

| | | |
|---|----------|------------|
|  Eskom | Standard | Technology |
|---|----------|------------|

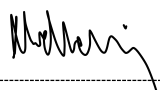
Title: **STANDARD PROCEDURE FOR SINGLE LINE DIAGRAM DEVELOPMENT** Unique Identifier: **240-68972308**

Alternative Reference Number: **N/A**

Area of Applicability: **Engineering**

Next Review Date: **STABILISED**

COE Acceptance



Subhas Maharaj

Senior Manager: Substation Engineering

Date: 22/2/2021

DBOUS Acceptance



Amelia Mtshali

Senior Manager: Design Base & Operating Unit Support

Date: 25/02/2021

This document is **STABILISED**. The technical content in this document is not expected to change because the document covers: *(Tick applicable motivation)*

| | | |
|---|---|---|
| 1 | A specific plant, project or solution | |
| 2 | A mature and stable technical area/technology | x |
| 3 | Established and accepted practices. | x |

This letter is for multiple documents:

PCM Reference: **Design Substations**

SCOT Study Committee Number/Name: **Substations**

| | | |
|--|-----------------|-------------------|
|  Eskom | Standard | Technology |
|--|-----------------|-------------------|

Title: **STANDARD PROCEDURE FOR
SINGLE LINE (STATION
ELECTRIC) DIAGRAM
DEVELOPMENT**

Unique Identifier: **240-68972308**

Alternative Reference Number: **N/A**

Area of Applicability: **Engineering**

Documentation Type: **Standard**

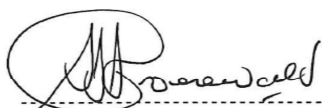
Revision: **2**

Total Pages: **25**

Next Review Date: **October 2020**

Disclosure Classification: **Controlled
Disclosure**

Compiled by

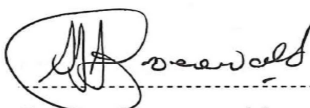


Braam Groenewald

**Corporate Specialist-
Substations**

Date: 13-10-2015

Approved by



Braam Groenewald

**Corporate Specialist-
Substations**

Date: 13-10-2015

Authorized by



Phineas Tlhatlhetji

**Senior Manager -
Substation Engineering**

Date: 13/10/2015

Supported by SCOT/SC



Phineas Tlhatlhetji

SCOT/SC Chairperson

Date: 13/10/2015

Content

| | Page |
|---|------|
| 1. Introduction..... | 4 |
| 2. Supporting clauses..... | 4 |
| 2.1 Scope..... | 4 |
| 2.1.1 Purpose..... | 4 |
| 2.1.2 Applicability..... | 4 |
| 2.2 Normative/informative references..... | 4 |
| 2.2.1 Normative..... | 4 |
| 2.2.2 Informative..... | 4 |
| 2.3 Definitions..... | 4 |
| 2.3.1 General..... | 4 |
| 2.3.2 Disclosure classification..... | 5 |
| 2.4 Abbreviations..... | 5 |
| 2.5 Roles and responsibilities..... | 5 |
| 2.6 Process for monitoring..... | 6 |
| 2.7 Related/supporting documents..... | 6 |
| 3. Document content..... | 6 |
| 3.1 One Line Diagram..... | 6 |
| 3.2 Single Line or Station Electric Diagram..... | 7 |
| 3.3 Protective Zones..... | 10 |
| 3.3.1 Protective Relays..... | 13 |
| 3.4 Instrument Transformers..... | 14 |
| 3.4.1 Current Transformers (See also SLDG 28-2)..... | 14 |
| 3.4.2 Voltage Transformers (See also SLDG 28-3)..... | 15 |
| 3.5 Pilot Channels for Protective Relays..... | 15 |
| 3.5.1 Line Trap (LT)..... | 16 |
| 3.5.2 Coupling Capacitor (CC)..... | 17 |
| 3.5.3 Line Tuner (CC)..... | 17 |
| 3.6 PTM&C Guideline for Checking and Approving of Station Electric Diagrams (SEDS)..... | 17 |
| 3.6.1 Bay CB notations..... | 17 |
| 3.6.2 Mechanism end for dead tank circuit breakers (Breaker and Half Stations)..... | 18 |
| 3.6.3 Station Auxiliary Power Supplies..... | 20 |
| 3.6.4 Buszone Ratio..... | 20 |
| 3.6.5 Line Traps..... | 20 |
| 3.6.6 Busbar Earths..... | 20 |
| 3.6.7 Transformer vector groups..... | 20 |
| 3.6.8 Positioning of current transformer..... | 21 |
| 3.6.9 Positioning of voltage transformers..... | 23 |
| 4. Authorization..... | 24 |
| 5. Revisions..... | 25 |
| 6. Development team..... | 25 |
| 7. Acknowledgements..... | 25 |

Figures

| | |
|---|----|
| Figure 1: High Level Substation Design Sequence | 6 |
| Figure 2: One-Line Diagram Development | 7 |
| Figure 3: Single Line Diagram Development | 8 |
| Figure 4: Flow Diagram for Single-Line Diagram Development | 9 |
| Figure 5: Buszone Protection | 11 |
| Figure 6: Feeder Protection | 11 |
| Figure 7: Transformer Protection | 12 |
| Figure 8: Major Components of Power Line Carrier Channel | 16 |
| Figure 9: Illustration of double busbar layout denoting bay prefixes | 17 |
| Figure 10: Schematic of bay feeding a shunt capacitor incorporating synchronized or (POW) switching | 18 |
| Figure 11: Busbar layout of a typical 765kV Breaker-and-Half Substation | 19 |
| Figure 12: Line CT on busbar side of line reactor | 21 |
| Figure 13: Line CT on line side of line reactor | 22 |
| Figure 14: List of line reactors deployed in Eskom as at Aug 2008 | 23 |
| Figure 15: Hybrid Bus Coupler with dedicated Transfer Busbar | 24 |
| Figure 16: Transfer bus coupler with Transfer Busbar | 24 |

Tables

| | |
|---|----|
| Table 1: Common to Substation Application | 13 |
| Table 2: Accuracy Class of CTs and VTs | 14 |

1. Introduction

A Single-Line Diagram (SLD) is a drawing that shows symbolically and in a single line form, the main electrical three-phase power circuits and associated protective relays and monitoring devices. A substation single-line diagram forms the basis of the substation layout, protection, control, measurements and metering, and DC Systems design.

PTM&C is a signatory on Station Electric Diagrams (SEDs) produced by the Substation Engineering Department within Power Delivery Engineering (PDE). The guideline given under paragraph 3.6 is required to facilitate the checking and approving of SEDs to ensure that there is standardization in the application of PTM&C schemes before PTM&C engineers commence with application designs.

2. Supporting clauses

2.1 Scope

This standard provides the procedure that is to be followed for developing a single line diagram for a Main Transmission Substation.

The document also describes specific requirements in the SED to be met in order for PTM&C applications to be standard.

2.1.1 Purpose

This document provides details of the procedure to be followed in order to develop Single Line Diagrams for Main Transmission Substations.

In addition the document required to equip PTM&C personnel with the necessary knowledge and skill needed to check SEDs. It is also the purpose of this guideline to standardise on PTM&C applications. Furthermore, the guide can be used by Substation designers to finalize their designs after having considered PTM&C's requirements.

2.1.2 Applicability

This document shall apply throughout Eskom Holdings Limited Divisions.

2.2 Normative/informative references

Parties using this document shall apply the most recent edition of the documents listed in the following paragraphs.

2.2.1 Normative

- [1] ISO 9001 Quality Management Systems.
- [2] Substation Layout Design Guide.
- [3] South African Grid Code.

2.2.2 Informative

None

2.3 Definitions

2.3.1 General

None

2.3.2 Disclosure classification

Controlled disclosure: controlled disclosure to external parties (either enforced by law, or discretionary).

2.4 Abbreviations

| Abbreviation | Description |
|--------------|--|
| BC | Bus Coupler |
| BCT | Bushing Current Transformer |
| BS | Bus Section |
| CB | Circuit breaker |
| CT | Current Transformer |
| CVT | Capacitor Voltage Transformer |
| EMVT | Magnetically coupled Voltage Transformer |
| GIS | Gas Insulated Substation |
| IM | Interchange Metering |
| LTC | Load Tap Changer |
| LTU or TU | Line Tuning Unit |
| PDE | Power Delivery Engineering division within Group Technology |
| PLC | Power Line Carrier |
| PM | Project Manager |
| POW | Point of Wave |
| PT | Potential Transformer |
| PTM&C | Protection, Telecommunications, Measurements and metering, and Control |
| RM | Revenue Metering |
| SAGC | South African Grid Code |
| SED | Station Electric Diagram |
| SLD | Single Line Diagram |
| SLDG | Substation Layout Design Guide |
| SS | Synchronized switching, also known as point on wave switching of a circuit breaker |
| SYN | Connection to Synchronising Equipment |
| TCUL | Tap Changing Under Load |
| TNSP | Transmission Network Service Provider |

2.5 Roles and responsibilities

Group lead engineers need to be fully briefed on the contents of this document. They will in turn be expected to instruct their direct reports in its use.

2.6 Process for monitoring

The tables at the end of the document are to become part of the design documentation.

All protection application designs are subjected to scrutiny by an applications design approver review team before being approved.

2.7 Related/supporting documents

Transmission Line Design

3. Document content

Figure 1 illustrates the substation design sequence. A substation design is started after the planning group identifies the need for either a new substation, or for the extension or up-rating of an existing substation. Based on the requirements specified by the planning group, a preliminary one-line diagram drawing is prepared as a working drawing. This drawing, when finalised, forms the basis for the entire substation design and it is also the seed drawing for the single-line diagram. Throughout this section, the development process for a sample substation single line diagram will be followed for illustrative purposes.

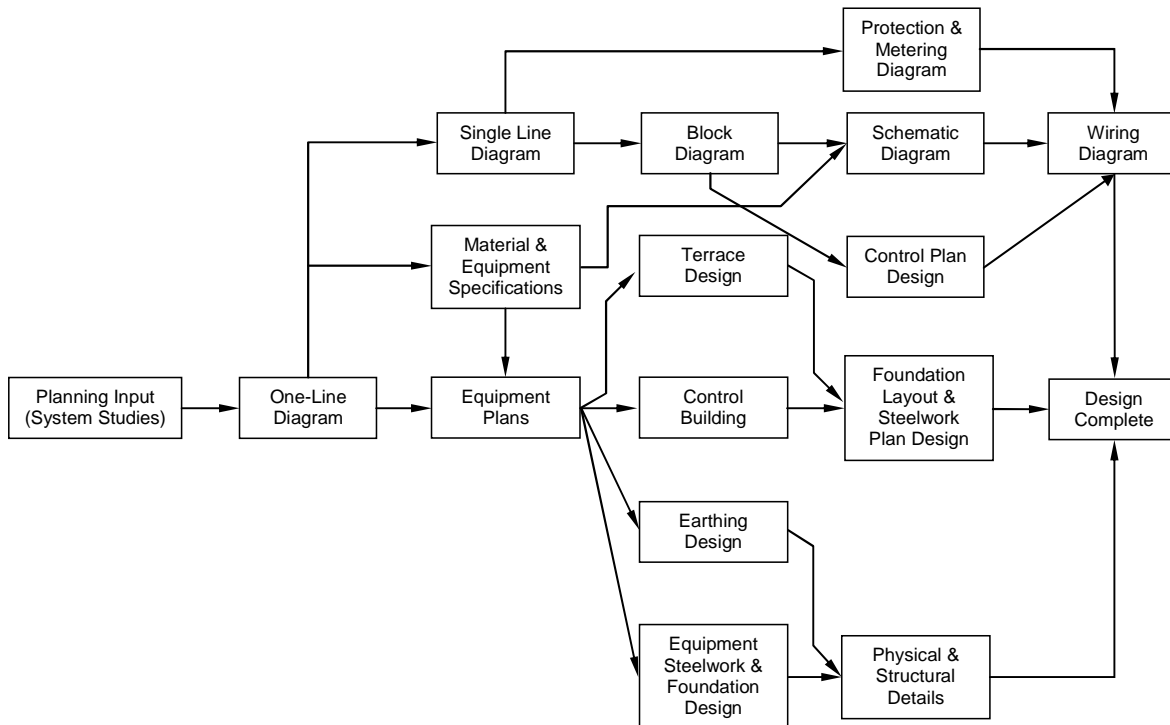


Figure 1: High Level Substation Design Sequence

3.1 One Line Diagram

Figure 2 is a one-line diagram of the substation specified above. A one-line diagram illustrates the electrical interconnection of the high voltage equipment and typically the following items:-

- All voltage busbars
- All feeders
- Power transformers

- Circuit breakers
- Isolators
- Shunt reactors and shunt capacitors

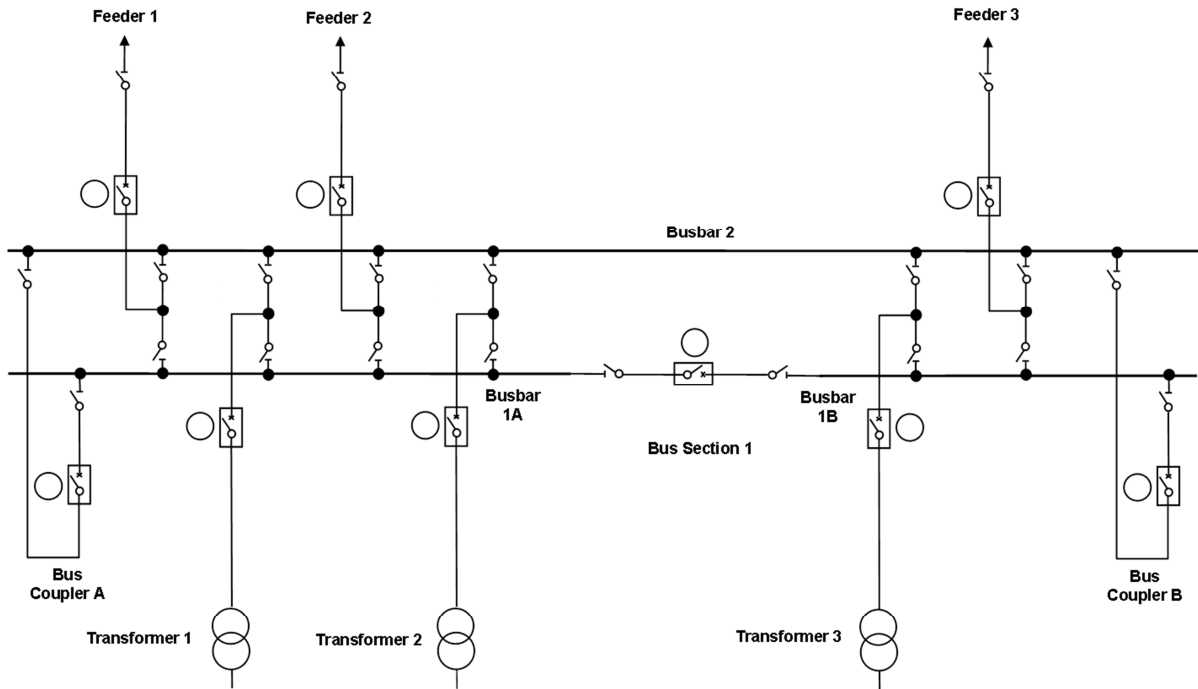


Figure 2: One-Line Diagram Development

In addition to showing the major components of the station, it provides an opportunity to ensure effective zoning of equipment bays for in and out flow of power through feeders, transformers and other compensation equipment. This will determine the number of bus coupler and bus section bays that would be required, and the positioning of equipment bays in order to provide the highest availability of equipment bays as well as providing a reliable supply in the event of busbar faults occurring.

3.2 Single Line or Station Electric Diagram

Figure 3 is a single line (station electric) diagram of the substation specified above. A single line diagram illustrates the electrical interconnection of the high voltage equipment shown in the one-line diagram as well as the following items:-

- Surge arresters
- Freestanding current transformers
- Voltage transformers and coupling capacitors
- Line traps
- Earthswitches
- All power cable runs

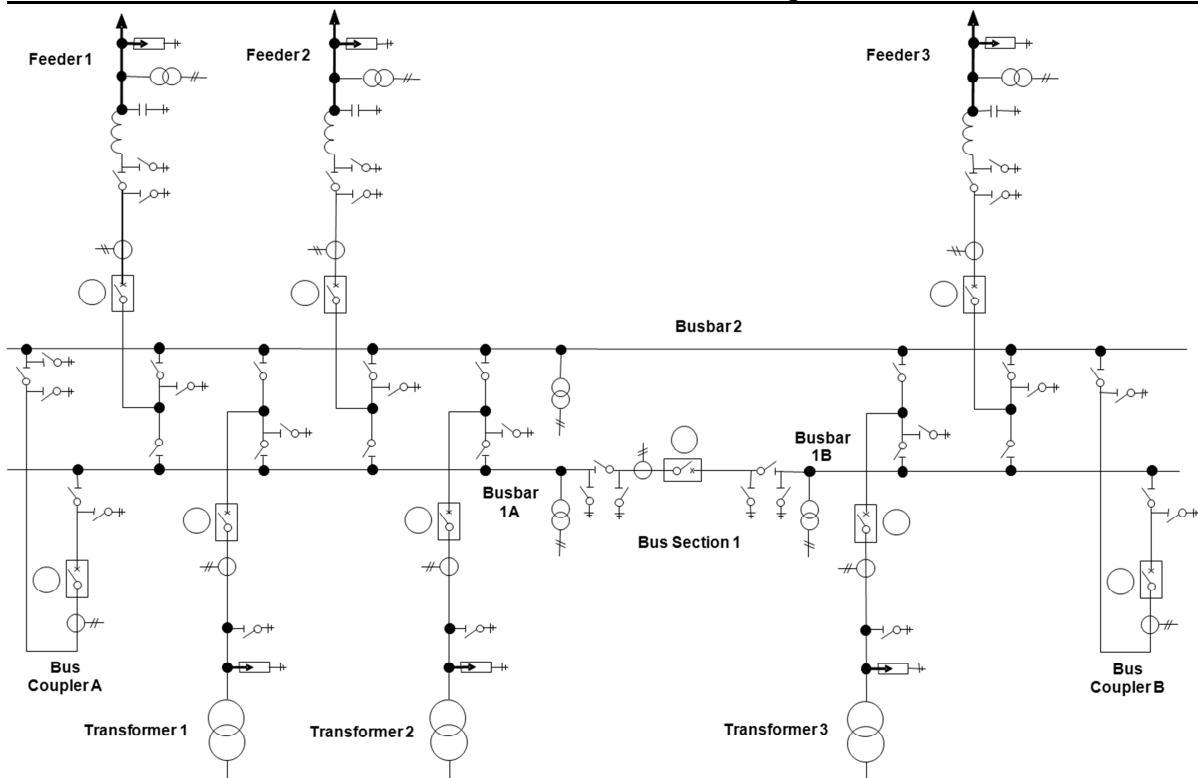


Figure 3: Single Line Diagram Development

Figure 4 is a Flow diagram showing the process of developing the single line diagram for the substation shown in Figure 2. The process of developing a single-line diagram from a one-line diagram includes the following steps (see Figures 5 and 6).

- Identification of protection zones
- Selection of protection schemes
- Identification of metering points
- Selection of metering schemes
- Selection of voltage and current sources
- Connection of the protection and metering schemes to the voltage and current sources
- Location of power line carrier (PLC) devices

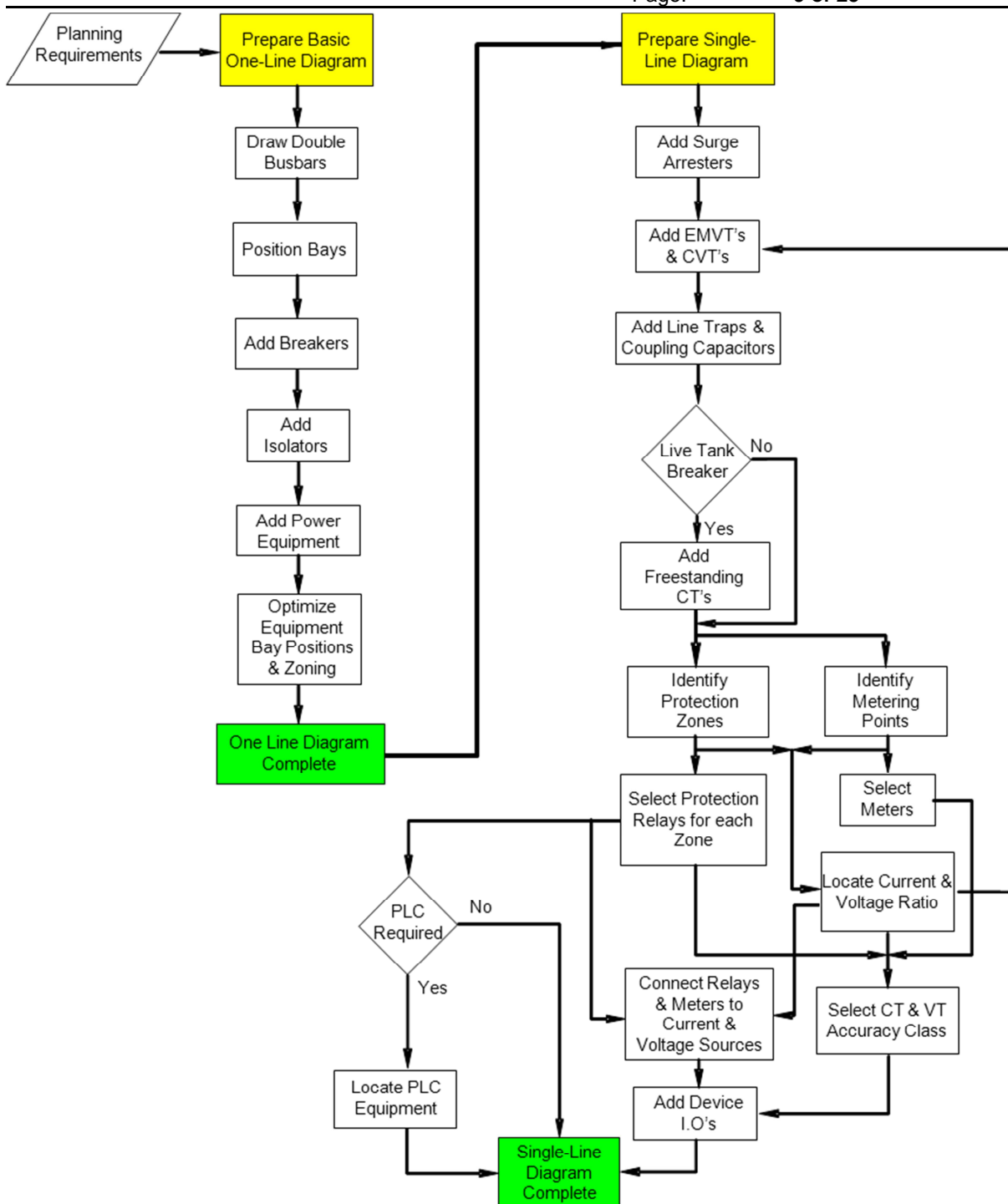


Figure 4: Flow Diagram for Single-Line Diagram Development

The busbar configuration and zone allocation adopted needs to be developed in conjunction with reading the relevant sections of the SAGC. Some of the principles given in the SAGC are outlined as follows:-

ESKOM COPYRIGHT PROTECTED

- 1) The standard substation arrangement shall be based on providing one busbar zone for every main transformer/line normally supplying that busbar. The TNSP shall, however, consider local conditions, type of equipment used, type of load supplied and other factors in the assessment of the required busbar redundancy. The TNSP shall also adhere to the system reliability criteria as described in section 7 of SAGC.
- 2) Earthing isolators shall be provided at new substations where the fault level is designed for 20 kA and above.
- 3) With one line or transformer or reactive compensation device out of service (n-1), it shall be possible to supply the entire load under all credible system operating conditions.
- 4) With the two most onerous line outages (n-2), it shall be possible to transmit the total output of the power station less its smallest unit to the system.
- 5) At power stations, busbar layouts shall allow for selection to alternative busbars. In addition, feeders must have the ability to go onto bypass.
- 6) The busbar layout shall ensure that not more than 1 000 MW of generation is lost as a result of a single contingency.

For a detailed discussion on Busbar Arrangements to satisfy the above requirements, refer to SLDG 6-4, particularly section 4 of this module.

3.3 Protective Zones

A protection zone is part of the substation high voltage interconnection that is identified to require dedicated protection for correct and efficient design of the entire substation protection scheme. The entire substation is divided up into different protection zones such that every high voltage part of the substation is covered by at least one protection zone, therefore, any fault in the substation high voltage busbar system or equipment, will be detected by at least one protection zone. To ensure complete coverage, all adjoining protection zones are overlapped. The overlapping area normally includes the common switching device for the two zones. The protection zones for the substation in Figure 2 and 3 are shown in Figures 5, 6 and 7.

There are two basic criteria for selecting a protection zone:-

- A common protection scheme will correctly detect any fault within the zone
- Disconnection of the zone from the balance of the substation will isolate the fault with a minimum impact on the healthy part of the system.

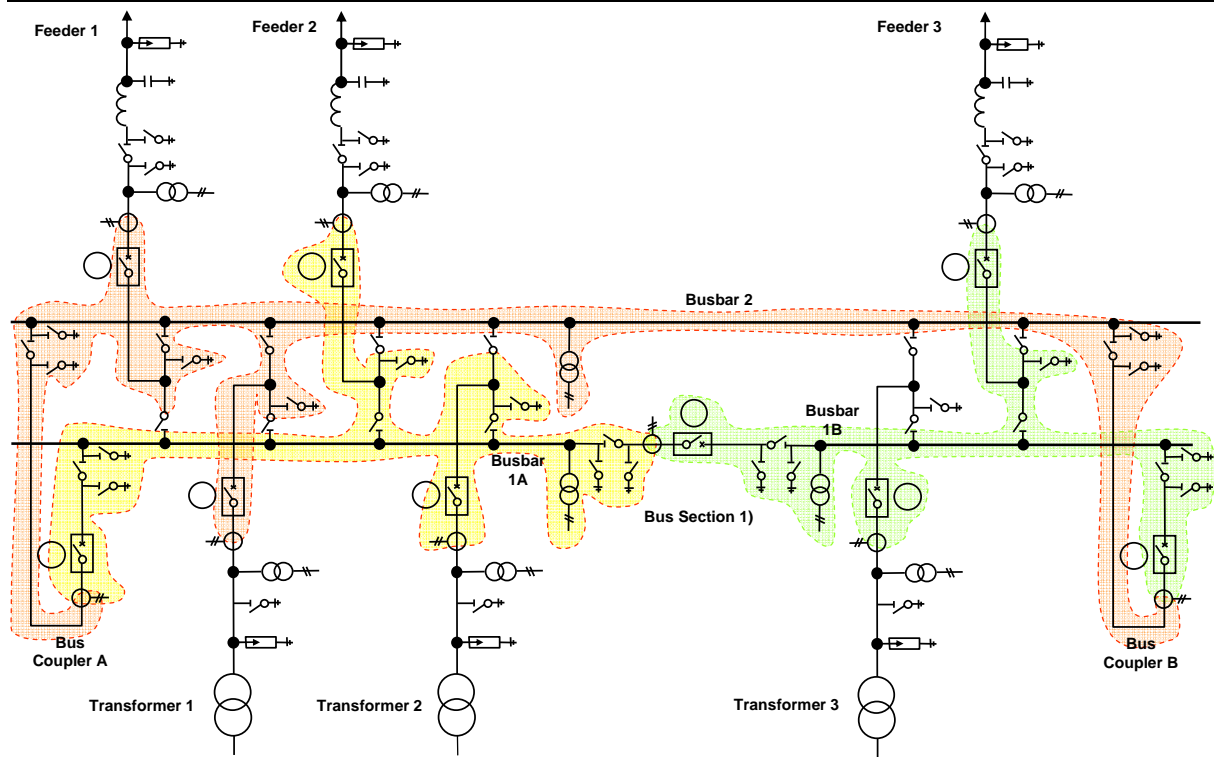


Figure 5: Buszone Protection

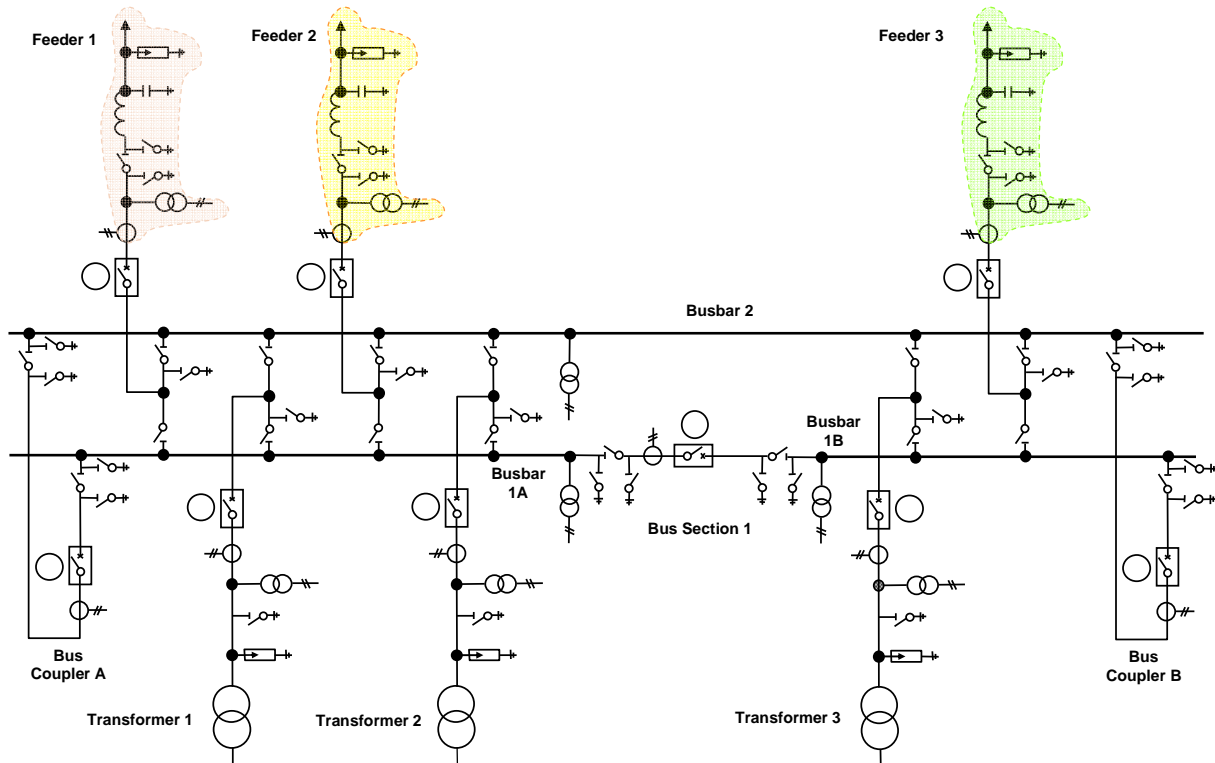


Figure 6: Feeder Protection

ESKOM COPYRIGHT PROTECTED

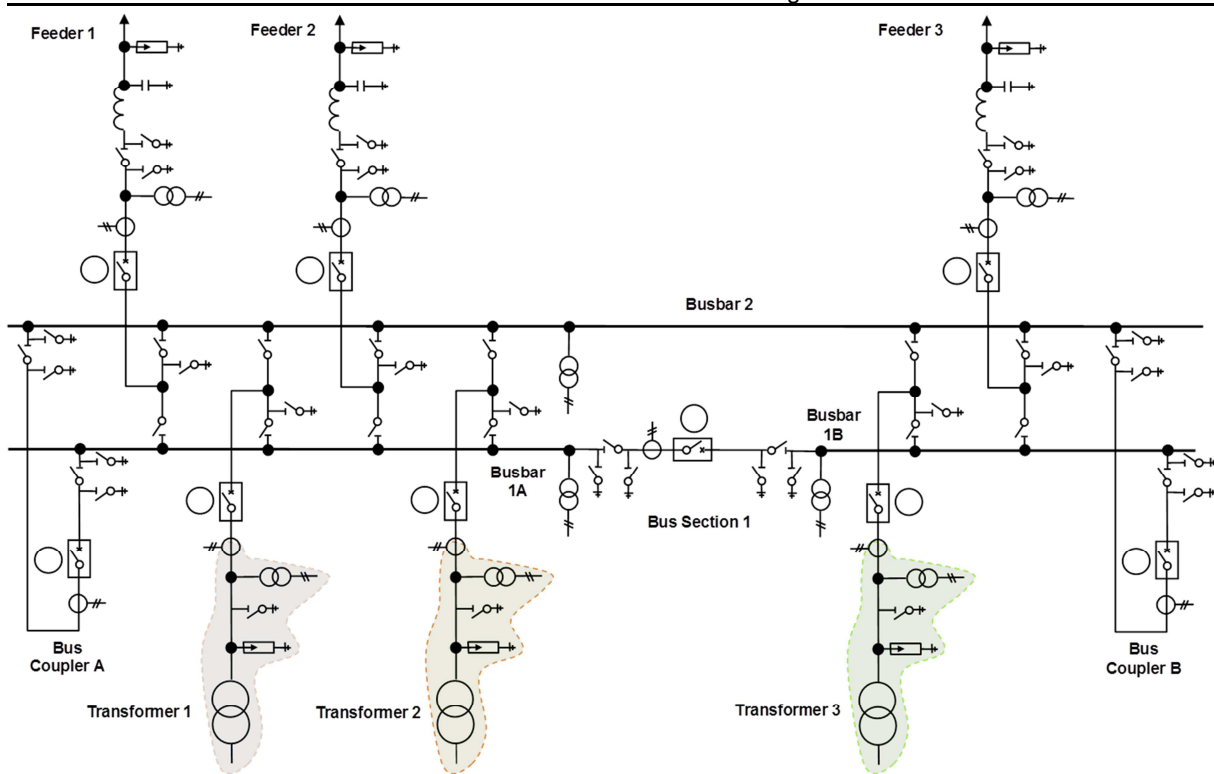


Figure 7: Transformer Protection

Generally, each of the following substation components is in a separate protection zone:-

- Transmission line
- Transmission power cable
- Main busbars
- Transformer
- Shunt or series capacitor bank
- Shunt reactor
- Generator connection (plant switchyards)

Special equipment considerations may result in small modifications to these basic zones. A Gas insulated Substation (GIS) and live tank breaker are two such applications where zone modifications may be required.

In GIS, the normal transmission zones would also include some gas-insulated equipment and busbar. A fault in the gas insulated chamber area needs to be treated differently compared to a transmission line fault (no auto re-closing for the GIS faults), therefore it is important for the protection system to segregate fault detection in the two areas. This would require a separate zone for the gas insulated equipment connected to the line.

In general, a live tank circuit breaker, unlike a dead tank circuit breaker, does not have bushing current transformers (CT's). The CT's required for the live tank breaker is mounted on a separate, freestanding, porcelain or composite material column. Due to economy, this CT column is only added to one side of the circuit breaker. Therefore, all CT's associated with a live tank breaker are on one side, compared to CT's provided on both sides of a dead tank breaker. This prevents inclusion of the live tank in the overlapped area of the two adjacent zones and creates a small blind spot (end zone) for the protection scheme on the CT column side of the breaker.

ESKOM COPYRIGHT PROTECTED

3.3.1 Protective Relays

A protection scheme is a fault-sensing device. A refresher discussion of relay and scheme types is provided below to supplement the single-line diagram development.

A protection relay evaluates the currents flowing in and out of the protected zone and decides if the fault is within the zone or outside of the zone. Some protective relays also require a voltage input for fault detection and so voltage transformers are usually connected to each zone of busbar. If the fault is detected to be inside the zone, the relay provides tripping signals to the appropriate switching devices, typically circuit breakers, to isolate the protected zone.

The protective relays used in substations can be classified in the following three broad categories:-

- Over-current relays
- Differential relays
- Distance relays

3.3.1.1 Over-current Relay

An over-current relay measures the current flowing through the CT it is connected to, and based on its settings, provides a tripping signal if the current exceeds its threshold. Variations of the over-current relay include directional and non-directional characteristics. These types of relays are normally used for protection of distribution lines and are also used as back-up protection for transmission lines, transformers, and various other devices.

3.3.1.2 Differential Relay

A differential relay compares the currents flowing into and out of the protected zone, and if the net current is not close to zero, it evaluates the situation as an internal fault. This type of relay is ideal for protecting busbars, transformers, reactors, and other protective zones where the current sources in the entire zone can be easily accessed. As a result of the difference in the electrical characteristics of a busbar fault as compared to a transformer or a reactor fault, these components require different types of differential relays.

3.3.1.3 Distance Relay

A distance relay requires both current and voltage inputs to evaluate a fault, however, it does not require input from all the terminals of the protected zone to perform its function. Based on the current and voltage inputs, the relay evaluates the distance of the fault from the measuring terminal, and provides a tripping signal if the fault is within a pre-set range. These relays are ideally suited to protect transmission lines, and sometimes, are also used to “backup” transformer protection.

In order to identify the function of various devices, IEEE has established a device numbering system. Table 1 shows the IEEE device numbers for the most commonly used substation equipment. These device numbers are used to identify the protective relay and other equipment on a protection scheme single-line diagram. Prefixes are added to these device numbers to identify the associated high voltage equipment and clarify the primary or backup application of the protective device.

Table 1: Common to Substation Application

| | | |
|-----------|---|---------------------------------------|
| 2 | = | Time Delay Relay |
| 21 | = | Distance Relay |
| 25 | = | Synchronizing or Synchro-Check Device |
| 27 | = | Under-voltage Relay |
| 50 | = | Instantaneous Over-current |
| 51 | = | AC Time Over-current Relay |
| 52 | = | AC Circuit Breaker |

ESKOM COPYRIGHT PROTECTED

| | | |
|----|---|-----------------------------------|
| 59 | = | Over-voltage Relay |
| 67 | = | AC Directional Over-current Relay |
| 85 | = | Carrier Pilot-wire Receiver Relay |
| 86 | = | Lock-out Relay |
| 87 | = | Differential Relay |

3.4 Instrument Transformers

Instrument transformers, as applied in substations, are devices that provide a lower level signal proportional to the high voltage currents and voltages (see SLDG 28-1, 2 and 3 for more detail). Their function is to provide the current and voltage information for relays, meters, and other measuring devices at a safe level to protect the maintenance and operating personnel, and to allow economical design of the measuring devices. The accuracy of the instrument transformers is also very critical to the proper operation of the protective and measuring devices. The instrument transformers used in a substation are classified in the following two categories:-

- Current transformers
- Voltage transformers

3.4.1 Current Transformers (See also SLDG 28-2)

For the purpose of developing a single-line diagram, the important items related to CT's are:-

- Selection of current ratio
- Selection of accuracy classification
- Selection of burden rating
- Connections to measuring devices

In the past, standard CT secondary ratings have been 5 A, but subsequent practice is to have 1 A represent the full rating. The CT primary rating is generally selected such that the maximum expected load current will result in slightly less than the 1 A or 5 A secondary output. Relaying CT's are available with multiple ratios to allow for any future increase in the load current while an appropriate lower tap is used to match the prevailing load current.

The CT's are broadly divided in two accuracy classifications:-

- Relaying Accuracy for protection purposes
- Metering Accuracy for billing purposes

Revenue metering applications require metering accuracy CT's. All relaying applications and a majority of the indicating applications use relaying accuracy CT's. Standardised CT accuracies for protection and metering purposes are provided under the detailed chapter on CT's, SLDG 28-2 and in the SAGC, section 3.3 (see Table 2 below).

Table 2: Accuracy Class of CTs and VTs

| Measurement Equipment | Accuracy Class |
|--|----------------|
| Current transformer (CT) | |
| Voltage transformer (VT) | 0,2 |
| Transducer | 0,5 |
| Analogue to digital conversion, i.e. RTU | 0,01 |

The standard metering CT accuracy addresses the ratio error as well as the phase angle error and is defined by standard combinations of these two errors. A specified CT accuracy is only applicable up-to its rated burden rating; therefore, it is important to verify that the connected secondary loads will not exceed the rated burden of a CT. It should be noted that the CT burden rating is based on its maximum ratio; and use of a lower tap will proportionately reduce the available burden rating.

The direction of the current flow in a CT secondary is determined based on the polarity marking on the CT. Except for non-directional relays, the protective relays require careful attention to the connection of the CT's to the relay or assigned protection scheme contacts. The connections should be such that when the primary current is flowing into the protected zone, the secondary current should be flowing into the relay. The CT connections for the metering devices are based on the direction of the power flow the device is expected to measure.

3.4.2 Voltage Transformers (See also SLDG 28-3)

Although there is development in other technologies taking place at present, two types of voltage transformers are currently being used in substations:

- Magnetically coupled voltage transformers (EMVT's)
- Capacitively coupled voltage transformers (CVT's)

The following are the key properties that determine their application in high voltage substations:-

3.4.2.1 Magnetically coupled voltage transformers (EMVT's)

- Better accuracy
- Higher burden rating
- Better transient performance
- Expensive at higher voltages in open air applications
- Preferred for GIS and SVC applications

3.4.2.2 Capacitively coupled voltage transformers (CVT's)

- Less expensive at higher voltage open air applications
- Permit power line carrier coupling
- Not preferred for GIS and SVC applications

Based on these features, GIS use EMVT's at all voltages. In open-air applications, EMVT's are preferred at voltages of 132 kV and below. For metering applications, there used to be a strong preference for EMVT's even as high as 330 kV, however, CVT's have become accurate and stable enough to fulfil this function. In any event, at above 330 kV, the cost of EMVT's becomes prohibitive for most open-air applications. They are still employed at high voltage for FACTS devices such as SVC's due to the very high accuracy required for voltage signal reproduction.

3.5 Pilot Channels for Protective Relays

Pilot channels are communication mediums used for transmission line protection systems to exchange the fault detection information between the transmission line terminals.

The distance relays detect a transmission line fault by measuring the distance of the fault location from the protected terminal. When the fault location approaches the opposite terminal, determination of whether the fault is within the protected line, or outside of it, becomes quite difficult and often requires slowing down of the trip signal to allow other relays to operate first. This delay in the fault clearing may not be desirable for system stability. Pilot channels allow the line relays, at the two terminals, to communicate with each other to determine the fault location, thus speed up the accurate fault detection for 100% of the protected line. The pilot channels are used for the protection of high voltage lines and critical lower voltage lines where a high speed clearing of the line faults is critical to the transmission system.

The pilot communication channels used for transmission line protection are:-

- Power line carrier (PLC)
- Pilot wire which has virtually completely disappeared in some countries
- Microwave
- Optical fibre ground wire (OPGW)

Only the PLC channel has a major impact on the single-line development since it requires high voltage equipment to couple a high frequency carrier signal to the protected transmission line.

Figure 8 illustrates the major components of a PLC channel. The following is a brief description of the function of each component:

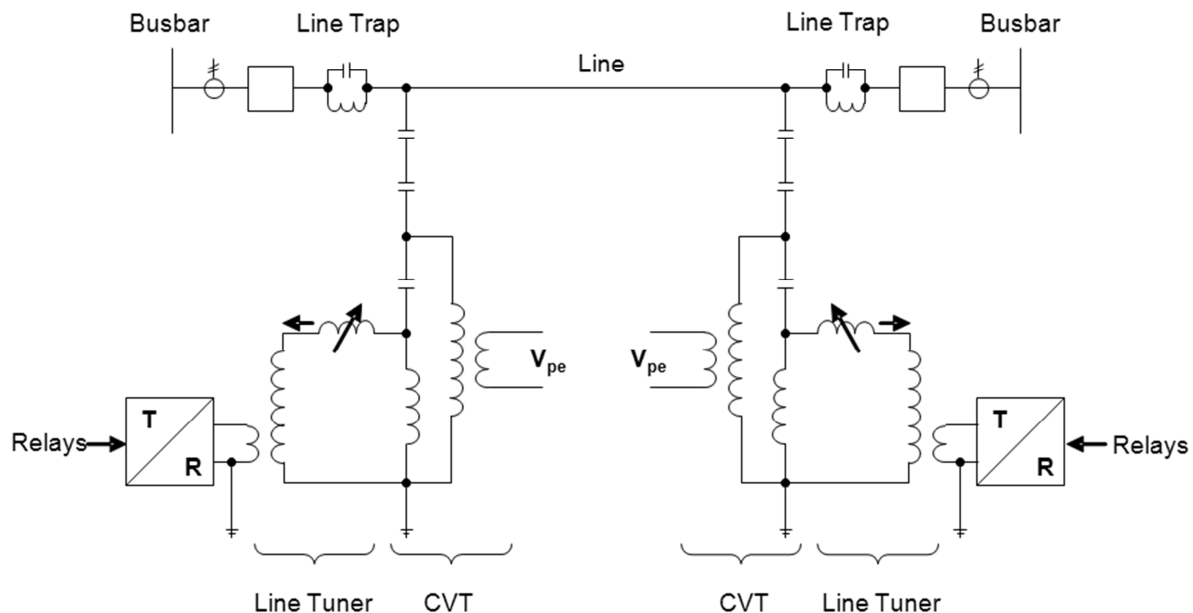


Figure 8: Major Components of Power Line Carrier Channel

3.5.1 Line Trap (LT)

The line trap is an inductor in parallel with a tuning capacitor circuit. It is tuned to present high impedance to the carrier frequency, but negligible impedance at the system frequency. A line trap serves two functions:-

- It prevents carrier energy from flowing into the substation busbar
- It prevents external earth faults from short-circuiting the carrier signal

3.5.2 Coupling Capacitor (CC)

A coupling capacitor is made up of a series of stacked capacitors mounted inside porcelain or composite material units. It is used to couple the carrier signal to the power line. By adding a relatively lower voltage transformer to the last capacitor stack of the coupling capacitor, the device becomes a CVT and doubles as a line voltage source for the relays and meters.

3.5.3 Line Tuner (CC)

A line tuner is a combination of impedance matching transformers, capacitors, and inductors. It is tuned to offset the capacitive reactance of the coupling capacitor, at the carrier frequency, to provide a low loss path for the carrier signal. It also provides an impedance match between the coaxial cable and the transmission line.

3.6 PTM&C Guideline for Checking and Approving of Station Electric Diagrams (SEDS)

In the interests of standardization, guidelines below serve as a tool to assist in the checking of SEDs before PTM&C engineers commence with application designs.

3.6.1 Bay CB notations

3.6.1.1 Cable number prefix

Cable number prefixes indicated on SEDs are denoted within a circle located adjacent to the circuit breaker (CB) on SEDs (Figure 9)

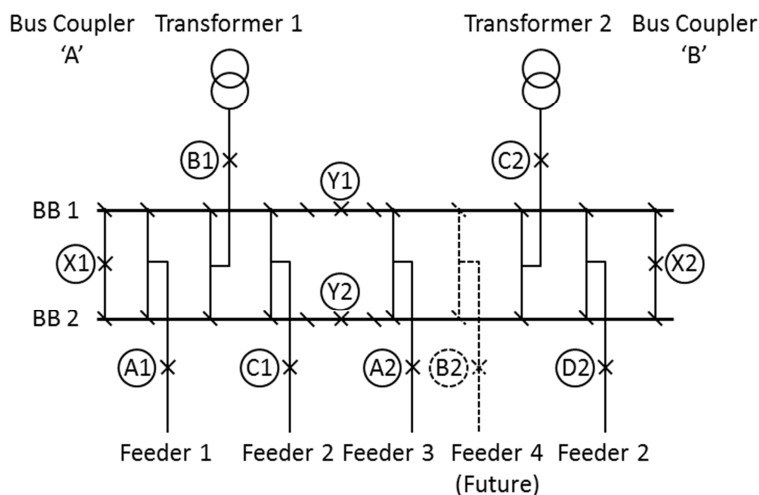


Figure 9: Illustration of double busbar layout denoting bay prefixes

Bay prefixes are allocated in alphabetical order according to the bay numbering order (Feeder 1, Feeder 2, etc.) from right to left or vice versa. Bay prefixes must be reserved for future bays so that the correct sequence is maintained. Bay prefixes for Bus Couplers (BC) begin with the letter **X** followed by the number. The prefix **X1** is used for Bus Coupler "A" and the prefix **X2** is used for Bus Coupler "B", and so on. If there is a Transfer Coupler, the prefix shall begin with **X** followed by the last number in the sequence of couplers.

Bay prefixes for Bus Sections (BS) begin with the letter **Y**, followed by the number. The numbers shall begin from the Bus Coupler A end and increase towards Bus Coupler B. The type of number, i.e. whether odd or even, must correspond with the busbar number type, odd or even (for Busbar 1, the numbers will be **Y1**, **Y3**, **Y5**, etc.). Furthermore, prefixes for bays other than BCs and BSs must follow a numbering sequence as illustrated in Figure 9; notice that the bay prefixes begin from the end where Bus Coupler A is situated and progress in the direction of Bus Coupler B, starting from **A1**. After each BS, the number assigned to the bay prefix increases by one, i.e. it changes to **A2**.

Bay prefixes are not necessary for Breaker-and-Half substations as the Diameter description, e.g. **MA**, **MB**, **MC**, etc. serves as the cable number prefix.

a) Point of wave (POW) switching

Where synchronized or Point on Wave (POW) switching is used, there shall be a symbol located adjacent to the bay CB to denote this. The symbol shall be as indicated in Figure 10

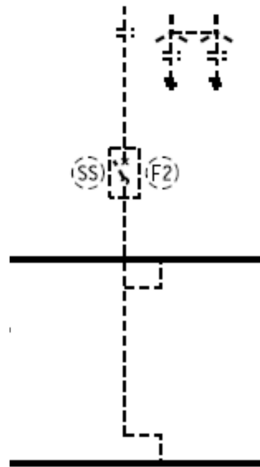


Figure 10: Schematic of bay feeding a shunt capacitor incorporating synchronized or (POW) switching

3.6.2 Mechanism end for dead tank circuit breakers (Breaker and Half Stations)

Some Breaker-and-Half substations incorporate dead tank breakers. These breakers have in-built CTs where a set of 3 cores are located on each side of the breaker. The total number of cores are numbered from 1 through to 6. There are 2 Protection cores and 1 Measurements core in each set of CT cores. Care must be taken when checking the SED that the orientation of dead tank breakers is consistent throughout the station. Figure 11 depicts a typical Breaker-and Half substation wherein the mechanism end of the dead tank breaker is indicated by a filled-in (Red) square block accompanied by a label saying "MECH. BOX". All the circuit breakers' orientation must be in a certain direction, either towards busbar 1 or busbar 2. This means of indication aids PTM&C application designers in maintaining a standard for a particular substation.

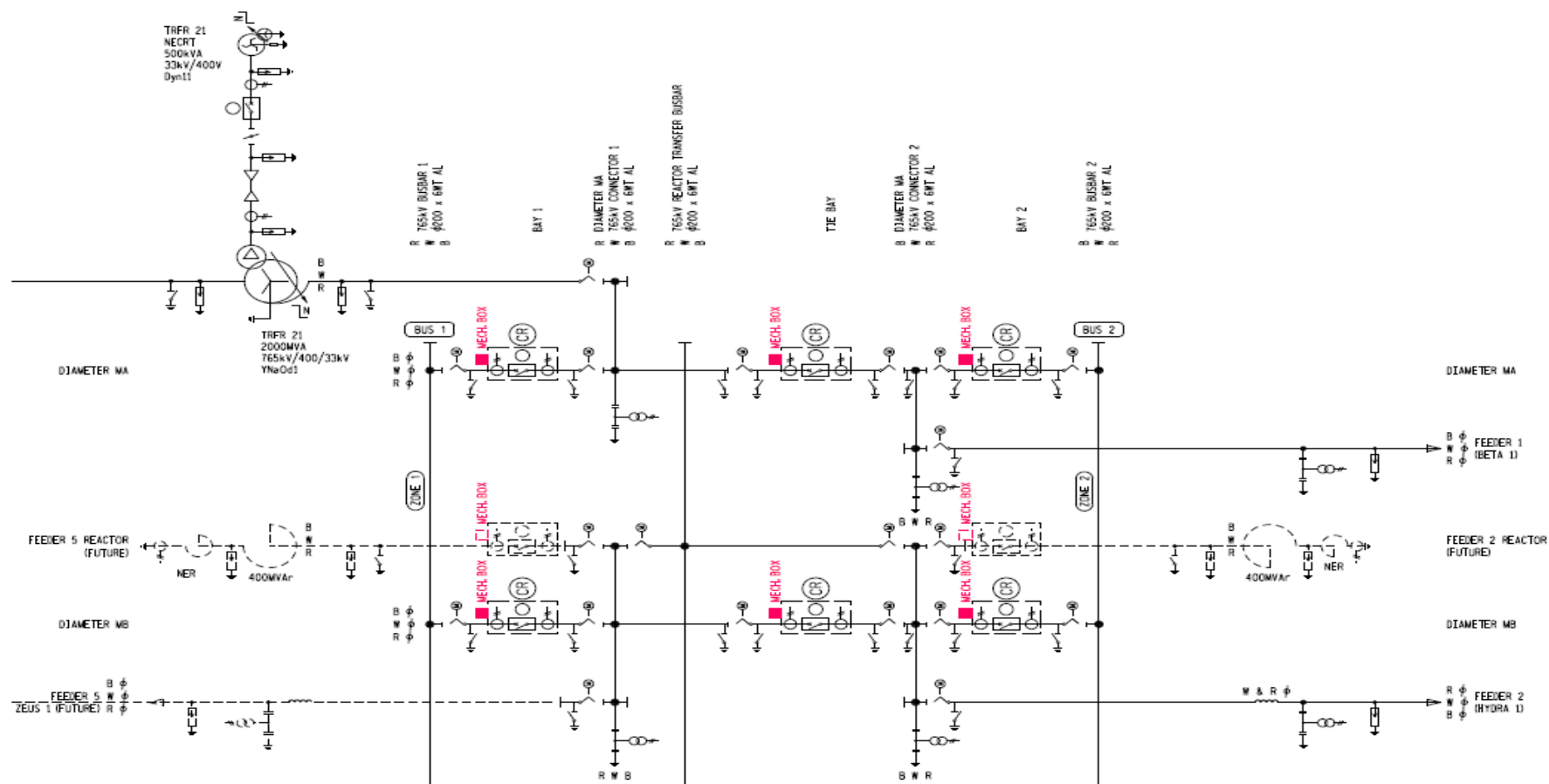


Figure 11: Busbar layout of a typical 765kV Breaker-and-Half Substation

ESKOM COPYRIGHT PROTECTED

When downloaded from the WEB, this document is uncontrolled and the responsibility rests with the user to ensure it is in line with the authorized version on the WEB.

3.6.3 Station Auxiliary Power Supplies

Some Breaker-and-Half substations incorporate dead tank breakers. These breakers have in-built CTs

3.6.3.1 Dual redundant AC power supplies

Check that there are a minimum of two separate sources of auxiliary AC power supplies; ie. separate auxiliary transformers. Furthermore, these auxiliary transformers must not be fed from a common coupling transformer, instead they must be fed from different coupling transformers. Where necessary, there might be a need for more than one auxiliary transformer connected to a coupling transformer. If there is just one coupling transformer at a substation, then this shall provide the first source of auxiliary AC power. The second source of auxiliary AC power shall be derived from a dedicated station transformer or nearby Eskom Distribution or Local Municipal reticulation network. The SED checker from PTM&C shall request proof of application for the second auxiliary AC power supply by the PTM&C project engineer. Until positive feedback is received from the PM, the SED may not be signed by PTM&C.

3.6.3.2 Station battery voltage

Station battery voltages for both primary and secondary plant can be either 110Vdc or 220Vdc. Verify that the station battery voltage indicated on the SED matches what is required in the Asset Specification document.

3.6.4 Buszone Ratio

This information was traditionally indicated on SEDs due to the requirement for High Impedance Buszone schemes needing all bays to have the same CT ratio. This information was good as long as all the bays in a particular substation had the same fixed Buszone CT ratio. However, due to refurbishments of certain bays or additional bays being added at substations, the new CTs do not necessarily maintain the same fixed Buszone CT ratio as the existing bays due to the advent of the Low Impedance Buszone protection scheme. Low Impedance Buszone protection schemes are able to accommodate CT mismatches across bays in a substation. The PTM&C SED approver needs to be mindful of this when checking SEDs. In other words, the Buszone CT Ratio indicated on SEDs is not necessarily true for the entire substation.

3.6.5 Line Traps

Line traps on feeders are indicated on SEDs. Normally, the PTM&C SED approver needs to look at local as well as remote ends of transmission lines to check if the line traps correspond. However, on long transmission lines, due to electromagnetic coupling (EMC) between phase conductors, carrier signals propagated on a particular phase can be induced in another phase. This scenario results in line traps not necessarily being inserted on the same phases of a feeder between the local and remote ends. The SED approver must always obtain Power Line Carrier phasing diagrams from PTM&C Power Telecommunications Department. for each and every feeder at a substation before approving the SED.

3.6.6 Busbar Earths

Care must be taken when checking for duplicate earthing isolators on busbars. If there are duplicate earthing isolators, there must be a note on the SED stating that the duplicate busbar earthing isolator shall be locked in the open position using a non-standard lock.

3.6.7 Transformer vector groups

The PTM&C SED approver must check and verify all transformer vector groups indicated on SEDs. For example, a Star-Star transformer compared to an Auto Star transformer must be applied differently on Restricted Earth Fault protection relays (the Star-Star transformer will have separate neutral CTs as opposed to a common neutral CT in an Auto Star transformer).

3.6.8 Positioning of current transformer**3.6.8.1 Overpasses**

If there is an overpass, let the location of the CT be such that the CT and the jumper forming part of the overpass shall belong to the same Bus Zone with respect to the Busbar Protection scheme. This is to ensure that a CT explosion shall not cause a Busbar fault in two zones. (Out)

3.6.8.2 Feeder bypass

CTs shall be positioned on the line side of the feeder breaker bypass point.

3.6.8.3 Bus couplers and bus sections

These shall have overlapping CTs when installed in HY yards at power stations, even if the Buszone protection scheme installed is a low impedance type.

3.6.8.4 Line reactors

Line CTs can be positioned on the busbar side of the line reactor, or they can be positioned on the line side of the reactor.

Please refer to figures 12 and 13 for single line representations of the two possible locations of the line CTs.

The issue of the location of the line CT for lines with reactors coupled to them has been debated in the past and a decision had been taken on 22 August 2008 as to the preferred location.

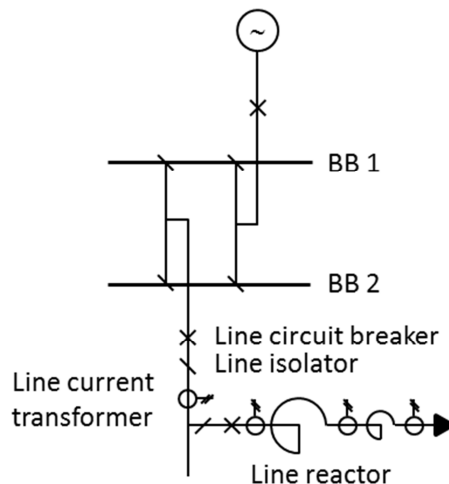


Figure 12: Line CT on busbar side of line reactor

Points to note:

- Reactor is “seen” as part of the line in respect of line protection
- No reactor “ring down” current through the line CT when the line breaker trips for line faults
- Reactor CT is not wired to the Buszone protection
- Faults within the reactor will be cleared by the reactor circuit breaker as well as the line circuit breaker
- Reactor circuit breaker failure will result in the circuit breaker being tripped if the fault is not seen by the instantaneous zone of the line protection

ESKOM COPYRIGHT PROTECTED

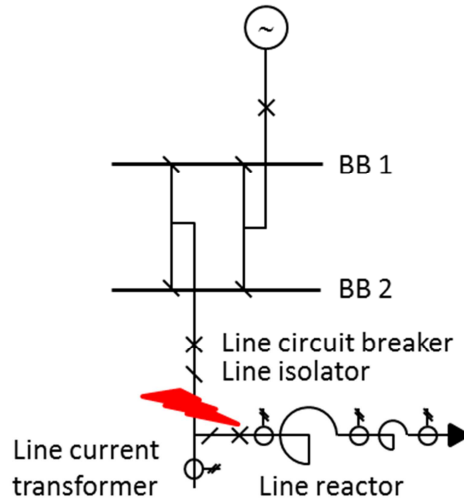


Figure 13: Line CT on line side of line reactor

Points to note:

- Reactor is “seen” in the reverse zone with respect of line protection
- No reactor “ring down” current flows through the line CT when the line breaker trips for line faults
- Reactor CT Buszone cores need to be wired to Buszone protection
- Faults within the zone of the reactor unit protection will be cleared by the reactor circuit breaker
- Reactor circuit breaker failure will result in the line circuit breaker being tripped
- Faults in the area indicated in Figure 13 will result in a bus zone operation

Reactor circuit breaker failure will result in the circuit breaker being tripped if the fault is not seen by the instantaneous zone of the line protection

The general practice within Eskom has been to place the CT on the line side of the reactor. Table 1 contains a list of all line reactors deployed in Eskom with a column indicating the Line CT position in each case.

STANDARD PROCEDURE FOR SINGLE LINE (STATION ELECTRIC) DIAGRAM DEVELOPMENTUnique Identifier: **240-68972308**Revision: **2**Page: **23 of 25**

| Substation | Reactor | MANUFAC. | MANUFAC. DATE | COMMISS. DATE | kV | Line CT position |
|------------|---|---------------|---------------|---------------|-----|------------------|
| Matimba | Matimba Marang No1 400kV Line Reactor | | | 08/06/2005 | 400 | line side |
| Matimba | Matimba Phokojie No1 400kV Line Reactor | | | 14/10/1995 | 400 | line side |
| Beta | Beta Hydra No2 765kV Line Reactor | | | 24/11/2004 | 765 | line side |
| Ferrum | Ferrum Garona No1 275kV Line Reactor | Elin | 01/01/1977 | 01/01/1986 | 275 | busbar side |
| Matimba | Matimba Pluto No1 400kV Line Reactor | Asea | 01/01/1988 | 01/01/1990 | 400 | line side |
| Poseidon | Poseidon Delphi No1 400kV Line Reactor | BBT | 01/01/1990 | 01/11/1988 | 400 | line side |
| Droerivier | Droerivier Muldersvlei No2 400kV Line Reactor | BBT | 01/01/1992 | 01/07/1993 | 400 | line side |
| Hydra | Hydra Poseidon No1 400kV Line Reactor | ABB | 01/01/1993 | 18/05/1997 | 400 | line side |
| Hydra | Hydra Poseidon No2 400kV Line Reactor | ABB | 01/01/1993 | 01/03/1997 | 400 | line side |
| Droerivier | Droerivier Bacchus No1 400kV Line Reactor | ABB | 01/01/1994 | 11/05/1996 | 400 | line side |
| Maputo | Maputo Arnot No1 400kV Line Reactor | ABB | 01/01/1998 | 02/05/2000 | 400 | line side |
| Hydra | Hydra Beta No2 765kV Line Reactor | Japan AE | 01/01/2003 | 23/11/2004 | 765 | line side |
| Matimba | Matimba Witkop No1 400kV Line Reactor | ABB | 01/01/2004 | 01/01/1987 | 400 | line side |
| Matimba | Matimba Witkop No2 400kV Line Reactor | ABB | 01/01/2005 | 17/06/2005 | 400 | line side |
| Alpha | Alpha No4 765kV Line Reactor | Fuji Electric | 01/02/1985 | 31/08/1987 | 765 | line side |
| Alpha | Alpha Beta No2 765kV Line Reactor | Fuji Electric | 01/03/1985 | 31/08/1987 | 765 | line side |
| Beta | Beta Alpha No1 765kV Line Reactor | Toshiba | 01/05/1985 | 17/08/1987 | 765 | line side |
| Beta | Beta 400kV Emergency Bypass Line Reactor | BBT | 01/07/1983 | 30/11/2004 | 400 | line side |
| Matimba | Matimba Midas No1 400kV Line Reactor | Asea | 01/07/1987 | 01/01/1988 | 400 | line side |
| Beta | Beta Alpha No2 765kV Line Reactor | Fuji Electric | 01/08/1986 | 17/08/1987 | 765 | line side |
| Umfolozi | Umfolozi Normandie No1 400kV Line Reactor | Asea | 02/01/1980 | 06/02/1980 | 400 | line side |
| Pegasus | Pegasus Athene No1 400kV Line Reactor | ABB | 02/01/1995 | 14/07/1995 | 400 | line side |
| Alpha | Alpha Beta No1 765kV Line Reactor | Fuji Electric | 02/01/2003 | 31/08/1987 | 765 | line side |
| Normandie | Normandie Camden No1 400kV Line Reactor | Asea | 05/01/1977 | 14/02/1977 | 400 | line side |
| Aries | Aries Kokerboom No1 400kV Line Reactor | ABB | 05/05/1998 | 21/08/2000 | 400 | line side |
| Beta | Beta Delphi 400kV Line Reactor | | | | 400 | busbar side |
| Delphi | Delphi Beta 400kV Line Reactor | | | | 400 | line side |

Figure 14: List of line reactors deployed in Eskom as at Aug 2008

The following new lines have line reactors which are not contained in the listing above:

Medupi – Marang 400kV

Ferrum – Vryberg 400kV

Ferrum – Garona 400kV

Perseus – Mercury 400kV emergency bypass

3.6.8.5 Final decision taken on 22 Aug 2008

- Having the line CT positioned on the Busbar side of the line reactor is the desired option, however it cannot be adopted as an accepted practice due to present Eskom feeder protection scheme limitations.
- In the short term, Eskom will continue to position the line CT on the line side of the reactor. In the long term, the decision is to position the line CT on the busbar side of the reactor, but only if the line protection scheme makes provision for subtracting the reactor current from the total line current. PTM&C was tasked to look into a new scheme design that satisfies this requirement both for Breaker-and-Half substations as well as conventional double busbar substations.

3.6.9 Positioning of voltage transformers**3.6.9.1 Transfer Busbar**

Any busbar that can be alive or dead, depending on the status of a switching device used to energise or de-energise that busbar, shall be equipped with a VT. The purpose of this VT is purely for SCADA measurements to satisfy ORHV safety requirements. Figures 15 and 16 illustrate transfer busbars equipped with VTs.

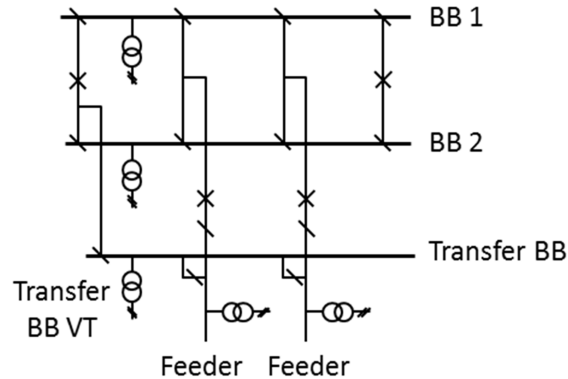


Figure 15: Hybrid Bus Coupler with dedicated Transfer Busbar

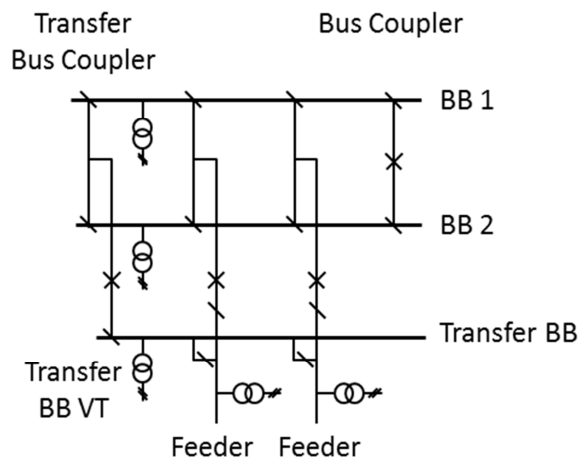


Figure 16: Transfer bus coupler with Transfer Busbar

3.6.9.2 Transfer Busbar

Traditionally, all EHV Feeders incorporated the use of line VTs. Where HV feeders emanate from Transmission substations, they did not incorporate line VTs. However, if HV feeders connect Distribution substations or IPPs where there are power sources, then such feeders shall be equipped with line VTs.

International customers will always have line VTs for synchronization purposes.

4. Authorization

This document has been seen and accepted by:

| Name and surname | Designation |
|---------------------|------------------------------|
| Phineas Tlhatthetji | Senior Manager - Substations |
| Enderani Naicker | Chief Engineer - Substations |
| Derrick Delly | Chief Engineer - Substations |
| Sipho Zulu | Chief Engineer - Substations |
| Theunus Marais | Chief Engineer - Substations |

ESKOM COPYRIGHT PROTECTED

| Name and surname | Designation |
|-------------------------|--------------------------------------|
| Ian Hill | Senior Engineer - Substations |
| Leon Kotze | Senior Consultant - Protection |
| Thys Bower | Corporate Specialist - Protection |
| Riyaz Gangat | Senior Technologist Protection T & S |

5. Revisions

| Date | Rev | Compiler | Remarks |
|-------------|------------|-----------------|---|
| Oct 2015 | 2 | AJS Groenewald | Addition of paragraph 3.6. Title revised. |
| Dec 2013 | 1 | AJS Groenewald | Initial Issue. |

6. Development team

The following people were involved in the development of this document:

- Abre le Roux Technology Group East London
- Braam Groenewald Technology Group Johannesburg
- Enderani Naicker Technology Group Johannesburg
- Phineas Tlhatlhetji Technology Group Johannesburg
- Thys Bouwer Technology Group Johannesburg
- Leon Kotze Technology Group Johannesburg
- Riyaz Gangat Technology Group Johannesburg
- Nombuso Msibi Technology Group Johannesburg
- Richard Mavuso Technology Group Johannesburg

7. Acknowledgements

With thanks to all members of the development team.