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Protection of Distribution Systems with Distributed Generation

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Problem Description

The number of small and medium sized generation units connected to the distribution grid are rapidly increasing, both in Norway and the rest of Europe. This causes problems in the protection of distribution feeders. The main issue are how coordination of protective devices should be handled, and if the best option is distance relays instead of over-current relays.

The objective of present thesis is to determine the most beneficial protection scheme to use in distribution systems with distributed generation(DG).

Using the simulation tool DigSILENT© PowerFactory, a model will be made to investigate performance of different DG units and protective relays. This model will be used to examine how a multi-machine network should be protected, and how to protect a radial network with one larger production unit. Interesting factors is how to set the relays under changing load conditions, and if the implementation of distance relays or directional over-current relays will have a positive effect on the protection scheme. A survey will be made to find out how different grid owners protects their distribution system.

Preface

Present thesis is written as the final part of the 5$^{\text{th}}$ year in the Master of Science program at the Department of Electric Power Engineering, Norwegian University of Science and Technology. Models are based on the work done in the project assignment fall 2014 writing for SFE Nett AS. Grids modeled are based on data from SFE Nett AS.

I would like to thank my supervisor Professor Kjetil Uhlen at NTNU for giving me the opportunity to write this thesis and for his guidance during this work. Gratitudes are also extended to Kristen Skrivarvik and Børge Svardal at SFE Nett AS for helping with grid data.

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Last but not least, I would thank my fiancée, Silje Lunde, for her support these past five years.

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Abstract

In recent years the amount of distributed generation(DG) in distribution systems have increased. This poses problems for the traditional protection scheme, with non-directional over-current relays and fuses. When DG is introduced the load flow in distribution systems are often reversed; there is a surplus of power on the radial. Present thesis seeks to determine the most beneficial protection scheme to use in distribution systems with DG.

To investigate the impact of different relays and its settings, two models where made in the simulation tool DigSILENT© Power Factory. First a grid with an inverter interfaced wind farm and a smaller DG unit. The second is a multi-machine network with six small synchronous machines. These grids were protected by both distance and over-current relays to determine advantages and drawbacks of the two types.

The simulations indicate that low impedance networks with production will be best protected with directional over-current relays. Long radials with higher impedance and production is best protected with distance relays.

Samandrag

Dei seinare år har mengda distribuert generering(DG) i distribusjonsnettet vore økande. Dette skaper problem for det tradisjonelle vernoppsettet med retningsubestemte overstraumsvern. Når ein introduserer DG i eit distribusjonsnett vert ofte lastflyten snudd, det er eit kraftoverskot i systemet. Denne oppgåva søkjer å finne svar på kva som er det beste vernoppsettet å bruke på distribusjonsradialer med DG.

For å undersøkje korleis ulike rele og dets innstillingar påverker systemet er to modellar laga. Desse er laga i DigSILENT© Power Factory. Det første nettet er eit nett med ein vindpark som er inverterdrifta og ein mindre generator. Det andre nettet er eit nett med seks mindre synkronmaskiner. Begge netta vart beskytta med distanse- og overstraumsvern for å sjå fordeler og ulemper.

Simuleringane som er gjennomført antyder at retningsbestemte overstraumsvern er det beste alternativet i nett med lav impedans og produksjon. På lange distribusjonsradialar med produksjon ser det ut til at distanse vern er det beste alternativet.

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1 Introduction

In recent years the amount of DG in distribution systems have increased rapidly. This poses problems for the traditional protection scheme, with non-directional over-current relays and fuses. When DG is introduced, the load flow in distribution systems are often reversed; there is a surplus of power on the radial. This leads to an increase in the relay settings. Thus a higher fault current is needed to trip the relay. In addition problems with reversed fault currents for fault on neighboring grids could occur. As power electronic devices improve and becomes cheaper, the introduction of inverter interfaced DG gets more and more common. This might cause its own set of problems with reduced short-circuit current. There might be issues with disconnecting the DG's, since the short-circuit current will be low and islanding might occur.

There are different recommendations on how to protect distribution feeders with DG, REN recommend to use distance relay in their standard [1]. Other propose an adaptive relay setting [2–6]. In the Norwegian power system it is a tradition for using over-current relays, this might impact the type of protection scheme chosen.

The present thesis will investigated and test two different grids with both over-current relays and impedance relays. They will be tested during different load conditions and fault locations, and the impact on fault detection will be investigated.

2 Load Flow and Short-Circuit Analysis

In order to understand how the simulation tool, Power Factory, calculates short-circuit and load flow, a brief theory background will be presented. This is not a complete background, so the reader is expected to have basic knowledge of both power system analysis and short-circuit analysis. Load flow will be presented since this is basis for the initial condition in both dynamic simulation and short-circuit calculation.

2.1 Load Flow Analysis

The load flow calculation are based on the Newton-Raphson method, this is an iterative algorithm. Before this method can be deployed there is some equations that need to be presented. This section is based on references [7–9].

The background for any calculation in a circuit, power grid or smaller circuit, is the impedance of its components. The calculation of node voltages is based on Kirchoff's current law. Therefore, it is beneficial to represent impedances as admittances. Admittance between node i and j are found as follows:

$$y_{ij} = \frac{1}{z_{ij}} = \frac{1}{r_{ij} + jx_{ij}} \tag{2.1}$$

When setting up the node voltage equations, it is found that:

$$Y_{ii} = \sum_{j=0}^{n} y_{ij} \quad \wedge \quad j \neq i \quad , \quad i \geq 1 \tag{2.2}$$

for all diagonal elements, and

$$Y_{ij} = Y_{ji} = -y_{ij} \tag{2.3}$$

for all off diagonal elements. Y_{i0} represents the internal impedance to earth when all infeed are transformed to current sources. When using equation 2.2 and 2.3, the bus admittance matrix can be set up as:

$$\begin{bmatrix} I_1 \\ \vdots \\ I_i \\ \vdots \\ I_n \end{bmatrix} = \begin{bmatrix} Y_{11} & \dots & Y_{1i} & \dots & Y_{1n} \\ \vdots & \ddots & \vdots & \iddots & \vdots \\ Y_{i1} & \dots & Y_{ii} & \dots & Y_{in} \\ \vdots & \iddots & \vdots & \ddots & \vdots \\ Y_{n1} & \dots & Y_{ni} & \dots & Y_{nn} \end{bmatrix} \begin{bmatrix} V_1 \\ \vdots \\ V_i \\ \vdots \\ V_n \end{bmatrix} \tag{2.4}$$

Matrix 2.4 gives us the current in every node. When implementing this and $S_i = V_i^* I_i$ it can be shown that:

$$P_i - jQ_i = |V_i|\angle - \delta_i \cdot \sum_{j=1}^{n} |Y_{ij}||V_j|\angle\theta_{ij} + \delta_j \tag{2.5}$$

where

θ_{ij}	is the polar angle of element Y_{ij}
δ_i, δ_j	is the voltage angle of node i and j

Re-writing equation 2.5 and separating the active and reactive power gives:

$$\begin{aligned} P_i &= \sum_{j=1}^{n} |V_i||V_j||Y_{ij}|\cos(\theta_{ij} - \delta_i + \delta_j) \\ Q_i &= -\sum_{j=1}^{n} |V_i||V_j||Y_{ij}|\sin(\theta_{ij} - \delta_i + \delta_j) \end{aligned} \tag{2.6}$$

2.1.1 Newton-Raphson Method

It was initially stated that the Newton-Raphson method was a iterative algorithm. The N-R algorithm is given by:

$$\begin{aligned} j^{(k)}\Delta x^{(k)} &= c - f(x^{(k)}) \\ x^{(k+1)} &= x^{(k)} + \Delta x^{(k)} \end{aligned} \tag{2.7}$$

where

$$j^{(k)} = \left(\frac{df}{dx}\right)^{(k)} \quad \text{is a jacobi element}$$
$$(k) \quad \text{is the iteration number}$$

The algorithm presented in 2.7 can be used to solve load flow. For this to work Equation 2.6 must be Taylor expanded. The Taylor expansion can be presented as:

$$\begin{bmatrix} \mathbf{\Delta P} \\ \mathbf{\Delta Q} \end{bmatrix} = \begin{bmatrix} \mathbf{J_1} & \mathbf{J_2} \\ \mathbf{J_3} & \mathbf{J_4} \end{bmatrix} \begin{bmatrix} \mathbf{\Delta}\delta \\ \mathbf{\Delta}|\mathbf{V}| \end{bmatrix} \tag{2.8}$$

Where $\mathbf{J_{1-4}}$, also known as H,M',N and K' [9], is the Jacobi matrix of the parameters. Combining Equation 2.7 and Equation 2.8 gives:

$$\begin{aligned} \Delta P_i^{(k)} &= P_i^s - P_i^{(k)} \\ \Delta Q_i^{(k)} &= Q_i^s - Q_i^{(k)} \end{aligned} \tag{2.9}$$

$$\begin{aligned} \delta_i^{k+1} &= \delta_i^{(k)} + \Delta\delta_i^{(k)} \\ |V_i^{(k+1)}| &= |V_i^{(k)}| + \Delta|V_i^{(k)}| \end{aligned} \tag{2.10}$$

where P_i^s and Q_i^s is infeed or consumption in node i.

2.2 Dynamic Fault Simulation

When simulating a fault, an impedance between phases, or between phase and earth, is added to the network [9]. This will affect the system matrix and lead to altered operation scenarios. Faults will affect generators and other machines, they will accelerate or decelerate and they may not be stable after the fault is cleared. Simulation programs usually use numerical integration methods such as the Runge Kutta method. This is an explicit integration scheme and the step size of the iterations needs to be adjusted to the eigenvalues. This results in a fast algorithm for small time steps but when the step sizes is increased it fails to converge, due to numerical instability. Hence, Runge Kutta is the best choice for classic transient stability calculations. [9, 10]

When simulating longer periods of time it is best to use an implicit integration method, as this will converge also for large step sizes. Implicit integration methods are also referred to as A-stable integration algorithms.

2.3 Short Circuit Calculation

There are several methods for performing short-circuit calculations. The simulation program, Power Factory, use ANSI, IEC60909 and complete short-circuit calculation(CSC). IEC60909 and CSC will be presented here. Additional methods are available for ship/offshore and DC purposes, they will not be discussed. The methods will have different application areas. The ANSI and IEC should be used for planning conditions and are a simplified method that uses a reduced data set. The CSC needs a complete dataset and should be used for operating conditions. [11]

In IEC60909 some simplifications is made to avoid taking initial load flow and actual operating conditions into account. IEC60909 set fault voltage by deploying a negative voltage source at the fault location. The most important simplifications are [11]:

- Nominal conditions are assumed, $U_i = U_{n,i}$
- Load currents are neglected, $I_0 = 0$
- Loads are not considered in the positive and negative sequence network.
- A correction factor is applied to the voltage at the fault location.

IEC60909 dictates that the initial short-circuit is calculated to find the missing physical quantities. These are functions of R/X-ratio, machine characteristics, excitation systems, contact parting time, network type and the contribution placement [11].

CSC also known as the superposition method, is the most accurate of the methods for short-circuit calculation, not included RMS/EMT simulations. CSC uses a superposition of an initial load flow, a situation where all voltage sources are set to zero and a negative voltage sources at fault location.

3 Protection

Protection of the power system is an important part of electrical power engineering. The purpose of protective relaying is to ensure stability of the system and to prevent harmful operating conditions. If a relay or fuse detects an abnormal system condition, it is important that a corrective action is taken as fast as possible. However, it is preferable that it causes a minimum of black out area. At lower system levels, where the cost and consequences of a disconnected line is lower, it is usually cheaper protective devices. A list of available devices for power line protection are shown in the list below in ascending cost and complexity [12]:

1. Fuses
2. Sectionalizers, reclosers
3. Instantaneous over-current
4. Inverse, time delay, over-current
5. Directional over-current
6. Distance
7. Pilot

A presentation of the most common devices and necessary equipment will be presented in the following.

3.1 Measurement Transformers

Measurement transformers are commonly used for metering or relaying purposes, and to provide galvanic isolation between relays and/or measurement devices.

3.1.1 Current Transformers

Current transformers(CT) are single core transformers that in principle are like a single phase power transformer. To ensure changeability there are standard values for the secondary side current. The most common is the 5A secondary side transformer; a 1A secondary is also in use. Many current transformers are multi ratio and can be changed depending on the primary side current. When choosing CT it is preferable to choose so that the primary side rating is as close to the nominal current as possible. If there is a 350A current flowing on the mains a 600:5A MR CT, set to 400A primary is preferable (see table 3.1). For relaying purposes the accuracy is most important when deviating from normal conditions. For metering purposes the accuracy at normal conditions is most important. Transformers for these two purposes are essentially identical, but the internal values determines in what range they are accurate. [12]

Table 3.1: Standard current transformers [12].

600:5 MR	1200:5MR	2000:5MR	3000:5 MR
50:5	100:5	300:5	300:5
100:5	200:5	400:5	500:5
150:5	300:5	500:5	800:5
200:5	400:5	800:5	1000:5
250:5	500:5	1100:5	1200:5
300:5	600:5	1200:5	1500:5
400:5	800:5	1500:5	2000:5
450:5	900:5	1600:5	2200:5
500:5	1000:5	2000:5	2500:5
600:5	1200:5		3000:5

3.1.2 Voltage Transformers

Voltage transformers are normal transformers connected to the line, with a rated secondary side voltage of 120V if connected phase-phase and 69,5V if connected phase-ground. The error of a voltage transformer are negligible for the entire operating range (from 0-110%) [12]. Voltage transformers are expensive equipment especially for higher voltages and are thus most common in low-, medium- and high-voltage systems(up to 345kV). Above 345kV coupling capacitor voltage transformers are commonly used, this is not in the scope of present thesis and will not be discussed further.

3.2 Over Current Protection

Over-current protection comes in many forms; the easiest and cheapest is fuses. Fuse designs vary, but the functionality is achieved the same way. Fuses are built up from a fuse-element that will, during overload, heat up and melt. Figure 3.1 shows a component drawing of a high voltage fuse. If disconnection of all phases is desirable, it is recommended to use fuses that are fitted with a striker. Striker action caused by fuse melt will trigger operation of connected switchgear. Fuses with strikers can be used in most cases. Also where there are no switchgear connected, in this case the sole purpose of the striker is to give a visual confirmation of a blown fuse. Fuses will have an inverse time-current characteristic shown in Figure 3.2. The characteristic of fuses are important to keep in mind when coordinating fuses with other protection devices such as reclosers and over-current relays.

Distribution systems are usually operated as radials, a radial is normally divided into mains and laterals. The mains are the backbone of the distribution radial, it is often a line with larger dimension than the laterals. The laterals are branching of the mains or is a continuation of it with a lower dimension. There are different ways of protecting the mains with the connected laterals, one common method is to have one circuit breaker and some sectionalizers throughout the length of the mains and fuses at transformers. Another similar method is where you add fuses at every lateral, this gives a disconnection of the phase with fault one the lateral by fuse melting. This may lead to an operating scenario where one phase is excluded from operation, this will lead to additional problems for the consumers on the lateral that will get full system voltage on two phases and possibly ground potential on the third phase.

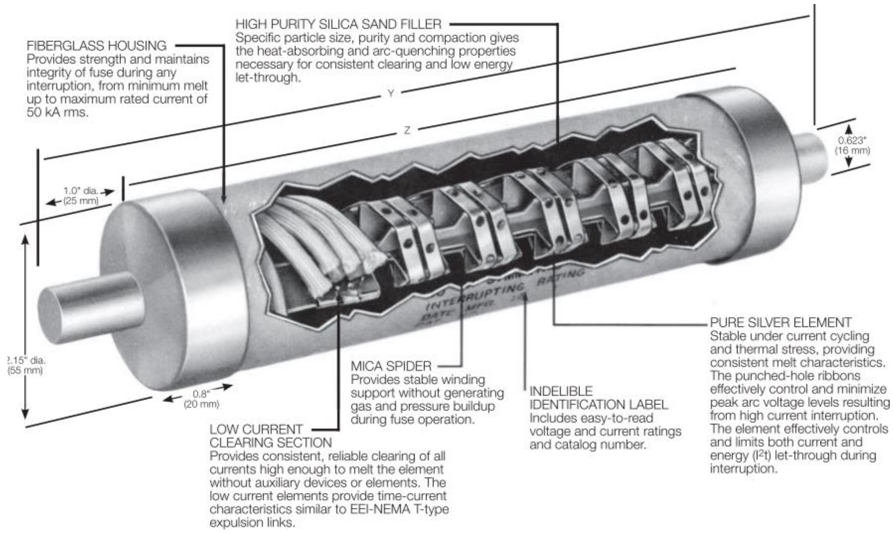


Figure 3.1: ELX fuse from McGraw-Edison fuses, shows the buildup of a high voltage current limiting fuse [13].

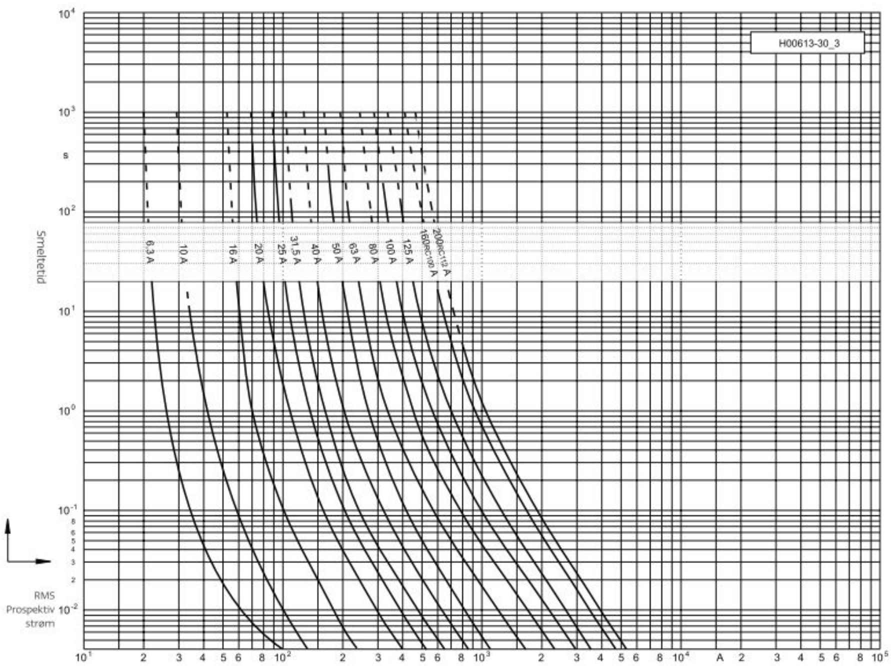


Figure 3.2: Time-current characteristic of SIBA high voltage fuses (10/24kV) [14].

3.2.1 Over Current relays

Time delay relays may have an inverse time characteristic or a definite time characteristic. The inverse time relay will have a time-current characteristic that is similar in shape, not necessarily in magnitude, to that in Figure 3.2. There are two settings for time dependent current relays, pickup-current and time-delay.

The pickup-current should be set so that the pickup is in between normal operating current and the minimum fault current, with some margins in both directions. The pickup-current is the lowest current where the relay will operate. If possible it should be set so that the relay will be a backup protection for directly connected equipment, such as transformers.

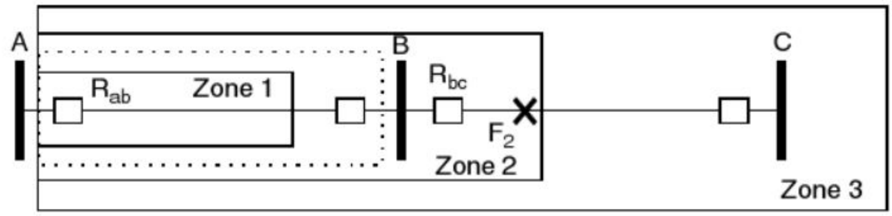
The time-delay is the parameter that determines if it is an inverse time relay or a definite time relay. The timing characteristic is achieved in different ways for different relay types. Time delays are used to ensure coordination between protection devices in the grid.

3.3 Distance Protection

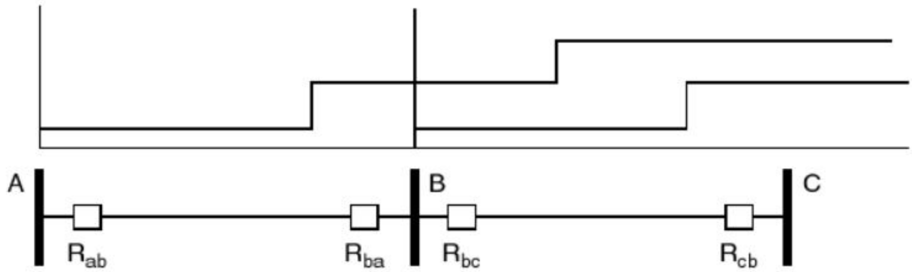
Distance relays are among the most expensive protection schemes, they are quite complex compared to a over-current relays. In the distribution system one tend to keep things easy and at a low cost. Distance relays are therefor more common in the transmission system. A distance relay measures current and voltage to calculate the impedance in a grid, hence it is also known as impedance relay. The functionality is ensured by setting impedance threshold zones, if the apparent impedance is below this threshold the relay disconnects the line. The shapes of zones wary it can be circular, quadratic, polygonal etc. Impedance is calculated using:

$$Z_{app} = \frac{E}{I} \tag{3.1}$$

Distance relays are, when used in the transmission system, tuned so that the protection zones are one line, bus A to bus B. It is also common that there is more than one protection zone, often three. Where zone 1 protects the succeeding line while zone 2 and 3 are backup for downstream relays. [12] For all relays there are measurement errors, which makes it necessary to have zones



(a) Over- and underreaching of protection zones .



(b) Coordination delays .

Figure 3.3: Protection zones of distance relay, cut from page 102 in reference [12].

that over- and underreach. Zone 1 needs to underreach the protected line, with a typical reach in between 85 and 90%. This to ensure that it does not trip instantaneously for a fault that should have been disconnected by relay at the succeeding bus (see Figure 3.3a). Zone 2 is supposed to overreach the protected line, and is usually set with a coordination delay of 0,3s (see Figure 3.3b).

3.3.1 Multi-terminal Lines

Distance relays are commonly used to protect transmission lines that goes from terminal to terminal, shown in Figure 3.3. In some cases the lines will be tapped or have a connected generator between the terminals, this is called a multi-terminal line. The tap is often built as an addition to existing lines, but it leads to problems for the protection of the line segment. An example of a grid with a multi terminal line is shown in Figure 3.4. The problem with this connection is that the impedance seen from the relay, R1, is distorted by the

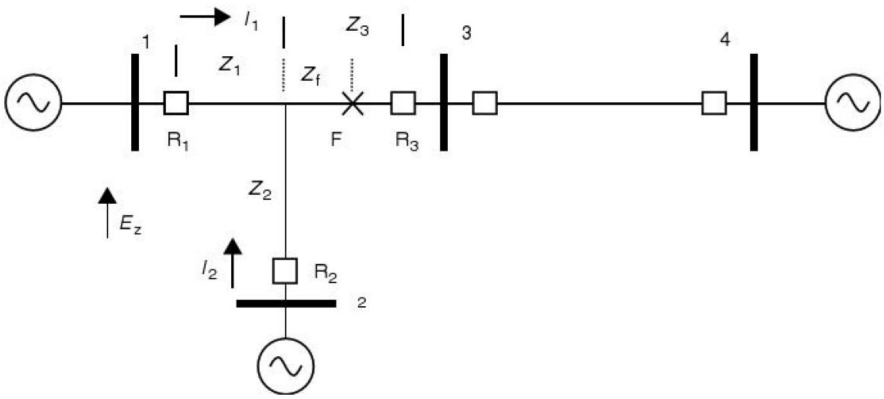


Figure 3.4: Multi-terminal line with infeed, cut from page 120 in reference [12].

connected equipment. This is because the voltage seen at bus 1 during a fault marked Z_f in Figure 3.4, is related to the current by the equation:

$$E_1 = Z_1 I_1 + Z_f(I_1 + I_2) \tag{3.2}$$

Equation 3.2 is for a single phase systems, but it relates to a three phase system as usual. It can be seen from Equation 3.2 and Ohms law that the apparent impedance at terminal 1 is :

$$Z_{app} = \frac{E_1}{I_1} = Z_1 + Z_f\left(1 + \frac{I_2}{I_1}\right) \tag{3.3}$$

Equation 3.3 is for the grid presented in Figure 3.4 but the same method is used if there are more than one tap. The fault contribution from the tap is known as infeed current when in phase with I_1 and as outfeed current when the phases are opposite [12]. Equation 3.3 shows that the impedance seen from relay R_1 is different from the true impedance. This needs to be taken into consideration when setting the protection zones of the relay.

4 | Protection of Distribution Systems

Most distribution systems are designed to supply energy to consumers along the length of the distribution radial. Introducing generation into this systems will reduce the load flow from the transmission system, or in many cases reverse the load flow. [15] This may lead to large problems when dealing with protection systems. The protection system depends largely on current levels and sometimes voltage at a few points in the grid. When introducing generation units the system parameters are manipulated, this is also true under faulted condition. The generation units will contribute to the fault current, this may affect the fuse-breaker coordination. [16] In Figure 4.1, it becomes clear that at PCC G2 there will be a higher fault current than at the bus.

4.1 Fuse Breaker Coordination

When coordinating fuse and breakers/reclosers it is important to ensure proper working, especially when dealing with reclosers since 80% of all faults in the distribution system are temporary [6]. Girgis and Brahma [17] gives an overview of the coordination of over-current devices. It is shown that the coordination needs to be done by time-current characteristic. The principle here is to ensure that the recloser will disconnect every fault before fuse operation,that is, before the current reaches minimum melt(MM). Then reconnect the grid, this time with a slower characteristic on the recloser, so that fuses will operate and clear potential faults. Such a setup will ensure that the fuse only operates for permanent faults, and any temporary fault will be cleared without fuse operation. The normal operation sequence for a recloser is recommended to be: fast-fast-

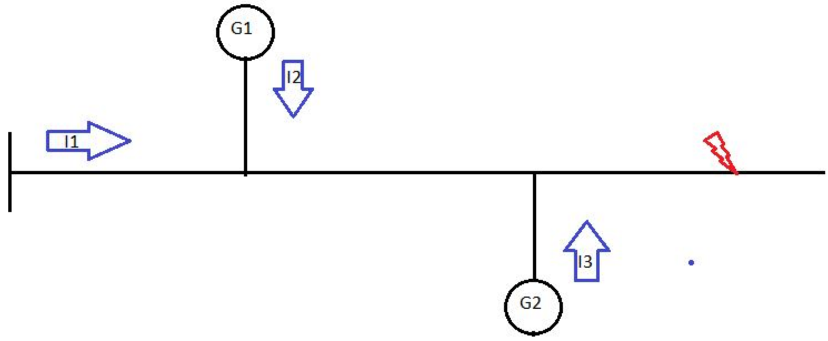


Figure 4.1: Distribution system with two DG units, the arrows show the infeed to the fault at the end of the feeder.

slow-slow [17]. Such a sequence ensures that after two failed attempts without damaging the fuses, a slower breaker operation will try to clear the fault by fuse operation.

Coordination is usually not a problem in radial distribution systems. However, when introducing DG problems will arise. When DG is installed the fault current will increase, as was shown in Figure 4.1. Also, the fuse might see a higher current than the recloser, for the scheme to work it is crucial that the fault currents lies between the I_{min} and I_{max} of the recloser relay. This means that the current seen by the fuse cannot exceed the I_{max}. In Figure 4.2 it is shown that that if the fault current after installing DG is within range, there is a protection margin. Where $I_{recloser}$ is the current seen by the recloser and I_{fuse} is the current seen by the fuse. If the disparity between the two currents gets larger than the margin, the fuse-breaker will no longer be coordinated [6, 17]. The size and placement of the DG unit is of importance for the disparity between them. If a unit is placed closer, the difference gets larger. The same relationship is valid for size; larger unit leads to a larger disparity.

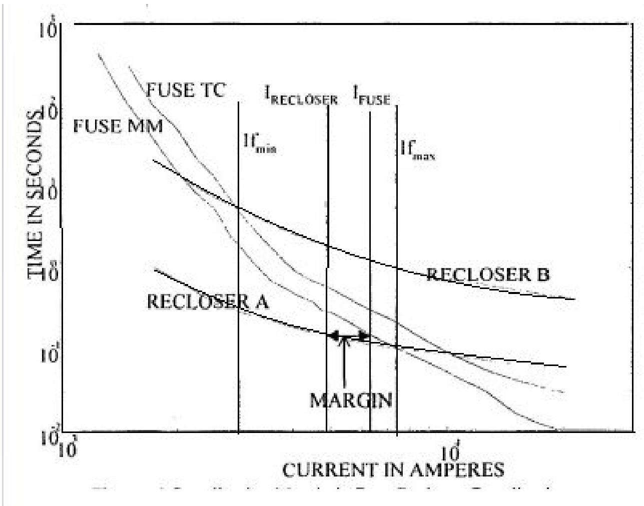


Figure 4.2: Fuse breaker coordination with DG [17].

4.2 Relay Coordination

Coordinating over-current relays are essentially the same as for fuses, the basis is the time-current characteristic which is similar to that shown in Figure 3.2 [12]. When no DG is present this coordination is usually not a problem, the relays are set to trip at the pickup current (see section 3.2). The coordination are ensured by shifting the disconnection time by a “Coordination Time Interval”. This interval depends on errors in measurement transformers, relays and circuit breakers, the time interval is usually decreased for downstream relays. [17]

Over-current relays are the most commonly used relay in the distribution system, but impedance relays may also be used. The coordination scheme of this relay type was discussed in section 3.3. For such a distribution system, some adaptions need to be made. It is usually operated radially with one circuit-breaker and thus only one relay. If there are other protection devices on the radial like over-current-relays or fuses, this needs to be taken into consideration by setting the zones with time delays long enough to ensure selectivity.

4.3 Distributed Generation Impacts

In distribution network with DG, islanding can cause severe problems [15, 16]. In the case of recloser action a temporary islanding will be created. A DG unit will drift out of phase and the recloser will reconnect out of phase, causing damage to utility, DG unit and consumer equipment. It is recommended to have a blocking for reconnecting into a energized grid, or a synchronization check before reconnecting [15]. Islanding of DG may prevent a recloser clearing a temporary fault as the DG will continue to feed the fault in the dead period [16]. It is recommended that DG units are equipped with voltage and frequency relays to prevent islanding. To prevent a inverter interfaced DG(IIDG) to maintain voltage and frequency in island mode, the inverter should be tuned to a slightly lower or higher frequency in order to trip the frequency relay [15].

Sympathetic tripping of a radial when a fault occur in a neighboring feeder is not uncommon when the protection is done by non-directional over-current relays. This problem can be solved by using a directional relay. [16]

When using impedance relays the reach of the relay will be decreased in the same way as for multi terminal lines. The apparent impedance seen by the relay for the grid in Figure 4.1 can be found using:

$$E_1 = Z_1 I_1 + Z_2(I_1 + I_2) + Z_f(I_1 + I_2 + I_3) \tag{4.1}$$

This gives the apparent impedance seen by the relay:

$$Z_{app} = Z_1 + Z_2 \left(1 + \frac{I_2}{I_1}\right) + Z_f \left(1 + \frac{I_2 + I_3}{I_1}\right) \tag{4.2}$$

here, Z_f includes the impedance in the line out to the fault and the fault impedance. This is only true if there is no feed-in on the far end of the line. Usually the fault is seen as ideal (i.e. zero ohms); this is not always the case. In a real life scenario there will be arc resistance and maybe the fault current goes through an object with a resistance. For relaying purposes it is assumed that the fault resistance is constant, given by [12]:

$$R_{arc} = \frac{76V^2}{S_{sc}} \tag{4.3}$$

where V is the system voltage and S_{sc} is the short-circuit capacity. If there is production on the far side of a fault, apparent impedance seen by the relay will change because voltage over the fault will be:

$$E = R_f(I + I_{far}) \tag{4.4}$$

If generation is placed at the end of the line in Figure 4.1, the apparent impedance will be:

$$Z_{app} = Z_1 + Z_2\left(1 + \frac{I_2}{I_1}\right) + Z_f\left(1 + \frac{I_2 + I_3}{I_1}\right) + R_f\left(1 + \frac{I_2 + I_3 + I_{far}}{I_1}\right) \tag{4.5}$$

When examining equation 4.5 it is easy to see that the impact on apparent impedance is higher for a large and/or close unit than for a small and remote unit. This is similar to the over-current relays.

5 | Survey

5.1 Inquiry

A survey has been sent out to 12 grid owners in Norway, to gain insight into how they work with planning of protection systems. The survey is also meant to find what type of protection devices that are most common. The survey is made in collaboration with Andreas Simonsen, also writing his thesis now. Not all questions in the survey are relevant to present thesis, the relevant ones are:

1. What is the most common protective device in the distribution system today?
2. What is the most common protective device in distribution systems with DG today?
3. In the future, when changing relays in the distribution system, what type will be chosen? Why is this preferred?
4. If DG is present, what type will then be chosen? Why?
5. How will protection challenges related to DG in the distribution system be handled?
6. Do you have any other comments related to this topic?

5.2 Response

The survey was sent out to 12 representative grid owners in Norway. It proved difficult to get answers on the survey, only three answers came in. It is hard to draw any conclusions from such a limited amount of data, but the trend that these data outlines will be presented.

Two out of three grid owners used non-directional over-current relays for protecting distribution systems with and without DG. The third grid owner used directional over-current relays in distribution grids with DG and non-directional where no DG is present. These responses indicate that the most common relay type at present is non-directional over-current.

Regarding the question of future relay installs the respondents are somewhat divided. One of the respondents are clear on directional over-current relays with synchronism check, no mater if there is DG or not. This is chosen to be prepared for future and to reducing reinvestments at a later point. Second grid owner will consider directional over-current relays with synchronism check on radials with DG, and non-directional in the rest of the distribution system. The last respondent have non-directional over-current relay as a standard, but will consider directional in cases where it is required. In cases with a high side feed-in or fluctuating short-circuit effects they will consider distance relays. The answers are somewhat diverse. It is still indicated that over-current relays will be the dominant relay type in the distribution system in the years to come. It is registered that all the respondents will consider directional over-current relays when evaluating future investments in the protection scheme. This indicates a change compared to the present situation.

6 Simulation

The simulation program used in this thesis is Power Factory. The software is designed to support the needs of many different users, this means that it has several possible settings and simulation options. In addition it is possible to write own scripts in the DPL language. The program has an advanced user interface, despite the graphical input window, an in-depth knowledge is required to operate the program properly. Present thesis has utilized four different Power Factory toolboxes; short-circuit calculation, load-flow calculation, RMS-simulation and protection.

6.1 Model

Two models have been created one with distance relays and one with overcurrent relays. Both models are identical, exept for the protection relays. The simulation models contain two distribution grids. The first is a multi-machine network with several small generation units. The other network have a 22MVA wind farm connected approximately half way out on the radial, this is the same network that was used in the project assignment [7]. The two networks are interconnected through 66kV and 132kV network. The multi machine network has two radials to test for sympathetic tripping in the case of faults on the neighboring radial. For relays and fuses Power Factory predefined models have been used, this to limit the amount of work needed to create the model. It is a quite extensive work to create a relay model and this is not necessary to complete the investigations of this thesis. The one line diagram for the model is presented in appendix A

In the absence of real machine parameters, data from papers and best practice values are used. Synchronous generator parameters are based on the data in [18], a overview of the actual used parameter are presented in table 6.1. The wind generator inverter was set to give a short-circuit contribution of two times the nominal current, which is a typical value for IIDG [16]. Line data are the same as was used in [7] and can be found in table 6.2. For AVR's it is used a simplified excitation system, this is a built-in model in Power Factory. Model data can be found in appendix B

In both grids the major part of the 22kV grid is made of a large LAHF 444 line with low impedance, this can be seen as the mains of both grids. Succeeding or branching of is the laterals that are built up of smaller KHF or FeAl lines, the impedance of these lines are much larger. The effect of increasing production on the network is, expected to have a larger impact as the faults are placed far out on the laterals. Because of this the fault cases are chosen to be far out on some laterals and close to the mains on others. The relays, current- and voltage transformers are chosen and set to match the highest load flows that occur during normal operation. The distance relays in zone 1 are set to reach approximately 90% of the highest occurring impedance, without any production on the radial. Zone 2 and 3 are set to overreach zone 1, the settings can be found in Table 6.3. Zone settings is also shown in Figure 6.2 and Figure 6.3. The overcurrent relays are set with the pickup current a little higher than the normal operating current, settings can be found in Figure 6.1. Every production unit in the grid is equipped with under voltage and under frequency relays. These are set to disconnect within one second if voltage gets below 0,8 nominal and if the frequency gets below 45Hz.

Table 6.1: Synchronous generator data for DG.

Generator Parameter	Generator size 1,6	2	2,6	3
Vn (kV)	0,69	5,25	0,69	0,69
Freq (Hz)	50	50	50	50
H (s)	0,322	1	0,347	1,01
R_d (pu)	0,003	0,01	0,003	0,003
x_l (pu)	0,08	0,1	0,05	0,15
x_d (pu)	2,89	2	2,4	2,32
x_q (pu)	1,72	2	1,77	1,18
x'_d (pu)	0,25	0,3	0,2	0,26
x''_d (pu)	0,17	0,2	0,15	0,16
x''_q (pu)	0,29	0,2	0,2	0,26
T'_d (s)	0,185	1	0,33	0,33
T''_d (s)	0,025	0,05	0,03	0,015
T''_q (s)	0,025	0,05	0,05	0,05

Table 6.2: Line and cable data.

Name	**Description**	**Resistance** $[\Omega/km]$	**Reactance** $[\Omega/km]$	**C** $[\mu F/km]$
KHF 25	Hardened copper wire	0,721	0,421	0,0088
KHF 50	Hardened copper wire	0,3611	0,3652	0,00535
FeAl 50	Aluminum wire with steel core	0,359	0,373	0,0048
FeAl 95	Aluminum wire with steel core	0,191	0,3537	0,005
LAHF 444	Alloyed(AlMgSi) self-supporting cable	0,06696	0,3439	0,013369
TSLF 630	PEX isolated cable ground cable	0,0469	0,15	0,4299
Sub 300	PEX isolated cable submarine cable	0,0609	0,103	0,36

Table 6.3: Distance relay settings.

Relay	Zone	Impedance	Relay angle	Time delay
Wind grid	Z1	12,801	70	0
	Z2	22	70	0,35
	Z3	30	50	0,7
Multi Machine	Z1	4,99	70	0
	Z2	11,98	70	0,35
	Z3	22,5	50	0,7

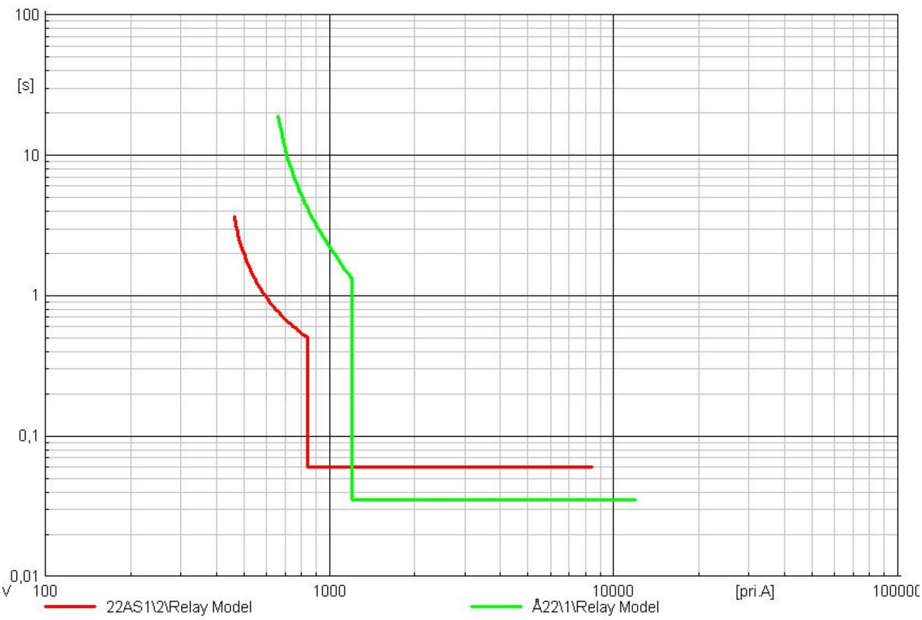


Figure 6.1: Time-overcurrent plot of the relays in the wind grid(Å22 \1 \Relay Model) and the multi machine network(22AS1\2 \Relay Model).

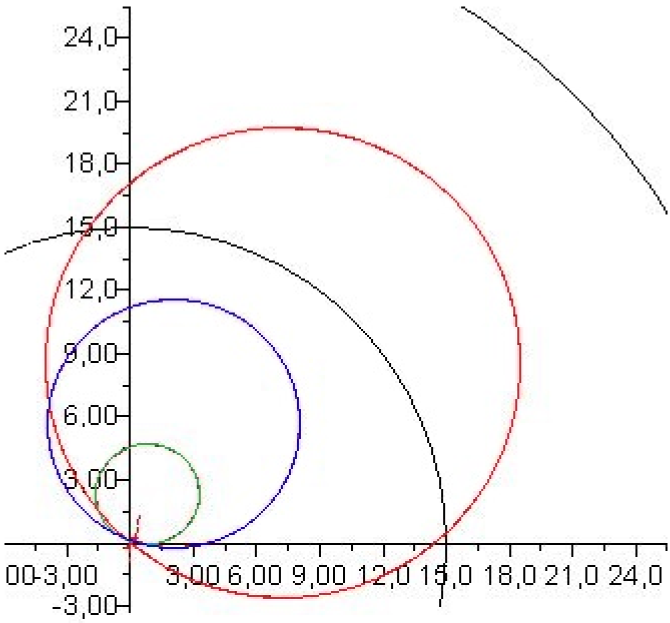


Figure 6.2: R-X plot of the zone setting on in the multi machine network.(Green: Zone 1, Blue: Zone 2, Red: Zone 3)

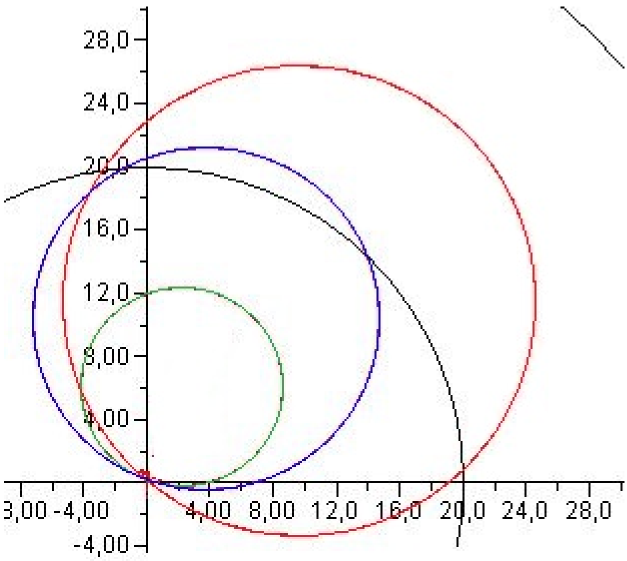


Figure 6.3: R-X plot of the zone setting on in the wind network.
(Green: Zone 1, Blue: Zone 2, Red: Zone 3)

6.2 Method

In order to find the reaction to different fault positions and different levels of DG production, a series of cases have been chosen. The simulation cases are similar for both impedance relays and over-current relays, to ensure that any differences in behavior is recorded. The simulation cases are presented in Table 6.4 and Table 6.5. All cases have been simulated in the RMS-simulating environment and in the short-circuit trace tool. This is done to check for differences between the two simulation methods, because it is useful to see the results presented in two different ways. All faults in the 22kV network are modeled with a fault resistance of 0,6Ω, this is the average fault resistance in the grid according to equation 4.3.

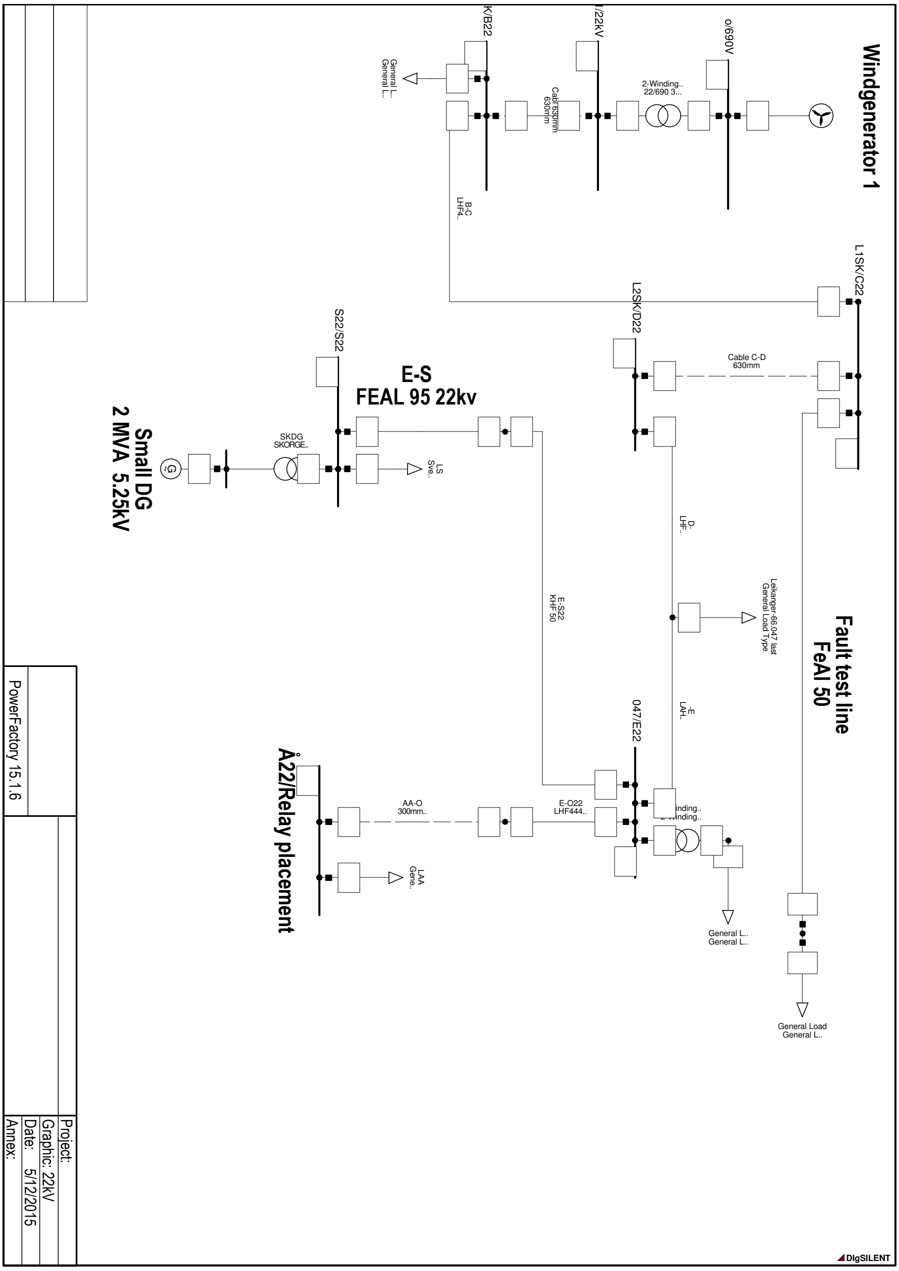
The one line diagram of the two distribution grids are presented in the end of this chapter, the one line diagram of the entire model can be found in appendix A. The most important components have enlarged description.

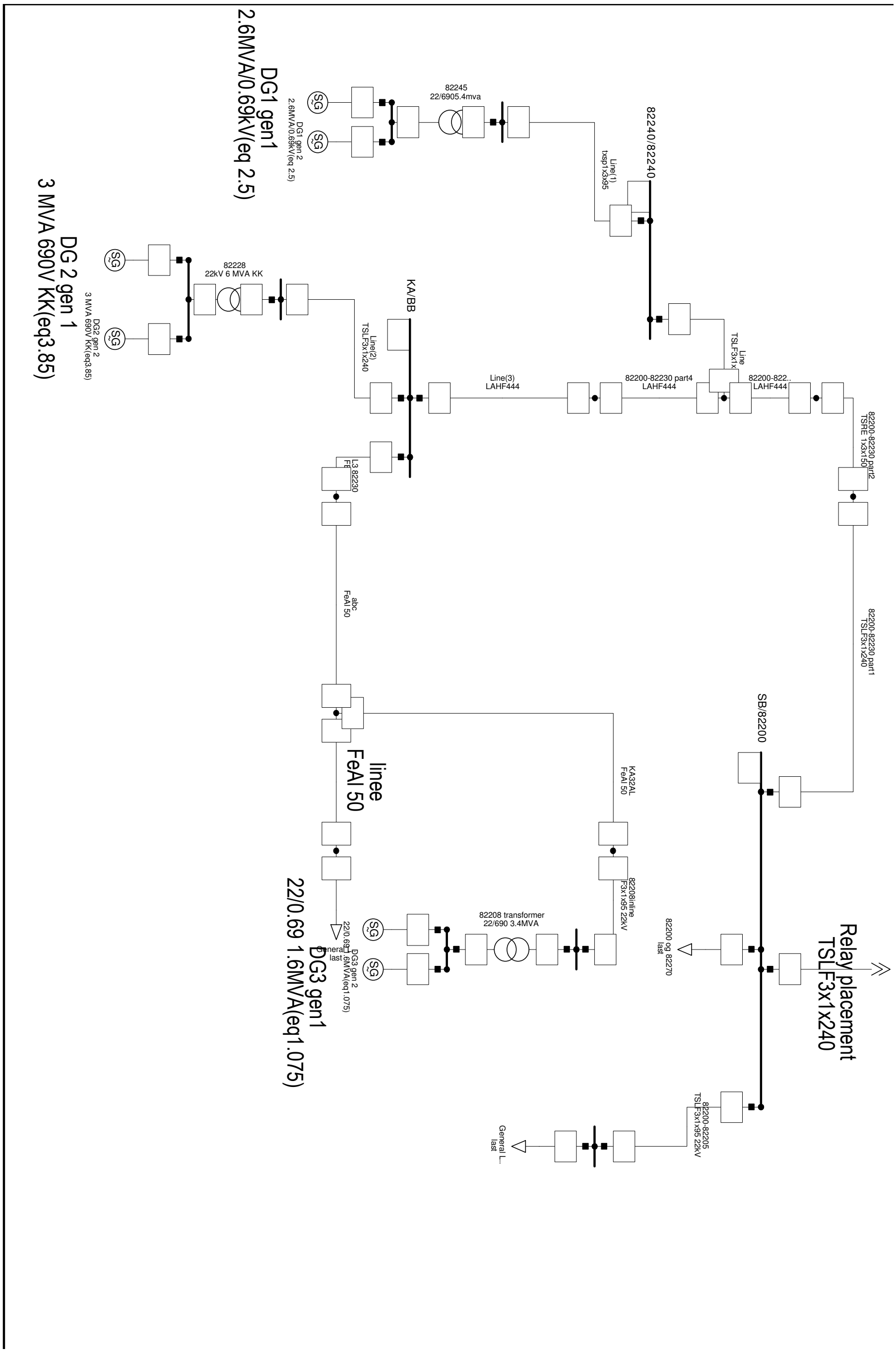
Table 6.4: Fault cases in grid with wind production and one small DG.

SC placement	Production Wind	Production small DG
Fault line 90%	0	0
Fault line 90%	10	0
Fault line 90%	20	0
Fault line 90%	0	1,6
Fault line 90%	10	1,6
Fault line 90%	20	1,6
Fault line 10%	0	0
Fault line 10%	10	0
Fault line 10%	20	0
Fault line 10%	0	1,6
Fault line 10%	10	1,6
Fault line 10%	20	1,6
240 V bus	0	0
240 V bus	0	1,6
240 V bus	20	1,6
Line E-S	0	0
Line E-S	10	0
Line E-S	20	0
Line E-S	0	1,6
Line E-S	10	1,6
Line E-S	20	1,6

Table 6.5: Fault cases and production in multi machine network.

SC placement	Production
Linee 90%	DG1;0 DG2;0 DG3;0
Linee 90%	DG1;2,6 DG2;0 DG3;0
Linee 90%	DG1;2,6 DG2;3 DG3;0
Linee 90%	DG1;2,6 DG2;3 DG3;1,6
Linee 90%	DG1;5,2 DG2;3 DG3;1,6
Linee 90%	DG1;5,2 DG2;6 DG3;1,6
Linee 90%	DG1;5,2 DG2;6 DG3;3,2
Grid 2 R-F 0%	Zero
Grid 2 R-F 0%	Half
Grid 2 R-F 0%	full
Linee 10%	DG1;0 DG2;0 DG3;0
Linee 10%	DG1;2,6 DG2;0 DG3;0
Linee 10%	DG1;2,6 DG2;3 DG3;1
Linee 10%	DG1;2,6 DG2;3 DG3;1,6
Linee 10%	DG1;5,2 DG2;3 DG3;1,6
Linee 10%	DG1;5,2 DG2;6 DG3;1,6
Linee 10%	DG1;5,2 DG2;6 DG3;3,2


Windgenerator 1
2-Winding..
22/690 3...
Cabl 630mm
630mm
B-C
LHF4..
General L..
General L..
L1SK/C22
L2SK/D22
Cable C-D
630mm
E-S
FEAL 95 22kv
S22/S22
SKDG
SKORGE..
LS
Sve..
Small DG
2 MVA 5.25kV
D-
LHF..
Leikanger-66,047 last
General Load Type
E-S22
KHF 50
Fault test line
FeAl 50
047/E22
E-O22
LHF444..
AA-O
300mm..
LAA
Gene..
Å22/Relay placement
General L..
General L..
General Load
General L..
PowerFactory 15.1.6
Project:
Graphic: 22kV
Date: 5/12/2015
Annex:
DIgSILENT


DG1 gen1
2.6MVA/0.69kV(eq 2.5)
DG 2 gen 1
3 MVA 690V KK(eq3.85)
82245
22/6905.4mva
82240/82240
82228
22kV 6 MVA KK
KA/BB
Line(3)
LAHF444
82200-82230 part4
LAHF444
82200-82230 part2
82200-82230 part1
TSLF3x1x240
SB/82200
linee
FeAl 50
abc
FeAl 50
KA32AL
FeAl 50
82208 transformer
22/690 3.4MVA
DG3 gen1
22/0.69 1.6MVA(eq1.075)
Relay placement
TSLF3x1x240
82200 og 82270
last
General L..
last

7 | Results

7.1 Impedance Relays

7.1.1 Multi Machine Network

Figure 7.1 and 7.2 show the change in apparent impedance seen by the relay for two different fault locations and with different production scenarios. From Figure 7.1 the effect of added production on the apparent impedance(see equation 4.2 for calculations) for a fault at 90% of the line, it is observed that when production increases apparent impedance gets larger. It is worth noticing that the power factor increases as the production increases. The same phenomena is observed when the fault is closer to the mains, but the effect is smaller than for a fault at the end of the line. When fault current goes into the grid, the relay detects apparent impedance in the right half plane of the R-X plot. When the flow is from the grid relays detect reversed power flow, the apparent impedance is in the left half plane. Reversed power flow during a fault may prevent the relay from disconnecting a fault. Relays can be set to detect impedance in the left half plane, but this will increase the chance for sympathetic tripping. It is also interesting to observe that the addition of production on DG unit 2 has a larger effect on the impedance compared to adding on DG1 and DG3. This is due to the placement and the size of the unit. It is placed at the end of the mains, and thus has a lower impedance to the relay than the other two units.

It is observed that the total impedance of this grid is quite low; this is because most of the grid length is on the mains, built with a LAHF 444 line with low impedance. All faults on the test line were outside the reach of zone 1 and inside the zone 2 setting when performing short-circuit calculations. The impedance relay have god disconnection and selection properties for this grid.

A R-X plot for the fault case with fault on a neighboring line is not included as all faults where in the left half plane and did not end up within the tripping zones. The impedance relay have good selectivity for sympathetic tripping.

Figure 7.3 and Figure 7.4 presents current-time plots for machines in this grid. Currents are ploted in p.u to make it easier to compare. Relay tripping is also plotted, here a distinct difference from the short-circuit calculation is found. Comparing the two figures a change in disconnection time is found for the two fault cases. For a fault at 90% zone 2 is tripping, for fault at 10% it is zone 1 that trips, this is not the case for short-circuit calculations. If the relay is the only protection device on this radial this is a good thing, however if there are fuse or other breakers a selectivity problem may occur. A reduction in zone 1 reach is recommended if other devices are set up.

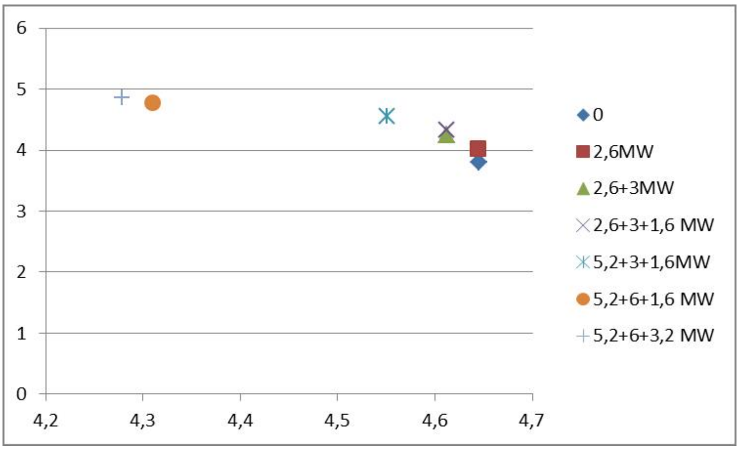


Figure 7.1: Apparent impedance for fault at 90% Linee, with increasing production.

In Figure 7.5 the effect of increasing fault resistance on the apparent impedance is shown. Fault location is at 90% of Linee. It is shown that the magnitude of the apparent impedance is increased over five times, when there is full production and seven ohms fault resistance compared to zero production and fault resistance. Here it is shown that the highest occurring apparent impedance is higher than the zone 3 setting. Thus, the radial is not disconnected.

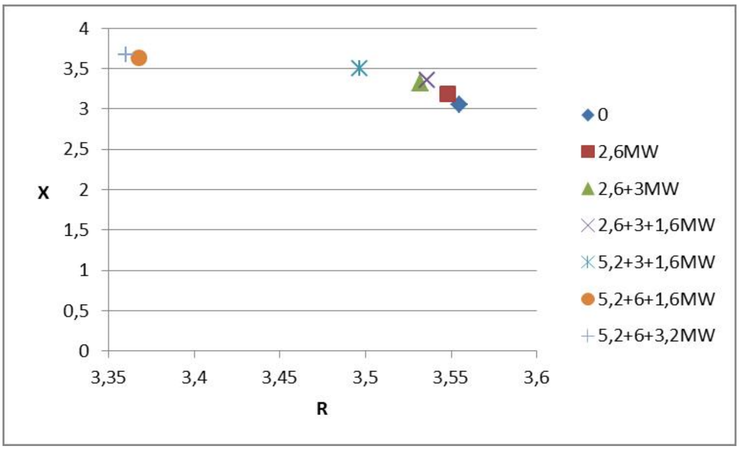


Figure 7.2: Apparent impedance for fault at 10% Linee, with increasing production.

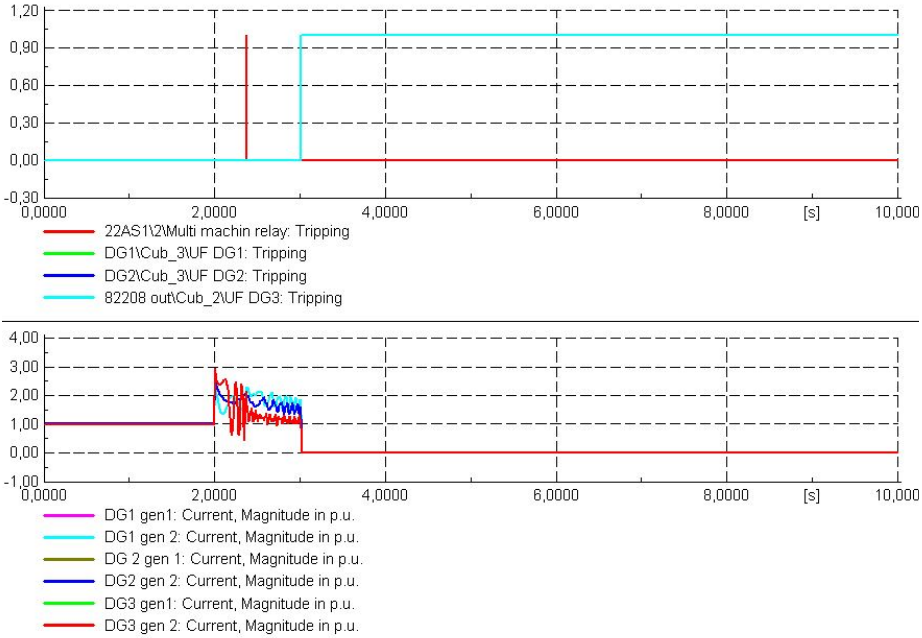


Figure 7.3: Dynamic response to fault at 90% Linee in multi machine network.

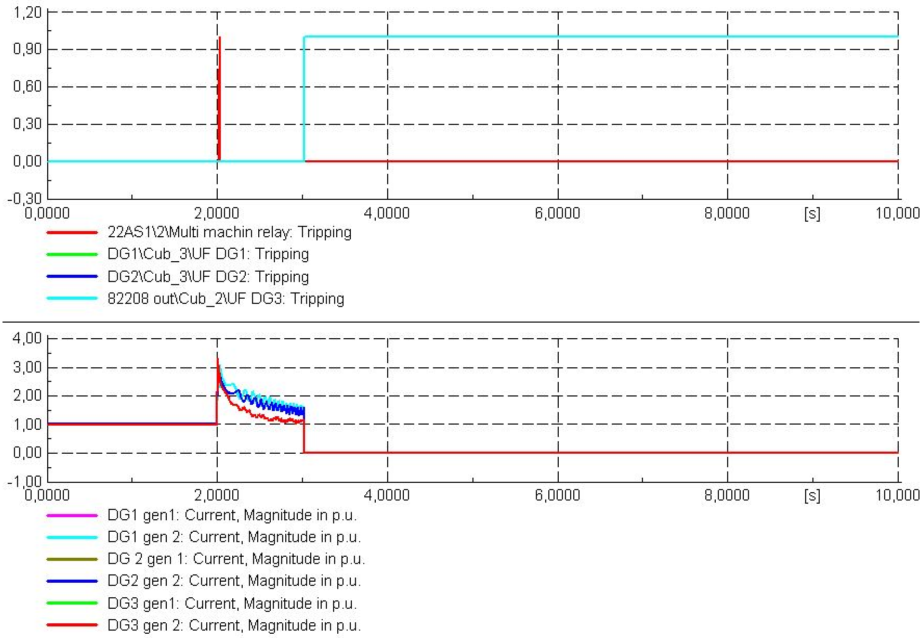


Figure 7.4: Dynamic response to fault at 10% Linee in multi machine network.

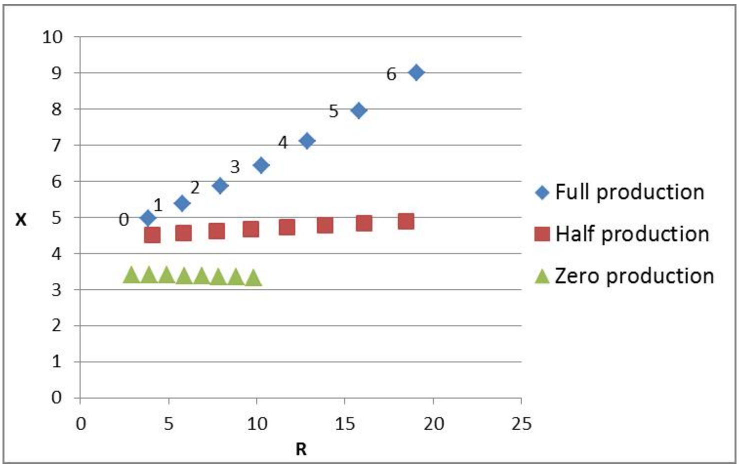


Figure 7.5: Impact on apparent impedance when increasing fault resistance.

7.1.2 Wind Production Network

The impact of a larger production unit is evident in this network. The impedance seen by the relay for faults at 90% and 10% on fault test line is shown in Figure 7.6 and in Figure 7.7. When comparing these two figures it becomes clear that the impact of the DG is larger when the fault position is further away from the feed in point. For faults at 90% distance (Figure 7.6) it is shown that when production is increased the fault impedance changes, the wind production unit is limited by the inverter to only feed in twice the nominal power. This reduces the fault contribution from this unit and the impact of a 20MVA synchronous machine would be higher. If as an example the wind unit was set with a maximum fault contribution of three times the nominal current, the apparent impedance during full production would have been $22,15\angle 49,9$ compared to $17,975\angle 55,82$ in the case analyzed here. This impact is important to notice as it will impact the zone settings. Figure 7.8 underlines the same thing as the short-circuit calculation, it is shown that the radial is disconnected in zone 2, additionally the frequency/voltage relays use 1 second to disconnect the DG units and they will feed the fault for 1 second.

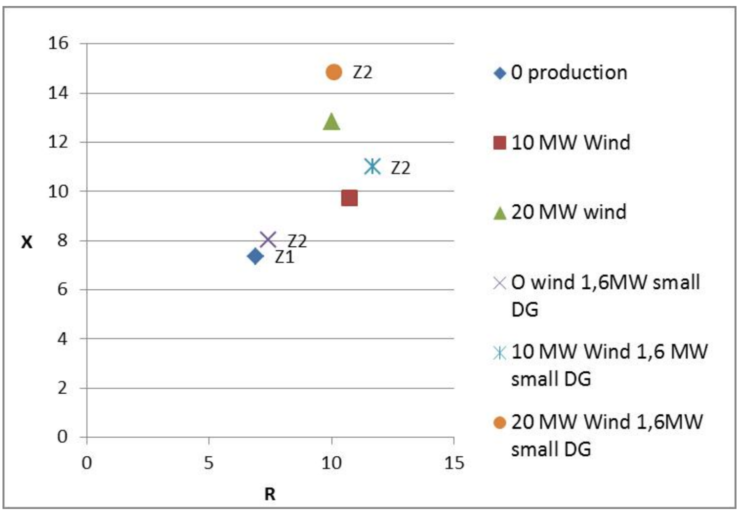


Figure 7.6: Apparent impedance seen by the relay when production is increased, fault placement at 90% of the fault test line.

In Figure 7.7 the impact of production is rather low, this is because the fault is close to the mains and the production unit is close to the fault. The impact of a production unit is larger if it is close to the relay, and the fault is further away. This fault is much closer to the relay in terms of impedance. All faults in this case fell into zone 1, something that might hamper selectivity if fuses or relays are used to protect the lateral. It is in the operator's interest to ensure that this lateral is disconnected without disconnecting the entire radial. In this case the relay setting is overreaching and should be reduced if there are other protective devices on this radial. Figure 7.9 shows that a fault at 10% of fault test line is disconnected from the main grid in zone 1, this may be a problem if other protective devices are set to protect the radial. With the relay setup that is used in present thesis a fast disconnection is desirable.

In Figure 7.10 a fault case with a three phase fault near the small DG unit is shown. This figure contains the same pattern for apparent impedance as in the other figures. When comparing the impedances of this fault with that on the fault test line, the impedances are in the same range for the two faults. This makes it difficult to ensure selectivity for faults on the fault test line and at the same time ensure proper disconnection of these faults. The Fault test line is connected to the mains close to the relay and it is desirable for this to be protected by the main relay.

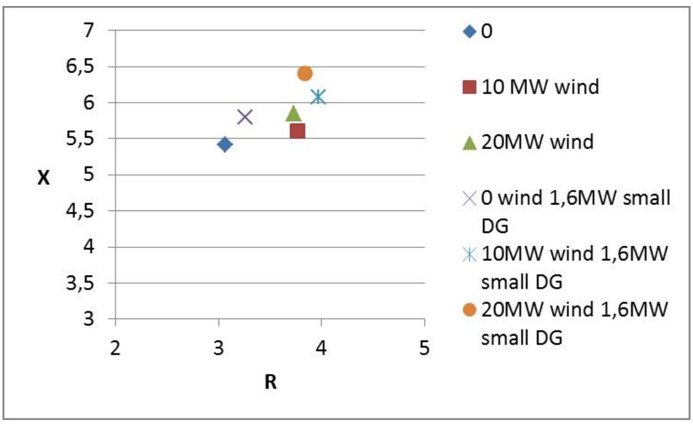


Figure 7.7: Apparent impedance seen by the relay when production is increased, fault placement at 10% of the fault test line.

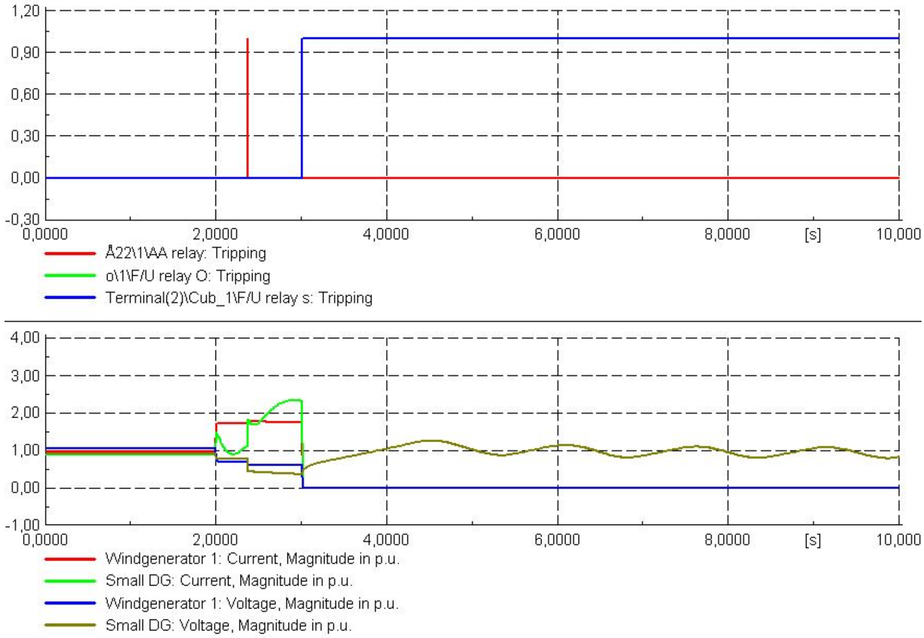


Figure 7.8: Dynamic response for fault at 90% fault line full production wind and small DG.

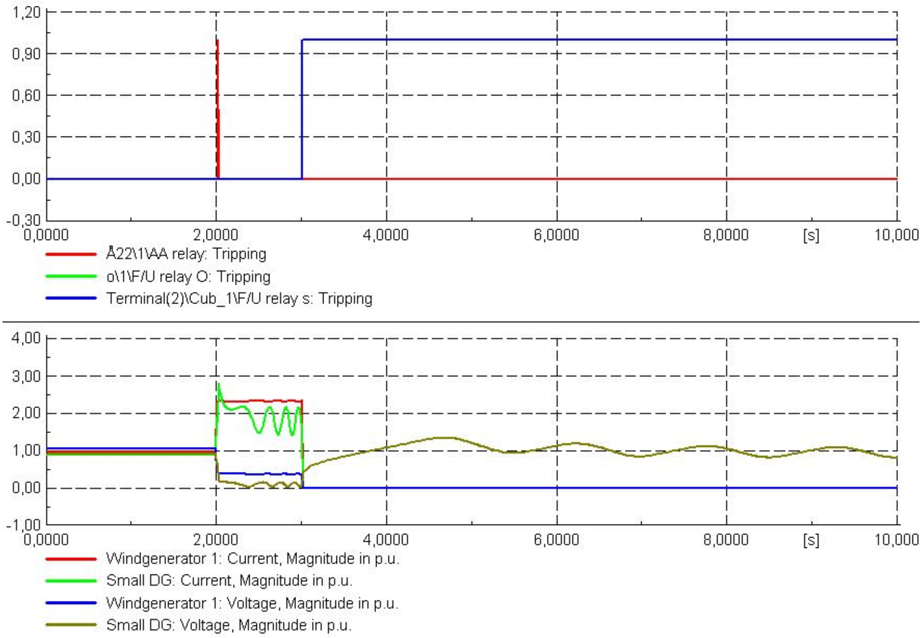


Figure 7.9: Dynamic response for fault at 10% fault line full production wind and small DG.

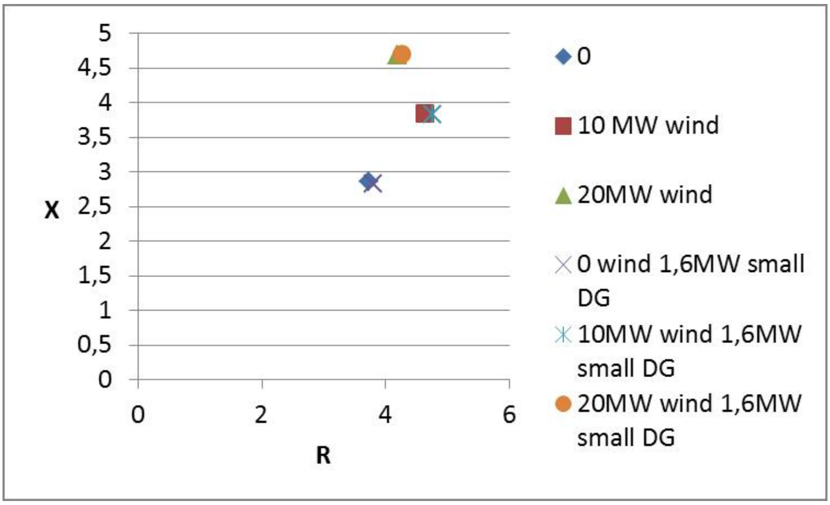


Figure 7.10: Apparent impedance seen by the relay when production is increased, fault placement at line E-F.

A three phase short-circuit placed on the low voltage side of a distribution transformer istested to see the response of the relay. The transformer have fuses on the high voltage side in this simulation, this disconnected all of the faults. The impact on the impedance relay are presented in Figure 7.11. It is shown that for faults at the LV side of the transformer, the fuses will disconnect the fault, the relay will serve as a backup because all of the fault cases are within the reach of zone 2.

Figure 7.12 shows the impact of increasing fault resistance is shown. This can either be an increase in fault resistance or an increase in line resistance. A higher fault resistance can be caused by trees or branches across the phases of a line. In this figure it is clear that the previous statements of DG vs. fault location are true. Higher resistance at the far end of the grid increases the impact of DG units. The added production increases voltage and reduces current at the relay, the same effect is found when increasing resistance. This is the reason for the large deviation on the apparent impedance for a fault resistance of 7 Ω, and the much smaller deviation on zero ohms. Figure 7.12 shows that during full production a fault resistance of seven ohm will bring the apparent impedance across the border of zone 3 setting and the fault will not be cleared by this relay.

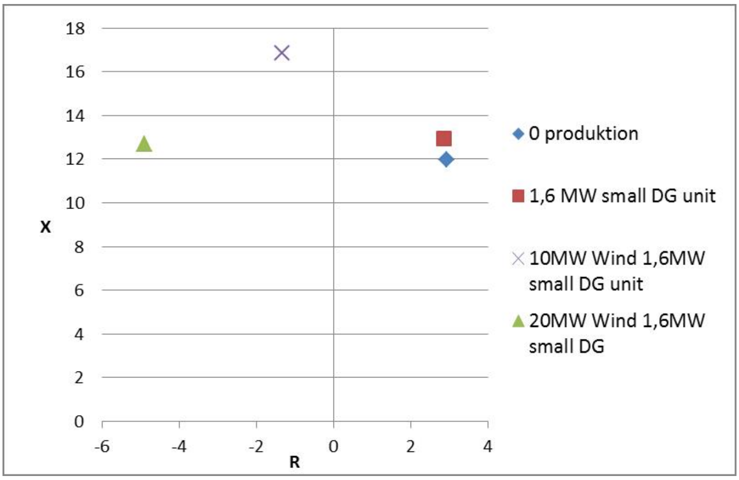


Figure 7.11: Apparent impedance(R-X plot) seen by relay for a fault at low voltage side of distribution transformer(1250kVA).

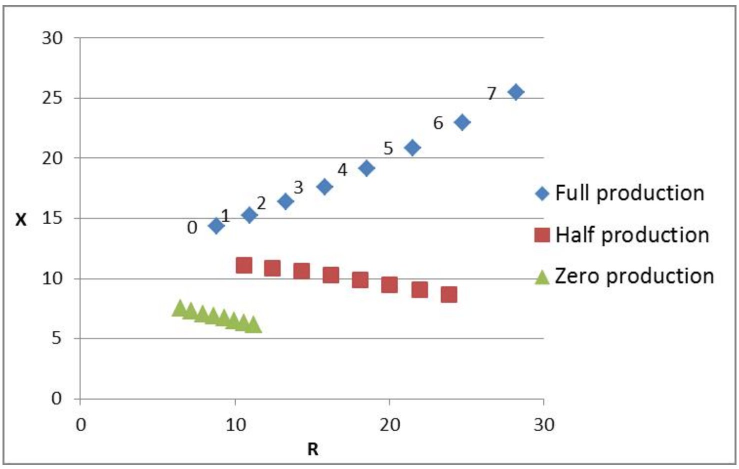


Figure 7.12: Impact of increasing fault resistance from 0 to 7 Ω, with different productions. Fault at 90% fault line.

7.2 Over Current Relays

7.2.1 Multi Machine Network

Figure 7.13 shows fault currents seen by the over-current relay in the multi machine network for faults at 90% distance and 10% distance of the line: Linee. In this network the impedance is quite low, this means that the short-circuit current seen by the relay is high, even when the fault is placed at the end of the grid. It is shown in the figure that the introduction of DG have some impact on the fault current level, with a reduction of about 300A for both the 10% fault case and the 90% fault case. This relay have a I» setting of 840 A and will disconnect all faults beyond this level within 0,06 seconds. The time-current characteristic of the relay can be found in Figure 6.1. This over-current relay are non-directional that means that it can disconnect also for faults on neighboring radials or higher up in the system. For the sympathetic tripping test a fault was simulated at 10% length of a neighboring radial, called line R-F. This relay is vulnerable to sympathetic tripping. The current detected by the relay during fault where 921 A for half production and 983 A for full production. Resulting in a disconnection time of 0,06 seconds. In this case a directional over-current relay or a impedance relay would have been preferable.

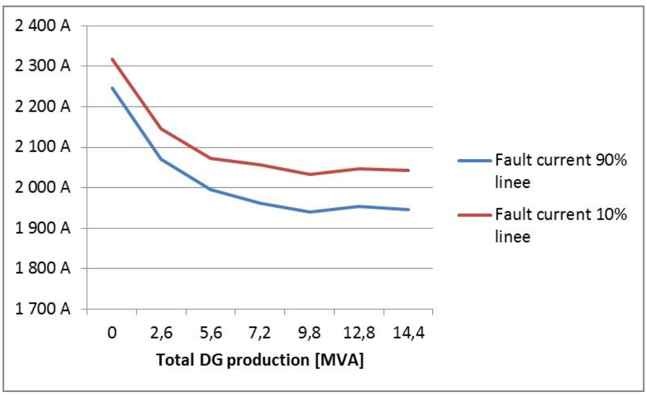


Figure 7.13: Fault currents seen by relay for faults at 90% and 10% of the line: Linee. The amount of production is increased in steps of 0,5 times maximum production for each DG unit, and added one at a time.

For the dynamic simulation Figures 7.14 and 7.15 shows that for this network the over-current relay have shorter disconnection time for faults at 90% than the impedance relay have. The total fault clearing time is still one seconds in this simulation, this is due to the settings of the frequency/voltage relay.

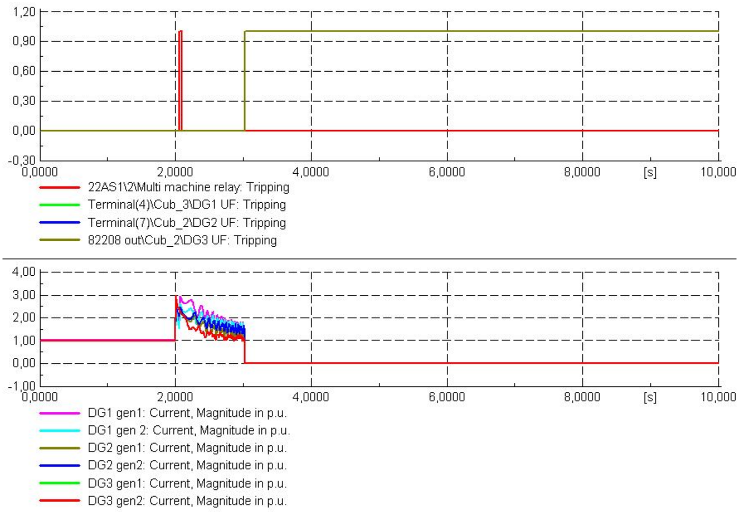


Figure 7.14: Dynamic response to fault at 90% Linee in multi machine network.

In Figure 7.16 shows the effect of increasing resistance of the fault resistance on the fault current. There is a factor of four separating the highest and lowest occuring current. It is shown that the lowest current is higher than nominal load current this ensures disconnection of the radial.

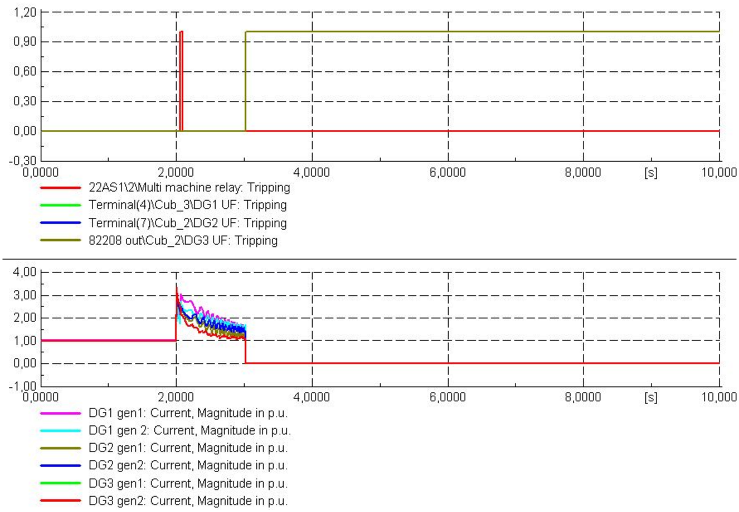


Figure 7.15: Dynamic response to fault at 10% Linee in multi machine network.

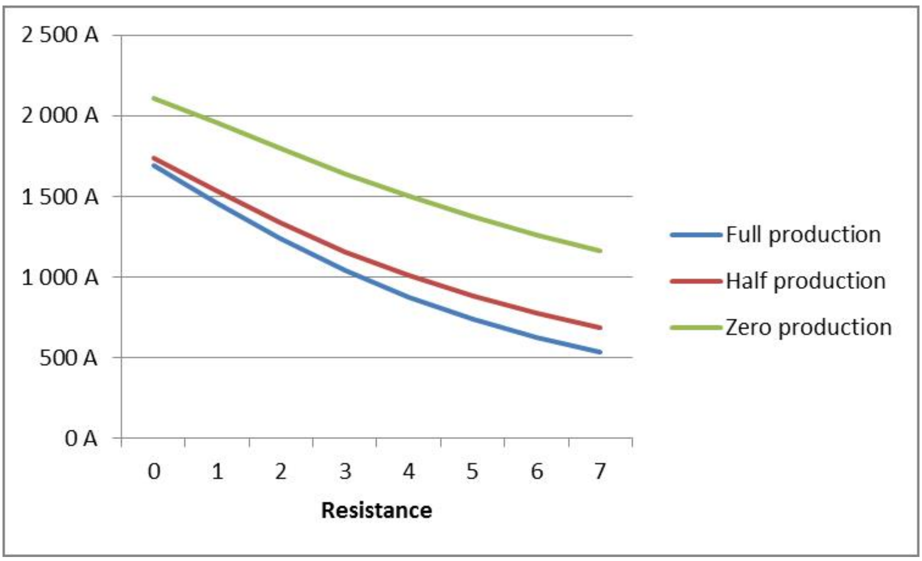


Figure 7.16: Effect on fault current when increasing fault resistance.

7.2.2 Wind Production Network

Figure 7.17 shows the fault current seen by the relay and the actual fault current at the fault location. The fault location is at 90% and 10% on fault test line. At zero production the wind farm is off-line, as a base case for comparison. From the figure it becomes clear that the largest effect on fault current in this network is getting the wind farm on-line, after this the actual fault current display almost no change. A slow decrease in detected current is found as the windproduction increases, this is expected because the wind farm will take a larger portion of the fault current. The small DG unit will have some effect on detected current, but almost no effect on the actual fault current. Examining Figure 7.18 it is shown that as the fault is initiated at 2 seconds on 90% fault test line, the voltage goes below 0.85 p.u. and stays there for more than one second, this leads to a disconnection of the DG units. The grid is still connected until 2,4 seconds after the fault was initiated. This delay is caused partially because of the displacement of fault current by DG and partly because a high pick up current for the relay is needed when there is full production. From Figure 7.19 it is shown that when the fault is at 10% of the test line, over-current relay disconnects instantaneous leaving the two DG units in an island mode until the voltage relay disconnects them. A similar dynamic response is observed for lower production, both in tripping times and profile, but the current level is of course lower.

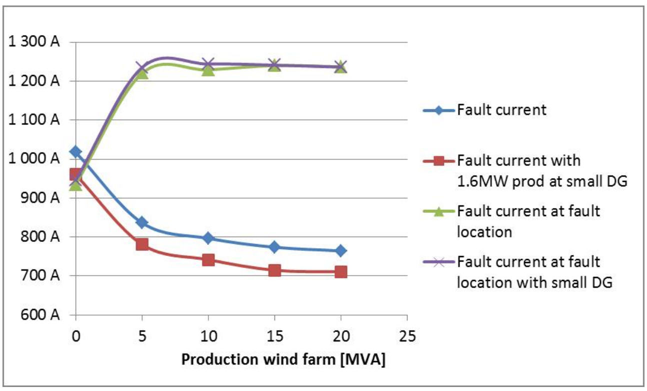


Figure 7.17: Fault current seen by the relay when production is increased, fault placement at 90% of the fault test line.

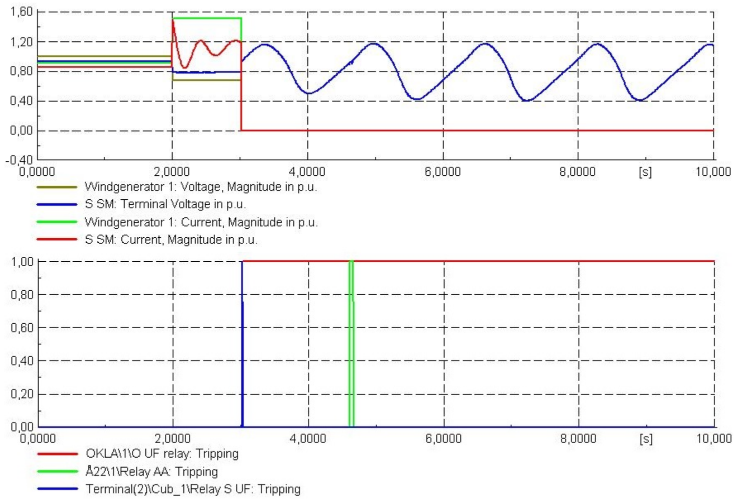


Figure 7.18: Dynamic response to fault at 90% fault line full production on wind and small DG.

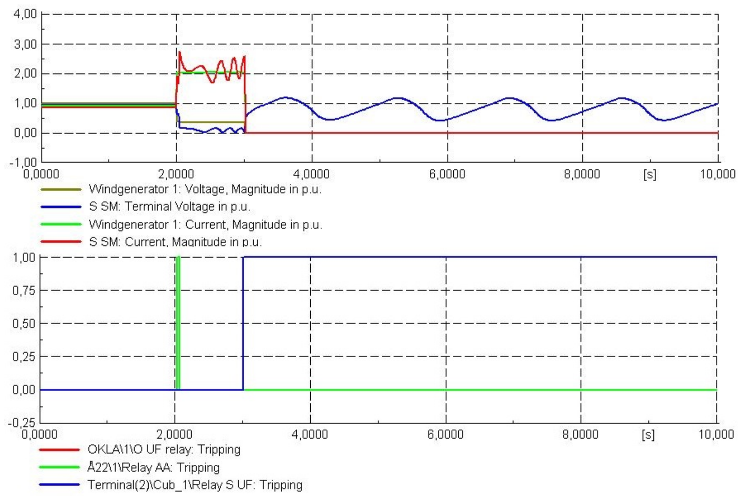


Figure 7.19: Dynamic response to fault at 10% fault line full production on wind and small DG.

In Figure 7.20 the detected fault current at the relay for a fault at line R-F is plotted. The shape of the curve is similar to that shown in Figure 7.17, but the current is higher. It is also observed that the small DG have a smaller impact, this is expected as it is on the far side of the fault place. The small change is due to the fault resistance of 0,6 Ω. The effect of production at the wind farm, will reduce the fault current detected by the relay with a little over 300 A. Fuse-breaker or breaker-breaker coordination may become a problem if a fuse or breaker is placed to protect fault test line, as it was for the impedance relay. It is recommended to add a coordination time interval to the main relay, this will increase the time a fault on the mains is connected and that might not be desirable.

In Figure 7.21 the effect of a increased fault resistance is shown. Here it becomes clear that the effect of production is largest when production first is added, and the effect slowly increases with a higher fault resistance. It is observed that the decrease in fault current due to added resistance is fairly linear. This can also be said about the added production, as was shown in Figure 7.17, after the production is started it is a linear relation. It is when a production unit shifts from off-line to on-line the system behavior changes.

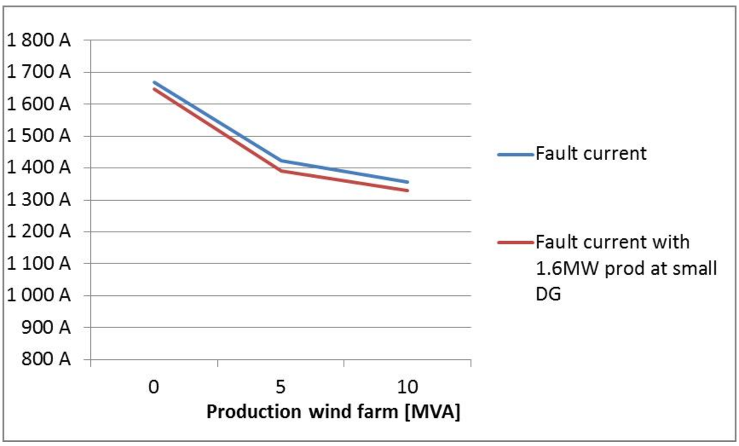


Figure 7.20: Fault current seen by relay for fault at line E-S.

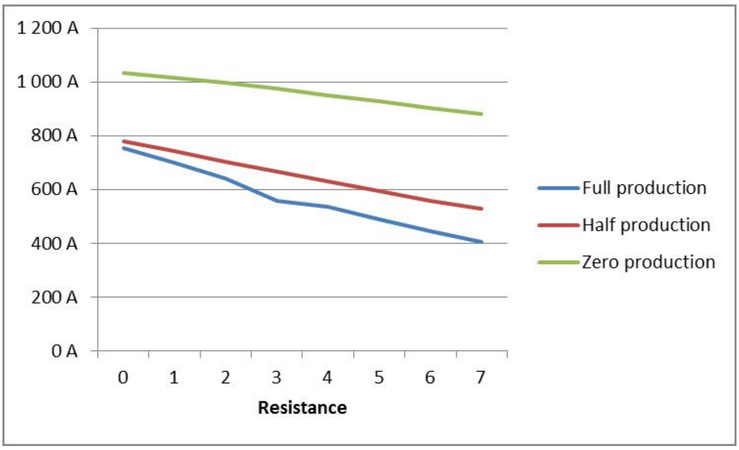


Figure 7.21: Effect of increasing fault resistance for a fault at 90% of the line: Linee.

8 Discussion

The simulations only utilized one relay to protect the radials. Not necessarily because this is the best solution, but because it provides a better insight into the effect of production on the protection scheme.

8.1 Multi Machine Network

In the multi machine network the impedance of the network is low, this is due to large lines and relatively short distances. The impact of adding production in the grid was limited. For faults at 90% of Linee the fault was in zone 2, this was expected as zone 1 is set to underreach the radial length. If the impedance relay is the only protection device this is not necessarily the best option. Zone 1 should reach all faults in the grid, a reach setting of 90% is recommended if selectivity for other protective devices is desirable. An impedance relay can be set to reach all faults in the network in zone 1. This might give disconnection for faults at low voltage side of transformers, if the fuses protecting the transformer are too slow. In the multi machine network it was shown that the over-current relay ensured faster disconnection than impedance relays could manage. This might be the result of an incorrect impedance relay setting, although the recommendations for setting up the impedance relay were followed. This shows that when protecting distribution radials, the zone settings should be considered to partly overreach the grid for zone 1 as well. Although a three zone setting has been used for all simulations in this thesis, it might be preferable to only use two zones, or in some cases only one. In this grid, with low impedance multiple zones only leads to a vast overreach for the zone 3 settings, and as shown in the simulations all fault cases fell within the zone 2 setting.

In this grid, fault currents supplied by the transmission grid are rather high. This ensures fast decoupling times, also for faults at the end of the radial. The effect of adding production is present, but the effect on the protection scheme is low. In this grid the largest problem with over-current relay is sympathetic tripping. Which leads to tripping of the radial when the fault occurs on the neighboring radial. This problem could be solved by a directional over-current relay.

When fault resistance increased the impedance relay were not able to disconnect faults with the zone settings chosen. Zone 3 setting of this network is set to overreach the lines in the radial 4.5 times. It is clear that the zone settings in this network could be set to reach these faults as well, by increasing the zones or by changing the appearance(i.e. not circular). It is clear that increasing fault resistance have a greater impact on a low impedance network than a high impedance. Increased fault resistance also had a great impact on short-circuit currents, but it did not reduce the current below pickup level for the relay.

8.2 Wind Production Network

In this network a larger difference between impedance and over-current relays are found. There are several reasons for this, number one and perhaps the most important contributor is that this grid have almost three times the impedance compared to the multi machine network. The placement of the production units are also different. A large wind production unit is placed at the end of the mains and are able to feed faults on a long lateral of 11 km. The impedance relays ensures short disconnection times for the entire grid, also at the end of the line even though that was in zone 2. Implementing zones in this grid provides a significant advantage, due to the high impedance. It was shown that the impedance relay will reach into the secondary side of the distribution transformer tested. The transformer has both high voltage and low voltage fuses, but it is important that the secondary side of the transformer do not end up in zone 1 of the impedance relay. If the zone 1 impedance is set so high that it reach the low voltage side, it can hamper selectivity and in a worst case scenario disconnects the entire radial due to a fault on secondary side of the transformer.

If a high resistance fault occur at the end of the production radial (e.g. a branch across the lines), the impedance relay will not detect the fault unless the impedance in either zone 2 or zone 3 are set to a very high value. This effect was proved in the simulation case with increasing fault resistance. Where during full production the change in apparent impedance were high. When increasing fault resistance the current at the relay decreased, here as for all faults the change was largest when connecting the production unit. Impact of a increasing fault resistance was large for both current and impedance relays. Impedance relays have the advantage of the ability to set trip for fault levels below nominal load current. This is an advantage in distribution systems with production, since the largest current often is in the reversed direction.

For this grid the use of over-current relay have some drawbacks. For faults at the end of the radial disconnection time is long. In the full production case, the voltage relays on DG units were the first to trip, greatly reducing the disconnection time. If a maloperation caused the voltage relay not to trip, the disconnection time would have been as long as 24 seconds. This would cause high strain on the network, connected generators and consumer equipment. If fault resistance increased the over-current relay would not be able to disconnect the fault from the current position. This confirms the statement by REN [1] that distance relay where the best choice for grids with low short-circuit effects.

In this grid it would have been preferable to have a second relay or at least fuses, to ensure that the production could have stayed on line if a fault occurred on the Fault test line. There are some problems with this setup, faults at 10% length of the Fault test line have the same fault level as fault at R-F. This produces some problems when it comes to using two different relays. To ensure short disconnection time on line R-F, the relay would reach into the second relays' protection area, this applies to both over-current relay and impedance relay. Although a circuit breaker with relays are preferable, the most likely choice if economics is considered is fuses with striker and a connected switch-disconnector, this would ensure disconnection of the lateral during fault.

8.3 Simulation Model

Both dynamic (RMS) and short-circuit simulations were performed, there were differences in findings for these two calculation methods. There may be several reasons for this; first it is two essentially different methods for calculation. In the RMS calculations a numerical integration algorithm is used and it is proved to be accurate. The short-circuit calculation uses a superposition method and calculates short-circuit one element at a time, this make this a less accurate method than the RMS. Another fault source when changing between these methods is the simulation model itself. If the wind generator model is inspected it becomes clear that when a short-circuit calculation is performed the maximum fault contribution is given as two times the nominal current limited by the inverter. For the RMS simulation, the wind farm is simulated as one out of three models: current source, voltage source or constant impedance. The voltage source model was chosen for the simulation cases, to limit the fault contribution a series reactor had to be defined, this was set to have a short-circuit impedance of 35%. These two very different ways of simulating the generation unit may impact the simulation results severely. If one of the other models had been chosen the short-circuit contribution in RMS would have been different.

All fault cases, independent of fault location , have been three phase short-circuits. If simulations with two phase short-circuit or phase to ground fault had been performed it would have affected the fault levels. Simulations should have been performed to investigate how this affected the disconnection times and fault detection. The machines in the simulation model are either inverter interfaced (wind farm) or synchronous machines. Many DG's installed in distribution systems are asynchronous machines, this should have been implemented in the model to see how this machines impacted the protection scheme.

In some fault cases a non circular zone setting would have improved impedance relay performance. Circular zones where chosen since this was the standard in Power Factory relay models. In the cases with increasing fault resistance a quadratic or polygon characteristic could have been more beneficial. These characteristics could be better since they can be fitted to follow the change in Z_{app} and the R-X axis.

9 | Conclusion

Present thesis have modeled two distribution grids. A multi-machine network with synchronous generators. The grid has a low impedance and a limited extent. The other network is a two machine grid, one large inverter interfaced wind farm and a smaller hydro power plant. This grid has a higher impedance and a larger extent.

The simulations show that the two grids have different properties and the protection scheme that is most beneficial for one, is not the best choice for the other. It is found that a short-circuit calculation gives a good indicator on how the system operates during faults, but one should keep in mind that if these calculations is on the operating border it can induce errors. If that is the case an RMS/EMT simulation should be performed.

When protecting a distribution radial with an impedance relay it is not necessary to use a three zone setting on distance relays, unless there are other protective devices requiring coordination. A two zone setting should be sufficient, it is important to keep in mind that the zone 1 setting do not reach into the secondary side of distribution transformers as this may hamper the fuse-breaker coordination and lead to an incorrect disconnection of the radial. Time delay on zone 2 should be adjusted to fit the connected grid with its connected protection devices, in the simulations a time delay of 0,35s were used.

Simulation results indicate that impedance relays are the best choice for high impedance network with production, since the relay can be set to operate for high apparent impedance faults. Setting of protection zones in network with production can be a challenge, simulations indicate that a zone 1 setting of 100% of the radial length is recommended. The zone 2 setting can be set to overreach 100% or more, without reducing the safety of normal operation to an unacceptable level. Over-current relays were shown to work well for faults in low impedance network, but the relay were vulnerable to sympathetic tripping and measures should be taken to prevent this.

10 | Further Work

Some problems pointed out in the discussion needs to be investigated further.

- Test how asynchronous generators affect the protection scheme.
- Test if different zone characteristic in the impedance relays will have a positive effect, especially in low impedance networks.
- Evaluate if an adaptive relay setting is practically applicable in distribution systems.

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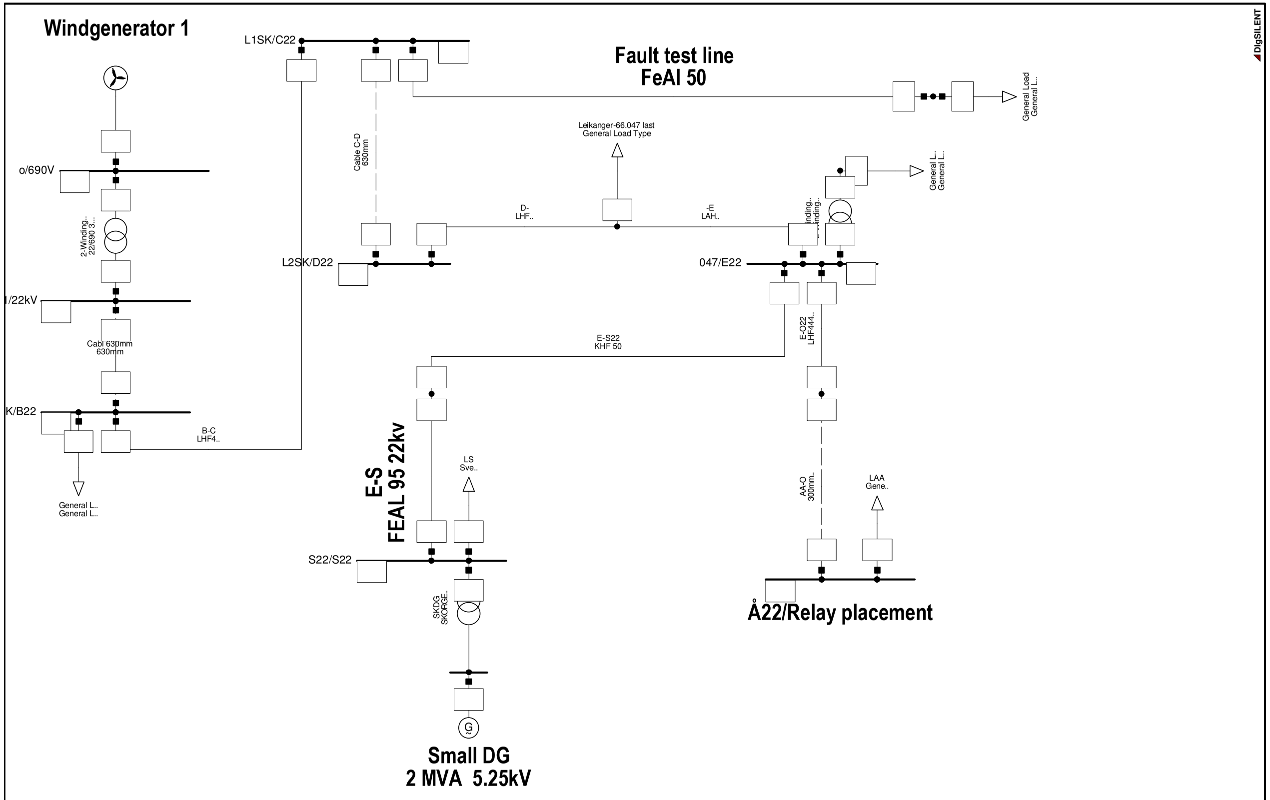
A | Model diagram



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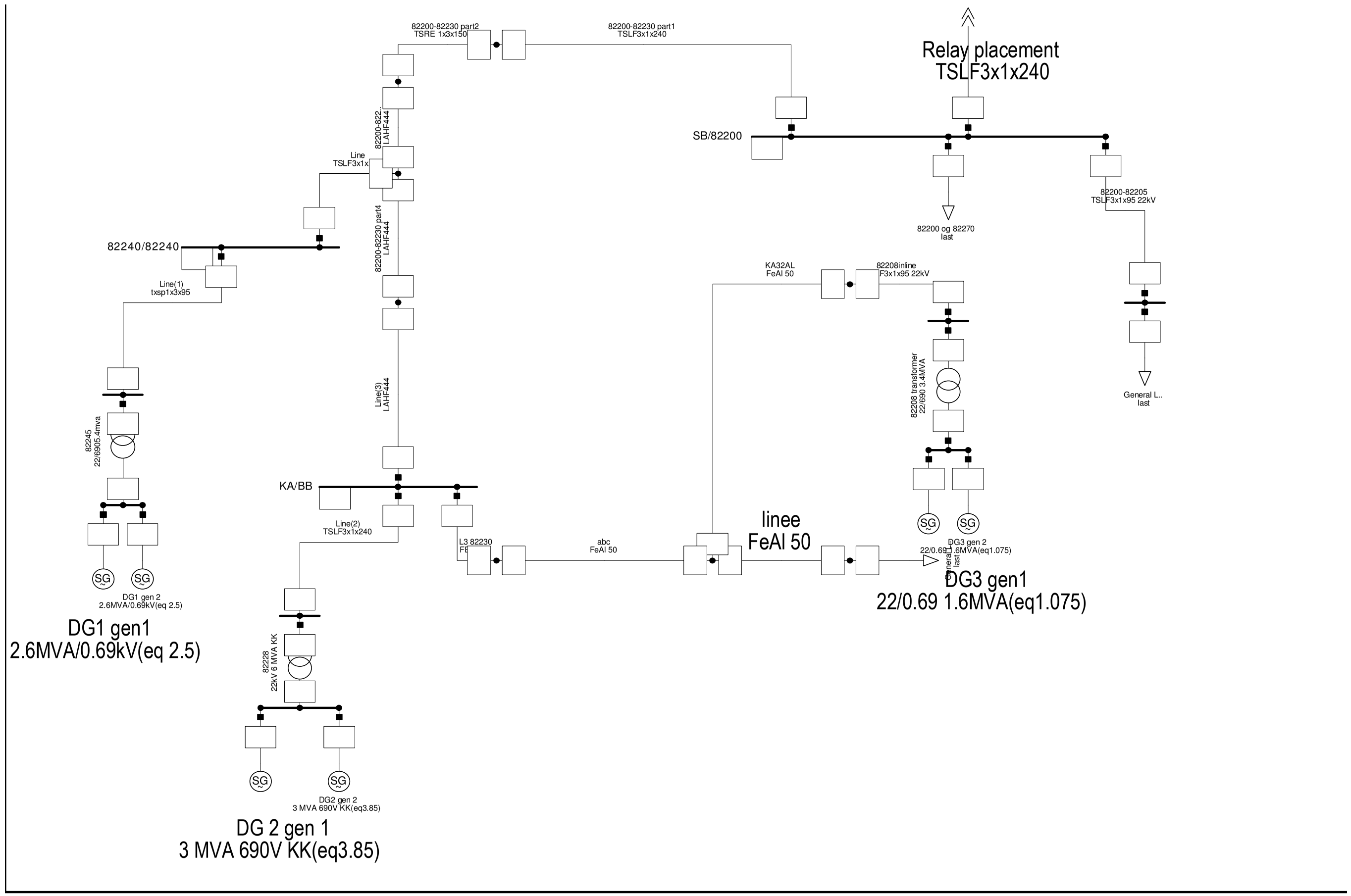
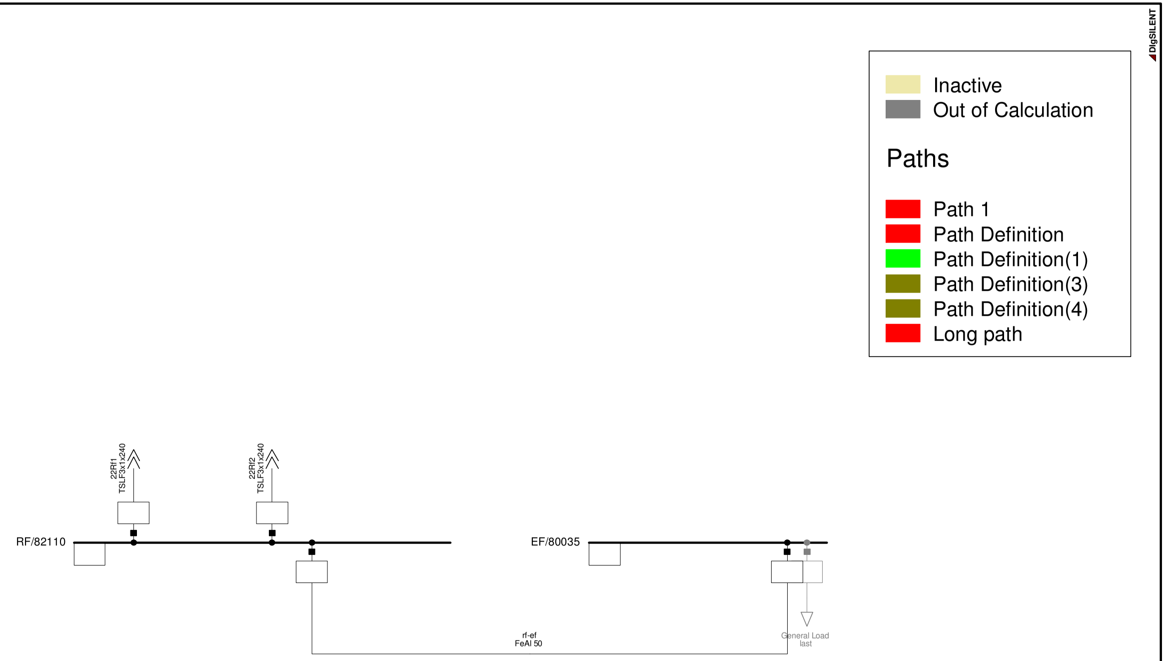
		Date: 5/12/2015
		Annex:


Relay placement
TSLF3x1x240
82200-82230 part2
TSRE 1x3x150
82200-82230 part1
TSLF3x1x240
SB/82200
82200-822..
LAHF444
Line
TSLF3x1x
82240/82240
82200-82230 part4
LAHF444
Line(1)
txsp1x3x95
82200-82205
TSLF3x1x95 22kV
82200 og 82270
last
KA32AL
FeAl 50
82208inline
F3x1x95 22kV
Line(3)
LAHF444
82245
22/6905.4mva
82208 transformer
22/690 3.4MVA
General L..
last
KA/BB
Line(2)
TSLF3x1x240
L3 82230
abc
FeAl 50
linee
FeAl 50
DG3 gen 2
22/0.69 1.6MVA(eq1.075)
DG3 gen1
22/0.69 1.6MVA(eq1.075)
DG1 gen 2
2.6MVA/0.69kV(eq 2.5)
DG1 gen1
2.6MVA/0.69kV(eq 2.5)
82228
22kV 6 MVA KK
DG2 gen 2
3 MVA 690V KK(eq3.85)
DG 2 gen 1
3 MVA 690V KK(eq3.85)



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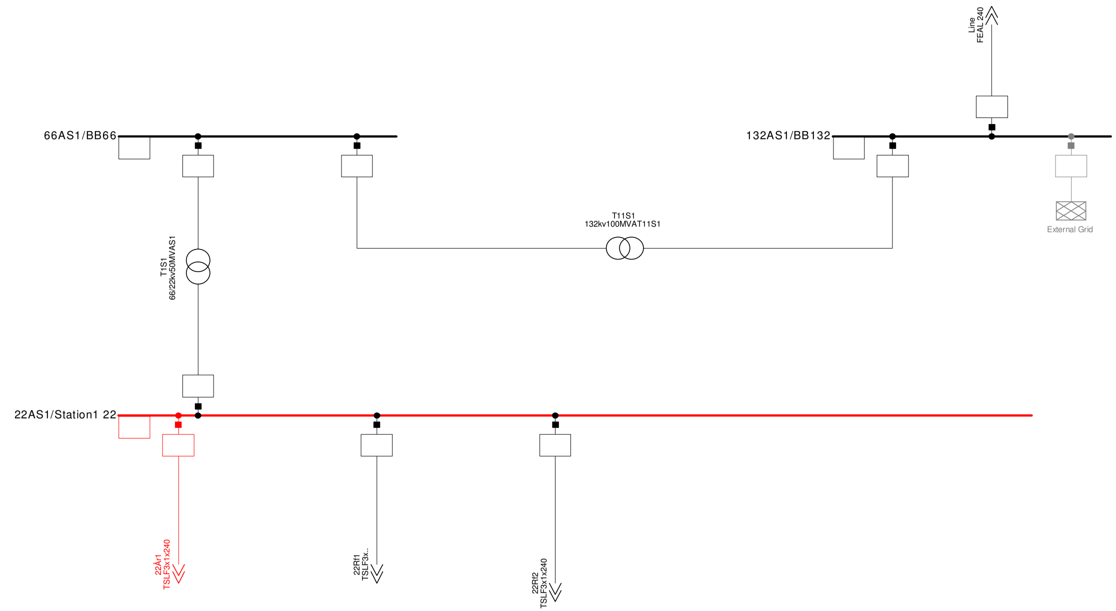

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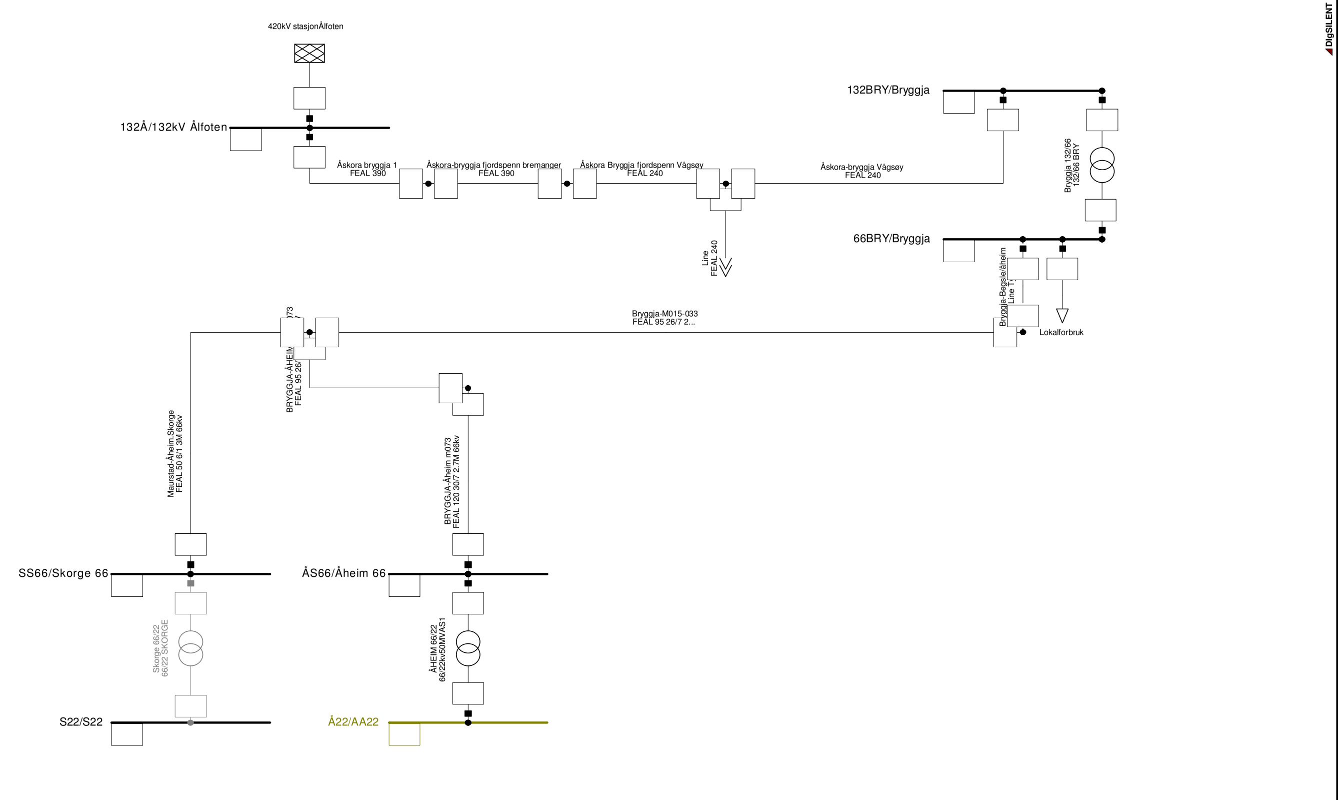
	Annex:



PowerFactory 15.1.6			Project:
			Graphic: Overliggande
			Date: 5/10/2015
			Annex:

B | Model data

Grid: 22kV | Study Case: Study Case
Equipment: Sub-Stations | Annex: / 1

Name	Sub-Elements	Element Type	From BusBar	To BusBar	Un [kV]
AA22					
	AA22	Terminal	AA22/AA22	AA22/AA22	22,00
B					
	B22	Terminal	B/B22	B/B22	22,00
C22					
	C22	Terminal	C22/C22	C22/C22	22,00
E					
	E22	Terminal	E/E22	E/E22	22,00
EL					
	D22	Terminal	EL/D22	EL/D22	22,00
O22					
	22kV	Terminal	O22/22kV	O22/22kV	22,00
O690					
	690V	Terminal	O690/690V	O690/690V	0,69
s22					
	S22	Terminal	s22/S22	s22/S22	22,00

Grid: 22kV | Study Case: Study Case
Equipment: Lines | Annex: / 2

Name	From Busbar	To Busbar	Type	Cross-Sec. [mm^2]	Num-ber	R [Ohm/km]	X [Ohm/km]	B [uS/km]	Distance [km]	In [kA]	Der. factor
-E	Terminal(4)	E/E22	LAHF444	0,00	1	0,0670	0,3440		6,500	1,133	1,00
AA-O	AA22/AA22	O	300mm 22kV	0,00	1	0,0601	0,1037		3,300	0,545	1,00
B-C	B/B22	C22/C22	LHF444AL95	0,00	1	0,0670	0,3439		3,000	1,133	1,00
Cabl 630mm	O22/22kV	B/B22	630mm	0,00	1	0,0469	0,1500		3,095	0,710	1,00
Cable C-D	EL/D22	C22/C22	630mm	0,00	1	0,0469	0,1500		3,296	0,710	1,00
D-	EL/D22	Terminal(4)	LHF444AL95	0,00	1	0,0670	0,3439		6,500	1,133	1,00
E-O22	O	E/E22	LHF444AL95	0,00	1	0,0670	0,3439		0,500	1,133	1,00
E-S	Terminal(3)	s22/S22	FEAL 95 22	0,00	1	0,1910	0,3537		1,634	0,579	1,00
E-S22	E/E22	Terminal(3)	KHF 50	0,00	1	0,3611	0,3652		6,000	0,353	1,00
Fault test 1	C22/C22	end	FeAl 50	0,00	1	0,3590	0,3730		11,000	0,362	1,00
Line(2)	Terminal(6)	AA22/4	FEAL 95 22	0,00	1	0,1910	0,3537		10,000	0,579	1,00

Grid: 22kV | Study Case: Study Case
Equipment: Loads | Annex: / 3

Name	Busbar	Out of Service	Type	S P Q		P Q cosphi	Voltage [p.u.]	System Type	No of Phases	Conn.
General Loa	end	No	General Lo	1,21	MW	0,25 Mvar	1,00	AC	3	D
General Loa	B/B22	No	General Lo	0,50	MW	0,00 Mvar	1,00	AC	3	D
General Loa	Feilterminal0.240kV	No	General Lo	1,20	MW	0,00 Mvar	1,00	AC	3	D
LAA	AA22/AA22	No	General Lo	14,10	MW	0,00 Mvar	1,00	AC	3	D
LS	s22/S22	No	Svelgen	6,40	MW	0,00 Mvar	1,00	AC	3	D
Leikanger-6	Terminal(4)	No	General Lo	0,47	MW	0,08 Mvar	1,00	AC	3	D

Grid: 22kV | Study Case: Study Case
Equipment: Synchronous Machines | Annex: / 4

Name Busbar	Type	Num-ber	Sn [MVA]	Un [kV]	cos phi	xd" [p.u.]	xd"sat. [p.u.]	R2 [p.u.]	x2 [p.u.]	R0 [p.u.]	x0 [p.u.]	Re [Ohm]	xe [Ohm]

AA SM	Terminal(5)	SKORGE gen	5	2,00	5,25	0,80	0,20	0,20	0,000	0,200	0,000	0,100	10,000	0,000
S SM	Terminal(2)	SKORGE gen	1	2,00	5,25	0,80	0,20	0,20	0,000	0,200	0,000	0,100	10,000	0,000

Grid: 22kV | Study Case: Study Case
Equipment: Terminals | Annex: / 5

Name	Inside Element	Type	Un [kV]	System Type	No. of Phases	Ithlim [kA]	Iplim [kA]
22kV	O22	22kVSk	22,00	AC	3	0,00	0,00
690V	O690	0.69kv	0,69	AC	3	0,00	0,00
AA22	AA22	22kVSk	22,00	AC	3	0,00	0,00
B22	B	22kVSk	22,00	AC	3	0,00	0,00
C22	C22	22kVSk	22,00	AC	3	0,00	0,00
D22	EL	22kVSk	22,00	AC	3	0,00	0,00
E22	E	22kVSk	22,00	AC	3	0,00	0,00
Feilterminal0.240kV			0,24	AC	3		
O			22,00	AC	3		
S22	s22	22kVSk	22,00	AC	3	0,00	0,00
Terminal(2)		22kVSk	5,25	AC	3	0,00	0,00
Terminal(3)			22,00	AC	3		
Terminal(4)			22,00	AC	3		
Terminal(5)			5,25	AC	3		
Terminal(6)			22,00	AC	3		
end		22kVSk	22,00	AC	3	0,00	0,00

Grid: 22kV | Study Case: Study Case
Equipment: 2-Winding Transformers | Annex: / 6

Name	From Busbar	To Busbar	Type	Num-ber	Sn [MVA]	HV-Side [kV]	LV-Side [kV]	Uk [%]	Pcu [kW]	Io [%]	Voltage/Tap [%]	[deg]
2-Winding Tr	O22/22kV	O690/690V	22/690 3.4	1	3,400	22,00	0,69	7,00		0,000	0,00	0,0
2-Winding Tr	E/E22	Feilterminal0...	2-Winding	1	1,200	22,00	0,24	3,00		0,000	0,00	0,0
AA S	Terminal(6)	Terminal(5)	SKORGE Kra	10	50,000	23,00	5,25	6,00		0,000	0,00	0,0
SKDG	s22/3	Terminal(2)	SKORGE Kra	1	50,000	23,00	5,25	6,00		0,000	0,00	0,0

Grid: Grid | Study Case: Study Case
Equipment: Sub-Stations | Annex: / 7

Name	Sub-Elements	Element Type	From BusBar	To BusBar	Un [kV]
132kVBRY					
	BRY132	Terminal	132kVBRY/BRY132	132kVBRY/BRY132	132,00
66kV Bry					
	BRY	Terminal	66kV Bry/BRY	66kV Bry/BRY	66,00
AA66-22					
	AA66	Terminal	AA66-22/AA66	AA66-22/AA66	66,00
AAL132					
	132kV AAL	Terminal	AAL132/132kV AAL	AAL132/132kV AAL	132,00
S66-22					
	S66	Terminal	S66-22/S66	S66-22/S66	66,00

Grid: Grid | Study Case: Study Case
Equipment: Lines | Annex: / 8

Name	From Busbar	To Busbar	Type	Cross-Sec. [mm^2]	Num-ber	R [Ohm/km]	X [Ohm/km]	B [uS/km]	Distance [km]	In [kA]	Der. factor
AAS_BRY1	Terminal	AAL132/132kV AAL	FEAL 390	0,00	1	0,0875	0,9600		11,924	1,300	1,00

```
|  AAS_BRY_FJOR  Terminal          Terminal(1)        FEAL 390          0,00   1   0,0875   0,9600               1,143   1,300  1,00 |
|  AAS_BRY_VÅ1   Terminal(1)       Terminal(2)        FEAL 240          0,00   1   0,0760   0,3900               1,174   1,106  1,00 |
|  AAS_BRY_VÅG   Terminal(2)       132kVBRY/BRY132    FEAL 240          0,00   1   0,0760   0,3900               3,350   1,106  1,00 |
|  B-AAm073      Terminal(5)       AA66-22/AA66       FEAL 120 3        0,00   1   0,1510   0,4040               1,000   0,685  1,00 |
|  B-aaM033-073  Terminal(4)       Terminal(5)        FEAL 95 26        0,00   1   0,1810   0,3880               7,777   0,579  1,00 |
|  BRY_BEG_AA    66kV Bry/BRY      Terminal(3)        Line Type         0,00   1   0,0770   0,1200               0,190   0,580  1,00 |
|  BY-M015-033   Terminal(3)       Terminal(4)        FEAL 95 26        0,00   1   0,1810   0,3880               2,919   0,579  1,00 |
|  Line          Terminal(2)       Station 1 132/B..  FEAL 240          0,00   1   0,0760   0,3900               6,000   1,106  1,00 |
|  M-AA-S        Terminal(4)       S66-22/S66         FEAL 50 6/        0,00   1   0,3610   0,4160               4,039   0,386  1,00 |
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| Grid: Grid                                                                                 | Study Case: Study Case              |
| Equipment: Loads                                                                           | Annex:                     /  9     |
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|                                    Out                        S               P                                  No              |
|                                    of                         P               Q            Voltage  System       of              |
| Name             Busbar          Service      Type            Q             cosphi          [p.u.]   Type       Phases     Conn.  |
------------------------------------------------------------------------------------------------------------------------------------
| Lokalforbru  66kV Bry/BRY          No                       2,00  MW        0,00 Mvar      1,00                                  |
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| Grid: Grid                                                                                 | Study Case: Study Case              |
| Equipment: Terminals                                                                       | Annex:                     /  10    |
------------------------------------------------------------------------------------------------------------------------------------
| Name                 Inside                      Type               Un      System     No. of      Ithlim         Iplim          |
|                      Element                                       [kV]      Type      Phases       [kA]          [kA]          |
------------------------------------------------------------------------------------------------------------------------------------
|  132kV AAL            AAL132                 132kV SK             132,00      AC         3          0,00          0,00          |
|  AA66                 AA66-22                66kVSS                66,00      AC         3          0,00          0,00          |
|  BRY                  66kV Bry               66kV busbar           66,00      AC         3          0,00          0,00          |
|  BRY132               132kVBRY               132kV SK             132,00      AC         3          0,00          0,00          |
|  S66                  S66-22                 66kVSS                66,00      AC         3          0,00          0,00          |
|  Terminal                                                        132,00      AC         3                                      |
|  Terminal(1)                                                     132,00      AC         3                                      |
|  Terminal(2)                                                     132,00      AC         3                                      |
|  Terminal(3)                                                      66,00      AC         3                                      |
|  Terminal(4)                                                      66,00      AC         3                                      |
|  Terminal(5)                                                      66,00      AC         3                                      |
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| Grid: Grid                                                                                 | Study Case: Study Case              |
| Equipment: 2-Winding Transformers                                                          | Annex:                     /  11    |
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| Name              From          To              Type         Num-   Sn     HV-Side  LV-Side   Uk      Pcu       Io     Voltage/Tap|
|                   Busbar        Busbar                       ber   [MVA]     [kV]     [kV]    [%]     [kW]      [%]    [%]   [deg]|
------------------------------------------------------------------------------------------------------------------------------------
|  Bry132/66    132kVBRY/BRY132  66kV Bry/BRY    132/66 BRY    1    50,000   132,00    66,00   10,82              0,000   1,67   0,0 |
|  Skorge 66/22 S66-22/S66       s22/S22         66/22 SKOR    1    12,000    60,00    23,00    7,07              0,500   1,98   0,0 |
|  ÅHEIM 66/22  AA66-22/AA66     AA22/AA22       66/22kv50M    1    50,000    66,00    22,00    9,54              0,000   1,67   0,0 |
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| Grid: Grid                                                                                 | Study Case: Study Case              |
| Equipment: External Grids                                                                  | Annex:                     /  12    |
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| Name                                              Sk"        Bus           R/X          Z2/Z1          X0/X1        R0/X0     |
|                               Busbar             [MVA]       Type                                                              |
------------------------------------------------------------------------------------------------------------------------------------
| 420kV                    AAL132/132kV AAL       2400,00       PQ          0,06            1,00           1,00         0,10     |
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| Grid: Grid1                                                                                | Study Case: Study Case              |
| Equipment: Sub-Stations                                                                    | Annex:                     /  13    |
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|                                                                     From                 To                   Un                |
| Name                 Sub-Elements          Element Type            BusBar               BusBar               [kV]               |
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82200	82200	Terminal	82200/82200	82200/82200	22,00
82230	BB	Terminal	82230/BB	82230/BB	22,00
82240	82240	Terminal	82240/82240	82240/82240	22,00

Grid: Grid1 | Study Case: Study Case
Equipment: Lines | Annex: / 14

Name	From Busbar	To Busbar	Type	Cross-Sec. [mm^2]	Num-ber	R [Ohm/km]	X [Ohm/km]	B [uS/km]	Distance [km]	In [kA]	Der. factor
82200-82205	82200/82200	82205	TSLF3x1x95	95,00	1	0,3200	0,1200		0,612	0,275	1,00
82200-82230	82200/82200	Terminal	TSLF3x1x24	240,00	2	0,1252	0,1100		0,644	0,455	1,00
82200-82230	Terminal	Terminal(1)	TSRE 1x3x1	0,00	2	0,1240	0,1200		2,247	0,400	1,00
82200-82230	Terminal(1)	Terminal(2)	LAHF444	0,00	1	0,0670	0,3440		2,351	1,133	1,00
82200-82230	Terminal(2)	Terminal(5)	LAHF444	0,00	1	0,0670	0,3440		0,718	1,133	1,00
82208inline	Terminal(13)	82208 in	TSLF3x1x95	95,00	1	0,3200	0,1200		0,569	0,275	1,00
KA32AL	Terminal(11)	Terminal(13)	FeAl 50	0,00	1	0,3590	0,3730		0,320	0,362	1,00
L3 82230	Terminal(10)	82230/BB	FEAL 25	0,00	1	0,7209	0,3950		0,825	0,235	1,00
Line	Terminal(2)	82240/82240	TSLF3x1x24	240,00	1	0,1252	0,1100		0,002	0,455	1,00
Line(1)	82240/82240	DG122	txsp1x3x95	0,00	1	0,3200	0,1200		0,399	0,240	1,00
Line(2)	82230/BB	DG222	TSLF3x1x24	240,00	1	0,1252	0,1100		0,179	0,455	1,00
Line(3)	Terminal(5)	82230/BB	LAHF444	0,00	1	0,0670	0,3440		1,754	1,133	1,00
abc	Terminal(10)	Terminal(11)	FeAl 50	0,00	1	0,3590	0,3730		1,441	0,362	1,00
lineeee	Terminal(11)	Terminal(12)	FeAl 50	0,00	1	0,3590	0,3730		2,000	0,362	1,00

Grid: Grid1 | Study Case: Study Case
Equipment: Loads | Annex: / 15

Name	Busbar	Out of Service	Type	S P Q	P Q cosphi	Voltage [p.u.]	System Type	No of Phases	Conn.
82200 og 82	82200/82200	No	last	0,20 MW	0,00 Mvar	1,00	AC	3	D
General Loa	82205	No	last	0,03 MW	0,00 Mvar	1,00	AC	3	D
General Loa	Terminal(12)	No	last	0,50 MW	0,01 Mvar	1,00	AC	3	D

Grid: Grid1 | Study Case: Study Case
Equipment: Synchronous Machines | Annex: / 16

Name	Busbar	Type	Num-ber	Sn [MVA]	Un [kV]	cos phi	xd" [p.u.]	xd"sat. [p.u.]	R2 [p.u.]	x2 [p.u.]	R0 [p.u.]	x0 [p.u.]	Re [Ohm]	xe [Ohm]
DG 2 gen 1	DG2	3 MVA 690V	1	3,00	0,69	0,90	0,16	0,20	0,000	0,200	0,000	0,100		
DG1 gen 2	DG1	2.6MVA/0.6	1	2,60	0,69	0,95	0,15	0,20	0,000	0,200	0,000	0,100		
DG1 gen1	DG1	2.6MVA/0.6	1	2,60	0,69	0,95	0,15	0,20	0,000	0,200	0,000	0,100		
DG2 gen 2	DG2	3 MVA 690V	1	3,00	0,69	0,90	0,16	0,20	0,000	0,200	0,000	0,100		
DG3 gen 2	82208 out	22/0.69 1.	1	1,60	0,69	0,90	0,17	0,20	0,000	0,200	0,000	0,100		
DG3 gen1	82208 out	22/0.69 1.	1	1,60	0,69	0,90	0,17	0,20	0,000	0,200	0,000	0,100		

Grid: Grid1 | Study Case: Study Case
Equipment: Terminals | Annex: / 17

Name	Inside Element	Type	Un [kV]	System Type	No. of Phases	Ithlim [kA]	Iplim [kA]
82200	82200	22kvbusbar	22,00	AC	3	0,00	0,00
82205		22kvbusbar	22,00	AC	3	0,00	0,00

82208 in		22kvbusbar	22,00	AC	3	0,00	0,00
82208 out		0.69kv	0,69	AC	3	0,00	0,00
82240	82240	22kvbusbar	22,00	AC	3	0,00	0,00
BB	82230	22kvbusbar	22,00	AC	3	0,00	0,00
DG1		0.69kv	0,69	AC	3	0,00	0,00
DG122		22kvbusbar	22,00	AC	3	0,00	0,00
DG2		0.69kv	0,69	AC	3	0,00	0,00
DG222		22kvbusbar	22,00	AC	3	0,00	0,00
Terminal		22kvbusbar	22,00	AC	3	0,00	0,00
Terminal(1)		22kvbusbar	22,00	AC	3	0,00	0,00
Terminal(10)		22kvbusbar	22,00	AC	3	0,00	0,00
Terminal(11)		22kvbusbar	22,00	AC	3	0,00	0,00
Terminal(12)		22kvbusbar	22,00	AC	3	0,00	0,00
Terminal(13)		22kvbusbar	22,00	AC	3	0,00	0,00
Terminal(2)		22kvbusbar	22,00	AC	3	0,00	0,00
Terminal(5)		22kvbusbar	22,00	AC	3	0,00	0,00

Grid: Grid1 | Study Case: Study Case
Equipment: 2-Winding Transformers | Annex: / 18

Name	From Busbar	To Busbar	Type	Num-ber	Sn [MVA]	HV-Side [kV]	LV-Side [kV]	Uk [%]	Pcu [kW]	Io [%]	Voltage/Tap [%]	[deg]
82208 transf	82208 in	82208 out	22/690 3.4	1	3,400	22,00	0,69	7,00		0,000	0,00	0,0
82228	DG222	DG2	22kV 6 MVA	1	1,000	22,00	0,69	7,00		0,000	0,00	0,0
82245	DG122	DG1	22/6905.4m	1	5,400	22,00	0,69	7,00		0,000	0,00	0,0

Grid: Grid2 | Study Case: Study Case
Equipment: Sub-Stations | Annex: / 19

Name	Sub-Elements	Element Type	From BusBar	To BusBar	Un [kV]
EF					
	80035	Terminal	EF/80035	EF/80035	22,00
RF					
	82110	Terminal	RF/82110	RF/82110	22,00

Grid: Grid2 | Study Case: Study Case
Equipment: Lines | Annex: / 20

Name	From Busbar	To Busbar	Type	Cross-Sec. [mm^2]	Num-ber	R [Ohm/km]	X [Ohm/km]	B [uS/km]	Distance [km]	In [kA]	Der. factor
rf-ef	EF/80035	RF/82110	FeAl 50	0,00	1	0,3590	0,3730		8,000	0,362	1,00

Grid: Grid2 | Study Case: Study Case
Equipment: Loads | Annex: / 21

Name	Busbar	Out of Service	Type	S P Q	P Q cosphi	Voltage [p.u.]	System Type	No of Phases	Conn.
General Loa	EF/80035	Yes	last	15,00 MW	0,00 Mvar	1,00	AC	3	D

Grid: Grid2 | Study Case: Study Case
Equipment: Terminals | Annex: / 22

Name	Inside Element	Type	Un [kV]	System Type	No. of Phases	Ithlim [kA]	Iplim [kA]

80035	EF	22kvbusbar	22,00	AC	3	0,00	0,00
82110	RF	22kvbusbar	22,00	AC	3	0,00	0,00

Grid: Station 1 | Study Case: Study Case
Equipment: Sub-Stations | Annex: / 23

Name	Sub-Elements	Element Type	From BusBar	To BusBar	Un [kV]
Station 1 132					
	BB132	Terminal	Station 1 132/..	Station 1 132/..	132,00
Station1 22					
	Station1 22	Terminal	Station1 22/St..	Station1 22/St..	22,00
Station1 66					
	BB66	Terminal	Station1 66/BB66	Station1 66/BB66	66,00

Grid: Station 1 | Study Case: Study Case
Equipment: Lines | Annex: / 24

Name	From Busbar	To Busbar	Type	Cross-Sec. [mm^2]	Num-ber	R [Ohm/km]	X [Ohm/km]	B [uS/km]	Distance [km]	In [kA]	Der. factor
22Rf1	Station1 22/Sta..	RF/82110	TSLF3x1x24	240,00	1	0,1252	0,1100		0,501	0,455	1,00
22Rf2	Station1 22/Sta..	RF/82110	TSLF3x1x24	240,00	1	0,1252	0,1100		0,838	0,455	1,00
22Ar1	Station1 22/Sta..	82200/82200	TSLF3x1x24	240,00	2	0,1252	0,1100		1,060	0,455	1,00

Grid: Station 1 | Study Case: Study Case
Equipment: Terminals | Annex: / 25

Name	Inside Element	Type	Un [kV]	System Type	No. of Phases	Ithlim [kA]	Iplim [kA]
BB132	Station 1 132	132kvbb	132,00	AC	3	0,00	0,00
BB66	Station1 66	66kV busbar	66,00	AC	3	0,00	0,00
Station1 22	Station1 22	22kvbusbar	22,00	AC	3	0,00	0,00

Grid: Station 1 | Study Case: Study Case
Equipment: 2-Winding Transformers | Annex: / 26

Name	From Busbar	To Busbar	Type	Num-ber	Sn [MVA]	HV-Side [kV]	LV-Side [kV]	Uk [%]	Pcu [kW]	Io [%]	Voltage/Tap [%]	[deg]
T11S1	Station 1 132/..	Station1 66/BB66	132kv100MV	1	100,000	132,00	66,00	11,00		0,000	1,67	0,0
T1S1	Station1 66/BB66	Station1 22/St..	66/22kv50M	1	50,000	66,00	22,00	9,54		0,000	1,67	0,0

Grid: Station 1 | Study Case: Study Case
Equipment: External Grids | Annex: / 27

Name	Busbar	Sk" [MVA]	Bus Type	R/X	Z2/Z1	X0/X1	R0/X0
External Grid	Station 1 132/BB132	10000,00	PV	0,10	1,00	1,00	0,10