Branch Procedure: Transmission and Sub-transmission Protection Guidelines CEOP8002.01

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1.0 PURPOSE

This Operational Procedure sets out the general requirements for the protection of Essential Energy's transmission lines, sub-transmission lines and plant contained within zone substations, sub-transmission substations or transmission substations. This also includes reclosers that are located between zone substations on a sub-transmission line.

Assets at 33kV and below that are not considered to be sub-transmission assets are covered separately in Operational Procedure CEOP8002.02

In the special case of a 'hybrid' feeder, both CEOP8002.01 and CEOP8002.02 should be referred to determine the most appropriate protection requirements.

It is the responsibility of the Network Protection Group to determine appropriate protection settings for the protection of assets covered by CEOP8002.01. The Network Protection Group also have the responsibility of creating PSAs and relay setting files for the protection of these assets, unless the protection device is owned by the TNSP.

It is the responsibility of Network Planning to determine appropriate protection settings for the protection of assets covered by CEOP8002.02. Network Planning also have the responsibility of creating PSAs and device setting files for the protection of these assets, excluding where the protection devices are within the zone substation. Primary distribution feeders shall have their protection settings such as overcurrent, earth fault, auto reclose etc determined by Network Planning per Operational Procedure CEOP8002.02, but the creation of relay setting files and PSAs for the protection devices within zone substations are to be undertaken by the Network Protection Group.

For hybrid feeders, appropriate protection settings are to be agreed upon by both the Network Protection Group and Network Planning. A protection setting review of a hybrid feeder can be initiated by either group. A review must consider all protection devices installed on the feeder, including those not in the main feeder segment (tee's and/or spur's). The Network Protection Group have the responsibility of creating PSAs and relay setting files for the protection devices located within zone substations and Network Planning have the responsibility of creating PSAs and setting files for the protection devices (reclosers) located along the feeder.

This document does not preclude the use of protection systems that exceed the requirements of this Operational Procedure; or protection that does not completely meet the requirements of this Operational Procedure where special considerations exist.

1.1 Role of Protection

On the Essential Energy network, the role of the protection systems is to quickly detect and isolate faulted parts of the network, thereby minimising:

- the danger to persons and livestock
- the threat to the environment
- further damage to the electricity network itself
- risk of network instability

Whilst it is not possible for the protection systems to eliminate all risk, the protection systems must reduce the level of risk to an acceptable minimum.

As an absolute minimum, no part of the HV network may ever be energised without at least one protection scheme that is capable detecting and isolating a short circuit fault within that part of the network.

The protection systems shall also endeavour to maintain supply to the largest possible proportion of the network following the detection and isolation of a fault.

It is generally not the purpose of the protection schemes on the Essential Energy network to protect equipment against being electrically overloaded.

2.0 ACTIONS

2.1 Protection General Requirements

Each protection scheme on the Essential Energy network must consider:

- sensitivity (detecting all possible faults that can occur within the protected zone)
- speed (isolating the fault as quickly as practical)
- selectivity (isolate the minimum proportion of the system consistent with clearing the fault)
- reliability (operate when it is required to)
- security (not operate when it is not required).

2.1.1 Protection Sensitivity

All protection schemes shall have sufficient sensitivity to detect all short circuit faults between phases and/or phase(s) and earth within their intended operating zones.

The protection operating factor of a protection device is calculated by dividing the fault level observed at the location of a protection device by the pickup of the protection device. Given that it is minimum protection operating factors that are being specified within this document, it means that the minimum fault level observed at the location of the protection device for a fault within a given protection zone must be found. This minimum fault level is determined by considering the worst case of any normal network operating state and at a system voltage of 1.0pu.

When the network is in an abnormal or temporary state (of short duration) the minimum fault current seen by a protection device may be further reduced, thus affecting the operating factor. The minimum fault levels would typically be reduced by an increase in source impedance at the location of the protection device, or due to an increase to the size (impedance) of the protected zone. It is recommended that any protected asset still has primary and backup protection that meets the requirements this document when the network is in an abnormal state. If this cannot be achieved, then the protected asset may rely on a single protection scheme only - this protection scheme must achieve the minimum requirements of backup protection (e.g. an operating factor of 1.5 for overcurrent protection, or the reliance on zone 3 for distance protection).

Settings should be chosen such that protection is as sensitive as possible without incurring spurious trips or limiting operation of the network under normal or expected system operating conditions.

It is recognised that some faults cannot be detected by the protection schemes, e.g., a broken conductor on the load side of the break.

2.1.2 Protection Speed

Protection systems are required to disconnect the faulted part of the network from the rest of the system in the minimum practical time in order to:

- minimise damage to the faulted equipment
- avoid damage to non-faulted parts of the network
- prevent loss of stability of the network
- minimise the probability of injury to personnel and livestock exposed to the faulty equipment / faulted part of the network
- minimise the extent and duration of interruption to supply as a result of the fault.
- To minimise the risks associated with step and touch potentials.

Fault clearance times should be as short as possible to prevent avoidable damage to personnel or plant. Table 1 shows the maximum clearing times (from fault inception to arc extinction) for zero impedance faults under normal conditions on the Essential Energy network.

Fault clearance times shall be in accordance with NER S5.1.9. All new investments should meet the automatic access fault clearance times.

Table 1

Fault Clearance Times (ms)			
Nominal Voltage	**Source End Fault Location**	**Remote End Fault Location**	**Backup**
More than 100kV but less than 250 kV	In accordance with NER S5.1.9, the automatic access standard clearing time of 120ms should be achieved	In accordance with NER S5.1.9, the automatic access standard clearing time of 220ms should be achieved	In accordance with NER S5.1.9, the automatic access standard clearing time of 430ms should be achieved
66kV	200	1000	4500
33kV	1000	2000	4500
22kV	1000	-	-
11kV and below	1000	-	-

2.1.3 Protection Selectivity (Discrimination)

Protection schemes shall operate to isolate the smallest portion of faulted network. This is achieved by only the nearest circuit breaker(s) or fuse(s) to a fault operating.

Protection should also be selective for all faults where all protection and circuit breakers (or other fault clearing devices) on the system function as designed when the network is in its normal operating arrangement.

It is desirable that selectivity be maintained where:

- a single item of protection or a circuit breaker has failed to operate correctly.
- the network is in an alternate or temporary configuration, including those that affect source impedance (maximum and minimum fault levels).

Selectivity is guaranteed for any kind of unit protection. This a differential type protection that is bound by two or more sets of current transformers. Tripping time is usually instantaneous as the fault location is known to be between specific current transformers.

For non-unit protection the primary system quantities are measured at a single location only. The protection device's sensitivity and the selectivity are dictated by its configurable protection settings. The selectivity is achieved by the coordination of protection devices by time. As such, appropriate grading (time) margins should be used between protection devices that are both capable of detecting the same fault.

Where the time margins cannot be achieved, lesser margins may be used, however consideration must be given to the effect of mal operation.

2.1.4 Protection Security (Stability)

All protection schemes shall allow the primary system to operate within its rated voltage range and carry its rated normal and emergency load currents, without the protection system operating, failing, or being damaged.

Allowance should be made for future growth in the network and changes in customer load requirements. Forecast loads are typically sourced from the Essential Energy "Distribution Annual Planning Report".

Unit protection schemes must remain stable when exposed to out of zone through-faults.

2.1.5 Protection Reliability

Protection schemes must be as reliable as possible within cost-justifiable limits.

The main protection scheme for a given protection zone shall be designed to meet the requirements of high reliability, sensitivity, speed, security and selectivity (discrimination).

To allow for the possibility of failures, the main protection scheme requires a backup protection scheme to significantly improve the protection reliability. If the probability of one protection failing is 'x', then the probability both protections failing is x^2. The resultant risk then becomes insignificant.

Except for the circuit breaker, the backup protection shall be separate from the main protection and shall also be designed to meet the requirements of high reliability, sensitivity, speed, security and selectivity (discrimination). The role of backup protection is to be available if the main protection is unavailable (due to repair or maintenance etc.) or if the main protection fails to operate.

To cater for the failure of a circuit breaker, a CB fail (local backup) scheme is required to trip any additional circuit breakers to isolate the fault. Where a CB fail scheme is not possible, backup shall be provided by non-unit protection schemes.

The backup protection should not, as far as is practical, share DC supplies, CT cores, VT cores, CB trip coils or test facilities with the main protection. The backup protection should be from a different manufacturer to the main protection.

Protection schemes should be designed (so far as is practical) so that failure of one component does not compromise the operation of other protection schemes.

2.2 Zone Substation General Requirements

2.2.1 Protection Schemes

For new or substantially refurbished sites, Essential Energy shall apply the following minimum protection schemes as shown in Table 2. Application detail is provided below.

Table 2

Plant	Protection No	Protection Requirements
Busbars >100kV	No1	• High impedance differential protection operating the No1 BBP multi-trip • The No1 BBP multi-trip shall trip the circuit breaker No1 trip coils • The No1 BBP multi-trip shall initiate CB Fail or inter-trip the No1 protection relay of all connected circuits • Supplied from No1 DC supply
	No2	• High impedance differential protection operating the No2 BBP multi-trip • The No2 BBP multi-trip shall trip the circuit breaker No2 trip coils • The No2 BBP multi-trip shall initiate CB Fail or inter-trip the No2 protection relay of all connected circuits • Supplied from No2 DC supply
Feeders >100kV	No1	• High-speed line-differential protection or comms assisted distance (where appropriate) • CB Fail inter-tripping to the No1 BBP multi-trip • CB Fail Inter-tripping to remote end (not mandatory for distance schemes that can meet the "backup" clearance times per Table 1 for a busbar fault) • Supplied from No1 DC supply • Operates the circuit breaker No1 trip coil
	No2	• High-speed line-differential protection or comms assisted distance (where appropriate) • CB Fail inter-tripping to the No2 BBP multi-trip • CB Fail Inter-tripping to remote end (not mandatory for distance schemes that can meet the "backup" clearance times per Table 1 for a busbar fault) • Supplied from No2 DC supply Operates the circuit breaker No2 trip coil
Transformers >8MVA	No1	• Biased Differential, Restricted Earth Fault, Oil Temperature, Winding Temperature • HV CB Fail inter-tripping to the HV No1 BBP multi-trip or fault thrower (where required) • LV CB Fail inter-tripping to the LV No1 BBP multi-trip (where applicable) • Backup LV IDMT OC and EF • Supplied from No1 DC supply • Operates the circuit breaker No1 trip coils

Plant	Protection No	Protection Requirements
	No2	• Biased Differential, Restricted Earth Fault, Main Tank Buchholz, Tap Changer Over Pressure, Main Tank Over Pressure • HV CB Fail inter-tripping to the HV No2 BBP multi-trip or fault thrower (where required) • LV CB Fail inter-tripping to the LV No1 (where LV switchboard does not have duplicated BBP) or LV No2 BBP multi-trip (where applicable) • Backup LV IDMT OC and EF • Supplied from No2 DC supply • Operates the circuit breaker No2 trip coils
Zone Substation Transformers <100kV & =< 8MVA (CBs and Relays)	No1	• HV IDMT OC and EF, LV IDMT NEF, Oil Temperature, Winding Temperature. • HV CB Fail inter-tripping to the No1 BBP multi-trip, fault thrower (where required) or reliance on remote backup • Supplied from No1 DC supply • Operates the circuit breaker No1 trip coil
	No2	• HV IDMT OC and EF, LV IDMT NEF, Main Tank Buchholz, Tap Changer Over Pressure, Main Tank Over Pressure • HV CB Fail inter-tripping to the No2 BBP multi-trip, fault thrower (where required) or reliance on remote backup • Supplied from No2 DC supply (where available) - backup must be provided remotely for sites with single DC supply. • Operates the circuit breaker No2 trip coil
Zone Substation Transformers <100kV & =<8MVA (Reclosers)	No1	• HV IDMT OC and EF • LV NEF, Oil Temperature, Winding Temperature, Main Tank Buchholz, Tap Changer Over Pressure, Main Tank Over Pressure (via recloser input card). • Backup must be provided for recloser failure
Zone Substation Transformers <100kV & =< 8MVA (Fuses)	No1	• Overcurrent protection of transformer via fuses only • LV OC and EF (LV CB/recloser only) • Oil Temperature, Winding Temperature (LV CB/recloser only) • Main Tank Buchholz, Tap Changer Over Pressure, Main Tank Over Pressure (indication only)
Sub-transmission Busbars (33kV and 66kV meshed network)	No1	• High impedance differential protection operating the No1 BBP multi-trip • The No1 BBP multi-trip shall trip the circuit breaker No1 trip coils • The No1 BBP multi-trip shall initiate CB Fail or inter-trip the No1 protection relay of all connected circuits that are protected with unit protection • Supplied from No1 DC supply

Plant	Protection No	Protection Requirements
	No2	• High impedance differential protection operating the No2 BBP multi-trip • The No2 BBP multi-trip shall trip the circuit breaker No2 trip coils • The No2 BBP multi-trip shall initiate CB Fail or inter-trip the No2 protection relay of all connected circuits that are protected with unit protection • Supplied from No2 DC supply
Transmission and Sub-transmission feeders (33kV and 66kV)	No1	• High-speed line-differential or distance protection (where appropriate). • CB Fail inter-tripping to the No1 BBP multi-trip or fault thrower (where required). • CB Fail Inter-tripping to remote end for line-differential schemes • Supplied from No1 DC supply • Operates the circuit breaker No1 trip coil
	No2	• High-speed line-differential or distance protection (where appropriate). • CB Fail inter-tripping to the No2 BBP multi-trip or fault thrower (where required). • CB Fail Inter-tripping to remote end for line-differential schemes • Supplied from No2 DC supply • Operates the circuit breaker No2 trip coil
Capacitor Banks (33kV and 66kV)	No1	• IDMT OC and EF • Neutral Unbalance (NUB) • CB Fail inter-tripping to the No1 BBP multi-trip • Supplied from No1 DC supply • Operates the circuit breaker No1 trip coil
	No2	• IDMT OC and EF • CB Fail inter-tripping to the No2 BBP multi-trip • Supplied from No2 DC supply • Operates the circuit breaker No2 trip coil
FI Units (33kV and 66kV)	No1	• IDMT OC and EF • CB Fail inter-tripping to the No1 BBP multi-trip • Supplied from No1 DC supply • Operates the circuit breaker No1 trip coil
	No2	• IDMT OC and EF • CB Fail inter-tripping to the No2 BBP multi-trip • Supplied from No2 DC supply • Operates the circuit breaker No2 trip coil

Plant	Protection No	Protection Requirements
Zone Substation Busbars < 33kV	No1	• High impedance differential protection operating the No1 BBP multi-trip. Arc-Flash schemes will be considered under special circumstances or for switchboards undergoing refurbishment. • The No1 BBP multi-trip shall trip the circuit breaker No1 trip coils • The No1 BBP multi-trip shall initiate CB Fail or inter-trip the No1 (and No2 where applicable) protection relay(s) of all connected circuits that are protected with unit protection • Supplied from No1 DC supply
Capacitor Banks < 33kV	No1	• IDMT OC and EF • SEF or NPS (where required) • Neutral Unbalance (NUB) • CB Fail inter-tripping to the No1 BBP multi-trip • Supplied from No1 DC supply • Operates the circuit breaker No1 trip coil
FI Units < 33kV	No1	• IDMT OC and EF • CB Fail inter-tripping to the No1 BBP multi-trip • Supplied from No1 DC supply • Operates the circuit breaker No1 trip coil
Primary Distribution Feeders and Auxiliary Transformers (Relays and circuit breakers)	No1	• IDMT OC, NPS, EF and SEF • CB Fail inter-tripping to the No1 BBP multi-trip • Supplied from No1 DC supply • Operates the circuit breaker No1 trip coil
	No2	• IDMT OC, NPS and EF • Supplied from No2 DC supply • Operates the circuit breaker No2 trip coil
Primary Distribution Feeders (Reclosers)	No1	• As required per CEOP8002.02

2.2.2 Substation Batteries

Substation batteries are identified as a critical single point of failure and should be duplicated. These duplicated battery supplies shall be electrically segregated from each other and be used to separately supply the main (No1) and backup (No2) protection schemes.

Existing substations that are substantially augmented shall meet the above requirement. Where this is not feasible and only a single trip battery is installed, remote backup protection shall be provided. The use of fuses mitigates the requirement for backup protection.

All battery supplies shall have DC monitoring to raise a remote alarm for low voltage of the battery as a minimum. Battery chargers used in these DC systems should also be separately monitored/alarmed.

2.2.3 Protection Tripping Alarms and Indication

All new micro-processor protection relays shall incorporate digital displays and/or LEDs to indicate the reason of a protection trip. Tripping information shall be reported via SCADA to the Network Operator.

Micro-processor protection relays shall also store event records and oscillography for post fault analysis.

2.2.4 Relay Fail Alarms

All new micro-processor protection relays shall be fitted with self-monitoring features and a fail-safe ‘Relay Fail’ or ‘Watchdog’ output contact. This output contact shall be hardwired to the local RTU. The Network Operator shall then receive this alarm via the SCADA system.

2.2.5 Trip Circuit / Trip Supply Supervision

The trip circuit of all high-voltage zone substation circuit breakers should be supervised.

Where trip circuit supervision is not possible, trip supply supervision is required as a minimum.

These alarms shall be reported via SCADA to the Network Operator.

2.2.6 Blind Spots and CB Fail

Where CB fail is required (refer Table 2), micro-processor protection relays shall incorporate current based CB fail checking with internal timing.

The CB fail protection shall trip the required circuit breakers to isolate the fault. Where this is not possible, non-unit protection must be relied upon to provide backup protection.

Where blind spots exist, the protection scheme must be capable of tripping the adjacent protection zone to isolate the fault.

CB Fail alarms shall be reported via SCADA to the Network Operator.

2.3 Power Transformer Protection

2.3.1 Transformer Differential Protection

2.3.1.1 Biased Differential Element Setting

The biased differential element must:

- remain stable under maximum through fault conditions, regardless of tap setting. This requires that the bias slope be set to compensate for CT errors and the transformer tapping range. Bias slopes should be set as per relay manufacturer’s recommendations.
- be restrained for inrush. Care needs to be exercised when setting or applying a biased differential relay which protects two or more transformers, as prolonged inrush imbalances can occur when a second transformer is energised. In such cases, additional precautions need to be taken, such as custom blocking logic.
- be sensitive enough to positively operate for faults inside the protected zone.
- not operate for loads within the transformer differential zone such FI units or auxiliary transformers.
- not operate for a fault on the secondary side of an auxiliary transformer that is within transformer differential zone.

2.3.1.2 Unrestrained Differential Element Setting

The unrestrained differential element is to very quickly detect high differential currents which clearly indicate the presence of an internal fault. The following should be considered:

- The unrestrained differential element is often not provided with any form of harmonic restraint or blocking and hence can operate for transformer inrush. Care must be taken to ensure the setting is not too low to operate during energisation.
- If possible, the unrestrained element should be set to cover source side terminal faults, although this may not always be achievable, depending upon the fault level.

2.3.1.3 Transformer Differential CT Requirements

Class PX CTs are to be used for all new transformer differential protection schemes as the knee point voltage and secondary resistance are well known.

The CT ratio should be chosen so that rated primary/secondary currents are not exceeded under any load conditions.

Where the rated continuous thermal current of the CT is greater than the rated primary/secondary current, a lower CT ratio can be used provided that:

- The rated continuous thermal currents are not exceeded under any load conditions.
- The transformer differential relay can continuously withstand the secondary current under any load conditions.

The minimum CT knee-point voltage shall be determined per manufacturers recommendations or per the following formula:

$$V_{k,Min} \geq I_{Fault,Sec} \times \left(1 + \frac{X}{R}\right) \times (R_{CT} + R_{Burden})$$

$V_{k,Min}$ is the minimum required knee point voltage of the CT

$I_{Fault,Sec}$ is the maximum through fault current in secondary amps

$\frac{X}{R}$ is the reactance/resistance ratio of the primary system

R_{CT} is the secondary resistance of the CT

R_{Burden} is the combined resistance of the CT's burden (leads, relays, interposing CT's etc)

A knee point voltage below $V_{k,Min}$ may cause the CT to saturate. This may cause:

- Spurious tripping for through faults.
- A delay in the relay's operate time due to the relay's harmonic blocking

2.3.2 Transformer Restricted Earth Fault Protection

Restricted Earth Fault (REF) is a form of unit protection employed on star transformer or generator windings. Faults that occur close to the star point do not usually cause a large amount of phase current to flow but may cause a large neutral current flow. The main advantage of this protection over differential protection is that it is highly sensitive to earth faults close to the neutral point.

There are two types of REF protection relays in use within Essential Energy:

2.3.2.1 High Impedance Restricted Earth Fault Protection

This protection works on the same principle as the high impedance busbar protection scheme. The high impedance REF protection scheme must remain stable under maximum through fault conditions. It must be sensitive enough to positively operate for faults inside the protected zone.

To prevent damage to equipment or secondary wiring the voltage across the element of a high impedance restricted earth fault protection relay shall be limited by a suitably rated voltage limiting device such as a ‘Metrosil’.

2.3.2.2 High Impedance Restricted Earth Fault Protection Relay Setting

Refer to 2.4.2.1 - High Impedance Busbar Protection Relay Setting Voltage

2.3.2.3 High Impedance Restricted Earth Fault Protection CT Requirements

Refer to 2.4.2.2 - High Impedance Busbar Protection CT Requirements

2.3.2.4 Low Impedance Restricted Earth Fault Protection

Low impedance restricted earth fault protection schemes are typically implemented in numerical or electronic protection relays. This protection is commonly applied in transformer differential relays in addition to the differential protection.

2.3.2.5 Low Impedance Restricted Earth Fault Protection Setting

The biased differential element must remain stable under maximum through fault conditions, particularly for earth faults.

The restricted earth fault relay should be restrained (or blocked) if the neutral CT current does not exceed a threshold value as an absence of neutral CT current indicates that there is no fault within the relay’s zone. Note that a three phase out of zone fault can produce significant “false” residual current.

2.3.2.6 Low Impedance Restricted Earth Fault Phase CT Requirements

Refer to 2.3.1.3 - Transformer Differential CT Requirements

2.3.2.7 Low Impedance Restricted Earth Fault Neutral CT Requirements

For relays that do not have internal CT tap compensation, the neutral CT must be connected at the same ratio as the phase CTs.

For relays that have internal CT tap compensation, it is preferred that the ratio of the neutral CT is not less than half of the ratio of the phase CTs.

The minimum CT knee-point voltage shall be determined per manufacturers recommendations or per the following formula:

$$V_{k,Min} \geq I_{Fault,Sec} \times \left(1 + \frac{X}{R}\right) \times (R_{CT} + R_{Burden})$$

$V_{k,Min}$ is the minimum required knee point voltage of the CT

$I_{Fault,Sec}$ is the maximum through fault current in secondary amps

$\frac{X}{R}$ is the reactance/resistance ratio of the primary system

R_{CT} is the secondary resistance of the CT

R_{Burden} is the combined resistance of the CT's burden (leads, relays, interposing CT's etc)

2.3.3 Transformer Thermal Protection

Transformer thermal protection is provided to ensure that the winding insulation is not subjected to excessive temperature rises for long durations. Insulation temperature rises above the design temperature can reduce the lifespan of the insulation. All the transformer's circuit breakers are to be tripped when the Hot Oil or Hot Winding trip thresholds are exceeded. Fused transformers should have the LV circuit breaker tripped.

There are cases however, where it is necessary to subject the transformer windings to temperatures marginally in excess of the design temperature for short durations. Whilst this does have a minor detrimental effect on the insulation life of the transformer, it allows supply to customers to be maintained.

There are two variations in design criteria applied, pre 1998 and post 1998. For simplicity, these have been combined to provide a standard for Essential Energy.

The Winding Temperature indicator is a summation of the oil temperature and the difference between the average winding temperature and the average oil temperature multiplied by 1.1 to account for the 'hottest spot', the latter provided through a CT and heater/shunt combination to simulate the winding temperature at varying loads.

Where fitted, thermal protection should be set as per the manufacturer's recommended settings (provided they are relevant to the transformer's present configuration)

If the manufacturer's settings cannot be obtained or are considered no longer applicable to the transformer in its present configuration (eg a transformer may have been upgraded from ONAN to ONAF). The following settings are to be applied:

Hot Oil Alarm setting = 90degC
Hot Oil Trip setting = 105degC

Hot Winding Alarm setting = 110degC
Hot Winding Trip setting = 125degC

Fan and Pump Control - based on winding temp sensor reading
Pumps On = 60degC
Pumps Off = 50degC (where sensor differential permits).

Fans On = 65degC
Fans Off = 55degC (where sensor differential permits).

Fan and Pump Control - based on Oil temp sensor reading
Pumps On = 55degC
Pumps Off = 45degC (where sensor differential permits).

Fans On = 60degC

Fans Off = 50degC (where sensor differential permits).

Winding Temperature Indicator Setting

The Temperature gradient (G) $= T - k\theta$

Where T = average winding temperature rise for steady conditions
k = constant ratio of average temperature rise to top oil temperature rise
= 0.8 for natural oil cooled transformers prior 1959
= 0.97 for forced oil cooled transformers prior 1959.

OR

Where test figures are available:

k = 1 – temperature difference between inlet and outlet / 2 X temperature rise of the top oil.
θ = top oil temperature rise for steady conditions at test load

Determination of Injection temperature rise

T' = 1.1 X G
T' = 1.1 $(T-k\theta)$.

Determination of Injection current

IT' = VAmax (OFAF) X CT ratio / $\sqrt{3}$ X V.

Determination of Heater/Shunt current

IH = IT' X RS/RH + RS
Where IH = Heater current
RH = Heater resistance + leads
RS = Shunt resistance.

2.3.4 Transformer Mechanical Protection

2.3.4.1 Main Tank Buchholz (MTB) Protection

A Main Tank Buchholz device shall be fitted to all transformers above 5MVA.

Where a Main Tank Buchholz device is fitted, it should trip all the transformer's circuit breakers for an oil surge.

Transformers above 15MVA in zone substations with a full n-1 capacity shall trip all the transformer's circuit breakers for low oil.

These devices will have an alarm for gas collection.

2.3.4.2 Tap Changer Buchholz (TCB) or Tap Changer Over Pressure (TCOP) Protection

A Tap Changer Buchholz or TCOP device shall be fitted to all transformers above 5MVA.

Where a Tap Changer Buchholz or TCOP device is fitted, it should trip all the transformer's circuit breakers.

2.3.4.3 Main Tank Over Pressure (MTOP) Protection

Where a MTOP device is fitted, it should trip all the transformer's circuit breakers.

2.3.5 Transformer High Voltage Overcurrent, Earth Fault and Negative Phase Sequence Protection (HV OC/EF/NPS)

2.3.5.1 HV OC Element Setting

IEC SI (preferred), VI or EI IDMT curves are to be used.

The HV OC relay shall be capable of detecting all three-phase faults within the primary zone of the relay with an operating factor greater than 2.0. Where the HV OC relay is required to provide backup, all three-phase faults within the backup zone of the relay should have an operating factor greater than 1.5.

Where the HV OC is the only protection capable of detecting phase-phase faults, the relay shall be capable of detecting all phase-phase faults within the primary zone of the relay with an operating factor greater than 2.0. Where the HV OC relay is required to provide backup, all phase-phase faults within the backup zone of the relay shall have an operating factor greater than 1.5.

Where the HV OC is the only protection capable of detecting phase-earth faults, the relay shall be capable of detecting all phase-earth faults within the primary zone of the relay with an operating factor greater than 2.0. Where the HV OC relay is required to provide backup, all phase-earth faults within the backup zone of the relay shall have an operating factor greater than 1.5.

The HV OC relay should be set to allow the full capacity of the transformer, plus a suitable margin (120%-140%). Where the pickup does not meet this requirement due to operating factor constraints, it shall be noted on the PSA.

The overcurrent timing shall be coordinated:

- Above all downstream protection devices with a 300ms margin for 3-phase and phase-phase faults. If the HV OC relay is an induction disc type this shall be increased to 400ms.
- Below all upstream protection devices with a 300ms margin. If the upstream relay is an induction disc type this shall be increased to 400ms. Note that this requirement does not apply for upstream distance relay Zone 2 reach when in accordance with section 2.5.2.6.

An instantaneous overcurrent (IOC) element may be used in addition to the IDMT OC provided the IOC pickup is selected so that it cannot see faults at the location of downstream relays. It is preferred that the IOC pickup be greater than eight (8) times the ONAN rating of the transformer, with the preferred value to be ten (10) times. Care should be exercised for relays that exhibit poor transient over-reach characteristics.

2.3.5.2 HV EF Element Setting

IEC SI (preferred), VI or EI IDMT curves are to be used.

The HV EF relay shall be capable of detecting all earth faults within the primary zone of the relay with an operating factor greater than 2.0. Where the HV EF relay is required to provide backup, all earth faults within the backup zone of the relay shall have an operating factor greater than 1.5.

The HV EF relay pickup should be set as low as possible whilst coordinating with downstream earth fault relays (for transformers that pass zero-sequence current). The HV EF pickup shall not be less than 10amps.

The earth fault relay timing shall be coordinated:

- Above all downstream earth fault protection devices with a 300ms margin (for transformers that pass zero-sequence current). If the HV EF relay is an induction disc type this shall be increased to 400ms.
- Below all upstream earth fault protection devices with a 300ms margin. If the upstream relay is an induction disc type this shall be increased to 400ms. Note that this requirement does not apply for upstream distance relay Zone 2 reach when in accordance with section 2.5.2.6.

An instantaneous earth fault (IEF) element may be used in addition to the IDMT EF provided the IEF pickup is selected so that it cannot see earth faults at the location of downstream relays.

2.3.5.3 HV Negative Phase Sequence Element Setting

IEC SI (preferred), VI or EI IDMT curves are to be used.

Where HV NPS is required for the detection phase-phase faults, the relay shall be capable of detecting all phase-phase faults within the primary zone of the relay with an operating factor greater than 2.0. Where the HV NPS relay is required to provide backup, all phase-phase faults within the backup zone of the relay shall have an operating factor greater than 1.5.

Where HV NPS is required for the detection phase-earth faults, the relay shall be capable of detecting all phase-earth faults within the primary zone of the relay with an operating factor greater than 2.0. Where the HV NPS relay is required to provide backup, all phase-earth faults within the backup zone of the relay shall have an operating factor greater than 1.5.

The NPS relay timing shall be coordinated:

- Above downstream protection devices that operate for unbalanced faults with a 300ms margin.
- Coordination is generally not required below upstream protection devices unless they also have NPS protection. Where required, a 300ms margin shall be used.

2.3.5.4 HV Overcurrent, Earth Fault and NPS CT Requirements

Class P or PX CTs are to be used for all transformer HV (OC/EF/NPS) protection schemes.

The CT ratio should be chosen so that rated primary/secondary currents are not exceeded under any load conditions.

Where the rated continuous thermal current of the CT is greater than the rated primary/secondary current, a lower CT ratio can be used provided that:

- The rated continuous thermal currents are not exceeded under any load conditions
- The overcurrent relay can continuously withstand the secondary current under any load conditions

The CTs shall be capable of driving the combined burden of the HV OC/EF/NPS relay(s) and secondary wiring.

For P class CTs, the Accuracy Limit Factor (ALF) should not be exceeded at the maximum fault level unless a high-set overcurrent element is set below the ALF.

2.3.6 Transformer Low Voltage Overcurrent, Earth Fault and Negative Phase Sequence Protection (LV OC/EF/NPS)

2.3.6.1 LV OC Element Setting

IEC SI (preferred), VI or EI IDMT curves are to be used.

The LV OC relay shall be capable of detecting all three-phase faults within the primary zone of the relay with an operating factor greater than 2.0. Where the LV OC relay is required to provide backup, all three-phase faults within the backup zone of the relay should have an operating factor greater than 1.5.

Where the LV OC is the only protection capable of detecting phase-phase faults, the relay shall be capable of detecting all phase-phase faults within the primary zone of the relay with an operating factor greater than 2.0. Where the LV OC relay is required to provide backup, all phase-phase faults within the backup zone of the relay shall have an operating factor greater than 1.5.

The LV OC relay should be set to allow the full capacity of the transformer, plus a suitable margin (120%-140%). Where the pickup does not meet this requirement due to operating factor constraints, it shall be noted on the PSA.

The overcurrent timing shall be coordinated:

- Above all downstream protection devices with a 300ms margin. If the LV OC relay is an induction disc type this shall be increased to 400ms.
- Below all upstream protection devices with a 300ms margin for 3-phase and phase-phase faults. If the upstream relay is an induction disc type this shall be increased to 400ms.

Instantaneous overcurrent elements are usually not used as they cannot coordinate with downstream feeder OC protection. These elements can however be used as part of a blocking scheme – refer to section 2.4.3.1.

2.3.6.2 LV EF Element Setting

IEC SI (preferred), VI or EI IDMT curves are to be used.

The LV EF relay shall be capable of detecting all earth faults within the primary zone of the relay with an operating factor greater than 2.0. Where the LV EF relay is required to provide backup, all earth faults within the backup zone of the relay shall have an operating factor greater than 1.5.

The LV EF relay pickup should be set as low as possible whilst coordinating with downstream earth fault relays.

The earth fault relay timing shall be coordinated:

- Above all downstream earth fault protection devices with a 300ms margin. If the LV EF relay is an induction disc type this shall be increased to 400ms.
- Below all upstream earth fault protection devices with a 300ms margin (for transformers that pass zero-sequence current). If the upstream relay is an induction disc type this shall be increased to 400ms.

Instantaneous earth fault elements are usually not used as they cannot coordinate with downstream feeder EF protection. These elements can however be used as part of a blocking scheme – refer to section 2.4.3.1.

2.3.6.3 LV Negative Phase Sequence Element Setting

IEC SI (preferred), VI or EI IDMT curves are to be used.

Where LV NPS is required for the detection phase-phase faults, the relay shall be capable of detecting all phase-phase faults within the primary zone of the relay with an operating factor greater than 2.0. Where the LV NPS relay is required to provide backup, all phase-phase faults within the backup zone of the relay shall have an operating factor greater than 1.5.

The NPS relay timing shall be coordinated:

- Above downstream protection devices that operate for unbalanced faults with a 300ms margin.
- Coordination is generally not required below upstream protection devices unless they also have NPS protection. Where required, a 300ms margin shall be used.

Instantaneous NPS elements are usually not used as they cannot coordinate with downstream feeder protection.

2.3.6.4 LV Overcurrent, Earth Fault and NPS CT Requirements

The LV OC/EF/NPS CTs are to meet the same requirements as the HV OC/EF/NPS CTs – refer to 2.3.5.4.

2.3.7 Transformer Low Voltage Neutral Earth Fault (NEF) Protection

Where a transformer's only short-circuit protection is HV OC/EF, NEF protection should be installed to trip the HV circuit breaker.

2.3.7.1 LV NEF Element Setting

IEC SI (preferred), VI or EI IDMT curves are to be used.

The LV NEF relay shall be capable of detecting all earth faults within the primary zone of the relay with an operating factor greater than 2.0. Where the LV NEF relay is required to provide backup, all earth faults within the backup zone of the relay shall have an operating factor greater than 1.5.

The LV NEF relay pickup should be set as low as possible whilst coordinating with downstream earth fault relays.

The neutral earth fault relay timing shall be coordinated:

- Above all downstream earth fault protection devices with a 300ms margin. If the LV NEF relay is an induction disc type this shall be increased to 400ms.
- Below all upstream earth fault protection devices with a 300ms margin (for transformers that pass zero-sequence current). If the upstream relay is an induction disc type this shall be increased to 400ms.

Instantaneous neutral earth fault elements are usually not used as they cannot coordinate with downstream feeder EF protection.

2.3.7.2 LV Neutral Earth Fault CT Requirements

Class P or PX CTs are to be used for all transformer LV NEF protection schemes.

The CT ratio shall not be less than 1/20th of the maximum fault level.

The CT shall be capable of driving the combined burden of LV NEF relay and secondary wiring.

For P class CTs, the Accuracy Limit Factor (ALF) should not be exceeded at the maximum fault level, unless a high-set NEF element is set below the ALF.

2.3.8 Transformer HV Fuses

Smaller power transformers in zone substations may be protected against short circuits with HV fuses; however, this is generally not recommended. Reasons for this include:

- no tripping for mechanical devices, ie Buchholz, temperature, Main Tank Over Pressure
- lack of supervisory control
- the clearing times, particularly for earth faults can be slow
- not all phases are interrupted

2.3.8.1 Transformer HV Fuse Sizing

HV fuses shall be selected such that they are capable of interrupting all short circuit faults within their primary AND backup zones with an appropriate operating time and an operating factor greater than 3.0.

The HV fuses should allow the full capacity of the transformer, plus a suitable margin (120%-140%). Where the fuses do not meet this requirement, it shall be noted on the PSA.

The minimum-melt characteristic of the fuse shall coordinate above all downstream protection devices with an appropriate grading margin for 3-phase and phase-phase faults. The pre-heating of the fuse, and the affect downstream auto-reclose should also be considered.

The total clearing time characteristic of the fuse shall coordinate below all upstream protection devices with an appropriate grading margin.

2.3.8.2 Loss of Phase Protection

Loss of Phase protection should be applied in protection devices immediately downstream of a Zone Substation transformer that is protected by fuses. Loss of Phase protection prevents abnormal system voltages when all three fuses have not operated.

The phase to neutral operating voltage is usually set to 70% of nominal. The time delay is typically set between 5 and 10 seconds.

2.4 Busbar Protection

All substation busbars must be protected with a primary and backup protection scheme.

At 33kV and above where there are circuit breakers on all circuits, this must be duplicated high impedance busbar protection.

Below 33kV, new installations must have circuit breakers on all circuits. It is typically not possible to fit the required current transformers for duplicated high-impedance busbar protection within an indoor switchboard – in this case, the primary busbar protection shall be high impedance, with backup provided by IDMT overcurrent and earth fault protection per section 4.6. Under special circumstances, arc flash protection may be considered in lieu of high impedance busbar protection as the primary busbar protection.

Arc flash schemes may be installed on refurbished indoor switchboards.

Frame leakage schemes, blocking schemes and IDMT overcurrent and earth fault (only) schemes are not to be used for new indoor switchboards.

2.4.1 Low Impedance Busbar Protection

Low impedance busbar protection is not typically used on the Essential Energy network – it may be used under special circumstances only and set per the relay manufacturers recommendations.

2.4.2 High Impedance Busbar Protection

The high impedance busbar protection scheme must remain stable under maximum through fault conditions. It must be sensitive enough to positively operate for faults inside the protected zone.

To prevent damage to equipment or secondary wiring the voltage across the element of a high impedance busbar protection relay shall be limited by a suitably rated voltage limiting device such as a 'Metrosil'.

2.4.2.1 High Impedance Busbar Protection Relay Setting Voltage

The minimum relay setting voltage shall be per the following formula:

$$V_{Relay} \geq I_{Fault,Sec} \times (R_{CT} + R_{Leads})$$

V_{Relay} is the minimum relay setting voltage

$I_{Fault,Sec}$ is the maximum fault current in secondary amps

R_{CT} is the highest secondary winding resistance of any CT in the scheme

R_{Leads} is the resistance of leads from the CT to the relay

2.4.2.2 High Impedance Busbar Protection CT Requirements

Busbar protection CT's must be located on the circuit side of each circuit breaker.

Class PX CTs are to be used for all new busbar protection schemes as the knee point voltage and secondary resistance are well known. All CTs in the scheme must be on the same ratio. Interposing CTs are not to be used.

The CT ratio should be chosen so that rated primary/secondary currents are not exceeded under any load conditions.

The minimum CT knee-point voltage shall be per the following formula:

$$V_{knee} \geq 2 \times V_{Relay}$$

V_{knee} is the lowest knee-point voltage of any CT in the scheme

V_{Relay} is the relay setting voltage

It is preferred that the CT knee-point voltage is 3 – 5 times the relay setting voltage.

2.4.3 Blocking Schemes for Busbar Speed Enhancement

Blocking schemes have occasionally been used in lieu of high impedance busbar protection to improve the clearing times of busbar faults. It is not used for new installations. Blocking schemes consist of high-set overcurrent and earth fault elements in the transformer and the bus section circuit breakers.

These fast elements will operate for high fault currents, unless a downstream relay also sees the fault and sends a blocking signal to prevent it from operating.

2.4.3.1 Transformer Low Voltage Overcurrent and Earth Fault Settings

The IDMT overcurrent and earth fault elements shall be set normally per sections 2.3.6.1 and 2.3.6.2

The relay should be configured with a directional overcurrent and earth fault blocking signal that detects faults within the transformer. This is used to provide a blocking signal to any relays behind it (typically a bus-section protection relay).

The blocked high-set Overcurrent tripping element would typically be set to pickup at 60% of the phase to phase fault current that would be seen by the element under system normal conditions. This pickup should also be at least twice the pickup of the highest downstream overcurrent element which blocks it.

The blocked high-set Earth fault tripping element would typically be set to operate at 40% of the phase to earth fault current that would be seen by the element under system normal conditions. This pickup should also be at least twice the pickup of the highest downstream earth fault element which blocks it.

Tripping of the blocked high-set overcurrent and earth fault elements only occur if a blocking signal is not received within the prescribed element time delay setting (usually no more than 200ms).

2.4.3.2 Bus Section Circuit Breaker Overcurrent and Earth Fault Settings

The relay shall be configured with two directional overcurrent and earth fault blocking signals that each detect faults in opposite directions. Each is used to provide blocking signals to any relays behind it (typically transformer LV protection relays and/or other bus-section protection relays).

If directional IDMT overcurrent elements are configured in the bus section relay, each element is to coordinate between the applicable Transformer IDMT Overcurrent element (refer 2.3.6.1) and the IDMT overcurrent elements of downstream relays. The pickup of the directional IDMT Overcurrent elements can be used to provide the above-mentioned blocking signals.

If directional IDMT Earth Fault elements are configured in the bus section relay, each element is to coordinate between the applicable Transformer IDMT Earth Fault element (refer 2.3.6.2) and the IDMT Earth Fault elements of downstream relays. The pickup of the directional IDMT Earth Fault elements can be used to provide the above-mentioned blocking signals.

The blocked high-set overcurrent tripping element would typically be set to pick up at 60% of the phase to phase fault current that would be seen by the element under system normal conditions. This pickup should also be at least twice the value of the highest downstream overcurrent element pickup which blocks it.

The blocked high-set Earth fault tripping element would typically be set to operate at 40% of the phase to earth fault current that would be seen by the element under system normal conditions.

This pickup should also be at least twice the pickup of the highest downstream earth fault element which blocks it.

Tripping of the blocked high-set overcurrent and earth fault elements only occur if a blocking signal is not received within the prescribed element time delay setting (usually no more than 200ms).

2.4.3.3 Feeder Circuit Breaker Overcurrent and Earth Fault Settings

The following applies to all outgoing feeder circuit breakers (primary distribution feeders, FI units, capacitor banks, auxiliary transformers etc):

- The IDMT overcurrent and earth fault elements shall be set normally – refer to sections 2.7, 2.8, 2.9 and 2.10.
- The pickup of the IDMT overcurrent and earth fault elements shall be configured to provide blocking signals to any upstream relays (typically transformer LV protection relays and other bus-section protection relays). Where bi-directional fault currents are possible through a feeder circuit breaker, the blocking signal must be directional.

2.4.4 Frame Leakage Protection

Frame leakage protection is a high-speed earth fault only protection to detect earth faults within metal clad switchgear. It is not used in new installations. The scheme measures the fault current flowing from the switchgear frame to earth - this requires that the switchgear is insulated from the ground. Each zone of the switchgear is earthed via a single conductor only, and a toroidal CT is installed on this earthing conductor.

For security, the scheme must incorporate a ‘check’ relay that measures the earth fault current flowing in the neutral of the transformer(s) supplying the switchgear.

If inadequately insulated (or if there is a second earthing point within a zone), spurious tripping may occur when out of zone earth faults cause fault current to flow though the switchgear frame and through the earth point. The resistance between the switchgear frame and ground should be greater than 10 ohms. The minimum pickup of the frame leakage scheme must consider the current that could flow through the frame leakage relay for through faults.

The frame leakage scheme shall trip all circuit breakers connected to the applicable zone.

2.4.5 Arc Flash Protection

Arc Flash protection is a high-speed protection scheme that is occasionally utilised on indoor switchgear and switchboards. Optic sensors are installed in each cubicle containing energised HV conductors for detection of arcing caused during internal faults. A current check function is also required to improve security of the scheme against inadvertent detection of torch light or camera flashes.

Arc sensors are typically located in cable boxes, switchgear chambers and busbar ducts on the switchboard and are connected to an arc fault relay that supervises all sensors in the scheme. Current check is typically provided by measuring current on transformer incomer circuits and is set with a threshold of 1.2-1.5pu of transformer full load current.

This scheme is used on smaller sized switchboards (630A CB) where there is insufficient space for high impedance BBP CTs. The scheme has also been retrofitted to switchboards with high fault level and no existing high-speed bus protection.

The arc flash scheme is configured to selectively trip each busbar section within the switchboard. The arc flash relay(s) with current check, are configured to operate a busbar multi-trip relay. Two sensors should be installed on the Bus Section CB chamber (one linked to each arc flash scheme) to ensure blind-spot protection coverage on the Bus Section CB.

2.4.6 Transformer IDMT Overcurrent and Earth Fault

Where a LV busbar is directly supplied from a transformer and none of the busbar protection schemes covered in sections 5.1, 5.2, 5.3, 5.4, 5.5 are installed, the busbar must be protected by the transformer overcurrent and earth fault protection as covered in sections 2.3.5,2.3.6,2.3.7 and 2.3.8

2.4.7 Remote Feeder Protection

Where a HV busbar is supplied directly from a remote substation (no incoming circuit breaker), then remote feeder protection must be relied upon – refer to section 2.5.2.

2.5 Transmission and Sub-Transmission Line Protection

Transmission and Sub-transmission lines shall be protected with line differential protection relays or distance protection relays.

Examples where line differential protection may be required are:

- The feeder is over 100kV and is required to meet the speed requirements of Table S5.1a.2 of the National Electricity Rules.
- The feeder is short (low ohmic value), or the source impedance is high (Source Impedance Ratio) and distance protection may not perform satisfactorily.
- The feeder requires fast protection to coordinate with protection elsewhere that over-reaches the feeder
- The feeder has a tee or a source of generation

Line differential relays shall be configured to provide backup distance protection functionality for a communications failure that renders the line differential protection inoperable.

Distance protection relays shall be configured to provide backup non-directional IDMT OC and EF protection functionality for VT failure that renders the distance protection inoperable.

Where practical, distance relays shall be configured with a permanently enabled IDMT directional earth-fault element that offers greater sensitivity than the quadrilateral ground-fault distance protection.

2.5.1 Communications Assisted Protection

2.5.1.1 Line Differential Protection

Line differential protection elements shall be set per the relay manufacturer’s recommendations. Consideration must be given to charging current upon inrush and steady state charging current. Charging currents are measured as a differential current and can be significant on long feeders or underground cables.

To provide redundancy, two diverse communications paths may be required. Two OPGW’s on a single structure are not considered independent communications paths. Where a single communications path is utilised, consideration must be given to the simultaneous loss of both the No1 and No2 line differential protection.

2.5.1.2 Communications Assisted Distance Protection

Communications assisted distance protection schemes may be considered under special circumstances (e.g. existing relaying, quality of available comms channel). Protection settings are to be determined case by case.

2.5.2 Distance Protection

Where traditional non-assisted distance schemes are employed, the following setting criteria shall be applied.

2.5.2.1 Number of Zones

Typically, three forward (towards feeder) zones shall be used. In unusual circumstances, a fourth forward reaching zone may be used if it can provide faster operating times whilst still providing suitable coordination with downstream protective devices.

Dedicated reverse reaching zones are typically not to be used unless unusual circumstances require such an element to be used (this excludes offset characteristics that have a small reverse reach to improve coverage for faults of very low impedance which result in a very low voltage).

In cases where a dedicated reverse reaching zone is configured, the following shall apply:

- A justification for the use of such an element is recorded in the file notes for that circuit breaker, and no other more conventional alternatives exist
- A note is made in the caution notes of the PSA regarding the use of the reverse element
- The reverse element is coordinated with all other protection that would operate for faults in the same direction
- The reverse element is only to be used as backup protection
- The protection relay must have clear indication / alarming that the reverse element operated.

2.5.2.2 Distance Protection Characteristics

It is preferred to use mho shaped characteristics for phase faults.

For ground faults, quadrilateral shaped characteristics are to be used as they provide more resistive coverage than a mho characteristic. Resistive reaches should be set per manufacturers recommendations to maximise coverage of resistive faults. Care should be taken to ensure that the resistive element is not set to an excessive level without considering any potential overreach caused by CT/VT errors and system non-homogeneity.

2.5.2.3 Zone 1 Reach

Zone 1 is used to provide instantaneous protection to as much of the feeder as possible. To ensure coordination, Zone 1 should not see into any part of the system which is covered by downstream protection.

Due to relay errors, instrument transformer errors, modelling errors etc, the relay may over-reach. The relay must therefore be set short of downstream protection. A setting value of 80-85% is typical, however this may need to be shortened if mutual coupling with adjacent feeders cause the relay to over-reach for earth faults.

Care should be exercised in circumstances where Zone 1 cannot be set such that it out-reaches an upstream Zone 2. In such cases, alternatives such as slowing the remote Zone 2, or installing line differential protection should be considered.

2.5.2.4 Zone 1 Timing

Zone 1 should be set to trip instantaneously with no intentional delay in all normal circumstances.

2.5.2.5 Zone 2 Reach

Zone 2 is used to provide fast protection of the remainder of the feeder that cannot be covered by Zone 1. As Zone 2 over-reaches downstream protection, it needs to have a time delay to ensure coordination.

Zone 2 reach shall be set to cover the entire impedance of the protected feeder. Again, due to relay errors, instrument transformer errors, modelling errors the relay may under-reach. The relay must therefore be set to at least 120% of the protected feeder.

Zone 2 will need to consider other factors that affect the apparent impedance seen by the relay (that may cause it to under-reach). These may include:

- Mutual coupling with adjacent feeders (for earth faults)
- Fault Resistance. Refer section 2.5.2.9
- Infeed from the remote end / infeed from a tee

Where studies indicate that zone 2 cannot be set large enough to cover all arcing faults per section 6.2.9, the zone 2 reach shall be set as large as practical and zone 3 should be used to cover such faults. Where the feeder is also protected with line differential or DEF protection, arcing faults to earth need not be covered by the Zone 2 earth protection.

2.5.2.6 Zone 2 Timing

Zone 2 must coordinate with a minimum 300ms margin over any downstream protection that will operate for faults within the Zone 2 reach. Zone 2 must also coordinate with a minimum 300ms margin under any upstream protection that sees beyond the Zone 1 reach.

Where the downstream protection is duplicated, the Zone 2 only needs to coordinate with the faster of the two protections. For example:

- Zone 2 would not need to coordinate with transformer high voltage overcurrent and earth fault (HVOC and EF) provided that the transformer is also covered by instantaneous differential protection AND Zone 2 does not extend into the transformer low voltage bus.
- Zone 2 would not need to coordinate with downstream feeder HVOC and EF, provided that the downstream feeder is provided with distance protection or line differential protection, AND Zone 2 does not extend past the instantaneous reaches of these downstream high-speed relays.

Timing for Zone 2 should not exceed the criteria as specified in Table 1 in section 2.1.2.

2.5.2.7 Zone 3 Protection

Zone 3 is typically used to provide remote backup for the failure of downstream equipment. It is important to note that Zone 3 should only provide backup for a single contingency event - that is the failure of one protective device only per event. Remote backup would normally be required for any circuit breakers at a remote substation that do not have all of the following:

- Fully duplicated protection schemes (including trip coils)
- Duplicated DC supplies
- CB Fail (local backup)

Where Zone 3 is set to provide remote backup, the effect of infeed from other circuits must be considered. The required reach of the relay should be calculated for system normal conditions only. Where Zone 3 is providing remote backup to a downstream transformer, three phase, two phase and phase to earth faults on the secondary (and tertiary) terminals must be considered. Note that zone substation transformers are cycled per CEOP2360.

Remote backup must also be provided to allow for the bypass of downstream circuit breakers or alternate network configurations. Remote backup is not required for faults beyond downstream fuses.

Zone 3 can also be used to cover arcing faults in the primary protection zone that could not be covered in Zone 2.

2.5.2.8 Zone 3 Timing

Zone 3 should coordinate with a minimum 300ms margin over any downstream protection that will operate for faults within the Zone 3 reach. Zone 3 should also coordinate with a minimum 300ms margin under any upstream protection that sees beyond the Zone 2 reach.

Where a downstream relay is also providing remote backup to further downstream equipment, it is not necessary to coordinate the Zone 3 timer of both relays with each other unless it is determined that a single contingency failure would cause an unnecessary loss of customers.

The Zone 3 timer should not be set to greater than 4.0 seconds. It is however preferred not to exceed 3.0 seconds. Downstream protection withdrawals should be considered – refer to CEOP2246. If coordination cannot be achieved with a 4.0 second delay, then a fourth zone should be considered to achieve the required backup. In this case, the Zone 3 reach should be reduced to achieve the 4.0 second delay.

2.5.2.9 Fault Resistance

Fault resistance can significantly affect the apparent impedance seen by a distance relay, particularly if there is a source of infeed.

For a phase to phase fault, the fault resistance will be the resistance of an arc between the two faulted phase conductors.

For a phase to earth fault, the fault resistance will be the resistance of an arc between the faulted phase conductor and the tower, plus the tower footing resistance.

Arc resistance shall be determined using a method recommended by the relay manufacturer, or via the formula:

$$R_{Arc} = \frac{28707 \times L_{Arc}}{(I_{Arc})^{1.4}}$$

derived by A.R. van C. Warrington

R_{Arc} is the arc resistance in ohms
L_{Arc} is the length of the arc in metres
I_{Arc} is the current in amps for a zero-ohm fault at the arc location

2.5.2.10 Switch On To Fault (SOTF)

SOTF protection shall be used to provide fault coverage if a circuit breaker is closed onto a line that is earthed – under this scenario the distance relay will not have any polarising (nor memory) voltage and cannot easily determine the fault location. Upon CB closing, the relay will therefore temporarily enable:

- Instantaneous distance protection (Zone 2 or Zone 3)
- Definite time overcurrent protection

Inrush caused by the energisation of zone substation transformers must be considered. When a large Zone 3 is required for backup fault coverage, Zone 2 should be considered for SOTF.

2.5.2.11 Load Encroachment

Where a large Zone 3 (or 4) is required for backup fault coverage, load encroachment can be used to prevent unwanted trips due to load current. The minimum load impedance and load angle limits must be selected whilst ensuring coverage still exists for all faults within the backup zone.

2.5.2.12 Loss of Potential

Loss of VT supply to a distance relay may either render it inoperable or cause it to trip.

Upon loss of the VT supply where the relay permits, the distance protection should be blocked, and non-directional overcurrent and earth fault elements enabled.

2.5.2.13 Auto-Reclose

Where Auto-Reclose is implemented (refer section 2.6), it shall be initiated by both the No1 and No2 protections.

Where Zone 3 acts as a backup for other downstream protection, it should not initiate an automatic reclose.

Auto reclose shall be blocked for a SOTF protection trip.

2.5.3 Directional IDMT Overcurrent and Earth Fault

IDMT Directional Overcurrent (DOC) and Earth Fault (DEF) protection can generally be set more sensitive and with a faster operating time than non-directional OC and EF protection.

IDMT Directional OC and Directional EF relays shall coordinate with:

- other directional relays that operate for faults in the same direction
- non-directional protection that can operate for faults in the same direction

2.5.3.1 IDMT Directional Overcurrent

The most common connection used in Essential Energy's older electro-mechanical DOC systems is the 90 deg connection with a 45 deg relay angle (quadrature connection) – The 'A' phase relay is supplied with Ia and Vbc which results in the current applied to the relay leading the volts applied to the relay by 45 deg. This connection gives a correct directional tripping zone over the range of currents 45 deg – 135 deg lagging.

Newer protection relays have varying methods of calculating DOC operating parameters and should be set in accordance with the manufacturers' recommendation.

IEC SI (preferred), VI or EI IDMT curves are to be used.

The IDMT Directional OC relay pickup shall be capable of detecting all three-phase and phase-phase faults within the primary zone of the relay with an operating factor greater than 2.0. Where the relay is required to provide backup, all required faults within the backup zone of the relay shall have an operating factor greater than 1.5.

Directional OC relays should be set above load even if the device is intended to detect faults in the direction opposite load.

The IDMT Directional OC relay pickup should be set to allow the full capacity of the feeder, plus a suitable margin (120%-140%). Where the pickup does not meet this requirement, it shall be noted on the PSA.

The overcurrent timing shall be coordinated:

- Above all downstream protection devices with a 300ms margin. If the directional OC relay is an induction disc type this shall be increased to 400ms.
- Below all upstream protection devices with a 300ms margin. If the upstream relay is an induction disc type this shall be increased to 400ms.

It is not recommended to apply high-set elements as their reach is impacted by source impedance.

2.5.3.2 IDMT Directional Earth Fault

Where possible, Directional Earth Fault protection is to be implemented on sub-transmission lines to detect high resistance faults that may not be detected by distance protection.

Electro-mechanical DEF relays are of a similar construction to the electro-mechanical DOC relays. These are polarised by the residual voltage, in this application the applied current lags the applied voltage, so the relay angle chosen would typically be -45 deg for distribution systems and -60 deg for sub-transmission systems.

The Voltage Transformers (VT) used for these schemes must be of the 5-limb type or 3 single phase units to obtain the correct residual voltage from an Open Delta connection. Modern relays simulate the Open Delta residual voltage within the relay.

Newer protection relays have varying methods of calculating DEF operating parameters and should be set in accordance with the manufacturers' recommendation.

IEC SI (preferred), VI or EI IDMT curves are to be used.

The Directional EF relay shall be capable of detecting all earth faults within the primary zone of the relay with an operating factor greater than 2.0. Where the Directional EF relay is required to provide backup, all earth faults within the backup zone of the relay shall have an operating factor greater than 1.5.

The Directional EF relay pickup should be set as low as possible whilst coordinating with downstream earth fault relays. The IDMT Directional EF pickup should generally not exceed 100amps.

The earth fault relay timing shall be coordinated:

- Above all downstream earth fault protection devices with a 300ms margin. If the directional EF relay is an induction disc type this shall be increased to 400ms.
- Below all upstream earth fault protection devices with a 300ms margin. If the upstream relay is an induction disc type this shall be increased to 400ms.

It is not recommended to apply high-set elements as their reach is impacted by source impedance.

2.6 Automatic Reclose (Auto-Reclose)

For assets that are prone to transient faults, it is normally advantageous (for reliability) to re-energise the asset following a protection operation. Statistics indicate that over 70% of faults on sub-transmission and transmission feeders are transient. Auto-Reclose shall therefore be considered where it is likely that supply can be restored without undue risk to personnel, livestock, or plant.

2.6.1 Automatic Reclose Attempts

Auto-reclose shall only be considered for assets that are likely to be exposed to transient faults, this may include:

- Transmission feeders with overhead sections
- Sub-Transmission feeders with overhead sections
- Busbars where there is a known history of transient faults (exceptional circumstance)

Auto-reclose is not to be considered for any other assets covered by this policy.

Most transient faults will be cleared by a single tripping operation and there is generally minimal benefit to a second or third Auto-Reclose attempt. Where utilised, there shall be a maximum of one Auto-Reclose attempt.

Automatic reclose shall be temporarily disabled prior to:

- live line work
- any manual close of a circuit breaker

Automatic reclose shall not be used for customer owned lines or for lines dedicated to one customer unless authorised by the customer.

2.6.2 Automatic Reclose Dead Time

The Auto-Reclose dead time is the time between the circuit breaker opening and the relay sending the close signal to the circuit breaker – refer to Attachment A – Auto Reclose

The minimum Auto-Reclose dead time is 5.0 seconds and should allow for:

- the circuit breaker's mechanical / thermal limitations (rated operating sequence)
- electro-mechanical protection relays to reset.
- the fault arc to de-ionise
- foreign objects to fall free

- fault induced conductor motion to decay

Due to safety concerns involving automobile accidents, the maximum dead time is 10.0 seconds.

2.6.3 Automatic Reclose Reclaim Time

The Auto-Reclose reclaim time is the time following a successful reclose where the Auto-Reclose trip counter is reset – refer to Figure 2. Once reset, a subsequent fault will be treated as a new event.

The reclaim time must be longer than the:

- operating time of any protection relay that may initiate an auto-reclose operation.
- circuit breaker's mechanical / thermal limits (rated operating sequence)

The maximum reclaim time shall consider the possibility of thunderstorms causing multiple transient faults in a short period.

2.7 Capacitor Bank Protection

A capacitor bank can be broken down into the following components:

- Each bank is comprised of one or more stages. A stage is basically a portion of the capacitor bank which can be energised separately to the rest of the bank via a contactor
- Each stage consists of a number of individual capacitor cans or units
- A can or unit is the smallest physical capacitor component in the bank. Each can typically consists of parallel and/or series combinations of smaller, lower voltage capacitors; however, these are sealed within the can. A can may be rated to the system voltage for lower voltages (22kV or less) or it may be placed in series with other capacitors to be used on higher voltages.

Shunt capacitors can be broadly put into two main types:

- Fused capacitors – These banks can be either internally fused or externally fused and can consist of series and/or parallel combinations of individual capacitor elements per phase. Externally fused capacitors have each unit or can protected by its own fuse. Internally fused capacitors have fuses on individual elements within each unit or can. Operation of a single fuse does not necessarily render the entire bank inoperative; however multiple failures can cause excess voltages to be impressed on the remaining cans.
- Unfused or Fuseless banks – These banks consist of one or more series strings of cans per phase. Should the dielectric of an individual capacitor element within a can fail, it is designed to weld the electrodes together, such that it can safely carry the string current. This also will impress higher voltages on the remaining elements.

The shunt capacitor configurations common within Essential Energy are:

- Ungrounded Double Star – Each stage is divided into two star connected half-stages. The neutrals of these half-stages are connected but are not earthed. A current transformer between the neutrals is used to detect unbalance between the two half-stages caused by element failures. This is the preferred arrangement for all new capacitor banks.
- Grounded Star – Each can (or combination of cans) is connected to a phase and to earth. CT's are sometimes placed on the earth connections. This is a legacy arrangement within Essential Energy's network.

Capacitor bank protection shall consist of a combination of neutral unbalance, overcurrent and earth fault. Voltage protections should be considered where there is a high risk of damage from over voltages. Other protection as recommended by the manufacturer shall be installed.

Backup protection is not required for neutral unbalance or over voltage.

Schemes shall have redundancy such that if one capacitor section is out of service (for maintenance or repair, or from an equipment failure) the protection will continue to adequately clear any fault in the assigned protection zone.

A capacitor bank must not be re-energised unless enough time has elapsed since the last trip. The capacitor cans must be allowed to discharge to a safe voltage. Close inhibit circuitry may be installed however this is not usually part of the capacitor protection scheme.

2.7.1 Capacitor Overcurrent and Earth Fault Protection

Overcurrent relays covering phase and earth faults shall be fitted to detect faults external to the capacitor cans. A single overcurrent and earth fault relay is adequate for a capacitor bank less than 33kV provided a backup overcurrent and earth fault scheme can see faults in the capacitor bank. A typical backup scheme would be a transformer overcurrent and earth fault relay. For sub-transmission capacitor banks duplicated protection is required.

2.7.1.1 Capacitor Bank Overcurrent Element Setting

The Capacitor Bank overcurrent pickup and timing should be set per the manufacturer's recommendation.

In the absence of recommended settings, the overcurrent relay pickup should be set as near as practical to 140% of capacitor rated current. This is because capacitor banks are generally rated for 130% of nameplate current

In the absence of recommended settings, the overcurrent timing should be set:

- not to operate for inrush when energising the capacitor bank. The minimum tripping time should be greater than 2 cycles to provide security against spurious tripping.
- above any individual can or bank fuses (where installed). A time grading margin of 200ms min, 300ms preferred should be used.
- below all upstream protection devices with a 300ms margin. If the upstream relay is an induction disc type this shall be increased to 400ms.
- Below any cable short circuit thermal ratings.

High-set Overcurrent elements if used, must have at least a two-cycle delay. It is recommended that high-set elements not be used unless recommended by the capacitor bank manufacturer

2.7.1.2 Capacitor Bank Earth Fault Element Setting

The Capacitor Bank earth-fault pickup and timing should be set per the manufacturer's recommendation.

In the absence of recommended settings, the earth fault relay pickup should be set to 20% of the capacitor bank current.

In the absence of recommended settings, the earth fault timing should be set:

- above any individual can fuses (where installed) – note that grading over entire bank fuses is not required due to the high settings that would be needed. A time grading margin of 200ms min, 300ms preferred should be used.

- below all upstream protection devices with a 300ms margin. If the upstream relay is an induction disc type this shall be increased to 400ms.
- not to operate for inrush when energising the capacitor bank. The minimum tripping time should be greater than 2 cycles to provide security against spurious tripping.
- Below any cable short circuit thermal ratings.

2.7.1.3 Capacitor Bank SEF / NPS Element Setting

Where a capacitor bank is fused, consideration shall be given to including a sensitive earth fault protection element that is sensitive enough to detect earth faults which remain back fed through the capacitors and reactors of the un-faulted phases after a fuse has operated. Negative phase sequence protection can also be used to detect these fault types if required.

2.7.2 Capacitor Neutral Unbalance Protection

Where capacitor banks are installed as parallel banks with a common ungrounded neutral, a sensitive overcurrent relay will be fitted to measure the current flowing between the banks in the neutral conductor. This will detect bank unbalance caused by capacitor element failure(s) in one of the banks. This protects healthy elements from excessive voltage and prevents unbalanced voltages from occurring on the busbar.

Capacitor Bank unbalance should be set per the manufacturer’s recommendation.

In the absence of recommended settings, the following should apply:

- Where the capacitor is configured such that the removal of one or more cans may place additional voltage stress on the remaining capacitors, the trip level should be set to the unbalance current value (for the protected stage) which corresponds to a 10% increase in voltage across any remaining can (compared to a fully balanced system). The trip should be delayed between 0.5 and 2.0 seconds in order to prevent spurious tripping. The alarm value should be set to 50% of the trip value and be delayed by 10 seconds.
- Where the capacitor is configured such that the removal of one or more cans will not place additional voltage stress on the remaining capacitors, the trip level should be set for a current equivalent to 15% of the rating of the protected stage. The trip should be delayed between 0.5 and 2.0 seconds in order to prevent spurious tripping. The alarm value should be set to 50% of the trip value and be delayed by 10 seconds.

2.7.3 Capacitor Overvoltage Protection

If required, capacitor overvoltage protection shall be set per the manufacturer’s recommendation.

2.7.4 Capacitor Bank Overcurrent, Earth Fault and Unbalance CT Requirements

2.7.4.1 Overcurrent and Earth Fault CT Requirements

Class P or PX CTs are to be used for all Capacitor Bank OC and EF protection schemes.

The CT ratio should be chosen so that rated primary/secondary currents are not exceeded at the maximum capacitor bank load.

Where the rated continuous thermal current of the CT is greater than the rated primary/secondary current, a lower CT ratio can be used provided that:

- The rated continuous thermal currents are not exceeded at the maximum capacitor bank load

- The overcurrent relay can continuously withstand the secondary current at the maximum capacitor bank load

The CTs shall be capable of driving the combined burden of the OC/EF relay(s) and secondary wiring.

For P class CTs, the Accuracy Limit Factor (ALF) should not be exceeded at the maximum fault level unless a high-set overcurrent element is set below the ALF.

2.7.4.2 Neutral Unbalance CT Requirements

The Neutral Unbalance CT's shall be selected as follows:

- To be accurate for the low levels at which the relays are anticipated to operate. For this reason, measurement class CT's may be used in this application
- The CT shall be capable of withstanding the primary prospective fault level that it may be subjected to. This is especially the case for wound primary CT's.

2.8 Primary Distribution Feeder Protection

Protection settings for primary distribution feeders shall be determined by Network Planning in accordance with CEOP8002.02.

Where protection setting changes are required for a protection device within a Zone Substation, a "Subtransmission Protection Design Request" (CEOF6186) shall be submitted to protection.manager@essentialenergy.com.au. The Network Protection Group have the responsibility of creating PSAs and relay setting files for these protection schemes within the zone substation.

Where the requested protection settings cannot be accommodated due to coordination problems or protection relay limitations, protection settings shall be jointly agreed upon.

The Network Protection Group shall have the responsibility to:

- ensure coordination with upstream Zone Substation protection devices
- ensure adequate backup coverage exists for the failure of the Zone Substation primary distribution feeder protection (where the primary distribution feeder protection is not fully duplicated). Where backup coverage cannot be achieved, a collaborative approach shall be taken to determine whether Zone Substation upgrades or distribution upgrades are the most cost-effective approach.
- create relay or recloser setting files (where applicable) for relays and reclosers within Zone Substations
- produce PSA documentation for protection devices within Zone Substations
- provide fault levels at the Zone Substation busbar
- ensure compliance with CEOP8002.01

Network Planning shall have the responsibility to:

- ensure coordination of the Zone Substation feeder protection with downstream distribution reclosers, relays and fuses
- ensure that the Zone Substation primary distribution feeder protection settings offers adequate primary fault coverage

- ensure that the Zone Substation primary distribution feeder protection settings offer adequate backup fault coverage for the failure of downstream devices, protection bypasses, or alternate network configurations
- ensuring compliance with CEOP8002.02
- provide fault levels within the distribution network to the Network Protection Group (for the failure of the Zone Substation primary distribution feeder protection)

2.8.1 Primary Distribution Feeder Protected with a Recloser

Where the Zone Substation primary distribution feeder protection is a recloser, all protection functionality required by CEOP8002.02 can be utilised.

2.8.2 Primary Distribution Feeder with a Protection Relay and Circuit Breaker

Where the Zone Substation primary distribution feeder protection is a separate relay and circuit breaker, protection settings are to be determined per CEOP8002.02, however Zone Substations protection relays may have many limitations. Examples of functionality that Zone substation relays may not be capable of include:

- Multiple setting groups
- High-set (or instantaneous) overcurrent and earth fault protection
- Live-line protection settings
- Loss of phase protection
- Negative Phase Sequence protection
- Inrush Restrain
- Cold Load Pickup
- Pickup and/or time multiplier settings with small step sizes

2.8.2.1 Overcurrent and Earth Fault CT Requirements

Class P or PX CTs are to be used for all primary distribution feeder OC/EF/NPS protection schemes.

The CT ratio should be chosen so that rated primary/secondary currents are not exceeded under any load conditions.

Where the rated continuous thermal current of the CT is greater than the rated primary/secondary current, a lower CT ratio can be used provided that:

- The rated continuous thermal currents are not exceeded under any load conditions
- The overcurrent relay can continuously withstand the secondary current under any load conditions

The CTs shall be capable of driving the combined burden of the OC/EF/NPS relay(s) and secondary wiring.

For P class CTs, the Accuracy Limit Factor (ALF) should not be exceeded at the maximum fault level unless a high-set overcurrent element is set below the ALF.

2.9 Frequency Injection (FI) System Protection

2.9.1 FI System Overcurrent Element Setting

FI System overcurrent pickup and timing should be set per the manufacturer's recommendation.

In the absence of recommended settings, the overcurrent relay pickup should be set to 120% of the rated 50Hz current of the FI plant (most numerical relays use 50Hz band pass filtering and do not typically respond to currents at the FI frequency).

In the absence of recommended settings, the overcurrent timing should be set:

- not to operate for inrush when energising the FI transformer.
- Above downstream protection devices (if fitted) with a 300ms margin. If the overcurrent relay is an induction disc type this shall be increased to 400ms.
- Below all upstream protection devices with a 300ms margin. If the upstream relay is an induction disc type this shall be increased to 400ms.
- Below any cable short circuit thermal ratings.

2.9.2 FI System Earth Fault Element Setting

FI System earth fault pickup and timing should be set per the manufacturer's recommendation.

In the absence of recommended settings, the earth fault relay pickup should be set to 20% of the rated current of the FI plant or 10A, whichever is greater.

In the absence of recommended settings, the earth fault timing should be set:

- Above downstream protection devices (if fitted) with a 300ms margin. If the earth fault relay is an induction disc type this shall be increased to 400ms.
- Below all upstream protection devices with a 300ms margin. If the upstream relay is an induction disc type this shall be increased to 400ms.
- not to operate for inrush when energising the FI transformer. An IEC 60255 curve time multiplier of 0.1 or more should be adequate.
- Below any cable short circuit thermal ratings.

2.9.3 Frequency Injection Overcurrent and Earth Fault CT Requirements

Class P or PX CTs are to be used for all Frequency Injection protection schemes.

The CT ratio should be chosen so that rated primary/secondary currents are not exceeded considering the 50Hz current and the Audio Frequency (AF) current.

Where the rated continuous thermal current of the CT is greater than the rated primary/secondary current, a lower CT ratio can be used provided that:

- The rated continuous thermal currents are not exceeded considering the 50Hz current and the AF current.
- The overcurrent relay can continuously withstand the secondary current considering the 50Hz current and the AF current.

The CTs shall be capable of driving the combined burden of the OC/EF relay(s) and secondary wiring.

For P class CTs, the Accuracy Limit Factor (ALF) should not be exceeded at the maximum fault level unless a high-set overcurrent element is set below the ALF.

2.10 Auxiliary Transformers

Auxiliary transformers within zone substations shall be fused per CEOS5099. As fuses do not require backup, a circuit breaker is only required to protect the high voltage conductor between the circuit breaker and the auxiliary transformer's fuses.

2.10.1 Auxiliary Transformer Overcurrent Element Setting

The overcurrent relay pickup should be set:

- greater than the effecting pickup of the auxiliary transformer's HV fuses
- such that it can detect faults at the auxiliary transformer's HV fuses with an operating factor of 2.0.

The overcurrent timing should be set:

- Above the auxiliary transformer's HV fuses
- Below all upstream protection devices with a 300ms margin. If the upstream relay is an induction disc type this shall be increased to 400ms.
- Below any cable short circuit thermal ratings.

2.10.2 Auxiliary Transformer Earth Fault Element Setting

The earth fault relay pickup should be set such that it can detect earth faults at the auxiliary transformer's HV fuses with an operating factor of 2.0.

The earth timing should be set:

- Below all upstream protection devices with a 300ms margin. If the upstream relay is an induction disc type this shall be increased to 400ms.
- Below any cable short circuit thermal ratings.

2.10.3 Auxiliary Transformer Overcurrent and Earth Fault CT Requirements

Class P or PX CTs are to be used for all Auxiliary Transformer protection schemes.

The CT ratio should be chosen so that rated primary/secondary currents are not exceeded at the maximum load.

Where the rated continuous thermal current of the CT is greater than the rated primary/secondary current, a lower CT ratio can be used provided that:

- The rated continuous thermal currents are not exceeded at the maximum load
- The overcurrent relay can continuously withstand the secondary current at the maximum load

The CTs shall be capable of driving the combined burden of the OC/EF relay(s) and secondary wiring.

For P class CTs, the Accuracy Limit Factor (ALF) should not be exceeded at the maximum fault level unless a high-set overcurrent element is set below the ALF.

2.11 Sub-transmission Undervoltage and Underfrequency Protection

Voltage and frequency protection may be required to detect abnormal network conditions which may lead to a failure or instability of the network, or an unsafe condition arising.

2.11.1 Undervoltage Protection

Where required, undervoltage protection settings shall be determined by the Transmission System Network Service provider as per S5.1.10.2 of the National Electricity Rules.

2.11.2 Underfrequency Protection

Where required, underfrequency protection settings shall be determined by AEMO, as per S5.1.10.2 of the National Electricity Rules.

2.12 Records

The Essential Energy employees associated with protection shall be responsible for the recording, storage and maintenance of all protection records. Details of all the current and historic settings, tripping schemes, instrument transformer ratios, reclose times, configurations, software files, firmware and software versions, calculations and analysis details etc of all transmission, sub-transmission and distribution protection equipment and devices, should be stored. All Essential Energy employees associated with planning, protection, control and maintenance should have read access to PSAs

2.13 High voltage customers

High voltage customers are required to provide a protective system approved by Essential Energy to disconnect their equipment from the supply in the event of a fault on their equipment. It is not Essential Energy’s practice to provide backup protection to a customer’s equipment.

- All protection settings shall provide suitable discrimination with Essential Energy’s system protection
- All protective equipment must be maintained to an industry recognised standard

2.14 Generators

All Generation proposed for installation on Essential Energy’s Network shall be assessed against CEOP8012 - Generation Connection: Protection Guidelines.

3.0 AUTHORITIES AND RESPONSIBILITIES

Position / Title	Responsibility
Protection Coordination Manager	• Shall be responsible for the maintenance of this procedure.
Specialist Engineering Manager	• Shall be responsible for the authorisation for approval of the policy and subsequent implementation once approved.
Manager Asset Engineering	• Shall be the Approver of the Policy document, as Head of Engineering

Modifications to protection systems or settings are to be undertaken by authorised protection personnel only. Disciplinary action will be taken against any employees found to be interfering with the protection systems without the appropriate authority.

4.0 DEFINITIONS

BBP
Busbar Protection – a type of protection used specifically to protect busbars; an example is high impedance BBP.

Bind Spot
A blind spot can occur where protection zones do not overlap across a circuit breaker. Plant between the circuit breaker and the current transformer are in the blind spot. The protection device that operates to isolate the fault does not trip the correct circuit breakers to isolate the fault. A special scheme is required to ensure the correct circuit breakers are tripped.

CB Fail
Circuit Breaker Fail – a protection function used to detect whether a circuit breaker has successfully interrupted a fault.

Class P CT
A current transformer as specified in AS 60044.1-2007.

Class PX CT
A current transformer as specified in AS 60044.1-2007.

CT
Current Transformer.

DC
Direct Current.

DEF
Directional Earth Fault - an earth fault (overcurrent) protection that will only operate for faults in a given direction (usually forward) with respect to the location of the protective device.

Discrimination
The coordination of non-unit protection by time.

DOC
Directional Overcurrent - an overcurrent protection that will only operate for faults in a given direction (usually forward) with respect to the location of the protective device.

EF
Earth Fault – typically refers to an earth fault (overcurrent) protection where the operating quantity is derived from the residual of the three phase quantities.

EI
Extremely Inverse characteristic as defined in IEC 60255.

Fault Thrower
A switch that intentionally applies a phase to earth fault to the network. This fault is then detected and isolated by upstream protection.

Forward
Towards the protected asset with respect to the location of the protective device (ie faults that are on the protected asset are forward of the protective device).

Grading
See discrimination.

High set
An instantaneous or definite time protection element used in conjunction with IDMT protection to provide faster operation for current exceeding the pickup of the element.

HV / High Voltage / Primary
When in reference to a transformer, refers to the highest voltage winding.

Hybrid Feeder
Feeders which supply/ interconnect between electrical/ terminal stations and/ or zone substations and have distribution customers connected directly to them.

IDMT
Inverse Definite Minimum Time – A relay with an operating characteristic that is inversely proportional to the measured quantity, eg, as the current increases, the operating time decreases. The definite minimum time varies between relay types, and typically occurs at 20 or 30 times the relay pickup.

kV
kilovolts.

LV / Low Voltage / Secondary
When in reference to a transformer, refers to the second highest voltage winding.

MVA
Mega Volt-Amps.

NEF
Neutral Earth Fault – An earth fault (overcurrent) protection where the operating quantity is from a current transformer fitted on the on the neutral of a grounded star transformer winding.

No1
The main protection scheme of a duplicated scheme.

No2
The backup protection scheme of a duplicated scheme. In many cases it will offer the same level of protection as the No1 protection.

Non-unit Protection
A protection where the zone is not clearly defined – this is because the primary system quantities are measured at a single point only. The protection zone begins at the location of the current / voltage transformers, however the 'reach' of the protection zone (sensitivity) is determined by the settings and the selectivity is achieved by time-grading.

NPS
Negative Phase Sequence – an overcurrent protection where the operating quantity is the I2 or Negative Phase Sequence current that is derived from the three phase quantities.

Operating Factor
The fault level measured by a protection device, divided by the pickup (setting value) with reference to an overcurrent, earth fault or NPS relay.

Overcurrent
An overcurrent protection where the operating quantity is derived from any of the three phase quantities.

Primary distribution feeder
A distribution line connecting a sub-transmission asset to either other distribution lines that are not sub-transmission lines, or to distribution assets that are not sub-transmission assets. (from NER)

PSA
Protection Setting Advice.

Reach
How far along a protected asset a non-unit protection will detect a fault.

Recloser
A protection device that typically incorporates a pole mounted circuit breaker, instrument transformers, battery supplies, a protection relay and communications. Also known as an Automatic Circuit Recloser (ACR).

REF
Restricted Earth Fault – A unit protection capable of detecting earth faults on star connected transformer or generator windings.

Reverse
Opposite to forward. Away from the protected asset with respect to the location of the protective device.

SCADA
Supervisory Control and Data Acquisition.

SI
Standard Inverse characteristic as defined in IEC 60255.

Source Impedance Ratio
The ratio of the source impedance to the impedance of the protected line.

Sub-transmission
Any part of the power system which operates to deliver electricity from the transmission system to the distribution network and which may form part of the distribution network, including zone substations.

Sub-transmission line
A power line connecting a sub-transmission asset to either the transmission system or another sub-transmission asset. (from NER)

TNSP
Transmission Network Service Provider.

Unit Protection
A differential protection that is intended to only operate for faults in a specific location. The protection zone is bounded by two or more sets of current transformers.

VI
Very Inverse characteristic as defined in IEC 60255.

VT
Voltage Transformer.

Zone Substation
A substation for the purpose of connecting a distribution network to a sub-transmission network. (from NER)

5.0 REFERENCES

Internal	
CEOP8002.02 – Branch Procedure: Distribution Protection Guidelines	Policy Library
CEOF6186 – Subtransmission: Protection Design Request	Policy Library
CEOP8012 – Generation Connection: Protection Guidelines	Policy Library
CEOP2246 – Operating Assets in Service with an Associated Protection Scheme out of Service	Policy Library
CEOP2360 – Transformers in Parallel: Operation Guidelines	Policy Library
CEOS5099 – Distribution: Transformer Fusing	Policy Library
CEOP2067 - Guidelines for Service Voltage Testing of Zone Substation and Subtransmission Assets	Policy Library

External
ENA C(b)1-2006 : Guidelines for design and maintenance of overhead distribution and transmission lines.
"Guide to the Application of Auto Reclosing to Radial Overhead Lines Supplying Urban and Rural Areas", D (b) 12 – 1991, Electricity Supply Association of Australia
Protective Relays Application Guide – Third Edition 1987
Network Protection & Automation Guide – First Edition 2002
AS 60044.1-2007 Instrument Transformers – Current Transformers
AS 3851-1991 (R2015) The calculation of short-circuit currents in three-phase a.c. systems
IEC 60255-151 Ed. 1.0 (Bilingual 2009) : Measuring relays and protection equipment - Part 151: Functional requirements for over/under current protection
National Electricity Rules Version 125 – 31 October 2019

6.0 RECORD KEEPING

Essential Energy employees associated with protection shall be responsible for the recording, storage and maintenance of all protection records. Details of all the current and historic settings, tripping schemes, instrument transformer ratios, reclose times, configurations, software files, firmware and software versions, calculations and analysis details etc of all transmission, sub-transmission and distribution protection equipment and devices, should be stored.

All Essential Energy employees associated with planning, protection, control and maintenance should have read access to PSAs.

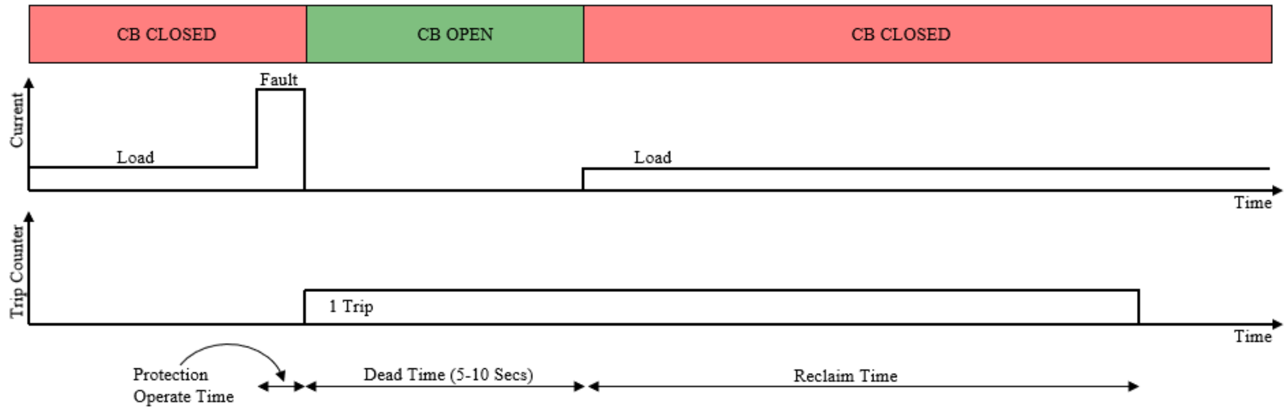
7.0 REVISIONS

Issue No.	Section	Details of changes in this revision	Change Risk Impact?

ATTACHMENT A – AUTO RECLOSE

Auto-Reclose - Transient Fault with Successful Reclose

Figure 1



Auto-Reclose - Permanent Fault Trip Sequence with One Reclose Attempt

Figure 2