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Fast fault detection for power distribution systems

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Abstract

THE main topic of this licentiate thesis is fast fault detection. The thesis summaries the work performed in the project “Fast fault detection for distribution systems”.

In the first chapters of the thesis the term “fast” is used in a general manner. The term is later defined based upon considerations and conclusions made in the first chapters and then related to a specific time.

To be able to understand and appreciate why fast fault detection is necessary, power system faults and their consequences are briefly discussed. The consequences of a fault are dependent of a number of different factors, one of the factors being the duration of the fault.

The importance of the speed of the fault detection depends on the type of equipment used to clear the fault. A circuit breaker which interrupt currents only when they pass through a natural zero crossing might be less dependent on the speed of the fault detection than a fault current limiter which limits the fault current before it has reached its first prospective current peak.

In order to be able to detect a fault in a power system, the power system must be observed, i.e., measurements of relevant quantities must be performed so that the fault detection equipment can obtain information of the state of the system. The fault detection equipment and some general methods of fault detection are briefly described.

Some algorithms and their possible adaptation to fast fault detection are described. A common principle of many algorithms are that they assume that either a signal or the power system object can be described by a model. Sampled data values are then fitted to the model so that an estimate of relevant parameters needed for fault detection is obtained. An algorithm which do not fit samples to a model but use instantaneous current values for fault detection is also described and evaluated.

Since the exact state of a power system never is known due to variations in power production and load, a model of the power system or of the signal can never be perfect, i.e., the estimated parameter can never be truly correct. Furthermore, errors from the data acquisition system contribute to the total error of the estimated parameter.

Two case studies are used to study the performance of the (modified) algorithms. For those studies it has been shown that the algorithms can detect a fault within approximately 1 ms after fault inception and that one of the algorithms can discriminate between a fault and two types of common power system transients (capacitor and transformer energization).

The second case study introduced a system with two sources which required a directional algorithm to discriminate between faults inside or outside the protection zone.

It is concluded that under certain assumptions it is possible to detect power system faults within approximately 1 ms and that it is possible to discriminate a power system fault from power system transient that regularly occurs within power systems but which not are faults.

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I dedicate this thesis to my dear family:
Hillevi, Jennifer and Cecilia

Chapter 1

Introduction

1.1 Background

TO prevent people and property from damage or injury, electrical faults in a power system must be cleared fast. In the early days of electrical power systems the fault clearing was administered by the maintenance staff, who visually detected the fault and manually operated a switch to clear the fault. As fault currents became larger and the operating requirements of the electric power system became more stringent, the need for automatic fault clearance became a necessity.

A typical fault clearing system consists of a circuit breaker and a relay protection system. The relay protection system consists of transducers, wiring, relay, auxiliary power supply, and the operating coil of the circuit breaker[1].

In the early days of automatic fault clearing, a fault was detected by electromechanical relays[2]. The measured quantity, such as for example a voltage or a current, was transformed to a mechanical force which operated the relay when a preset threshold was exceeded. Following the advent of electronics such as transistors and operational amplifiers, solid-state relays were developed. The characteristic of such relays were implemented by circuit design. Today, new relays are normally numerical relays. They are

[1] It might seem odd that the operating coil is included in the relay protection system, but since the operating coils is connected in series with the wiring of the relay protection system, it is closely integrated with the relay protection system.

[2] In fact, electromechanical relays are still in common use and can be obtained by a few manufacturers. However, numerical relays are taking over more and more.

built around a microprocessor in which the relay characteristic is digitally implemented. The analogue measurements are converted to digital signals for evaluation within the microprocessor. The recent development of fast microprocessors has led to the possibility to implement highly sophisticated relay characteristics within the microprocessor.

The trend in protection relay seems to go towards so-called relay terminals which for example can contain all protection relay functions needed to protect a power transformer. This is opposite to a couple of years ago when it was necessary to have one relay for differential protection, one relay for earth-fault protection and so on.

The other main part of the fault clearing system is the circuit breaker. The operating times of circuit breakers have gradually been reduced, but since all circuit breakers are dependent on a current zero-crossing to interrupt the current, they can never protect the power system from the first peak of the short-circuit current. Fault current limiters have been proposed and evaluated for almost 30 years by now. Recent research has proposed a number of installations of fault current limiters based on solid-state breakers or superconducting properties. Another approach to limit the fault current is to install a series reactor.

Since it is easier to close a current path than to open it (provided that the switch is dimensioned for the mechanical forces that will stress the switch during the closing), the possibility to commutate a fault-current to earth at the source with an earthing-switch has been proposed. The possibilities of today to supervise and control a power system seem to be sufficient to allow such a solution. The required apparatus and the control system exist but a field installation is required to prove the design.

The detection of faults is an essential part of the installation irrespective of whether a current-limiter or an earthing-switch is used. Allowing for a mechanical operating time of a few milliseconds, faults must have been detected within one millisecond or so to allow the power system to be protected from the first peak of the fault-current.

1.2 Objectives

The objective of this licentiate thesis is to present results from the project “Fast fault detection in power distribution systems” performed at the Royal Institute of Technology in Stockholm, Sweden since the spring of 2000. Within the project algorithms suitable for fast fault detection have been investigated and their performance evaluated. It turned out that the expression "fast" is not defined in the context of fault detection. A study of expressions used for speed requirements of protection equipment has been performed. The process of measuring and conversion of measurands has been investigated and the need of processing capacity has been discussed.

1.3 Outline

The thesis begins with a chapter (chapter 2) on electrical faults and their consequences in a power system. Methods and apparatus for mitigation and clearing of faults are described in chapter 3. The fault protection system is briefly outlined in chapter 4 together with common general principles for fault detection. Next, a few algorithms used for relaying purposes are described in chapter 5. Some common sources of errors and how they effect the fault detection are discussed in chapter 6. The application of the algorithms to two case studies are presented in chapter 7. Finally, conclusions and ideas for future work are discussed in chapter 8.

To put the work within this thesis in perspective, two appendices have been included. Appendix A contains a study on voltage dips, possibly caused by short-circuit faults and appendix B contains a study on simulations of power systems.

1.4 Main contributions of the thesis

The main contributions of this thesis are:

- a structured survey on the speed of fault detection and on the benefits of fast fault detection. In particular, "fast" fault detection is defined.
- an evaluation of possible algorithms appropriate for fast fault detection.
- requirements on equipment and algorithms used for fast fault detection.
- a case study of the application of fast fault detection in one typical grid and in one grid at a Swedish steel plant.

1.5 List of publications

The work during the project has been described in the following publications:

Conference papers

- Öhrström, M. and Söder, L., "Fast fault detection for power distribution systems" [1], presented at the 7th IASTED conference, Marina del Rey, California, USA, 12–15 May, 2002
- Watson, J. and Öhrström, M., "Current transformers, couplers & coils: A century of Overcurrent Measurement for Power System Protection" [2], presented at the 37th International Universities Power Engineering Conference, Staffordshire University, 9–11 September 2002
- Öhrström, M., Söder, L. and Breder, H., "Fast Fault Detection for Peak Current Limitation Based on Few Samples" [3], accepted for the CIRED2003 conference in Barcelona, Spain, 12–15 May, 2003
- Öhrström, M. and Söder, L., "A Comparison of Two Methods used for Voltage Dip Characterization" [4], accepted for the IEEE Power Tech conference in Bologna, Italy, June, 2003

Technical reports

- Öhrström, M., "Characterization of voltage dips recorded at a Swedish industrial plant during 1999" [5], internal KTH-report
- Öhrström, M., "Analysis of voltage dips" [6], internal KTH-report

Chapter 2

Faults and their consequences

THE detection and clearing of electrical faults in power systems is the main topic of this licentiate thesis. To appreciate why a fast and reliable fault clearing is important this chapter contains an overview of the consequences caused by electrical faults and relates the consequences to the duration of the fault.

2.1 Faults

The consequences (in most cases damage or potential hazard to humans and property) caused by electrical faults in power systems strongly depend on the magnitude of the fault current, which in turn depends on the type of fault, the location of the fault, the system earthing, the source impedance, and the impedance of the fault. The duration of the fault is also of considerable importance when estimating the consequences of a fault.

One way to characterize the types of faults is to describe them as shunt- or series faults. Shunt faults are faults when one or more of the phases are short-circuited (possibly to earth). Shunt faults are in general more severe than series faults, which could be described as an interruption in one or more of the phases.

The following definition of a short-circuit is taken from an IEEE standard [7]:

> "An abnormal connection (including an arc) of relatively low impedance, whether made accidentally or intentionally, between

two points of different potential. *Note:* The term fault or short-circuit fault is used to describe a short-circuit."

2.1.1 Shunt faults

An IEC-standard [8] has the following definition of a shunt fault[1]:

> A fault that is characterized by the flow of current between two or more phases or between phase(s) and earth at the *frequency of the associated power system.*

It is important to realize that fault currents are mainly of power frequency character but that they also can contain high-frequency components. Such high-frequency components can consist of the discharge current of a capacitor bank or stray capacitances in cables and bushings. As will be discussed later many fault detection algorithms use only the power frequency component of the current to detect a fault.

The different types of shunt faults are illustrated in figure 2.1. Fault

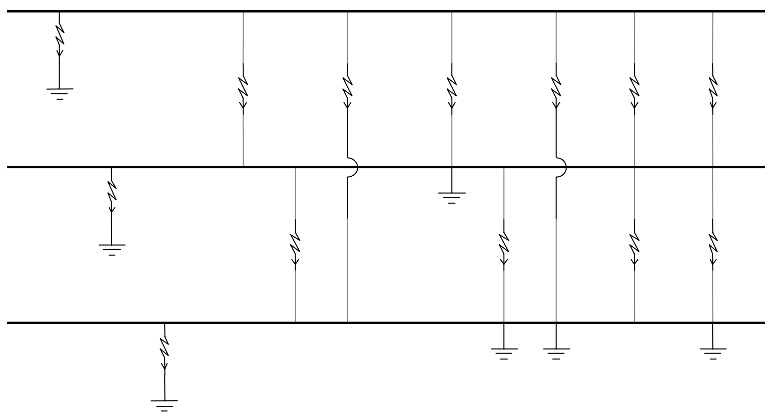

Figure 2.1. Shunt faults

currents due to shunt faults depend on the system impedance as seen from the fault location, and of the fault impedance. In general, fault currents

[1]The *I*nternational *E*lectrotechnical *C*ommittee (IEC) publish standards that are used by manufacturers and customer for standardization purposes.

are much larger than load currents. However, the magnitude of single-phase fault currents is largely dependent on the system grounding[2] and can be large in magnitude (of the same order as three-phase fault currents in solidly grounded systems) or small (a few Amperes in high-impedance grounded systems).

2.1.2 Series faults

An IEC-standard [8] has the following definition of a series fault:

> "A fault for which the impedances of each of the three phases are not equal, usually caused by the interruption of one or two phases."

Series faults give rise to fault currents proportional to the load currents. Series faults can be due to a broken conductor, a fuse operation in one or two phases, or a circuit breaker malfunction in one or several phases.

2.2 Consequences

The consequences of a fault can be divided into one part caused by the initiation of the fault (e.g. insulation breakdown) and one part which is dependent on the duration of the fault. The initial consequences cannot be reduced by faster fault detection whereas the part dependent on the duration of the fault can.

2.2.1 General

Mechanical forces

For parallell conductors in a single- or a three-phase system, the maximal force imposed on one of the conductors can be calculated by using equation 2.1 [9].

$$F_{max} = k \cdot k_r \cdot \frac{2}{d} \cdot i_s^2 \quad \text{kp/m} \tag{2.1}$$

where F_{max} is the largest force (in kp[3]/m) imposed on the conductors, i_s is the peak current expressed in kA, d is the distance between neighboring

[2] In Sweden, the transmission system (voltages more than 130 kV) is solidly earthed, but the distribution system (at least for 10 – 40 kV) is either non-earthed or high impedance earthed. The impedance can be a resistance, an inductance, or a combination thereof.

[3] 1 kp (kilopond) is equal to 9.82 kN.

conductors expressed in cm, and k and k_r are constants. Since k, k_r, and d are design parameters, it can be concluded that for a given power system component, the maximal force imposed upon it is proportional to the square of the peak-current. Thus, when a short-circuit current is carried by the phase conductors, there will be a mechanical force upon them and that force will grow rapidly with increasing short-circuit currents since it depends on the square of the current.

In case of a short-circuit, the fault current will contain a decaying dc-component that depends on the instant of fault initiation. Thus, the fault current is largest immediately after the fault initiation and the largest mechanical force imposed on the power system components is caused by the largest peak current. An example of typical fault phase currents is illustrated in figure 2.2.

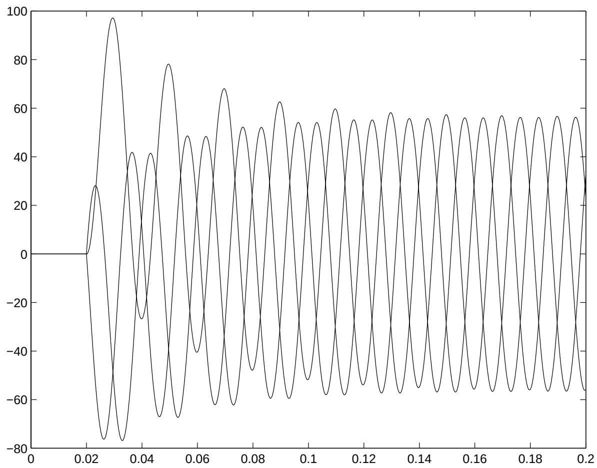

Figure 2.2. Typical fault phase currents, each including a dc-component

Power system equipment is designed to manage a current peak of a certain magnitude. The organisation IEC[4] have published a proposed standard value of the maximal allowed peak current expressed in terms of a peak factor that relates the RMS[5]-value of the short-circuit current to the peak current (equation 2.2)[6].

$$I_{peak} = 2.5 \cdot I_{rms} \tag{2.2}$$

[4]International Electrotechnical Commission

[5]*R*oot *M*ean *S*quare

[6]The figure 2.5 is based upon measurements and calculations in a multitude of actual power systems. Another figure $2 \cdot \sqrt{2} \approx 2.83$ is often used as an estimate of the peak

Thermal stress

Due to resistance in the conductors of a power system, heat losses according to equation 2.3 are produced when a current flows through them.

$$P = R \cdot I^2 \tag{2.3}$$

In equation 2.3, P denotes the heat losses for a conductor caused by the current I, when passing through the resistance R. I is the RMS-value of the current.

Since the losses depend on the square of the current, fault currents give rise to major heating. Depending on the size and material of the conductor, the heating will eventually lead to meltdown and destruction of the conductor. Power system equipment is designed to manage fault currents for a certain amount of time. The organisation IEC have published standard values of allowed short-circuit currents and how long they are allowed to persist. If the fault current is lower than the rated value, the time before meltdown occurs is increased. An estimation of the allowed period of time can be obtained by calculating the heat loss developed in the conductor when the rated short-circuit current I_1 is passed through the conductor during the rated time t_1. If the actual current is I_2, an estimation of the allowed time t_2 can be calculated by using equation 2.4.

$$I_1^2 \cdot t_1 = I_2^2 \cdot t_2 \tag{2.4}$$

Power system apparatus are normally designed to carry fault currents during a rather long time (one or three seconds are common rated values according to the IEC). If the thermal consequences where the only consequences there would be plenty of time to detect and clear faults.

2.2.2 Faults involving an arc

If the fault occurs outdoors (or at least in a non-enclosed environment) the fault current will be limited due to the resistance of the arc which can be estimated by an empirical formulae published by Warrington [10]. Still, an electric arc burning outdoors will eventually cause damage to the power line and the fault current must be cleared.

factor. It is derived by assuming a dc-component of 100 % and that there is no damping in the system so that the fault current barely approaches zero. Close to large generators, the dc-component can be even larger and if the damping is poor, the fault current might not pass through zero for several periods.

If the fault occurs in an enclosed environment there is no empirical formulae for the arc resistance and the fault current limitation due to the arc is negligible. When an arc burns in an enclosed environment, such as for example a switchgear cubicle, the damage will be severe. First, the power dissipation will cause heating of the air inside the cubicle. The pressure inside the cubicle will increase and a pressure wave will travel through the switchgear. Approximately 10 ms [11] after the initiation of the arc the pressure wave will be fully developed. Modern switchgear cubicles are in general equipped with pressure relief valves that open to prevent some of the damage caused by the rise in pressure. If the arc is not interrupted the temperature will continue to rise. After approximately 100 ms [11] the conductors will begin to melt and the switchgear will need extensive repair or most likely a replacement. A fault current of 40 kA through an arc will vaporize approximately 4 kg of material[7] if burning for 1 s [11].

2.2.3 Consequence steps

Once a fault has been initiated it will cause some initial consequences which are difficult (impossible) to do something about. What one can do is to protect the system from further consequences. The concept of consequence steps starts with the initial consequences. Subsequent consequences are time-dependent. The faster the fault can be cleared, the less are the consequences. Based on the previous discussion some steps can be identified such as: reduction of the pressure caused by an open arc, reduction of the mechanical stresses by limiting the first current peak, and limitation of the thermal consequences by minimizing the fault time.

2.2.4 Cost

The concept of consequence steps could also be related to the cost caused by the fault. The initial consequence could for example lead to insulation breakdown in a cable so that the cable needs to be repaired. If the fault current is allowed to persist, the cable will be more and more damaged so that it might need to be replaced. Eventually, the fault current will damage not only the cable, but also other equipment in the faulted current path, such as circuit breakers, instrument transformers, transformers, or even generators. Replacing or repairing part of a cable might not be very

[7] If the conductor is made out of copper with an area of 10x100 mm^2, 4 kg of copper corresponds to a meltdown of approximately 10 cm of the conductor.

expensive, but replacing a power transformer most certainly is. Another aspect of cost is that the larger the damage is the longer time the repair will take before the cable can be put into service again. Depending on the layout of the power system more or less customers might be without power during the repair.

2.2.5 System aspects

A short-circuit normally gives rise to high fault currents in the faulted current path and consequences associated therewith. At the same time, the voltage will drop, giving rise to a voltage dip that can be noted throughout large parts of the power system and disturb sensitive processes. A study of voltage dips measured at an industrial plant is included in appendix A. For that particular study, the critical duration of a voltage dip depended on the remaining voltage during the dip[8], but many processes managed a voltage dip if the duration was less than 100 ms. However, if the duration of the dip were even shorter, its consequences would be further reduced. Transient stability considerations is generally not considered for distribution systems. However, the increasing amount of distributed generation, might lead to such considerations even for distribution systems.

[8] The magnitude of the dip is an expression that sometimes is used. But if the magnitude of a dip is say 30% it is unclear if the remaining voltage is 30 % or if the missing voltage is 30%.

Chapter 3

Fault clearing

In the early days of power systems (late 1800s), an electrical fault could be detected visually by the operator and then manually removed. Today, electrical faults are automatically cleared by fuses and circuit breakers, or limited by fault-current limiters. This chapter gives an overview of methods and apparatus used for fault clearing.

3.1 Fuses

Fuses have been used in power systems since the late 19th century [12]. A fuse is a device which can carry load currents, but when the current rises above a certain threshold for a certain time, the conducting path will break down and the fuse will clear the current. Fuses are common in low voltage systems and in some extent in medium voltage systems but not so common in high voltage systems. Depending on the design (there are fuses that are non-current limiting and there are fuses that are current limiting), a fuse can limit the first current peak of the short-circuit current. The fuse is thus an excellent device for fault clearing but they have a number of disadvantages which limit their use:

- After a fuse has cleared a current it has to be replaced.
- When load currents flow through a fuse they give rise to losses proportional to the square of the current (as previously discussed in chapter 2 equation 2.3). For large load currents the losses can be unacceptably high.

- There are power systems where it can be difficult to coordinate fuses with the remaining protection system so that selectivity[1] is obtained.

3.2 Circuit-breakers

Power circuit-breakers are used at all voltage levels in a power system. Most common today in medium voltage systems are either SF_6 circuit-breakers[2] or vacuum circuit-breakers. The basic principle of current interruption of an alternating current is based on the natural zero-crossings of the current twice per period of the power frequency. Once the contacts of the circuit-breaker is opened, the current will continue to flow through an arc until a natural zero-crossing is reached. At that moment the arc is extinguished and if the contact separation is large enough and the arcing channel has cooled sufficiently, the current will be interrupted. Otherwise, the current will flow in the circuit until next natural zero crossing before an interruption can take place.

Since the interruption principle is based on the natural zero-crossings of the short-circuit current it is impossible to protect the system from the mechanical forces caused by the first current peak by using a circuit-breaker. There is no way the first current peak can be avoided with such circuit-breakers. Even if the operating time of the contacts is made infinitely small, the circuit-breaker would still need a zero-crossing to interrupt the current.

3.3 Current limiting

The expression "current limiting" is used for apparatus which can protect the power system from the mechanical forces associated with the first current peak of the fault current by either interrupt or limit the fault current before the prospective current peak is reached.

3.3.1 Series reactor

A traditional method of limiting short-circuit currents has been to install a so-called series reactor in the main circuit. However, the reactor does not

[1] Selectivity is a term used for the coordinated operation of a protection system so that only as small part of the power system as possible is disconnected due to the clearance of a fault.

[2] Due to environmental considerations there is a discussion whether the use of SF_6 should be prohibited by regulation or not.

only limit the short-circuit current but the installed short-circuit power is also reduced. Since the reactor is a series circuit element it also contributes with additional losses when load currents pass through it. The series reactor is always connected to the circuit[3] and needs no external signal or control to limit the fault current. Actually, the fault current is not limited very much, just as much as needed for the existing protection system to cope with it.

3.3.2 Fuses

There are fuses that are of so-called current limiting type i.e. they can limit the fault current before the first current peak of the prospective fault current. When the fault current exceeds a certain threshold, the fuse rapidly melts and the fault current flows through an arc within the fuse until the next current zero where it is extinguished. The impedance of the arc limits the fault current during the arcing time. Even though the current limitation can be significant, the limited current still flows in the circuit until it is finally cleared. As for the series reactor the fuse does not need any external signal or control to operate but is "triggered" by the fault current itself.

3.3.3 A switch-fuse combination current limiter

In general, the designer of a power system wants to have as high available short-circuit power as possible to allow smooth operation of the power system. A higher short-circuit power allows the connection of larger loads without voltage reductions or special considerations when connecting the load[4]. However, a higher short-circuit power has the side-effect that in case of a fault, higher short-circuit currents will flow in the power system. When the power system is supplied from several sources a solution utilizing fuses have been used for several years by now. The system is sectionalized through a switch-fuse combination, which in case of a short-circuit operates the fuse, hence separating the two sources from each other. After the fuse has operated, the protection system of each individual source detects and clears the fault, leaving healthy parts of the power system in operation.

The switch-fuse combination consists of a conductor in parallell with a current-limiting fuse. When a short-circuit fault is detected, the conductor

[3] In some installations, the reactor can be removed from the circuit by a bypass switch.

[4] A synchronous machine can for example be started directly which is the most severe way to start the machine or by using thyristors to gradually increase the power to the machine which is a nicer way to start the machine.

is forced open by a small explosive charge forcing the current to commutate to the fuse. Due to the high current, the fuse melts down and limits the current before the first peak of fault current, hence providing a protection from the mechanical force associated with the first current peak.

The benefit with using a switch-fuse combination is that connections otherwise not allowed due to possibly high short-circuit currents can be used. The disadvantage of using a switch-fuse combination is that after it has operated, parts of it must be manually replaced before it can be taken into service again.

3.3.4 Solid-state fault current limiters

The advent of high power solid-state devices such as thyristors, GTOs, and IGBTs has provided a means of building a solid-state breaker which is not dependent on a natural zero crossing to interrupt the current. Once a short-circuit is detected, a signal is sent to the control-gear of the solid-state breaker, which turns off the current in the main circuit immediately.

Inductances are not only explicitly as components in a power system but also natural as currents give rise to magnetic flux. Magnetic energy is stored in the inductances according to $W = Li_c^2$, where i_c is the current immediately before interruption. When the current is interrupted close to the peak of the current, the energy is at its maximum and manifests as a transient over-voltage across the breaker which can be of such magnitude as to disturb or damage equipment in the system. When i_c is high the energy must be handled by for example a varistor across the breaker. The advantages of a solid-state breaker is that they can break the current in practice instantaneously. The disadvantages with a solid-state breaker are however:

- the cost[5].
- depending on the components used, the components can not extinguish large currents[6].
- the losses are quite high.

By adding a switch in parallel with the solid-state equipment that commutates the current to the solid-state breaker just before switching, some of the disadvantages might be resolved. In that way it is possible to use less

[5] The cost of solid-state equipment has been an issue for discussions for several years. The trend seems to be towards better performance and towards lower cost.

[6] A thyristor is dependent on the zero-crossing of the current for its interruption.

expensive solid-state components[7] thus lowering the cost (as long as the switch is cheaper than the solid-state components). The control system of the apparatus can be constructed so that the switch never operates if the current is larger than the solid-state components can handle. Then a new disadvantage is that the component might not be able to limit the current before the first current peak (if the switch is slow). The losses can also be reduced with a switch in parallel that carries the load current. It is easier to construct a mechanical switch with low impedance than a solid-state component with low impedance. It must be observed that to commutate a current can be a difficult task and that the operating time of the switch adds to the total fault clearing time.

3.3.5 Superconducting fault current limiters

One type of superconducting fault current limiter is based on a transformer that has a secondary winding that is made as a superconductor. In normal service operation the superconducting state persists but in case of a short-circuit, the superconducting state is disturbed causing the secondary winding to be normal-conducting. The inductance of the secondary winding is then changed drastically and the current hence limited. A disadvantage with superconducting current limiters are that they are quite expensive. One advantage of superconducting current limiters is that no equipment to detect a short-circuit current is needed, since the short-circuit current by itself disturbs the superconducting state.

3.3.6 Current diverter

Since interrupting a current is more difficult than closing a switch in a faulted circuit another solution that provides functionality similar to current limiting apparatus is to divert the fault current from the power system at the source [13]. One or a number of fast switches diverts the current to earth once a short-circuit is detected. The current is then interrupted by the ordinary protection system. In case of a meshed grid with several sources[8], a switch is placed at each source, responsible for diverting that sources part of the fault current. The effect of using current diverters are that the current

[7] The components might be degraded because they are not in the main circuit all the time but only when a switching takes place.

[8] The word source is used to denote either a local generator or a transformer that is connected to a transmission grid or a local distribution grid.

at the fault point becomes virtually zero, but instead a temporary voltage dip down to zero is imposed on the system for the time it takes for the ordinary protection to interrupt the fault, open the current diverters, and close the current path again. But then again, without the current diverter this type of power system connection would be difficult to realize. Other types of current interruption equipment also give rise to a voltage dip when clearing the fault current. A current limiter might get away with a less severe voltage dip but the cost is considerable higher than that of a bypass switch.

3.4 Motivation for fast fault detection

Except for the fuse and the superconducting current limiter all of the components mentioned in this chapter are in need of fast and reliable fault detection to operate as intended and to protect the power system. To be able to limit the fault current before the first current peak, the fault has to be detected in at least five ms after fault initiaton[9] (if it is assumed that the apparatus used to clear the fault has an operating time that is zero). In practice, the operating time of a switch that is used for current diversion is approximately 2–3 ms. If a safety margin of 1–2 ms is enough to make sure that the fault current is limited before the first current peak, approximately 1 ms is left for the fault detection.

[9]corresponding to a quarter of a period of the power frequency.

Chapter 4

Fault protection systems

4.1 Fault clearing systems

A fault clearing system consists of a relay protection system and a circuit-breaker. In case of a fault, the task of the circuit-breaker is to clear the fault and the task of the relay protection system is to detect the fault. The circuit-breaker has already been discussed in the previous chapter 3. It is important to understand that the time to clear a fault is dependent on both the time required to detect the fault and the time needed for the circuit-breaker to clear the fault.

4.2 Relay protection system

The relay protection system can be further divided into transducers, auxiliary power, trip-circuits, and relays. The relay performs the actual detection but cannot work without proper inputs and outputs.

4.2.1 Transducers

To be able to detect a fault, the state of the power system must be observed and analyzed. The most common signals used for fault detection are currents, and voltages. Furthermore, light can be used to detect an open arc fault inside an enclosed switchgear and is not further treated here. A pressure gauge can be used in a transformer to detect pressure waves generated by a fault.

Currents and voltages cannot be measured directly, i.e. it is not possible to connect an amperemeter or a voltmeter at high voltage, but some measuring equipment that reduces the voltage must be used. Some common groups of measuring equipment are described below.

Instrument transformers

Instrument transformers has been in use since the late 19th century. They are commonly abbreviated as CT for current transformers, VT for voltage transformers (or PT for potential transformers), and CVT for capacitive voltage transformers. Instrument transformers consists in principle of two windings wound round an iron core. The connection of a CT and VT is different since the CT is connected in series with the main current path and the VT is connected as a shunt-device to earth (if phase-to-earth voltages are measured) or between phases (if phase-to-phase voltages are measured). During the years CTs and VTs have been extremely reliable components (with respect to their accuracy of reproducing the primary voltage or current at the secondary terminals) and their behavior is with a few exceptions well known to power system engineers. Things to consider when using VTs, CTs or CVTs as inputs for fast fault detection are:

- Saturation of the core of the CT, which is caused either by a high ac-component or a dc-component. A saturated CT supply little or no secondary current (at least when the primary current is of power frequency character) depending on the secondary burden and the amount of saturation. However, it takes a while for a CT to saturate so for fast fault detection CT saturation might not be a problem. If fast fault detection is supposed to be used in systems where fast reclosing is used, CT saturation could be a consideration if the fault still persists when the reclosing is made and there is remanent flux in the core.
  Saturation of the core of a VT is not considered as a problem for fast fault detection since the voltage normally is reduced during a fault thus providing larger margins to the knee-point on the BH-curve where saturation commences.[1]
- The bandwidth of an instrument transformer is a measure on how the instrument transformer will behave at various frequencies. An instrument transformer for use in power systems is normally designed for

[1] A saturation phenomenon related to VTs is ferroresonance which is a resonance between the non-linear inductance of the VT and the capacitances of the network in which the VT is connected.

use at 50 or 60 Hz. For fast fault detection, it might be of interest to study transients at higher frequencies than 50 or 60 Hz. The bandwidth will then tell us how the instrument transformer is likely to react for those transients. If the power frequency component is used for the fault detection the bandwidth of instrument transformers is of course sufficient since they are designed for such frequencies.

- Impulse and step responses are tools used to estimate the bandwidth of an instrument transformer. An impulse contains by definition all frequencies. A comparison of the frequency content on the secondary side of an instrument transformer will reveal the frequency response of the instrument transformer. The step response gives additional information regarding possible delay and oscillations introduced by the instrument transformer.
- Accuracy of the instrument transformer. The error of an instrument transformer can be expressed as either a magnitude error and a phase error or as a composite error that is a mean value over a period of power frequency. The composite error takes into account both the magnitude and the phase error. The phase error of an instrument transformer is a measure of the delay of the instrument transformer. The phase error of typical voltage and current transformers are small and no significant time delays are introduced. In IEC-standards, proposed standard values of the magnitude and phase errors of instrument transformers are published. The maximal phase error that is allowed is in the range of 3 degrees, which corresponds to a delay of $20 \times 3/360\,\mathrm{ms} \approx 0.17\,\mathrm{ms}$ in a power system with fundamental frequency of 50 Hz, and approximately 0.14 ms in a power system with a power frequency of 60 Hz.

It is important to consider instrument transformers as an integral part of the power system since the connected burden effects its performance.

Non-conventional transducers

Non-conventional transducers is a bad expression and is used by power system engineers to describe other transducers than instrument transformers. Well known examples of non-conventional transducers are:

- Voltage dividers that are mainly capacitive, resistive or combinations thereof. A capacitive voltage divider is used as the front-end in a capacitive voltage transformer.

- Rogowski coils, which are wound round a non-magnetic structure (i.e. the Rogowski coil is an air core transformer) and are sensitive to the flux change caused by the power system current. The output is proportional to the time-derivative of the current and is a small voltage signal (millivolts). The output is integrated and processed in a microprocessor to give the current in the conductor. The Rogowski coil is not a new concept but was investigated and published by Rogowski as early as in the 1920s.
- Low power current transducers which in fact is a current transformer with the secondary winding connected to a fixed resistance. The secondary output is taken as the voltage drop across the resistance and processed in a microprocessor to give the current.
- Optical sensors are sensitive to either the magnetic (Faraday-effect) field or the electric field (Pockel-effect).

Of the above mentioned transducers the voltage divider, the Rogowski coil, and the low power current transducer have found some use for switchgear manufacturers. The optical sensors are typically on the development stage and awaits further investigation.

Location of transducers

The location of transducers in the power system can be a difficult issue. There is a fine balance between the room and the cost as opposed to the requirement of the protection system. Conventional instrument transformers with their large amount of transformer iron in the core are expensive apparatus in the power system. Non-conventional transducers are much cheaper if only the single component is studied. However, to interpret the signals some kind of merging unit and processing capability is needed. However, non-conventional transducers are often possible to integrate in other power system equipment such as bushings, circuit breakers, insulators, or cables. This way a larger number of measuring points are economically feasible as compared to when conventional instrument transformers are being used. The nonconventional transducers can also be performed as combined sensors that give both voltage and current measurement where conventional instrument transformers would have given only one of the quantities or both CTs and VTS would have had to be used.

4.2.2 Wiring

In a distribution system, the transducers are typically located close to the relay so that the amount of wiring is limited. In a large transmission substation the distance from the transducer to the relay can easily be 50 m or more.

4.2.3 Trip coil

Traditionally, circuit breakers are operated by releasing energy stored in a large spring. The latch which holds the spring is released by energizing a coil that provides a force that acts on the latch thus releasing it. The opening coil needs a rather large power to operate the latch. The power is supplied by a circuit to which the contact of the relay is connected. Thus the relay must have contacts that are capable of closing and opening currents of say 2–3 A. Such contacts contribute to the operating time of the relay and is added to the detection time. The additional operating time must be considered when comparing the operating times of different relays. The contacts of a relay can typically have an operating time of 5 ms, which means that relays are not suitable for fast fault detection. However, the operating time can be reduced by using for example a field effect transistor to close the contacts of the relay, a method that has been used for an application where it is important with a well defined closing time.

4.2.4 Relays

Electromechanical relays

Electromechanical relays were the first relays to be used in power systems for protection purposes. The inputs to an electromechanical relay are currents and voltages from CTs and VTs in the power system.

Solid-state relays

Solid-state relays also take their input signals from the power system with the aid of CTs and VTs. The relay characteristic in a solid-state relay is achieved by circuit design based on operational amplifiers.

Digital and numerical relays

The advent of the microprocessor led to the investigation of using computers for the protection of power systems. Since the cost of components were high it was thought that one computer would be used for all protection tasks in a substation. A numerical relay[2] consists of a signal conditioning subsystem, a conversion subsystem, and a digital processing subsystem [14].

The signal conditioning subsystem contains transducers, and analogue filtering. The conversion system contain the A/D converter and sample-and-hold circuits. Analogue to Digital (A/D) converters are essential in modern protective relay equipments to be able to handle the data digitally. The A/D conversion can be treated in many different ways. Often it is important to have simultaneously taken samples of say phase voltages and phase currents. One way of achieving that is to put A/D converters on every input. However, the A/D converter is an expensive component so it would be advantageous to use less A/D converters. A solution is to sample-and-hold which means that the samples are taken simultaneously on all input channels, hold by a circuit consisting of a capacitor and then selected for digital conversion by a so-called multiplexer. The samples is then sequentially converted but due to the hold-process they are in fact simultaneous. The A/D converter can be one of typically three of the following types which are discussed in more detail by Johns and Salman [14] or Demler [15]:

- sequential counter. A counter is started from zero and the output of the counter is compared to the analogue input after a D/A[3] conversion. If the input is larger than the counter, the counter is incremented and the comparison is performed again. The process will continue until the input is larger than the value of the counter which then is taken as the digital representation of the analogue input. The principle is easy, but a disadvantage is that the conversion takes longer time for large numbers since the counter starts from zero for each sample.
- single or dual slope. The input of the A/D converter is integrated for a fixed time T_1 and stored in a register. At that time, a fixed reference voltage is connected to the input of the A/D converter and integrated. The time T_2 required for the value in the register to become zero is a measure of the input of the A/D converter.

[2] A microprocessor relay where the relay characteristic can be programmed into the microprocessor.

[3] Digital to Analogue

- parallel comparators. This type of A/D converter consists of equally many comparators as the resolution of the A/D converter, i.e. a 8-bit A/D converter consists of $2^8 = 256$ comparators. The input of the A/D converter is applied to the comparators. The output of the comparators are either zero if the input is less than the value of that comparator or one if the input is larger than the value of that comparator. The number of zeros and ones is then converted to a 8-bit digital number that is the digital representation of the input.

The three types of A/D converters are quite similar and all of them will suffice for fast fault detection purposes. For measuring equipment intended for very high frequencies, the choice of A/D converter is of more concern and it is probable that the last described type will be used, i.e. parallel comparators.

PC platform based relays

An early paper on digital protection predicted that all protective task within a substation would be handled by a single computer due to cost reasons. Instead the trend has been towards single protective relays for each feeder of the substation (and also one single protective relay for different protection tasks in that feeder). The advent of bay terminals made it possible to gather different protective tasks in a feeder into one single unit. Today, thirty years later, there exists system where all protective tasks of a substation is performed by one single industrial pc. One such system is described in (x) where its primary function is the control of an HVDC converter station, but all protective tasks in the substation was possible to implement in the industrial pc. The feeders are equipped with I/O circuit boards which gather current and voltage signals from the feeders and transfer them to the pc. It is possible to implement simple protective task in the I/O circuit board which contains a processor.

4.3 Basic protection principles

4.3.1 Magnitude relays

The magnitude of for example a current is compared to a predetermined threshold level. Whenever the magnitude is above the threshold it is determined that a fault is detected. The magnitude is not the instantaneous value of the current but instead the RMS-value or the peak value of the current.

4.3.2 Directional relays

The magnitude relay is extended so that a phase angle between the current and a so-called polarizing quantity is estimated. Then it is possible to determine whether the fault is in the forward or in the reverse direction as seen from the relay depending on the value of the estimated phase angle compared to the expected phase angle.

4.3.3 Impedance relays

The impedance relay measures a voltage and a current and makes an estimate of the impedance of the protected object. The impedance relay can be made directional and newer relays can have very complicated tripzones (i.e. the part of the power system that the relay is designed to protect). Distance relays are another name for an impedance relay but can also be equipped with a magnitude relay to further improve its ability to provide protection for the power system object that it is designed to protect.

4.3.4 Differential relays

The principle of differential relaying is always a unit protection, i.e. a differential relay protects only the object it is supposed to protect. It cannot be used for backup protection. The principle is simple; the current measured into the zone of protection must be equal the current measured out of the zone of protection, otherwise a fault has occurred within the zone of protection. Even though the principle is simple many things must be considered when implemented in a power system such as rated burden and turn ratio. A single relay requires inputs from at least two different sets of CTs thus the communication of those signals within the substation must be considered. Differential protection is a common protection principle for transformers, motors, and generators.

4.3.5 Pilot relaying

Pilot relaying is not really a relaying principle. It can consist of any of the basic types mentioned above, the difference is that a communication link is added so that two relays that protect a transmission line can communicate with each other even when placed at separate ends of a transmission line. If the concept of pilot relaying is interpreted as the ability of two or more relays to communicate with each other the increased use of numerical relays for power system protection will provide an excellent platform for all relays to be pilot relays.

4.4 Speed of protection

Fault detection has traditionally been performed by protection relays taking a certain amount of time to detect a fault. The time needed for the fault clearing is thus dependent on the fault detection time and the apparatus operating time and in case of an ac-breaker it is also dependent on the time until next natural current zero crossing. However, the speed of the protection equipment is not well-defined in standards. When discussing the speed of fault detection a number of key expressions are commonly used such as:

- High-speed relay, defined by IEEE standard [7] as: "A relay that operates in less than a specified time. Note: The specified time in present practice is fifty milliseconds (three cycles on a 60 Hz basis)"
- Fast fault detection, commonly used for fault detection within a period of power frequency but sometimes used for fault detection as fast as 40 microseconds [16].
- Very fast fault detection, commonly used for fault detection within half a period of power frequency but sometimes as fast as a few milliseconds [17].
- Ultra high speed relaying, commonly used for fault detection within a quarter of a cycle. Often implemented to detect the travelling waves caused by faults in EHV or UHV overhead lines [18].

For the remainder of this thesis fast fault detection is defined as:

Definition 4.1 F*ast* f*ault* d*etection (FFD) is defined as "fault detection for systems that require fault removal or limitation before the first current peak after the initiation of the short-circuit."*

Chapter 5

Algorithms

Algorithms for fault detection in numerical protection relays have been of academic and industrial interest since around 1970. Early algorithms were constrained by the available computer performance of that time and commonly implemented in a low level machine language[1] in order to speed up the algorithm. The performance of computers of today makes it possible to implement algorithms in a high-level language such as for example c or c++ thus making it possible to use the same software in different microprocessors. This chapter contains a brief description of common algorithms used in numerical protection relays. The source of the original material is Johns and Salman [14], and Phadke and Thorp [19]. The additional discussion on the suitability to use the algorithms for fast fault detection is contributed by the author (except when explicitly stated).

5.1 Waveform algorithms

This class of algorithms has a common property, namely the assumption that the post-fault voltage and current can be described by a sinusoidal signal $s(t)$ as for example in equation 5.1.

$$s(t) = S_{magn} \cdot \sin(\omega t + \varphi) \tag{5.1}$$

Sampled data values of current and/or voltage are then fitted to the sinusoidal waveform using one of a number of available methods. The result is

[1] Often unique to a family of microprocessors and not easily transferred to other microprocessors.

estimated values of S_{magn}, $\omega = 2\pi f$, and φ. The frequency f of the sinusoidal signal is often assumed to coincide with the nominal power frequency[2] of the power system so that only the magnitude and the phase needs to be estimated. By comparing the estimated magnitude with the magnitude during normal operation, a fault can be detected (the principle of a so-called magnitude relay as described in chapter 4).

The short-circuit current due to a fault often contains a decaying dc-component with a magnitude depending on the fault inception angle (as illustrated in figure 2.2). Equation 5.1 does not take into account that dc-component. Whenever the fault current contains a dc-component, the estimation of the fault current will therefore contain an error. The waveform algorithm that was selected for the case studies (the LSQ-algorithm of section 5.1.3) does not take into account the dc-component. However, it was demonstrated in chapter 6 that the error introduced by the dc-component in the fault current was negligible (for this algorithm) for the first current peak of the fault current.

5.1.1 Two samples

Description

Assume that two consecutive current samples i_0 and i_1 at the time instants t_0 and t_1 respectively are available and that the angular frequency ω in equation 5.1 corresponds to the nominal power frequency of the power system. Substituting into equation 5.1 gives two equations for solving the unknown parameters (I_{magn}, and φ).

$$i_0 = i(t_0) = I_{magn} \sin(\omega_0 t_0 + \varphi) \tag{5.2}$$
$$i_1 = i(t_1) = I_{magn} \sin(\omega_0 t_1 + \varphi) \tag{5.3}$$

I_{magn}, and φ can now be solved from equations 5.2 and 5.3.

If it is first observed that the time-derivative of equation 5.1 is:

$$i'(t) = \omega I_{magn} \cos(\omega t + \varphi) \tag{5.4}$$

[2] A reasonable assumption because the fault current caused by a shunt-fault is of power frequency character. Furthermore, the subject of this thesis being FFD a frequency deviation will not cause any significant error within the detection time (approximately 1 ms).

and then that:

$$
\begin{aligned}
i^2(t) + \frac{i'^2(t)}{\omega^2} &= I_{magn}^2 \sin^2(\omega t + \varphi) + I_{magn}^2 \cos^2(\omega t + \varphi) \\
&= I_{magn}^2 (\sin^2(\omega t + \varphi) + \cos^2(\omega t + \varphi)) = I_{magn}^2
\end{aligned}
\tag{5.5}
$$

Then the magnitude I_{magn} can be estimated from one current sample and one current derivative sample. The current derivative however is not always readily available. Two consecutive current samples can be used to estimate the derivative 5.6.

$$i'(t) = (i(t_1) - i(t_0))/\Delta t \tag{5.6}$$

where Δt is the time between the two samples ($\Delta t = t_1 - t_0$). The magnitude can then be estimated from equation 5.5 by substitution of equation 5.6 which gives equation 5.7.

$$I_{magn}^2(t_1) = i_1^2 + \frac{1}{\omega^2 \Delta t}(i_1 - i_0)^2 \tag{5.7}$$

Suitability for fast fault detection

Since only two samples are needed to estimate the magnitude, the algorithm has the potential to be fast. However, the calculation of the derivative can produce poor estimates if the samples are noisy or of poor quality. The derivative is calculated by taking the differential between two current samples and then divide the differential with the time difference between the two samples 5.8.

$$(i(t) - i(t - \Delta t))/\Delta t \tag{5.8}$$

If the time difference Δt is small the differential will be divided with a small number, hence magnifying possible errors in the differential. An example of this is given in chapter 6, where the algorithm is applied to an actual sampled voltage signal that is sampled at a high frequency but with poor quality of the samples. The algorithm may be interesting for FFD, but not further studied in this thesis. Another waveform algorithm (see section 5.1.3) was selected for further investigations.

5.1.2 Fourier methods

Description

The discrete Fourier transform (DFT) can be used to estimate the magnitude of a sampled signal. The assumption that the signal can be described by equation 5.1 still holds, i.e. , the signal is assumed to be sinusoidal and of a known frequency which coincides with the nominal power frequency of the power system. The literature describes full-wave and half-wave versions of DFT based algorithms. The full-wave algorithm uses sampled data from a full period of the nominal power frequency, whereas the half-wave algorithm uses sampled data from a half period of the nominal power frequency.

If the measurement noise is assumed to have zero mean and to be uncorrelated between samples, the DFT can be shown to give the optimum fit of the sampled data to the sinusoidal waveform. Algorithms based on DFT methods are used in many modern numerical relays due to its excellent properties (optimum fit, noise reduction, and harmonic filtering) and simplicity. The fast Fourier transform (FFT) is an algorithm which calculates the DFT of a discrete signal. The FFT can be applied when the signal is of a length N (N = number of samples) so that $2^n = N$ for some integer value of n.

Suitability for fast fault detection

Algorithms based on the discrete Fourier method are not sensitive to an increase in the sampling rate (as the derivative was) as will be shown in chapter 6, where the algorithm (calculation of the DFT and identification of the power frequency component) is applied to actual sampled data. However, since sampled data from at least half a period is used, the speed of protection is not increased by raising the sampling frequency. The estimate of the magnitude will still only be available after at least half a period (corresponding to 10 ms when the power frequency is 50 Hz).

Therefore, fault detection within 1 ms from fault inception is not possible with the described method.

5.1.3 LSQ-methods

Description

The abbreviation LSQ is a short notation for *L*east *Sq*uares. Phadke and Thorp [19] describes an algorithm for estimation of the magnitude and the phase of a voltage or a current signal based on three consecutive samples; each sample giving one equation for solving the magnitude and the phase. Since only two unknowns are estimated and three equations are available, the system of equations is over determined and the algorithm fits the samples by a least square error method to a sinusoidal of nominal power frequency (see equation 5.9, which can be derived from 5.1 by using a trigonometric identity $sin(x+y) = sin(x)cos(y) + cos(x)sin(y)$).

$$i(t) = I_c \cos(2\pi f t) + I_s \sin(2\pi f t) \tag{5.9}$$

If i_{-1}, i_0 and i_1 denote three consecutive current samples, the estimated magnitude of the current (at time t_0) is given by:

$$|I| = \sqrt{I_c^2 + I_s^2} \tag{5.10}$$

where

$$I_c = \frac{i_1 \cos\theta + i_0 + i_{-1} \cos\theta}{1 + 2\cos^2\theta}, \tag{5.11}$$

and

$$I_s = \frac{i_1 - i_{-1}}{2\sin\theta} \tag{5.12}$$

and θ is the power frequency angle between two consecutive samples $\theta = 2\pi f_0 \cdot \Delta t$, where f_0 is the power frequency of the power system and Δt is the time difference between two consecutive samples.

Suitability for fast fault detection

This algorithm is also potentially fast since only three consecutive samples are needed for an estimate of the magnitude. However, a similar reasoning as when taking the derivative of a signal is applicable (see section 5.1.1). The division by $2\sin\theta$ in equation 5.12 (a small number for high sampling frequencies ($\Delta t \to 0$)) is numerically sensitive to errors in the sampled signal. This is further illustrated in chapter 6, where the algorithm is applied to actual sampled data of poor quality.

The algorithm will be further investigated in the case studies in chapter 7.

5.2 Model algorithms

Description

A common property for model algorithms are that the protected power system object is modelled by differential equations. A transmission line can for example be modelled by an RL-link or a pi-link. Sampled values of voltage and current measured in the power system are then fitted to the differential equations. The result from the algorithm is estimates of the impedance of the protected power system objects. A fault is detected by comparing the estimated impedance to the nominal impedance of the protected object, i.e. a ratio relay as described in chapter 4.

Phadke and Thorpe [19] describe an algorithm for estimation of apparent impedance to a fault based on three consecutive samples. The algorithm fits the samples by solving a differential equation that models the protected object as a resistance in series with an inductance (see figure 5.1).

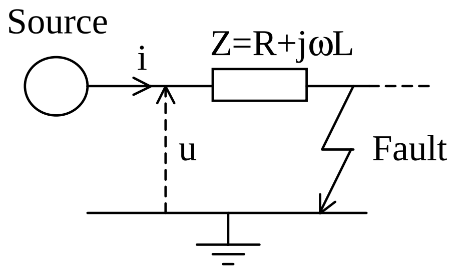

Figure 5.1. The power system used in the differential equation algorithm.

The relationship between i and u can be written:

$$u = L\frac{di}{dt} + Ri \tag{5.13}$$

The impedance $R + j\omega L$ can now be estimated by fitting current and voltage samples to equation 5.13. Let $(i_k,\, i_{k+1},\, i_{k+2})$, and $(u_k,\, u_{k+1},\, u_{k+2})$ denote the sampled values of current and voltage, the estimated impedance of the protected object are then given by equation 5.14. If the estimated impedance is high there is no fault and $R + j\omega L$ is an estimation of the impedance of the load. If the estimated impedance is low there is a fault and $R + j\omega L$ is an estimation of the impedance of the fault.

$$\begin{aligned} R &= \left[\frac{(u_{k+1}+u_k)(i_{k+2}-i_{k+1})-(u_{k+2}+u_{k+1})(i_{k+1}-i_k)}{(i_{k+1}+i_k)(i_{k+2}-i_{k+1})-(i_{k+2}+i_{k+1})(i_{k+1}-i_k)}\right] \\ L &= \frac{\Delta t}{2}\left[\frac{(i_{k+1}+i_k)(u_{k+2}+u_{k+1})-(i_{k+2}+i_{k+1})(u_{k+1}+u_k)}{(i_{k+1}+i_k)(i_{k+2}-i_{k+1})-(i_{k+2}+i_{k+1})(i_{k+1}-i_k)}\right] \end{aligned} \tag{5.14}$$

The dc-component in the fault current does not introduce errors with this algorithm because it is accounted for in the model. A decaying dc-component $C_1 e^{-\frac{R}{L}t}$ is a part of the solution to equation 5.13.

Suitability for fast fault detection

Even this algorithm has the potential of being fast. The denominator, however, will become small for high sampling frequencies introducing similar numerical difficulties as previously discussed. This algorithm will be further investigated in chapter 7.

5.3 UHS-relaying

Description

The abbreviation UHS is a short notation for *U*ltra *H*igh *S*peed. As mentioned in section 4.4, the expression UHS-relaying is used for fault detection within a quarter of a period of the power frequency. Common algorithms used for UHS-relaying are so-called travelling wave algorithms. Travelling wave algorithms measure the travelling waves generated by the initiation of the fault. One algorithm uses measurements from both ends of a transmission line to determine whether the fault is on the transmission line or not [18].

Suitability for fast fault detection

The travelling waves travel along the transmission line with a speed close to that of light. For distribution systems, which in general deliver power to a rather small area, travelling wave algorithms have the potential of being fast. Travelling wave algorithms are mostly used for transmission systems were the damping of the transients is low ($R \ll X$) and the transients are easier to detect. In distribution systems however, the damping is often higher and the travelling waves not easily detected. A further consideration regarding travelling waves is that a distribution system is smaller (but can have more feeders) than a transmission system. Distribution systems are often (at least in Sweden) a mixture of overhead lines and cables with lots of junctions. When a travelling wave reaches a junction, one part of it is reflected and one part of it is transmitted but now even more attenuated making it harder to detect.

5.4 Instantaneous current algorithm

Description

A straightforward method to detect a fault is to use the instantaneous value of the sampled current and determine that a fault has occurred when a certain level has been exceeded. However, any error in the data acquisition system or a power system transient could give a single current value higher than the trigger level, thus causing a false fault detection. To make the fault detection less sensitive to random instantaneous current values above the trigger level, a technique similar to the fault type classifier described by Phadke and Thorp [19] can be used. Phadke and Thorp uses a fault type classifier algorithm to determine which phase(s) that possibly is faulted and performs further calculations on that phase(s) to reduce the computational burden of the microprocessor. No trip signal is based solely on the fault type classification scheme. In this thesis the fault type classifier algorithm will be used to detect a fault and a trip signal will be issued if the threshold is exceeded. Furthermore, a higher sampling frequency (as compared to Phadke and Thorp [19]) is used in this thesis.

The algorithm can be described by the following steps:

(i) Set the counter to zero
(ii) Take samples of the three phase-currents. The phase-currents are filtered before the samples are taken. The filter is a low-pass filter that will filter out high-frequency components such as for example capacitor energization currents from the measured currents. The low-pass filter will be described in section 5.4.1.
(iii) If the absolute value of the current is larger than the trigger level increase the counter by one. Otherwise decrease the counter by one (unless the counter is zero).
(iv) If the counter is equal to five, calculate the differential of the current and if the differential is above a threshold, issue a trip signal. The current differential is used to discriminate a fault from a transformer energization as described in section 5.4.2.
(v) Repeat from (ii)

The original fault type classifier is extended with a low-pass filter and a current differential criteria.

Suitability for fast fault detection

A sampling frequency high enough to allow fault detection within 1 ms will be selected. If no delays whatsoever are added to the sampled data values, the condition of a fault detection within 1 ms would correspond to a sampling frequency of $f_s = 5 \cdot \frac{1}{1e^{-3}}$ Hz $\approx$ 5 kHz. In practice, a higher sampling frequency will be used, since the sampled data values will be somewhat delayed. This algorithm will be further investigated in the case studies (chapter 7).

5.4.1 Low-pass filter

Capacitor energization can produce high inrush currents with high derivatives. The inrush current however is not of nominal power frequency but of higher frequencies determined by the inductance and capacitance of the actual circuit. One method to discriminate a capacitor inrush current from a fault current is to use a low-pass filter that can be applied before the instantaneous samples are taken in the algorithm. The anti-aliasing filter in the data acquisition system is a low-pass filter that makes sure no frequencies above half the sampling frequency is included in the signal to avoid erroneous result when reconstructing the signal (half the sampling frequency is called the Nyqvist frequency) [3]. However, since it is desired to use a high sample rate so that the time for five consecutive samples to fall above the trigger level is small, the anti-aliasing filter determined by the sampling frequency will let through much of the capacitor energization transient. To filter the capacitor energization transient the cut-off frequency of the anti-aliasing filter will be modified (lowered). It is possible to use such a filter since the fault current given by a shunt fault is of power frequency. Furthermore, a low-pass filter introduces a phase delay that also must be taken into account when studying the fault detection time. The phase delay grows larger as the cut-off frequency is decreased. Once a cut-off frequency is determined it must be verified that the phase delay is not too large so that the fault detection takes more than 1 ms. If the phase delay is less than 1 ms it is possible to achieve FFD within 1 ms by increasing the sampling frequency sufficiently.

A low-pass filter is not ideal[4], i.e. frequency components lower than the cut-off frequency will be attenuated as well as frequency components higher

[3] A classical result from signal processing theory. See for example Proakis et. al. [20].

[4] Ideal as in mathematically perfect.

than the cut-off frequency will be passed through the filter. The actual properties of low-pass filters has not been investigated in this thesis. In the chapter on case studies (chapter 7), existing models of low-pass filters have been used and the cut-off frequencies has been selected as if the low-pass filters were ideal.

5.4.2 Current differential

Power system transients such as for example capacitor energization or transformer energization could give rise to current values above the trigger level even though no fault has occurred. Sometimes it is possible to increase the trigger level to make sure that capacitor energization is not detected as a fault. If it is not possible to raise the trigger level, the derivative (throughout this thesis, the derivative is always assumed to be taken with respect to time if not otherwise stated) of the current can be used as a conditional fault detector so that the trip signal is only given at the same time as the derivative is above a certain level. As previously discussed, there might be numerical difficulties to calculate the derivative since the division with a small time step will magnify possible errors in the sampled signal. The differential current in-between two time steps $(i(t) - i(t - \Delta t))$ will be used instead of the derivative $((i(t) - i(t - \Delta t))/\Delta t)$ to avoid some of the numerical difficulties. At least, potential errors in the measured signal are not amplified. A study of the differential in case of a fault will be compared to the differential when energizing a capacitor and a transformer to determine whether the differential can be used to discriminate between the three events.

5.4.3 Extension of the method to provide directional properties

The algorithm based on instantaneous current samples described above is not directional. If the power system contains two sources (as for example a local generator), high currents may flow in the system for faults outside the protection zone that shall not be detected as a fault. In [1] the application of an algorithm (described in section 5.2) that uses three consecutive samples to form an estimate of the impedance of the protected object is described. Such an algorithm has directional properties but is sensitive to errors in the sampled signals if the sampling rate is selected too high. For that particular study, the estimated impedance was reasonable at a sampling rate of 4 kHz.

At that sampling rate it is possible to calculate an estimate of the impedance in less than 1 ms. If the two methods are executed in parallel, a fast directional algorithm can be obtained. The extension of the algorithm (which will be executed in parallel to the instantaneous current value method) can be described as:

(i) Sample the current and voltage at 4 kHz.
(ii) Estimate the impedance of the protected object using equation 5.14.
(iii) If a fault is detected inside the protection zone and if the instantaneous current value method has produced a trip signal, forward the trip signal as an output of the algorithm.

5.5 Arc detector

In case an arcing fault occurs inside an enclosed switchgear, the damage can be extensive as previously discussed in chapter 2. Thus, it is of great value to be able to disconnect such faults as quickly as possible independent of the method used to mitigate the fault. A typical magnitude relay can detect a fault within 20 ms after the fault inception. It is relatively easy to reduce that time if the detection is based on the light from the arc. Such a device can detect arcing faults within 1 ms after fault inception. However, whenever the light is not easily available or ambiguous, fault detection based on other principles such as those described in this chapter are required.

Chapter 6

Sources of errors

6.1 Reliability

Reliability of a relay protection system can be described from two aspects: *dependability* and *security*. The *dependability* of a relay protection system is the ability to detect and disconnect all faults within the protected zone. The *security* of a relay protection system is the ability to reject all power system events and transients that are not faults so that healthy parts of the power system are not unnecessarily disconnected . The two aspects are contradictive in the way that the more dependable the system is, the more sensitive it is and the risk for false detection is then increased.

6.2 Power system transients

A power system normally is in a quasi-static state (quasi because it is impossible to achieve a perfectly static state since the load and the generation change and because most power systems are AC-systems, i.e. the voltage and current changes from sample to sample). Whenever an electrical path is changed in the power system, a transient state will occur until the power system has settled in a new quasi-static state. The change of the electrical path can be due to for example circuit breaker operation and power system faults. A few frequently occurring transients which might give rise to currents similar to those of a fault are briefly discussed here.

6.2.1 Capacitor energization

When energizing a capacitor there is a transient in form of an inrush current. The magnitude and frequency of the current transient depends on the impedance of the actual circuit and the instant when the switching takes place. If the capacitor is energized when the voltage across the switch is zero there is a small transient; if the capacitor is energized when the voltage across the switch is near its peak the transient will be larger. If the capacitor is used solely for reactive power generation, the transient will be larger than if it is equipped with an inductor, thus forming a filter. The current transient will cause a transient in the voltage as well. The magnitude of the voltage transient depends on the strength of the system and of the magnitude of the current transient.

When a charged capacitor is located electrically close to an uncharged capacitor the current transient (measured between the capacitors) when charging the capacitor will be very large since only the impedance between the capacitors limit the inrush current. That impedance is small if the capacitors for example are connected to the same busbar with only a few meters of cables and/or conductors in-between.

A remedy against capacitor switching transients has already been touched upon, namely to make sure that the capacitor is energized at zero voltage, thus limiting the transient. Such solutions, known as synchronized switching, exist and have been proven in service for many years. Protection systems based on a common hardware platform can, as previously discussed in section 4.2.4, perform more tasks than just protection. If the capacitor switch (and as will be shown later also transformer switch) can be synchronized, the transients will be mitigated thus making it less likely that the fault detection algorithm is disturbed. Low-pass filtering also reduces the probability that the inrush current will influence the fault detection since the inrush current is of a high frequency character (see figure 6.2).

6.2.2 Transformer energization

The energization of an unloaded power transformer can sometimes lead to current transients which can be large in magnitude and highly distorted. Since the resistive load is low (the transformer is unloaded), the damping is also low and such transients can last for many seconds before they are attenuated. The distortion has a typical second harmonic content [19] that can be used to discriminate between transformer inrush currents and power system faults. However, estimating the level of the second harmonic current takes too long time and for fast fault detection other means of discrimination must therefore be investigated. The magnitude of the inrush current transient depends on the switching instant and on the remanence of the transformer core [19]. If the direction of the inrush current is so that the flux in the core coincides with the direction of the remanence flux, the core might become saturated, hence providing large currents for its magnetization.

A remedy against transformer inrush current has already been touched upon, namely to make sure that the transformer is energized when the voltage is at its peak (another example of synchronized switching). The inrush current which is of an inductive nature will lag the voltage by a quarter of a period of power frequency, hence starting from a low value. The probability that the core will be driven into saturation is lowered and the inrush currents will be smaller. If the direction of the remanent flux can be estimated or measured, the synchronized switching can be made even better if the switch is controlled so that it closes its contacts in a way so that the remanence flux decreases with the first current half-period.

When no synchronized switching is used, unfavorable switching instants will occur from time to time so the worst case scenario is not an unusual event. Low-pass filtering will not help to discriminate between a fault and transformer energization as it could for capacitor energization. Since the transformer inrush-current has a high content of the second harmonic, a low-pass filter designed to filter out the second harmonic will contribute with a phase error, hence introducing a delay. A second order Butterworth filter for example will contribute with a time delay of approximately 3.5 ms when the cut-off frequency is selected to 75 Hz[1]. It will be demonstrated in the case study that it is possible to discriminate between a transformer inrush current and a fault by evaluating the current derivative. The current derivative is larger for a power system fault than for a transformer energization.

[1]The time delay has been estimated with EMTDC simulations by using a Butterworth filter from a library with common power system components available within EMTDC.

6.2.3 Faults

Power system electrical faults are also of transient character. Faults that are inside the zone of protection [2] are not considered as errors because they are meant to be detected. Faults outside the zone of protection can disturb the algorithm if the fault currents are close to, or larger than, the trigger level. Even though a fault is detected it might be so that the protection system of a neighboring system should have cleared that fault.

Another potential source of error with respect to fault currents is the decaying dc-component (as illustrated in figure 2.2) that is appearing in the fault current immediately after fault inception. For example the LSQ-algorithm described in chapter 5, three consecutive samples are used to estimate the magnitude of the fault current under the assumption that they can be fitted to a sinusoidal waveform. The dc-component however is not a sinusoidal waveform and will lead to an error of the estimated current. Figure 6.1 contains the estimated current and the instantaneous current for a fault where the fault current contains maximal dc-component. The figure is taken from the IEC case study (chapter 7) and the sampling frequency is 4 kHz. It can be concluded by analyzing figure 6.1 that the dc-component does not contribute with a large error and for the purpose of fault detection within 1 ms from the fault inception the error is negligible.

6.2.4 Identification of differences

The differences between capacitor energization, transformer energization, and a fault current is summarized in this section. The currents associated with each of the three power system transients are plotted in figures 6.2, 6.3, and 6.4. The load current before the transients were applied was 630 A_{RMS}. The current associated with the energization of a capacitor is plotted in figure 6.2. The current is higher than the load current, and contains lots of high frequency components that depends on the inductance and capacitance of the actual circuit. The current associated with the energization of a transformer is plotted in figure 6.3. The current is higher than the load current, and contains a dc-component and a second harmonic current. Finally, a fault current is plotted in figure 6.4. The fault current is (in this case) much higher than the load current and is of power frequency character. For this

[2] The zone of protection is a part of the power system that a protective device is designed to protect. All faults inside the zone of protection will be detected by the relay, but not faults outside the zone.

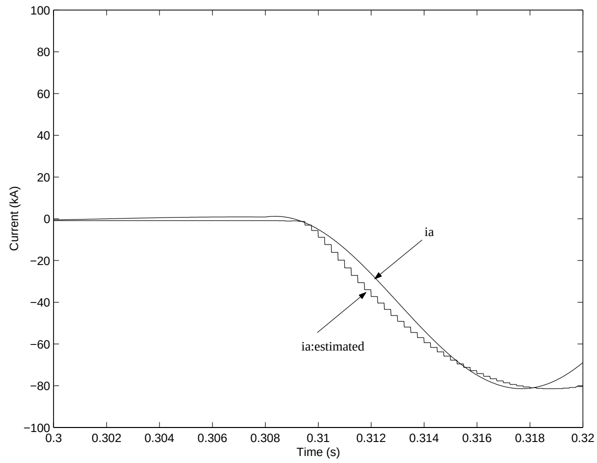

Figure 6.1. The effect of the dc-component on the estimated current (expressed in kA)

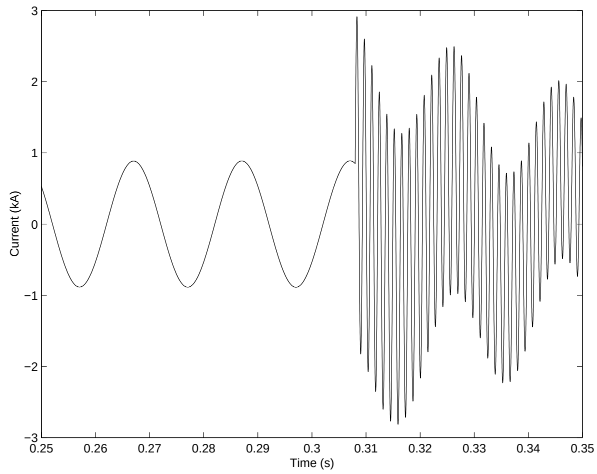

Figure 6.2. The current associated with capacitor energization

particular case it is possible to discriminate between a fault and the other two power system transient by selecting the current level for which a fault is detected (trigger level) sufficiently high. For other power systems the gap between the load current and the fault current might be smaller, thus making it difficult to find a trigger level with which it is possible to discriminate between the three events. In sections 5.4.1, and 5.4.2 it is described an

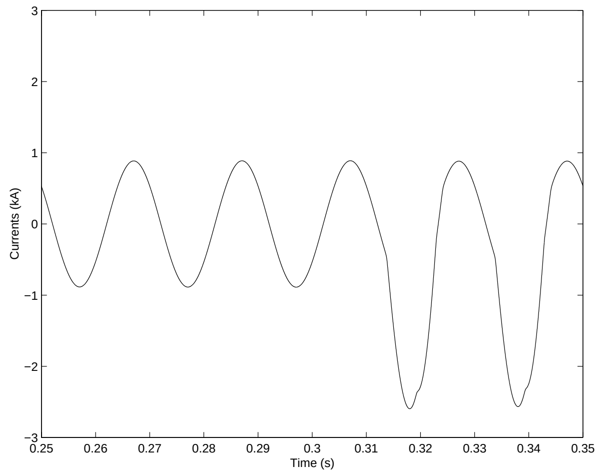

Figure 6.3. The current associated with transformer energization

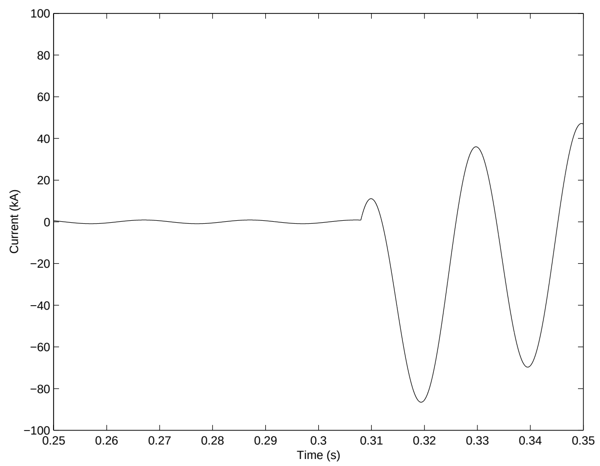

Figure 6.4. The current associated with a power system fault

alternative way to discriminate between the three power system transients.

6.3 Data acquisition equipment

Before power system data can be used in the microprocessor for fault detection, it must be measured in the power system and then transferred to a format that the microprocessor can handle. The microprocessor works with digital signals whereas the output of the measurement equipment often is an analogue signal. The analogue signal must be converted to a digital signal before it is further processed. Communication channels are also needed to transfer both analogue and digital signals between transducers, protection equipment and possibly other equipment within the substation.

6.3.1 Transducers

The word transducer is in this thesis used in the sense that it is a power system component used to create an image of the signal under study which can be used by the protection equipment (after processing).

Voltage transformers

Voltage transformers (sometimes referred to as potential transformers) has been subject to standardization by for example IEC and IEEE. The accuracy of a voltage transformer is well-defined by the standards. The IEC proposes two accuracy classes for voltage transformers used for protective purposes[3], namely class 5P and 10P. A voltage transformer that is rated according to class 5P has an error of less than 5% at rated voltage and rated burden. A voltage transformer that is rated according to class 10P has an error of less than 10% at rated voltage and rated burden. The voltage transformer is rated for a given frequency (most often 50 or 60 Hz), but the standard does not specify how a voltage transformer behaves at frequencies other than the rated one. For transient measuring the step-response and the bandwidth of a voltage transformer is crucial. For voltage transformers used for fast fault detection according to principles previously mentioned, the high frequency properties are not that important since the fault detection mainly is based on investigating the power frequency current or voltage. According to Lehtonen [21], the magnitude response of a magnetic voltage transformer is flat up to at least 1000 Hz. For certain burdens the phase error might be an issue but not for the power frequency component. In the case studies (chapter 7) it was assumed that the magnitude response of both CTs and VTs is equal to one for all frequencies so the possible attenuation of high frequencies inherent to a VT is not accounted for.

Saturation of the iron core is normally not considered an issue for voltage transformers since the voltage usually drops in case of a fault, thus increasing

[3] There are other accuracy classes for voltage transformers used e.g. for instruments or revenue metering.

the marginal to saturation. However, a single line to earth fault in a power system with high impedance system earthing will produce a voltage rise in the two healthy phases. Voltage transformers used in such systems are constructed to cope with the voltage rise (at least for a limited time). It is instead more crucial that the accuracy is maintained even for low voltages if the voltage samples are used in fault detection algorithms such as described in section 5.2.

Voltage transformers used in distribution systems (typically up to say 66 kV [12]) are typically pure magnetically coupled iron core transformers. Due to cost reasons it would be disadvantageous to build such transformers for higher voltages. At these voltages *C*apacitive *V*oltage *T*ransformers (CVTs) are used instead. They consist of a capacitive voltage divider which has an output in the kV-range. A magnetically coupled core type voltage transformer is then connected in series with the capacitive divider, providing an output of reasonable magnitude for use with secondary equipment such as protection equipment. An inductor is also connected in series with the capacitor voltage divider and the magnetic voltage transformer [22]. The inductor is selected so that the LC-circuit thus formed is tuned to the power frequency of the power system. As for the magnetic voltage transformer, the behavior of the CVT at frequencies other than the power frequency is not specified by the standards. Capacitive voltage transformers produce a voltage transient when the voltage is suddenly changed such as when a fault occurs. Generally, the voltage transient must be considered when applying algorithms that use the voltage but is not further considered in this thesis.

Current transformers

Current transformers also have been subject to standardization. The accuracy of a current transformer is well defined by standards and IEC allows a multitude of accuracy classes for current transformers for protective purposes. A current transformer rated for protective purposes might for example be designated 5P20, where the P stands for *P*rotection, the number 5 stands for the maximum allowed composite error of the current transformer expressed in percent, and the figure 20 stands for the overcurrent factor for which the maximum error is allowed (and for all currents lower than that given by the overcurrent factor). The overcurrent (I_{oc}) is related to the rated current of the current transformer by multiplying the overcurrent factor with the rated current $I_{oc} = 20 \cdot I_n$, where I_n is the rated current of the current transformer.

When a fault occurs in the power system the probability that the current transformer will become saturated is quite high. Especially in power systems where fault current limiters are used where the fault currents are likely to be large. A fault current has previously been demonstrated to contain a decaying dc-component as well as a steady state ac-component (fig 2.2). A current transformer can be saturated due to the dc-current and due to the ac-current. The result of the saturation however is the same; the output of the current transformer will be small or even zero depending on the connected burden. It is not sure whether saturation is a concern when applying fast fault detection since it depends on the choice of transformer, the burden of the connected data acquisition equipment, and the fault current. The fault is probably detected and cleared before the current transformer becomes saturated. The use of correctly rated current transformer however is crucial. If two power systems are connected with a sectionalizing fault current limiter, consideration must be made to make sure the current transformers are correctly rated to avoid possible saturation.

The step-response and the bandwidth of a current transformer is also crucial when fast fault detection algorithms are applied. However, the methods described previously (chapter 5) in this thesis use primarily the power frequency component of the fault current for the fault detection. When applying fault detection based on other principles such as for example a travelling wave, the high frequency properties of the current transformer must be considered. High frequency properties of a current transformer is better than the corresponding property for a voltage transformer. Lehtonen [21] has shown that the magnitude response for a particular current transformer was flat up to almost 10000 Hz.

6.3.2 A/D converter

The properties of an A/D (Analogue/Digital) converter including anti-aliasing filter, sample (and hold) circuits, and quantization circuits also contributes to the error of the measured data.

When the sampling rate has been selected the characteristics of the anti-alias filter can be determined. Due to the Nyqvist criteria the anti-aliasing filter must be a low-pass filter with a cut-off frequency corresponding to half the sampling rate. For high sampling frequencies the cut-off frequency of the anti-aliasing filter is also high, thus letting through much of the content within the signal including high-frequency noise which can be interpreted as an error by the fault detection algorithms. The phase error introduced by the anti-aliasing filters however tends to zero when the cut-off frequency tends to infinity. For a method discussed earlier 5.4, it was proposed that to be able to discriminate a capacitor switching from a fault, a low-pass filter could be used. The cut-off frequency of such a filter should be set much lower than a regular anti-aliasing filter (i.e. half the sampling frequency), hence introducing a phase error upon the signal. The phase error constitutes a delay in the sampled signal and the delay depends on the design of the filter and in particular on the choice of the cut-off frequency.

For cost saving reasons, one A/D converter is often used together with an analogue multiplexer so that the samples of different signals are not truly simultaneously but instead sequentially sampled. The speed of the conversion determines the maximal allowed sampling rate and the number of signals that can be multiplexed into one A/D converter. If better performance is required, one A/D converter per channel can be used.

The accuracy of the A/D converter is often expressed in bits. An 8-bit A/D converter provides $2^8 = 256$ possible digital levels for the signal. The analogue signal will be rounded to fit into one of these 256 digital levels. If the signal is ± 10 kV (peak value), each digital level will correspond to $20000/256 \approx 78$ V. If a 12-bit A/D converter is considered, then it provides $2^{12} = 4096$ possible digital levels for the signal. The analogue signal will be rounded to fit into one of these 4096 digital levels. If the signal is ± 10 kV (peak value), each digital level will correspond to $20000/4096 \approx 4.88$ V. As will be shown later in the section on algorithm dependent errors, an 8-bit A/D converter can limit the sampling frequency for a certain algorithm though it provides quite a lot of noise in terms of round-off errors, which the algorithm is sensitive to.

6.3.3 Processor word length

The word length of the processor also contributes to the error. However, microprocessors used in modern protection relays typically have a word length of 16 bits. If the accuracy of the A/D converter is 8-bits or 12-bits, the word length will not be a limiting factor. If complicated algorithms are used then there might be a small error due to the word length but probably not of any importance. For an algorithm that uses only the instantaneous current values, the word length is not a limiting factor because no calculations are performed, only a comparison with the trigger level.

6.3.4 Processor speed

The processor speed determines how fast an algorithm can be executed. It is essential that the algorithm can be executed in between two consecutive samples, otherwise the sampling rate has been selected too high for that particular algorithm. Choosing a low-level program language such as assembler instead of a high-level program language such as Fortran or c++, may increase the execution speed but is seldom necessary for standard fault algorithms used in existing relay protection of today. Industrial PCs used in so-called common hardware platforms are probably fast enough to allow sampling rates much higher than those proposed in this thesis. An example of such a system is manufactured under the designation MACH-II [23]. Microprocessors used for calculating time instants for triggering pulses in power electronics applications such as current controlled thyristor converters should be suitable for fault detection as well. The hardware platform used for controlling large HVDC converters (manufactured as MACH-II) surely manages sampling frequencies at those rates proposed in this thesis especially since the algorithm is very simple.

6.4 Algorithm dependent errors

Algorithms contribute to the error in the estimated signal (which could lead to a false fault detection) in various ways. It is important to realize that the actual signal is not known in advance. An algorithm that assumes that the signal is a perfect sinusoidal signal will generate an error due to the harmonic content and other noise in the power system signal. Another type of "error" an algorithm can contribute to is to amplify errors in the sampled data if not carefully designed. The word "error" is put inside quotes because the algorithm is correct under the assumptions made. However, the algorithm can amplify potential errors in the sampled signal. Numerically unstable might be a better word to use than "error".

An algorithm that is used to estimate the magnitude of a voltage or a current signal (studied in more detail in section 5.1.3) was found to be dependent on the sampling rate. The algorithm fits sampled data values to a sinusoidal signal and the magnitude is given by equation 6.1. The magnitude of the current at sampling value k is denoted by $|I|$.

$$\begin{aligned}
|I| &= \sqrt{I_C^2 + I_S^2}, \text{ where} \\
I_C &= \frac{[i_1 \cos\theta + i_0 + i_{-1}\cos\theta]}{1 + 2\cos^2\theta}, \text{ and} \qquad (6.1)\\
I_S &= \frac{[i_1 - i_{-1}]}{2\sin\theta}
\end{aligned}$$

The sampling rate determines the value of Δt and if selected too high, Δt will be a small number, thus any error contributed by the measurement and by the subtraction of two almost equal numbers will be amplified when divided by a small number. This is illustrated when applying the algorithm from equation 6.1 on measured data sampled at 20 kHz and data from the same measurement downsampled to 1 kHz. As can be seen in figure (6.5), the algorithm gives a much smoother estimation of the magnitude when sampled at 1 kHz as compared to when sampled at 20 kHz.

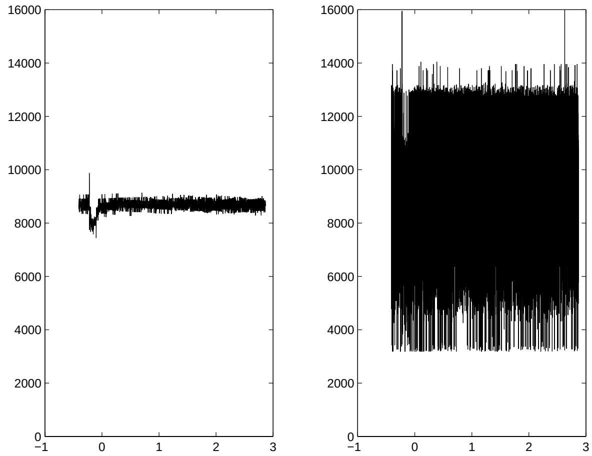

Figure 6.5. Estimated magnitude when applying a sensitive algorithm to measurements with different sampling rates. The left-hand graph contains an estimation of a voltage downsampled to 1 kHz and the right-hand graph contains an estimation of the same voltage sampled at 20 kHz. The timescale of the x-axis is seconds.

The algorithm based on the discrete Fourier transform (see section 5.1.2) is not so sensitive to the sampling rate. This algorithm uses data samples from a whole period and the result is given in figure (6.6) for two different sampling rates (1 kHz and 20 kHz respectively.) However, since data samples

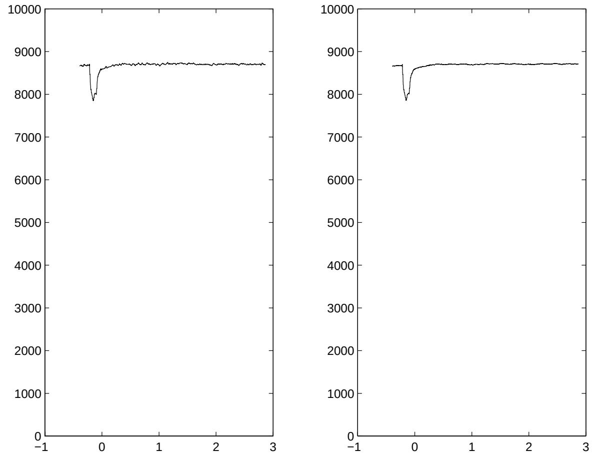

Figure 6.6. Estimated magnitude when applying a not so sensitive algorithm to measurements with different sampling rates. The left-hand figure contains a plot of the estimated magnitude when the sampling frequency was 1 kHz and the right-hand figure contains a plot of the estimated magnitude when the sampling frequency was 20 kHz.

from a whole period is used not much is gained by raising the sampling frequency. The estimate of the current magnitude is not available until after about 20 ms (corresponding to one period of power frequency).

The algorithm based on three consecutive samples of voltage and current (see section 5.2) shows to be equally sensitive to errors in the data as the algorithm described by equation 6.1. This time the algorithm assumes that the protected power system can be described by a differential equation e.g. a RL-link describing a transmission line (or/and a load). If three consecutive samples of voltage and current are available, the apparent impedance of the transmission line can be estimated by using equation 6.2 that was given in section 5.2. If the apparent impedance of the transmission line deviates from the expected, it is likely that a fault is present.

$$\begin{aligned} R &= \left[\frac{(v_{k+1}+v_k)(i_{k+2}-i_{k+1})-(v_{k+2}+v_{k+1})(i_{k+1}-i_k)}{(i_{k+1}+i_k)(i_{k+2}-i_{k+1})-(i_{k+2}+i_{k+1})(i_{k+1}-i_k)}\right] \\ L &= \frac{\Delta t}{2}\left[\frac{(i_{k+1}+i_k)(v_{k+2}+v_{k+1})-(i_{k+2}+i_{k+1})(v_{k+1}+v_k)}{(i_{k+1}+i_k)(i_{k+2}-i_{k+1})-(i_{k+2}+i_{k+1})(i_{k+1}-i_k)}\right] \end{aligned} \tag{6.2}$$

Simplification of the common denominator of equation 6.2 gives that it can be written as:

$$-2\left[i_{k+1}^2 - i_k i_{k+2}\right] \tag{6.3}$$

The expression given by equation 6.3 tends to zero as the sampling rate tends to infinity. A small denominator tends to amplify errors in the sampled signals, which was demonstrated for the LSQ-method earlier in this section.

Taking the numerical approximation of a derivative of a sampled signal is subject to numerical difficulties. The derivative of a signal $f(t)$ is defined as:

$$f'(t) = \lim_{h \to 0} \frac{f(t) - f(t-h)}{h} \tag{6.4}$$

When the signal $f(t)$ is not known analytically an estimate of the derivative can be formed by taking the differential between two samples and dividing with the time difference between the samples.

$$f'(t) \approx \frac{f(t) - f(t - \Delta t)}{\Delta t} \tag{6.5}$$

The estimate will be poor if Δt is selected too large and the signal varies rapidly. On the other hand, the estimate can also be poor if Δt is selected too small, possible errors in the sampled signal will be magnified when their differential is divided by a small number Δt. This is illustrated in figure 6.7, where the derivative has been calculated at a sampling frequency of 20 kHz and after that the signal has been down sampled to 1 kHz. The derivative calculated at 20 kHz sampling frequency is extremely noisy and difficult to analyze, whereas the derivative calculated at 1 kHz sampling frequency is quite smooth.

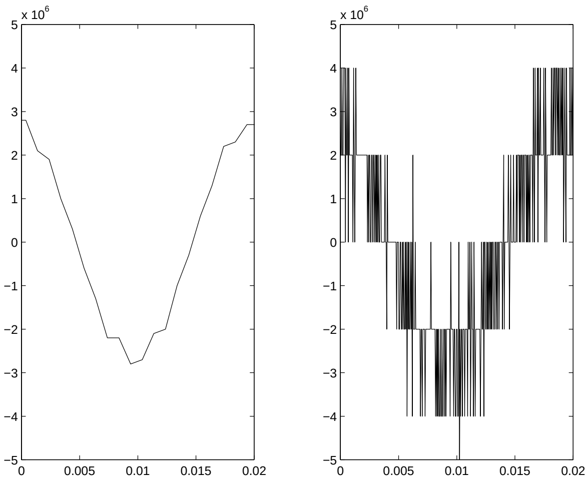

Figure 6.7. The derivative of a signal sampled at two different sampling frequencies

Chapter 7

Case Studies

Two case studies have been performed in order to investigate the performance of algorithms for fault detection and current limiting concepts on a model of a real power system. The modelling and simulation has been performed with EMTDC[1] — a computer program for studying transient electrical problems [24]. The case studies were performed using two power systems, the first one based on standard values of rated system voltage, rated nominal load current, and rated short-circuit current as given by the IEC (denoted as the IEC case study), and the second case study was based on power system data from an electrical power distribution system at SSAB Oxelösund, Sweden (denoted as the SSAB case study). Three different types of fault detection algorithms have been studied; one waveform algorithm (see section 5.1), one model algorithm (see section 5.2), and one instantaneous current algorithm (see section 5.4).

7.1 IEC case study

The international standard IEC 60694 [25] publish preferred ratings of switchgears and controlgears. For this case study the following ratings have been selected and power system impedances have been calculated based upon them:

- system voltage $u_h = 12$ kV
- nominal load (phase) current $i_n = 630$ A (measured at the load Z_L in figure 7.1)

[1]**E**lectro-**M**agnetic **T**ransients in **DC** systems

- short-circuit phase current in case of a solid three-phase fault
  $i_k = 40$ kA

The time-constant[2] of the power system (when no load is connected to the power system) was selected to 45 ms, corresponding to a power factor of $\cos\varphi = 0.0705$. The power factor of the load was selected to $\cos\varphi = 0.8$, a typical value for common load types. Figure 7.1 contains the single line

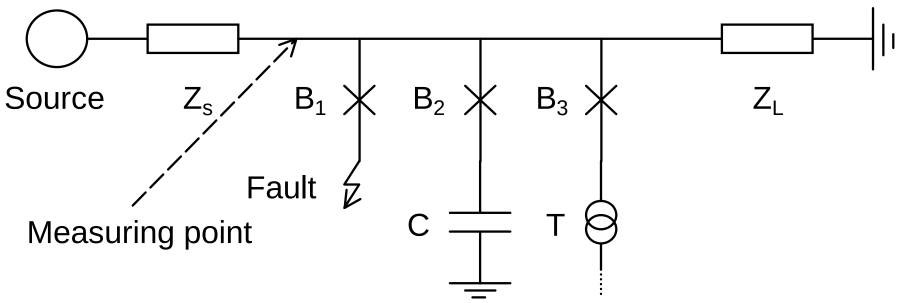

Figure 7.1. IEC case study single line diagram

diagram of the power system used in the IEC case study. The source is modelled as an infinite source, that is with no limits on active or reactive power production. The source impedance is $Z_S = 0.0122 + j \cdot 0.173$ Ω, which corresponds to a short-circuit current of 40 kA_{RMS}. The load impedance was $Z_L = 8.79 + j \cdot 6.44$ Ω, which corresponds to a load current of 630 A_{RMS}. Three circuit-breakers, B_1, B_2, and B_3 respectively, were used to apply three power system transients. The first circuit-breaker was used to simulate faults imposed on the power system. Mostly three-phase faults were studied, however a few two-phase faults were also studied to investigate if they also could be detected using algorithms from this thesis. Single-phase faults are only briefly considered within this thesis, since distribution systems are commonly high impedance earthed[3] so that the fault current of a single-phase fault is in the order of a few Amperes. The second circuit-breaker was used to simulate capacitor energization, and the third

[2]The time constant of a power system is a measure of the time it takes for transients to develop or to attenuate.

[3]At least in Sweden except for the 400 V distribution system that is solidly earthed.

circuit-breaker was used to simulate transformer energization. The capacitor and transformer data was taken from data sheets of an actual power system, namely the same power system as that one used in the SSAB case study below. The capacitor was rated at 4.08 MVAr at 12 kV (10.5 kV in the SSAB case study) corresponding to a capacitance of 90.19 μF, and the transformer was rated at 10.2 MVA at 12 kV (10.5 kV in the SSAB case study). The capacitor and the transformer was implemented in EMTDC, using basic building blocks from a library with common power system components available within EMTDC. The transformer model is not just a ratio changer but saturation is also included. Since not all parameters of the actual transformer were known, standard values from the EMTDC power system component library were used. Finally, a user defined component was used to implement three algorithms that were investigated with respect to speed of fault detection. The user defined component can be described by the block diagram of figure 7.2.

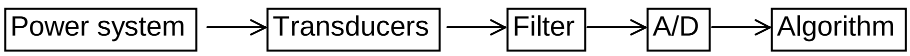

Figure 7.2. A block diagram describing the implementation of algorithms in EMTDC

7.1.1 Common considerations

The trigger level of the fault detection, i.e. a fault is detected when the current exceeds the trigger level, was selected to 3 times the RMS-value of the nominal load current (a typical setting of an overcurrent relay is within 2.5 – 6 times the nominal load current according to an experienced relay protection engineer). A simple data acquisition system consisting of a low-pass filter and a simplified A/D converter[4] was added to the case study to be able to study some of the requirements and limitations of such a system. The measuring transformers however were implemented as ideal ratio-changers. For two of the fault detection algorithms that were implemented (the LSQ-method and the differential equation method), the low-pass filter was designed with a cut-off frequency equal to half the sampling frequency to avoid

[4] The Analogue to Digital converter model did not include quantization, i.e. no round off errors were introduced.

aliasing. For the third method (the instantaneous current method) the low-pass filter was selected in a different manner that is described in more details later in this chapter. The input data to the algorithms (i.e. sampled values of voltage and current) was measured close to the source (to the right of Z_S in figure 7.1). Since the scope of this thesis is fast fault detection for power systems where current limitation or interruption before the first peak is required, the algorithms studied are intended to detect all faults within the power system[5]. In a power system with a traditional relay protection system, each feeder (the source, the capacitor, the transformer, and the load in figure 7.1) would have had its own protection equipment[6], but in a power system where current limiting is used it is likely that most faults have to be limited rapidly by a current diverter (see chapter 3) or a current limiter (see chapter 3), which are typically located at the source or at a sectionalizing position. There is however an advantage to perform measurements in several feeders, namely that the location of a fault might be easier to find.

7.1.2 Fault detection with the LSQ-method

A LSQ-method proposed by Phadke and Thorp [19] was previously described in section 5.1.3. The method uses three consecutive current samples and fit them to a sinusoidal current of unknown magnitude and phase by a LSQ-method. The result is an estimate of the magnitude (and phase) of the current. Whenever the estimated current exceeds the predetermined trigger level a fault is likely to have occurred and a trip-signal is issued[7].

First, three-phase faults were imposed on the power system. The fault inception angle, i.e. the phase angle of the system voltage when the fault occurs, was swept over a time interval corresponding to one period of fundamental power frequency. A total of 20 simulations were performed and for each simulation the fault detection time was observed. The sampling frequency was also allowed to vary and the 20 simulations were repeated for four different sampling frequencies, namely 1, 2, 4, and 8 kHz respectively.

[5]At least all faults that will give rise to fault currents that will be potentially high and have to be limited.

[6]Even though fast fault detection is implemented, the existing protection equipment in each feeder is still important. It will protect the feeder for all faults that do not require fast fault detection, such as for example interturn faults in the stator of a rotating machine.

[7]The trip-signal is implemented in EMTDC as a binary signal which can take two values, the binary signal is zero if no fault is detected and one if a fault is detected. The binary signal can be used to control e.g. a circuit-breaker or a fault current limiting apparatus, but that is not included in this case study.

The result is summarized in table 7.1 from which it can be concluded that to achieve a fault detection time within 1 ms a sampling frequency of at least 2 kHz is required, but to allow for a margin, 4 kHz was selected as an appropriate sampling frequency. The estimated current magnitude at a sampling

Sampling frequency	Maximum detection time
1 kHz	3 ms
2 kHz	1 ms
4 kHz	0.5 ms
8 kHz	0.38 ms

Table 7.1. The maximum fault detection time for different sampling frequencies.

frequency of 4 kHz is shown in figure 7.3 together with the instantaneous current samples. When the sampling frequency was increased to 16 kHz, it was apparent that the estimated current contained bad estimates similar (but not as bad) as illustrated in figure 6.5.

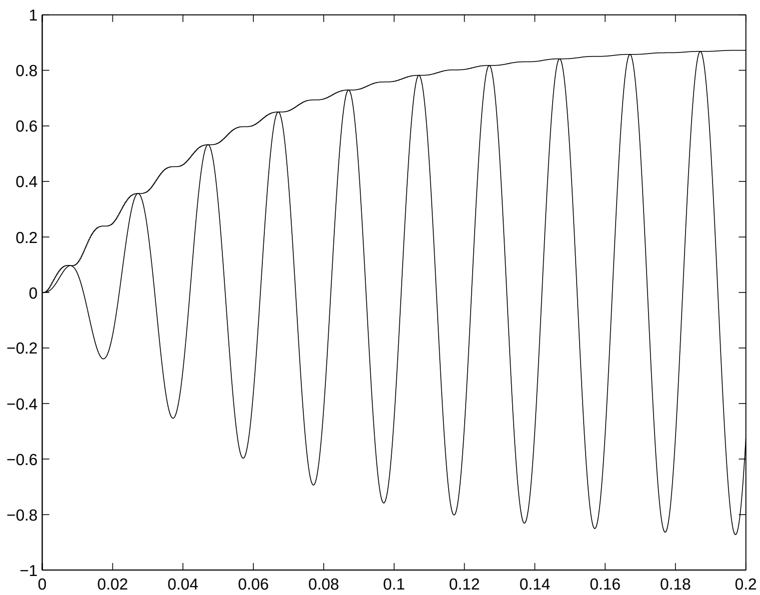

Figure 7.3. The estimated current and the instantaneous current values. In EMTDC the source voltage is ramped up to its nominal value at the start of the simulation and consequently the current is also ramped to its nominal value since the load is a pure impedance.

Transformer and capacitor energization were also simulated. The capacitor energization gave rise to large currents that was falsely interpreted as a fault. An attempt to lower the cutoff frequency of the low-pass filter was not successful. Even though the cutoff frequency was lowered to 300 Hz, the inrush current due to the capacitor energization was still interpreted as a fault. The low-pass filter was replaced with a bandpass filter that was given such a characteristic as to let through the power frequency component ($\pm10\%$). The simulation was repeated but this time the capacitor energization was not interpreted as a fault. A further simulation was performed to study the speed of the fault detection with the new filter. The fault detection time was prolonged to approximately 1.25 ms.

A few two-phase faults were also simulated. With nothing else changed, the fault detection time was now approximately 3.5 ms for some fault inception angles. When the sampling frequency was raised to 8000 Hz, it was possible to lower the fault detection time to 3.38 ms, and when the sampling frequency was raised to 16000 Hz, the fault detection time was lowered to 3.32 ms. No further attempt was made to raise the sampling frequency since the LSQ-algorithm produced bad estimates (similar to figure 6.5) for sampling frequencies above 16000 Hz.

Finally, single phase faults were simulated to verify that such faults were not detected by the algorithm. For some fault inception angles, a fault was detected in that phase were the single-phase fault was applied. However, such situations can be avoided by the requirement that a fault must be detected in at least two phases. For this particular study, the reason that a single phase fault gave rise to fault currents large enough to be detected as a fault is probably that the modelling of the system grounding resistance is inaccurate. The grounding resistance has no or little effect on three and two phase faults so the inaccurate choice of grounding resistance does not effect the results obtained in this case study concerning three and two phase faults.

7.1.3 Fault detection with the differential equation method

A differential equation method (described in section 5.2) was implemented as a user defined component in EMTDC to investigate if it was a possible algorithm to use for fast fault detection. The trigger level was treated in a slightly different manner for the differential equation method than for the LSQ-method since a low value of estimated resistance and inductance is a sign of a fault in the power system, whereas a higher value of estimated resistance and inductance is a sign of normal operating conditions. Trying to find a trigger level that makes it possible to compare the different methods to each other, the trigger level was selected to one third of the nominal resistance and inductance of the protected object[8]. A first simulation was made to determine the nominal resistance and inductance of the protected power system i.e. the source and the load of figure 7.1. It was concluded that the nominal impedances of the protected power system were: $R_{nom} = 8.791\ \Omega$, and $L_{nom} = 0.0205$ H corresponding to a reactance of $X_{nom} = 6.44\ \Omega$. I.e. the estimated impedances are equal to the load impedance if no fault is applied. Hence, the trigger level was set to $R_{nom}/3$ and $L_{nom}/3$. An example of an estimated resistance is given in figure 7.4, where the resistance and the trigger level is plotted. For that particular simulation, the sampling frequency was 1 kHz and the fault was applied at t = 0.32 s. The fault detection in this particular phase was 5 ms. Once the trigger

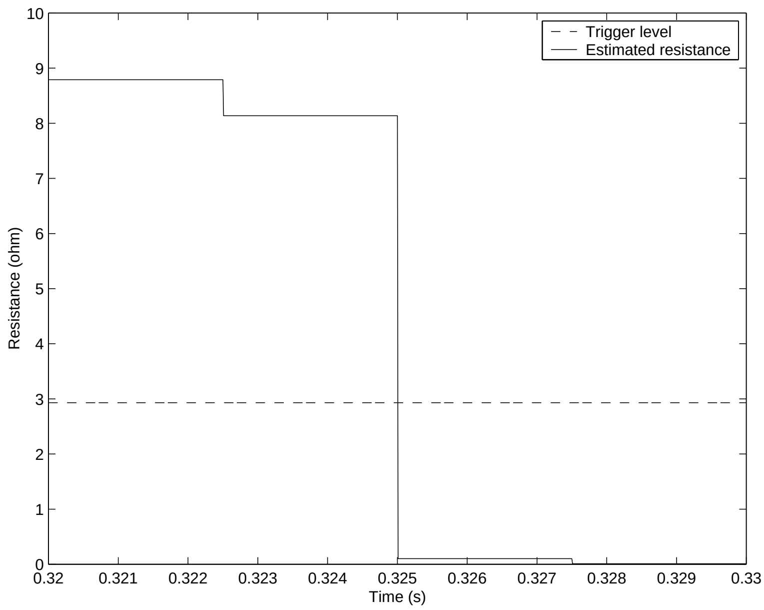

Figure 7.4. The estimated resistance during a fault.

level was selected, a number of simulations were performed (20) and the fault inception angle was moved 1 ms in between each simulation. The fault

[8]Instead of 3 times the nominal current as for the LSQ-method and the instantaneous current values method.

detectors were placed in each of the three phases of the power system and the sampling frequency was 1 kHz as earlier mentioned. The 20 simulations were then repeated but now with sampling frequencies of 2, 4, and 8 kHz respectively. The result of the $4 \cdot 20$ simulations is summarized in table 7.2, where the largest detection time for each sampling frequency is given. Since the point of wave of the fault initiation is a random value, fault initiation will eventually take place in a time so that the maximum fault detection time is obtained. The maximum detection time must always be shorter than approximately 1 ms if fault clearing before the first prospective current peak is the target. From the maximum fault detection times given in table 7.2 it

Sampling frequency	Maximum detection time
1 kHz	3 ms
2 kHz	1 ms
4 kHz	0.75 ms
8 kHz	0.38 ms

Table 7.2. The maximum fault detection time for different sampling frequencies.

can be concluded that for this particular system, fast fault detection can be obtained with the differential equation method with a sampling frequency of at least 2 kHz. To provide a larger margin it would be appropriate to select the sampling frequency to at least 4 kHz.

Once the sampling frequency had been determined to 4 kHz, further simulations were performed. The energization of a power transformer and a capacitor were simulated for a number of simulations (20) were the point of wave of the switching instant was varied over a period of power frequency. The trigger level was the same as before and the purpose of the simulations was to find out how the differential equation algorithm responded to common power system transients that are not faults. The energization of the capacitor proved to constitute a problem since it was falsely detected as a fault. An attempt was made to lower the cutoff frequency of the low-pass filter since capacitor energization produces a high frequency (with respect to the power frequency of the power system) inrush current. However, it turned out that it was not possible to filter out all of the high frequency content of the inrush current. Even though the cutoff frequency was selected to 100 Hz, a fault was still detected when the capacitor was energized. When the low-pass filter was replaced by a bandpass filter that was designed to let through only the power frequency component (±10%), the capacitor energization was not detected as a fault. A bandpass filter however produces a phase error which will constitute as a time delay so that the fault detection is delayed. At 4 kHz sampling frequency the fault detection time was now approximately 1.8 ms (as compared to 0.75 ms when using the conventional low-pass filter as determined by the Nyqvist criterion). An attempt was made to raise the sampling frequency and it turned out that when the sampling frequency was set to 8 kHz the time to detect a fault was still approximately 1.5 ms. An attempt to further increase the sampling frequency to 16 kHz did not turn out well since the algorithm did not respond well at that frequency and produced bad estimates (similar to figure 6.5) that were not reliable. Thus, the differential equation method (at least this version) does not seem appropriate for fast fault detection in power systems where capacitors are present. It is likely that other transients such as for example cable energization, asynchronous motor starts, synchronous motor starts, and incipient cable faults will disturb the algorithm.

Transformer energization was also simulated, both with the conventional low-pass filter (according to the Nyqvist criterion) and with the bandpass filter that was described above. With the conventional low-pass filter faults were falsely detected when the transformer was energized. The cutoff frequency of the low-pass filter was lowered in order to find out if it was possible to find a cutoff frequency for which the algorithm did not interpret transformer energizations as faults. Similar to the capacitor energization it was not possible to find a cutoff frequency so that the transformer energization was not interpreted as a fault. If the low-pass filter is replaced by a bandpass filter, the algorithm will probably discriminate faults from transformer energization, but it is not necessary to perform that simulation because the fault detection time will be more than 1 ms and not possible to improve by raising the sampling frequency as was discussed above.

7.1.4 Fault detection based on instantaneous current values

The trigger level was selected to 3 times the nominal load current. The fault type classifier (without the current differential and the modified low-pass filter) that was described in section 5.4 was implemented in EMTDC and three power system events were simulated. The three-phase fault was correctly detected and when the sampling frequency was selected to 10 kHz, the fault detection time was never more than 0.5 ms for 20 different fault inception angles corresponding to a complete power frequency period. However, both the transformer energization and the capacitor energization also produced a trip signal. Investigation of the sampled data signals revealed that it would be quite easy to raise the trigger level to avoid false trip signals for this particular case and still be able to detect faults within 1 ms. However, for systems were it is not possible to raise the trigger level other solutions must be investigated.

First the differential of the current ($\Delta i = i_n - i_{n-1}$) was investigated. The differential between the current value when the trip signal was issued and the current value one sample earlier was compared for the fault current, the capacitor energization and the transformer energization respectively. It turned out that it was possible to discriminate between a fault and a transformer energization by using the current differential, but not between a fault and a capacitor energization. The current differential for a fault current was more than seven times the current differential for a transformer inrush current.

Second, the characteristics of the low-pass filter was modified so that the cut-off frequency was lowered below the cut-off frequency determined by the Nyqvist criterion. A second order Butterworth filter with a cut-off frequency of 300 Hz was found to be suitable for this particular study. Now it was possible to discriminate between a fault and a capacitor energization.

With the current differential criteria and the modified low-pass filter the fault detection time was now approximately 1.0 ms and the simulated fault was the only power system event for which a trip signal was issued. The capacitor energizing was discriminated from a fault by low-pass filtering of the signal and the transformer energization was discriminated from a fault by using the current differential. The phase delay of the filter was estimated to be approximately 0.75 ms (included in the detection time of 1 ms) by investigating the sampled signals.

7.1.5 Results of the IEC case study

It was found that the method of using instantaneous current values (without the modified low-pass filter and without the current differential criterion described in section 5.4) and combine those instantaneous current samples in an appropriate manner was suitable for fast fault detection for the IEC case study. With a sampling frequency of 10 kHz the fault detection time was less than 1 ms.

It was also found that the method could discriminate between power system faults and capacitor energization but then the method would have to be extended so that the instantaneous current samples are subject to low-pass filtering before processed.

A further extension of the method was to study the current differential between two samples in order to be able to discriminate between a fault and a transformer energization. It was shown that transformer energization could be discriminated from a fault by using the current differential.

A method based on a differential equation that fitted sampled voltage and current signals to a power system model in order to produce an estimate of the apparent impedance of the protected object was shown to be not particularly well suited for fast fault detection (at least not for this particular power system). Three phase faults were correctly detected by the method but capacitor and transformer energization imposed problems that could not be solved without exceeding a fault detection time of 1 ms.

A method based on a least-square fitting algorithm to produce an estimate of the peak value of the measured current was also proven to detect faults within 1 ms with a sampling frequency of 4 kHz. However, with the traditional filter settings given by the Nyqvist criterion, capacitor energization also produced estimated currents that were interpreted as faults. When substituting the low-pass filter with a bandpass filter it was possible to discriminate between a three-phase fault and a capacitor energization. Further simulations proved that the energization of a transformer also was possible to discriminate from a fault by using the bandpass filter. Two-phase faults were also possible to detect but then the fault detection time was more than 1 ms, even after the sampling frequency was raised to 16 kHz.

7.2 SSAB case study

SSAB[9] is a Swedish steel company with business at several locations in Sweden as well as abroad.

The steel plant at SSAB Oxelösund, Sweden, is the largest Nordic manufacturer of heavy plate [26]. SSAB Oxelösund has participated in the project "New techniques for electricity supply of industrial systems including e.g. local generators."[10] and has provided the power system data used in this case study.

[9]**S**venskt **S**tål **A**ktie**B**olag

[10]The project was performed at the Competence center in electric power engineering at KTH from 1997 until 2002.

7.2.1 The electrical power system at SSAB

A reconnection of the local generator at SSAB has been investigated by Wikström et.al. [27]. Such a reconnection would be beneficial since it would lower the power losses in the system and since the short-circuit power at 10.5 kV would be higher, also allowing for a more efficient operation of the power system. However, the reconnection would not be possible without major strengthening of the 10.5 kV power system since the short-circuit withstand capability would be exceeded. An alternative to strengthening of the system could be to use so-called fault current limiters (see chapter 3). If the fault current limiters shall be able to limit the current before the first peak of the prospective fault current, fault detection within 1 ms combined with an apparatus fault clearing time of not more than 2 ms is required.

Currently, the steel plant at SSAB is supplied by three power lines at the voltage level 130 kV. The short-circuit power at the 130 kV terminals at SSAB is approximately 2250 MVA. In addition SSAB has a local generator supplied with process gas. The local generator is rated 81.25 MVA at 10.5 kV, but is usually operated at 30-40 MVA[11]. The single-line diagram in figure 7.5 gives a brief summary of (a simplified part of) the electrical power system at SSAB after the reconnection of the local generator.

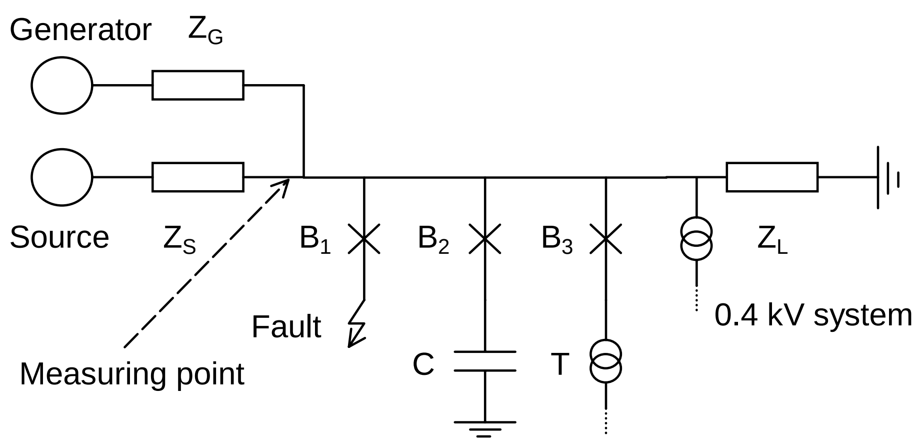

Figure 7.5. SSAB case study single line diagram

[11] According to Pasi Hyvönen at SSAB

The 130-kV grid and a 55 MVA transformer (130 kV/10.5 kV) were implemented as an infinite source in series with an impedance (source and Z_S in figure 7.5). The local generator was implemented in EMTDC using a basic building block from a library with common power system components available within EMTDC (generator and Z_G in figure 7.5). Most of the parameters of the local generator were known but for a few parameters that were not known, standard values values from the EMTDC power system component library were used. The load is implemented as an impedance ($Z_L = 5.84 + j \cdot 2.83$ in figure 7.5). Three circuit-breakers, B_1, B_2 and B_3 respectively, were used to apply three power system transient. The first circuit-breaker was used to simulate faults imposed on the power system. Mainly three-phase faults were studied, but a few two-phase faults were studied to investigate whether such were possible to detect within 1 ms using algorithms from this thesis. Single-phase faults were not studied since the system is high impedance earthed so that fault currents caused by single-phase faults are in the order of a few Amperes. The second circuit-breaker was used to simulate capacitor energization and the third circuit-breaker was used to simulate transformer energization. The capacitor and transformer data was taken from data sheets of the actual power system at SSAB. The capacitor was rated at 4.08 MVAr at 10.5 kV corresponding to a capacitance of 117.8 μF. The capacitor and the transformer was implemented in EMTDC using basic building blocks from a library with common power system components available within EMTDC. The transformer model is not just a ratio changer but saturation is also included. Since all parameters of the actual transformer not were known, standard values from the EMTDC power system component library were used. Finally, an user defined component was used to implement three algorithms that were investigated with respect to speed of fault detection.

To determine an appropriate trigger level, three-phase faults were first simulated at the 0.4 kV level for different fault inception angles. The maximal current measured in the 10.5 kV system was 1.75 kA_p, which is approximately 1.5 times the peak current of the nominal load current. Thus it can be concluded that the trigger level can be set to 3 times the nominal current for this system.

7.2.2 Fault detection with the LSQ-method

A number of simulations have been performed to estimate the current magnitude when a fault occurs, using the equations of section 5.1.3. The sampling rate, fault inception angle and the detection level, i.e. when the magnitude of the current exceeds a set value corresponding to a fault in the system, have been varied throughout the calculations and their effect on the fault detection time evaluated. When setting the detection level to 3 times the pre-fault current in the load, it is possible to reach a detection time of just about 3 ms with a sampling rate of 1 kHz, a detection time of just about 1.5 ms with a sampling rate of 2 kHz and a detection time of 0.75 ms with a sampling rate of 4 kHz. Hence, for this case study fast fault detection can be achieved based on monitoring the current magnitude. However, the energization of a capacitor or a transformer were also (falsely) detected as faults.

7.2.3 Fault detection with a differential equation method

To be able to distinguish a fault in the 10.5 kV system from a fault in the 135 kV system, some kind of directional criterion is required. Otherwise, a fault in the 135 kV system would operate the current limiter or diverter even though the 10.5 kV system can withstand such a fault. The second algorithm proposed (equations from section 5.2) can provide such a directional criterion. For faults within the 10.5 kV system the apparent resistance and inductance will always be positive whereas a fault in the 135 kV system will yield negative apparent resistances and inductances. Faults in the 0.4 kV system correspond to much higher apparent resistance and inductance than the other two fault locations. Hence, it is possible to distinguish a fault in the 10.5 kV system from a fault in the 0.4 kV and the 135 kV systems by measuring the voltage and current at a single location. However, also for this algorithm, capacitor and transformer energization were falsely detected as faults.

7.2.4 Fault detection based on instantaneous current values

The algorithm using instantaneous current values (see section 5.4) have also been applied to the SSAB case study.

The same power system events as for the IEC case study were simulated. For faults at the 0.4 kV level no trip signal was issued but for faults at the 130 kV level a trip signal was issued. The calculation of apparent impedance was now added to the simulation and the trip signals of the two algorithms were connected in series so that a trip signal was issued only if both algorithms detected a fault. The instantaneous current method detects fault both in the 130 kV and in the 10.5 kV system whereas the impedance algorithm can distinguish between faults at different voltage levels (or at least if the fault is upstream or downstream as seen from the measuring transformers). The simulations showed that it was possible to select trigger levels so that fault detection was possible within 1 ms and so that faults at the 130 kV level did not produce a trip signal. Furthermore, capacitor and transformer energizations were simulated. None of those energization produced a false trip.

7.2.5 Results

The application of the LSQ-method and the differential equation method gave as result that it is possible to use them for fast fault detection — at least in the simplified system. However, since both capacitor and transformer energization were falsely detected as faults, the methods are severly limited

The instantaneous current method however, was able to detect a fault within 1 ms from fault inception and to discriminate a fault from capacitor and transformer energization.

7.3 Shortcomings of the simplified power systems

Both of the power systems used for the case studies are quite oversimplified. No consideration is given to transient phenomena that is not related to power system faults except for transformer and capacitor energization. It is of course possible to model more possible sources of errors in the simplified model of SSAB but impractical to consider all sources of errors. The IEC case study is purely theoretical i.e. there is no measurements made that could be used to verify that the model is implemented correctly and that the results obtained are reliable. The SSAB case study is built upon a model developed by Wikström [28] and to some extent verified against measured power system data.

A simulation can never substitute actual measurements and experiments in a real power system, only complement it. In practice there are very few power system engineers that would be allowed to perform actual testing of power system protection equipment in a real power system. Since faults in a power system has great consequences it is not advisable to create real faults in the power system just to test the fault protection equipment. Simulations are a better way to test the power system protection equipment. It is important to realize that a simulation is (even if quite complex events can be simulated) a simplified model of the real power system. Some thoughts on making calculations instead of performing experiments in the power system is available in appendix B.

Chapter 8

Conclusions and future work

8.1 Conclusions

Lets for a moment consider the list of the main contributions of this thesis as given in chapter 1. The list is repeated here for convenience.

- a structured survey on the speed of fault detection and on the benefits of fast fault detection. In particular, "fast" fault detection is defined.
- an evaluation of possible algorithms appropriate for fast fault detection.
- requirements on equipment and algorithms used for fast fault detection.
- a case study of the application of fast fault detection in one typical grid and in one grid at a Swedish steel plant.

Fast fault detection was defined in chapter 4 after finding out that the existing definitions of speed of protection were quite crude. When the rate of rise of the fault current and the operating time of the fault clearing equipment was taken into account, fast fault detection was defined to mean fault detection within 1 ms measured from the inception of the fault.

The evaluation of algorithms suitable for fast fault detection led to the selection of three algorithms that would be further investigated, namely the LSQ-method, the differential equation method, and the instantaneous current values method.

The requirements on equipment and algorithms pointed out items to consider when dimensioning a system for implementation of fast fault detection. Many of the requirements were related to high frequency sampling of analogue signals. The case study showed that a sampling frequency of

10 kHz was suitable for the instantaneous current method. A sampling frequency of 10 kHz is not a particularly high sampling frequency so that existing microprocessor-based platforms currently used for power systems applications should be able to serve as a platform even for fast fault detection.

The case study was performed using two power systems and by using the simulation software EMTDC. The three algorithms mentioned above were implemented in EMTDC and several simulations were performed. It was concluded that the algorithm using instantaneous current values was suitable for fast fault detection for the systems under study. The differential equation algorithm was also suitable for detecting faults but it turned out that it was difficult to discriminate between faults and common power system transients that are not faults but still produce higher currents than the nominal load current. The LSQ algorithm gave somewhat better results than the differential equation algorithm and it turned out to correctly detect three phase fault while still discriminating between faults and common power system transients. When two-phase faults were simulated the LSQ algorithm detected them but not within 1 ms for a few fault inception angles. The instantaneous current values algorithm did manage to detect two phase faults within 1 ms, thus determined to be the most suitable for fast fault detection out of the three algorithms under study.

8.2 Future work

Some ideas for future work are summarized in this section. The algorithm based on instantaneous current values will be further investigated with an extended set of power system transients. Modifications in order to make the algorithm more robust will be proposed and evaluated. Since a fault current contains a large power frequency component it could for example be possible to use a PLL (**P**hase **L**ocked **L**oop) and build criteria for fault detection on deviations from the locked state. Methods (including PLL) that also, in addition to detect faults, could be used to control apparatus used for fault current limitation or solid-state circuit breakers will be investigated. Fault current limiters built from controllable power electronics need a reference to generate trigger signals at appropriate time instants. Some configurations of fault current limiters are dependent on operation close to a natural current zero crossing which the above mentioned methods (including PLL) might be able to predict. A proposed continuation of the project will concentrate on:

1. A case study on how current diverters, fault current limiters, solid-state breakers, and conventional circuit breaker can be combined in a power system. Different combinations will be studied and possible advantages and disadvantages of those combinations will be discussed. An important issue to be examined is whether protection and control algorithms can be used by all apparatus in a combination, thus providing coordination benefits.
2. Signal processing methods to enhance the understanding and behavior of methods which extract the power frequency component (including PLL) in a short time.
3. Evaluate criteria for fault based on the use of methods that extract the power frequency component. The criteria will be evaluated with the aid of EMTDC or SIMPOW simulations of power systems, preferably correlated with actual measurements. An important work will be to study deviations in the methods and how sensitive apparatus depending on current or voltage zero are to those deviations. In case of large harmonic content in the signals (e.g. capacitor bank switching) extra voltage or current zero crossings can occur. What are the consequences in terms of transients in the power system if the methods falsely predicts one of the extra zero crossings instead of the power frequency component zero crossing?
4. Alternative criteria for fault detection such as:
   (a) Injection of unique frequency components into the power system. The unique frequency should be selected as to not interfere with any resonance frequencies in the system and higher than the power frequency of the power system. In case of a fault involving zero-sequence components it might be possible to make a fast fault detection by analyzing zero-sequence components. Since the injected frequency is unique, precise filters can be used to find that frequency and since the frequency is selected higher than the power frequency, it will rise faster.
   (b) Use methods from transmission systems to detect faults by observing the so-called travelling waves caused by the initiation of the fault.

Appendix A

Analysis of voltage dips measured at SSAB Oxelösund

A.1 Introduction

THE content of this appendix is based upon work carried out within the project "*New techniques for electricity supply of industrial systems including e.g. local generators*" performed at the *Competence center in electric power engineering* at KTH[1] since 1997. The project team consists of members from KTH, ABB, Birka Energi, Vattenfall, and SSAB[2] Oxelösund (denoted as SSAB for the remainder of this chapter).

Power quality was early identified as an important topic within the project. Voltage dips were identified as the main cause of electrical disturbances within industries. SSAB had for many years been aware of the problem, which even led to the building of a new overhead line (three 130 kV lines altogether) in order to strengthen the grid at SSAB. The number of voltage dips at SSAB is well documented by years of measurements in the local 230 V grid [29]. The measurements were performed as single-phase measurements using the electrical outlets. I.e. the voltages that were measured was phase-voltages.

[1] Kungl Tekniska Högskolan, Stockholm, Sweden
[2] *S*venskt *S*tål *A*ktie*b*olag

Since the measurements at SSAB were performed in the 230 V grid, i.e. single-phase measurements, the project team decided to make measurements in the 10 kV grid in order to collect data from a three phase system. The measurement equipment was installed and monitored by ABB Corporate Research from May 1999 until March 2000. During that time nearly 40 voltage dips were recorded, most of them during the summer.

In this report two methods for characterization of voltage dips are described. Furthermore, voltage dips measured in three different voltage levels are correlated and compared. Finally, causes and consequences of some of the recorded voltage dips are investigated.

A.2 Methods

A.2.1 Characterization of voltage dips

This report describes two methods of voltage dip characterization and present the result of the methods applied to measurements. The measurements were made at SSAB in Oxelösund by ABB Corporate Research during 1999. Altogether 112 recordings are available spanning from 1999-06-13 until 2000-03-16. However, out of the 112 recordings only 38 have captured voltage dips. Due to a broken tap-changer, the power system was operated at a higher voltage than normal, thereby causing unwanted trigging of the measurement equipment.

The equipment used for the measurements was:

- 3 pieces of Fluke 42 for RMS voltage measurement
- a SMR transient recorder
- and 3 pieces voltage probes (x10)

Furthermore, a modem was installed so that the measurement equipment could be monitored and the measurements downloaded for off-line evaluation. The measuring equipment was installed in a 10.5 kV switchgear, using three existing voltage transformers[3]. The measurement equipment was trigged when the RMS-voltage was outside the interval $5600\,\mathrm{V} < U_{rms} < 6500\,\mathrm{V}$. Each measurement contains four channels, time and three phase-voltages. Each channel contains 65536 samples. The sampling frequency was $f = 20$ kHz, corresponding to a recorded time of $3.2768s$ for each measurement. Thus, the resolution in time is good, but the resolution in voltage magnitude is poorer since the resolution of the A/D converter only was 8

[3]I mina anteckningar p KTH

bits peak-to-peak i.e. each quantization level corresponds to a voltage of 100 V[4].

Characterization by the RMS-method

A straightforward way to characterize a single-phase voltage dip is to calculate the minimum value of the RMS-voltage during the dip (see figure A.1). For each time instant, the RMS-voltage is calculated over a time window corresponding to one period of power frequency. If the number of samples per period is denoted by N, the RMS-voltage at sample point n is calculated by using equation (A.1), which is valid from sample $n = N$:

$$V_{rms}(n) = \sqrt{\frac{1}{N} \sum_{i=n-N+1}^{i=n} v_i^2} \tag{A.1}$$

The duration of the dip is also of importance. In this report the duration is defined as the time during which the RMS-voltage is below 90% of the pre-fault value (see figure A.1). In the case of a three-phase system, a voltage

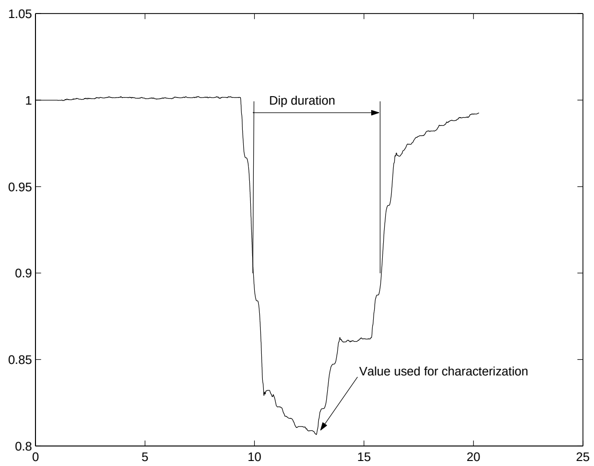

Figure A.1. Characterization with the RMS-method

dip can be characterized by the minimum RMS-voltage during the dip. In case of a symmetrical voltage dip, the minimum RMS-voltage is the same

[4]The quantization level depends on the voltage range and on the bit resolution as $V/2^8$. For these measurements V was selected so that the quantization level was 100 V.

in all phases. For unsymmetrical voltage dips, the phase with the deepest dip is selected for the characterization.

Characterization by characteristic voltage

The material in this subsection was derived by Zhang [30] and summarized here for convenience.

A three-phase voltage dip can be characterized by three parameters:

1. The dip-type is either A, C or D. The dip is of type A if equally deep in all three phases. The dip is of type C if deeper in two phases than in the third one. The dip is of type D if deeper in one phase than in the other two.
2. The characteristic voltage is a phasor which quantifies the severity of a three-phase voltage dip. It is defined as the subtraction of positive-sequence voltage and negative-sequence voltage of type[5] C_a.
3. The Positive and Negative factor (PN-factor) is an additional phasor to quantify a three-phase unbalanced dip where the system's positive- and negative- sequence impedances are not equal. If the PN-factor is close to unity, the dip can be quantified by the characteristic voltage alone.

Furthermore, the duration of the voltage dip is given. I have used the same duration as for the RMS-characterization for easy comparison of the two methods.

A.2.2 Comparison of voltage dips recorded at different voltage levels

Whereas the mechanical, and thermal consequences of a short-circuit fault often is limited to small areas of the power distribution system, the voltage dip associated with the fault can often be noticed in large parts of surrounding power systems. For example, a fault in Hallsberg (120 km from SSAB as the crow flies), would give a voltage dip down to 77% at the 130 kV terminals at SSAB in Oxelösund [29].

Measurements at 130 kV and 0.4 kV voltage levels are available from the same time period as the measurements at 10.5 kV. The measurements at 130 kV were performed by Vattenfall in a power system electrically close to SSAB. The measurements at 0.4 kV were performed in the electrical socket

[5] C_a denotes a dip of type C, with phase a being the deviant. The same notation is used for C_b, C_c, D_a, D_b and D_c.

in an office at SSAB. There have been no synchronization of the clocks of the three measurement devices, but recordings differing not more than a couple of minutes have been defined as simultaneous, at least if the magnitude of the recorded dips are in the same range and no other events have occurred in the same period.

A.2.3 Cause and consequences

In order to cope with voltage dips it is important to know how they are caused and what consequences they have. SSAB has provided event data from the plant related to the times when voltage dips have occurred. Furthermore Vattenfall, the supplier of power to SSAB, has provided event data from the 130 kV grid related to the times when the voltage dips occurred. For each dip, the RMS-voltage, duration, cause, and consequences are tabulated.

A.3 Results

A.3.1 Characterization of voltage dips

Characterization by applying the RMS-method to the recordings resulted in table A.1 which is copied from the report [5] and also the plot in figure A.2. Only measurements where the RMS-voltage during the dip dropped below 0.90 p.u. are presented. Furthermore, the characterization by characteristic voltage resulted in table A.2 taken from the report [5] and also the plot in figure A.3. Only recordings were the voltage dropped below 0.90 p.u. are presented. The dip-type is either A, C or D. The dip is of type A if it is equally deep in all three phases. The dip is of type C if it is deeper in two phases than in the third one. The dip is of type D if it is deeper in one phase than in the other two. Furthermore, C_a denotes a dip of type C, with phase a being the deviant. The same notation is used for C_b, C_c, D_a, D_b and D_c.

A.3.2 Comparison of voltage dips recorded at different voltage levels

Table A.3 contains dip magnitudes of voltage dips measured simultaneously at three different voltage levels. The measurements on 130 kV and 10.5 kV were made in three phases, whereas the measurement on 0.4 kV were made

Date and number	Minimum remaining voltage (pu.)			Duration (ms)
	Phase A	Phase B	Phase C	
1999-06-13-01	0.90	0.95	0.81	120
1999-06-30-02	0.85	0.86	0.86	130
1999-06-30-03	0.76	0.77	0.77	110
1999-07-07-04	0.89	0.90	0.90	190
1999-07-11-05	0.80	0.87	1.16	230
1999-07-14-06	0.84	0.85	0.84	620
1999-07-14-08	0.83	0.84	0.84	1240
1999-07-14-10	0.75	0.89	0.76	100
1999-07-14-11	0.75	0.77	0.90	90
1999-07-14-12	0.87	0.88	0.88	90
1999-07-14-13	0.85	0.94	0.86	170
1999-07-14-14	0.86	0.87	0.87	60
1999-07-14-15	0.82	0.82	0.82	350
1999-07-14-16	0.84	0.85	0.85	900
1999-07-14-17	0.93	0.66	0.85	270
1999-07-17-18	0.95	0.86	0.94	80
1999-07-20-19	0.82	0.83	0.83	100
1999-07-20-20	0.67	0.67	0.67	90
1999-07-20-21	0.65	0.83	0.93	140
1999-07-20-22	0.56	0.57	0.67	100
1999-07-22-23	0.86	0.93	0.92	100
1999-07-27-24	0.99	0.87	0.95	390
1999-07-29-26	0.96	0.81	0.93	60
1999-07-30-27	0.95	0.87	0.96	80
1999-07-31-28	0.96	0.83	0.94	70
1999-08-07-29	1.09	0.84	0.90	160
1999-08-09-30	0.68	0.52	0.91	170
1999-08-18-31	0.91	0.96	0.84	70
1999-11-22-67	0.81	0.88	0.97	110
1999-11-29-69	0.83	0.82	1.12	150
1999-11-29-70	0.83	0.83	1.13	150
1999-11-29-71	0.83	0.83	1.13	140
1999-11-29-72	0.78	0.78	0.94	160

Table A.1. Minimum remaining voltages and duration of the dips.

Date and number	Diptype	Characteristic voltage	PN-factor	Duration (ms)
1999-06-13-01	D_c	0.81	0.95	120
1999-06-30-02	A	0.86	0.86	130
1999-06-30-03	A	0.77	0.77	110
1999-07-07-04	A	0.89	0.89	190
1999-07-11-05	D_a	0.83	0.93	230
1999-07-14-06	A	0.84	0.84	620
1999-07-14-08	A	0.83	0.83	1240
1999-07-14-10	C_b	0.71	0.86	100
1999-07-14-11	C_c	0.72	0.86	90
1999-07-14-12	A	0.87	0.87	90
1999-07-14-13	C_b	0.84	0.89	170
1999-07-14-14	A	0.87	0.86	60
1999-07-14-15	A	0.81	0.82	350
1999-07-14-16	A	0.85	0.85	900
1999-07-14-17	D_b	0.69	0.88	270
1999-07-17-18	D_b	0.85	0.96	80
1999-07-20-19	A	0.83	0.82	100
1999-07-20-20	A	0.67	0.67	90
1999-07-20-21	D_a	0.67	0.82	140
1999-07-20-22	A	0.65	0.56	100
1999-07-22-23	A	0.94	0.86	100
1999-07-27-24	D_b	0.92	0.95	390
1999-07-29-26	D_b	0.81	0.96	60
1999-07-30-27	D_b	0.87	0.96	80
1999-07-31-28	D_b	0.83	0.96	70
1999-08-07-29	D_b	0.87	0.95	160
1999-08-09-30	C_c	0.55	0.79	170
1999-08-18-31	D_c	0.84	0.92	70
1999-11-22-67	D_a	0.86	0.94	110
1999-11-29-69	C_c	0.86	0.87	150
1999-11-29-69-2	C_c	0.87	0.88	140
1999-11-29-70	C_c	0.87	0.93	150
1999-11-29-71	C_c	0.88	0.83	140
1999-11-29-72	C_c	0.71	0.88	160

Table A.2. Minimum characteristic voltages and duration of the dips.

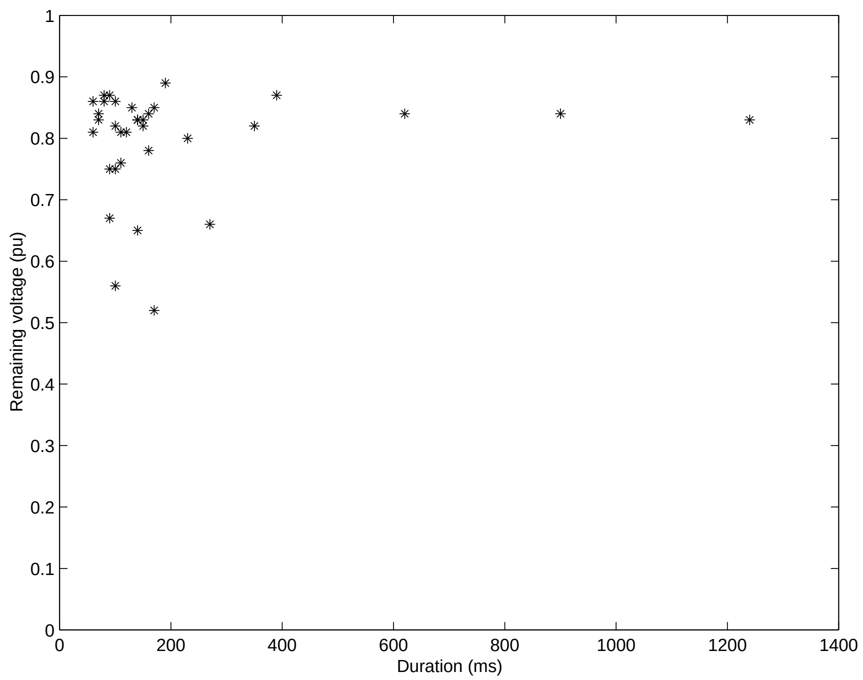

Figure A.2. Minimum remaining RMS voltage as function of the duration

in one phase since the measuring equipment was installed in an electrical socket. Some of the voltage dips are deeper at 130 kV than at the lower voltage levels, probably because synchronous machines connected at 10.5 kV strengthens the 10.5 kV grid during the dips.

Voltage dips can transform when propagating through transformers[6]. According to Zhang [30], and taking into account the transformer connections at SSAB (table (A.4)), a dip propagating from 130 kV to 10 kV will not transform. However, a dip propagating from 10 kV to 0.4 kV will transform so that a two-phase dip turns into a single-phase dip (or the other way around). The theory is verified by calculations with EMTDC. The result from a dip originating in the 130 kV grid looks exactly the same when measured in the 130 kV grid or in the 10 kV grid respectively (see figure (A.4)).

[6] Depending on the transformer connections (Y-Y, Y-Δ, Δ-Y, Δ-Δ), a single-phase dip can transform into a two-phase dip (or the other way around). The details are described by Zhang [30] and not further considered in this thesis.

Date and number	Vattenfall (130 kV) in p.u.	SSAB (10 kV) in p.u.	SSAB (0.4 kV) in p.u.
1999-06-13-01	0.64	0.81	0.84
1999-06-30-02	0.83	0.85	0.84
1999-06-30-03	0.78	0.76	0.75
1999-07-07-04	-	0.89	-
1999-07-11-05	-	0.80	-
1999-07-14-06	0.82	0.84	0.84
1999-07-14-07	0.89	0.91	-
1999-07-14-08	0.82	0.83	0.84
1999-07-14-09	-	0.91	0.92
1999-07-14-10	0.71	0.75	0.72
1999-07-14-11	0.70	0.75	0.83
1999-07-14-12	0.85	0.87	0.87
1999-07-14-13	0.82	0.85	0.83
1999-07-14-14	0.84	0.86	0.86
1999-07-14-15	0.79	0.82	0.82
1999-07-14-16	0.82	0.84	0.84
1999-07-14-17	0.56	0.66	-
1999-07-17-18	-	0.86	-
1999-07-20-19	0.80	0.82	0.82
1999-07-20-20	0.79	0.67	0.67
1999-07-20-21	0.44	0.65	0.74
1999-07-20-22	0.16	0.56	0.60
1999-07-22-23	0.87	0.86	0.88
1999-07-27-24	-	0.87	-
1999-07-29-26	0.78	0.81	-
1999-07-30-27	0.83	0.87	-
1999-07-31-28	0.78	0.83	-
1999-08-07-29	-	0.84	-
1999-08-09-30	-	0.52	0.78
1999-08-18-31	0.79	0.84	-
1999-11-22-67	0.28	0.81	-
1999-11-29-69	-	0.82	-
1999-11-29-69-2	-	0.83	-
1999-11-29-70	-	0.83	-
1999-11-29-71	-	0.83	-
1999-11-29-72	-	0.78	-

Table A.3. Dip magnitude at different voltage levels

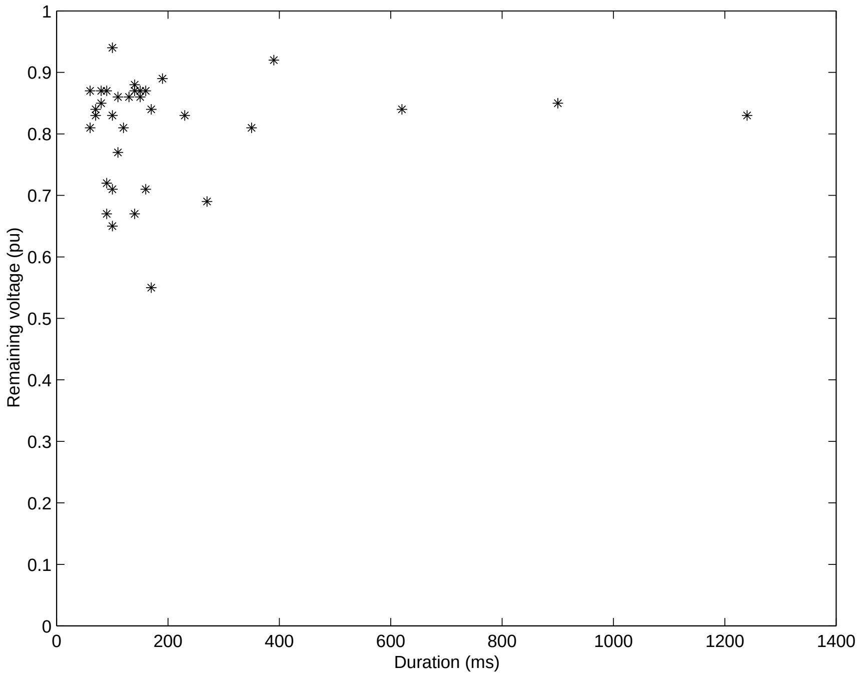

Figure A.3. Minimum characteristic voltage as function of the duration

Transformer	High-voltage	Low-voltage
130/10	Star, solidly earthed	Star, Impedance earthed
10/0.4 (kv/kv)	Delta	Star, solidly earthed

Table A.4. Transformer connections

A.3.3 Causes and consequences

According to [29] non of the recorded dips gave a disturbance of the blast furnace whereas almost all dips during production time gave a disturbance of the plate making plant. The probable causes of the voltage dips are tabulated in table (A.5).

A.4 Discussion

The large amount of voltage dips recorded and their consequences, indicates that they are a major problem for the industry. However, one must bear in

Date and number	Probable Cause
1999-06-13-01	Lightning — 130 kV
1999-06-30-02	Lightning — 130 kV
1999-06-30-03	Lightning — 130 kV
1999-07-07-04	Unknown
1999-07-11-05	Unknown
1999-07-14-06	Lightning — 130 kV
1999-07-14-07	Unknown
1999-07-14-08	Lightning — 130 kV
1999-07-14-09	Lightning — 130 kV
1999-07-14-10	Lightning — 130 kV
1999-07-14-11	Lightning — 130 kV
1999-07-14-12	Lightning — 40 kV
1999-07-14-13	Lightning — 130 kV
1999-07-14-14	Lightning — 130 kV
1999-07-14-15	Vattenfall, 130 kV, Other
1999-07-14-16	Lightning — 130 kV
1999-07-14-17	Lightning — 130 kV
1999-07-17-18	SVK, 400 KV, Unknown
1999-07-20-19	Lightning — 130 kV
1999-07-20-20	Unknown
1999-07-20-21	Lightning — 130 kV
1999-07-20-22	Lightning — 130 kV
1999-07-22-23	SVK, 220 kV, Lightning
1999-07-27-24	Unknown
1999-07-29-26	Vattenfall, 130 kV, Other nature
1999-07-30-27	SVK, 400 kV, Unknown
1999-07-31-28	Vattenfall, 130 kV, Other nature
1999-08-07-29	Unknown
1999-08-09-30	Lightning — 130 kV
1999-08-18-31	SVK, 400 kV, Unknown
1999-11-22-67	Lightning — 130 kV
1999-11-29-69	Unknown
1999-11-29-69-2	Unknown
1999-11-29-70	Unknown
1999-11-29-71	Unknown
1999-11-29-72	Unknown

Table A.5. Cause and consequences

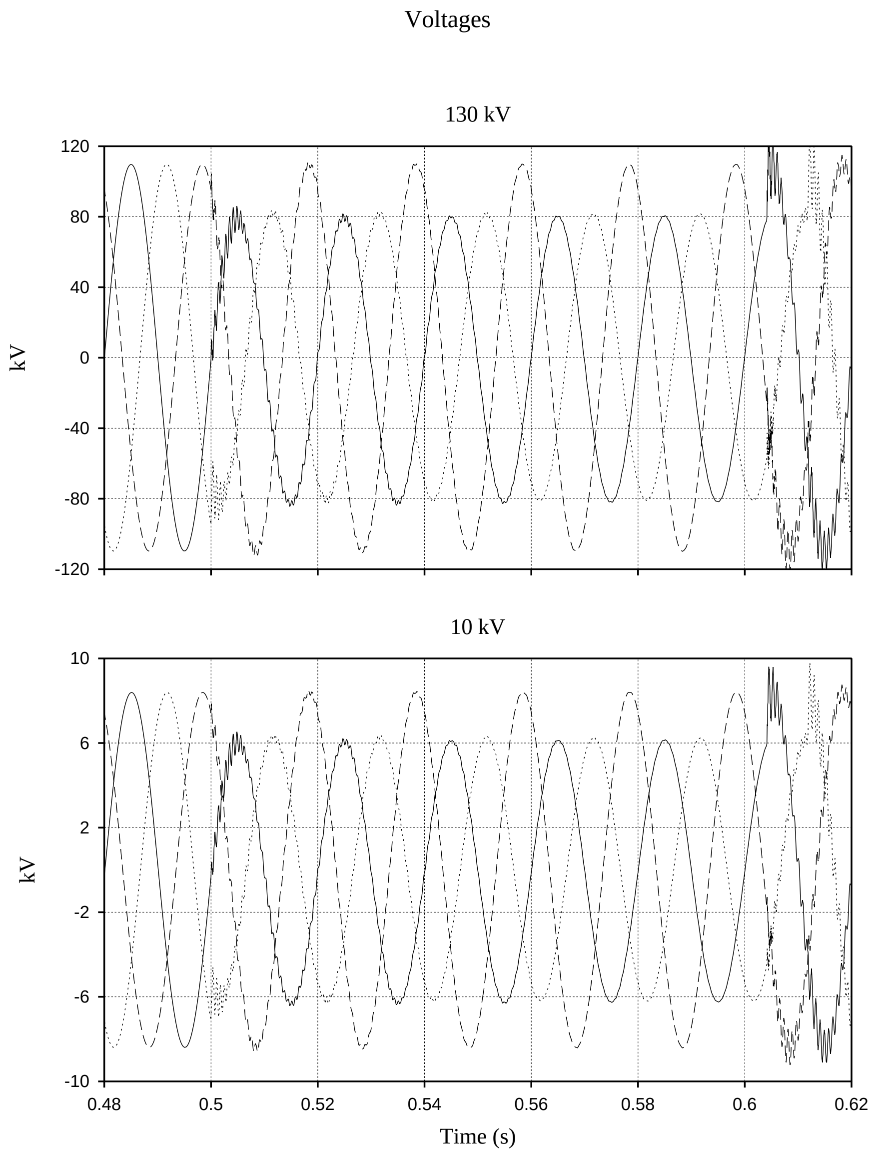

Figure A.4. Propagation of voltage dips

mind that many of the voltage dips occurred close in time to each other. In those cases when a voltage dip caused the plant to trip, the plant would most probably not have started again when the following dip occurred. Hence, the only voltage dip having consequences was the one which tripped the plant. Secondly, many of the voltage dips occurred during July, a month when the plant usually is shut down for maintenance, thereby causing no consequences.

The duration of the majority of the measured voltage dips was less than 200 ms, but a typical high-voltage circuit-breaker interrupts a short-circuit current within 40 ms [31]. Hence, by examining the relay protection it might be possible to reduce the duration of most voltage dips to less than 100 ms. Further possible solutions to the problem with voltage dips are:

- Strengthen the grid by increasing the short-circuit power.
- Disconnect the plant from the grid during bad weather, relying on a local generator.
- Installation of a *D*ynamic *V*oltage *R*egulator (DVR).
- Improve the lightning protection of the overhead lines by for example top lines or surge arrestors.

The first solution mentioned will lead to an increase in the short-circuit power. In an existing grid, however, it might not be possible to add that power without rebuilding or substituting large parts of the equipment in the grid. The problem is that an increased short-circuit power leads to an increased short-circuit current in case of an electrical fault in the grid. Two solutions that allows the benefit of increasing the short-circuit power without the disadvantage of increasing the short-circuit current is described below:

- The installation of a fault current limiter at one or more properly selected places in the power system will in case of a short-circuit limit the fault current to a level that the components of the system will manage. There are fault current limiters available to the market today [32] and research towards new types of fault current limiters are performed at several universities [27] [33].
- A fault diverter system [34] placed at every source feeding the power system will divert the fault current contribution from each source to ground, thereby preventing superimposed fault currents in the power system. Dynamic simulations of a fault diverter system has been performed and the results seem promising [28].

A.5 Future work

Future possible connections at SSAB, which will give a more flexible grid will be studied. Then again, the problem with a stronger grid will be apparent.

The methods discussed to control the short-circuit currents need further investigation and the focus will be on fault detection and fault handling. The methods described in this report will not be used for fault detection due to a delay time of at least one period of power frequency when performing the RMS-calculation. Conventional protection relays using Fourier algorithms are also out of the question due to the delay time introduced by the Fourier-calculation. Methods that will be studied are:

- detection of the wavefront caused by the fault using for example wavelet analysis
- current differential algorithms based on sample-to-sample comparison
- algorithms based on current level and current derivative

Dynamic simulations, preferably performed with EMTDC, will be used to:

- test algorithms for fault detection and fault handling.
- find how fast fault current limitation that actually is needed.

Appendix B

Experiments performed as computer based calculations

B.1 Introduction

Before an experiment is started it is important to sort out what will be observed. Furthermore, the experiment shall be planned so that the observation really can take place [35]. A theoretical model of the experiment (if such exists) can be of great help when planning the experiment.

B.1.1 Basics

My experiments are carried out with the aid of a calculation program implemented in a computer. My research focuses on fast and automatic fault disconnection in electrical distribution systems and is a project carried out at the department of electrical power systems at KTH. The projects performed at the Electric Power Systems group at the department of Electrical Engineering span issues from modelling of power system equipment to modelling of electrical markets. For most of the projects performed in the group calculation programs are frequently used . What is calculated and in how fine details varies between projects. Common types of calculations are:

- load flow calculations, which are carried out to calculate power flows within electrical power systems.
- system planning calculations, which are carried out to estimate the operation of an electrical power system in different time scales such as yearly, monthly and weekly.

- short-circuit calculations, which are used as a basis for determination of protection settings and testing of protection systems.

The above mentioned types of calculations have in common that they are possible to perform by hand given that the power system under study is small. The number of components and state of operations grows fast as the power system grows, which means that calculation by hand becomes impractical (or even impossible). The level of detail differs between the three types of calculations mentioned above. In a system planning calculation it is possible to lump several loads together into one equivalent component. But for short-circuit calculations to study protection setting for different loads in a power system more detailed models are needed.

The remainder of this article will focus on short-circuit calculations performed in purpose to study methods for fast and automatic disconnection of faults.

One alternative method to calculate short-circuit currents by hand has already been mentioned for small power systems. A third alternative is to build a scaled model of the power system under study in an electrical laboratorium. Experiments performed with a scaled model of the power system would probably give a good understanding of the power system since physical components are used.

The benefit of using computer calculations is that it is relatively easy to start using the program and get results.

B.1.2 Theory dependence

Methods for short-circuit calculations is either based on the assumption that the quantities under study always is periodic so that RMS-values[1] of voltages, currents and circuit impedances can be used, or based on the solving of the differential equations describing the system. The first method is used when the so-called steady state[2] values of voltages and currents are of interest. The other method is used when the instantaneous values of voltages and currents are of interest. In case of an electrical fault in a power system

[1]RMS is an abbreviation of *R*oot *M*ean *S*quare, which is a mean value for periodic signals. For sinusoidal signals the RMS-value is calculated as the peak value of the sinusoidal signal divided by the square root of two.

[2]A power system is said to be in a steady state when the RMS-values of all signals and parameters do not change. Even though the power system is in steady state the instantaneous signals do change since power systems mainly contains sinusoidally varying signals.

the steady state is disturbed and during a transient state transferred to a new steady state corresponding to the current circuit parameters. Transients are possible to study with calculation programs based on the second method mentioned above.

When choosing a calculation program it is not only needed to consider whether the program calculates RMS-values or instantaneous values but also to consider how the program solves the differential equations, and if the program uses a fixed time step or a time step that is allowed to change during the course of the calculation. A fixed time step is determined before the calculation starts and remains the same throughout the calculation whereas a time step that is allowed to change is made small when the solution changes rapidly and made larger when the solution changes slowly.

In the market lots of calculation programs are available for short-circuit studies. One of the programs we use at my department is EMTDC [24]. The modelling of the power system is made through a graphical interface and the differential equations are hidden in the calculation program. The differential equations are solved by the trapezoidal method described in a paper by Dommel [36] in the early seventies.

To evaluate whether the calculations are performed correctly it is advisable to start with a small power system which easily can be calculated by hand for comparison. Furthermore so-called benchmark systems have been published which can be used to calibrate the models [37]. Further verification is possible by comparing the calculated results with actual measurements in a real power system, modelled in the calculation program.

B.2 Methods

The next step in designing the experiment is to determine which parameters that will be included in the experiment and how they will be treated during the experiment. It must also be possible to make observations (measurements) in the calculation program. Measurements in a real power system always influence the observation, but in a calculation program there is usually ideal observations.

B.2.1 Parameters and variables

For all types of calculations of power systems it can be difficult to separate between parameters and variables. For one calculation the system voltage of a node might be considered as constant and consequently treated as a parameter. For another type of calculation the system voltage of the same node might depend on the load and consequently vary throughout the calculation. When performing short-circuit calculations one often studies what happens when a switching or a sudden change of circuit topology is introduced in the power system. Then the system voltage of a node is considered as a parameter until the time of the switching and thereafter treated as a variable. Thus, the system voltage is treated as both a parameter and a variable for that particular calculation.

The independent variable in short-circuit calculations are most often the time. Currents, voltages and other variables are calculated as functions of the time. Sometimes the time step can be thought of as a parameter (fixed time step) or as a variable (variable time step). Stochastic variables can be used to simulate switchings or changes in the power system such as location of the fault, the type of the fault, and the duration of the fault.

B.2.2 Observations and measurements

To make observations in a calculation program is easy. As a rule there are no limitations to which quantities one is allowed to measure. Furthermore there are seldom limitations on how many measurements that are allowed. In a real power system there are limitations with respect to space and cost reasons on how many measurement transducers that can be used. Furthermore, the more measurements one makes the more difficult it is to analyze them. After a computer calculation the calculated values can be saved and analyzed afterwards but in a real power system the analyze must take place in real time.

Most calculation programs offers the possibility of using ideal voltage and current transducers. An ideal transducer does not contribute any error but are simplified and hence not possible to use for all types of calculations. One can choose to make more detailed models of measuring transducers and calibrate those models with actual measurements but often it is enough to know the range of the fault current. When calculating short-circuit currents with the purpose of studying fast and automatic disconnection of faults the measurement error must be accounted for and implemented in the calculation. The actual measuring fault (in case of sinusoidal signals) is composed by a magnitude error and a phase error. Phase errors introduce a time delay, which can be of importance when estimating how fast fault disconnection is possible.

B.2.3 Effects of observation

All measurements in a real power system affects the accuracy of the observation, but in a calculation program the observation sometimes can be ideal. Compared to a real power system observational effects depending on the calculation program is also an issue to consider. Since the calculation program solves the differential equations at discrete time steps a small error is introduced in each time step and adds up in the final solution [38]. Such faults can be minimized by careful selection of solving method and by suitable choice of fault tolerance. Depending on how the discrete time step is treated by the calculation program there might be an additional error depending on the properties of the system under study. For each power system one or more time constants can be calculated. These time constants reflects the response of the power system to a disturbance. If the discrete time step is larger that the time constants of the power system it is not possible to observe all phenomenons in the calculation. Calculation programs using a variable time step automatically adapts to the time constants of the power system but for calculation programs using a fixed time step the choice of time step is a science in itself. If time constants are possible to calculate or estimate they can be used as a guide. If one is unsure if the correct time step is chosen one can repeat the calculation with half the time step and then compare the results. If the results differ significantly the time step is not chosen correctly but should be even smaller. On the other hand, if a too small time step is chosen, the calculations will take unreasonably long time depending on the size of the power system and how the parameters are varied.

B.3 Results

B.3.1 Interpretation problems

When comparing the results from a calculation with measurements made in the real power system one should thoroughly study which parameters that have been used and how they have been selected. Loads can for example be modelled as constant power loads, constant current loads, and constant impedance loads, or a combination of those[3] [39]. Loads can vary with time.

[3] A constant power load draws a specified power from the source independent of the voltage, a constant current load draws a specified current from the source independent of the voltage, and a constant impedance load draws a current depending on the voltage.

In most cases one never sees the real power system but instead works with drawings and product data sheets. A visit to the real power system can explain differences in the results because it often happens that the reality and the drawings do not agree. The actual operating conditions can not be seen in a drawing. Does one really compare the calculation with the real power system under the same conditions?

When comparing results obtained with different calculation programs one should study how the calculation programs work, how they solve the differential equations, how fault tolerance is treated, and how the time step is treated. If both calculation programs use a fixed time step it is important to check that the time step is equal for both programs. Modelling of components can differ between different calculation programs and also depends on the level of detail wanted. A more realistic model might give more accurate results but in turn take longer to calculate. Calculation programs using a graphical interface often hides the differential equations that describe the component and it can be difficult to compare between program for example how a power transformer is modelled. Further differences might be explained by examining how switchings are treated by the programs. In calculation programs based on a fixed time step one can imagine a switching event taking place between two discrete time steps. Then you can have differences in the results depending on how that is treated by the programs. The calculation program EMTDC allows switching in between discrete time steps because the program uses an advanced algorithm for interpolation between time steps so that the switching is correctly treated [40]. One more reason for differences between calculation programs can be that different parameters have been used which can be easy to do depending on if the parameters are given as for example inductances or impedances, or in Ohm or per unit[4]. Overhead lines or cables can be modelled in a number of ways as for example pi-link, t-link or as a distributed model with or without transposing the phases [40]. Some models make use of the length of the line or cable and its geometrical shape to estimate its parameters, but in other models impedance values might be given.

[4] A short definition of per unit is given by IEEE standards as "The reference unit, established as a calculating convenience, for expressing all power system electrical parameters on a common reference base." [7]

B.4 Discussion

B.4.1 Summary

In a calculation program one always makes a model of reality. The model can be made more or less detailed depending on the purpose of the study and which level of detail that one is interested in. One must find a balance between the level of detail, the clearness, and the amount of time needed to perform the calculation. In my opinion one of the reasons that calculation programs are widely spread is that one can quite fast get results that one can work with. Another reason is that the simulated results is in good agreement with actual measurements. The models are quite accurate. Thanks to the rapid improvement of computer performance a power system can be calculated quite fast. The calculation programs available today often have the possibility to perform multiple calculations varying the parameters in between. The calculation program EMTDC gives the possibility to vary a parameter linearly, nonlinearly, or stochastically within a given intervall.

Another reason for using a calculation program is that it is easy to share models between users and relatively easy to find another user having similar problems or possibilities.

An alternative to computer calculations is to build a scaled model of the real system, equip the model with a control system and a data acquisition system. Such a model would probably give a better understanding of the power system because it contains physical components whose behavior can be studied and explained. The drawbacks of building a scaled model is that it takes time to get started and obtain results, and that it would cost more than performing computer calculations.

To perform calculations based only on data obtained from drawings and product data sheets is not recommended. A visit to the real power system is strongly recommended. Partly to verify that the right data is used as previously discussed but also to obtain the understanding that a power system is not merely lines on a drawing but has a rather large physical extension.

Since results are easily obtained with a calculation program there is a risk to put to much trust in the results. One should have a theoretical knowledge of electricity and power systems to understand the result and to eliminate obviously false results.

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