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Electrical Power Engineering

# Testing All-in-one protection for any power distribution application using real time simulation

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**Summary**

Modern power systems are incorporating ICT technologies. The usage of sensors and different communication protocols are opening up an era of networks with interconnected nodes. This is helping to monitor and maintain power networks much easier as the data is now more readily available than ever before. This is, however, exposing power networks to new vulnerabilities of cyber threats. Generally, protective relays are the backbone of power system networks. Hence, relay testing before its actual deployment in power networks is extremely crucial.

The objective of this thesis is to study the overcurrent protection relay and selective coordination of two relays in a 110/20 KV MV European network. Short circuit study and relay coordination on this MV network was done in PSS CAPE software by setting the relay parameters. Coordination graphs were generated for different types of faults. This was followed by modeling the network in Typhoon HIL and eventual testing of the relays for tripping.

The selective coordination of the relays and its testing in Typhoon HIL went according to the desired goals and, therefore, the setting chosen for the relays was validated.

# Preface

The work presented in this thesis was conducted as part of Master studies at the Department of Electrical Power Engineering, USN, Porsgrunn Norway under the supervision of Mr. Franciso Gonzalez-Longatt.

In my workplace, there have been many projects in which short circuit and protection coordination studies were carried out by my colleagues for different clients. This inspired and instilled in me the importance and motivation to learn about this and broaden my horizon.

I must admit that this has been quite an interesting, but an arduous journey. It was, however, challenging at times too because of the time constraints. Relay protection is one of the most complex disciplines in electrical engineering and writing a thesis report on the subject serves injustice to it. There is no doubt that it require years of experience in the field to have a thorough understanding of the subject. However, this thesis is just the start and I am very eager to equip myself with more valuable and practical knowledge within the discipline of relay protection. It was, therefore, because of the time limitations that the testing could not be done on a physical relay.

I would like to thank my supervisor Mr.Franciso Gonzalez-Longlatt for providing guidance and support during the process. I would also like to thank Ronny Goin, relay protection specialist at Statkraft for his guidance, whenever I needed. I also wish to thank my family especially my wife for being patient during the course of my Master studies.

Porsgrunn, 08th June, 2021

Ammar Lodhi

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## Nomenclature

| | |
|---|---|
| **API** | Application Programming Interface |
| **CTI** | Coordination Time Interval |
| **CT** | Current transformer |
| **CAPE** | Computer-Aided Protection Engineering |
| **CIGRE** | International Council on Large Electric Systems |
| **DT** | Definite Time |
| **HIL** | Hardware-in-the-loop |
| **IED** | Intelligent Electronic Device |
| **IDMT** | Inverse Definite Minimum Time |
| **IOC** | Instantaneous Overcurrent |
| **IoT** | Internet of Things |
| **IEC** | International Electrotechnical Commission |
| **MV** | Medium Voltage |
| **PHxPTOC** | Three-phase non-directional overcurrent protection |
| **TOC** | Time Overcurrent |

# 1 Introduction

## 1.1 Background

Due to the constant evolution of power system networks in smart grids, and the usage of sensor technologies and communication protocols, the IED's shall need to be tested before deployment in the power network.

The conventional method of relay testing (Blop Opal-rt Technologies) uses steady state or dynamic tests where the signals are injected into the relay and the response of the relay with regards to pick up and detection time is measured.

However, due to the integration of renewable energy sources into the power grid, the power grid can be subjected to various fault scenarios. Therefore, the conventional method of relay testing is not suitable.

In hardware-in-the-loop testing methodology the system model is loaded with test scenarios on the real time simulator which is interfaced to an amplifier. The amplifier is then connected to the physical relay. The model parameters can be modified in real time and then tested (Beaudoin).

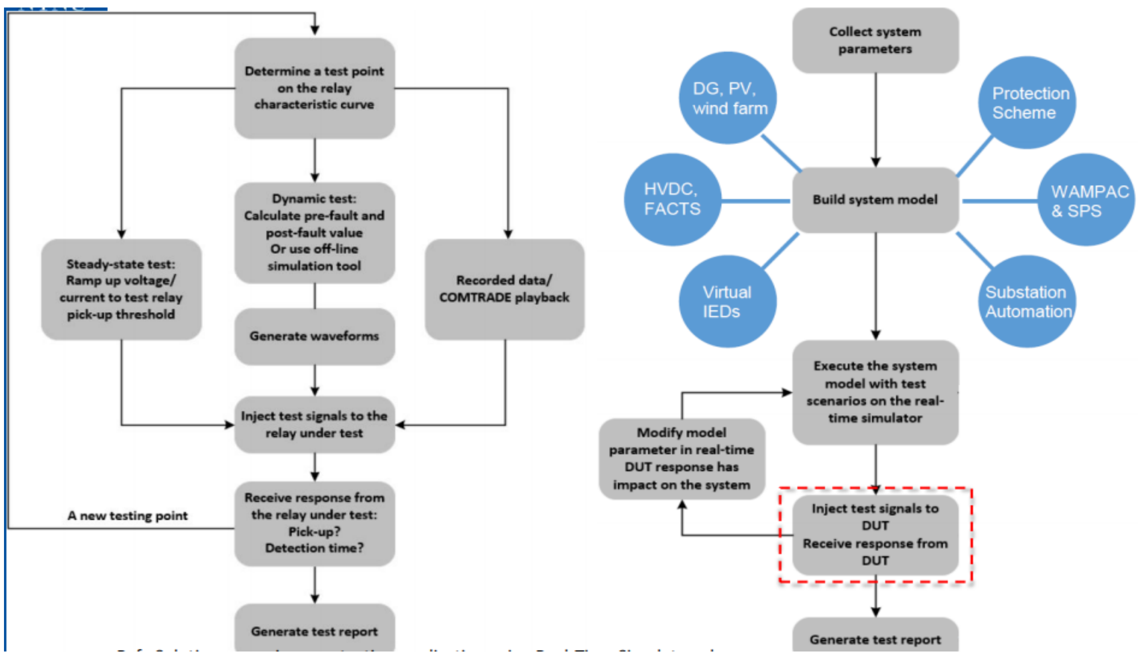


Figure 1-1. Traditional Testing Versus HIL Testing

## 1.2 Objective

The objective of this thesis is to perform selectivity analysis on ABB relays by using them into a power system network and then validating the setting of the relay by building the network, and testing the relays in Typhoon HIL.

## 1.3 Methods

The European 110/20 KV MV network was used for selectivity analysis and overcurrent protection. The power network model was first built in PSS CAPE software and then different faults inside the network were generated. These faults were then used to find the relay parameter settings. Later, the coordination graphs for the two relays were produced.

Tools used in the thesis were PSS CAPE and Typhoon HIL. PSS CAPE is a specialized tool for relay protection engineering whereas Typhoon HIL was used to validate the setting of the relay by first building the model in schematic editor and then loading the model in the virtual HIL device. Finally, the relay was tripped for the different type of faults from SCADA Panel interface.

## 1.4 Scope

Study Area: 110/20KV MV CIGRE network was used for analysis.

Tools: PSS CAPE and Typhoon HIL

Timeline: 11$^{th}$ January to 10 June 2021

Helping Aids: Professor Francisco Gonzalez provided the Python Code for HIL API.

## 1.5 Report Structure

Chapter 2 discusses the basic concepts of protection relay regarding its performance requirements and the flow for carrying out the coordination study. At the end, the different types of earthing systems are discussed along with the significance of real time simulators.

Chapter 3 discusses the methodology in order to find the settings of the two relays deployed in the CIGRE power network followed by generation of coordination graphs for the different type of faults.

Chapter 4 deals with the validation of the relay settings in the Typhoon HIL software.

Chapter 5 concludes the work in the thesis.

# 2 Theoretical Background and Literature Review

This chapter covers the theoretical background for protection system, overcurrent protection and coordination followed by types of earthing systems. The different types of protection provided by REF630 and RE640 are discussed briefly. An introduction to Hardware-in-the-Loop (HIL) simulation is provided with focus on Typhoon HIL technology.

### 2.1.1 Protection system

The function of the protective relay is to sense and isolate faults quickly, thereby preventing unnecessary equipment outages or equipment damage. The important aspects of protection system are:

### 2.1.2 Reliability:

The reliability of a protection system depends on two main factors.

**Dependability:** A protective relay must operate when required. The operation of relay at the correct instance is ensured by proper settings of a relay. It is also extremely important to provide backup protection in case if the main protection fails. The hardware and software of the relay should be tested before putting it into deployment in the power grid.

**Security:** Security is measured by the degree of certainty that the relay will not operate incorrectly. Nowadays, the false tripping of circuit breakers initiated by cyberattacks on protective relays is a growing concern in power systems. This is the reason that different detection systems are undergoing extensive research for cyberattack prevention (Khaw & Amir, 2019).

### 2.1.3 Performance Requirements

The performance of a protection relay is measured by its extent to provide proper sensitivity, selectivity, and the speed at which the relay operates.

**Sensitivity:** A protection relay should be able to detect the smallest possible fault current. Earth faults have lowest magnitude and a relay should be able to detect these faults.

**Selectivity:** In case of a fault, selectivity in a power network is achieved by allowing the closest protective relay to operate. The power network that must be shutdown due to this fault is thus kept to the minimum. Several protective devices can respond to the fault condition, but the protective device close to the fault must operate and clear the fault.

**Speed:** In order to maximize safety and minimize damage to power system components, a fault should be cleared quickly. The operating speed of microprocessor-based relays, which are widely used nowadays, is much faster than electromechanical relays.

Protective relays are generally referred by standard device numbers as shown in Table 2-1.

Table 2-1 Abbreviated List of Commonly Used Relay Device Function Numbers

| Relay Device Function No | Protective Function |
|---|---|
| 21 | Distance |
| 25 | Synchronizing |
| 27 | Under voltage |
| 32 | Directional Power |
| 40 | Loss of Excitation |
| 46 | Phase Balance |
| 47 | Phase-sequence voltage |
| 49 | Thermal (Generally Thermal Overload) |
| 50 | Instantaneous Overcurrent |
| 51 | Time-Overcurrent |
| 59 | Overvoltage |

| | |
|---|---|
| 60 | Voltage Balance |
| 67 | Directional Overcurrent |
| 81 | Frequency |
| 86 | Lockout |
| 87 | Differential |

## 2.2 Time-overcurrent and Instantaneous Overcurrent Relays

The most commonly used protective relays are the time-overcurrent and instantaneous overcurrent relays. They are used as both primary and backup protection devices.

The time overcurrent relays are used to provide a time delay tripping versus current whereas instantaneous overcurrent relays are selected to provide high-speed tripping.

## 2.3 Coordination Study

The purpose of the coordination study is to find out the characteristics, ratings, and settings of protective devices to be deployed in power system network and to interrupt short circuits as rapidly as possible.

Protective devices are used in power systems as primary and backup protection. When a fault occurs, the primary protection should operate and isolate the fault. Backup protection only takes over when primary protection fails to clear the fault.

### 2.3.1 Short Circuit Currents

When performing coordination study, short circuit currents for each bus is necessary (society, 2001). This includes the following:

- Maximum and minimum three phase short circuit current.
- Maximum and minimum ground fault current.

The maximum short circuit current may be used to set the Coordination Time Interval (CTI) for time overcurrent devices in the system. When plotting time current curves for each protective device, certain time interval should be maintained to ensure selective operation. This time interval is called the Coordination Time Interval (CTI). The minimum short circuit current is needed to determine if the protective device is sensitive to trip the fault.

### 2.3.2 Load Flow Currents

For coordination study, it is necessary to calculate the load currents through each feeder circuit. The load current is used to establish protective device continuous current ratings.

### 2.3.3 Pickup Current

The pickup of an overcurrent protective relay is the minimum value of current that causes the relay to close its contacts

### 2.3.4 Time-Current Characteristic Plots

Understanding of time-current characteristic plots is essential for coordination study. The TCC curves give the operating time of a protective device for various magnitudes of operating current. A TCC curve is shown in Figure 2-1.

The TCC curves are plotted with current on the x-axis and time on the y-axis. The region below and to the left of the characteristic curve is the area where the protective device does not operate whereas the region to the right is the tripping or operating area.

Starting at given value of fault current on the x-axis and proceeding upward, the first device whose curve is intersected shall be the first device to operate. Continuing further, the next curve should be the closest upstream protective device, which provides backup protection as shown in Figure 2-1.

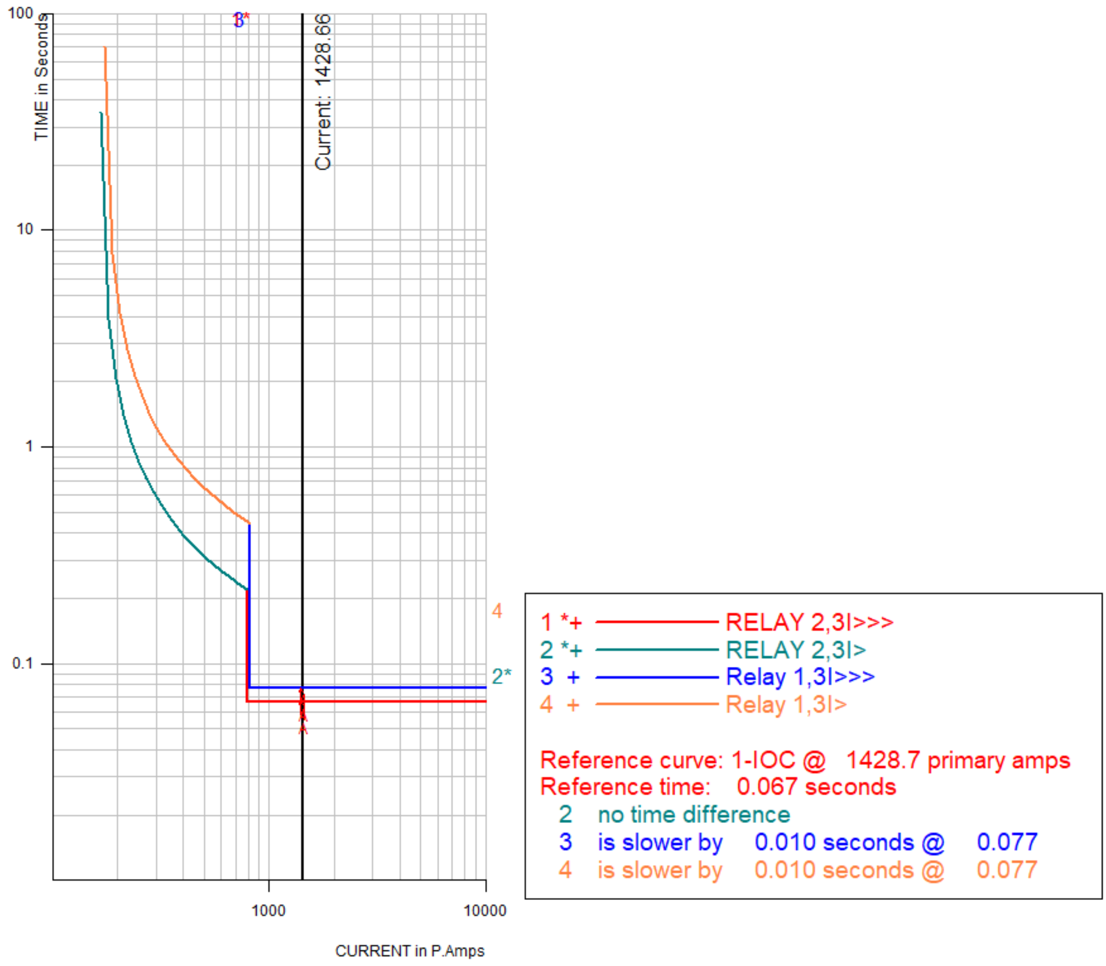


Figure 2-1 Time Current Characteristic Curve

## 2.4 Types of Earthing Systems

The different types of earthing systems are given below:

### 2.4.1 Solid Earthing

When the neutral of a transformer is solidly earthed, it is directly connected to earth. This type of earthing gives low over-voltages, but causes large fault currents.

### 2.4.2 Isolated Neutral

In this type of earthing method, the neutral of transformer is isolated and, hence, there is no connection between neutral and earth. This type of earthing system is used in applications where shutdowns are unwanted e.g. intensive care units. In this type of earthing system, the fault current magnitude is low and depends upon capacitance of the conductors to earth. European networks have isolated neutral (K. & Ehsan, 2014).

### 2.4.3 Resistance Earthed

A resistance is connected between the transformer neutral and earth in resistance earthed system. This type of earthing system is used to limit phase to ground fault currents. Resistance earthing system is of two types:

#### 2.4.3.1 Low Resistance Earthing

In Low resistance earthing, the neutral grounding resistor limits the fault current to 200-400 A.

#### 2.4.3.2 High Resistance Earthing

In high resistance earthing system, the neutral grounding resistor limits the current to 5-10 A.

## 2.5 ABB Relays REF615 and REX640

REF615 is ABB's protection relay for overhead lines and cable feeders in isolated neutral, resistance and solidly earthed networks, and in industrial and utility power systems. It also provides protection in redial and meshed distribution networks.

The different protection functions offered by the relay are: directional and non-directional overcurrent and earth fault protection, and voltage and frequency-based protection.

REX640 is an all in one protection for any power distribution networks. REX640 is a modular relay which means that it is easy to build the base functionality on it by adding hardware cards and application packages, depending upon the intended application (Protection and control REX640) .

The base functionality is always included and comprises of overcurrent protection, earth fault protection, voltage protection, frequency protection, load shedding, and restricted earth fault.

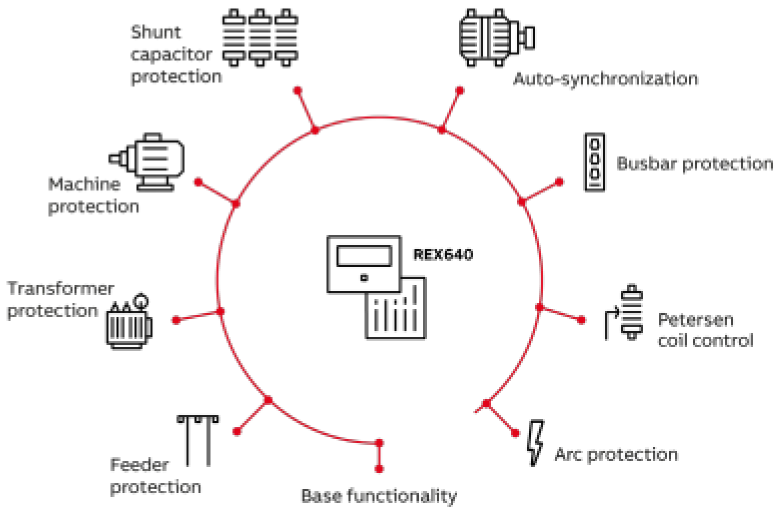


Figure 2-2 REX640 Protection Functions


Figure 2-3 ABB REX640 Relay


Figure 2-4 ABB REF615 Relay

## 2.6 Real Time Simulation

The legacy power infrastructure was simple, but the modern-day power network is supplemented with several IT applications and computer plays an important role. Internet of things (IoT) is becoming integral part of legacy power infrastructure thus leading to the emergency of smart grid. IoT refers to a type of network where various components of the system connect to each other using advance ICT systems including sensors, meters, and controllers (Hossein & Jalal). Enhanced integration of information and communication technologies in the smart grid have led to the possibility of a cyber-attack.

Consequently, testing relays in a real power network is not advisable since it can jeopardize the reliability of the system. An electric power grid is critical and experimenting on the actual grid is not allowed.

The challenge of today's grid digitalization is to make sure that all grid components work together in all possible real-life scenarios. This requires new testing requirements which should enable to test different control schemes under different fault conditions.

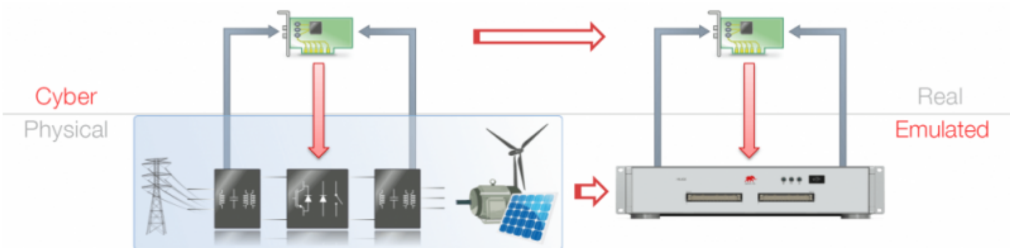


Figure 2-5 Typhoon HIL as a Cyber Physical Test Bed [9]

Controller Hardware in Loop (C-HIL) enables to digitalize (emulate) the physical components of the power network while running the control software on top of the digital layer. Secondly, the Real-Time Cyber-Physical Test bed is used to simulate the power system in real time along with the actual hardware (relays etc.) (Venkataramana, 2016).

Moreover, Typhoon HIL provides a test bed with integrated controllers and allows connecting and communicating with actual hardware protection relays. This in turn enables to comprehensively test and validate the control, and communicate under all operating conditions, including all fault scenarios. Models comprising of transformers and loads are simulated on ultra-low latency micro grid test bed with time steps as low as 500 ns (Common methodologies).

# 3 Methodology

This chapter covers the method of finding the overcurrent relay settings for ABB relay REF615 by deploying it in a European MV distribution network, shown in Figure 3-1. The relay settings are then validated with respect to selectivity by generating Coordination graphs.

## 3.1 Introduction

Both Relays REF630 and REF615 are used as single-phase, two-phase and three-phase non-directional overcurrent and short circuit protection for feeders, i.e. PHxPTOC (630 Series Technical Manual). PHxPTOC is used in several applications in power systems, but here we will use it for two purposes. These are given below as:

- Selective overcurrent and short circuit protection of feeder in the distribution system.
- General backup protection.

The overcurrent function has a low stage overcurrent protection, high stage overcurrent protection, and instantaneous stage overcurrent protection. The low stage is used for overcurrent protection and contains several types of time-delay characteristics, whereas high stage and instantaneous stage are used for fast clearance of very high overcurrent situations. Moreover, the low and high stage overcurrent protection can be selected to be either definite time (DT) or inverse definite minimum time (IDMT).

The instantaneous stage always operates with the definite time characteristic. The overcurrent protection function of the relay and its identification is given in Table 3-1.

Table 3-1 Identification of Protection Functions

| Functional Description | IEC 60617 IDENTIFICATION |
|---|---|
| Three-phase non-directional overcurrent protection - Low stage | 3I> |
| Three-phase non-directional overcurrent protection - High stage | 3I>> |
| Three-phase non-directional overcurrent protection - Instantaneous stage | 3I>>> |

Relay REF615 has been selected as the relay for protection since the relay REF630 and REX640 are not available in the PSS CAPE library.

## 3.2 Overcurrent Relay Setting and Coordination

A one-line diagram of the 20 kV distribution network with European configuration is depicted in Figure 3-1.

In normal operating conditions, the circuit breakers S1, S2, and S3 are open. Hence, the relay settings have been done on Feeder 1 with the circuit breakers S1, S2, and S3 open. This type of network is known as the Radial network. The data for the power transformer, lines and load are shown in the following section, Table 3-2 and Table 3-3 respectively.

In distribution networks, S1, S2 and S3 are not closed because it is not recommended to have closed loops. In case of closed loops, the fault current is split and supplied from both sides. Circuit breakers S1, S2, and S3 are closed only in case of fault on a feeder line that is first isolated by opening disconnected switches for backup power supply from the other side.

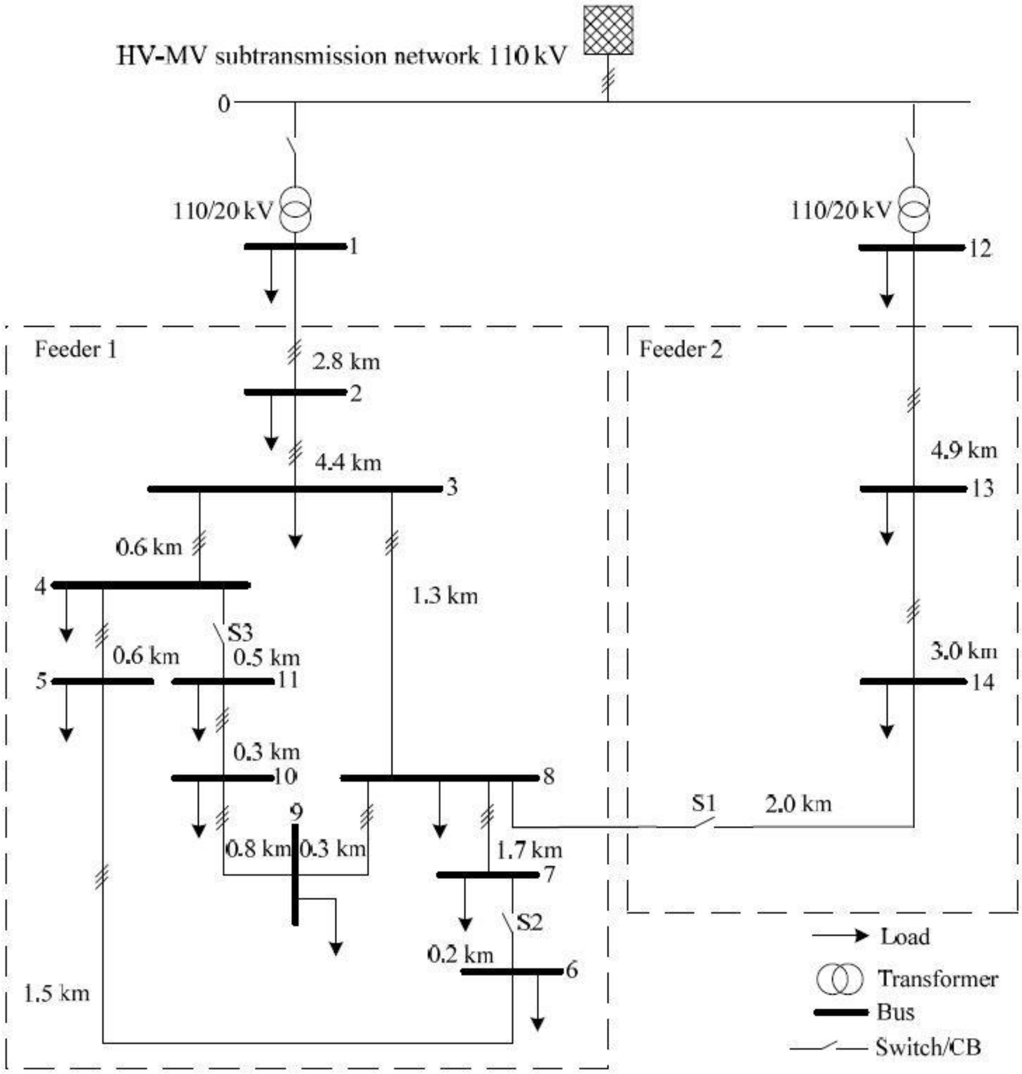


Figure 3-1 Topology of European MV Distribution Network

## 3.3 Network data

The equivalent 110 kV network parameters are given as:

- Three-phase short circuit power: 5000 MVA
- Nominal system voltage: 110 kV
- R/X ratio: 0.1

Power transformer parameters are:

- Vector group: YNd1
- Rated power: 25 MVA

- Primary voltage: 110 kV
- Secondary voltage: 20 kV

The Line parameters are shown in the Table 3-2.

Table 3-2 Line Data

| **Line Segment** | **Node from** | **Node to** | **Conductor ID** | $R'_{ph}$ | $X'_{ph}$ | $B'_{ph}$ | $R'_{o}$ | $X'_{o}$ | $B'_{o}$ | $I$ | **Installation** |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | $[\Omega/\mathrm{km}]$ | $[\Omega/\mathrm{km}]$ | $[\mu\mathrm{S}/\mathrm{km}]$ | $[\Omega/\mathrm{km}]$ | $[\Omega/\mathrm{km}$ | $[\mu\mathrm{S}/\mathrm{km}]$ | $[\mathrm{km}]$ | |
| 1 | 1 | 2 | 2 | 0.501 | 0.716 | 47.493 | 0.817 | 1.598 | 47.493 | 2.82 | Underground |
| 2 | 2 | 3 | 2 | 0.501 | 0.716 | 47.493 | 0.817 | 1.598 | 47.493 | 4.42 | Underground |
| 3 | 3 | 4 | 2 | 0.501 | 0.716 | 47.493 | 0.817 | 1.598 | 47.493 | 0.61 | Underground |
| 4 | 4 | 5 | 2 | 0.501 | 0.716 | 47.493 | 0.817 | 1.598 | 47.493 | 0.56 | Underground |
| 5 | 5 | 6 | 2 | 0.501 | 0.716 | 47.493 | 0.817 | 1.598 | 47.493 | 1.54 | Underground |
| 6 | 6 | 7 | 2 | 0.501 | 0.716 | 47.493 | 0.817 | 1.598 | 47.493 | 0.24 | Underground |
| 7 | 7 | 8 | 2 | 0.501 | 0.716 | 47.493 | 0.817 | 1.598 | 47.493 | 1.67 | Underground |
| 8 | 8 | 9 | 2 | 0.501 | 0.716 | 47.493 | 0.817 | 1.598 | 47.493 | 0.32 | Underground |
| 9 | 9 | 10 | 2 | 0.501 | 0.716 | 47.493 | 0.817 | 1.598 | 47.493 | 0.77 | Underground |
| 10 | 10 | 11 | 2 | 0.501 | 0.716 | 47.493 | 0.817 | 1.598 | 47.493 | 0.33 | Underground |
| 11 | 11 | 4 | 2 | 0.501 | 0.716 | 47.493 | 0.817 | 1.598 | 47.493 | 0.49 | Underground |
| 12 | 3 | 8 | 2 | 0.501 | 0.716 | 47.493 | 0.817 | 1.598 | 47.493 | 1.30 | Underground |
| 13 | 12 | 13 | 1 | 0.510 | 0.366 | 3.172 | 0.658 | 1.611 | 1.280 | 4.89 | Overhead |
| 14 | 13 | 14 | 1 | 0.510 | 0.366 | 3.172 | 0.658 | 1.611 | 1.280 | 2.99 | Overhead |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 15 | 14 | 8 | 1 | 0.510 | 0.366 | 3.172 | 0.658 | 1.611 | 1.280 | 2.00 | Overhead |

Load Parameters are also shown through the Table 3-3 below:

Table 3-3 Load Data

| Node | Apparent Power, $S[\mathrm{kVA}]$ | | Power Factor, $pf$ | |
|---|---|---|---|---|
| | **Residential** | **Commercial/Industrial** | **Residential** | **Commercial/Industrial** |
| 1 | 15300 | 5100 | 0.98 | 0.95 |
| 2 | --- | --- | --- | --- |
| 3 | 285 | 265 | 0.97 | 0.85 |
| 4 | 445 | --- | 0.97 | --- |
| 5 | 750 | --- | 0.97 | --- |
| 6 | 565 | --- | 0.97 | --- |
| 7 | --- | 90 | --- | 0.85 |
| 8 | 605 | --- | 0.97 | --- |
| 9 | --- | 675 | --- | 0.85 |
| 10 | 490 | 80 | 0.97 | 0.85 |
| 11 | 340 | --- | 0.97 | --- |
| 12 | 15300 | 5280 | 0.98 | 0.95 |
| 13 | --- | 40 | --- | 0.85 |
| 14 | 215 | 390 | 0.97 | 0.85 |

In Figure 3-1 is a 14 Busbar power network with a 110/20 kV main power transformer. Each 20 kV Busbar has several number of distribution feeders feeding three-phase residential, commercial, and industrial loads via a 20 kV/400V transformer. This is not shown in Figure 3-1 for the purpose of simplicity. The MV network was built in PSS CAPE software as shown in Figure 3-2 for fault analysis, relay setting and generating coordination graphs.

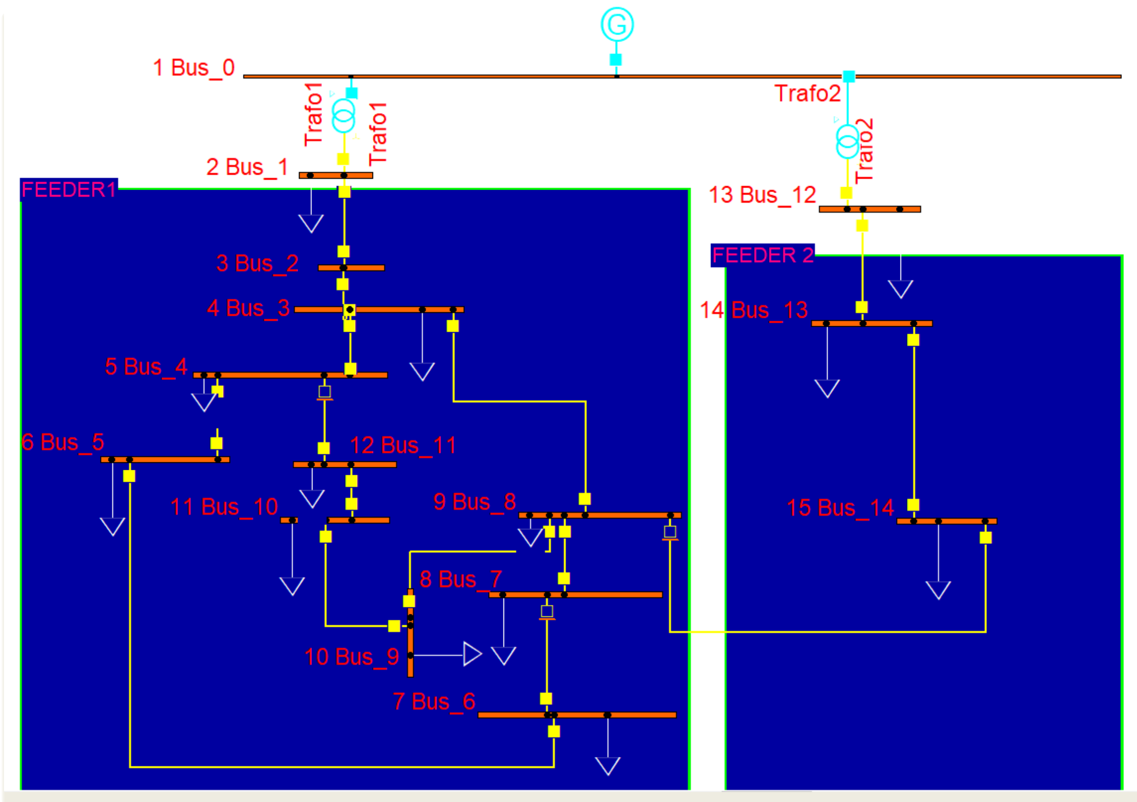


Figure 3-2 PSS CAPE Version of MV Network

The task is to set up two ABB relays R1 and R2 and model REF615 at Bus 1 and Bus 2 respectively. It is also to establish the coordination and selectivity between the two relays in the radial network, i.e. Feeder 1. This objective has been achieved by finding the relay pickup, time multiplier 'K' of the low stage overcurrent protection 3I>. The relay pickup of overcurrent protection, instantaneous stage 3I>> and operating time of the stage has been calculated.

One of the main objectives of a good protection system is selectivity, which implies that in case of a fault in the network only the protective device that is closest to the fault shall respond and isolate the fault. If the protective device closest to the fault is unable to isolate the fault, the device upstream should isolate the fault after some time delay. This difference in operating times between upstream and downstream relays for coordination is called Coordination Time Interval (CTI). The CTI is dependent upon the total time of operation of relay and the circuit breaker opening time. The electromechanical relays and static relays are slower than the modern-day numerical relays, which are faster. The time of operation of relay REF615 is shown in Table 3-4. It is subdivided into the following sub-intervals:

Table 3-4.Relay Operating Time

| **Characteristics** | **Max Values** |
|---|---|
| Start Time | |
| -Overcurrent Protection Low Stage 3I> and High stage 3I>> | 25ms |
| -Overcurrent Protection Instantaneous Stage (3I>>>) | 14ms - 23 ms |
| Reset Time | < 40 ms |
| Retardation Time | < 30 ms |
| Operation time accuracy in DT and IT mode | 20 ms |

**Start and Trip Signal**: Every protection stage has two internal binary output signals: start, and trip. When the phase current exceeds the start value of the low, high, or instantaneous stage; the stage will generate a start signal after 25ms and 23ms, respectively, shown in Table 3-4. When the calculated operation time of IDMT or DT characteristic of Low, high, or Instantaneous stage elapses, the respective stages will generate a trip signal.

**Reset Time:** The reset time of all the stages in REF615 is less than 40ms.

**Retardation Time:** The retardation time is when a protection relay needs to notice that a fault has been cleared during the operation time delay. The retardation time of REF615 is less than 30ms.

The operation time inaccuracy of different stages of REF615 is a maximum of 20ms. In addition to the relay operation time, the time of opening of circuit breakers has been considered, which for fast circuit breakers is less than 60ms is. Consequently, based on the characteristics of relays and circuit breaker operating time, as discussed above, the coordination time interval between the different numerical relays will be set to approximately 200ms.

## 3.4 Calculation of line 2-3 Overcurrent Protection Settings (REF615)

The overcurrent protection of line 2-3 will be realized using two stages. These stages are:

- Inverse time overcurrent low stage 3I>
- Instantaneous overcurrent high stage 3I>>>

Many applications require several steps using different current start levels and time delays. REF615 has the option to choose a low, high, or an instantaneous stage.

### 3.4.1 Selection of CT:

#### 3.4.1.1 NAMEPLATE: -

The reliability and correct operation of overcurrent protection is determined by the correct selection of the current transformer. An example of nameplate of a protection CT is shown below:

$$15VA \quad 5P \;\; 10 \text{ ----------------------------(1)}$$

In the above equation, 15VA refers to the burden of the CT and is specified in Volt-Ampere. The burden of the CT is the total resistance of the secondary circuit of CT and is the sum of resistances of CT secondary winding, connecting wires and the resistance of the relay. 5P10 shows that the CT is used for protection applications and will maintain its measurement accuracy of 5% over $10 \times$ In. This factor of 10 is called the Accuracy Limit Factor, and the accuracy class is 5P. Accuracy class of 5P and 10P are both suitable for non-directional overcurrent protection.

### 3.4.2 Requirements for Current Transformers (Non-Directional Overcurrent Protection)

The major criterion of the selection of current transformer ratio is maximum load current. The current transformer secondary current at maximum load currents should not exceed the continuous current rating of the relay. There are certain requirements that need to be fulfilled when specifying a CT for protection relays which are given in equation (2) and (3).

$$\mathrm{I1n} > Ikmax/100 \text{-----------------------(2)}$$

Where $\mathrm{I1n}$ is the nominal primary current of CT and $Ikmax$ is maximum fault current.

### 3.4.3 Recommended Start Current Settings

The recommended start current, or the pickup current of the relay should fulfill the following requirements:

$$\text{Current start value} < 0.7\ x\ (\mathrm{Ikmin}/\mathrm{I1n}) \text{-----------------(3)}$$

$\mathrm{I1n}$ is the nominal primary current of the CT, and $\mathrm{Ikmin}$ is the lowest primary current at which the highest set overcurrent stage, i.e. 3I>>> is to operate.

The protection zone of relay R2 at bus 2 is till the far end of busbar 6, 7, and 11. Hence, the highest set overcurrent stage, i.e. Instantaneous 3I>>> of relay R2 should be set to operate at the minimum amongst the 3 phase faults on busbar 6, 7, and 11.

The max 3 phase faults at busbar 6, 7, and busbar 11 are calculated using PSS CAPE software and are listed in the following Table 3-5.

Table 3-5: 3 Phase Faults at Busbar 6, 7, and 11

| **3 Phase fault** | **Max Values** |
|---|---|
| Busbar 6 | 1220 A |
| Busbar 7 | 1194 A |
| Busbar 11 | 1219 A |

The minimum of the faults currents in Table 3-5 is at busbar 7, i.e. 1194 A. Hence, the Instantaneous stage should trip at 1194 A. The factor 0.7 considers the protection relay inaccuracy, current transformer errors, and imperfections of the short circuit calculations.

$$Current\ start\ value\ <\ 0.7\ X\ 1194/200$$

$$Current\ start\ value\ <\ 4.1\text{------------------------------------------}(4)$$

The overcurrent protection current start value is, therefore, <4.1.

In order to verify the selected CT, that if it fulfills the requirements in equation (2) or not, $Ikmax$ i.e. max 3 phase fault close to Relay R2 was calculated using PSS CAPE software.

$$Close - in\ fault\ (Amps)\ =\ 1576.19$$

$$I1n\ >\ 1576.19/100\ =\ 15.7919$$

$$The\ CT\ 2_{ratio} = 200{:}1$$

Where

$$I1n\ =\ 200\ >\ 15.79\ (Hence\ criterion\ in\ equation\ (2)\ is\ fulfilled)$$

### 3.4.4 Overcurrent Protection Low Stage 3I> Pickup Setting

Low stage 3I> is used in the IDMT curves for overcurrent protection. In IDMT curves, the operation time depends on the value of the current i.e. the higher the current, the faster the operating time.

The total load current seen by relay R2 at Bus 2 is the sum of load at Bus 2 and all the loads downstream i.e. 132 Amps, as shown in Table 3-6.

Table 3-6 Load Current Relay R2

| **Bus No.** | **Load in Amps** |
|---|---|
| Bus 2 | ____ |
| Bus 3 | 15.8 Amps |
| Bus 4 | 12.8 Amps |
| Bus 5 | 21.6 Amps |
| Bus 6 | 16.3 Amps |
| Bus 7 | 2.5 Amps |
| Bus 8 | 17.4 Amps |
| Bus 9 | 19.4 Amps |
| Bus 10 | 16.4 Amps |
| Bus 11 | 9.8 Amps |
| Total | 132 Amps |

$$I^{pick\text{ - }up}_{51}(3I>) = 1.25 \cdot 132 = 165\ Amps$$

The appropriate ratio of the current transformer which fulfills the criterion in (2)can be selected as:

$$CT\ 2_{ratio} = 200{:}1$$

$I^{pick\text{ - }up}_{51}(3I>) = \frac{165}{200} Amps =$ 0.825< 4.1 (fulfills the criterion in equation (4)

The following equation gives the standard equation for the IEC Normal Characteristic curve:

$$t[s] = \left[\left(\frac{A}{\left(\frac{I}{I>}\right)^{c} - 1} + B\right)\right].K \text{ --- } (5)$$

t[s]= Relay operating time in seconds

I = measured current

I> set Start value

k = set Time multiplier

For relay R2, the time multiplier i.e. K is chosen as 0.05.

Where,

A = 0.14

B = 0

K = 0.05

C= 0.02 for IEC Normal Inverse curves

I = 1194 Amps

I>= 165 Amps.

Putting in the values in equation (5), we get

$$t[s] = 0.1733\ sec$$

Adding circuit breaker operating time $T_{CB,OP}$ to the relay operating time t[s],

$$T = 0.1733 + 0.06 = 0.23\ sec$$

Hence the Coordination time Interval for Relay R1 at bus 1 shall be $CTI = 0.23\ sec$. The value of K is called the Time Setting Multiplier which determines the operating time of relay. The higher its value is, the more time the relay will take to operate. Figure 3-3 shows the different time multiplier setting values and the respective operating time of relay.

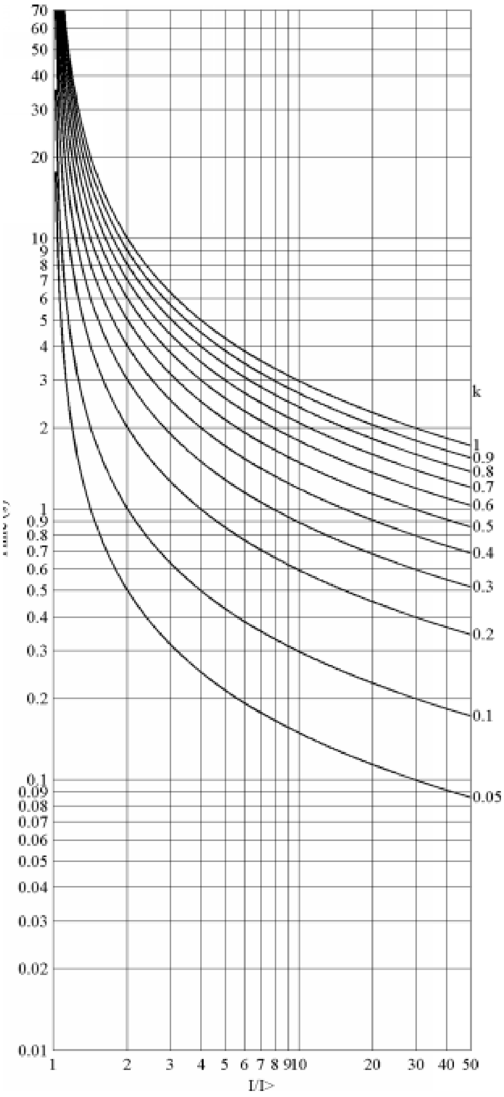


Figure 3-3 IEC Normal Inverse Curve, REF615

## 3.4.5 Overcurrent Protection Instantaneous Stage 3I>>> Pickup Setting

The overcurrent protection high stage 3I>>> pickup setting should be set to comply with the following

$$\text{Current start value} < 0.7\ x\ (\text{Ikmin}/\text{I1n})$$

$$Current\ start\ value < 0.7\ X\ 1194/200$$

Hence, the value is:

$$I_{51}^{pick\text{-}up}(3I \gg >) = 4$$

The relay setting of relay R2 at bus 2 can be summarized with the help of Table 3-7 as follows:

Table 3-7 Relay Settings REF615 for Relay R2 at Bus 2.

| **Tap Name/Description** | **Setting** |
|---|---|
| Start value of stage 3I> | 0,83×In |
| Time/current characteristic for stage 3I> | IEC Normal Inverse |
| Time multiplier k | 0.05 |
| Start value of stage 3I>>> | 4×In |
| Operate time of stage 3I>>> | 0.05 s |

Please note that the start value of stage 3I>>> is selected as 50ms so that the relay should not trip for initial inrush currents for loads such as motors.

## 3.5 Calculation of line 1-2 Overcurrent Protection Settings (REF615)

For proper coordination settings, the protection relay should not only be selective, but also sensitive. It is to be ensured that if the relay R2 at bus 2 malfunctions, then the Relay R1 at bus 1 shall provide backup protection. This is achieved by time grading, which is done by choosing an appropriate coordination time interval based on relay, and circuit breaker operation time.

The current sensed by Relay R1 is the sum of current at Bus 1 and all the currents downstream of bus 1 at all the respective buses. This is given in Table 3-8 for further understanding:

Table 3-8 Load Current Relay R1

| **Bus No.** | **Load in Amps** |
|---|---|
| Bus 1 | 573 Amps |
| Bus 2 | _____ |
| Bus 3 | 15.8 Amps |
| Bus 4 | 12.8 Amps |
| Bus 5 | 21.6 Amps |
| Bus 6 | 16.3 Amps |
| Bus 7 | 2.5 Amps |
| Bus 8 | 17.4 Amps |
| Bus 9 | 19.4 Amps |
| Bus 10 | 16.4 Amps |
| Bus 11 | 9.8 Amps |
| Total | 705 Amps |

The protection zone of relay R1 is until busbar 2. The max 3 phase fault at busbar 2 calculated using PSS CAPE software is listed in the following Table 3-9.

Table 3-9 3 Phase Fault at Busbar 2

| **3 Phase fault** | **Max Values** |
|---|---|
| Busbar 1 | 2975 A |

$$I_{51}^{pick\text{-}up}(3I>) = 1.25 \cdot 705 = 881\ Amps$$

The appropriate ratio of current transformer can be selected as:

$$CT\ 2_{ratio} = 1000{:}1$$

$$I^{pick\text{-}up}_{51} 3I> \; = \frac{881}{1000} Amps = \; 0.881 < \; 4.1 \; (fulfils \; the \; criterion \; in \; 4)$$

The standard equation for the IEC Normal Characteristic curve is given by the following equation:

$$t[s] = \left[\left(\frac{A}{\left(\frac{I}{I>}\right)^{c} - 1} + B\right)\right] .K \text{ ---- } (6)$$

t[s] Operate time in seconds

I measured current

I> set Start value

k set Time multiplier

Where

A = 0.14

B = 0

C= 0.02 for IEC Normal Inverse curves

I = 2975 Amps

I>= 881 Amps.

T= 0.23 sec

Where T = 0.23 is the relay operating time of Relay R2 and circuit breaker operating time. The time of operation of a REF615 relay is 140ms and as referred in Table 3-4. So, the total coordination time interval between the Relay R1 and Relay R2 is:

$$T \; = \; CTI \; = \; 0.23 \; + 0.14 \; = \; 0.37 \; sec$$

Putting values in (6), we get:

$$K = 0.065$$

### 3.5.1 Overcurrent Protection Instantaneous Stage 3I>>> Pickup Setting

The overcurrent protection high stage 3I>>> pickup setting should be set to comply with the equation (4). The relay R1 at bus should trip for the lowest of the three-phase fault current on busbar 6, 7, and 11 since it has to provide backup protection to relay R2. Therefore, $Ikmin = 1194\ Amps$, as according to Table 3-5.

$$\text{Current start value} < 0.7\ x\ (\text{Ikmin/I1n})$$

$$Current\ start\ value < 0.7\ X\ 1194/200$$

Hence, the equation becomes:

$$I_{51}^{pick\text{-}up}(3I \gg >) = 4$$

Table 3-10 Relay Settings REF615 for Relay R1 at Bus 1

| **Tap Name/Description** | **Setting** |
|---|---|
| Start value of stage I> | 0,881×In |
| Time/current characteristic for stage I> | IEC Normal Inverse |
| Time multiplier k | 0,065 |
| Start value of stage 3I>>> | 4×In |
| Operate time of stage 3I>>> | 0.05 s |

## 3.6 Coordination Graphs

The relay settings for relay R1 and relay R2 were put into the respective ABB REF615 relays using PSS CAPE software and then coordination graphs were generated for 3 phase fault, line to line fault, and line to ground fault at different busbars in the radial network.

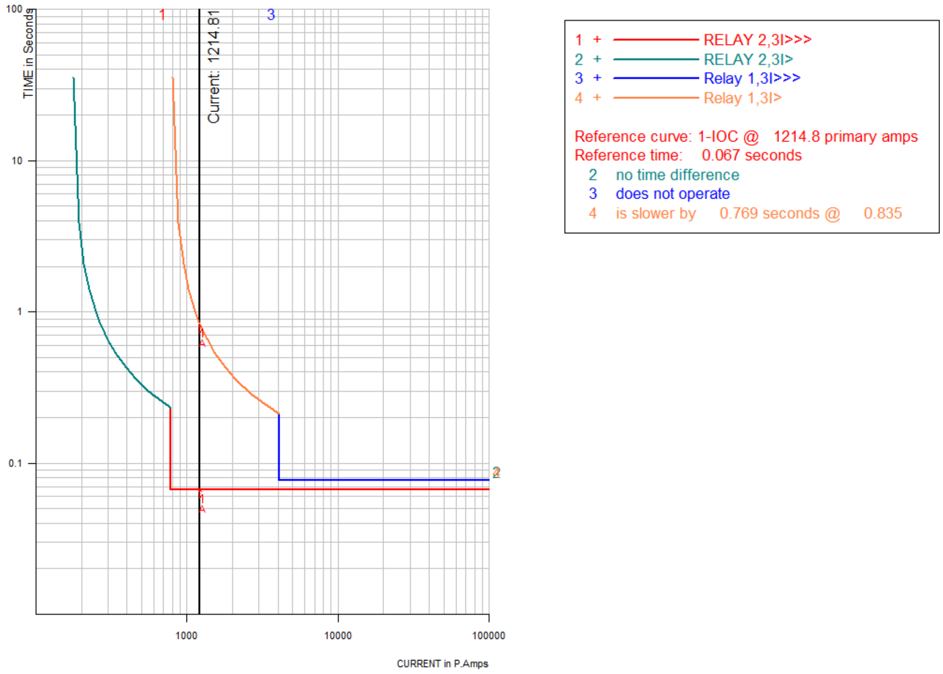


Figure 3-4 Relay Characteristics for 3 Phase Fault, Bus 6.

As shown in Figure 3-4, the relay R1 provides a backup protection to relay R2 in case if R1 malfunctions. The graph also shows that the three phase fault current of 1214 Amps at Bus 6 trips the relay R2 in 0.067 seconds while the relay R1 is slower than the R2 by 0.769 seconds and will trip in 0.835 seconds.

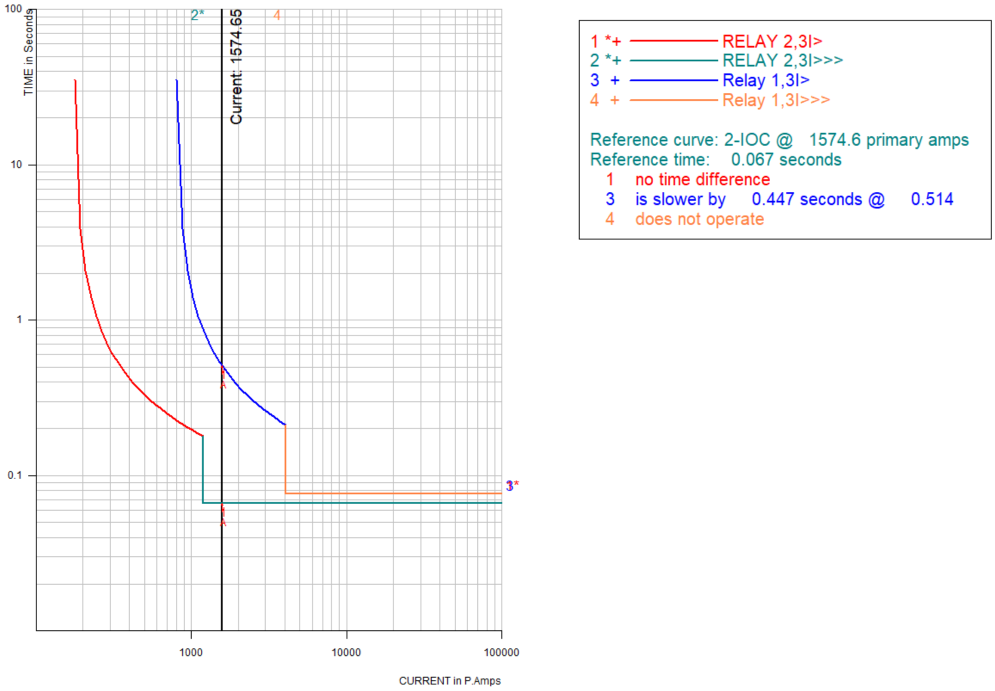


Figure 3-5 Relay Characteristics for 3 Phase Fault, bus 2.

A three phase fault was generated at busbar 2, and as shown in Figure 3-5 , relay R2 trips in 0.067 seconds for a three phase fault of 1574 Amps while the relay R1 provides backup protection incase relay R1 malfunctions and trips in 0.514 seconds.

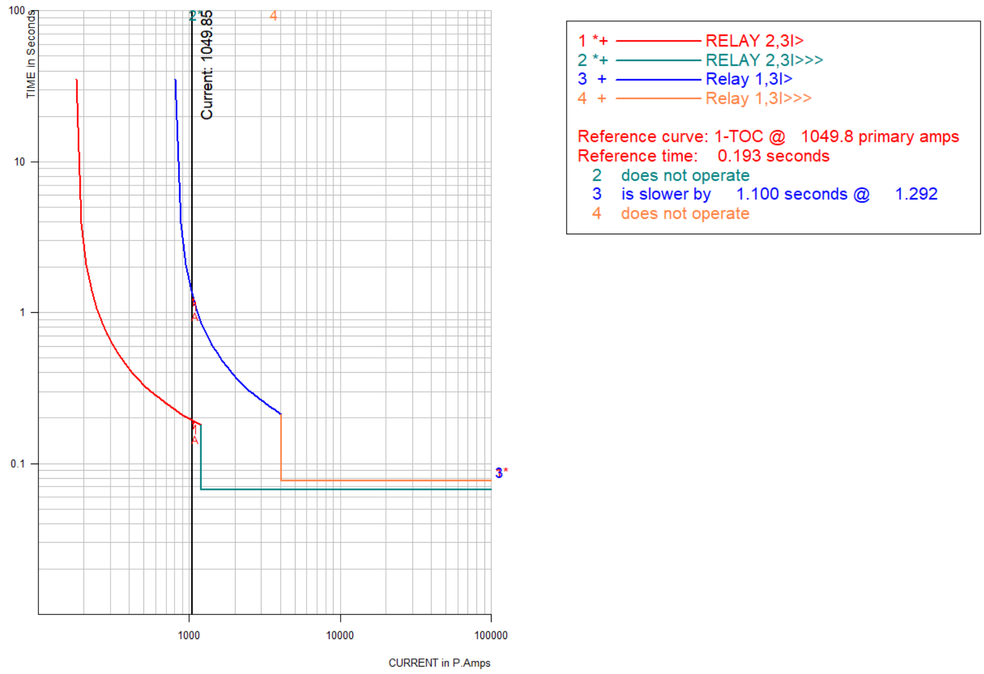


Figure 3-6 Relay Characteristics for L-L Fault at Bus 6

A line to line fault was generated at busbar 6. As shown in Figure 3-6, the relay R2 trips in 0.193 seconds for a line to line fault of 1049 Amps while the relay R1 provides backup protection to relay R2 and trips in 1.292 seconds.

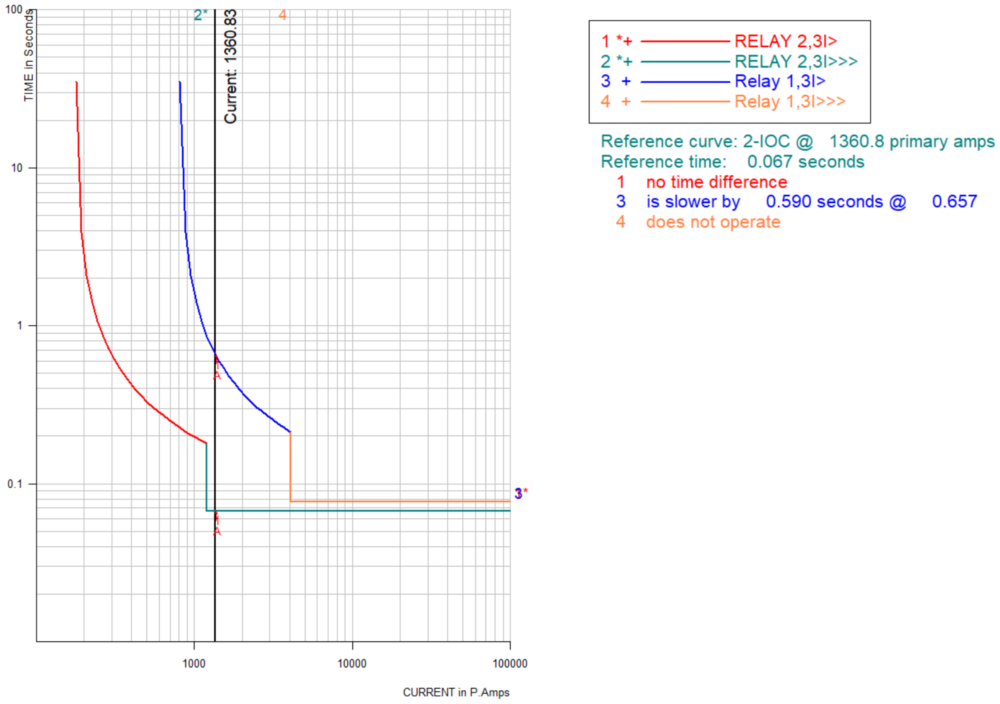


Figure 3-7 Relay Characteristics for L-L Fault at Bus 2

A line to line fault was generated at busbar 2. As shown in Figure 3-7, the relay R2 trips in 0.067 seconds for a line to line fault of 1360.83 Amps while the relay R1 provides backup protection to relay R2 and trips in 0.657 seconds.

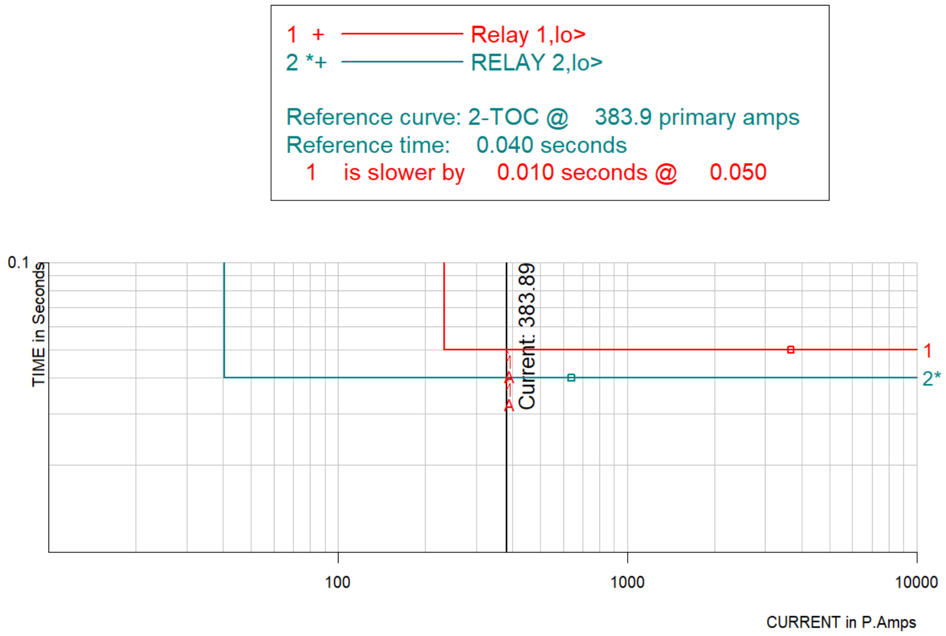


Figure 3-8 Line to Ground Fault at Busbar 6

A line to ground fault was generated at busbar 6 and it was observed that relay R1 provided backup protection to relay R2 as shown in Figure 3-8, Relay R2 tripped in 0.040 seconds whereas the relay R1 tripped in 0.050 seconds.

# 4 Implementation and Testing in Typhoon HIL

## 4.1 Introduction

This chapter covers the implementation and testing of ABB relay REF615 by modeling it into Typhoon HIL. The Power network shown in Figure 3-1 was modeled in schematic editor in Typhoon HIL followed by deployment of relays R1 and R2 at bus 1 bus 2 respectively. The relay settings given in Table 3-10 and Table 3-7 were fed into the relays R1 and R2 for the power system model in Typhoon HIL. The fault was then generated, and the relay was tested for the tripping scenario.

## 4.2 Modeling Of Network in Typhoon HIL

The MV CIGRED network was modeled in Typhoon HIL using schematic editor. All the power network components i.e. transformer, underground cables, and loads with their data were added to the model. Python code provided by Professor Francisco Gonzalez-Longatt was used which facilitated in using Load and cable data without entering data for each component in the power system network.

```python
# Numpy module is imported as 'np'
# Scipy module is imported as 'sp'
# The Schematic API is imported as 'mdl'
# To get the model file path, use 'mdl.get_model_file_path()'
# To print information to the console, use info()

Ts = 120e-06
VLL_LV = 20000
f = 50

class cable():
    def __init__(self, R0=1.33023, R1=0.16684, X0=0.98301, X1=0.12862,
                 C0=508.91, C1=0, fn=50, unit='km'):
        self.R0 = R0  # ohms per self.unit [zero sequence resistance]
        self.R1 = R1  # ohms per self.unit [positive sequence resistance]
        self.X0 = X0  # ohms per self.unit [zero sequence reactance]
        self.X1 = X1  # ohms per self.unit [positive sequence reactance]
        self.C0 = C0  # nF per self.unit [zero sequence capacitance]
        self.C1 = C1  # nF per self.unit [positive sequence capacitance]
        self.fn = fn  # Hz [nominal grid frequency]
        self.unit = unit  # [distance unit used]
        self.w = 2*np.pi*self.fn  # rad/s [angular speed]

        self.Rseq_matrix = np.matrix([[self.R0, 0, 0],
                                      [0, self.R1, 0],
                                      [0, 0, self.R1]])  # ohms/unit [sequence resistance matrix]
        self.Xseq_matrix = np.matrix([[self.X0, 0, 0],
                                      [0, self.X1, 0],
                                      [0, 0, self.X1]])  # ohms/unit [sequence reactance matrix]
        self.Zseq_matrix = self.Rseq_matrix + 1j*self.Xseq_matrix  # ohms/unit [sequence impedance matrix]
        self.Lseq_matrix = self.Xseq_matrix/self.w  # H/unit [sequence inductance matrix]
        self.Cseq_matrix = np.matrix([[self.C0, 0, 0],
                                      [0, self.C1, 0],
                                      [0, 0, self.C1]])  # nF/unit [sequence capacitance matrix]

        alphax, alphay = np.cos(120.0*np.pi/180.0), np.sin(120.0*np.pi/180.0)
        alpha = complex(alphax, alphay)
        A = np.matrix([[1, 1,         1],
                       [1, alpha**2.0, alpha],
                       [1, alpha,      alpha**2.0]])  # sequence to phase components transf. matrix

        self.Zabc_matrix = np.dot(np.dot(A, self.Zseq_matrix), A.I)  # ohms/unit [phase impedance matrix]
        self.Rabc_matrix = self.Zabc_matrix.real  # ohms/unit [phase resistance matrix]
        self.Xabc_matrix = self.Zabc_matrix.imag  # ohms/unit [phase reactance matrix]
        self.Labc_matrix = self.Xabc_matrix/self.w  # H/unit [phase inductance matrix]
        self.Cabc_matrix = np.dot(np.dot(A, 1j*self.Cseq_matrix), A.I).imag  # nF/unit [phase capacitance matrix]
```

Figure 4-1 Python Code

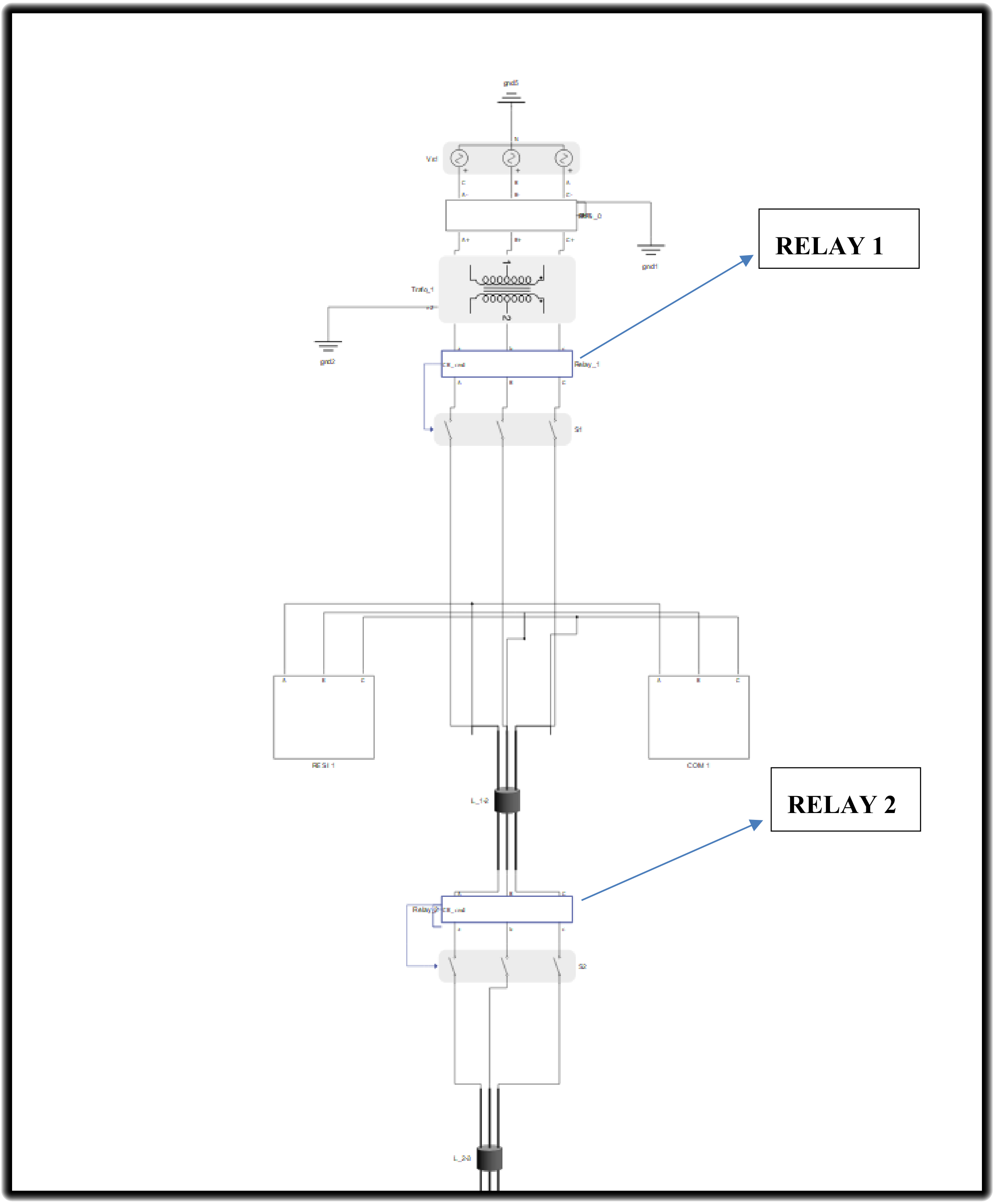


Figure 4-2. CIGRE Network Model in Typhoon HIL

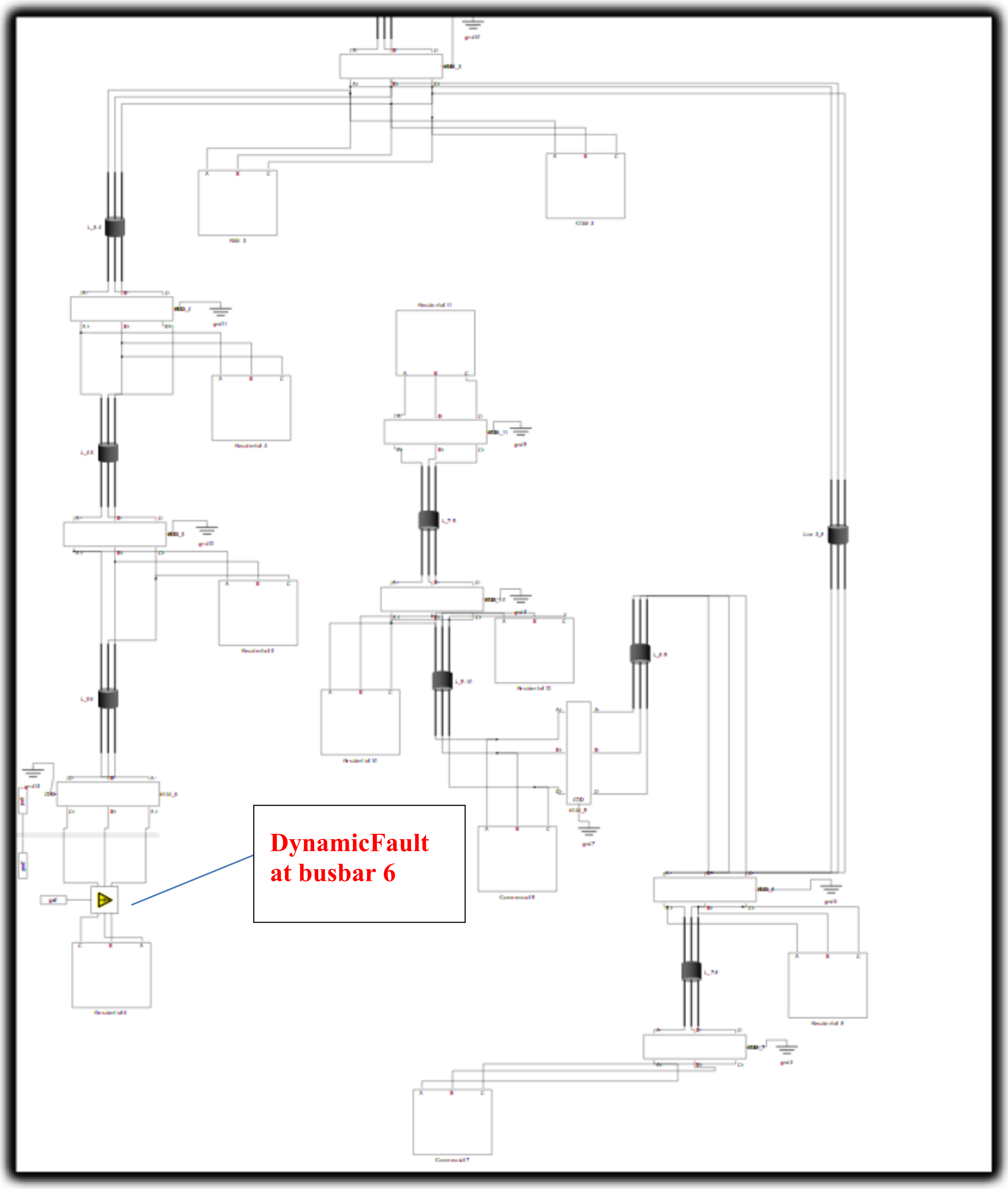


Figure 4-3 CIGRE Network Model in Typhoon HIL - 1

## 4.3 Relay Settings in Typhoon HIL

Relay R1 and R2 at Bus 1 and 2 were fed with relay settings according to Table 3-10 and Table 3-7 and as shown in Figure 4-4 and Figure 4-5 below:

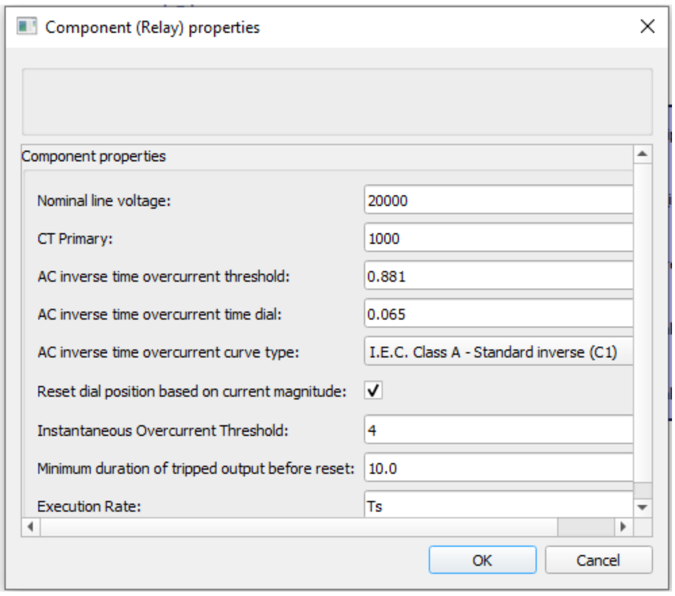


Figure 4-4 Relay R1 Setting in Typhoon HIL

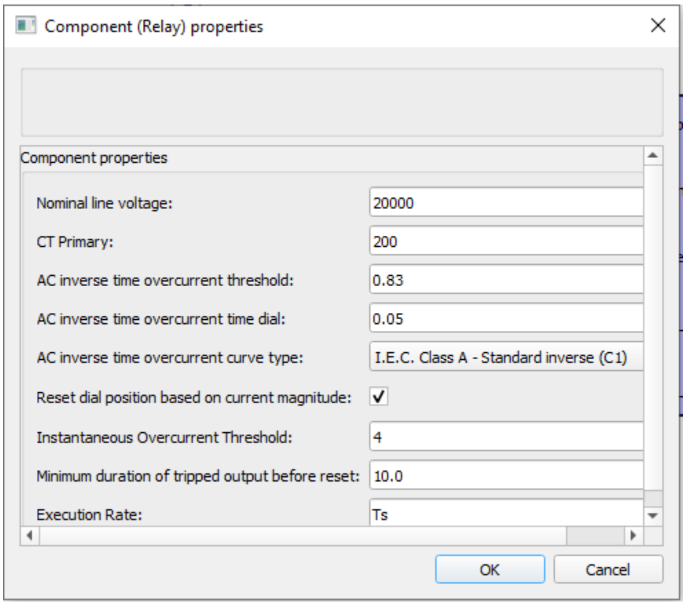


Figure 4-5 Relay R2 Setting in Typhoon HIL

## 4.4 Scada Panel Interface

Typhoon HIL SCADA is a simple and easy to use graphical environment that allows creating user defined interface, which communicates with the power network model built in the schematic editor. Hence, SCADA Panel Interface with appropriate inputs and probes was designed.

As shown in Figure 4-6, the current at Bus 1 and Bus 2 is 697 Amps and 130 Amps respectively which validate the actual current consumption of load at bus 1 and 2 respectively.

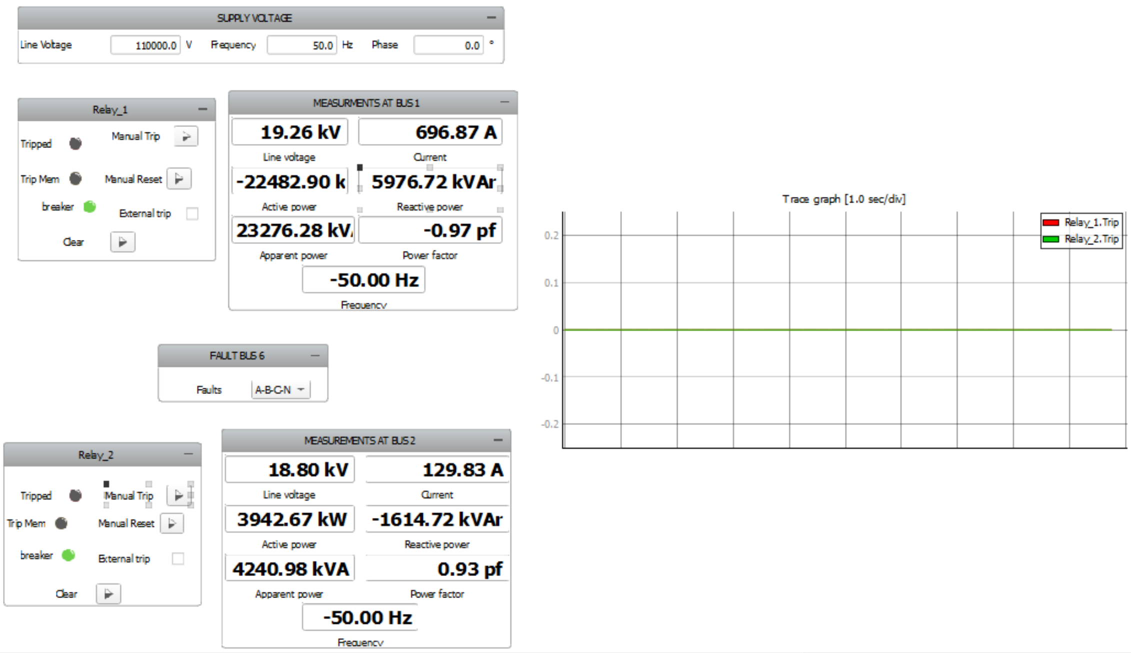


Figure 4-6 SCADA Panel Interface

The compilation of the power network was run successfully after which the model was loaded into the virtual device and then the simulation was run again.

## 4.5 Generation Of Fault

A dynamic fault was added to the model in schematic editor at busbar 6 which was then triggered from the SCADA interface panel. Three phase fault and Line to Line faults were generated which successfully tripped the relay as shown in Figure 4-7:

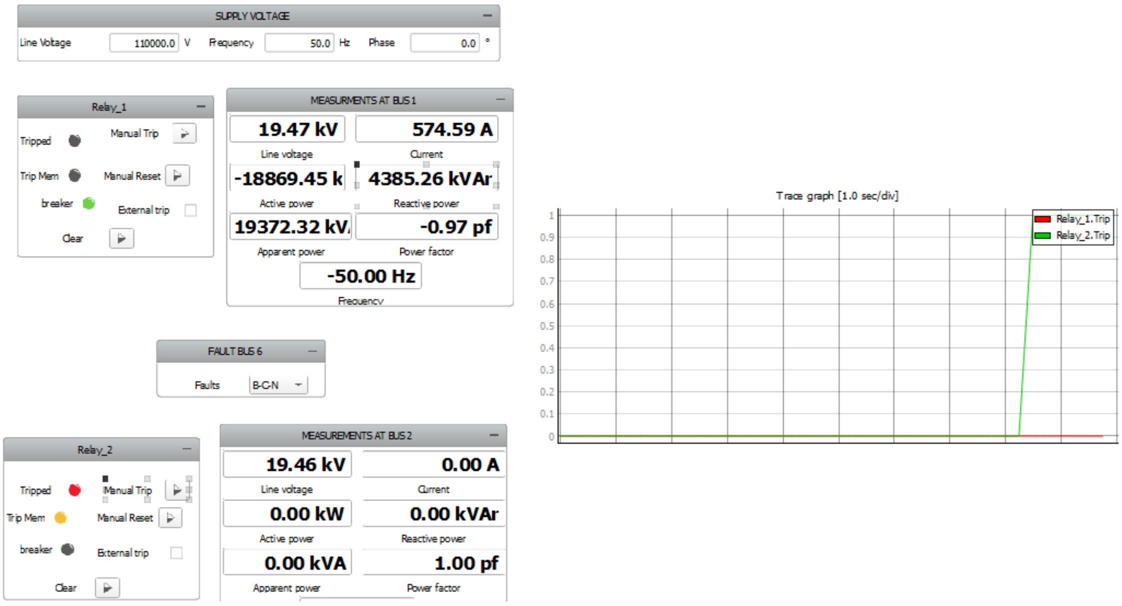


Figure 4-7 Tripped Relay

# 5 Conclusion

The ABB REF615 relays R1 and R2 at bus 1 and 2 were analyzed for overcurrent protection and selectivity by deploying them into the 110/20 KV MV CIGRE network. The different types of short circuit faults were plotted on the coordination graphs for the two relays and the response time comparison was observed. Consequently, it was proved that the relay R1 provides backup protection to Relay R2 if the Relay R1 malfunctions. The MV network was analyzed and the radial configuration of the network was chosen as the base case. However, it can be a topic for further research if the whole network is analyzed by closing breakers S1, S2, and S3.The protection relay settings were then validated in the Typhoon HIL software by first building the power system network in schematic editor and then generating fault and testing if the relay tripped. It was observed that the relay tripped for different types of faults by triggering the fault from the SCADA panel interface. Ironically, one of the objectives of the thesis was also to test the physical relay as part of the Typhoon HIL test bed but due to time constraints, this was not achieved.

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