CHALMERS

Ride-through of Offshore Wind Parks

Master of Science Thesis

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Abstract

Wind power has proven to be a good alternative in the quest for renewable energy sources. One way to increase the efficiency is to construct large wind parks situated at sea. At the time of writing, wind parks containing more than a hundred wind turbines with a capacity of several hundred megawatts are being planned. Since wind turbines are rather sensitive to reduction in the system voltage, protection devices might disconnect the park from the grid when exposed to a voltage dip. Loosing a large generating unit like a large wind park may lead to instability problems. To prevent this, many system operators have started to include so-called ride-through requirements in their grid codes.

This thesis presents an overview and comparison of a number of grid codes. Most of the ride-through requirements apply to the connection point of the whole wind park which makes it difficult to know how the voltage dip requirement actually looks like at the wind turbine terminals. The voltage dip profiles have therefore been "translated" to the wind turbine terminals. The impact on these requirements with different power system grounding methods as well as transformer winding connections has also been analyzed in the report.

Keywords: Voltage dips, grid codes, wind park, grounding.

Preface

This master thesis was performed at ABB Corporate Research as the final part of my master's degree in electrical engineering at Chalmers University of Technology.

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1 Introduction

1.1 Background and Problem Definition

The amount of installed wind power capacity is expected to increase rapidly in the near future. The trend is to construct large wind parks located offshore and with enough capacity to be installed to the transmission power grid. Until some years ago, the impact of wind power on the electric power system was limited and wind power installations were allowed, or even required, to disconnect during a disturbance in the grid [1]. However, disconnecting a large offshore wind park would result in a significant loss of generation that could cause instability problems. Transmission system operators in strong wind power nations have realized this problem and it is nowadays often required that wind parks stay connected under certain disturbances in the grid [1]. This is normally regulated in so-called grid codes and often referred to as (low-voltage) ride-through.

The new requirements have forced wind power designers and researchers to find technical solutions to improve the ride-through capability. Naturally, the main focus has been the improvement of wind turbines. Simulation models have been developed and measurement data has been collected, see for example [2] and [3]. Further, various suggestions for improvement have been made; some of them presented in [4] and [5]. However, the requirements of different system operators not only vary considerably, they have also been frequently updated. This makes it difficult for a wind power developer to know the design criteria for the equipment. Further, the requirements often apply to the connection point of the whole wind park and not to each turbine. Hence, there is a need for an overview of the different requirements and also an understanding of how a ride-through requirement at the wind park connection point actually affects the wind turbine. The question also arises how the design of the wind park influence the possibility of riding through a disturbance in the grid.

1.2 Aim

The aim of the thesis is to investigate how the system grounding and transformer winding connections in an offshore wind park influence a voltage dip propagating from the grid through the wind park. The requirements of different grid code documents will serve as a base for the study.

1.3 Thesis Layout

Chapter 2 Voltage Dips gives an introduction to the power quality phenomena of voltage dips. The chapter includes definitions, examples and classification methods.
Chapter 3 Overview of Existing Grid Codes presents and compares the connection requirements of six European transmission system operators. The focus of the comparison concern ride-through requirements and reactive power compensation.
Chapter 4 Power System Grounding gives an overview of common grounding methods used in power systems. The advantages and disadvantages as well as areas of use are presented.
Chapter 5 Symmetrical Components presents a short introduction to the use of symmetrical components in power system calculations. A presentation of models of cables and transformers is also given.
Chapter 6 Wind Park Equations and Grounding Calculations provides circuits and equations needed for the analysis of the voltage dip propagation in a wind park. The parameters used for the system grounding are also calculated.

Chapter 7 Calculation Set-Up and Results discusses which calculations that are relevant for the analysis and presents the results of the calculations.
Chapter 8 Translation of Dip Requirements gives some examples of how a specific ride-through requirement at the PCC may be translated to the wind turbine terminals.
Chapter 9 Discussion and Conclusions summarizes the report and presents the most important findings. Recommendations for future work are then given.

Glossary of Terms

AWEA	American Wind Energy Association
ESBNG	Electricity Supply Board National Grid
EWEA	European Wind Energy Association
HV	High-Voltage
IG	Induction Generator
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
LV	Low Voltage
MITYC	Ministerio de Industria, Turismo y Comercio
MV	Medium Voltage
NGET	National Grid Electricity Transmission
PCC	Point of Common Coupling
PN-factor	Positive-Negative factor
REE	Red Eléctrica de España
RMS	Root Mean Square
SG	Synchronous Generator
STATCOM	Static Synchronous Compensator
SVC	Static VAR Compensator
SvK	Svenska Kraftnät
TSO	Transmission System Operator
WP	Wind Park
WT	Wind Turbine

2 Voltage Dips

This chapter provides an introduction to the concept of voltage dips in power systems. Definitions according to international standards as well as origin, electrical models and classification of different types of dips will be presented and discussed. The main focus in this section will be voltage dips due to power system faults.

2.1 Introduction

A voltage dip (or sag) is a reduction of the root-mean-square (RMS) voltage under a short duration of time (a few ms up to a minute). Voltage dips are usually associated with power system faults, but can also be caused by switching of heavy loads or starting of large motors [6]. A fault on a parallel feeder results in a voltage drop at the substation bus that affects all connected feeders until fault clearance according to Figure 1.

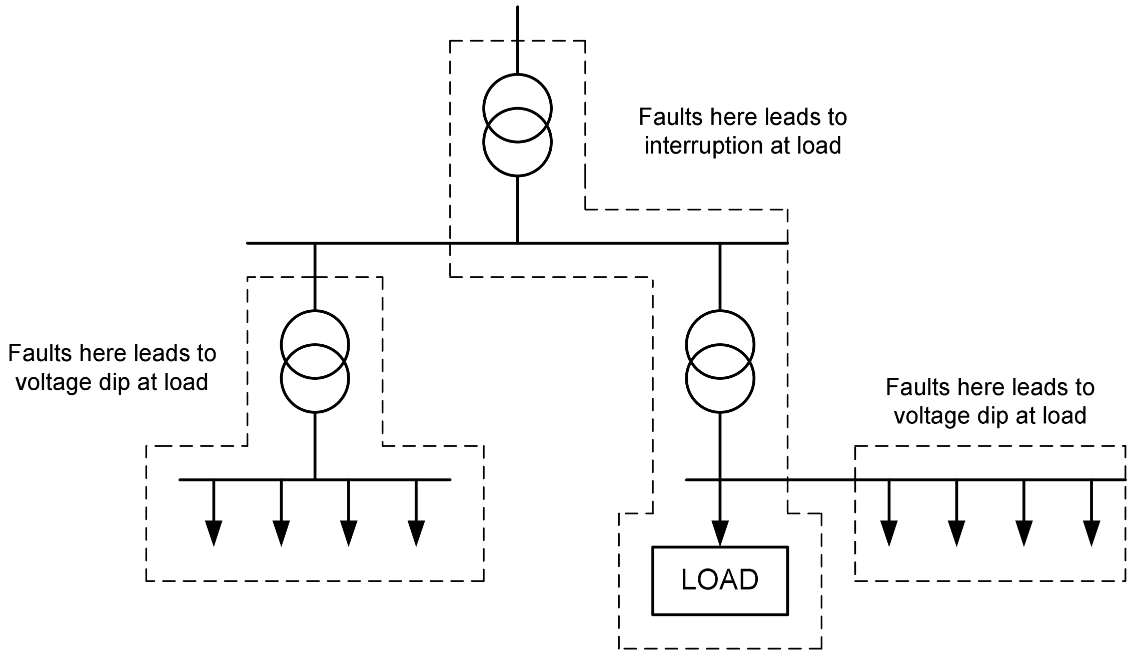


Figure 1. Origin of Voltage Dips due to Faults on Parallel Feeders.

While short and most long interruptions are rather unusual and originate in the local distribution network, voltage dips occur more frequently and can be due to faults hundreds of kilometres away [7]. Despite the rather short duration, a voltage dip may cause tripping of relays and sensitive equipment. Disconnection of large wind parks due to faults in adjacent feeders are unwanted and in most cases not permissible as will be evident in Chapter 3. It is therefore desirable to have an understanding of the definitions and characteristics of voltage dips. It could also be useful to classify different types of dips to get a clearer insight of the phenomenon.

2.2 Definitions

The International Electrotechnical Commission, IEC, defines a voltage dip as a "temporary reduction of the voltage at a point in the electrical system below a threshold" [8]. The somewhat general definition also includes interruptions, which are considered a special case of a voltage dip. Further, the detection of a voltage dip is defined as follows:

– On single-phase systems a voltage dip begins when the $U_{\mathrm{rms}(1/2)}$ voltage falls below the dip threshold, and ends when the $U_{\mathrm{rms}(1/2)}$ voltage is equal to or above the dip threshold plus the hysteresis voltage.

– On polyphase systems a dip begins when the $U_{\mathrm{rms}(1/2)}$ voltage of one or more channels is below the dip threshold and ends when the $U_{\mathrm{rms}(1/2)}$ voltage on all measured channels is equal to or above the dip threshold plus the hysteresis voltage.

The dip threshold and the hysteresis voltage are both set by the user according to the use.

Another definition is set by the Institute of Electrical and Electronics Engineers, IEEE. The existing standard [6], defines a dip as "a decrease to between 0.1 p.u. and 0.9 p.u. in rms voltage or current at the power frequency for durations from 0.5 cycles to 1 minute". To avoid confusion the p.u. values refer to the remaining voltage. A revision of this standard is under development but according to the latest draft version [9] this definition remains unchanged.

2.3 Characterization

A voltage dip is characterized by its magnitude and duration. The definitions described in the former section include the thresholds defining a voltage dip but say nothing about the shape of the dip. Different sources give rise to different dip characteristics.

2.3.1 Balanced dips

A fault that affects all three phases, e.g. a three-phase fault, gives rise to a balanced voltage dip. Figure 2 shows an example of a fault that leads to a balanced voltage dip, occuring between 0.18 and 0.21 seconds in the graph.

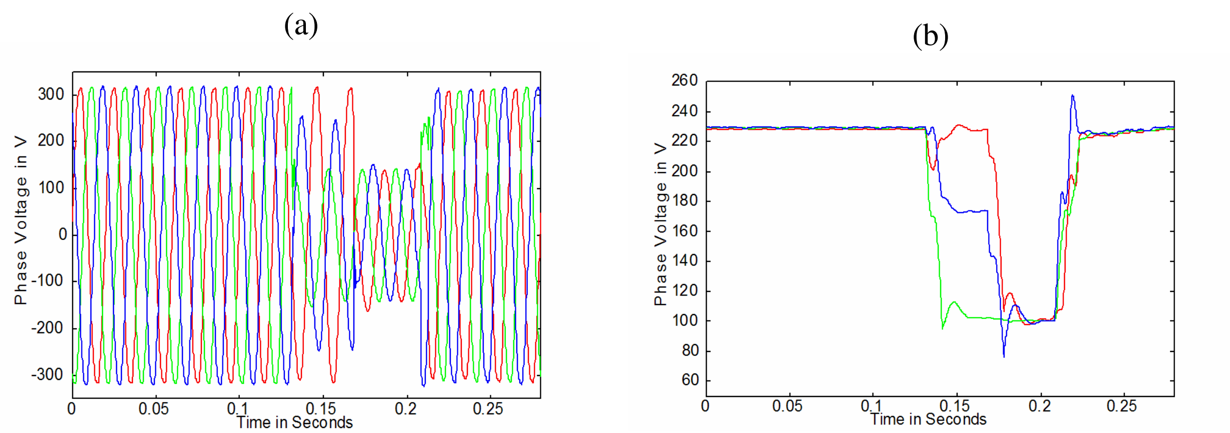


Figure 2. Phase voltages (a) and RMS voltages (b) of a balanced fault (By permission of [10]).

To calculate the magnitude of a balanced dip in radial systems, the voltage divider model in Figure 3 can be used. Although simple it is a very useful tool to predict certain properties of a dip [7]. Neglecting the load current during the fault, the voltage at the point of common coupling, PCC, can be found from

$$\overline{V}_{\mathrm{dip}} = \frac{\overline{Z}_{\mathrm{F}}}{\overline{Z}_{\mathrm{S}} + \overline{Z}_{\mathrm{F}}}. \qquad (1)$$

Z_F denotes the impedance between the PCC and the fault, Z_S the source impedance at the PCC and E the pre-fault voltage. It can be concluded from (1) that the closer the fault is to the customer and the smaller the system fault level, the deeper the dip.

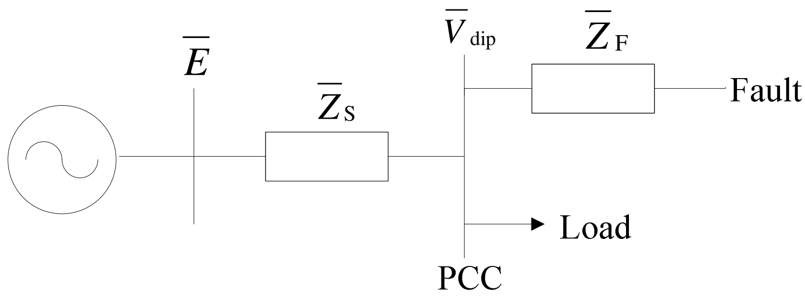


Figure 3. The voltage divider model.

(1) can also be used to calculate the phase-angle jump. By writing $\overline{Z}_F = R_F + jX_F$ and $\overline{Z}_S = R_S + jX_S$, (1) gives the phase-angle jump as

$$\Psi = \arg(\overline{V}_{dip}) = \arctan\left(\frac{X_F}{R_F}\right) - \arctan\left(\frac{X_F + X_S}{R_F + R_S}\right). \tag{2}$$

By setting $\overline{Z}_F = \overline{Z}_S$, Ψ becomes zero, thus, a phase-angle jump occurs when there is a difference of the X/R ratio of the fault impedance and the source impedance. Using the same substitution also gives the dip magnitude

$$\left|\overline{V}_{dip}\right| = \frac{\sqrt{R_F{}^2 + X_F{}^2}}{\sqrt{(R_F + R_S)^2 + (X_F + X_S)^2}}. \tag{3}$$

In transmission systems, Z_F and Z_S are mainly formed by transmission lines resulting in a small phase-angle jump [11]. Thus, neglecting the resistances, the phase-angle becomes zero and the dip magnitude can be expressed as

$$\left|\overline{V}_{dip}\right| = \frac{X_F}{X_F + X_S}. \tag{4}$$

2.3.2 Unbalanced Dips

Unbalanced voltage dips are more common than balanced voltage dips in the power system. An unbalanced dip can be due to single-phase faults, two-phase faults and two-phase-to-ground faults. Figure 4 gives an example of an unbalanced dip.

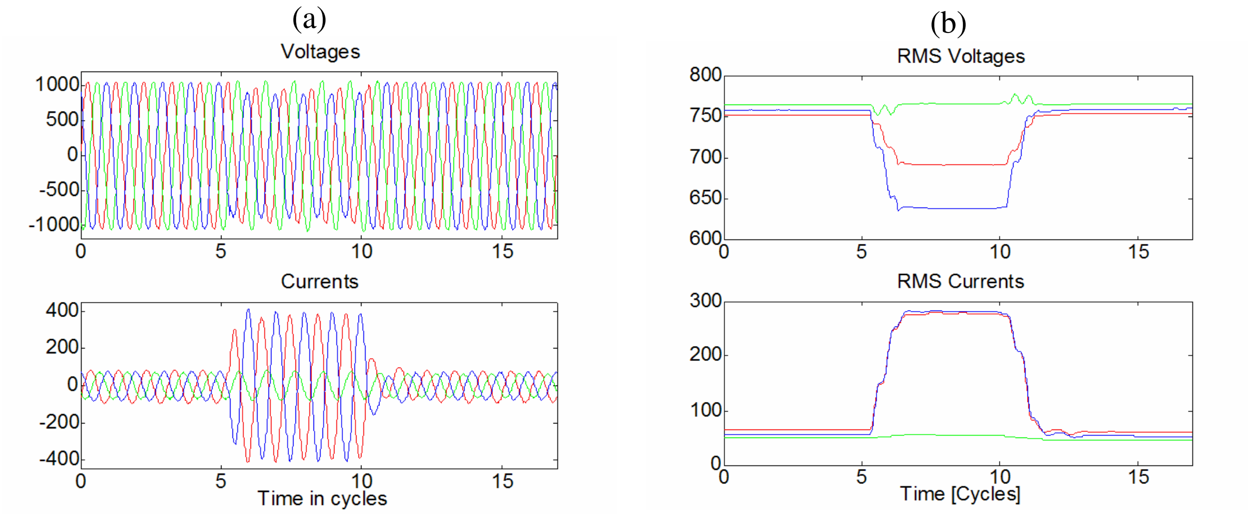


Figure 4. Phase voltages and currents (a) and RMS voltages and currents (b) of an unbalanced (By permission of [10]).

Voltage characteristics due to the three types of faults leading to unbalanced dips are presented in the following sections. By the use of symmetrical components, (1) can be applied to unbalanced faults as well. However, it first has to be split into its three components, i.e. a positive-sequence network, a negative-sequence network and a zero-sequence network. A thorough explanation of the zero-sequence networks forming the equations needed for the use of the voltage divider model is given in [7]. The equations will not be derived here.

2.3.2.1 Single-Phase Faults

The following sections will use the notation according to Table 1.

Table 1. List of Parameters.

Notation	Significance
$\overline{Z}_{S1}$	Positive sequence source impedance
$\overline{Z}_{S2}$	Negative sequence source impedance
$\overline{Z}_{S0}$	Zero sequence source impedance
$\overline{Z}_{F1}$	Positive sequence fault impedance
$\overline{Z}_{F2}$	Negative sequence fault impedance
$\overline{Z}_{F0}$	Zero sequence fault impedance
a	$1e^{j120°}$

Single-phase faults (or single-phase-to-ground faults) are the most common fault type in the power system. In [7], the phase voltages during the fault are shown to be

$$
\begin{aligned}
\overline{V}_a &= 1 - \frac{\overline{Z}_{S1} + \overline{Z}_{S2} + \overline{Z}_{S0}}{\left(\overline{Z}_{F1} + \overline{Z}_{F2} + \overline{Z}_{F0}\right) + \left(\overline{Z}_{S1} + \overline{Z}_{S2} + \overline{Z}_{S0}\right)} \\
\overline{V}_b &= a^2 - \frac{a^2\overline{Z}_{S1} + a\overline{Z}_{S2} + \overline{Z}_{S0}}{\left(\overline{Z}_{F1} + \overline{Z}_{F2} + \overline{Z}_{F0}\right) + \left(\overline{Z}_{S1} + \overline{Z}_{S2} + \overline{Z}_{S0}\right)} \\
\overline{V}_c &= a - \frac{a\overline{Z}_{S1} + a^2\overline{Z}_{S2} + \overline{Z}_{S0}}{\left(\overline{Z}_{F1} + \overline{Z}_{F2} + \overline{Z}_{F0}\right) + \left(\overline{Z}_{S1} + \overline{Z}_{S2} + \overline{Z}_{S0}\right)}
\end{aligned} \tag{5}
$$

where $\overline{Z}_{\mathrm{S1}}, \overline{Z}_{\mathrm{S2}}$ and $\overline{Z}_{\mathrm{S0}}$ are the source impedance values in the three components. $\overline{Z}_{\mathrm{F1}}, \overline{Z}_{\mathrm{F2}}$ and $\overline{Z}_{\mathrm{F0}}$ are the fault impedance values in the three components.

For static elements such as cables, lines and transformers it is reasonable to assume that $\overline{Z}_{\mathrm{S1}} = \overline{Z}_{\mathrm{S2}}$, also assuming $\overline{Z}_{\mathrm{F1}} = \overline{Z}_{\mathrm{F2}} = \overline{Z}_{\mathrm{F0}}$ and denoting $\overline{Z}_{\mathrm{a}}$ as the impedance between the faulted phase a and ground, (5) simplifies to

$$\begin{aligned}
\overline{V}_{\mathrm{a}} &= 1 - \frac{2\overline{Z}_{\mathrm{S1}} + \overline{Z}_{\mathrm{S0}}}{2\overline{Z}_{\mathrm{S1}} + \overline{Z}_{\mathrm{S0}} + 3\overline{Z}_{\mathrm{a}}} \\
\overline{V}_{\mathrm{b}} &= \mathrm{a}^2 - \frac{\overline{Z}_{\mathrm{S0}} - \overline{Z}_{\mathrm{S1}}}{2\overline{Z}_{\mathrm{S1}} + \overline{Z}_{\mathrm{S0}} + 3\overline{Z}_{\mathrm{a}}} \\
\overline{V}_{\mathrm{c}} &= \mathrm{a} - \frac{\overline{Z}_{\mathrm{S0}} - \overline{Z}_{\mathrm{S1}}}{2\overline{Z}_{\mathrm{S1}} + \overline{Z}_{\mathrm{S0}} + 3\overline{Z}_{\mathrm{a}}}.
\end{aligned} \tag{6}$$

This equation can be used to analyze the impact of different grounding system as will be explained later in the thesis.

2.3.2.2 Two-Phase Faults

For faults between two phases, [7] derives the phase voltages as

$$\begin{aligned}
\overline{V}_{\mathrm{a}} &= 1 - \frac{\overline{Z}_{\mathrm{S1}} - \overline{Z}_{\mathrm{S2}}}{\left(\overline{Z}_{\mathrm{F1}} + \overline{Z}_{\mathrm{F2}}\right) + \left(\overline{Z}_{\mathrm{S1}} + \overline{Z}_{\mathrm{S2}}\right)} \\
\overline{V}_{\mathrm{b}} &= \mathrm{a}^2 - \frac{\mathrm{a}^2\overline{Z}_{\mathrm{S1}} - \mathrm{a}\overline{Z}_{\mathrm{S2}}}{\left(\overline{Z}_{\mathrm{F1}} + \overline{Z}_{\mathrm{F2}}\right) + \left(\overline{Z}_{\mathrm{S1}} + \overline{Z}_{\mathrm{S2}}\right)} \\
\overline{V}_{\mathrm{c}} &= \mathrm{a} - \frac{\mathrm{a}\overline{Z}_{\mathrm{S1}} - \mathrm{a}^2\overline{Z}_{\mathrm{S2}}}{\left(\overline{Z}_{\mathrm{F1}} + \overline{Z}_{\mathrm{F2}}\right) + \left(\overline{Z}_{\mathrm{S1}} + \overline{Z}_{\mathrm{S2}}\right)}.
\end{aligned} \tag{7}$$

With the same assumptions as in the previous section and setting $\overline{Z}_{\mathrm{bc}}$ as the impedance between the faulted phases, (7) can be simplified to

$$\begin{aligned}
\overline{V}_{\mathrm{a}} &= 1 \\
\overline{V}_{\mathrm{b}} &= \mathrm{a}^2 - \frac{\left(\mathrm{a}^2 - \mathrm{a}\right)\overline{Z}_{\mathrm{S1}}}{2\overline{Z}_{\mathrm{S1}} + 2\overline{Z}_{\mathrm{bc}}} \\
\overline{V}_{\mathrm{c}} &= \mathrm{a} + \frac{\left(\mathrm{a}^2 - \mathrm{a}\right)\overline{Z}_{\mathrm{S1}}}{2\overline{Z}_{\mathrm{S1}} + 2\overline{Z}_{\mathrm{bc}}}.
\end{aligned} \tag{8}$$

2.3.2.3 Two-Phase-to-Ground Faults

For faults between two phases and ground, [7] derives the phase voltages to be

$$
\begin{aligned}
\overline{V}_{a} &= 1+\frac{\left(\overline{Z}_{S2}-\overline{Z}_{S1}\right)\left(\overline{Z}_{S0}+\overline{Z}_{F0}\right)}{D}+\frac{\left(\overline{Z}_{S0}-\overline{Z}_{S1}\right)\left(\overline{Z}_{S2}+\overline{Z}_{F2}\right)}{D}\\
\overline{V}_{b} &= a^{2}+\frac{\left(a\overline{Z}_{S2}-a^{2}\overline{Z}_{S1}\right)\left(\overline{Z}_{S0}+\overline{Z}_{F0}\right)}{D}+\frac{\left(\overline{Z}_{S0}-a^{2}\overline{Z}_{S1}\right)\left(\overline{Z}_{S2}+\overline{Z}_{F2}\right)}{D}\\
\overline{V}_{c} &= a+\frac{\left(a^{2}\overline{Z}_{S2}-a\overline{Z}_{S1}\right)\left(\overline{Z}_{S0}+\overline{Z}_{F0}\right)}{D}+\frac{\left(\overline{Z}_{S0}-a\overline{Z}_{S1}\right)\left(\overline{Z}_{S2}+\overline{Z}_{F2}\right)}{D}\\
D &= \left(\overline{Z}_{S0}+\overline{Z}_{F0}\right)\left(\overline{Z}_{S1}+\overline{Z}_{F1}+\overline{Z}_{S2}+\overline{Z}_{F2}\right)+\left(\overline{Z}_{S1}+\overline{Z}_{F1}\right)\left(\overline{Z}_{S2}+\overline{Z}_{F2}\right).
\end{aligned}
\tag{9}
$$

2.3.3 Post-Fault Dips

In some cases, the voltage recovers slowly after the fault has been cleared. This phenomenon is referred to as post-fault dips [7]. The RMS voltage for a typical post-fault dip is shown in Figure 5, where only one phase is shown as an example.

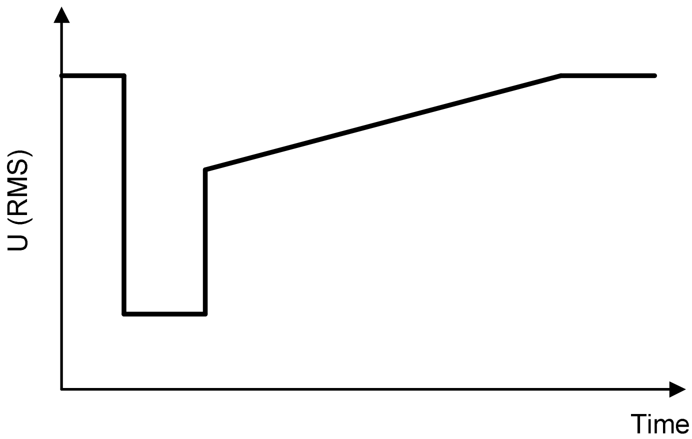


Figure 5. RMS voltage of a post-fault dip.

This effect can be especially severe for dips due to three-phase faults and can be explained as follows [7]. During a voltage dip, the frequency of induction motors will decrease. Since the torque of an induction motor is proportional to the square of the voltage this effect is apparent even for small reductions in voltage. After fault clearing, the voltage starts to recover and the induction motor starts to reaccelerate. Due to the larger slip, the motor will initially draw a large current that decays when the slip gets smaller. This post-fault inrush current is the reason for the prolonged dip. A post-fault dip can last several seconds.

2.4 Classification

Two methods of classifying voltage dips will be discussed in this section. Classification of voltage dips is very useful when analyzing the propagation of dips through transformers. The oldest and most intuitive method is the ABC classification that was first proposed in [12] and later extended in [7]. Although simple to understand, this method is based on incomplete assumptions and cannot be implemented directly in order to obtain the characteristics of measured dips [13]. A more general method, the symmetrical component classification, was introduced in [14] and offers a direct link to measured voltages. However, this method requires knowledge of the use of symmetrical components.

2.4.1 The ABC Classification

The ABC classification identifies seven types of three-phase unbalanced dips. Table 3 shows the different types together with their phase-voltages and phasor-diagrams. $\overline{E}_1$ denotes the pre-fault voltage in phase a and $\overline{V}^*$ is the voltage in the faulted phase or between the faulted phases. This model is only valid under the assumption that the positive-sequence, negative-sequence and zero-sequence impedances are equal for all phases.

Figure 6 together with Table 2 originate from [13] and describes how a voltage dip propagates through two Dy transformers. All seven dip types presented in Table 3 can be found in a system like this. The superscript (*) after a dip type indicates that the dip magnitude is equal to $\frac{1}{3}+\frac{2}{3}V$ instead of just V although the dip characteristics are the same.

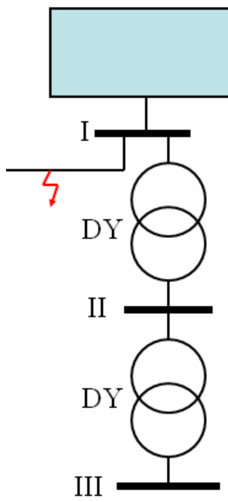


Figure 6. Dips at different voltage levels due to different fault types.

Table 2. Dips at different voltage levels due to different fault types.

Fault type	Measurement location		
	I	II	III
Three-phase	A	A	A
Two-phase-to-ground	E	F	G
Two-phase	C	D	C
Single-phase-to-ground	B	C*	D*

It can be concluded that a voltage dip sometimes changes its characteristics when propagating through a transformer. A complete representation of the change in dip characteristics after passing a transformer with different connections can be found in [7] and is presented here in Table 4. The transformations through a Yd transformer are also valid for the dip experienced by a delta-connected load, i.e. the line-to-line voltage. The possibility to describe the propagation of dips through transformers was one of the reasons for introducing this method.

Table 3. Seven types of three phase unbalanced voltage dips according to the ABC classification.

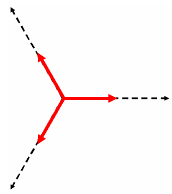
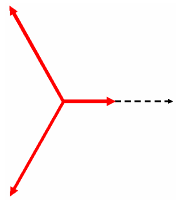
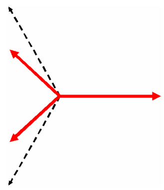
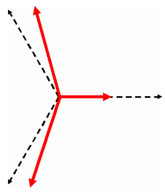
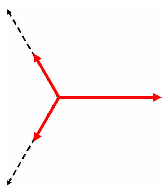
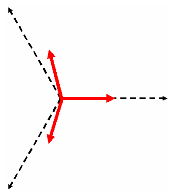
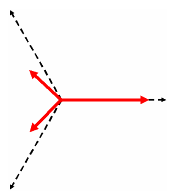
Type	Voltages	Phasors
A	$\overline{U}_a = \overline{V}^*$ $\overline{U}_b = -\frac{1}{2}\overline{V}^* - \frac{1}{2}\mathrm{j}\overline{V}^*\sqrt{3}$ $\overline{U}_c = -\frac{1}{2}\overline{V}^* + \frac{1}{2}\mathrm{j}\overline{V}^*\sqrt{3}$	
B	$\overline{U}_a = \overline{V}^*$ $\overline{U}_b = -\frac{1}{2}\overline{E}_1 - \frac{1}{2}\mathrm{j}\overline{E}_1\sqrt{3}$ $\overline{U}_c = -\frac{1}{2}\overline{E}_1 + \frac{1}{2}\mathrm{j}\overline{E}_1\sqrt{3}$	
C	$\overline{U}_a = \overline{E}_1$ $\overline{U}_b = -\frac{1}{2}\overline{E}_1 - \frac{1}{2}\mathrm{j}\overline{V}^*\sqrt{3}$ $\overline{U}_c = -\frac{1}{2}\overline{E}_1 + \frac{1}{2}\mathrm{j}\overline{V}^*\sqrt{3}$	
D	$\overline{U}_a = \overline{V}^*$ $\overline{U}_b = -\frac{1}{2}\overline{V}^* - \frac{1}{2}\mathrm{j}\overline{E}_1\sqrt{3}$ $\overline{U}_c = -\frac{1}{2}\overline{V}^* + \frac{1}{2}\mathrm{j}\overline{E}_1\sqrt{3}$	
E	$\overline{U}_a = \overline{E}_1$ $\overline{U}_b = -\frac{1}{2}\overline{V}^* - \frac{1}{2}\mathrm{j}\overline{V}^*\sqrt{3}$ $\overline{U}_c = -\frac{1}{2}\overline{V}^* + \frac{1}{2}\mathrm{j}\overline{V}^*\sqrt{3}$	
F	$\overline{U}_a = \overline{V}^*$ $\overline{U}_b = -\frac{1}{2}\overline{V}^* - (\frac{1}{3}\overline{E}_1 + \frac{1}{6}\overline{V}^*)\mathrm{j}\sqrt{3}$ $\overline{U}_c = -\frac{1}{2}\overline{V}^* + (\frac{1}{3}\overline{E}_1 + \frac{1}{6}\overline{V}^*)\mathrm{j}\sqrt{3}$	
G	$\overline{U}_a = \frac{2}{3}\overline{E}_1 + \frac{1}{3}\overline{V}^*$ $\overline{U}_b = -\frac{1}{3}\overline{E}_1 - \frac{1}{6}\overline{V}^* - \frac{1}{2}\mathrm{j}\overline{V}^*\sqrt{3}$ $\overline{U}_c = -\frac{1}{3}\overline{E}_1 - \frac{1}{6}\overline{V}^* + \frac{1}{2}\mathrm{j}\overline{V}^*\sqrt{3}$	

Table 4. Transformation of dip type to lower voltage levels.

Transformer connection	Dip on primary side						
	Type A	Type B	Type C	Type D	Type E	Type F	Type G
YNyn	A	B	C	D	E	F	G
Yy, Dd, Dz	A	D*	C	D	G	F	G
Yd, Dy, Yz	A	C*	D	C	F	G	F

This classification was in the beginning used together with statistics in order to make a stochastic prediction of the frequency of occurrence of different types of voltage dips. However, the classification is also a useful tool when testing equipment against voltage dips. By using this model, the voltage dip that is expected at the terminals of the equipment to be tested, can be generated. The drawback of this method is that it is only simulation-based and it is not immediately possible to extract the dip type from measured voltage waveforms for dips with too big phase-angle jumps [13].

2.4.2 The Symmetrical Component Classification

The symmetrical component classification is a more general method that, unlike the ABC classification, is also valid when positive and negative sequence impedances are not equal. The classification separates dips in two main categories:

- Type C - a dip with the main voltage drop between two phases.
- Type D - a dip with the main voltage drop in one phase.

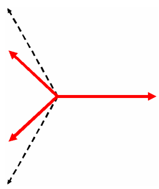
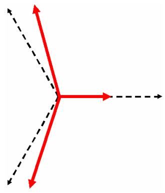
The notation is chosen to be consistent with the ABC classification. Although only two categories are used, all dip types in the ABC classification can be transformed into these categories by asserting different values to the variables just mentioned. This relation will be analysed later on.

In this method, the complex phase voltages are expressed as compositions of two main complex parameters, the "characteristic voltage" $\overline{V}$, and the "PN-factor" $\overline{F}$. The characteristic voltage is the main characteristic describing the event and is determined by the positive-sequence source and feeder impedance for two-phase and three-phase faults. For single-phase faults, the zero-sequence impedance influences the characteristic voltage [15]. The PN-factor (Positive-Negative factor) is a measure of the unbalance of the event. A low value of the PN-factor corresponds to a balanced event while a high value corresponds to a more unbalanced event. For unbalanced events such as a single-phase and a phase-to-phase fault, the PN-factor is close to 1 p.u. [15]. For balanced three-phase faults, the PN-factor is equal to the characteristic voltage. Hence, the PN-factor cannot be lower than the characteristic voltage.

A third parameter, the zero-sequence voltage $\overline{U}_0$ is treated as a separate characteristic. It gives information about the location of the underlying event but is often neglected because of its low impact on the operation of equipment [15].

Table 5 presents the phase voltages of the different dip types according to the symmetrical component classification together with their phasor-diagrams. For dip type $\mathrm{D_a}$ the voltage dip has the main drop in phase a, while dip type $\mathrm{C_a}$ has the main drop between phases b and c. Hence there are six different dip types, depending on which phase is the symmetrical one.

Table 5. Two types of three phase unbalanced voltage dips according to the Symmetrical components classification.

Type	Voltages	Phasors
$\mathbf{C_a}$	$\overline{U}_a = \overline{F}$ $\overline{U}_b = -\tfrac{1}{2}\overline{F} - \tfrac{1}{2}\mathrm{j}\overline{V}\sqrt{3}$ $\overline{U}_c = -\tfrac{1}{2}\overline{F} + \tfrac{1}{2}\mathrm{j}\overline{V}\sqrt{3}$	
$\mathbf{D_a}$	$\overline{U}_a = \overline{V}$ $\overline{U}_b = -\tfrac{1}{2}\overline{V} - \tfrac{1}{2}\mathrm{j}\overline{F}\sqrt{3}$ $\overline{U}_c = -\tfrac{1}{2}\overline{V} + \tfrac{1}{2}\mathrm{j}\overline{F}\sqrt{3}$	

The advantage of this method is that it covers all cases of voltage dips and do not suffer from the limitations in the ABC method. The symmetrical component classification leads to a well-defined algorithm for extracting voltage dip types and characteristics from measurement values [13]. The drawback of this method is that the use of symmetrical components makes it more complicated and requires basic knowledge of its use.

2.4.3 Comparison of the Two Methods

If the assumptions made for the ABC classification holds, there is a clear relation between the two classifications. Table 6 is reproduced from [13], and shows the transformation from the ABC classification to the symmetrical component classification assuming phase a as the symmetrical one.

Table 6. Relation between the ABC classification and the Symmetrical components classification for three-phase unbalanced voltage dips.

Symmetrical component classification				
Type		Characteristic voltage	PN factor	Zero-sequence voltage
A	Any	$\overline{V} = \overline{V}^*$	$\overline{F} = \overline{V}^*$	$\overline{U}_0 = 0$
B	D_a	$\overline{V} = \frac{1}{3}\overline{E}_1 + \frac{2}{3}\overline{V}^*$	$\overline{F} = \overline{E}_1$	$\overline{U}_0 = \frac{1}{3}\overline{V}^* - \frac{1}{3}\overline{E}_1$
C	C_a	$\overline{V} = \overline{V}^*$	$\overline{F} = \overline{E}_1$	$\overline{U}_0 = 0$
D	D_a	$\overline{V} = \overline{V}^*$	$\overline{F} = \overline{E}_1$	$\overline{U}_0 = 0$
E	C_a	$\overline{V} = \overline{V}^*$	$\overline{F} = \frac{2}{3}\overline{E}_1 + \frac{1}{3}\overline{V}^*$	$\overline{F} = \frac{1}{3}\overline{E}_1 - \frac{1}{3}\overline{V}^*$
F	D_a	$\overline{V} = \overline{V}^*$	$\overline{F} = \frac{2}{3}\overline{E}_1 + \frac{1}{3}\overline{V}^*$	$\overline{U}_0 = 0$
G	C_a	$\overline{V} = \overline{V}^*$	$\overline{F} = \frac{2}{3}\overline{E}_1 + \frac{1}{3}\overline{V}^*$	$\overline{U}_0 = 0$

Dip types C_a and D_a are the same as types C and D with the additional information of which phase is considered the symmetrical one.

By setting $\overline{F} = \overline{V}$, both types of faults according to the symmetrical component classification becomes a balanced three-phase dip. Hence a type A dip is a special case of both dip types according to the symmetrical components classification as shown in Table 6.

As previously shown in Table 2, dip types F and G are both a result of two-phase-to-ground faults after propagating through transformers. They have the same characteristics as type D and C respectively and thus can be seen as variants of the same dips.

Type B and type E are the only faults with a zero-sequence component, resulting from the ground connection of the fault. However, three-phase equipment are mostly connected in delta or in star without neutral connection and the number of dips originating in the low-voltage system are small [16]. Hence, if types B and E are disregarded, the symmetrical component classification represents all dip types described by the ABC classification.

2.5 Summary

In this chapter, general theory on voltage dips has been presented. The voltage divider method was explained. The method uses an equivalent circuit of the fault conditions, providing an easy way of calculating the dip magnitude and phase-angle jump.

To get a better understanding of voltage dips in power systems, two methods of classifying different types of voltage dips were discussed. The symmetrical component classification identifies two types of voltage dips. It is valid without restrictions, and is based on the decomposition of the three voltages into symmetrical components. The method provides a theoretical basis for describing voltage dips but requires knowledge of the use of symmetrical components. The ABC classification is more intuitive and thus easier to grasp. It is more suitable for practical applications like equipment testing and interpretation of voltage dips through the system because of its straightforward use. The ABC classification is based on incomplete assumptions and should be considered a special case of the symmetrical component classification.

3 Overview of Existing Grid Codes

This chapter provides an overview and comparison of existing interconnection requirements for wind power to the electrical transmission system within seven European countries. The scope of this chapter is limited to wind parks with an active power capacity of at least 30 MW connected at voltage levels exceeding 100 kV.

3.1 Introduction

A grid code contains interconnection and operational requirements set by a Transmission System Operator, TSO, and applies to all network users. A TSO can be a government-owned national company like Svenska Kraftnät in Sweden or a private-owned regional company like E.ON. Netz in Germany. Since this thesis focuses on offshore wind parks, this section will provide an overview of the existing interconnection rules of wind turbines and wind parks of various European TSO's.

To get an overview of existing grid codes can be somewhat cumbersome since harmonisation seldom surpasses a national level and the differences can be considerable. Reasons for the differences are often a result of environmental conditions, government interest in renewable energy sources and amount of installed wind power in the power system. The structure of the requirements varies between the grid codes, but a division into groups of requirements is common. A typical structure of a grid code and also the structure of this chapter are as follows:

- Active power control
- Frequency and voltage range
- Frequency control
- Voltage control
- Wind park protection
- Wind park modelling and verification
- Communication and external control

Existing grid codes often contain costly and challenging requirements that sometimes have no technical justification. Many requirements have been developed by vertically-integrated power companies that are in competition with wind park operators [1]. There are also rather frequent changes of the regulations. With this in mind, it is evident that a harmonisation of the interconnecting rules would decrease the costs and facilitate the development process for the wind turbine manufacturing companies. The benefits of a comparison of grid codes are discussed in [17] and can be concluded as follows:

- Controversies between wind park developers and network operators regarding interconnection rules will be reduced.
- The developers of wind park interconnection rules will gain a better understanding of the relevant issues, which in turn will contribute to a harmonisation worldwide.
- The wind turbine manufacturers will get an overview of the requirements that have to be met.
- The understanding of the differences between requirements will contribute to the harmonisation of the rules.

The connection requirements that will be treated in this document come from TSO's in Sweden, Denmark, Germany, Spain, Great Britain, Ireland and Norway. These are among the most interesting nations in the world regarding wind power, mostly because of the great amount of installed capacity, large integration of wind power into their power system and great potential and interest in installing wind power. The grid code documents belonging to the selected TSO for all seven countries are listed in Table 7. Information is also provided of the year of publication and the scope of the specific document. Energinet, ESBNG and Statnett have separate grid codes or sections that treat requirements for wind parks. In the other documents all generating units are treated together although special requirements and exceptions for wind power are occasionally given in the text.

Table 7. Grid code documents compared in this section.

Country	TSO/publisher	Reference	Year	Scope
Sweden	Svenska Kraftnät (SvK)	Affärsverket svenska kraftnäts föreskrifter och allmänna råd om driftsäkerhetsteknisk utformning av produktionsanläggningar [18]	2005	Production units connected to the transmission net
Denmark	Energinet (Elkraft and Eltra)	Teknisk Forskrift for vindmøllers egenskaber og regulering[19]	2004	Wind power plants connected to transmission level (>100kV)
Germany	E.ON. Netz	Grid code – High and extra high voltage [20]	2006	All connections to the high (60<U>110kV) and extra high voltage network (>220kV)
Spain	Ministerio de Industria, Turismo y Comercio, MITYC Red Eléctrica de España (REE)	P.O. 12.2: Instalaciones conectadas a la red de transporte de energía eléctrica: Requisitos mínimos de diseño, equipamiento, funcionamiento y seguridad y puesta en servicio. (Suplemento del BOE núm.129) [21] P.O. 12.3: Requisitos de respuesta frente a huecos de tensión de las instalaciones eólicas. (Suplemento del BOE núm.254) [22]	2006	All connections to the transmission system (220, 132, 66kV)
Great Britain, GB	National Grid Electricity Transmission, NGET Scottish Hydro-Electric Transmission Ltd Scottish Power Transmission Ltd	The Grid Code, Issue 3, Revision 16 [23]	2006	All connections to the GB transmission system
Ireland	Electricity Supply Board National Grid, ESBNG	Grid Code version 1.2 [24]	2005	All users of the transmission system. Separate chapter regarding wind park power stations.
Norway	Statnett SF	Veiledende systemkrav til anlegg tilknyttet regional- og sentralnettet i Norge [25]	2005	Wind parks with rated power ≥ 10 MVA connected to the transmission system.

3.2 Connection Requirements

The following sections compare the grid codes between the documents listed in Table 7. Each section handles a different category of requirements that are often dealt with in modern grid codes. It should be mentioned that the grid codes, although very detailed at times, can be seen as guidelines rather than absolute rules. The connection of a large wind park to the transmission system is preceded by extensive planning and discussions with the TSO. Hence the requirements are negotiable, which is also often mentioned in the grid code.

3.2.1 Active Power Control

In order to keep the system stable in an electric power system, generation and consumption must be in balance. To satisfy this condition, TSOs require large wind parks to be able to control their active power output, often specified as a certain percentage of the rated power. To avoid instability in the frequency, there are often additional requirements regarding ramp rates, i.e. the rate of change in active power output from the wind park.

3.2.1.1 Regulation Range and Ramp Rates

All compared documents include requirements on the wind parks to be able to regulate their active power output. Although NGET, ESBNG and REE do not explicitly specify a certain regulation range, it can be understood from the context that the active power output must be adjustable.

SvK requires that the active power production must be able to be regulated so that it can be reduced to below 20% of P_{max} within 5 seconds. The same range is specified in Energinet's and Statnett's grid codes with the difference that the rate of change has to be adjustable within 10-100% of the rated power per minute. Further, Energinet requires that the deviation of a production reference value and a measured 5 minutes average value must not exceed ± 5% of the wind park's rated output.

E.ON. states that a wind park must be capable of reducing its power output down to a certain pre-defined set-point value. Further the reduction to this value must be *at least* 10% of the network connection capacity per minute without disconnection from the grid. The wind park must also be capable of to use a ramp rate of 1 % of the rated power per minute across the entire range between minimum and continuous power output.

The ramp rates of the ESBNG grid code are set individually by the TSO for every wind park. The TSO will set two maximum ramp rates, one that applies to the MW change per minute and one that applies to the MW average change per minute over 10 minutes. These settings shall also be possible to vary independently between 1 and 30 MW per minute. ESBNG also requests the wind parks that as far as possible avoid disconnection of individual wind turbines and divide the output change between them.

3.2.1.2 Start-Up and Disconnection Requirements

SvK and Energinet allow wind turbines to be disconnected when the wind is too strong, but SvK limits the disconnection capacity to 30 MW per minute. When reconnecting the wind turbines, Energinet permits automatic reconnection if the average wind speed falls under a certain limit while SvK *advices* the wind park operator to reconnect with the same limitations as under disconnection.

Energinet together with Statnett require a wind park to go from full power to complete shut down within 30 seconds upon request from the system operator.

E.ON. requires the approval of the system operator when connecting a generating unit with a rated power of 50MVA or more.

REE will decide an allowed start-up/disconnection capacity per minute for each wind park.

3.2.2 Frequency Range and Voltage Range

These ranges specify the deviations from nominal frequency and voltage that a wind park should be able to manage without disconnecting. The requirements often apply under certain time duration or for a reduced requirement of active power output. In some grid codes, the voltage range depends on the actual frequency and vice versa. Figure 7 (a)-(g) gives a graphical view of the different requirements.

From Figure 7 it can be concluded that the frequency ranges are rather similar and vary between 47 and 52 Hz in the majority of the documents. The voltage ranges are also rather similar, mostly varying between 0.9 and 1.1 p.u. In contrast to this, the requirements are very different concerning ranges of continuous operation, i.e. when the wind park should run without disconnecting. Further, some codes specify the amount of reduced active power output that is allowed under abnormal conditions, while others just specify requirements on time limits.

SvK requires the wind parks to operate according to Figure 7(a). Compared to the other grid codes, they have the lowest requirement on voltage deviations. The region of continuous operation ranges from 49 to 51 Hz and 90 to 105 percent of nominal voltage. Outside this region, reduction of active power is always allowed.

Energinet's requirements are presented in Figure 7(b) and are different depending on the voltage level. In comparison, they have a rather wide range of voltage deviation, ranging from 80 to 117 percent of nominal voltage for the most extreme cases. They also put the toughest requirement of staying connected at over-frequencies, 53Hz, although for just a short time and without requirements on the active power output. The wind park should run continuously between 49 and 50.5 Hz and at a voltage range between 95 and 110 percent at the 132kV-level.

E.ON. has, like Energinet, different requirements for different voltage levels as shown in Figure 7(c). The continuous operation ranges are also similar. In addition, if the frequency gets higher than 51.5 Hz the wind park must disconnect without delay. If there is provision for auxiliary load, and the voltage falls below 85 % of the reference voltage, disconnection must take place after a delay of 5 seconds.

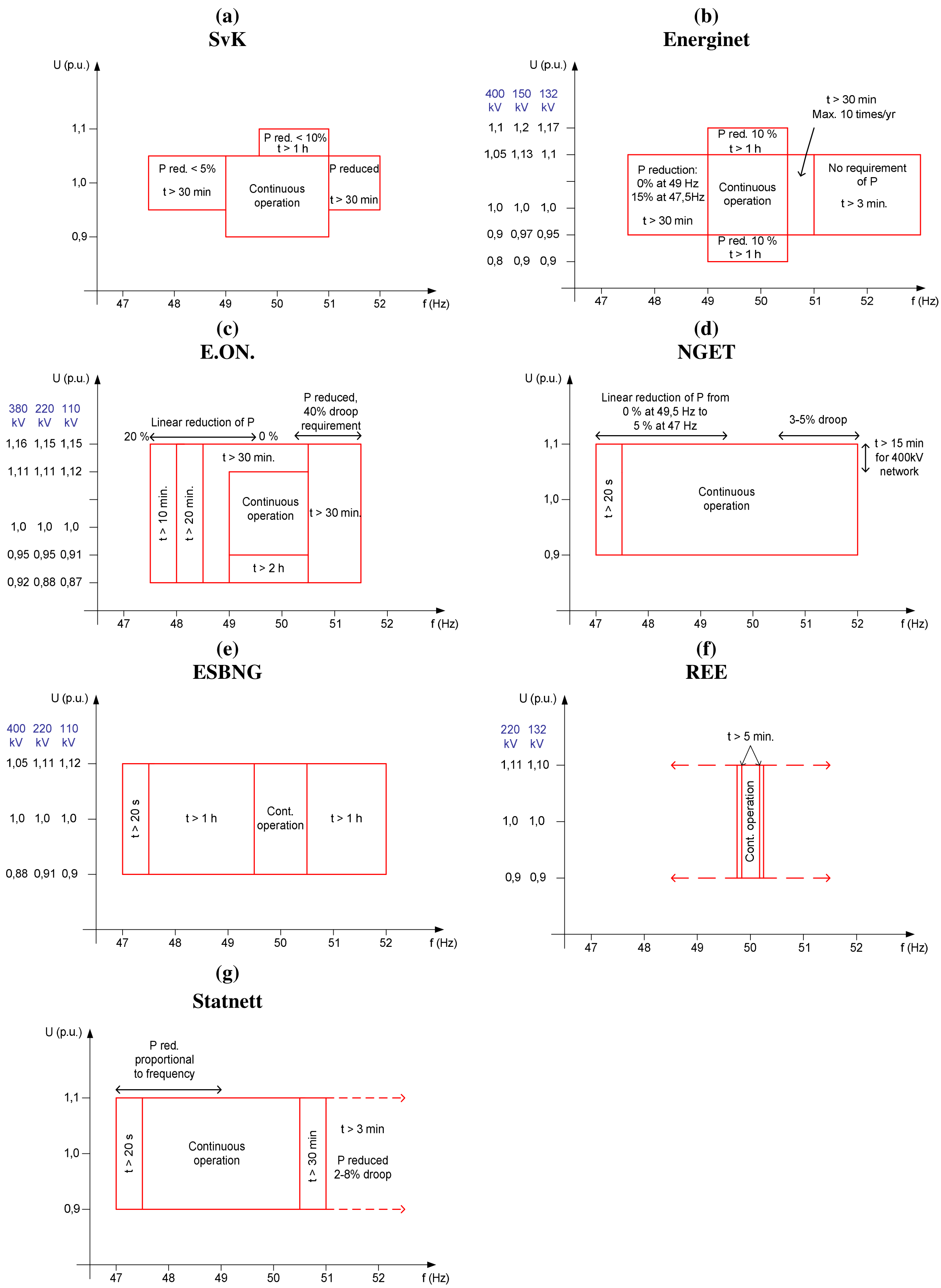


Figure 7. Frequency and voltage ranges for the different grid codes (a) to (g).

Further, E.ON requires the wind park to follow the requirements shown in Figure 8. Under short time frequency variations, the active power output must not be reduced as long as the frequency is above the bold red line in the figure.

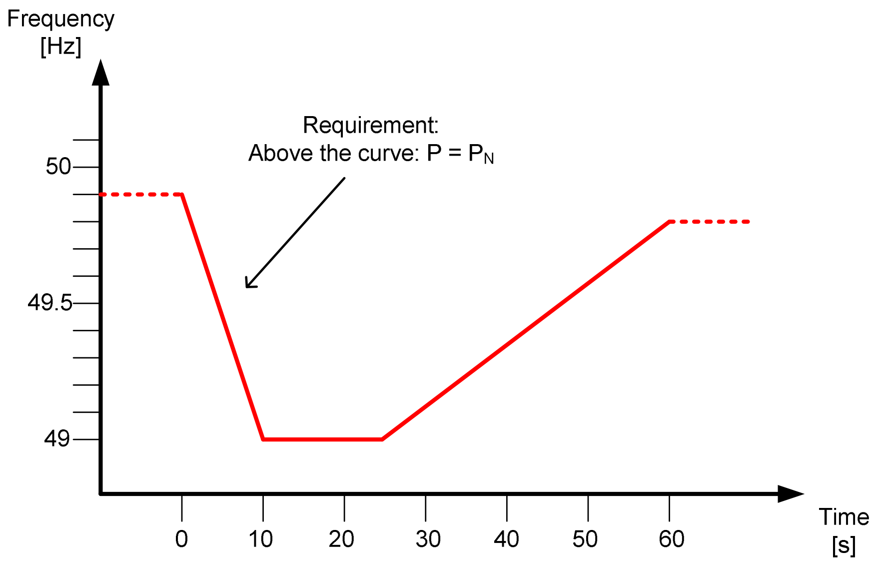


Figure 8. Additional requirements to frequency ranges given by E.ON. (Reproduced from [20])

The NGET requirements presented in Figure 7(d) apply to network voltages of 132 kV and higher. For lower voltage levels the voltage range is ± 6%. The requirements of continuous operation are the toughest in comparison, ranging from 47.5 to 52 Hz. However, there are relieves in active power output for frequencies outside the region 49.5 to 50.5 Hz. The 400kV grid is expected to have lesser voltage variations and for voltages exceeding 1.05 p.u. the wind park must only stay connected for 15 minutes. Upon agreement with the TSO, a wind park can receive other requirements than those in the figure.

ESBNG requires the wind parks to operate at frequency and voltage variations according to Figure 7(e). The continuous operating range is between 49.5 and 50.5 Hz while the voltage range depends on the voltage level. Interesting to note is that the requirements say nothing about the active power output. In addition, a wind park must remain connected to the system at a frequency rate of change up to 0.5 Hz per second. No additional wind turbines may be started when the system frequency is greater than 50.2 Hz. Further a wind park must stay continuously connected at voltage step changes up to 10 %.

REE is vaguer and in the grid code it is stated that a wind park is required to handle the deviations that are allowed for the system operator. The requirements are shown in Figure 7(f). As shown in the figure, continuous operation is only required between 49.85 and 50.15 Hz. For frequencies outside this interval down to 49.75 Hz and up to 50.25 Hz, the wind park may disconnect after 5 minutes. Events such as larger generation or demand variations that result in a frequency deviation outside these intervals must also be handled as long as they are temporary.

Statnett requires a wind park to operate without restrictions between 49 and 50.5 Hz and a voltage deviation of 10 percent as shown in Figure 7(g). Deviations outside this interval are not expected to exceed 10 hours per year. However, a wind park is required to run without disconnection in the interval 47.5 and 50.5 Hz.

3.2.3 Frequency Control

Frequency control includes primary and secondary control. Generators with responsibility of primary control automatically adjust their active power output until the frequency has stabilized. Since this stabilization usually does not occur at nominal frequency there is a need for secondary control to restore the frequency. This is done either automatically or manually.

Because of the uncontrollable nature of the wind, wind parks with responsibility of frequency control need to operate below their capacity so that they can contribute to increasing the frequency when the demand is higher than the generation. Therefore most grid codes that implement frequency control for wind parks require that the wind park only has to maintain the active power output at low frequencies but limit their output at high frequencies.

The Energinet grid code states that all production units connected to the transmission grid shall be able to contribute with fast active power regulation to restore the system frequency when deviations occur. It is not, however, specified how much a wind park must contribute. If the active power output from a generating unit drops below 20 % of the rated capacity, the unit must be able to disconnect.

E.ON. requires a wind park to reduce the presently available active power output with a gradient of 40 % per Hz if the frequency goes above 50.2 Hz, see Figure 7(c) from the previous section.

The NGET grid code requires the wind park to be equipped with a fast acting proportional frequency control device (or turbine speed governor) to provide frequency response under normal operating conditions. Further the device must be capable of being set so that it operates with an overall speed droop of between 3 and 5 %.

The ESBNG grid code includes frequency control for both high and low frequencies according to Figure 9. The power output should follow the line in both directions. The points A-E depend on a combination between system frequency and MW ramp rate and may therefore be different for different wind parks depending on system conditions and geographical location of the wind park. The TSO can also change these set-points when needed.

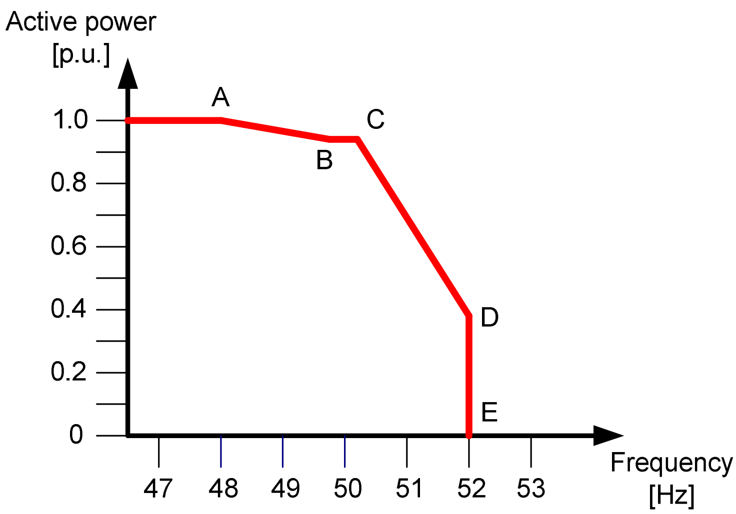


Figure 9. Frequency set-points given by ESBNG. (Reproduced from [24])

The set-point ranges (A-E) are presented in Table 8.

Table 8. ESBNG set-point ranges for frequency control.

Set-point	Frequency range (Hz)	Available active power (%)	
		Rated power > 10MW	*5 MW < Rated power < 10MW*
A	47.0 – 51.0	50-100	100
B	49.5 – 51.0	50-100	100
C	49.5 – 51.0		
D	50.5 – 52.0	20-100	20-100
E		0	0

REE states that the participation in frequency control applies to all production companies. All their units must have the capability of frequency control. However, if a generating unit, e.g. a wind park, has technical difficulties of providing frequency control, the TSO can relieve the unit from this requirement. In this case, the control must be taken over from another generating unit belonging to the production company. If this possibility does not exist, the production company can buy this service from another company.

Statnett requires wind parks to be equipped with fast frequency control possibilities so that they can respond to frequency variations if needed. Operation below rated power in order to participate in frequency control for under-frequencies will generally not be required under normal conditions. The active power droop must be adjustable between 2 and 8 %. The frequency control must be continuous at a power level exceeding more than 20 % of the rated power. At lower power levels, discrete frequency control is allowed when connecting/disconnecting wind turbines.

SvK does not require the wind parks to participate in frequency control.

3.2.4 Voltage Control

In order to keep the voltage within required limits to avoid voltage stability problems there is a need for voltage control. This can be done by reactive power compensation and/or with an automatic voltage regulator that is either installed at each wind turbine or at the point of connection of the whole wind park. In some grid codes there are also requirements that the wind parks must be equipped with a tap-changing transformer that can change the voltage ratio between the high and low voltage side and thus change the voltage at the connection point to the grid. Several TSOs also include requirements on the voltage quality influence from the wind parks. They mainly concern rapid voltage changes, voltage flicker and harmonics.

3.2.4.1 Reactive Power Compensation and Voltage Control

The different TSO's grid code requirements on reactive power compensation regions are shown in Figure 10.

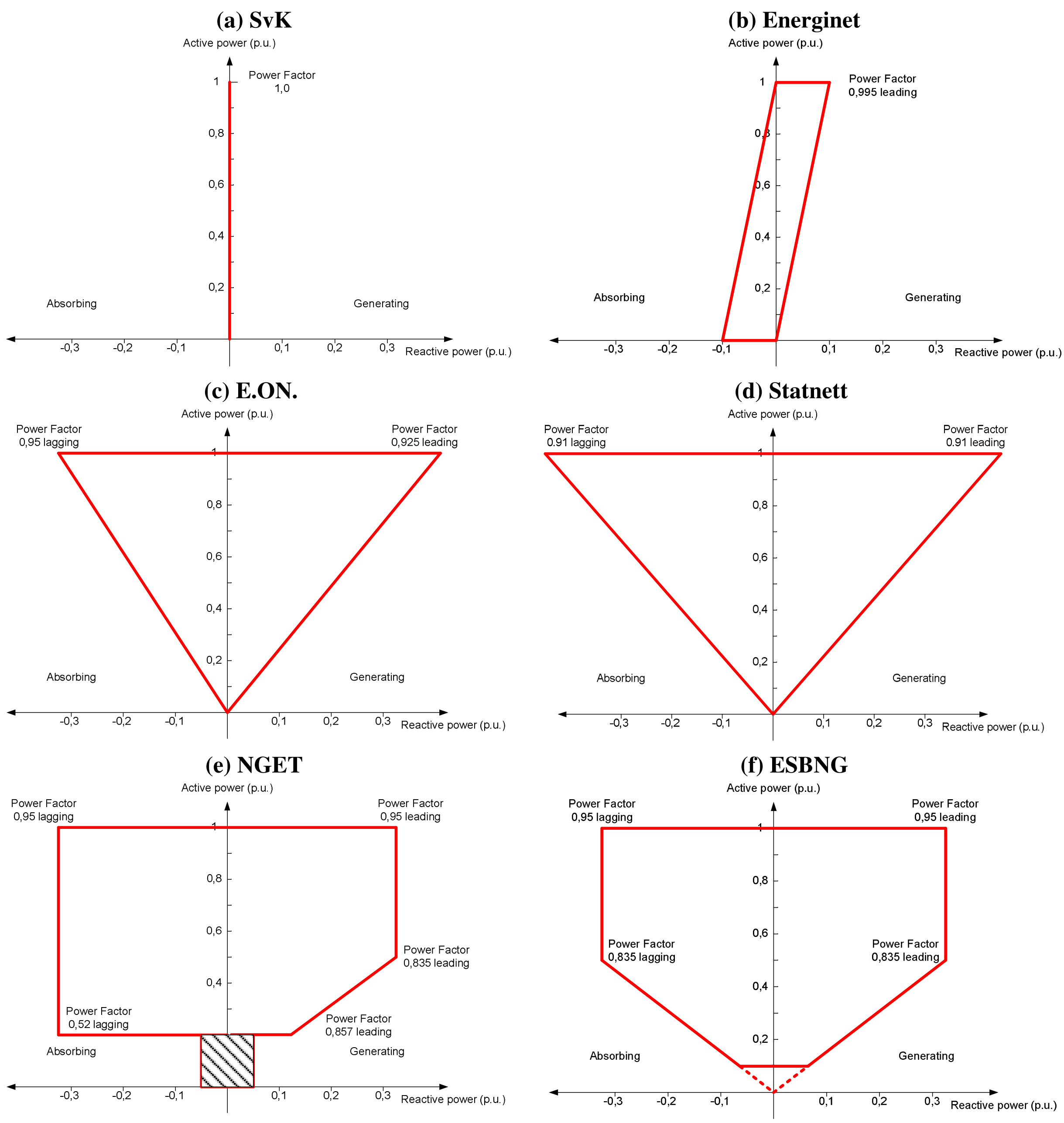


Figure 10. Reactive power compensation regions.

SvK requires the wind park to be equipped with automatic voltage control that is adjustable within at least ±5 % of nominal voltage. The requirement on reactive power compensation is shown in Figure 10(a). As the figure shows, the wind park must always keep the reactive power exchange to the power system at zero. In other words, it must be possible to operate at unity power factor. This means that the wind park must be able to compensate for any reactive power consumption within the park while it is not required to produce reactive power to the grid if needed.

Energinet states that the 10 seconds average reactive power exchange at the wind parks point of connection should be able to stay within the boundaries according to Figure 10(b). Hence the reactive power exchange from the wind park is not required to remain at unity power factor as was the case in Sweden. In comparison, this is the mildest requirement of all grid codes since the reactive power area depicted in the figure is an allowed region and not a region in which the wind park must be able to operate at any point. However, the wind park owner must provide the system operator with information about the capability of regulation within this area so that the system operator can ask the wind park to contribute with as much compensation as possible when needed.

At nominal voltage, E.ON.s requirement for reactive power exchange is presented in Figure 10(c). This figure is extrapolated from the information in the more general requirements shown in Figure 11. In contrast to Energinets requirement, the wind park must have the capability of operating at any point within these areas within a few minutes.

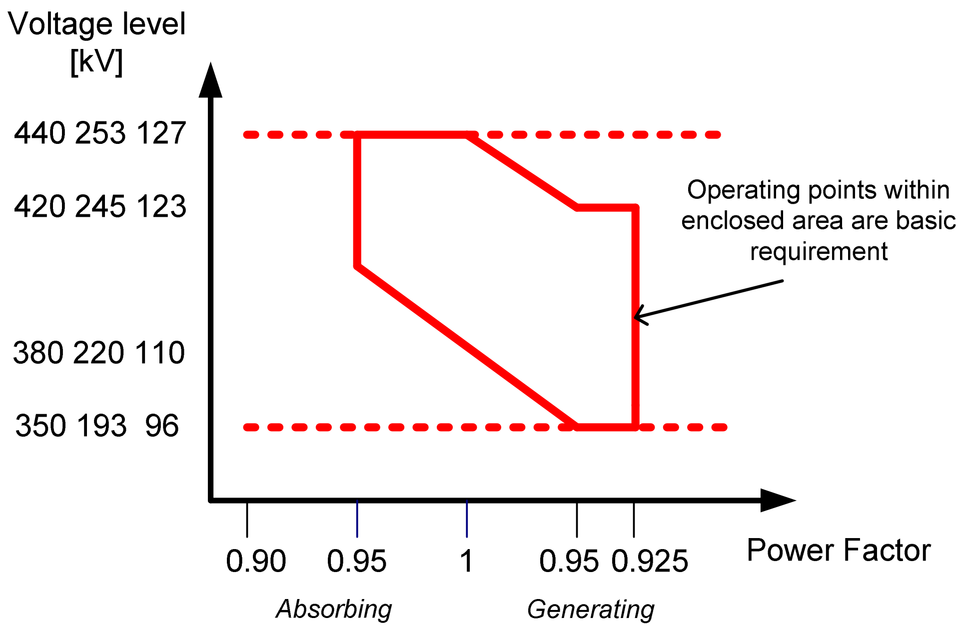


Figure 11. Variations at nominal voltage according to E.ON.

E.ON. also has requirements regarding step changes in reactive power output. If the reactive power exchange is altered, reactive power step changes exceeding 2.5 % in the high voltage grid, and 5 % in the extra high voltage grid are not permitted. Further, switching-related voltage changes at the grid connection point must not exceed 2 %.

Statnett requires a wind park to have the possibility of regulating the voltage and reactive power at the connection point. The reactive power exchange must be adjustable to all points in the region shown in Figure 10(d). The requirements apply to the point were the power is fed into the grid. It shall be possible to set the regulator to a certain fixed power factor (normally power factor = 1) while it must handle a changeable set point for the voltage control. The reactive power regulation should not be applied unless agreed with the system operator while the voltage control should normally be carried out continuously. The voltage control set point must be adjustable within ± 10 % of nominal voltage at the connection point. The rate of change of voltage should be adjustable between 0 and 10 % and can be both continuous and discrete.

NGET has the requirements according to Figure 10(e). As for E.ON. and Statnett, the wind park must be capable of supporting the grid with reactive power compensation at all points within the enclosed area. The reactive power output under steady state conditions should be fully available within the voltage of ±5 % from nominal value. The requirements apply to the grid entry point in England and Wales, while in Scotland the requirements apply to the high voltage side of the transformer directly connected to the transmission system.

ESBNG's requirements are shown in Figure 10(f). Unlike the other grid codes, ESBNG applies its requirements to the low voltage side of the grid connected transformer. The wind park must have the capability of operating at all points within this region. For operation below 10% of the wind park maximum capacity, the operation of the wind park must be inside the dotted triangle-area. However, this requirement can be changed by ESBNG if the wind park cannot operate within these limits without exceeding the allowed voltage ranges.

REE has no specified limits; instead the TSO specifies the limits of generation and absorption of reactive power for each wind park that is to be connected to the grid. For already installed wind parks, the TSO gives instructions on voltage control and reactive power compensation when needed. Under faulted conditions, specified requirements of reactive power exchange exist and will be discussed later on in the chapter.

The American Wind Energy Association, AWEA, a national trade association representing the wind power industry, has in [26] stated requirements that the wind power industry believe are technologically feasible. Regarding reactive power compensation, a power factor requirement of up to 0.95 leading/lagging is proposed. This is in compliance with the E.ON. requirement on wind parks with rated power below 100 MW. It can be concluded that SvK and Energinet's requirements are milder, while the requirements of Statnett, NGET and ESBNG may be a challenge for the wind power industry to meet. To be able to contol the reactive power exchange according to the requirements, there may be a need for installing additional equipment at the wind park terminals. For the requirements of SvK and Energinet, there is a need for compensating the reactive power exchange from the wind park. This can for example be done by installing capacitor banks in order to compensate for the inductive properties of a fixed-speed wind turbine. To meet the requirements of E.ON and Statnett, which requires the wind park to both consume and produce reactive power according to directions from the system operator, the linear relation between active and reactive power implies the need for an SVC, Static Var Compensator. This device enables the possibility of controlling the generation and consumption of reactive power by using thyristor switched capacitors and thyristor controllable inductors [27]. For the more complicated control areas required by NGET and ESBNG, the use of a Static Synchronous Compensator, STATCOM, is more suitable. The STATCOM is a power electronic device containing transistors that can be controlled so that the desired reactive power exchange is obtained. However a STATCOM is more costly than an SVC of the same rating.

3.2.4.2 Tap-Changing Transformers

E.ON. and ESBNG are alone to include a requirement to equip a wind park with tap-changing transformers at the grid connected transformer.

E.O.N. requires the block or power transformer to be fitted with a tap-changer that must be harmonised with the properties of the wind park regarding control range and step size.

ESBNG requires on-load tap-changing transformers for all wind parks connected to the grid. It must be designed so that the tap step does not alter the voltage ratio at the high voltage terminals more than 2.5 % on the 110kV system and 1.6% on the 220kV and 400kV systems, unless agreed otherwise.

3.2.4.3 Voltage Quality

ESBNG requires the users of the transmission grid to follow the limits of voltage distortion and fluctuation that are allocated to them following consultations of ESBNG. Limits are outlined in the standards IEC 61000-3-6 (Harmonics) and IEC-61000-3-7 (Voltage fluctuation). Energinet also follows the limits of IEC standards. Their grid code puts requirements on rapid voltage changes, flicker and harmonic distortion.

E.ON. requires the user of the transmission grid to design its electrical system, so that it avoids interaction with the TSO's network or a third party, during their operation. In addition, information and signal transmissions must not be unacceptably affected. The user must also demonstrate the absence of system interaction caused by his system and ensure remedial measures if required.

NGET grid code requires that the phase unbalance, under planned outage, does not exceed 1% in England and Wales, and 2% in Scotland, unless abnormal conditions prevail. Further, the voltage fluctuations at the connection point shall not exceed 1% of the voltage level for step changes that may occur repeatedly. Regarding flicker severity, for voltages above 132kV, the short term flicker severity may not exceed 0.8 and the long term flicker severity may not exceed 0.6.

SvK and Statnett do not mention voltage quality in their grid codes.

3.2.5 Wind Park Protection

Faults and disturbances in the network such as lightning, equipment failure or third party damage [1] may damage wind turbines and associated equipment and previous recommendations were to disconnect the wind turbines from the system [17]. However disconnection of large wind parks will put great stress on an already disturbed system [17]. Therefore most updated grid codes include requirements of fault ride-through capabilities of the wind parks. Hence, the design of the relay protection system must comply with these requirements. Faults in the system can also lead to isolation of parts of the electric system, so-called islanding. Some grid codes also put requirements on the wind parks to stay connected during such conditions and even contribute to frequency control.

3.2.5.1 Ride-Through Requirements

A comparison of the different TSO requirements regarding fault ride-through capabilities is presented in Figure 12. The figures display the most severe voltage dip at the connection point that the wind park must be able to ride through.

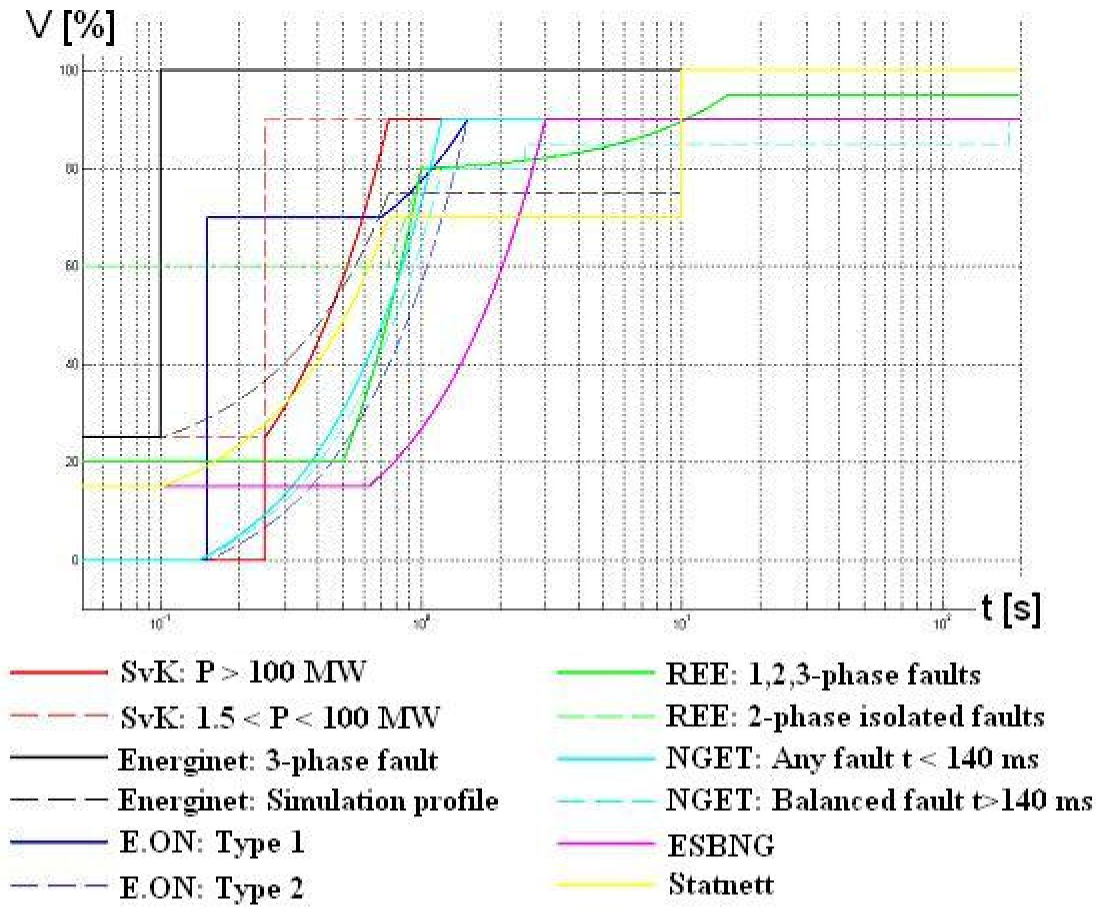
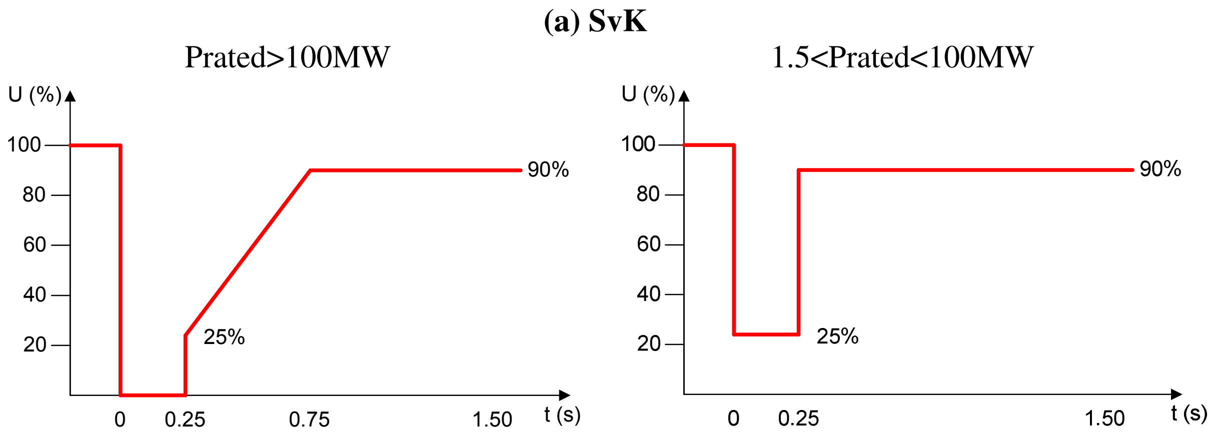


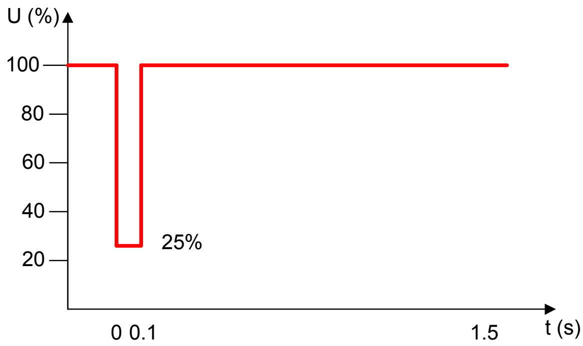
Figure 12. Comparison of Ride-Through Requirements.

Figure 13 presents separate ride-through requirements for each grid code.

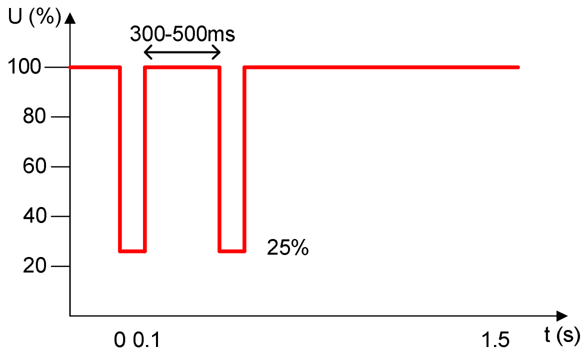


(b) Energinet

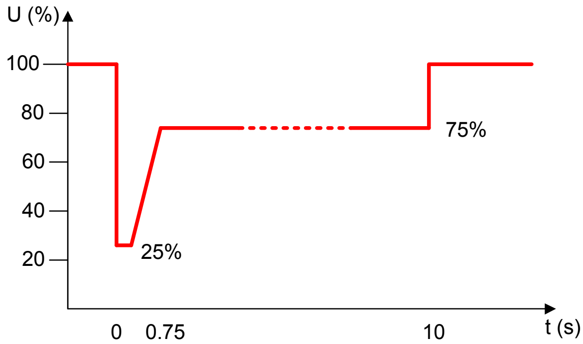
3-phase faults



1-phase faults and 2-phase faults, requirement on faulted phases.

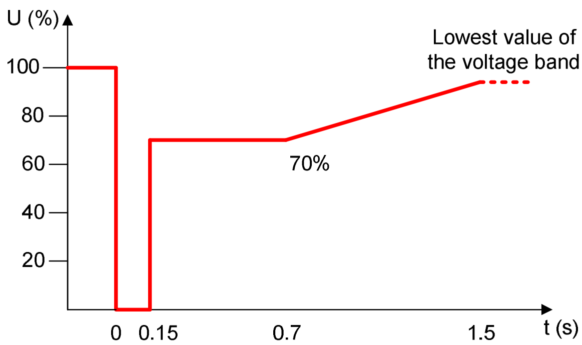


3-phase faults (simulation profile)

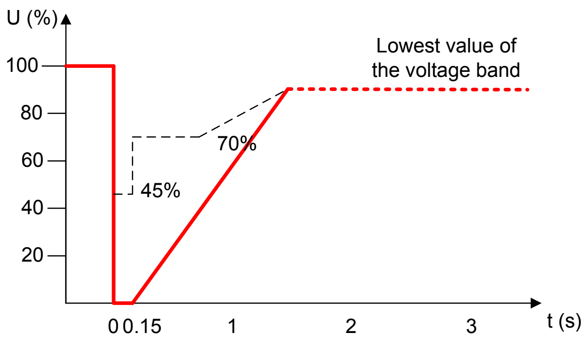


(c) E.ON.

Type 1 (Synchronous generators)

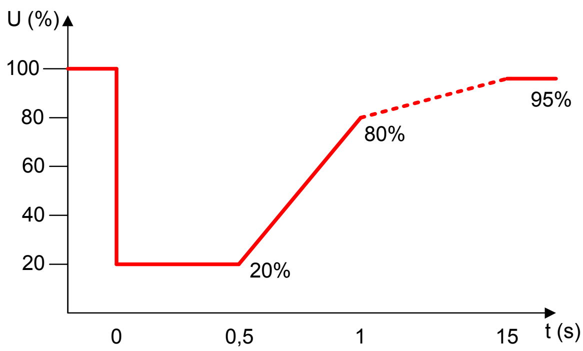


Type 2

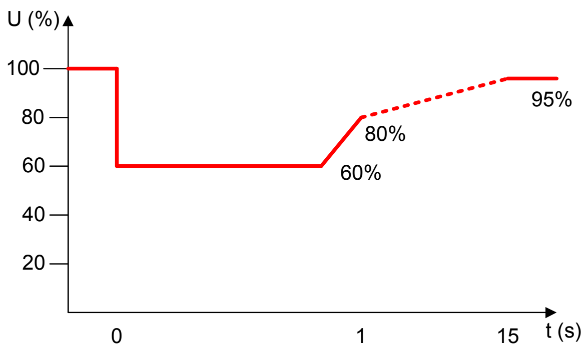


(d) REE

1,2 and 3-phase faults



Isolated 2-phase faults



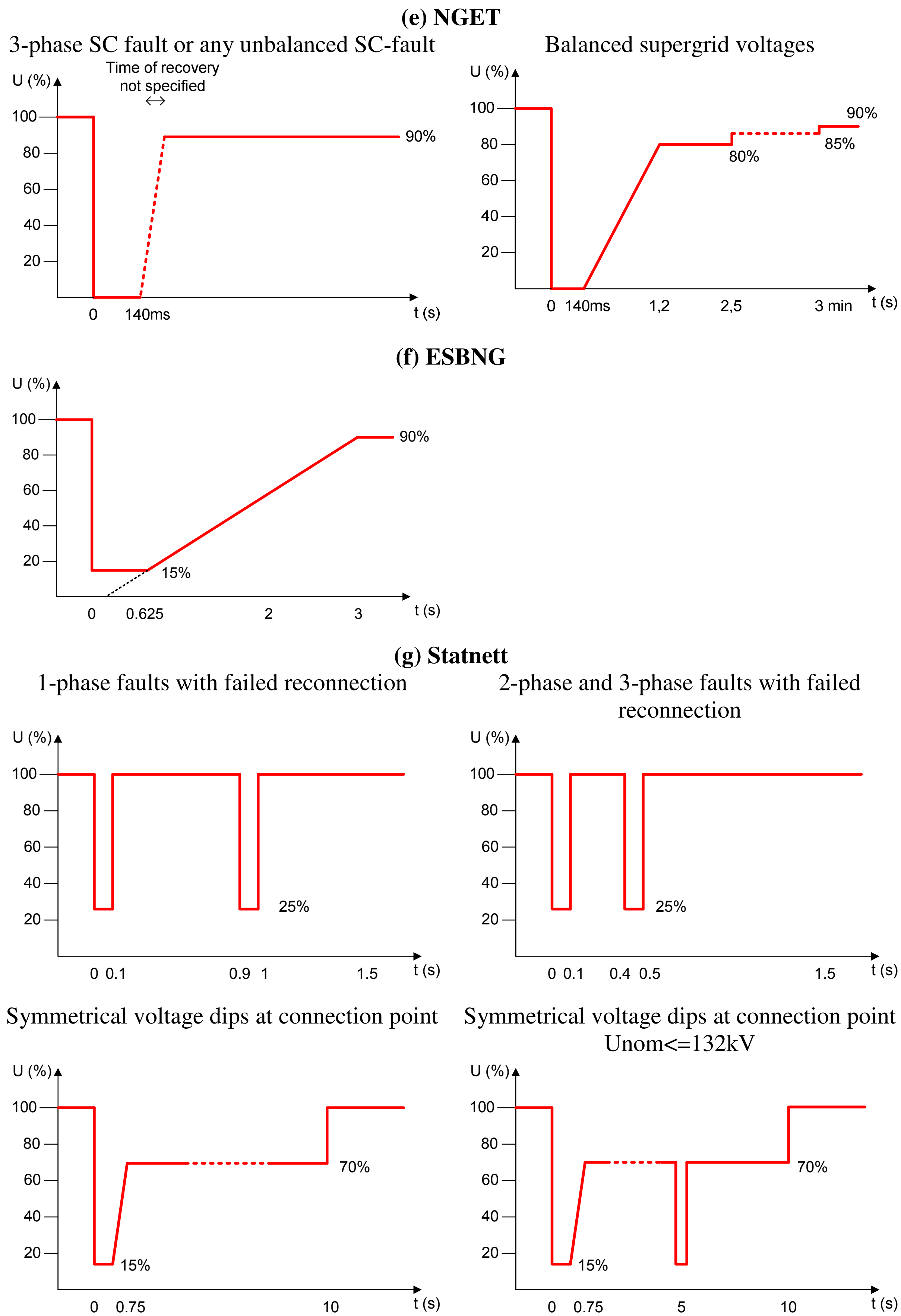


Figure 13. Fault ride-through requirements

SvK states that all units should cope with short voltage variations without losing connection to the grid due to frequent events such as lightning and switching. Its grid code has different requirements for wind parks with a rated active power output of more than 100 MW and those between 1.5 and 100 MW. The requirements are shown in Figure 13(a). For the larger wind park, the requirement is to stay connected for a voltage dip down to zero voltage during 250 ms followed by a linear rise between 0.25 p.u. to 0.90 p.u. the next 500 ms. For wind parks with less capacity the requirement is milder. These wind parks must ride through dips down to 0.25 p.u. during 250 ms followed by a voltage above 0.90 p.u.

Energinet has the mildest requirement of all TSO's compared regarding the severity of the voltage dip that must be handled. On the other hand they put additional requirements on the capability of coping with successive one and two phase dips as shown Figure 13(b). The wind park must stay connected during two successive 0 p.u. dips during 100 ms with 300 to 500 ms between them. The requirements in Figure 13(b) only apply to the faulted phases. In addition they require the wind park to have enough capacity to handle the following events:

- At least 2 single-phase faults within 2 minutes.
- At least 2 two-phase short circuit faults within 2 minutes.
- At least 2 three-phase short circuit faults within 2 minutes.

And also

- At least 6 single-phase faults with 5 minutes in between.
- At least 6 two-phase short circuit faults with 5 minutes in between.
- At least 6 three-phase short circuit faults with 5 minutes in between.

The wind park shall also be able to resist disturbances due to unsymmetrical faults in the grid when they occur due to failure in automatic re-closing. Further, the wind park owner must simulate the wind park response of a voltage dip with the characteristics according to the third voltage profile presented in Figure 13(b). The simulation must show that the wind park fulfil certain requirements in active and reactive power output during and after this dip.

E.ON. distinguishes synchronous generators directly connected to the grid from other generating units. These units are referred to as type 1, while the others are sorted as type 2. The requirements for these two categories are shown in Figure 13(c).

Wind parks with type 1 generators must stay connected at 0 p.u. voltage dips during 150 ms followed by a step to 0.70 p.u. maintained under 550 ms and finally a linear increase of the voltage for 800 ms up to a lower value of the voltage band limit. By agreement with the TSO, it is possible to use a shorter dip duration requirement. In this case, shorter fault-clearing times must be guaranteed by means of suitable protective and switching equipment.

Wind parks with type 2 generators must, due to a symmetrical voltage dip, stay connected at voltages above the dotted line in Figure 13(c), i.e. 0.45 p.u. dip during 150 ms followed by a step rise to 0.70 p.u. during 550 ms and then a linear increase up to the lowest value of the voltage band before 1.5 seconds after fault initiation. More severe faults must also be handled according to the solid line in the same figure, i.e. a 0 p.u. voltage dip lasting 150 ms followed by a linear increase reaching the lowest value of the voltage band limit 1.5 seconds after fault initiation. However, this requirement can be changed after agreement with the system operator if the wind park cannot handle this dip. Then the wind park owner must ensure a minimum reactive power infeed during the fault and also reduce the resynchronisation time. Further, a brief disconnection above this line is allowed after agreement with the system operator in case of an unstable generator. In this case, the resynchronisation must take place within 2 seconds at the re-starting of the generator.

For wind parks with type 2 generators, the plant is required to feed a short-circuit current into the grid during a fault. This size of this contribution is decided individually depending on the technology used, e.g. asynchronous generators or frequency converters. E.ON. also states that the operator of the wind park must take measures to avoid damages in the wind park due to automatic reclosure in the transmission operator's grid.

E.ON. also requires the generating units connected to the grid to support the voltage during a network disturbance. If a voltage drop of more than 10 % of the RMS value at the generator terminal voltage occurs, the unit must switch over to voltage support according to Figure 14. The support must be provided within 20 ms after fault identification, and is undertaken by providing reactive power with a factor of 2 % of the rated current per percent of the voltage drop. Switching back to normal operation is possible after 3 seconds.

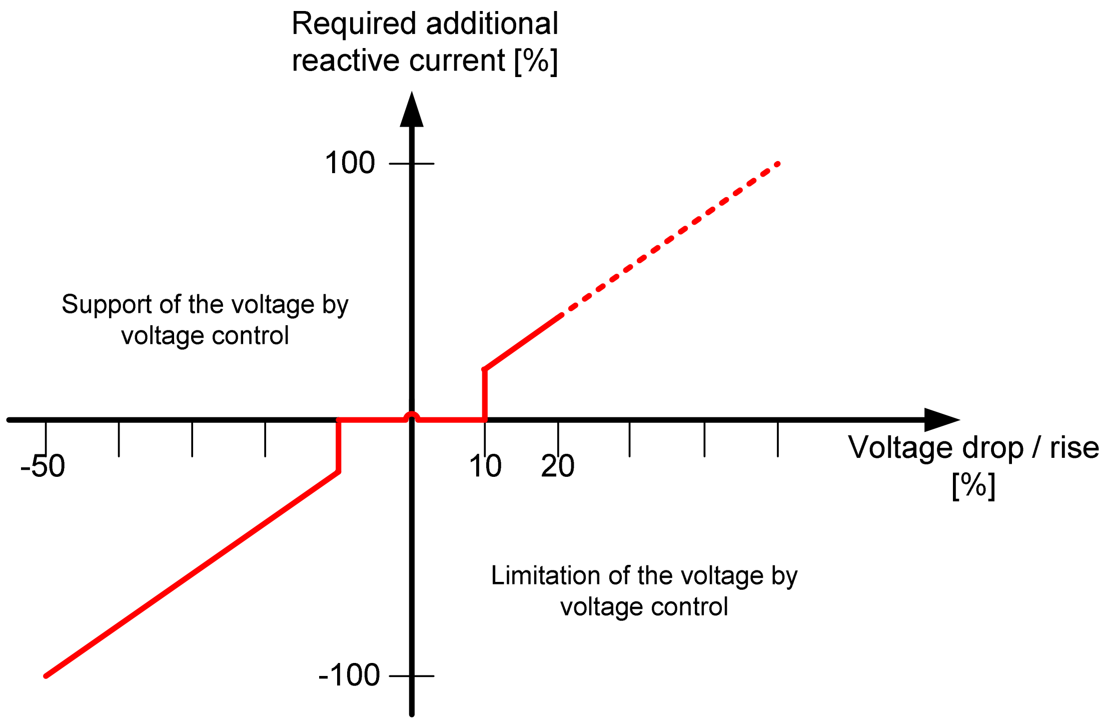


Figure 14. E.ON. requirement on voltage support under fault conditions (Reproduced from [20]).

If reactive power is injected to the wind park from the grid (under-excited operation), the wind park must disconnect if all three line-to-line voltages fall below 0.85 p.u.

REE has different voltage ride-through requirements for dips due to isolated two-phase faults and those due to single, two and three-phase faults. The requirements are shown in Figure 13(d). For single, two and three-phase faults, the wind park must stay connected for dips down to 0.20 p.u for 500 ms rising linearly to 0.80 p.u. the next 500 ms, from this level the voltage must return to 0.95 p.u. within the next 14 seconds. For isolated two-phase faults the dip requirement of 0.20 p.u. is replaced with 0.6 p.u. according to the figure. However, if the rated power of the wind park exceeds 5 % of the short circuit power at the connection point, these curves may be altered.

During faulted conditions, REE also puts requirements on active and reactive power control according to Figure 15. For balanced faults, the wind park must not consume more than 0.1 p.u. active power or any reactive power, except for the first 150ms immediately after the beginning of the fault. During these 150ms, the reactive power consumption must stay below 0.6 p.u. Further, the wind park must support the grid with as much reactive power as possible during a fault, even though the requirement in the figure is met. Figure 15 also applies to unbalanced faults. The exceptions are similar: the active power must not exceed 0.45 p.u. and the reactive power consumption must not exceed 0.4 p.u. during a continuous time span of 100ms. Temporary active and reactive power consumption is allowed during the first 150ms after the beginning of the fault.

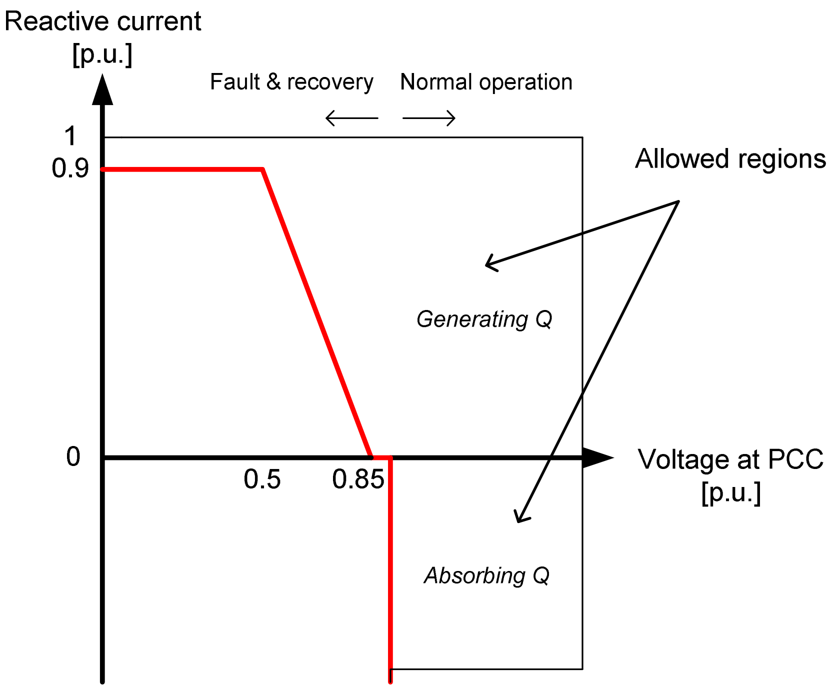


Figure 15. REE's allowed reactive power region during fault conditions (Reproduced from [22]).

The NGET ride-through requirements apply to voltage levels exceeding 200kV. The first figure in Figure 13(e) applies to all faults while the second only applies to balanced three-phase dips for faults with a duration exceeding 140 ms. For faults shorter than 140 ms, the wind park must stay connected during the fault time even if the dip is 0 p.u. After fault clearance the recovery time until reaching 0.90 p.u. is not specified and "may take longer than 140 ms" as stated in the document. For faults longer than 140 ms, the wind park must handle three-phase dips with a 0 p.u. dip during 140 ms followed by a linear increase up to 0.80 p.u. within 1.2 seconds after fault initiation and then remaining at this level for 1.3 seconds. This is followed by a step increase of 0.05 p.u. remaining up to 3 minutes when the voltage must be restored to 0.90 p.u. The NGET grid code also specifies requirements of active power generation during faults. For faults with duration of less than 140 ms, a wind park must restore the active power output to at least 90 % of the pre-fault level within 0.5 s after fault clearing. This time period is extended to 1 second for balanced three-phase faults with duration exceeding 140 ms. During all faults, a wind park must generate maximum active power possible without exceeding the transient rating limit. The wind park is exempted from these rules if it is operating at less than 5 % of rated power or has disconnected more than 50 % of the wind turbines due to heavy wind.

The ESBNG grid code applies to all types of faults and is presented in Figure 13(f). The dip characteristic is almost identical to the E.ON. requirement for wind parks with low symmetrical short circuit current. Similar to the NGET grid code ESBNG also has requirements on voltage support under fault conditions. During a fault, the wind park is required to provide active power in proportion to the retained voltage and maximise the reactive power output without exceeding the limits of the wind turbines. Further, 90% of the available active power must be provided within at least 1 second after fault clearing.

Statnett requires the wind parks to ride through dips according to Figure 13(g). No disconnection is allowed for dips down to 0.15 p.u. during 750 ms followed by a rise to 0.70 p.u. that can remain up to 10 seconds until the voltage is completely restored. Similar to Energinet, they require withstanding of successive dips with minimum time difference according to the figure. For single voltage dips, the requirement of coping with a 70% dip magnitude for 10 seconds is tough in comparison. Wind parks are also required to produce maximal reactive power during 10 seconds for voltages down to 0.7 p.u.

AWEA has also proposed requirements on voltage ride-through capabilities [26], The voltage ride-through characteristic is identical to the requirements stated by ESBNG and also very similar to the E.ON. requirement on wind parks with low symmetrical short-circuit current. The proposed requirements apply to voltage measured at the point of interconnection, i.e. on the high voltage side of the wind plant substation transformer.

3.2.5.2 Island Operation

If a wind park becomes isolated from the system but still supplies customers, NGET requires wind parks to be able to control the frequency below 52 Hz. This requirement is only valid as long as the wind park is not forced to operate below its designed minimum operating level and therefore may trip after a while. In addition the NGET grid code specifies special requirements for wind parks in Scotland. In order to avoid unwanted island operation, wind parks in Scotland shall be tripped if:

- The frequency is outside the interval 47 to 52 Hz for more than 2 seconds.
- The voltage at the connection point is below 0.8 p.u. for more than 2 seconds.
- The voltage at the connection point is above 1.2 p.u. for more than 1 second.

Energinet has similar requirements regarding over-voltages during island operation. The wind park must not give rise to temporary overvoltages exceeding 1.3 p.u. directly after the incident and then below 1.2 p.u. within 100 ms, except from this, island operation is not further mentioned in the Danish grid code.

REE wind parks have to handle island operation according to the frequency and voltage ranges previously specified in Figure 7(f).

Similar to REE, the E.ON. grid code states that wind parks must be able to temporarily handle island operation as long as the voltage and frequency do not go outside the allowed ranges. Further the circuit breakers of grid transformer must send a trip signal to all the individual wind turbines so that the island operation is ended no later than after 3 seconds.

SvK, ESBNG and Statnett do not mention any operational requirements on wind parks in case of isolation from the system.

3.2.6 Wind Park Modelling and Verification

To verify that a wind park meets all requirements, it is important for the system operator to investigate the impact a certain wind park has on the power system. This can for example be achieved through full-scale tests, technical calculations or modelling and simulations in computer programmes.

All TSO's require verification that the wind park meets the requirements specified in their grid codes. All wind park owners must submit technical data and calculations of important parameters when applying for permission to connect a wind park to the transmission grid.

ESBNG, Statnett and REE require a computer model that is executable in PSS/E. Energinet also require a computer model together with response of simulations performed with previously defined voltage characteristics (see Figure 13(b)).

3.2.7 Communication and External Control

The wind farm operator should provide signals corresponding to a number of parameters important for the system operator to enable proper operation of the power system (typically voltage, active and reactive power, operating status, wind speed and direction etc.). Moreover some require the possibility to connect and disconnect wind turbines externally.

The different TSO's in this report all have similar requirements regarding communication and external control. They include topics as real-time information of important parameters or possibility of controlling active and reactive power output.

3.3 Summary

In this chapter, seven different grid codes have been compared and analyzed regarding their requirements for large wind parks. The comparison has shown that the differences in requirements are sometimes big. This is true regarding both the scope of the requirements as well as their level of difficulty to meet for the wind turbine manufacturer. The requirements have been categorized into seven groups: Active power control, Frequency and voltage range, Frequency control, Voltage control, Wind park protection, Wind park modelling and verification and Communication and external control. Due to the subject of this thesis, the focus has been the requirements of ride-through and reactive power compensation.

4 Power System Grounding

This chapter deals with the topic of power system grounding. The aim of system grounding is to control the fault current due to a fault with ground connection. This is achieved by connecting a neutral point of the system to ground in order to create a return path for the fault current. How this connection is designed, i.e. which electrical properties it will have, decides the magnitude of the fault current. Depending on factors such as the need for continuous operation of equipment, actual voltage level and personal safety, different types of system grounding may be suitable for different parts of the power system. Since 60-90 % of the faults in a power system are single-phase-to-ground [28], the focus of this chapter is on these faults.

4.1 Single-Phase Fault Currents

For a single-phase-to-ground fault the three sequence networks can be interconnected according to Figure 16, where Z0, Z1 and Z2 is the zero-, positive- and negative-sequence impedances respectively and U0, U1 and U2 are the component voltages (see Chapter 5).

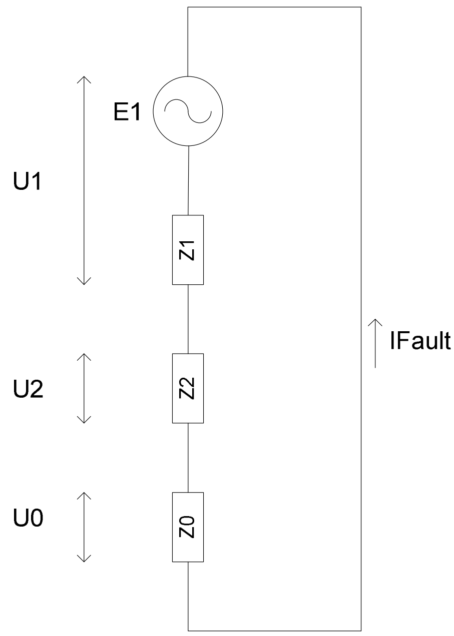


Figure 16. Sequence network for a single-phase fault.

From the figure, the fault current can be expressed as

$$\left|\bar{I}_{\text{Fault}}\right| = \left|\bar{I}_0 + \bar{I}_1 + \bar{I}_2\right| = 3\left|\bar{I}_0\right| = \left|\frac{3\bar{E}_1}{\bar{Z}_0 + \bar{Z}_1 + \bar{Z}_2}\right| \tag{10}$$

Or in per-unit

$$\left|\bar{I}_{\text{Fault, p.u.}}\right| = \left|\frac{3}{\bar{Z}_{0\text{pu}} + \bar{Z}_{1\text{pu}} + \bar{Z}_{2\text{pu}}}\right| \tag{11}$$

From (10) and (11) it can be concluded that the zero-sequence impedance, i.e. the grounding impedance, can be chosen so that it limits the fault current.

4.2 Effectively Grounded Systems

In effectively grounded systems (sometimes called solidly grounded), the neutral is connected directly to ground. This results in large fault currents, which, depending on location, may even exceed the fault current in a three-phase fault [28]. The non-faulted feeders may experience a small decrease or increase in voltage [28]. A schematic representation of effectively grounding is shown in Figure 17.

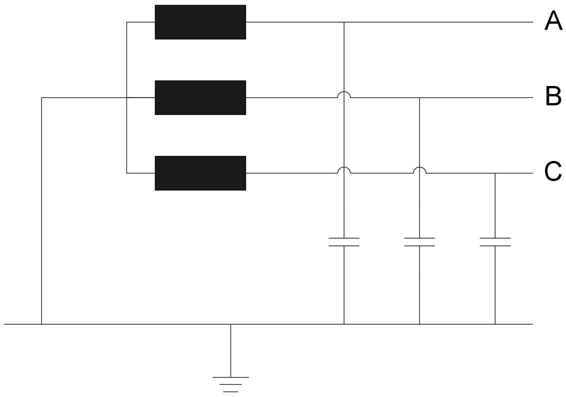


Figure 17. Effectively grounding.

Because of the high currents, fault detection and clearing via standard overcurrent protection is fast, easy and requires no special ground-fault protection. A disadvantage with this method is the difficulty of tripping faults with high resistance such as arcing ground faults. The arcing can therefore be sustained for a longer time, thus increasing the risk of equipment damage.

The fast clearing time together with the small voltage variation in the non-faulted feeders, thus avoiding the need for higher insulation levels, has made this method extensively used in high-voltage transmission systems. In Sweden, the transmission system (130kV and higher) is effectively grounded.

In Australia, Great Britain and the USA, effectively grounded systems are also common in the MV-system [29].

In low-voltage systems (e.g. 400/230V), personal safety is of utmost importance. By connecting metal surfaces of electrical household equipment to ground, a fault will lead to a high fault current so that the fuse will go off. Hence, almost all low-voltage systems are effectively grounded [28].

4.3 Low-Resistance Grounded Systems

To avoid the risk of sustained arcing ground faults, a low-ohmic resistor can be installed between the neutral and ground. The resistance is chosen so that the fault current is around 2-3 times the nominal load current. With this arrangement, the advantages of fast clearing time is kept while the additional advantage of this method is the possibility to trip arcing faults since the relays now trip for a smaller current. A schematic representation of resistance grounding is shown in Figure 18.

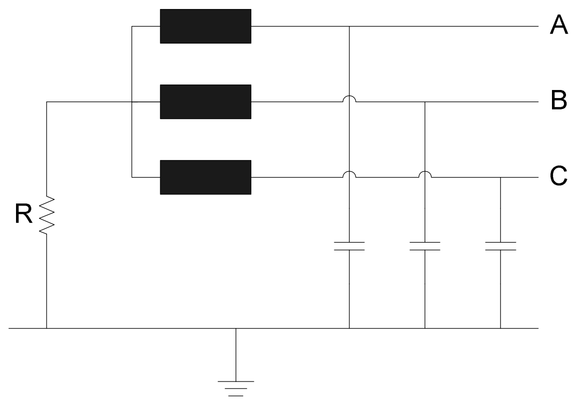


Figure 18. Resistance grounding.

This method is used in public and industrial medium voltage systems [28], and is quite common in the USA [29].

4.4 Isolated Grounded Systems

In some parts of the power system, the risk of personal danger is improbable and the tripping of relays because of ground faults can lead to instability and/or have serious economical consequences. Therefore, a low impedance grounded system may not be the most suitable choice. In (6), the voltages for a single-phase-to-ground fault were presented. If the fault impedance between phase a and ground is denoted $\overline{Z}_{\mathrm{a}}$ the voltages on all phases are described by

$$\begin{aligned} \overline{V}_{\mathrm{a}} &= 1 - \frac{2\overline{Z}_{\mathrm{S1}} + \overline{Z}_{\mathrm{S0}}}{2\overline{Z}_{\mathrm{S1}} + \overline{Z}_{\mathrm{S0}} + 3\overline{Z}_{\mathrm{a}}} \\ \overline{V}_{\mathrm{b}} &= \mathrm{a}^2 - \frac{\overline{Z}_{\mathrm{S0}} - \overline{Z}_{\mathrm{S1}}}{2\overline{Z}_{\mathrm{S1}} + \overline{Z}_{\mathrm{S0}} + 3\overline{Z}_{\mathrm{a}}} \\ \overline{V}_{\mathrm{c}} &= \mathrm{a} - \frac{\overline{Z}_{\mathrm{S0}} - \overline{Z}_{\mathrm{S1}}}{2\overline{Z}_{\mathrm{S1}} + \overline{Z}_{\mathrm{S0}} + 3\overline{Z}_{\mathrm{a}}}. \end{aligned} \tag{12}$$

From (12) it can be seen that if the impedance between the neutral point and ground, $\overline{Z}_{\mathrm{S0}}$, approaches infinity, i.e. an open-circuit, the phase voltages turn into

$$\begin{aligned} \overline{V}_{\mathrm{a}} &= 0 \\ \overline{V}_{\mathrm{b}} &= \mathrm{a}^2 - 1 = \sqrt{3} \cdot \mathrm{e}^{-\mathrm{j}150^\circ} \\ \overline{V}_{\mathrm{c}} &= \mathrm{a} - 1 = \sqrt{3} \cdot \mathrm{e}^{\mathrm{j}150^\circ}. \end{aligned} \tag{13}$$

This can be achieved by selecting a grounding system with no intentional ground connection, a so called isolated grounding system. Although a complete isolation is not possible because of the capacitive connection between the phases and ground, the impedance is normally so big that the fault current will be kept very small. A schematic representation of isolated grounding is shown in Figure 19.

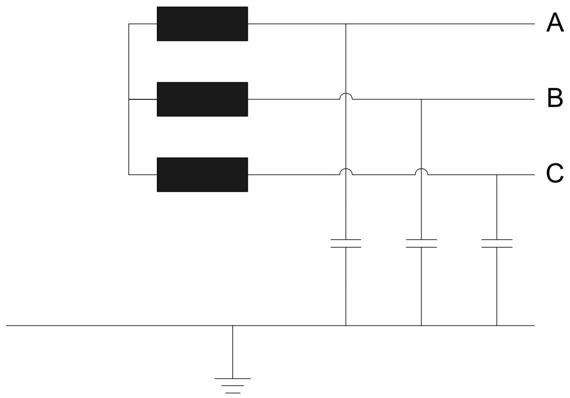


Figure 19. Isolated grounding.

If loads are connected between phases or behind a Dy-connected transformer, this grounding system has one important advantage. From (11) it can be seen that the voltage on the non-faulted phases rises by a factor $\sqrt{3}$ so that the line-to-line voltages will remain unchanged, hence there will be no interruption because of a ground fault. However, a negative side-effect is the voltage increase that creates a need for higher insulation levels in order to avoid flashovers. For lower voltage levels, this is usually not a problem since normal insulation levels are higher than 173% of nominal [28]. However, the small fault current and continuous operation makes it difficult to detect and localize the fault. Further, the long duration of over-voltages may stress weak parts of the insulation such as cable joints leading to a second fault. These so-called "cross-country" faults lead to very high fault currents because of the effective grounding that arise through the first fault. Since this can occur far away from the original fault, incorrect tripping of relays may occur, thus disconnecting even more system components than would originally be affected.

In Finland, 70-80 % of the MV-networks are isolated grounded [30]. This type of grounding is also used in the MV-networks of Germany, Italy and Japan to mention a few [29].

In some LV-systems where high reliability is of importance and planned interruptions acceptable, isolated systems can be found [28].

4.5 High-Resistance Grounded Systems

In order to have a high reliability as for the isolated grounding systems, but increase the ability of fault detection and selective protection, a high-ohmic resistance can be placed between the neutral point and ground. This method is called high-resistance grounding.

Typically, the resistances in MV-systems are chosen so that the fault currents are between 5 and 25 A depending on the application [31]. The resistance should be chosen so that the resistive part of the fault current exceeds the capacitive part; otherwise selective protection will be very difficult. One drawback with this method is that in order to achieve selective protection, special ground-fault protection is needed.

The method is normally used in medium voltage distribution systems and is frequent in e.g. France, Great Britain and Portugal [29].

4.6 Reactance Grounded Systems

Another way of reducing the fault current is to connect a reactor between the neutral point and ground, a method called reactance grounding. Since the capacitive coupling between the phases and ground and the grounding reactance will be in parallel, the impedance can be expressed as follows

$$\overline{Z}_{\text{Fault}} = \frac{\dfrac{3 \cdot L_0}{C_{\text{tot}}}}{\mathrm{j}\left(3 \cdot \omega L_0 - \dfrac{1}{\omega C_{\text{tot}}}\right)} \tag{14}$$

Where L_0 is the inductance of the Petersen coil, C_{tot} the total capacitance between the phases and ground and ω is the power frequency. The objective is to achieve an open circuit to get zero current. It can be seen from (14) that this is achieved if

$$L_0 = \frac{1}{3 \cdot \omega^2 C_{\text{tot}}} \tag{15}$$

However, a small resistive current will still flow because of the leakage via the network insulation resistance to ground [31]. The great advantage of this method is that an arcing fault is likely to self-extinguish since the voltage and current are in phase and the current is very low. This means that protection to remove the fault is only needed for permanent faults. A schematic representation of isolated grounding is shown in Figure 20.

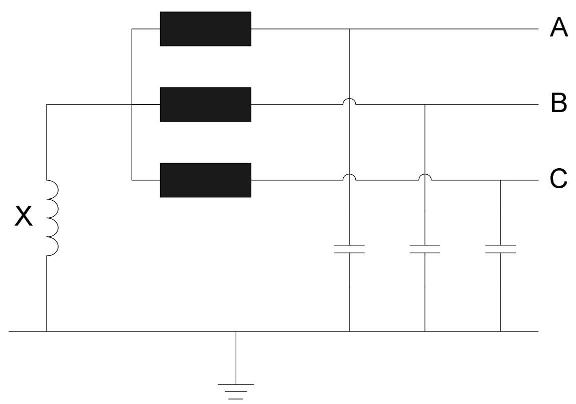


Figure 20. Reactance grounding.

To clear permanent faults in a reactance grounded system, the lines or cables must be manually removed one by one. This method is mainly used in meshed system so that system operation is not affected. In radial systems, resistances could be connected in parallel with the reactance. By doing this, the system becomes resistance grounded and the fault can be detected by over-current ground-fault relays.

In Finland, 20-30 % of the MV-networks are reactance grounded [30].

4.7 Grounding in Large Offshore Wind Parks

A large offshore wind park situated far from land is typically connected to the grid via a high voltage sub-sea cable as shown in Figure 21. Since the collection grid in the wind park is connected through medium voltage cables, there is a need for a step-up transformer between the collection grid and the high voltage cable. This transformer can be placed on a platform according to the figure. Each wind turbine generator is usually operated at 690 V and is connected to the collection grid via another transformer. Hence, three grounding systems are formed by the transformers, one for the HV-cable, one for the collection grid and one in the nacelle.

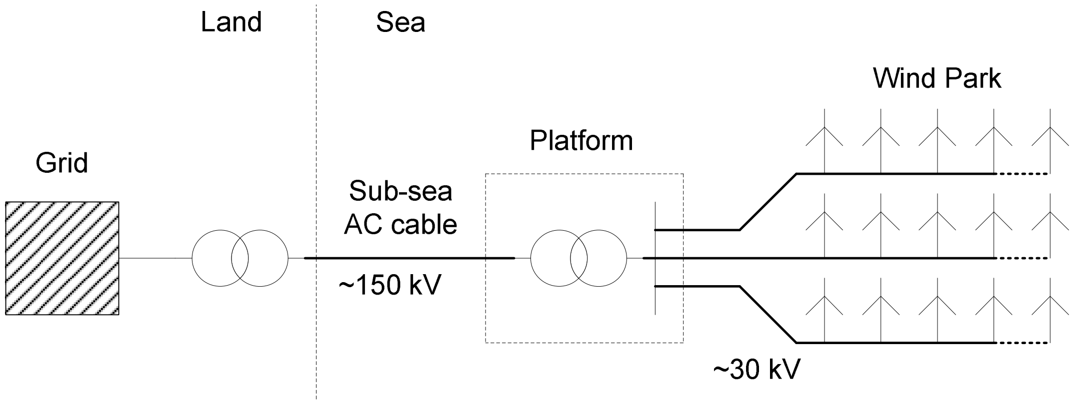


Figure 21. Layout of a Typical Large Offshore Wind Park.

Since an offshore wind park often is situated far from land and the weather conditions may at times be quite harsh, the accessibility for maintenance and repair is an issue. This calls for high reliability. Therefore, isolated, high-resistance or reactance grounding may be favourable options for the designer. However, the calculations later in the report will show that the fault current can not be sufficiently reduced. Therefore, isolated and high-resistance grounding types are not recommended. Further, the cost may increase significantly with a high impedance system since the insulation level must then adapt to the line-to-line voltages.

In a cable system, most ground faults are likely to be permanent since the phase conductors are protected by the surrounding material. Hence, the risk of arcing ground faults is low, thus reducing the advantages with reactance grounding and low-resistance grounding. Further, loosing a cable in the collection grid would change the conditions so that a reactance grounding system would no longer make the system resonant. This can be solved by distributing the reactors so that each reactor compensates for each cable.

Regarding grounding in the nacelle, two systems are dominant: effectively grounded and isolated grounded (often called insulated terra, IT). Isolated grounding can be permitted since it is very unlikely of human interaction in such an isolated environment as in the nacelle. A summary of the grounding systems relevant in a wind park are shown in Table 9.

Table 9. Relevant grounding systems in a wind park.

Sub-sea cable system	Collection grid system	Nacelle
Effectively grounded Low resistance grounded Reactance grounded	Effectively grounded Low resistance grounded Reactance grounded	Isolated Effectively grounded

4.8 Summary

This chapter has presented an overview of common power system grounding methods and their characteristics. The objective when choosing a particular type of system grounding is often to find the best compromise between the conflicting advantages and disadvantages. Considerations have to be taken regarding factors such as system reliability, possibility of fault clearing, personal safety, cost, insulation level and risk of equipment damage. Different countries have different grounding system philosophies, even though some general conclusions can be made. A low-impedance grounded system should be selected when there is a need for fast clearing times and/or the cost of increasing the insulation levels is high. A high-impedance or a reactance grounded system should be chosen when the need for high reliability is important.

In a large offshore wind park, it was concluded that the relevant power system grounding alternatives are effectively, low-resistance or reactance grounding except for the inside of the nacelle where isolated or effectively grounding should be the selection.

5 Symmetrical Components

This chapter gives an introduction to the method of symmetrical components and how cables and transformers can be modelled.

5.1 Introduction

The use of symmetrical components is advantageous when describing unbalance in a three-phase system since it simplifies the calculations. The symmetrical components can be calculated from the complex phase voltages as

$$\begin{aligned}\overline{U}_0 &= \frac{1}{3}\left(\overline{E}_A + \overline{E}_B + \overline{E}_C\right)\\ \overline{U}_1 &= \frac{1}{3}\left(\overline{E}_A + a\overline{E}_B + a^2\overline{E}_C\right)\\ \overline{U}_2 &= \frac{1}{3}\left(\overline{E}_A + a^2\overline{E}_B + a\overline{E}_C\right)\end{aligned} \tag{16}$$

Where “a” denotes a rotation of +120^o in the complex plane which means that a^2 is a rotation of -120^o. Given the component voltages, back transformation gives

$$\begin{aligned}\overline{E}_A &= \overline{U}_0 + \overline{U}_1 + \overline{U}_2\\ \overline{E}_B &= \overline{U}_0 + a^2\overline{U}_1 + a\overline{U}_2\\ \overline{E}_C &= \overline{U}_0 + a\overline{U}_1 + a^2\overline{U}_2\end{aligned} \tag{17}$$

A more detailed explanation of the method of symmetrical components can be found in the literature, see for example [28].

5.3 Cables

At the power system frequency, a cable can be represented by the so-called pi model shown in Figure 22. This model is valid when the capacitive coupling between the phases and ground is not negligible but the cable is short enough so that a distributed parameter model of the cable is not needed [32].

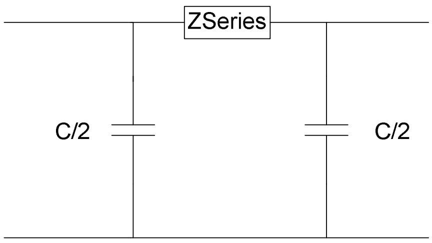


Figure 22. Pi Representation of a Cable.

In the figure, $\overline{Z}_{\text{Series}}$ includes the resistive and reactive parameters of the cable while C is the total capacitance to ground. To get a more accurate model, this capacitance is divided in half and put on each side of the series impedance.

A cable is a static element so that the positive and negative sequence impedances are equal but the zero sequence impedance differs when there is a mutual coupling between phases [28].

5.3 Transformers

As the cables, transformers are static devices so that the positive and negative sequence impedances are equal. An equivalent circuit of the positive and negative sequence impedances of a transformer is shown in Figure 23. In the model, $\overline{Z}_M$ represents the magnetizing inductance and iron losses while $\overline{Z}_L$ is the equivalent leakage reactance and resistance in the transformer windings. It should also be mentioned that depending on how the windings of the HV-side and the LV-side are connected, different phase shifts occur between the two sides of the transformer.

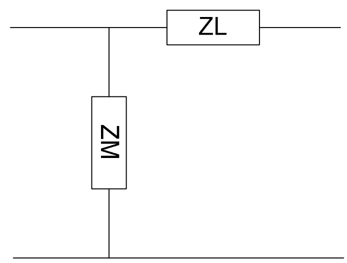


Figure 23. Positive and Negative Sequence Impedances of a Transformer.

For the zero sequence impedance, the model differs depending on the winding connections. In addition, the neutral point of a wye-connected transformer can be connected to ground via an impedance. This impedance must be added three times since the current through the impedance is the sum of the phase currents that equals three times the zero-sequence current. Zero-sequence impedance models for a set of different transformers are shown in Figure 24. In the figure, $\overline{Z}_N$ is the ground impedance at the high-voltage side and $\overline{Z}_n$, the ground impedance at the low-voltage side of the transformer. Depending on the clock number of the transformer, a phase shift of 180 degrees is possible.

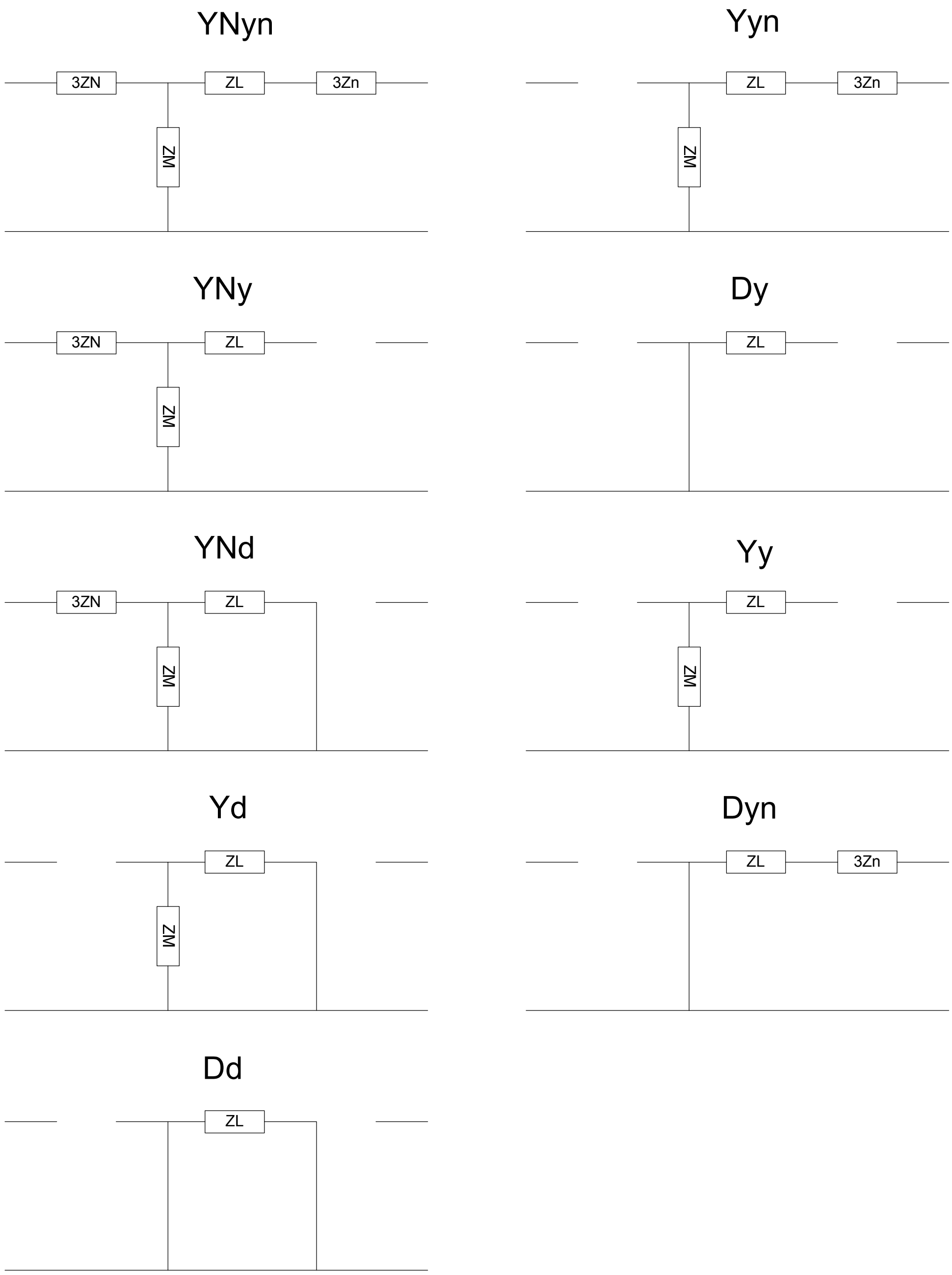


Figure 24. Zero Sequence Models of a Transformer.

5.4 Summary

This chapter has dealt with the use of symmetrical components and how to model cables and transformers in sequence networks. The pi-model of a cable has been presented as well as models of transformers that take the magnetizing inductance and the leakage reactance into account. Finally, zero-sequence impedance models of transformers connected in different ways have been shown.

6 Wind Park Equations and Grounding Calculations

This chapter aims at deriving equations and calculate parameters in order to analyze the voltage dip propagation in an offshore wind park. The chapter will start by defining the layout of the wind park that is used for the calculations, then positive and negative sequence networks will be presented together with equations that describe them. Zero-sequence networks will be treated separately since they are dependent on the choice of transformer winding connections. Finally, values of the grounding-impedances used for system grounding will be calculated. Putting together the results from this chapter will make it possible to analyze and calculate voltages throughout the wind park for different combinations of grounding and transformer connections.

6.1 Derivation of Wind Park Voltages

In order to fully understand the influence of different grounding systems and transformer connections in a wind park, it is useful to derive a theoretical description of how the voltages can be calculated given a certain voltage profile at the connection point to the grid. This will also be useful when trying to interpret the grid code ride-through requirements “translated” to the terminals of the wind turbine.

6.1.1 Wind Park Layout

To have a realistic model, the layout of one of the largest offshore wind parks in the world, Horns-reef, has been chosen as a reference (see Horns-reef website [33]). A schematic representation of the park is presented in Figure 25. The park is connected to the onshore grid via a long sub-sea cable. At sea, a platform is located, containing a transformer. From the platform, five feeders of different length connect the transformer at one end and 16 wind turbine towers at the other. In the tower, an 80 m cable leads up to a transformer that is connected to a generator with a rated power of 2 MVA. Data for the components of the wind park can be found in Appendix A.

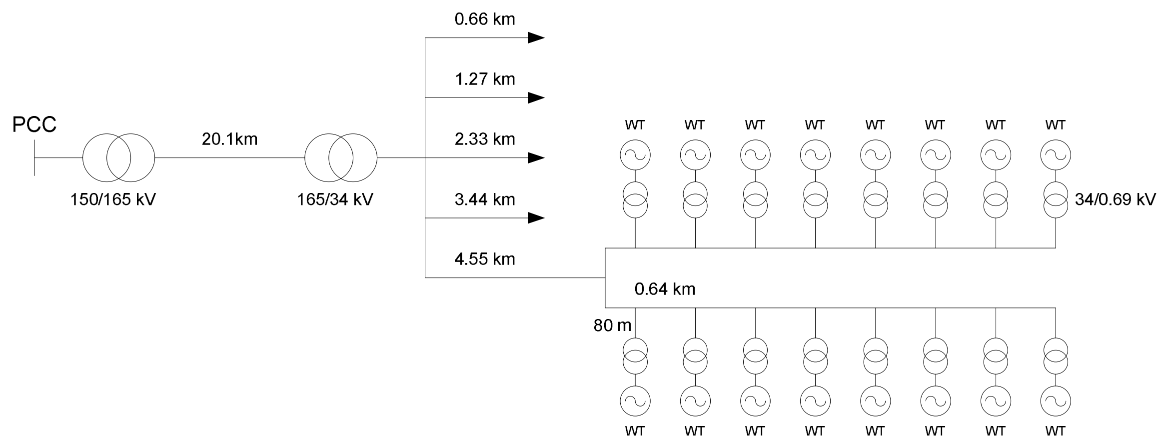


Figure 25. Layout of Horns-reef Wind Park.

6.1.2 Sequence Networks and Voltage Equations

As presented in the chapter about grid codes, the voltage profile requirements were specified at the PCC. These voltages will serve as a starting point of the calculations. Symmetrical components will be used to simplify the calculations. From (16), the component voltages can be found from the phase voltages. If the phase voltages of the ride-through requirements of any grid code are expressed as $\overline{E}_A$, $\overline{E}_B$ and $\overline{E}_C$, transformation to component voltages yields:

$$\begin{aligned}\overline{U}_0 &= \frac{1}{3}\left(\overline{E}_A + \overline{E}_B + \overline{E}_C\right) \\ \overline{U}_1 &= \frac{1}{3}\left(\overline{E}_A + a\overline{E}_B + a^2\overline{E}_C\right) \\ \overline{U}_2 &= \frac{1}{3}\left(\overline{E}_A + a^2\overline{E}_B + a\overline{E}_C\right)\end{aligned} \tag{18}$$

These sequence voltages are from now on assumed fixed so that they represent a given voltage profile at the PCC. An electric circuit description for the positive, negative and zero sequence voltages will now be derived.

6.1.2.1 Positive- and Negative-Sequence Networks

A list of all variables used in this section can be found in Table 10 on page 52.

Figure 26 presents a general circuit for the positive- and negative-sequence network of the wind park. The system voltage, U, denotes the component voltages $\overline{U}_1$ or $\overline{U}_2$ in (18) for the positive and negative sequence network respectively.

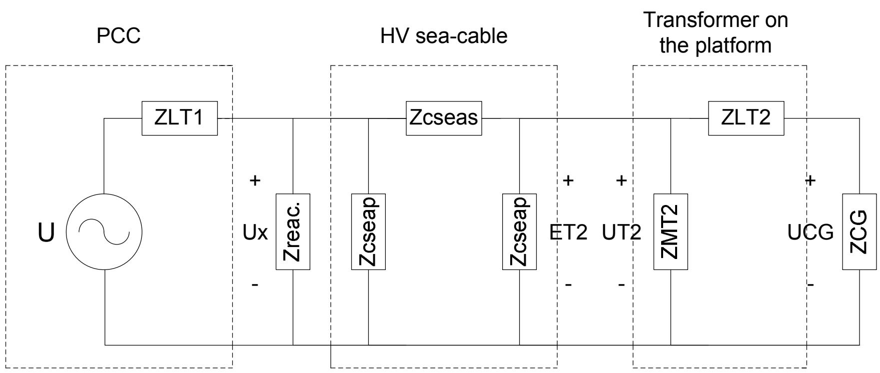


Figure 26. General positive and negative sequence network.

In the figure, the equivalent collection grid impedance, ZCG consists of the five feeders connected in parallel, where each feeder-impedance can be represented according to Figure 27.

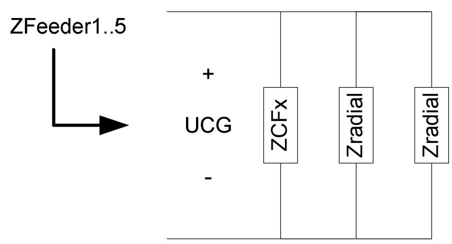


Figure 27. Positive and negative sequence network for feeder impedances.

Table 10. List of Positive and Negative Sequence Variables.

Variable	Explanation	Variable	Explanation
U	*System Voltage at PCC. Either* $\overline{U}_1$ *or* $\overline{U}_2$.	ZLT1	*Leakage impedance of transformer at PCC.*
Ux	*Voltage over the reactive power compensation impedance.*	Zreac.	*Optional impedance for reactive power compensation.*
Zcseap	*Shunt impedance containing half of the capacitance of the sea-cable according to the pi model.*	Zcseas	*Series impedance of the sea-cable using the pi model.*
ET2	*Voltage to ground at the platform based transformer terminals.*	UT2	*Winding voltage at the platform based transformer terminals.*
ZMT2	*Magnetizing impedance of the platform based transformer.*	ZLT2	*Leakage impedance of the platform based transformer.*
UCG	*Voltage at the LV-side at the platform based transformer terminals (Collection grid voltage).*	ZCG	*Total impedance of the collection grid seen from the LV-side of the platform based transformer.*
ZFeeder1..5	*Total impedance of each of the feeders 1 to 5 seen from the LV-side of the platform based transformer.*	ZCFx	*Shunt impedance of each feeder cable, where x is the feeder number (1 to 5).*
Zradial	*Total impedance of one of the two radials starting from the end of each feeder cable. This impedance includes cables, transformers and 8 wind turbines.*	ZTow	*Total impedance of the cable in the turbine tower and the transformer in the nacelle.*
ZCra1	*Shunt impedance of the cables between the first 4 turbine towers.*	ZCra2	*Shunt impedance of the cables between the last 4 turbine towers.*
ZCtow	*Shunt impedance of the cable in the turbine tower.*	ET3	*Voltage at the nacelle transformer terminals.*
UT3	*Voltage at the nacelle transformer terminals.*	ZMT3	*Magnetizing impedance of the nacelle transformer.*
ZLT3	*Leakage impedance of the nacelle transformer.*	EWT	*Voltage at the wind turbine terminals.*
UWT	*Voltage at the wind turbine terminals.*	ZWT	*Equivalent impedance of the wind turbine.*

To simplify the calculations, series impedances of the feeder cables have been omitted. To estimate the loss of accuracy, consider the following reasoning:

For the longest feeder (4.55km), i.e. the “worst case” regarding the voltage drop, the absolute value of the impedance is:

$$\left|\overline{Z}_{\text{CF5}}\right| = \sqrt{(r \cdot l)^2 + (x \cdot l)^2} = \sqrt{(0.042 \cdot 4.55)^2 + (0.11 \cdot 4.55)^2}\,\Omega = 0.536\Omega$$

At rated power the current flowing in this feeder will be

$$\left|\overline{I}_{\text{rated}}\right| = \frac{\left|S_{\text{phase}}\right|}{\left|U_{\text{phase}}\right|} = \frac{\dfrac{16}{3 \cdot 80} 160 \cdot 10^6}{\dfrac{1}{\sqrt{3}} 34 \cdot 10^3}\text{A} = 543\text{A}$$

Hence, the voltage drop per phase according to Ohm's law is:

$$\left|\overline{U}_{\text{drop}}\right| = \left|\overline{Z}_{\text{CF5}}\right| \cdot \left|\overline{I}_{\text{rated}}\right| = 0.536 \cdot 543 = 291\text{V}$$

which is small compared to nominal phase voltage (~20kV).

The equivalent impedance of each radial consisting of 8 wind turbines is presented in Figure 28.

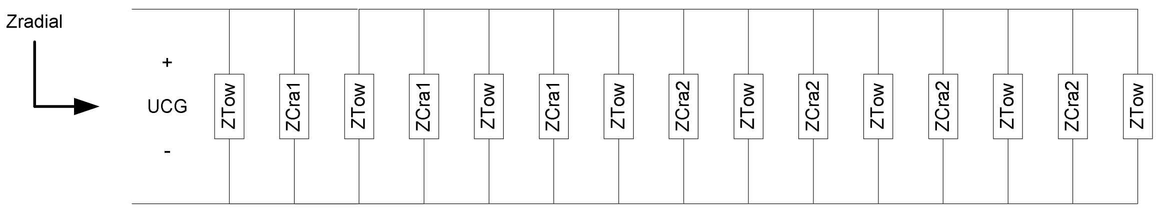


Figure 28. Positive and negative sequence network for each radial impedance.

The series branches of the cables are also omitted here. An equivalent circuit of the total impedance of the components inside the wind turbine tower, ZTow is presented in Figure 29.

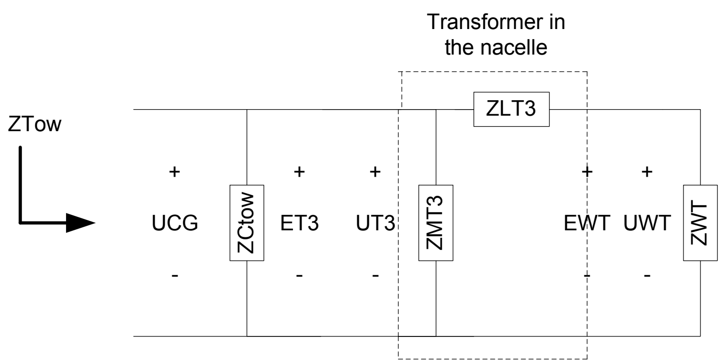


Figure 29. Positive and negative sequence network for the equivalent tower impedance.

From the circuits in Figure 26 to Figure 29, equivalent impedances can now be calculated:

$$\overline{Z}_{\text{Tow}} = \left(\left(\overline{Z}_{\text{WT}} + \overline{Z}_{\text{LT3}}\right) // \overline{Z}_{\text{MT3}}\right) // \overline{Z}_{\text{Ctow}} \tag{19}$$

$$\overline{Z}_{\text{radial}} = \left(\frac{1}{4}\left(\overline{Z}_{\text{Tow}} \mathbin{//} \overline{Z}_{\text{Cra2}}\right)\right) \mathbin{//} \left(\frac{1}{3}\left(\overline{Z}_{\text{Tow}} \mathbin{//} \overline{Z}_{\text{Cra1}}\right)\right) \mathbin{//} \overline{Z}_{\text{Tow}} \tag{20}$$

$$\begin{aligned}
\overline{Z}_{\text{Feeder1}} &= \overline{Z}_{\text{radial}} \mathbin{//} \overline{Z}_{\text{CF1}} \\
\overline{Z}_{\text{Feeder2}} &= \overline{Z}_{\text{radial}} \mathbin{//} \overline{Z}_{\text{CF2}} \\
\overline{Z}_{\text{Feeder3}} &= \overline{Z}_{\text{radial}} \mathbin{//} \overline{Z}_{\text{CF3}} \\
\overline{Z}_{\text{Feeder4}} &= \overline{Z}_{\text{radial}} \mathbin{//} \overline{Z}_{\text{CF4}} \\
\overline{Z}_{\text{Feeder5}} &= \overline{Z}_{\text{radial}} \mathbin{//} \overline{Z}_{\text{CF5}}
\end{aligned} \tag{21}$$

$$\overline{Z}_{\text{CG}} = \overline{Z}_{\text{Feeder1}} \mathbin{//} \overline{Z}_{\text{Feeder2}} \mathbin{//} \overline{Z}_{\text{Feeder3}} \mathbin{//} \overline{Z}_{\text{Feeder4}} \mathbin{//} \overline{Z}_{\text{Feeder5}}. \tag{22}$$

The positive and negative sequence voltages can now be calculated from the circuits together with equations (19) to (22). Voltage division gives

$$\begin{aligned}
\overline{U}_{\text{WT}} &= \overline{E}_{\text{WT}} = \overline{U}_{\text{T3}} \cdot e^{\mathrm{j}\frac{\pi}{6}\cdot k3} \cdot \frac{\overline{Z}_{\text{WT}}}{\overline{Z}_{\text{WT}} + \overline{Z}_{\text{LT3}}} \\
\overline{U}_{\text{T3}} &= \overline{E}_{\text{T3}} = \overline{U}_{\text{CG}} = \overline{U}_{\text{T2}} \cdot e^{\mathrm{j}\frac{\pi}{6}\cdot k2} \cdot \frac{\overline{Z}_{\text{CG}}}{\overline{Z}_{\text{CG}} + \overline{Z}_{\text{LT2}}} \\
\overline{U}_{\text{T2}} &= \overline{E}_{\text{T2}} = \overline{U}_{\text{X}} \frac{\left(\left(\overline{Z}_{\text{CG}} + \overline{Z}_{\text{LT2}}\right) \mathbin{//} \overline{Z}_{\text{MT2}}\right) \mathbin{//} \overline{Z}_{\text{cseap}}}{\left(\left(\overline{Z}_{\text{CG}} + \overline{Z}_{\text{LT2}}\right) \mathbin{//} \overline{Z}_{\text{MT2}}\right) \mathbin{//} \overline{Z}_{\text{cseap}} + \overline{Z}_{\text{cseas}}} \\
\overline{U}_{\text{X}} &= \overline{U} \cdot \mathrm{e}^{\mathrm{j}\frac{\pi}{6}\cdot k1} \cdot \frac{\left(\left(\left(\overline{Z}_{\text{CG}} + \overline{Z}_{\text{LT2}}\right) \mathbin{//} \overline{Z}_{\text{MT2}}\right) \mathbin{//} \overline{Z}_{\text{cseap}} + \overline{Z}_{\text{cseas}}\right) \mathbin{//} \overline{Z}_{\text{cseap}} \mathbin{//} \overline{Z}_{\text{Reactor}}}{\left(\left(\left(\overline{Z}_{\text{CG}} + \overline{Z}_{\text{LT2}}\right) \mathbin{//} \overline{Z}_{\text{MT2}}\right) \mathbin{//} \overline{Z}_{\text{cseap}} + \overline{Z}_{\text{cseas}}\right) \mathbin{//} \overline{Z}_{\text{cseap}} \mathbin{//} \overline{Z}_{\text{Reactor}} + \overline{Z}_{\text{LT1}}}.
\end{aligned} \tag{23}$$

Where $k1$, $k2$ and $k3 = 0$ for Yy and Dd transformers. For Dy and Yd transformers $k1$, $k2$ and $k3 = 1$ for the positive sequence network while $k1$, $k2$ and $k3 = -1$ for the negative sequence network.

6.1.2.2 Zero-Sequence Networks

Since zero-sequence networks differ depending on the transformer windings, equations and circuits have to be deduced for each combination of transformers in the wind park. The transformer models in Chapter 5 will be used according to the present combination by just inserting the models in the right position.

A list of all variables used in this section can be found in Table 11.

Table 11. List of Zero Sequence Variables.

Variable	Explanation	Variable	Explanation
U0	*System Voltage at PCC*	U0x	*Voltage over the optional reactor.*
E0T2	*Voltage at the platform based transformer terminals to ground potential.*	U0T2	*Voltage at the platform based transformer terminals to the common point of the wye-connection.*
U0CG	*Voltage at the LV-side at the platform based transformer terminals (Collection grid voltage).*	E0T3	*Voltage at the nacelle transformer terminals to ground potential.*
U0T3	*Voltage at the nacelle transformer terminals to the common point of the wye-connection.*	E0WT	*Voltage at the wind turbine terminals to ground potential.*
U0WT	*Voltage at the wind turbine terminals to the common point of the wye-connection.*	ZnT1	*Grounding impedance at LV-side of the transformer at PCC.*
Z0csea	*Zero sequence series impedance of the sea-cable using the pi model.*	ZNT2	*Grounding impedance at HV-side of the platform based transformer.*
ZnT2	*Grounding impedance at LV-side of the platform based transformer.*	Z0CG	*Total impedance of the collection grid seen from the LV-side of the platform based transformer.*
Z0rad	*Total impedance of one of the two radials starting from the end of each feeder cable. This impedance includes cables, transformers and 8 wind turbines.*	Z0Tow	*Total impedance of the cable in the turbine tower and the transformer in the nacelle.*
ZNT3	*Grounding impedance at HV-side of the nacelle transformer.*	ZnT3	*Grounding impedance at LV-side of the nacelle transformer.*
ZNwt	*Grounding impedance of the wind turbine.*		

Combination 1:
PCC Transformer=Yy; Platform Transformer=Yy; Nacelle Transformer=Yy

When all three transformers are connected in wye-wye, the networks are similar as those previously derived for positive and negative sequences except for the addition of grounding impedances. The circuits are presented in Figure 30.

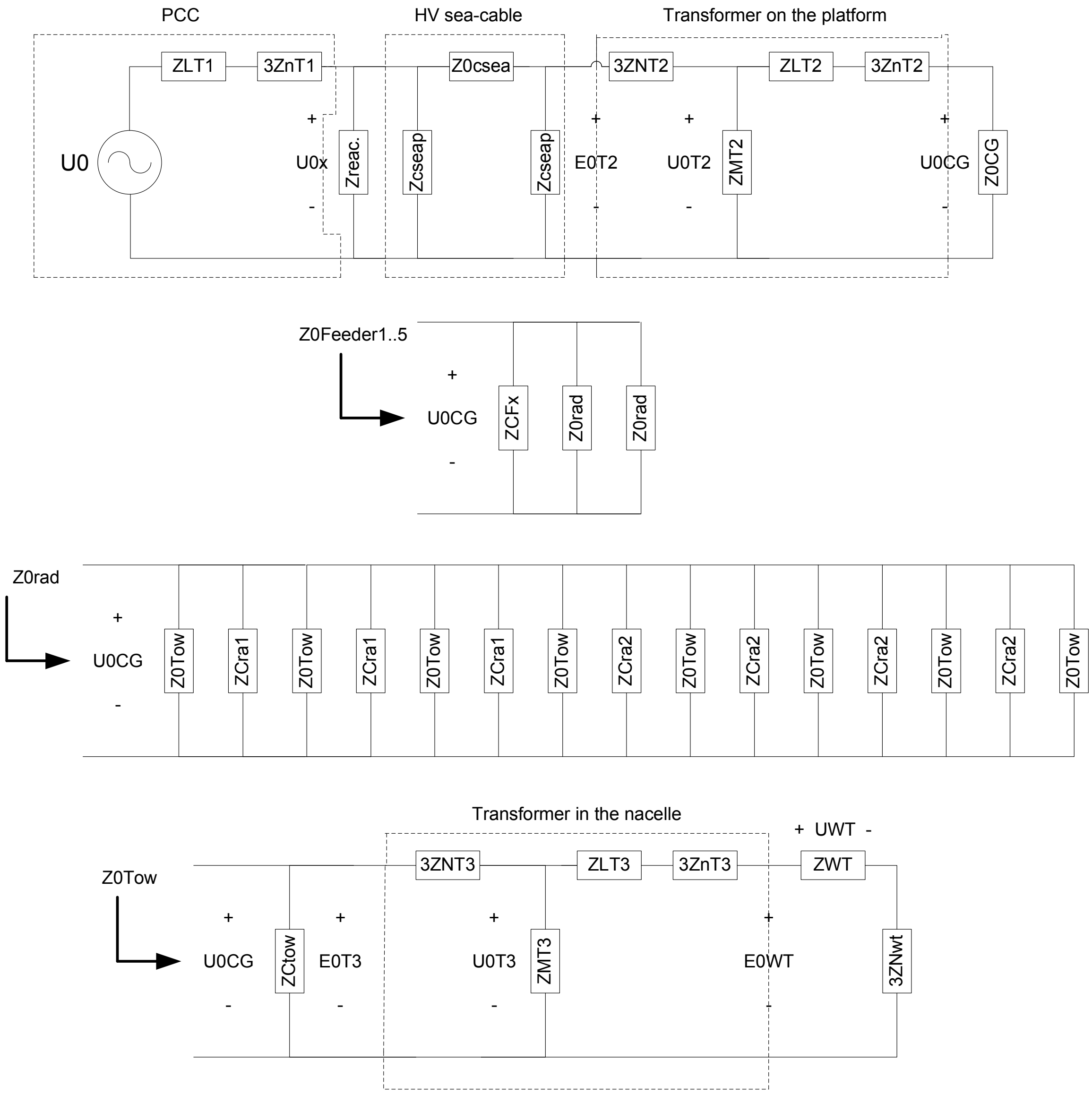


Figure 30. Zero-sequence networks for Yy+Yy+Yy connected transformers.

The impedances in the figure can be expressed as follows:

$$\overline{Z}_{0CG} = \overline{Z}_{0Feeder1} \,//\, \overline{Z}_{0Feeder2} \,//\, \overline{Z}_{0Feeder3} \,//\, \overline{Z}_{0Feeder4} \,//\, \overline{Z}_{0Feeder5} \quad (24)$$

$$\begin{aligned}
\overline{Z}_{0\mathrm{Feeder1}} &= \overline{Z}_{0\mathrm{rad}} // \overline{Z}_{\mathrm{CF1}} \\
\overline{Z}_{0\mathrm{Feeder2}} &= \overline{Z}_{0\mathrm{rad}} // \overline{Z}_{\mathrm{CF2}} \\
\overline{Z}_{0\mathrm{Feeder3}} &= \overline{Z}_{0\mathrm{rad}} // \overline{Z}_{\mathrm{CF3}} \\
\overline{Z}_{0\mathrm{Feeder4}} &= \overline{Z}_{0\mathrm{rad}} // \overline{Z}_{\mathrm{CF4}} \\
\overline{Z}_{0\mathrm{Feeder5}} &= \overline{Z}_{0\mathrm{rad}} // \overline{Z}_{\mathrm{CF5}}
\end{aligned} \tag{25}$$

$$\overline{Z}_{0\mathrm{rad}} = \left(\frac{1}{4}\left(\overline{Z}_{0\mathrm{Tow}} // \overline{Z}_{\mathrm{Cra2}}\right)\right) // \left(\frac{1}{3}\left(\overline{Z}_{0\mathrm{Tow}} // \overline{Z}_{\mathrm{Cra1}}\right)\right) // \overline{Z}_{0\mathrm{Tow}} \tag{26}$$

$$\overline{Z}_{0\mathrm{Tow}} = \left(\left(3\overline{Z}_{\mathrm{Nwt}} + \overline{Z}_{\mathrm{WT}} + 3\overline{Z}_{\mathrm{nT3}} + \overline{Z}_{\mathrm{LT3}}\right) // \overline{Z}_{\mathrm{MT3}} + 3\overline{Z}_{\mathrm{NT3}}\right) // \overline{Z}_{\mathrm{Ctow}} \tag{27}$$

The zero-sequence voltages can now be calculated from the circuits together with equations (24) to (27). Voltage division gives

$$\begin{aligned}
\overline{U}_{0\mathrm{WT}} &= \overline{E}_{0\mathrm{WT}} \frac{\overline{Z}_{\mathrm{WT}}}{\overline{Z}_{\mathrm{WT}} + 3\overline{Z}_{\mathrm{Nwt}}} \\
\overline{E}_{0\mathrm{WT}} &= \overline{U}_{0\mathrm{T3}} \frac{\overline{Z}_{\mathrm{WT}} + 3\overline{Z}_{\mathrm{Nwt}}}{\overline{Z}_{\mathrm{WT}} + 3\overline{Z}_{\mathrm{Nwt}} + \overline{Z}_{\mathrm{LT3}} + 3\overline{Z}_{\mathrm{nT3}}} \\
\overline{U}_{0\mathrm{T3}} &= \overline{E}_{0\mathrm{T3}} \frac{\left(\overline{Z}_{\mathrm{WT}} + 3\overline{Z}_{\mathrm{Nwt}} + \overline{Z}_{\mathrm{LT3}} + 3\overline{Z}_{\mathrm{nT3}}\right) // \overline{Z}_{\mathrm{MT3}}}{\left(\overline{Z}_{\mathrm{WT}} + 3\overline{Z}_{\mathrm{Nwt}} + \overline{Z}_{\mathrm{LT3}} + 3\overline{Z}_{\mathrm{nT3}}\right) // \overline{Z}_{\mathrm{MT3}} + 3\overline{Z}_{\mathrm{NT3}}} \\
\overline{E}_{0\mathrm{T3}} &= \overline{U}_{0\mathrm{CG}} = \overline{U}_{0\mathrm{T2}} \frac{\overline{Z}_{0\mathrm{CG}}}{\overline{Z}_{0\mathrm{CG}} + \overline{Z}_{\mathrm{LT2}} + 3\overline{Z}_{\mathrm{nT2}}} \\
\overline{U}_{0\mathrm{T2}} &= \overline{E}_{0\mathrm{T2}} \frac{\left(\overline{Z}_{0\mathrm{CG}} + \overline{Z}_{\mathrm{LT2}} + 3\overline{Z}_{\mathrm{nT2}}\right) // \overline{Z}_{\mathrm{MT2}}}{\left(\overline{Z}_{0\mathrm{CG}} + \overline{Z}_{\mathrm{LT2}} + 3\overline{Z}_{\mathrm{nT2}}\right) // \overline{Z}_{\mathrm{MT2}} + 3\overline{Z}_{\mathrm{NT2}}} \\
\overline{E}_{0\mathrm{T2}} &= \overline{U}_{0\mathrm{X}} \frac{\left(\left(\overline{Z}_{0\mathrm{CG}} + \overline{Z}_{\mathrm{LT2}} + 3\overline{Z}_{\mathrm{nT2}}\right) // \overline{Z}_{\mathrm{MT2}} + 3\overline{Z}_{\mathrm{NT2}}\right) // \overline{Z}_{\mathrm{cseap}}}{\left(\left(\overline{Z}_{0\mathrm{CG}} + \overline{Z}_{\mathrm{LT2}} + 3\overline{Z}_{\mathrm{nT2}}\right) // \overline{Z}_{\mathrm{MT2}} + 3\overline{Z}_{\mathrm{NT2}}\right) // \overline{Z}_{\mathrm{cseap}} + \overline{Z}_{0\mathrm{Csea}}} \\
\overline{U}_{0\mathrm{X}} &= \overline{U}_{0} \frac{\left(\left(\left(\overline{Z}_{0\mathrm{CG}} + \overline{Z}_{\mathrm{LT2}} + 3\overline{Z}_{\mathrm{nT2}}\right) // \overline{Z}_{\mathrm{MT2}} + 3\overline{Z}_{\mathrm{NT2}}\right) // \overline{Z}_{\mathrm{cseap}} + \overline{Z}_{0\mathrm{Csea}}\right) // \overline{Z}_{\mathrm{cseap}} // \overline{Z}_{\mathrm{Reactor}}}{\left(\left(\left(\overline{Z}_{0\mathrm{CG}} + \overline{Z}_{\mathrm{LT2}} + 3\overline{Z}_{\mathrm{nT2}}\right) // \overline{Z}_{\mathrm{MT2}} + 3\overline{Z}_{\mathrm{NT2}}\right) // \overline{Z}_{\mathrm{cseap}} + \overline{Z}_{0\mathrm{Csea}}\right) // \overline{Z}_{\mathrm{cseap}} // \overline{Z}_{\mathrm{Reactor}} + \overline{Z}_{\mathrm{LT1}} + 3\overline{Z}_{\mathrm{nT1}}}
\end{aligned} \tag{28}$$

Combination 2:
PCC Transformer=Yy; Platform Transformer=Yy; Nacelle Transformer=Dy or Dd

When the transformer in the nacelle is delta-wye or delta-delta connected, the last circuit in Figure 30 must be replaced by the one in Figure 31.

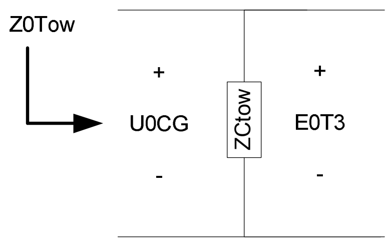


Figure 31. Zero-sequence network for Z0Tow when T3 is connected in Dy/Dd.

Thus (27) must be replaced by

$$\overline{Z}_{0\text{Tow}} = \overline{Z}_{\text{Ctow}} \tag{29}$$

This gives the zero-sequence voltages as:

$$\begin{aligned}
&\overline{U}_{0\text{WT}} = \overline{E}_{0\text{WT}} = \overline{U}_{0\text{T3}} = 0\\
&\overline{E}_{0\text{T3}} = \overline{U}_{0\text{CG}} = \overline{U}_{0\text{T2}} \frac{\overline{Z}_{0\text{CG}}}{\overline{Z}_{0\text{CG}} + \overline{Z}_{\text{LT2}} + 3\overline{Z}_{\text{nT2}}}\\
&\overline{U}_{0\text{T2}} = \overline{E}_{0\text{T2}} \frac{\left(\overline{Z}_{0\text{CG}} + \overline{Z}_{\text{LT2}} + 3\overline{Z}_{\text{nT2}}\right) // \overline{Z}_{\text{MT2}}}{\left(\overline{Z}_{0\text{CG}} + \overline{Z}_{\text{LT2}} + 3\overline{Z}_{\text{nT2}}\right) // \overline{Z}_{\text{MT2}} + 3\overline{Z}_{\text{NT2}}}\\
&\overline{E}_{\text{T2}} = \overline{U}_{0\text{X}} \frac{\left(\left(\overline{Z}_{0\text{CG}} + \overline{Z}_{\text{LT2}} + 3\overline{Z}_{\text{nT2}}\right) // \overline{Z}_{\text{MT2}} + 3\overline{Z}_{\text{NT2}}\right) // \overline{Z}_{\text{cseap}}}{\left(\left(\overline{Z}_{0\text{CG}} + \overline{Z}_{\text{LT2}} + 3\overline{Z}_{\text{nT2}}\right) // \overline{Z}_{\text{MT2}} + 3\overline{Z}_{\text{NT2}}\right) // \overline{Z}_{\text{cseap}} + \overline{Z}_{0\text{Csea}}}\\
&\overline{U}_{0\text{X}} = \overline{U}_{0} \frac{\left(\left(\left(\overline{Z}_{0\text{CG}} + \overline{Z}_{\text{LT2}} + 3\overline{Z}_{\text{nT2}}\right) // \overline{Z}_{\text{MT2}} + 3\overline{Z}_{\text{NT2}}\right) // \overline{Z}_{\text{cseap}} + \overline{Z}_{0\text{Csea}}\right) // \overline{Z}_{\text{cseap}} // \overline{Z}_{\text{Reactor}}}{\left(\left(\left(\overline{Z}_{0\text{CG}} + \overline{Z}_{\text{LT2}} + 3\overline{Z}_{\text{nT2}}\right) // \overline{Z}_{\text{MT2}} + 3\overline{Z}_{\text{NT2}}\right) // \overline{Z}_{\text{cseap}} + \overline{Z}_{0\text{Csea}}\right) // \overline{Z}_{\text{cseap}} // \overline{Z}_{\text{Reactor}} + \overline{Z}_{\text{LT1}} + 3\overline{Z}_{\text{nT1}}}
\end{aligned} \tag{30}$$

Combination 3:
PCC Transformer=Yy; Platform Transformer=Yy; Nacelle Transformer=Yd

When the transformer in the nacelle is wye-delta connected, the last circuit in Figure 30 must be replaced by the one in Figure 32.

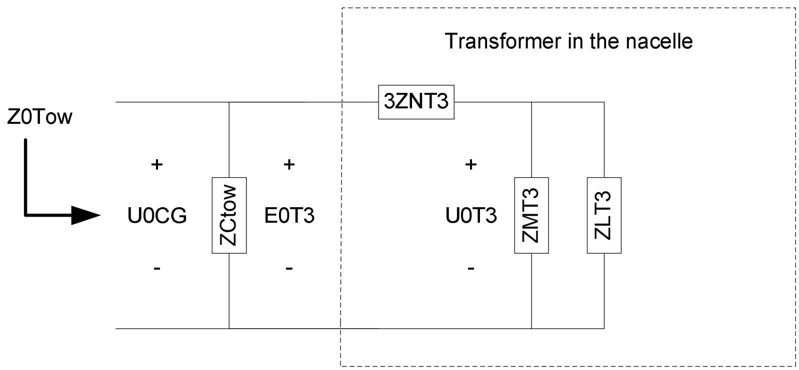


Figure 32. Zero-sequence network for Z0Tow when T3 is connected in Yd.

Thus, (27) must be replaced by

$$\overline{Z}_{0\text{Tow}} = \left(\overline{Z}_{\text{LT3}} // \overline{Z}_{\text{MT3}} + 3\overline{Z}_{\text{NT3}}\right) // \overline{Z}_{\text{Ctow}} \tag{31}$$

This gives the zero-sequence voltages as:

$$
\begin{aligned}
&\overline{U}_{0\mathrm{WT}} = \overline{E}_{0\mathrm{WT}} = 0\\
&\overline{U}_{0\mathrm{T3}} = \overline{E}_{0\mathrm{T3}} \frac{\overline{Z}_{\mathrm{LT3}} // \overline{Z}_{\mathrm{MT3}}}{\overline{Z}_{\mathrm{LT3}} // \overline{Z}_{\mathrm{MT3}} + 3\overline{Z}_{\mathrm{NT3}}}\\
&\overline{E}_{0\mathrm{T3}} = \overline{U}_{0\mathrm{CG}} = \overline{U}_{0\mathrm{T2}} \frac{\overline{Z}_{0\mathrm{CG}}}{\overline{Z}_{0\mathrm{CG}} + \overline{Z}_{\mathrm{LT2}} + 3\overline{Z}_{\mathrm{nT2}}}\\
&\overline{U}_{0\mathrm{T2}} = \overline{E}_{0\mathrm{T2}} \frac{\left(\overline{Z}_{0\mathrm{CG}} + \overline{Z}_{\mathrm{LT2}} + 3\overline{Z}_{\mathrm{nT2}}\right) // \overline{Z}_{\mathrm{MT2}}}{\left(\overline{Z}_{0\mathrm{CG}} + \overline{Z}_{\mathrm{LT2}} + 3\overline{Z}_{\mathrm{nT2}}\right) // \overline{Z}_{\mathrm{MT2}} + 3\overline{Z}_{\mathrm{NT2}}}\\
&\overline{E}_{0\mathrm{T2}} = \overline{U}_{0\mathrm{X}} \frac{\left(\left(\overline{Z}_{0\mathrm{CG}} + \overline{Z}_{\mathrm{LT2}} + 3\overline{Z}_{\mathrm{nT2}}\right) // \overline{Z}_{\mathrm{MT2}} + 3\overline{Z}_{\mathrm{NT2}}\right) // \overline{Z}_{\mathrm{cseap}}}{\left(\left(\overline{Z}_{0\mathrm{CG}} + \overline{Z}_{\mathrm{LT2}} + 3\overline{Z}_{\mathrm{nT2}}\right) // \overline{Z}_{\mathrm{MT2}} + 3\overline{Z}_{\mathrm{NT2}}\right) // \overline{Z}_{\mathrm{cseap}} + \overline{Z}_{0\mathrm{Csea}}}\\
&\overline{U}_{0\mathrm{X}} = \overline{U}_{0} \frac{\left(\left(\left(\overline{Z}_{0\mathrm{CG}} + \overline{Z}_{\mathrm{LT2}} + 3\overline{Z}_{\mathrm{nT2}}\right) // \overline{Z}_{\mathrm{MT2}} + 3\overline{Z}_{\mathrm{NT2}}\right) // \overline{Z}_{\mathrm{cseap}} + \overline{Z}_{0\mathrm{Csea}}\right) // \overline{Z}_{\mathrm{cseap}} // \overline{Z}_{\mathrm{Reactor}}}{\left(\left(\left(\overline{Z}_{0\mathrm{CG}} + \overline{Z}_{\mathrm{LT2}} + 3\overline{Z}_{\mathrm{nT2}}\right) // \overline{Z}_{\mathrm{MT2}} + 3\overline{Z}_{\mathrm{NT2}}\right) // \overline{Z}_{\mathrm{cseap}} + \overline{Z}_{0\mathrm{Csea}}\right) // \overline{Z}_{\mathrm{cseap}} // \overline{Z}_{\mathrm{Reactor}} + \overline{Z}_{\mathrm{LT1}} + 3\overline{Z}_{\mathrm{nT1}}}
\end{aligned}
\tag{32}
$$

Combination 4:
PCC Transformer=Yy; Platform Transformer=Dy or Dd; Nacelle Transformer=Any

When the transformer connecting the sub-sea cable and the collection grid is delta-wye or delta-delta connected, all circuits in Figure 30 can be expressed by the one in Figure 33.

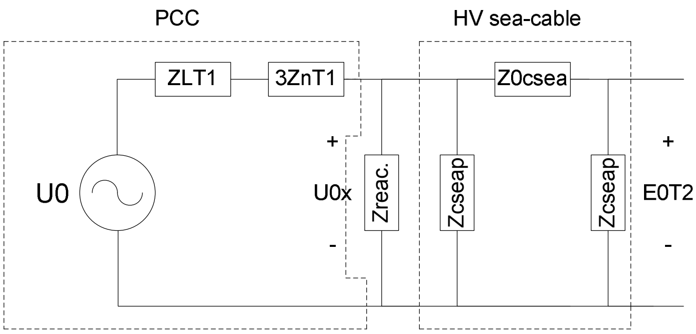


Figure 33. Zero-sequence network for Yy+Dy/Dd+-- connected transformers.

From the figure, the zero-sequence voltages can be derived as:

$$
\begin{aligned}
&\overline{U}_{0\mathrm{WT}} = \overline{E}_{0\mathrm{WT}} = \overline{U}_{0\mathrm{T3}} = \overline{E}_{0\mathrm{T3}} = \overline{U}_{0\mathrm{CG}} = \overline{U}_{0\mathrm{T2}} = 0\\
&\overline{E}_{0\mathrm{T2}} = \overline{U}_{0\mathrm{X}} \frac{\overline{Z}_{\mathrm{cseap}}}{\overline{Z}_{\mathrm{cseap}} + \overline{Z}_{0\mathrm{Csea}}}\\
&\overline{U}_{0\mathrm{X}} = \overline{U}_{0} \frac{\left(\overline{Z}_{\mathrm{cseap}} + \overline{Z}_{0\mathrm{Csea}}\right) // \overline{Z}_{\mathrm{cseap}} // \overline{Z}_{\mathrm{Reactor}}}{\left(\overline{Z}_{\mathrm{cseap}} + \overline{Z}_{0\mathrm{Csea}}\right) // \overline{Z}_{\mathrm{cseap}} // \overline{Z}_{\mathrm{Reactor}} + \overline{Z}_{\mathrm{LT1}} + 3\overline{Z}_{\mathrm{nT1}}}
\end{aligned}
\tag{33}
$$

Combination 5:
PCC Transformer=Yy; Platform Transformer=Yd; Nacelle Transformer=Any

When the transformer connecting the sub-sea cable and the collection grid is wye-delta connected, all circuits in Figure 30 can be expressed by the one in Figure 34.

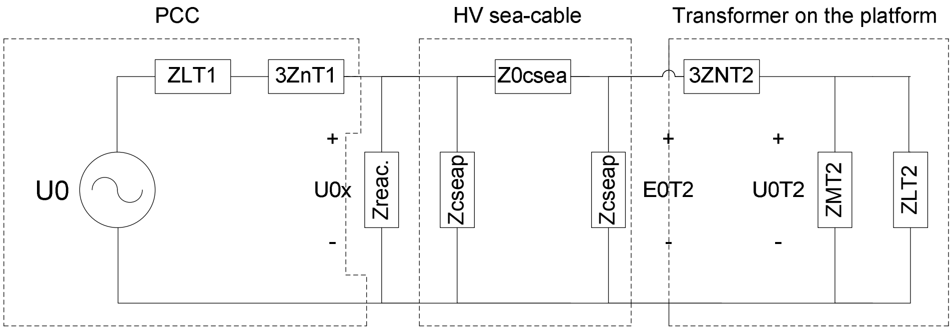


Figure 34. Zero-sequence network for Yy+Yd+-- connected transformers.

From the figure, the zero-sequence voltages can be derived as:

$$
\begin{aligned}
&\overline{U}_{0WT} = \overline{E}_{0WT} = \overline{U}_{0T3} = \overline{E}_{0T3} = \overline{U}_{0CG} = 0 \\
&\overline{U}_{0T2} = \overline{E}_{0T2}\frac{\overline{Z}_{LT2} // \overline{Z}_{MT2}}{\overline{Z}_{LT2} // \overline{Z}_{MT2} + 3\overline{Z}_{NT2}} \\
&\overline{E}_{0T2} = \overline{U}_{0X}\frac{\left(\overline{Z}_{LT2} // \overline{Z}_{MT2} + 3\overline{Z}_{NT2}\right) // \overline{Z}_{cseap}}{\left(\overline{Z}_{LT2} // \overline{Z}_{MT2} + 3\overline{Z}_{NT2}\right) // \overline{Z}_{cseap} + \overline{Z}_{0Csea}} \\
&\overline{U}_{0X} = \overline{U}_{0}\frac{\left(\left(\overline{Z}_{LT2} // \overline{Z}_{MT2} + 3\overline{Z}_{NT2}\right) // \overline{Z}_{cseap} + \overline{Z}_{0Csea}\right) // \overline{Z}_{cseap} // \overline{Z}_{Reactor}}{\left(\left(\overline{Z}_{LT2} // \overline{Z}_{MT2} + 3\overline{Z}_{NT2}\right) // \overline{Z}_{cseap} + \overline{Z}_{0Csea}\right) // \overline{Z}_{cseap} // \overline{Z}_{Reactor} + \overline{Z}_{LT1} + 3\overline{Z}_{nT1}}
\end{aligned}
\tag{34}
$$

Combination 6:
PCC Transformer=Dy, Yy or Yd; Platform Transformer=Any; Nacelle Transformer=Any

If the transformer at the PCC is delta-wye, delta-delta or wye-delta connected, all zero-sequence currents due to unbalance in the grid are blocked from the wind park. Therefore, all zero-sequence voltages in the wind park will be zero.

6.1.2.3 Wind Park Phase Voltages

Now, using (23) for the positive and negative sequence voltages together with one of (28), (30), (32), (33) or (34) for the actual transformer combination for the zero-sequence voltage all sequence voltages can be back-transformed to get the phase voltages. The winding phase voltages at the transformers and the wind turbine then follow from (17):

$$
\begin{aligned}
\overline{U}_{aWT} &= \overline{U}_{0WT} + \overline{U}_{1WT} + \overline{U}_{2WT} \\
\overline{U}_{bWT} &= \overline{U}_{0WT} + a^2\overline{U}_{1WT} + a\overline{U}_{2WT} \\
\overline{U}_{cWT} &= \overline{U}_{0WT} + a\overline{U}_{1WT} + a^2\overline{U}_{2WT}
\end{aligned}
\tag{34}
$$

$$\begin{aligned}\overline{U}_{aT3} &= \overline{U}_{0T3} + \overline{U}_{1T3} + \overline{U}_{2T3}\\ \overline{U}_{bT3} &= \overline{U}_{0T3} + a^2\overline{U}_{1T3} + a\overline{U}_{2T3}\\ \overline{U}_{cT3} &= \overline{U}_{0T3} + a\overline{U}_{1T3} + a^2\overline{U}_{2T3}\end{aligned} \tag{35}$$

$$\begin{aligned}\overline{U}_{aT2} &= \overline{U}_{0T2} + \overline{U}_{1T2} + \overline{U}_{2T2}\\ \overline{U}_{bT2} &= \overline{U}_{0T2} + a^2\overline{U}_{1T2} + a\overline{U}_{2T2}\\ \overline{U}_{cT2} &= \overline{U}_{0T2} + a\overline{U}_{1T2} + a^2\overline{U}_{2T2}\end{aligned} \tag{36}$$

The phase to ground voltages at the transformer and wind turbine terminals are:

$$\begin{aligned}\overline{E}_{aWT} &= \overline{E}_{0WT} + \overline{E}_{1WT} + \overline{E}_{2WT}\\ \overline{E}_{bWT} &= \overline{E}_{0WT} + a^2\overline{E}_{1WT} + a\overline{E}_{2WT}\\ \overline{E}_{cWT} &= \overline{E}_{0WT} + a\overline{E}_{1WT} + a^2\overline{E}_{2WT}\end{aligned} \tag{37}$$

$$\begin{aligned}\overline{E}_{aT3} &= \overline{E}_{0T3} + \overline{E}_{1T3} + \overline{E}_{2T3}\\ \overline{E}_{bT3} &= \overline{E}_{0T3} + a^2\overline{E}_{1T3} + a\overline{E}_{2T3}\\ \overline{E}_{cT3} &= \overline{E}_{0T3} + a\overline{E}_{1T3} + a^2\overline{E}_{2T3}\end{aligned} \tag{38}$$

$$\begin{aligned}\overline{E}_{aT2} &= \overline{E}_{0T2} + \overline{E}_{1T2} + \overline{E}_{2T2}\\ \overline{E}_{bT2} &= \overline{E}_{0T2} + a^2\overline{E}_{1T2} + a\overline{E}_{2T2}\\ \overline{E}_{cT2} &= \overline{E}_{0T2} + a\overline{E}_{1T2} + a^2\overline{E}_{2T2}\end{aligned} \tag{39}$$

6.2 Calculation of Grounding Impedances

This section aims to calculate realistic values of the grounding impedances to be used in the equations. Although this thesis regards voltage dips due to faults *outside* the wind park it should be emphasized that the values of the grounding impedances are chosen to limit the fault current for a fault *within* the wind park.

Two assumptions are made in the calculations:

Assumption 1:
The transformers adjacent to the applied fault are assumed to be delta-wye connected, with the wye connection against the fault side.

Assumption 2:
The fault occurs at the terminals of the low-voltage side of the first transformer in the actual grounding region.

In the calculations, the parameters of the equipment in Horns-reef wind park will be used (see appendix A).

6.2.1 Grounding Impedances in the Sea-Cable Region

The positive and negative sequence impedances can be calculated from the circuit in Figure 35.

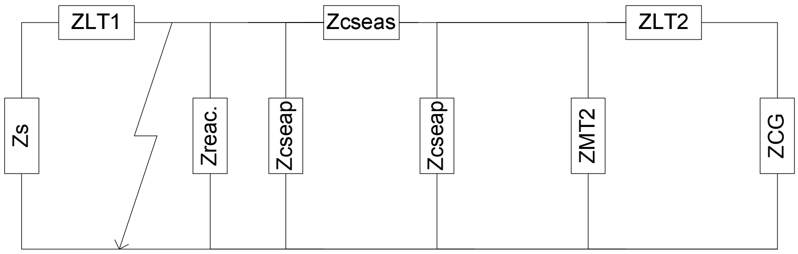


Figure 35. Positive and negative sequence impedance network of area 1.

The fault is marked in the figure and divides the circuit into two parallel impedances. The equivalent positive and negative sequence impedances are then:

$$\overline{Z}_{1pu} = \overline{Z}_{2pu} = \left(\overline{Z}_{S} + \overline{Z}_{LT1}\right) // \left(\left(\left(\overline{Z}_{LT2} + \overline{Z}_{CG}\right) // \overline{Z}_{MT2} // \overline{Z}_{cseap} + \overline{Z}_{cseas}\right) // \overline{Z}_{reac.} // \overline{Z}_{cseap}\right) \qquad (40)$$

The zero sequence circuit is pictured in Figure 36.

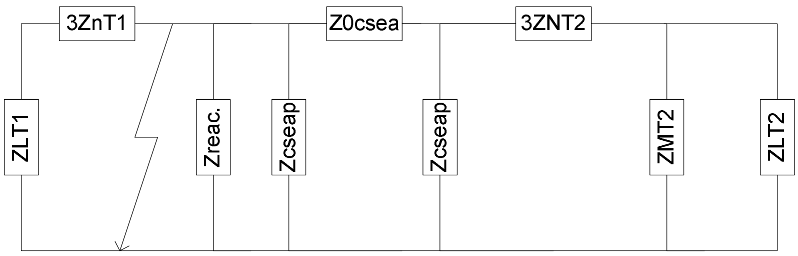


Figure 36. Zero sequence impedance network of area 1

From the figure, the equivalent zero-sequence impedance can be derived as

$$\overline{Z}_{0pu} = \left(\overline{Z}_{LT1} + 3\overline{Z}_{nT1}\right) // \left(\left(\left(\overline{Z}_{LT2} // \overline{Z}_{MT2} + 3\overline{Z}_{NT2}\right) // \overline{Z}_{cseap} + \overline{Z}_{0csea}\right) // \overline{Z}_{reac.} // \overline{Z}_{cseap}\right) \qquad (41)$$

The rated current of an area can be calculated as

$$\left|\overline{I}_{rated}\right| = \frac{\frac{1}{3} S_{base}}{\frac{1}{\sqrt{3}} U_{nom}} \qquad (42)$$

The calculation results of the grounding impedances are shown in Table 12. The fault current was calculated in MatLab using (10) in Chapter 4. The rated current was calculated from (42) to be 560 A. From the calculations it was clear that an isolated grounding system gave a fault current of 349 A. The reason for this high value is the high capacitance of the rather long sea-cable. As a consequence, high resistance grounding is abundant since it is impossible to limit the fault current as much as desired. However, reactance grounding seems to be a good alternative. The value of the reactance was derived by tuning the inductance to the capacitance according to (15).

Table 12. Grounding Impedances of Area 1.

System Grounding	Grounding Impedance	Fault Current	Rated Current
Effective	0 Ω	23.6 kA	
Low-resistance	140 Ω	1.4 kA	
Isolated	Open circuit	349 A	560 A
High-resistance	-	-	
Reactance	277.83 Ω	0.77 A	

6.2.2 Grounding Impedances in the Collection Grid Region

The positive and negative sequence impedances can be calculated from the circuit in Figure 37.

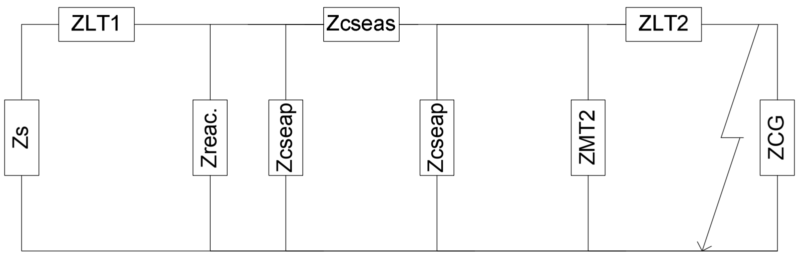


Figure 37. Positive and negative sequence impedance network of area 2.

The equivalent positive and negative sequence impedances are then:

$$\overline{Z}_{1\text{pu}} = \overline{Z}_{2\text{pu}} = \left(\left(\left(\overline{Z}_{\text{S}} + \overline{Z}_{\text{LT1}}\right) // \overline{Z}_{\text{reac.}} // \overline{Z}_{\text{cseap}} + \overline{Z}_{\text{cseas}}\right) // \overline{Z}_{\text{cseap}} // \overline{Z}_{\text{MT2}} + \overline{Z}_{\text{LT2}}\right) // \overline{Z}_{\text{CG}} \qquad (43)$$

The zero sequence circuit is pictured in Figure 38.

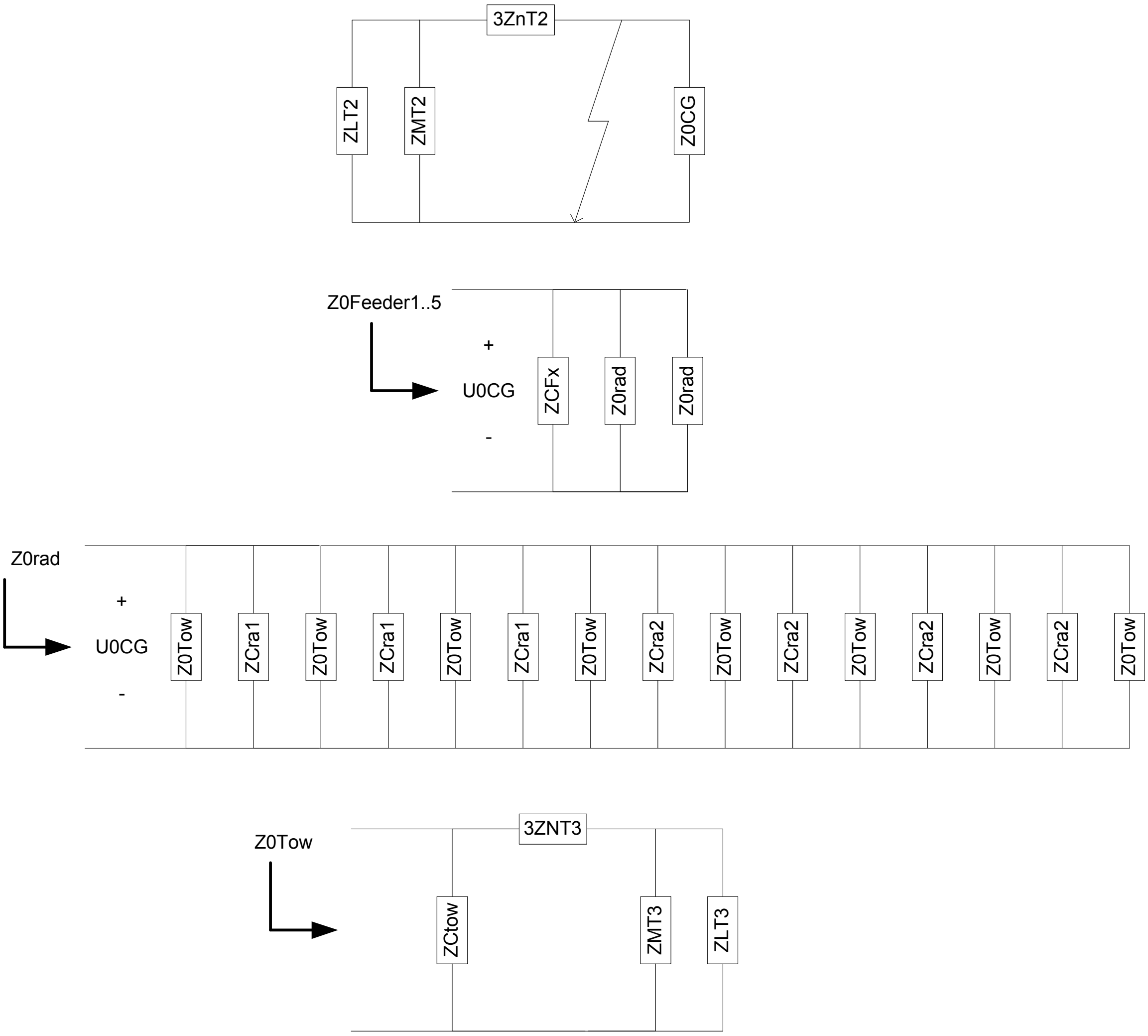


Figure 38. Zero sequence impedance network of area 2

From the figure, the equivalent zero sequence impedance can be derived as

$$\overline{Z}_{0\mathrm{pu}} = \left(\overline{Z}_{\mathrm{LT2}} // \overline{Z}_{\mathrm{MT2}} + 3\overline{Z}_{\mathrm{nT2}}\right) // \overline{Z}_{0\mathrm{CG}}. \tag{32}$$

Further, $\overline{Z}_{0\mathrm{CG}}$ can be found from (24), $\overline{Z}_{0\mathrm{Feeder1..5}}$ from (25) and $\overline{Z}_{0\mathrm{rad}}$ from (26). The last circuit in the figure gives

$$\overline{Z}_{0\mathrm{Tow}} = \left(\overline{Z}_{\mathrm{LT3}} // \overline{Z}_{\mathrm{MT3}} + 3\overline{Z}_{\mathrm{NT3}}\right) // \left(0.5\overline{Z}_{\mathrm{Ctow}}\right). \tag{33}$$

The calculation results of the grounding impedances are shown in Table 13. The rated current was calculated from (42) to be 2717 A. From the calculations it was given that an isolated grounding system gave a fault current of 225 A. The reason for this high value is also in this area a result of the high capacitance of the cables.

Table 13. Grounding Impedances of Area 2.

System Grounding	Grounding Impedance	Fault Current	Rated Current
Effective	0 Ω	19.9 kA	2717 A
Low-resistance	200 Ω	1.43 kA	
Isolated	Open circuit	225 A	
High-resistance	-	-	
Reactance	87.91 Ω	0.85 A	

6.3 Summary

This chapter has derived equations that can be used to analyze the propagation of a voltage dip throughout a wind park. The phase voltages were transformed into component voltages and sequence networks describing the wind park was introduced. The chapter also calculated relevant grounding impedances for the the sea-cable region, area 1, and the collection grid region, area 2. The result is summarized in Table 14.

Table 14. Summary of Grounding Impedances.

Grounding type	Area 1	Area 2
Effectively	0 Ω	0 Ω
Low-resistance	140 Ω	200 Ω
Isolated	Open circuit	Open circuit
High-resistance	-	-
Reactance	277.83 Ω	87.91 Ω

7 Calculation Set-Up and Results

This chapter presents the results of the simulations and some examples are given to show how the ride-through requirements can be translated to the wind turbine terminals. A discussion about relevant grounding systems in a wind park will be done as well as a discussion about relevant calculations needed for the analysis. The work in this chapter has led to a MatLab file that can be used as an aid to analyze a specific ride-through requirement.

7.1 Calculation set-up

The effect of the choice of system grounding and transformer winding connections on the voltage profile at the PCC will be analysed by calculating the voltages of each combination with (34) to (39). However, the number of combinations is high which makes the calculations time consuming. To avoid this, and at the same time getting a better understanding of the wind park design, an effort to identify and exclude combinations leading to the same result will be made.

7.1.1 Strategy

The grid codes specify the voltage dip profiles that have to be handled at the PCC. However, most grid codes do not mention if the dip is on one or more phases. Hence, it has to be assumed that all cases are possible. According to the ABC classification, described in section 2.4.1, seven dip types can occur in a power system, although they might have different magnitudes. Thus, applying the seven dip types at the PCC with a magnitude and duration as specified in each grid code, all possible dips will be covered. Now, the focus is to decrease the number of simulations by discarding abundant combinations leading to the same results. This is possible considering the following:

- Balanced dips are not affected by the choice of transformer nor the system grounding.
- Only dip types stemming from a fault with ground connection are influenced by the system grounding.
- Successive transformers may change the dip back to the original type.
- Delta connected transformers and systems with isolated grounding blocks out any zero sequence current component.

As an additional limitation, the transformers are limited to have the windings connected as YGyg, Dyg, YGd or Dd where G and g represents the system groundings relevant in a wind park earlier presented in Table 9.

7.1.2 Relevant Combinations

In Appendix B, all possible combinations according to the actual limitations are listed. The combinations that may be affected by the system grounding are marked in bold. From the reasoning discussed in the previous section, only one of each combination leading to the same result at the wind turbine will be presented here. The choice of a certain combination within a group giving the same results is chosen randomly. Later, the simulations will show whether the number of combinations can be reduced even more. The summary of the simulation set-up is provided in Table 15.

Table 15. Summary of Simulation Set-Up.

Dip at PCC	Trafo 1	Trafo 2	Trafo 3	Expected dip at WT
A	YGyg	YGyg	YGyg	A
B	YGyg	YGyg	YGyg	B+grounding effect
B	YGyg	YGyg	Dyg	C*+grounding effect
B	YGyg	YGyg	YGd	C*+grounding effect
B	YGyg	YGyg	Dd	D*+grounding effect
B	YGyg	Dyg	YGyg	C*+grounding effect
B	YGyg	Dyg	Dyg	D*+grounding effect
B	YGyg	Dyg	YGd	D*+grounding effect
B	YGyg	Dyg	Dd	C*+grounding effect
B	YGyg	YGd	YGyg	C*+grounding effect
B	YGyg	YGd	YGd	D*+grounding effect
B	YGyg	Dd	YGyg	D*+grounding effect
B	YGyg	Dd	YGd	C*+grounding effect
B	Dyg	YGyg	YGyg	C*
B	Dyg	YGyg	Dyg	D*
C	YGyg	YGyg	YGyg	C
C	YGyg	YGyg	Dyg	D
E	YGyg	YGyg	YGyg	E+grounding effect
E	YGyg	YGyg	Dyg	F+grounding effect
E	YGyg	YGyg	YGd	F+grounding effect
E	YGyg	YGyg	Dd	G+grounding effect
E	YGyg	Dyg	YGyg	F+grounding effect
E	YGyg	Dyg	Dyg	G+grounding effect
E	YGyg	Dyg	YGd	G+grounding effect
E	YGyg	Dyg	Dd	F+grounding effect
E	YGyg	YGd	YGyg	F+grounding effect
E	YGyg	YGd	YGd	G+grounding effect
E	YGyg	Dd	YGyg	G+grounding effect
E	YGyg	Dd	YGd	F+grounding effect
E	Dyg	YGyg	YGyg	F
E	Dyg	YGyg	Dyg	G

As a reminder, g can be reactance, low-resistance or effectively grounded for the sea-cable system and collection grid and isolated or effectively grounded in the nacelle. Thus, summarizing the number of dips to be simulated gives a total of 133 calculations for each dip requirement.

7.2 Calculation Results

Simulations of each combination earlier presented in Table 15 have been carried out in MatLab. The dips "translated" to the wind turbine terminals at the secondary side of the nacelle transformer have been analysed. Each dip was classified according to the ABC-classification discussed in Chapter 2. To analyse the impact of the wind park layout, a test dip of 0 p.u. magnitude and 1 second duration, as the one in Figure 39, was chosen as the "input" at the PCC. Since most grid codes only state the magnitude and duration of the dip requirement, this test profile was applied as the characteristic voltage, $\overline{V}^*$, according to the equations presented in Table 3.

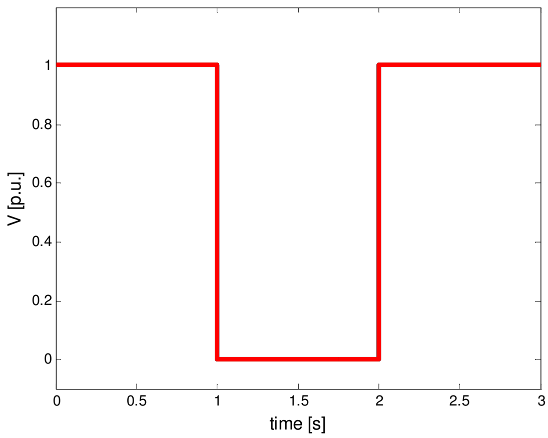


Figure 39. Dip on the affected phase used for simulations.

In the following tables, effectively grounding has been denoted E and low-resistive grounding as R.

Table 16 shows how a dip of type A will appear at the wind turbine. Since balanced dips are unaffected by the choice of grounding as well as the transformer winding connections, a type A dip at the PCC will remain unchanged throughout the wind park.

Table 16. Wind Turbine Dips of Type A.

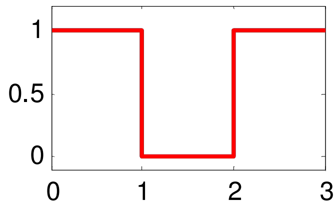
Dip at PCC	T1	T2	T3	System Grounding	Voltage Profile at WT	Dip Voltage [p.u.]
A	Any	Any	Any	Any		$\overline{E}_A = 0\angle 0^\circ$ $\overline{E}_B = 0\angle -120^\circ$ $\overline{E}_C = 0\angle 120^\circ$

Table 17 shows the only combinations that can give rise to a type B dip at the wind turbine. It can be seen that a low resistance grounding affect the magnitude of the dip on the three phases. It can be seen that the resistive grounding changes the voltage magnitude distribution between the three phases. Thus, if the designer wants to distribute the voltage dip as much as possible, low-resistance grounding should be selected in the sea-cable region as well as in the collection grid. An interesting result is also the phase-angle jump in the calculations with the low-resistance grounding. The impact this change has to wind turbines is not analyzed in this report but may be interesting to investigate.

Table 17. Wind Turbine Dips of Type B.

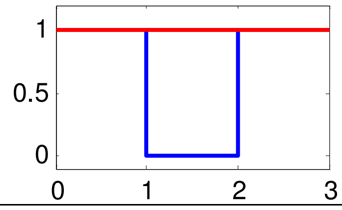
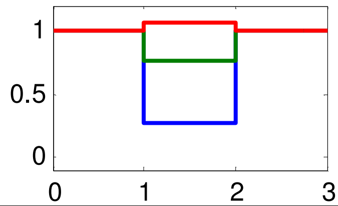
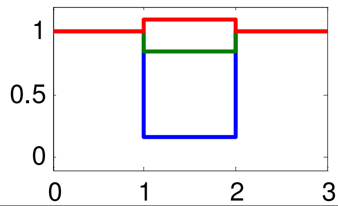
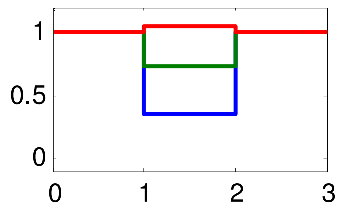
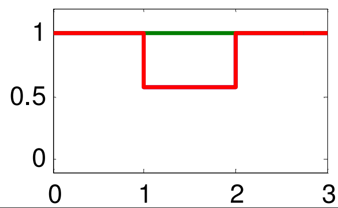
Dip at PCC	T1	T2	T3	System Grounding	Voltage Profile at WT	Dip Voltage [p.u.]
B	YGyg	YGyg	YGyg	E+E+E		$\overline{E}_A = 0\angle 0^\circ$ $\overline{E}_B = 1.0\angle -120^\circ$ $\overline{E}_C = 1.0\angle 120^\circ$
B	YGyg	YGyg	YGyg	E+R+E		$\overline{E}_A = 0.27\angle 35^\circ$ $\overline{E}_B = 0.77\angle -112^\circ$ $\overline{E}_C = 1.06\angle 105^\circ$
B	YGyg	YGyg	YGyg	R+E+E		$\overline{E}_A = 0.16\angle 63^\circ$ $\overline{E}_B = 0.84\angle -121^\circ$ $\overline{E}_C = 1.10\angle 113^\circ$
B	YGyg	YGyg	YGyg	R+R+E		$\overline{E}_A = 0.34\angle 28^\circ$ $\overline{E}_B = 0.73\angle -106^\circ$ $\overline{E}_C = 1.05\angle 101^\circ$

Table 18 presents two possible combinations leading to a type C dip at the wind turbine. Observe that there are more combinations that lead to the same dips as the ones presented here. The first dip profile in the table is the result when a type B dip propagates through an odd number of Dy or Yd connected transformers. This dip was in chapter 2 referred to as type C*. The second dip profile is of type C and is a result of a type C dip propagates through an even number (or zero) of Dy or Yd connected transformers. The grounding is also here of no importance since a type C dip is a result of a fault without ground connection.

Table 18. Wind Turbine Dips of Type C.

Dip at PCC	T1	T2	T3	System Grounding	Voltage Profile at WT	Dip Voltage [p.u.]
B	YGyg	YGyg	Dyg	Any		$\overline{E}_A = 0.58\angle 60^\circ$ $\overline{E}_B = 1.0\angle -90^\circ$ $\overline{E}_C = 0.58\angle 120^\circ$

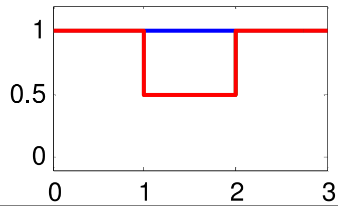
C	YGyg	YGyg	YGyg	Any		$\overline{E}_A = 1.0\angle 0^\circ$ $\overline{E}_B = 0.50\angle 180^\circ$ $\overline{E}_C = 0.50\angle 180^\circ$

Table 19 shows two combinations leading to a type D dip at the wind turbine. Similar to the previous table, the first dip profile is a type D* dip while the second is type D. A type D* dip is the result of a type B dip propagating through only Yy transformers and at least one isolated grounding system, or if it propagates through an even number of delta connected phases, for example one Dd or two Dy transformers. A type D dip is a result of a type C dip propagating through an odd number of Dy/Yd transformers. The system grounding does not affect a type C dip as mentioned.

Table 19. Wind Turbine Dips of Type D.

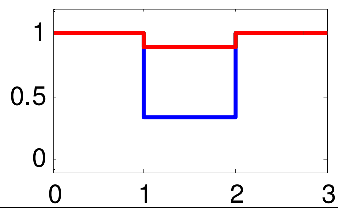
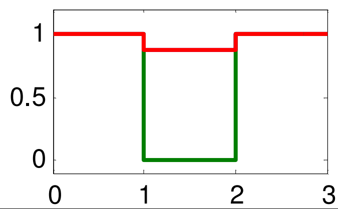
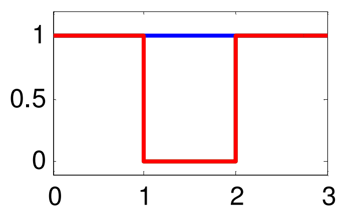
Dip at PCC	T1	T2	T3	System Grounding	Voltage Profile at WT	Dip Voltage [p.u.]
B	YGyg	YGyg	YGyg	E+E+I		$\overline{E}_A = 0.33\angle 0^\circ$ $\overline{E}_B = 0.89\angle -101^\circ$ $\overline{E}_C = 0.89\angle 101^\circ$
C	YGyg	YGyg	Dyg	Any		$\overline{E}_A = 0.87\angle 0^\circ$ $\overline{E}_B = 0\angle 0^\circ$ $\overline{E}_C = 0.87\angle 180^\circ$

Table 20 shows the only combinations leading to a type E dip at the wind turbine. As for type B dips, the low resistance grounding affects the dip magnitude and phase angle.

Table 20. Wind Turbine Dips of Type E.

Dip at PCC	T1	T2	T3	System Grounding	Voltage Profile at WT	Dip Voltage [p.u.]
E	YGyg	YGyg	YGyg	E+E+E		$\overline{E}_A = 1.0\angle 0^\circ$ $\overline{E}_B = 0\angle -120^\circ$ $\overline{E}_C = 0\angle 120^\circ$

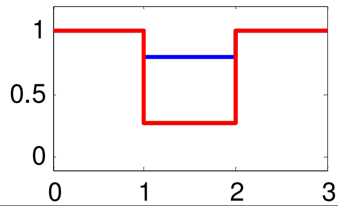
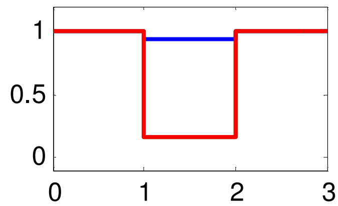
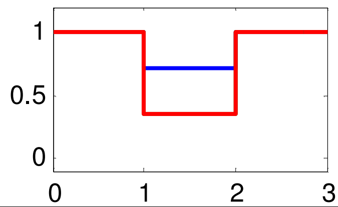
E	YGyg	YGyg	YGyg	E+R+E		$\overline{E}_A = 0.80\angle -11^\circ$ $\overline{E}_B = 0.27\angle -145^\circ$ $\overline{E}_C = 0.27\angle -145^\circ$
E	YGyg	YGyg	YGyg	R+E+E		$\overline{E}_A = 0.94\angle -9^\circ$ $\overline{E}_B = 0.16\angle -117^\circ$ $\overline{E}_C = 0.16\angle -117^\circ$
E	YGyg	YGyg	YGyg	R+R+E		$\overline{E}_A = 0.72\angle -13^\circ$ $\overline{E}_B = 0.34\angle -152^\circ$ $\overline{E}_C = 0.34\angle -152^\circ$

Table 21 shows one combination leading to a type F dip at the wind turbine. This dip type is experienced when a type E dip propagates through an odd number of Dy/Yd transformers, no matter the system grounding.

Table 21. Wind Turbine Dips of Type F.

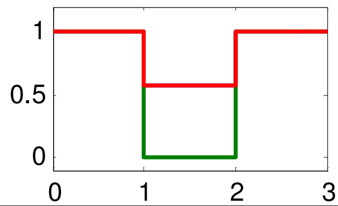
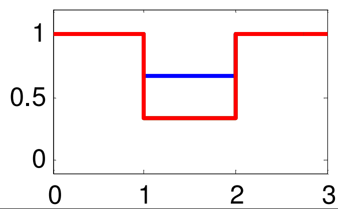
Dip at PCC	T1	T2	T3	System Grounding	Voltage Profile at WT	Dip Voltage [p.u.]
E	YGyg	YGyg	Dyg	Any		$\overline{E}_A = 0.58\angle 0^\circ$ $\overline{E}_B = 0\angle 90^\circ$ $\overline{E}_C = 0.58\angle 180^\circ$

Table 22 shows one combination leading to a type G dip at the wind turbine. A type E dip is the result of a type E dip propagating through at least one isolated grounding system, or if it propagates through an even number of delta connected phases, for example one Dd or two Dy transformers.

Table 22. Wind Turbine Dips of Type G.

Dip at PCC	T1	T2	T3	System Grounding	Voltage Profile at WT	Dip Voltage [p.u.]
E	YGyg	YGyg	YGyg	E+E+I		$\overline{E}_A = 0.67\angle 0^\circ$ $\overline{E}_B = 0.33\angle 180^\circ$ $\overline{E}_C = 0.33\angle 180^\circ$

7.3 Summary and Conclusions

This chapter has discussed which calculations that are relevant for the analysis of the voltage dip propagation in a wind park and the relevant design factors. It also presents the results of the calculations.

In the calculation set-up, it was assumed that if a dip that reaches a delta connected transformer (or a grounding system that is either isolated or reactance grounded), the dip would look different when it had passed the transformer depending on the grounding before. However, the calculation showed that this was not the case. In the end, all the combinations from the set-up list in Table 15 could be translated to any of the 15 dips presented in Table 16 to Table 22.

Since a dip of type A, C, D, F or G at the PCC, is unaffected by the system grounding, these voltage dip types can always be expected to be present at the wind turbine terminals, no matter the choice of grounding or transformer winding connections. This implies that the only dip types that can actually be affected by the wind park design are the ones of type B or E at the PCC, i.e. the dips with a zero-sequence component. However, the possibility of these types to be present at the wind turbine terminals requires the wind park designer to only use wye-wye connected transformers with either effectively grounding or low-resistance grounding. Observe that this reasoning is only true for voltage dips originating in the power system grid outside the wind park.

Finally it was shown that low-resistance grounding re-distributes the voltage drop among the three phases for dip types B or E.

8 Translation of Dip Requirements

This Chapter shows examples of how some dip requirements can look after translation to the wind turbine terminals.

8.1 Translation

The results given in the previous section gives an insight to the changes a voltage dip can undergo when propagating through the wind park. The developed code in MatLab can now be applied to the dip requirements presented in the chapter about grid codes. Some examples will now be presented.

8.1.1 SvK Dip Requirement Translation

Svenska Kraftnät's dip requirement for installations with a capacity of more than 100 MW is shown in Figure 40. The voltage requirement applies to the faulted phase and describes the RMS voltage at the PCC.

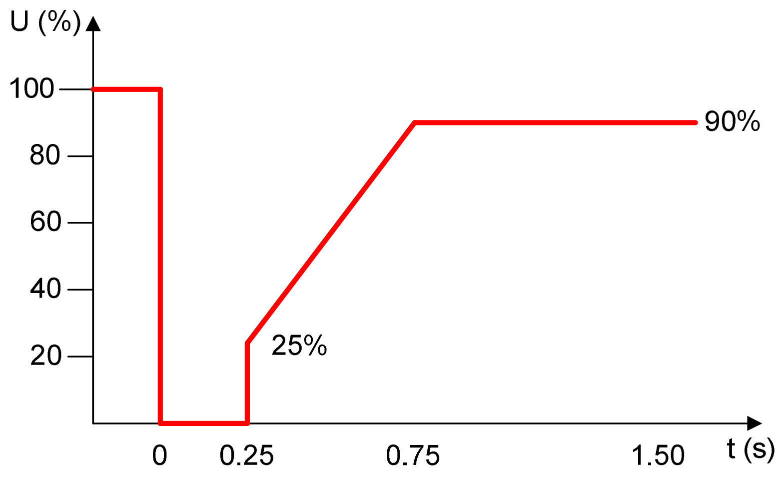
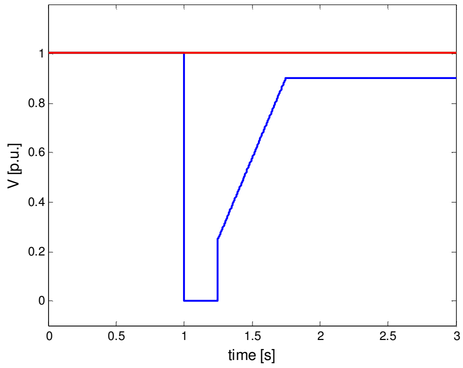
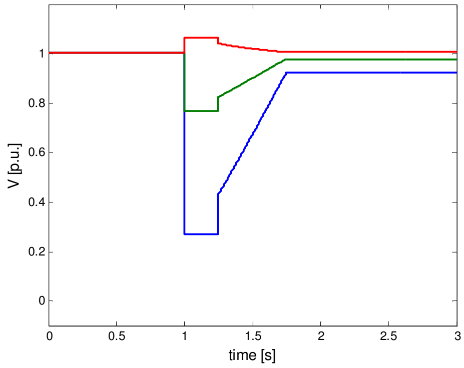


Figure 40. SvK ride-through requirement for large installations.

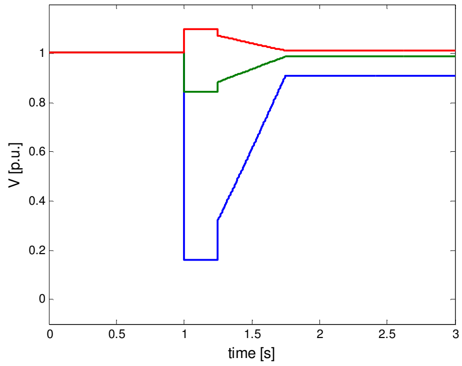
If the voltage dip from Figure 40 is a type B dip, i.e. single-phase, the grounding affects the voltage characteristics at the wind turbine terminals according to Figure 41. EEE means effectively grounding in the sea cable region, the collection grid and in the nacelle while ERE means effectively grounding in the sea cable region, low-resistance grounding in the collection grid and effectively grounding in the nacelle etc.

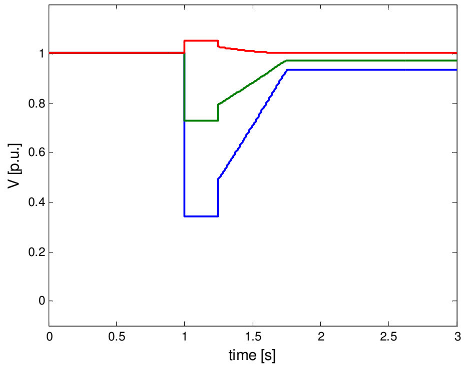
If the voltage dip from Figure 40 is a type E dip, i.e. two-phase-to-ground, the grounding affects the voltage characteristics at the wind turbine terminals according to Figure 42. In both Figure 41 and Figure 42, the low-resistance grounding according to Figure 41(d) and Figure 42(d), seems to be the best alternative when looking at the resulting dip at the wind turbine terminals, at least when the phase-angle jump is not considered.





(a) **(b)**

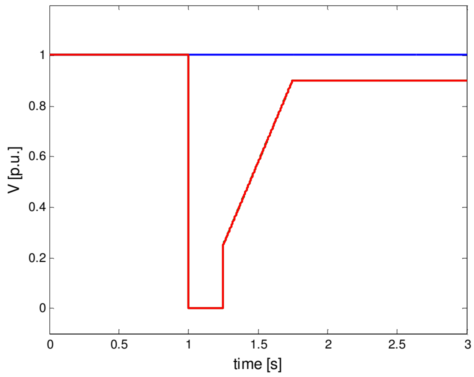


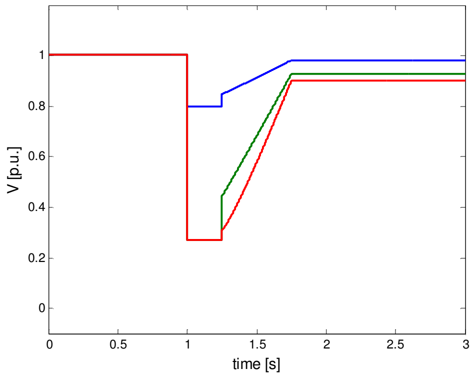


(c) **(d)**

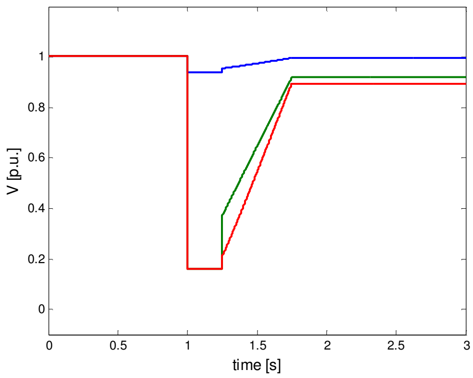
Figure 41. Dip requirement of SvK translated to the wind turbine.

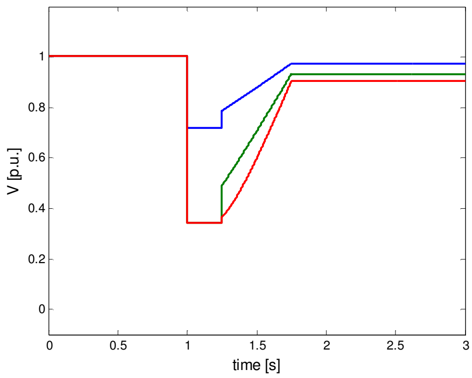
a) EEE b) ERE c) REE d) RRE.





(a) **(b)**





(c) **(d)**

Figure 42. Dip requirement of SvK translated to the wind turbine.

a) EEE b) ERE c) REE d) RRE.

8.1.2 E.ON. Dip Requirement Translation

E.ON's dip requirement for non-synchronous generators is shown in Figure 43. The voltage requirement applies to the faulted phase and describes the RMS voltage at the PCC.

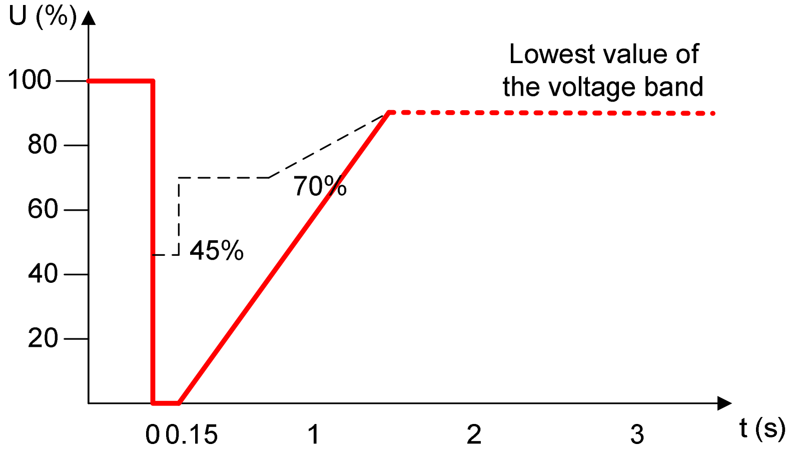


Figure 43. E.ON. ride-through requirement for type 2 generators.

If the voltage dip from Figure 43 is a type B dip, i.e. single-phase, the grounding affects the voltage characteristics at the wind turbine terminals according to Figure 44. The figure also presents the reactive power support that E.ON requires during a grid fault. This requirement was also presented in Figure 14. From the figures it can be seen that in addition to the voltage, the reactive power contribution also distributes between the phases due to the low-resistance grounding. Observe that this is the reactive current that must be produced by each generator.

If the voltage dip from Figure 43 is a type E dip, i.e. two-phase-to-ground, the grounding affects the voltage characteristics at the wind turbine terminals according to Figure 45. This figure also shows the required reactive power support. Compared to Figure 44, the reactive power support is higher, which is logical since the PCC dip here is on two phases.

These additional requirements supports the conclusion that a low-resistance grounding probably is a better alternative than effective grounding, since the reactive current that needs to be produced then is shared between the phases.

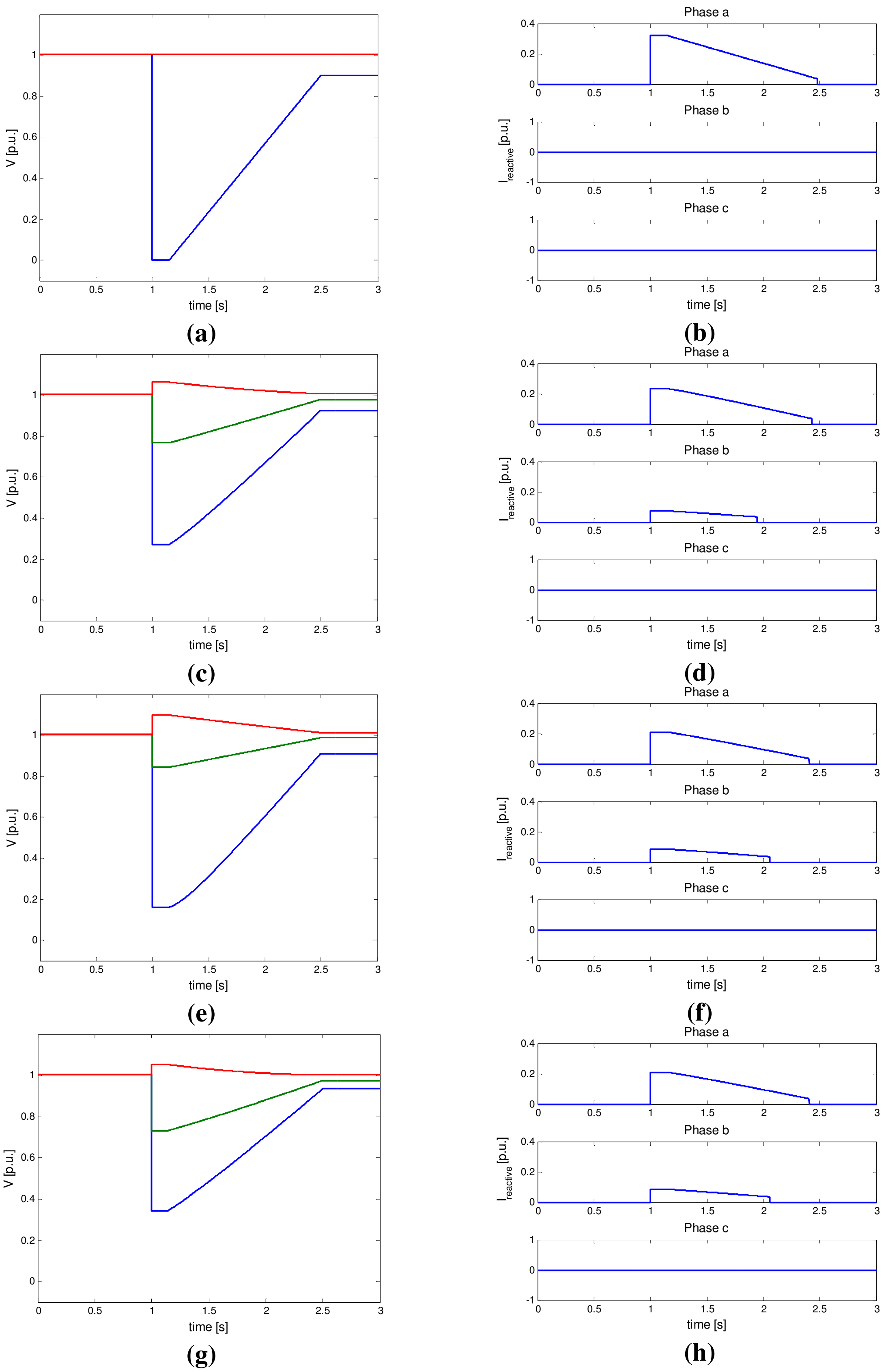


Figure 44. Dip requirement of EON translated to the wind turbine.

a) Dip with EEE b) Ireactive with EEE c) Dip with ERE d) Ireactive with ERE

e) Dip with REE f) Ireactive with REE g) Dip with RRE h) Ireactive with RRE.

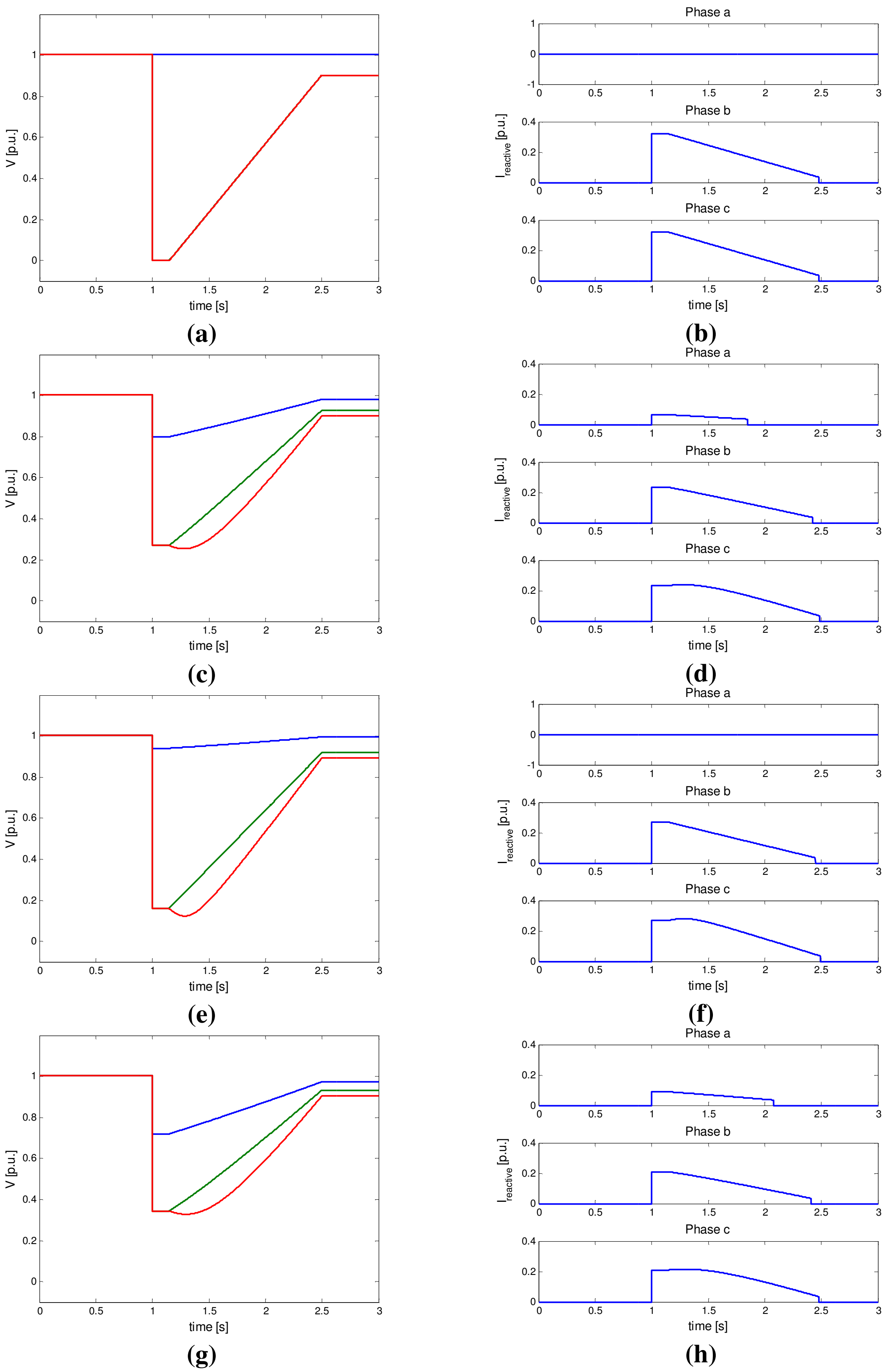


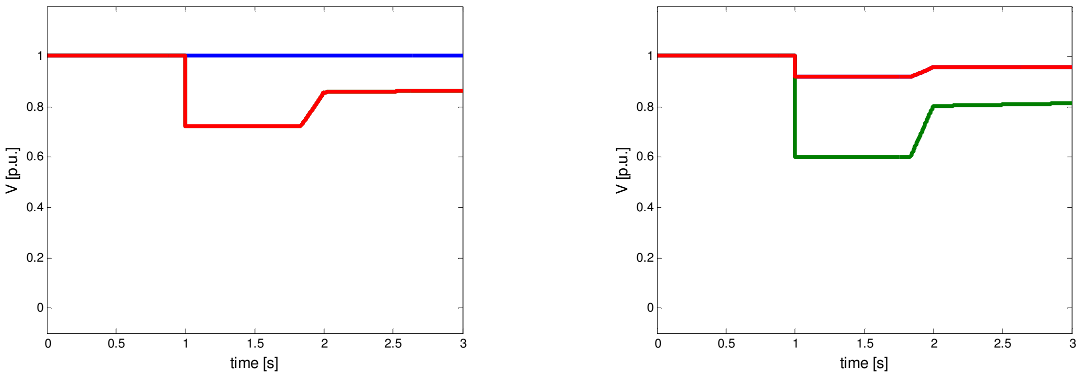
Figure 45. Dip requirement of EON translated to the wind turbine.

a) Dip with EEE b) Ireactive with EEE c) Dip with ERE d) Ireactive with ERE

e) Dip with REE f) Ireactive with REE g) Dip with RRE h) Ireactive with RRE.

8.1.3 REE Dip Requirement Translation

REE is the only TSO that has a separate requirement for dips due to isolated 2-phase faults. Two possible voltage profiles at the wind turbine are presented in Figure 46. The requirement at the PCC is equal to Figure 46 (a).



(a) **(b)**

Figure 46. REE's dip requirement due to an isolated 2-phase fault.

a) Dip requirement at PCC b) Dip translated to wind turbine terminals.

8.2 Summary and Conclusions

This chapter has shown examples of voltage dip requirements at the PCC and how they can be affected by the system grounding in the wind park. Translated requirements were shown for SvK, E.ON. and REE. Since E.ON also requires voltage support during the dip, the reactive power injection was also presented. It was concluded that the reactive power injection could be distributed between the phases under a type B or E dip, by using low-resistance grounding instead of effective grounding.

9 Discussion and Conclusions

This chapter presents a discussion of the results and makes a final conclusion. It also provides the reader with recommendations and suggestions of future work that might be interesting to pursue.

9.1 Discussion

The aim of the thesis was to investigate how the system grounding and transformer winding connections in an offshore wind park influence a voltage dip propagating from the grid through the wind park. A discussion about the relevant grounding systems in a wind park with respect to faults within the park, served as a limiting factor of the investigations. According to the ABC-classification, 7 dip-types occur in a power system. The results showed that a given time-magnitude relation of each dip type at the PCC can give rise to a total of 15 different dips at the wind turbine terminals. Among these dips, type A, C, C*, D, D*, F and G can always occur at the wind turbine terminals with unchanged amplitude. The remaining 8 dips stem from faults with ground connection, i.e. dip types B or E. Thus, adding any delta connected transformer or having at least one isolated or reactance grounded system blocks these dips from ever reaching the wind turbine terminals.

For any of the remaining 8 dips to be expected at the turbines, the wind park designer must design a park with only wye-wye connected transformer with their neutral either effectively or low-resistance grounded. This has to do with the fact that a wye-wye connected transformer with its neutral points connected to the ground does not block the zero-sequence current. However, only two of these dips will then have the possibility of reaching the turbine. Which two is decided by the combination of low-resistance and effectively grounding that is selected.

The most severe dip that will appear at the wind turbine is the balanced three-phase dip. This dip is not affected by transformers or grounding, therefore it may be the most important design criterion for the wind turbine manufacturers. Nevertheless, the most common faults in a power system are single-phase-to-ground, so the grounding and transformer connections are still important for the wind park designer to reduce the stress of the turbines.

The report does not discuss the design of the power system grid outside the wind park, hence a propagating voltage dip is likely to have passed a delta connected transformer before reaching the PCC. This of course reduces the likelihood of a type B or E dip at the PCC. Further, the expected voltage dips at the wind turbine terminals are assumed to have its origin outside the park. Naturally, a fault occurring inside the park may give rise to dips that otherwise might be blocked by the wind park design.

Finally, the comparison of a number of grid codes showed a substantial difference in the scope of the requirements as well as their level of difficulty to meet.

9.2 Conclusions

The main purpose of this thesis was to provide a tool for the designer of wind parks to gain a better understanding of primarily two things:

1. The requirements that must be fulfilled to get permission to construct a wind park.

2. How the grounding systems and transformer winding connections should be chosen so that the requirements con more easily be fulfilled.

In addition to this, the results in the thesis can also be used for the wind turbine manufacturers, since their interest should be of the ride-through requirement that must be handled at the wind turbine terminals, and not at the PCC.

The analysis of the results from the calculations together with previous understanding of voltage dips came to the following conclusions:

1. 7 variants of voltage dips can always reach the wind turbine terminals no matter the choice of grounding and transformer connections in the park. They are of type A, C, C*, D, D*, F and G.

2. If the designer only wants the occurrence of the variants in paragraph 1, the wind park should include any of the following:
    a. At least one transformer with a delta connection on any side.
    b. At least one area with isolated grounding.
    c. At least one area with reactance grounding.

3. If the designer instead chooses a wind park with only wye-wye connected transformers and the system grounding is low-resistance or effective, two more dip variants can be expected at the wind turbine terminals. These two dips are of type B and E but the magnitude of the phases is decided from the combination of the two grounding types.

9.3 Recommendations and Future Work

The results showed that the choice of transformer winding connections and power system grounding in a wind park may affect a voltage dip originating outside the park. However, a wind park often includes a delta connected transformer. The recommendation is therefore to choose the grounding and transformer connections with respect to other issues such as blocking third harmonics or faults within the park.

In this work, the response of the wind turbine to the dip was not considered. The behaviour of the wind turbine subjected to a voltage reduction will probably be different for different turbine technologies and will influence the shape of the voltage dip. This work could be extended by including proper wind turbine models.

Finally, the grid codes need constant updates since they tend to be changed rather often. The system operators are encouraged to harmonize their codes to simplify the development and research in the wind power industry.

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Appendix A: Horns-Reef Parameters

General data
$U_{\text{Grid}} = 150\text{kV}$
$U_{\text{Sea-cable}} = 165\text{kV}$
$U_{\text{Collection-grid}} = 34\text{kV}$
$U_{\text{Nacelle}} = 690\text{V}$

$S_{\text{kmax}} = 4.459\text{GVA}$
$S_{\text{kmin}} = 1.647\text{GVA}$

Sea-cable
L = 20.1 km
r = 0.039 Ω/km
x = 0.12 Ω/km
c = 0.19 μF/km
$r_0 = 0.117$ Ω/km
$x_0 = 0.36$ Ω/km
$c_0 = 0.19$ μF/km

Feeder cables
L = 0.66/1.27/2.33/3.44/4.55 km
r = 0.042 Ω/km
x = 0.11 Ω/km
c = 0.28 μF/km
$r_0 = 0.126$ Ω/km
$x_0 = 0.33$ Ω/km
$c_0 = 0.28$ μF/km

Radial feeder 1
L = 0.64 km
r = 0.112 Ω/km
x = 0.118 Ω/km
c = 0.194 μF/km
$r_0 = 0.336$ Ω/km
$x_0 = 0.354$ Ω/km
$c_0 = 0.194$ μF/km

Radial feeder 2
L = 0.64 km
r = 0.1768 Ω/km
x = 0.127 Ω/km
c = 0.167 μF/km
$r_0 = 0.5304$ Ω/km
$x_0 = 0.381$ Ω/km
$c_0 = 0.167$ μF/km

Tower cable
L = 0.08 km
r = 0.78 Ω/km
x = 0.35 Ω/km
c = 0.10 μF/km
$r_0 = 2.34$ Ω/km
$x_0 = 0.405$ Ω/km
$c_0 = 0.10$ μF/km

Platform transformer
160 MVA
165/34 kV
$\mu_x = 13.8$ %

Nacelle transformer
2.1 MVA
34/0.69 kV
$\mu_r = 0.7$ %
$\mu_x = 7$ %

Appendix B: Complete Tables of Transformer Combinations

Dip type at PCC: B (1-phase-to-ground faults)

Table B 1. Possible transformer connections to receive dip-type B at WTG terminals.

Trafo 1	Trafo 2	Trafo 3
YNyg	**YGyg**	**YGyn**

Table B 2. Possible transformer connections to receive dip-type C* at WTG terminals.

Trafo 1	Trafo 2	Trafo 3
YGyg/Yyg	YGy	Dyn
YGy/Yy/Dd	Yy/Dd	Dyn
YGd/Yd/Dy	Yd/Dy	Dyn
Dyg	YGd	Dyn
YGy/Yy/Dd	Dyg	YGyn
YGd/Yd/Dy	Yyg	YGyn
Dyn	YGyg	YGyn
YGyg/Yyg	YGd	Yyn
YGy/Yy/Dd	Yd/Dy	Yyn
YGd/Yd/Dy	Yy/Dd	Yyn
Dyg	YGy	Yyn
YGy/Yy/Dd	Dyg	YGy
YGd/Yd/Dy	Yyg	YGy
Dyg	YGyg	YGy
YGyg/Yyg	YGd	Yy
YGy/Yy/Dd	Dy /Yd	Yy
YGd/Yd/Dy	Dd/Yy	Yy
Dyg	YGy	Yy

Table B 3. Possible transformer connections to receive dip-type D* at WTG terminals.

Trafo 1	Trafo 2	Trafo 3
Yyg	YGd	Dyn
YGy/Yy/Dd	Yd/Dy	Dyn
YGd/Yd/Dy	Dd/Yy	Dyn
Dyg	YGy	Dyn
Yyg	YGyg	YGyn
YGy/Yy/Dd	Yyg	YGyn
YGd/Yd/Dy	Dyg	YGyn
YGyg/Yyg	YGy	Yyn
YGy/Yy/Dd	Yy/Dd	Yyn
YGd/Yd/Dy	Yd/Dy	Yyn
Dyg	YGd	Yyn
YGyg/Yyg	**YGyg**	**YG**y
YGy/Yy/Dd	Yyg	YGy
YGd/Yd/Dy	Dyg	YGy
YGyg/Yyg	YGy	Yy

YGy/Yy/Dd	Yy/Dd	Yy
YGd/Yd/Dy	Yd/Dy	Yy
Dyg	YGd	Yy

Dip type at PCC: E (2-phase-to-ground faults)

Table B 4. Possible transformer connections to receive dip-type E at WTG terminals.

Trafo 1	Trafo 2	Trafo 3
YGyg	**YGyg**	**YGyg**

Table B 5. Possible transformer connections to receive dip-type F at WTG terminals.

Trafo 1	Trafo 2	Trafo 3
YGyg/Yyg	YGy	Dyn
YGy/Yy/Dd	Yy/Dd	Dyn
YGd/Yd/Dy	Yd/Dy	Dyn
Dyg	YGd	Dyn
YGy/Yy/Dd	Dyg	YGyn
YGd/Yd/Dy	Yyg	YGyn
Dyn	YGyg	YGyn
YGyg/Yyg	YGd	Yyn
YGy/Yy/Dd	Yd/Dy	Yyn
YGd/Yd/Dy	Yy/Dd	Yyn
Dyg	YGy	Yyn
YGy/Yy/Dd	Dyg	YGy
YGd/Yd/Dy	Yyg	YGy
Dyg	YGyg	YGy
YGyg/Yyg	YGd	Yy
YGy/Yy/Dd	Dy /Yd	Yy
YGd/Yd/Dy	Dd/Yy	Yy
Dyg	YGy	Yy

Table B 6. Possible transformer connections to receive dip-type G at WTG terminals.

Trafo 1	Trafo 2	Trafo 3
Yyg	YGd	Dyn
YGy/Yy/Dd	Yd/Dy	Dyn
YGd/Yd/Dy	Dd/Yy	Dyn
Dyg	YGy	Dyn
Yyg	YGyg	YGyn
YGy/Yy/Dd	Yyg	YGyn
YGd/Yd/Dy	Dyg	YGyn
YGyg/Yyg	YGy	Yyn
YGy/Yy/Dd	Yy/Dd	Yyn
YGd/Yd/Dy	Yd/Dy	Yyn
Dyg	YGd	Yyn
YGyg/Yyg	**YGyg**	**YG**y
YGy/Yy/Dd	Yyg	YGy
YGd/Yd/Dy	Dyg	YGy

YGyg/Yyg	YGy	Yy
YGy/Yy/Dd	Yy/Dd	Yy
YGd/Yd/Dy	Yd/Dy	Yy
Dyg	YGd	Yy

Dip type at PCC: C (2-phase faults)

Table B 7. Possible transformer connections to receive dip-type C at WTG terminals.

Trafo 1	Trafo 2	Trafo 3
Yyg	YGd	Dyn
YGy/Yy/Dd	Yd/Dy	Dyn
YGd/Yd/Dy	Dd/Yy	Dyn
Dyg	YGy	Dyn
YGyg	**YGyg**	**YGyn**
Yyg	**YGyg**	**YGyn**
YGy/Yy/Dd	Yyg	YGyn
YGd/Yd/Dy	Dyg	YGyn
YGyg/Yyg	YGy	Yyn
YGy/Yy/Dd	Yy/Dd	Yyn
YGd/Yd/Dy	Yd/Dy	Yyn
Dyg	YGd	Yyn
YGyg	**YGyg**	**YGy**
Yyg	**YGyg**	**YGy**
YGy/Yy/Dd	Yyg	YGy
YGd/Yd/Dy	Dyg	YGy
YGyg/Yyg	YGy	Yy
YGy/Yy/Dd	Yy/Dd	Yy
YGd/Yd/Dy	Yd/Dy	Yy
Dyg	YGd	Yy

Table B 8. Possible transformer connections to receive dip-type D at WTG terminals.

Trafo 1	Trafo 2	Trafo 3
YGyg/Yyg	YGy	Dyn
YGy/Yy/Dd	Yy/Dd	Dyn
YGd/Yd/Dy	Yd/Dy	Dyn
Dyg	YGd	Dyn
YGy/Yy/Dd	Dyg	YGyn
YGd/Yd/Dy	Yyg	YGyn
Dyg	**YGyg**	**YGyn**
YGyg/Yyg	YGd	Yyn
YGy/Yy/Dd	Yd/Dy	Yyn
YGd/Yd/Dy	Yy/Dd	Yyn
Dyg	YGy	Yyn
YGy/Yy/Dd	Dyg	YGy
YGd/Yd/Dy	Yyg	YGy
Dyg	**YGyg**	**YGy**
YGyg/Yyg	YGd	Yy
YGy/Yy/Dd	Yd/Dy	Yy

YGd/Yd/Dy	Yy/Dd	Yy
Dyg	YGy	Yy

Dip type at PCC: A (3-phase faults)

Table B 9. Possible transformer connections to receive dip-type A at WTG terminals.

Trafo 1	Trafo 2	Trafo 3
YGyg/Yyg/Dyg	YGy/YGd	Dyn
YGy/Yy/Yd/YGd/Dy/Dd	Yy/Yd/Dd/Dy	Dyn
YGyg/Yyg/Dyg	**YGyg**	**YGyn**
YGy/Yy/Yd/YGd/Dy/Dd	Yyg/Dyg	YGyn
YGyg/Yyg/Dyg	YGy/YGd	Yyn
YGy/Yy/Yd/YGd/Dy/Dd	Yy/Yd/Dd/Dy	Yyn
YGyg/Yyg/Dyg	**YGyg**	**YGy**
YGy/Yy/Yd/YGd/Dy/Dd	Yyg/Dyg	YGy
YGyg/Yyg/Dyg	YGy/YGd	Yy
YGy/Yy/Yd/YGd/Dy/Dd	Yy/Yd/Dd/Dy	Yy

Dip type at PCC: D

Can only give rise to type D or type C and grounding has no influence, these cases have already been covered so there is no need to simulate with this input.

Dip type at PCC: F

Can only give rise to type F or type G and grounding has no influence, these cases have already been covered so there is no need to simulate with this input.

Dip type at PCC: G

Can only give rise to type G or type F and grounding has no influence, these cases have already been covered so there is no need to simulate with this input.