

It is imperative that earthing and protection systems be restored to normal conditions, after any temporary alteration, as soon as possible.

13.3.1.7 Earth Fault Check or Frame Leakage Check

A system of earth fault check or frame leakage check as installed generally at a zone type substation, is as the name implies a back-up to other systems of earth fault or frame leakage protection. Mal-operation may often occur in earth fault systems of protection due to out-of balance currents rather than genuine earth faults.

The function of this system of protection is to discriminate between these two conditions.

Any genuine earth fault current must return to the transformer from which it emanated. This return path is normally provided by the cable sheaths, water-pipes or the general mass of earth which allows the earth fault current from the fault condition, which may in fact be some miles from the transformer source, to return to the earthed neutral point of the supply transformer.

By installing a current transformer in the transformer neutral, again between the star point of the secondary winding and the station earth mat, it is possible to monitor such returning currents.

The secondary of this current transformer is connected to an earth fault check or frame leakage check relay.

The contacts of the frame leakage check relay are then connected in series with the contacts of any other earth fault relay within the zone and the appropriate circuit breakers that it is desired to trip in the event of a genuine fault. A counter relay may also often be connected to the frame leakage check. relay. By this means the occurrence of any earth fault may be checked on inspection.

13.3.1.8 Fault Throwing Switches

These switches are now not very common. They were generally installed in rural zone substations. They consist of a weight or spring-operated earthing switch, usually single pole, which may be unlatched by the action of a small solenoid.

They are used to deliberately connect an earth fault through a resistor to one phase of a line, or bus, in order to make a distant circuit breaker operate and disconnect that area of the distribution system. For example, where transformer circuit breakers are not fitted at a substation, the transformer Buchholz trip circuit may be arranged to operate a fault-throwing switch and hence improve the degree of transformer protection.

At some rural zone substations where supply to the primary feeders is from a delta-connected winding, an artificial earthed star point is established by using an earthing transformer. These earthing transformers are short time rated and any sustained earth fault may result in the earthing transformer being burnt out.

To guard against this situation a current transformer is inserted in the earthing transformer earth connection. The current transformer supplies a sensitive earth fault relay which after a time delay (usually 5-10 seconds), trips a fault-throwing switch which removes supply to the substation by tripping a remote feeder circuit breaker.

Where a fault-throwing switch is installed on a feeder, the phase to which it connects should be known. This then aids the analysis of upstream relay operations and could suggest the possibility that a feeder fault has been caused by operation of a fault-throwing switch.

13.3.2 HV Switchboard Protection

13.3.2.1 Frame Leakage

This form of protection is applicable to some types of high voltage switchboard in which all components are enclosed in a metal frame or cubicle. The complete frame is provided with suitable insulation between the frame and station earth. This insulation normally consists of bakelite sheeting or similar material between the floor of the substation and the switchboard.

This system also requires an insulated gland in cable terminations between the cable sheath and the cable box mounted on a switchboard frame.

A current transformer is connected between the switchboard frame and the station earth mat.

This current transformer is generally of a fairly low ratio such as 150 to 5 amps, or maybe a 400/5 ratio. The secondary of the current transformer supplies a frame leakage detection relay that is designed to operate almost instantaneously at a low predetermined setting. The detection relay will then supply the trip coil of relevant circuit breakers. In the case of multi circuit breaker switchboards a multi trip relay would also be required between the detection relay and the circuit breakers in order to trip all possible sources of high voltage supply.

Such a system will detect the passage of any current between the switchboard frame and earth, which may result from the breakdown of insulation between high voltage conductors and the switchboard frame. The high-speed operation of the relay will ensure speedy clearing of a fault before the occurrence of excessive damage.

Where frame leakage protection is installed it is essential that the switchboard frame should not be accidentally connected to station earth thereby bypassing the frame leakage current transformer and rendering the protection inoperative.

13.3.3 HV Feeder Protection

13.3.3.1 Over-current – Non-directional

The simplest and the most usual method of protecting a feeder, either underground or overhead, is by means of applying non-directional over-current protection.

The protection system is designed to detect any situation where two or more energised conductors are brought together in a fault situation. It is not necessary for the neutral point, if any, of the supply transformer to be earthed. The protection may be installed on either the high voltage or low voltage systems. The protection may also operate for earth faults on an earthed neutral system if the value of the fault current is large enough.

The requirements include current transformers inserted in the outgoing active conductors from the controlling circuit breaker, and a simple detection relay. The ratio of the current transformer in a high voltage system may be, for example, 200/5 amps or 400/5 amps. The relay used would generally be of the induction disc type in older installations, or solid-state type in newer installations, and generally have an inverse operating characteristic (where the higher the fault current the shorter will be the operating time of the relay) and a definite minimum time of operation. More fixed time relays are now being installed in new substations and unless the fault is very large the operating time is independent of the value of the fault current.

The secondary of the current transformer is connected directly to the current coils of the relay, which are normally energised and normally passing load current. On the occurrence of a phase-to-phase fault on the protected feeder, the current rises to several thousand amps in the primary side with a consequent proportional increase in the secondary of the current transformers and the relay. When the fault current passing through the relay exceeds the setting, with respect to both current and time, the contacts of the relay are closed by the rotation of the relay disc, or solid state circuit, and the tripping circuit of the circuit breaker is energised.

The actual time of operation and the relationship between the current plug settings and the time multiplier settings for a relay of this type is generally shown on a small graph on the nameplate of the relay.

Earth faults will normally be detected by an earth fault relay but may also operate an overcurrent relay, if the fault current is high.

As the name implies, this type of non-directional relay will actually operate in either direction of current flow. This means that in a case of overcurrent protection installed either at the beginning of a feeder or further out in a feeder that is paralleled with an alternative supply, it is possible for the protection to operate for a fault on either side of the current transformers and relays. In some cases this could be a disadvantage that must be guarded against.

Earth faults will normally be detected by an earth fault relay, but may also operate an overcurrent relay, if the fault current is high or continues for excessive time.

13.3.3.2 Over-current – Directional

In some areas of the system there may be two or more high voltage feeders, supplying a zone substation for example, which are permanently paralleled.

In this situation, it is necessary to provide protection which will not only open the circuit breaker at the sending end of a feeder but also to open the receiving end at the zone substation.

It is also particularly essential to discriminate between the faulted feeder and the paralleled feeders that should remain energised. In this application, at the receiving end of the feeder a directional overcurrent relay is installed.

The function of this type of relay in conjunction with its current transformers is to pass any current in the normal direction of supply, that is either normal load current or even fault current, but to operate for any reverse current flow indicating a fault between the point of supply and the receiving end.

This is achieved by the use of an overcurrent relay similar to that previously described but with the addition of a second element in series.

This second element, namely the directional element, is supplied with both voltage and current from the feeder being protected. The directional element ensures through its appropriate connections that the fault current being measured is in the reverse direction. The overcurrent element of the relay then operates in a normal manner.

13.3.3.3 Earth Leakage – Non-directional

Earth leakage or earth fault protection is the normal companion to overcurrent protection for protecting a feeder, either underground or overhead, or a transformer. The system is designed to detect any situation where one or more energised conductors are brought to the ground or in contact with any form of earth return.

When applied to feeder protection it is necessary for the star point of the supply transformer to be earthed.

The current transformers used for this protection are normally the same as those previously described which supply overcurrent system of protection. However, in the case of the simple form of unrestricted earth fault protection the element of the earth fault relay is connected between the star point of the current transformer windings and earth.

The relay used may be instantaneous in operation or fixed time or more generally of the induction disc type with an inverse operating characteristic and definite minimum time of operation.

On the occurrence of a phase to earth fault, the operation of the relay and tripping sequence is as previously described for overcurrent protection.

In order to provide fast and effective clearing of earth faults, the setting of the relay is usually fairly low, such as 20% with a 400/5 current transformer. That is, the relay will operate at faults in excess of 80 amps in the high voltage feeder.

Care is necessary before paralleling high voltage feeders employing earth fault protection, which are supplied from different sources. If such paralleling is made or broken with single phase isolators or single phase switchgear it is quite possible that out-of-balance currents in excess of the setting may occur. Such out-of-balance currents will operate the relay and consequently trip the circuit breaker at either end.

If calculation indicated that a load transfer or out-of-balance of the order of the relay setting is likely to occur, and unless other more suitable means (e.g. frame leakage check relay or shorting plugs) to prevent possible mal-operation are available, it is necessary to increase the setting of the earth fault relay prior to the paralleling. Such action must only be taken on the advice of or request from System Control or Distribution Control

If alteration to relay settings is necessary it is essential that such alterations exist for a minimum period and in particular it is essential that the relays be reset on completion of the operation.

13.3.3.4 Earth Fault – Directional

The directional earth Fault protection by way of an earth fault relay is the companion to the directional overcurrent relay. The function of this type of protection is to detect earth fault conditions occurring in a system of two or more paralleled high voltage feeders. The same current transformers are used as for the directional overcurrent system and the relay itself has an additional element to detect a fault current in the reverse to normal direction of power flow.

13.3.3.5 Sensitive Earth Fault

On some feeders within the distribution system sensitive earth fault (sensitive earth fault) protection is installed. This type of protection will detect earth faults of relatively low values.

In substations where the secondary winding of the power transformer is delta connected an artificial earthed star point is established by using an earthing transformer.

Feeders originating from these substations have sensitive-earth-leakage-protection as the single phase to earth fault currents are limited to a maximum value of approximately 200 amps. Settings are normally very low 3% on 200/5 amp C.T. with a time setting of 4.0 to 5.0 seconds.

In other situations sensitive earth leakage protection is installed in substations where earth fault currents may be very high.

In these substations the settings may be increased to values such as 16 amps primary current with a 5.0 second time delay. The sensitive earth fault relay is an instantaneous relay and has an auxiliary time delay relay to provide the time component. The facility is provided to switch this protection to an instantaneous mode. This is achieved by switching the instantaneous sensitive earth fault 'IN/OUT' switch to the 'IN' position. The time delay shall be removed when live line work is being carried out on feeders.

Sensitive earth fault relays are provided on 11 kV and 22 kV pole mounted line reclosers. In the case of the 11 kV reclosers they are connected to core balance or residually connected current transformers through which insulated cable leads to the recloser pass and in the case of the 22 kV reclosers they are connected to built in residually connected current transformers.

The relays operate at nominal pre-set 4 to 6 amp primary currents except on the newer 11 kV reclosers where the current is adjustable between 0.5 and 5 amps. Some relays have pre-set time delays of 0.3 seconds, 0.5 seconds or higher and in other cases time delay setting ranges between 0.1 and 15 seconds are incorporated.

13.3.3.6 Translay – Pilot Wire

Translay-Pilot Wire, or Feeder Protection, describes the type of protection applicable to high voltage feeders, generally underground, which is used where a high accuracy of discrimination is necessary.

The system requires a set of current transformers at each end of the feeder or section thereof being protected, together with reliable pilot wires between the associated relays. The system is capable of detecting phase to phase or phase to earth faults. The principle of operation is similar to that previously described under the heading Differential Protection for Transformers. The principle of the system being that the current entering the protected zone is normally equal to that leaving it.

When applied to the protection of a feeder there can be a considerable distance between the current transformers at the respective ends of the protected zone. This gives rise to a principle difference between the differential system used on the transformers and the system for use on feeders. Namely, it would not be acceptable to have a current circulating system operating over the pilot wires for a considerable distance. Namely, in this system the pilots are normally energised but no current flows under normal conditions.

The relays used are an induction disc type current relay. Variable current settings are provided but no variation in time setting is possible. The operation of the relays is very fast but somewhat dependent upon the magnitude of fault current. The type of relay in general use has a restriction on the amount of load that can be tee-connected between the current transformers and each end of the protected feeder. Generally this intermediate load can be up to approximately 500 kVA.

Larger feed or intermediate loads require a special type of relay.

13.3.3.7 Distance

Distance protection relays are used primarily to protect sub-transmission feeders and some distribution feeders. As their name implies they measure distance, i.e. they recognise a fault occurring within the protected section of the line from the fact that the distance from the relay to the fault is less than the setting of the relay. The distance to the fault is measured in terms of line length. This is done by measuring the impedance of the line, which is almost directly proportional to its length. Normally the relay measures a higher impedance than that of the line because it also measures the impedance of the load.

To a limited extent, these combined overcurrent and earth leakage measuring relays may indicate the distance from the substation to the fault position. They may also be used to clear close-in faults, normally the heaviest ones, quickly. A Zone 1 indication on the relay may mean the fault was somewhere in the first half or three quarters of the feeder. Zone 2 or 3 indication means the fault was towards the end of the feeder or well down lighter spur lines.

When a fault occurs this short-circuits the load and the relay measures only the remaining impedance of the line. If, however, the fault is not a dead short-circuit its impedance in parallel with that of the load and the lines to the load is added to that faulted line section

This makes the fault appear to be more distant than it really is. For this reason and because the relay cannot be made with complete accuracy there has to be a second distance measuring unit to take care of faults at the far end of the protected line section. Further, a third unit is generally provided to give back-up protection for the first two units of the distance relay in further sections.

The distance relays used are of two types, namely Reyrolle Type TS1, having three zones of operation, and the Siemens relay having up to five zones of operation.

The system of protection and both relays are capable of detecting phase to phase or phase to earth faults. In the case of the simpler Reyrolle relay, there are three flags to indicate the faulted phase plus two flags to indicate the zone of operation. There is no positive indication of earth fault on the Reyrolle relay; this can only be deduced. The Siemens relay has positive flag indication for a phase fault or an earth fault, plus indicators for the respective time zones.

The operation of this method of protection requires current transformers at the sending end only, namely the protection is completely at the sending end, no pilot wires or remote connections being involved. The relays comprise overcurrent starting elements plus impedance measuring elements and finally timing elements that provide the appropriate zone of operation of the relay.

It is essential that a record be maintained at the substation containing such equipment, of the significance of the particular zones as applicable. Namely, the first zone of operation of the relay may include say 85% of the feeder. The second zone of operation may include the remaining 15% of the feeder to the substation at the receiving end. And finally, the third zone may include the transformer at the receiving end substation.

When such relays operate it is essential to carefully study the flags that have operated and decide the probable location of the fault before any further action is taken.

13.3.3.8 Overcurrent Series Trips

In some situations where overcurrent and possibly earth fault protection on a feeder is desirable, it is not necessary to provide the full facilities of a circuit-breaker together with overcurrent and earth fault relay protection. A cheaper form of protection may be achieved by the use of circuit breakers or reclosers having in-built series trip coils.. Tripping is achieved by the coil due to its solenoid operation applied to an internal piston mechanically coupled to the tripping mechanism. Variation in timing is achieved through an oil dash-pot device.

The fault current at which such trip coils operate is determined at the time of manufacture and no further on site adjustment is possible. Minimum operating current is approximately twice the rating of the trip coil. Earth fault protection requires the inclusion of additional current transformers and appropriate earth fault relay and circuitry.

13.3.4 Alarm Systems

13.3.4.1 General Functions

13.3.4.1.1 Operation

Some form of alarm system, generally supervises the operation of protection equipment in substations where continuity of supply or continuous functioning of equipment is of high priority.

The function of all alarm systems is to bring to attention an abnormal condition that requires investigation and rectification.

13.3.4.1.2 Initiation

The alarms are initiated from the secondary contacts of protection relays or suitable contact-making devices. The alarms may operate audible or visible signals, either locally or remotely or both. Visible alarms may be of the illuminated lamp type or flag type annunciators.

13.3.4.2 Types of Alarm Condition

The type of condition originating the alarm will dictate priority of attention to alarm signals. Alarm conditions may be classified into two general types:

13.3.4.3 Urgent Alarm Conditions

Any abnormal condition involving interruption to supply or loss of equipment. Fire Alarms.

13.3.4.4 Non-Urgent Alarm Conditions

Various warning conditions, such as:

Tap-changers out of step.

Transformer oil and winding temperatures high.

DC bus - under or over voltage.

AC or DC failure.

Trip supply failure.

Water level high.

Cable oil pressure low.

Regulator - motor supply failure.

13.3.4.5 Priority of Action

13.3.4.5.1 *Urgent Alarm Conditions:*

Every endeavour should be made to reach the point of origin of the alarms within 10-30 minutes.

13.3.4.5.2 *Non-Urgent Alarm Conditions:*

Such conditions should be investigated as expeditiously as possible, within 1 to 2 hours of initiation.

13.3.4.5.3 *Unclassified Alarm Conditions:*

If the type of alarm condition is unknown, then it should be treated as potentially urgent.

13.3.4.5.4 *General Procedure*

Acknowledge and silence audible alarm.

Examine annunciator panel - record indications - acknowledge.

Examine protection relays - record indications.

Proceed in accordance with Manual Instructions for restoration after fault conditions, or in accordance with local instructions.

14. APPENDIX B: METERING CIRCUITS AND EQUIPMENT

14.1 Voltage Metering

Indicating or instantaneous voltmeters are generally confined to terminal substations and larger zone type substations.

14.1.1 Indication

The voltmeters may be connected directly to fixed phases or connected via a voltmeter phase change switch. If the latter, a difference in phase-to-phase voltages may be noted. Such difference is caused by load out-of-balance in the system. The average or mean phase to phase voltage should normally be read and recorded, unless automatic voltage regulating equipment is installed, in which case the phases to which that equipment is connected should be observed.

14.1.2 Accuracy

Substation or protection personnel will normally perform periodic testing and adjustment of indicating voltmeters. The accuracy of indicating voltmeters is not always high. Occasionally there may be an intentional zero error. An attached label will usually indicate this. Operators should not attempt to adjust readings by alteration of zero adjustment

14.1.3 Abnormal Readings

Any abnormal difference between phases should be followed up immediately. Such difference may be due only to a blown voltage transformer fuse, primary or secondary, or more seriously due to an open phase conductor in the system. If a recording voltmeter is not installed the indicating voltmeter should be read and recorded in the Substation Log, or similar, at suitable intervals.

14.1.4 *Voltage – Recording*

Continuous voltage recording at major substations is achieved by the installation of recording-voltmeters..

Where a recording voltmeter is not permanently installed in a substation a portable instrument may be temporarily installed. These voltmeters are normally at 110 volts.

The chart record from the instruments should be examined at regular intervals, dated and any abnormal differences in voltage noted and reported.

14.2 Current Metering

14.2.1 *Ammeters*

Indicating ammeters are generally installed on either incoming or outgoing high voltage feeders at major substations. Again, these instruments may be permanently connected to particular phases or installed with a phase change switch.

Where phase change switches are installed they should be used to maximum advantage.

On restoration of supply to a feeder that has been interrupted the load in all phases should be checked to ensure that open circuit has not occurred in any of the phases. This would be indicated by the obvious out-of-balance in ammeter readings, due to the blowing of line fuses or actual burning through of a conductor.

The feeder ammeters should also be consistently used to ensure that the current rating of switchgear, conductors and equipment is not exceeded.

14.2.1.1 Maximum Demand Ammeter

In some types of distribution substations the total load on the substation is measured by means of a maximum demand ammeter. Such ammeters are usually supplied from current transformers installed on the low voltage busbars.

The M.D. ammeters use two pointers, the first driving a slave pointer which remains in a maximum position. This type of instrument usually contains a thermal movement with a delay of approximately 30 minutes for correct indication of applied current. Care must be exercised in resetting the maximum pointer - it should only be returned to the position of the driving pointer.

14.2.2 Energy and Demand Metering

In some terminal substations, zone substations and distribution substations, a combination energy and maximum demand meter meters the load on the substation. The energy component of the meter is a standard kilowatt/hour meter.

14.2.2.1 Operation

The maximum demand component of the meter is driven from the kilowatt/hour section for an interval generally of 15 minutes, after which it is reset. Care must be exercised in resetting the maximum demand pointer - this should only be returned to the position of the pusher pointer.

Maximum demand meters should be read, recorded and reset frequently. In the event of addition or subtraction of load to a substation the maximum demand meters should also be read and reset.

14.2.3 Temporary Metering

Periodically it is necessary to install temporary portable instruments such as recording voltmeters or recording ammeters in substations.

It is essential that the utmost care be employed in the connection and wiring of such portable instruments to ensure that they do not cause an accident or failure in the substation.

Recording voltmeters should preferably be plugged in to a power outlet or connected via voltage test terminals provided for the purpose. Temporary connections must never be made direct to bus-bars and must always be appropriately fused.

When it is necessary to connect portable recording ammeters in a substation they should always be connected in a metering circuit rather than in a protection circuit. It is essential that the secondary of a current transformer never be open circuited.

14.3 Voltage Regulation – Automatic

14.3.1 General Principles

The voltage applied to the system is automatically regulated at various levels.

Normally this is carried out at terminal substations, zone substations or major substations and voltage regulating transformers on long feeders.

The type of equipment used and the detailed method of operation varies slightly according to the type of installation - in particular determined by the requirement of controlling one transformer or a group of transformers. The general principle, however, is fairly uniform.

14.3.1.1 Operation

A voltage transformer, as previously described, is connected to the secondary side of the power transformer. The secondary of this V.T. is connected to a voltage regulating relay.

In mechanical types, such as the AVR relay the voltage supplies the coil of a solenoid in the relay. A pivoted beam, attached to a restraining spring, mechanically balances the force on the solenoid. In the simplest type of relay the desired balance between the voltage on the solenoid and the restraining spring is achieved by manual variation of the tension on the spring.

After initial setting any variation of voltage as applied to the solenoid results in a movement of the balanced beam which can be utilised to close contacts, initiating corrective action. The corrective action involves a signal to the onload tap changing motor in the power transformer to raise or lower the taps in the appropriate direction to correct the variation in voltage.

In order to avoid unnecessary operation of tap changers for variations in voltage of only short duration, a time delay device is incorporated, which may be set from 10 seconds to 120 seconds.

More modern regulating transformers are fitted with solid state relays which achieve the same as described above but in some units there is no visible indication of the balance between the voltage setting and the actual voltage.

14.3.2 Line Drop Compensation

The principal function of automatic voltage regulation is to maintain a reasonably constant system voltage by applying correction when the voltage drops according to increase in load and vice versa at off-peak periods. A further improvement is possible if the voltage in fact is boosted at periods of peak load in order to compensate for voltage drop at points farther from the sending substation. The line drop compensation equipment provides this latter facility.

14.3.2.1 Operation

A supplementary circuit is connected in series with the solenoid coil of the voltage-regulating relay.

the use of a current transformer connected in the outgoing feeder or in the supply transformer it is possible to reproduce a voltage drop proportional to the load occurring. This additional voltage drop is injected in the solenoid circuit of the voltage-regulating relay. The desired amount of boost is determined by settings of resistance and reactance in the supplementary circuit that are determined by calculations of the equivalent impedance of the outgoing feeders.

Since there is some variation in functions and labelling of tap change equipment in various situations it is necessary for local instruction to be given. Complete familiarity with the tap change controls is essential. As described elsewhere, it is necessary when paralleling feeders from different zone or terminal substations to take various actions including rendering the tap change controls non-automatic.

Mal-operation or out-of-step conditions between group transformers should be corrected and/or reported to Distribution Control.

14.3.3 Group Control

The foregoing describes the method of operation for a single transformer or the principle for a group of transformers. To apply automatic voltage regulation to a group of transformers, one set of equipment as described above is required, namely voltage transformer, voltage regulating relay and auxiliary equipment.

The control of additional transformers is then achieved by signalling from the master or initiating transformer tap changing equipment to the tap changing equipment of the other transformers in the group.

There are two basic means of achievement of this multiple transformer tap changing system.

Firstly, a group/individual system in which the voltage-regulating relay initiates tap changes to all transformers in the group simultaneously.

The second system in general use employs a master/follower system in which the voltage regulating relay initiates a tap change to the master transformer which then in turn initiates the corresponding tap change to the follower transformer.