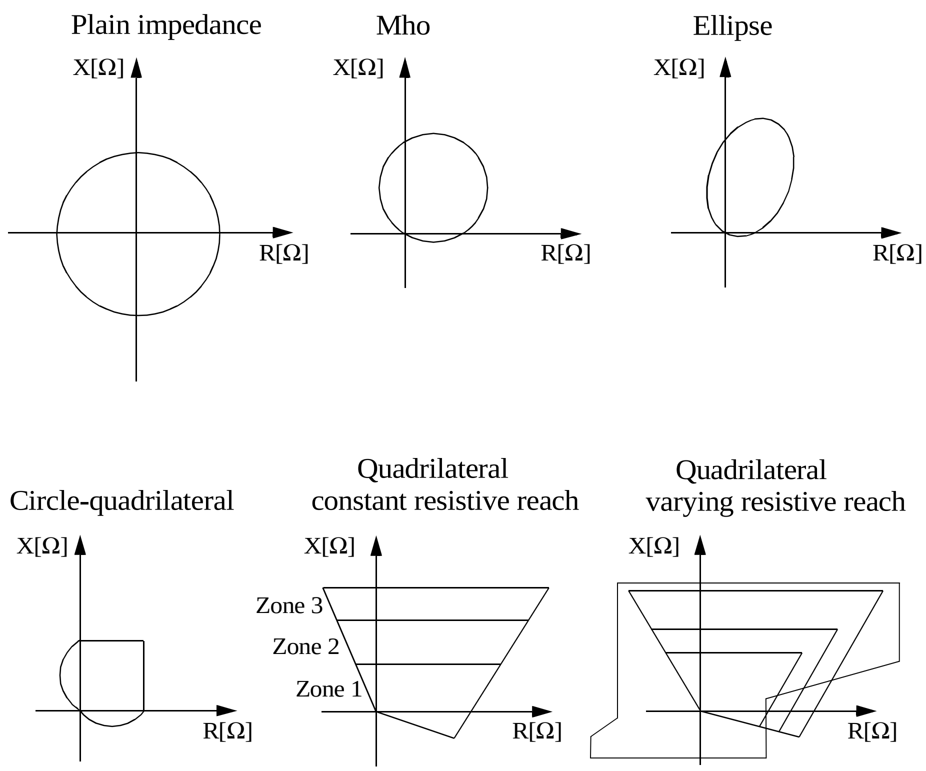

Line Protection and Power System Collapse

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Göteborg, Sweden 2001

THESIS FOR THE DEGREE OF LICENTIATE OF ENGINEERING

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by

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Cover: The development of the distance protection characteristic. From the early plain impedance characteristic to the modern quadrilateral characteristic including a supervising characteristic which obstructs load encroachment.

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Abstract

In this report the influence of line protection on transient- and voltage instability is investigated. Different types of line protection applications are discussed and their likelihood of contributing to power system instability is analysed. It is concluded that distance protection is one of the most critical issues in EHV systems with respect to transient- and voltage instability.

Different types of relay characteristics used in distance protection are analysed. Additionally the significance of coordination between distance protection and generator current limiters in case of voltage instability is investigated. Subsequently the interaction between distance protection and other protection devices during power system instability is discussed. Conventional Power Swing Detectors and Out of Step Protection have also been examined.

New distance protection algorithms based on mathematical logic blocks are introduced. These algorithms use conventional distance relaying in combination with certain additional criteria to increase the relay security with respect to voltage- and transient instability. To prevent undesirable distance protection operation during voltage instability, an adaptive algorithm is proposed where the derivative of the voltage is applied as an additional relay criterion. In addition algorithms which prevent mal-trips due to power oscillations are developed. The additional criteria applied for these algorithms are based on symmetrical component theory and the derivative of the phase angle of the current as seen by the relay. To increase robustness a scheme is developed where all additional criteria mentioned above are applied in a single algorithm.

Studies undertaken are based on simulations using two different test systems; a fifteen bus system developed by the author and the well known Nordic32 system. When the fifteen bus system is used for transient stability studies three additional buses are added.

Statistics of zone 3 distance protection operation in the Swedish transmission system are presented for the period 1985 - 2000. Additionally a number of disturbances related to distance protection and power system instability is investigated.

The work shows that undesirable zone 3 distance relay operation during voltage instability can make the difference between a total blackout and a recovering system. Simulations have shown that the adaptive algorithm proposed may save the system from collapse.

Although the algorithm prevents mal-trips due to load encroachment associated with voltage instability the reach of the distance relay will not be restricted.

Poor coordination between generator current limiters and zone 3 elements may restrict the possibility to utilize the generator to its maximum capacity.

Transient instability may lead to undesirable distance relay operation. To prevent this Power Swing Detectors can be used. However the performance and availability of conventional Power Swing Detectors may be affected in case of long lines, different cycle times of the power oscillations or faults with a slowly decreasing impedance. Additionally they will not provide fault clearing immediately after a power swing has been detected as the tripping relay will be blocked. The algorithms proposed here are not affected by these shortcomings.

Keywords: Distance protection, Voltage stability, Transient stability, Power swings, Power oscillations, Back-up protection, Power Swing Detector, Out of Step Protection, Numerical relays, Adaptive relaying, Distance protection statistics.

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LIST OF PUBLICATIONS

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II Jonsson M, Daalder J, ”A new protection scheme to prevent mal-trips due to power swings”, Accepted for IEEE/PES Transmission and Distribution Conference and Exposition, October 28 - November 2, 2001, Atlanta, USA.

III Jonsson M, Daalder J, ”A distance protection scheme to prevent mal-trips during abnormal power system conditions”, Accepted for Cigré Study Committee 34 Colloquium and Meeting, September 10 - 14, 2001, Sibiu, Romania.

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Chapter 1 Introduction

Short circuit faults are unavoidable in a power system. These faults should be removed fast and the affected part should be isolated quickly with a minimum of disturbance to the remaining system. To this purpose a reliable and fast acting protection system is essential. It will minimise the risk that a local occurrence is leading to a threat for the entire system, thereby avoiding major calamities as e.g a system collapse.

Abnormal operating conditions can be divided into several stages. Fink and Carlsen [1] define the phases alert, emergency, in extremis and restorative; the latter condition being a phase in which the system will return to its normal operative stage. During these stages the likelihood of incorrect performance of a protection system increases as compared with normal operation. Undesirable behaviour of the protection system during these phases will further aggravate the prevailing conditions and enhance the danger to the entire system. Clearly a correct performing protection system even under stressed conditions is a major issue in power system operation.

Of particular importance is the line protection. Generally circuits should be the last devices to be tripped, even under stressed conditions. The possibilities to utilise other equipment for restorative actions will be severely limited after line outages. When for example generators are used to their maximum capacity after a grid weakening the result may be cascading line outages.

On the other hand it may be advisable to sever the system in case of transient instability to attain stable subsystems. However in that case line tripping should be performed in a planned, controlled and predictive manner.

When a protection system is designed a compromise must be made between economy and performance, dependability and security, complexity and simplicity, speed and accuracy. In this thesis the focus is on the optimal relay performance as seen from a system point of view. Hence the emphasis is on dependability and security although the remaining requirements are carefully considered in the proposed applications.

Two aspects of reliability are usually addressed in case of relay engineering [36]; *dependability* being a measure of the relaying equipment's ability to correctly clear a fault while *security* is a measure of the relaying equipment's tendency not to trip incorrectly.

Traditionally the dependability has been emphasized. However during abnormal operating conditions security may become more of an issue. Numerical relays will account for an increasing share of all relays in operation and solutions necessary for complex system configurations and system conditions will be easier to realise. Often software is implemented where the user can create individual functions based on mathematical logic blocks. This in combination with the fast development of information technology in power system applications makes adaptive relaying a powerful tool. Consequently protection schemes can easily be developed where the degree of dependability and security is optimized with respect to the prevailing system conditions.

From a technical point of view correct relay performance has been of great importance throughout the years. However the issue has become even more important in a deregulated system. No actor wants to be temporarily removed from the system due to incorrect protection behaviour as this may lead to an (unnecessary) absence of income, penalty fees and advantages for competitors. Hence if devices are disconnected incorrectly by the protection system there is a chance that attitudes towards relay settings will become less strict. As a worst case this behaviour may result in the absence of relay operation in case of a true fault. Consequently the system security may be threatened.

In early transmission systems remote back-up protection was used to clear faults in case of failure of the main protection whereas today local back-up is often provided. In many cases the local and remote back-up are both in operation leading to duplicated back-up systems. Certain aspects significantly complicate the setting process of remote back-up protection. Accordingly there may be reasons for not applying remote back-up at all when local back-up is provided. As the remote back-up offer little improvement in fault clearance but may be a considerable threat to system security. Additionally the work effort in determining the settings for the remote back-up should be considered as the calculation process might be relatively time consuming and costly.

The type of events examined in this thesis are rare occasions. However if they occur usually a major part of the system load is affected. These disturbances may therefore be extremely costly and can cause much social inconvenience. It is not unlikely that the frequency of these events will increase in the future as power systems are operated closer to their stability limits due to environmental constraints and deregulation.

In the Swedish transmission system the number of power oscillations has increased significantly during recent years. One reason may be the deregulation which was initiated in 1996. In a deregulated system, power flows are decided by the complex market arrangements between suppliers and demand and the system may operate under conditions for which the system was not originally designed. Consequently the system may become more sensitive to power oscillations. This is especially true for deregulated systems which are composed by a few originally regulated sub-systems. One example is the Scandinavian power system where larger power flow variations have been observed after deregulation. In fact, in a few cases operating conditions have occurred where the system was close to its limits (and on the brink of a severe disturbance).

1.1 The Nordic transmission system

In figure 1.1 the Nordic transmission system is shown. In case of Sweden a substantial amount of (hydro) generation is located in the northern part whereas the main load is located in the middle and southern parts. As a result a large amount of power is transported through long distance transmission lines from the north towards the south. This is a typical system configuration which may encounter voltage instability. Another aspect of the Nordel system is that each country has its own generation interconnected through relatively weak tie-lines to the others countries. Power oscillations occur occasionally, especially when certain ”key lines” are out of operation. Typically, generators in southern Norway oscillates against generators in Sweden or Finland.

Both voltage instability and power oscillations are abnormal operating conditions that may lead to incorrect relay behaviour which in turn may aggravate the overall system situation. Ultimately this may lead to a system blackout. However if the protection system performs correctly blackouts can be mitigated or completely avoided.

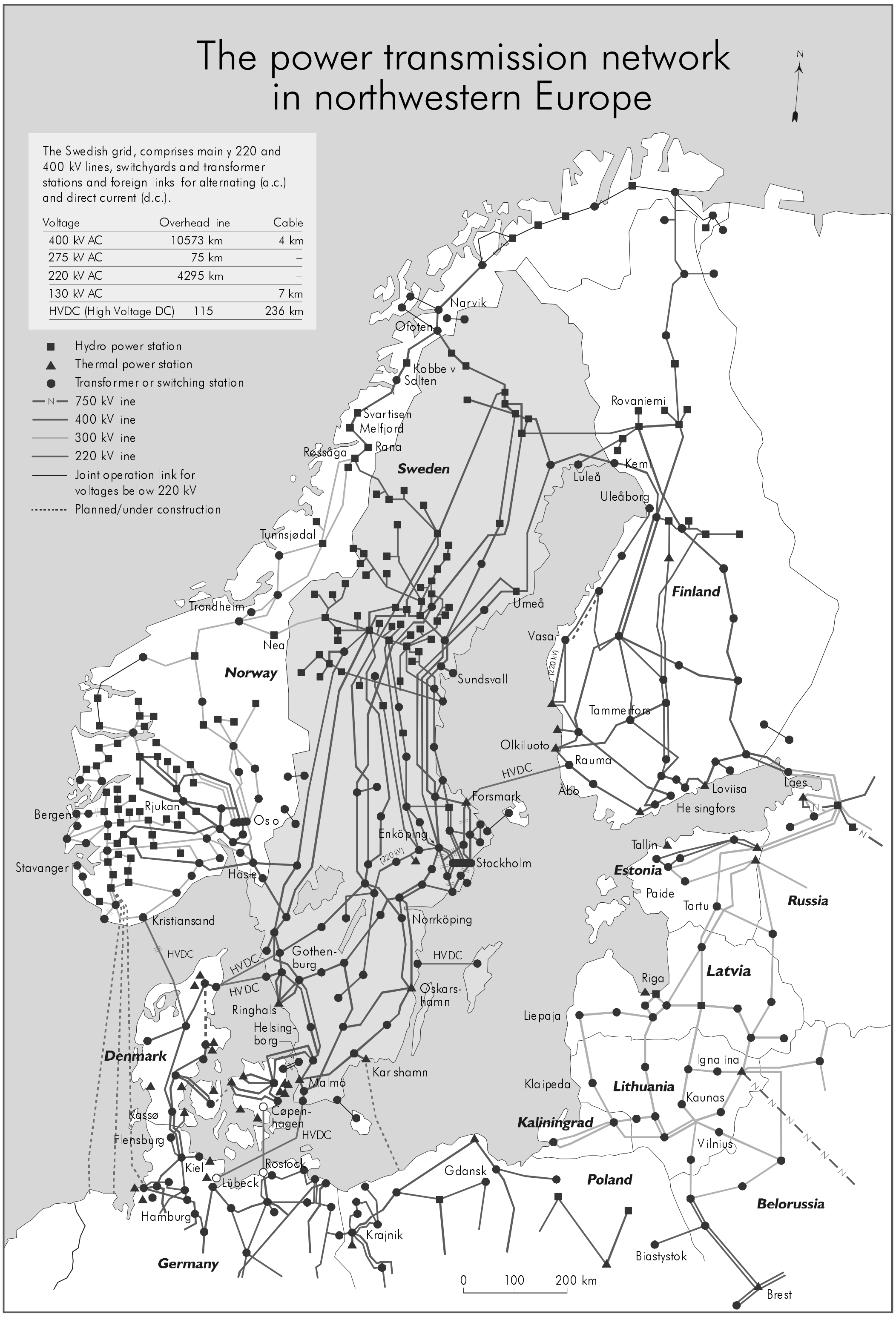

Figure 1.1 The Nordel system.

1.2 Outline of the thesis

In chapter 2 different types of line protection are described and the likelihood of mal-operation due to power system instability is discussed. Special emphasis is given to distance protection. Additionally the line protection system and the mixture of different types of distance relays applied in the Swedish transmission is presented. Further the advantages and disadvantages of local and remote back-up are discussed.

Chapter 3 investigates the relation between distance protection and voltage instability. Theoretical studies and an investigation of real disturbances are presented. An adaptive algorithm is introduced to increase the relay security with respect to undesirable distance relay operations during voltage instability. Also the number of zone 3 distance protection operations in the Swedish transmission system between 1985 and 2000 is presented and the most important cases are further described.

The relation between distance protection and transient stability is examined in chapter 4. Power Swing Detectors and Out of Step Protection are introduced. Additionally protection schemes are developed where the relay security is increased as compared to conventional distance relaying. Also a number of disturbances related to distance protection and transient stability is examined.

In chapter 5 the algorithms introduced in chapters 3 and 4 are further developed to avoid incorrect distance protection performance in case of power system instability.

The conclusions and future work are presented in chapter 6.

Chapter 2 Line Protection in EHV Power Systems

In this chapter different line protection schemes are introduced. Their likelihood of contribution to voltage- and transient stability is briefly discussed. Finally the Swedish standard line protection scheme is described and the mixture of electromechanical, solid-state and numerical distance relays used in the Swedish transmission system is presented.

2.1 Differential protection

Differential protection is based on the principle that in case of normal operation the current injected into an object on one side is extracted at the other side of the object. If this criterion is not fulfilled, part of the current is obviously deviating via some unwanted path and the protection scheme should operate. However a certain difference between the injected and extracted current is always present due to e.g. losses and therefore a threshold is given to the relay which must be exceeded to initiate operation.

Differential protection is mainly used as line protection for circuits which are too short to receive reliable protection by distance protection. Other examples of applications were differential protection is applied are busbar protection and transformer protection.

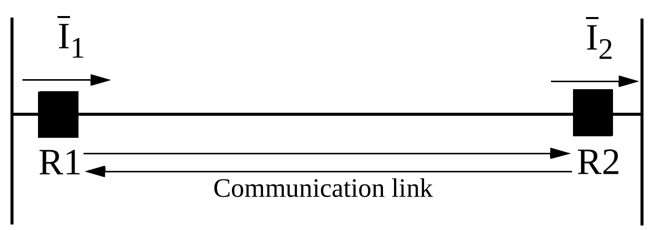

Figure 2.1 A single line protected by a differential protection scheme.

In figure 2.1 a differential protection scheme for a single transmission line is shown. The currents as seen by R1 and R2 are continuously compared. During normal operation $\bar{I}_1$ and $\bar{I}_2$ are approximately the same whereas during a fault the difference is large. When the pre-set threshold is exceeded the line is tripped.

To be able to exchange the value of the current there must be a communication link between relays R1 and R2 which is able to transmit real data. This is a disadvantage of differential protection as the sending and receiving transmitters are relatively expensive. Obviously the communication medium is also expensive in case of long lines. However this is about to change as fibre optics become more customary.

Differential protection is inherently reliable with respect to voltage instability and power oscillations.

2.2 Phase comparison relays

Phase comparison schemes compare the phase angle of the injected current into the object and the phase angle of the extracted current out from the object [35]. For the system in figure 2.1 the currents are given by (2.1) and (2.2) during normal operation whereas they are given by (2.3) and (2.4) in case of an internal fault.

$$\bar{I}_1 = I_1 \angle \delta \tag{2.1}$$

$$\bar{I}_2 \approx I_1 \angle \delta \tag{2.2}$$

$$\bar{I}_1 = I_{1fault} \angle \theta \tag{2.3}$$

$$\bar{I}_2 \approx I_{2fault} \angle (\theta + 180°) \tag{2.4}$$

Hence during normal operation the phase angle of the injected current at R1 and the extracted current at R2 is similar (though the difference may be up to 30 degrees for a real line). Accordingly the protection scheme is not activated. However in case of an internal fault $\bar{I}_2$ switches direction and thus $\bar{I}_1$ and $\bar{I}_2$ will be phase shifted approximately 180º. Consequently when the two currents are phase shifted about 180º the protection scheme operates.

Also for this scheme a pre-set threshold must be exceeded by the difference of the phase angle of the currents to initiate relay operation.

The threshold is given to assure operation although the phase angle difference will most likely not be exactly 180º.

Similar to the differential protection scheme the phase comparison scheme relies on communication devices. Consequently it is insensitive to abnormal operating conditions such as voltage instability and transient instability.

2.3 Overcurrent protection

There are three different types of overcurrent protection relays; short circuit, earth-fault and overload. The operation principle for all three applications is based on the comparison of the current as seen by the relay and a pre-set value. When the current exceeds the threshold the relay operates. Both momentary and time delayed tripping are common.

Overcurrent protection is simple, cheap and reliable. However it performs best in radial systems as selectivity is hard or sometimes impossible to achieve in meshed system configurations.

2.3.1 Short circuit overcurrent protection

During fault conditions the current usually increases considerably with respect to normal operation. This behaviour is used by short circuit overcurrent protection to distinguish fault conditions from normal operation.

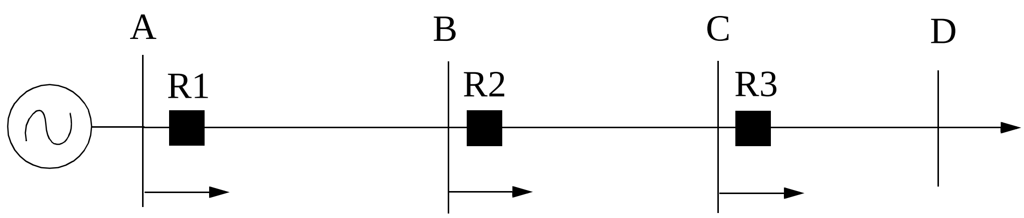

Figure 2.2 A radial fed system equipped with non-directional overcurrent protection.

In figure 2.2 a radial fed system is shown where each line section is equipped with an non-directional overcurrent relay. To achieve proper operation each relay must be given a operation current which is larger than the largest possible overload current. Obviously the operation current must also be lower than the smallest possible fault current. To calculate the smallest possible fault current a phase to phase fault is usually applied at the remotest terminal for the lowest possible short circuit power present at the feeding terminal [2]. To obtain selectivity a higher operating value is given to the relay the closer to the source the relay is located. Usually selectivity can not be achieved exclusively by the current settings. To assure satisfactory selectivity a certain time delay is given to the relays. Normally the relay at the remotest bus operates instantaneously whereas the time delay increases for relays situated nearer to the feeder.

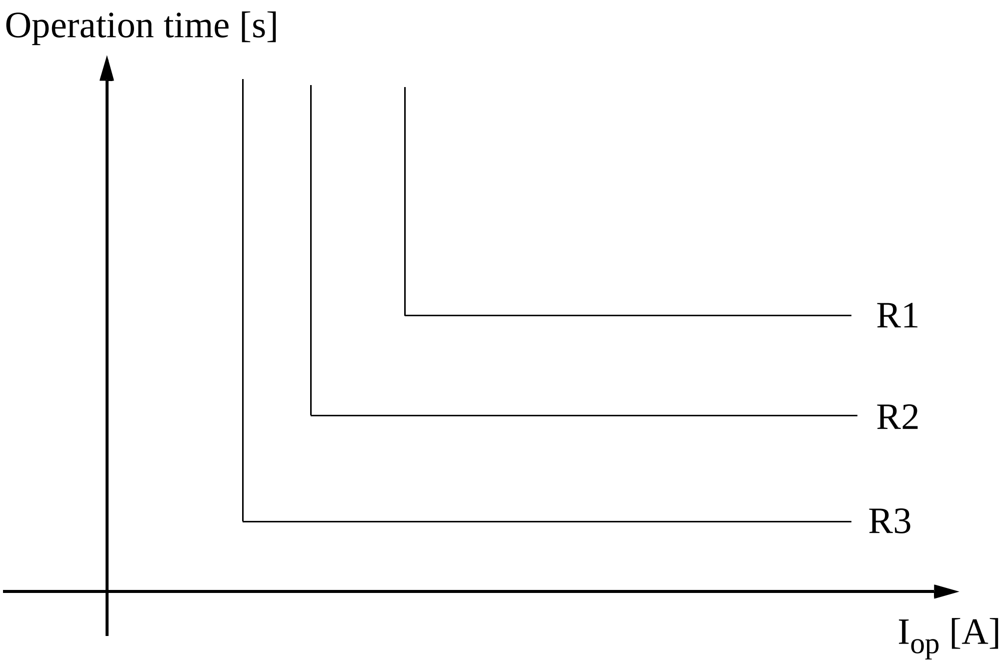

Figure 2.3 Overcurrent device coordination for the relays in figure 2.2.

In case of meshed system configurations it may be impossible to give settings to the overcurrent protection discussed above which provides a selective protection system. Hence the overcurrent unit which is exclusively based on the magnitude of the current is supplemented by a directional element. This application is usually named ”directional overcurrent protection” and is further described in [3,35,67,70].

Often the definite overcurrent relay characteristic as shown in figure 2.3 is replaced by an inverse-time characteristic. The delay time of an inverse time overcurrent relay decreases with increasing current.

Hence a large fault current will be tripped faster than a small fault current. An inverse-time overcurrent relay also enables the combination of short-circuit protection and overload protection in the same device.

A disadvantage of short circuit overcurrent protection is that the settings sometimes must be recalculated due to the prevailing operating condition. Varying short circuit power of the source and/or large differences between the load current during base load and peak load or topological changes are some reasons.

For overcurrent relays used for short circuit protection, the risk for mal-trips at stressed conditions such as voltage instability and transient stability is usually low. The short circuit fault current, i.e the operating value of the relay, is generally much larger than the current during stressed operating conditions. This is especially true for direct grounded systems which most often is the case on the transmission level.

At locations where a low short circuit power is present the overcurrent relay must be given a fairly low operating current. Hence undesirable relay operation may occur due to large reactive power flows during voltage instability or severe power oscillations related to transient instability.

However short circuit overcurrent relays are rarely used on the transmission level. For example in the Swedish transmission system they are only used in a few devices to supervise distance protection elements. Short circuit overcurrent protection as an individual protection measure will therefore not be further investigated in this report.

2.3.2 Earth-fault overcurrent protection

During normal operation the power system is usually balanced and thus the residual currents small. However when an earth fault occurs the residual currents increase significantly and thus the zero sequence current may be used to detect this type of faults. Earth faults may also be detected by conventional short circuit protection e.g short circuit overcurrent protection or distance protection. However the main advantage of the overcurrent device based on the zero sequence current is its insensitivity to the load current. Especially in non-solid earthed systems this type of earth-fault protection usually performs better than conventional ones with respect to selectivity and reliability.

Apart from the direct effect on the system caused by earth-faults a further inconvenience with the associated residual currents is that they induce currents in parallel lines when they flow back to the source via earth. Examples of circuits which may be affected are overhead lines, low voltage lines and telecommunication lines. Especially telecommunication facilities require fast and reliable clearing of this type of faults. Even very small earth currents are of great concern.

In Sweden an earth-fault protection device based on three definite time directional overcurrent elements and one non-directional inverse time element is used for this purpose in the transmission system. The characteristic of the device is illustrated in figure 2.4. Sweden is one of the few countries where the earth-fault protection is used as the main protection with respect to earth-faults. In most countries impedance measuring methods are used.

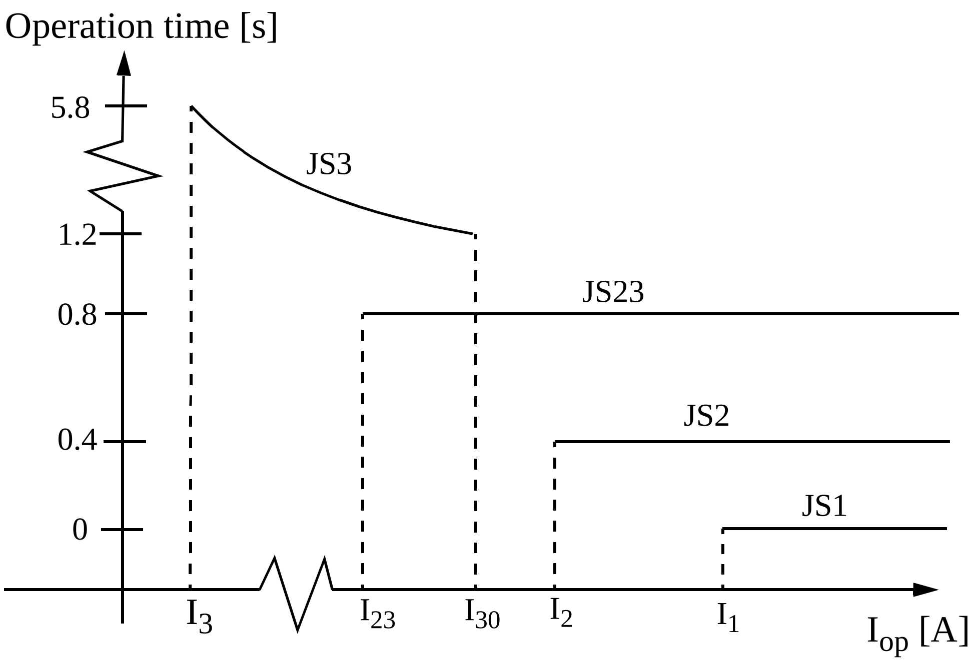

Figure 2.4 Earth-fault protection characteristic in the Swedish transmission system.

For all earth-fault protection devices the directional elements JS1, JS2 and JS23 are all given an unique operating current with respect to the system surroundings of the relay. Typically I_1 is in the range of 4 kA, I_2 in the range of 3 kA and I_{23} in the range of 0.1 - 2 kA. The time delays are indicated in figure 2.4. The non-directional JS3 element has basically the same settings for all devices throughout the entire system.

The timer settings are indicated in figure 2.4 and the value of I_3 and I_{30} are usually 80 A and 2400 A respectively. Equation (2.5) describes the inverse time characteristic for the JS3 element where the determination of the constants in (2.5) is further described in [4].

$$t = 5,8 - 1,35 \cdot ln\frac{I_{30}}{I_3} \tag{2.5}$$

The earth-fault protection device used in Sweden has been developed and modified throughout the years. Originally the non-directional JS3 element was of the definite time characteristic and the JS23 element was not present. Hence the gap between the operating currents I_2 and I_3 was large and many faults were cleared unselective by the non-directional JS3 element. To increase the selectivity the third directional element JS23 was introduced at exposed locations. However neither this measure achieved satisfactory selectivity as the gap was still too large. For that reason the non-directional definite time characteristic of JS3 was replaced by an inverse time characteristic. When all inverse time elements are given the same settings selectivity is achieved for the time inverse characteristic in (2.5). The background for this result is that the faulted line is usually fed by more than one line at the terminal. Accordingly the total current in the faulted line is the sum of the incoming line currents and thus the largest current flows in the faulted line. Accordingly selectively is achieved when the time inverse characteristic is applied.

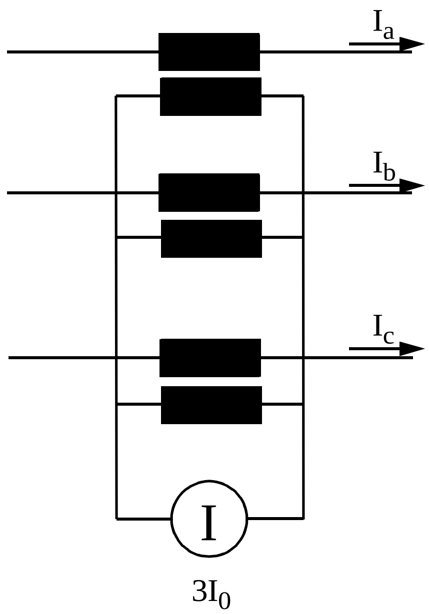

Figure 2.5 Connection of current transformers for earth-fault overcurrent protection.

The zero sequence component can be obtained by a special connection of the current transformers. See figure 2.5 and equation (2.7). Note that equation (2.7) can be used interchangeable for the zero sequence components of the voltage and the current respectively. In numerical applications the zero sequence current can easily be calculated from the phase currents.

Earth-fault overcurrent protection based on the zero sequence component are unlikely to operate undesirable during voltage and transient instability as these are phase symmetrical phenomena.

2.3.3 Overload overcurrent protection

The function of overload overcurrent protection is similar to the short circuit overcurrent protection. Although the operating value given to the relay is much lower and the time delay usually much longer. An overcurrent relay is typically set to operate for currents 10 % to 50 % above the rated limit [5] and the time delays are in the range of seconds.

Overload overcurrent protection may operate during stressed operating conditions. For example high reactive power flows during voltage instability may lead to tripping. However this behaviour is desirable as the relay protects the line from damage due to overload.

2.4 Distance protection

Distance protection is the most widely used method to protect transmission lines. The fundamental principle of distance relaying is based on the local measurement of voltages and currents, where the relay responds to the impedance between the relay terminal and the fault location. As compared to differential protection, distance protection can operate properly without any communication device. This aspect is attractive from both a reliability and an economical point of view. However in some applications communication links are used as a supplement to speed up the fault clearing time [6]. A distance relay is more expensive than an overcurrent relay but is more reliable in case of meshed system configurations. Additionally the settings of the distance protection do not need to be recalculated due to the prevailing operating condition as may be the case for overcurrent protection.

2.4.1 The operating principle of distance protection

During normal operation the apparent impedance as seen by a distance relay is large whereas during a fault condition the apparent impedance is small. To discriminate between normal and fault conditions a zone of operation (fault detector zone, tripping zone) is used. If the apparent impedance as seen by the relay is outside the zone of operation the relay will not trip whereas when the apparent impedance is within the zone of operation the relay operates.

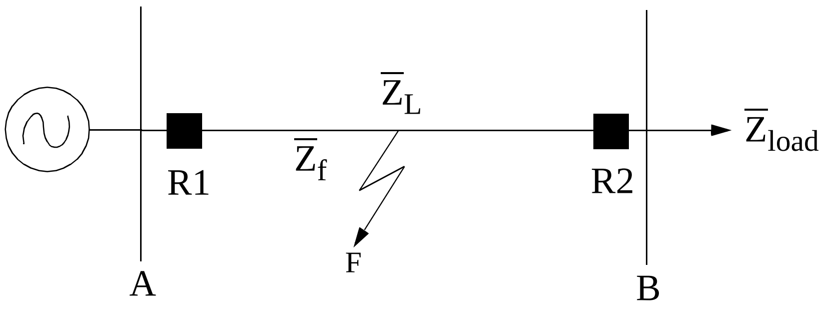

Figure 2.6 An one line system protected by the distance relays R1 and R2. The total line impedance is $\overline{Z}_L$, the load impedance is $\overline{Z}_{load}$ and the impedance between terminal A and the fault location F is $\overline{Z}_f$.

In figure 2.6 the generator and the load are connected through a transmission line where the line is protected by the two distance relays R1 and R2. Figure 2.7 shows the operating principle for distance protection. During normal conditions the apparent impedance as seen by R1 is approximately the load impedance $\overline{Z}_{load}$. Hence the apparent impedance as seen by R1 is located far outside the zone of operation; in this case at indication 1. When the short circuit fault occurs at F the apparent impedance ”jumps” into the zone of operation and the relay operates. The new apparent impedance as seen by R1 is the impedance $\overline{Z}_f$ between terminal A and the fault location F which is less than the pre-set impedance value of the zone of operation.

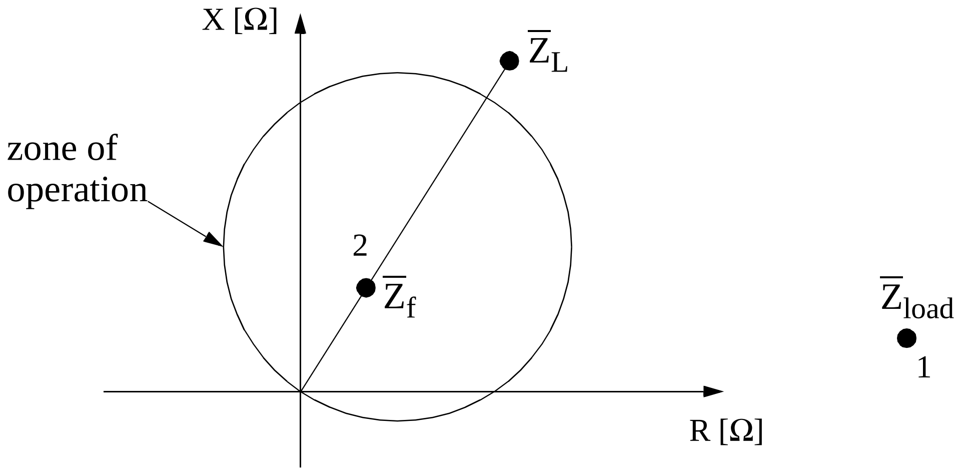

Figure 2.7 RX-diagram for the distance relay R1 in figure 2.6. Indication 1 refers to normal operation whereas 2 indicates the fault situation.

There is always an uncertainty in the parameters involved in a protection system. For example, the line impedance may vary due to the outside temperature and/or the polarization voltage may be distorted. Because of these uncertainness the entire line in figure 2.6 is not covered by R1’s zone of operation as this may lead to undesirable relay operations for faults immediately behind terminal B. Usually 80-85 % of the line is covered. However to assure fault clearing throughout the entire line an additional zone is used.

Figure 2.8 shows three subsequent lines. The zone 1 associated to R1 operates instantaneously for faults located between terminal A and the point which refers to 80 % of the line length between terminals A and B. To cover the remaining 20 % of the line zone 2 is used. Thus to assure fault clearing for the entire length zone 2 is typically set to cover 120% of the line length. However for a fault close to terminal B on the line between B and C both zone 1 of R3 and zone 2 of R1 will see the fault. To avoid unnecessary line tripping and achieve selectivity the zone 2 is given a single time delay. Further a third zone is used to give remote back-up protection in case of failure of the primary protection. Zone 3 is typically set to cover about 120 % of the longest adjacent line [67]. Hence when a fault occurs in the middle of the line between B and C zone 1 and zone 2 of R3 will see the fault. Additionally zone 3 of R1 will see the fault. Thus if R3 fails to operate then R1 will operate as remote back-up protection. To achieve time selectivity between the different relays and zones of operation zone 3 is given a double delay time. The time delays for zones 2 and 3 are typically in the range of 0.4 s and 1 - 2 s respectively.

The same performance and interaction will take part for relays R2, R4 and R6 as for R1, R3 and R5. However R2, R4 and R6's directional reach is of course reversed as compared to R1, R3 and R5.

In case of series compensated lines some complexity is added to the setting process of the distance protection. These complicating features related to series compensated lines are further described in [7,8].

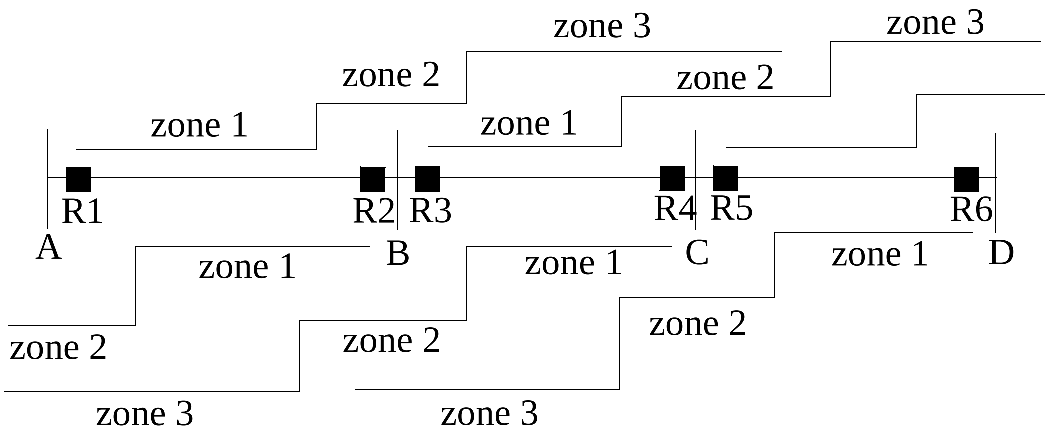

Figure 2.8 The reach of the different zones of operation.

Zones 1 and 2 are mainly used to clear local faults on the primary protected line. However zone 3 is used in a number of different applications where the main ones are listed below:

I. To provide remote back-up for phase to ground and/or phase to phase faults on adjacent sections of transmission circuits in case of failure of the primary protection at remote substations when local back-up protection is not available. For example, in figure 2.8 zone 3 of R3 composes the remote back-up for the line between terminals C and D.

II. To provide a remote breaker failure protection for phase faults on adjacent circuits beyond the remote terminal, coincident with failure of a circuit breaker to operate, on the faulted line at the remote terminal. An example of this kind of application is shown in the right part of figure 2.9 where zone 3 of R4 provides remote breaker failure protection in case the circuit breaker associated to R2 fails to operate.

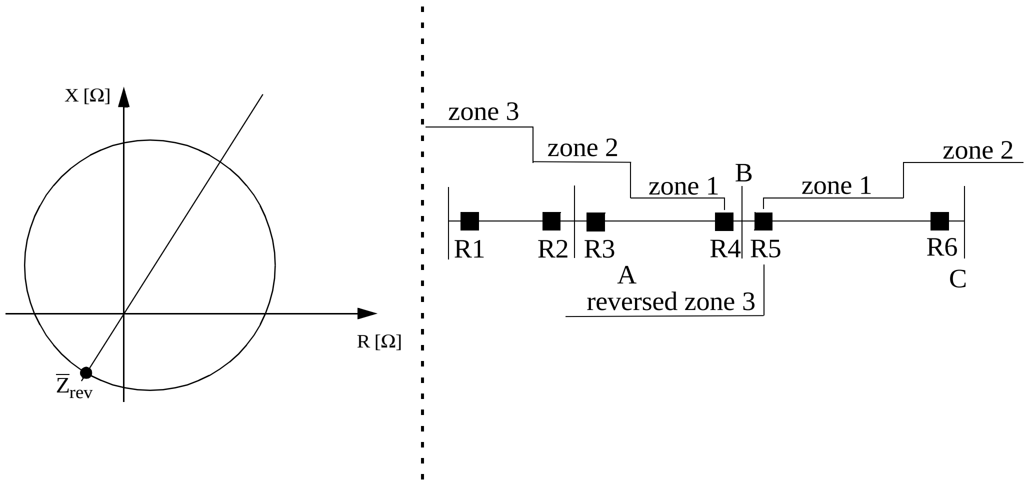

Figure 2.9 To the left a reversed tripping characteristic where $\overline{Z}_{rev}$ is the reach of the element in the backward direction. In the right figure examples of local and remote breaker failure protection are given.

III. Reversed zone 3 elements may provide local breaker failure protection if the impedance characteristic includes the origin; figure 2.9. An example is given in the right part of the figure where the reversed zone 3 element of R5 operates as local breaker failure protection in case the circuit breaker associated to R4 fails to operate.

IV. As a starting function for zone 1 and/or zone 2 relays.

V. In some pilot relaying a reverse-looking impedance relay is used to detect faults behind the terminal of the protected line and send a blocking signal to the remote terminal.

VI. In permissive underreach protection schemes [9] the zone 3 may be used as the permissive criterion.

VII. In accelerated overreach protection schemes [6] the zone 3 may be used as the extended zone.

VIII. As a reverse-looking impedance relay in some pilot relaying schemes used for weak infeed system configurations [9,67]. If the reversed zone 3 relay located at the weak infeed terminal, does not see the fault at the time the relay at the remote strong infeed terminal announces the fault, then the relay at the weak infeed terminal operates or returns the acceleration signal.

IX. As local back-up to achieve selectivity in case of infeed from T-lines.

However the fundamental idea of zone 3 distance relaying is to provide 100% remote back-up protection to all adjacent circuits and also to be discriminative in time with zone 2 of all adjacent circuits [10,12]. Unfortunately this is not always so easy to accomplish due to long lines, infeed and load encroachment. In some cases more than three zones are used. Usually this is to support more than one of the zone 3 functions listed above.

In fact certain utilities have taken their remote back-up zone 3 relays out of operation. The main reason is that they are not needed when local back-up is provided. Local back-up may include redundant relay sets that are largely independent, local breaker failure protection and/or busbar protection. Also when reliable pilot relaying schemes and separate directional earth-fault overcurrent protection are used the likelihood for remote back-up operation is very small. Zone 3 relays cost money, are adding complexity, are taking up rack space and may potentially operate in an undesirable manner during overload. In case of digital relays the space argument is not longer valid. Additionally the hardware cost will not increase much when zone 3 is used in digital applications. However due to the setting complexity the cost for zone 3 is still large.

NERC[1] Planning Standards Guide III.A.G17 states: ”*Application of zone 3 relays with settings overly sensitive to overload or depressed voltage conditions should be avoided where possible*.” [11]. The background for this statement is further discussed in chapter 3. However to point out the complexity of the issue related to applying zone 3 as remote back-up the following sentence is quoted from [13]: ” *This led to a suggestion for removing line zone 3 protection, an approach which tackles the symptoms but not the cause of system voltage instability and should not even be considered”*.

1. North American Electric Reliability Council

2.4.2 The impedance characteristic

The shape of the zones of operation has developed throughout the years. In figure 2.10 an overview of the different characteristics is given. There exists a large variety among the different characteristics with respect to different brands and generations. Originally the characteristic was a circle located in the origin. A disadvantage of this shape is that the relay becomes non-directional. Additionally the characteristic is highly sensitive to power swings and load encroachment because of the large area covered by the impedance circle. To avoid these problems the circle was decreased in size and its origin moved to the first quadrant of the impedance plane leading to the directional mho relay. In fact in case of extra long transmission lines also the reach of the mho relay may be to large in the resistive direction leading to load encroachment. Therefore the area covered by the tripping zone was decreased and thus the ellipse characteristic was introduced.

When voltage and current are compared in an amplitude comparator a circle located in the origin of the RX-diagram can be obtained. When the same signals are compared in a phase comparator a straight line passing through the origin is acquired. By modulating the comparator inputs these circles and lines can be moved in the RX-diagram. Also by adding lines the circular shapes could be limited, leading to shapes like the circle-quadrilateral characteristic in figure 2.10. These lines may also be used in applications such as load blinders, Power Swing Detectors and/or Out of Step Characteristic; see section 4.1.1. They have also been used to develop simple quadrilateral characteristics, as for example the characteristic where all zones have the same resistive reach.

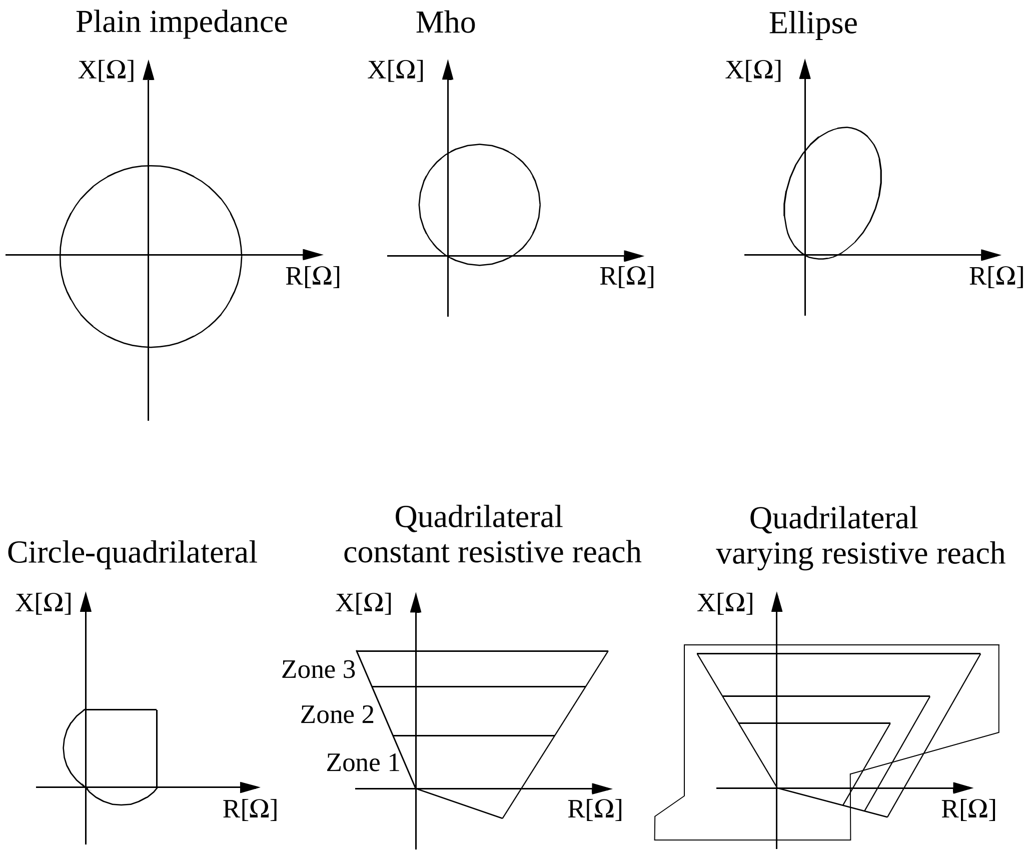

Figure 2.10 The development of the distance protection characteristics. From the early plain impedance characteristic to the modern quadrilateral characteristic including a supervising characteristic which obstructs load encroachment.

The setting possibilities of circular characteristics are fairly restricted. Usually the reach in resistive and reactive direction can not be set independently. Consequently load encroachment can be a restriction when the settings are given to the relay in case of long lines. In case of short lines the reach in restive direction may be too short to clear high resistance faults. For quadrilateral characteristics the reach in resistive and reactive direction can usually be set independently.

A general categorization can be made between the different shapes of the zone of operation and the different relay types. Electromechanical relays usually have a circular shape. For example the ASEA RYZKC relay based on the mho characteristic. Solid-state relays have a combination of circular and quadrilateral characteristic or a simple quadrilateral characteristic. Examples are the ASEA RAZOA relay which has the circle-quadrilateral shape or the SIEMENS 7SL24 relay with the quadrilateral constant resistive reach characteristic. Numerical relays generally have a quadrilateral characteristic where the reach can be set independently in resistive and reactive directions. An example is the ABB REL 5xx relay group.

2.4.3 Distance relay types

Distance protection are usually divided in to two groups; switched scheme and full scheme. In figure 2.11 the block schemes for a switched scheme and a full scheme distance protection are illustrated. Switched relays only have one measuring unit. The fault is detected by the start elements and the correct input signals with respect to the fault type for the measuring element are determined by the start elements and mathematical logic blocks. Additionally timers are used to decide which zone of operation (reach) has to be applied. When the apparent impedance as seen by the measuring element is within the (pre-set threshold for the) active tripping zone, and the directional element sees the fault, the tripping signal is sent. Examples of switched distance relays are the Siemens 7SL24 relay and the ASEA RAZOA relay.

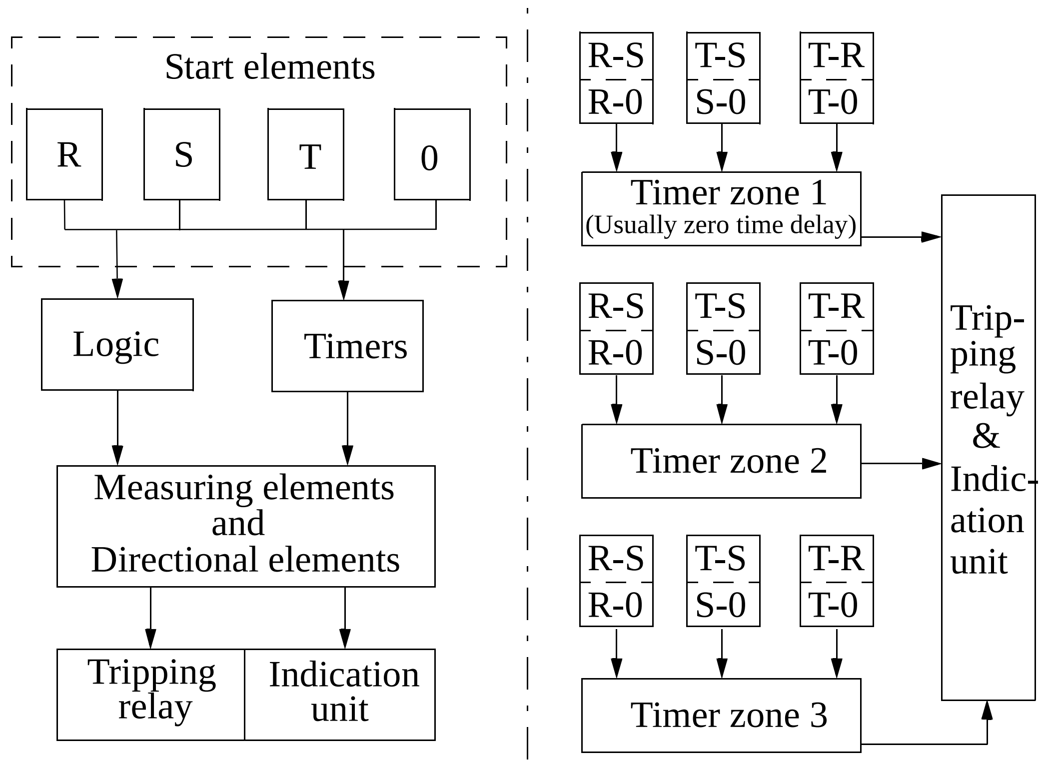

Figure 2.11 Blocks schemes for a switched distance relay (left) and a full scheme distance relay (right).

The full scheme relay has measuring elements for each phase and each zone. There are elements for both phase to phase faults and for phase to ground faults. Hence the start elements are not required. Each measuring element is working independently and thus the full scheme relays are inherently redundant. During operation no switching occurs and the operation is faster than for switched relays. This is especially true for electromechanical devices. Examples of full scheme distance relays are relays included in the REL 5xx group.

Relays like the ASEA RYZKC relay are of an intermediate nature and may be considered to be either a modified switched scheme or a simplified full scheme relay.

Electromechanical relays are based on capacitors, inductances and mechanical components. Solid state relays use transistors and in some cases digital circuits whereas numerical relays are based on microcomputers performing calculations. Figure 2.12 illustrates a block scheme of a typical numerical relay [14].

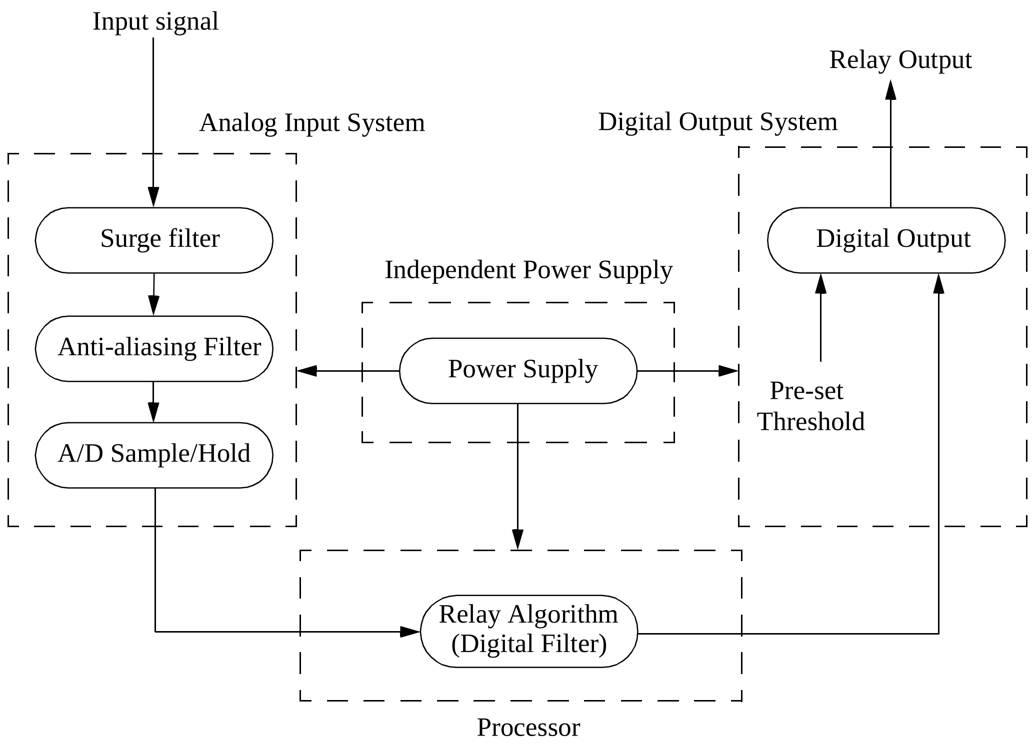

Figure 2.12 Block diagram of a numerical relay.

2.4.4 Theoretical background of distance protection

Distance protection is intended to clear all types of phase to phase faults and phase to ground faults. Series faults are most often not cleared by distance protection. Using symmetrical components and the small system in figure 2.13, the inputs required for the distance relay to distinguish all possible fault conditions may be determined.

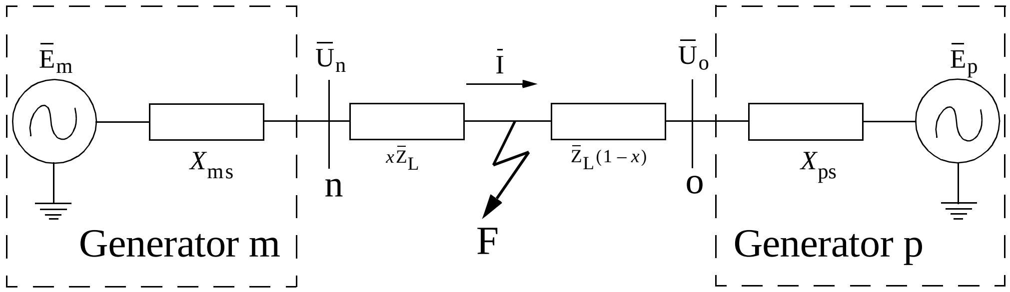

Figure 2.13 A two machine system.

In figure 2.13 two generators at terminals n and o are connected through a transmission line. Different fault types at the location F are studied where F is located at the point referring to x % of the total line length as seen from terminal n. The impedances included in the small system are indicated in figure 2.13 where the line impedance is divided into two sections with respect to the fault location. The positive and negative sequence impedances are considered to be the same for the line. This is an common assumption made during these types of studies. For the symmetrical component circuits in figures 2.14 and 2.15 the same notation is used where subscript 1 relates to the positive sequence component and the subscripts 2 and 0 to the negative and zero sequence component respectively.

A detailed introduction to symmetrical components can be found in [15]. However the main equations for the voltages are repeated below where the a-operator is defined as in (2.6). Equations (2.7) to (2.12) may also be used for currents. In that case the voltages are replaced by the corresponding currents.

$$a = e^{j\frac{2\pi}{3}} \tag{2.6}$$

$$\overline{U}_0 = \frac{1}{3}(\overline{U}_a + \overline{U}_b + \overline{U}_c) \tag{2.7}$$

$$\overline{U}_1 = \frac{1}{3}(\overline{U}_a + a \cdot \overline{U}_b + a^2 \cdot \overline{U}_c) \tag{2.8}$$

$$\overline{U}_2 = \frac{1}{3}(\overline{U}_a + a^2 \cdot \overline{U}_b + a \cdot \overline{U}_c) \tag{2.9}$$

$$\overline{U}_a = \overline{U}_0 + \overline{U}_1 + \overline{U}_2 \tag{2.10}$$

$$\overline{U}_b = \overline{U}_0 + a^2 \cdot \overline{U}_1 + a \cdot \overline{U}_2 \tag{2.11}$$

$$\overline{U}_c = \overline{U}_0 + a \cdot \overline{U}_1 + a^2 \cdot \overline{U}_2 \tag{2.12}$$

In case of a phase to phase fault between phases b and c at F the corresponding symmetrical component network is shown in figure 2.14. Hence $\overline{U}_1$ and $\overline{U}_2$ are equal which gives the relation in (2.13).

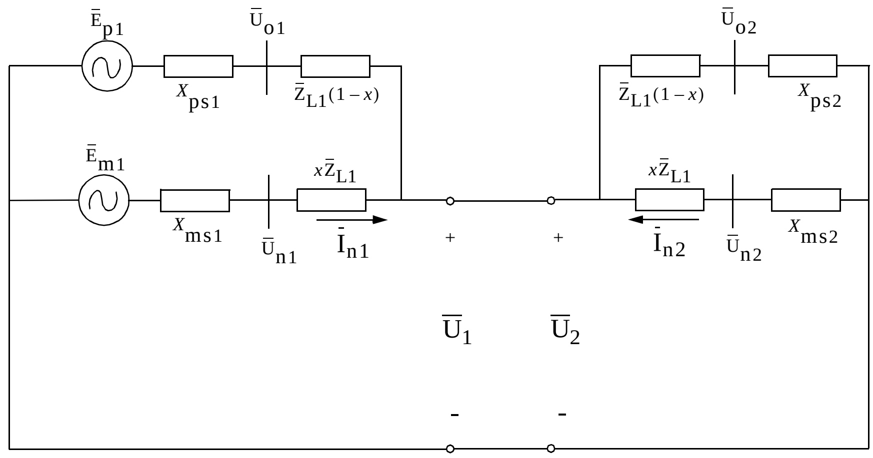

Figure 2.14 Symmetrical component circuit for a phase to phase fault between phases b and c.

$$\overline{U}_{n1} - x\overline{Z}_{L1} \cdot \bar{I}_{n1} = \overline{U}_{n2} - x\overline{Z}_{L1} \cdot \bar{I}_{n2} \tag{2.13}$$

After some rearrangement (2.13) is given as in (2.14).

$$x\overline{Z}_{L1} = \frac{\overline{U}_{n1} - \overline{U}_{n2}}{\bar{I}_{n1} - \bar{I}_{n2}} \tag{2.14}$$

When (2.8), (2.9) and the corresponding equations for the currents are inserted into (2.14) the following expression is given for the impedance between terminal n and the fault location.

$$x\overline{Z}_{L1} = \frac{\overline{U}_{nb} - \overline{U}_{nc}}{\bar{I}_{nb} - \bar{I}_{nc}} = x\overline{Z}_{L} \tag{2.15}$$

In other words to detect the correct fault location for phase to phase faults between phases b and c the input signals for the distance relay should be the phase currents and voltages for these phases. If a similar investigation is made for all the remaining combinations of possible phase to phase faults it is found that equation (2.15) is also applicable in these cases though the input signals must be changed to the affected phases.

Equation (2.15) is also applicable for three phase faults or double phase to earth faults. This can easily be verified by performing a similar analysis based on symmetrical components for these specific fault cases [16].

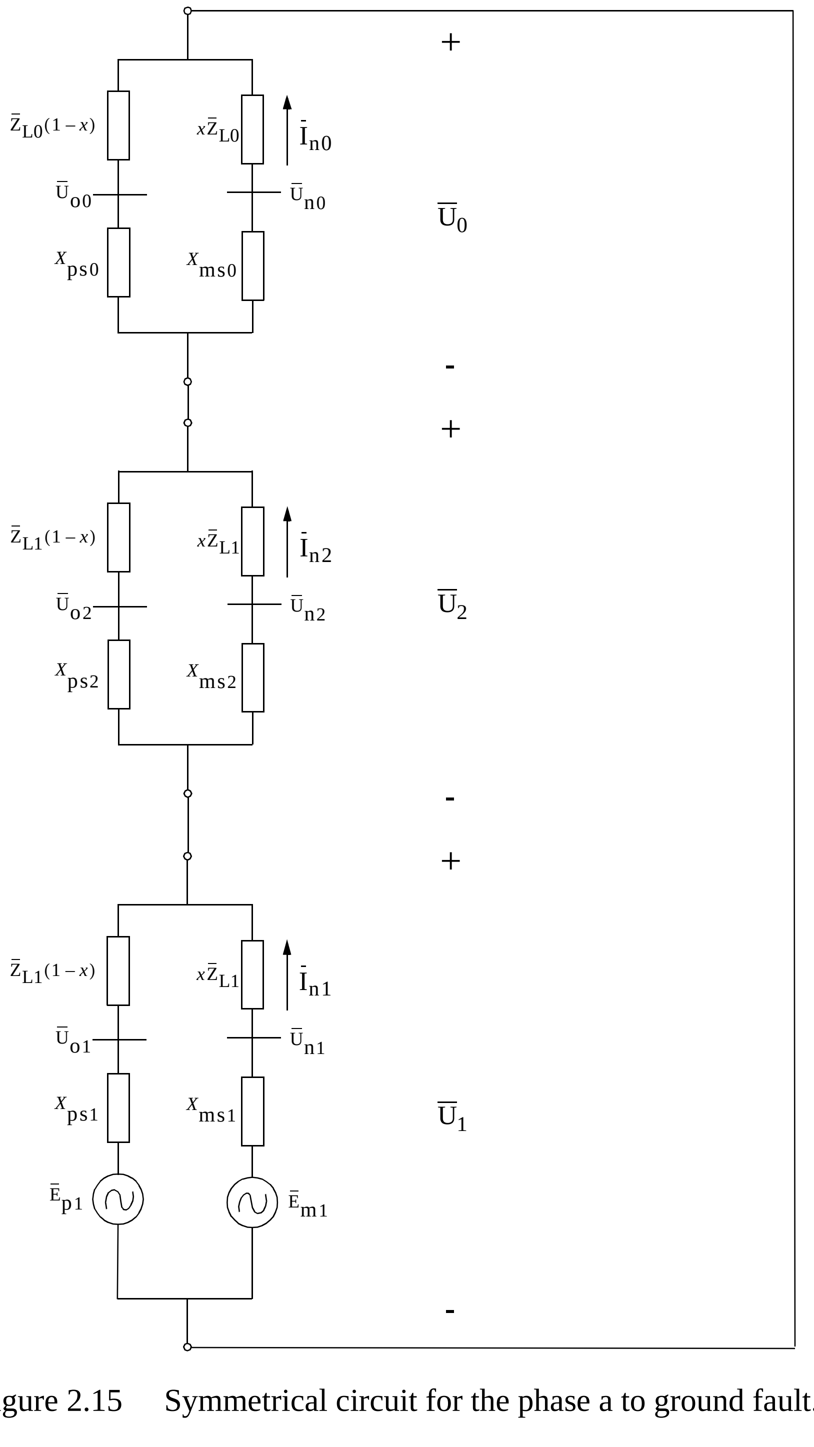

Figure 2.15 Symmetrical circuit for the phase a to ground fault.

When a short circuit is applied between phase a and ground at F in figure 2.13 the corresponding symmetrical component network is given as in figure 2.15. Relations (2.16) to (2.19) can be determined from figure 2.15. As indicated above the positive and negative sequence impedance for the transmission line are identical. However the zero sequence impedance is typically three times larger in case of transmission lines.

$$\bar{U}_{n1} = \bar{U}_1 + x\bar{Z}_{L1} \cdot \bar{I}_{n1} \tag{2.16}$$

$$\bar{U}_{n2} = \bar{U}_2 + x\bar{Z}_{L1} \cdot \bar{I}_{n2} \tag{2.17}$$

$$\bar{U}_{n0} = \bar{U}_0 + x\bar{Z}_{L0} \cdot \bar{I}_{n0} \tag{2.18}$$

$$\bar{U}_1 + \bar{U}_2 + \bar{U}_0 = 0 \tag{2.19}$$

When (2.16), (2.17) and (2.18) are inserted into (2.19) and equation (2.10) and the corresponding current equation is applied, the impedance between terminal n and the fault is given as in (2.20).

$$x\bar{Z}_{L1} = \frac{\bar{U}_{na}}{\bar{I}_{na} + \bar{I}_{n0} \cdot \dfrac{\bar{Z}_{L0} - \bar{Z}_{L1}}{\bar{Z}_{L1}}} = x\bar{Z}_L \tag{2.20}$$

In order to decide the correct fault distance for a single short circuit fault between phase a and ground the phase voltage and phase current at the relay location should be used as inputs to the distance relay. Additionally the residual current as seen by the relay must be included. The same equation is applicable for all combinations of single phase to ground faults, though the associated voltages and currents must be applied as relay inputs.

Equations (2.15) and (2.20) explain that distance relays use the phase voltages and currents to determine the apparent impedance for fault localization. Consequently operating conditions where no short circuit fault is present but are characterized by low voltage levels and/or high (power flows) currents may lead to that the relay measures a small apparent impedance. Hence the tripping zones may be entered and the relay operates incorrectly. Examples of such events are voltage instability and transient instability.

In the development of equations (2.15) and (2.20) the fault impedance is neglected. However the fault impedance may have a significant influence on the apparent impedance as seen by the relay.

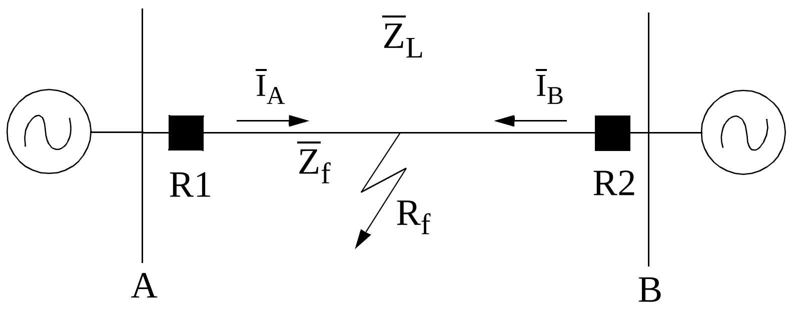

Figure 2.16 A two bus system where a symmetrical three phase fault has occurred. The fault resistance is R_f and the line impedance $\overline{Z}_L$. The impedance between terminal A and the fault locations is $\overline{Z}_f$.

Figure 2.17 shows the apparent impedance as seen by R1 for the three phase fault in figure 2.16. The same apparent impedance is described mathematically in equation (2.21).

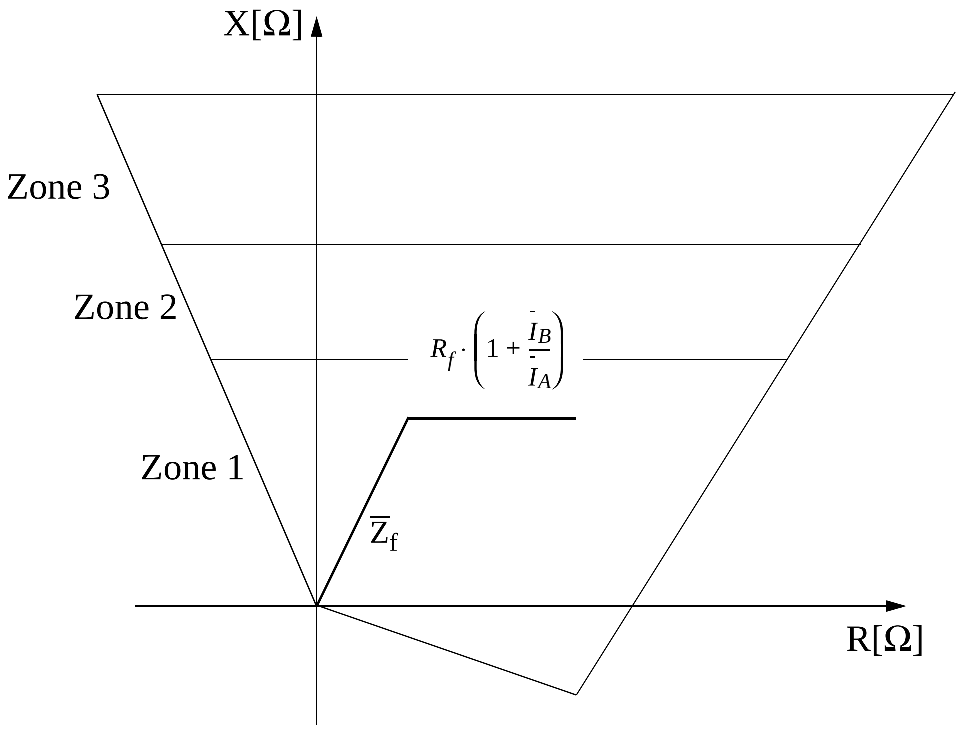

Figure 2.17 Apparent impedance as seen by R1 in figure 2.16.

$$\bar{Z}_A = \bar{Z}_f + R_f \cdot \left(1 + \frac{\bar{I}_B}{\bar{I}_A}\right) \tag{2.21}$$

Equation (2.21) and figure 2.17 indicate that a large fault resistance or a large infeed from the remote terminal causes the relay to underreach in the resistive direction. Also, as the currents are complex quantities, certain relations between them may lead to that the relay underreaches for zone 1 faults and thus the fault is cleared by the time delayed zone 2 element. Similarly the relay may overreach for some zone 2 faults during certain relations between the currents. As a result the zone 2 fault is cleared by the zone 1 element.

Infeed at the remote terminal may cause the relay to underreach in case the relay is used as remote back-up protection. Similarly when the relay is used as main protection it may underreach in case of infeed from T-lines.

Equation (2.21) is valid for symmetrical three phase faults. Similar equations are valid for unsymmetrical faults. However minor modifications are necessary to adjust for the unsymmetrical conditions.

2.4.5 Adaptive distance protection

In [36] Horowitz, Phadke and Thorp define adaptive protection as: ”*Adaptive protection is a protection philosophy which permits and seeks to make adjustments to various protection functions in order to make them more attuned to prevailing power system conditions*”. A simplified but more straightforward explanation of adaptive relaying is made by Perez et al. in [17]: ” *the ability to change relay parameters on-line depending on present operating conditions*”.

As microprocessor based techniques have became widely used in the power system protection area, adaptive applications have become an attractive tool. Many different approaches have been proposed and a short survey will be given here.

An adaptive method to avoid the underreach of zone 1 in case of different phase angles of the currents feeding the fault is widely implemented in numerical relays. One approach of this method is further descried in [18].

In [19] an adaptive distance relay is introduced. As input signals the relay algorithm uses the phase angle of the fault current, the phase angles of the voltages at the relay terminal and at the point on the line related to the boundary of the reach of zone 1. By applying the relationships between these quantities the relay adapts to the load current and the fault resistance.

In [20] and [21] the boundary of the relay characteristic is continuously updated in accordance with the prevailing operating condition. For these applications the boundary of the zones of operation is not restricted to straight lines or symmetrical circular shapes as is the case for conventional distance relays.

Properly trained artificial neural networks are robust and insensitive to noise in the input data. These features have made them attractive for power system protection applications. For example in [22] and [23] two adaptive distance protection applications are proposed using this technique.

Adaptive techniques have also been used to avoid under- or overreaching of the remote back-up zone with respect to infeed and load encroachment [24]. Further adaptive approaches can be found in [25, 26, 27, 28].

2.5 Thermal overload protection

Thermal relays are rarely used for overhead lines. The reason is that the heat dissipation of overhead lines is so good that it would be uneconomical to load a line anywhere near its heating limit with respect to the ensuing voltage drop [29]. However as voltage control has improved, for example by FACTS[1] devices, this opinion should perhaps be reevaluated.

In contrast to overhead lines, thermal overload is an important issue for underground cables as the ageing of their insulation is considerable accelerated in case of high temperatures. Cables are usually protected by time-current relays.

The maximum temperature rise of the protected equipment is proportional to the heat generated in it [29]. In the case of a cable this corresponds to RI^2 and hence the temperature rise is a function of RI^2t. Accordingly a time-current relay with an I^2t operating characteristic should provide a good protection.

The ambient temperature influences the conductor and insulation temperature. Since it is the actual temperature and not the temperature rise which damages equipment, ambient temperature compensation is

1. Flexible AC Transmission Systems

usual for most thermal protection relays. The compensation makes it possible to utilize the equipment to its thermal maximum limit for all possible ambient temperatures. Although great effort is given to the setting procedure of the relays the method may sometimes be unreliable as the surrounding weather situation influences the equipment temperature. Instead of using the (uncertain) circuitous method based on current relays, temperature measuring devices could be applied directly. However the line temperature may be difficult to measure as suitable measuring points can be complicated to access for temperature sensors. A thermal line model may be applied as an alternative where the voltage and/or current is used to calculate the prevailing temperature of the line. Still the weather parameters must be included in the thermal model to be able to utilize the line to its maximum capacity.

As the purpose of the thermal overload protection is to protect equipment from damages, their operation must be considered to be correct in case they operate during abnormal conditions. Because of their time settings they are more likely to operate during long term voltage instability than in case of transient instability.

However in certain cases there may be an incentive to overload transmission lines for a short period. Even overloading during a longer period which may lead to conductor damage may be considered if this can avoid a blackout. This proceeding can be justifiable in case the cost of the damaged transmission line is lower than the total cost associated with the blackout and the system can be operated as normal when the line is out of operation during the maintenance period.

2.6 Travelling wave relays

Travelling wave relays are used to achieve very fast fault clearing. The operating principle is based on the behaviour of the voltage and current waves which arise in case of short circuit faults. The background theory of travelling wave relays is further described in [30,31].

The relays are intended to operate for waves caused by sudden system disturbances, as for example, phase to phase faults and phase to ground faults. The relays will most likely operate properly during voltage instability and transient stability as their associated time domains are much longer and consequently no appreciable waves will arise.

2.7 Line protection in the Swedish transmission system

The Swedish transmission system consists of the two voltage levels 400 kV and 220 kV and has two independent redundant protection systems for each line called SUB1 and SUB2[1]. The main reasons for this is to provide local back-up giving fast fault clearing and to limit the affected area by ensuring that only the faulted line is disconnected. Additionally maintenance work can be performed on protection equipment at the same time as the line is loaded and still have the line satisfactorily protected.

2.7.1 Outline of the protection scheme at the line terminal

Figure 2.18 shows an outline of the standard line protection system in the Swedish transmission system. All line terminals in the Swedish transmission system, apart from a limited numbers of 220 kV terminals, are equipped with a system identical or similar to the one in figure 2.18.

Most devices are duplicated though a few components are shared by the two SUB groups. The same voltage and current transformers are used. Neither the circuit breaker is duplicated. However the voltage signals from the VT into the two SUB groups are protected by independent fuses and different CT coils are used for the current signals. The DC supply for the two SUB groups are separated and are not allowed to share any fuse. Below a description of the abbreviations in figure 2.18 is given:

DP = Distance Protection

JS1-JS23 = Zones 1 to 3 of the directional definite time overcurrent elements

JS3 INV.= The non-directional inverse time overcurrent element

U_0 = Zero voltage protection

COM. = Pilot Relaying equipment

AR = Auto Recloseing

BFP = Breaker Failure Protection

SS = Busbar protection

1. Abbreviation for Subsystem. Often the terms main 1 and main 2 are used.

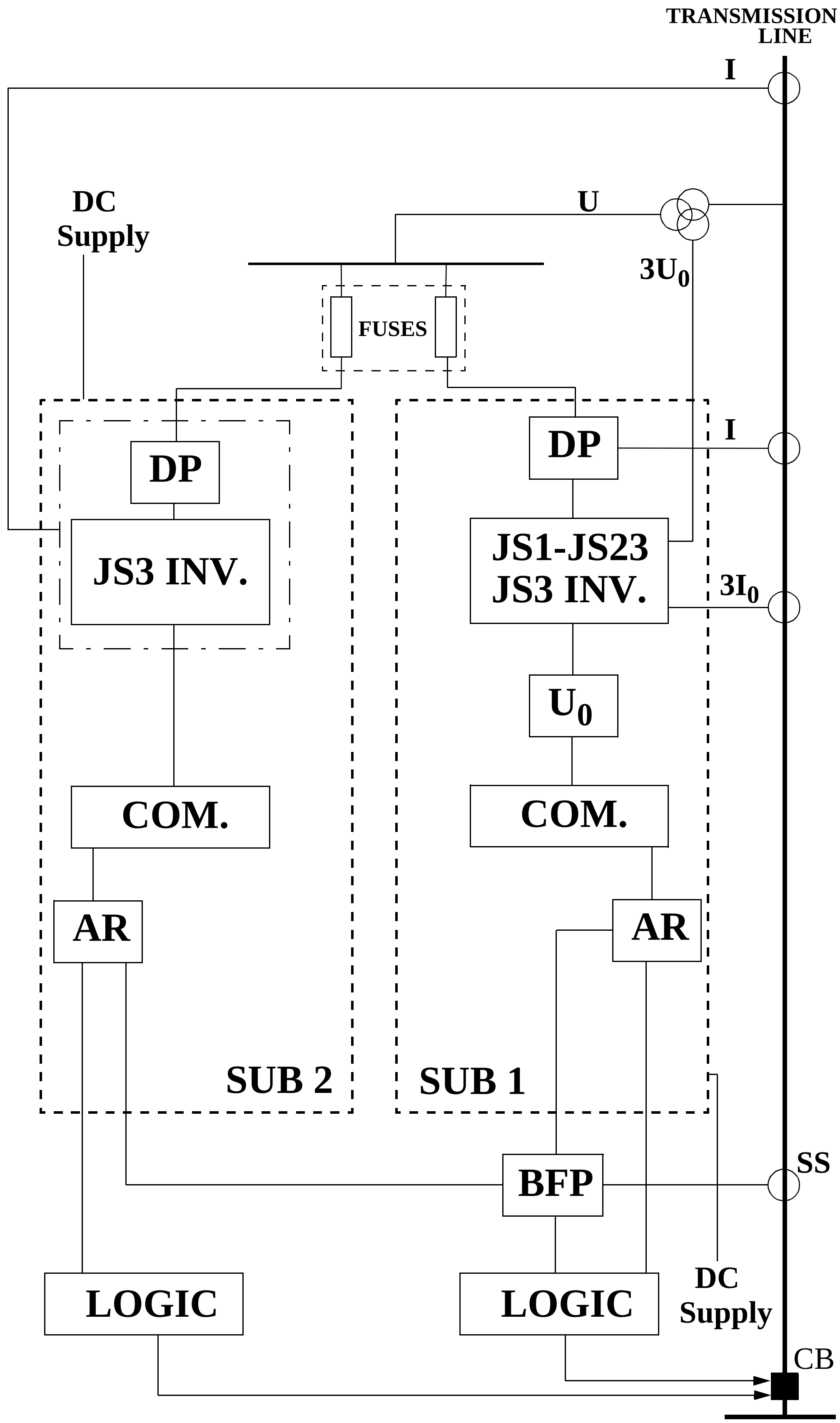

Figure 2.18 Line protection system.

Both SUB 1 and SUB 2 contain a distance relay which is intended to clear short circuit faults. Additionally SUB 1 includes the four zones earth-fault overcurrent relay as described in section 2.3.2. However to assure clearing of small residual currents in case of maintenance work on SUB 1, an inverse time earth-fault overcurrent relay is required in SUB 2. Usually this overcurrent function is included in the distance relay. As discussed in section 2.3.2, Sweden is one of the few countries where earth-fault overcurrent protection is used as the main earth-fault protection whereas distance protection is used as local back-up. Generally the earth-fault overcurrent protection performs better than distance protection in case of a large fault resistance and gives a higher number of successful auto-reclosures. In the Swedish transmission system about 80 % of the faults are earth-faults which are mainly cleared by the earth-fault overcurrent protection [32].

The disadvantages of the zero-sequence based overcurrent protection is that their reach is dependent of the prevailing network configuration. Hence when extensive network reconfigurations are made the relays must be given new settings to operate as intended. However in case of an interruption this is not practicable and consequently the relays have incorrect settings with respect to the post fault grid configuration. Adaptive techniques may solve this problem. However until today no severe accidents have happened due to this phenomenon. Another drawback with the earth-fault overcurrent protection is that a good knowledge about the positive-, negative and zero sequence impedances of the system is required to give the relay proper settings. Additionally the calculation process is complicated; however computer software can be used for this process.

Breaker failure protection and busbar protection are included in the scheme although they may be considered to be classified as substation protection. Additionally zero voltage protection is required for either SUB 1 or SUB 2. This protection device opens all circuit breakers at a certain voltage level. Usually the setting is somewhere between 0.3 and 0.5 pu. The purpose of this function is to simplify the restoration process after an interruption.

Pilot relaying is widely used to decrease the fault clearing time. Mainly the pilot relaying schemes ”accelerated underreach” and ”intertripping underreach” are practised [6].

At a few substations the distance protection in one SUB group is replaced by differential protection as the surrounding system configuration makes it preferable.

When the duplicated protection system was introduced in the middle of the seventies it was decided that each SUB group should contain distance relays based upon different principles and/or from two different brands. For example, an electro-mechanical relay should be combined with a solid-state relay or a switched relay should operate in parallel with a full-scheme relay. The background for the decision was to increase reliability as two different relays probably will not suffer from the same design inadequacies. Today this philosophy is slowly changing because (almost) all relays manufactured are numerical and largely based on the same algorithms. However, still different designs of relays are required in the two SUB groups although they must not necessarily be of different brands. The main reason for this requirement is to safeguard against software inadequacies. Another reason may be that it is harder to give two different relay types incorrect settings as compared to identical relays as the ”copy and paste” technique may be avoided.

2.7.2 Mixture of distance relays

The depreciation period for protection relays is 15 years but usually they are used longer. Today there are distance relays which are more than 30 years old in the Swedish system. However the technical life time will probably decrease for computer based devices. About 700 distance protection devices are installed and the mixture based on the type of relay is shown in table 2.1.

Table 2.1: Mixture of different types of distance relays.

	Electro mechanical [%]	Solid-state [%]	Numerical [%]
SUB 1	65.5	16.5	18.0
SUB 2	-	72.5	27.5
Total	37.5	40.5	22.0

SUB 2 was introduced in the middle of the seventies. Therefore no electro-mechanical relays were used since solid-state relays already had entered the market.

The zones of operation for all electromechanical relays have the shape of a (mho)circle. Solid-state and numerical relays have a quadrilateral shape or a combination of a circle and a quadrangle. Table 2.1 shows that electromechanical relays still compose a large fraction of the line protection devices and probably will be used for a long time into the future. Therefore it is very important to consider this type of relay when stability studies are made. Numerical relays not only offer improvement in protection but are also predicted to entail overall system improvement to meet the demands of deregulation [33]. A new problem which possibly can occur with computer based relays is that the software will be frequently updated. Accordingly there will be a lot of different models in the system but only a few of each device. This may complicate support and maintenance work.

2.8 Advantages and disadvantages with local and remote back-up protection [34]

The main advantage with remote back-up is that less relay devices are required as compared to local back-up. Additionally circuit breaker back-up is inherently provided and the security of the protection system is increased.

One disadvantage with remote back-up is that infeed may cause the relay to underreach. Alternatively if the relay is given a long reach to avoid underreach this may result in load encroachment. Also the fault clearing time increases significantly in case of remote back-up as compared to local back-up. The increased fault clearing time may be detrimental with respect to system stability. Another disadvantage of remote back-up is that not only the faulted line is disconnected but also additional lines.

When remote back-up is applied for two subsequent long distance transmission lines large capacitive currents may be present in case of a fault situation. Consequently complicated interruption may occur which could lead to circuit breaker failure.

Obviously in case of local back-up the apparent impedance is unaffected by infeed which is of great advantage. A further advantage of local back-up is that the area affected by the fault clearing is limited; only the faulted line is tripped. When local back-up is applied the main and back-up relays obviously see the same current and voltage which contributes to correct relay performance. In case of local back-up protection the fault clearing time is not increased which is most desirable. Another advantage is that maintenance work can be performed on a protection group whereas the line stays in service and is protected by the other protection system.

As stated above more relays are used in case of local back-up as compared to remote back-up. Consequently the dependability of the protection system increases but the security decreases. Economical aspects limit the duplication of current and voltage transformers which means that there is no redundancy for these devices. Also the local control and monitoring system in the substation is more complicated for local back-up systems as compared to remote back-up systems. Although local back-up is provided by the extra protection group breaker failure protection must usually be applied as well to safeguard for circuit breaker failure. As a result there is in fact a duplicated back-up protection which may not be justified from an economical point of view.

Chapter 3 Distance Protection and Voltage Stability

In case of voltage instability usually generator current limiters, tap-changers and dynamic loads are considered as the dominant components. However also the (line) protection system is important to consider as it may influence the system behaviour. In chapter 2 it is concluded that distance protection is a main concern with respect to mal-tripping during abnormal operating conditions. In this chapter the performance of distance protection during voltage instability is further investigated. When we discuss voltage stability we refer to long term voltage instability. The performance of distance protection during short term voltage stability can be considered to be similar to the performance during transient stability. This will be further examined in the next chapter.

This chapter analyses why and how distance protection may contribute to voltage instability, the advantages and disadvantages of different kinds of relay characteristics and the significance of the coordination between distance protection and generator current limiters. Also the behaviour of the distance protection during a few disturbances associated to voltage instability are investigated. Finally an adaptive algorithm is proposed which prevents undesirable distance relay operation during voltage instability.

3.1 Distance protection may contribute to voltage instability

One can define 10 distinct types of possible short circuit faults in a three phase power system [35]. In order to calculate the correct fault distance for all types of faults, different voltage and current signals are used by the distance relay. Basically two types of equations are applied. For three phase faults and phase to phase faults equation (3.1) is used where L1 and L2 are the faulted phases. Equation (3.2) is valid for phase to ground fault involving phase L1. Refer to section 2.4.4.

$$\overline{Z_r} = \frac{\bar{U}_{L1} - \bar{U}_{L2}}{\bar{I}_{L1} - \bar{I}_{L2}} \tag{3.1}$$

$$\overline{Z_r} = \frac{\bar{U}_{L1}}{\bar{I}_{L1} + \dfrac{\overline{Z_0} - \overline{Z_1}}{\overline{Z_1}} \cdot \bar{I}_0} \tag{3.2}$$

$\overline{U}_{L1}$, $\overline{U}_{L2}$: Phase voltages at the relay location.

$\bar{I}_{L1}$, $\bar{I}_{L2}$: Phase currents at the relay location.

$\bar{I}_0$: Residual (zero sequence-) current at the relay location.

$\overline{Z}_1$: Positive sequence impedance for the primary protected circuit.

$\overline{Z}_0$: Zero sequence impedance for the primary protected circuit.

$\overline{Z}_r$: the apparent impedance as seen by the distance relay.

Voltage instability is a phase symmetrical phenomenon. Hence no zero sequence component is present and the phase voltages and currents are symmetrical. Thus the apparent impedance; Z_r as seen by a distance relay during voltage instability may be written as in (3.3). Here U is the line to line voltage and P and Q are the injected active and reactive power at the location of the relay.

$$\overline{Z_r} = \frac{\bar{U}_{L1}}{\bar{I}_{L1}} = \frac{|\bar{U}|^2 \cdot (P + jQ)}{P^2 + Q^2} \tag{3.3}$$

In case $\overline{Z}_r$ is within the area of one of the pre-defined zones of operation during a time exceeding the setting of the timer associated to the zone, the relay will operate. Low system voltages and high power flows are typical for voltage instability events. It follows from (3.3) that these events may cause distance relays to mal-trip. This behaviour is undesirable since it will aggravate the status of the power system which is already in a severe situation.

Case a in figure 3.1 corresponds to a short circuit fault whereas case b corresponds to a scenario where the zones of operation are slowly (seconds to minutes) approached from outside as the voltage and/or the reactive power increase. Hence undesirable relay operations due to voltage instability will mainly be initiated by the zone with the longest reach. Normally this is the zone used for remote back-up protection; i.e zone 3. In some applications start elements are applied which have a longer reach than the zone 3. However they can usually not trip the line but only activate the tripping elements.

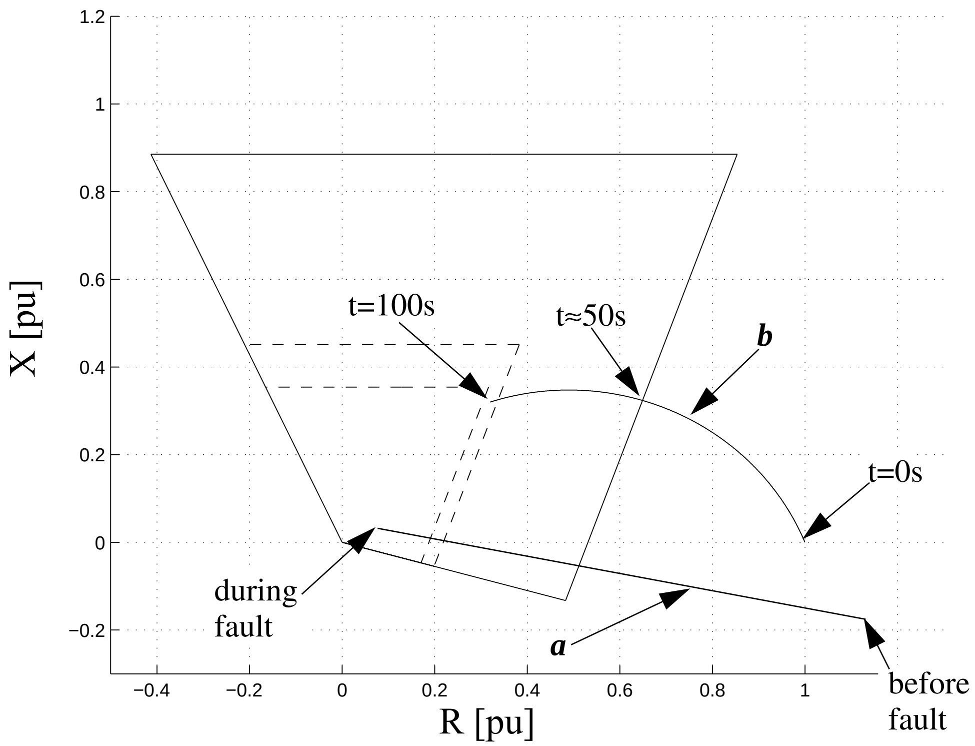

Figure 3.1 Apparent impedance as seen by a distance relay during different power system events. ***a***: Short circuit fault involving the primary protected circuit. ***b***: A case where the voltage linearly decreases from U=1 pu to U=0.8 pu and the reactive power linearly increases from Q=0 pu to Q=1 pu during a time interval of 100 s. The injected active power is held constant at P=1 pu.

The sensitivity for mal-trips due to voltage instability is depending on the length of protected lines, the relay characteristic, the devices used to prevent load encroachment, the safety margins concerning overload and the robustness of the system. Also the philosophy of the relay engineer in his choice of the settings of the distance relay with the longest reach is important. Is he considering dependability of prime importance or is he favouring security?

It should be stressed that mal-tripping distance protection in case of low system voltages and high (reactive) power flows are most likely to happen when there is a significant weakness in the grid. This can be illustrated by a simple example where the power flows are considered to be unaffected by the initial disturbance. This assumption is reasonable as the power flows will not change dramatically in the initial stage of a long term voltage instability. In (3.4) x is the fraction of the pre-disturbance voltage level and can be calculated when the change in power flows P and Q is neglected. Z_3 is the pre-defined impedance for which the zone 3 will operate and U is the pre-disturbance voltage.

$$x = \frac{\sqrt{|Z_3| \cdot |P - jQ|}}{|\bar{U}|} \cdot 100\ \% \tag{3.4}$$

Example: An active power of 780 MW and an reactive power of 57.5 MVAR is injected in a 200 km transmission line with a voltage of 412 kV and a line impedance of 60 ohm. The zone 3 distance relay is set to cover 200% of the actual line impedance. The distance relay used in the example has a circular shape where the centre is located in the origin.

In Case 1 a voltage reduction in the system is caused by a generator trip. The voltage necessary to trip the line as calculated from (3.4) is approximately 75% of the pre-disturbance voltage. In this case it is most unlikely that the distance protection alone will initiate voltage instability as other protection devices will be activated earlier at higher voltage levels and hopefully bring the system back to a stable operating point. However if these protection devices fail and the voltage level is reached where the zone 3 relay trip the line, the system condition will most likely be seriously aggravated by the distance relay operation.

In case 2 a voltage reduction occurs due to a trip of one of three identical parallel lines with the same data as the line described above. The amount of power in the remaining lines will increase with 50% and the distance relays will trip the remaining lines at 91% of the pre-fault voltage level. At this level it is likely that the distance protection itself will cause voltage instability before other types of power system protection start to take action.

Transfer cuts are typical sources of voltage instability. Usually they are dimensioned such that it will be possible to run the system almost as normal (within the stability margin) when a single line in the section is tripped. However it is important to keep in mind that the transfer capacity of the section will decrease as the voltage decreases. There are two reasons for this. The first reason is because of pure system stability where protection devices are not considered. As when the voltage decreases the transfer section will be more sensitive to both transient- and voltage instability. The second reason is with respect to distance relay settings. As the distance relay settings usually are calculated for nominal voltage this may lead to that the apparent impedance enters the fault detector zone due to the decreasing voltage. Consequently distance protection will likely initiate or accelerate voltage instability in transfer cuts.

It should also be kept in mind that when the system is weakened due to maintenance work the robustness (voltage stiffness) of the system is reduced. Distance relays serving lines included in a transfer cut may become extra sensitive to further disturbances as they consequently will experience low voltage and high (reactive) power flows.

3.1.1 Different operating characteristics

Not only the prevailing power system conditions and the settings of zone 3 distance element are important when voltage instability scenarios are examined but also the shape of the zones of operation. Roughly two types of operating characteristics are used today; circular (mho) and quadrilateral characteristics. Sometimes they are used in combination with a characteristic that restricts the tripping area of the relay to avoid mal-trips due to load encroachment. Refer to the ”Quadrilateral varying resistive reach” characteristic in figure 2.10.

Mechanical and solid-state relays not only have regular zones of operation but also a start element which activates the relay and prepares it for a ”ready to work” mode. This mode is reached when the apparent impedance enters the area of the start element in the R-X diagram. Hence the criteria to trip a circuit breaker are not fulfilled when only the impedance reaches the area within the different zones of operation but it also has to be within the area of the start zone. In early days the operating characteristic of the start zone usually covered the whole area of the different zones of operation and had the shape of a circle centred in the origin. As relays where further developed the location of the circle and/or the shape was changed to an ellipse or a ”cornet”. In this way the covered area in the resistive direction was decreased to reduce the risk of load encroachment in case of long lines. In some relay applications the zone 3 element itself is used as a starter.

A hazard may occur when the whole area in the RX-diagram of the different zones of operation are covered by the start element and at the same time the start element controls the timers. During unfavourable peak load conditions the start zone may be entered and hence the timers will start. When the time delay for zone 3 has expired the zone 3 element will operate instantaneously when the apparent impedance enters zone 3. This phenomenon may cause difficulties in obtaining selectivity in case of a short circuit fault on an adjacent circuit.

When numerical relays were introduced the start function was not longer needed to activate the relay. Still in some cases a function is applied where a particular zone is used in almost the same way as a start element. The function is here called general start criteria and makes it possible to prevent mal-trips due to load encroachment among others. To activate a circuit breaker the apparent impedance has to be within the area which activates the general start criteria and a zone of operation respectively.

In some applications the start function alone is set to cause a trip signal but with a comparative long time delay; usually 3 - 4 seconds.

During normal operating conditions or at the onset of a voltage instability the amount of active power in a transmission circuit is considerably higher than the reactive power. Thus the power factor is rather high and the apparent impedance is dominated by the resistance. Hence the zones of operation will be approached close to the resistance axis in the RX-diagram. The design of start elements and general start criteria are mainly based on this phenomenon and therefore often gives a possibility to exclude the area close to the resistance axis.

Relays with operating zones formed as an ellipse as well as mho relays usually offer a limited number of adjustments. Still they are very reliable when protecting long lines since they have a natural defence to load encroachment depending on how much the circle ”leans” in the RX-diagram.

Quadrilateral relays usually offer more possibilities of settings compared to the mho relays. Generally the settings in the reactive and the resistive direction can be made independently. Long settings of the reach in the reactive direction are not a major threat to unwanted relay operations. However they are sensitive to load encroachment when adjusted to trip high resistance faults.

For quadrilateral relays where the setting in the resistive direction is the same for all zones of operation the start element or general start criteria form an important function since the apparent impedance may enter directly into the zone 1 element during highly stressed operating conditions. Often a start function activated by a high value of the current is used for this type of impedance relay characteristic.

3.1.2 The interaction between distance protection and other protection devices during voltage instability

In an emergency state there will be a race between different protection devices and protection systems such as distance relays, low voltage protection or load shedding. One or more of these functions will operate and hopefully bring the system back to a normal or an alert state. Also current limiters will take part in this race and most likely aggravate the system condition when they are activated. Except in case of thermal overload distance relays should not trip circuits before generators are disconnected by their own protection equipment as this possibly will cause cascading outages when all of the remaining generation capacity is further used. Especially during emergency or extreme situations the settings of current limiters and zone 3 elements must be well coordinated to make it possible to utilize the generator to its maximum capacity. This will be further demonstrated in a simulation below.

Also the coordination between distance protection and low voltage protection for generators is important. A typical scenario observed both in simulations and from real disturbances is that the low voltage protection for one or a few generators usually operate first. Hence the voltage decreases in the system and instantaneously or after some time distance protection operations cause single or cascading line outages.

Consequently additional generators will also trip and eventually the system will collapse.

Generally protection applications based on the power system frequency are of less importance when voltage instability is studied. The frequency deviation usually is very small until the very ultimate phase of any collapse. Protection devices which operate when a low voltage level is reached together with distance protection is the main concern.

3.2 An adaptive algorithm to prevent mal-trips due to voltage instability

The contents of this section are published in condensed form as [I].

Adaptive relaying may be a suitable tool in case of stressed power system conditions. In [36] a scheme is described where dependability is provided during normal system conditions but security is emphasized during abnormal conditions. This approach may also be used to avoid load encroachment during voltage instability. One way is relay adaptation to the system load where the relay subtracts the load current from the post disturbance current and determines the difference. From this current change the relay can distinguish between faults and abnormal system conditions. Sometimes this discrimination is not that simple, particularly not in case of zones of operation protecting adjacent circuits or when the differences in power flows between base load and peak load are considerable.

Generally numerical relays (with a non-active Power Swing Detector (PSD)) will operate if the apparent impedance is within zone 3 and the associated timer expires a pre-set time delay. When the impedance leaves zone 3 the timer is usually reset. Older electro-mechanical relays without any PSD device work pretty much the same except for the associated timer which will not necessarily be reset when the impedance leaves or re-enters zone 3. Hence there is a possibility that the relay will operate although the apparent impedance has not been within zone 3 during the whole period it takes for the time delay to expire. Neither of these applications consider why and how zone 3 has been entered. Power Swing Detectors are widely used in combination with distance relays to avoid mal-trips due to power oscillations and are further discussed in section 4.1.1.

As discussed earlier modern numerical relays give the relay operator a wide range of relay inputs to choose between and thus unique protection schemes can easily be developed. The algorithm proposed here utilizes these new possibilities by using the derivative of the voltage as relay input. Additionally the algorithm is based on mathematical logic blocks which makes it easy to realize for numerical relays where the relay scheme is developed in a user friendly computer software.

For numerical relays it is usually possible to choose between different setting groups; i.e choose different settings of the zones of operation depending on the prevailing power system state. This could be done by the relay itself; e.g. based on a voltage criterion or manually by the network operator.

The adaptive part of the algorithm proposed here is based on the same principle but instead of solely changing the reach of the zones of operation the whole relay algorithm is changed; figure 3.2. During normal operation the conventional distance protection algorithm is in operation but when a stressed operation condition occurs, where security is more of an issue, the relay switches to the algorithm in figure 3.4. The criterion used to decide which algorithm to be applied may be based on the voltage level, the reactive power, the PV-curve or the impedance method proposed in [37].

The algorithm in figure 3.4 may also be used as a non-adaptive algorithm where it is applied as the exclusive distance relay algorithm.

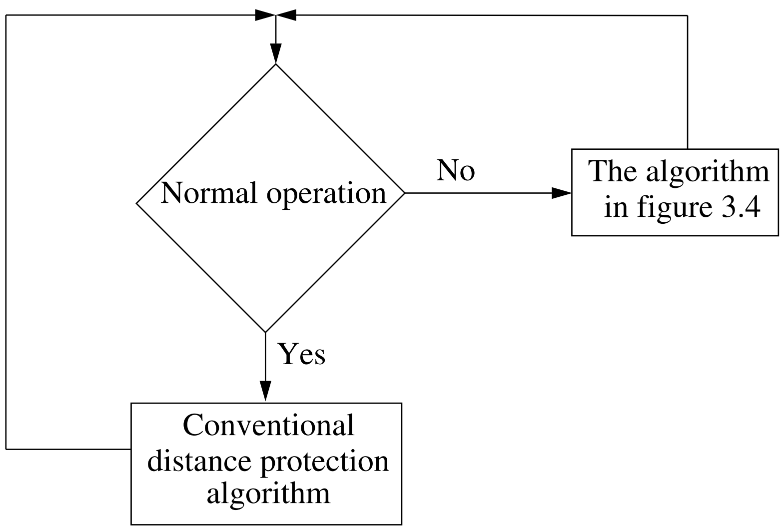

Figure 3.2 Adaptive distance relay.

The algorithm proposed in figure 3.4 is based on simple mathematical logic blocks where the dependability is decreased and the security is increased as compared to traditional distance relaying. The algorithm avoids mal-trips due to voltage instability. The idea is not only to consider the relation between the apparent impedance and the zones of operation but also the different events which occur in the system when the zone 3 is entered. These events can be decided from changes in the voltage.

When a short circuit fault occurs (particularly three phase faults) the change of the voltage is substantial in the faulted phases in the area close to the location of the fault [38]. For a phase to ground fault an example is given in figure 3.3. Observe that the signal processing technique used to develop this figure is poor, however the principle can easily be realised.

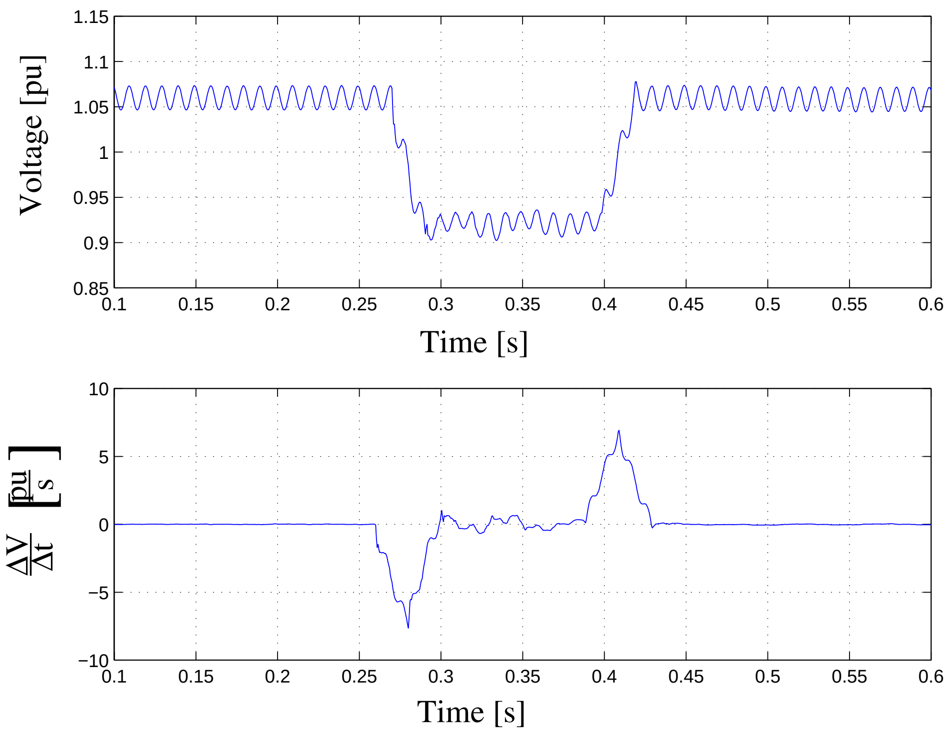

Figure 3.3 Voltage and the derivative of the voltage for the faulted phase at the location of a distance relay in case of a phase to ground fault.

In case of voltage instability the voltage changes are mostly low to moderate until close to the final collapse. Hence the derivative of the voltage may be used to distinguish between short circuit faults and voltage changes due to stressed system conditions. In the algorithm of figure 3.4 the voltage is measured continuously and used as an input. The main challenge in the algorithm is to determine the different types of events based only on information from the derivative of voltage, and this with a high degree of reliability. However simulations and measurements have shown that there is a considerable difference between a short circuit fault, a fault clearance and other power system events.

It is very important that the relay will operate as planned when a short circuit fault occurs at the same time as voltage instability is present. Therefore when the apparent impedance has entered the zone 3 the derivative of the voltage is continuously analysed and thus used to detect short circuit faults. In figure 3.4 the quantities with a subscript (except t_{start} which is associated to the start of the timer) are given a fixed value by the relay operator. The remaining quantities are continuously updated by the relay during operation. Throughout operation the pre-set values are compared with the real-time updated values to obtain correct relay activity.

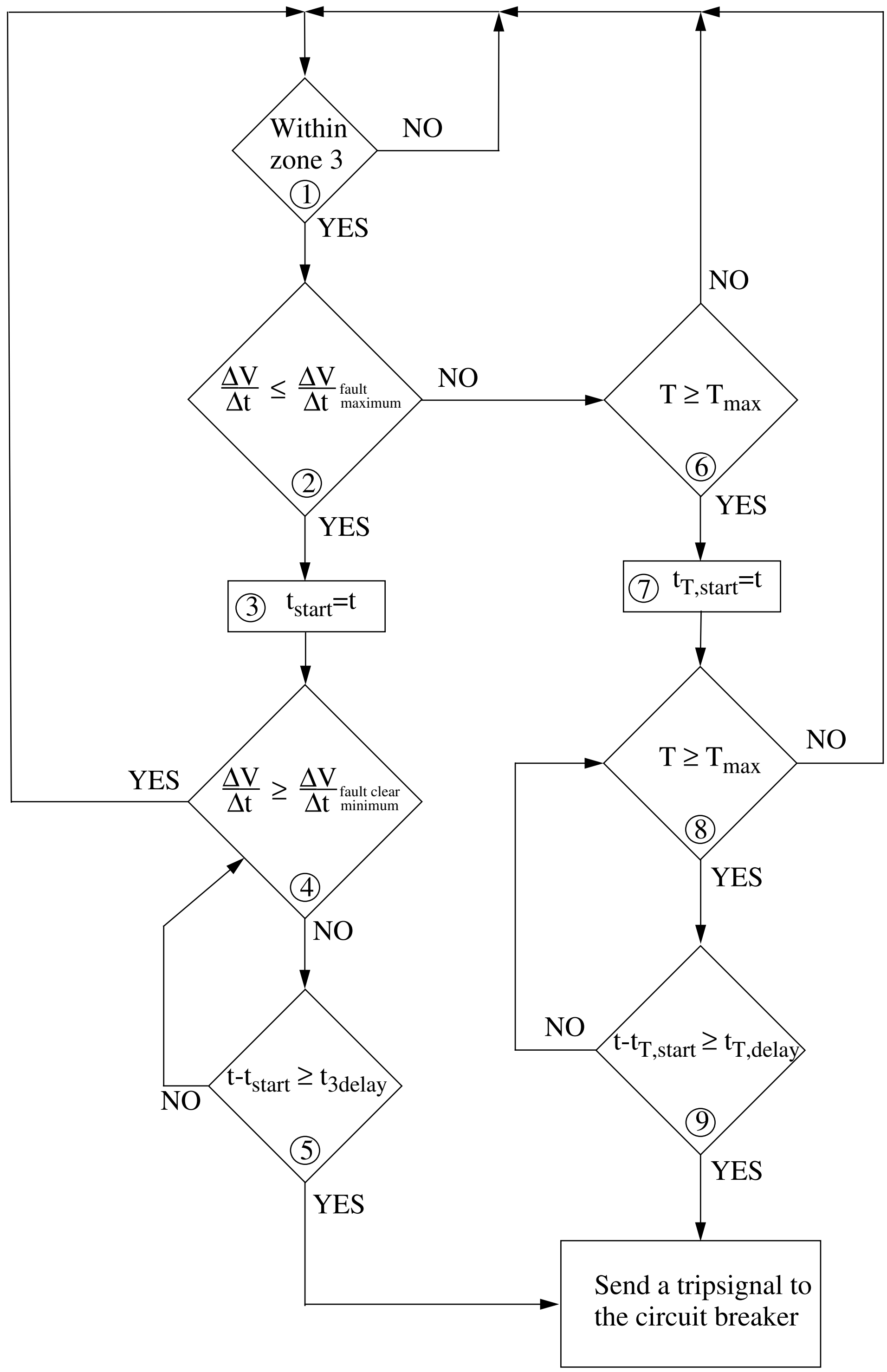

Figure 3.4 Relay algorithm used during abnormal operating conditions.

The following is a description of the block functions.

Block 1: Checks if the apparent impedance is within zone 3.

Block 2: Decides if a short circuit fault has occurred.
When a fault occurs ΔV/Δt will have a negative value with a high magnitude.

$\frac{\Delta V}{\Delta t} \leq \frac{\Delta V}{\Delta t}_{\substack{fault \\ maximum}}$ A fault has occured.

$\frac{\Delta V}{\Delta t} > \frac{\Delta V}{\Delta t}_{\substack{fault \\ maximum}}$ No fault has occured.

Block 3: The timer associated to zone 3 is started.
t_{start} = time when zone 3 is entered.

Block 4: Decides if the fault is cleared by primary protection.
When the fault is cleared ΔV/Δt will have a positive value with a high magnitude.

$\frac{\Delta V}{\Delta t} \geq \frac{\Delta V}{\Delta t}_{\substack{fault\ clear \\ minimum}}$ The fault has been cleared.

$\frac{\Delta V}{\Delta t} < \frac{\Delta V}{\Delta t}_{\substack{fault\ clear \\ minimum}}$ The fault has not been cleared.

Block 5: Waits for the fault to be cleared by the primary protection.
t_{3delay} = time delay for zone 3 to operate.

Blocks 6 to 9 may be implemented in the algorithm when distance protection is used to protect overhead lines due to overload etc.

Block 6: Checks if the line temperature exceeds the pre-set maximum limit.
T_{max}= maximum allowed temperature in the circuit.

Block 7: Timer is started for the thermal overload protection.
$t_{T,\ start}$ = time when the maximum allowed temperature is reached.

Block 8: Identical to Block 6.

Block 9: Regulates temporary overload.
$t_{T,delay}$ = time delay for the thermal overload protection to operate.

Most cases are handled well by the algorithm. However a few cases may cause the algorithm difficulties to operate as planned. The reason for this is that unexpected values of the derivative of the voltage may occur for some events in combination with tight or wrong settings of the parameters. The most dangerous case is when a voltage step increasing action occurs between a short circuit fault and a fault clearance. Block 4 may apprehend the positive voltage step as fault clearance by primary protection. Thus the algorithm will not clear the fault. During voltage instability scenarios load shedding and manually or automatic capacitor switching may be the source of this type of problem. Shunt capacitor switching will not have a significant impact during the time when a fault is present as the voltage will be extremely low and therefore a capacitor will not increase the voltage much when it is connected. When load shedding is performed some communication device can be used in combination with logic blocks to set the output from block 4 to NO during the moment of action. In this way the security will be increased.

Most likely current limiters will be activated and generators tripped during a severe voltage instability. This will cause voltage decreases of a more or less outspoken nature. Close to a collapse the negative derivative of the voltage may be difficult to distinguish from the one caused by a short circuit fault. Still it is undesirable that these negative derivatives are treated as faults. These inadequacies can be avoided by using communication devices. When a generator is tripped or a current limiter activated a notifying signal can be sent to the relay. Hence the output from block 2 can be set to NO for a few cycles and the event will not be treated as a fault.

To find suitable values of the settings, events such as shunt capacitor switching, line tripping, load shedding and short circuit faults must be considered for each relay bus at different operation modes. Modern communication technology has created the possibility for centralised calculation of settings and local in-service adjustment and therefore suits the purpose well. A computer based network model may be used for on-line calculations. Hence the relay settings can continuously be updated to the prevailing power system condition. Today these type of calculations are usually done manually.

One may ask oneself, why not use the derivative of the measured impedance as a criterion in the algorithm? Simulations have shown that the derivative of the impedance does not act logically stringent for similar power system occurrences; especially when long and heavily loaded lines are considered. Also the fault location versus relay bus location has a strong influence on the apparent impedance in the R-X diagram; e.g if a fault occurs on an adjacent or a parallel line.

The derivative of the resistance and reactance has similar disadvantages compared to the derivative of the impedance. Another disadvantage is that the derivative of the impedance is more complicated to obtain as compared to the derivative of the voltage.

For contemporary numerical relays the algorithm as shown in figure 3.4 can easily be implemented but for older electro-mechanical and solid-state relays the implementation may not be as straightforward. However after minor adjustment existing PSDs, supplemented with some numerical equipment, may be used. Thus the PSD may be applied to block relay operations when the apparent impedance is within zone 3 and no fault is present. However a few modifications are necessary. Timers and the operating characteristic for the PSD must be set suitable to deal properly with time frames and impedance changes occurring in voltage instability events. Accordingly the impedance must be able to move much slower inside the zone 3 of operation as compared to a case of power oscillation but still be treated as one.

The discussion in this section is to demonstrate the principles of a new adaptive algorithm. In case of actual implementation attention has to be paid to practical issues such as communication devices, data memory, window size, noise in measurements etc. Also when the algorithm is programmed some functions have to be added. For instance in case of a short circuit fault occurring at the same time as the line is overloaded, block 2 has to be activated in parallel with the alternating blocks 8 and 9. Depending on how $t_{T,delay}$ is chosen in relation with t_{3delay} a timer coordination may be necessary to determine whether the trip signal will be sent due to the short circuit fault or due to the overload.

3.3 Results of simulations in two different test systems

Two different test systems have been used for simulations. The first one is a 15 bus system representative for the Swedish transmission grid; the second is the more extensive Nordic32 system [39]. The 15 bus system is mainly used to illustrate the influence distance protection has on voltage instability. The Nordic 32 system is used to compare results of the 15 bus system with results of a more realistic grid.

In figure 3.5 the 15 bus system is shown. Two voltage levels are used where the main part of the equipment is connected to the 400 kV level. However, the loads and a few shunt devices are connected to the 130 kV level. The generation in the system is a mixture of hydro- and nuclear power. All generator units are equipped with field current limiters, in addition the nuclear units have armature current limiters. In the NORTH area all generators are hydro units which are responsible for the frequency control; in the MIDDLE and SOUTH areas the nuclear power units have a fixed active output. The loads in the MIDDLE and SOUTH areas dominate the total consumption in the system. Thus a large amount of power will be transported from NORTH to MIDDLE and also from MIDDLE towards SOUTH. The transmission lines between bus 2 and bus 3 are equipped with series capacitors giving a line compensation of 50 %. Observe that the electrical parallel circuits in the system are not considered to be geographically parallel. The load models used in the system are based on the work of le Dous et al. [40] and all the other models are identical with the ones applied in the Nordic32 system.

Obviously low voltage and frequency protection devices for generators may also have an impact on the behaviour of a power system during severe operation conditions. These devices are not considered in our 15 bus test system but are incorporated in the Nordic32 system.

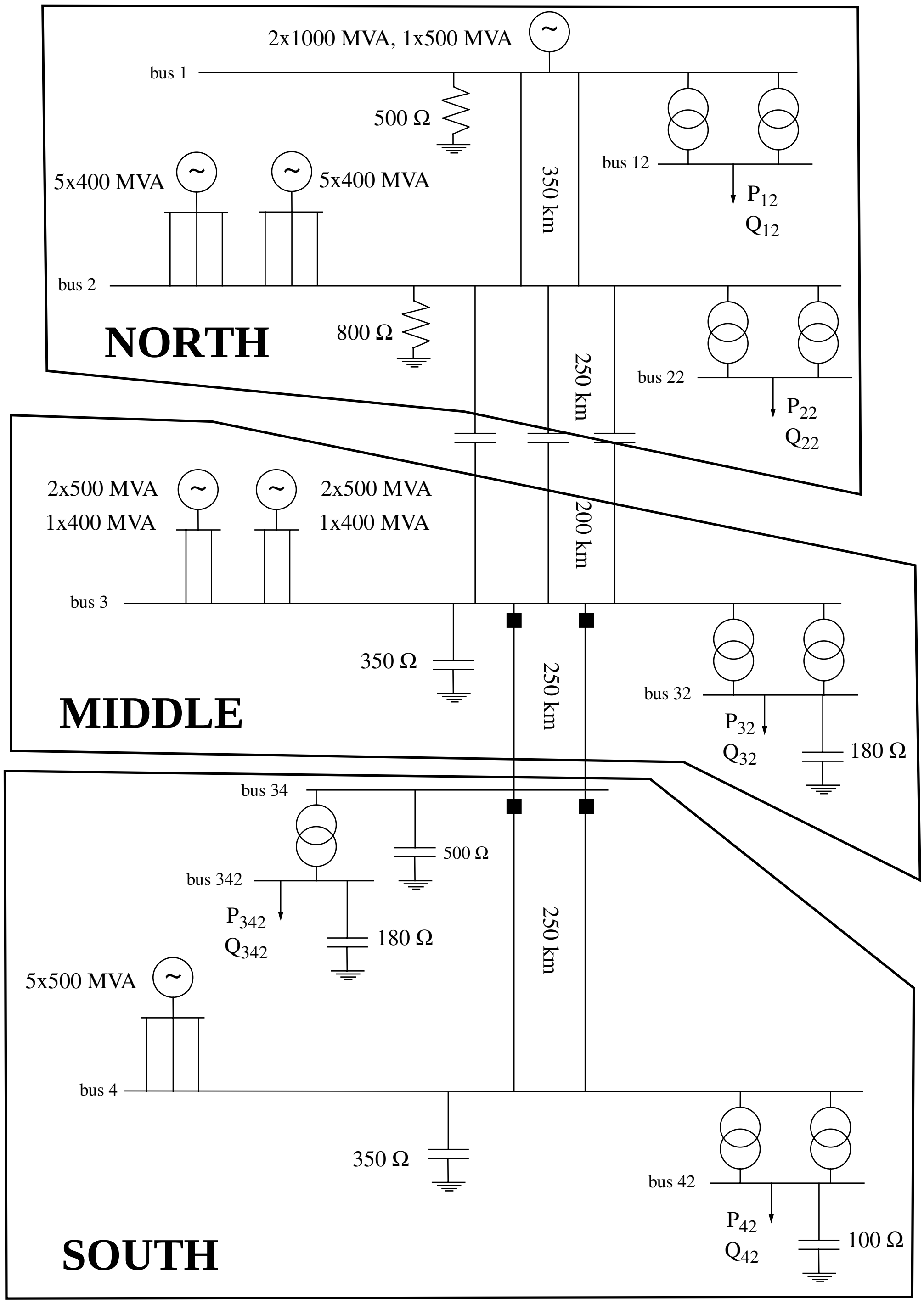

Figure 3.5 15 bus system representative for the Swedish transmission system.

3.3.1 Simulations in the 15 bus system

All simulations in the 15 bus system have been performed in SIMPOW [41]. Two different cases have been analysed. In CASE 1 the influence of mho and quadrilateral zone 3 relays on voltage instability is illustrated, and the improvement due to the adaptive algorithm proposed above is demonstrated. In CASE 2 the significance of a proper coordination between current limiters and the settings of zone 3 distance elements is shown.

When the reach of the zones of operation below is determined infeed is considered and the idea is that the whole length of all adjacent lines should be protected. In both cases the zone 3 element itself is assumed to be the startfunction of the relay.

CASE 1:

Below the course of events is explained where the numbers inserted in the figures indicate the different quasi stationary states arising after the initial fault.

At the pre-fault state the system is extremely heavily loaded in the SOUTH area. The power transfer from bus 3 towards bus 34 is about 2200 MW and from bus 34 to bus 4 around 1200 MW. The initial disturbance is a permanent three phase short circuit fault having zero fault resistance and located in the middle of one of the transmission lines between bus 34 and bus 4. The fault is cleared by the primary protection. To demonstrate the performance of the algorithm in figure 3.4 an additional fault is applied. This fault is a busbar fault at bus 342 and occurs when the apparent impedance already is within the zone 3.

Figure 3.6 shows the voltages at bus 3 and bus 34 before and after the faults. When conventional zone 3 distance relaying is applied with settings based on the criteria mentioned earlier the system will collapse approximately 83 seconds after the initial fault independent of the shape of the operating zone used. In the case of mho relays the collapse will be initiated by the zone 3 elements at bus 3 protecting the lines between bus 3 and bus 34. When quadrilateral relays are used the collapse will be initiated by the zone 3 element located at bus 34 protecting the remaining line between bus 34 and bus 4.

This can be compared with the situation that either the reach of the conventional relays is decreased or the algorithm in figure 3.4 is applied. In these cases the system will recover to a stable operation state. Without the adaptive algorithm the reach of the mho relays at bus

3 protecting the lines between bus 3 and bus 34 must be decreased to avoid a voltage collapse. If this approach is applied only 60 % or less of the adjacent lines will be remote back-up protected. When quadrilateral relays are in operation their reach at bus 34 must be decreased in resistive direction from 105 Ω to about 85 Ω to avoid a collapse.

Note that the collapse plotted in figure 3.6 is valid for the case of mho relays.

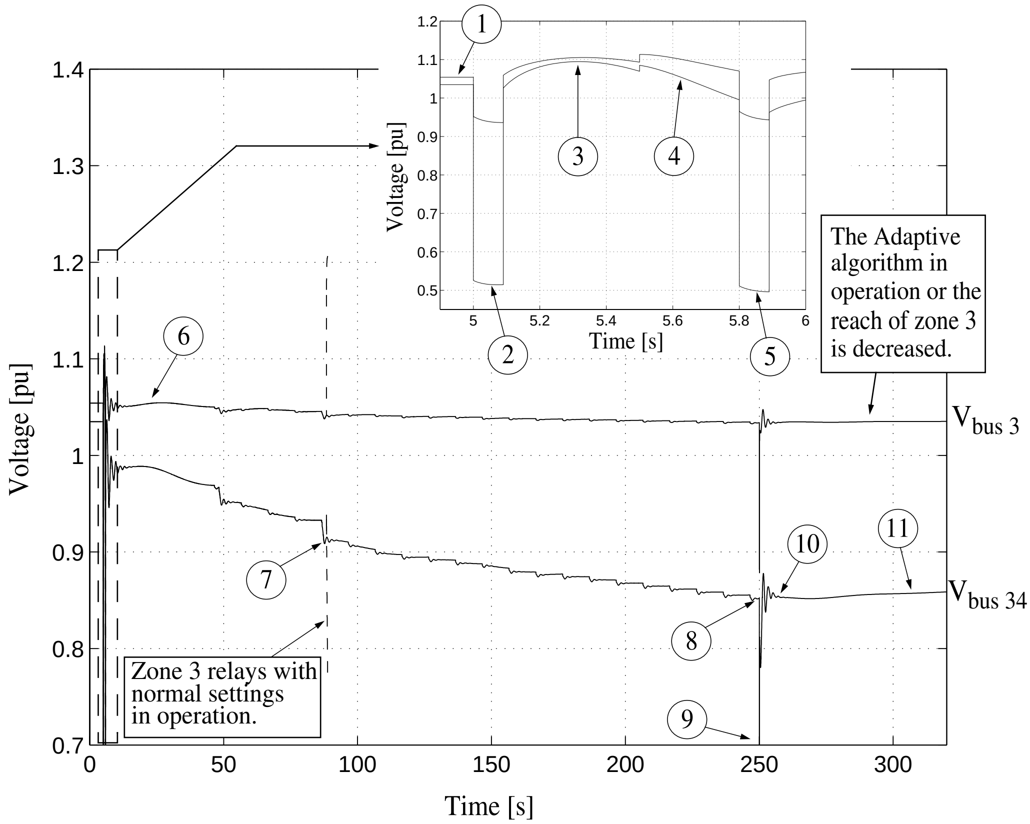

Figure 3.6 Voltages at bus 3 and bus 34. In case of normal zone 3 settings collapse occurs at indication 7 whereas using the adaptive algorithm or a decrease in element reach the system survives.

1: Pre fault state.

1-2: At t=5 s a three phase fault occurs on one of the lines between bus 34 and bus 4.

2-3: At t=5.09 s the fault is cleared.

3-4: At t=5.5 s the shunt capacitor at bus 32 is connected and the reactors at bus 1 and bus 2 are disconnected.

4-5: At t=5.8 s auto reclosing.

5-6: At t=5.89 s the faulted line is permanently disconnected.

6-8: The impedance as seen by the relays is slowly decreasing due to decreasing voltages and increasing (reactive) power flows.

7: At t=87.2 s the zone 3 of the mho relays located at bus 3 protecting the lines between bus 3 and bus 34 are entered. About the same time zone 3 of the quadrilateral relay located at bus 34 protecting the remaining line between bus 34 and bus 4 is also entered.

8-9: At t=250 s a bus fault occurs at bus 342.

9-10: At t=250.09 s the bus fault is cleared.

11: The system starts to recover and will attain a stable operation state.

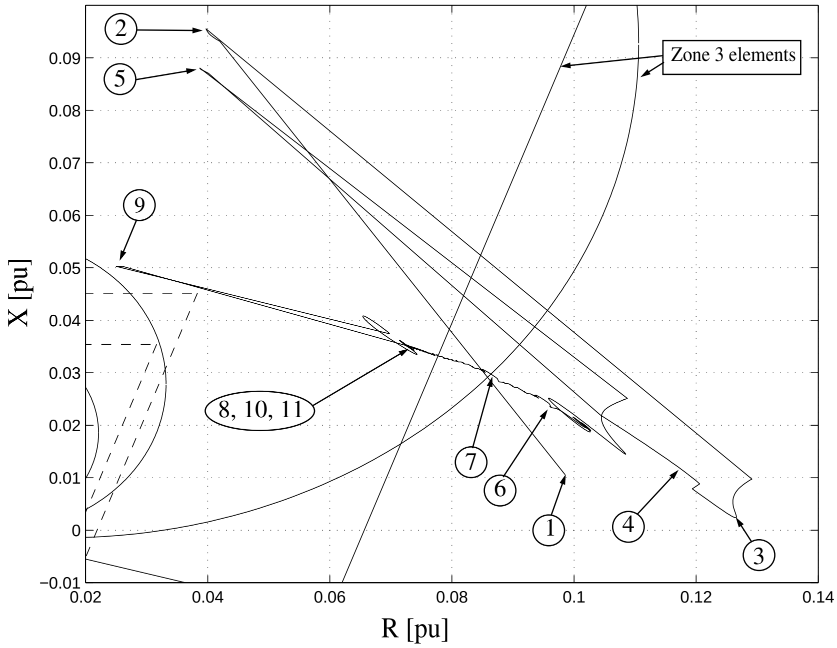

Figure 3.7 The impedance as seen by a mho and quadrilateral relay located at bus 3 protecting one of the transmission lines between bus 3 and bus 34.

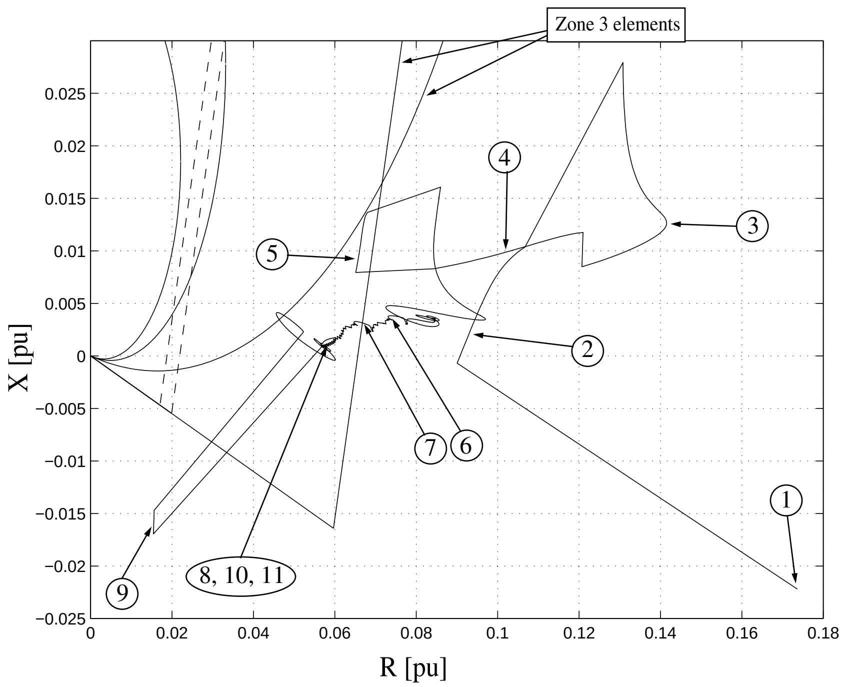

Figure 3.8 The impedance as seen by a mho and quadrilateral relay located at bus 34 protecting the non faulted transmission line between bus 34 and bus 4.

The RX diagram for the relay located at bus 34 indicates that the mho relay has a natural defence against load encroachment when the impedance as seen by the relay is located close to the resistive axis. However if the injected reactive power increases a higher value of the reactance will be seen by the relay and hence it is more likely that a mho relay will mal-trip in comparison with a quadrilateral relay.

In this simulation the injected reactive power at bus 3 towards bus 34 increases about 100 % during the first 83 seconds after the initial three phase fault. The other power flows in the system are approximately the same. When mho relays are used it is not the relay located at the bus with the lowest voltage level which operates first but the relays that meet the largest increase in power flows. This shows that it is not only low voltage levels which are important to consider in order to avoid mal-trips due to voltage instability but also reactive power flows which may increase considerably.

The procedure for the algorithm included in the distance relays at bus 3 protecting the lines between bus 3 and bus 34 is examined below.

The criterion used to choose between the conventional and the proposed relay algorithm is based on the reactive power. Basically the criterion applies the conventional distance relay algorithm when the protected line generates reactive power. When the line consumes reactive power the proposed algorithm is activated emphasizing security. This criterion is suitable in systems where the lines generally are operated below the surge impedance load. For example in the Swedish transmission system. However in systems where the lines normally are loaded above the surge impedance load the algorithm in figure 3.4 can be activated when the reactive power consumed by the protected line exceeds a certain level.

One reason why the reactive power and not the voltage is used to decide which algorithm should be used is that the voltage generally is a bad indicator of the system state. For example, bus 3 is located close to a generator bus. Consequently and as illustrated in figure 3.6, the voltage at bus 3 will be held at a fairly high voltage level by the voltage control of the generators until very close to a collapse. Hence if the relay would base its adaptivity on the voltage level, then the probability for a too late change of algorithms would be high. In this case the lines between bus 3 and bus 34 are heavily loaded, i.e they consume reactive power prior to the initial fault. As a consequence the relays located at bus 3 have already adjusted their relay algorithm to the one proposed in figure 3.4 before the three phase fault occurs. The lines between bus 34 and bus 4 generate reactive power before the initial three phase fault and thus the relays located at bus 34 are applying the conventional distance relay algorithm. However as the faulted line is disconnected the remaining line between bus 34 and bus 4 start to consume reactive power and thus the associated relay adjusts its relay algorithm.

Since the derivative of the voltage due to the disturbance is the same at bus 3 and bus 34 apart from the magnitude the fundamental method of operation will be the same at these two buses. Hence only the derivative of the voltage as seen by the relays located at bus 3 is investigated.

In figure 3.9 we see that there is a considerable difference in the magnitude of the negative peaks of the derivative of the voltage (which fall in between indications 6 and 8) caused by tap-changer operations and current limiter actions as compared with the peaks caused by the short circuit faults. As described this is the phenomenon used by the algorithm to distinguish short circuit faults from other events in the system.

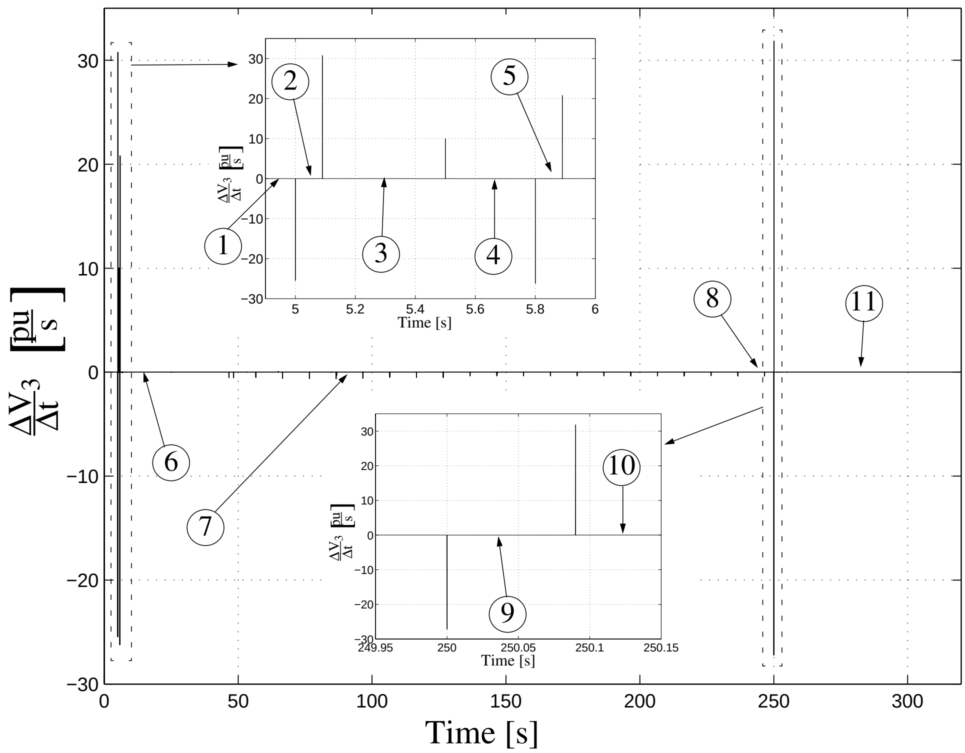

Figure 3.9 The derivative of the voltage at bus 3.

The negative and positive peaks of the voltage derivative which are generated when the initial fault occurs and is cleared (between indications 1 to 6), make that the proposed algorithm achieves the same result as conventional remote back-up distance relaying. When the initial three phase fault occurs the apparent impedance enters the zone 3; figure 3.7. At the same time the relays see a high peak of the derivative of the voltage with a negative sign. Hence the criteria in blocks 1 and 2 are fulfilled and the timer in block 3 is started. The algorithm starts to alternate between blocks 4 and 5 waiting for the fault to be cleared by the main protection. This happens 90 ms after the initial fault. Consequently the relays located at bus 3 see a positive peak of the derivative of the voltage and the apparent impedance leaves the zone 3 of operation. Hence the algorithm again starts to wait for the criterion in block 1 to be fulfilled. The criterion in block 1 is once again fulfilled when the auto-reclosing is performed. As the auto-reclosing is not successful the operating sequence described is repeated for the algorithm.

When the zone 3 elements are entered at 87.2 s due to the decreasing voltages and increasing power flows, block 2 in figure 3.4 will not treat this as a fault as no high negative peak of the derivative of the voltage occurs. Thus when the apparent impedance as seen by the relay further moves into zone 3 the algorithm will make the relay to continue to work as normal since the algorithm will alternate between blocks 1,2 and 6. This will continue until the impedance leaves zone 3, the line is thermally overloaded or a high negative peak of the derivative of the voltage occurs.

When the bus fault at indication 8 occurs the impedance as seen by the relay will be within zone 3 at the same time as the relay will sense a high negative peak of the derivative of the voltage. Hence the algorithm will start to alternate between blocks 4 and 5 waiting for a high positive peak to arise; i.e the fault to be cleared. This process may continue until the time delay of zone 3 expires and a trip signal will be sent to the circuit breaker. However in this case the fault is cleared by the primary protection. Thus the algorithm will be reset and continue to alternate between blocks 1,2 and 6. The line will not be tripped and the system starts to recover.

Bus 3 is a typical bus where the algorithm may be expected to work inadequately. When the initial fault is cleared the algorithm may meet a proportionally low positive peak of the derivative of the voltage since the relay is located quite far from the fault. At the same time the capacity of shunt capacitors close to the bus is high. This may cause trouble when the values of the parameters in the algorithm are selected. In figure 3.9 we see that the shunt switching between indication 3 and 4 causes a positive peak which is about 50 % of the derivative of the voltage caused by the final fault clearing. If the capacitor switching occurs during the time when the fault is present the algorithm may interpret this as a fault clearance. This set of events has been simulated where the result shows that the positive peak of the derivative of the voltage due to the shunt switching in this case will only be about 15 % of the peak caused by the fault clearance. This is due to the low voltage in the system when the fault is present. Thus no trouble should occur when the settings of the parameters are made.

Simulations have also shown that different fault resistances have little impact on the magnitude of the derivative of the voltage.

CASE 2:

In this case high and low settings of the generator current limiters in relation to distance protection are investigated. For the study mho relays are used. The system is heavily loaded and one generator is not running in the SOUTH area. The active power transport from bus 3 to bus 34 is about 1500 MW and from bus 34 towards bus 4 about 1000 MW.

Also in this case the initial disturbance is a permanent three phase fault having zero fault resistance and is located in the middle of one of the transmission lines between bus 34 and bus 4. Here the fault will cause the system to collapse regardless of the settings of the zone 3 element. Yet the collapse is accelerated by the zone 3 elements located at bus 3 protecting the lines between bus 3 and bus 34. The adaptive algorithm will give similar result, although it prevents that the time to collapse is reduced. For that reason the adaptive algorithm is not applied here. As the simulation aims first of all to demonstrate the importance of coordination between the current limiters and conventional zone 3 relaying.

The different settings of the current limiters are executed in the MIDDLE and the SOUTH areas. In table 3.1 the values used are displayed together with results from the simulations.

Observe that in the Nordic32 system the field current limiter is set 20 % above the rated limit and the armature current limiter 5 % above the rated limit [39].

Table 3.1: Current limiter settings and times between the line fault and the system collapse.

Settings of current limiters	Field current limiter I_{flim} [pu]	Armature current limiter I_{slim} [pu]	Time to collapse when zone 3 relays *are not* in operation [s]	Time to collapse when zone 3 relays *are* in operation [s]
LOW	1.06	1.03	129	122
HIGH	1.2	1.2	455	200

When low settings are applied the distance protection will shorten the time to the collapse up to 5 %. However when the current limiters have high settings the distance protection will shorten the time to the collapse with approximately 56 %. This shows that if current limiters have high settings unwanted zone 3 operations may accelerate a voltage collapse considerably.

3.3.2 Simulations in the NORDIC32 test system

The Nordic32 system has been simulated in ARISTO [42]. Compared to the 15 bus system developed by the author the Nordic 32 system is a more complex and electrical robust system. Thus it gives realistic simulation results and therefore may be used to study actual system behaviour.

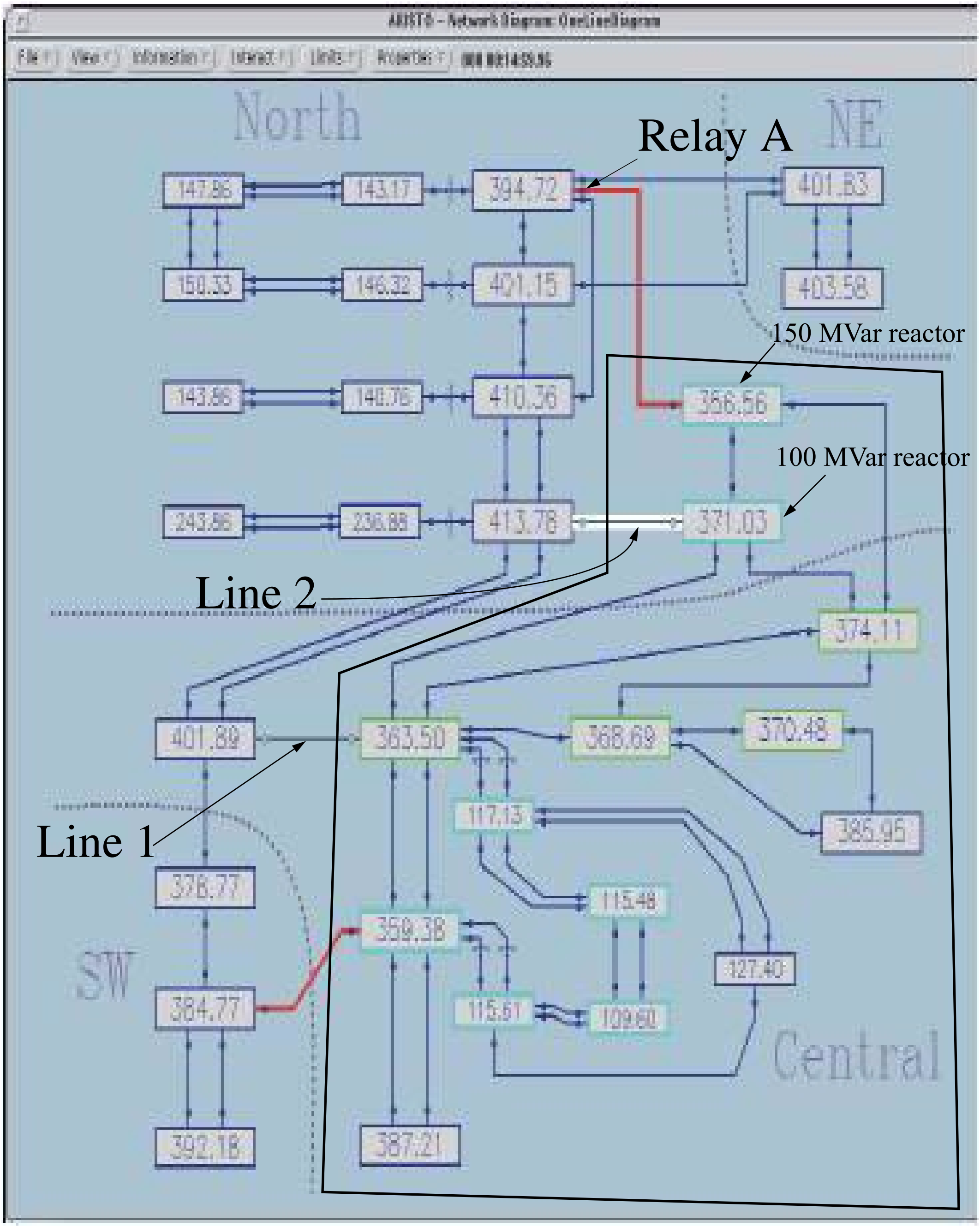

Figure 3.10 Final system conditions after a three phase short circuit on line 2 when the adaptive algorithm is applied for Relay A. The voltage at each bus is displayed.

In this simulation the initial disturbance is a permanent three phase short circuit fault located in the middle of the transmission line indicated as Line 2 in figure 3.10. Thirty seconds before the fault occurs the system is weakened as Line 1 is manually taken out of operation. Still the power flows from the North to the Central region are fairly normal and the voltage is close to 400 kV at all system buses. As shown in figure 3.11 the fault occurs at 150 seconds and is immediately cleared by primary protection. The voltage levels start to decrease and the reactive power demand starts to increase, especially in the outlined area. As a result Relay A switches from the conventional distance protection algorithm to the algorithm as proposed in figure 3.4 (the choice of relay algorithm is based on the same criterion as in the previous simulation). Automatic shunt switching is performed to decelerate the voltage reduction and to restore the voltage level. This proceeding will succeed if the adaptive algorithm is used or when the reach of the zone 3 element of Relay A is decreased. As in case the adaptive algorithm is used Relay A will not then operate when zone 3 is entered due to the voltage instability, whereas in case the reach is decreased so much that zone 3 is never entered the incorrect relay operation is obviously avoided.

In figure 3.10 the system is displayed in the stable operating state which is reached approximately 9 minutes after the short circuit fault when one or both of these actions are taken. However if neither the algorithm is applied nor the reach of the zone 3 element is decreased Relay A will operate about 8 minutes after the fault and initiate a total blackout in the outlined region.

On the basis of this simulation the same conclusion can be drawn as in the previous analysis of CASE 1 for the 15 bus system. Necessarily it is not the distance relay at the bus with the lowest voltage which causes the collapse but a relay located at a station with fairly low voltage in combination with high and increasing reactive power flows.

The impedance relay characteristic of the distance element applied is of the quadrilateral type operated without any devices such as load blinders, start relays or general start criteria. All zone 3 elements in the system are set to cover all adjacent lines in reactive direction. In resistive direction the sensitivity among the relays varies but Relay A is set to operate for fault resistances of 115.2 Ω or less. The reach in resistive direction is fairly long especially as no load blinders etc. are used.

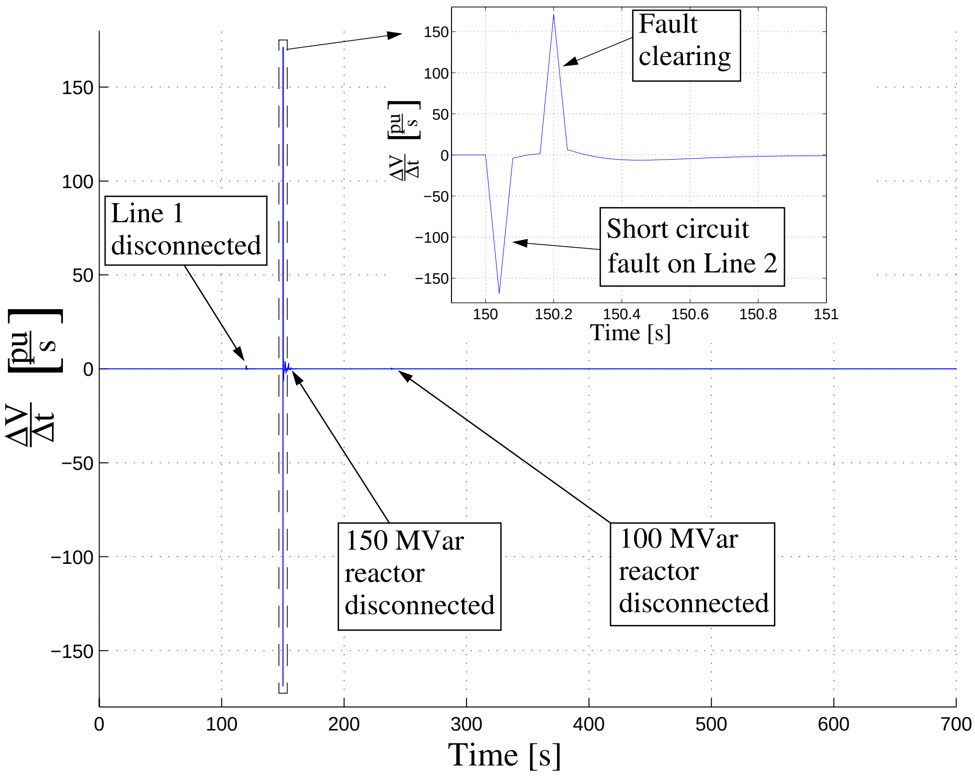

Figure 3.11 The derivative of the voltage at the location of Relay A.

From figure 3.11 we see that the peaks of the derivative of the voltage for the three phase fault and fault clearing are totally dominating if compared to the peaks caused by the automatic shunt switching and the disconnection of Line 1. Notice that the peaks of the derivative with origin in the disconnection of Line 1 and the reactor switching are less than 2% of the magnitude of the derivative for the fault and fault clearing. Hence the algorithm will not have any trouble in operating correctly.

It should be stressed that the system is very sensitive during operation conditions where distance protection may be the initiating source of a voltage collapse. A few MW or MVar change in power flow may be the difference between a collapse or a recovering system. Also a small change in power transport may change the cause (e.g low voltage generator protection or distance protection) which initiates the collapse.

Simulations in the Nordic 32 system show (and as indicated in section 3.1.2) that the low voltage protection for the generators fairly often initiates the collapse. Usually what happens during this course of events is that the current limiters of the generator have been activated and the generator is not able to maintain voltage. The low voltage protection trips the generator and hence the system voltage continues to decrease. Instantaneously or after some time distance relays will most likely operate and accelerate the collapse.

The input voltage used for the calculation of the derivative of the voltage is in this simulation sampled with a lower frequency than used for the 15 bus system. Therefore the peaks of the derivative in figure 3.11 are not as distinct as in figure 3.9.

3.4 Experience of distance relay operation and voltage instability in different countries

Undesirable (zone 3) distance protection operations have contributed to blackouts worldwide. Examples are the ¨November 9, 1965 Northeastern U.S/Canada disturbance and the August 22, 1987 Western Tennessee U.S blackouts [43]. Below a few similar disturbances are further described.

3.4.1 Zone 3 distance relay operation in the Swedish transmission grid

The system regulator[1] of the Swedish transmission system maintains a database where information about all disturbances in the system is stored. From the start of the year 1985 until the end of 2000 about 4050 disturbances were recorded. During this period the recordings indicated about 1100 distance relay operations at the 220 kV level and 1430 at the 400 kV level. Observe that due to auto reclosing and duplicated main protection systems one disturbance may lead to several recorded distance relay operations.

1. Svenska Kraftnät

Table 3.2: Zone 3 operations in the Swedish transmission system from the start of year 1985 until the end of 2000.

Voltage level [kV]	220	400
Number of correct operations	5	0
Number of incorrect operations	1	1
Total number of operations	6	1

From table 3.2 we see that zone 3 operations are very rare occasions. The incorrect operation on the 220 kV level was due to human activity during maintenance work whereas hardware failure was the reason for the incorrect operation on the 400 kV level. From the simulations and statements above it may seem remarkable that no zone 3 operations have caused or aggravated power system instability events in Sweden during this period. Of course operating conditions where these type of events occur are rare, but other reasons might be that start elements and in case of numerical relays the so called general start criteria, which obstruct mal-trips due to load encroachment are widely used. Also a restrictive view concerning line loading is applied when the reach of the zone 3 element is determined. A safety margin of at least 2 is used between peak load and the load which makes the relay to operate. However the consequence is that the whole length of all adjacent lines is not always remote back-up protected by distance protection. An additional aspect for no zone 3 mal-trips might be that the settings of the relays actually are continuously updated to incorporate changing system configurations and/or new system operating conditions.

One way to find out the necessity of zone 3 elements is the study of what had happened if the elements had not been in operation for the correct operations in table 3.2.

In one case zone 3 has been applied as local back-up to achieve satisfactory selectivity due to infeed from T-lines. According to the plan zone 3 can in fact be considered to have been operating as the main protection. Obviously if zone 3 is not applied as local back-up for T-line configurations the selectivity or the fault clearing capability is deteriorated with respect to the varying operating conditions.

An unplanned local back-up zone 3 operation occurred due to a two phase to ground fault where the fault current was too low to initiate momentary zone 1 operation. Another unplanned zone 3 operation occurred during a high resistance phase to ground fault where the zone 3 element initiated the local fault clearing. For these two unplanned operations the omission of a zone 3 distance element had not mattered since the zero sequence overcurrent protection had cleared the faults in approximately the same time.

Finally in two cases zone 3 has operated as remote back-up, which may have saved the system from costly consequences. However it should be observed that in these cases duplicated line protection was not accessible, and in one case the distance protection operated as back-up protection for a generator fault.

The case where the zone 3 element operated unplanned due to the two phase to ground fault and the cases where zone 3 operated as remote back-up protection are further described in section 3.4.2.

Additionally two times the zone 3 has been entered and the associated timers started. In the first case the zone 3 was entered at the local terminal due to a phase to ground fault. In the second case where the zone 3 was used as local back-up to achieve satisfactory selectivity with respect to infeed from T-lines, a two phase to ground fault was the reason for the entrance. However in both cases the faults were cleared by other protection devices before the zone 3 timer had expired. In the first case by the zero sequence overcurrent protection and in the second case by accelerated distance protection tripping initiated by pilot relaying.

3.4.2 Further investigations of three zone 3 operations of particular interest in the Swedish transmission system

Hjälta 1988-10-12

During maintenance work on one group of the duplicated local dc supply in the Hjälta hydro power station, inadvertent switching of the operative group led to a total absence of active dc supply. Consequently the majority of all protection and control devices in the station went out of operation and the excitation was lost for one of the three generators. The excitation of the other two generators was maintained by static dc sources.

The generator which had lost excitation started to operate in induction mode. This behaviour led to a very high field current which resulted in broken damping windings. Due to the overheating and breakdown of the damping windings transients aroused in the air-gap flux which thereby induced voltage transients in the armature winding. Consequently a three phase fault occurred close to the generator terminal about 103 seconds after the loss of the active dc supply. The zone 3 distance element in Stadsforsen, indicated as R1 in figure 3.12 detected the three phase fault through the transformer and operated after the associated time delay. As the protection and control system in Hjälta was not in operation the generators found a new equilibrium mode, where the three phase fault was continuously fed from the generators which were still magnetized and where the generator which had lost excitation operated as an induction machine. This operating mode continued for 30 to 40 minutes until all generators were manually disconnected. Due to the long fault clearing time a fire broke out in the station.

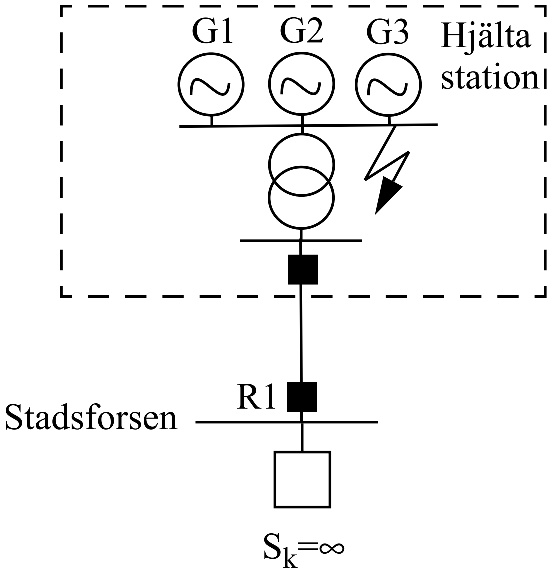

Figure 3.12 The interconnection between Hjälta hydro power station and the Swedish transmission system.

In this case the zone 3 distance element in Stadsforsen operated as remote back-up protection for the protection devices in the generator station. Due to the severe operating conditions experienced by the generators the stator had to be replaced for the generator which had lost excitation, to an estimated cost of about 30-35 MSEK in todays money value. Additionally the power producer faced a lack of income during the period for the replacement of the stator and other necessary repairing. Although the total repairing cost, excluding lack of income, may be estimated to about 140 MSEK in todays money value the cost for the owner of the hydro station (insurance company) could have been far greater. Imagine that R1 had not operated and the fault had been further fed from the Swedish transmission system which may be associated to an unlimited amount of short circuit power. This proceeding could possible have led to a more extensive fire in the station.

For this scenario the investment necessary to restore the station vary a lot. However in worst case they may be comparable to building a new station. Additionally the station will be out of operation for a particularly long time with associated absence of income. Thus in this case protection equipment belonging to the transmission company may have saved a significantly amount of money for the power producing company (insurance company).

Vaple 1991-06-21

Lightning caused a three phase fault on the line between Stadsforsen and Hällsjö. Almost simultaneously a short circuit fault occurred on the 130 kV line between Granlo and Vaple. Consequently the relays R1, R2 and R7 operated. However the relays R3 and R6 located in Vaple did not operate. Most likely this behaviour was related to the low supply of short circuit power from Turinge and Järnvägsforsen. Neither R4 in Turinge operated but R5 in Rätan did. However as the pilot tripping of the generators in Järnvägsforsen controlled from Rätan failed to operate the faults were still fed. Yet the generators in Järnvägsforsen did not manage to maintain the voltage level and as a result the zero voltage protection[1] tripped the circuit breakers in Järnvägsforsen, and in Turinge as well.

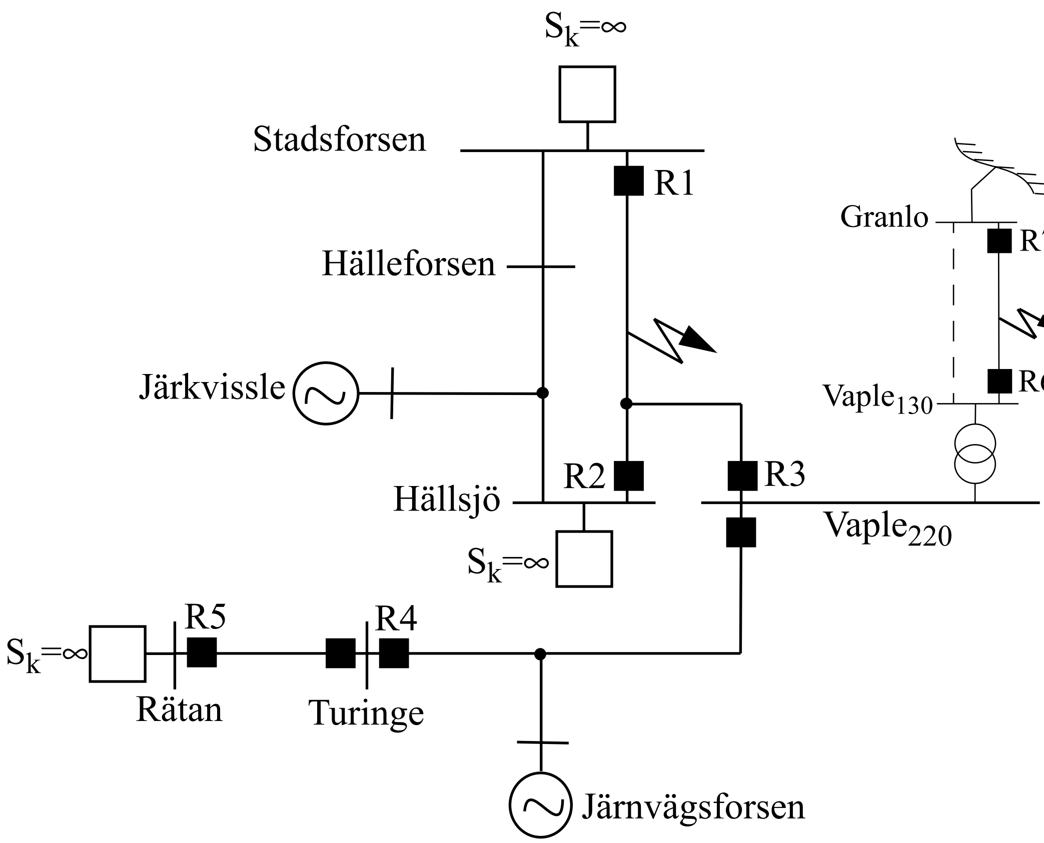

Figure 3.13 The area involved in the disturbance June 21 1991 which led to a zone 3 remote back-up operation. The dashed line between Granlo and Vaple was out of operation before the short circuit faults occurred.

1. A low voltage protection scheme which disconnect all devices in the station at a certain voltage level. The settings vary between 0.3 - 0.5 pu dependent on the location of the station.

In this case zone 3 of R5 operated as remote back-up. However this behaviour was more a coincident then a planned relay operation, as R4 is the relay which should supply remote back-up for R3. The most likely reason for the absence of correct operation in Vaple and Turinge was jamming in the old electromechanical relays of the L3ws type. To prevent similar occasions all old electromechanical relays were replaced by new numerical ones. Additionally duplicated line protection was enforced.

In case the zone 3 element in Rätan had not operated, most likely the voltage decrease had been decelerated in the area. Hence it would have taken longer time for the zero voltage protection to operate. Alternatively the zero voltage protection had never operated and the fault had been fed until the short circuit fault had developed to an earth fault which could have been cleared by the zero sequence overcurrent protection. In any case the fault would have been fed during an extended period which could have led to extensive damage on equipment.

Gulsele 1991-07-13

Figure 3.14 shows the network configuration for the area involved in one of the (unplanned) local zone 3 operations briefly mentioned in section 3.4.1. Initially a two phase to ground fault occurred on the line between Hällby and Gulsele. Relay R2 in Gulsele tripped the circuit breaker instantaneously, however the fault current in Hällby was too low to initiate zone 1 tripping for relay R1. After R2 had operated the generators in Stenkullafors, Åsele and Hällby were forced into island operation. Because of this the fault current in Hällby became even lower which led to that also zone 2 for R1 did not manage to initiate relay operation. Eventually zone 3 of R1 initiated relay operation. In Stenkullafors the timer started for R3:s zone 3. However as the fault current decreased the apparent impedance left zone 3 and the generator was finally tripped by overfrequency protection. Additionally the generators in Åsele and Hällby were tripped due to overspeed.

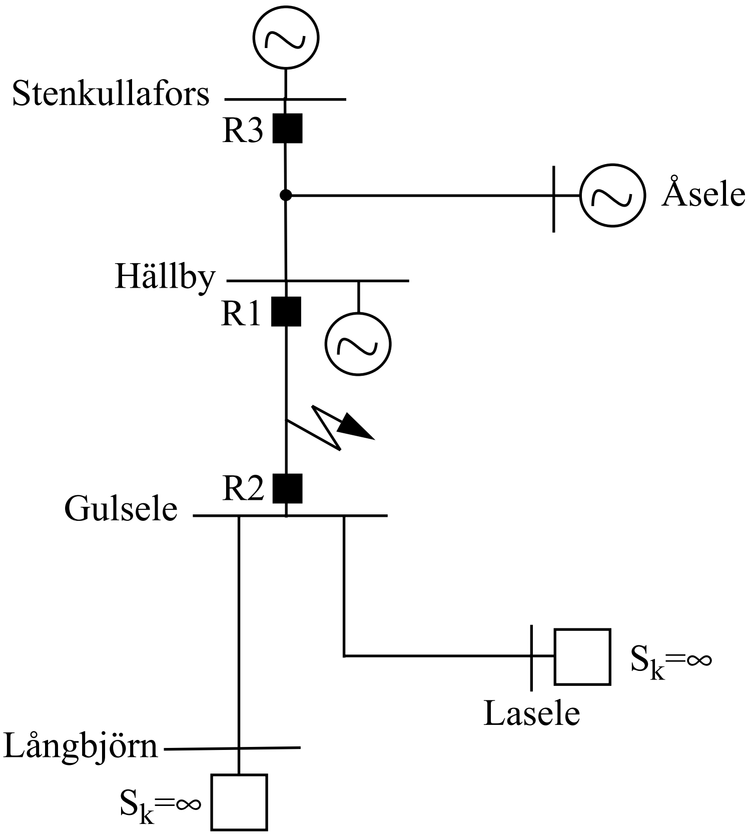

Figure 3.14 The area for a local zone 3 operation in the Swedish transmission system on July 13, 1991.

In this case the zone 3 element of R1 facilitated the fault clearing by operating as local back-up. However as zero sequence overcurrent protection is used in parallel with distance protection in the Swedish transmission system, the fault had most likely been cleared in about the same time in case the zone 3 element had not existed. However if this behaviour of the distance relay had occurred for a pure phase to phase fault located in a more central part of the system, where the generation had not reach overfrequency so quickly, the clearing time had probably increased considerably and thus aggravated the disturbance. However this behaviour of the distance relay is unlikely in a central part of the system as the associated short circuit power usually is large.

This disturbance also gives an example of a method which sometimes is practiced where overfrequency protection for generators is used as ”line protection”. By experience from this case among others, the method is applied for limited areas having a low short circuit power capacity within the area but being supplied from outside by a large short circuit power. The reason for applying this method is that these system configurations may lead to difficulties for distance protection to initiate relay operation.

Hence, as practiced in this case, the method is based on that the relay located between the fault and the system with the larger short circuit capacity operates first. This leads to island operation of the generators in the area associated with the low short circuit capacity. As the generators supply the fault they will accelerate. Due to the limited interia the control equipment will not have enough time to adjust the power output. The frequency will increase until the overfrequency protection for the generators operates and the fault is cleared.

Hence in case neither the zone 3 element or the zero sequence overcurrent protection had existed at the location for R1 the fault should still have been cleared satisfactory. However this protection method may entail fairly long generation outages as the generators must be re-synchronised etc.

3.4.3 The Swedish blackout in 1983

At about 13.00 hrs. on Tuesday December 27th 1983 the Swedish transmission system faced the most severe disturbance over a period of almost 30 years [44, 45, 46, 47].

Before the disturbance the consumption was about 18 000 MW. The load was supplied by 60% hydro power, 32% nuclear power, 2% other thermal production and the remaining 6% was imported. Maintenance work was performed to a very limited extent and the network was almost fully in operation. Hence the power transfers in the limiting sectors were also within their margins. Figure 3.15 shows the 400 kV lines constituting the crucial bottleneck in the Swedish transmission system; the section between the North and South parts. For this section the pre-disturbance power transfer was 5 600 MW from the north area towards the south area. This was 200 MW less then the maximum allowed transfer limit. In parallel with the 400 kV lines six additional 220 kV lines were in operation.

The disturbance was initiated by an earth fault at the Hamra station; figure 3.15. Because of certain unfortunate circumstances the earth fault resulted in that the entire station was tripped by the busbar protection. As the two dashed 400 kV lines in figure 3.15 serving the Hamra station were tripped the transmission grid between the North and South parts of Sweden faced a substantial weakens. Additionally the two dashed 220 kV lines supplying the area of Stockholm were lost. Consequently the overall system voltage started to decrease at the same time as line currents increased.

As a next step the dashed 220 kV line between Beckomberga and Bredäng, serving within the area of Stockholm and supplying the south parts from the north was disconnected due to overcurrent 8 seconds after the initial disturbance. From previous simulations and experience the line was known to become highly stressed during this type of operational conditions and was therefore equipped with an extra overcurrent device set to operate for currents over 2240 A and with a time delay of 3.6 s. As the overcurrent device did not operate instantaneously but after 8 seconds, most likely load recovery was the reason for the operation.

Figure 3.15 shows the prevailing voltages and active power flows [48] immediately after the disconnection of the line between Beckomberga and Bredäng. The voltages are very low and hence tap-changers tried to restore the voltages in the regional transmission and distribution networks. However this behaviour led to increased (reactive) power demands and thus the overall transmission system voltage continued to decrease.

About 52 seconds after the initial disturbance at a voltage level of approximately 300 kV a distance relay located in the receiving end of the long distance transmission line between Kilforsen and Hallsberg operated. Roughly 1 second later cascading outages followed and almost instantaneously south Sweden faced a blackout. About 65% of the pre-fault load was lost.

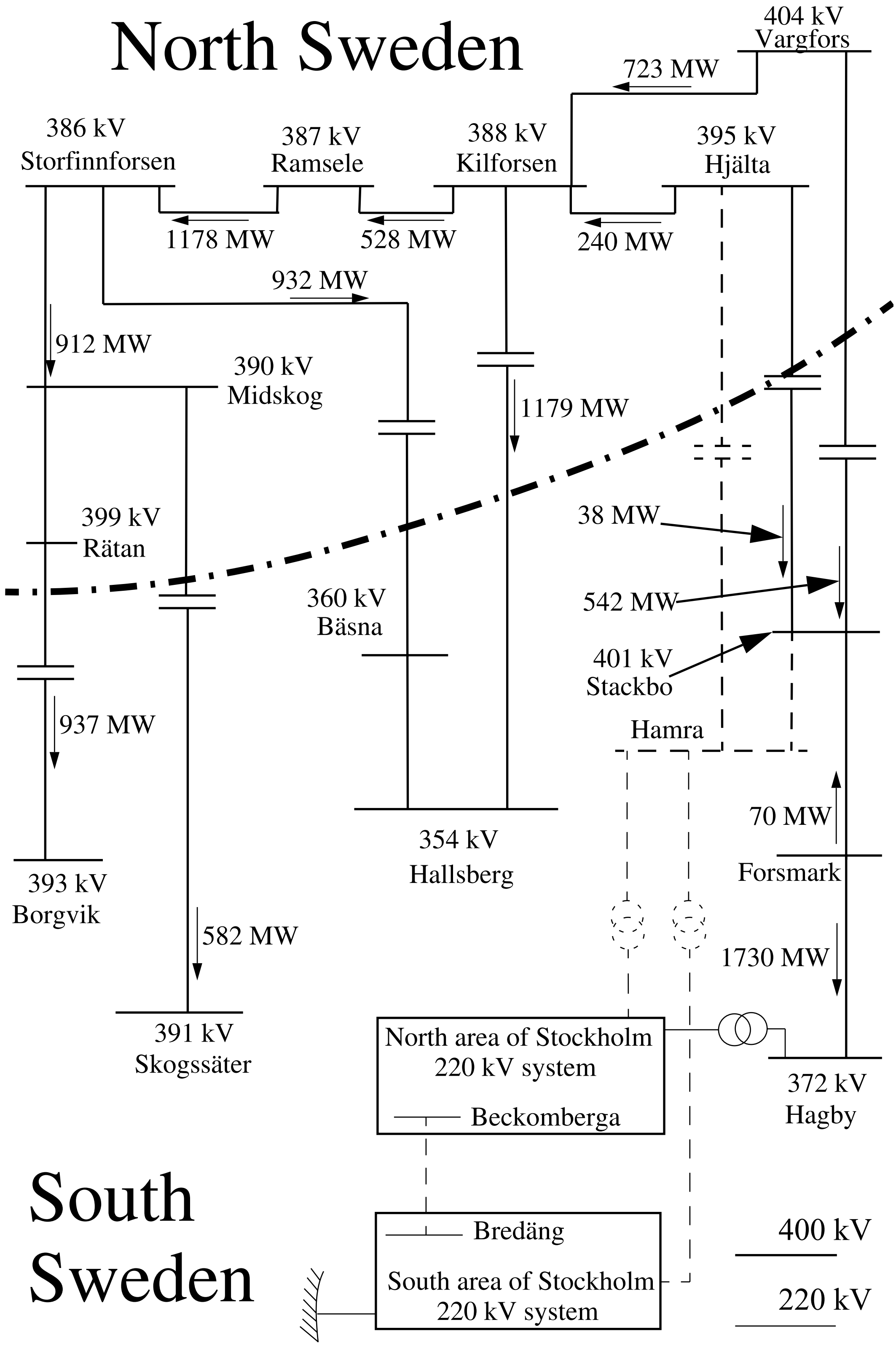

Figure 3.15 The bottleneck (dash dotted line) in the Swedish transmission system between the North and South parts. The voltages and power flows indicated aroused immediately after the line between Beckomberga and Bredäng was tripped.

As distance protection usually is directional it may seem a bit remarkable that the relay in the receiving end of the line between Kilforsen and Hallsberg operated. However the relay in Hallsberg which initiated the cascading outages was a L3ws relay manufactured by BBC. It was operated in such a way that when the apparent impedance is within the start zone for a longer time than 3.2 seconds without any relay operation, the start elements alone initiated tripping. Hence the relay converted to a non-directional unit with a long reach having a circular impedance characteristic where operation due to load encroachment was not obstructed.

The decreasing station voltage in Hallsberg combined with the increasing current on the line between Kilforsen and Hallsberg was the reason that the start zone of the relay eventually was entered. As the relay was located in the receiving end of the line the apparent impedance approached the zone from the left in the RX-diagram; figure 3.16. As long as the relay was directional nothing happened. However after 3.2 seconds when the relay converted to a non-directional unit the decreasing voltage combined with the increasing current managed to initiate relay operation, although the current had ”the wrong direction”. Consequently the voltage at Forsmark decreased and 1.3 seconds later the line between Forsmark and Hagby was tripped by the zone 3 distance protection in Forsmark which led to cascading outages and the final collapse.

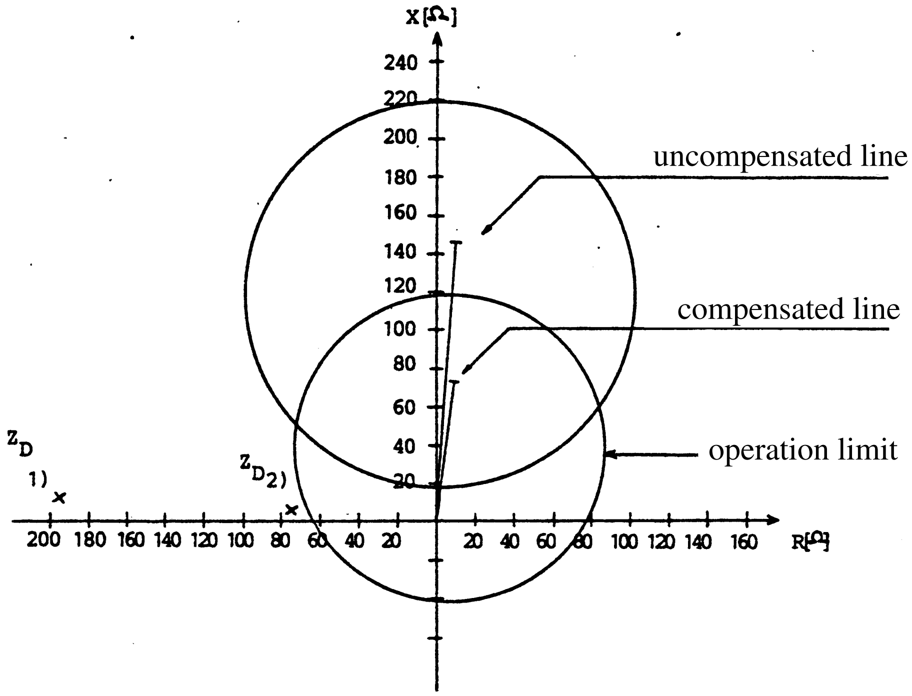

Figure 3.16 The start zone for the relay located in Hallsberg protecting the line between Kilforsen and Hallsberg. Z_{D1} is the apparent impedance two minutes before the initial disturbance. Z_{D2} is the apparent impedance calculated for a station voltage immediately above 300 KV. After the calculation was done further information indicated that the real station voltage had been even lower. The figure is taken from [48].

Today the relay in Hallsberg would not have performed in the same way. One measure taken to prevent similar relay occurrences was that start elements should not trip circuits. However this would most likely not have saved the system from collapse. The voltage instability was significantly developed 52 seconds after the initial disturbance and thus the system voltages would have continued to decrease until some other protection device would have operated initiating the cascading outages.

However in this case non-tripping start elements could have been beneficial to some extent. The time to collapse could have been extended in this way leading to improved possibilities for activation of a load shedding scheme based on low voltage. However no such scheme was in operation.

3.4.4 The July 2, 1996 disturbance in the WSCC system

In WSCC's service territory more than 59 million people, representing approximately 20 million customers are provided with electric service. The system had a peak summer load of around 118 000 MW in 1996 [49].

Because of temperatures around 38° C, loads were very high in Southern Idaho and Utah on Tuesday, July 2, 1996 [50,51]. As usual during hot summer days the power was mainly flowing from north to south. The 230 kV system of Idaho Power Company was moderately loaded in the (unusual) west to east direction. Before the disturbance the WSCC transmission system was operated within all known transfer limits and only a few facilities were out of operation.

In figure 3.17 the key areas involved in the disturbance are indicated by number (1) - (4). Around 2:24 p.m. a 345 kV line between Idaho and Wyoming (1) sagged into a tree. A single phase to ground fault occurred and the line was tripped. Twenty milliseconds later a parallel line was tripped due to mal-operation of the ground element of the relay in Wyoming.

Now the interconnection between Idaho and Wyoming was significantly weakened which led to remedial actions including generator tripping (1), bypassing of series capacitors (3) and shunt capacitor switching (1). Almost simultaneously a 230 kV line in Oregon (2), about 500 km from the initial phase to ground fault, was tripped due to mal-operation of a KD 11 zone 3 relay. The remedial actions should have ensured stability and prevented further outages. However the combination of the 230 kV line tripping in Oregon and the bypassing of series capacitors led to voltage depression in Wyoming, Idaho and Oregon. Consequently several relatively small hydro units in the (3) area tripped because of high field currents.

About 24 seconds after the initial phase to ground fault an important 230 kV line feeding Idaho from Montana - the Amps line (4) - was tripped by a zone 3 distance relay. When the Amps line was tripped, cascading outages followed and approximately 10 seconds later the system had separated into five electrical islands; figure 3.17. The line trippings were mainly performed by zone 1 and zone 2 distance relays.

About 2 million customers; i.e 10 % of all customers in the WSCC system were affected by the disturbance. In figure 3.17 the load and generation loss within each island is indicated.

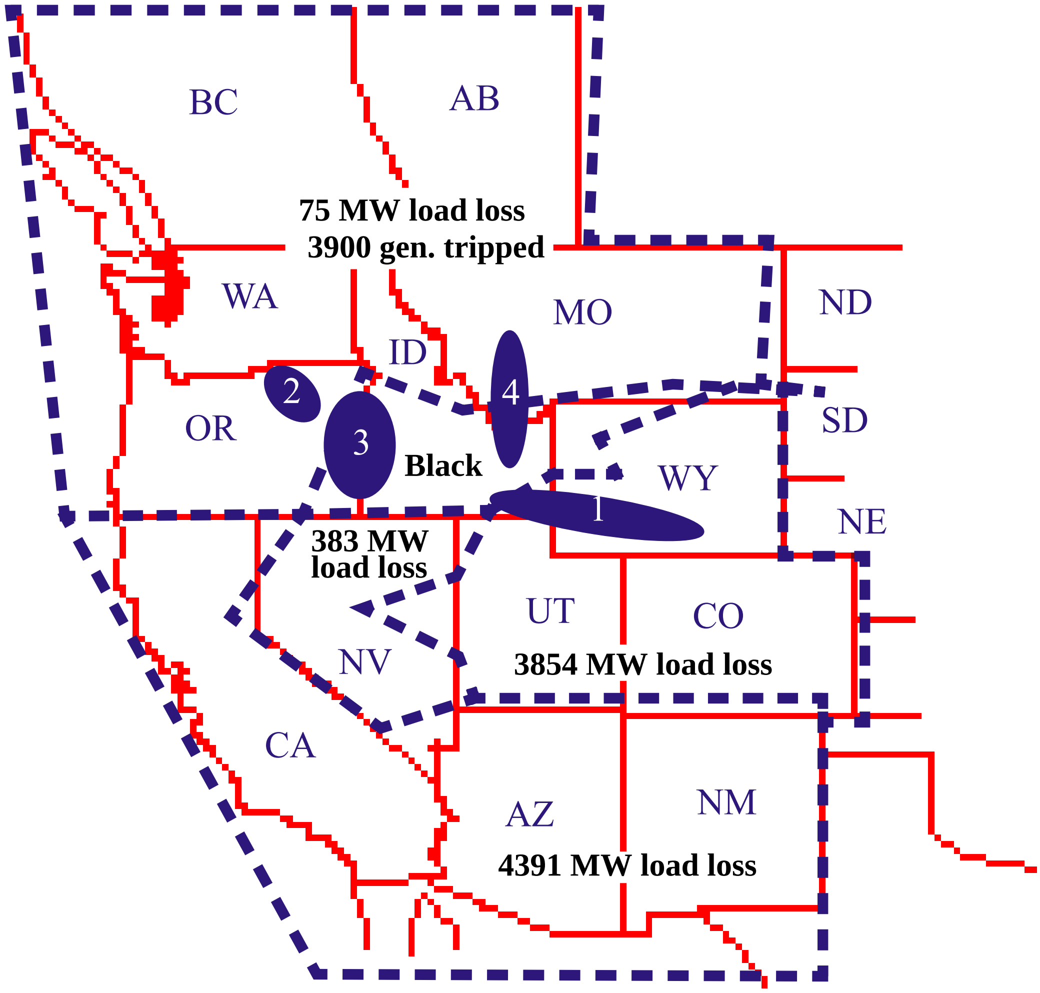

Figure 3.17 The WSCC power system showing the key areas of the disturbance. Additionally the resulting five islands and the load and generation loss within each island are indicated.

The faulty ground element in Wyoming which tripped the line between Idaho and Wyoming (1) was later identified as the ground sub-system of a Westinghouse SPCU relay. The component that failed was a local delay timer in the ground element. As the faulty relay was not immediately identified it also contributed significantly to an additional disturbance the following day. In fact, if the faulty relay had been taken out of service immediately after the July 2 interruption the July 3 [49] interruption could have been avoided.

The KD 11 zone 3 relay that tripped the 230 kV line in Oregon (2) had a faulty phase to phase impedance element. Therefore the relay only depended on the fault current detector element to operate. When the power flows increased towards Idaho due to the generator tripping, the relay timed out and tripped the line.

An investigation of the relay showed corrosion under the crimp-on lug to the phase to phase voltage restraint element. This resulted in an open restraint circuit which caused the phase to phase impedance element to close. As the relay is supervised by a fault detector the failure was not apparent until a disturbance occurred that created enough current to operate the fault detector and lasted long enough for the relay to time out. Although this relay had been calibrated and tested four months earlier it mal-operated. Corrosion of crimp-on lugs is not a common problem and can not be expected to be detected by routine maintenance.

Due to moderate overload and moderate voltage depression the zone 3 relay in Montana tripped the Amps line (4). The mal-tripping relay was most likely of the conventional mho type without any device like start zone, general start criteria or load blinders. The tripping of the Amps line was most unfortunate as 400 MVar of capacitor banks were about to be inserted in the south part of Oregon, possibly stabilizing the voltage decay.

After the disturbance the Montana Power Company changed the relay setting to 120 % of the thermal limit at normal voltage.

Clearly mal-operations of protective devices contributed significantly to the disturbance. The entire grid was weakened considerably due to mal-functioning relays (1,2,4). Particularly the zone 3 relay which initiated the cascading outages (4) accelerated the collapse. Additionally a zone 3 distance relay operated incorrectly during the restorative process due to load encroachment and decelerated the restoration of the system.

After the disturbance all grid owners involved were encouraged to review the applications and settings of the relays for their respective lines and make changes where appropriate. Moreover it was discussed that tight settings which led to the Amps line scenario are not acceptable.

Although the WSCC system was operated within its transfer limits before the disturbance, it was concluded in the disturbance report [49] that parts of the system were unknowingly operated in a manner not in compliance with the WSCC Minimum Operating Reliability Criteria [52]. The initiating contingency i.e the almost simultaneous outages of the two lines between Idaho and Wyoming (1) should not have resulted in the disturbance experienced on July 2, 1996. The main reason why these contingencies have led to a blackout was insufficient voltage support in the Northwest and Idaho for the prevailing operation conditions, combined with an insufficient performance of the protection system.

3.4.5 The Brazilian blackout on March 11, 1999

On March 11, 1999, Brazil [53] faced the most severe power interruption in its history. About 72 % of the pre-disturbance load amounting to 34 200 MW was affected.

In the Brazilian electric power system about 90 % of the total installed generation capacity is hydropower. Due to the remote location of the hydro units large amounts of energy are transferred from the generation sites to the load centres through long distance EHV power corridors. Because of hydroelectric coordination for optimal water usages, operation involving heavy power transfers frequently occurs. In fact these heavy power transfer conditions occur both for light and heavy load demands.

Figure 3.18 gives an overview of the 440 kV system around the Bauru substation. The figure indicates that the main part of the generation is located in the upper part of the system and the load in the lower part of the system. At the stations A.Vermelha, Araraquara, Assis, Jupia, Embu-Guacu, Cabreuva, S. Angelo and Sumare the 440 kV system in figure 3.18 is connected to the remainder of the Brazilian EHV system.

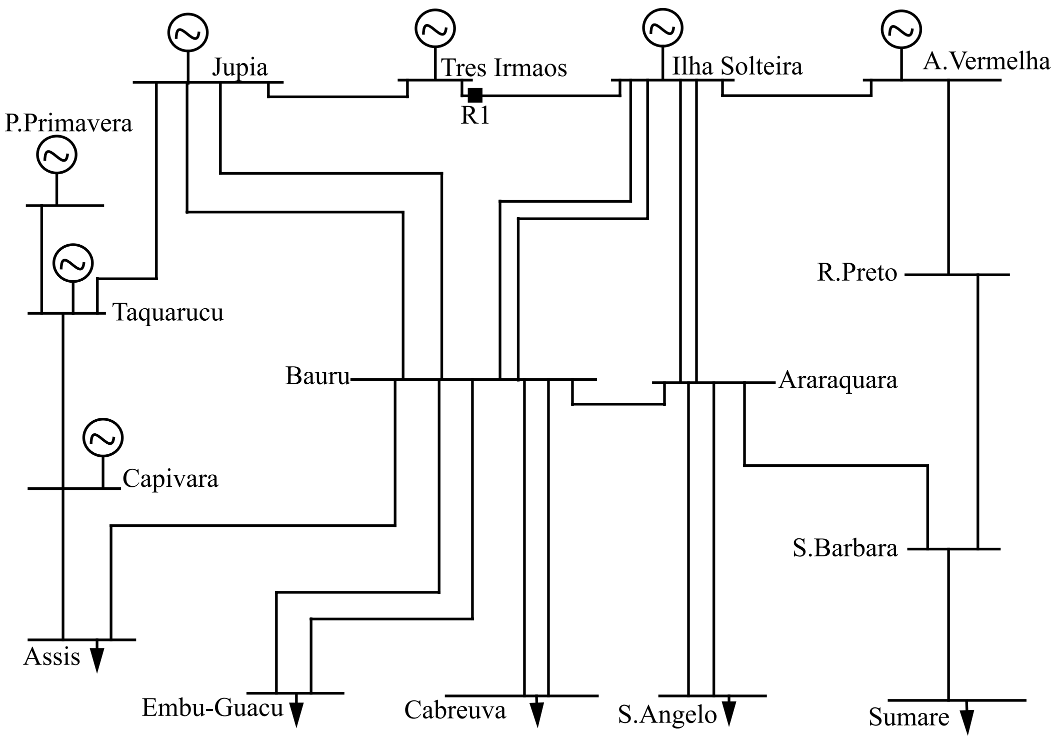

Figure 3.18 The 440 kV system around the Bauru substation.

The initiating event of the March 11 blackout was a phase to ground fault at the Bauru 440 kV substation which led to the loss of the five incoming 440 kV lines from Jupia, Assis and Embu-Guacu respectively. The system survived this contingency and recovered to a quasi stable operating point. About 12 seconds after the phase to ground fault the line between Tres Irmaos and Ilha Solteria tripped. Cascading outages followed and approximately 18 seconds later the entire network in figure 3.18 collapsed.

The tripping of the line between Tres Irmaos and Ilha Solteria was initiated by the start unit of the distance protection indicated as R1 in figure 3.18. The start unit had the longest reach of all zones of operation to provide remote back-up for all adjacent lines which are much longer than the Tres Irmaos - Ilha Solteria line. The start unit had been given a setting corresponding to a very long reach with an associated time delay of 1.5 seconds. Hence when the line loading increased after the initial fault and likely in combination with an increasing reactive power demand throughout the entire system, the apparent impedance entered the start zone and the relay operated.

If the start zone had not provided for remote back-up protection, the reach could have been shorter and the line had stayed in service. In that case automatic or manual actions to avoid the collapse could have been taken. The reason why the start zone was used as remote back-up protection was that the 440 kV system in the area is old. When the substations were built, complicated busbar arrangements with three or four bus sections were chosen. A great variety of busbar configurations due to the different combinations of the positions of the circuit breakers/disconnectors resulted. When these substations were built no busbar or breaker failure protection able to cope with the variable bus configurations existed. Therefore busbar protection and breaker failure protection is not widely used in the area and distance protection is the main remote back-up method. At the time of the building of the substations the 440 kV system was mainly radial and a remote back-up system based on distance protection operated satisfactory. Due to the system growth this is not the case today.

In fact during the early eighties personal from ONS (Operador Nacional do Sisterna Elétrico) strongly recommended the implementation of busbar and breaker failure protection schemes in the area as applied in the rest of the Brazilian system. However the utility did not agree. Today, after the great disturbance of 1999, all 440 kV substation in the area are undergoing a refurbishing process, including the implementation of selective busbar and breaker failure digital protections.

Chapter 4 Distance Protection and Transient Stability

Power oscillations are inherent to occur in power systems. They usually arise as a consequence of an event, for example line switching, short circuit faults, generator tripping or load shedding. During normal operation the magnitude of the oscillations are usually small and quickly damped out. However during abnormal operation the oscillations can be more severe and in some cases even have an increasing magnitude. In this chapter the relation between different types of power oscillations and distance protection is examined. Additionally distance protection schemes are introduced to increase the security with respect to incorrect distance relay operation during transient stability. A few disturbances related to the subject are discussed as well.

4.1 Distance protection during transient stability

Generally power oscillations can be divided into three different categories; local plant mode oscillations or inter machine oscillations with a frequency range of 0.7 - 2 Hz (6 Hz), groups of generators swinging against each other in the frequency range of 0.4 - 0.7 Hz and large sub-systems oscillating against each other where the swinging frequency usually is in the order of 0.1 - 0.3 Hz. Consequently power oscillations may be the source of incorrect relay behaviour as the cycle times of the oscillations are in the same time domain as the timer settings of the protection devices.

In Florida [54] and in South Africa [55] incorrect relay behaviour during power swings has been (and still is) a major concern. An unwarranted distance relay operation due to a power swing was the immediate reason for the system breakdown in the south-western part of Sweden and Denmark in 1956 [56].

The two machine system in figure 4.1 can be used to analyse the performance of distance protection during power oscillations. The machines are interconnected through a 200 km long transmission line and they are represented by voltage sources with constant magnitude behind their transient reactances. By studying the apparent impedance as seen by a relay located at C for different transfer angles the effect of power oscillations can be examined. The analysis made in this section is similar to the one made by Kundur in [57].

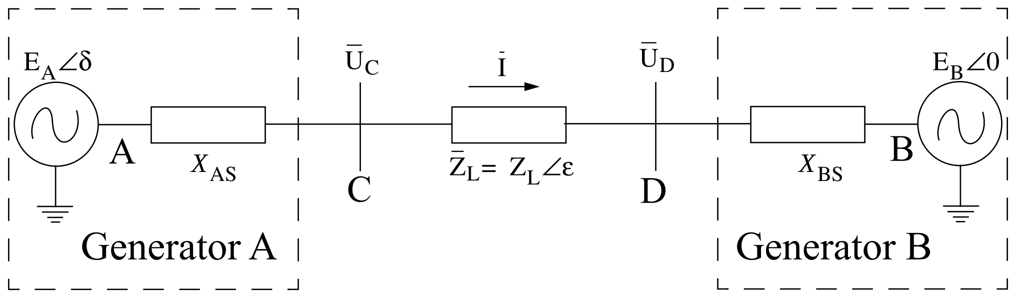

Figure 4.1 Two machine system.

In figure 4.1 $\overline{E}_A$ and $\overline{E}_B$ are the internal voltages of the machines and X_{AS} and X_{BS} are the transient reactances. E_B is assumed to be the reference phasor and δ represents the angle by which E_A leads E_B. Hence the current I is given as in (4.1) and the voltage U_C as in (4.2).

$$\bar{I} = \frac{E_A\angle\delta - E_B\angle 0}{jX_{AS} + \bar{Z}_L + jX_{BS}} \tag{4.1}$$

$$\bar{U}_C = E_A\angle\delta - jX_{AS}\bar{I} \tag{4.2}$$

The apparent impedance as seen by the relay at C during phase symmetrical operation can be determined when (4.1) and (4.2) are inserted into (4.3).

$$\bar{Z}_C = \frac{\bar{U}_C}{\bar{I}} = \frac{E_A\angle\delta}{\bar{I}} - jX_{AS} \tag{4.3}$$

$$\bar{Z}_C = -jX_{AS} + (jX_{AS} + \bar{Z}_L + jX_{BS}) \cdot \frac{E_A\angle\delta}{E_A\angle\delta - E_B\angle 0} \tag{4.4}$$

Figure 4.2 shows the locus of $\overline{Z}_C$ as a function of the transfer angle δ in the RX-diagram when different ratios of the magnitude of the internal voltages of the generators are applied in (4.4). The zones of operation of the relay are set to cover 80%, 120% and 200% of the line length respectively.

During a power swing the transfer angle δ will vary. For a stable swing, δ gradually increases until the maximum value is reached where the trajectory shifts direction and δ decreases until the minimum value is reached where the trajectory ones again shifts direction. This sequence of events is repeated until the oscillations are damped out. If the trajectory of δ reaches beyond 180° the swing can be considered to be unstable.

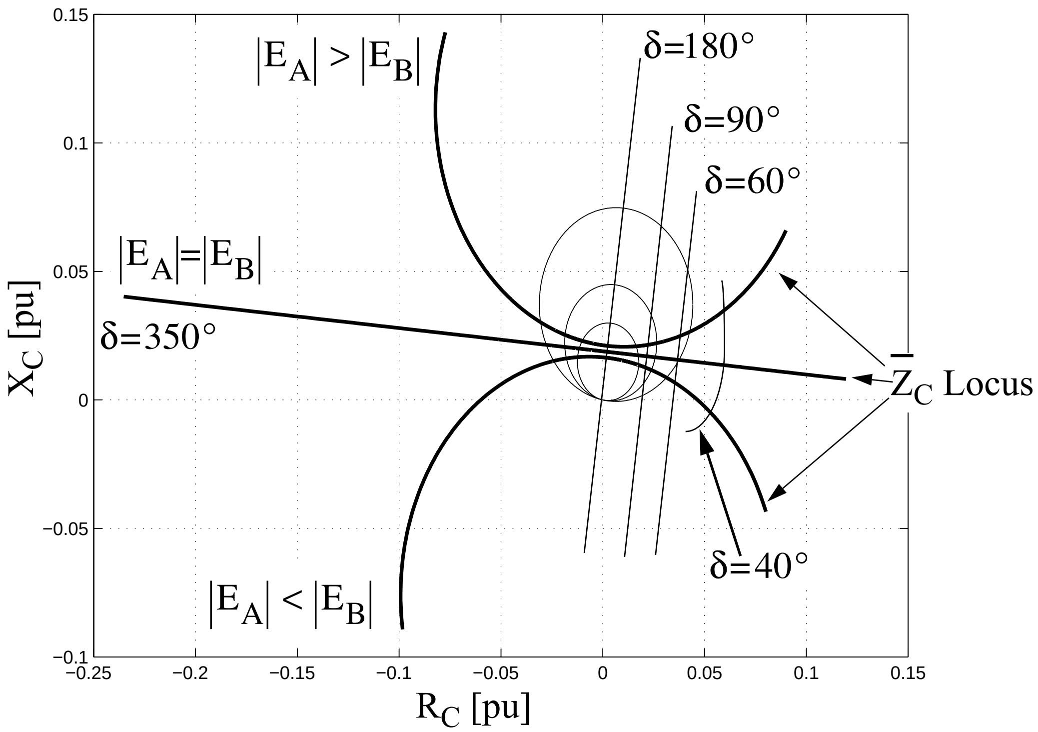

Figure 4.2 The locus of $\overline{Z}_C$ (bold curves) for different values of the ratio $|E_A|/|E_B|$ when δ is increased from 20° to 350°. Specific values of $\overline{Z}_C$ at a given transfer angle δ are given by the intersection of the locus of $\overline{Z}_C$ and the characteristic for constant δ. In addition the three zones of operation of the relay are indicated.

For the transfer angle δ=0, the current $\overline{I}$ in (4.1) is zero and thus the apparent impedance $\underline{Z}_C$ is infinite. As the transfer angle increases the apparent impedance Z_C moves towards, and finally enters the zones of operation. Figure 4.3 shows that the point where the locus crosses the total system impedance corresponds to a transfer angle of 180 ˚. If the angle reaches 180 ˚ loss of synchronism occurs (a pole is slipped for generator A). Unless the system is separated by protective devices the initial pole slipping will be followed by repeated pole slips in rapid succession. During pole slipping the voltages and apparent impedances at points near the electrical centre, i.e the intersection point between the system impedance and the δ trajectory or, alternatively, the middle of the total system impedance, oscillates rapidly. Additionally the voltage at the electrical centre is zero for a transfer angle of 180 ˚. Consequently the relay at C will actually see a three phase fault at the electrical centre.

In case of identical internal voltage magnitude the locus of $\bar{Z}_C$ is a straight line. The impedance loci are circles with their centres on the extensions of the impedance line AB in case the internal voltage magnitudes differ. For $|E_A| > |E_B|$ the electrical centre will be above the impedance centre whereas it will be below when $|E_A| < |E_B|$.

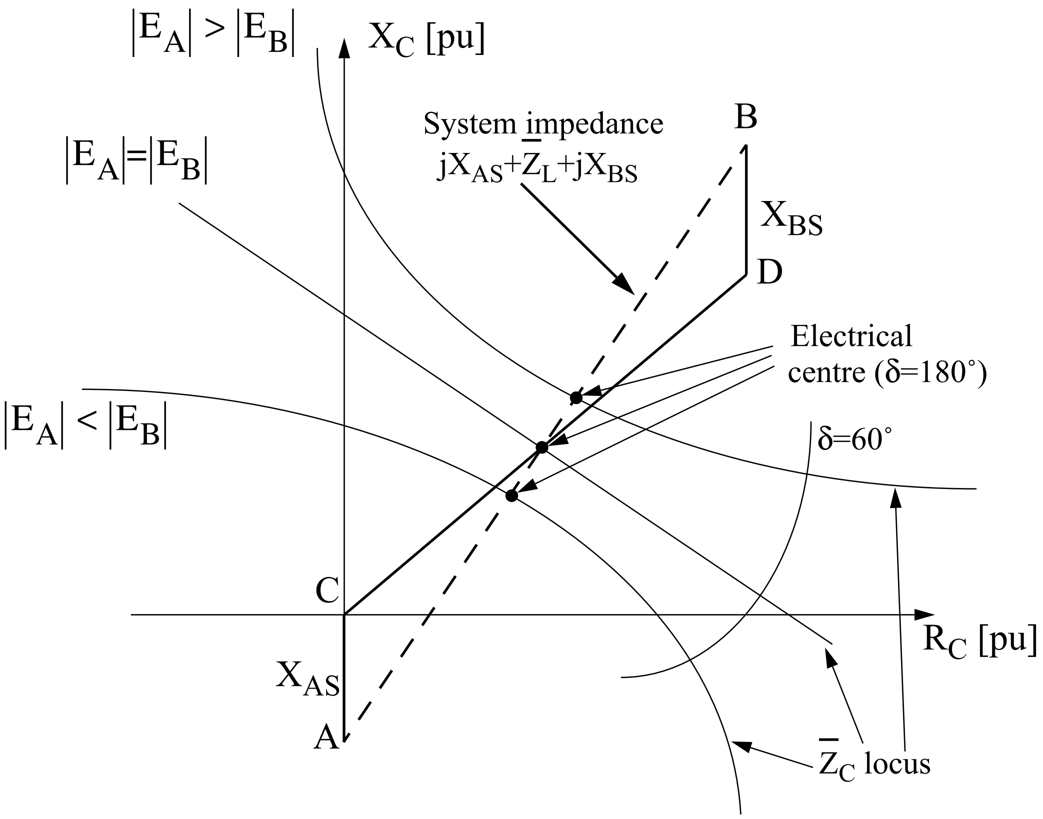

Figure 4.3 The electrical centre for the two machine system in figure 4.1.

From figure 4.2 we realize that when a power swing with a given cycle time reaches a certain angle the apparent impedance will remain within a zone of operation during a certain time. The timer of the zone may expire and consequently the relay operates. In this way the distance relay may operate undesirable for a stable power swing.

Also the relay type decides the sensitivity for this type of mal-trips. Numerical relays usually reset the associated timer when the apparent impedance leaves the tripping zone. This means that the impedance must remain within the area of the tripping zone during the entire timer setting period to initiate a tripping signal. For relays supervised by a start element, the apparent impedance must not necessarily remain within the tripping zone during the entire timer setting period to initiate tripping. As the timers usually are not reset until the impedance leaves the start zone. Hence as long as the impedance remains within the area associated to the start element the impedance can enter, leave and re-enter the zones of operation unlimited times and the timer will in any case continue to count. This means that a tripping signal is generated immediately when the zone of operation is entered after the timer has expired. If the start element has a shape which surrounds all the tripping zones the area which decides the likelihood for mal-trips due to power swings has increased. Therefore it is very important to take this effect into account when power oscillations are considered with respect to undesirable distance protection operations. Refer to section 3.1.1.

Figures 4.2 and 4.3 illustrate the impedance trajectories for a relay located in the sending end of a line. The trajectories for the receiving end are identical but reversed.

Observe that the assumption made above where the internal machine reactances and voltages are given fixed values is usually not applicable in real power system analyses. Consequently the electrical centres are not fixed points as the internal machine impedances and voltages will vary during dynamic conditions.

As indicated above the distance protection should not operate for stable swings. For unstable power swings the protection system should operate to divide the system into stable sub-systems or to separate the ”sick” part of the system from the ”healthy” parts. The importance of this behaviour is illustrated in the next example.

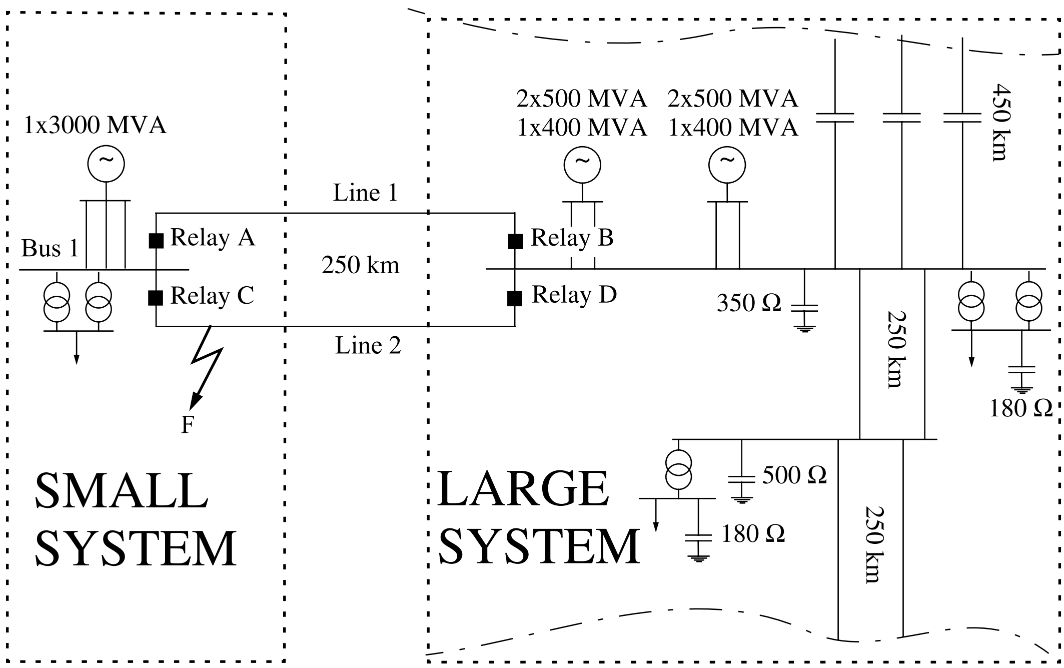

Figure 4.4 System applied in Example 4.1.

Example 4.1:

For the system in figure 4.4 two different cases are discussed. The first case is almost identical to the simulation performed in section 4.2.4. and in the second case some load is disconnected in the small system when the interconnection between the SMALL SYSTEM and LARGE SYSTEM is already weakened. Mho relays with similar relay settings as in section 4.2.4 are used.

CASE 1:

Initially about 1800 MW is transferred from the SMALL SYSTEM towards the LARGE SYSTEM. Five seconds after the simulation is started Line 2 is permanently disconnected due to a short circuit fault. This leads to severe power oscillations on Line 1 but eventually the system recovers to a stable operating point; figure 4.5. However this is only true when the function of the distance protection is disregarded. When the distance protection is included zone 3 of Relay A operates on the first swing after the fault clearing and consequently both the SMALL SYSTEM and the LARGE SYSTEM collapse.

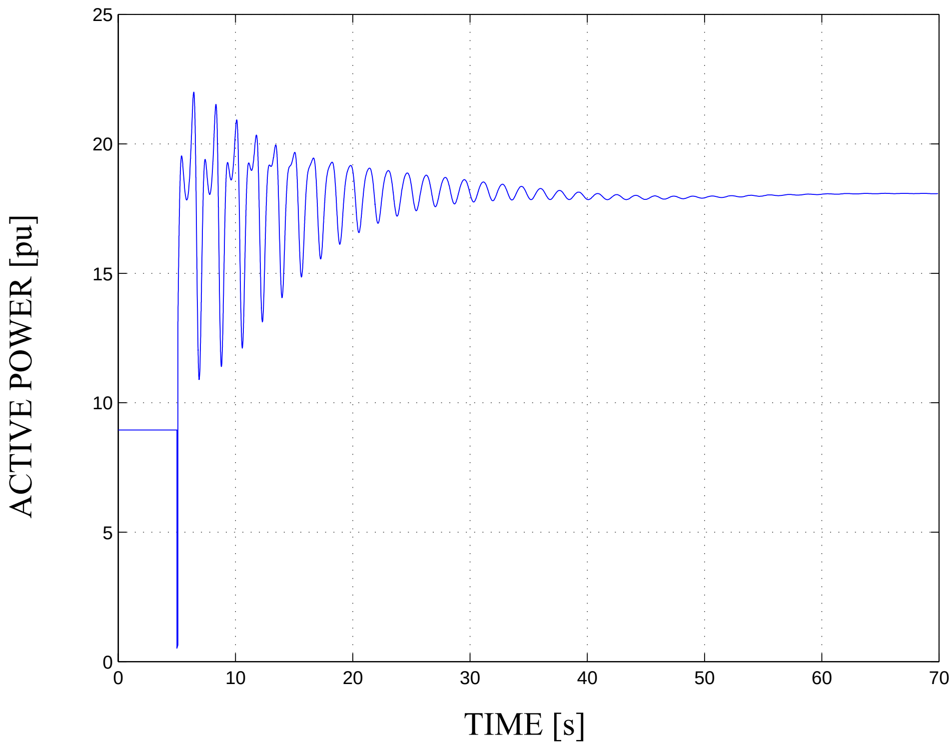

Figure 4.5 Active power injected into Line 1 at Bus 1 when Line 2 is disconnected at t=5 s.

CASE 2:

Before the simulation is started Line 2 is taken out of operation and about 1500 MW is transported from the SMALL SYSTEM towards the LARGE SYSTEM on Line 1. Five seconds into the simulation, load corresponding to about 100 MW is disconnected in the SMALL SYSTEM. Consequently undamped power oscillations occur on Line 1 and the magnitude of the oscillations increases; figure 4.6. About 62 seconds into the simulation the generator close to Bus 1 slips a pole and both systems collapse. During the entire sequence shown in figure 4.6 the apparent impedance for Relay A does not remain within a tripping zone during the total time period which is necessary to initiate relay operation. However if Relay A or B should have operated and separated the systems before pole slipping the LARGE SYSTEM could have survived.

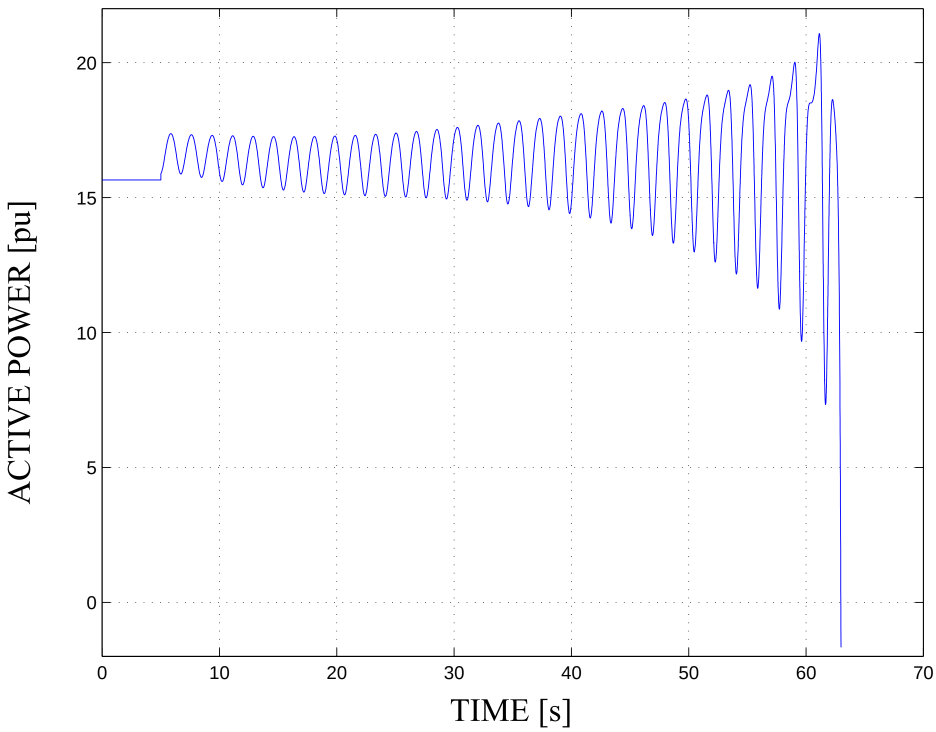

Figure 4.6 Active power injected into Line 1 at Bus 1 when 100 MW load is disconnected at Bus 1 at t=5 s.

In case 1 the distance protection operated undesirable due to a stable swing whereas in case 2 the distance protection did not operate although the system was moving away from a stable operating condition. Thus instead of preventing or limiting the disturbances the distance protection contributed in both cases to the collapses. To perform correct relay operation during such situations, Power Swing Detectors and Out of Step Protection are used.

4.1.1 Power Swing Detectors - Out of Step Protection

Different approaches for Power Swing Detectors and Out of Step Protection have been suggested throughout the years. In [58] a method to avoid mal-trips due to high frequency (above 6 Hz) power swings is proposed based on the phase angle of the voltages at the line terminals and at the fault location. The method is restricted to avoid zone 1 mal-operations due to power swings. Another indicator is proposed in [59,60,61] where tripping is prevented if the rate of change of an electric quantity exceeds a threshold value. In [62] decision trees are used to classify a transient swing on the basis of real time phasor measurement. Further neural networks are used in [63] to detect power swings. An adaptive out of step relay is proposed in [64,65] which uses the equal area criterion and GPS technology. Also the algorithm introduced in [66] applies the equal area criterion to assess the stability of the generators and determine when they are going to slip a pole. However the most common method used for Power Swing Detectors and Out of Step Protection is based on the transition time through a blocking impedance area in the RX-diagram.

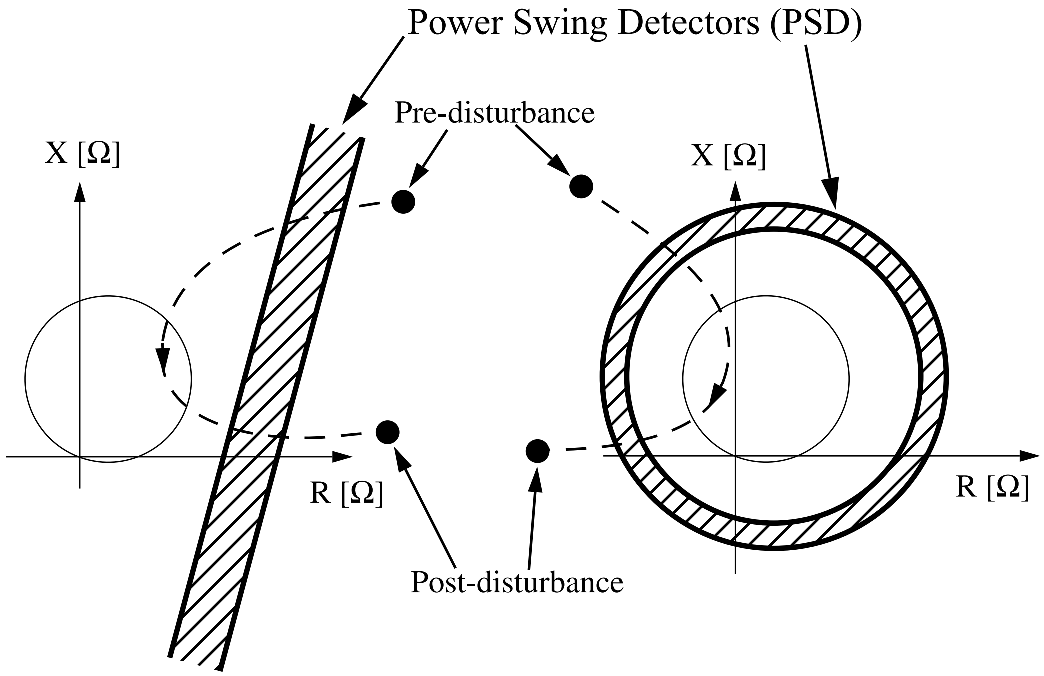

Figure 4.7 Vertical and circular characteristics for Power Swing Detector schemes. Additionally the dashed lines indicate trajectories for the apparent impedance during a power swing. The left scheme is operated at the sending end of a line and the right scheme is located at the receiving end of a line.

Basically the method uses the feature that the movement of the apparent impedance during power swings is slow as compared to its movement for short circuit faults. Figure 4.7 shows two different characteristics of Power Swing Detector (PSD) schemes. When the apparent impedance penetrates the outer circle or line of the PSD schemes a timer is started. If the impedance crosses the dashed area very rapidly the PSD determines a short circuit fault and tripping is permitted. If the transition time for the apparent impedance through the dashed area exceeds the pre-set timer value, the tripping function is blocked during a certain time. Usually the pre-set value for the timer amounts to about 80 ms and tripping is blocked during a couple of seconds.

A circular PSD device is discussed in [67] where the inner circle is composed by the outermost zone of operation i.e zone 3. In order to cater for the fastest possible swings the outer circle is normally set with a reach as large as possible and consistent with load discrimination. However to achieve satisfactory performance the reference asserts that the outer circle should have a diameter of at least 1.3 times the diameter of the outermost zone of operation.

In some protection schemes the PSD is applied exclusively. This means that the distance relays will not operate due to stable power swings but neither the unstable power swings will be taken care of. Thus some device is needed as a supplement to the PSD to distinguish stable power swings from unstable ones so that adequate relay action can be obtained. This can be achieved by adding an additional circle (mho relay) or line (blinder) to the characteristics in figure 4.7. If the PSD has detected a power swing, the Out of Step Characteristic (OSC) is activated to decide if the swing is stable or unstable. The location of the line and circle related to the OSC in figure 4.8 is usually determined by simulating numerous power swings cases [35]. The impedance trajectory as seen by the distance relay for each of the stable cases is analysed. It will be found that all stable swings come no closer than a certain minimum distance from the origin in the RX-diagram. In order to detect unstable swings the OSC is usually given a position at a shorter distance from the origin than the minimum distance obtained from the simulations.

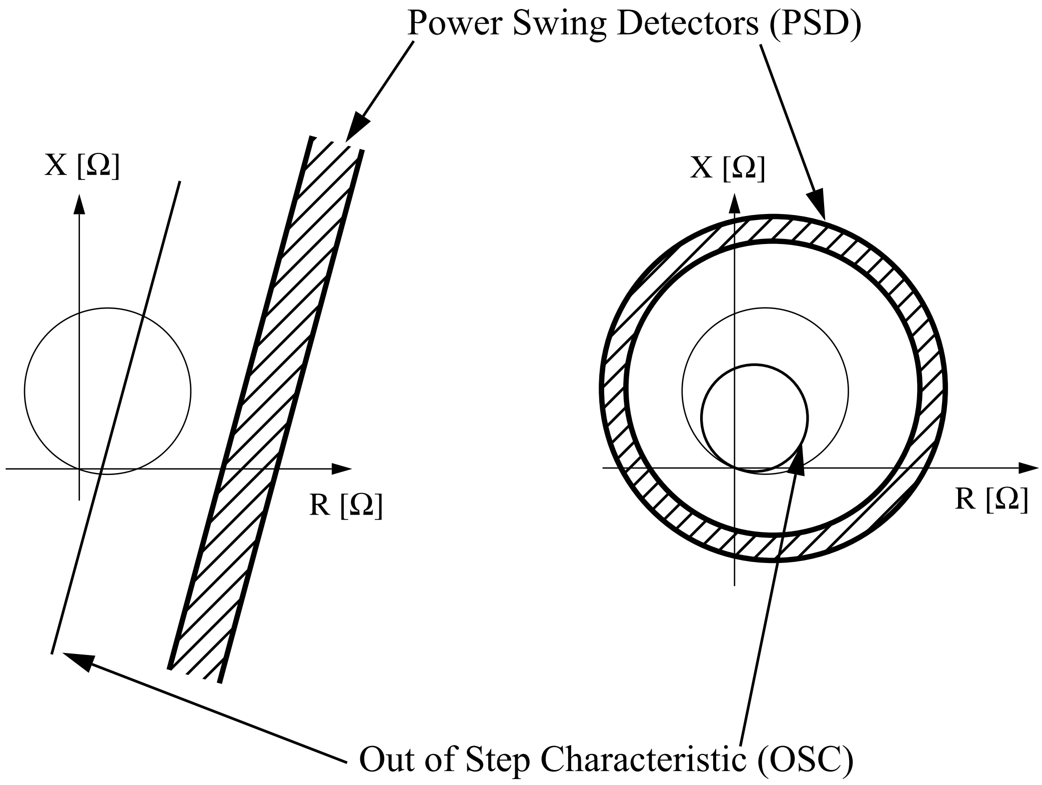

Figure 4.8 Power Swing Detectors and Out of Step scheme for relays located at the sending end.

When the PSD in figure 4.8 detects a power swing the distance relay waits for the apparent impedance to pass the OSC. If the swing is stable the OSC is not passed and the relay will not operate whereas if the swing is unstable the OSC will be penetrated and the relay initiates tripping.

In some cases it may be desirable to prevent tripping of lines at the inherent separation point and choose a separation point leading to balanced sub-systems. Other reasons for choosing a different separation point than the inherent one may be to save critical load or locate the separation to a corporate boundary. This can be achieved in a smooth and controlled way by using different system splitting schemes based on computer and communication devices.

A useful criterion to ensure stable sub-systems after splitting is to identify small inertia machines located electrically close to large inertia machines and perform islanding in such a way that these machines are grouped together.

As far as ”forced” system splitting is concerned it has been experienced that it may be beneficial to use relay devices based on the same algorithms for schemes were computer and communication devices are not applied. The main reason for this is to achieve a reliable coordination where all relays interpret the situation identically.

Sometimes the inner circle or the inner line of the PSDs in figure 4.7 is applied as the boundary for stable swings. When the apparent impedance passes the outer circle or line the timer is started. If the inner circle or line is penetrated shortly after the timer is started the device declares a short circuit fault. Alternatively if the inner circle or line is not passed the device declares a stable swing. Though if the inner line or circle is penetrated after the timer has expired the device signals an unstable swing. However depending on the system configuration around the relay this solution is not always applicable with respect to the tripping area among others.

Another aspect to keep in mind is that when settings are given to PSDs and OSCs is that tripping should be initiated for unstable swings but no load conditions should be picked up under any circumstances.

To ensure tripping in case of OSC failure it may be advisable to give the PSD a setting value where very fast swings are not blocked as they usually are unstable and these swings can be cleared by the zones of operation.

If the line flow is in both directions the PSD and the OSC must be duplicated; one application for sending and one for receiving operating conditions. The applications for the receiving operating condition look similar as for the devices in figures 4.8 but is located on the opposite side of the tripping characteristic.

Another way of avoiding mal-trips due to power swings is a restriction of the reach of the relay. For example, although mho relays have a smaller tripping characteristic than impedance and reactance relays, their zones of operation may be too large to avoid tripping of long lines during swings. In a two generator systems where swings up to 120 $^\circ$ are permitted, the mho characteristic is satisfactory for line impedances less than half the total impedance of the two generators. For lines with a greater impedance load blinders are usually used to restricted the reach of the relays. However, the probability of clearing high resistance faults is reduced with this method.

In the Swedish transmission system almost all Power Swing Detectors, except for a limited number serving some interconnections between Sweden and the other nordic countries, were taken out of operation in the middle of the seventies. To the author's knowledge no formal investigation was made and the decision was most likely based on the following arguments. As the transmission system recently had been reinforced power oscillations were not expected to cause any trouble. Therefore PSDs were not considered to be necessary. Additionally some doubts were addressed towards their operational reliability. However this decision perhaps should be reconsidered as the deregulation of the Swedish system has led to frequently occurring power flows for which the system originally was not designed. (Refer to chapter 1 and section 4.3.1.)

The system in figure 4.9 can be used to study the influence from the source impedance on the apparent impedance as seen by a relay located at bus T during power swings. In the system one generator is connected to an infinite system through a single transmission line. Two different swing loci as seen by the relay are generated (figure 4.10) where the ratio between the impedance of the transmission line and the source impedance is varied.

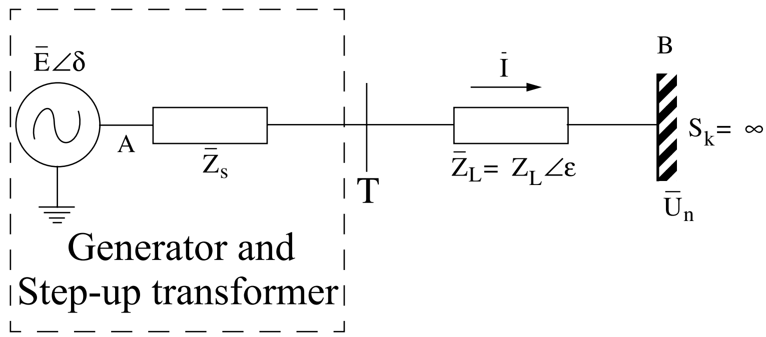

Figure 4.9 A generator connected to an infinite system through a transmission line.

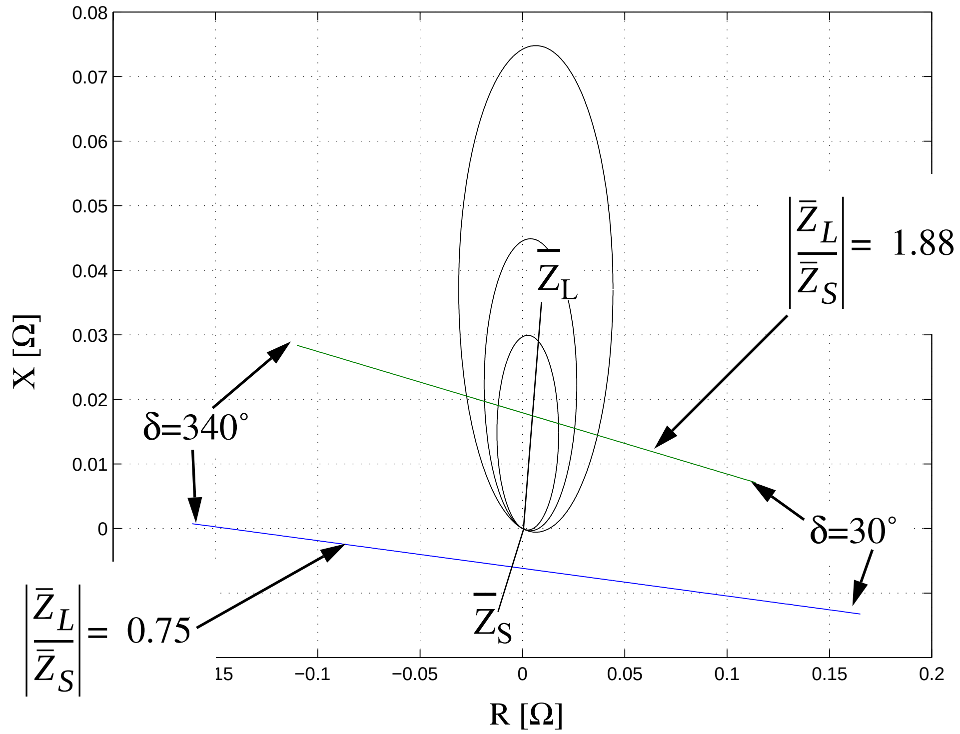

Figure 4.10 The apparent impedance trajectories as functions of the transfer angle δ for two different ratios of the relation between the line impedance and the source impedance as seen by the relay located at T in figure 4.9.

Figure 4.10 indicates that for generators connected to the main grid through a weak interconnection (high line impedance) the electrical centre may appear on the transmission line. However for generators connected via a strong grid the electrical centre will be in the step-up transformer or in the generator itself. Although power oscillations are mainly happening in case of weak connections, they may also be present in strong line configurations. Consequently the Power Swing Detector and the Out of Step Characteristic included in the line protection is not always capable to detect swings in case of this type of line configurations. To cope with this phenomenon the Generator Out of Step Protection is introduced.

Observe that this phenomenon is not a problem for all relays. Some (mho) relays inherently adjust their tripping zones with respect to the source impedance [68].

Not only the ratio of the source impedance and the line impedance contributes to a impedance trajectory through the step-up transformer or the generator. Also a low excitation level tends to contribute to such a condition. See the case $|E_A|<|E_B|$ in figure 4.2.

The Generator Out of Step Protection [69] operates similar to Out of Step Protection for transmission lines and is used to clear unstable swings when the electrical centre is within the generator or step-up transformer.

During an out of step condition the related generator meets large cyclic variations in currents and voltages and the frequency is a function of the rate of slip of its poles. The high magnitude of the currents and the frequency deviation can result in winding stresses and pulsating torques that can excite potentially damaging mechanical vibrations. Additionally the auxiliaries may be lost for the affected machine and for nearby stable machines. To avoid these adverse effects on the affected generator and the surrounding system it is desirable to have an out of step protection that will trip the unit. Additionally it is important that the disconnection of the unit is restricted to tripping of the circuit breaker and not does shut down the entire unit. This proceeding leads to a minimum outage time as the generator can be resynchronized as soon as conditions stabilize.

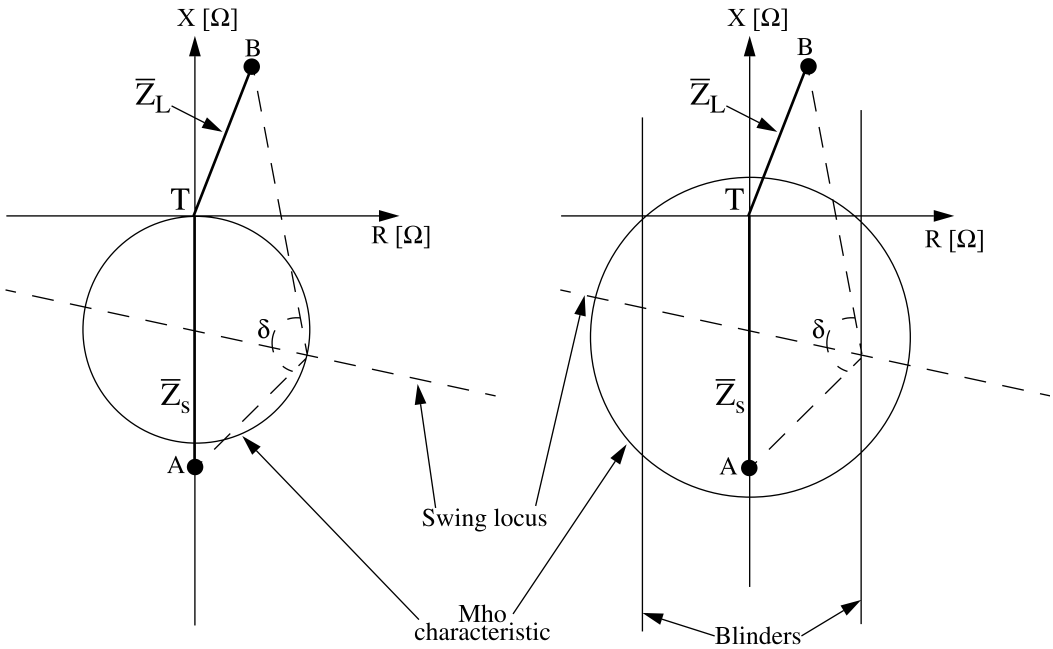

Figure 4.11 Two types of Generator Out of Step Protection schemes located at bus T in figure 4.9.

In figure 4.11 two different schemes of Generator Out of Step Protection are shown. In both applications a reversed mho relay (the relay reach into the generator) located at bus T in figure 4.9 monitors the apparent impedance.

For the left scheme the relay immediately trips the generator when the apparent impedance enters the mho characteristics. The size of the mho characteristic is chosen such that the angle δ is about 120 ˚ when the swing impedance enters the relay characteristic. This setting usually ensures that only unstable swings leads to tripping. If the mho circle is too large the relay may trip the generator for stable swings whereas if the circle is too small the scheme may not trip the generator for unstable swings. Additionally if the mho circle is too small the tripping may occur when δ approaches 180 ˚. This should be avoided as it subjects the circuit breaker to the maximum recovery voltage during interruption. To minimize the probability of incorrect tripping due to loss of potential condition an overcurrent relay is sometimes used to supervise the mho characteristic.

In the right scheme two blinders are used together with the off-set mho relay. There are many possible ways of applying blinders but in the scheme referred to here the generator is tripped when the impedance locus is within the mho characteristic and crosses both blinders coincident with that the crossing time exceeds a pre-set value (typically 0.15 s). The right scheme offers more selectivity than the simpler left scheme. It is also easier to set the scheme so that circuit breaker operation is effected at a favourable swing angle. The time delay involved in detecting the out of step condition is easy to coordinate with the line protection. Hence the scheme can be set to see beyond the T bus into the line as indicated in figure 4.11. In figure 4.9 both the impedances of the generator and of the step-up transformer are included in Z_S and the relay is assumed to be located at T. However in certain applications it may be suitable to place the scheme at the generator terminal. Thus the impedance Z_S must be split into its two components and the origin of the RX-diagram in figure 4.11 is shifted downwards to the generator terminal point.

As intimated in the beginning of this section many approaches of Power Swing Detectors and Out of Step schemes have been proposed throughout the years. One reason is that the conventional schemes described in this section have their limitations and thus sometimes operate unsatisfactory. In section 4.2 a proposal is discussed which avoids most of the disadvantages analysed here.

4.1.2 The interaction between distance protection and other protection devices during transient stability

The most obvious interaction is between distance tripping relays, Power Swing Detectors and Out Of Step Protection. However usually these functions are all included in the same distance relay and may therefore be considered to be one device.

Protection devices may interact with distance protection during transient stability but this is much dependent on how the protection system is designed and intended to operate. The main interaction will be from protection devices operating within the same time domain as distance protection. For example, a 0.4 s delayed overcurrent relay may fairly easy be fooled to operate due to a power swing whereas the likelihood for activation of a 20 s delayed generator current limiter during transient stability is very low. The activation of the current limiter is considerably higher when the reset criterion for the associated timer is exclusively based on a single ”snapshot value” 20 s after the start of the timer. As compared to when the current continuously must be above the pre-set threshold during the 20 s to initiate current limiter activation.

During transient instability voltages, currents, power flows and the frequency oscillate and the magnitude of these quantities may reach high values. Hence protection devices based on these quantities operating within the same time domain as the distance protection are likely interaction candidates.

Operation due to power swings of protection devices intended to avoid equipment damages due to abnormal values of the associated quantities must be considered to be correct; of course under the condition that their timer settings are correct. Examples of this type of protection may be high and low voltage generator protection. However relay tripping of protection devices intended to protect equipment from short circuit faults e.g Under Impedance Protection for generators should be avoided during transient instability.

When impedance relays are used to clear internal generator short circuit faults (Under Impedance Generator Protection (UIGP)) they have a similar characteristic as the Generator Out of Step Protection in figure 4.11. This means that the UIGP application may interpret a power swing as a short circuit fault and initiate incorrect relay operation. Likewise Loss of Excitation Protection for generators based on an impedance relay may mal-operate due to power swings [57]. Similarly as for the Generator Out of Step Protection an extra mho characteristic or load blinders are used for both applications to restrict the reach of the relays and thus prevent incorrect operation.

Additionally there exist a few mechanical protection devices for generators that will interact with distance protection during power swings. An example is overspeed protection. As the protection scheme for generator stations vary widely, each station must be investigated individually to find out the most important interactors.

Usually the performance of differential protection is not affected by transient instability. An exception is if power oscillations lead to transformer saturation.

Sometimes low frequency load shedding may operate during transient instability. Usually the load shedding is initiated when the frequency is below a pre-set threshold during a certain time delay. The time delay should be larger than the longest possible time the frequency is below the threshold during a stable swing. In this way unnecessary load shedding can be avoided. Unplanned load shedding should be avoided during transient instability as the unbalance between generation and load demand in the system may increase and consequently the power oscillations may be aggravated.

Protection devices based on the derivative of the voltage, current, power and the frequency may also interact with distance protection during fast swings. This is mainly a concern for protection schemes based on the derivative of the frequency. Protection devices using the derivative of the voltage and current must be exposed to much faster changes to operate as will ever occur during transient instability. Usually the schemes using the derivative of the frequency protect the power system from collapse by initiating load shedding when the frequency decreases rapidly. These schemes are generally set to operate fast and to be activated when the system is near collapse. Consequently incorrect activation of these schemes due to stable power swings is not very likely. However if extremely fast swings occur in the system at the same time as the scheme is set to operate for relatively slow frequency changes then the scheme may be activated incorrectly.

4.2 A protection scheme to prevent mal-trips due to power swings

The contents of this section are published in condensed form as [II].

Transient instability in power systems generate power oscillations. These oscillations may cause unwanted tripping of distance relays. To prevent these mal-trips the distance relay is often combined with a Power Swing Detector (PSD). The conventional PSD introduced in section 4.1.1 usually measures the time it takes for the apparent impedance to travel through a pre-defined impedance area in the RX-diagram located outside the area of the zones of operation. Due to the varying cycle times of the power oscillations a satisfactory setting of the timer associated with the PSD may be difficult to obtain. In a yet unpublished CIGRÉ WG34.09 investigation several cases of incorrect PSD behaviour due to this phenomenon are reported. For long transmission lines difficulties may occur in choosing the location of the pre-defined PSD impedance area. As the operation point at peak load may be close to the boundary of the fault detector zone there may not be enough space for the impedance area of the PSD [61]. Hence a PSD which is not sensitive to the cycle time of power swings or the line length would be desirable. In particular the limitations of the PSD associated with line length are undesirable as power oscillations mainly occur on tie-lines and long transmission lines.

From a technical point of view correctly operating relays have obviously been an important issue throughout the years. However the issue grow even more important in a deregulated market. An incorrect outage of a transmission line may lead to advantages for competitors, penalty fees and an (unnecessary) absence of income. Unreliable relays may lead to situations where grid owners give their protection equipment narrow settings to avoid unwanted relay operations due to power swings. In some cases the settings may be too narrow and the relays will not operate for all possible fault conditions. In a broader perspective this behaviour may be a threat to system security.

Many relay solutions applied today have their origin in former technical hardware limitations and thus the possibilities given by new numerical and communication technologies are not always utilized to their maximum capacity. An example is the PSD based on the transition time through a blocking impedance area. As already mentioned the solution have not operated as desired several times throughout the years. Nevertheless it is still the main method used in numerical distance relays to prevent mal-trips due to power oscillations. As numerical and signal processing technologies develop, new electrical quantities may become attractive as relay inputs. For example, as the sampling frequency increases the derivative of electrical quantities may become a widely used relay criterion. Additionally the fast development of information technology in power system applications may lead to the launch of economical and reliable protection strategies based to a great extent on communication devices.

In modern numerical relays a computer software is used to create the operation scheme of the relay based on mathematical logic blocks. Hence unique solutions suitable for each user can easily be obtained. The PSD suggested here utilises this new user friendly relay approach and is incorporated in the relay algorithm. The algorithm is based on traditional distance relaying in combination with additional criteria. To initiate relay operation not only the apparent impedance has to be within the zone of operation during a pre-defined time but at least one additional criterion has also to be fulfilled.

4.2.1 Additional criteria for a distance relay algorithm

The criteria which may be combined with the conventional distance relay methods vary for different types of distance elements. For phase to ground elements the zero sequence current may be used. During unsymmetrical phase to phase faults a negative-sequence current will arise in the system and may therefore be a suitable criterion. However phase to phase elements must also be able to distinguish symmetrical three phase faults. A criterion associated with a negative- or zero-sequence current will not achieve this demand and therefore another method is introduced below.

The fundamental behaviour of the phase angles of the voltage and current at the sending end of a transmission line immediately before and after a three phase short circuit fault is briefly studied using the small power system in figure 4.12. During normal operation the voltage V and current I are given as in (4.5) and (4.6).

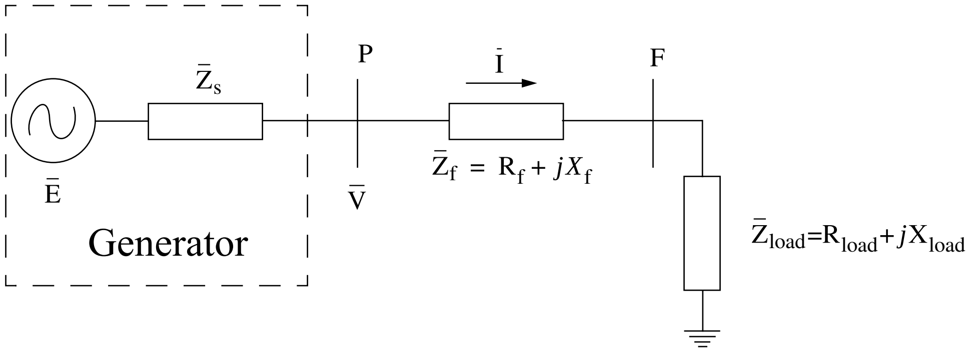

Figure 4.12 A small transmission system during normal operation.

$$\bar{V} = \frac{\bar{Z}_f + \bar{Z}_{load}}{\bar{Z}_s + \bar{Z}_f + \bar{Z}_{load}} \cdot \bar{E} \approx \bar{E} \qquad \forall \begin{Bmatrix} \bar{Z}_{load} \gg \bar{Z}_f \\ \bar{Z}_{load} \gg \bar{Z}_s \end{Bmatrix} \tag{4.5}$$

$$\bar{I} = \frac{\bar{V}}{\bar{Z}_f + \bar{Z}_{load}} \approx \frac{\bar{V}}{R_{load}} \qquad \forall \begin{Bmatrix} R_{load} \gg X_{load} \\ R_{load} \gg X_f \gg R_f \end{Bmatrix} \tag{4.6}$$

When a three phase fault occurs at node F the voltage and current can be written as in (4.7) and (4.8). The voltage at the fault location is assumed to be zero when the fault is present.

$$\bar{V} = \frac{\bar{Z}_f}{\bar{Z}_s + \bar{Z}_f} \cdot \bar{E} \sim \bar{E} \qquad \forall \begin{Bmatrix} X_f \gg R_f \\ X_s \gg R_s \end{Bmatrix} \tag{4.7}$$

$$\bar{I} = \frac{\bar{V}}{\bar{Z}_f} \approx \frac{\bar{V}}{jX_f} \qquad \forall \{X_f \gg R_f\} \tag{4.8}$$

Immediately before and after the fault the phase angle of the internal generator voltage may considered to be the same. Accordingly (4.5) and (4.7) show that the phase angle associated with the voltage V will not change significantly. When the fault occurs the system impedance as seen at P instantaneously changes from a primarily resistive to a primarily reactive impedance. Hence the phase angle associated with the current will make a substantial change as can be seen from (4.6) and (4.8).

Observe that these assumptions are not always applicable. The fault impedance will never be zero for a real short circuit fault although the approximation is often applied in EHV studies. Additionally the assumptions made in (4.5) and (4.6) are not true for all line configurations and load conditions.

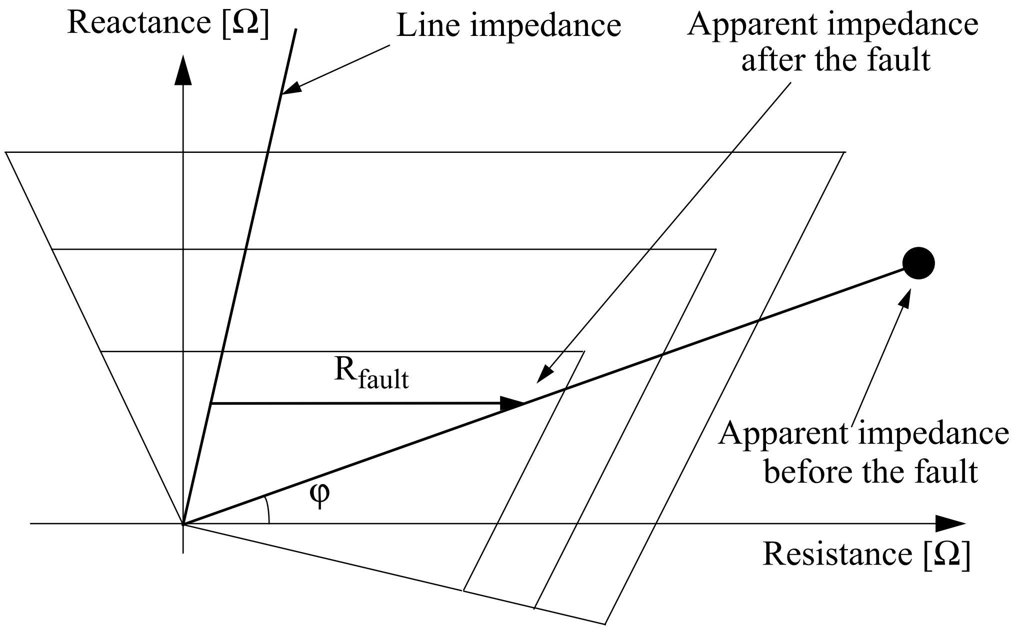

Figure 4.13 Possible behaviour of the characteristic angle φ of the apparent impedance as seen by a distance relay during a three phase short circuit fault.

In case of some specific relations between the pre-fault operating point, the fault location and the fault impedance, the characteristic angle φ of the apparent impedance as seen by a distance relay may not change during a fault; see figure 4.13. Hence the phase angle associated with the current will not change either. However as the fault impedance is usually a resistance of a few ohms this behaviour will mainly occur for fault locations close to the relay. Fortunately the closer the fault occurs to the line terminal the larger the fault current will be from nearby generators. Hence the fault impedance will also for this application be negligible in many cases [71] and thus the phase angle associated with the current will change substantially for nearby faults as well.

For relays located at the receiving end of a transmission line the current usually will switch direction when the fault occurs and thus the phase angle will change approximately 180 degrees.

Power swings are phase symmetrical events with fairly long cycle times. Accordingly the derivative of the phase angle of the current can be used as an additional criterion in a distance relay algorithm to distinguish symmetrical three phase faults from power swings. However, as shown in figure 4.13 the criterion performs better the larger the fault distance. Therefore the criterion is particularly suitable for zones 2 and 3 distance protection. To cope with nearby faults in zone 1, when the fault impedance is not negligible, the criterion may be used in combination with pilot relaying. Alternatively the criterion is only applied for the time delayed zones as power swings are rarely a major concern for zone 1 elements. In fact if power swings are so severe that the zone 1 is entered it may be advisable to trip the circuit breaker and split the system.

When a three phase fault occurs in case of an open line situation or a pure reactive load, the phase angle of the current will not change significantly. However for these operating conditions power oscillations are not a major concern. Therefore the conventional distance relay method can be applied to these cases whereas a method based on the derivative of the phase angle of the current is used for operating conditions associated to power oscillations. The appropriate choice of the correct method can easily be determined by adaptive relaying.

Our intention is to introduce a new criterion to distinguish symmetrical three phase faults from power swings and explain its fundamental behaviour. Therefore we will assume zero or negligible fault impedance from now on.

4.2.2 A momentary distance relay algorithm

In figure 4.14 an algorithm for a zone 1 phase to phase relay is proposed. To initiate a trip signal not only the apparent impedance has to be within the zone 1 of operation of the traditional distance element, but at least one of two additional criteria has to be fulfilled.

The quantities marked with the subscript Set are assigned a fixed value by the relay operator. The remaining quantities are continuously updated by the relay during operation.

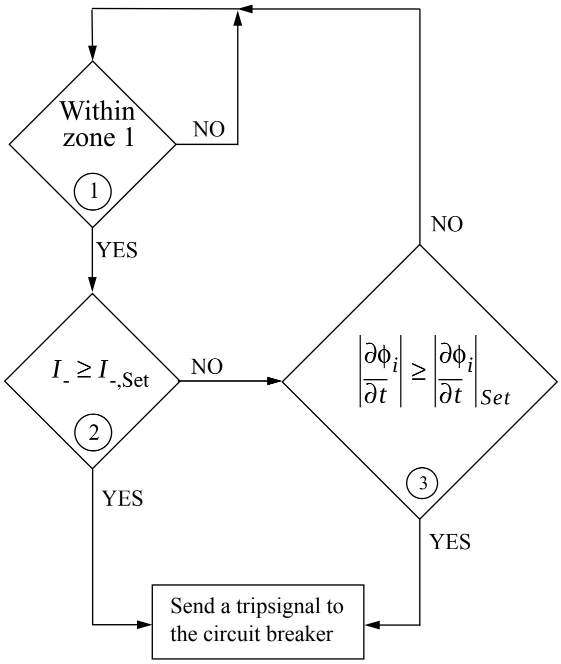

Figure 4.14 Zone 1 algorithm for a phase to phase distance relay.

Block 1 consists of the traditional zone 1 distance protection function. When block 1 signals a fault blocks 2 and 3 are applied to verify that a short circuit fault and not a power swing is the reason for the YES signal out from block 1. Verification is carried out by comparing the fixed values of the quantities with the values continuously updated. When the updated value in a block exceeds the fixed value the trip signal is initiated. By studying the negative-sequence current block 2 examines if an unsymmetrical fault is the reason for the activation of block 1. If not, a final check is made in block 3 to validate if a symmetrical three phase fault has occurred using the criterion based on the derivative of the phase angle of the current.

In the case of a phase to ground element the criterion in block 2 is replaced by one based on the residual current and block 3 may be eliminated.

4.2.3 Time delayed distance relay algorithms for single and parallel lines

For the introduction of the time delayed algorithms zone 3 is studied where the traditional zone 3 blocks are considered to cover the whole length of all adjacent sections. However the operation characteristics are similar for the zone 2 algorithms, except for the reach of the traditional distance elements and the timer settings.

First consider a case where the circuit between relay C and relay D in figure 4.15 has been removed by a fault. Thus a system consisting of two subsequent single transmission lines is studied where the algorithm in figure 4.16 is applied for relay A.

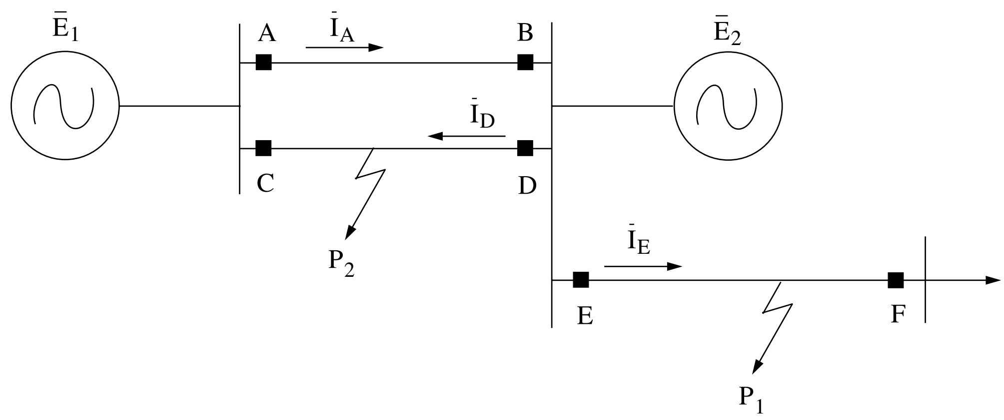

Figure 4.15 A system including remote back-up protection.

When a phase to phase fault occurs at P_1 the traditional distance element of both the main protection at E and the remote back-up protection at A will be entered. Additionally the relays will experience at least one of the following events: a high peak of the derivative of the phase angle of the current or a negative-sequence current. Hence the timer in block 4 will be started and the algorithm will begin to alternate between blocks 5 and 6, waiting for the main protection E to clear the fault. However if the main protection fails, the algorithm will send a trip signal when the criterion in block 6 is fulfilled.

In case the fault is cleared by the main protection the apparent impedance will leave zone 3 for relay A. Assume that a power swing occurs as a consequence of the grid weakening and the apparent impedance again enters zone 3. This time no high peak of the derivative of the phase angle of the current or negative-sequence current will arise and accordingly the out signal from blocks 2 and 3 will be NO. Thus the timer in block 4 is not started and the algorithm will continue to wait for a true short circuit fault.

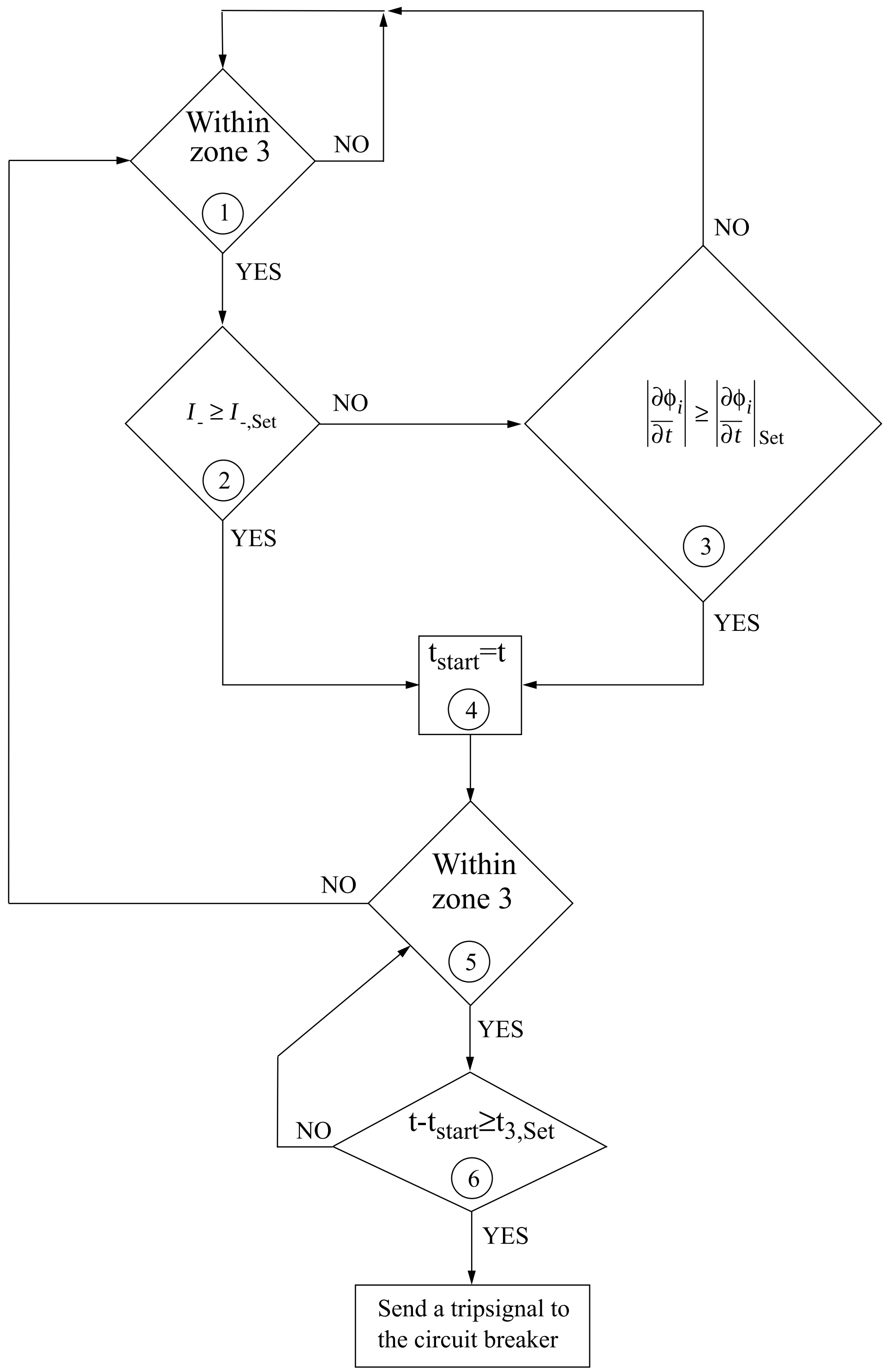

Figure 4.16 Zone 3 algorithm for a phase to phase distance relay protecting two subsequent single lines.

In the case of parallel lines the algorithm in figure 4.16 needs some modification in order to operate properly. The main reason for this is that the derivative of the phase angle of the current as seen by relay A is strongly dependent on the location of the fault P_2.

Simulations were performed for the grid configuration of figure 4.15, varying the fault location along the line between the relays C and D. It appeared that for a fault close to relay C the relay A experienced a positive derivative of the phase angle, whereas the derivative was negative in case of a fault close to relay D.

This behaviour can easily be understood by studying three different fault cases for the system in figure 4.17 composed by two identical lines interconnecting two identical systems. In the first case the three phase short circuit fault is applied directly outside terminal 1 on the line parallel to the line protected by relays K and L; in case 2 the fault is applied directly outside terminal 2 on the same line. In the third case the fault is applied in the middle of the line protected by relays M and N. For these three cases the Thevenin theorem is used and the fault current as seen by relay K is studied.

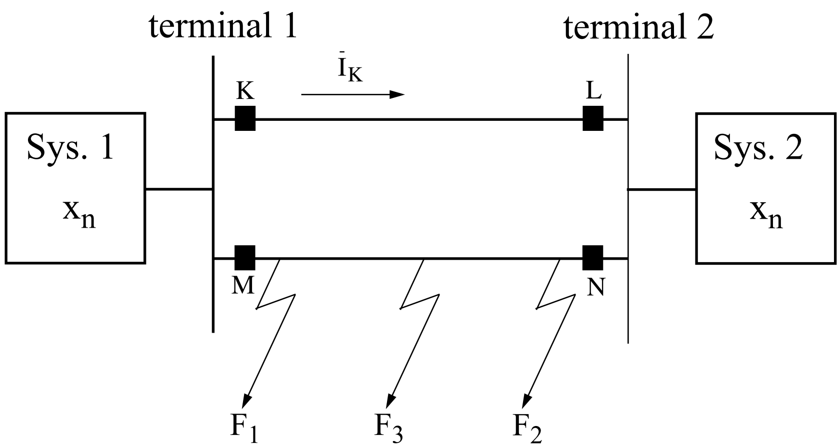

Figure 4.17 Small system including two identical systems interconnected via two identical parallel lines. F_1 is located close to terminal 1 and F_2 close to terminal 2. F_3 is located in the middle of the line. x_n is the short circuit impedance for Sys.1 and Sys.2 respectively.

An approximate pre-fault current as seen by relay K during normal operation is given in (4.9). In the Thevenin networks below, U is the pre-fault voltage at the fault location and x_l is the line reactance.

$$\bar{I}_{K,\text{pre-fault}} \approx i\angle 0° \tag{4.9}$$

The total fault current through relay K is the sum of the pre-fault current and the Thevenin fault current as given in (4.10) where the pre-fault current usually is neglected.

$$\bar{I}_{K,\text{fault}} = \bar{I}_{K,\text{pre-fault}} + \bar{I}_{K,\text{thev}} \approx \bar{I}_{K,\text{thev}} \tag{4.10}$$

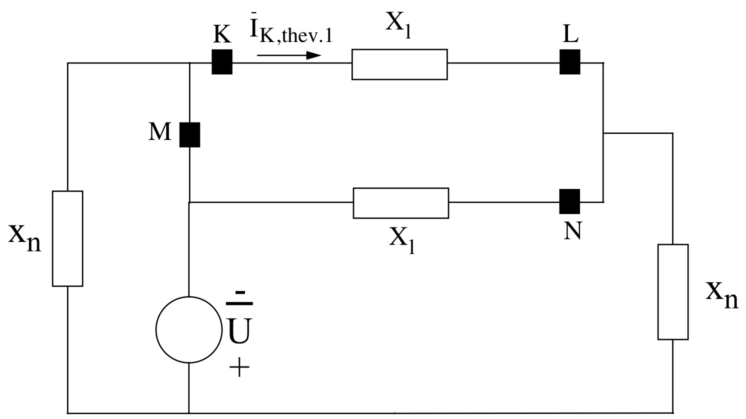

Figure 4.18 Thevenin network for fault location F_1.

Figure 4.18 can be used to calculate the fault current as seen by relay K when the fault occurs at F_1. When the pre-fault current is neglected the fault current for this case is given as in (4.11).

$$\bar{I}_{K,\text{fault},1} \approx \bar{I}_{K,\text{thev}.1} = -\frac{\bar{U}}{j\left(x_n + \frac{x_l}{2}\right)} \cdot \frac{1}{2} = \frac{\bar{U}}{2x_n + x_l}\angle 90° \tag{4.11}$$

Similarly figure 4.19 may be used to describe the fault current through relay K when the fault is located at F_2. For this fault location the current is given as in (4.12).

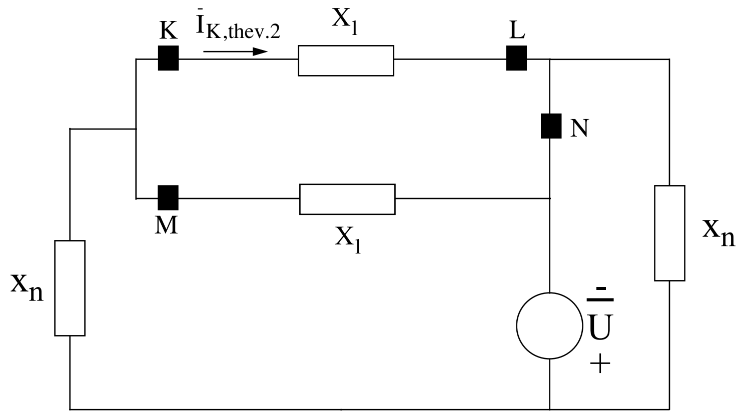

Figure 4.19 Thevenin network for fault location F_2.

$$\bar{I}_{K,fault,2} \approx \bar{I}_{K,thev.2} = \frac{\bar{U}}{j\left(x_n + \frac{x_l}{2}\right)} \cdot \frac{1}{2} = \frac{\bar{U}}{2x_n + x_l}\angle{-90°} \quad (4.12)$$

When (4.11) and (4.12) are compared to the expression in (4.9) the observations from the simulations are confirmed. Accordingly one may expect that somewhere along the line the fault current as seen by relay K will be in phase with the pre-fault current. By using figure 4.20 where the three phase fault is applied at F_3 this expectation is confirmed.

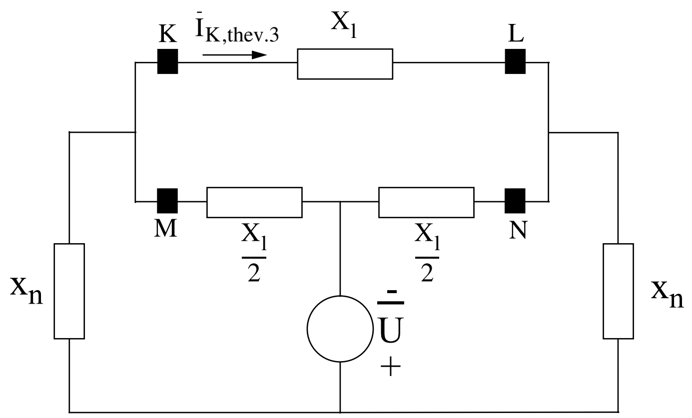

Figure 4.20 Thevenin network for the fault location F_3.

From the symmetry in the network in figure 4.20 we realize that the thevenin fault current $I_{K,thev.3}$ as seen by relay K will be zero. Consequently the total fault current in (4.10) is identical to the pre-fault current and thus the current as seen by relay K will not change its phase angle.

For the simple and symmetrical system introduced in figure 4.17 it is quite obvious that this phenomenon will occur when the fault is located in the middle of the parallel line. A similar behaviour will occur for all parallel line configurations. Though the particular fault location that result in no change of the phase angle as seen by relay K vary with respect to the surrounding system configuration. To overcome this problem an extra logic block is added to the algorithm of figure 4.16.

The suggested algorithm in figure 4.21 relies to a certain degree on communication devices. However conventional ”tripping” or ”blocking” communication techniques fulfil all necessary requirements; also the area of communication will be restricted to the substation.

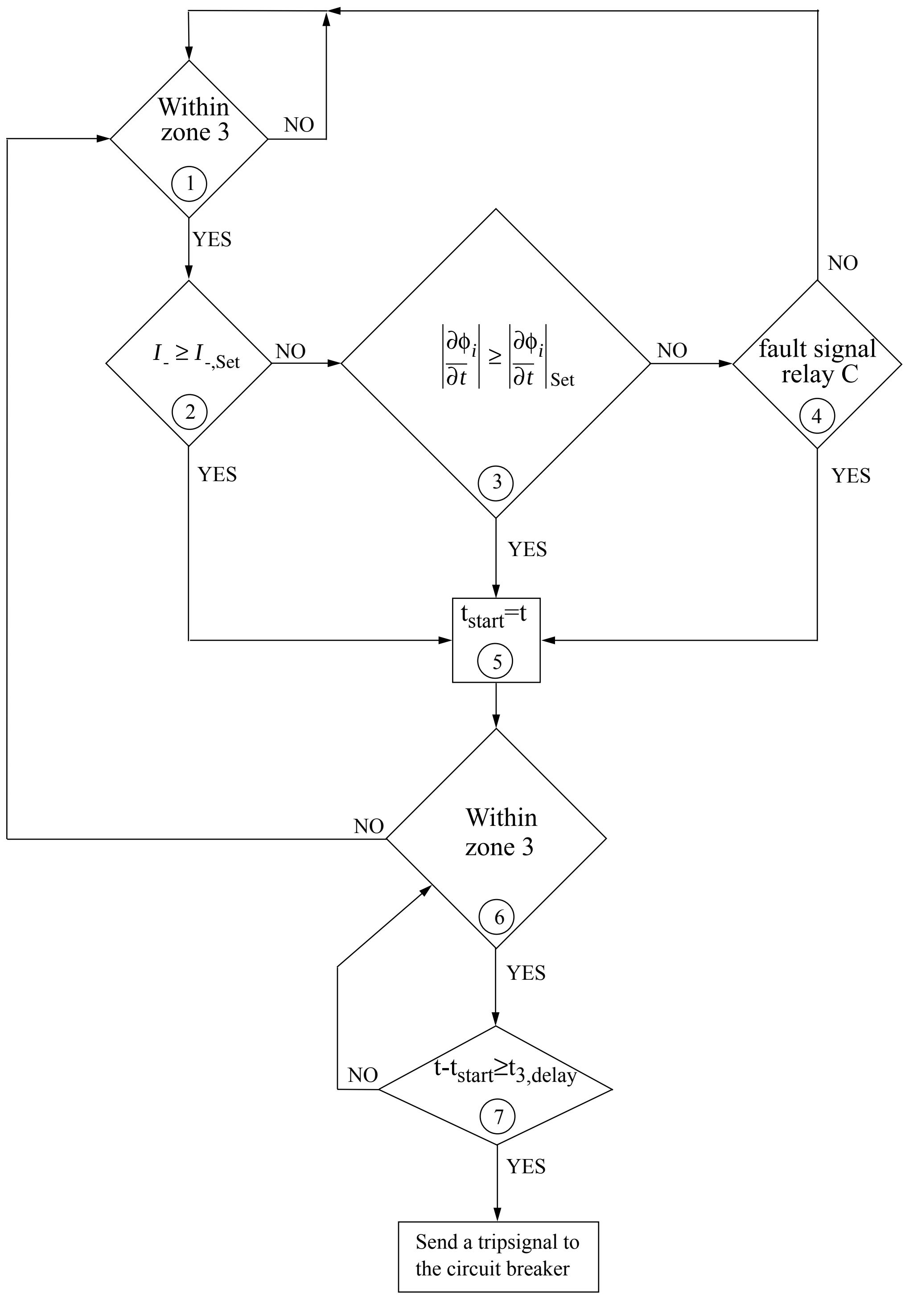

Figure 4.21 Zone 3 algorithm for a phase to phase distance relay serving parallel lines.

For faults located on the line between relay E and relay F in figure 4.15 the operation principle is identical for the algorithm in figure 4.21 as for the algorithm in figure 4.16. However as discussed a high peak of the derivative of the phase angle of the current will necessarily not be present when a fault occurs on the line between relay C and relay D. Therefore a signal used as an input in block 4 goes active when the timer in the zone 2 algorithm of relay C is started. For cases where the fault impedance for nearby faults can not be neglected the signal may also be activated when the zone 1 protection at relay C sees a fault. Hence a symmetrical three phase fault on the line between relay C and relay D where no high peak of the derivative is observed by relay A, will instead be distinguished in block 4.

When directional forward reaching distance elements are used the fault P_2 is not always instantaneously seen by relay A as the apparent impedance is dependent on the location of P_2 and the system configuration around the faulted line. In cases where the fault current is injected at relay A this phenomenon will not arise. However if the initial fault current is extracted at relay A its traditional zone 3 element may not be entered until relay C has operated. As the current switches direction and consequently the phase angle shifts approximately 180 degrees, both the traditional zone 3 will be entered and a high peak of the derivative of the phase angle will occur. Thus the algorithm in figure 4.21 will cope with this phenomenon.

4.2.4 Simulation in a eighteen bus system to analyse the performance of the algorithm

Simulations have been performed using SIMPOW [41] and the test system used is based on the grid already introduced in section 3.3. To this grid a small system consisting of a large hydro generator and a small load is connected through two transmission lines. The algorithms introduced above are implemented in Relays A and C where the traditional zone 3 elements are of the offset mho type and set to cover 185% of the line length.

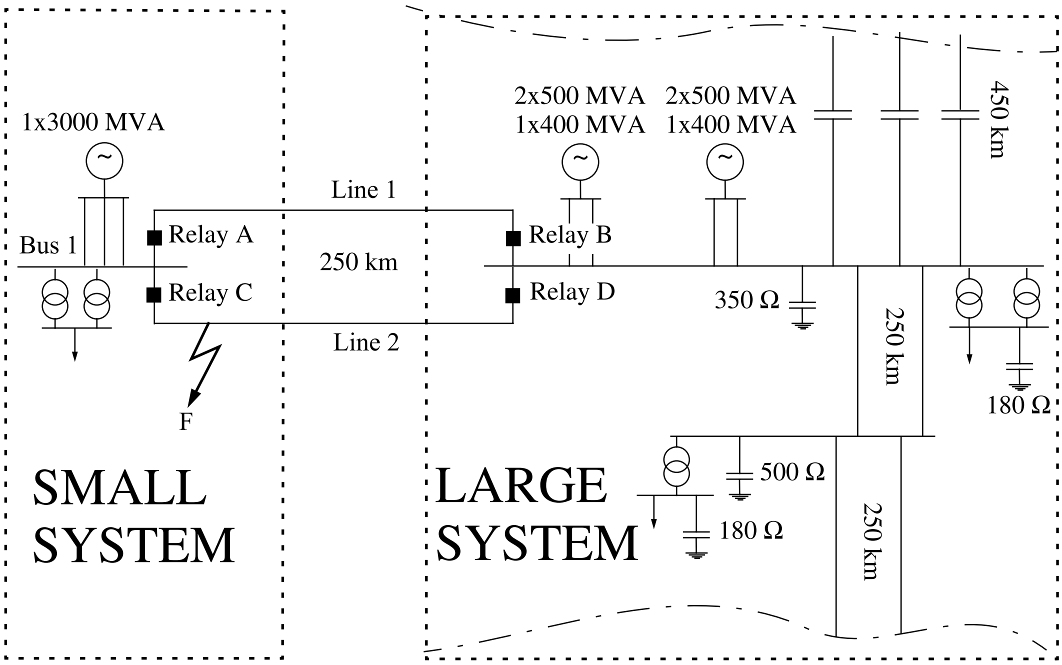

Figure 4.22 Test system.

Initially about 1800 MW is transported from the small system towards the large system. Five seconds after the simulation is started a symmetrical three phase fault with zero fault resistance occurs on Line 2, 50 km from Bus 1. The faulted line is disconnected by the main protection. Figure 4.23 shows the damped power oscillations occurring after the disconnection where the system eventually will return to a stable operating state. However if traditional distance relays without PSDs are used Line 1 will incorrectly be tripped by Relay A as the apparent impedance will stay within zone 3 for more than 1.2 seconds during the first swing after the fault clearance; see figure 4.25. Consequently the whole system will collapse approximately five seconds after the fault has occurred.

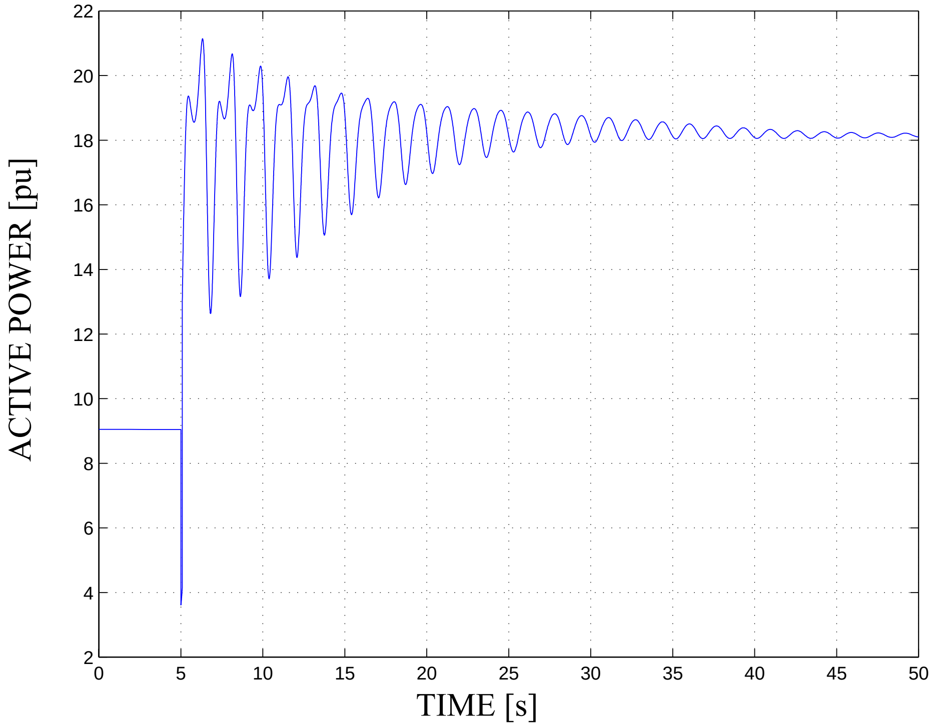

Figure 4.23 Active power injected at Relay A.

First we examine the operation of Relay C by studying the algorithm shown in figure 4.14. Immediately after the fault has occurred the apparent impedance will enter the traditional zone 1 element. At the same time the relay will see a high peak of the derivative of the phase angle of the current injected into Line 2; see figure 4.24. Hence the output signal from blocks 1 and 3 will be YES and a trip signal will be sent to the circuit breaker. The fault is cleared in 90 ms which is the total operation time for the relay and the circuit breaker.

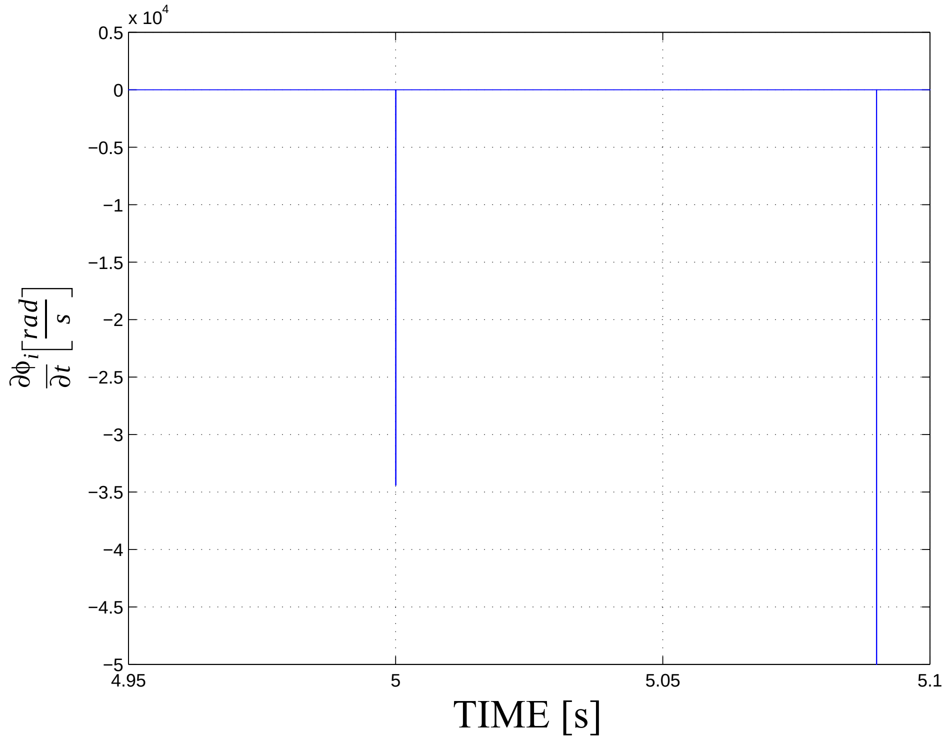

Figure 4.24 The derivative of the phase angle associated with the current injected into Line 2 at Relay C. The fault occurs at 5 s and the fault is cleared at 5.09 s.

In figure 4.25 the apparent impedance as seen by Relay A is shown. During the short circuit fault the conventional zone 3 mho element will not be entered. However some time after the disconnection of Line 2, zone 3 will be entered by the first power swing. The output from Block 1 in figure 4.21 will then be YES. The power swing is a phase symmetrical event, no high peak of the derivative associated with the current injected into Line 1 is present at 5.26 s in figure 4.26 and no fault signal is received from Relay C. Therefore the output signals from blocks 2,3 and 4 will be NO. The algorithm will not start the timer and no trip signal will be sent to the circuit breaker. Line 1 will not be tripped and the system recovers to a stable state.

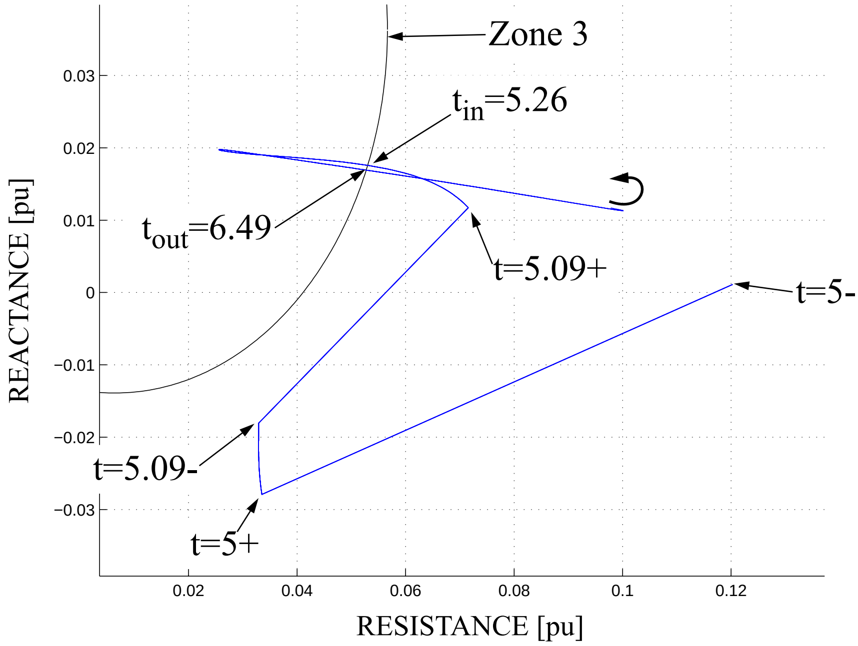

Figure 4.25 RX-diagram for traditional zone 3 element at Relay A. The different points of time are indicated in the figure where a minus sign refers to the moment immediate before the indicated time whereas a plus sign refers to the moment immediate after the indicated time.

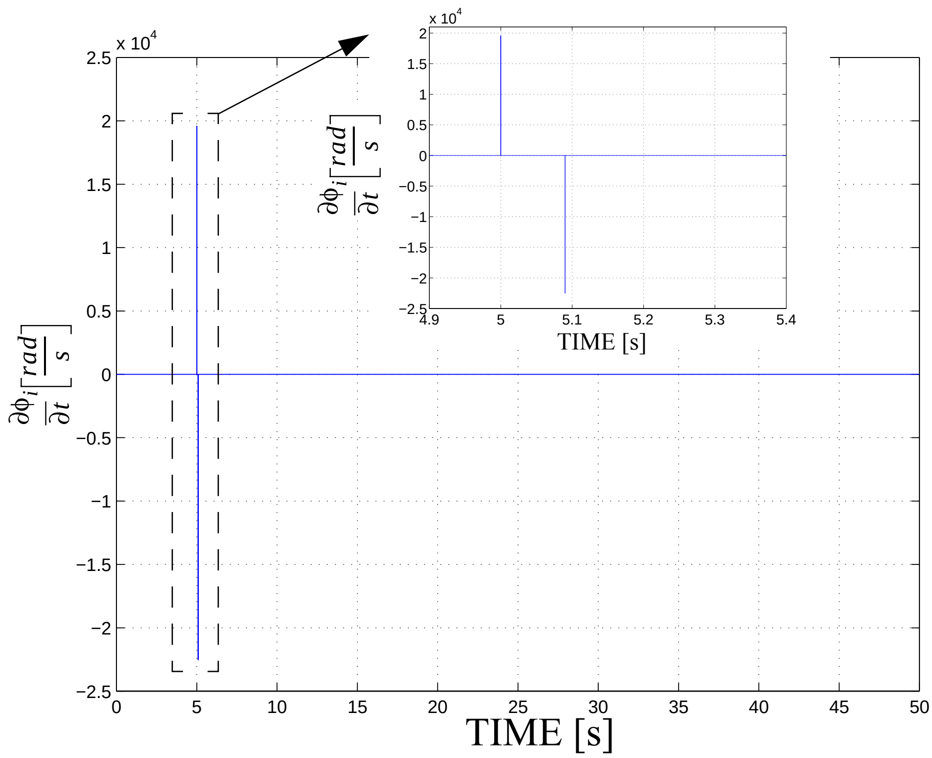

Figure 4.26 The derivative of the phase angle of the current injected into Line 1 at Relay A.

4.2.5 Discussion

In case of systems where the lines are untransposed a certain unbalance is always present. Still when a short circuit or a phase to ground fault occurs the unbalance increases significantly. Hence to increase the reliability of the algorithms proposed in case of this type of conductor configuration, the criteria based on the magnitude of the symmetrical component currents may be replaced by a criteria based on the derivative of the currents.

A question which may arise is: why not use the criterion based on the derivative of the phase angle of the current as the only criterion in the algorithms? Simulations have shown that the peak of the derivative of the phase angle of the current is considerably larger for a three phase fault as compared to faults involving two phases or one phase to ground. In order to obtain a high security the settings in the blocks associated with the criterion are made with respect to three phase faults. Apart from short circuit faults, there exist a few additional power system events associated with power oscillations that may have some influence on the phase angle of the current. For example if the settings are done with respect to other faults involving less than three phases there might be a few cases where the algorithms have difficulties to distinguish a power swing caused by load shedding or generator tripping from a long distance fault. The reasons why these events affect the phase angle of the current are as follows: during load shedding or generator tripping the phase angle of the current will not be much affected by the actual load or generation tripped as about the same relative amount of active and reactive power is removed. However as a new load condition may occur the phase angle of the current as seen by the relay may be altered due to the change in reactive power generated or consumed by the transmission line and/or adjacent shunt devices.

Events such as shunt and transformer switching may also affect the phase angle of the current. However such changes are usually less then in case of a short circuit fault and will most likely not occur in combination with an entrance of zone 3 due to a power swing.

An advantage of the algorithms proposed as compared to PSDs using the conventional method is that the short circuit fault detection function is never completely blocked. The algorithms also initiate tripping for short circuit faults which occur when the apparent impedance locus already is within the zones of operation but tripping has not been initiated as the entrance has been detected as a swing.

This is not the case for conventional PSDs where the tripping zones are blocked once the PSD has detected the swing. To unblock the tripping zones in case of conventional PSD applications different approaches are used. However usually the tripping zones are activated after a certain time delay; typically 3 - 60 s. Consequently the fault clearing time may be fairly long which may be aggravating when the system already is operating at an abnormal operating point.

Conventional Power Swing Detectors usually interpret a fault with a slowly decreasing impedance as a power oscillation and thus the fault is not cleared. The algorithms proposed here will only clear all unsymmetrical faults of this type. However pure symmetrical faults with a slowly decreasing impedance are very unlikely to occur.

Similarly as for the algorithm introduced in section 3.2 and for conventional PSDs numerous simulations of different power system events must be performed to find suitable values for the parameters in the algorithms in this chapter. Also here modern communication technology can be used for centralised calculation of settings and local in-service adjustments where a computer based network model may be used for on-line calculations. The relay settings can then continuously be updated to the prevailing power system condition.

Also for the algorithms introduced in this chapter the purpose is to demonstrate the principles of a new protection scheme. In case of actual implementation attention has to be paid to the same practical issues as mentioned for the algorithm in figure 3.4. Also when the algorithms are programmed some functions have to be added. For example the algorithm in figure 4.21 may need a short time delay between blocks 3 and 4 to adjust for the communication time.

4.3 Experience of distance relay operations due to transient stability

Unexpected relay performance due to power oscillations have occurred in several countries throughout the years. For example, July 27, 1989 in Portugal where a Power Swing Detector failed to operate and August 24, 1993, in Spain where three distance relays operated due to power swings (and voltage collapse) as the swings had a higher frequency than the effective range of the blocking unit. In this section we will describe a few cases to highlight the features of distance protection related to transient stability.

It should be kept in mind that although power swing recorders are used many cases of transient behaviour fall into oblivion as they do not lead to disturbances. Still a lot of knowledge can be obtained from these occasions as the performance of the protection system for actual system events are given. This information can further be used to increase the reliability as far as the protection system is concerned.

4.3.1 Distance protection operations in the Nordic transmission grid due to transient instability

In the database introduced in section 3.4.1 not a single distance protection operation is classified to be initiated by power swings. Still a few (the only) cases are described below where the distance protection had a significant influence on the course of events. Unfortunately events including power oscillations but not leading to a disturbance were not stored in the database between 1985 and 1998. However the general opinion is that power oscillations were not frequent in the Swedish transmission system during this period. From 1999 these occasions were also recorded in the database. Three cases were recorded in 1999 and seventeen in the year 2000. Observe that one recording may include more than one power oscillation event. The number of power oscillation events was about 50 in 1997 whereas in 2000 they were amounting to 300. However bout 30 % of the events recorded in 2000 were related to a specific maintenance job during a period of three weeks. None of these cases led to undesirable distance relay operation and all cases can be classified as inter-area oscillations with neighbouring countries.

The icicle on New Year 1997:

In the late evening of the New Years day 1997 an icicle caused a phase to ground fault in the substation Stenkullen [72]; figure 4.27. The busbar protection cleared the fault by tripping all devices connected to one of the busbars in the station. This led to that the (dashed) lines towards Strömma and Timmersdala were tripped.

Prior to the fault the load demand in Sweden was 20 000 MW and the system was operating at a normal operating point; the reserves were satisfactory and the regulation was about 7000 MW/Hz which is 1000 MW/Hz over the requirements. However almost all power generated in Ringhals 1 and 2 was transported in northerly direction on the line from Strömma towards Stenkullen. The power flow on the line between Strömma and Stenkullen was 1800 MW whereas the power flow from Lindome towards Strömma was about 350 MW.

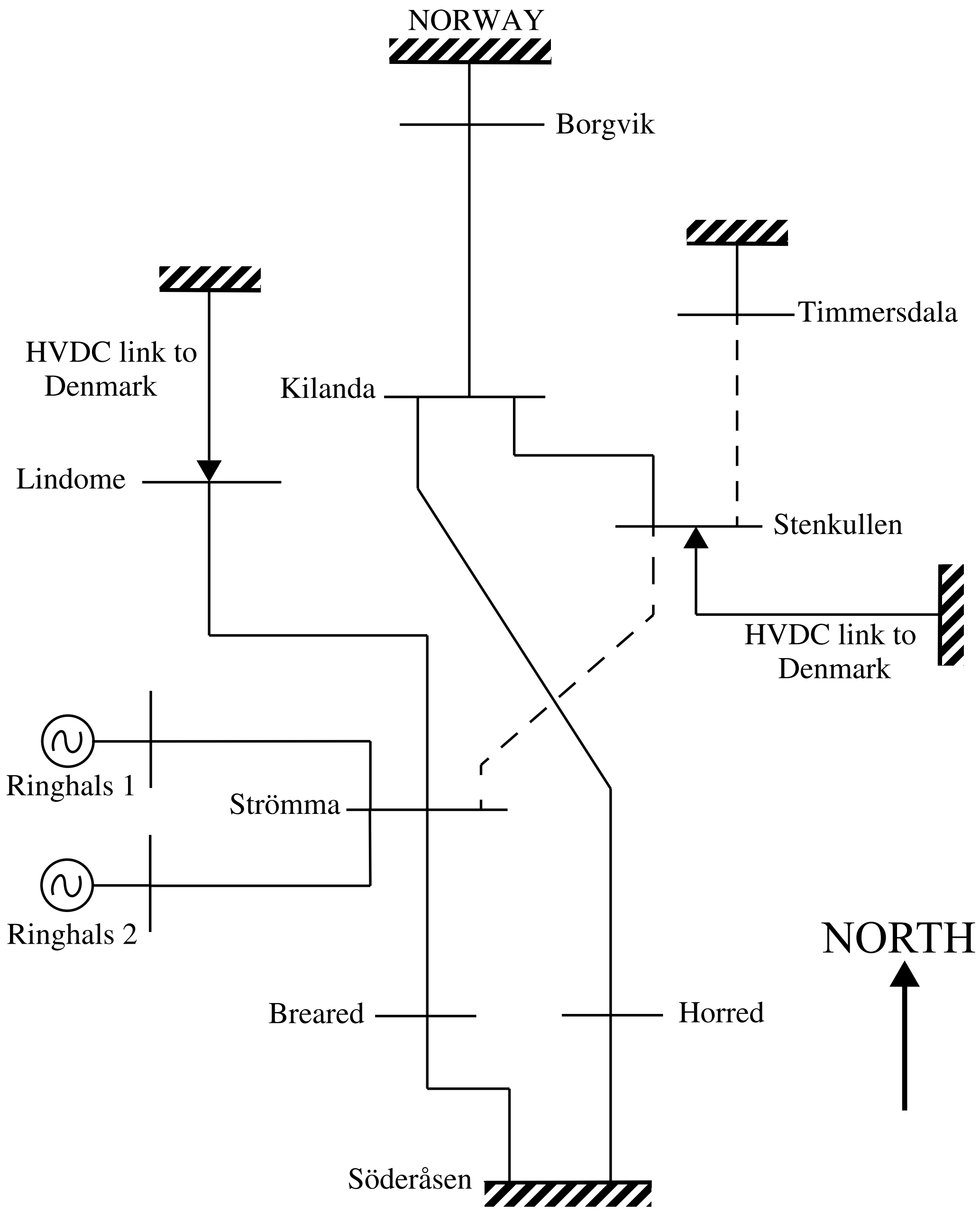

Figure 4.27 The 400 kV lines involved in the New Year 1997 disturbance in the Swedish transmission system. The dashed lines were tripped due to the initial phase to ground fault in Stenkullen.

When the two dashed lines in figure 4.27 were disconnected the power output from Ringhals 1 and 2 had to be redistributed towards Breared and Lindome. Consequently the power flow on the line between

Söderåsen and Breared switched from about 400 MW injected to 600 MW received in Söderåsen, as the generated power from Ringhals 1 and 2 had to flow via Söderåsen due to the prevailing grid configuration for further transport up North. The Ringhals generators started to swing against Norway, Finland and the island of Zealand leading to increasing power oscillations. Figure 4.28 shows the power flow on the interconnection between Sweden and Norway.

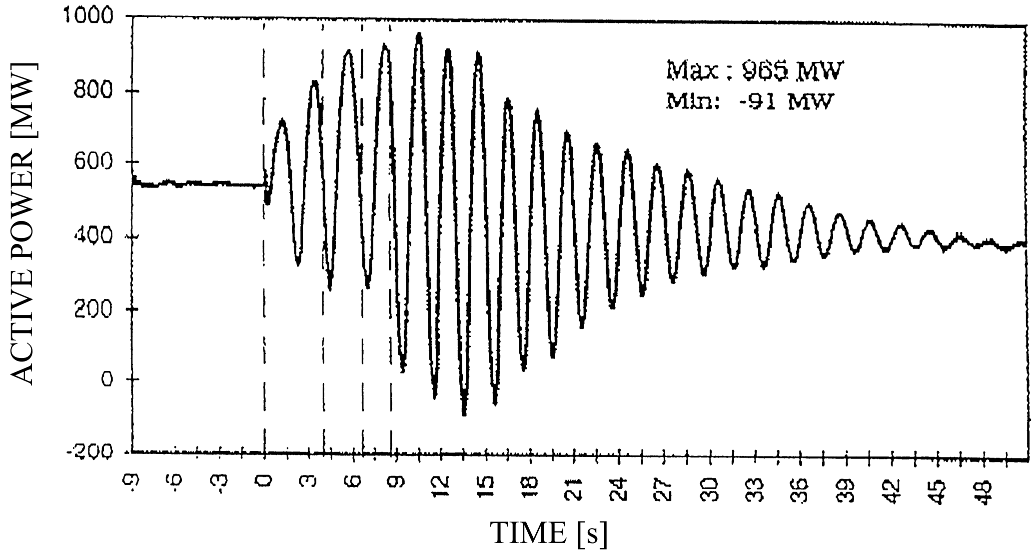

Figure 4.28 The power flow towards Norway at the Borgvik substation where the phase to ground fault in Stenkullen occurs at TIME equals zero.

When the generator output was redistributed the underlaying 130 kV system between Lindome and Stenkullen became overloaded (4-5 kA) and one line tripped and severed the connection. The 130 kV line was tripped 4.1 seconds after the initial phase to ground fault by the residual overcurrent protection set to 60 Amps. It may seem remarkable that the residual overcurrent protection operated but during overload condition a residual current may arise for current transformers connected in series which was true in this case. However, if the overcurrent protection had not operated the start element of the distance protection had activated and was about to trip the line within the same timespace.

As the grid was further weakened the oscillations increased and the voltage in Söderåsen temporary reached 340 kV. About 6.5 seconds after the initial fault the low impedance generator protection for Ringhals 1 operated during a moment of low voltage and high current.

Recordings showed that Ringhals 1 lost synchronism at the same moment.

At the same time as the low impedance relay for Ringhals 1 saw a fault the apparent impedance shortly entered the zone 2 for the sub 1 (mho) RYZKC relay in Horred protecting the line towards Kilanda but then moved out and continued to oscillate immediately outside the start zone. Fortunately the zone 2 timer never expired and thus the relay did not operate. Additionally the apparent impedance was very close to enter the zone 3 of the sub 2 RELZ 100 relay, luckily it never did so.

During the power oscillations the voltage in Strömma became almost as low as 100 kV. Low voltage in combination with high current led to tripping of the line between Ringhals 2 and Strömma about 8.3 seconds after the initial fault. The tripping of the line was initiated as the apparent impedance as seen by the RYZKC distance relay located at Ringhals 2 had decreased below 30 Ω which led to zone 2 tripping. Additionally when the line was tripped a remote tripping signal was sent to Ringhals 2 by the distance relay. Also the low impedance protection for Ringhals 2 had simultaneously sent a tripping signal but the distance relay operated faster. In figure 4.28 it can be seen that when Ringhals 2 was tripped the increasing oscillations became damped and the system recovered to a stable operating point.

In the investigation of the disturbance made by the regulator of the Swedish transmission system[1] it was concluded that all relay operations were correct.

In a similar way as the zone 2 for the relay in Horred was entered also the start zone for the distance relay located in Strömma protecting the line towards Breared was entered for a short period about 4.5 seconds after the initial fault. If any of these relays had operated the situation could have aggravated significantly. When the units Ringhals 1 and 2 were disconnected about 1700 MW generation was lost in the Nordel system. This generation loss was larger than what the active operation reserves are intended to handle. Imagine that one of the lines between Strömma and Breared or between Horred and Kilanda had been tripped. Consequently the 350 MW supported by the HVDC link entering Lindome had been cut and the rest of the Swedish system had faced an even larger generation deficit. Most likely the reserves had not been able to compensate for this extra lack of generation and the oscillations had propagated in the system. Consequently the

1. Svenska Kraftnät

disturbance would have been more extensive and simulations have actually shown that this scenario most likely would have led to a disturbance similar to the Swedish blackout in 1983. Fortunately in this case the apparent impedances were such that none of these encroachments led to tripping. Nevertheless it may be advisable to install Power Swing Detectors together with the associated Out of Step Protection on exposed lines to ensure a satisfactory splitting of the system.

The low impedance generator protection for Ringhals 1 and 2 is primarily operated as a back-up for the generator differential protection to clear internal generator short circuit faults. Inherently it may also provide protection against power swings. However this secondary effect is not considered when the settings are given to the relays. In fact the Ringhals units have no dedicated out of step protection but the generators are supposed to be disconnected by the nearby distance relays when they operate. This means that the line protection is expected to save the generators from power swings. However when the settings are calculated for the distance relays, out of step conditions are not considered but only encroachment due to overload. Consequently it may be concluded that no individual protection device is operated to preserve the Ringhals generators from power swings. Obviously the high and low voltage generator protection may operate during power swings. Still the purpose of the voltage protection is to preserve the generator from damaging voltages and therefore the generator will most likely not be tripped at the most efficient moment from a stability point of view which may lead to subsequent pole slipping.

The reason why the low impedance protection systems did not start simultaneously for Ringhals 1 and 2 was because they had different settings. The relay for Ringhals 2 had been given new settings after modernization of the protection system. The relay of Ringhals 1 had the greatest reach of the two and both relays included a part of the subsequent transmission lines. After the disturbance the settings of the low impedance relays were investigated and it was concluded by Ringhals personal that the reach of the relays should not be decreased. The primary purpose of the low impedance generator protection is to operate as back-up protection during internal generator short circuit faults, the performance of the relay will get worse if the reach is decreased. Additionally the disturbance could be considered to be extremely severe. Therefore the risk for undesirable disconnection of the Ringhals generators due to power oscillations is very low even for this relatively long reach of the relays.

One reason why a fault which the system is intended to handle led to such a serious disturbance where generation loss occurred exceeding the design criteria, may be that the main power transfer had the south north direction for which the system was not originally designed.

To prevent similar occasions in the future the following measures were suggested. A simple measure was to restrict the maximum allowed power flow on the line between Strömma and Horred. Using special protection systems one Ringhals unit can be tripped when the line between Strömma and Stenkullen is disconnected. Additionally when the line is tripped the power flow on the HVDC link to Lindome should be adjusted to the most favourable operating state. By these measures the active reserves were increased and the power support from the HVDC link entering Lindome is steered down to zero for similar occasions. Additionally the settings of the start zone for the relay in Horred were reassessed. As the apparent impedance had been oscillating for a long time directly outside the boundary of the start zone the reach was decreased.

Vietas November 14, 2000.

Before the disturbance the Nordel system operated at a normal operating point though the transfer sections in the northern parts of Norway were operating close to or at their limits. About 600 MW was transported from Vietas towards Porjus where the generators in Vietas contributed with 140 MW and 145 MW respectively. The output of the generator in Ritsem was zero and the Rana cross section operated at the maximum allowed load level for the current grid configuration amounting to 850 MW in the southern direction. The second transfer section composed by the Rana cross section plus the line between Ofoten and Ritsem transported about 50 MW less than the maximum limit of 1200 MW. For the latter transfer section the maximum power limit is 1200 MW when the minimum amount of possible generation shedding exceeds 250 MW in Svartisen. When this requirement is not fulfilled the maximum transfer level is 1000 MW.

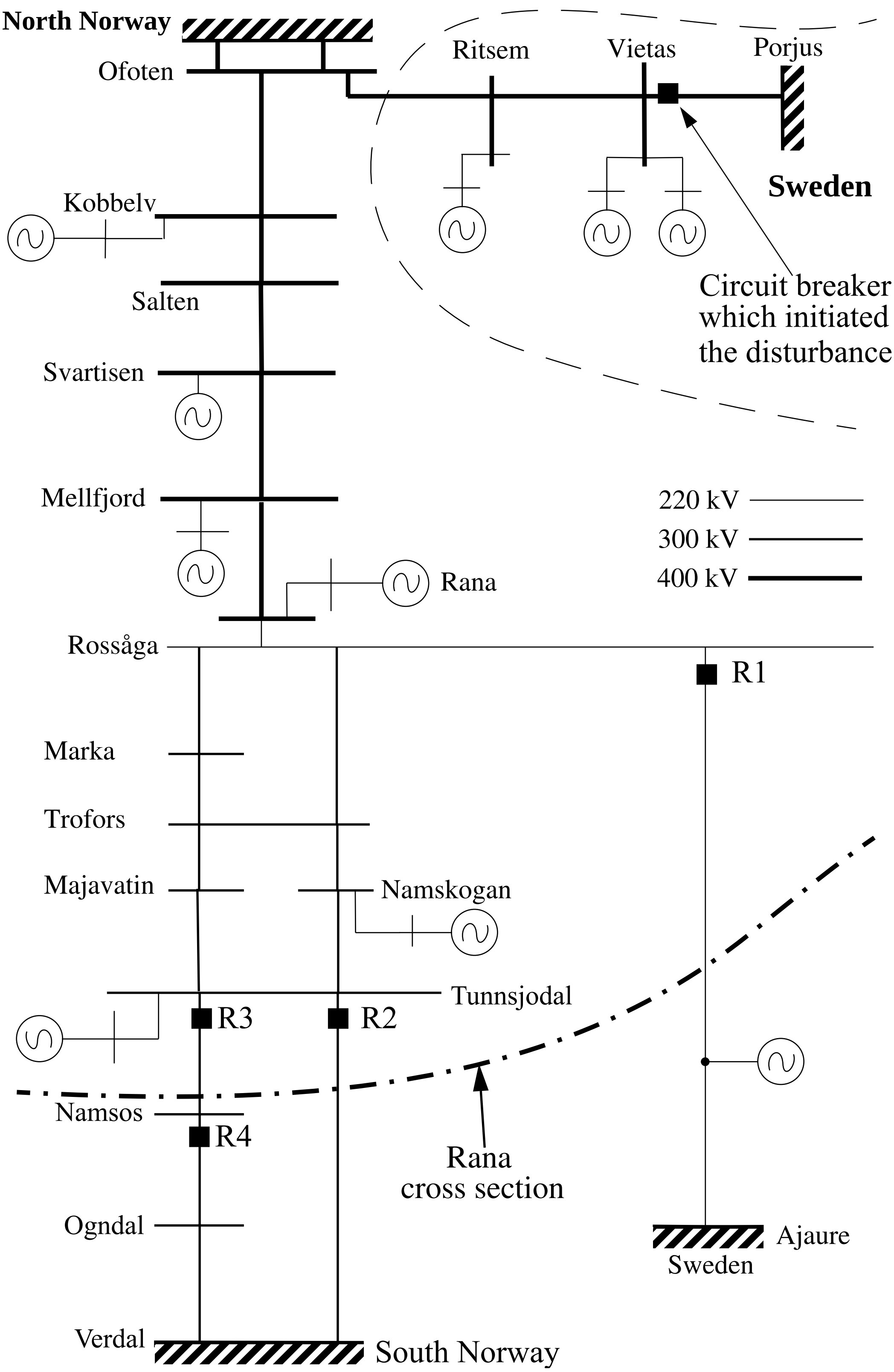

Figure 4.29 The lines involved in the disturbance November 14, 2000. The relays indicated with R1, R2 and R4 operated due to the power swings. Observe that the stations Nedre Rossåga and N.Rossåga are treated as one station called Rossåga.

As a result of work on the relay and control signal system at Vietas substation the circuit breaker on the line towards Porjus was opened. To avoid power oscillations when this line is tripped the Vietas generators are instantaneously disconnected to compensate for the weakened grid. However in this case the circuit breaker operation was not initiated from the distance relay but from the station monitoring and control system and therefore no tripping signal was sent to the generators. A large amount of power had to be redistributed and the power injected at Vietas towards Porjus was shifted over to Norway. The loading of the Rana cross section increased to about 1450 MW. Consequently severe power oscillations aroused which led to tripping of the 300 kV lines between Tunnsjodal - Verdal, Namsos - Ogndal and the 220 kV line between Rosshåga - Ajaure within approximately 1.2 seconds; see figure 4.29. Additionally the interconnection between Russia and Norway and one 130 kV line was disconnected. Hence the northern part of Norway was separated from the rest of the Nordel system having a large surplus of generation. The frequency reached 53 Hz in the northerly island and shortly brushed 49.57 Hz in the other part of the Nordel system. One 450 MW unit in Svartisen tripped due to high frequency about 2.5 seconds after the circuit breaker operation in Vietas. Additionally one unit in Vietas tripped due to high frequency 0.8 seconds later. These generator disconnections were beneficial for the restoration of the frequency, but still about 200 MW of industrial load was tripped in Verdal the by low voltage protection. In the Nordel system the frequency recovered to about 50.00 Hz within five minutes. To make resynchronization possible the generation was reduced in the northern part of Norway. However due to inadequate communication between the control rooms and insufficient information obtained by the control room operators the generation was increased in the Swedish part of the island which led to that about 350 MW was injected into Ofoten from Ritsem. Obviously this complicated the synchronization of the two systems. Additionally (due to lack of experience) the routines for the generation coordination during the restorative process worked unsatisfactory in Norway. About one hour after the initial event in Vietas the two systems were resynchronized by Swedish personnel through the connection between Vietas and Porjus and the entire system could be restored. Though at the same time the system was about to be resynchronized via Tunnsjodal and Namsos by control room personnel in Norway.

In the description of the performance of the protection system made below all times associated to the relay performance are obtained from simulations [73] whereas all tripping times are obtained from event recorders located in the system.

Immediately after the initial circuit breaker operation in Vietas the ABB RAZFE[1] distance relay R1 in Rosåga detected a power swing. The transition time through the Power Swing Detector area for R1 was 60 ms. This was related to the setting value of 25 ms which is the limit for the initiation of reduction of the generator output in Svartisen. The signal was sent to Svartisen and 950 ms after the circuit breaker operation in Vietas the line between Rosåga and Ajaure was disconnected due to zone 1 operation. The tripping zones of the R1 RAZFE relay operate for all swings and all short circuit faults which fulfil the criteria for tripping. The purpose of the Power Swing Detector included in the RAZFE device is to detect power swings with a cycle time larger than 25 ms and for these swings initiate power output reduction in Svartisen. The setting of 25 ms is fairly short related to the standard setting for the timer of the Power Swing Detector which is 40 ms. However a few years ago 25 ms was agreed to ensure fast detection of all (high frequency) power swings at the same time as all requirements concerning fault clearing were fulfilled.

RAZFE devices can distinguish power swings from a short circuit fault. However they cannot make a distinction between unstable and stable swings. One Siemens 7SL32 relay installed in Rosåga signalled for an unstable swing. The method used by the Siemens relay is similar to the application in figure 4.8 although the line representing the Out of Step Characteristic is composed by the reactance axis in the RX-diagram. Hence the relay works as follows; first the Power Swing Detector detects the power swing and if the resistance value changes sign then the swing is considered to be unstable whereas it is considered to be stable if the resistance value does not change sign. However although the relay signalled for the unstable swing the relay did not initiate tripping as the single time delayed zone was entered whereas the RAZFE relay initiated instantaneously tripping.

In the simulations both the ASEA REZ 1 and the Siemens 7SA513 relays located at R2 in figure 4.29 initiated instantaneous tripping about 1060 ms after the Vietas incident. However during the disturbance only the 7SA513 relay performed relay operation. The reason for the absence of a tripping signal from the REZ 1 relay is still not identified. Further simulations have shown that although Svartisen is momentary disconnected when the line between Rosåga and Ajaure

1. Quadrilateral distance relay equipped with a Power Swing Detector similar to the left one in figure 4.7.

is tripped the operation of R2 could not have been avoided.

The operation of R2 in Tunnsjodal and R4 in Namsos was almost simultaneously. The reason why R4 operated instead of R3 is most likely due to the relay settings. R4 is a RAZFE relay where the reach in resistive direction was set to 33 Ω/phase whereas the REZ 1 and 7SA513 relays at indication R3 were set to 20 Ω/phase and 15 Ω/phase respectively. As the RAZFE relay had the longest reach it operated first. In the simulations it can be seen that when zone 1 is entered for R4 the apparent impedance is still within zone 2 for the R3 relays.

All distance relay operations during the disturbance were concluded to be correct and as expected with respect to the settings. The incident has not led to any changes of the distance relay settings.

Simulations show that when the correct generator shedding is performed in Vietas the power oscillations are decelerated but still the system is splitted in a similar way as during the real disturbance. To maintain the system coherent instantaneous generator shedding is required in both Vietas and Svartisen when the initial circuit breaker operation occurs. This observation has led to some reflection among the experts concerning the generator shedding program. For example, today about 1800 A (935 MW) is required to initiate tripping of Svartisen from instantaneous overcurrent relays located at R2 or R3 whereas the current during the disturbance only approached 1400 A although the tripping of Svartisen was very desirable.

A limited number of Power Swing Detectors are applied in Norway. Mainly they are used to control remedial actions during abnormal conditions. Rarely the relay itself is used to block relay operation or distinguish unstable from stable swings. When the settings of the Power Swing Detectors are made the load impedance is carefully considered.

4.3.2 A typical transient instability case involving distance protection

The disturbance described in this section took part in the middle of the nineties in a transmission system on the African continent.

A current transformer exploded in the H station leading to a phase to ground fault (and a major fire). The fault was not cleared instantaneously and in a selective way by the busbar protection. This resulted in that the remote back-up zone 2 distance protection tripped all incoming 400 kV lines and consequently the whole 400 kV H station was permanently out of operation. Half an hour later an additional phase to ground fault occurred, this time in the G1 station. The fault was rapidly cleared by the busbar protection. Hence the infeed from transformer 1 in G1 was cut and also the line towards M. Obviously these occasions had weakened the grid between S and X significantly. At this stage the only remaining interconnections between S and X were the 400 kV line between E and K and the 275 kV lines from I to A and B. As the interconnection was very weak power oscillations developed leading 1.5 seconds later to zone 1 trips at L of both 400 kV lines towards N. The situation was seriously aggravated 1.1 seconds later when the third phase to ground fault occurred, this time at the G2 station. The busbar protection failed to operate as the fault current was too low and thus the fault was cleared by the distance protection in M operating on the single delay time zone. After this fault heavy oscillations of voltages and currents were present in the system. Three seconds later the lines Q-R, Q-Y and N-O were disconnected at R, Y and N respectively. Referring to the system operators all this lines tripped undesirable where the reason for the trips were inadequate power swing blocking. Thus X and S were separated and cascading outages followed. Although there was no generation shortage in the system some underfrequency load shedding was reported before the separation. The reason for this behaviour is still not clear. However one theory is that for one swing the frequency stayed below the pre-set threshold of the underfrequency relays during a time exceeding the associated timer setting.

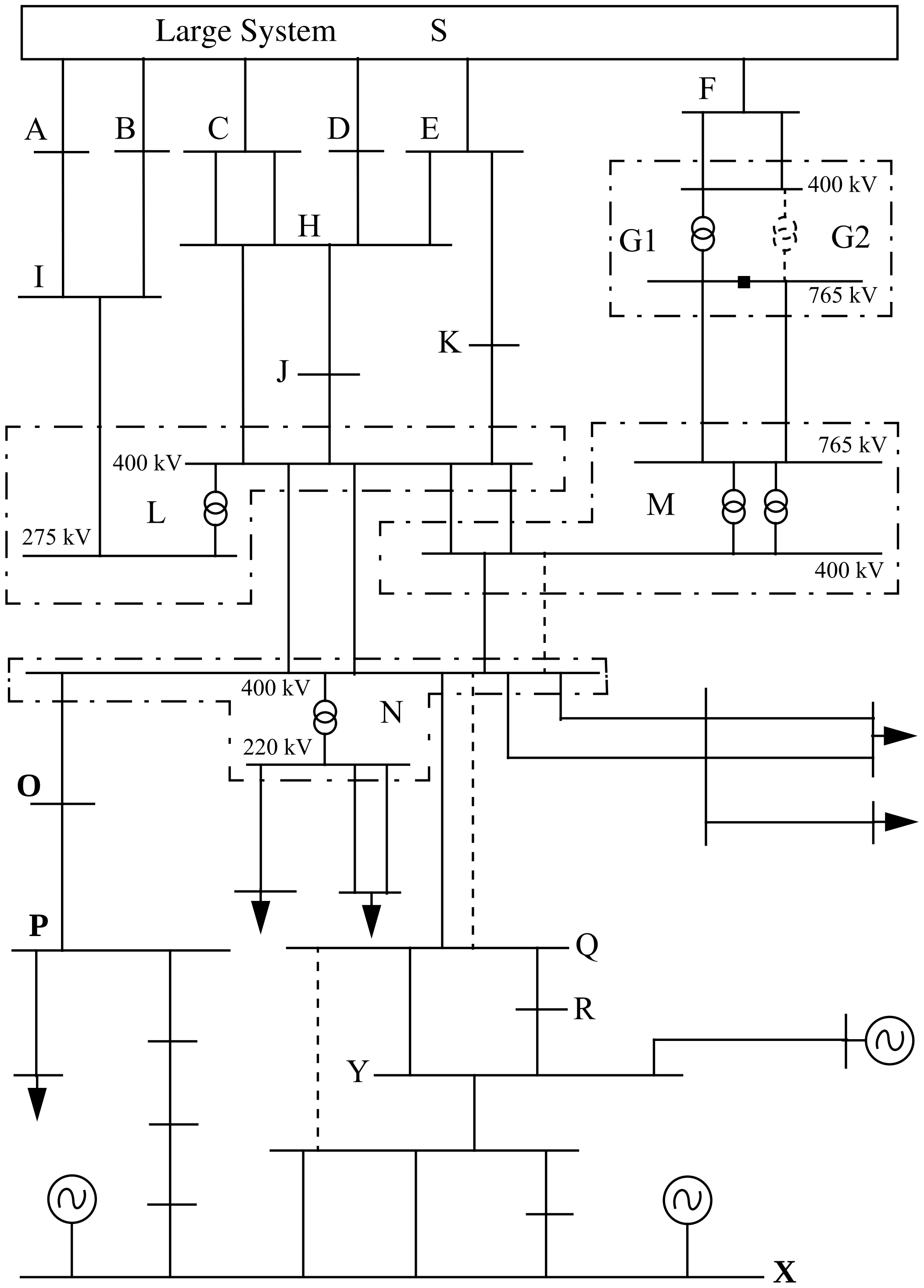

Figure 4.30 The grid involved in the African disturbance where the dashed lines were out of operation before the disturbance. Substations having more than one voltage level are framed.

The relays used were General Electric (GE) TLS 1000 with a modified (lens/tomato) mho characteristic and the digital quadrilateral/mho Siemens 7SA513 relay.

All operations of the distance relays due to power swings were correct in terms of their design and settings. However they did not perform as desired since effective power swing blocking was not achieved for the fast swings experienced (2.5 Hz). The Power Swing Detectors were of the classical type and the main reason for the ineffective blocking was the setting given to them. In fact the PSDs were set to provide blocking only for swing frequencies up to 1.2 Hz. The value 1.2 Hz was based on numerous dynamic simulations of cases which could lead to system instability. Additionally real cases had been studied which showed that faster swings never had been experienced in the system.

This disturbance was a multicontingency case. In fact the system survived the first contingency and was stable until the second event occurred which was at least a N-4 condition. Such a serious case had not been considered during simulations. Consequently similar as for the settings of the PSDs the locations of the Out of Step tripping relays were not adequate for this disturbance. They were situated much to close to X and were not able to detect the swings. None of them operated during the incident and consequently three unstable swings occurred.

During the first unstable swing (estimated to 1 Hz) zone 1 at L for the lines towards N was entered. The Siemens relays used the rate of change of the apparent resistance for power swing detection. The setting values based on 1.2 Hz were calculated with respect to the classical theory of impedance locus movement through the RX-plane during power swings. However the real rate of change of the resistance was higher and the relays of both lines operated. Simultaneously the apparent impedance entered zone 1 for the line between M and N. This line was equipped with a GE relay using the modified mho characteristic as Power Swing Detector characteristic and detects the swings through the rate of change of the impedance. This relay detected the swing and prevented tripping.

After the tripping of the two lines between L and N the interconnection between S and X was maintained exclusively by the 400 kV line between N and O. The swing frequencies increased from approximately 1 Hz to 1.85 Hz and the electrical centre moved closer to X. When the electrical centre moved closer to X the tripping characteristic of the Out of Set tripping relays was entered. However as the swing frequencies were higher than 1.2 Hz the associated PSDs were unable to detect the power swings and thus the Out of Step tripping relays were not activated. Consequently the system was separated in an unplanned way as zone 1 initiated tripping of the lines between Q-R, Q-Y and N-O.

The location given to the PSD characteristics in the RX-diagram is usually 80% of the apparent impedance at maximum load. One reason for this relative small safety margin is to optimize protection performance during high resistance faults as the fault impedance sometimes can become as high as 200 Ω.

After the disturbance the power swing blocking policy was revised to ensure blocking for the fastest possible swings. However this task was only given to relays where out of step tripping was guaranteed.

It was found out that the digital Siemens relay did not provide sufficient setting range to detect the fast swings experienced. This was rectified by upgrading the relay software. Additionally Siemens suggested a PSD algorithm were the impedance locus is monitored continuously to distinguish power swings from short circuit faults. In this way the relay is able to block up to 5 Hz swings and may trip for all types of faults during the swing.

4.3.3 A disturbance where the start function of a distance relay and several out of step blocking relays did not operate as desired

The disturbance described in this section occurred in North America and included the voltage levels 120 kV and 345 kV.

The disturbance was started by a lightning stroke which hit close to the tap on the three terminal line involving stations C, D and E. R6 in station E detected the fault and operated instantaneously whereas the zone 2 element disconnected the line at station D. However R4 at station C did not operate until 6 to 8 seconds later. As a consequence the line between stations F and G was tripped by R9's zone 3. When the supply from station G was cut the line between stations F and H was instantaneously opened at both terminals by a direct transfer scheme activated by the high line flows from station H towards station F.

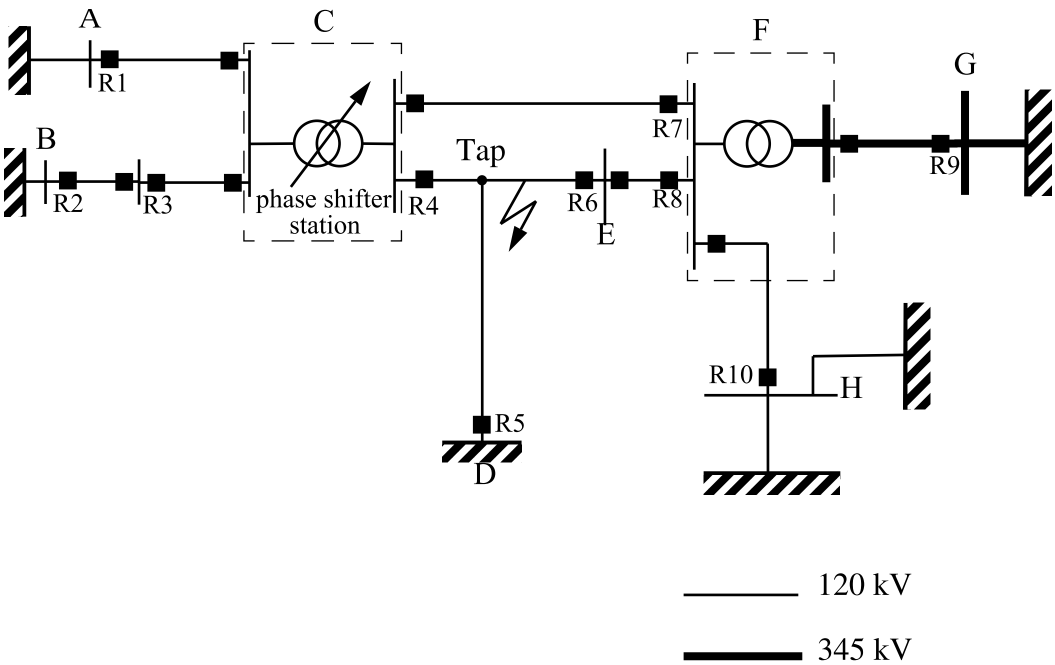

Figure 4.31 The interconnections between the area of the disturbance and the surrounding power system, where the important stations and relays are indicated.

R4 experienced an out-of-step block (OSB) operation at the time of the initial fault. This relay uses an OSB scheme which supervises three phase and phase to phase elements for both zone 1 and zone 3, while supervising only the three phase element for zone 2. Usually zone 1 faults are detected and cleared before the OSB relay operates. Even if the OSB had blocked zone 1, the fault should have been cleared in zone 2 time because, zone 2 phase to phase elements are not supervised by OSB.

An investigation showed that 35 to 40 years old insulation of the control wiring between the control house and the circuit breaker had deteriorated due to age. This defective wiring might explain the OSB operation and the delayed tripping of R4.

Four seconds after the initial lightning stroke R6 auto-reclosed into the still active fault and remained closed for about 40 seconds. The reason why it took as long as 40 seconds for R6 to disconnect the faulted line was because the long operation time for R4 had caused low voltage in the area to the left of stations A and B which led to generator tripping. Consequently the fault current through R6 was just below the 900 A current supervision level programmed into the start function of the SEL relay. This current varied somewhat, eventually exceeding the 900 A level so that the fault finally could be cleared. Before the final fault clearing the voltage in station E was about 0.16 pu. After the fault clearing the voltage immediately recovered to the normal level, however due to the low voltage some load was lost in station E.

In this case R6 operated as ”designed” but clearly not as desired. Therefore the overcurrent supervision level has been reduced to 500 A, which is more in line with other current supervision levels in the area.

When R6 closed into the fault and did not instantaneously disconnect the line, R8 should have detected the fault in zone 3 and operated as remote back-up protection. However the OSB relay for R8 operated; first to block tripping and then to allow tripping. This sequence was repeated twice until the OSB relay finally allowed tripping. At this time the fault had developed to a fairly well balanced three phase fault which is confirmed by the OSB relay operations as OSB functions for R8 only can occur for symmetrical three phase events.

R8 was a General Electric SLS relay which uses a switched distance method to measure impedance. If the fault for example evolves from a phase to phase fault to a three phase fault during a zone time delay, the relay would not use the correct algorithm to determine whether tripping should occur for the evolved fault. Investigations have shown that for a developing fault all protection elements of this relay could be fooled and inappropriately fail to trip. In this case it was discovered that the start element started and reset several times during the 40 seconds when the fault was fed through station E; but no protection element managed to initiate relay operation. However this is just a theory why R8 failed to clear the fault as all necessary data to verify the scenario are not available.

Zone 2 had initiated tripping for R5 and therefore the KD relay did not try to reclose the line as auto-reclosing is only performed for zone 1 operation.

The relay operation at station G was not correct with respect to the design of the protection system. In fact, no system configuration allows R9 to see the fault in zone 3. The system configuration during the time for the trip should have resulted in an apparent impedance about five times the zone 3 reach and at least 10 % larger than the zone 4 element (Anyhow timing for tripping in zone 4 (4 seconds), which in any case has been confirmed as disabled, does not agree with the actual times for the different events).

Since R9 is the same switched distance relay as R8, calculations were done to see if the relay could be fooled into tripping by an evolving fault. Although the calculations were done the engineers were not able to establish what the reason was for the mal-trip.

Immediately after the lightning stroke had hit the three terminal line, the SEL relay at the location of R1 identified the fault as a phase to ground fault well outside its protection zones and correctly did not trip the line between stations A and C.

At the same time as the OSB for R4 operated, the OSB (General Electric SLL relay) for R2 blocked the operation for all distance elements for relays R2 and R3. This OSB relay had an unresolved history of operations due to unsymmetrical three phase events. Also this mal-function could not be explained.

If an appropriately set zone 3 had been installed for R1 and R3, in combination with a correct operating OSB relay for R3, the fault would have been cleared faster and the overall impact had most likely been less. At least the generation tripping to the left of stations A and B could have been avoided.

Due to the generator tripping the voltage dropped as low as 0.6 pu in the area to the left of stations A and B. However, despite the low voltage the lines supplying the area represented in figure 4.31 fortunately were not tripped.

Chapter 5 Further Development of Protection Schemes

In sections 3.2 and 4.2 algorithms have been proposed to avoid undesirable distance protection operation during abnormal conditions. These algorithms enhance security with respect to conventional distance relaying. This was achieved by using traditional distance relaying in combination with additional criteria. In this way one is able to distinguish encroachment of the fault detector zone caused by voltage instability and power oscillations from encroachment caused by short circuit faults. The distance protection scheme proposed here is a further development of the algorithms introduced in sections 3.2 and 4.2.

The contents of this section are published in [III].

5.1 Further improvement of relay algorithms

As indicated in section 4.2.5 there are, apart from short circuit faults, events that may lead to sudden changes of the phase angle of the current. Events associated with voltage instability and power oscillations are load shedding and generator tripping. Usually the peak value of the derivative of the phase angle of the current caused by generator tripping and load shedding are less than for three phase faults. However in order to obtain a high security and to assure that the relay will not mal-operate due to such events additional criteria may be used as a supplement to the derivative of the phase angle of the current. To distinguish load shedding from three phase short circuit faults the derivative of the voltage is a good indicator. Whereas a three phase short circuit fault will decrease the voltage, the opposite is true in case of load shedding. To avoid any mal-operation due to generator tripping some communication device may be used to inform the relay that generator tripping has been performed. When the operation scheme of the relay is programmed the signal received from the generator may be used to block undesirable relay operation.

5.1.1 A high security zone 3 distance protection scheme

In figure 5.1 a scheme for a zone 3 phase to phase relay is proposed as an extension of the algorithm introduced in figure 4.16 and having a increased degree of security. To initiate a trip signal not only the apparent impedance has to be within the zone 3 of the traditional distance element, but at least one of three additional criteria has to be fulfilled.

The quantities marked with the subscript *Set* are assigned a fixed value by the relay operator. The remaining quantities are continuously updated by the relay during operation.

Block 1 consists of the conventional zone 3 distance protection function. When block 1 signals a fault blocks 2, 3 and 4 are applied to verify that a short circuit fault is the reason for the YES signal out from block 1 and not power oscillations or voltage instability. Verification is carried out by comparing the fixed values of the quantities with the values continuously updated.

By studying the negative-sequence current block 2 examines if an unsymmetrical fault is the reason for the activation of block 1. If not, final checks are made in blocks 3 and 4 to validate if a symmetrical three phase fault has occurred using the criteria based on the derivative of the phase angle of the current and the derivative of the voltage. Accordingly when the real time value in block 2 exceeds the fixed value or the real time value in block 3 exceeds the fixed value at the same time as the real time value in block 4 falls below the fixed value the timer in block 5 is started.

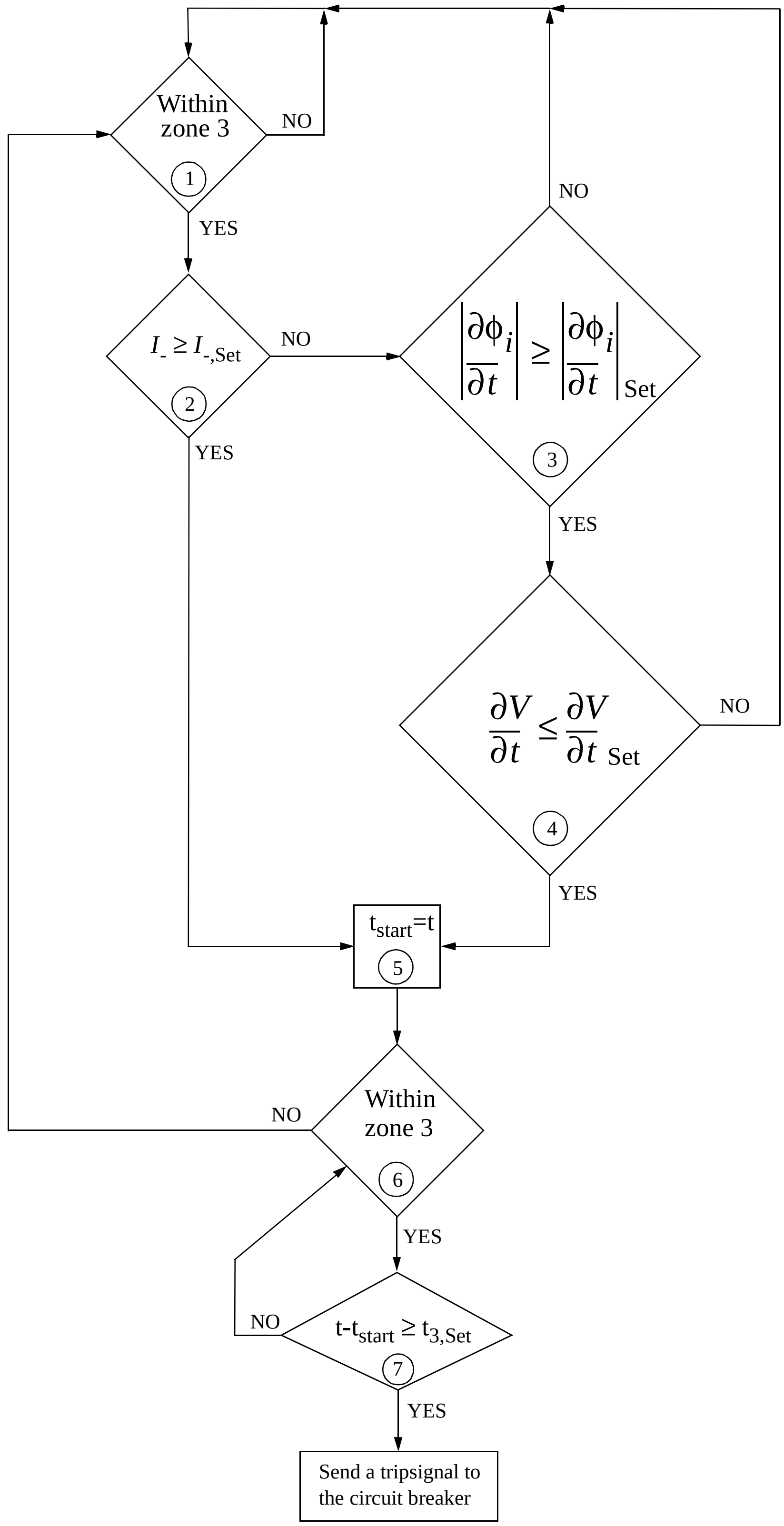

Figure 5.1 Zone 3 scheme for a phase to phase distance element.

When a phase to phase fault occurs in the protected area the traditional distance element will be entered. Additionally the relay will experience at least one of the following events: a negative-sequence current or a high peak of the derivative of the phase angle of the current combined with a substantial voltage reduction. Hence the timer in block 5 will be started and the scheme will begin to alternate between blocks 6 and 7, waiting for the main protection to clear the fault. However if the main protection fails the scheme will send a trip signal when the criterion in block 7 is fulfilled.

In case the fault is cleared by the main protection the apparent impedance will leave zone 3. Assume that a power swing occurs as a consequence of the grid weakening and the apparent impedance again enters zone 3. This time no high peak of the derivative associated with the current or negative-sequence current will arise and accordingly the out signal from blocks 2 and 3 will be NO. Thus the timer in block 5 is not started and the scheme will continue to wait for a true short circuit fault.

When zone 3 is entered by a slowly decreasing apparent impedance due to voltage instability the criterion in block 1 will be fulfilled. However the criteria in blocks 2 and 3 will not be fulfilled as there is no negative sequence current present in the system. Neither will the derivative of the phase angle associated with the current have a value which exceeds the pre-set value in block 3. The impedance stays within zone 3 as the scheme continues to wait for a true short circuit fault. If the voltage instability aggravates load shedding might be performed as a remedial action. Suppose that the load shedding generates an unexpected high absolute peak value of the derivative of the phase angle of the current so that the criterion in block 3 is fulfilled. Consequently the out signal from block 3 is YES. However block 4 will prevent an incorrect start of the timer in block 5 as the peak value of the derivative caused by the load shedding will have a positive sign and thus the criterion in block 5 is not fulfilled. As a result also for this sequence of events the relay scheme will maintain a high security.

In case of generator tripping the output from block 3 can be set to NO for a short time to prevent undesirable relay operation.

For applications serving parallel lines further improvements are required for the scheme in figure 5.1 in order to guarantee reliable operation. The main reason for this is that the derivative of the phase angle of the current as seen by the relay is strongly dependent on the fault location when a fault occurs on a parallel line. This phenomenon and its solution has been described in detail in section 4.2.3.

5.1.2 Simulation

Simulations have been performed using SIMPOW [41] and the test system introduced in figure 4.22. The protection scheme of figure 5.1 is implemented in relays A and B where the traditional distance elements are of the conventional mho type and zone 3 is set to cover 230% of the line length. A global low voltage load shedding scheme is in operation. When the voltage at a bus in the EHV system decreases to 0.7 pu approximately 50% of the load at the closest load bus is disconnected. In this simulation the performance of the scheme of figure 5.1 is examined with respect to voltage instability. To investigate the performance of the scheme with respect to transient instability the simulation made in section 4.2.4 can be used. It is found that if the zone 3 algorithm applied in that simulation is replaced by the algorithm in figure 5.1 identical performance is obtained.

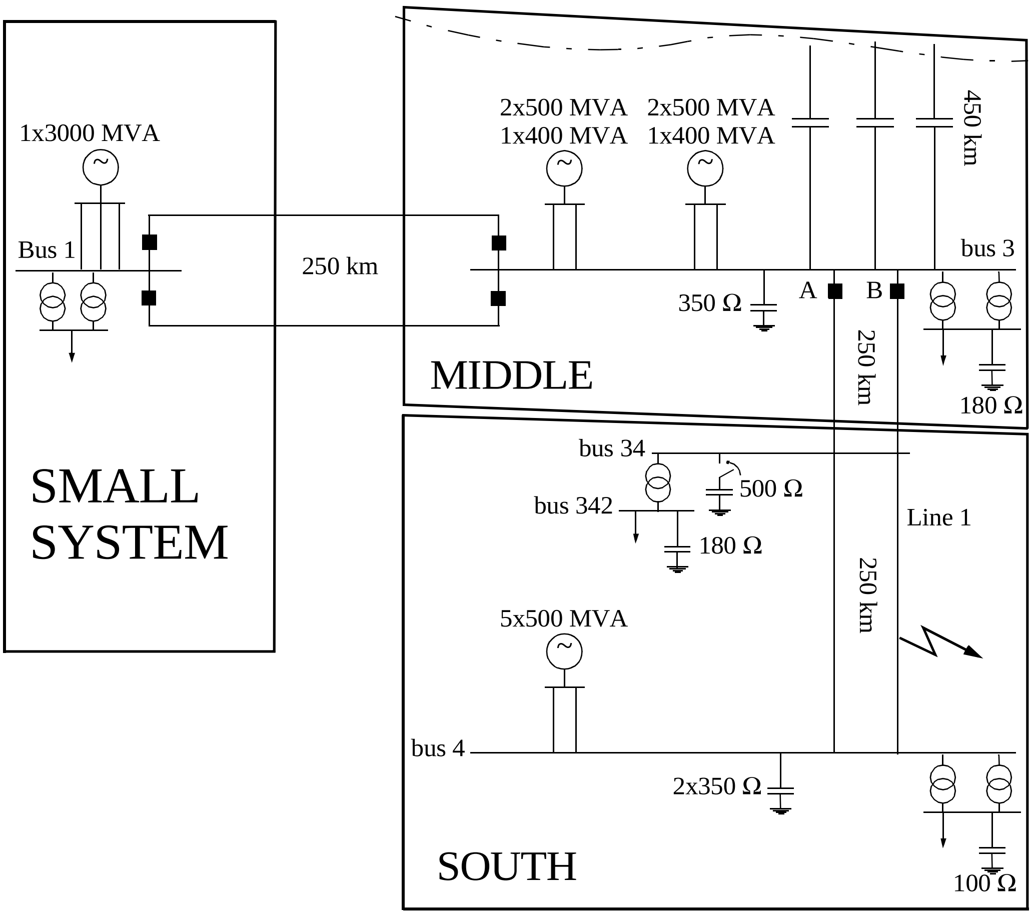

Figure 5.2 Test system.

Initially the MIDDLE and SOUTH areas are heavily loaded with large power flows from the MIDDLE towards the SOUTH area. In the pre-fault state the power transfer from bus 3 towards bus 34 is about 2200 MW and from bus 34 to bus 4 1200 MW. Five seconds after the simulation has started a permanent symmetrical three phase fault with zero fault resistance occurs 150 km from bus 34 on Line 1. After 90 ms the main protection disconnects the faulted line. Consequently the voltage starts to decrease at bus 3 and bus 34 although the shunt capacitor at bus 34 is taken into operation 500 ms after the initiation of the fault; figure 5.3. About 81 seconds after the fault occurrence the apparent impedance enters the zone 3 of the relays A and B; figure 5.4. In case of traditional distance relays undesirable operation will occur and consequently the whole system will collapse almost instantaneously. However when the scheme in figure 5.1 is used the relays will not operate but the voltages at bus 3 and bus 34 will continue to decrease. At 95.5 seconds the voltage at bus 34 has reached 0.7 pu and thus 50% of the load at bus 342 is disconnected. Instantaneously the voltages in the system increase and the system recovers to a stable operating point.

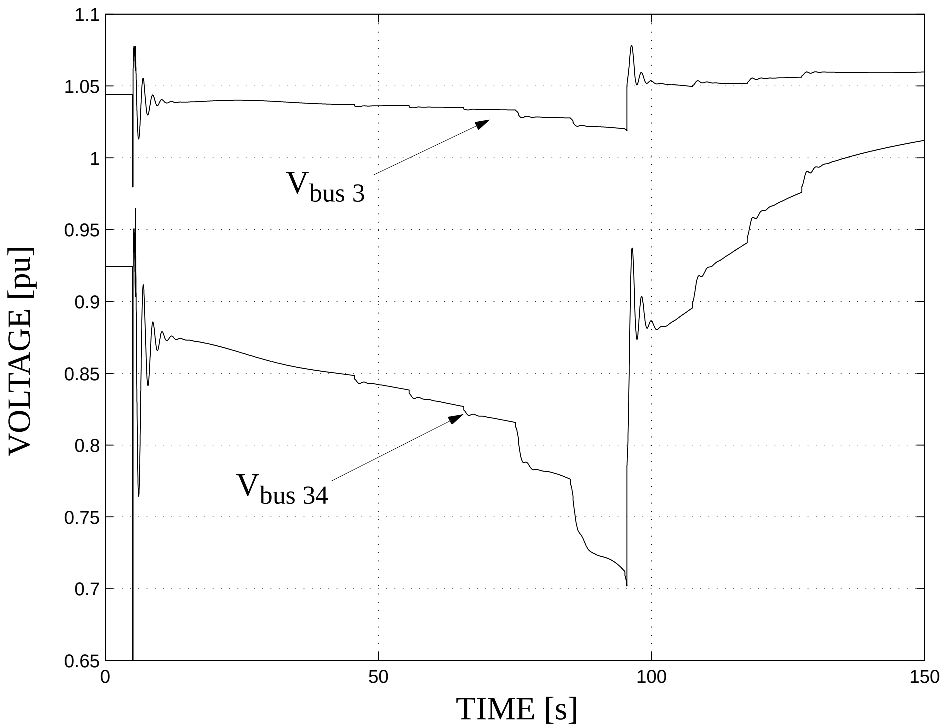

Figure 5.3 The voltages at bus 3 and bus 34.

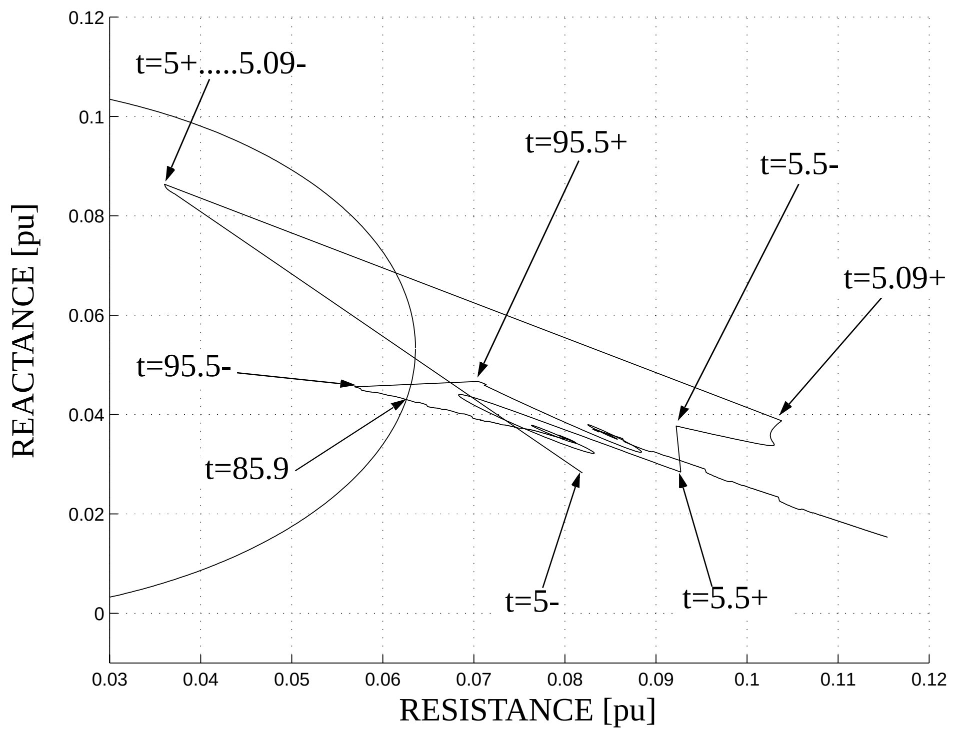

Figure 5.4 RX-diagram for relays A and B. The different points of time are indicated in the figure where a minus sign refers to the moment immediate before the indicated time whereas a plus sign refers to the moment immediate after the indicated time.

If the performance of the scheme is further analysed we can see that when the initial three phase fault occurs the zone 3 of relays A and B is entered; figure 5.4. Figure 5.5 shows that at the same time the derivative of the phase angle of the current has a negative peak with a large magnitude. In addition the derivative of the voltage shows a negative peak; figure 5.6. Thus the criteria in blocks 1, 3 and 4 are fulfilled and the timer in block 5 is started. The scheme starts to alternate between blocks 6 and 7, waiting for the main protection to clear the fault. When the main protection clears the fault the apparent impedance leaves zone 3. However as the voltages decrease and the reactive power demand increases the zone 3 is again entered at 85.9 seconds. The criterion in block 1 is again fulfilled but this is not the case for blocks 2 and 3. Hence the relays will not start their timers but continue to wait for a true short circuit fault.

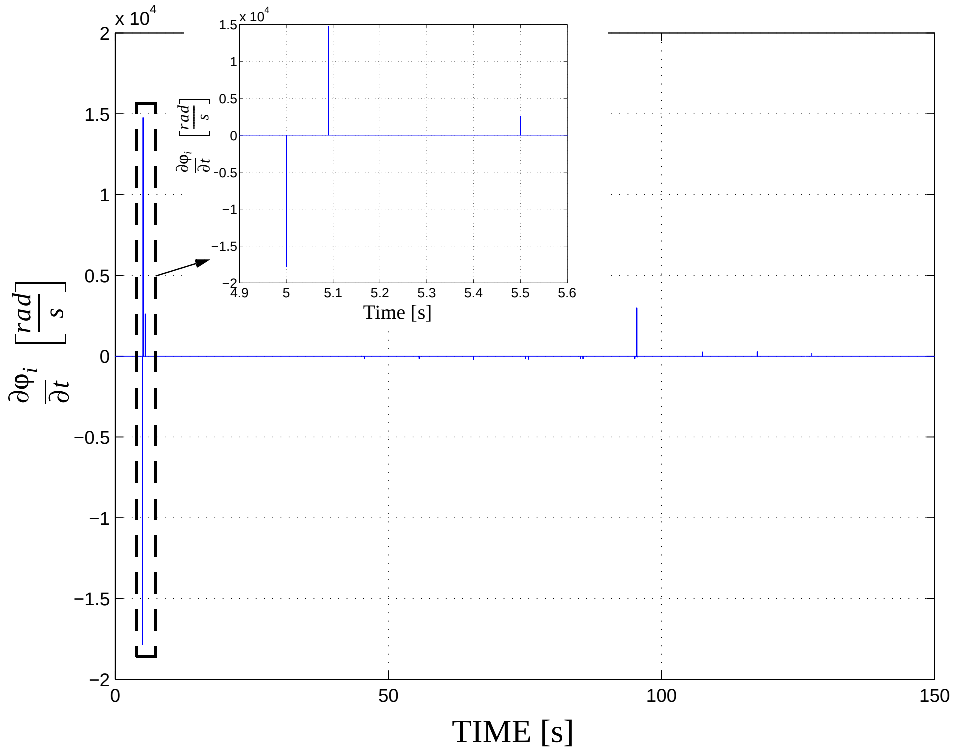

Figure 5.5 The derivative of the phase angle of the current as seen by relays A and B.

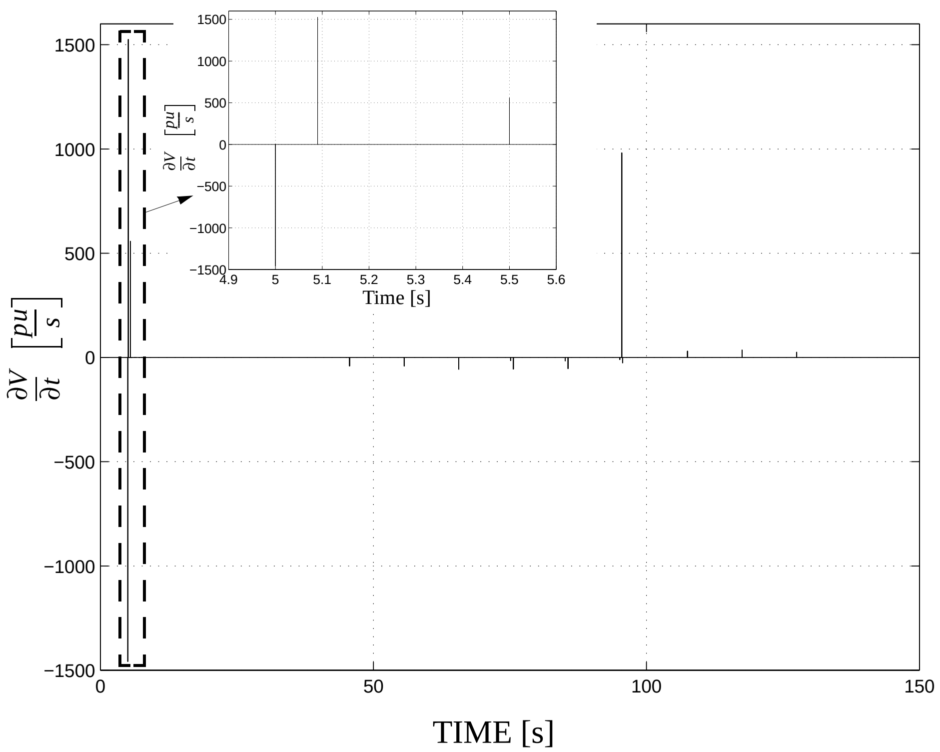

Figure 5.6 The derivative of the voltage at bus 3.

By adding block 4 an increased relay security is achieved for the algorithm in figure 5.1 as compared to the algorithm in figure 4.16. Assume that a too narrow setting is given to the fixed parameter in block 3. Consequently the peak of the derivative in figure 5.5 caused by the load shedding may be treated as a short circuit fault (output YES from block 3). This will lead to incorrect relay behaviour in case the algorithm of figure 4.16 is applied. However for the algorithm in figure 5.1 block 4 will prevent a mal-operation as the peak of the derivative of the voltage at the time for the load shedding has a positive value; figure 5.6.

The load shedding in this case is performed at a very low voltage level leading to large changes of the electrical quantities. However there is still a significant difference between the absolute value of the peaks of the derivative of the phase angle of the current caused by the three phase fault and by the load shedding. This should be kept in mind when the reliability aspect of the derivative of the phase angle of the current as a relay criterion is discussed.

Chapter 6 Conclusions and future work

6.1 Conclusions

Distance protection has contributed to voltage- and transient instability worldwide. Zone 3 is the main concern in case of voltage instability. In addition to zone 3 also zone 2 may be important in case of transient instability.

Recordings from the Swedish transmission system show that zone 3 operations are rare events. No incorrect operations are reported but there are examples where zone 3 elements have operated as remote back-up protection when local back-up was not provided. In the Swedish system measures taken to prevent load encroachment have a high priority and relay settings are frequently checked. These are most likely the reasons for the absence of zone 3 mal-operations. However as a consequence back-up protection is not provided for all line sections during shorter periods in case of maintenance work of certain protection devices.

The number of events leading to power oscillations has increased significantly during recent years in the Swedish transmission system. So far no incorrect operation of distance protection has been recorded although it has been close. One option to ensure correct distance protection performance in the future with respect to transient instability is to install Power Swing Detectors on exposed lines. Additionally Out of Step Protection should be applied to obtain a desired splitting of the system.

An adaptive algorithm which prevents mal-tripping due to voltage instability has been proposed. The algorithm not only considers the relation between the apparent impedance and the zone of operation but also uses the derivative of the voltage to distinguish short circuit faults from other events in the system.

Although the algorithm prevents mal-trips due to load encroachment associated with voltage instability, the reach of the distance relay will not be restricted.

Additionally, new distance protection algorithms which prevent mal-trips due to power oscillations have been proposed. Both momentary and time delayed algorithms are introduced where the dependability is decreased and security is increased with respect to traditional distance relaying. This is achieved by requiring additional criteria to be fulfilled at the same time as the apparent impedance enters the traditional distance element in order to initiate a relay operation. These additional criteria are based on symmetrical components and the derivative of the phase angle associated with the current.

Neither the line length, different cycle times of the power oscillations or faults having a slowly decreasing impedance will affect the performance and availability of the scheme as may be the case with conventional Power Swing Detectors. Additionally, as the relay is never blocked the schemes provide fault clearing also immediately after a power swing has been detected.

Applications for single and parallel lines have been presented. The solution for parallel lines require some internal communication between the relays at the terminal.

The algorithms are based on mathematical logics blocks. Thus numerical relays applying a user friendly computer software to create the operation scheme of the relay make it easy for relay engineers to implement the algorithms.

In order to further increase the relay security, the zone 3 algorithms, developed to avoid undesirable distance relay operation in case of transient stability, are combined with the algorithm developed to avoid mal-operation in case of voltage instability. Consequently the robustness of the algorithm is increased, particularly in case of load shedding.

For conventional zone 3 distance relaying the settings of generator current limiters and zone 3 elements must be well coordinated to make it possible to utilize the generator to its maximum capacity during emergency or extreme situations. This is particularly true if the current limiters have high settings.

In system analysis it is important to consider relays with both circular and quadrilateral shapes as each constitutes about half of the distance relays used today in the Swedish transmission system. For line loading at a high power factor mho relays have a natural defence against load encroachment. During voltage instability the reactive power demand will most likely be increasing and thus quadrilateral relays may became preferable. To increase the relay security, devices which restrict the area of coverage in the resistive direction may be used in combination with the zone 3 elements.

For certain system configurations the power swings can not be detected by the line protection. In these cases generator impedance protection and the related Generator Out of Step Protection must be applied.

If zone 3 is used as remote back-up protection, such a solution may be critical with respect to distance protection and voltage instability. However in certain cases it may be the start element which is the main concern.

6.2 Future work

Traditionally protection devices are used to locally protect power system equipment from damages whereas the system itself does not have an overall protection system. The trend today is that power systems are operated closer to their limits due to environmental constraints and deregulation. Hence the likelihood of power system instability increases. However to protect the system from collapse and to be able to utilize the existing system to a greater extent in a controlled and secure way a Wide Area Protection System can be installed. In fact Wide Area Protection Systems is a non-polluting and cost-effective way of increasing the capacity of the power system as no additional overhead lines or HVDC links are required.

Another trend is that the control room operators are given a larger responsibility today as compared to the past. To lighten the burden of the operators one could automatize the power system to a greater extent. This is particularly important in case of an emergency situation. Wide Area Protection suits this purpose well.

During the last decades thoughts have been raised on wide area power system protection systems. For example in [74] the optimization of the overall protection performance during large system disturbances is discussed. A limited number of protection systems have been implemented worldwide to protect the system from voltage collapse [75]. All these schemes are fairly effective though they are relatively simple and based on classical voltage instability indicators. Typically inputs like the voltage level and power flows are used and the remedial actions taken is often a pre-defined standard sequence. Some of the measures which usually are included: shunt switching, tap-changer blocking, HVDC control and load shedding. The measures included in these type of schemes may be too exhaustive. The remedial actions are not adjusted to each specific disturbance and this may result in needless social inconvenience and an unnecessary large disturbance cost.

To achieve tailor made actions optimized for each disturbance Wide Area Protection Systems applying more extensive input data can be developed. Obviously new opportunities are given as the computer and communication devices become more cost-effective. This in combination with the fast development of numerical techniques makes an adaptive Wide Area Protection System attractive. For example, an adaptive Wide Area Protection System may be obtained by using on-line calculations of a network model. ARISTO [42] and WAMS[1] [51] may be used for the application.

As communicative numerical relays become more widely used they can easily be included in the Wide Area Protection System. Hence a large amount of data is easily available but also the number of possible remedial actions increases significantly. The data can both be used as straight indicators but can also be applied to determine more sophisticated indicators which can point out how far from the stability margin the system is operating. Additionally the Wide Area Protection System may prevent incorrect unit protection actions as their algorithms can be based on extensive data supplied from the Wide Area Protection System.

In [76] one new approach is applied in a Wide Area Protection System. The scheme uses a search method adapted from the research on artificial intelligence which is used to coordinate the optimal performance of generators, tap-changers and load shedding schemes. Most likely this type of new computer based technologies can be used to improve the performance of Wide Area Protection Systems.

Finally the big challenge in relay development may be to eliminate the relay settings completely as they are often the source of incorrect relay performance in one way or another. Hence the relays must be given some kind of seances which they can use to evaluate the complete fault situation based on extensive input information. Accordingly to initiate the optimal action the relay makes a judgment based on the evaluation.

Apart from the technical issues also the economical, organizational and practical topics must be carefully considered when a Wide Area Protection System is introduced, particularly in deregulated power systems.

1. Wide Area Measurement System

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