NTNU – Trondheim
Norwegian University of
Science and Technology

Relay Lab at NTNU

Emil Anthonsen Dyrstad

Master of Energy and Environmental Engineering
Submission date: June 2014
Supervisor: Hans Kristian Høidalen, ELKRAFT

Norwegian University of Science and Technology
Department of Electric Power Engineering

Problem Description

Relay protection is essential for reliable operation of power supply. Distributed generation, increased complexity of power systems, and new communication solutions require increased focus on protection. Protective relays and their settings are commonly tested in hardware. Simulation results (typically fault currents and voltages) are through an amplifier applied to the actual relay and its response is verified or settings adjusted. Traditionally only sinusoidal steady-state responses are used, but transients may be of importance. At NTNU there is a plan to expand and build competence in relay protection with a relay lab and a future specialization course. The simple relay protection lab planned at NTNU should include a test bench with distance, over-current and differential relays, and a relay tester for applying simulated waveforms to the relays. A strategic co-operation with Michigan Technological University, Statnett SF and ABB is under establishment and ABB is gifting four Relion 670 relays for transformer, generator and line protection.

The project will consist of:

- Study and document power system protection principles
- Study the different software available to obtain the simulated values
- Develop lab exercise tasks for a future specialization course, with inspiration from a Michigan Technological University
- Design and arrange the practical set-up of the laboratory, including documentation and proposals for future expansions
- Test the preliminary laboratory set-up and create plug-and-play relay configuration files to be used in the different lab exercises.

Preface

This report is the result of the authors Master's thesis at the Department of Electric Power Engineering at the Norwegian University of Science and Technology. The work for the thesis was performed and written in the spring semester of 2014.

I would like to express gratitude towards my supervisor, Professor Hans Kristian Høidalen, for providing guidance during the semester, and towards Professor Bruce Mork for providing useful input. I would like to thank ABB for their contribution to the relay lab with new and modern protective relays. I am very grateful for the help, guidance and training I have received from Odd Werner-Erichsen at ABB in Västerås, Sweden during the spring of 2014. Siemens Norway also deserves some gratitude on my behalf for letting me participate in their relay seminar for new employees as a third party in October 2013. I would also like to thank Bård Almås, Vladimir Klubicka and Aksel Hanssen for assisting me with the set up of the relay lab.

Notice: Some of the content was included in the authors specialization project report with the same title in the 2013 fall semester. This was deliberate as it functions as pre-project for the Master's thesis. The content has been edited where deemed necessary.

June, 2014
Trondheim, Norway

Emil A. Dyrstad

Emil Anthonsen Dyrstad

Abstract

This thesis presents background on power system protection, relay principles, modern relay technology and relay testing, to support the design, practical set up and proposals for use of a new relay lab at NTNU.

The paper includes a theoretical part describing the components of power system protection, their function and attributes. To better the understanding of the importance of power system protection, a short study of the different types of faults that may occur in a power system and how they can be calculated has been made.

One chapter covering the principles of protective relaying functions relevant for the lab, is included. It covers the theory of overcurrent (including directional), distance and differential protection, as well as challenges one may encounter when applying these protective functions.

A chapter on modern relay technology, describing the possibilities and benefits of micro-processor based relays, especially with regards to communication, is a part of the report. This chapter also includes sections describing the inputs and outputs, logic and function of modern relays.

The essentials of relay testing is described in the paper. The different methods available for the testing of relays; scaled physical networks, relay testers and fault simulators are mentioned. Focus has been put on use of relay testers as it is most relevant for the lab. A description of common test procedures is also included. Selected relevant software has been studied to find a software which can be used in the lab exercises.

Discussion of practicalities regarding the lab, i.e. the design and set up of the lab is also made in the thesis. Opportunities for, and use of the lab have been discussed. The basics of relay configuration is explained. Proposals for lab exercises that can be performed in the new relay lab are presented near the end.

A list covering proposals for further work for the relay lab is the final part of the thesis.

Sammendrag

Denne rapporten inneholder teoretisk bakgrunn om beskyttelse av kraftsystemer, relévernsfunksjoner, moderne relévernsteknologi og testing av relévern. Den teoretiske delen støtter det praktiske arbeidet med design, montering og forslag til bruk av en ny relévernlab ved NTNU.

Teoridelen inkluderer beskrivelse av de forskjellige komponentene i ett relévernsystem, inkludert deres funksjonalitet og egenskaper. Ett kapittel som forklarer beregninger av kortslutningsstrømmer, er med for å illustrere størrelsen på disse strømmene og viktigheten av relévern.

De mest brukte relévernsprinsippene; overstrøm, distanse og differensial, er beskrevet i rapporten. Utfordringer med bruken av disse er også diskutert. I tillegg er moderne, mikroprosessor-baserte relévern og deres virkemåte forklart. Fordeler med denne teknologien, spesielt med tanke på kommunikasjon, har blitt diskutert.

Forskjellige metoder for reléverntesting er diskutert. Det inkluderer testing i skalerte kraftsystem, testing ved bruk av relétester og bruk av feilsimulator. Programvare relevant for laben og labøvinger er også beskrevet.

Den praktiske delen av oppgaven, det vil si design og montering av relévernlaben, er en viktig del av rapporten. Dette kapittelet inneholder diskusjon rundt laben, beskrivelse av komponenter, forslag til fremtidige utvidelser og konfigurering av relévernene. Slutten av rapporten inneholder forslag til labøvinger, samt forslag til videre arbeid.

Contents

List of Figures

Abbreviations

ANSI	American National Standards Institute
IEEE	Institute of Electrical and Electronics Engineers
IEC	International Electrotechnical Commission
NTNU	Norges teknisk-naturvitenskapelige universitet (Norwegian University of Science and Technology)
MTU	Michigan Technological University

A/D	Analog to Digital Converter
AC	Alternating Current
BIM	Binary Input Module
BOM	Binary Output Module
CB	Circuit Breaker
CCVT	Coupling Capacitive Voltage Transformer
COMTRADE	Common format for Transient Data Exchange for power systems
CT	Current Transformer
CTR	Current Transformer Ratio
DC	Direct Current
DFT	Discrete Fourier Transformation
EMTP	ElectroMagnetic Transients Program
GOOSE	Generic Object Oriented Substation Event
GPS	Global Positioning System
HF	High Frequency
HMI	Human-Machine Interface
IED	Intelligent Electronic Device
LED	Light-Emitting Diode
MRCT	Multi-Ratio Current Transformer
PE	Protective Earth
PMU	Phasor Measurement Unit
PSM	Power Supply Module
RCCB	Residual Current Circuit Breaker
SG	Smart Grid
TCC	Time-Current Curve
TRM	Transformer Input Module
USB	Universal Serial Bus
VT	Voltage Transformer
VTR	Voltage Transformer Ratio
WAMS	Wide Area Measurement Systems
WAP	Wide Area Protection

ANSI Device Numbers

21	Distance Relay
50	Instantaneous Overcurrent Relay
51	AC Inverse Time Overcurrent Relay
52	AC Circuit Breaker
67	AC Directional Overcurrent Relay
87	Differential Protective Relay

1. Introduction

Electrical energy is one of the cornerstones of modern society. Having access to electrical energy, with stable nominal values, is something we take for granted every day. Trying to have a normal day without electrical energy is close to impossible. Why can we take it for granted? Why is electrical energy so reliable?

Protective relaying is an important part of the answer to these questions. Protective relaying has the role of quickly detecting and clearing faults in power systems. Without protective relaying, a fault could lead to major damage to power system components, causing outage of electric power for long periods of time. The objective of protective relays is to isolate the smallest possible area after a fault whilst clearing it as fast as possible. This minimizes the consequences of the fault.

Protective relays are becoming more advanced to keep up with more complex and integrated power systems. From a traditional radial design, where the flow of power moves in one direction, the design of power systems has been transformed into a design with a higher number of interconnections and where the power flows in both directions. The future of power systems is smart grids, meaning more complex designs, with distributed generation, smart meters and continuous surveillance to ensure optimal operation and power flow at every instant.

The electrical engineers of the future should be educated with this in mind. To enlighten today's and future students about protective relaying, a solid theoretical background part is a fundamental first step. To complement the theory and to better the understanding of the topic, a practical component, to understand how power system protection works in real life, is vital. A protective relay lab can be the foundation of such a practical, hands-on component.

Designing the lab at NTNU to make it useful for students and easy to grasp is therefore crucial. Designing it with a future specialization course for last year Master's students in mind, as well as for integrating it into current courses, is important. Creating a lab which is well documented and ready for future expansions, to accommodate future protective trends, is important to keep in mind. The motivation should be that lab is to provide the students with a practical understanding of protective relays, without being too complicated.

2. Power System Protection

This chapter provides a theoretical background of the components and attributes for the protection of a power system.

2.1. Power System Protection Components

A power system protection scheme consists of several elements that work together for the detection and clearing of faults and other abnormal conditions. Figure 2.1 illustrates the key components of a protection system; Transducers (CTs/VTs), relays, power supply and circuit breakers (CBs).[28][31]

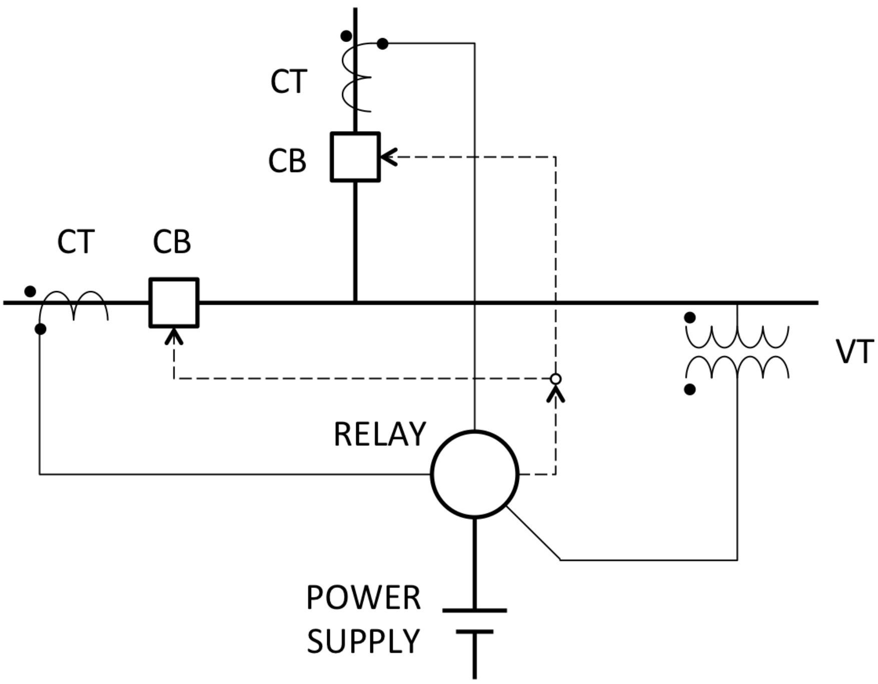


Figure 2.1.: Principles of Power System Protection

Transducers

The transducers, i.e. the current (CT) and voltage transformers (VT), are the sensors of the protection system, feeding the relays with continuous current and voltage values reflecting the state of the power system. They step down the values to a level that is safe for the relays.

Relays

Relays are the physical devices that interpret the data from the transducers. If the data indicates a fault the relay will trip and forward an operating signal to the circuit breaker(s). Traditional protective relays were electromechanical devices, which utilized the relationship between electricity and magnetism. In these relays, a measured current would flow through a coil, creating a magnetic force, which would then act on mechanical parts, such as an induction disk or clapper contact. These relays were quite slow compared to todays micro-processor based relays which are significantly faster. Modern relays are also capable of providing several protective functions in one unit; i.e. one modern relay can replace several traditional units. The communication possibilities of modern relays are also a major advantage over traditional devices.[32][31]

Power Supply

The power supply of a protection system should be independent of the AC voltage of the grid. This is due to the fact that a fault may lead to the AC supply becoming unreliable at a point of time when a reliable supply of power to the protection system is at its most critical. Therefore, batteries are used as a main power supply. The batteries are connected to the AC voltage via a charger and during normal operating conditions the batteries will float on the charger.[32]

Circuit Breakers

Circuit breakers (CBs) have two distinct tasks; operating as a part of the power system under normal conditions, and providing the protection system with the ability to clear a fault. Under normal conditions the CBs can receive manual and automatic commands from the control center to open or close. If the relay detects a fault, it will send a trip signal to the CB for it to break the current and isolate the faulted network area. Since a normal load current is much lower than the maximum fault current, the rating of the CB must be according to the higher fault current.[32][28]

2.2. Current Transformers

The basic design and behavior of current transformers (CTs) are similar to other two-winding transformers. They are used to step up or down voltage (and current). The power entering the primary side must be equal to the power out of the secondary side, i.e. $U_p \cdot I_p = U_s \cdot I_s$. Current transformers are used in protection systems to step down the high currents that flows in the network to values that are sufficiently low and safe for the relays. In other words they have a single turn, or few primary turns and several secondary turns ($N_p < N_s$).

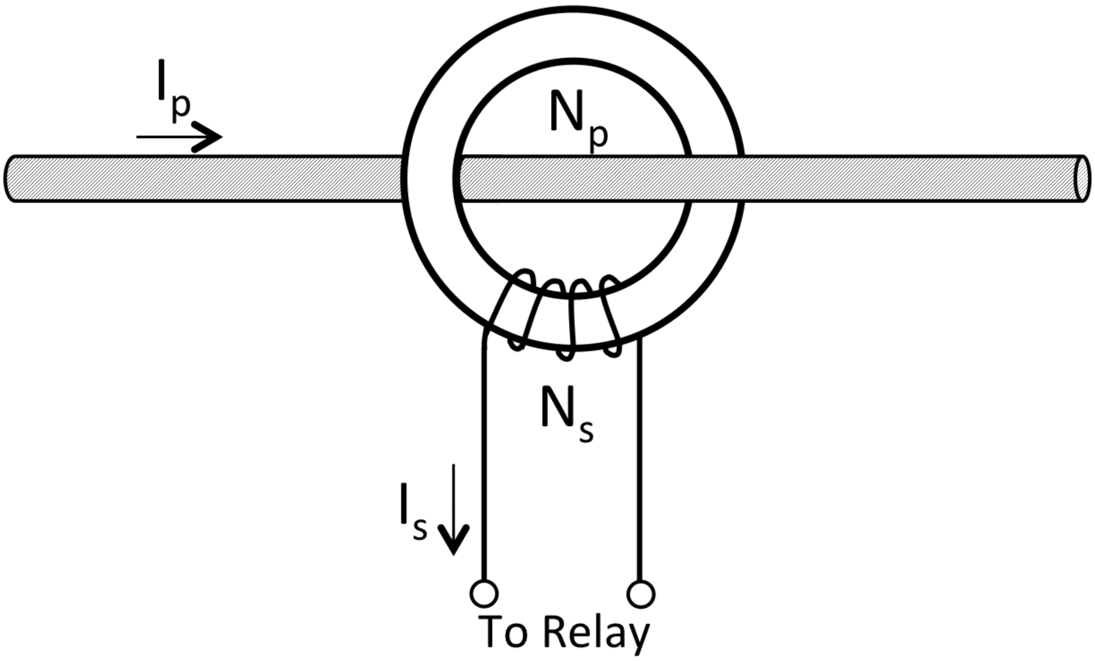
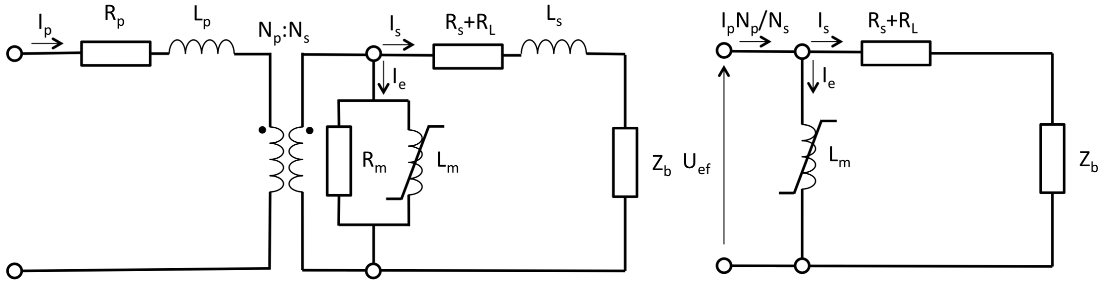


Figure 2.2.: Conceptual Illustration of a Current Transformer

Figure 2.2 illustrates conceptually how a CT is connected to the power system. In contrary to regular power transformers, CTs are connected in series with conductors of the power system. Because of this, the voltage over both sides of a CT is independent of the system voltage. Under normal steady-state operation the voltage on the primary side is usually less than 1 volt, and under 10 volts on the secondary (depending on the turns ratio). A fault will lead to an increase in the voltages on both sides, typically to a couple of hundred volts on the secondary side, and up to a few volts on the primary.[28] These values are valid when the secondary side is short-circuited, as an open secondary circuit will lead to very high voltages, only limited by saturation of the core on the secondary side. Thus should the secondary circuit never be left open.



(a) Complete Equivalent (b) Simplified Equivalent

Figure 2.3.: Equivalent Circuit for a Current/Voltage Transformer. Based on Figure 2.3 in [33] and Figure 5.6 in [15]

Figure 2.3 above displays an equivalent circuit for a CT, where Figure 2.3b is a simplified equivalent where the primary winding resistance, R_p, and the magnetizing resistance, R_m are omitted. The primary and secondary leakage inductances L_p, L_s are also neglected. The primary winding magnetizing inductance is also negligible and omitted in both representations. The secondary winding resistance R_s is proportional to the number of secondary windings, while the secondary lead resistance R_L is dependent on the metal, cross-section and length of the lead itself. Under fault conditions the secondary lead resistance can be one-way (1xR_L) or two-way (2xR_L) depending on the type of fault. If it is a phase fault, it is one-way, for ground faults it is two-way. Z_b represents the burden caused by the resistance of cables, wiring and internal impedance of relays. The burden is normally given in volt-amperes with a corresponding ampere value.

$$Z_b = \frac{VA}{I^2}\Omega \tag{2.1}$$

From Figure 2.3b we can easily derive the expression for the secondary current I_s. This is the output value of the CT that feeds the relay(s).

$$I_s = I_p \cdot \frac{N_p}{N_s} - I_e \tag{2.2}$$

As Equation 2.2 shows, I_s will not be equal to the current from the primary side, $I_p \cdot \frac{N_p}{N_s}$, as long as the the excitation current, I_e, is of significant value. In other words, I_e represents the degree of error in a CT. Designing a CT so that I_e becomes insignificant for expected fault conditions is therefore important.

I_e is non-zero as long as the CT is energized, and is dependent on the magnetizing impedance, here represented by the magnetizing inductance L_m and the loss resistance R_l. The magnetizing impedance varies with the flux in the core, which is needed to provide exciting magnetizing force U_{ef}. U_{ef} is the force that pushes

I_s through the secondary circuit. The core flux has a non-linear characteristic, meaning that the excitation current, I_e, also will have a non-linear characteristic.

In addition, I_e is inversely proportional to the CT ratio. This can be seen from Equation 2.2; I_s a function of the current from the primary side, $I_p \cdot \frac{N_p}{N_s}$, and U_{ef} is the driving force for I_s. And as shown above, I_e is indirectly dependent on U_{ef}. This also indicates that I_e is dependent of the burden Z_b.

A CT may also have several different tap settings, commonly referred to as a multi-ratio CT (MRCT), which allows the end user to select whichever tap is most beneficial for each case, i.e. which tap setting will give the smallest error. Typically the ratio, $N_p : N_s$, for the different taps, can be 600:5, 500:5, 400:5 and 450:5[15]. Figure 2.4 below illustrates the excitation curve for a MRCT, i.e. the relationship between the exciting magnetizing force U_{ef} and the excitation current I_e.

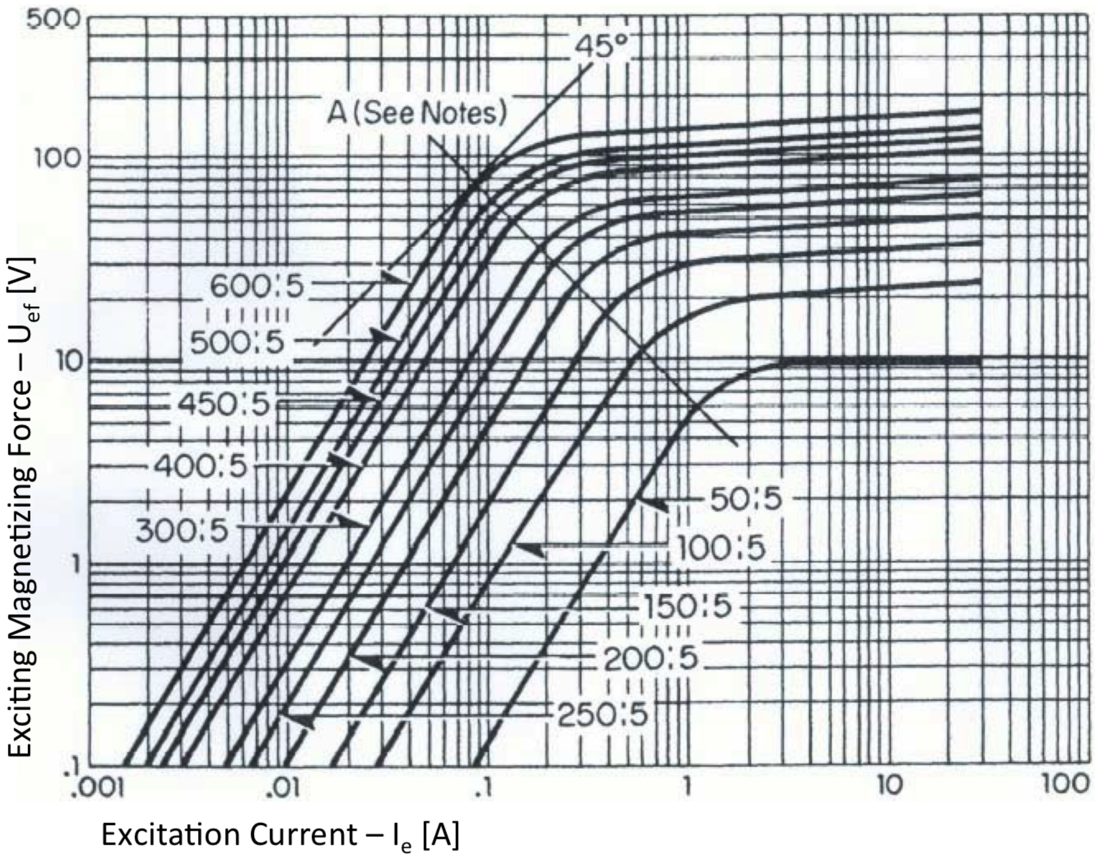


Figure 2.4.: Excitation Curve for a Multi-Ratio CT[21]

2.3. Voltage Transformers

Voltage transformers are used in the same way as CTs, but their task is to step down the high voltage of the power system to a low voltage which the relays can handle. The basic design is similar to the one of CTs, so the equivalent circuit in Figure 2.3a is still valid. VTs, in contrary to CTs, normally have two or more windings on the secondary side, and multiple windings on the primary side ($N_p > N_s$). The burden here becomes:

$$Z_b = \frac{V^2}{VA}\Omega \tag{2.3}$$

2.3.1. Coupling Capacitor Voltage Transformers

For voltages up to roughly 115 kV electromagnetic VTs (Equvialent Circuit shown in Figure 2.3) are used, while for higher voltages, capacitive dividers are introduced to the transformer design. It is referred to as a coupling capacitor voltage transformer (CCVT).[15] An equivalent circuit can be seen in Figure 2.5, while a cross-section illustation of a CCVT from Alstom Grid is shown in Figure 2.6.

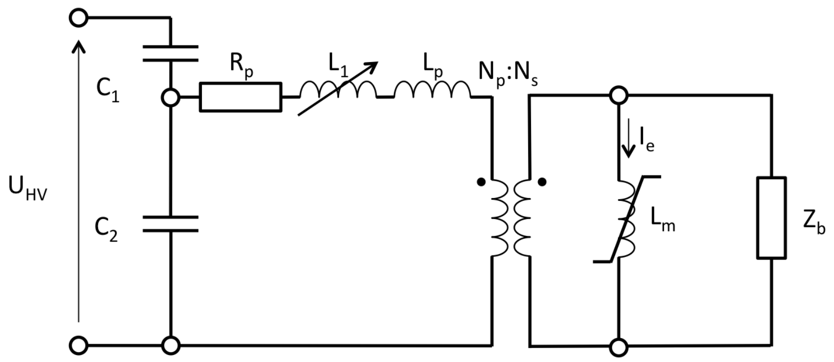


Figure 2.5.: Simplified Equivalent Circuit for Coupling Capacitive Voltage Transformer with Tuning Inductor. Based on Figure 3.7a/3.8 in [33]

Since the output voltage at the secondary terminal normally is set to a fixed value (e.g. 120 V) the ratio, $N_p : N_s$, in the transformer is proportional to the voltage level at the high voltage terminal, U_{HV}. When the voltage is higher than a certain value, commonly around 115 kV[15], the cost of the additional turns makes a CCVT a more economical choice. The capacitance C_1 in Figure 2.5 is in reality constructed of a stack of capacitors connected in series, i.e. $C_1 < C_2$. This means most of the high voltage U_{HV} will be distributed over C_1, with the remaining, lower proportion over C_2. This allows the voltage over the primary side of the transformer to be relatively low. The number of primary windings needed to achieve an output voltage low enough for the connected relays, can then be reduced substantially.

Assuming the CCVT is unloaded, the voltage over C_2, becomes:

$$U_{C_2} = U_{HV} \frac{C_1}{(C_1 + C_2)} \tag{2.4}$$

L_1 in Figure 2.5 is a tuning inductor that is introduced to cancel out the impedance caused by the capacitors C_1 and C_2, i.e. setting the source impedance to zero. The CCVT will then provide the relay with the actual voltage measured. To achieve this the value of L_1 is selected as follows:[33]

$$L_1 = \frac{1}{\omega^2(C_1 + C_2)} - L_m - L_p \tag{2.5}$$

Equation 2.5 assumes the secondary leakage inductance L_s is negligible. L_m is the magnetizing inductance of the VT, while L_p is the primary leakage inductance.

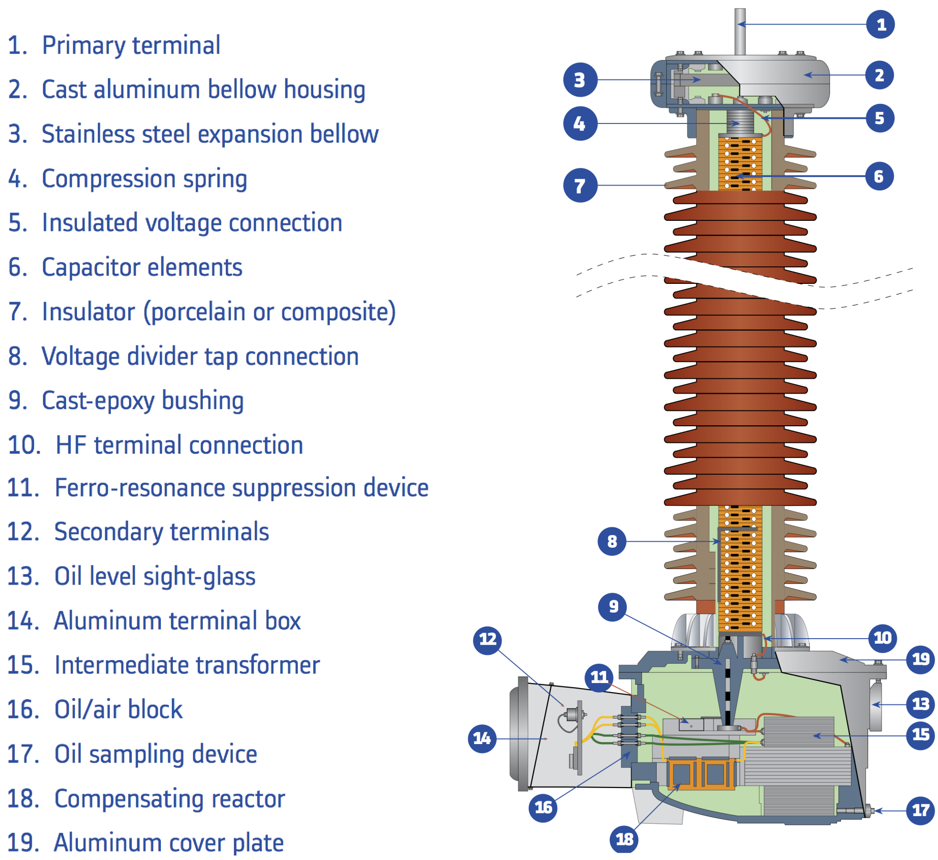


Figure 2.6.: Cross-Section of a Coupling Capacitive Voltage Transformer from Alstom Grid[11]

2.4. Power System Protection Attributes

Power system protection is supposed to operate in such a way that the consequences of a fault in the network is reduced to a minimum. Relays cannot operate before a fault, as a fault is a condition for it to operate. Therefore we want it to detect the fault and operate accordingly as soon as possible. Protection systems should also be designed so that isolating a faulted area is as easy as possible. We can therefore identify certain wanted attributes when talking about protective relaying. Some of these attributes conflict with each other and should therefore be considered accordingly for each type of relays.[15]

Zones of Protection

The protection of power system consists of zones of protection as seen in Figure 2.7. One protected component normally has its own zone, and it is normally defined by the location of the CTs at each end. The zones overlap each other, and this is one important feature of a well designed protection system. Parts of a power system has more than one relaying protecting it; primary and back-up protection. Back-up protection is normally divided between local and remote back-up. Local back-up is provided by the same relay providing primary protection, however it uses a different relay principle or setting, i.e. overcurrent function as local back-up for a primary differential function. Remote back-up is provided by a relay at another location/zone, and it utilizes the same, or a different, relay principle as the primary relay. The remote relay may again have the primary relay as its remote back-up.[21]

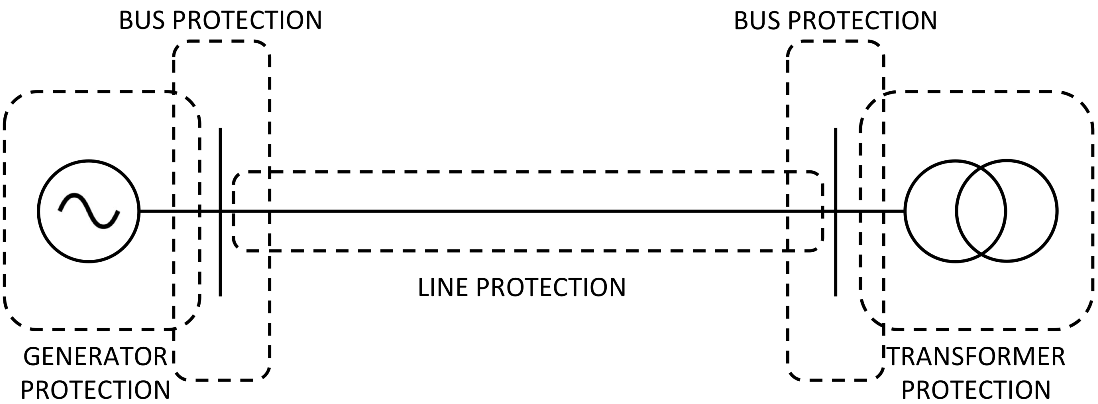


Figure 2.7.: Protection Zones of a Power System

Relay Coordination

In many parts of the power system two or more relays are able to detect a fault in a given component/location, i.e. a primary relay and one or remotes back-up relays. Making sure that the primary relay gets the first attempt to clear the fault is important to ensure high selectivity (see below). If the relay and/or its corresponding circuit breaker(s) fail to clear the fault for some reason, the back-up relay should clear the fault. In other words the relays need to be coordinated, both upstream and downstream, to ensure that they operate in the correct order. Relay coordination is normally made by introducing time delays to the relay operation. The time delay will vary depending on the ambient power system, but it should be as small as possible, while still giving the primary protection enough time to operate, i.e. initiation of trip signal from relay and circuit breaker(s) opening. A security margin for relay/CT accuracy is also added. Typically the added time delay is in the order of 300-500 ms.[21][28]

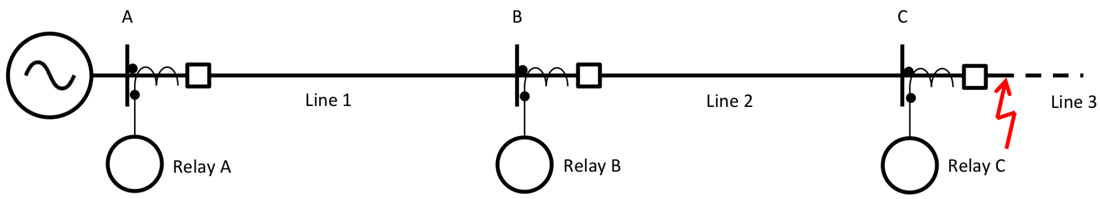


Figure 2.8.: Example - Relay Coordination for Adjacent Lines - Fault at Line 3

Figure 2.8 illustrates three adjacent lines with their respective protection system. If a fault occurs at Line 3, the primary protection is Relay C, i.e. it should operate first without any intentional time delay. Relay B should have an added time delay, so that it will function as remote back-up protection if the primary protection fails. At the same time, Relay A should be coordinated with both relays, typically the intentional time delay will here be double the one for Relay B. This is due to the fact that Relay A should function as remote back-up for Relay B, meaning it indirectly has the role as remote back-up protection for Relay C.

With communication (simple boolean or IEC61850 compliant) between the relays, relay coordination can become easier and operating times can become faster. As soon as the primary relay detects it failed to clear the fault, for instance due to CB malfunction, it can forward a trip signal to the remote back-up protection. The operating times will then decrease, improving the overall protection system.

Speed

Naturally, we want to clear a fault in a power system as quickly as possible. Relays rely on continuous monitoring of current and voltage waveforms. A fault will cause the values and shape of these waveforms to change. In the transient stage after a fault, the waveforms will be significantly distorted. The relay must be able to filter out the useful information, and use it to make a reasoned decision as fast as possible. If the relay decides to trip, it should send a signal to the circuit breaker momentarily, so that it can operate. We can generally classify relays according to their operation speed as given below.[31]

- Instantaneous
  - Instant operation as soon as a secure decision has been made by the relay
- Time-Delay
  - Time delay is introduced after the relay decision, and before trip signal is sent. Introduced to increase reliability and/or coordinate with other relays.
- High-Speed
  - Capable of operating in less than a set time. Modern relays are in most cases high-speed relays.[2]

Selectivity

An important feature of a well designed protection system is how it should be designed to discriminate between a fault within a given zone of protection, and a fault outside of the protected zone. This attribute conflicts with speed and dependability.

Dependability

A relays dependability is given by the probability it will operate when it is supposed to. This is a vital attribute, a relay without dependability is as good as useless. It can be considered as worse than not having a relay installed at all, since it gives a false assurance of protection.

Security

The certainty a relay will not operate when it is not supposed to. Security conflicts with a relays dependability. Protection systems today are normally set towards high dependability, to obtain this it is sacrificing some level of security. This is done deliberately as most power systems today have several paths to deliver power from generator to consumer. However, one should be careful with this relationship when looking at a power system with limited re-routing options for power transfer, e.g. in a radial power system.

Reliability

Reliability describes the relationship between dependability and security, i.e. the probability a relay will perform as required. High reliability is desirable, however how it is achieved may vary from scenario to scenario.

Economics

As with most engineering projects, one of the most, if not the most, important aspects is the cost-benefit relationship. A protection system will have a high investment cost and may lead to increased complexity and maintenance costs of the overall power system. The benefits of a protection system should, if designed correctly, be higher than the cost. A protection system that is able to clear a fault quickly, i.e. minimizing the total outage time, and damage to vital components, will without a doubt make up the investment cost.

3. Short-Circuits and Abnormal Conditions

Unwanted connections between points of different potential in a power system is called a short-circuit, or a fault. Such an event will lead to high currents, and lowered voltage levels at the fault location. A short-circuit does not necessarily imply that the impedance between the points are zero. For instance, if an arc occurs at the fault location, there will be some resistance in the arc itself. In other words, depending on the cause of the fault, the fault impedance may vary. The fault impedance is decisive for the magnitude of the fault current (ref. Ohm's law), a negligible to low fault impedance can cause a high fault current, while a high fault impedance will contribute to a lower fault current, for the same fault. Bolted faults, e.g. caused by a downed pole, have negligible fault impedance and can lead to fault currents in the order of 1-100 kA, depending on the location. If the fault is near a generator, switchyard and/or substation it will be on the high end, and vice versa.

The different fault types can be divided into four groups. Looking at all faults over a statistical significant time and area, the different faults will have the following approximate percentage distribution:[15]

- Three-Phase(-to-Ground) Faults: 2-3 %
- Phase-to-Ground Faults: 70-80 %
- Phase-to-Phase Faults: 8-10 %
- Double-Phase-to-Ground Faults: 10-17 %

Short-circuits can be classified by whether they are symmetrical or asymmetrical. In this chapter the different fault types will be examined. The simple network in Figure 3.1 will be used to illustrate how symmetrical component networks can be used to calculate fault currents. Background for symmetrical components can be found in Appendix A. The network consists of two buses with respective loads and generation, as well as a line between the buses for power transmission. The fault situations below describe bolted faults, and where Phase a is used as reference. In this situation current can flow from both buses to the fault area, in contrary to a radial system, where the current flows in one direction.

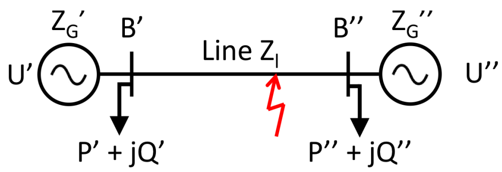


Figure 3.1.: Simple Two Bus Network with Fault on Line

- Z'_g, Z''_g - Respective Generator Impedances
- U', U'' - Respective Generator Voltages
- $P' + jQ'$, $P'' + jQ''$ - Respective Active and Reactive Power Consumption
- Z_l - Line Impedance
- Line Part 1 - From Bus B' to Fault Location
- Line Part 2 - From Fault Location to Bus B"

3.1. Three-Phase(-to-Ground) Faults

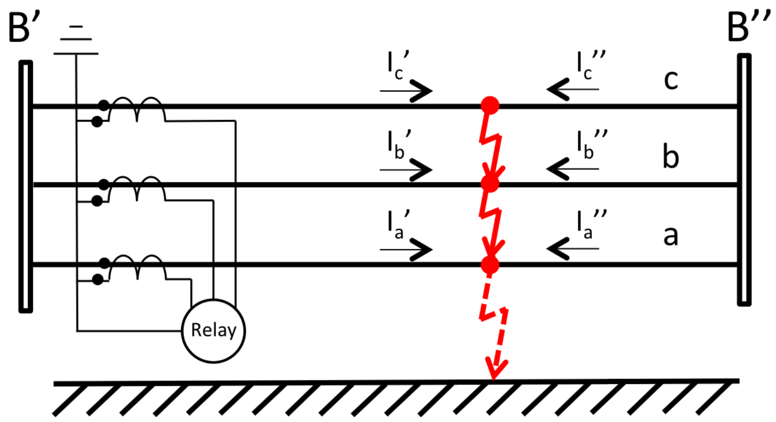


Figure 3.2.: Three-Phase(-to-Ground) Fault

A Three-Phase fault is a condition where all three phases in a network is short-circuited. This is characterized as a symmetrical fault, given that the system was symmetrical pre-fault. There can also be connection between the three phases and ground, however assuming the system is symmetrical, Kirchoff's current law yields that the sum of the three phase current is equal, i.e. no current will be flowing to ground.

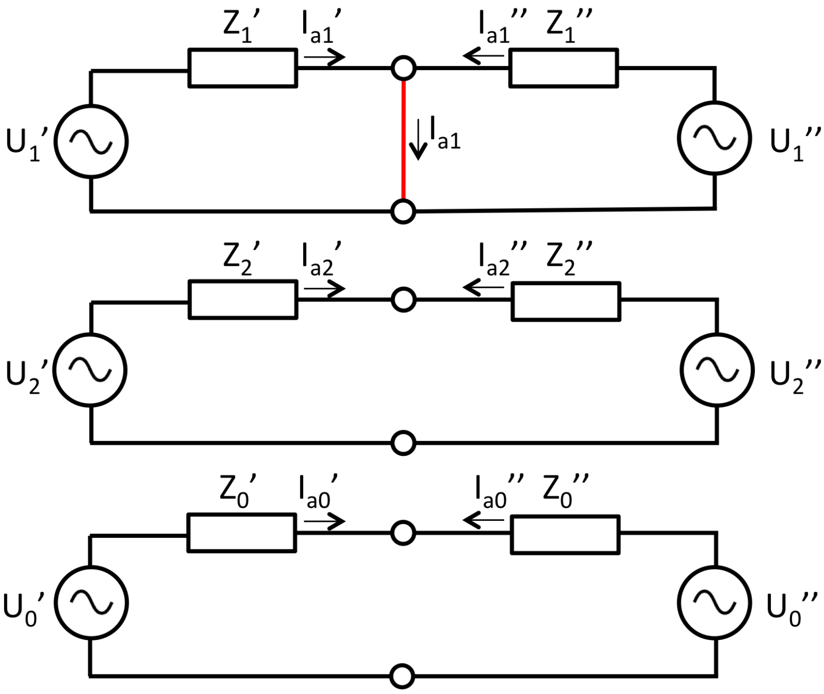


Figure 3.3.: Reduced Sequence Networks Interconnection for Three-Phase Fault. No Negative or Zero Sequence Network Component

- Z_1', Z_2', Z_0' - Positive, Negative and Zero Sequence Impedance of Generator at bus B' and Line Part 1
- Z_1'', Z_2'', Z_0'' - Positive, Negative and Zero Sequence Impedance of Generator at bus B" Line Part 2

From Equation A.1 in Appendix A it can be seen that the positive sequence current, I_{a1}, is equal to the fault current, I_F. This is illustrated in Figure 3.3. In other words, the original three-phase system can be represented with just the positive sequence components of the symmetrical components, which is the same as the original phasors (ref. Equation A.2).

$$I_F = I_{a1} = I_{a1}' + I_{a1}'' \tag{3.1}$$

In this case, the relay at bus B' will not see the entire fault current, it will see the current contribution flowing from bus B':

$$I_{a1}' = I_a' = \frac{U_1'}{Z_1'} \tag{3.2}$$

3.2. Phase-to-Ground Faults

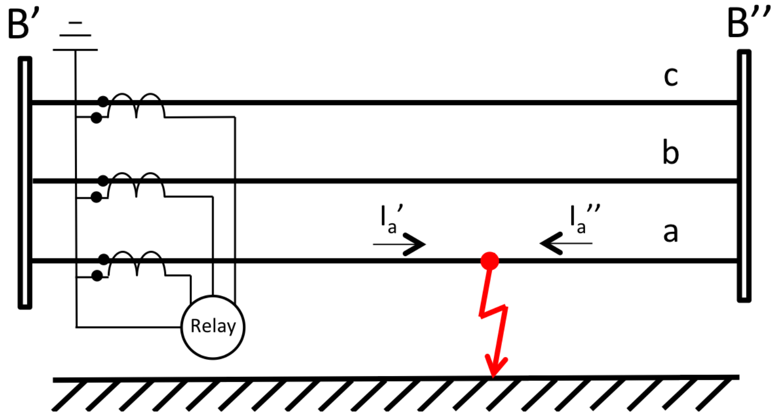


Figure 3.4.: Phase-to-Ground Fault

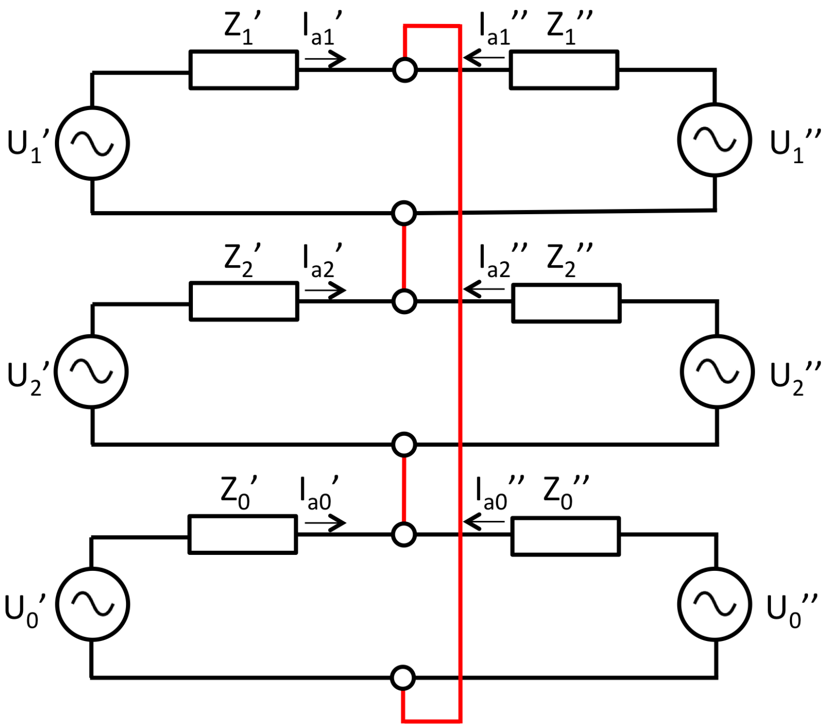


Figure 3.5.: Reduced Sequence Networks Interconnection for Phase-to-Ground Fault

Single Phase-to-Ground faults are the most common fault types in common three-phase networks. They may be caused by direct or indirect lightning strokes, leading to transient overvoltages. Falling trees or other objects may also lead to a short circuit between phase and ground.[15] In a situation where Phase a experiences a bolted fault to ground, as illustrated in Figure 3.4, the current in Phase b and c becomes zero, while Phase a will carry the entire fault current:

$$\begin{aligned} I_a &= I_F \\ I_b &= 0 \\ I_c &= 0 \end{aligned} \tag{3.3}$$

Inserting this into Equation A.1 leads to the following relationship:

$$I_{a1} = I_{a2} = I_{a0} = \frac{I_a}{3} = \frac{U_1'}{Z_1' + Z_2' + Z_0'} + \frac{U_1''}{Z_1'' + Z_2'' + Z_0''} \tag{3.4}$$

The currents can be divided up in to the two parts as earlier:

$$\begin{aligned} I_a &= I_a' + I_a'' \\ I_{a1} &= I_{a1}' + I_{a1}'' \\ I_{a2} &= I_{a2}' + I_{a2}'' \\ I_{a0} &= I_{a0}' + I_{a0}'' \end{aligned} \tag{3.5}$$

The fault current may then be expressed as follows:

$$I_F = I_a = 3I_{a1} = 3I_{a2} = 3I_{a0} = \frac{3U_1'}{Z_1' + Z_2' + Z_0'} + \frac{3U_1''}{Z_1'' + Z_2'' + Z_0''} \tag{3.6}$$

This can be represented by connecting all of the sequence networks in series, as shown in Figure 3.5. Again, the relay will only see the current from bus B':

$$I_a' = \frac{3U_1'}{Z_1' + Z_2' + Z_0'} \tag{3.7}$$

If $Z_1' = Z_2' = Z_3'$, then the relay will see the a current of the same magnitude during a Three-Phase-to-Ground Fault as during a Phase-to-Ground Fault.

3.3. Phase-to-Phase Faults

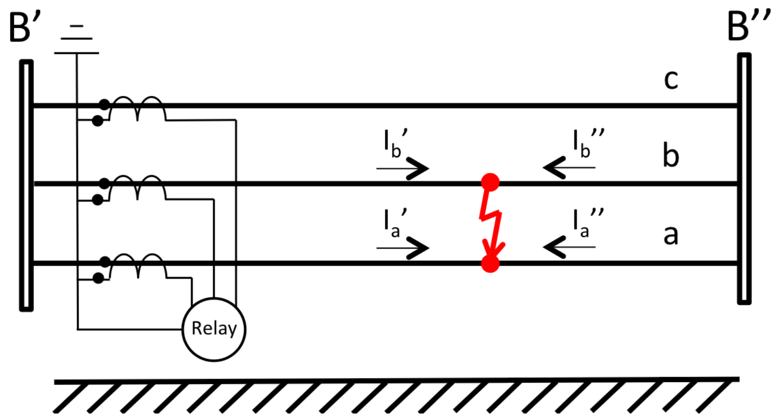


Figure 3.6.: Phase-to-Phase Fault

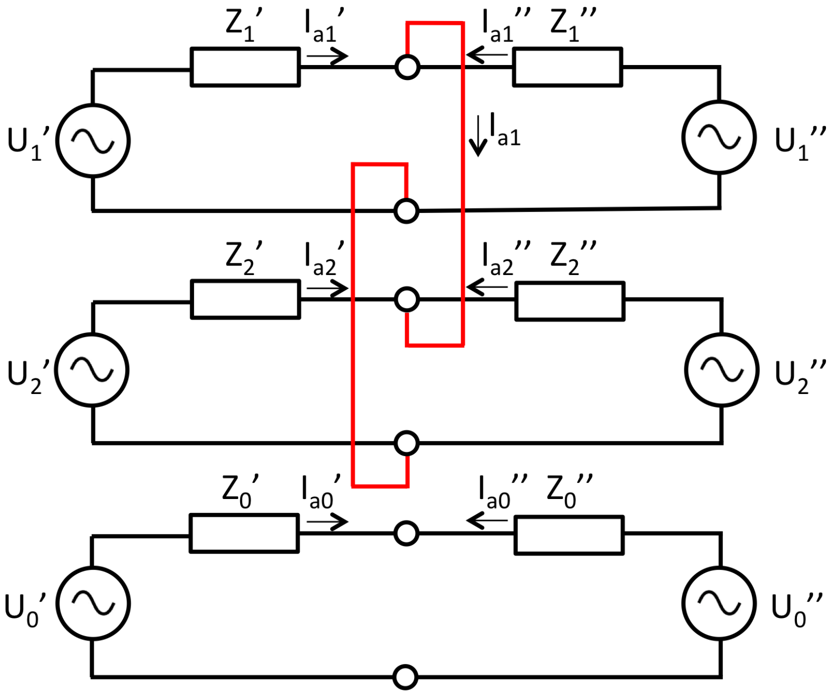


Figure 3.7.: Reduced Sequence Networks Interconnection for Phase-to-Phase Fault. No Zero Sequence Network Component

When two phases in a three-phase system comes in contact with each other it is called a phase-to-phase fault. This is an asymmetrical fault. Consider a case where Phase a and b are the faulted phases. Then the currents in the phases would be of equal amplitude, with reverse polarity, and the current in Phase c will be zero:

$$
\begin{aligned}
I_a &= I'_a + I''_a = I_F \\
I_b &= I'_b + I''_b = -I_F \\
I_c &= 0
\end{aligned}
\tag{3.8}
$$

Assuming the respective positive and negative sequence impedances are equal, Equation A.1 yields the following expression for the magnitude of the fault current:

$$
I_F = I_a = \frac{\sqrt{3}U'_1}{2Z'_1} + \frac{\sqrt{3}U''_1}{2Z''_1} \tag{3.9}
$$

This shows that the magnitude of the fault current during a bolted phase-to-phase fault is $\frac{\sqrt{3}}{2} \approx 0.866$ to the one of a bolted three-phase fault.

In the same way as before the relay will only see the current contribution from bus B', which in this case is I'_a and I'_b.

3.4. Double-Phase-to-Ground Faults

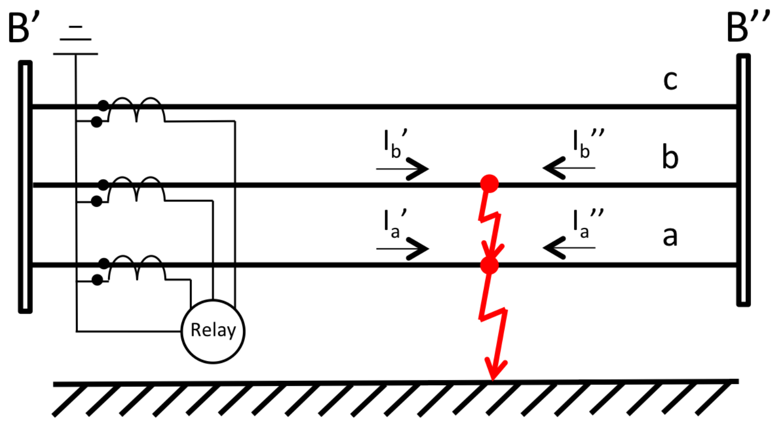


Figure 3.8.: Double-Phase-to-Ground Fault

Double-Phase-to-Ground faults occur when two phases come in contact with each other and ground at the same time. It occurs relatively rarely, nevertheless it should be mentioned.

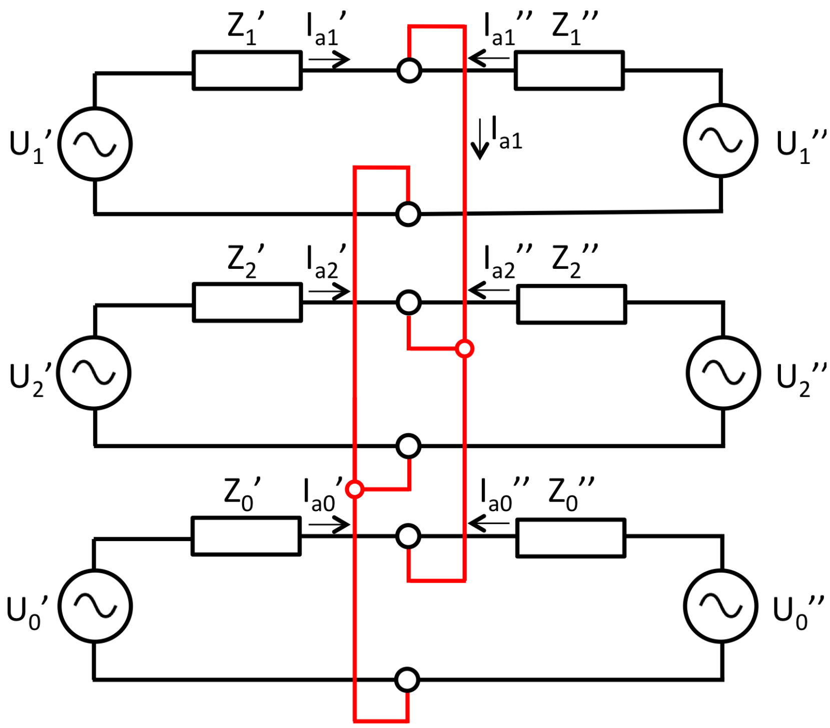


Figure 3.9.: Reduced Sequence Networks Interconnection for Double-Phase-to-Phase Fault

Figure 3.8 illustrates a Double-Phase-to-Ground Fault where Phase a and b are faulted. The current in Phase c becomes zero, $I_c = 0$. This fault can be represented by interconnecting the three sequence networks in parallell. This gives:

$$I_{a1} = I'_{a1} + I''_{a1} = \frac{U'_1}{Z'_1 + \frac{Z'_2 Z'_0}{Z'_2 + Z'_0}} + \frac{U''_1}{Z''_1 + \frac{Z''_2 Z''_0}{Z''_2 + Z''_0}}$$

$$I_{a2} = I'_{a2} + I''_{a2} = -I_{a1}\left(\frac{Z'_0}{Z'_2 + Z'_0} + \frac{Z''_0}{Z''_2 + Z''_0}\right) \tag{3.10}$$

$$I_{a0} = I'_{a0} + I''_{a0} = -I_{a1}\left(\frac{Z'_2}{Z'_2 + Z'_0} + \frac{Z''_2}{Z''_2 + Z''_0}\right)$$

The relay at bus B’ will also here just see the proportion of the fault currents coming from bus B: I'_a and I'_b.

4. Protection Principles

There exists several different protection techniques and principles. Fuses are the simplest and cheapest technology, however they need to be manually replaced when they melt (operate). Protective relays are used when fuses are not feasible. Different relays can have different inputs, and they will treat the information differently, but their objective is shared; to correctly detect and clear a fault as soon as possible. A closer look at overcurrent, distance and differential relay principles will be made in this chapter, as they are the most common protection applications in power systems today. Other protection principles also exists, e.g. overvoltage, undervoltage, volts per Hertz, however they are not the scope of this thesis.

4.1. Fuses

The first type of protection for electrical networks were fuses. As they are simple and cheap, they are still commonly used for protection purposes today. The most common type of fuses consists of a short conducting wire inside a casing, capable of carrying the current permitted for the protected zone. The cross-section and material of the wire decides how much current the fuse can conduct without melting. The wire will melt if the temperature increase caused by the current going through the fuse, which has some resistance, becomes higher than the melting temperature of the wire material. The fuse can melt almost instantaneously or with some time delay as seen in Figure 4.1. A melted fuse will need to be manually replaced, and this is one of the drawbacks of using fuses for protection. Overcurrent relays, which will be looked at later in this chapter, can have a time-current characteristic similar to fuses.[33]

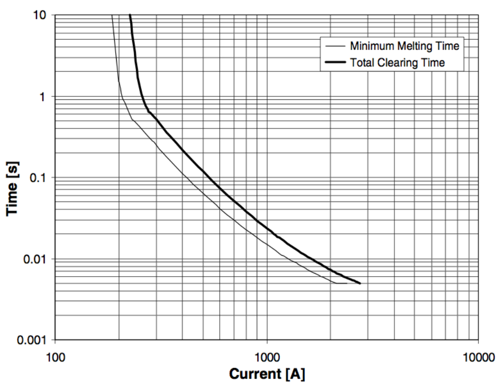


Figure 4.1.: Time-Current Characteristics for a Fuse[19]

4.2. Overcurrent Relay

In most cases fault currents are several times higher than load currents. In other words, currents significantly higher than load currents equals fault. This simple principle is what overcurrent relays is based on. The inputs of overcurrent relays are currents from CTs, which continuously measure currents flowing in the system. Normally, in a three-phase system, there are three CTs per location, one per phase. This supplies the relay with information about current in each phase, as well as the current flowing in the neutral (ground). The current in the neutral is normally measured by joining the three phase leads inside the physical relay itself, as illustrated in Figure 4.2. In a perfectly symmetrical system the current in the neutral will be zero (Kirchoff's law). During an asymmetrical fault this current will be of significantly higher magnitude. This principle is therefore used as a fault indicator in overcurrent relays.

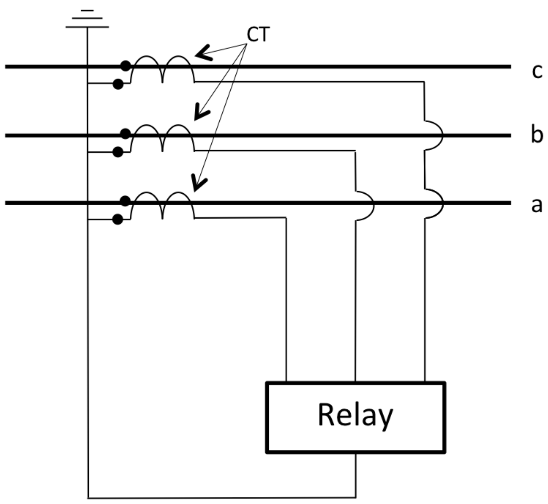


Figure 4.2.: Connection of Current Transformers for Overcurrent Relay

Overcurrent relays operate with inverse/definite time and instantaneous characteristics. The relays have a set pick-up current, I_s, and when the current reaches and/or surpasses this value a timer starts. The relationship between the magnitude of the current and the time needed for tripping is inverse or definite. When the timer reaches its corresponding point on the time-current curve, without the current dropping, the relay will trip. The relay will trip instantaneously if the current reaches the instantaneous trip setting. An example is shown in Figure 4.3. The inverse curves are usually divided into normal, very or extreme inverse characteristics. ANSI and IEC have standards for the characteristics of these time-current curves (TCCs) which are commonly used, however the user may choose/create tailored characteristics.[2]

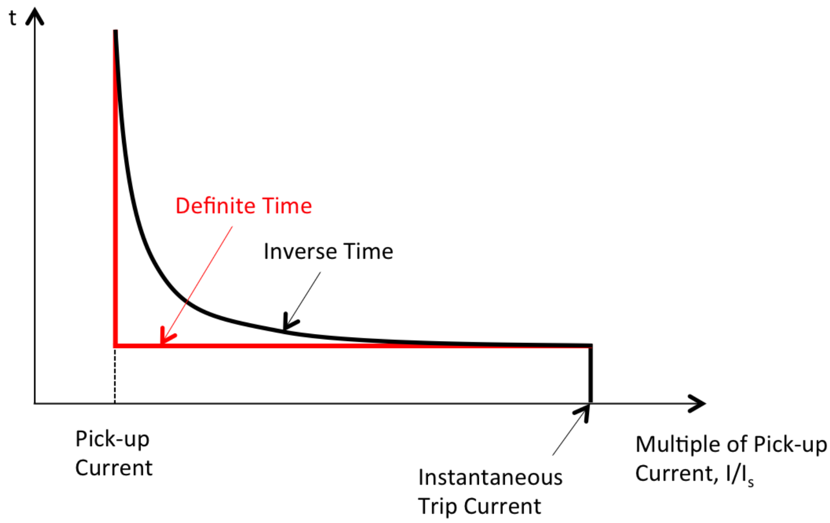


Figure 4.3.: Inverse Time and Instantaneous Characteristics - Overcurrent Protection

The setting of the pick-up current is the key element for overcurrent protection. This setting is crucial for the reliability of the protection system. Put differently, the relay should trip when it is supposed to, and should not trip when it is not supposed to. The relay should operate when there is a fault in its protection zone, or as remote back-up for downstream protection. It should not operate for high load currents or before downstream protection. To achieve this, relay coordination, is very important. Relays should be set so that they do not operate before downstream protection has time to operate, but still be able to operate, with a certain delay, if the downstream protection fails. The setting for overcurrent relays may vary between situations, however a rule of thumb, is to set the pick-up current as follows:[14]

$$1.5I_{MaxLoad} < I_s < 0.8I_{MinFault} \tag{4.1}$$

This provides a sufficient safety margin for fault and load current calculation errors.

The drawback of overcurrent relays is that they are not very good at pinpointing the fault location. The impedance between two possible fault locations can be small, i.e. the fault currents are similar, compared to the impedance back to the CT location. This can make it hard for the relays to discriminate between a fault inside or outside its zone.

4.3. Directional Overcurrent Relay

A regular overcurrent relay is not sensitive to the direction of the measured current. An overcurrent relay only looks at the magnitude of the current and will initiate pick-up and trip according to its time-current characteristics, regardless of the way the current is flowing. In many power system scenarios it can be very beneficial to have an overcurrent relay that is sensitive to both magnitude and direction of the current flow, i.e. a directional overcurrent relay. This can increase the selectivity and the reliability (ref. Chapter 2.4) of an overcurrent relay application significantly.

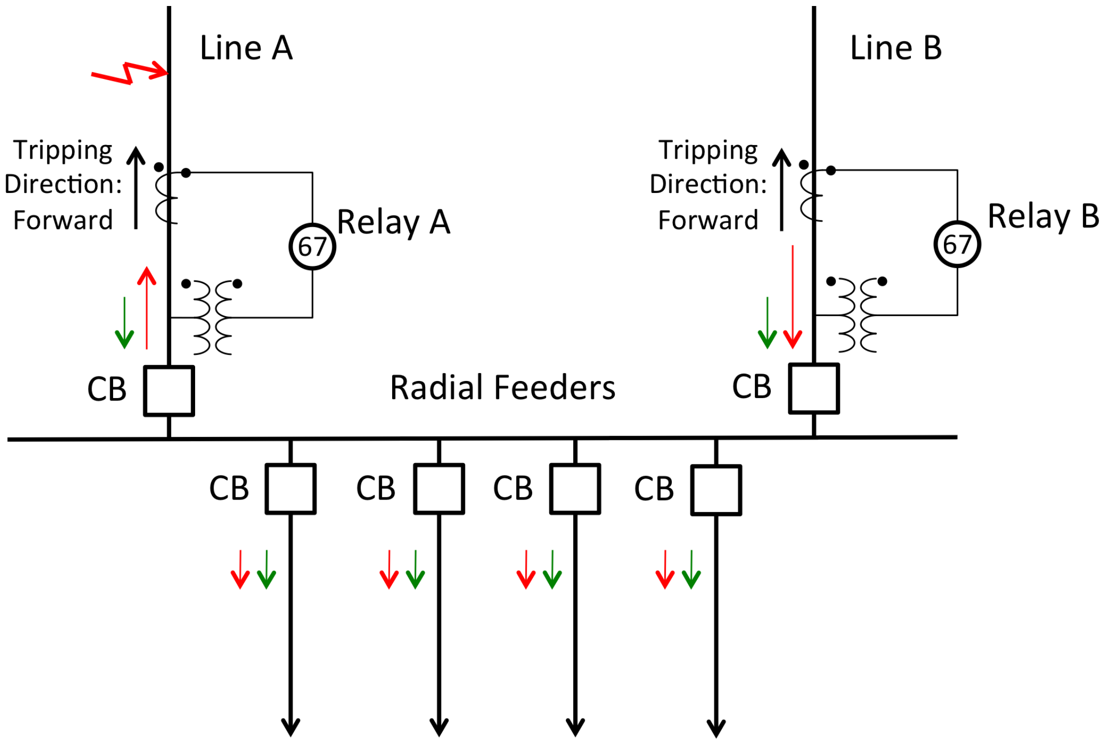


Figure 4.4.: Simplified One Line Diagram of Substation with Directional Overcurrent Relay

Figure 4.4 illustrates a substation with two main transmission lines, i.e. Line A and Line B, supplying four radial feeders with power. The main transmission lines are protected with a directional overcurrent relay, i.e. Relay A and Relay B (the busbar will have its own protection, which is not illustrated here). The green arrows illustrate how the current in the network will flow during normal operation.

If a fault were to occur at one of the transmission lines, e.g. at Line A as illustrated, current will flow from Line B, via the busbar, and upstream in Line A towards the fault, while still supplying load current to the feeders. The current flow during this fault is illustrated with the red arrows. In other words; Relay B will see a higher current than the relay in Line A during this scenario. If the relays have pick-up and time-current characteristics similar to each other and initially assume they have no directional element, it is possible that Relay B will trip before Relay A. However, ideally, Relay A is supposed to operate first as it is the primary protection for Line A. Assuming the relays now are directional, with forward tripping directions, i.e. towards protected object, Relay B will be blocked during the fault, due to the direction of the current it sees. This will lead to high selectivity as Relay B will trip first and clear the fault.

A reference, commonly referred to as polarizing quantity, is used to provide the directional function. This reference, either voltage or current, is utilized by the relay to compare the angle, ϕ, between the measured current, I_{CT}, and the reference, to determine the direction of the current flow. Normally, a voltage quantity is used as a reference, as seen in Figure 4.4 and shown in the phasor diagram in Figure 4.5 as U_{ref}, since a current reference may not be non-zero at all times.

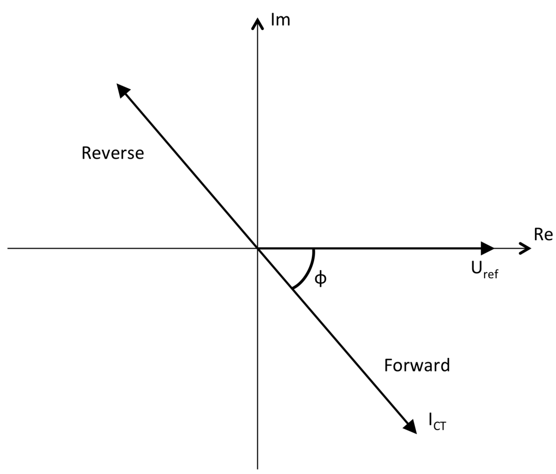


Figure 4.5.: Phasor Diagram for Directional Relay using Voltage Reference. Based on Figure 194 in [2]

The tripping direction of the directional overcurrent relay can be set to forward, reverse or it can be both, i.e. having a regular overcurrent function. Forward direction is usually defined towards the protected object, which normally also is towards the grounded side of the CT, as in the example in Figure 4.4. Reverse direction is naturally the opposite.

4.4. Distance Relay

Distance relays, sometimes referred to as impedance relay, measure the impedance of its protected unit, e.g. a line, using current and voltages supplied by CTs and VTs. The relay have been provided with the calculated impedance of the line, and continuously compare the two. Should the measured impedance at any time drop below the known line impedance, it will know that there is a fault and trip.

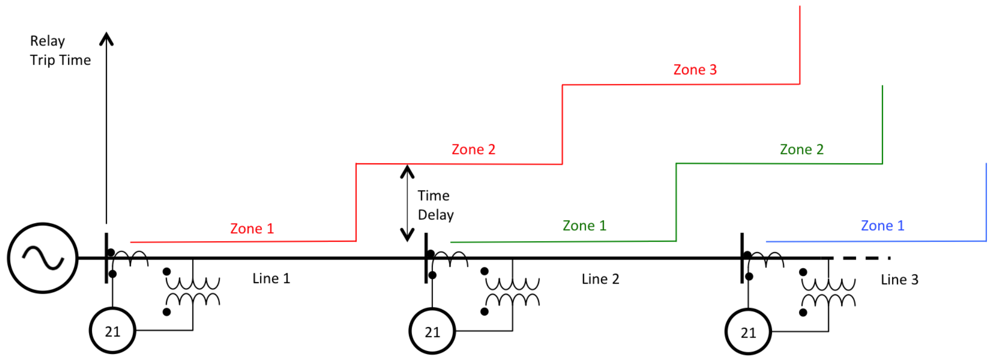


Figure 4.6.: Distance Relay Principle

Since the relay relies on measured values from transducers, and compares it with a calculated value, some safety margin is necessary. It is common to let the relay under-reach the line by 15-20 %, to make sure it does not operate before other relays downstream when it is not supposed to. This is illustrated in Figure 4.6 (Zone 1). To provide remote back-up for the relays protecting adjacent lines, the relay has another setting which over-reaches into the adjacent line (Zone 2). Typically the setting is 125-130 % of the impedance of Line 1. This setting has an added intentional time delay, to make sure the primary protection has a chance to operate first. A third protection zone is also common, and it will function as remote back-up for an even greater portion of adjacent lines. An extra, longer time delay is added here.[21] The distance relays will have protection zones in both directions, however this is not illustrated in Figure 4.6.

Traditionally relay settings have been in secondary values. However, with the introduction of modern transducers, e.g. optical CTs, which have no ratio, and therefore no secondary value, it is common that modern relay have settings in primary values.[2]

On the other hand, if a distance relay were to use secondary values, the impedance settings must be converted:

$$Z_{sec} = Z_{pri} \cdot \frac{CTR}{VTR} \tag{4.2}$$

Where CTR and VTR are the ratios of the current and voltage transformer.

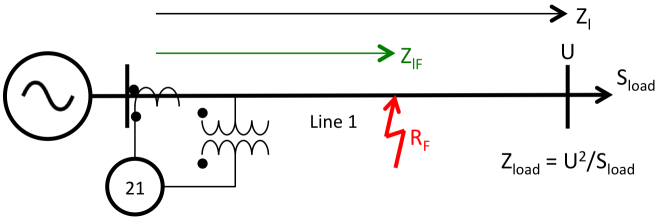
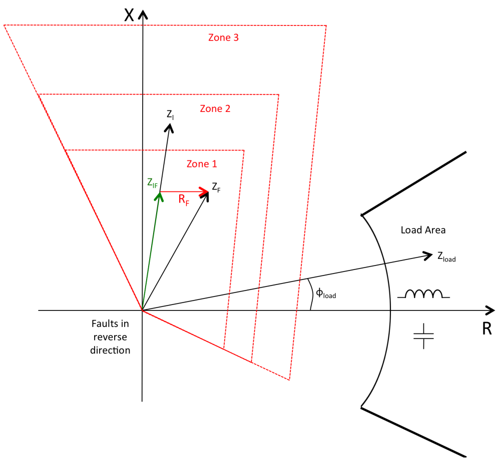
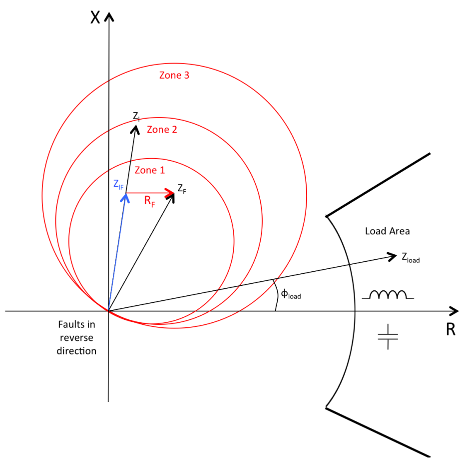


Figure 4.7.: Line 1 from Figure 4.6 with Mid-Line Fault



(a) Quadrilateral Zone Settings



(b) Circular (Mho) Zone Settings

Figure 4.8.: Corresponding RX-diagrams with Zone Settings, Line, Load and Fault Impedances for Line 1 in Figure 4.7

The impedance settings for the different zones are normally shown using an impedance, or RX-diagram. Modern numerical distance relays have the ability to let the impedance characteristics have whichever shape is desirable, however they normally have a quadrilateral or circular shape.[35] Figure 4.8a displays an example of the settings of a distance relay with three zones. During normal operation, the distance relay will see the impedance of the line, Z_l, plus the impedance of the load, Z_{load}. Under a fault the relay will see the impedance of the line to the fault location, Z_{lF}, and the impedance of the fault itself, here illustrated with an arc flash resistance, R_F. This yields the total fault impedance Z_F.

A common application for distance protection of a line is to have two distance relays at both ends of the line looking towards each other, as seen in Figure 4.9. The zone settings of the relays are set equal and in opposite direction, with Zone 1 normally being set to 80-85 % of the line length. The main purpose of using dual relays is to improve reliability for far-bus faults, i.e. faults outside of Zone 1.

Assuming a fault occurs close to bus B, Relay A will see the fault in Zone 2, while Relay B will see it in its Zone 1. This means Relay A will have longer operating time than Relay B, due to the added time delay. To improve operating time, and allow both relays to operate instantaneously communication between the relays can be added. The communication can be simple with transferring of one or more boolean variables, i.e. trip signals and breaker positions. This type of communication can be made over radio wave, copper wire or fiber optic cables. For more advanced communication, with transmission of, for instance, time-stamped current and voltage values, fiber optic communication according to the IEC61850 standard (ref. Chapter 5.4/5.5) is used.

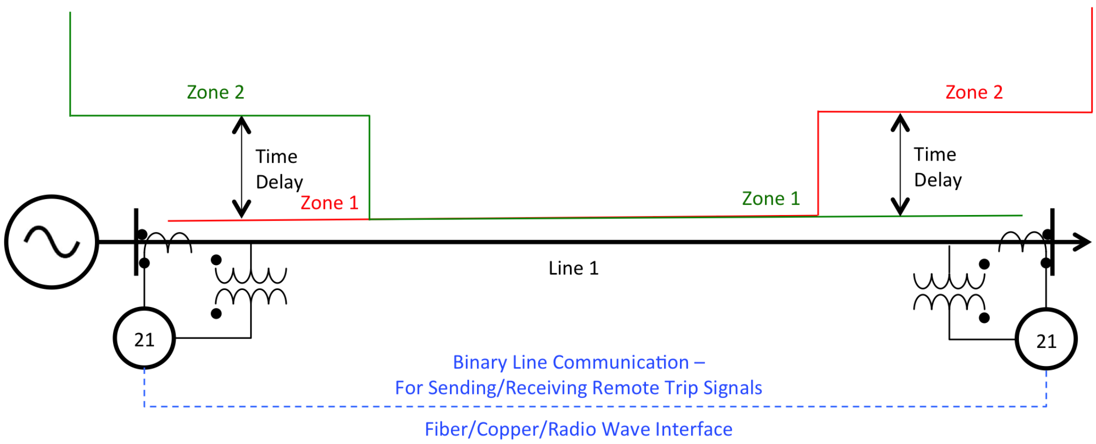


Figure 4.9.: Protection of Line with Distance Relay at Both Ends of the Line

4.5. Differential Relay

Differential relay protection is considered to be one of the most versatile protection techniques available today.[15] A differential relay compare two or more currents flowing into and out of the protected zone/equipment. The basic principle relies on the fact that under normal conditions, the current(s) entering the zone should be equal to the current(s) leaving it. If this condition is not satisfied, it is an indication that there is a fault within the zone. This makes differential relays ideal for the protection of generators, transformers, busbars and transmission lines.[15]

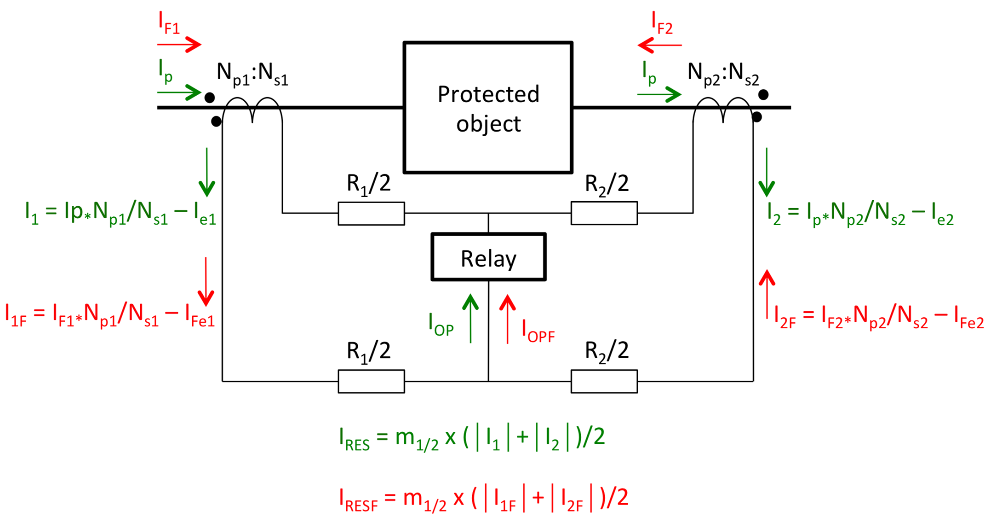


Figure 4.10.: Differential Relay Principle

Figure 4.10 illustrates the basic principle of differential relay protection. This relay has an input of two currents, however it is possible for a differential relay to have additional inputs, if protection of the zone/equipment requires it. The protection of a busbar with a differential relay is an example which may require more than two current inputs.

I_p is the current that flows through the zone during normal operation. The relay's input is the secondary current from both sides, i.e. the primary current times CT ratio, minus the respective excitation current. The CT ratios will be equal, unless there is a transformer within the protected zone. If that is the case, the CT ratios will be set so that secondary currents will be equal. Kirchoff's law yields that the relay will have zero contribution from the secondary currents. The excitation currents however, I_{e1}, I_{e2}, can not be considered to be equal at all times. They are dependent on the burdens R_1 and R_2, which is proportional to the length of the cables between CTs and the relay. If the respective length of the cables are significantly different, the excitation currents may differ. In addition, the excitation currents is inversely proportional to the CT ratios, as shown in Chapter 2.2. If they are different the excitation currents characteristics may also be different. The operating current, I_{OP}, which the relay sees will then be the difference between the two. An important design criteria for differential protection systems is therefore to take this into account when placing, sizing and setting the components.[21]

During an internal fault, both fault currents will flow into the zone. The magnitude of the currents will also, in most cases, be much higher than normal operation currents. The fault currents will not necessarily be equal, as they are dependent on the external system on both sides. This will lead to an increased operating current, I_{OPF}.

Percentage differential relays are the most common type of differential relays[15]. They compare a restrain current with the operating current; if the operating current I_{OP} is greater than the restrain current I_{RES} times a gradient m, it will operate. A lower gradient will increase the sensitivity of the relay. Figure 4.11 shows the current characteristics of a typical fixed percentage differential relay. It has two gradients m_1 and m_2. m_2 is greater to improve security at high restrain currents. To add security at low restrain currents, the operating current has a minimum pick-up value.

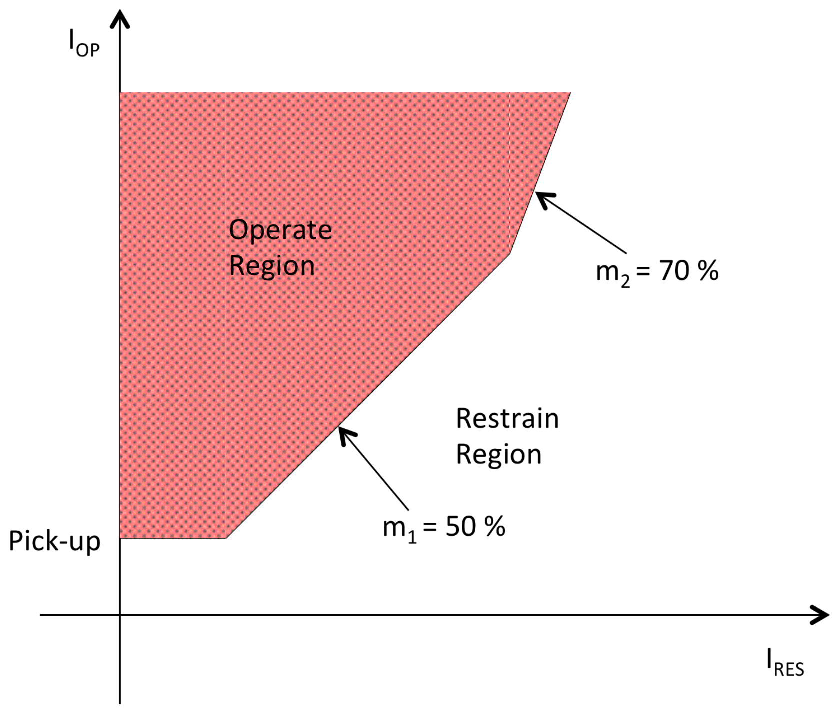


Figure 4.11.: Percentage Differential Relay Current Characteristics

One of the main problems with differential protection is that the CTs may experience different degrees of saturation. External faults may lead to high through currents of the protected object and may cause the corresponding CTs to saturate, creating distorted waveforms, leading to an unnecessary tripping. Carefully selecting CTs for each protection scenario is therefore important. Figure 4.12 displays how the secondary current affected by CT saturation compared to the actual secondary current.

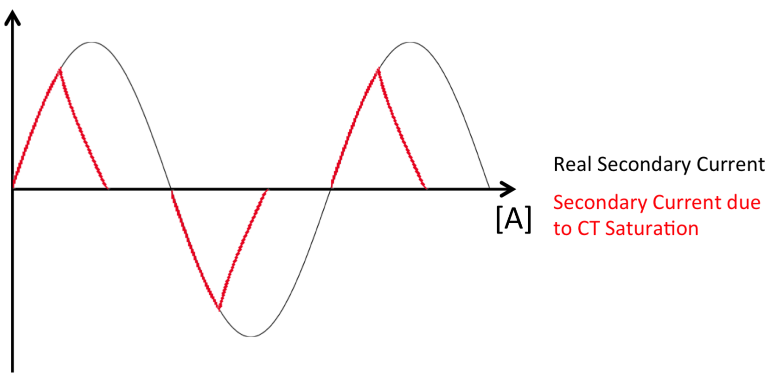


Figure 4.12.: Secondary Current Waveforms with/without CT Saturation

Another limitation for differential relays are that they can not protect a zone where the distances from CTs to the relay is long or varies too much. This is because the error of the CTs are dependent on the burden, which again is proportional to the length of the cables connecting the CTs and the relay. For the protection of a long line, it is therefore common to have two differential relays with corresponding CTs on each side of the line, and communication able to transfer current values between the two relays. For the protection of transmission and distribution lines, the relay engineer must be aware of the challenges occurring when energizing a line. Due to the shunt capacitance (length dependent) of a line, a significant capacitive current will flow in the line during energizing/de-energizing. This current contribution may not be equal at both sides, so the relay should block during this phenomena.

The described principles and challenges are valid for differential protection of busbars, transformers and generators, however some extra considerations must be made for these components.

4.5.1. Generator Differential Protection

A generator is normally protected with several types of protective relay functions in addition to differential protection, e.g. volts per Hertz (overexcitation), thermal overload and overvoltage protection. The number and types of protection will vary with the size, type, location and significance of the generator. However, differential protection is almost always a part of the protection system for generators, as it provides fast and sensitive protection for internal generator faults. It is not always used on generators under 1 MVA.[15]

Differential protection needs two sets of current transformers; one at the generator terminals and one in the neutral leads. It is common that they have the same ratio, and preferably be of the same model, to reduce potential mismatch errors for external faults. Since a generator can be wye- or delta-connected it is important that this is taken into consideration when setting the relay. The percentage characteristics, or gradients, $m_1/(m_2)$, are usually set to a relatively low value, typically to 10-25 %, to increase sensitivity.

4.5.2. Transformer Differential Protection

For the protection of transformers over 10 MVA, differential protection is widely used. This is due to the same reasons as to why they are used for generators; it provides fast, reliable and sensitive protection. Transformers normally have two windings, with a primary and secondary side, requiring one set of CTs on each side. In some cases one may encounter a three-winding transformer, which naturally would require three sets of CTs, i.e. on the primary, secondary and tertiary. Transformer differential protection is normally configured with a variable percentage characteristics. In other words this means the slope of the gradient increases with increasing restraint current. The change is either continuous or in discrete steps. This characteristics is used to prevent mis-operation due to CT saturation during external faults.

When designing a differential protection scheme for a transformer, one faces some extra challenges which needs to be taken into account:

- Magnetizing Inrush Current
- Overexcitation
- Different Voltage Levels → Different CT Types, Ratios and Characteristics
- Wye/Delta/Zigzag Winding Combinations → Phase Shifts
- Transformer Taps → Varying Voltage Levels and/or Phase Shifts

Magnetizing Inrush Current

During a rapid change in the voltage applied to a transformer, a current transient, known as magnetizing inrush current may occur. This is caused by an exciting current trying to create flux in the transformer corresponding to the change applied voltage. Magnetizing inrush current can, in other words, occur during energizing of the transformer itself, during energizing of a nearby transformer or during other faults in the network which causes a momentary voltage dip. Initially, the magnetizing current may be up to 8-30 times higher than full-load current. The current decays to normal exciting current after some time, typically the time constant can be everything from 10 cycles to 1 minute, depending on several factors, most notably the resistance and stray losses in the transformer. This phenomena is important to be aware about when applying differential protection to a transformer, is at can cause unbalance to the currents measured by the CTs, and falsely indicating an internal fault and leading to unnecessary tripping. The differential relay should therefore be able to detect the phenomena when it happens and block the relay for the required period.[15]

Overexcitation

Overexcitation is caused by overvoltage and/or underfrequency, and it may lead to saturation of the transformer and subsequent heat buildup and internal damage. Larger transformers usually have separate protection for overexcitation, as differential protection is not practical to use explicitly for this. However, overexcitation is a concern for differential protection as it can lead to tripping on overexcitation far below dangerous values. The relay should in this case be blocked from operating currents caused by overexcitation.[15]

Different CT Characteristics due to Different Voltage Levels

A transformer will have different voltage levels at the different terminals. To compensate for this, the ratio of the CTs at each terminal is chosen accordingly, so that secondary currents, i.e. the current that the relay sees, has the same base value on all terminals. Due to the needed difference in CT ratio one may come across sets of CTs of a different type/model and/or from a different manufacturer. This can also mean that the CTs will have different performance characteristics. This is another factor that must be taken into account.[15]

Phase Shifts

Depending on how the transformer windings are connected to each other on each side, there may be a phase shift from one side to the other. For instance will a delta-wye connected transformer, experience a phase shift where the delta side will lead the wye side with 30°. It is therefore important to input correct information about each respective winding, when setting the relay.[15][28]

Tap-Changing Transformers

Selected transformers can have the possibility of adjusting the ratio with built-in tap-changers. This feature is used for voltage control to achieve desired power system operation, e.g. controlling reactive power flow, and is in most cases controlled remotely. Normally, the tap-changers are able to adjust the voltage ratio by ±10 %. Since CTs are set at a fixed ratio, this is a concern for the purpose of differential protection. Some CTs, as previously mentioned, may have multiple tap settings, but their intention is not to be remotely controlled, e.g. to accommodate tap-changing transformers. By setting the CT ratio according to the center of the voltage range, the error is minimized to half of the overall voltage range. For a transformer with a tap-changing voltage range of ±10 %, the maximum error caused by the tap-changer is 10 %. Selecting the percentage characteristics for the differential protection accordingly, to prevent mis-operation, is therefore vital when dealing with tap-changing transformers.[15]

4.5.3. Busbar Differential Protection

The main challenge when applying differential protection of busbars is achieving sufficient selectivity to avoid mis-operation during close-in faults, i.e. faults in close proximity of the bus, but outside the bus protection zone. CT saturation may occur during close-in faults and the busbar differential protection must therefore be accordingly delayed to coordinate with the relay providing the primary protection function for the adjacent, faulted line. In some cases distributed devices for each line connected to the bus which transmits measured values to a central unit. The differential function is then performed in the central unit, which compares the values from all lines continuously. There exist other types of busbar differential protection which are commonly used, e.g low-impedance and high-impedance differential protection, however they will not be described closer in this report.[28]

5. Modern Relay Technology

The technology behind microprocessors continuously improves, leading to them becoming more powerful, faster and smaller. Todays modern relays, commonly referred to as Intelligent Electronic Devices (IEDs), are microprocessor based devices. This technology development has allowed relay manufacturers to make complex devices containing several protective functions, as well as metering, event recording functions and communication features.

This all-in-one philosophy lets one device replace the functions of several stand alone devices, significantly decreasing investment costs. Should one protective function not operate as intended during a fault, another function will detect and cause the relay to trip. For instance; if there is problems with a VT, leading to the distance protection not being dependable (the relay should detect this and disable the distance function), the overcurrent protection function will detect the fault and operate. This is in Chapter 2.4 referred to as local back-up.

However, should the entire relay fail, one is left without protection, unless there is a separate relay (similar or different model) providing redundancy. Digital relays have two main sources of error; hardware and software, software being introduced by the transition into digital relays. Periodic, maintenance testing of relays, to ensure their reliability, especially after software updates/revisions, is therefore key. To avoid potential recurring problems, it might be beneficial to install relays of a different model/series, or perhaps even better; from a different manufacturer. A redundant protection system is also important to have since relays has to been to taken out of service for maintenance testing. The alternative; testing relays while leaving the system unprotected, is not viable.

The increased complexity of modern digital relays provides challenges for relay operators. Software allows the number of settings for the different integrated protective functions to be substantial. It is therefore important that the relay operator is well known with the capabilities of the relay and its software, to prevent misapplications. The software of the relays are also frequently updated and it requires the operator to stay up-to-date, as software updates may bring new and added functions, but also change existing functions.[32]

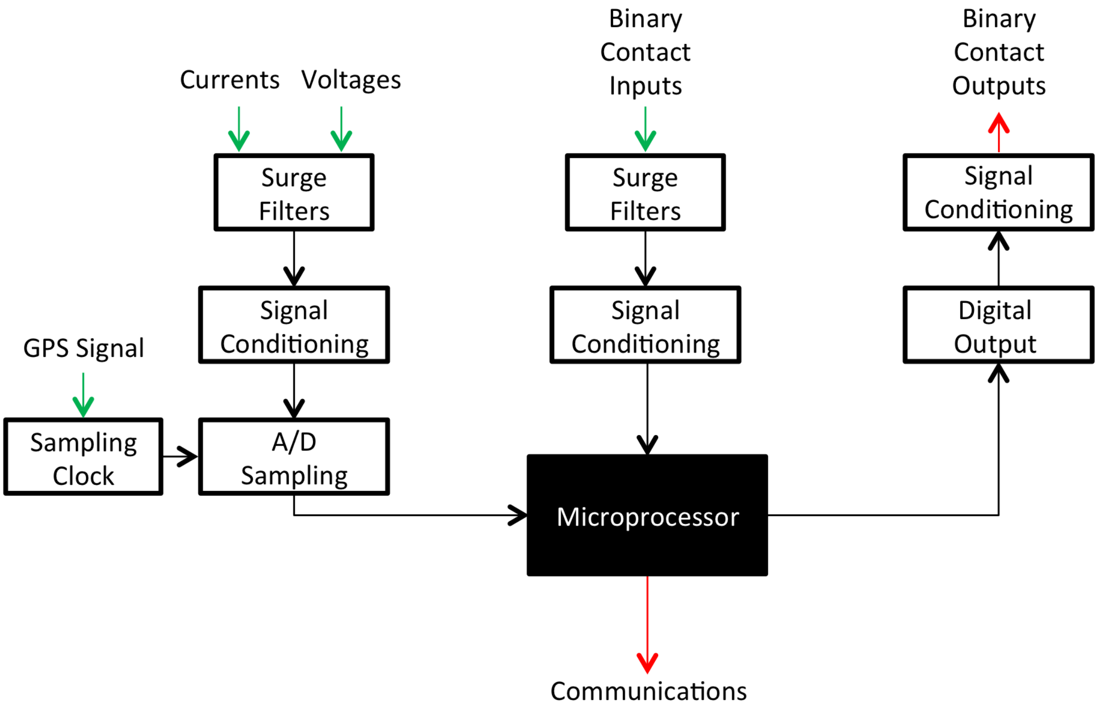


Figure 5.1.: Architecture of Modern Relays, based on Figure 1.1 in [8] and Figure 1.6 in [32]

5.1. Transducer Input and A/D Sampling

Figure 5.1 illustrates the architecture of a modern relay, with hard wired conventional transducers. The number of current and voltage inputs can be specified according to the buyers needs, as most modern relays have interchangeable input/output modules. This is as long as practical restrictions of the relay models are followed. All currents must be converted to voltage signals which are suitable for digital sampling, usually done by shunt resistors. The digital sampling is done by the Analog to Digital Converter (A/D), whose inputs are in parallel with the shunt resistors. The A/D normally has a peak voltage restriction of $\pm$ 10 V. Voltage inputs from VTs/CCVTs must therefore be scaled according to this input range. It is worth mentioning that if electronic transducers are used, the internal architecture will be different. The data is then sampled in the transducers, and can then be directly input to the microprocessor.[8]

Figure 5.2 illustrates a continuous sinusoidal signal being sampled to discrete values.

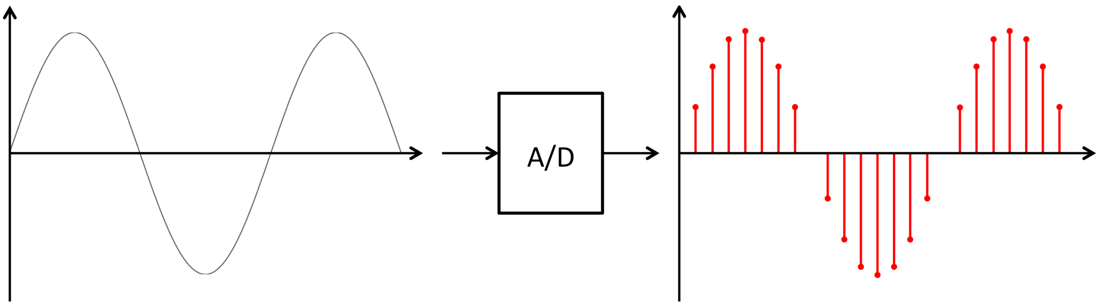


Figure 5.2.: Sampling of Analog Signal to Digital Values by an Analog to Digital Converter (A/D)

Before reaching the A/D the currents and voltages pass through surge filters, whose role is to block potentially harmful transients. These transients can be signals in the order of mega-Hertz, created by arcing or switching off components. The cut-off frequency of a surge filters are therefore in the range of several hundred kilo-Hertz. The currents and voltages also pass through anti-aliasing filters. These filters has a cut-off frequency of a few hundred Hertz, adjusted to the desired sampling rate of the A/D. The A/D can also include several other signal processing functions, e.g. DFT (Discrete Fourier Transformation) and Windowing.[30] Details of advanced signal processing are not in the scope of the thesis, therefore a study on this subject will not be made.

The sampling rate, i.e. the interval between each sampling, must be selected so that the error created by going from continuous to discrete values is negligible.[8] The IEC61850 standard, which will be studied later in this chapter, defines two distinct sampling rates for current and voltage transformers, 80 and 256 samples per cycle. In a 50Hz system, this equals a sampling rate of 4kHz and 12.8kHz respectively.[26] However, the relay manufacturer may choose to filter signals to a lower sampling rate for internal use in selected relay models if deemed advantageous.[2]

5.2. Digital Inputs and Outputs

The digital inputs are binary signals, normally used for indicating positions of contacts, e.g. if a circuit breaker is open or closed. The inputs are DC voltage signals, with a low/high(0/1) value, indicating open/closed. An applied voltage in the range of e.g. 24-30 V will be interpreted by a corresponding transistor in the relay as high(1), while no applied voltage will equal low(0).[2] These signals also pass through surge and anti-aliasing filters.

Digital outputs are similar to the digital inputs, and their purpose is mainly to send trip signals to circuit breakers if the relay detects a fault. The number of digital inputs and outputs will vary with models and specific needs from the buyer.

5.3. Logic and Function

Modern relays are logic devices, constantly processing input values to check whether they represent a normal or faulted system. The input values are processed in different function blocks with a fixed time interval giving the sampling rate of the values. The most notable function blocks represent the protective functions, e.g. overcurrent (as shown in Figure 5.3 as *OC4PTOC*) and distance protection. The protective function blocks contains advanced algorithms designed to operate with highest possible speed and reliability, and this is a well kept secret of the relay manufacturers, as this is what separates them from each other.

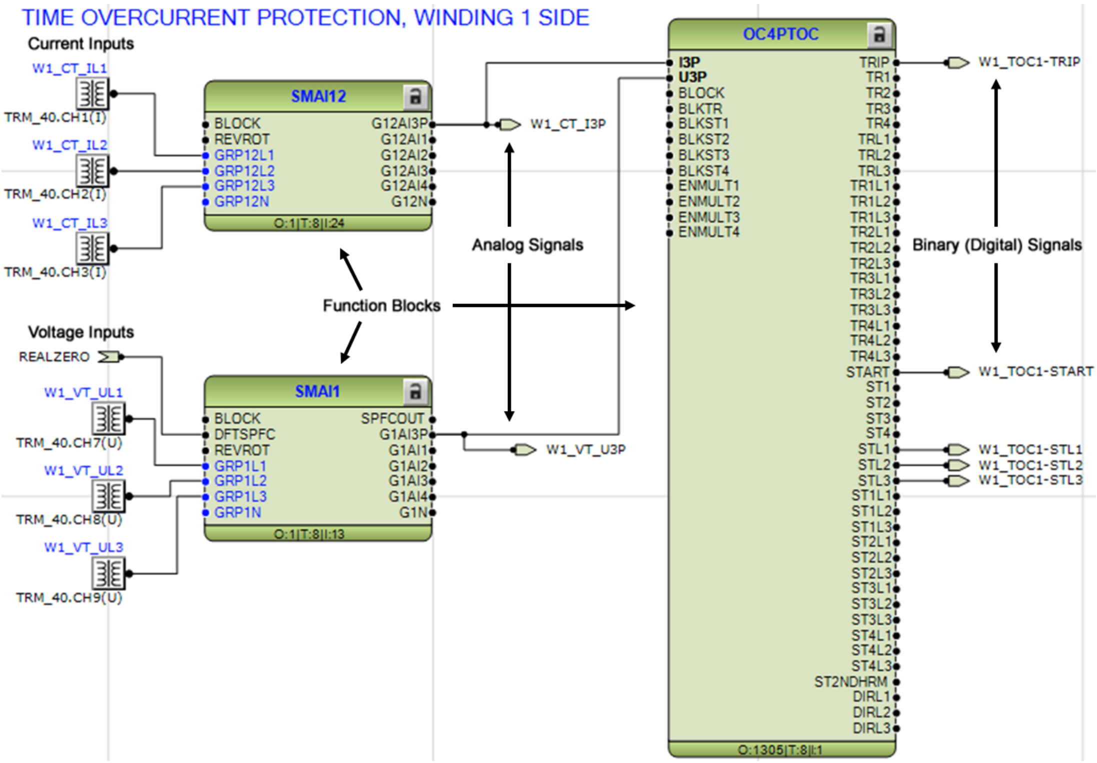


Figure 5.3.: Signal and Function Blocks for Overcurrent Protection in ABB RET670 Relay

The output signals of the protective function blocks are binary signals, most importantly trip and start signals, e.g. $W1\_TOC1 - TRIP$ and $W1\_TOC1 - START$ shown in Figure 5.3. These signals are forwarded to tripping logic schemes, which typically contains AND, OR and NOR blocks, used to combine several signals to achieve the desired functions. The signals are also connected to other function blocks controlling LEDs on the HMI (Human-Machine Interface) and most importantly the binary output signals, which is the communication between the relay and the circuit breaker. This description is simplified, as the logic of modern relays is quite complex, however it explains the general principles.

5.4. Communication

The possibilities for communication is a major benefit of digital relays. Communication allows relays to cooperate in real-time, e.g. communication between distance relays at each end of a line will provide excellent reliability. Continuous monitoring of entire protection systems, with communication between relays and central data systems, in the substation or at a remote location, is beneficiary for the system operator. It also allows the system operator to make changes to relay parameter settings, all from remote locations if desirable. Communication is also used between relays and non-conventional transducers. This is contrary to traditional transducers which are hard wired to the relays.

Early generation digital relays had simple communication outputs through serial and/or parallel ports. With the technology advancing, the latest relay generations has fiber optic, Ethernet communication. Fiber optic communication technology is fast, reliable and provides high transfer capacity.

There are mainly two ways a set of relays can be connected to each other; direct fiber optic connection or fiber optic connection via a central network system. One of the main differences between these two options, is the time delay. If the there is a direct connection between the relays, there will be no time delay. This allows the time stamped sampled values to be used by both relays without any problems. However, if they are connected via a central network system, the data packets will pass through a rugged switch environment. Rugged switches are used since they can handle the level of interference which may occur in substation data/network systems. The cost of this is an extra, varying time delay. The sampled data can now not be used by both relays, since there is no guarantee that the time stamp is valid. The solution for this is to make sure that the internal clocks of both relays are synchronized at all times. This can be accomplished by synchronizing the clocks with GPS signals. This is more closely described in Appendix B.

5.5. IEC61850 - Standard for Design of Substation Automation

The standard for communication between IEDs is provided by the International Electrotechnical Commission's standard IEC61850 - Standard for Design of Substation Automation. The main purpose of IEC61850 are to meet the increasing demand for communication, by creating standards for communication between devices from different manufacturers, while reducing investment, operating and maintenance costs.[26].

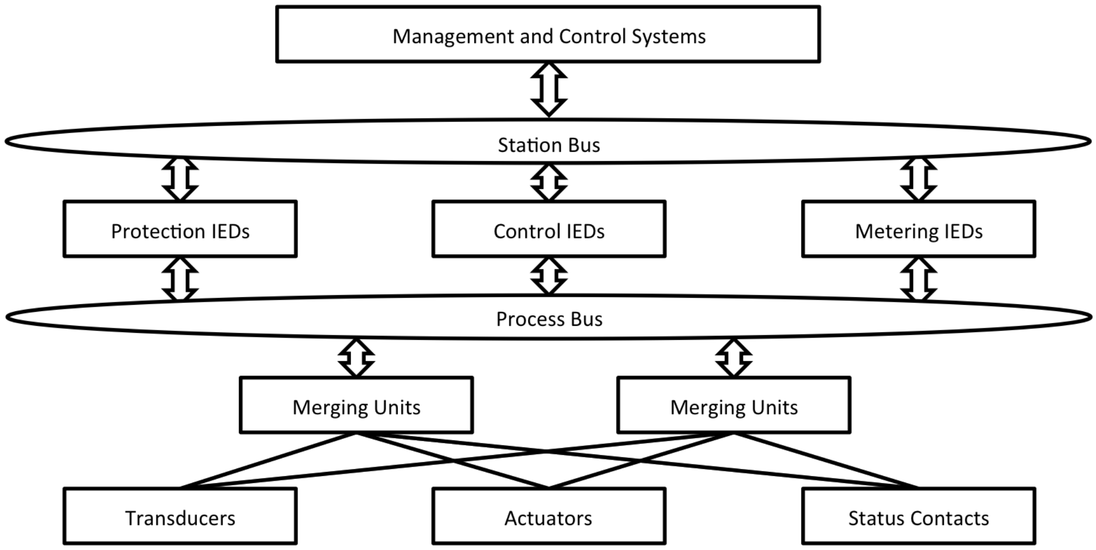


Figure 5.4.: IEC61850 Framework - Substation Communication System, Based on Figure 1 in [26]

Figure 5.4 illustrates a substation communication system in compliance with the framework defined in IEC61850. The information from transducers, actuators and status contacts are gathered, and sampled if necessary, in a merging unit and distributed to the protection, control and metering devices via a process bus. The IEDs are now reduced to just a processing element with a human interface, as they get all their data via the process bus. The IEDs are connected to the overseeing management and control system through a station bus. The buses are normally fiber optic, Ethernet networks. The design of a sub-station communication system will vary, e.g. the merging units can be directly connected to the IEDs, not via a process bus, however the main principles remains the same.[18][26]

GOOSE (Generic Object Oriented Substation Events) is a high speed peer-to-peer communication model used to transmit status information, e.g. trip signals and breaker positions. GOOSE is a part of the IEC61850 standard and it allows this vital information to be prioritized and transferred with minimum delay.[34]

5.6. The Future of Relay Technology and Power System Protection

IEC61850 is designed with future sub-station communication designs in mind. There will be a shift from separate devices for each protection, metering and control function into more integrated solutions where all functions have access to the same real-time information. As computer technology develops, we will likely see scenarios where have a main processor system, with dedicated computer power for each function. However, the increasing integration and complexity of system will also lead increased vulnerability. It is therefore important to have redundancy in the system, maybe also back up of the most vital functions at a different location. In the future we will also see more electronic transducers, which can feed digital data directly to merging units/process bus. This is a major development from conventional transducers, as the distance from the relay to the transducers becomes irrelevant. Today, many relays are hard-wired to transducers, where increasing burden limits the distance.[26][32]

Wide Area Measurement Systems (ref. Appendix B) is an emerging trend in power systems. PMUs (and other IEDs) carefully placed at important locations in the power system provide real-time data of the status of the power system. Comparing data from different locations will give information about the health of the power system, which can be used to predict potential unwanted scenarios at an early stage. Applying intelligent load shedding and power system control, it can be used to prevent unwanted conditions before they arise, in other words it can provide Wide Area Protection (WAP).

6. Relay Testing

Modern relays are becoming more advanced with the number of built-in features and capabilities increasing. Most relays will not only have one protective relaying function, it will have several. The relay functions will be dependent on the software/firmware of the relay and only be limited by the number of inputs and outputs the physical relay has. For instance will a comprehensive line differential function require several current inputs; one per phase times number of lines.

At the same time the relay testing methods and equipment are become more powerful. The need for relay testing can be divided into five categories[32]:

- Type Testing
  - Type testing is performed by the relay manufacturer or the end user. It is an extensive process, where the manufacturer controls the quality of a newly fabricated relay, or tests a new software revision for a relay model. End users may perform type testing to check that the relay operates as promised and within their needs.
- Acceptance Testing
  - The relay is tested to prove that is the correct model and that all features are working as they should. It consists functional tests of inputs, outputs, displays, communcation, and in some cases pre-defined pick-up and timing tests. Acceptance tests are generic and its main purpose is to prove that model ordered has been delivered without damage during transportation.
- Commissioning
  - Commissioning is a site specific test, and is considered the most important test during the lifetime of a relay. It confirms that all protective elements and logic settings are correct for its intended use.
- Maintenance Testing
  - To ensure a relay continues to operate as it should, maintenance tests are performed at set intervals. Modern digital relays have internal self-testing that check for many errors. Maintenance testings is therefore not as crucial as it used to be with electromechanical relays, which were less reliable, e.g. due to functions drifting.

- Troubleshooting
  - Troubleshooting is important to perform after a fault if the relay did not operate, or if the relay operated when the system was operating in normal, steady-state conditions. This entails checking the log of the relay, and adjust settings accordingly. Then the relay should be re-tested, to ensure the new settings are correct.

There are three different methods to test relays, however only two of them are feasible in this context; testing with relay tester, with full-scale physical network (not feasible) or with a scaled physical network.

6.1. Testing - Relay Tester

A relay tester is a device that is able to induce secondary currents and voltages at one location of a power system. It is able to induce and output currents and voltages as if they were provided by transducers connected to a real three-phase system. Commonly, testers have three voltage and three current outputs. Some high-end models may have additional current outputs (e.g. for the testing of differential relays). The tester also has binary outputs (e.g. to simulate breaker positions) and inputs (e.g. to receive trip signals from relay). Some relay testers also have the capability of producing the current and voltage output as sampled digital values, instead of live currents and voltages. The sampled values are then fed directly to a compatible relay, according to the IEC61850 standard, mentioned in Chapter 5.5. An illustration of a front panel with inputs and outputs of relay tester from Omicron is shown in Figure 6.1.

Figure 6.1.: Front Panel of Omicron CMC 356 Relay Tester [23]

The relay tester is normally connected to a computer that runs the software to control and use the relay tester. Earlier versions had a parallel port interface, newer models use an Ethernet or USB interface. Some high-end models also have

Wi-Fi capabilities. Combined with its software the relay tester is a very powerful tool. The testing routines of the relay tester and software can be divided in three main parts:

- Manual Testing
- Software Routine Testing
- Event Recording/Simulated Waveform Playback

The voltages and currents induced by the relay tester is wired to the CT and VT inputs of the relay, i.e. the test object. Connections between digital inputs and outputs, to indicate trip signals and breaker positions, are made as shown in Figure 6.2. This is vital, since it, among other things, allows the relay tester to record the trip time of the relay and to compare the value with an expected result.

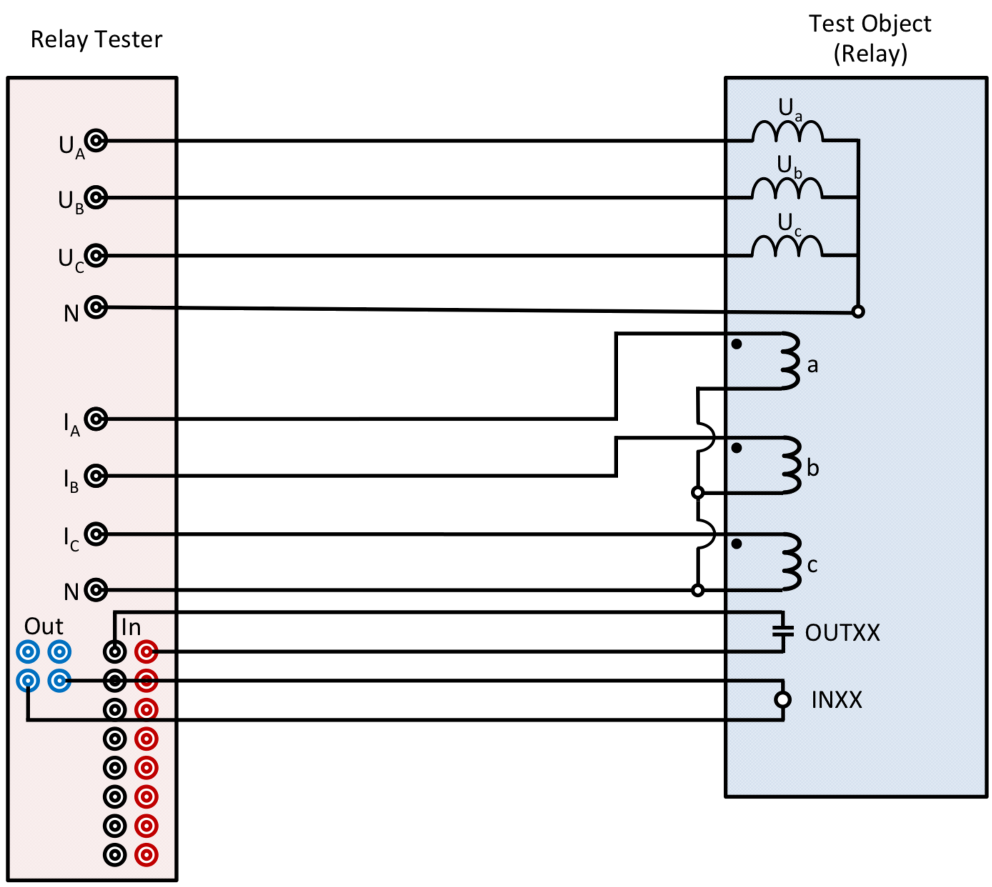


Figure 6.2.: Connection Diagram for Three-Phase Testing of Relays using a Relay Tester

6.1.1. Manual Testing

The software for relay testers normally comes with a control panel function, where the current and voltage outputs can be set manually. Figure 6.3 shows a screenshot from the control panel function of Omicron's software, Test Universe. The control panel gives the user full control over amplitude, phase angle and amplitude of the relay testers current and voltage outputs. A phase diagram with the corresponding phasors provides the user with a visual overview over the output. The settings can be adjusted off-line or when the outputs are live (in real-time).

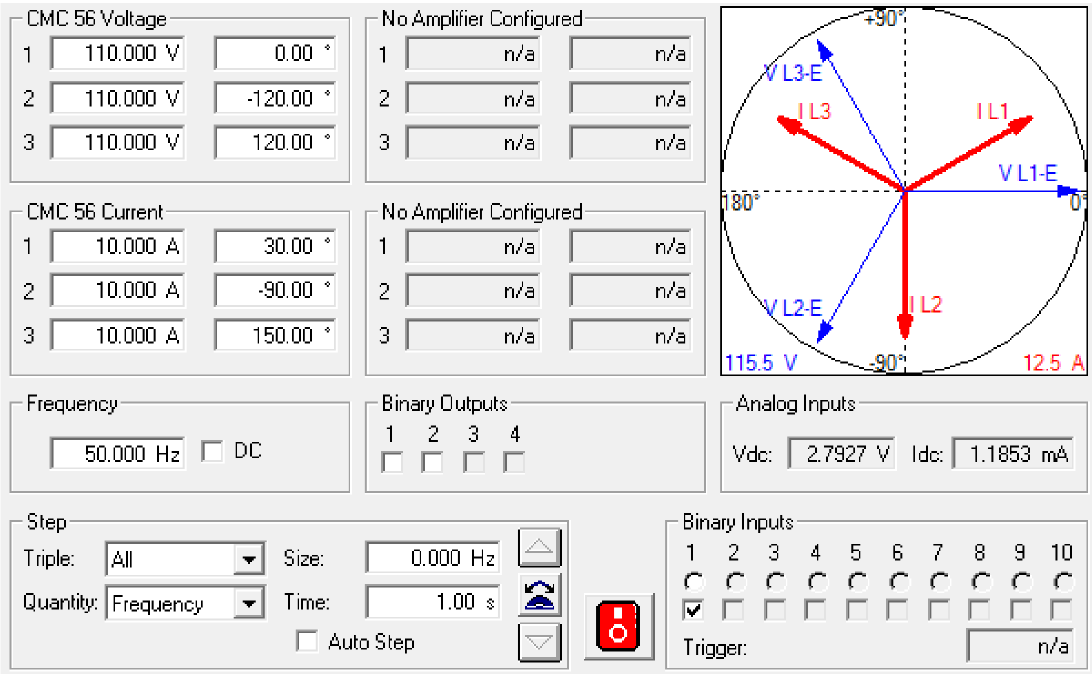


Figure 6.3.: Screenshot from Omicron Test Universe 1.61 SR1 - QuickCMC (Control Panel)

The control panel also allows the user to define the use of the digital output and input contacts. A timer function, which can be set to start and stop at a given events, is useful, e.g. for simple relay tests.

Instantenous Overcurrent Test

A simple instantaneous overcurrent function test can be performed in a manual way using the control panel:

- Check that relay tester outputs are off
- Verify relay settings and trip circuit settings
- Connect relay tester to relay (Example shown in Figure 6.2)
- Set the timer to start when the current in phase a becomes non-zero
- Set the timer to stop when the digital input (make sure correct input is assigned) receives a trip signal from the relay.
- Set the current output of one phase to be 5-10 % over instantaneous pickup and enable outputs
- Wait for trip signal
  - If there is no trip signal within reasonable time, double check pick-up and relay output settings and re-run test. If settings are correct, the relay failed the test.
- Note the trip time and compare with expected value
- Conclude whether the relay passed/failed the test

The timing test should be performed again while decreasing pickup values until the relay no longer trips and then increasing it until it trips again to determine the error of the instantaneous pick-up (Equation 6.1), as described in Chapter 6.5.

The control panel also has step/ramp options, where the user can step/ramp amplitude, phase angle or frequency, manually or with fixed time intervals. The stepping/ramping can be stopped automatically with an external signal to one of the digital inputs. This can be used to test or verify relay settings, by increasing/decreasing current/voltage amplitude, frequency or phase angle until the relay trips and record how much the increasing/decreasing value changed, e.g. for testing of an undervoltage or overvoltage function.

6.1.2. Software Routine Testing

The software packages of relay testers normally include aids to make relay testing faster and more efficient. A well developed software will have a comprehensive database with characteristics of different relay models. The basic software packages will include automated testing tools for the most used protection schemes, i.e. overcurrent, distance and differential protection.

For instance can the characteristics of a relays overcurrent function be imported from the database to the overcurrent testing tool. The user then inputs the pick-up current, selects the different testing points, i.e. multiples of the pick-up current, and the types of faults (three-phase, phase-to-ground etc.) to be tested, as shown in the screenshot in Figure 6.4. The relay tester will then apply the corresponding currents and voltages in an automatic order, while noting the different trip times and calculating the error for each case.

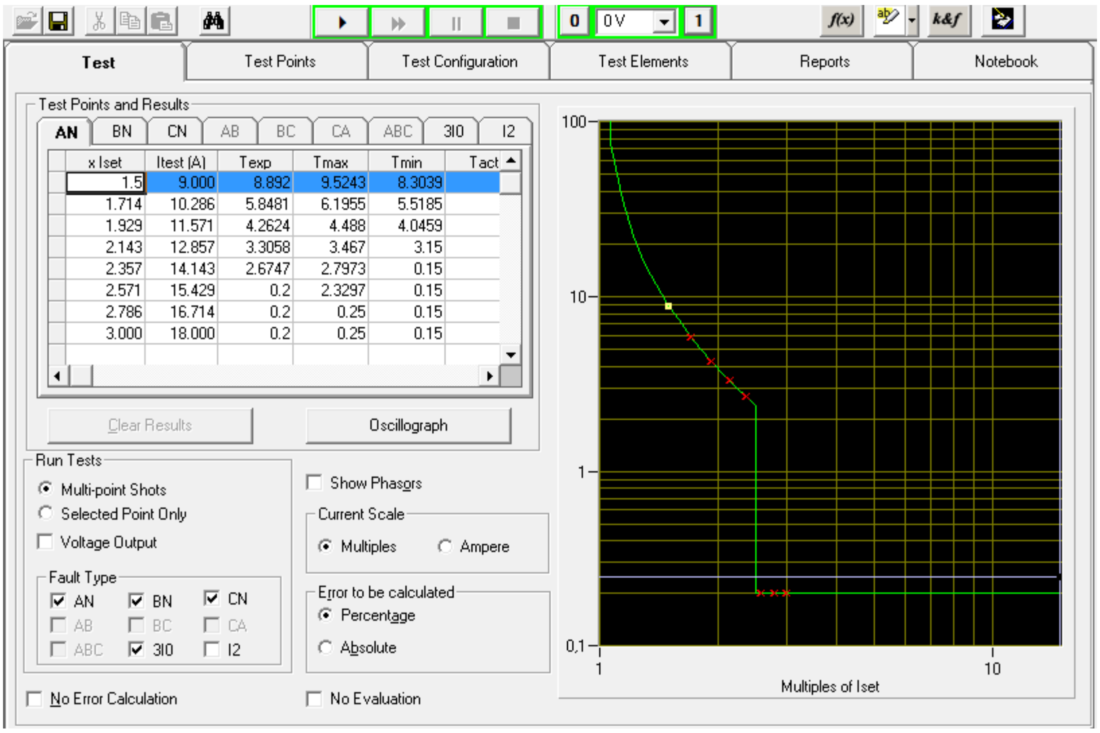


Figure 6.4.: Screenshot from Overcurrent Relay Test - Doble F6Test 3.12.0

Automated differential tests is another example of what a well equipped software package is capable of performing. A screenshot from Omicron's software differential test is shown in Figure 6.5. The procedure is similar to the overcurrent test; the user inputs a number of test points, selects type of fault and the relay runs the test and determines pass/fail depending on the results.

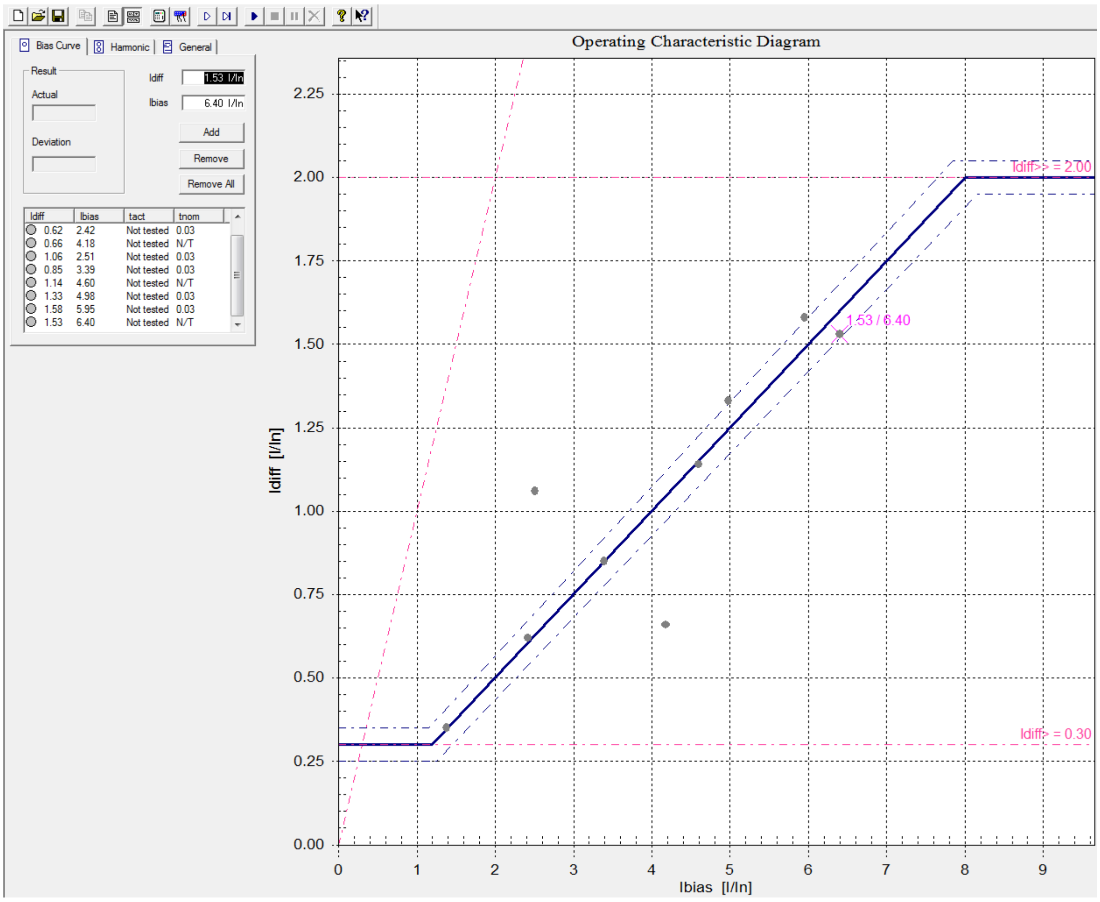


Figure 6.5.: Screenshot from Differential Relay Test - Omicron Test Universe 1.61 SR1

6.1.3. Event Recording/Simulated Waveform Playback

A relay tester is also capable of producing uploaded current and voltage waveforms. COMTRADE and PL4-files are the most used file formats. The waveforms can be recorded events from a relay/IED. Relay testing using waveforms from a real fault scenario can be very interesting for students. The waveforms can also be created by simulation programs, e.g. EMTP-programs as shown in Figure 6.6. This is a useful feature as the user can verify a relays reliability. The relay tester can play back a scenario where the relay tripped when it was not supposed to, giving the user an opportunity to locate the reasoning behind the mis-operation and improve the protection systems security in future events, whether it was a hardware, software error, or simply an error in the setting of the relay. Another significant event is when a relay does not trip for a fault it was supposed to trip for, i.e. the relays dependability was not sufficient. Studies of such scenarios are important to improve the overall reliability of protection systems.

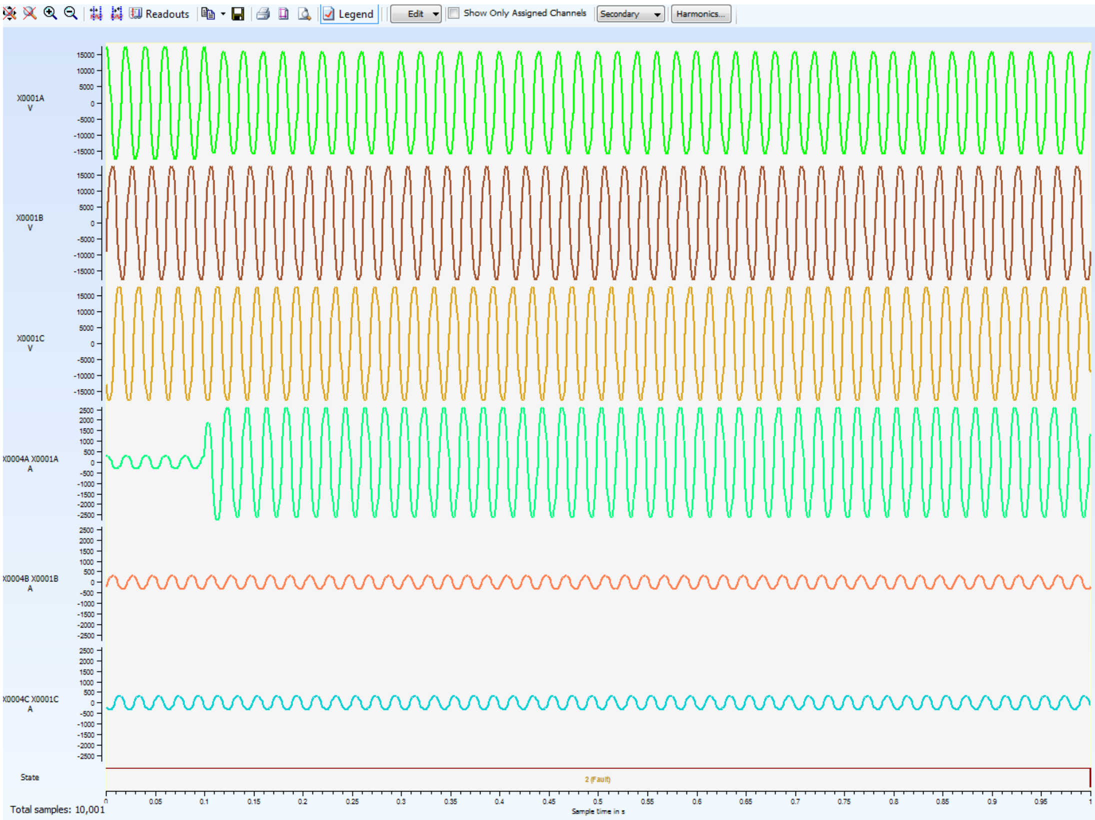


Figure 6.6.: Screenshot from Playback of *.pl4-file in Doble Protection Suite 3.0. Displays Currents and Voltages in a Three-Phase System During a Phase-to-Ground Fault

6.2. Testing - Fault Simulator

Simpler devices that can be used for certain types of relay tests, e.g. logic testing and simple overcurrent tests, exist. They are autonomous devices and not dependent on an auxiliary computer and software package. As relay testers, they produce secondary currents and voltages at one location of the power system. Amplitudes of currents and voltages, as well as phase angles are adjustable for two states; pre-fault and fault. It can normally just produce symmetrical values, in other words it can simulate steady state symmetrical conditions and three-phase faults. However, this is sufficient when one is only looking to trig a trip signal. Figure 6.7 shows the front panel of a fault simulator from Cebec AB. It is able to deliver up to 2 A line currents and line voltages up to 130 V. The major benefit of a fault simulator versus a relay tester is that it is only a fraction of the cost.

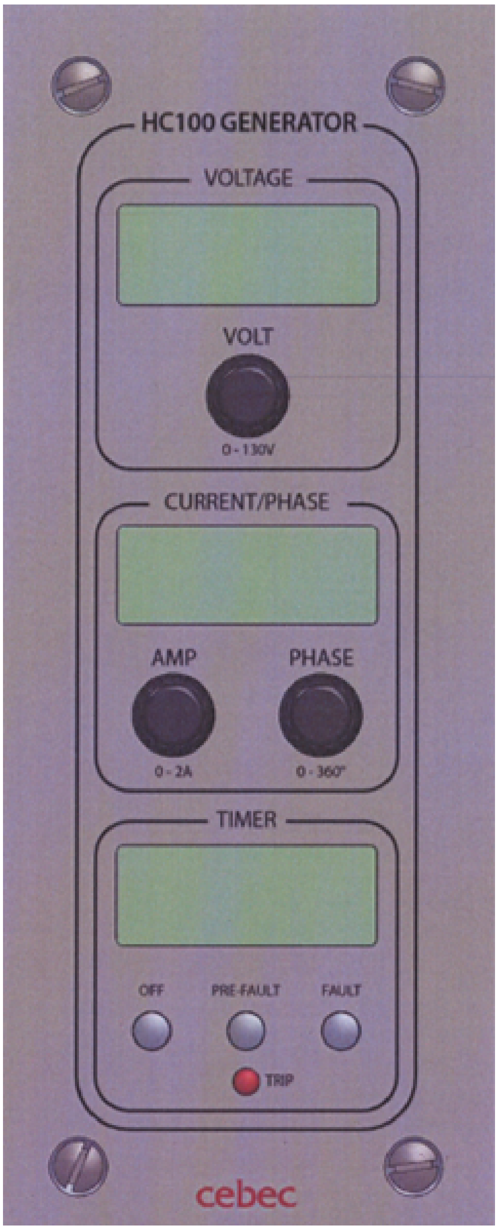


Figure 6.7.: Front Panel of Fault Simulator from Cebec AB

6.3. Testing - Scaled Physical Network

An alternative to using a relay tester, is to use a scaled physical network. Here, one uses known characteristics of power system components and try to implement them with reduced size. Normally, variable resistance, inductance and capacitance are used, this allows modeling of e.g lines with different lengths/types.

Naturally a construction like this is expensive, nor built overnight. The best solution is to cooperate with other parties who would have interest in using such a scaled network for testing on other, similar fields. At NTNU, such a scaled network exists in the form of a renewable energy/smart grid/wind power lab (SG Lab). The lab is quite comprehensive, and includes several types of generator models, a distribution network model (lines, transformers, loads), energy storage capabilities and a short circuit emulator, as shown in Figure 6.8.

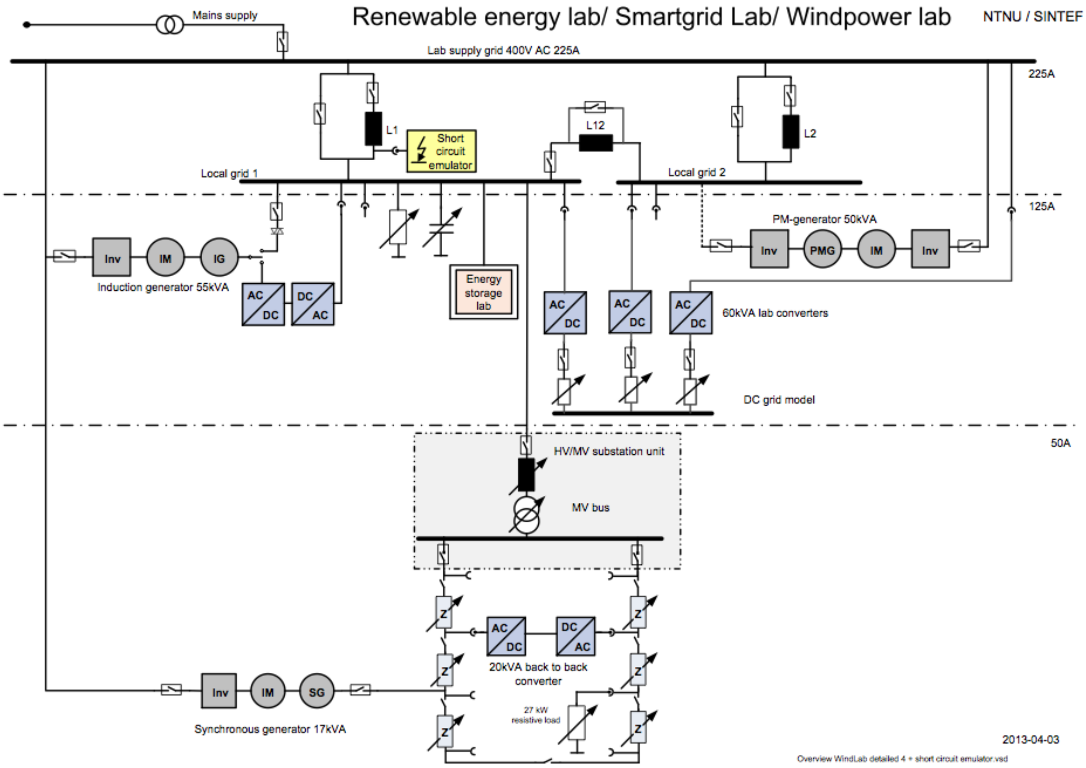


Figure 6.8.: One Line Diagram of SG Lab at NTNU

The lab provides several opportunities for relay testing, the short circuit emulator is especially of importance. It allows the emulation of different fault scenarios, i.e phase-to-ground and three-phase faults, with corresponding fault currents flowing in the network. However, traditional CTs and VTs does not exist in the lab today. Transducers outputting current values scaled as a mV/A signal is installed. The currents from these transducers are also sampled and used for other purposes than protective relaying today. Traditional CTs and VTs could possibly be installed, however the amount of space in the switchgear cabinet is limited. Because of this, using the sampled values in an IEC61850 compliant lab system might be a good idea. This is a possible future step for the relay lab and not the focus of this report. Any further studies of this opportunity will not be made in this report.

6.4. Testing - Summary

For the purpose of the relay lab, using a relay tester for testing of relays is a safe start. It is a powerful tool capable of doing tests with varying degrees of complexity, which suits a lab with prospective expansions perfectly. NTNU currently owns an old relay tester from Omicron (CMC 56), whose functionality and software is somewhat limited; only three current and three voltage outputs, in other words three-phase differential testing is not possible. In addition the software support for this model was discontinued in 2004. A new and up-to-date relay tester should therefore be acquired as soon as possible. For simple tests, it could also be possible to acquire fault simulators, which is much cheaper, but with limited functionality. In the future, the expanding SG Lab could be used for testing, possibly the relay lab could be integrated to this lab. However, for the first part of the lab, using a relay tester is considered the best option.

For the lab exercises, manual testing using the control panel is a good way to make the students understand what kinds of currents and voltages they are dealing with. In addition, the playback function is very useful for lab exercises purposes as it allows the students to simulate a fault scenario and play it back on the relay tester and check the relay response. Using software capable of simulating relay operations and comparing it with real relay behavior, is also a possibility with the relay tester.

6.5. Test Procedures

Test procedures for relays can be separated in three parts:[32]

- Pick-up Testing
  - This testing involves applying the current/voltage corresponding to the relays pick-up setting and check that pick-up is indicated by the relay. The next step is to slowly decrease the current/voltage until pick-up is no longer indicated. Then increase the current/voltage again, until the relay indicates pick-up. Logging the actual values, calculating the error with these values and the expected values, and comparing them with the manufacturers data is the final step.

$$\frac{ActualValue - ExpectedValue}{ExpectedValue} \cdot 100 = \%error \tag{6.1}$$

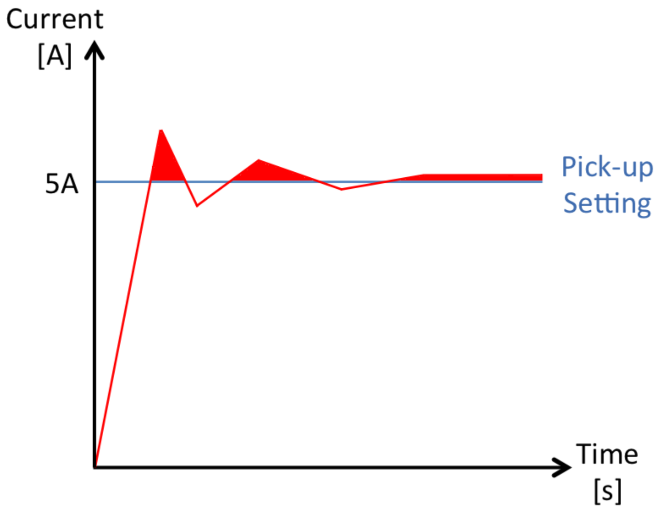


Figure 6.9.: Pick-up Indication Testing

- Timing Testing
  - This test is performed to measure the time difference (delay) between test initiation; applying a current/voltage within the pick-up region, and when the relay output indicates trip. The relay output contact should preferably be the same contact as used in service. The error is again calculated according to Equation 6.1 and compared with data specified by the manufacturer.
- Logic Testing
  - This testing is made without changing relay settings or monitor any relay output contacts. The first step is to make sure all drawings match the settings of the relay, by checking the documentation of the site and the appropriate relay settings. Checking for logic impossibilities and other possible errors is important here. The output logic of each contact should be listed with simple AND, OR statements. The main testing then consists of checking that the output is correct according to what is expected.

To make relay testing faster and more efficient it is common to combine test procedures and make a test plan. As mentioned, modern relay testers are, in combination with its software, powerful tools capable of automating test plans. This makes testing of relays efficient, as it is possible to make standardized plans tailored to relay models/types, where only minor adjustments have to be made for each test case.

7. Software

This chapter includes an overview and study of the different software that is relevant for the relay lab. Software for relay testers have already been discussed in Chapter 6.1. That leaves a section regarding short-circuit and relay coordination software, as well as a section on the software used to communicate with and configure the relays.

7.1. Short-Circuit Calculation Software

The fault currents in a power system will vary depending on the location of the fault and the characteristics of the power system itself. For small, simple and radial power system the calculations may be performed by hand. However, when the system is larger and more complex, hand calculations are close to impossible. Here, calculations are made by computer software. In most software programs you build a model of the power system, input known data (measured or provided by manufacturers), simulate different fault scenarios and the software outputs the fault currents. Some programs also include models of relays and a database of different relay types from different manufacturers, where one can simulate relay operations. For the purpose of the teaching part of the lab, i.e. for the lab exercises, this is an important feature.

For the lab exercises software that meet the following requirements

- Simple, intuitive and user-friendly
- Short-circuit calculation and protection coordination capabilities
- Relay models/database
- Reasonable licensing costs (NTNU already have licenses for some programs)
- Relevance of software (use in Norway/previously used in university courses)

On the market today there exist several different software[10], with varying degree of complexity and features, that cover the set requirements. A study of selected programs and how good they meet requirements have been made. The selected programs include:

PowerFactory

- Developed by DIgSILENT (Germany)[9]
- Common users include: Statkraft

PSS®E - Power System Simulator for Engineering

- Developed by Siemens AG (Germany)[7]
- Common users include: Statnett

ASPEN OneLiner

- Developed by Advanced Systems for Power Engineering, Inc.[6]
- Used by Michigan Technological University for Relay Lab Exercises

ETAP - Electrical Transient Analyzer Program

- Developed by Operation Technology, Inc. (USA)
- Popular among utility companies in North America (Ontario Power Generation, Hydro-Quebec)[24]

ATPDraw

- Graphical preprocessor to ATP[13]
- Developed by Hans Kristian Høidalen at NTNU

For some of the programs it has only been possible to obtain trial versions with various limitations, however, they gave a fair overview of their functionality and user interface. The table below summarizes how well the different software meet the set requirements.

	PowerFactory	PSS®E	ETAP	Aspen OneLiner	ATPDraw
Easy to Use					
SC Calc.					
Relay Models					
Licence Cost					
Relevancy					

Table 7.1.: Summary of Short-Circuit Calculation Software - Green = Good, Yellow = Fair, Red = Poor

For the purpose of software use for lab exercises, PowerFactory, PSS®E and ETAP are considered too complex. It takes a significant amount of time, more than what should be required for lab exercises, to reach a sufficient level of proficiency in these programs. However, when the user is familiar with the programs and their capabilities, they are very useful tools.

Aspen OneLiner is used by MTU in their relay lab exercises. It is fairly easy to get to know for first-time users and has a good module for coordination of overcurrent protection. The drawbacks of the program is that is not common in Norway and that the licensing fee is high. The program also has a relay database available for an extra significant fee.

ATPDraw is an EMTP with a graphical user interface. The benefits of ATPDraw is that it is free and being developed at NTNU, it includes relay models and that it is fairly easy for students to get to know. Most students will also have encountered the program in a previous course. The closeness to the program developers is a major benefit, both for the users of the relay lab and the developers of the program. The relay lab can, among other things, be used to verify the relay models in the program. ATPDraw is a good choice for using together with the relay lab.

7.2. Relay Configuration and Parameter Setting Software

This section describes the use and functionality of ABBs software for configuring and setting ABB relays, officially named "PCM600 2.6 - ABB Protection and Control IED Manager". Although it is specific for ABB and their relays, the principles are similar for software from other relay manufacturers.

ABB - PCM600 2.6 - ABB Protection and Control IED

The screenshot in Figure 7.1 displays the user interface of PCM600. Normally the user would create one project for each substation, and set up the project according to the one line diagram of the substation. This means creating a folder for each voltage level, and folders for each bay inside these. Inside the bay folders, the relay configurations are placed. They can be made from scratch or templates can be imported. The most important modules in the software for relay engineers are described on the following pages.

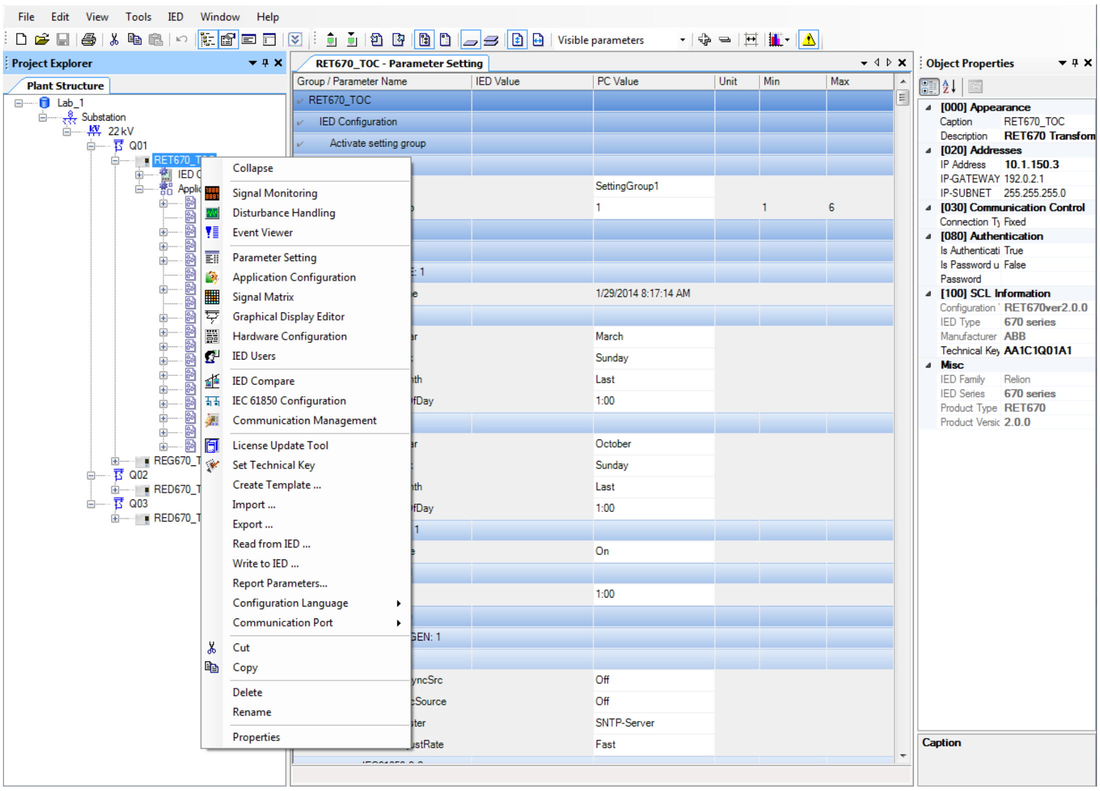


Figure 7.1.: Screenshot - PCM600 2.6 - ABB Protection and Control IED Manager

Parameter Setting

The parameter setting module is used to set all changeable parameters of the relay. This includes time and date, global base values, HMI and communication settings. The most importing settings however, are the parameters for the protective functions. This module also allows the user to read the values from the relay, e.g. for comparison or verification. The table format view of the parameter setting module is shown in the background in Figure 7.1. The table view gives the user a good overview of the parameters, including units and min/max for the parameters.

Application Configuration

In the application configuration module the relay engineer can tailor the functions and logic of the relays. This means assigning currents and voltages to hardware channels, selecting function and logic blocks and forwarding analog and digitals signals according to the desired relay functionality. The application configuration module is therefore normally used exclusively before the relay is set into operation, while the signal matrix and parameter setting modules are used to adjust the relay during operation. However, the application configuration module can be used after commissioning if an error in the configuration is discovered. Most configurations errors should be detected during the commissioning test. The use of the application configuration module is more closely described in Chapter 8.4 and 5.3.

Signal Matrix

The signal matrix provides a good overview over the signals out of the binary output module (BOM) and into the binary input module (BIM). The signal matrix is an easier way of assigning binary signals (e.g. trip signals) to the BOM and BIM than using the application configuration module. Figure 7.2 displays a screenshot of the Signal Matrix in PCM600.

Graphical Display Editor

The graphical display editor is used to create single line diagrams of the surrounding power system to be shown on the relay display. Templates of the most relevant components are included in the editor. Examples of a single line diagram can be seen in Figure 8.6. In addition to single line diagrams, the display can include measured values, e.g. currents and voltages. The single line diagram can also show updated breaker positions, and with the the front panel buttons the user can select and operate breakers (if user is permitted).

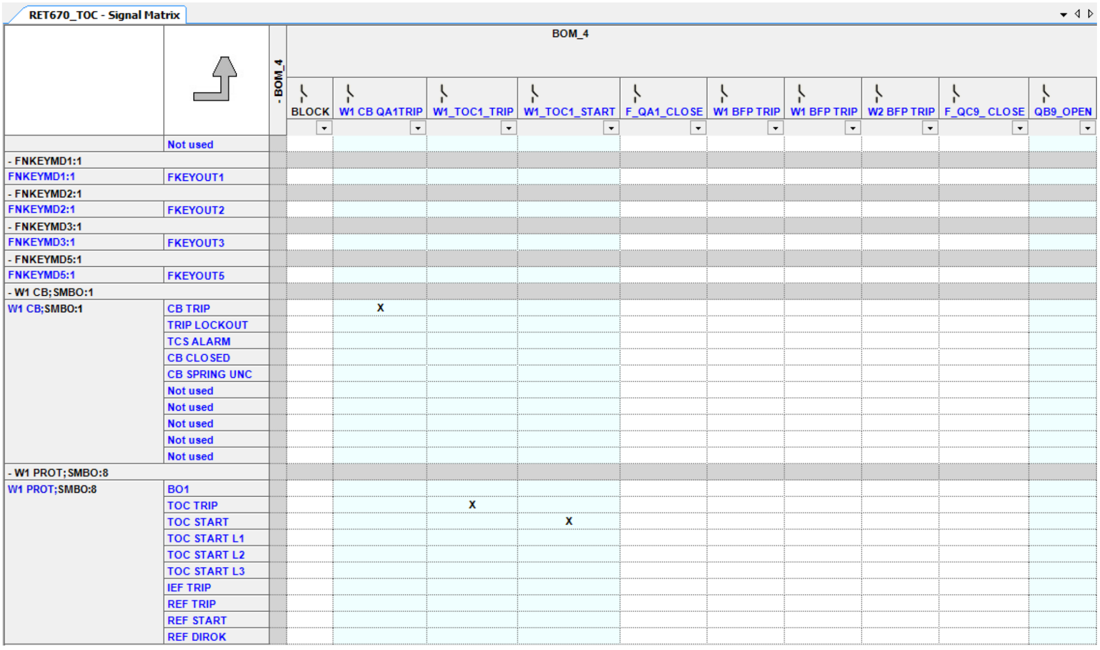


Figure 7.2.: Screenshot - Signal Matrix - PCM600 2.6

The communication between the computer and the relay is also configured in PCM600. To achieve communication between the two devices the user has to connect an Ethernet cable between the front panel of the relay and the computers network card and input the IP address and the technical key of the relay into PCM600. The technical key is a unique ID for each relay. The user can now read from/write to the relay.

8. Relay Lab

After talking to relay engineers from utility companies (TrønderEnergi, NTE, Røros E-verk, Statkraft, Statnett) and from the industry (ABB, Siemens) it became quite clear that there is a gap between their respective protection system strategies. The relay engineers in the utility companies are fairly conservative in their strategy. They use methods, equipment and devices they are familiar with, instead of exploring the opportunities that lies in modern relay technology and its communication possibilities. This is justifiable to some extent as the risk of making an error increases with new and more complex systems. The consequence of such an error can also be major, in a worst-case scenario it may lead to blackouts of major areas.

The industry is the driving force behind the development of relay technology and the protection of power systems. This is understandable as they want to develop better devices and solutions to be competitive and to meet further protection challenges with a shift to more complex power systems and Smart Grids.

The type of skills and knowledge the utility companies and industry would prefer students to graduate with, is naturally reflected in their protection strategies. Utility companies prefer students to have knowledge about past and present technologies with a practical feel for the entire protection chain, while the industry is more future oriented and focused on how modern relay technology can supply the protection needs of smart grids and more complex power systems.

A new relay lab in combination with a future power system protection course is a golden opportunity to educate students with knowledge of and a drive for the opportunities that lay within modern relaying technologies. However, most of the old protection principles/strategies are valid and still being practiced by the utilities. The students should therefore also have a fundamental knowledge of traditional power system protection, to be aware of the limitations and challenges of adapting to modern protection schemes. Students graduating from NTNU with this competence can be a valuable contribution to utility companies, as it may lead to broaden their view of power system protection and the possibilities of modern relay technology. It is therefore vital that the relay lab is designed and used in such a way that students gain the knowledge of past and future strategies, and their advantages and limitations.

8.1. Relay Lab at Michigan Technological University

When designing a university relay lab it might be a good idea to contact other universities which has such lab facilities. Michigan Technological University (MTU) and NTNU cooperate in several areas, and MTU is in possession of a well developed relay lab, primarily used for a power system protection lab course.

The lab at MTU consists of six parallel work benches, each equipped with a relay tester from Doble, where students work in pairs, i.e. 12 students can work in the lab simultaneously. The lab course consists of 9 sessions with different topics, including (directional) overcurrent, distance and differential protection. Some of the sessions are more advanced, e.g. one session focuses on challenges with distributed generation and distance protection. In the lab exercises the students face practical challenges; they are handed a relay, with no cables connected, and have to use the manual to figure how to connect input and outputs. The lab exercises also consists of a pre-lab part, which should be completed before the actual lab session. This part makes the students prepared for the exercise, making the session itself more efficient.

One of the most interesting features of the MTU lab is how it has been expanded in steps, vertically and horizontally, over the years, with different types of equipment and added parallel work benches. It is important to build a lab which is capable of being gradually expanded with up-to-date and desired features, and this is something which should be a focus when designing the lab at NTNU. However, since the lab at NTNU is not supposed to be used in a separate lab course, but as a smaller lab part of standard course, it should not be as demanding when it comes to practical challenges. A focus on principles and an overall understanding of power system protection and the relays role, is essential.

8.2. Expansion Steps of Relay Lab

As mentioned earlier, building the lab gradually is desirable. It is therefore important to have a vision for the future expansions and use of the lab. The final outlook for the relay lab may change as it is developed, but having a next step defined is vital for ensuring a steady development. Ideas for future expansion steps are outlined on the next page.

1. Autonomous System
   - A system with autonomous devices and testing of the basic protection functions; overcurrent, distance and differential protection, is a good start. This first part is the focus of this thesis.
2. Simple Communication
   - The next step should be setting up communication between relays. It can consist of simple boolean communication, used between relays at both ends of a line, as described in Chapter 4.4. Or it can be communication capable of transmitting time stamped currents, for instance between two relays providing differential protection of a line.
3. Advanced IEC61850 Communication
   - To demonstrate the many capabilities of an IEC61850 compliant protection system, the relay lab should be further developed to meet the requirements of this standard. The relays provided by ABB are IEC61850 compatible, however switches, fiber optic cables and configurations are needed before communication is up and running. At this stage, it could be very interesting to incorporate relays from other manufacturers, especially other IEC61850 compatible relays, to study interoperability opportunities and challenges.
4. WAP Protection Lab with PMUs
   - As mentioned in Chapter 5.6, Wide Area Protection is considered to be a part of the future for power system protection. Therefore the lab should be developed to include PMUs and other devices used for WAP in a few years time. A relay lab with this capability allows students to do research on WAP, which is important for the future.

These are just proposals for future expansions of the lab, and they should be continuously revised as work progresses, to ensure optimal development of the lab.

8.3. Practical Set Up of Lab

This thesis focuses on the first step of the relay lab, as described in the previous section, a lab with autonomous relays. Practically this means mounting the relays in a rack, together with power supply and necessary wiring/cabling. In addition, as discussed later in Chapter 8.3.1, a test switch/test handle solution will be used in the lab, as it, among other things, gives easy access to relay inputs and outputs. The lab system proposed is shown in Figure 8.1.

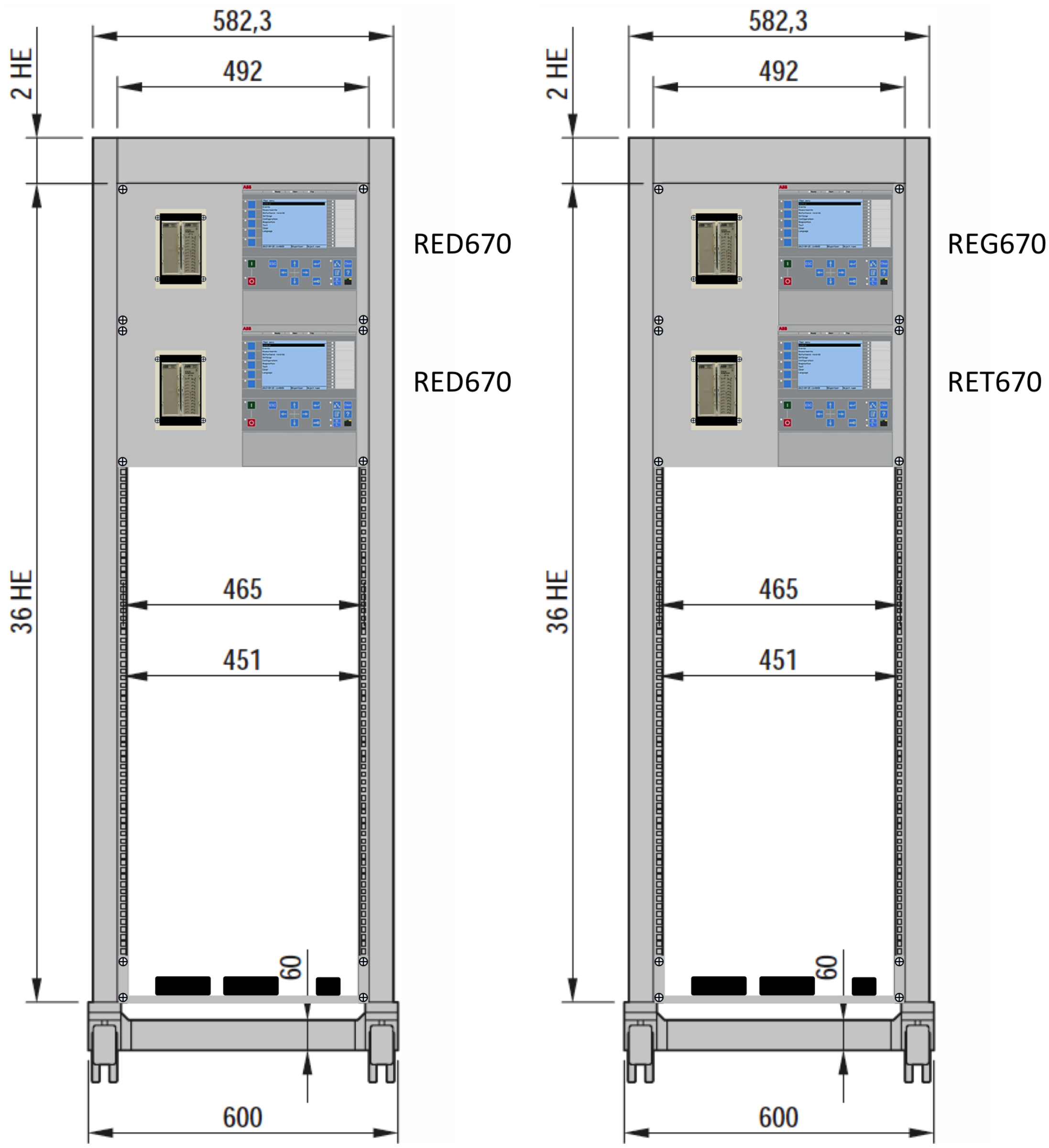


Figure 8.1.: Conceptual Illustration of Relays in Mobile Rack

The vital components of the relay lab consists of the following (a more detailed equipment list can be found in Appendix D):

- Relays
  - 2x ABB RED670V2.0 Line Differential and Line Distance Protection
  - 1x ABB RET670V2.0 Transformer Differential Protection
  - 1x ABB REG670V2.0 Generator Protection
- Racks
- Power Supply with Accessories
  - Input: 100-240 VAC Output: 48 V DC
- Relay Tester
- Test Switches
- Test Handles
- Lab Computer

ABB has decided to supported the relay lab and gift new, modern relays from their Relion 670 series. The relays are IEC61850 compliant, in other words, they are ready for the proposed expansions. However, for the first part of the lab they can be used as simple stand alone devices. The RED670 relays is also equipped with a GPS unit, which can be used for time synchronization.

The relays from ABB comes with one Transformer Input Module (TRM) capable of handling up to 12 current and voltage inputs, in this case six current and six voltage inputs (6I+6U). The current and voltage inputs are rated at 1 A and 110-220 V respectively. They are all capable of receiving 16 binary signals via the Binary Input Module (BIM) and output 24 binary signals through the Binary Output Module (BOM).

To make the lab mobile, two racks on wheels is used. This is useful as the lab can be used to demonstrate relay functionality, for instance during a lecture. The relays are mounted, together with their respective test switch, to the racks, two relays on each rack. An illustration is shown in Figure 8.1. Connection diagrams of the wiring between the relays and the test switches is located in Appendix C. Figure 8.2 displays the backside of the relays and the test switch in the rack.

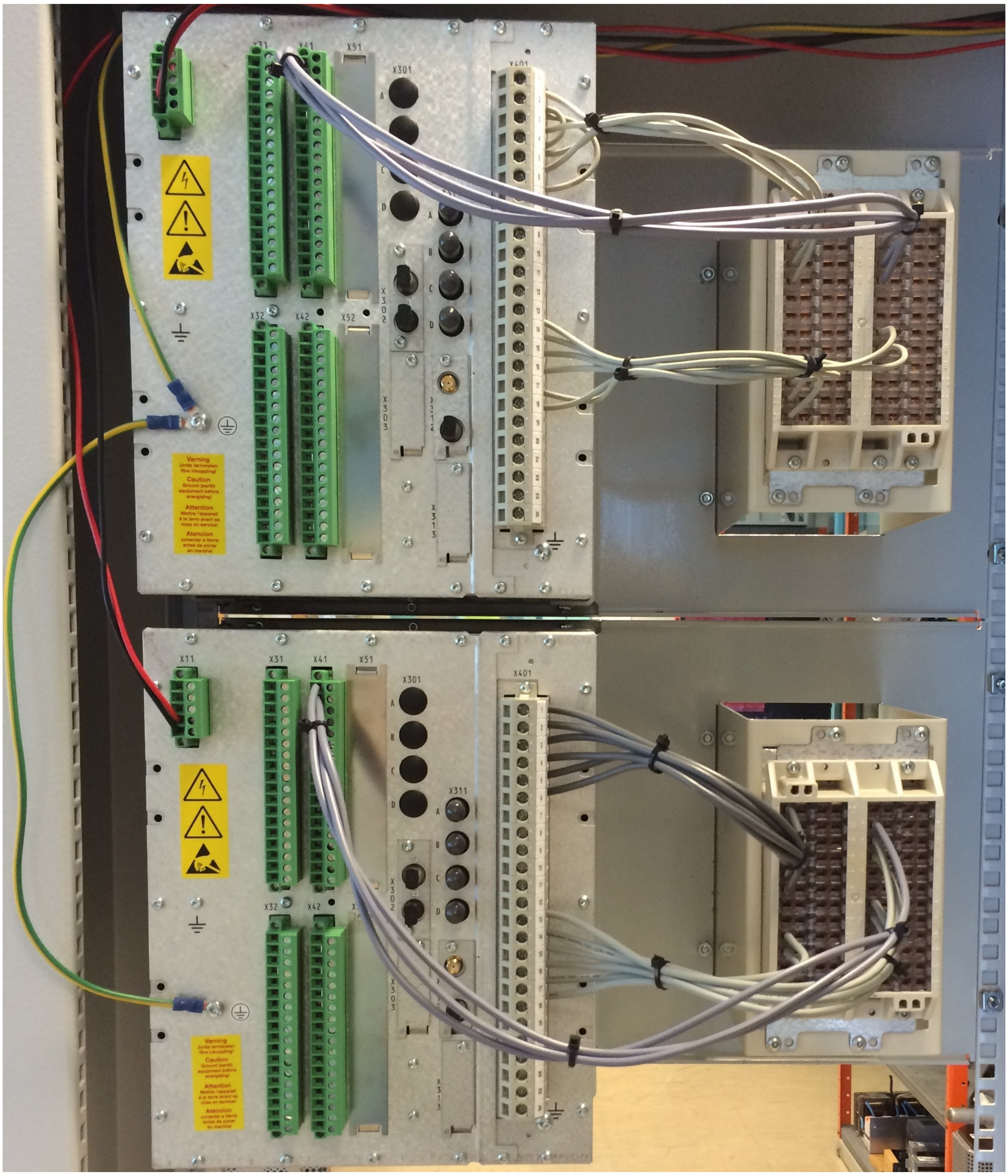


Figure 8.2.: Backside of Relay and Test Switch

The terminals on the right side of the relay is the TRM, i.e. current and voltage inputs. The green, long terminal blocks are the BOM (right) and the BIM (left). The Power Supply Module (PSM) is in the top left corner, with the black and red wire connected to a green terminal block.

The relays require a 48 V DC supply, and AC/DC converters is therefore needed. This voltage level is selected mainly for personnel safety reasons.[2] The relays have one converter each, which are connected to the AC power supply through power strips. Between the power strips and their plug, a residual-current circuit breaker has been installed, which also is for personnel safety reasons. The power supply can be seen in Figure 8.3, schematics over it is shown in Appendix C.

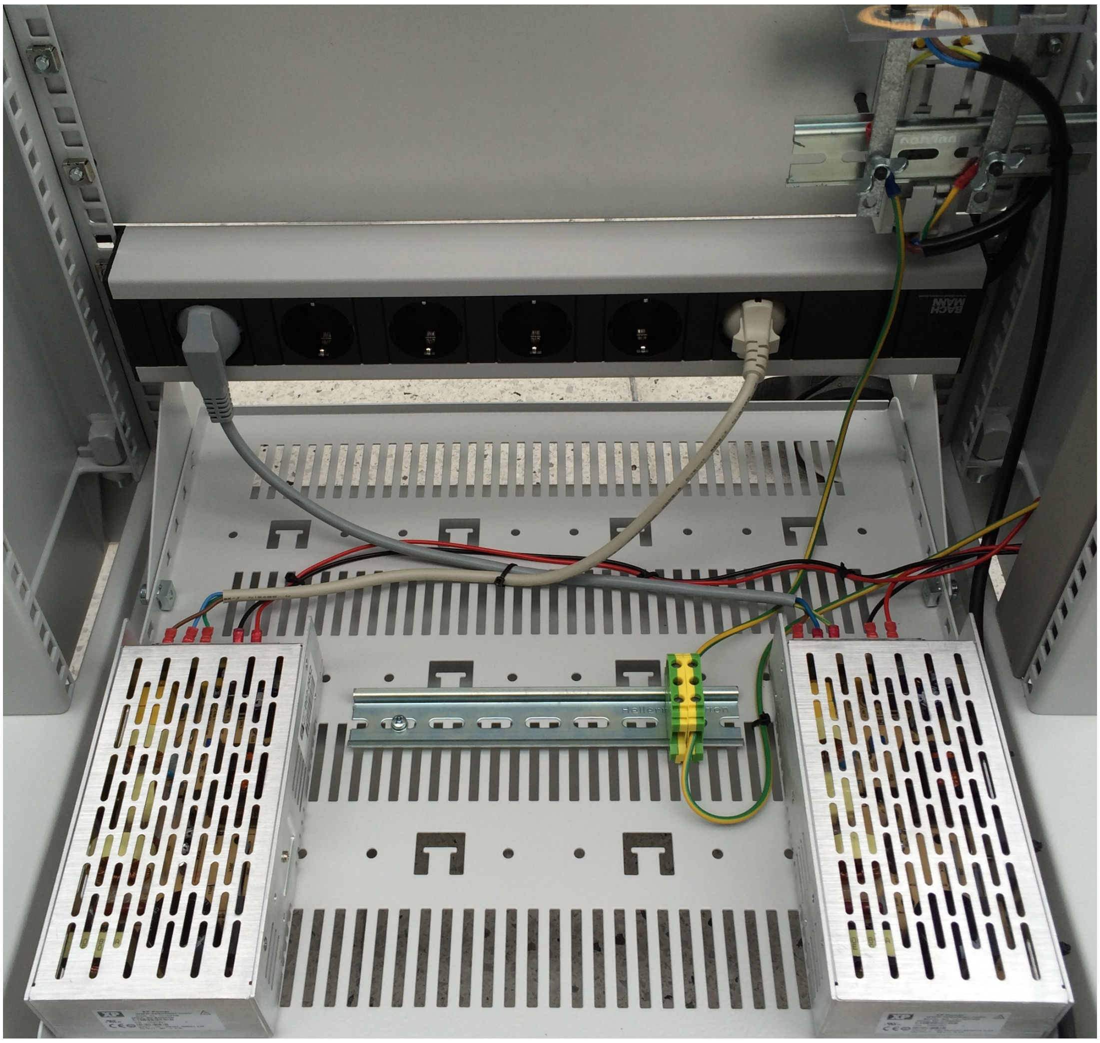


Figure 8.3.: Relay Power Supply

For safety purposes the chassis of the relays are grounded (can be seen in Figure C.1). The grounding wires from the relays are fastened to terminal blocks in its respective rack. The protective earth (PE) lead is wired to the terminal blocks and provides the grounding potential.

As discussed in Chapter 6, using a relay tester is the best testing tool for the first step of the relay lab. The relay tester NTNU currently owns, an Omicron CMC 56 as previously mentioned, is somewhat limited due to its age and the fact that it only has three current and three voltage outputs. However, it can still be used, until a new and up-to-date tester is acquired.

Since different software is required to communicate with both the relays and the relay tester, the lab should have a designated computer with the required software installed. A computer is required to control and use the relay tester. The relays parameter settings can be adjusted using the HMI, however the computer software provides a better overview and is more efficient if a group of parameters are being set. It is also required for more advanced configurations of the relay, e.g. application configuration. The CMC 56 requires a parallel port for communication. This is no longer standard on most computer motherboards, as it has been superseded by the USB port. However, parallel-to-USB port adapters exist, which means the CMC 56 can be used with most computers. Since the lab is supposed to be mobile, a laptop computer would be ideal.

8.3.1. Test Switch/Test Handle

The test switch/test handle solution provides the user of the lab with easy access to the relay inputs and outputs. The test switch is wired to the relay, i.e. current/voltage inputs, digital inputs and digital outputs. The test switches in this case consists of 24 connection points, each with an A and a B side. The B side is wired to the relay, while the A side would be wired to CTs/VTs and circuit breakers. However, for the purpose of the relay lab, the A side will normally be wired to a relay tester.

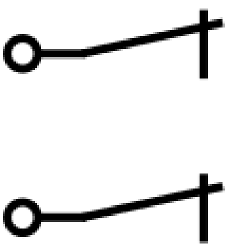
The alternative to using a test switch is connecting the relay tester directly to the relays. This solution is used at the lab course at MTU. The students must then read the relay manual to figure out the connections each time the lab is used. For students on a university level, this is not optimal use of time in the lab. The test switch/test handle solution saves time, since it will be well documented, allowing students to easily connect banana plug leads correctly without having to browse a relay manual.

Between the A and B side there can be three types of switches, all shown in Figure 8.5. The three switches have different characteristics tailored to the function they are supposed to have. Figure 8.5a illustrates the switch used for trip signals, it is normally closed, i.e. trip signals are forwarded to CB(s). When the switch is opened, the trip signal will be blocked.

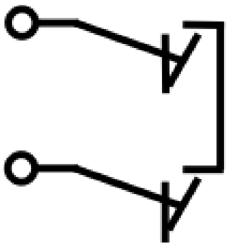
Figure 8.4.: ABB RTXP24 Test Switch (right) and RTXH24 Test Handle (left)[4]

As mentioned in Chapter 2.2, the secondary side of a CT should never be left open. Current inputs are therefore wired to the types of switches shown in Figure 8.5b. This switch is normally closed, but in its other position it will short-circuit the current circuit. The three-phase current circuits can be short-circuited separately or to a common point. If the relay is the last in a chain of relays using the same currents, the short-circuiting is made to a common point. Else, it is made separately to allow the currents to flow to the relay(s) downstream in the chain.

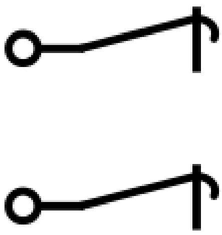
The third type of switch, shown in Figure 8.5c, is used to open the voltage circuits. It is normally closed.



(a) Blocking of Trip Circuit



(b) Short-Circuiting of Current Circuit



(c) Opening of Voltage Circuit

Figure 8.5.: Contact Functions - ABB RTXP 24 Test Switch/Handle

The test handle is used to operate the switches. It operates the different types of switches depending on the test handle position. It can be in three positions; out, half, in. Out is the normal position, the test handle is then not attached to the test switch. If you insert the test handle into the test switch it will first stop at one position; this is the half position. Pushing a lever and fully inserting the test handle, yields the in position.

At half position the trip circuit blocking switching will occur, while fully inserting the test handle to the in position will result in switching of the two other types of switches. The reason behind this logic, i.e. to block trip signals first, is to prevent any mis-operation, as the relay may trip due to the short-circuiting of the current and opening of the voltage circuits.[4]

The test switch/test handle solution is used by several utility companies in Norway, as it provides fool-proof testing capabilities. On the front of the test handle, you can access both the A and B side connections of the test switch, via banana plug slots. This is where you connect the outputs and inputs of your relay tester. The banana plug option makes this solution ideal for lab purposes, since it makes for easy wiring between the relay tester and the relay. In addition, it displays how relay testing is performed in real life.

8.4. Configuration of ABB Relays

Modern relays are usually delivered with a configuration and functions corresponding to the needs of the end user.

Pre-made configurations for relatively simple lab exercises at a university are not supplied by ABB, since most configurations are delivered with many more functions than needed for this purpose. To avoid confusion for students when they are in the lab testing basic protection principles, e.g. overcurrent protection, it is a good idea to have the configurations as simple as possible in each case. In other words, this means stripping the relay configuration down to a level where there is only the desired functions left. This has been a very time consuming task, as one needs to be very careful when removing a signal or a function block in the configuration. One wrong step can make the relay performance unreliable. In many cases the signals have to be reassigned to other function blocks, in correct order.

The relay configurations have been made in ABBs software; PCM600. Three projects (*.pcmp-files) have been created containing configuration files for the relays relevant for the lab:

- Lab 1 - Overcurrent Protection
  - RET670_TOC
  - REG670_TOC
- Lab 2 - Distance Protection
  - RED670_TOC_IMP (x2)
- Lab 3 - Differential Protection
  - RET670_TOC_DIFF
  - REG670_TOC_DIFF

The main parts of the relay configurations are created in the following procedural way (see also Chapter 5.3):

- Currents and voltages from hard-wired CT(s) and VT(s) are assigned to the physical hardware channels of the relay, i.e. phase current I_{L1} from CT1 is connected to hardware channel 1. It is important that the type of input, i.e. current or voltage, match the assigned hardware channel. Binary inputs, if relevant, are also assigned a hardware channel.
- The hardware channels are then connected to function blocks (SMAI Blocks) which outputs signals with the sampled currents and voltages. These signals are forwarded to several function blocks; most notably the protection, measuring, disturbance recording function blocks.
- The output signals of the protection function blocks of significant importance are two binary signals; start signals and trip signals.
- The trip signals are then assigned a binary output channel. They may pass through other logic elements merging/comparing several trip signals beforehand.
- Next step is to assign front panel LEDs to every relevant signal, e.g. start, trip, disturbance record start/stop etc.
- Finally, the display is configured with a one line diagram of the surrounding power system, normally a substation.

In addition to this, there are several other small parts in the configuration that must be made correctly, however the procedure describes the most important steps generally, although somewhat simplified. The step after the configuration is made, which is a vital one, is setting the parameters of the relay according to the surrounding power system/protected device.

As mentioned, the relays are also capable of displaying a one line diagram of the surrounding power system, for instance a substation. The configurations made for the relays include one line diagrams of their respective parts of a power plant substation. The power plant substation consists of one generator (REG670), one transformer (RET670) and two transmission lines (2xRED670) connected by double busbars, as shown in Figure 8.6.

The purpose of the one line diagrams is to display how the relays would be used in real life. Another benefit is that the one line diagram will display a simulated opening of the circuit breaker if the relay trips, as it would in real life. The display also shows the measured currents, voltages and other relevant values. The measurements have been configured in such a way that if the circuit breaker is open, the currents and other values which is a function of current will be zero. The different breakers are also interlocked as they would be if they were used in a real substation. For instance, disconnectors can not be opened before the corresponding circuit breaker is open. These features are useful as they give students a better understanding of how modern relays are used for more than just protection, they are also an important part of substation automation and control.

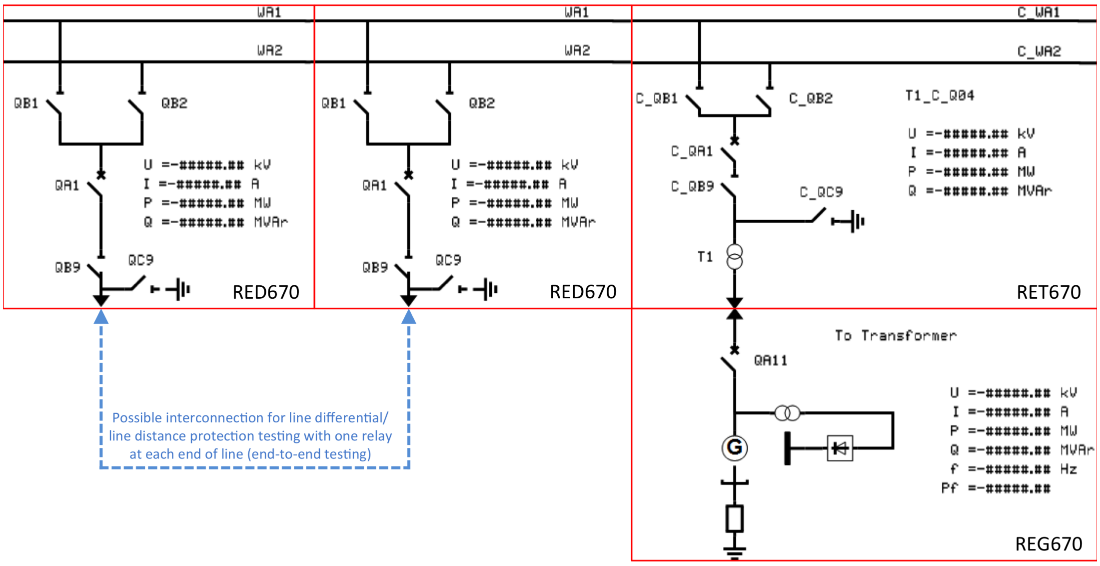


Figure 8.6.: One Line Diagrams for ABB Relion 670 Relays

9. Lab Exercise Proposals

The lab exercises should give students insight in the practical world of power system protection. The exercises should demonstrate the different protection principles and the function of modern relays. Setting of parameters for the relays based on calculated values is also an important part. The students should have knowledge of the lab exercise topic before entering the lab. A pre-lab part is a good way for the students to refresh their knowledge and come prepared to the lab.

It is vital that the scientific assistant and the student assistants are familiar with the software and the different components, most notably the relay and the relay tester. Before the lab session starts the relay should be connected to the lab computer through an Ethernet connection and it should be verified that it is working correctly. This will allow students to get the most out of their session, without spending too much time on practicalities outside the focus of the exercise.

9.1. Introduction to Relay Function and Overcurrent Protection

The purpose of this exercise is to get an introduction to the non-directional overcurrent protection function of a modern relay. It includes parameter setting of relay based on fault current calculations for a radial system. The relay, with the set parameters, will be tested using a relay tester. The results of the tests will be analyzed to see whether the relay performed as required.

Pre-lab Work

	PC Value	Unit	Min	Max
DirMode1	Non-directional			
Characterist1				
I1>		%IB	5	2500
t1		s	0.000	60.000
IMin1		%IB	1	10000
I1Mult			1.0	10.0

Table 9.1.: Parameter Settings for Overcurrent Protection Relevant

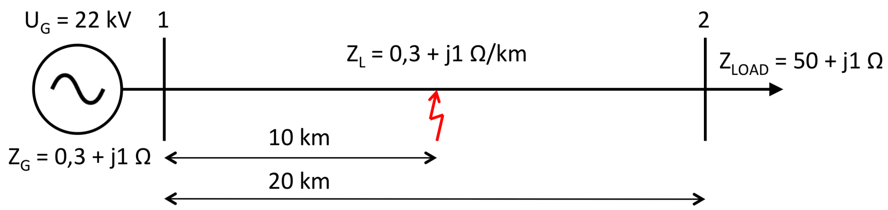


Figure 9.1.: Network - Lab Exercise

1. A fault occurs on the system in Figure 9.1. Calculate the fault currents analytically (ref. Chapter 3) during a
   a) Phase-to-Ground Fault
   b) Three-Phase Fault
   c) The current magnitudes are equal, why? Is this realistic? (Hint: Chapter 3.2)
2. What happens to the fault currents if the fault occurs at the very end of the line?
3. To protect the line an overcurrent relay is placed at bus 1. The relevant parameters for the relay is shown in Table 9.1.
   a) The relay can have an inverse or definite time-current curve. What is the difference between the two? Sketch a graph illustrating the difference.
   b) Use the calculated values to fill Table 9.1 (IB = 1200 A).
4. Use ATPDraw to model the network in Figure 9.1.
   a) Simulate Phase-to-Ground Fault and Three-Phase-Fault. Pre-fault time in the simulation should be around one second. Store the *.pl4-files on a memory stick and bring it to the lab exercise.
   b) Compare the simulated currents with your calculations. Are they equal?

Lab Work

1. The first part of the lab includes using software on the lab computer to communicate with and set the parameters of the relay:
   - Open PCM600 2.6 - Software for communicating with ABB relays
   - Open the project file Lab1.pcmp, expand the plant structure matching the relay configuration with the relay model you are working on. Select "Parameter Setting" as shown in Figure 9.2 (RET670 is used as

an example in this case). Make sure the communication between the computer and the relay is online (it should be, if not ask the scientific/student assistant(s)).

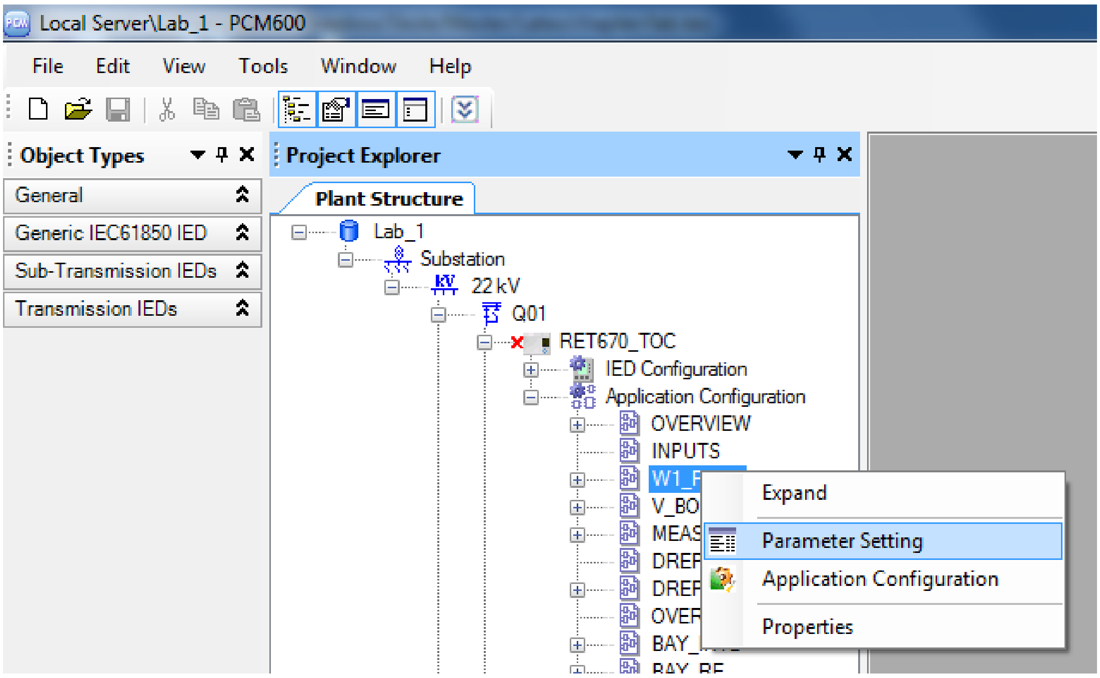


Figure 9.2.: Screenshot - Plant Structure - PCM600 2.6

- Scroll down to "Current Protection" and "Step 1". This is where you input the parameters for the overcurrent protection.

a) To confirm that the logic and the digital outputs of the relay is functioning and correctly configured, simple logic testing should be performed. This means having the relay trip and checking that the correct digital output contact closes. Configure the relay so that it will trip on a set of given input currents and voltages (this is a challenge, try before asking). Use the "Signal Matrix" module in PCM600 to check where the trip signals are assigned in the Binary Output Module. Write the configuration to the relay.

b) Open the relay tester software and the manual control panel (ref. Chapter 6.1.1). Set the relay tester with current and voltages necessary for the relay to trip.

c) Connect the relay tester to the relay according to Figure 6.2 and the connection diagrams in Appendix C. Apply to set currents and voltages to the relay. If things are set correctly, the relay should trip. Check which binary outputs forwards the trip signal.

2. Calculated values
    a) Input the values from Table 9.1 into the corresponding relay in PCM600.
    b) Select IEC Definite Time Characteristics. Write configuration to relay. Use the relay tester to apply the calculated currents and voltages. Note the trip time.
    c) Select IEC Inverse Time Characteristics (the exact parameters of the curve is not vital, but remember them). Write configuration to relay. Use the relay tester to apply the calculated currents and voltages. Note the trip time.
3. ATPDraw
    a) Use the Event Recorder Playback function of the relay tester to apply the currents and voltages simulated with ATPDraw (both fault types). Use the same relay settings as (IEC Def. Time and IEC Inv. Time). Compare trip times for both simulated and calculated values. Explain any differences.

9.2. Distance Protection

The purpose of this lab task is to get an introduction to distance protection. Calculation of zone settings and comparison of trip times between overcurrent and distance protection is vital.

1. Consider the same network and fault scenarios as used in the previous lab exercise, see Figure 9.1. Open the project file Lab2.pcmp and select the corresponding RED670 configuration.
    a) Study the parameters needed to set the distance protection. Calculate the zone settings for a 2-zone distance protection. Zone 1 should cover 85 % of the line, while Zone 2 should cover 125 %. Remember the time delay between the zones.
    b) Write the calculated values to the relay using PCM600.
    c) Use the relay tester to apply currents and voltages as before. Apply the calculated fault currents. Note the trip time.
    d) Use the event recorder playback to apply currents and voltages simulated in ATPDraw (same *.pl4-files as before). Note the trip time. Compare trip times for both simulated and calculated values. Explain any differences.
    e) Compare trip times for overcurrent protection and distance protection. Which one is faster? Why is that?

10. Conclusion

A relay lab consisting of modern relays is an essential component to educate students in the field of power system protection. The relay lab should function as an arena to demonstrate protection principles and practical challenges. Further developing of the lab to include communication, especially IEC61850 compliant communication, is vital, as this is important for the future of power system protection. Utility companies in Norway have a conservative protection strategy, which is not feasible in the long run with a trend shift from radial grids to more complex power systems. Students should be educated with knowledge of the possibilities within modern relay technology. After graduation, they can contribute to a shift in protection strategies within utility companies to meet the demands for power system protection in the future.

Using a relay tester as a testing tool for the relay lab is a good, versatile and flexible solution. It is easy to use for the beginner, while having advanced features for the more advanced user. A new relay tester should be acquired, as the Omicron CMC 56 NTNU currently owns is quite old and is not supported by the newest software. It is also limited by the fact that it has only three current and three voltage outputs.

The relays have been mounted in the mobile racks and wired to the test switches and power supply as discussed in 8.3 and according to the connection diagrams in Appendix C. The lab stands in a fully operational condition, however, getting to know the equipment and software will take some effort for someone new to the lab. The relay configurations, as described in Chapter 8.4, have been written to the relays and successfully tested. The relays are currently configured with Lab 1 (RET670/REG670) and Lab 2 (RED670) configurations (ref. Chapter 8.4).

If utilized properly the relay lab can contribute to increased interest and knowledge of power system protection among students at NTNU for many years to come. Educating future engineers with this knowledge is important for the protection and reliability of future power systems. If the lab is well maintained and expanded to keep up with trends in the field it could last many years.

11. Further Work

As mentioned, the relay lab should be further developed, to keep up with emerging technologies and to act as a useful supplement to future power system protection courses at NTNU. Further work to ensure the development of the relay lab should include:

- Testing and verification of the contents in the proposed lab exercises with the relays in the lab. Modification of exercise proposals where necessary. Draft solutions to exercises.
- Develop more advanced lab exercises. Interesting topics could be challenges with differential protection as described in Chapter 4.5, especially with regards to CT saturation. Exercises focusing on communication between line differential relays is also a possibility. Comparing simulated relay operations from ATPDraw with results in the lab is another interesting topic. Using the event recorder to playback waveforms from real fault scenarios
- Creating a simple user manual for use of the relay lab. This will make it easier for students to use the lab for research purposes. It should include information on how to communicate with the relay and the relay tester, as well as other practical information.
- Perform a study of different models of relay testers to be able to make a recommendation for a future purchase/acquisition of a new tester.
- Continue with the expansion of the relay lab to include IEC61850 communication and WAP/PMU capability as described in Chapter 8.2. The possibilities of use for the lab will increase significantly when it becomes fully IEC61850 compliant. A lot of interesting topics could be studied. Benefits of using communication for relay coordination is an example (ref. Chapter 2.4).

A. Appendix - Symmetrical Components

Line currents and voltages in a three phase system can be represented by a phasor sum of a balanced positive sequence vectors, balanced negative sequence vectors and identical zero sequence vectors, as illustrated in Figure A.1. These sets of vectors systems are referred to as symmetrical components.[25]

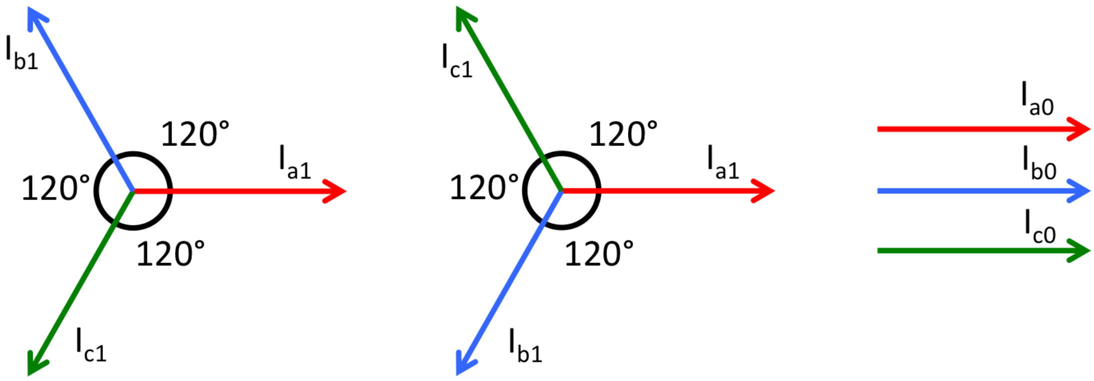


Figure A.1.: Positive, Negative and Zero Sequence Vectors

Sequence Equations

The sequence equations, Equation A.1 and A.2, are used to go from one representation to the other:

$$\begin{bmatrix} I_0 \\ I_1 \\ I_2 \end{bmatrix} = \frac{1}{3} \begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix} \begin{bmatrix} I_a \\ I_b \\ I_c \end{bmatrix} \tag{A.1}$$

$$\begin{bmatrix} I_a \\ I_b \\ I_c \end{bmatrix} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix} \begin{bmatrix} I_0 \\ I_1 \\ I_2 \end{bmatrix} \tag{A.2}$$

B. Appendix - Wide Area Measurement Systems

Wide Area Measurement Systems, abbreviated WAMS, transmits time stamped analogue and/or digital information via telecommunication protocols. Time stamping is the key word, as it allows information from several IEDs to be compared at a central unit.

Time Synchronization - GPS

The time in each device is synchronized with GPS - Global Positioning System signals. The GPS signals provide a time reference with an accuracy of around 1 μs. For the measurement of a 50 Hz AC phasor, where a 360° rotation equals $20 \cdot 10^3 \mu$s the maximum angle error becomes[16]:

$$\frac{360°}{20 \cdot 10^3 \mu s} \cdot 1\mu s = 0.018° = 0.005\% \tag{B.1}$$

The GPS signals are provided by satellites orbiting the earth, and they are transferred to the IEDs via an external GPS receiver system. The antenna of the GPS system needs to be located where it has a clear path to the sky.

Phasor Measurement Unit - PMU

A Phasor Measurement Unit is a device used under WAMS which is capable of measuring phases of currents and voltages in a power system. The unit is supplied with analogue data, containing current/voltage values for the three phases, from CTs and VTs. The analogue data is then filtered by an anti-aliasing filter and the data is converted into digital samples by an analogue-digital converter. At the same time the data is time stamped with the GPS synchronized clock of the PMU. The three-phase phasors are then transformed into positive sequence components. The time stamped positive sequence components are then stored with a fixed interval, typically every 40 or 100 ms, and sent to other WAMS devices. Modern digital relays with micro-processors are theoretically capable of functioning as a PMU in addition to its protective functions. The relays must then have firmware/software that supports it.[16]

C. Appendix - Connection Diagrams

Figure C.1 shows the numbering and placement of card slots for the Relion 670 relays. The card slots can be equipped with different modules.

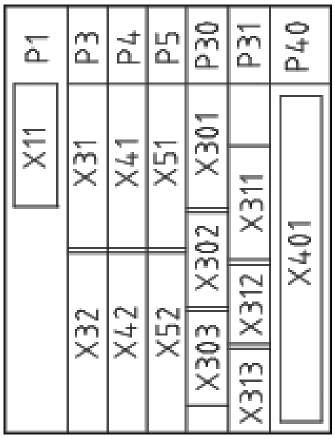


Figure C.1.: Card Slots - ABB Relion 670 (6U 1/2 19")

The following card slots/modules are relevant:

- X11 - Power Supply Module - Connection of 48 V DC supply
- X31/X32 - Binary Input Module (BIM) - Input of Binary Signals
  - Not used in the first step of the relay lab. Should be included for more advanced relay testing.
- X41/X42 - Binary Output Module (BOM) - Output of Binary Signals
- X401 - Transformer Input Module (TRM) - Input of currents and voltages

The power to the relays is provided through rectifiers as shown in Figures C.2 and C.3. The equipment is protected with a residual-current circuit breaker (RCCB); one for each rack.

In Figure C.4 - C.7 similar connection diagrams of wiring between the BOM and test switch is displayed. Two binary output signals have been forwarded through the test switch for each relay. The two letter combination at the end of top text in each figure represents the respective model configuration for the test switch.

Figure C.8 - C.11 contains connection diagrams of the wiring between the TRM and test switch. Notice how different test switch configurations have been used and how it affects the wiring.

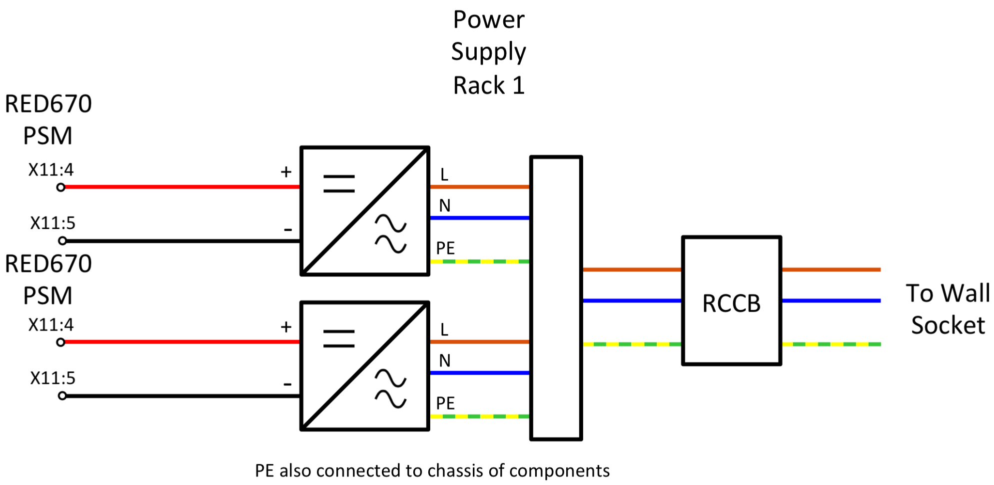


Figure C.2.: Connection Diagram - Power Supply Rack 1

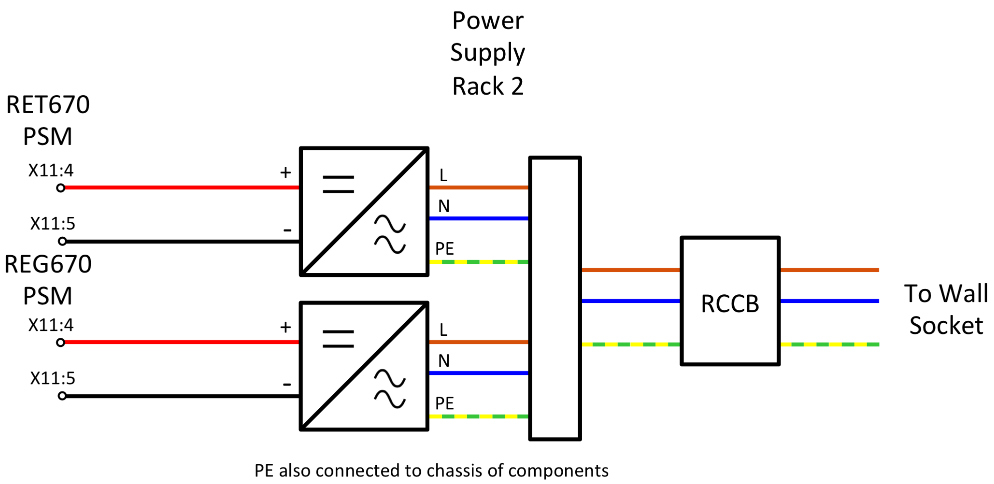


Figure C.3.: Connection Diagram - Power Supply Rack 2

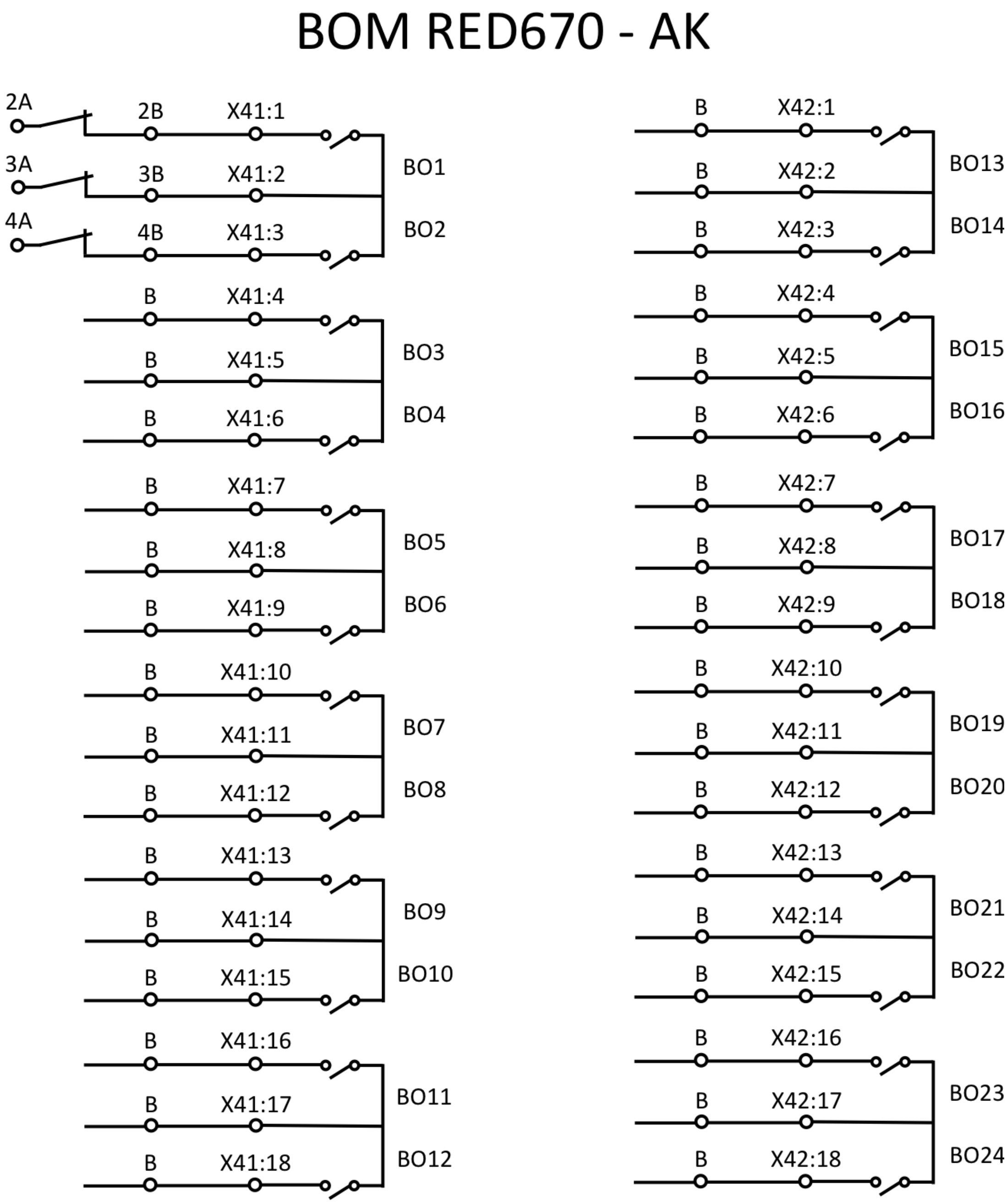


Figure C.4.: Connection Diagram - RED670-1 - Current and Voltage Leads between BOM and Test Switch

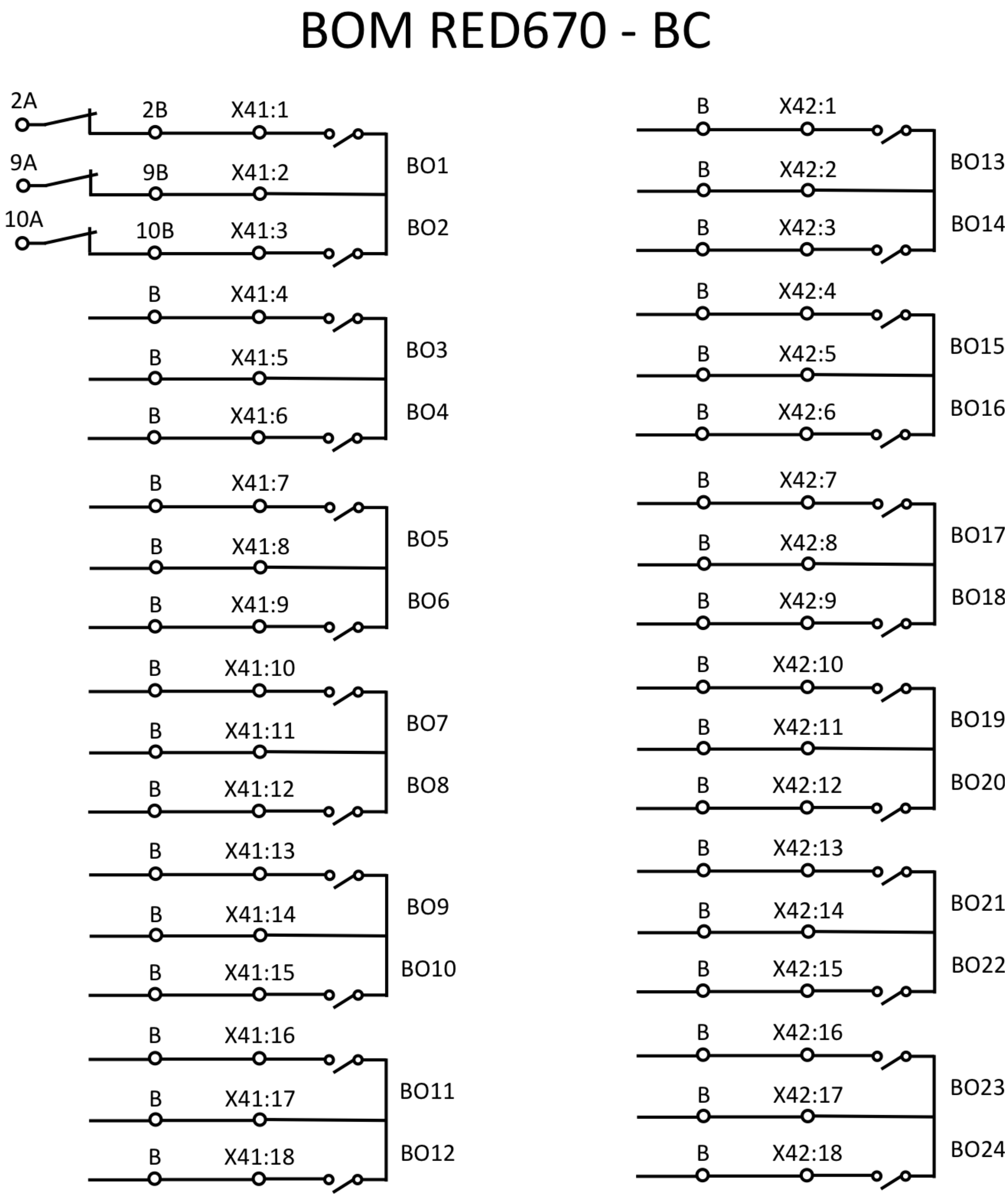


Figure C.5.: Connection Diagram - RED670-2 - Current and Voltage Leads between BOM and Test Switch

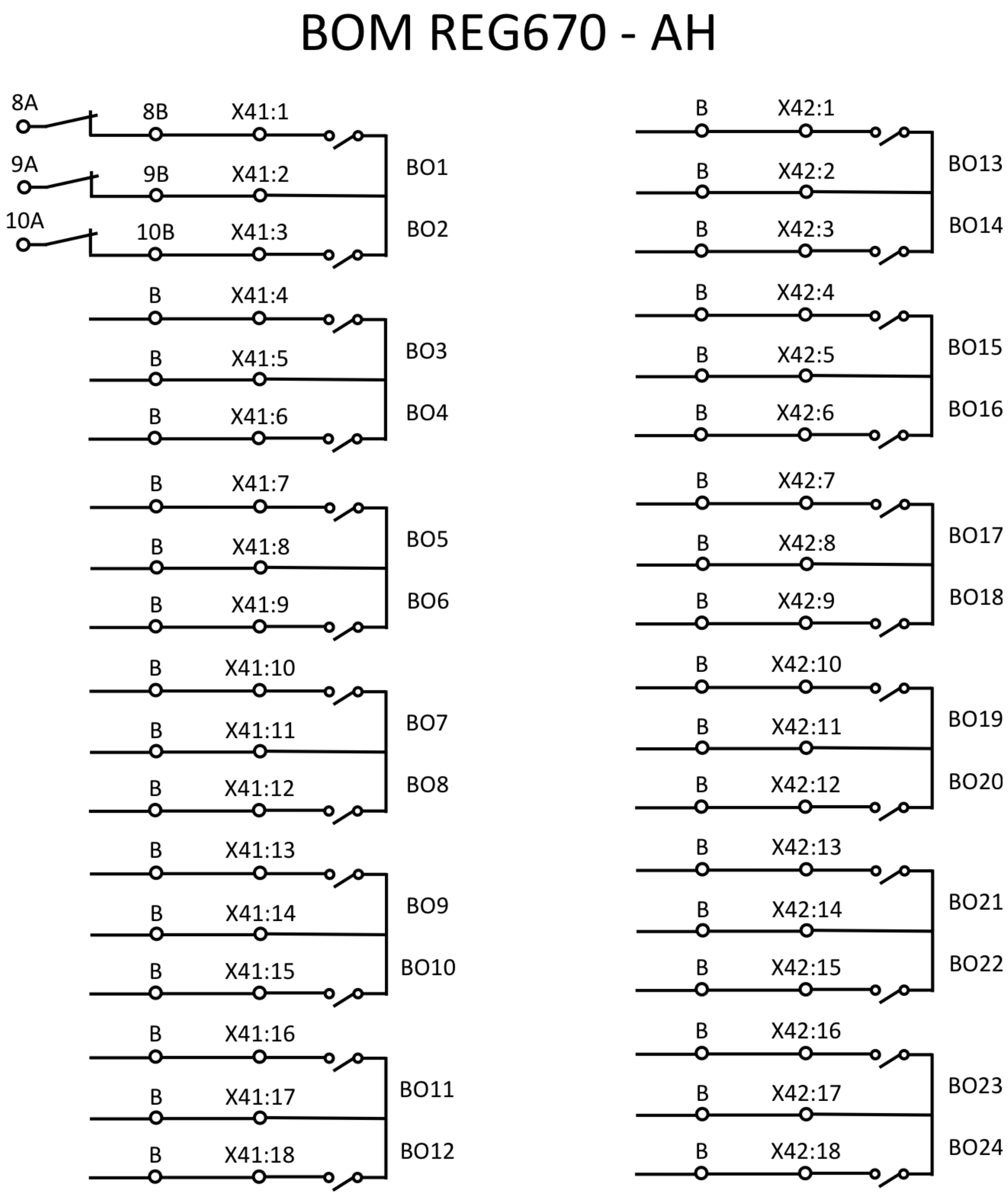


Figure C.6.: Connection Diagram - RET670 - Current and Voltage Leads between BOM and Test Switch

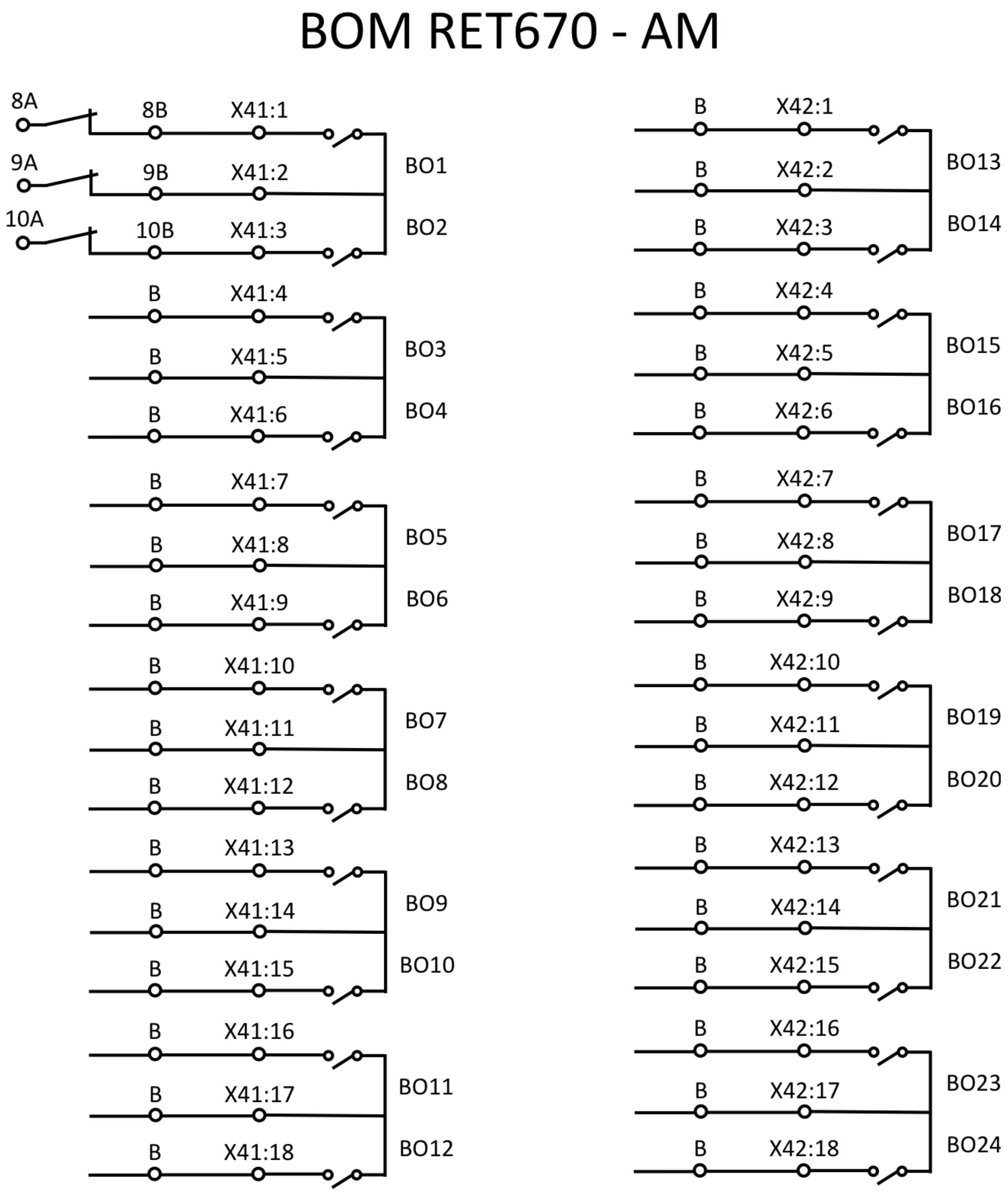


Figure C.7.: Connection Diagram - REG670 - Current and Voltage Leads between BOM and Test Switch

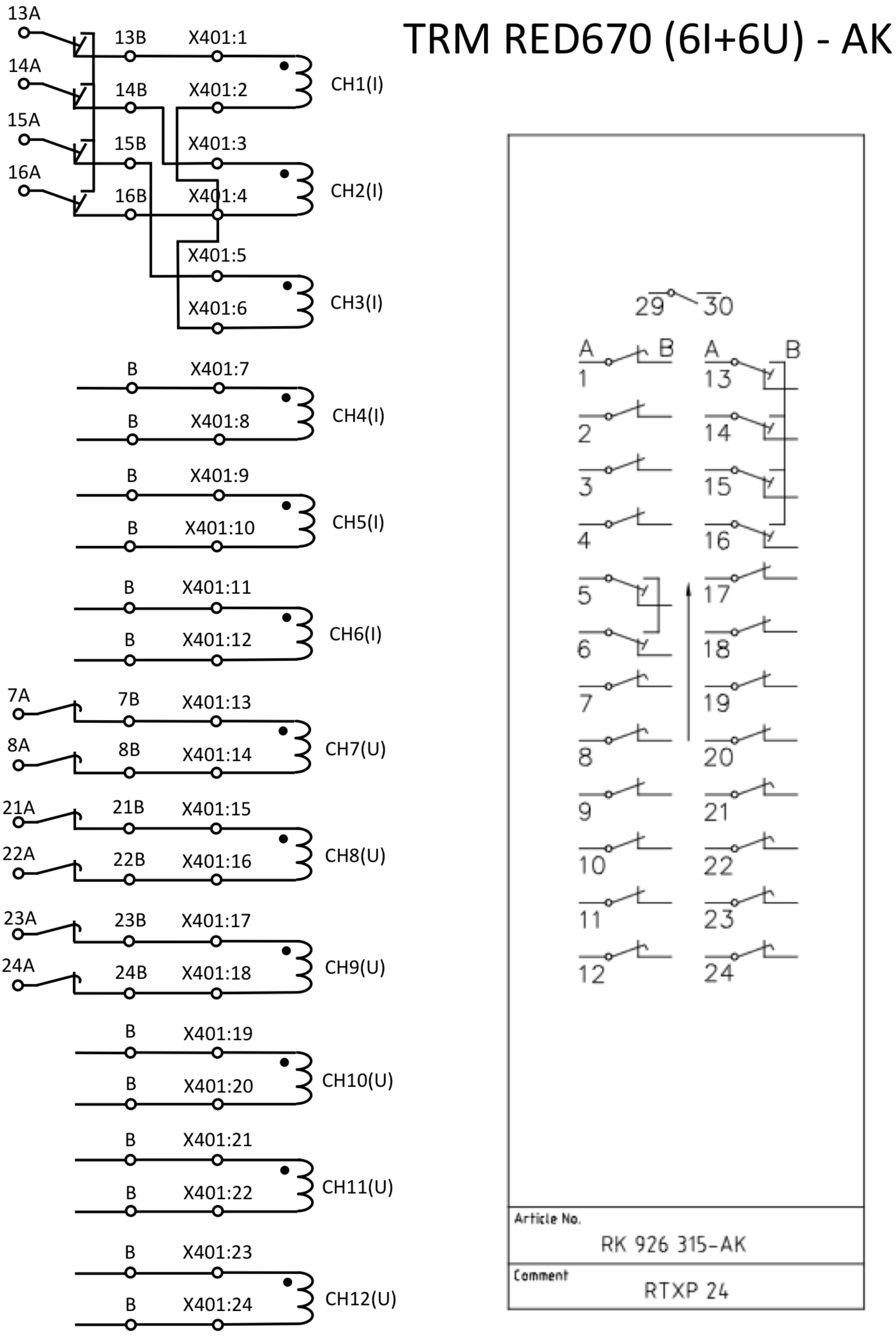


Figure C.8.: Connection Diagram - RED670 - Current and Voltage Leads between TRM and Test Switch[5]

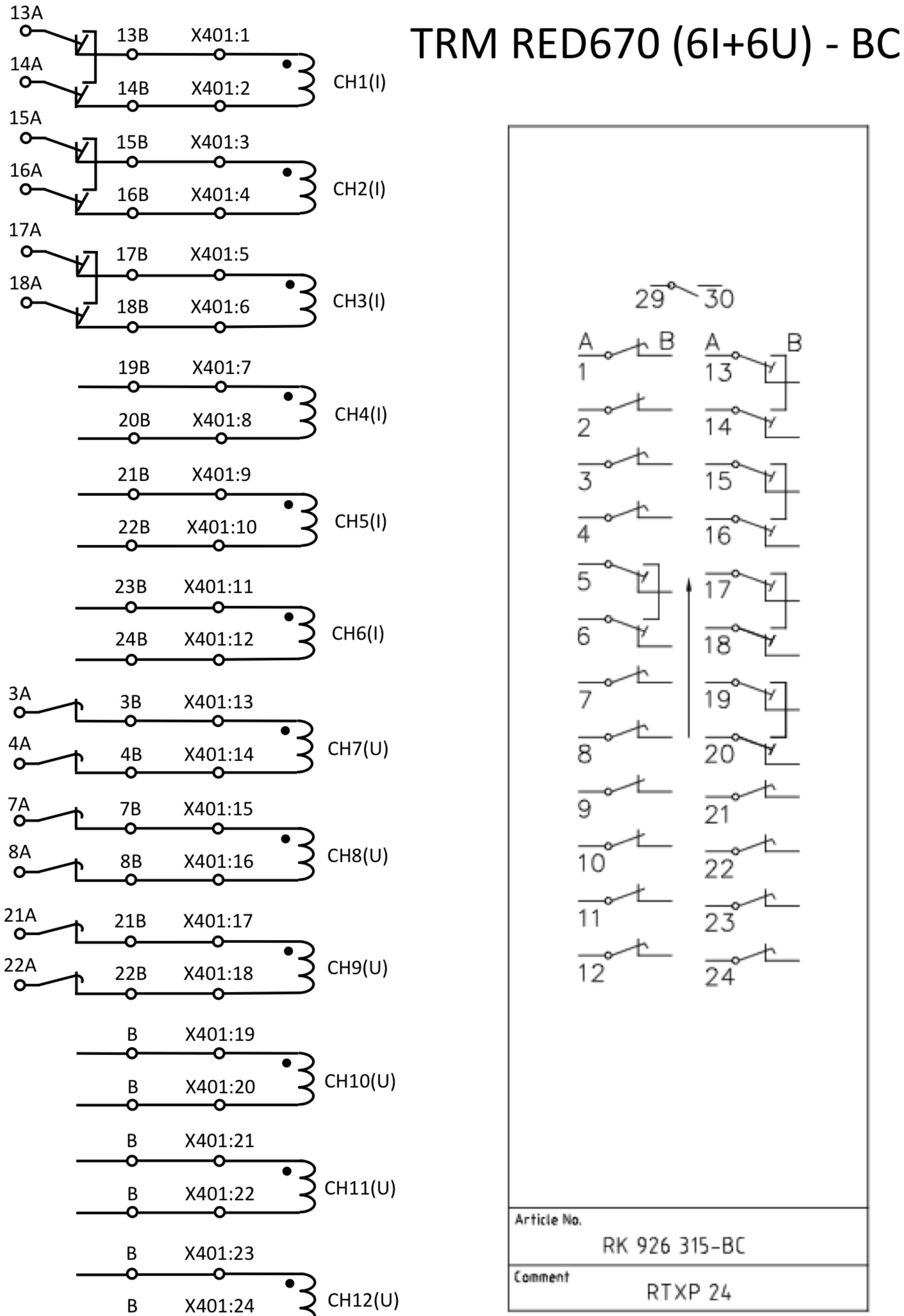


Figure C.9.: Connection Diagram - RED670 - Current and Voltage Leads between TRM and Test Switch[5]

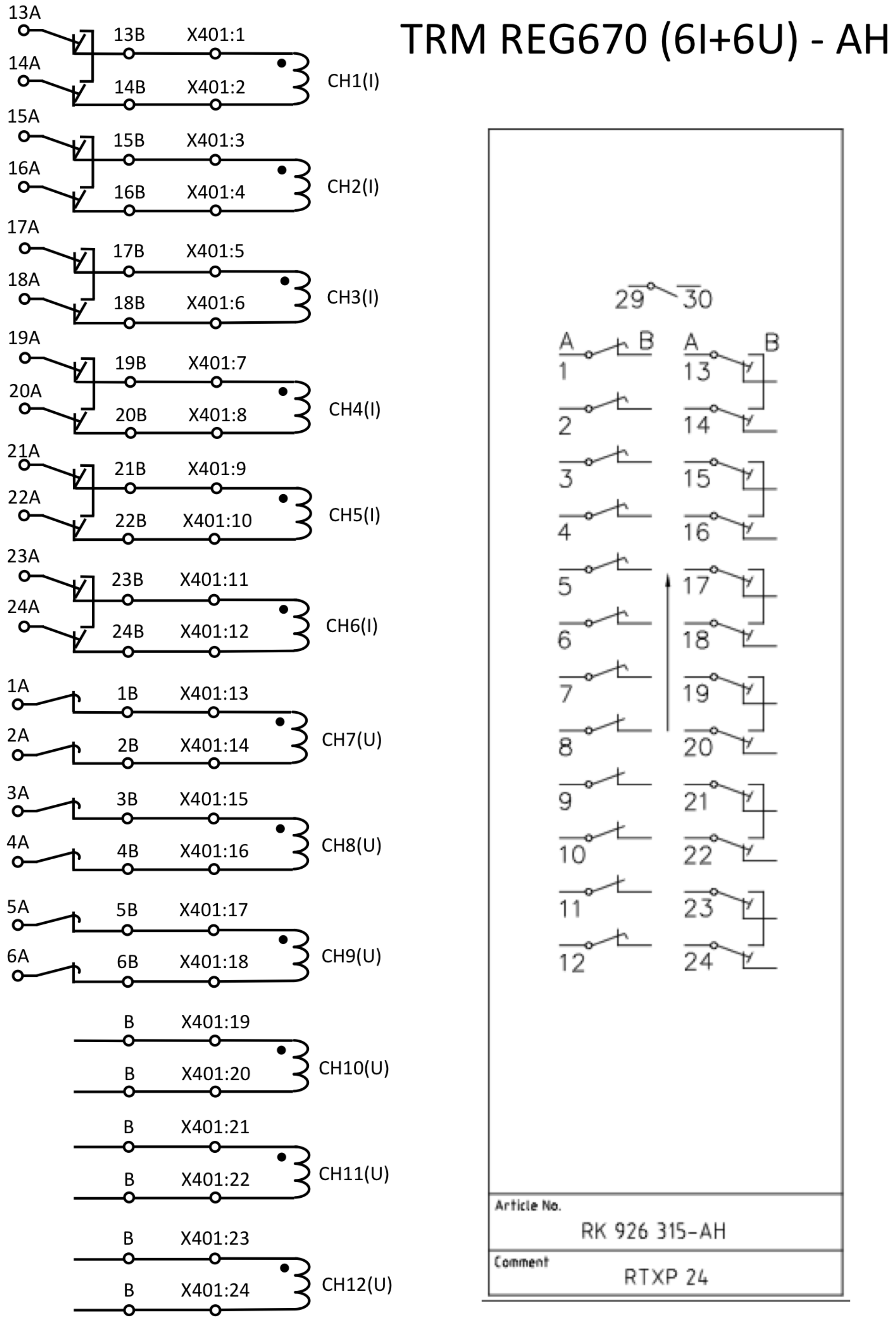


Figure C.10.: Connection Diagram - REG670 - Current and Voltage Leads between TRM and Test Switch[5]

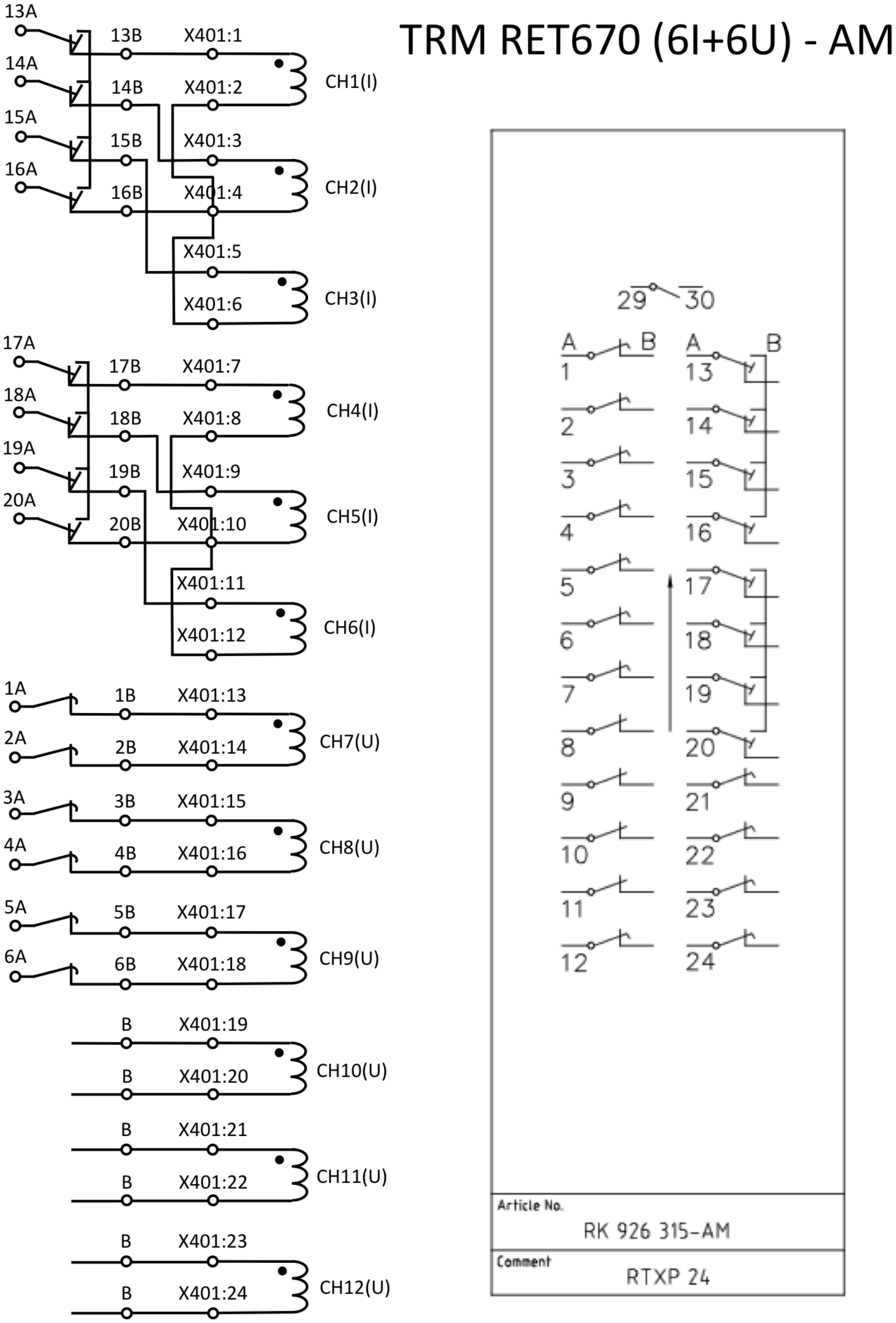


Figure C.11.: Connection Diagram - RET670 - Current and Voltage Leads between TRM and Test Switch[5]

D. Appendix - Equipment List

Description	Name	Model Info	#
Line Differential Protection Relay	ABB RED670V2.0	IEC 6U 1/2 19" - 6I+6U	2
Generator Protection Relay	ABB RET670V2.0	IEC 6U 1/2 19" - 9I+3U	1
Transformer Protection Relay	ABB REG670V2.0	IEC 6U 1/2 19" - 7I+5U	1
Test Switch	ABB RTXP24	RK926315-AH	1
Test Switch	ABB RTXP24	RK926315-AK	1
Test Switch	ABB RTXP24	RK926315-AM	1
Test Switch	ABB RTXP24	RK926315-BC	1
Test Handle	ABB RTXH24	RK926016-AA	4
Relay Mounting Kit	ABB 19" Mounting Kit	1MRK002930-BB	4
Mobile Lab Rack	Schroff 19" Cabinet	36U - 10117-498	2
Rack Shelf	Schroff 19"	2U Depth: 400 mm	2
AC/DC Converter	XP Power LCL150PS48	100-240VAC/48VDC 150 W	4
Power Strip	Bachmann 6-fach	19" 16 A/230 VAC	2
Residual-Current Circuit Breaker	Schneider El. DCP H Vigi	30mA MGN19752	2
Relay Tester	Omicron CMC 56	3U+3I	1

Bibliography

[1] ABB AB. Relion®670 series Generator protection REG670 Pre-configured Product Guide, 2012.

[2] ABB AB. Relion®670 series Line differential protection RED670 Pre-configured Product Guide, 2012.

[3] ABB AB. Relion®670 series Transformer protection RET670 Pre-configured Product Guide, 2012.

[4] ABB AB. Test system COMBITEST BuyerÕs guide - 1MRK 512 001-BEN Revision: E. http://www05.abb.com/global/scot/scot354.nsf/veritydisplay/c60fcdc986d039fcc1257b6000485353/$file/1MRK512001-BEN_E_en_Test_System_COMBITEST.pdfs, 2013.

[5] ABB AB. Specification Test switch RTXP 24 Symbol Catalogue - 1MRK 001 024-CA. http://www05.abb.com/global/scot/scot301.nsf/veritydisplay/1154cc88eea72c0ac1257cd1002c52ab/$file/1MRK001024-CA_U_en_Test_switch_RTXP_24_Symbol_catalogue.pdf, 2014.

[6] Inc. Advanced Systems for Power Engineering. ASPEN One-Liner. http://www.aspeninc.com/web/index2256.html?option=com_content&view=article&id=91&Itemid=64.

[7] Siemens AG. PSS®E. http://www.energy.siemens.com/hq/en/services/power-transmission-distribution/power-technologies-international/software-solutions/pss-e.htm.

[8] James S. Thorp Arun G. Phadke. *Computer Relaying for Power Systems*. Wiley, Second edition, 2009.

[9] DIgSILENT. PowerFactory. http://www.digsilent.de/index.php/products-powerfactory.html.

[10] Open Electrical. http://www.openelectrical.org/wiki/index.php?title=Power_Systems_Analysis_Software, March 4th 2014.

[11] Alstom Grid. OTCF - Capacitor Voltage Transformers - 72.5 to 765 kV. http://www.alstom.com/Global/Grid/Resources/Documents/Products/High%20voltage%20products/OCTF%20Capacitor%20Voltage%20transformers%2072,5%20to%20765%20kV%20-%20Brochure%20ENG.pdf, November 2011.

[12] J. Holbach. Modern Solutions to Stabilize Numerical Differential Relays for Current Transformer Saturation during External Faults. In *Power Systems Conference: Advanced Metering, Protection, Control, Communication, and Distributed Resources, 2006. PS '06*, pages 257–265, March 2006.

[13] Hans Kr. Høidalen. ATPDraw - The graphical preprocessor to ATP . `http://www.atpdraw.net/`.

[14] Hans Kr. Høidalen. Lecture Notes - Over-Current Protection. In *TET4115 Power System Analysis - Norwegian University of Science and Technology*, 2013.

[15] Thomas J. Domin J. Lewis Blackburn. *Protective Relaying: Principles and Applications*. CRC Press, Third edition, 2007.

[16] James R. Bumby Jan Machowski, Janusz W. Balek. *Power System Dynamics - Stability and Control*. Wiley, Second edition, 2012.

[17] Il-Dong Kim. Experiences and future prospects on the digital relay application and substation automation. In *Transmission and Distribution Conference and Exhibition 2002: Asia Pacific. IEEE/PES*, volume 1, pages 613–617 vol.1, Oct 2002.

[18] R.E. Mackiewicz. Overview of IEC 61850 and Benefits. In *Power Engineering Society General Meeting, 2006. IEEE*, pages 8 pp.–, 2006.

[19] Juan A Martínez-Velasco, Jacinto Martín-Arnedo, and Ferley Castro-Aranda. Modeling Protective Devices for Distribution Systems with Distributed Generatio Using an EMTP-Type Tool. *Ingeniare. Revista chilena de ingeniería*, 18:259–274, August 2010.

[20] C. Russell Mason. *The Art & Science of Protective Relaying*. General Electric, 1956. `http://www.gedigitalenergy.com/multilin/notes/artsci/`.

[21] Mukesh Nagpal and Charles Henville. Lecture Notes. In *EECE 497 Power System Protection - University of British Columbia*, 2013.

[22] Nhat Nguyen-Dinh, Gwan-Su Kim, and Hong-Hee Lee. A study on GOOSE communication based on IEC 61850 using MMS ease lite. In *Control, Automation and Systems, 2007. ICCAS '07. International Conference on*, pages 1873–1877, October 2007.

[23] Omicron. CMC 356. `https://www.omicron.at/typo3temp/pics/CMC-356-1_bbf8f3db84.png`.

[24] Inc. Operation Technology. ETAP. http://etap.com/industries/etap-user-list.htm.

[25] Electrical Engineering Portal. Symmetrical Components. http://electrical-engineering-portal.com/resources/knowledge/electrical-formulas/symmetrical-components.

[26] M.A. Redfern, X. Sun, Wen An, P.A. Crossley, Li Yang, and H. Grasset. IEC61850 and Designs for Future Relays. In *Developments in Power System Protection (DPSP 2010). Managing the Change, 10th IET International Conference on*, pages 1–5, March 2010.

[27] M. Harry Hesse Robert C. Degeneff. *Principles of Power Engineering Analysis*. CRC Press, First edition, 2012.

[28] Anthony F. Sleva. *Protective Relay Principles*. CRC Press, First edition, 2009.

[29] smartgrids.no. http://smartgrids.no/nytt-nasjonalt-laboratorium-for-smartgrid-i-trondheim/, November 4th 2013.

[30] Torstein Stadheim. Implementering av relévern i ATPDraw. Master's thesis, NTNU, June 2012.

[31] Arun G. Phadke Stanley H. Horowitz. *Power System Relaying*. Research Studies Press Ltd., Second edition, 1995.

[32] Chris Werstiuk. *The Relay Testing Handbook - Relay Testing Fundamentals*. Valence Electrical Training Services LLC, 2012.

[33] A. Wright and C. Christopoulos. *Electrical Power System Protection*. Chapman & Hall, First edition, 1993.

[34] Zengli Yang, Dongyuan Shi, and Xianzhong Duan. Study on flexible power system protection relay coordination software based on user-defined principle. In *Universities Power Engineering Conference, 2007. UPEC 2007. 42nd International*, pages 277–282, Sept 2007.

[35] Gerhard Ziegler. *Numerical Distance Protection*. Publicis Corporate Publishing, Second edition, 2006.