REG670 Generator Protection Relay – Commissioning Guide

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BACHELOR'S THESIS

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Summary

This bachelor's thesis comprises the generation of a user manual and MEGGER FREJA 300 test templates for ABB's generator protection relay REG670. The commissioner is Wärtsilä Finland OY, Field Services department in Runsor, Vaasa.

A combination of VAMP's protection relays 210, 260 and 265 is used as a standard generator protection solution in power plant solutions from Wärtsilä. ABB's REG670 is a protection relay that has recently been included in Wärtsilä power plant solutions due to customer demands. Therefore, a user manual had to be created to describe how to use ABB's configuration program PCM600 and MEGGER's testing device FREJA 300 with associated software, FREJA Win.

Test templates were created to be used for the secondary testing of the protective relay. These secondary tests are made as a certification to prove that the protective relay meets the protection requirements. Test templates are imported and used in FREJA Win. The final result is a user manual consisting of 80 pages and 9 test templates.

Language: English Key words: generator protection, relay, testing

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EXAMENSARBETE

Författare:	Anders Hermans
Utbildningsprogram och ort:	Elektroteknik, Vasa
Inriktningsalternativ/Fördjupning:	Elkraftsteknik
Handledare:	Erik Englund

Titel: *REG670 Generator Skyddsrelä – Idrifttagnings Manual*

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Abstrakt

Detta examensarbete omfattar skapandet av en användarmanual och testbottnar till MEGGERs FREJA 300 för ABBs generatorskyddsrelä REG670. Uppdragsgivare är Wärtsilä Finland Oy, Field Service i Runsor, Vasa.
En kombination av VAMPs skyddsreläer 210, 260 och 265 används som ett standard generatorskydd i kraftverkslösningar från Wärtsilä. Men på grund av kundkrav så har även ABBs REG670 börjat förekomma som lösningsförslag till generatorskydd. Av dessa skäl behövdes en användarmanual som beskriver hur man använder ABBs reläkonfigurationsprogram PCM600 och MEGGERs relätestningsutrustning FREJA 300 med tillhörande programvara, FREJA Win 5.3.
Testbottnar skapades också för användning vid sekundärtestning av skyddsreläet vilka utförs för att visa att reläskyddet uppfyller dess funktionskrav. Testbottnarna används i FREJA Win.
Resultatet blev en användarmanual på 80 sidor och 9 stycken testbottnar.

Språk: engelska Nyckelord: generatorskydd, relä, testning

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Tiivistelmä

Opinnäytetyö sisällyttää käyttöohjeen ja testipohjien luomisen FREJA 300:lle, ABB:n generaattorinsuojareleelle REG670. Työnantajana toimii Wärtsilä Finland Oy, Field Service-osasto Runsorissa, Vaasassa.

Yhdistelmä VAMPin suojareleistä 210, 260 ja 265 käytetään standardina generaattorinsuojareleenä Wärtsilän voimalatoksissa. Asiakkaiden vaatimuksien seurauksena ABBn REG670 käyttö on yleistynyt. Tämän ansiosta syntyi tarve käyttöohjeelle, joka kuvailee, miten käytetään ABB:n relekonfigurointiohjelmaa PCM600 ja MEGGER:in releen testausvarustukseen FREJA 300:n liittyvää ohjelmisto, FREJA Win.

Testipohjat kehitettiin myös käytettäväksi suojareleen toissijaistestauksessa, joka suoritetaan todistaakseen, että relesuoja tavoittaa tarvittavat vaatimukset. Testipohjat käytetään myös FREJA Win:ssä. Tulokseksi tuli 80 sivun pituinen käyttöohje ja 9 käyttöpohjaa.

Kieli: englanti Avainsanat: generaatorinsuoja, rele, testaus

Contents

1 About this thesis

1.1 Commissioner

Wärtsilä is a global leader in complete lifecycle power solutions for the marine and energy markets. The flagship of their products is the large combustion engines which are implemented in marine products as well as in power plants. Numbers from the year 2013 show that Wärtsilä's net sales totaled EUR 4.654 billion with approximately 18600 employees. Wärtsilä has operations in nearly 170 locations in 70 countries. Wärtsilä is divided into three different departments:

- Wärtsilä Services: Service department at Wärtsilä which gives support to Wärtsilä's customers. Wärtsilä provides high quality service, maintenance and reconditioning solutions for both ship machinery and power plants.
- Wärtsilä Power Plants: Power Plants department offers flexible power plants of up to 600 MW operating on gas or liquid fuels. Wärtsilä has, for the moment, a 55 GW power plant capacity installed in 169 countries.
- Wärtsilä Ship Power: Ship Power provides ship machinery and solutions for propulsion and maneuvering. Ship Power provides products that are flexible, efficient, economically sound and sustainable. (Wärtsilä OY, 2014)

1.2 Background

Wärtsilä includes three different VAThe reason why both the IEC and the ANSI standard is used in the list of protection functions is that Wärtsilä is an international corporation with customers in countries that doesn't use the IEC standardMP relays, models like VAMP 210, VAMP 260 and VAMP 265 as a standard solution in power plants to handle the protection of generators and transformers and the communication with other IEDs. But due to requests from customers Wärtsilä has started to include a new generator protection relay, ABB's REG670. Since the ABB REG670 relay is not commonly included as a protective relay solution in power plants sold by Wärtsilä, Wärtsilä required a user guide, adapted for their purposes, for ABB's REG670 generator protection relay to be used by field service engineers on power plant sites for the commissioning. When field service engineers are testing protective devices installed in the power plant, they need a report as evidence, showing what functions that have been tested and the result of the tests. The two most important data they need is the pick up value of the protection function and the operation time. Tests are done with the help of a fault simulation unit, MEGGER FREJA 300. This thesis is partly done for Wärtsilä Power Plant department and Field Service department in Runsor, Vaasa.

1.3 Goals

The goal of this thesis is to create a user manual for the tools needed to edit protection functions for REG670 and to test them with a relay testing device, FREJA 300 from MEGGER. With PCM600-software from ABB, it is possible to edit parameters, modify protection functions and run online monitoring of REG670. In addition to the user manual, test templates will be created for PC-controlled testing of the protection relay REG670. MEGGER's software, FREJA Win 5.3, makes it possible to test different protection functions on a relay from a PC connected to FREJA 300. These templates will be available for downloading for electrical field service engineers from Wärtsilä's internal web pages. From Wärtsilä's point of view, the most vital functions of PCM600 and FREJA Win 5.3 will be summarized to one document which was compiled from different manuals from ABB and MEGGER to save precious time for the intended user. Test templates for the following protection functions are to be created:

- Overcurrent $I>$, ANSI 51
- Overvoltage $U>$, ANSI 59
- Undervoltage $U<$, ANSI 27
- Reverse power $P<$, ANSI 32
- Underexcitation $Q<$, ANSI 40

- Unbalanced current I_2>, ANSI 46
- Overfrequency $f >$, ANSI 81
- Underfrequency $f <$, ANSI 81
- Thermal overload $T >$, ANSI 49
- Groundfault $I_0 >$ and I_{0Dir} , ANSI 51N and ANSI 67N
- Zero-sequence voltage $U_0 >$, ANSI 59N

Wärtsilä is an international corporation and they have many customers that don't use the IEC standard. This is why both the ANSI standard and the IEC standard are used for the protection functions listed above. All test templates will be created according to Wärtsilä's standard protection settings.

2 Power generation

Electricity is produced by converting one energy form to another. Energy sources can be hydro, nuclear, wind and fossil fuel used in utilities and a synchronous motor is used to convert the energy source to electricity. The stator of the generator is connected to the external system, which consists of transformers, lines, circuit breakers etc. These devices make up the primary system parts. The secondary system parts consist of devices for regulation, controlling, supervision, protection and voltage supply. To be able to guarantee a stable and reliable energy supply a correct interaction between these devices is needed. Figure 1 illustrates an example of an engine generator set. Figure 2 illustrates a typical Wärtsilä power plant layout. (Andersson, L. et al. , 2012, p 326)

Figure 1: Engine generator set. (Wärtsilä OY)

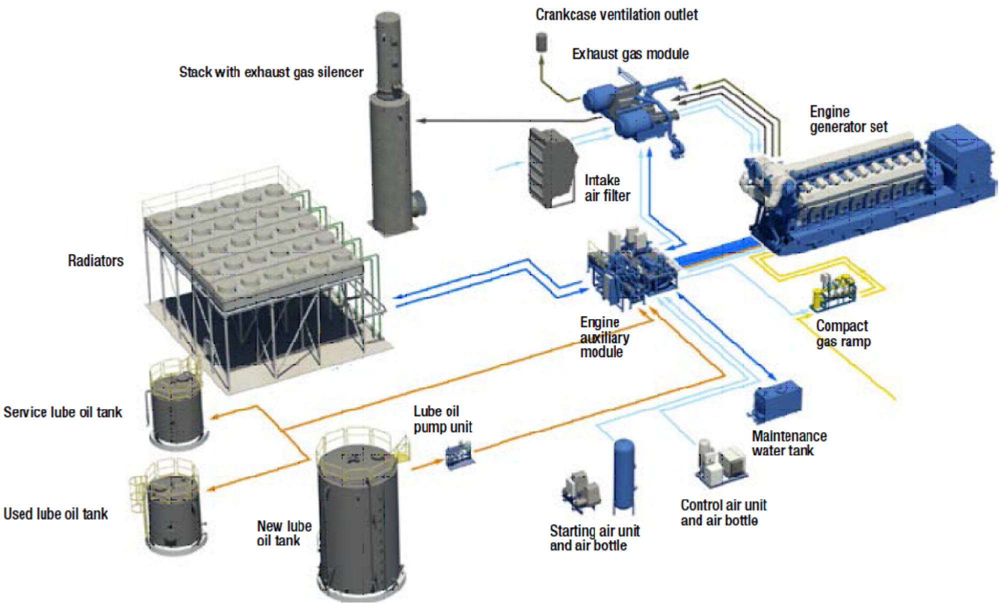


Figure 2: Power plant layout. (Wärtsilä OY)

3 Protective relays

What is a protective relay? IEEE, the Institute of Electrical and Electronic Engineers, defines a relay as "an electric device that is designed to respond to input conditions in a prescribed manner and, after specified conditions are met, to cause contact operation or similar abrupt change in associated electric control circuits." A note adds the following: "Inputs are usually electric, but may be mechanical, thermal, or other quantities or a combination of quantities. Limit switches and similar simple devices are not relays" (IEEE C37.90). IEEE also defines a protective relay as "a relay whose function is to detect defective lines or apparatus or other power system conditions of an abnormal or dangerous nature and to initiate appropriate control circuit action" (IEEE 100). (Blackburn, J.A, et al. , 2007, p 1)

Protective relays are used in power systems to assure maximum continuity of service and to minimize the outage times. This is the main objective in a power system. As it was also stated in the IEEE standard (IEEE C37.90), the task of protective relays is to constantly monitor the power system to detect unwanted conditions that can result in damage to property or in a worst case scenario, loss of personnel. Protective relaying is not necessary in normal operation of an electrical power system until a fault occurs. The relays can also be considered a form of insurance to provide protection against property damage and damage to life. Even though the main objective in power systems was to maximize the continuity of the service, loss of power, voltage dips, and over voltage will occur. It is almost impossible to predict and avoid the aftermath of natural events, physical accidents, equipment failure, or misoperation because of human error. Some of these elements will result in faults like: inadvertent, accidental connections, and "flashovers" between the phase wires or between phase wire(s) and ground. The natural events that can be the cause to short-circuit faults are:

- Falling trees
- Lightning
- Wind
- Ice
- Fire
- Explosions
- Physical contact by animals
- Flying objects
- Pollution. (Blackburn, J.A, et al. , 2007, p 1; Gill, P. , 1998, p 323)

A decent effort is made to reduce the damage possibilities but, as was said before, it is impossible to eliminate all the possibilities that can cause damage. (Blackburn, J.A, et al. , 2007, p 1; Gill, P., 1998, p 323)

The main task of the protective relay is to initiate a fault isolation of the defect device in the power system before its dynamical and thermochemical maximum values are reached. To achieve this, the protective relays affect circuit breakers electrically. In other words, one can say that relays are the “brains” in the power system that sense if there is an abnormal or intolerable situation. The protective relay itself is not able to open a circuit. It is here the circuit breakers come into the picture. Circuit breakers and various types of different circuit interrupters are the “muscle” that performs the fault isolation. The protective relays can also have the task of supervising the operation in the power system and, when there is a risk of a fault, the protective relay has to initiate commands for arrangements. Examples of this kind of actions are disconnection of the load when the frequency is too low in the power system, or disconnection of the production when there is too high frequency or too much load somewhere in the power system. By studying the change in voltage and current, the protective relay can supervise and protect the power system and its devices. (Andersson, L. et al. , 2012, p 274; Blackburn, J.A., et al., 2007, p 8)

3.1 Thoughts about relay protection

Safety requirements for personnel and material are the two primary elements that have an impact on the magnitude and the establishment of a protective relay. The secondary elements are technical and economical aspects. The following elements have more or less impact on the establishment of a protective relay:

- Personnel and material safety requirements affected by laws and directives
- The establishment of high-voltage power stations
- The power station’s value or importance for the power system in general
- Availability of personnel that can monitor and act if a fault occurs

- Other systems for protection, supervision and management. (Andersson, L. et al. , 2012, p 363; Blackburn, J.A, et al., 2007, p 17)

By taking these elements into consideration, requirements can be made on the protective relay in the following respects:

- Reliability
- Selectivity
- Speed of operation
- Sensitivity. (Andersson, L. et al. , 2012, p 363; Blackburn, J.A, et al., 2007, p 17)

Before addressing these four features it is important to point out that the term "protection" does not mean that the protective equipment can completely prevent disturbance and trouble, such as equipment failure and faults, or electric shocks caused by unintentional human contact. Protective relays will only act after an abnormal or an unacceptable condition has occurred so that as much as possible of the power system is left in service. The protective system will in other words limit the duration of the unacceptable condition or trouble and therefore minimize the damage, outage time and other related problems. (Andersson, L. et al. , 2012, p 363; Blackburn, J.A, et al., 2007, p 17)

3.1.1 Reliability

The relay protection system's task is to give a signal to disconnect a part or device in the power system when a fault or an unacceptable condition occurs. The relay protection system can be categorized into three function groups depending on how the fault or the unacceptable condition is handled.

1. Correct operations
   (a) As planned

   (b) Not as planned or expected

2. Incorrect operations, either failure to trip or false tripping

   (a) Not as planned or wanted

   (b) Acceptable for the particular situation

3. No conclusion. (Andersson, L. et al. , 2012, p 368)

A more detailed description of the function groups follows:

- Correct operation. What indicates a correct operation? First of all, at least one of the primary relays managed to operate correctly. Secondly, none of the backup relays tripped for the fault. And thirdly, the area of the fault was isolated within the expected time. (Andersson, L. et al. , 2012, p 368)

- Incorrect operation is a consequence of an unplanned operation, a malfunction, or a failure of the protective system. An incorrect operation can cause a failure to isolate a zone where a fault occurs or fail to properly isolate the fault zone. The reasons that lie behind the incorrect operations can be one of the following or a combination of incorrect settings, misapplication of relays, personnel errors and equipment failures. (Andersson, L. et al. , 2012, p 368)

- No conclusion; This happens if a relay has operated, such as tripping a circuit breaker, during a condition and no reason or cause can be found. Modern microprocessor relays can provide clues or direct evidence to the problem thanks to data recording and oscillographs. (Andersson, L. et al. , 2012, p 368)

The consequences of a false operation vary from case to case but generally it is said that the function that causes the greatest negative consequences is when a protective relay fails to operate. The reasons why a protective relay fails to operate correctly can be many. It is surprisingly unusual that a fault occurs in the protective relay itself. The main reasons for the incorrect functions are faults in voltage or current circuits, low voltage supply, inadequate settings or that protection principles can't handle the current faults. To be able to guarantee a high dependability it is necessary to study the whole protection system including, current transformers, low voltage feeding, protection relays and circuit breakers. (Blackburn, J.A, et al. , 2007, p 19)

The risk that the relay protection can fail to operate means that there should always be a back-up protection system that is able to isolate or disconnect the fault if the primary protection system fails to do so. When it comes to implementing a back-up system there are mainly two options, a local back-up system or a remote back-up system. The local back-up system means that the primary protection system and the back-up system work together in parallel and affect the same circuit breaker. The remote back-up system, on the other hand, means that the back-up system affects a different circuit breaker than the primary system protection. (Andersson, L. et al. , 2012, p 368)

Reliability has two aspects, dependability and security. *Dependability* is defined as “the degree of certainty that a relay or relay system will operate correctly” (IEEE C37.2). *Security* “relates to the degree of certainty that a relay or a relay system will not operate incorrectly” (IEEE C37.2). To put it in other words, dependability means that the relay protection system must be able to operate correctly when it is required to do so and security refers to the protection system’s ability to avoid unnecessary actions during normal operation and to avoid problems and faults outside its protection zone. Security is hard to verify since there can be infinite disturbances, or transients, that might upset the relay protection system and it is quite a struggle to predetermine all of these disturbances. Dependability, on the other hand, is easy to verify by testing the protection system and making sure that it will operate as intended when unacceptable conditions occur and operating limits are exceeded. Increasing the security will in general decrease the dependability of a protective system. (Blackburn, J.A, et al. , 2007, p 19)

3.1.2 Selectivity

Protective relays have an area that they have been assigned as a primary protection zone but, in addition, they can also operate and respond to conditions outside the primary zone. In this way the protective relays can operate and provide backup outside their primary zone.

When assigning an additional protection zone to a protective relay outside its primary zone, the protective relay is still set to operate as fast as possible in its primary zone and with a little delay of operation in its backup zone. The process is called *selectivity.* The reason for setting a delay time for relays operating in backup zones is simply that one wants to permit the primary relay sets in the overreached zone to operate first. Otherwise there will be two sets of relays operating in the overreached zone: the assigned primary relay set and the overreached backup relay set. (Blackburn, J.A, et al. , 2007, p 20)

Protective relays are, as stated before, assigned different protection zones but relays can also be assigned different protective objects. The different objects can be:

- Generator protection
- Transformer protection
- Generator-Transformer protection
- Motor protection
- Line protection
- Reactor protection
- Capacitor protection
- Inductor protection
- Rectifier protection
- Bus protection. (Andersson, L. et al. , 2012, p 364)

The protection of different objects will be briefly discussed in later chapters but the generator protection will be discussed more thoroughly in section 4.4. Selectivity can be obtained in four different ways:

- Function selectivity: This is based on the setting's function value.

- Time based selectivity: The selectivity is based on the settings for the protection relay's functionality time.
- Direction based selectivity: The protection relay must detect the direction of the fault.
- Absolute selectivity: The protection relay's ability to react to a fault in its own protection object. (Andersson, L. et al. , 2012, p 364)

3.1.3 Speed of operation

The expectations from a protection system is that it should isolate a fault as fast as possible. This is not hard to achieve for some applications, but for applications that include selectivity it can be. Very high speed protection may result in undesirable increasing numbers of incorrect operations. Short circuits in a power system can generate very high fault currents that will expose the power system to mechanical and thermal stress. If a fault remains it can make the power system network oscillate and in worst cases, it can lead to a collapse of the whole power system network. In this case the relay speed is very important when the facility exists in a stability-sensitive area of the network. If a fault makes the power system network oscillate, the generator will also be affected and start to accelerate during the fault. The amount that the generator can accelerate can be reduced by faster fault clearing and also this will also improve stability margins. This does not mean that fast operation can be a positive thing. In general, the faster the operation the higher the probability will be that an incorrect operation will occur. (Blackburn, J.A, et al. , 2007, p 21)

A short circuit's highest instantaneous value is called *inrush current*. Inrush current is what causes the electrodynamic powers that can mechanically cause damage to the facility. The maximum current value that a device or part can be exposed to during one second without being damaged is called thermal short-circuit durability. The time it takes for high-speed circuit breakers to operate is within the range of 17-50 msec, in other words within one to two and a half cycles at 50 Hz. Other circuit breakers operate at less than 83 msec, within five cycles at 50 Hz. High-speed relays operate in less than 50 msec, two and a half cycles at 50 Hz. The total time of operation for circuit breakers plus relays is within 35-130 msec, in other words approximately within two to seven cycles at 50 Hz. (Andersson, L. et al. , 2012, p 366)

Since the time for the circuit breaker plus the protection relay to operate is always longer than half a cycle, no fault will be cleared fast enough to limit the inrush current. In this case, fuses are superior to protection devices, circuit breakers and relays. Fuses will disconnect the current before the inrush current rises to its first peak value and therefore the fuse will limit the inrush current and this will also limit the electrodynamic effects considerably. The operation time of circuit breakers and relays must be adapted to the facility's thermal short-circuit strength. Faults that cause very serious voltage drops in the network must be dealt with quickly by the protection devices so the stability in the network remains and pole slip doesn't occur. To limit the damages it is normal that relay protection offers a momentary function at short circuit and that the time of operation is kept under 0.1 sec. For other types of faults the requirements on speed of operation vary, from a tenth of a second to tens of seconds. (Andersson, L. et al. , 2012, p 366)

3.1.4 Sensitivity

To guarantee that isolation of all faults will be done, the protective relay must be sensitive enough. This is extremely important in those cases where a descended network line may come in contact with personnel and generate serious damage or in worst cases loss of lives whilst the fault current can be of a few ampere. Simultaneously as the sensitivity is increased the risk of undesirable operations is also increased. For example, current generated from energizing a transformer can cause undesirable functions in a transformer protection relay and in the line relay protection's most sensitive step. Another example is the current generated from starting motors which can cause undesirable operations in over-current protection with sensitive settings. In these cases the problems can be solved with a time delay function or by blocking during start-up. The sensitivity of a relay protection usually becomes a compromise where one partly takes into account faults that are generated during normal operation, and partly one tries to handle as many fault scenarios as possible. When it comes to high-impedance earth faults, where the fault current becomes considerably lower than the operating current, it becomes hard to implement this kind of compromise. It is possible to detect very small fault currents even if the load current is much higher by measuring zero-sequence currents and zero-sequence voltage. (Andersson, L. et al. , 2012, p 367)

3.2 Protection relay's objective

As stated in chapter 3, the protective relay, in cooperation with fuses, is the monitoring and fault detecting system in the protection system. The protective relay's primary objective is to monitor a certain object in the power system and to detect when a fault occurs. When an unacceptable condition takes place, the protective relay gives a signal or an impulse for the disconnection of the malfunctioning device or power system zone. The protective relay often gets its name from the fault type it is intended for, e.g. short-circuit protection, earth-fault protection and disconnection protection. The disconnection protection acts when there is a disconnection of a conductor. Earth-fault protection acts simply when there is an earth connection. The short-circuit protection acts when there is a short circuit between different conductors, e.g. a two- or three-phase earth fault as well as a one-phase earth fault in power systems with a directly earthed neutral point. Different faults have different characteristics, and, when a fault takes place, the voltage and current will change according to the fault's characteristics. This will also have an impact on power and impedance compared with the normal operation. A fault may also have an impact on the frequency depending on the magnitude of the fault or if a part of the power system gets separated from the rest of the power network. The protective relay has to measure the listed base units to determine if there is a fault in the power system and also determine the type of fault and state of fault. (Andersson, L. et al. , 2012, p 349)

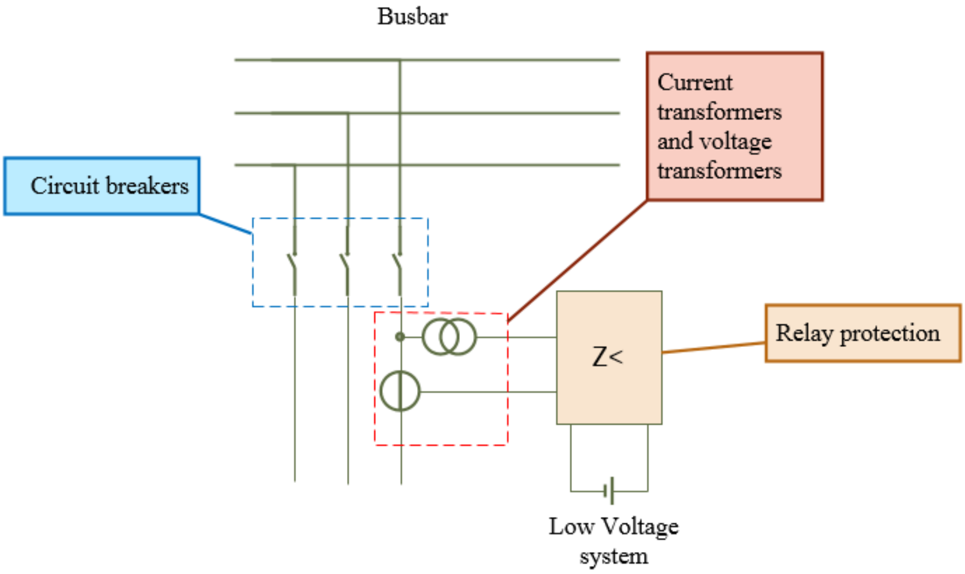


Figure 3: Main parts of the fault-handling system.

3.2.1 A protective relay's operating principles

The protective relay's input quantities are current, voltage and/or phase angle. The quantity that decides the way the protective relay operates is called affecting quantity. This can be current (I), voltage (U), power (P), impedance (Z) or frequency (f).

- Input quantity: As described earlier, this is can be e.g. current or voltage.
- Affecting quantity: Electrical quantity that decides the way the protective relay operates. For voltage relays, power relays, frequency relays and current relays the affecting quantity is either voltage (U), power (P), frequency (f) or current (I). The relay characteristics are useful when determining the relay setting, which will determine relay sensitivity, selectivity and speed in order to protect the power system from short circuits.
- Function value: The limit for the affecting quantity at which the relay starts to operate.
- Return value: The limit for the affecting quantity which the relay returns to.

- Return ratio: The ratio of the return value and the function value expressed in percentage (%). (Andersson, L. et al. , 2012, p 350)

A relay operates when the affecting quantity equals the *function value* and returns when the affecting quantity equals the *return value.* The function value does not always correspond to the value set on the relay because of inaccuracy in relay scaling and in instrument transformers. (Andersson, L. et al. , 2012, p 350)

Protective relays can be instantaneous, working without time-delay, or time delayed, working with a certain time delay. The operating time for instantaneous protections is within the range of 2-40 msec. Time-delayed relays can have a constant time delay independent of the function value or they can work according to an inverted time, in other words a varying time delay dependent on the magnitude of the input quantity. Several measuring relays can be included in one relay protection. The relay will operate when the affecting quantity undercuts the input value. This is called a minimum relay. The opposite type of relay, maximal relay, operate when the affecting quantity exceeds the function value. (Gill, P. , 1998, p 324)

- Measuring relays: Relay unit that predetermined operates with a certain accuracy depending on the value of the affecting quantity.
- Minimum relays: A measuring relay unit that operates when the affecting quantity undercuts the function value.
- Maximum relays: A measuring relay unit that operates when the affecting quantity exceeds the function value.
- Directional relay: Relay unit that operates depending on the angle (φ) between current and voltage, in other words the direction of the active power (P) or reactive power (Q), shown in figure 4. (Andersson, L. et al. , 2012, p 350)

$$P = U * I * \cos\varphi \tag{1}$$

$$Q = U * I * \sin\varphi \tag{2}$$

$$S = \left| \sqrt{P^2 + Q^2} \right| \tag{3}$$

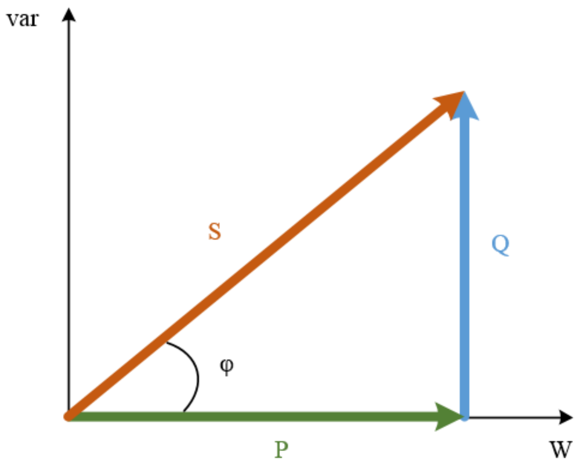


Figure 4: Diagram of angle φ between active power and reactive power.

Based on the relay characteristics and requirements the classification of the relay application practices will be made, e.g. differential relaying and directional relays. (Andersson, L. et al. , 2012, p 350)

3.3 Relay application

3.3.1 Overcurrent relays

It is necessary to protect a circuit by tripping the circuit breaker when there is excessive current flowing in the circuit. When the current exceeds the rated current of the system, it is called an overcurrent. Overcurrents can be generated by overload or short-circuit faults. Overcurrents caused by overload can usually be in the same range as the rated currents for the system while short-circuit faults can generate overcurrents multiple times higher than the rated current. Short circuits can be detected by using overcurrent relays. Overcurrent protection is normally provided by either instantaneous relays or time-delayed relays. Although instantaneous relays operate fast they have a slight, almost insignificant delay. As mentioned in chapter 3.2.1, the instantaneous relay operates within 2-40 msec. Time-delayed relays, on the other hand, have an intentional built-in time delay to provide collaboration with other overcurrent relays for selectivity. The relay time characteristics vary depending on the rate at which the relay's time of operation decreases at same time as the current increases. According to IEC, there are three different time inverse characteristics that can be implemented for time-delayed relays.

IEC Normal Inverse:

$$t = K * \frac{0.14}{\left(\frac{I}{I_S}\right)^{0,02} - 1} \tag{4}$$

IEC Very Inverse:

$$t = K * \frac{13.5}{\frac{I}{I_S} - 1} \tag{5}$$

IEC Extremely Inverse:

$$t = K * \frac{80}{\left(\frac{I}{I_S}\right)^{2} - 1} \tag{6}$$

(Andersson, L. et al. , 2012, pp 352-353)

If we suppose that we have the starting current, I_S, at 1 A and a K factor at 1 we will get the following tripping times for two different fault currents, I. In this case the Extremely

Inverse curves will generate the steepest curve and the Normal Inverse curves will generate the flattest curve. In table 1, values for tripping time (t) is calculated for 2 A and 8 A fault currents. This is also plotted in figure 5.

Table 1: Tripping time for different time inverse characteristics

Fault Current	2 A	8 A
Normal Inverse (s)	10.03	3.30
Very Inverse (s)	13.50	1.97
Extremely Inverse (s)	26.67	1.27

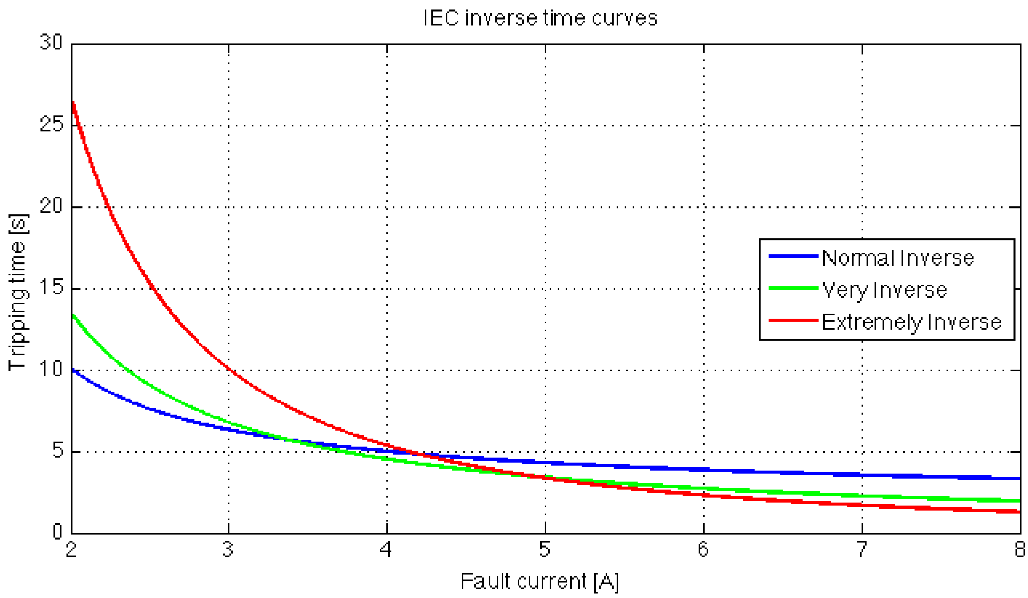


Figure 5: Time-current characteristics

As mentioned before, you can clearly see that the extremely inverse function will generate the steepest curve and the normal inverse function generates the flattest curve. (Andersson, L. et al. , 2012, pp 352-353)

3.3.2 Voltage relays

With the help of voltage regulators it is possible to maintain the voltage levels within certain limits. Overvoltage caused by misregulation can be detected by voltage surge protections. Generators always have this kind of protection. When a short circuit occurs in a power system it will cause a decrease in voltage. Due to risk of pole slip, bigger motors may be equipped with undervoltage protection. Undervoltage protection can be given an inverted time characteristic which will be adapted for the motor so it can stay in sync in case of a decrease of voltage. (Andersson, L. et al. , 2012, p 354; Gill, P., 1998, pp 327-328)

3.3.3 Distance relaying

The main application principle for distance relays is transmission lines. The distance relay measures the ratio between the current and voltage in the power system, in other words measuring the impedance to locate short-circuits. (Gill, P. , 1998, p 328)

$$Z = \frac{U}{I} \tag{7}$$

The distance relay operates whenever the impedance value decreases under the predetermined value during an abnormal situation. The impedance is a function of the line length. When a short circuit occurs within the given length of the transmission line that the relay has as an assigned protection zone, the distance relay will operate. Distance relays are built in three different ways: (1) impedance, (2) admittance (MHO) and (3) reactance. (Gill, P. , 1998, p 328)

The operation principle of the distance relay is basically a direct application of Ohm's law. Z_D can be called operation impedance and is the ratio between the normal operation voltage and load current. When a fault occurs, the measured impedance will change from operation impedance to fault impedance Z_M. The fault impedance consists of the impedance of the transmission line between the protection relay and the location of the fault, Z_F, and also the resistance at the fault location, R_F. (Andersson, L. et al. , 2012, p 355)

$$Z_M = Z_F + R_F \tag{8}$$

The characteristics of a distance relay are often either circular or polygonal or a combination of these two characteristics. The characteristics are a combination of four measuring units. As illustrated in figure 6, the units consist of two resistive units on the left and right side, a reactance unit at the top and a directional element at the bottom. This is applicable for distance relaying, using impedance as measuring unit, and will result in tripping of the protection relay when the impedance is inside these characteristics. An example of this is shown in figure 7. Protective relays measuring impedance must be connected both to voltage and current. (Andersson, L. et al. , 2012, p 355)

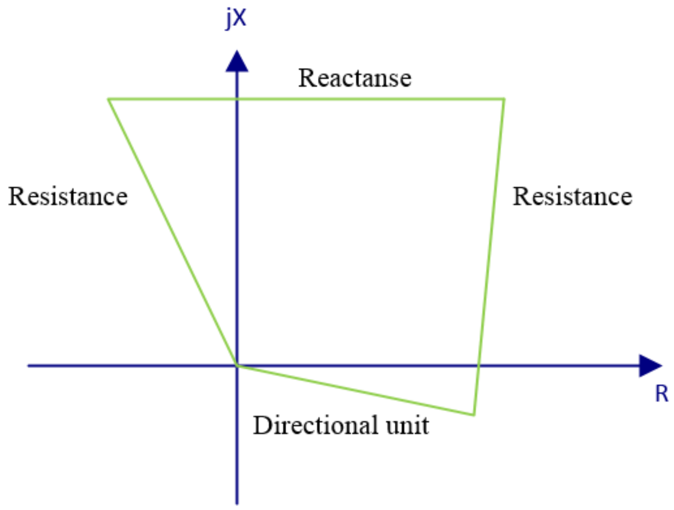


Figure 6: Polygonal characteristics. (Andersson, L. et al. , 2012, p 355)

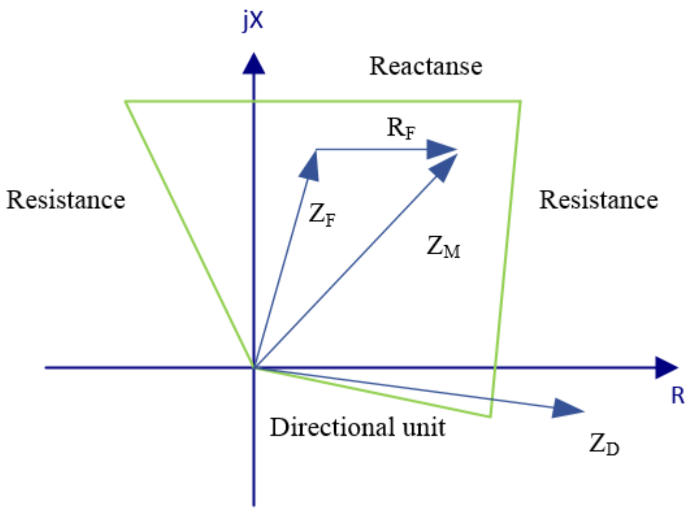


Figure 7: Impedance measuring with polygonal characteristics. (Andersson, L. et al. , 2012, p 355)

3.3.4 Differential relaying

According to Kirchhoff's circuit law, the current entering a junction is equal to the current leaving the junction, or that the algebraic sum of currents in a network of conductors meeting at a point is zero. This is the way of working of differential relays. Figure 8 illustrates the connection to a protected object, which in this case is generator windings. At normal operation the current fed, I_1, will be equal to the output current I_2. This means that the secondaries of the current transformers are identical: $i_1 = i_2$. No current will flow through the differential relay at this point since Kirchhoff's law states that $i_d = i_1 - i_2$. If a fault occurs in the protected object, the I_1 will differ from I_2 and the fault current $I_F = I_1 + I_2$ will be generated. This will also have an impact on the direction of i_2, which will start to flow in the opposite direction compared with in normal operation. The differential current will be $i_d = i_1 + i_2$. Differential relays can also be used for measuring the zero-sequence currents and, in cases like this, the protective relay will be connected to sum-current transformers on both sides of the protected object. This is used for earth-current differential protection of generators and transformers. (Andersson, L. et al. , 2012, pp 360-361)

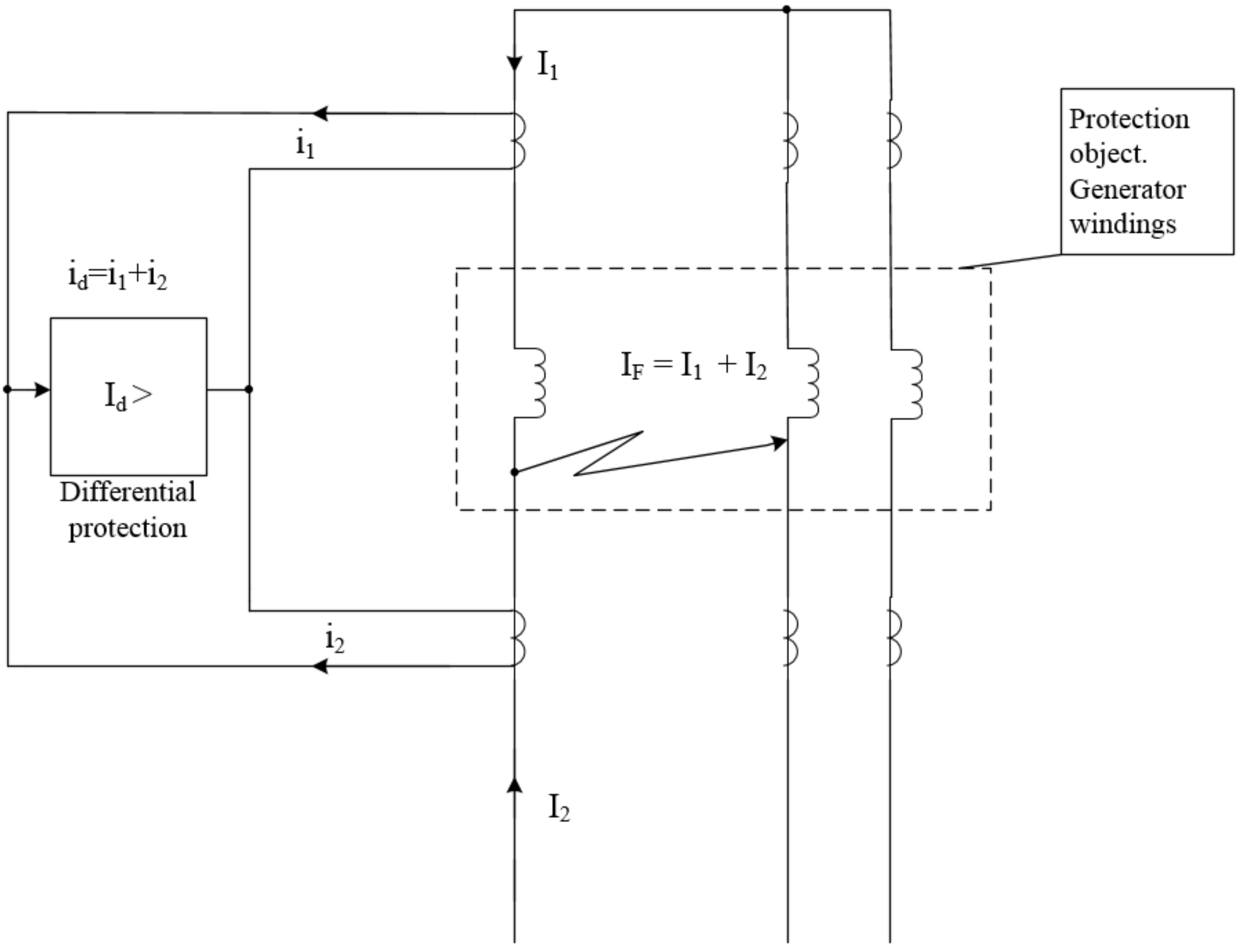


Figure 8: Differential protection during a fault. (Andersson, L. et al. , 2012, p 360)

3.3.5 Power measuring protection relays

Power measuring relays that are included in the protective relay franchise mainly have two different functions:

1. Relays that measure the amplitude and direction of the electrical power.
2. Relays that solely measure the direction of the electrical power.

Relays that measure both amplitude and direction of the electrical power commonly respond to reverse power flow, loss of power protection, power surge protection and loss of excitation. The second type of relays, also called *directional relays*, is included in overcurrent protections and earth-fault protections. Directional relays are set to trip the circuit breaker for currents or power flowing in one direction. The protective relay can pick out differences in phase angle between current and reference voltage. To be able to provide the circuit voltage for polarizing the relay, the directional winding is connected to the potential transformers and the current winding is connected to current transformers. (Andersson, L. et al. , 2012, p 361)

3.3.6 Protection with symmetrical components

Symmetrical components emerge because of faults like:

- Three-phase short circuit, results in a *positive sequence.*
- Two-phase short circuit, results in a *positive sequence or negative sequence.*
- Two-phase earth fault, one-phase earth fault, results in *positive sequence, negative sequence* or *zero sequence.* (Blackburn, J.A, et al. , 2007, pp 76-77)

In a positive sequence set, the three-phase currents have the same magnitude and will have a 120° phase displacement. The current's symmetrical component sequence quantity in this case is line-to-neutral or line-to-ground. The power system phase sequence is *a, b, c*. The same goes for the voltage set with the difference line-to-neutral voltage of the three phases. Also here, the symmetrical components for voltage are the same in magnitude with a phase displacement of 120º. The rotation direction for these phasors is counterclockwise and uses the same frequency as the power system. A unit phasor with an angle displacement of 120º is used to document the angle displacement. The unit phasor is defined as *a*;

$$
\begin{aligned}
a &= 1\angle 120^{\circ} = -0.5 + j0.866 \\
a^2 &= 1\angle 240^{\circ} = -0.5 + j0.866 \\
a^3 &= 1\angle 360^{\circ} = 1\angle 0^{\circ} = 1.0 + j0
\end{aligned} \tag{9}
$$

The positive sequence can be defined as:

$$
\begin{aligned}
I_{a1} &= I_1 \\
I_{b1} &= a^2 I_{a1} = a^2 I_1 = I_1\angle 240^{\circ} \\
I_{c1} &= a I_{a1} = a I_1 = I_1\angle 120^{\circ}
\end{aligned} \tag{10}
$$

The positive-sequence set for voltage can be defined as:

$$
\begin{aligned}
V_{a1} &= V_1 \\
V_{b1} &= a^2 V_1 = V_1\angle 240^{\circ} \\
V_{c1} &= a V_1 = V_1\angle 120^{\circ}
\end{aligned} \tag{11}
$$

(Blackburn, J.A, et al. , 2007, pp 76-77)

The sequence currents and voltages will exist as defined. Phasors I_{a1}, $I_{b1}$and I_{c1} will always exist in a set of three, they can never exist in pairs or alone. The positive sequence can be measured with the help from a positive-sequence filter. Positive-sequence voltages can be used as an undervoltage protection for motors and generators and also as a direction quantity for distance protection. Figure 9 shows the positive-sequence set for current phasors. (Blackburn, J.A, et al. , 2007, pp 76-77)

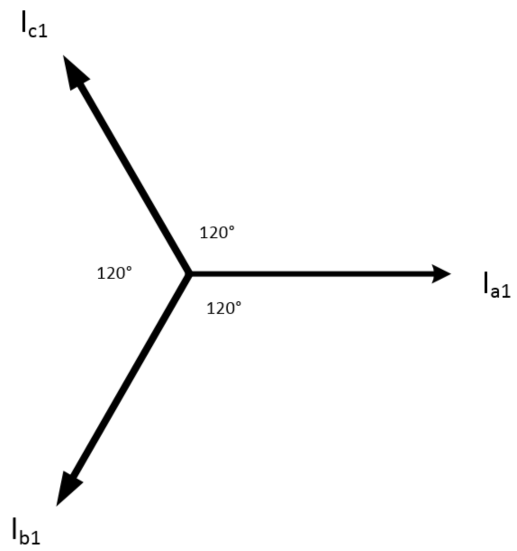


Figure 9: Positive-sequence set for current phasors with a counterclockwise rotation.

A negative-sequence set also contains three quantities with the same magnitude and with the phase displacement of 120º. Negative sequence has a reversed phase rotation, meaning that if the phase rotation for the positive sequence is *a, b, c*; then the negative sequence is *a, c, b*. For some power systems the phase rotation for positive sequence can be *a, c, b*. This results in an *a, b, c* phase rotation for negative sequence. Figure 10 illustrates the negative sequence. The negative-sequence set can be defined as:

$$\begin{aligned} I_{a2} &= I_2 \\ I_{b2} &= aI_{a2} = aI_2 = I_2\angle 120^\circ \\ I_{c2} &= a^2 I_{a2} = a^2 I_2 = I_2\angle 240^\circ \end{aligned} \tag{12}$$

The negative-sequence set for voltage can be defined as:

$$
\begin{aligned}
V_{a2} &= V_2 \\
V_{b2} &= aV_2 = V_2\angle 120^{\circ} \\
V_{c2} &= a^2V_2 = V_2\angle 240^{\circ}
\end{aligned}
\tag{13}
$$

(Blackburn, J.A, et al. , 2007, pp 76-77)

The same applies to negative-sequence set as for a positive-sequence set. I_{a2}, I_{b2} and I_{c2} always exist as a set of three, they cannot exist alone. Unsymmetrical short circuits will generate negative-sequence currents. By measuring the negative-sequence currents, two-phase short circuits can be detected. Negative-sequence protection is often applied to generators and its objective is to detect unsymmetrical loads which can harm the generator. (Blackburn, J.A, et al. , 2007, pp 77-78)

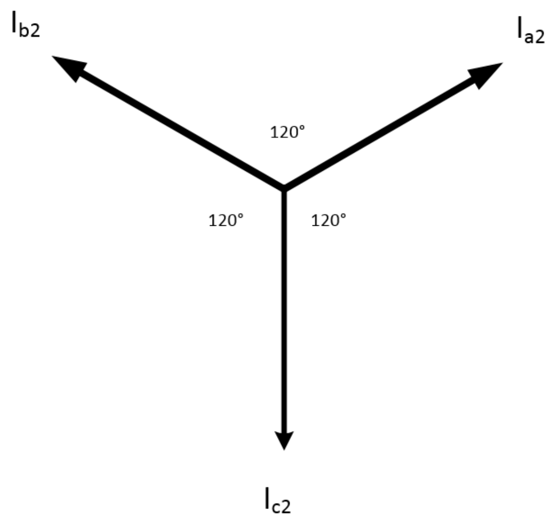


Figure 10: Negative-sequence set for current phasors with a counterclockwise rotation.

In the zero-sequence set, the phasors have the same magnitude and exist in phase, see figure 11. The zero-sequence set can be defined as:

$$
I_{a0} = I_{b0} = I_{c0} = I_0 \tag{14}
$$

The zero-sequence set for voltage can be defined as:

$$V_{a0} = V_{b0} = V_{c0} = V_0 \tag{15}$$

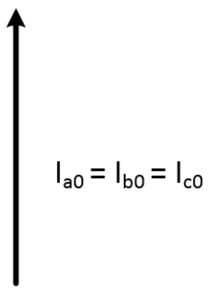


Figure 11: Zero-sequence set for current phasors with a counterclockwise rotation.

Zero sequence is generated by earth faults. Relays can detect an earth fault by measuring the zero-sequence currents and voltages. (Blackburn, J.A, et al. , 2007, p 78)

3.4 Relay history

3.4.1 Electromechanical relays

According to Engineer's Relay Handbook (1969), an electromechanical relay or electromagnetic relay is "a relay whose operation depends upon the electromagnetic effects of current flowing in an energizing winding". From the beginning, all the protective relays were electromechanical relays, and still in this day and age, electromechanical relays are in widespread use and continue to be manufactured. The functionality of electromechanical relays is simple: they use electromagnets that will create a mechanical motion in an armature that will allow contact transfer. These types of relays are used in many different areas of protection, such as fault detectors, overcurrent or over- or under-voltage protection. See figure 12. (Andersson, L. et al. , 2012, p 369)

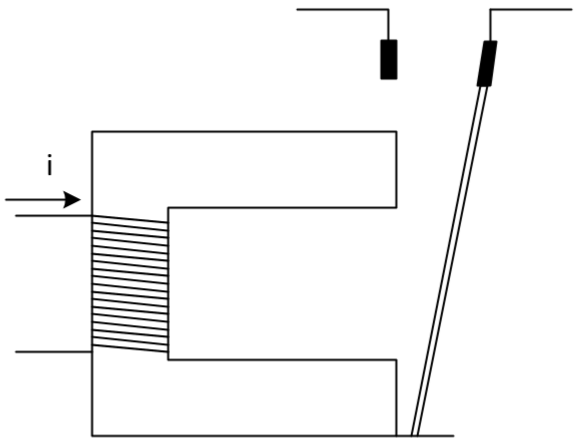


Figure 12: Electromechanical relay.

3.4.2 Static relays

Various functions of level detection, measurement of phase angle, timing functions etc. can be provided by basic relay circuits. A static relay's circuits, also called solid-state relays, use basic power system inputs to provide standard output functions. These basic power system inputs are: frequency, current, voltage, power and phase angle. Static relays are very fast in operation since they lack moving parts, as the relay consists of transistors and diodes. Static relays were under development already in the middle of the 1960's. (Gill, P. , 1998, p 325)

3.5 Microprocessor-based protective relays

Microprocessor-based relays and static relays share the same principle building foundation. Figure 13 illustrates typical logical units of a microprocessor-based relay. Currents and voltages are connected from current and voltage transformers to the IED's input transformer that reduces the power system current and voltage quantities to low voltages (1). Voltages and currents are filtered through a filtering circuit, which in some cases can be a simple RC-circuit or some kind of an active filter that will remove high-frequency noise (2). Analog signals will be held in the sample-hold amplifier (3), in time intervals which are determined by the sampling clock to maintain the phase information. The multiplexer selects one sample-hold signal at a time for further conversion to digital format and scaling. Next is the programmable gain amplifier, (5), used for current signals that possess a wide dynamic range. In the analog-to-digital converter (6), the analog signals will be converted to digital signals for further processing in a microprocessor (7) with numerical algorithms. Required protection characteristics are provided by suitable software implemented in the microprocessor. Signals for closing, alarms, tripping and so on are amplified to operate auxiliary units. (Blackburn, J.A, et al. , 2007, pp 189-190)

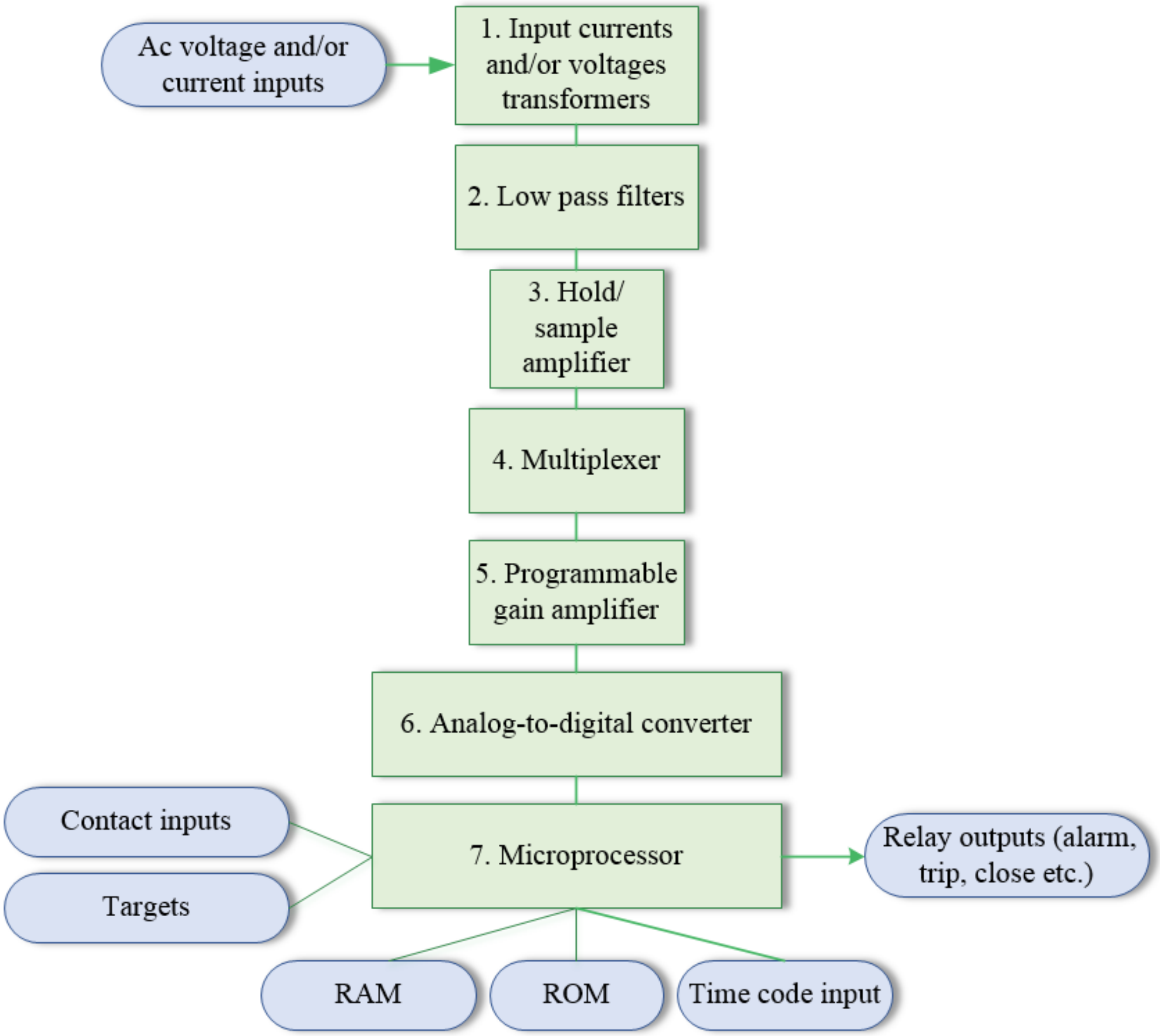
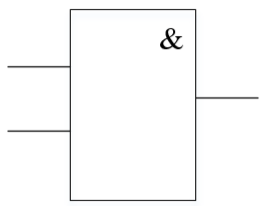


Figure 13: Building principles of a microprocessor-based relay. (Blackburn, J.A, et al. , 2007, p 190)

In most microprocessor-based relays there is a great number of different measuring functions which later on have to be combined internally and with external requirements, *Binary In*. This is done in the logical part of the relay, which consists of a microprocessor. The signals are combined by OR- or AND- gates and time functions which will finally send a start or trip signal, indications and other signals, which is mapped through *Binary Out*. The programming of a numerical relay is done by Boolean algebra and mathematical operations. Logical gates and truth tables are illustrated in figure 14, figure 15 and figure 16. In ABB's protection relays can the structuring of the IED, such as setting parameters and connecting signals to hardware outputs, be done with the aid of a computer with PCM600 software installed. It can also be done directly on the IED through the local human-machine interface (LHMI). REG670's local HMI is shown in figure 17. The local HMI is divided into zones with different functionality. Alarm indication LEDs, which consist of 15 LEDs (6 red and 9 yellow) with user printable label. All LEDs are configurable from PCM600.

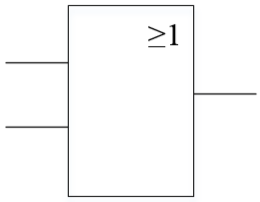
- Liquid crystal display (LCD).
- Isolated RJ45 communication port.
- Keypad with push buttons for control and navigation purposes, switch for selection between local and remote control and reset.
- Status indication LEDs. (ABB OY, 2014)

REG670 has a power supply module that requires DC-voltage from a low-voltage system. Numerical relays have the ability to store indications and current and voltage values with the help of a memory function. (Andersson, L. et al. , 2012, pp 371-372)



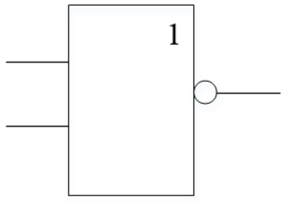
INPUT		OUTPUT
A	B	A AND B
0	0	0
0	1	0
1	0	0
1	1	1

Figure 14: AND gate with truth table, according to IEC standards.(Almgren, Å. et al. , 1997, p 416)



INPUT		OUTPUT
A	B	A OR B
0	0	0
0	1	1
1	0	1
1	1	1

Figure 15: OR gate with truth table, according to IEC standards. (Almgren, Å. et al. , 1997, p 416)



INPUT	OUTPUT
A	NOT A
0	1
1	0

Figure 16: NOT gate with truth table, according to IEC standards. (Almgren, Å. et al. , 1997, p 416)

3.5.1 Input and output modules

Standard values for input-transformers follow the current- or voltage transformer's secondary values. For current, the value is I_r= 1 A or 5 A. For voltage, the value is $U_r = \frac{110}{\sqrt{3}}$. Lower rated currents can occur for sensitive earth-fault protections. The following can be given as typical maximum values, $4 * I_r$continuous and $100 * I_r$ under one sec. And for voltages, $1,5 * U_r$ continuous and $2,5 * U_r$under one sec. (Andersson, L. et al. , 2012, p 372)

3.5.2 Analog-to-digital converter

An analog signal can be converted to a digital value with the help of an analog-to-digital converter. In microprocessor-based protective relay applications, physical quantities, cur-

Figure 17: ABB REG670 protection relay. (ABB OY)

rents and voltages are converted to a digital number that represents the quantity's amplitude when a fault occurs. A clean 50 Hz signal can be sampled and illustrated with only four sample points per period. But if the same period is measured after a fault, the current signal will contain transients and harmonics. For currents and voltages, harmonics have a different frequency compared to the fundamental frequency. Transient is a short burst of energy in a system. Transients occur when a sudden change takes place in the system. Some of these can be filtered analogically but that will cause a slight time delay. It is desirable to measure harmonics in several protection functions. (Andersson, L. et al. , 2012, pp 372-373)

Instantaneous relays, like distance relays and differential relays, use 20-40 sampled points per period to create a more exact sample. It is commonly said that the measurement of the bandwidth should be 1/3 of the sampling frequency. If 20 sampling points are used per period, a sampling frequency of 1 kHz will be obtained. This will result in a bandwidth of approximately 300 Hz. This is normally enough for most relay applications. (Andersson, L. et al. , 2012, p 373)

Analog-to-digital (A/D) conversion means that an analog signal is converted to a digital number, a binary number, that represents the amplitude of the analog signal, for example, if an analog signal is converted to a digital value consisting of four bits where every bit can be a “0” or a “1”. Every binary number has a different value depending on its position in the number. In table 2 the values of a binary number are represented, e.g. a binary number “1111” has the value 15 (8+4+2+1). This means that a number from 0-15 or 16 numbers can be represented with a four-bit binary number. Number 8 can be represented with the binary number “1000” and so on.

Table 2: Values of a binary number(Mäntylä, R. , 2012, p 18)

	Position 3	Position 2	Position 1	Position 0
Value	8	4	2	1
	2^3	2^2	2^1	2^0

Suppose that a current from 0.01-100 times the rated current needs to be measured. To be able to do this with A/D conversion and to have an acceptable accuracy a resolution of several bits is needed to provide the dynamic range $\frac{100}{0{,}01} = 10000$. It is known that a 14 bits binary number gives a value of 16383. The maximal value of the current is 1.73 times the RMS value, its polarity can change and additionally it can contain DC-components, which is why more bits are needed to get a more trustworthy value. If 16 bits are used, and one bit is reserved for “+” or “-”, it will result in a value of 32768. This ought to be enough for most relay applications. (Andersson, L. et al. , 2012, p 372; Mäntylä, R., 2012, p 18)

3.5.3 Event report

Microprocessor-based relays can record disturbances and events. Through event reports it is possible to study the nature of power system disturbances and the related actions taken by the relay units and interrupting devices. Event reports are basically a summary of what the relay saw and how it responded during a fault. Information being recorded is: programmable logic, the status of input and output contacts, sampled analog voltages and currents, the currently active related relay settings. Event reports are formatted as ASCII text files with the data represented in columns. (Blackburn, J.A, et al. , 2007, p 566)

3.5.4 IEC 61850

IEC 61850 is a standard that defines rules for how data should be constructed and organized, allowing IEDs from different manufacturers to understand and communicate with each other. The standard is presented by the International Electrotechnical Commission. Implementation of the IEC 61850 standard reduces the effort required to configure the substation automation system. IEC 61850 consists of several existing standards. A communication protocol can be defined as “a set of rules that must be obeyed for orderly communication between two or more parties.” (Söderbacka, C. , 2013, pp 13-14)

4 Synchronous machine

A synchronous machine is mostly used as a generator in a power plant, driven by a so-called prime mover (diesel engine, steam turbine, hydro power etc.). The two most important parts of the device are the rotor and the stator. The design and functionality are briefly discussed in this chapter.

4.1 Stator design

The stator is built as a cylinder composed of ferromagnetic material which is laminated. Around the inner hole of the cylinder, slots are placed at equal distance from each other, running parallel with the machine axis. Insulated coils will be placed in the slots inside the cylinder and connected to each other, forming windings. The windings can be connected as a three-phase delta or wye configuration. (Alfredsson, A. et al. , 2002, pp 117-119)

4.2 Rotor design

A rotor also has a cylindrical shape and is composed of laminated ferromagnetic material. There are two types of rotor designs, salient rotor design and nonsalient rotor design. If a rotor has a salient design, it means that the poles in the rotor stick out from the structure. By either permanent magnets or by current-carrying windings it is possible to create the rotor magnetic field. Each pole in the salient rotor is surrounded by an insulated winding, containing DC-current, which enables direct control of the strength of the magnetic field. The number of poles is always an even number and the poles are of symmetrical design. In the nonsalient design, the poles do not stick out from the rotor structure, making a consistent air gap. See figure 18. The rotor's magnetic field is created by either permanent magnets or by current-carrying windings. A synchronous machine with a salient rotor is designed to serve as a low-speed generator and a synchronous machine with nonsalient rotor is designed to serve as a high-speed generator. (Gross, C.A. , 2007, pp 236-237)

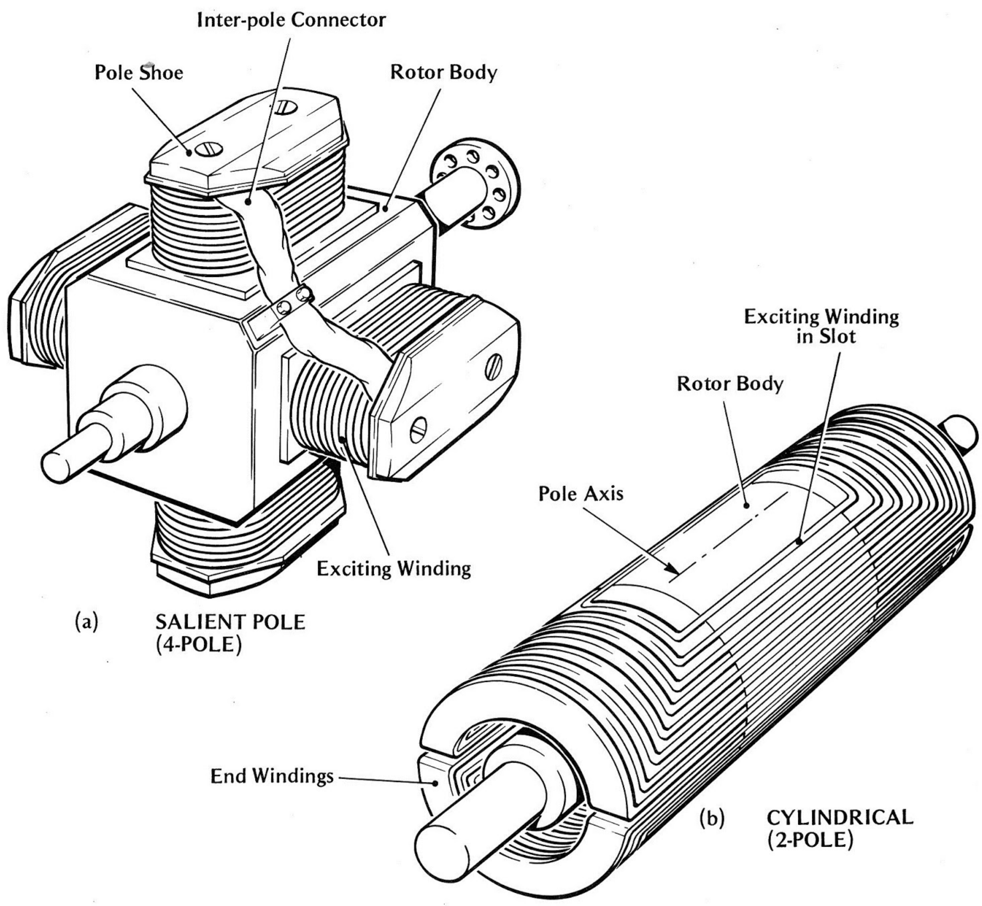


Figure 18: Different rotor designs. (Generator rotor design)

4.3 Functionality

The device connected to the generator's rotating shaft (rotor) is called a prime mover. This prime mover can be a hydraulic turbine, steam turbine or gas turbine. The prime mover rotates the generator shaft in interaction with an excitation system that supplies field current to the rotating machine creating a rotating magnetic flux. The rotating speed will be decided by the connected network but the more torque applied the more electricity will be generated. (Gross, C.A. , 2007, p 269)

4.4 Generator protection

The main objective of the generator is to produce active power. But a generator cannot produce infinite active or reactive power, as this is limited by the generator's rated data. The frequency in the network is dependent on the fact that the balance between consumption and production is maintained. The produced active power can be regulated in power systems by automated frequency-regulating units. For every generator it is possible to draw the operating limits in which the generator should be operated. This is called a *capability curve*, see figure 21. Thermal limitations for stator and rotor windings and also limitations from a stability point of view are taken into account when creating a capability curve. Modern voltage regulators for bigger generators are equipped with limiters which prevent operation outside the allowed operation area. Stator current regulators and under excitation regulators are examples of a regulator. If a generator is operated outside the allowed operation area despite this supervision, it becomes the relay's responsibility to operate and to prevent damage from occurring. Short circuits in a generator are unusual but can have devastating consequences for the generator. This makes it very important that the relay has a trustworthy and fast operation to prevent short circuits. (Andersson, L. et al. , 2012, pp 377-378)

4.4.1 Ground-fault protection

A ground fault in a generator can occur due to turn-to-turn faults which are developed by insulation failure. The grounding of a generator can be of three types:

1. Generator neutral grounded
   (a) High-resistance or resonant, in general 1-10 A primary
   (b) Low-resistance, resistor or reactor, normally 50-600 A primary
   (c) Solid for very small generators
2. Generator low-impedance grounded by the connected system
3. Generator and the connected system ungrounded. (Blackburn, J.A, et al. , 2007, pp 248-249)

Category 1a is used for large utility generators and critical process generators. Category 1b is usually used for small and medium generators. The main goal of these types of grounding is to limit ground-fault current by resistance or reactance in the neutrals of the ground connections so that the damage to the generator is reduced. Solid grounding, category 1c, indicates that there can be no impedance between system ground and neutral. (Blackburn, J.A, et al. , 2007, pp 248-249)

The reason for grounding a generator through for example resistance or impedance, is to limit the ground-fault current. Distribution transformers are used to achieve resistance grounding for generators. The grounding system in figure 19 uses an overvoltage relay for supervision. One can limit the fault currents generated by phase-to-ground faults furthermore by adding impedance (usually resistance). In this case the neutral has to be grounded. Ground-fault currents can be limited to generator-rated current if the neutral impedance is high enough. If the impedance is too high it may affect the sensitivity of the phase relay since the fault current decreases to a low value. (Anderson, P.M. , 1999, p 718)

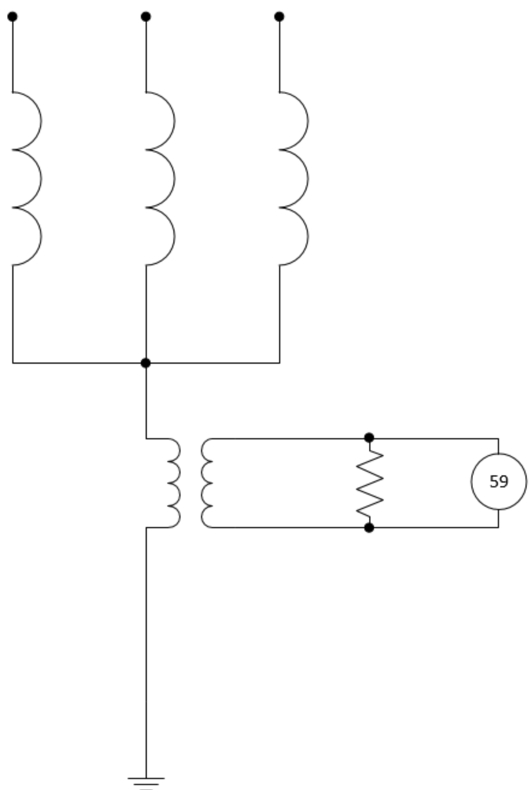


Figure 19: Generator neutral grounding through distribution transformer. ANSI number 59 refers to an overvoltage relay used for supervision. (Anderson, P.M. , 1999, p 718)

For a one-phase ground fault, the neutral point will get phase voltage and the other healthy phases will obtain main-voltag -to-neutral. The increase of voltage in the healthy phases can generate another ground fault with very high fault-currents. In case of a ground fault in the generator it is important that the protective relay operates fast and disconnects the unit. (Andersson, L. et al. , 2012, pp 380-381)

4.4.2 Unbalanced current protection

Unbalanced loading of a synchronous generator causes a negative-sequence current to flow in the stator windings. This affects the rotor since these currents are reflected into the rotor iron, obtaining double-frequency currents. This reflection causes a heating of the rotor. The reason for this type of faults can be:

1. One open pole of a circuit breaker
2. An unbalanced fault near the generator that is correctly cleared.
3. A stator-winding fault
4. One open phase of a line. (Anderson, P.M. , 1999, p 726)

One of the reasons listed is an internal fault. Balanced faults near a synchronous generator cause less damage than an unbalanced fault. If the unbalanced fault isn't cleared fast, the overheating may cause melting of the rotor metal. (Anderson, P.M. , 1999, p 726)

The magnitude of the negative-sequence current that a generator can withstand during a certain time can be calculated with equation (16) where I_{2k} is the continuous unsymmetrical current the generator can withstand and I_2 is the negative-sequence current. K is a characteristic constant for the generator. (Andersson, L. et al. , 2012, p 381)

$$I_2^2 = \frac{K}{t} * I_{2k}^2 \tag{16}$$

4.4.3 Generator motoring protection

This type of protection is applied to power systems and not to the generator. Motoring is not harmful for the generator. If an engine fails, there are two very important reasons to have a motoring protection:

1. One failed engine is a big loss of load. After an engine has failed, the generator will start to consume approximately 15% of its rated power from the power system. This can be more than the system can supply and may result in an oscillating power system.

2. A generator driven by the power system can cause a fire or explosion due to diesel fuel left in the engine. (Anderson, P.M. , 1999, p 738)

Generator motoring protection measures the active power fed to the generator and is set to approximately 1-4% of the rated current. This results in a very high demand on the accuracy of the angle measurement since a low value for active power can exist at the same time as a high value for reactive power. (Andersson, L. et al. , 2012, p 382)

4.4.4 Loss of excitation protection

During normal operation of a synchronous generator, the rotor will move at synchronous speed and the magnetic field created by rotor windings will rotate in synchronism with the magnetic field of the stator windings. In a synchronous generator, dc-current is supplied to the rotor for excitation. A loss of excitation will result in a rotor magnetic field moving away from the synchronism with the magnetic field of the stator. Even though the excitation is lost, the motor driving the generator will continue to deliver a given amount of power, meaning that the generator will start to accelerate and induce large slip frequency currents in the rotor to be able to maintain the power output as an induction generator. Due to loss of excitation, the generator will start to consume reactive power in a very large amount from the power system which will cause a voltage drop. This can have a very serious impact on the power system if the system isn't stable enough. The large increase of reactive power causes an increase of the stator currents, resulting in an overheating rotor. There are several other possible causes to which field excitation may be lost, e.g. accidental tripping of the field breaker, short circuit in the field winding, poor brush contact in the exciter, field circuit breaker latch failure or loss of ac-supply to the excitation system. (Anderson, P.M. , 1999, p 732)

Distance relays can be applied to protect a synchronous generator against loss of excitation. It is commonly desired to adjust the generator field so that a little lagging power is moved into the power system. Synchronous machine operation is illustrated in figure 20. The normal operation area is shown in the first quadrant. The current moves into the fourth quadrant if the excitation is lost. In this quadrant it is the power system that is the supplier of the reactive power and the stability of the synchronous generator is reduced in this area. (Blackburn, J.A, et al. , 2007, pp 259-260)

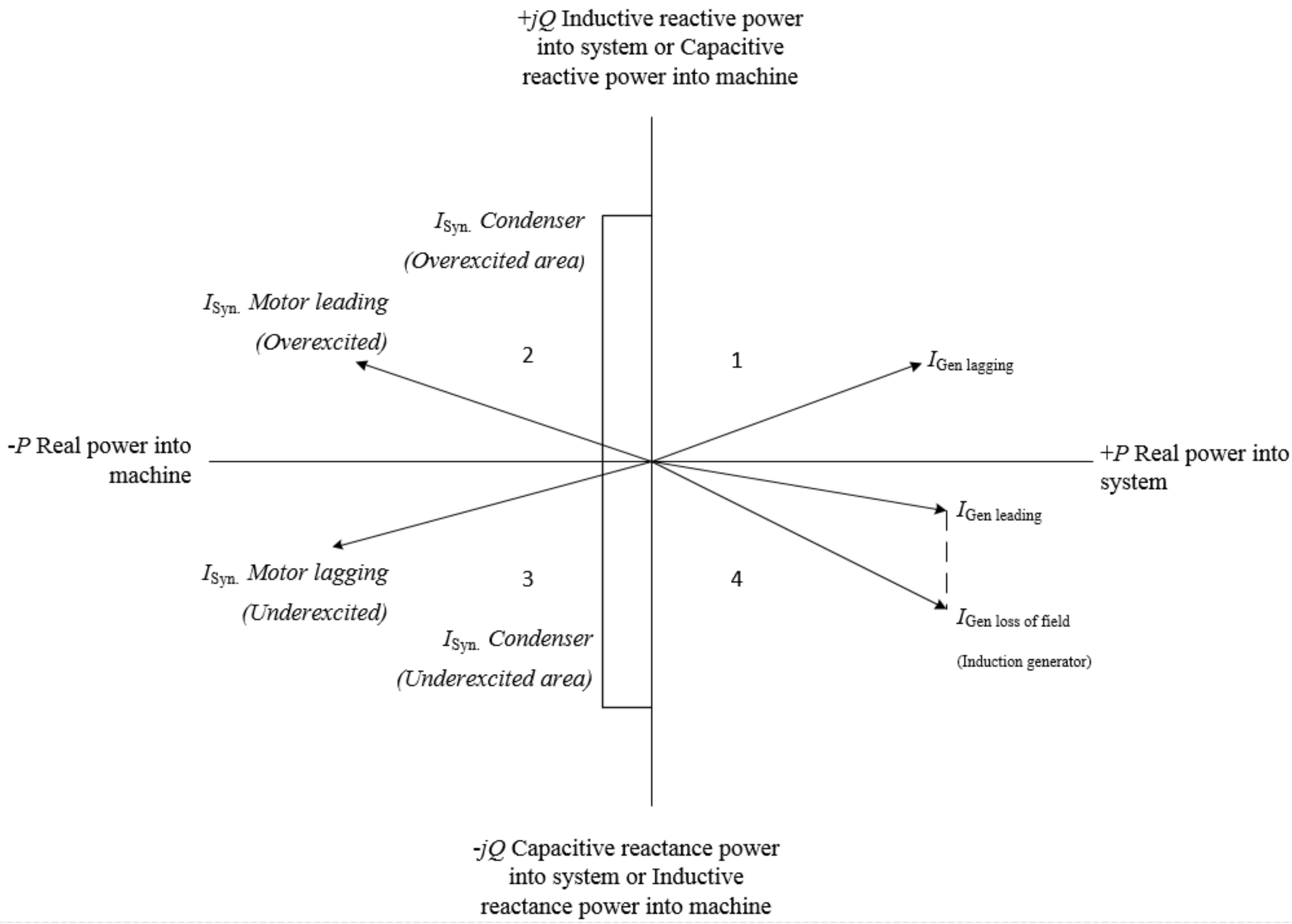


Figure 20: Power and related current diagram for a synchronous machine (Blackburn, J.A, et al. , 2007, p 259)

Generators have a capability curve where temperature limits are primary zones. See figure 21. In other words, these are the manufacturer's thermal limits for the generator. Three arcs define the limits for overheating that occurs during operation. Area limits for overheating apply to overheating in stator windings, stator iron and rotor windings. (Blackburn, J.A, et al. , 2007, p 260)

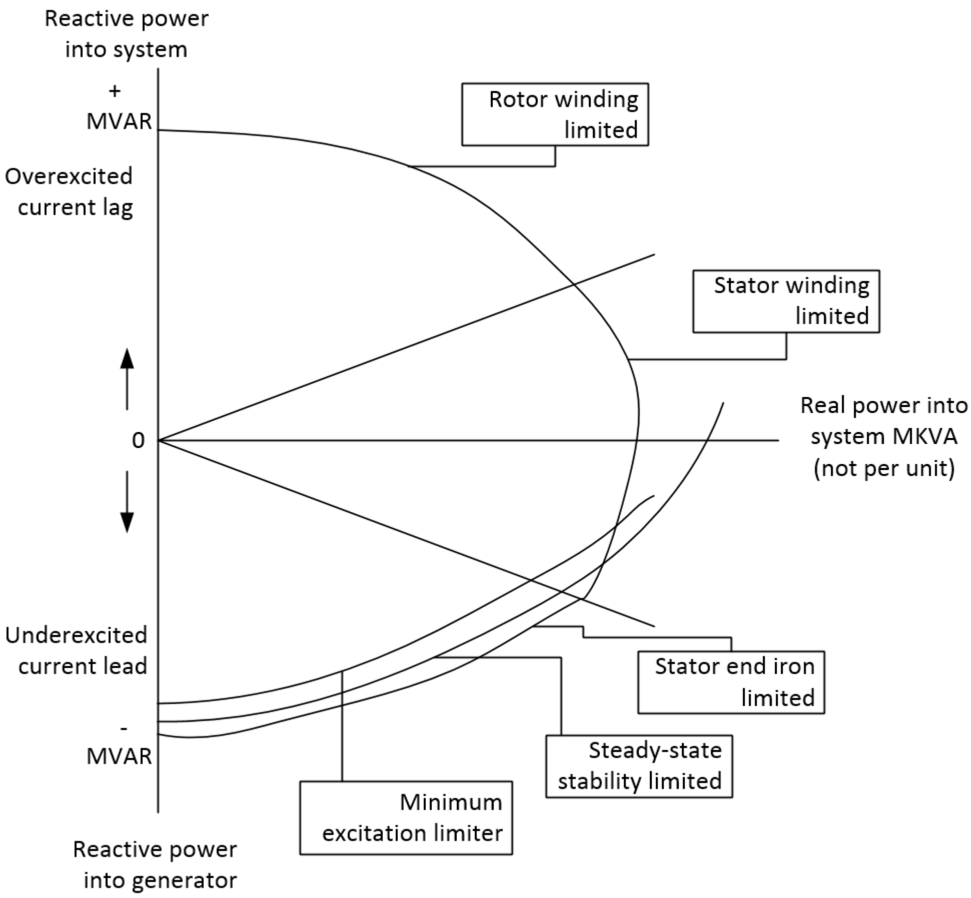


Figure 21: Capability curve for a generator (Blackburn, J.A, et al. , 2007, p 261)

4.4.5 Short-circuit protection

Phase faults in a generator may occur but are rare. Even though it is a rare fault, a generator still needs to be protected. Phase faults can develop in the winding end turns, where all three phases are close to each other. Phase faults also have the ability to evolve into ground faults if not detected in time. Differential relays are often used to protect generators from this type of fault. (Andersson, L. et al. , 2012, p 716)

Short-circuit protection operates for two and three phase short circuits as long as a generator is grounded over a resistor. Overcurrent protections can also be used to protect a generator from this type of faults and are set to a value of 150-250% of the rated current. The differential protection is set to 0.5-0.7 times a generator's rated impedance. In both cases a time delay is applied so that selectivity is available for other protections in the system. (Andersson, L. et al. , 2012, p 379)

5 Test equipment for relays

5.1 Maintenance planning and testing methods

In modern days, a power system has a very high technical-economical lifetime, in numbers: 30-40 years. This estimated age is affected by the manners in which a power system is operated and maintained. From an economical perspective the desire is to increase this estimated lifetime as much as possible without endangering the requirements on availability, safety and reliability. In the overall economical estimation one has to include the yearly maintenance cost and at the same time, calculate how modern technology can reduce the operation and maintenance costs and increase the income from a power system. (Almgren, Å. et al. , 1997, p 380)

The modern power system is driven more and more towards its technical limits and thereby it is run more and more efficiently. In those cases where the maintenance costs are driven downwards, one must have a defined maintenance plan for different equipment that can be found in a power system. This is also called "Asset and maintenance management". The type of maintenance practise that has been used has been a combination of periodical maintenance and corrective maintenance. Briefly, this meant that the equipment, e.g. a breaker or a reactor, was regularly decommissioned to be opened, inspected and to get parts replaced even if it wasn't always necessary. The second alternative was to wait for a fault to occur and at that point the equipment was decommissioned and repaired. The disadvantage with this type of maintenance plan was that no connection is made with the plant's actual condition and the need of maintenance, which leads to increased maintenance cost and less availability. (Almgren, Å. et al. , 1997, p 380)

The modern electrical devices have considerably lower maintenance requirements than older technology. Since modern technology is more complex it has brought about different maintenance planning aspects. There are three types of expressions that are frequently used:

- *Preventative maintenance* is a combination of preparatory measures that include inspection, supervision, testing and replacement of parts *before* an error has occurred. (Almgren, Å. et al. , 1997, p 380)
- *Condition-based maintenance* is a combination of preparatory measures to *determine the condition of the plant* and therefore the need of a thorough inspection and maintenance. This can include continuous condition supervision, action based analysis, e.g. how the plant reacts during a short circuit fault, historical data from a point when the plant has been under heavy load, operation test of different critical parameters and comparison with reference values. (Almgren, Å. et al. , 1997, p 380)
- *Reliability centered maintenance* is an analysis method that links the plant's reliability and availability with the maintenance requirements. This means that a a component or a device in the plant that will, in the state of a fault, generate extensive consequences to the whole system needs more extensive supervision, testing and maintenance than a component or a device that can malfunction without generating extensive consequences. RMC (reliability centered maintenance) therefore requires extensive statistics of deviant frequencies and consistency analysis for the different devices' functions. (Almgren, Å. et al. , 1997, p 380)

5.2 FREJA 300

Figure 22: FREJA 300 (MEGGER)

FREJA 300 is a testing device for relays and a simulation system from MEGGER. FREJA 300 can be controlled with or without a PC. In order to be able to use FREJA 300 with a PC, a specified software is required, Freja Win, from which all tests, simulations and analyses can be made. FREJA 300 is mainly intended for secondary testing of protective relays. FREJA 300 also contains three-phase voltage and current outputs intended for fault simulation. It is also possible to set an independent frequency for every generator output. (MEGGER, 2014)

Table 3: Generator data for FREJA 300.

Generator data	
Outputs	Range
Current 3-phase AC	3 x 15 A
Current 1-phase AC	1 x 45 A
Voltage 4-phase AC	4 x 150 V
Voltage 1-phase (L-L) AC	2 x 300 V

5.3 OMICRON

Figure 23: CMC 353 (OMICRON)

OMICRON also has devices that can be used for three-phase protection testing, simulating faults and analysis. OMICRON provides devices with different three-phase outputs e.g. CMC 310, CMC 353 and CMC 356. These devices can also be controlled by a PC-operated software, Test Universe. (OMICRON, 2014)

6 Methods

In the beginning of this thesis work, material and manuals were gathered for the PCM600 configuration program, the protective relay REG670, FREJA 300 and FREJA Win 5.3. The author installed the required softwares and started to collect information and learn how to use these software tools.

REG670 had already been included in a few power plant solutions from Wärtsilä before this thesis work had begun. This made it possible to get a configuration file from a relay in use. The author was able to get his hands on a REG670 relay from Wärtsilä's Power Plant department since one had recently been used for educational purposes. The author also attended two relay seminars held at ABB in Vaasa to furthermore develop an understanding of how ABB's configuration program and REG670 protective relay work.

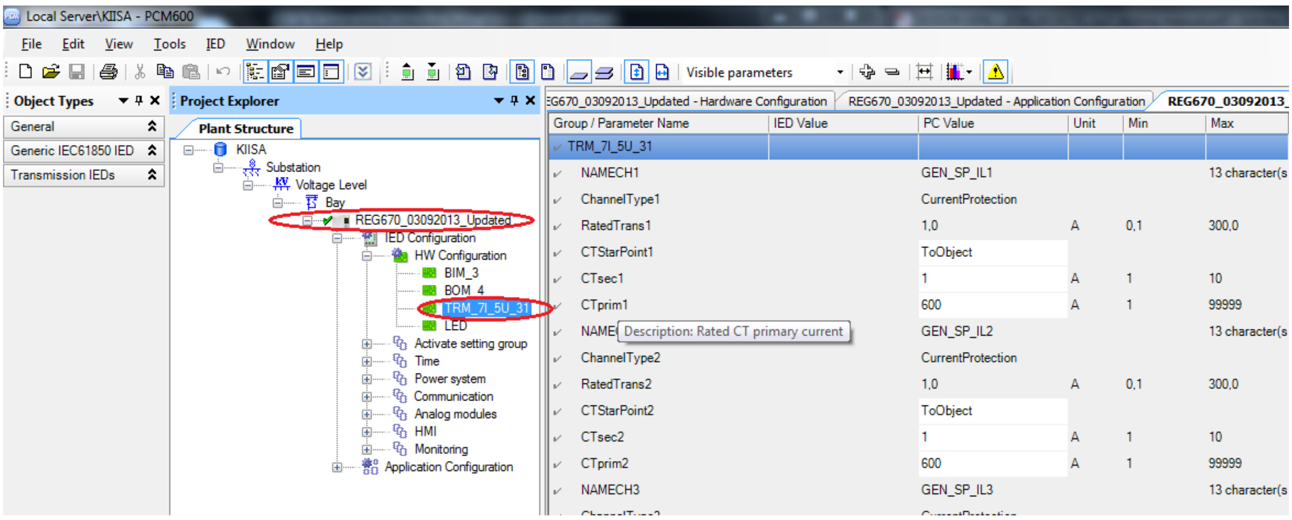


Figure 24: Screen shot from PCM600. Scaling settings in the relay for current and voltage transformers.

After that the REG670 had been energized and connected to a laptop, a configuration file was downloaded to the REG670. The set-up of the REG670's transformer module was verified from PCM600 and the scaling was verified at the same time, see figure 24. Three-phase voltage and current were connected from FREJA 300's voltage-and current-generating outputs to appropriate input channels on the REG670's transformer module. Secondary voltages and currents were now injected into the REG670 to verify the scaling of FREJA 300. The measured secondary values were displayed in the local HMI of the REG670. The REG670 also calculate the voltages and currents generated on the primary side of the transformers.

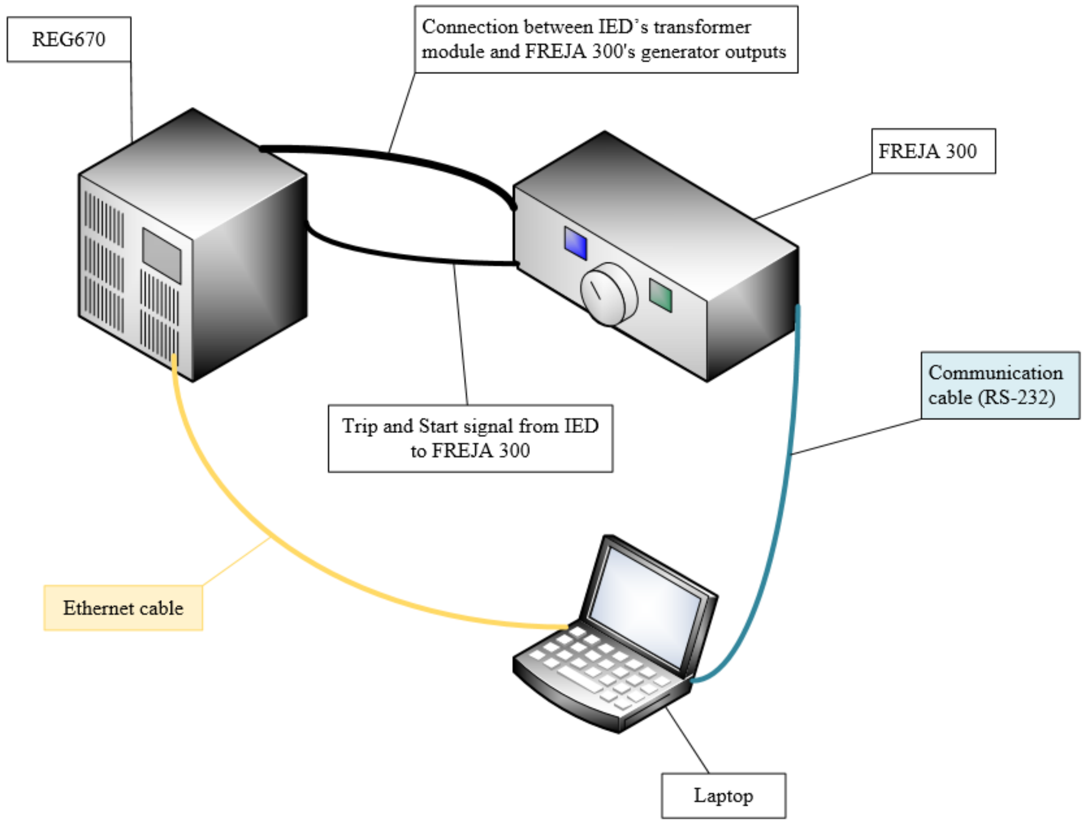


Figure 25: Overview of devices.

From REG670, "Start" and "Trip" signals were connected back to FREJA 300's binary inputs 1 and 2. Binary inputs are closing contacts in a "normally open" state. These contacts would close when either a "Start" or "Trip" signal was sent from REG670. The "goal" for a binary input on FREJA 300 could be set in FREJA Win 5.3 to be e.g. "not in use" or "close". A protection function's operation time is set in PCM600. The operation time of the relay is the time it takes for the relay to operate after the predefined limit value is exceeded. REG670 was put in *TestMode,* which blocks all protection functions in the relay. The user himself has to release the protection function to be tested. By doing this, one can ensure that no other protection functions interfere during the secondary testing procedure. *TestMode* is activated from the local HMI on the REG670. All protection functions were tested to get pick-up values and operation times. After each test was made, the test template was saved.

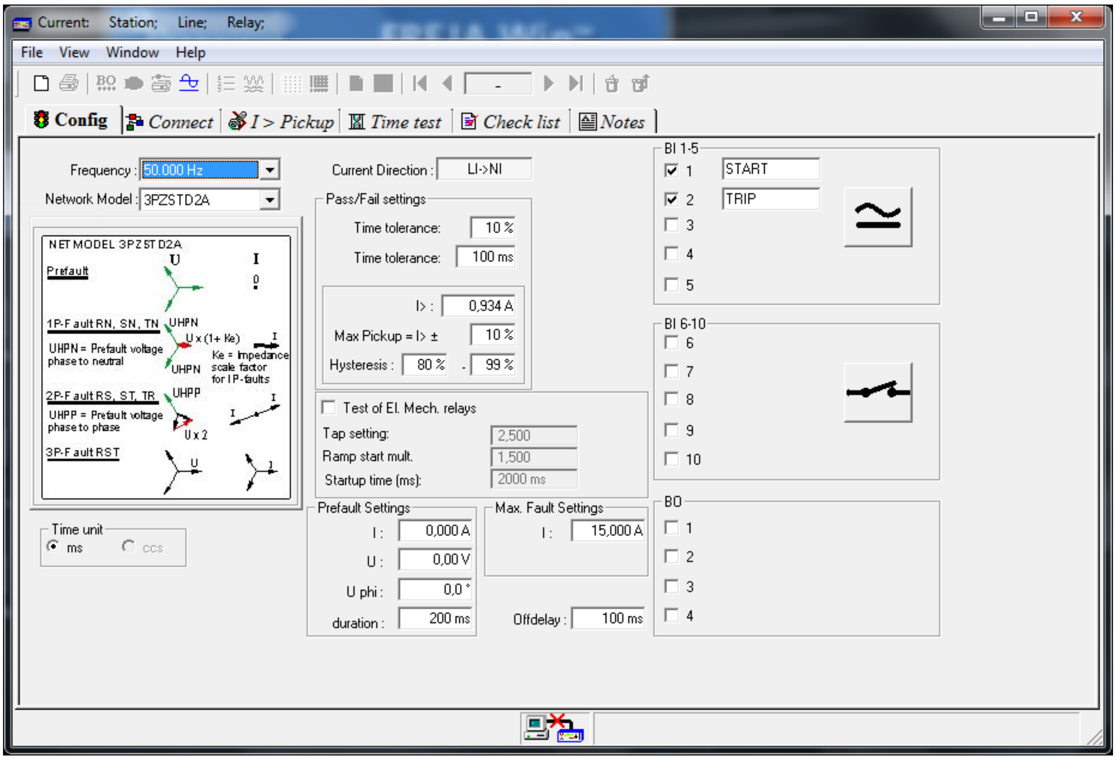


Figure 26: Screen shot from FREJA Win 5.3. Configurations for overcurrent test.

In figure 26, the configurations for an overcurrent $I >$ test in FREJA Win 5.3 are visible. The author had access to an Excel calculation sheet in which the amplitude of secondary voltages and currents to be injected was calculated, based on the protection settings in the relay. The Excel calculation sheet also calculated theoretical trip times. In the used configuration file, I_{Base} is set to 467 A, the current transformer rating, I_{CT} , is 600/1 A and the nominal secondary current would be:

$$
\begin{aligned}
I_N &= \frac{I_{Base}}{I_{CT}} \\
I_N &= \frac{467}{600} A \\
I_N &= 0.78\, p.u
\end{aligned}
\tag{17}
$$

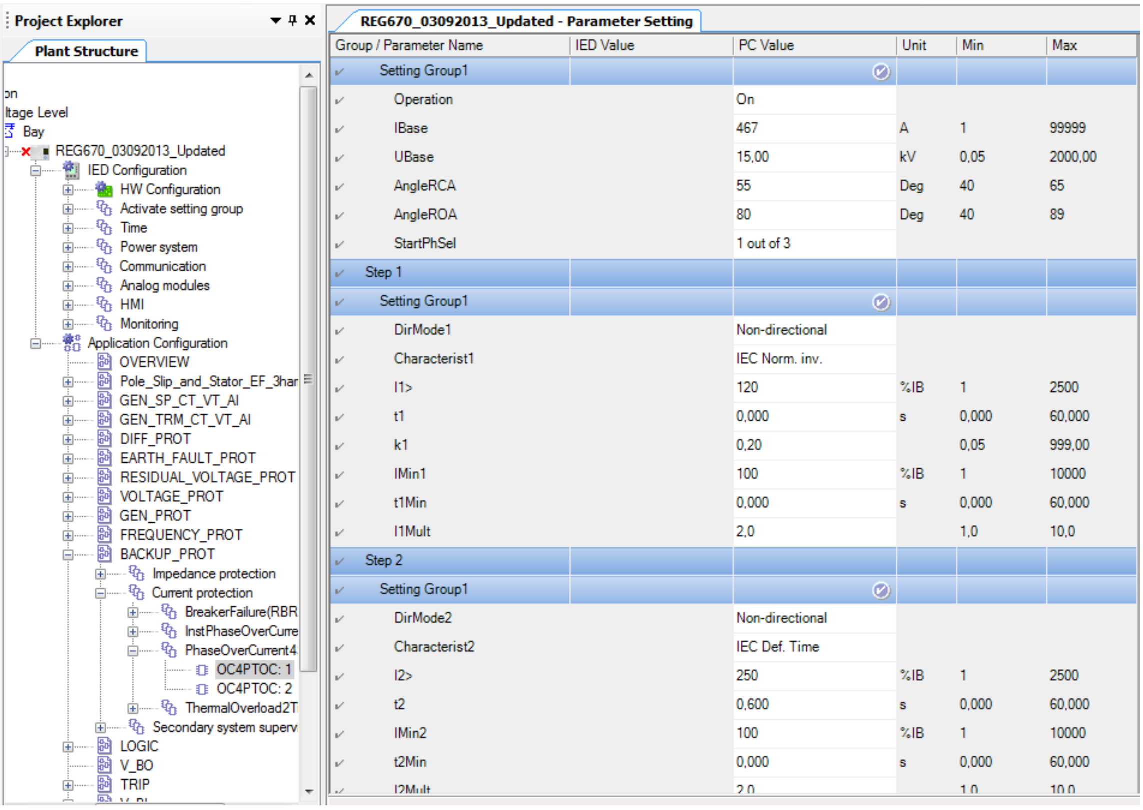


Figure 27: Screen shot from PCM600. Parameter settings for I> protection.

The operation value for the first step is 120% of I_{Base}, which also equals 120% of I_N for the secondary injection. The characteristics of the first step are IEC normal inverse and the second stage has IEC definite time characteristics. This means that the operation time of the relay will decrease when the injected fault current increases. See figure 28. The relay will have a constant operation time for currents exceeding 250% of I_N in this case. The operation time for the second stage is 0.6 sec.

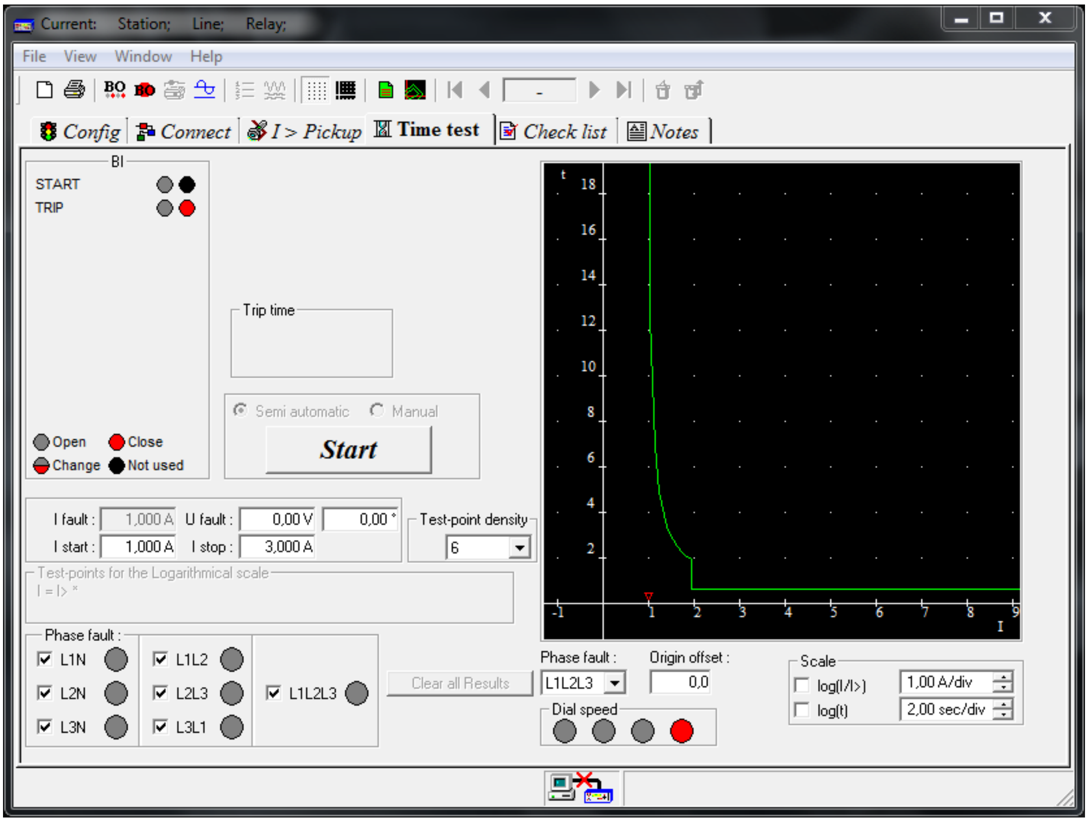


Figure 28: Screen shot from FREJA Win 5.3. Time test for overcurrent protection.

The author used the "Current" tool in FREJA Win 5.3 to test the following protection functions:

- Overcurrent $I>$, ANSI 51
- Unbalanced current $I_2>$, ANSI 46
- Thermal overload $T >$, ANSI 49
- Groundfault $I_0 >$ and I_{0Dir} ANSI 51N and ANSI 67N.

The "Current" instrument is designed for testing overcurrent protection functions. In the config menu one has to set up pass/fail settings and the calculated secondary fault current $I>$ tolerance for the pick-up. In the pick-up menu, "I start", "I stop", ramp speed (dI/dt) and the goal for each binary input in use had to be defined. The current will slowly increase until the pick-up value is activated (start signal is generated), then the current will decrease until the dropout value is activated (start signal degenerated). Hysteresis was calculated by the software. In the “Time test” menu, operation time was tested. Before the test began one had to select fault types to be tested and define start and stop value for the current. When the “Start” button is pressed, FREJA 300 starts to generate currents from the defined values. If a trip signal is received, a purple mark will appear in the reference graph. Operation time and current amplitude can be read for each mark.

Testing of the directional ground fault was also made in the “Current” tool since one had the possibility to inject voltage used for polarization. Groundfault $I_0 >$ and I_{0Dir} were both configured in the same protection block. It wasn’t enough to have the REG670 in *TestMode*. The author had to block stages 2 and 3 which were the non-directional ground-fault protection stages. According to the calculations, a 10V polarizing voltage had to be injected at the same time as the current was ramped up to a value above the theoretical operation value. Pick-up value and operation time were successfully generated.

The following tests were made in the “Voltage” tool in FREJA Win 5.3:

- Overvoltage $U>$, ANSI 59
- Undervoltage $U<$, ANSI 27
- Zero-sequence voltage $U_0 >$, ANSI 59N.

The voltage instrument is designed for testing over- and undervoltage protection functions. In the config menu one has to set up pass/fail settings, the calculated secondary fault voltage U> or U< and tolerance for the pick-up. In the pick-up menu, “U start”, “U stop”, ramp speed (dU/dt) and the goal for each binary input in use had to be defined. The voltage will slowly increase until the pick-up value value is activated (start signal generated), then the current will decrease until the dropout value value is activated (start signal degenerated). Hysteresis was calculated by the software. In the “Time test” menu operation time was tested. Before the test begun one had to select fault types to be tested and define a start and stop value for the voltage. When the “Start” button is pressed, FREJA 300 starts to generate voltages from the defined values. If a trip signal is received, a purple mark will appear in the reference graph. Operation time and voltage amplitude can be read from each mark.

Frequency-protection functions were tested with a dedicated frequency tool in FREJA Win 5.3. Pick-up test were made so that frequency was ramped from a pre-fault value up/down to a faulty value. FREJA 300 would automatically stop the test when a “Start” signal was received from the REG670. The pick-up value for the frequency-protection function was displayed in FREJA Win 5.3. See figure 29. After this, the author made an operation time test with a “Scan” function in FREJA Win 5.3. For this function one can set the start value and the stop value for frequency and nominal secondary voltages to be injected. FREJA Win 5.3 will ramp the frequency and measure the operation time for each frequency level tested. The reference graph in FREJA Win 5.3 would limit the duration time for each frequency level, marking the result of the value as an “X” if no trip signal was generated. Trip signals will be marked with a green dot in the reference graph. See figure 30.

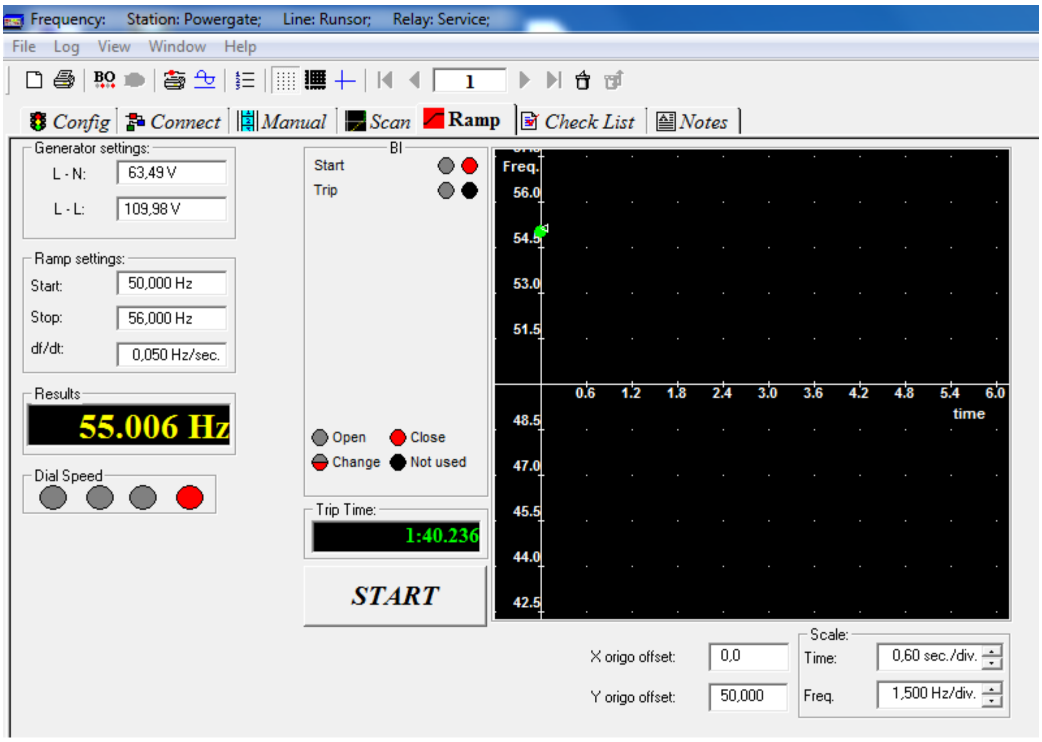


Figure 29: Screen shot from FREJA Win 5.3. Pick-up testing of a frequency protection function. The reference graph shows at which the protection function is activated. This is also visible in the “Results” box.

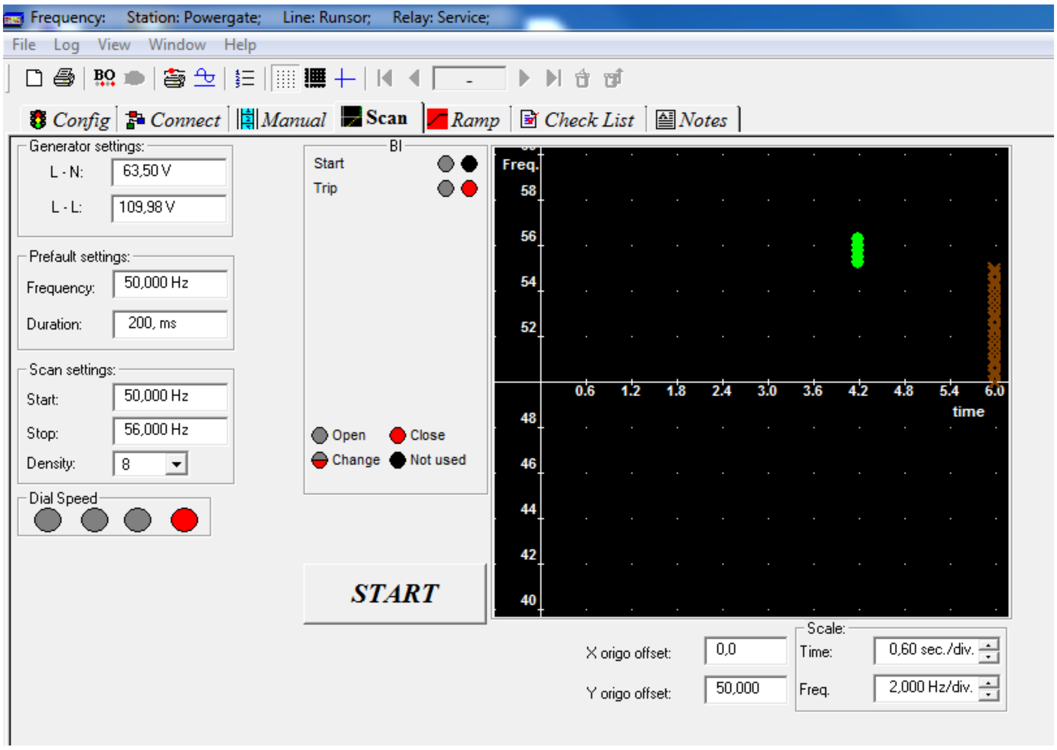


Figure 30: Screen shot from FREJA Win 5.3. Frequency tool. Time testing of a frequency protection function. For each “Trip” signal FREJA 300 receives, a mark will be generated in the reference graph, containing the amplitude of the frequency and the time it takes for the REG670 to operate. The brown “X” mark indicates that no trip signal has been received. The reference graph limits how long the test will run for each frequency value.

Reverse power and under-excitation protection functions can either be built on impedance functions or directional functions. For this project it was made with directional protection functions. Affecting quantities are apparent power and phase angle. For reverse power, the angle displacement between injected secondary voltage and current had to be 180°, meaning that the generator consumes active power from the power system instead of generating it, as stated in section 4.4.3. Under-excitation operates when the angle displacement is -90° between the injected secondary voltage and the current. Depending on which protection stage that was tested, the other stage had to be blocked. These protection functions had to be tested in the “General” tool in FREJA Win 5.3, in which one can change angles for each phase. But due to some software limitations, the test for one protection function had to be made three times in order to get the pick-up value, the operation value (at which value a trip signal was initiated) and the operation time. For the pick-up value and the operation value, the phase angles and voltages were kept constant when the current was ramped from zero. FREJA Win 5.3 automatically stopped the test when a “Start” or “Trip” signal was initiated.

Current values were displayed in FRJEA Win and these had to be used in a calculation sheet to calculate the value of apparent power. The operation time was later tested by simulating a faulty state. Phase angles, currents and voltages were set in FREJA Win 5.3 to simulate a situation where the generator consumes active power. FREJA Win 5.3 automatically stopped the test when the REG670 initiated a “Trip” signal and displayed the operation time.

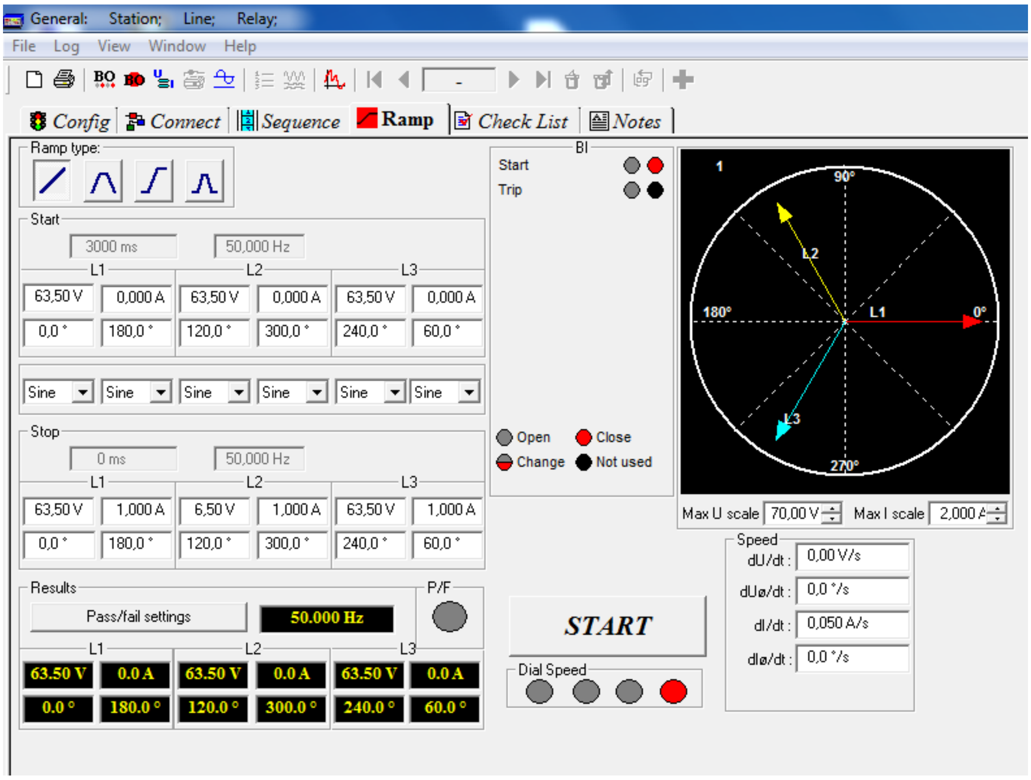


Figure 31: Screen shot from FREJA Win 5.3. Testing reverse power. The settings made in this test simulate a situation where reverse power occurs in the power system. It is only the current which will be ramped. FREJA 300 will automatically stop the test when a “Start” signal is sent from REG670. The amplitude of the current will be visible in the “Results” box. The values of the reactive power and the active power have to be calculated separately.

7 Result

This bachelor's thesis work resulted in 9 different test templates for FREJA Win 5.3 and a user manual comprising 80 pages. See Appendix 1 - Commissioning Manual for the table of content of the manual. Some of the created test templates could be re-used for some protection functions e.g. by importing an overfrequency test template and changing the ramp settings, it was possible to test an underfrequency protection function. The user manual contains instructions how to use the different software tools needed when performing REG670 commissioning tests. When the user manual was created, the author wanted it be very easy to understand. Along with the text, many screen shots from PCM600 and FREJA Win 5.3 were taken and imported to the user manual. The following was described:

- How to establish communication between REG670 and a computer.
- How to import and export REG670 configurations.
- Application configuration tool: With this tool one can do the engineering of a relay such as configuring hardware channels, variables and connections. With the help of different function blocks, which perform e.g. mathematical operations, one can build a protection function. The application configuration tool is in other words a graphical programming tool.
- Parameter setting tool: The parameter setting of PCM600 enables viewing and setting REG670 parameters offline (stored in the tool) and online (stored in both the tool and the REG670). The parameters can be read from the REG670 to PCM600 or written from PCM600 to the REG670 while the REG670 is in use.
- Graphical display editor: The graphical display editor is used for configuring the display of REG670. The graphical display consists of one or more pages. A display page contains the drawing area where the actual display configuration is made.
- Disturbance handling: With this tool one is able to monitor disturbances recorded in REG670 and create a report.

- How to use FREJA Win 5.3. FREJA Win 5.3 is used in combination with FREJA 300. The simulation definitions are set in FREJA Win 5.3 and later transferred to FREJA 300 which generates the fault simulation.

- How to test REG670 protection functions.

Templates for the required protection functions were successfully created. For each test performed, a test report can be created and attached to the test certificate. These test reports contain the actual operation time and the pick-up and drop-out value for the relay. Appendix 2 - Overcurrent test is a test report for an overcurrent protection test. The test performed in “Voltage” tool is visible in Appendix 3 - Overvoltage test. Test results from a frequency test are shown in Appendix 4 - Overfrequency test. The problems that occurred when testing the thermal overload protection function was discussed in section §6. Some of the parameter settings for this protection had to be changed so that the operation time of the relay would be a couple of seconds instead of several minutes. How to change these parameters and what to use were described in the user manual and the test result can be seen in Appendix 5 - Thermal Overload test.

The user manual and the test templates will later be uploaded to Wärtsilä’s internal pages. Step-by-step descriptions of how to test a certain protection function were also saved in the specific test template itself. This makes it possible to get guidance even if one doesn’t have the manual.

8 Conclusion and discussion

The goal of this bachelor's thesis was to create a commissioning guide for a generator protection relay, ABB's REG670, and test templates created in FREJA Win 5.3 for the FREJA 300 relay testing unit. This bachelor's thesis was surely an interesting and educational task. REG670 and FREJA 300 were devices that the author hadn't worked with before. That was also the case with FREJA Win 5.3 and PCM600. It took a while to understand how the devices work and what the software was capable of. It was also challenging but, at the same time, very educational, to understand how to correctly simulate a faulty state.

The downside with this thesis was that FREJA Win 5.3 had a limited usage. Small problems occurred when the protection functions reverse power and under excitation were tested. There were no possibilities to add mathematical functions in FREJA Win 5.3 to perform calculations of active power, reactive power and apparent power from the measured secondary values when a "Trip" or "Start" signal was generated. This had to be done separately in the calculation sheet which the author had access to. Problems also occurred when a reference graph for the undervoltage test was to be created. It was not simply possible to create a correct definite time curve by modifying an existing curve. The reference graph tool didn't allow the secondary time value to be greater than the first time value. A separate ".txt" file can be created and imported to FREJA Win 5.3. The ".txt" file must contain the amplitude of the secondary injection value and a calculated operation value. But since the ratio of measurement transformers and nominal currents and voltage values can vary from project to project, it was decided not to draw the reference graph in the undervoltage test. It has no impact on the test results either. The amplitude of the injected value and the operation time will still be plotted in the graph.

When the author tested the Thermal overload $T>$ protection, the theoretical trip times were not achieved after the first initiated trip signal. The final temperature for this protection is calculated from the highest of the three-phase currents. Even though the thermal time constant (τ) was set a minimum value for the protection, it was not enough to get the heat counter down to zero between each shot. This was because the calculated heat value of the protected object was not reset after the trip signal. After some reading the author found out that a "reset" input existed in the function block. See figure 32. A variable was created and mapped to a binary input on the REG670. The variable was connected to the "reset" input in the function block. The trip signal was connected to this binary input. See figure 33. When the protection function were tested after this modification, correct operation times was achieved when the current was ramped.

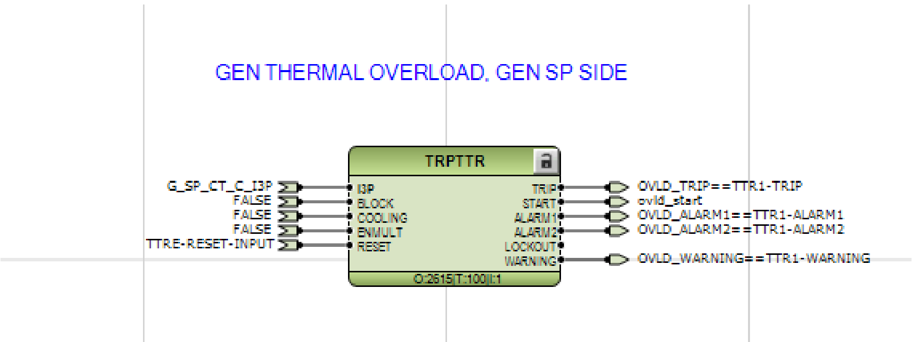


Figure 32: Screen shot from PCM600. Thermal overload protection block.

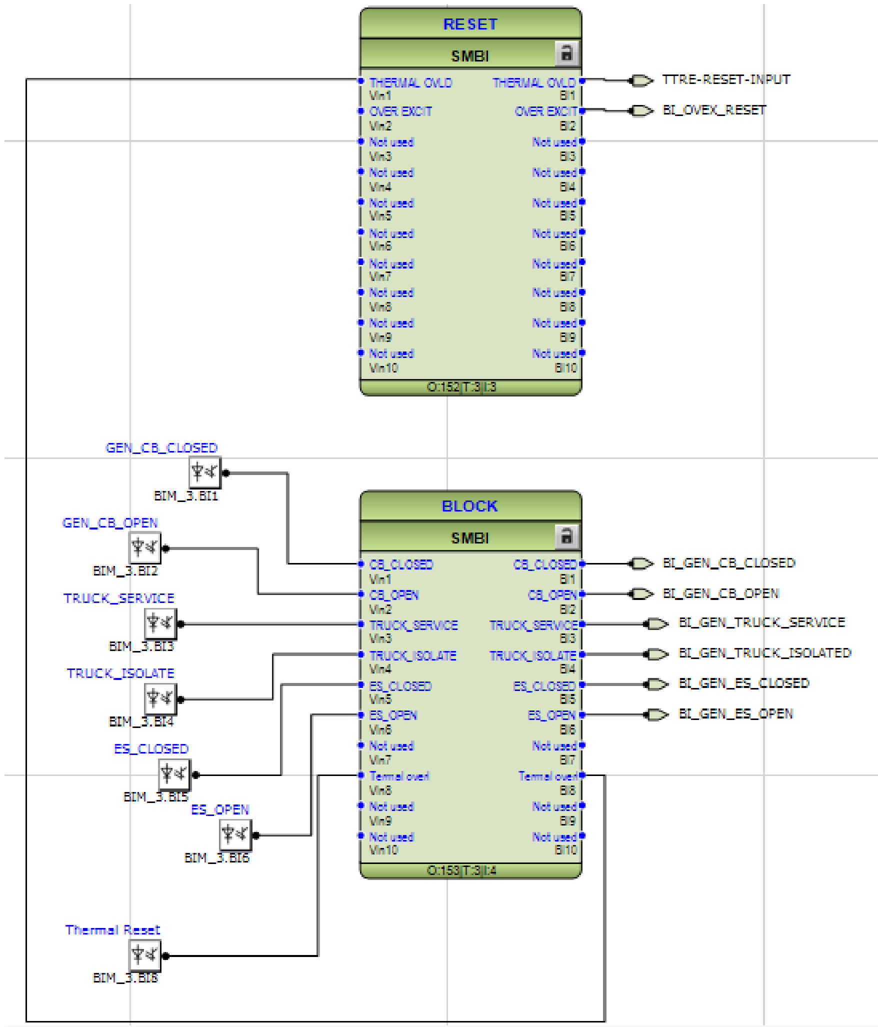


Figure 33: Screen shot from PCM600. Binary input mapping with the application configuration tool.

The main assignment, to create a user manual and test templates for computer controlled secondary testing with FREJA 300, has been successfully completed. Each tool in PCM600 was described in the manual with text and screen shots from the software in order to achieve a good visibility. The same was done with FREJA Win 5.3. Everything was compiled into one document. This is better for the intended users since they will not need to search through several manuals to find information about PCM600, FREJA Win 5.3 and how to perform tests of protection functions. The author is quite satisfied with the result even if the testing software FREJA Win 5.3 didn't allow the user to insert rated generator and protection function values for the calculation of active power, apparent power, reactive power and theoretical trip times. If this was possible in FREJA Win 5.3, the Excel calculation sheet wouldn't have to be used as a complementary tool. This work can be further developed by creating a single test template that tests all protection functions in one test run.

The secondary testing of the relay was very time consuming. It took some time to understand how to use FREJA Win 5.3 and its testing tools since the manual the author had access to was very limited. PCM600, on the other hand, had several good manuals so it wasn't too difficult to develop an understanding of how the software worked. The same procedure would be used if this thesis work were to be done again. The author had the chance to learn how to use FREJA Win and PCM600 software in the beginning of the work while writing the user manual so later on when the secondary testing of REG670 begun, the author didn't have any problems using the softwares.

The learning outcome of this thesis work is how to perform a secondary test of the REG670 relay with FREJA 300 and how to use ABB's relay configuration software PCM600. This thesis work was a very enlightening experience since the secondary testing procedure was not familiar to the author.

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Appendices

A Appendix 1 - Commissioning Manual

REG670 Generator Protection Relay - Commissioning Guide

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B Appendix 2 - Overcurrent test

Freja Report

1. Relay ID

Station	**Powergate**	Line	**Runsor**
Relay	**Service**		
Type	**Generator Protection**	Serial No	
Manufacturer	**ABB**	Model	**REG670**

2. Test ID

Company	**Wärtsilä**	Operator	**Anders Hermans**
Test type	**Overcurrent protection**	Date: 26.2.2014	Time: 12:37:26
Description			
Program	**Current**		

3. Config

Frequency : 50.000 Hz Network Model : 3PZSTD2A Current Direction : LI->NI

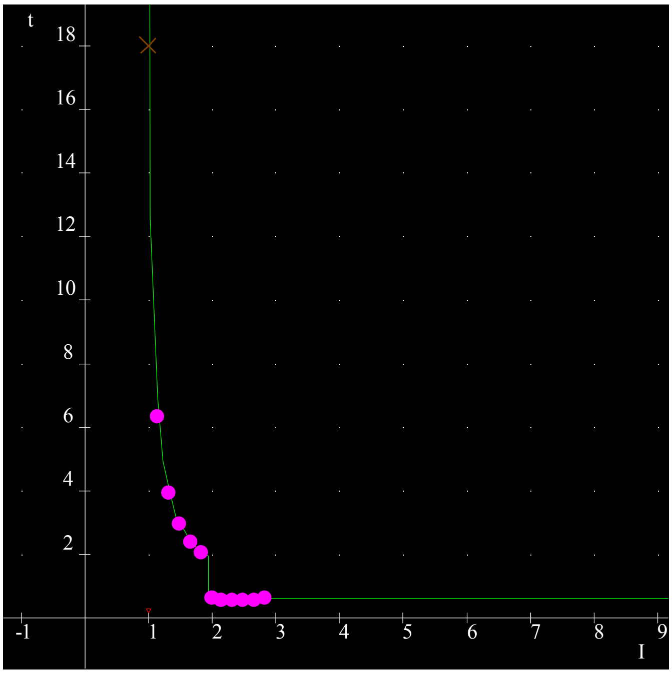
4. Summary **PASS**

I > Pickup	L1N:	**PASS**	L2N:	**PASS**	L3N:	**PASS**		
	L1L2:	**PASS**	L2L3:	**PASS**	L3L1:	**PASS**	L1L2L3:	**PASS**
Time test	L1N:	**PASS**	L2N:	**PASS**	L3N:	**PASS**		
	L1L2:	**PASS**	L2L3:	**PASS**	L3L1:	**PASS**	L1L2L3:	**PASS**

Approved by	*Rev.B*	Remarks
Signature		

Freja Report

Time test L1N



Time test (L1N)

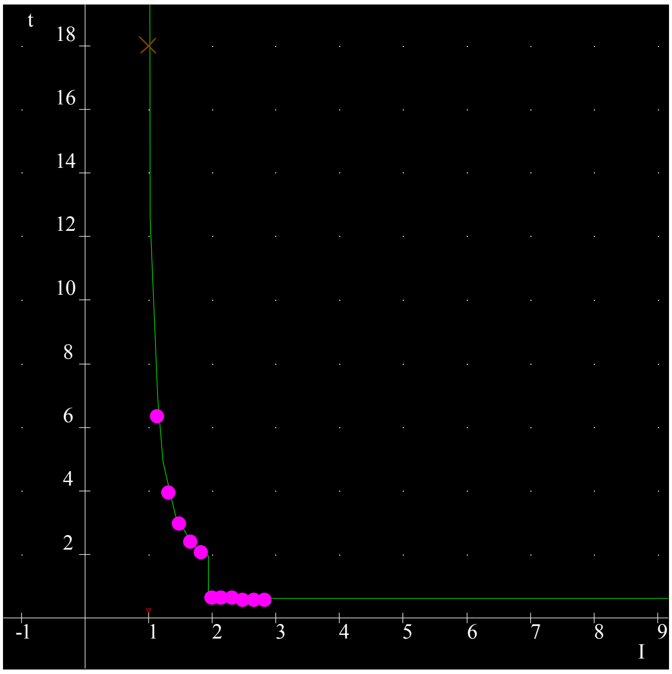
No.	I (A)	Trip time	Theoretical time	Time tol. (%)	Time tol. (ms)	Time diff. (%)	Pass/ Fail
1	1.000	----	----	10	100	----	x
2	1.167	6.367	6.280	10	100	1.4	·
3	1.333	3.968	3.919	10	100	1.3	·
4	1.500	2.980	2.941	10	100	1.4	·
5	1.667	2.439	2.404	10	100	1.5	·
6	1.833	2.093	2.062	10	100	1.5	·
7	2.000	0.631	0.600	10	100	5.4	·
8	2.167	0.628	0.600	10	100	4.7	·
9	2.333	0.628	0.600	10	100	4.7	·
10	2.500	0.626	0.600	10	100	4.5	·
11	2.667	0.625	0.600	10	100	4.3	·
12	2.833	0.629	0.600	10	100	5.0	·

I > Pickup (L1N)

Phase	I > setting	Pickup (A)	Pickup tol.(%)	Pickup diff.(%)	Drop out (A)	Hysteresis min.(%)	Hysteresis max.(%)	Hysteresis (%)	Pass/ Fail
L1N	0.934	0.928	10	-0.6	0.864	80	99	93.2	·

Freja Report

Time test L2N



Time test (L2N)

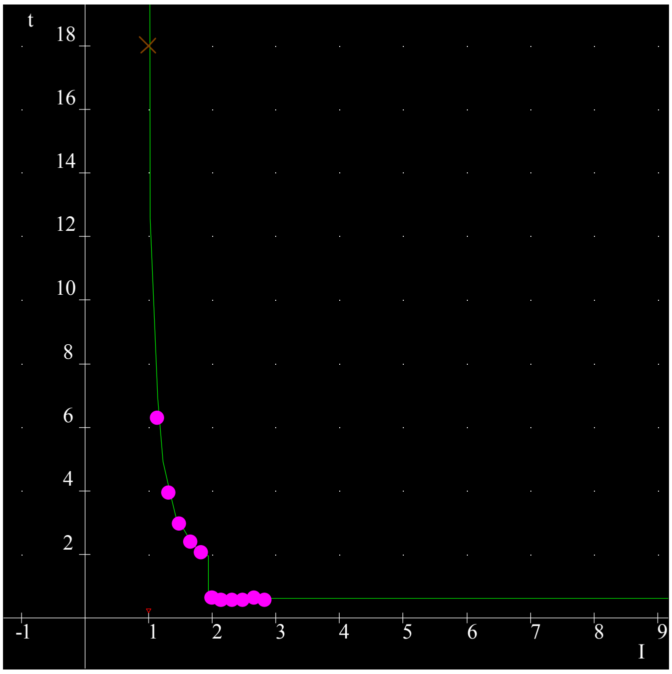
No.	I (A)	Trip time	Theoretical time	Time tol. (%)	Time tol. (ms)	Time diff. (%)	Pass/ Fail
1	1.000	----	----	10	100	----	x
2	1.167	6.363	6.280	10	100	1.4	·
3	1.333	3.968	3.919	10	100	1.3	·
4	1.500	2.980	2.941	10	100	1.4	·
5	1.667	2.436	2.404	10	100	1.4	·
6	1.833	2.099	2.062	10	100	1.8	·
7	2.000	0.629	0.600	10	100	4.9	·
8	2.167	0.629	0.600	10	100	5.0	·
9	2.333	0.628	0.600	10	100	4.8	·
10	2.500	0.627	0.600	10	100	4.7	·
11	2.667	0.627	0.600	10	100	4.7	·
12	2.833	0.623	0.600	10	100	4.0	·

I > Pickup (L2N)

Phase	I > setting	Pickup (A)	Pickup tol.(%)	Pickup diff.(%)	Drop out (A)	Hysteresis min.(%)	Hysteresis max.(%)	Hysteresis (%)	Pass/ Fail
L2N	0.934	0.928	10	-0.6	0.848	80	99	91.4	·

Freja Report

Time test L3N



Time test (L3N)

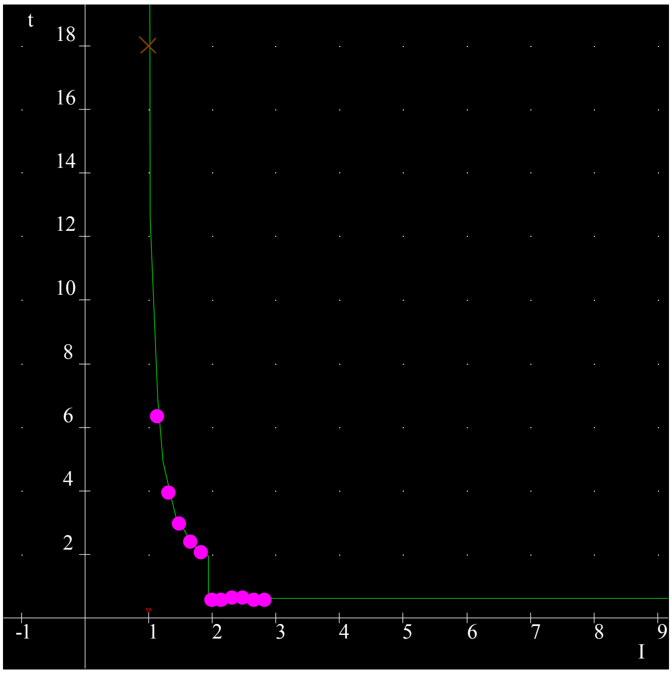
No.	I (A)	Trip time	Theoretical time	Time tol. (%)	Time tol. (ms)	Time diff. (%)	Pass/ Fail
1	1.000	----	----	10	100	----	x
2	1.167	6.324	6.280	10	100	0.7	·
3	1.333	3.960	3.919	10	100	1.1	·
4	1.500	2.973	2.941	10	100	1.1	·
5	1.667	2.437	2.404	10	100	1.4	·
6	1.833	2.092	2.062	10	100	1.5	·
7	2.000	0.632	0.600	10	100	5.4	·
8	2.167	0.626	0.600	10	100	4.4	·
9	2.333	0.625	0.600	10	100	4.3	·
10	2.500	0.626	0.600	10	100	4.5	·
11	2.667	0.630	0.600	10	100	5.1	·
12	2.833	0.622	0.600	10	100	3.8	·

I > Pickup (L3N)

Phase	I > setting	Pickup (A)	Pickup tol.(%)	Pickup diff.(%)	Drop out (A)	Hysteresis min.(%)	Hysteresis max.(%)	Hysteresis (%)	Pass/ Fail
L3N	0.934	0.928	10	-0.6	0.800	80	99	86.3	·

Freja Report

Time test L1L2



Time test (L1L2)

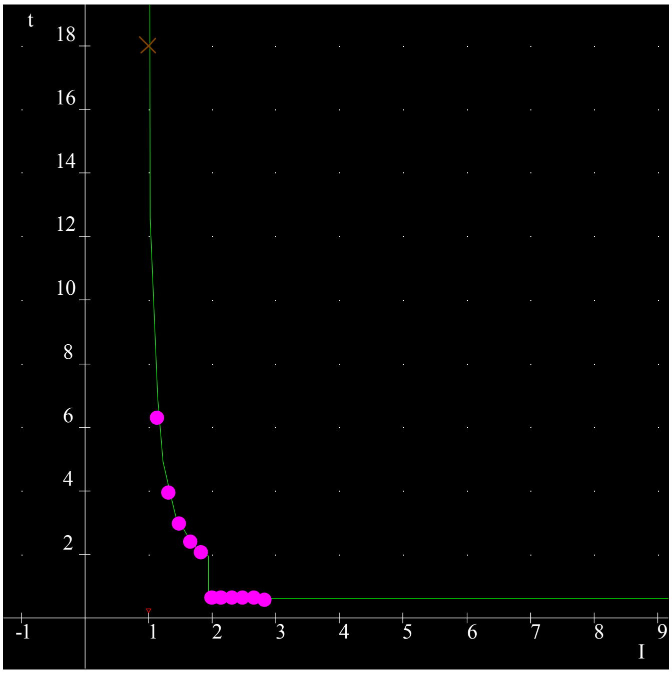
No.	I (A)	Trip time	Theoretical time	Time tol. (%)	Time tol. (ms)	Time diff. (%)	Pass/ Fail
1	1.000	----	----	10	100	----	x
2	1.167	6.355	6.280	10	100	1.2	·
3	1.333	3.969	3.919	10	100	1.3	·
4	1.500	2.981	2.941	10	100	1.4	·
5	1.667	2.436	2.404	10	100	1.4	·
6	1.833	2.090	2.062	10	100	1.4	·
7	2.000	0.628	0.600	10	100	4.8	·
8	2.167	0.627	0.600	10	100	4.7	·
9	2.333	0.631	0.600	10	100	5.3	·
10	2.500	0.631	0.600	10	100	5.3	·
11	2.667	0.627	0.600	10	100	4.6	·
12	2.833	0.626	0.600	10	100	4.5	·

I > Pickup (L1L2)

Phase	I > setting	Pickup (A)	Pickup tol.(%)	Pickup diff.(%)	Drop out (A)	Hysteresis min.(%)	Hysteresis max.(%)	Hysteresis (%)	Pass/ Fail
L1L2	0.934	0.928	10	-0.6	0.848	80	99	91.4	·

Freja Report

Time test L2L3



Time test (L2L3)

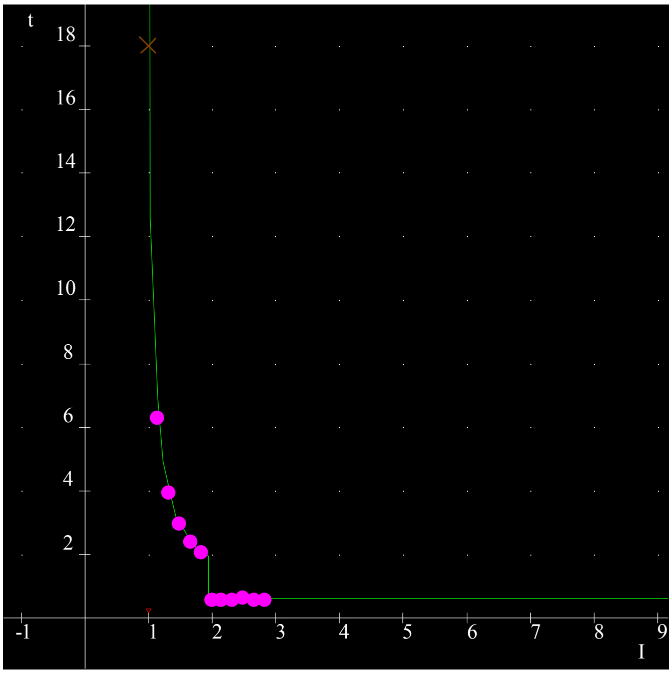
No.	I (A)	Trip time	Theoretical time	Time tol. (%)	Time tol. (ms)	Time diff. (%)	Pass/ Fail
1	1.000	----	----	10	100	----	x
2	1.167	6.328	6.280	10	100	0.8	·
3	1.333	3.958	3.919	10	100	1.0	·
4	1.500	2.972	2.941	10	100	1.1	·
5	1.667	2.441	2.404	10	100	1.6	·
6	1.833	2.094	2.062	10	100	1.6	·
7	2.000	0.630	0.600	10	100	5.2	·
8	2.167	0.630	0.600	10	100	5.2	·
9	2.333	0.630	0.600	10	100	5.1	·
10	2.500	0.629	0.600	10	100	5.0	·
11	2.667	0.628	0.600	10	100	4.8	·
12	2.833	0.627	0.600	10	100	4.7	·

I > Pickup (L2L3)

Phase	I > setting	Pickup (A)	Pickup tol.(%)	Pickup diff.(%)	Drop out (A)	Hysteresis min.(%)	Hysteresis max.(%)	Hysteresis (%)	Pass/ Fail
L2L3	0.934	0.928	10	-0.6	0.864	80	99	93.2	·

Freja Report

Time test L3L1



Time test (L3L1)

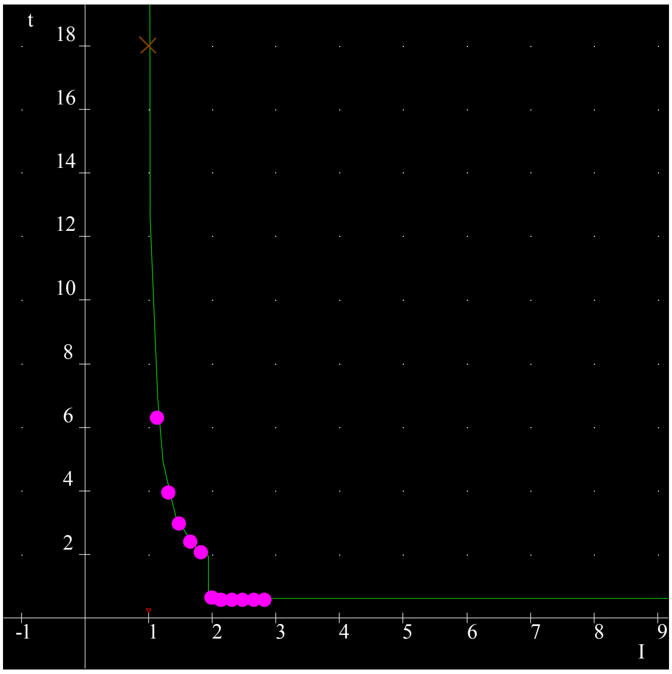
No.	I (A)	Trip time	Theoretical time	Time tol. (%)	Time tol. (ms)	Time diff. (%)	Pass/ Fail
1	1.000	----	----	10	100	----	x
2	1.167	6.326	6.280	10	100	0.8	·
3	1.333	3.962	3.919	10	100	1.1	·
4	1.500	2.974	2.941	10	100	1.2	·
5	1.667	2.439	2.404	10	100	1.5	·
6	1.833	2.094	2.062	10	100	1.6	·
7	2.000	0.627	0.600	10	100	4.6	·
8	2.167	0.627	0.600	10	100	4.6	·
9	2.333	0.627	0.600	10	100	4.7	·
10	2.500	0.628	0.600	10	100	4.8	·
11	2.667	0.627	0.600	10	100	4.6	·
12	2.833	0.627	0.600	10	100	4.7	·

I > Pickup (L3L1)

Phase	I > setting	Pickup (A)	Pickup tol.(%)	Pickup diff.(%)	Drop out (A)	Hysteresis min.(%)	Hysteresis max.(%)	Hysteresis (%)	Pass/ Fail
L3L1	0.934	0.928	10	-0.6	0.864	80	99	93.2	·

Freja Report

Time test L1L2L3



Time test (L1L2L:

No.	I (A)	Trip time	Theoretical time	Time tol. (%)	Time tol. (ms)	Time diff. (%)	Pass/ Fail
1	1.000	----	----	10	100	----	x
2	1.167	6.327	6.280	10	100	0.8	·
3	1.333	3.962	3.919	10	100	1.2	·
4	1.500	2.973	2.941	10	100	1.1	·
5	1.667	2.438	2.404	10	100	1.5	·
6	1.833	2.092	2.062	10	100	1.5	·
7	2.000	0.632	0.600	10	100	5.5	·
8	2.167	0.622	0.600	10	100	3.9	·
9	2.333	0.623	0.600	10	100	3.9	·
10	2.500	0.623	0.600	10	100	4.0	·
11	2.667	0.623	0.600	10	100	3.9	·
12	2.833	0.623	0.600	10	100	4.0	·

I > Pickup (L1L2L

Phase	I > setting	Pickup (A)	Pickup tol.(%)	Pickup diff.(%)	Drop out (A)	Hysteresis min.(%)	Hysteresis max.(%)	Hysteresis (%)	Pass/ Fail
L1L2L:	0.934	0.928	10	-0.6	0.864	80	99	93.2	·

C Appendix 3 - Overvoltage test

Freja Report

1. Relay ID

Station	**Powergate**	Line	**Runsor**
Relay	**Service**		
Type	**Generator Protection**	Serial No	
Manufacturer	**ABB**	Model	**REG670**

2. Test ID

Company	**Wärtsilä**	Operator	**Anders Hermans**
Test type	**Overvoltage protection**	Date: 26.2.2014	Time: 12:50:42
Description			
Program	**Voltage**		

3. Config

Frequency : 50.000 Hz Network Model : 3PZSTD2A

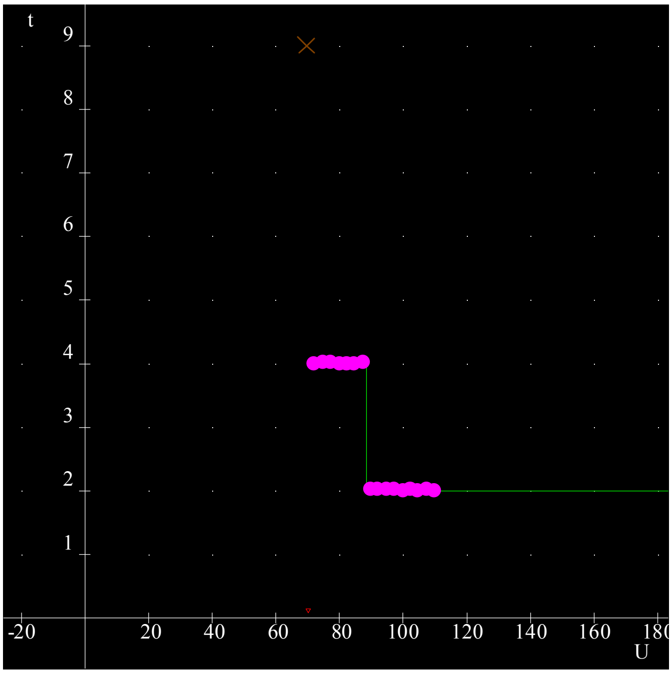
4. Summary

Pickup	L1N:	**PASS**	L2N:	**PASS**	L3N:	**PASS**		
	L1L2:	**PASS**	L2L3:	**PASS**	L3L1:	**PASS**	L1L2L3:	**PASS**
Time test	L1N:	**PASS**	L2N:	**PASS**	L3N:	**PASS**		
	L1L2:	**PASS**	L2L3:	**PASS**	L3L1:	**PASS**	L1L2L3:	**PASS**

Approved by	*Rev.B*	Remarks
Signature		

Freja Report

Time test L1N



Time test (L1N)

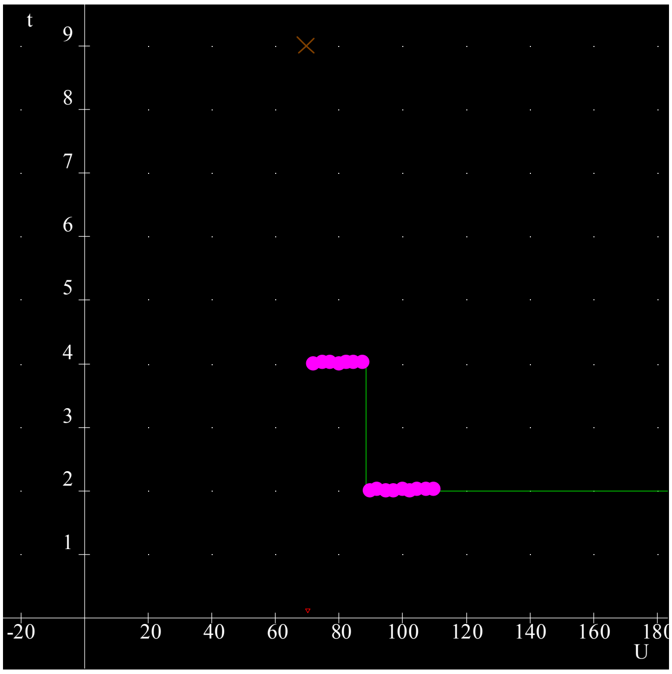
No.	U (V)	Trip time	Theoretical time	Time tol. (%)	Time tol. (ms)	Time diff. (%)	Pass/ Fail
1	70.00	----	----	10	100	----	x
2	72.50	4.028	4.000	10	100	0.8	·
3	75.00	4.032	4.000	10	100	0.8	·
4	77.50	4.038	4.000	10	100	1.0	·
5	80.00	4.028	4.000	10	100	0.8	·
6	82.50	4.027	4.000	10	100	0.7	·
7	85.00	4.028	4.000	10	100	0.8	·
8	87.50	4.040	4.000	10	100	1.1	·
9	90.00	2.031	2.000	10	100	1.6	·
10	92.50	2.037	2.000	10	100	1.9	·
11	95.00	2.033	2.000	10	100	1.7	·
12	97.50	2.029	2.000	10	100	1.5	·
13	100.0	2.026	2.000	10	100	1.3	·
14	102.5	2.030	2.000	10	100	1.5	·
15	105.0	2.026	2.000	10	100	1.4	·
16	107.5	2.032	2.000	10	100	1.7	·
17	110.0	2.024	2.000	10	100	1.3	·

Pickup (L1N)

Phase	U>/U< setting	Pickup (V)	Pickup tol.(%)	Pickup diff.(%)	Drop out (V)	Hysteresis min.(%)	Hysteresis max.(%)	Hysteresis (%)	Pass/ Fail
L1N	71.12	71.02	10	-0.1	70.22	80	99	98.9	·

Freja Report

Time test L2N



Time test (L2N)

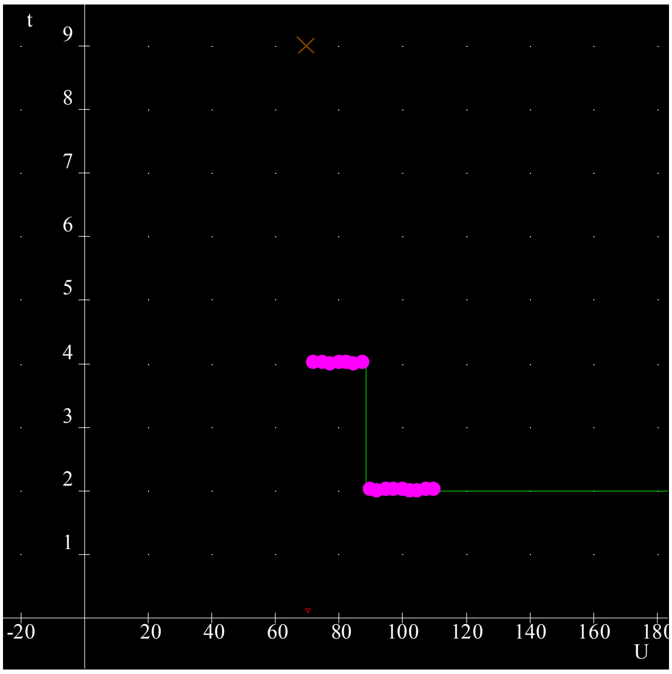
No.	U (V)	Trip time	Theoretical time	Time tol. (%)	Time tol. (ms)	Time diff. (%)	Pass/ Fail
1	70.00	----	----	10	100	----	x
2	72.50	4.028	4.000	10	100	0.8	·
3	75.00	4.032	4.000	10	100	0.8	·
4	77.50	4.030	4.000	10	100	0.8	·
5	80.00	4.028	4.000	10	100	0.8	·
6	82.50	4.034	4.000	10	100	0.9	·
7	85.00	4.032	4.000	10	100	0.8	·
8	87.50	4.030	4.000	10	100	0.8	·
9	90.00	2.027	2.000	10	100	1.4	·
10	92.50	2.032	2.000	10	100	1.6	·
11	95.00	2.028	2.000	10	100	1.5	·
12	97.50	2.025	2.000	10	100	1.3	·
13	100.0	2.031	2.000	10	100	1.6	·
14	102.5	2.027	2.000	10	100	1.4	·
15	105.0	2.032	2.000	10	100	1.6	·
16	107.5	2.029	2.000	10	100	1.5	·
17	110.0	2.035	2.000	10	100	1.8	·

Pickup (L2N)

Phase	U>/U< setting	Pickup (V)	Pickup tol.(%)	Pickup diff.(%)	Drop out (V)	Hysteresis min.(%)	Hysteresis max.(%)	Hysteresis (%)	Pass/ Fail
L2N	71.12	71.02	10	-0.1	70.22	80	99	98.9	·

Freja Report

Time test L3N



Time test (L3N)

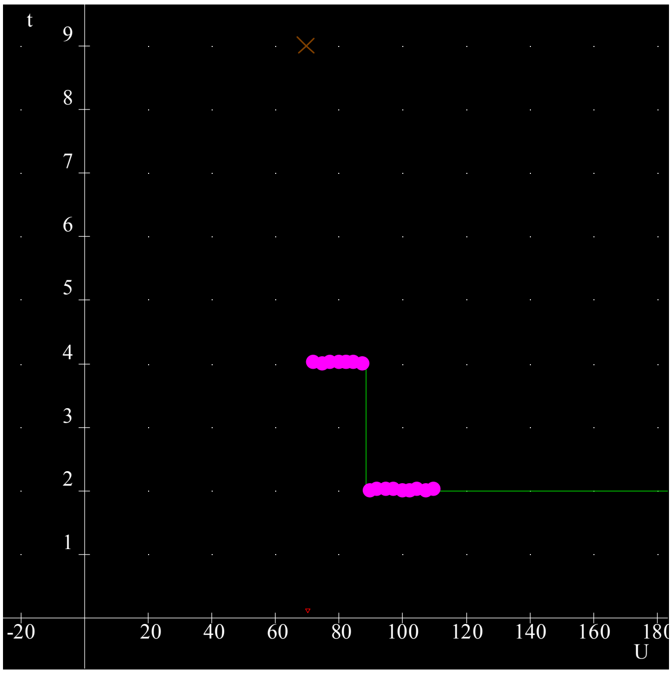
No.	U (V)	Trip time	Theoretical time	Time tol. (%)	Time tol. (ms)	Time diff. (%)	Pass/ Fail
1	70.00	----	----	10	100	----	x
2	72.50	4.034	4.000	10	100	0.9	·
3	75.00	4.042	4.000	10	100	1.1	·
4	77.50	4.026	4.000	10	100	0.7	·
5	80.00	4.032	4.000	10	100	0.9	·
6	82.50	4.030	4.000	10	100	0.8	·
7	85.00	4.024	4.000	10	100	0.7	·
8	87.50	4.040	4.000	10	100	1.1	·
9	90.00	2.041	2.000	10	100	2.1	·
10	92.50	2.027	2.000	10	100	1.4	·
11	95.00	2.033	2.000	10	100	1.7	·
12	97.50	2.029	2.000	10	100	1.5	·
13	100.0	2.035	2.000	10	100	1.8	·
14	102.5	2.026	2.000	10	100	1.4	·
15	105.0	2.024	2.000	10	100	1.3	·
16	107.5	2.029	2.000	10	100	1.5	·
17	110.0	2.035	2.000	10	100	1.8	·

Pickup (L3N)

Phase	U>/U< setting	Pickup (V)	Pickup tol.(%)	Pickup diff.(%)	Drop out (V)	Hysteresis min.(%)	Hysteresis max.(%)	Hysteresis (%)	Pass/ Fail
L3N	71.12	71.02	10	-0.1	70.22	80	99	98.9	·

Freja Report

Time test L1L2



Time test (L1L2)

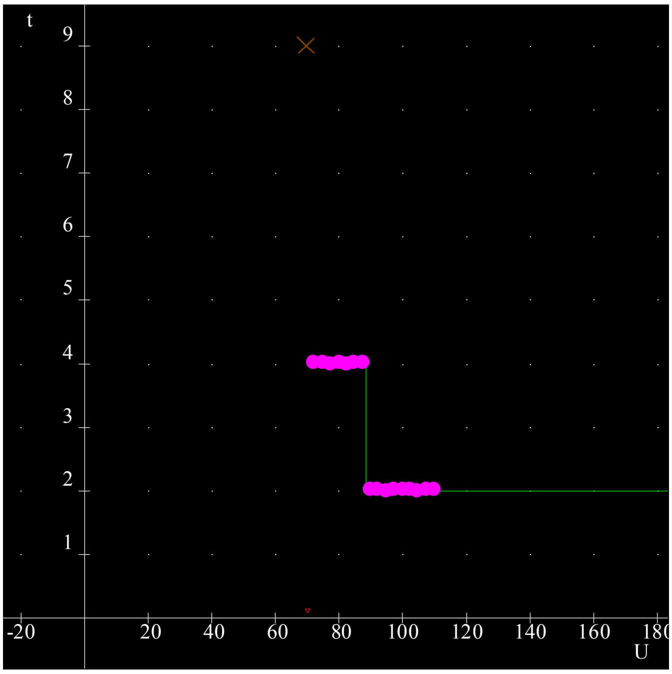
No.	U (V)	Trip time	Theoretical time	Time tol. (%)	Time tol. (ms)	Time diff. (%)	Pass/ Fail
1	70.00	----	----	10	100	----	x
2	72.50	4.038	4.000	10	100	1.0	·
3	75.00	4.028	4.000	10	100	0.8	·
4	77.50	4.030	4.000	10	100	0.8	·
5	80.00	4.038	4.000	10	100	1.0	·
6	82.50	4.036	4.000	10	100	1.0	·
7	85.00	4.030	4.000	10	100	0.8	·
8	87.50	4.028	4.000	10	100	0.7	·
9	90.00	2.028	2.000	10	100	1.4	·
10	92.50	2.034	2.000	10	100	1.8	·
11	95.00	2.031	2.000	10	100	1.6	·
12	97.50	2.038	2.000	10	100	2.0	·
13	100.0	2.028	2.000	10	100	1.5	·
14	102.5	2.025	2.000	10	100	1.3	·
15	105.0	2.035	2.000	10	100	1.8	·
16	107.5	2.026	2.000	10	100	1.4	·
17	110.0	2.032	2.000	10	100	1.7	·

Pickup (L1L2)

Phase	U>/U< setting	Pickup (V)	Pickup tol.(%)	Pickup diff.(%)	Drop out (V)	Hysteresis min.(%)	Hysteresis max.(%)	Hysteresis (%)	Pass/ Fail
L1L2	71.12	71.02	10	-0.1	70.22	80	99	98.9	·

Freja Report

Time test L2L3



Time test (L2L3)

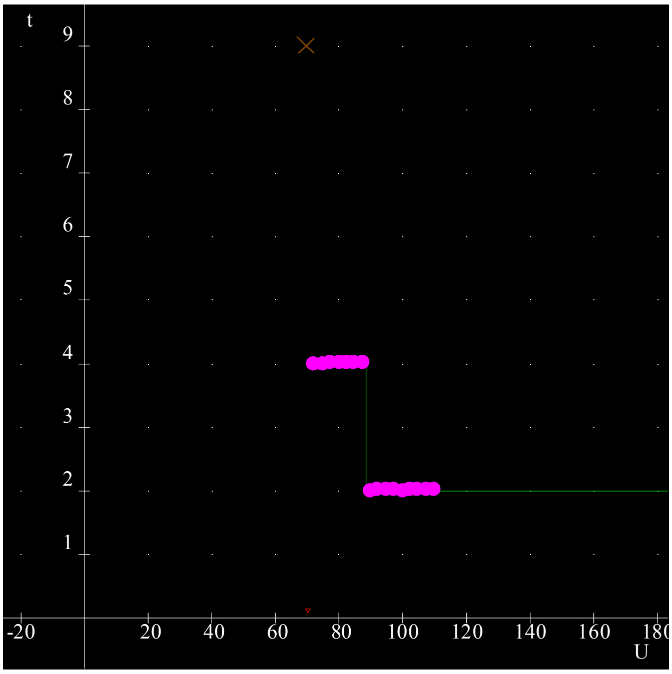
No.	U (V)	Trip time	Theoretical time	Time tol. (%)	Time tol. (ms)	Time diff. (%)	Pass/ Fail
1	70.00	----	----	10	100	----	x
2	72.50	4.033	4.000	10	100	0.9	·
3	75.00	4.030	4.000	10	100	0.8	·
4	77.50	4.028	4.000	10	100	0.8	·
5	80.00	4.030	4.000	10	100	0.8	·
6	82.50	4.024	4.000	10	100	0.7	·
7	85.00	4.040	4.000	10	100	1.0	·
8	87.50	4.039	4.000	10	100	1.0	·
9	90.00	2.035	2.000	10	100	1.8	·
10	92.50	2.041	2.000	10	100	2.1	·
11	95.00	2.027	2.000	10	100	1.4	·
12	97.50	2.033	2.000	10	100	1.7	·
13	100.0	2.039	2.000	10	100	2.0	·
14	102.5	2.030	2.000	10	100	1.5	·
15	105.0	2.027	2.000	10	100	1.4	·
16	107.5	2.033	2.000	10	100	1.7	·
17	110.0	2.039	2.000	10	100	2.0	·

Pickup (L2L3)

Phase	U>/U< setting	Pickup (V)	Pickup tol.(%)	Pickup diff.(%)	Drop out (V)	Hysteresis min.(%)	Hysteresis max.(%)	Hysteresis (%)	Pass/ Fail
L2L3	71.12	71.02	10	-0.1	70.22	80	99	98.9	·

Freja Report

Time test L3L1



Time test (L3L1)

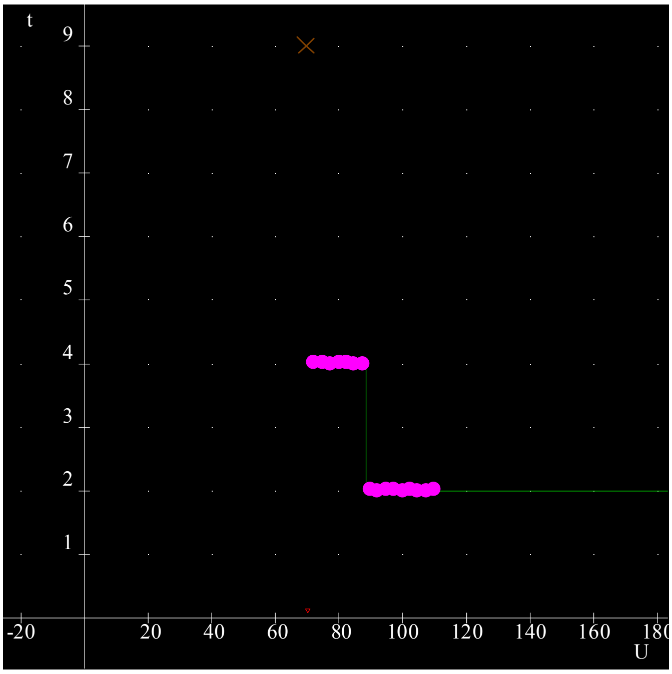
No.	U (V)	Trip time	Theoretical time	Time tol. (%)	Time tol. (ms)	Time diff. (%)	Pass/ Fail
1	70.00	----	----	10	100	----	x
2	72.50	4.028	4.000	10	100	0.7	·
3	75.00	4.026	4.000	10	100	0.7	·
4	77.50	4.038	4.000	10	100	1.0	·
5	80.00	4.036	4.000	10	100	0.9	·
6	82.50	4.034	4.000	10	100	0.9	·
7	85.00	4.032	4.000	10	100	0.8	·
8	87.50	4.030	4.000	10	100	0.8	·
9	90.00	2.027	2.000	10	100	1.4	·
10	92.50	2.033	2.000	10	100	1.7	·
11	95.00	2.039	2.000	10	100	2.0	·
12	97.50	2.031	2.000	10	100	1.6	·
13	100.0	2.027	2.000	10	100	1.4	·
14	102.5	2.032	2.000	10	100	1.7	·
15	105.0	2.039	2.000	10	100	2.0	·
16	107.5	2.035	2.000	10	100	1.8	·
17	110.0	2.031	2.000	10	100	1.6	·

Pickup (L3L1)

Phase	U>/U< setting	Pickup (V)	Pickup tol.(%)	Pickup diff.(%)	Drop out (V)	Hysteresis min.(%)	Hysteresis max.(%)	Hysteresis (%)	Pass/ Fail
L3L1	71.12	71.02	10	-0.1	70.22	80	99	98.9	·

Freja Report

Time test L1L2L3



Time test (L1L2L:

No.	U (V)	Trip time	Theoretical time	Time tol. (%)	Time tol. (ms)	Time diff. (%)	Pass/ Fail
1	70.00	----	----	10	100	----	x
2	72.50	4.034	4.000	10	100	0.9	·
3	75.00	4.042	4.000	10	100	1.1	·
4	77.50	4.026	4.000	10	100	0.7	·
5	80.00	4.032	4.000	10	100	0.9	·
6	82.50	4.034	4.000	10	100	0.9	·
7	85.00	4.028	4.000	10	100	0.7	·
8	87.50	4.026	4.000	10	100	0.7	·
9	90.00	2.041	2.000	10	100	2.1	·
10	92.50	2.027	2.000	10	100	1.4	·
11	95.00	2.033	2.000	10	100	1.7	·
12	97.50	2.039	2.000	10	100	2.0	·
13	100.0	2.025	2.000	10	100	1.3	·
14	102.5	2.030	2.000	10	100	1.6	·
15	105.0	2.026	2.000	10	100	1.3	·
16	107.5	2.023	2.000	10	100	1.2	·
17	110.0	2.029	2.000	10	100	1.5	·

Pickup (L1L2L3)

Phase	U>/U< setting	Pickup (V)	Pickup tol.(%)	Pickup diff.(%)	Drop out (V)	Hysteresis min.(%)	Hysteresis max.(%)	Hysteresis (%)	Pass/ Fail
L1L2L:	71.12	71.02	10	-0.1	70.22	80	99	98.9	·

D Appendix 4 - Overfrequency test

Freja Report

1.Relay ID

Station	**Powergate**	Line	**Runsor**
Relay	**Service**		
Type	**Generator protection**	Serial No	
Manufacturer	**ABB**	Model	**REG670**

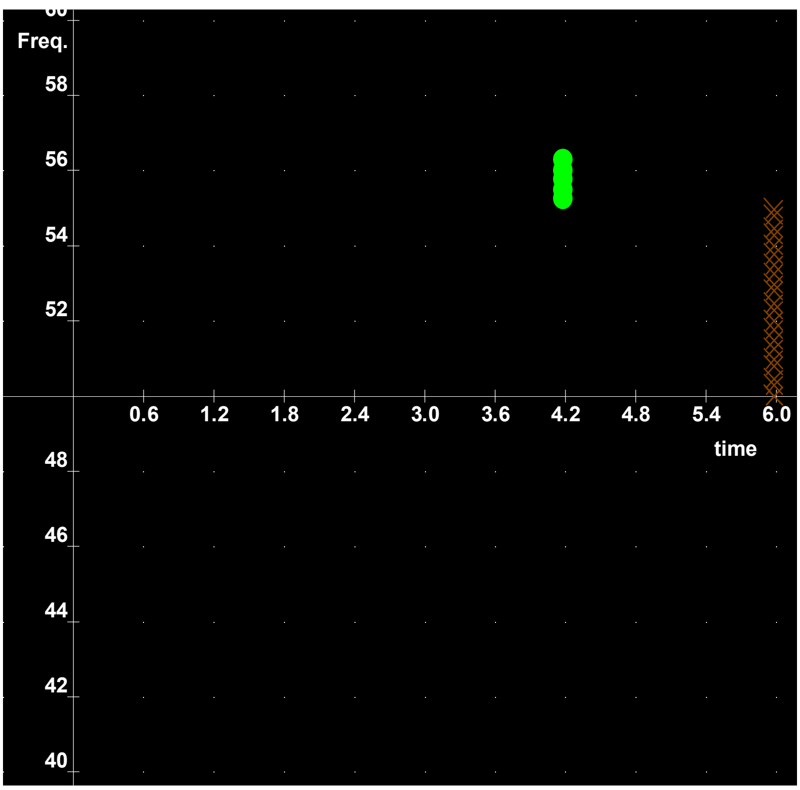
2.Test ID

Company	**Wärtsilä**	Operator	**Anders Hermans**
Test type	**Frequency**	Date:	Time:
Description			
Program	**Frequency**		

Approved by	*Rev.B*	Remarks
Signature		

Freja Report

SCAN



No.	*Prefault frequency(Hz)*	*Prefault duration(s)*	*Frequency (Hz)*	*Trip Time (s)*
1	50.000	1.000	50.000	10.000
2	50.000	1.000	50.114	10.000
3	50.000	1.000	50.229	10.000
4	50.000	1.000	50.371	10.000
5	50.000	1.000	50.486	10.000
6	50.000	1.000	50.600	10.000
7	50.000	1.000	50.743	10.000
8	50.000	1.000	50.857	10.000
9	50.000	1.000	50.000	-
10	50.000	1.000	50.000	-
11	50.000	1.000	50.229	-
12	50.000	1.000	50.457	-
13	50.000	1.000	50.743	-
14	50.000	1.000	50.971	-
15	50.000	1.000	51.200	-
16	50.000	1.000	51.486	-
17	50.000	1.000	51.714	-
18	50.000	1.000	52.000	-
19	50.000	1.000	52.229	-
20	50.000	1.000	52.457	-
21	50.000	1.000	52.743	-
22	50.000	1.000	52.971	-
23	50.000	1.000	53.200	-
24	50.000	1.000	53.486	-

Freja Report

No.	Prefault frequency(Hz)	Prefault duration(s)	Frequency (Hz)	Trip Time (s)
25	50.000	1.000	53.714	-
26	50.000	1.000	54.000	-
27	50.000	1.000	54.229	-
28	50.000	1.000	54.457	-
29	50.000	1.000	54.743	-
30	50.000	1.000	54.971	-
31	50.000	0.200	55.200	4.200
32	50.000	0.200	55.486	4.197
33	50.000	0.200	55.714	4.200
34	50.000	0.200	56.000	4.183
35	50.000	0.200	56.229	4.186

Freja Report

RAMP

Start frequency (Hz)	*Stop frequency (Hz)*	*dF/dt (Hz/s)*	*Frequency (Hz)*	*Trip Time (s)*
Batch number 1				
50.000	56.000	0.050	55.006	100.236

E Appendix 5 - Thermal Overload test

2014-03-17

Freja Report

1. Relay ID

Station	**Powergate**	Line	**Runsor**
Relay	**Service**		
Type	**Generator Protection**	Serial No	
Manufacturer	**ABB**	Model	**REG670**

2. Test ID

Company	**Wärtsilä**	Operator	**Anders Hermans**
Test type	**Thermal Overload**	Date:	Time:
Description			
Program	**Current**		

3. Config

Frequency : 50.000 Hz Network Model : 3PZSTD2A Current Direction : LI->NI

4. Summary

PASS

I > Pickup

L1L2L3: **PASS**

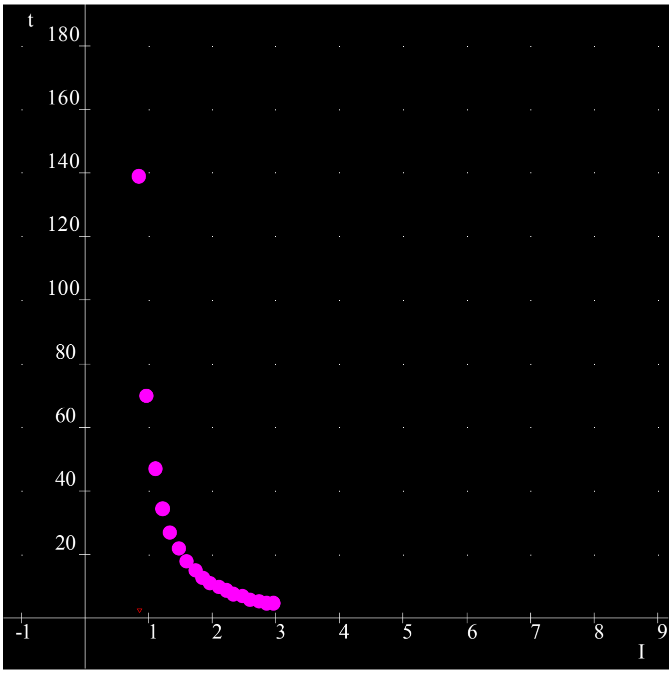
Time test

L1L2L3: **PASS**

Approved by	*Rev.B*	Remarks
Signature		

Freja Report

Time test L1L2L3



Time test (L1L2L:

No.	I (A)	Trip time	Theoretical time	Time tol. (%)	Time tol. (ms)	Time diff. (%)	Pass/ Fail
1	0.870	2:19.325	----	10	100	----	·
2	0.995	1:09.931	----	10	100	----	·
3	1.120	47.001	----	10	100	----	·
4	1.245	34.790	----	10	100	----	·
5	1.370	27.101	----	10	100	----	·
6	1.495	21.791	----	10	100	----	·
7	1.620	17.941	----	10	100	----	·
8	1.745	15.200	----	10	100	----	·
9	1.870	13.001	----	10	100	----	·
10	1.995	11.291	----	10	100	----	·
11	2.120	9.900	----	10	100	----	·
12	2.245	8.689	----	10	100	----	·
13	2.370	7.802	----	10	100	----	·
14	2.495	6.989	----	10	100	----	·
15	2.620	6.231	----	10	100	----	·
16	2.745	5.700	----	10	100	----	·
17	2.870	5.131	----	10	100	----	·
18	2.995	4.730	----	10	100	----	·

I > Pickup (L1L2L

Phase	I > setting	Pickup (A)	Pickup tol.(%)	Pickup diff.(%)	Drop out (A)	Hysteresis min.(%)	Hysteresis max.(%)	Hysteresis (%)	Pass/ Fail
L1L2L:	0.870	0.826	10	-5.1	0.813	80	99	98.5	·

Freja Report

dI/dt).
\par 4.\tab Choose a three phase fault type.
\par 5.\tab Do the scaling of the reference graph.
\par 6.\tab Click \ldblquote\i Start\rdblquote \i0 button and run the test.
\par 7.\tab Create a report after both tests are done.
\par \pard\ltrpar\keep\keepn\s5\sb200\sl276\slmult1\cf2 After the test
\par \pard\ltrpar\fi-360\li720\sa200\sl276\slmult1\cf0\f1\'b7\tab\f0 Undo changes made in the configuration file! Set them back to default values!
\par \f1\'b7\tab\f0 Disable the tested protection function on the IED, set parameter \b Blocked \b0 to \b YES.\b0
\par \pard\ltrpar\b\f2\fs20
\par }