Czech Technical University in Prague

Faculty of Electrical Engineering

Department of Electroenergetics

# Diploma Thesis

## Possible Issues in Distributed Generation Network Protection

## Problematika chránění sítí s decentralizovanou výrobou energie

Study programme: (MP1) Electrical Engineering, Power Engineering and Management

Branch of study: (3907T001) Electrical Power Engineering

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Department of Electrical Power Engineering

# DIPLOMA THESIS ASSIGNMENT

Student: **Dang Minh Quan**

Study programme: Electrical Engineering, Power Engineering and Management
Specialisation: Electrical Power Engineering

Title of Diploma Thesis: **Possible Issues in Distributed Generation Network Protection**

Guidelines:

1. Analyze the protection issues related to power network with presence of distributed generation.
2. Compare conventional and distributed generation network protection.
3. Summarize known so far protection methods used for this type of networks.
4. Create a simple model of distributed generation network and use it to assess the impact of distributed generation on network protection.

Bibliography/Sources:

[1] ANDERSON, P. "Analysis of faulted power systems", New York: IEEE Press, 1995, xix, 513 p., ISBN 0-7803-1145-0.
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[4] "Applications for SIPROTEC Protection Relays", Nuernberg: Siemens Aktienges-ellschaft, 2005, 228 s.

Diploma Thesis Supervisor: Ing. Jakub Ehrenberger

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## Abstract

The connection of distributed generation (DG) to a distribution network causes various changes in voltage profile, fault level and power flow direction. In this work, the effects of DG on radial distribution network protection have been identified. Common issues of false tripping, blinding of protection and lost of coordination are investigate for several different DG locations and penetration levels. The modified relay setting to adapt with each situation was also computed. The results indicated that necessary to upgrade new devices as directional relays and implementation of communication technologies to ensure the correct operation of protection system.

## Abstrakce

Připojení distribuované výroby (DG) do distribuční sítě způsobuje změny napěťového profilu, hodnot zkratových proudů a směrů výkonových toků. Tato práce se zabývá prověřením účinků DG na ochranu radiální distribuční sítě, jako nesprávné odepnutí nepostižené sekce, nereagující ochrany, či porušení selektivity ochran. Ochrana sítě byla prověřena pro několik poruchových stavů v různých místech sítě a zároveň byl vytvořen algoritmus umožňující správné nastavení ochran dle aktuální konfigurace sítě. Průzkum ukázal, že pro správné fungování systému ochran, je při změnách konfigurace sítě nutno provést jejich přenastavení.

## ***Keywords***

*Distributed Generation, Overcurrent Relay, distribution network, Protection, Power system analysis.*

## Declaration

I hereby declare that this thesis is the result of my own work and all the sources I used are in the list of references, in accordance with the Methodological Instructions on Ethical Principles in the Preparation of University Theses.

In Prague, May 23, 2016

Student's signature

Minh-Quan DANG

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# Acronyms

**Terms**

| | |
|---|---|
| $DG$ | Distributed generation |
| $MOC$ | Minimum operating current |
| $TDS$ | Time dial setting |

**Subscripts**

| | |
|---|---|
| (1) | Positive-sequence component |
| (2) | Negative-sequence component |
| (0) | Zero-sequence component |
| $k3$ | Three-phase short circuit |
| $k1$ | Line-to-earth short circuit |
| $k2$ | Line-to-line short circuit |
| $k2g$ | Line-to-line-to-ground short circuit |

# Introduction

The contribution of distributed generations (DG) on the power system and special on distribution level is an irreversible trend. More and more distributed power sources are implemented to the power network especially in small town, villages and rural farm areas, where those distributed generations could contribute the most [1].

Under the normal operation, the DG could operate as independent power source which satisfy customer's demand on reactive power, higher harmonic components, compensation of power quality event, reduce grid losses (typically 10% - 15%), improve voltage profile, peak load shaving and play the role of a backup generator to improve reliability of the system [2, 3, 4].

However, presence of DG also have several impacts such as alter power flow especially in radial topology, loss of coordination of protection, nuisance tripping, overvoltages, unwanted islanding, have been documented [5, 6]

This paper focus on impacts of DG on protection practices of radial distribution power network. The method allows analyzing the effects of DG penetration and location, and also a necessarily modified protective devices setting will be found. The assessment considers problems with voltage profile, fault level, false tripping, blinding of protection and loss of coordination.

To fulfill the study objectives, the following tasks have been accomplished:

1. A review of related literature to be the background from further research (Chapter 1)
2. Distribution network modeling, power flow and fault analysis (Chapter 2)
3. Relay setting process based on network topology (Chapter 2)
4. Investigate the issues when DG installed into the network (Chapter 3 and 4)
5. Compute modified relay setting (Chapter 3 and 4)

All analyses in this work had been programed and evaluated with the software Mathematica version 10.4 provided by the Czech Technical University.

# 1 Literature Review

This chapter presents a few fundamental knowledge of power system, protection in power system and distributed generators problem related to it. These information will latter be used as the background to form processes for test network analysis and investigate the issues with DG on protection system.

## 1.1 General characteristics of power system

Power system includes all facilities to generate and deliver electric power to loads [7]. Power system must be well designed and operated to fulfill four basic missions [8]:

1. **Providing electric power to all customers**: Customer of a power system could varying from high population density such as cities to scattering over a wide area in remote mountain places. In any circumstances, the power system must provide electricity of all its customers. Moreover, customer's demand could be different not only in size but also in term of voltage level.

2. **Having sufficient capacity to cover peak demands of customers**: This is the task of engineers during designing and dimensioning of the power system. The considerations must install adequate power supply along with a vision for future explanation.

3. **Providing electric power continuously with minimum interruption**: This is one of the most important mission of power system. The system must have not only very high reliable facilities but also providing the same level of reliability for every customers. This indicates by very small number of power interruptions and very short interrupted interval.

4. **Providing electric power with high quality**: provide adequate power all the time is not enough, the power system must ensure the power quality. In other words, the voltages and frequency though the system must be kept at a certain level within limits.

By structure, the traditional electric power system is hierarchical, in which power production is concentrated at several huge, remote and isolated power stations far form residential areas and near the fuel's resources. The transmission and distribution system carry power from those distant power plants to the customers. The voltage level is boosted up at the transmission system and gradually step down throughout the services territories. In brief, power system contains [9]:

**Power plants:** Large power plants convert potential energy (hydro) or heat (by burning coal, oil, gas or by nuclear reaction) into mechanical energy and then into electrical energy by generators. Those power plants have very high efficiency up to 99% in large generators and also could be operate with small number of personnels. Advantages of large power plants are providing adequate power reserve, power could be transmitted for a long distance with only small losses.

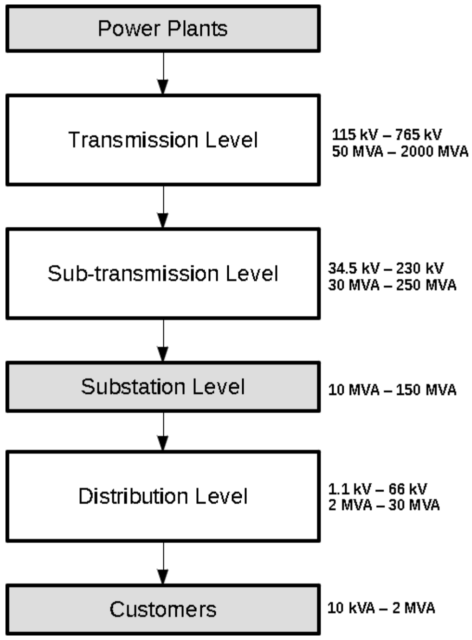



Figure 1: Structure of traditional power system [9]

**Transmission systems:** Electric power is produced at power system then be boosted to very high voltage level and connected to transmission system for long distant power delivery. The transmission system usually contain three-phase over head lines and be designed in the the way that if any one element fails there are always an alternative way and power flow interruption is as less as possible.

**Sub-transmission systems:** This system take power from the power plants or transmission switching stations and send it to substations. Sub-transmission lines are part of network grid, that means every substation will be supplied by two or more lines. This feature help to increase reliability of the power system again fault conditions.

**Substations:** The power from sub-transmission system enter the substations, then the voltage is converted to lower primary voltage for distribution. Substation contains high and low voltage racks and buses for the power flow, circuit breakers, metering equipments and protective devices.

**Distribution systems:** This system contains over head lines mounted on poles or underground cables from substation throughout the service area. The primary voltage level will be converted to utilize voltage if necessary by service transformer before power come to the customers.

**Customers:** Each customer required power could be in the range from 10 kVA to 2 MVA. Customer demand could be supply by distribution system by one phase or all three-phase in case of large demand to reduce dimension of conductor and avoid imbalance of the system.

In the frame of this work the main effort will be made to analyze the problem of distribution system while distributed generation presence. Therefore, in the next section the more detail feature of distribution system is presented.

## 1.2 Features of Distribution System

As discussed in Section 1.1, the distribution system transport power from substations to customers. The voltage level could be at medium or low voltage level. The number of customer is many but demand for each is relatively small. There are three fundamental different concepts to design a power distribution system, namely: radial network, loop network and meshed network.

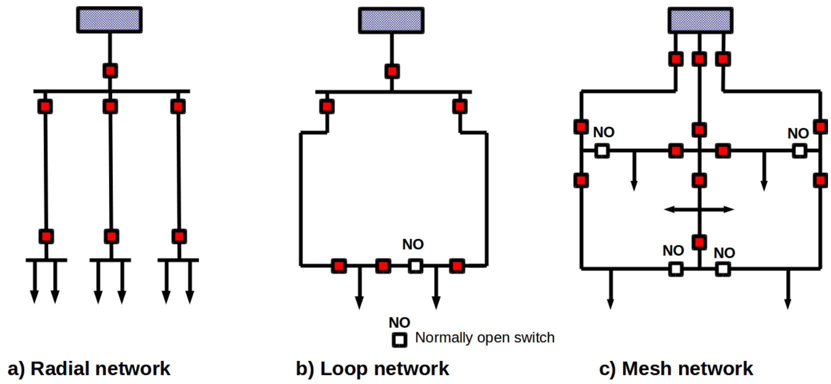



Figure 2: Concepts of power distribution system

**Radial Network Concept:** Most of distribution systems are designed to be radial. The power have only one way to flow from the substation to customers. In the case of interruption at a feeder of in the system, customers on that feeder will be disconnected completely. However, the radial structure are much less expensive than other structures and also more simpler in planning, designing and operating.

Moreover, other structures could easily be operated radially by opening switches at certain points throughout the network configuration as on Figure 2. Because the power flow is unidirectional from the substation to customers then voltage profile could be determined with high level of accuracy without resorting to complex calculation methods. If all data about equipment are known, the fault level can be predicted and protective devices as circuit breakers, relays and fuses can be coordinated in an proper manner. Nevertheless, the main drawback of radial network structure is less reliable than loop and mesh concepts.

**Loop Network Concept:** If the distribution system is designed with this concept, every customer will be provided by two different paths from the substations. This structure is preferred in many European utilities [8]. Loop structure is more complicated than radial because power usually flow from both side to the load. However, the loop system is more reliable than radial system. The main disadvantage is higher investment cost. Every path of the loop must be dimensioned to withstand the peak load demand for the case one path is fail and the system become radial network.

**Meshed Network Concept:** This is the most sophisticated concept but also the most reliable. A network involves multiple paths between all points in the network. Network cans provide continuity of service much higher than both loop and radial design. If fault happens in one line then power will be instantly and automatically supply by other paths. In the case of high density urban area, network structure might be the best option when repairs and maintenance are difficult. Obviously, meshed concept cost much more investment also analysis and operation is very difficult.

Because of the popularity of radial network and auspicious opportunity to introduce distributed generation into this network will be discussed latter. The radial network will be the subject for this work. Before investigating the distributed generation and its issues, next section will present briefly features and requirements of protection in radial network system.

## 1.3 Features of Protection system

Protection for power system is means identify the faults and undesirable conditions, then take the appropriated measure to isolate the fault in an accurate and selective manner by proper setting of relays and other protective devices. Power system spreads on very wide area of service; therefore, it is the target of many types of disturbance as showed in Figure 3.

Faults could be divided into several categories; however, the frequency of occurrence for each type is different. Ground fault or parallel fault is the most likely to happen. The series fault such as broken conductor or blow fuse are much less common. Single phase-to-ground fault and three-phase fault are the most severe cases depends on how ground connection used.

| **Types of faults** | **Occurrence** |
|---|---|
| Single phase-to-ground | 70% to 80% |
| Phase-to-phase-to ground | 17% to 10% |
| Phase-to-phase | 10% to 8% |
| Three-phase | 3% to 2% |

Table 2: Approximate percentage of occurrence for types of parallel fault [10]

During fault many quantities of the system are changed for example: overcurrent, over/under voltage, power, power factor, phases angle, power flow and current flow direction, line's impedance, frequency, temperature, physical movement, pressure and contamination of insulating quantities. Usually the quantity used to indicate the fault is current, the fault current magnitude is multiple times higher than the nominal current. Protection system is designed to recognizes and automatically take action against these negative impacts of faults.

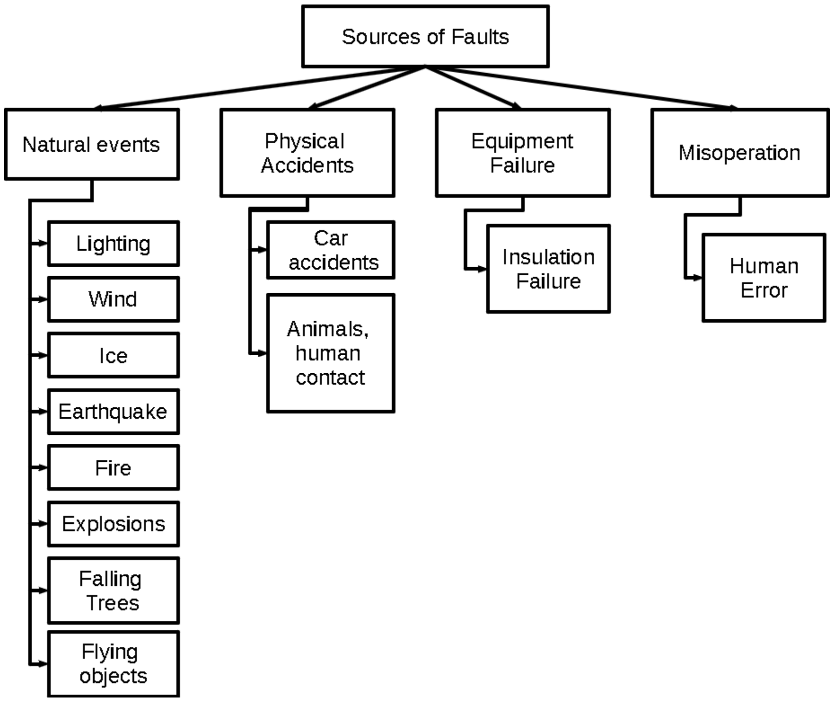



Figure 3: Sources of faults in power system [10]

Protection system must satisfy five main criteria [10]:

- **Reliability:** In order to reach high reliability the protection system must provide high level of dependability and security. The devices must operate correctly and the possibility of malfunction is very small. In general, the reliability of protective relays in power system is greater than 99%.
- **Selectivity:** Protective devices must have ability to discriminate the fault and healthy sections to disconnect only the problem one. Also devices must not only protect system against the highest short-circuit current ($I_{F-max}$) but also provide adequate protection for the lowest short-circuit current ($I_{F-min}$).
- **Speed:** Quickly isolate the affected section of the system in order to minimize the magnitude of the available short-circuit current and then, minimize potential damage to the system, its components, and the utilization equipment it supplies.
- **Simplicity:** The power system usually contains may components and equipments inside. Therefor, engineers should have a design with minimum protective equipment and

associated circuit to achieve the protection level.

- **Economics:** Cost is always one of the main consideration during designing process. The protectives devices such as circuit breakers are realizably expensive and usually does not working during normal condition. This preventive cost which seem to be not essential. However, the repairing cost to fix the consequences of fault will be much higher and fault cause problem which unmeasurable. Thus, a best design must be a combination between protection and minimize cost.

The protection system divided the power system into protective zones overlaying on each other. The protection of each zone contain of relays and also provide the back-up for the nearby protective zones. In Figure 4, typical protection zones are presented.

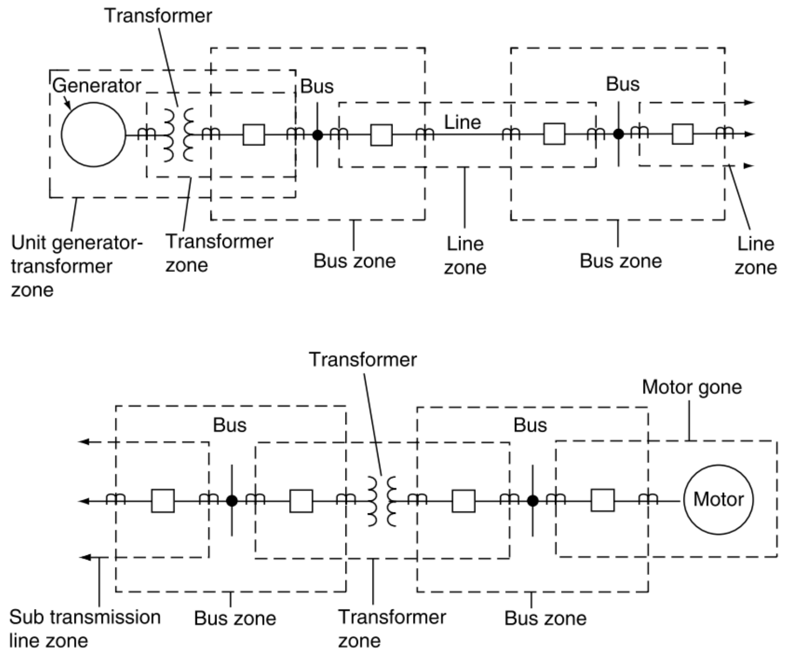



Figure 4: Typical relay primary protection zones in a power system [10]

This work focuses to line protection in radial network, which typical with source at only one terminal. During fault current to the fault only from this source. In order to meet criteria above, the distribution circuits are sectionalized with several fault interrupting devices. Those devices will be discuss in the next section.

## 1.4 Basic protective devices

Basis elements in protection system are: **Instrument transformers** (like current or voltage transformers), **Signaling devices** (overcurrent relay, directional relay, impedance relay, differential relay...), **Interrupting devices** (circuit breaker, fuse, recloser, sectionalizer) [11].

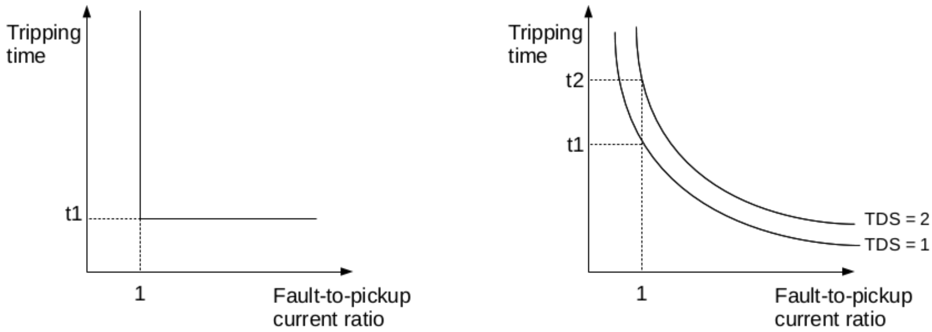



Figure 5: Definite and inverse-time overcurrent relay characteristics

***Current (Voltage) transformers*** reproduce a current (voltage) in its secondary winding. These secondary output has much smaller magnitude in comparison to primary, in CT (up to 5A) and in VT (up to 1V). This small magnitude of outputs guarantee safety for personal working with relay especially in case of isolated problem occurs. Other reasons are lower investment and cost of low voltage devices.

***Overcurrent relay*** detects short circuit current in power system. If the $I_{fault} > I_{pickup}$, the relay will signal circuit breaker to trip. In this work, the protective relays are used as inverse-time overcurrent relays which the tripping time vary response to the magnitude of the input current. Operation of inverse-time overcurrent is controlled by time-dial setting (TDS) see Figure 5.

Inverse time overcurrent relays are classified according their time-current characteristic curve as follow:

$$t_{trip} = TDS\left(\frac{K}{(\frac{I_p}{I_{pick-up}})^E - 1} + X\right) \tag{1}$$

Where

$I_p$ : Current sees by relay.

$I_{pickup}$ : Pick up current

$TDS$ : time-dial setting of relay

$K, E, X$ : Coefficients for different types of relay in Table 3

| | IEC | | ANSI | | |
|---|---|---|---|---|---|
| | **K** | **E** | **K** | **E** | **X** |
| **Normal inverse** | 0.14 | 0.02 | 8.9341 | 2.0938 | 0.17966 |
| **Very inverse** | 13.5 | 1 | 3.922 | 2 | 0.0982 |
| **Extremely inverse** | 80 | 2 | 5.64 | 2 | 0.02434 |
| **Long time inverse** | 120 | 1 | 5.6143 | 1 | 2.18592 |

Table 3: Characteristic of inverse time overcurrent relay [12]

## 1.5 Protection for radial system

Protective devices must be coordinated in the manner that when the fault occurs, the primary protective device which is located inside the protection zone will operate first. If they fail the various backup devices must operate and clear the fault by isolate the upstream protection zone.

The **coordinating time interval (CTI)** is the interval between the operation of protection devices at a near-fault location (R) and the protection devices at a upstream location (H) from the fault (see Figure 6). Thus, for the fault, the upstream devices operating times must be greater than the sum of the near-fault devices operating time and the CTI. Fault should be cleared by the near-fault protection device and backed up by the upstream devices. The typical CTI value are 0.2 to 0.5 seconds [11].

$$t_{upstream} \geq CTI + t_{near-fault} \tag{2}$$

Proper design for protection system require preparing and collecting data of the power system and other relative information as [10]:

- Single-line diagram of the power system and area involved
- Impedance and connections of the power equipment, system frequency, voltage and phase sequence.
- If possible, existing protection and problem records.
- Requirement for protection system (pilot, non pilot...)
- System fault analysis
- Maximum load and system swing limits
- CT and VT locations, connections and ratios.
- Future expansions expected or anticipated.

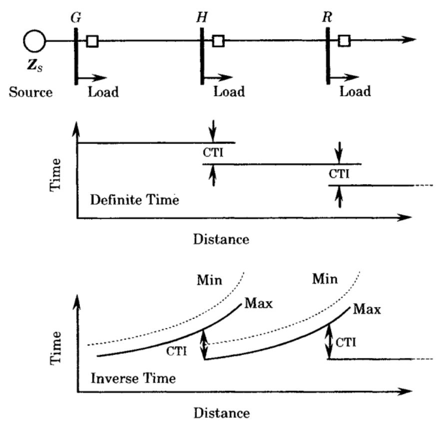



Figure 6: Radial protection characteristics of overcurrent relays [13]

This work focuses in how the distributed generation effects the protection system for radial network. Then for the first step the protective relays setting for test network without DG is compute to be a reference. The main characteristics of DG will be investigated in the next section.

## 1.6 Characteristic of distributed generations

Distributed generation is a common term which has the same meaning as embedded generation, dispersed generation and decentralized generation. It could be define as a source of electric power connected to the distribution network that has much smaller power size compare to central generating plants [14]. Many distributed generation exploits power from renewable energy with typical power range shows in Table 4.

| Type | Size |
|---|---|
| Photovoltaic panlels | 100 W - 100 kW |
| Wind power plant | 200 W - 5 MW |
| Fuel cells | 1 kW - 10 MW |
| Combined head and power | 10 kW - 10 MW |
| Battery storage | 100 kW - 5 MW |
| Gas turbine | 5 kW - 5 MW |
| Small hydropower plants | 35 kW - 5 MW |

Table 4: Typical overview of distributed generation technologies [15]

As part of the Kyoto Protocol [16] and recently Paris Agreement on climate change [17], many countries have to reduce substantially emission of $CO_2$ to help counter climate change. Hence most governments have programs to support renewable energy resources. The main motivation for using distributed generation from renewable energy was investigated by CIRED working group [9]:

- Reduction in gaseous emissions (mainly $CO_2$).
- Energy efficiency or ratilonal use of energy.
- Deregulation or competition policy.
- Diversification of energy sources.
- National power requirement.
- Availability of modular generating plant.
- Ease of finding sites for smaller generators.
- Short construction times and low capital cost of smaller plant.
- Generation may be sited closer to load, which may reduce transmission costs.

From the power system point of view, DG could be classified to the principles and interface between distribution network and the DG. The rough distinction of DG technologies is presented in Figure 7. Rotating machine DG as induction generator and synchronous generator could be connected directly to grid. Other DG technology generate voltage in DG form or AC form but under various magnitude and frequency. This kind of DG required inverter to change voltage and frequency to the nominal values.

In this work the different in technologies of DG will be ignored, the DG will be consider like an external power source connected to some points within the system. From literatures there are several issues when DG is installed had been expected and presented in the next section.

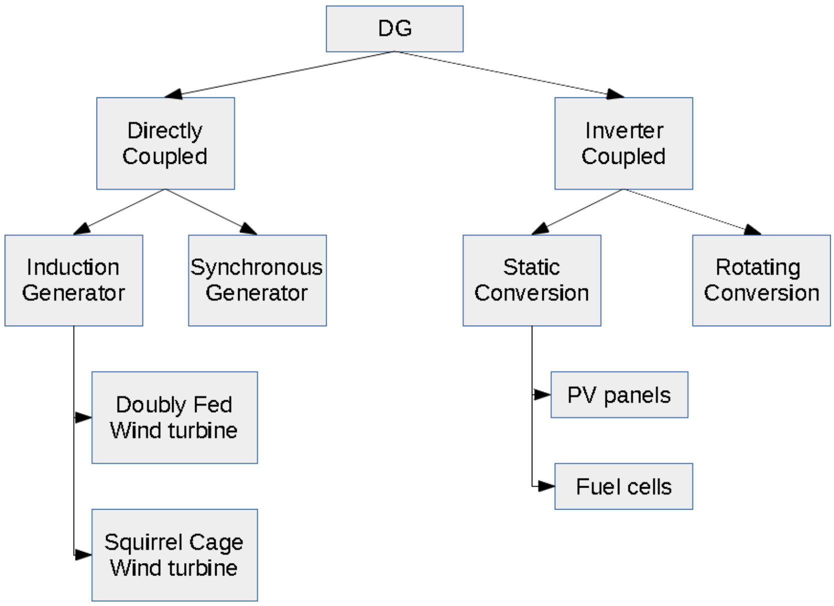



Figure 7: DG classification [5]

## 1.7 Problem with DG connected to power system

When DG is connected to distribution system will have impacts on several parameters of power system such as voltage profile, fault level, power quality, stability, operations and protection.

**Voltage profile:** To ensure the power quality or in other word remain voltage with specified limits. The capacity of DG which should not be exceed the limits as shown in Table-5.

| Network location | Maximum capactity of DG |
|---|---|
| $\leq 400V$ network | 50 kVA |
| $400V$ busbar | 200 - 250 kVA |
| 11 kv - 11.5 kV network | 2 - 3 MVA |
| 11.5 kV busbar | 8 MVA |
| 15kV - 20 kV network and busbar | 6.5 - 10 MVA |
| 63 kV - 90 kV network | 10 - 40 MVA |

Table 5: Limit of DG capacity on different distribution power system [9]

**Fault level:** DG usually be used under type of synchronous generator or induction generator. Those generators will contribute to the fault current when the fault occurs. To reduce the impact of DG on fault level, the transformers is introduced to separate DG from the network. Other method is using reactor; however, with the cost of power losses and larger voltage variations at DG terminal [4, 9].

**Power Quality:** DG can cause transient voltage variation on the network and especially during connecting and disconnecting large DG. However, DG also support the network voltage when fault occurs at the customer's side. The DG with power electronic interface may inject harmonic contents which can make unacceptable network voltage distortion [18].

**Stability:** the DG generate power rate up to kWh does not effect much to the power system. However, DG which is viewed as supporting for power system with significant power capacity, its transient stability must be carefully consider [10, 19].

**Network operation:** With DG presence, the circuit energized from many points throughout the network. This affect on policies of isolation and earthing for safety before work is undertaken. Also planning for maintenance and flexibility for work is reduced.

**Protection:** Many issues to protection of power system are consequence of changes in voltage profile, reversed power flow and fault level while DG is installed. Depending on location of installation the DG could create potential isolated operating area where the system is not designed to handle [5, 6]. Some of these problems will be discussed below:

- ***False tripping of feeders:*** This problem happens when DG is install on an adjacent branch will contribute to the fault current (Figure 8). This contributed current of DG could exceed the pick-up current of healthy branch and false tripping occur there.

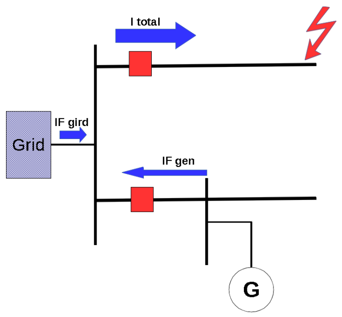



Figure 8: Principle of false tripping

- ***Nuisance tripping:*** This problem happens while the coordination margin between protective devices are set at too small values. With DG connection the transient current magnitude become larger an trip the backup device instead the primary one.

- ***Blinding of protection:*** The contribution of DG to the short-circuit current will reduce the contribution of grid to total fault current. This reduction could make the fault current from the grid smaller than pick-up current set on relay and cause blinding of protection problem (Figure 9).

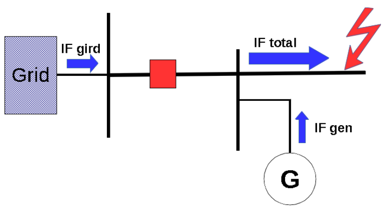



Figure 9: Principle of Blinding of protection

- ***Loss of coordination:*** This is the consequence of raising fault level in the network. Higher short-circuit current during fault causes relay operate in shorter interval and then the coordination margin between primary and backup relay could be loss (Figure 10).

- ***Unwanted islanding:*** Islanding state happen when DG start to supply the local loads even after disconnection of the grid. In most cases this phenomenon can occur unwanted and this may cause potential hazards to line men and equipment damage due to instability in voltage and frequency. The reconnection process also become more difficult and could lead to loss of synchronism problem [20].

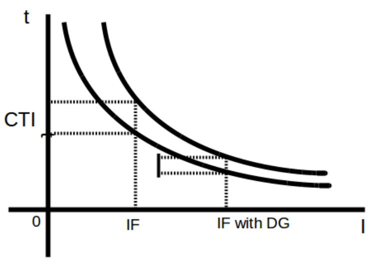



Figure 10: Principle of Loss Of Coordination

- ***Prohibition of automatic reclosing:*** Islanding and reclosing problem are closely related. When the autorecloser open the circuit the DG could still operates and sustain the fault current. This could prevent fault arc extinction and leads to unsuccessful reclose the circuit. The temporary fault become permanent fault and reliability of power system decrease significantly. Network component have to withstand more stress because circuit breaker must operate to clear the fault [21].

In this work, problem with protection system related to false tripping, blinding of protection and loss of coordination while DG is installed to the radial network will be investigated.

# 2 Relay setting for radial network

In this section, the objective is present a method to analysis the test power network and setting relays. The result will be consider as reference values to evaluate the influence of DG afterward.

All calculation in this work will be made in the Mathematica environment. Mathematica provides human friendly syntax structure and powerful tools for analyses.

## 2.1 Test Network and Proposed Methodology

The radial distribution system in the study is a 27.6 kV three-phase system base on a rural feed network [22, 3]. This type of network is chosen because of its promising potential to implement DG. The network has radial topology as well as large area of services and low density of loads provide opportunity to use DG for improvement system operation and reliability.

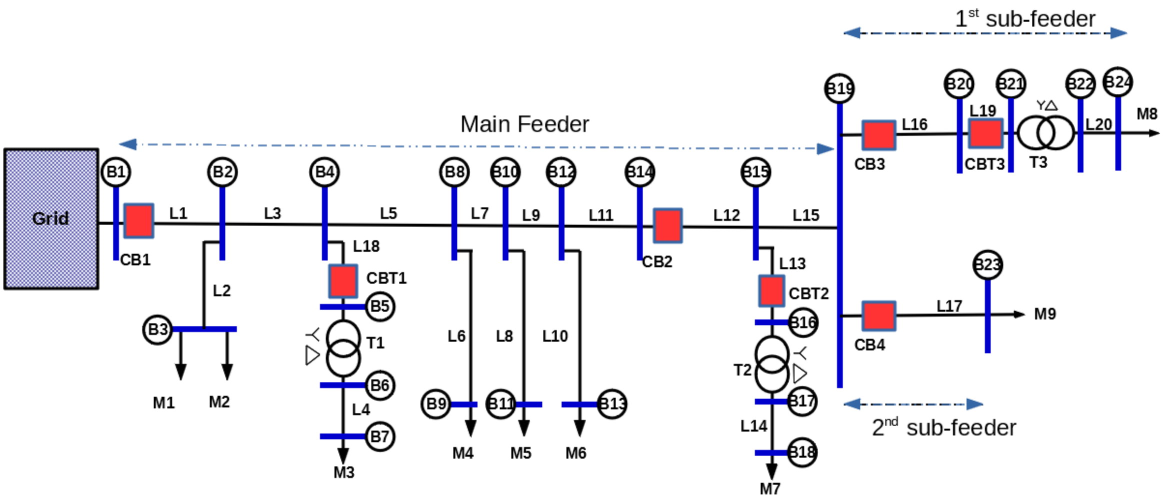



Figure 11: Single line diagram of test network

The system include several three-phase loads on the main feeder and two sub-feeders. The substation rating is 20 MVA and equivalent three-phase short circuit MVA is 885.33 MVA. There are 3 transformers (T1, T2, T3) and 9 loads in total. Single line diagram of the test network is shown of Figure 11. In order to further analysis, the test network is divided into 24 test buses (B1 to B24) and then 20 overhead line (L1 to L20) sections.

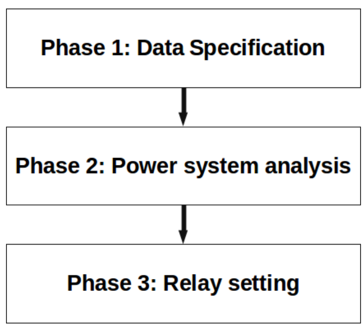



Figure 12: Methodology for network analysis

***Methodology*** will be used to analyze the test net-
work is a process with 3 phases. Firstly, the data of test network are collected. The necessary data about loads, lines and transformers will be recorded under proper format to be handle in the next phase. With the collected data, a program for load flow analysis and fault analysis will provide steady state condition as well as fault level information of the test network. Also the voltages and currents flow between buses are also found. Finally, setting of relays will be chosen based on the results of fault analysis.

The relays setting will ensure all faults will be interrupted within required time and all relays are coordinated with a proper manner. Detail and results of analysis will be presented in the next sections.

## 2.2 Phase 1: Data Specification

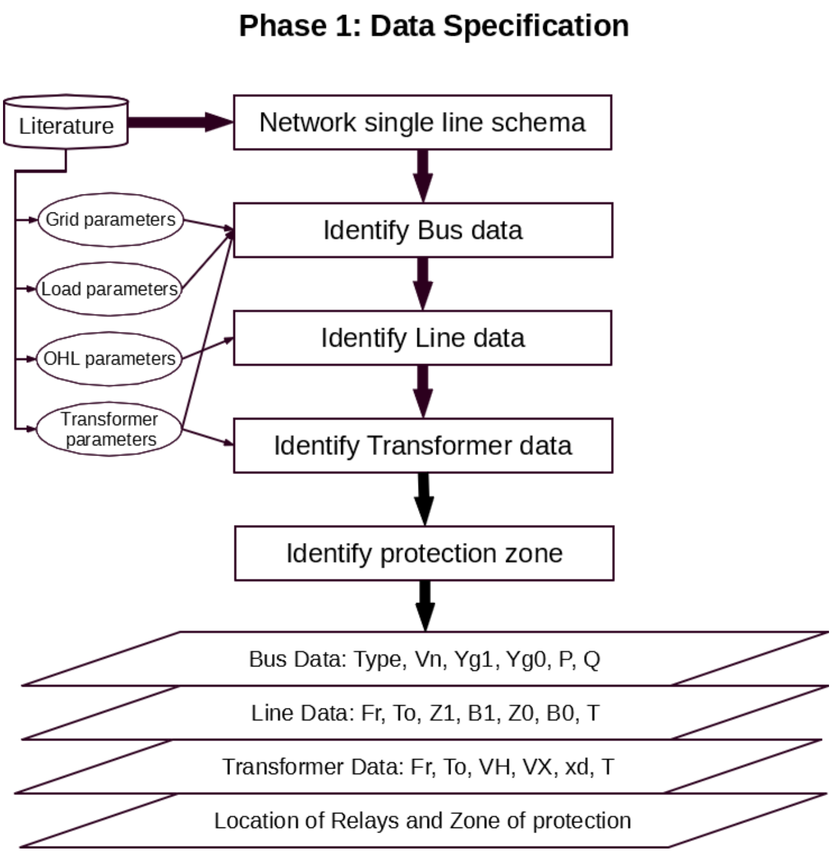



Figure 13: Flow chart - Phase 1: Data Specification

**Network single line schema** is shown in Figure 11. This the sample for a rural network each bus is a connection point of different over head line sections, transformers or loads.

***Identify bus data:*** Every bus has four variables related: voltage magnitude in RMS value and pu value ($V_{RMS}$, $V_{pu}$), phase angle $\delta$, real power P and reactive power Q supplied. The bus number 1 is the slack bus and also the place connected to the substation (grid). All other buses are consider like PQ buses. When bus is a load bus without generation, P and Q has negative values. The bus data is shown in Appendix B.

***Identify line data:*** ***Grid equivalent circuit*** is shown in Figure 14 similar for all sequence components. The substation (grid) has nominal capacity 20 MVA, nominal voltage 27.5kV(LL). Positive sequence equivalent resistance: $R_{1-Grid} = 0.027\Omega$, positive sequence equivalent reactance: $X_{1-Grid} = 0.86\Omega$. Zero sequence equivalent resistance $R_{0-Grid} = 0.07796\Omega$, zero sequence equivalent reactance: $X_{0-Grid} = 2.85\Omega$.

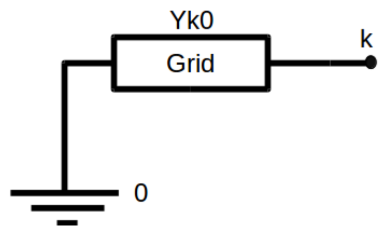



Figure 14: Grid equivalent circuit

The overhead lines are represented by the equivalent $\pi$ circuit (Figure 15). The overhead line type 336Al has positive parameters as: $r_1 = 0.1696\Omega/km$, $x_1 = 0.3809\Omega/km$, $b_1 = 4.33\mu S/km$ and negative parameter as: $r_0 = 0.4689\Omega/km$, $x_0 = 1.2808\Omega/km$, $b_0 = 1.90\mu S/km$. The test network have 20 line section denoted by L1 to L23 in Appendix B.

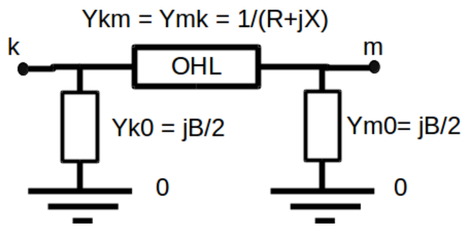



Figure 15: Overhead line equivalent circuit

The transformers positive sequence are represented by the $\pi$ equivalent circuit in Figure 17. The transformer connection is $Y - \Delta$, the equivalent circuit of zero sequence shown in Figure 16. The transformer data is shown in Appendix B.

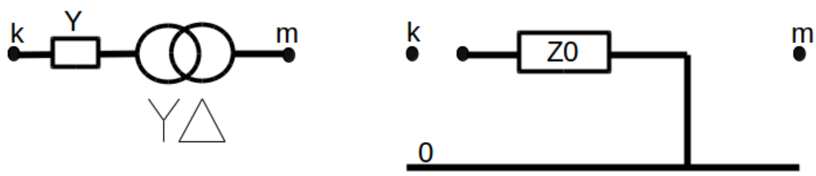



Figure 16: Transformer Zero sequence equivalent circuit

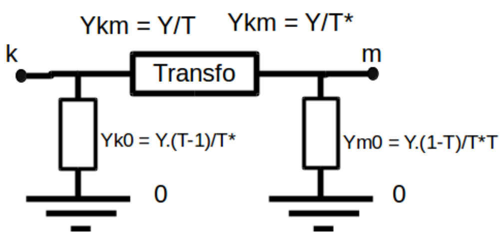



Figure 17: Transformer Positive sequence equivalent circuit [23]

***Identify protection zones:*** The test network will be separated into 7 protection zones base on location of protective relays (Figure 18).

- ***Zone 1:*** protects the first half of the main feeder and several branches with load without transformer.

- ***Zone 2:*** protects the branch with transformer T1 supplies for load M3.

- ***Zone 3:*** protect the second half of the main feeder which intersect with 2 sub-feeder.

- ***Zone 4:*** protects the branch with transformer T2 supplies for load M7.

- ***Zone 5:*** protects the overhead line of the $1^{st}$ sub-feeder.

- ***Zone 6:*** protects the end of the $1^{st}$ sub-feeder with the transformer T3 supplies for load M8

- ***Zone 7:*** protects the overhead line of the $2^{nd}$ sub-feeder.

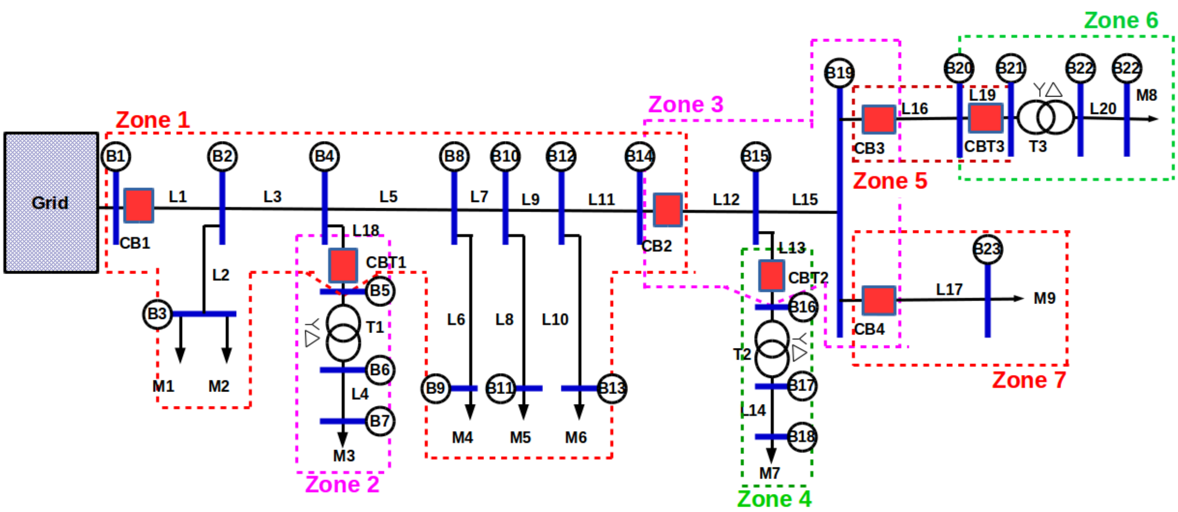



Figure 18: Protective zones of test power network

In further study, magnitude of currents be seen by the relays will be defined as the current flow on the line section where the relay is located. The maximum short circuit current flow though relays is when the fault occur at an location near to the from bus and behind the relay. All overcurrent relays are normal inverse (NI) type see Table 3 page 9.

| | on Line | From | To | Imax at | Protect Zone | Back up | Type |
|---|---|---|---|---|---|---|---|
| **CB1** | L1 | 1 | 2 | B1 | Zone 1 | - | NI |
| **CB2** | L12 | 14 | 15 | B14 | Zone 14 | CB1 | NI |
| **CB3** | L16 | 19 | 20 | B19 | Zone 5 | CB2 | NI |
| **CB4** | L17 | 19 | 23 | B19 | Zone 7 | CB2 | NI |
| **CBT1** | L18 | 4 | 5 | B5 | Zone 2 | CB1 | NI |
| **CBT2** | L13 | 15 | 16 | B16 | Zone 4 | CB2 | NI |
| **CBT3** | L19 | 20 | 21 | B20 | Zone 6 | CB3 | NI |

Table 6: Location and type of relays

## 2.3 Phase 2: Power system analysis

In this phase, the steady state and fault condition of the test network are analyzed. First, the load flow analysis is conducted using Newton-Raphson method. The input are network data gathered from phase 1 and the result will be steady-state voltage on each bus. Then with the steady-state voltage, the short circuit current of different type of fault are analyzed. The voltage and current flow during fault are also found.

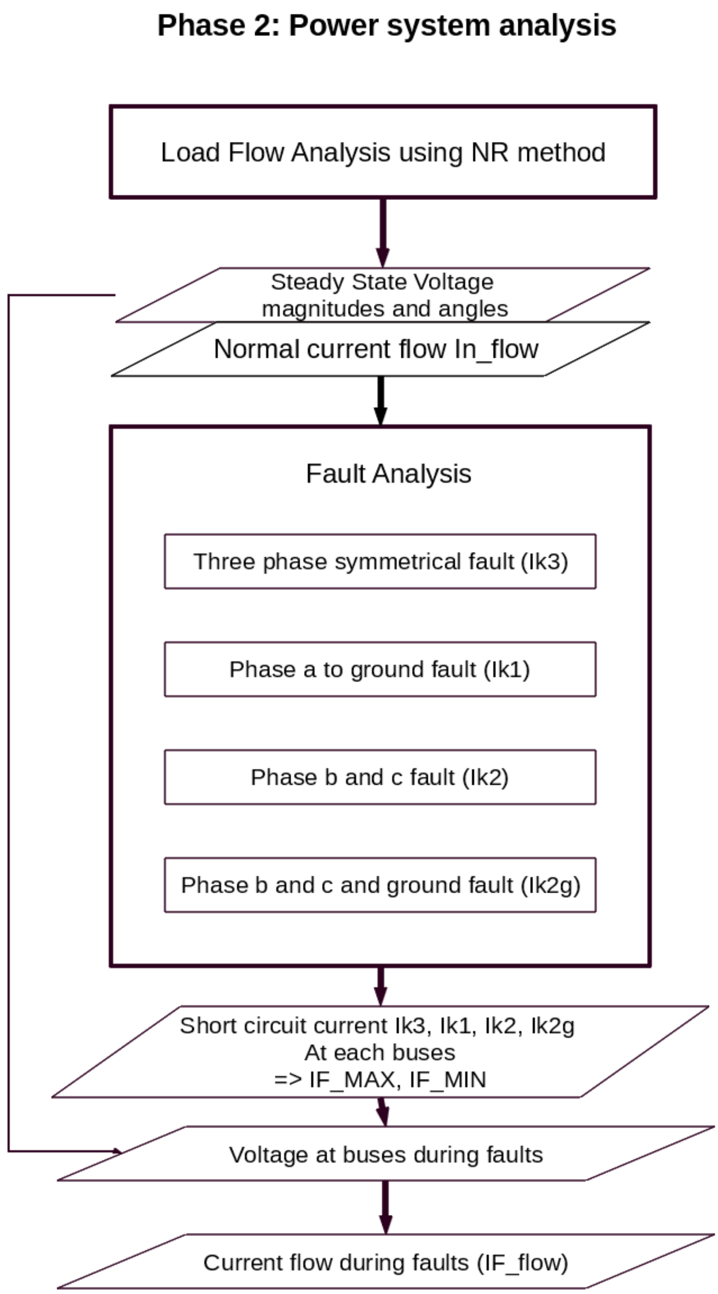



Figure 19: Flow chart - Phase 2: Power system analysis

### 2.3.1 Load flow analysis

Load flow analysis investigate the normal balanced three-phase steady-state condition of the power system. The analysis computes the voltage magnitude and angle at each bus in the system, and from those value the current flow in the system is calculated.

In this thesis the program for load flow analysis follow the Newton-Raphson's method. The method could be found in [11] and will be briefly described as follow:

We denote number of buses in the power system as N

Bus admittance matrix:

$$[Y_{bus}] = \begin{bmatrix} Y_{11} & \cdots & Y_{1N} \\ \vdots & \ddots & \vdots \\ Y_{N1} & \cdots & Y_{NN} \end{bmatrix} \tag{3}$$

Where

$$Y_{kk} = Y_{k0} + \sum_{i=1}^{N} \left( \frac{1}{R_{ki} + jX_{ki}} + j\frac{B_{ki}}{2} \right) \quad ; \quad k = 1, 2, ...N \ and \ i \neq k \tag{4}$$

$$Y_{kn} = \frac{-1}{R_{kn} + jX_{kn}} \quad k \neq n \tag{5}$$

Vectors for load flow analysis:

$$\vec{x} = \begin{bmatrix} \vec{\delta} \\ \vec{V} \end{bmatrix} ; \vec{y} = \begin{bmatrix} \vec{P} \\ \vec{Q} \end{bmatrix} ; \vec{f}(\vec{x}) = \begin{bmatrix} \vec{P}(\vec{x}) \\ \vec{Q}(\vec{x}) \end{bmatrix} \tag{6}$$

The slack bus variables of voltage ($V_1$) and angle ($\delta_1$) are omitted since they are given. Other bus's variables are calculated by equations:

$$P_k = P_k(\vec{x}) = V_k \sum_{n=1}^{N} Y_{kn} V_n \cos(\delta_k - \delta_n - \theta_{kn}) \tag{7}$$

$$Q_k = Q_k(\vec{x}) = V_k \sum_{n=1}^{N} Y_{kn} V_n \cos(\delta_k - \delta_n - \theta_{kn}) \tag{8}$$

$$k = 2, 3, \ldots, N$$

With the prepared data as above the NR method could be conducted with 4 Steps:

**Step 1:** Compute power mismatches at the *ith* iteration:

$$\Delta \vec{y(i)} = \begin{bmatrix} \Delta \vec{P(i)} \\ \Delta \vec{Q(i)} \end{bmatrix} = \begin{bmatrix} \vec{P} - \vec{P(i)} \\ \vec{Q} - \vec{Q(i)} \end{bmatrix} \tag{9}$$

**Step 2:** The Jacobian matrix is computed as:

$$[J] = \begin{bmatrix} \frac{\partial P_k}{\partial \delta_k} & \frac{\partial P_k}{\partial V_k} \\ \frac{\partial Q_k}{\partial \delta_k} & \frac{\partial Q_k}{\partial V_k} \end{bmatrix} \tag{10}$$

**Step 3:** Use Gauss elimination and back substitution to find phase angle and voltage mismatches

$$[J] \begin{bmatrix} \Delta\vec{\delta(i)} \\ \Delta\vec{V(i)} \end{bmatrix} = \begin{bmatrix} \Delta\vec{P(i)} \\ \Delta\vec{Q(i)} \end{bmatrix} \tag{11}$$

**Step 4:** Compute phase angle and voltage magnitudes of (i+1)th iteration

$$x(i\vec{+}1) = \begin{bmatrix} \delta(i\vec{+}1) \\ V(i\vec{+}1) \end{bmatrix} = \begin{bmatrix} \vec{\delta(i)} \\ \vec{V(i)} \end{bmatrix} + \begin{bmatrix} \Delta\vec{\delta(i)} \\ \Delta\vec{V(i)} \end{bmatrix} \tag{12}$$

The process is started with initial value x(0) (flat voltage condition) and continues until convergence or maximum number of iteration is reached. Convergence criteria are set as: $\Delta y(i) \leq \epsilon$. For the PV bus because we already know the $V_k$ values then the function $Q_k(\vec{x})$ are crossed from vector $\vec{y}$ as well as $V_k$ from vector $\vec{x}$. The result of power flow analysis is shown in Table 7, the base power is 1 MW and base voltages are taken as nominal voltage at buses.

| **Bus** | **1** | **2** | **3** | **4** | **5** | **6** |
|---|---|---|---|---|---|---|
| **Voltage [V]** | 1 | 0.972573 | 0.970521 | 0.970197 | 0.969089 | 0.969073 |
| **Angle [$^o$]** | 0 | -1.66793 | -1.7993 | -1.81813 | -1.88733 | -0.8751 |
| **Bus** | **7** | **8** | **9** | **10** | **11** | **12** |
| **Voltage [V]** | 0.934249 | 0.968931 | 0.968669 | 0.967927 | 0.9679 | 0.964669 |
| **Angle [$^o$]** | -3.09976 | -1.89961 | -1.90676 | -1.97407 | -1.97776 | -2.21041 |
| **Bus** | **13** | **14** | **15** | **16** | **17** | **18** |
| **Voltage [V]** | 0.964502 | 0.962572 | 0.960992 | 0.960894 | 0.962252 | 0.959068 |
| **Angle [$^o$]** | -2.22141 | -2.36573 | -2.48278 | -2.49581 | -2.48834 | -2.91083 |
| **Bus** | **19** | **20** | **21** | **22** | **23** | **24** |
| **Voltage [V]** | 0.960275 | 0.957741 | 0.957105 | 0.987686 | 0.959821 | 0.967861 |
| **Angle [$^o$]** | -2.53014 | -2.694 | -2.73499 | -2.20073 | -2.56178 | -3.45446 |

Table 7: Load Flow Results

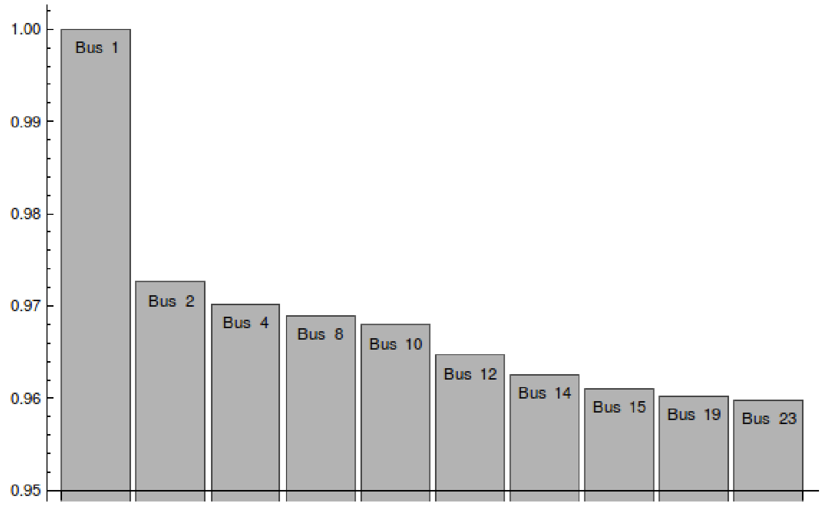



Figure 20: Voltage Profile on the main feeder and $2^{nd}$ sub-feeder

### 2.3.2 Fault analysis

The nature of fault in power system was discussed in section 2.3. Before computation some assumptions are taken for simplification as stated in standard IEC 60909-0 [24]:

- There is no change in type of fault during the short circuit.
- During the short circuit, there is no change in the network involved.
- The arc resistances are not taken in to consideration

#### Method of calculation with equivalent voltage source

In order to find the short circuit current, an equivalent voltage source is introduced at the short circuit location. This source is the only active voltage source of the system and all the network lines and machines are replaced by their internal impedances.

The positive-sequence impedance matrix $[Z_{bus-1}]$ is build by inverting $[Y_{bus}]$ matrix. The negative-sequence impedance matrix $[Z_{bus-2}]$ is assumed equal to $[Z_{bus-1}]$. The zero-sequence impedance $[Z_{bus-0}]$ is built from manufacture technical data.

Matrix diagonal element $Z_{nn}$ is used to find the total fault current and the other elements of the n-column $Z_{kn}$ are used to find other bus voltages and branch currents [25].

#### Three-phase fault calculation (k3)

The three-phase fault current at bus n depends on the diagonal impedance element $Z_{nn}$ of the impedance matrix which could be though as the impedance seen looking into the network at bus n with all buses expect the n-th bus open.

Three-phase fault sequence current at short circuit location bus-n is calculated as:

$$I_{n-1} = \frac{V_{n-pre}}{Z_{nn-1}} \quad ; \quad I_{n-0} = I_{n-2} = 0 \tag{13}$$

**Single line-to-ground fault calculation (k1)**

The sequence components of the fault currents at phase a :

$$I_{n-0} = I_{n-2} = I_{n-1} = \frac{V_{n-pre}}{Z_{nn-0} + Z_{nn-1} + Z_{nn-2} + 3Z_F} \tag{14}$$

In this work the author made a assumption $Z_F = 0$.

**Line-to-line fault analysis (k2)**

The sequence components of the fault currents at phase b and c:

$$I_{n-1} = -I_{n-2} = \frac{V_{n-pre}}{Z_{nn-1} + Z_{nn-2} + Z_F} \quad ; \quad I_{n-0} = 0 \tag{15}$$

In this work the author made a assumption $Z_F = 0$.

**Double line-to-ground fault analysis (k2g)**

The sequence components of the fault currents at phase b to c to ground:

$$I_{n-1} = \frac{V_{n-pre}}{Z_{nn-1} + \frac{Z_{nn-2}.(Z_{nn-0}+3Z_F)}{Z_{nn-2}+Z_{nn-0}+3Z_F}} \tag{16}$$

$$I_{n-2} = (-I_{n-1})\frac{Z_{nn-0} + 3Z_F}{Z_{nn-2} + Z_{nn-0} + 3Z_F} \tag{17}$$

$$I_{n-0} = (-I_{n-1})\frac{Z_{nn-2}}{Z_{nn-2} + Z_{nn-0} + 3Z_F} \tag{18}$$

In this work the author made a assumption $Z_F = 0$.

**Phase short circuit currents calculation**

Using the transformation we can find the line current on each phase from the sequence components currents calculated above.

$$\begin{bmatrix} I_a \\ I_b \\ I_c \end{bmatrix} = \begin{bmatrix} 1 & 1 & 1 \\ a^2 & a & 1 \\ a & a^2 & 1 \end{bmatrix} \cdot \begin{bmatrix} I_1 \\ I_2 \\ I_3 \end{bmatrix} \tag{19}$$

Where

$$a = \frac{-1}{2} + j\frac{\sqrt{3}}{2} \tag{20}$$

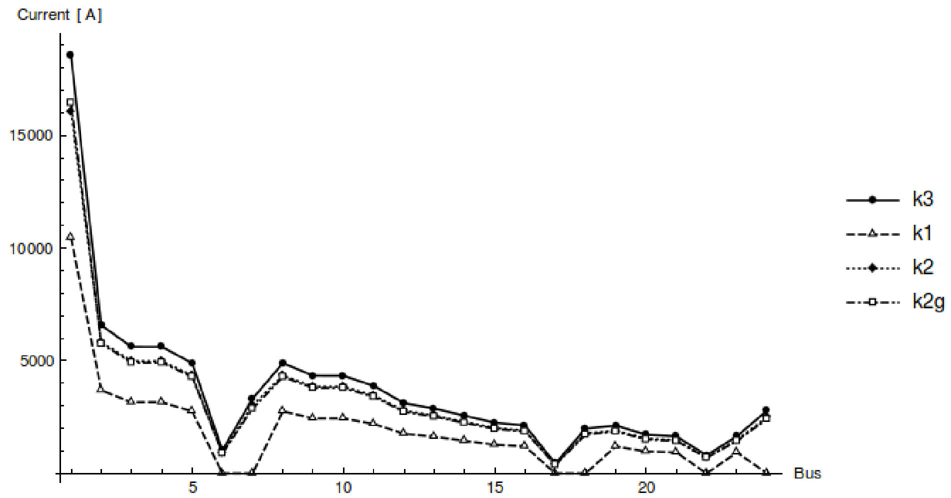



Figure 21: Short circuit current profile for different type of faults

The detail results of short-circuit current at every bus is shown in the Appendix section. The Figure 21 shows the magnitude of short-circuit current at every buses in the network. The nearer to the grid, the fault is more dangerous to the network with higher short-circuit current. The single phase to ground fault (k1) at buses 5, 6, 17, 18, 22, 24 are zero because of there are no ground connection.

### Faulted bus voltage calculation

The line-to-ground voltage at any bus k during a fault at bus n in the power system

$$\begin{bmatrix} V_{k-0} \\ V_{k-1} \\ V_{k-2} \end{bmatrix} = \begin{bmatrix} 0 \\ V_{k-pre} \\ 0 \end{bmatrix} - \begin{bmatrix} Z_{kn-0} & 0 & 0 \\ 0 & Z_{kn-1} & 0 \\ 0 & 0 & Z_{kn-2} \end{bmatrix} \cdot \begin{bmatrix} I_{n-0} \\ I_{n-1} \\ I_{n-2} \end{bmatrix} \tag{21}$$

similar to current, the phases voltage is found by transformation:

$$\begin{bmatrix} V_a \\ V_b \\ V_c \end{bmatrix} = \begin{bmatrix} 1 & 1 & 1 \\ a^2 & a & 1 \\ a & a^2 & 1 \end{bmatrix} \cdot \begin{bmatrix} V_1 \\ V_2 \\ V_3 \end{bmatrix} \tag{22}$$

**Short circuit currents on branches**

The current from bus k to bus n:

$$I_{kn-0} = (V_{k-0} - V_{n-0})/\bar{z}_{kn-0} \quad (23)$$

$$I_{kn-1} = (V_{k-1} - V_{n-1})/\bar{z}_{kn-1} \quad (24)$$

$$I_{kn-2} = (V_{k-2} - V_{n-2})/\bar{z}_{kn-2} \quad (25)$$

Where:

$\bar{z}_{kn}$ is the line impedance between bus k and n

Detail analyzed results for voltage and current flow on the system during fault at every bus could be found in the CD attached with this work.

## 2.4 Phase 3: Relay Setting procedure

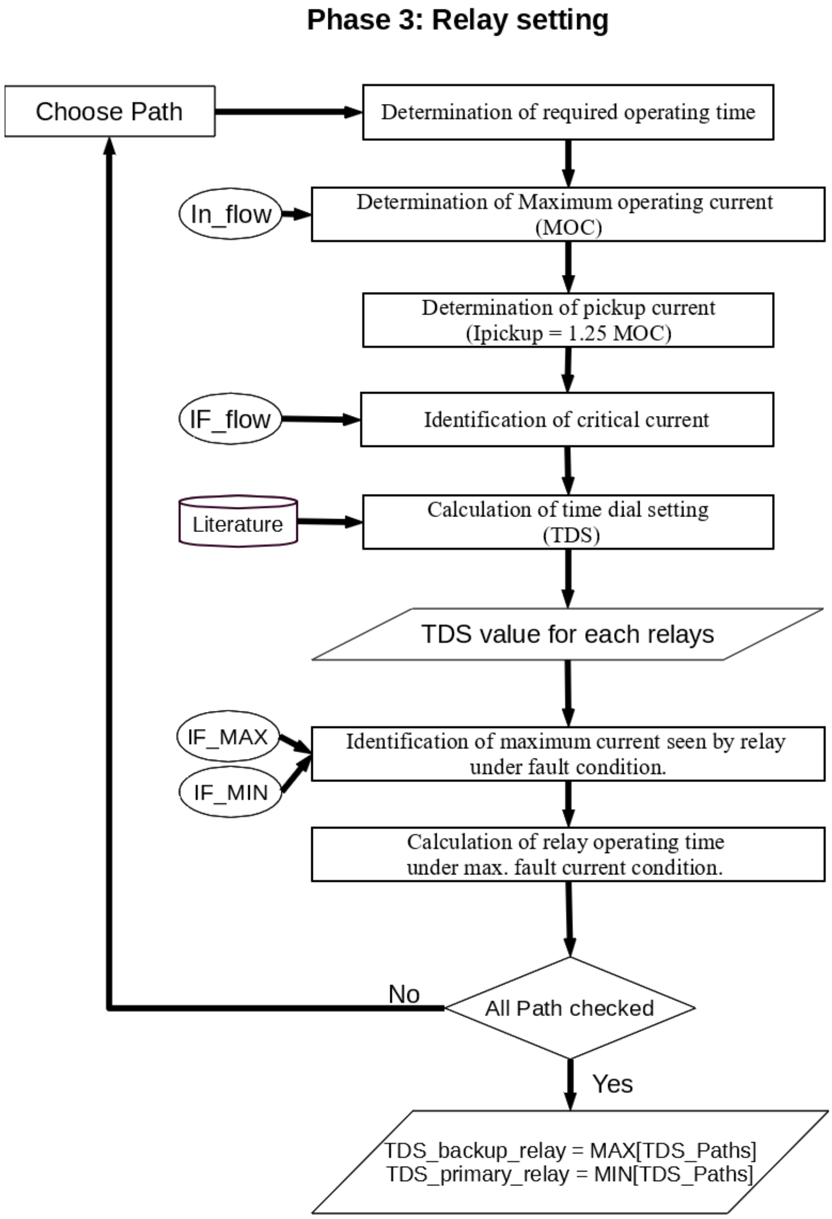



Figure 22: Flow chart Phase 3: Relay setting

Successful relay operation is achieved when a fault is isolated while disconnecting the smallest necessary portion of feeder. For the radial case, this is realized through the opening of the closest relay from fault. Fault locations inside the circuit breakers are not considered. Method to determine relay setting can be summarized in the following step (Figure 22):

**Step 1: Define different protection coordination paths**

There are four coordination path is defined based on location of relays, the detail schema could be seen in section 3.5.

- **Path A** include buses 1, 2, 4, 8, 10, 12, 14, 15, 19, 20, 21, 22, 24.
- **Path B** include buses 1, 2, 4, 8, 10, 12, 14, 15, 19, 23.
- **Path C** include buses 1, 2, 4, 5, 6, 7.
- **Path D** include buses 1, 2, 4, 8, 10, 12, 14, 15, 16, 17, 18.

**Step 2: Determine of required operating time**

Operating time of circuit breaker is 5 cycles: $t_{breaker} = 0.1s$

Desired coording time between 2 protection zones $t_{Coor} = 0.2s$

The overcurrent relays are normal inverse type.

Relay response of CB4, CBT1, CBT2, CBT3 must be as fast as possible and set as 0.05s

**Step 3: Determination of Maximum operating current (MOC)**

The maximum operating current of load under normal condition can be calculated by load flow solution using formula:

$$MOC_{ij} = Y_{ij}(V_i - V_j) \tag{26}$$

Result shows MOC values of the line sections where relays are placed (see Table 6 page 20)

| Relay | CB1 | CB2 | CB3 | CB4 | CBT1 | CBT2 | CBT3 |
|---|---|---|---|---|---|---|---|
| **MOC [A]** | 248.7504 | 49.65905 | 35.67412 | 5.333192 | 61.60669 | 9.156889 | 40.1072 |

Table 8: Maximum Operating Current

**Step 4: Determination of pickup current**

Pickup current decide when the relay start to operate, the value of $I_{pickup}$ will be set by 25% higher than maximum operating current to ensure the short-circuit current would be eliminate fast.

$$i_{pickup} = 1.25.|MOC| \tag{27}$$

Figure 9 present the setting value for pickup current on each relay.

| Relay | CB1 | CB2 | CB3 | CB4 | CBT1 | CBT2 | CBT3 |
|---|---|---|---|---|---|---|---|
| $i_{pickup}$ **[A]** | 310.938 | 62.07381 | 44.59265 | 6.66649 | 77.00836 | 11.44611 | 50.13399 |

Table 9: Pickup currents setting

The pickup current must not higher than the minimum short circuit currents as stated in [26]:

$$I_{nominal} < I_{pickup} < I_{sc-Min} \tag{28}$$

The minimum short circuit current see by relays are found when apply 1 phase to ground fault at the farthest bus inside protective zones counted from the grid.

| **Relay** | **CB1** | **CB2** | **CB3** | **CB4** | **CBT1** | **CBT2** | **CBT3** |
|---|---|---|---|---|---|---|---|
| $i_{MIN}$ **[A]** | 1449.465 | 1202.806 | 975.9899 | 934.5198 | 2756.51 | 1203.678 | 931.8767 |

Table 10: Minimu short circuit currents

By comparing the Figure.10 and Figure.9 it can be concluded that the pickup currents are appropriate for all fault conditions.

**Step 5: Identification of critical current $I_{critical}$**

The maximum current observed by the relay for a fault in the next downstream relay's zone of protection.

| | $I_{critical}$ **[A]** **Path A** | $I_{critical}$ **[A]** **Path B** | $I_{critical}$ **[A]** **Path C** | $I_{critical}$ **[A]** **Path D** |
|---|---|---|---|---|
| **CB1** | 2818.312 | 2818.312 | 5180.343 | 2818.312 |
| **CB2** | 2240.563 | 2240.563 | - | 2240.597 |
| **CB3** | 1740.204 | - | - | - |
| **CB4** | - | 2123.126 | - | - |
| **CBT1** | - | - | 4893.963 | - |
| **CBT2** | - | - | - | 2124.563 |
| **CBT3** | 1643.034 | - | - | - |

Table 11: Critical currents on each Coordination path

**Step 6: Calculation of time dial setting (TDS)**

TDS value is derived from equation 30:

$$TDS = t_{trip} \left( \frac{0.14}{(\frac{I_{critical}}{i_{pickup}})^{0.02} - 1} \right)^{-1} \tag{29}$$

| | TDS Path A | TDS Path B | TDS Path C | TDS Path D |
|---|---|---|---|---|
| **CB1** | 0.305847 | 0.209264 | 0.144683 | 0.209264 |
| **CB2** | 0.345233 | 0.185895 | - | 0.185896 |
| **CB3** | 0.19009 | - | - | - |
| **CB4** | - | 0.043635 | - | - |
| **CBT1** | - | - | 0.030922 | - |
| **CBT2** | - | - | - | 0.039331 |
| **CBT3** | 0.025816 | - | - | - |

Table 12: Time dial setting values for each specific paths

**Step 7: Identification of maximum current seen by relay under fault condition** $I_{Fmax}$

Maximum fault current is found by fault analysis of the power system.

| Relay | CB1 | CB2 | CB3 | CB4 | CBT1 | CBT2 | CBT3 |
|---|---|---|---|---|---|---|---|
| $i_{MAX}$ [A] | 18519.72 | 2560.827 | 2123.126 | 2123.126 | 4893.963 | 2124.563 | 1643.034 |

Table 13: Maximum short circuit currents

**Step 8: Calculation of relay operating time under maximum fault current condition** $t_{trip_{max}}$

Inverse time overcurrent relays are classified according their characteristic curve as follow:

$$t_{trip} = TDS \frac{0.14}{(\frac{I_p}{I_{pick-up}})^{0.02} - 1} \tag{30}$$

| | **TDS Path A** | **TDS Path B** | **TDS Path C** | **TDS Path D** |
|---|---|---|---|---|
| **CB1** | 0.502722 | 0.343968 | 0.237817 | 0.343968 |
| **CB2** | 0.625807 | 0.336973 | - | 0.336974 |
| **CB3** | 0.331313 | - | - | - |
| **CB4** | - | 0.05 | - | - |
| **CBT1** | - | - | 0.05 | - |
| **CBT2** | - | - | - | 0.05 |
| **CBT3** | 0.05 | - | - | - |

Table 14: Operating times during Maxium short circuit currents

**Step 9: Comparison of TDSs to decide final TDSs**

After running relay setting process for each path, the TDS value of relays for each individual path are found. Then final TDS values must be evaluate to ensure proper coordination for all network.

The primary protective relay (CB4, CBT1, CBT2, CBT3) must reacts as fast as possible then the smallest TDS value from each paths should be chosen.

$$TDS_{primary-protection} = Min[TDS_{Path-i}] \tag{31}$$

However, backup protective relay (CB1, CB2,CB3) should operate in the manner to keep the coordination of all devices. Then the highest TDS values should be chosen.

$$TDS_{backup-protection} = Max[TDS_{Path-i}] \tag{32}$$

| **Relay** | **CB1** | **CB2** | **CB3** | **CB4** | **CBT1** | **CBT2** | **CBT3** |
|---|---|---|---|---|---|---|---|
| **TDS** | 0.3058 | 0.3452 | 0.1900 | 0.04364 | 0.03092 | 0.03938 | 0.0258 |

Table 15: Final TDS values setting for relays

## 2.5 Results for relay setting and verification

### Result for coordination path A

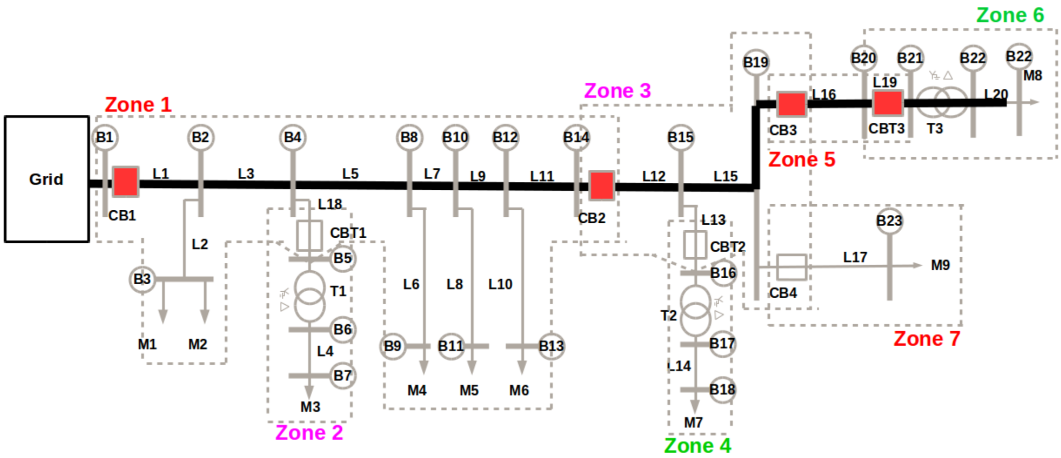



Figure 23: Schema of coordinated Path A

Figure 24 below shows the setting for relays on Path A. Path A is the path with the most number of relays (CB1, CB2, CB3, CBT3); therefore, such as discussed before the TDS setting were found. The selectivity between $t_{trip}$ of primary and backup relay are always equal to coordination time $t_{breaker} + t_{coor} = 0.1s + 0.2s = 0.3s$. Also the pickup current of each relays and tripping time while maximum short circuit current was found.

| Path A - final | | | | | | | |
|---|---|---|---|---|---|---|---|
| | MOC | iPickup | iCritical | $t_{trip}$ final | TDS | $I_{Max}$ | $t_{trim}$ at $I_{Max}$ |
| CBT3 | 40.107 | 50.134 | 1643. | 0.05 | 0.025816 | 1643. | 0.05 |
| CB3 | 35.674 | 44.593 | 1740.2 | 0.35 | 0.19009 | 2123.1 | 0.33131 |
| CB2 | 49.659 | 62.074 | 2240.6 | 0.65 | 0.34523 | 2560.8 | 0.62581 |
| CB1 | 248.75 | 310.94 | 2818.3 | 0.95 | 0.30585 | 18 520. | 0.50272 |

Figure 24: Final Setting for Relays on Path A

To verify the coordination of relays on Path A, relay responses during the fault at bus 21 is show in Figure 25. This fault causes the maximum fault current through CBT3. In that figure, the relay CBT3 response after 0.0492s, the the backup relay for CBT3 is CB3 response after 0.35s in case CBT3 fail. Similarity for CB2 is 0.7s and CB1 is 1.17s. The coordination margin 0.3s shown in Gray color after the moment relays response. The same test had been taken for fault at the nearest and furthest bus on each protec-

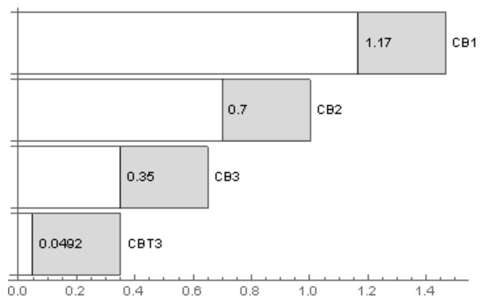



Figure 25: Relay response for fault at Bus 20

tion zones. Results show coordination between relays is always kept.

### Result for coordination path B

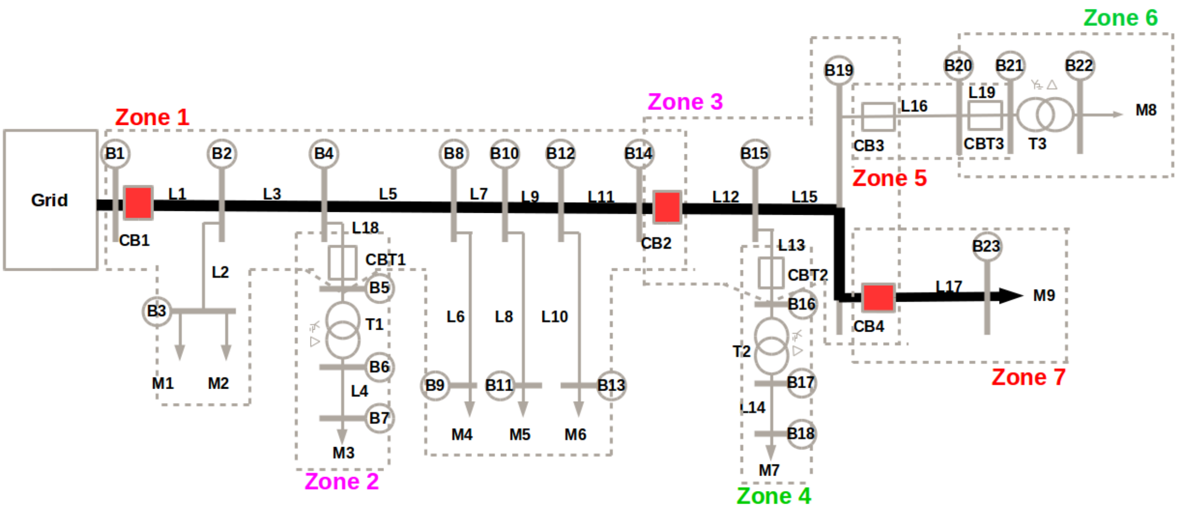



Figure 26: Schemta for coordinated Path B

Figure 27 below shows the setting for relays on Path B. In this path, there are 3 relays (CB1, CB2, CB4) located. The selectivity between $t_{trip}$ of primary and backup relay are always equal or longer than coordination time $t_{breaker} + t_{coor} = 0.1s + 0.2s = 0.3s$. Also the pickup current of each relays and tripping time while maximum short circuit current was found.

| Path B- final | | | | | | | |
|---|---|---|---|---|---|---|---|
| | MOC | iPickup | iCritical | $t_{trip}$ final | TDS | $I_{Max}$ | $t_{trim}$ at $I_{Max}$ |
| CB4 | 5.3332 | 6.6665 | 2123.1 | 0.05 | 0.043635 | 2123.1 | 0.05 |
| CB2 | 49.659 | 62.074 | 2240.6 | 0.65 | 0.34523 | 2560.8 | 0.62581 |
| CB1 | 248.75 | 310.94 | 2818.3 | 0.95 | 0.30585 | 18 520. | 0.50272 |

Figure 27: Final Setting for Relays on Path B

To verify the coordination of relays on Path B, relay responses during the fault at bus 23 is show in Figure 28. In that figure, the relay CB4 response after about 0.052s, if CB4 fail then CB2 will operates after 0.7s. And if CB2 fail to operate then CB1 will response after 1.17s. The coordination margin 0.3s shown in Gray color after the moment relays response. The same test had been taken for fault at the nearest and furthest bus on each protection zones. Results show coordination between relays is always kept.

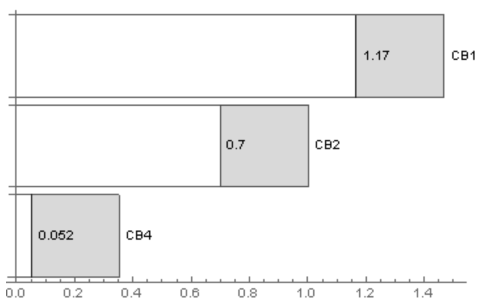



Figure 28: Relay response for fault at bus 19

### Result for coordination path C

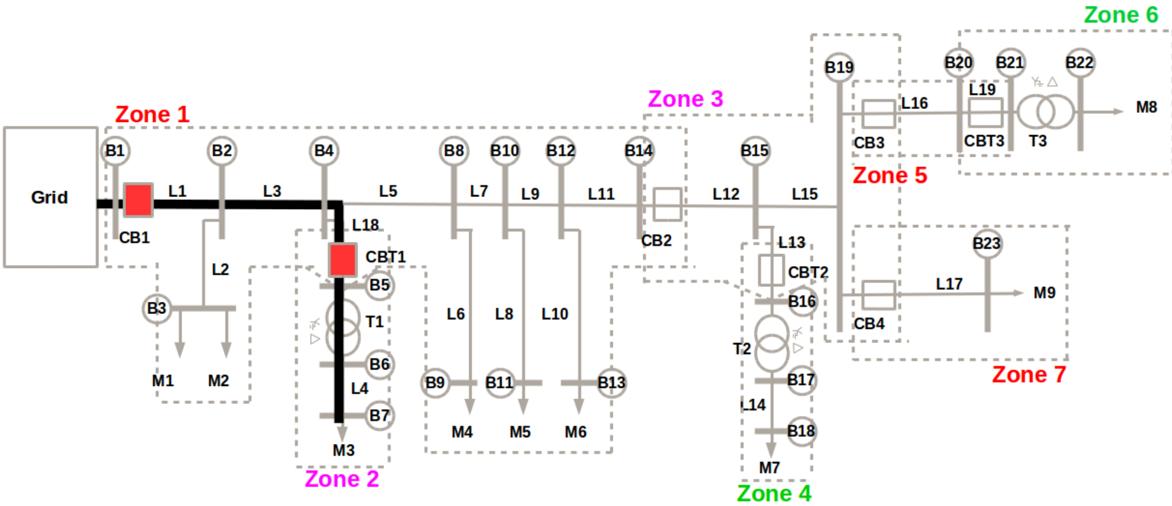



Figure 29: Schemta for coordinated Path C

Figure 30 below shows the setting for relays on Path C. In this path, there are 2 relays (CB1, CBT1) located. The selectivity between $t_{trip}$ of primary and backup relay are much longer than coordination time $t_{breaker} + t_{coor} = 0.1s + 0.2s = 0.3s$. Also the pickup current of each relays and tripping time while maximum short circuit current was found.

| Path C- final | | | | | | | |
|---|---|---|---|---|---|---|---|
| | MOC | iPickup | iCritical | $t_{trip}$ final | TDS | $I_{Max}$ | $t_{trim}$ at $I_{Max}$ |
| CBT1 | 61.607 | 77.008 | 4894. | 0.05 | 0.030922 | 4894. | 0.05 |
| CB1 | 248.75 | 310.94 | 5180.3 | 0.73987 | 0.30585 | 18 520. | 0.50272 |

Figure 30: Final Setting for Relays on Path C

To verify the coordination of relays on Path C, relay responses during the fault at bus 5 is show in Figure 31. Fault at this position cause the largest short circuit current to Zone 2. The CBT1 will response after about 0.0495 and the backup relay CB1 operate after 0.74s. The same test had been taken for fault at the nearest and furthest bus on each protection zones. Results show coordination between relays is always kept.

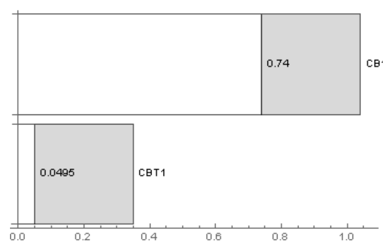



Figure 31: Relay response for fault at bus 5

### Result for coordination path D

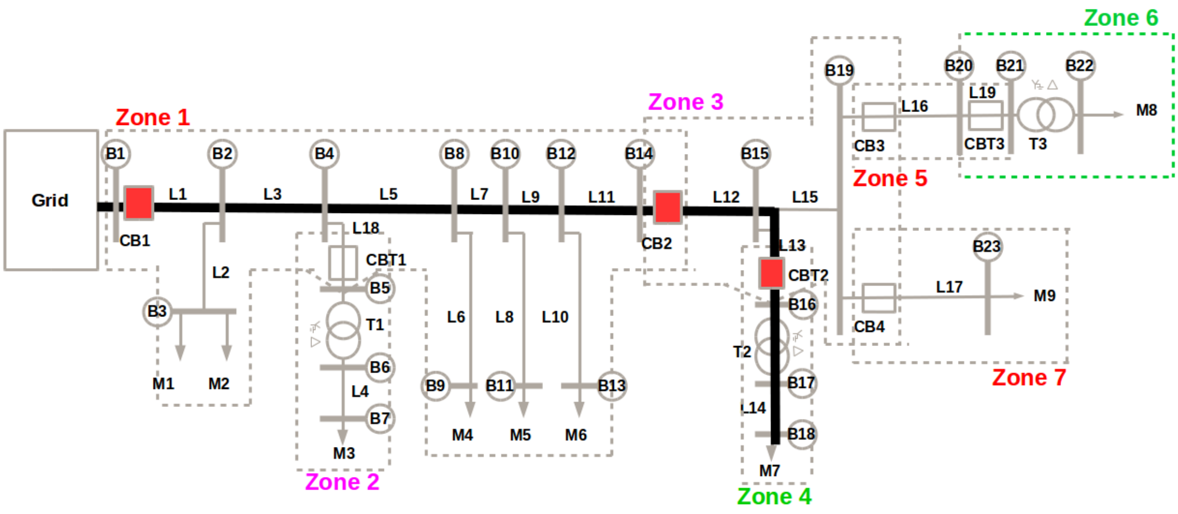



Figure 32: Schemta for coordinated Path D

Figure 33 below shows the setting for relays on Path D. In this path, there are 3 relays (CB1, CB2, CBT2) located. The selectivity between $t_{trip}$ of primary and backup relay are always equal or longer than coordination time $t_{breaker} + t_{coor} = 0.1s + 0.2s = 0.3s$. Also the pickup current of each relays and tripping time while maximum short circuit current was found.

| Path D- final | | | | | | | |
|---|---|---|---|---|---|---|---|
| | MOC | iPickup | iCritical | $t_{trip}$ final | TDS | $I_{Max}$ | $t_{trim}$ at $I_{Max}$ |
| CBT2 | 9.1569 | 11.446 | 2124.6 | 0.05 | 0.039331 | 2124.6 | 0.05 |
| CB2 | 49.659 | 62.074 | 2240.6 | 0.65 | 0.34523 | 2560.8 | 0.62581 |
| CB1 | 248.75 | 310.94 | 2818.3 | 0.95 | 0.30585 | 18 520. | 0.50272 |

Figure 33: Final Setting for Relays on Path D

To verify the coordination of relays on Path D, relay responses during the fault at bus 16 is show in Figure 34. In that figure, the relay CBT2 response after about 0.0792s, if CBT3 fail then CB2 will operates after 0.65s. And if CB2 fail to operate then CB1 will response after 1.03s. The coordination margin 0.3s shown in Light Gray color after the moment relays response. The same test had been taken for fault at the nearest and furthest bus on each protection zones. Results show coordination between relays is always kept.

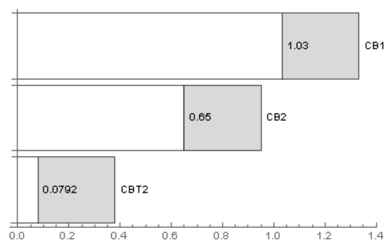



Figure 34: Relay response for fault at bus 16

# 3 Impact of single DG on radial network protection

As discussed in section 1.3, the installation of DG into traditional radial distribution network could leads too several problems, such as [27]:

- Reverse power flow from DG, during fault condition or even in normal condition.
- False tripping of healthy feeders due to fault being fed from the DG connected to a healthy feeder
- Blinding of protection caused by decrease of fault current contributed by the grid.
- Loss of coordination of over-current protective devices such as fuse-fuse coordination, fuse-relay coordination and relay-relay coordination due to DG penetration in a radial distribution networks.

The problem effects depend on the location, where DG is connected and also on the penetration level of DG. In this work, problems with fault tripping, blinding of protection and loss of coordination will be examined. Other problem with islanding operation of DG also is not the subject of this study.

## 3.1 Process for analysis DG impacts

In order to analysis the impacts of DG on network protection system, a process contains 8 steps is introduced:

- **Step 1: Determine DG Location**

  There are 4 case studies will be conducted depends on location inserted DG.

  ◇ Case 1: DG is installed at the end of the $2^{nd}$ sub-feeder (Bus 23).

  ◇ Case 2: DG is installed at the end of the main feeder (Bus 19).

  ◇ Case 3: DG is installed at the middle of the network (Bus 14).

  ◇ Case 4: DG is installed at the beginning of the network (Bus 4).

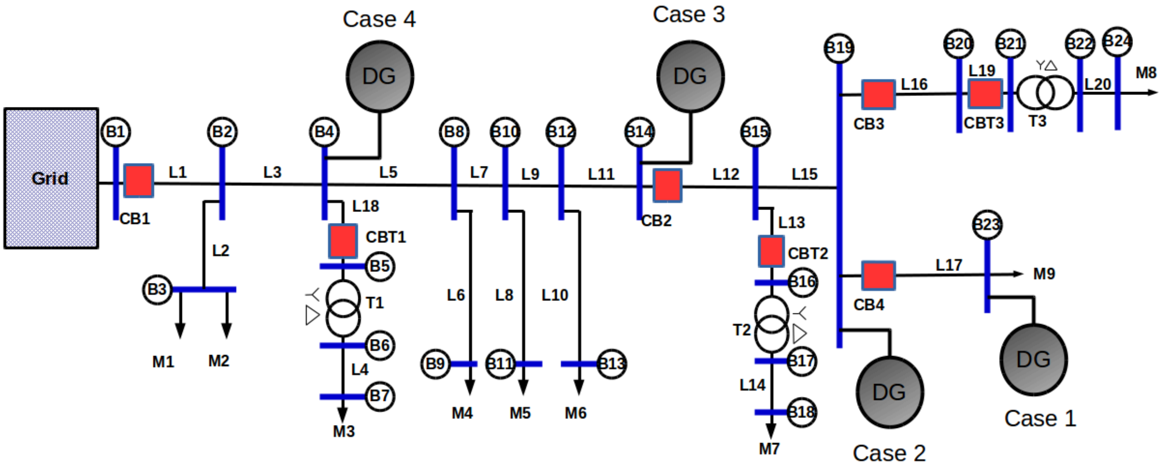



Figure 35: Location for installation of DG

- **Step 2: Determine DG Penetration level**

  DG penetration level are 5%, 10%, 30% and 50%. Penetration level of DG will be limited to 50% of total demanded power. The larger penetration level are difficult to reach for this radial network and not likely to concentrate at only one individual bus.

- **Step 3: Conduct load flow analysis**

  The process for this step had been discussed in section 2.3.1. After load flow analysis the change in voltage profile will be recored. This result will help to indicate the most desirable location for DG.

- **Step 4: Conduct fault analysis**

  This analysis follow process in section 2.3.2 result from this analysis will be used for further examinations.

- **Step 5: Examine problem with False tripping**

  ◇ ***Condition***: False tripping problem happen only if DG is connected to sub-feeder (Figure 9).

  ◇ ***Subject***: Relay at the healthy sub-feeder could mis-operates during fault at the neighbor sub-feeder.

  ◇ ***Cause***: Reverse current from DG at the healthy sub-feeder.

  ◇ ***Test method***: Check the current flow direction at the healthy sub-feeder with DG by comparing phase angle of currents during fault [10, 28]. Then calculate the short circuit current contribution of DG during 3 phase fault and compare with pickup current. If the tripping time of relay on the sub-feeder with fault slower than tripping time at healthy sub-feeder, then the tripping problem occurs.

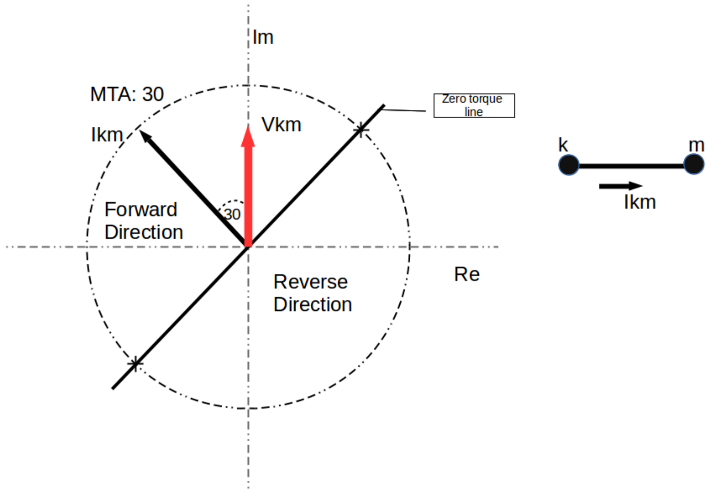



Figure 36: Principle to determine of current flow polarity

- **Step 6: Examine problem with Blinding of protection**

  ◇ ***Condition:*** The relay fail to operate during fault condition at downstream, while DG is installed upstream (Figure 9).

  ◇ ***Subject:*** Relay of upstream protective zone from DG location.

  ◇ ***Cause:*** The short circuit current contribution of DG is high enough to make short circuit current from the gird reduce to pickup current. When short circuit current from the grid is equal or smaller pickup current then the relay will not operate to interrupt the fault.

  ◇ ***Test method:*** Observe the contribution of short circuit current to the fault at downstream where DG is connected. Compare this value with the reference value where there is no DG and the pickup current.

- **Step 7: Examine problem with Lost of coordination**

  ◇ ***Condition:*** Coordination margin between primary and backup protective relay reduce below CTI value.

  ◇ ***Subject:*** Backup and primary relay.

  ◇ ***Cause:*** DG installation could increase the fault level of downstream network. Then the coordination could be loss by this increment.

  ◇ ***Test method:*** Calculate the tripping time of relays on each coordination path with the old relay setting. Evaluate the result to determine whether CTI is kept.

- **Step 8: Increase of penetration level and back to Step 2**

Finally the modified TDS values for relays to recover the proper selectivity between relays are calculated by using the method stated in the Chapter 2.

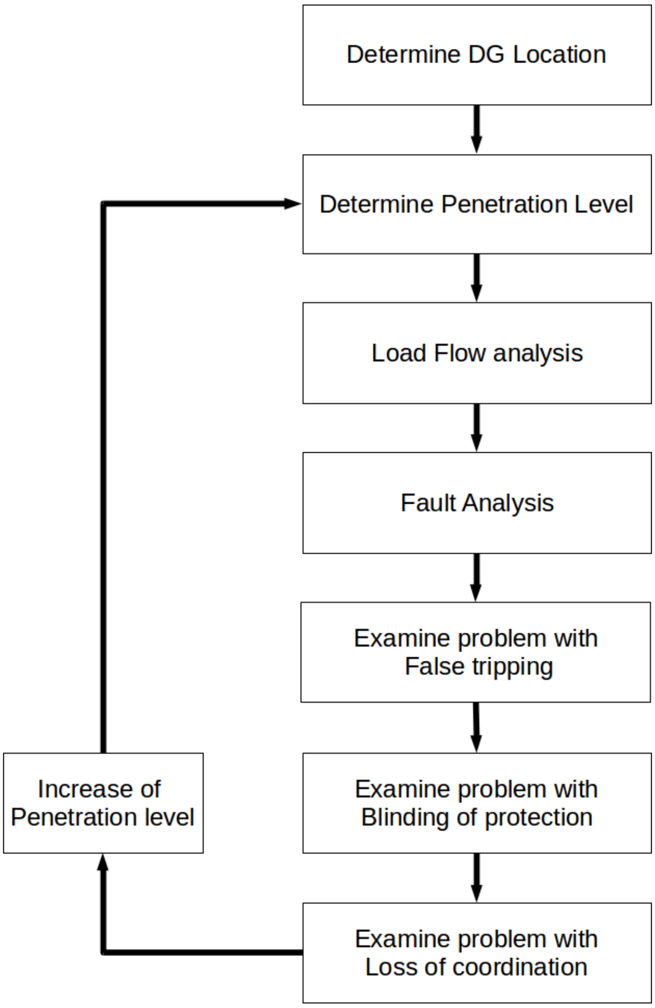



Figure 37: Process to analyze impacts of DG

## 3.2 Equivalent circuit of DG

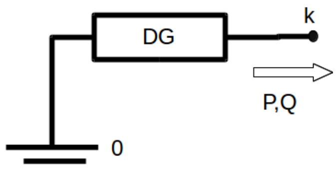



Figure 38: DG equivalent circuit

In order to examine the impact of DG the first step is define the model for DG which will be insert into the test network. For simplification, in this work DG will be model as and power source with parameters defined as follow:

$$P_{DG} = PL \sum P_i \quad i = 1..24 \tag{33}$$

$$Q_{DG} = PL \sum Q_i \quad i = 1..24 \tag{34}$$

$$Y_{DG} = 10 \frac{\sqrt{P_{DG}^2 + Q_{DG}^2}}{V_{DG}^2} \tag{35}$$

Where:

**PL:** Penetration level of distributed generation (5%, 10%, 30% and 50%)

$P_{DG}$, $Q_{DG}$**:** Real and reactive power generated by DG

$P_i$, $Q_i$**:** Real and reactive power consumed at bus i

$Y_{DG}$**:** Admittance of DG for all sequence components

## 3.3 Case Study 1: DG is installed at the end of the sub-feeder (Bus 23)

In this case study, DG is connected to the bus 23. This bus is located at the end of the $2^{nd}$ sub-feeder, therefore, the voltage at this bus is low (0.95 pu) as the consequence of long transmission distance. This bus belongs to a sub-feeder then the nominal current flow on this section is smaller than on the main feeder. Then DG installation will have the great impacts on current flow.

The result after analysis are presented below:

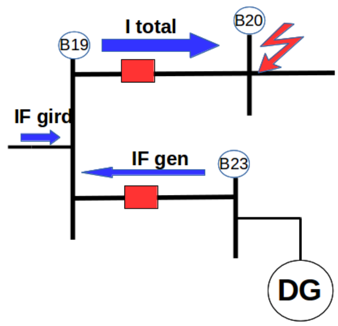



Figure 39: Faulted current flows while DG connected to bus 23

**Voltage Profile:**

When DG is connected into Bus 23 at the end of the radial network, the voltage profile of the system will be improved, see Figure,40. It could be seen that the most influence of DG on the voltage of buses at the end of the network. At 50% of penetration level still no signal of overvoltage appeared yet; however, if the penetration level increase further it could cause overvoltage. Further study will be conducted in the case study 5 page 57.

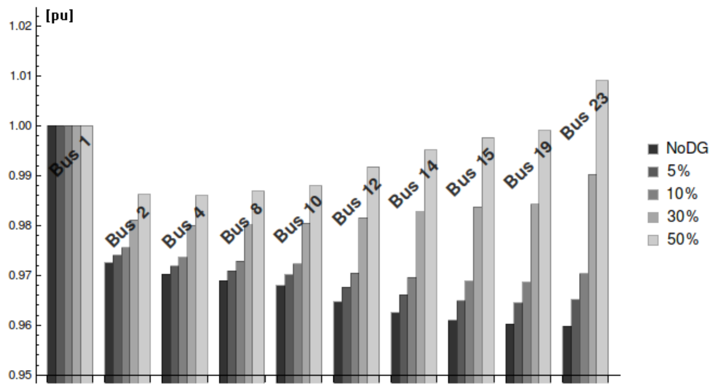
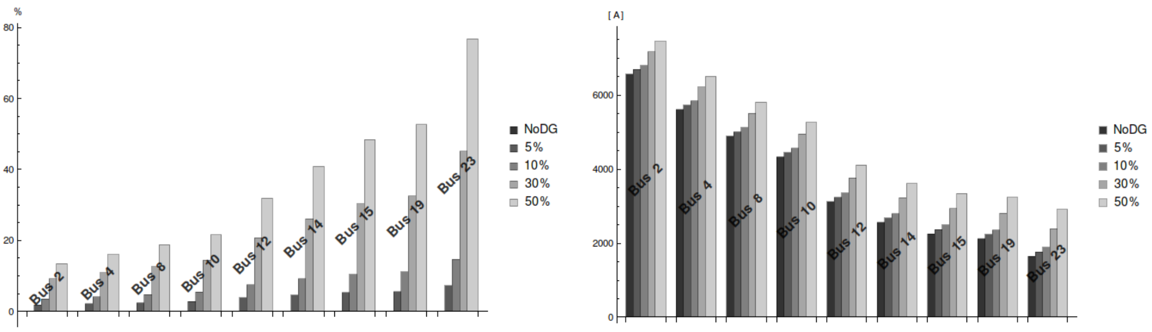



Figure 40: Voltage Profile on main feeder with different Penetration Level - DG at bus 23

**Fault Level**

The figure below presents the relative values of fault levels with and without DG on the system. DG has a strong impact on fault level at the buses at the end of the network. For example, fault level at bus 23 increase about 80 % compare to no DG case. This would cause stress on the overhead lines and other electrical equipments on this sub-feeder.




(a) Relative value of fault level

(b) Fault level magnitude in RMS

Figure 41: Change of Fault level - DG at bus 23

**False tripping problem:**

Beside the benefit for voltage profile, DG could contribute the short circuit current when fault occurs at the neighbor branch, such as at Bus 20. This contribution could be high enough to trick the CB4 to false tripping. In the phasor diagram shows that the current with DG flow in reverse direction.

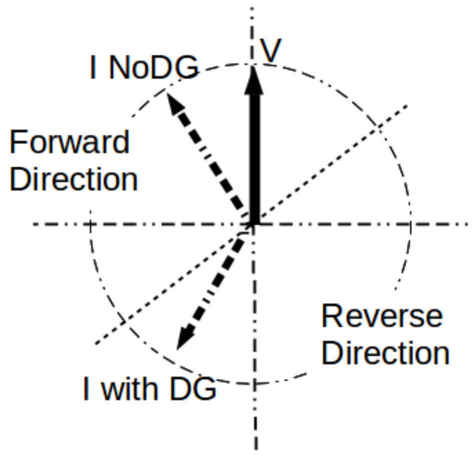



Figure 42: Phasor of current from 19 to 23 - DG at bus 23

The specific RMS value of short circuit current flow are:

- Pick-up current of CB4: 6.67 [A]

| | No DG | | 5% | | 10% | | 30% | | 50% | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Ik [A] | $t_{trip}$ [s] | Ik [A] | $t_{trip}$ [s] | Ik [A] | $t_{trip}$ [s] | Ik [A] | $t_{trip}$ [s] | Ik [A] | $t_{trip}$ [s] |
| CB 3 | 1820.6 | 0.079 | 1895.3 | 0.078 | 1967.1 | 0.077 | 2227.7 | 0.075 | 2450 | 0.073 |
| CB 4 | 5.3836 | not trip | -99.045 | 0.110 | -196.09 | 0.087 | -545.74 | 0.066 | -843.43 | 0.060 |

Table 16: Current through CB3 and CB4 with their operating time - DG at bus 23

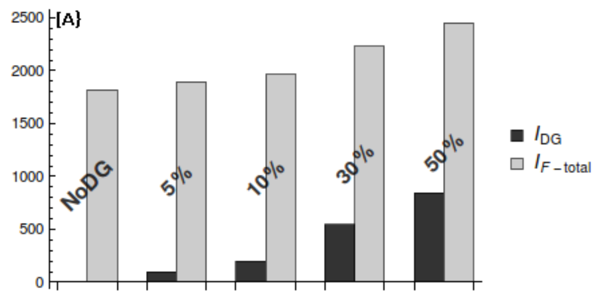



Figure 43: Short circuit contribution of DG compare to total faulted current - DG at bus 23

The negative sign indicates that current flow in opposite direction. From results obviously with current setting of relay CB4 then installation of DG into the system could cause false tripping. In this case, the DG till 10% penetration does not make the CB4 trips sooner than CB3. When the penetration level is increase then CB4 will trip before CB3 then the healthy branch will be disconnected.

**Solution** propose to deal with this problem are:

- Apply the directional overcurrent relay to ignore the problem of reverse current flow.

- Increase the pick-up current for CB4 to comply with change of DG size
- Apply the protective measure at DG's terminals to disconnect the DG from the system when fault occurs as soon as possible.

### Blinding of protection

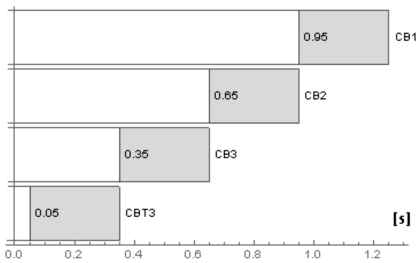
Because Bus 23 is located at the end of the network, then there is no downstream bus from there. Therefore, no blinding problem happens when DG is connected here.

### Loss of coordination

Results show lost in coordination on path A and more specific between CB3 and CBT3. Reasons for this is the extra short circuit current from DG flow to the fault at buses located in the end of path A. The fault current increase leads to shorter tripping time of CB3 and the coordination margin is reduced. For other paths the coordination margin are increased.

| | $t_{trip}$ A | $t_{trip}$ B | $t_{trip}$ C | $t_{trip}$ D |
|---|---|---|---|---|
| CB1 | 0.95 | 0.95 | 0.73987 | 0.95 |
| CB2 | 0.65 | 0.7002 | – | 0.65 |
| CB3 | 0.35 | – | – | – |
| CB4 | – | 0.05 | – | – |
| CBT1 | – | – | 0.05 | – |
| CBT2 | – | – | – | 0.05 |
| CBT3 | 0.05 | – | – | – |

(a) Operating time without DG installation

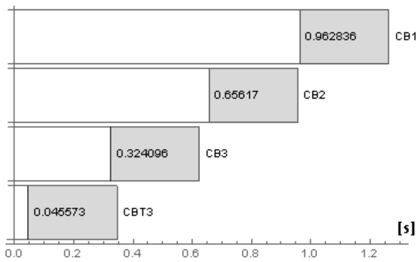



(b) Relay response for Path A

Figure 44: Penetration 0% - DG at bus 23

| | $t_{trip}$ A | $t_{trip}$ B | $t_{trip}$ C | $t_{trip}$ D |
|---|---|---|---|---|
| CB1 | 0.96284 | 0.96284 | 0.74819 | 0.96284 |
| CB2 | 0.65617 | 0.70972 | – | 0.66085 |
| CB3 | 0.3241 | – | – | – |
| CB4 | – | 0.046381 | – | – |
| CBT1 | – | – | 0.048407 | – |
| CBT2 | – | – | – | 0.046502 |
| CBT3 | 0.045573 | – | – | – |

(a) DG - 50% penetration




(b) Relay response for Path A

Figure 45: Penetration 50% - DG at bus 23

### Modified relay setting

Applying the process in Chapter 2, the modified parameter for relays to ensure the correct operation are shown in Figure 46 and Table 17. The pickup current of CB2 decrease while

DG at the small penetration level, but with the DG penetration is great (30% or more) the current flow is reverse at relay CB2 position, then pickup current eventually increased.

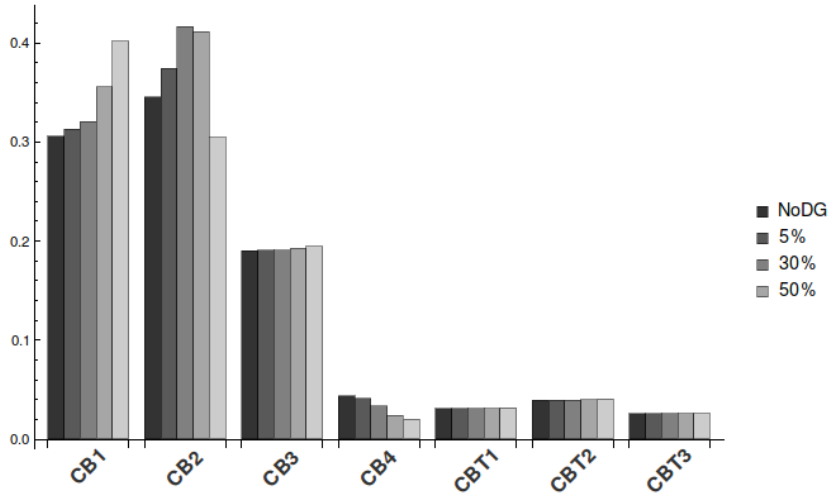



Figure 46: Modify TDS value for relays - DG at bus 23

| $I_{pickup}$ [A] at | **CB1** | **CB2** | **CB3** | **CB4** | **CBT1** | **CBT2** | **CBT3** |
|---|---|---|---|---|---|---|---|
| **noDG** | 311 | 62.1 | 44.6 | 6.67 | 77 | 11.4 | 50.1 |
| **5%** | 294 | 46.1 | 44.4 | 9.05 | 76.8 | 11.4 | 50.7 |
| **10%** | 278 | 30.4 | 44.2 | 24.6 | 76.7 | 11.3 | 51.2 |
| **30%** | 215 | 31.6 | 43.4 | 85.2 | 76.1 | 11.2 | 53.3 |
| **50%** | 154 | 90.7 | 42.7 | 144 | 75.5 | 11 | 55.2 |

Table 17: Modified pickup currents for relays - DG at bus 23

## 3.4 Case Study 2: DG is installed at the end of the main feeder (Bus 19)

In this case, DG is connected at bus 19 where is the final bus of the main feeder and also at the beginning of the sub-feeders. The results lead to some discussion below:

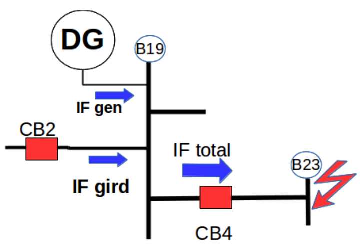



Figure 47: Faulted current flows while DG connected to bus 19

**Voltage Profile:**

As discussed in Case study 1, here when DG is connected at the end side of the network, far from the grid then DG increase the voltages of the buses and most for buses at the ends.

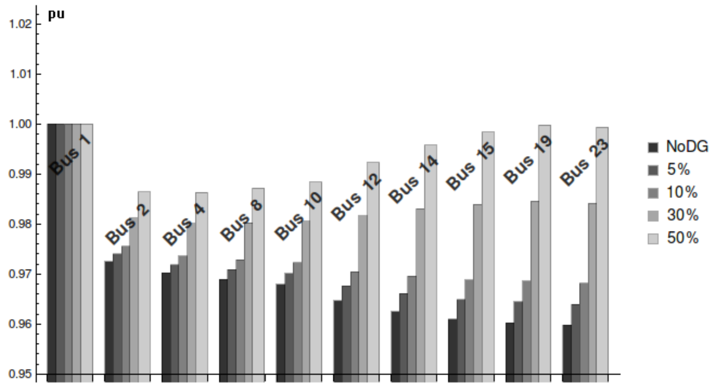
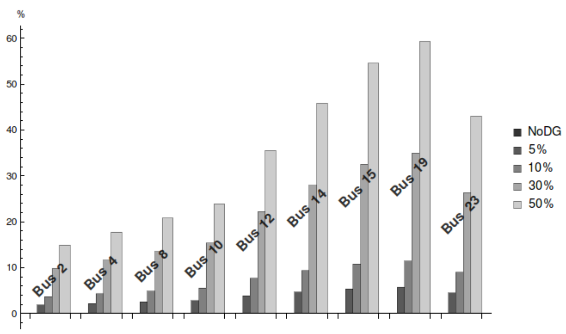


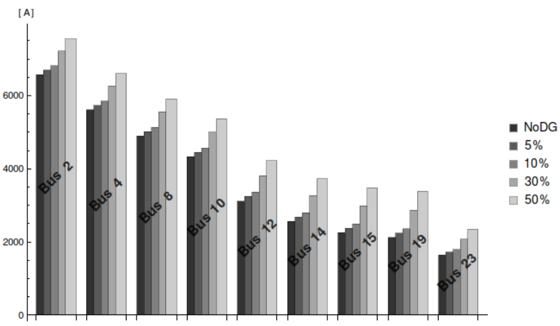

Figure 48: Voltage Profile on main feeder with different Penetration Level - DG at Bus 19

**Fault level:**

Similar to the Case study 1 the DG has great impact on fault current of buses at the far side and lighter impact to upstream buses. The fault level increase here smaller than in the case of DG connect to bus 23. Maximum increment happened at bus 19 is about 60 % smaller than Case study 1 but still able to cause problem for equipments. In this case DG has less effect on the sub-feeder than in previous case.




(a) Relative value of fault level




(b) Fault level magnitude in RMS

Figure 49: Change of Fault level - DG at Bus 19

**False Tripping Problem:**

In this case, no neighbor branch exist when bus 19 is located at the main feeder, then no false tripping problem will happen.

**Blinding Problem:**

From bus 19 there are 2 sub-feeder downstream, in this work the author will analysis for the $2^{nd}$ sub-feeder with the fault at bus 23 only with assumption that similar phenomenon when fault occurs at the other sub-feeder.

When fault occurs at bus 23, the DG will contribute to total short circuit current as long as current from the grid. As can be seen in the Figure 50, the contributions of the grid to total short circuit current slightly decrease while penetration of DG increase. The short circuit current from DG in other hand increase significantly. From this results, it could be said that the blinding problem will not happen because pick up current of CB2 is 62.1 A much smaller than $I_{F-Grid} = 1489.8[A]$ when penetration level is 50%.

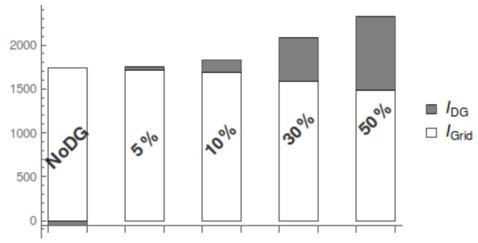



Figure 50: Contribution of total short circuit current - DG at Bus 19

| | NoDG | 5% | 10% | 30% | 50% |
|---|---|---|---|---|---|
| **IF-grid [A]** | 1743.7 | 1716.1 | 1689 | 1585.7 | 1489.8 |
| **IF-DG [A]** | 0 | 37.781 | 133.26 | 498.19 | 836.6 |

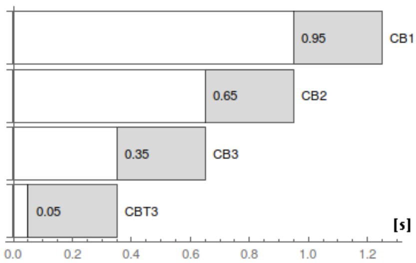
Table 18: Short circuit current from Grid and DG while fault at bus 23

**Loss of Coordination:**

In this case, the coordination is lost between CB3 and CBT3 for Path A. The reason is the increasing in fault level as case study 1. Tripping time of CB3, CBT3, CB4, CBT1 and CBT2 decrease. However, the responding time for other relays are increased. Therefore, coordination between CB3 and CBT3 will be lost and other coordination margins will be increased.

| | $t_{trip}$ A | $t_{trip}$ B | $t_{trip}$ C | $t_{trip}$ D |
|---|---|---|---|---|
| CB1 | 0.95 | 0.95 | 0.74 | 0.95 |
| CB2 | 0.65 | 0.7 | - | 0.65 |
| CB3 | 0.35 | - | - | - |
| CB4 | - | 0.05 | - | - |
| CBT1 | - | - | 0.05 | - |
| CBT2 | - | - | - | 0.05 |
| CBT3 | 0.05 | - | - | - |

(a) Operating time without DG installation

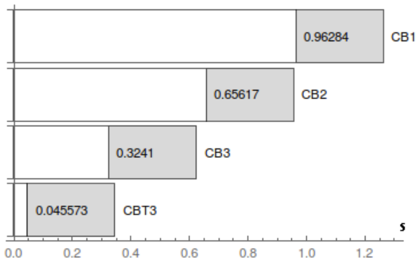



(b) Relay response for Path A

Figure 51: Penetration 0% - DG at Bus 19

| | $t_{trip}$ A | $t_{trip}$ B | $t_{trip}$ C | $t_{trip}$ D |
|---|---|---|---|---|
| CB1 | 0.963 | 0.963 | 0.748 | 0.963 |
| CB2 | 0.656 | 0.71 | - | 0.661 |
| CB3 | 0.324 | - | - | - |
| CB4 | - | 0.0464 | - | - |
| CBT1 | - | - | 0.0484 | - |
| CBT2 | - | - | - | 0.0465 |
| CBT3 | 0.0456 | - | - | - |

(a) DG - 50% penetration




(b) Relay response for Path A

Figure 52: Penetration 50% - DG at Bus 19

### Modified relay setting

Applying the process in Chapter 2, the modified parameter for relays to ensure the correct operation are shown in Figure 53 and Table 19 below. While DG is connected to bus 19 then the relays CB1 and CB2 must be modified to adapt with the change of fault level. Pickup current of CB1 decreased due to less contribution of grid by high penetration of DG.

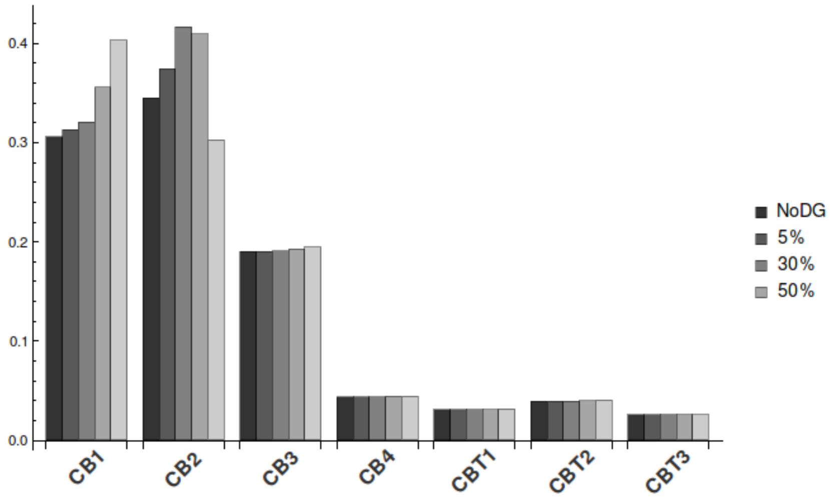



Figure 53: Modify TDS value for relays - DG at Bus 19

| $I_{pickup}$ [A] at | **CB1** | **CB2** | **CB3** | **CB4** | **CBT1** | **CBT2** | **CBT3** |
|---|---|---|---|---|---|---|---|
| **noDG** | 311 | 62.1 | 44.6 | 6.67 | 77 | 11.4 | 50.1 |
| **5%** | 294 | 46.1 | 44.4 | 6.64 | 76.8 | 11.4 | 50.7 |
| **10%** | 278 | 30.4 | 44.2 | 6.61 | 76.7 | 11.3 | 51.2 |
| **30%** | 214 | 32.1 | 43.4 | 6.5 | 76.1 | 11.2 | 53.3 |
| **50%** | 153 | 92.1 | 42.6 | 6.4 | 75.5 | 11 | 55.3 |

Table 19: Modified pickup currents for relays - DG at bus 19

## 3.5 Case Study 3: DG is installed at the middle of the network (Bus 14)

In this case DG is connect to Bus 14 at the middle of the main feeder. Current flow on the main feeder is larger than on sub-feeder as investigated at in previous case study, then the impact of DG is also expected less than before. The result from analysis is shown below:

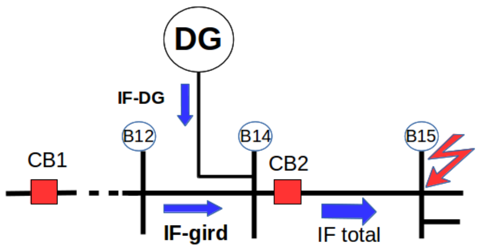



Figure 54: Faulted current flows while DG connected to bus 14

**Voltage Profile:**

As usual the DG improve the voltage profile of the network. Still impact on the buses at the end of the network is more than for the bus at the beginning.

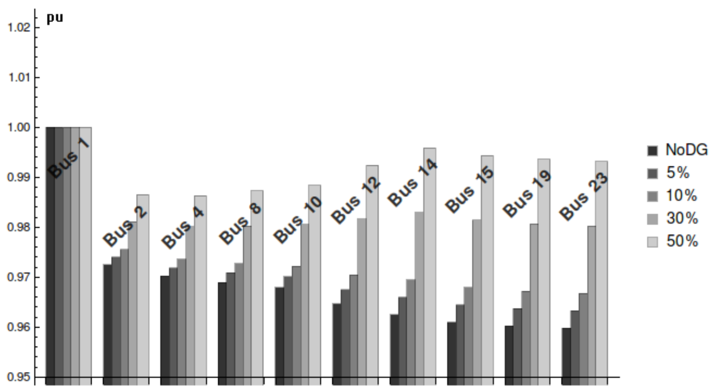
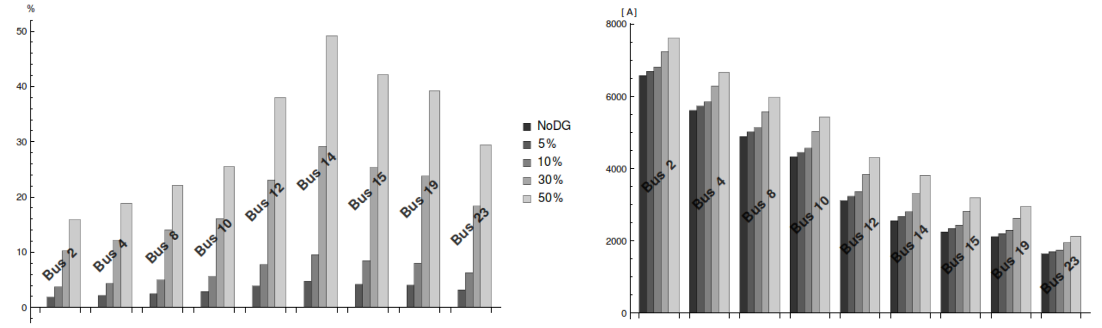



Figure 55: Voltage Profile on Path B - DG at bus 14

**Fault Level:**

Similar to the Case study 2, the DG increase the fault level of overall network and the most increment (50 %) at bus 14 where DG is connected.




(a) Relative value of fault level

(b) Fault level magnitude in RMS

Figure 56: Change of Fault level - DG at bus 14

**Blinding Problem:**

To examine this problem during 3 phase fault at bus 15, the current flow from grid $I_{gid}$ from bus 12 to 14 during 3 phase fault at bus 15 and $I_{F-total}$ from Bus 14 to Bus 15 were calculated. The results shows on Figure.. The short circuit current from the grid decrease with the increasing ot DG penetration. However, the reduction is not enough to cause blinding problem for CB1.

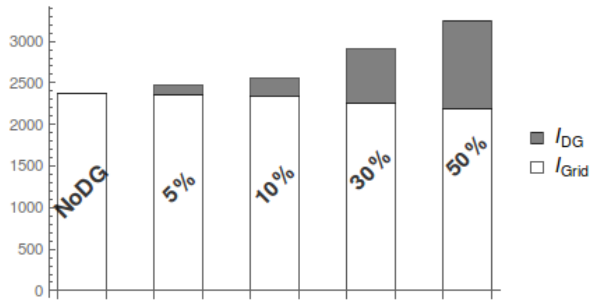



Figure 57: Contribution of DG to total short circuit current- DG at bus 14

| | NoDG | 5% | 10% | 30% | 50% |
|---|---|---|---|---|---|
| **IF-grid [A]** | 2375.3 | 2355.6 | 2336.2 | 2260.9 | 2189.2 |
| **IF-DG [A]** | 0 | 109.41 | 218.04 | 644.4 | 1056.9 |

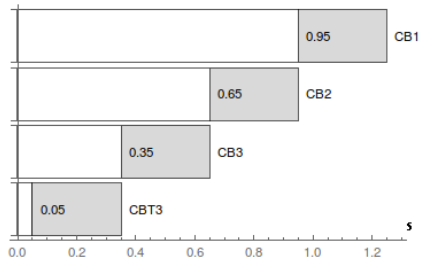
Table 20: Short circuit current from Grid and DG - DG at bus 14

**Lost of Coordination :**

Coordination for relays between CB3 and CBT3 and between CB2 and CB3 are loss due to increase of short circuit current during fault. The coordination margin between CB2 and CB4 and between CB2 and CBT2 are reduced.

| | $t_{trip}$ A | $t_{trip}$ B | $t_{trip}$ C | $t_{trip}$ D |
|---|---|---|---|---|
| CB1 | 0.95 | 0.95 | 0.74 | 0.95 |
| CB2 | 0.65 | 0.7 | – | 0.65 |
| CB3 | 0.35 | – | – | – |
| CB4 | – | 0.05 | – | – |
| CBT1 | – | – | 0.05 | – |
| CBT2 | – | – | – | 0.05 |
| CBT3 | 0.05 | – | – | – |

(a) Operating time without DG installation

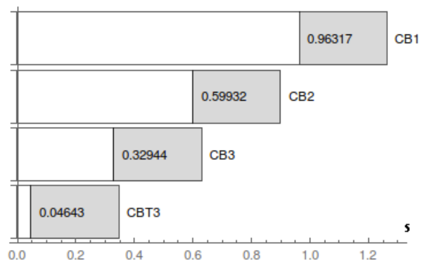



(b) Relay response for Path A

Figure 58: Penetration 0% - DG at Bus 14

| | $t_{trip}$ A | $t_{trip}$ B | $t_{trip}$ C | $t_{trip}$ D |
|---|---|---|---|---|
| CB1 | 0.963 | 0.963 | 0.748 | 0.963 |
| CB2 | 0.656 | 0.71 | – | 0.661 |
| CB3 | 0.324 | – | – | – |
| CB4 | – | 0.0464 | – | – |
| CBT1 | – | – | 0.0484 | – |
| CBT2 | – | – | – | 0.0465 |
| CBT3 | 0.0456 | – | – | – |

(a) DG - 50% penetration




(b) Relay response for Path A

Figure 59: Penetration 50% - DG at Bus 14

### Modified relay setting

Applying the process in Chapter 2, the modified parameter for relays to ensure the correct operation are show in Figure 60 and Table 21. In this case the DG is connected at bus 14 then only the CB1 relay faced to great impact while the contribution of the grid decrease with the increasing of DG penetration. The voltage profile is improved lead to slightly reduction of pickup current at all other relays.

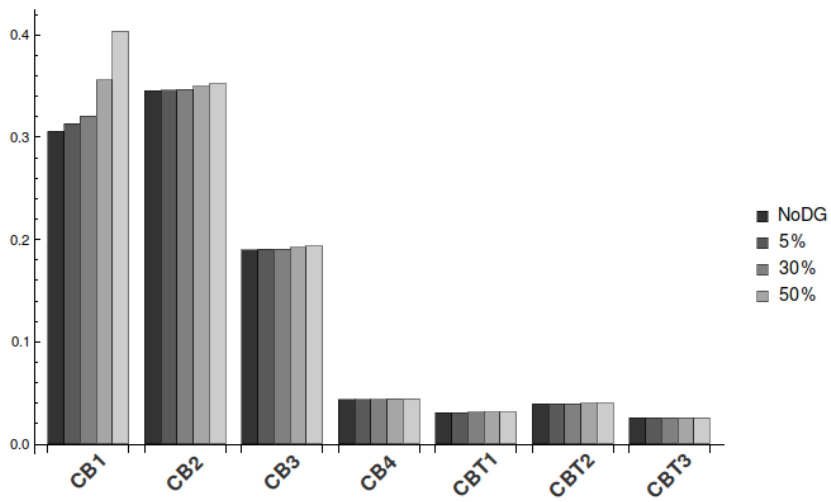



Figure 60: Modify TDS value for relays - DG at Bus 14

| $I_{pickup}$ [A] at | **CB1** | **CB2** | **CB3** | **CB4** | **CBT1** | **CBT2** | **CBT3** |
|---|---|---|---|---|---|---|---|
| **noDG** | 311 | 62.1 | 44.6 | 6.67 | 77 | 11.4 | 50.1 |
| **5%** | 295 | 61.8 | 44.4 | 6.64 | 76.8 | 11.4 | 50.6 |
| **10%** | 278 | 61.6 | 44.2 | 6.62 | 76.7 | 11.4 | 51.1 |
| **30%** | 215 | 60.7 | 43.6 | 6.52 | 76.1 | 11.2 | 52.8 |
| **50%** | 152 | 59.8 | 42.9 | 6.44 | 75.5 | 11 | 54.5 |

Table 21: Modified pickup currents for relays - DG at bus 14

## 3.6 Case Study 4: DG is installed at the beginning of the network (Bus 4)

In this case DG is connected to Bus 4 at the beginning of the network.

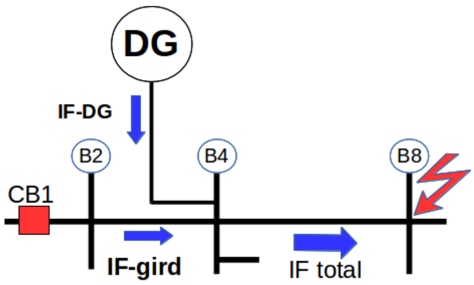



Figure 61: Faulted current flows while DG connected to bus 4

### Voltage Profile:

The Figure.62 shows that DG improve the voltage profile of the network and the improvement for each bus is similar.

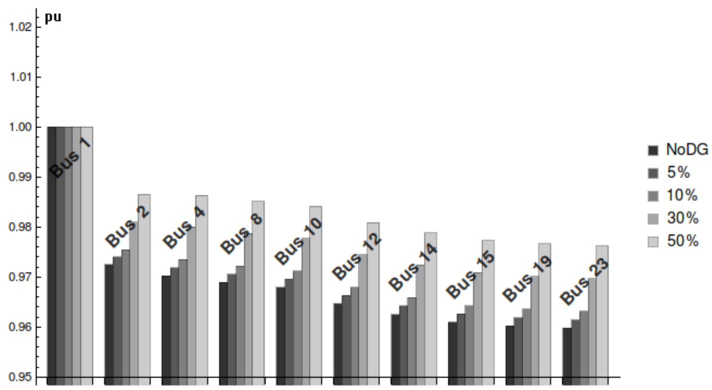
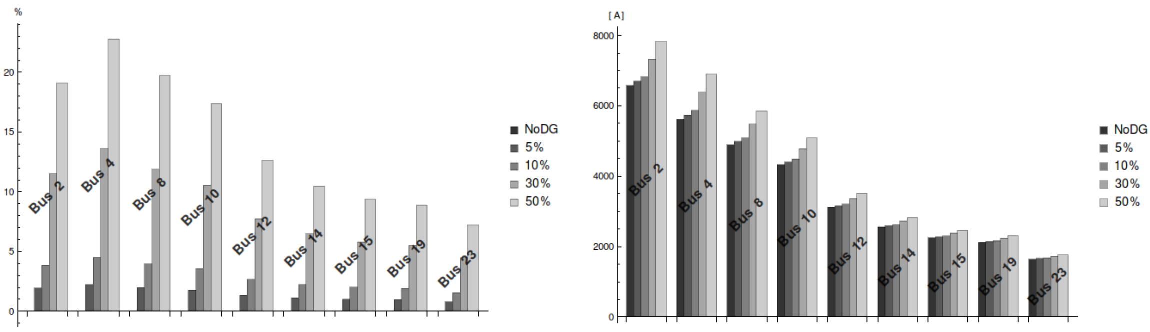



Figure 62: Voltage profile of path B while DG connected to bus 4

### Fault Level

The fault level of the network increase even with smaller percentage than previous cases. Maximum increment is 24% at bus 4.




(a) Relative value of fault level

(b) Fault level magnitude in RMS

Figure 63: Change of Fault level while DG connected to bus 4

**Blinding Problem:**

Similar to case study 3, the short circuit current from the grid and DG is computed during fault at Bus 8.

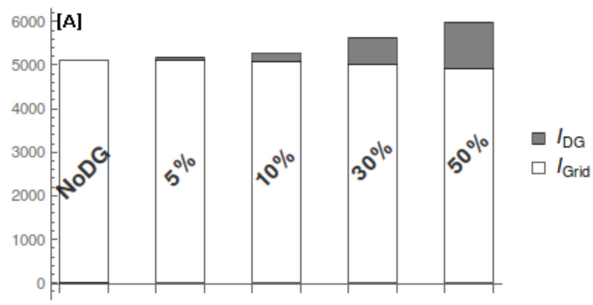



Figure 64: Contribution of DG to total short circuit current - DG at bus 4

| | **NoDG** | **5%** | **10%** | **30%** | **50%** |
|---|---|---|---|---|---|
| **IF-grid [A]** | 5119.7 | 5100.2 | 5080.8 | 5004.6 | 4930.2 |
| **IF-DG [A]** | 0 | 140.01 | 250.16 | 685.28 | 1111.7 |

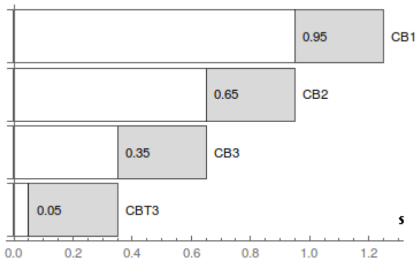
Table 22: Short circuit current from Grid and DG while DG connected to bus 4

**Lost of Coordination :**

Except for CB1 the tripping time of other relays are faster than case noDG. Then coordination between relays neither lost or reduced.

| | $t_{trip}$ A | $t_{trip}$ B | $t_{trip}$ C | $t_{trip}$ D |
|---|---|---|---|---|
| CB1 | 0.95 | 0.95 | 0.74 | 0.95 |
| CB2 | 0.65 | 0.7 | - | 0.65 |
| CB3 | 0.35 | - | - | - |
| CB4 | - | 0.05 | - | - |
| CBT1 | - | - | 0.05 | - |
| CBT2 | - | - | - | 0.05 |
| CBT3 | 0.05 | - | - | - |

(a) Operating time without DG installation

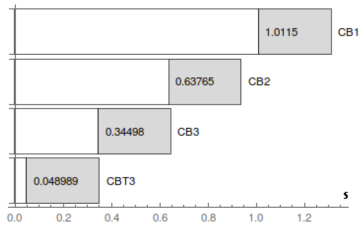



(b) Relay response for Path A

Figure 65: Penetration 0% - DG at Bus 4

| | $t_{trip}$ A | $t_{trip}$ B | $t_{trip}$ C | $t_{trip}$ D |
|---|---|---|---|---|
| CB1 | 1.01 | 1.01 | 0.75 | 1.01 |
| CB2 | 0.638 | 0.689 | - | 0.638 |
| CB3 | 0.345 | - | - | - |
| CB4 | - | 0.0492 | - | - |
| CBT1 | - | - | 0.0478 | - |
| CBT2 | - | - | - | 0.0492 |
| CBT3 | 0.049 | - | - | - |

(a) DG - 50% penetration




(b) Relay response for Path A

Figure 66: Penetration 50% - DG at Bus 4

### Modified relay setting

Applying the process in Chapter 2, the modified parameter for relays to ensure the correct operation are shown in Figure 67 and Table 23. Similar to the previous case, when the DG is connected to the bus 4, then CB1 mus change the most.

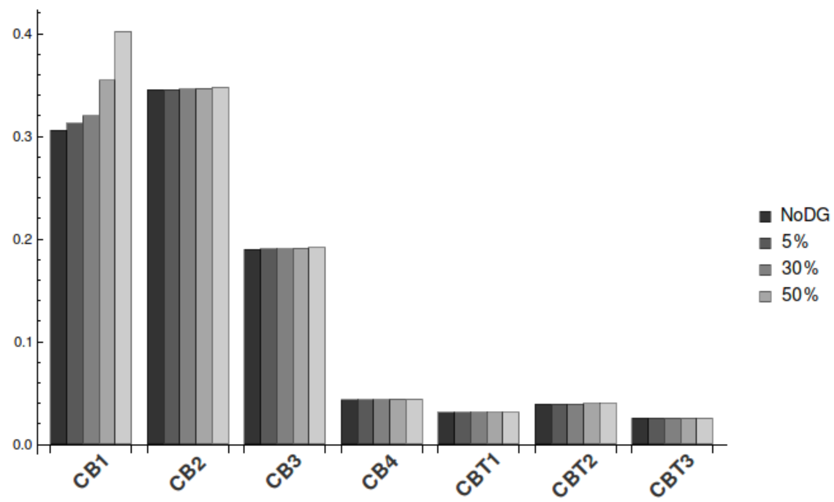



Figure 67: Modify TDS value for relays - DG at Bus 4

| $I_{pickup}$ [A] at | **CB1** | **CB2** | **CB3** | **CB4** | **CBT1** | **CBT2** | **CBT3** |
|---|---|---|---|---|---|---|---|
| **noDG** | 311 | 62.1 | 44.6 | 6.67 | 77 | 11.4 | 50.1 |
| **5%** | 295 | 62 | 44.5 | 6.65 | 76.9 | 11.4 | 50.4 |
| **10%** | 279 | 61.8 | 44.4 | 6.64 | 76.7 | 11.4 | 50.6 |
| **30%** | 215 | 61.4 | 44.1 | 6.6 | 76.1 | 11.3 | 51.4 |
| **50%** | 152 | 60.9 | 43.8 | 6.55 | 75.5 | 11.2 | 52.3 |

Table 23: Modified pickup currents for relays - DG at bus 4

# 4 Impact of numerous DGs on radial network protection

Applying the same process in chapter 3, this chapter will investigate the impact of two cases when:

- two DGs are connected at the ends of the network at Bus 23 and Bus 24 (Figure 68)

- multiple Ds are connected to all buses where load extract power from the network. (Figure 76)

The main purpose of this investigation is to simulate the situation when customer install their own sources for example wind turbines or PV panels.

In this case the penetration level of total DG connected could lead to 100%. The power size of each DG will be simplified the same.

Then in the case of 2 DGs then DG power size of each will be set at: $S_{DG} = [0, 5\%, 25\%, 50\%]$ to simulate the penetration level at 0, 10%, 50% and 100%.

In the case of multiple DGs, power size of each DG is $S_{DG} = [0, 1.25\%, 6.25\%, 12.5\%]$ to simulate the penetration level at 0, 10%, 50% and 100%.

## 4.1 Case Study 5: 2 DGs installed at the ends of the network

In this case, the DGs is connected to bus 23 and 24 where are located at the end of radial network. This is expected to be the most problematic location to connect the DG because of the strong impact to all system's parameters.

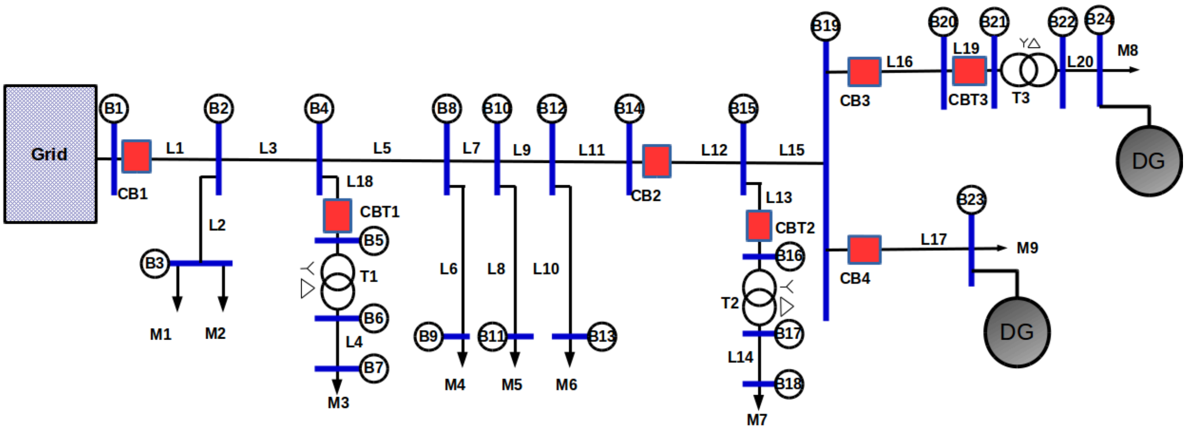



Figure 68: Schemat of network while DG is connected at Bus 23 and 24

### Voltage Profile

The signal of overvoltage appears when penetration level of DG is high. Compare to the Case study 1 when only single DG is connected to the bus 23, here under the same penetration level at 50% the voltage profile increased less. This indicated that by allocated the DG in different location, the DG penetration could be increase without breaking the limit for voltage.

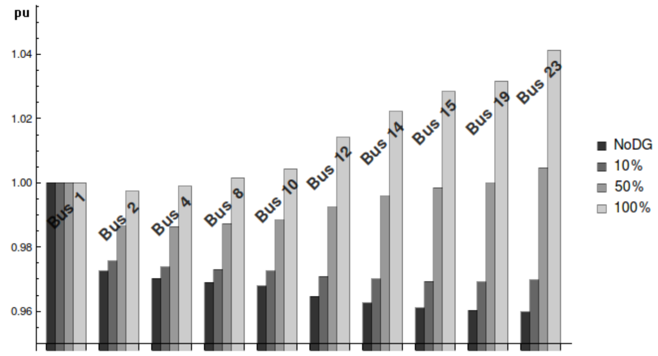
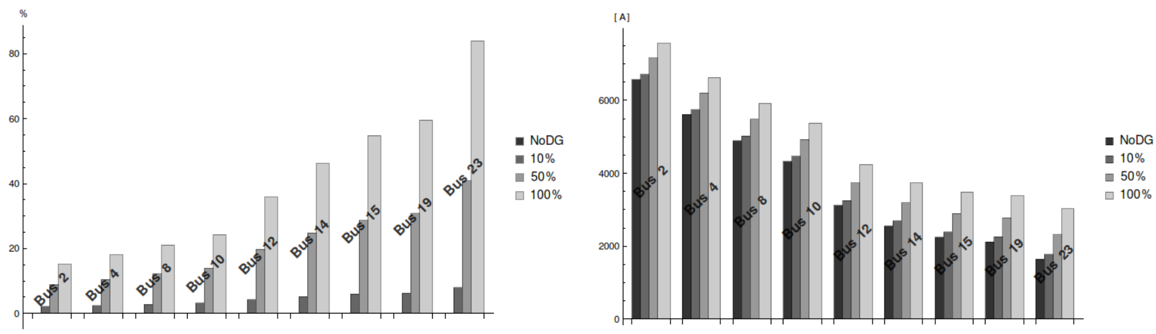



Figure 69: Voltage Profile while DG is connected at Bus 23 and 24

### Fault level

Fault level of the system is generally increased but the increment is less than in case of singe DG at the same penetration level.




(a) Relative value of fault level

(b) Fault level magnitude in RMS

Figure 70: Comparison of Fault level while DG is connected at Bus 23 and 24

### False Tripping problem

To test the problem, the fault will occur at the bus 20. Contribution to the total fault current from DG at the healthy sub-feeder (Bus 23) is shown in Table 24.

At high penetration the false tripping problem occurs. Compare to the section 4.3, contribution of DG on the healthy sub-feeder is smaller. Then the problem with false tripping will be reduce.

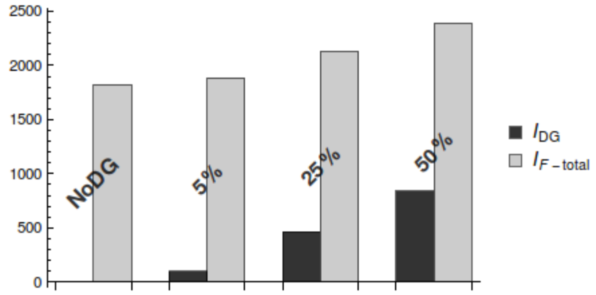



Figure 71: Short circuit current from Grid and DG while DG connected to bus 23 and 24

| | No DG | | 10% | | 50% | | 100% | |
|---|---|---|---|---|---|---|---|---|
| | Ik [A] | ttrip [s] | Ik [A] | ttrip [s] | Ik [A] | ttrip [s] | Ik [A] | ttrip [s] |
| CB 3 | 1820.5 | 0.079329 | 1886.1 | 0.07855 | 2130.3 | 0.075984 | 2392.5 | 0.073682 |
| CB 4 | 5.3834 | not trip | 99 | 0.11018 | 462.12 | 0.069049 | 837.87 | 0.060184 |

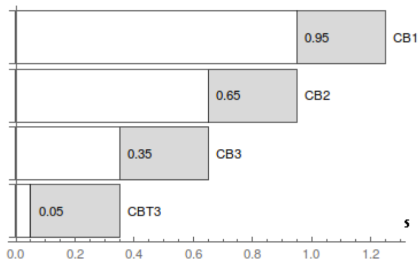
Table 24: Contribution of to short circuit current

**Lost of Coordination :**

As we could see from Tables and Figures below, the coordination is lost for Path A and reduce for Path B. For other paths the delay time is increase because of reduction in operating time of primary relays.

| | $t_{trip}$ A | $t_{trip}$ B | $t_{trip}$ C | $t_{trip}$ D |
|---|---|---|---|---|
| CB1 | 0.95 | 0.95 | 0.73987 | 0.95 |
| CB2 | 0.65 | 0.7002 | - | 0.65 |
| CB3 | 0.35 | - | - | - |
| CB4 | - | 0.05 | - | - |
| CBT1 | - | - | 0.05 | - |
| CBT2 | - | - | - | 0.05 |
| CBT3 | 0.05 | - | - | - |

(a) Operating time without DG installation

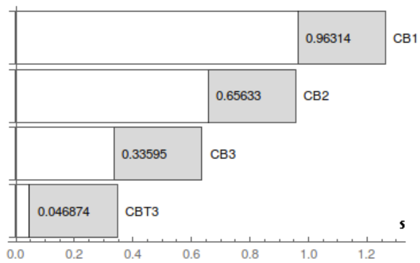



(b) Relay response for Path A

Figure 72: Penetration 0% - DG at Bus 24 and 23

| | $t_{trip}$ A | $t_{trip}$ B | $t_{trip}$ C | $t_{trip}$ D |
|---|---|---|---|---|
| CB1 | 0.96314 | 0.96314 | 0.74636 | 0.96314 |
| CB2 | 0.65633 | 0.7104 | - | 0.65893 |
| CB3 | 0.33595 | - | - | - |
| CB4 | - | 0.047643 | - | - |
| CBT1 | - | - | 0.048903 | - |
| CBT2 | - | - | - | 0.047695 |
| CBT3 | 0.046874 | - | - | - |

(a) DG - 50% penetration

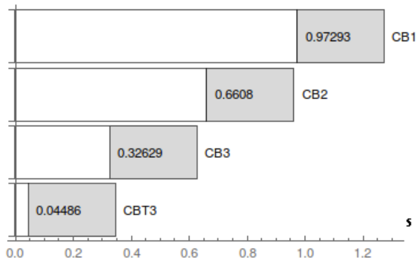



(b) Relay response for Path A

Figure 73: Penetration 50% - DG at Bus 24 and 23

| | $t_{trip}$ A | $t_{trip}$ B | $t_{trip}$ C | $t_{trip}$ D |
|---|---|---|---|---|
| CB1 | 0.97293 | 0.97293 | 0.75098 | 0.97293 |
| CB2 | 0.6608 | 0.71783 | - | 0.66591 |
| CB3 | 0.32629 | - | - | - |
| CB4 | - | 0.046032 | - | - |
| CBT1 | - | - | 0.048218 | - |
| CBT2 | - | - | - | 0.046149 |
| CBT3 | 0.04486 | - | - | - |

(a) DG - 100% penetration




(b) Relay response for Path A

Figure 74: Penetration 100% - DG at Bus 24 and 23

### Modified relay setting

Applying the process in Chapter 2, the modified parameter for relays to ensure the correct operation are shown in Figure 75 and Table 25. With the increasing of DG penetration the pickup current of CB4 and CBT3 also increase. Note that in this solution the required response time for CB4 and CBT3 still be choose at 0.05s which is not necessary true while DG penetration at 100%.

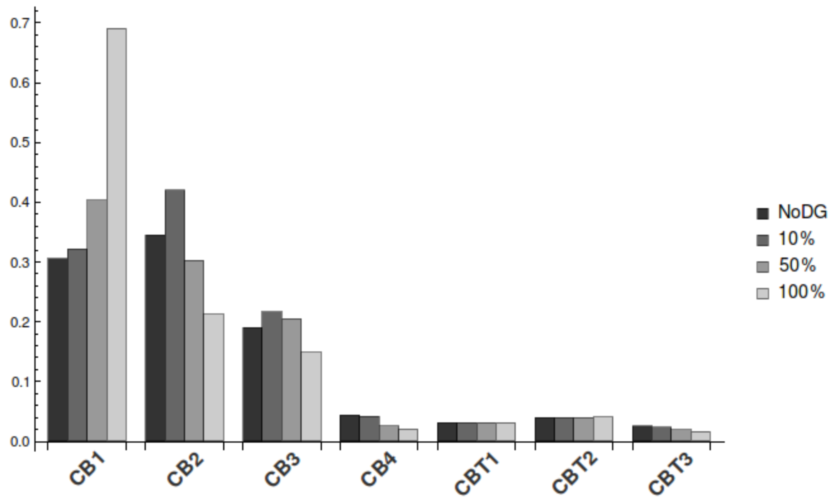



Figure 75: Modify TDS value while DG is connected at Bus 23 and 24

| $I_{pickup}$ [A] at | **CB1** | **CB2** | **CB3** | **CB4** | **CBT1** | **CBT2** | **CBT3** |
|---|---|---|---|---|---|---|---|
| **noDG** | 311 | 62.1 | 44.6 | 6.67 | 77 | 11.4 | 50.1 |
| **10%** | 277 | 49.4 | 40 | 2.71 | 72.1 | 7.62 | 54.5 |
| **50%** | 147 | 4.33 | 22.6 | 12.7 | 53.3 | 9.29 | 71.9 |
| **100%** | 6.7 | 54.4 | 2.85 | 30.9 | 31.7 | 26.2 | 92.8 |

Table 25: Modified pickup currents for relays - DG at bus 23 and 24

## 4.2 Case Study 6: Multiple DGs installed at the ends of the network

In the case study 5, it showed that by having DG in various location could improve the network voltage profile better. Here the case while all buses with loads will have DG installation.

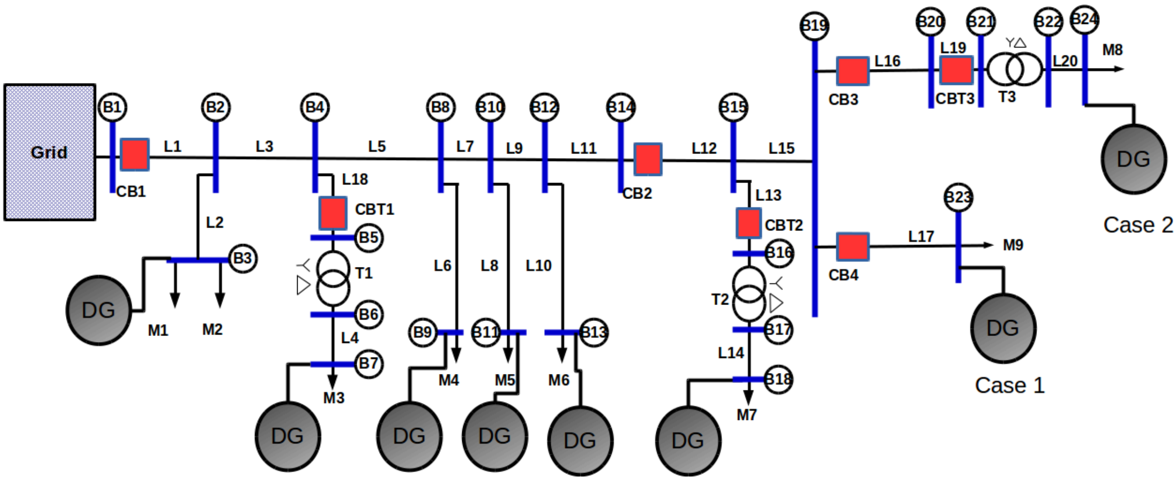



Figure 76: Schemat of network while multiple DGs connected

### Voltage profile

The voltage profile is the best in this case. Even with 100% of penetration still no sign of overvoltage.

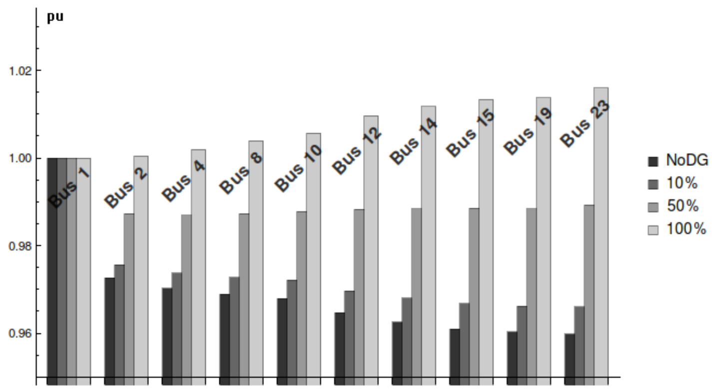
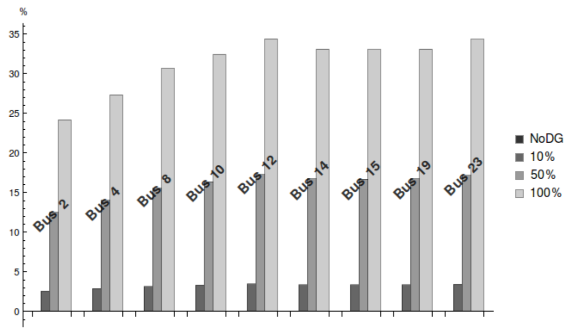


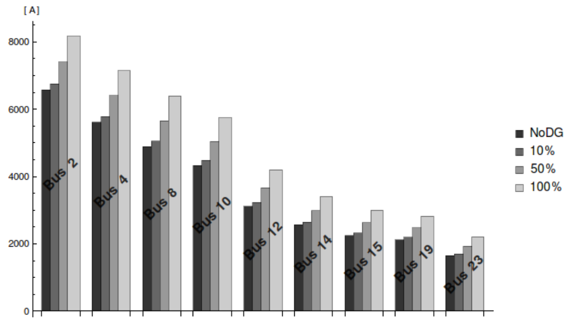

Figure 77: Voltage Profile while Multiple DGs connected

### Fault Level

Fault level is increase but lest than most of other cases. This is the good sign to be examine in the future work.




(a) Relative value of fault level




(b) Fault level magnitude in RMS

Figure 78: Change of Fault level for Multiple DGs connected

## False Tripping

Similar as previous cases, the behavior of the system while fault at bus 20 is investigate. Problem with false tripping does not occur here because of the small power rating for each individual DG.

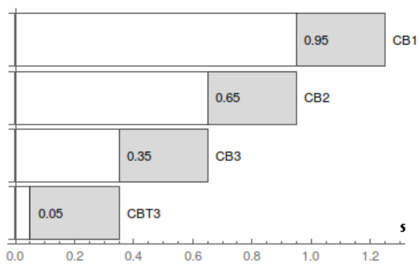
| | No DG | | 10% | | 50% | | 100% | |
|---|---|---|---|---|---|---|---|---|
| | Ik [A] | ttrip [s] | Ik [A] | ttrip [s] | Ik [A] | ttrip [s] | Ik [A] | ttrip [s] |
| CB 3 | 1820.5 | 0.079329 | 1857.2 | 0.078889 | 1997.1 | 0.077325 | 2157.8 | 0.075723 |
| CB 4 | 5.3834 | not trip | 0.23792 | 0.11018 | 121.94 | 0.10207 | 236.32 | 0.082586 |

Table 26: Short-circuit current seen by CB3 and CB4 during Multiple DGs connected

## Lost of coordination

| | $t_{trip}$ A | $t_{trip}$ B | $t_{trip}$ C | $t_{trip}$ D |
|---|---|---|---|---|
| CB1 | 0.95 | 0.95 | 0.74 | 0.95 |
| CB2 | 0.65 | 0.7 | - | 0.65 |
| CB3 | 0.35 | - | - | - |
| CB4 | - | 0.05 | - | - |
| CBT1 | - | - | 0.05 | - |
| CBT2 | - | - | - | 0.05 |
| CBT3 | 0.05 | - | - | - |

(a) Operating time without DG installation

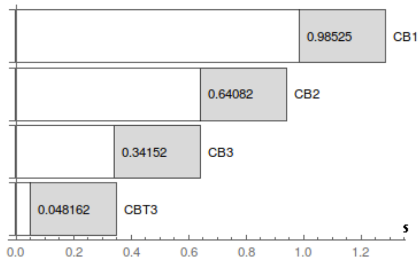



(b) Relay response for Path A

Figure 79: Penetration 0% - DG at all Buses with loads

| | $t_{trip}$ A | $t_{trip}$ B | $t_{trip}$ C | $t_{trip}$ D |
|---|---|---|---|---|
| CB1 | 0.985 | 0.985 | 0.748 | 0.985 |
| CB2 | 0.641 | 0.694 | – | 0.641 |
| CB3 | 0.342 | – | – | – |
| CB4 | – | 0.0486 | – | – |
| CBT1 | – | – | 0.0486 | – |
| CBT2 | – | – | – | 0.0486 |
| CBT3 | 0.0482 | – | – | – |

(a) DG - 50% penetration

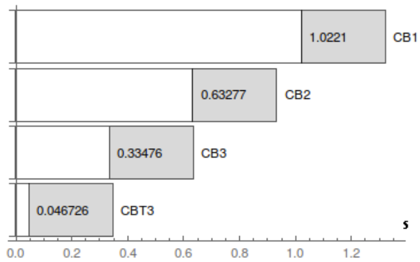



(b) Relay response for Path A

Figure 80: Penetration 50% - DG at all Buses with loads

| | $t_{trip}$ A | $t_{trip}$ B | $t_{trip}$ C | $t_{trip}$ D |
|---|---|---|---|---|
| CB1 | 1.02 | 1.02 | 0.757 | 1.02 |
| CB2 | 0.633 | 0.688 | – | 0.634 |
| CB3 | 0.335 | – | – | – |
| CB4 | – | 0.0475 | – | – |
| CBT1 | – | – | 0.0474 | – |
| CBT2 | – | – | – | 0.0474 |
| CBT3 | 0.0467 | – | – | – |

(a) DG - 100% penetration




(b) Relay response for Path A

Figure 81: Penetration 100% - DG at all Buses with loads

**Modified relay setting**

Applying the process in Chapter 2, the modified parameter for relays to ensure the correct operation are shown in Figure 82 and Table 27. Obviously all relay setting must be modified.

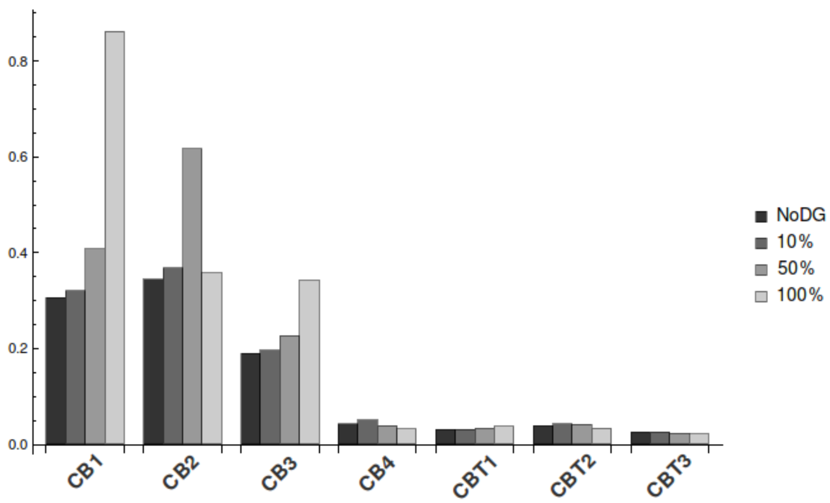



Figure 82: Modify TDS value for relays on Case multiple DGs

| $I_{pickup}$ [A] at | **CB1** | **CB2** | **CB3** | **CB4** | **CBT1** | **CBT2** | **CBT3** |
|---|---|---|---|---|---|---|---|
| **noDG** | 311 | 62.1 | 44.6 | 6.67 | 77 | 11.4 | 50.1 |
| **10%** | 277 | 29.1 | 27.2 | 9.01 | 76.7 | 11.3 | 65.9 |
| **50%** | 152 | 92.5 | 33.8 | 68.9 | 75.5 | 11 | 127 |
| **100%** | 21.1 | 227 | 97.6 | 139 | 74.4 | 10.7 | 193 |

Table 27: Modified pickup currents for relays - DG at multiple buses

# 5 Discussion and Conclusion

## 5.1 Discussions

Generally the DG installation helps to improve the voltage profile of the network. The best area for introducing DG is in the middle part of the network such as in Case Study 2 and 3 (Bus 19 and 14). When DG is connected to the very end, it could lead to over voltage if the penetration level is high enough. The nearer to the grid the DG has less impact on voltage profile of the system. Moreover, the case study 5 and 6 indicate that the potential problem with overvoltage could be eliminate by allocate DGs to several position in the power system.

In any cases, the DG will cause increase in fault level. The most severe impact happen while DG is connected at the end of the network faraway from the grid. This part of the network is designed to deliver small amount of power, less thermal durability and isolation; therefore become victim for increase of short circuit current during fault. In the Case study 1, the fault level could increase up to 80% at buses at the ends. Impact of DG on fault level will be reduce when DG location moved toward the grid in Case study 4 the impact is only 25%. However, it must be noticed that the relative value reduce does not mean the RMS value of short circuit currents reduce. It only indicates that DG has less chance to damage the power system equipments during fault.

The problem of false tripping will happen when DG is connected to sub-feeders from the same root only. Even in this test network there is only 2 sub-feeder, in practice, a main feeder is used to supply more sub-feeder. As discussed in case study 1, the problem with reverse power flow and reverse short-circuit current during fault at the neighbor sub-feeder from the one has DG could be severe. Then the traditional unidirectional overcurrent relay does not provide adequate protection for the system. The directional over current relay should be introduce to eliminate the problem and protect healthy sub-feeder from interruption and in some cases islanded operation.

From the results of all case studies, the blinding problem does not happen. During fault, the contribution of DG to short circuit current increase the total current magnitude and the contribution of grid is decrease slightly. The reduction is not enough to cause any blinding problem. The closer DG location to the grid, the less percentage of contribution to the the the fault.

As a result of fault level increase, the loss of coordination problem occurs in all cases. Because the relay operations is coordinate between them along a coordination path and also between coordinator paths, the coordination for relays at the longest with most number of relays will have the most narrow coordination. In this work the path A is the object of loss of coordination in all case studies. For other coordination paths, depending on location of DG it could leads to reduction of coordination margins.

Applying the traditional process for relay setting which introduced in chapter 2, the modified relay setting have been found. This modified values able to return the proper operation of protection system comply to the required conditions (section 2.4). However, with the high penetration level of DG, the required condition should be changed to adapt with the new situation but purpose of this changing is not the purpose of this work.

Even with the relatively small cases like which was presented in this work, the amount of data is considerable. The further study should be conduct using some kind of database structure instead of pure algorithms based.

## 5.2 Solutions

The increase of DG penetration level in distribution network is a irreversible trend. The preparation must be start to ensure the high reliability and safety for the power system and people. Several suggested solution to deal with problems are:

- Any DG must have their own protection system which allow to disconnect them from the network as soon as fault occurs.

- DG should be install in the middle part of the radial network, if DG is connected to the end of the network then a thorough study must be conduct to ensure no risk to power quality happen.

- The power size of DG connected to the end of the network should not be great to reduce risk of overvoltage during fault and light load condition.

- Directional relays should be used, especially for sub-feeder where false tripping problem is significant.

- The predetermined relay setting is not sufficient to ensure coordination between relays when DG is connected. In this particular case; however, only coordination of Path A faces this problem. Then by simply change the TDS value of relays located in path A could solve the problems.

- The better solution for lost of coordination problem is an method applying communication technology. This will provide information of DG penetration level in the system and the location of DGs. From this information the relay parameters could be recalculated and reset to ensure proper operations.

## 5.3 Future work

After noticing the issues as well as benefits of DG in radial network, the future work could be conducted to explore the best location which able to insert highest DG penetration level.

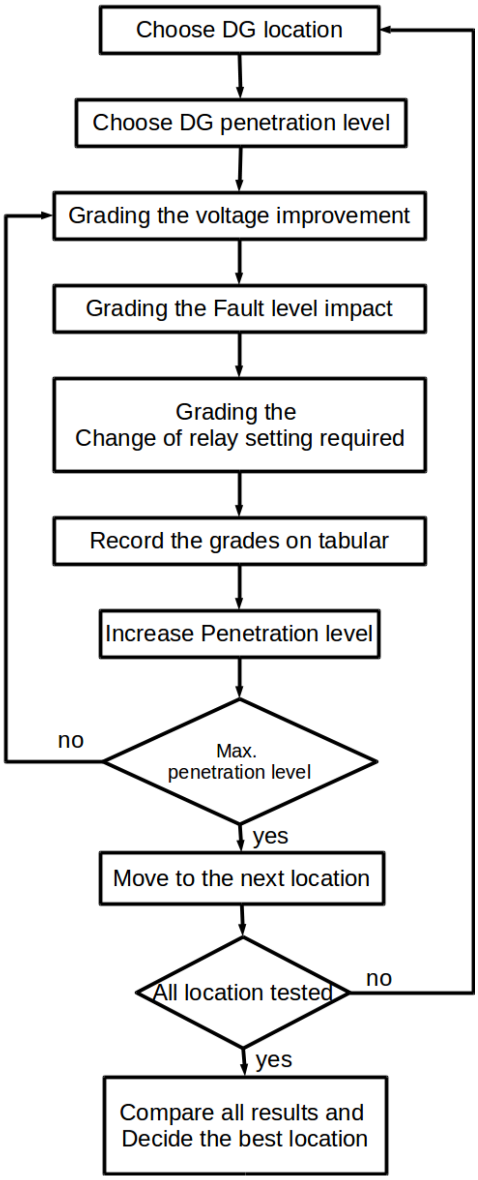



Figure 83: Flow chart for Future study

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# Appendices

## A Fault Analysis results

| Bus | a | b | c |
|---|---|---|---|
| 1 | 18520. | 18520. | 18520. |
| 2 | 6573.3 | 6573.3 | 6573.3 |
| 3 | 5616.1 | 5616.1 | 5616.1 |
| 4 | 5613.7 | 5613.7 | 5613.7 |
| 5 | 4894. | 4894. | 4894. |
| 6 | 1032. | 1032. | 1032. |
| 7 | 3322.7 | 3322.7 | 3322.7 |
| 8 | 4892.8 | 4892.8 | 4892.8 |
| 9 | 4335.1 | 4335.1 | 4335.1 |
| 10 | 4331.5 | 4331.5 | 4331.5 |
| 11 | 3886.6 | 3886.6 | 3886.6 |
| 12 | 3121.3 | 3121.3 | 3121.3 |
| 13 | 2879.9 | 2879.9 | 2879.9 |
| 14 | 2560.8 | 2560.8 | 2560.8 |
| 15 | 2254.4 | 2254.4 | 2254.4 |
| 16 | 2124.6 | 2124.6 | 2124.6 |
| 17 | 441.64 | 441.64 | 441.64 |
| 18 | 1986.7 | 1986.7 | 1986.7 |
| 19 | 2123.1 | 2123.1 | 2123.1 |
| 20 | 1721.1 | 1721.1 | 1721.1 |
| 21 | 1643. | 1643. | 1643. |
| 22 | 806.49 | 806.49 | 806.49 |
| 23 | 1647.7 | 1647.7 | 1647.7 |
| 24 | 2793.1 | 2793.1 | 2793.1 |

(a) 3-phase fault currents

| Bus | a | b | c |
|---|---|---|---|
| 1 | 10456. | 0 | 0 |
| 2 | 3688. | 0 | 0 |
| 3 | 3158.2 | 0 | 0 |
| 4 | 3156.5 | 0 | 0 |
| 5 | 2756.5 | 0 | 0 |
| 6 | 0.0060671 | 0 | 0 |
| 7 | 0.033632 | 0 | 0 |
| 8 | 2755.6 | 0 | 0 |
| 9 | 2444.7 | 0 | 0 |
| 10 | 2442.5 | 0 | 0 |
| 11 | 2193.9 | 0 | 0 |
| 12 | 1764.6 | 0 | 0 |
| 13 | 1629.1 | 0 | 0 |
| 14 | 1449.5 | 0 | 0 |
| 15 | 1276.8 | 0 | 0 |
| 16 | 1203.7 | 0 | 0 |
| 17 | 0.0060244 | 0 | 0 |
| 18 | 0.034526 | 0 | 0 |
| 19 | 1202.8 | 0 | 0 |
| 20 | 975.99 | 0 | 0 |
| 21 | 931.88 | 0 | 0 |
| 22 | 0.0061836 | 0 | 0 |
| 23 | 934.52 | 0 | 0 |
| 24 | 0.034842 | 0 | 0 |

(b) Phase to ground fault current

Figure A.1: Results of 3-phase fault and 1 phase fault

| Bus | a | b | c |
|---|---|---|---|
| 1 | 0 | 16 039. | 16 039. |
| 2 | 134.17 | 5821. | 5724. |
| 3 | 123.64 | 4981.8 | 4892.4 |
| 4 | 124.94 | 4981.1 | 4890.7 |
| 5 | 113.12 | 4346.4 | 4264.6 |
| 6 | 18.311 | 912.03 | 904.02 |
| 7 | 149.38 | 3024.7 | 2931.8 |
| 8 | 113.76 | 4346. | 4263.6 |
| 9 | 101.42 | 3851.3 | 3778. |
| 10 | 104.41 | 3850.8 | 3775. |
| 11 | 93.819 | 3455.4 | 3387.3 |
| 12 | 83.812 | 2782.9 | 2721.6 |
| 13 | 77.716 | 2568. | 2511.2 |
| 14 | 73.363 | 2287.4 | 2233.6 |
| 15 | 67.643 | 2016.5 | 1966.7 |
| 16 | 64.008 | 1900.6 | 1853.5 |
| 17 | 13.061 | 394.79 | 385.02 |
| 18 | 66.725 | 1782.6 | 1731. |
| 19 | 64.935 | 1900.3 | 1852.5 |
| 20 | 56.134 | 1543.8 | 1502.5 |
| 21 | 54.424 | 1474.5 | 1434.5 |
| 22 | 16.375 | 710.46 | 694.88 |
| 23 | 51.017 | 1475.3 | 1437.8 |
| 24 | 97.334 | 2500.9 | 2415.3 |

(a) 2 phase fault currents

| Bus | a | b | c |
|---|---|---|---|
| 1 | 0 | 16 434. | 16 460. |
| 2 | 0 | 5755.2 | 5913.6 |
| 3 | 0 | 4917.4 | 5053.7 |
| 4 | 0 | 4915.4 | 5051.5 |
| 5 | 0 | 4285.5 | 4404.4 |
| 6 | 0 | 893.75 | 893.75 |
| 7 | 0 | 2877.5 | 2877.5 |
| 8 | 0 | 4284.5 | 4403.3 |
| 9 | 0 | 3796.5 | 3901.7 |
| 10 | 0 | 3793.4 | 3898.4 |
| 11 | 0 | 3404.1 | 3498.2 |
| 12 | 0 | 2734.3 | 2809.4 |
| 13 | 0 | 2523. | 2592.2 |
| 14 | 0 | 2243.7 | 2304.9 |
| 15 | 0 | 1975.4 | 2029.1 |
| 16 | 0 | 1861.7 | 1912.3 |
| 17 | 0 | 382.47 | 382.47 |
| 18 | 0 | 1720.5 | 1720.5 |
| 19 | 0 | 1860.5 | 1910.9 |
| 20 | 0 | 1508.4 | 1549.1 |
| 21 | 0 | 1440. | 1478.8 |
| 22 | 0 | 698.44 | 698.44 |
| 23 | 0 | 1444.1 | 1483. |
| 24 | 0 | 2418.9 | 2418.9 |

(b) 2 phase to ground fault

Figure A.2: Results of 2-phase fault and 2 phase to ground fault

# B Network Data

| No | $V_{RMS}$ [kV] | $V_{pu}$ | P [MW] | Q [MVar] | Note |
|---|---|---|---|---|---|
| 1 | 27 600. | 1 | 0 | 0 | Grid |
| 2 | 27 600. | 1 | 0 | 0 | |
| 3 | 27 600. | 1 | -5.09 | -1.712 | Load M1+M2 |
| 4 | 27 600. | 1 | 0 | 0 | |
| 5 | 27 600. | 1 | 0 | 0 | |
| 6 | 27 600. | 1 | 0 | 0 | |
| 7 | 4800. | 1 | -2.49 | -0.818 | Load M3 |
| 8 | 27 600. | 1 | 0 | 0 | |
| 9 | 27 600. | 1 | -0.384 | -0.338 | Load M4 |
| 10 | 27 600. | 1 | 0 | 0 | |
| 11 | 27 600. | 1 | -0.12 | 0 | Load M5 |
| 12 | 27 600. | 1 | 0 | 0 | |
| 13 | 27 600. | 1 | -0.418 | -0.138 | Load M6 |
| 14 | 27 600. | 1 | 0 | 0 | |
| 15 | 27 600. | 1 | 0 | 0 | |
| 16 | 27 600. | 1 | 0 | 0 | |
| 17 | 27 600. | 1 | 0 | 0 | |
| 18 | 4800. | 1 | -0.4116 | 0 | Load M7 |
| 19 | 27 600. | 1 | 0 | 0. | |
| 20 | 27 600. | 1 | 0 | 0. | |
| 21 | 27 600. | 1 | 0 | 0 | |
| 22 | 27 600. | 1 | 0 | 0 | |
| 23 | 27 600. | 1 | -0.2346 | -0.0772 | Load M9 |
| 24 | 4800. | 1 | -1.482 | -0.487 | Load M8 |

Figure B.1: Bus Data of test network

| No | From | To | Connection | S [MVA] | VH [kV] | VX [kV] | xd [pu] | T |
|---|---|---|---|---|---|---|---|---|
| 1 | 5 | 6 | Y-Δ | 3.6 | 27.6 | 4.8 | 0.06 | 1.05 |
| 2 | 16 | 17 | Y-Δ | 1 | 27.6 | 4.8 | 0.04 | 1.02 |
| 3 | 21 | 22 | Y-Δ | 3.6 | 27.6 | 4.8 | 0.0565 | 1.06 |

Figure B.2: Transformer Data

| No | From | To | R1 [Ω] | X1 [Ω] | B1 [μS] | R0 [Ω] | X0 [Ω] | B0 [μS] | Length [km] |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 | 2 | 1.0346 | 2.3235 | 26.413 | 2.8603 | 7.8129 | 11.59 | 6.1 |
| 2 | 2 | 3 | 0.1696 | 0.3809 | 4.33 | 0.4689 | 1.2808 | 1.9 | 1 |
| 3 | 2 | 4 | 0.1696 | 0.3809 | 4.33 | 0.4689 | 1.2808 | 1.9 | 1 |
| 4 | 6 | 7 | 0.1696 | 0.3809 | 4.33 | 0.4689 | 1.2808 | 1.9 | 1 |
| 5 | 4 | 8 | 0.1696 | 0.3809 | 4.33 | 0.4689 | 1.2808 | 1.9 | 1 |
| 6 | 8 | 9 | 0.1696 | 0.3809 | 4.33 | 0.4689 | 1.2808 | 1.9 | 1 |
| 7 | 8 | 10 | 0.1696 | 0.3809 | 4.33 | 0.4689 | 1.2808 | 1.9 | 1 |
| 8 | 10 | 11 | 0.1696 | 0.3809 | 4.33 | 0.4689 | 1.2808 | 1.9 | 1 |
| 9 | 10 | 12 | 0.56477 | 1.2684 | 14.419 | 1.5614 | 4.2651 | 6.327 | 3.33 |
| 10 | 12 | 13 | 0.1696 | 0.3809 | 4.33 | 0.4689 | 1.2808 | 1.9 | 1 |
| 11 | 12 | 14 | 0.43757 | 0.98272 | 11.171 | 1.2098 | 3.3045 | 4.902 | 2.58 |
| 12 | 14 | 15 | 0.32902 | 0.73895 | 8.4002 | 0.90967 | 2.4848 | 3.686 | 1.94 |
| 13 | 15 | 16 | 0.1696 | 0.3809 | 4.33 | 0.4689 | 1.2808 | 1.9 | 1 |
| 14 | 17 | 18 | 0.1696 | 0.3809 | 4.33 | 0.4689 | 1.2808 | 1.9 | 1 |
| 15 | 15 | 19 | 0.1696 | 0.3809 | 4.33 | 0.4689 | 1.2808 | 1.9 | 1 |
| 16 | 19 | 20 | 0.6784 | 1.5236 | 17.32 | 1.8756 | 5.1232 | 7.6 | 4 |
| 17 | 19 | 23 | 0.848 | 1.9045 | 21.65 | 2.3445 | 6.404 | 9.5 | 5 |
| 18 | 4 | 5 | 0.1696 | 0.3809 | 4.33 | 0.4689 | 1.2808 | 1.9 | 1 |
| 19 | 20 | 21 | 0.1696 | 0.3809 | 4.33 | 0.4689 | 1.2808 | 1.9 | 1 |
| 20 | 22 | 24 | 0.1696 | 0.3809 | 4.33 | 0.4689 | 1.2808 | 1.9 | 1 |

Figure B.3: Line data of test network